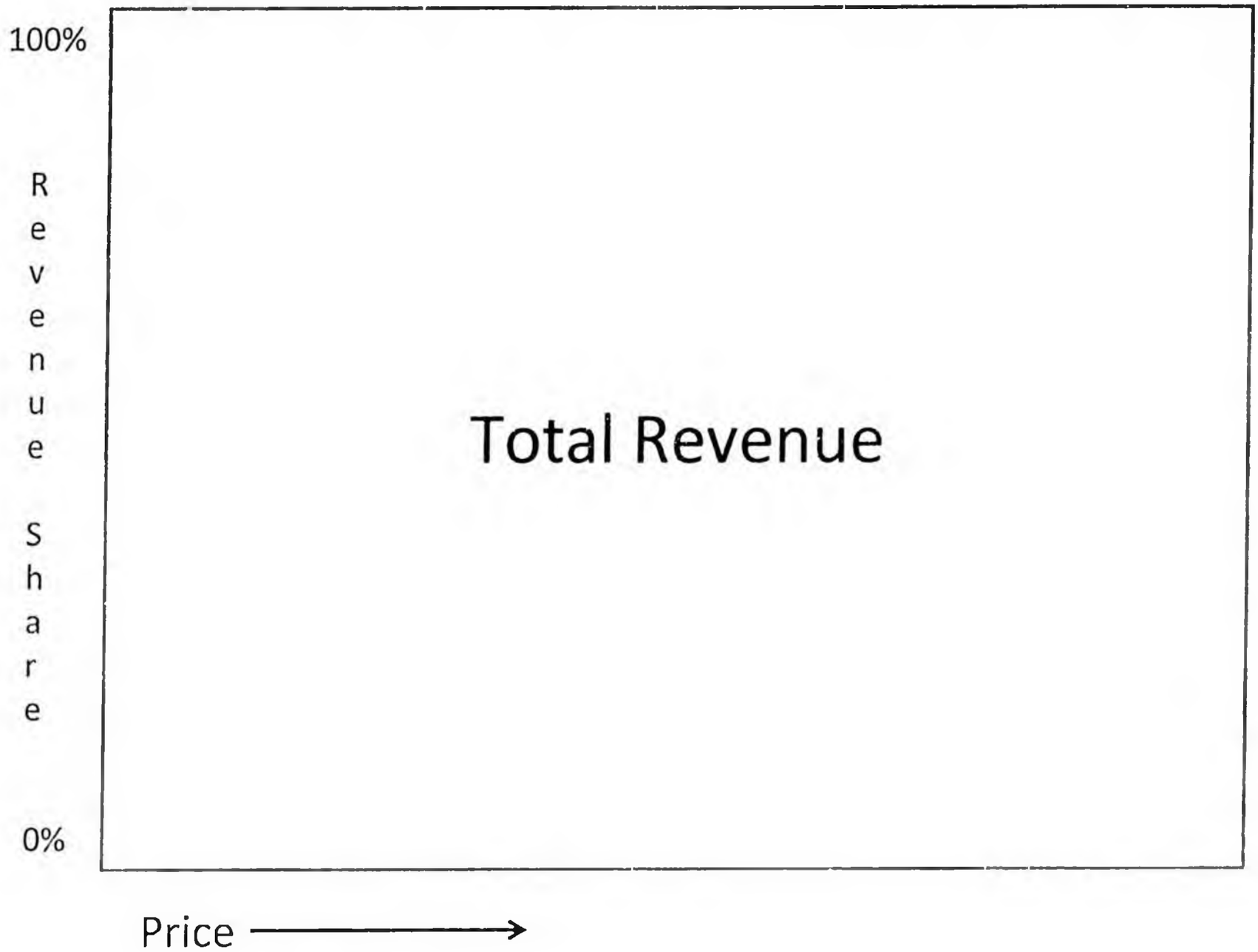
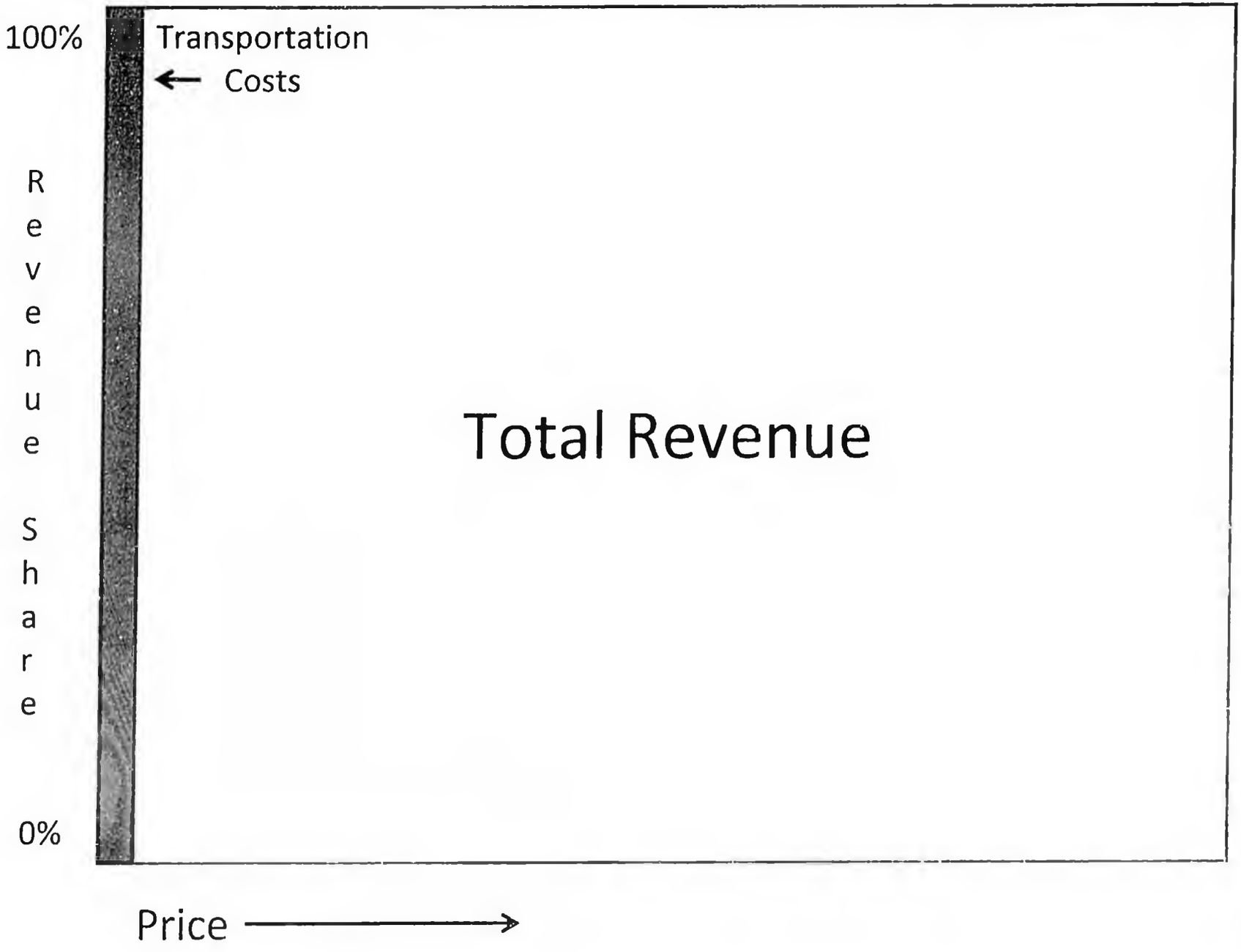
SB

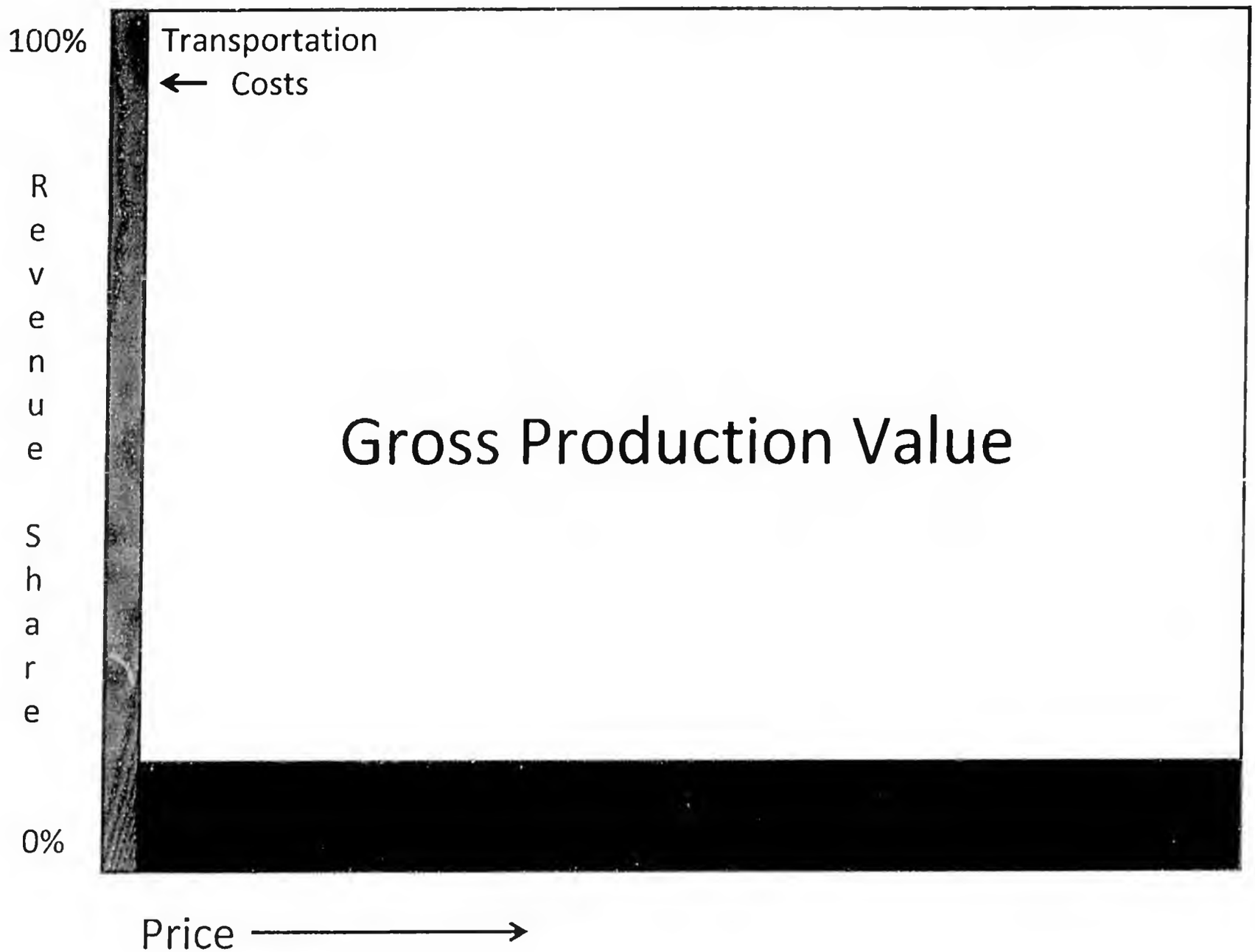
2001

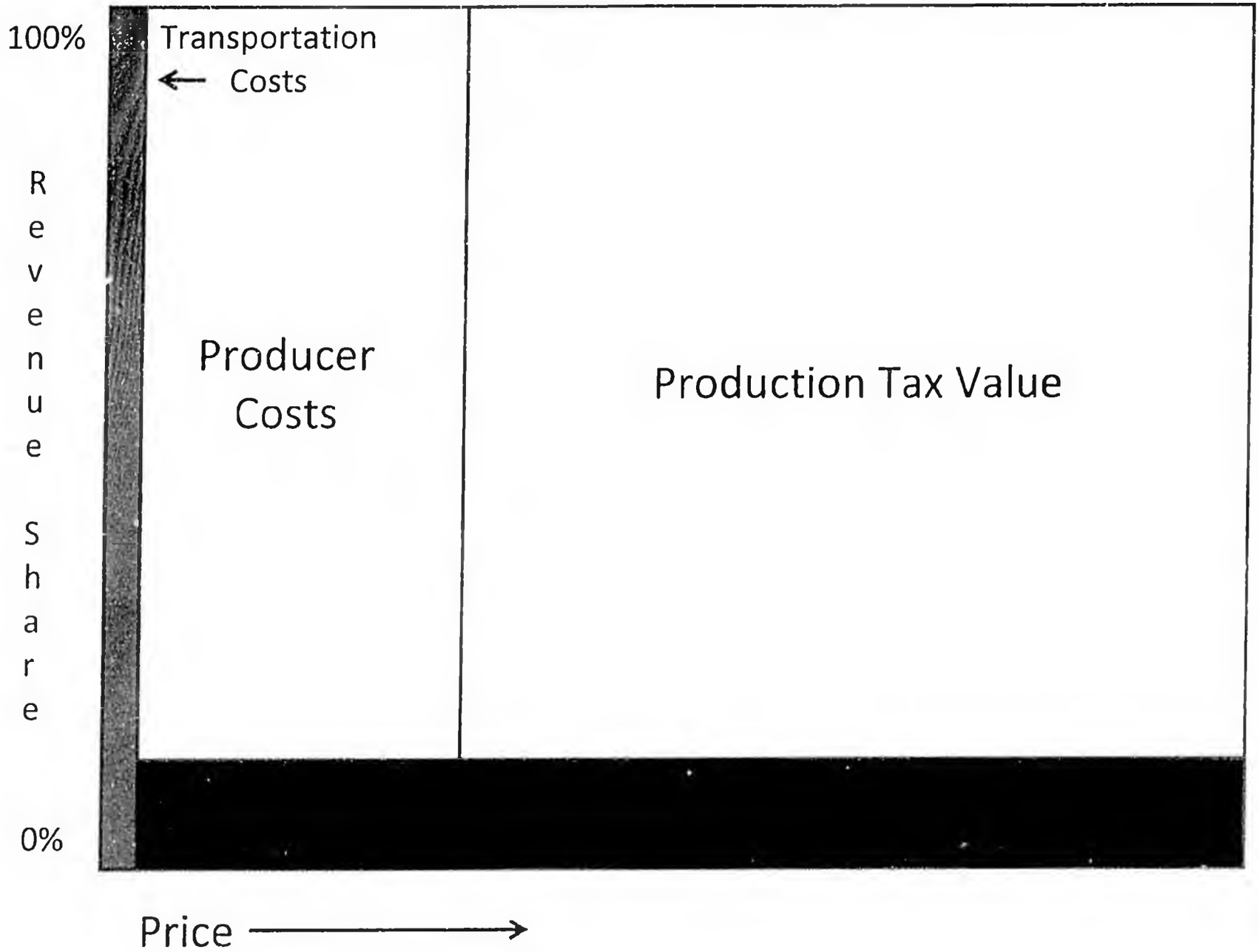
(FILE 3)

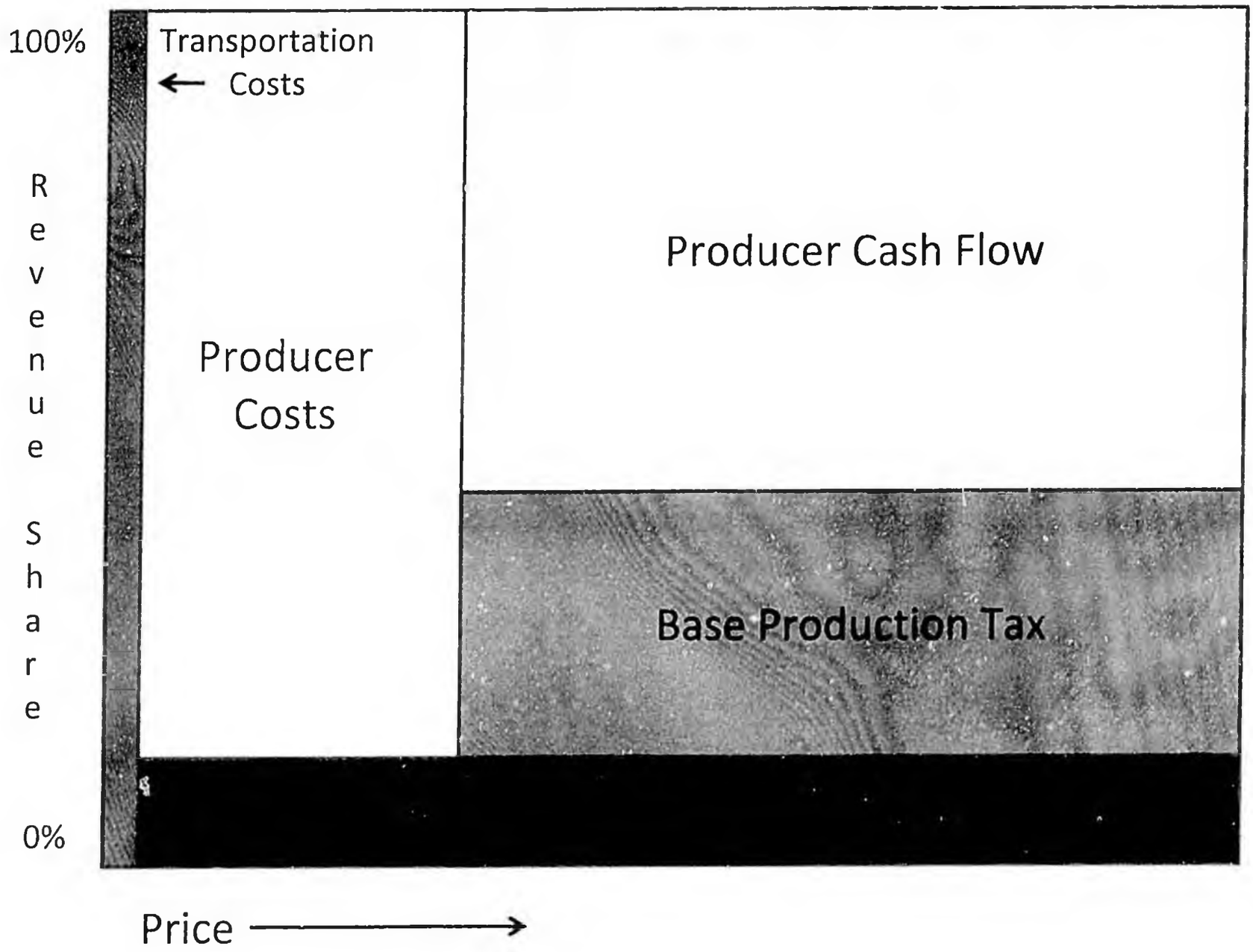
DOR-SHARE

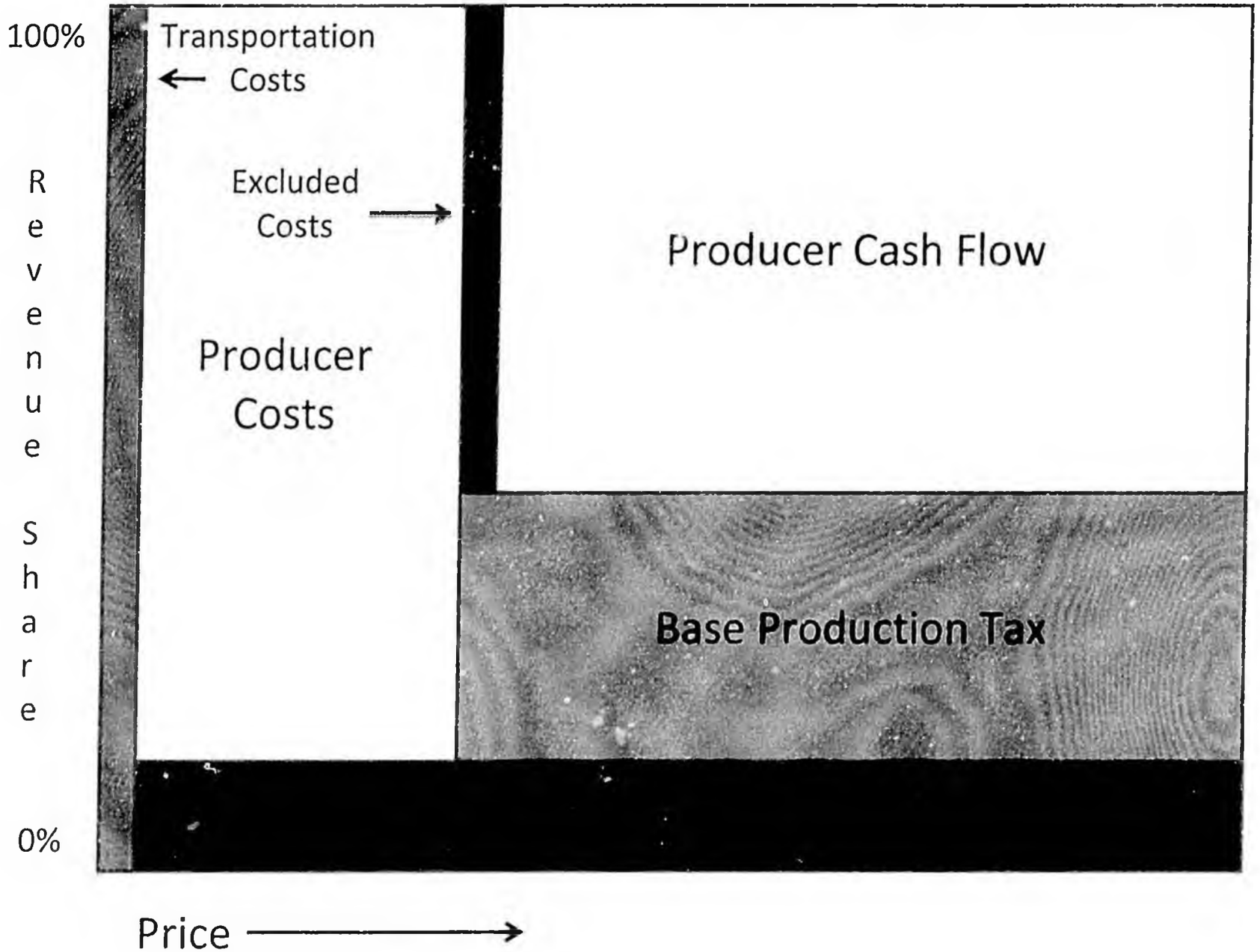

100%
Revenue Share
0%
Total Revenue
Price

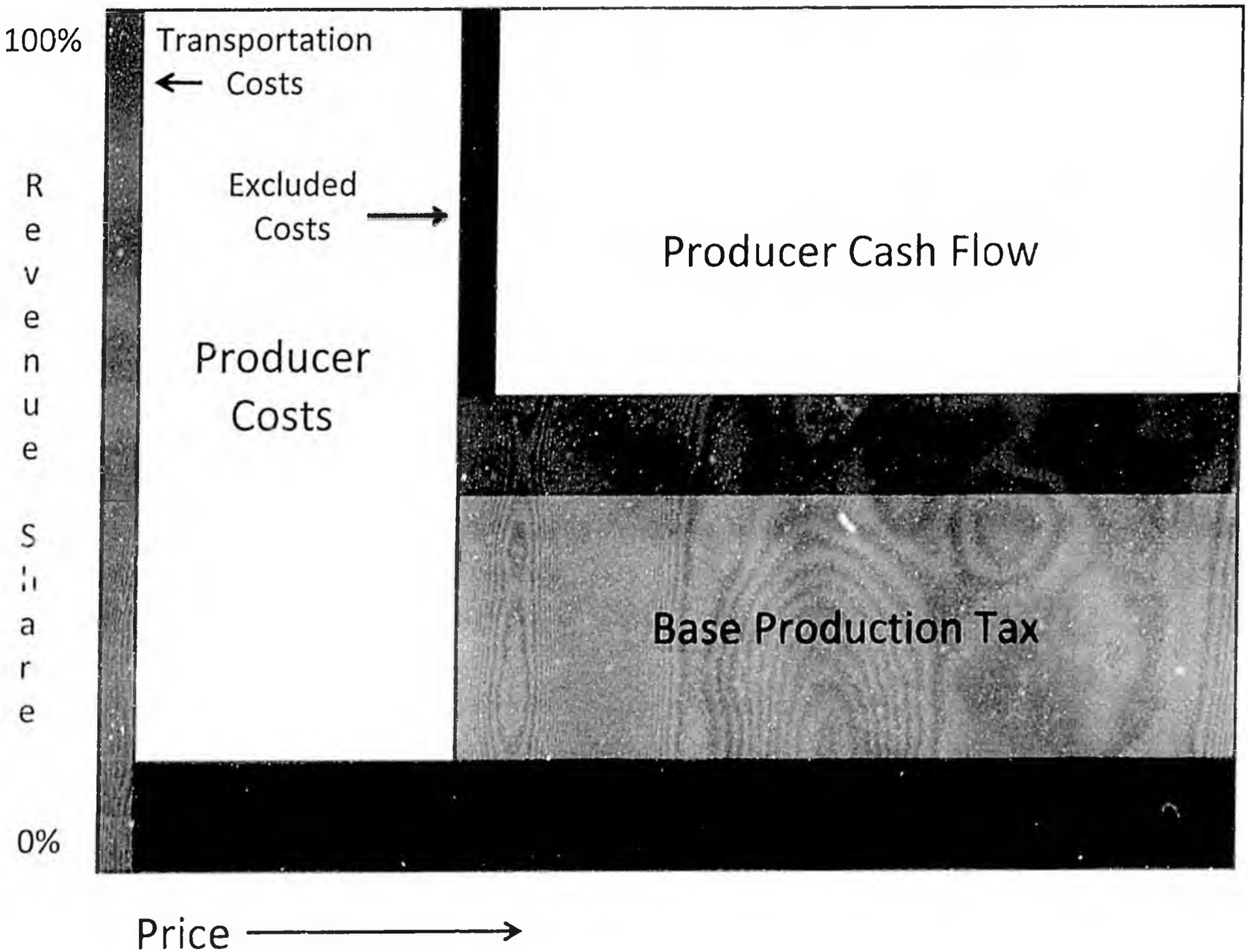

100%
Transportation
Costs
Revenue Share
0%
Total Revenue
Price

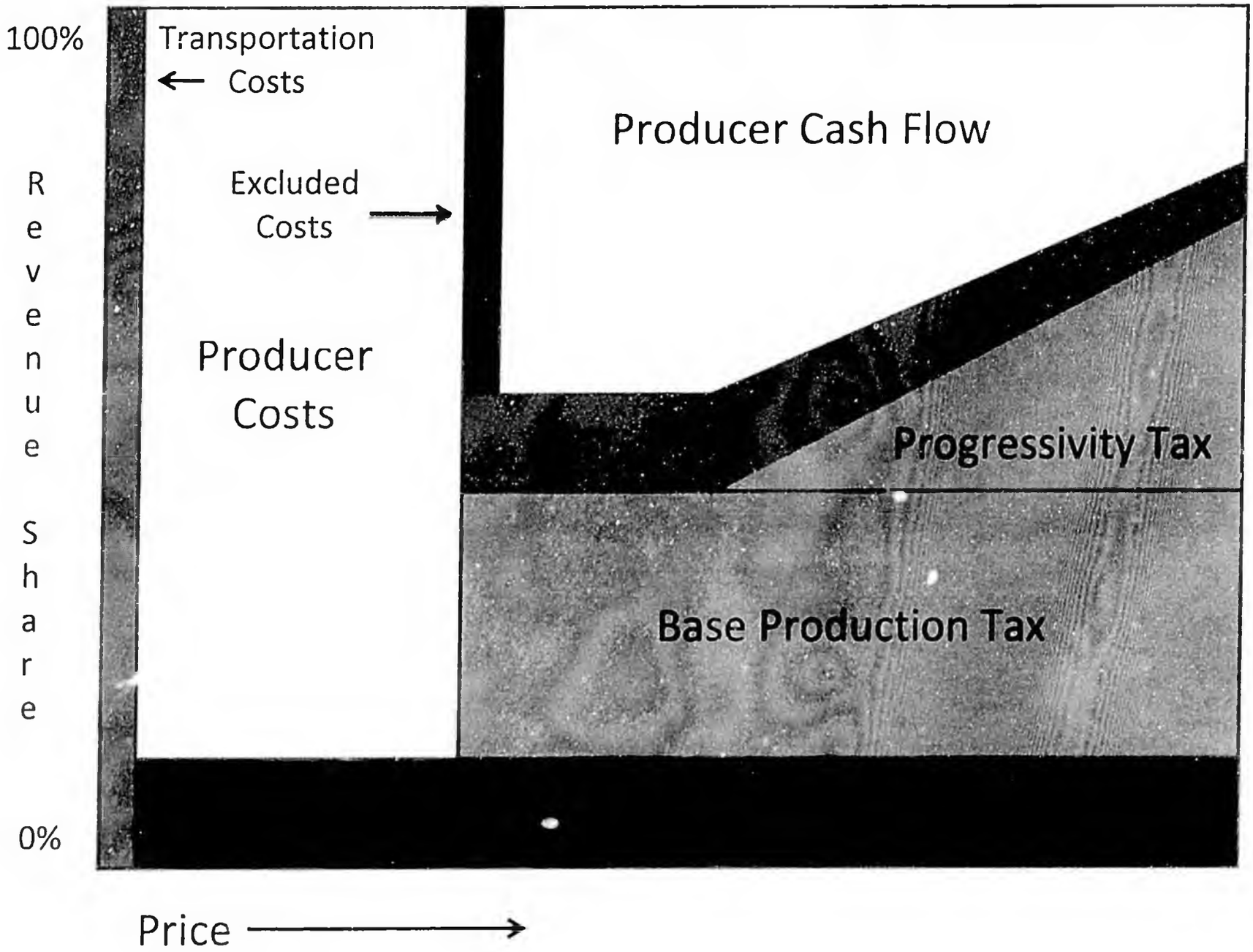

100%
Transportation
← Costs
Revenue Share
Gross Production Value
0%
Price →

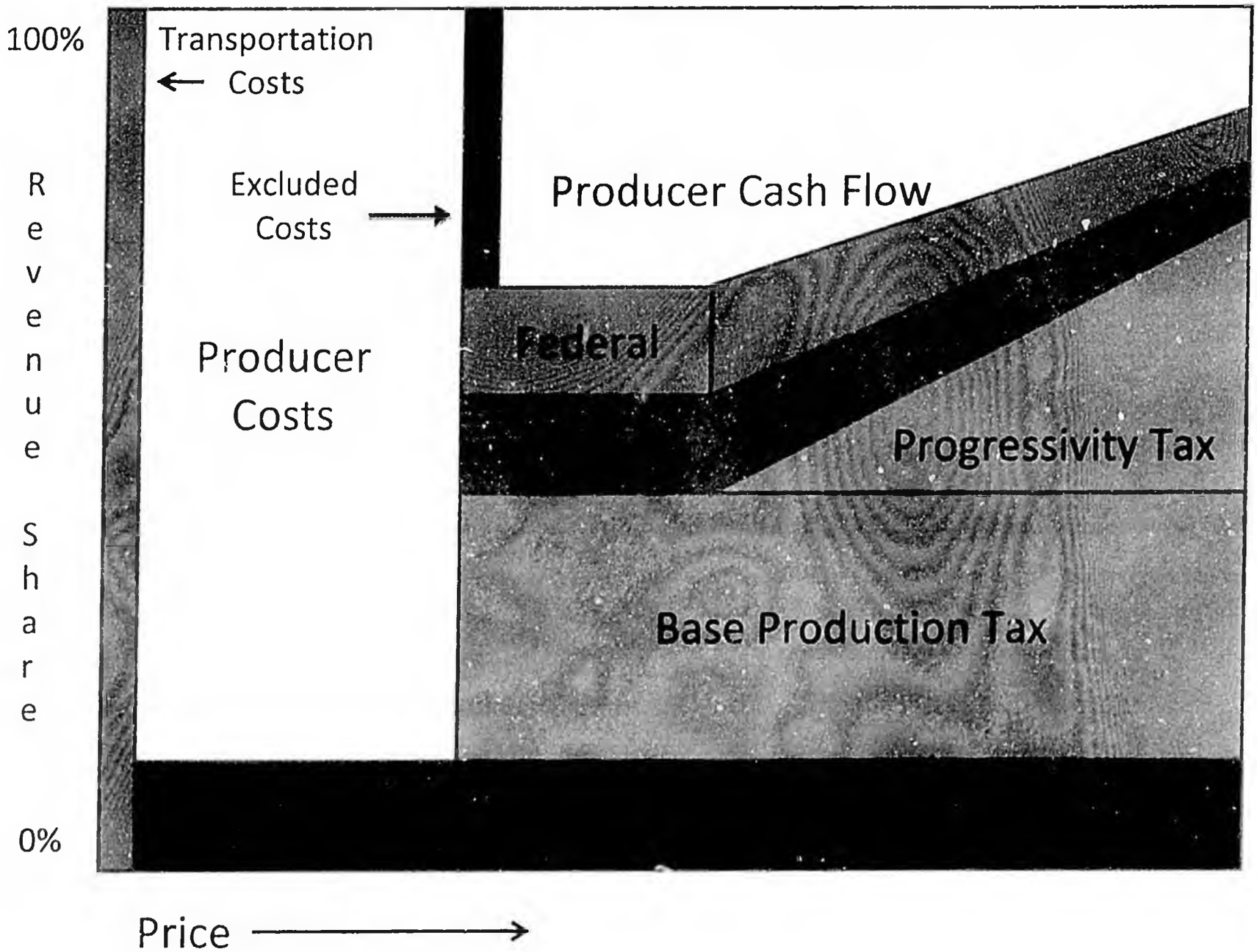

100%
Transportation
Costs
Revenue Share
Producer Costs
Production Tax Value
0%
Price

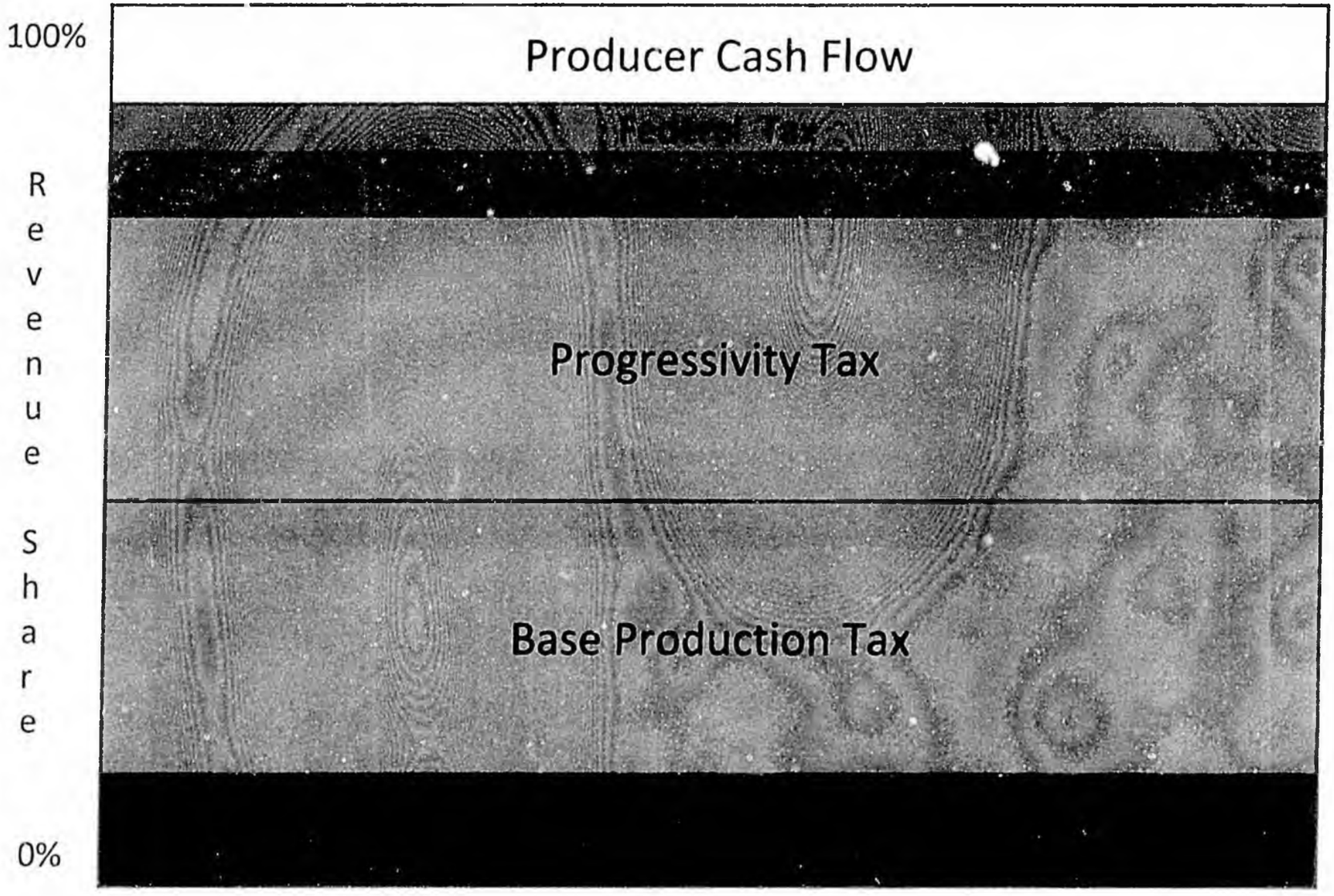

100%
Transportation
Costs
Revenue Share
Producer Costs
Producer Cash Flow
Base Production Tax
0%
Price


100%
Transportation
Costs
Excluded
Costs
Producer
Costs
Producer Cash Flow
Base Production Tax
0%
Revenue Share
Price


100%
Transportation
Costs
Excluded
Costs
Producer
Costs
Producer Cash Flow
Base Production Tax
0%
Revenue Share
Price


100%
Transportation
Costs
Producer Cash Flow
Revenue Share
Excluded
Costs
Producer
Costs
Progressivity Tax
Base Production Tax
0%
Price


100%
Transportation
Costs
Excluded
Costs
Producer
Costs
Producer Cash Flow
Federal
Progressivity Tax
Base Production Tax
0%
Revenue Share
Price


100%
Producer Cash Flow
Revenue Share
Progressivity Tax
Base Production Tax
0%

PRODUCTION TAX - DAN DICKERSON

Summary Comparison between Various Approaches to Production Tax

Issue	Current Law	SB/HB 2001 (ACES) as introduced	CS HB 2001(FIN)am
Base Rate	***AS 43.55.011 (e) & (g)***	***Bill Sections 15 & 17***	***Bill Sections 15***
Base Tax Rate	[redacted]	25%	25%
Progressivity	***AS 43.55.011(g) & (h)***	***Bill Sections 17,18***	***Bill Sections 17,18***
$/bbl Starting point	$40 net	$30 net	$30 net
Tax/$ of Price Index	0.25%	0.20%	0.40%
Average Value over	[redacted]	year	[redacted]
Applied to	[redacted]	net	[redacted]
Cap	[redacted]	25% of net	[redacted]
Gross Value Floor	***AS 43.55.011(f)***	***Bill Section 15, 16, 31-36, & 41-42***	***Bill Section 16***
Base	[redacted]	Prudhoe, Kuparuk	[redacted]
Rate	[redacted]	10%	[redacted]
Credits further reduce floor tax?	[redacted]	No	[redacted]
Apply .024 and .025 credits against floor	[redacted]	No	[redacted]
Investment Credits	***AS 43.55.023***	***Bill Section 26-28, 38-44 & 63***	***Bill Section 26-28***
Investment Credits	[redacted]	1/2 in each of two years	[redacted]
Loss Carry Forward Credits	20%	25%	25%
Transitional Investment Credits	Yes	No	All taxpayers allowed application of TIE matching spending in April 1 2006 - Dec 31, 2007, even if application deferred

Summary Comparison between Various Approaches to Production Tax

Issue	Current Law	SB/HB 2001 (ACES) as introduced	CS HB 2001(FIN)am
Exploration Credits	***AS 43.55.025***	***Bill Section 36 - 44***	***Bill Section 29-35***
Rates	20; 40%	20; 40%	30;40%
General &Admin Costs	disallowed	bad acts I	costs arising from Bad Acts III - criminal
DNR approval required?	In CI, to avoid 3 mile limit	Always	Always, w/ language changes
Confidentiality of well data	10 years	2 years	2 years, or if DNR declines to, or private landowner declines
Seismic on non state land	silent	included	explicit exclusion without permission
Pre-existing well	One drilling season	Two consecutive drilling seasons	Two consecutive drilling seasons
"DNR TIE" Credits for pre 2003 seismic work?	no	5%	5%
Exceptions to Tax Credits			***Bill Section 41***
none	none	none	unpaid judgment
State Purchase of Credits		***AS 43.55.023(f) & (g)***	
Paid from:	[redacted]	oil and gas credit fund, funded from production taxes	[redacted]
Annual dollar cap per taxpayer?	$25 million	none	$ 25 million (however ARM unlimited)
ARM Board Purchases?	n/a	n/a	yes

Summary Comparison between Various Approaches to Production Tax

Issue	Current Law	SB/HB 2001 (ACES) as introduced	CS HB 2001(FIN)am
Allowable Lease Expenditures	*AS 43.55.165*		*Bill Section 46-51*
Allowed by regulation	no language	must be	must be
Use producer audits of operators?	Explicit	Explicit repealed; Implicit	Explicit repealed; Implicit
Disallow bad acts II?	yes	add violation of law, lease or license	costs arising from Bad Acts III - criminal
Dispute resolution			
DR&R Allowed?	Allocated	No	No
"Corrosion" Issue		$0.30 + unscheduled events disallowed	$.30 a bbl disallowed+ intent language
Field Topping Plants allowed?	Yes	No	No
Off Lease allowed			
Public Outreach costs	not explicit	not explicit	no; listed
Opex			Yet to be written regulations will define 2006; then 3% annual increase; (regardless of production or ownership?)

Summary Comparison between Various Approaches to Production Tax

Issue	Current Law	SB/HB 2001 (ACES) as introduced	CS HB 2001(FIN)am
Information	*AS 43.05.230 and royalty statutes*		*Bill Sections 2-9,11,13,36-39, 52*
forward looking information required	none	information "necessary to forecast ... revenues under AS 43.55". Penalty up to $1000 a day.	information "necessary to forecast ... revenues under AS 43.55". Penalty up to $1000 a day if demanded information not forthcoming.
Disclosure of tax information	[redacted]	if aggregated w/2 other producers, no requirement to prevent identification	if aggregated w/2 other producers, [still under umbrella -required to prevent identification]
DNR sharing royalty information w/ DOR	limited ability	expanded ability	expanded ability
DOR sharing tax information with DNR	limited ability	expanded ability	expanded ability
Statute of Limitations	*AS 43.05.260*	*Bill Sections 1,14,50 new AS 43.55.075*	*Bill Sections 1,14,41 new AS 43.55.075*
State assessment must be issued within	3 yrs	6 yrs	6 yrs
DOR Auditors	*As 39.25.100*	*Bill Sections 10, 65, 67*	*Bill Sections 10, 56*
DOR & DNR auditors exempt employees?	no	yes	2 DNR and 4 DOR exempt master auditors authorized
Effective Date		*Bill Section 64*	*Bill Section 1, 60-61*
Generally	n/a	Jan 1 2008	Jan 1 2008
Retroactive to April 1 2006	n/a	deferred maintenance issues	deferred maintenance issues (Intent language)

Summary Comparison between Various Approaches to Production Tax

Issue	Current Law	SB/HB 2001 (ACES) as introduced	CS HB 2001(FIN)am
Downstream Costs	*As 43.55.150*		*Bill Section 43*
Reasonable v actual	[redacted]		Downstream Tanker and Pipelines = Actual, except, reasonable if lower
Prima facie reasonable Taps Tariff			"just and reasonable" and arms' length transactions
Gas Ceilings thru 2022		*As 43.55.011*	*Bill Section 22*
Where	CI	CI	CI + gas used in the state
Additional Penalties	*new As 43.55.055*		*Bill Section 40*
Penalty for under estimated payments	[redacted]		
Additional Penalties for Under reporting	none	none	10% for 10% or 10mm understmnt, 20% for 20% or 20mm understmnt
Intent Language			*Bill Section 1*
overall intent of legislation	n/a	no	included
long standing interpretation of SOL	n/a	included	included
Half the money from certain retroactive applications to PERS and public education fund	[redacted]		[redacted]
tax savings from gas ceilings outside CI passed on to ultimate consumers	n/a	no	encourage availability of affordable gas

Summary Comparison between Various Approaches to Production Tax

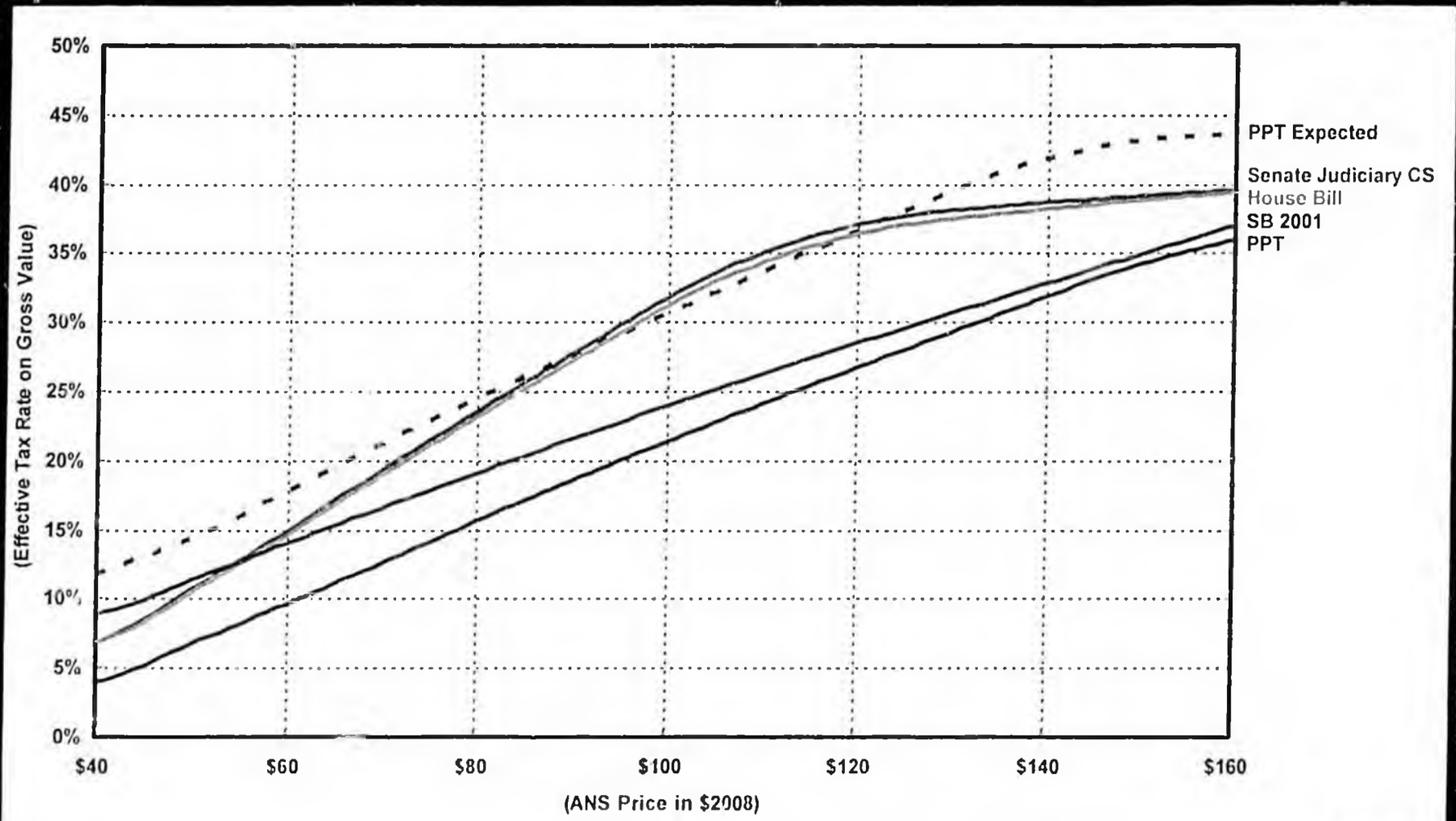
Issue	Current Law	SB/HB 2001 (ACES) as introduced	CS HB 2001(FIN)am
Admin	***AS 43.55.020(a)***		***Bill Sections 12,23-25,42***
Monthly Estimated payments	Estimated payments without ceilings, refund due taxpayer at year end	Ceilings applied monthly	Ceilings applied monthly (A and C) could be more parallel
LIHEAP funding	No	No	may appropriate $50 mm from progressivity
Whistleblower language	No	No	yes - with limitation for bad faith
DNR NPSL regulations	n/a	general grant for retroactive applications	may be retroactive
Required 2011 Report -	Yes	Yes	deleted

EconOne Charts

11/12/07 Barry Pullium

Estimated Average Effective Tax Rate on Gross Taxable Value at Various West Coast ANS Price Levels

(FY 2008-2014)



Note: Volumes per current Fall 2007 DOR Forecasts.

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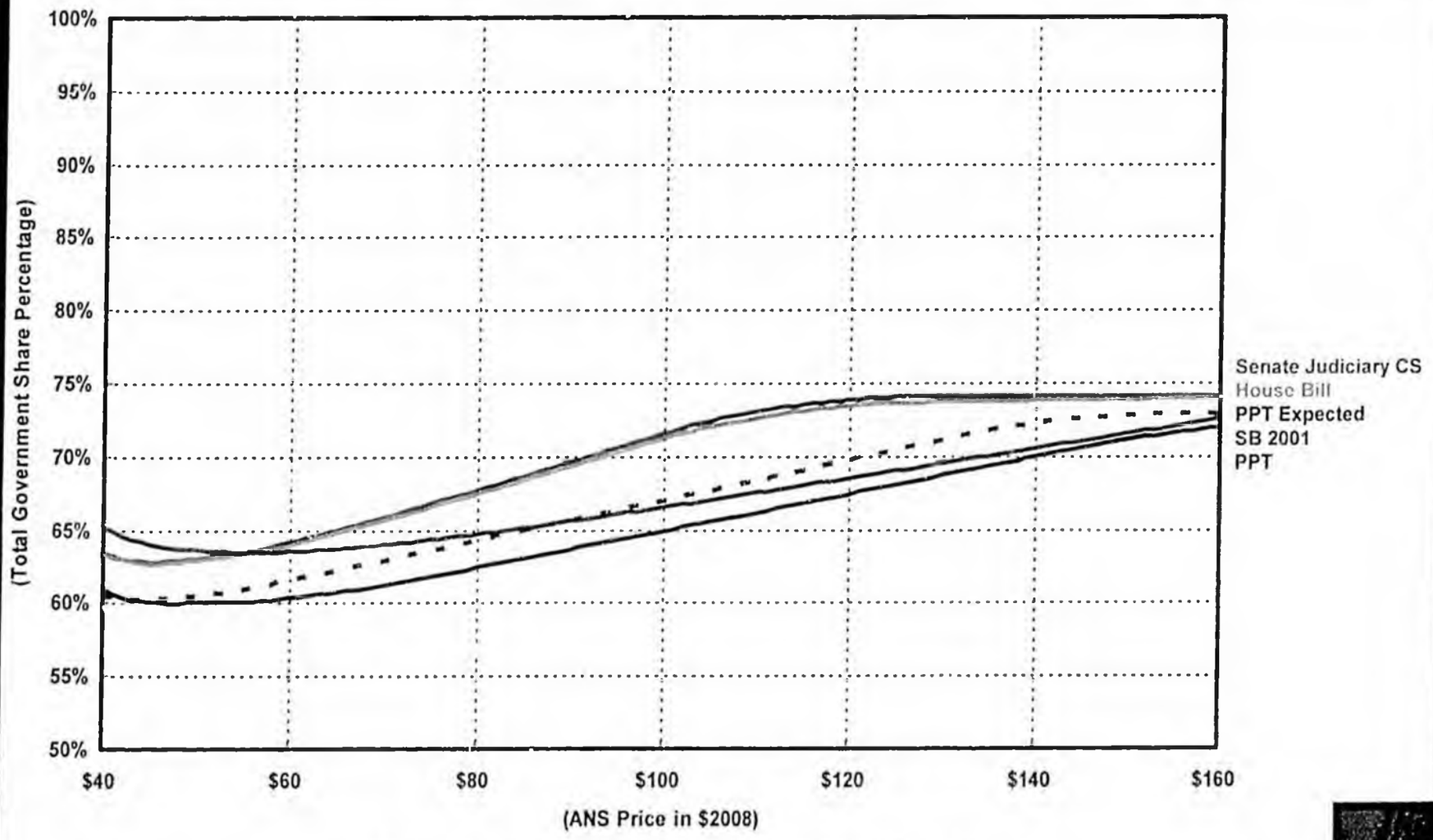
PPT Expected: Current Law using costs per Revit note to HB3001.

Senate Judiciary: SB2001 using 0.4% progressivity rate, 54% overall cap, TIE credit 2Q06-2007 for new producers, does not include TAPS adjustment.

House Bill: SB2001 using 0.4% progressivity rate, 50% overall cap, TIE credit 2Q06-2007 for new producers, Opex indexed to 2006 figures.

Estimated Total Government Share at Various West Coast ANS Price Levels
(FY 2008-2014)



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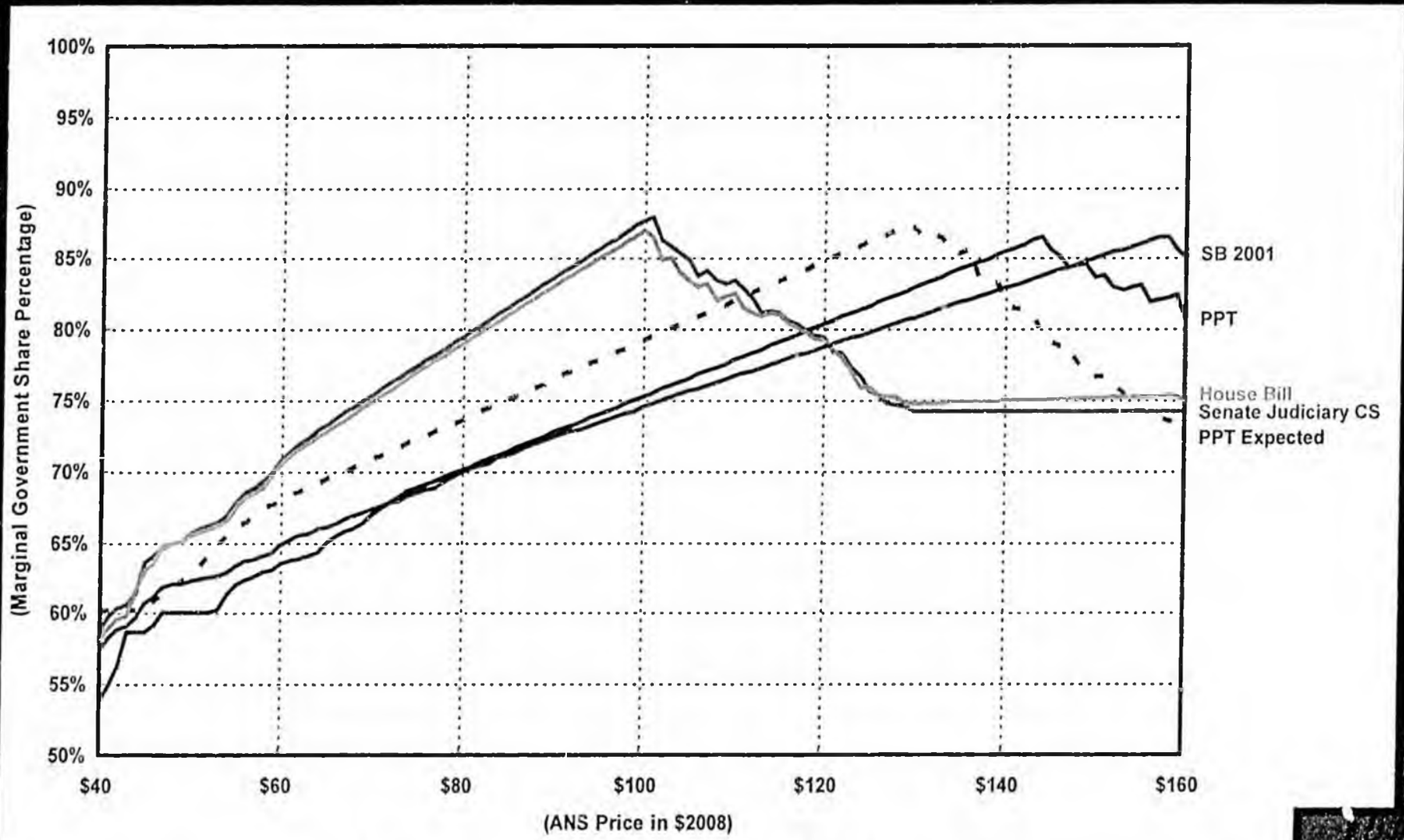
House Bill: SB2001 using 0.4% progressivity rate, 50% overall cap, TIE credit 2Q06-2007 for new producers, Opex indexed to 2006 figures.

11/12/07

Estimated Marginal Government Share at Various West Coast ANS Price Levels
(FY 2008-2014)



Note: Volumes per current Fall 2007 DOR Forecasts.

PPT Expected: Current Law using costs per fiscal note to HB3001.
Senate Judiciary: SB2001 using 0.4% progressivity rate, 60% overall cap, TIE credit 2Q06-2007 for new producers, does not include TAPS adjustment.
House Bill: SB2001 using 0.4% progressivity rate, 60% overall cap, TIE credit 2Q06-2007 for new producers, Opex indexed to 2006 figures.

