Changing Alaska's Oil and Gas Production Taxes:
Issues and Consequences

An Understanding Alaska Policy Paper

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The Alaska legislature is currently considering a major change to the state system of taxation for oil and gas. The proposed new tax system would replace a tax on gross wellhead production value of oil and a tax on gross wellhead value of gas with a single tax on net income earned at the wellhead. This article attempts to put the decision in context. It discusses some of the major issues related to oil taxes, summarizes the historical pattern of state petroleum revenues, and considers the consequences of the major features of the current tax proposals.

How does the state collect revenue from the oil industry?

Alaska state government collects revenue from two distinct roles that it plays with respect to the oil industry. As a resource owner, the state leases its mineral rights, and collects payments such as royalties from the lessee. As a sovereign, the state collects taxes from oil and gas production, property, and income. Once established, lease terms are part of a contract and can only be changed by mutual consent. The state has a right under its constitution to change its tax regime at any time, however.

Governments own exclusive rights to subsurface resources in nearly every country in the world except the United States. In the U.S., however, private landowners may also own underground resources.[1] The state therefore plays two distinct roles with respect to the oil and gas industry, which are carried out in two state departments: Natural Resources and Revenue. Nevertheless, most oil companies operate internationally and generally view the lease and tax payments as a package, often called the *fiscal regime*.

Why are petroleum revenues different from other government revenues?

A truly "marginal" oil field generates just enough income to pay for the cost of inputs used in production and exploration and yield a competitive return to investors. Most productive oil and gas fields typically generate more income than the marginal field, potentially paying more than the cost of labor and capital used in exploration and production. In theory, the government can appropriate this surplus -- the so-called *economic rent* -- while still leaving adequate incentives for industry to continue searching for more oil and gas. In practice, however, every possible way to collect the economic rent through taxes or lease payments has some adverse effects. Some of these effects can have significant unintended consequences. There is no perfect mechanism to collect oil revenues; all involve tradeoffs of some kind or another.

Why does Alaska need to change its tax system?

[1] Alaska Native regional corporations, for example, own mineral rights to lands granted to village and regional corporations under the Alaska Native Claims Settlement Act. The state of Alaska, however, has retained subsurface ownership when it disposed of the lands it acquired under at statehood, which generally parallels the situation in other countries.

The state collects most of its oil and gas taxes from the production tax (severance tax). Ever since the giant Prudhoe Bay oil field was developed, Alaska's production tax structure has been designed to tax Prudhoe Bay at a high effective rate, while taxing most other oil and gas fields lightly, if at all. Alaska's production tax structure includes a complicated formula, called the Economic Limit Factor (ELF), which varies the tax rate for each field, depending on the average production rate per well and the total oil production from the field. As an oil field becomes depleted, production rates per well and total production both decline, causing the ELF -- and therefore the effective tax rate -- to decline faster than production. Within a few years, the state average effective tax rate will be less than one-third what it was in 1989 -- the last time the production tax was changed -- and most fields will be paying no production tax at all. Unless the tax structure is changed, Alaska will soon collect little tax revenue from oil. Sooner or later, oil companies reason, the legislature will have to address this problem. The companies are reluctant to commit a huge investment in a natural gas pipeline without knowing what "fix" the legislature will come up with.

Three big questions about oil and gas taxes

The legislature could address the issue of declining oil revenues as it has several times in the past: by changing the ELF formula. This time, however, the Murkowski administration has proposed replacing the oil and gas production tax entirely with a new Profit-based Production Tax (PPT). Three big questions about oil and gas taxes help provide context for this decision.

Foremost on the minds of some legislators and of clear importance to industry is the amount of revenue that the fiscal regime collects: *the government take*. Often the issue of government take is portrayed as a simple tradeoff between revenue to the government and revenue to industry. In fact, though, the way that the government collects its revenue also matters. All fiscal instruments create some negative incentives for industry investments. But for any given government take, some instruments have bigger effects than others.

A second key issue, which is related to incentives, concerns the effect of the fiscal regime on *risk sharing* between industry and government. For example, a tax that increases exploration and development risk for investors, especially in an industry like oil that is already very risky, may discourage investment more than a tax that reduces the risk.

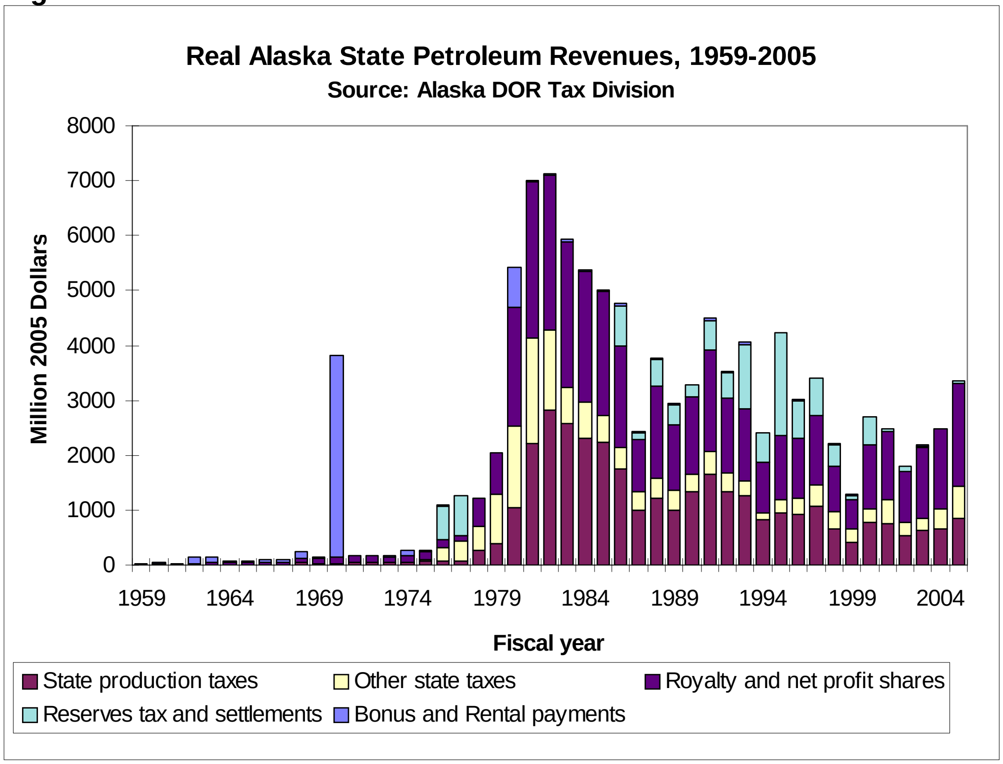
A third key issue involves the *nature of the relationship* between industry and government. An arms-length relationship characterized by unilateral moves and frequent conflict may be more rigid in adapting to change and have different long-term outcomes than one based on negotiation and compromise.

We examine the proposed PPT in the context of these three big questions, comparing patterns and trends over time in Alaska and relative to other states and nations. There is no perfect tax mechanism, and each question involves a principal tradeoff.

