

State of Alaska
Department of Revenue

Commissioner Bryan Butcher



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The Honorable Eric Feige
State Capitol Room 126
Juneau AK, 99801

February 23, 2011

The Honorable Paul Seaton
State Capitol Room 102
Juneau AK, 99801

SUBJECT: Response to Questions from House Resources Meeting on February 21, 2011

Dear Representatives Feige and Seaton:

The purpose of this document is to respond to the follow-up questions from the House Resources Committee meeting on February 21, 2011. The requests/questions and responses follow.

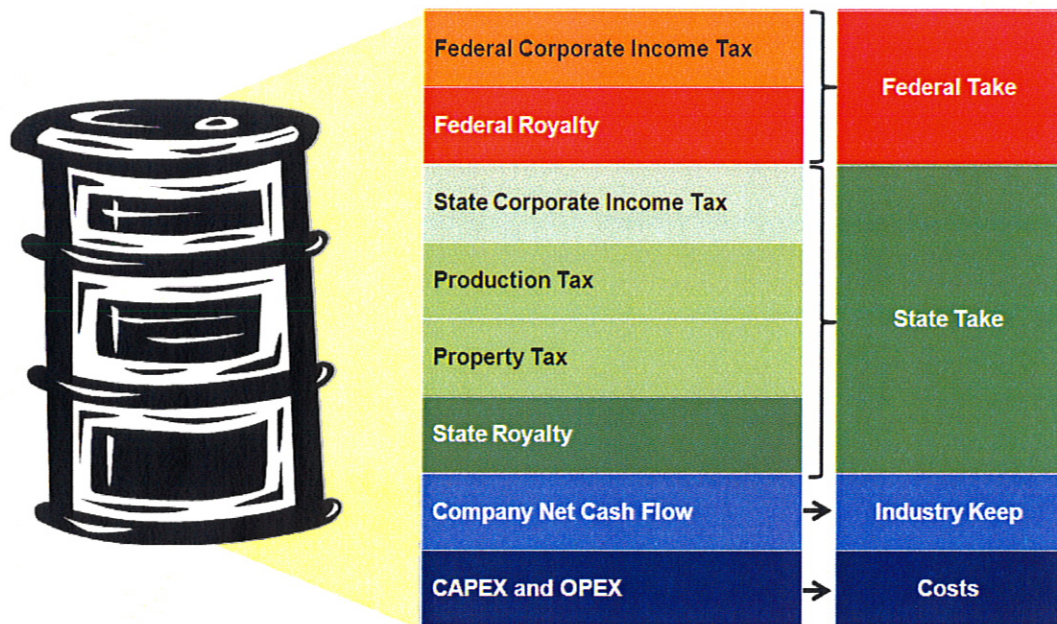
1) Compare effective tax rates to other jurisdictions where major producers are investing.

In comparing Alaska to other jurisdictions it is informative to look at total government take, as opposed to just taxes. Total government take includes all aspects of a particular fiscal regime including royalties, corporate income taxes, and production shares. The total government take is calculated as:

Federal Take + State Take

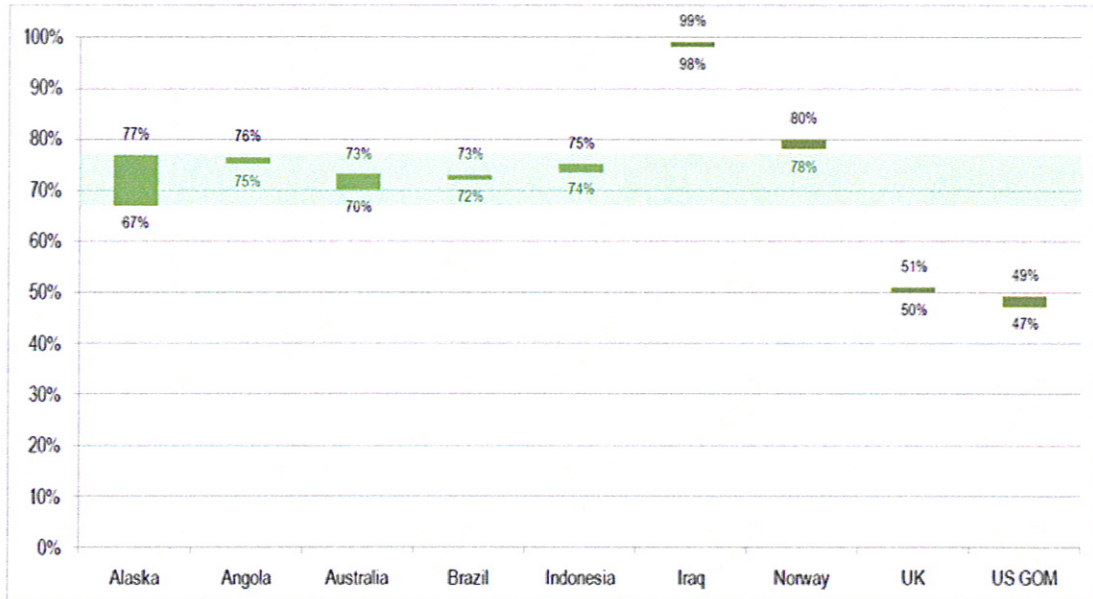
Field Revenue – Capex – Opex

The following graphic illustrates the components that comprise government take.



The following chart, extracted from a presentation given to Senate Finance on 2/22/10, presents total government take at oil prices of \$70 and \$150, in jurisdictions selected for their ability to attract hydrocarbon investments. The government take calculations are based on a production profile and costs similar to those in Alaska, with the various fiscal systems applied. The chart shows that Alaska's current total government take (about 67% at \$70 oil and about 77% at \$150 oil) is similar to the government take in a number of these jurisdictions; though significantly higher than the government take in the UK and the US Gulf of Mexico. Although Alaska's government take is similar to some other jurisdictions, Alaska is not currently attracting the desired level of exploration and development.

Remaining NS Oil Profile Total Government Take



Note: Oil price \$70-\$150/bbl

Total Government Take - Alaska

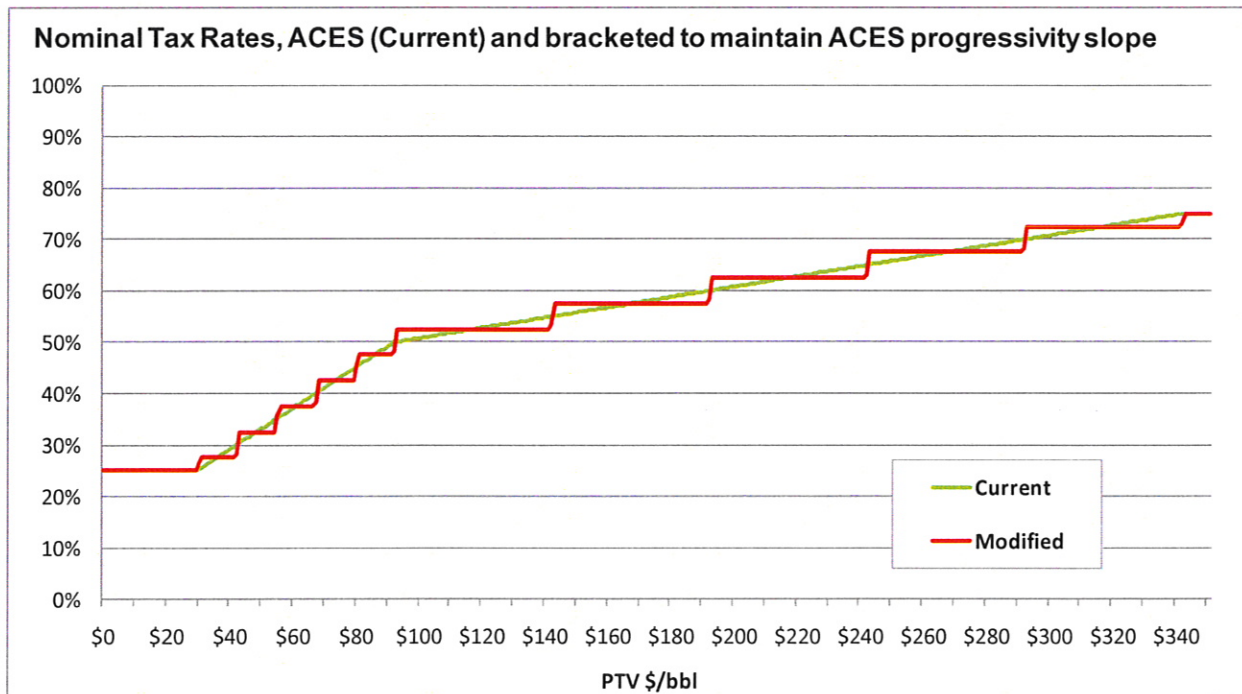
2) How much reinvestment of tax savings would occur if HB 110 passes as written?

