

**2/11/11  
PRESENTATION:  
OIL AND GAS  
PRODUCTION TAX  
STATUS REPORT**

<TARGET><BILL></BILL><SUBJECT>2-11-11 PRESENTATION OIL  
AND GAS PRODUCTION TAX STATUS  
REPORT</SUBJECT><COMM>HRES27</COMM></TARGET>



*Presentation to the  
House Resources Committee  
February 11, 2011  
Alaska Department of Revenue*



# ACES Status Report



- **Overview of the Publication**
- **What We Know**
  - ***Required report to the legislature under AS 43.55.180***
  - ***Released January 18, 2011***



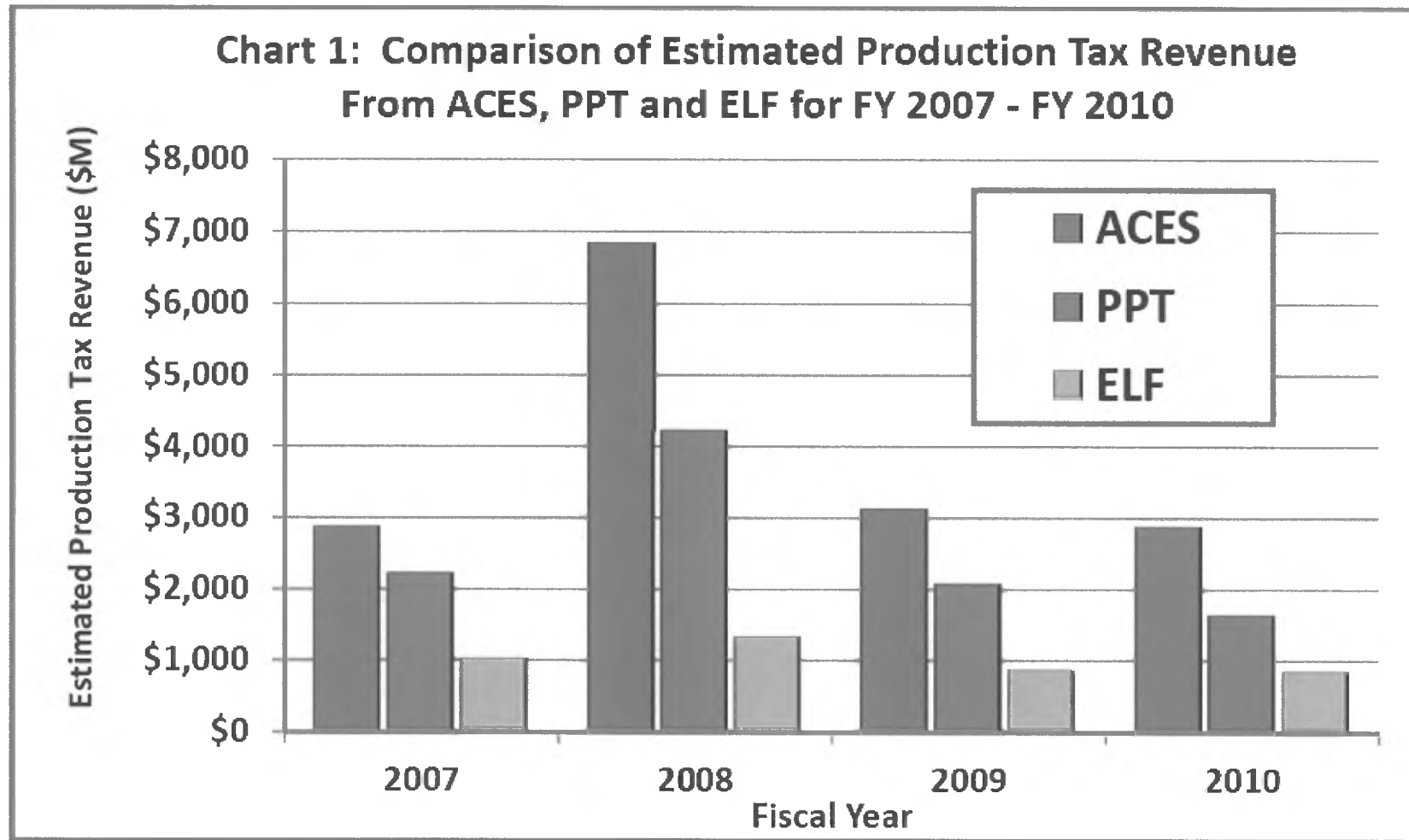
## Overview of ACES Status Report



- 1. Revenue Generation / Tax Rate**
- 2. Industry Investment**
- 3. Impact on Exploration, Development, Production**
- 4. Industry Employment and New Entrants**
- 5. Use and Expansion of Tax Credits**
- 6. Tax Administration and Compliance**
- 7. Conclusions and Recommendations**



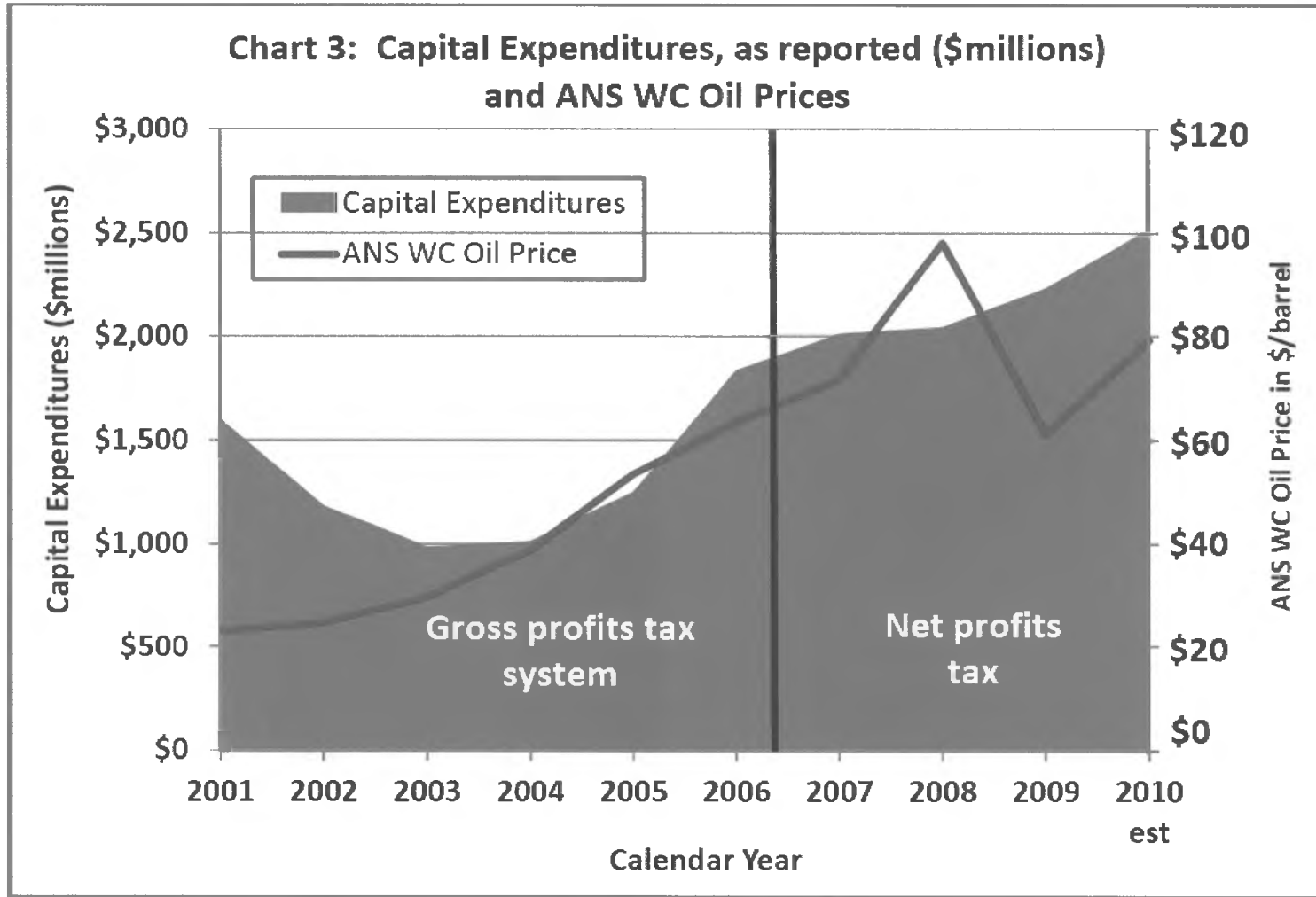
# What We Know: State Revenue Has Increased



