SB 21

(FILE 2)

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Review of SB 21 (HB 72)
Response to Sen. Meyer

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Prepared under LB&A Contract
February 5, 2013

I. Overview

The following is a review of SB 21, the Governor's proposal for oil production tax reform. This report is a response to Sen. Kevin Meyer's January 28 request through LB&A.

This report will explain the process I use to evaluate the proposal. A crucial element of Alaska receiving a fair share is the necessity for international competitiveness in the tax system to attract investment. The tax also needs to minimize other features that may inhibit optimal development, and needs to promote the state's best interests. The report will describe:

- The role of competitiveness
- Measuring competitiveness
- The quantification of competitiveness
- Analysis of the bill as to how it affects competitiveness, investment behavior, and the state's interests
- Measuring the impacts of the bill on state revenue

II. Introduction

The oil tax reform issue is followed by many Alaskans. In prior testimony and writings I have expressed my concerns about the current oil and gas production (severance) tax system, ACES. Respectfully, many Alaskans do not believe tax reform is necessary. It is not an easy issue.

The focus of the tax structure driving this review is that the progressivity mechanism creates high tax rates at high prices. This diminishes upside potential, the opportunity to make a lot of money when prices are high. Upside potential is important in making investment decisions. The tax is much higher than the comparable international competition.

As a result investment in North Slope development has been sluggish and production is declining at an unsatisfactory rate. For example, producers are currently investing about $1.5 billion annually in existing fields, mostly for maintenance. This is about the same amount they were investing in 2007 ($1.3 billion, when ACES was enacted), when oil prices were $60 per barrel. In the rest of the world, ConocoPhillips', BP's, and ExxonMobil's upstream capital expenditures increased from $53 billion in 2007 to $82 billion in 2011.

Currently 100,000 barrels per day identified in the Department of Revenue's production forecast in 2007 in existing fields for 2013 have not materialized. Though all of these barrels may not be

attributable to the tax, the oil is there (this is discussed below), and the producers have identified several projects they would undertake with a competitive tax.

The goal of tax reform is to enact a different tax to encourage investment and stem decline, while providing a "fair share" of revenues for the public.

In the current age of globalization capital is very fluid, but also finite. Corporations will allocate their resources to their most highly valued uses. There is currently no shortage of investment opportunities for oil and gas development. Over the last twenty years virtually every region on earth has seen sizeable increases in oil reserve growth. Worldwide, oil reserves have increased by 60% to 620 billion barrels.

Jurisdictions compete for capital. Fiscal terms, which often exceed development costs, are a significant component in determining competitiveness. "Fair share" is defined as what Alaska can get in the competitive environment.

I have reviewed the presentations by EconOne and PFC. Those analyses are astute. Here I offer additional perspectives for the legislature to consider.

III. Measuring Competition and Fair Share

Companies are willing to pay more tax when the reward is greater (more oil / less cost / lower risk). Thus in comparing regimes it is necessary to look at comparable jurisdictions in terms of the risk / reward balance. Alaska cannot be usefully compared to every other jurisdiction on earth.

Of course nowhere is exactly like Alaska, so it is somewhat a matter of judgment as to what Alaska's "peer group" is. Nonetheless it is necessary to come to terms with compiling such a group.

In establishing Alaska's peer group four parameters have been chosen: North American regimes, tax and royalty (concession) regimes in Western democracies, Arctic regimes, and as a proxy for the resource base, jurisdictions with similar production and proved reserves to Alaska. For the latter, the Alaska North Slope currently produces about 550,000 barrels per day and has about 4 billion barrels in proved reserves. So jurisdictions were chosen that produce between 400,000 and 800,000 barrels per day and have between 2 and 6 billion barrels of proved reserves. This established a peer group of the following 17 jurisdictions:

- U.S. Gulf of Mexico
- Oklahoma
- California
- Texas
- North Dakota
- Alberta Oil Sands
- Newfoundland

- Saskatchewan
- Alberta Conventional Oil
- Brazil
- Australia
- Argentina
- United Kingdom
- Egypt
- Russia
- Malaysia
- Norway

In measuring the competition one primary metric is used: government take. Government take is the total amount of state and federal taxes (production tax, property tax, income tax) and royalties as a percentage of the total net value (market sales price less all costs [marine transportation, pipeline, upstream capital for exploration, development, and production, and upstream operating costs]). As shown below, the production tax under ACES is a significant component of the total taxes.

The exact costs and production response for individual projects are very uncertain. Moreover, they vary widely from project to project and from jurisdiction to jurisdiction. Accordingly, evaluation metrics that look at full life-cycle economics are de-emphasized, such as rate of return or net present value.

Instead, in comparing Alaska with its peers, the government take shows at a given market price what percentage of the net value goes to the government in all forms. The government take provides a systematic comparison.

For the Alaska North Slope three types of development are examined: existing production from existing fields, new production from existing fields, and new production from new fields. The Department of Revenue has provided cost estimates for existing production from new fields at $7 per barrel capital cost and $13 per barrel operating cost. New production from existing fields is estimated at $17 per barrel capital cost and $14 per barrel operating cost, and new fields at $27 per barrel capital and $15 per barrel operating. These could also be characterized as low, medium, and high cost fields.

Long-run production forecasts show that nearly 90% of all future North Slope production will come from existing fields.

Figure 1 shows the government takes under ACES for existing production, new production in current fields, and new fields. At current prices ($110 per barrel) existing fields have a government take of about 73%.

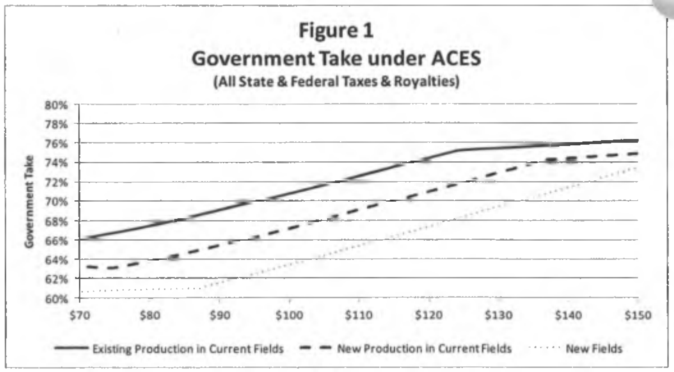
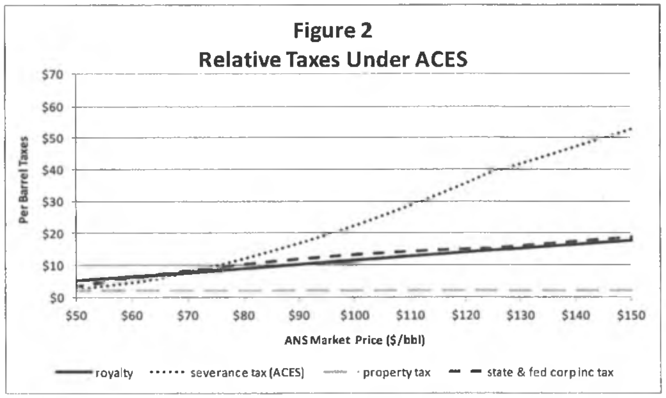


Figure 2 shows the relative magnitude of each specific tax and royalty element under ACES. It indicates the production tax under ACES is a significant component in determining the total government take. This figure is for existing production. At current prices, for instance, about half of the total state and federal taxes and royalties are attributable to the production tax.



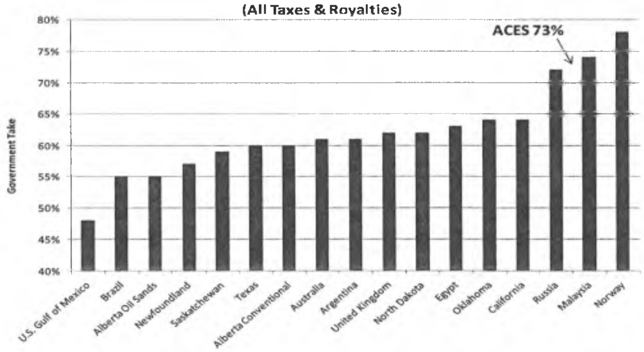
IV. The Competition

Figures 3-5 show the government takes for the competition at current prices ($110 per barrel), $80 per barrel, and $140 per barrel, respectively.

The source for most of these is PFC Energy's January 31, 2013 presentation to the Senate TAPS Throughput Committee, "Alaska Hydrocarbons Fiscal Systems." Whereas the tax terms themselves are readily available, PFC has an excellent worldwide field-specific data base, and their estimates as to how specific operating conditions and costs would interact with the tax terms are very credible. It also provides consistency. For those jurisdictions not covered in their data base (Newfoundland, Saskatchewan, Oklahoma, California) I used my data base.

The figures also show the government takes under ACES for existing production. They provide an indicator of what fair share should be. ACES is clearly high compared to most of the peer group.

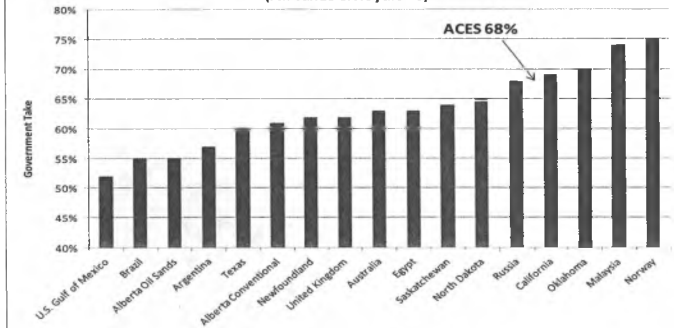
Figure 3
Alaska Peer Group*
Government Take at $110/bbl Market Price
(Total Taxes as a Percentage of Net Value)
(All Taxes & Royalties)



* North America regimes (U.S. states & Canadian provinces with greater than 200,000 bbl/day prod)
Tax & royalty regimes
Arctic regimes
Regimes with similar production and reserves (between 400,000-800,000 bbl/day prod and between 2-6 billion bbls proved reserves)

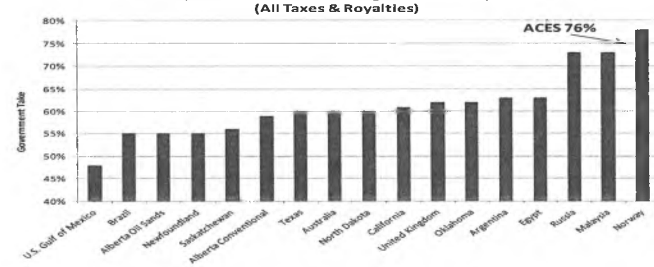
Source: PFC Energy

Figure 4
Alaska Peer Group*
Government Take at $80/bbl Market Price
(Total Taxes as a Percentage of Net Value)
(All Taxes & Royalties)



* North America regimes (U.S. states & Canadian provinces with greater than 200,000 bbl/day prod)
Tax & royalty regimes
Arctic regimes
Regimes with similar production and reserves (between 400,000-800,000 bbl/day prod and between 2-6 billion bbls proved reserves)

Figure 5
Alaska Peer Group*
Government Take at $140/bbl Market Price
(Total Taxes as a Percentage of Net Value)
(All Taxes & Royalties)



* North America regimes (U.S. states & Canadian provinces with greater than 200,000 bbl/day prod)
Tax & royalty regimes
Arctic regimes
Regimes with similar production and reserves (between 400,000-800,000 bbl/day prod and between 2-6 billion bbls proved reserves)

Source: PFC Energy

Figures 6-8 illustrate what these differences in government takes are worth to the producers on existing fields. Figure 6 converts the government takes to actual taxes in dollars per barrel at current prices ($110 per barrel).

Figure 6
Total Taxes & Royalties @ $110/bbl Market Price
($/bbl)

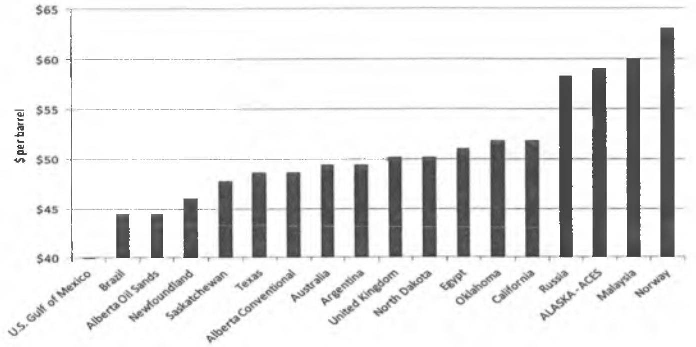


Figure 7 illustrates how much less taxes and royalties are per barrel compared to Alaska.

Figure 7
How Much Less Taxes are Per Barrel
Compared to Alaska @ $110/bbl
($ per barrel)

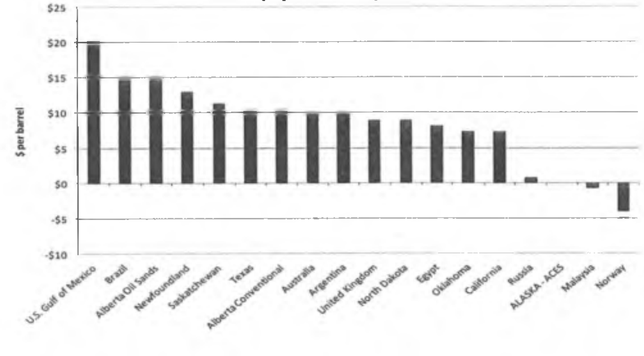
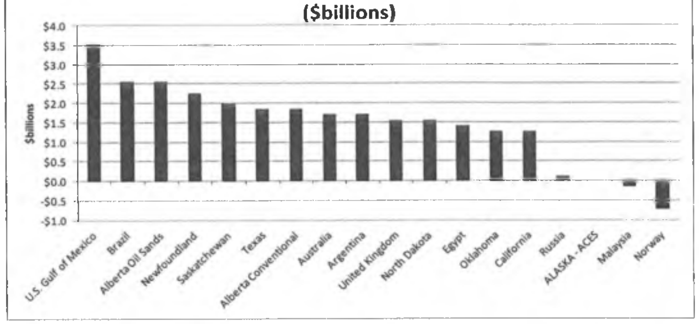


Figure 8 illustrates how much more producers earn annually after tax compared to Alaska at current production of 550,000 barrels per day. This shows how much more they can make by investing elsewhere.

Figure 8
How Much More Producers Earn After-Tax @ $110/bbl
($billions)



At current prices and production each percentage point in government take is worth about $137 million annually to the producers. Each percentage point matters. Thus in crafting a tax it is important to be as precise as possible in determining the fair share target and attaining it.

V. Analysis of SB 21 with Possible Options

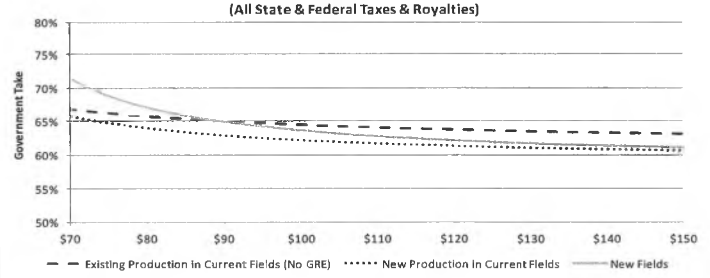
SB 21 does three main things:

- Removes progressivity
- Removes the 20% capital cost credit
- Provides a 20% gross revenue exclusion (GRE) on new fields

The legislature may want to consider deliberately determining what government take target they are aiming for in order to be competitive. In looking at Figures 3, 4, and 5, the legislature may want to consider a government take target of 63% at all prices in order to be competitive.

Figure 9 shows the government takes under SB 21.

Figure 9
Government Take under SB 21
(All State & Federal Taxes & Royalties)



At first glance three things are striking:

- SB 21 is much more competitive than ACES.
- Given a 63% target, the tax may be too high at low prices, especially for high cost development.
- SB 21 is regressive; i.e., the tax rate is lower at high prices and higher at low prices. (Progressive, on the other hand. means the tax rate is lower at low prices and higher at high prices.) It is more regressive for the high cost fields.

Regressivity is a problem for two reasons. First, it creates a burden for the taxpayers at low prices. And second, it may deprive the public of revenue at high prices.

What makes the SB 21 government take regressive is the royalty. The royalty is based on gross value, rather than net value; it excludes deducting the upstream capital and operating costs. As price increases it is a declining percentage of net.

For example, assume oil price is $50 per barrel and pipeline and marine shipping costs are $10 per barrel. So the gross value is $40. With a one-eighth royalty the royalty would be $5 per barrel.

Assume the upstream capital and operating costs are $30 per barrel. So the net is $10 per barrel. The royalty would be 50% of the net.

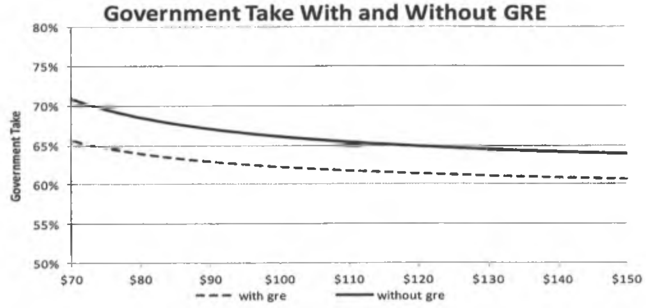
Now assume oil prices are $100 per barrel. The gross value would be $90 per barrel and the royalty would be $11.25. The net value would be $60 per barrel. So the royalty would 19% of the net.

It is more regressive for high cost fields because at low prices the gross is increasingly larger than the net. By eliminating progressivity in SB 21 there is nothing to offset the regressivity of the royalty.

Note, though, that SB 21 is not excessively regressive on the lower cost fields. In addition, most of the rest of the world, including the peer group, have regressive systems, mainly due to their similar royalty structure.

The gross revenue exclusion (GRE) reduces the gross revenue on new fields by 20% in the net value calculation for determining the tax. Figure 10 shows the impact of the GRE on medium cost fields. In reduces government take by about 5 percentage points at lower prices and about 3 percentage points at higher prices.

Figure 10
Medium Cost Fields
Government Take With and Without GRE

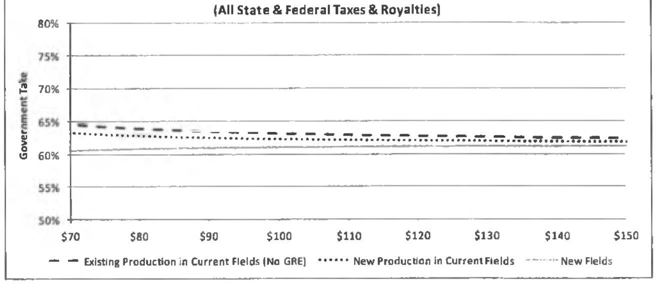


Tax provisions based on gross value by definition are divorced from the upstream economics, and consequently have an element of arbitrariness about them. In this case it will not differentiate between higher and lower cost development. Moreover, since it is based on gross value, the exclusion is low at low prices when the producers need it the most, and high at high prices when they need it less. As a simple example, if oil prices drop, not only does the producer make less money, but since the gross revenue drops, the gross revenue exclusion drops, which makes the tax go up. So they are doubly affected in a negative manner. For that reason the legislature may want to consider not retaining the gross revenue exclusion in the proposed legislation.

In regard to the proposition in SB 21 to only have the GRE for new fields, both existing and new production benefit from both old and new investments. In addition, there are undeveloped targets in existing fields. These include stratigraphic traps and isolated fault blocks that require distinct extraction. These projects can be costly. The 20% capital credit mechanism that is eliminated in the proposal would automatically gives a bigger boost to higher cost development. Accordingly, the legislature may want to be wary of treating existing fields and new fields distinctly.

As an evaluative exercise, dropping the gross revenue exclusion and retaining the 20% capital credit was examined. The result is shown in Figure 11.

Figure 11
25% Base Rate / 20% Capital Credit / No GRE
(All State & Federal Taxes & Royalties)



Interestingly, the curves are flat, and very close to each other for all types of fields. It creates a neutral tax system, that is neither regressive or progressive. It is an improvement over the regressivity. Moreover it gets close to the target rate. The flat government take could be moved up or down to a different target by simply adjusting the 25% severance tax rate up or down.

The credit creates this flat curve by a self-adjusting mechanism. For the high cost fields that are more regressive because of the royalty, the credit as applied to a higher cost is greater to neutralize the royalty. And for the lower cost fields that are less regressive, the credit is applied to a lower cost.

Since the bulk of the capital costs are incurred early the credit also provides a boost to net present value, an important enhancement to project economics. The legislature may want to consider retaining the 20% capital credit.

An alternative to credits is an uplift system where more than 100% of the capital cost can be deducted in calculating taxable income. For example, with a 20% uplift, if $100 is spent, $120 can be deducted. Uplift is used widely around the world.

Note though that a 20% uplift has much less clout that a 20% credit. With the 20% uplift capital costs are elevated 20% to make a larger deduction. The deduction is subject to the base tax rate, in this case 25%. So the uplift would only reduce taxes by 25% of the 20%, or 5% of the capital cost, rather than the full 20% from a credit.

The legislature may still want to consider a progressive system. Progressive systems can be competitive if they properly balance low-price risk. For example, Norway has the highest tax rate of the peer group. But Norway is also the only jurisdiction with no royalty. Thus there is no regressivity, and the fiscal structure presents no low-price risk to the investors.

(There are other reasons why Norway may not be the ideal peer. A large portion of Norwegian production is owned by Statoil, and a large portion of Statoil is owned by the Norwegian government. Thus to a large extent the government is paying tax to itself.)

There is one more provision of SB 21 to note. Section 9 eliminates monetizing loss carry-forward credits until they can offset actual income. Under ACES, income losses can immediately be converted to a credit at a rate of 25% of the loss and sold to the state (AS 43.55.023(b)). Under the provision in the bill the loss cannot be monetized until it can offset income, and the amount carried forward accrues 15% annual interest until it is used.

This provision will mainly affect dry-hole exploration by companies with no other operations in the state, and who consequently will never have offsetting income. They will never be able to monetize the loss.

Currently exploration carries a 30% or 40% credit, depending on location, different than this loss carry-forward credit, and not affected by SB 21.

With the 30% credit, for example, and the current monetization of losses, the state and federal government through credits and deduction pay for about 72% of the exploration expense, essentially incurring that share of the dry-hole risk. (Of that 72%, about 56% is incurred by the state through the credit and deductions for production and state corporate income tax.) With this provision that would be reduced to about 59% (for entities that cannot use the carry-forward credit). (Of that 59%, about 37% is incurred by the state.)

This provision creates differential treatment between explorers with and without other operations in the state, and may deter new entrants.

VI. Production Response to Tax Structure: Historical Context

The principle that investors allocate capital to its value use, and tax structure has a significant influence, is well established in economic theory. There can be little doubt that lower taxes, if competitive, will attract more investment and increase production.

Prior to the enactment of the PPT in 2006 and ACES in 2007 Alaska was under a tax regime called the Economic Limit Factor, or ELF. Under that regime, as structured, as production declined tax rates were falling. Some critics of tax reform have used that as evidence that lower tax rates will not affect investment and production. However, ELF was technically complex, and had some dysfunctional properties that may have caused some irrational investment behavior. Looking at the dynamics of what occurred may lead one to draw a much different conclusion.

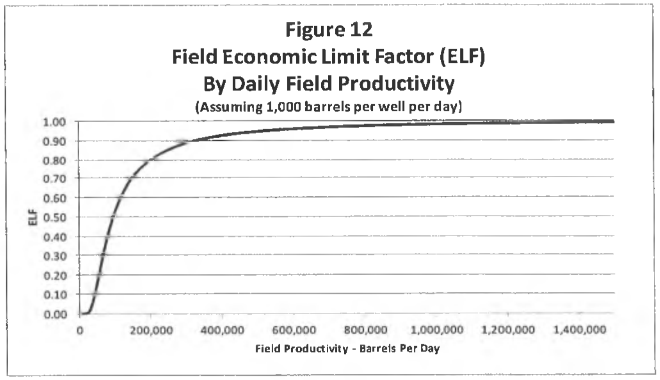
The ELF was enacted in 1978 just after Prudhoe Bay started up. The ELF itself was a fraction between 0 and 1. The fraction was determined field by field based on average well productivity for the field. Every well received 300 barrels per day tax free. The ELF was the percentage of the well productivity above 300 barrels per day. So if a field had an average well productivity of 1,000 barrels per day, 70% of the production was above 300 barrels per day, and the ELF was

0.7. That fraction was applied to the nominal tax rate of 15% to make the government take. So if the ELF was 0.7, the government take would be 10.5% (0.7 X 15%).

In 1989 the ELF formula was changed so that it was also based on field size. The greater the daily field productivity, the higher the tax rate. It was deliberately structured to create a bifurcated system where large fields would have high ELFs and small fields would have low ones. So the bigger fields like Prudhoe Bay and Kuparuk had fairly material rates. The tax was based on gross value under ELF, but if calculated under the current net value system like we have today, it was in excess of 30% of net on Prudhoe Bay.

The smaller fields, on the other hand, had very low tax rates, near zero.

Figure 12 shows the ELF depending on daily field production assuming average well productivity of 1,000 barrels per day.



For example, any field producing less than 50,000 barrels per day paid very little tax.

At the time of the 1989 change the concept of "satellite field" was not well known. But soon many of them started up. So while the production on the higher tax fields decreased, many new fields with low taxes came into existence.

ELF was in existence until 2006. In looking at the last ten years of ELF, in 1996 there were four fields with high production that had high taxes: Prudhoe, Kuparuk, Endicott, and Pt. McIntyre. The rest had small production and low taxes.

Over time as production and well productivity declined for these four fields, the ELF declined, as well. By 2006 it was still high for Prudhoe Bay, but not very high for the other three.

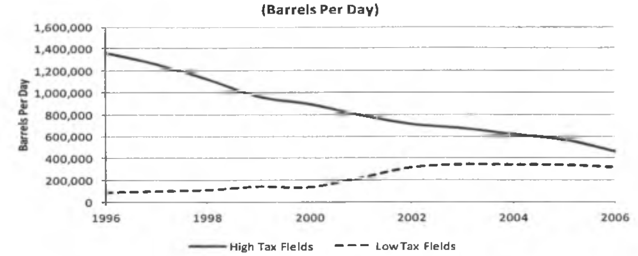
By 2006, for example, Kuparuk, which was producing 133,000 barrels per day, had a near zero ELF. The reason was that its average well productivity was very low, just barely over 300 barrels per day. (The field average well productivity component was still in the equation.)

The ELF structure itself created a disincentive to increase field size or well productivity in Kuparuk. Any investment that increased field size and average well productivity would increase the tax rate. And being a field-wide tax rate, it would increase for every single barrel. If the total tax increase for the entire field was allocated to just the incremental barrels from such an investment, the marginal taxes attributed to those new barrels were very high, and their marginal economics poor, especially compared with the alternative of diverting the capital to the low tax fields.

In fact, given the relationship between the cost of a well, and the tax savings on the entire field from bringing average well productivity down, it is plausible that the ELF structure may have created an incentive at Kuparuk early on to simply drill wells to get the average well productivity down to reduce tax.

Figure 13 shows what happened with production between the high tax and low tax fields.

Figure 13
The ELF Years: High Tax vs. Low Tax Fields
(Barrels Per Day)



In 1996 production from the four fields with high taxes was 1,359,000 barrels per day. By 2006 it was 463,000 barrels per day. Production had fallen almost 900,000 barrels per day, an average annual decline of 10%.

In 1996 production from the other fields with low taxes was 90,000 barrels per day. There were eight such fields. By 2006 there were 25 of these fields. Their production was 318,000 barrels per day. Production had increased 228,000 barrels per day, an average annual increase of 13%.

So while total North Slope production fell, the entire decrease was attributable to the fields with the high taxes. Oil prices averaged $28 per barrel over the last ten years of ELF.

VII. Revenue Estimates from Tax Reform

As discussed above, a competitive tax structure will attract investment and enhance production. How much investment and how much production is impossible to say. There is a long list of specific projects in existing fields the producers have cited that could be developed with a competitive tax system. (These include I Pad development at Prudhoe, M & S Pad expansions, low salinity water flooding, Lisburne expansion, Sag reservoir development, T Pad development at Milne Pt., and viscous and heavy oil.) Repsol has suggested publicly that should it make discoveries on the North Slope it would be hesitant to develop under ACES. EconOne in their presentation to the Senate laid out what the vast size of the prize may be in terms of total North Slope resources.

The Department of Energy estimates there are 5 billion barrels of potential economically recoverable reserve growth from existing North Slope fields. Two billion barrels of this is conventional oil, not heavy or viscous oil. There is another possible 5 billion barrels of economically recoverable oil available through exploration in the core producing area on state land. This totals 10 billion barrels.

In estimating the revenue impacts from tax reform it is crucial to keep two things in mind. First, as there is most certain to be an investment / production response from tax reform, revenue estimates comparing a proposal with the status quo cannot be measured using the same number of barrels.

As stated above it is impossible to know exactly what the investment / production response will be. However, it is possible to do sensitivity analyses. In sensitivity analysis a spectrum of possible production responses to tax reform are set out, with the revenue impact from each. An example sensitivity analysis is presented below. The legislature would need to judge the plausibility of those production responses.

The second crucial thing to keep in mind is that there are lead times for any response and so reducing the tax rate will initially cause revenue losses, with associated consequences to the state budget. Tax reform is a strategy for the long-term. That is one reason why it is not an easy issue.

There is no doubt the state has made a lot of money in the short term from ACES, and in many ways this depicts the situation. When ACES passed in 2007, with the high tax rates at high prices, there were tens of billions of dollars in infrastructure from past investments that had nowhere to go. (I estimate approximately $60 billion including TAPS.) It was "captive" investment. This infrastructure was put in place to produce oil over an extended number of years, including the present and the future. So after 2007 production from that past investment continued, paying much higher taxes.

The following is but one possible sensitivity analyses approach for gauging the revenue response from SB 21.

Again, there are 10 billion barrels of potential reserve growth. Figure 14 compares at current prices total petroleum revenues (royalties, production taxes, property taxes, and state corporate income tax) over the next 20 years between ACES and a spectrum of reserve growth scenarios under SB 21.

Under ACES the forecasted decline rate is extended for 20 years. It is estimated to bring in a little under $100 billion over the next 20 years in total petroleum revenue. Under SB 21 there is an assumed five year ramp-up for the investment / production response to begin.

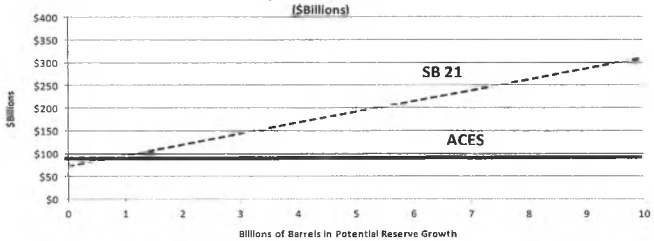
Figure 14

Total Petroleum Revenues over 20 Years*

ACES at Trended Current Production Forecast vs. SB 21 with Various Potential Reserve Growth

$110/bbl ANS Market Price

($Billions)



* Royalties, production tax, property tax, state corporate income tax

Figure 13 shows that if tax reform opens up more than about 10% of the resource to development, about 1 billion barrels, Alaska will be ahead in the long-run.

This is but one way to look at the revenue impact. And lawmakers will need to judge the plausibility of any outcome.

In closing, the alternative to tax reform is the status quo. One element of the status quo is the business climate. This is a key driver for corporations in decision-making. Legislators may want to reflect on what that status quo business climate is, and what it means, or may not mean, for the future.

There are many forces that shape the climate. One of but many pieces to that puzzle that legislators may want to consider is the context of the enactment of ACES in 2007. In 2008 when oil prices hit $150 per barrel, ACES subjected the captive investment (described above) to a tax rate that was one of the highest in the world, and nearly six times that of what was in place just three years prior. This could hardly have been foreseen in any business plan. It may be difficult to see how much new oil investment, much less a major natural gas pipeline, could happen in such an environment.

ALASKA STATE LEGISLATURE

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Senate Resources Committee

Butrovich Room 205

Wednesday, February 6, 2013

3:30-6:00 p.m.

AGENDA

- **The Alberta Experience**

  Mr. Mel Knight

  Testimony: By Invitation

- **PFC Energy – Capital Allocation and Global Portfolio Review**

  Tony Reinsch, Senior Director, Upstream

  Testimony: By Invitation

- **5:15 BPH/S**
  - **SB 27 Regulation of Dredge and Fill Activities**
  - **SB 26 Public Testimony** - Time limit

Teleconference

Project Committee Final Technical Report

on Alberta's Natural Gas & Conventional Oil Investment Competitiveness

to the Alberta Department of Energy

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Date: February 16, 2010

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

This is the report of the project committee assembled by Alberta Department of Energy to undertake a review of Alberta's competiveness for investment in the natural gas and conventional oil industry[1]. The review included technical analysis led by the Alberta Department of Energy and supported by consultants' reports. The project committee consulted with industry and financial sector executives to gain insight on the factors influencing investment decisions. Alberta's natural gas and conventional oil industry competes for investment capital that moves to where investors believe the best opportunities exist.

Alberta's energy resources are the basis for the largest industry in the province and the largest single source of government revenue. Energy companies develop Alberta's energy resources by investing in exploration and production projects that create economic activity and jobs and generate government revenues (through royalties, land sales, taxes). Governments are an important part of helping to attract that investment.

Government policies influence investment decisions. Investment competitiveness is based in part on the royalty system, but the project committee found that other important factors influenced investment in Alberta's resources. These factors include: the regulatory system; support for innovation and technology; and the business climate. The business climate encompasses the quality of the partnership of citizens and government with investors and entrepreneurs. The Natural Gas and Conventional Oil Investment Competitiveness Study found that all of these factors have an impact on Alberta's ability to attract investment.

Changes in the Business

Alberta's natural gas resource faces strong competition from significant new supplies located much closer to the large markets in Eastern Canada and the United States (U.S.). Large supplies have also been found in Northeastern British Columbia (B.C.) where Alberta-based companies have been attracted by resource opportunities and active B.C. government support for the industry. In this environment of abundant supply, the price of natural gas has been, and is expected to continue to be significantly reduced from previous highs of $10.00 to 12.00 per thousand cubic feet (Mcf). To compete for investment Alberta needs to enable natural gas producers to operate amidst a drastically altered economic environment of limited markets, higher costs and lower natural gas prices.

The challenges facing the conventional oil sector have emerged over time. Alberta's declining conventional oil resources are more difficult and expensive to extract. Significant oil still remains in the ground and there will continue to be huge demand for oil as conventional oil fields elsewhere are diminishing. Exploiting Alberta's remaining oil resources will require more expensive and innovative approaches.

[1] In this report the term 'industry' or 'energy industry' refers to private sector oil and gas companies and the financial companies that are a source of investment capital. The term 'sector' will be used when referring to natural gas and conventional oil independently, for example 'the natural gas sector'.

The significant changes in the natural gas and conventional oil business are features that are not going to disappear as the global economy recovers. In the competition for investment Alberta needs to ensure that fiscal, regulatory and policy conditions encourage investment in the oil and gas industry to ensure growing and sustainable production contributing to the provincial economy.

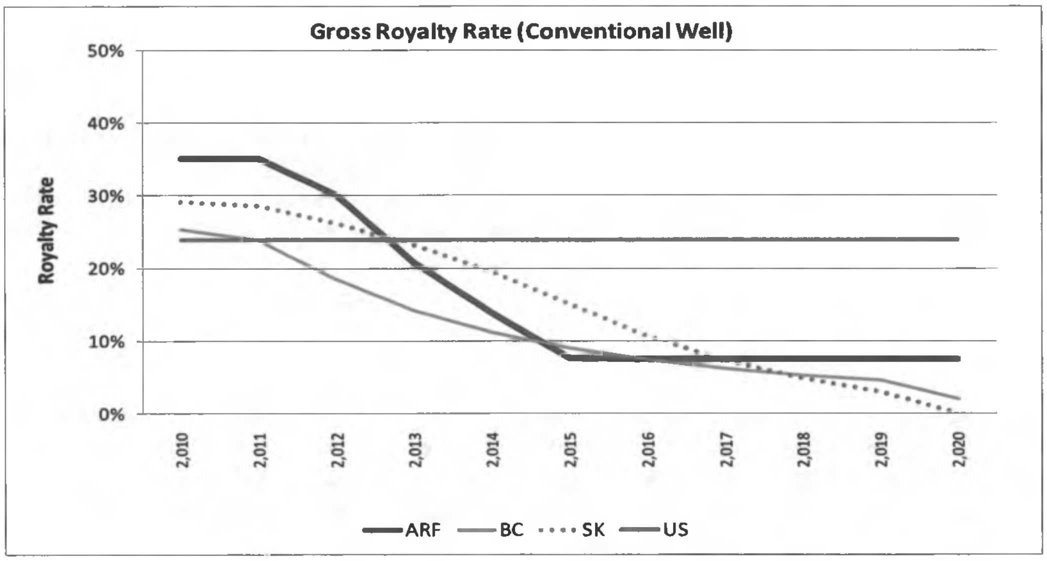
Alberta's Impact on Investment Decisions

Royalties

Companies and their investors compare royalties and taxes of various jurisdictions as they assess investment opportunities in the energy sector. An effective mechanism to mitigate investment risk is to recover spent capital as soon as possible. This is particularly important in the oil and gas business given the rapid decline in initial well productivity and the volatility of commodity prices. Alberta's royalty charges are higher in the early days of production than those of competing jurisdictions of British Columbia, Saskatchewan and United States. Alberta's higher "front-end" royalties makes investment less attractive and it delays the reinvestment of recovered capital.

The following chart illustrates that the Alberta Royalty Framework (ARF) has a higher royalty rate at the "front-end" then other jurisdictions for a typical conventional natural gas well.

Illustration of Royalty Rates – Natural Gas (Conventional Well at $6.00/GJ)
Source: Alberta Department of Energy



When a company is fortunate enough to get high production from a well at a time when prices are high there is an opportunity for significant revenue. In periods of high prices Alberta's maximum royalty rate is higher than in any competing North American jurisdiction. At the "high end" the

Alberta system can charge a 50% royalty which is considerably more than the 31% that the next highest jurisdiction charges. Investments in high producing wells during high price periods yield returns that help to offset losses suffered from unproductive and unsuccessful wells. When too much of the upside is taken in royalties the economic and financial risk of the industry increases making investments less attractive.

The following table illustrates that the Alberta Royalty Framework (ARF) has a maximum royalty rate that is higher in high price periods than other jurisdictions for a typical conventional natural gas well.

Comparison of Maximum Natural Gas Royalties in Different Price Scenarios
Source: Alberta Department of Energy

Jurisdictions	Maximum Natural Gas Royalty Rates	
	$6.00/Mcf	*$8.00/Mcf*
ARF	35%	42%
SK	29%	31%
BC	25%	25%
US	24%	24%

Other Competitiveness Factors

The Investment Competitiveness Study included industry and financial sector consultation regarding competiveness factors. There was significant feedback on the royalty rates. There was also considerable feedback on the other factors that influence investment decisions and future success: regulatory, technology and government policy.

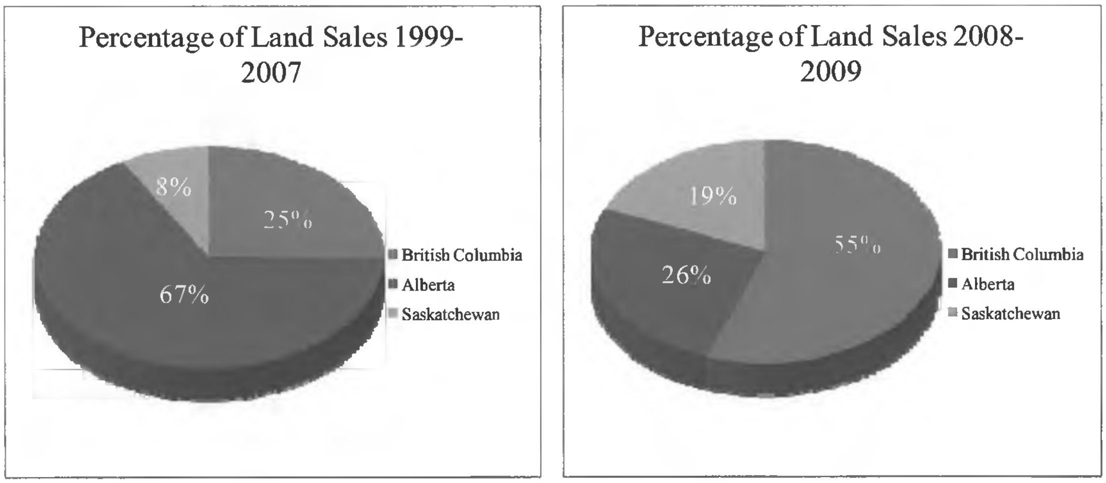
Alberta prides itself as a jurisdiction that enables significant oil and gas production in an environmentally sustainable manner. The impact of the regulatory process is a significant factor in making investment decisions. While not disputing the goals of the regulatory system, Alberta's industry and investors believe that Alberta's system has become cumbersome and costly compared to competing jurisdictions. Stakeholders suggested that other North American jurisdictions maintain high standards without the complex and costly application processes and operating requirements.

Stakeholders stated their belief that government and the people of Alberta are all in the oil and gas business. All parties in this partnership stand to gain from improving Alberta's investment competiveness and therefore all have a role to play in the improvement process and in understanding the importance of natural gas and conventional oil as an engine of Alberta's economy and the sustainable way in which these resources can be developed. Government is seen as having a leadership role in supporting the energy business and the innovation and entrepreneurship required.

The Case for Change

The loss of investment is already becoming evident. Alberta's natural gas and conventional oil is in an environment of reduced investor confidence. Land sales for oil and gas leases are an indicator of where companies intend to invest in the future. The chart below illustrates the shift away from Alberta to neighbouring provinces.

Percentage of Western Canada Land Sales (1999-2007 vs. 2008- 2009)
Source: Alberta Department of Energy - Province of British Columbia, Government of Saskatchewan



Improving Alberta's Competitiveness

If Alberta does not address the challenges of investment competitiveness a continued decline in investment will reduce the opportunities for Albertans to benefit from their resources. Solutions are needed to address the fiscal and regulatory issues. Government, the public and industry need to find ways to work more effectively to make Alberta a more competitive jurisdiction for oil and gas investment.

During the Investment Competitiveness Study principles were developed to guide development of recommendations for improved competitiveness. The principles are:

Partnership

- Alberta's resources are developed in a spirit of mutual trust, respect, and cooperation among industry, government and its citizens.

Equal Opportunity

- Alberta's resources are developed through open, transparent, and competitive markets.

Predictability

- Alberta's regulatory and fiscal policies promote confidence, predictability and stability.

Environment and Conservation

- Alberta's resources are developed in a manner that is consistent with good conservation practices and respect for the environment.

Knowledge and Innovation

- Alberta's resources are developed through practices that promote the advancement of technology;
- Alberta's resources are developed through practices that are based on a broad understanding of the opportunities and challenges faced by Alberta's oil and natural gas industry; and
- Sustainable and vibrant industry activity enables Alberta to be at the forefront of knowledge and innovation advances in the sector.

The following recommendations are provided as advice from the project committee to the government (Department of Energy). The recommendations are based on a common understanding of the business and incorporate the multiple factors that influence investment decisions.

Fiscal Regime

RECOMMENDATION 1:

Modify Alberta's royalty framework to address competitiveness and ensure industry activity in Alberta is sustainable and vibrant. The following design criteria should be considered when modifying the royalty framework for natural gas and conventional oil:

Ensure that the modifications consider the fiscal impact and align with the provincial energy strategy, economic policy and objectives;

Re-balance the royalty curves using current price and production variables so Alberta remains competitive with other jurisdictions;

Reduce front end royalties. This recognizes high upfront costs and returns capital to companies quicker resulting in increased investment;

Reduce royalties at higher price levels;

Develop a transition program from the current system which does not disadvantage current drilling activity; and

Enhance the simplicity of the royalty framework.

RECOMMENDATION 2:

Develop programs if necessary to support strategic initiatives focused on specific resources or technology.

RECOMMENDATION 3:

Continually monitor the fiscal regimes of competing North American jurisdictions to ensure that Alberta is an attractive place in which to invest and do business.

RECOMMENDATION 4:

Examine the broader fiscal regime, including taxes, in partnership with Alberta Finance and Enterprise, to ensure investment competitiveness.

Regulatory Framework

RECOMMENDATION 5:

Reduce the regulatory burden and costs by redesigning the regulatory regime to: eliminate duplicate processes; reduce unnecessary delays and costs; reduce unnecessary requirements; and ensure alignment across government to make the system more competitive.

RECOMMENDATION 6:

Set measureable objectives for the regulatory regime (e.g., costs, timelines, and regulatory standards) and benchmark against other jurisdictions in North America to support continued competitiveness.

RECOMMENDATION 7:

Improve the flexibility of the regulatory regime to address new technology and resource opportunities.

Technology and Innovation

RECOMMENDATION 8:

The government must continue to leverage its innovation system in partnership with industry, the research community and other partners, to pursue joint technology and innovation strategies encompassing:

The fiscal system;

The regulatory system;

Knowledge transfer;

Educational investments; and

Research funding.

RECOMMENDATION 9:

Enhance technology development and deployment that supports industry in addressing the environmental impacts of the oil and gas sectors, and encourage the use of natural gas, a more environmentally friendly fuel source.

Business Climate

Leadership and Partnerships

RECOMMENDATION 10:

As a major partner in the energy business government (coordinated by DOE) should demonstrate stronger leadership by:

- Ensuring connection and alignment within government's policy and strategy;

Advocating on behalf of industry with other governments;

Removing obstacles to achieve strategic goals;

Influencing demand and seeking new markets;

Promoting the understanding of environmental impacts; and

Encouraging technology development.

RECOMMENDATION 11:

Establish regular interactions between government and industry to share information, ideas and discuss issues that support responsible and proactive resource development. Suggestions for interactions include:

Joint advisory committees of oil and gas executives and members of the financial sector;

Cross sector secondments; and

Information and education sessions on industry issues (e.g. Shale Gas Symposium).

Communication and Education

RECOMMENDATION 12:

Ensure that government better articulates and shares the vision of the Provincial Energy Strategy with Albertans, and the contribution of oil and gas to our economy, business and environment.

RECOMMENDATION 13:

Develop a communications strategy on the importance of the oil and gas business to Albertans and government's role in promoting responsible energy development.

RECOMMENDATION 14:

Government should improve its efforts to communicate the policies and actions that Alberta is undertaking toward the development of cleaner energy sources and the potential of natural gas as a source of that clean energy.

Huge Alberta land sale sets fiscal year record of $2.66 billion

BY SHAUN POLCZER, CALGARY HERALD MARCH 23, 2011

Alberta's final land sale of the fiscal year was also the highest of 2011, bring the 12-month total to a record $2.66 billion.
Photograph by: From Merlin Archive

Provincial coffers swelled by another $200 million on Wednesday after the Alberta government hosted another record-breaking auction of oil and gas and oilsands rights that set a new high water mark for land sales in a fiscal year.

Oil and gas producers spent $189.19 million to buy 109,000 hectares of conventional mineral leases and drilling rights a an average price of $1,741 a hectare. A separate offering of oilsands leases added another $11 million to the total.

Two parcels near Fox Creek accounted for $135 million of the sale proceeds including a single parcel that fetched a record $97 million, making it one of the most expensive drilling licences ever sold in Alberta.

Scott Land and Lease placed the bid on behalf of anonymous buyers that paid more than $11,000 a hectare for the right to drill deep oil and gas wells on it.

Charter Land Services bought an adjacent parcel that went for $38 million or $8,225 a hectare.

Brad Hayes, the president of Petrel Robertson geological consultants, said producers are chasing what could be a new shale oil play in Alberta.

Hayes said the rights are so deep the bidder has to be targeting either Duvernay formation or one of the deeper pinnacle reef plays.

“My inclination is to think it’s the Duvernay because they’re covering such a big broad area. If it were one of the reef plays, they tend to be a bit more focused so that even though the oil in place is quite high, the reef itself doesn’t cover a big area like the Duvernay shales would.”

The shallower zones in the area have been highly explored, but deeper rights in many cases reverted to the Crown because they weren’t being drilled.

“There are a lot of deep rights available,” he said. “It’s below most of the other targets people play in that area. A lot of the formations that are higher up have been the real focus.”

He said the Duvernay shale is known for liquids rich natural gas but some producers think it could also hold oil. Oil prices rose to the highest level since September of 2008 on Wednesday, eclipsing $105 US a barrel.

It was the largest land sale of 2011 and the second-largest since an auction last July brought in $452 million. A similar sale two weeks ago brought in $160 million to push the total for the fiscal year that ends March 31 to $2.66 billion, which Energy ministry representatives said is a record for conventional oil and gas rights in the province.

Department spokesman Jay O’Neill said the high sale numbers are partly a reflection of changes introduced last year to improve the oil and gas industry’s competitiveness, but also a recognition of Alberta’s prospectivity and exploration potential. Land sale numbers tend to move higher in tandem with oil prices and are considered a leading indicator of future industry activity.

“I think it’s partly industry recognizing that Alberta is the place to be again,” he said. “But there has to be something there, industry is obviously confident there’s something worth investing in to spend those kind of dollars.”

With files from Dan Healing

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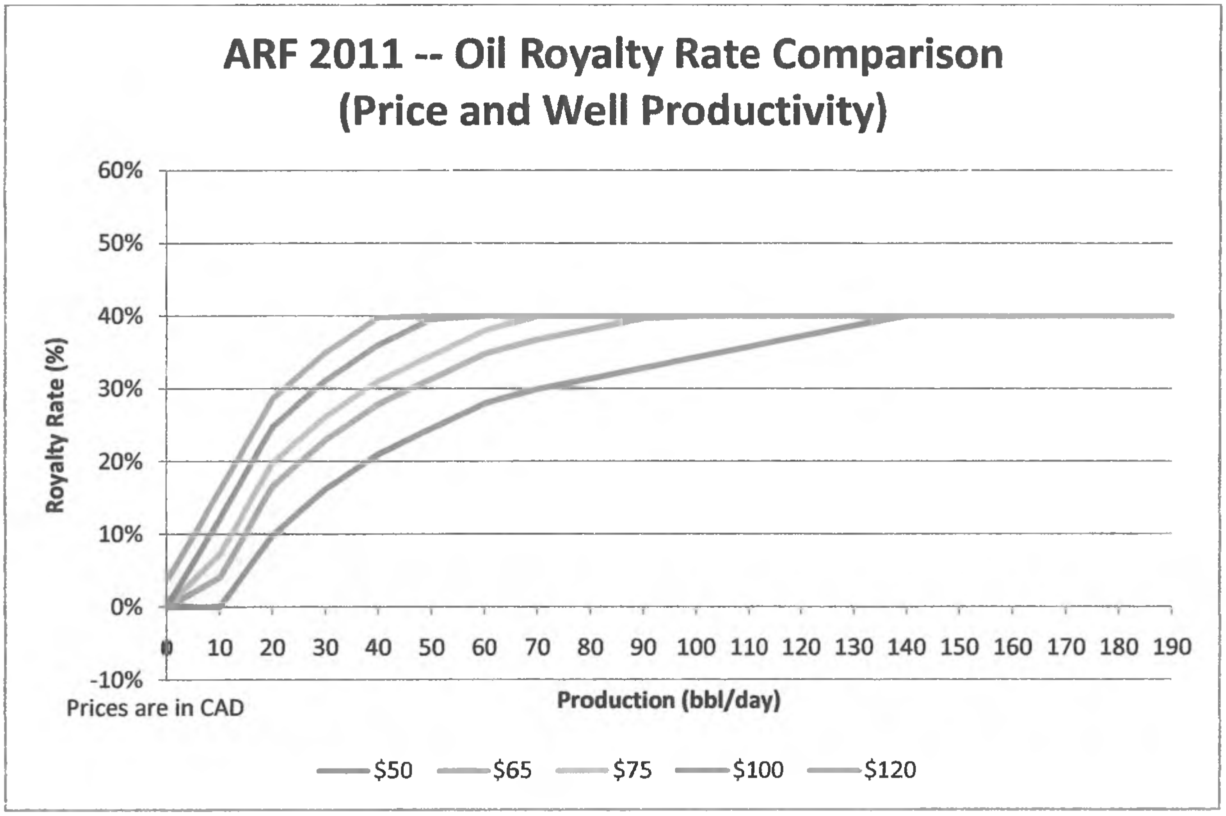
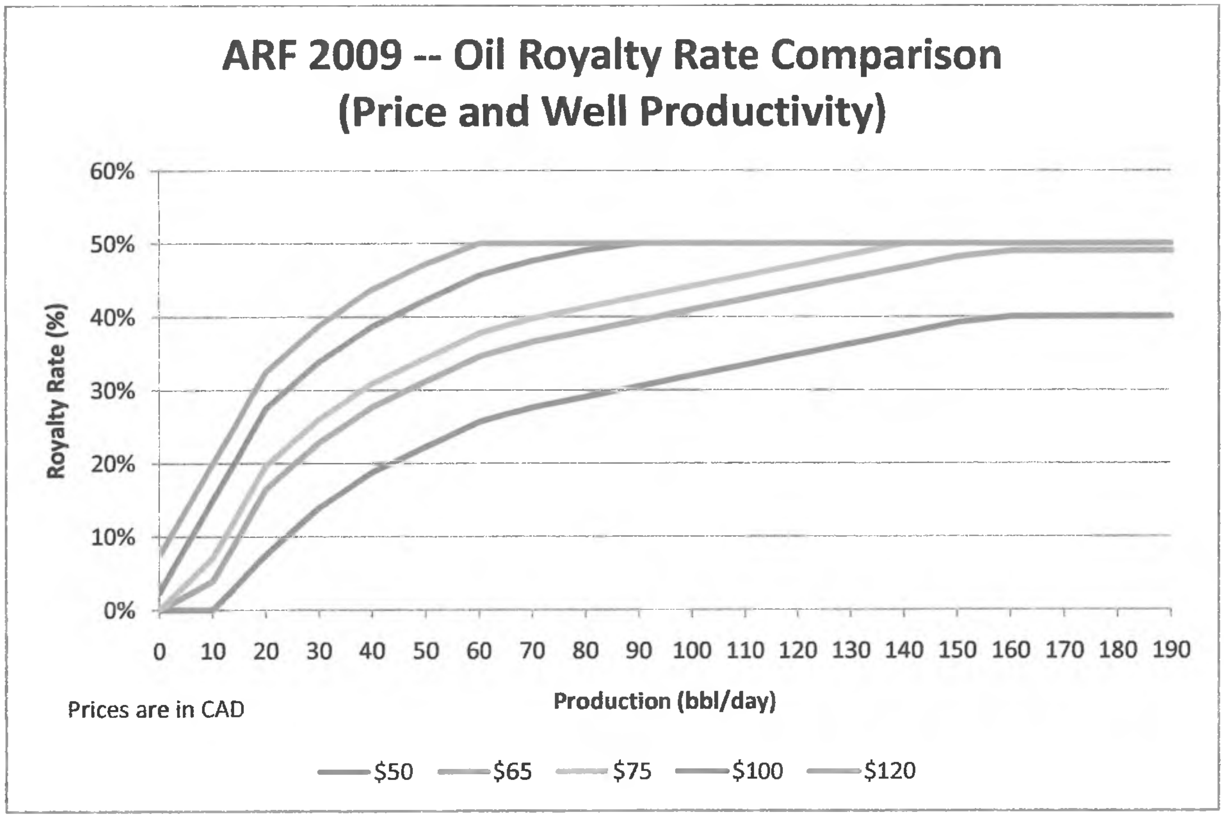
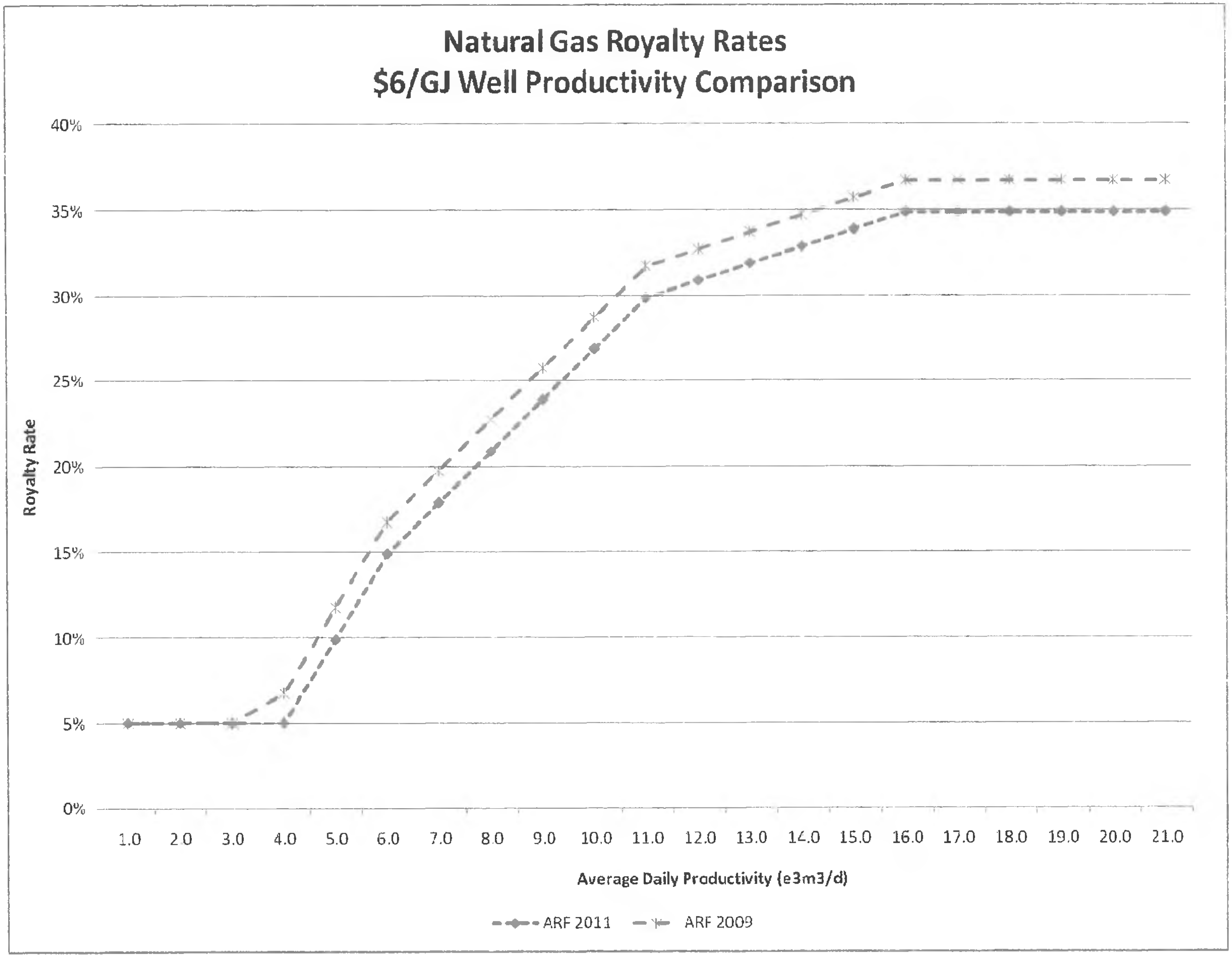
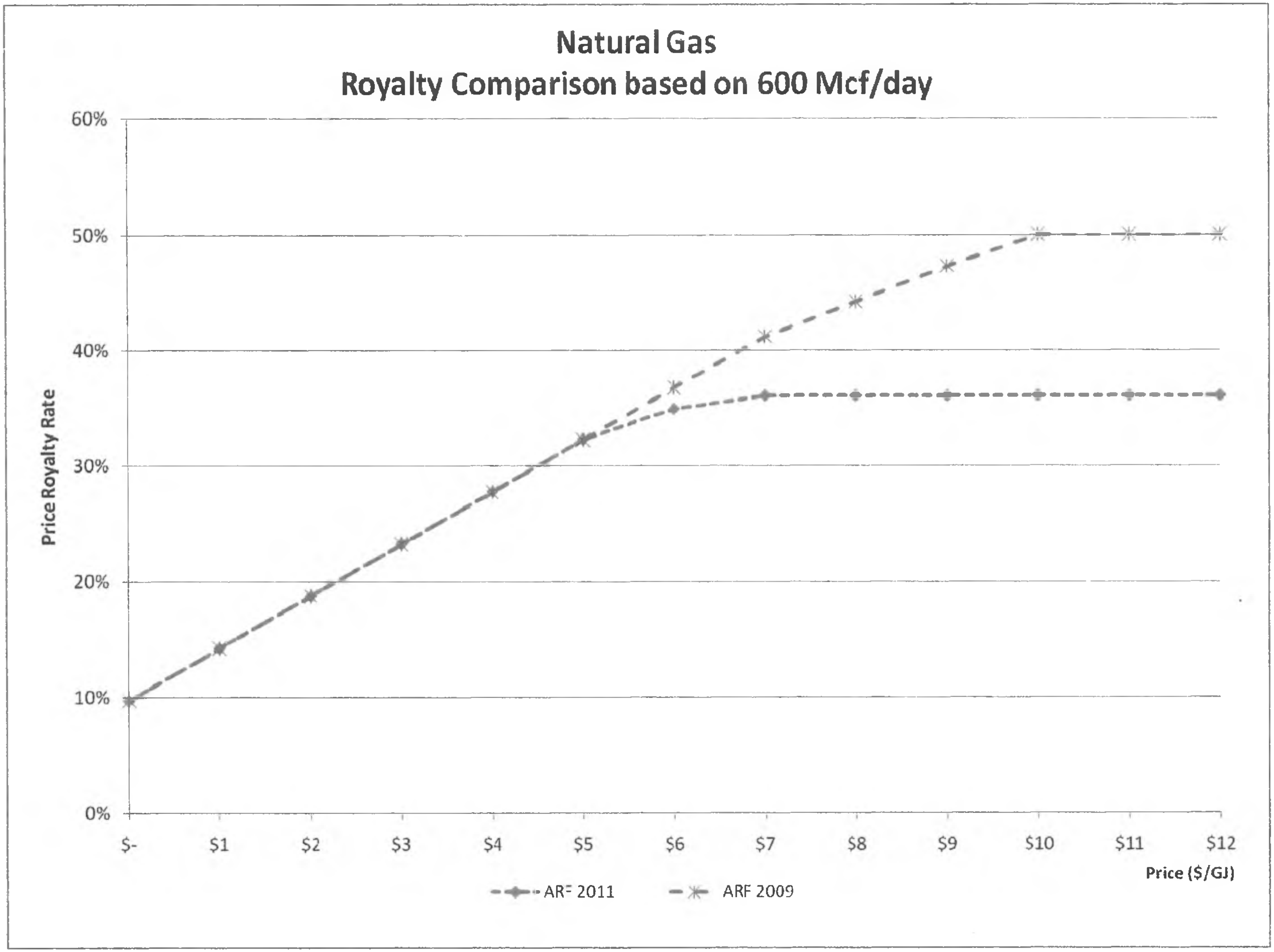

ARF 2011 -- Oil Royalty Rate Comparison
(Price and Well Productivity)
60%
50%
40%
30%
20%
10%
0%
-10%
Royalty Rate (%)
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
190
Production (bbl/day)
Prices are in CAD
$50
$65
$75
$100
$120


ARF 2009 -- Oil Royalty Rate Comparison
(Price and Well Productivity)
60%
50%
40%
30%
20%
10%
0%
Royalty Rate (%)
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
190
Production (bbl/day)
Prices are in CAD
$50
$65
$75
$100
$120


Natural Gas Royalty Rates
$6/GJ Well Productivity Comparison
40%
35%
30%
25%
20%
15%
10%
5%
0%
Royalty Rate
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
10.0
11.0
12.0
13.0
14.0
15.0
16.0
17.0
18.0
19.0
20.0
21.0
Average Daily Productivity (e3m3/d)
ARF 2011
ARF 2009


Natural Gas
Royalty Comparison based on 600 Mcf/day
60%
50%
40%
30%
20%
10%
0%
Price Royalty Rate
$-
$1
$2
$3
$4
$5
$6
$7
$8
$9
$10
$11
$12
Price ($/GJ)
ARF 2011
ARF 2009

Royalty Formulas – Conventional Oil
Effective January 1, 2011

R% = Price Component (r_p) + Quantity Component (r_q)
ARF (2011): R% has a minimum of 0% and a maximum of 40%
Transition: R% has a minimum of 0% and a maximum of 50%

Royalty Parameters				
	Price ($\$/m^3$)		**% Change ($\%/\$/m^3$)**	
	ARF (2011)	Transition Wells	ARF (2011)	Transition Wells
P_1	190.00	210.00	0.06%	0.035%
P_2	250.00	250.00	0.10%	0.01%
P_3	400.00	350.00	0.05%	0.005%
P_4	535.00	--	0.03%	--
	Q (m^3/month)		**% Change ($\%/m^3$/month)**	
	ARF (2011)	Transition Wells	ARF (2011)	Transition Wells
Q_1	106.4	30.4	0.26%, 0.10%	0.13%
Q_2	197.6	152.0	0.07%	0.08%
Q_3	304.0	273.6	0.03%	0.02%

Price Component (r_p)			
Alberta Royalty Framework (2011)		**Transition Wells**	
Price ($\$/m^3$)	**r_p**	**Price ($\$/m^3$)**	**r_p Transition Wells**
PP ≤ 250.00	((PP – 190.00) * 0.0006)*100	PP ≤ 250.00	((PP – 210.00) * 0.00035)*100
250.00 < PP ≤ 400.00	(((PP – 250.00) * 0.0010) + 0.0360)*100	250.00 < PP ≤ 350.00	(((PP – 250.00) * 0.00010) + 0.0140)*100
400.00 < PP ≤ 535.00	(((PP – 400.00) * 0.0005) + 0.1860)*100	PP > 350.00	(((PP – 350.00) * 0.00005) + 0.0240)*100
PP > 535.00	(((PP – 535.00) * 0.0003) + 0.2535)*100	--	--
Maximum	35%	Maximum	35%
PP is the par price for the month in $\$/m^3$			
Note: r_p can be negative			

Quantity Component (r_q)			
Alberta Royalty Framework (2011)		**Transition Wells**	
Quantity (m^3/month)	**r_q**	**Quantity (m^3/month)**	**r_q Transition Wells**
Q ≤ 106.4	((Q – 106.4) * 0.0026)*100	Q ≤ 30.4	((Q – 30.4) * 0.0013)*100
106.4 < Q ≤ 197.6	((Q – 106.4) * 0.0010)*100	30.4 < Q ≤ 152.0	((Q – 30.4) * 0.0013)*100
197.6 < Q ≤ 304.0	(((Q – 197.6) * 0.0007) + 0.0912)*100	152.0 < Q ≤ 273.6	(((Q – 152.0) * 0.0008) + 0.1581)*100
Q > 304.0	(((Q – 304.0) * 0.0003) + 0.1657)*100	Q > 273.6	(((Q – 273.6) * 0.0002) + 0.2554)*100
Maximum	30%	Maximum	35%
Q is the monthly production in m^3			
Note: r_q can be negative			

Examples

Price ($/m3)	Quantity (m3/month)	ARF (2011)			Transition Wells		
		r_p	r_q	R%	r_p	r_q	R%
400.00	50.0	18.60%	-14.66%	3.94%	2.65%	2.55%	5.20%
400.00	200.0	18.60%	9.29%	27.89%	2.65%	19.65%	22.30%
600.00	50.0	27.30%	-14.66%	12.64%	3.65%	2.55%	6.20%
600.00	200.0	27.30%	9.29%	36.59%	3.65%	19.65%	23.30%

Alberta Royalty Framework: Formulas – Natural Gas
Effective January 1, 2011

R% = Price Component (r_p) + Quantity Component (r_q)
R% has a minimum of 5% and a maximum of 36%
For Transition Wells* R% has a minimum of 5% and a maximum of 30%

Royalty Parameters				
	Price ($/GJ)		**%Change (%/$/GJ)**	
	ARF (2011)	Transition Wells	ARF (2011)	Transition Wells
P_1	4.50	2.00	4.5%	3.5%
P_2	5.25	3.25	2%	0.5%
P_3	9.00	5.00	1%	0%
	Q ($10^3m^3/d$)		**% Change ($\%/10^3m^3/GJ$)**	
	ARF (2011)	Transition Wells	ARF (2011)	Transition Wells
Q_1	4	2	5%	5%
Q_2	6	4	3%	2%
Q_3	11	9	1%	1%

Price Component (r_p)			
Alberta Royalty Framework (2011)		**Transition Wells**	
Price ($/GJ)	**r_p**	**Price ($/GJ)**	**$r_{p\ Transition\ Wells}$**
PP ≤ 5.25	((PP – 4.50) * 0.0450)*100	PP ≤ 3.25	((PP – 2.00) * 0.0350)*100
5.25 < PP ≤ 9.00	((PP – 5.25) * 0.0200 + 0.03375)*100	3.25 < PP ≤ 5.00	((PP – 3.25) * 0.0050 + 0.0437)*100
PP > 9.00	((PP – 9.00) * 0.0100 + 0.10875)*100	PP > 5.00	((PP – 5.00) * 0.0000 + 0.0525)*100
Maximum	30%	Maximum	5.25%
PP is the par price for the month in $/GJ			
Note: r_p can be negative			

Quantity Component (r_q)			
Alberta Royalty Framework (2011)		**Transition Wells**	
Quantity ($10^3m^3/d$)	**r_q**	**Quantity ($10^3m^3/d$)**	**$r_{q\ Transition\ Wells}$**
ADP ≤ (6*DF)	([ADP - (4*DF)]*(0.0500/DF))*100	ADP ≤ 4	([ADP - 2]*0.0500)*100
(6*DF) < ADP ≤ (11*DF)	([ADP - (6*DF)]*(0.0300/DF) + 0.1000)*100	4 < ADP ≤ 9	([ADP - 4]*0.0200 + 0.1000)*100
ADP > (11*DF)	([ADP – (11*DF)]*(0.0100/DF) + 0.2500)*100	ADP > 9	([ADP – 9]*0.0100 + 0.2000)*100
Maximum	30%		25%
PP is the par price for the month in $/GJ			
Note: r_q can be negative			
DF is a depth factor that applies only to the quantity component and is based on the measured depth (MD) of a well where: DF = 1 for all transition wells and for MD ≤ 2000 m; DF = $(MD/2000)^2$ for MD > 2000 m; and, The depth factor is capped at 4.			