1. How much is the government take?

Figure 1 shows the pattern over time of Alaska state oil and gas lease payments and taxes since statehood, in constant prices. Except for the $900 million in bonus bids collected in the 1969 North Slope lease sale -- worth about four times that amount in 2005 prices -- royalties and production taxes have dominated state petroleum revenues. The pattern over time shows a peak in fiscal years 1981 and 1982, followed by a general downward trend until the price spike of the past two years.

Figure 1.



The simplest way to assess trends in government take implied by the revenues shown in Figure 1 is to compare oil and gas production taxes over time as a percentage of wellhead oil and gas value. The lower line in Figure 2 shows recurring revenues as a percentage of wellhead oil and gas production value.[2] Recurring revenues include all revenues except bonus and rental payments, the 1976-77 conservation tax, and tax and royalty settlements, which tend to come sporadically and unpredictably. The upper line adds the non-recurring revenues converted to an amortized constant dollar amount per barrel during the period, like a mortgage payment.[3] Figure 2 shows that the amortized

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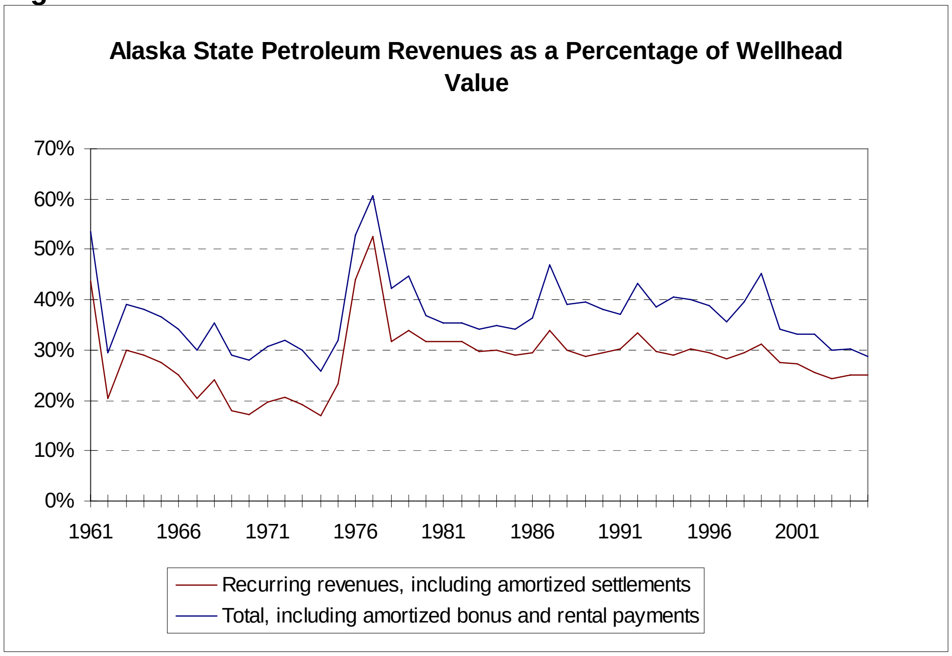
[2] Comparing trends in state revenues as a percentage of wellhead value ignores the effect of trends in costs and federal taxes on industry profits. It also overstates the true percentage take from the wellhead somewhat because income and property taxes collected on the Trans-Alaska Pipeline are included in the numerator but not in the denominator. Taxes collected on pipelines -- especially income taxes -- vary over the years and would be difficult to separate out from taxes collected at the wellhead.

[3] That is, the non-recurring revenues are expressed as the constant real dollar amount per barrel, adjusted for remaining reserves in currently known fields, that has the same value, with interest, as the stream of non-recurring revenues invested at the same interest rate. The interest rate used for the calculation is a 10 percent real annual rate, reflecting the high risk involved. This is the same rate used in the analysis of the PPT prepared for the Alaska Department of Revenue: Pedro van Meurs, *Proposal for a Profit Based Production Tax for Alaska*, February 14, 2006.

value of these non-recurring revenues is quite large -- $1.48 per barrel for bonus and rental payments (primarily the 1969 bonuses) and about $.50 per barrel for the non-recurring tax and royalty revenues.[4]

Figure 2.



The state take spiked in the 1970s, due to property tax collections just before Prudhoe Bay oil began flowing through the Trans-Alaska Pipeline, then stabilized at a higher rate. When commercial production of North Slope oil began, the legislature had also raised the severance tax rate and introduced the ELF, with the rationale that the Prudhoe Bay field could afford to pay a higher tax rate than less productive, Cook Inlet fields. During the 1980s and 1990s, the state take was nearly constant at about 30 percent of wellhead value in recurring revenues and 35-40 percent, considering all petroleum revenues. Since the late 1990s, the state take has been declining, due primarily to the falling ELF in the production tax, as mentioned above.

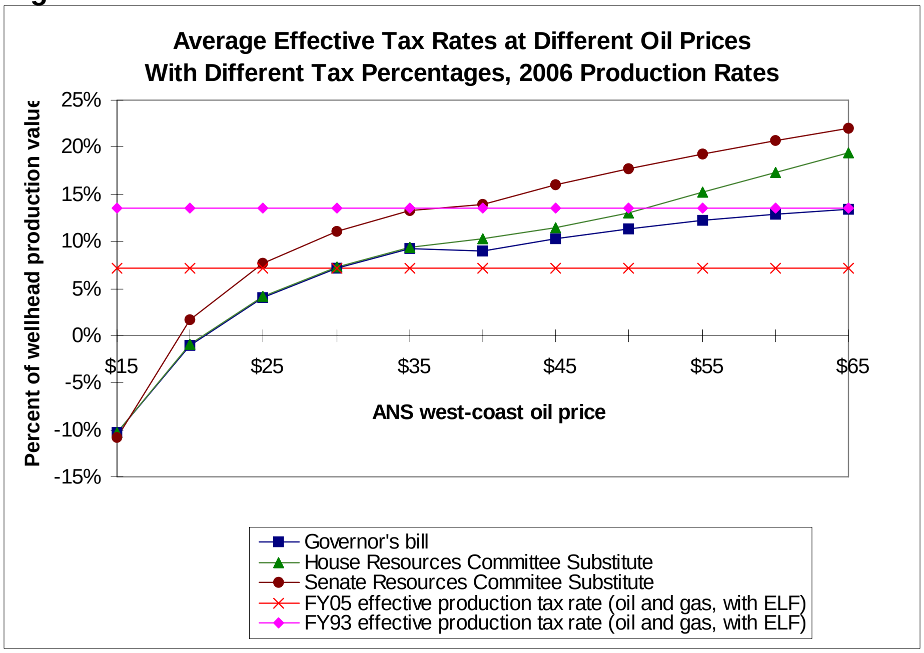
The state take as a percentage of wellhead value has varied little over time, despite fluctuating oil prices, because most revenues came from royalties and production taxes that were assessed as a fixed percent of wellhead value. The proposed PPT would change this pattern significantly. Figure 3 shows that the PPT projected take as a percentage of wellhead value would vary considerably with oil prices. The figure compares how the estimated take varies with Alaska North Slope (ANS) west-coast oil prices for three different versions of the tax bill.[5] According to these estimates, the state take under the PPT would exceed the 2005 average effective tax rate at market prices of

[4] Although the reserves tax and the tax and royalty settlements collectively totaled several billion of dollars and were much larger, even after adjusting for inflation, than the bonus bids, they were collected much more recently, and therefore do not carry nearly as much interest as do the bonus bids, resulting in a lower amortized value per barrel.

