April 29, 2017

RE: SCS CSHB 111(RES) – Public Comment

Dear Senate Finance Committee Members:

I am writing in regard to SCS CSHB 111(RES), changes to Alaska's oil and gas production tax. Given my recent employment with the legislature, for the record, I am no longer a legislative employee and these comments are my own.

Attached is a summary of the changes to the production tax over the years, starting from the first tax established in 1955. This history is relevant because of concerns that the oil tax should not be changed due to the number of changes in the past, and the history can help inform today's debate.

Past changes in Alaska's production tax system were often the result of tax incentives designed to encourage investment in Alaska that either failed to deliver or ended up costing the state billions in lost revenue. The same is true today. The current oil and gas production tax system became so weighted with tax incentives that, under certain conditions, the state pays out more than it takes in tax revenue. Although legislation passed last year helped the situation, more is needed to better balance the tax structure.

Over the years, a lack of adequate information from oil and gas companies hampered decision-makers ability to design a tax structure that worked for both the state and industry. Again, the state faces a similar situation today. Multiple incentives were provided without requiring information regarding a company's financial capability, expertise, or the economic viability of a project. As is evident by the recent report revealing the companies cashing in credits, millions have gone to companies that went bankrupt or left the state. With more information upfront and focused incentives, there would be a better chance for more efficient and cost effective development of future oil and gas production.

In addition, while recent increases in production are encouraging, there is no quantitative analysis of whether, how or which tax incentives factored into the increase. Companies decline to provide information about how incentives, or the tax system generally, rank among other factors such as oil prices, operating costs, economic and political stability, infrastructure, and the accessibility, quantity, and quality of the resource.

Oil and gas companies consistently call for tax stability, yet the very incentives they support and the lack of useful information they could provide are a root cause of previous tax changes. The House version of HB 111 seeks to mitigate the complicating effects of eliminating the cash credit program, to get more information moving forward, and to establish a tax system with more stability over the long-term. With these changes, oil and gas companies would have more incentive to provide information and to cooperate in discussions about whether and what type of incentives may be needed to ensure projects are developed to production. There would also be the opportunity to consider ways other than tax incentives to maximize economic recovery from Alaska's oil and gas fields.

It is time to break the long cycle of hit and miss incentives and establish a more stable and better balanced production tax system.

Thank you for your consideration of these comments.

Lisa Weissler, Juneau Alaska

History Summary

Since commercial oil production began, Alaska has attempted to design an oil and gas production tax structure that compensates Alaskans for the removal of our nonrenewable oil and gas resources without discouraging exploration and development by oil and gas companies. Numerous factors complicated these attempts, including volatile oil prices, Alaska's challenging climate and distance to market, high costs, varying fossil fuel resources and types of companies, fluctuating world energy markets, and differing geological conditions across the state. The result is an ever-evolving tax structure, each change aimed at addressing the problems of the day.

A 1970s stair-step approach did not adequately address the varying economic factors for different types of fields in different regions of the state. Its 1977 replacement, the economic limit factor (ELF) tax system, was designed to be more responsive to the regional differences in production operations. It was believed that application of the ELF would keep declining fields in production longer and encourage company investment in Alaska. Over time however, companies were not significantly investing in the state even when their production tax obligations were at or approaching zero; and application of the ELF to large productive fields was costing the state billions in lost revenue.

Failure of the ELF led to introduction of the net profits tax in 2006, the Petroleum Production Tax (PPT). In addition to allowing the deduction of capital and operating costs, the new tax system included multiple tax incentives in the form of tax credits. Three additional credits were added in 2010.

In 2013, changes to the production tax were proposed partly due to concerns about the cost of tax incentives to the state and questions about their effectiveness. During legislative hearings on SB 21, the Department of Revenue commissioner testified that the administration was unable to find a connection between future oil production and almost $6 billion in tax credits paid in cash or used to reduce companies' tax liability. This, and a concern that increasing company investments could cause a deficit in "the billions of dollars" if oil prices dropped, was the basis for the elimination of the North Slope qualified capital expenditure credit.[1]

In 2016, low oil prices necessitated changes to the production tax because of the costs associated with tax incentives.