Illustration of Depth Factor Adjustment			
MD	**DF**	**Quantity**	**r_q**
$\leq$ 2000 m	1.0000	ADP $\leq$ 6 $10^3m^3/d$	(ADP – 4) * 0.0500
		6 $10^3m^3/d$ <ADP $\leq$ 11 $10^3m^3/d$	(ADP – 6) * 0.0300 + 0.1000
		ADP >11 $10^3m^3/d$	(ADP-11)*0.0100 + 0.2500
		Maximum	30%
2500 m	1.5625	ADP $\leq$ 9.3750 $10^3m^3/d$	(ADP-6.25)*0.032
		9.3750 $10^3m^3/d$ < ADP $\leq$ 17.1875 $10^3m^3/d$	(ADP-9.3750)*0.0192 + 0.1000
		ADP >17.1875 $10^3m^3/d$	(ADP-17.1875)*0.0064 + 0.2500
		Maximum	30%
3000 m	2.2500	ADP $\leq$ 13.5 $10^3m^3/d$	(ADP-9)*0.0222
		13.5 $10^3m^3/d$ < ADP $\leq$ 24.75 $10^3m^3/d$	(ADP-13.5)*0.0133 + 0.1000
		ADP > 24.75 $10^3m^3/d$	(ADP - 24.75)*0.0044 + 0.2500
		Maximum	30%
3500 m	3.0625	ADP $\leq$ 18.375 $10^3m^3/d$	(ADP-12.25)*0.0163
		18.375 $10^3m^3/d$ <ADP $\leq$ 33.6875 $10^3m^3/d$	(ADP-18.3750)*0.0098+ 0.1000
		ADP >33.6875 $10^3m^3/d$	(ADP-33.6875)*0.0033 + 0.2500
		Maximum	30%
$\geq$ 4000 m	4.000	ADP $\leq$ 24 $10^3m^3/d$	(ADP-16)*0.0125
		24 $10^3m^3/d$ <ADP $\leq$ 44 $10^3m^3/d$	(ADP-24)*0.0075 + 0.1000
		ADP >44 $10^3m^3/d$	(ADP-44)*0.0025 + 0.2500
		Maximum	30%

Conventional Oil -- ARF (effective Jan 1, 2009)

Quantity		Price $/m3	$ 126	$ 157	$ 189	$ 220	$ 252	$ 283	$ 315	$ 346	$ 378	$ 409	$ 441	$ 472	$ 503	$ 535	$ 566	$ 598	$ 629	$ 661	$ 692	$ 724	$ 755	$ 787	$ 818	$ 850	$ 881
		$/bbl	$ 20	$ 25	$ 30	$ 35	$ 40	$ 45	$ 50	$ 55	$ 60	$ 65	$ 70	$ 75	$ 80	$ 85	$ 90	$ 95	$ 100	$ 105	$ 110	$ 115	$ 120	$ 125	$ 130	$ 135	$ 140
		Price Rate	-4%	-2%	0%	2%	4%	7%	10%	13%	16%	19%	21%	22%	24%	25%	27%	28%	30%	32%	33%	35%	35%	35%	35%	35%	35%
m3/month	bbl/d	Quantity Rate	Combined Royalty Rate																								
0	0	-28%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	6%	7%	7%	7%	7%	7%	7%
5	1	-26%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	7%	8%	9%	9%	9%	9%	9%
10	2	-25%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	5%	6%	8%	10%	10%	10%	10%	10%	10%
15	3	-24%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	5%	6%	8%	9%	11%	11%	11%	11%	11%	11%
19	4	-23%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	4%	6%	7%	9%	11%	12%	12%	12%	12%	12%	12%
24	5	-21%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	6%	7%	9%	10%	12%	13%	14%	14%	14%	14%	14%
48	10	-15%	0%	0%	0%	0%	0%	0%	0%	0%	1%	4%	6%	7%	9%	10%	12%	13%	15%	17%	18%	20%	20%	20%	20%	20%	20%
73	15	-9%	0%	0%	0%	0%	0%	0%	1%	4%	8%	10%	12%	13%	15%	17%	18%	20%	21%	23%	24%	26%	26%	26%	26%	26%	26%
97	20	-3%	0%	0%	0%	0%	1%	4%	8%	11%	14%	17%	18%	20%	21%	23%	24%	26%	28%	29%	31%	32%	32%	32%	32%	32%	32%
121	25	1%	0%	0%	1%	3%	5%	8%	12%	15%	18%	20%	22%	24%	25%	27%	28%	30%	32%	33%	35%	36%	36%	36%	36%	36%	36%
145	30	4%	0%	2%	4%	6%	8%	11%	14%	17%	20%	23%	24%	26%	28%	29%	31%	32%	34%	35%	37%	39%	39%	39%	39%	39%	39%
169	35	6%	2%	4%	6%	8%	10%	13%	16%	19%	23%	25%	27%	28%	30%	32%	33%	35%	36%	38%	39%	41%	41%	41%	41%	41%	41%
193	40	9%	5%	7%	9%	11%	12%	16%	19%	22%	25%	28%	28%	31%	32%	34%	36%	37%	38%	40%	42%	43%	44%	44%	44%	44%	44%
218	45	11%	7%	9%	10%	12%	14%	17%	21%	24%	27%	30%	31%	33%	34%	36%	37%	39%	41%	42%	44%	45%	46%	46%	46%	46%	46%
242	50	12%	8%	10%	12%	14%	16%	19%	22%	25%	29%	31%	33%	34%	36%	38%	39%	41%	42%	44%	45%	47%	47%	47%	47%	47%	47%
266	55	14%	10%	12%	14%	16%	18%	21%	24%	27%	30%	33%	35%	36%	38%	39%	41%	42%	44%	46%	47%	49%	49%	49%	49%	49%	49%
290	60	16%	12%	14%	16%	17%	19%	23%	26%	29%	32%	35%	36%	38%	39%	41%	43%	44%	46%	47%	49%	50%	50%	50%	50%	50%	50%
314	65	17%	13%	15%	17%	19%	21%	24%	27%	30%	33%	36%	37%	39%	41%	42%	44%	45%	47%	49%	50%	50%	50%	50%	50%	50%	50%
338	70	18%	14%	16%	18%	19%	21%	25%	28%	31%	34%	37%	38%	40%	41%	43%	45%	46%	48%	49%	50%	50%	50%	50%	50%	50%	50%
363	75	18%	14%	16%	18%	20%	22%	25%	28%	32%	35%	37%	39%	41%	42%	44%	45%	47%	48%	50%	50%	50%	50%	50%	50%	50%	50%
387	80	19%	15%	17%	19%	21%	23%	26%	29%	32%	35%	38%	40%	41%	43%	44%	46%	48%	49%	50%	50%	50%	50%	50%	50%	50%	50%
411	85	20%	16%	18%	20%	22%	24%	27%	30%	33%	36%	39%	40%	42%	44%	45%	47%	48%	50%	50%	50%	50%	50%	50%	50%	50%	50%
435	90	20%	17%	19%	20%	22%	24%	27%	31%	34%	37%	40%	41%	43%	44%	46%	47%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%
459	95	21%	17%	19%	21%	23%	25%	28%	31%	34%	38%	40%	42%	43%	45%	47%	48%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
483	100	22%	18%	20%	22%	24%	26%	29%	32%	35%	38%	41%	43%	44%	46%	47%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
508	105	23%	19%	21%	23%	24%	26%	30%	33%	36%	39%	42%	43%	45%	46%	48%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
532	110	23%	20%	21%	23%	25%	27%	30%	33%	37%	40%	42%	44%	46%	47%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
556	115	24%	20%	22%	24%	26%	28%	31%	34%	37%	40%	43%	45%	46%	48%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
580	120	25%	21%	23%	25%	27%	29%	32%	35%	38%	41%	44%	45%	47%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
604	125	26%	22%	24%	26%	27%	29%	32%	36%	39%	42%	45%	46%	48%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
628	130	26%	22%	24%	26%	28%	30%	33%	36%	40%	43%	45%	47%	48%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
653	135	27%	23%	25%	27%	29%	31%	34%	37%	40%	43%	46%	48%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
677	140	28%	24%	26%	28%	30%	32%	35%	38%	41%	44%	47%	48%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
701	145	28%	25%	27%	28%	30%	32%	35%	39%	42%	45%	48%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
725	150	29%	25%	27%	29%	31%	33%	36%	39%	42%	46%	48%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
749	155	30%	26%	28%	30%	32%	34%	37%	40%	43%	46%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
773	160	30%	26%	28%	30%	32%	34%	37%	40%	43%	46%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
798	165	30%	26%	28%	30%	32%	34%	37%	40%	43%	46%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
822	170	30%	26%	28%	30%	32%	34%	37%	40%	43%	46%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
846	175	30%	26%	28%	30%	32%	34%	37%	40%	43%	46%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
870	180	30%	26%	28%	30%	32%	34%	37%	40%	43%	46%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
894	185	30%	26%	28%	30%	32%	34%	37%	40%	43%	46%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
918	190	30%	26%	28%	30%	32%	34%	37%	40%	43%	46%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
943	195	30%	26%	28%	30%	32%	34%	37%	40%	43%	46%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
967	200	30%	26%	28%	30%	32%	34%	37%	40%	43%	46%	49%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%

Conventional Oil -- ARF (effective Jan 1, 2011)

		Price	$/m3	$ 126	$ 157	$ 189	$ 220	$ 252	$ 283	$ 315	$ 346	$ 378	$ 409	$ 441	$ 472	$ 503	$ 535	$ 566	$ 598	$ 629	$ 661	$ 692	$ 724	$ 755	$ 787	$ 818	$ 850	$ 881
			$/bbl	$ 20	$ 25	$ 30	$ 35	$ 40	$ 45	$ 50	$ 55	$ 60	$ 65	$ 70	$ 75	$ 80	$ 85	$ 90	$ 95	$ 100	$ 105	$ 110	$ 115	$ 120	$ 125	$ 130	$ 135	$ 140
Quantity			Price Rate	-4%	-2%	0%	2%	4%	7%	10%	13%	16%	19%	21%	22%	24%	25%	26%	27%	28%	29%	30%	31%	32%	33%	34%	35%	35%
m3/month	bbl/d	Quantity Rate	Combined Royalty Rate	Combined Royalty Rate																								
0	0	-28%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	2%	3%	4%	5%	6%	7%	7%
5	1	-26%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	5%	6%	6%	7%	8%	9%
10	2	-25%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	10%
15	3	-24%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	11%	11%
19	4	-23%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	4%	5%	6%	6%	7%	8%	9%	10%	11%	12%	12%
24	5	-21%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	6%	7%	8%	9%	10%	11%	12%	12%	13%	14%
48	10	-15%		0%	0%	0%	0%	0%	0%	0%	0%	1%	4%	6%	7%	9%	10%	11%	12%	13%	14%	15%	16%	17%	18%	19%	20%	20%
73	15	-9%		0%	0%	0%	0%	0%	0%	1%	4%	8%	10%	12%	13%	15%	17%	17%	18%	19%	20%	21%	22%	23%	24%	25%	26%	26%
97	20	-3%		0%	0%	0%	0%	1%	4%	8%	11%	14%	17%	18%	20%	21%	23%	24%	25%	26%	27%	28%	28%	29%	30%	31%	32%	32%
121	25	1%		0%	0%	1%	3%	5%	8%	12%	15%	18%	20%	22%	24%	25%	27%	28%	29%	30%	31%	32%	32%	33%	34%	35%	36%	36%
145	30	4%		0%	2%	4%	6%	8%	11%	14%	17%	20%	23%	24%	26%	28%	29%	30%	31%	32%	33%	34%	35%	36%	37%	38%	39%	39%
169	35	6%		2%	4%	6%	8%	10%	13%	16%	19%	23%	25%	27%	28%	30%	32%	33%	34%	34%	35%	36%	37%	38%	39%	40%	40%	40%
193	40	9%		5%	7%	9%	11%	12%	16%	19%	22%	25%	28%	29%	31%	32%	34%	35%	36%	37%	38%	39%	40%	40%	40%	40%	40%	40%
218	45	11%		7%	9%	10%	12%	14%	17%	21%	24%	27%	30%	31%	33%	34%	36%	37%	38%	39%	40%	40%	40%	40%	40%	40%	40%	40%
242	50	12%		8%	10%	12%	14%	16%	19%	22%	25%	29%	31%	33%	34%	36%	38%	38%	39%	40%	40%	40%	40%	40%	40%	40%	40%	40%
266	55	14%		10%	12%	14%	16%	18%	21%	24%	27%	30%	33%	35%	36%	38%	39%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
290	60	16%		12%	14%	16%	17%	19%	23%	26%	29%	32%	35%	36%	38%	39%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
314	65	17%		13%	15%	17%	19%	21%	24%	27%	30%	33%	36%	37%	39%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
338	70	18%		14%	16%	18%	19%	21%	25%	28%	31%	34%	37%	38%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
363	75	18%		14%	16%	18%	20%	22%	25%	28%	32%	35%	37%	39%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
387	80	19%		15%	17%	19%	21%	23%	26%	29%	32%	35%	38%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
411	85	20%		16%	18%	20%	22%	24%	27%	30%	33%	36%	39%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
435	90	20%		17%	19%	20%	22%	24%	27%	31%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
459	95	21%		17%	19%	21%	23%	25%	28%	31%	34%	38%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
483	100	22%		18%	20%	22%	24%	26%	29%	32%	35%	38%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
508	105	23%		19%	21%	23%	24%	26%	30%	33%	36%	39%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
532	110	23%		20%	21%	23%	25%	27%	30%	33%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
556	115	24%		20%	22%	24%	26%	28%	31%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
580	120	25%		21%	23%	25%	27%	29%	32%	35%	38%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
604	125	26%		22%	24%	26%	27%	29%	32%	36%	39%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
628	130	26%		22%	24%	26%	28%	30%	33%	36%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
653	135	27%		23%	25%	27%	29%	31%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
677	140	28%		24%	26%	28%	30%	32%	35%	38%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
701	145	28%		25%	27%	28%	30%	32%	35%	39%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
725	150	29%		25%	27%	29%	31%	33%	36%	39%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
749	155	30%		26%	28%	30%	32%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
773	160	30%		26%	28%	30%	32%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
798	165	30%		26%	28%	30%	32%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
822	170	30%		26%	28%	30%	32%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
846	175	30%		26%	28%	30%	32%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
870	180	30%		26%	28%	30%	32%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
894	185	30%		26%	28%	30%	32%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
918	190	30%		26%	28%	30%	32%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
943	195	30%		26%	28%	30%	32%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
967	200	30%		26%	28%	30%	32%	34%	37%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%

Natural Gas- ARF (effective January 1, 2011)

		Price	$/GJ	$ 0.50	$ 1.00	$ 1.50	$ 2.00	$ 2.50	$ 3.00	$ 3.50	$ 4.00	$ 4.50	$ 5.00	$ 5.50	$ 6.00	$ 6.50	$ 7.00	$ 7.50	$ 8.00	$ 8.50	$ 9.00	$ 9.50	$ 10.00	$ 10.50	$ 11.00	$ 11.50	$ 12.00	$ 12.50	$ 13.00	$ 13.50	$ 14.00	$ 14.50	$ 15.00
			$/Mcf	$ 0.53	$ 1.06	$ 1.58	$ 2.11	$ 2.64	$ 3.17	$ 3.69	$ 4.22	$ 4.75	$ 5.28	$ 5.80	$ 6.33	$ 6.86	$ 7.39	$ 7.91	$ 8.44	$ 8.97	$ 9.50	$ 10.02	$ 10.55	$ 11.08	$ 11.61	$ 12.13	$ 12.66	$ 13.19	$ 13.72	$ 14.24	$ 14.77	$ 15.30	$ 15.83
Quantity			Price Rate	-18%	-16%	-14%	-11%	-9%	-7%	-5%	-2%	0%	2%	4%	5%	6%	7%	8%	9%	10%	11%	11%	12%	12%	13%	13%	14%	14%	15%	15%	16%	16%	17%
$e3m^3/d$	Mcf/d	Quantity Rate	Combined Royalty Rate	Combined Royalty Rate																													
0	0	-20%		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
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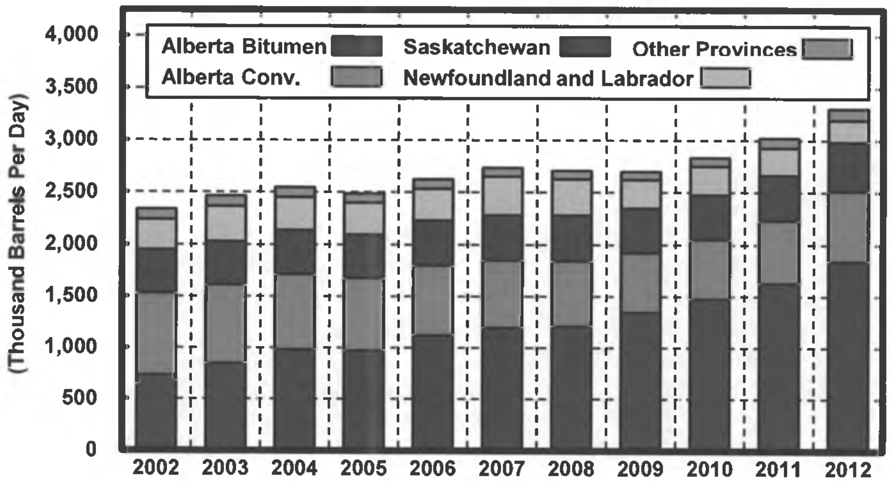
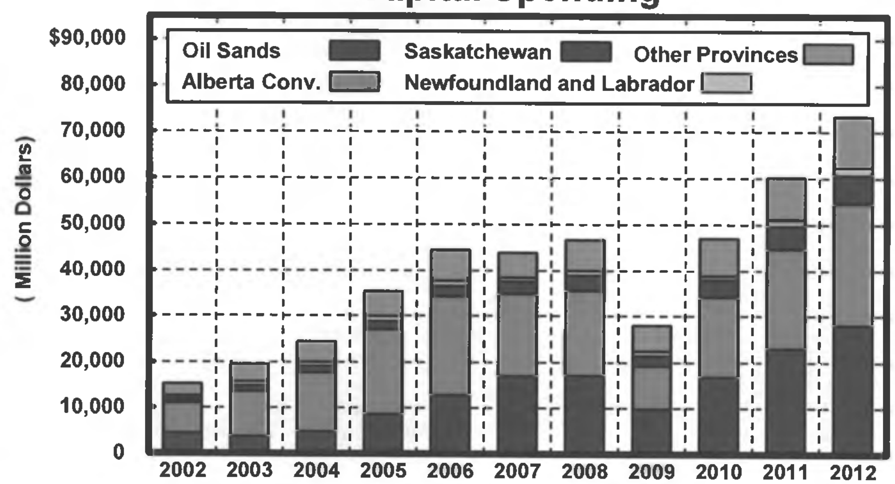
Country/Area Profile
Canada

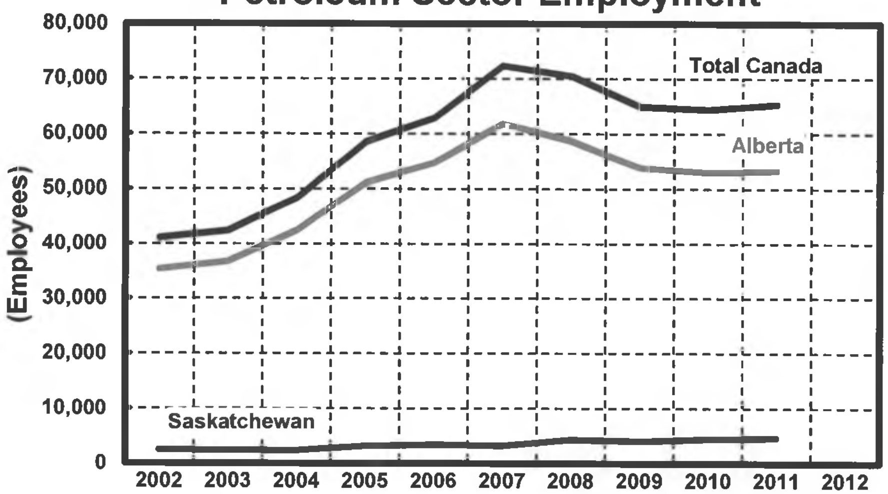
Crude Oil Production



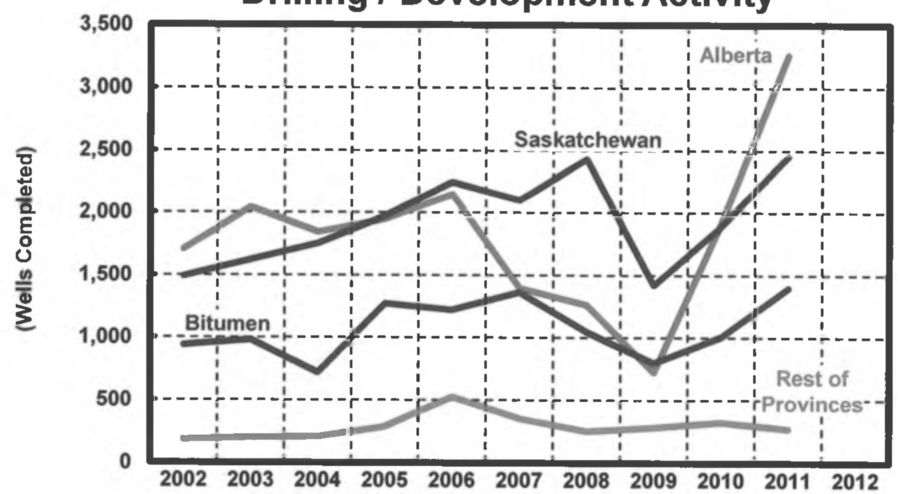
Capital Spending



Petroleum Sector Employment



Drilling / Development Activity



Note: 2012 figures are preliminary.

Capital Allocation and Global Portfolio Review:

Testimony to the Alaska Senate Resources Committee

February 6, 2013

Tony Reinsch
Senior Director, Upstream
PFC Energy

PFC Energy

Part 1:

Oil & Gas Company Decision Making: Capital Allocation, Budget, and Long-Range Planning

Points to Address: Discussion of Company Behaviors and Decision Making

- **Key considerations for companies in making investment decisions, including decisions on whether to develop particular resources in the near term or postpone development**
- **Key metrics including ROCE, NPV, IRR, consideration of asset metrics versus portfolio metrics**

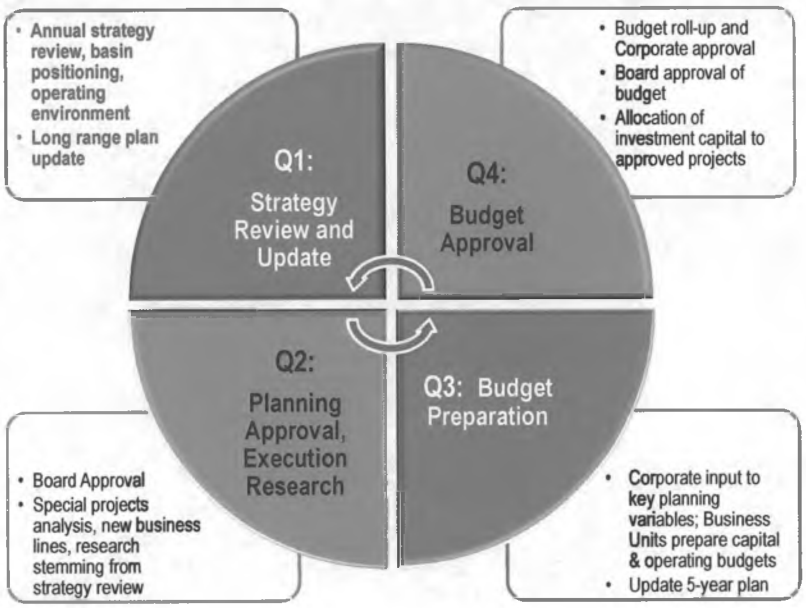
Part 2:

Global Strategy & Portfolio Overview of Major Alaska Producers: BP, ConocoPhillips, and ExxonMobil

PFC Energy

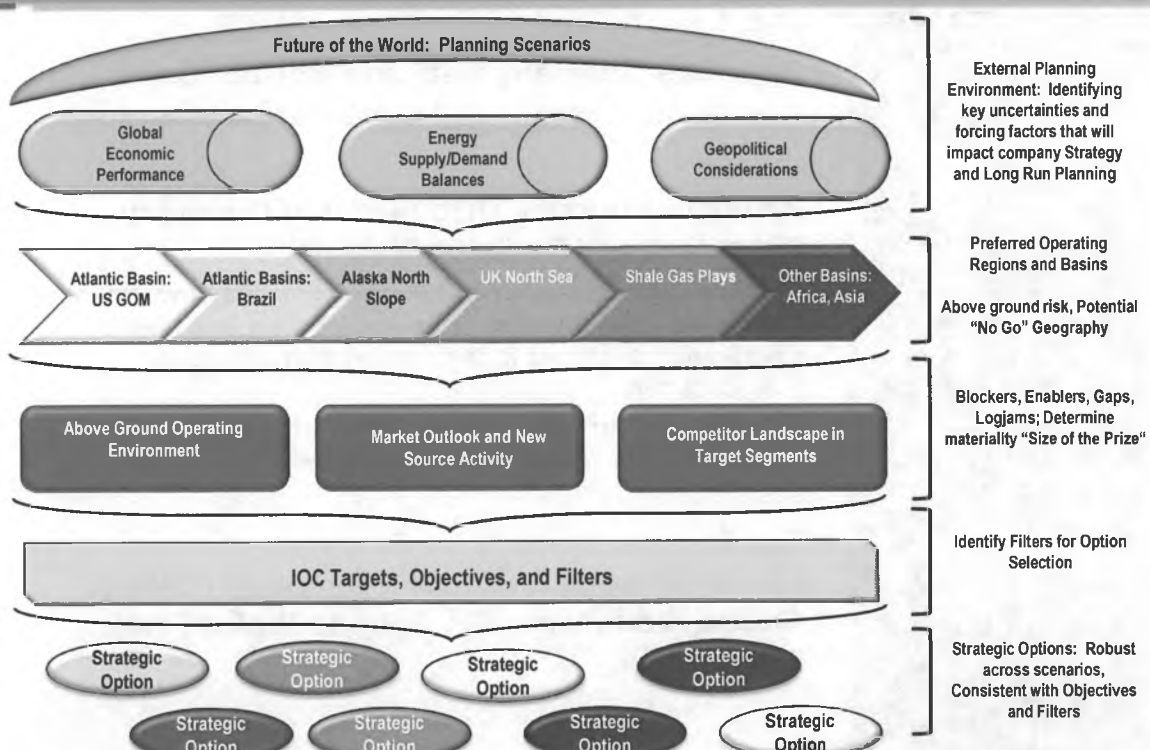
Annual Planning Cycle

Oil and gas companies follow a standardized process linking the annual Budget cycle to the Long Range Plan and corporate Strategy



PFC Energy

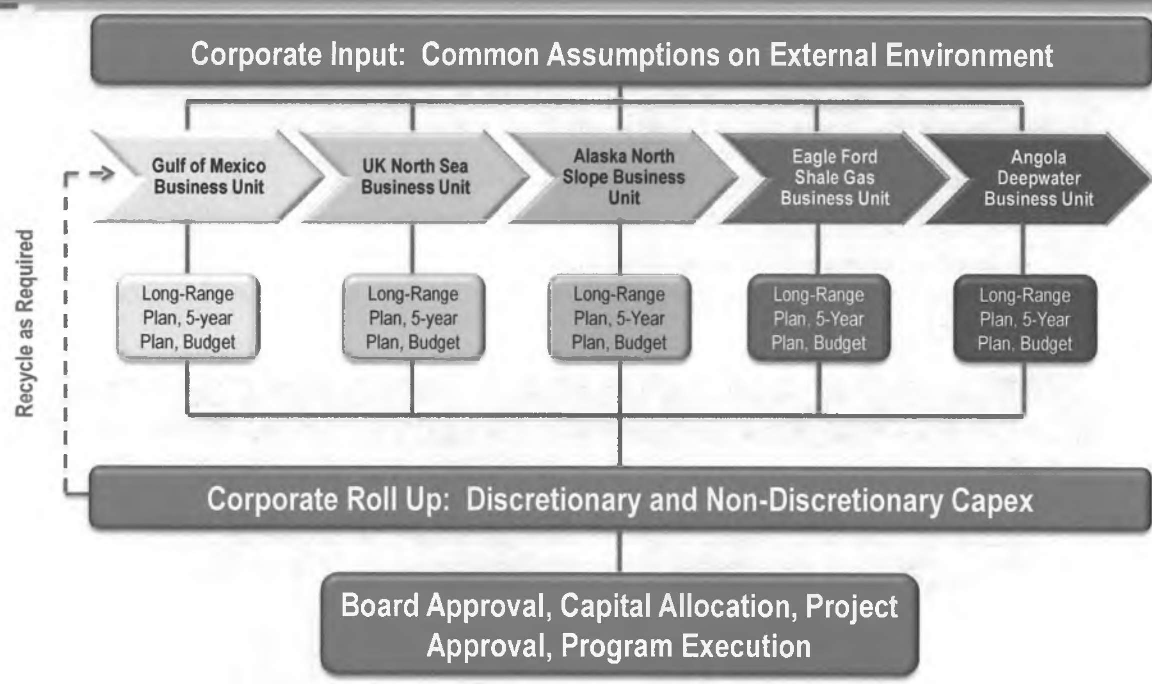
Strategy, Planning and Positioning



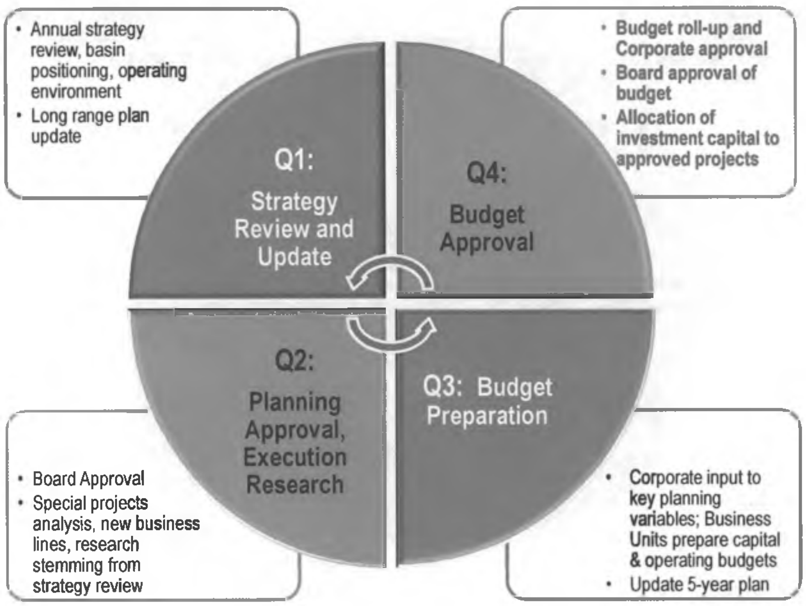
PFC Energy

Annual Planning Cycle

Planning Cycle and Capital Allocation



Annual Planning Cycle

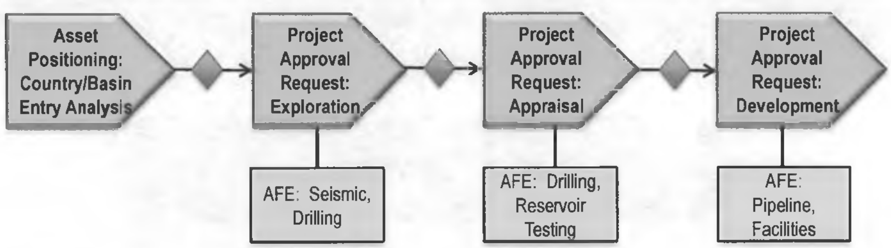


PFC Energy

Attracting Capital: The Project Approval Process

- Materiality, total capex exposure, full-cycle economics/metrics, are all considerations in determining whether an IOC will position, or continue to invest, in a particular asset or basin.
- Each project is disaggregated into "discrete investment decisions", in the form of Project Approval Requests (PARs), creating a natural *stage-gate* for capital approval and allocation.
  - A PAR can extend beyond a single fiscal year budget, depending on scope of the work program. Represents ***non-discretionary*** capex at the start of the budget year
  - Each PAR has one or a series of associated ***Approval for Expenditure (AFE)*** documents for a specific activity or capex element
  - Sum of AFEs for a calendar year = ***capital Budget***
- Each stage-gate creates an opportunity for Management/Board to determine whether to *continue, amend, suspend, or exit/divest*

Asset Modelling and Decision Process: Materiality and Total Capex Exposure

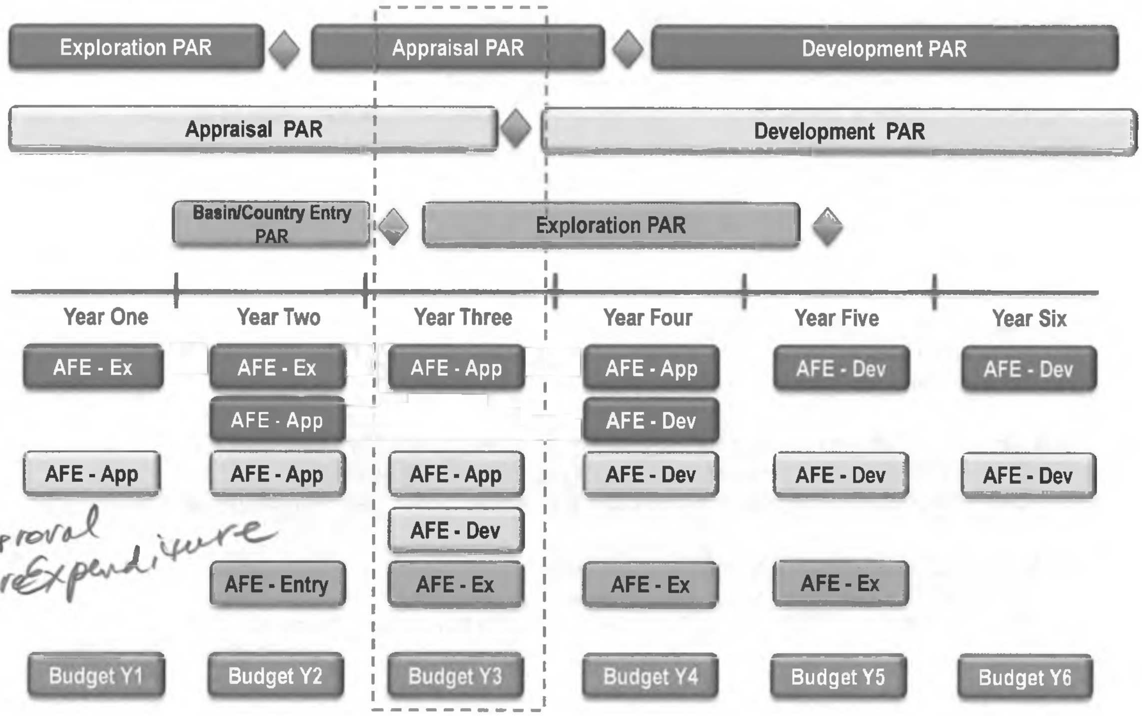


Request for capital budget allocation; decision to continue, amend, suspend, or divest

PFC Energy

40s Field to Apache

Business Control Architecture:
PAR => AFE => Budget



Approval For Expenditure

BP Forties Field to 2003 (UK North Sea)
4.5-5 B Barrels
$670m to Apache
144m bbls remain
170 m produced
(50-60,000 bbls/day

Question: On what basis does an E&P company allocate investment capital to opportunities?

- **There are a core set of metrics that allow comparison of projects and investments *within* a given basin/area, and *across* the portfolio of available investment opportunities**
- **For example, an enhanced recovery project in Alaska will compete for capital against:**
  - **Capex investments in Alaska;**
  - **Enhanced recovery projects elsewhere in the portfolio;**
  - **Capex investments elsewhere in the portfolio**
- **Capital programs must also compete against debt repayment, share buyback, and dividend policies**

Exxon has done a lot of this

Upstream Financial Metrics: Measuring Performance

- **Growth** .. Ability to manage the "top line"
  - CAGR in Production and Reserves relative to target
  - Quality of growth .. Where, how, consistent or not (room to run)
  - Plowback Rate. .. Showing relative growth intentions between different regions
- **Profitability** .. Ability to manage the "bottom line"
  - Upstream Cash Flows
  - Upstream Net Income
  - Upstream Production Costs

  Absolute and "per boe" basis
- **Efficiency** .. Ability to manage capital   grow or destroy
  - Upstream ROCE
  - Finding costs, F&D costs, Replacement Costs
- **Cash Flow** .. Ability to manage investment/re-investment in the portfolio
  - Financial Strategy (debt targets, debt/capital ratio, dividend requirements)
  - Self-financing nature of portfolio (free cash flow versus capex: regional and global)
- **Risk** .. Ability to manage a diversified portfolio
  - Financial Risk: Debt-to-Capital ratio, financial flexibility
  - New Source Risk: Thinner margin barrels dominating new source volumes

Project Selection and Decision Metrics

Energy companies employ a variety of Benchmarks or Metrics to rank investment opportunities and to allocate financial capital. Some of the more common include:

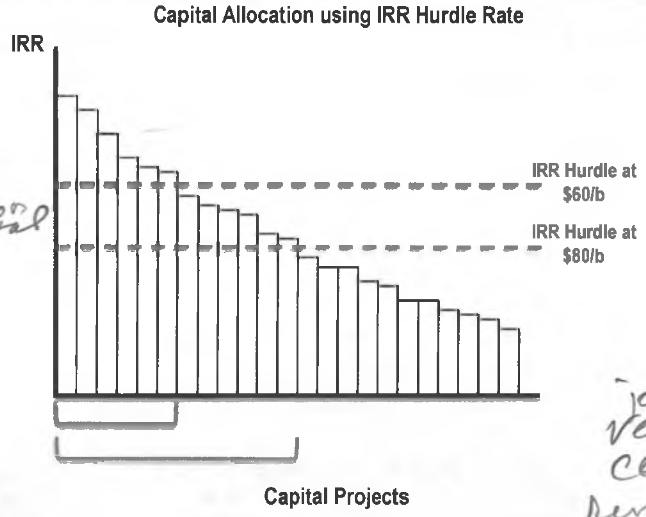
- Pay-out period: length of time required to recoup financial capital being placed at risk. Simplest selection metric, important to firms with scarce capital resources. No reference to project value after pay-out
- Internal Rate of Return: discount rate at which PV of costs = PV of revenues
- Net Present Value: PV of costs less PV of revenue flows (using discount rate reflecting cost of capital, cost of borrowing, or other);
  - NPV/boe: measure of investment efficiency
  - NPV/Investment (or PVPI): assessment of return to the investment dollar.
- Recycle Ratio: Profit per boe divided by F&D cost per boe. A measure of project or corporate profitability (target >1)   find & development
- Discounted and Undiscounted Net Cash Flow Profiles: measure of availability of free cash flow for follow on or alternative investments
- Maximum Negative Cash Flow Exposure: useful in situations where access to financial capital is an issue. Measures the maximum exposure being committed to by the firm
- Net Booked Reserves: contribution of the projects to corporate value (based on bookable reserves, amongst other measures)
- Capex/boe: cost per barrel of production capacity. Burdens the projects by the cost of infrastructure, facilities, etc. Tends to favor less complex, more mature capex alternatives

multi-decade - time value of money

Russia or US were all developed off revenue from Russia or US in 1800 - 1900

Capital Allocation: IRR Hurdle Rate

- A project will be "eligible" for budget capex allocation given it meets or exceeds absolute project metric requirements
  - Example:
    - NPV10 > 0
    - PVPI > 1.3 30% return on capital
    - Payback < 3 years
  - NOTE: These metrics will change over the project cycle, as risks are addressed and estimates become more certain (e.g., 60:40 to 80:20)
- However, the allocation decision is both specific to given project performance, and relative to alternative use of funds.

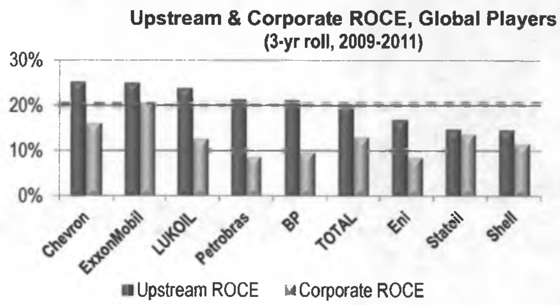


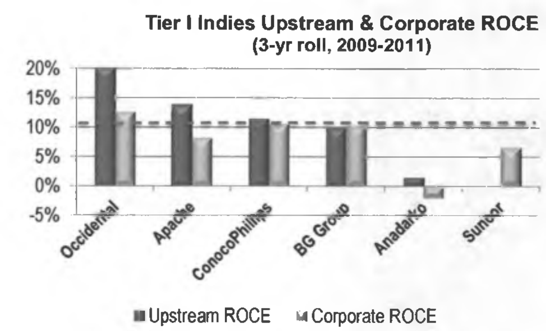
joint venture committee run by operators

  - To allocate scarce capital to competing uses, Corporate will establish "hurdle rates" on key performance metrics, such as IRR.
  - Projects with an IRR in excess of the hurdle rate attract budget capital, while those below the hurdle rate are not funded
  - An increase in available investment capital (say, through an increase in crude prices) may be reflected in a lower hurdle, allowing more projects to be funded

Portfolio Efficiency: Return on Capital Employed (ROCE)

- Efficiency in capital allocation and use over time is reflected in the Return on Capital Employed (ROCE)
- ROCE = [(Net profit before interest and taxes) / (Gross Capital employed)] x 100
  - Where:
    - Gross capital employed = Fixed assets + Investments + Current assets *OR*
    - Gross capital employed = Share Capital + General & Capital Reserves + Long term loans
- The higher the return on capital employed, the more efficient the firm is in using its funds. Over time, ROCE reveals whether the profitability of the company is improving or eroding
- Generally speaking, larger E&P firms focus on ROCE, while smaller players focus on Growth



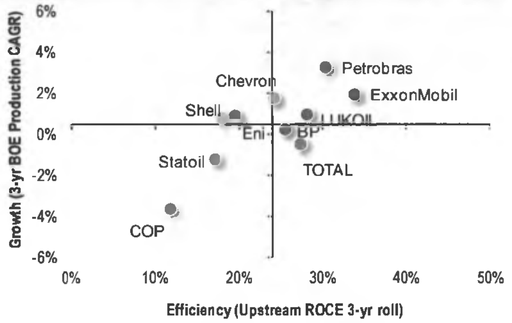


Global Players Average Upstream ROCE: 20.4%
Tier I Independents Average Upstream ROCE: 11.4%

Portfolio Efficiency: Return on Capital Employed (ROCE)

- **Issues with ROCE**:
  - Major capital project investments increase the denominator in advance of revenue (profit) impacts in the numerator => *penalizes the IOC for major capital investment undertakings*
    - Explains in part why it is unusual to find companies with high ROCE and high growth metrics
  - Once commissioned, the scale of major capital project investments tend to deliver superior ROCE performance => *bias toward large asset portfolios*
    - Exception is deepwater developments, where high, short plateaus and steep production declines can result in highly volatile ROCE outcomes
  - Depreciation creates *bias in favor of mature portfolio*: More mature the asset base, the lower the denominator (capital exposed) and the higher the ROCE (all else being equal)

Global Players Peer Group: Growth v Efficiency



ROCE Drivers: $\dfrac{\text{Price, Volume}}{\text{Accum. Capital and Capital Spending}}$

PFC Energy

3-5yrs heavy investments to
then ↑ productions (can't sustain)
then steep decline

Questions & Discussion

PFC Energy

Part 2:

Global Strategy & Portfolio Overview of Major Alaska Producers

- BP
- ConocoPhillips
- ExxonMobil

Points to Address: Discussion of Portfolio Composition and Growth/Capex Focus

- Where are these companies looking to grow. Which plays and basins are attracting investment capex
- What is the position and role of Alaska within these portfolios

PFC Energy

BP: Company Overview

Strategic Signature

- Global integrated company; production in 23 countries, upstream operations in an additional 6 countries.
- 2011 worldwide production of ~3,400 mboe/d, making it the second largest company in the peer group (after ExxonMobil with ~4,513 mboe/d).
  - The Russia & Central Asia (RCA) and North America regions = ~55% of 2011 production.
- Post-Macondo portfolio rationalization program (~$28 bn in asset sales and ~$17 bn in GOM production allocation to Macondo fund) completed in 2013. The result is a pared down and more focused geographic portfolio.
- Executing on a 3-pronged growth strategy:
  - **Deepwater Basins**: US GOM, Angola, Egypt, Brazil
  - **Global Gas**: US, Trinidad & Tobago, North Sea
  - **Giant Oil Fields**: Alaska, Iraq, others.
- Committed ~$20 bn net investment to 16 projects sanctioned over 2010-2011. Will curb ROCE performance for the coming 2-3 years.
- Sale of TNK-BP (~$22 bn proceeds) => ~1 mmboe/d production decline in 2013 from 2012. BP will be hard pressed to outperform its peers on any key metrics.

Company Overview

- **HQ:** London
- **Employees:** 83,400
- **2011 Reserves:** 17,750 mmboe
- **2011 Production:** 3,400 mboe/d
- **3 Yr Production Growth:** -3.53% CAGR (2009-2011)
- **Jan 2013 Market Cap:** $141 bn
- **Jan 2013 P/E Ratio:** 8
- **2011 Corp Revenue:** $375 bn
- **2011 Upstream Capex:** $17 bn

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	LNG
✓	✓	✓	✓	✓	✓

Partnership History

Date	Partner	Region (or Country)	Type
2007	Husky	Canada	Sunrise Oil Sands
2008	Chesapeake	US	Unconventional
2009	CNPC	Iraq	Rumaila TSA
2011	Reliance	India	Offshore Gas

PFC Energy

BP: Global Areas of Upstream Operations

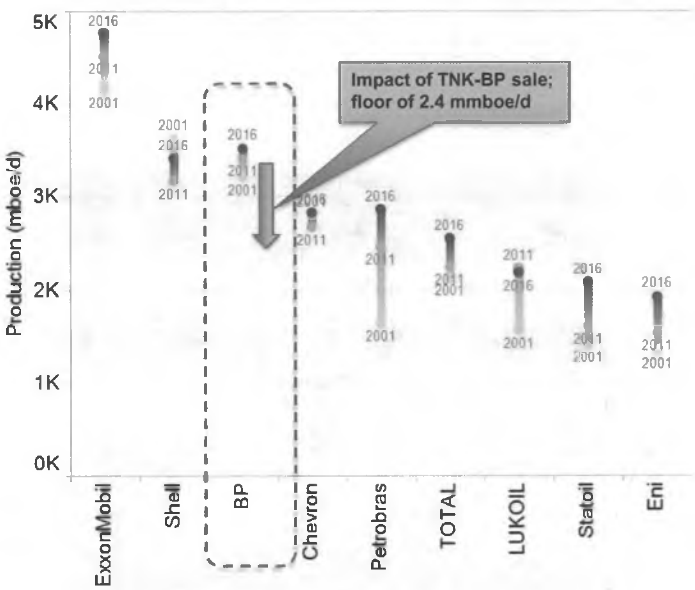
Designation	Country	2011 Total (mboe/d)
Core	United States	760
	Trinidad & Tobago	397
	United Arab Emir..	216
	Angola	123
Exit/Potential Exit	Russia	982
	Argentina	136
	Venezuela	17
	Pakistan	17
	Vietnam	13
	Colombia	2
	Chile	
	Ukraine	
Focus	Egypt	119
	Azerbaijan	117
	Australia	99
	Indonesia	73
	Algeria	41
	Norway	34
	Iraq	31
	India	24
	China	12
	Brazil	7
	Canada	4
	Oman	3
	Bolivia	2
Harvest	United Kingdom	172
New Venture	Jordan	
	Libya	
	Namibia	
	Uruguay	

harvest means
Sustained
but unlikely to
be sustained
$ going to another
location

PFC Energy

Total Portfolio Evolution: BP vis-à-vis the Competition

Production (mboe/d) in 2001, 2011 and 2016 (PFC Forecast): BP and Peers



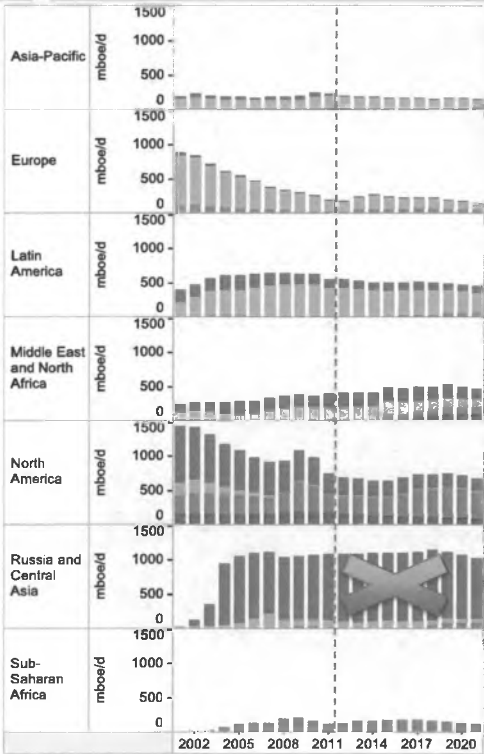
In 2011, BP was the second largest producer of the peer group. BP and COP are the only two companies forecast to deliver production declines over the 2010-2015 period.

2001-2011: Production increases from ~3,080 mboe/d to ~3,400 mboe/d due to addition of Russia (~960 mboe/d), Trinidad & Tobago (~250 mboe/d) and Angola (~170 mboe/d). This expansion offsets declines from Europe (-660 mboe/d and North America -350 mboe/d), and portfolio divestitures .

2012-2016: BP was forecast to show modest production gains over the period. The sale of its stake in TNK-BP lowers this outlook by ~1 mmboe/d, a volume that would be offset (with improved upside) should the 19.74% equity positioning in Rosneft be concluded

PFC Energy

BP: Regional Trajectories



Asia-Pacific: ~246 mboe/d in 2011, centered on LNG feedstock. Expanding deepwater exploration acreage and a growing exposure to CBM. Reliance partnership in India offshore coinciding with divestiture of Pakistan and Vietnam portfolios.

Europe: ~206 mboe/d in 2011; Mature offshore asset portfolio in UK and Norway. Steep fall from ~895 mboe/d in 2001. Harvest Area with near-term production gains through a series of field redevelopment projects.

Latin America: ~561 mboe/d in 2011 (~34% of global gas volumes). Sale of assets in Colombia, reduced exposure in Venezuela (sold to TNK-BP); shift in regional strategy to South Atlantic deepwater exploration and development (Brazil, Uruguay).

Middle East & North Africa: ~410 mboe/d in 2011, a decade high. Large development portfolio (Iraq, Oman, Egypt deepwater) challenged by above ground issues.

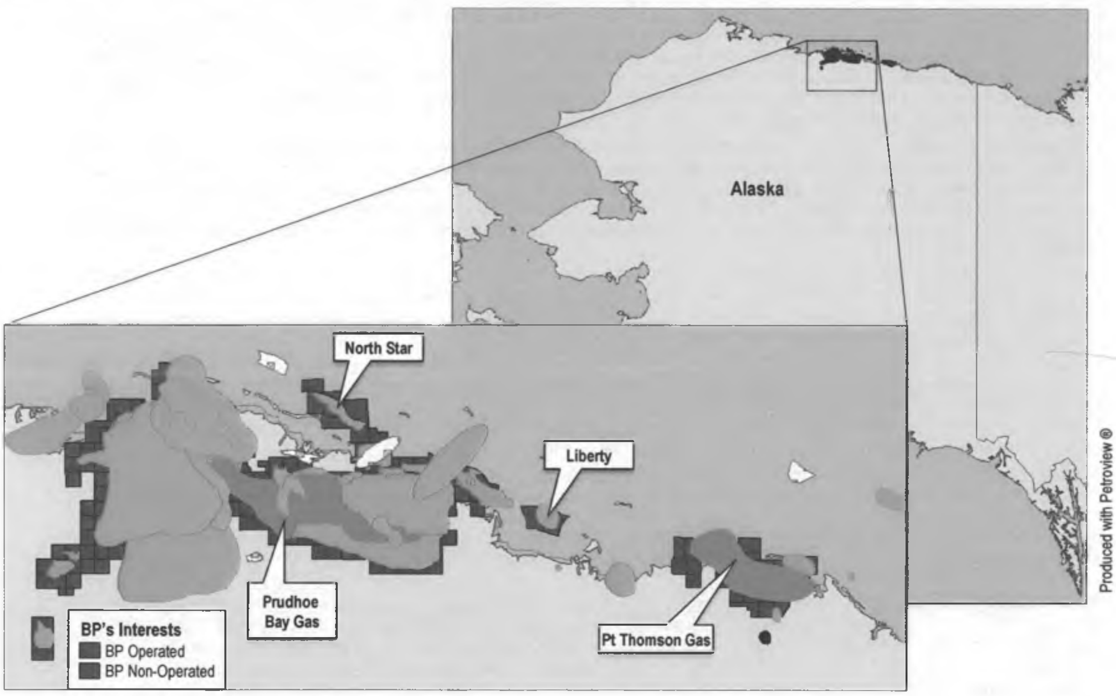
North America: ~764 mboe/d in 2011, 2nd largest production region, focused on Deepwater GOM. Sale of conventional oil and gas assets in Onshore L48, growing focus on shale gas and oil sands development(first oil from the in-situ (SAGD) Sunrise project expected in 2014).

Russia & Central Asia: ~1,099 mboe/d in 2011; dominated by TNK-BP in Russia (divested 2013). Leave Azerbaijan as the sole source of medium-term volume growth, pending Rosneft equity deal.

Sub-Saharan Africa: ~123 mboe/d in 2011, sourced from Angola deepwater. New source volumes from a suite of multi-field deepwater development projects. Positioned to test the pre-salt analog in the Kwanza basin in Angola and further south in Namibia.

Asset Type
- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

BP in North America: Alaska



BP Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
Harvest Area	• Asset concentration on the **North Slope**, where production volumes have generally declined because of the maturity of the asset base and/or gas infrastructure constraints. Liquid production has declined from ~224 mboe/d in 2006 to ~153 mboe/d in 2011, while gas production has fallen from ~67 mmcf/d to ~22 mmcf/d over the same period. • BP's largest source of production is the **Greater Prudhoe Area** (26% w.i., operated), covering ~150,000 acres with more than 1,000 active wells. Gas resources are currently stranded. BP and ConocoPhillips withdrew the 4 bcf/d **Denali** pipeline proposal (Prudhoe Bay => western Canada => US markets) in May 2011, citing the lack of long-term purchase contracts. • In March 2012 ExxonMobil, ConocoPhillips and BP settled litigation with the Alaskan government over the development of Point Thomson gas reserves, publicly announcing their interest in gas commercialization and export opportunities from Alaska • BP and partners are moving forward with the development of gas liquids on the ~8 tcf **Point Thomson** field (32% w.i., non-operator). The gas cycling project is expected to produce ~10 mb/d of liquids; first production is targeted for 2014. Full field development awaits gas transport infrastructure. • In the **Beaufort Sea**, BP has suspended work on the extended-reach drilling program on the **Liberty** oil field (100% w.i.), pending revision of project design and schedule. • BP is also seeking to develop viscous (**Kuparuk**) and heavy (**Milne**) oil resources on the North Slope.	**Current production volumes are modest and declining. Significant potential lies in the long-term commercialization of Prudhoe Bay and Point Thomson gas resources. Cancellation of the Denali gas pipeline proposal leaves BP as a potential supplier to an alternative pipeline/LNG export option, should one be approved and developed.**

PFC-Identified Challenges

- Bring a close to the portfolio rationalization process: With ~$16 bn in upstream asset divestitures announced since June 2010 and another $17 bn in royalty over-rides redirected to the Deepwater Horizon Oil Spill Reparation Fund, BP indicated in 2Q:2012 a further ~$12 bn in total portfolio asset sales before end-2013 – excluding the net ~$22 bn from the TNK-BP sale. The portfolio repositioning represents an exchange of secure production and proved reserves for higher-risk, less certain, but potentially more material future growth opportunities (Krishna-Godavari basin offshore India, Kwanza pre-salt analog offshore Angola, Equatorial Margin analog offshore northern Brazil).
- Secure a new Core Area: With positioning in both Russia and the UAE in question, BP faces the prospect of a diminished number of Core areas capable of delivering material, sustained production and free cash flow. This places significant pressure on the transitioning of Focus areas into larger, stable Core operations in order to remain above the targeted 2.4 mmboe/d production floor (ex-TNK-BP volumes). BP is betting heavily on the potential of nascent deepwater plays in the South Atlantic and Asia-Pacific – a strategy that will hinge on exploration success and performance of newly established and uncertain partnerships.
- Execute the exit from TNK-BP JV and Repositioning in Russia: Russia production tied to TNK-BP accounted for ~29% of BP's global production in 2011 (and ~25% of total production since 2004), and the second largest source of free cash flow after the US. BP will look to secure a position in Russia's emerging Arctic Resource play through equity positioning (19.74%) in Rosneft – a move with greater upside than TNK-BP, but markedly less control.
- Develop deepwater partnership with Petrobras: Having secured Brazil government approval for its acquisition of the Devon asset portfolio (potentially the largest operated pre-salt portfolio outside Petrobras), BP has moved to deepen its ties with the Brazil NOC, farming into Petrobras operated licenses in the pre-salt analog basin areas offshore Angola and Namibia. Subsequent partnering in the Brazil Equatorial Margin suggests a budding deepwater strategic alliance between the two premier deepwater developers, with the prospects of substantial, long term rewards.
- Accelerate development of US Onshore unconventional gas resource: BP received a very competitive price for the Permian Basin and Western Canada conventional gas assets sold to Apache (totaling ~75 mboe/d of production and ~340 mmboe of reserves, equivalent to ~$24.60/boe of reserves in the ground or ~$109,000/flowing boe of production). This is particularly so given what is shaping up to be an extended period of gas price weakness in the North America market. To make up for lost volumes, BP may look to accelerate production from its ~10 tcf of reserves in the Woodford, Fayetteville, Haynesville, and Eagle Ford shale gas plays.
- Accelerate development of BP's oil sands leases: BP has built up a material oil sands lease portfolio in Western Canada, including 50% w.i. in the Sunrise in situ development project (sanctioned in November 2010), a 75% w.i. in the Terre de Grace in situ project (secured in March 2010 from Value Creation for ~$900 mn), and 50% w.i. in the Kirby in situ oil sands leases (with the other 50% divested to Devon in March 2010). Full development of these projects could represent 500-600 mbo/d of stable, long-life oil production, complementing the "Giant Oil Fields" growth platform and providing a portfolio buffer against the steep decline production profiles associated with deepwater developments.

ConocoPhillips: Company Overview

Strategic Signature

- March 2010: new strategic pathway => ~$15 bn asset and joint venture divestment program, targeting:
  - Debt reduction;
  - Near-term shareholder returns;
  - Shift out of downstream; and
  - Growth from smaller, higher-value portfolio position.
- 2010-2012 Restructuring Plan:
  - ~$7 bn in asset sales
  - Divested i20% equity interest in LUKOIL
  - Poceeds to debt reduction and share repurchase.
- July 2011: Announces restructuring into ***two separate corporate entities***, Downstream (Phillips 66) and a pure play, E&P company (ConocoPhillips).
- Net impact:
  - Production decline to ~1.5 mmboe/d in 2012, recovering to 1.64-1.69 mmboe/d by 2015.
  - Portfolio focus in OECD countries (US, Canada, Australia, UK, and Norway, which accounted for ~75% of worldwide production in 2011).
- Grow 0.5% per annum from 2012 through 2015 from ***Global Gas/LNG, SAGD Oil Sands, and Unconventional Resource*** developments.

Company Overview

- **HQ:** Houston, TX
- **Employees:** ~16,000
- **2011 Reserves:** 8,387 mmboe
- **2011 Production:** 1,610 mboe/d
- **3 Yr Production Growth:** -30.68% CAGR (2008-2011)
- **Jan 2013 Market Cap:** $74 bn
- **Jan 2013 P/E Ratio:** 7.5
- **2011 Corp Revenue:** $235 bn
- **2011 Upstream Capex:** $13.5 bn

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	Other
✓	✓		✓	✓	

Partnership History

Date	Partner	Region (or Country)	Type
2003	LUKOIL	Russia	Various
2006	Cenovus	Canada	Oil Sands
2008	Origin Energy	Australia	LNG

PFC Energy

ConocoPhillips: Global Areas of Upstream Operations

Designation	Country	2011 Total (mboe/d)
Core	United States	653
	Canada	250
	Norway	147
	United Kingdom	132
Focus	Indonesia	86
	Qatar	85
	Timor Leste/Australia JPDA	63
	China	52
	Australia	26
	Libya	8
	Kazakhstan	
	Malaysia	
Exit/Potential Exit	Nigeria	45
	Russia	29
	Vietnam	20
	Algeria	13
	Peru	
New Venture	Angola	
	Bangladesh	
	Brunei	
	Greenland	
	India	
	Poland	
Grand Total		1,610

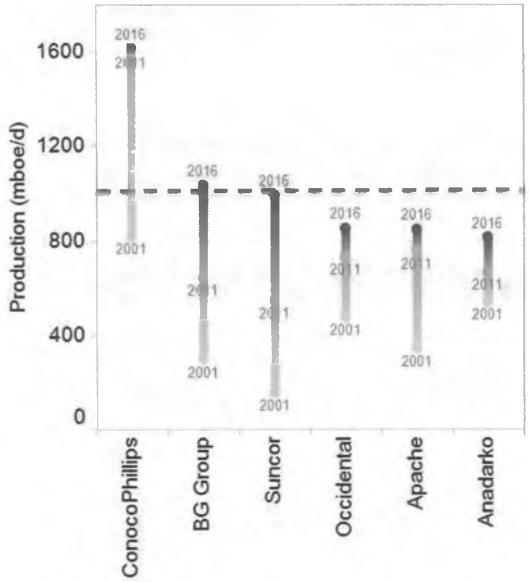
- Core
- Exit/Potential Exit
- Focus
- Harvest
- New Venture

safe haven
upheaval

PFC Energy

Total Portfolio Evolution: ConocoPhillips vis-à-vis the Competition

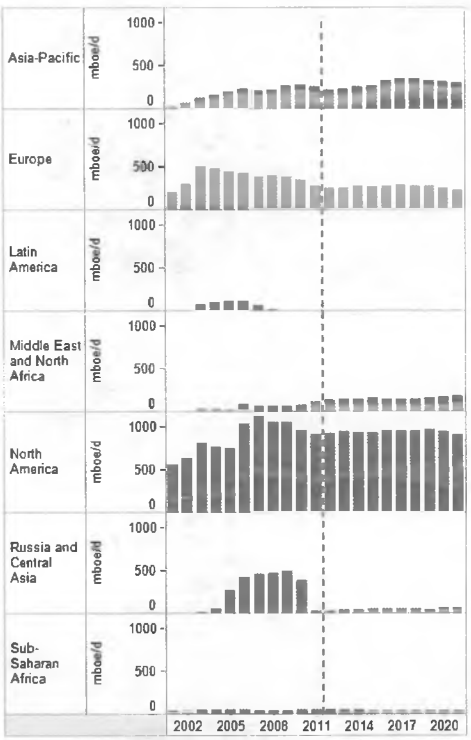
Tier I International Independents Production 2001, 2011 and 2016 (PFC Forecast)



- The Tier I peer group is comprised of Independents with portfolios capable of delivering ~1 mmboe/d of production over the next 5-7 years
- ConocoPhillips joined the Tier I peer group following its de-integration. Will see production continue to slide (floor in 2013), before recovering to slightly above 2011 levels by 2016
- Production increases over 2001-2011 driven by:
  - the merger of Conoco and Phillips in the beginning of the decade (growing volumes from 698 mboe/d in 2000 to 1,082 mboe/d in 2002);
  - the Burlington Resources purchase in 2006 (growing volumes from 1,824 mboe/d in 2005 to 2,358 mboe/d in 2006); and
  - the gradual acquisition of a 20% stake in LUKOIL later in the decade

PFC Energy

ConocoPhillips: Regional Trajectories



Asia-Pacific: ~247 mboe/d in 2011. Core area of operations and future growth. Commissioning of APLNG will add long-term volumes, offsetting decline from conventional shallow water assets.

Europe: ~279 mboe/d in 2011. Mature asset portfolio with satellite field development slated to offset base declines and maintain free cash flows from this Harvest region.

Latin America: 0 mboe/d in 2011. Position secured through Burlington transaction. Not material to global operations.

Middle East & North Africa: ~106 mboe/d in 2011. Legacy oil positions in Libya and Algeria augmented by commissioning of Qatargas III LNG project => long-life, cash generating production to the region.

North America: ~903 mboe/d in 2011 (~56% of global volumes). New Ventures in Oil Sands, Unconventional Onshore resource plays, and GOM deepwater will provide regional growth.

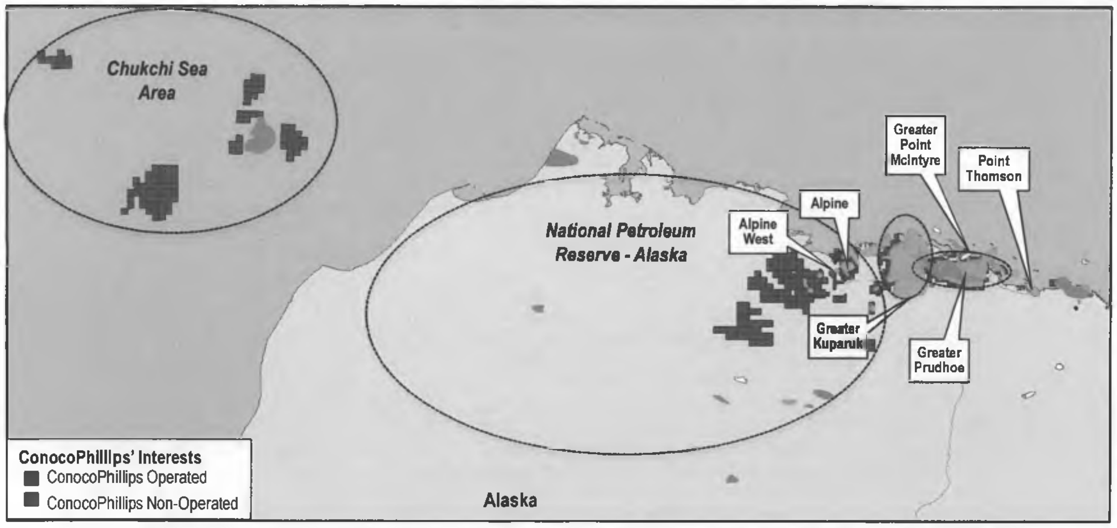
Russia & Central Asia: ~29 mboe/d in 2011. Following sale of LUKOIL equity stake, production is sourced entirely from the Polar Lights and NMNG joint ventures in Russia. New Source volumes come from Kazakhstan's Kashagan development.

Sub-Saharan Africa: ~45 mboe/d in 2011; sourced from legacy assets in Nigeria, which are likely to be divested by mid-2013.

