

**Alaska's Progressivity Tax Fulfilled the Legislature's Intent
During 2008 Oil-Price Spike
Will it Work for Natural Gas?**

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Final draft of article published in two parts in the Oil & Gas Journal:

Part 1. Alaska tax reform: intent met with oil (Part 1 of 2), Oil & Gas Journal, 2009 (May 25 edition), p.20-26.

Part 2. Alaska tax reform: gas raises questions (Part 2 of 2), Oil & Gas Journal, 2009 (June 1 edition), p.20-24.

Alaska's oil & gas fiscal objectives

In 2006 and 2007 the State of Alaska undertook fundamental reforms to its oil and gas production tax, making it much more progressive. Among the goals of these reforms, two were key. One was to capture more value for the state at higher energy prices. After all, as the Legislature was debating the reforms in 2006, prices for Alaska North Slope (ANS) crude for the first time crossed the \$40/barrel barrier. Another equally or even more important goal was to create a better environment to attract the investments needed to at least slow or even reverse the decline in the state's oil production. Forecast to average 701,000 barrels a day in the current state Fiscal Year of 2009 – production once reached over 2 million barrels a day in the late 1980s.

This paper will show the production tax reforms of 2006 and 2007 were phenomenally successful, with the state collecting several billion dollars in additional oil production tax revenues as prices for ANS crude peaked above \$140 per barrel in the summer of 2008. The state's take from the tax hike was almost 500% higher than it would have been without the reforms. However, as oil production from the super-giant Prudhoe Bay field that anchors the North Slope declines, focus in the state has turned toward Alaska's immense reserves of unexploited natural gas. Assuming sufficient investment can be attracted to build a project to transport some of that gas from the North Slope to market, this paper identifies a feature of the state's production tax that suggests it may not perform nearly as well under high oil prices similar to the 2008 spike. Finally, although it is too early to tell how well the second goal of increased investment has been achieved, there are additional concerns about how some of the investment incentives might work if a new pipeline to export gas is added to the mix.

Alaska's fiscal system

State government in Alaska gets most of its general fund revenue from four oil and gas mechanisms that are a mixture of progressive and regressive elements. Over the past decade, depending on prices, oil and gas have provided between 68% and 93% of state general fund revenues. The components of the state's fiscal system are summarized in Figure 1.

Because most oil and gas production is from state land, there is **royalty** paid to the state averaging just under 13% of gross value, less costs to get the commodity to market. This is regressive because it does not factor in the investment required or the expense of finding, developing and producing the oil or gas.

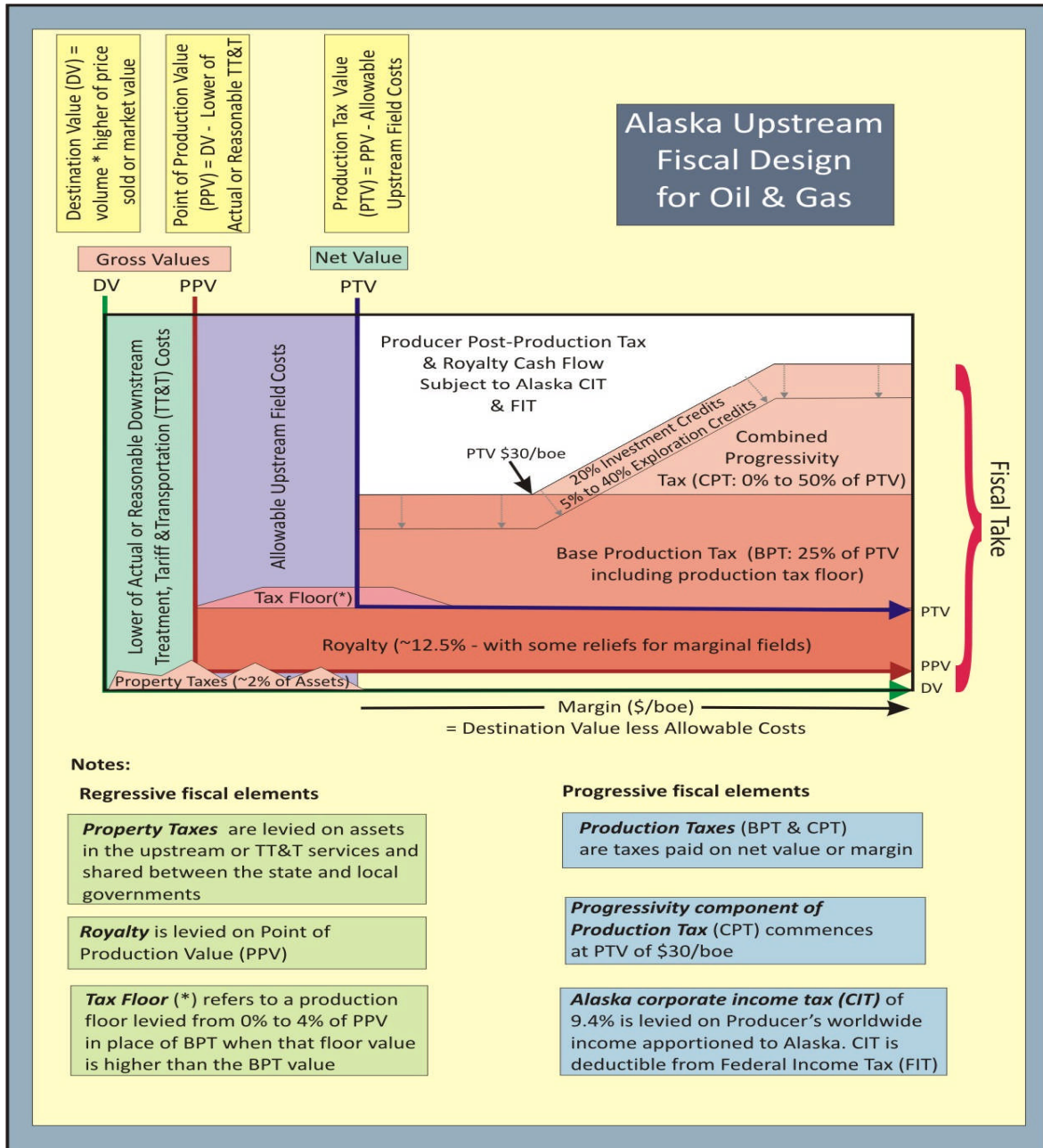


Figure 1. Alaska's prevailing upstream fiscal design for oil and gas. Alaska's fiscal design for oil and gas has evolved substantially in the past three years and consists of four mechanisms. Some key terms relevant to the tax bases for the different components are defined in this figure.

There is also a **property tax** on oil and gas real property (though not on the lease or hydrocarbons) of 2% of assessed value, split between the state and municipalities where the property is located. This is relatively insensitive to the profits (or losses) generated by changes in the price of the oil or gas in the market.

