

ALASKA LEGISLATURE COMMITTEE FILES 2007-2008 RES 12688

As a rule of thumb, add \$24 per barrel to the net prices shown in Figure 1 to obtain the selling price of ANS crude. ACES calculates the surcharge on the average annual price rather than monthly price as under PPT. Unless prices and production are highly volatile, the change in methodology should have relatively little impact.

The relevant portion of the chart for the near-term is between \$30 and \$80 per barrel, which is roughly equivalent to West Coast market prices of \$54 to \$104 per barrel. In that range, the total tax rate under ACES would average about 3.5 percentage points higher than under PPT. The maximum difference occurs when ANS crude sells for approximately \$64 per barrel (profit of \$40 per barrel), which is near the Department of Revenue's mid-term forecast. Because the surcharge rate under ACES is lower than under PPT, the difference in the total tax rate declines as the net price of oil increases.

The question begging discussion is whether ACES should be considered a tax increase. Figure 1 clearly shows that production taxes are generally higher under ACES than under PPT, but there is another factor to consider. That factor is that annual revenue under PPT is about \$800 million less than anticipated.

ACES will generate more state revenue than the tax system the legislature implemented (PPT), but less state revenue than legislators *thought* they would get from the tax system they implemented. Those that argued that PPT provides an insufficient amount of oil revenue to the state will almost certainly point out that anticipated revenue under ACES is below levels anticipated under PPT. These people will argue that ACES is not a tax increase; it is a partial correction of a compromise that was based on inappropriate or inaccurate information.

On the other side of the argument, people will focus on the *share* of revenue rather than on the *amount* of revenue that goes to the state. State revenue under PPT is less than anticipated because the profit per barrel is much less than anticipated. Legislative Finance does not have the data required to determine whether or not actual shares of revenue are close to what was anticipated under PPT, but it is obvious that unanticipated production costs—which reduce profit and therefore reduce state revenue—do not accrue to the producers. From the perspective that ACES has generally higher tax rates than PPT (so increases the state share of revenue and reduces the share retained by producers at any given levels of price and costs of production) it is clear that ACES is a tax increase.

Converting *tax rates to revenue impacts* provides a less accurate (but more interesting) view. The following graphs are based on a simple model that holds production constant at 244 million barrels annually and deductible costs of production constant at \$23.85 per barrel—numbers based on data published in the Spring 2007 Revenue Sources Book.

Figure 2 shows that changes to the base and surcharge tax rates under ACES can be expected to increase revenue by \$450 million to \$515 million annually in the \$65 to \$100 market price range. That amount is based on current levels of production and excludes

the impact of potential changes to tax credits. Revenue under ACES (relative to PPT) will fall if oil prices exceed \$90, going negative at prices between \$155 and \$165.

Figure 2. State Revenue Change Under the ACES Proposal

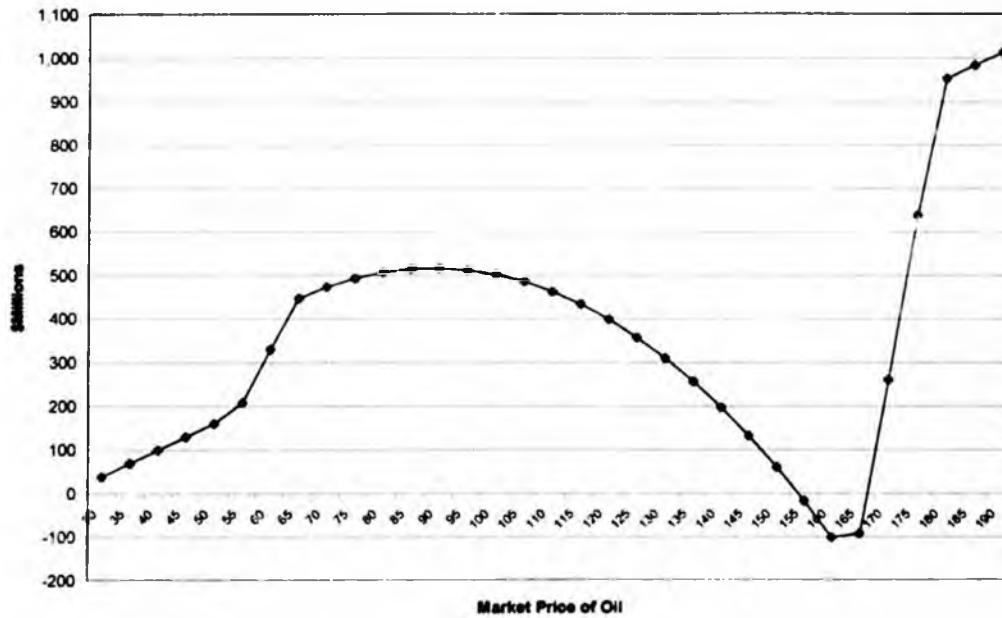
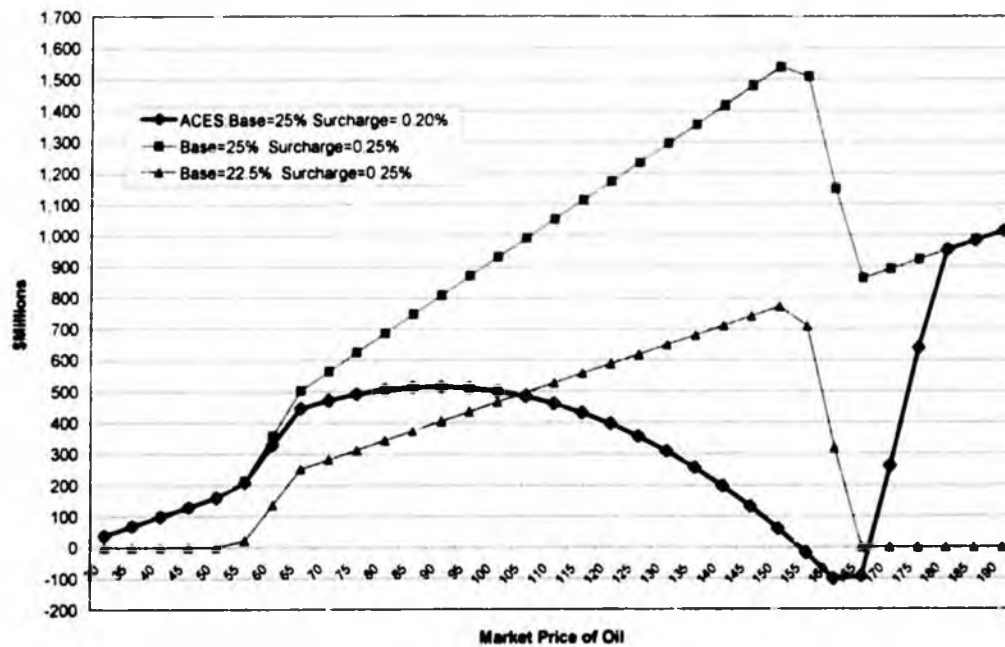


Figure 3 shows the sensitivity of revenue to changes in the base and surcharge tax rates. Adopting a 25% base rate and a \$30 trigger point without reducing the surcharge rate

Figure 3. State Revenue Change Under Variations of the ACES Proposal



would generate significantly more revenue than PPT (or ACES) at all oil prices above \$60. Retaining a 22.5% base rate and 0.25% surcharge rate while adopting a trigger point of \$30 would generate less revenue than ACES at oil prices below \$105, but more revenue at higher oil prices.

With variations in the base rate, surcharge rate and trigger point(s), the revenue curve can be designed to reflect whatever policy the legislature desires.

3. Tax Credits. Credits are arguably the most complex topic in the bill. A discussion of the fiscal impact of changes to tax credits would require knowing the amount (and type) of eligible credits that might be claimed. Legislative Finance does not have sufficient information to make projections. It should be clear, however, that reducing credits will increase revenue by more than indicated by a comparison of tax rates. In the figures above, the ACES line would be higher than shown if producers were allowed to claim fewer credits.

There are three types of tax credits. ACES makes a number of changes to tax credits as discussed below:

1. **Transitional Investment Credits.** These credits are for eligible capital expenditures incurred during the five years prior to the enactment of PPT. Statements in the press argue that because past investment events cannot be affected by changes to the production tax, these credits are essentially bonuses that reduce the tax liability of the major producers. ACES eliminates transitional credits.

Legislative Finance has no projection of the value of transitional credits that would be claimed under PPT or the value of credits that ACES would eliminate, but a few conceptual statements may clarify the analysis. The credits:

- are capped by time (they expire in 2013), by the amount invested in the transition period and by the amount invested in future years.
- are not simply giveaways; they cannot be claimed without additional investment.
- can be viewed as one-time bonuses that have no long-term impact on the tax structure.

Lest these points be taken as supporting retention of the credits, it should be noted that the credits are likely to cost the state several hundred million dollars in lost revenue.

2. **Direct tax credits.** These credits are deducted directly from producers' tax liability. The state has little control over the amount of the direct credits applied; they require no appropriation and are deducted from revenue projections.

Under ACES, tax credits remains at 20% of qualified capital expenditures, but no more than half the credit may be applied in any single year. This change may reduce volatility in the amount of credits applied in a given period and increase

the accuracy of revenue forecasts, but it has no significant long-term fiscal impact.

The allowable credit applied to a carried-forward annual loss is increased from 20% to 25% of the loss. This increase in available credits is offset by excluding losses based on lease expenditures in legacy fields. Legislative Finance has no projection of the fiscal impact of this change.

- 3. Transferable tax credits.** These credits are generally applicable to small producers who make qualified expenditures but whose current tax liability is insufficient to apply the credits to their tax bill. Under PPT, small producers can claim a cash refund or sell/transfer the credits to a producer with tax liability sufficient to apply the credits. ACES eliminates the credits/refunds limit of \$25 million per applicant per year.

ACES establishes a new fund designed to ease the process of claiming/purchasing transferable tax credit certificates. Approximately \$100 million to \$200 million (dependent on the price of oil) would be appropriated annually to the fund. The Department of Revenue can use the fund to purchase eligible certificates, presumably without further appropriation. If the Department expects to expend the fund without further appropriation, a statement to that effect would reduce uncertainty regarding the need for an appropriation from the fund and the status of the fund with regard to the constitutionally mandated sweep of available general fund balances to the Constitution Budget Reserve Fund.

An appropriation to purchase transferable credits was an item of contention in the FY08 budget process. The governor proposed an open-ended appropriation to pay for an estimated \$25 million in claims. The legislature capped the appropriation at \$25 million, but left the appropriation for FY07 open-ended. Based on the amount of credits purchased in FY07, a supplemental appropriation of \$75 million may be required for FY08.

- 4. Information requirements and other changes.** ACES includes several significant changes to the information that producers must provide to the state. The bill also includes several technical and conforming changes, and addresses unscheduled production interruption costs and auditing requirements of the Department. Explanation of these topics is best left to the Department of Revenue: the fiscal impact of such changes is minor relative to the impact of changes to tax rates and credits.

10-10-07

ACES Brief - Gous Confm - Atwood Bldg Anch

- Galvin, ^{P.} ^{M.} ^{Sen} ^{Sen} ^{Sen} ^{Sen} ^{Sen} ^{Sen}
Davis, Ellis, Stevens, French, Olson, Wiebeck, Thomas,
^{Sen} ^{Sen} ^{Sen} ^{Sen}
Green, Stedman, Huggins, Hoffman - multiple staff

- Galvin ^{current} PPT not stable.