Asset Type
- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

PFC Energy

ConocoPhillips in North America—Alaska



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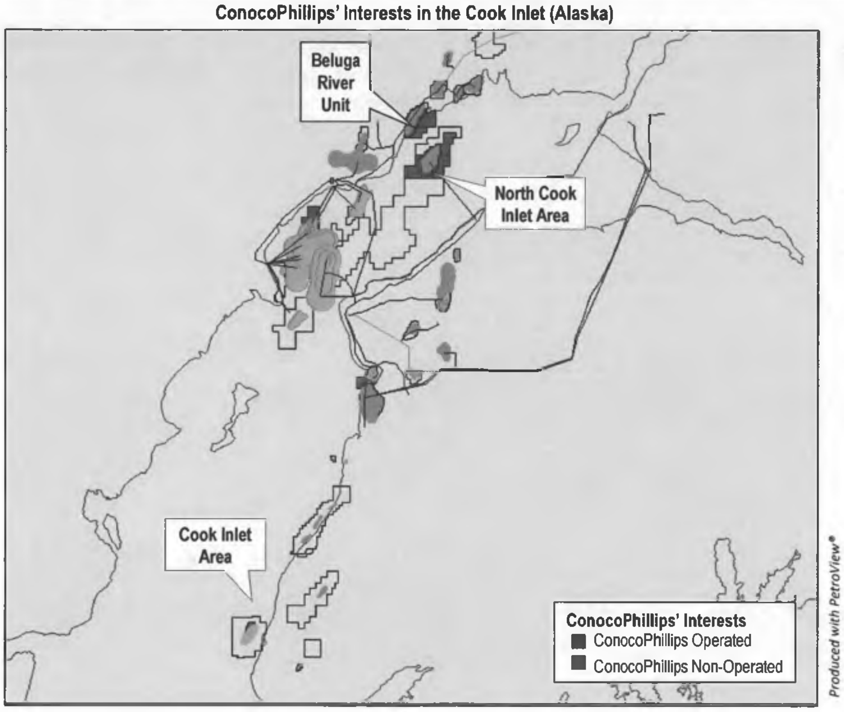
ConocoPhillips in North America—Alaska Cook Inlet

ConocoPhillips' Interests in the Cook Inlet (Alaska)



ConocoPhillips **Alaska Activity & PFC Energy Assessment**

Alaska Designation	Activity	PFC Energy Assessment
Core Area	• Legacy portfolio acquired from Arco Alaska in 2000; includes the Greater Prudhoe Area (largest production), Greater Prudhoe Bay Area, Greater Kuparuk Area, Western North Slope, and Cook Inlet Area. • Production from the mature Alaska portfolio has been in slow decline since the late 1980s. In 2011, net production from Alaska averaged 215 mb/d of oil and 61 mmcf/d of gas, accounting for ~35% of US production. • Activity in the ConocoPhillips-operated Greater Kuparuk Area (GKA), has recently focused on development of viscous oil resources. The GKA, located 40 miles west of Prudhoe Bay on the North Slope, includes the Kuparuk field and its satellites: West Sak, Tarn, Tabasco, Meltwater, and Palm. Heavy oil resources **West Sak** and **Ugnu** (52.2% w.i., operated) are potential projects currently in the appraisal phase. Expected gross peak production is ~23 mboe/d. • While ConocoPhillips has three primary gas fields in the Alaska region–the North Cook Inlet, Beluga River, and Point Thomson–**Point Thomson** (5% w.i., non-operated) remains the only potential new source development. In 2010, development activities continued with the drilling of two appraisal wells. First production of gas liquids is anticipated in 2015-2016. Longer-term growth potential lies in commercialization of the gas reserves, which is in turn dependent on construction of a long-distance gas trunk line.	**Alaska's largest oil and gas producer. While continuing to target smaller projects within the GKA (West Sak and Ugnu) and NPR-A (Alpine West, Greater Moose's Tooth unit and Fiord West), ConocoPhillips will ultimately need expanded access to Asia gas markets in order to reverse the downward production trend in Alaska.**

PFC Energy

COP Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
Core Area	• In the Western North Slope, ConocoPhillips faces regulatory challenges surrounding project development in the NPR-A region. In order to offset declines at the **Alpine** field (78% w.i., operated) and its three satellites, Nanuq, Fiord, and Qannik, ConocoPhillips is exploring development of additional satellite fields in the adjacent NPR-A, an area that requires distinct permit approval. **Alpine West** (or **CD-5**), a proposed Alpine satellite project, has been significantly delayed due to local opposition and regulatory barriers. Most recently, in early 2010, the U.S. Army Corps of Engineers denied a permit for a bridge that would provide access to the CD-5 site, a move that will further delay the project (originally planned for 2012) and several additional developments that would depend on the infrastructure. Other possible projects on the NPR-A include the **Greater Moose's Tooth** unit and **Fiord West**, which are both in appraisal phases. • In 2010, ConocoPhillips and Statoil engaged in an asset swap wherein ConocoPhillips sold a 25% w.i. in 50 of its **Chukchi Sea** leases to Statoil in exchange for financial payment and a 50% w.i. interest in 16 Statoil-operated Gulf of Mexico leases, as well as Statoil's 25% w.i. in five additional GOM leases already operated by ConocoPhillips. All of the involved GOM blocks are in the emerging Lower Tertiary play. ConocoPhillips plans to begin exploratory drilling on its Chukchi acreage in 2014.	

PFC Energy

PFC-Identified Challenges

- **Competing as a "Pure Play" E&P Company**: Repositioned as the largest Independent E&P company by a considerable margin. In the near-term, COP is a smaller company with limited near-term production growth and improved, but unlikely to be leading, ROCE and financial performance.
  - Has the company simply re-introduced its prior dilemma—too large to compete with the smaller International Independents on volume growth, and too small to compete effectively with the Global Players on efficiency metrics? Or can the company successfully deliver both volume and value/efficiency performance form its high-graded, down-sized asset portfolio?
- **Effectively Positioning in High Value Assets**: Sale of low margin, non-core (and largely non-OECD) assets => loss of optionality and diversity within its portfolio that can act as a hedge against commodity cycles and changing market conditions over the long term. Targeting of low risk (OECD) and high margin assets (such as US unconventional oil plays) raises the risk of destroying value by overpaying for competitive assets.
- **Defining Operational Strengths**: Strong partnerships => majority of growth will come from non-operated and/or JV related activity with specialized developers – FCCL JV with Cenovus in the Canadian Oil Sands; Australia Pacific LNG JV with Origin Energy; non-operated assets in the US GOM; Shell in the Malaysia deepwater. Also building considerable expertise in unconventional resource exploitation (both shale gas and tight oil) in the US Onshore.
  - Successful leveraging to unconventional resource plays outside North America could deliver the differentiating competitive advantage and volume growth required for ConocoPhillips to compete effectively within the Independent E&P peer group over the long term.
- **Effectively Managing Base Production**: Minimizing the decline in production from the company's base portfolio—which has a high proportion of gas production exposed to continued weak North American gas prices—is essential for the company to deliver simultaneous production and margin growth.
- **Delivering Production Growth**: Production has fallen by 30% since 2009 (2,286 mboe/d to 1,610 mboe/d in 2011). New source developments basically keep pace with mature asset declines in the MENA, Europe, and RCA regions => material net growth must come from ***North America and Asia Pacific***. US Onshore unconventional liquids plays are currently projected to deliver ~22% of total worldwide new source volumes in 2021

ExxonMobil: Company Overview

Strategic Signature

- Largest of the Global Players
  - ~4,513 mboe/d in 2011; production in 21 countries, with upstream operations in an additional 20 countries.
- Growth strategy based on scale, basin dominance, and execution excellence => continuously seek access to investment opportunities of adequate size and materiality.
- Move into unconventional resource plays was a default for ExxonMobil:
  i. Commissioning of the final elements of the company's Qatar project portfolio in 2011
  ii. Declining production from its Europe and Asia-Pacific portfolios
  iii. Roadblocks to materiality in Brazil deepwater, Venezuela extra-heavy, and Equatorial Margin
  iv. Already holding a considerable stake in the Canadian oil sands, ExxonMobil took an aggressive move into unconventional shale gas exploitation.
- 2009 acquisition of XTO Energy brings materiality to ExxonMobil's technical expertise in tight gas, CBM, and shale oil and gas exploitation (~2.3 bcf/d and 87 mboe/d of production, proved reserves of ~2.3 bn boe, resource base of 7.5 bn boe).
- Leveraging XTO into a global unconventional portfolio.

Company Overview

- **HQ:** Irving, Texas
- **Employees:** 83,600
- **2011 Reserves:** 24,922 mmboe
- **2011 Production:** 4,513 mboe/d
- **3 Yr Production Growth:** 4.53% CAGR (2008-2011)
- **Jan 2013 Market Cap:** $415 bn
- **Jan 2013 P/E Ratio:** 9.6
- **2011 Corp Revenue:** $486 bn
- **2011 Upstream Capex:** ~$28 bn

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconventionals	Oil Sands	Other
✓	✓		✓	✓	✓

renewables ethanol

Partnership History

Date	Partner	Region (or Country)	Type
2011	Sinopec	China	Unconventional
2011	Rosneft	Russia	Offshore Oil & Gas

ExxonMobil has a limited history of partnership, preferring instead to purchase and operate material positions independently

ExxonMobil: Global Areas of Upstream Operations

Designation	Country	2011 Total (mboe/d)
Core	United States	1,076
	Qatar	972
	Nigeria	325
	Norway	315
	Canada	313
	Netherlands	311
Harvest	United Arab Emirates	278
	United Kingdom	129
	Malaysia	108
	Germany	89
	Equatorial Guinea	45
	Chad	40
	Azerbaijan	21
	Thailand	3
Focus	Kazakhstan	151
	Australia	100
	Angola	99
	Russia	57
	Indonesia	39
	Papua New Guinea	6
New Venture	Iraq	27
	Argentina	8
	China	
	Colombia	
	Congo, Republic of the (Brazz..	
	Greenland	
	Guyana	
	Ireland	
	Madagascar	
	Poland	
	Romania	

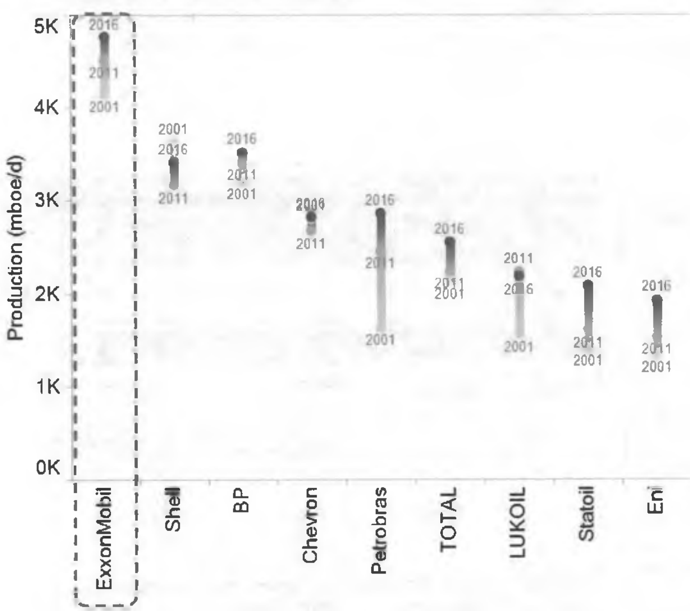
Designation	Country	2011 Total (mboe/d)
New Venture	Tanzania	
	Turkey	
	Vietnam	
Exit/Potential Exit	Brazil	
	Cameroon	
	Italy	
	Libya	
	Philippines	
	Yemen	
Grand Total		4,513

- Core
- Exit/Potential Exit
- Focus
- Harvest
- New Venture

XTO purchase

Total Portfolio Evolution: ExxonMobil vis-à-vis the Competition

Production (mboe/d) in 2001, 2011 and 2016 (PFC Forecast): XOM and Peers

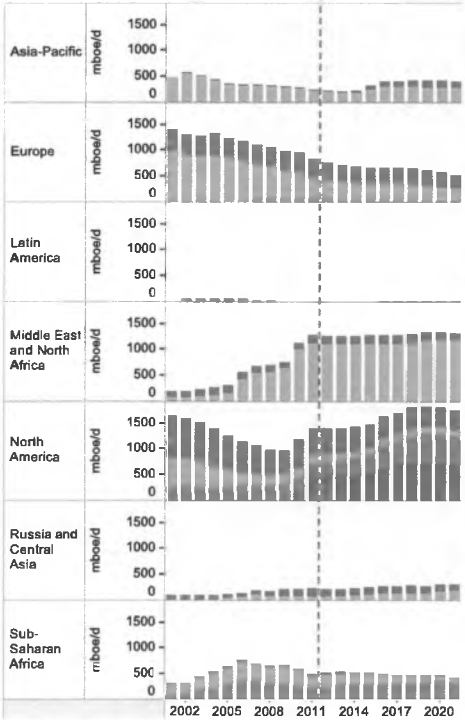


Averaging ~4.5 mmboe/d in 2011, ExxonMobil continues to lead its peer group in terms of production.

2001-2011: Production oscillated through the decade, landing in 2009 at roughly the same level as 2001 (~4.0 mmboe/d), before rising 13% in 2010 (~6% excluding the XTO acquisition) to ~4.45 mmboe/d. The XTO acquisition marked a considerable departure from ExxonMobil's longstanding organic growth strategy.

2011-2016: Modest volume growth, reaching ~4.69 mmboe/d in 2016. While PFC Energy estimates are lower than ExxonMobil targets, the absence of guidance regarding growth projects associated with the XTO portfolio makes the pace of future growth uncertain.

ExxonMobil: Regional Trajectories



Asia-Pacific: ~256 mboe/d in 2011. Focus on strengthening gas position in the region, to offset rapidly declining oil production base. Several MT/LT gas export projects including Gorgon and PNG LNG.

Europe: ~845 mboe/d in 2011. Mature asset decline and accelerating divestiture program have eroded region production from 1,393 mboe/d in 2001. New source volumes not expected to reverse this downward trend.

Latin America: ~8 mboe/d in 2011. Sole new source production is forecast from Argentina's Neuquen Basin, where ExxonMobil is a relatively early entrant to the unconventional shale gas play

Middle East & North Africa: ~1,277 mboe/d in 2011. Growth over the last decade driven by LNG projects in Qatar (stalled by ongoing moratorium on North Field development). Large legacy position in the UAE, a challenged upstream position in southern Iraq, and new exploration in Kurdistan.

North America: ~1,389 mboe/d in 2011. Expanded positioning in the US Onshore shale gas plays, material deepwater US GOM portfolio, development projects in the Canadian Oil Sands combine to deliver material production growth over the long term.

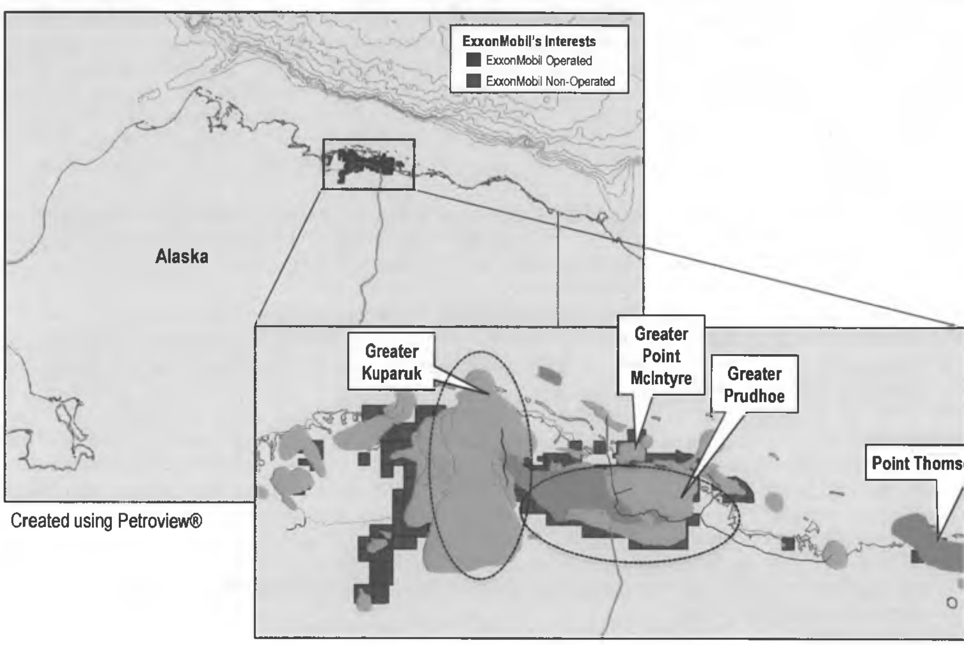
Russia & Central Asia: ~229 mboe/d in 2011. Growth from a small portfolio of large-scale assets, most of which face above ground challenges. Project execution on unsanctioned development queue remains critical.

Sub-Saharan Africa: ~509 mboe/d in 2011. A "treadmill" operation, with robust new source volumes centered in deepwater Nigeria and Angola keeping pace with field declines.

Asset Type
- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

PFC Energy

ExxonMobil in North America: Alaska



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PFC Energy

ExxonMobil **Alaska Activity & PFC Energy Assessment**

Alaska Designation	Activity	PFC Energy Assessment
Harvest Area	• In Alaska, ExxonMobil holds interests in the **Greater Prudhoe, Greater Point McIntyre,** and **Greater Kuparuk** areas. The company is one of the largest North Slope producers, although production from the region is declining; 2010 net production averaged 114 mb/d of liquids. • Development activities continued at **Point Thomson** in 2010 (35% w.i., operated), and first production of gas liquids is anticipated in 2015-2016. Longer-term potential lies in commercialization of the gas reserves, which is dependent on building a gas pipeline and accessing export markets.	**Material harvest position. As the largest holder of discovered gas resources on the North Slope and a co-operator of the Prudhoe Bay Western Region development, ExxonMobil holds a leading position in Alaska. Maintaining and growing upstream investment increasingly hinges on a gas commercialization/export scheme.**

PFC-Identified Challenges

- **Adapting to the unconventional resource play business environment** : The XTO Energy acquisition and subsequent shale gas acreage transactions have made ExxonMobil a force in the North America unconventional resource play, shifting growth focus to a business model that is quite different from the large-scale, major capital projects that have driven core growth for the company over the last decade. With more than two-thirds of its unconventional resource acreage holdings (excluding the oil sands) positioned in gas plays, the company is clearly challenged by the ongoing weakness in natural gas realizations in North America. This is reflected in the company's growing interest in US LNG exports—both from Alaska and the US Onshore. However, this is a long-term fix for a near-term challenge, and one with considerable arbitrage risk in the form of firming Henry Hub gas prices over the latter half of the decade.
- **Delivering on a new growth strategy based on strategic partnerships and frontier exploration opportunities**. The development moratorium on the Qatar North Field has left ExxonMobil searching for new engines of growth. One response has been a shift in strategy towards strategic partnerships and frontier exploration – reflected in the Rosneft strategic agreement covering frontier exploration in the Russia Arctic.
- **Execution or rationalization of challenged reserves and/or developments positions**. These include:
  - Monetization of captured frontier gas resources in North America (Alaska North Slope, Mackenzie Delta);
  - Development of captured oil reserves in the Caspian region, plagued by delays, cost over-runs, and accelerating resource nationalism;
  - Delivering on the West Qurna I redevelopment project in Iraq, which remains challenged by export infrastructure constraints. The securing of six exploration licenses in the northern Kurdistan region is the latest signal of ExxonMobil's concern over the ability of Iraq to evolve into a Core area for the company.
- **Maintain leadership in share buy-back and dividend performance**: ExxonMobil has been a clear peer group leader in returns to shareholders, distributing ~\$29 bn through dividends and share buy-backs in 2011 and spending ~\$109 bn on share repurchase over the 2007-2011 period. With the increased emphasis being placed on unconventional gas resources to deliver future volume growth, shareholders will be looking for ExxonMobil to continue its leading dividend and share buy-back performance, as the core differentiator from its faster growing (in volumetric terms) peer group companies.

Questions & Discussion

2011	Alaska	% US	% Global	% Trend
BP	173 mboe/d	17	5	↓
COP	244 mboe/d	36	14	↑
XOM	117 mboe/d	14	3	↓

Criteria:
Competitive

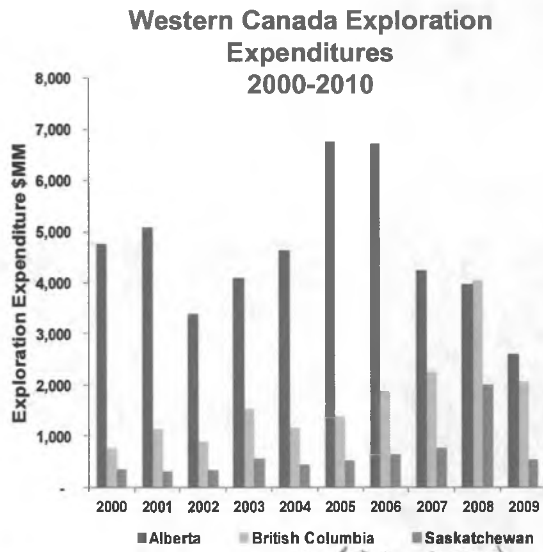
PFC Energy

APPENDIX

Impact of Changes in Fiscal Terms on Upstream Investment: Assessing Data from Alberta, Canada

Exploration Spending in Western Canada

- Alberta has historically accounted for the majority of exploration expenditures in western Canada
- The less competitive fiscal terms introduced in Alberta in 2007—which eliminated royalty holidays on new wells—were accompanied by a sharp decrease in exploration activity in that province, and a reallocation of exploration spending to Saskatchewan and British Columbia (BC)
- In 2010, responding both to this competition and to reduced expenditures resulting from the 2008-2009 economic crisis, the Alberta Government approved a new fiscal framework, designed to "position Alberta as one of the most competitive North American destinations for energy investment"
- Since then, exploration expenditures in Alberta have recovered from the crisis far more quickly than in other jurisdictions



- **Question**: Is the relationship between exploration spending and fiscal change causal, or merely correlative?

Impact in 2007 (like ACES) harvest more

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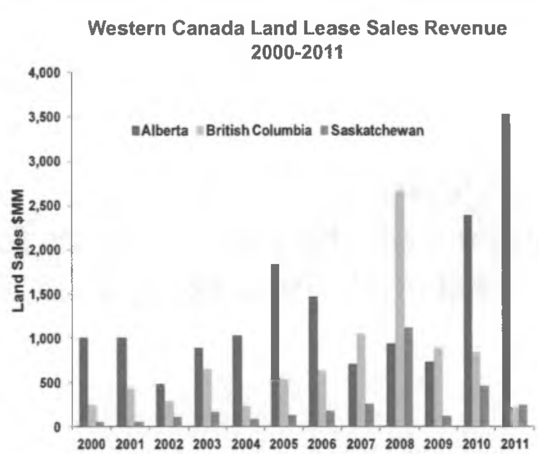
Land Lease Revenue, Western Canada

- Historically, roughly one-third of exploration spending in Western Canada is accounted for by *land lease sales*—securing acreage rights for future drilling. Strength in land lease revenue is a signal of future drilling intentions, as acreage can only be held for a defined period without seismic and drilling activity before reverting to the government
- For both Saskatchewan and BC, the rise in land lease sales revenue in 2007 and, in particular, 2008 accounted for a significant share of the rise in overall exploration expenditures
  - Land lease spending over the 2000-2010 period accounted for ~31% of total exploration spending for Alberta, and a higher 36% for Saskatchewan and 44% for BC
  - In 2008, land lease spending accounted for ~66% of total exploration spending for BC and ~56% in Saskatchewan, while that number reached only 24% for Alberta (an improvement over the 17% recorded in 2007)



- While a share of this land lease spending in Saskatchewan and BC can be ascribed to upstream players "voting with their feet" in order to send a signal to the Alberta Government regarding fiscal changes, it is also the case that:
  - In BC, the 2007-2008 period marked a major positioning by the exploration & production sector in the emerging Horn River and Montney shale gas plays in the northeast area of the province;
  - In Saskatchewan, 2008 marked a major positioning in the emerging Exhaw/Bakken play, being the northern extension of the Bakken light tight oil (shale oil) play in North Dakota

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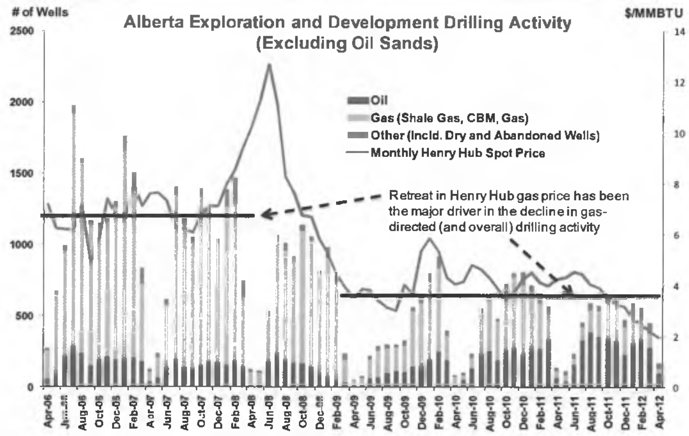
Commodity Prices Drive Upstream Activity

- However, it has been movements in commodity prices—and in particular, the dramatic downward shift in natural gas prices—that has been the largest contributor to changes in upstream activity in Alberta over the past 5 years
  - Apr 2006 – Dec 2007: Henry Hub gas price averaged $6.74/mmbtu (~$6.15/mmbtu at the AECO-C Alberta border pricing point)
  - July 2008: HH price reaches $11.70/mmbtu;
  - Dec 2008 – Apr 2012: HH price averages $3.98/mmbtu (and as low as $1.95/mmbtu Apr 2012), or ~$3.38/mmbtu at AECO-C.



reinvent itself c̄ tech

- Oil-directed and gas-directed drilling have responded to these movements in commodity prices
  - Gas-directed drilling has fallen in step with weak gas prices and increasing production
  - Oil-directed drilling (excluding the oil sands) has risen over the period to a decade high in 2011-2012

Alberta Drilling Data	Oil-Directed Drilling	Gas-Directed Drilling
Apr 2006-Mar 2007	1,669	11,540
Apr 2008 – Mar 2009	1,376	6,895
Apr 2011 – Mar 2012	3,157	1,641

Summary Comments

- There is no disputing that upstream E&P activity responds to changes in fiscal terms. All else being equal, E&P companies will allocate their upstream investment dollars to those opportunities most likely to deliver best on performance metrics (IRR, NPV, PVPI, ROCE).
- However, as seen in the case of Alberta/Western Canada, upstream E&P activity responds most to movements in commodity price.
  - In Western Canada in general, and Alberta specifically, the greatest impact on upstream activity levels has come from the sharp and continuing decline in natural gas prices
  - Exploration expenditures ramped up sharply in BC and Saskatchewan in 2007-2008, coincident with a shift in fiscal terms that lowered drilling incentives in Alberta.
  - This particularly ill-timed fiscal change coincided with the maturing of shale oil and shale gas development technologies in the US Onshore basins, which manifested in the large land lease expenditures directed to the Horn River/Montney shale gas plays in northeast BC and Exshaw/Bakken shale oil play in southern Saskatchewan
- Alberta's reduced fiscal burden meant that it was very well positioned to compete for investment when economic activity in the Canadian upstream sector improved.
  - This can particularly be seen by the dramatic shifts in land lease sales revenues in Alberta in recent years
  - The impact on actual drilling activity has been more muted, however, because of the adverse impact of low North American gas prices

Notice

PFC Energy has prepared the materials utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice, based on information available at the time such materials were created. To the extent these materials contain forecasts or forward looking statements, such statements are inherently uncertain because of events or combinations of events that cannot reasonably be foreseen, including the actions of governments, individuals, third parties and market competitors. **ACCORDINGLY, THESE MATERIALS AND THE INFORMATION CONTAINED THEREIN ARE PROVIDED "AS IS" WITHOUT WARRANTY OF ANY KIND, EITHER EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO THE IMPLIED WARRANTIES OF MERCHANTABILITY, ACCURACY, OR FITNESS FOR A PARTICULAR PURPOSE.** Conclusions presented herein are intended for information purposes only and are not intended to represent recommendations on financial transactions such as the purchase or sale of shares in the companies profiled in this report.

PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable across all companies and all countries.

This report reflects information available to PFC Energy as of the date of publication. Clients are invited to check our web site periodically for new updates.

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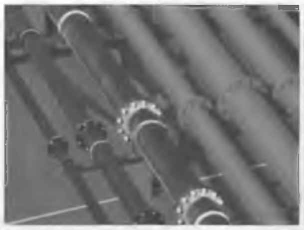

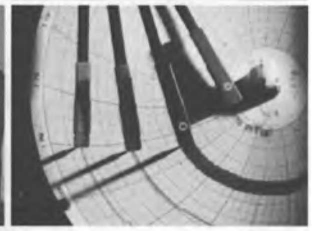
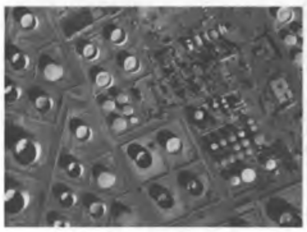
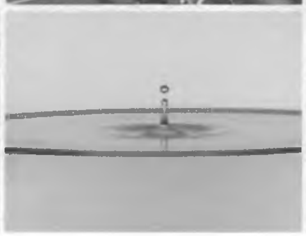


PFC Energy

ALASKA STATE LEGISLATURE

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Senate Resources Committee

Butrovich Room 205
Friday, February 8, 2013
3:30-5:30 p.m.

AGENDA

- **BPH/S**
  - **SB 27 Regulation of Dredge and Fill Activities**
  - **SB 26 Land Disposal/Exchanges; Water**

- **What It Takes To Keep Our Legacy Fields Alive**
  ConocoPhillips
  BP
  ExxonMobil

Teleconference

ConocoPhillips Alaska

Senate Resources

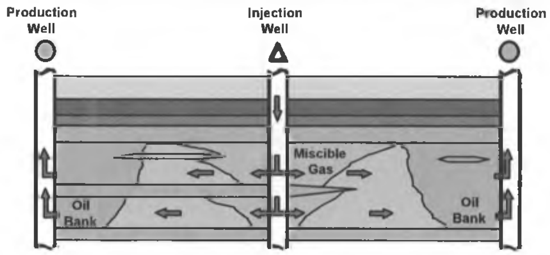
Technology Impact on North Slope Fields

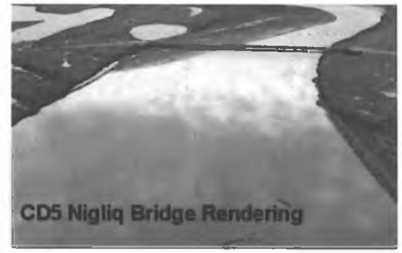
Scott Jepsen, VP External Affairs
Bob Heinrich, VP Finance
Alan Campbell, GKA Reservoir and Planning Supervisor
ConocoPhillips Alaska

February 8, 2013

NS Development Evolution

ConocoPhillips Alaska





1981: Kuparuk Waterflood Pressure Maintenance

1988: SSEOR and MWAG startup

1998: Tabasco and **Tarn** startup

2001: Meltwater startup

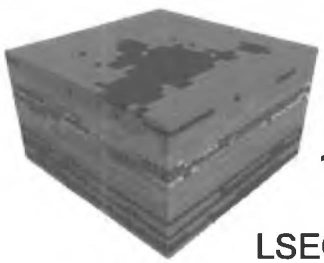
2000: Alpine startup

2012: CD5 Sanction

1981 1986 1991 1996 2001 2006 2011 2012

1981-1986: Gas storage

1985: STP, IWAG, & Frac'ing startups

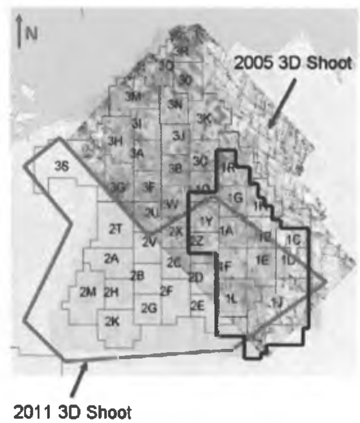


1996: NGL import and LSEOR startup

1997: West Sak startup

1999+: DS footprint reduction and Extended Reach Drilling

2005 and 2011: 3D and 4D seismic

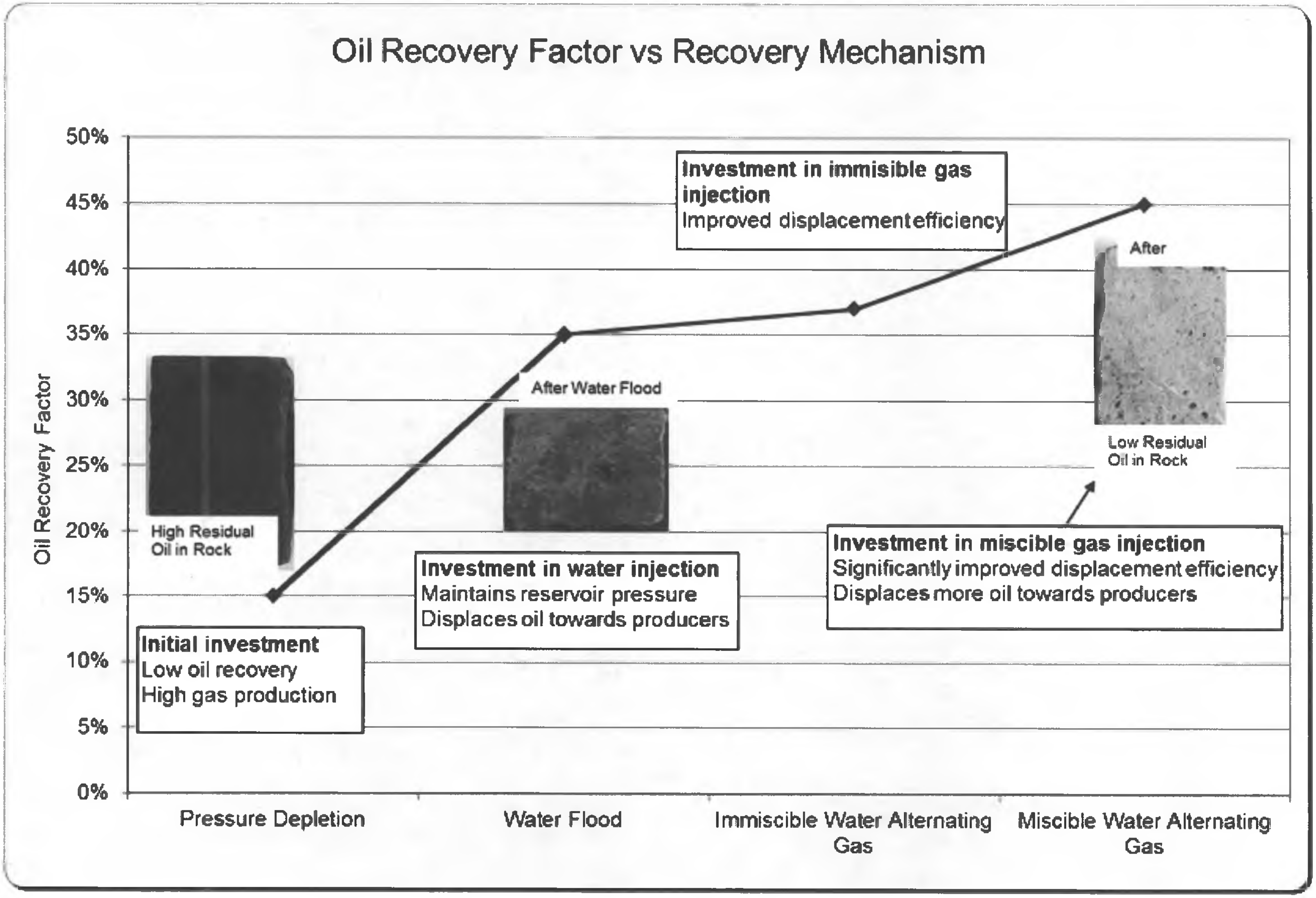


2009+: Coil Tubing Drilling rig

Future: Viscous, Low Perm, EOR+, Heavy

Recovery Efficiency Evolution

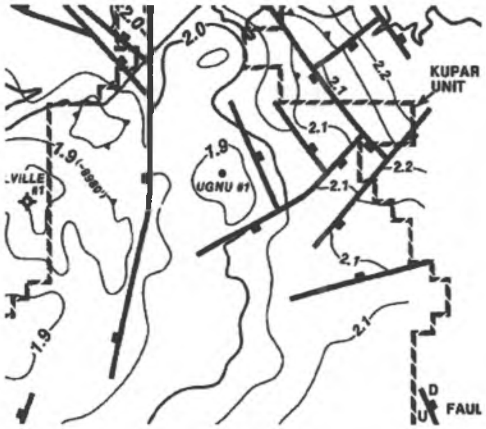
ConocoPhillips Alaska



Seismic Evolution
GKA Legacy Asset

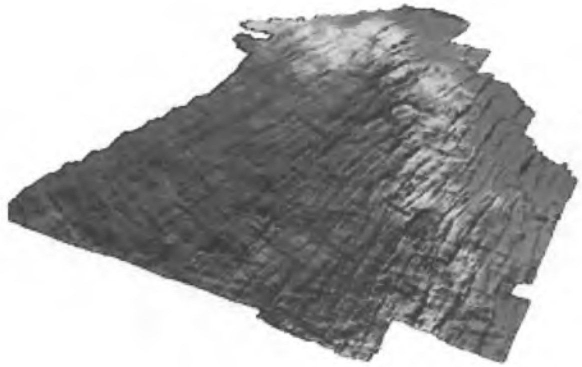
ConocoPhillips Alaska

Field Discovery
1967



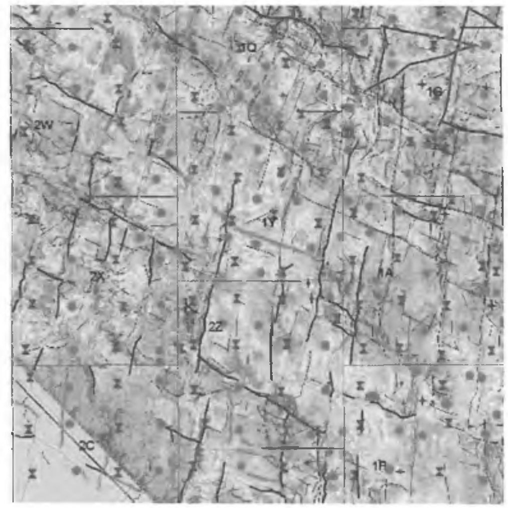
Sparse 2D seismic
Faulting believed to be simple
Few wells drilled

3D Seismic
1988-2011



Improving 3D Technology reveals 1000's of faults - Reservoir Compartments
1000+ wells drilled

4D Seismic
2005 - forward



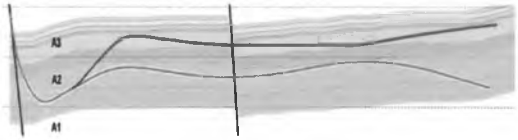
Emerging 4D Seismic Technology reveals field changes and more infill targets/unswept oil

Coil Tubing Drilling Evolution

GKA Legacy Asset

ConocoPhillips Alaska

2006: Slimhole resistivity



2004 through December 2012: 232 CTD laterals, 470,196' drilled

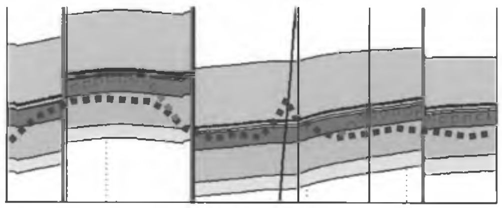
1998: CTD BHAs downsized

Aug. 2004:1st lined multi-lat

2009: Directional

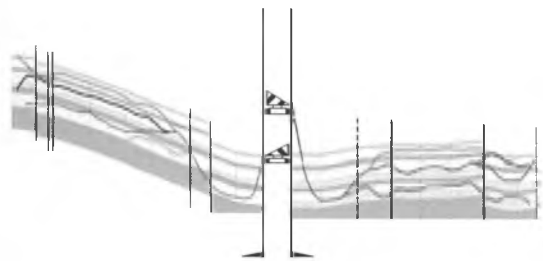
1998 2004 2005 2006 2009 2010 2012

2005:1st quad-lat; KWS 3D seismic

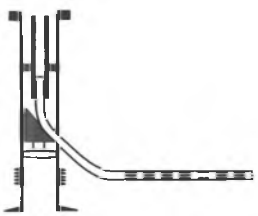


Jan. 2010: WK 3D survey

2012: 1st octa-lat



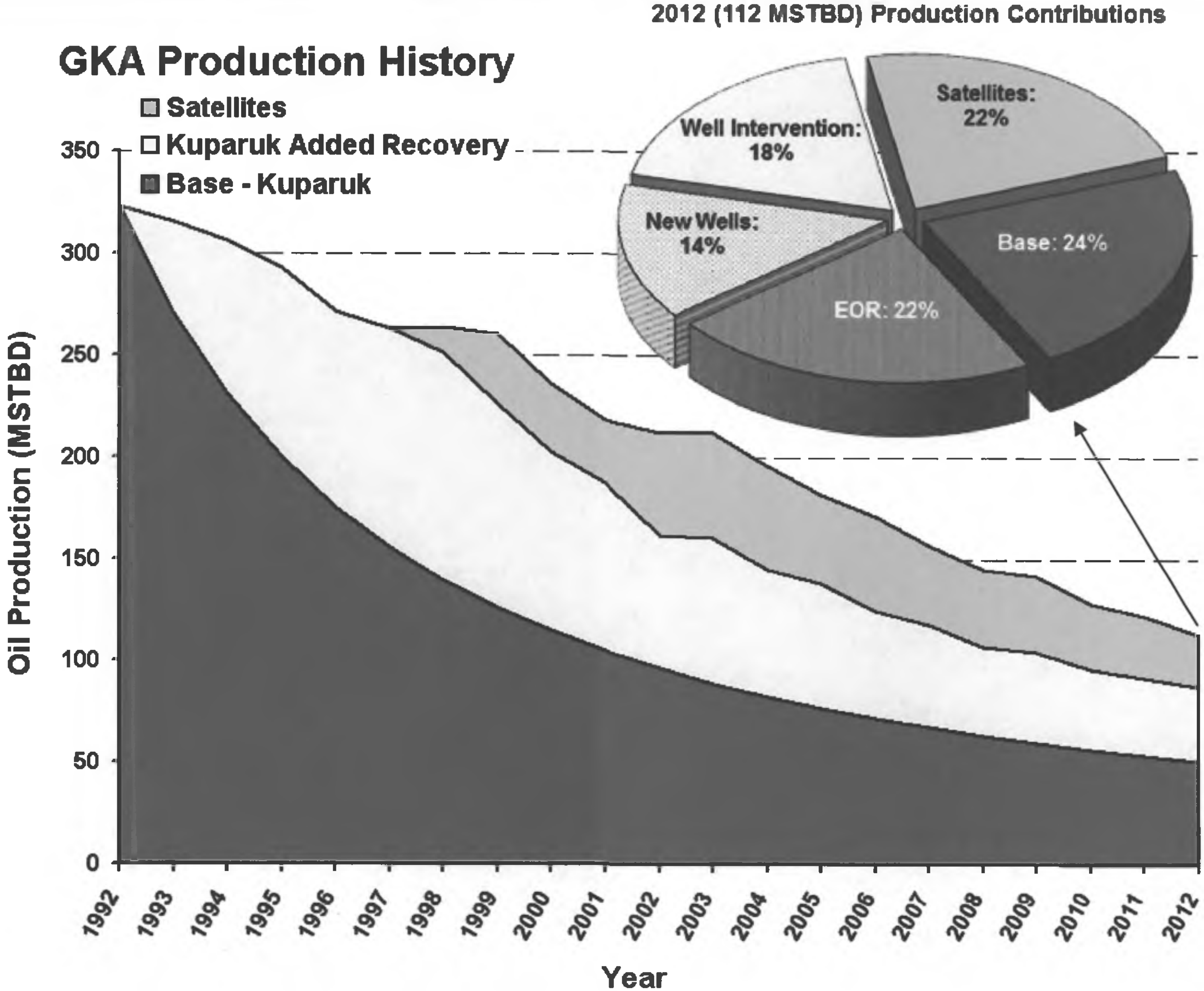
1998-2004: single-laterals



May 2009: Dedicated, purpose-built rig

GKA Legacy Asset
Production History

ConocoPhillips Alaska

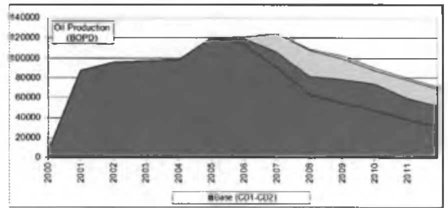


WNS Development Evolution

ConocoPhillips Alaska

2000: Alpine Start-up (CD1)

2005: CD3,CD4 New Drillsites



1994: Alpine Discovery

2001: CD2 New Drillsite

2002-2006: Alpine Central Facility Expansions

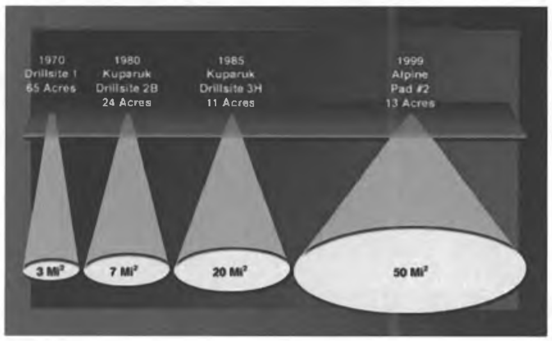
2007: Qannik

2008-2012: CD3 & CD4 slot additions

2012: CD5 Sanction

1994 2000 2002 2004 2006 2008 2010 2012

2000+: Optimized Field Development
-1st horizontal well development on NS
-Extended Reach Drilling

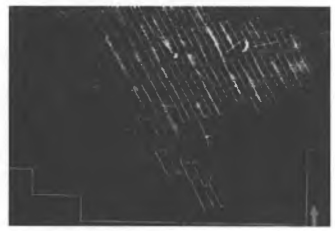


2000+: Near zero discharge facility

Remote Operations
-Alpine Resupply Ice Road
-CD3 Remote Operations

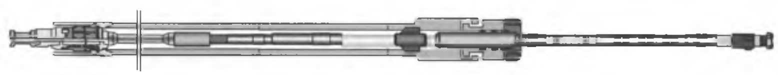
2000+: Improved Recovery
-Waterflood (incl. seawater)
-Enriched gas injection

2010: 3D&4D seismic



2012+: Steerable Liner Drilling

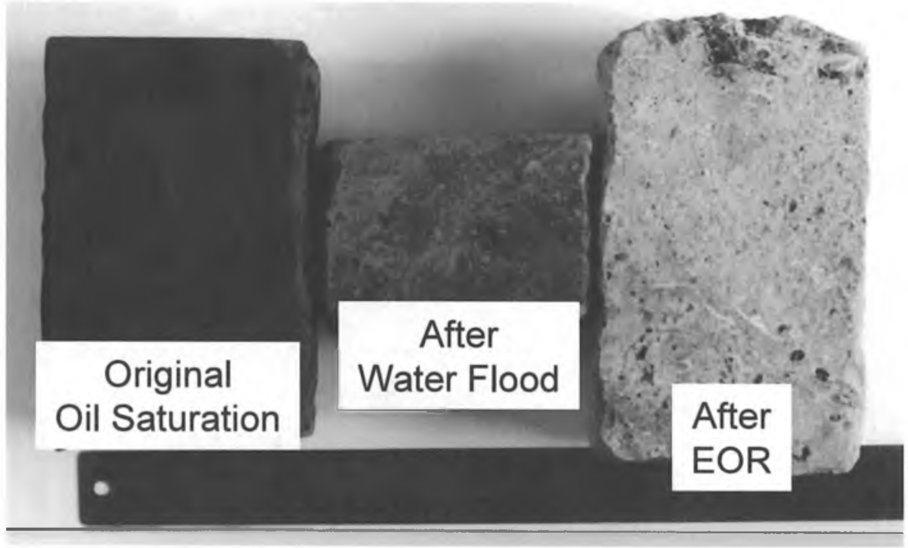
2008+: Well drilling in ultra thin sands

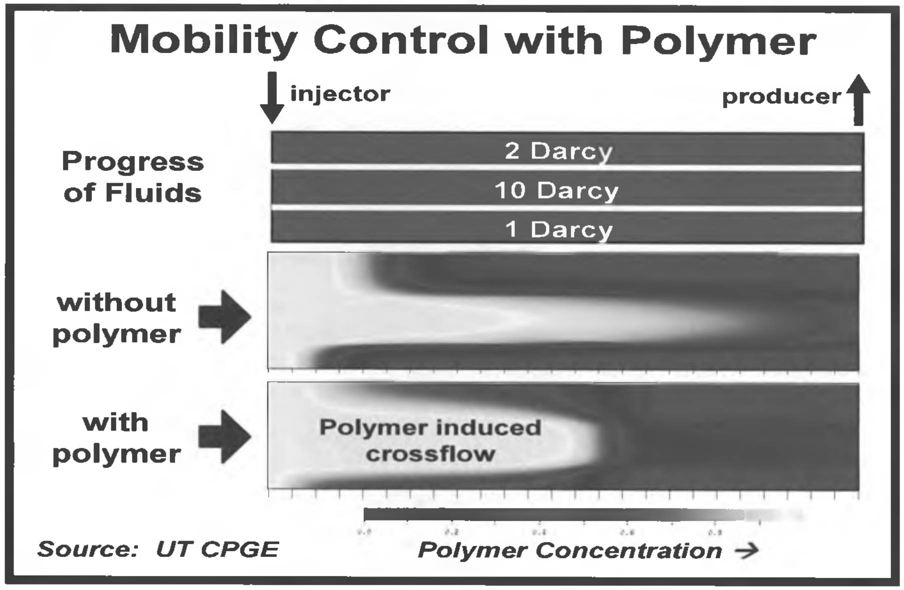


Future EOR Technology Opportunity

ConocoPhillips Alaska

- Chemical EOR
- Flood Conformance Polymers
- Thermal & Non-Thermal Heavy Oil Recovery





"Easy Oil" In the Legacy Fields Is Gone

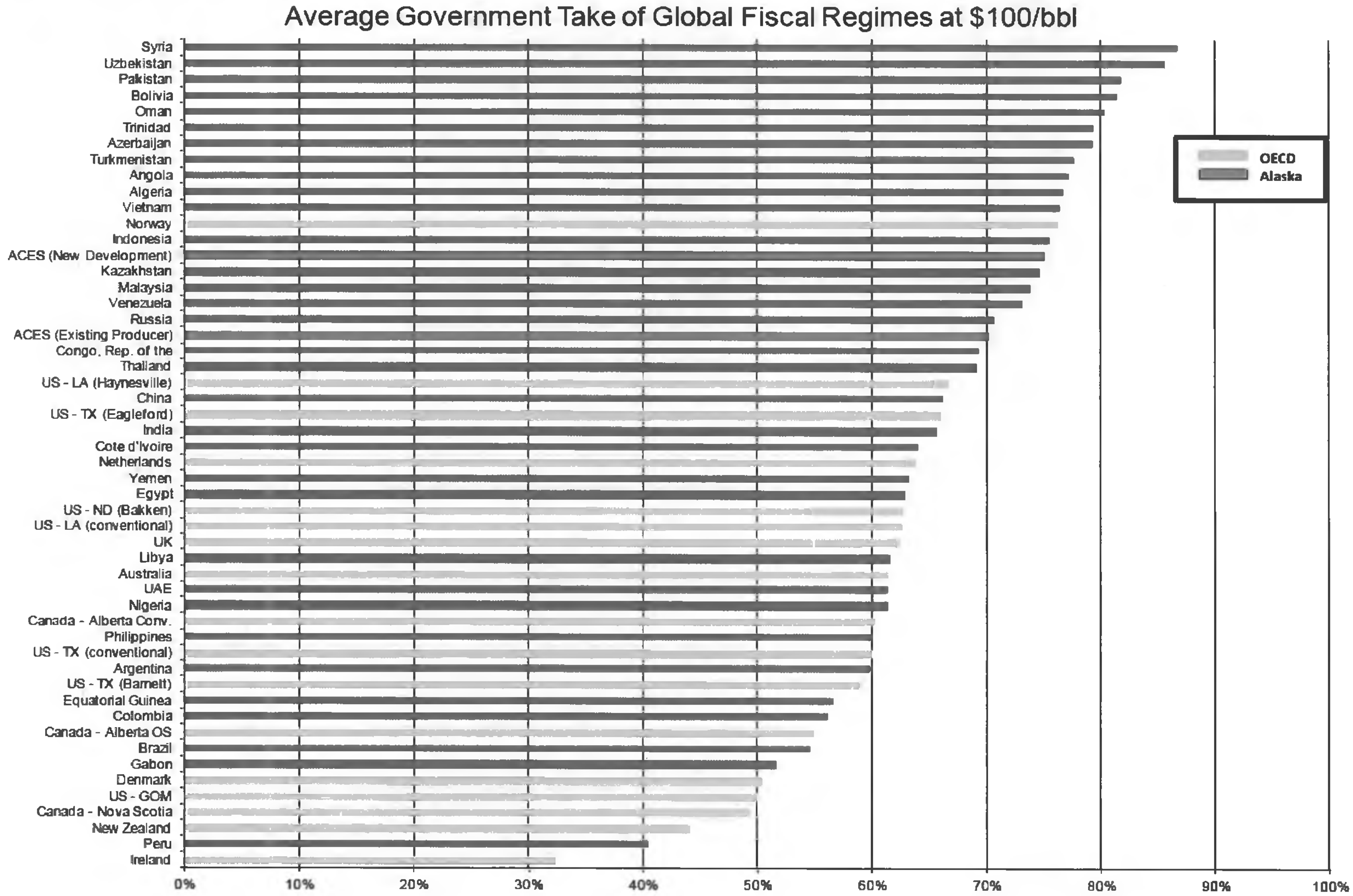
ConocoPhillips Alaska

- Challenged oil remains
  - Complex, high cost wells
  - Smaller reserve targets
  - Fault blocks, flank oil
  - Satellites, viscous oil
  - Most new wells produce oil AND water
  - Facilities handling ~ three times as much water as oil
- **A billion dollars does not go as far as it used to…**
  - 2000 Alpine development ~80,000 BOPD
  - 2012 CD-5 Drillsite ~18,000 BOPD

Initial Alpine Development

CD-5 Type Development

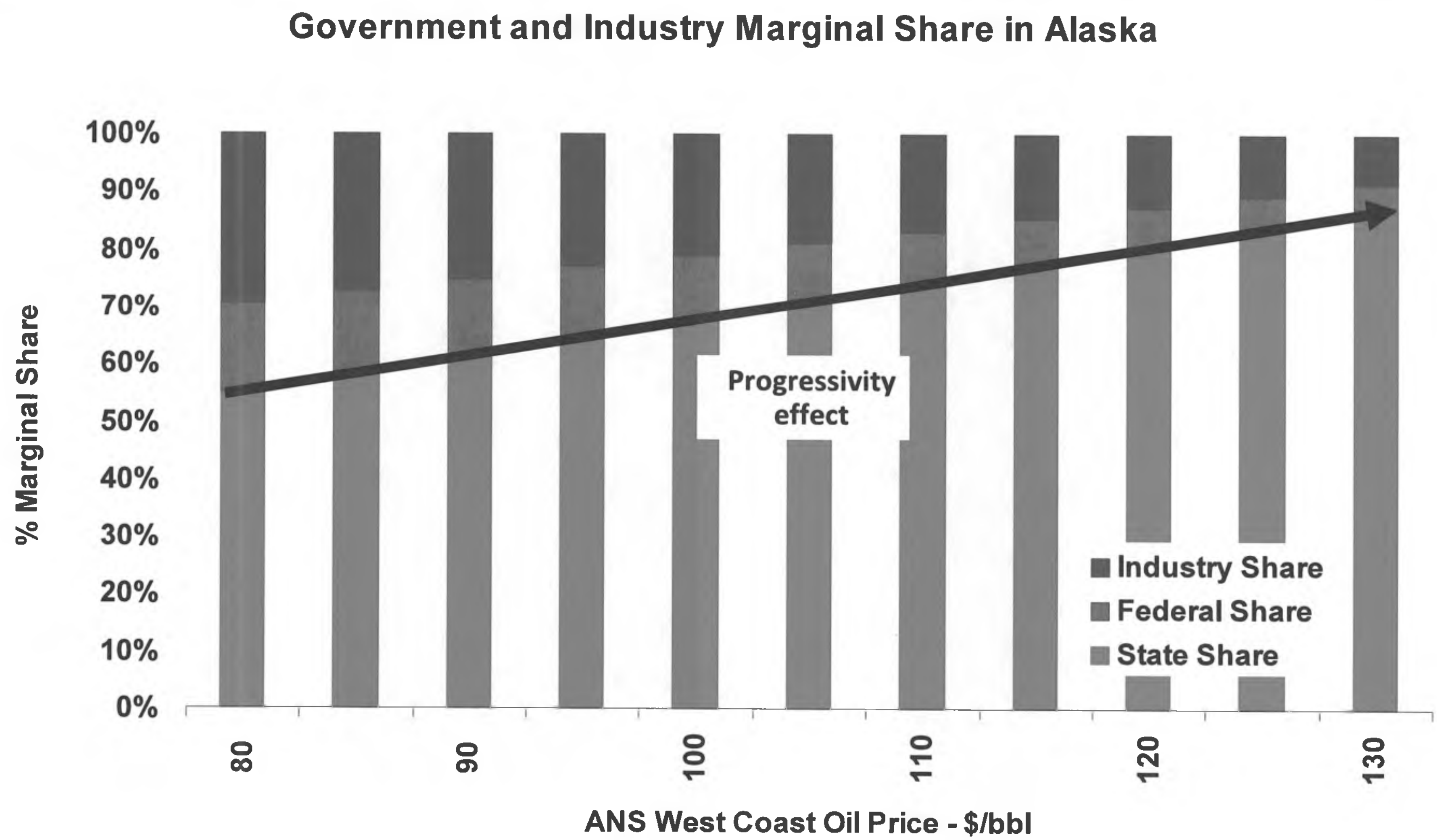
Regime Competitiveness: Average Government Take at $100/bbl



PFC Energy

ACES Marginal Industry Share

ConocoPhillips Alaska



Based on Fall 2012 Revenue Sources Book data for FY2014

Summary

ConocoPhillips
Alaska

- Technology and innovation have played a key role in the development and increased recovery of North Slope legacy fields and satellites
- The legacy fields provide the resource base to continue development and implementation of new technology
- Application of new technologies is not inexpensive – costs can be high
- Alaska's oil tax system puts the North Slope business climate at a disadvantage

Acronyms

ConocoPhillips Alaska

- BHA = Bottom Hole Assembly
- BOPD = Production rate in Barrels of oil per day
- CTD = Coil Tubing Drilling
- DS = Drill Site
- EOR = Enhanced Oil Recovery
- GKA = Greater Kuparuk Area
- ICD = Injector Control Device
- IWAG = Immiscible Water Alternating Gas
- KWS = Kuparuk West Sak Survey
- LSEOR = Large Scale Enhanced Oil Recovery
- MMBO = Million barrels of oil
- MSTBD = Production rate in 1000's of stock tank barrels of oil per day
- Multi-lat = Multilateral well
- MWAG = Miscible Water Alternating Gas
- NEWS = North East West Sak
- NS = North Slope
- NGL = Natural Gas Liquids
- Octa-lat = Octalateral well
- Perm = Permeability
- Quad-lat = Quadralateral well
- SSEOR = Small Scale Enhanced Oil Recovery
- STP = Seawater Treatment Plant
- WAG = Water Alternating Gas
- WK = Western Kuparuk Survey
- WNS = Western North Slope

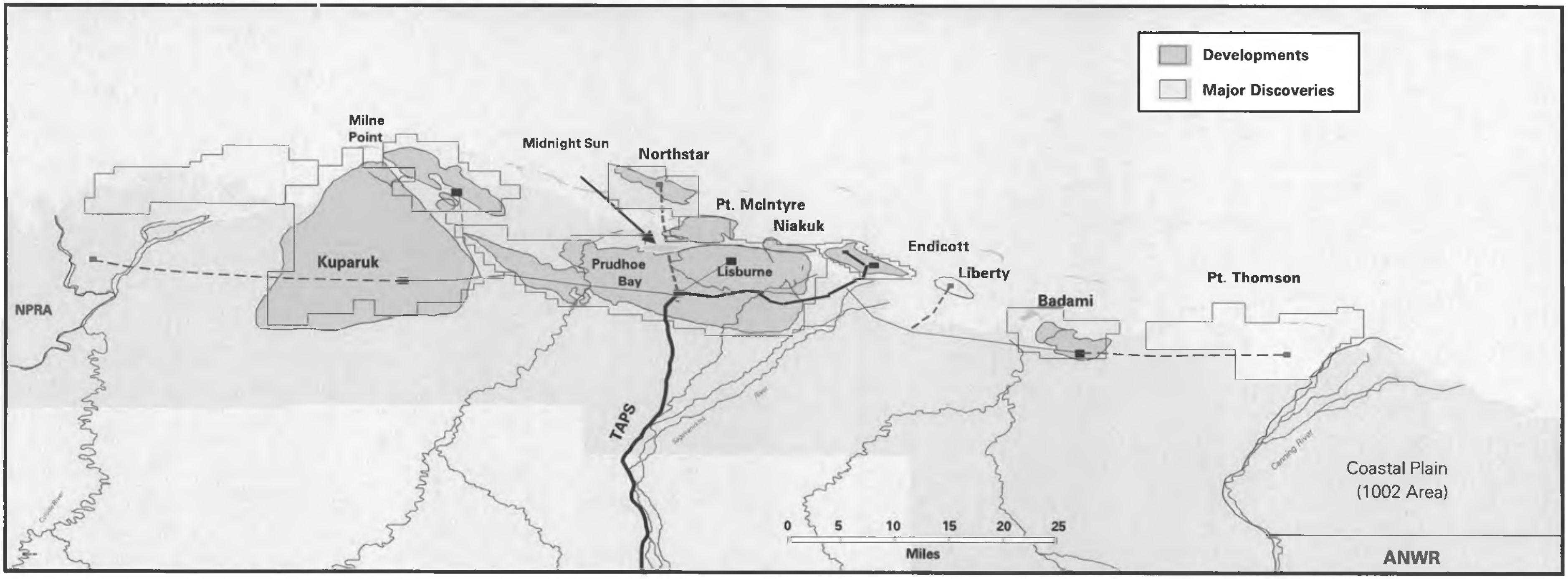
BP Testimony to Senate Resources

Damian Bilbao, Head of Finance

Scott Digert, Reservoir Management Team Lead

February 8, 2013

Prudhoe Bay – 35 years later……

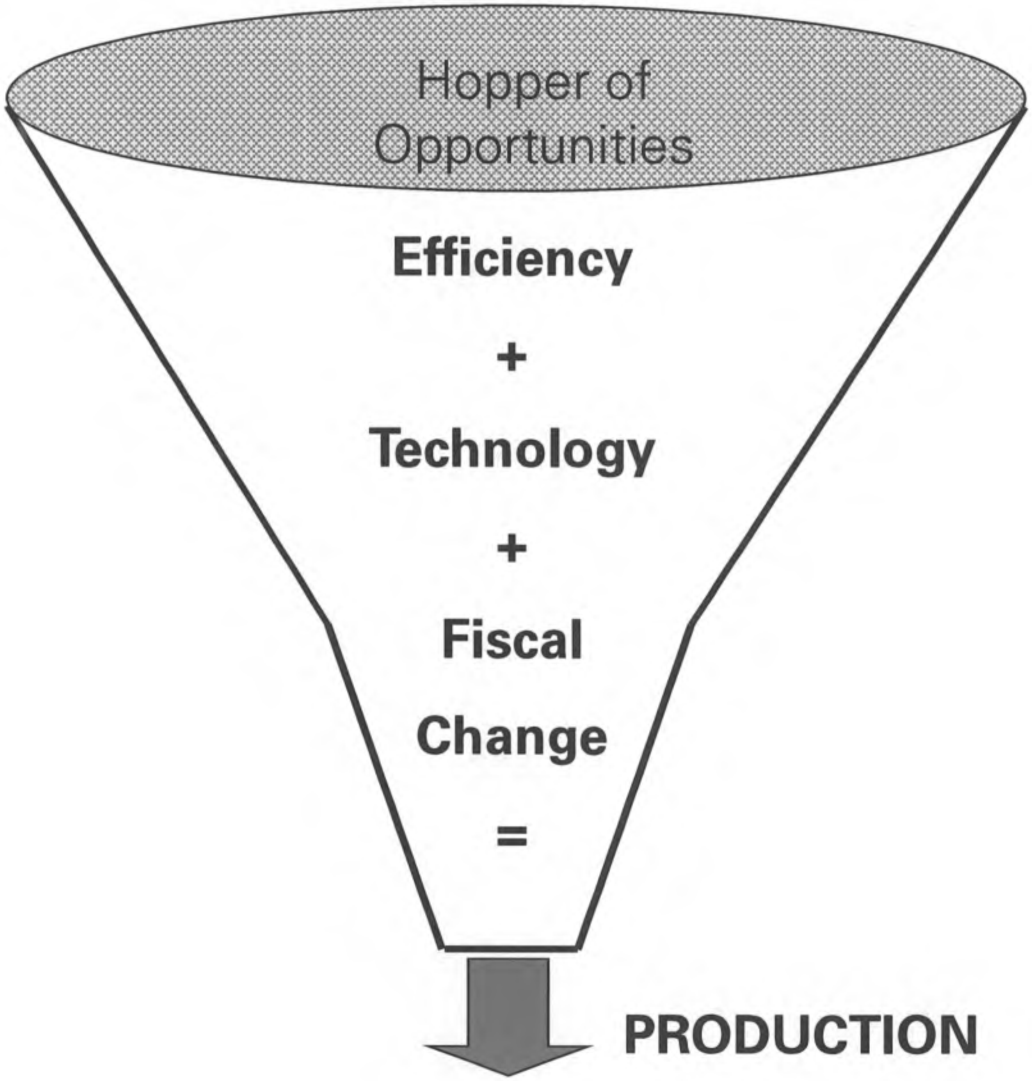


Ownership

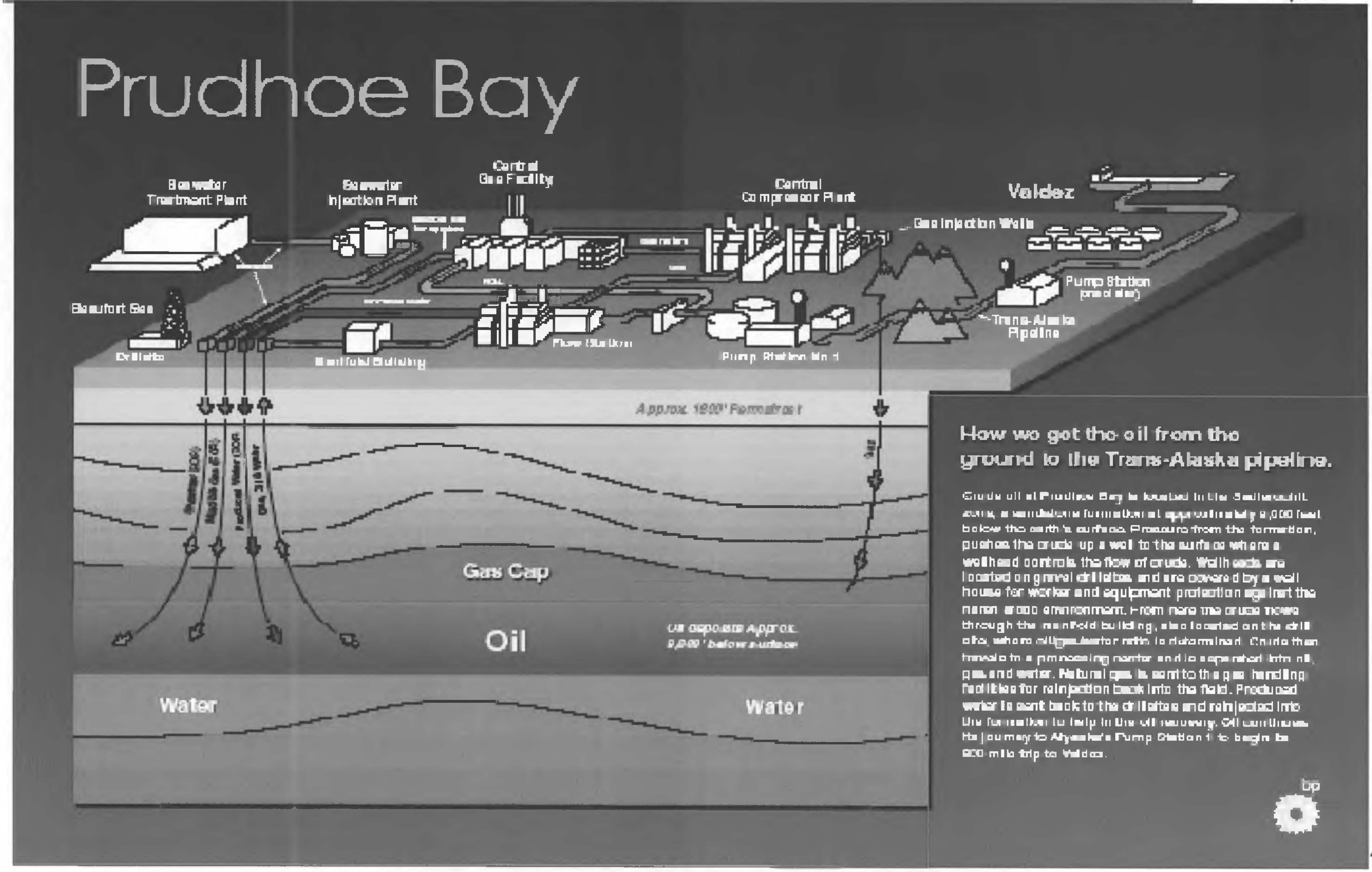
- ConocoPhillips ~ 36%
- ExxonMobil ~ 36%
- **BP ~ 26%**
- Chevron ~ 1%

- Prudhoe Bay is the largest field in North America
  - Over 300 sq miles
  - Original in place: ~23 billion bbls; ~40 trillion cubic feet
  - Over 12 billion bbls recovered
- 200+ Society of Petroleum Engineers technical papers have been written

What Drives Investment?