There is a **corporate net income tax** (abbreviated here as CIT, but defined by the Alaska Net Income Tax Act or ANITA) of 9.4% of that portion of an oil-and-gas producing taxpayer's worldwide income apportioned to Alaska. While an income-based tax, the link with specific Alaska investments, costs and income is broken by the apportionment mechanism (production, sales and property). Higher operating costs in Azerbaijan or Alaska will have the same depressing effect on the income taxable in Alaska. Higher income from ANS or Angola crude will increase the amount of Alaska CIT paid equally.

The final mechanism is the oil and gas **production tax**, and the next section sets out its history, politics and mechanisms in more detail. An interesting aside is how distinct each of these four mechanisms is. For example, each has a different depreciation or cost-allocation mechanism for upstream capital investment. For royalty there is no deduction driven by upstream investment, so no mechanism is needed. For purposes of the property tax, units of production essentially determine the rate of depreciation. The corporate income tax preserves the pre-1980 asset depreciation range (ADR) system from federal income tax while the production tax allows instantaneous depreciation or expensing of capital costs. Meanwhile, a producer in Alaska will be subject to U.S. federal income tax (FIT) with its current modified accelerated cost-recovery system (MACRS).

Alaska's hydrocarbon production comes primarily from the North Slope, with oil and some natural gas liquids sent through the trans-Alaska oil pipeline (TAPS) and tankers to U.S. West Coast refineries. North Slope oil production in FY 2008 -- including natural gas liquids mixed with crude and shipped down the pipeline -- totaled roughly 261 million barrels, or 716,000 barrels a day. Annual net gas production was closer to a half a bcf a day, although most of that is non-taxable gas and is used for enhanced oil recovery purposes and as fuel to run the North Slope production facilities. The majority of the taxable gas comes from a smaller production center in Alaska's Cook Inlet, now a gas province where the gas is used mostly in local population centers with some export from an LNG facility. However, Cook Inlet accounts for less than 5 million barrels of the state annual oil production. While other areas of the state and offshore show prospectivity for oil and/or gas, none has yet been commercialized. Major North Slope gas sales await a pipeline to carry the gas to markets, leaving a valuable resource stranded at the northern edge of North America.

Alaska's production tax - 2006

Prior to the reforms discussed in this article, Alaska's oil production tax was a maximum 15% of gross value (calculated under the same general principles as royalty), multiplied by the so-called Economic

Limit Factor (ELF). The ELF was 0.0 (hence leading to zero tax) for small fields and by 2006 averaged around 0.50 for fields with a positive ELF, for an effective tax rate of less than 8% of gross. Although the nominal tax on gas was 10% and the ELF mechanism involved a different calculation, by 2006 the effective rate on gas was also coincidentally around 8% of the gross. Price was not a factor in calculating the ELF multiplier. The ELF, adopted in 1979 and amended in 1989, was intended to reduce production taxes on smaller, less productive, older and declining fields.

In 2006, Frank Murkowski – then Alaska’s Governor -- proposed replacing the gross tax and ELF with a 20% tax rate (base production tax, referred to then as PPT, but referred to in this article as BPT) applied to the net. The tax would be applied after allowing a deduction for upstream exploration, development and production costs. Furthermore, to make investment more attractive, capital investment could be deducted as a cost as spent, and also would generate an additional 20% credit applicable against the BPT. The proposal came to be known as the 20:20 PPT proposal.

In addition to proposing a major change in oil taxes, Gov. Murkowski, under the Alaska Stranded Gas Development Act, negotiated a gas pipeline fiscal contract with the state’s three largest holders of gas-rich leases (BP, ConocoPhillips and ExxonMobil). The administration hoped that the fiscal stability built into that contract would create a viable investment climate to enable financing and construction of a gas line to Lower 48 energy markets.

After extensive hearings consuming the better part of several special legislative sessions (note: author Dan E. Dickinson was a registered lobbyist for the administration during those sessions), the legislature passed a reformed oil and gas production tax in August 2006, retroactive to April 1, 2006. Although the key ideas from Gov. Murkowski’s proposal remained intact, the legislature imposed its own amendments to the administration’s proposal and added a higher base tax rate and a progressivity mechanism.

This progressivity feature (which we call the combined progressivity tax, or CPT, for reasons set forth below) added an extra 0.25% to the overall tax rate for every dollar the per-barrel net (production tax value, or PTV) was above \$40. For example, if per-barrel costs were \$25 and that barrel could be sold for \$85 in the market, an additional 5% CPT would be added to the base production tax rate. How was this CPT calculated? For the sake of simplicity we will ignore royalty for the moment and start with \$85 oil minus \$25 in costs equals a PTV of \$60. Subtracting the \$40 progressivity trigger from the \$60 yields \$20. The CPT rate was calculated as 0.25% times \$20, which equals 5% additional tax above the base rate. The legislature (along with many other changes) also increased the BPT to 22.5% from the proposed 20%, so in this example the nominal tax rate would be 27.5%, the sum of 22.5% BPT and 5% CPT.

Meanwhile, the legislature declined to take up Gov. Murkowski’s controversial gas line contract. Natural gas production taxes, however, were included in the oil reform legislation. Under the new law, any taxable gas was converted to oil on an energy-equivalent basis as 6 million Btus per barrel (approximately 6 million cubic feet of gas equals 1 barrel of oil). Then these “energy equivalent barrels”

of gas were added to the oil for the calculation of progressivity. We call this the combined progressivity tax (CPT) because oil and gas are taxed under a single combined formula. The tax reform legislation was created for oil but was applied to all hydrocarbon production. The consequences of this are explored in this article (e.g. see Figure 3). To protect in-state consumers, the legislature capped the production tax on Cook Inlet gas at its existing ELF-calculated rates and values.

August 2006

August 2006 was a pivotal month in this story. On August 10 the legislature voted to approve the production tax reform, including the reforms detailed above. On August 19 Gov. Murkowski signed the legislation into law. On August 22 Sarah Palin won the Republican gubernatorial primary with more than 50% of the vote, relegating Murkowski -- with only 19% of the vote -- to third place. Then, on August 30, the FBI raided the offices of six legislators, carrying off in their gloved hands boxes of papers, documents and computer hard drives. Publicly available warrants made clear the FBI was seeking information relating to votes on the PPT and the activities of VECO, an oil field services contractor active in the tax debate.

Gov. Palin went on to win the November 2006 election. She campaigned -- in part -- on returning the production tax from a net tax back to a gross tax. It was not until April 2007 that taxpayers had to file returns for 2006 under the new law. Although the state had predicted catch-up payments from North Slope producers of close to \$1 billion, the checks totaled \$880 million and the new administration expressed concern over compliance. In August 2007 indictments were finally brought against VECO officials and three of the legislators whose offices had been raided a year earlier (only one was still a sitting legislator). Subsequent VECO-related charges have been brought against one other legislator, a former legislator, U.S. Senator Ted Stevens (who later lost his re-election bid in November 2008) and Gov. Murkowski's chief of staff, resulting in three guilty pleas and Stevens' conviction.