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Estimated Average Effective Tax Rate, Government Shares and Revenue Impacts at Various West Coast ANS Price Levels
(FY 2008-2014)

Average ANS West Coast Price in Real 2008 Dollars:	*$40.00*	*$60.00*	*$80.00*	*$100.00*	*$120.00*	*$140.00*	*$160.00*
Effective Tax Rate on Gross Taxable Value (Percent)							
PPT	4.0%	9.6%	15.6%	21.3%	26.7%	31.8%	36.0%
PPT Expected	11.6%	17.7%	24.4%	30.6%	36.5%	41.8%	43.6%
SB 2001	8.9%	14.0%	19.1%	23.9%	28.5%	32.8%	37.0%
Senate Judiciary CS	6.8%	14.9%	23.6%	31.8%	37.1%	38.7%	39.6%
House Bill	6.8%	14.6%	23.1%	31.2%	36.4%	38.2%	39.4%
Total Government Share of Net Cash (Percent)							
PPT	60.9%	60.3%	62.4%	64.9%	67.4%	69.9%	71.9%
PPT Expected	60.4%	61.5%	64.2%	66.9%	69.7%	72.2%	72.9%
SB 2001	65.3%	63.5%	64.7%	66.5%	68.5%	70.5%	72.6%
Senate Judiciary CS	-63.4%	64.1%	67.7%	71.5%	73.9%	74.1%	74.1%
House Bill	63.4%	64.0%	67.5%	71.2%	73.4%	73.8%	74.0%
Marginal Government Share of Net Cash (Percent)							
PPT	53.8%	63.4%	70.1%	75.2%	80.4%	85.5%	80.6%
PPT Expected	60.2%	68.0%	73.5%	79.1%	84.7%	81.9%	73.0%
SB 2001	57.4%	64.8%	70.0%	74.5%	78.8%	83.0%	85.0%
Senate Judiciary CS	58.7%	70.7%	79.5%	87.7%	79.4%	74.1%	74.1%
House Bill	58.1%	70.5%	79.0%	87.0%	79.2%	75.0%	74.9%
Annual Average Tax Difference Above/(Below) PPT (Nominal $M)							
PPT Expected	$622	$1,036	$1,545	$2,062	$2,651	$3,153	$2,776
SB 2001	$402	$566	$611	$573	$484	$309	$372
Senate Judiciary CS	$230	$673	$1,394	$2,320	$2,796	$2,158	$1,305
House Bill	$229	$644	$1,329	$2,204	$2,614	$2,006	$1,238

Note: Volumes per current Fall 2007 DOR Forecasts.

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PPT Expected: Current Law using costs per fiscal note to HB3001.
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Estimated Average Effective Tax Rate, Government Shares and Revenue Impacts at Various West Coast ANS Price Levels
(FY 2008-2014)

Average ANS West Coast Price in Real 2008 Dollars:	*$40.00*	*$60.00*	*$80.00*	*$100.00*	*$120.00*	*$140.00*	*$160.00*
Effective Tax Rate on Gross Taxable Value (Percent)							
PPT	4.0%	9.6%	15.6%	21.3%	26.7%	31.8%	36.0%
PPT Expected	11.6%	17.7%	24.4%	30.6%	36.5%	41.8%	43.6%
SB 2001	8.9%	14.0%	19.1%	23.9%	28.5%	32.8%	37.0%
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House Bill	6.8%	14.6%	23.1%	31.2%	36.4%	38.2%	39.4%
Total Government Share of Net Cash (Percent)							
PPT	60.9%	60.3%	62.4%	64.9%	67.4%	69.9%	71.9%
PPT Expected	60.4%	61.5%	64.2%	66.9%	69.7%	72.2%	72.9%
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Marginal Government Share of Net Cash (Percent)							
PPT	53.8%	63.4%	70.1%	75.2%	80.4%	85.5%	80.6%
PPT Expected	60.2%	68.0%	73.5%	79.1%	84.7%	81.9%	73.0%
SB 2001	57.4%	64.8%	70.0%	74.5%	78.8%	83.0%	85.0%
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LFD -

TAX RATES

Tax Rates in Various Versions of SB 2001

November 12, 2007

David Teal

Major Provisions of a Tax System

1. Taxable Revenue (Gross or Net)
2. Base Rate
3. Surcharge (Progressive Rate)
4. Trigger Point for Surcharge
5. Maximum Rate

All Tax Systems Discussed are Based on Net Cash Flow

	Base	Trigger	Rate	Trigger	Rate	Trigger	Rate	Trigger	Rate	Maximum
PPT	22.5%	$ 40	0.25%							47.5%
ACES	25.0%	$ 30	0.20%							50.0%
Sen Jud	25.0%	$ 30	0.40%							50.0%
House	25.0%	$ 30	0.40%							50.0%
Sen Fin	22.5%	$ 30	0.60%	$ 30	0.50%	$ 50	0.35%	$ 70	0.10%	75.0%

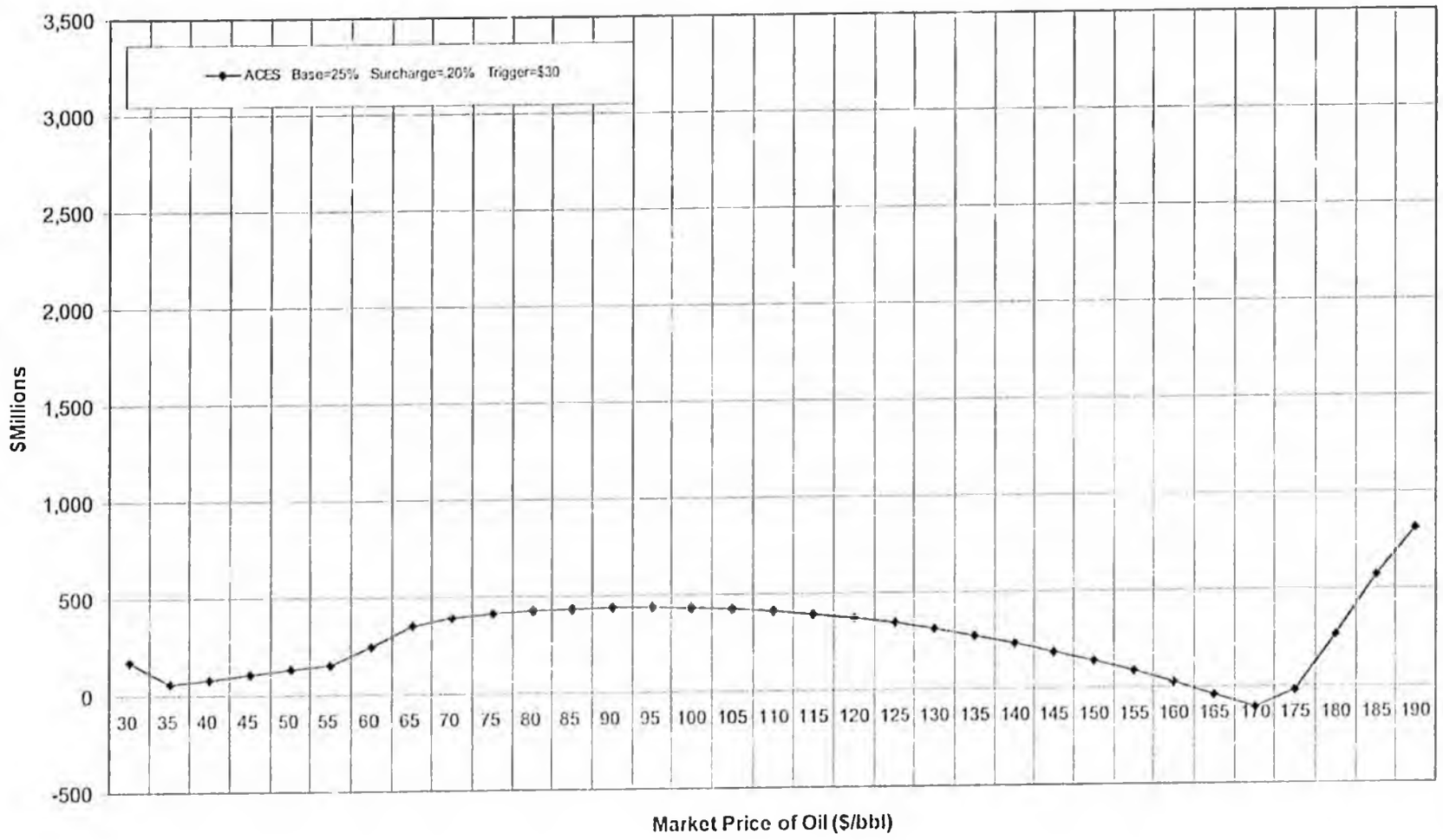
Comparing the Tax Systems

1. Increase in Revenue (relative to PPT)
2. Total Revenue
3. Government Share

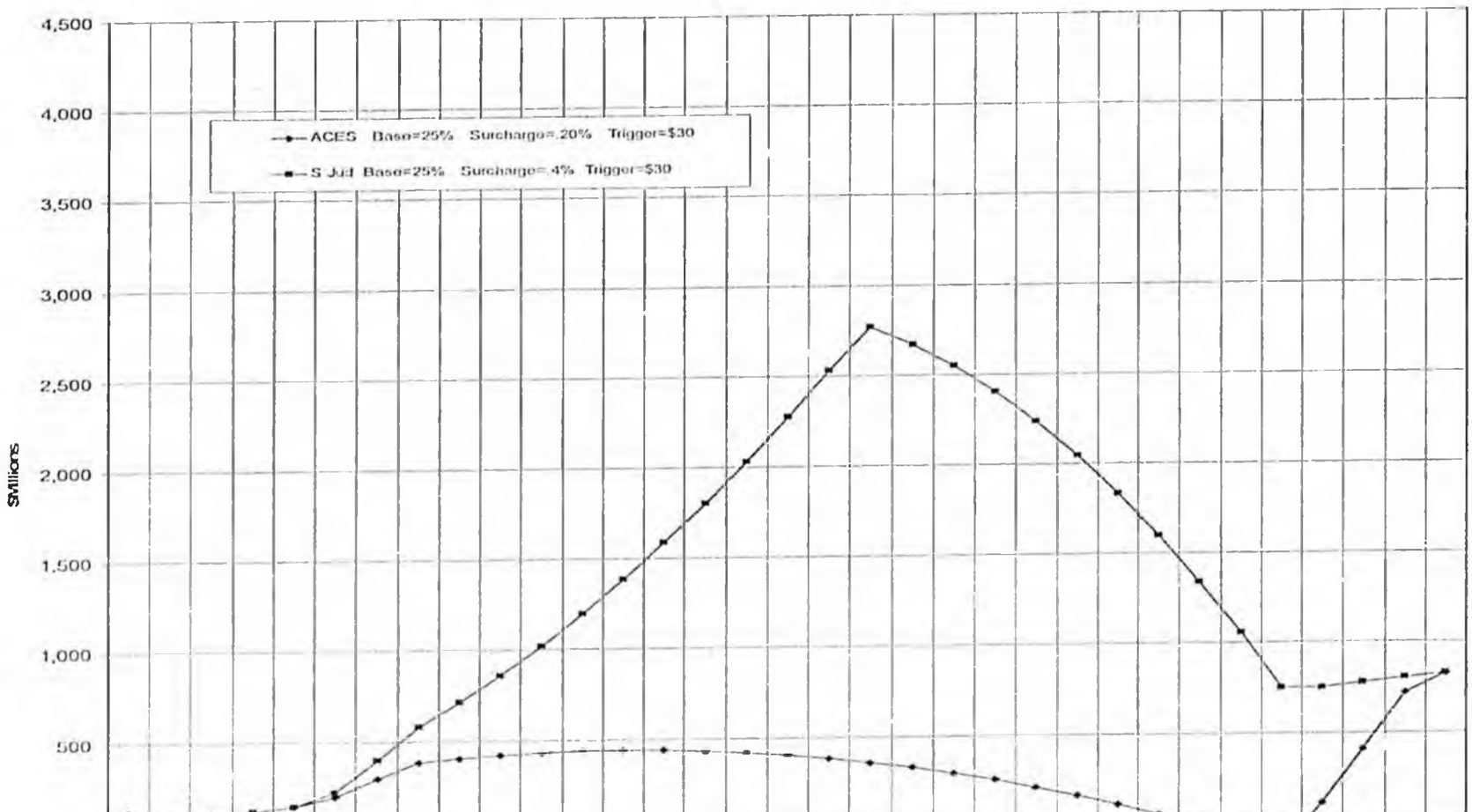
Things to Remember

- Focus on curve shape and location—projections are affected by production volume, costs of production and other factors that cannot be predicted accurately.
- Projections are based on the Fall 2007 Revenue Forecast, but even if the variables—production volume, costs of production, etc.—change, the projections do not change much in relative terms.

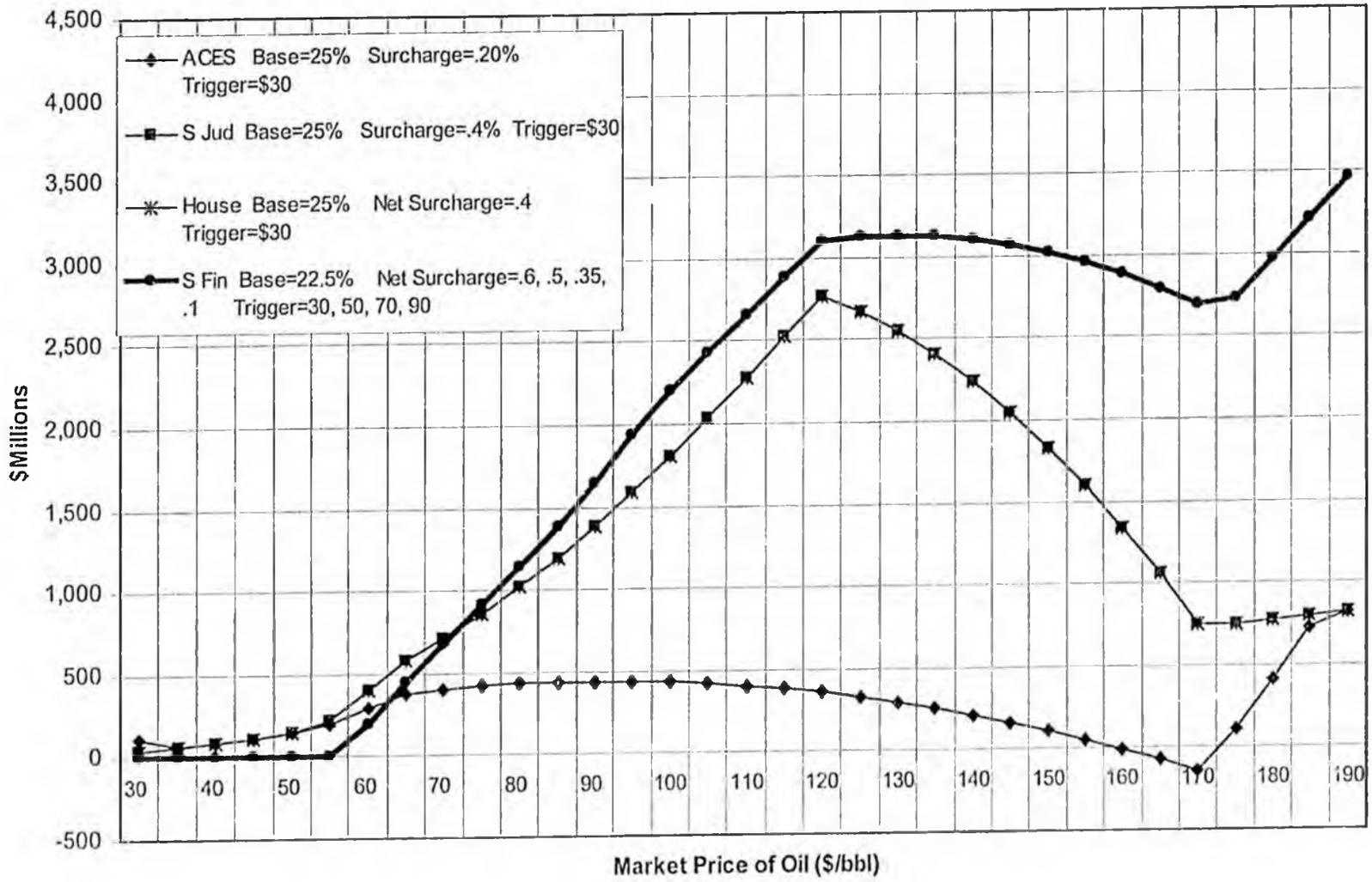
Increases in Total State Revenue Under Various Production Tax Systems



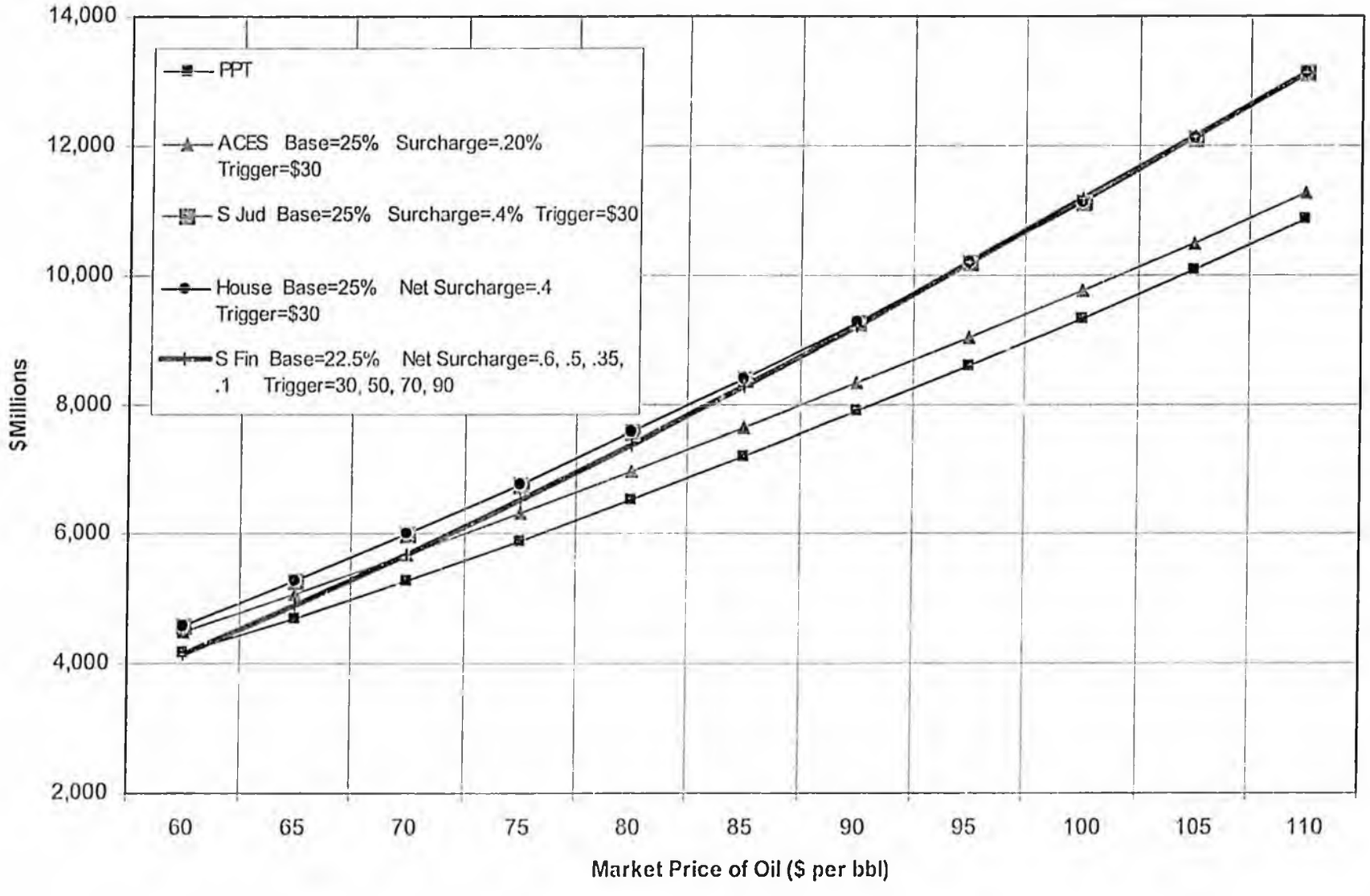
Increases in Total State Revenue Under Various Production Tax Systems



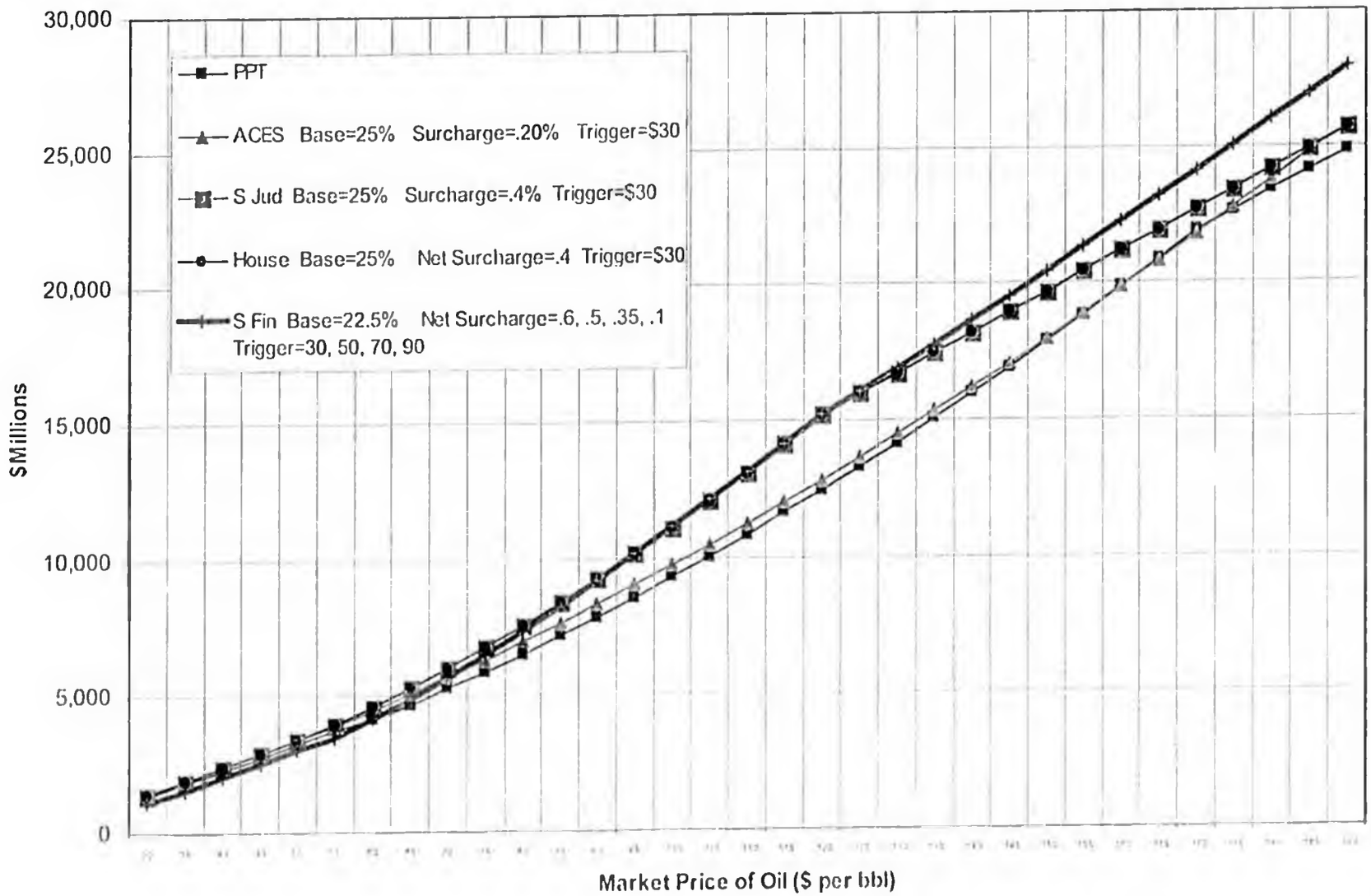
Increases in Total State Revenue Under Various Production Tax Systems



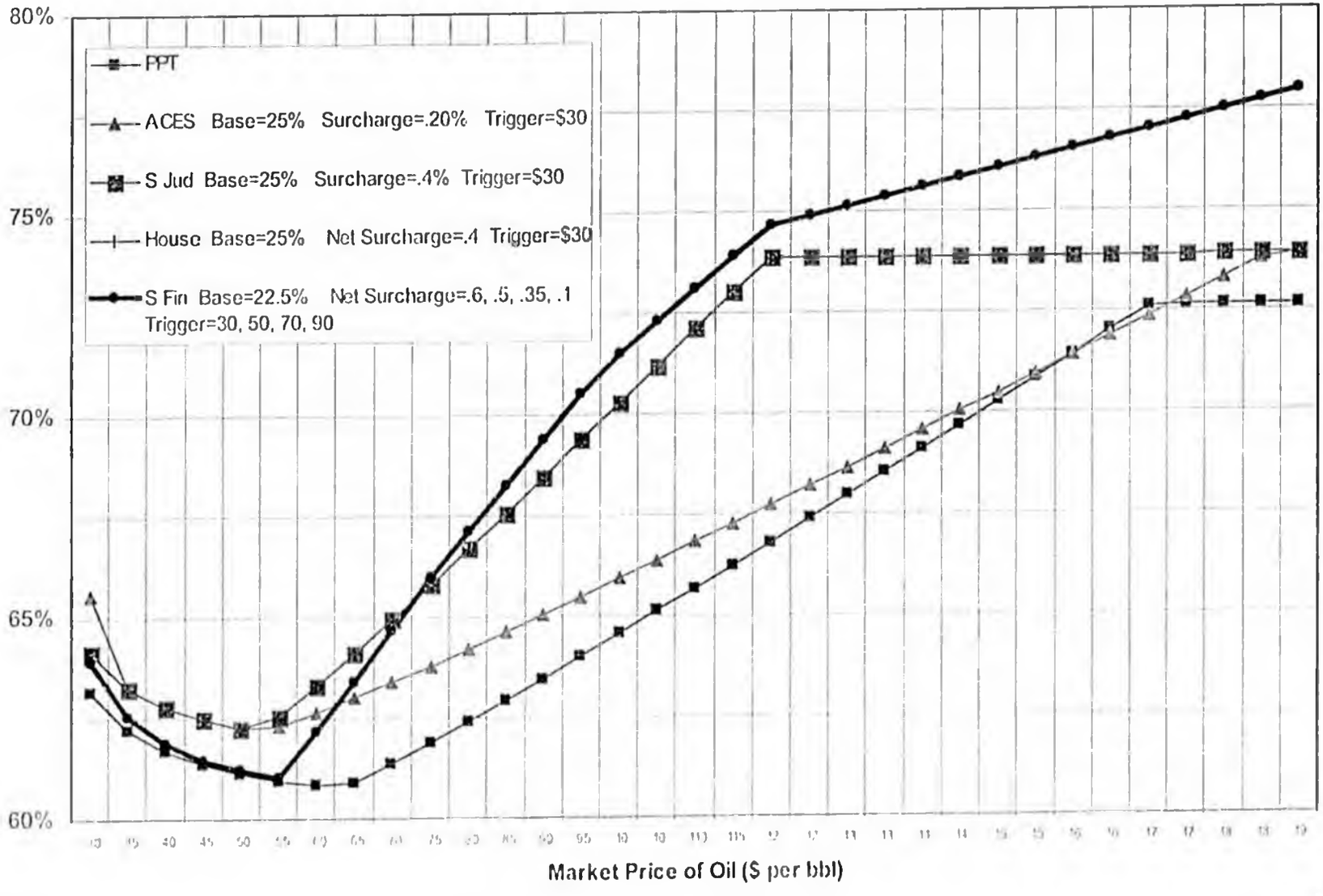
Total State Revenue Under Various Scenarios



Total State Revenue Under Various Scenarios



Government Share of Revenue Under Various Scenarios



FISCAL NOTES

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: CSHB2001(FIN)am
() Publish Date:

Identifier (file name): CSHB2001(FIN)am-DOR-TAX-11-12-07
Dept. Affected: Revenue 04
Title: An Act relating to the production tax on oil and gas..
RDU: Taxation and Treasury
Component: Tax Division
Sponsor: Governor
Requester: Senate Finance
Component Number: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2009**	**FY 2009**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**
Personal Services	915.7		915.7	915.7	915.7	915.7	915.7
Travel							
Contractual	1,018.4		1,018.4	1,018.4	511.8	5.2	5.2
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	**1,934.1**		**1,934.1**	**1,934.1**	**1,427.5**	**920.9**	**920.9**
CAPITAL EXPENDITURES							
CHANGE IN REVENUES (							

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF	**1,934.1**		**1,934.1**	**1,934.1**	**1,427.5**	**920.9**	**920.9**
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	**1,934.1**		**1,934.1**	**1,934.1**	**1,427.5**	**920.9**	**920.9**

Estimate of any current year (FY2008) cost: 3,409.2

POSITIONS

Full-time	5	5	5	5	5	5	5
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessa*

This bill makes economic and several administrative changes to the state's current petroleum profits tax. The bill retains the current tax system's structure, which taxes the net value of petroleum resources.

This fiscal note shows operating and capital expenses related to the change in reporting and administering the tax

Prepared by: Johanna Bales, Roger Marks, Cherie Nienhuis
Phone 269-6628
Division: Tax Division
Date/Time 11/12/07 1:00 PM
Approved by: Jerry Burnett
Date 11/12/2007
Department of Revenue

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. CSHB2001(FIN)am

ANALYSIS CONTINUATION

Administrative changes to the current tax system include the following: requires taxpayers to provide cost projections to allow the state to better forecast state revenues and pursue changes in reported costs; authorizes public reporting of some cost data; authorizes a short-term audit program; and designates an exempt class of oil and gas audit masters.

Personal Services: The department will create 4 senior level auditor master positions in the exempt service with extensive industry oil and gas auditing experience. These positions will be classified as the Department's most senior level auditor positions and will have salaries that are consistent with market comparables beyond the current salary levels allowed under the existing Oil and Gas Revenue Auditor (OGRA) pay classification system. The need for exempt status is based upon the difficulties the department has recruiting experienced auditors to administer the tax. The department estimates the new exempt positions will cost the state approximately $800,000 annually. The bill also requires the Department of Administration to create a new class and pay system for Oil and Gas revenue auditors. We have no basis on which to estimate additional costs arising under this pay plan and these costs will be presented to the legislature in a future budget. In addition to the costs for auditors, the department expects that it will need one additional Programmer Analyst V position to maintain and manage the new oil and gas production tax database system at a cost of $115,700 annually.

Contractual: Contractual expenditures include $1,013,200 annually to contract for audit assistance. This estimate is based on 3 auditors, working 40 hours per week each, for 4 years starting in January 2008 at an average rate of $100 per hour, plus estimated transportation and lodging costs, and additional costs for training auditors. The need for such assistance is based upon the department's substantial difficulty in recruiting enough auditors to administer the oil and gas production tax. The department only anticipates the need for contract audit assistance for 4 years while the department recruits and trains auditors for positions that are currently vacant. The contract auditors would work in conjunction with department auditors during this time to maximize department resources and help train department auditors. The department will also need an additional $5,200 each year in contractual costs associated with the new Analyst Programmer V position.

Current FY2008 costs: The department expects it will incur costs beginning January 2008 to immediately implement the new production tax structure. Those costs include: **Contractual** - $2,620,800 capital funding to fund the scoping and development of an oil and gas production tax database system (including associated hardware) and $506,600 to contract for audit assistance (as described above). The new database system will permit accurate and efficient management of information submitted by taxpayers to facilitate auditing and forecasting of revenues, and timely and accurate reports for internal and public uses. The proposed system will accommodate the migration of ELF-based data and continue to collect supplemental data from producers on volumes, wells and production. The system will include income-based data, including tracking credits, required under PPT and upon which the ACES tax structure is based. The system will also integrate into the division's accounting systems. **Personal Services** - $218,000 from the period January 1, 2008 through June 30, 2008 due to creating an exempt class of oil and gas revenue auditors and increasing pay to more closely reflect what the market in Alaska pays for roughly similar positions. In addition, we will recruit for the Analyst Programmer V and bring that person on board to participate in the database scoping meetings. We estimate FY 2008 costs for this position to be approximately $57,800. **Supplies** - $6,000 for a computer and software for the new analyst programmer V position.

Revenue changes will be shown in another fiscal note.

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: CSHB2001(FIN)am
() Publish Date:

Identifier (file name): CSHB2001(FIN)am-DOR-REV-11-12-07
Title An Act relating to the production tax on oil and gas..
Sponsor Governor
Requester Senate Finance

Dept. Affected: Revenue 04
RDU Taxation and Treasury
Component Tax Division
Component Number 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURE	**FY 2009**	**FY 2009**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**
Personal Services							
Travel							
Contractual							
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING							
CAPITAL EXPENDITURES							
CHANGE IN REVENUES (		1,008,740	778,522	782,003	794,462	809,402	590,048

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF							
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	0.0		0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2008) cost

POSITIONS

Full-time							
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessa*

This fiscal note shows changes in revenues resulting from this legislation; operating and capital costs pertaining to the Department of Revenue for the implementation of this legislation are shown on a separate fiscal note.

This bill makes several economic changes to the state's current petroleum profits tax. Although the bill retains the current tax system's structure, which taxes the net value of petroleum resources, the changes it makes are as follows: the base tax rate is raised from 22.5% to 25%; the progressive surcharge is raised to an index of .4% per dollar multiplied by the net value that exceeds $30 per barrel with a ceiling of 25%; the costs for transportation are set at the lower of actual or reasonable costs; legacy fields, instead of being allowed to deduct actual operating costs, must substitute a standard deduction based on 2006 operating costs (inflated at 3% per year); the transition investment expenditure credit is eliminated, except to the extent that transition credits earned from April 1, 2006 to December 31, 2007 can be carried forward to offset a future tax liability; and EIC credits are increased from 20% to 30%.

Prepared by: Johanna Bales, Roger Marks, Cherie Nienhuis — Phone 269-6628
Division: Tax Division — Date/Time 11/12/2007 2:30PM
Approved by: Jerry Burnett — Date 11/12/2007
Department of Revenue

(Revised 10/5/2006 OMB)

ANALYSIS CONTINUATION

Other changes to the current tax system include the following: ; excludes dismantlement, removal & restoration (DR&R) costs from allowable expenditures; requires taxpayers to provide cost projections to allow the state to better forecast state revenues and pursue changes in reported costs; authorizes public reporting of some cost data; and authorizes a short-term audit program..

The tax proposal becomes effective January 1, 2008.

See page 3 for projected revenue estimates.

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. CSHB2001(FIN)am

ANALYSIS CONTINUATION

Estimated Production Tax Revenues, PPT, ACES and CSHB2001(FIN)am, at Various Prices (in $millions nominal)

Fall 2007 DOR Official Forecast Prices

Fiscal Year	ANS WC $ per barrel (in REAL dollars)	ANS WC $ per barrel (in NOMINAL dollars)	Status Quo - PPT	ACES	CSHB2001 (FIN)am	Increase or (Decrease) from PPT	Increase or (Decrease) from ACES
2008	71.65	71.65	1,947	2,368	2,619	672	251
2009	64.55	66.30	1,430	1,985	2,439	1,009	454
2010	60.05	63.40	1,217	1,767	1,995	779	229
2011	59.70	64.75	1,250	1,766	2,032	782	267
2012	59.55	66.35	1,174	1,701	1,969	794	267
2013	58.90	67.45	1,151	1,685	1,961	809	276
2014	58.25	68.55	1,217	1,558	1,807	590	249

DOR Forecast nominal prices rounded to the nearest $0.05

$60 per barrel in REAL dollars

Fiscal Year	ANS WC $ per barrel (in REAL dollars)	ANS WC $ per barrel (in NOMINAL dollars)	Status Quo - PPT	ACES	CSHB2001 (FIN)am	Increase or (Decrease) from PPT	Increase or (Decrease) from ACES
2008	60.00	60.00	1,073	1,452	1,569	496	118
2009	60.00	61.65	1,197	1,698	2,039	843	341
2010	60.00	63.35	1,247	1,802	2,019	772	216
2011	60.00	65.09	1,272	1,795	2,065	793	270
2012	60.00	66.88	1,204	1,737	2,016	812	278
2013	60.00	68.72	1,225	1,772	2,076	852	304
2014	60.00	70.61	1,334	1,696	1,991	658	295

$80 per barrel in REAL dollars

Fiscal Year	ANS WC $ per barrel (in REAL dollars)	ANS WC $ per barrel (in NOMINAL dollars)	Status Quo - PPT	ACES	CSHB2001 (FIN)am	Increase or (Decrease) from PPT	Increase or (Decrease) from ACES
2008	80.00	80.00	2,693	3,137	3,612	919	475
2009	80.00	82.20	2,640	3,294	4,286	1,646	992
2010	80.00	84.46	2,751	3,431	4,327	1,576	896
2011	80.00	86.78	2,782	3,431	4,399	1,617	968
2012	80.00	89.17	2,698	3,360	4,346	1,648	986
2013	80.00	91.62	2,783	3,451	4,508	1,725	1,057
2014	80.00	94.14	2,950	3,407	4,478	1,528	1,071

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: CSHB2001(FIN) am
() Publish Date:

Identifier (file name): HB2001CSFINam-DNR-O&G-11-12-07(2)
Title Oil and Gas Tax Amendments
Sponsor Rules Committee
Requester Senate Finance

Dept. Affected: Natural Resources
RDU Resource Development
Component Oil and Gas Development
Component Number 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2009**	**FY 2009**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**
Personal Services	450.0		450.0	450.0	450.0	450.0	450.0
Travel							
Contractual	10.4		10.4	10.4	10.4	10.4	10.4
Supplies	4.0		4.0	4.0	4.0	4.0	4.0
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	**464.4**	**0.0**	**464.4**	**464.4**	**464.4**	**464.4**	**464.4**
CAPITAL EXPENDITURES							
CHANGE IN REVENUES ( )	** INDETERMINATE POSITIVE **						

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF	464.4		464.4	464.4	464.4	464.4	464.4
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	**464.4**	**0.0**	**464.4**	**464.4**	**464.4**	**464.4**	**464.4**

Estimate of any current year (FY2008) cost: 172.4

POSITIONS

Full-time	2	0	2	2	2	2	2
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessary)*

This bill would amend the oil and gas production tax under AS 43.55 to increase the base tax rate from 22.5% to 25% of net income with no retroactivity. The bill has a progressivity surcharge increasing at 0.4% per dollar between the per barrel net revenue and $30. The bill also reduces the period by which past investments are recognized in the transition investment expenditure credits (AS 43.55.023(l)) to three years. Some EICs are increased from 20% to 30%.

Administrative changes to the current tax system include changes in the administration of EICs under AS 43.55.025 relating to the kind of information that EIC applicants must provide to the state and time that this information may be kept confidential.

Prepared by: Kevin Banks, Acting Director — Phone 269-8800
Division Oil and Gas — Date/Time 11/12/2007
Approved by: Tom Irwin, Commissioner — Date 11/12/2007
Natural Resources

(Revised 10/05/2006 OMB)

ANALYSIS CONTINUATION

**Indeterminate Positive: The royalty revenue impact to the State of ACES is indeterminate positive. The improvements of EICs will bring favorable economics to exploration projects. Increasing the tax rate, and the reduction of TIE credits available to lessees, will alter project specific economics. Furthermore, the progressivity element that has an impact only when oil prices or margins are high, will also alter project specific economics.

Personal Services: This bill would create two new oil and gas revenue audit master positions in the Division of Oil and Gas. These two positions would be the senior level auditors and are expected to have extensive oil and gas auditing experience. They will be the division's most senior auditor positions and will have salaries that are consistent with market comparables and will be above the current salary levels allowed under the existing Oil and Gas Revenue Auditor pay classification system. The division shares the experience with the Department of Revenue in failing to successfully recruit auditors with the required industry experience. These two positions will direct and provide training to existing staff. Salary and benefits for these positions plus other salary adjustments within the audit staff will be $450.0 per year. Any contractual, supplies, and equipment line items listed on page 1 support these two new exempt positions.

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number: 5
Bill Version: CSSB 2001(JUD)
(S) Publish Date: 11/5/07

Identifier (file name): CSSB2001(JUD)-DOR-TAX-11-3-07
Title: An Act relating to the production tax on oil and gas..
Sponsor: Governor
Requester: Senate Judiciary

Dept. Affected: Revenue 04
RDU: Taxation and Treasury
Component: Tax Division
Component Number: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2009**	**FY 2009**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**
Personal Services	915.7	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7
Travel							
Contractual	1,018.4	1,018.4	1,018.4	1,018.4	511.3	5.2	5.2
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	**1,934.1**	**2,234.1**	**2,234.1**	**2,234.1**	**1,727.0**	**1,220.9**	**1,220.9**
CAPITAL EXPENDITURES							
CHANGE IN REVENUES (		**1,085,000.0**	**838,000.0**	**875,000.0**	**962,000.0**	**935,000.0**	**704,000.0**

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF	1,934.1	2,234.1	2,234.1	2,234.1	1,727.0	1,220.9	1,220.9
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	**1,934.1**	**2,234.1**	**2,234.1**	**2,234.1**	**1,727.0**	**1,220.9**	**1,220.9**

Estimate of any current year (FY2008) cost: 3,409.2

POSITIONS

Full-time	5	5	5	5	5	5	5
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessary)*

This bill makes several economic and adminstrative changes to the state's current petroleum profits tax. The bill retains the current tax system's structure, which taxes the net value of petroleum resources. The bill makes the following economic changes to the current system: the tax rate is raised from 22.5% to 25%; the progressive surcharge is raised to an index of .4% per dollar multiplied by the net value that exceeds $30 per barrel with a ceiling of 25%; the costs for transportation are set at the lower of actual or reasonable costs; the transition investment expenditure credit is elimated, except to the extent that transition credits earned from April 1, 2006 to this bill's effective date can be carried forward to offset a future tax liability.

The Department of Revenue does not currently have accurate estimates for lease expenditure activity occurring outside Alaska. This amount is considered indeterminate at this time.

Prepared by: Johanna Bales, Roger Marks, Cherie Nienhuis — Phone 269-6628
Division: Tax Division — Date/Time 11/3/07 9:30 AM
Approved by: Jerry Burnett — Date 11/3/2007
Department of Revenue

(Revised 10/05/2007 OMB)

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STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. CSSB 2001(JUD)

ANALYSIS CONTINUATION

Adminstrative changes to the current tax system include the following: excludes from qualified lease expenditures those expenses related to unscheduled production interruptions; excludes dismantlement, removal & restoration (DR&R) costs from allowable expenditures; excludes lease expenditures from activities occurring outside Alaska; requires taxpayers to provide cost projections to allow the state to better forecast state revenues and pursue changes in reported costs; authorizes public reporting of some cost data; authorizes a short-term audit program; and designates an exempt class of oil and gas audit managers.

Certain lease expenditure allowance provisions are retroactive to April 1, 2006; the other provisions of the tax proposal become effective January 1, 2007.

Personal Services: The department will create 4 senior level audit manager positions with extensive industry oil and gas auditing experience. These positions will be classified as the Department's most senior level auditor positions and will have salaries that are consistent with market comparables and will be beyond the current salary levels allowed under the existing Oil and Gas Revenue Auditor (OGRA) pay classification system. In addition, the department expects that it will need one additional Programmer Analyst V position to maintain and manage the new oil and gas production tax database system at a cost of $115,700 annually.

The need for exempt status for the audit manager series is based upon the difficulties the department has recruiting experienced auditors to administer the tax. The current pay range for an Oil and Gas Revenue Auditor is on the low range of the pay range for roughly similar jobs. The department estimates the new exempt positions, along with other salary adjustmentswill cost the state approximately $900,000 annually.

Contractual: Contractual expenditures include $1,013,200 annually to contract for audit assistance. This estimate is based on 3 auditors, working 40 hours per week each, for 4 years starting in January 2008 at an average rate of $100 per hour, plus estimated transportation and lodging costs, and additional costs for training auditors. The need for such assistance is based upon the department's substantial difficulty in recruiting enough auditors to administer the oil and gas production tax. The department only anticipates the need for contract audit assistance for 4 years while the department recruits and trains auditors for positions that are currently vacant. The contract auditors would work in conjunction with department auditors during this time to maximize department resources and help train department auditors. The department will also need an additional $5,200 each year in contractual costs associated with the new Analyst Programmer V position.

Current FY2008 costs: The department expects it will incur costs beginning January 2008 to immediately implement the new production tax structure. Those costs include: **Contractual** - $2,620,800 capital funding to fund the scoping and development of an oil and gas production tax database system (including associated hardware) and $506,600 to contract for audit assistance (as described above). The new database system will permit accurate and efficient management of information submitted by taxpayers to facilitate auditing and forecasting of revenues, and timely and accurate reports for internal and public uses. The proposed system will accommodate the migration of ELF-based data and continue to collect supplemental data from producers on volumes, wells and production. The system will include income-based data, including tracking credits, required under PPT and upon which the ACES tax structure is based. The system will also integrate into the division's accounting systems. **Personal Services** - $218,000 from the period January 1, 2008 through June 30, 2008 due to creating an exempt class of oil and gas revenue auditors and increasing pay to more closely reflect what the market in Alaska pays for roughly similar positions. In addition, we will recruit for the Analyst Programmer V and bring that person on board to participate in the database scoping meetings. We estimate FY 2008 costs for this position to be approximately $57,800. **Supplies** - $6,000 for a computer and software for the new analyst progammer V position.

See page 3 for projected revenue estimates.

STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. CSSB 2001(JUD)

ANALYSIS CONTINUATION

Estimated Production Tax Revenues, PPT and ACES, at Various Prices (in $millions nominal)

*For the months of January 2007 through May 2007, the proposal would have generated approximately $400 million over the payments received for that period.

Fall 2007 DOR Official Forecast Prices

Fiscal Year	ANS WC $ per barrel (in REAL dollars)	ANS WC $ per barrel (in NOMINAL dollars)	Status Quo - PPT	CSSB2001 (JUD)	Increase or (Decrease) from PPT
2008	71.65	71.65	1,915	3,324	1,409
2009	64.55	66.30	1,693	2,778	1,085
2010	60.05	63.40	1,531	2,370	838
2011	59.70	64.75	1,670	2,545	875
2012	59.55	66.35	1,746	2,709	962
2013	58.90	67.45	1,647	2,581	935
2014	58.25	68.55	1,642	2,345	704

DOR Forecast nominal prices rounded to the nearest $0.05

$60 per barrel in REAL dollars

Fiscal Year	ANS WC $ per barrel (in REAL dollars)	ANS WC $ per barrel (in NOMINAL dollars)	Status Quo - PPT	CSSB2001 (JUD)	Increase or (Decrease) from PPT
2008	60.00	60.00	1,051	2,003	952
2009	60.00	61.65	1,435	2,334	899
2010	60.00	63.35	1,562	2,393	831
2011	60.00	65.09	1,695	2,583	888
2012	60.00	66.88	1,783	2,767	984
2013	60.00	68.72	1,733	2,719	986
2014	60.00	70.61	1,776	2,560	785

$80 per barrel in REAL dollars

Fiscal Year	ANS WC $ per barrel (in REAL dollars)	ANS WC $ per barrel (in NOMINAL dollars)	Status Quo - PPT	CSSB2001 (JUD)	Increase or (Decrease) from PPT
2008	80.00	80.00	2,650	4,426	1,776
2009	80.00	82.20	3,031	4,789	1,759
2010	80.00	84.46	3,266	4,973	1,707
2011	80.00	86.78	3,481	5,297	1,816
2012	80.00	89.17	3,668	5,642	1,974
2013	80.00	91.62	3,619	5,603	1,984
2014	80.00	94.14	3,690	5,466	1,776

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number: 4
Bill Version: CSSB 2001(RES)
(S) Publish Date: 10/29/07

Identifier (file name): CSSB2001(RES)-DOR-TAX-10-28-07
Title: An Act relating to the production tax on oil and gas..
Sponsor: Governor
Requester: Senate Judiciary

Dept. Affected: Revenue 04
RDU: Taxation and Treasury
Component: Tax Division
Component Number: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2009**	**FY 2009**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**
Personal Services	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7
Travel							
Contractual	1,018.4	1,018.4	1,018.4	511.8	5.2	5.2	5.2
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	**2,234.1**	**2,234.1**	**2,234.1**	**1,727.5**	**1,220.9**	**1,220.9**	**1,220.9**
CAPITAL EXPENDITURES							
CHANGE IN REVENUES ( )		**198,000.0**	**161,000.0**	**170,000.0**	**198,000.0**	**197,000.0**	**0.0**

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF	2,234.1	2,234.1	2,234.1	1,727.5	1,220.9	1,220.9	645.9
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	**2,234.1**	**2,234.1**	**2,234.1**	**1,727.5**	**1,220.9**	**1,220.9**	**645.9**

Estimate of any current year (FY2008) cost: 3,409.2

POSITIONS

Full-time	1	1	1	1	1	1	1
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessary)*

This bill makes one economic and several administrative changes to the state's current petroleum profits tax. The bill retains the current tax system's structure, which taxes the net value of petroleum resources. The bill makes the following change to the current system: it eliminates the transition investment expenditure credit (AS 43.55.023(i)), except to the extent that transition credits earned from April 1, 2006 to this bill's effective date that could not be used to offset tax liability can be carried forward.

Administrative changes to the current tax system include the following: excludes from qualified lease expenditures those expenses related to unscheduled production interruptions; excludes dismantlement, removal & restoration (DR&R) costs from allowable expenditures; requires taxpayers to provide cost projections to allow the state to better forecast state revenues and pursue changes in reported costs; authorizes public reporting of some cost data; authorizes a short-term audit program; and designates an exempt class of oil and gas auditors.

Prepared by: Johanna Bales, Roger Marks, Cherie Nienhuis — Phone 269-6628
Division: Tax Division — Date/Time 10/27/07 2:00 PM
Approved by: Jerry Burnett — Date 10/28/2007
Department of Revenue

(Revised 10/05/2006 OMB)

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STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. CSSB 2001(RES)

ANALYSIS CONTINUATION

Certain lease expenditure allowance provisions are retroactive to April 1, 2006; the other provisions of the tax proposal become effective January 1, 2008.

Personal Services: The department will reclassify the existing 5 vacant auditor positions, and create 4 to 5 senior level auditor positions with extensive industry oil and gas auditing experience. These positions will be classified as the Department's most senior level auditor positions and will have salaries that are consistent with market comparables and will be beyond the current salary levels allowed under the existing Oil and Gas Revenue Auditor (OGRA) pay classification system. In addition, the department expects that it will need one additional Programmer Analyst V position to maintain and manage the new oil and gas production tax database system at a cost of $115,700 annually. The existing oil and gas specialist, oil and gas revenue auditors, and their immediate supervisor will be offered the opportunity to opt into an exempt status with individual salaries established commensurate with experience and skill level, and consistent with market comparables.

The need for exempt status is based upon the difficulties the department has recruiting experienced auditors to administer the tax. The current pay range for an Oil and Gas Revenue Auditor is on the low range of the pay range for roughly similar jobs. The department estimates the new exempt positions and the potential salary increases associated with the change of existing staff to exempt status, will cost the state approximately $1,100,000 annually.

Contractual: Contractual expenditures include $1,013,200 annually to contract for audit assistance. This estimate is based on 3 auditors, working 40 hours per week each, for 4 years starting in January 2008 at an average rate of $100 per hour, plus estimated transportation and lodging costs, and additional costs for training auditors. The need for such assistance is based upon the department's substantial difficulty in recruiting enough auditors to administer the oil and gas production tax. The department only anticipates the need for contract audit assistance for 4 years while the department recruits and trains auditors for positions that are currently vacant. The contract auditors would work in conjunction with department auditors during this time to maximize department resources and help train department auditors. The department will also need an additional $5,200 each year in contractual costs associated with the new Analyst Programmer V position.

Current FY2008 costs: The department expects it will incur costs beginning January 2008 to immediately implement the new production tax structure. Those costs include: **Contractual** - $2,620,800 capital funding to fund the scoping and development of an oil and gas production tax database system (including associated hardware) and $506,600 to contract for audit assistance (as described above). The new database system will permit accurate and efficient management of information submitted by taxpayers to facilitate auditing and forecasting of revenues, and timely and accurate reports for internal and public uses. The proposed system will accommodate the migration of ELF-based data and continue to collect supplemental data from producers on volumes, wells and production. The system will include income-based data, including tracking credits, required under PPT and upon which the ACES tax structure is based. The system will also integrate into the division's accounting systems. **Personal Services** - $218,000 from the period January 1, 2008 through June 30, 2008 due to creating an exempt class of oil and gas revenue auditors and increasing pay to more closely reflect what the market in Alaska pays for roughly similar positions. In addition, we will recruit for the Analyst Programmer V and bring that person on board to participate in the database scoping meetings. We estimate FY 2008 costs for this position to be approximately $57,800. **Supplies** - $6,000 for a computer and software for the new analyst progammer V position.

See page 3 for projected revenue estimates.

STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. CSSB 2001(RES)

ANALYSIS CONTINUATION

Estimated Production Tax Revenues, PPT and ACES, at Various Prices (in $millions nominal)

Fall 2007 DOR Official Forecast Prices

Fiscal Year	ANS WC $ per barrel (in REAL dollars)	ANS WC $ per barrel (in NOMINAL dollars)	Status Quo - PPT	CSSB2001 (RES)	Increase or (Decrease) from PPT
2008	71.65	71.65	1,915	2,022	107
2009	64.55	66.30	1,693	1,891	198
2010	60.05	63.40	1,531	1,693	161
2011	59.70	64.75	1,670	1,840	170
2012	59.55	66.35	1,746	1,944	198
2013	58.90	67.45	1,647	1,844	197
2014	58.25	68.55	1,642	1,642	0

DOR Forecast nominal prices rounded to the nearest $0.05

$60 per barrel in REAL dollars

Fiscal Year	ANS WC $ per barrel (in REAL dollars)	ANS WC $ per barrel (in NOMINAL dollars)	Status Quo - PPT	CSSB2001 (RES)	Increase or (Decrease) from PPT
2008	60.00	60.00	1,051	1,158	107
2009	60.00	61.65	1,435	1,623	188
2010	60.00	63.35	1,562	1,719	158
2011	60.00	65.09	1,695	1,865	170
2012	60.00	66.88	1,783	1,981	198
2013	60.00	68.72	1,733	1,931	198
2014	60.00	70.61	1,776	1,776	0

$80 per barrel in REAL dollars

Fiscal Year	ANS WC $ per barrel (in REAL dollars)	ANS WC $ per barrel (in NOMINAL dollars)	Status Quo - PPT	CSSB2001 (RES)	Increase or (Decrease) from PPT
2008	80.00	80.00	2,650	2,757	107
2009	80.00	82.20	3,031	3,235	205
2010	80.00	84.46	3,266	3,441	175
2011	80.00	86.78	3,481	3,670	189
2012	80.00	89.17	3,668	3,886	218
2013	80.00	91.62	3,619	3,837	217
2014	80.00	94.14	3,690	3,690	0

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number: 3
Bill Version: SB 2001
(S) Publish Date: 10/18/07

Identifier (file name): LL 08-0014-DOA-DAS-10-17-07
Dept. Affected: Administration
Title: An Act relating to the production ta. on oil and gas...
RDU: Centralized Admin. Services
Component: Office of the Commissioner
Sponsor: Governor
Requester:
Component Number: 45

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2009**	**FY 2009**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**
Personal Services							
Travel							
Contractual							
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES ( )							

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF							
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2008) cost:

POSITIONS

Full-time							
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessary)*

This legislation has no fiscal impact on the Department of Administration.

Prepared by: Eric Swanson
Phone 465-5655
Division: Administrative Services
Date/Time:
Approved by: Annette Kreitzer
Date Oct. 12, 2007
Commissioner

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FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number: 2
Bill Version: SB 2001
(S) Publish Date: 10/18/07

Identifier (file name): #773-08-0014-DNR-10-17-07
Title: ACES
Sponsor: Rules Committee
Requester: Governor

Dept. Affected: Natural Resources
RDU: Resource Development
Component: Oil and Gas Development
Component Number: 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2009**	**FY 2009**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**
Personal Services	303.5	0.0	303.5	303.5	303.5	303.5	303.5
Travel							
Contractual							
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	**303.5**	**0.0**	**303.5**	**303.5**	**303.5**	**303.5**	**303.5**
CAPITAL EXPENDITURES							
CHANGE IN REVENUES ( )							

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF	303.5	0.0	303.5	303.5	303.5	303.5	303.5
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	**303.5**	**0.0**	**303.5**	**303.5**	**303.5**	**303.5**	**303.5**

Estimate of any current year (FY2008) cost: 177.0

POSITIONS

Full-time							
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessary)*

This bill would amend the oil and gas production tax under AS 43.55 to increase the base tax rate from 22.5% to 25% of net income and have the index-based progressive tax apply when net income per barrel exceeded $30 rather than the current $40 per barrel. In addition, this bill would change the minimum tax that currently applies to taxable income generated from North Slope fields, and which, for ANS West Coast prices above $25 per barrel, is now 4% of gross receipts at the lease boundary. The bill would increase the minimum tax rate to 10 percent gross, but apply this minimum tax only to large North Slope legacy units (Prudhoe Bay Unit and the Kuparuk River Unit). This minimum tax would also prevent these legacy field owners from using credits or deductions generated at these fields to lower their tax burden elsewhere when the minimum tax applies. In addition, the bill allows for tax credits on future work rather than previous work and expands the current exploration incentive credit program to include as many wells that can be drilled in two drilling seasons. It also restricts capital expense deductions to scheduled maintenance and would implement audit and information sharing provisions.

Prepared by: Kevin Banks, Acting Director — Phone 269-8800
Division: Oil and Gas — Date/Time: 10/17/2007
Approved by: Tom Irwin, Commissioner — Date: 10/17/2007
Natural Resources

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STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. SB 2001

ANALYSIS CONTINUATION

**Indeterminate Positive: The royalty revenue impact to the State of ACES is indeterminate, but most likely positive. ACES improves the economics for new entrants or small Alaska producers, but decreases the attractiveness of investments in legacy fields.

Improvement in new entrant/small producer economics: ACES improves the economics of investing in Alaska for new entrants and small Alaska producers, an improvement that should lead to more investment and resulting royalty revenue. For new entrants and small producers, capital spent to find and develop oil or gas resources will generate a carried-forward annual loss credit of 25 percent rather than the current 20 percent AS 43.055.023(b).

