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# Alaska's Oil and Gas Production Tax
# Tax Credits History

## 2006 – The Petroleum Production Tax (PPT)

In 2006, after fifty-one years of a gross value oil and gas production tax, Alaska switched to a net profit tax system known as the Petroleum Production Tax or "PPT." Reasons for the change included that the existing gross tax system resulted in almost no production tax revenue from even very productive fields; the system was unable to adjust for increasing oil prices and differences in field conditions between the North Slope and Cook Inlet; and it provided insufficient incentives for investment in Alaska's oil and gas fields. The PPT was intended to increase Alaska's share of oil production revenue and provide incentives for oil and gas companies to invest in the state.[1]

- Major Producers' Incentives. It was believed that the tax advantages of the net profit system would increase the major producers' (ExxonMobil, BP, ConocoPhillips) investment in enhanced production from the large legacy Prudhoe Bay and Kuparuk oil fields. A taxpayer could deduct certain operating and capital lease expenditures as part of the calculation for determining their tax liability. In addition, the PPT offered a 20 percent tax credit for qualified capital expenditures. In effect, the more a producer spent in Alaska's oil fields, the lower their tax.

- Independent Companies' Incentives. The PPT offered several tax credits to encourage independent companies to explore for and develop smaller oil fields. Companies could accrue the 20 percent credit for qualified capital expenditures, including exploration costs. In addition, a producer with less than 100,000 barrels production per day could qualify for up to a $12 million tax credit provided the producer had a positive tax liability. The PPT also provided a credit of up to $6 million annually for oil or gas produced from leases outside Cook Inlet and the North Slope (known as "Middle Earth").

- Net Operating Loss. The PPT provided for a carried-forward annual loss credit, referred to as net operating loss (NOL). Net operating losses are lease expenditures that would be deductible except when the deduction would cause the net value of taxable oil and gas to be less than zero. A percentage of the lost deductions are converted to tax credits that can be applied against future tax obligations. The PPT provided for a 20 percent net operating loss credit.

  The NOL credit was introduced primarily as a benefit to independent companies who would not have enough oil production to generate a tax liability against which to apply their lease expenditure deductions. The major producers were expected to have enough production tax liability to realize the full benefit of their deductions in the year the expenditure occurred.

- Tax Credit Purchase. Because explorers and new producers would not produce enough oil or gas to have much of a tax liability against which to apply tax credits, independent companies doing business in the state asked the legislature to establish a credit purchase program. As originally introduced, the PPT legislation allowed certain tax credits to be transferred and traded on the open market. Since the market was limited to the three major producers, independent

[1] The gross value is determined at the point of production by subtracting transportation costs from the destination sales price (transportation costs include pipeline tariffs). With a net tax, the net income value is determined by deducting from the gross value certain lease expenditures.

- companies were concerned they would not receive full value for their credits, while the buyer could apply 100 percent of the credit against the buyer's tax liability.

  The final PPT included a provision for the state to provide for the purchase of certain tax credits. Because legislators and administration officials worried about the potential impact to state revenue should oil prices drop, purchases were limited to companies producing not more than 50,000 barrels of oil per day and there was a $25 million cap per company. In addition, an applicant was required to incur a qualified capital expenditure or be the successful bidder for a state oil and gas lease within 24 months after applying for a transferable tax credit certificate. The purchase payment could not exceed the total of the expenditures or bid.

  Tax credits that qualified for purchase were the net operating loss credits, qualified capital expenditure credits and credits offered under a 2003 exploration credit program.

**2007 – Alaska's Clear and Equitable Share (ACES)**

In 2007, changes were made to the PPT under the Alaska's Clear and Equitable Share Act or"ACES." The changes were made because of lower tax revenue from higher than anticipated lease expenditure deductions. A corruption scandal that tainted the vote of several legislators during the PPT debate led legislators to be more receptive to making changes. Though the administration considered switching the tax system to a gross value tax, they concluded that a gross tax was not flexible enough to address the differences between oil and gas fields, and didn't account for expensive resource development such as heavy oil. Among other things, ACES retained the PPT tax credits and cash purchase program; and established an oil and gas tax credit fund to pay for the credits.