Gov. Palin in September 2007 called a special legislative session to modify the production tax reforms and adopt a production tax that Alaska's citizens could believe was free of corruption. Her administration, after some initial hesitance, did not propose a return to a gross tax and renewed its commitment to a net tax. Her proposal -- tagged as ACES, or Alaska's Clear and Equitable Share -- included raising the BPT from 22.5% to 25%. The governor also proposed (1) that for purposes of administrative ease, progressivity be calculated on an annual basis instead of monthly, (2) the progressivity trigger would kick in at \$30 boe instead of \$40 boe, and (3) the rate of progressivity would increase more slowly at 0.2% per \$1 above the trigger instead of 0.25%.

The legislature met in special session during October and November 2007 with oil prices in the \$80/barrel range -- about double where they had been during the 2006 special session (note that author Dan E. Dickinson was on contract to the legislature during the 2007 special session). Just as it did when adopting the original reform under Gov. Murkowski's tenure, the legislature also imposed its own distinctive stamp on the law adopted under Gov. Palin -- again focusing on progressivity. The BPT was

increased to 25% -- as the governor had requested. However, the CPT remained on a monthly basis, and while the trigger dropped to the suggested \$30 per boe, the rate was increased to 0.4% per \$1 above the trigger. Using the example above of \$85 oil and \$25 per-barrel costs, the total production tax rate becomes 37%. The BPT is 25% and the CPT calculation is still \$85 less \$25 for a PTV of \$60, but then subtract the \$30 trigger and multiply the resulting \$30 times 0.4% for a CPT of 12% and a total tax of 25% + 12% or 37%. As detailed above this example produced a 27.5% total tax rate under the 2006 law. The less simplified version that includes royalty can be seen in Table 3 below.

Did the reform achieve its goals?

Oil prices in 2008 hit extraordinary levels. How did the legislature do at capturing those premiums? There are several ways of looking at this, and we present two.

Alaska's Fiscal Changes Yield Substantial Tax Revenue Increases in 2007 and 2008									
Fiscal Year (July to June)	Production Taxes (BPT + CPT) applied from 2007		Production Value				Royalty		
	Production Tax Revenue PTV (\$ millions)	Year \$ / 2004\$	West Coast ANS Price (\$/barrel)	Production (million barrels / day)	Production (million barrels / year)	Value = Price * Volume	Year \$ / 2004\$	Royalty Revenue (\$ millions)	Year \$ / 2004\$
A	B	C = Current B / 2004 B	D	E	F = E * Days	G = D * F	H = Current G / 2004 G	I	J = Current I / 2004 I
2004	642.7	1.0	32.36	0.999	365.6	11,831.9	1.0	1,042.8	1.0
2005	854.9	1.3	44.85	0.931	339.8	15,240.7	1.3	1,401.1	1.3
2006	1,191.7	1.9	62.12	0.858	313.2	19,454.1	1.6	1,772.2	1.7
2007	2,198.3	3.4	61.60	0.750	273.8	16,863.0	1.4	1,583.8	1.5
2008	6,867.3	10.7	96.51	0.730	267.2	25,785.5	2.2	2,420.6	2.3
Production Tax Revenue Increase Attributable to Fiscal Changes in 2006 & 2007							=		
10.7 / 2.2 = 4.9									
Data source: Alaska Dept of Revenue (DOR), Fall 2008 Revenues Sources Book (RSB), (Dec 2008) Appendices, A-5a, B-1a, C2a.									

Note: Because of DOR methodological changes, historical data in the Fall 2008 RSB may differ from same data presented in earlier RSBs

Table 1 Annual comparisons reveal almost a five-fold increase in state revenues from 2004 to 2008 due to fiscal reforms. In that period there was a two-fold increase in the value of oil produced, as verified by price, volume and royalty values recorded. The additional production tax increases are the result of fiscal reforms.

The first looks at the increase in production taxes from FY 2004 through FY 2008 (Table 1). While Column B – annual production tax revenue -- shows the increase is more than an order of magnitude from roughly \$650 million to \$6.9 billion, it doesn't tell how much of the change was due to the change in rules and how much was due to the change in prices and production and costs. At least the first two can be factored out in the following exercise. Table 1 shows that over that same period the product of market value times volume roughly doubled. Similarly, the royalty paid the state doubled. Thus it appears the net effect of the change in tax was the 10-fold increase divided by two-fold increase caused mostly by rising oil prices. That is a five-fold increase caused by the change to the production tax fiscal mechanism. (More specifically 10.7 divided by 2.2 equals 4.9.)

Another way of comparing these is to look at the high prices that prevailed in FY 2008 and assuming both constant costs and volumes to evaluate them under the five different production tax designs discussed from 2005 to 2007. Table 2 summarizes such an analysis.

Table 2

FY 2008 Production Tax Revenues: Actual Versus Potential Under Alternative Mechanisms

(Analysis Based on Actual US West Coast Prices and Cost Data)