[5] Most ANS oil is is sold on the U.S. west coast. The wellhead price is lower than the market price by the amount charged for transportation from the point of production to the point of sale. For Alaska oil, this differential varies somewhat over time, but is currently about $6 per barrel.

$25 to $30 per barrel. The estimated take from the 25 percent tax with the 20 percent investment credit (Senate Resources Committee Substitute bill) would exceed the 1993 average effective rate (13 percent) at a $40 oil price. However, the House Resources Committee Substitute bill with a 20 percent tax and progressive surcharge would not exceed the 1993 rate unless prices surpassed $50. The administration's original bill would not attain the 1993 effective take until oil prices exceeded $65.[6]

Figure 3.



The tax rate comparisons in Figure 3 are estimates made under the investment, operating cost, price, and production assumptions used in the respective fiscal notes.[7] They estimate the effects of the PPT, based on the current composition of oil production, which could change over time. For example, North Slope gas sales and heavy oil development could change the pattern in ways that are difficult to predict. Nevertheless, the implication is clear that government takes will be lower than today at low oil prices, and higher at high prices. But oil prices would have to remain at today's historical high levels to keep the state take from a 20 percent PPT as high as it was during the 1980s and early 1990s. If history is a guide, oil prices are more likely to be much lower than they are today. In only nine out of the past 45 years has the real wellhead price averaged more than $25 per barrel, which is the point at which the PPT would collect more revenue than the current tax. At real world oil prices below $20, the

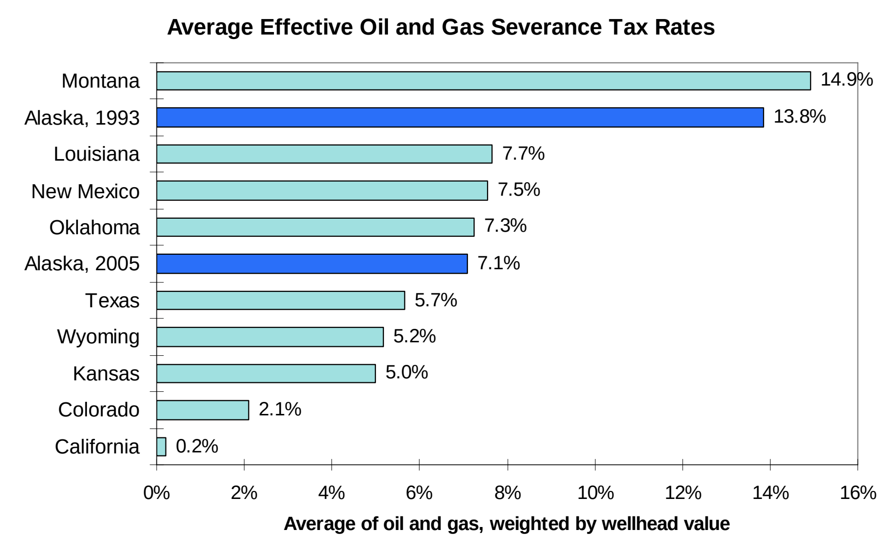
[6] The rate curve for the administration bill show a slight dip between $35 and $40 reflecting the threshold in HB488 for "transitional deductions." Each bill has a different transitional feature that expires at different times. The estimates in Figure 3 include an estimate of the transitional deductions for the first year, based on the assumptions contained in the fiscal notes submitted for the bills. These three versions were included because they are the only ones for which fiscal notes were available at the time the paper was completed.

[7] These assumptions are estimates made by Alaska Department of Revenue professionals with access to confidential company tax data. Consequently, it is not possible to verify independently how accurate they might be.

state would lose money.[8] Oil prices stayed below that threshold nearly 30 percent of the time during the past 45 years, including during two years out of the past ten.

Alaska has a reputation as a high-tax state for oil and gas. While the reputation may have been deserved in the past, Figure 4 shows that it no longer is. The figure compares average effective oil and gas severance (production) tax rates in major oil-producing states in of the U.S.[9] Most states base severance taxes on gross wellhead value. The highest current nominal tax rate for oil is about the same in Louisiana and Montana as in Alaska, But Louisiana taxes gas at a very low rate, and produces lots of gas. The figures for other states are for 1993, because that is the latest year for which comparable data are available. Effective rates have changed little for most states since 1993, but Alaska's has dropped by nearly 50 percent, due to the decline in the ELF. Alaska's average 2005 effective tax rate now puts it in the middle range of U.S. oil states, and the effective rate will continue to decline under the current tax structure.[10]

Figure 4.



Source:
Alaska: Alaska Dept. of Revenue, Tax Division, *Revenue Sources Book* , Fall 2005, and unpublished data from the Division. Montana: Montana Department of Revenue, Tax Reform Committee Memo, March 2004; other states: US DOE Energy Information Administration (EIA), State Energy Severance Taxes, 1985-1993, http://www.eia.doe.gov/emeu/sevtax/ accessed March 15, 2006. New Mexico includes severance taxes assessed by local governments. Analysis provided by Pete Larsen.

When comparing Alaska's fiscal regime to those of other nations, one must consider federal taxes in addition to state taxes and lease terms. Pedro van Meurs recently compared Alaska's fiscal regime to nine representative jurisdictions (Table 1). The U.S.

[8] The PPT allows losses and unused tax credits to be carried forward indefinitely and sold to firms with tax liability. In years when no company has a positive tax liability, the industry would essentially be loaning money to the state, which would have to pay it back as soon as the industry returned to profitability.
[9] The oil and gas industry pays other taxes besides severance taxes, but these are ignored because other industries generally pay them, too, and they are not specific to oil and gas.
[10] Official state revenue projections show the oil ELF -- and therefore the oil severance tax -- declining by about one-third over the next seven years (Alaska Department of Revenue, Tax Division, *Revenue Sources Book, Fall 2005*, p. 14).

federal government levies a 35 percent tax on corporate income. There are no state taxes on oil and gas produced in federal offshore waters, helping to give the U.S. Gulf of Mexico regime the lowest ranking on government take among those van Meurs analyzed. The proposed PPT would place Alaska in the middle of the group.

Table 1. International comparison of selected petroleum fiscal regimes, ranked by attractiveness to industry

Fiscal regime	Government take ranking	Overall competitiveness ranking
US Gulf of Mexico	1	1
UK	4	2
Alberta-Oil Sands	2	3
Nigeria	3	4
Angola	7 (tie)	5
PPT-20	7 (tie)	6
Azerbaijan	5	7
PPT-25	9	8
Alaska Current	6	9
Norway	11	10
Russia-Sakhalin	10	11

Note: Fiscal regimes are ranked from most attractive to industry (#1) to least attractive (#11). The overall competitiveness ranking is based on three financial performance measures in additional to government take.