**The Oil and Gas Tax Credit Fund and Credit Purchases**

ACES established the oil and gas tax credit fund as a way to purchase qualifying credits more efficiently. The amount of money available to the fund was based on a set percentage of production tax revenue; 10 percent when oil prices were $60 or more, 15 percent when oil prices were less than $60. The $25 million cap established under the PPT was repealed. The $25 million per company cap was lifted because small producers found the cap too low to be useful.

In response to legislators' questions regarding what would happen to the fund if oil prices dropped, an administration official explained that regulations would determine how to allocate payments when there was an insufficient fund balance. He said, "a long period of low prices could lead to insufficient money in the fund after lots of credits have been paid out, and the legislature might choose to not spend the money on credits." He stated that remaining credits not purchased by the state could either be carried forward or transferred to another taxpayer who had sufficient tax liability.[2]

- Appropriations to the Oil and Gas Credit Fund. In 2008, the first year after the oil and gas tax credit fund was created, the legislature followed the prescribed formula in appropriating money to the fund. Starting in 2009, the legislature provided an open-ended appropriation to cover all tax credit purchase applications. During the following years the legislature continued this

[2] Senate Resources Committee, October 22, 2007, page 31; Senate Judiciary Committee, October 30, 2007, page 24-25.

practice, creating an expectation among oil and gas companies that all qualifying credits would be purchased.

- Easing Restrictions. In 2010, the requirement that an applicant incur a qualified capital expenditure or buy a state oil and gas lease to qualify for a purchase payment was repealed. This was done to help companies get project financing – companies looking to invest wanted to know they would get full value for the credit without worrying about whether the credit would meet the investment requirement. The legislature also added a new tax well lease expenditure credit program targeted at Cook Inlet gas exploration and production. The new credits could be purchased by the state.

- Tax Credit Purchases and Private Financing. In 2013, the legislature passed an amendment to the production tax that specifically allowed for the assignment of production tax credits to a third-party assignee without the state's consent. This meant companies could use their tax credits as collateral for loans or sell credits to a bank or investment institution.

  There is evidence the provision went farther than intended. The provision was offered as an amendment in House Finance to a Senate bill dealing with fish taxes. An administration official testified that the amendment would help open private equity markets to smaller investors in the state. When asked about whether the provision applied to North Slope producers, the maker of the amendment said she "believed that the amendment applied only to Cook Inlet and Middle Earth" and to gas. The senator whose bill was being amended stated "The goal was to bring additional gas to Cook Inlet consumers." As it turned out, the amendment applied to both oil and gas and to all net operating loss, qualified capital expenditure and well lease expenditure credits.[3]

- The Sure Thing. In 2015, a Wall Street Journal article titled "How Wall Street Makes Money on Alaska's Oil Tax Breaks" described how Alaska oil and gas companies would sell their rights to a credit or use the rights as collateral for a loan. The companies would give up between five to twenty percent to a lender or buyer, who would get the right to collect the entire state payment. It has become apparent that lenders saw little risk given the state's track record in fully funding tax credit cash purchase applications.

- Not Such a Sure Thing After All. The estimated amount of purchasable credits grew from $180 million in 2009 to $700 million in 2015. In 2015, the legislature passed an open-ended appropriation to cover all purchase applications. Had the statutory formula been followed, approximately $91 million would have been available for appropriation. With oil prices plummeting and a $3 billion deficit, the governor vetoed $200 million of the appropriation. In 2016, facing a $4 billion deficit, he vetoed $430 million, leaving the $30 million required by the statutory formula. The question remains how to deal with the remaining tax credit purchase applications.

[3] House Finance Committee Minutes, April 12, 2013, page 4-5.

**2013 – Senate Bill 21**

In 2013, oil and gas companies' discontent with some ACES provisions and concerns about declining North Slope oil production and the fracking boom in the Lower 48 led the Parnell administration to introduce Senate Bill 21. Administration officials also expressed concern that their analysis of $6 billion in tax credits found no direct connection to future production. They worried that if oil prices dropped and company investments increased, the state budget would have a deficit of billions of dollars and the state would "still be on the hook for the credits."[4]

- Tax Credit Policy Change. For North Slope companies, SB 21 changed the state's oil tax policy from tax credits based on investment to credits based on production; the more production from a field, the lower the tax. The theory was that companies would be more inclined to invest in the state and increase their production.[5]

- SB 21 Tax Credit Changes.