Month	US West Coast Oil Price	Per Barrel Total Costs	Per Barrel Production Tax Value	PTV less Progressivity Threshold	PTV less Progressivity Threshold	PTV Rate per Dollar of Adjusted PTV	Incremental Progressivity Rate	Volume (Millions barrels)	Combined Progressivity Tax (CPT)	Base Production Tax (BPT) Rate	Base Production Tax (BPT) Value	CPT + BPT Value	CPT + BPT less \$400 in credits (except ELF)	~2% Adjustment to RSB 2008 Actual
	\$/barrel	\$/barrel	PTV \$/barrel	\$/barrel	\$/barrel	%	%	millions barrels	\$ millions	%	\$ millions	\$ millions	\$ millions	\$ millions
A	B	C	D= (B + C)	E	F= (D + E)	G	H= (F * G)	I	J= (D * H * I)	K	L= (D * I * K)	M= (J + L)	N= (M - 411.5)	O= (N * 0.977)
1. Pre-2006 law - Economic Limit Factor (ELF) Mechanism														
year	96.52	-6.05	90.4725	-	-	0.00%	0.00%	228.7	0.0	7.49%	1549.5	1549.5	1549.5	1513.1
2. Murkowski Proposal: 20 20 PPT (2006), no progressivity														
year	96.52	-22.88	73.6425	-	-	0.00%	0.00%	228.7	0.0	20.00%	3367.8	3367.8	2956.3	2886.9
3. Monthly Analysis, \$40 PTV \$/boe threshold and .0025% progressivity parameter under law as enacted in 2006														
Jul	75.93	-22.88	53.05	-40	13.05	0.25%	3.26%	19.4	33.6	22.50%	231.8	265.4		
Aug	73.83	-22.88	50.95	-40	10.95	0.25%	2.74%	19.4	27.1	22.50%	222.6	249.7		
Sep	79.92	-22.88	57.04	-40	17.04	0.25%	4.26%	18.8	45.7	22.50%	241.2	286.9		
Oct	84.77	-22.88	61.89	-40	21.89	0.25%	5.47%	19.4	65.8	22.50%	270.4	336.2		
Nov	92.98	-22.88	70.1	-40	30.1	0.25%	7.53%	18.8	99.1	22.50%	296.4	395.6		
Dec	88.64	-22.88	65.76	-40	25.76	0.25%	6.44%	19.4	82.2	22.50%	287.3	369.6		
Jan	91.16	-22.88	68.28	-40	28.28	0.25%	7.07%	19.4	93.7	22.50%	298.4	392.1		
Feb	94.42	-22.88	71.54	-40	31.54	0.25%	7.89%	17.5	98.9	22.50%	282.3	381.3		
Mar	105.06	-22.88	82.18	-40	42.18	0.25%	10.55%	19.4	168.3	22.50%	359.1	527.4		
Apr	112.37	-22.88	89.49	-40	49.49	0.25%	12.37%	18.8	208.1	22.50%	378.4	586.5		
May	125.41	-22.88	102.53	-40	62.53	0.25%	15.63%	19.4	311.3	22.50%	448.0	759.3		
Jun	133.78	-22.88	110.9	-40	70.9	0.25%	17.73%	18.8	369.4	22.50%	468.9	838.4		
							Totals:	228.7	1603.3	22.50%	3785.0	5388.3	4976.8	4860.1
4. Palin Proposal (2007): Yearly Analysis \$30 PTV \$/boe adjustment and .002% progressivity parameter														
Year	96.52	-22.88	73.64	-30	43.64	0.20%	8.73%	228.7	1469.8	25.00%	4209.7	5679.5	5268.0	5144.5
5. Monthly Analysis, \$30 PTV \$/boe threshold and 0.004% progressivity parameter under Current Law as enacted in 2007														
Jul	75.93	-22.88	53.05	-30	23.05	0.40%	9.22%	19.4	95.0	25.00%	257.6	352.5		
Aug	73.83	-22.88	50.95	-30	20.95	0.40%	8.38%	19.4	82.9	25.00%	247.4	330.3		
Sep	79.92	-22.88	57.04	-30	27.04	0.40%	10.82%	18.8	115.9	25.00%	268.0	383.9		
Oct	84.77	-22.88	61.89	-30	31.89	0.40%	12.76%	19.4	153.3	25.00%	300.5	453.8		
Nov	92.98	-22.88	70.1	-30	40.1	0.40%	16.04%	18.8	211.3	25.00%	329.4	540.7		
Dec	88.64	-22.88	65.76	-30	35.76	0.40%	14.30%	19.4	182.7	25.00%	319.3	501.9		
Jan	91.16	-22.88	68.28	-30	38.28	0.40%	15.31%	19.4	203.0	25.00%	331.5	534.5		
Feb	94.42	-22.88	71.54	-30	41.54	0.40%	16.62%	17.5	208.5	25.00%	313.7	522.2		
Mar	105.06	-22.88	82.18	-30	52.18	0.40%	20.87%	19.4	333.1	25.00%	399.0	732.1		
Apr	112.37	-22.88	89.49	-30	59.49	0.40%	23.80%	18.8	400.2	25.00%	420.5	820.7		
May	125.41	-22.88	102.53	-30	72.53	0.40%	29.01%	19.4	577.7	25.00%	497.8	1075.5		
Jun	133.78	-22.88	110.9	-30	80.9	0.40%	32.36%	18.8	674.5	25.00%	521.1	1195.5		
							Totals:	228.7	3238.1	25.00%	4205.5	7443.7	7032.2	6867.3
Data Source: Alaska Department of Revenue (DOR), Fall 2008 Revenues Sources Book (RSB), (Dec 2008)														
FY2008 Taxable North Slope barrels /day: 626,456 228.7 millions barrels in FY2008 Lease Expenditures (\$/bbl): 16.83 TT&T (\$/bbl): 6.05 Capex Credits (\$ millions): 411.5														

Table 2. Analysis of Alaska Fiscal Year 2008 production tax computations (i.e. BPT plus CPT) for the five different tax designs considered from 2005 to 2007. Note that Methodology No. 5 is the prevailing regime and this simplified model produces a production tax liability of \$7.057 million, about 3% different from the actual production tax liabilities for FY 2008, \$6,867.3 million as seen in the last row column one of Table One, above. Given the fact that Table 2 uses an average, while the tax effects from deviation from the average are not symmetrical, and this analysis ignores other details such as the small producer tax credit, this is a surprisingly close match.

Notes: (1) FY2008 production in Table 2 is for North Slope taxable barrels only, whereas in Table 1 FY2008 production includes total Alaska barrels. (2) \$16.83/bbl lease expenditures value is calculated from information derived from the Fall 2008 RSB (i.e. $3848 / (0.626456 * 365)$), where the dollar upstream expenditure is \$3,848 million and daily production rate of 626,456). (3) FY 2008 ELF estimate from Fall 2008 RSB.

Table 2 also confirms a five-fold increase due to the tax reforms excluding oil price changes. Gov. Murkowski’s proposal would have been a doubling of the production tax from the ELF-driven tax structure in 2006. The legislature made that a tripling over the status quo. Gov. Palin’s 2007 proposal would have had little effect under the prices that were realized in FY 2008, but the legislature pushed up the progressivity feature to achieve the nearly five-fold increase illustrated. Figure 2 illustrates the impact for Fiscal Year 2008 of the legislature’s changes to the progressivity component of production taxes from 2006 to 2007 (i.e. comparisons of Methodologies No. 3 and No. 5 in Table 2) against a background of the Palin administration’s proposal on progressivity (Item No. 4 in Table 2).