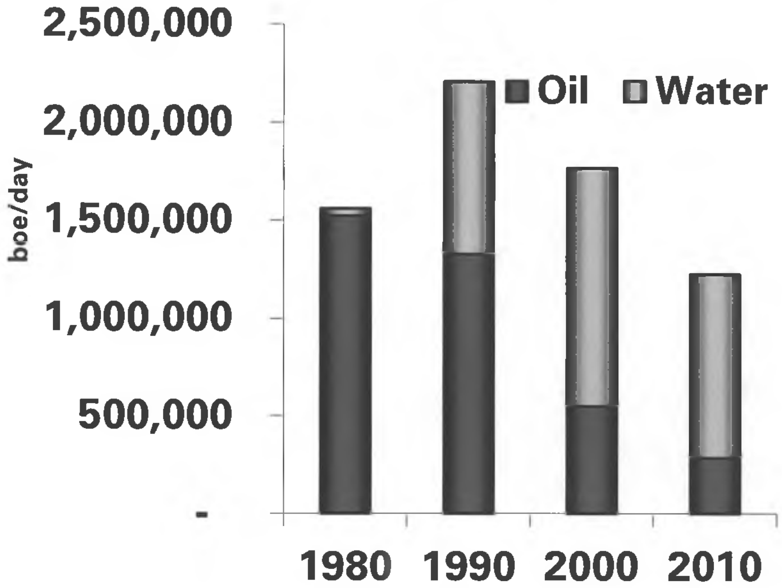
Prudhoe Bay - Largest Field in North America



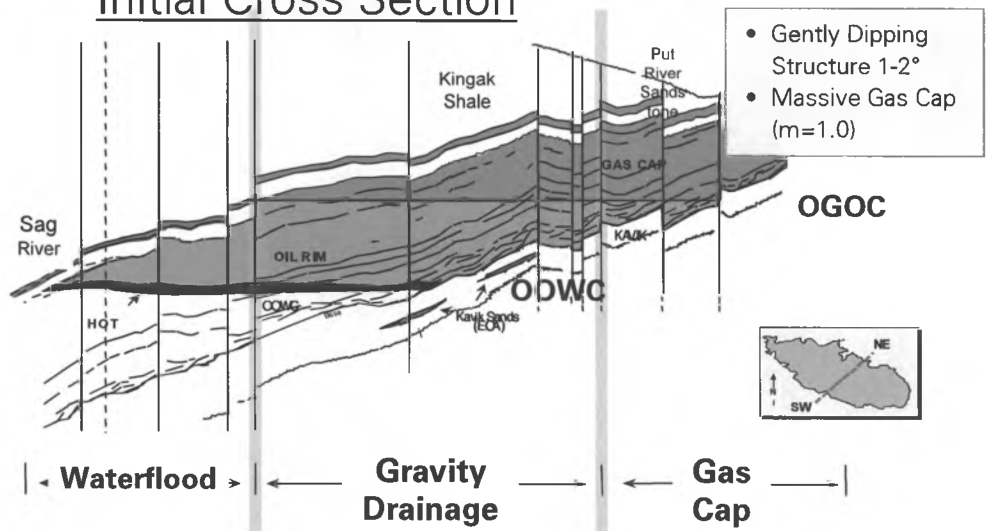
Alaska has historically driven global technology

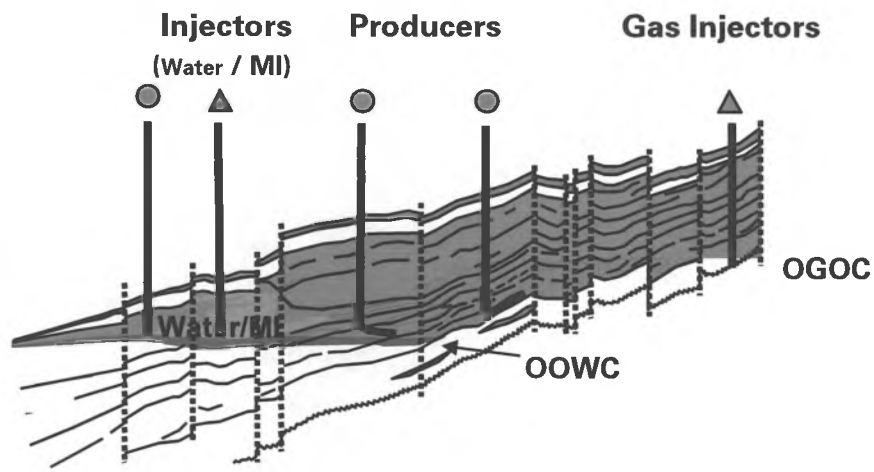
- Gravity Drainage
- Vaporization (Lean Gas Injection)
- Waterflood
- Miscible Gas Injection (MI)
- Drilling Technology

Production profile



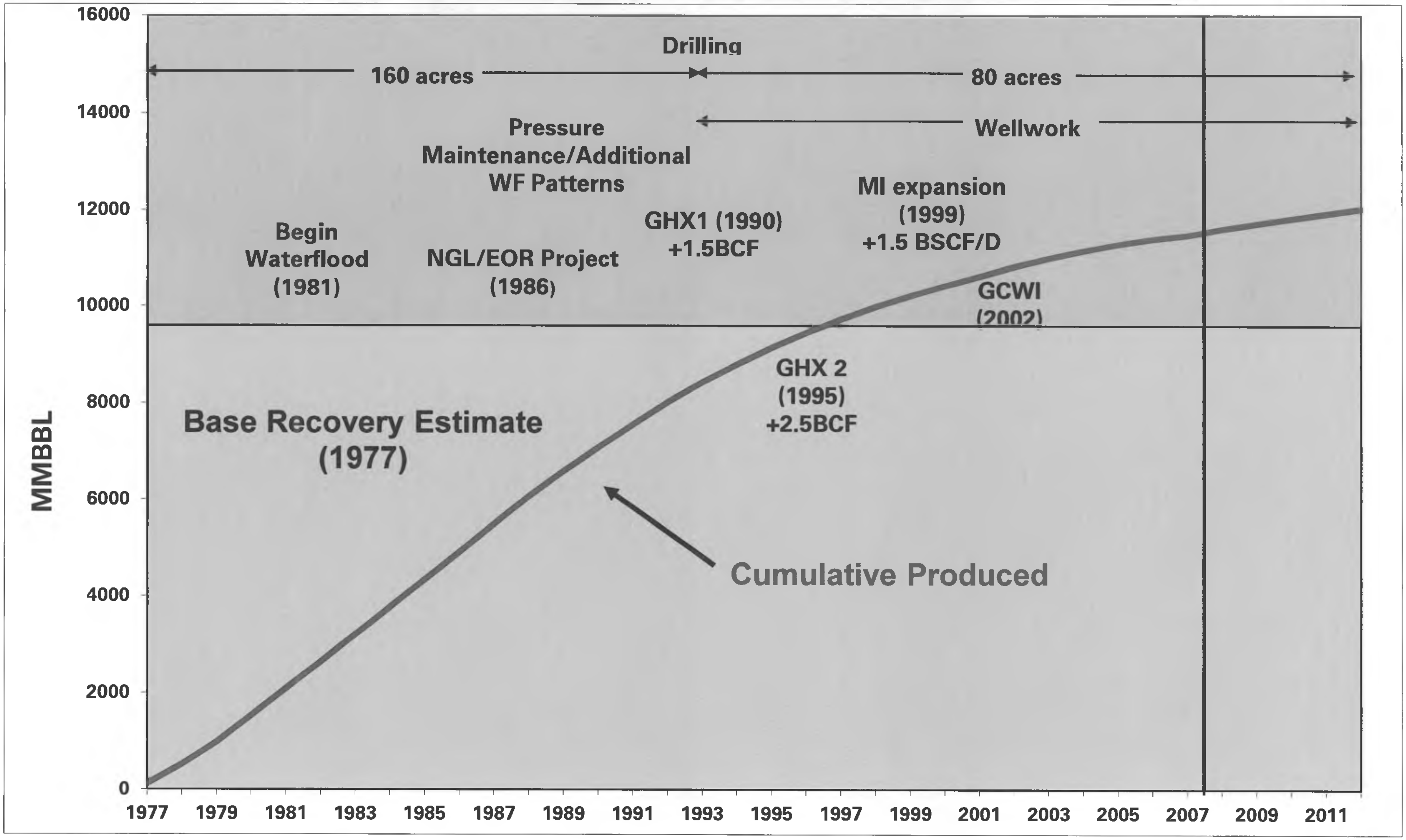
Initial Cross Section



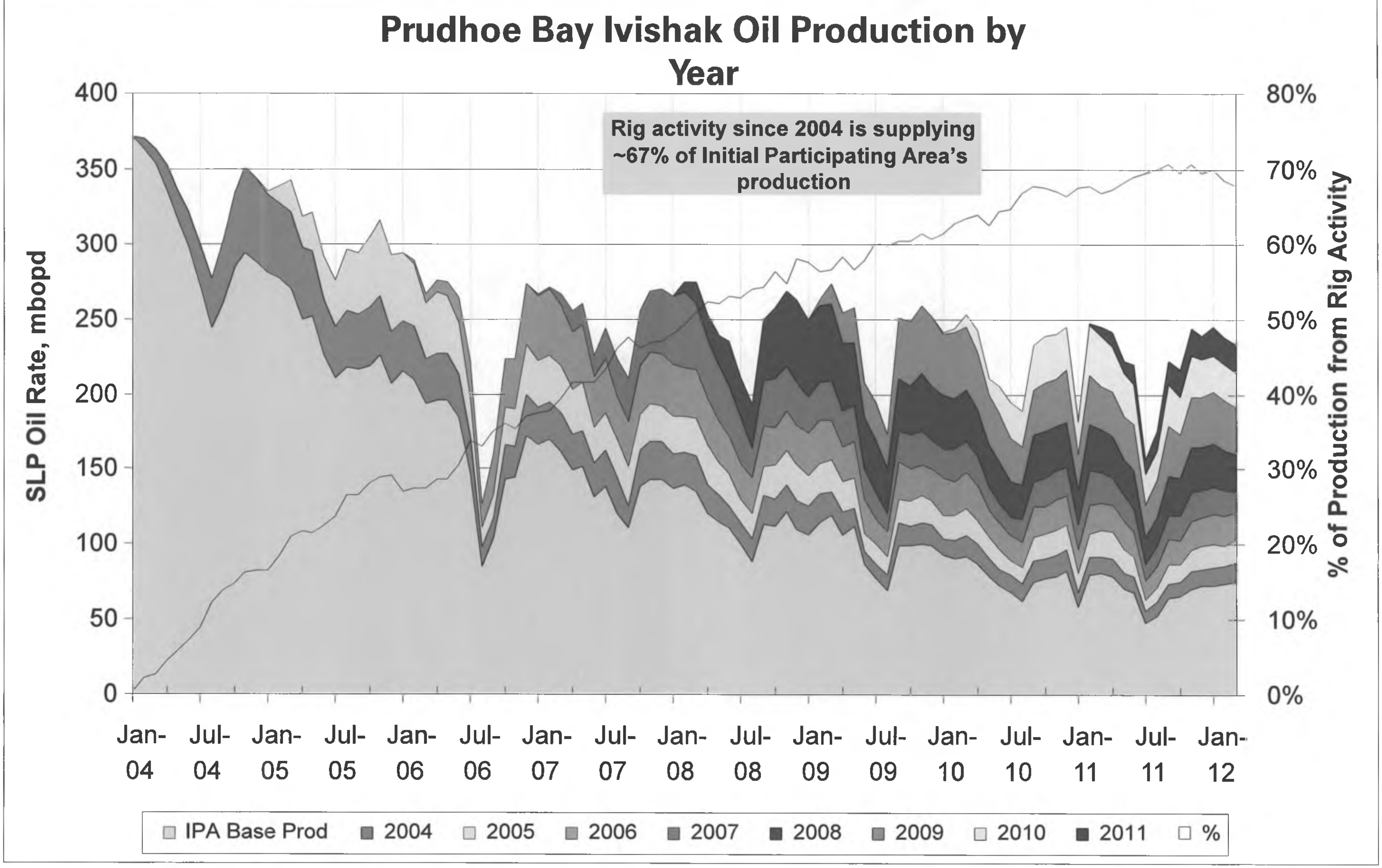


Current Cross Section

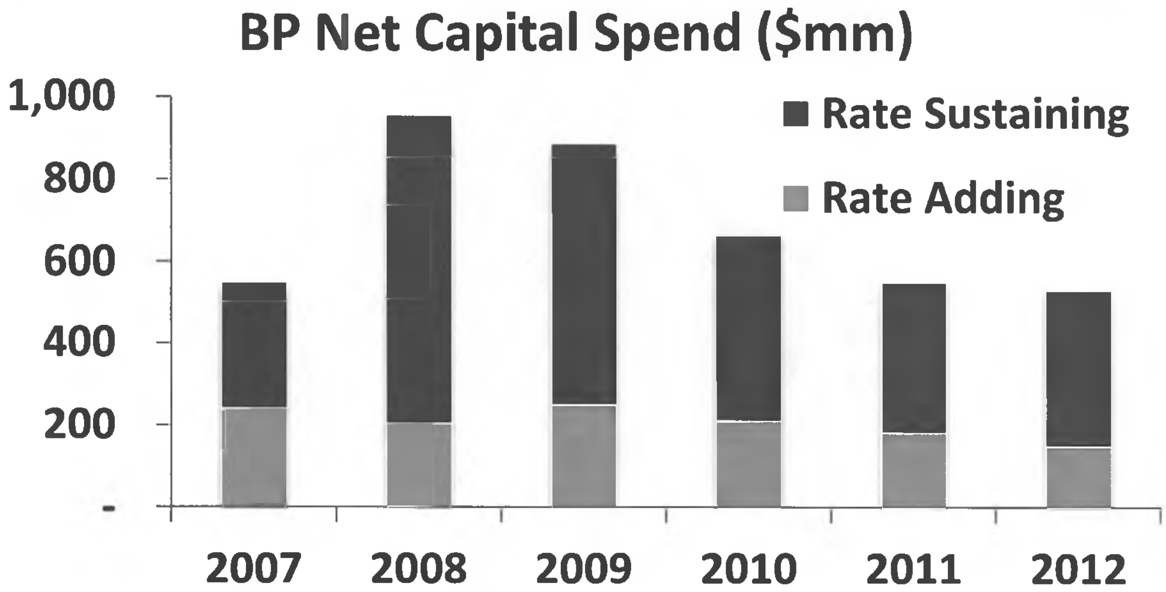
ACES discourages investment in technology



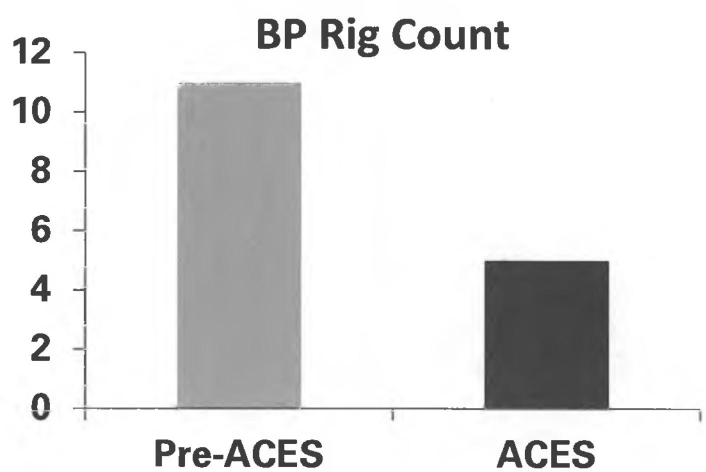
Without investment production declines sharply



Government policy is driving investment down



Excludes Liberty and mid-stream investments



- TAPS is three-quarters empty
- Policy drives investment decisions
- Producers control efficiency and technology
- State Gov'ts direct fiscal policy to compete for investment

In summary

- BP has been in Alaska for over 50 years
- Billions invested in development and technology advancements
- Leveraged technology to exceed original production expectations
- Significant opportunities remain, but they are economically and technologically challenged
- Increasing production will require new long-term technology investments

TESTIMONY OF EXXONMOBIL
ON ALASKA'S INVESTMENT CLIMATE
TO THE ALASKA SENATE REOURCES COMMITTEE ON
FEBRUARY 8, 2013

Madam Chair, members of the committee:

For the record, my name is Dan Seckers. I am ExxonMobil's Tax Counsel, based in Anchorage. I want to thank the committee for the opportunity to express ExxonMobil's views on Alaska's current investment climate and the impacts of Alaska's oil and gas production tax or ACES.

You have heard today the testimony of the operators of the legacy fields, BP and ConocoPhillips, expressing their views on the impact of ACES on Alaska's global competitiveness and the future of the State's investment climate. ExxonMobil shares many of the concerns raised in those testimonies.

Let me begin by underscoring what many of you have likely heard ExxonMobil say throughout the years - that Alaska has been and continues to be an important component of ExxonMobil's world-wide investment portfolio. We have had a presence in Alaska for over 50 years and have been a key player in Alaska's oil industry development. We are the operator of Point Thomson, hold the largest working interest at Prudhoe Bay (36.4%) and are the largest lease holder of discovered Alaska gas resources. We are committed to Alaska and its future and expect to be involved here for many years to come.

Let me also state that ExxonMobil continues to support Governor Parnell's efforts toward substantive reform of ACES. We appreciate his willingness to champion this difficult issue for the past two years and his committed effort again this legislative session. The need for Alaska to develop a competitive, stable fiscal regime that attracts the levels of investments that Alaska's North Slope requires is one of the most, if not the most, important issues facing the State. We believe the Governor's four core "principles", as emphasized in his State of the State speech that any reform of ACES:

- Be fair to Alaskans
- Encourage new oil production
- Simplify and restore balance to Alaska's fiscal system
- Make Alaska competitive for the long term

can form the foundation of a successful, long-term taxation policy for the State.

The Governor has not been alone in his efforts. Many members of the Legislature have worked hard the past two years to examine and understand the impact of ACES on Alaska's global competitiveness. That hard work has been having a positive effect as it appears legislators and most Alaskans now recognize that Alaska's production tax system is not well designed to tackle the production decline and attracting investments to develop new production.

Consistent with the testimony we have given over the past several years, ExxonMobil believes that the changes made to Alaska's oil and gas production tax since 2005 have had a negative impact on business activity in Alaska and Alaska's overall investment climate. Fundamentally, the progressivity component of the ACES tax regime, on top of an already high base tax rate, creates a major disincentive to invest in the high-risk, high-cost opportunities available in Alaska. These two features must be addressed for any tax policy to be successful in meeting the State's desired production and long-term revenue goals.

Two aspects of the current tax policy, however, are pro-development. The deduction of operating and capital expenditures before applying the tax rates recognizes the high cost of doing business in Alaska. The further tax credit for capital expenditures rewards those who invest in future production and infrastructure. These are key components of the current ACES whose benefits should be reflected in any revised tax policy the State is considering.

As the Legislature's and State's own consultants have indicated over the previous two legislative sessions and during the current hearings in the Senate Special Committee on TAPS Throughput, Alaska has one of the highest and most punitive tax systems in the world. The high progressivity is directly impeding Alaska's global competiveness. To significantly grow state revenues, secure jobs and stem the production decline, it is essential that Alaska's tax structure encourages long-term development of all of Alaska's resource potential.

As the Governor has stated, Alaska's fiscal regime must be competitive and durable for the long term. ExxonMobil values a predictable fiscal environment in which to make long term investment decisions. Our investments are capital intensive and are evaluated over timeframes of decades. Any change in the fiscal regime has a direct impact on how we view stability of the Alaskan fiscal environment, which in turn impacts how we evaluate the risk basis of future investment decisions. Because of the nature and magnitude of the risks associated with any oil or gas investment, coupled with the long lead time required to recoup that investment, stable fiscal terms are key to any investment decision.

To date, Alaska has produced more than 16 billion barrels of oil from the North Slope, and according to the Department of Natural Resources there are over 5 billion barrels of known resources remaining. These undeveloped resources represent a substantial opportunity, but their development is at risk under the current ACES tax system. Oil production today is less than one-third of the peak oil production of more than 2 million barrels per day in 1988, and annual production continues to decline.

You have heard about the continued and alarming decline of North Slope oil production from the Department of Revenue, State consultants and individuals that have testified earlier. But it is important to reemphasize that industry currently invests more than $1 billion per year just to maintain current North Slope oil production decline at six to seven percent. The substantial majority of that annual investment is in the legacy fields – Prudhoe Bay and Kuparuk. Absent that continued investment, the annual production decline would likely be in the range of 12 to 15 percent annually. Without meaningful tax reform that includes Alaska's legacy fields, Alaska can expect production declines to continue.

Production from the legacy fields not only provides the majority of the State's revenues, it sustains the current North Slope infrastructure and the operation of TAPS, which are critical to enabling new production. The infrastructure from these legacy fields has been leveraged historically for satellite developments, such as Pt. McIntrye, Orion, Borealis and other non-legacy fields to economically process and transport their oil from the North Slope to refinery destinations. If the large legacy fields did not exist, it is unlikely any of these other developments would have been economic.

Without healthy legacy fields, the prospects of any future new fields or developments become even more economically challenged and the probabilities of Alaska reaching its desired goal of long-term sustained production levels more difficult.

Encouraging increasing investment to keep these key fields healthy is therefore at least as important as encouraging investment in exploration and development of new fields. For any tax reform to contribute to the Governor's stated objectives for Alaska's long-term production, it must also be applicable to the legacy fields where the State's near and long term economic future rests.

Considerable attention has been placed on making Alaska more competitive relative to other regimes. While that focus is extremely important, it is only part of the overall picture. Benchmarking government take against other producing areas is a useful tool for gauging basic competitiveness, but does not provide the full picture of investment health. As the Department of Revenue and various consultants have testified, spending on the North Slope has remained relatively flat since the enactment of ACES. But what needs to be clarified is that the majority of that spending has been for maintenance and upkeep to sustain existing operations, not for new development. Under ACES, the State has not attracted the new investment needed to increase production.

Complicating Alaska's production decline is its high exploration, development and production costs. Alaska is one of the most expensive places in the world to develop and produce oil and gas. Many factors contribute to Alaska's higher costs including:

- Severe arctic conditions, placing limitations on when drilling and other operations can be undertaken
- Environmental challenges
- Remote location of the resource and distance to market
- Restriction of exploration opportunities

These are complications that Alaska faces that most other areas do not; but they do factor into the economic decisions being taken by investors and need to be considered when assessing what is Alaska's optimum production tax regime.

ExxonMobil is willing to accept the risks of long-term, capital intensive investments when a stable tax structure allows and encourages investment and ensures a corresponding opportunity for upside potential. Upside factors such as increased production and higher prices can compensate for risks taken by investors, because companies are certainly negatively impacted when lower than expected production or prices occur. The high marginal tax rates under the progressive structure of ACES take away the upside potential and reduce the attractiveness of those capital intensive investments, compared to other locations where the upside benefit can be retained.

Alaska faces significant challenges. As I mentioned, costs are high and production continues to decline. We all need to work together to achieve the right balance – as Governor Parnell stated - a balance that maximizes the benefit to Alaskans while encouraging industry to continue to invest in Alaska.

ExxonMobil recognizes the difficulty you face as policy makers in tackling the State's tax policy while protecting current revenue streams and addressing the revenue problems just over the horizon due to the production decline. We appreciate how hard and difficult that task is.

Today's production rates are the product of government policies, technical work, and investment decisions that in many cases were made decades ago. Increasing production rates in the decades to come will result from sound policies, decisions, and commitments that are made by this Legislature. As policy makers, you will need to decide whether Alaska's current high production tax regime is the right course for Alaska or if another course is necessary to harness the remaining resource potential, given the high costs and steadily declining oil production rates we as Alaskans face.

It is important to recognize that any decision made by this Legislature impacts much more than tax revenue in the near term and in the future. Decisions made today will influence the life of production in existing fields and investments required to develop Alaska's remaining resource potential. This will in turn impact jobs for Alaskan workers, revenue for many Alaska businesses, infrastructure that benefits Alaskan communities, and set the stage for the future of Alaska for many generations to come.

As I indicated, ExxonMobil fully supports the Governor's and this Legislature's efforts to reform ACES and to make Alaska's investment climate globally competitive. To maximize its resource potential while receiving a fair share of the resource revenues, Alaska needs a long-term resource development policy that will encourage increasing investment. The reform of ACES needs to result in a competitive, stable and predictable fiscal environment that will encourage investment at all price levels and incentivize the development of remaining resources that are economically challenged, including both new fields and resource development opportunities in existing fields. ExxonMobil believes the key focus of the reform needs to create a balanced program using a combination of changes to progressivity, the base tax rate and capital expenditure tax credits to provide a competitive balance of government take across all price bans.

Let me conclude by reiterating that ExxonMobil is committed to Alaska and to pursuing competitive investment opportunities here in the future. Unfortunately, the resource and cost structure in Alaska is becoming increasingly challenging. It is ExxonMobil's firm belief that passage of meaningful changes to ACES this year will support additional investments in Alaska that will lead to greater development and production as well as economic opportunities for Alaskans.

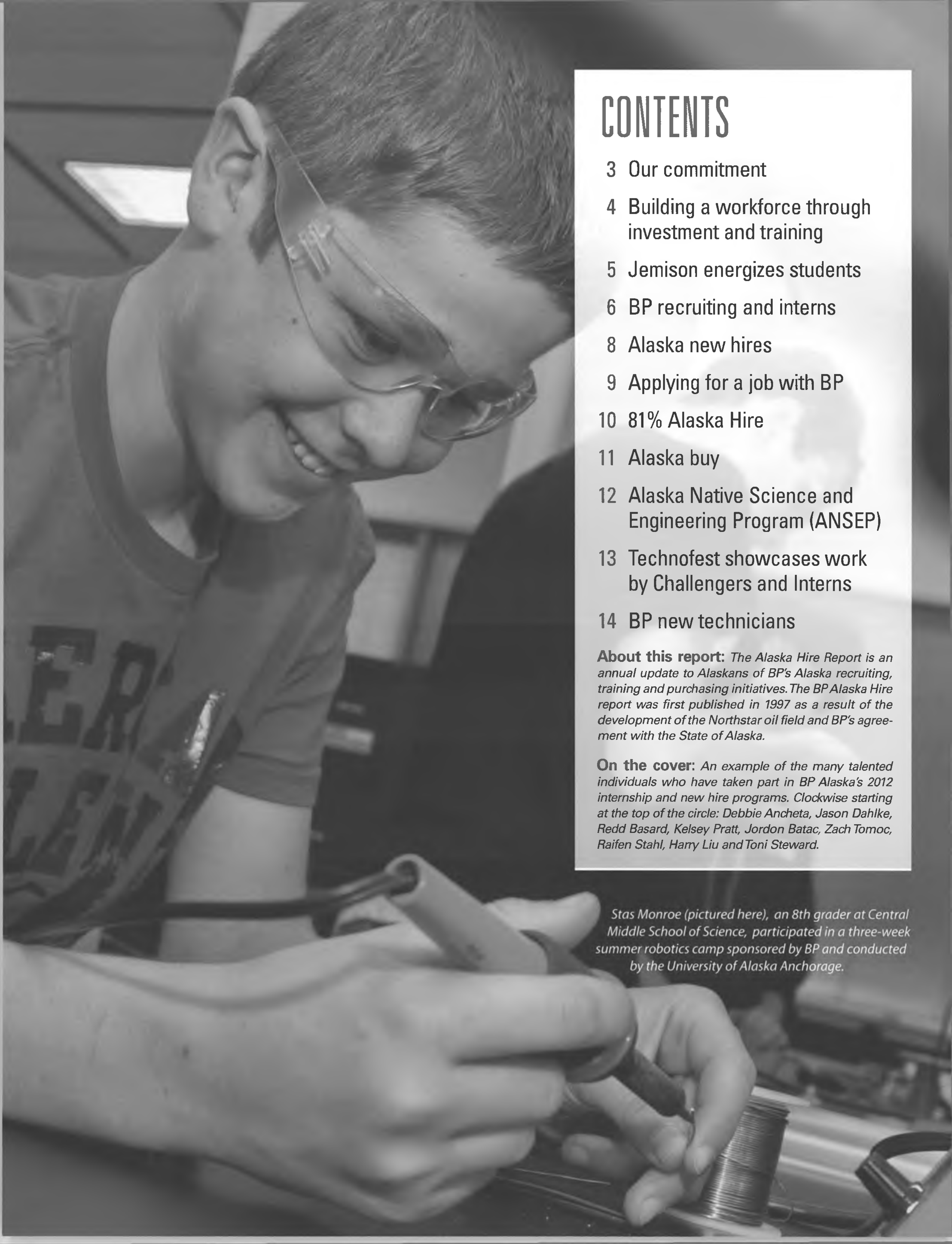
ExxonMobil looks forward to working with the Administration, the Legislature, industry and the people of Alaska in the pursuit and development of Alaska's oil and gas resources.

Thank you again Madam Chair for the opportunity to testify today.

2012

bp

ALASKA HIRE



CONTENTS

About this report: *The Alaska Hire Report is an annual update to Alaskans of BP's Alaska recruiting, training and purchasing initiatives. The BP Alaska Hire report was first published in 1997 as a result of the development of the Northstar oil field and BP's agreement with the State of Alaska.*

On the cover: *An example of the many talented individuals who have taken part in BP Alaska's 2012 internship and new hire programs. Clockwise starting at the top of the circle: Debbie Ancheta, Jason Dahlke, Redd Basard, Kelsey Pratt, Jordon Batac, Zach Tomoc, Raifen Stahl, Harry Liu and Toni Steward.*

Stas Monroe (pictured here), an 8th grader at Central Middle School of Science, participated in a three-week summer robotics camp sponsored by BP and conducted by the University of Alaska Anchorage.

Alaska Hire Report

Our commitment

John Mingé

BP's commitment to recruiting, training and hiring Alaskans is at the heart of our strategy for success. A strong Alaska workforce is key to building a sustainable business, and I am pleased to bring you our 2012 Alaska Hire Report to update you on our progress.

In 2012, BP's workforce in Alaska included 2,300 employees and roughly 6,000 contractors. Behind those numbers are thousands of Alaskans who share our commitment to building a strong economy and keeping the home-grown knowledge and expertise in the Last Frontier. Alaskans know their state the best and are united in their commitment to developing Alaska's incredible resources and opportunities.

Part of our success each year is our continued strong relationship with the University of Alaska (UA). We are fortunate to be able to recruit graduates from a number of programs from UA campuses across the state. The world-class training they offer allows them to move seamlessly into our BP team. Our long-term partnership has helped build strong programs at the University campuses and we host many interns each year who often go on to become part of the BP workforce. This partnership with the UA remains a priority as we continue to invest in the students and the programs.

It's no secret the business climate in Alaska is becoming more and more challenging for oil and gas companies. The easy oil is gone and the fields are aging. We face technical and financial obstacles as we continue to look for ways to get to the already-discovered harder-to-reach oil resources and the huge volumes of natural gas. BP and its workforce want to create a long-term future for Alaska, but it will take the right policy environment to attract the necessary investment to unlock that future.

BP's commitment to maintaining a safe, reliable and efficient business in Alaska includes engaging with Alaskans on a regular basis. This 2012 Alaska Hire Report is part of that effort, and I hope you find the information interesting and useful. Alaska's best resources are its people – many whom you will meet in these pages.

Sincerely,
John Mingé
President
BP Exploration (Alaska) Inc.

Building a Workforce Through Investment and Training

BP's relationship with the University of Alaska is apparent through many investments and support for a variety of programs. From buying equipment to supporting engineering camps and helping students get ready to join the workforce, it's an important and dynamic relationship. The end result is a stronger university system that gives students hands-on, real life experiences so they can be prepared for jobs in Alaska's oil and gas industry.

BP Donates $1 million for Integrity and Corrosion Lab at UAA

A first-of-its-kind Asset Integrity and Corrosion Lab is set to open in Feb. 2013 at the University of Alaska Anchorage (UAA), thanks to a $1 million donation from BP Alaska. The lab will enable the UAA mechanical engineering program to expand its corrosion engineering curricula and offer critical hands-on experience and marketable skills to Alaska's next generation of engineering professionals. The creation of the lab and the corresponding expansion of the engineering program will create new and advanced training opportunities for engineering students. The lab will provide BP with local graduates skilled in corrosion engineering and the ability to have North Slope materials analyzed; both currently not available in Alaska.

Corrosion Lab Ceremony: *(left to right) UAA mechanical engineering assistant professor Matt Cullin, UA President Pat Gamble, BP Alaska President John Mingé and UAA Chancellor Tom Case at the December 2012 ribbon cutting of the Asset Integrity & Corrosion Lab.*

Support for Petroleum Lab at UAF

In the summer of 2012, BP donated $110,000 to acquire state-of-the-art lab equipment for the petroleum development lab in the College of Engineering and Mines at UAF. Having this equipment gives graduate students research opportunities, helps train future petroleum engineers, and strengthens Alaska's workforce. The gift followed last year's donation of $4 million worth of equipment when a working wellhead was given by BP to the UAF Community and Technical College process technology department.

Summer Intern Earns Top Honor

BP summer intern Jaime Bronga, a skier, earned recognition for being a top athlete and student. Bronga was awarded the Dresser Cup for having the UAA Seawolves' highest GPA with a 3.99. Bronga has interned twice with BP and graduated in December 2012 with a degree in civil engineering.

Robotics Camp Helps Build Engineering Skills

Playing with robots is a hobby many of us thought we had to leave behind with childhood. But the three-week summer robotics camp sponsored by BP Alaska and conducted by the University of Alaska Anchorage is all about growing up and growing future engineers. Middle and high school students are taught basic skills in working as a team to build robots that accomplish specific tasks; all designed to get the students thinking about careers in engineering. Run by UAA associate professor of computer engineering Jeffrey Miller, with assistance from engineering students, an average of 40 students a week went through the camp. Classroom instruction, group discussions and building and operating robots all lead to learning how accomplishing many small tasks can ultimately result in solving a larger problem.

Jemison's passion is to produce energy and energize students

BP Alaska Reservoir Engineer Jenny Jemison knows a lot about energy – not just the kind that comes from hydrocarbon molecules – but the energy of young engineering students who are beginning to take those first critical steps toward a future career.

She interned with BP Alaska in 2006 and 2007, and then joined the company fulltime in 2008 after graduating from the University of Alaska Anchorage (UAA) with a bachelor's degree in civil engineering. She later earned a master's degree in petroleum engineering from the University of Alaska Fairbanks (UAF).

Wanting to give back to her alma mater, Jemison became involved in lobbying BP for scholarship funds and expanding the UAA's School of Engineering academic scholarship program to include students from UAA's College of Business and Public Policy, the project management and construction management programs.

"The expanded scholarship program has been such a success that BP plans to continue awarding the scholarships annually," she says.

In 2011, Jemison took on the role of UAA Campus Champion and, not long after that, became the youngest member of the UAA School of Engineering Advisory Board. "I was totally humbled when I was named to the Advisory Board," she recalls. "Most of the people on the board are decades my senior. They are all chief executive officers, professional engineers and presidents of companies – and then there's me."

On having UAA advocacy as part of her job description, Jemison says: "I love being able to have that face-time with students. They have such a positive view of what it means to be an engineer.

It's very easy to get bogged down in the day-to-day grind of what we do and forget just how lucky we are. We get to work with great people and solve challenging problems. It takes the perspective of a student, being inspired by what I do, to inspire me to do more."

Jemison's accomplishments as UAA Champion include BP's title sponsorship of the American Society of Civil Engineers Student Chapter Regional Conference and establishing the BP Innovation in Engineering awards at the annual UAA Engineering Student Design Competition.

On an ongoing basis, she sets up technical talks and presentations with UAA engineering classes and student clubs and advocates for new engineering facilities at UAA and UAF.

BP hosted 55 graduate summer interns from the geo-sciences, business and engineering fields in 2012.

Harry Liu was a reservoir intern in the Anchorage office this summer where he worked with reservoir engineering specialists to better estimate the Prudhoe Bay vapor-borne liquid production and to analyze trends on liquid movement. A graduate of West Anchorage High School, Liu is earning a chemical engineering degree at Columbia University. He says his summer internship was a "huge eye-opener into the oil industry" and helped him link the theory he learns in school with the real-world application.

Sierra Sadler is currently pursuing an MBA in capital markets at the University of Alaska Fairbanks. As a summer intern with BP she worked in the finance department in Anchorage where she was able to work closely with the BP finance team on a non-financial data project designed to get a better understanding of costs. Sadler is a graduate of Monroe Catholic High School in Fairbanks. She says her BP internship was a great opportunity to get exposed to finance. "I also like working in the oil industry. It's fast-paced and one of the best industries to work in in Alaska."

Vahid Nourpour Aghbash worked this summer as a reservoir specialist intern in Anchorage with the Western Tier Light Oil team to develop a mechanistic model of the Borealis field and utilize it to optimize enhanced oil recovery processes. Aghbash is pursuing a master's degree in petroleum engineering at the University of Alaska Fairbanks.

Kyle Emery is a graduate of Bethel Regional High School and is pursuing a master's degree in mechanical engineering at UAF. Emery interned with the Pipeline Renewal Program and begins a job at BP as a surface engineer in January 2012.

Lilan Smith earned a bachelor's degree in mathematics and biology from the University of Denver and is now pursuing her bachelor's in mechanical engineering at UAA. Her summer internship at BP was as a surface intern on the Corrosion, Inspection and Chemicals team in Anchorage assessing corrosion threat levels to North Slope pipelines and facility piping.

Heather Hopkins worked this summer as a surface engineering intern in Anchorage with the Process Safety and Risk Team to develop models to represent and evaluate potential risk scenarios. A graduate of Lathrop High School in Fairbanks, Hopkins is pursuing both a civil engineering and biological sciences degree at the University of Alaska Fairbanks.

BP recruiting and interns

Recruiting and training skilled workers to fill its workforce is a priority for BP. With the right mix of investment, a trained workforce and a stable tax environment, Alaska's North Slope fields will continue to provide a secure domestic energy supply to America, revenue to the state and jobs for Alaskans. To maintain those goals BP continues to support advanced programs in engineering and science at the University of Alaska.

BP has been actively recruiting Alaska graduates, from colleges both in and out-of-state, since the mid-1990s. The opportunities for graduates are many, including jobs in technical fields such as process control operator, as well as in petroleum, process and mechanical engineering. The company also recruits and hires commercial analysts, environmental scientists and other positions.

The partnership between BP and the University of Alaska is a valuable one. Over the past five years, BP has provided internships for 125 UA students and has extended full-time job offers to 143 students. In 2012, BP hosted 55 graduate summer interns and 14 operator interns from the geosciences, business and engineering fields. From the two college recruiting programs the company hired 80 new full-time employees.

Debbie Ancheta is earning an electrical engineering degree at Portland State University. In the summer of 2012 she worked as an electrical engineering surface intern helping to evaluate the reliability of the current process control systems at the field fuel gas unit at the Central Compression Plant on the North Slope. Ancheta describes her internship as a rewarding and amazing experience.

BP summer interns

engineering, business and sciences

Kurstin Adamson, MT Tech
Debbie Ancheta, Portland State
Breanna Bence, WSU
Wade Boman, UAF
Justin Brady, UAA
Jaime Bronga, UAA
Tiia Carraway, LSU
Spence Carter, OSU
Michael Chavez, UCSB
Michael Connolly, Penn State
Sharon Cox, WSU
Kaitlin Dennehy, WSU
Casey Denny, UAF
Eric Dickerman, MT Tech
Ada Dominguez, U MI
Kyle Drew, U Tulsa
Mark Drotar, CSM
Andria Ellis, U WI
Kyle Emery, UAF
Jessica Feenstra, U WI
Charles Frey, OSU
John Fryman, Marietta
Susanne Grobler, MSU
Jordan Haffener, KSU
Heather Hopkins, UAF
Andrew Ivy, U ID
Brendon Johnson, U AZ
Jennifer Josefy, TX A&M
Barton Lefler, UCSD
Rebecca Lewallen, UAA
Harry Liu, Colombia
Kevin McElhaney, OR State
David Mingé, UW
Zachary Morton, U Houston
Corey Munk, Portland State
McKenzie Nelson, WSU
Andrew Neuerburg, UAA
James Niedermeyer, UAF
Vahid Nourpor Aghbash, UAF
Ryan Oba, CO State
Kristine Odom, UAF
Daniel Olivas, OSU
Matthew Petrowsky, CO State
Sierra Sadler, UAF
Max Shayer, Harvard
Ralph Sinnok, UAF
Lilan Smith, UAA
Weston Smith, BYU
Matt Summers, WSU
Frazer Tee, UAA
Josh Tempel, UAA
Troy Tempel, MSU
Carla Tomsich, UAF
Susanna Webb, U WI
Kenneth Wolkoff, UAA

Alaska new hires

Sarah Aiken came to work as a facility engineer at Prudhoe Bay in January of 2012. A graduate of Petersburg High School, Aiken has a mechanical engineering degree from UAA.

Kelsey Pratt works as an indirect procurement specialist in procurement and supply chain management. A graduate of South Anchorage High School, Pratt earned a bachelor's of science degree in business administration with an emphasis in supply chain management from the University of Nevada, Reno. A BP intern in the summer of 2008, Pratt returned as a contractor in 2010 and joined BP a year later.

Eric Holland works as a facility engineer at Gathering Center 3 on the North Slope. A graduate from South Anchorage High School, Holland received a degree in chemical engineering from Washington State University.

Tully LaBelle-Hamer works as a facility engineer at Flow Station 3 on the North Slope. La-Belle-Hamer graduated from Monroe Catholic High School in Fairbanks, then received a B.S. in electrical engineering from the University of Vermont and a B.A. in engineering from Saint Michael's College in Vermont.

Applying for a job with BP

It's easy to apply for internships or jobs with BP.

Check out

www.bp.com/uscampus

- At the site, select "apply now."
- Click on "login to your account" or "register and apply online."
- Register or create a new user login.
- Upload your resume into the system.
- Apply!
- To see which jobs are currently open in Alaska go to **alaska.bp.com** and click on "Jobs in Alaska."

BP's employment needs are mainly in technical fields like process control operators and engineering disciplines in petroleum, process and mechanical engineering. The company also recruits commercial analysts, environmental scientists and professionals in a number of other fields. BP's contractors are also actively recruiting, and most jobs in the oil and gas industry are with contractors, not the producing companies. To see a list of contractors, their needs and requirements, go to the Alaska Support Industry Alliance website at www.alaskaalliance.com.

***BP 2012 new hires** from left to right, **front row:** Raifen Stahl, Ossip Camahuali, Sara Huemann, Kelsey Pratt, Julie Michel, Sarah Aiken and Kali Bergeron - **back row:** Matt McCoy, Brennen Chamberlain, Jose Satteone, Allison Meyers, Joshua Smith, Tully Labelle-Hamer, Lina Klotz, Eric Holland and Ruben Crane.*

Allison Meyers works as a planning and marketing intelligence specialist in procurement and supply chain management. Originally from Bethel, she graduated from Dimond High School in Anchorage and has a finance degree from UAA.

Brennen Chamberlain works as a financial analyst with BP. He interned with BP during the summer of 2011 and earned an MBA from UAF after receiving a bachelor's degree in finance from Central Washington University. Chamberlain has lived in Alaska for three years and says he loves everything about the state.

BP's major contractors

Alaska Hire Annual Average 2011
Alaska Dept. of Labor

ASRC Energy Services

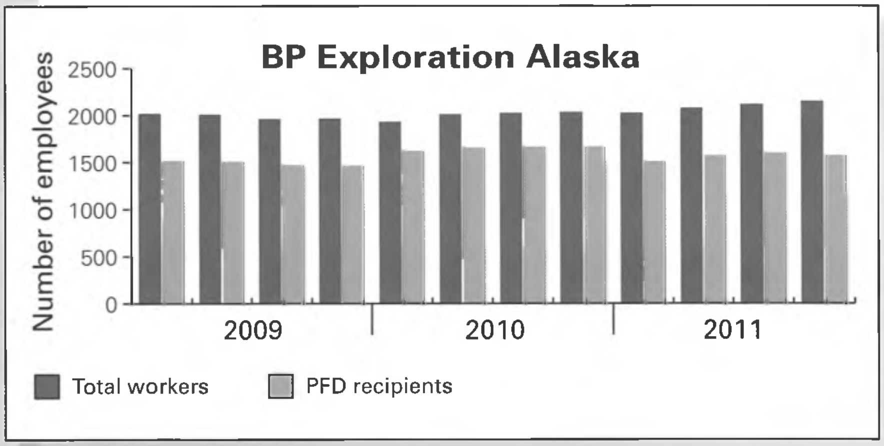
CH2M Hill
(all Alaska Divisions)

Doyon Drilling

NANA Management Services

Schlumberger

Source: Alaska Department of Labor and Workforce Development Research and Analysis Section



Alaska Residency 81% (BP data)
PFD eligibility 71% (Alaska Dept. of Labor)

81% Alaska hire

Alaska resident hire statistics

BP continues its focus on Alaska hire and each year we maintain a workforce that includes more than 80 percent Alaskans of our more than 2,300 employees statewide. The company is also pleased to work with a number of major contractors who also make hiring Alaskans a priority.

BP's internal measurement of the residency of employees shows that, on average, 81 percent lived in Alaska during 2011. On the graph above, the dark green bars represent the total number of employees in Alaska by quarter for 2010 and 2011; these numbers include any person who worked for the company during the year and was paid for either full-time or temporary work. BP defines residency as having a primary residence in Alaska with the intent to stay. BP employees are required to certify Alaska residency each year.

The light green bars on the graph represent the Alaska Department of Labor's calculations of Alaska hire. The department's percentage is traditionally lower because it is based on the number of employees who applied to receive an Alaska Permanent Fund Dividend (PFD) in the current or previous year. The pie charts represent the total Alaska employment for some of BP's largest contractors.

All of the companies listed here employ a number of workers whose primary residence is in Alaska, but who have not lived in the state long enough to receive or be eligible for a PFD.

The Alaska hire percentages are reported annually to the Alaska Department of Labor and Workforce Development.

Alaska buy

More than $1.59 billion spent with Alaska companies

In-state spending is a key part of supporting the local economy and BP spent more than $1.59 billion with Alaska companies in 2011. A look at the numbers shows 78 percent of all BP's purchases were made with Alaska-based firms.

BP's purchases range from large-scale projects to buying goods and services for daily operations. For example, in the summer of 2012, BP completed the successful turnaround at the Central Compressor Plant at Prudhoe Bay. The project, designed to improve safety by replacing aging components, involved roughly 40 different contracting companies, 320 workers and 100,000 hours of work.

As prices increase each year, so do overall costs to the industry. BP remains committed to working with contractors to keep costs at a competitive level, while maintaining a focus on safety and the renewal of infrastructure on Alaska's North Slope.

Total 2011 Spending

$2.03 Billion

Alaska spending

$1.59 Billion (78%)

Central Compressor Plant at Prudhoe Bay

ANSEP interns *Kyle Egly, Alejandro Johnson-Eusebio, Skyler Kern, (seated) Jordan Batac and Joyell Acuna*

ANSEP - A pathway to oil and gas industry careers

The University of Alaska Native Science and Engineering Program, or ANSEP, has graduated nearly 250 Alaska Native engineers and scientists since BP helped to initiate the program 14 years ago. Many of the ANSEP graduates were from small rural communities where local schools have few resources.

The Alaska Native Science & Engineering Program (ANSEP), a University of Alaska program that helps Alaska Native students, mostly from rural schools, has been operating since 1995. BP helped establish ANSEP and remains a strong partner for more than a decade.

ANSEP helps Alaska Native students stay the course through difficult four and five-year engineering and science degree programs, and its success is now being widely recognized.

"ANSEP is effecting a systemic change in our state and it would not be happening without the advocacy, financial support, and student internships BP has provided through the years," says Dr. Herb Schroeder, ANSEP's director.

In 1998 BP was the founding partner for ANSEP's Summer Bridge, a core program with eight students. The company has also given $500,000 in funding to support construction of the ANSEP Building on the UAA campus; $500,000 to support an endowed chair for ANSEP; and ongoing financial support for ANSEP Summer Bridge.

Since 2002 the University of Alaska has graduated 250 engineers and scientists through ANSEP. All now have good jobs. There are about 750 more in the "pipeline," from middle school and continuing through science and engineering degree programs at the University, Schroeder says. BP hosted seven summer interns in 2012.

ANSEP has a solid track record and is now attracting national attention from organizations like the National Science Foundation. This is due largely to the high retention rate which has consistently been about 66 percent; far higher than the one-third retention rate for minority students across the nation and roughly 50 percent for all U.S. engineering students.

There's no secret to ANSEP's success: "High standards and a disciplined learning environment are part of it, as well as a lot of work in peer groups, study sessions and mentoring of young Native students by older ones, who also become role models," Schroeder says.

"We've learned that rural students have to be better prepared when they get here, and we have to start working with them early to get them ready," he adds.

Following high school graduation, many Alaska Native and rural students attend ANSEP's eight-week "summer bridge" which prepares them for their freshman year at the university. Supported by BP, the summer bridge component has an academic focus on math. Students spend part of their time in class instruction and part of the time working alongside professionals with companies such as BP.

ANSEP Summer Bridge interns *John Street and Koliah Baker*

The net effect of all this is that all ANSEP students now entering the university are proficient in the math and science they need. Many have advanced farther, having completed first and second year university courses in ANSEP's pre-university program, and ultimately leading them on a path of employment in Alaska's oil and gas industry.

Technofest showcases work by Challengers and Interns

They wore black shirts, but BP Alaska's Challengers* and interns were clearly the "good guys" as they proudly showcased their work in July at the 2012 Technofest, presenting an array of technical projects and programs that could potentially help sustain the company's business in Alaska for years to come.

The project presentations, more than 60 in all, were separated into three groups: Business Impact, Safety and Organizational Risk and Technical Excellence. Colorfully illustrated, the presentations kept visitors actively engaged for hours as interns and Challengers enthusiastically explained their projects, some of which have taken months to complete with the assistance of BP Alaska coaches and mentors.

Technofest is an excellent demonstration of the value Challengers and interns bring to BP's business in a wide range of areas. They work together to solve real problems while enhancing the understanding of reservoirs, wells, facilities and business support processes. Sharing the innovative thinking that comes from the participants ultimately improves the bottom-line delivery of the business in Alaska.

Pictured is reservoir specialist intern Vahid Nourpour Aghbash.

Pictured is geology intern Andria Ellis.

***Ralph Sinnok** worked as a surface intern in Anchorage this summer on the Operations Engineering team focused on North Slope projects. A graduate of Shishmaref High School, Sinnok is earning a bachelor's degree in mechanical engineering at UAF.*

***The BP Challenger program is a 3-4 year development program for full-time college graduate hires in engineering, science and business.**

BP 2012 operator interns from left to right, *front row:* Toni Steward, Derek Tarr, Casey Watson, Zachary Forshaw, Jason Dahlke, Basard Redd and Tracy Lorenz - *back row:* Michael Nelson, Kevin McGowan, William Christianson, Travis Ellingson, Blake Niver, Gabriel Abel and Sandy Gilliland.

New BP technicians

In the past five years, BP has hired 269 graduates comprising 146 operator interns and graduates and 123 engineering, geoscience and business interns and graduates. These new employees come from the Alaska Processing Technology degree programs at the University of Alaska's campuses in Anchorage, Fairbanks and on the Kenai Peninsula.

With the support of BP, the Alaska process Industry Careers Consortium (APICC) was established to enhance the quality of training and educational programs designed to prepare Alaskans for careers in the process industries. APICC is a statewide, vocational and college program that promotes careers in oil, gas, mining and other process industries, and it gives Alaska students the opportunity for scholarships, internships and successful careers.

The process industries include oil and gas production, transportation and refining, mining and power generation; all fields important to Alaska's future and job creation. In 2012, BP hired 14 summer interns and 21 full-time technician new hires from the APICC program. Students in the internship program gain valuable hands-on experience in oil and gas production plants and BP actively recruits graduates of APICC.

Employers today demand workers with multiple skills. This is another reason APICC, supported by BP, has launched two other programs: an instrument technician program at the university's Kenai Peninsula College; and a combined instrument and electrical technician program offered jointly at the Kenai campus and the Alaska Vocational Technical Center in Seward. Graduates of these programs come into the workforce highly-skilled and ready to work in industries that are key to Alaska's economic future.

Redd Basard, operator intern, UAA

Tracy Lorenz, operator intern, UAA

Blake Howe, entry level operator, UAA

2012 BP Entry Level Operators
New Hires

Austin Bundy, entry level operator, KPC

Douglas Hallmark, entry level operator, UAA

Joshua Aliberti	GC1	KPC
Michael Barker	GPMA	KPC
Randy Berg	FS1	KPC
Austin Bundy	GPMA	KPC
Serhat Cetinkaya	GC1	KPC
Daniel Christianson	CGF	UAA
Jacque Drumm	STP SIP	UAA
Dustin Grimes	FS1	UAA
Douglas Hallmark	FS2	UAA
Blake Howe	FS2	UAA
Eric Lindner	FS1	BTC
Joshua Lorence	FS2	KPC
Matthew McDonald	END	KPC
Christopher Meltz	STP	UAA
Danielle Newberry	FS3	UAA
Drew Olson	GPMA	UAF
Jay Ranson	STP	UAF
Taylor Richey	FS1	UAA
Eric Rodgers	GC1	KPC
Travis Sommer	GC3	UAF
Joshua Tonione	CCP	KPC

2012

ALASKA HIRE

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Anchorage, AK 99519-6612

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A Durable Tax System that is Competitive for the Long Term

Senate Resources Committee

Monday, February 11, 2013

Juneau, Alaska

Dan Sullivan, Commissioner

Alaska Department of Natural Resources

Bryan Butcher, Commissioner

Alaska Department of Revenue

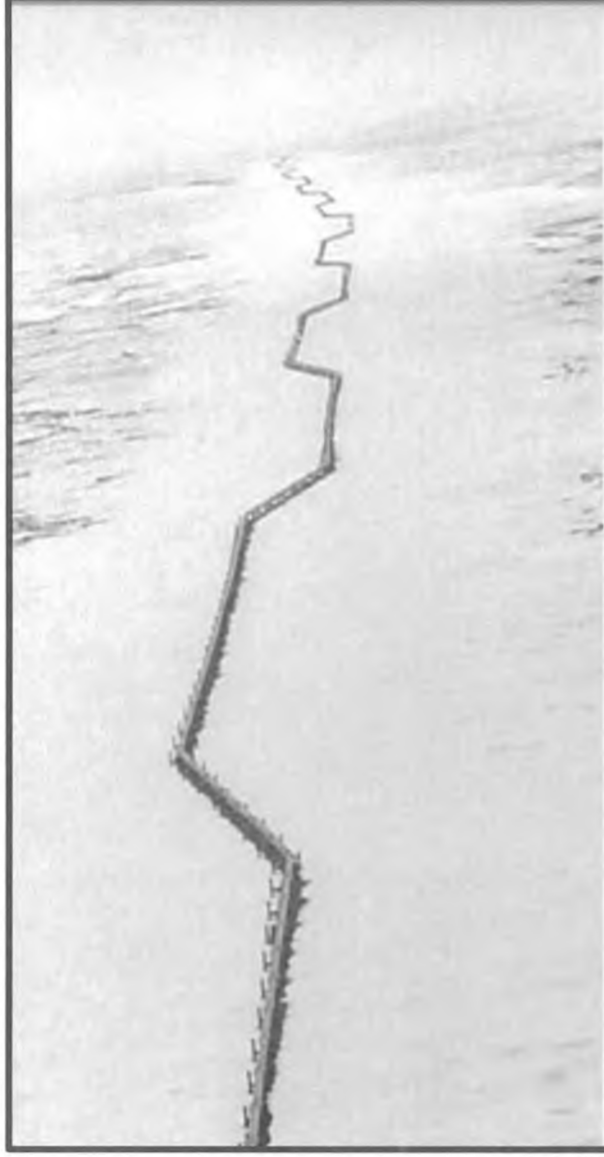
TAPS

- A Critical State & National Energy Asset -

- The Trans Alaska Pipeline, 11 pump stations, several hundred miles of feeder pipelines, and the Valdez Marine Terminal constitute the Trans-Alaska Pipeline System (TAPS).
- At 800 miles long, the Trans Alaska Pipeline is one of the longest pipelines in the world; it crosses more than 500 rivers and streams and three mountain ranges as it carries Alaska's oil from Prudhoe Bay to Valdez.
- The U.S. Congress was instrumental in the approval and rapid development of TAPS. Congress approved construction of the pipeline with the Trans Alaska Pipeline Authorization Act of 1973.
- The principle focus of this Act is as relevant today as it was in 1973: *"the early development and delivery of oil and gas from Alaska's North Slope to domestic markets is in the national interest because of growing domestic shortages and increasing dependence upon insecure foreign sources."*

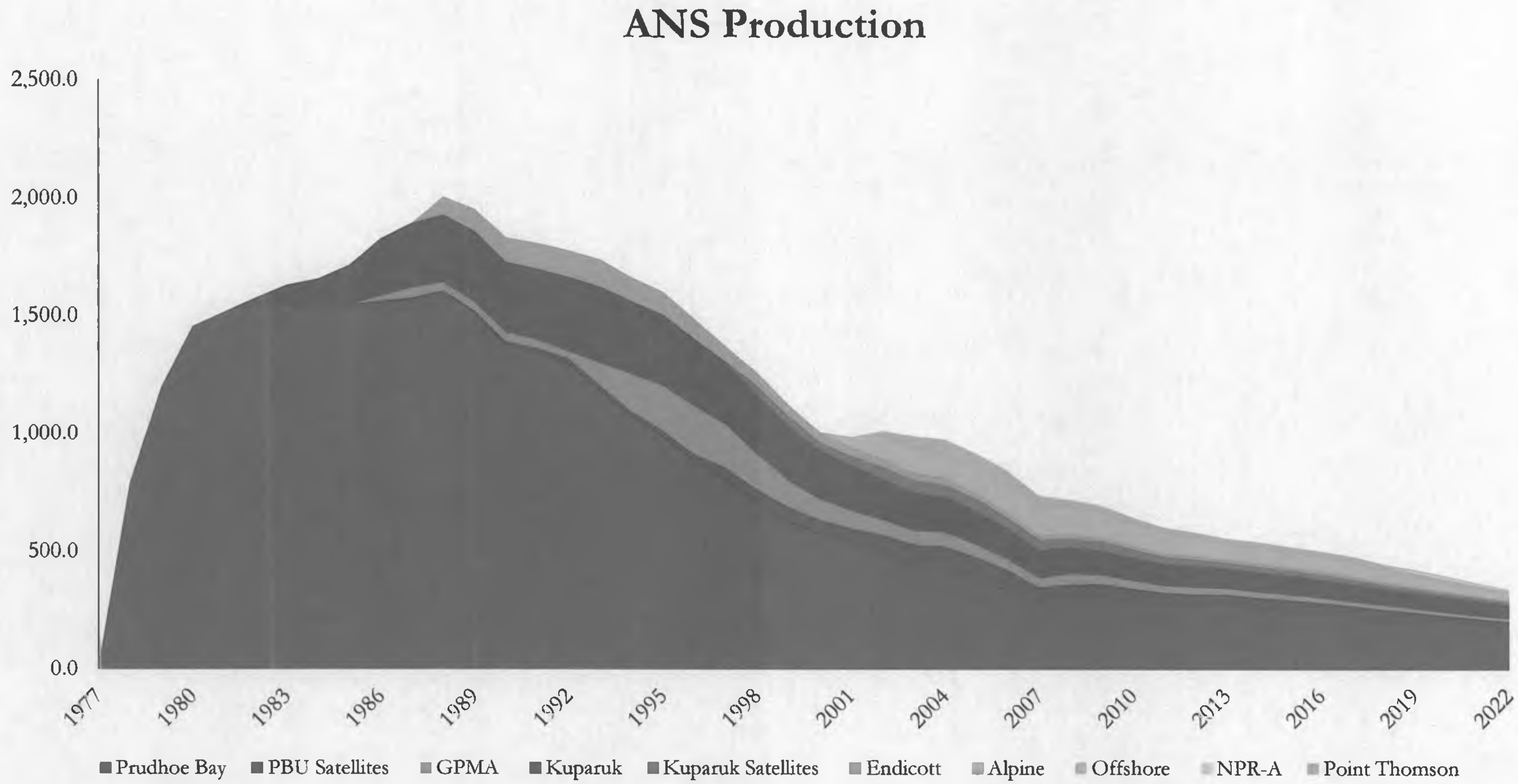
TAPS

- A Critical State & National Energy Asset -



- TAPS has transported over 16.3 billion barrels of oil and natural gas liquids since June of 1977. Production peaked at 2.2 million barrels per day in the late 1980s, representing 25% of U.S. domestic production
- Since its peak, however, throughput has steadily declined; today, TAPS is 2/3 empty and declining at an average of 6% per year
- TAPS throughput decline threatens economic disruption and the very existence of our pipeline
- We must encourage industry to invest in exploration and development of conventional and unconventional resources on state and federal land, onshore and offshore
- TAPS has plenty of capacity for increased throughput
- Most near-term critical economic issue facing the state
- Less oil in the pipeline year after year takes away revenue from future generations—the ultimate giveaway
- Reconfiguration, 1.2 million barrels/day

OIL TAX REFORM
- PRODUCTION HISTORY -



Source: Alaska Department of Revenue Fall 2012 Revenue Sources Book: http://www.tax.alaska.gov/programs/documentviewer/viewer.aspx?2682f

TAPS

- Throughput Decline is an Urgent Problem -

- TAPS throughput decline is the MOST URGENT issue facing the State's economic future
- January 2011 TAPS shutdown

Petroleum News, February 27, 2011:
"Jan. shutdown puts TAPS close to brink:

Alyeska executives describe efforts to prevent freezing in pipeline after pump station oil leak in era of low oil throughput"

WSJ, May 11, 2011:

"Shrinking Oil Supplies Put Alaskan Pipeline at Risk"

"Now, dwindling oil production along Alaska's northern edge means the pipeline carries less than one-third the volume it once did—and the crude takes five times as long to get to its destination.

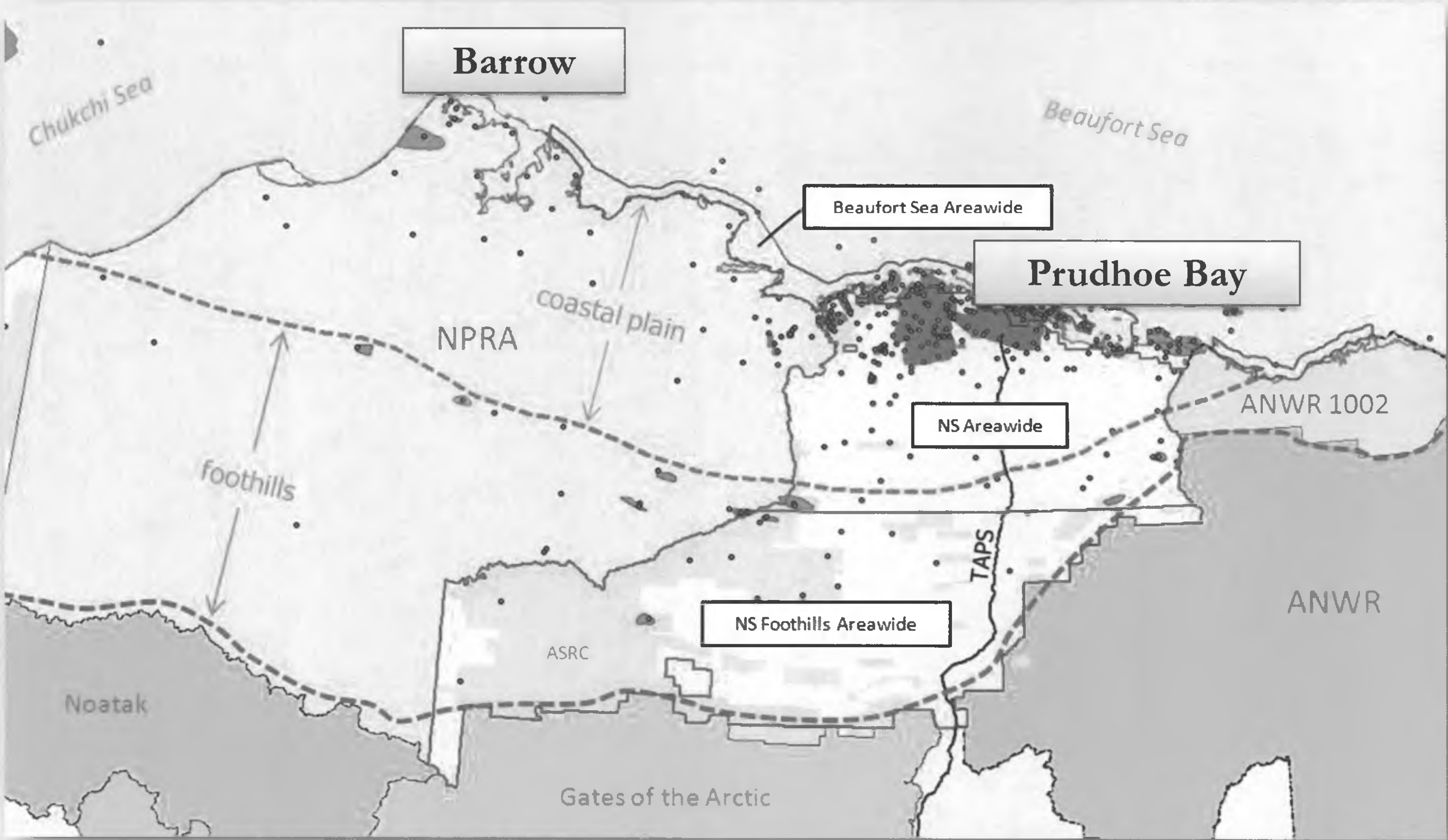
That leisurely flow means the oil is above ground longer and more exposed to Alaska's frigid weather; the crude sometimes arrives chilled to 40 degrees. As the flow and temperature continue to drop, experts say the risks of a clog or corrosion increase, as do the odds of ruptures and spills."