The Department cannot say for certain the amount of reinvestment that will occur if HB 110 is enacted. A primary goal of the bill is to improve the investment climate in Alaska. Many companies that are currently producing, or hope to pursue new exploration and development, have testified to the beneficial impact this bill will have in terms of encouraging new investment and production.

3) Provide a slide showing tax rates if we were to maintain the same tax rates as ACES, but bracket progressivity.

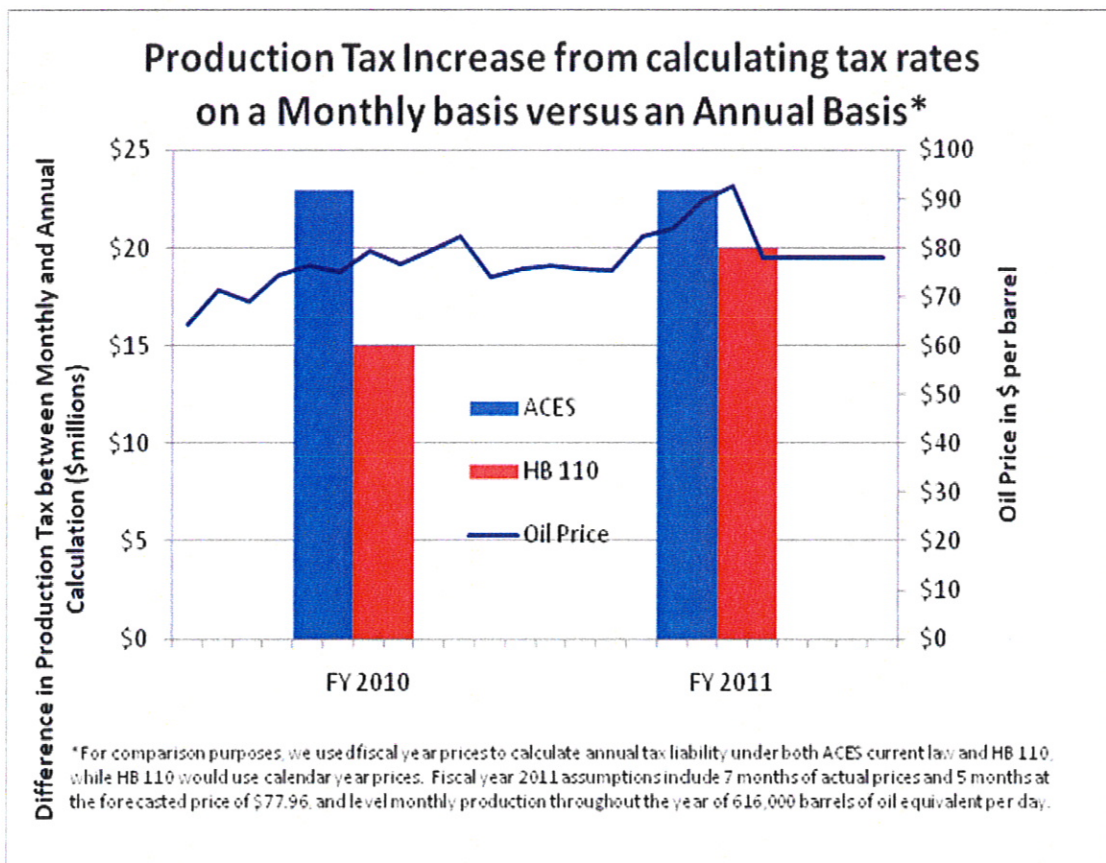
The following table and graph show how a marginal bracket approach could be applied to the production tax, while maintaining the same progressivity slope that exists currently under ACES. HB 110 implements this approach, with the exception that HB 110 caps the total tax rate at 50% compared to 75% under ACES.