Source: Oil & Gas Tax Status Report 2011



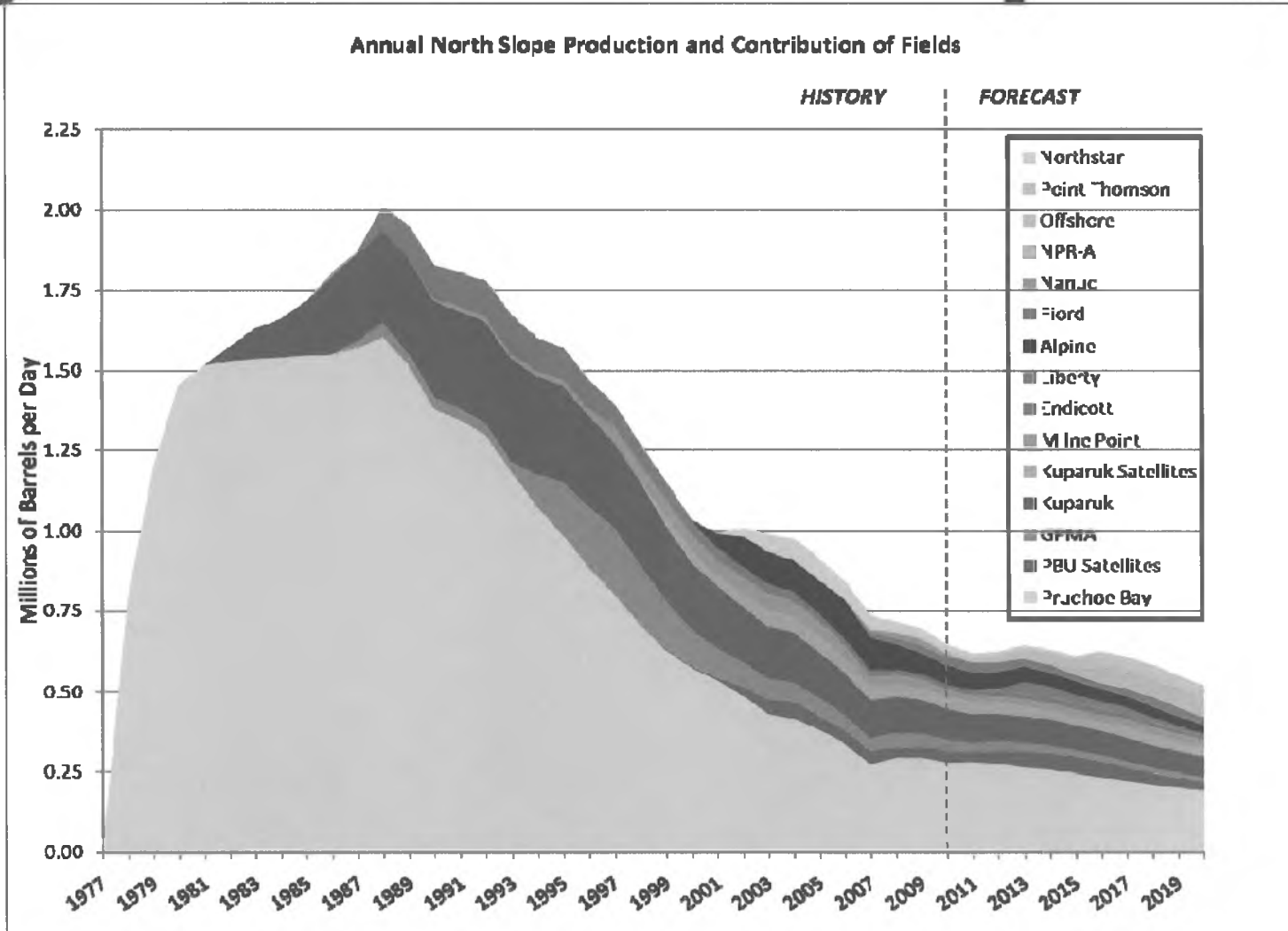
# What We Know: Companies are spending more



Source: Oil & Gas Tax Status Report 2011



# What We Know: Production Is Declining



Source: Oil & Gas Tax Status Report 2011, and Fall 2010 Revenue Sources Book





## Conclusion



- **Cannot conclusively identify the ACES impact compared to all the other factors in recent years**
- **We know we have more revenue in the short term**
- **We know oil production keeps declining**
- **We know there is little exploration taking place**



# Fall 2010 Oil Production Forecast



## North Slope Production Decline



**FY 1988: production peak → 2.01 million barrels per day (bpd).**

**FY 2010: production → 644,000 bpd, a 68% decline since peak.**

**FY 1988 to date: production decline rate ~ 5% per year, on average.**

**Over the last 10 years, production decline rate ~ 4.2% per year, on average.**

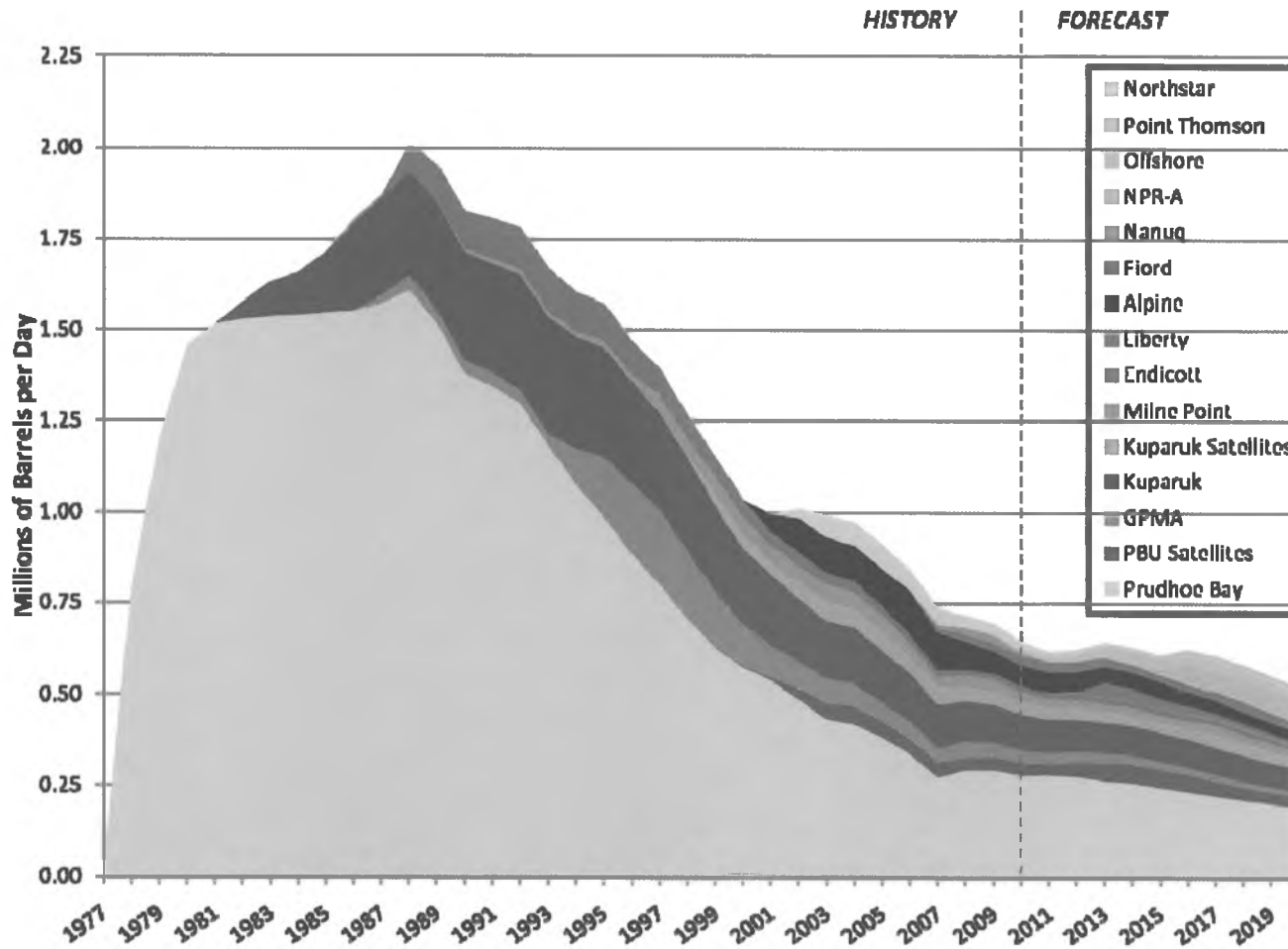
**We expect the decline rate to flatten out to 3.2% per year, on average, through FY 2030.**



# ANS Production History & Forecast



Annual North Slope Production and Contribution of Fields





# **Petroleum Fiscal System Design**

**House Resources Committee  
February 11, 2011**

TECHNICAL AND MANAGEMENT ADVISORS TO THE INTERNATIONAL PETROLEUM INDUSTRY

# Fiscal System Design

- **2 Parts *Art* to every 1 Part *Science***
- **What works well for one state/country does not necessarily work for another**
  - ↳ Over time it may actually no longer work optimally where it once did
- **Influencing factors include (but not limited to):**
  - GDP & GDP/Capita
  - Energy as % of GDP
  - Infrastructure Availability
  - Infrastructure Capacity
  - Competition from elsewhere
  - Hydrocarbon Basin Maturity
  - Skilled Local Labor Force
  - H S & E
  - Institutional Capacity

# The “Pressure” to Change

- Fiscal system change occurs generally because:
  - a) Governments want their perceived fair share; or
  - b) Attract Investment/Industry

★ *The two are not always the same or even near the same*

- Request for change justified by:
  - ‘Objective’ Calculations – model results based on a large number of assumptions
  - ‘Subjective’ Calculations – experts assessing major changes in direction or behavior

# Producer's View of Fiscal Systems

Never met a tax they liked!

<p>Less Tax Means More Investment</p> <p>Illinois Low Gov't Take Limited E&amp;P Investment by Big Oil</p>	<p>More Tax Means Less Investment</p> <p>Iraq Highest Gov't Take Huge Investment by Big Oil</p>
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Always making comparisons to Lower 48 as best place to invest

“More taxes....push investment....abroad”

API 2011 in response to possible new US taxes on energy activities.