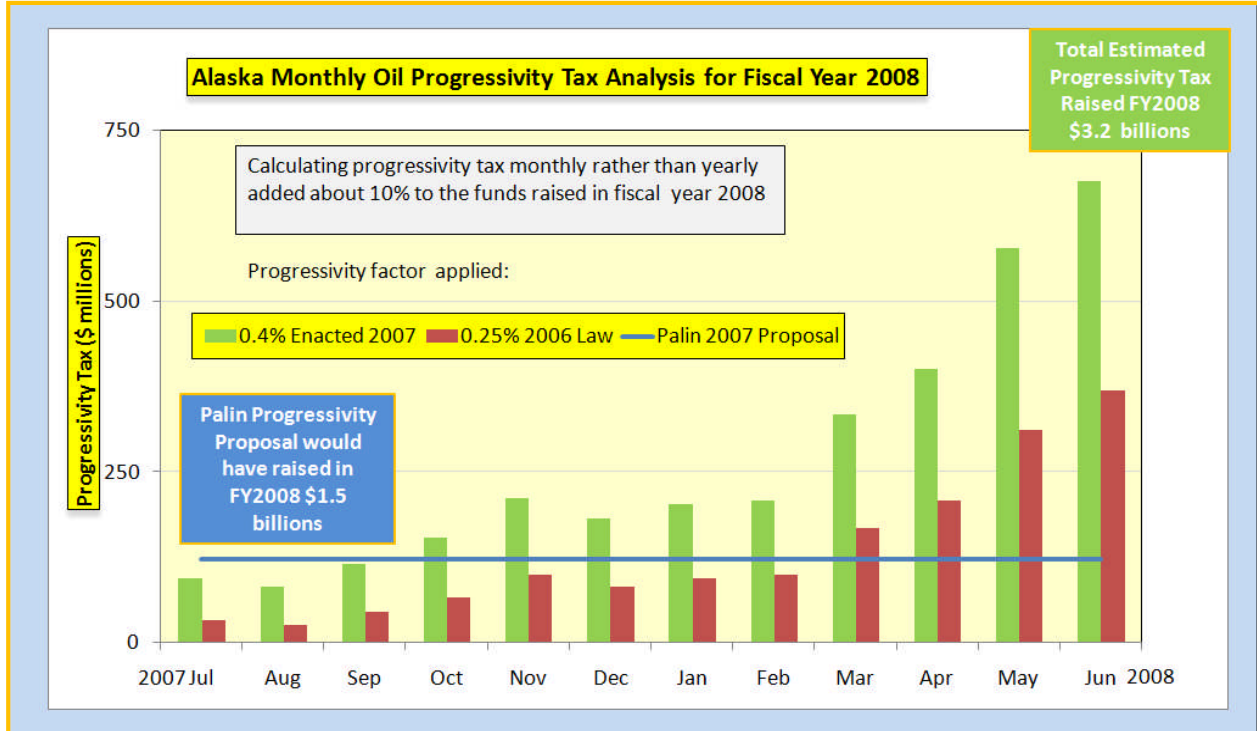


Figure 2 Monthly progressivity calculations based on Fiscal Year 2008 data using the 2007-enacted mechanism (0.4% factor and \$30/boe PTV threshold) and comparing it to the 2006 law (0.25% factor and \$40/boe PTV threshold) that it replaced.

We do not have sufficient data to say whether the goals pertinent to increased investment are being achieved. Furthermore, whatever capital budgeting announcements made by producers when prices were high must be re-examined in the context of lower crude oil price environments. It is worth noting that Pioneer brought on the new 90 million barrel Oooguruk field in August of 2008 under the new fiscal regime, but that Eni in March 2009 announced it was delaying development at Nikaitchuq, a \$1.5 billion project.

Marginal rates

A side effect of high progressivity is a very high marginal rate. Recall that as the progressivity charge rises, it affects the tax rate applied to all the taxed hydrocarbons. This effect is most pronounced, for example, when the PTV is around \$92.50, when approximately 93 cents of an extra \$1 per barrel of revenue goes to the state. Why? Before adding the extra dollar the BPT was 25% and the CPT was 24.6% for a total of 49.6%. Adding 0.4% times \$92.5 is only 37 cents more in tax – but that is 37% of the additional dollar that triggered the higher tax. Add the 49.6% to that 37% and, on different bases, 12.5% royalty, 9.4% income tax and 2% property tax and you have reached 93% (Table 3).

Such circumstances could encourage producers to gold-plate field costs in order to lower PTV. Incremental costs are met mainly by the state with every additional dollar per barrel of spending potentially offsetting the increased state take from an extra dollar per barrel of revenue (Table 4). Actually, once investment credits are factored in and even with no boost from royalty, the marginal rate (or state underwriting of the investment) can reach the vicinity of 100%.

These prices have been chosen to illustrate the point that in general for energy scenarios with both higher and lower values the marginal tax rate falls. The rest of this article focuses on one scenario likely to lead to a much lower marginal tax rate; a producer of oil adds a significant gas stream to its portfolio.

Maximal Marginal Impact of Incremental of \$1/ barrel of WC ANS Oil Price Increase in Alaska's Upstream Fiscal System

Formulas Simplified (\$/barrel) Analysis	Base Case	+\$1 Price	Difference
A Destination Price West Coast ANS	\$120.36	\$121.36	\$1.000
B Less Transportation Costs (TT&T)	6	6	
A - B = C Gross value at Point of Production (PPV)	\$114.36	\$115.36	\$1.000
D Royalty (12.5% of Gross Value)	\$14.30	\$14.42	
E Less Upstream Costs	20.00	20.00	\$0.000
C - D - E = F PTV or Net Value	\$80.07	\$80.94	\$0.875
G Taxable Barrels (exclude 12.5% royalty)	87.5%	87.5%	
F / G = H PTV / Taxable Barrel	\$91.50	\$92.50	
(H-30)*.004 = I Production Tax Progressivity (CPT %) (see note)	24.60%	25.00%	
J Base Production Tax (25%)	25.00%	25.00%	
I + J = K Total Production Tax Rate (%)	49.60%	50.00%	0.399%
F * K = L Pre-credits Production Tax (Rate*PTV)	\$39.71	\$40.47	\$0.757
M Production Tax Credits (assumed)	-10.00	-10.00	0.000
N Property Tax (assumed)	0.50	0.50	0.000
F- (L + M + N) = O Simplified income tax base ignoring worldwide income (CIT) and different depreciation mechanisms for CIT & FIT			
O * 9.4% = P State Income Tax (9.4% * net less taxes)	4.69	4.70	0.011
(O - P) * 35% = Q Federal Income Tax (35% * net less taxes)	15.81	15.85	0.037
D+L+M+N+P+Q = R Government Take Including CIT & FIT	\$65.00	\$65.93	\$0.931
D+L+M+N = S Government Take Excluding CIT & FIT	\$44.51	\$45.39	\$0.882

Note: a different progressivity formula applies when H is below \$30 or above \$92.5

Table 3. Maximal marginal impact on government take of a \$1 increase in oil price on a high production tax value field (for PTVs above and below \$92.5 the marginal effect will be smaller). Note that the government takes most of the financial gains from an incremental price increase at high oil prices.