Also, for new entrants and small Alaska producers, the transferable credits (the carried-forward annual loss credit and the 20 percent qualified expenditure credit (AS 43.55.023(a)) will be worth more under ACES. Small producers have indicated that they have been unable to sell their credits to larger tax payers. Under AS 43.55.028, ACES establishes an oil and gas tax credit fund that will help ensure these new and small producers will receive full value for these transferable credits.

Without the fund, the small producer or new entrant may have to carry-forward their credits until they have tax liability. By providing full value up-front for these credits, ACES improves the internal rate of return (IRR) by three to six percent at $40 per barrel ANS WC.

As a partial offset to this incentive, ACES increases the tax rate from 22.5 to 25.0 percent; has the progressive, index-based, rate kicking in at a lower level; and has credits being spread over two years rather than one. However, on balance, ACES will improve new project economics for new entrants and small Alaska producers.

Decrease in attractiveness of investments in legacy fields: ACES will decrease the attractiveness of investments made by larger, existing producers for three reasons: the higher tax rate, the elimination of the Transition Investment Expenditure (TIE) credit, and the 10 percent minimum tax on legacy fields.

First, ACES increases the tax rate from 22.5 percent to 25.0 percent. In addition, the progressive, index-based rate will start at a lower ($30) net value per barrel, but escalate at a lower rate (0.20 percent rather than 0.25 percent. Second, by eliminating the TIE credit, new capital spending by existing producers will no longer increase the ability of those producers to take the TIE credit by 10 percent of the capital invested. Third, at lower prices (prices far below where they are today) the minimum 10 percent gross tax applies, lowering or postponing the ability to take the capital expenditure credits. The floor also could eliminate the ability to use deductions generated by new spending to decrease tax liability. If the producers in these legacy fields (Prudhoe Bay Unit and Kuparuk River Unit) believe there is a good chance that prices will decline or costs will increase to the point where the floor applies, they might invest less in additional reserves in these legacy fields.

If these measures (the higher rate, the TIE credit elimination, and the 10 percent floor) cause less investment by existing producers to add reserves, the State will receive less in royalty.

Personal Services: Sections 10 and 67 would reclassify the current oil and gas auditors to exempt status employees. DO&G currently has seven oil and gas auditor positions. The total salary/benefit costs for these seven employees currently equals approximately $849,147. An increase to exempt status is estimated to cost up to an additional $303,500 in FY09. The FY08 amount of $177,000 covers an estimated 7-months at the higher rate.

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number: 1
Bill Version: SB 2001
(S) Publish Date: 10/18/07

Identifier (file name): LL 08-0014-DOR-TAX-10-17-07
Title: An Act relating to the production tax on oil and gas..
Sponsor: Governor
Requester:

Dept. Affected: Revenue 04
RDU: Taxation and Treasury
Component: Tax Division
Component Number: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2009**	**FY 2009**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**
Personal Services	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7
Travel							
Contractual	1,018.4	1,018.4	1,018.4	511.8	5.2	5.2	5.2
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	**2,234.1**	**2,234.1**	**2,234.1**	**1,727.5**	**1,220.9**	**1,220.9**	**1,220.9**
CAPITAL EXPENDITURES							
CHANGE IN REVENUES ( )		**675,000.0**	**603,000.0**	**589,000.0**	**624,000.0**	**597,000.0**	**416,000.0**

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF	2,234.1	2,234.1	2,234.1	1,727.5	1,220.9	1,220.9	645.9
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	**2,234.1**	**2,234.1**	**2,234.1**	**1,727.5**	**1,220.9**	**1,220.9**	**645.9**

Estimate of any current year (FY2008) cost: 3,409.2

POSITIONS

Full-time	1	1	1	1	1	1	1
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessary)*

This bill makes significant changes to the state's current petroleum profits tax. The tax proposal, also known as the Clear and Equitable Share (ACES) plan, like the current tax system, taxes the net value of petroleum resources. The ACES proposal makes the following changes to the tax system: raises the tax rate to 25% on net profits of oil and gas production subject to a 10% floor on legacy fields; adjusts the progressive tax feature to trigger at $30 net value (annual) and rise at two tenths of a percent per dollar; eliminates the transitional investment expenditures "TIE" credits; requires that capital costs be taken as credits over two years, rather than immediately; addresses the "corrosion" expense issue; excludes dismantlement, removal & restoration (DR&R) costs from allowable expenditures; expands exploration incentive credit program to cover two field seasons; requires taxpayers to provide cost projections to allow the state to better forecast state revenues and pursue changes in reported costs; authorizes public reporting of some cost data; authorizes a short-term audit program; and designates an exempt class of oil and gas auditors.

Prepared by: Cherie Nienhuis, Roger Marks, Johanna Bales — Phone 269 6628
Division: Tax Division — Date/Time 10/17/07 12:00 AM
Approved by: Jerry Burnett — Date 10/17/2007
Department of Revenue

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FISCAL NOTE #1

STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. SB 2001

ANALYSIS CONTINUATION

The tax proposal would also authorize a fund to be established for the purpose of purchasing tax credit certificates. The func would receive 10% - 15% of total production tax revenues annually (roughly $150 million to $300 million); up to $250 million of fund revenues would be paid to purchase credits in any given year.

Certain lease expenditure allowance provisions are retroactive to April 1, 2006; the other provisions of the tax proposal become effective January 1, 2008.

Personal Services: The department will reclassify the existing 5 vacant auditor positions, and create 4 to 5 senior level auditor positions with extensive industry oil and gas auditing experience. These positions will be classified as the Department's most senior level auditor positions and will have salaries that are consistent with market comparables and will be beyond the current salary levels allowed under the existing Oil and Gas Revenue Auditor (OGRA) pay classification system. In addition, the department expects that it will need one additional Programmer Analyst V position to maintain and manage the new oil and gas production tax database system at a cost of $115,700 annually. The existing oil and gas specialist, oil and gas revenue auditors, and their immediate supervisor will be offered the opportunity to opt into an exempt status with individual salaries established commensurate with experience and skill level, and consistent with market comparables.

The need for exempt status is based upon the difficulties the department has recruiting experienced auditors to administer the tax. The current pay range for an Oil and Gas Revenue Auditor is on the low range of the pay range for roughly similar jobs. The department estimates the new exempt positions and the potential salary increases associated with the change of existing staff to exempt status, will cost the state approximately $1,100,000 annually.

Contractual: Contractual expenditures include $1,013,200 annually to contract for audit assistance. This estimate is based on 3 auditors, working 40 hours per week each, for 4 years starting in January 2008 at an average rate of $100 per hour, plus estimated transportation and lodging costs, and additional costs for training auditors. The need for such assistance is based upon the department's substantial difficulty in recruiting enough auditors to administer the oil and gas production tax The department only anticipates the need for contract audit assistance for 4 years while the department recruits and trains auditors for positions that are currently vacant. The contract auditors would work in conjunction with department auditors during this time to maximize department resources and help train department auditors. The department will also need an additional $5,200 each year in contractual costs associated with the new Analyst Programmer V position.

Current FY2008 costs: The department expects it will incur costs beginning January 2008 to immediately implement the new production tax structure. Those costs include: **Contractual** - $2,620,800 capital funding to fund the scoping and development of an oil and gas production tax database system (including associated hardware) and $506,600 to contract for audit assistance (as described above). The new database system will permit accurate and efficient management of information submitted by taxpayers to facilitate auditing and forecasting of revenues, and timely and accurate reports for internal and public uses. The proposed system will accommodate the migration of ELF-based data and continue to collect supplemental data from producers on volumes, wells and production. The system will include income-based data, including tracking credits, required under PPT and upon which the ACES tax structure is based. The system will also integrate into the division's accounting systems. **Personal Services** - $218,000 from the period January 1, 2008 through June 30, 2008 due to creating an exempt class of oil and gas revenue auditors and increasing pay to more closely reflect what the market in Alaska pays for roughly similar positions. In addition, we will recruit for the Analyst Programmer V and bring that person on board to participate in the database scoping meetings. We estimate FY 2008 costs for this position to be approximately $57,800. **Supplies** - $6,000 for a computer and software for the new analyst programmer V position.

See page 3 for projected revenue estimates.

STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. SB 2001

ANALYSIS CONTINUATION

Estimated Production Tax Revenues, PPT and ACES, at Various Prices (in $millions)

Fall 2007 DOR Official Forecast Prices

Fiscal Year	ANS WC $ per barrel (in REAL dollars)	ANS WC $ per barrel (in NOMINAL dollars)	Status Quo - PPT	ACES	Increase or (Decrease) from PPT
2008	71.65	71.65	1,915	2,330	415
2009	64.55	66.30	1,693	2,369	675
2010	60.05	63.40	1,531	2,134	603
2011	59.70	64.75	1,670	2,258	589
2012	59.55	66.35	1,746	2,370	624
2013	58.90	67.45	1,647	2,244	597
2014	58.25	68.55	1,642	2,058	416

DOR Forecast nominal prices rounded to the nearest $0.05

$60 per barrel in REAL dollars

Fiscal Year	ANS WC $ per barrel (in REAL dollars)	ANS WC $ per barrel (in NOMINAL dollars)	Status Quo - PPT	ACES	Increase or (Decrease) from PPT
2008	60.00	60.00	1,051	1,421	371
2009	60.00	61.65	1,435	1,977	542
2010	60.00	63.35	1,562	2,170	608
2011	60.00	65.09	1,695	2,291	596
2012	60.00	66.88	1,783	2,414	631
2013	60.00	68.72	1,733	2,347	614
2014	60.00	70.61	1,776	2,218	442

$80 per barrel in REAL dollars

Fiscal Year	ANS WC $ per barrel (in REAL dollars)	ANS WC $ per barrel (in NOMINAL dollars)	Status Quo - PPT	ACES	Increase or (Decrease) from PPT
2008	80.00	80.00	2,650	3,089	438
2009	80.00	82.20	3,031	3,717	686
2010	80.00	84.46	3,266	3,988	722
2011	80.00	86.78	3,481	4,189	708
2012	80.00	89.17	3,668	4,404	736
2013	80.00	91.62	3,619	4,327	708
2014	80.00	94.14	3,690	4,204	514

PRESENTATIONS AGENCY + CONSULTANTS

Gross Price $	50	60	70	80	90	100
Net Price $	30	40	50	60	70	80
PPT	22.5	22.5	25	27.5	30	32.5
ACES*	25	27*	29*	31*	33*	35*
House	25	29	33	37	41	45
S(FIN)	22.5	28.5	34.5	39.5	44.5	48

* Progressive tax actually slightly lower because of annual basis
- Gross Floor Not included

Mark Hanley
Anadarko

Proposed Senate Finance CS illustrated

Presentation to Senate Finance

November 14, 2007

Dan E. Dickinson, CPA

11/14/07

Structure of the levy

AS 43.55.xx	Current Law	SB 2001 (ACES)	CSHB 2001 (FIN) am	Proposed Senate Fin CS
.011(e)	22.5%	Rate in (g)	25% + progressivity in (g)	Rate in (g)
.011(g)	.25% Progressivity in Addition using price index in (h)	Rate=25%+.20 % progressivity using price index in (h)	.4% Progressivity in Addition using price index in (h)	Rate=22.5%+ sliding progressivity scale
.011(h)	Price index derived using 40	Price index derived using 30	Price index derived using 30	Repealed

Credits against Floor

Credits	Current Law	SB 2001 (ACES)	CSHB 2001 (FIN) am	Proposed Senate Fin CS
.023	no	no	no	no
.024	yes	no	yes	yes
.025	yes	no	yes	no

CS HB 2001(FIN) am TIE credits

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013

CSHB 2001(FIN) am

"Capital spending fills the bucket"

Spending: X Y Y

Prod's use TIEs

Producer Credit min (10% of Y, 20% of X)

Non Prod Spend	Non pre- 2008 Prod Uses tax credits

Non pre-2008 Producer credits min (10% of Y, 20% of X)

Everyone's TIE credits are limited to 10% of spending in 21 Months between April 1 2006 and December 31, 2007

CS CB 2001(FIN) TIE credits

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013

Senate(FIN) CS

"Capital spending fills the bucket"

Spending: X Y Y W W W W W W

Prod's use TIEs

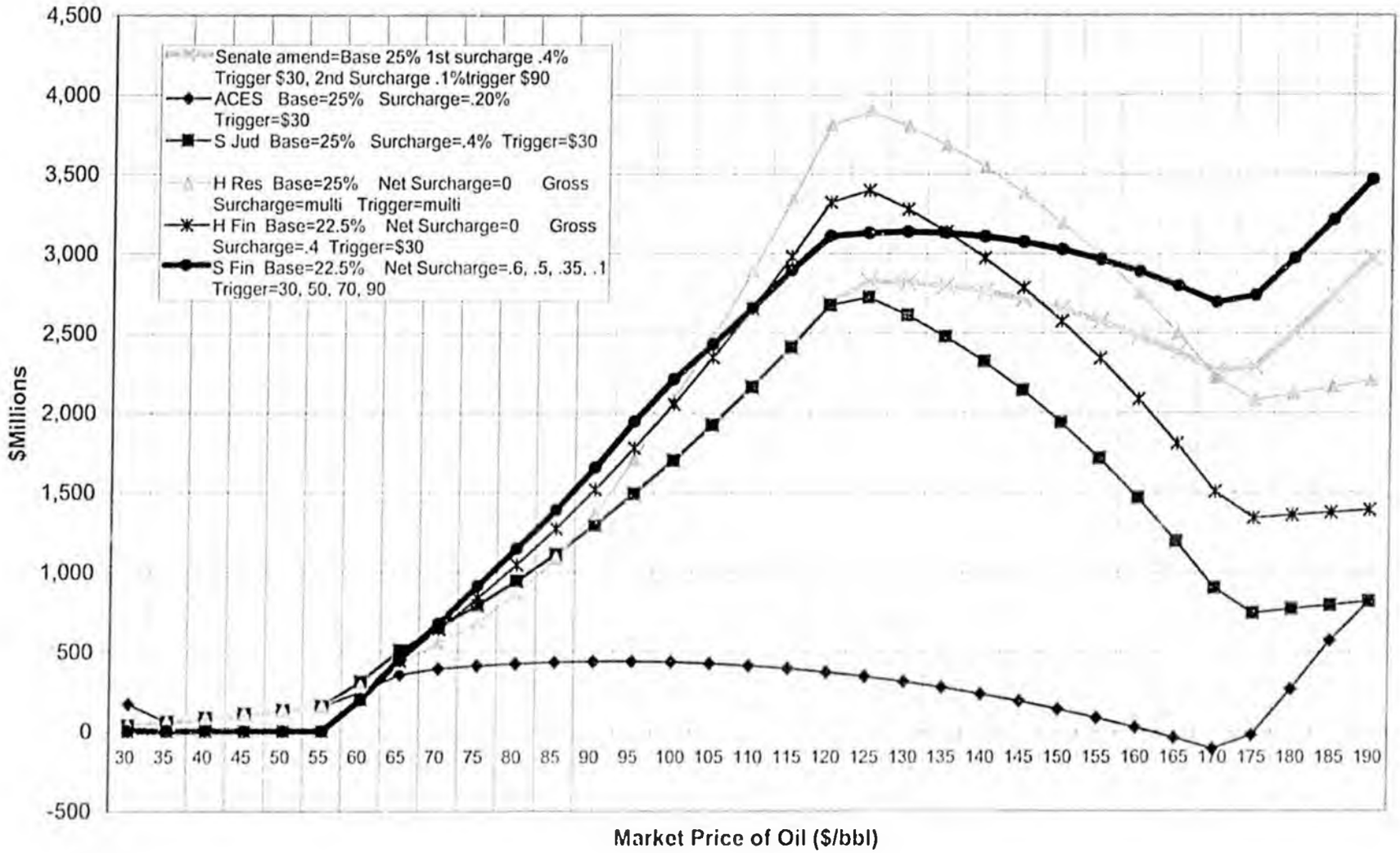
Producer Credit min (10% of Y, 20% of X)

Non pre-2006 Prod Uses tax credits

non pre-2006Producer credits min (10% of **W**, 20% of X)

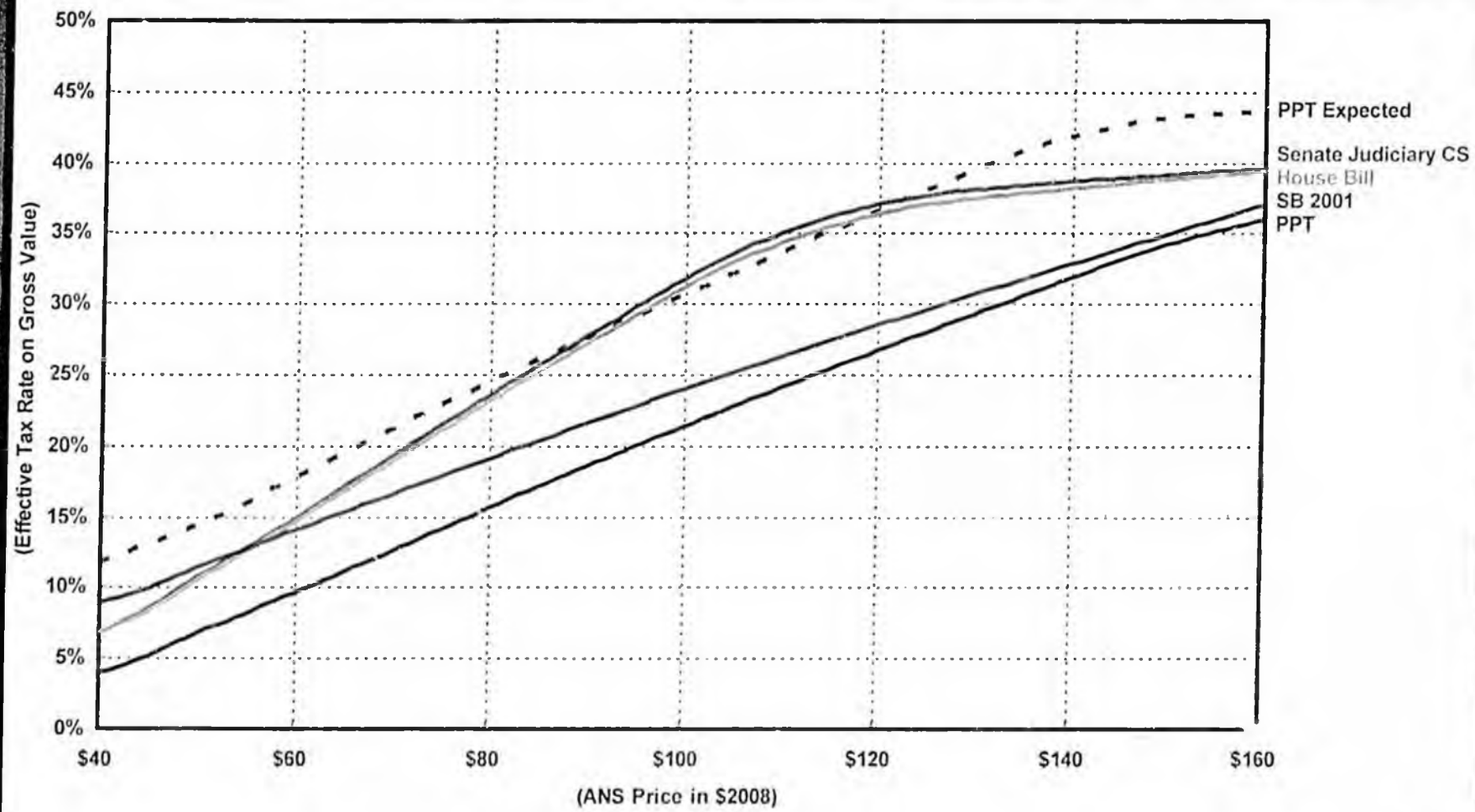
Entity that did not produce between April 1, 2006 and December 31, 2007 is no worse off than if the TIE credit were not repealed (except 2013 vs. six years)

Increases in Total State Revenue Under Various Production Tax Systems



t0-11-11

Estimated Average Effective Tax Rate on Gross Taxable Value at Various West Coast ANS Price Levels
(FY 2008-2014)



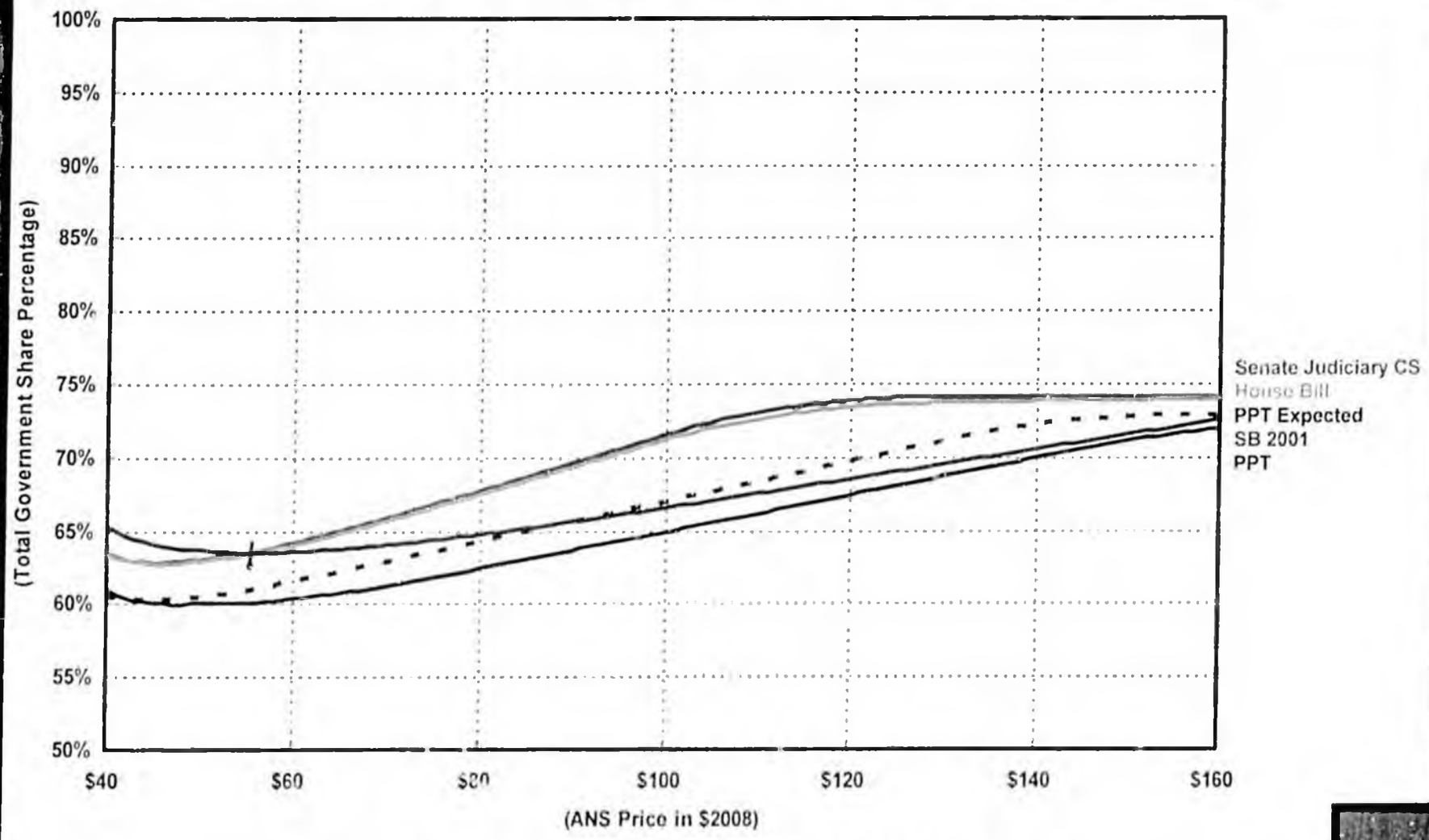
Note: Volumes per current Fall 2007 DOR Forecasts.

PPT Expected: Current Law using costs per fiscal note to HB3001.
Senate Judiciary: SB2001 using 0.4% progressivity rate, 50% overall cap, TIE credit 2006-2007 for new producers, does not include TAPS adjustment.
House Bill: SB2001 using 0.4% progressivity rate, 40% overall cap, TIE credit 2006-2007 for new producers, Opex indexed to 2006 figures.

11/12/07

econ ONE

Estimated Total Government Share at Various West Coast ANS Price Levels
(FY 2008-2014)



Note: Volumes per current Fall 2007 DOR Forecasts.

PPT Expected: Current Law using costs per fiscal note to HB3001.

Senate Judiciary: SB2001 using 0.4% progressivity rate, 50%-overall cap, TIE credit 2006-2007 for new producers, does not include TAPS adjustment.

House Bill: SB2001 using 0.4% progressivity rate, 50% overall cap, TIE credit 2006-2007 for new producers, Opex indexed to 2006 figures.

11/12/07

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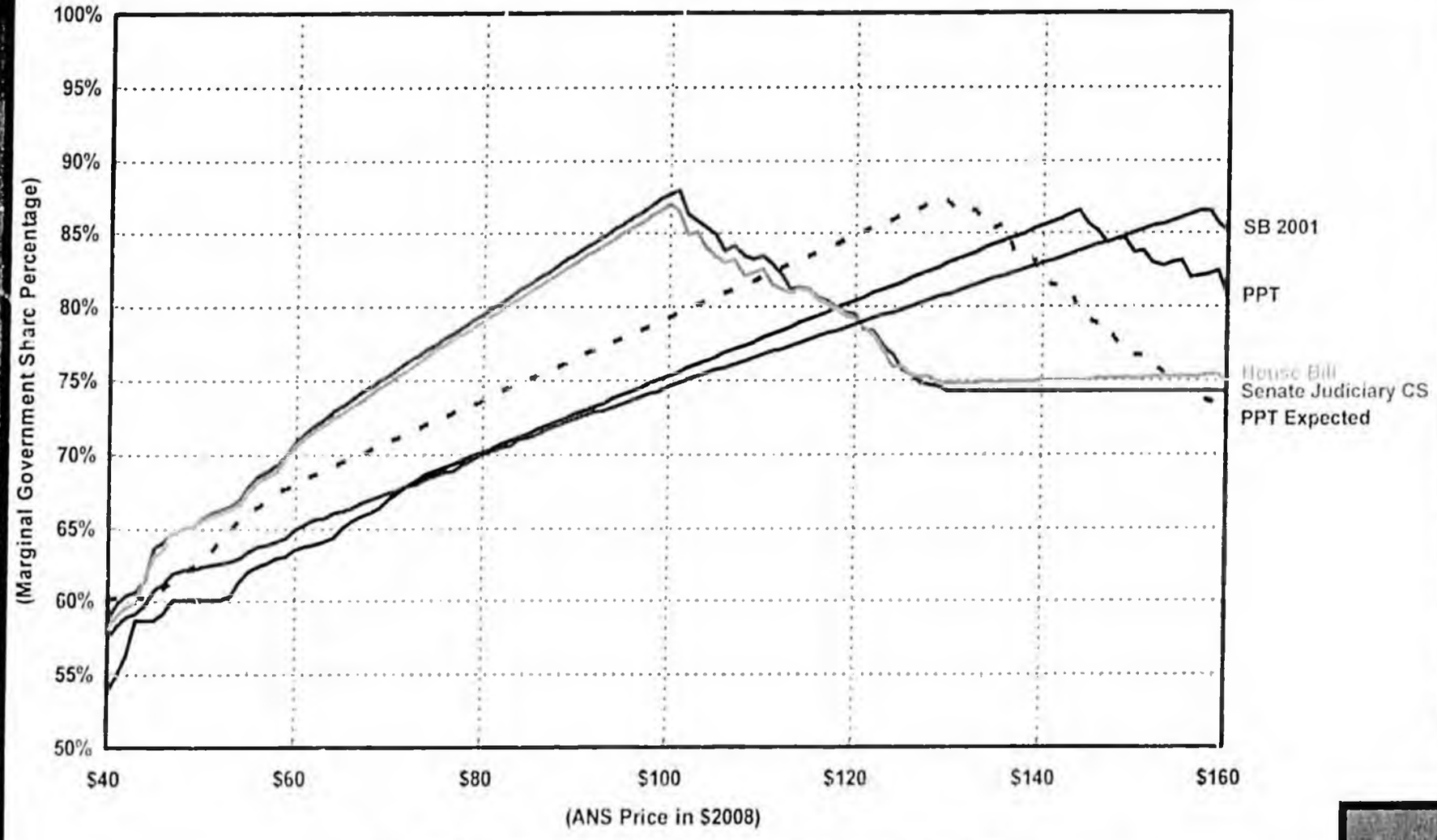
Estimated Marginal Government Share at Various West Coast ANS Price Levels
(FY 2008-2014)



Note: Volumes per current Fall 2007 DOR Forecasts.

PPT Expected: Current Law using costs per fiscal note to HB3001.

Senate Judiciary: SB3001 using 0.4% progressivity rate, 80% overall cap, TIE credit 2006-2007 for new producers, does not include TAPS adjustment.

progressivity rate, 80% overall cap, TIE credit 2006-2007 for new producers, Opex increased to 2008 figures.

11/12/07

econ ONE

Comparison

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013

CSHB 2001(FIN) am

"Capital spending fills the bucket"

Spending: X Y

Prod's use TIEs

Producer Credit min (10% of Y, 20% of X)

Non Prod Spend | Non 2006-2007 Prod Uses tax credits

Non 2006-2007 Producer credits min (10% of Y, 20% of X)

Senate(FIN) CS

"Capital spending fills the bucket"

Spending: X Y W

Prod's use TIEs

Producer Credit min (10% of Y, 20% of X)

Non 2006-2007 Prod Uses tax credits

non 2006-2007 Producer credits min (10% of W, 20% of X)

Summary Comparison between Various Approaches to Production Tax

Issue	Current Law	SB/HB 2001 (ACES) as introduced	CS HB 2001(FIN)am	Senate Finance CS
Base Rate	*AS 43.55.011 (e) & (g)*	*Bill Sections 15 & 17*	*Bill Sections 15*	*Bill Sections 15 & 17*
Base Tax Rate	[redacted]	25%	25%	[redacted]
Progressivity	*AS 43.55.011(g) & (h)*	*Bill Sections 17,18*	*Bill Sections 17,18*	*Bill Sections 17*
$/bbl Starting point	$40 net	$30 net	$30 net	$30;50;70;90 net
Tax/$ of Price Index	0.25%	0.20%	0.40%	.6;.5;.35;.1%
Average Value over	[redacted]	year	[redacted]	[redacted]
Applied to	[redacted]	net	[redacted]	[redacted]
Cap	[redacted]	25% of net	[redacted]	50% of net
Gross Value Floor	*AS 43.55.011(f)*	*Bill Section 15, 16, 31-36, & 41-42*	*Bill Section 16*	*Bill Section 16*
Base	[redacted]	Prudhoe; Kuparuk	[redacted]	[redacted]
Rate	[redacted]	10%	[redacted]	[redacted]
Apply .024 credits against floor?	[redacted]	No	[redacted]	[redacted]
Apply .025 credits against floor?	[redacted]	No	[redacted]	No
Investment Credits	*AS 43.55.023*	*Bill Section 26-28, 38-44 & 63*	*Bill Section 26-28*	*Bill Section 25-29*
Investment Credits	[redacted]	1/2 in each of two years	[redacted]	1/2 in each of two years
Loss Carry Forward Credits	20%	25%	25%	22.5%
Transitional Investment Credits	Yes	No	All taxpayers allowed application of TIE matching spending in April 1 2006 - Dec 31, 2007, even if application deferred	TIE credits end for producers Dec 31, 2008, current non producers can use through 2013

Summary Comparison between Various Approaches to Production Tax

Issue	Current Law	SB/HB 2001 (ACES) as introduced	CS HB 2001(FIN)am	Senate Finance CS
Exploration Credits	*AS 43.55.025*	*Bill Section 36 - 44*	*Bill Section 29-35*	*Bill Section 31-39*
Rates	20; 40%	20; 40%	30;40%	20; 40%
General &Admin Costs	disallowed	bad acts I	costs arising from Bad Acts III - criminal	bad acts I
DNR approval required?	In Cl. to avoid 3 mile limit	Always	Always, w/ language changes	Always,
Confidentiality of well data	10 years	2 years	2 years, or if DNR declines to, or private landowner declines	2 years, or if DNR declines to,
Seismic on non state land	silent	included	explicit exclusion without permission	silent
Pre-existing well	One drilling season	Two consecutive drilling seasons	Two consecutive drilling seasons	Two consecutive drilling seasons
"DNR TIE" Credits for pre 2003 seismic work?	no	5%	5%	5%
Exceptions to Tax Credits			*Bill Section 41*	*Bill Section 30,35,*
None	none	none	unpaid judgment	none
Tax Exempt entities take credits?	[redacted]	no	[redacted]	no
State Purchase of Credits		*AS 43.55.023(l) & (g)*		
Paid from:	[redacted]	oil and gas credit fund, funded from production taxes	[redacted]	
Annual dollar cap per taxpayer?	$25 million	none	$ 25 million (however ARM unlimited)	none
ARM Board Purchases?	n/a	n/a	yes	n/a

Summary Comparison between Various Approaches to Production Tax

Issue	Current Law	SB/HB 2001 (ACES) as introduced	CS HB 2001(FIN)am	Senate Finance CS
Allowable Lease Expenditures	*AS 43.55.165*		*Bill Section 46-51*	*Bill Section 46-51*
Allowed by regulation	no language	must be	must be	must be
Use producer audits of operators?	Explicit	Explicit repealed; Implicit	Explicit repealed; Implicit	Explicit for WICs
Disallow bad acts II?	yes	add violation of law, lease or license	costs arising from Bad Acts III - criminal	Disallow bad acts II?
DR&R Allowed?	Allocated	No	No	No
"Corrosion" Issue	[redacted]	$0.30 + unscheduled events disallowed	$.30 a bbl disallowed+ intent language	$.30 a bbl disallowed+ unscheduled interruption
Field Topping Plants allowed?	Yes	No	No	No
Off Lease allowed	[redacted]	[redacted]	must be in state	[redacted]
Public Outreach costs	not explicit	not explicit	no; listed	no; listed
Opex	actual	actual	Yet to be written regulations will define 2006; then 3% annual increase; (regardless of production or ownership?)	actual
Information	*AS 43.05.230 and royalty statutes*		*Bill Sections 2-9,11,13,36-39, 52*	*Bill Sections 2-9,11,13,36-39, 52*
forward looking information required	none	information "necessary to forecast ... revenues under AS 43.55". Penalty up to $1000 a day	information "necessary to forecast ... revenues under AS 43.55". Penalty up to $1000 a day if demanded information not forthcoming	information "necessary to forecast ... revenues under AS 43.55". Penalty up to $1000 a day if demanded information not forthcoming
Disclosure of tax information	[redacted]	if aggregated w/2 other producers, no requirement to prevent identification	if aggregated w/2 other producers, [still under umbrella required to prevent identification]	if aggregated w/2 other producers, no requirement to prevent identification
DNR sharing royalty information w/ DOR	limited ability	expanded ability	expanded ability	expanded ability
DOR sharing tax information with DNR	limited ability	expanded ability	expanded ability	expanded ability
Statute of Limitations	*AS 43.05.260*	*Bill Sections 1,14,50 new AS 43.55.075*	*Bill Sections 1,14,41 new AS 43.55.075*	*Bill Sections 1,14,41 new AS 43.55.075*
State assessment must be issued within	3 yrs	6 yrs	6 yrs	4 yrs
DOR Auditors	*As 39.25.100*	*Bill Sections 10, 65, 67*	*Bill Sections 10, 56*	*Bill Sections 10, 56*

Summary Comparison between Various Approaches to Production Tax

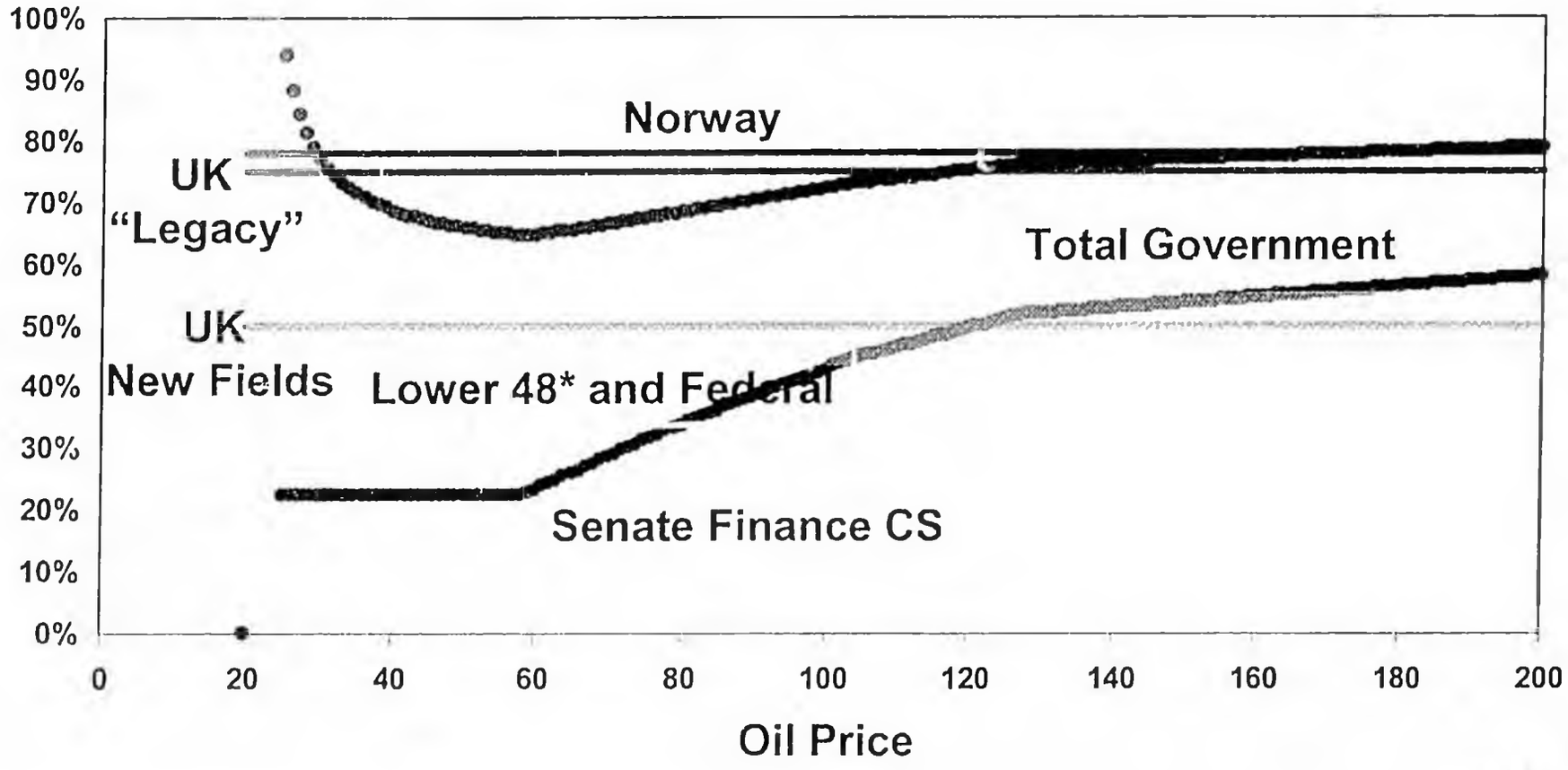
Issue	Current Law	SB/HB 2001 (ACES) as introduced	CS HB 2001(FIN)am	Senate Finance CS
DOR & DNR auditors exempt employees?	no	yes	2 DNR and 4 DOR exempt master auditors authorized.	2 DNR and 4 DOR exempt master auditors authorized.
Effective Date		***Bill Section 64***	***Bill Section 1, 60-61***	***Bill Section 1, 60-61***
Generally	n/a	Jan 1 2008	Jan 1 2008	July 1 2007
Retroactive to April 1 2006	n/a	unscheduled interrpution	deferred maintenance issues (Intent language)	TECHNICAL AMENDMENT: unscehduled interruption
Downstream Costs	***As 43.55.150***		***Bill Section 43***	***Bill Section 43***
Reasonable v actual	[redacted]		Downstream Tanker and Pipelines = Actual, except, reasonable if lower	Downstream Tanker and Pipelines = Actual, except, reasonable if lower
Prima facie reasonable Taps Tariff	[redacted]		"just and reasonable" and arms' length transactions	"just and reasonable" and arms' length transactions
Gas Ceilings thru 2022		***As 43.55.011***	***Bill Section 22***	***Bill Section 20,22***
Where	CI	CI	CI + gas used in the state	
Interaction with credits	implicit	explicit importing from regs	implicit	explicit high-level statement of rules
Additional Penalties	***new As 43.55.055***		***Bill Section 40***	***Bill Section 24,40***
Additional Penalties for Under reporting	none	none	10% for 10% or 10mm understmnt, 20% for 20% or 20mm understmnt	none

Summary Comparison between Various Approaches to Production Tax

Issue	Current Law	SB/HB 2001 (ACES) as introduced	CS HB 2001(FIN)am	Senate Finance CS
Intent Language			*Bill Section 1*	*Bill Section 1*
overall intent of legislation	n/a	no	included	no
long standing interpretation of SOL	n/a	included	included	included
Half the money from certain retroactive applications to PERS and public education fund	[redacted]			retroactivity dollars to public education fund, incremental dollars to other listed investments
tax savings from gas ceilings outside CI passed on to ultimate consumers	n/a	no	encourage availability of affordable gas	no
Admin	*AS 43.55.020(a)*		*Bill Sections 12,23-25,42*	*Bill Sections 12,23-25,42*
Monthly Estimated payments	Estimated payments without ceilings, refund due taxpayer at year end	Ceilings applied monthly	Ceilings applied monthly (sec A and C could be parallel)	Ceilings applied monthly (sec A and C could be parallel)
LIHEAP funding	No	No	may appropriate $50 mm from progressivity	No
Whistleblower language	No	No	yes - with limitation for bad faith	yes - with limitation for bad faith
DNR NPSL regulations	n/a	general grant for retroactive applications	may be retroactive	may be retroactive
Required 2011 Report -	Yes	Yes	deleted	Yes

Government Take
Senate Finance CS

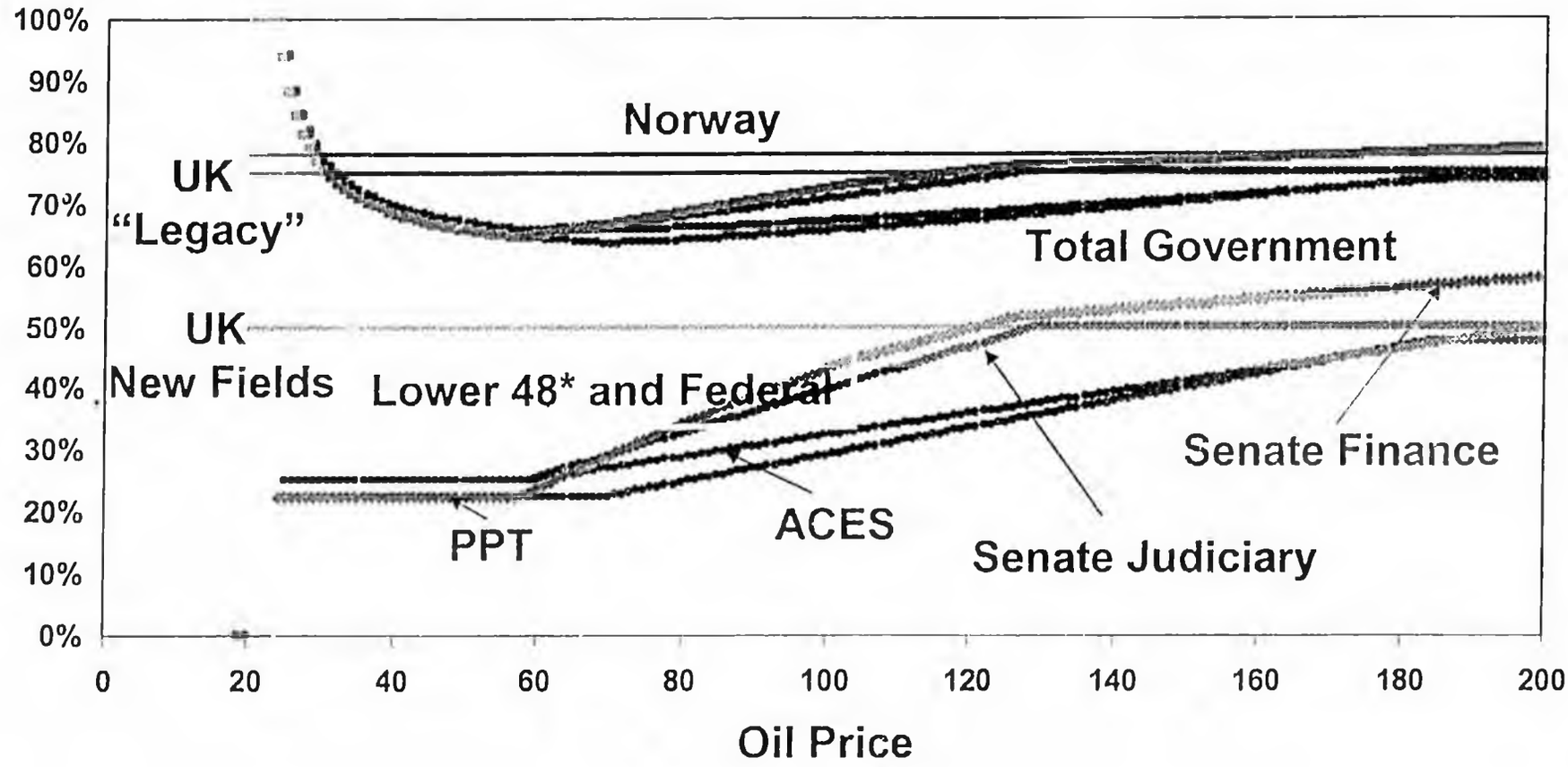
* For Lower 48, State lands / Federal assumes with 12.5% - 18.75% royalty. Private royalty trend is higher



Assumes $20 costs

Government Take
Senate Finance CS

* For Lower 48, State lands / Federal assumes with 12.5% - 18.75% royalty. Private royalty trend is higher



Assumes $20 costs

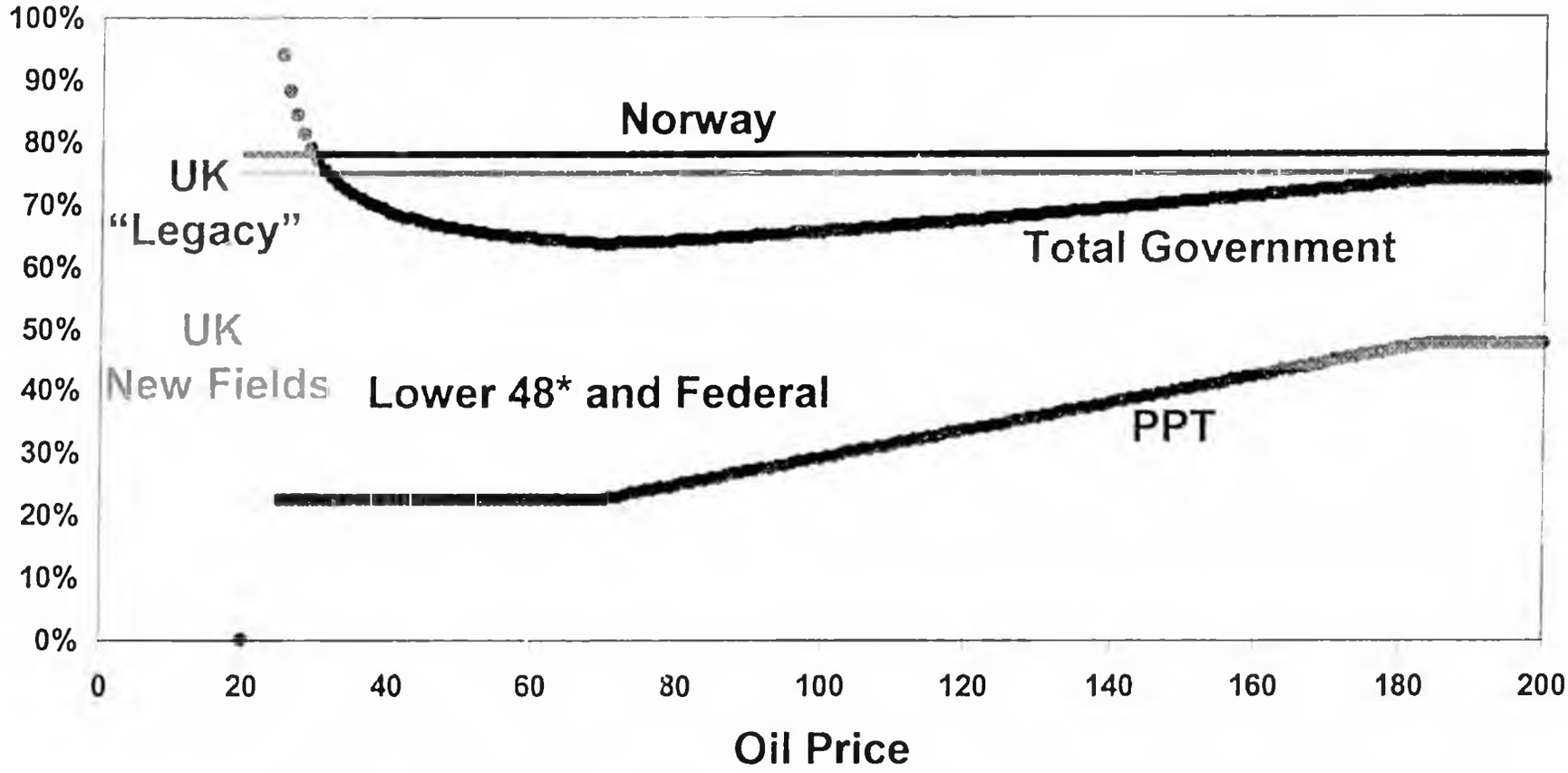
Government and Petroleum Tax Take

PPT, ACES, Senate Judiciary CS
Compared To UK, Norway, US Lower 48

11/14/07

Government Take
PPT

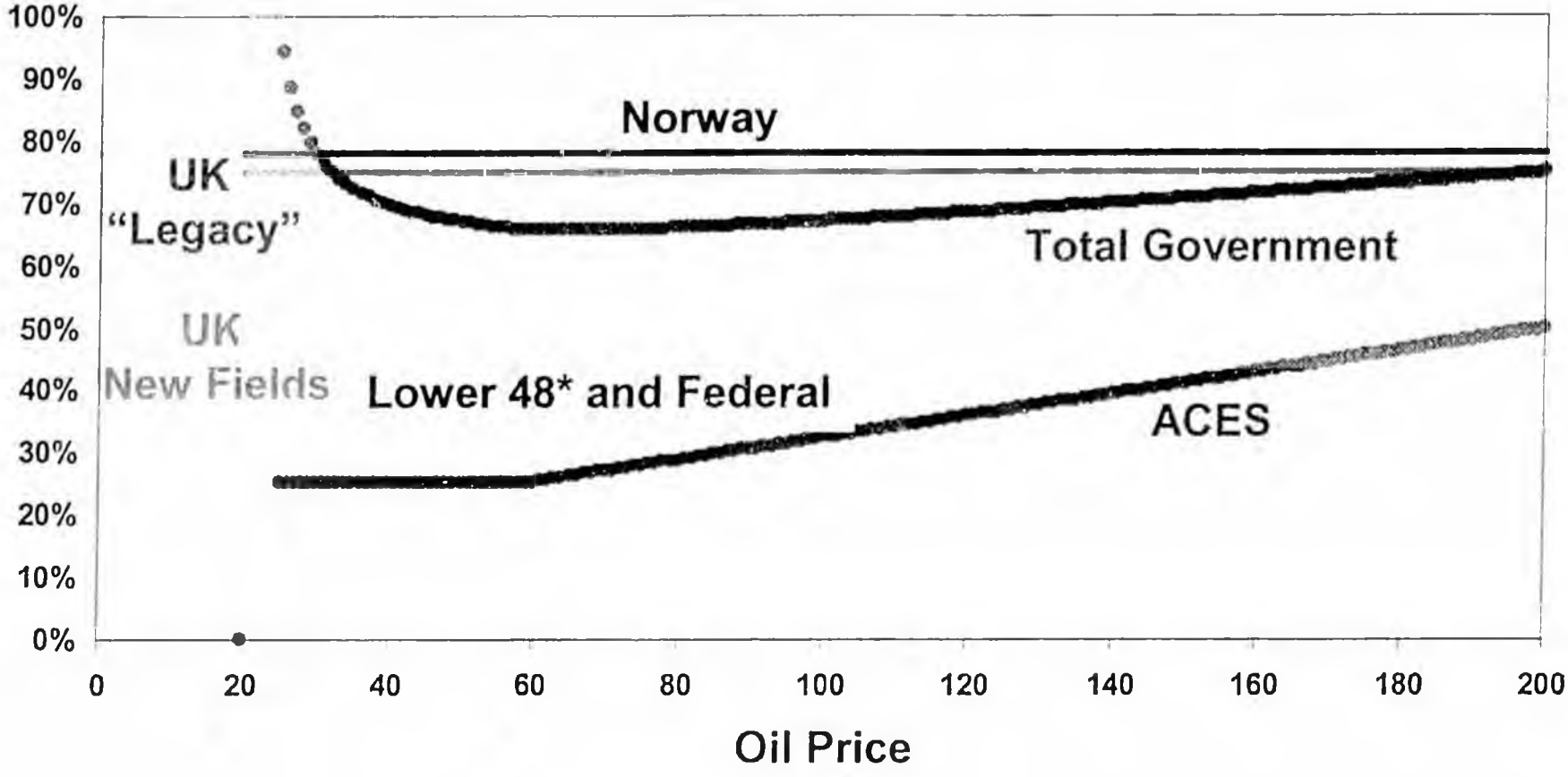
* For Lower 48, State lands / Federal assumes with 12.5% - 18.75% royalty. Private royalty trend is higher



Assumes $20 costs

Government Take
SB 2001 (ACES)

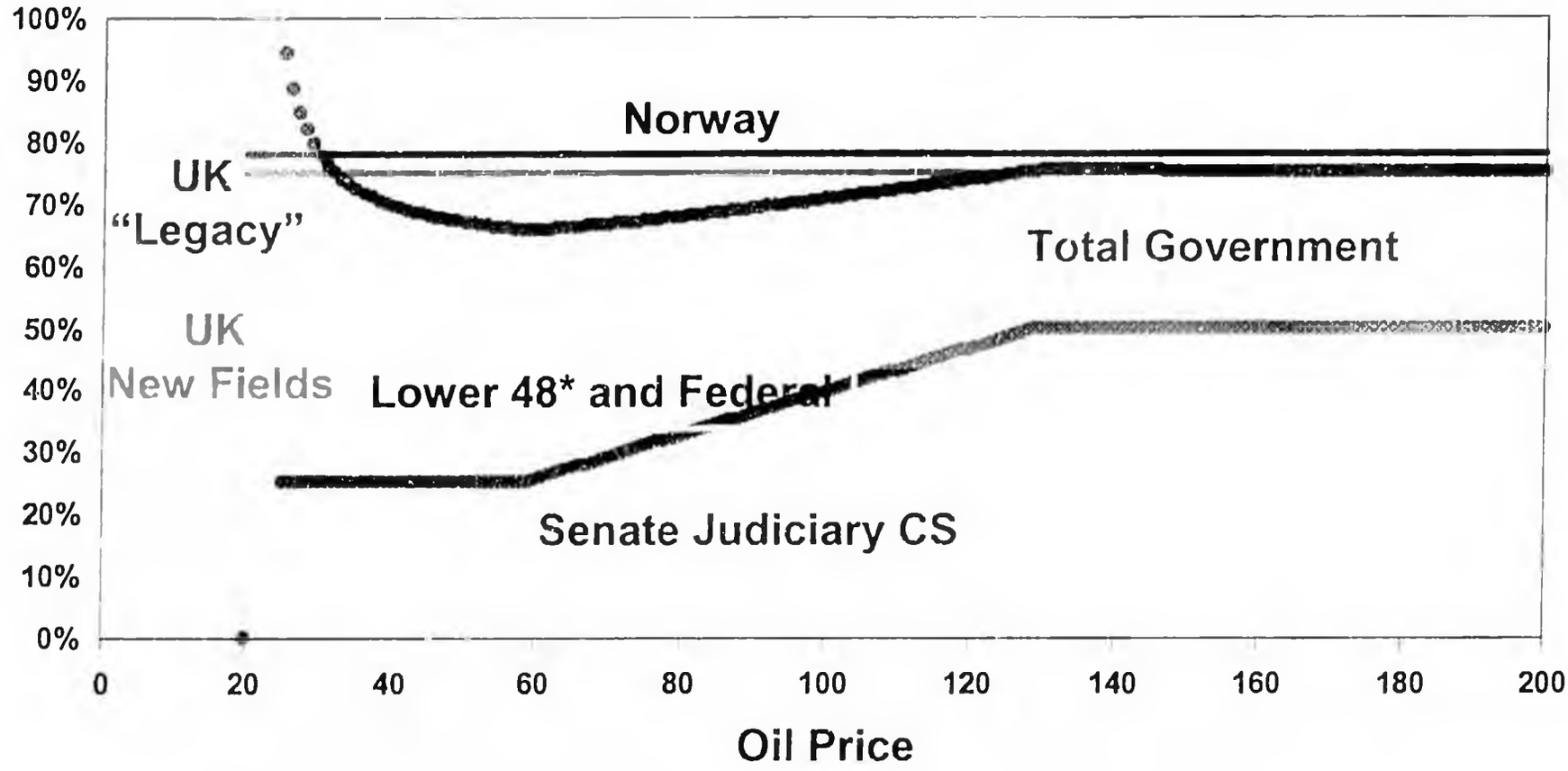
* For Lower 48, State lands / Federal assumes with 12.5% - 18.75% royalty. Private royalty trend is higher