# Ranking Fiscal Systems

## Materiality, NPV, Rate of Return

Which is better?	A PSC	B PSC	C Concession
Average Govt Take	30%	50%	60%
Marginal Govt Take (highest)	45%	65%	90%
Capex Recovery Period (minimum)	7yr	5yr	1yr
Investment Credit	0%	0%	20%
Cost Oil Cap	60%	100%	100%
Unrecovered Cost Uplift	0%	5% annum	0%
Ringfenced by Field	Yes	Yes	No

# Where is Alaska today?

1. Production declining despite unprecedented prices
2. Looming issue of TAPS mortality
  - Could be either physical limit or economic limit
3. New resources viewed by some as “Stranded”
  - Access to infrastructure
4. Long lead times to bring on new fields
5. Which path are we on?
  - If **Harvest**, then need to get fair share
  - If **Growth**, then need to encourage investment

# Same Item- Different Perceptions

Level of Producer Profit	Loss	Break Even	Small	Moderate	Large
<b>Gov't</b>	Gov't Needs Minimum Cash Flow		About Right	More than Fair	Greedy & Outrageous
<b>Producers</b>	To be avoided Downside Protection	Nice but not why we exist	Only if I have more \$ & people than projects	The Target	Quid Pro Quo for taking downside (loss) risk

Many times it is not the numbers or reality that drive decisions, but perceptions, “matters of principle” or fear of precedents

# Future Scenarios for Alaska

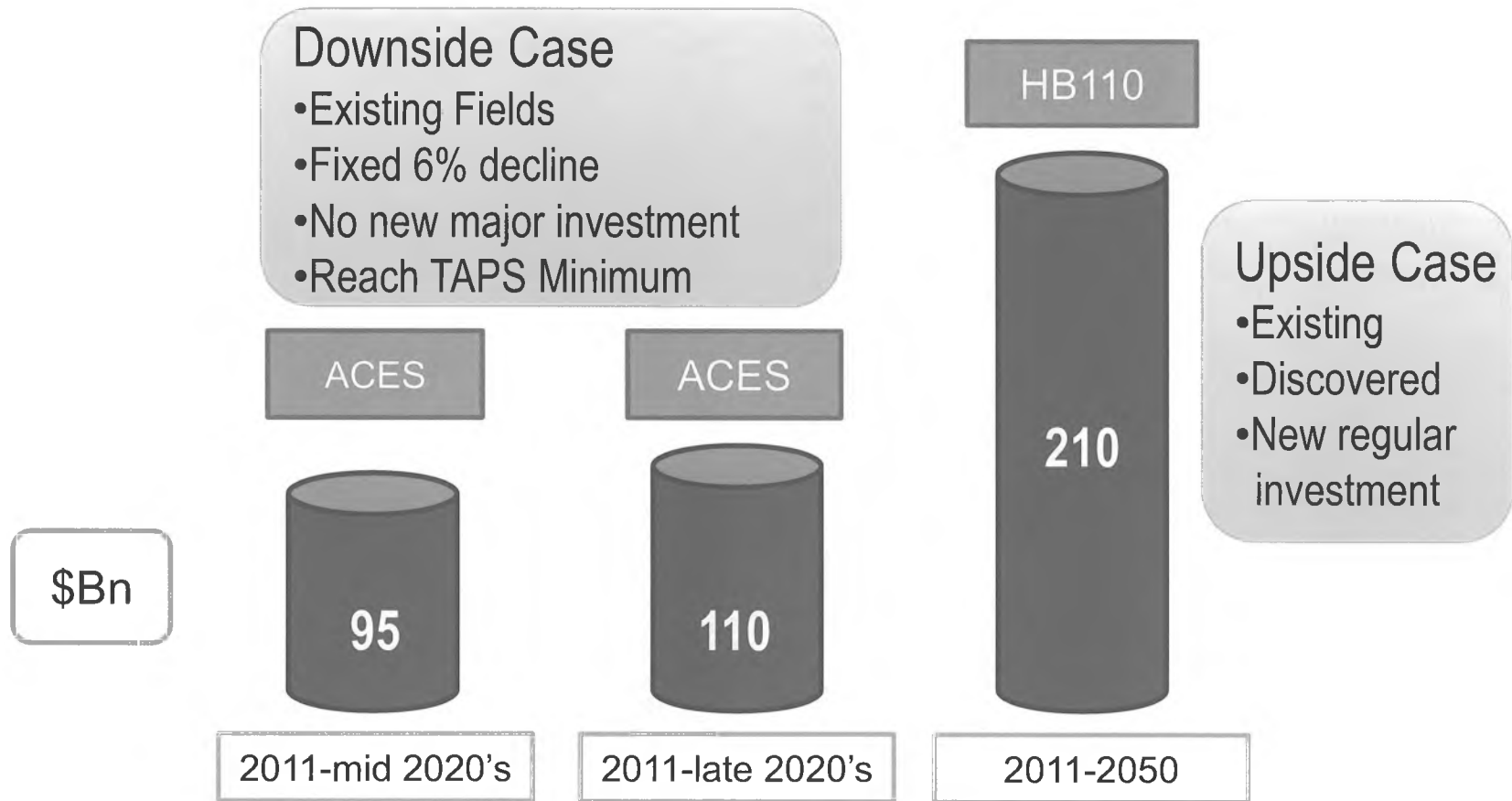
Hard to predict the future in a nice tidy narrow range

- Requires many assumptions that leads to ‘noise’ and time and focus taken away from discussing and understanding root causes and the real issues
- Lack of data transparency, that many other regimes have

What are the possible upside/downside scenarios to consider in looking to change ACES?

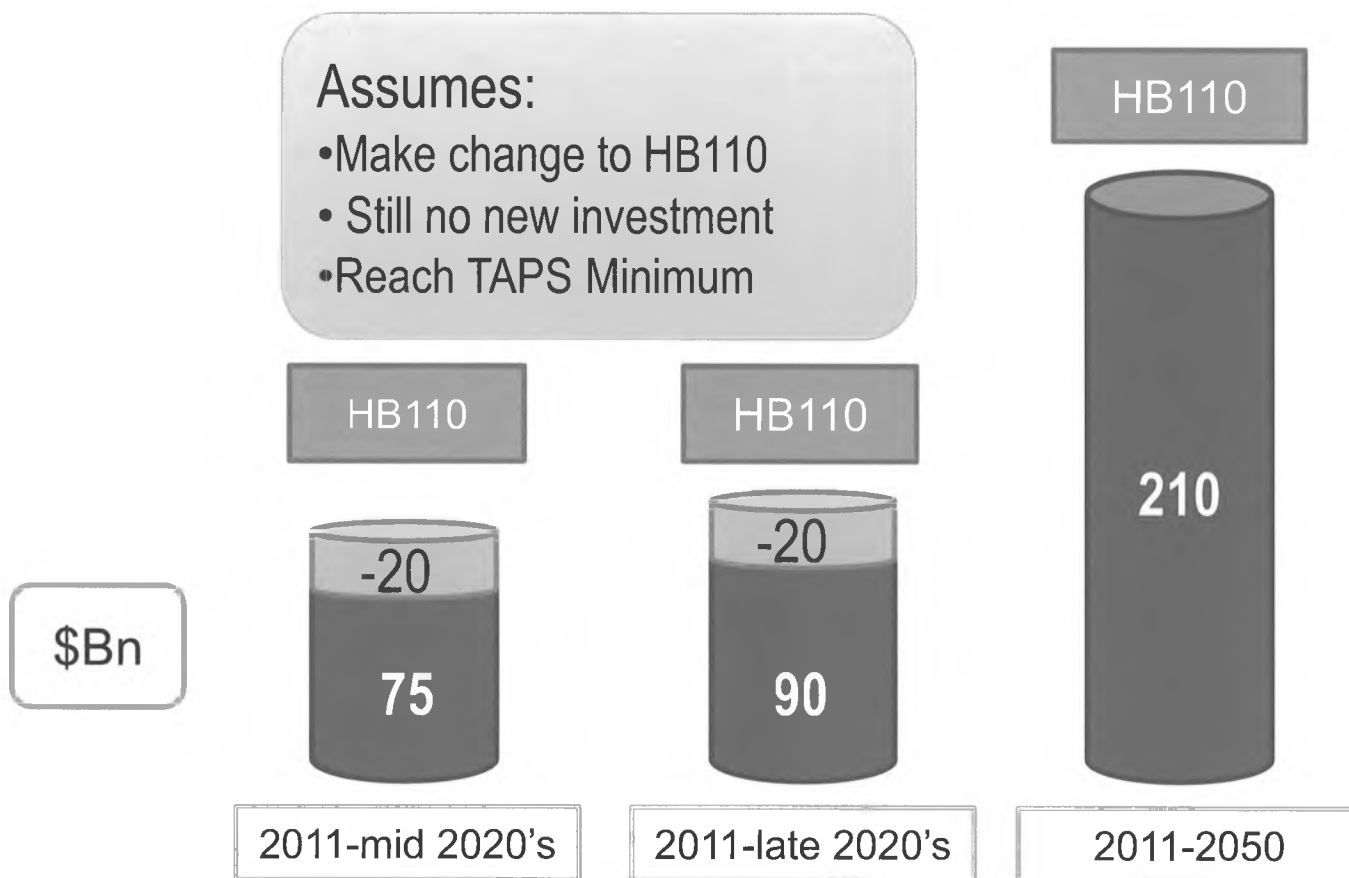
- Upside – Reduced taxes leads to investment in new resources that keeps TAPS flowing through 2050
- Downside – Reduced taxes, still no new fields brought on line, TAPS reaches limit in the 2020’s