Source: Derived from analysis presented in Pedro van Meurs, *Proposal for a Profit Based Production Tax for Alaska*, February 14, 2006, pages 107-118.

Oil taxes generally involve a tradeoff between the share of the rent collected by the government and industry profits. Higher government takes increase the likelihood of adverse effects on business decisions. But not all taxes are equal. Some ways of taking revenue have bigger effects than others per dollar of revenue collected. As Table 1 shows, some fiscal systems have a higher ranking for government take than for overall competitiveness.

Two main factors contribute to the disparity. First, fiscal instruments that defer collection of revenues allow companies to recover investment costs faster, increasing the rate of return. Second, taxes and lease payments assessed without taking costs or profit into consideration may make some marginal fields uneconomic to develop that could be profitably developed without the tax or royalty.[11] Alaska's current system, with its reliance on up-front lease bonuses, property taxes, fixed royalties, and production taxes,

[11] Another problem with royalties and taxes based on production rather than net income is that they may lead to premature abandonment of oil and gas fields. This was the original rationale for the ELF. While the ELF does eliminate tax incentives for premature abandonment by lowering the tax rate to zero as production rates decline, it poorly addresses the much bigger problem of investment in new high-cost fields.

ranks poorly on both criteria. The PPT, with a tax credit for capital expenses and cash flow deductions for capital and operating costs, fares much better. Consequently, changing to the PPT would reduce the relative ranking on government take (meaning more revenue paid to governments) while increasing the overall competitiveness ranking.

2. How does the fiscal regime share risk?

Another problem with not taking costs into account in the tax system concerns the way that the fiscal regime affects the risk of oilfield investments. Oil companies face several different types of risk. Only a small fraction of exploration wells find developable oil or gas (exploration risk). Once oil is found, the size of reserves and cost of extracting them are uncertain (development risk). Oil and gas prices fluctuate unpredictably (market risk). Finally, governments may change the tax regime or impose unforeseen costly regulations (political risk). The *progressivity* of the fiscal regime relates to the degree to which the government shares these risks with the developer.

A progressive fiscal instrument collects a larger proportion of net income as income increases, while a regressive measure collects a larger share of net income as income declines.[12] Table 2 summarizes common lease terms and taxes by degree of progressivity. Generally speaking, the more regressive the tax or lease payment, the more it increases the developer's exploration, development, and market risk, which are all very high in the oil business. Because a regressive tax regime stabilizes government revenues while increasing the volatility of industry profits, it is likely to be changed more frequently by governments as conditions in the industry change. Therefore, regressive taxes increase political risk as well as financial risk. On the other hand, progressive measures are often more complex and challenging to administer and modify. The simplest revenue measure – the cash bonus bid – is also the most regressive. There is therefore a tradeoff between risk, and stability or simplicity.

[12] These terms "progressive" and "regressive" are sometimes popularly associated with various concepts of the revenue base: oil price, production level, and net profit. Here, the term applies to net income, as is the convention with economists.

Table 2. Relative progressivity of different lease payments and taxes

Progressivity class	*Explanation*	*Lease terms*	*Taxes*
Highly regressive	Revenue unrelated or negatively related to production	Bonus bids, rental payments, work commitments	Property tax, reserves tax
Moderately regressive	Based on production, ignoring price or cost	Fixed dollar per barrel royalty	Apportioned income tax, fixed dollar per barrel tax
Somewhat regressive	Based on gross production value, ignoring cost	Fixed percentage ad valorem royalty [a]	Fixed rate ad valorem severance tax [a]
Neutral	Fixed percentage of net income	Fixed net profit share	Fixed rate producer profits tax
Progressive	Percentage of net income rises as income rises	Variable rate net profit share	Variable rate producer profits tax, producer profits tax with investment credit

[a] Royalty rates and production tax rates that vary with oil and gas prices may be regressive or progressive, depending on whether the variation in costs (which are not taken into account) matters more or less to investment returns than does the variation in prices.

Figure 5 shows that Alaska has relied historically on regressive lease and tax payments, except for a brief period when it levied the separate accounting income tax.[13] Alaska has had net profit share leases since 1979, but these account for a small fraction of lease revenues.[14] The line in the figure plots the average wellhead oil price, adjusted for inflation. The share of wellhead value collected by the fiscal regime does not rise when oil prices rise; in fact, there is a clear inverse relationship.

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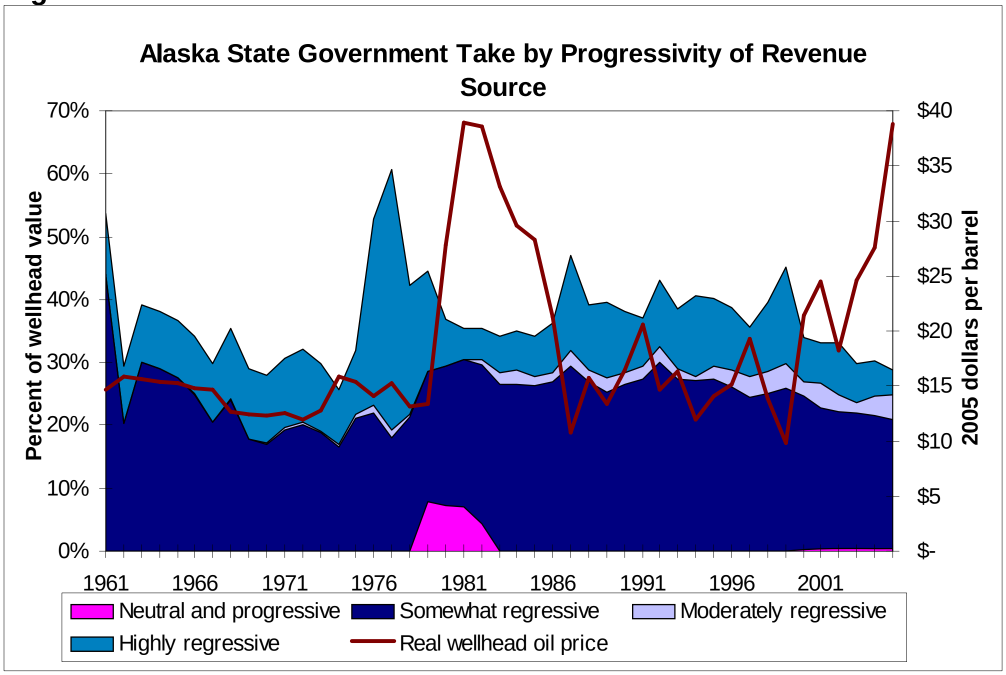
[13] Alaska's Separate Accounting Corporate Income Tax (AS 43.21) defined the tax base as net income earned with Alaska. This is sometimes called a "ring-fenced" income tax. In contrast, most state income taxes apply to a fraction of total company income that is apportioned to the state based on a formula that does not include income earned in that state. The separate accounting tax was repealed in 1981 under intense industry lobbying and litigation pressure.