ALASKA'S NORTH SLOPE OIL & GAS POTENTIAL

- USGS estimates that Alaska's North Slope has more oil than any other Arctic nation
  - **OIL:** Est. 40 billion barrels of conventional oil *(USGS & BOEMRE)*
  - **GAS:** Est. over 200 trillion cubic feet of conventional natural gas *(USGS)*
- Alaska has world-class unconventional resources, including tens of billions of barrels of heavy oil, shale oil, and viscous oil, and hundreds of trillions of cubic feet of shale gas, tight gas, and gas hydrates
  - Positive methane hydrate test production

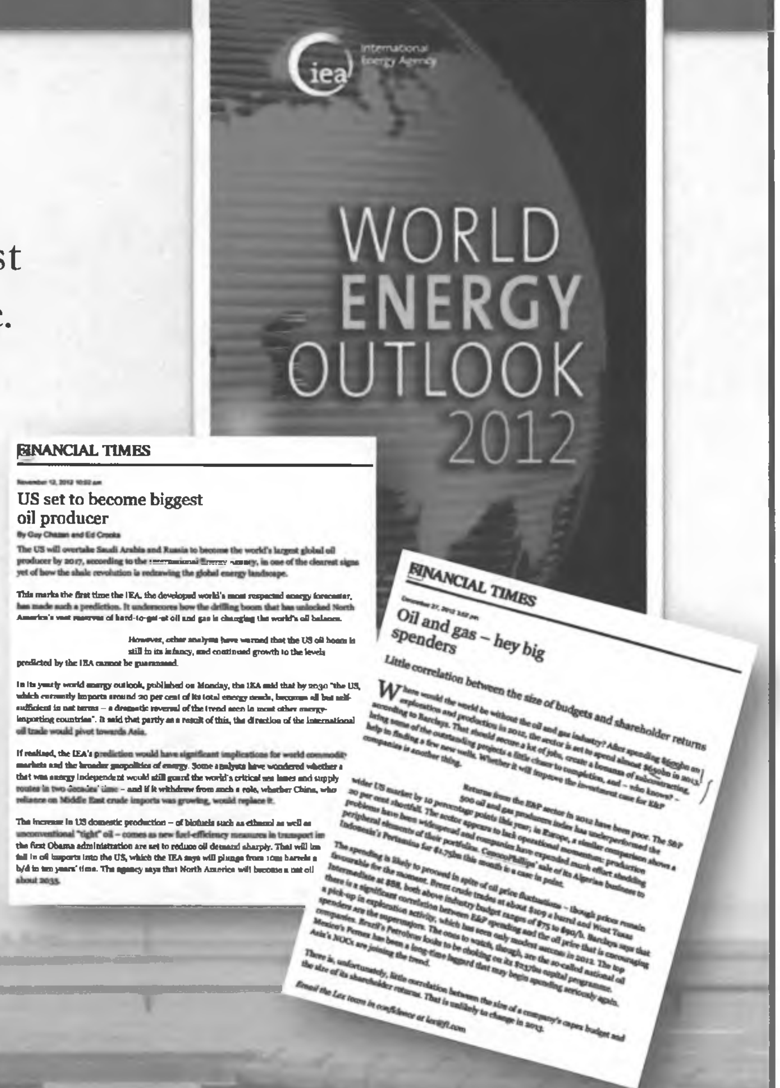
Compared to most hydrocarbon basins, Alaska is relatively underexplored, with 500 exploration wells on the North Slope, compared to Wyoming's 19,000.

ALASKA'S NORTH SLOPE OIL & GAS POTENTIAL



U.S. ENERGY RENAISSANCE

- Global and U.S. hydrocarbon boom
- IEA World Energy Outlook 2012 – U.S. to overtake Saudi Arabia and Russia to become the world's largest global oil producer by the second half of this decade.
- **Financial Times, November 12, 2012 –** ***"U.S. set to become biggest oil producer"***
- **Financial Times, December 27, 2012 –** ***"Oil and gas – hey big spenders"***
  - o 2012 - $600 billion on exploration and production in oil and gas industry
  - o 2013 projected - $650 billion on exploration and production in oil and gas industry



Other Basins have Turned Decline Around

THE INDEPENDENT

North Sea set to create 50,000 new jobs as investment soars

Tom Bawden

Monday, 14 January 2013

North Sea employment is set to boom this year. Up to 50,000 new jobs are expected in
Britain's oil and gas in

The jobs bonanza wil
support-services staff
North Sea to nearly ha

"There's been a lot of
at the moment," said
behind the research.
their life. At the same
have made it economi
he added.

Further down the line,
35,000 jobs in the nex
Institute of Directors.

The expansion has bee
set to be ploughed int
be the biggest creator
the North Sea for a de
Shetland Isles, that wi

The surge in investme
Sea development, pro
Energy and Climate Ch

Although North Sea p
output was 4.5m barr
2m barrels. On the do
to compete for emplo
more than twice the n

"The expansion has been spurred by record-breaking levels of investment, with about £40bn set to be ploughed into North Sea production in the next three years…"

"The surge in investment comes after the government relaxed the tax regime around North Sea development, prompting a record-breaking licensing round when the Department of Energy and Climate Change awarded 167 new licenses on 330 blocks last October."

"Budget 2012: North Sea oil tax reforms 'to lead to £50bn investment':
An extra £50bn could be pumped into the North Sea oil and gas industry thanks to a new package of tax reforms."

Budget 2012: North Sea oil tax reforms 'to lead to £50bn investment'

An extra £50bn could be pumped into the North Sea oil and gas industry thanks to a new package of tax reforms.

The Budget was a "turning point" for industry relations with the Treasury. Photo: Rex Features

By Emily Gosden

10:11PM GMT 21 Mar 2012

Industry body Oil & Gas UK said the Chancellor's promise of certainty on decommissioning tax relief and new tax breaks on small and deepwater fields would stimulate tens of billions of pounds of additional investment.

The Budget was a "turning point" for industry relations with the Treasury after outrage at the surprise tax rise in last year's Budget, Oil & Gas UK said. The measure means more than 2bn barrels of the UK's oil and gas reserves that would otherwise have been left in the ground will now eventually be recovered at no net cost to the Exchequer.

The Treasury estimates that the reforms could actually boost its coffers by £1bn over the next five years, due to tax on projects that would not otherwise have gone ahead.

The Chancellor confirmed that he would draw up a contract with the industry to permanently guarantee levels of tax relief on the £30bn bill for decommissioning old infrastructure, a move that Oil & Gas UK said could stimulate up to £40bn investment during the lifetime of the North Sea basin. Anxiety over whether rates might be cut has blocked some deals.

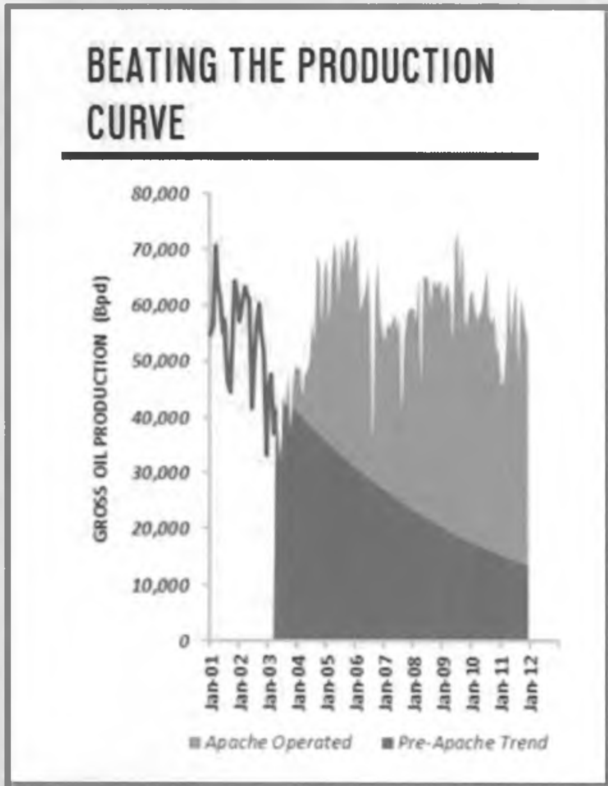
The Chancellor unveiled new 'field allowances', doubling tax breaks for developing smaller fields and introducing a £3bn allowance for some deepwater fields with significant reserves in the new exploration frontier West of Shetland. The allowances should see £10bn extra investment, the industry body said.

Malcolm Webb, Oil & Gas UK's chief executive, said the Budget was a "turning point for the UK's oil and gas industry" toward "a more stable future fostered by constructive collaboration between government and industry".

Other Basins have Turned Decline Around

Apache Corporation: Forties Field Acquisition

- Field discovered in early 1970s by BP; purchased by Apache in 2003
- Contains estimated 4.2 to 5.0 billion barrels of oil in place
- Production peaked at over 500,000 Bpd, but by 2003, had declined to 40,000-45,000 Bpd
- Apache has "beaten the curve" by adding reserves, production, and value
- Have returned over 400% of their original 2003 investment



Data from www.apachecorp.com

SECURE ALASKA'S FUTURE—*OIL*

- ***Secure Alaska's Future—Oil*** is the State's comprehensive strategy to increase TAPS throughput to one million barrels a day

  I. Enhance Alaska's global competitiveness and investment climate

  II. Ensure the permitting process is structured and efficient

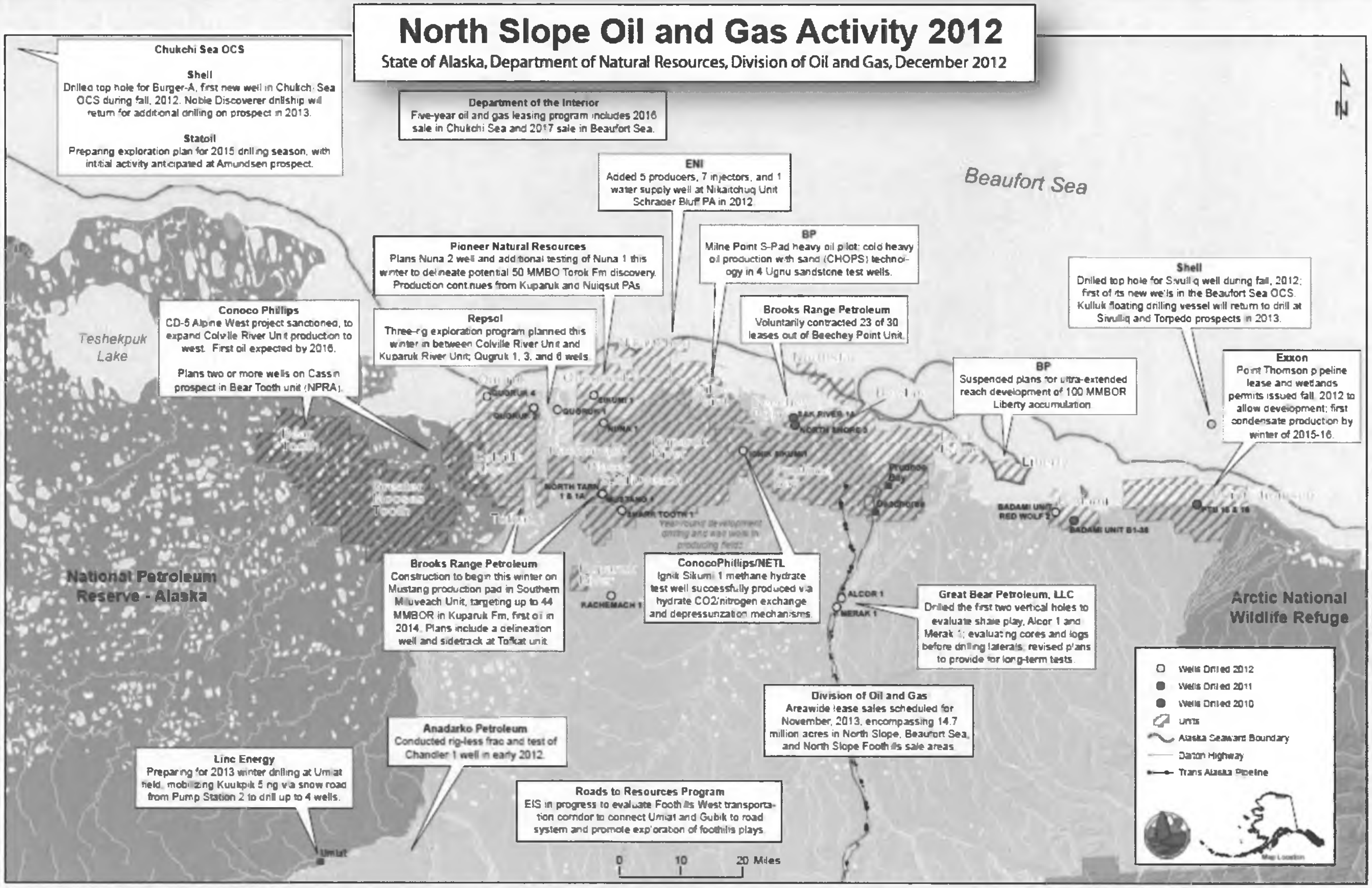
  III. Facilitate and incentivize the next phases of North Slope development

  IV. Promote Alaska's resources and positive investment climate to world markets

- **Governor Parnell's 2013 State of the State: *"Our problem is not below the ground. Our problem is above the ground."***
  - The missing piece is meaningful tax reform
  - "Our state's prosperity has always rested on natural resources. Tonight, that foundation is at risk, not because we are running out of oil, but because we are running behind the competition."

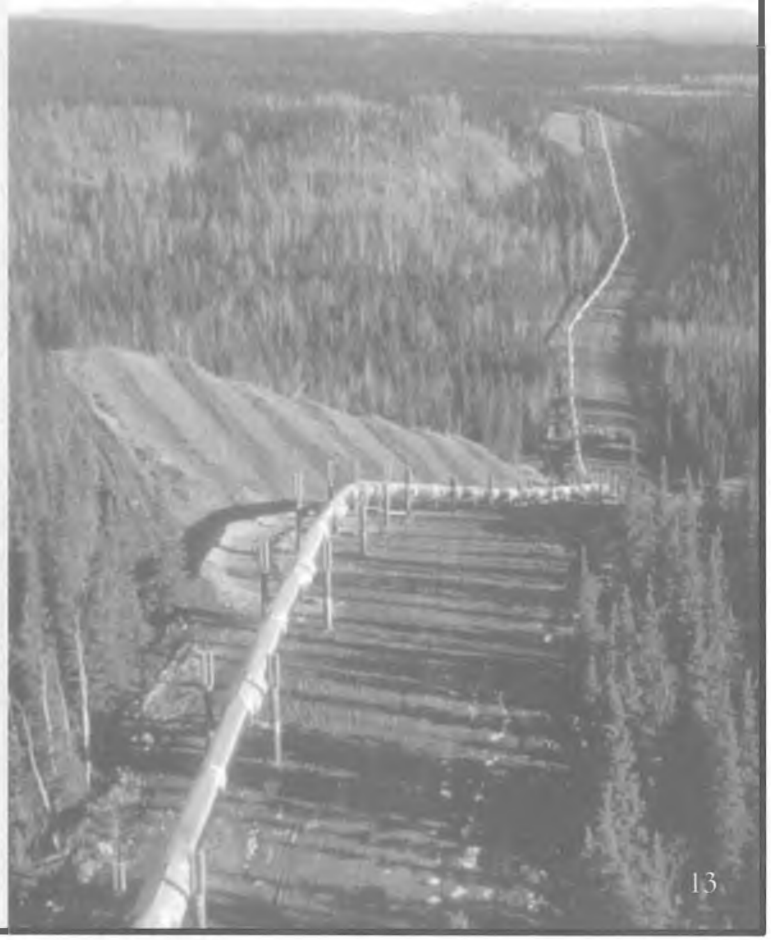
SECURE ALASKA'S FUTURE: *OIL*

- NORTH SLOPE RECENT & PROPOSED ACTIVITY FOR OIL & GAS -



OIL TAX REFORM
- PRINCIPLES -

- Governor reiterated his principles:
    - o Tax reform must be fair to Alaskans
    - o Encourage new production
    - o Simple so that it restores balance to the system
    - o Durable for the long-term
- Integrated team – DOR and DNR
- Consultants - EconOne



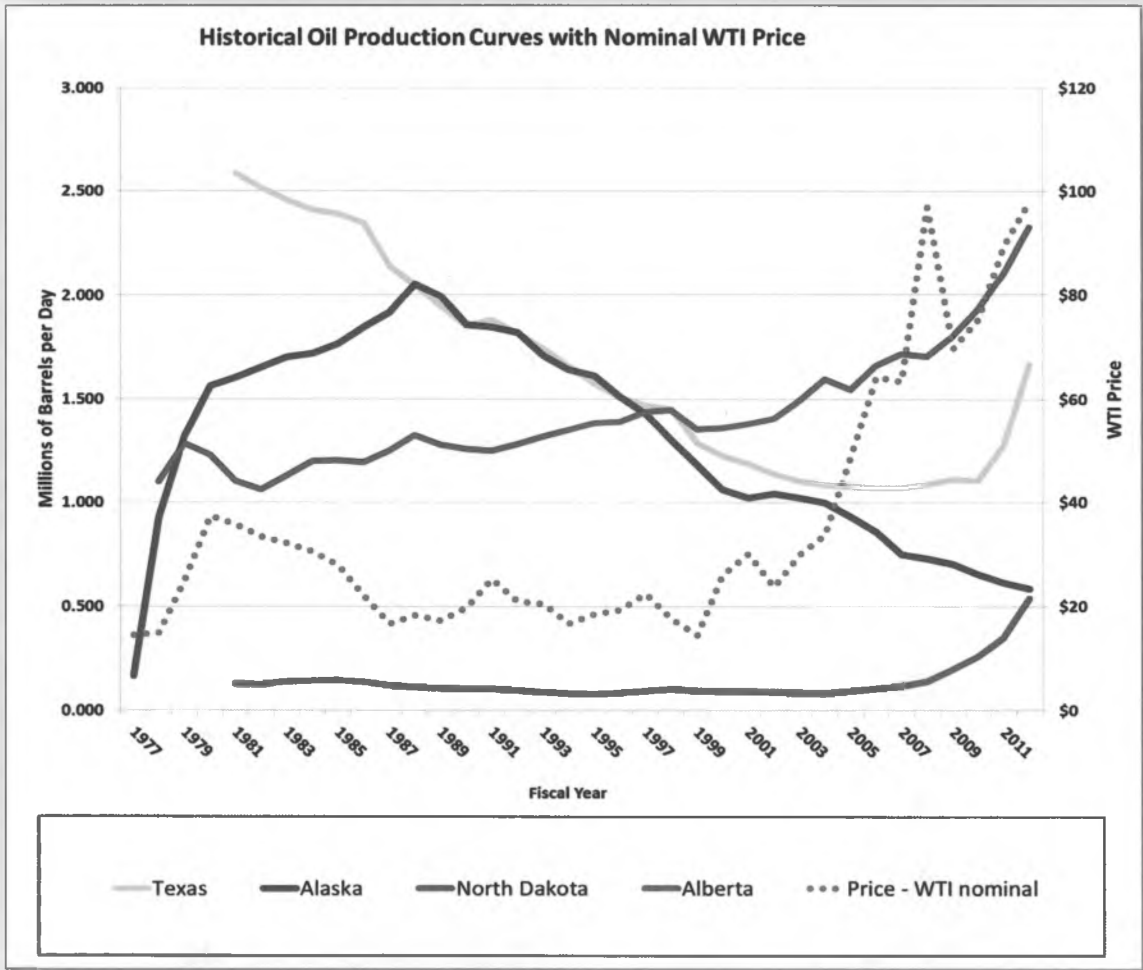
OIL TAX REFORM
- THE PROCESS -

- The team reviewed previous work by both the Legislature and the Administration
- Identified problems with the current tax system
  - Declining Production
  - Competitive Environment
  - Progressivity
  - Tax Credits
- Coordinated effort to understand impacts of production decline on TAPS/Revenues

Other Basins have Turned Decline Around

- Historical Oil Production -

How Did Our Competition Fare When Prices Spiked?



COMPARING ALASKA

- Consultants have compared Alaska to other opportunities using detailed models and analyzing a variety of financial metrics.
- The following example is for a 50 million barrel development in Alaska and comparable developments in the Lower-48, Canada and United Kingdom North Sea.
  - Developed by a new entrant to the State.
  - Compares net present value (NPV) per barrel of oil equivalent discounted 12%

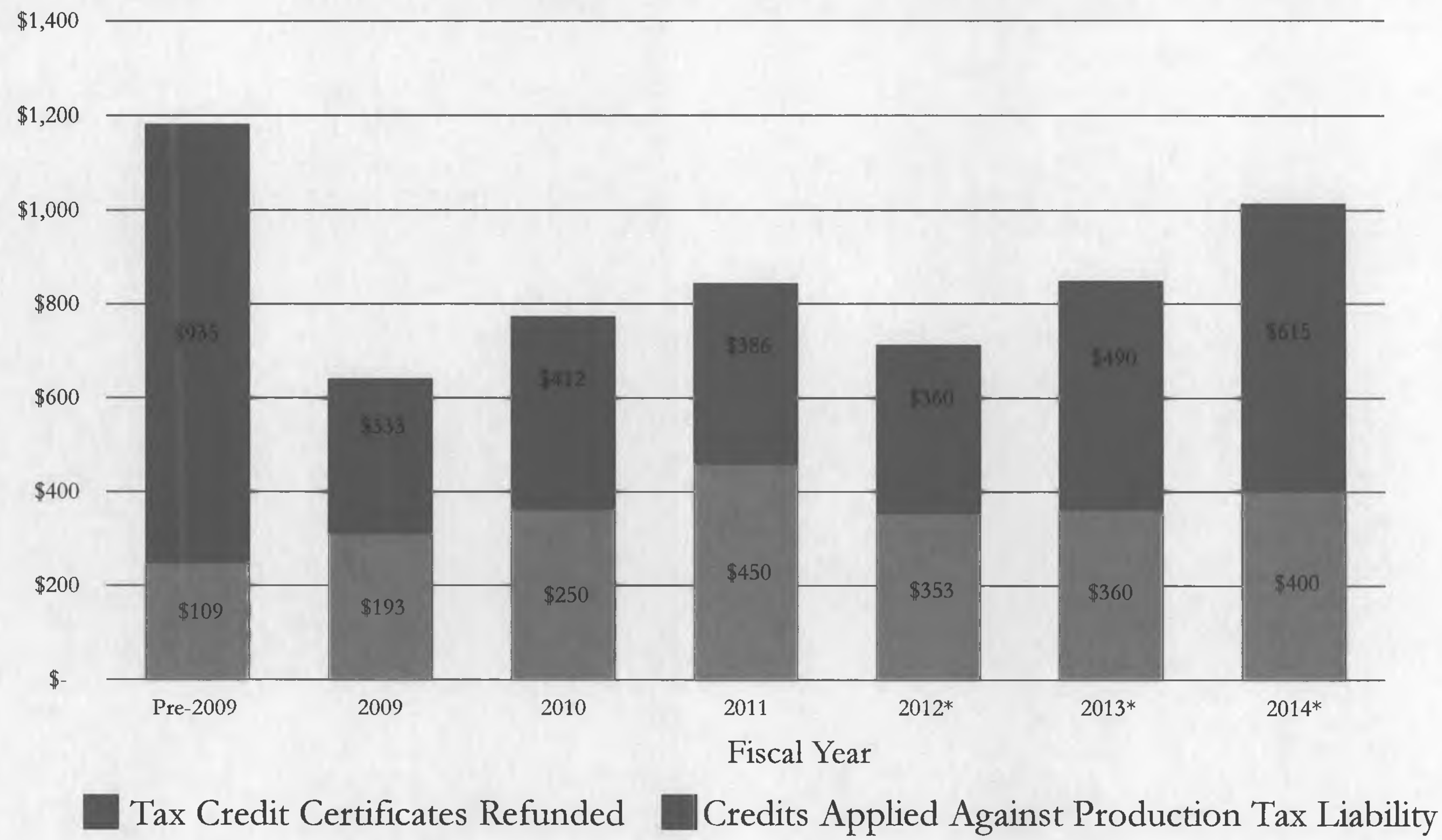
West Coast ANS Prices	NPV-12% ACES (Current)	NPV-12% Average L48 Unconventional	NPV-12% Norway	NPV-12% UK Post-1993 with Brownfield
$80	$2.73	$2.14	$.24	$4.62
$100	$4.07	$5.52	$2.34	$8.25
$120	$5.74	$10.17	$4.44	$11.88

Example: ***at $100 a barrel, a company would earn $4.07 in Alaska but $5.52 in the Lower 48 and $8.25 in the U.K. North Sea.***

OIL TAX REFORM
- PROGRESSIVITY-

- Progressivity is complicated and unpredictable, both for the state and investors
  - Tax rate increases by .4% for every $1 per barrel that the production tax value (price minus transportation costs minus lease expenditures) exceeds $30/barrel up to $92.50 per barrel, then .1% until the total tax rate equals 75%
  - Calculated Monthly
- High marginal tax rates

OIL TAX REFORM
- PRODUCTION TAX CREDITS -



*Estimated pending final true-ups

** Fall 2012 Revenue Sources Forecast

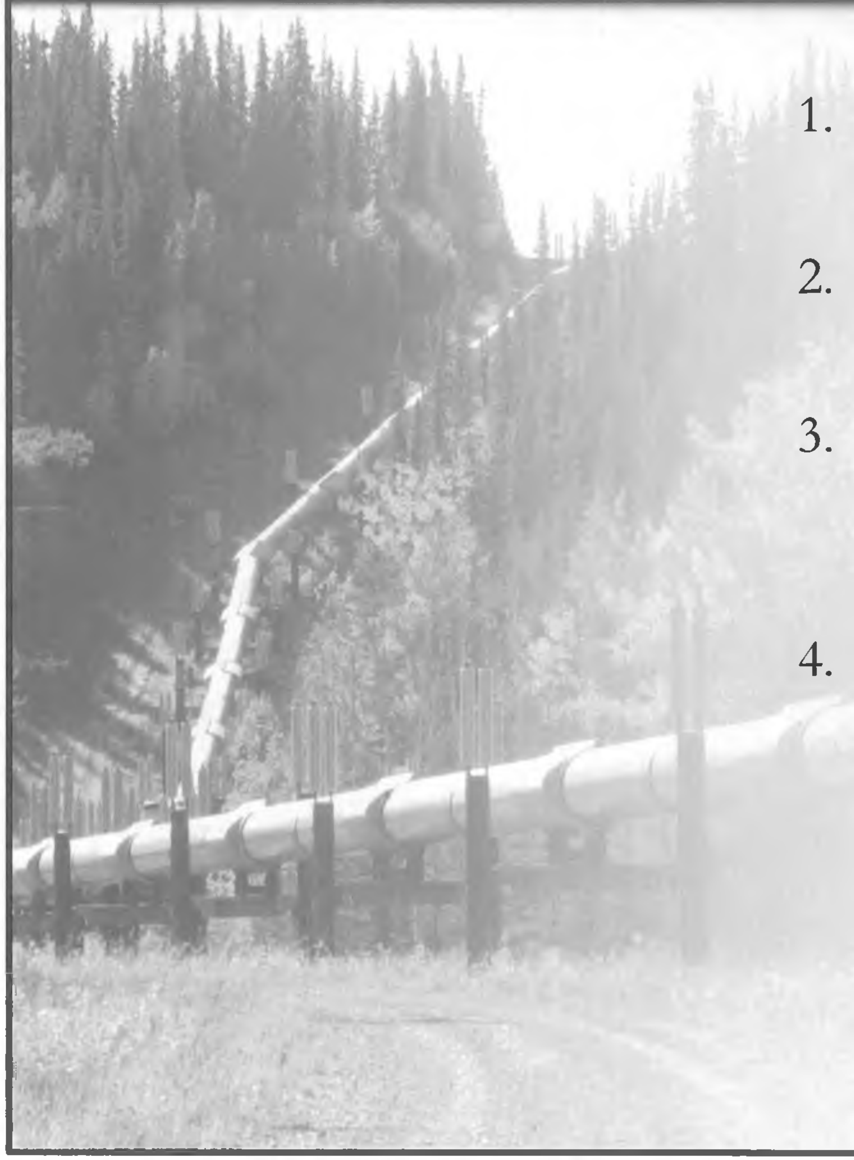
Source: Alaska Department of Revenue

OIL TAX REFORM
- TAPS TARIFFS—WORK TO DATE-

- Identified growing concern in DOR and DNR that TAPS tariffs in our revenue modeling did not dynamically link throughput with tariff rates or capture any added capex or opex spending for low-throughput mitigation measures
- Current work **NOT** designed to find the optimal low-flow mitigation option or forecast specific operational outcomes and exact tariffs

- Preliminary Observations:
  - Low flow mitigation capital and operating expenditures could increase tariffs by as much as $1 (18%) per barrel by 2019 and as much as $2.50 (33%)per barrel in 2022
  - Assuming price, production and tariff provided in the Fall 2012 Revenue Sources Book, a $1 increase in the TAPS tariff will decrease state oil and gas revenue by an average of $110 million

OIL TAX REFORM
- THE PROPOSAL: HIGHLIGHTS -



1. Eliminate Progressivity and Credits Based on Capital Expenditures
2. Reform remaining credits to be carried forward to when there is production
3. Establish a "Gross Revenue Exclusion" for newer units and new participating areas in existing units (NEW OIL)
4. Hold Cook Inlet and Middle Earth Harmless

Oil Tax Reform
- Simple & Balances is the Goal-

Current	Proposed

Current

- 25% Base Rate
- Progressivity – 0.4% for every $ per barrel that PTV exceeds $30, up to $92.50, then 0.1% until 50% is reached
    - Approximately $1.5 billion in FY14
- Tax Credits – Cash reimbursements + reduced tax revenue to state
    - Approximately $1 billion in FY 14

Proposed

- 25% Base Rate
- Gross Revenue Exclusion (GRE) for New Oil

Overview of SB 21
Oil & Gas
Production Tax

February 11, 2013
Alaska Department of Revenue

Principles

- Governor' Principles:
  - –Tax reform must be fair to Alaskans.
  - –Encourage new production.
  - –Simple so that it restores balance to the system.
  - –Durable for the long-term.

The Proposal (Highlights)

1. Eliminate Progressivity and Credits Based on Capital Expenditures.
2. Reform remaining credits to be carried forward to when there is production.
3. Establish a "Gross Revenue Exclusion" for newer units and new participating areas in existing units (NEW OIL).
4. Hold Cook Inlet and Middle Earth Harmless.

Eliminate Progressivity & Credits Based on Capital Expenditures

Progressivity

Main Sections: 1,2,26

Conforming Sections: 5,6,22,23

North Slope QCE Credits

Main Sections: 8

Conforming Sections: 7, 11, 12

Reform remaining credits to be carried forward to when there is production.

North Slope Net Operating Loss Credits

Main Sections: 9, 15

Conforming Sections: 10, 19, 20

Small Producer Tax Credits

Main Sections: 16

Establish a “Gross Revenue Exclusion” for newer units and new participating areas in existing units.

Gross Revenue Exclusion (The GRE)

Main Sections: 24

Conforming Sections: 5

No Changes to Cook Inlet & Middle Earth

Main Sections: 3

Conforming Sections: 4, 13, 14, 17, 18, 21, 25

Analysis of Alaska's Tax System, North Slope Investment and The Administration's Proposal SB 21

Barry Pulliam
Managing Director
Econ One Research, Inc.

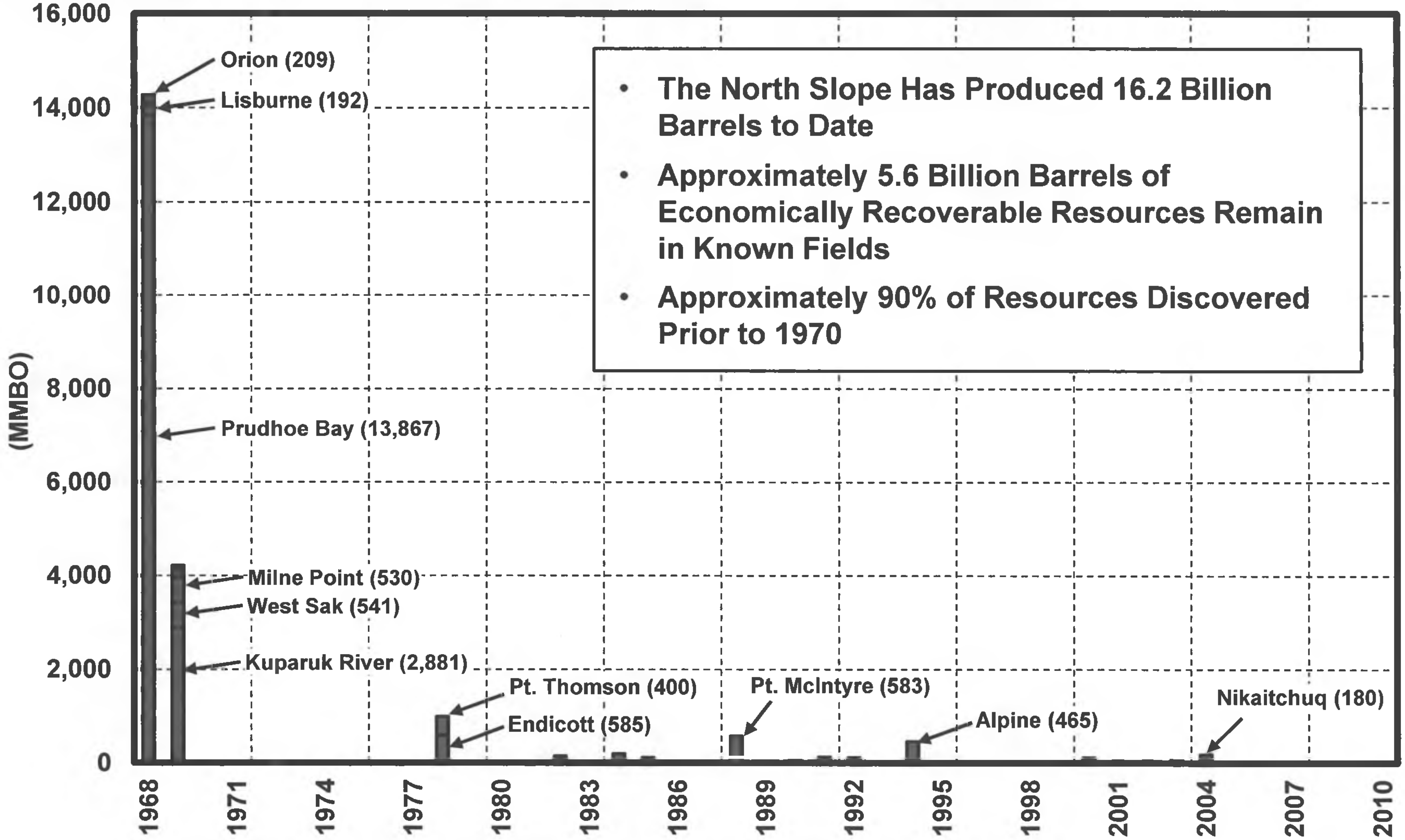
February 13, 2013

Econ One: Who We Are

- Economic Research and Consulting Firm
  - Provides Economic Analysis In Energy and Other Industries
- Advised the State of Alaska on Petroleum Related Matters For Over Two Decades
- Worked With the Cowper, Hickel, Knowles, Murkowski, Palin, and Parnell Administrations
- Assisted the Legislature Between 2005 and 2008 on Tax and Gas Development Issues
- Energy-Related Work Outside Alaska
  - State Governments: Texas, Louisiana, New Mexico, Oklahoma, California
  - Federal Government Agencies: Department of Interior, Federal Trade Commission
  - Energy Companies: Producers, Refiners, Mid-Stream Services, Pipelines, Chemicals

Background

Alaska North Slope Discovered Resources by Discovery Year (1969 – 2010)

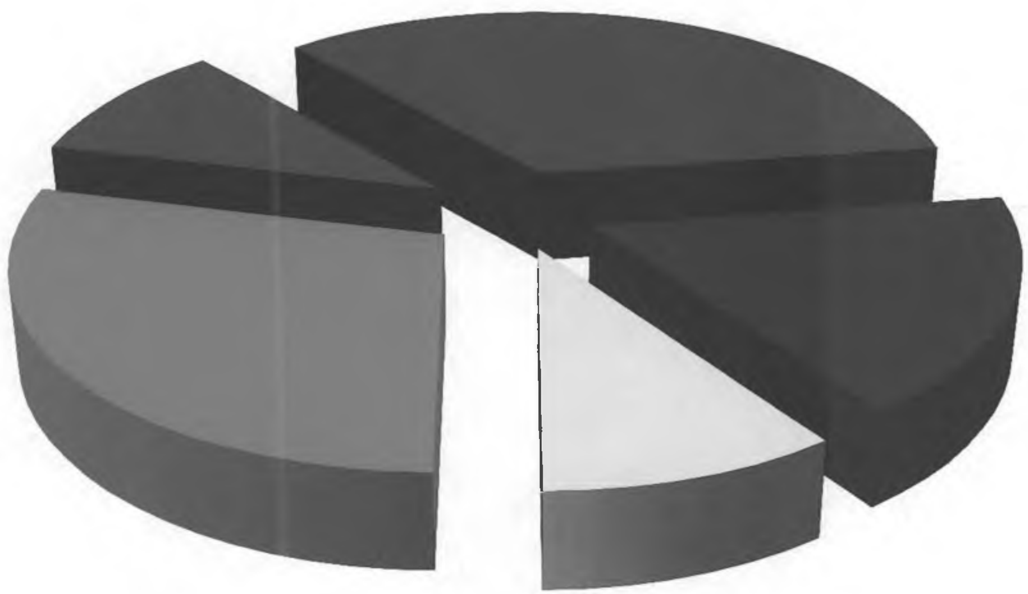


- The North Slope Has Produced 16.2 Billion Barrels to Date
- Approximately 5.6 Billion Barrels of Economically Recoverable Resources Remain in Known Fields
- Approximately 90% of Resources Discovered Prior to 1970

Source: DNR: The Historical Resource and Recovery Growth in Developed Fields, Arctic Slope of Alaska, 2004; DOE/NETL-2009/1385; AOGCC.

Alaska North Slope Production and Resources

- Many North Slope Fields are Now at Mature Stages. However, Less Than Half of its Potential Economic Oil Resources Have Been Produced to Date
- In Total, the North Slope Contains Approximately 40 Billion Barrels of Additional Estimated Economic Recoverable Resources at Today's Prices



- Historical Production (16.2 BBO)
- Conventional Resources - Discovered (5.6 BBO est.)
- Conventional Resources - Undiscovered (19.2 BBO est.)
- ANWR (9.9 BBO est.)
- Unconventional Resources (5.5 BBO est.)

Estimated Undiscovered Conventional Oil Resources on Alaska North Slope

	Technically Recoverable Resources			Economically Recoverable	Expected Typical
	P95	Mean	P5	@ $90/bbl	Field Size
	(Million Barrels)				
	(1)	(2)	(3)	(4)	(5)
Central North Slope	2,800	3,400	3,900	3,000	32 - 64
Beaufort Sea	400	8,200	23,200	5,800	-
Chukchi Sea	2,300	15,400	40,100	9,900	-
NPRA	400	900	1,700	500	32 - 64
ANWR	5,900	10,400	15,200	9,900	64 - 128
Total		**38,300**		**29,100**	

Source:
USGS Reports 2011–1103 and 2009-1112;
BOEM, Assessment of undiscovered technically recoverable oil and gas resources of the nation's outer continental shelf.

Estimated Undeveloped Unconventional Oil Resources on Alaska North Slope

econ ONE

Shale — **~ 1 Billion Bbls**

(Mean Estimated Technically Recoverable Barrels)

(USGS, 2012)

Viscous and Heavy Oil

(Includes All Schrader/West Sak and Ugnu Reservoirs in the Kuparuk River, Prudhoe Bay, Milne Point and Nikaitchuq Units, Not Just PAs or Areas Under Development)

Total In-Place Resource — **24 - 27 Billion Bbls**

(Hartz, et al., 2007; AOGCC)

Economically Recoverable — **3.6 - 5.6 Billion Bbls**

(Assuming 15% Average Recovery)

A History of Alaska's Production Tax System: North Slope

1977
- Gross Tax System
- Max Rate 12.25%
- ELF Introduced

1981
- Maximum Rate Increased to 15%
- New Fields at 12.25% for Five Years

1989
- ELF Modified to Include Field Size Factor

2003
- Exploration Credits 20-40% Introduced

2005
- Prudhoe Bay Fields Aggregated For Calculating ELF

2006
- PPT Introduced
- 22.5% Base Net Tax Rate, Increasing at 0.25% Per $1 Over $40 Net
- 20% Capital Credit
- Maximum Rate Set at 47.5%

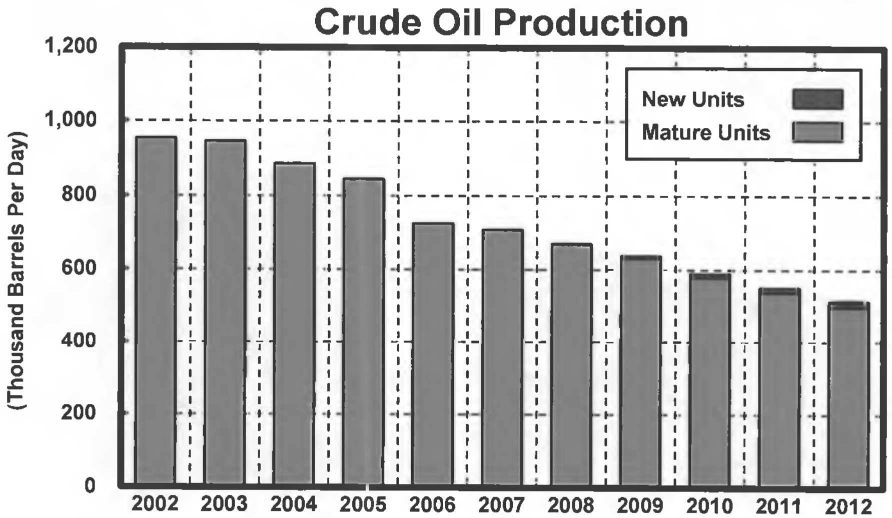
2007
- PPT Amended in Nov 2007; Effective Jul 2007
- 25% Base Net Tax Rate, Increasing at 0.4% Per $1 Over $30 Net, 0.1% Per $1 Over $92.50 Net
- Maximum Rate Set at 75%

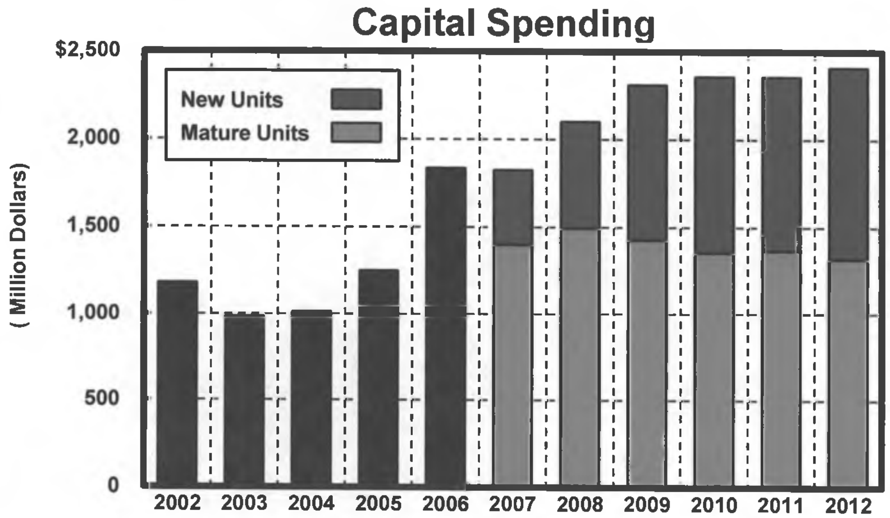
Benchmarking North Slope Activity Over The Past Decade Against Other Areas

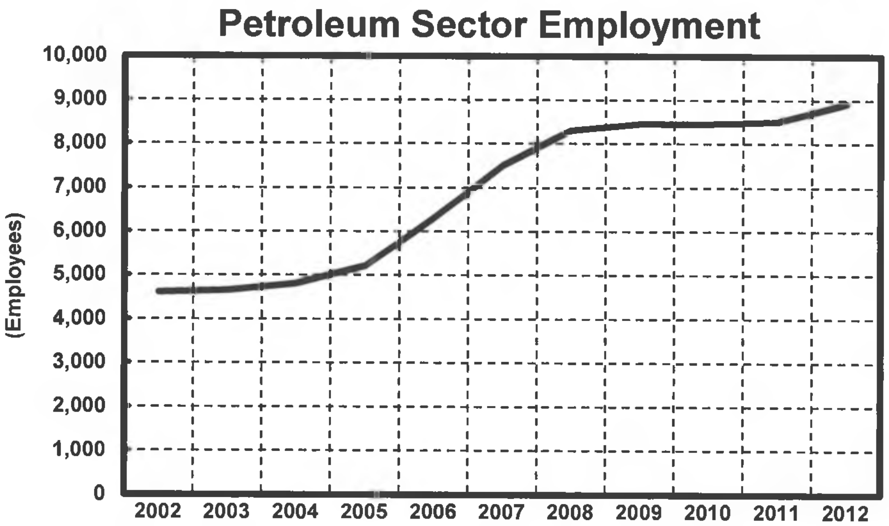
Benchmarking

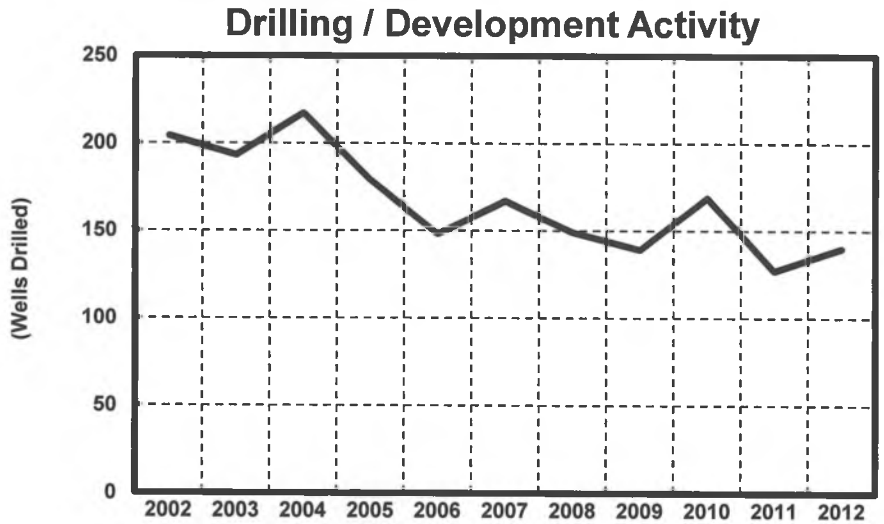
- Benchmarking Allows Us to Evaluate Activity in Alaska by Controlling for Significant Variables That are Common to All Oil Producing Properties
- No Two Producing Areas are Exactly Alike. We Attempt to Choose Locations That Share a Number of Similar Characteristics, Allowing for the Most Meaningful Comparisons
- We Benchmark the North Slope Against Significant Producing Areas in OECD Countries
    - The North Sea
    - The U.S. and Several Key Producing States / Areas
    - Canada and Producing Provinces
    - Australia
- All of These OECD Areas Have Many Characteristics in Common With North Slope
    - Similar Political and Legal Structure / Risk
    - Significant Prospectivity
    - But, Much of the "Low-Hanging" Fruit Has Been Produced
    - Development of Remaining Resources are Largely High-Cost, Either Conventional or Unconventional
    - Resources are Developed in Large Part by the Private Sector

Country/Area Profile
Alaska North Slope

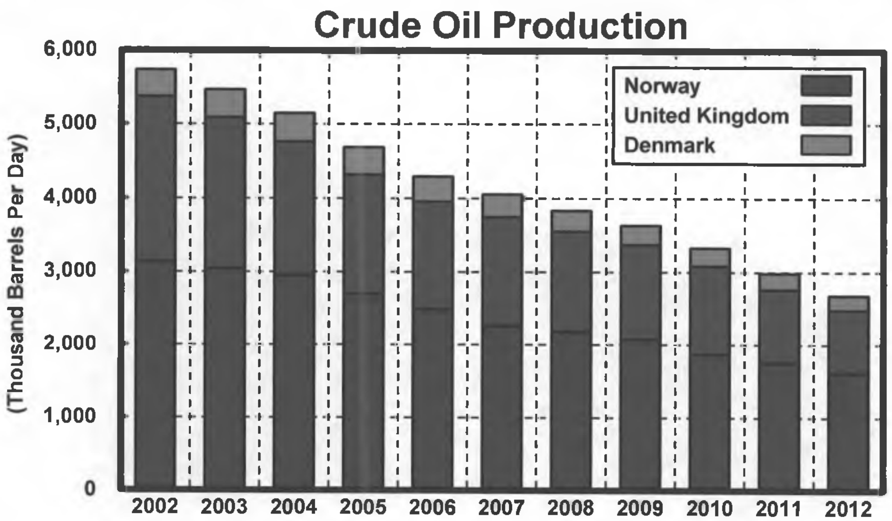


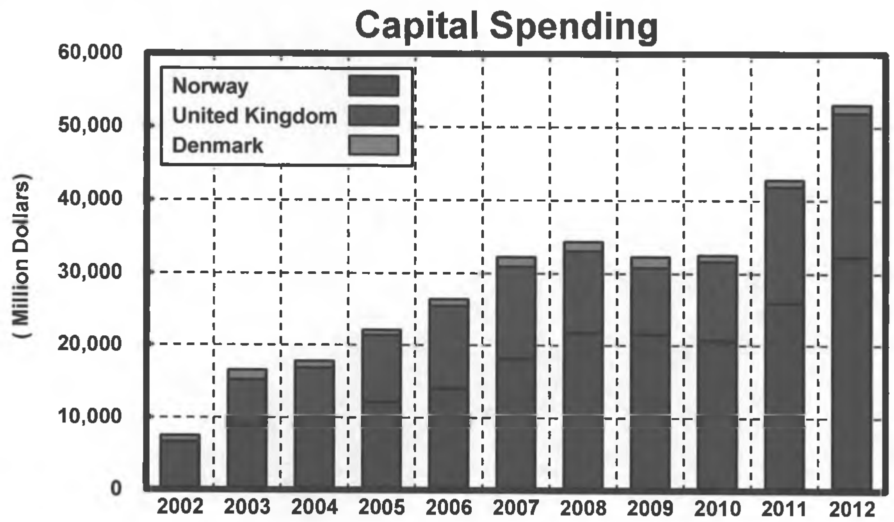


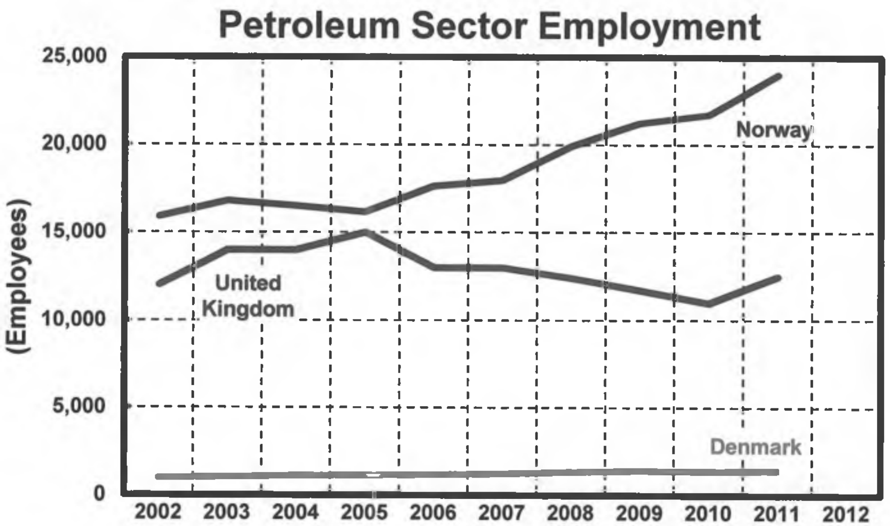


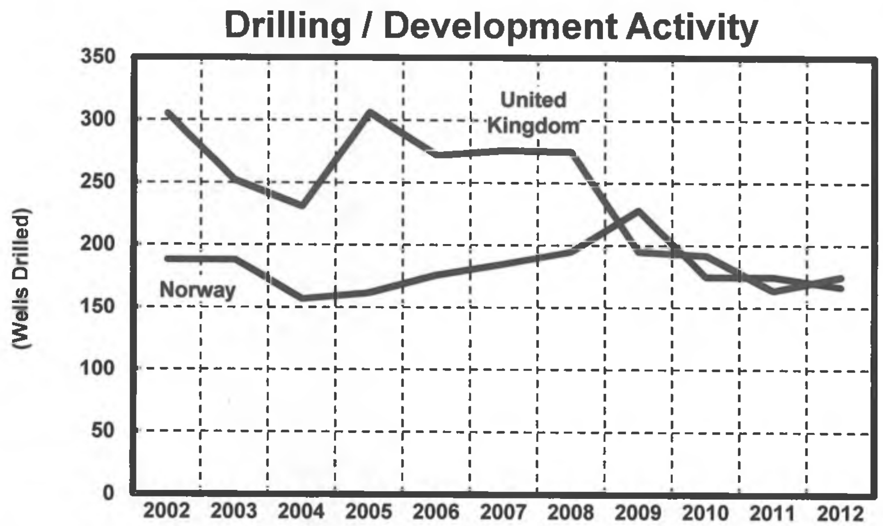


Country/Area Profile
Northwest Europe (North Sea)



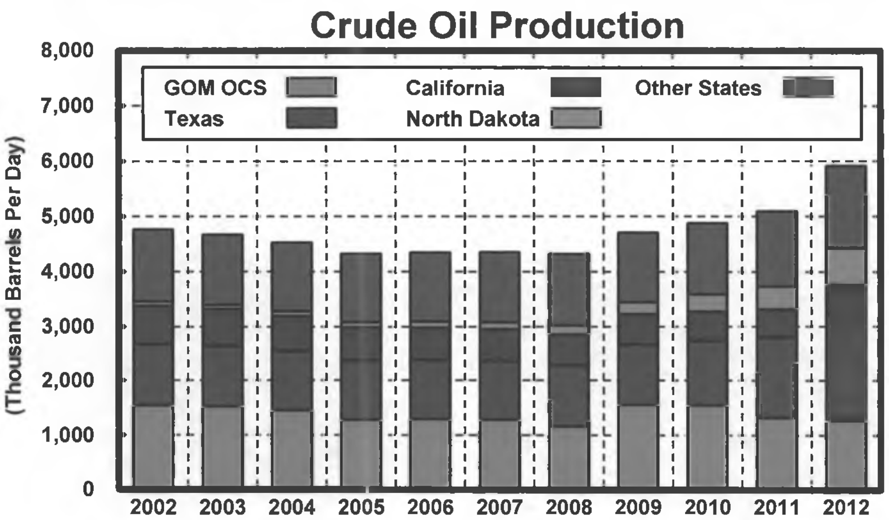


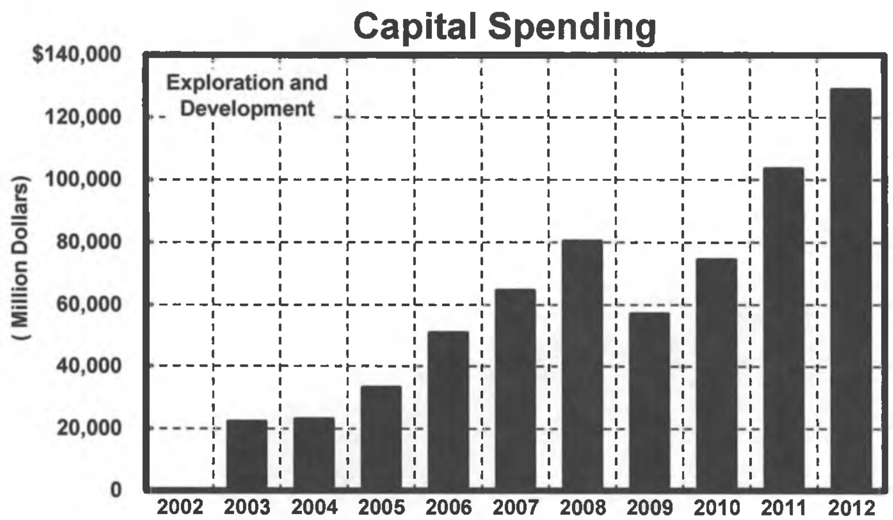


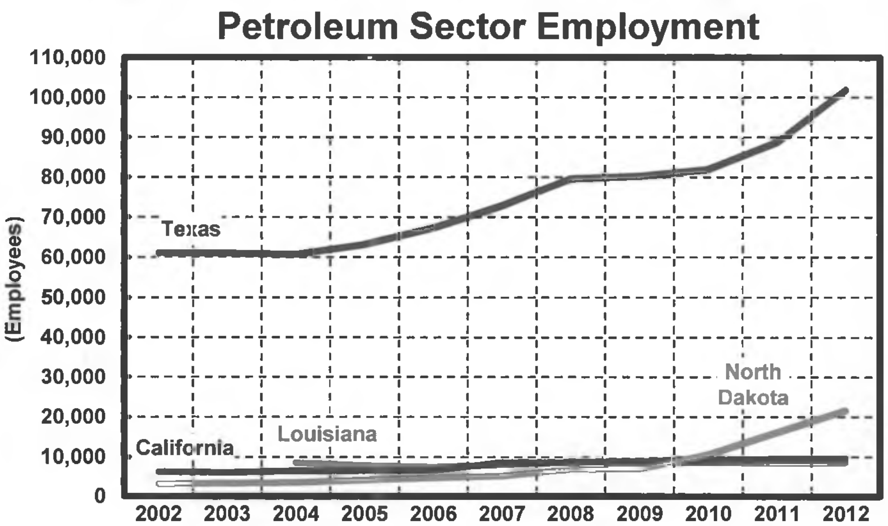


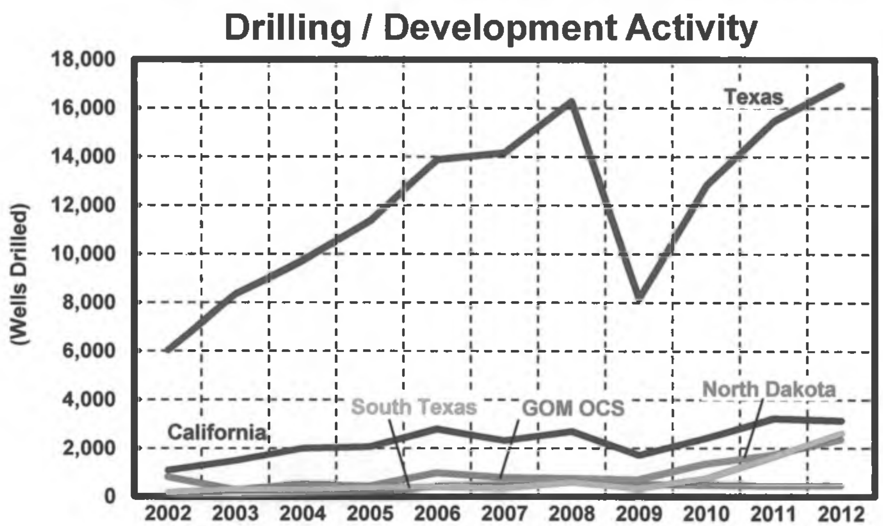
Note: 2012 figures are preliminary.

Country/Area Profile
United States Excluding Alaska North Slope





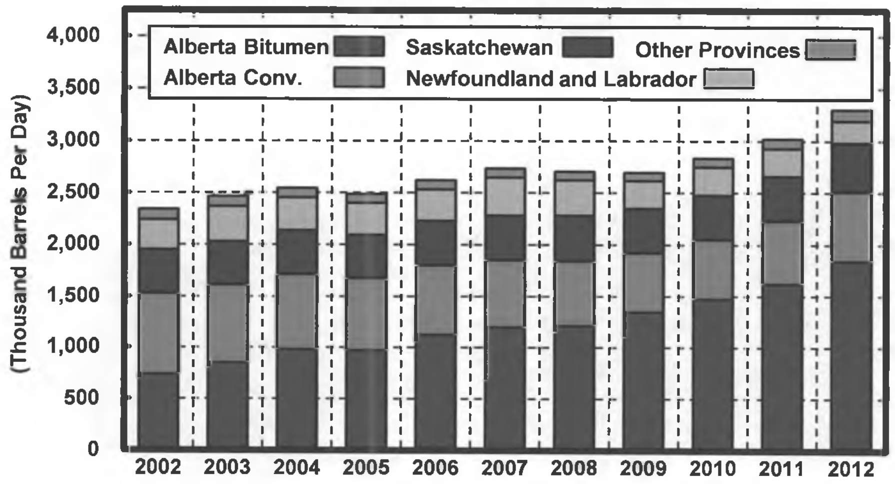




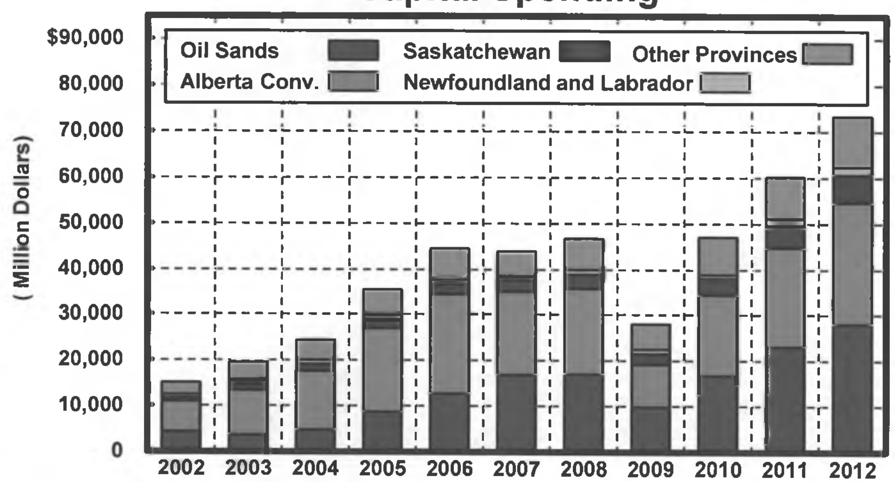
Note: 2012 figures are preliminary.

Country/Area Profile
Canada

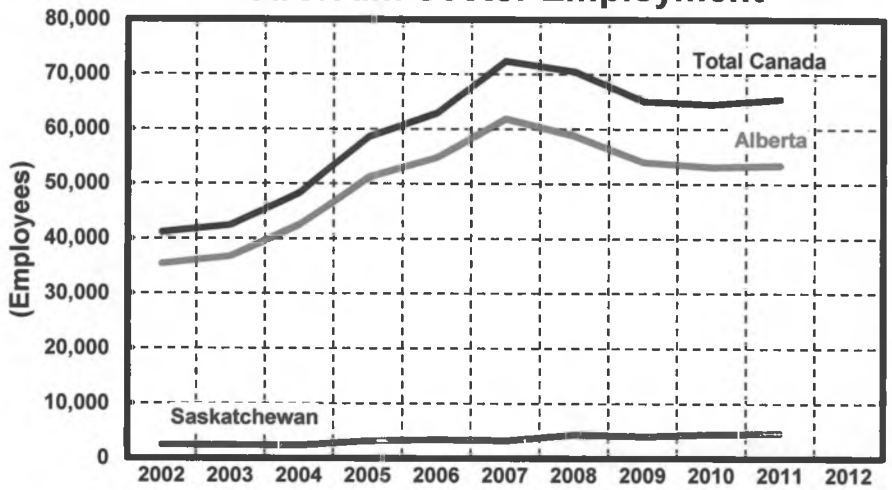
Crude Oil Production



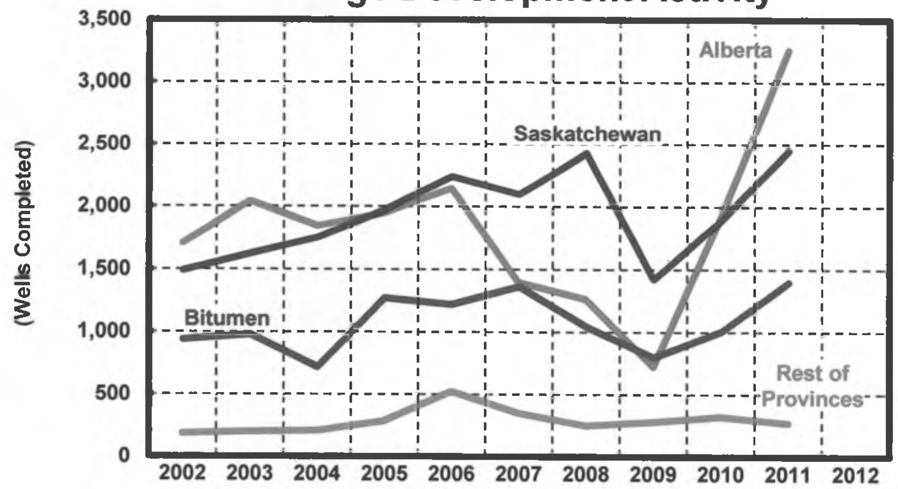
Capital Spending



Petroleum Sector Employment

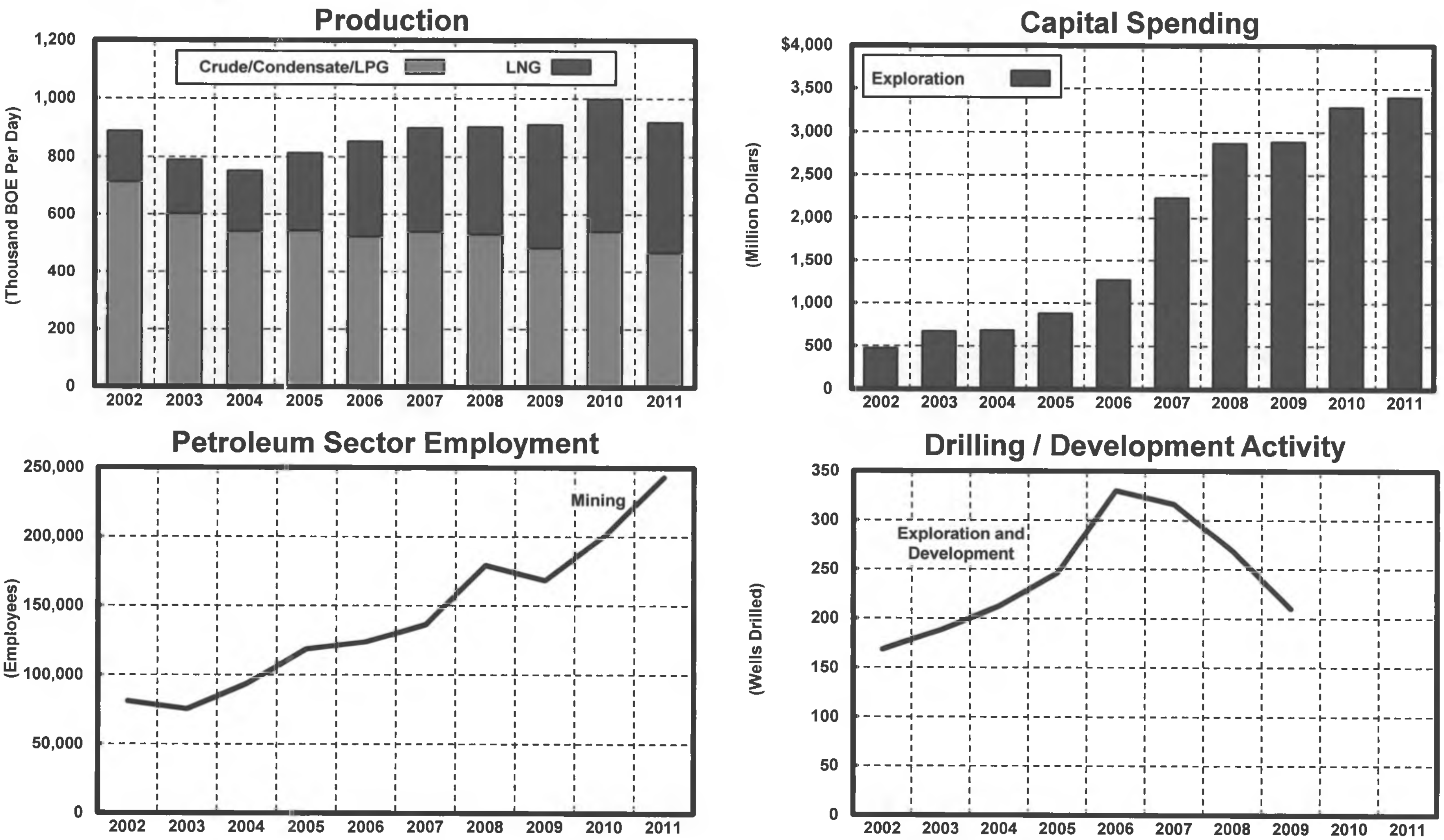


Drilling / Development Activity

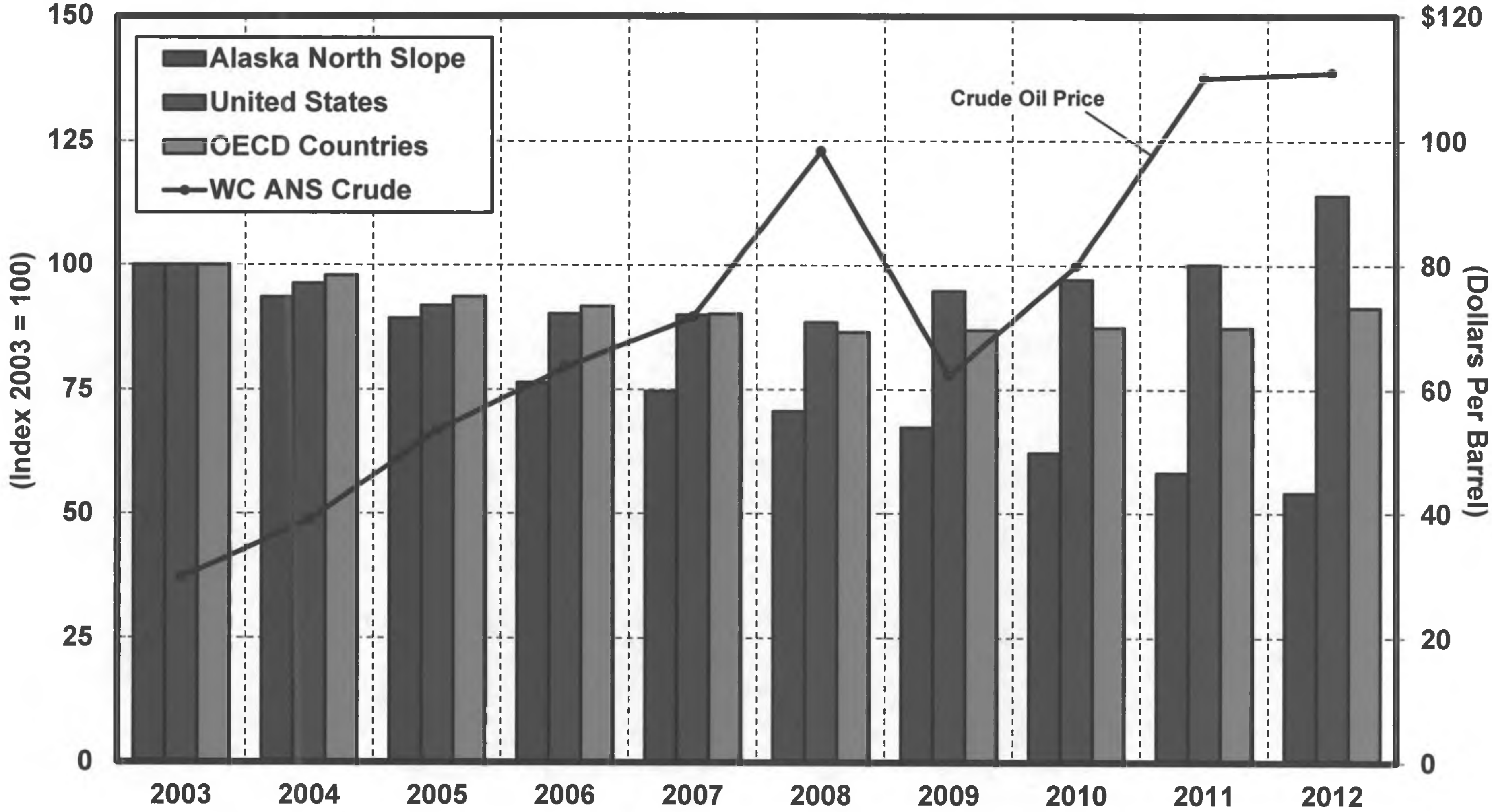


Note: 2012 figures are preliminary.