- lack tools we need to adeq implement requirements of law
- gross base tax ^{does} not deliver flexibility to exercise economic drives necessary to sustain future exploration & dev
- gross tax "off the table" (Q by Green)
- tried multiple permutations of tax mechanisms including separating gas & oil = unmanageable
- gross "floor" kicks in in low price/high cost circumstances

- ACES

Q. Hoffman - did u consider effect of this on

! Galvin gasline - won't effect cost of line - may affect economics of fields

- we'll acquire cost data in AGIA apps & during open season which will show effect on gas development -

- gas field economic analysis will be worked back from tariff

Q Sted: does it disadvantage use to set rate prior to apps

Can they provide copy of "ACES Powerpoint"

Stedman - 30¢ barrel -

Galum - 30¢ revolved around "regular maintenance costs" - 30¢ was a proxy for ongoing maintenance (so we wouldn't have to constantly be auditing those)

dir: tax division - John Drensen - to Hollis F Q. re: nature of CO's tax returns
tax return is not itemized - items would be revealed thru audit

C.H. we're addressing symptoms to which we have no details

L. Hoffman: - this is rewrite of PPT -
will be quite difficult to accomplish in 30 days

- C.H. - have we briefed this off explorers -
Marsha yes - as well as large producers

- G. Starns - What is AK's "fair share"
how do we recognize it?
is it a dollar amt?

Galum - it's the line @ highest rate short
of squelching - ^{future} investments & exploration
- can not be based on expectation of a certain #
- must engender a positive investment environment

Stedman: re: ^{max} dollars in state coffers - state revenue needs
1) positive investment climate

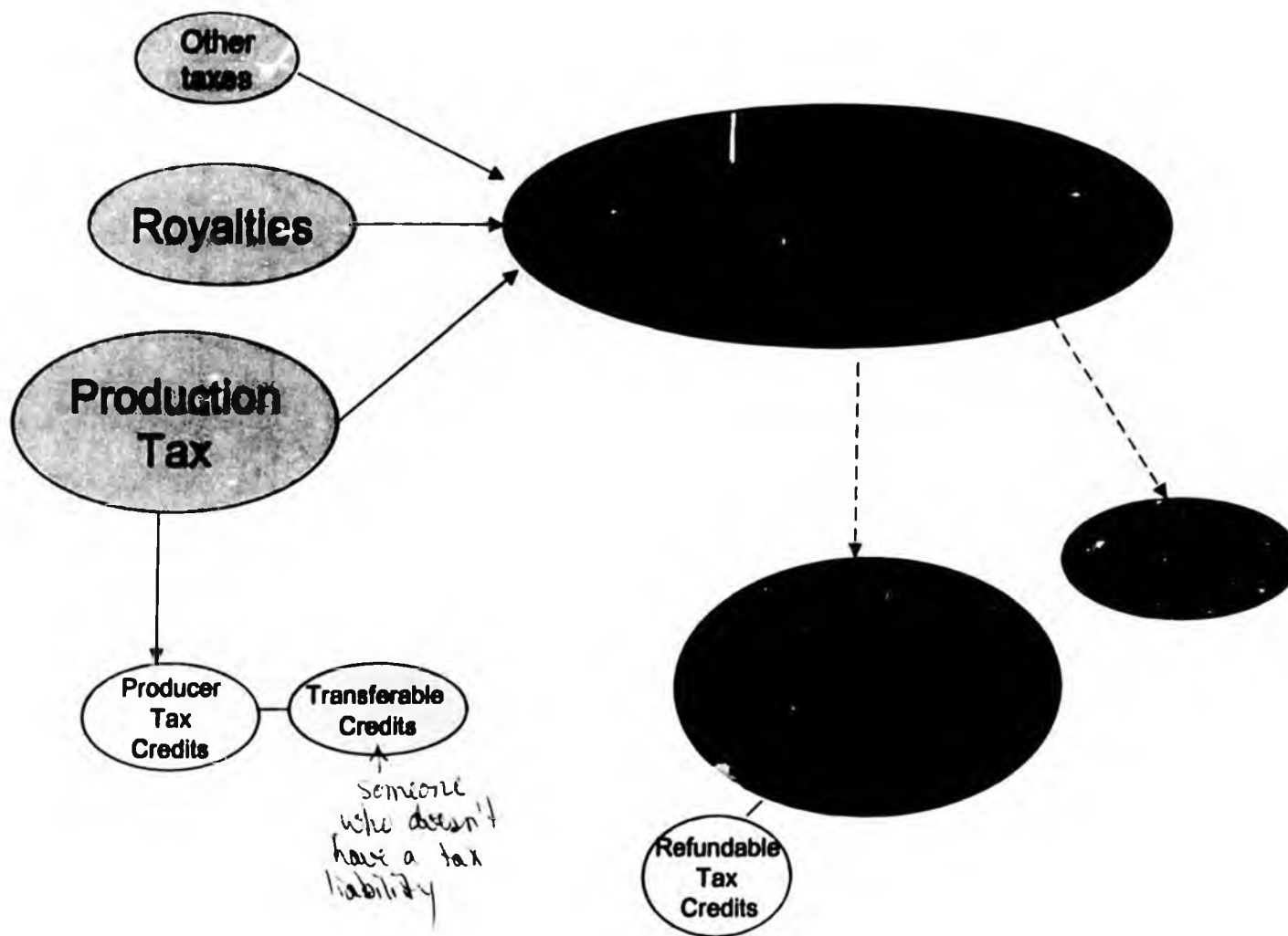
- Galvin - "not based on revenue needs"
- Sted - we'll look @ that when we address "tax floor"

▷ call G. Stambaugh ▷

Jerry Burnett -
DOR
Dir of Administration
@ STUD Oct 30, 2007

Current PPT Payment of Tax Credits

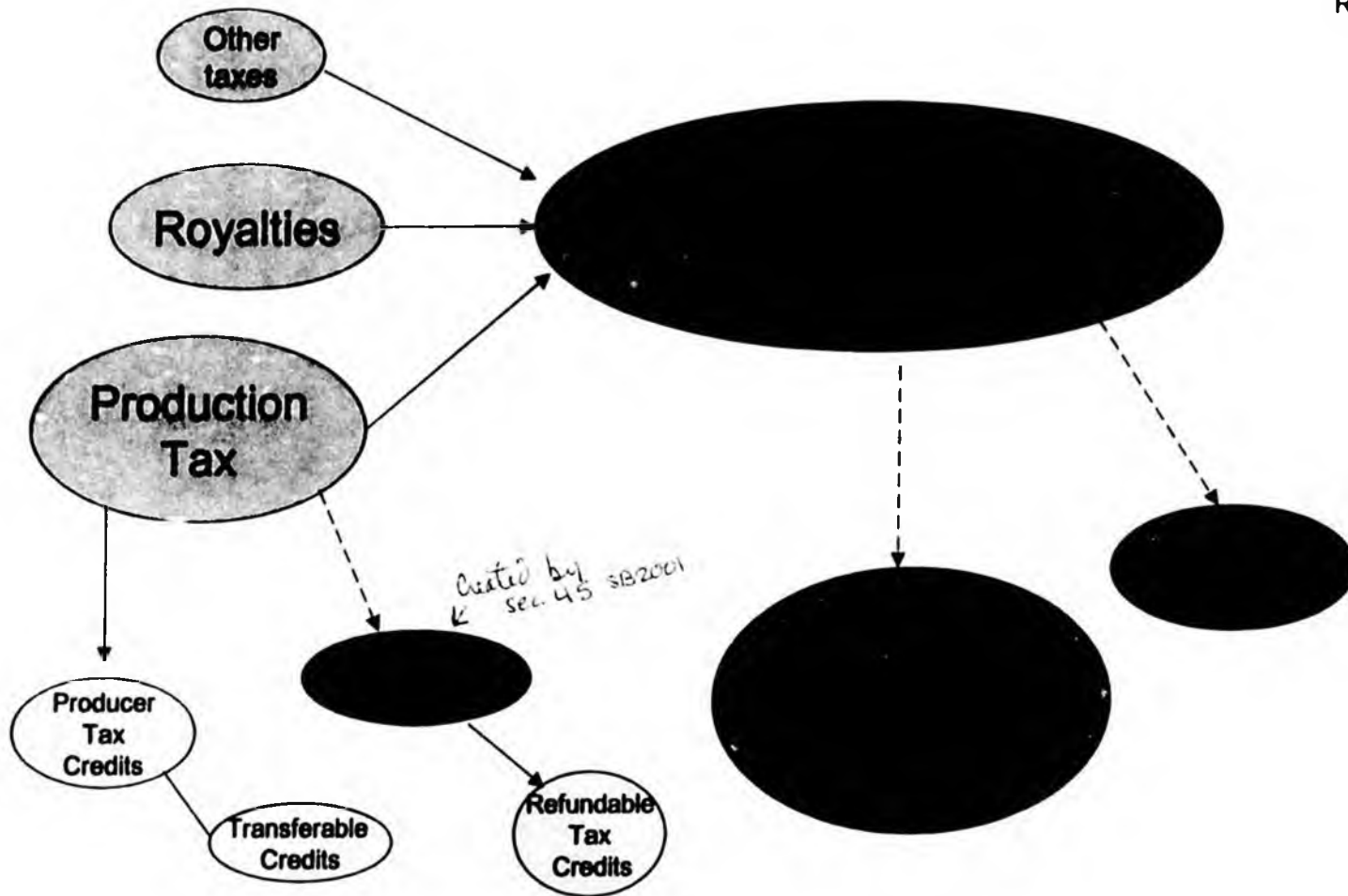
Blue=Revenue
Green=Fund
Orange=Budget
Yellow=Payment
Red Dotted Line=Appropriation



SEES
Gov Sec. 45

ACES Proposal Payment of Tax Credits

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



Tax Rates and Progressivity

November 8, 2007

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econ
ONE

Key Fiscal Terms

Production Taxes Under Current & Proposed Systems

Tax Rate:

$$\begin{aligned} & \text{Base Rate} \\ & + \\ & \text{Progressivity Rate} \\ & = \\ & \text{Total Tax Rate} \end{aligned}$$