[14] Net profit share leases became controversial in 1996 when BP insisted on renegotiating lease terms for its Northstar prospect to eliminate net profit shares, some of which ranged as high as 90 percent, before developing the field (see Figure 10). However, BP and several other companies have been producing oil from several North Slope fields with smaller net profit shares -- generally 30 percent -- for many years without conflict or controversy.

Figure 5.



The PPT would significantly change this pattern, by replacing about half the "somewhat regressive" revenues with "neutral or progressive" revenues. Figure 6 illustrates how the PPT would change the distribution of revenue streams from the market value of oil at the point of sale, and a low and a high oil price.[15] At a $20 sale price, transportation costs take about one-fourth of the market value, leaving a wellhead price of about $15. The share of the market value distributed to royalties, bonus and rental payments, operating, exploration and development costs, is identical under the current and proposed state tax regimes. However, Figure 6 shows that the current severance tax would on average collect about five percent of market value, while the PPT would collect nothing (actually, a slight credit). Under the PPT, the share of value collected by the industry investors would rise from zero to three percent. At a $50 oil price, the situation would be reversed. The producer profit would be smaller under the PPT and the state take larger compared to the current tax structure.

[15] Exploration and development costs in Figure 6 may appear low because they do not include interest, depreciation, or return on investment. Consequently, some producer profit is needed on average in order just to cover depreciation on past investments and provide a return to investors.

Figure 6. Distribution of revenue from oil sales: PPT vs. current state severance tax, at two oil prices

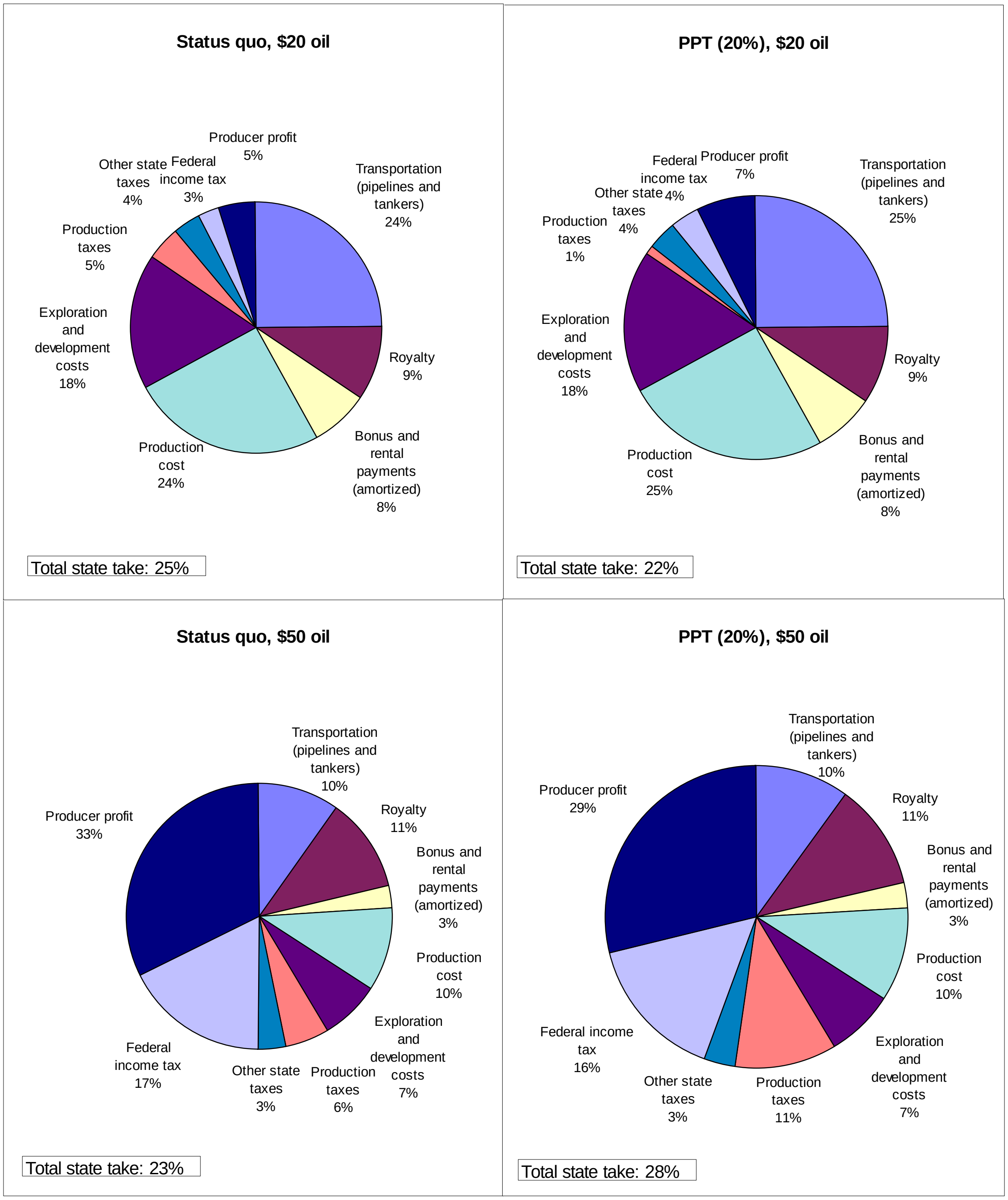


Figure 6 illustrates the effect of the PPT on the distribution of one component of risk: market risk. Table 3 summarizes an example calculation that shows the way that the PPT changes the distribution of exploration and development risk. The table shows a calculation of the after-tax cost, expected present value at a 10 percent real discount rate, the expected rate of return to industry, and total (undiscounted) state revenues, for a hypothetical exploration investment, a development investment, and an investment to prolong the life of an aging field. All calculations take federal income taxes into account. The exploration investment represents an example of a high-risk investment. The development investment is somewhat less risky, but very expensive, while the investment to prolong field life represents a low-risk, low-return investment. The costs and revenues from the three examples are designed to show examples of truly marginal investments -- those that are close to breaking even, or barely break even -- at three stages in the life cycle of an oil field..

Table 3. Examples of expected cash flows and investment returns under the current and proposed tax systems

	After-tax cost ($millions)	*Expected net present value ($millions)*	*Expected rate of return*	*Expected state revenues ($millions)*
Exploration investment[a]				
Current tax	($40)	($6.1)	8.8%	$162
20% PPT	($30)	$4.8	11.2%	$160
Heavy oil development investment[b]				
Current tax	($624)	($6.3)	9.5%	$109
20% PPT	($462)	$23.6	12.2%	$109
Investment to prolong field life				
Current tax	($6.5)	$4.8	-[c]	$0
20% PPT	($3.9)	$4.3	-[c]	$0

[a] Assuming a 15 percent chance of finding 150 million barrels of oil with a $40 million exploration program, $20 million lease acquisition cost in year 1, $1 million/yr lease rental until production starts in year 9, 1/8 royalty, $30 real wellhead oil price, $4 million/bbl development cost, $4 million operating cost per initial barrel produced, 50 mb/d initial production rate, declining at 10 percent per year. Development costs do not include interest, depreciation, or investment returns. With a discounted cash-flow analysis, these items factor into the rate of return and net present value, instead of showing up as costs.