Assumes $20 costs

Government Take
Senate Judiciary CS

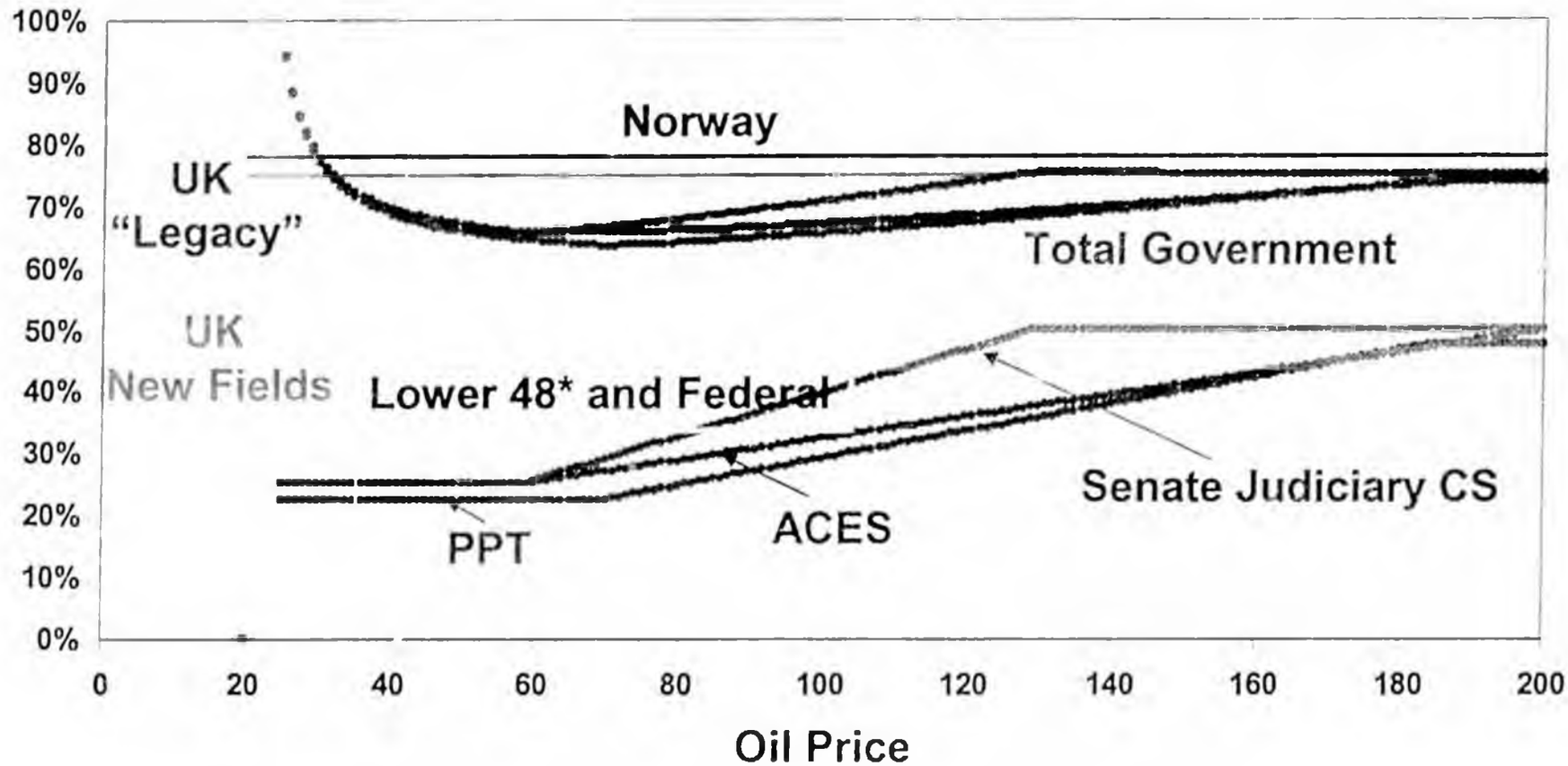
* For Lower 48, State lands / Federal assumes with 12.5% - 18.75% royalty. Private royalty trend is higher



Assumes $20 costs

Government Take
Senate Judiciary CS Finance

* For Lower 48, State lands / Federal assumes with 12.5% - 18.75% royalty. Private royalty trend is higher



Assumes $20 costs

Tax Rates in Various Versions of SB 2001

November 12, 2007

David Teal

Major Provisions of a Tax System

1. Taxable Revenue (Gross or Net)
2. Base Rate
3. Surcharge (Progressive Rate)
4. Trigger Point for Surcharge
5. Maximum Rate

All Tax Systems Discussed are Based on Net Cash Flow

	Base	Trigger	Rate	Trigger	Rate	Trigger	Rate	Trigger	Rate	Maximum
PPT	22.5%	$ 40	0.25%							47.5%
ACES	25.0%	$ 30	0.20%							50.0%
Sen Jud	25.0%	$ 30	0.40%							50.0%
House	25.0%	$ 30	0.40%							50.0%
Sen Fin	22.5%	$ 30	0.60%	$ 30	0.50%	$ 50	0.35%	$ 70	0.10%	75.0%

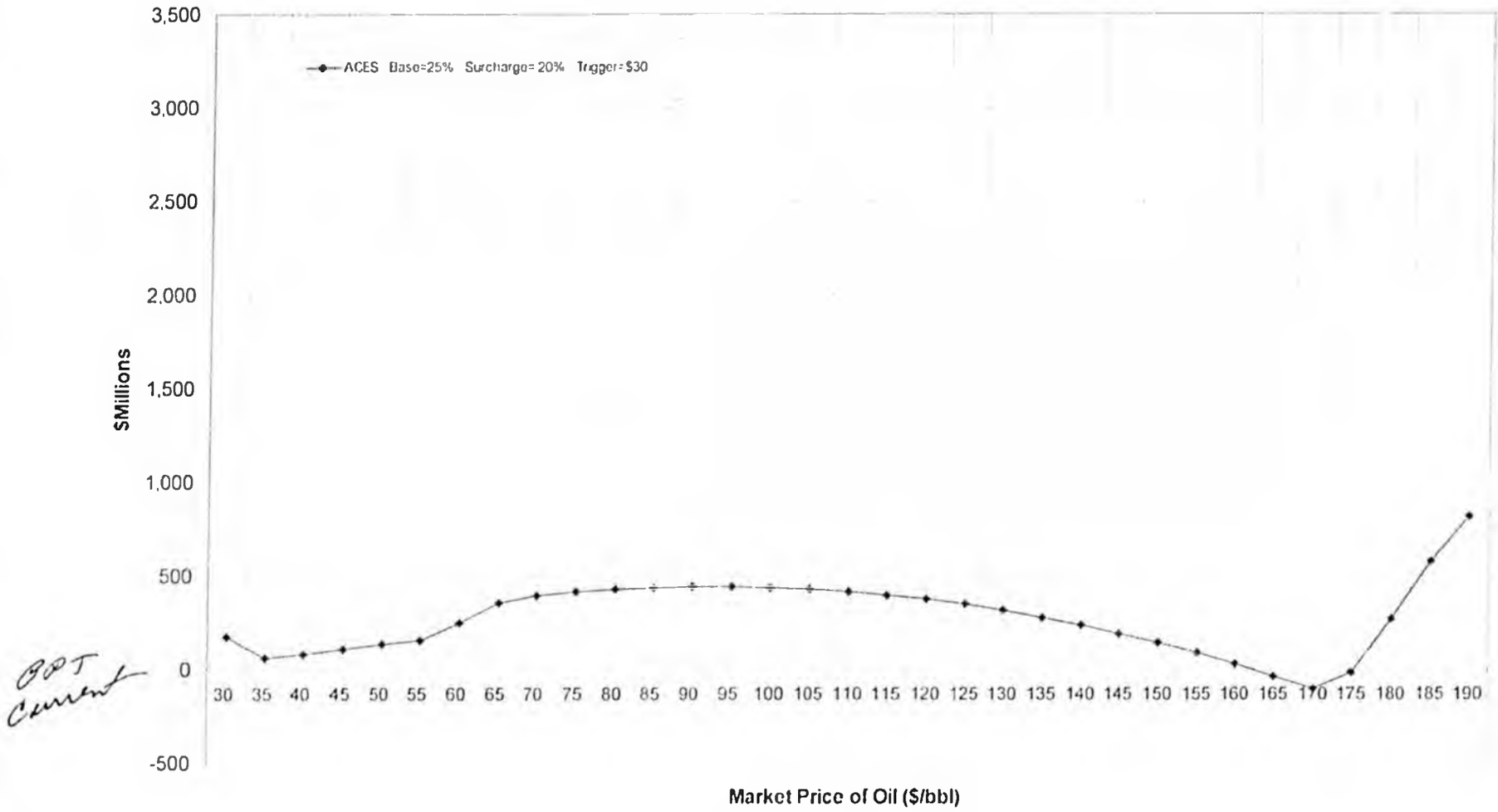
Comparing the Tax Systems

1. Increase in Revenue (relative to PPT)
2. Total Revenue
3. Government Share

Things to Remember

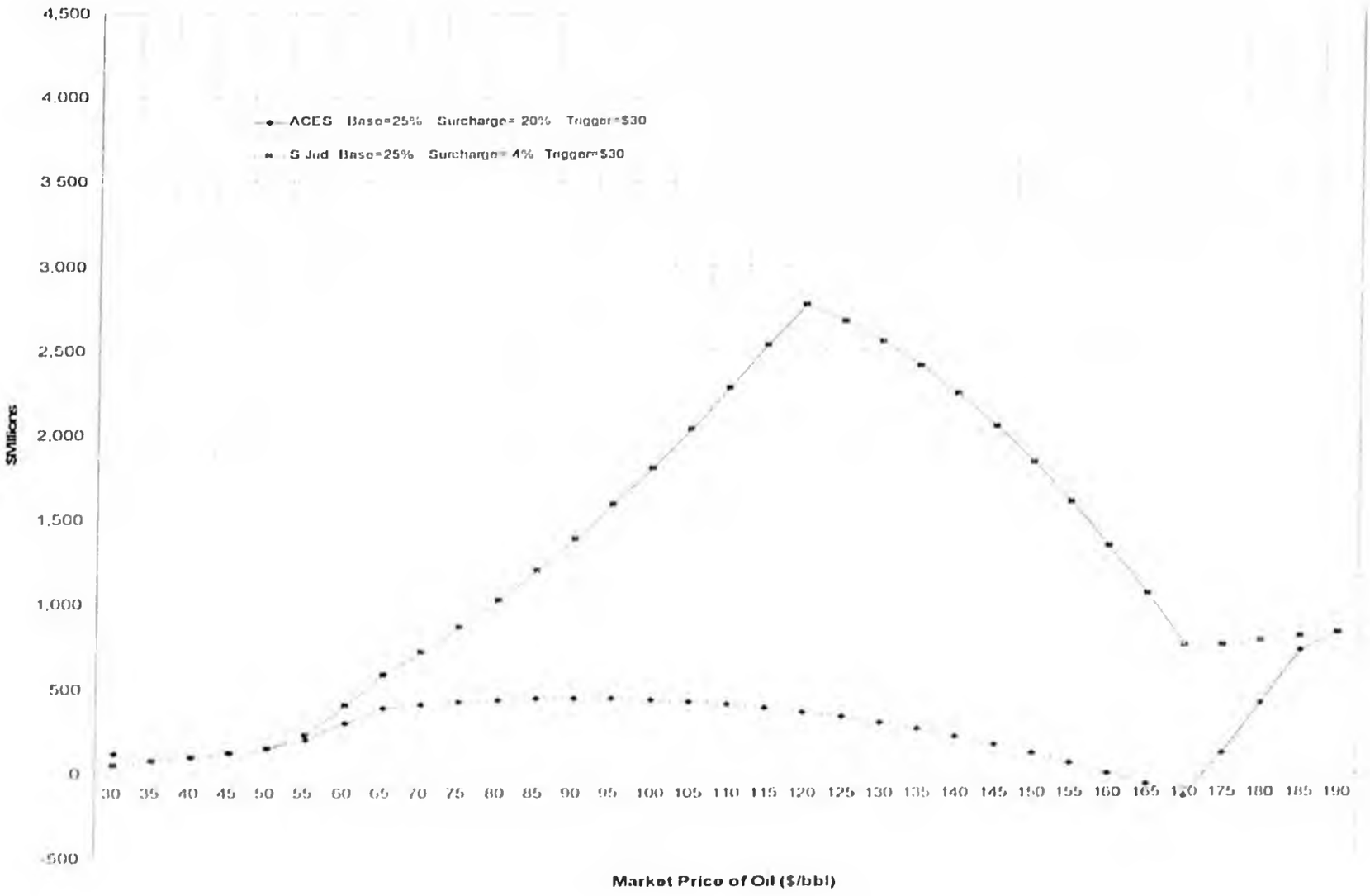
- Focus on curve shape and location—projections are affected by production volume, costs of production and other factors that cannot be predicted accurately.
- Projections are based on the Fall 2007 Revenue Forecast, but even if the variables—production volume, costs of production, etc.—change, the projections do not change much in relative terms.

Increases in Total State Revenue Under Various Production Tax Systems

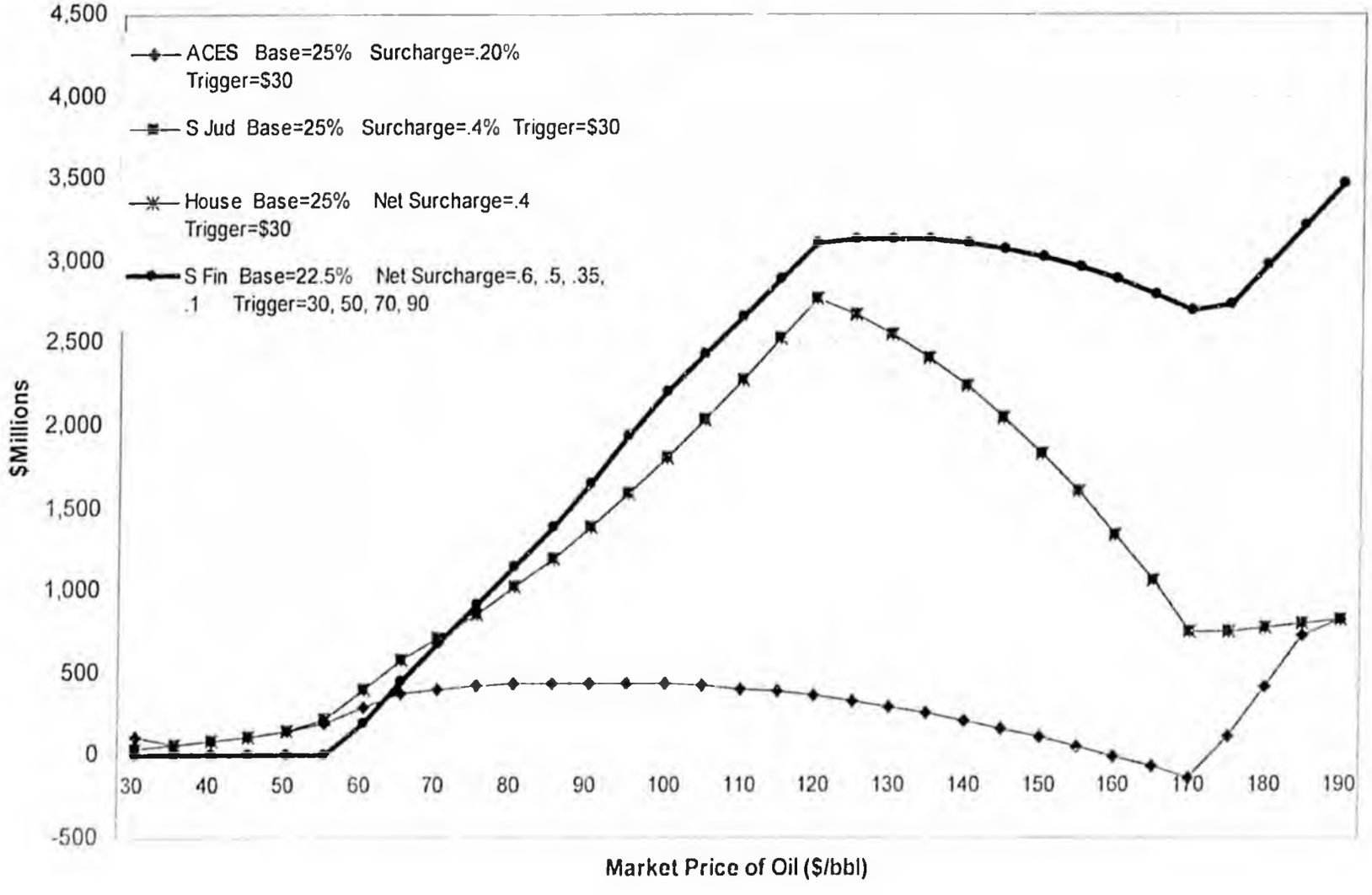


BPT Current

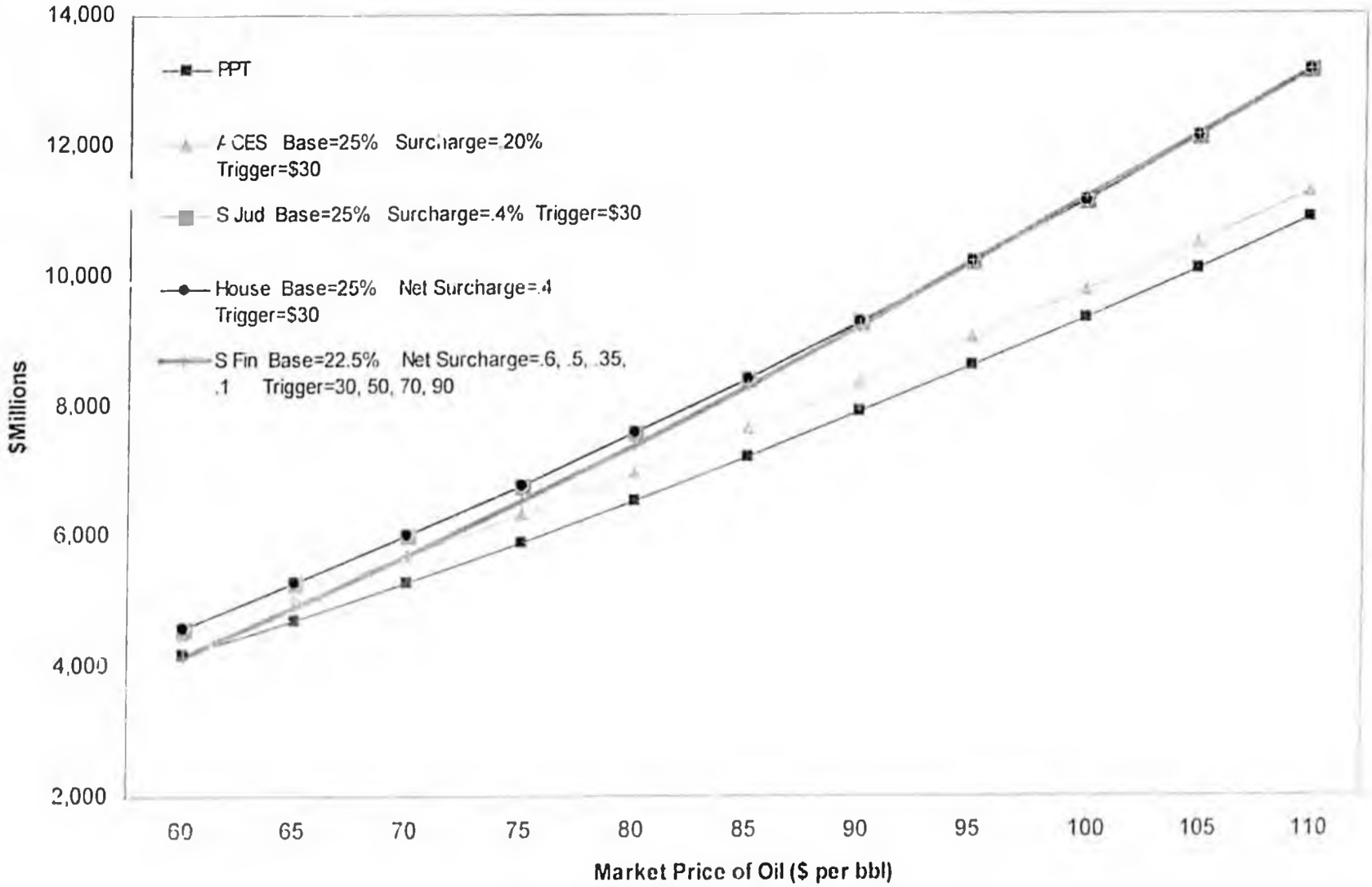
Increases in Total State Revenue Under Various Production Tax Systems



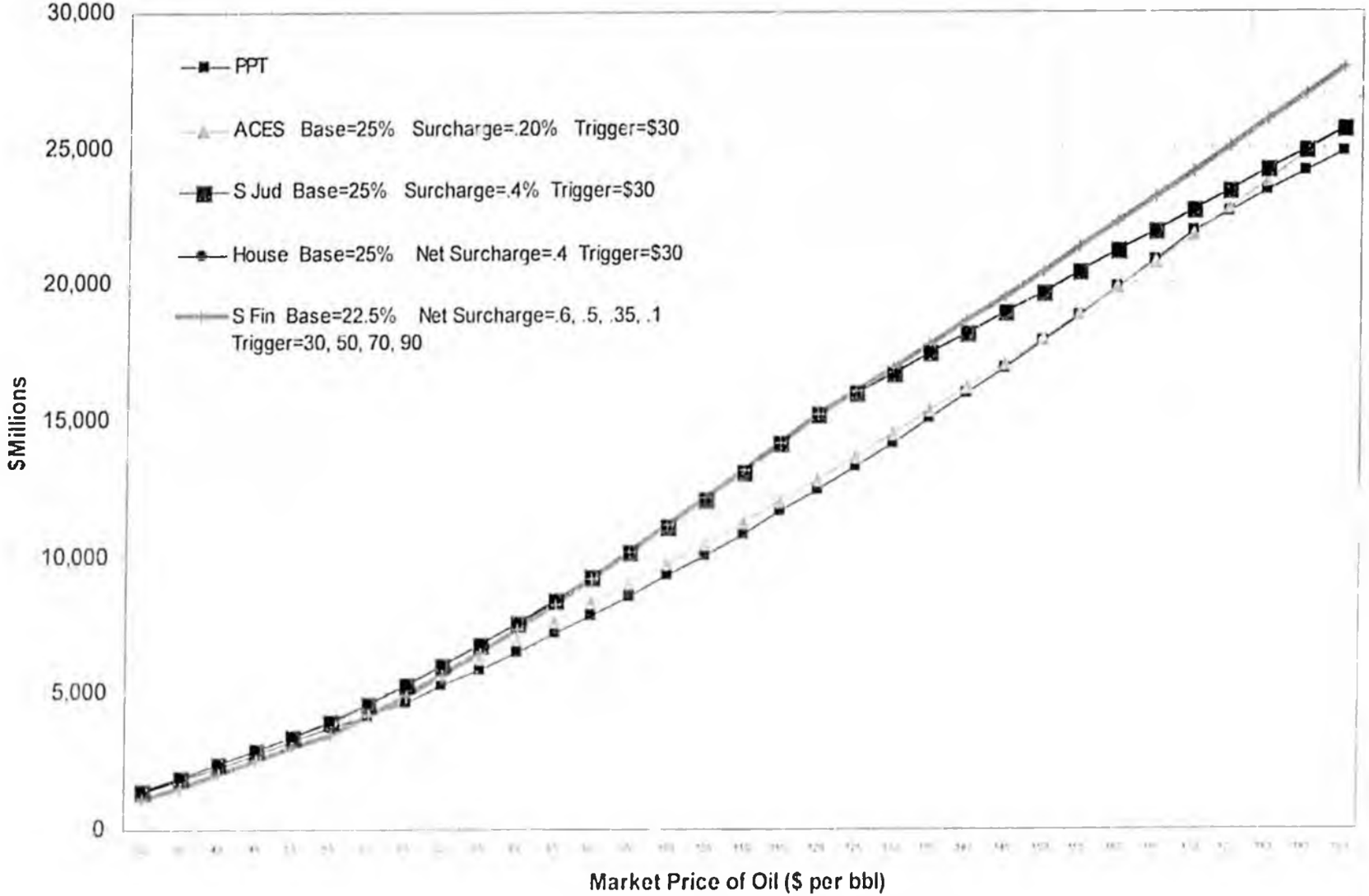
Increases in Total State Revenue Under Various Production Tax Systems



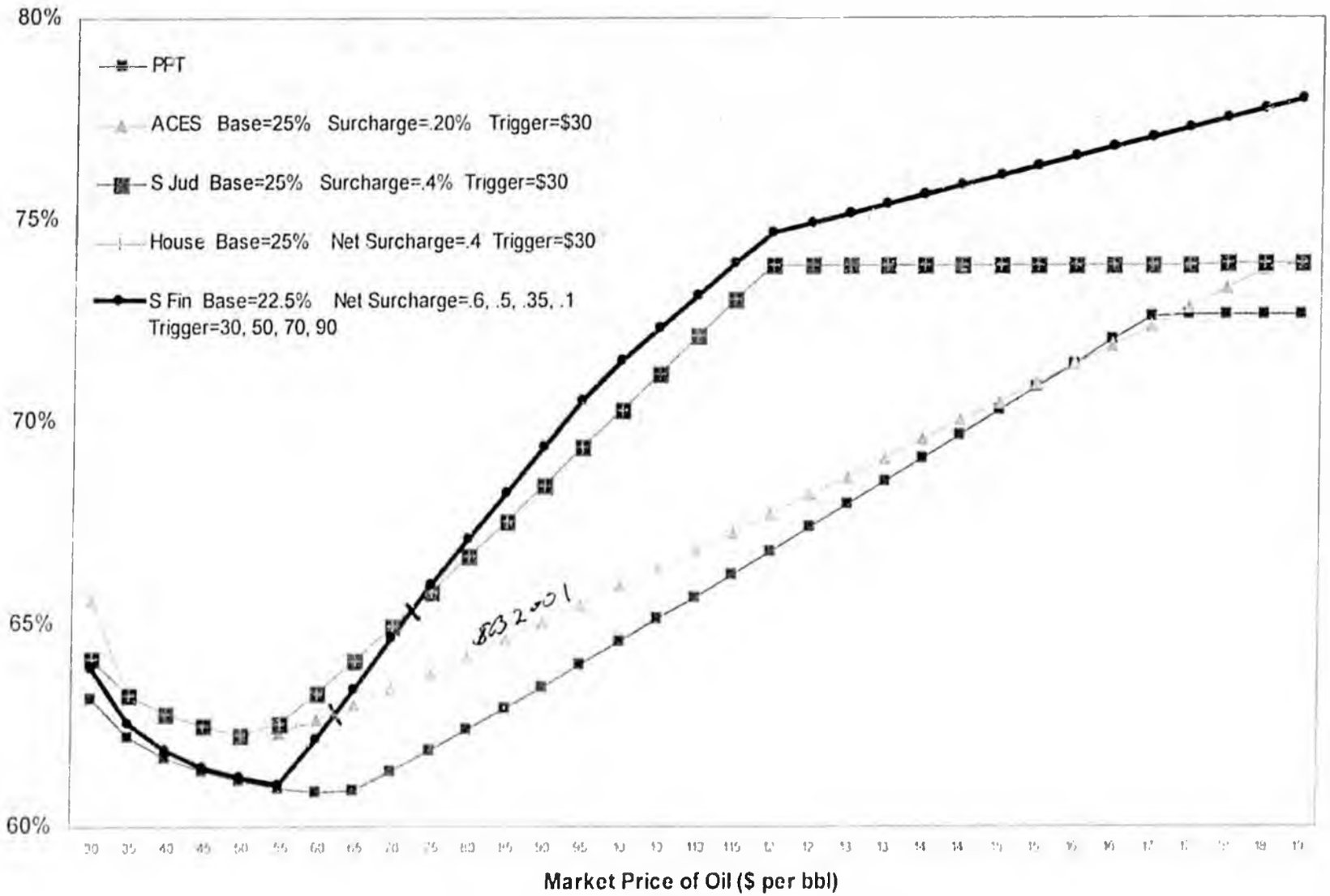
Total State Revenue Under Various Scenarios



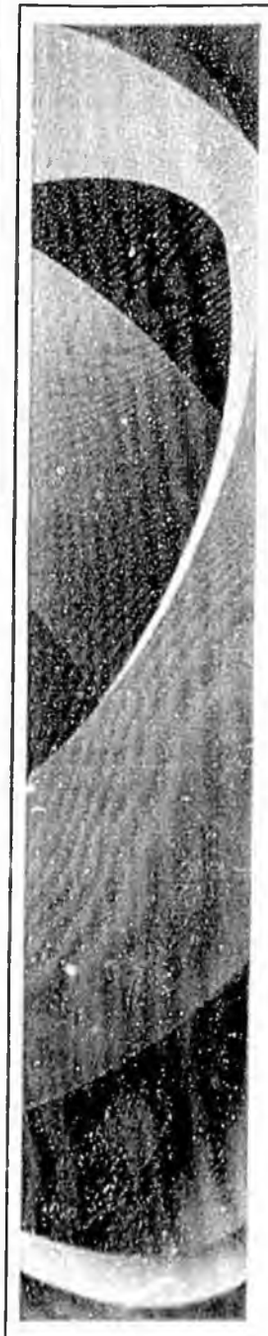
Total State Revenue Under Various Scenarios



Government Share of Revenue Under Various Scenarios



CAMBRIDGE
ENERGY
RESEARCH
11/10/07



A Comparison of Fiscal Regimes

Prepared by Cambridge Energy Research Associates

October 18, 2007

CERA
An IHS Company

A COMPARISON OF FISCAL REGIMES

Cambridge Energy Research Associates (CERA) has been requested by ExxonMobil to consider how the current and proposed fiscal regimes in Alaska compare with other fiscal regimes for both oil and gas developments around the world.

APPROACH

When comparing fiscal regimes, most analyses focus on the level of "state take" as a tool for ranking. This is an oversimplification. Ranking by state take is only a proxy for what really influences investment decisions—the value creation resulting from the deployment of investors' capital.

More useful, detailed fiscal analyses can be obtained by applying different fiscal regimes to an example model field and comparing the resulting development economics and levels of state take. However, this approach still oversimplifies the situation by assuming a world devoid of varying climates, topographies, and reservoir conditions, not to mention market conditions (including distance to liquid markets).

By contrast, in forming our opinion, CERA has considered which countries' oil and gas resources face technical and commercial challenges similar to Alaska's. We have selected conceptual development plans for sample oil and gas fields that are appropriate to each environment—in a range of sizes and at a range of product prices. These analyses are generated using the data and tools of our parent company, IHS Inc., and allow a true "apples-to-apples" comparison of what is left to the concessionaire.

Our approach in the comparison of fiscal terms is to consider what share of the barrel is left to the concessionaire in each jurisdiction. State take competes with capital and operating costs and the time value of money for the remainder. Unless this share of the barrel compensates the risks of exploration, development, production, and eventual decommissioning, the oil and gas resources will not be developed.

In its document *Guiding Principle for New Production Tax System*, the State of Alaska ranks the Marginal Government Take (including federal taxes) under its ACES plan at 68 percent—in line with an average for "all fiscal regimes" of 67 percent. Although it does not specify what regimes have been included, this latter figure is very similar to CERA's own analysis of a wide range of fiscal regimes performed for its 2005 Special Report *In Search of Reasonable Certainty: Oil and Gas Reserves Disclosures*. Among these regimes were a variety of operating environments including Algeria, China, Libya, Qatar, and other low-cost operating countries that are very dissimilar to Alaska for the purposes of valid comparison. The pre-tax profitability of activities in such countries leaves more room than a high-cost environment for government take without undermining the attractiveness of investment in exploration and development of their hydrocarbon resources.

How, then, should we select suitable peers against which to compare both current and proposed Alaskan fiscal regimes? CERA selected a peer group consisting of basins—typically situated in offshore or arctic-like environments or where their remoteness from markets results in significant costs—that are comparable to those experienced in Alaska.

KEY FINDINGS

The mean government take of the relevant peer group across a range of oil and gas prices and field sizes, to the extent that this is the appropriate measure, is 57 percent. This compares to a range of 70–75 percent for Alaska under the ACES proposals and 65–71 percent under the existing Petroleum Profits Tax regime.* These figures are based on the undiscounted government take as a percentage of the undiscounted net revenue. This suggests that the current regime favors the government (the combination of federal and state) over the leaseholder when compared to competing opportunities. The ACES proposals worsen this position.

In CERA's opinion a more appropriate measure of the attractiveness of a fiscal regime is the rate of return on development and the profit-to-investment ratio of development (a measure of the capital efficiency and therefore a guide to where a company should direct its capital). These measures indicate that Alaska is not competitive with other similar regimes.

*The range for Alaska depends on the underlying lease royalty rates ranging from 12.5 percent to 20 percent.

CHOOSING THE RIGHT PEER GROUP

To select relevant peers for Alaska, CERA began by identifying countries and basins in which the cost structure was comparable to that found in Alaska. Our assessment excluded field operating costs, but did include the price penalties of quality differentials (such as might apply to heavy, sour crudes) and the costs of bringing products to market. These costs can be calculated as capital sums—such as the cost of a pipeline from Alaska to liquid North American markets for both oil and gas or the costs of building liquefied natural gas (LNG) liquefaction, shipping and regasification. We have employed the convention of using tariff equivalents since this avoids complex issues of allocating capital to fields that share the same infrastructure. However, we have not included the capitalized liability of capacity bookings. Thus, if a field would cost $12 of capital expenditure (capex) per barrel to develop, the pipeline tariff to get it to market were $6 per barrel, and the crude quality resulted in a $5 per barrel discount to West Texas Intermediate (WTI), our analysis would treat it as having a $23 per barrel total cost.

CERA selected from among those countries and basins where these total costs exceeded $20 per boe for reserves with a scale exceeding 200 million boe. The list therefore excludes some high-cost regions such as the US Lower 48 where the scale of resource is simply not comparable to Alaska and also a number of LNG producers where the underlying costs of feed gas are low (including economic credit for associated liquids, e.g., Qatar, Nigeria, and Australia).

A feature of many of these high-cost basins is that long lead times between discovery and development result from the challenge of developing the fields profitably. Long lead times also limit the scope for fiscal take that does not recognize the time value of money without damaging the economics of the project.

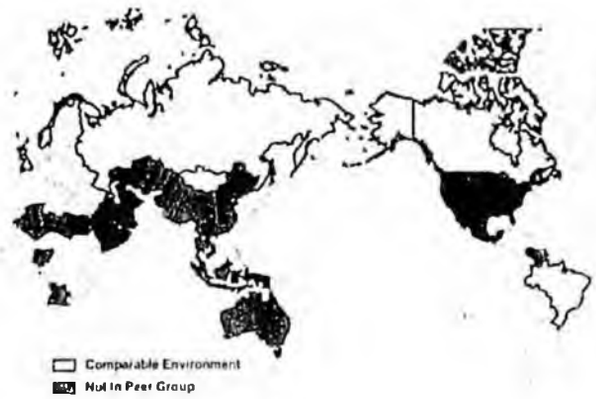
Taking into account these criteria, CERA's selected peer group (illustrated in yellow on Figure 1) includes the following regimes:

- Azerbaijan offshore
- Brazil deepwater (Campos Basin)
- Canada (Alberta oil sands in situ production, Atlantic coast offshore—Newfoundland and Nova Scotia—and gas from the Northwest Territories)
- Norway arctic offshore
- Russia (East Siberia, Sakhalin)
- UK West of Shetlands

The fiscal terms that we examined for each peer are included in Appendix 1 along with the representative field development examples for each.

Countries and regions that did not make the peer group because their cost structures and risk profiles differed too significantly from Alaska's are shown in red in Figure 1.

Figure 1
Choosing the Right Peer Group



Source: Cambridge Energy Research Associates
71018-1

PLACING ALASKA IN ITS PEER GROUP

CERA has ranked the fiscal regimes by assessing the full cycle exploration and development economics of a range of field sizes at a range of oil and gas prices. The example developments have been analyzed by applying the costs of developing a field in each operating environment to a standard production profile for each field size. In our analysis, we chose

- oil fields of 100 million barrels, 200 million barrels, and 500 million barrels
- gas fields of 1 trillion cubic feet (Tcf), 5 Tcf, and 10 Tcf
- WTI oil prices of $40, $60, and $80 per barrel
- gas prices in each end market of $7, $10, and $13 per million British thermal units (MMBtu)

We applied costs of transportation to markets in which these prices could be accessed and the "costs" of quality differentials for heavy or sour crudes where these are typical of a basin or play.

The economics were run in real terms to exclude the requirement to make assumptions about escalation rates for oil and gas prices and costs. We used costs based on 2007 market conditions for each hydrocarbon province. The relative ranking of each province would not change by using nominal economics.

Furthermore, we have assumed fiscal stability in all markets. For example, we have made no attempt to predict the outcome of the review of royalties currently under way in Alberta, Canada.

Figures 2–4 rank the attractiveness of activity under the existing and proposed regimes for Alaska versus the peer group.

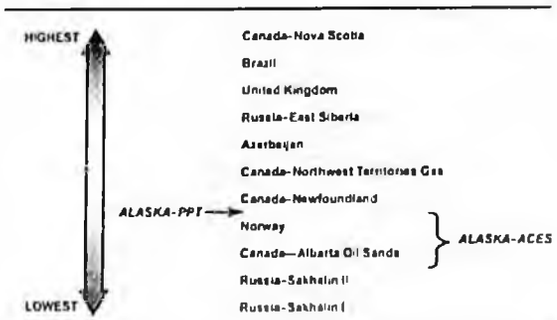
Based on ranking by government take, Alaska's fiscal regime lies towards the bottom of the peer group. But as we have explained, this oversimplifies the question. Companies do not invest on the basis of a notional share of the returns; they focus on the cash returns and value creation.

Figures 3 and 4 show the rankings based on real rate of return and the profit to investment ratio (calculated using a 10 percent real discount rate).

Figure 2
Government Take

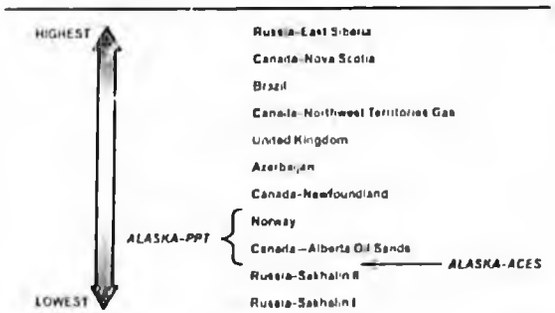
Source: Cambridge Energy Research Associates
Note: Bracket displays range of positions for Alaska regimes depending on royalty level
7.0183.2

Figure 3
Full Cycle Rate of Return



Source: Cambridge Energy Research Associates
Note: Bracket displays range of positions for Alaska regimes depending on royalty level
7.0183

Figure 4
Profit-to-Investment Ratio
(10 percent real DCF)



Source: Cambridge Energy Research Associates
Note: Bracket displays range of positions for Alaska regimes depending on royalty level
7.0184

However, this analysis covers only the development of hydrocarbon resources—it excludes the risks and costs of abortive exploration. The other important factor is whether the value created through successful exploration is sufficient to support the costs and risks of exploration. Companies will not typically invest in exploration unless they expect to create significant value. One of the commonest ways of measuring the value expected to be created through an exploration program is to calculate the expected monetary value (EMV) of the exploration prospects covered by the program. In its simplest form, this can be calculated as

$$EMV = Value_{Success} \times Probability_{Success} - Cost_{Exploration} \times Probability_{Failure}$$

It is important to stress that the aggregate shows results for a portfolio rather than assigning value to any individual prospect (where the outcome is often binary—either zero or high value). Furthermore, one can also calculate an "exploration cover ratio"—the result of dividing $Value_{Success}$ by $Cost_{Exploration}$. When exploring in a frontier basin, it is not uncommon to seek exploration cover ratios of 10 and more. Figure 5 ranks Alaska's peer group by their exploration cover ratios.

The Alberta oil sands have been included in this comparison even though the resource has been discovered. In situ production operations do still rely on some delineation of the resource to optimize development.

By any of the measures shown, Alaska's current fiscal regime lies in the bottom half of its peer group, and the proposed ACES regime would only cause Alaska's position to fall.

Figure 5
Exploration Cover Ratio

Source: Cambridge Energy Research Associates
Note: Bracket displays range of positions for Alaska regimes depending on royalty level
71318.5

APPENDIX-1

Alaska–Generic Gas Development

Onshore development. Fully winterized drilling facilities and all production facilities and pipelines raised above ground to protect the permafrost. Infrastructure (including airstrip and roads) constructed only during winter. Sweet gas and no associated liquids result in minimum processing, and 200 kilometer (km) pipeline connecting to the main pipeline is included. Six years from discovery to first production and up to 23 years production life.

Alaska–Generic Oil Development

Onshore winterized development similar to gas example. Associated gas disposal at zero cost. Oil stabilization and 200 km pipeline to Trans-Alaska Pipeline System line.

Alaska–Petroleum Profits Tax (PPT) Regime

Royalty

Royalty rates vary depending on the terms under which a lease was granted. We have run the economics at 12.5 percent and 20 percent royalty rates to account for different terms.

Property (Ad Valorem) Tax

The property tax is assumed to be 2 percent per year of the replacement cost of the assets. We have assumed that the cost is equal to the cumulative development capital less the accumulated book depreciation where book depreciation is assumed to be figured using a straight-line method over the life of the project.

Miscellaneous Fees

There are minor fees of no significance to the economics and thus have not been modeled.

Petroleum Profits Tax

Taxable income for the PPT in Alaska is defined as the total gross revenues less deductions for royalties, tariffs, operating expenses, and capital expenditures. The base PPT tax rate is 22.5 percent, but it increases .25 percent for every $1 per barrel that the taxable income divided by the production exceeds $40 per barrel, up to a maximum PPT tax rate of 47.5 percent. A 20 percent credit to PPT is given for each dollar of capital spent in Alaska operations. This credit may be carried forward indefinitely.

There is a minimum PPT payable of 4 percent of gross revenues less transportation expenses if the oil price exceeds $25 per barrel, 3 percent if it is between $20 and $25 per barrel, 2 percent if it is between $17.50 and $20 per barrel and 1 percent if it is between $15 and $17.50 per barrel. There is no minimum payment if the price is at or below $15 per barrel.

Alaska State Income Tax

Taxable income for the Alaska state income tax is a complex calculation based on the percentage of worldwide income that was earned in Alaska. Effectively, the taxable income is the same as for US federal income tax, and the tax rate is 9.4 percent.

US Federal Income

The US federal income tax is 35 percent of gross revenues less royalty, property, and severance taxes; miscellaneous fees; PPTs, Alaska state income taxes; transportation expenses; operating expenses; and depreciation of capex. The depreciation rules are as follow:

- Exploration dry holes are expensed.
- Bonuses are subject to cost depletion, which utilizes a unit-of-production method.
- Geological and geophysical costs are depreciated on a 2-year straight-line basis with only half of the first year's depreciation allowable.
- Intangible drilling capital is depreciated on a 5-year straight-line basis using the half-year rule in the first depreciable year; however, 70 percent of the capital may be expensed in the first depreciable year.
- Development tangible capital is depreciated on a double declining balance basis over 7 years using the half-year rule in the first depreciable year.

Alaska–Clear and Equitable Share Plan (ACES): Proposed Changes from PPT Regime

Royalty, Property Tax, and Miscellaneous Fees

No Change.

Petroleum Profits Tax

Taxable income for the PPT in Alaska is defined as the total gross revenues less deductions for royalties, tariffs, operating expenses, and capital expenditures. The base PPT tax rate is 25 percent, but it increases .2 percent for every $1 per barrel that the taxable income divided by the production exceeds $30 per barrel, up to a maximum PPT tax rate of 50 percent. A 20 percent credit to PPT is given for each dollar of capital spent in Alaska operations, but this credit must be split over 2 years. This credit may be carried forward indefinitely.

There is a minimum PPT payable of 10 percent of gross revenues less transportation expenses.

Alaska State Income Tax

No Change.

US Federal Income Tax

No Change.

Azerbaijan–Generic Gas Development

Offshore development in the Caspian (based around Shah Deniz development concept scaled up and down appropriately for fields in the range 1 Tcf to 10 Tcf) employing 8-leg jacket for gas processing and drilling facilities. Processing includes amine treatment of sour gas and there is a 200 km pipeline to the shore. Five years from discovery to first production and up to 34 years production life.

Azerbaijan–Generic Oil Development

Offshore development. Wells drilled from artificial islands, with production facilities on barges, including water injection. Gas disposal at zero cost and 130 km offshore pipeline for oil. Up to 9 years from discovery to first production and a 28-year production life.

Azerbaijan–Production-sharing Agreement

State Participation

State is assumed to take a 10 percent interest upon commencement of the development and production period and repays its share of carried exploration and appraisal (E&A) costs with interest (8 percent assumed) from its share of production.

Royalty

None.

Cost Recovery

Under the terms of recent production-sharing agreements (PSAs) recoverable costs are expensed and recovered immediately from production according to the following schedule:

- All operating costs, including contributions to the abandonment fund, are recovered from 100 percent of gross production.
- All capital costs (including E&A costs and development costs) are recovered from a negotiable percentage (50 percent assumed here) of production remaining after the recovery of operating costs.
- Unrecovered costs may be carried forward indefinitely for recovery in subsequent years, but not beyond the duration of the contract.

Profit Sharing

Production (after cost recovery) is shared between the state and the contractor on an incremental sliding scale based on an R factor (a proxy for rate of return), with the contractor's share ranging from 55 percent down to 10 percent in the most profitable case.

Income Tax

Paid by the State Oil Company of Azerbaijan Republic on the contractor's behalf from its share of production at a special rate of 25 percent.

Brazil–Generic Oil Development

Subsea wells tied back to a newbuild floating production, storage, and off-loading (FPSO) facility in about 1,000 meters (m) of water. Includes a pipeline to the shore and zero cost gas disposal. Development is modeled after Block 1-RJS-597 with costs adjusted to optimize for field sizes from 100 million barrels to 500 million barrels. Producing field life of up to 15 years.

Brazil–Deep Water > 400 Meters Fiscal Terms

State Participation

None.

Royalty

A production royalty is payable to the state and levied on gross revenue. The standard rate of 10 percent has been assumed here.

Special Participation Fee

The concessionaire is subject to payment of a special participation fee (SPF). The SPF is calculated quarterly and levied on net revenue before income tax from each field under the concession agreement. Net revenue for SPF is gross revenue from the field less signature bonuses, royalty, research and development expenses, operating costs, E&A costs, a quarterly allowance, depreciation of development costs over 10 years straight-line, and abandonment costs (amounts set aside for future abandonment or current costs). Losses may be carried forward indefinitely. There is no provision for the carry-back of losses. The rate of SPF is linked to production and the year of production as defined in the 1998 Fiscal Decree.

Income Tax

Income tax is levied on gross revenue less operating costs, royalty, research and development expenses, special participation fee, depreciation of all capex (assumed to include bonuses) over 10 years straight-line, and abandonment costs (IHS assumption). Losses may be carried forward indefinitely, but they cannot exceed 30 percent of the company's taxable income for a tax period. There is no carry-back provision. The basic rate of corporate income tax is 15 percent, increased by a surtax of 10 percent on taxable profits exceeding R$240,000.

A Social Contribution Tax (SCT) is imposed on Brazilian-source corporate income. The taxable base and deductions are identical to those for income tax, and the rate of SCT is 9 percent. Effective January 1, 1997, SCT is not deductible in calculating the tax base for either income tax or SCT itself. Losses for SCT purposes are subject to the same tax rules as for the income tax purposes.

Thus, the effective income tax rate is 34 percent (15 percent basic rate + 10 percent surtax + 9 percent SCT).

Other Taxes

Local taxes include a Municipal service tax (ISS), excise tax (IPI), municipal sales tax (ICMS), social contribution for welfare programs (COFINS), and Social Integration Program (PIS) contribution.

Canada–Alberta Oil Sands Generic Development

In situ production of oil sands in Alberta. Integrated upgrader produces synthetic crude selling at approximately WTI prices.

Canada–Alberta Fiscal Terms

Bonus and Other Payments

None included in this analysis.

State Participation

None.

Royalty

The *Oil Sands Royalty Regulation, 1997* provides for royalty to be determined on a project basis and applies to all new investment in oil sands whether they are new projects or expansions of existing projects. Before payout the applicable royalty is 1 percent of the gross revenue of the oil sands project. After a project reaches payout, the Crown's royalty share calculation is equal to the greater of 1 percent gross revenue and 25 percent net revenue. A return allowance is calculated on the balance of cumulative costs less cumulative revenues based on the Canadian government's long-term bond rate.

The analysis excludes the impact of the royalty credit implemented by Alberta under the *Innovative Energy Technologies Program.*

Provincial Income Tax

Levied on gross revenue less operating and E&A costs, depreciation of capital costs (on a 30 percent declining balance basis), and the greater of resource allowance (see below) or royalty. Losses may be carried forward for a maximum of 7 years. Since April 2004 the provincial income tax rate is 10 percent, having been gradually reduced from 15.5 percent over a 5-year period from 2000.

Federal Income Tax

Federal income tax is levied on gross revenue less operating costs, E&A costs, royalty, and depreciation of development costs at 30 percent on a declining balance basis. Noncapital losses may be carried forward for a maximum of 7 years; capital losses may be carried forward indefinitely.

The basic federal corporate income tax rate in Canada is 38 percent. However, corporations liable for provincial income tax receive abatement equal to 10 percent, reducing the basic rate of federal income tax to 28 percent. The rate had been reduced to 21 percent in 2004 and will be further reduced to 19 percent between January 2008 and 2010.

Large Corporations Tax

Large corporations tax is effectively a minimum tax that may be reduced by the surtax. Large corporations tax is levied on the capital employed in Canada in excess of C$50 million. The rate is 0.0625 percent for 2007. This is ignored in the analysis as it will not apply after 2008.

Canada–Generic Gas Development–Northwest Territories

Arctic type onshore development modeled after proposed Lake Parsons development with two well pads separated by 15 km, elevated equipment, high winterization factor for drilling rig and sour gas processing facilities. Pipeline of 45 km to gas processing facility. Five years from discovery to first production (i.e., assumes main export line already exists) and field life up to 49 years.

Canada–Northwest Territories Fiscal Terms

Royalty

A royalty is levied at 1 percent of gross revenue for the first 18 months, followed by 2 percent for the following 18 months, etc. up to a maximum of 5 percent. After project payout, royalty is paid at a rate of 5 percent of gross revenue, or 30 percent of net revenue, which ever is greater.

Provincial Income Tax

Provincial income tax in both the Northwest Territories and Nunavut is levied at a rate of 11.5 percent (reduced from 12 percent effective July 1, 2006) of the taxable income as assessed for federal tax, resulting in a combined federal and provincial income tax of 33.62 percent for 2007.

Federal Income Tax

As for the other provinces.

Canada–Generic Oil Development–Newfoundland

Offshore development modeled after the Hibernia offshore development (adjusted for field size range). Gravity base structure with extra concrete included for ice protection. Offshore-loaded crude and zero cost gas disposal. Onshore infrastructure includes facilities for permanent residence and airstrip.

Canada–Newfoundland Fiscal Terms

Bonus and Other Payments

A signature bonus in the form of an up-front competitive bid may be required when applying for a license but has not been assumed here. There are no further bonuses or other payments.

Royalty

The *2003 Royalty Regulations* provide for royalty rates starting at 1 percent and rising to 7.5 percent after 200 million barrels of production for leases issued after November 30, 2001.

Tier I Incremental Royalty is levied at 20 percent of net revenue after Tier I payout is reached. The Tier I payout is reached when the project reaches a 5 percent rate of return plus a long-term government bond rate (assumed to be 6 percent). As basic royalty paid is creditable against Tier I royalty payable, the effective royalty rate will be equal to or greater than the basic royalty.

Tier II Incremental Royalty is levied as an incremental 10 percent of net revenue after Tier II payout occurs. The Tier II payout occurs when the project reaches a rate of return of 15 percent plus a long-term government bond rate (assumed to be 16 percent). Tier I royalty paid is an allowed cost for the purposes of calculating the Tier II payout.

For royalty purposes the allowed costs are uplifted by 1 percent for capital costs, 10 percent for operating costs, 5 percent for exploration costs, and 1 percent for decommissioning costs.

Provincial Income Tax

Provincial income tax is levied on gross revenue less operating costs, E&A costs, and depreciation of capital costs at 30 percent per year on a declining balance basis. Losses may be carried forward 7 years. The provincial income tax rate is 14 percent.

Federal Income Tax

As for the other provinces.

Canada–Generic Gas Development–Nova Scotia

Modeled after the Deep Panuke development (adjusted for field size range) involving two platforms bridged with accommodation and processing facilities in 44 m water depth. Drilling is conducted in two phases with the second phase deploying subsea tie back of wells and acid gas reinjection. A 120 km pipeline to shore. Six years from discovery to first production and a field life of up 23 years.

Canada–Nova Scotia Fiscal Terms

Bonus and Other Payments

A signature bonus in the form of an up-front competitive bid may be required when applying for a license but has not been assumed here. There are no further bonuses or other payments.

Royalty

Royalty is levied on the revenue due to an interest holder arising from its interest in a field. Royalty is calculated on a monthly basis and is determined by a sliding scale linked to dates of field payout (i.e., profitability).

In summary, the royalty rate is 2 percent of gross revenue until a first rate-of-return threshold is reached, after which it becomes 5 percent until a second rate-of-return threshold. After the second rate-of-return threshold has been reached, the royalty rate is the maximum of 5 percent of gross revenue and 20 percent of net revenue until a third rate-of-return threshold is reached, after which the royalty rate becomes the maximum of 5 percent of gross revenue and 35 percent of net revenue. If the resource being developed has been designated by the minister as the first to be developed in a high risk area, the 35 percent rate is reduced to 20 percent.

Provincial Income Tax

Provincial income tax is levied on gross revenue less E&A costs, operating costs, a capital cost allowance in the case of acquisitions, and depreciation of development capital at 30 percent per year on a declining balance basis.

The rate of provincial income tax is 16 percent.

Federal Income Tax

As for the other provinces.

Norway–Generic Gas Development

Modeled after the Ormen Lange development in the Barents Sea (adjusted for the range of field sizes). Utilizes subsea development tied back to shore by 108 km multiphase pipeline in 1,000 m of water. Seven years from discovery to first production and up to 32-year field life.

Norway–Generic Oil Development

Modeled after the offshore Goliat development (adjusted for the range of field sizes). Utilizes subsea wells tied back to a fifth generation newbuild semisub with offshore loading of crude and zero cost gas disposal. Eight years from discovery to first production and a 15-year producing life.

Norway–Royalty Tax Terms

Bonus and Other Payments

None assumed.

State Participation

State takes a direct financial interest (DFI) from day one. It is paid its share from the beginning and therefore has not been modeled as a fiscal impost. State participation of 20 percent has been assumed, reflecting some of the preliminary awards of the Eighteenth Licensing Round.

Royalty

None.

Carbon Dioxide Tax

Carbon dioxide (CO_2) tax is levied on the volume of petroleum flared, on the volume of natural gas vented, and on CO_2 separated from petroleum and vented on platforms or other installations used for production or transportation of petroleum. CO_2 tax is deductible for income tax and special petroleum tax. The intention is to abolish this tax and replace it with tradable "Emissions Quotas."

Income Tax

The taxable base for income tax is gross revenue less exploration costs, operating costs, royalty, CO_2 tax, and depreciation of development costs (6 years straight-line). Losses from 2002 onward may be carried forward with interest (calculated as a risk-free interest plus a margin after deducting income tax at the prevailing income tax rate). The income tax rate is 28 percent.

Special Petroleum Tax

The taxable base for Special Petroleum Tax (SPT) is the same as for income tax but includes an extra allowance in the form of an uplift equal to 5 percent of the capital investment (excluding exploration costs) rolled up annually to a maximum 130 percent of development costs. Unused uplift can be carried forward. The SPT rate is 50 percent.

Russia–Generic Gas Development–East Siberia

Modeled after Kovykta onshore development (adjusted for range of field sizes). Production from two well pad locations to a central processing facility with compression which feeds to a 250 km pipeline connecting to the main Gazprom export pipeline.

Russia–Generic Oil Development–East Siberia

Modeled after Ardalin onshore development (adjusted for range of field sizes). The onshore production facility is positioned 30 km from field infrastructure and feeds to an 85 km pipeline connecting to main Transneft export pipeline.

Russia–East Siberia Fiscal Terms

State Participation

None.

Minerals Production Tax

The Minerals Production Tax is based on gross sales revenue less tariffs. The tax rate is 16.5 percent. As of January 2007 a holiday of up to 15 years or until oil production from the field exceeds 25 million metric tons per year.

Property Tax

Property tax is levied on cumulative capex less cumulative capex depreciation as for profits tax purposes. The rate of property tax is 2 percent.

Land and Pollution Taxes

Modeled to be equivalent to 0.1 percent of operating costs.

Single Social Tax

Introduced on January 1, 2001, the Single Social Tax (SST) is levied on the "salary fund." We understand the "salary fund" is 6 percent of operating costs. The rate of SST is 36.4 percent, but taking into account life insurance (1 percent) the rate of SST will be 37.4 percent.

Income Tax

The income tax rate is 24 percent as of January 1, 2002.

Russia–Generic Gas Development–Sakhalin Offshore

Developed with subsea wells tied back to production facilities onshore; $500 million on local infrastructure upgrade. Onshore pipeline to coastal terminal for gas export via assumed existing LNG facilities.

Russia–Generic Oil Development–Sakhalin Onshore

Production and injection wells tied back 30 km to central facility. Crude stabilization and zero cost gas disposal before export through 226 km pipeline to coastal terminal.

Russia–Sakhalin I PSA Indicative Example

Bonus and Other Payments

We have modeled a $45 million production bonus. Also $100 million payable to Sakhalin Development Fund, over 5 years ($20 million per year) after the first development plan is approved.