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**

Key Fiscal Terms

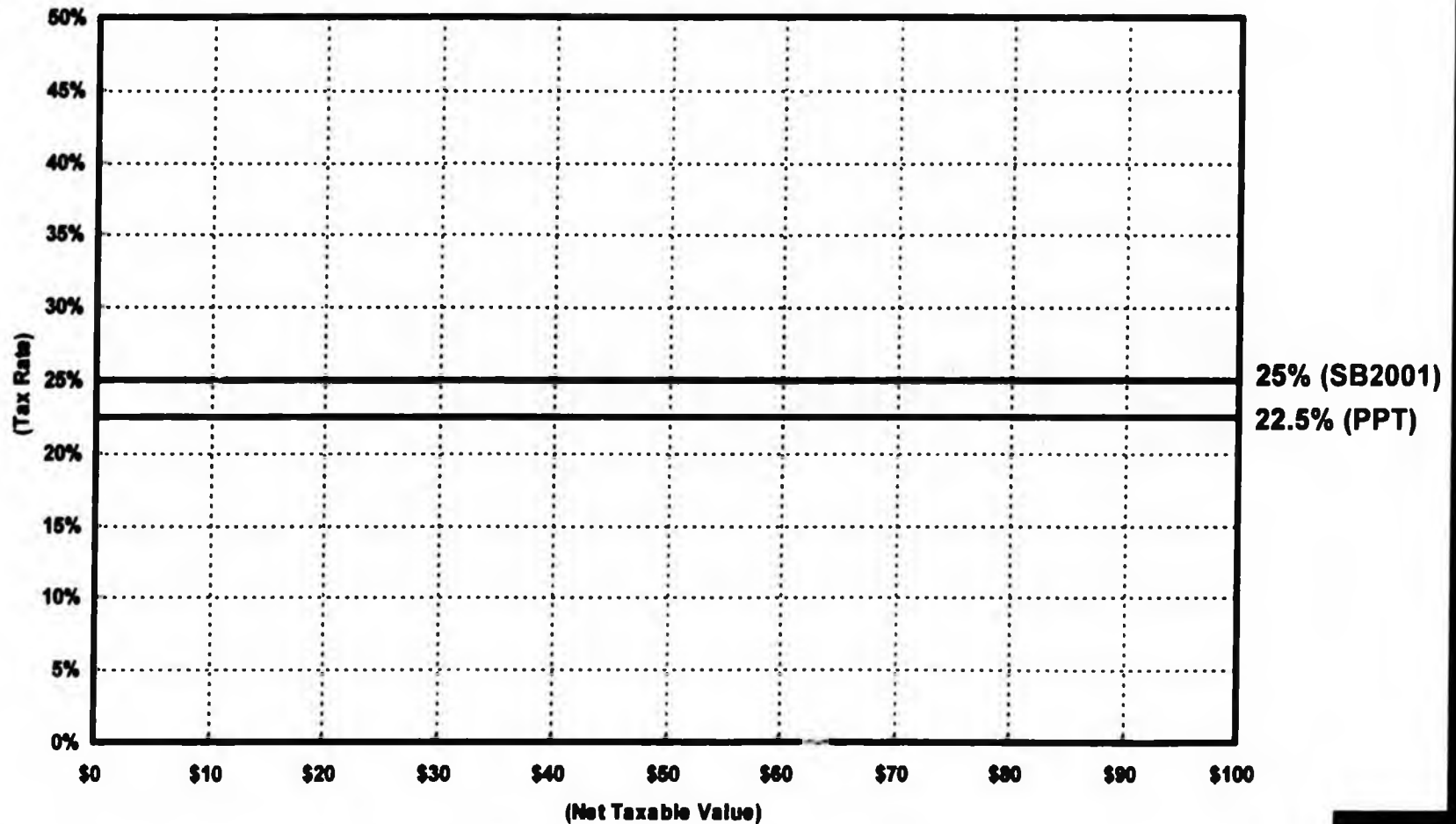
Production Taxes Under Current & Proposed Systems

Other Items:

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

Base Tax Rate

- **Applied to Taxable Value at All Price Levels**



- **It Does Not Vary with Prices**

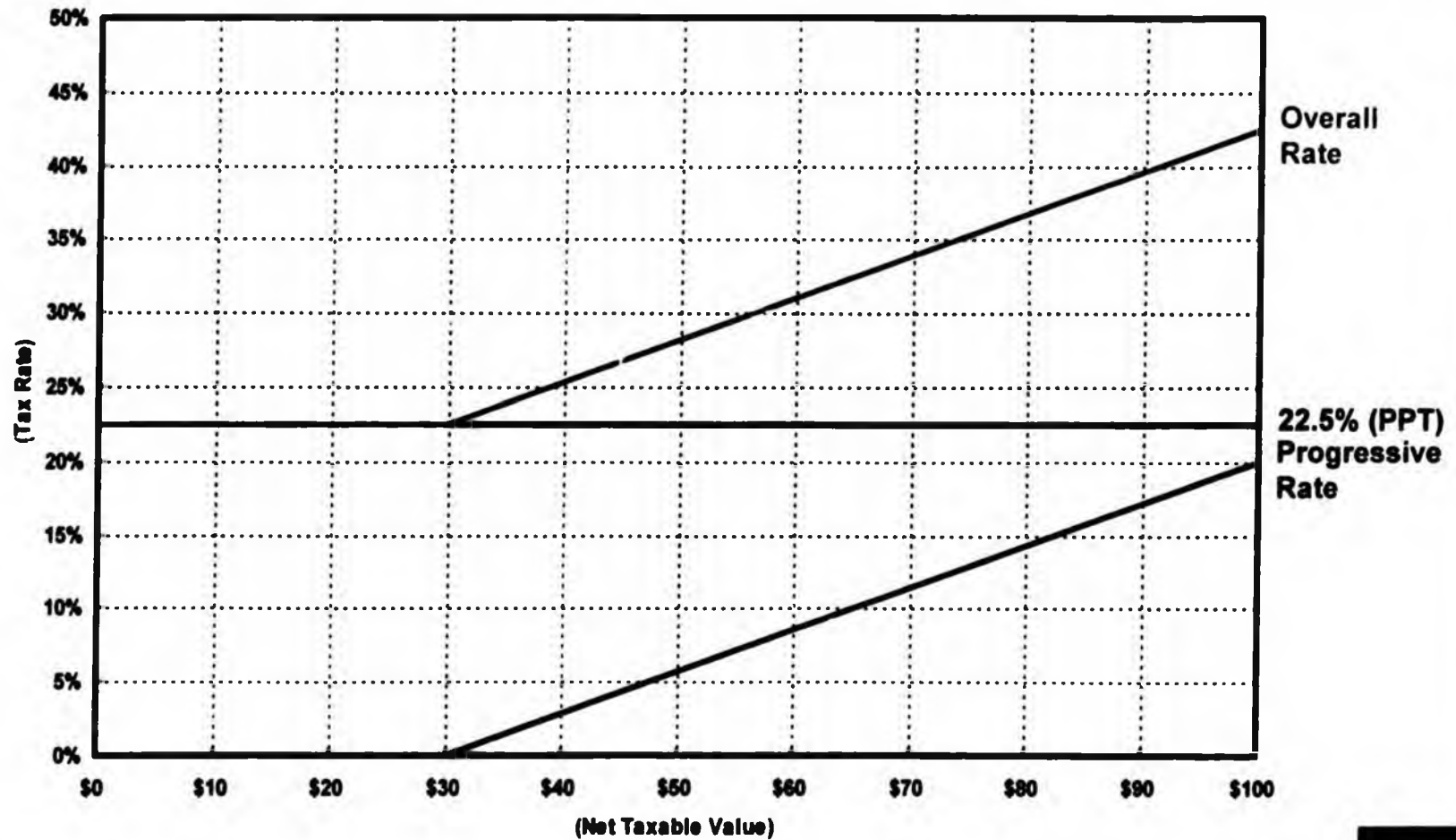
Progressive Tax

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



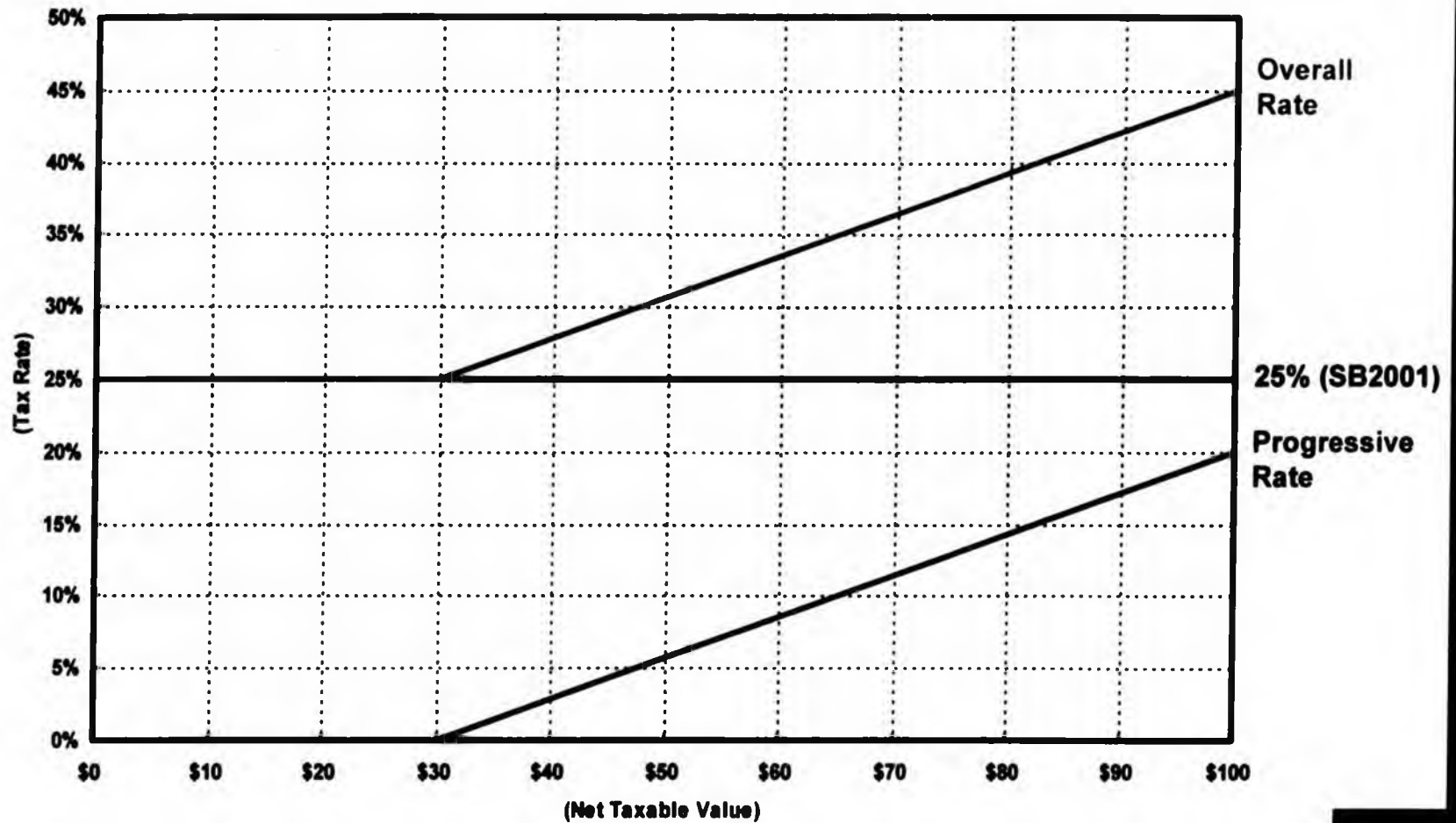
Progressive Tax

- Example of Progressive Tax Under Current & Proposed Systems



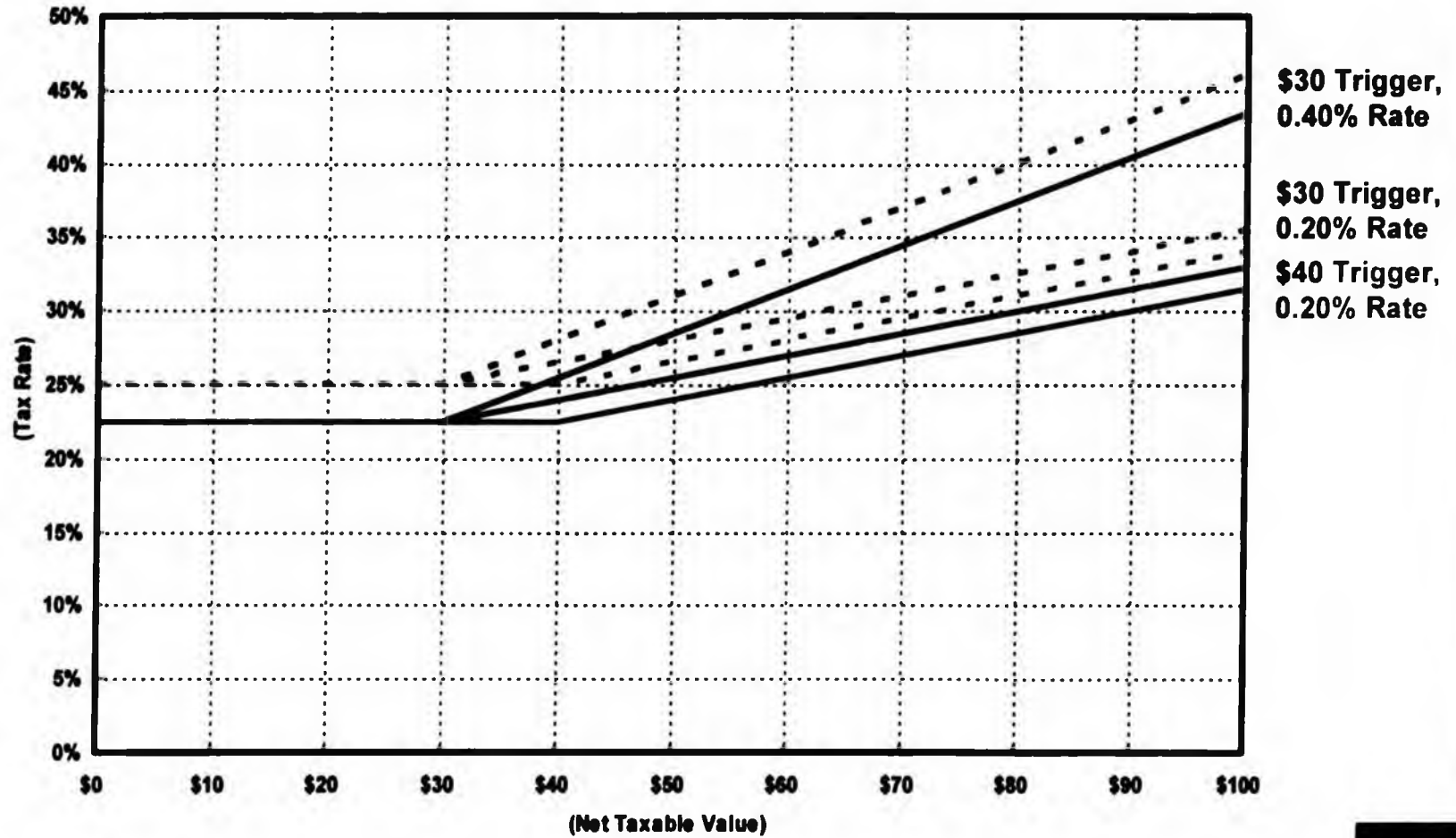
Progressive Tax

- Example of Progressive Tax Under Current & Proposed Systems

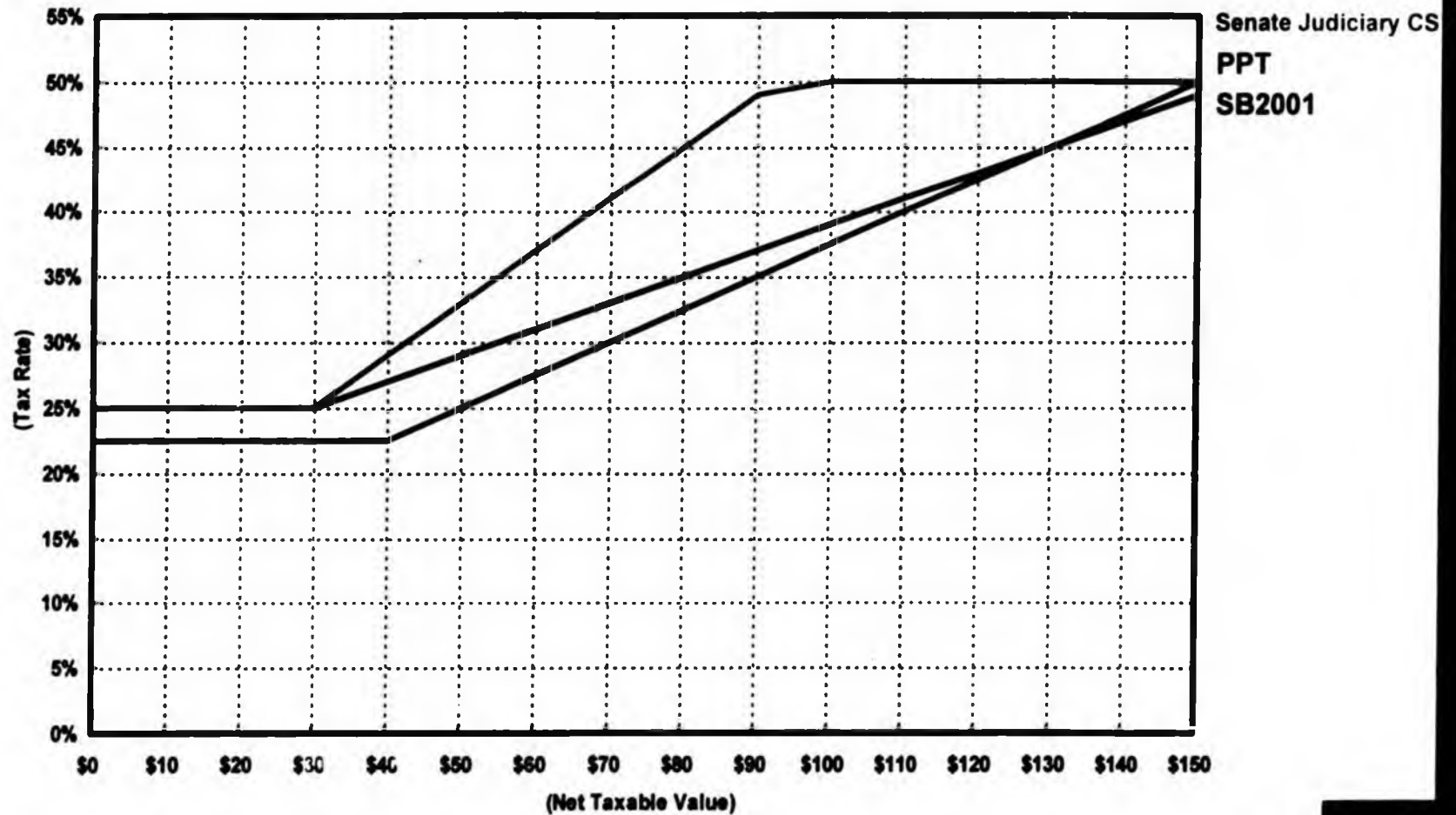


Progressive Tax & Impact on Overall Tax Rate

- **At 22.5% and 25% Tax Rates**

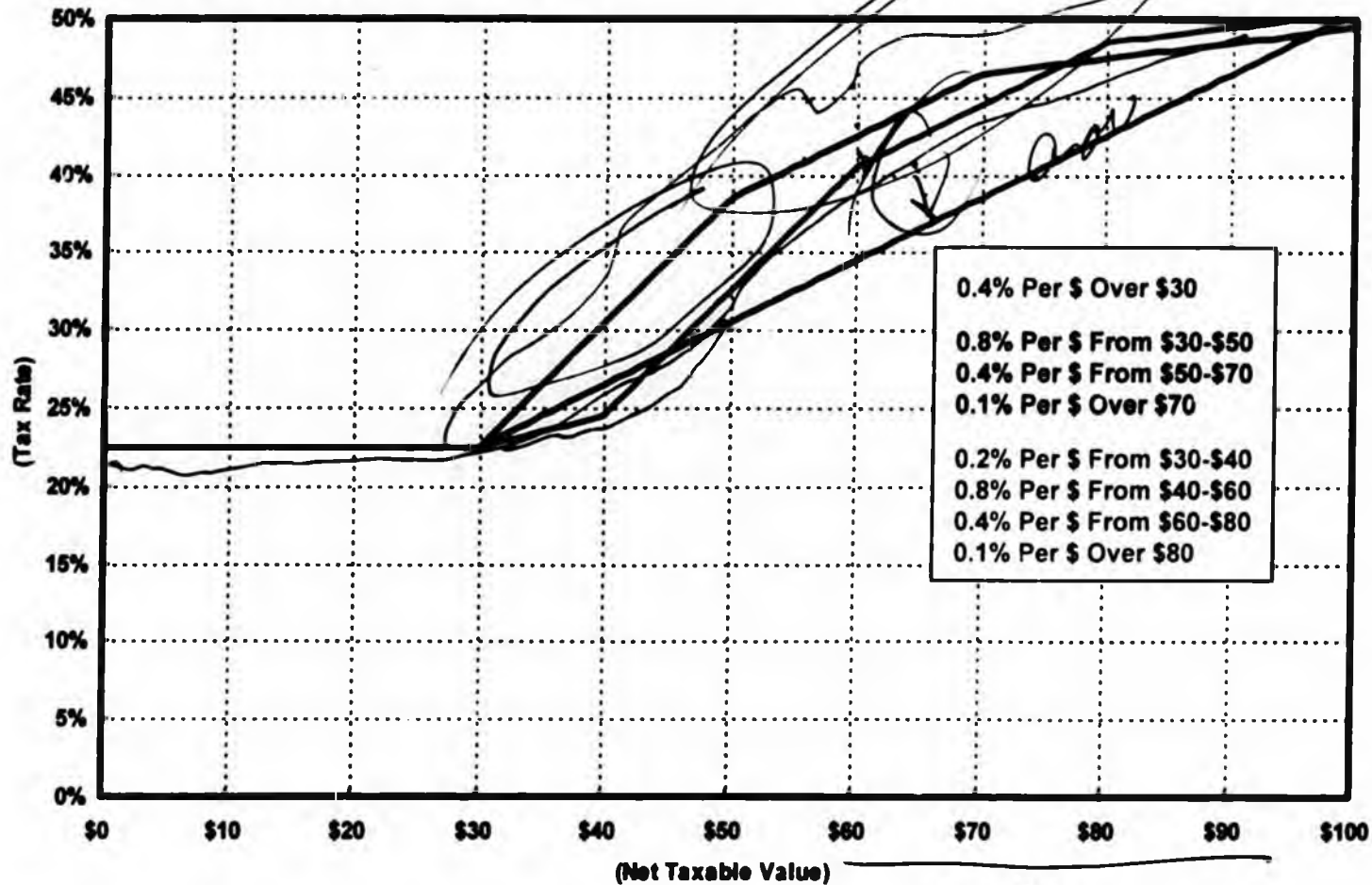


Overall Tax Rates: PPT, SB2001 and Senate Judiciary CS



Progressive Tax & Impact on Overall Tax Rate

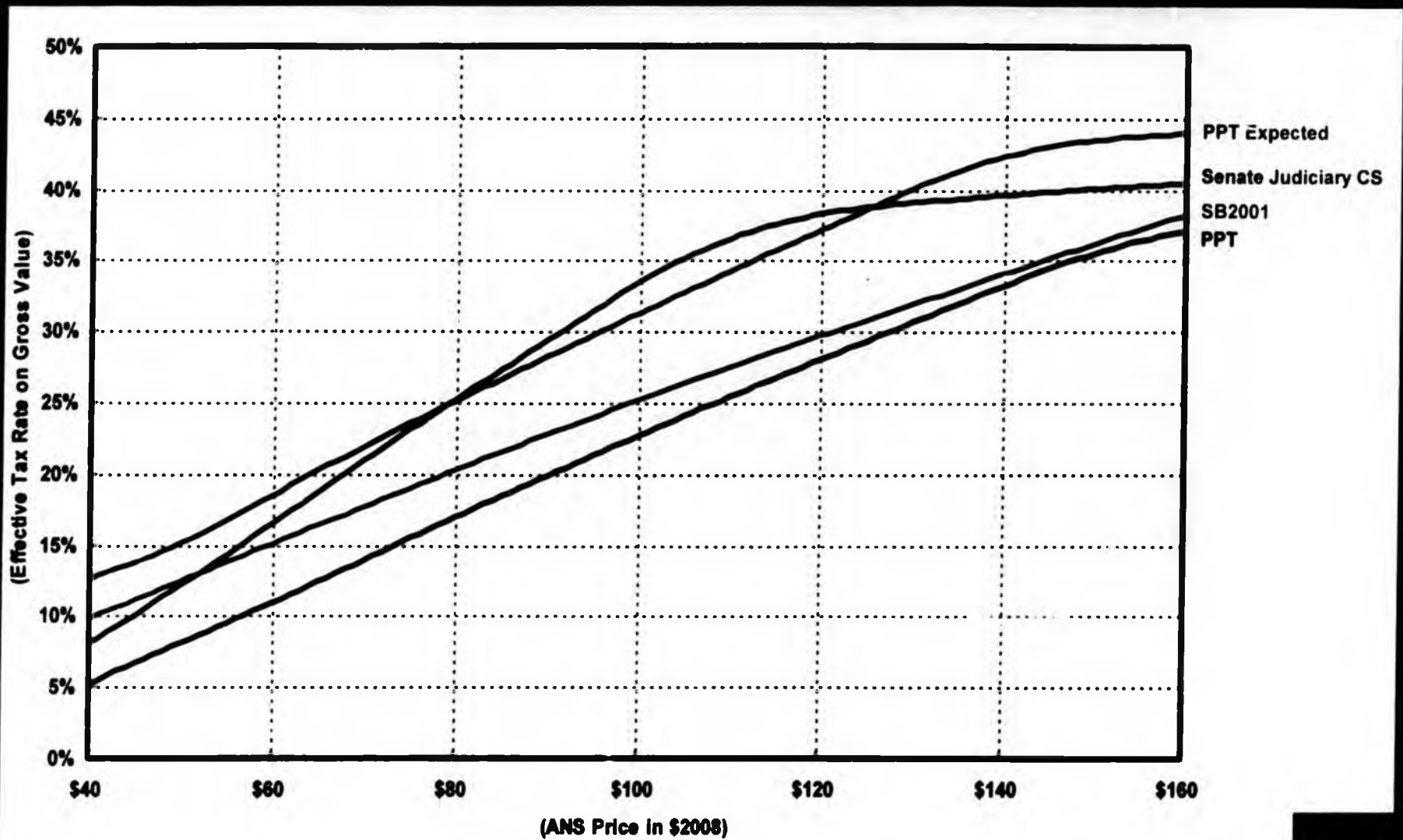
• Assume a 22.5% Tax Rate



22.5

margin

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



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%	18.6%	25.2%	31.3%	37.2%	42.3%	43.9%
Total Government Share of Net Cash (Percent) <i>(State & Fed: Manic)</i>							
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) <i>each 1/10 increase = production tax increase - state's percent take increases</i>							
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	\$1,565	\$2,088	\$2,682	\$3,132	\$2,688

% of net income after costs deducted

% change of govt share w/ price increase

25% tax rate
25%
different progressivity

Hoffman - money isn't in the tax rate but rather in the progressivity slope



Tax Floor Issues

PPT (Current Law)

**1-4% of Gross
Wellhead Value
(\$15 - \$25 WC ANS)**

SB2001 (Proposed)

**10% of Gross
Wellhead Value
(Prudhoe & Kuparuk)**

Senate Judiciary CS

**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?**

ACES Proposal for Petroleum Taxation
Tax Rate at Various Values of a Barrel of Oil

Base Tax Rate: 22.5%
 Surcharge: 0.25%
 Trigger Point: \$ 40.00
 Maximum Surcharge: 25.0%

Base Tax Rate: [REDACTED]
 Surcharge: [REDACTED]
 Trigger Point: [REDACTED]
 Maximum Surcharge: [REDACTED]

Existing Tax Structure (PPT)			ACES Proposal					ACES Increase									
Market Price	Taxable Value	Net Price	Surcharge Rate	Total Tax Rate	Base Revenue	Surcharge Revenue	Total Revenue	Surcharge Rate	Total Tax Rate	Base Revenue	Surcharge Revenue	Total Revenue	Base Revenue	Surcharge Revenue	Total Revenue	Percent of Revenue	Total Tax Rate
30	1.500	8.15	0.00%	22.50%	337.5	-	337.5	0.00%	25.00%	375.0	-	375.0	37.5	-	37.5	11.1%	2.50%
35	2.720	11.15	0.00%	22.50%	612.0	-	612.0	0.00%	25.00%	680.0	-	680.0	68.0	-	68.0	11.1%	2.50%
40	3.940	16.15	0.00%	22.50%	886.5	-	886.5	0.00%	25.00%	985.0	-	985.0	98.5	-	98.5	11.1%	2.50%
45	5.160	21.15	0.00%	22.50%	1,161.0	-	1,161.0	0.00%	25.00%	1,290.0	-	1,290.0	129.0	-	129.0	11.1%	2.50%
50	6.380	26.15	0.00%	22.50%	1,435.5	-	1,435.5	0.00%	25.00%	1,595.0	-	1,595.0	159.5	-	159.5	11.1%	2.50%
55	7.600	31.15	0.00%	22.50%	1,710.0	-	1,710.0	0.23%	25.23%	1,900.0	17.5	1,917.5	190.0	17.5	207.5	12.1%	2.73%
60	8.820	36.15	0.00%	22.50%	1,984.5	-	1,984.5	1.23%	26.23%	2,205.0	108.5	2,313.5	220.5	108.5	329.0	16.6%	3.73%
65	10.040	41.15	0.29%	22.79%	2,259.0	28.8	2,287.8	2.23%	27.23%	2,510.0	223.9	2,733.9	251.0	195.0	446.0	19.5%	4.44%
70	11.260	46.15	1.54%	24.04%	2,533.5	173.1	2,706.6	3.23%	28.23%	2,815.0	363.7	3,178.7	281.5	190.6	472.1	17.4%	4.19%