Maximal Marginal Impact of Incremental Investment of \$1/ barrel of Capital in Alaska's Upstream Fiscal System

Formulas Simplified (\$/barrel) Analysis	Base Case	+\$1 Capex	Difference
A Destination Price West Coast ANS	\$121.36	\$121.36	\$0.000
B Less Transportation Costs (TT&T)	6	6	
A - B = C Gross value at Point of Production (PPV)	\$115.36	\$115.36	\$0.000
D Royalty (12.5% of Gross Value)	\$14.42	\$14.42	
E Less Upstream Costs	20.00	21.00	\$1.000
C - D - E = F PTV or Net Value	\$80.94	\$79.94	-\$1.000
G Taxable Barrels (exclude 12.5% royalty)	87.5%	87.5%	
F / G = H PTV / Taxable Barrel	\$92.50	\$91.36	
(H-30)*.004 = I Production Tax Progressivity (CPT %) (see note)	25.00%	24.54%	
J Base Production Tax (25%)	25.00%	25.00%	
I + J = K Total Production Tax Rate (%)	50.00%	49.54%	-0.456%
F * K = L Pre-credits Production Tax (Rate*PTV)	\$40.47	\$39.61	-\$0.865
M Production Tax Credits (assumed)	-10.00	-10.10	-0.100
N Property Tax (assumed)	0.50	0.50	0.000
F - (L + M + N) = O Simplified income tax base ignoring worldwide income (CIT) and different depreciation mechanisms for CIT & FIT			
O * 9.4% = P State Income Tax (9.4% * net less taxes)	4.70	4.69	-0.003
(O - P) * 35% = Q Federal Income Tax (35% * net less taxes)	15.85	15.83	-0.011
D+L+M+N+P+Q = R Government Take Including CIT & FIT	\$65.93	\$64.95	-\$0.979
D+L+M+N = S Government Take Excluding CIT & FIT	\$45.39	\$44.43	-\$0.965

Note: a different progressivity formula applies when H is below \$30 or above \$92.5

Table 4. Maximal marginal impact of \$1 of producer capital investment on government take. Note that the government revenue share absorbs most of the incremental investment at oil high prices.

How will this tax work in conjunction with a major gas sale?

The progressivity mechanism has been through one test (high oil prices), and from the state's point of view it worked. Prices went to levels in 2008 only previously dreamed of and the progressivity mechanism worked to produce the intended result of a significantly higher state take.

However, modeling suggests there may be other tests ahead with less felicitous outcomes. The state hopes that more than 35 trillion cubic feet of proved gas on the North Slope, plus more yet-to-find gas, can be monetized, and continues to explore ways to bring about its commercialization. If a gas line (or other gas revenue-generating project) were in place, how would the prevailing CPT mechanism operate? Recall that the gas sold would be converted to oil on a boe basis and taxed using the progressivity mechanism. What are some of the consequences of that?

The general effect for any taxpayer with gas and oil production might be that adding gas production actually lowers their production tax liability. Why? Consultants for the current administration have suggested that the gas line tariff is likely to be in the \$5 per mmBtu range, which translates into a tariff of \$30 a boe of gas. Even if oil and gas were sold and taxed at a Btu parity in the market, a \$30 transportation deduction for gas would compare to an average cost to market of approximately \$6 for oil. PTVs will be significantly lower for combined oil and gas streams than they are for oil alone streams. This point is illustrated in Figure 3.

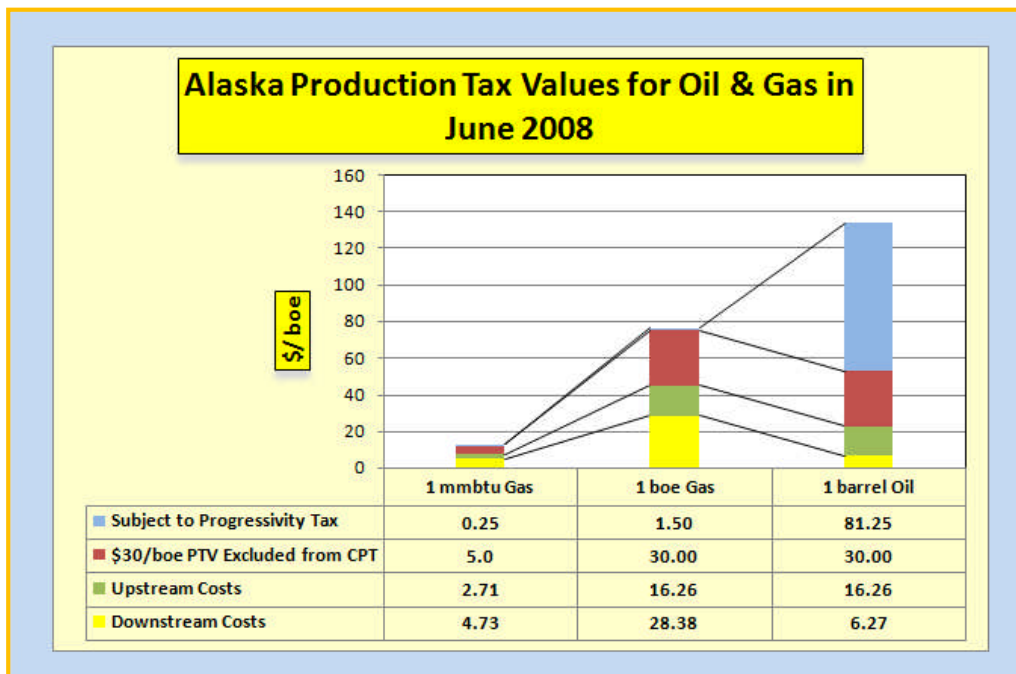


Figure 3 shows that a lack of oil and gas price parity and quite different downstream and upstream cost structures mean that under current CPT mechanisms Alaska gas would pay little or no CPT, whereas Alaska oil would pay substantial CPT. Blending the two streams together results in gas diluting the CPT computation and cross-subsidizing oil.

However, as figure 3 also illustrates, the notion of oil and gas selling at a Btu parity is elusive. As the world has found, oil and gas prices do not always move in tandem. Ignoring location differentials for the moment, for more than a year from the summer of 2007 through the summer of 2008, the ANS monthly price was more than 12 times the Henry Hub benchmark price for natural gas and double the Btu-parity relationship. At those kinds of parities it is possible to construct scenarios where Alaska could achieve its long-held dream of a gas pipeline but generate less production tax revenue with a gas pipeline than without it. How? Because the fall in progressivity that comes about when oil and gas are combined in the CPT calculation. Figure 4 illustrates the production tax consequences of a wide range of oil and gas PTV \$/boe combinations but focuses on the impact of adding a low PTV \$/boe gas stream to oil streams varying in PTV from \$0/boe to \$400/boe.