State Participation

None.

Royalty

Royalty of 8 percent is levied on gross production.

Cost Recovery

All recoverable costs are expensed and recovered immediately from revenue from gross production less royalty. Cost recovery ceiling is 85 percent.

Profit Sharing

Production remaining after royalty and cost recovery is shared between the state and the contractor as specified in the PSA. The profit sharing has been assumed to be on a sliding scale with state share of 70 percent after a 28 percent rate of return has been achieved.

Income Tax

The income tax rate is 35 percent.

Deductions and Depreciation

Capex is depreciated over 3 years straight-line. Bonuses are tax deductible. Losses are carried over for 15 years.

Russia– Sakhalin II PSA Indicative Example

Bonuses

There is a signature bonus payable; however, no signature bonuses have been modeled. No discovery or production bonuses are payable.

State Participation

None assumed in the context of this analysis.

Royalty

Royalty of 6 percent is levied on gross production.

Cost Recovery

All recoverable costs are expensed and recovered immediately from revenue from gross production less royalty. There is no cost recovery ceiling.

Profit Sharing

Production remaining after royalty and cost recovery is shared between the state and the contractor as specified in the PSA. The profit sharing has been assumed to be on a sliding scale with state share of 70 percent after a 24 percent rate of return has been achieved.

Other Payments

Exploration costs incurred by the Russian party are paid in quarterly installments of $4 million until $80 million has been paid. When 17.5 percent internal rate of return has been reached, another $80 million is disbursed in the same manner.

Income Tax

The income tax rate is 32 percent.

Deductions and Depreciation

Capex is depreciated over 3 years straight-line. Bonuses are tax deductible. Losses are carried over for 15 years.

United Kingdom–Generic Gas Development

Modeled after the Lagan development west of the Shetland Islands (adjusted for the range of field sizes). Utilizes a tension leg platform in 620 m water depth and a 380 km pipeline to St. Fergus in Scotland.

United Kingdom–Generic Oil Development

Modeled after the Rosebank development offshore west of the Shetland Islands (adjusted for the range of field sizes) with subsea wells in 1,100 m water tied back to an FPSO. Oil is offloaded to tankers.

United Kingdom–Fiscal Terms

Royalty

None.

Income Tax

The Corporation Tax is 30 percent of corporate taxable income, which is defined as gross revenues less all capex and operating expenses in the year they are spent. Losses may be carried forward indefinitely and earn interest at the rate of 6 percent per year for the first 6 years of carry-forward.

Supplementary Corporation Tax

The tax rate is 20 percent of corporate taxable income, as defined above. Losses may be carried forward and earn interest in the same manner as the corporation tax.

"GOVERNMENT TAX TAKE GAFFNEY CLINE 11/9/07"

Alaska's Equitable Share

Senate Finance Committee

09 November 2007

Topics

- GCA's understanding of the goals or drivers for Alaska's Petroleum Fiscal System?
- Description and comparison of the four fiscal structures under consideration
- Working from a portfolio of projects representative of the opportunities described by industry, show the impacts of each fiscal system
- Analysis of industry returns from the Prudhoe Bay drilling program

Goals

Goals for Fiscal Design

- **Based on the past two weeks we (GCA) see the State trying to achieve the following 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)
       - Gas
  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

Goals 1, 2 & 4
The Fiscal Design Challenge

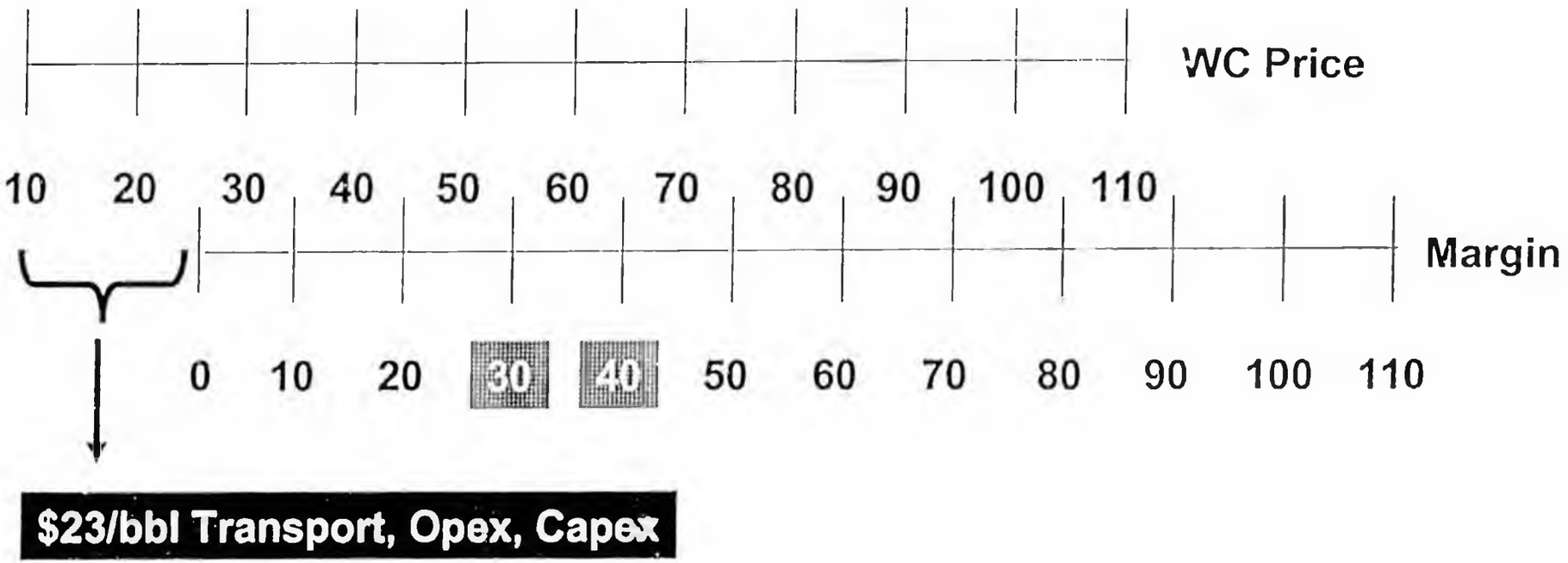
- **At the same time the State must address "The Take"**
  - (1) Capture the State's equitable share when margins are very high (as they are today)
  - (4) Include a form of progressive structure to adapt to the inevitable changes in the three main variables of the business:
    - Price
    - Production
    - Cost
- **...as well as "The Give Back"**
  - (2) Encouragement to reinvest profits for more development inside legacy units

Goal 3: Encourage New Investment

- **The proposed legislation appears to provide the right incentives to encourage investment in new fields**
  - Investment credits
  - Net Operating Loss credits
    - Aid to new entrants with no existing tax base
  - The net based systems by design lower the applicable production tax rate for fields with higher cost structure
    - More distant from infrastructure
    - Heavy Oil
    - Gas
- **Beyond the individual project, the State and industry benefit from new developments as they provide additional barrels down TAPS thus extending the productive life of existing reservoirs**

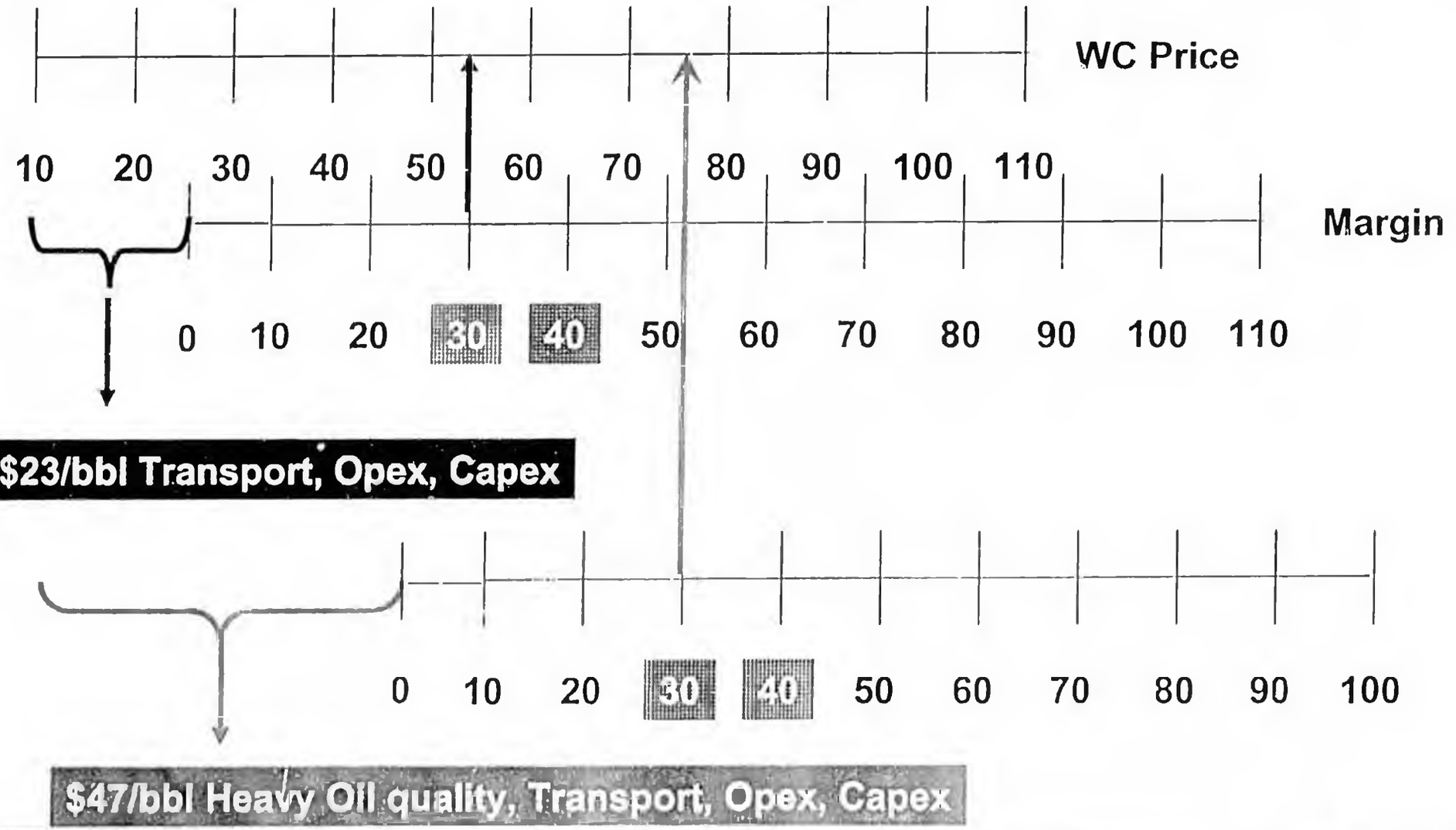
Key Point Easily Misunderstood

Price ≠ Margin



$23/bbl Transport, Opex, Capex

Margin/Price relationship changes with time and with project addition

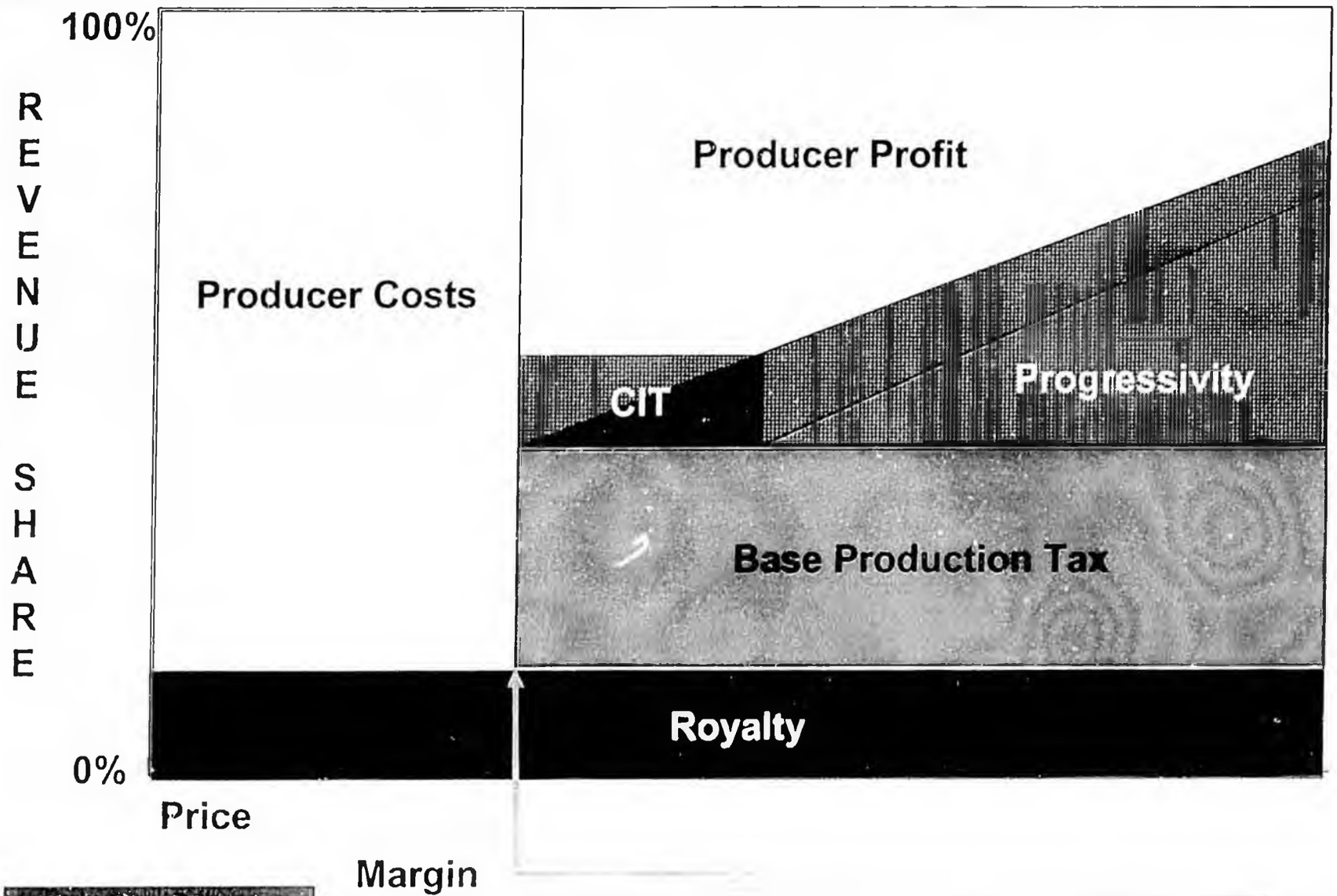


Regime Comparison

Regime Review

- **Three fiscal systems in discussion**
  - PPT
  - ACES
  - Senate CS

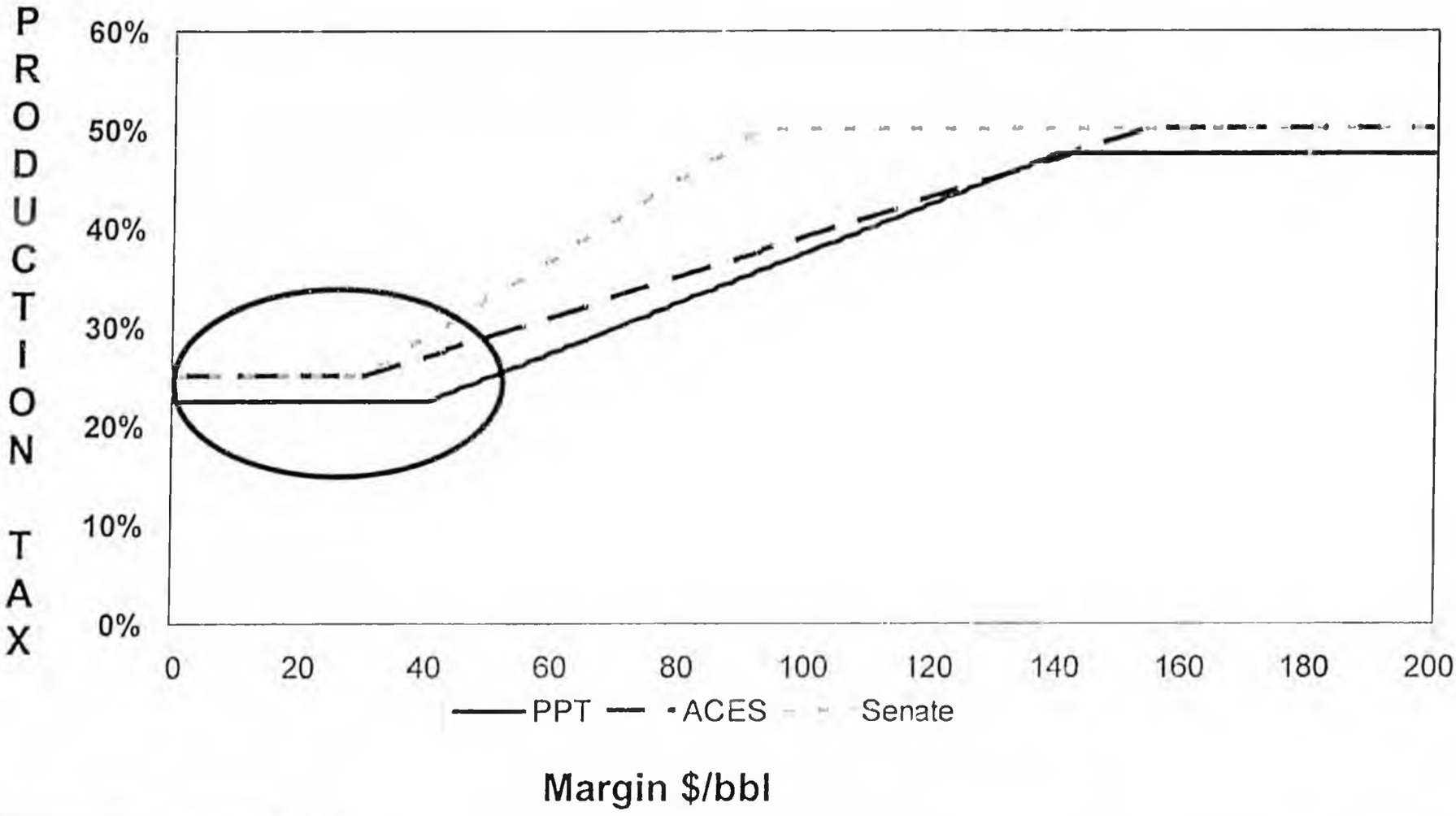
For PPT, ACES and Senate CS



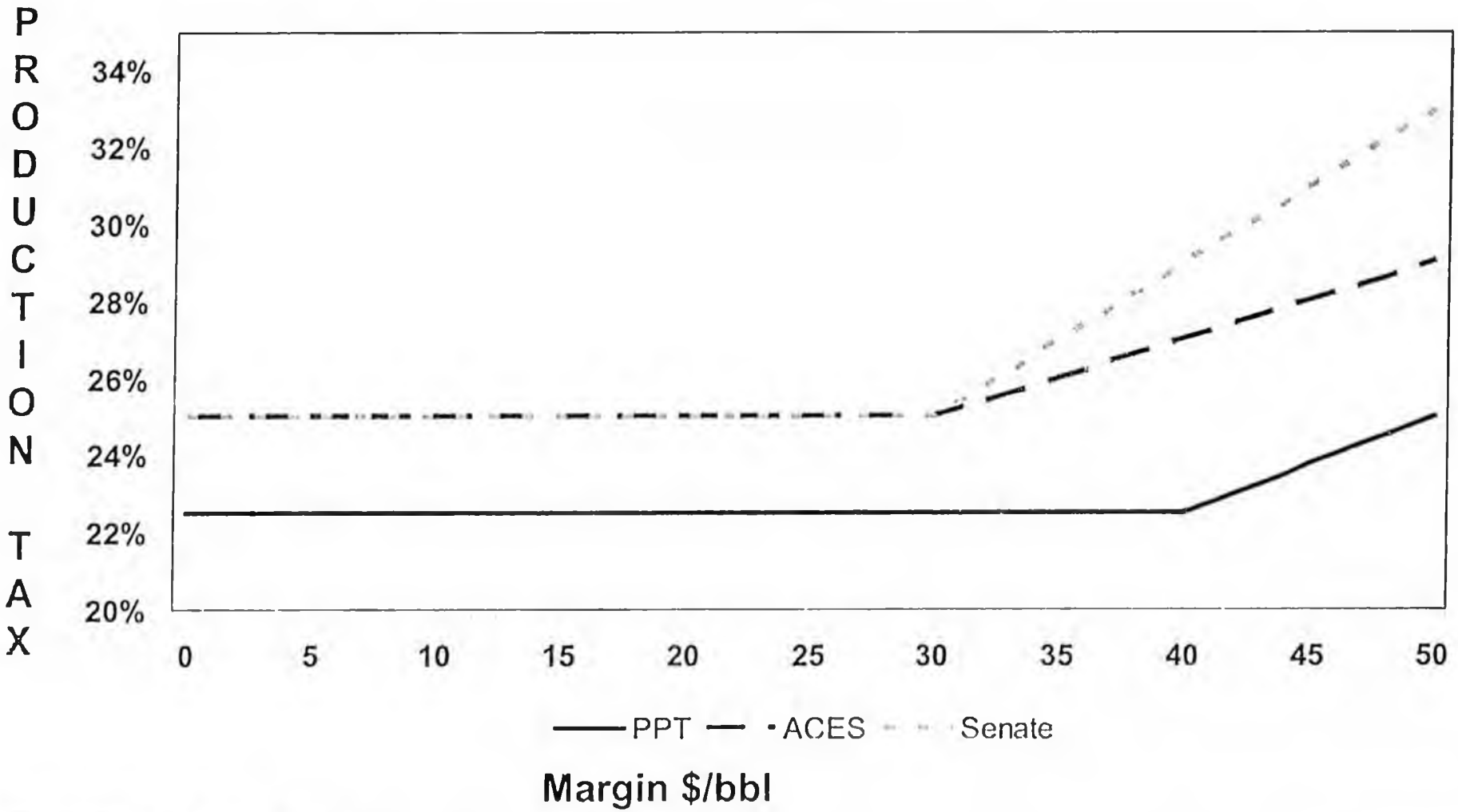
Summary of Terms

	Base	Kick-off	Progressivity	Cap
PPT	22.5%	$40	0.25%	47.5%
ACES	25%	$30	0.2%	50%
Senate	25%	$30	0.4%	50%

Three Fiscal Systems



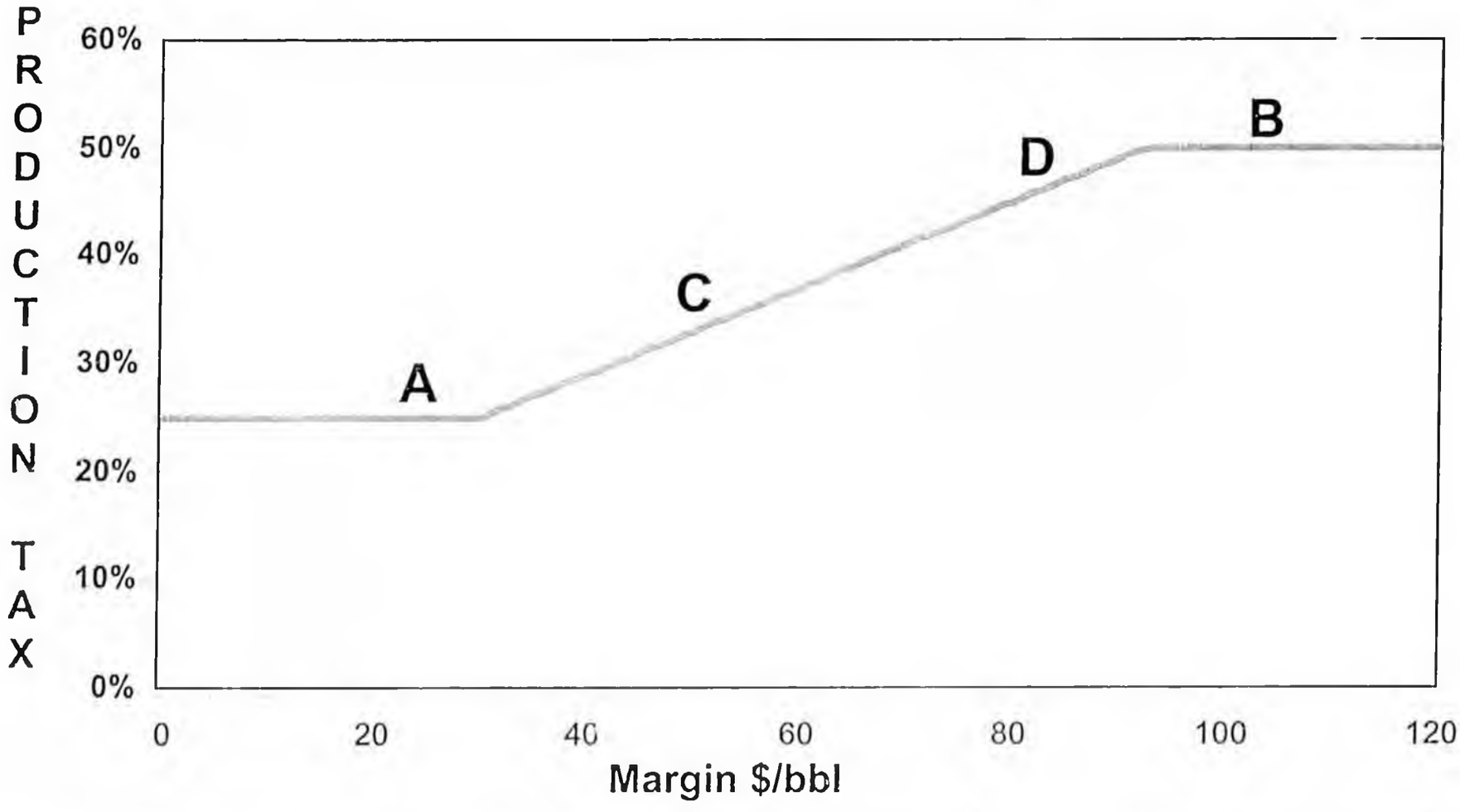
Likely Zone Of Operation



Progressivity Impacts

- **The use of progressivity creates a sizeable difference between the effective rate and the marginal rate of tax in relation to investment decisions**
  - This is present with the existing PPT language
  - The impact provides either:
    - A good sized "carrot" to invest; or
    - A good sized "stick" to not export after tax cash flow from Alaska

Margin Cases



Federal and State Income tax impacts excluded

An Example of Progressivity Impacts

- **Let's assume a company has $1000 before tax cash flow and is deciding whether or not to make a $100 investment (or roughly reinvest 10%)**
  - If the net margin before investment is under $30/bbl
    - Production tax savings associated with the $100 investment is 25%
  - If the net margin is greater than $92.5/bbl
    - Production tax savings associated with the $100 investment is 50%
  - If the net margin is between $31/bbl and $92.5/bbl
    - Production tax savings associated with the $100 investment ranges from 25% to over 100%

Taxpayer 'A' - Low Margin

- **$1000 net revenue @ a margin of $25/bbl**
  - Tax = $1000 x 25%
    Tax = $250
- **Now we invest $100- reduces net revenue to $900 and our margin to $22/bbl**
  - Tax = $900 x 25%
  - Tax = $225
- **Production Tax savings due to the investment**
  - Tax Savings = ($250 – $225)/$100
  - Tax Savings = 25/100
  - New Marginal Tax Rate = 25%

Taxpayer 'B' - High Margin

- **$1000 net revenue @ a margin of $125/bbl**
  - Tax = $1000 x 50%
    Tax = $500
- **Now we invest $100 that takes our net revenue to $900 and our margin to $110/bbl**
  - Tax = $900 x 50%
  - Tax = $450
- **Production Tax savings due to the investment**
  - Tax Savings = ($500 – $450)/$100
  - Tax Savings = 50/100
  - New Marginal Tax Rate = 50%

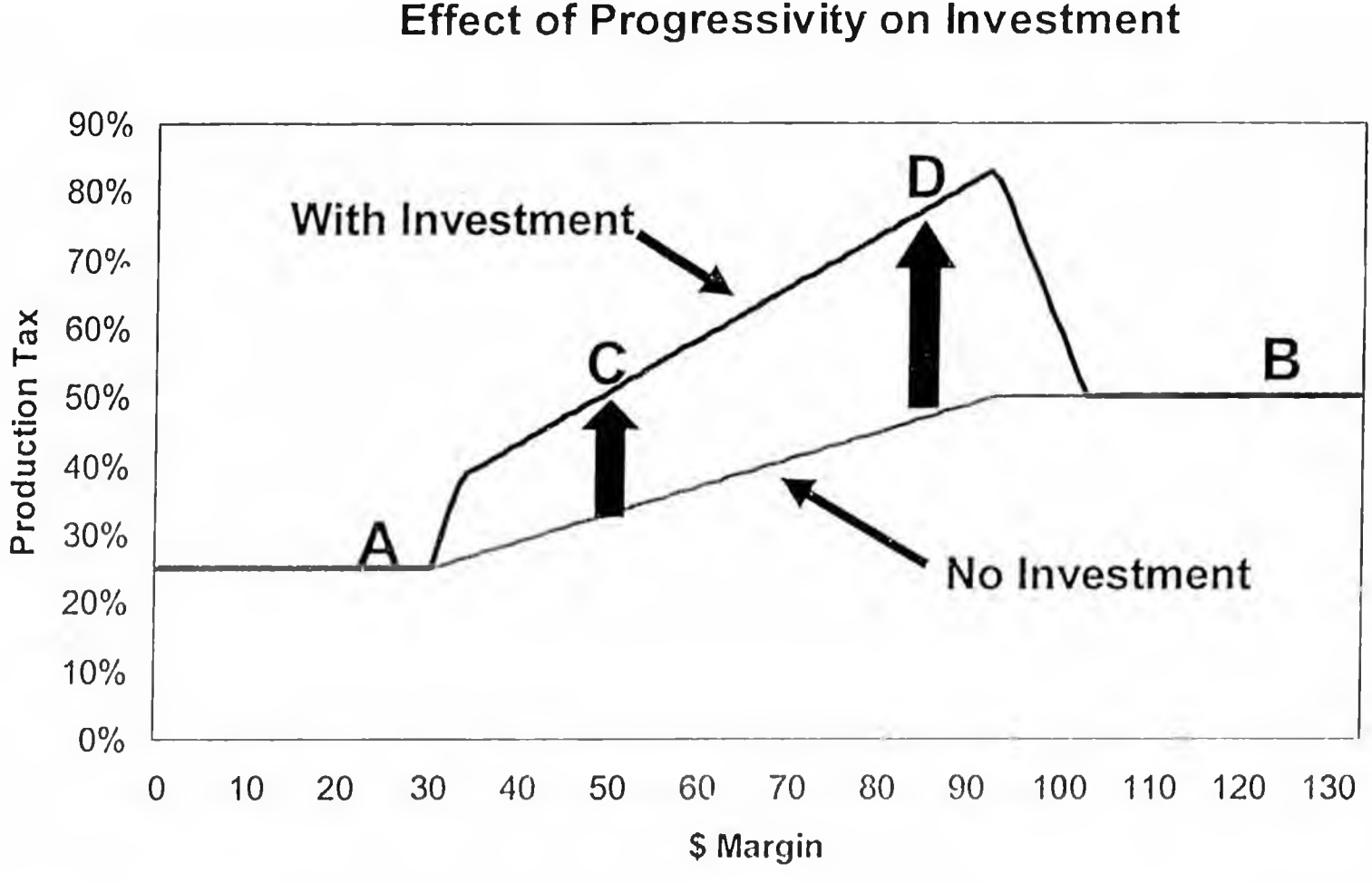
Taxpayer 'C' – Low on the slope

- **$1000 net revenue @ a margin of $50/bbl**
  - Tax = $1000 x 33%
    Tax = $330
- **Now we invest $100 that takes our net revenue to $900 and our margin to $45/bbl**
  - Tax = $900 x 31%
  - Tax = $279
- **Production Tax savings due to the investment**
  - Tax Savings = ($330 – $279)/$100
  - Tax Savings = 51/100
  - New Marginal Tax Rate = 51%

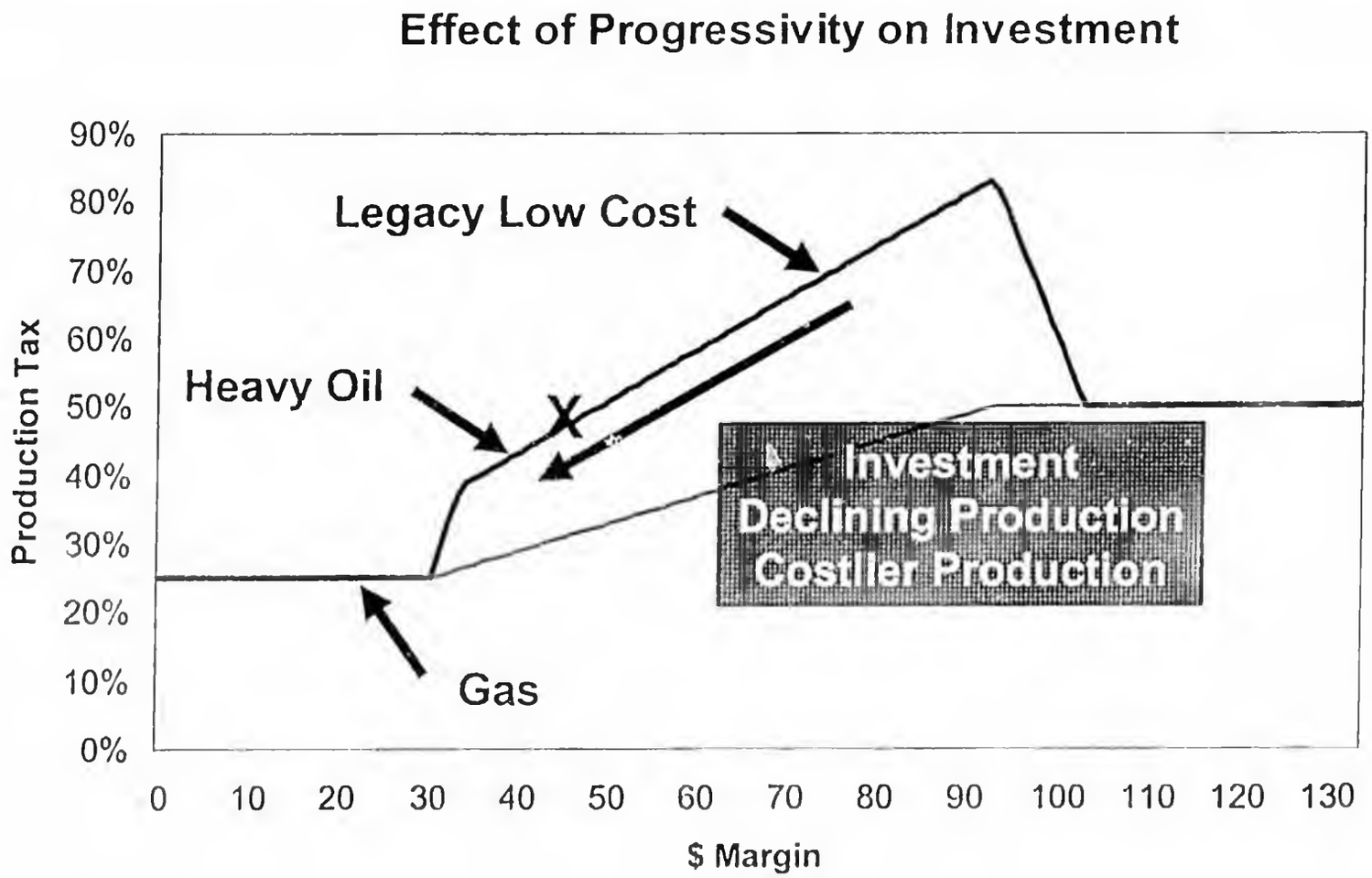
Taxpayer 'D' – High on the slope

- **$1000 net revenue @ a margin of $85/bbl**
  - Tax = $1000 x 47%
    Tax = $470
- **Now we invest $100 that takes our net revenue to $900 and our margin to $72/bbl**
  - Tax = $900 x 43.6%
  - Tax = $392
- **Production Tax savings due to the investment**
  - Tax Savings = ($470 – $392)/$100
  - Tax Savings = 78/100
  - New Marginal Tax Rate = 78%

'C' & 'D' New Marginal tax rate higher



Progressivity and Goals 1,2 & 3



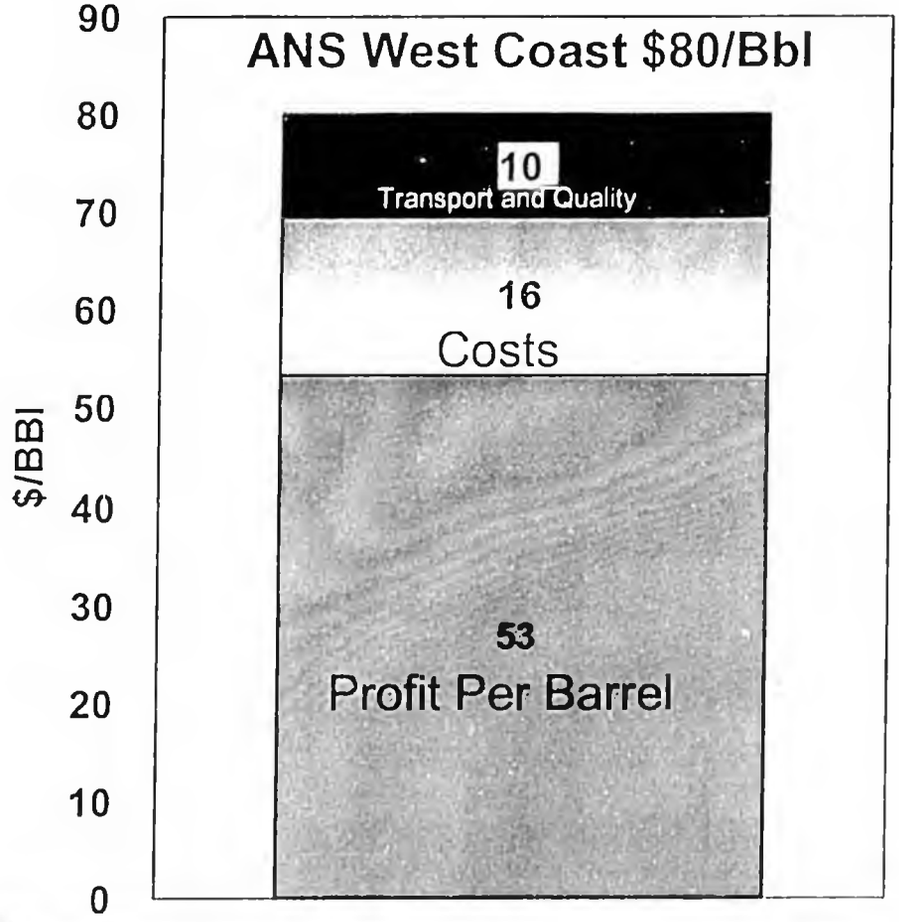
The Net Tax Structure

Net Tax Structure – "Headlines"

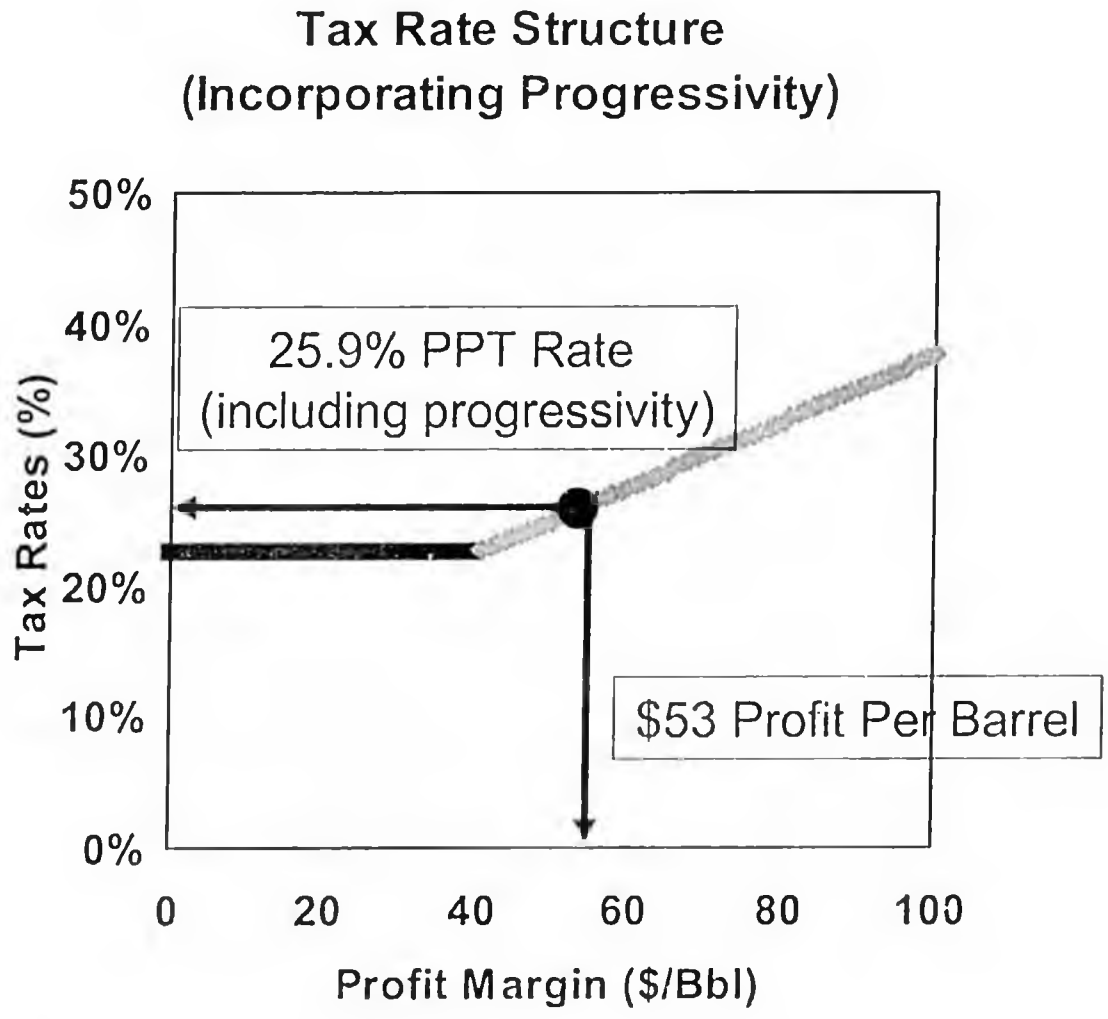
- Tax on net profits
- Contains progressivity feature that increases tax rate with increasing profitability per barrel
- Ringfenced so that profit per barrel reflects a company's entire portfolio

Profitability As Typically Described

Portfolio Profitability



PPT - Based On $53/Bbl Profit ...

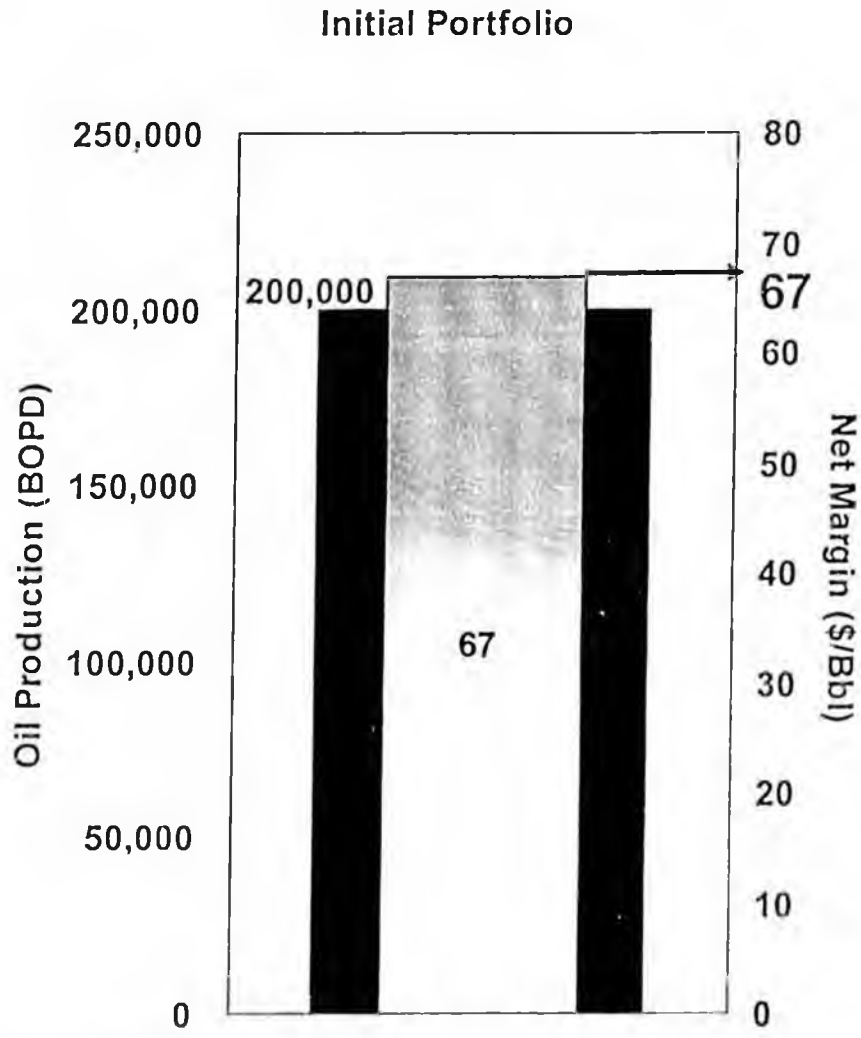


Misconception – Net Progressivity

- **"Net" taxes all fields at a single rate**
  - If only looking at the "headline" net tax rate, this would be the perception
  - In reality, when looking at the marginal impact of different parts of the portfolio, it taxes different fields or reservoirs at different rates
    - Based upon their individual profitability

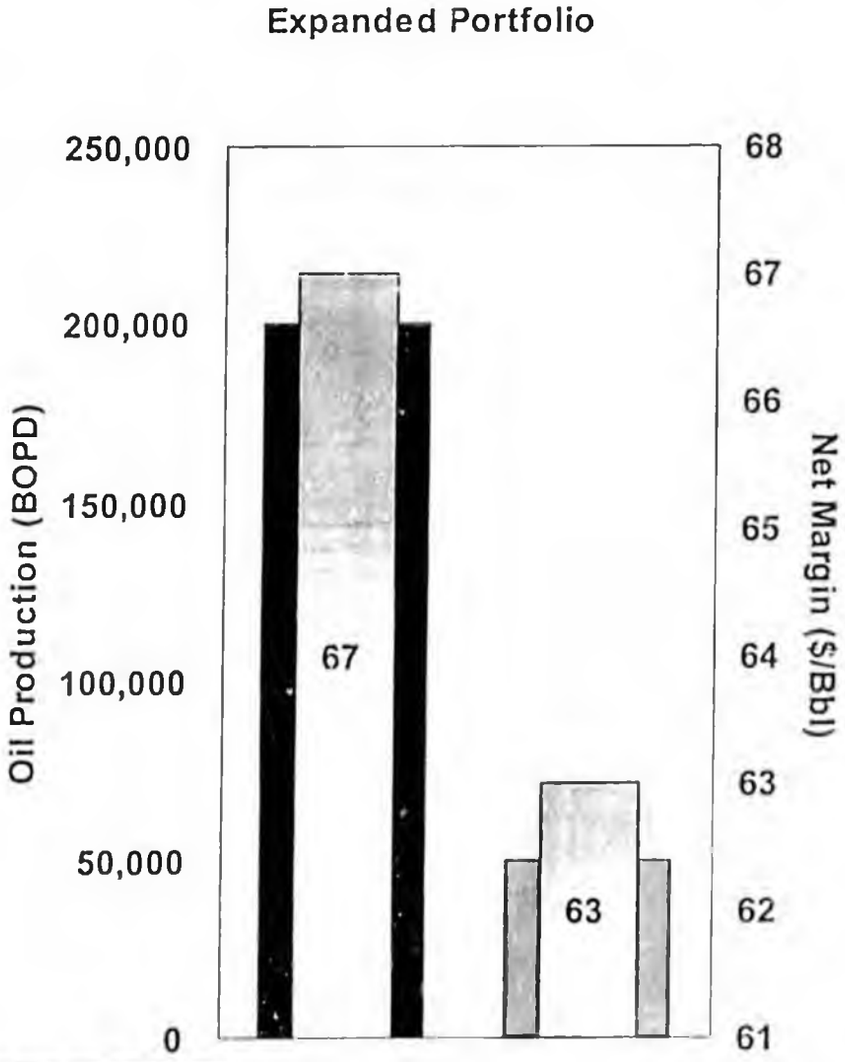
Understanding How "Net" Works

Start With A Single Asset



PPT Rate on this would be 29.25%

Now, Add Another Field



Average Net Margin on the expanded portfolio Is $66.20

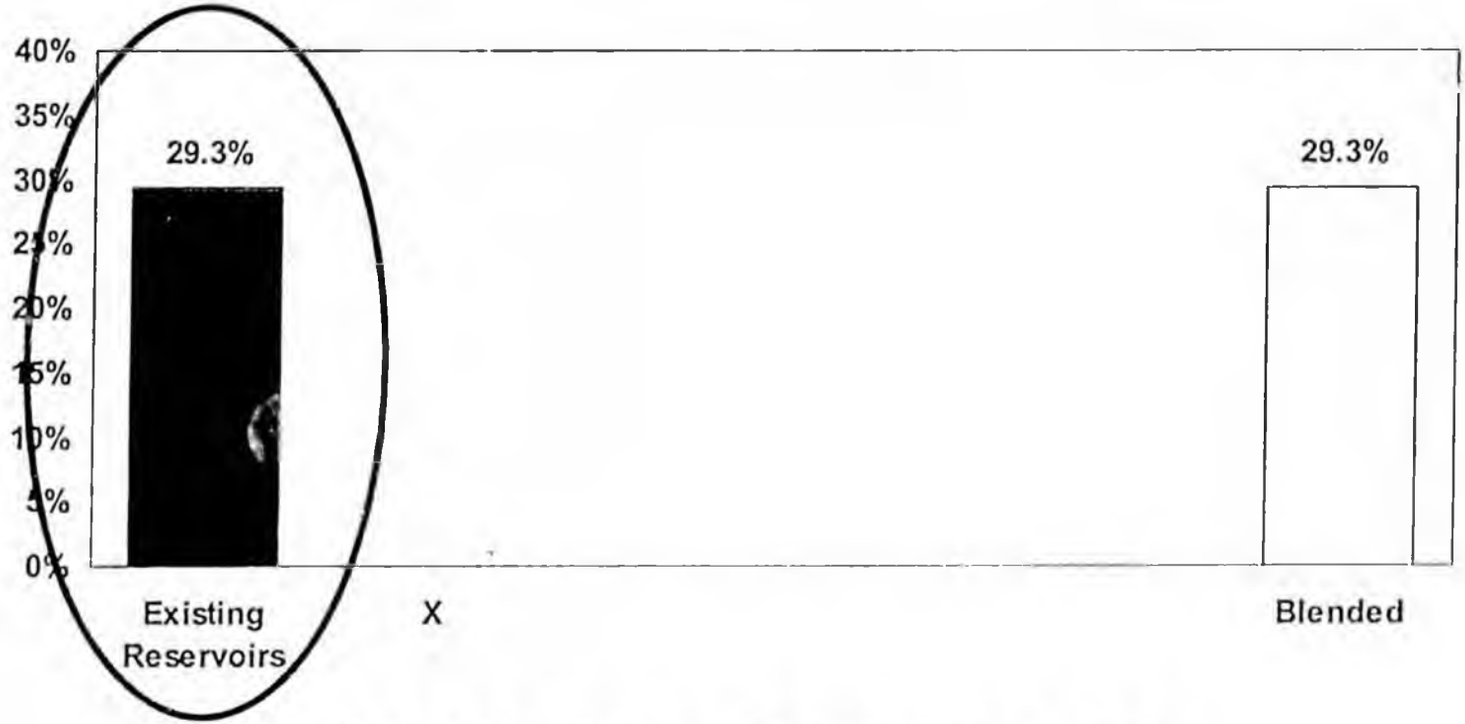
PPT Rate on these fields Combined would be 29.1%

So, does this mean that I am paying 29.1% on each field ?

No ....

So, Does That Mean I Am Paying 29.1% On Each Field ?

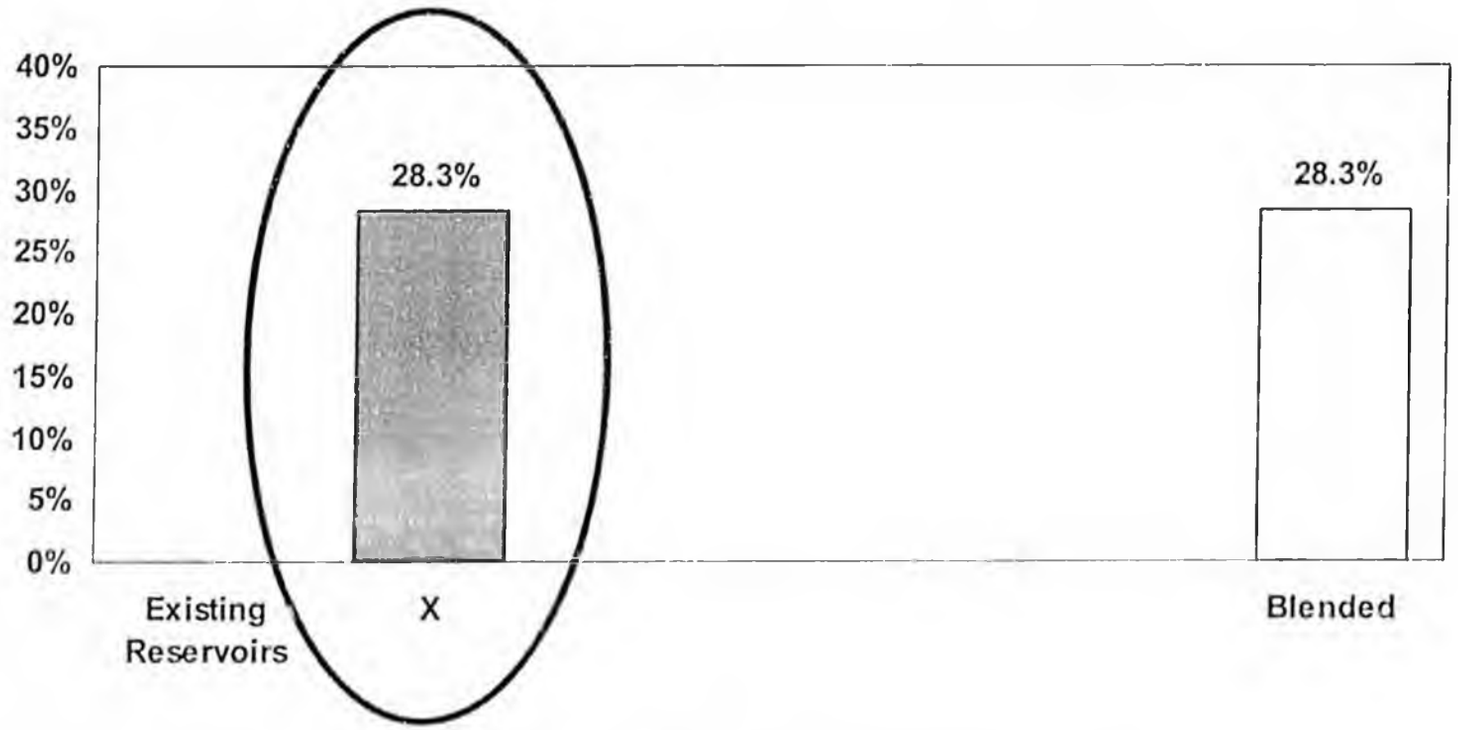
Tax Rate By Field Within A Company - As Affected By Portfolio Blending



If I had just Existing Reservoirs, and did not develop anything new, I would pay tax on my profits at 29.3%

So, Does That Mean I Am Paying 29.1% On Each Field ?