# State Undiscounted Cash Flow



\* DOR price & cost forecasts

# State Undiscounted Cash Flow



\* DOR price & cost forecasts

# ACES vs HB110 - Risk vs Reward

- Analyze the State's decision in similar way to Producer decision-making in looking at the probability and cost of a dry hole versus probability and value of a developed discovery

\$Bn

## Viewed Conservatively:

75% downside outcome  
25% upside outcome

$$\begin{array}{r} -20 * 0.75 = -15 \\ 120 * 0.25 = 30 \\ \hline \$+15 \end{array}$$

## Viewed More Optimistically:

25% downside outcome  
75% upside outcome

$$\begin{array}{r} -20 * 0.25 = -5 \\ 120 * 0.75 = 90 \\ \hline \$+85 \end{array}$$

# Outsiders' View of Alaska

	<b>Rank*</b>	<b>Economic Impact</b>
<b>Immediate Deduction of Capex</b>	Top 1-3	High
<b>Investment Credits</b>	Top ¼	Moderate-High
<b>Amount (up to 40%)</b>	Top 10	High
<b>Credits to Cash</b>	Top 1 or 2	Moderate, Big, Huge Ind.
<b>No ringfence (Exploration/Appraisal)</b>	Top 10	Huge
<b>87% Marginal Rate</b>	Bottom 5-10	Moderate (Huge Optically)
<b>Cost per bbl</b>	Bottom ¼	High
<b>Environmental Costs</b>	Bottom 10	High

\* Where Top is best Bottom is worst from Producer viewpoint

# Data Transparency

- **Relative to other regimes Alaska is handicapped in its decision making by the small amount of either confidential or reliable public data on energy operations**
  
- **Consequently, the producers are the only ones that can provide the legislators with the true picture**
  - Where is the money being spent?
  - What is the upside potential?
  - Why isn't more investment occurring?
  - With HB 110, will they now be investing for the upside ?

**State of Alaska**  
Department of Revenue

*Commissioner Bryan Butcher*



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**Oil and Gas Production Tax  
Status Report to the Legislature  
Alaska Department of Revenue  
January 18, 2011**

## **Report Purpose**

In August 2006, the 24<sup>th</sup> Alaska state legislature approved House Bill 3001, which represented a major restructuring of the state's oil and gas production tax. As part of the legislation, lawmakers asked that the Department of Revenue study the impact of the production tax changes on several criteria and produce a report on or before the first day of the 2011 legislative session on the findings of that study.<sup>1</sup> This report summarizes those findings.

## **Executive Summary**

This report evaluates six elements of Alaska's production tax system since implementation of the Petroleum Profits Tax (PPT) in 2006 and Alaska's Clear and Equitable Share (ACES) in 2007. The six elements and our key findings with respect to each of them are described briefly below.

- 1. Revenue Generation/Tax Rate** – State revenues under PPT and ACES exceeded the amount that would have been received under ELF for each of the four fiscal years since implementation of a net profits tax. Although the production tax rate under ACES may be as high as 75%, tax rates in each of the

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<sup>1</sup> **AS 43.55.180 Required Report.** (a) *The department shall study*  
(1) *the effects of the provisions of this chapter on oil and gas exploration, development, and production in the state, on investment expenditures for oil and gas exploration, development, and production in the state, on the entry of new producers into the oil and gas industry in the state, on state revenue, and on tax administration and compliance, giving particular attention to the tax rates provided under AS 43.55.011, the tax credits provided under AS 43.55.023 - 43.55.025, and the deductions for and adjustments to lease expenditures provided under AS 43.55.160 - 43.55.170; and*  
(2) *the effects of the tax rates under AS 43.55.011 (i) on state revenue and on oil and gas exploration, development, and production on private land, and the fairness of those tax rates for private landowners.*  
(b) *The department shall prepare a report on or before the first day of the 2011 regular session of the legislature on the results of the study made under (a) of this section, including recommendations as to whether any changes should be made to this chapter. The department shall notify the legislature that the report prepared under this subsection is available.*

four years were much lower than the maximum rate.

The oil tax rate of 5% of the gross value at the point of production at AS 43.55.011(i) for private landowners has not raised any significant concerns that have been communicated to the Department of Revenue.

2. **Industry Investment** – Investment in the form of capital expenditures has increased in each of the four fiscal years since implementation of the net profits tax, however, it is unclear how much of the capital expenditures were drilling or well-related and how much were maintenance or facilities-related.
3. **Impact on Exploration, Development, and Production** – Exploration has generally increased from 2003, when the EIC credit was implemented, but has dropped off in 2010. Development continues in three relatively new North Slope projects, yet production continues to decline.
4. **Industry Employment and New Entrants** – Industry employment rose steadily from 2006 through 2009, but dipped slightly in 2010. The number of companies filing annual tax returns doubled between 2006 and 2009, indicating interest by companies that are either new or returning to the Alaska oil and gas industry.
5. **Use and Expansion of Tax Credits** – The amount of credits used has increased annually since 2006 and we expect the trend to continue as new credit programs were added in the 2010 legislative session.
6. **Tax Administration and Compliance** – The department continues to write regulations for the new tax system, and the first audits under the net profits tax have been completed. The department has, however, been hampered in its tax reporting and compliance efforts by the lack of a centralized database to house and manage the large volumes of oil and gas data it receives.
7. **Conclusions and Recommendations** – Based on the multiple changes to the tax laws over the past few years, drawing any conclusion about their effect on Alaska's investment climate is difficult. However, what is clear is that production continues to decline. The state should continue to monitor its competitiveness with other oil and gas jurisdictions worldwide and be prepared to change its tax structure as needed.

## Overview

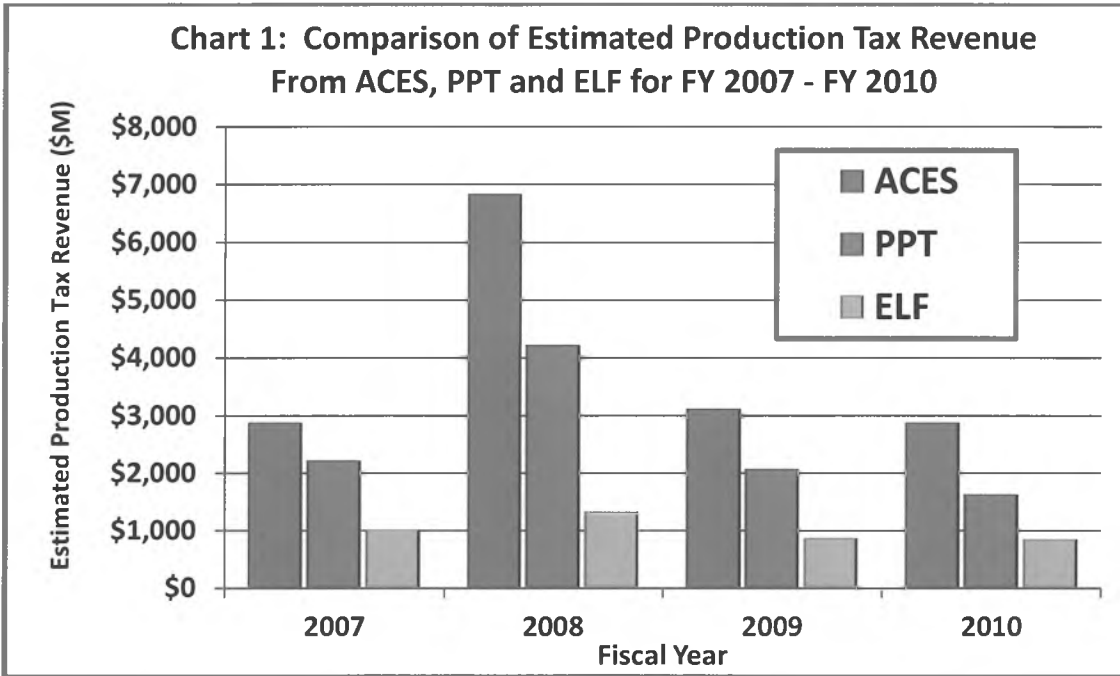
This report reviews and summarizes information gathered over the approximate five-year period since the implementation of the Petroleum Profits Tax (PPT) in 2006, and in 2007, Alaska's Clear and Equitable Share (ACES). The report covers six critical elements for evaluation and a section with conclusions and recommendations, as follows:

1. Revenue Generation/Tax Rate
2. Industry Investment
3. Impact on Exploration, Development and Production
4. Industry Employment and New Entrants
5. Use and Expansion of Tax Credits
6. Tax Administration and Compliance
7. Conclusions and Recommendations

## Revenue Generation/Tax Rate

Both PPT and ACES have generated more production tax revenue for the State than would have been received under the previous production tax system, which used the Economic Limit Factor (ELF). In the one year that PPT was in place, FY 2007, the production tax totaled \$2.2 billion. That year, the ANS West Coast oil price averaged \$61.60 and production on the North Slope averaged 734,000 barrels per day. In contrast, the average oil price one year earlier, in FY 2006, was \$62.12, production averaged 840,000 barrels per day, and the production tax under ELF totaled \$1.2 billion--\$1 billion, or 45% less than collected under PPT. It should be noted that PPT became effective on April 1, 2006, adding two months of tax collections to the FY 2007 total, making FY 2007 effectively a 14-month fiscal year. Regardless, the level of PPT collections above those that would have been collected under ELF, at least at moderately high prices, is significant.