75	12.480	51.15	2.79%	25.29%	2,808.0	347.8	3,155.8	4.23%	29.23%	3,120.0	527.9	3,647.9	312.0	180.0	492.0	15.6%	3.94%
80	13.700	56.15	4.04%	26.54%	3,082.5	553.1	3,635.6	5.23%	30.23%	3,425.0	716.5	4,141.5	342.5	163.4	505.9	13.9%	3.69%
85	14.920	61.15	5.29%	27.79%	3,357.0	788.9	4,145.9	6.23%	31.23%	3,730.0	929.5	4,659.5	373.0	140.6	513.6	12.4%	3.44%
90	16.140	66.15	6.54%	29.04%	3,631.5	1,055.1	4,686.6	7.23%	32.23%	4,035.0	1,166.9	5,201.9	403.5	111.8	515.3	11.0%	3.19%
95	17.360	71.15	7.79%	30.29%	3,906.0	1,351.9	5,257.9	8.23%	33.23%	4,340.0	1,428.7	5,768.7	434.0	76.8	510.8	9.7%	2.94%
100	18.580	76.15	9.04%	31.54%	4,180.5	1,679.1	5,859.6	9.23%	34.23%	4,645.0	1,714.9	6,359.9	464.5	35.8	500.3	8.5%	2.69%
105	19.800	81.15	10.29%	32.79%	4,455.0	2,038.9	6,493.9	10.23%	35.23%	4,950.0	2,025.5	6,975.5	495.0	(11.4)	483.6	7.4%	2.44%
110	21.020	86.15	11.54%	34.04%	4,729.5	2,425.1	7,154.6	11.23%	36.23%	5,255.0	2,360.5	7,615.5	525.5	(64.6)	460.9	6.4%	2.19%
115	22.240	91.15	12.79%	35.29%	5,004.0	2,843.9	7,847.9	12.23%	37.23%	5,560.0	2,719.9	8,279.9	556.0	(124.0)	432.0	5.5%	1.94%
120	23.460	96.15	14.04%	36.54%	5,278.5	3,293.1	8,571.6	13.23%	38.23%	5,865.0	3,103.7	8,968.7	586.5	(189.4)	397.1	4.6%	1.69%
125	24.680	101.15	15.29%	37.79%	5,553.0	3,772.9	9,325.9	14.23%	39.23%	6,170.0	3,511.9	9,681.9	617.0	(261.0)	356.0	3.8%	1.44%
130	25.900	106.15	16.54%	39.04%	5,827.5	4,283.1	10,110.6	15.23%	40.23%	6,475.0	3,944.5	10,419.5	647.5	(338.6)	308.9	3.1%	1.19%
135	27.120	111.15	17.79%	40.29%	6,102.0	4,823.9	10,925.9	16.23%	41.23%	6,780.0	4,401.5	11,181.5	678.0	(422.4)	255.6	2.3%	0.94%
140	28.340	116.15	19.04%	41.54%	6,376.5	5,395.1	11,771.6	17.23%	42.23%	7,085.0	4,882.9	11,967.9	708.5	(512.2)	196.3	1.7%	0.69%
145	29.560	121.15	20.29%	42.79%	6,651.0	5,996.9	12,647.9	18.23%	43.23%	7,390.0	5,388.7	12,778.7	739.0	(608.2)	130.8	1.0%	0.44%
150	30.780	126.15	21.54%	44.04%	6,925.5	6,629.2	13,554.7	19.23%	44.23%	7,695.0	5,918.9	13,613.9	769.5	(710.2)	59.3	0.4%	0.19%
155	32.000	131.15	22.79%	45.29%	7,200.0	7,291.9	14,491.9	20.23%	45.23%	8,000.0	6,473.5	14,473.5	800.0	(818.4)	(18.4)	-0.1%	-0.06%
160	33.220	136.15	24.04%	46.54%	7,474.5	7,985.2	15,459.7	21.23%	46.23%	8,305.0	7,052.5	15,357.5	830.5	(932.6)	(102.1)	-0.7%	-0.31%
165	34.440	141.15	25.00%	47.50%	7,749.0	8,610.0	16,359.0	22.23%	47.23%	8,610.0	7,655.9	16,265.9	861.0	(954.1)	(93.1)	-0.6%	-0.27%
170	35.660	146.15	25.00%	47.50%	8,023.5	8,915.0	16,938.5	23.23%	48.23%	8,915.0	8,283.7	17,198.7	891.5	(631.3)	260.2	1.5%	0.73%
175	36.880	151.15	25.00%	47.50%	8,298.0	9,220.0	17,518.0	24.23%	49.23%	9,220.0	8,935.9	18,155.9	922.0	(284.1)	637.9	3.6%	1.73%
180	38.100	156.15	25.00%	47.50%	8,572.5	9,525.0	18,097.5	25.00%	50.00%	9,525.0	9,525.0	19,050.0	952.5	-	952.5	5.3%	2.50%
185	39.320	161.15	25.00%	47.50%	8,847.0	9,830.0	18,677.0	25.00%	50.00%	9,830.0	9,830.0	19,660.0	983.0	-	983.0	5.3%	2.50%
190	40.540	166.15	25.00%	47.50%	9,121.5	10,135.0	19,256.5	25.00%	50.00%	10,135.0	10,135.0	20,270.0	1,013.5	-	1,013.5	5.3%	2.50%

Taxable value is estimated by subtracting variable costs (\$7.22/bbl) and upstream costs (\$4.058 billion) from the product of price and volume (244 mmbbls).
 Net price subtracts \$23.85/bbl (as determined by the computation for taxable value) from market price.