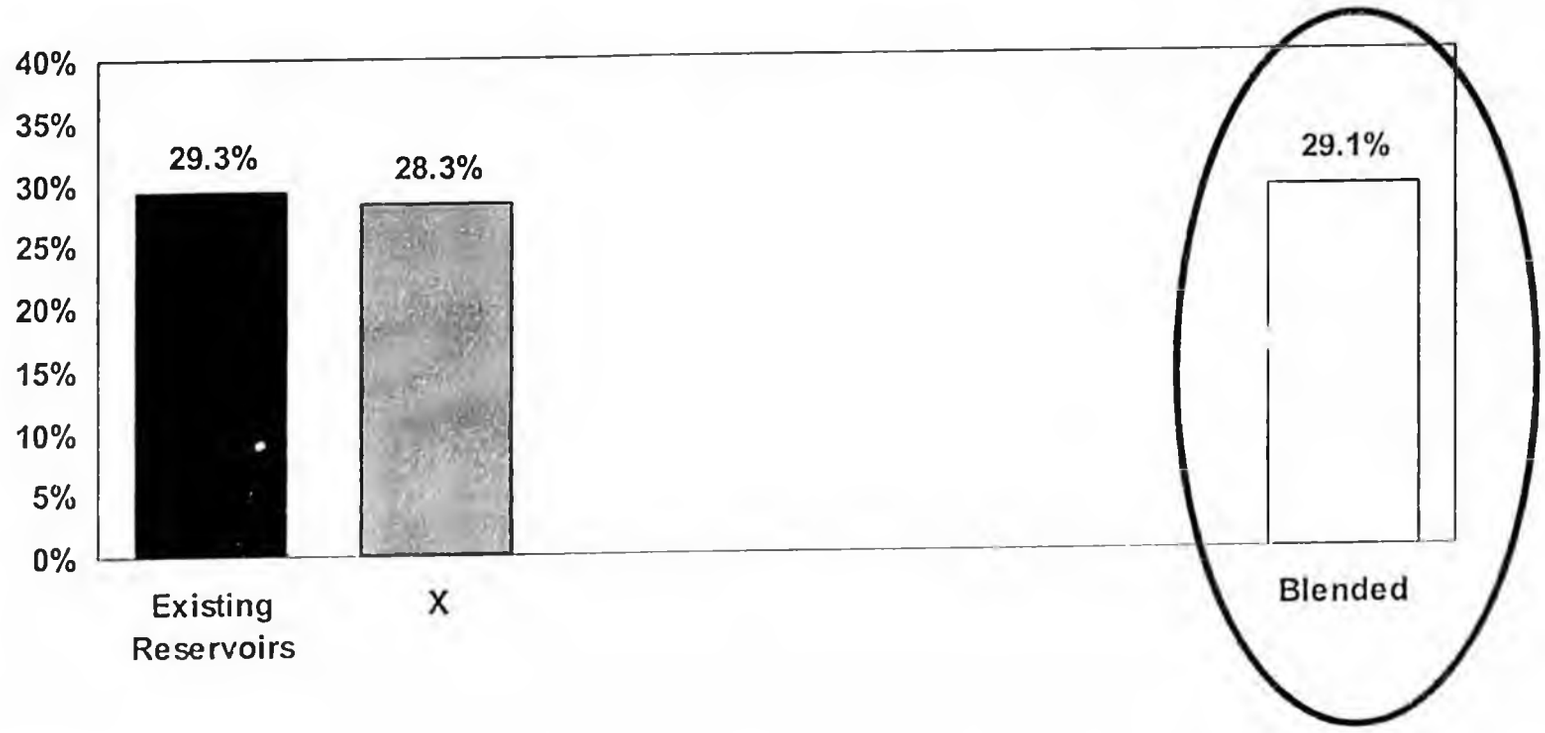
Tax Rate By Field Within A Company - As Affected By Portfolio Blending



If I had just Field X, I would pay tax on my profits at 28.3% - its margin is slightly lower

So, Does That Mean I Am Paying 29.1% On Each Field ?

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



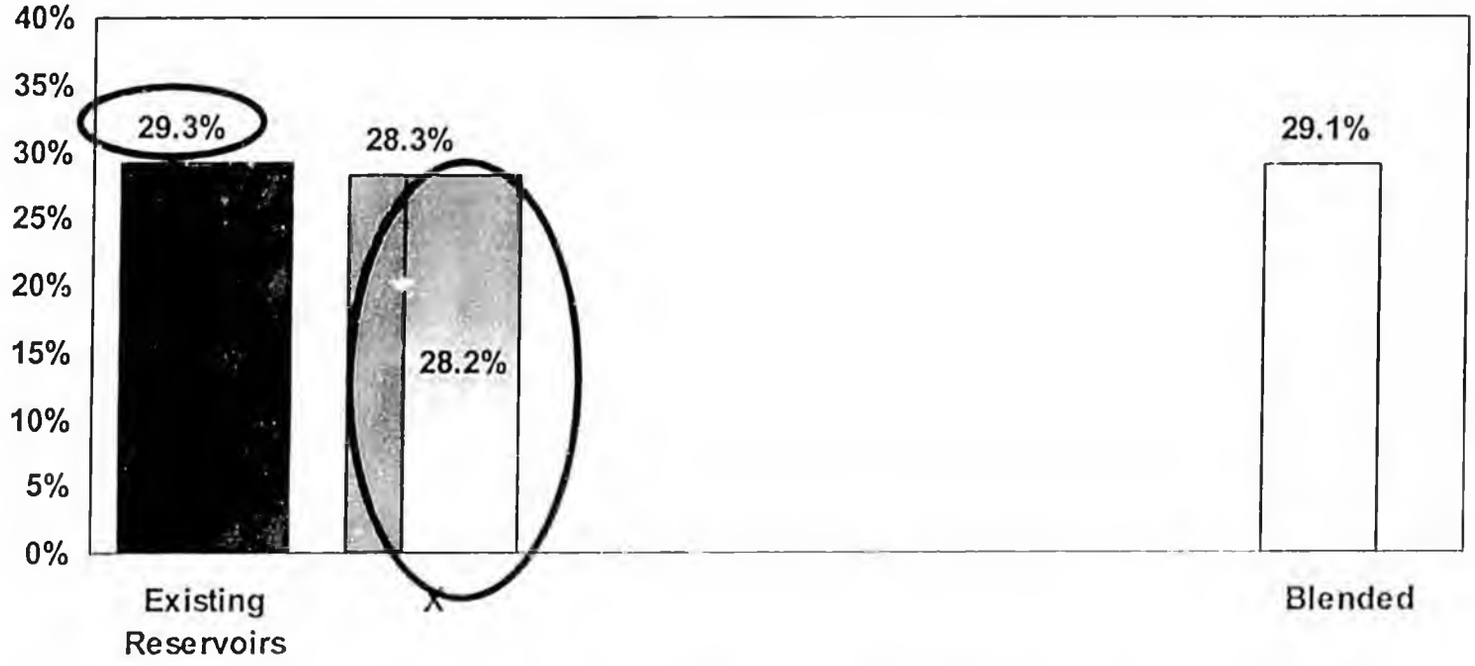
Both fields together, the rate is 29.1%

However, this does not tell the whole story .. .

The lower profitability field benefits from the progressivity structure

So, Does That Mean I Am Paying 29.1% On Each Field ?

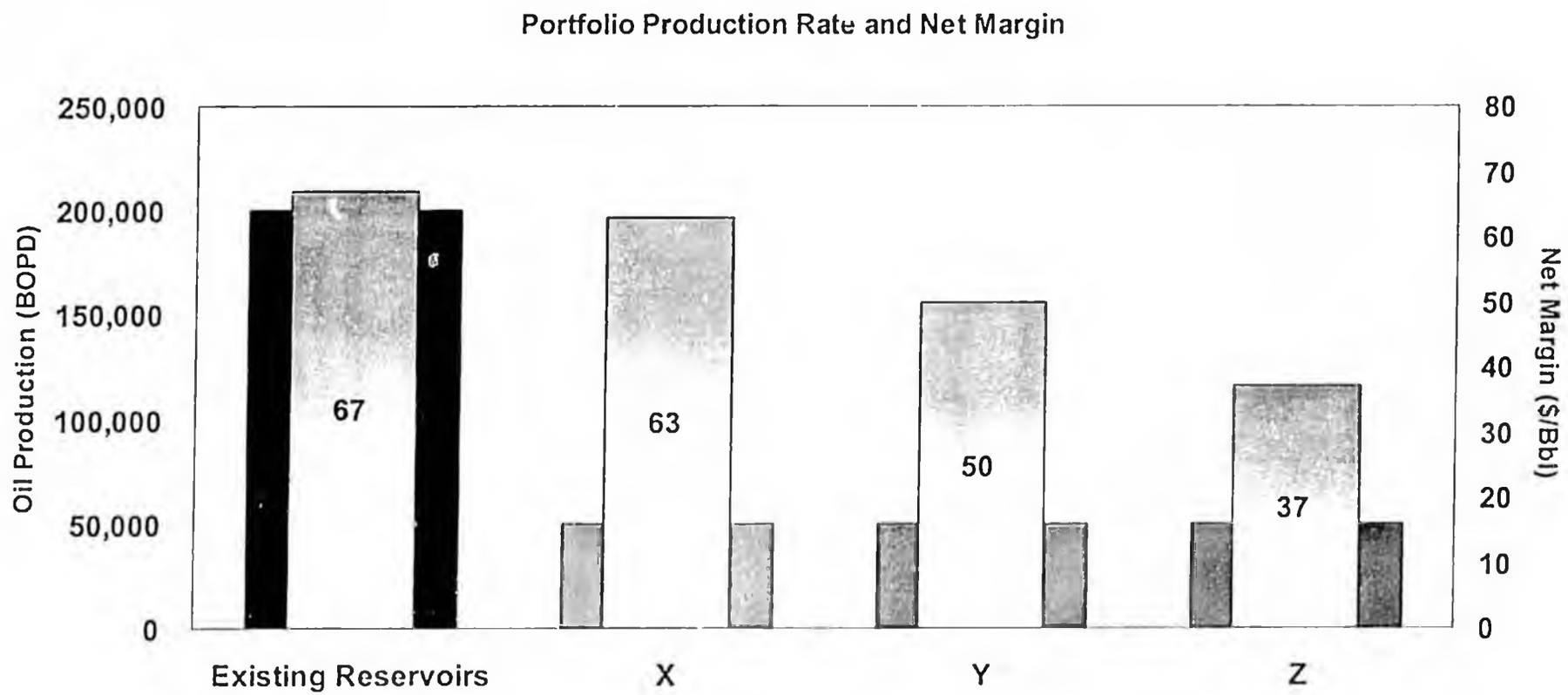
Tax Rate By Field Within A Company - As Affected By Portfolio Blending



The mathematics of this reduction means that actually while Existing Reservoirs continue to pay tax at a rate of 29.3%, The effective rate on Field X is actually 28.2% .... less than it would be if it were developed stand-alone

This Impact Can Be Seen Further In A Broader Portfolio

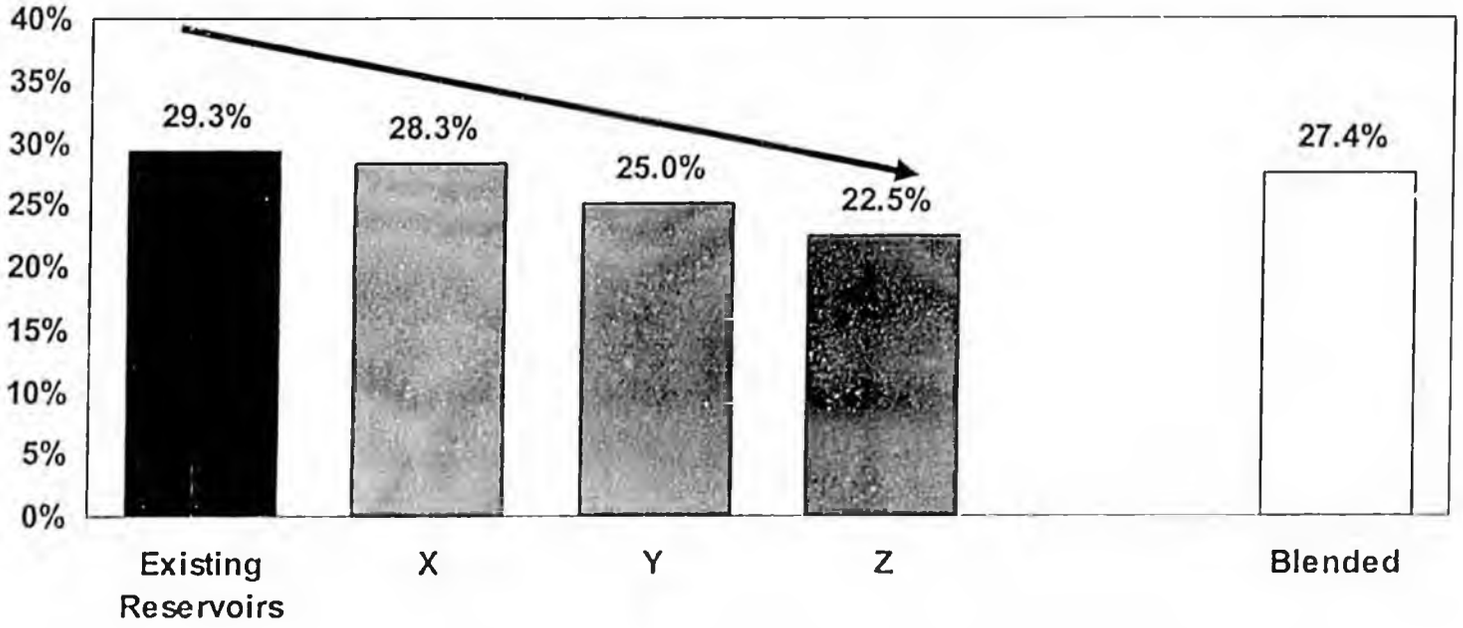
Consider A Portfolio Of 4 Fields



.. One producing 200,000 bopd and three others, each producing 50,000 bopd, and each of decreasing profitability

Tax rates if stand alone development

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



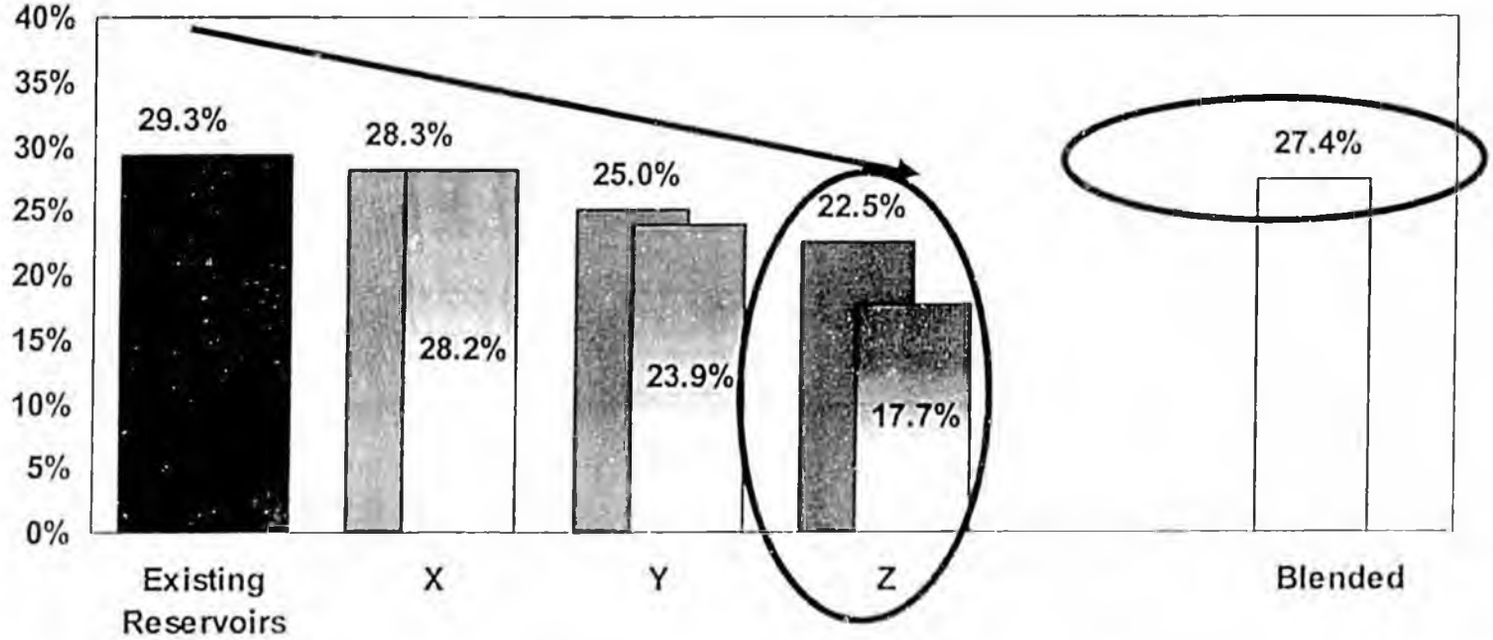
The progressivity can be seen through the lower tax rate on lower margin fields

The Least Profitable Field ..

... can actually have an effective rate
below the basic rate

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

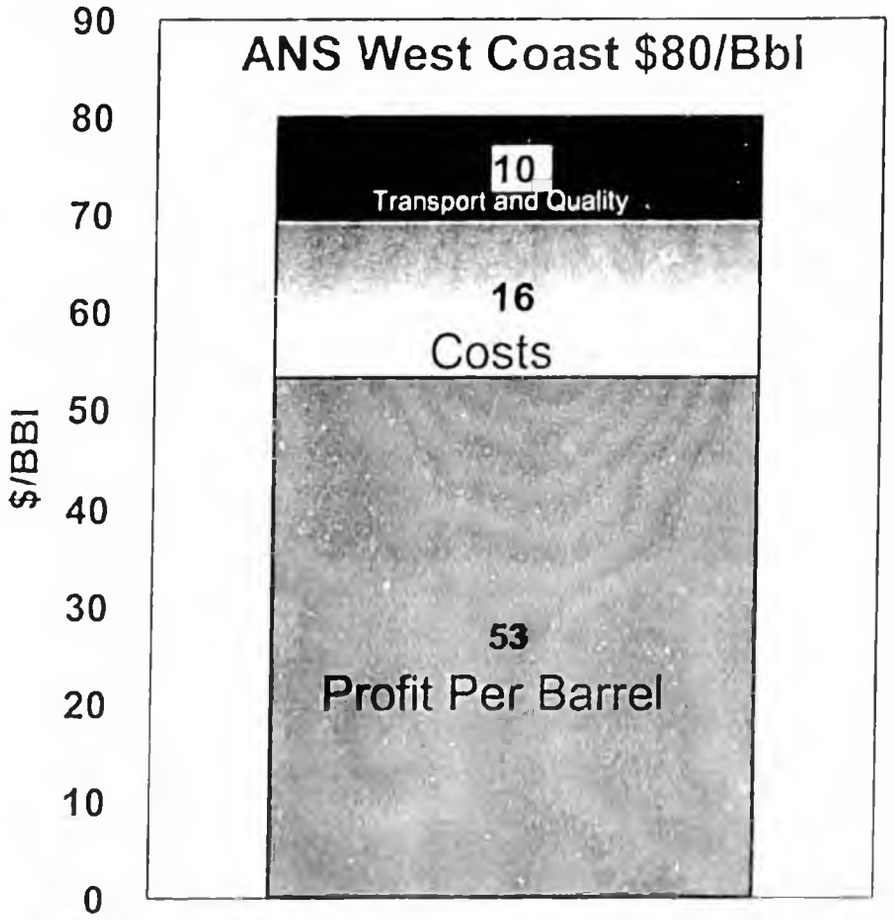
The Impact Of Capital Investment

How The Net Tax System Operates

- **"Net" taxes all fields at a single rate**
  - If only looking at the "headline" net tax rate, this would be the perception
  - In reality, when looking at the marginal impact of different parts of the portfolio, it taxes different fields or reservoirs at different rates
    - Based upon their individual profitability
- **Further, it doesn't tax operating profits, but retained cash flow after reinvestment**

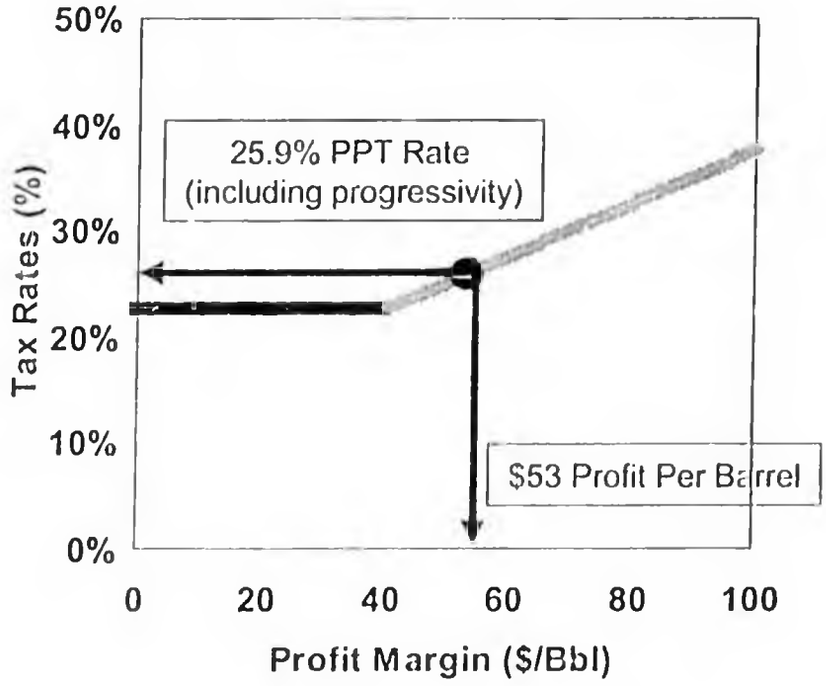
Remember These Slides ?

Portfolio Profitability



The portfolio in the previous slides had a blended rate of 27.4%, not 25.9% ....

Tax Rate Structure
(Incorporating Progressivity)

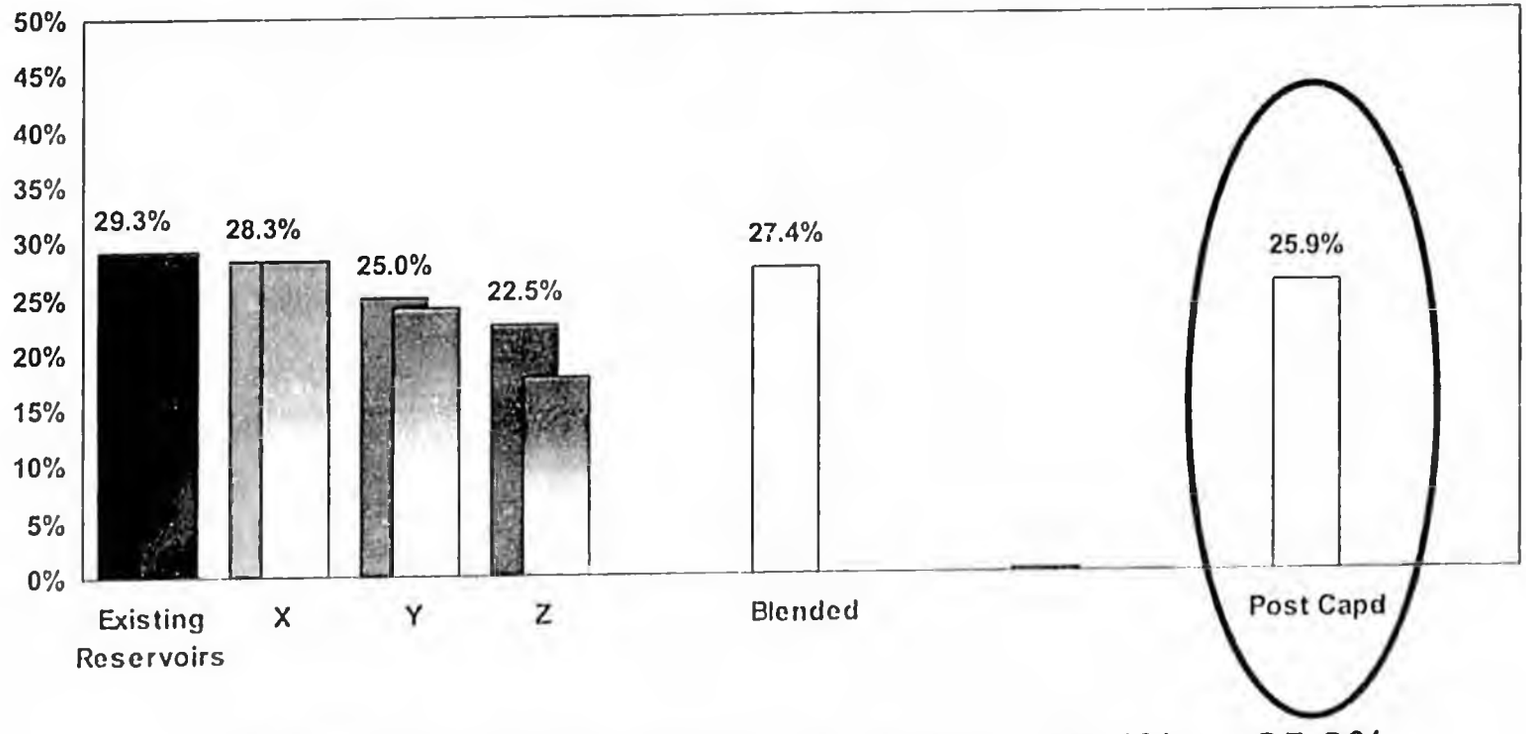


Assume that 27.4% is the rate that will be payable before further capital investment decisions are made ...

... 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

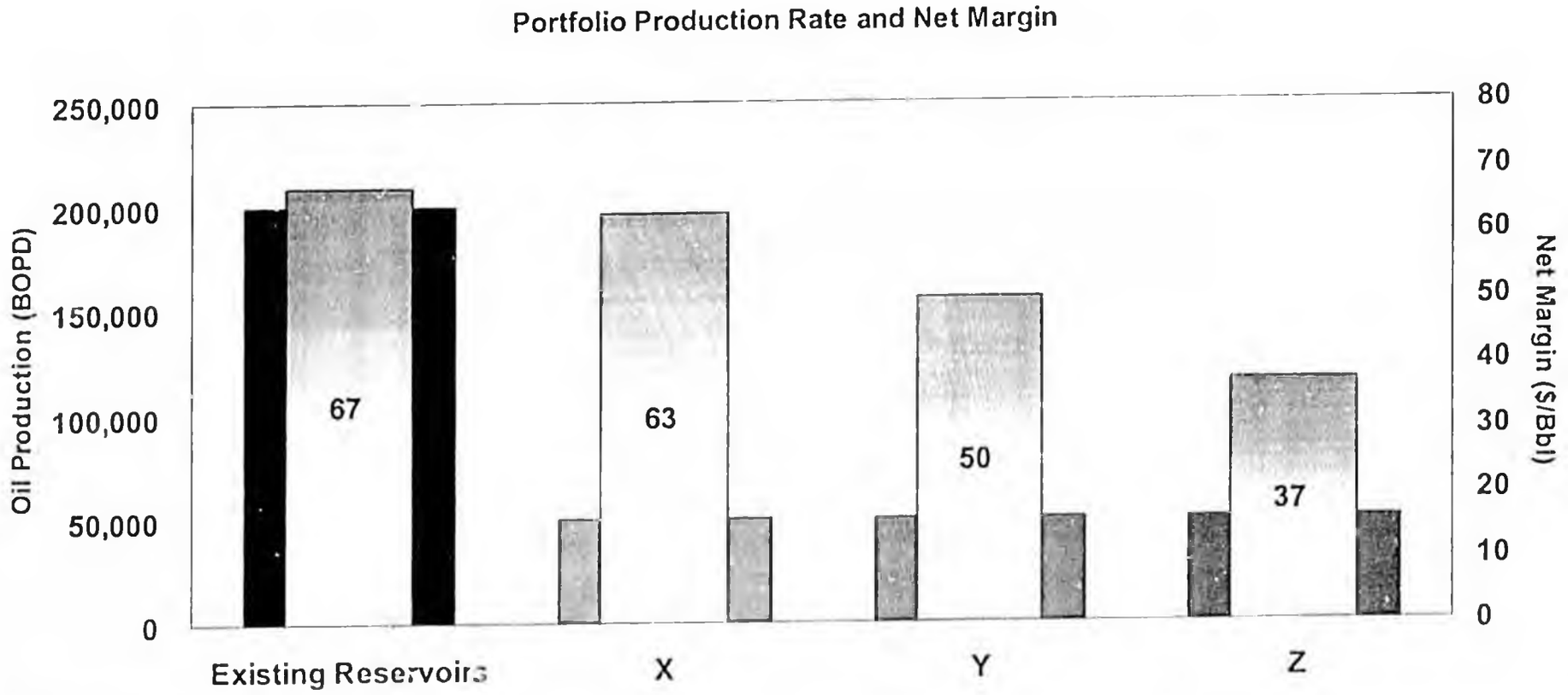


This reduces the rate payable from 27.4% to 25.9%

How ?

The Portfolio Produces 350,000 Bopd

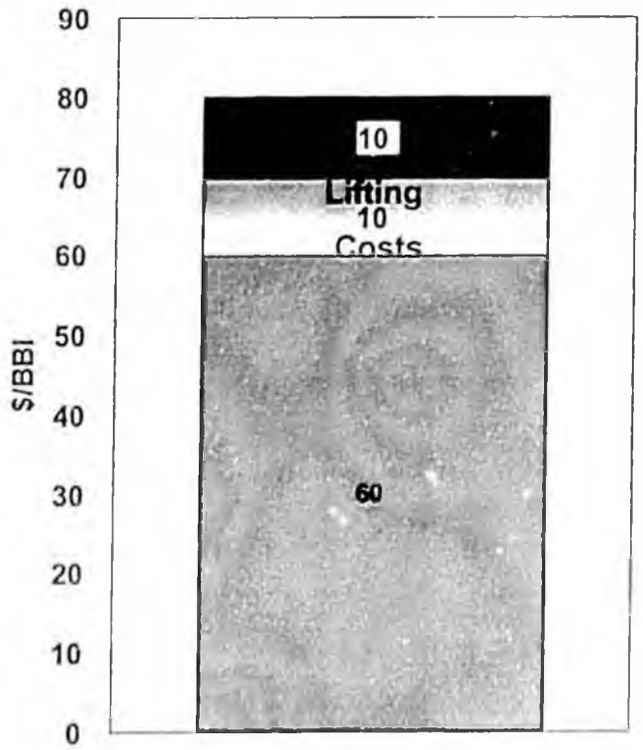
this is 127.75 Million Barrels Per Year



$800 million of capex is $6.26 per barrel of production at 350,000 Bopd (127.75 million barrels per year)

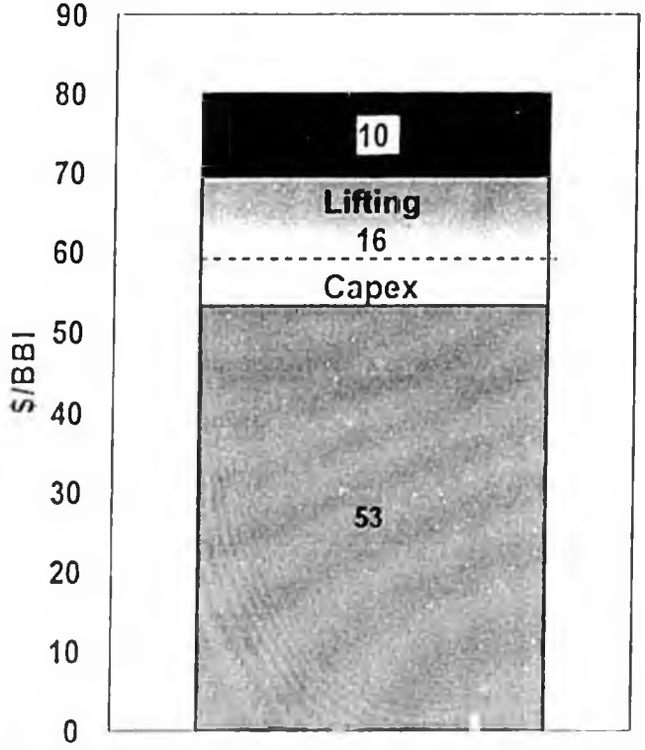
The $6.26 Per Barrel Capital Increases "Costs" And Lowers The Tax Rate

Pre-Capex Margin



Tax Rate
27.4%

Portfolio Profitability



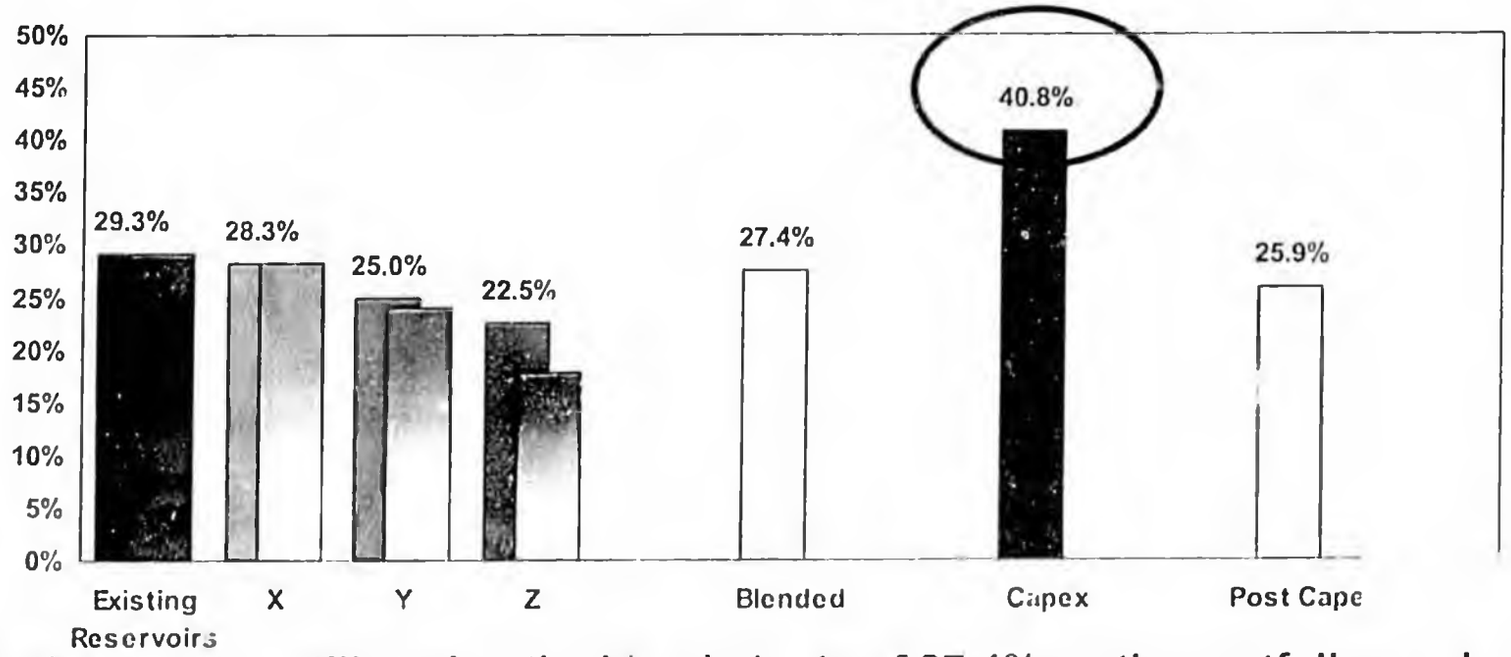
Tax Rate
25.9%

This Can Be looked At Differently Though ...

... as a tax rebate on the capex

The Reduction In Tax Rate Lowers The Net Investment Cost To Companies

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

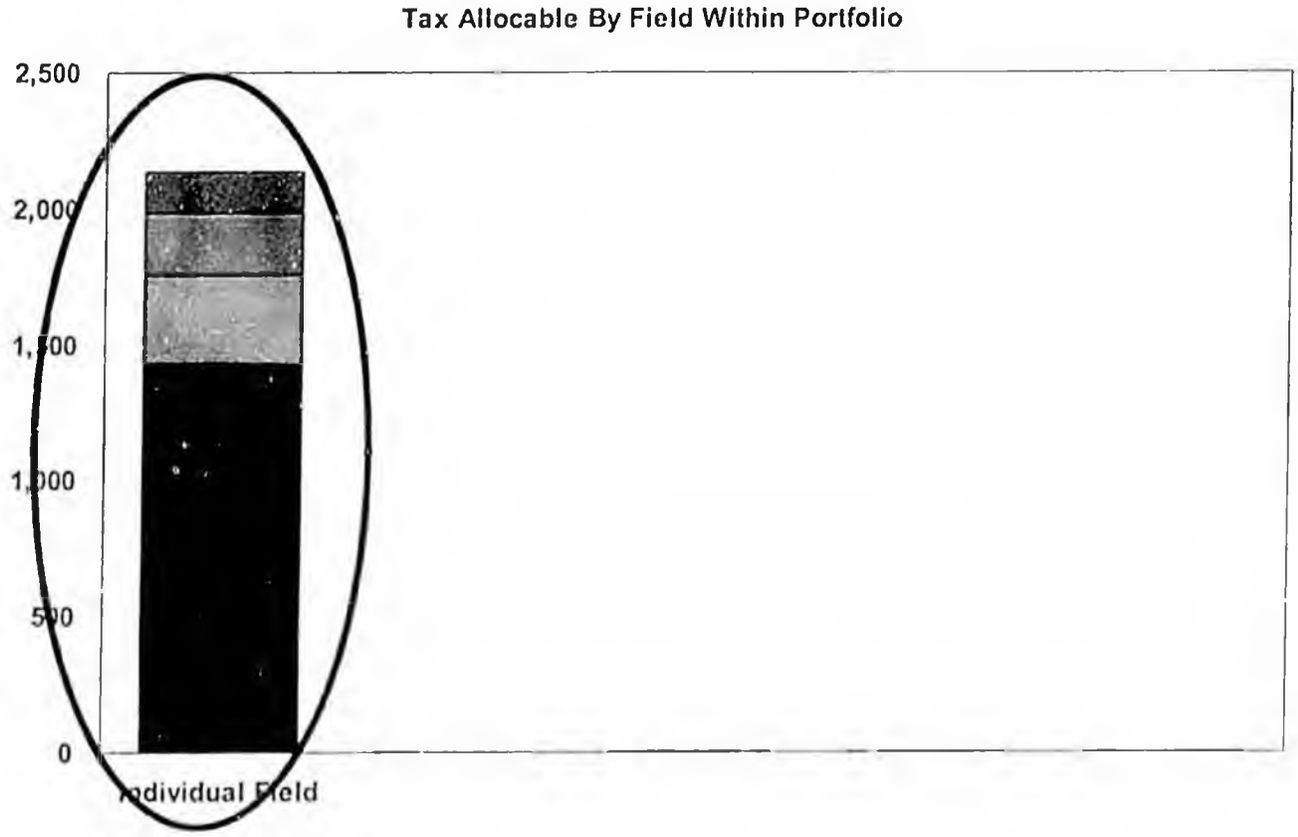


It is the same as still paying the blended rate of 27.4% on the portfolio production (or having an effective rate of 29.3% on Existing Reservoirs .. down to 17.7% on Field Z) and Alaska paying* 40.8% of that $800 million capital

This 40.8% 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

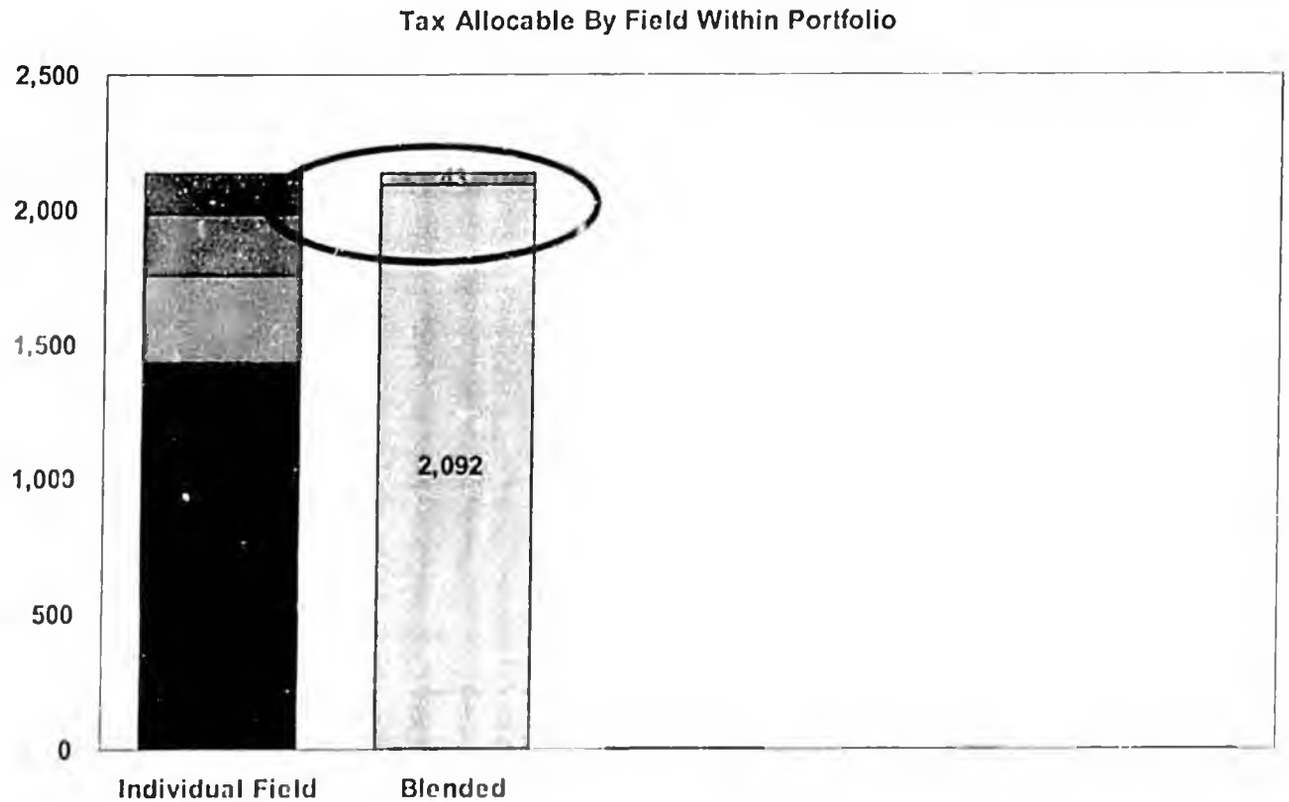
Look At The Tax System Through The Amount Of Tax Payable ...



As individual fields, and at these assumed oil prices and costs, this portfolio would pay $2,135 million in PPT

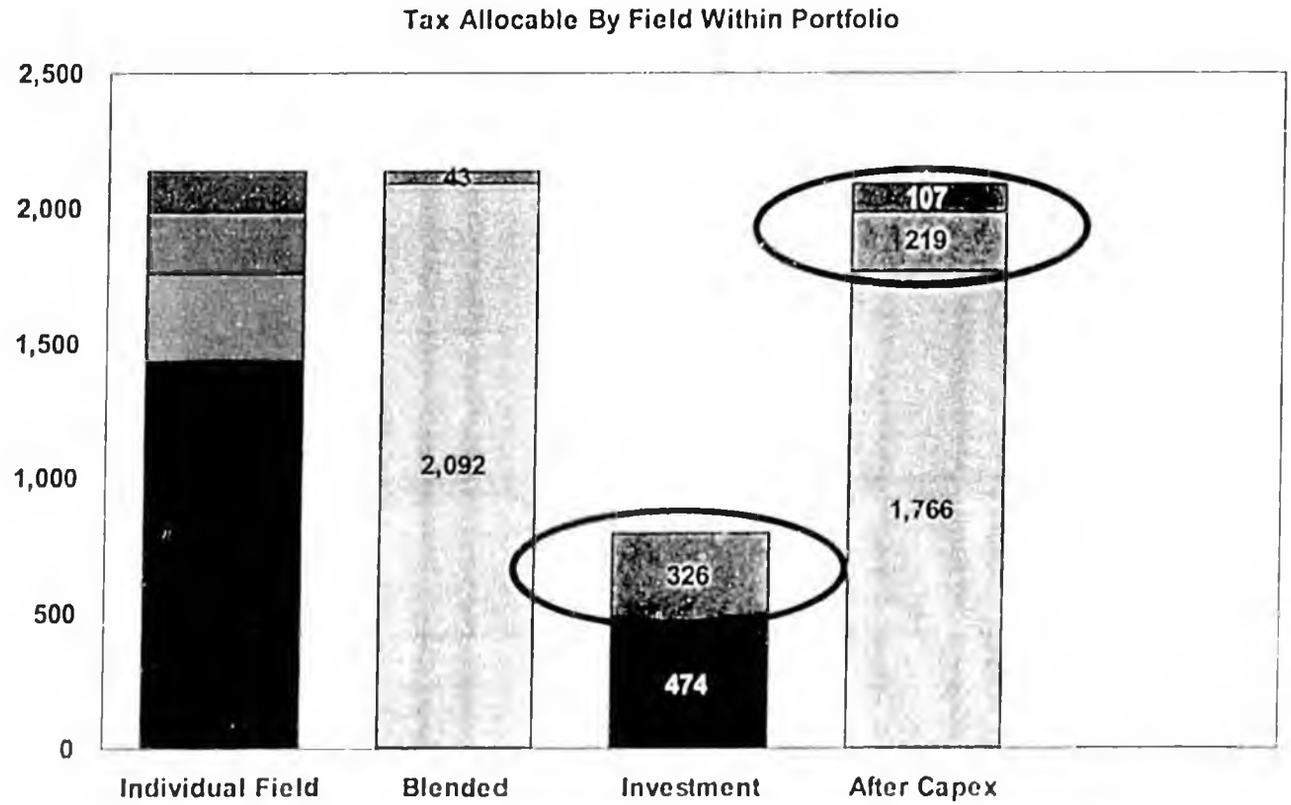
* from PPT only – does not include State and Federal tax effects

Portfolio Effects Lower Total Tax



Putting all fields in one portfolio (company) lowers this to $2,092 million
... a saving of $ 43 million

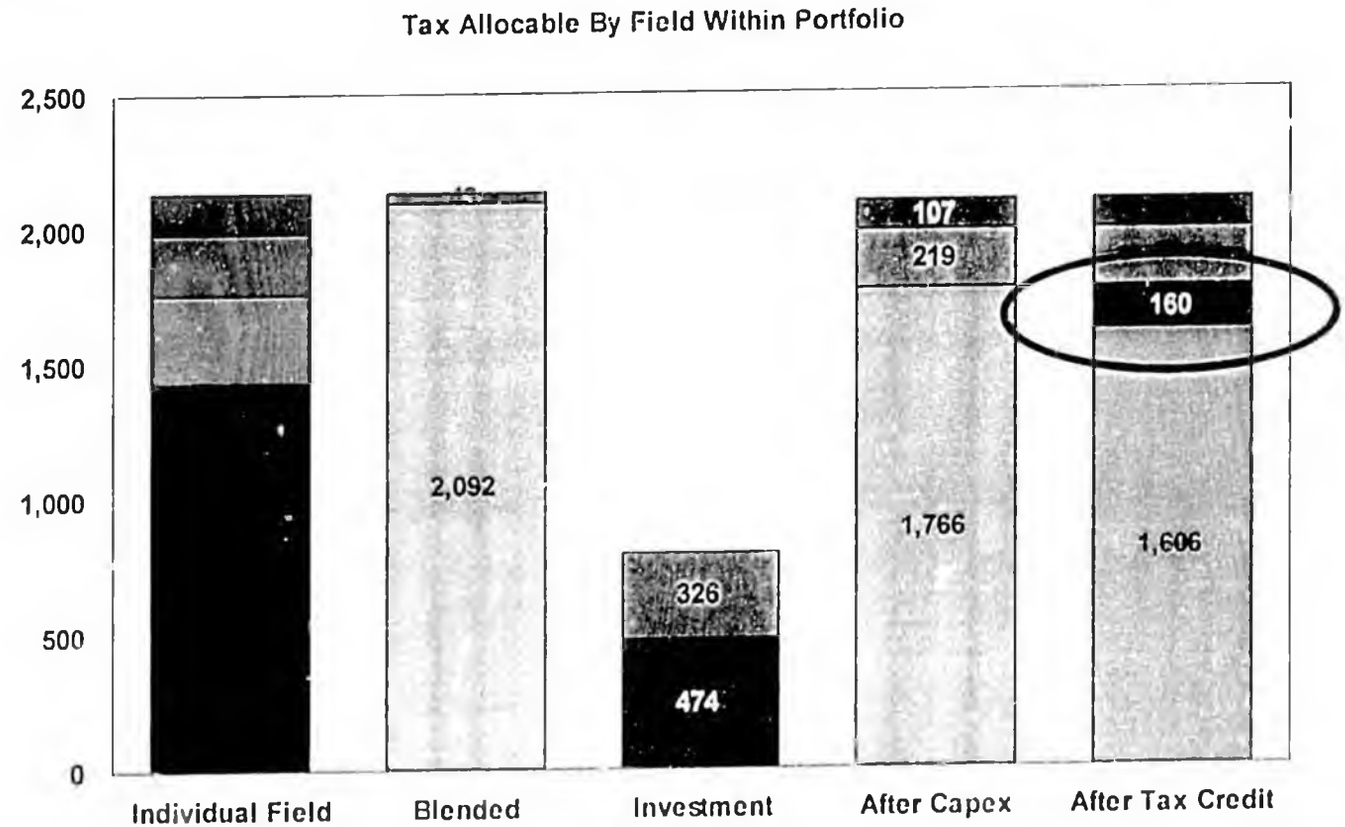
The Big Winner Though Is Capex



In this example the State pays $326 million (40.8%) of the capital
(the percentage will vary based on overall portfolio net margin per barrel)
The $326 million can be allocated as $219 million from reducing taxable income at 27.4% and $107 million from lowering the rate from 27.4% to 25.9%

But Wait ! That Is Not All ....

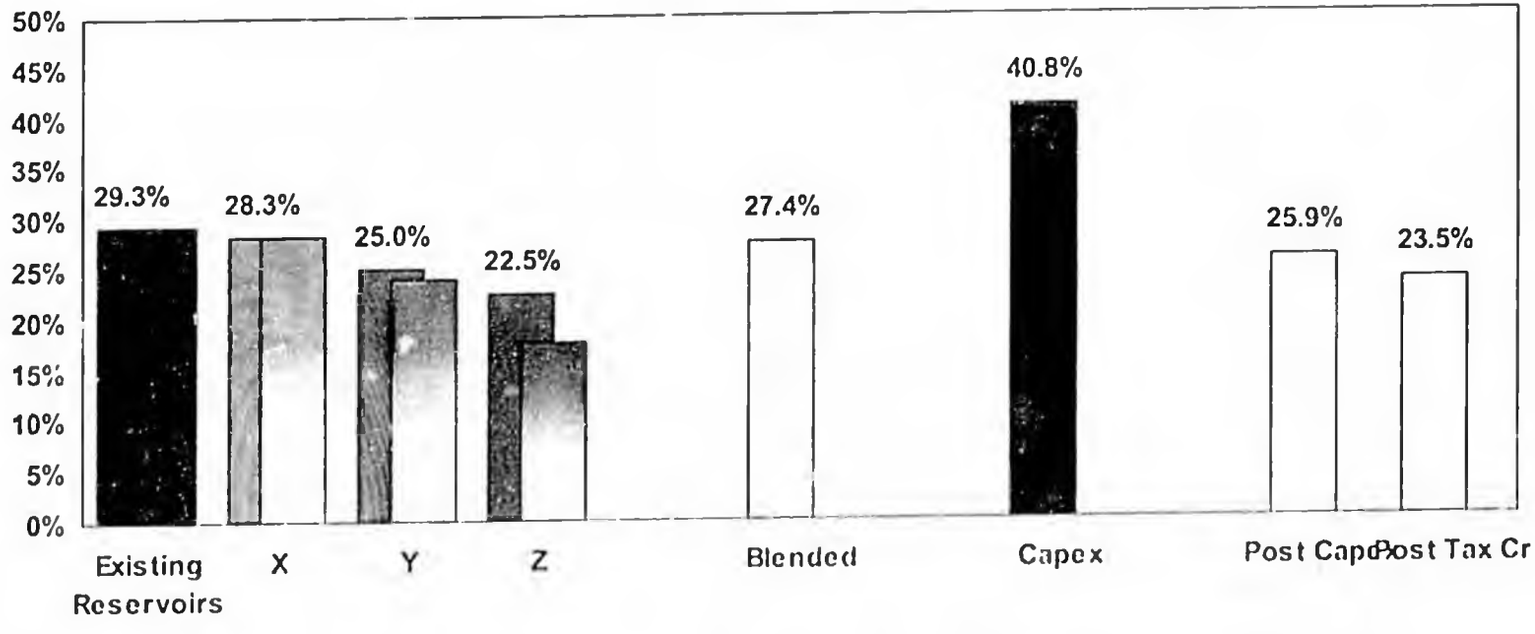
Investment Credits Also Apply ..



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



... has the effect of lowering the tax rate further, to 23.5%*

(note: the tax rate is not actually lowered, but this is the mathematical effect)

* In this example

Tax Structure As Applied Under Various Structures

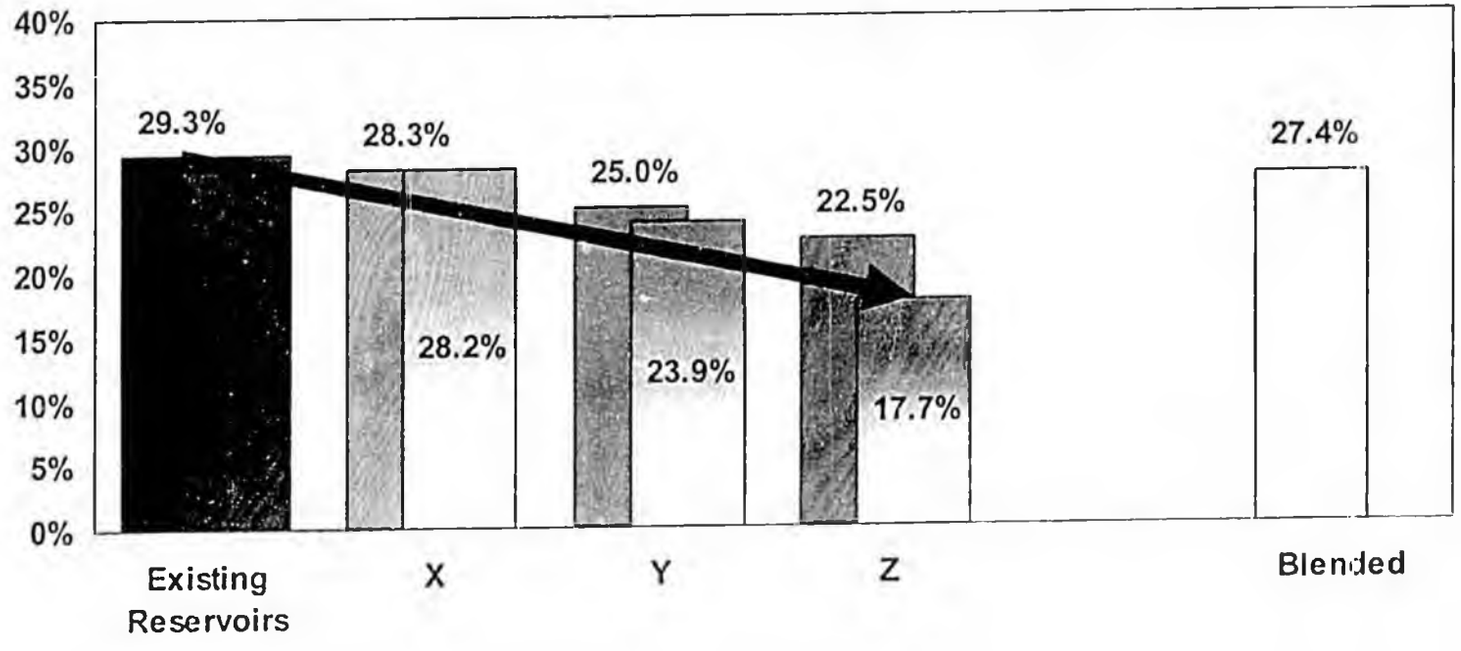
PPT
ACES
Senate Judiciary

Progressivity

- PPT
  - Basic rate of 22.5%
  - Tax rate increases 0.25% for every dollar that net cash flow per barrel exceeds $40
- ACES
  - Basic rate of 25%
  - Tax rate increases 0.2% for every dollar that net cash flow per barrel exceeds $30
- Senate Judiciary
  - Basic rate of 25%
  - Tax rate increases 0.4% for every dollar that net cash flow per barrel exceeds $30

PPT Progressivity

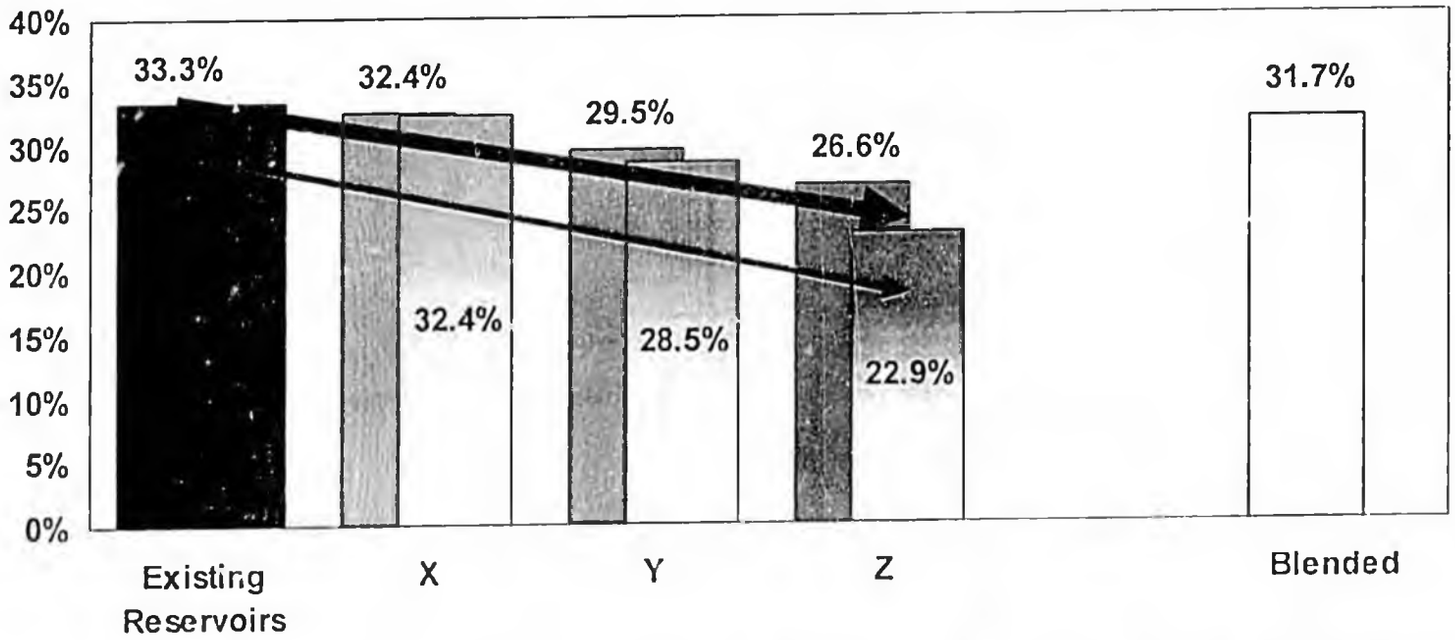
Tax Rate By Field Within A Company - As Affected By Portfolio Blending



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

ACES Progressivity

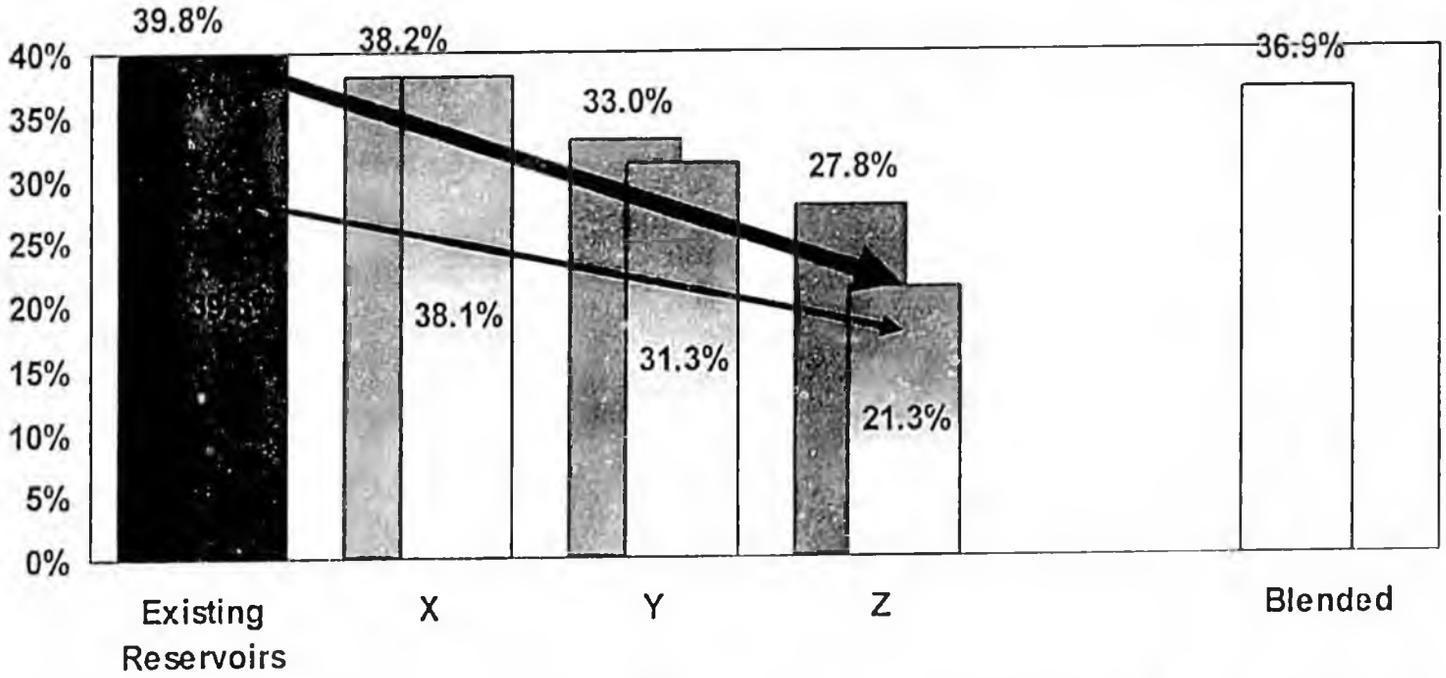
Tax Rate By Field Within A Company - As Affected By Portfolio Blending



The progressivity feature is maintained, although ACES has a higher base rate (25% compared to PPT 22.5%) and a shallower progressivity (0.2% compared to 0.25%), starting $10 earlier ($30 rather than $40 net cash flow per barrel)

Senate Judiciary Progressivity

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



The Senate Judiciary CS starts at the same point as ACES, but has a progressivity of 0.4%, rather than 0.2%

As a result, while this results in an overall larger take, the less profitable field in this example actually benefits from a lower rate

Slide left intentionally blank

Conclusions

- A net tax on the "profit margin" is actually a tax on a company's retained cash flow and not just a tax on simple profitability

- The progressive feature in PPT, in ACES, and in the Senate Judiciary CS allows fields of different profitability within the same company to have different effective tax rates

- More aggressive net progressivity provides a greater differentiation on the effective rate

Actual Prudhoe Results

Where is the tipping point?