As far back as 1968, a lack of information frequently hampered decision-makers ability to design a tax system that worked for both the state and industry. In 1968, legislators sought to increase the oil and gas production tax to capture more economic value from the booming Cook Inlet oil and gas fields and anticipated North Slope production. Legislators felt that, in order to determine an appropriate tax rate, they needed to know how much the companies stood to make from Alaska oil production.

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[1] Senate Special Committee on TAPS Throughput, January 22, 2013, page 11; Senate Resources Committee, February 11, 2013, page 10.

An industry representative repeatedly declined to give legislators any information on industry profits. This led one senator to complain that industry was asking them "to take their word for the fact that an increase in tax would inhibit the oil industry in expansion." He opined that to arrive at a "fair tax," they would need more information and until they got that they were "just crawling around in the dark."[2]

In objecting to the tax changes, the industry representative made what has become a familiar refrain, "The short-term benefits of imposing additional severance taxes must be balanced against the longer term benefits of maintaining, as you have in the past, a political climate and incentive atmosphere that will be conducive to further expansion of our industry in Alaska." He warned that allocation of capital by oil companies in Alaska was in competition with "alternative opportunities in the rest of the United States;" and he cautioned the legislators against creating an unstable tax picture.[3]

Forty-nine years later, companies are making the same arguments today. And the state is still trying to figure out a tax system that works for both Alaskans and for industry without getting the necessary information from oil and gas companies – still "crawling around in the dark."

[2] "Oil and Gas Hearings; House and Senate Finance Committee; February 19-20, 1968, page 50 (Legislative Library Catalog #6800140).
[3] "Oil and Gas Hearings," 1968, page 36.

Alaska's Oil and Gas Production Tax
Chronology of Changes

1955: To establish an effective tax base for any future oil production, territorial legislators passed an oil and gas production tax of 1% of the gross value at the wellhead. The tax was in lieu of territorial and local property taxes.

1957: Cook Inlet oil production began.

1967: A Disaster Severance Tax of 1% was imposed in addition to the 1% oil and gas production tax to help Fairbanks recover from a devastating flood.

1968: Cook Inlet oil fields were booming and Atlantic Richfield announced a significant oil discovery in the Prudhoe Bay oil field on the North Slope. The production tax was increased to a total of 4% to help fund state and local government public services and infrastructure.

1969: The magnitude of the Prudhoe Bay oil field discovery became known. Oil companies paid a record $900 million in bonus bids for the right to drill on state-owned land.

1970: Consultants advised the legislature to design an oil and gas production tax that would encourage continuing exploration and development and account for the difference between Cook Inlet and the coming oil production from the North Slope. For oil, a stair-stepped rate structure was established where the more a well produced, the greater the tax rate – from 3% to 8% of wellhead value. The disaster tax was repealed and a 4% tax rate was set for gas.

1972: Due to concerns that cost overruns during the construction of the Trans-Alaska Pipeline would result in pipeline tariffs overwhelming state returns on future North Slope oil production, the legislature established a minimum cents-per-barrel tax that would be calculated at wellhead values below $2.65 a barrel; the tax paid was the greater of the wellhead value tax or the cents-per-barrel tax.

1973: TAPS construction continued facing delays. Ten oil companies sued the state over the 1972 tax; they objected that the production tax was designed to go up if royalty payments fell. The legislature effectively settled the litigation by changing the stair-step tax rates on both the cents-per-barrel and wellhead value tax. The legislature also enacted a 20-mill property tax agreed to by the companies (the rate has not changed in 44 years).

1977: Economic Limit Factor (ELF). Prudhoe Bay oil production was beginning while Cook Inlet production was declining. A study found that the stair-step tax system did not adequately address the varying economic factors for field production operations. A new production tax system established an economic limit factor. The ELF was part of a formula for scaling down the tax rate as field production declined toward its economic limit. The aim was to reduce the tax rate for fields reaching the end of their economic life in order to encourage continued investment and production, and to get more revenue for the state from productive fields.