Attached is response to Senate Resources Chairman, Sen. Huggins request for an illustration of ALL sources of revenue/income from the oil industry in Alaska, by category, showing actuals for years '05, '06, '07 and projected for 2008.

From DOR 10/23/07

Title: FY2005 to FY 2008 Petroleum Revenue

Data Sources: Alaska Department of Revenue, Tax Division
FY 2005 & FY 2006 from DOR historical database
FY 2007 Preliminary estimates
FY 2008 forecast from the Spring 2007 *Revenue Sources Book*

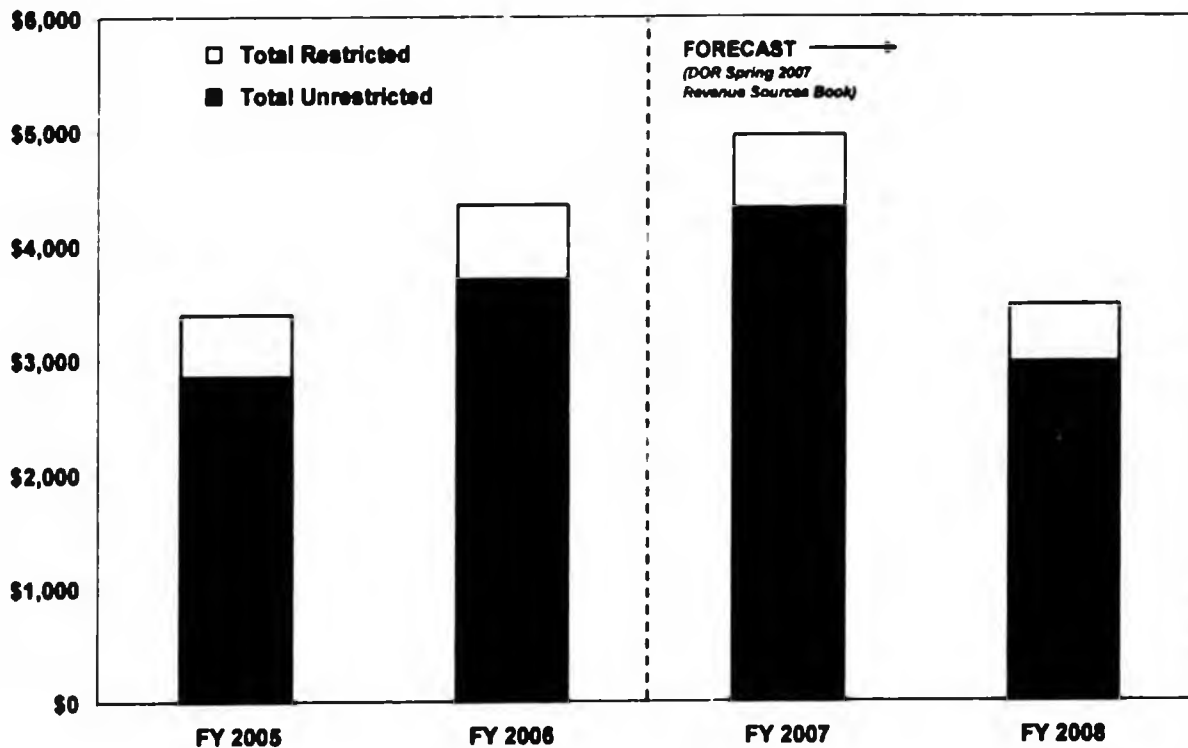
Prepared by: Jennifer Duval, Economist
jennifer.duval@alaska.gov

Date: October 23, 2007

Purpose: Request by Senator Huggins

Notes: Dollar amounts are millions of nominal dollars

Total Oil Revenue
in Millions of Dollars



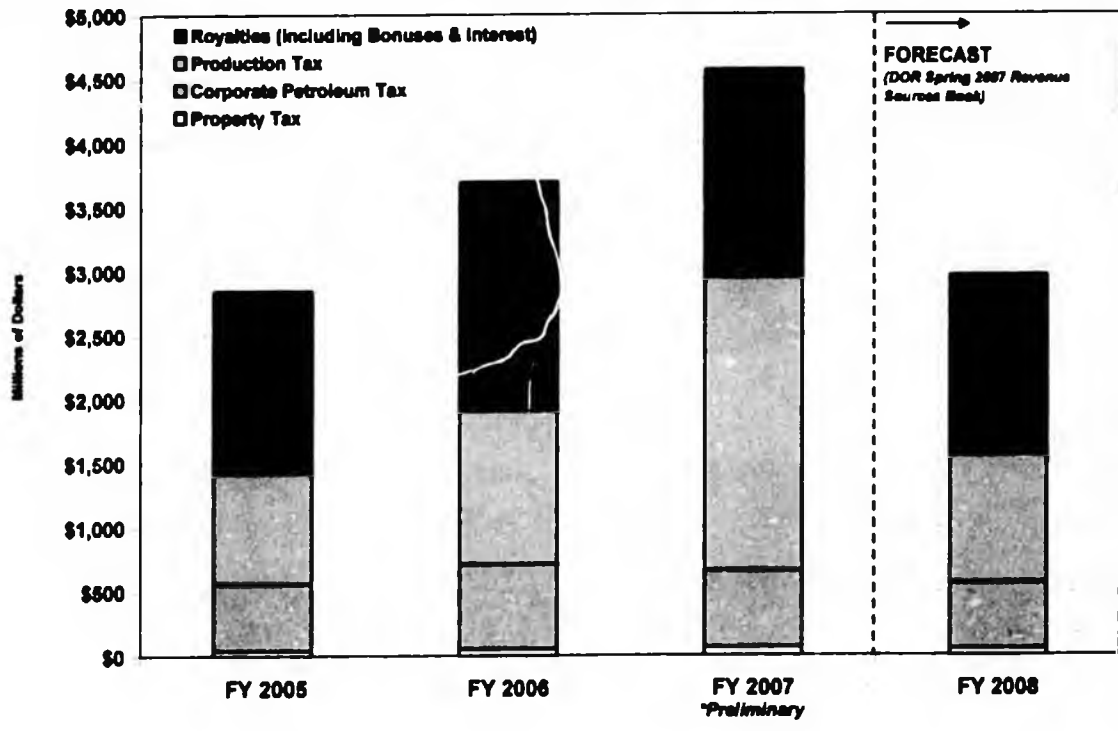
Historical and Forecast Oil Revenues FY 2005 - FY 2008

Source: DOR Spring 2007 Revenue Sources Book

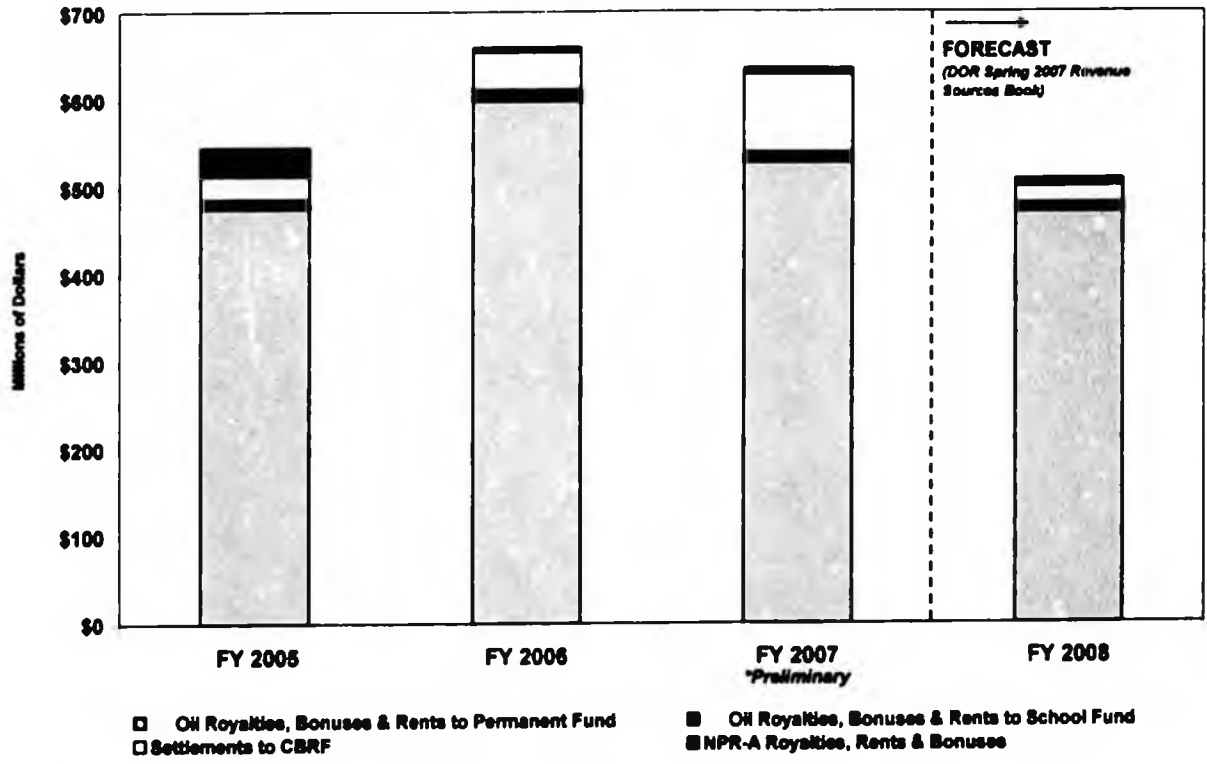
<i>In Millions of Dollars</i>	ACTUAL FY 2005	ACTUAL FY 2006	PRELIM ACTUAL FY 2007 (10/22/07)	SPR 07 FORECAST FY 2008
Unrestricted				
Property Tax	42.5	54.5	65.6	59.2
Corporate Petroleum Tax	524.0	661.1	594.4	512.1
Oil & Gas Production	854.9	1,191.7	2,282.2	983.1
Oil & Gas Hazardous Release	8.3	7.8	10.1	12.3
Production Tax	863.2	1,199.5	2,292.3	995.4
Mineral Bonuses & Rents	17.4	11.6	22.2	14.8
Oil and Gas Royalties	1401.1	1772.2	1,583.8	1,390.3
Interest	1.4	0.3	7.0	1.4
Royalties (including Bonuses & Interest)	1419.9	1784.1	1,613.0	1408.4
Total Unrestricted	2,849.6	3,699.2	4,565.3	2967.10
Year-over-Year change	795.5	849.6	866.1	-1,598.2
Year-over-Year % change	38.7%	29.8%	23.4%	-35.0%
Restricted				
Oil Royalties, Bonuses & Rents to Permanent Fund	478.9	599.5	535.0	471.8
Oil Royalties, Bonuses & Rents to School Fund	9.8	12	10.6	9.4
Royalties to Permanent Fund & School Fund + Bonuses & Interest	488.5	611.5	545.7	480.9
Settlements to CBRF	27.4	43.7	113.6	20
NPR-A Royalties, Rents & Bonuses	31.6	4.5	12.8	7.6
Total Restricted	648.5	669.7	672.1	609.5
Total Oil	3,398.1	4,368.9	5,237.4	3,476.6