- **Quite legitimately several legislators have asked how far (increasing taxes) is just right and how far is too far?**
  - The companies, for obvious reasons, have passed on the opportunity to describe in numerical terms what impact a change in Alaska taxes will have
    - Decision making process has many factors
    - Worldwide better rock trumps fiscal systems
    - Appears the majority of capital spending of the major Alaskan oil companies is in regimes with higher government take
  - All consultants acknowledged 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

- **Industry testimony to previous committees paints a fairly clear picture of one very important aspect of North Slope operations**
  - 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

- **Based on the testimony and presentations from industry GCA believes:**
  - There is significant upside in terms of barrels of oil to be produced by investing to reduce the natural field decline rate in the major North Slope fields
  - The economics of reinvestment in existing 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

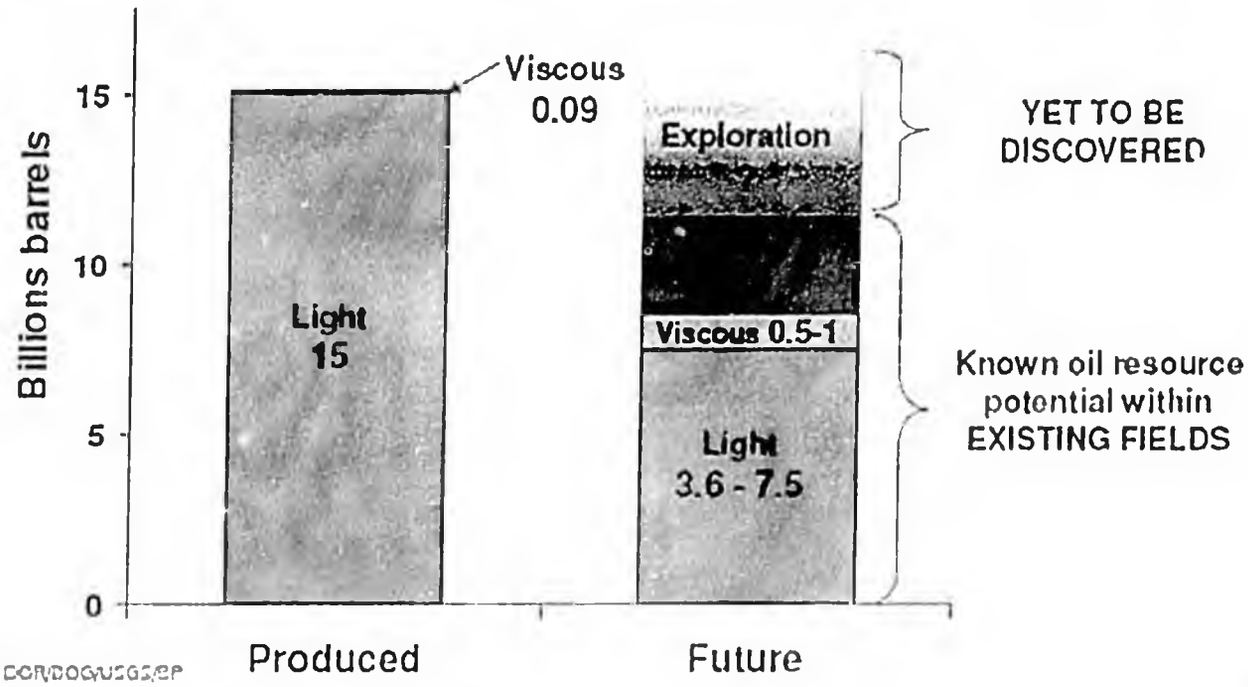
This gets us to investment in currently producing fields. Fortunately, there are investments that can be made, and are being made, in these fields to slow their decline. In the short term, this is in-fill drilling — that is, drilling new wells into the portions of a reservoir that are between the wells 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, with the 100% backing of their member organization touted the importance of infill drilling along with its success
- Additional production of 70,000 bopd was achieved with the 2006 infill drilling program.

Potential infill upside

The future of North Slope oil still tied to existing fields

Sustained investment in light oil development is critical to developing heavy oil and new fields

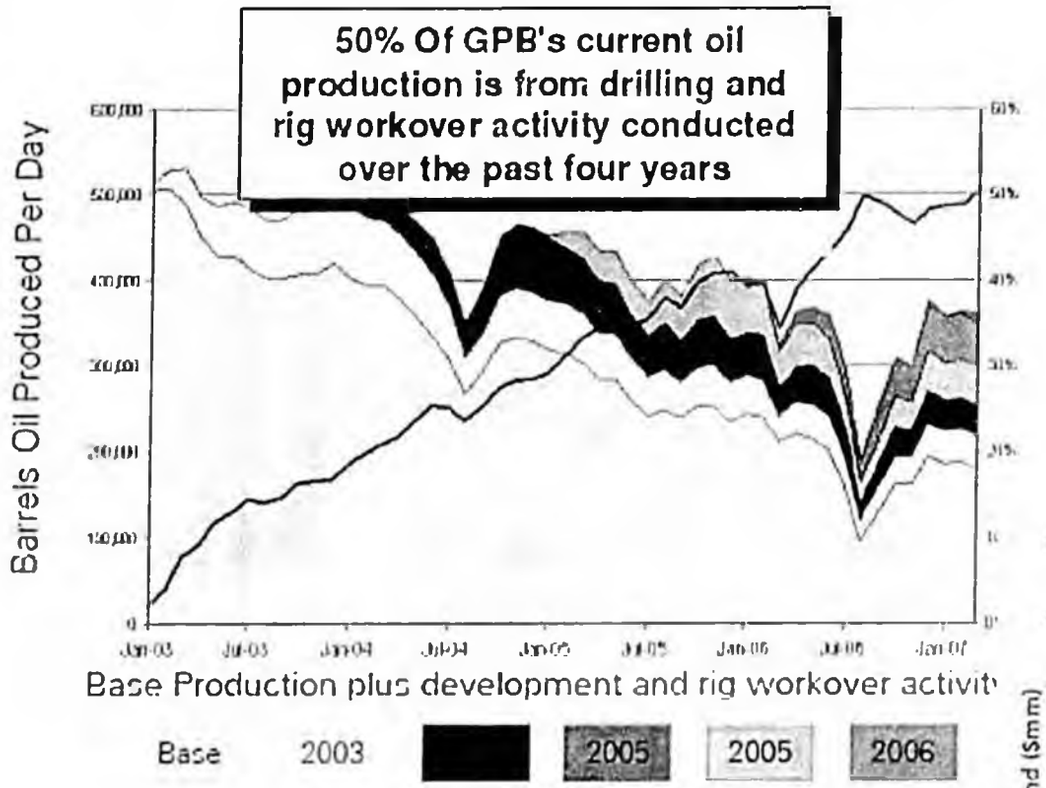


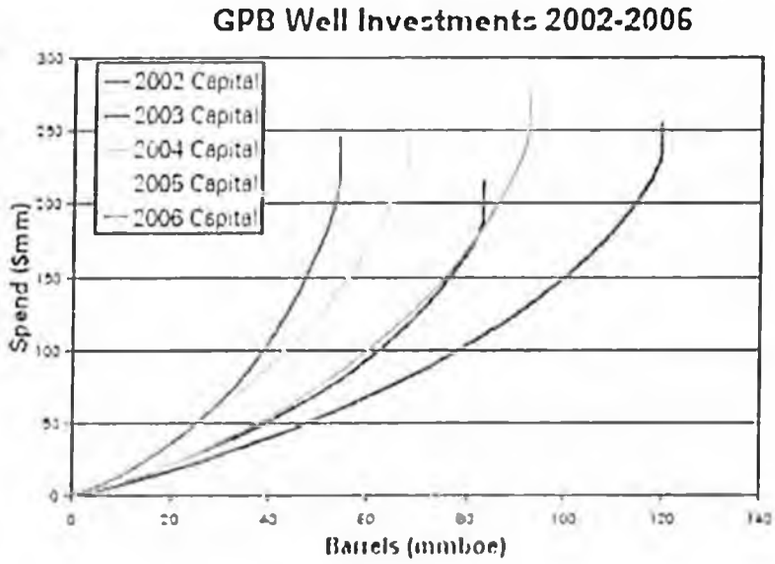
Source: DOR/DOG/USGS/BP

BP noted that light oil represented as much as 7.5 Bn bbls out of a total of 11.5 Bn bbls

Light oil ~ 70% of the identified potential

Prudhoe Bay infill drilling results





BP House testimony page 12

Costlier Development

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

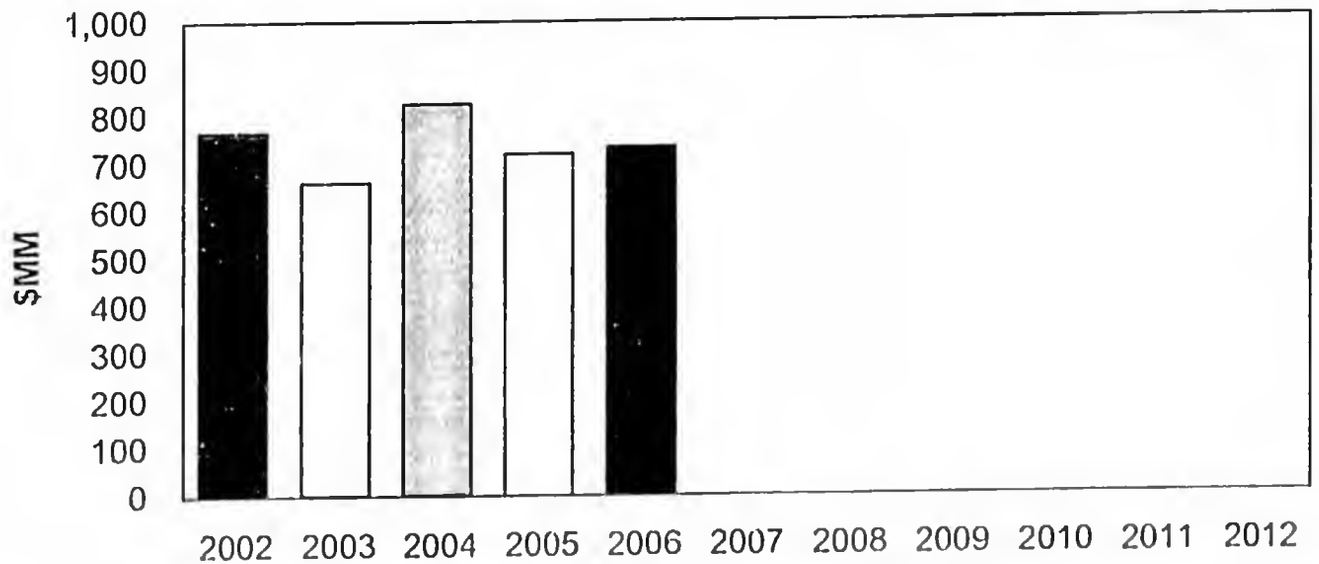
	2002	2003	2004	2005	2006
Capex	255	220	275	240	245
MMbls	120	90	80	60	50
$/bbl	2.13	2.44	3.44	4.00	4.90

- **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

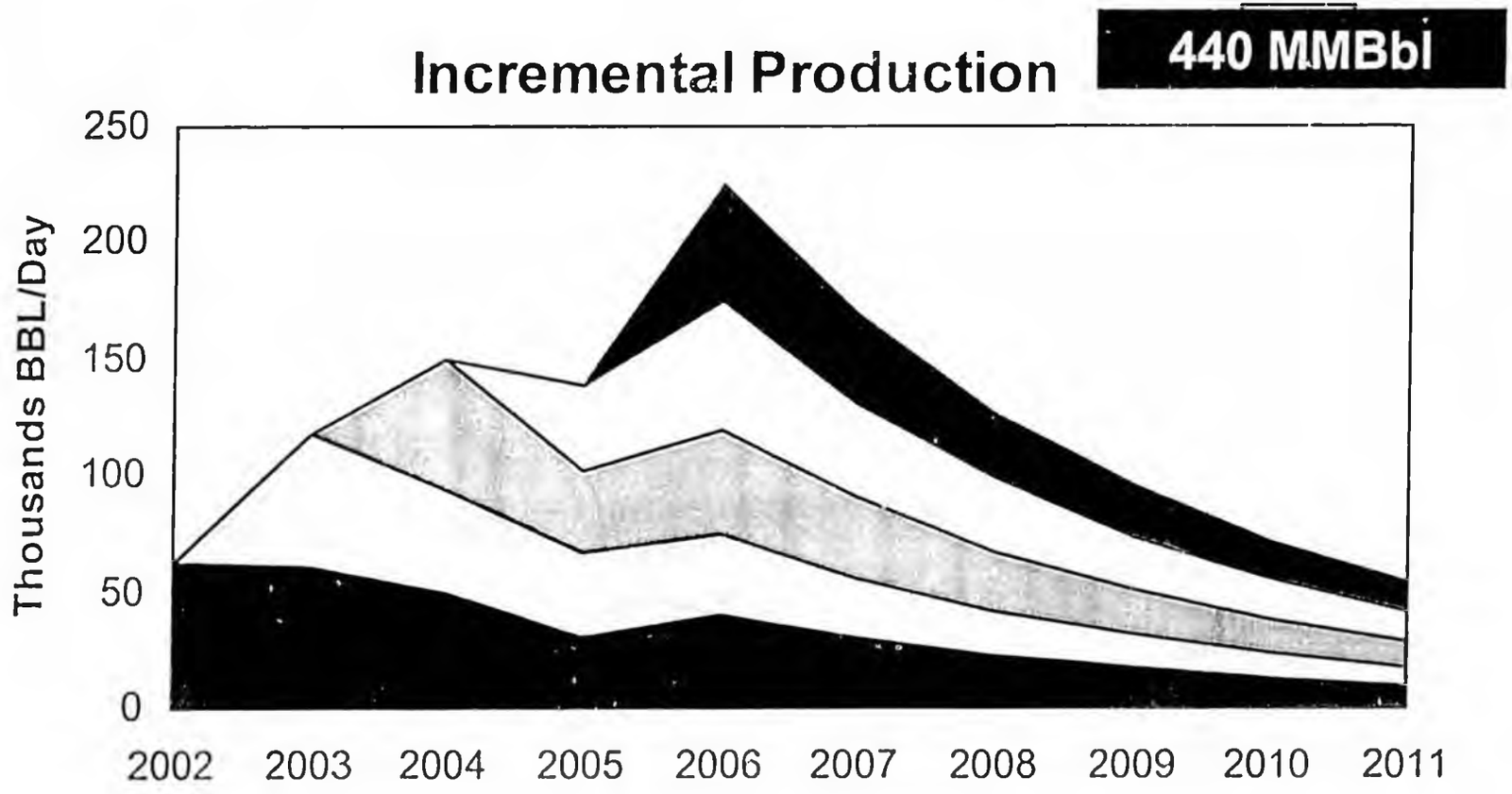
- BP noted that for every dollar spent on an infill well another two dollars were spent on injection and surface facilities – base case is 300% Capex

CAPEX for Drilling Program **Over $3.7 Bn**



BP – Prudhoe Bay

- Production from infill program as presented by BP



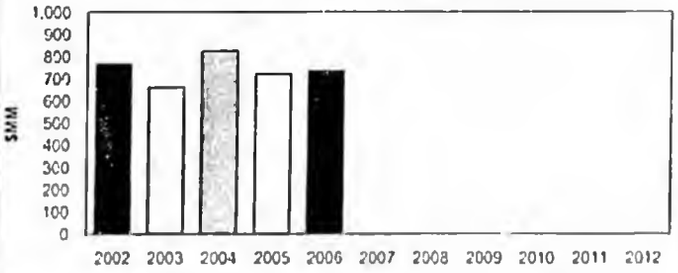
Input Controls

Modeling the Prudhoe Success contained in AOGA/BP Testimony

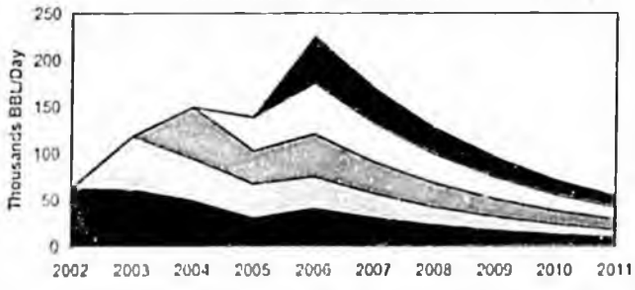
Drilling Prgram Year
2002 ☑
2003 ☑
2004 ☑
2005 ☑
2006 ☑

Capex Multiplier	300%	◀ ▶
Opex Multiplier	100%	◀ ▶
Production Multiplier	100%	◀ ▶
Discount Rate	15%	◀ ▶
Royalty	12.5%	◀ ▶
Net Tax Rate	22.5%	◀ ▶
Progressivity	0.25%	◀ ▶
Progressivity Start	40	◀ ▶
Price	80	◀ ▶

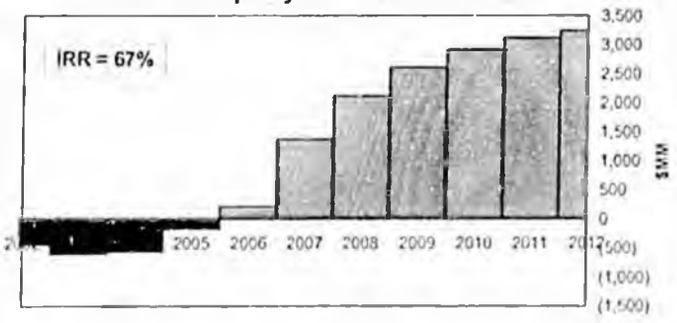
CAPEX for Drilling Program 3,705



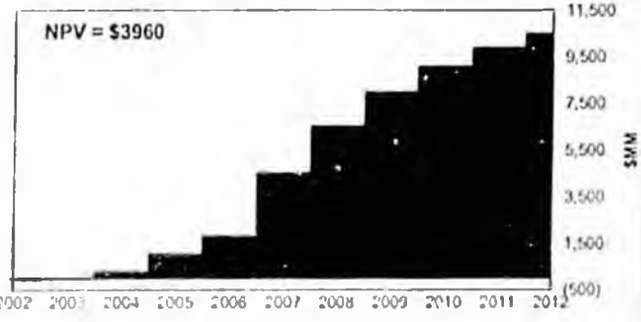
Incremental Production 440



Oil Company Net Present Value 3,243



Alaska Royalty And Taxes 10,484



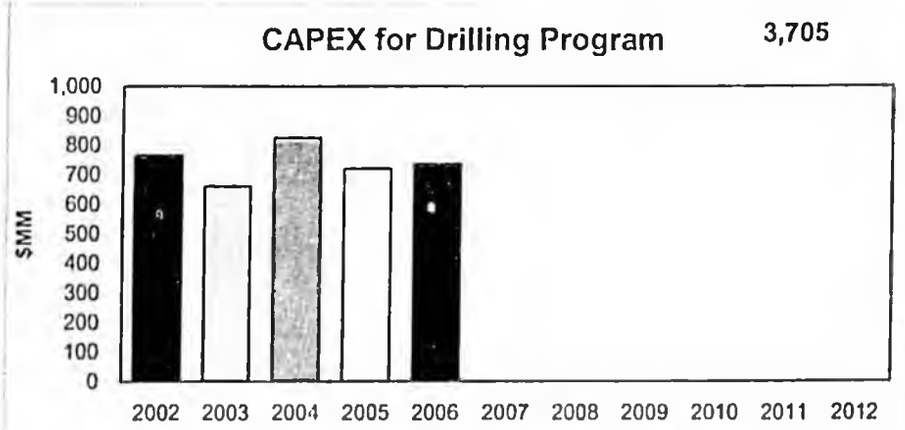
☑ Tax Credits from outset

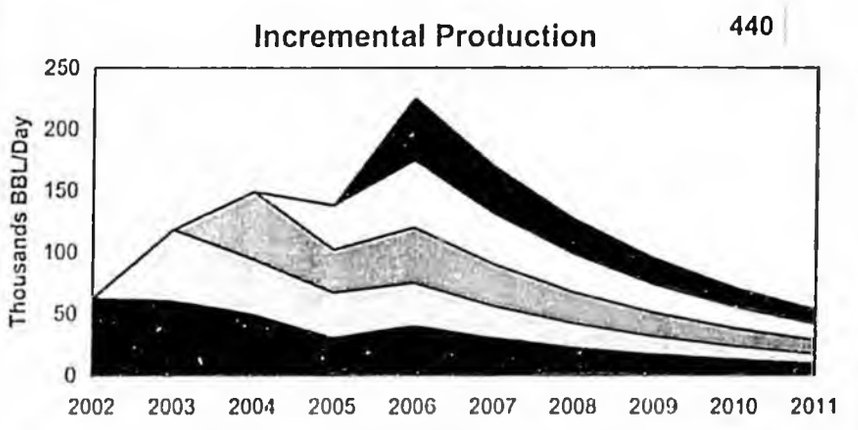
☐ Actual oil price (but based on PPT) thru 2006, then Fcst

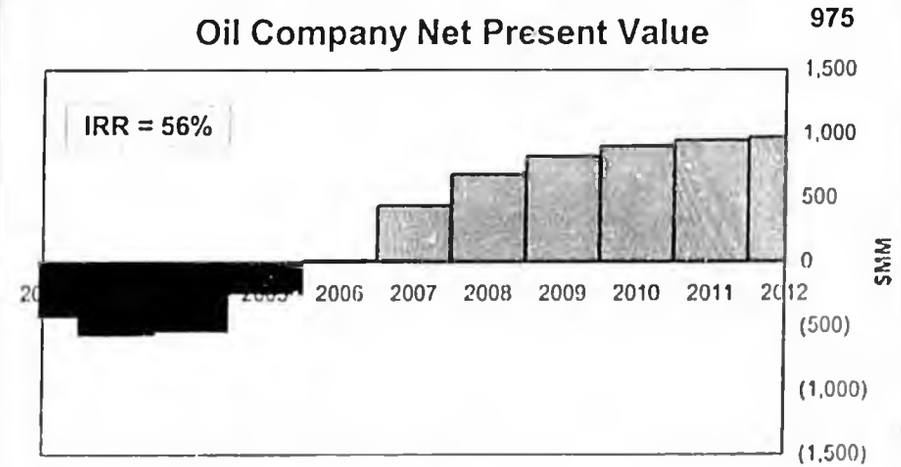
Robust drilling program

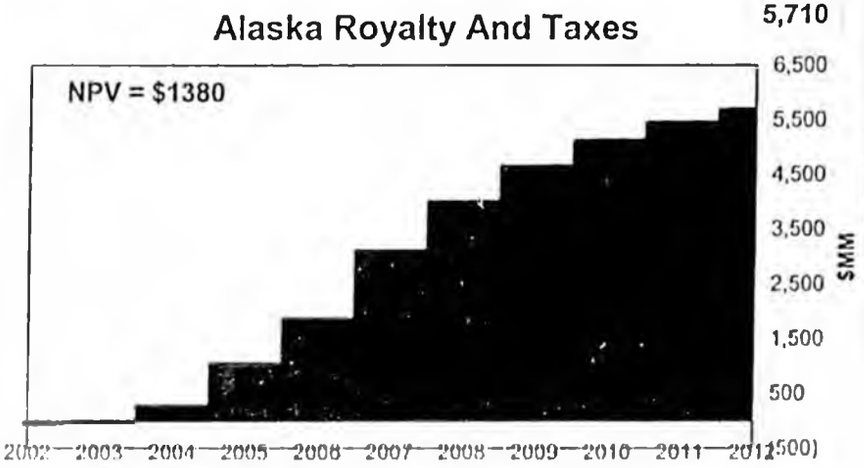
- **Remains profitable at:**
  - 300% capex
  - 200% opex
  - 25% discount rate
  - $50 ANS
  - High progressivity

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
    (Based on the oil companies' and AOGA presentation of the mechanical limit of 300,000 bpd for TAPS and the above decline rates and produced barrels)

Under PPT

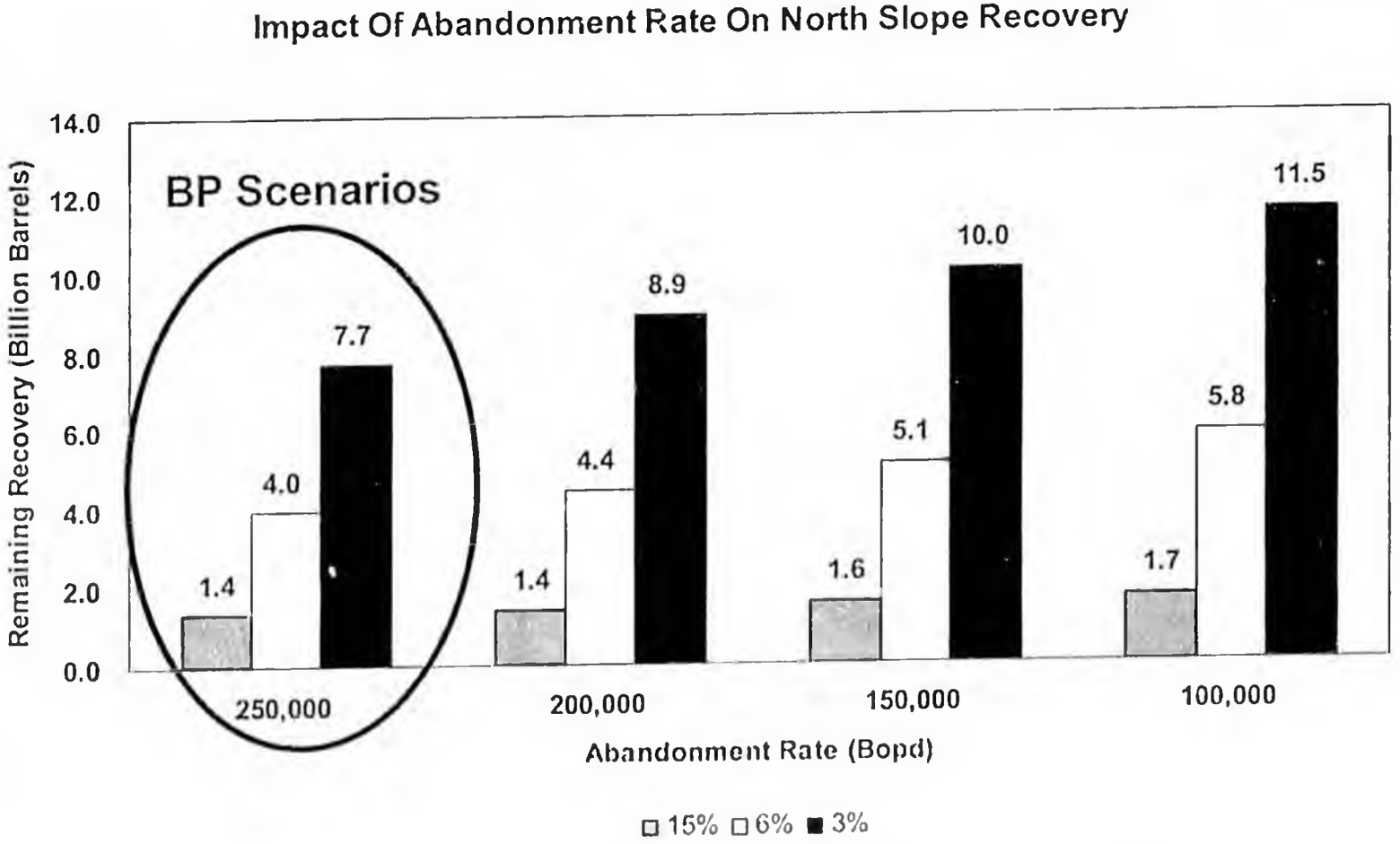
Production Drives Revenue

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

Delaying TAPS Abandonment



Summary

- **Oil Companies must show "reasonable certainty" about future investments and expected production to be able to book oil in the ground as reserves**
  - There is pressure in the market place to declare 'proved reserves' as soon as feasible -- important to shareholder and analyst growth expectations and stock price
  - 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 infill investments would require a significant write down of reserves

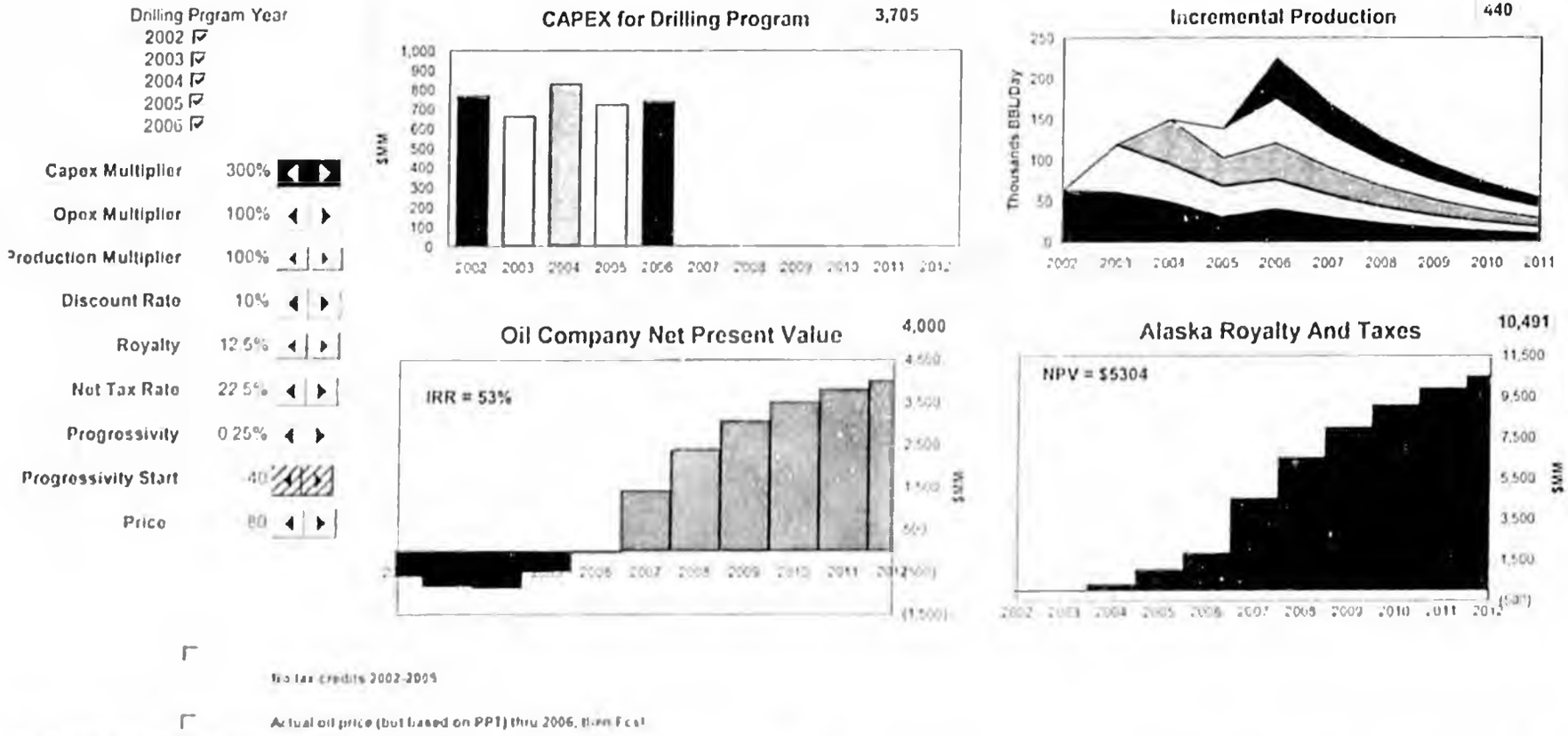
- **The Prudhoe Bay infill drilling program as presented by AOGA and BP is so profitable that under even the most extreme net tax structure, oil companies should want to continue their reinvestment program.**

Backup

Actual drilling program assuming PPT applies throughout

- Without investment credits pre 2006
- Oil Company IRR = 53%, NPV10 = $4 billion

Modeling the Prudhoe Success contained in AOGA/BP Testimony



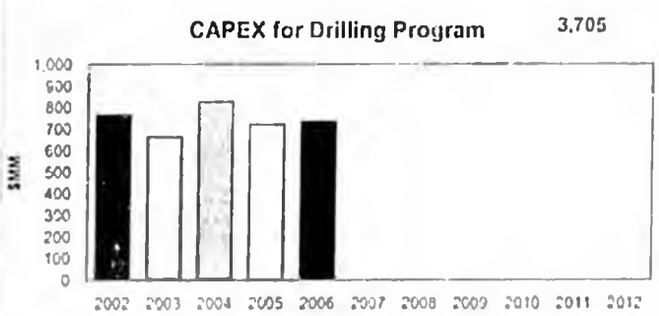
Assuming PPT from 2002 with credits

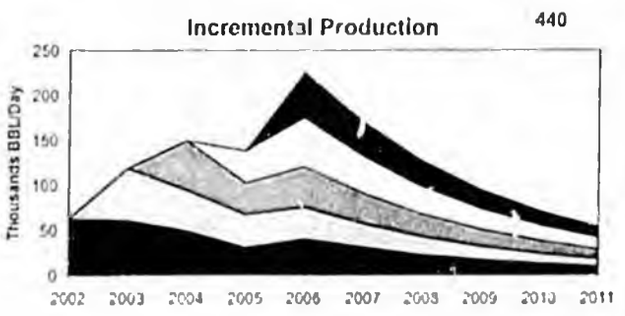
- With investment credits pre 2006
- Oil Company IRR = 67%, NPV10 = $4.4 billion

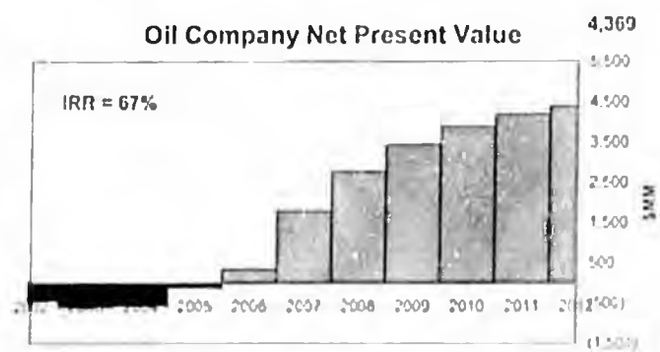
Modeling the Prudhoe Success contained in AOGA/BP Testimony

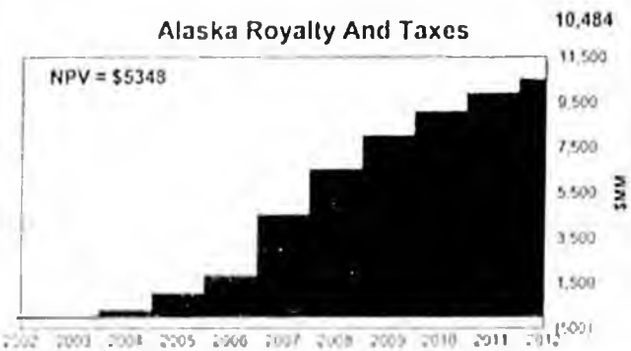
Drilling Prgram Year
2002 ☑
2003 ☑
2004 ☑
2005 ☑
2006 ☑

Capex Multiplier	300%
Opex Multiplier	100%
Production Multiplier	100%
Discount Rate	10%
Royalty	12.5%
Net Tax Rate	22.5%
Progressivity	0.25%
Progressivity Start	40
Price	80









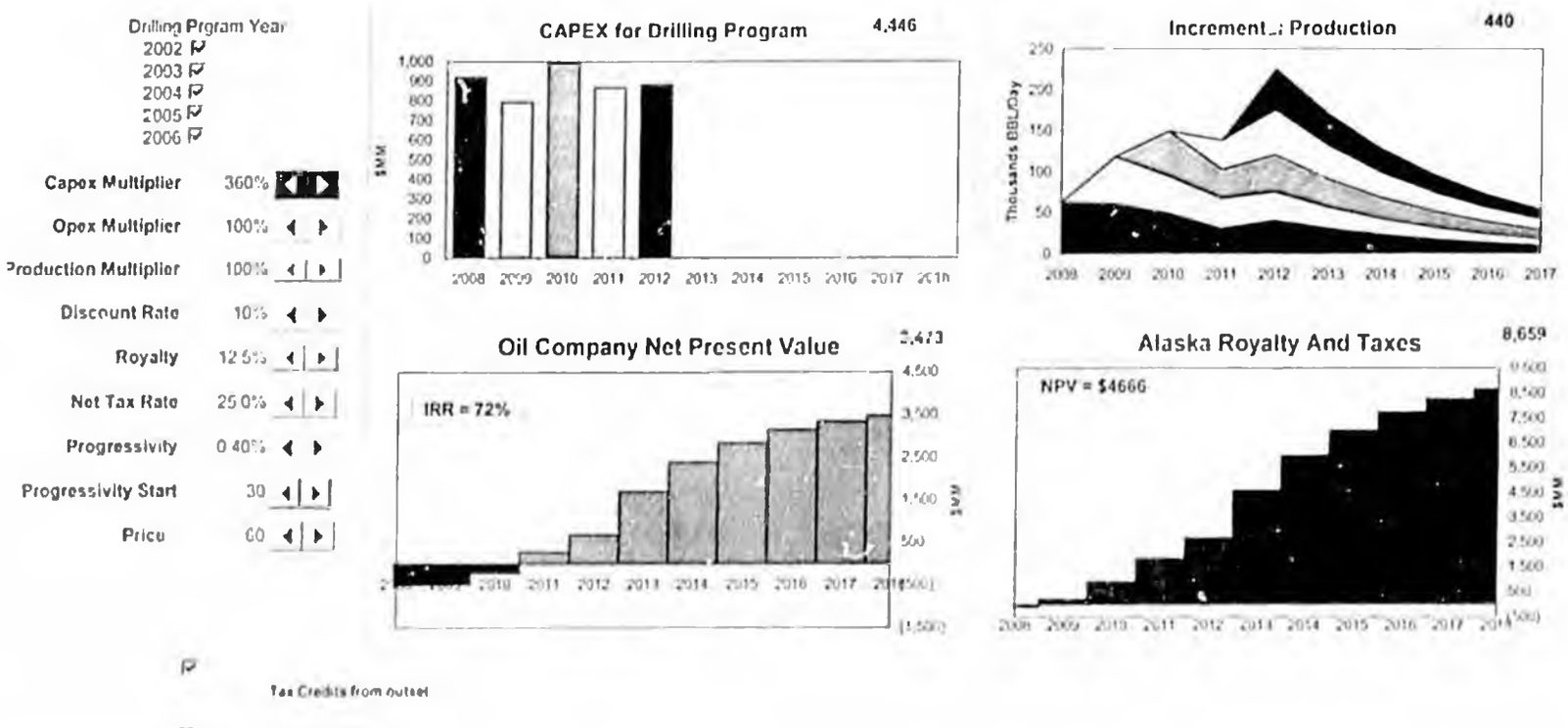
☑ Tax Credits from outset

☐ Actual oil price (but based on PPT) thru 2006, then Fcst

Duplicate 2002 – 2006 Program Starting in 2008

- Capex to 360%, $60 oil, Senate CS, Forecast mode
- Oil Company IRR = 72% and NPV10 = $3473 MM

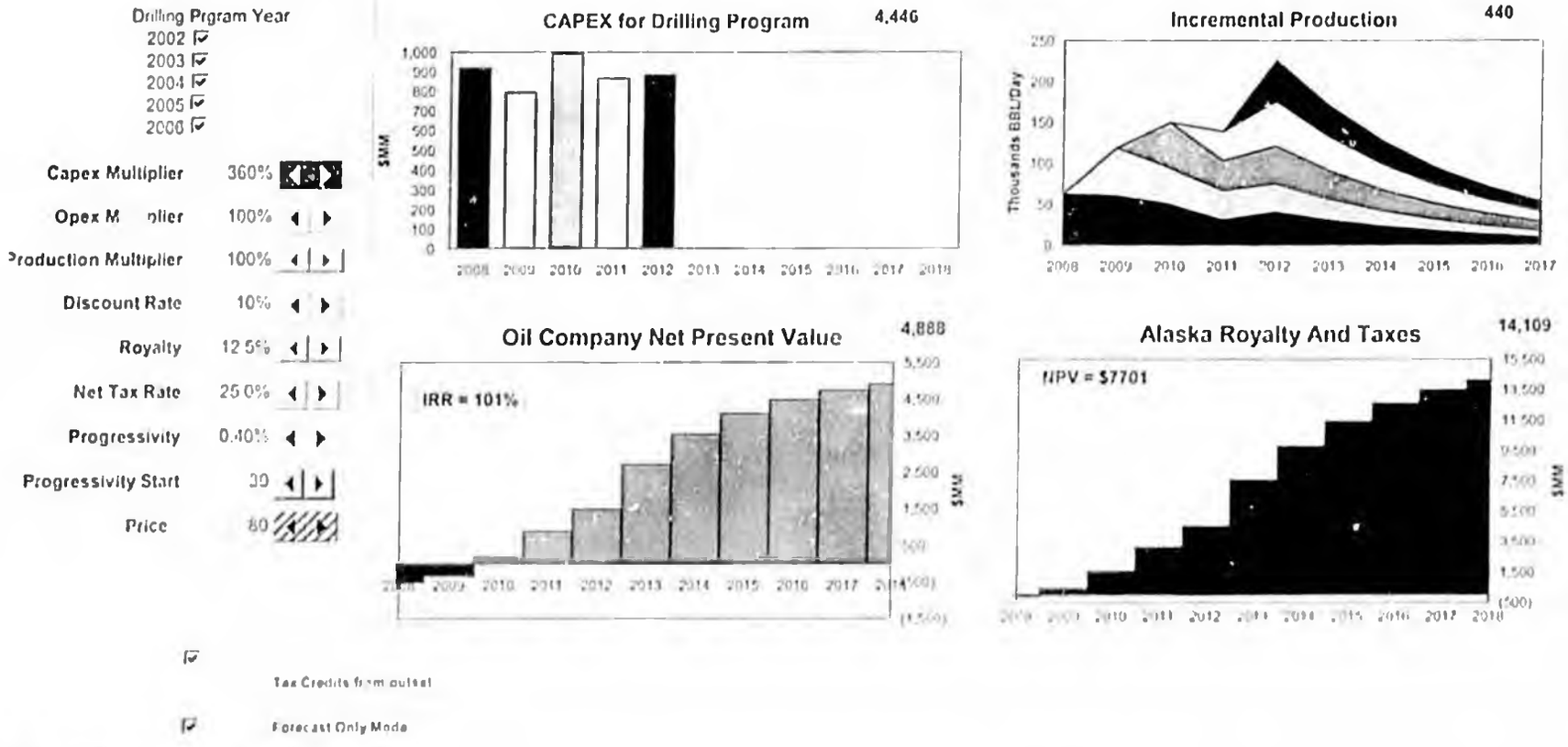
Modeling the Prudhoe Success contained in AOGA/BP Testimony



Forecast at the NYMEX strip price

- All things the same, but oil at $80 per barrel
- Oil Company IRR = 101%, NPV10 = $4,888 MM

Modeling the Prudhoe Success contained in AOGA/BP Testimony



Senate CS – Forecast Mode, $80 oil

- **IRR = 123%, NPV10 = $5.375 billion**

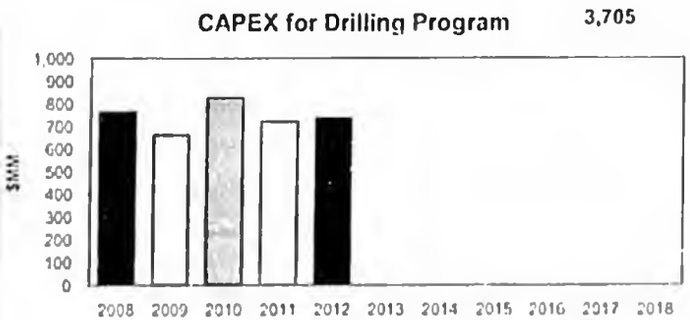
Modeling the Prudhoe Success contained in AOGA/BP Testimony

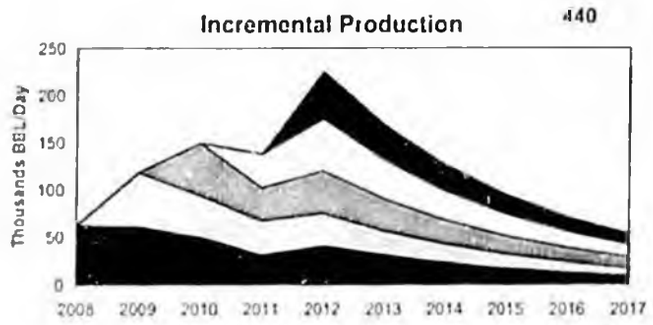
Drilling Prgram Year
2002
2003
2004
2005
2006

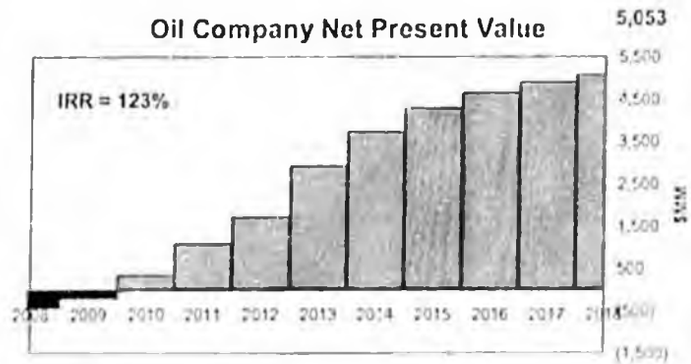
Capex Multiplier	300%
Opex Multiplier	100%
Production Multiplier	100%
Discount Rate	10%
Royalty	12.5%
Net Tax Rate	25.0%
Progressivity	0.40%
Progressivity Start	30
Price	80

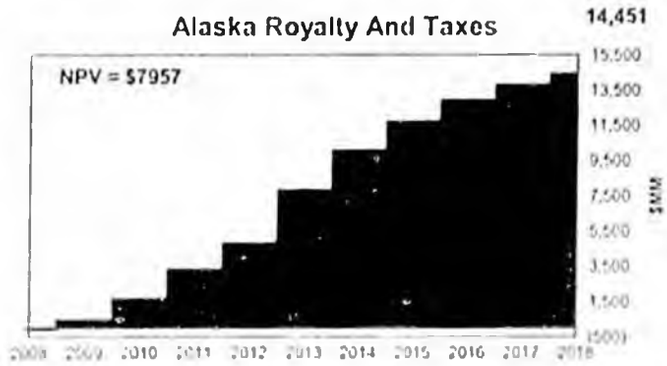
Tax Credits from outset

Forecast Only Mode









TAX RATES + PROGRESSIVITY

11/8/07

Tax Rates and Progressivity

November 8, 2007

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Suite 230
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Austin, Texas 78701
512 476 3711

Key Fiscal Terms

Production Taxes Under Current & Proposed Systems

Tax Rate:

Base Rate

+

Progressivity Rate

=

Total Tax Rate

Applied to:

Taxable Value

Key Fiscal Terms

Production Taxes Under Current & Proposed Systems

Taxable Value:

- Gross Sales Price (West Coast)

  less

- Transportation Costs from Wellhead

  =

- Gross Wellhead Value

  less

- Operating Costs (All Barrels),
- Capital Costs (All Barrels)

  =

- Net Taxable Value

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Key Fiscal Terms

Production Taxes Under Current & Proposed Systems

Other Items:

- Floor
- Capital Credits
- TIE Credits
- Small Producer Credits
- Exploration Credits (EIC)

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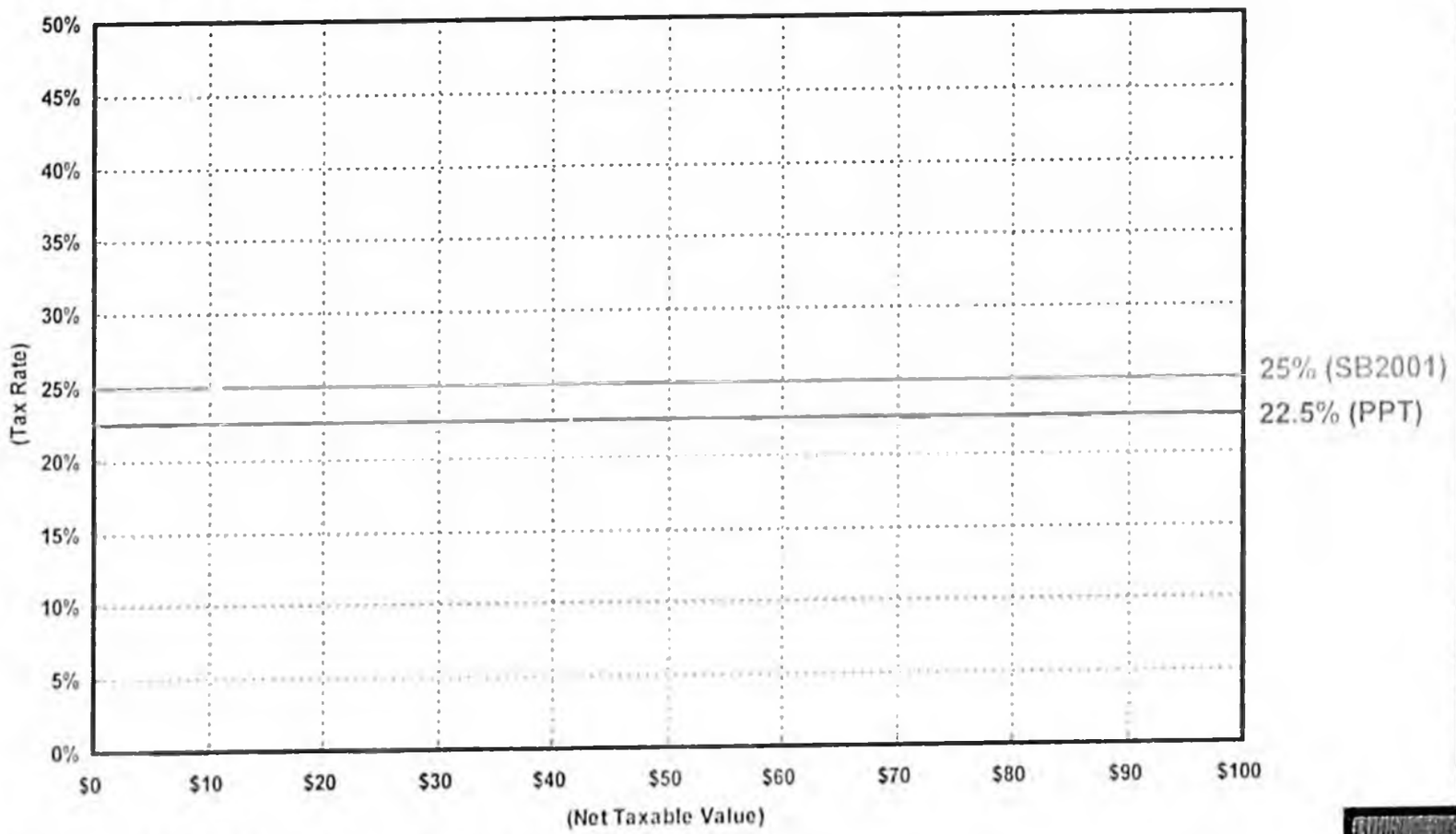
Base Tax Rate

- Applied to Taxable Value at All Price Levels



- It Does Not Vary with Prices

Progressive Tax

	PPT	SB2001
• Trigger Level	$40(Net)	$30(Net)
• Slope	0.25% per Dollar	0.20% per Dollar
• Gross or Net Value	Net	Net

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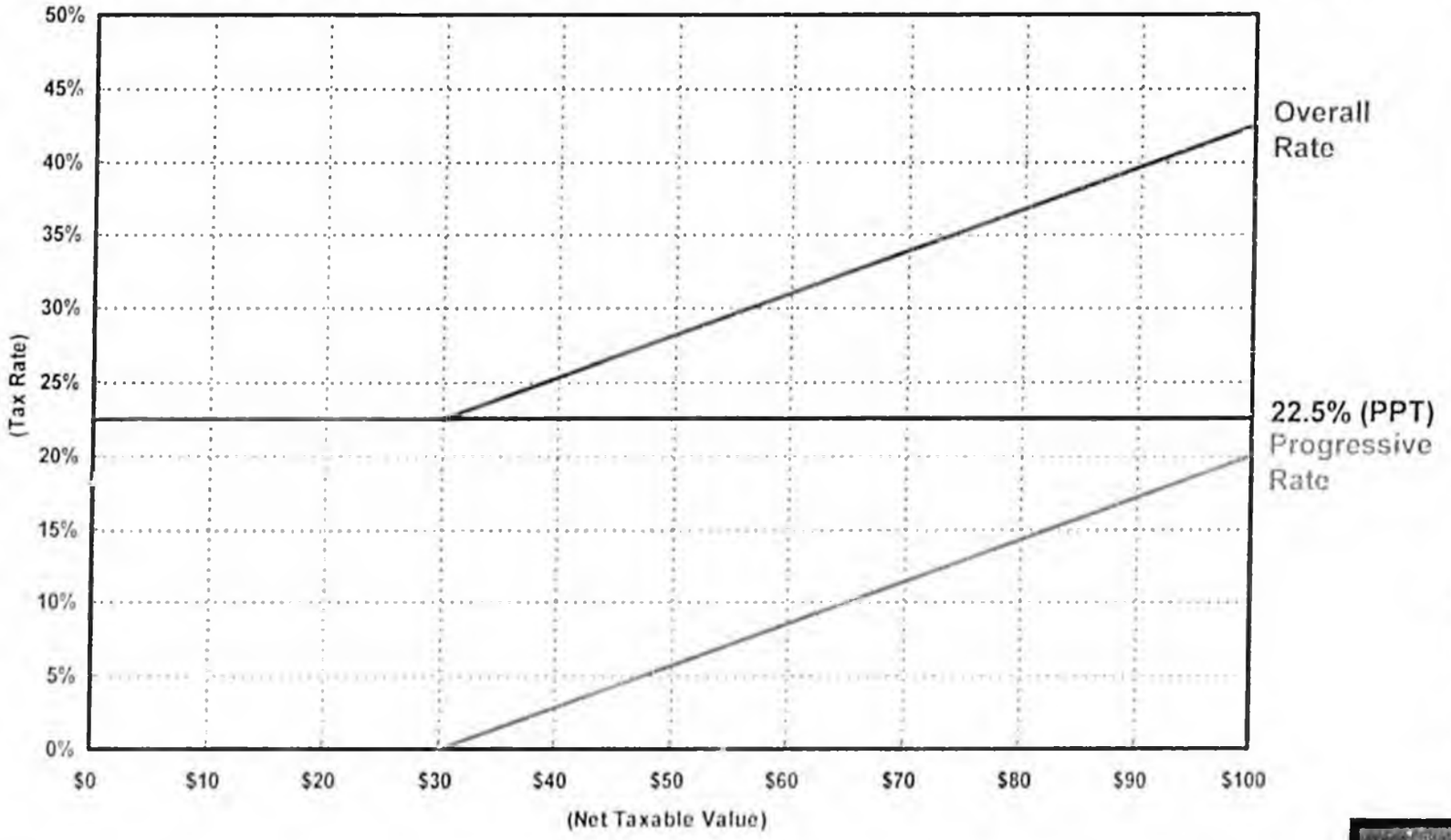
Progressive Tax