Production Tax Value Bracket (\$/boe)	Production Tax Rate (%)
0 to 30	25.0%
30 to 42.5	27.5%
42.5 to 55	32.5%
55 to 67.5	37.5%
67.5 to 80	42.5%
80 to 92.5	47.5%
92.5 to 142.5	52.5%
142.5 to 192.5	57.5%
192.5 to 242.5	62.5%
242.5 to 292.5	67.5%
292.5 to 342.5	72.5%
More than 342.5	75.0%



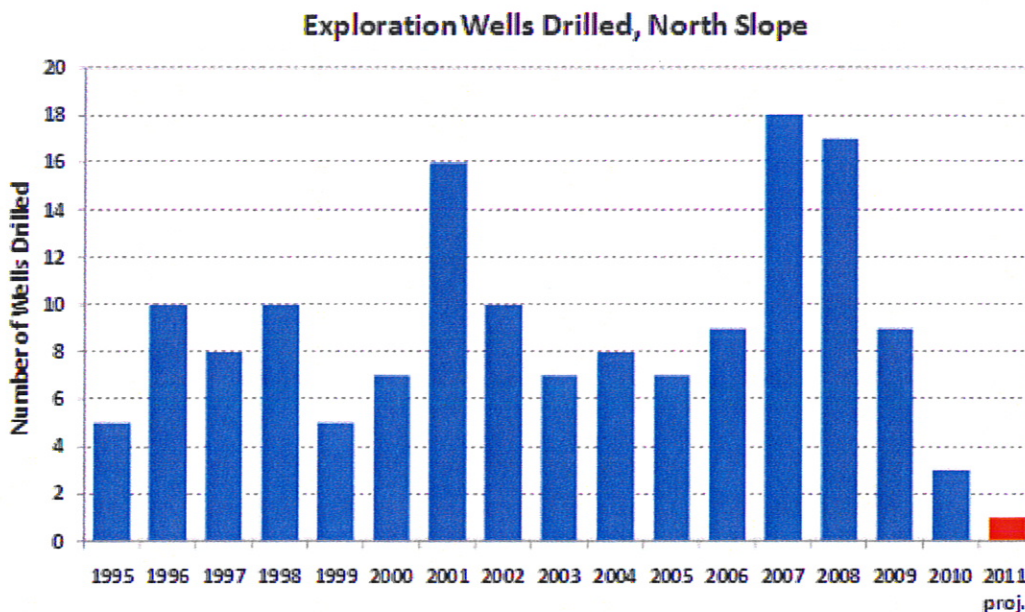
4) **Provide estimates of the revenue impact of switching from monthly to annual progressivity calculation.**

House Bill 110 proposes a change to the production tax rates and with it, a change to the calculation of those rates from a monthly calculation to an annual calculation. Depending on the monthly volatility in oil prices, the tax rate calculated annually may be different than the tax rate calculated monthly, thereby affecting total production tax revenues. Under most scenarios, the annual calculation will yield a lower tax rate and therefore lower production tax revenues than the monthly calculation. The difference in production tax revenue calculated monthly versus annually is much less under HB 110 than it is under ACES, however. We provide the following graph which shows the production tax increase for FY10 and projected for FY11 from calculating the tax rate monthly versus annually for both ACES and for HB 110.