1981: Following a legislative coup in the House of Representatives, the corporate income tax was changed from using separate accounting to using a modified apportionment method. The oil and gas production tax rate for existing production was raised from 12.25 percent to 15 percent to offset the revenue reduction resulting from the change to the corporate income tax. The lower tax rate of 12.25 percent applied for the first five years of production from new fields. Application of the ELF formula was suspended on the productive Prudhoe Bay field until June 1987.

1989: From 1987 to 1989, there were multiple attempts by House legislators and the administration to fix the ELF formula to prevent a premature reduction to the tax rate on Prudhoe Bay and Kuparuk oil and the loss of billions in state revenue. The Senate thwarted the attempts until the Exxon Valdez hit a reef in 1989. Public disapproval of the industry led key senators to agree to pass the proposed fix to the ELF.

2006: Petroleum Production Tax (PPT). Over time, the ELF formula resulted in little to no production tax revenue to the state from even the most productive fields. Despite almost no tax, there was minimal investment activity by oil and as companies. To address both revenues to the state and incentives for increased industry investment, the production tax was changed to one based on net profit value rather than gross value. The change originated as part of negotiations between the state and the three major North Slope producers for a contract aimed at getting the producers to develop a natural gas pipeline. The state offered a contractual term of 20 years of fiscal certainty for oil if the production tax was changed. Though the contract was not approved by the legislature, the tax change was enacted.

The PPT established a base tax rate of 22.5% on the net value of oil and gas and a progressivity provision that increased or decreased the tax rate as oil and gas prices went up or down. The PPT offered a 20% qualified capital expenditure credit; a 20% carried-forward annual loss credit; a small producer credit up to $12 million; a $6 million credit applicable to regions outside Cook Inlet and the North Slope; and a transitional investment credit for costs incurred in the five years before the new production tax took effect. Companies producing less than 50,000 barrels per day could qualify for a cash refund of qualified capital expenditure and annual loss credits if they met certain conditions.

2007: Alaska's Clear and Equitable Share (ACES). Because of lower tax returns due to higher than anticipated lease expenditure deductions and a corruption scandal involving several legislators and an oil field service company, the PPT was changed under the Alaska's Clear and Equitable Share Act (ACES). ACES increased the base tax rate to 25% and accelerated the rate of increase under the progressivity provision. ACES maintained the PPT tax credits and established the oil and gas tax credit fund for cash payments for purchasable credits.

2010: Three new credits were added to the production tax – a Cook Inlet "jack-up rig" credit; a 40% well lease expenditure credit that applied in Cook Inlet and Middle Earth; and a Middle Earth credit for the first four exploration or seismic projects in the region.

2013: SB 21 changed the net profits tax to address oil and gas companies' objections to the ACES progressivity provision and the administration's concerns that tax credits were costing the state billions without evidence of a connection to future oil production. SB 21 eliminated the ACES progressivity provision, eliminated the qualified capital expenditure credit for North Slope activities, and provided a 20% gross value reduction for "new oil" with an additional 10% GVR for fields with higher royalty. Two credits were added to create "a mild form of reverse progressivity;" a $5 per barrel credit for new oil and a sliding scale credit based on oil price for legacy oil. The tax rate was capped at 35% - the effective tax rate would be lower due to the application of the per barrel credits until oil prices reached $160 per barrel.[4]

2016: Low oil prices and a mounting state deficit prompted the modification of some tax credit programs to help ease the pressure on future state budgets. HB 247 ended Cook Inlet tax credits so they would phase out by 2018. For Middle Earth, credits were approximately halved. The bill implemented a $1 per-barrel tax on Cook Inlet oil. For the North Slope, the legislation set a time limit on the gross value reduction for how long oil would be considered "new" oil excluded from taxation. The exclusion expires after seven years of production or three years if the price of oil is greater than $70 per barrel.

[4] House Resources Committee, April 2, 2013 (evening meeting), pages 7 to 12.