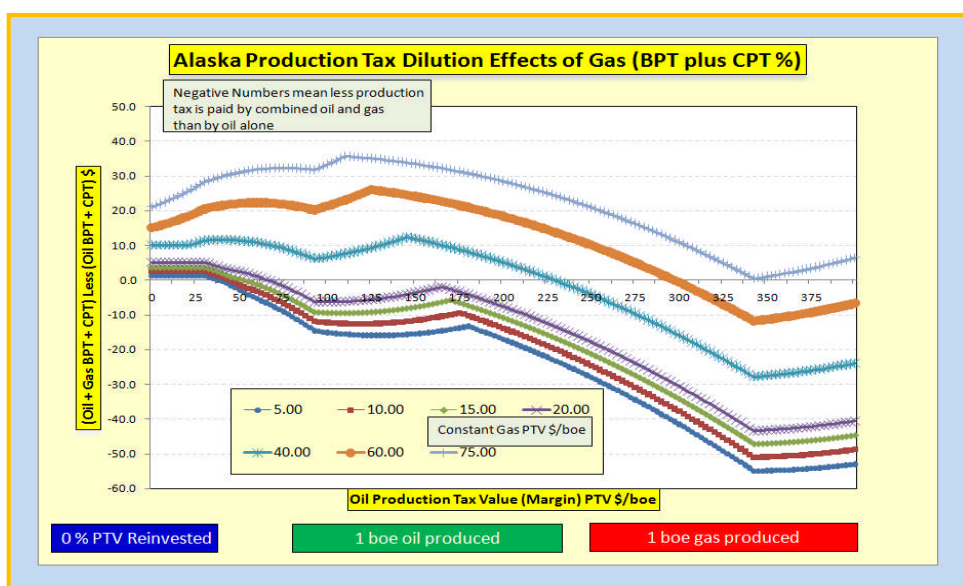


Figure 4. Low-value gas revenue streams reduce the overall production tax paid by an oil revenue stream by the CPT mechanism over most of the oil PTV \$/boe range above the CPT threshold of \$30/boe. Negative values in the figure illustrate where the combined oil and gas revenue stream pays less production tax (BPT + CPT) than an oil-only revenue stream.

Of course, the whole idea behind a net tax is that investment gets a boost from its favored tax status. Investment in producing more oil and gas should lower taxes. However, the upstream infrastructure to produce most of the gas that that would feed a gas line has already been developed. State policy makers might think about oil and gas as a combined stream, and be perfectly sanguine that adding the lower-value gas to Alaska's production portfolio may enhance development by increased tax incentives. On the other hand, if state policy makers continue to think about distinct oil and gas streams, then as a consequence of these high oil-only marginal rates there are some potential outcomes waiting in the way the CPT works that they may be less comfortable with.

Finally – more important though much less open to illustrative modeling – is the effect the tax, including some of the outcomes illustrated above, will have on reinvestment. For example, looking at Figure 4, and assuming a constant gas PTV, consider a producer evaluating an investment that will also lower the oil PTV in the year of that investment. Sometimes that increased oil investment will lead to a higher relative tax (i.e. moving from right to left on a portion of the illustrated curve that has a positive slope) and sometimes it will lead to a lower relative tax (i.e. moving from right to left is on a negatively sloped portion of the curve). How companies make long-term investment decisions, and how those decisions fit in with taxes and tax stability, remains a huge unknown to state policy makers. Figures 5 and 6 illustrate how reinvestment leads to complex variations in production tax liabilities under the prevailing production tax methodology.

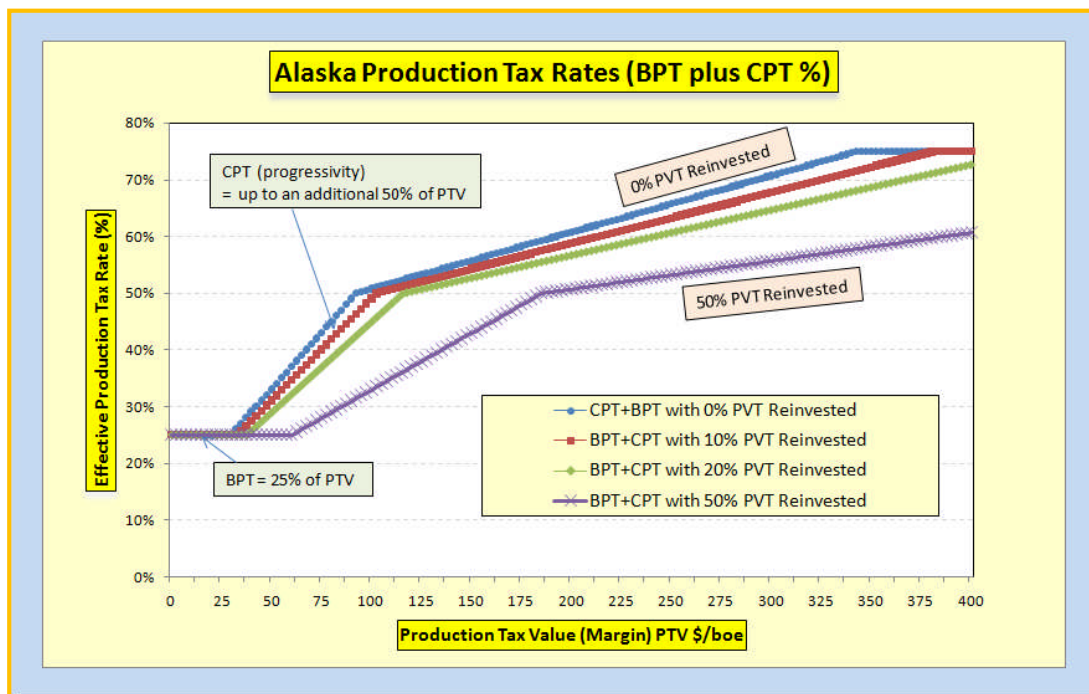


Figure 5. The non-linearity of the CPT mechanism results in different impacts of capital reinvestment on producer's CPT liability depending upon the prevailing PTV \$/barrel. Production tax rates for producers can be substantially reduced over a wide range of PTV \$/boe (above the \$30/boe CPT threshold) by reinvestment of post-tax dollars.