In the three years that ACES has been in place, production tax revenues have increased to higher levels than under PPT. This is largely because ACES has higher base and progressivity tax rates than did PPT, and because one of the credits under PPT – the transition investment expenditure credit – was reduced substantially. The chart below shows production tax revenue collections under PPT and ACES as compared to how production tax revenue collections would have looked under two tax systems that were not in place during those years.



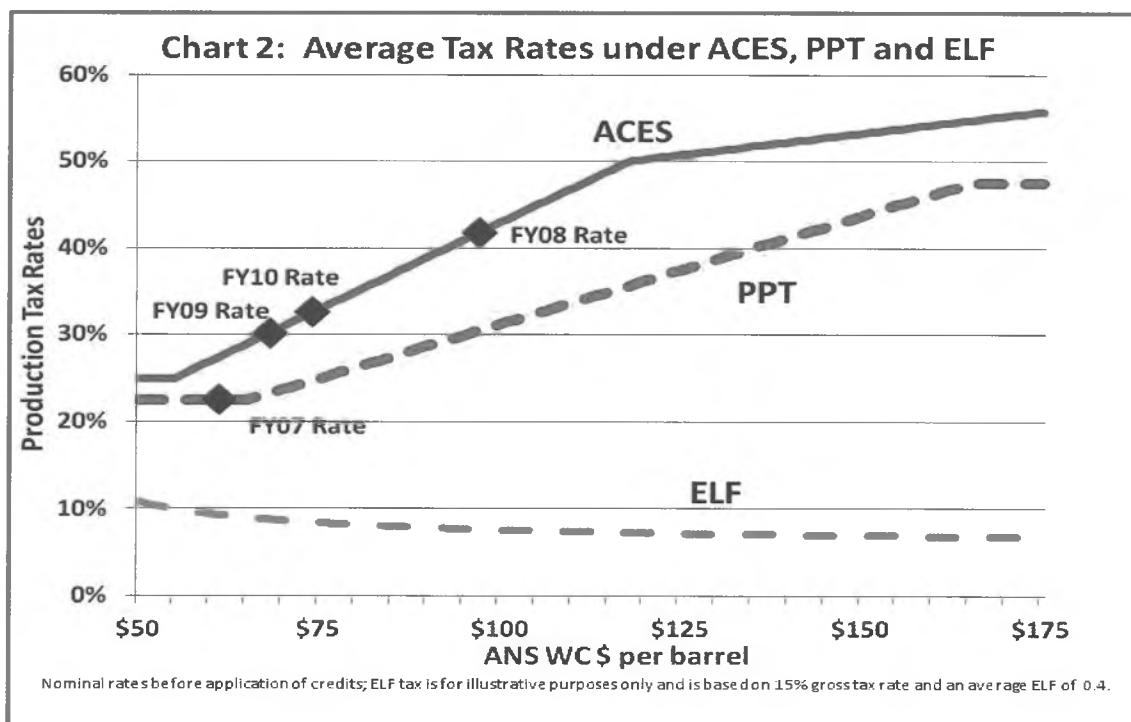
Production tax under both PPT and ACES is calculated on the net profits of oil and gas production, whereas ELF production tax was calculated on the gross profits of oil and gas production. Relative to taxes based on the gross value of production, net profit tax systems generally provide more tax revenue when oil prices are high and less tax revenue when prices are low. The progressive tax mechanism, designed to increase the total tax rate when per-barrel profit exceeds a pre-determined threshold, can increase the tax rate substantially. In addition to the progressive tax rate, the per-barrel profit level where the progressive tax is triggered is important. In the case of ACES, the progressive tax trigger is \$30 net profit per barrel, whereas with PPT, the progressive tax trigger was \$40 net profit per barrel.

Alaska North Slope (ANS) oil prices over the past four fiscal years were high relative to previous fiscal years. ANS crude prices over the four fiscal years of 2007 through 2010 averaged about \$75 per barrel compared to \$42 per barrel for the fiscal years of 2003 through 2006. Under ACES, an average price of \$75 per barrel would yield an average profit of \$50 per barrel, producing a combined base and progressivity tax rate of 33% (25% + [(\$50-\$30)\*.004]). The tax under this scenario before credits would be \$16.50 per barrel. In contrast, the tax rate under ELF of 15% of the gross value at the point of production, even if the ELF calculated to 1, would yield a production tax of \$10.50 per barrel, assuming transport costs of \$5 per barrel.

When oil prices are low, however, a net profits-based tax structure would likely provide less production tax revenue than a gross profits-based tax. For example, a tax of 15% on the gross value, regardless of profit, could create a loss for companies producing oil

if profits were equal to or less than the tax. Because PPT and ACES recognize the costs of production in their calculation, a company with no profit would not pay any production tax and would likely get tax credits to offset future tax liabilities. Low oil prices experienced late in the year 2008 and early 2009 generated tax liabilities for many companies operating on the North Slope that were lower than they would have been under the ELF system.

Chart 2 below shows the average tax rates of PPT, ACES and ELF under a range of oil prices. Also shown is the average tax rate in each of the years that a net profits tax has been in place.



The department was also asked to review the tax rate for oil produced from private land of 5% of the gross value at the point of production.<sup>2</sup> The department is not aware of any concerns expressed on behalf of industry or private landowners as to the fairness of this tax.

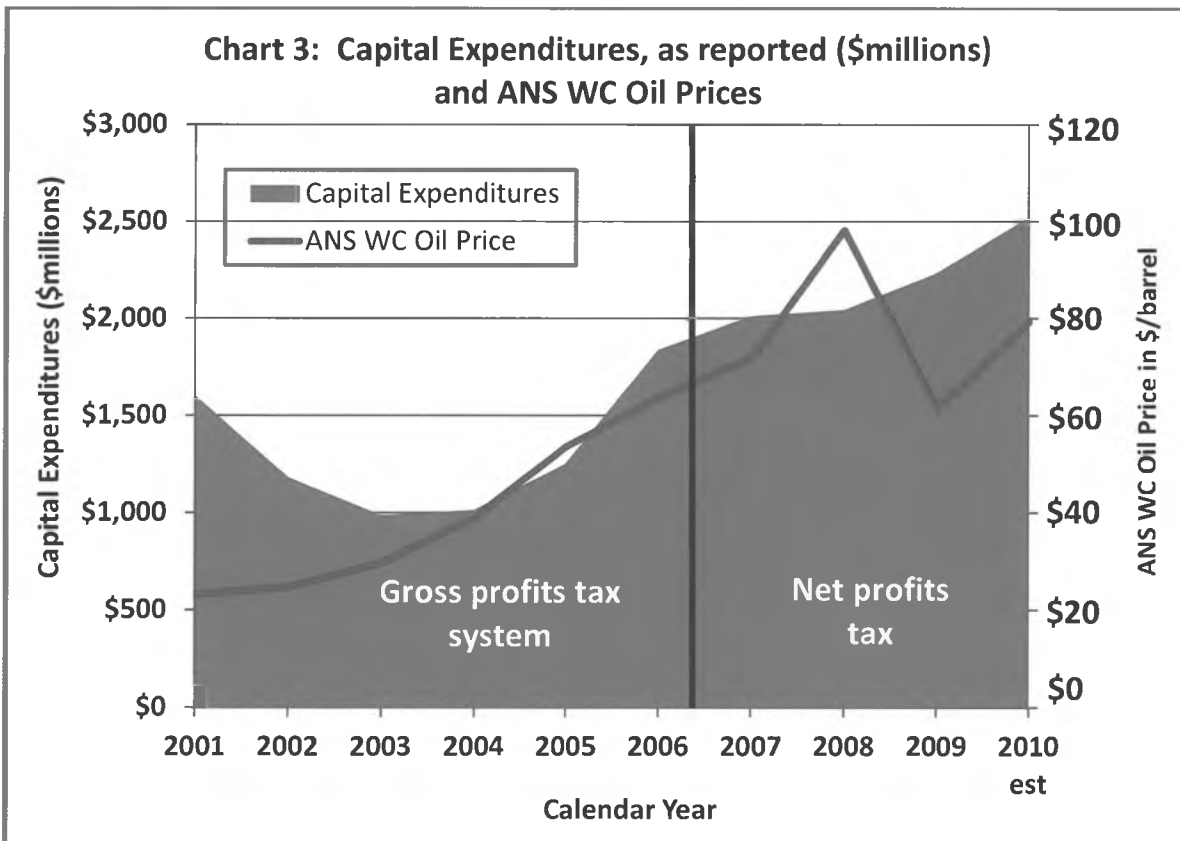
## Industry Investment

Investment is an important component in Alaska’s oil and gas industry. Producing oil, especially in an arctic environment, requires substantial financial outlays before, during