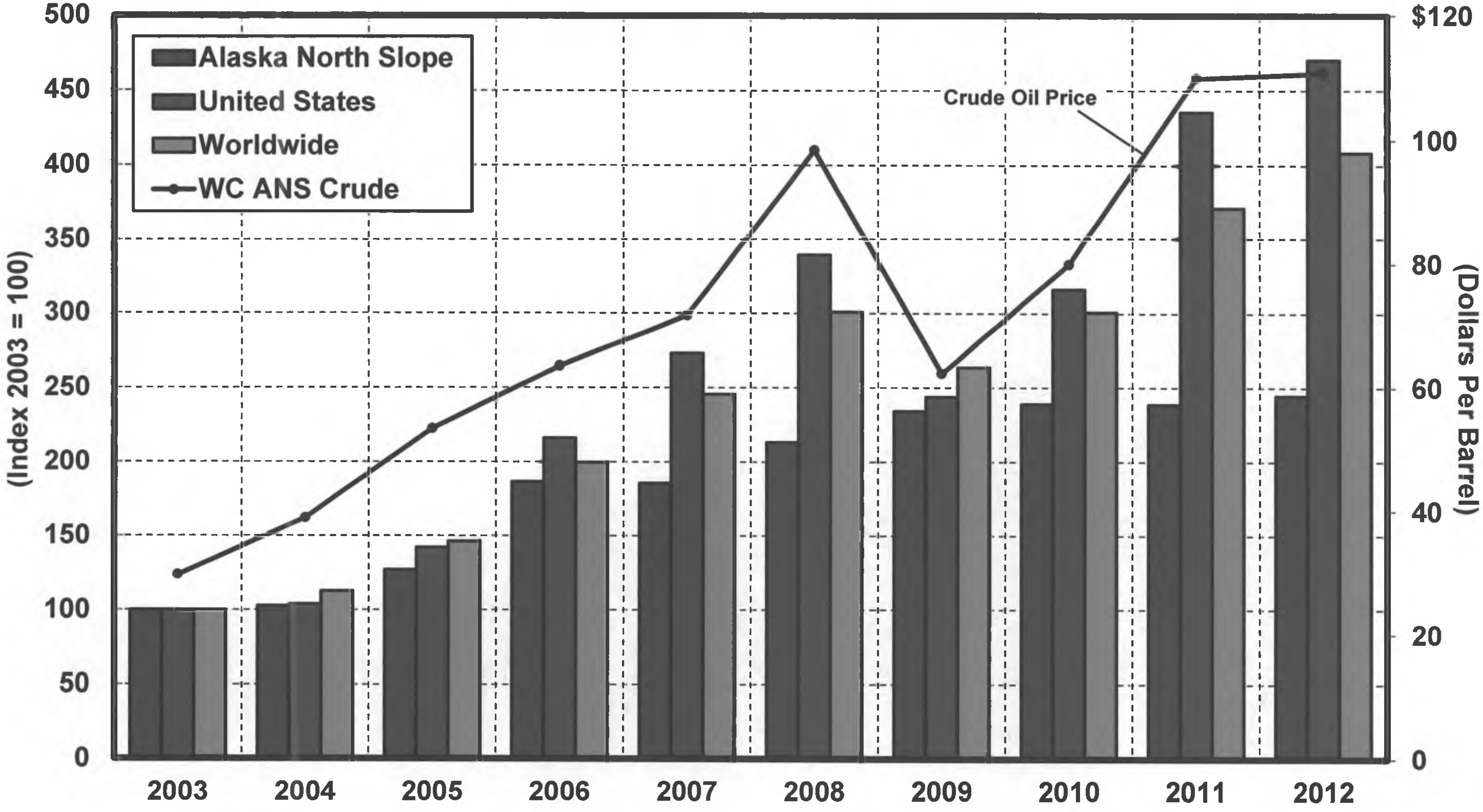
Country/Area Profile
Australia



Crude Oil Production
Alaska North Slope vs. United States and OECD Countries
2003 - 2012



Estimated Capital Spending for Exploration and Development Alaska North Slope vs. United States and Worldwide Spending* 2003 - 2012



* North Slope based on tax return information; U.S. based on top 50 public companies; worldwide based on top 75 public companies

Fundamentals of ACES Calculation

How ACES Works

- Tax is Calculated on "Net Value" of Taxable Production
  - Taxable Production is Total Production Less Royalties
  - Net Value is Gross Wellhead Value Less Cost of Production
  - Costs of Production are Capital Expenses, Operating Expenses and Property Tax Payments
- Base Tax Rate of 25%
- Progressive Tax Rate of 0.4% Per $1/Barrel (4% Per $10/Barrel) Increase Over $30/Barrel Net Value and 0.1% Per $1/Barrel (1% Per $10/Barrel) Over $92.50, Capped at 50% Total
- Example: Taxable Value = $100/Barrel "Production Tax Value"
Base Rate = 25%
Progressive Rate = ($92.50 - $30) x 0.4% + ($100 - $92.50) x 0.1% = 25.75%
Total Rate = 25% + 25.75% = 50.75%
- Credit of 20% for Capital Expenditures (Taken Over 2 Years)
- Small Producer Credit of $12 Million Per Year (Phased Out for Production over 50 MBD)
- State Purchases Credits and Net Operating Losses (NOLs) From Companies Without Tax Obligation
  - Equals 45% of Capital Expenditures and 25% of Operating Expenditures

Calculation of ACES Tax: Varying Prices

Annual Taxable Production (Bbls)		50,000,000	50,000,000	50,000,000
West Coast ANS Price ($/Bbl)		$80.00	$100.00	$120.00
Transportation Costs ($/Bbl)	-	10.00	10.00	10.00
Wellhead Value ($/Bbl)	=	$70.00	$90.00	$110.00
Operating Costs ($/Bbl)	-	$15.00	$15.00	$15.00
Capital Expenditures ($/Bbl)	-	15.00	15.00	15.00
Taxable Value ($/Bbl)	=	$40.00	$60.00	$80.00
ACES Base Tax Rate (%)		25.0%	25.0%	25.0%
ACES Progressive Tax (%)	+	4.0%	12.0%	20.0%
Total Tax Rate (%)	=	29.0%	37.0%	45.0%
Total Wellhead Value ($)		$3,500,000,000	$4,500,000,000	$5,500,000,000
Operating Expenditures ($)	-	750,000,000	750,000,000	750,000,000
Capital Expenditures ($)	-	750,000,000	750,000,000	750,000,000
Production Tax Value ($)	=	$2,000,000,000	$3,000,000,000	$4,000,000,000
Production Tax Before Credits (PTV x Total Tax Rate) ($)		$580,000,000	$1,110,000,000	$1,800,000,000
Capital Credits (20% x Capital Expenditures) ($)	-	150,000,000	150,000,000	150,000,000
Production Tax After Credits ($)	=	$430,000,000	$960,000,000	$1,650,000,000
Effective Tax Rate After Credits (%)		21.5%	32.0%	41.3%

Calculation of ACES Tax: Varying Costs
$100 West Coast ANS Price

Annual Taxable Production (Bbls)		50,000,000	50,000,000	50,000,000
West Coast ANS Price ($/Bbl)		$100.00	$100.00	$100.00
Transportation Costs ($/Bbl)	-	10.00	10.00	10.00
Wellhead Value ($/Bbl)	=	$90.00	$90.00	$90.00
Operating Costs ($/Bbl)	-	$10.00	$20.00	$30.00
Capital Expenditures ($/Bbl)	-	10.00	15.00	20.00
Taxable Value ($/Bbl)	=	$70.00	$55.00	$40.00
ACES Base Tax Rate (%)		25.0%	25.0%	25.0%
ACES Progressive Tax (%)	+	16.0%	10.0%	4.0%
Total Tax Rate (%)	=	41.0%	35.0%	29.0%
Total Wellhead Value ($)		$4,500,000,000	$4,500,000,000	$4,500,000,000
Operating Expenditures ($)	-	500,000,000	1,000,000,000	1,500,000,000
Capital Expenditures ($)	-	500,000,000	750,000,000	1,000,000,000
Production Tax Value ($)	=	$3,500,000,000	$2,750,000,000	$2,000,000,000
Production Tax Before Credits (PTV x Total Tax Rate) ($)		$1,435,000,000	$962,500,000	$580,000,000
Capital Credits (20% x Capital Expenditures) ($)	-	100,000,000	150,000,000	200,000,000
Production Tax After Credits ($)	=	$1,335,000,000	$812,500,000	$380,000,000
Effective Tax Rate After Credits (%)		38.1%	29.5%	19.0%

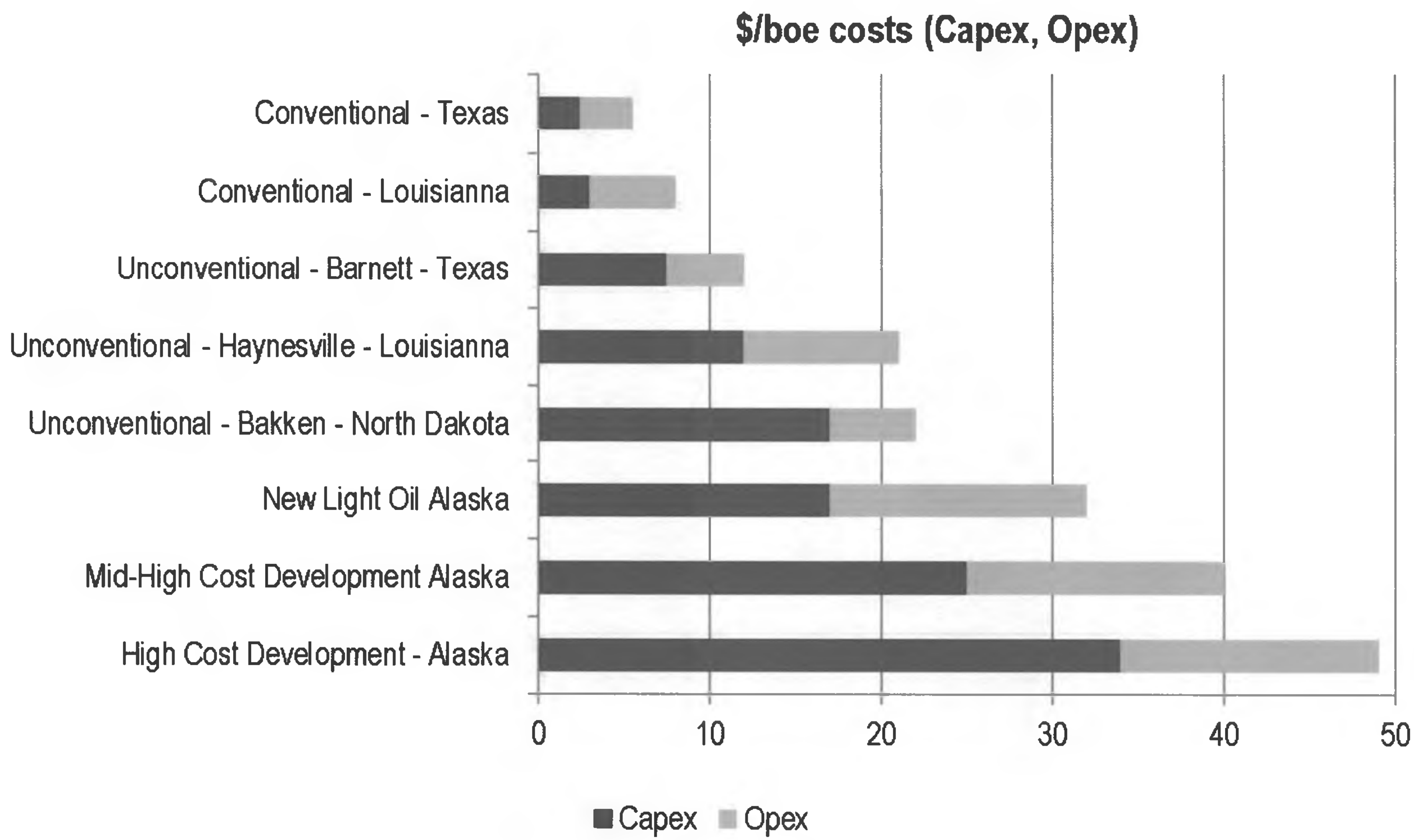
Calculation of ACES Tax: Varying Costs
$80 West Coast ANS Price

Annual Taxable Production (Bbls)		50,000,000	50,000,000	50,000,000
West Coast ANS Price ($/Bbl)		$80.00	$80.00	$80.00
Transportation Costs ($/Bbl)	-	10.00	10.00	10.00
Wellhead Value ($/Bbl)	=	$70.00	$70.00	$70.00
Operating Costs ($/Bbl)	-	$10.00	$20.00	$30.00
Capital Expenditures ($/Bbl)	-	10.00	15.00	20.00
Taxable Value ($/Bbl)	=	$50.00	$35.00	$20.00
ACES Base Tax Rate (%)		25.0%	25.0%	25.0%
ACES Progressive Tax (%)	+	8.0%	2.0%	0.0%
Total Tax Rate (%)	=	33.0%	27.0%	25.0%
Total Wellhead Value ($)		$3,500,000,000	$3,500,000,000	$3,500,000,000
Operating Expenditures ($)	-	500,000,000	1,000,000,000	1,500,000,000
Capital Expenditures ($)	-	500,000,000	750,000,000	1,000,000,000
Production Tax Value ($)	=	$2,500,000,000	$1,750,000,000	$1,000,000,000
Production Tax Before Credits (PTV x Total Tax Rate) ($)		$825,000,000	$472,500,000	$250,000,000
Capital Credits (20% x Capital Expenditures) ($)	-	100,000,000	150,000,000	200,000,000
Production Tax After Credits ($)	=	$725,000,000	$322,500,000	$50,000,000
Effective Tax Rate After Credits (%)		29.0%	18.4%	5.0%

Calculation of ACES Tax: Additional Capital Spending

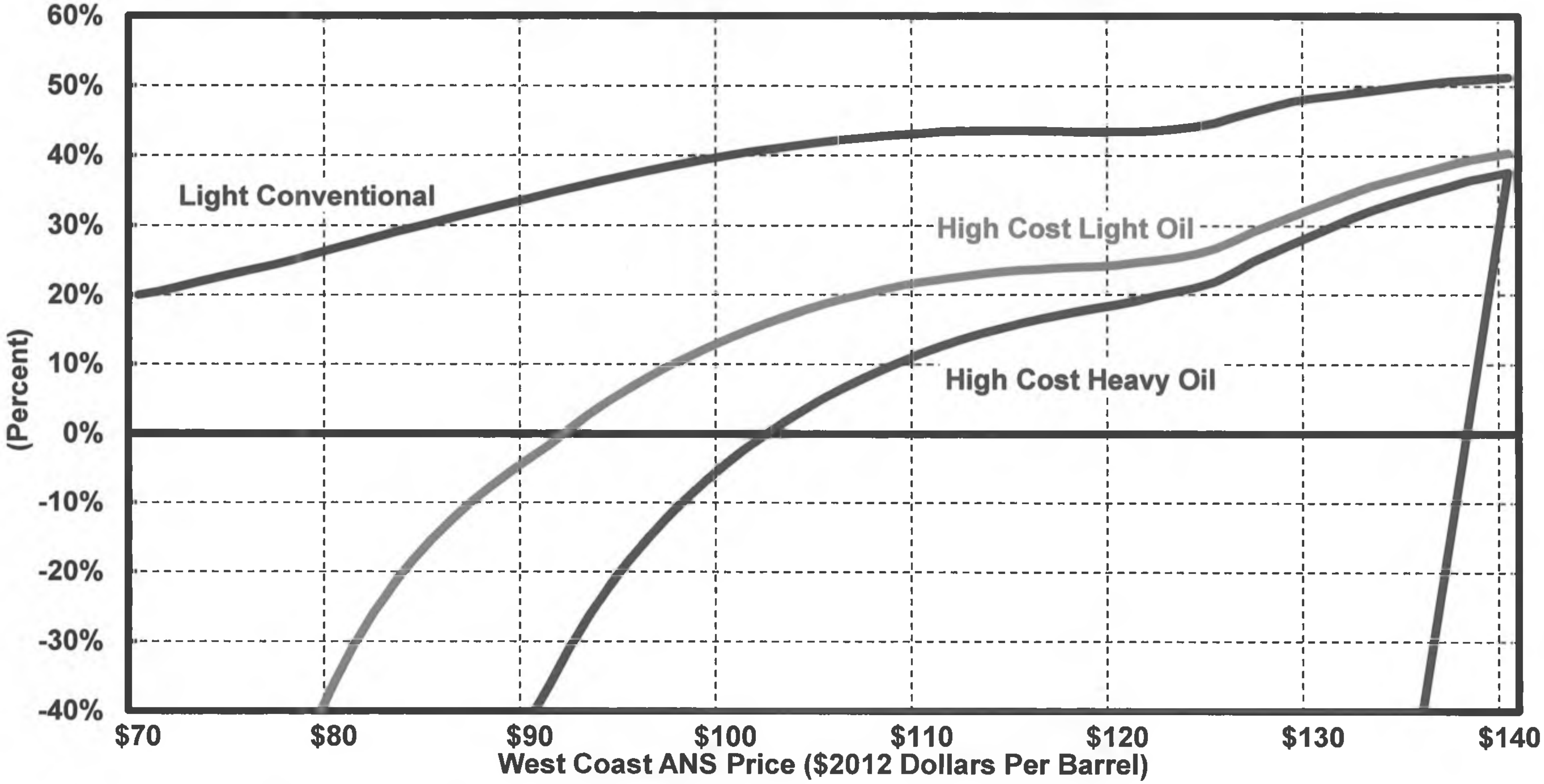
Annual Taxable Production (Bbls)		50,000,000	50,000,000	50,000,000
Initial Expenditure ($)		$1,500,000,000	$1,500,000,000	$1,500,000,000
Additional Expenditure ($)	+	250,000,000	250,000,000	250,000,000
Total Lease Expenditure ($)		$1,750,000,000	$1,750,000,000	$1,750,000,000
WC ANS Price ($/Bbl)		$80.00	$100.00	$120.00
Tax Value Prior To Additional Expenditure ($/Bbl)		$40.00	$60.00	$80.00
Additional Capital Spending Per-Barrel of Existing Production ($/Bbl)	-	5.00	5.00	5.00
Tax Value After Additional Expenditure ($/Bbl)	=	$35.00	$55.00	$75.00
Taxes Before Additional Expenditure				
Tax Rate (%)		29.0%	37.0%	45.0%
Production Tax Before Credits ($)		$580,000,000	$1,110,000,000	$1,800,000,000
Capital Credits (20% x Capital Expenditures) ($)	-	300,000,000	300,000,000	300,000,000
Production Tax After Credits ($)	=	$280,000,000	$810,000,000	$1,500,000,000
Taxes After Additional Expenditure				
Tax Rate (%)		27.0%	35.0%	43.0%
Production Tax Before Credits ($)		$472,500,000	$962,500,000	$1,612,500,000
Capital Credits (20% x Capital Expenditures) ($)	-	350,000,000	350,000,000	350,000,000
Production Tax After Credits ($)	=	$122,500,000	$612,500,000	$1,262,500,000
Reduction in Taxes From Additional Expenditure				
Before Credits		$107,500,000	$147,500,000	$187,500,000
Additional Credits	+	50,000,000	50,000,000	50,000,000
Total Reduction in Taxes After Credits	=	$157,500,000	$197,500,000	$237,500,000
Reduction in Tax as % of Expenditure		63%	79%	95%
Due to Change in Taxes (Buy Down Effect)		43%	59%	75%
Due to Additional Credits		20%	20%	20%

PFC Costs
Various Projects



Source: Excerpted from January 31, 2013 PFC Presentation to Senate TAPS Throughput Committee.

Effective Tax Rates For New Development Under ACES
Additional Tax as % of Production Tax Value: Incumbent Producer



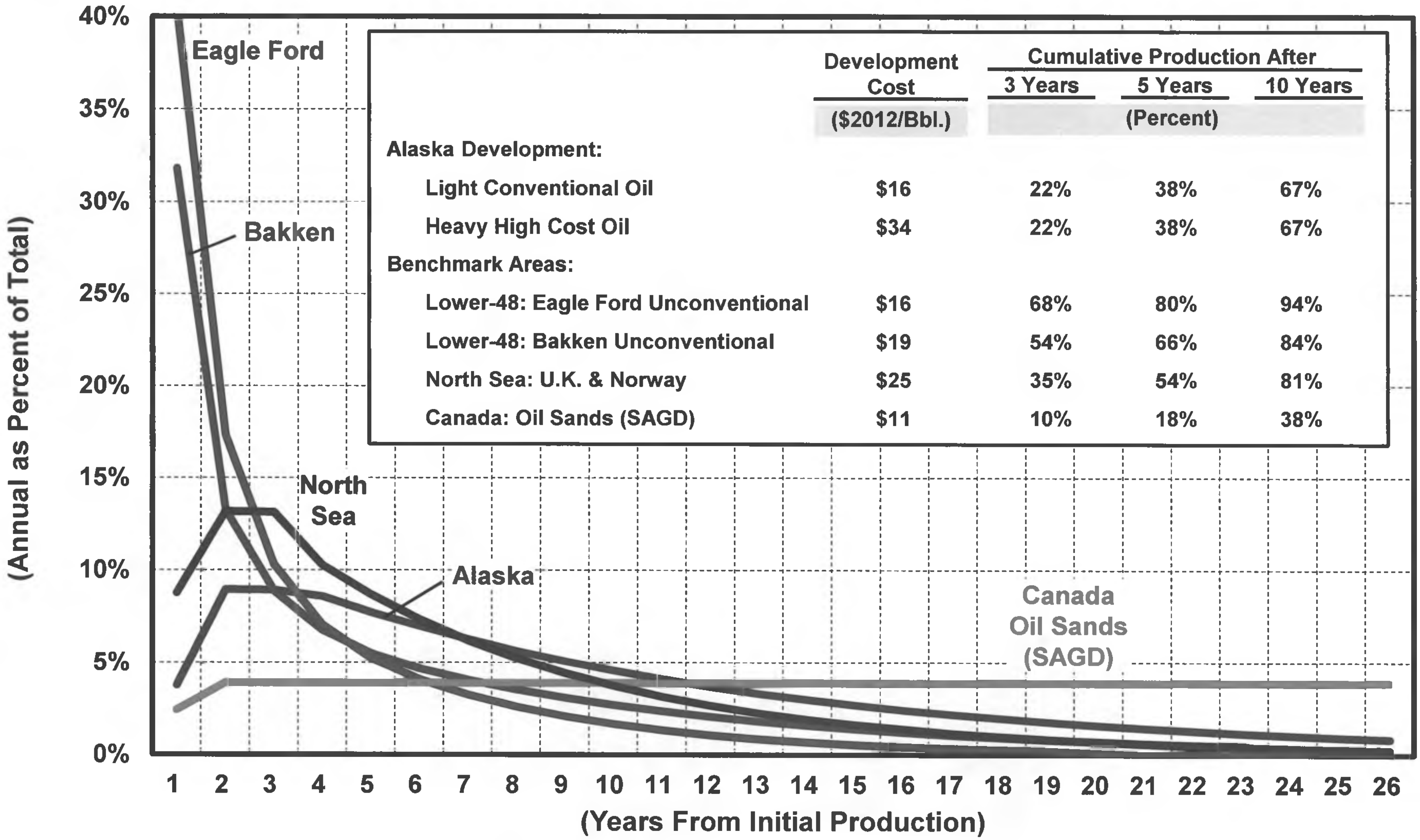
Light Conventional Oil: $16 Per Barrel Development Capex; $14 Per Barrel Opex; 16.67% Royalty Rate; 50 MMBO New Development by Existing Owner With Initial Ongoing Production of Approximately 100 MBD and Costs Consistent with Prudhoe Bay/Kuparuk River Units

High Cost Light Oil: $34 Per Barrel Development Capex; $19 Per Barrel Opex; 16.67% Royalty Rate; 50 MMBO New Development by Existing Owner With Initial Ongoing Production of Approximately 100 MBD and Costs Consistent with Prudhoe Bay/Kuparuk River Units

High Cost Heavy Oil: $34 Per Barrel Development Capex; $19 Per Barrel Opex; 12.5% Royalty Rate; $10 Below Stream Price; 50 MMBO New Development by Existing Owner With Initial Ongoing Production of Approximately 100 MBD and Costs Consistent with Prudhoe Bay/Kuparuk River Units

Analysis of Potential Investments In Alaska Under ACES Versus Other Areas

Summary of Production Profiles Examined For Alaska and Benchmark Developments



	Development Cost	Cumulative Production After 3 Years	5 Years	10 Years
	($2012/Bbl.)	(Percent)		
Alaska Development:				
Light Conventional Oil	$16	22%	38%	67%
Heavy High Cost Oil	$34	22%	38%	67%
Benchmark Areas:				
Lower-48: Eagle Ford Unconventional	$16	68%	80%	94%
Lower-48: Bakken Unconventional	$19	54%	66%	84%
North Sea: U.K. & Norway	$25	35%	54%	81%
Canada: Oil Sands (SAGD)	$11	10%	18%	38%

Investment Measures Analyzed

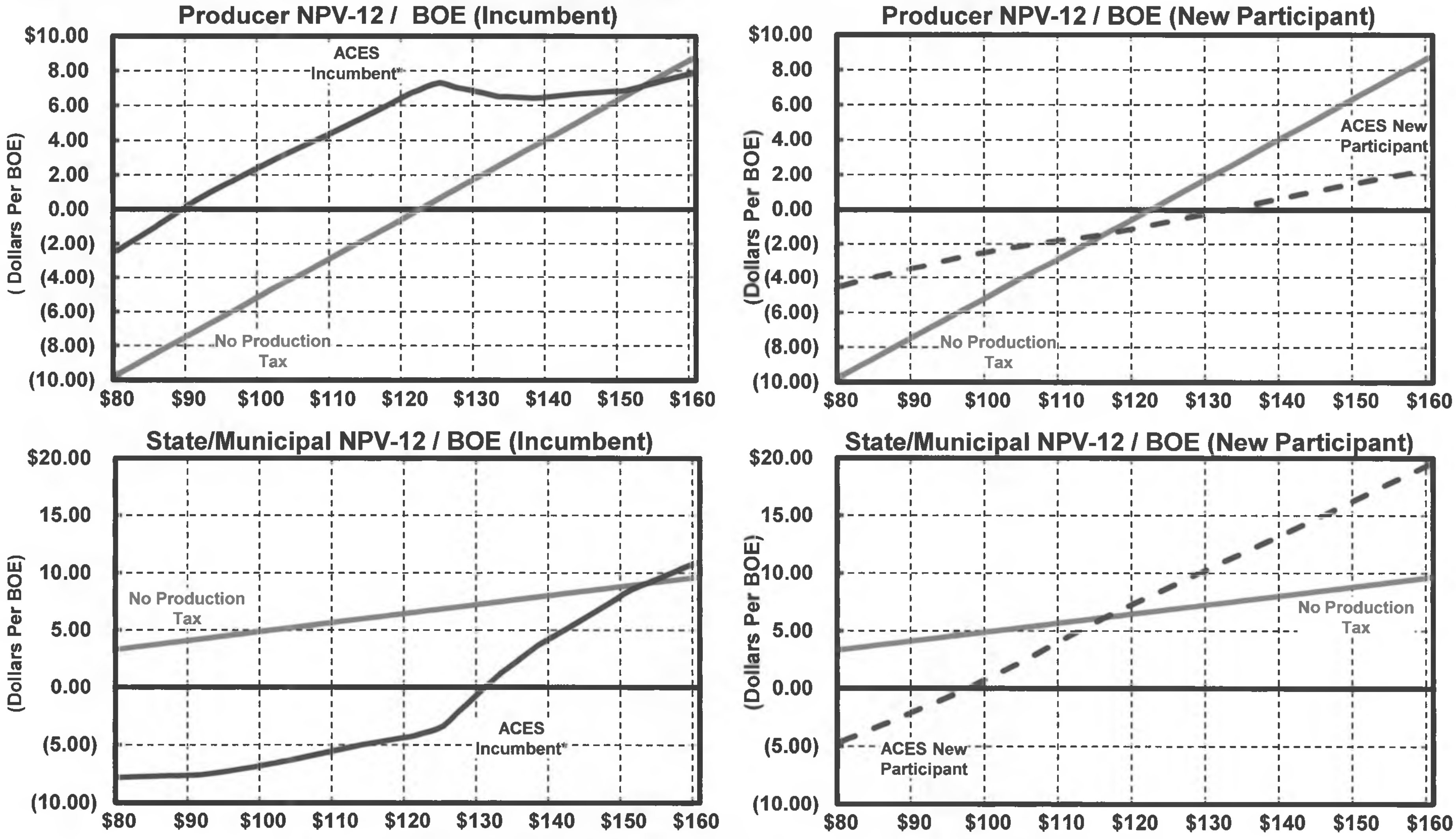
- Producer NPV-12 Per BOE
- Internal Rate of Return (IRR)
- 5-Year Cash Margins
- Profitability Index-12
- Government Take
- State NPV-12 Per BOE

Summary of Investment Measures

West Coast ANS Price	Alaska 50 MMBO: Light Conventional Oil: New Participant	Alaska 50 MMBO: Light Conventional Oil: Incumbent Participant	Alaska 50 MMBO: Heavy High Cost Oil: New Participant	Alaska 50 MMBO: Heavy High Cost Oil: Incumbent Participant	Unconventional Lower-48: Eagle Ford	Unconventional Lower-48: Bakken	Canada Oil Sands SAGD	Norway	U.K. Development & Fiscal System: Pre-1993	U.K.: Pre-1993 w/ Brownfield Allowance*	U.K.: Post-1993	U.K.: Post-1993 w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Producer NPV-12 / BOE (Dollars Per BOE)												
$80	$2.55	$3.71	($4.51)	($2.43)	$3.61	$0.67	($0.93)	$0.24	$1.20	$4.81	$2.41	$4.62
$100	$3.85	$6.14	($2.45)	$2.48	$6.75	$4.29	$0.46	$2.34	$3.02	$7.09	$6.04	$8.25
$120	$5.48	$8.82	($1.09)	$6.53	$11.17	$9.16	$2.01	$4.44	$4.83	$9.09	$9.67	$11.88
Profitability Index-12												
$80	1.19	1.28	0.84	0.91	1.25	1.04	0.88	1.01	1.06	1.22	1.11	1.21
$100	1.29	1.46	0.91	1.09	1.47	1.28	1.06	1.14	1.14	1.33	1.28	1.38
$120	1.41	1.67	0.96	1.23	1.78	1.60	1.26	1.27	1.22	1.42	1.45	1.55
IRR (Percent)												
$80	19.7%	26.2%	4.3%	7.1%	29.9%	13.6%	9.7%	12.4%	18.4%	34.5%	18.4%	24.7%
$100	23.4%	41.1%	8.1%	18.2%	46.3%	22.7%	13.1%	16.0%	27.0%	45.2%	27.0%	32.9%
$120	27.6%	65.3%	10.3%	33.6%	73.6%	37.0%	16.3%	19.3%	34.6%	53.5%	34.6%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)												
$80	$25.84	$24.26	$27.58	$25.52	$23.39	$28.39	$26.07	$34.51	$12.45	$22.94	$24.91	$29.35
$100	$28.84	$27.22	$32.42	$30.33	$29.99	$36.48	$29.14	$39.42	$16.69	$28.85	$33.38	$37.82
$120	$33.13	$31.18	$35.48	$33.41	$36.87	$44.91	$33.37	$44.32	$20.93	$31.29	$41.86	$46.30
Government Take (Percent)												
$80	70.8%	68.9%	61.5%	45.0%	71.7%	77.1%	63.4%	67.8%	81.0%	61.0%	62.0%	52.0%
$100	75.8%	73.0%	71.6%	58.3%	67.9%	72.1%	63.5%	71.7%	81.0%	68.6%	62.0%	55.8%
$120	77.2%	73.8%	76.8%	63.4%	65.1%	68.7%	63.0%	73.4%	81.0%	72.0%	62.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)												
$80	$6.67	$4.88	($4.61)	($7.81)	-	-	-	-	-	-	-	-
$100	$13.32	$9.79	$0.86	($6.73)	-	-	-	-	-	-	-	-
$120	$19.46	$14.31	$7.41	($4.31)	-	-	-	-	-	-	-	-

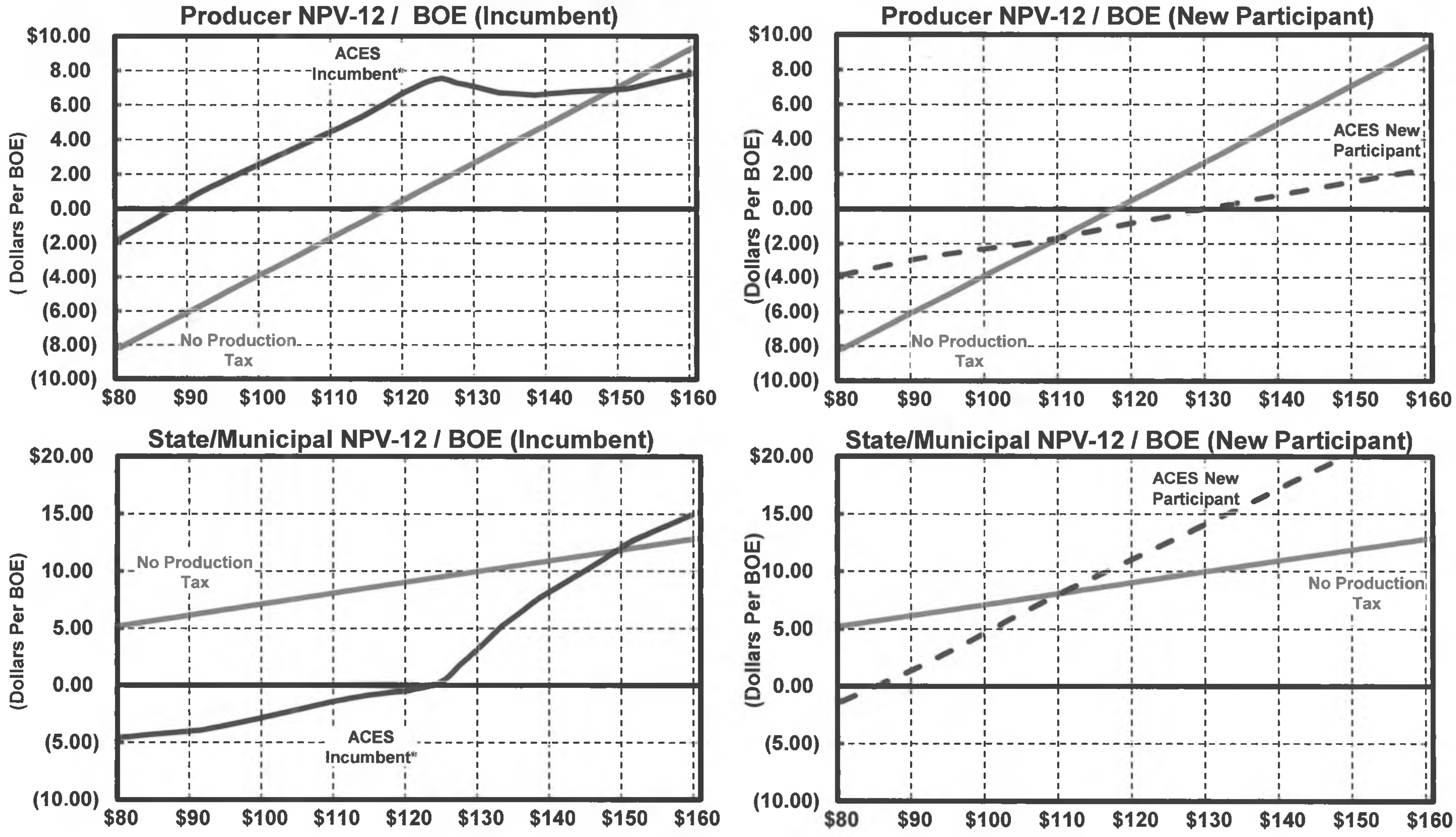
*** Brownfield Allowance applied to 100 MMBOE development.**
Note: Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

The Economics of High Cost Heavy Oil Development



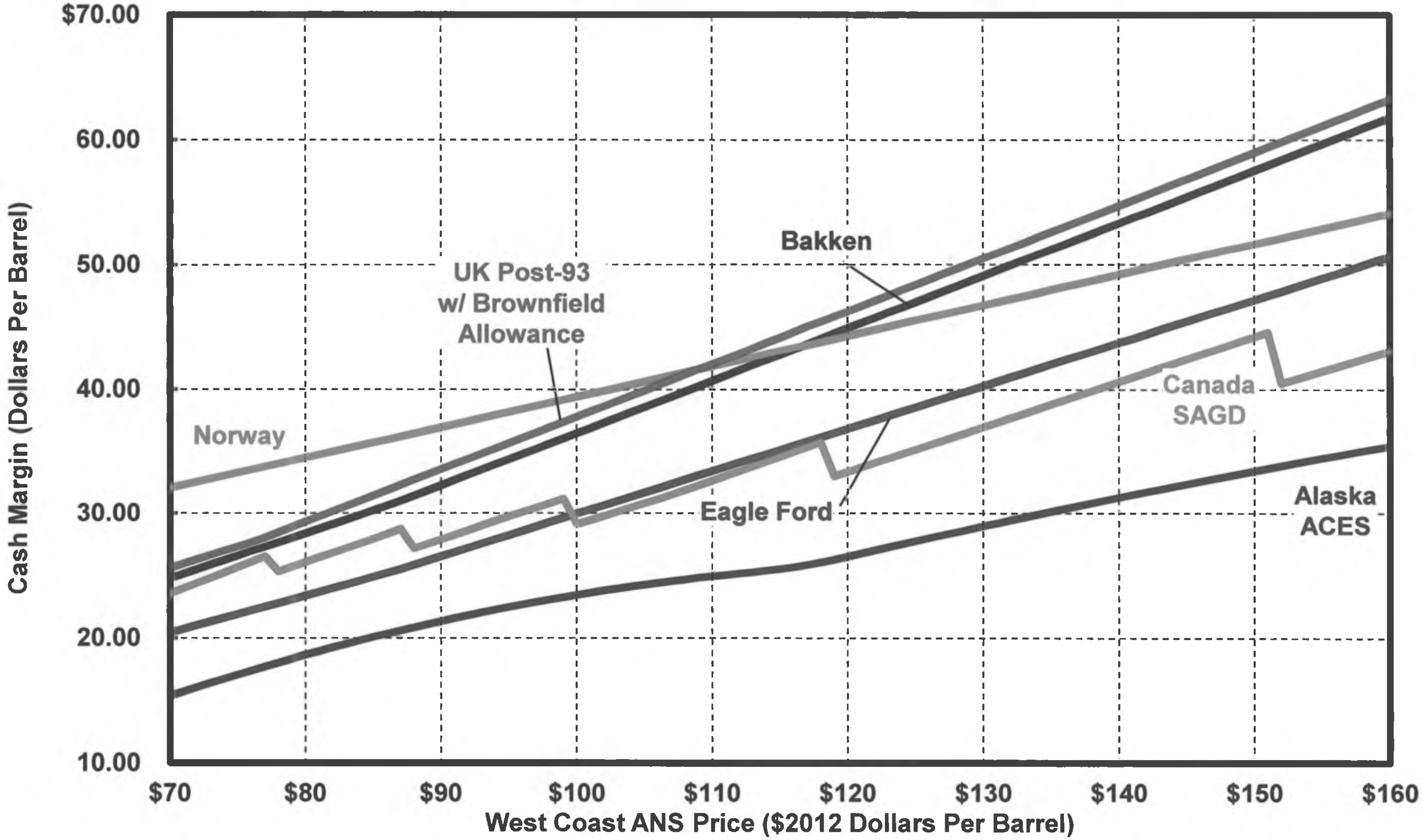
* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

The Economics of High Cost Light Oil Development



* Analysis of incumbent production includes “buy-down” impact for reduced taxes on existing production.

Projected Cash Generation From Ongoing North Slope Production (2017-2021) Under ACES and Other Jurisdictions



22. *UNITED STATES—ALASKA: STATE LANDS*

Table II-LVI: Alaska State Lands Assumed Terms

FISCAL SYSTEM	Alaska—State Lands Concessionary Terms
BONUSES	Fixed or biddable signature bonus; US$0.5 million assumed
OTHER PAYMENTS	Production rental: US$1–$3 per acre
STATE PARTICIPATION	None
ROYALTY	12.5 percent of gross revenue
PROFIT TAX	ACES production tax: profit based tax levied between 25 to 75 percent.
PROPERTY TAX	2 percent of accumulated capital expenditure less accumulated depreciation
INCOME TAX	State Income Tax levied on gross revenue less deductions and depreciation. The state income tax rate is in the range 1.0 to 9.4 percent Federal income tax levied on gross revenue less deductions and depreciation. The federal income tax rate is 35 percent
OTHER TAXES	Property tax: 2 percent of accumulated capital expenditure less accumulated depreciation State conservation surcharges: US$0.005 per barrel on crude oil and US$0.0083 per Mcf on natural gas

BONUSES AND OTHER PAYMENTS

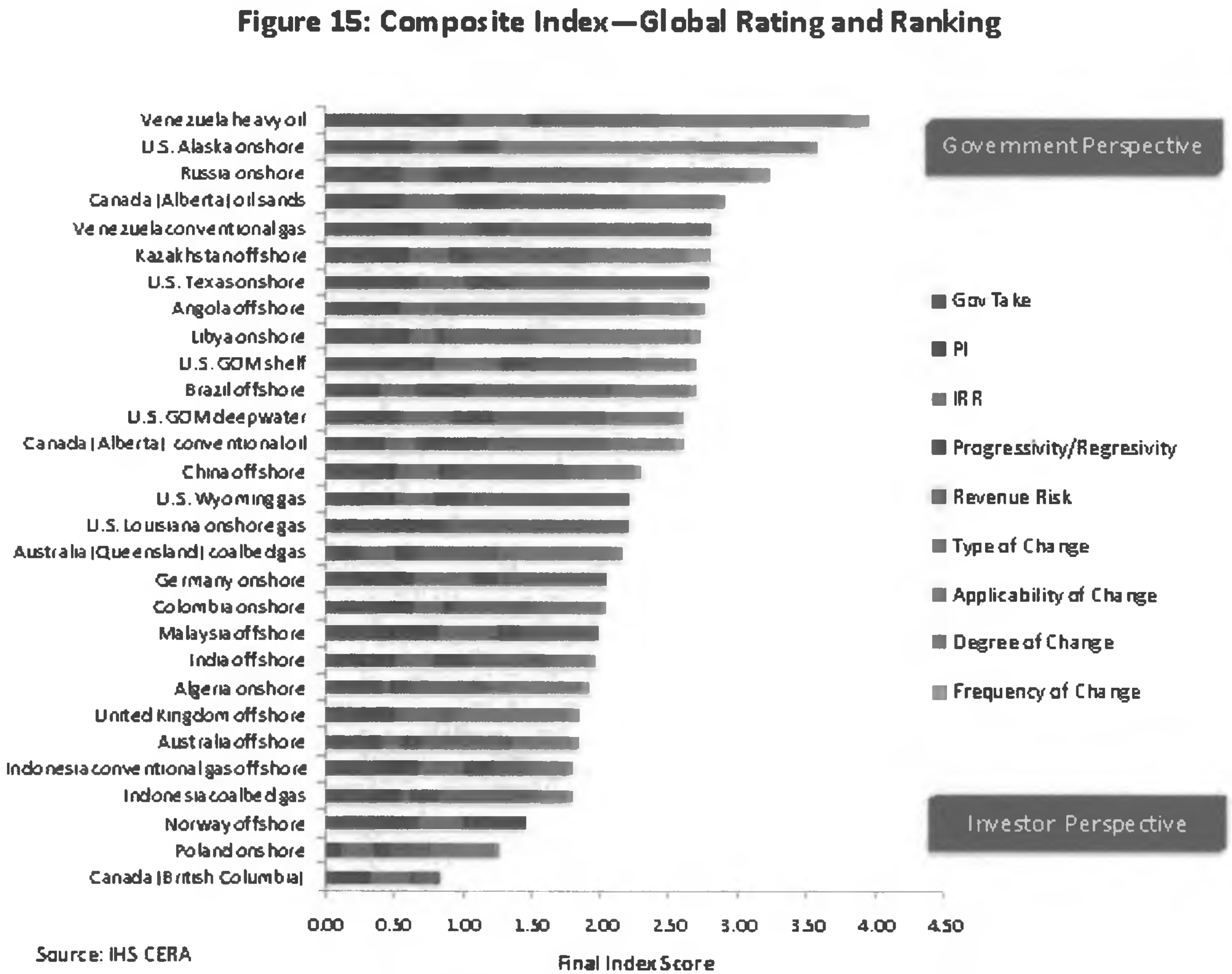
The cash bonus may be fixed in advance or subject to bidding. In the latter case, the minimum cash bonus that will be accepted in any lease sale is prescribed. US$5 to US$10 per acre is typical, although higher minimums may apply to highly prospective blocks. A signature bonus of US$0.5 million has been assumed.

Rental

Rentals range between US$1 and US$3 per acre as follows:

Source: Excerpted from page 225 of IHS CERA Report.

IHS CERA 2011 Report to the U.S. Department of Interior (cont'd)



Source: Excerpted from page 24 of IHS CERA Report.

The Administration's Proposed Changes SB21/HB72

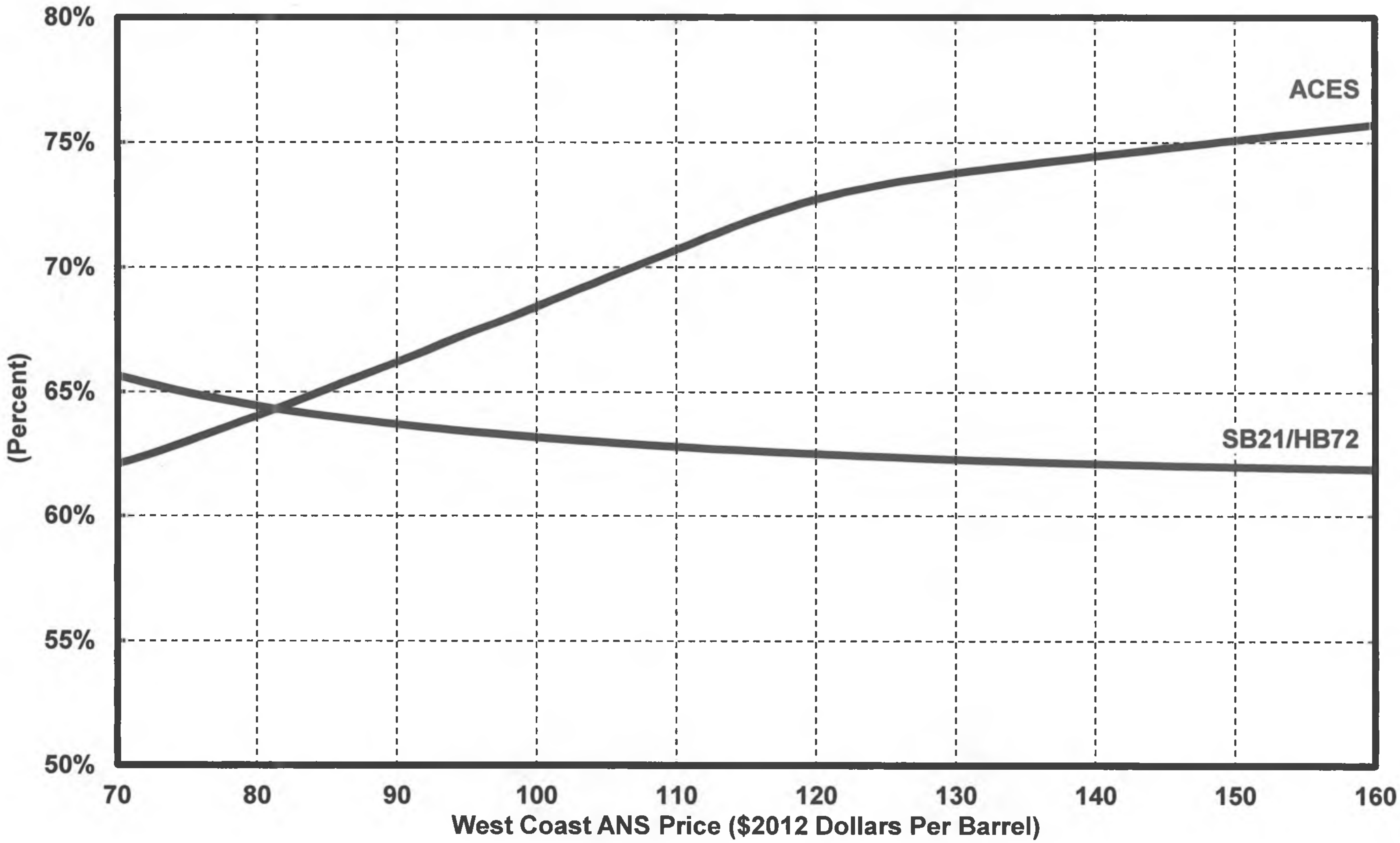
Key Aspects of Administration's Proposal

- Establishes 25% Flat Net Tax Rate; No Progressivity
- Eliminates Capital Credit and State Purchase of Losses
- Establishes 20% Gross Revenue Exclusion (GRE) to Incent Production of New Oil
- Losses May be Carried Forward and Applied Against Tax Obligation When Production Occurs
- Extends New Entrant Credits Through 2022
- No Change Outside of North Slope

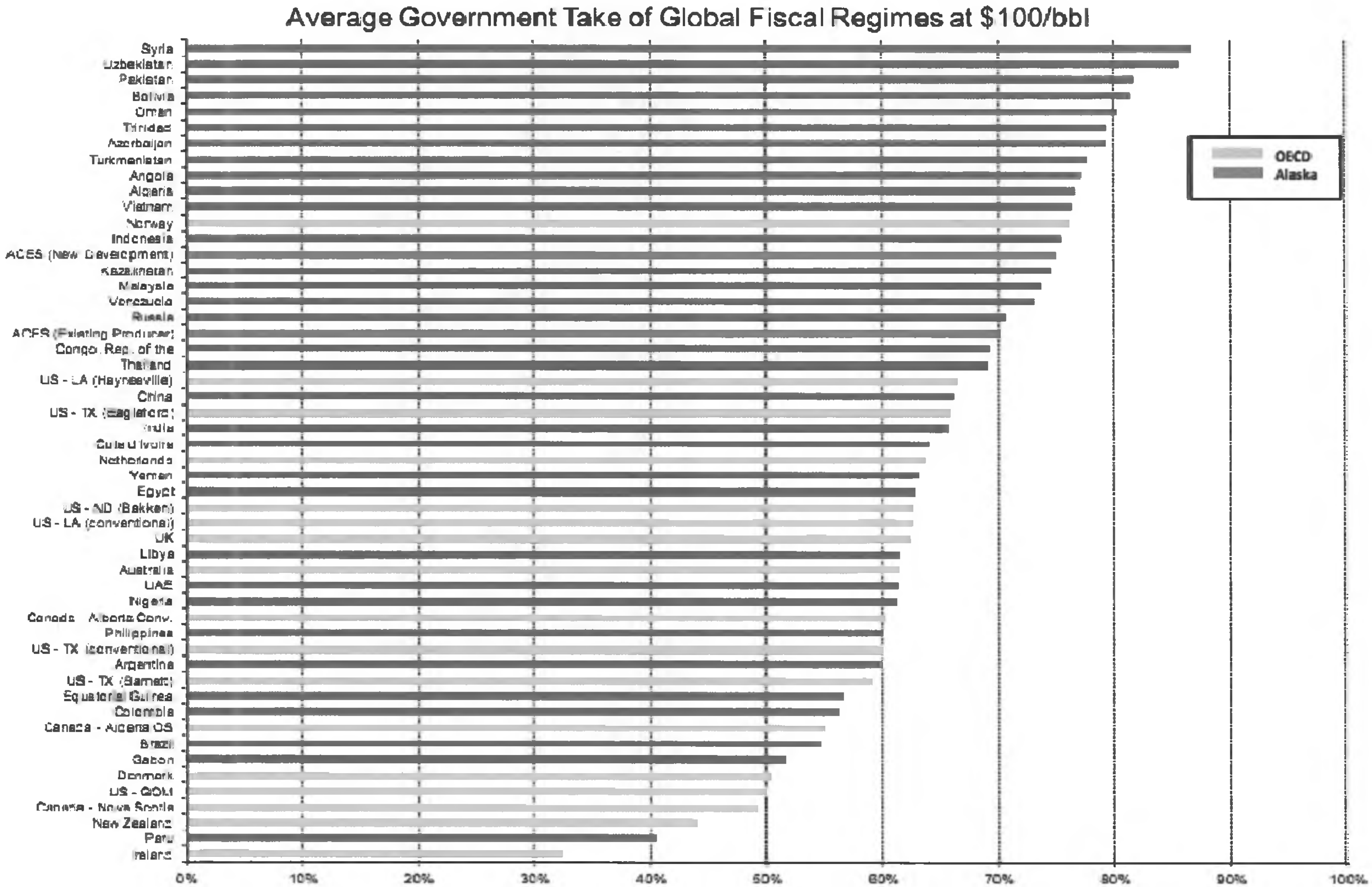
Key Aspects of Administration's Proposal (cont'd)

- Provides Balance Between State and Producers
  - Reduction of Tax Rates at High Prices, Balanced with Elimination of Credits
  - State Continues to Receive Largest Percentage of Oil Production Revenues at Any Price
  - Provides Tax Relief and Higher Margins in Sustainable Price Ranges
- Simplifies Tax System and Provides Clarity for Planning
  - Eliminates Question of Marginal Tax Rate / Take for Investment Planning
  - Eliminates Incentives for "Gold Plating" Caused by High Marginal Rates
- Maintains Alignment Between State and Producer Incentives
  - Net Tax Allows for Deduction of Costs Against Tax
- Provides Incentive for Development of New Resources Without Taxing State Treasury
  - GRE Provides Lower Effective Tax Rate for New Development
  - New Developers can Recover Costs of Development Once Production Begins
  - Does Not Require State to Fund Development Costs Through Potentially Expensive Credit Purchases
- Extremely Positive Message to Potential Investors
  - Will Encourage Broader Participation in Development of Alaska's North Slope
  - Economics of New Participants Closer to Incumbents'

Average Government Take
ACES v. SB21/HB72 for All Existing Producers (FY2015-FY2019)

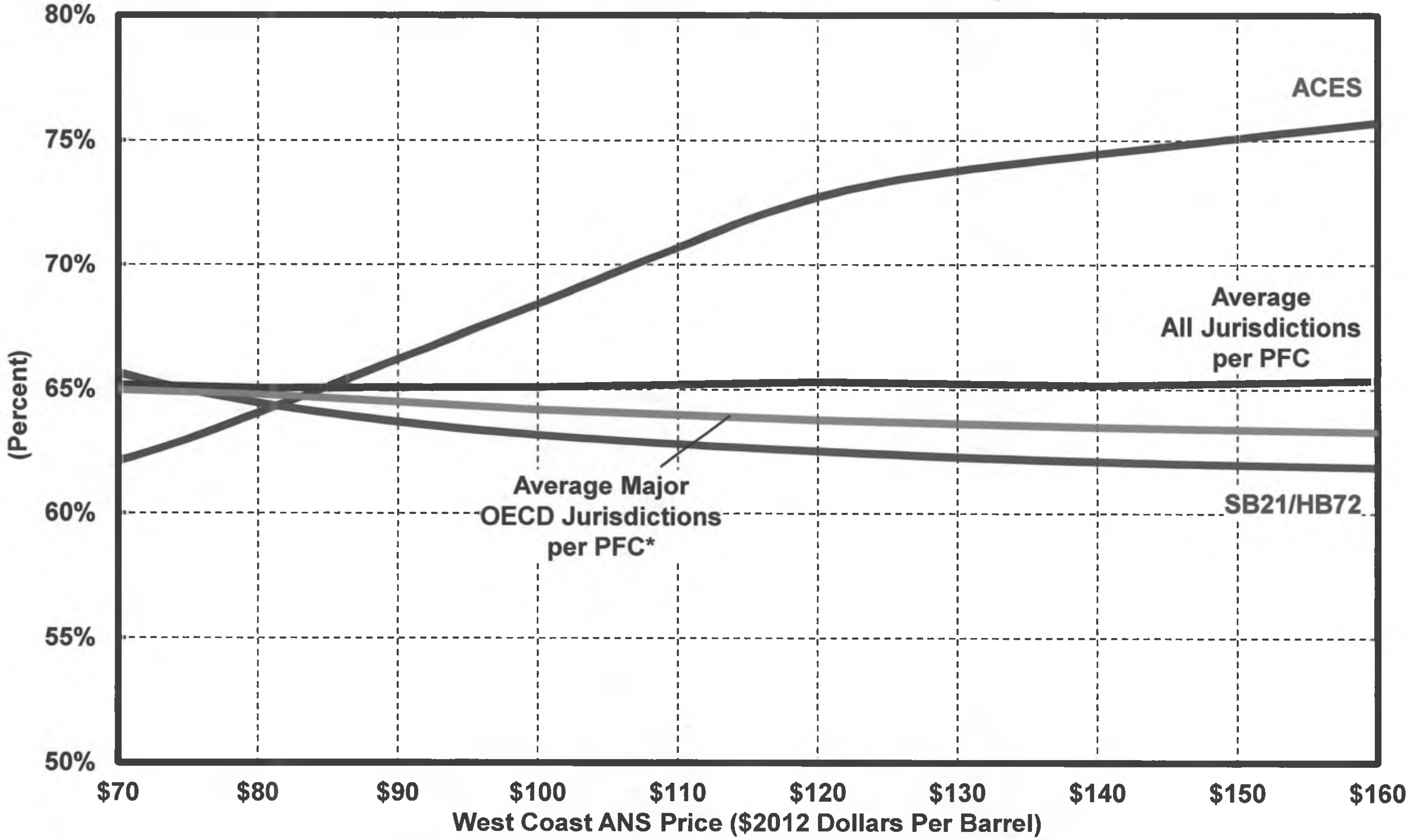


Average Government Take at $100 Per Barrel
Other Jurisdictions



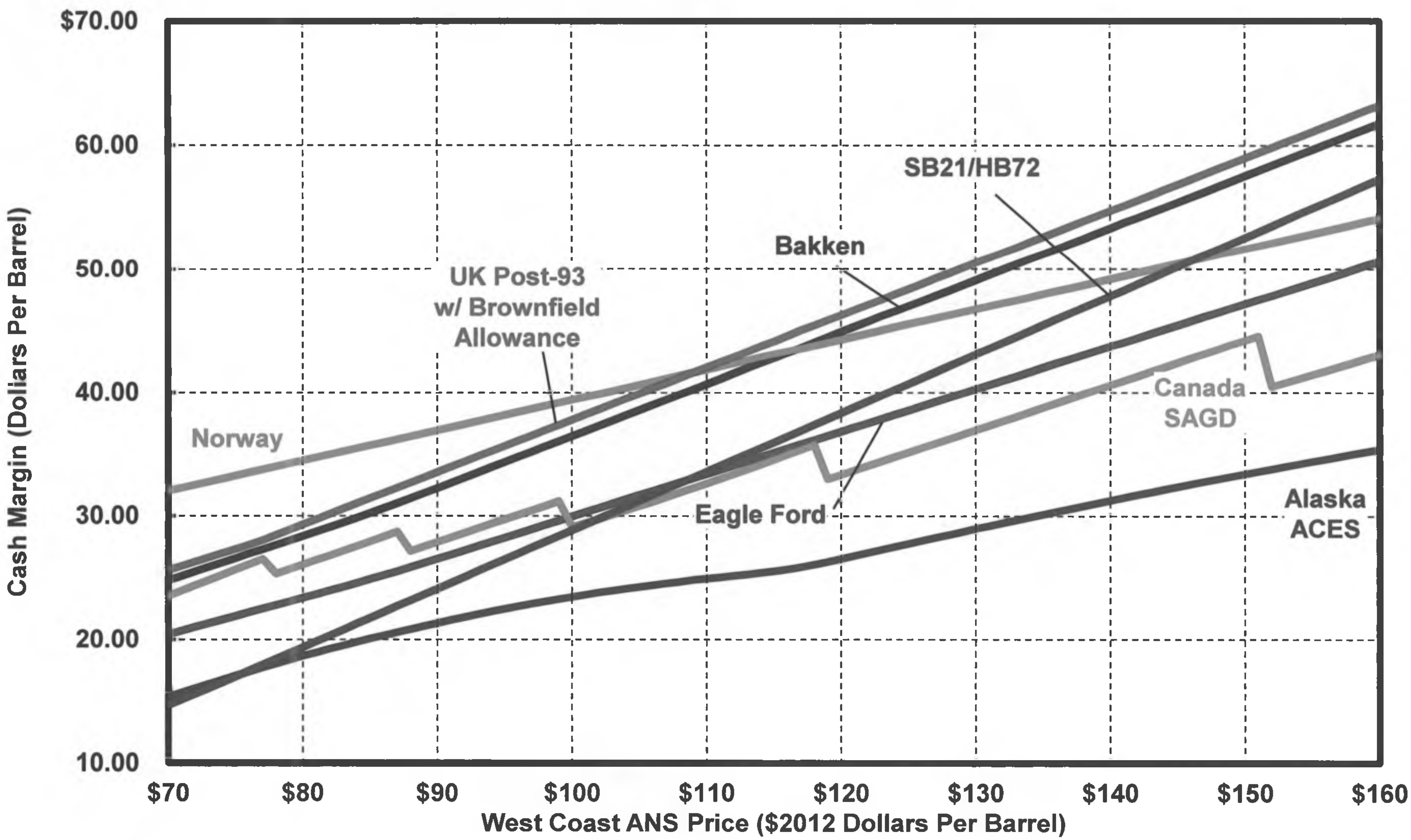
Source: PFC Energy.

Average Government Take
ACES v. SB21/HB72 for All Existing Producers (FY2015-FY2019) and Other Jurisdictions

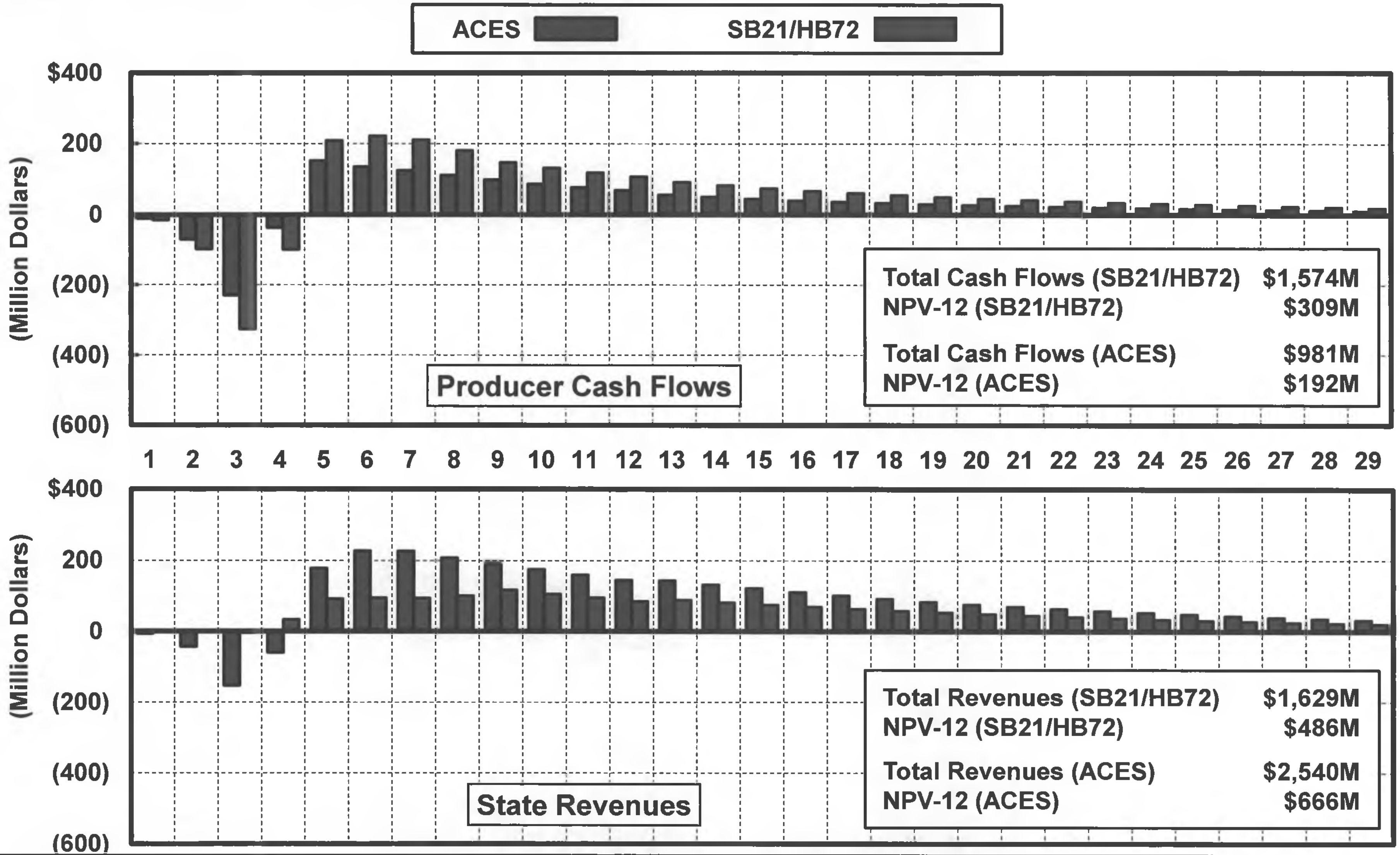


* Australia, Canada (Alberta Conventional), Norway, United Kingdom and United States.