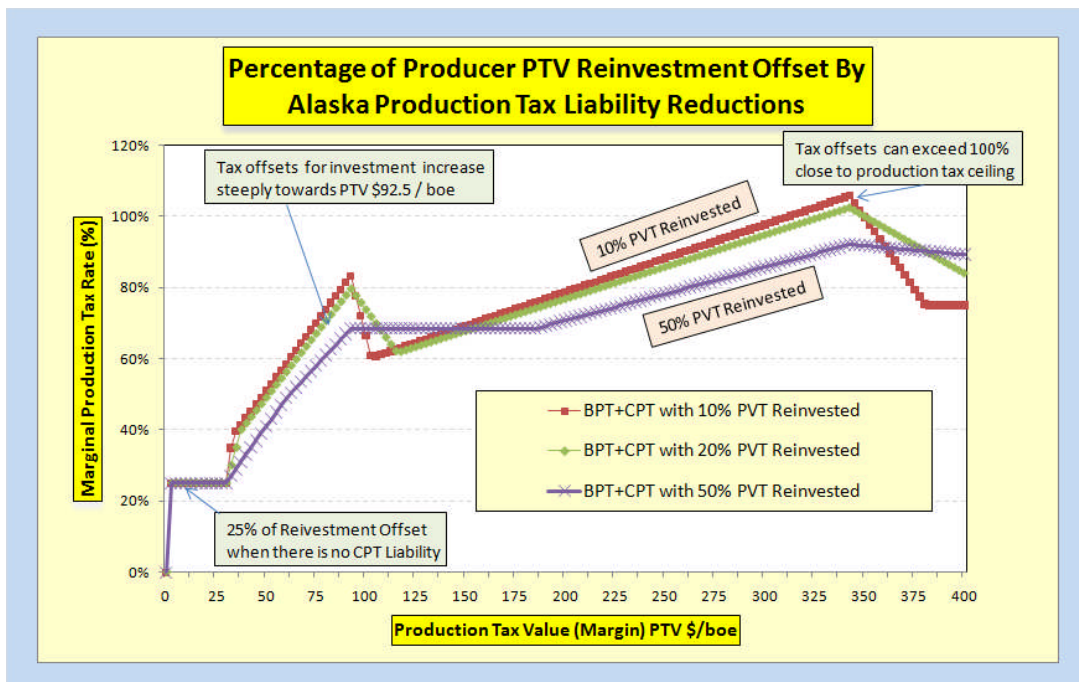


Figure 6. Percentage tax reduction associated with the incremental re-investment (or the marginal tax rate offset by the producer by its reinvestment). Note the peak around PTV\$90/boe and values above 100% at PTV \$350/boe. These high marginal tax rates should act as significant incentives for reinvestment. However, the non-linearity of the benefits and steep gradients complicates prediction and tax planning for investors. Generally incentives for reinvestment are higher when PTV is higher.

How might Alaska respond to these production tax issues?

A paragraph of history might shed some light on how Alaska’s fiscal design could evolve in the future. The period 1973 through 1981 was a time of huge turmoil in Alaska’s fiscal system for royalties and all three oil and gas taxes. The driving event was the opening of the trans-Alaska pipeline in June 1977. The period started off with a special legislative session in which the state added the statewide oil and gas property tax to its fiscal take. It also created a special oil and gas corporate income tax based on separate accounting (taxing only profits earned in Alaska), and then four years later switched back to apportionment of worldwide earnings – with the special rules detailed above for oil and gas companies. In 1977 the state filed a lawsuit against royalty payers that was not resolved for 18 years, but the settlement of which finally set out the ground rules for calculation of royalties. In this period the state changed the production tax several times, going from stair-step production rates driven by well size to various versions of the ELF. (Outside of oil and gas law, but driven by the receipts from those royalties and taxes, the state also repealed its personal income tax and gross receipts business tax, and began the practice of distributing some of the state’s oil wealth directly to its citizens in annual checks that have ranged from \$331.29 in 1984 to \$3,269 in 2008.) Will the period of transition from North Slope oil to North Slope gas be as tumultuous?

Stability concerns for progressivity tax when gas comes on line

This prospect of fiscal instability may appear daunting to potential investors in a North Slope gas line and future exploration and production activities. Many public statements can be heard these days that the state is staking its fiscal future on a gas line. In 2007 there was a great fuss when the extra oil taxes that were paid for 2006 as a consequence of the first round of reforms were about 14% below anticipation. What would happen if the long-awaited gas line were built and instead of proving to be the financial future of the state it actually lowered tax production revenues? The history of the past three decades leads these authors to conclude that such an outcome would more than likely lead to revisions in the tax code. As an alternative, if Alaska were to establish a stable fiscal design for natural gas in advance of contractual commitments associated with a gas line being made, it might make those commitments more likely.

Fiscal stability issues that have arisen around the world in the past five years have highlighted that fiscal stability clauses in contracts and licenses do not guarantee long-term fiscal stability and are easily circumvented by those prepared to exert political pressure on producers. An alternative approach to attempting to lock in fiscal stability via legislation or contract is to establish a rational tax system tied to a long-term, widely agreed upon state fiscal strategy and associated policies and targeted incentives. With all stakeholders recognizing the objectives of the stated strategy, it should be possible to secure investments in the relative security from an investor's perspective that short-term changes to fiscal terms are not going to be made as short-term reactions to changing market conditions. A rational tax system appropriate to such a strategy would need to be flexible and predictable and contain the following elements:

1. ***Some regressive elements*** targeted specifically at high-volume production that provide the state with a baseline revenue stream regardless of prevailing prices.
2. ***Some progressive elements*** that only impact the producers when prices are such that substantial net revenues can be secured by producers while also providing the state with higher net takes from high-margin production.
3. ***Targeted allowances to the regressive elements*** that stimulate capital investment in higher-cost, difficult fields.

Systems with a balance of all three components are more likely to be efficient in raising taxes and promoting investment in a wide range of market and reservoir conditions without prompting frequent fiscal restructuring by a government. If the state's long-held and widely articulated belief is that taxes from oil and gas should provide the baseline revenues needed to run the state, then in a low-price environment a fiscal mechanism driven solely by progressive elements cannot be considered a very stable approach. Conversely, a fiscal mechanism dominated by regressive elements such as royalties and property taxes (without any allowances or investment incentives) is going to be ineffective at promoting investment in high-cost developments because of its negative consequences for producers in low-price environments and may even cause temporary shut-in or premature abandonment of marginal

fields. The challenge for Alaska is to find the right fiscal balance soon for future gas revenues and to promote upstream investment to achieve long-term sustainable gas production a decade or more from now.

One of the alternatives to a CPT combined progressivity tax mechanism is a distinct oil progressivity tax (OPT) and gas progressivity tax (GPT). Typically, with no allowances, such an approach would have the effect of raising the total progressivity taxes paid compared to the CPT approach. However, incentives and allowances could be targeted and tailored specifically at more marginal gas (or oil) streams to avoid inhibiting development capital investment. Our point is that if the state is unlikely to be willing to live with a pipeline causing a significant drop in revenues, a substantial drop in tax revenue caused by a CPT mechanism conceived with oil in mind but diluted by gas is likely to lead the state to change the law. The industry's perception of the possibility or likelihood of such a tax change to fix the issues posed by gas for a CPT mechanism is likely to provide its own inhibition to further development capital investment.

Acknowledgement

Dickinson and Wood have performed and continue to perform advisory and evaluation work for Alaska's Legislative Budget and Audit committee on Alaska's oil and gas fiscal design and a substantial amount of that work is now in the public domain. However, the ideas expressed here are their own.

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