- Example of Progressive Tax Under Current & Proposed Systems



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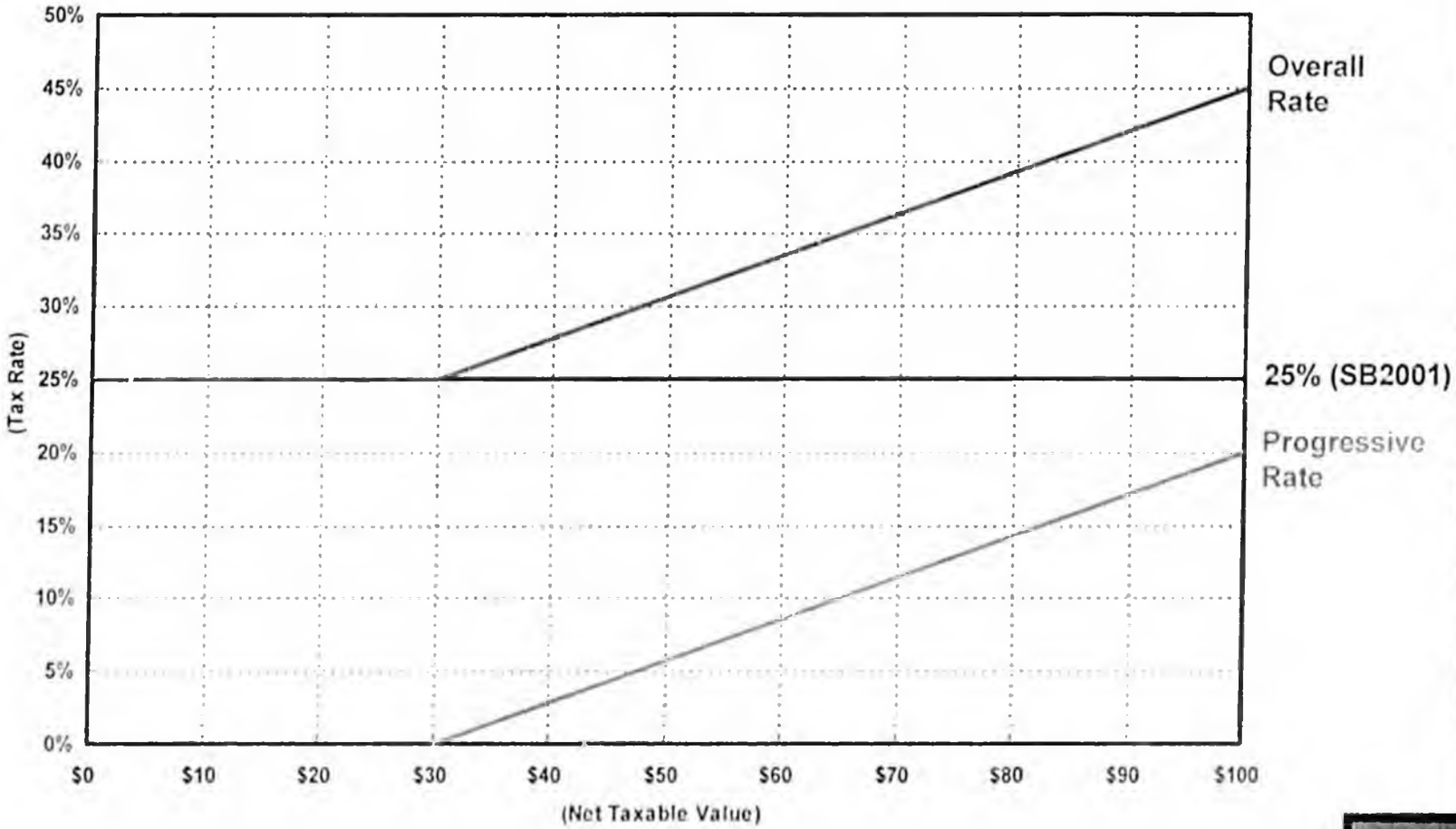
Progressive Tax

- Example of Progressive Tax Under Current & Proposed Systems



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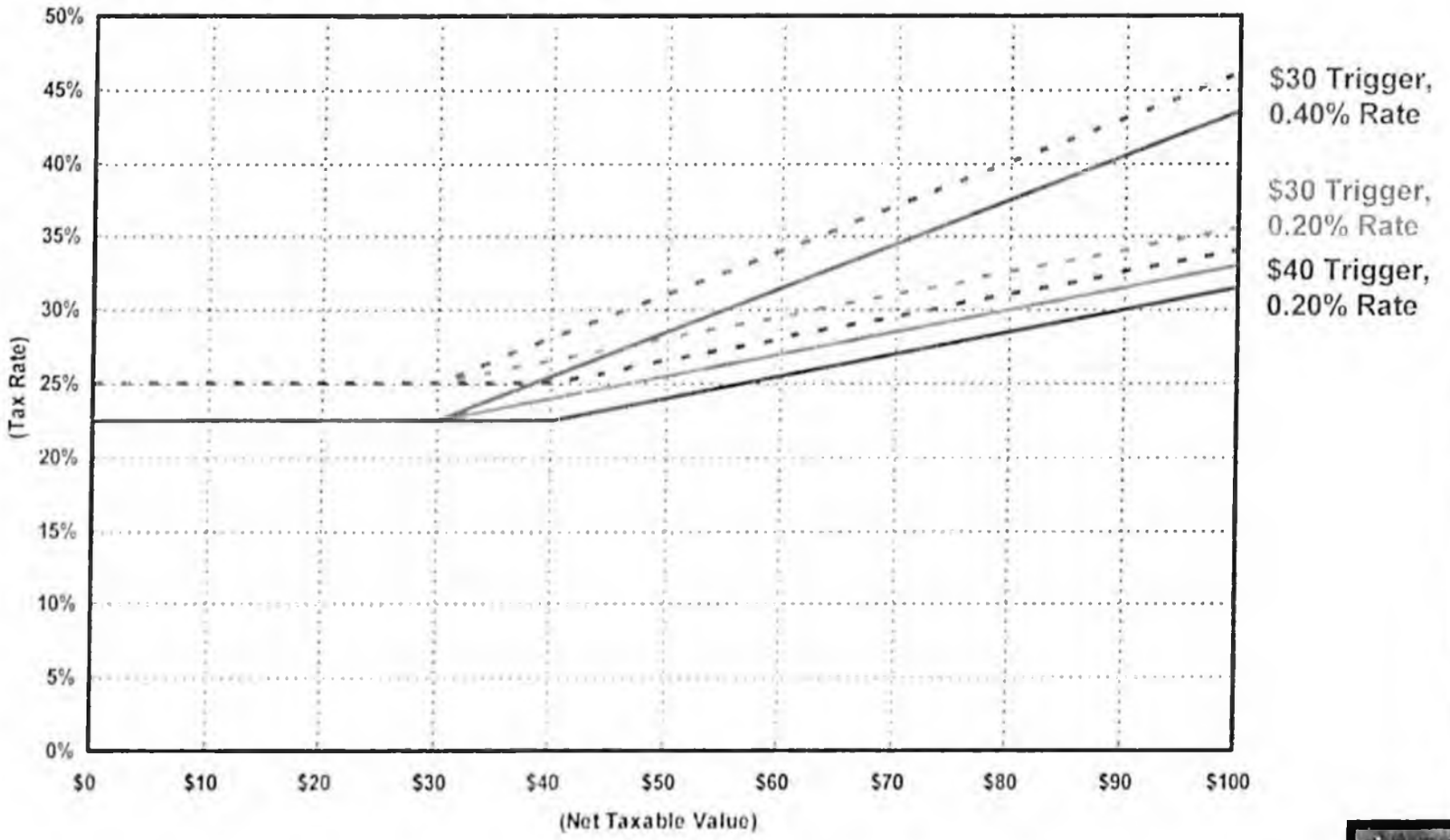
Progressive Tax & Impact on Overall Tax Rate

- At 22.5% and 25% Tax Rates



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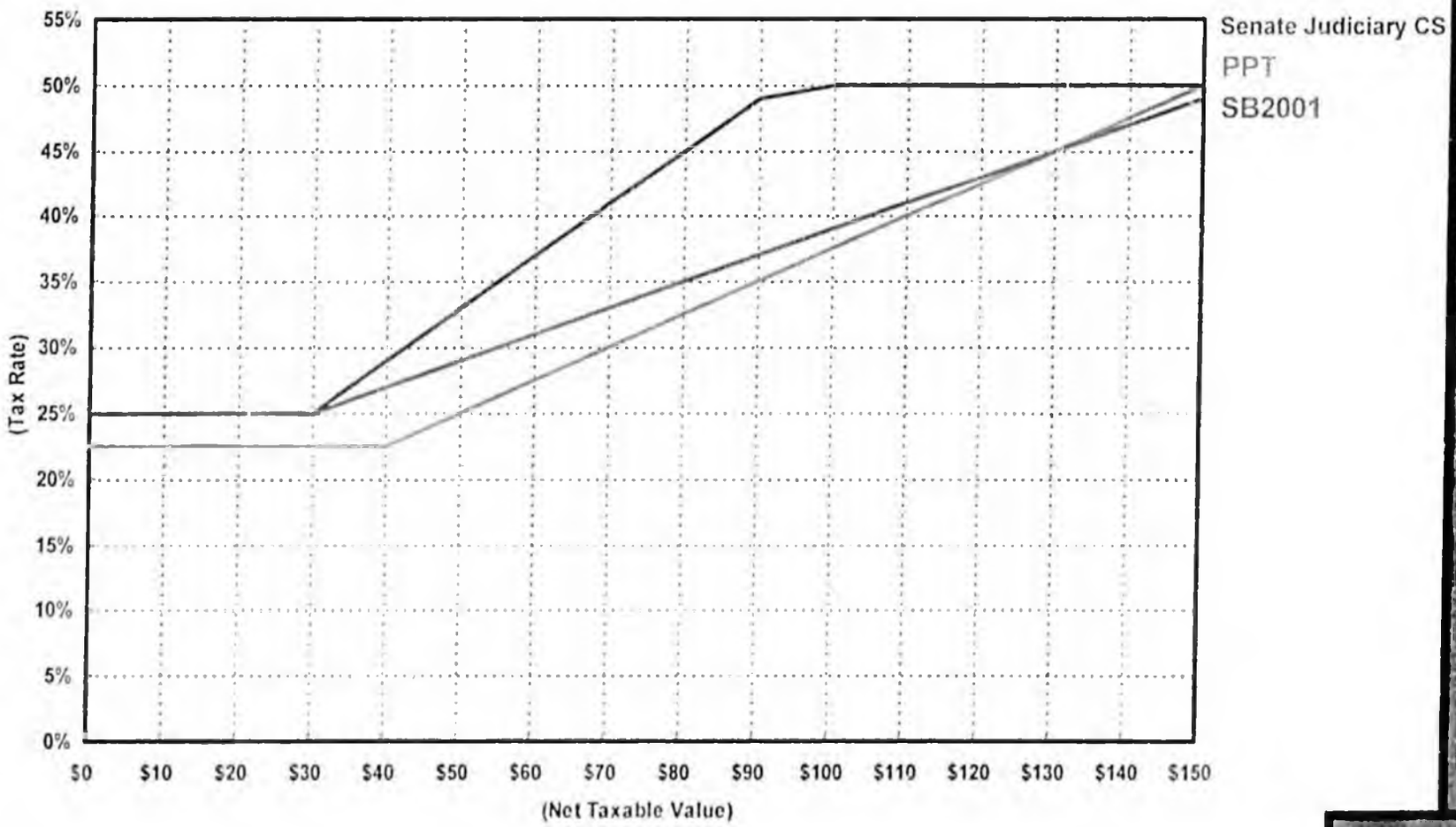
Overall Tax Rates: PPT, SB2001 and Senate Judiciary CS



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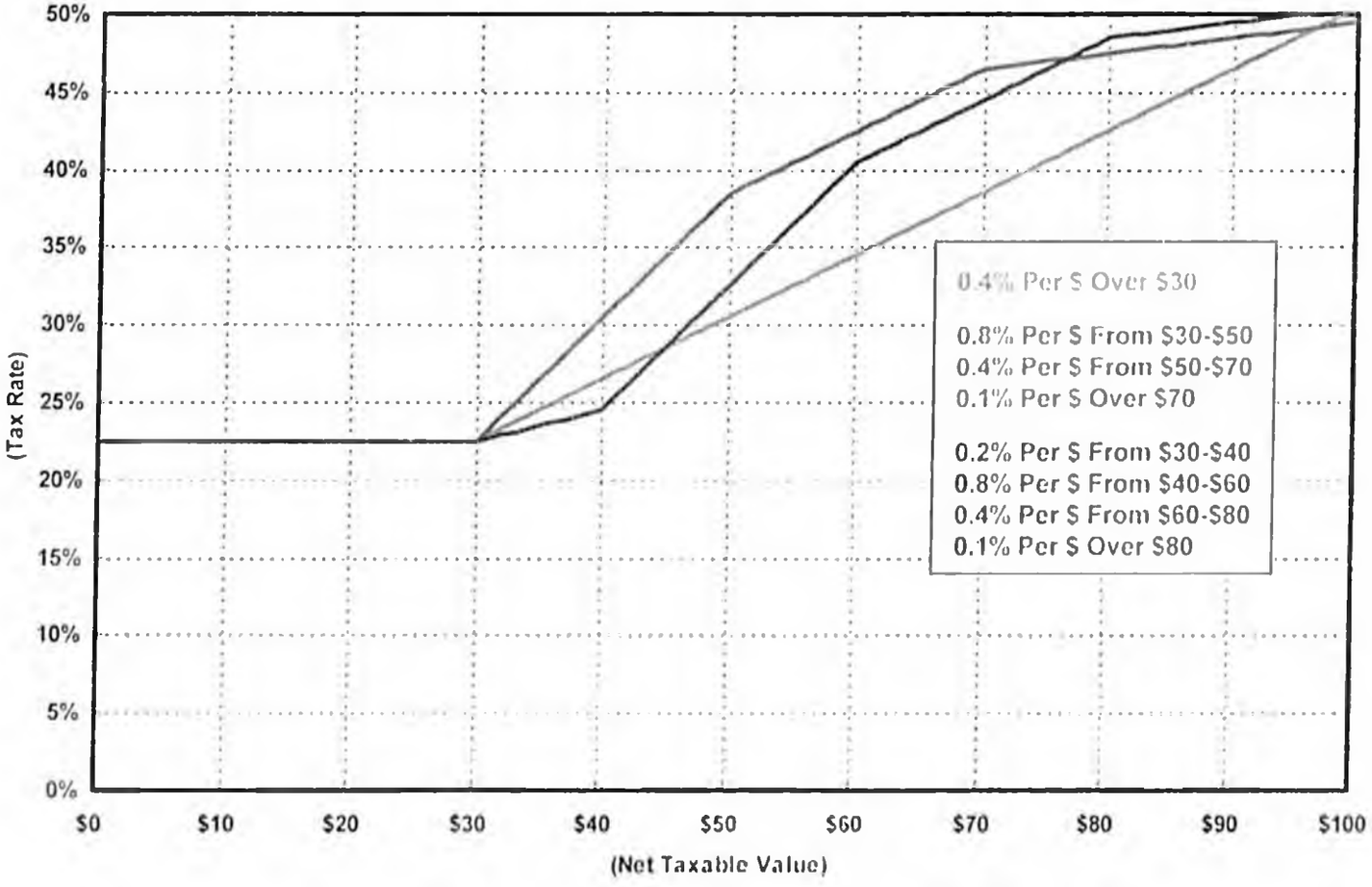
Progressive Tax & Impact on Overall Tax Rate

- Assume a 22.5% Tax Rate



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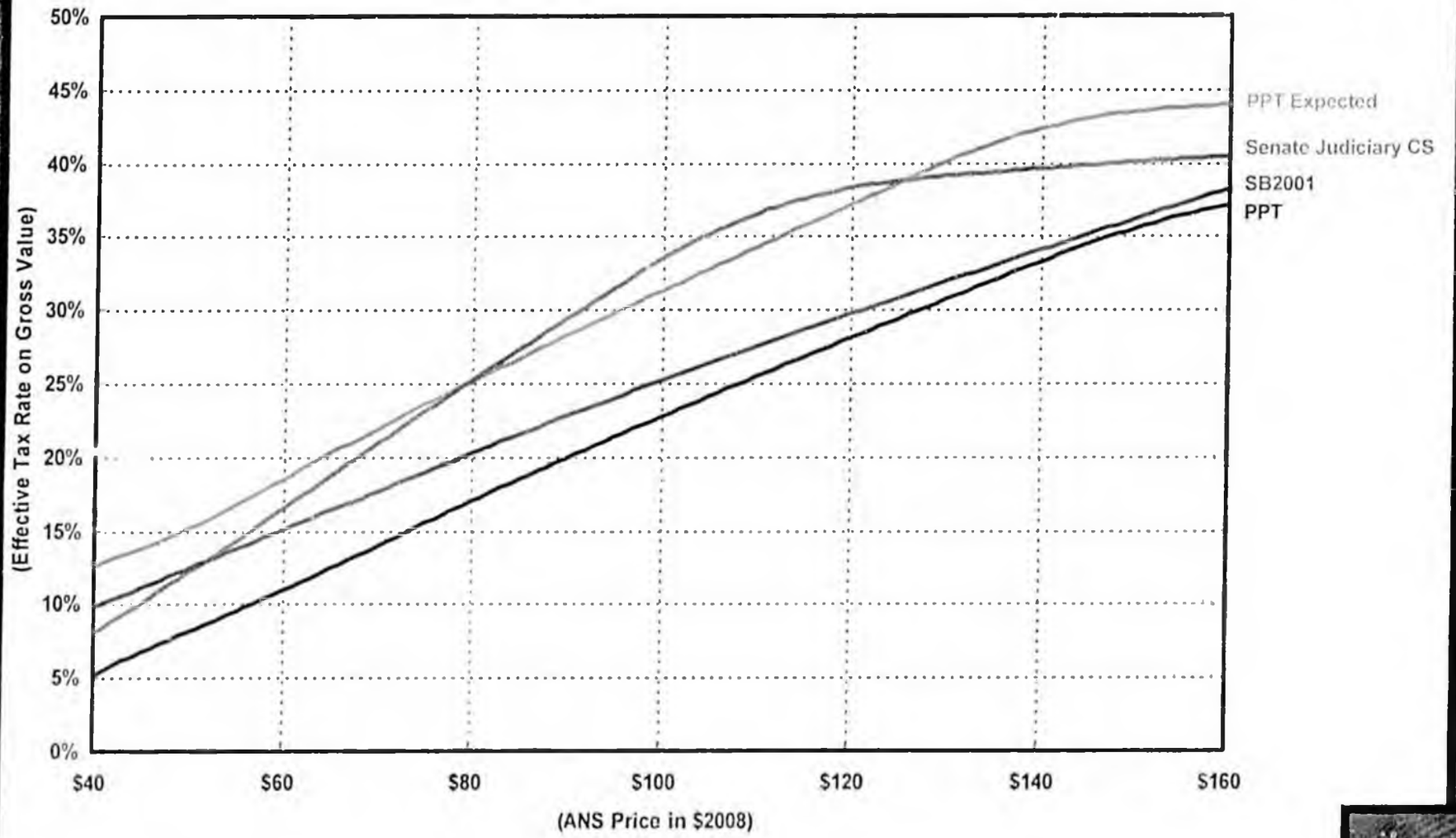
Estimated Average Effective Tax Rate on Gross Taxable Value at Various West Coast ANS Price Levels
(FY 2008-2014)



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Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).
PPT Expected: PPT using costs per Fiscal Note to HB 3001.
Senate Judiciary: SB2001 using 0.4% progressivity rate, 80% overall cap, TIE credit 2006-2007 for new producers, does not include TAPS adjustment.

Estimated Average Effective Tax Rate, Government Shares and Revenue Impacts at Various West Coast ANS Price Levels (FY 2008-2014)

Average ANS West Coast Price in Real 2008 Dollars:	$40.00	$60.00	$80.00	$100.00	$120.00	$140.00	$160.00
Effective Tax Rate on Gross Taxable Value (Percent)							
PPT	5.1%	10.9%	17.0%	22.7%	28.1%	33.2%	37.2%
SB2001	9.9%	15.1%	20.3%	25.2%	29.7%	34.1%	38.2%
Senate Judiciary CS	7.9%	16.1%	24.7%	32.8%	37.5%	39.1%	40.2%
PPT (Expected)	12.6%	18.5%	25.2%	31.3%	37.2%	42.3%	43.9%
Total Government Share of Net Cash (Percent)							
PPT	60.5%	60.6%	62.7%	65.3%	67.8%	70.4%	72.2%
SB2001	64.5%	63.5%	64.9%	66.8%	68.8%	70.9%	72.9%
Senate Judiciary CS	62.9%	64.2%	67.8%	71.6%	73.6%	73.8%	74.0%
PPT (Expected)	60.4%	61.7%	64.4%	67.1%	69.9%	72.3%	72.9%
Marginal Government Share of Net Cash (Percent)							
PPT	58.9%	63.7%	70.7%	75.9%	81.0%	86.2%	78.9%
SB2001	59.7%	65.4%	70.7%	75.1%	79.3%	83.5%	84.9%
Senate Judiciary CS	60.7%	71.5%	79.8%	85.6%	77.2%	74.9%	74.9%
PPT (Expected)	60.2%	68.3%	73.9%	79.4%	85.0%	81.0%	73.0%
Annual Average Tax Difference Above/(Below) PPT (Nominal $M)							
SB2001	$423	$587	$635	$608	$493	$287	$423
Senate Judiciary CS	$251	$726	$1,476	$2,454	$2,782	$2,002	$1,190
PPT (Expected)	$665	$1,067	$1,566	$2,088	$2,682	$3,132	$2,688

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).
PPT Expected: PPT using costs per Fiscal Note to HB 3001.
Senate Judiciary: SB2001 using 0.4% progressivity rate, 50% overall cap, TIE credit 2008-2007 for new producers, does not include TAPS adjustment.

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Tax Floor Issues

PPT (Current Law)	SB2001 (Proposed)	Senate Judiciary CS
1-4% of Gross Wellhead Value ($15 - $25 WC ANS)	10% of Gross Wellhead Value (Prudhoe & Kuparuk)	Same as Current Law

- Presence of Higher Floor Introduces Regressivity at Lower Prices
- Is Like an Insurance Policy. What Does it Cost?
- What are State's Expectations as to ANS Prices?

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AK CURRENT PRODUCTION TAX

11/6/07

PPT [illegible]culation

				State	Producers	Fed.
Price (West Coast) (RSB Spring 07, Page 10, $51.72)	$71.65		Annual Barrels			
Daily Volume (RSB Spring 07, Page 13, 740,000 bpd)	722,000		263,530,000			
Royalty %	12.50%		32,941,250			
Annual Volume (without Royalty)			230,588,750			
Gross Value (Taxable Value + Royalty Value)		$ 18,881,924,500.00				
Royalty Value (RSB Spring 07, Page 24)						
Gross			2,138,545,950			
Net of Permentfund @ 25%	25.48%		(544,901,508)			
Net Roalty Value (unrestricted)			1,593,644,442			
Gross Revenue (West Coast)		$ 16,521,653,937.50				
Downstream Costs (RSB [illegible])						
ANS Marine Trapsortation	1.79	($ 412,753,863)				
TAPS Tariff	5.06	($ 1,166,779,075)				
Othe Deductions & Adjustments	-0.12	$ 27,670,650				
Total Downstream Cost (transportation costs)	6.73	($ 1,551,862,288)				
ANS Wellhead Value	$64.92	$ 14,969,821,650.00				
Upstream Costs (RSB)						
Operating Costs	9.31	($ 2,146,000,000)				
Capital Costs	9.57	($ 2,206,176,625)				
Total Upstream Costs	18.87	($ 4,352,176,625)				
Production Tax Value	46.05	$ 10,617,645,025.00			$ 10,617,645,025	

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Prepared by Sen Stedman's Office

			State	Producers	Fed.
PPT: Sec 43 55 011 (e)					
PPT Base Tax Rate	22.5%				
PPT Gross Tax		(2,388,970,131)	2,388,970,131	(2,388,970,131)	
Progressivity: Sec 43 55 011 (g) & (h)					
Trigger (net)	40.00				
Rate per Price Index Dollar	0.25%				
Per Barrel Production Tax Value		46.05			
Per Barrel Production Tax Value Less Trigger (Price Index)		6.05			
Resulting Progressive Rate		1.51%			
Progressivity Surcharge		(160,480,575)	160,480,575	(160,480,575)	
PPT + Progressivity		(2,549,450,706)			
Pre-Credit Adjusted Revenue		= 8,068,194,319.04			
$0.30 Barrel Exclusion (Sec. 43.55.165(e)(18))					
Capital Cost Available for Capital Credits		(2,206,176,625)			
Exclusion	0.30	69,176,625	69,176,625	(69,176,625)	
Capital Cost Less $0.30 Exclusion		(2,137,000,000)			
Credits: Sec 43.55.023					
Capital (023a) [20%]	20.0%	(427,400,000)	(427,400,000)	427,400,000	
NOL (023b)		-	-	-	
Transitional Investment Expenditures [TIE] (023c)	Fixed Estimated Costs	(213,700,000)	(213,700,000)	213,700,000	
Small Producer (024) [$12mm]		(48,000,000)	(48,000,000)	48,000,000	
Exploration (025)		(50,000,000)	(50,000,000)	50,000,000	
Net Revenue to State, Producers & Fed			1,579,627,331	3,738,117,693	
State Property Tax (RSB Spring'07, Page 26)	0.2% adjusted up for Borough claim		261,000,000	(261,000,000)	
State Corporate Income Tax (RSB Spring'07, Page 26)	9.4%		821,383,063	(821,383,063)	
Royalties (Gross of Restreed)			2,138,545,950		
Federal Income Tax				(3,058,341,193)	3,058,341,193
Total Revenue (Take)			5,100,456,344	4,597,393,438	3,058,341,193
			39.98%	36.04%	23.98%

Take Percentages	Dollar	Percentage
State Take	5,100,456,344	39.98%
Producer Take	4,597,393,438	36.04%
Federal Gov't Take	3,058,341,193	23.98%
	12,756,190,975	100.00%
Total Government Take		63.96%

GOVERNMENT TAKE (AMENDED) 11/6/07

Senate Finance

November 5, 2007

Senate Finance

November 5, 2007

Topics

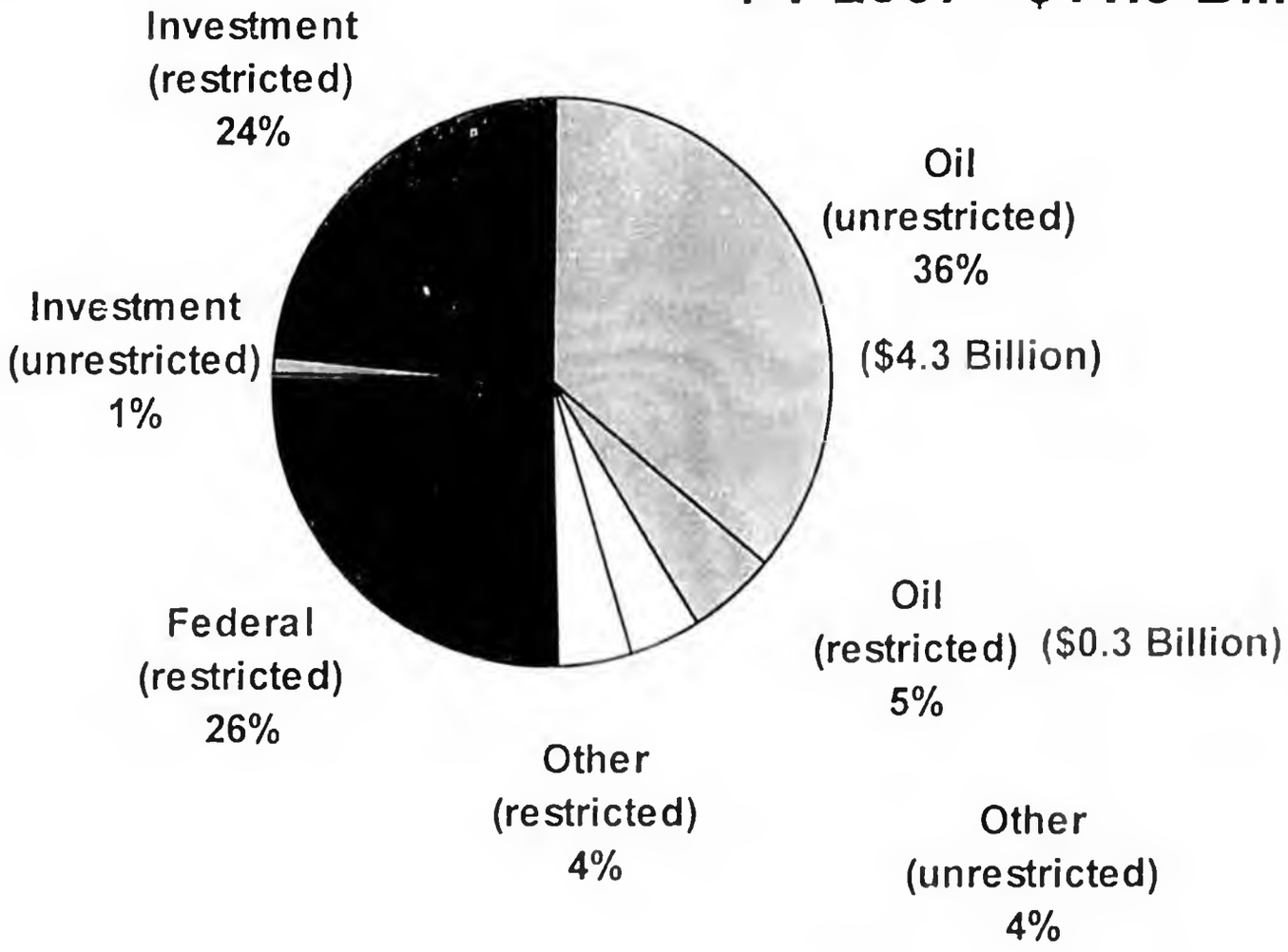
- **Oil's importance to overall Alaska State revenue**
- **Producer Economics**
  - PPT
  - Senate CS
- **Government Take**
  - Alaska and Federal
  - Under PPT and Senate CS

Sources Of Alaska Government Revenue From Petroleum

- **Royalty**
  - Based on the gross value at the "point of production"
  - Rate established in lease contract
- **Property Tax**
  - Based on adjusted (for inflation) depreciated investment costs and remaining useful life
- **Production Tax**
  - Based on company's net cash flow per barrel of production after costs and reinvestment
- **State Income Tax**
  - After deduction of allowed costs, including Royalties, Property Tax and Production Tax based on apportioned worldwide income

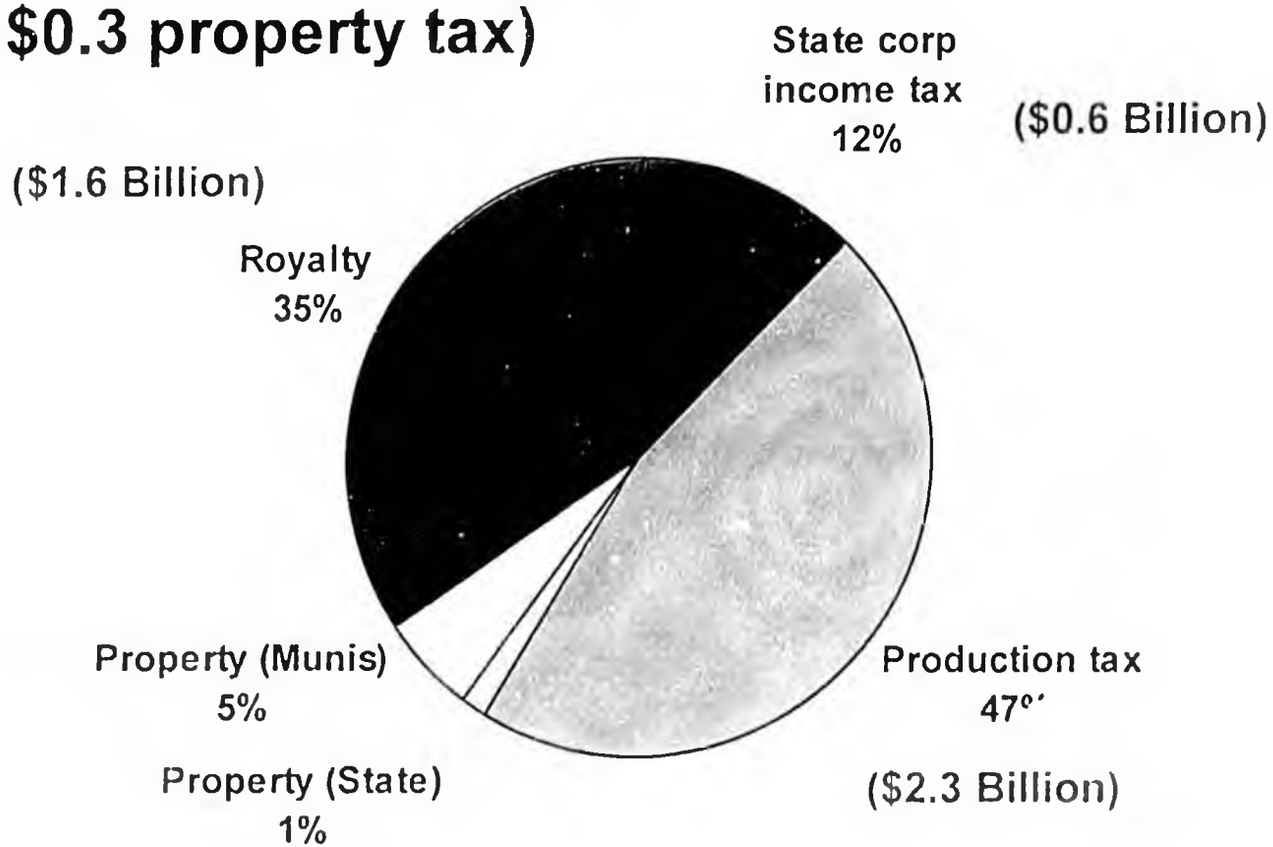
Total State Revenues

FY 2007 - $11.9 Billion



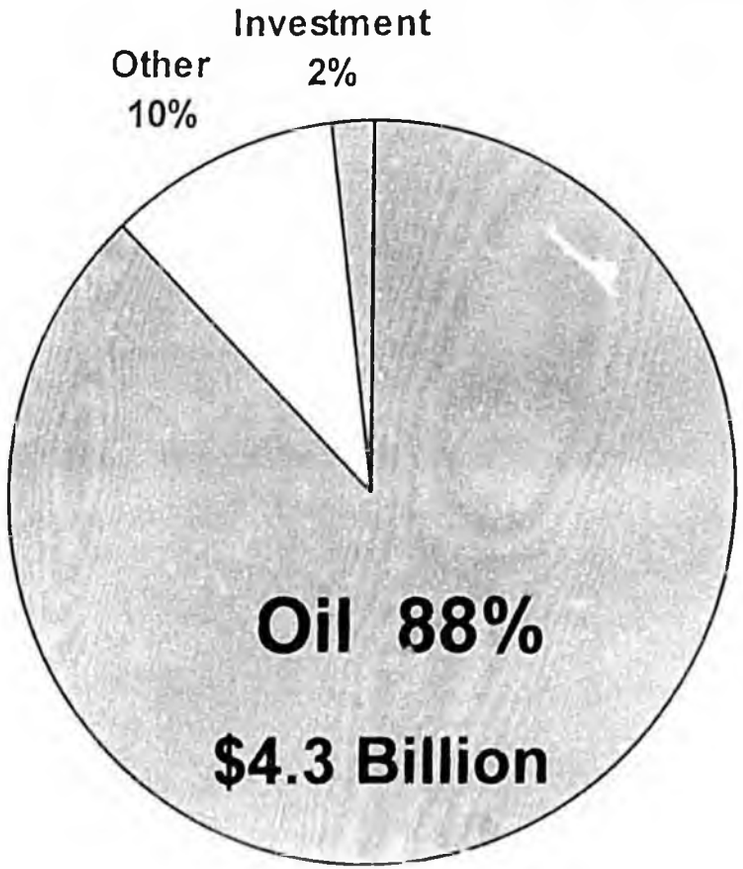
Unrestricted Petroleum Revenues

FY 2007 - $4.6 Billion State (plus $0.3 property tax)



General Fund Unrestricted Revenues

FY 2007 - $4.9 Billion



Producer Share Of Revenues

FY 2009

FY 2009
Producer Revenues Under PPT

		FY 2009 $ MM	%	$/Bbl
Sales Revenue		**18,125**	100%	**66.30**
less	Shipping	470	3%	1.72
	TAPS	673	4%	2.46
	Royalty	2,075	11%	7.59
Gross Value At PoP		**14,907**	**82%**	**54.53**
	Capex	2,029	11%	7.42
	Opex	2,063	11%	7.55
	Property Tax	312	2%	1.14
Net Value At PoP		**10,503**	**58%**	**38.42**
less	Production Tax	1,693	9%	6.19
Detail	*Base Production Tax*	*2,285*	*13%*	*8.36*
	Progressivity	*115*	*1%*	*0.42*
	Small Prod Credit	*(48)*	*0%*	*(0.18)*
	EIC	*(50)*	*0%*	*(0.18)*
	Capital Credit	*(406)*	*-2%*	*(1.49)*
	TIE Credit	*(203)*	*-1%*	*(0.74)*
Pre-CIT Revenue		**8,810**	**49%**	**32.23**
less	State Income Tax	763	4%	2.79
	Federal Income Tax	2,574	14%	9.42
Producer Income		**5,473**	30%	**20.02**

TAPS cost shown is actual cost. However, deduction allowed for PPT is approximately $5/Bbl

Assumes 749,000 Bopd at official forecast $66.30/bbl ANS West Coast

FY 2009
Producer Revenues Under Senate CS

		FY 2009 $ MM	FY 2009 %	FY 2009 $/Bbl
Sales Revenue		**18,125**	100%	**66.30**
less	Shipping	470	3%	1.72
	TAPS	673	4%	2.46
	Royalty	2,075	11%	7.59
Gross Value At PoP		**14,907**	**82%**	**54.53**
	Capex	2,029	11%	7.42
	Opex	2,063	11%	7.55
	Property Tax	312	2%	1.14
Net Value At PoP		**10,503**	**58%**	**38.42**
less	Production Tax	2,778	15%	10.16
Detail	*Base Production Tax*	*2,628*	*14%*	*9.61*
	Progressivity	*654*	*4%*	*2.39*
	Small Prod Credit	*(48)*	*0%*	*(0.18)*
	EIC	*(50)*	*0%*	*(0.18)*
	Capital Credit	*(406)*	*-2%*	*(1.49)*
	TIE Credit	*0*	*0%*	*0.00*
Pre-CIT Revenue		**7,725**	**43%**	**28.26**
less	State Income Tax	700	4%	2.56
	Federal Income Tax	2,361	13%	8.64
Producer Income		**4,664**	26%	**17.06**

Assumes 749,000 Bopd at official forecast $66.30/bbl ANS West Coast

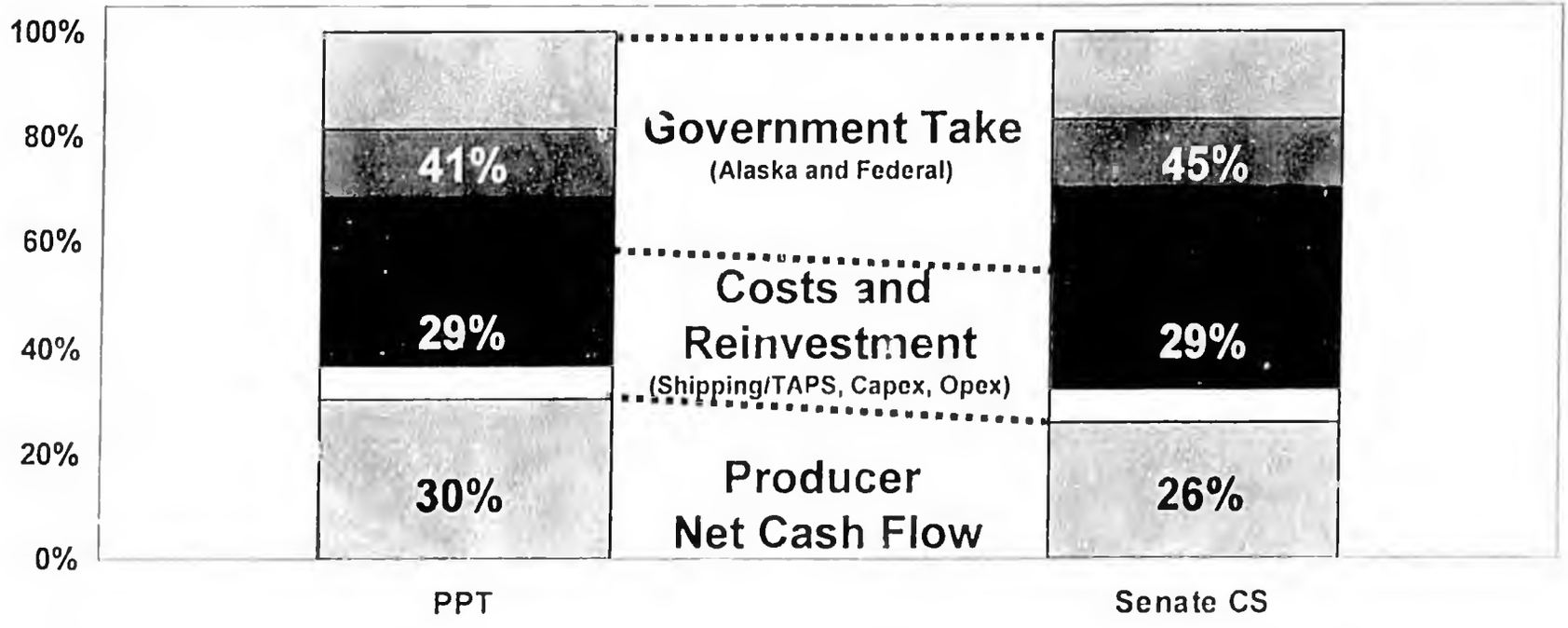
FY 2009 Producer Income
PPT Compared To Senate CS

	FY 2009, $MM		
	PPT	Senate	Diff
Sales Revenue	**18,125**	**18,125**	**0**
less Shipping	470	470	0
TAPS	673	673	0
Royalty	2,075	2,075	0
Gross Value At PoP	**14,907**	**14,907**	**0**
Capex	2,029	2,029	0
Opex	2,063	2,063	0
Property Tax	312	312	0
Net Value At PoP	**10,503**	**10,503**	**0**
less Production Tax	1,693	2,778	1,085
Detail Base Production Tax	*2,285*	*2,628*	*343*
Progressivity	*115*	*654*	*539*
Small Prod Credit	*(48)*	*(48)*	*0*
EIC	*(50)*	*(50)*	*0*
Capital Credit	*(406)*	*(406)*	*0*
TIE Credit	*(203)*	*0*	*203*
Pre-CIT Revenue	**8,810**	**7,725**	**(1,085)**
less State Income Tax	763	700	(63)
Federal Income Tax	2,574	2,361	(213)
Producer Income	**5,473**	**4,664**	**(809)**

Assumes 749,000 Bopd at official forecast $66.30/bbl ANS West Coast

FY 2009
Sharing Of Sales Revenue

Comparison Of PPT and Senate Judiciary CS



Assumes 749,000 Bopd at official forecast $66.30/bbl ANS West Coast

Government Share Of Revenues

FY 2009

FY 2009
Government and Alaska Share

PPT

	FY 2009		
	$ MM	%	$/Bbl
Net Cash Flow	**12,890**		**47.15**
Producer share	5,473	42%	20.02
Government Take	**7,417**	**58%**	**27.13**
Federal Income Tax	2,574	20%	9.42
Royalty	2,075	16%	7.59
Production Tax	312	2%	1.14
Petroleum Tax	1,693	13%	6.19
State Income Tax	763	6%	2.79
Alaska State Take	**4,843**	38%	**17.71**

Assumes 749,000 Bopd at official forecast $66.30/bbl ANS West Coast

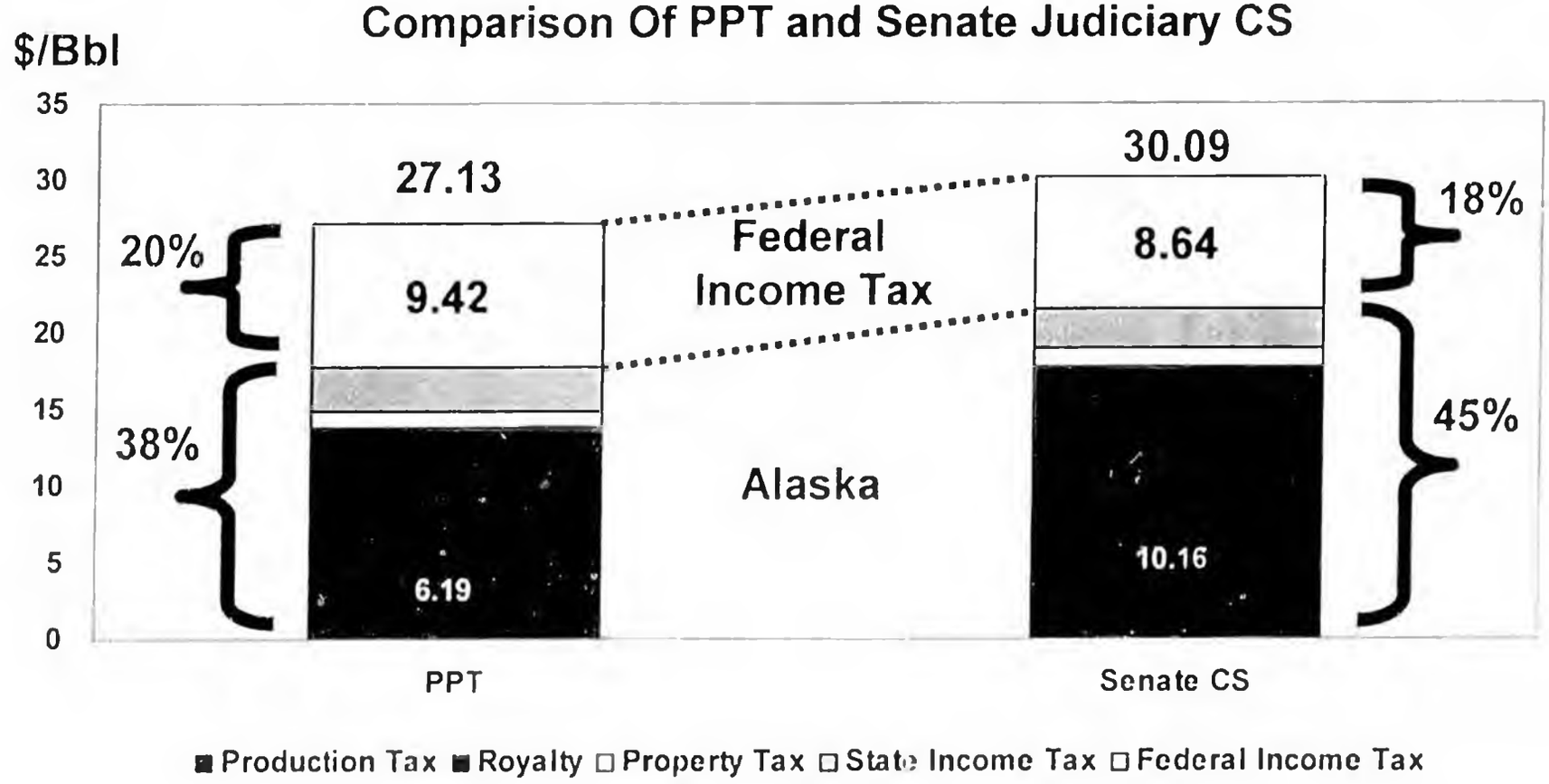
FY 2009
Government and Alaska Share

Senate Judiciary CS

	FY 2009		
	$ MM	%	$/Bbl
Net Cash Flow	**12,890**		**47.15**
Producer share	4,664	36%	17.06
Government Take	**8,226**	**64%**	**30.09**
Federal Income Tax	2,361	18%	8.64
Royalty	2,075	16%	7.59
Property Tax	312	2%	1.14
Production Tax	2,778	22%	10.16
State Income Tax	700	5%	2.56
Alaska State Take	**5,865**	45%	**21.45**

Assumes 749,000 Bopd at official forecast $66.30/bbl ANS West Coast

FY 2009
Government and Alaska Share



Assumes 749,000 Bopd at official forecast $66.30/bbl ANS West Coast

FY 2009
Change In Production Tax

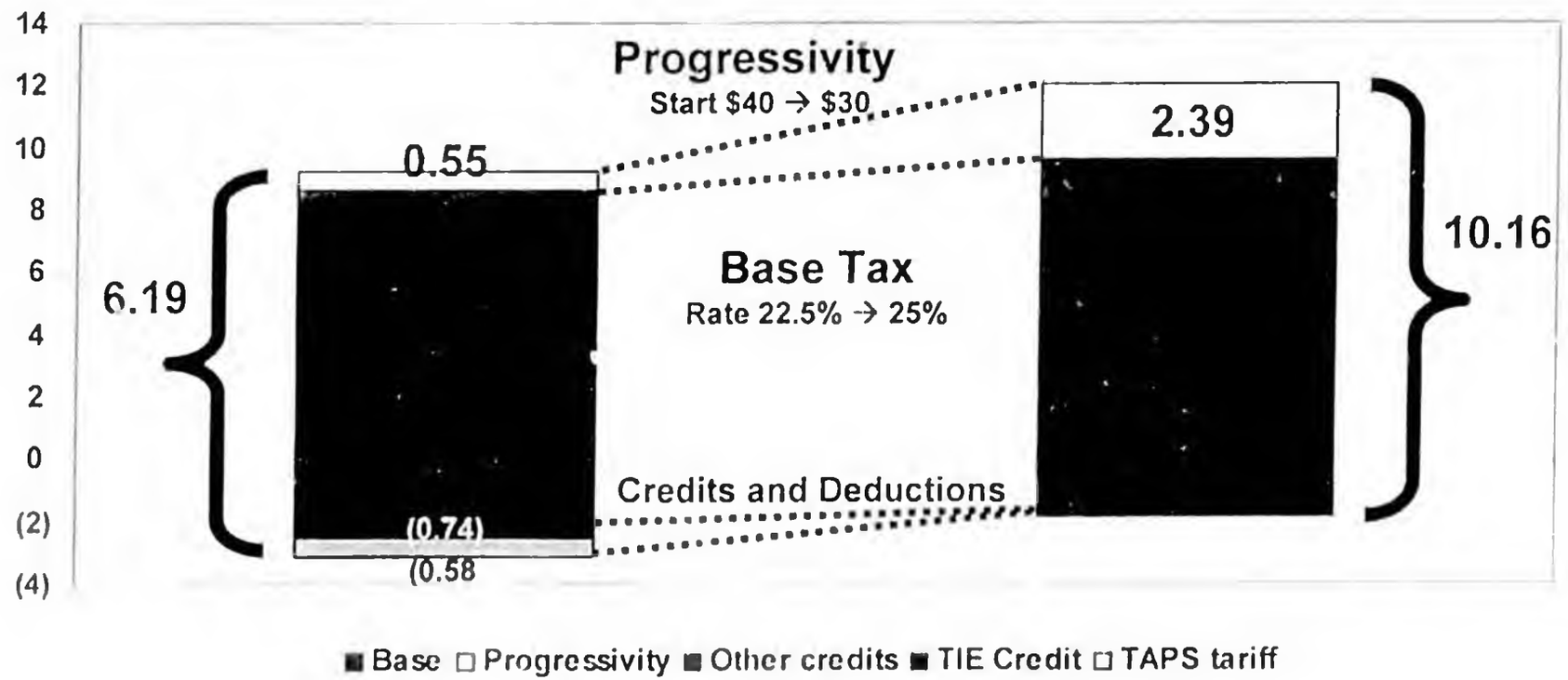
	FY 09 $ MM	FY 09 %	FY 09 $/Bbl
Prod Tax under PPT	**1,693**	100%	**6.19**
Base	285	17%	1.04
Progressivity	439	26%	1.61
TIE Credit	203	12%	0.74
TAPS tariff	158	9%	0.58
Prod Tax under Senate	**2,778**	164%	**10.16**

TAPS tariff impact reflected in both Base and Progressivity

Assumes 749,000 Bopd at official forecast $66.30/bbl ANS West Coast

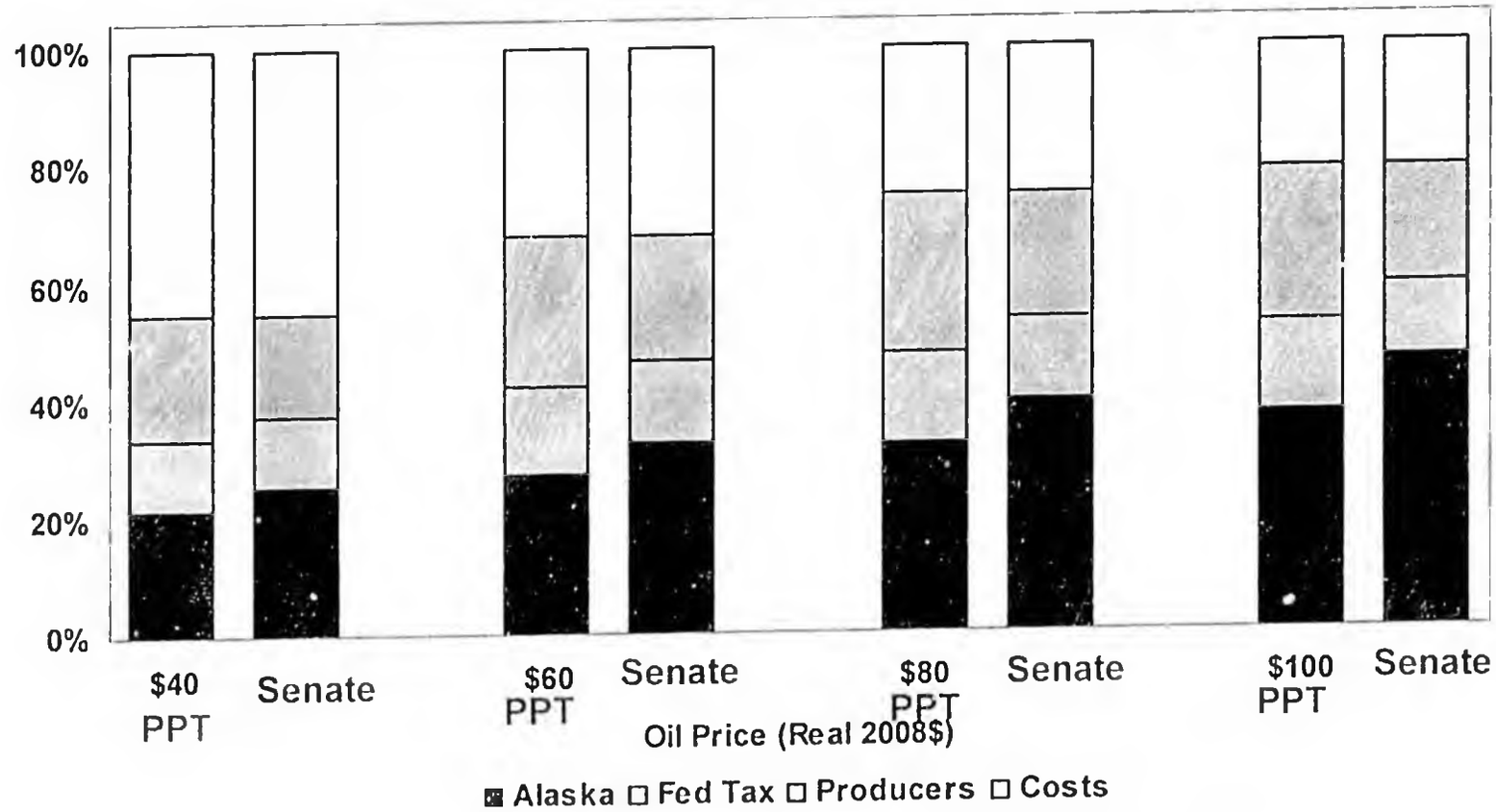
FY 2009
Key Changes Within Senate CS

Production Tax and TAPS Tariff Impacts



Assumes 749,000 Bopd at official forecast $66.30/bbl ANS West Coast

FY 2009
Share Of Sales Revenue



FY 2009
Share Of Profit (Revenue Less Costs)