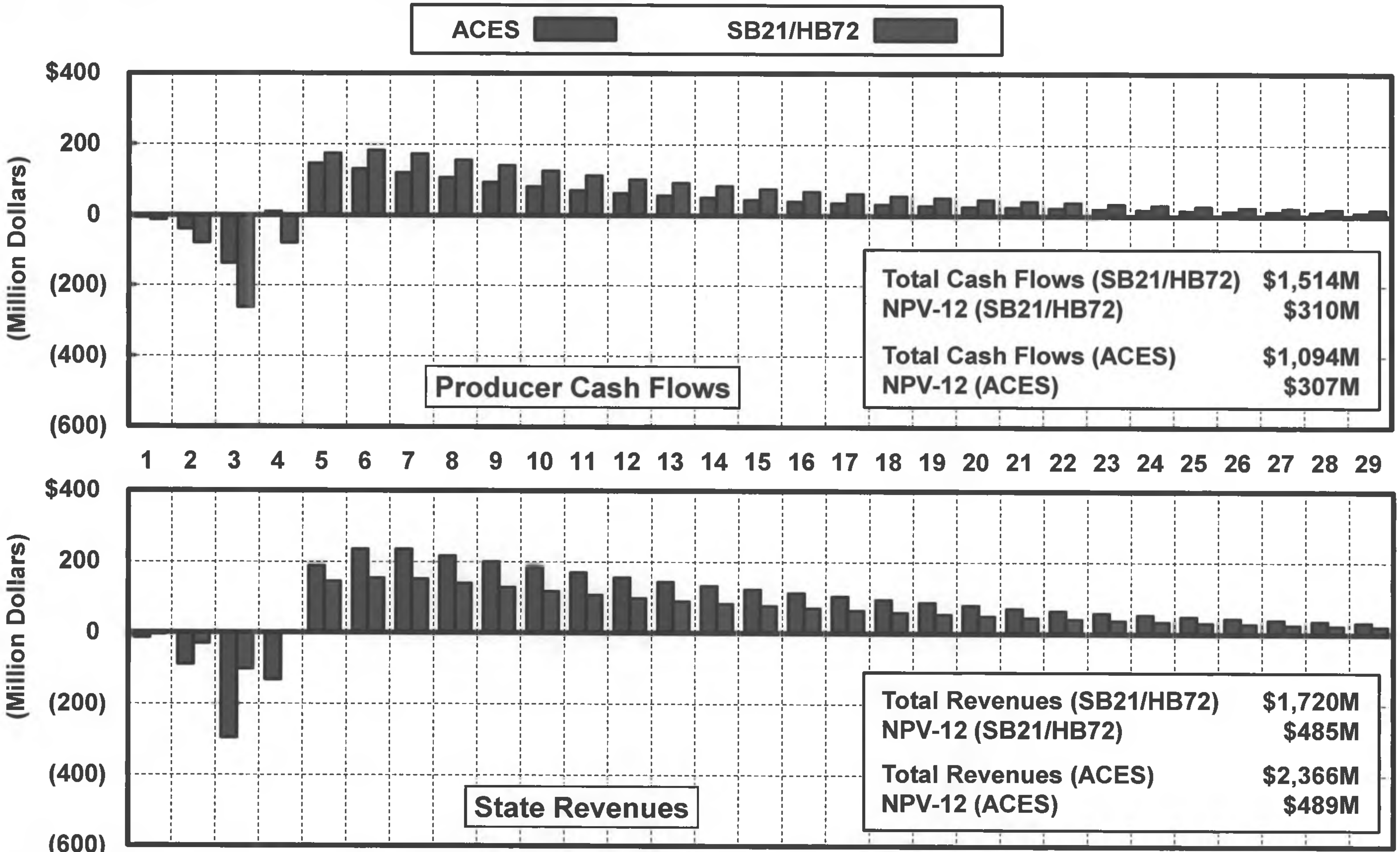
Projected Cash Generation From Ongoing North Slope Production (2017-2021) Under ACES v. SB21/HB72 and Other Jurisdictions



Annual State Revenues and Producer Cash Flows at $100 West Coast ANS Light Conventional Oil Alaska Development New Participant in Alaska



Annual State Revenues and Producer Cash Flows at $100 West Coast ANS Light Conventional Oil Alaska Development Incumbent Participant in Alaska



Summary of Investment Measures for New Participant Light Conventional Oil Alaska Development ACES and SB21/HB72 v. Benchmark Areas

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West Coast ANS Price	ACES	SB21/HB72 With GRE	SB21/HB72 Without GRE	Unconventional Lower-48 Eagle Ford	Unconventional Lower-48 Bakken	Canada Oil Sands SAGD	Norway	U.K. Development & Fiscal System Pre-1993	U.K. Pre-1993 w/ Brownfield Allowance*	U.K. Post-1993	U.K. Post-1993 w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Producer NPV-12 / BOE (Dollars Per BOE)											
$80	$2.55	$2.54	$1.94	$3.61	$0.67	($0.93)	$0.24	$1.20	$4.81	$2.41	$4.62
$100	$3.85	$6.18	$5.34	$6.75	$4.29	$0.46	$2.34	$3.02	$7.09	$6.04	$8.25
$120	$5.48	$9.74	$8.71	$11.17	$9.16	$2.01	$4.44	$4.83	$9.09	$9.67	$11.88
Profitability Index-12											
$80	1.19	1.19	1.15	1.25	1.04	0.88	1.01	1.06	1.22	1.11	1.21
$100	1.29	1.47	1.40	1.47	1.28	1.06	1.14	1.14	1.33	1.28	1.38
$120	1.41	1.74	1.66	1.78	1.60	1.26	1.27	1.22	1.42	1.45	1.55
IRR (Percent)											
$80	19.7%	17.1%	16.1%	29.9%	13.6%	9.7%	12.4%	18.4%	34.5%	18.4%	24.7%
$100	23.4%	23.9%	22.6%	46.3%	22.7%	13.1%	16.0%	27.0%	45.2%	27.0%	32.9%
$120	27.6%	30.0%	28.6%	73.6%	37.0%	16.3%	19.3%	34.6%	53.5%	34.6%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)											
$80	$25.84	$36.94	$34.44	$23.39	$28.39	$26.07	$34.51	$12.45	$22.94	$24.91	$29.35
$100	$28.84	$45.89	$42.59	$29.99	$36.48	$29.14	$39.42	$16.69	$28.85	$33.38	$37.82
$120	$33.13	$54.69	$50.89	$36.87	$44.91	$33.37	$44.32	$20.93	$31.29	$41.86	$46.30
Government Take (Percent)											
$80	70.8%	61.9%	66.0%	71.7%	77.1%	63.4%	67.8%	81.0%	61.0%	62.0%	52.0%
$100	75.8%	61.1%	64.7%	67.9%	72.1%	63.5%	71.7%	81.0%	68.6%	62.0%	55.8%
$120	77.2%	60.8%	64.0%	65.1%	68.7%	63.0%	73.4%	81.0%	72.0%	62.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)											
$80	$6.67	$6.68	$7.60	-	-	-	-	-	-	-	-
$100	$13.32	$9.72	$11.02	-	-	-	-	-	-	-	-
$120	$19.46	$12.89	$14.48	-	-	-	-	-	-	-	-

*** Brownfield Allowance applied to 100 MMBOE development.**

Summary of Investment Measures for Incumbent Light Conventional Oil Alaska Development ACES and SB21/HB72 v. Benchmark Areas

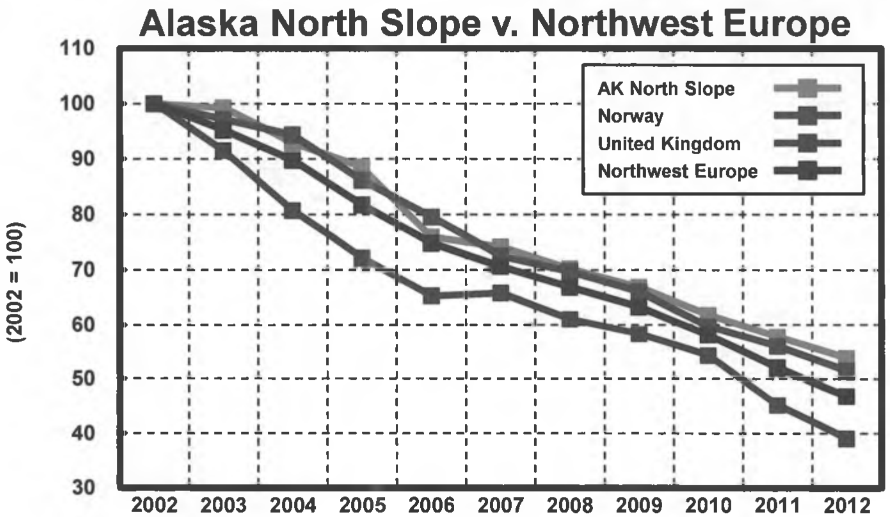
West Coast ANS Price	ACES	SB21/HB72 With GRE	SB21/HB72 Without GRE	Unconventional Lower-48 Eagle Ford	Unconventional Lower-48 Bakken	Canada Oil Sands SAGD	Norway	U.K. Development & Fiscal System Pre-1993	U.K. Pre-1993 w/ Brownfield Allowance*	U.K. Post-1993	U.K. Post-1993 w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Producer NPV-12 / BOE (Dollars Per BOE)											
$80	$3.71	$2.71	$2.02	$3.61	$0.67	($0.93)	$0.24	$1.20	$4.81	$2.41	$4.62
$100	$6.14	$6.20	$5.30	$6.75	$4.29	$0.46	$2.34	$3.02	$7.09	$6.04	$8.25
$120	$8.82	$9.69	$8.58	$11.17	$9.16	$2.01	$4.44	$4.83	$9.09	$9.67	$11.88
Profitability Index-12											
$80	1.28	1.20	1.15	1.25	1.04	0.88	1.01	1.06	1.22	1.11	1.21
$100	1.46	1.47	1.40	1.47	1.28	1.06	1.14	1.14	1.33	1.28	1.38
$120	1.67	1.73	1.65	1.78	1.60	1.26	1.27	1.22	1.42	1.45	1.55
IRR (Percent)											
$80	26.2%	18.5%	16.9%	29.9%	13.6%	9.7%	12.4%	18.4%	34.5%	18.4%	24.7%
$100	41.1%	25.8%	24.1%	46.3%	22.7%	13.1%	16.0%	27.0%	45.2%	27.0%	32.9%
$120	65.3%	32.5%	30.6%	73.6%	37.0%	16.3%	19.3%	34.6%	53.5%	34.6%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)											
$80	$24.26	$30.63	$28.57	$23.39	$28.39	$26.07	$34.51	$12.45	$22.94	$24.91	$29.35
$100	$27.22	$40.27	$37.61	$29.99	$36.48	$29.14	$39.42	$16.69	$28.85	$33.38	$37.82
$120	$31.18	$49.90	$46.65	$36.87	$44.91	$33.37	$44.32	$20.93	$31.29	$41.86	$46.30
Government Take (Percent)											
$80	68.9%	64.1%	68.1%	71.7%	77.1%	63.4%	67.8%	81.0%	61.0%	62.0%	52.0%
$100	73.0%	62.6%	66.1%	67.9%	72.1%	63.5%	71.7%	81.0%	68.6%	62.0%	55.8%
$120	73.8%	61.9%	65.1%	65.1%	68.7%	63.0%	73.4%	81.0%	72.0%	62.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)											
$80	$4.88	$6.42	$7.49	-	-	-	-	-	-	-	-
$100	$9.79	$9.70	$11.08	-	-	-	-	-	-	-	-
$120	$14.31	$12.98	$14.67	-	-	-	-	-	-	-	-

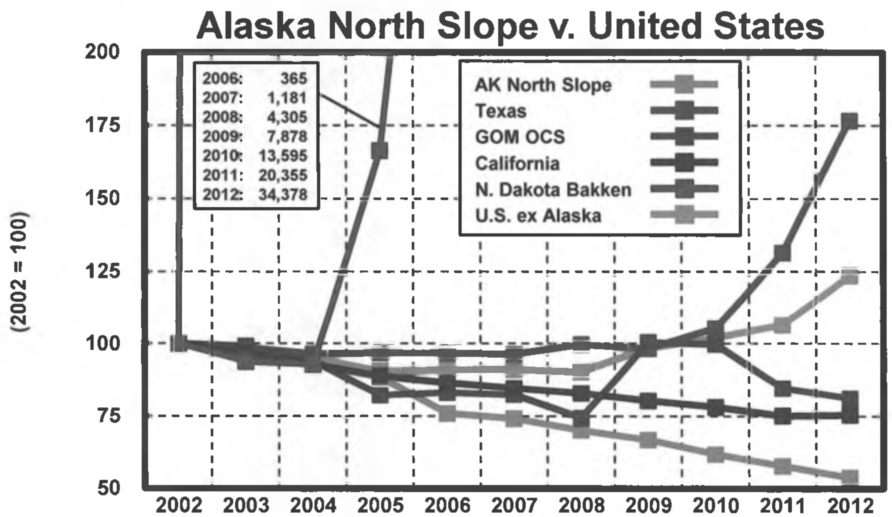
* Brownfield Allowance applied to 100 MMBOE development.

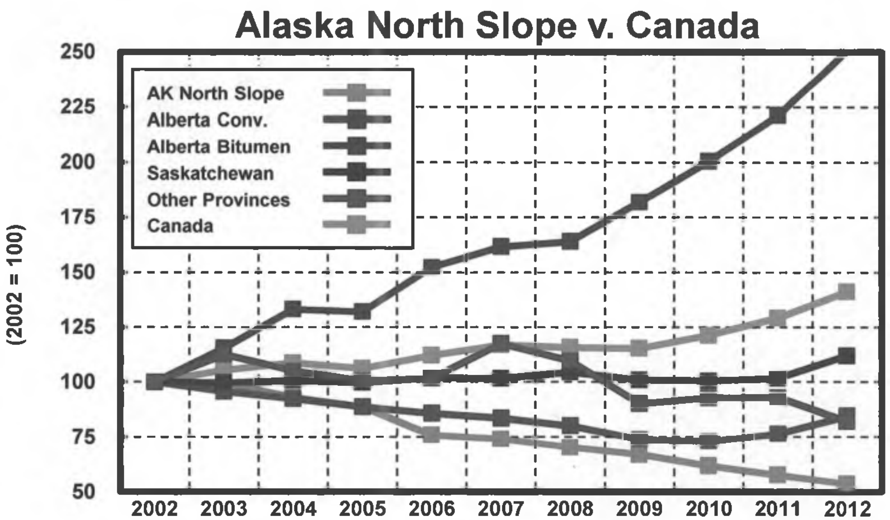
Note: Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

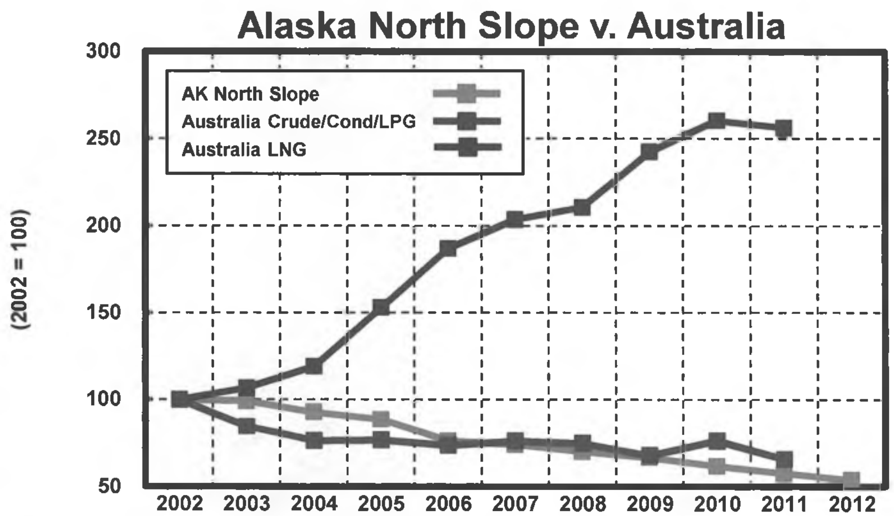
Appendix

Crude Oil Production Comparisons to Alaska



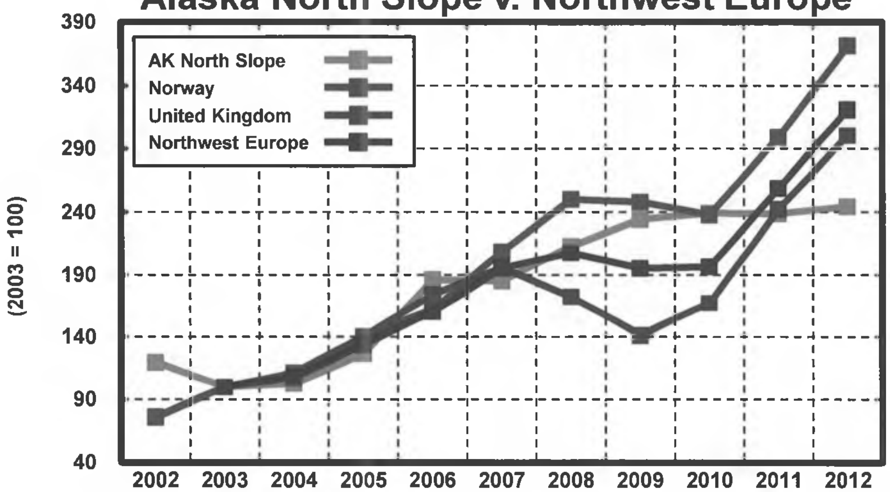




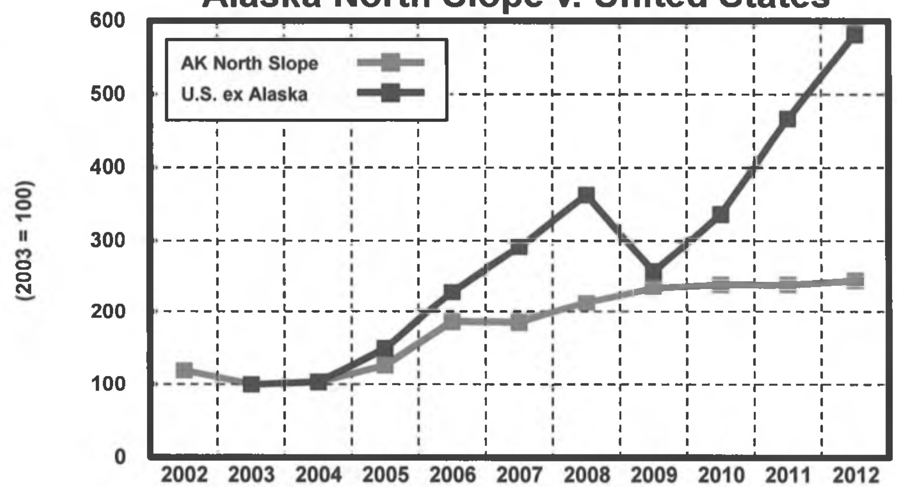


Capital Spending Comparisons to Alaska

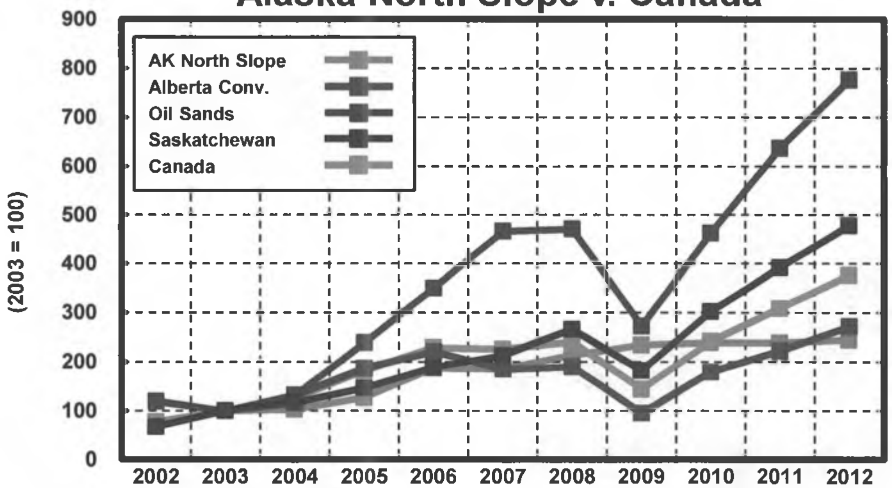
Alaska North Slope v. Northwest Europe



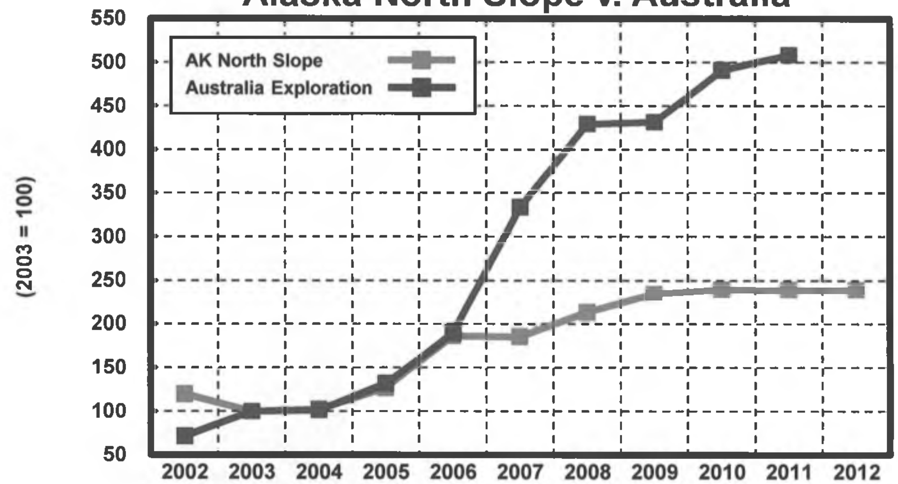
Alaska North Slope v. United States



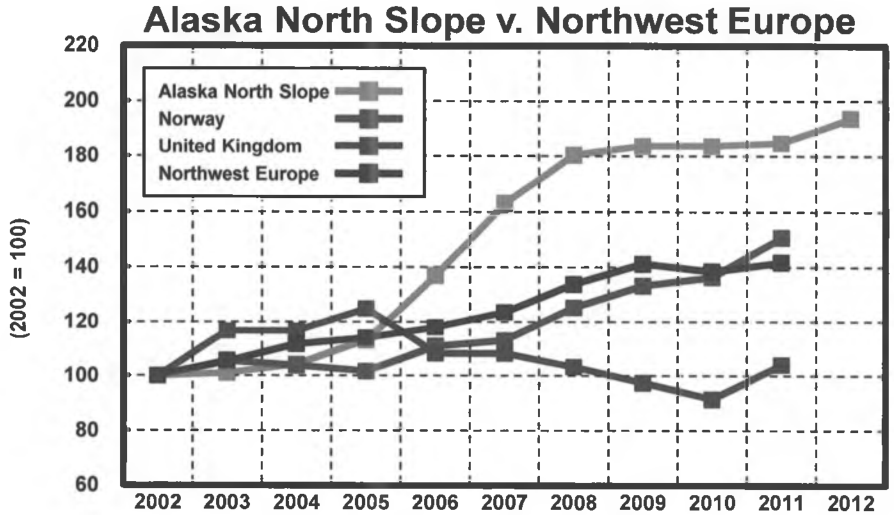
Alaska North Slope v. Canada

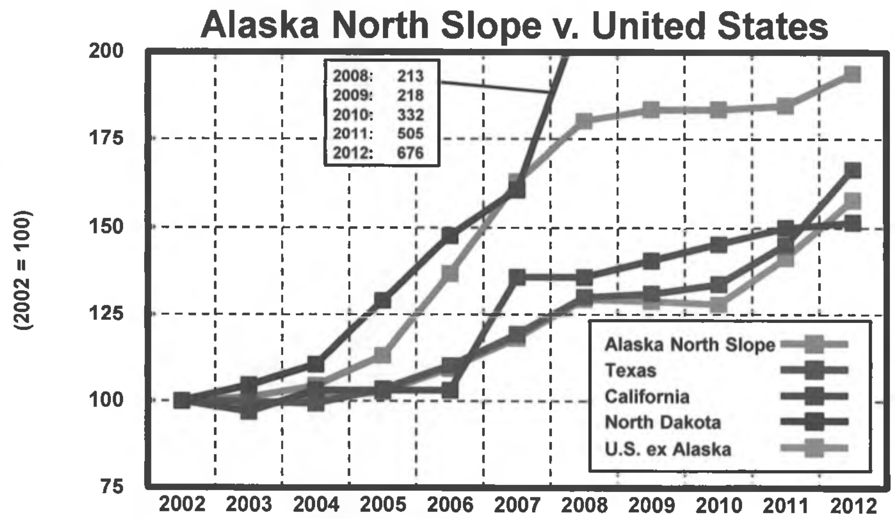


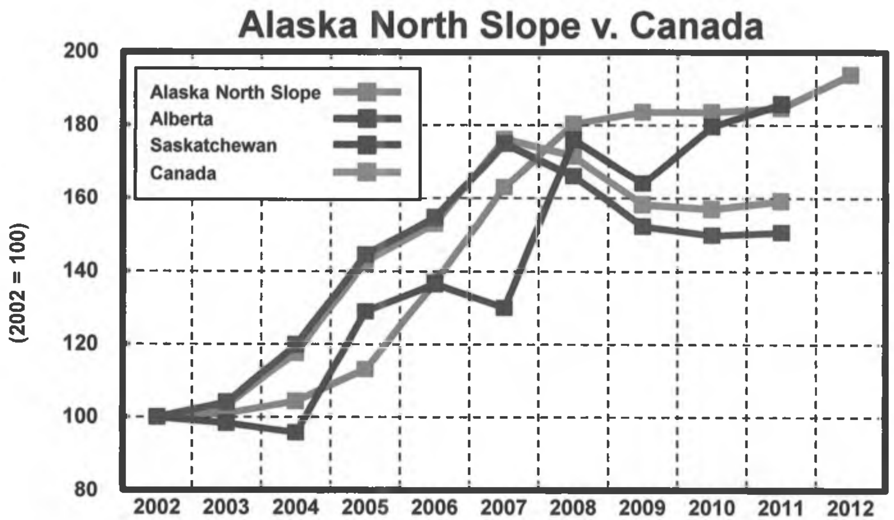
Alaska North Slope v. Australia

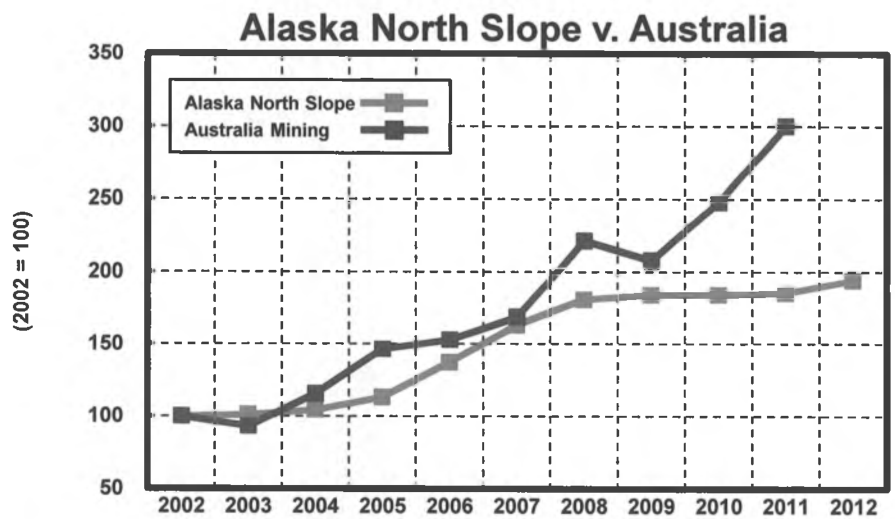


Employment Comparisons to Alaska

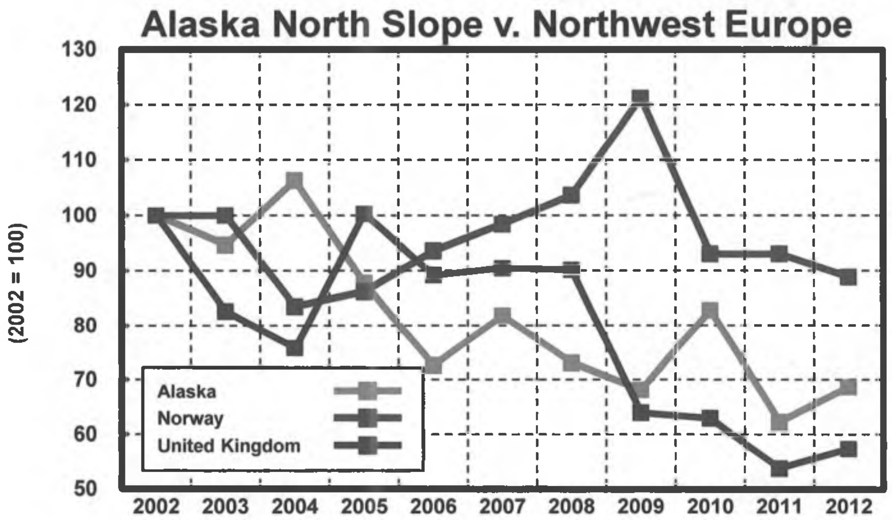


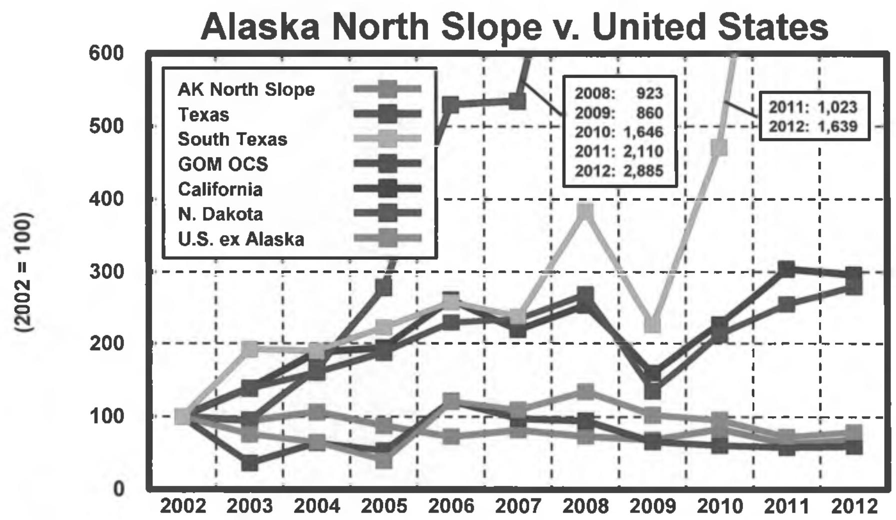


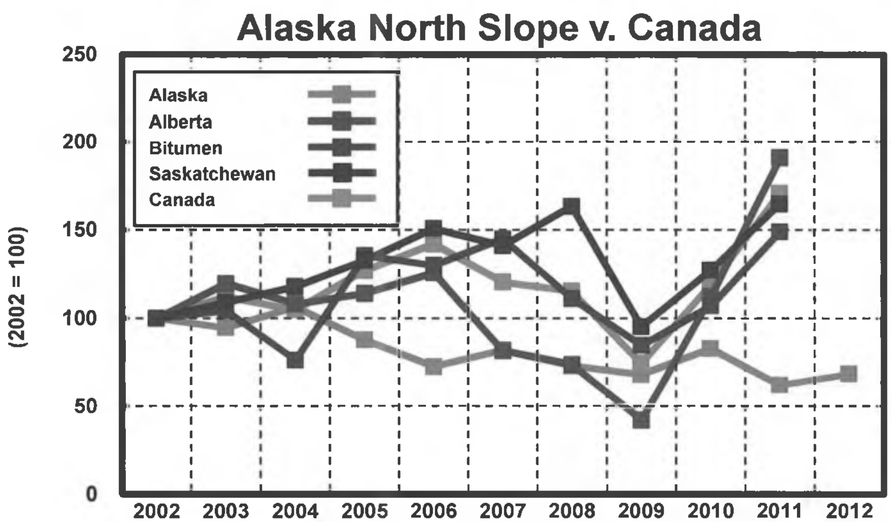


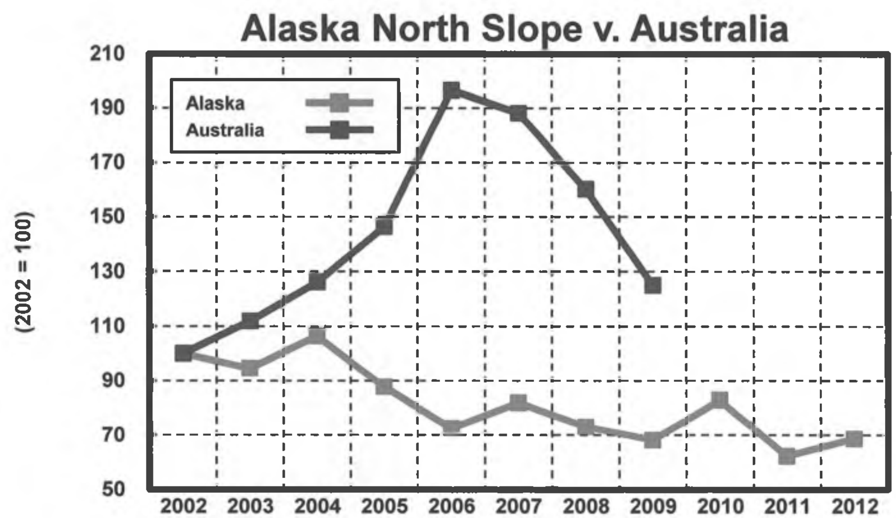


Drilling / Development Activity Comparisons to Alaska



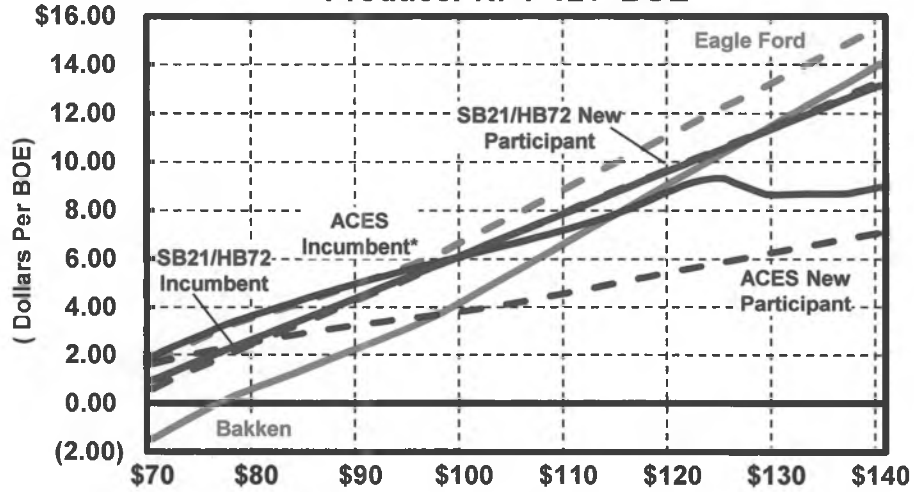




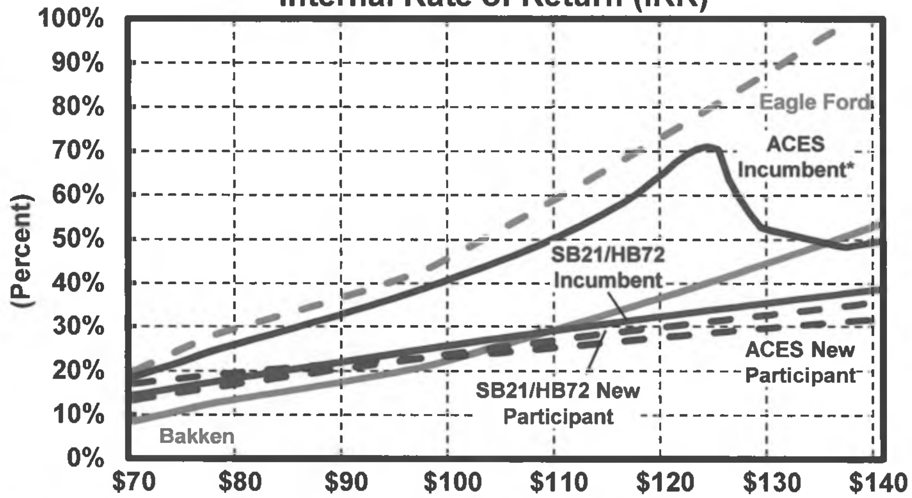


Investment Measures
Light Conventional Oil Alaska Development
v. Unconventional Lower-48

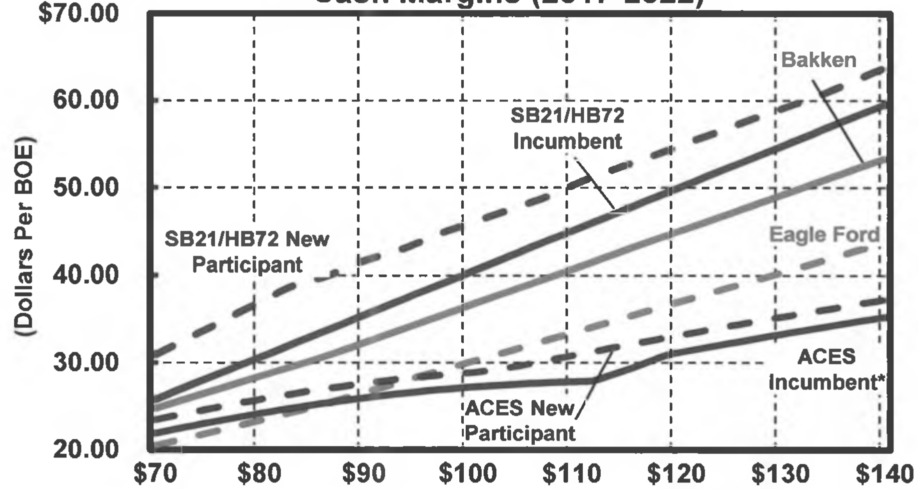
Producer NPV-12 / BOE



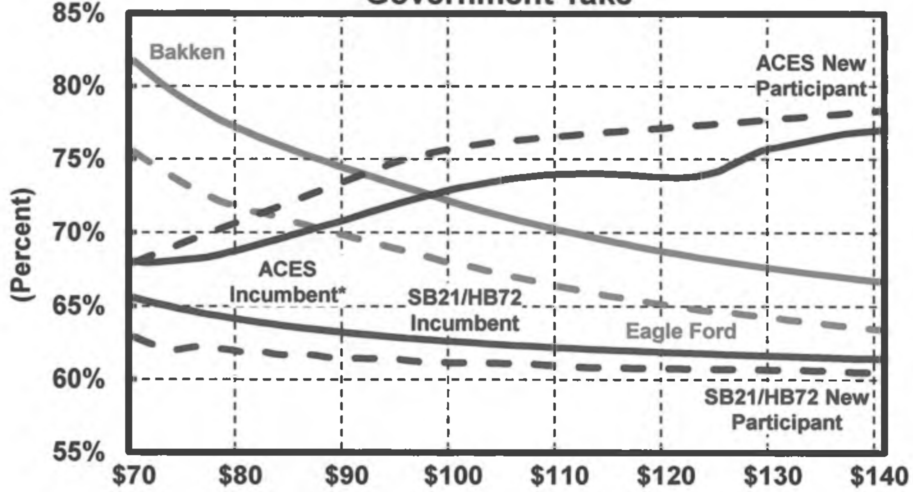
Internal Rate of Return (IRR)



Cash Margins (2017-2022)



Government Take



* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Investment Metrics
Light Conventional Oil Alaska Development
v. North Sea (United Kingdom with Brownfield Allowance)

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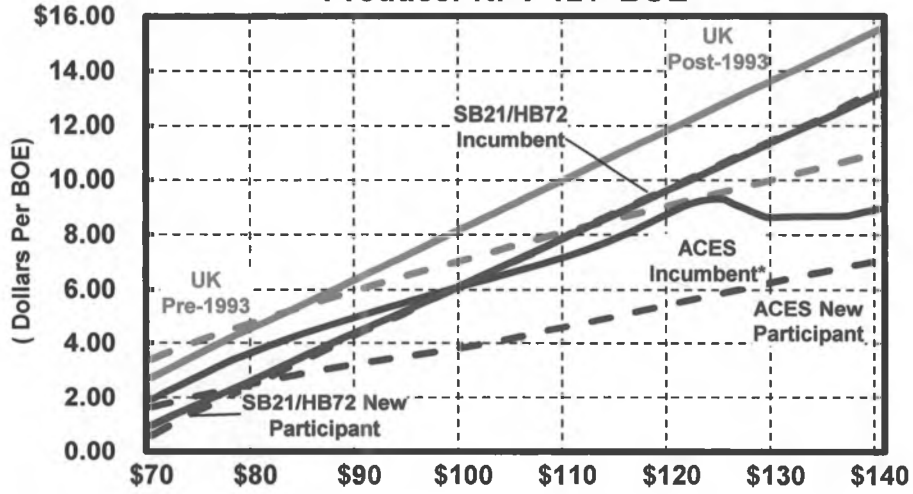
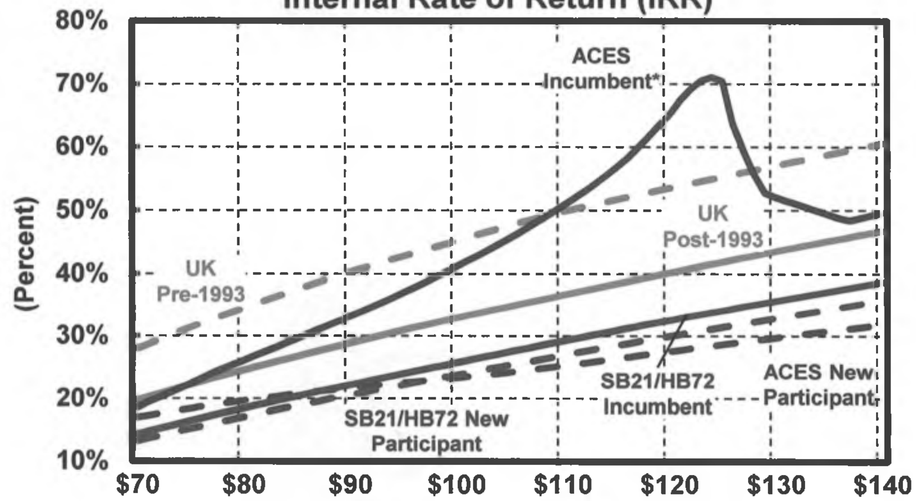
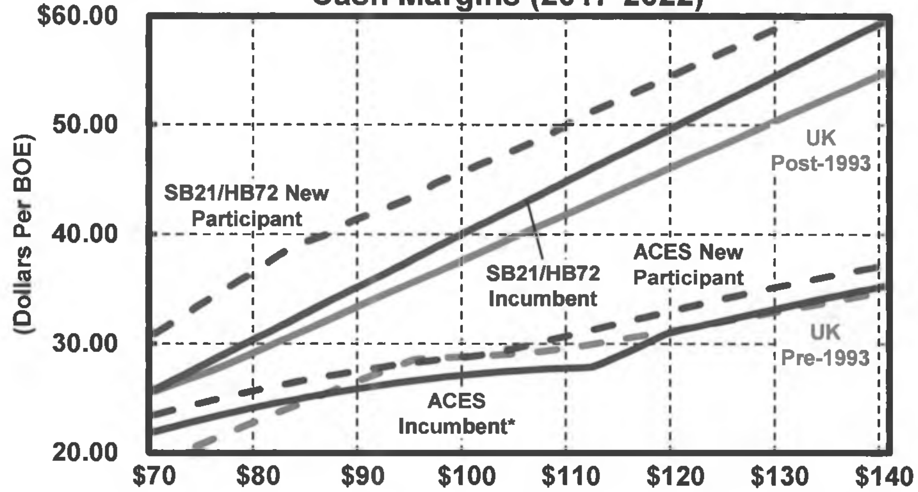
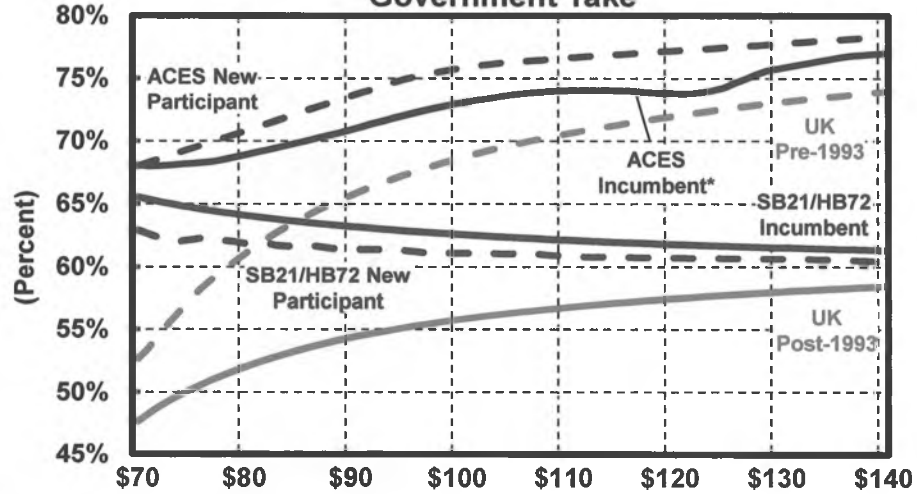


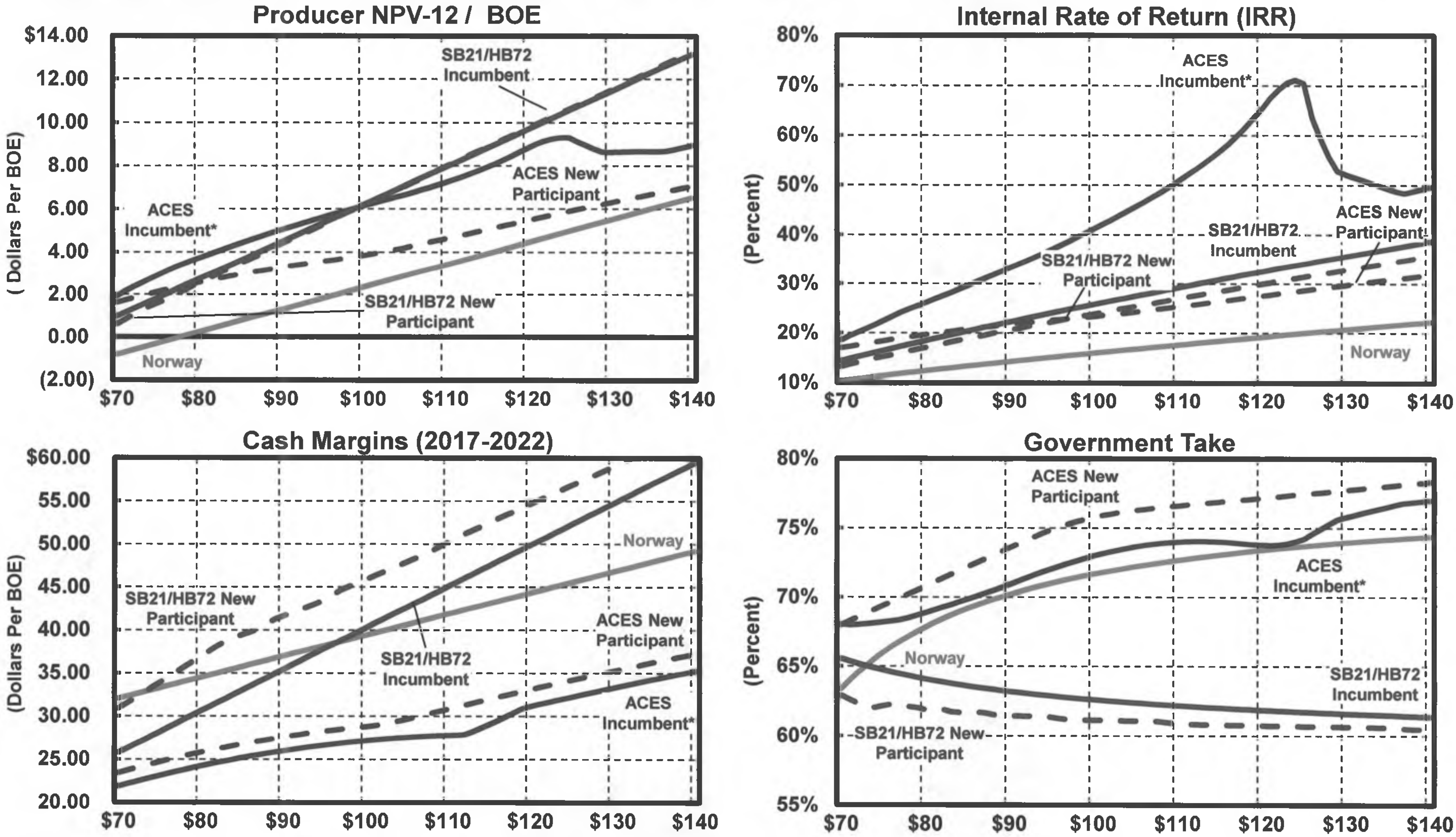






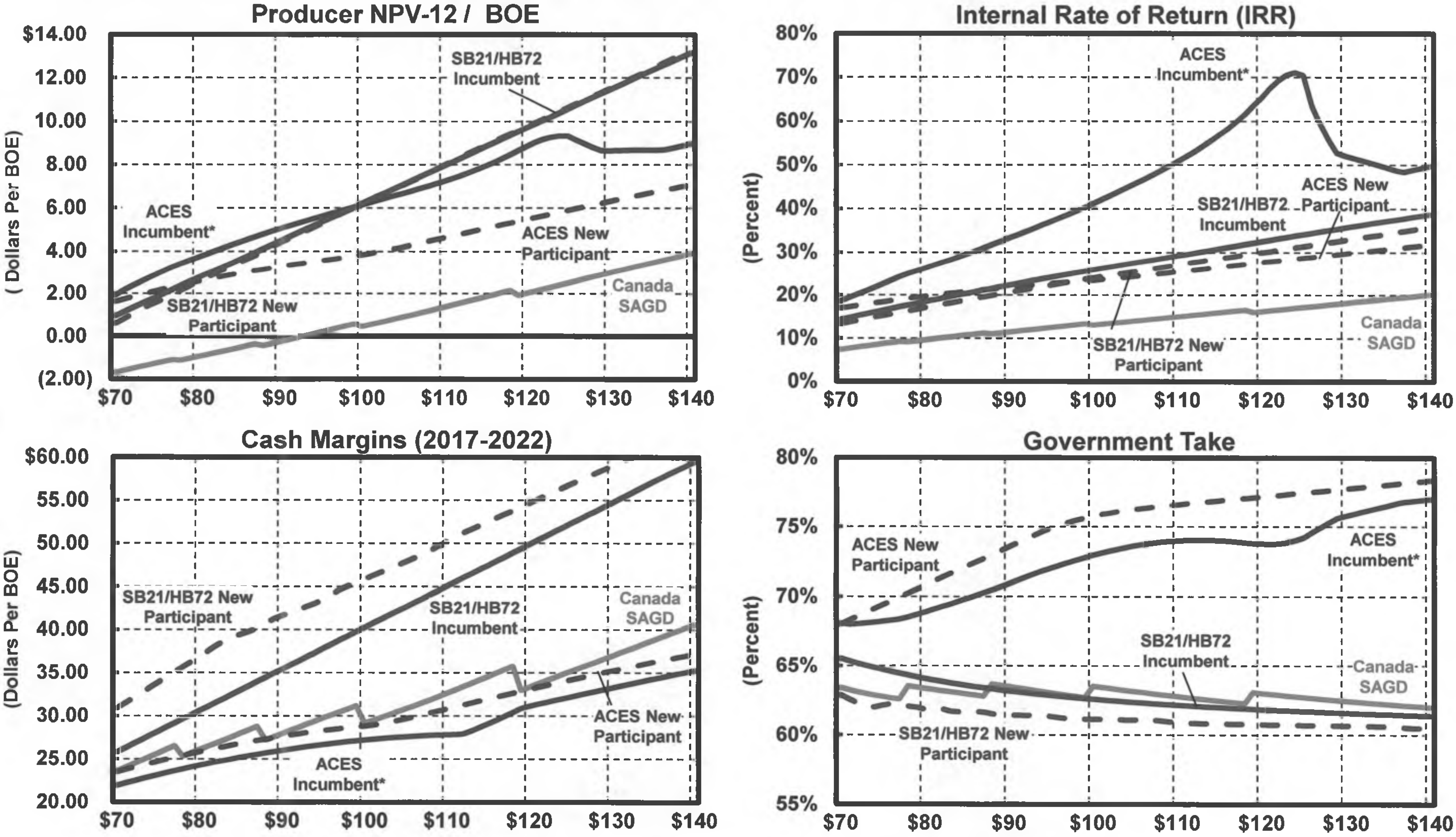
* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Investment Metrics
Light Conventional Oil Alaska Development
v. North Sea (Norway)



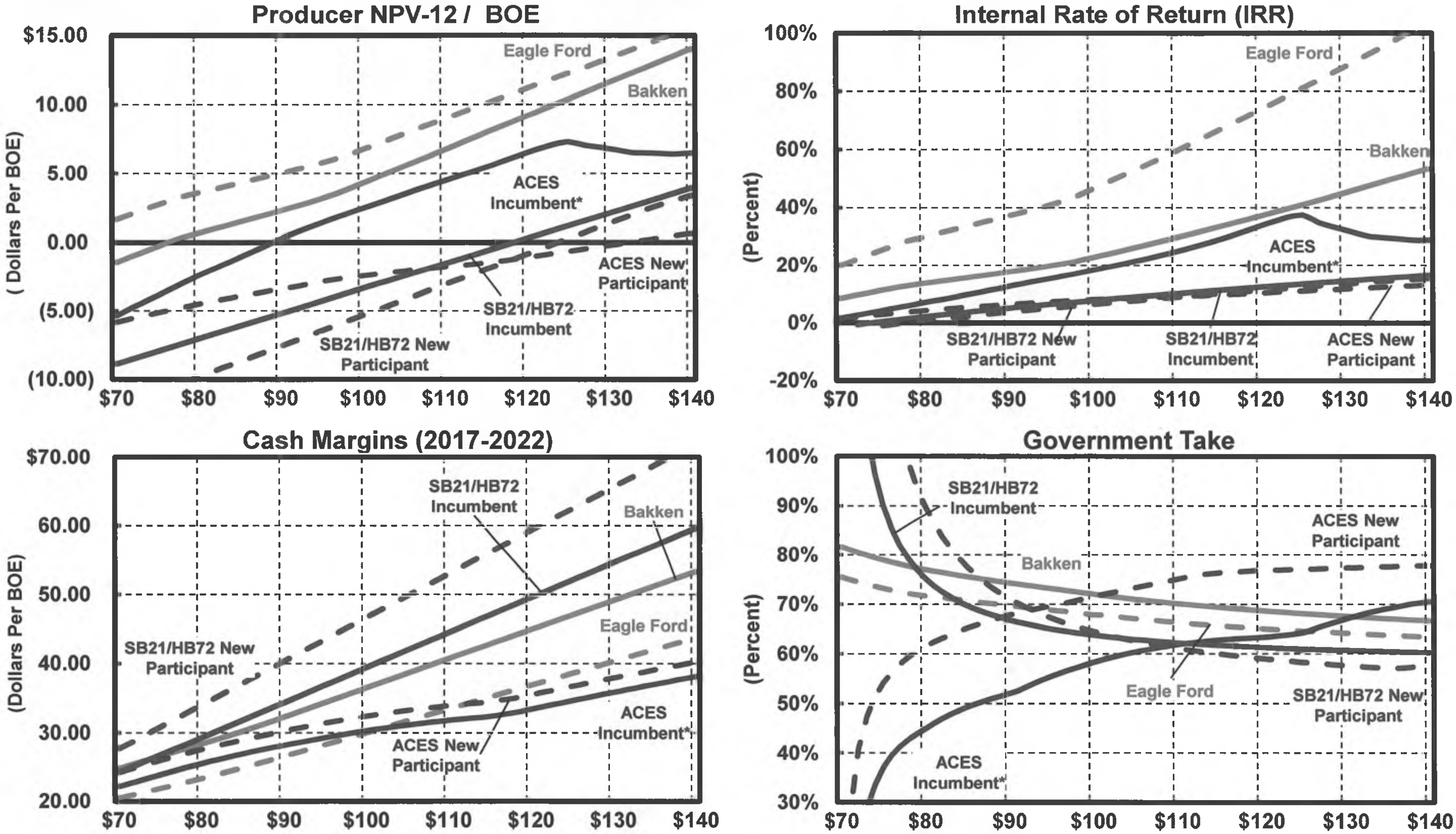
* Analysis of incumbent production includes “buy-down” impact for reduced taxes on existing production.

Investment Metrics
Light Conventional Oil Alaska Development
v. Canada Oil Sands (SAGD)



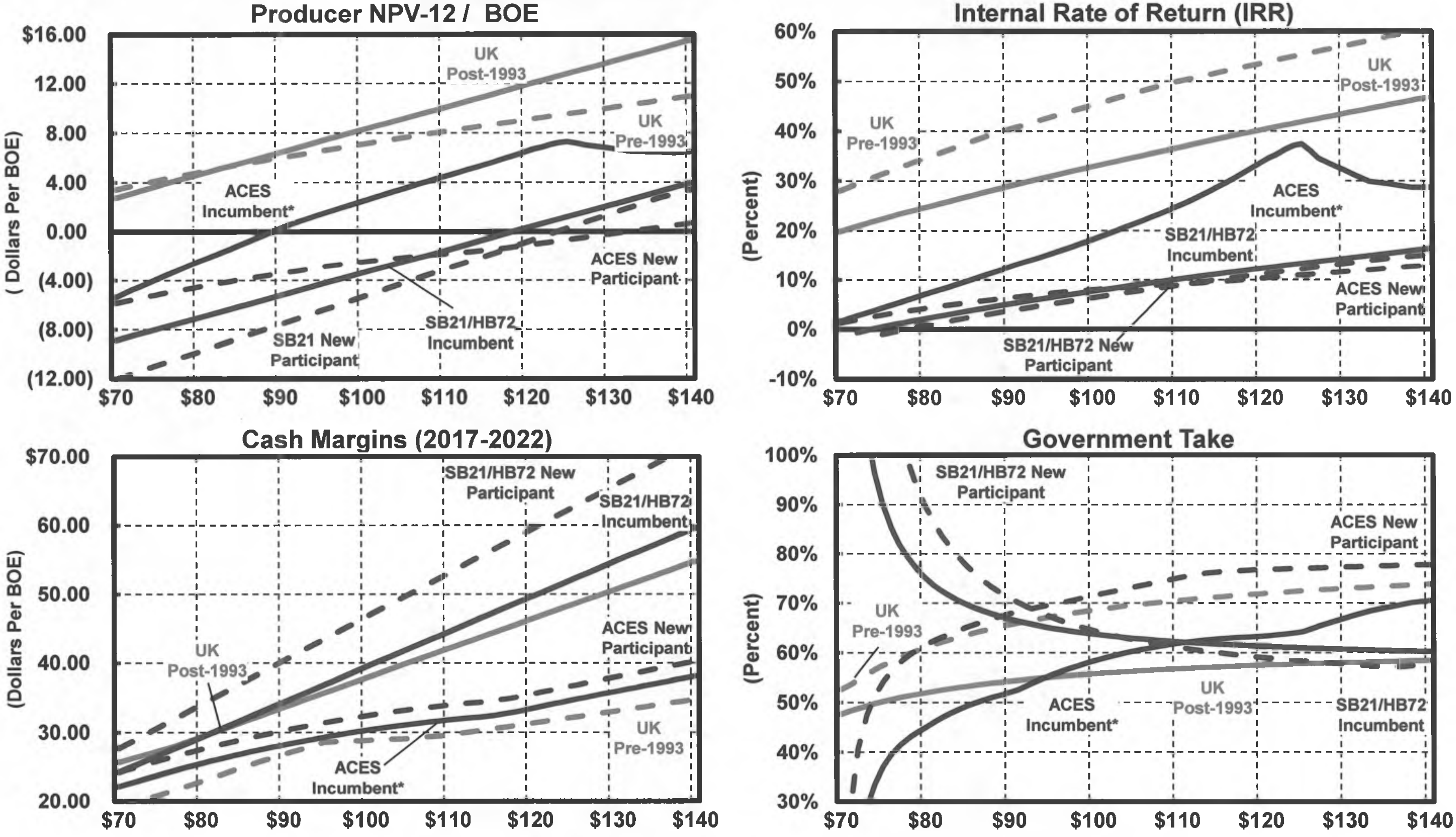
* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Investment Measures
Heavy High Cost Oil Alaska Development
v. Unconventional Lower-48



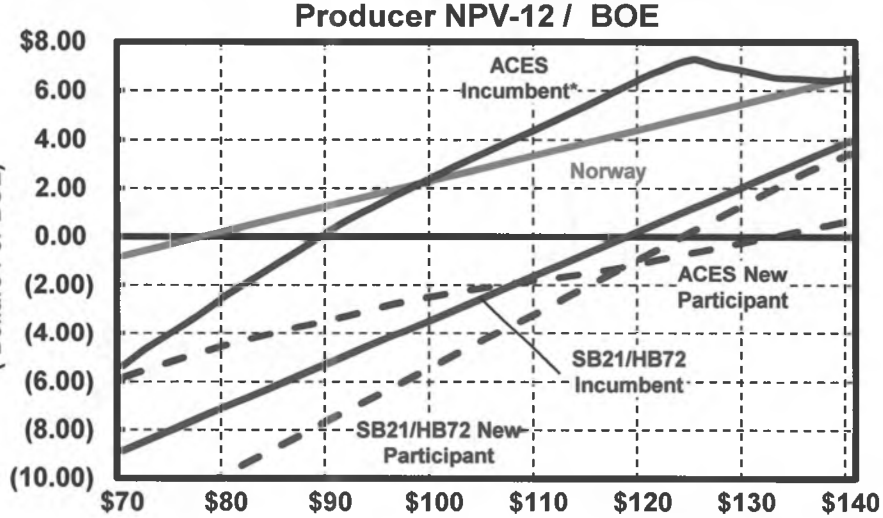
* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

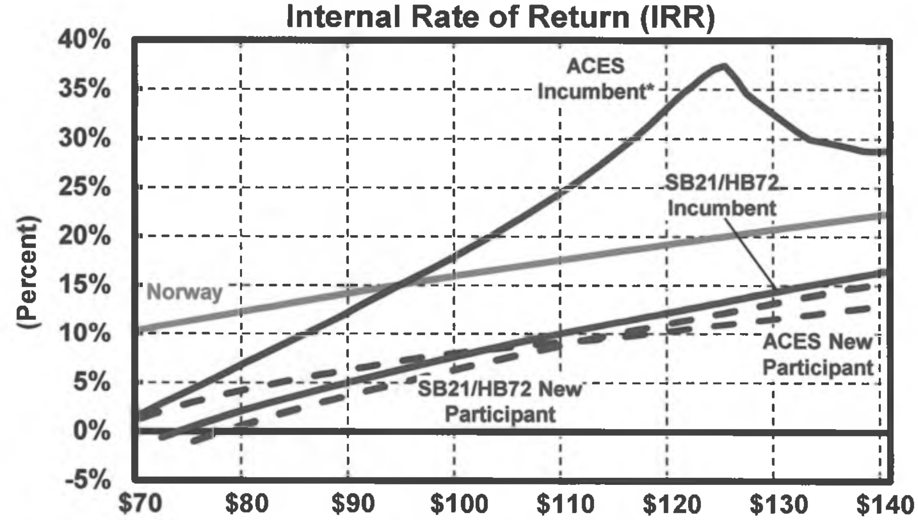
Investment Metrics
Heavy High Cost Oil Alaska Development
v. North Sea (United Kingdom with Brownfield Allowance)

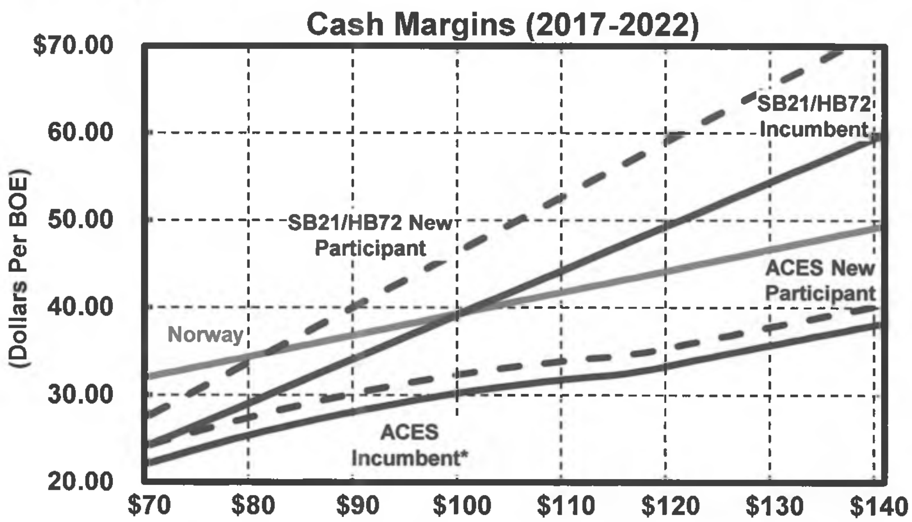


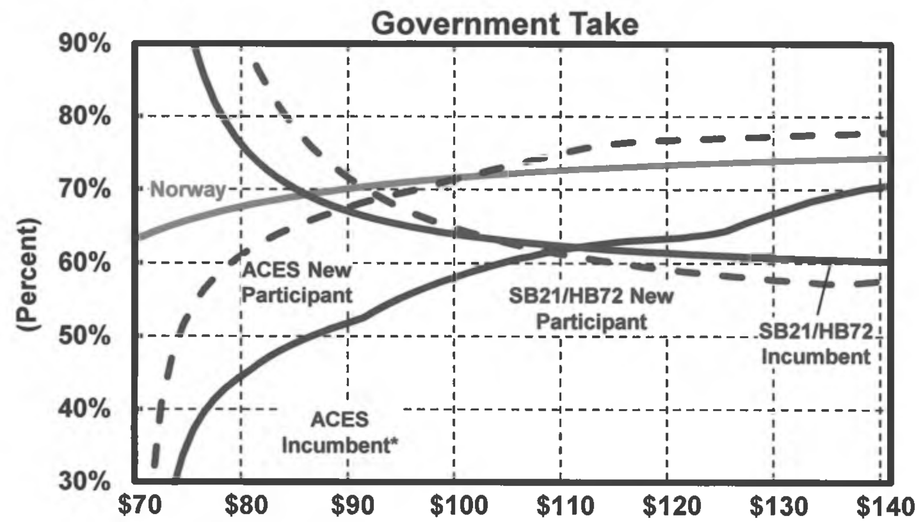
* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Investment Metrics
Heavy High Cost Oil Alaska Development v. North Sea (Norway)



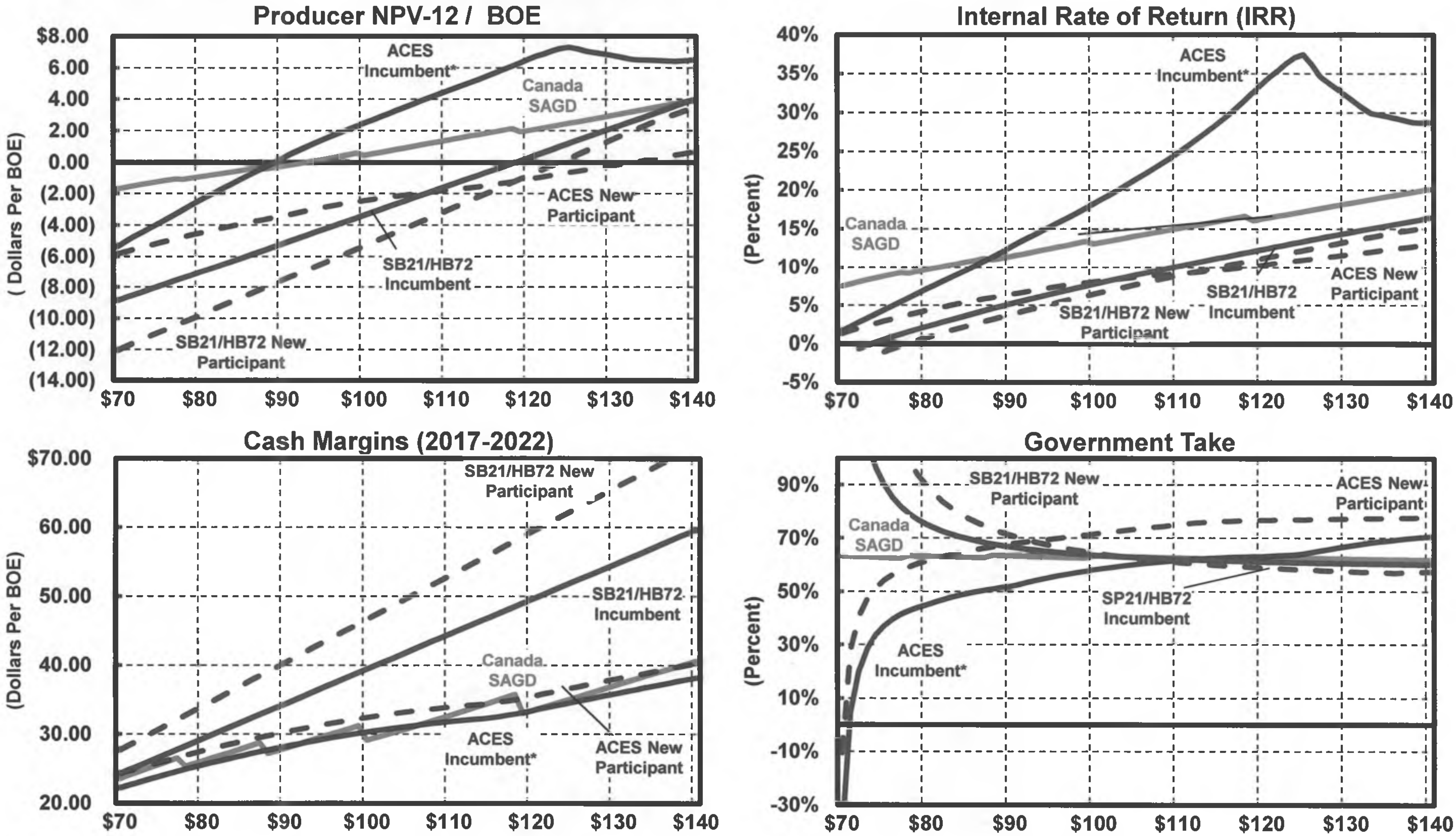






* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Investment Metrics
Heavy High Cost Oil Alaska Development v. Canada Oil Sands (SAGD)



* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Summary of Investment Measures for New Participant Heavy High Cost Oil Alaska Development ACES and SB21/HB72 v. Benchmark Areas

econ ONE

West Coast ANS Price	ACES	SB21/HB72 With GRE	SB21/HB72 Without GRE	Unconventional Lower-48 Eagle Ford	Unconventional Lower-48 Bakken	Canada Oil Sands SAGD	Norway	U.K. Development & Fiscal System Pre-1993	U.K. Pre-1993 w/ Brownfield Allowance*	U.K. Post-1993	U.K. Post-1993 w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Producer NPV-12 / BOE (Dollars Per BOE)											
$80	($4.51)	($9.80)	($9.89)	$3.61	$0.67	($0.93)	$0.24	$1.20	$4.81	$2.41	$4.62
$100	($2.45)	($5.33)	($5.45)	$6.75	$4.29	$0.46	$2.34	$3.02	$7.09	$6.04	$8.25
$120	($1.09)	($0.85)	($1.29)	$11.17	$9.16	$2.01	$4.44	$4.83	$9.09	$9.67	$11.88
Profitability Index-12											
$80	0.84	0.65	0.65	1.25	1.04	0.88	1.01	1.06	1.22	1.11	1.21
$100	0.91	0.81	0.81	1.47	1.28	1.06	1.14	1.14	1.33	1.28	1.38
$120	0.96	0.97	0.95	1.78	1.60	1.26	1.27	1.22	1.42	1.45	1.55
IRR (Percent)											
$80	4.3%	0.8%	0.4%	29.9%	13.6%	9.7%	12.4%	18.4%	34.5%	18.4%	24.7%
$100	8.1%	6.5%	6.2%	46.3%	22.7%	13.1%	16.0%	27.0%	45.2%	27.0%	32.9%
$120	10.3%	11.2%	10.7%	73.6%	37.0%	16.3%	19.3%	34.6%	53.5%	34.6%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)											
$80	$27.58	$34.02	$34.02	$23.39	$28.39	$26.07	$34.51	$12.45	$22.94	$24.91	$29.35
$100	$32.42	$46.67	$46.67	$29.99	$36.48	$29.14	$39.42	$16.69	$28.85	$33.38	$37.82
$120	$35.48	$59.32	$59.32	$36.87	$44.91	$33.37	$44.32	$20.93	$31.29	$41.86	$46.30
Government Take (Percent)											
$80	61.5%	89.9%	94.6%	71.7%	77.1%	63.4%	67.8%	81.0%	61.0%	62.0%	52.0%
$100	71.6%	64.5%	66.8%	67.9%	72.1%	63.5%	71.7%	81.0%	68.6%	62.0%	55.8%
$120	76.8%	59.1%	62.6%	65.1%	68.7%	63.0%	73.4%	81.0%	72.0%	62.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)											
$80	($4.61)	$3.53	$3.66	-	-	-	-	-	-	-	-
$100	$0.86	$5.29	$5.47	-	-	-	-	-	-	-	-
$120	$7.41	$7.05	$7.72	-	-	-	-	-	-	-	-

* Brownfield Allowance applied to 100 MMBOE development.