    - SB 21 repealed the qualified capital expenditure credit for North Slope oil and gas activities. The credit remained in place for other areas of the state.

    - SB 21 included a gross value reduction (GVR) where a certain percentage of "new oil" on the North Slope would be tax-free. The bill added a $5 per barrel credit for production that qualified as new oil subject to the gross value reduction. The GVR and new oil credit applied for the life of the field.

    - For production that did not qualify as new oil, such as oil from the Prudhoe Bay oil field, a sliding-scale production based tax credit was added; from $8 per barrel when the gross value of oil was $80 or less, to $1 per barrel between $140 and $149 gross value, and zero after that. The credit is not available for purchase by the state.

    - For the North Slope, SB 21 increased the net operating loss credit to 45 percent until 2016 to ease the transition away from qualified capital expenditure credits. After 2016, the percentage was set at 35 percent – the same as the new production tax rate of 35 percent. For other areas, the rate was set at 25 percent.

- 2014 Repeal Referendum. In 2014, public dissatisfaction over the new oil and gas production tax system prompted a citizens' referendum to repeal SB 21. The repeal would have reinstituted ACES in its entirety. Among other issues, supporters of the repeal argued that over time an increasing percentage of oil would qualify for the new oil tax breaks and the state's percentage of profit would decrease indefinitely into the future. There were also concerns that tax credits on production would not encourage Alaska investment since the credits did not require instate investment. The opposition argued SB 21 was working to attract Alaska investment and would increase state revenue over the long-term by increasing production. The referendum failed by a vote of 99,855 (52.7%) to 89,608 (47.3%).

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[4] Senate Special Committee on TAPS Throughput, January 22, 2013, pages 11-12; Senate Resources Committee, February 11, 2013, page 10.
[5] Senate Resources Committee, Econ One, February 13, 2013, page 22.

**2016 – HB 247**

Starting in 2015, oil prices dropped from over $100 per barrel to below $40 per barrel. With a $4 billion deficit, the state could no longer afford all the tax credit incentives offered as part of Alaska's oil and gas production tax. To ease the pressure on future state budgets, the administration introduced and the legislature passed HB 247 making changes to several tax credits.

- HB 247 amended Cook Inlet tax credits to phase out by 2018, including the net operating loss credit. For Middle Earth, credits were approximately halved. The bill also placed a cap on cash purchases to individual companies; $35 million would be purchased at full value, and another $35 million discounted by 25 percent. Any additional credits would have to be carried into a future year for either a cash purchase or use against a tax liability.

- For North Slope activities, HB 247 added a provision to the gross value reduction setting a time limit on how long the oil would be considered "new" oil excluded from taxation. The reduction expires after seven years of production or three years if the price of oil is greater than $70 per barrel.

**2017 – What's Next**

Most of the changes in HB 247 took effect on January 1, 2017. There are still credit programs and other provisions that could cost the state millions, possibly billions, in the coming years.

- <u>Net Operating Loss</u>. The North Slope net operating loss credit remains at 35 percent. Without changes, there is the risk the credits could take the production tax to zero and increase the amount of credits available for purchase. The risk increases with continuing low oil prices and increasing North Slope activities.

- <u>Minimum Floor</u>. Starting with the PPT, the production tax included a tax floor of not less than four percent of the gross value when oil prices were more than $25 per barrel. While the sliding-scale per barrel tax credit cannot reduce a North Slope producer's tax liability below the floor, net operating loss credits can take the tax to zero. Purchasable credits can take the tax below zero.

- <u>Migrating Credits</u>. Currently, a taxpayer can apply sliding-scale per barrel tax credits that cannot be used in one month to offset a tax liability from a different month in that calendar year. This occurs in a year where the minimum tax is in effect in some months and not in others in a year.

- <u>Outstanding Credit Purchase Applications</u>. The Department of Revenue's Fall 2016 Forecast estimates there will be over $887 million in outstanding credits available to purchase at the end of fiscal year 2018, assuming around $74 million is appropriated under the credit fund statutory formula. If cash purchases continue to be permitted and appropriations are limited to the statutory formula over the next decade, this balance is expected to grow to $1.6 billion by the end of fiscal year 2026.