[b] 150 million barrels of reserves developed at $4 million per barrel development cost, $8/bbl operating cost per initial barrel produced, 7% decline rate, no severance tax.

[c] An internal rate of return cannot be computed for the investment to prolong field life, because cash flows are positive in every year.

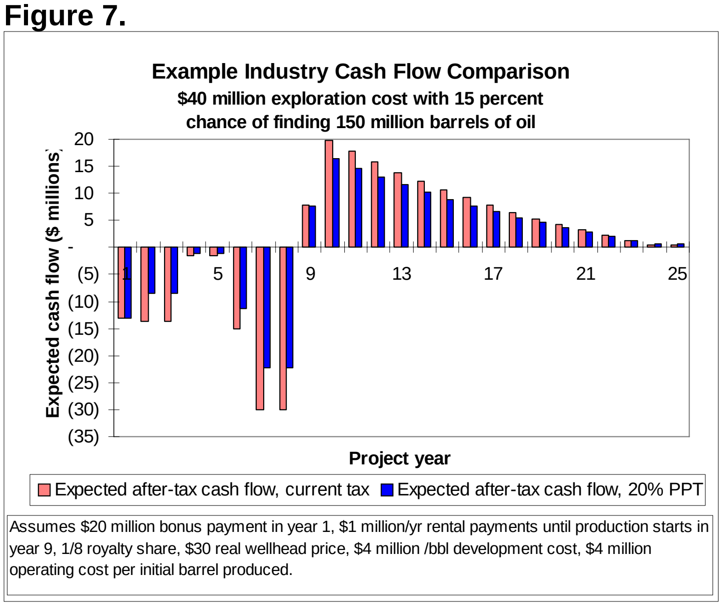
The estimates in Table 3 show that the state revenues are nearly identical under the proposed new and existing tax regime for all three examples. However, the effect for industry differs. At all three stages of an oil field's life cycle, the 20 percent tax credit greatly reduces the after-tax investment cost. However, the expected present value and rate of return are much higher under the PPT than under the current production tax for the exploration and development investments. These are investments at earlier stages of the life cycle that have the biggest effects on future production, industry profits, and state revenues.

One simple measure of the relative development costs of different oil basins is the Minimum Economic Field (MEF) size, defined as the smallest size field that is generally profitable to bring into production if oil is discovered. Alaska's high MEF, caused by remoteness and lack of infrastructure, is often cited as the main barrier to increased exploration by independent firms in the state.[16] For the example exploration and development investments that Table 3 summarizes, a 20% PPT with a 20 percent tax credit reduces the MEF by one-third compared to the current tax system. That is, if a 150 million barrel field is the smallest that can be profitably developed under the current tax system, the PPT would move that limit down to 100 million barrels.

A big reason that the returns to industry are much higher under the PPT is that the tax credit and deduction for field investments result in a deferral of state tax payments. Figures 7 and 8 illustrate the pattern of cash flows to industry and state government, respectively, for the exploration investment summarized in Table 3. In this example, the state receives a bonus payment in the first year, which neither tax considers. After that, the state gives up revenue for exploration and development investments under the PPT, then gets it back later during the production phase.[17]

One can usually assume that higher taxes discourage investment. However, the 20 proposed PPT with its investment tax credit and deductible capital costs actually generate a higher rate of return in this example (11.2% for the exploration investment in Table 3) than investors would realize with a zero production tax (9.7%). A 25 percent PPT with a 20 percent investment credit would also generate a higher return (11.0%). Of course, if the field is a lot more profitable than the one used for this example, investment returns would be lower with the PPT.

Figure 7.



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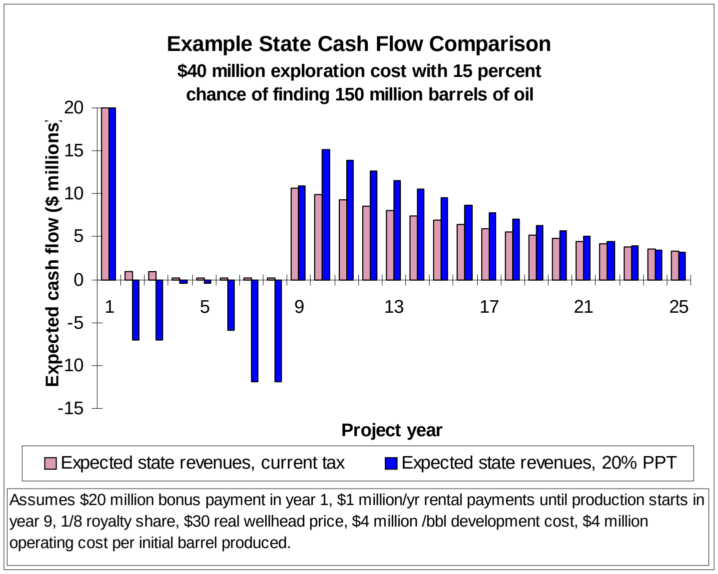
[16] Mike Dunn, Alaska Engineering and Development Manager for Pioneer Natural Resources, in remarks at a panel discussion sponsored by the International Association for Energy Economics, Alaska Chapter, Anchorage, April 20, 2006.

[17] The figures assume a 15 percent chance of finding developable oil reserves. Consequently, the development expenditures and production revenues are 15 percent of the estimated amounts if oil were actually found.

Figure 8.



When North Slope oil was first being developed, the state had few financial assets and lots of debt obligations. The state could not afford to gamble on the oil business. Regressive taxes may have made sense for Alaska thirty years ago. Today, however, with a mature oil industry and tens of billions of dollars of assets in the Permanent Fund and Constitutional Budget Reserve, the state can much better afford to share the risks with the industry.

3. What is the nature of the relationship between government and industry?

Governments around the world differ dramatically in the approach they take to building a relationship with the oil industry. One measure of the relationship between industry and government is *administrative distance*: the degree to which industry and government participate in setting the terms of the fiscal regime. Some countries operate their own oil companies that participate with international firms in joint ventures to develop local reserves or take an equity interest in development projects. At the other extreme are governments such as most U.S. states that deal only on an arms-length relationship with industry. Figure 9 summarizes some common lease terms and taxes by the administrative distance.

Table 4. Administrative distance of industry-government relations

Distance of relationship	*Lease terms*	*Taxes*
High	Competitive lease auctions, state sets lease terms and bid method	State sets tax regime unilaterally
Medium	Solicitation of competitive development proposals	Industry participates in drafting proposals for tax changes, legislature may amend before ratification
Low	Negotiated development and revenue terms, government participation as equity investor	Negotiated settlements of tax disputes

Advantages of closer industry-government relations include more rapid adaptation to changing economic conditions, less conflict and litigation, and ability to accommodate specific needs of one party or the other. The main disadvantage with closer relations is the loss of transparency, making it difficult for citizens to know exactly what each party gives up and gets in return, and be able to hold public officials to account for their decisions. That is, there is a tradeoff with administrative distance between flexibility and transparency. The closer the relationship, the more critical it is to have highly qualified state employees with high ethical standards working on oil and gas fiscal issues.