5) **Provide a slide showing exploration wells drilled each year, including prior to 2005.**

The following chart shows exploration wells drilled on the North Slope since 1995, according to the Alaska Oil and Gas Conservation Commission. The Department of Natural Resources currently projects one exploration well for 2011.



Source: Alaska Oil and Gas Conservation Commission and Department of Natural Resources

6) Provide information on the components of federal government take, and explain why the federal government does not reduce their take to encourage exploration.

For production on state land, the primary component of federal government take is the corporate income tax, with a top marginal tax rate of 35%. State taxes are deductible in calculating federal taxable income. If a company is paying at the top marginal tax rate, then of the profit that remains after state taxes and royalties, the federal government receives 35% through the corporate income tax.

The federal government does have certain tax credits that help to encourage development at lower oil prices. These were discussed in the Department's response to questions raised at the February 7, 2011 hearing for HB 110, and that response is included again in its entirety below.

The following list presents the primary oil and gas related tax credits that are available against federal corporate income tax. There are also many federal tax credits that are available to all corporations which are not detailed here.

Enhanced Oil Recovery Credit (EOR)

- Credit of 15% of qualified costs against federal tax.
- Credit phases out when price of oil exceeds \$28 /bbl (adjusted for inflation).
- No EOR allowed since 2005, because the list price exceeded the inflation adjusted price of oil. The list price for 2009 was \$56.39 /bbl

Marginal Well Credit

- Credit up to \$3/bbl available only to owner of operating interest.

- Marginal well = oil production not more than 25 bbls/day, and not less than 95% water.
- Credit available only when price of oil less than \$18/bbl.

Nonconventional Fuel Source Credit

- Credit up to \$3 (adjusted for inflation) per BOE (barrel of oil equivalent, with 5.8 million Btu content)
- Credit completely phased out when inflation adjusted price of oil exceeds \$33.46/bbl. List price of oil in 2009 was \$56.39 /bbl.
- Credit on oil only from shale or tar sands.
- Credit on synthetic fuels from coal.
- Credit on gas produced only from:
 1. Devonian shale
 2. coal seams
 3. tight formations
 4. biomass
 5. geo pressured brine

7) Provide our legal opinion regarding whether new information about company spending could be collected by statute, versus by regulation.

Under current statutes, the Department may request taxpayer information needed to provide forecasts and to administer the production tax, including information needed to audit claimed capital credit expenditures. Current statutes authorize the Department to adopt regulations requiring taxpayers to submit more detailed information about capital expenditures.

Under AS 43.05.230 (e), the Department would be able to release information about classification of capital spending only to the extent that it could be compiled as a general statistic that would prevent the identification of a particular return or report.

Under AS 43.55.890, the Department can publish information on qualified capital expenditures, as defined in AS 43.55.023, if aggregated among three or more producers or explorers, by month or calendar year and lease or property, unit, or area of the state.

8) Does Section 20 of the bill allow small producers to “double up” on credits?

Section 20 of HB 110 does not allow small producers to “double up” on credits. Section 20 of HB 110 makes no change to the AS 43.55.024(a) new area development credit or to the .024(c) credits for small producers. House Bill 110 simply cleans up the reporting to address the .024 credits since current AS 43.55.160 does not take into account the fact that for some producers, those credits will sunset in 2016, while for other producers the credit will be available for 9 years after they commence production. The amendments to

AS 43.55.160 in HB 110 simply take this into account, no change is made to how the AS 43.55.024 credits apply.

9) Provide information about the state revenues and other benefits that would accrue from OCS development.

The Outer Continental Shelf (OCS) encompasses submerged lands and waters between state jurisdiction and the extent of federal jurisdiction. State jurisdiction in Alaska extends three miles from the coastline. Federal jurisdiction extends 197 miles beyond the state jurisdiction for a total of 200 miles total from the coastline.