<i>Percent of Total Oil</i>	FY 2005	FY 2006	FY 2007	FY 2008
Property Tax	1.3%	1.3%	1.3%	1.6%
Corporate Petroleum Tax	15.4%	15.2%	11.3%	14.7%
Oil & Gas Production	25.2%	27.3%	43.6%	28.3%
Oil & Gas Hazardous Release	0.2%	0.2%	0.2%	0.4%
Production Tax	25.4%	27.5%	43.8%	28.6%
Mineral Bonuses & Rents	0.5%	0.3%	0.4%	0.4%
Oil and Gas Royalties	41.3%	40.7%	30.2%	40.0%
Interest	0.0%	0.0%	0.1%	0.0%
Royalties (including Bonuses & Interest)	41.8%	40.9%	30.8%	40.5%
Total Unrestricted	83.9%	84.9%	87.2%	85.4%
Restricted				
Oil Royalties, Bonuses & Rents to Permanent Fund	14.0%	13.8%	10.2%	13.6%
Oil Royalties, Bonuses & Rents to School Fund	0.3%	0.3%	0.2%	0.3%
Royalties to Permanent Fund & School Fund + Bonuses & Interest	14.3%	14.0%	10.4%	13.8%
Settlements to CBRF	0.8%	1.0%	2.2%	0.6%
NPR-A Royalties, Rents & Bonuses	0.9%	0.1%	0.2%	0.2%
Total Restricted	16.1%	15.1%	12.8%	14.6%
Total Oil	100%	100%	100%	100%

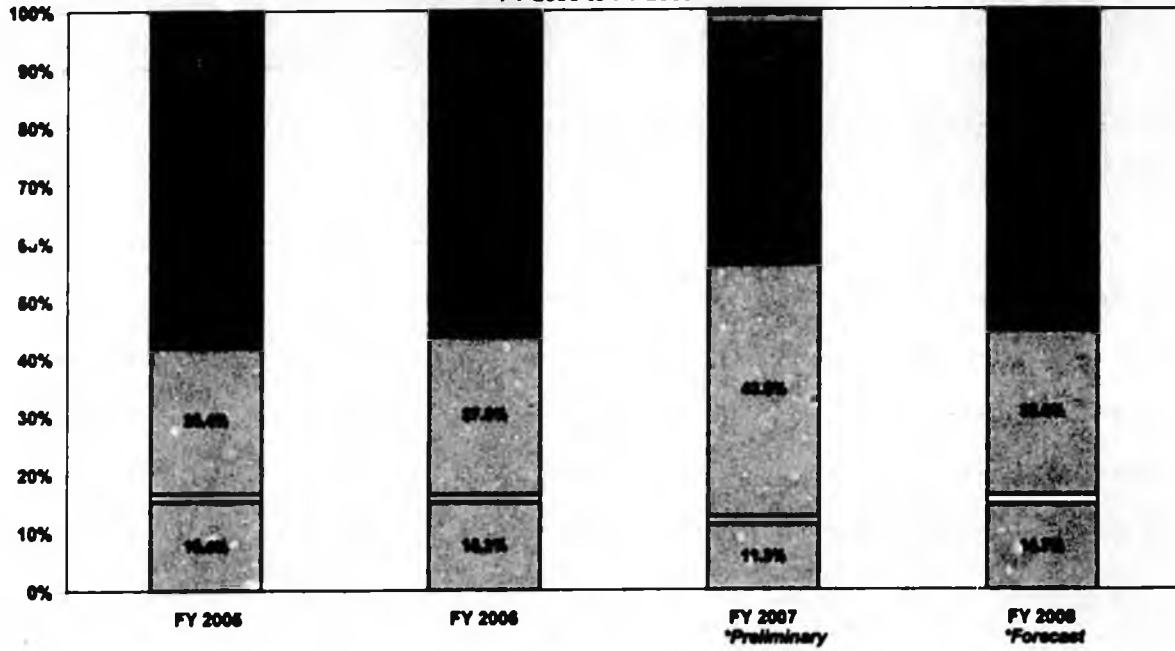
Unrestricted Oil Revenue by Category FY 2005 to FY 2008



Restricted Oil Revenue FY 2005 to FY 2008

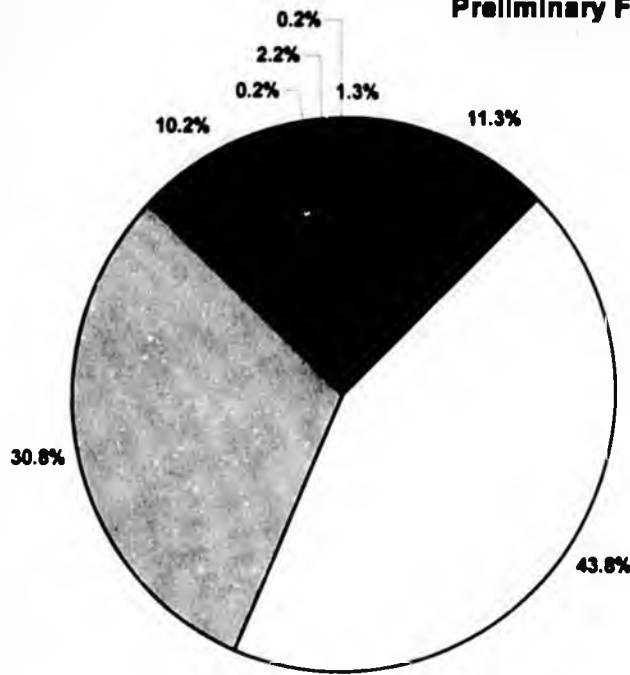


Percent Distribution of Total Oil Revenues by Year
FY 2005 to FY 2008



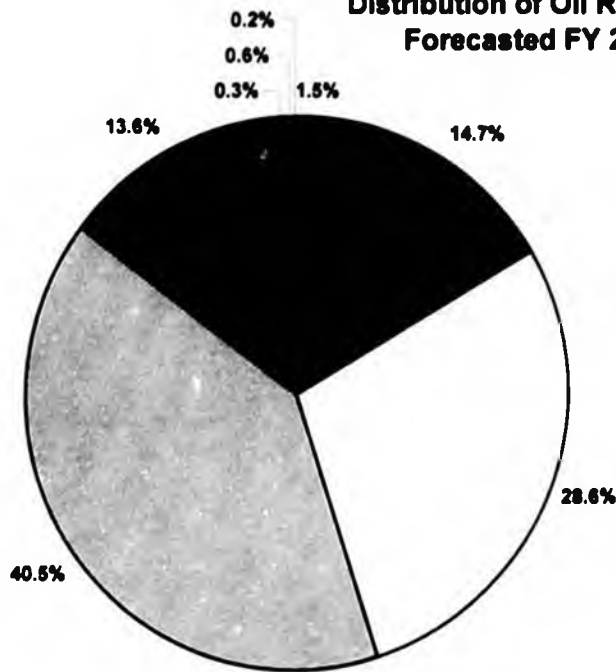
- Corporate Petroleum Tax
- Production Tax
- Oil Royalties, Bonuses & Rents to Permanent Fund
- Other Restricted
- Property Tax
- Royalties (including Bonuses & Interest)
- Settlements to CBRF

**Distribution of Oil Revenues
Preliminary FY 2007**



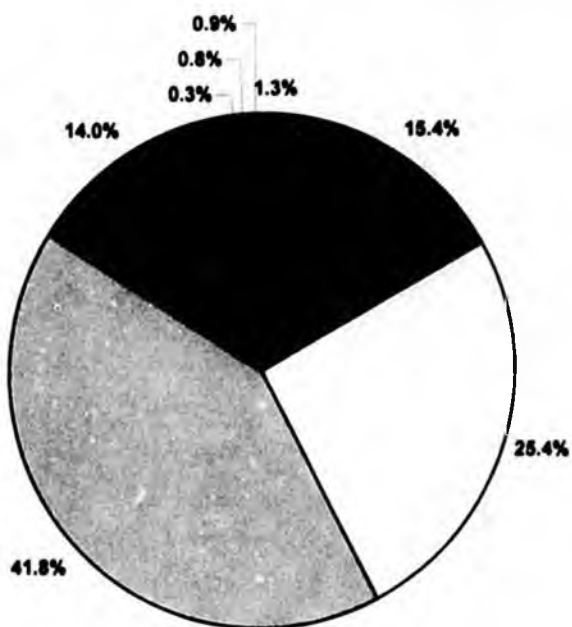
- Property Tax
- Corporate Petroleum Tax
- Production Tax
- Royalties (including Bonuses & Interest)
- Oil Royalties, Bonuses & Rents to Permanent Fund
- Oil Royalties, Bonuses & Rents to School Fund
- Settlements to CBRF
- NPR-A Royalties, Rents & Bonuses

**Distribution of Oil Revenues
Forecasted FY 2008**



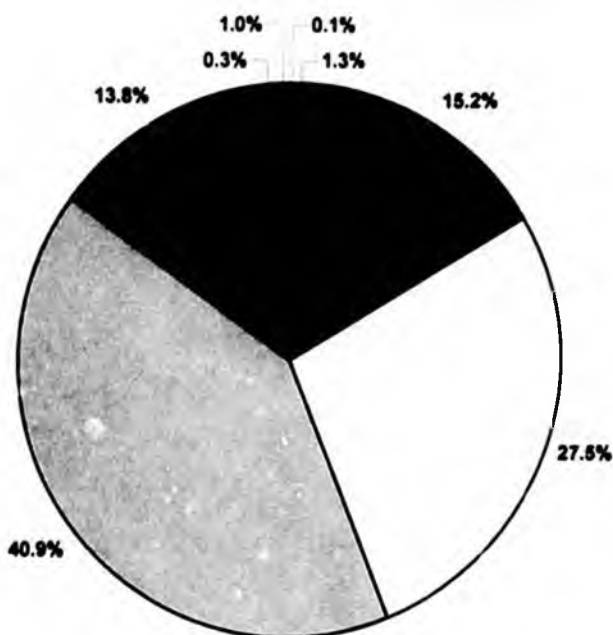
- Property Tax
- Corporate Petroleum Tax
- Production Tax
- Royalties (including Bonuses & Interest)
- Oil Royalties, Bonuses & Rents to Permanent Fund
- Oil Royalties, Bonuses & Rents to School Fund
- Settlements to CBRF
- NPR-A Royalties, Rents & Bonuses

**Distribution of Oil Revenues
FY 2005**



- Property Tax
- Corporate Petroleum Tax
- Production Tax
- Royalties (including Bonuses & Interest)
- Oil Royalties, Bonuses & Rents to Permanent Fund
- Oil Royalties, Bonuses & Rents to School Fund
- Settlements to CBRF
- NPR-A Royalties, Rents & Bonuses

**Distribution of Oil Revenues
FY 2006**



- Property Tax
- Corporate Petroleum Tax
- Production Tax
- Royalties (including Bonuses & Interest)
- Oil Royalties, Bonuses & Rents to Permanent Fund
- Oil Royalties, Bonuses & Rents to School Fund
- Settlements to CBRF
- NPR-A Royalties, Rents & Bonuses

Tax Interest and Penalties Under ACES and Current Law

Distributed by the Department of Revenue

October 29, 2007

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

Basic Penalty

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

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

Negligence Penalty

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

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

² 15 AAC 05.200.

intentional disregard may be shown by any relevant evidence including that the taxpayer has substantially deviated from the statutes or regulations, failed to keep adequate records, exaggerated deductions, or understated income without justification.³

Fraud Penalty

If a deficiency is due to fraud, the department shall add a penalty equal to 50% of the tax due or \$500, whichever is greater. The penalty is calculated based on the total deficiency, even if only a part of the deficiency is due to fraud. To establish fraud, the department must show by clear and convincing evidence that the taxpayer understated a tax liability with the intent to evade tax. The intent to evade the tax may be shown by any relevant evidence including evidence of false explanations regarding income, false source documents, unjustified omissions or significant understatements of income, or substantial overstatement of a deduction.⁴

In addition to the three civil penalties discussed above, AS 43.05.290 provides for a number of criminal penalties for tax evasion and willful failure to comply with payment, filing, truthful accounting and information requirements, and for perjury. Along with several misdemeanors, penalties include felonies for willfully attempting to evade a tax, willfully failing to truthfully account for and pay a tax, and willfully and knowingly assisting in preparing or presenting a false return.