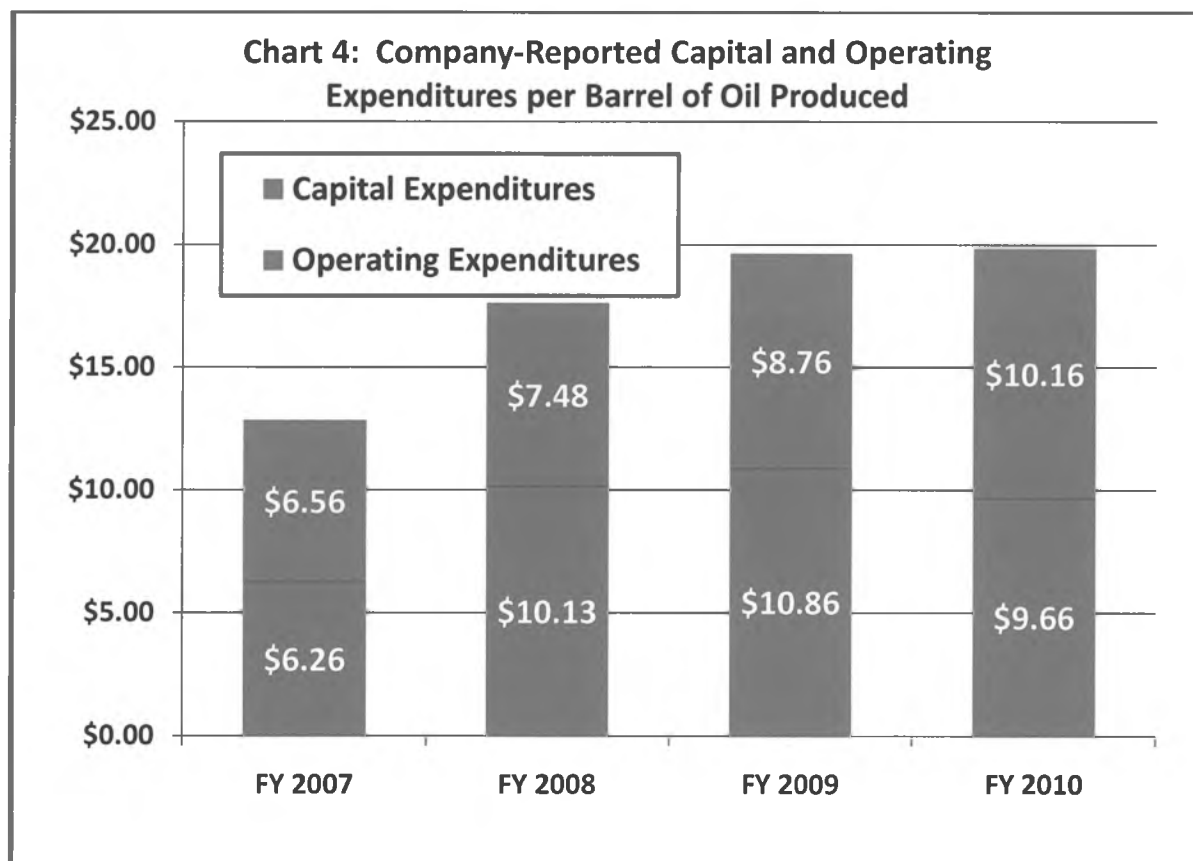
<sup>2</sup> AS 43.55.011(i)

and after producing the oil. In massive oil fields such as Prudhoe Bay, which has been operating for more than 30 years, maintaining and upgrading equipment and facilities is key to continued undisrupted oil production. Companies must also invest in research and new technologies in order to achieve the maximum recoverability of petroleum from the reservoirs they have developed. Because the companies that invest in petroleum projects can and do operate in areas outside of Alaska and the country, Alaska oil projects must compete with other petroleum opportunities throughout the world for those investment dollars.

Industry investment is generally reflected in capital expenditures, as opposed to operating expenditures, which are normally considered day-to-day expenditures for producing oil and gas. Alaska's fiscal system, which gives credits for capital expenditures, theoretically encourages these types of investments. Our review of the past 10 years of data appears to bear this out. Chart 3 below shows company-reported data from tax filings from calendar year 2001 through calendar 2010 (estimated). While capital expenditures over the five-year period (2006 through 2010) since the implementation of a net profits tax with credits for capital expenditures have increased each year, we have limited data as to the nature of the expenditures.

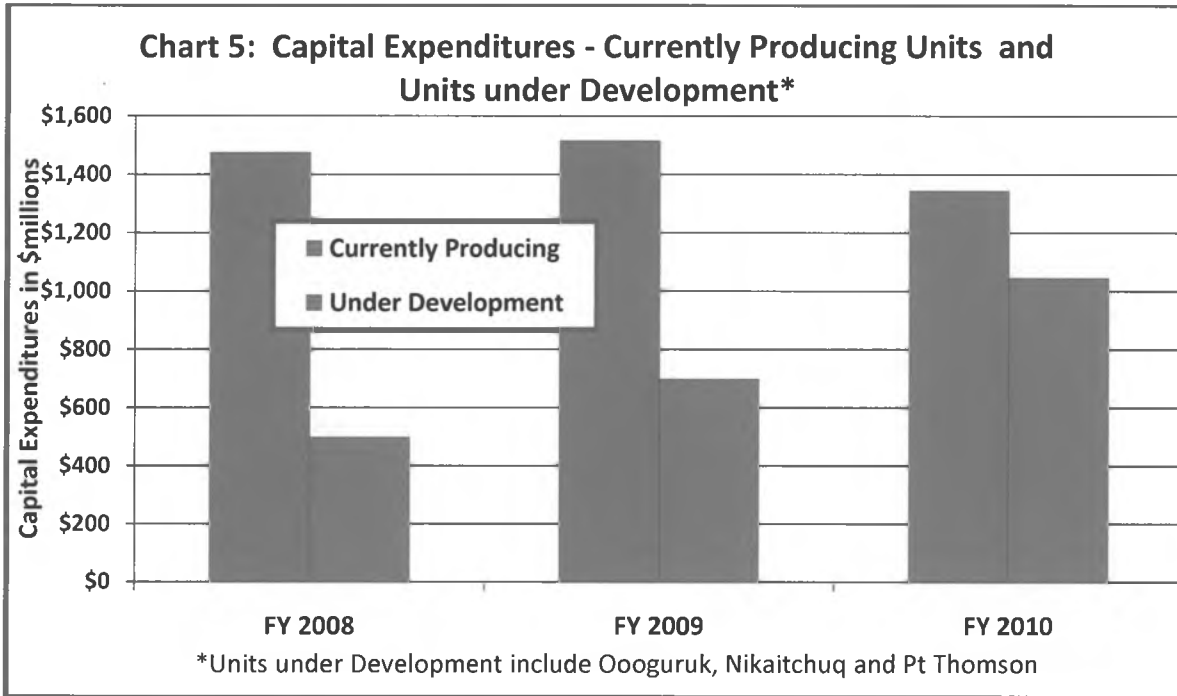


In the context of petroleum basin operations, capital expenditures are generally an indicator of expanding production or enhancing or extending the life of facilities or equipment. Expenditures for drilling wells normally fall into the category of capital expenditures as do expenditures for building housing or processing facilities. The Department of Revenue has extremely limited data from which to determine the nature of the capital expenditure increases. Given the age of North Slope facilities and infrastructure, it is quite possible that much of the capital investment in currently producing properties such as Prudhoe Bay is to extend the life of the facilities or infrastructure. Production on the North Slope continues to decrease, with a 7% decline rate between FY 2009 and FY 2010. The end result is that capital expenditures per barrel of oil produced are rising, while operating expenditures per barrel have leveled off and even decreased somewhat, as shown in Chart 4 below.<sup>3</sup>



<sup>3</sup> The slight decline in capital expenditures per barrel between FY 2007 and FY 2008 can be explained by the fact that FY 2007 included 14 months of expenditures, due to the effective date of the tax change of April 1, 2006.

One trend that has been observed in annual capital expenditures figures is that the proportion of capital spending in units under development has been increasing relative to the total capital expenditures spent on the North Slope. Chart 5 below shows expenditures by currently producing units and units under development over the past three fiscal years.

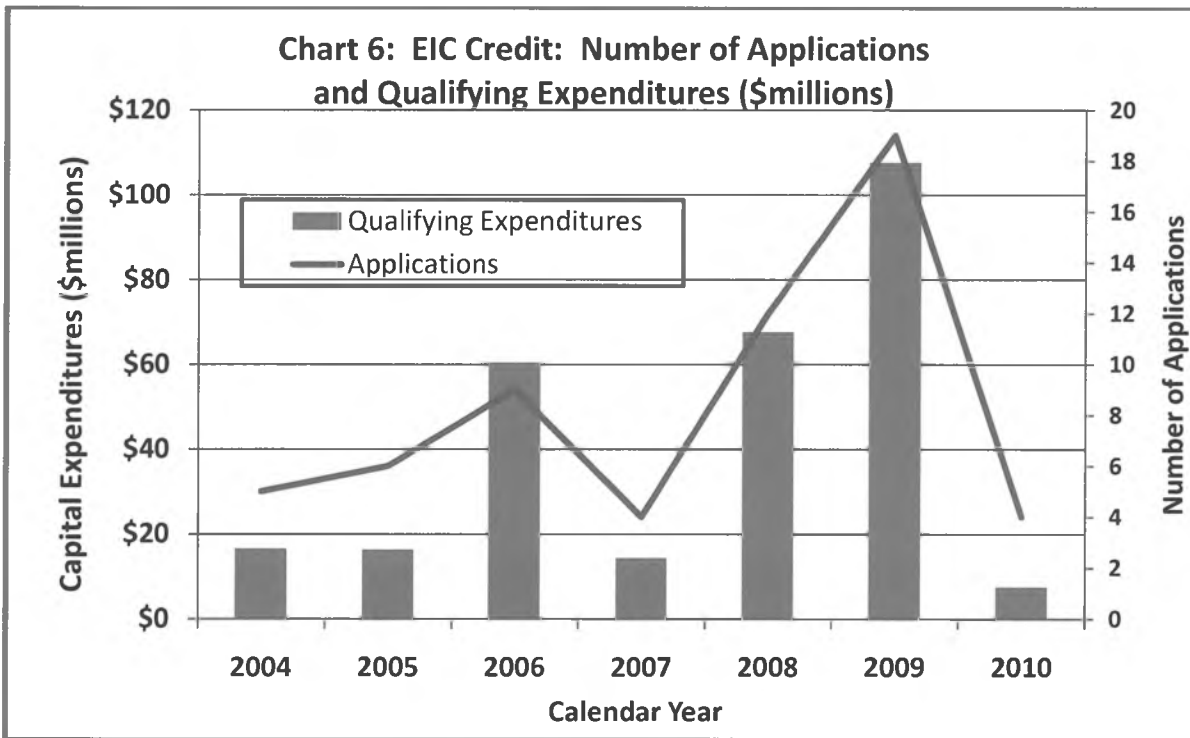


Capital expenditures also earn credits under the new production tax system. The credit system for capital expenditures on the North Slope does not distinguish between types of capital expenditures in existing units. The legislature in 2010 expanded the credit program in Cook Inlet to include an additional 20% credit (total of 40% credit) for lease expenditures related to wellwork. A credit increase of this nature may also prove beneficial to incentivize capital expenditures on drilling and increased wellwork on the North Slope.