Table 5 summarizes major changes in Alaska's oil and gas fiscal regime since North Slope oil started to be developed. The changes with a shaded background involved large amounts of state revenue. The pattern shown in Table 5 suggests that the administrative distance has generally declined over these past three decades. The relationship between the state and the oil industry has gradually moved from a more confrontational stance to one of accommodation and negotiation. The conflict characteristic of the 1970s and early 1980s appears to have eased. The maturing of the oil industry from a geologic and economic standpoint seems associated with a maturing administrative relationship, as each side gains more confidence that its needs will be met. Alaska state agencies have developed a much stronger institutional capacity for negotiating with the oil industry. However, starting with the large tax and royalty settlements in the 1980s, and continuing today with the negotiations over North Slope gas pipeline financing, there has been a significant loss of transparency. Alaskans, aside from the few officials involved in the negotiations, will never know what their public servants left on the table to achieve these agreements.

Table 5. Major changes in Alaska's oil and gas fiscal regime.

Year	*Authority*	*Brief description*	*Administrative distance*	*State take*	*Progressivity*
1973	AS43.56	Enact property tax	High	Increase	Highly regressive
1975	AS43.58	Reserves tax (temporary)	High	Exceeds 100%	Highly regressive
1977	AS43.55	Severance tax with ELF	High	Large increase	Reduce regressivity
1978	AS 43.21	Separate accounting income tax	High	Large increase	Increase progressivity
1979	AS38.05	Expanded lease bidding options	High	Neutral	Options to increase used in major lease sale
1981	AS 43.55; AS 43.20; repeal AS 43.21	Change income tax and severance tax	High	Decrease	Regressive
1989	AS 43.55	Change in ELF	High	Increase	Regressive
1990	AS 38.05	Royalty reduction option	Decrease	Decrease	Reduce regressivity
1994	AS 43.55	Make hazardous release tax permanent	High	Increase	Regressive
1994	AS 38.05	Exploration licensing, credit	Decrease	Decrease	Progressive
1986-2000	Attorney general	Settlement of major tax and royalty disputes	Low	Unknown	Highly regressive
1996	Ch. 139 SLA	1996 Northstar lease renegotiation	Low	Neutral	Change from progressive to regressive
1998	AS 43.82	Stranded Gas Development Act	Decrease	Decrease	Neutral
2003	AS 55.025	Exploration tax credit expanded	Decrease	Decrease	Progressive
2005	Administrat ive	Aggregation of small field ELF	High	Increase	Neutral
2006	Proposed	Producer Profits Tax	Moderate	Neutral	Change from regressive to progressive
2006	Proposed	State investment in natural gas pipeline	Low	Unknown	Progressive

Specific features of the proposed PPT

Alaska has a 9.4 percent corporate income tax. However, that tax is computed from a formula that allocates a portion of each company's worldwide income to Alaska, based on production, assets and sales, rather than on profits earned in the state.[18] Alaska had a "separate accounting" income tax between 1978 and 1981, but the PPT has some important differences from that tax, and most other income taxes.

First, the PPT allows taxpayers to deduct the full cost of capital investments in exploration and production as they are made (cash flow). This provision increases industry profitability -- by allowing companies to recover investments faster -- without reducing state take in the long run. The old state income tax allowed capital expenditures to be deducted from income only through a depreciation allowance (the state even required some costs to be depreciated that could be taken as cash flow deductions on the federal income tax). Governments typically prefer depreciation to cash flow deduction in income taxes because the cash flow method yields no revenue from new development until industry recovers all the capital costs. Alaska can afford to enact a cash-flow-based tax now because the industry has large current cash flows from mature producing fields.

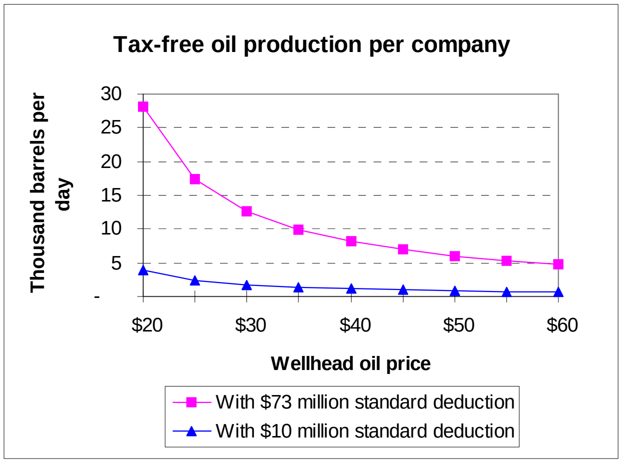
A second important feature is the 20 percent tax credit for exploration and development expenditures. In essence, this enables firms to deduct their capital expenses twice: once to reduce taxable income, and again as a credit to a portion of their taxes on that income. If the company incurring the expense has insufficient income, it may carry forward or sell the tax credit to another firm that has a tax liability, just as it may carry forward or sell tax losses. The Department of Revenue assumptions for the fiscal note to HB488 imply that this tax credit would reduce revenue by about $200 million on average, but the actual cost will likely vary greatly from year to year.

A third important feature of the PPT is the ability of firms to carry losses forward forever, or trade (sell) them to companies that have a tax liability. This provision causes the state to share the losses as well as the gains with the industry. These three provisions are common to all versions of the bill. The bill also has several additional features, however, that vary among the different versions.

One of these additional features is the so-called "transitional deduction," that, in essence, allows firms to depreciate investments made during the recent past. Although producers would generally favor a cash flow treatment of new investment, some Alaska producers have recently incurred large expenses to bring new oil fields into production, and would like to be able to deduct depreciation on those investments from their taxable income. The Department of Revenue estimates that the generous transitional deduction in the administration's bill could reduce tax revenues by $170 million per year until it expires in six years.

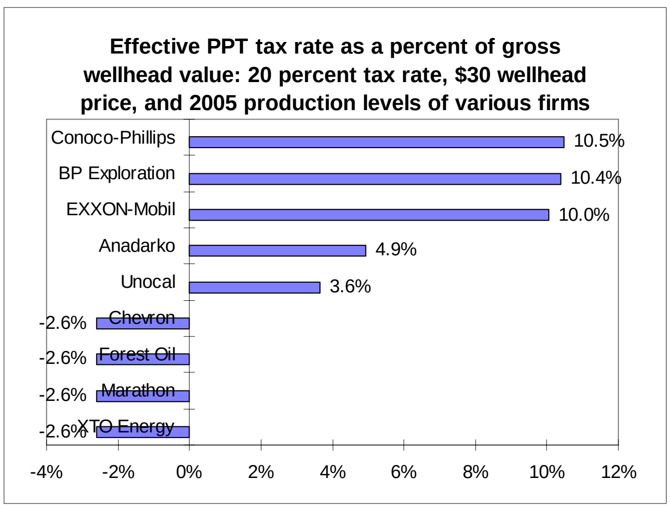
Figure 9.