ACES does not propose any change to these penalties or their current application to the oil and gas production tax. ACES does, however, add penalties for failure to comply with the various information reporting requirements contained in the bill. The penalty provisions allow the department to assess against a person that fails to make the required report a penalty of not more than \$1000 per day for each day the person fails to file the document. The reason for these additional penalty provisions is to ensure compliance with reporting requirements regardless of whether there is any tax deficiency. Unlike other penalties currently available to the department, the new penalties in ACES are not calculated based on a tax deficiency. This is important because the department needs timely and complete reporting of costs, potential tax credits, etc., even from explorers and producers that may not currently owe any tax.

³ AS 43.05.220(b); 15 AAC 05.210(g). For more detail on the additional penalty for negligence or intentional disregard, see 15 AAC 05.220.

⁴ AS 43.05.220(c); 15 AAC 05.230.

Interest

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

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

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

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

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

⁵ AS 43.55.020(g); 26 U.S.C. 6621.

⁶ AS 43.55.020(h); 26 U.S.C. 6621.

⁷ AS 43.55.020(g); 43.05.225.

⁸ AS 43.55.020(h); 43.05.225.

Capital Spending on Alaska's North Slope Wells, Field Facilities and Exploration

Millions of nominal Dollars (dollars of the day)

	BP			ARCO/ConocoPhillips			Exxon			Other			All Companies		
	Exp	Dev	Tot	Exp	Dev	Tot	Exp	Dev	Tot	Exp	Dev	Tot	Exp	Dev	Tot
1975															3,827
1976															1,106
1977															890
1978													274	400	674
1979													174	1,282	1,456
1980													178	1,804	1,780
1981													419	3,104	3,523
1982													647	3,839	4,486
1983													818	1,100	1,918
1984													258	1,193	1,451
1985													514	1,547	2,061
1986													288	771	1,059
1987													288	1,020	1,308
1988													38	765	801
1989													132	748	880
1990													98	1,081	1,157
1991		684	684		43	343		151	151				120	1,178	1,288
1992		573	573		294	294		124	124				216	991	1,207
1993		591	591		416	416		140	140				192	1,148	1,220
1994		564	564		152	152		93	93				72	808	892
1995		542	542		124	124		82	82				84	748	856
1996		551	551		188	188		87	87				108	828	922
1997		687	687		274	274		109	109				96	1,070	1,142
1998		700	700		705	705		155	155				72	1,560	1,608
1999		400	400		684	684		115	115		50	50	48	1,179	1,239
2000		670	670		725	725		150	150		100	100	80	1,545	1,697
2001	34	714	748	108	612	720		200	200	10	110	120	152	1,636	1,788
2002	9	439	448	182	434	538		172	172	15	9	24	126	1,054	1,180
2003	0	416	416	75	386	461		180	180	15	8	23	90	970	1,080
2004		412	412	35	400	435		160	160	32	8	40	87	980	1,047
2005													30	1,288	1,301
2006													123	1,591	1,714
2007													194	1,787	1,981

Sources: 1975-1989: Data from the "International Oil Tax Comparison Study", April 1990. Study did not provide a breakdown by company and no detail for the years 1975-1977.

1990-2000: BP and Arco annual reports; Communications with BP, Arco Alaska. Various published sources. A breakdown by company provided, but no breakout of exploration cost and development costs. Exploratory costs assumed to follow \$12 million dollar per well rule of thumb.

2001-2004: Communication with BP, ConocoPhillips 2002 & 2003 Annual Reports, publications/estimations for others. Breakout of capex by company & type Capex spending.

2005-2007: Unaudited taxpayer submitted EIC and PPT credit information as of 10/3/07. Exploration and development spending breakdown may contain inaccuracies, due to limited information and to the fact that costs that do not qualify for exploration credits may qualify under the PPT as development capital credits.

Definitions: Exp = Exploration, Dev. = Development spending, Tot = Explorations and development spending

Note: ARCO/Conoco Phillips exploration expenses in their Annual Reports include acquisition costs, lease rentals, and expensed overhead. BP's capex spend for 2001 and 2002 was only for capex.

State of Alaska
Department of Revenue
Commissioner's Office



SARAH PALIN, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0405
Phone: (907) 465-2300
Fax: (907) 465-2394

To: All Members of the Legislature

October 24, 2007

Dear Members:

I am distributing this attached document for your records entitled, *Capital Spending on North Slope Wells, Field Facilities and Exploration*. The document was compiled by the Department from publicly available data (individual company data) and tax data aggregated by the Department (All Companies data) relating to North Slope production costs.

A previous version, distributed as an attachment to a 10-17-07 letter from the Department of Revenue to Representative Doogan contained erroneous 2005 and 2006 data. Please replace any copies you may have with the attached document. We apologize for the confusion.

Sincerely,

Marcia Davis, Deputy Commissioner
Department of Revenue

State of Alaska
Department of Revenue
Commissioner's Office



SARAH PALIN, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0405
Phone: (907) 465-2300
Fax: (907) 465-2394

To: All Legislators
From: Marcia Davis, Deputy Commissioner, DOR
Re: North Slope Production Data Request

October 23, 2007

North Slope Production

FY 2007	Thousand Bls/day
June	794
July	685
August	623
September	668
October	739
November	670
December	810
January	799
February	778
March	767
April	760
May	787
FY 2008	
June	726
July	727
August	672
September	651
October	723 (10 days est.)

State of Alaska

Department of Revenue
Commissioner's Office



SARAH PALIN, GOVERNOR

333 Willoughby Avenue, 11th Floor

P.O. Box 110400

Juneau, Alaska 99811-0405

Phone: (907) 465-2300

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

October 25, 2007

Dear Members:

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

Sincerely,

Marcia Davis, *Deputy Commissioner*
Department of Revenue

MEMO

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

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

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

I. THE ANS ROYALTY LITIGATION.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Alternative Tax Credits for Oil and Gas Exploration

ACES Amendments to AS 43.55.025

**Kurt Gibson
Julie Houle
Division of Oil and Gas**

October 31, 2007



Alaska Department of

**NATURAL
RESOURCES**

Division of Oil and Gas



- Before PPT, DOR offered credits for exploration wells and seismic surveys
 - AS 43.55.025 - Alternative tax credit for oil and gas exploration
- ACES original language intended to do the following
 - Provide additional predictability to explorers by establishing a pre-approval process
 - Shore up data sharing requirements

Broaden existing program



- Creates new 5% credits for old seismic surveys if the DNR commissioner determines that the acquisition is in the best interest of the state
- Extends the timeline allowed to drill wells from 150 to 540 days

Enhances Predictability



Pre-approval process identifies up front whether or not activity qualifies for tax credit

- More fair to investors to inform them (going forward) whether or not they are credit eligible
- Predictability reduces the state's exposure to litigation by stripping out uncertainty
- Prudent practice for the state as a "working interest" owner to make forward looking investment decisions

Data Sharing



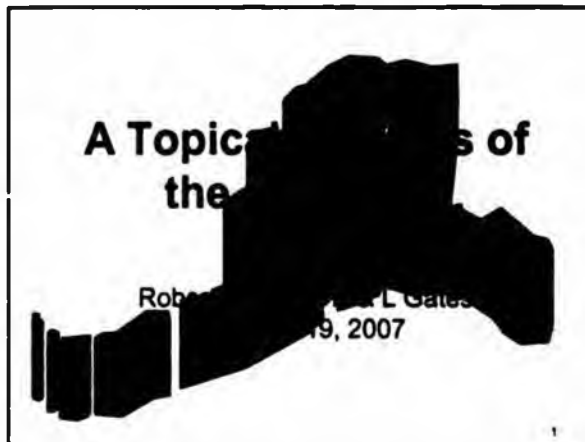
State has a right to certain data stemming from its decision to invest in project

- Seismic**
- Well data**
- Fluid data**
- Core data**

New language provides clarity and consistency in what data must be shared

These data sharing requirements are consistent with those of other jurisdictions

By shoring up the data sharing language the state preserves its ability to pursue long-range exploration incentive goals



A Few Background Basics:
The oil and gas production tax . . .

- is in AS 43.55
- is in addition to royalties, property tax, and income tax
- has existed since before statehood
- generally applies a percentage tax rate to the *value* of oil and gas produced
- unlike royalties, applies to production from private and federal leases as well as state leases

2

**Core Provisions of HB 3001
(enacted in 2006)**

- AS 43.55.011(e) – (l): tax levied on value of oil and gas produced
- AS 43.55.160: calculation of taxable value of oil and gas
- AS 43.55.165 & .170: determination of upstream costs that may be deducted in calculating taxable value of oil and gas

(cont.)

3

Core Provisions (continued)

- AS 43.55.023 & 43.55.024: new tax credits
- AS 43.55.020(a): monthly estimated tax payments and final payment on March 31 of year following production (because this is now an annual, not a monthly, tax)
- AS 43.55.030(a): just one annual return

4

AS 43.55.011(e) (current)

- There is levied on the producer . . . a tax for all oil and gas produced . . . equal to 22.5 percent of the production tax value of the taxable oil and gas as calculated under AS 43.55.160 . . .
- Note: “production tax value” is net value

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AS 43.55.011(e) (continued)

Exceptions:

- Tax does *not* apply to
 - state or federal share
 - landowner’s royalty share (which is subject to a different tax provision)
- Cook Inlet production subject to ceilings based on past taxes (AS 43.55.011(j) & (k))
- North Slope production subject to a minimum tax depending on price of ANS (AS 43.55.011(f))

6

AS 43.55.011(g) (current)

- For each month when the net value of a producer's oil and gas exceeds \$40 per barrel, the tax rate under subsec. (e) is in effect increased by 1/4 of a percentage point for each dollar per barrel over \$40
- Informally known as "progressivity tax"
- Gas and oil are added together by treating 6 million Btu of gas as equivalent to one barrel of oil (see AS 43.55.011(h), 43.55.900(17), (18) & (24))

progressivity # is a net #

**AS 43.55.011(e) (new)
Bill sec. 15**

- There is levied on the producer . . . a tax for all oil and gas produced . . . equal to the production tax value of the taxable oil and gas as calculated under AS 43.55.160 multiplied by the tax rate determined under (g) of this section.

**AS 43.55.011(g) and (h) (new)
Bill secs. 17 and 18**

- "The tax rate . . . is 25 percent plus" the progressivity tax rate
- The progressivity tax rate is 1/5 of a percentage point for each dollar per barrel over \$30 net value
- Progressivity is calculated on an annual, not monthly, basis

**North Slope Tax Floor
Bill sec. 16**

- New AS 43.55.011(f): minimum tax is 10 percent of gross value at the point of production of oil and gas from a unit (or nonunitized reservoir) that
- (1) has produced a cumulative total of 1 billion barrels; and
- (2) is producing over 100,000 barrels a day (average during the most recent calendar year)

applies to legacy fields

**Cook Inlet Tax Ceilings
Bill secs. 19 and 20**

- Tax ceilings are not changed (conforming amendments only)
- Note: sec. 21 of the bill adds language dealing with Cook Inlet tax credits to be consistent with sec. 55, which clarifies how excess lease expenditures are treated

AS 43.55.160 (bill secs. 52-55)

- The basic principle is unchanged: taxable value = gross value at the point of production minus lease expenditures
- Wording has been changed:
- (1) monthly values are no longer needed (progressivity is now annual)

govt bill not RRS bill