## Impact on Exploration, Development and Production

As discussed in the previous section, the net profits tax system includes credits for capital expenditures, without distinction as to the nature of the expenditure. The tax system also includes credits for exploration expenditures through its exploration incentive credit (EIC) at AS 43.55.025. This credit was implemented in 2003 and was expanded with the ACES tax changes. If a project meets certain exploration criteria, it may be eligible for 40% credit under the EIC program.

The department began receiving applications under the EIC program in 2004, and the number of applications and amount of qualifying expenditures has generally increased each year peaking in the winter of 2008/2009<sup>4</sup>. The number of applications for EIC credit decreased significantly in 2010, reflecting a decrease in activity for the winter of 2009/2010. Chart 6 shows the number of applications and the expenditures that qualify under the EIC program from 2004 through 2010.

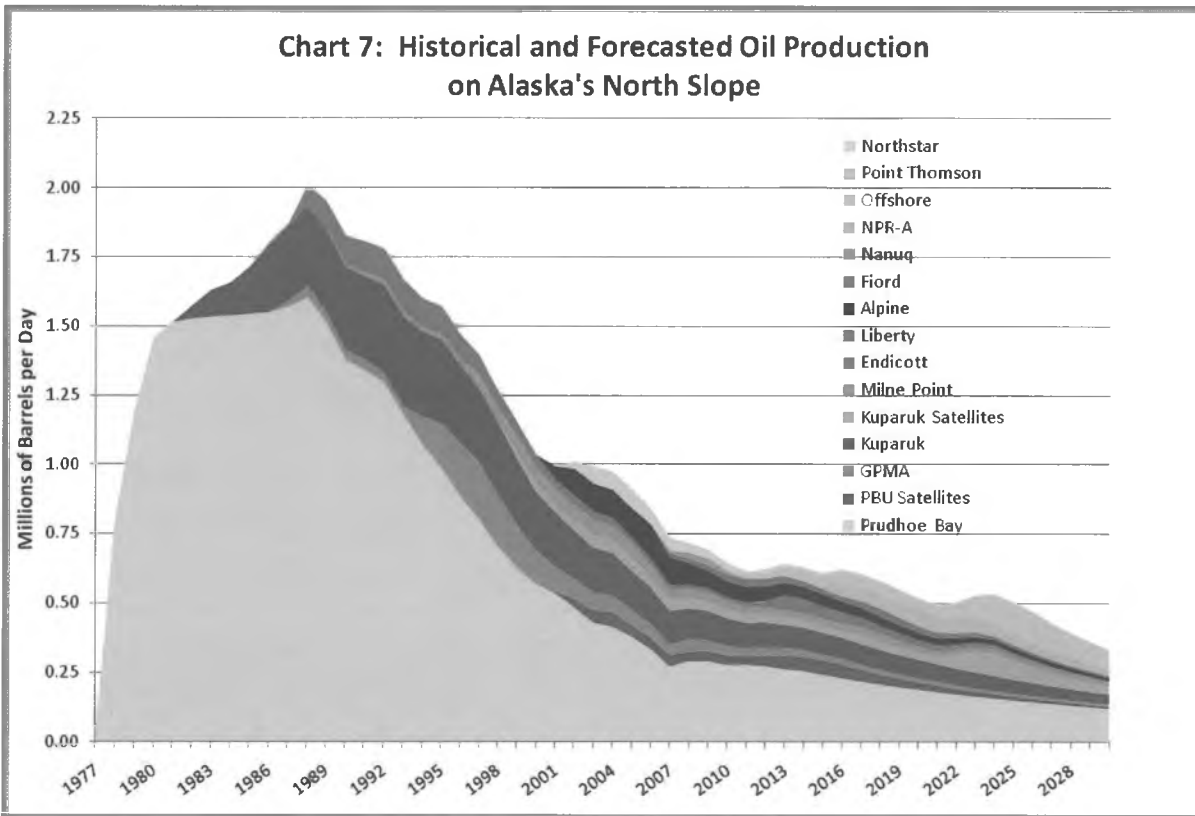


It is much more difficult to measure a tax system's impact on oil development and production from existing fields. The department's production forecasters twice annually create production profiles from limited information about an area's geology, drilling results, and other information exchanged in confidential discussions with operators. The compilation of production profiles for each North Slope field is a challenging task, employing the use of an engineering consultant, generally accepted engineering principles, and special software. The results of this compilation are subject to further revision as projects face delays that are typical in the petroleum industry such as reservoir challenges, permitting difficulties or lack of project funding.

New commercial developments on the North Slope include the Ooguruk Unit, which began production in 2009, and the Nikaitchuq Unit, which is expected to begin production in 2011. The Point Thomson Unit is also under development, expected to

<sup>4</sup> The sharp decrease in 2007 may be due to the tax change to the PPT, which at the time provided credit equal to the lower credit rate of the EIC program, without the reporting requirements.

begin production in 2015. Despite the addition of these developments, North Slope production continues to decline. From FY 2009 to FY 2010, oil production declined 7%; another 4% decline is projected between FY 2010 and FY 2011. Chart 7 below shows historical and projected oil production from the North Slope.

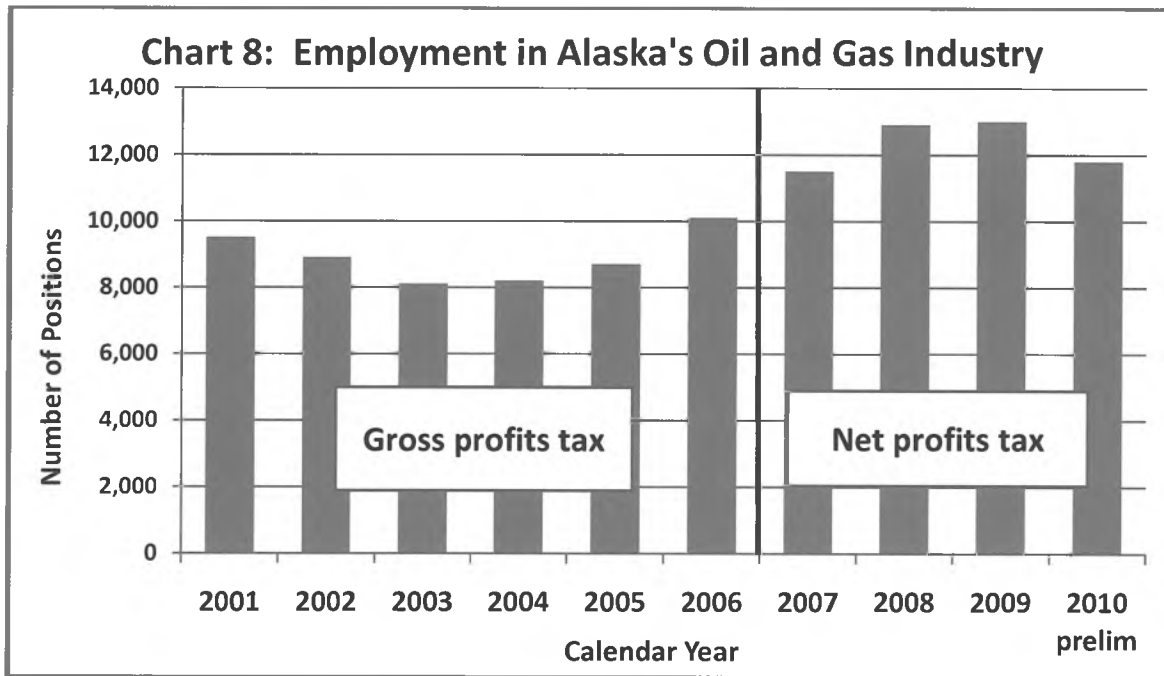


## Industry Employment and New Entrants

Employment in the oil and gas sector is another important measure of the health of the oil and gas industry in Alaska. Although oil and gas employment is not the largest category in the state, it is among the most sought-after employment, due to high wages. The Alaska Department of Labor and Workforce Development (DOLWD) reports that in 2009, the average earnings for a person employed in the oil and gas extraction industry was close to \$14,000 per month. These earnings are more than 3 times higher than the average earnings for all industries and government in the state of about \$4,000 per month.