[18] The tax apportions income to Alaska based on the average of the ratios of production, assets, and sales plus tariffs received in Alaska. Prior to 1978, the tax apportioned income to Alaska based on sales, assets, and employment. Alaska accounts for a relatively small part of worldwide operations of most companies, so the main effect of a new investment in Alaska on the corporate tax base comes from increasing the share of income allocated to Alaska, not from the additional income itself.



Another special feature is a large "standard deduction" from taxable income: $73 million in the administration bill, with amounts tied to investment in other versions. The provision adds progressivity for new entrants to Alaska. Depending on the wellhead price and average company costs, however, it could lead to substantial tax-free production in low-price years. Figure 9 shows the amount of tax-free oil implied by the standard deduction at $73 million and at $10 million with different wellhead oil prices, under the cost assumptions of the HB488 fiscal note.

Figure 10.



Although sixteen companies currently produce oil or gas in Alaska, and several more are exploring, only a few would pay any tax in most years with a $73 million standard deduction. Figure 10 shows estimated PPT rates as a percentage of gross wellhead value at a $30 wellhead price, assuming average projected deductions and tax credits, at production levels corresponding to wellhead values produced by the nine largest Alaska operators in 2005. The figure shows that effective tax rates vary even for companies with net income that substantially exceeds the $73 million threshold. The negative numbers for low-volume producers imply a tax credit, which, as mentioned above, may be sold to producers with a positive tax liability.

Figure 11.

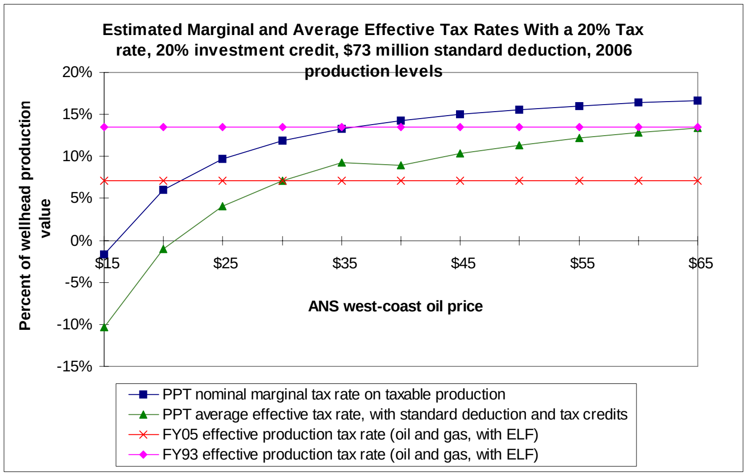


Figure 11 shows the combined effect of the transitional deduction, standard deduction, and investment tax credit, as set forth in the administration version of the PPT, on the state government take at different oil price levels. With all three of these special provisions removed, the state take at a 20 percent tax rate on profits approximates the take at a 25 percent profits tax rate with the three provisions included. In other words, the provisions together cost the state about five percent of net production income.

Conclusions

Much has been said in the recent debate over the PPT about the amount of revenues that the state might collect over the next several years. One must keep in mind that these revenue projections represent educated guesses; it becomes increasingly difficult to forecast revenues from a tax change as projections move farther into the future. What matters most for the state in the long run is not what revenues are next year, but rather what oil and gas production and revenues might be in 10 or 20 years. Long-run revenues depend on two factors: (1) whether the incentives built into the PPT will work to bring on new investment, and (2) whether the added investments actually result in increased oil and gas production and revenues. The Alaska legislature has no influence on the latter factor, but it can certainly affect former.

As it debates and modifies the administration's proposed PPT, the legislature must address a number of unresolved questions. Some of the most important are:

1. Should the tax contain a large standard deduction? Historically, Alaska's production tax system has been designed to tax Prudhoe Bay oil heavily while taxing less productive fields lightly, if at all. Replacing the ELF-based severance with the PPT moves the state from taxing oil from different fields at different rates to taxing different companies at different rates.
2. Should different regions be taxed differently? Oil production from Cook Inlet has not paid severance tax for decades due to a zero ELF, although producers there have been paying gas severance taxes.
3. Should costly heavy oil have additional incentives?
4. Should natural gas be included in the PPT? The proposal replaces the gas production tax as well as the oil tax. Some people have questioned passing a major change to the way that natural gas is taxed before the fiscal details of the North Slope gas pipeline contract are known. The effects on Cook Inlet gas are uncertain, and some Cook Inlet gas taxes get passed on to Alaskan consumers.

5. Should a transition deduction be included? is it fair to give companies a break that have recently incurred large investments that would not be credited on the cash flow basis of the PPT, or would the state just give up revenue and get nothing in return?
6. Should the tax include a progressive rate structure, so that the tax rate increases at high oil prices? If so, should the tax brackets be indexed with the general price level?
7. Is the PPT too complicated; will it inevitably lead to disputes and litigation over the definition of deductible costs and credits? Differences of interpretation are likely with any major change in the tax structure, and ultimately judges will have to sort them out. The fiscal note for the bill includes additional costs for auditors, but it does not include an allowance for litigation.

The analysis presented here cannot definitively answer all these questions. However, it does provide some insights and suggestions:

- ***The PPT is an improvement over the old production tax.*** The state could easily raise its percentage take to the level of the early 1990s by simply reducing the Economic Limit in the ELF formula from its current level of 300 barrels per day per well to a more realistic level of 100 barrels per day. But by changing to a tax on net income instead of gross revenues, the state would better share risk with oil companies and cause fewer adverse effects per dollar of revenue collected. Alaskans should anticipate disputes and litigation if the PPT is implemented. But the state has weathered these before. With proper information, Alaska's elected representatives can determine the tax structure that best balances the level of government take and economic incentives.

- ***Don't expect too much*****.** The PPT should not be viewed as an opportunity to increase the state's take from its oil and gas. Oil prices are more likely to fall from their current levels than rise. In the long run, meaning that the state take from the PPT may be no more, and possibly less, than it is now. Alaska's experience with a major oil tax overhaul in 1981 suggests that it is impossible to know exactly how much revenue will change when the basis for taxation shifts. The PPT will not solve the long-term problem of the fiscal gap caused by declining oil production. No oil tax can.

- ***Keep it simple*****.** Switching from a tax on gross revenues to a tax on net income automatically adjusts for differing ability to pay among different investments. The more complicated the bill becomes, with attempts to treat different income and operations differently, the more opportunities for disputes and litigation. Royalty relief -- available under existing state law -- provides a better solution for Cook Inlet fields and other high-cost operations. The gas pipeline contract, not a broad tax bill, is the place to special provisions related to North Slope gas development. The large standard deduction encourages large producers to take on numerous minority partners in order to reduce their tax. Once passed, these complexities generate their own constituencies and become very difficult to remove once the unintended consequences are revealed. It is better to keep tax rates low and the tax base large.