Revenue from oil and gas activity in Federal waters within three nautical miles of state waters is subject to Section 1337 (8)(g) of the Outer Continental Shelf Lands Act (OCSLA), which requires 27% of the total revenue to be shared with the state.

According to reports released by the MMS in 2006, the Alaska OCS is estimated to contain at least 50 billion barrels of oil equivalent (BOE) at the 50% confidence level. It is unclear what percentage of the estimated 50 billion BOE of technically recoverable resource would fall within the three to six mile region requiring revenue sharing with the state of Alaska. However, the State of Alaska would likely benefit indirectly from any development in the OCS.

In addition to direct revenue sharing the state would be entitled to from any development within three miles of state waters, the State of Alaska would benefit from OCS development through increased employment, increased throughput on the Trans-Alaska Pipeline System (TAPS), increased property tax payments and multiple other sources of revenue enhancement through the multiplier effect. Specifically, increased TAPS throughput would reduce the tariff on a per barrel basis increasing wellhead value for all production including, taxable production on state lands. Further, increased throughput on TAPS would likely assist in extending the operating life of TAPS allowing for increased recovery of oil in North Slope fields that might not otherwise have been recovered.

10) Produce an estimate of what the price of oil would have to be to cover the cost of the Governor's proposed FY 12 budget were all the provisions of HB 110 in effect currently.

The Governor's proposed FY 12 budget, with proposed amendments as of February 16, 2011, includes a total authorization to spend of \$5,466.2 million of Unrestricted General Funds, after accounting for transfers and savings.

House Bill 110 is written to gradually phase in the provisions of the production tax changes. As such, our analysis shows that there is little to no direct fiscal impact in FY 12 from the provisions of HB 110 other than agency costs of approximately \$100,000 to adjust the Tax Division's accounting system. Under the provisions in HB 110, therefore,

the price of oil would have to average approximately \$81 per barrel to provide sufficient unrestricted revenue to cover the Governor's budget for FY 12.

If we assume that all of the provisions of HB 110 are in place prior to the start of FY 12, a price of approximately \$90 to \$92 per barrel would be needed to provide sufficient unrestricted revenue to cover the Governor's budget for FY 12. This figure is calculated using the bracketed annual tax rates included in HB 110, as well as the annual \$200 to \$400 million estimate for the well lease expenditure credit (which accounts for the range of oil prices in the result). We did not include estimates for provisions that were revenue neutral or for those that did not have a quantifiable impact on our revenue forecast. Our analysis included adjustments to only production tax and royalty; all other revenues were assumed to be the same as estimated in our Fall 2010 forecast.

11) Provide clarification on how the minimum tax is applied.

In response to discussion in the committee hearing, we would like to provide clarification regarding how the minimum tax under ACES is applied. HB 110 would strengthen the minimum tax by adjusting the price thresholds used in calculating the minimum tax.

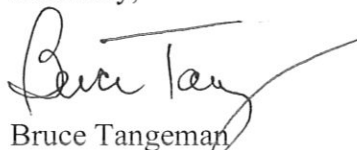
Under current law, the production tax is the higher of the minimum tax under AS 43.55.011(f) and the tax under AS 43.55.011(e). At an oil price of \$21 per barrel, the tax calculated under AS 43.55.011(e) would likely be zero, as the costs of the oil production would overtake any profit from that production. In that case, the minimum tax under AS 43.55.011(f) would apply. The minimum tax under current law would be 3% of gross value at the point of production, or about \$0.42 [3% x (\$21-\$7 transit costs)]. Because HB 110 lowers the threshold so that 4% of gross value applies to oil prices at \$20 and above, the minimum tax would be 4% of the gross value at the point of production, or about \$0.56 [3% x \$21-\$7].

12) Modeling request from Co-Chair Seaton

Co-chair Seaton has requested that the Department prepare models of ACES and HB 110, using a specific set up assumptions. The result of this analysis will be provided to the committee separate from this letter.

We hope our responses fully answer your questions.

Sincerely,


Bruce Tangeman
Deputy Commissioner