The department also reports number of employees by industry. Oil industry employment in the state includes jobs with duties that would fall into one of three categories: (1) oil and gas extraction; (2) drilling oil and gas wells; and (3) support activities for oil and gas operations. Officials at DOLWD acknowledge that the definition

is fairly narrow, leaving out important oil-related employment, such as jobs at Alyeska Pipeline Service Company and at refineries in the state. Employment in the oil and gas industry has increased in the years since PPT was implemented, although the department projects a slight decrease in 2010. These data are shown in Chart 8 below.



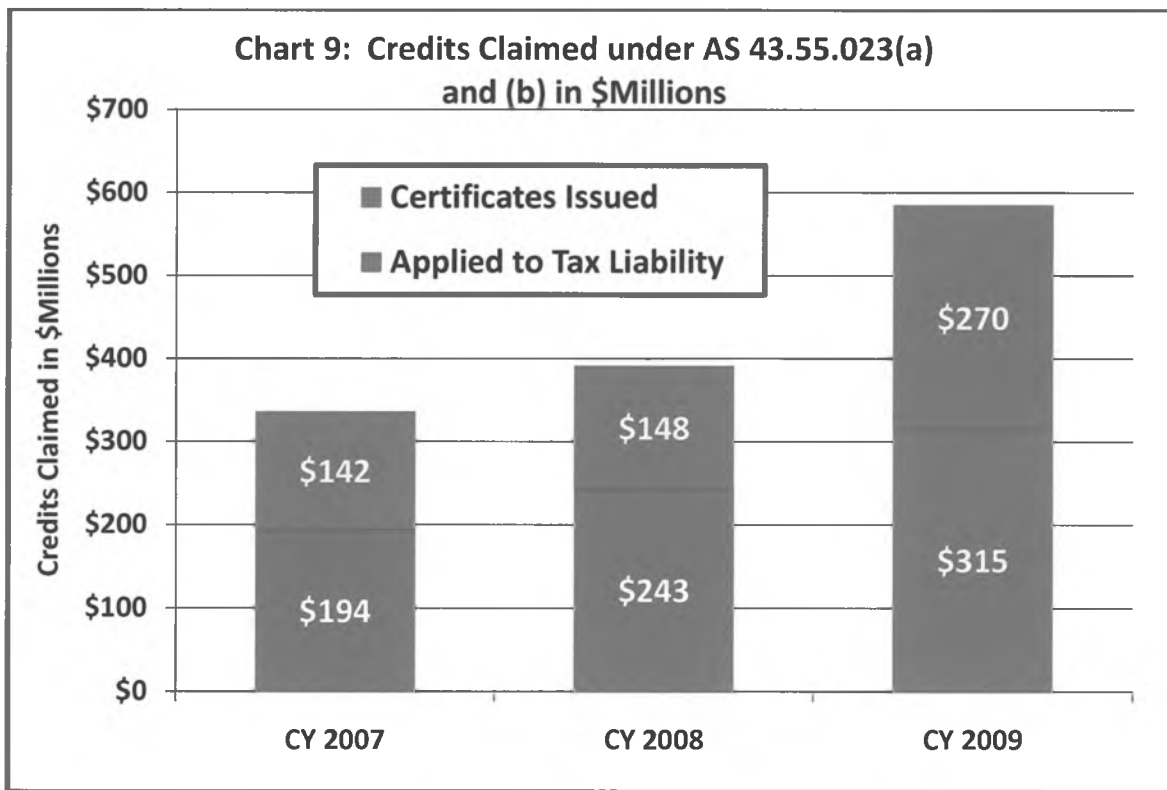
The state has seen new entrants into the Alaska oil and gas industry since the implementation of a net profits production tax. At the most recent lease sale held in October of 2010, a company new to Alaska successfully bid on over 100 tracts of oil and gas property. The steadily increasing number of production tax returns filed annually also indicates companies' new or renewed interest in Alaska's oil and gas opportunities. In 2006, the first year that filings were made under a net profits tax, there were 19 companies filing annual returns. In 2007, the number of companies filing production tax returns totaled 26, and in 2008, 36 companies filed annual production tax returns. The filing for 2009 increased only slightly from 2008, with 39 companies filing returns.

## Use and Expansion of Tax Credits

Tax credits have played and continue to play an important role in the net profits production tax system. There are currently five credit programs specific to the oil and gas production tax, and each of the programs have had substantial interest, and in most cases, use from taxpayers. Alaska's tax credit programs are intended to steer spending to certain in-state activities.

The most widely used credits under the production tax system are the qualified capital expenditure credits at AS 43.55.023(a). Tax credits under this program may be applied to production tax to reduce a taxpayer’s tax liability. If an oil and gas company has no tax liability, the credit may be carried forward, transferred to another company, or sold to the state. AS 43.55.023(b), credits for carried-forward net operating losses, are also widely used and may also be carried forward, transferred to another company, or sold to the state. Combined, these credits made up over 80% of the credits issued by the DOR Tax Division over the past three years.

Chart 9 below shows the total number of tax credits claimed under AS 43.55.023(a) and (b), categorized by the number of tax credits applied against a tax liability and the number of credits that were issued credit certificates for future use. We note that credits increased in each of the three years shown. The forecast for increased capital expenditures will translate to more credits applied against tax liabilities as well as more credits certificated.



Other credits include Small Producer/New Area Development credits (AS 43.55.024(a) and (c)) and Alternative Credit for Exploration (AS 43.55.025). These credits have seen less use than the credits under .023.

Credits have been expanded – both in credit rate and number of credits available – over the past year. The credit rate under the Qualified Capital Expenditure credit (AS 43.55.023) was increased for well lease expenditures relative to projects in Cook Inlet from 20% to 40%. Credit under the corporate income tax was also increased and extended (AS 43.20.043) for exploration and development of natural gas in Cook Inlet. The credit rate increased from 10% of qualified capital expenditures and qualified services to 25% of these costs and the credit program was extended from 2013 to 2016. For a complete listing of tax credits available against the production tax and other taxes, see the Fall 2010 *Revenue Sources Book*, at:

<http://www.tax.alaska.gov/programs/documentviewer/viewer.aspx?2126f>

## **Tax Administration and Compliance**

The numerous changes associated with the shift from a tax on gross value to a tax on profits have been a challenge for the Department of Revenue in a few specific areas. The first order of business under a tax system with a new, different way of calculating the tax is to define the inputs. This has taken place over the past several years in the process of creating, vetting, and implementing regulations. The regulations writing process for the production tax change has been extraordinarily interactive with the taxpayers, incorporating their input in all phases of development. Although this process may have slowed the pace of development, it resulted in more clarity in a complex set of regulations. The regulations writing process continues to date.

The change to a production tax on net profits also posed challenges for the audit staff in the areas of hiring qualified auditors and training auditors for the new demands of the position. The department has had difficulties attracting qualified auditors under the state pay schedule. New and expanded credit programs have also added to their workload. Despite these challenges, the audit staff has completed most of the audits under the PPT system.

The greatest difficulties faced by the department since the implementation of a net profits production tax system are the collection, use, and storage of the huge amounts of data received monthly and annually. As an example, the department receives monthly information from each active oil and gas company regarding the amount of oil and gas produced, the amount spent in operating and capital expenditures, the amount of credits earned and used, and the payment submitted. The department also receives documents pertaining to petroleum sales and netback calculations, most of which are submitted in Adobe Acrobat pdf format, which is not a suitable format for data storage or use. Assembling this data in a useable format is time-intensive and subject to error, as the data are cut and pasted into spreadsheets manually. Further compilations and changes subject the data to additional error and distortion.

The department's access to and use of this important data would be substantially improved if the information were housed in a central database, with access provided to all users of the data. The department believes securing a database will assist in operating more efficiently and effectively as an interface with both taxpayers and the public.

## Conclusions and Recommendations

A government's fiscal regime is just one element for oil and gas companies to consider when weighing options for where to invest. Many other elements, such as resource risk, political risk, environmental factors, and availability of labor and equipment, also play a part in companies' decisions about where to invest. It is very difficult to separate these factors in order to determine the extent to which a government's fiscal system influences investment choices.

While it is untenable to blame a tax system for the lack of industry investment, it is equally untenable to claim that the tax system is the reason increased activity or investment occurs. The past three years have seen dramatic swings in oil prices from a high of \$134 per barrel to a low of \$38 per barrel just 6 months later. An economic recession stifled investment and business activity in the United States and much of the developed world for over a year. The economic activity of the past three years may not have been the best benchmark by which to judge the impact of a tax system.

Nevertheless, it is prudent for state officials to monitor praise for and criticisms of its fiscal systems from both industry and the general population that they serve. High oil prices of recent years have swelled state bank accounts and some have suggested that the state is in the best financial position since statehood. Business periodicals and industry journals report that state is benefitting at the expense of a single industry – petroleum – and that the tax rate under ACES is too high and “takes away the upside” for the oil and gas producers. Criticism is often centered around the marginal tax rate under ACES, under which the government share of each additional dollar of profit may be as high as 93%.

State officials also make efforts to stay informed on the global oil and gas markets and opportunities in other jurisdictions, including how Alaska ranks competitively against them. Among the recent events in government taxation was the royalty modification undertaken by the Canadian province of Alberta. Studies conducted for the Alberta government showed that the royalty changes made in 2007, combined with the recession, the changes in natural gas markets, and other jurisdictions' efforts to attract investment, were making Alberta less competitive for limited petroleum investment

capital. The government responded to this information by changing its royalty structure in a way that the government's share of oil and gas profits would be lower.

The State of Alaska depends heavily on the oil industry, with more than 80% of its unrestricted revenue coming from oil taxes and royalties. State officials should continue to monitor the state's competitiveness in oil and gas opportunities, and be prepared to modify it as the need arises.