Summary of Investment Measures for Incumbent Heavy High Cost Oil Alaska Development ACES and SB21/HB72 v. Benchmark Areas

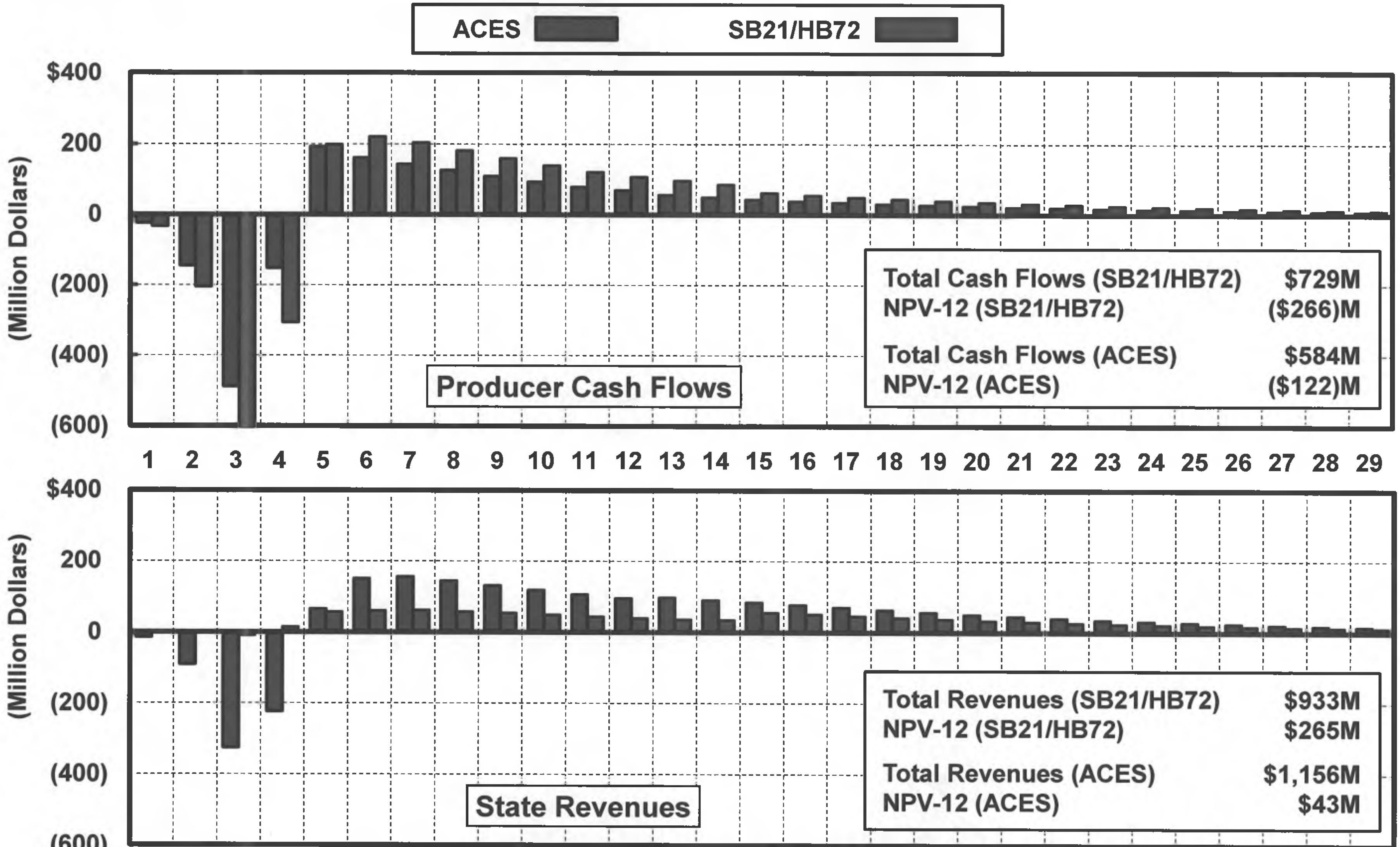
econ ONE

West Coast ANS Price	ACES	SB21/HB72 With GRE	SB21/HB72 Without GRE	Unconventional Lower-48 Eagle Ford	Unconventional Lower-48 Bakken	Canada Oil Sands SAGD	Norway	U.K. Development & Fiscal System Pre-1993	U.K. Development & Fiscal System Pre-1993 w/ Brownfield Allowance*	U.K. Development & Fiscal System Post-1993	U.K. Development & Fiscal System Post-1993 w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
				Producer NPV-12 / BOE (Dollars Per BOE)							
$80	($2.43)	($7.04)	($7.66)	$3.61	$0.67	($0.93)	$0.24	$1.20	$4.81	$2.41	$4.62
$100	$2.48	($3.37)	($4.21)	$6.75	$4.29	$0.46	$2.34	$3.02	$7.09	$6.04	$8.25
$120	$6.53	$0.29	($0.77)	$11.17	$9.16	$2.01	$4.44	$4.83	$9.09	$9.67	$11.88
				Profitability Index-12							
$80	0.91	0.75	0.73	1.25	1.04	0.88	1.01	1.06	1.22	1.11	1.21
$100	1.09	0.88	0.85	1.47	1.28	1.06	1.14	1.14	1.33	1.28	1.38
$120	1.23	1.01	0.97	1.78	1.60	1.26	1.27	1.22	1.42	1.45	1.55
				IRR (Percent)							
$80	7.1%	2.2%	1.1%	29.9%	13.6%	9.7%	12.4%	18.4%	34.5%	18.4%	24.7%
$100	18.2%	7.8%	6.6%	46.3%	22.7%	13.1%	16.0%	27.0%	45.2%	27.0%	32.9%
$120	33.6%	12.3%	11.1%	73.6%	37.0%	16.3%	19.3%	34.6%	53.5%	34.6%	40.2%
				5-Year (2017-2021) Cash Margins (Dollars Per BOE)							
$80	$25.52	$29.32	$27.46	$23.39	$28.39	$26.07	$34.51	$12.45	$22.94	$24.91	$29.35
$100	$30.33	$39.44	$36.95	$29.99	$36.48	$29.14	$39.42	$16.69	$28.85	$33.38	$37.82
$120	$33.41	$49.56	$46.44	$36.87	$44.91	$33.37	$44.32	$20.93	$31.29	$41.86	$46.30
				Government Take (Percent)							
$80	45.0%	75.3%	88.7%	71.7%	77.1%	63.4%	67.8%	81.0%	61.0%	62.0%	52.0%
$100	58.3%	63.8%	70.3%	67.9%	72.1%	63.5%	71.7%	81.0%	68.6%	62.0%	55.8%
$120	63.4%	61.4%	66.3%	65.1%	68.7%	63.0%	73.4%	81.0%	72.0%	62.0%	57.5%
				State/Municipal NPV-12/BOE (Dollars Per BOE)							
$80	($7.81)	($0.73)	$0.23	-	-	-	-	-	-	-	-
$100	($6.73)	$2.28	$3.57	-	-	-	-	-	-	-	-
$120	($4.31)	$5.29	$6.91	-	-	-	-	-	-	-	-

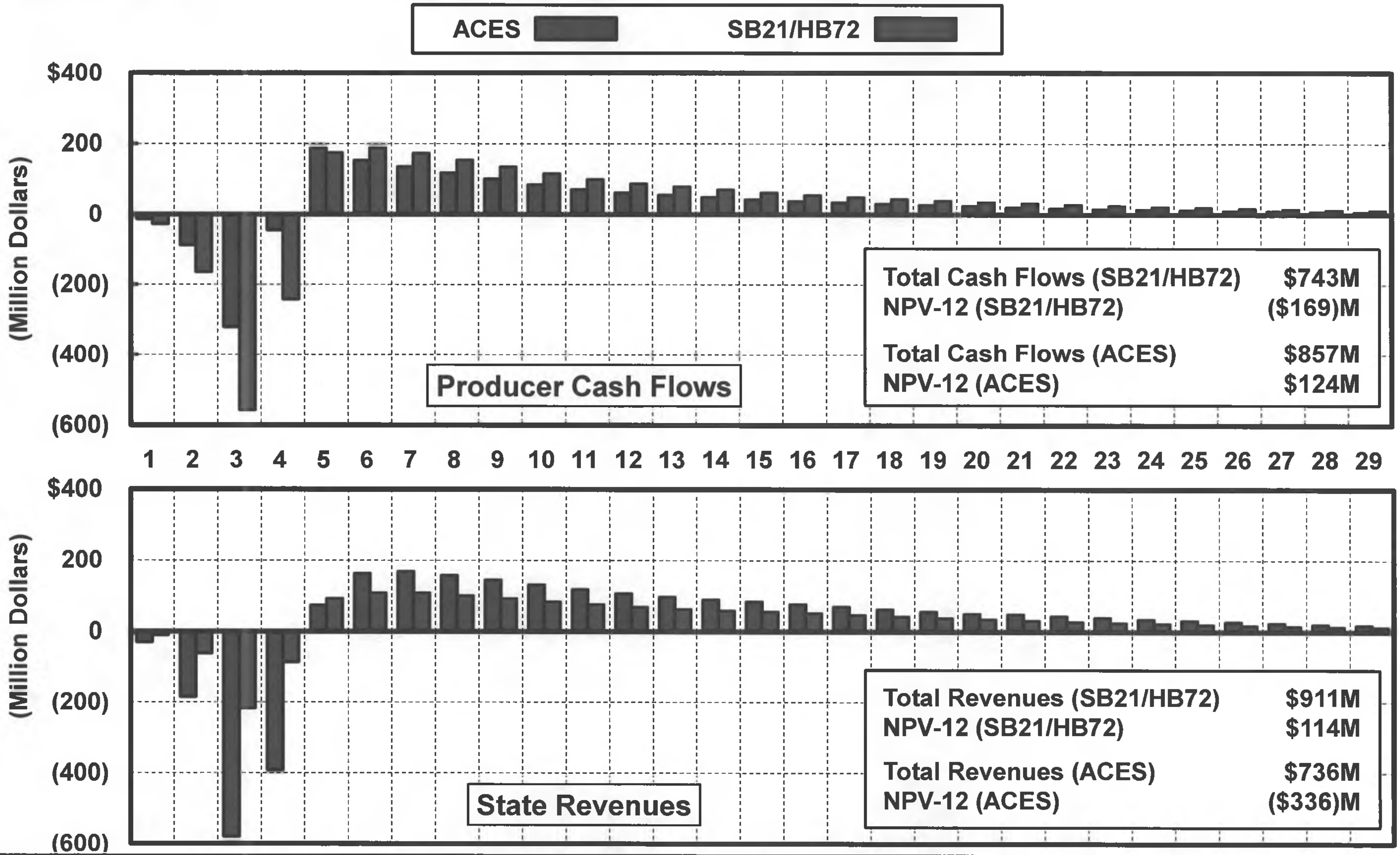
*** Brownfield Allowance applied to 100 MMBOE development.**

Note: Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Annual State Revenues and Producer Cash Flows at $100 West Coast ANS Heavy High Cost Oil Alaska Development
New Participant in Alaska



Annual State Revenues and Producer Cash Flows at $100 West Coast ANS Heavy High Cost Oil Alaska Development
Incumbent Participant in Alaska



Senate Resources Committee

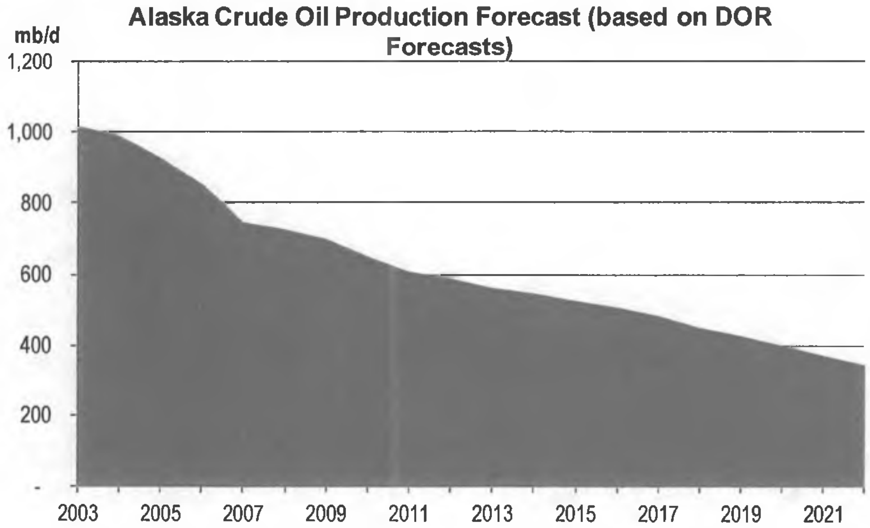
Alaska Fiscal System Discussion Slides

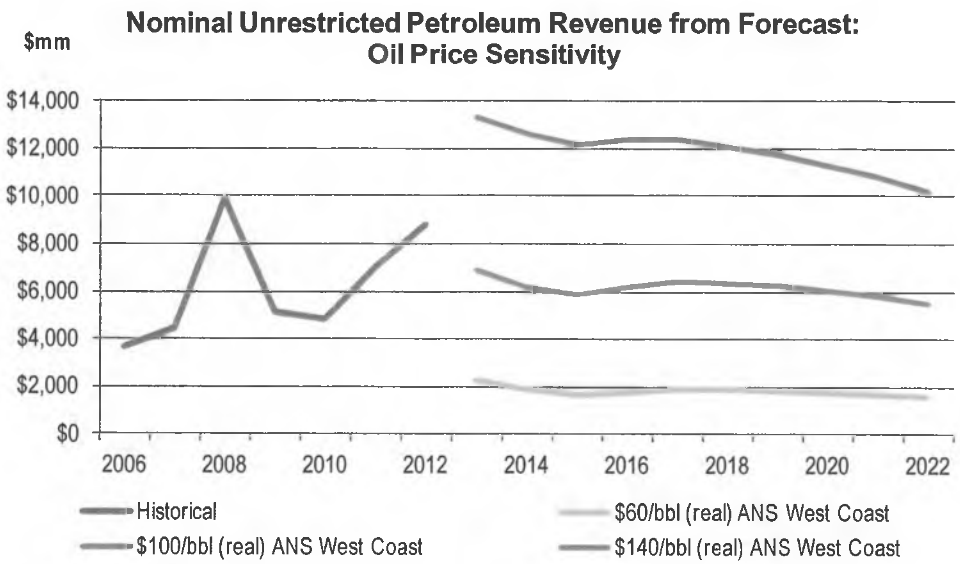
February 15 2013

Janak Mayer
Manager, Upstream
PFC Energy

Alaska's Future Petroleum Revenues: Sensitivities to Oil Price, Production Decline, and Fiscal Terms

Oil Price is the Major Determinant of Alaska's Future Petroleum Revenue





- The major factor determining Alaska's future petroleum revenue is not oil & gas fiscal terms, or even, in the short run, production levels, but rather something entirely outside Alaska's control: the crude oil price
- Restricting a sensitivity analysis only to the a range of oil prices observed in the last 5 years, and **holding future production constant** (based on DOR forecasts) the potential variation in possible future petroleum revenue is substantial:
  - In a $140/bbl environment, revenue in 2022 under ACES would approach $10bn
  - In a $60/bbl environment, revenue in 2022 under ACES would be as low as $1.8bn

In reality, the potential for variation is even greater than this, since production also responds to price:
  - In a sustained high price environment, more projects would be economic, and long-run production would improve
  - In a sustained low price environment, fewer projects would be economic and sustaining capital would be lower, resulting in a more rapid decline in long run production

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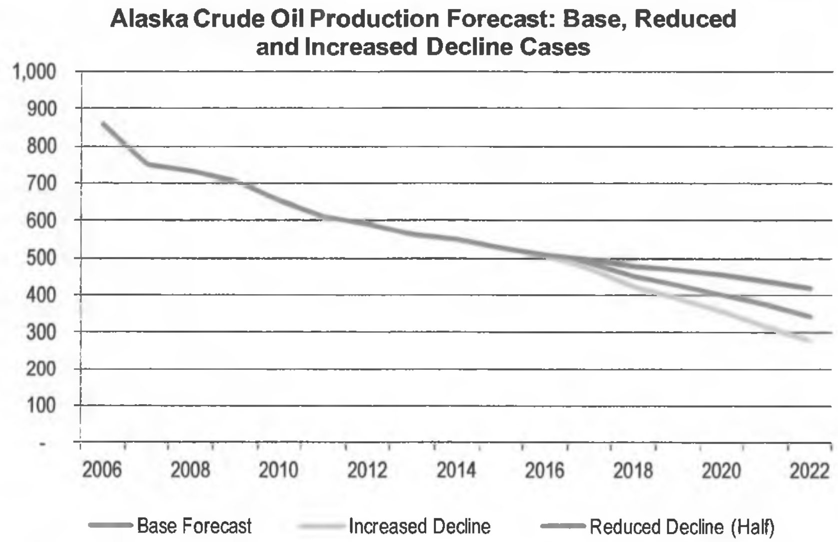
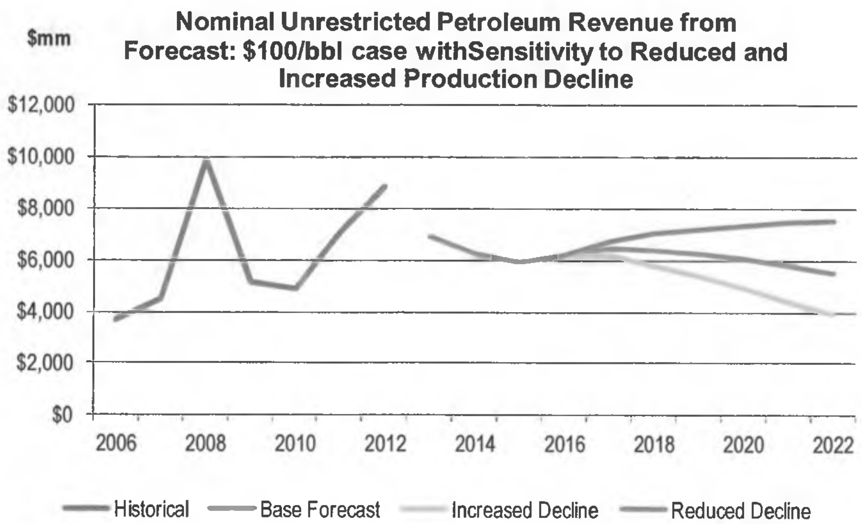
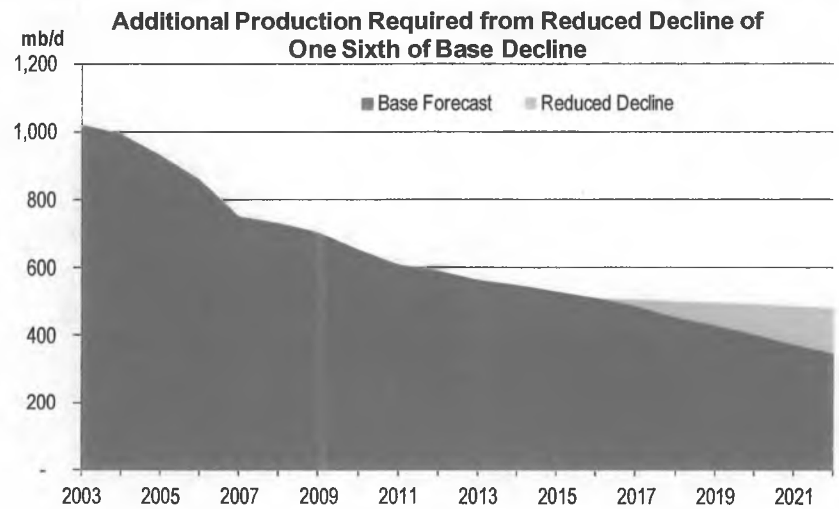
Decline Rate is the Other Major Determinant

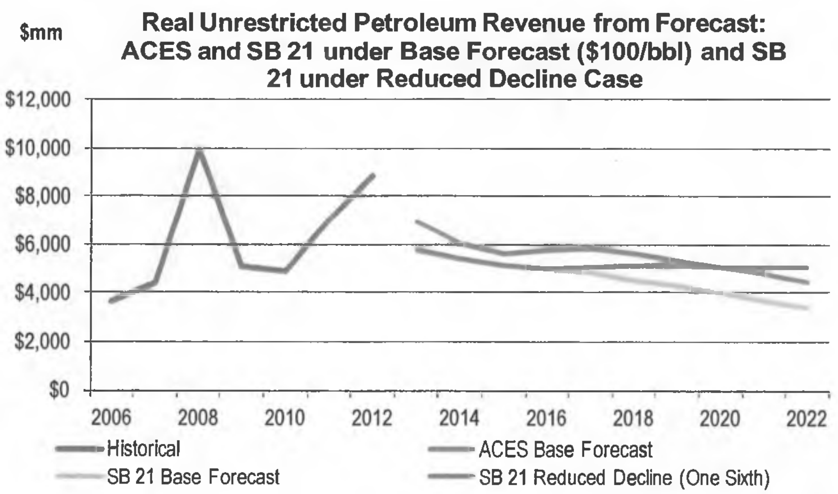




- The Base Forecast anticipates an average annual production decline between 2017 and 2022 of **~6%** (including the contribution from new producing areas brought on-stream), yielding production of ~344 mb/d in 2022
- Increasing the average decline rate by half to **9%** in every year from the base case would see production declining to ~280 mb/d in 2032
- Reducing the average decline rate by half to **3%** in every year from the base case would see production of ~419 mb/d in 2032
- In the low decline scenario, more robust production combined with the impact of inflation mean that nominal revenues would continue to grow beyond 2017, reaching ~$7.8 bn at a nominal crude price of $100/bbl
- In the high decline scenario, 2022 nominal revenues would fall well below the $4 bn level anticipated in the Base Forecast case, reaching less than ~$4 bn even with nominal crude prices at $100/bbl

Fiscal Terms Changes and Investment Impacts





Year	2017	2018	2019	2020	2021	2022
Additional Production (mboe/day)	20	48	66	88	111	133

- Even significant changes to fiscal terms, by contrast, have a far smaller impact on future revenues than either oil price or future production declines
  - Under the Base Forecast decline case, at $100/bbl crude oil, SB 21/HB72 results in a parallel shift of the revenue curve, reducing the state's petroleum revenue by a little over $1 bn each year
- If an improvement in fiscal terms can stimulate sufficient new investment to stem declines, it has the long run potential to increase revenue, despite the near-term cost of the change
  - To maintain revenues to the state at a steady level in real terms, a reduction in government take such as that under SB 21 would need to spur sufficient investment to **reduce the North Slope base decline from 6%** as currently forecast **to 1%**

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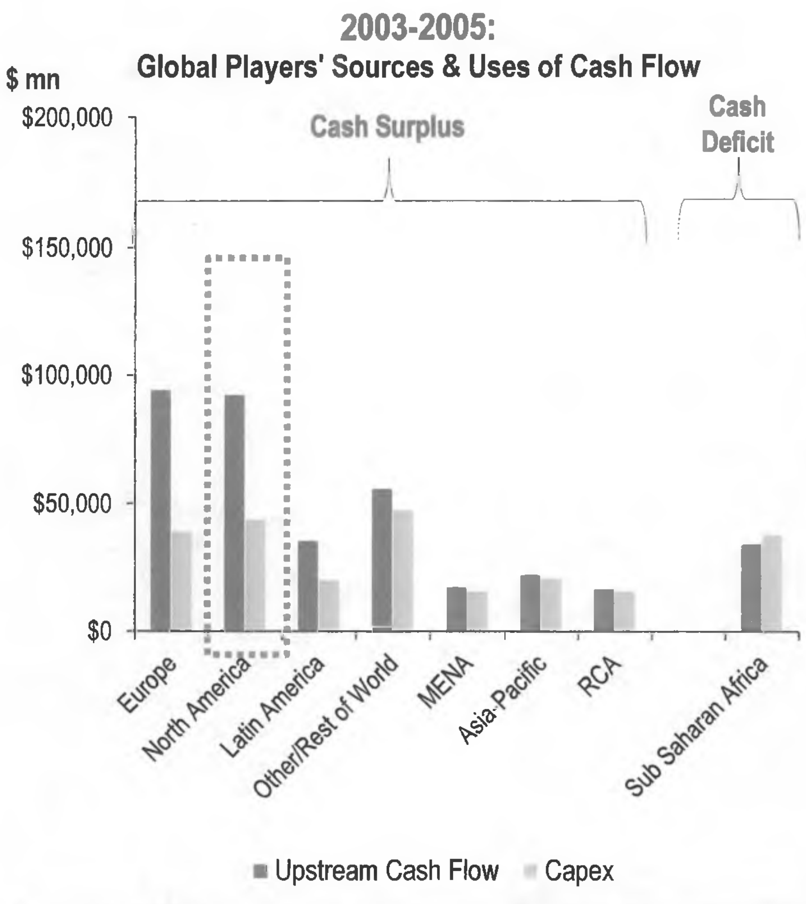
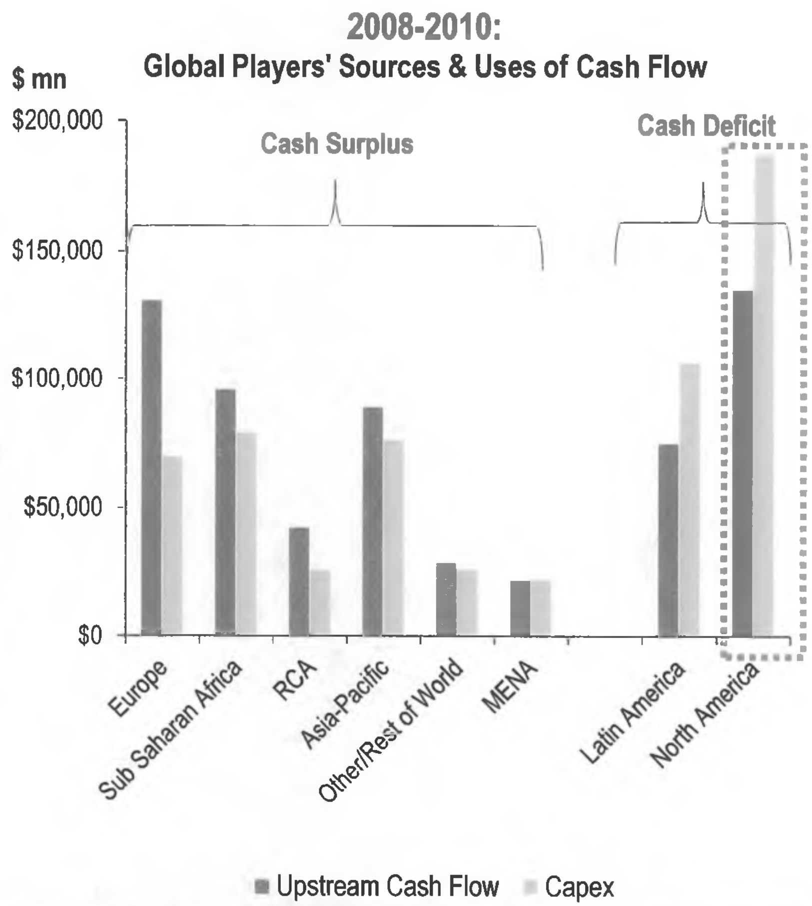
Context: Investment Competition & Global Oil Price Environment

Fixed-Royalty Jurisdictions in US Lower 48 Are A Key Competitor to Alaska for Investment Dollars

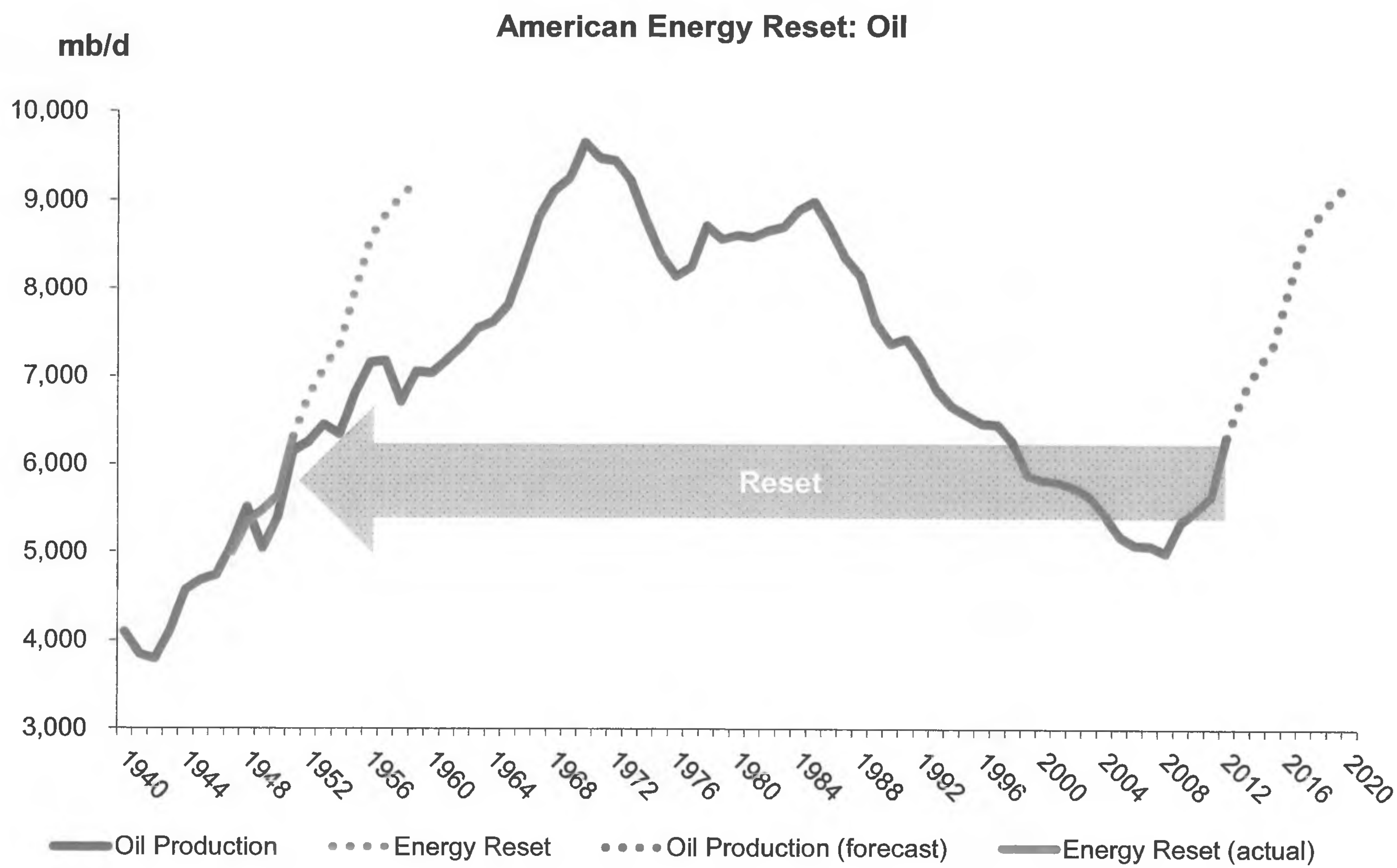




It is now an exception not to be targeting unconventionals in North America as a major growth platform.

American Energy Reset

United States Production – Back at Post-War Period



Anatomy of the Physical Market for Crude Oil

Final Product Consumption

- Fuel needed for economic activity
- Main ingredient in hot dogs

Refining Demand for Crude

- Inputs needed to provide fuel demanded by consumers

Non-OPEC Crude

- As price takers, will produce at capacity given positive project economics

OPEC Crude

- Plays a balancing role, adjusting output as needed in line with overall objectives

Four broad segments to balance the market

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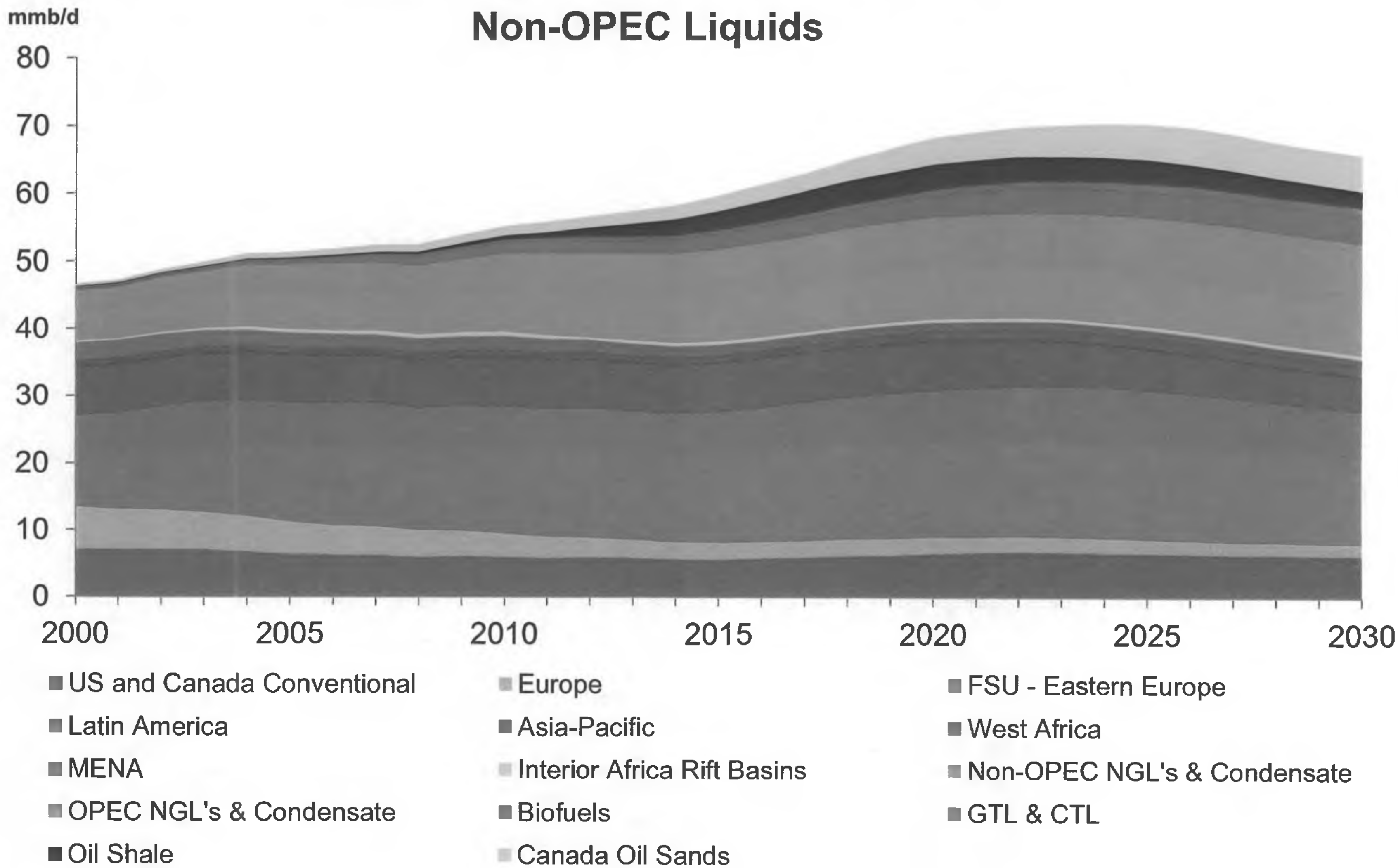
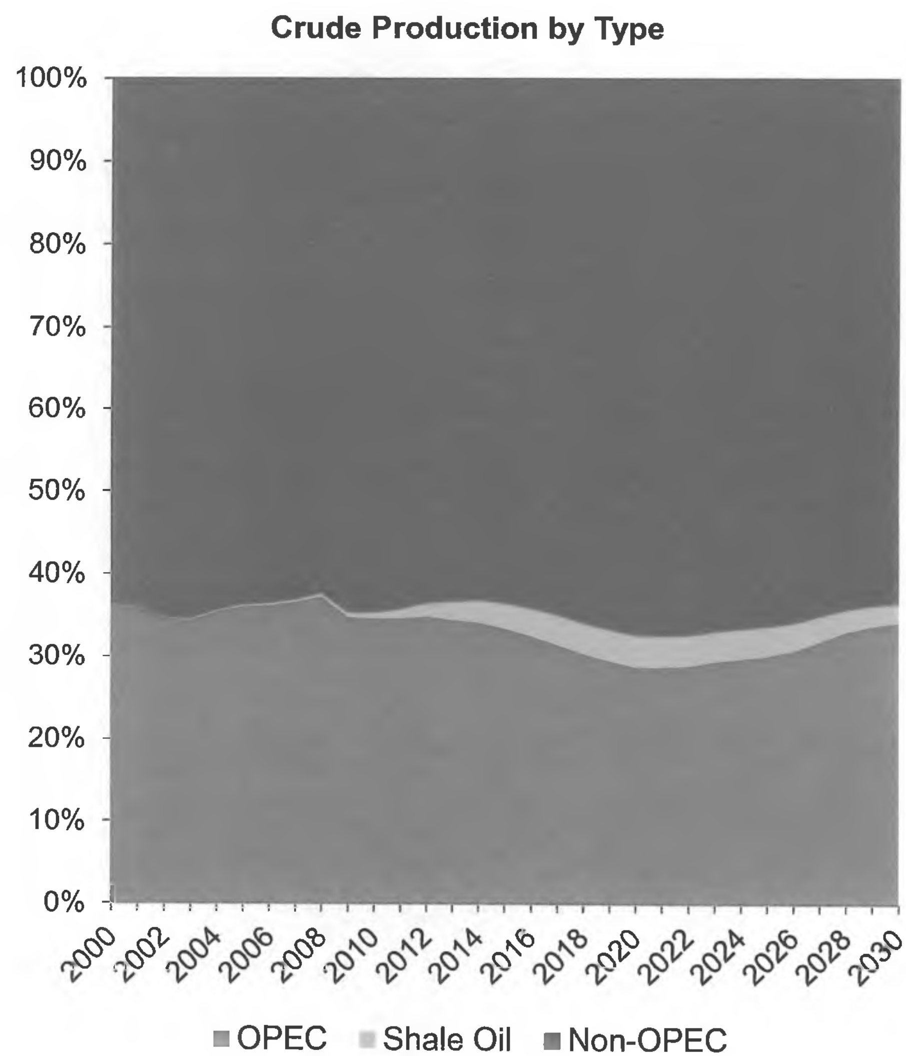
Non-OPEC Liquids Will Show Substantial Growth

In the past production not affected by price swings



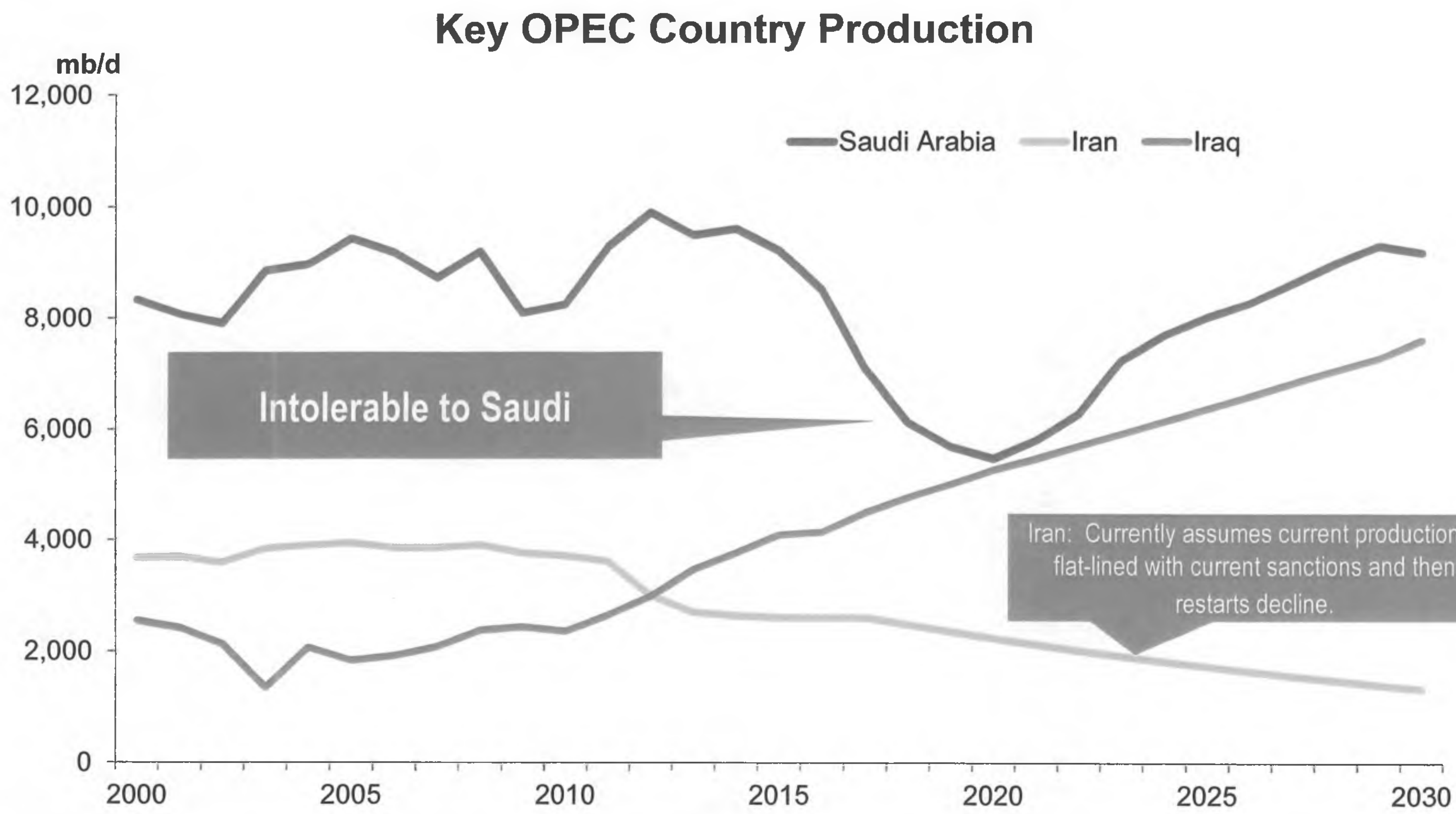
Shale Oil Major Factor in Reducing OPEC's Share
Potentially upsetting to long-time oil market balancer

- Shale oil now forecast to reach ~4 mmb/d of production by end of the decade (largest recent Saudi swing was 2.2 mmb/d – post recession through Libya response)
- Shale oil production joins ranks of potential short-term global oil balancers. Traditionally made up of:
  - OPEC (Primarily Saudi Arabia)
  - IEA/SPR stocks
  - Demand destruction (potential is diminishing with rise of non-OECD demand growth given subsidies)
- OPEC has yet to begin grasping both the scale and potential impact that shale oil will have on its traditional role.
  - Is only now beginning to address Iraqi production



Initial Output Implications for Major OPEC Producers

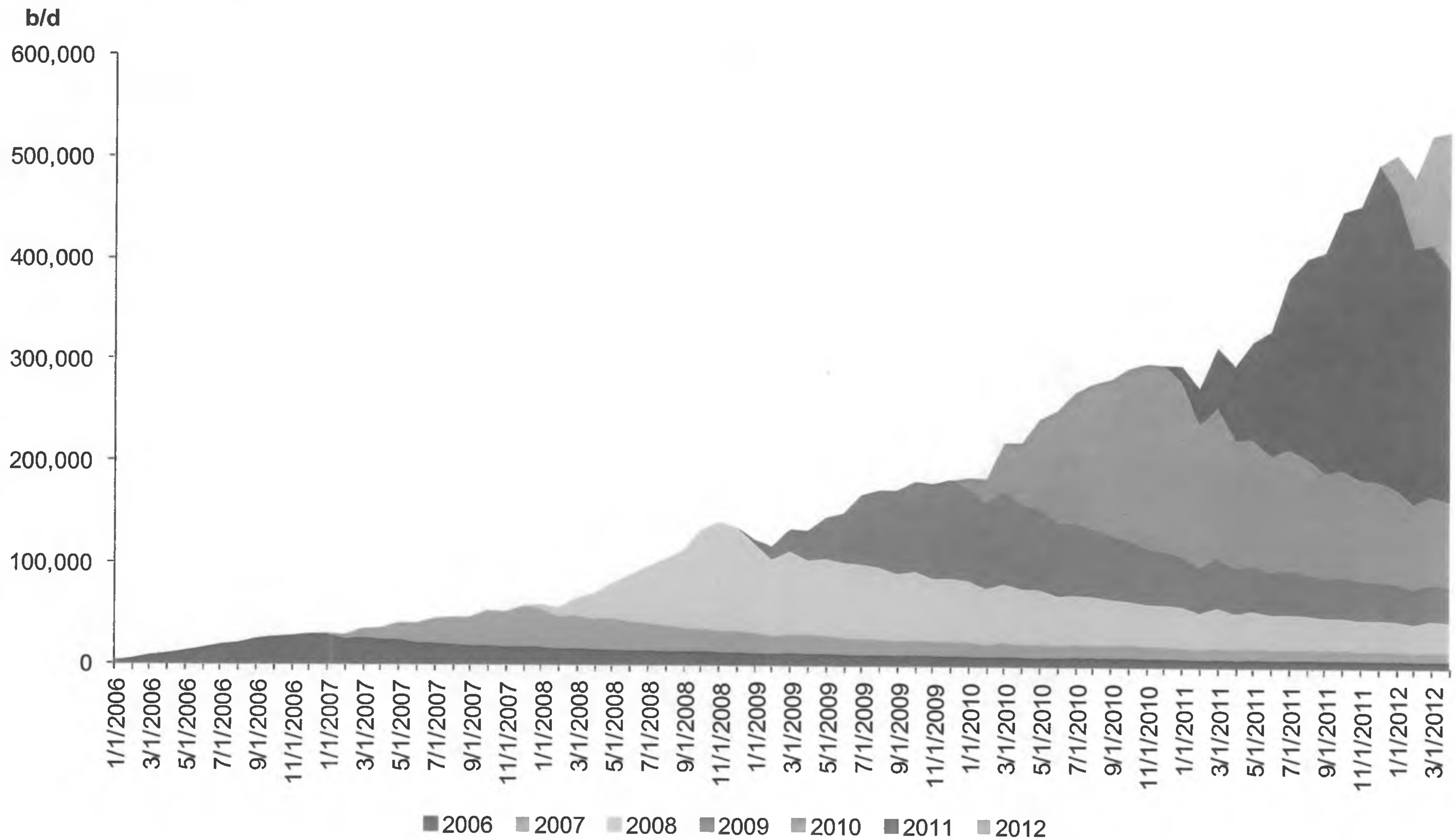
Iran and Iraq complicate market management



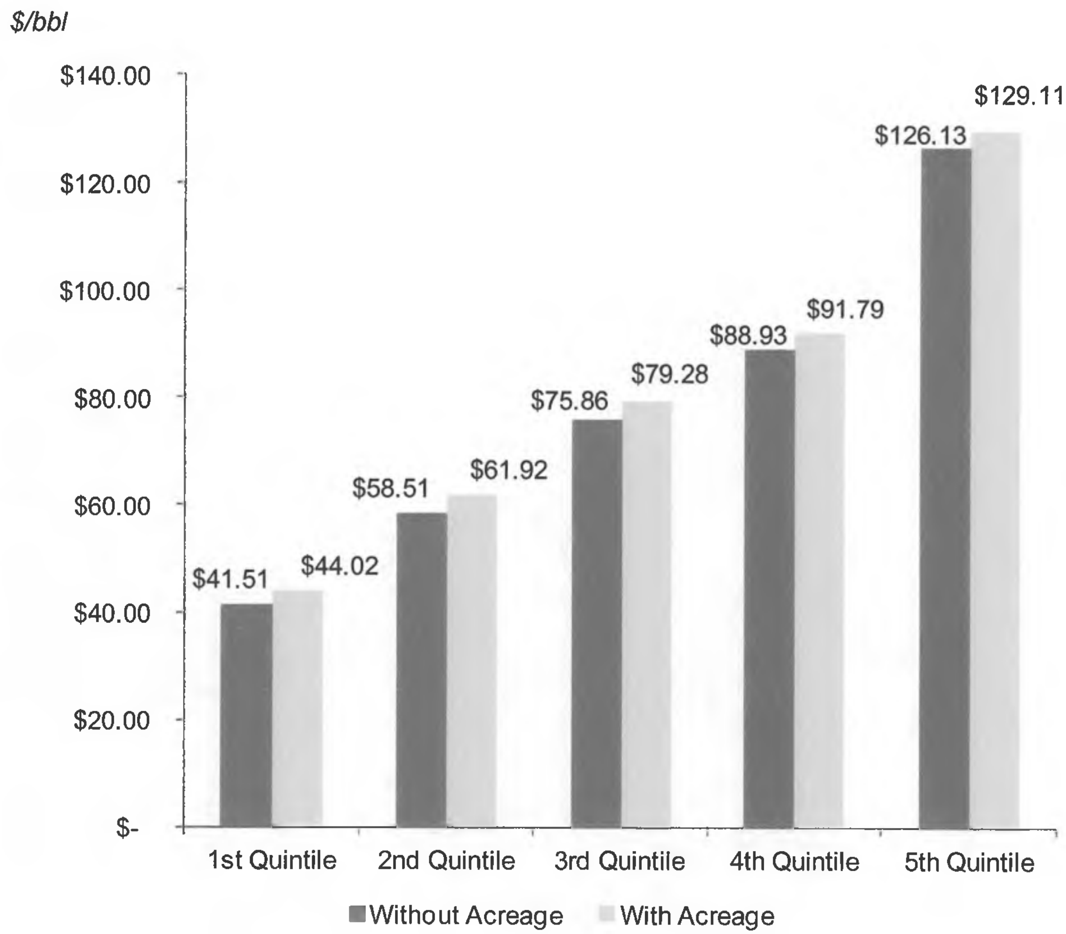
A diplomatic solution that brings Iran back into the oil markets makes OPEC management worse via increased volumes

Character of US Growth Changing
Potential for sudden stop to growth or even declines on price softness

- Each year more production must be brought on just to maintain the prior year's levels.



Bakken Quintile Breakeven PV 10



Assumptions for Breakeven are:

Drilling Cost: $8MM

Acreage Costs by Class:
Class 1 $20,000/acre
Class 2 $13,333/acre
Class 3 $8,889/acre
Class 4 $5,926/acre
Class 5 $3,951/acre

Risked : 95%

Basis : $(10.00)/bbl

Severance taxes:
Gas: 7.5%
Oil: 4.6%

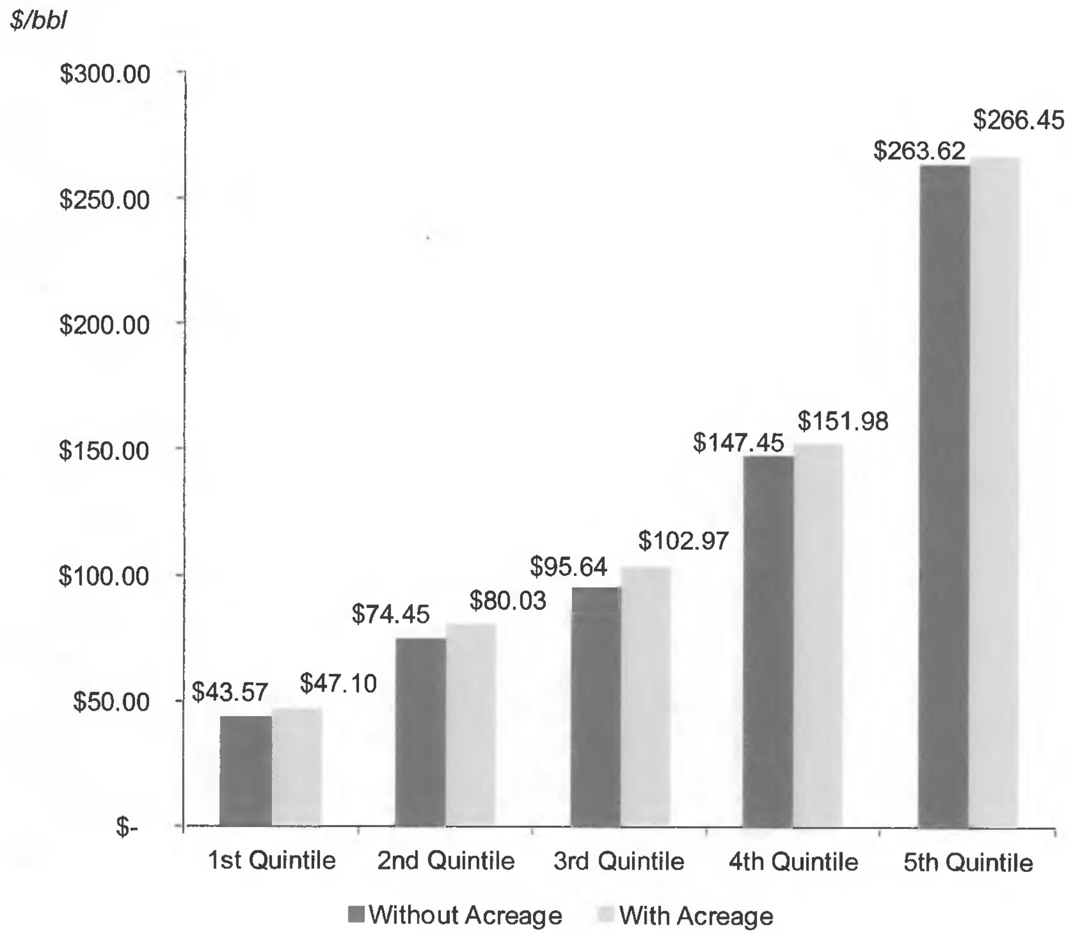
Fed taxes: 35%

Operating Costs:
Fixed: $1,000/well/month
Variable: $7.00/ boe

Gen/Admin costs: $1.50 / boe

Royalty Rates:
Q 1: 18.8%
Q 2: 14.1%
Q 3: 10.6%
Q 4: 7.9%
Q 5: 5.9%

Eagleford Quintile Breakeven PV 10



Assumptions for Breakeven are:

Drilling Cost: $7.5 MM

Acreage Costs by Class:
Class 1 $20,000/acre
Class 2 $15,000/acre
Class 3 $10,000/acre
Class 4 $5,000/acre
Class 5 $2,000/acre

Risked : 95%

Basis : $(4.00)/bbl

Severance taxes:
Gas: 7.5%
Oil: 4.6%

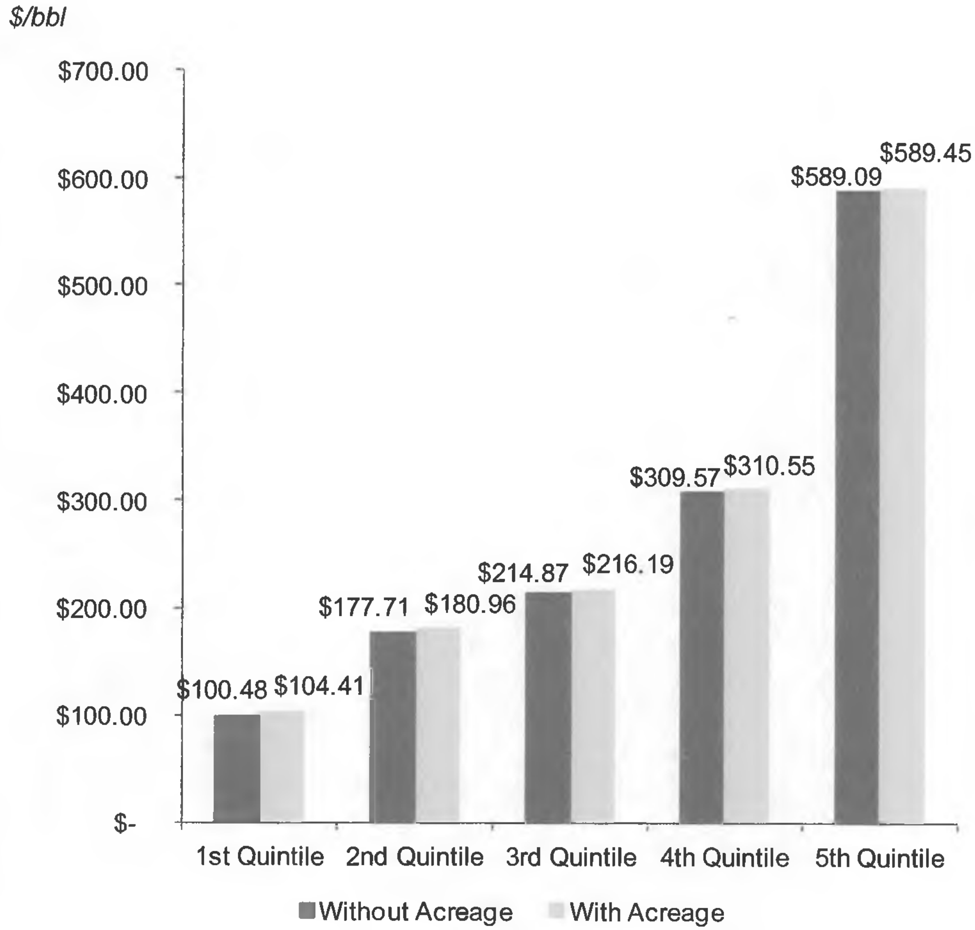
Fed taxes: 35%

Operating Costs:
Fixed: $1,000/well/month
Variable: $3.00/ boe

Gen/Admin costs: $1.50 / boe

Royalty Rates:
Q 1: 25%
Q 2: 20%
Q 3: 18%
Q 4: 14%
Q 5: 12.5%

Granite Wash Quintile Breakeven PV 10



Assumptions for Breakeven are:

Drilling Cost: $7.5 MM

Acreage Costs by Class:
Class 1 $6,000/acre
Class 2 $3,000/acre
Class 3 $1,000/acre
Class 4 $500/acre
Class 5 $100/acre

Risked : 95%

Basis : $(4.00)/bbl

Severance taxes:
Gas: 7.3%
Oil: 7.3%

Fed taxes: 35%

Operating Costs:
Fixed: $1,000/well/month
Variable: $3.00/ boe

Gen/Admin costs: $1.50 / boe

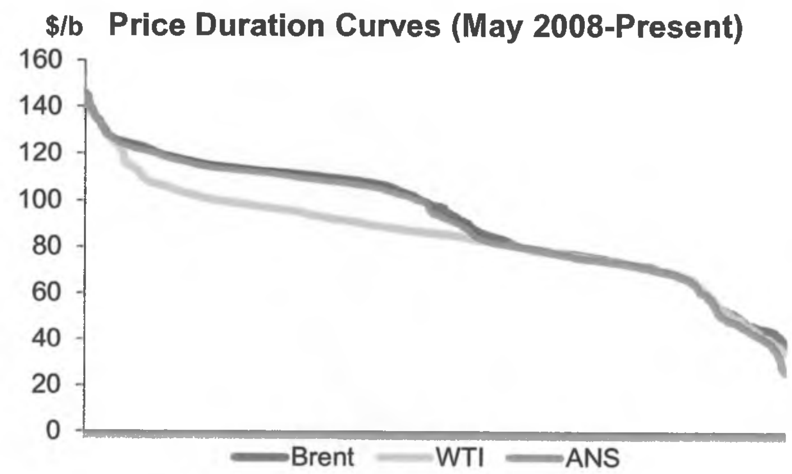
Royalty Rates:
Q 1: 1/6
Q 2: 1/6
Q 3: 1/6
Q 4: 1/8
Q 5: 1/8

Risks to Price Forecast

	Risk	Description
Upside Price Risk	Strong global economic growth	• Increases demand strongly, tightening supply/demand balance
Upside Price Risk	Instability removes barrels from market	• Repeat of Libya-type event • Confrontation with Iran
Downside Price Risk	American Energy Reset	• US production boom is now delivering most of the worlds incremental demand growth, leaving little room for additional growth from other countries
Downside Price Risk	Economic slowdown	• Eurozone, US or China slowdown causing demand slowdown. Loosens supply/demand balance
Downside Price Risk	OPEC mismanagement	• OPEC will need to cut barrels in the future but may have difficulty organizing this among its members
Downside Price Risk	US WTI disconnect expands geographic scope	• Discounts to WTI and other inland markers may begin to affect US west coast markets as Bakken and Eagle Ford crudes increase into those areas.

What is the Potential Floor for ANS West Coast Crude?

- Since 2008, the average for the 100 lowest priced days ranged form $38-44/b for the three key markers.
- **In the short-term, the potential floor price for ANS is in the mid-$30/b range.**
  - Would require substantial global oversupply, likely through a combination of OPEC mismanagement and booming US production
  - This low price is not sustainable for long as it will begin to cut US production within 60-90 days.



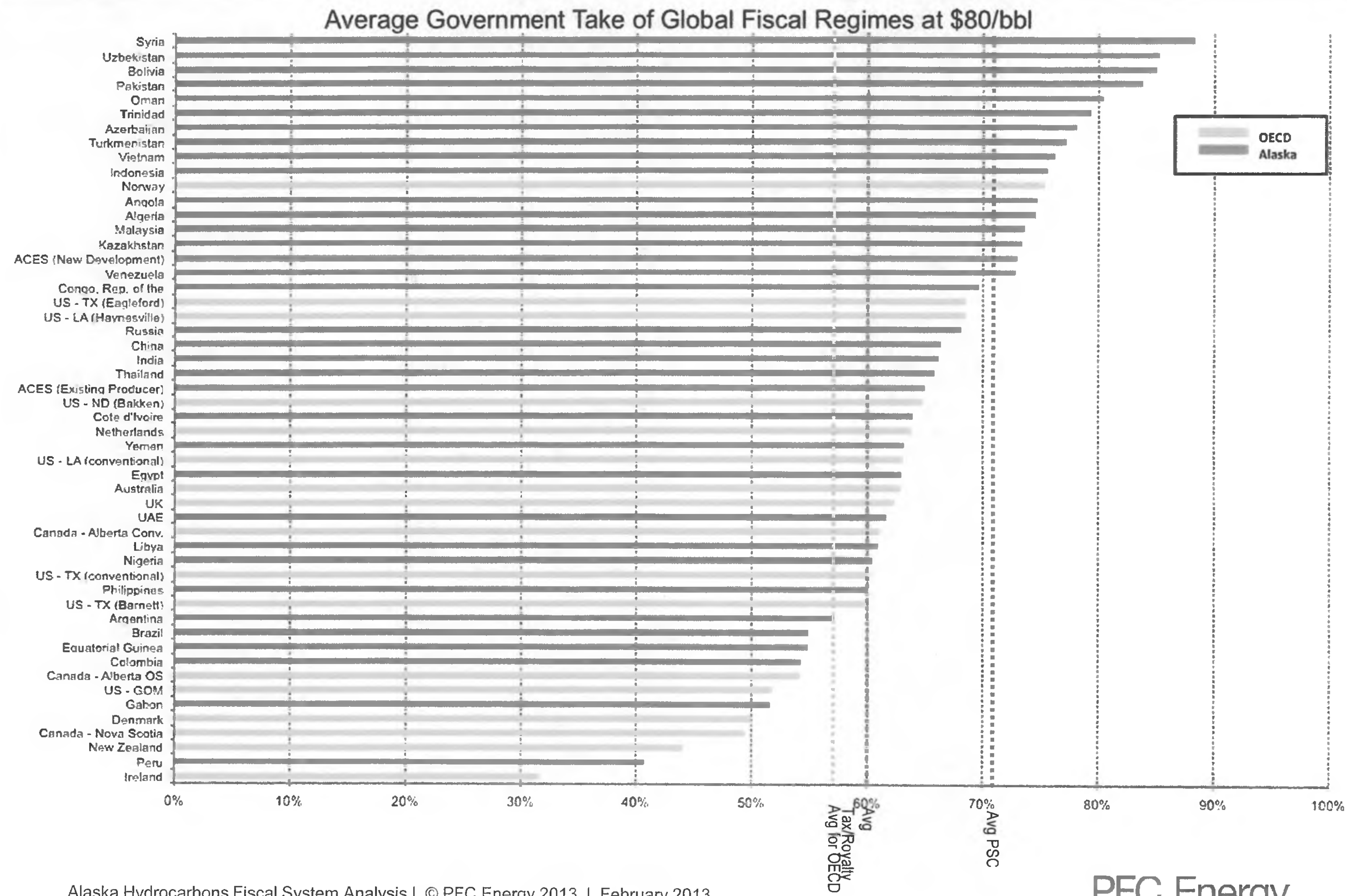
- **In the medium- to long-term, the floor price is near the cost of the marginal barrel**:
  - If US constrained, potential for $55-60/b
  - If global (and assuming US production does not again surprise to the upside), the price floor is higher at $70-75/b

Alaska's Fiscal System: Problems and Approaches

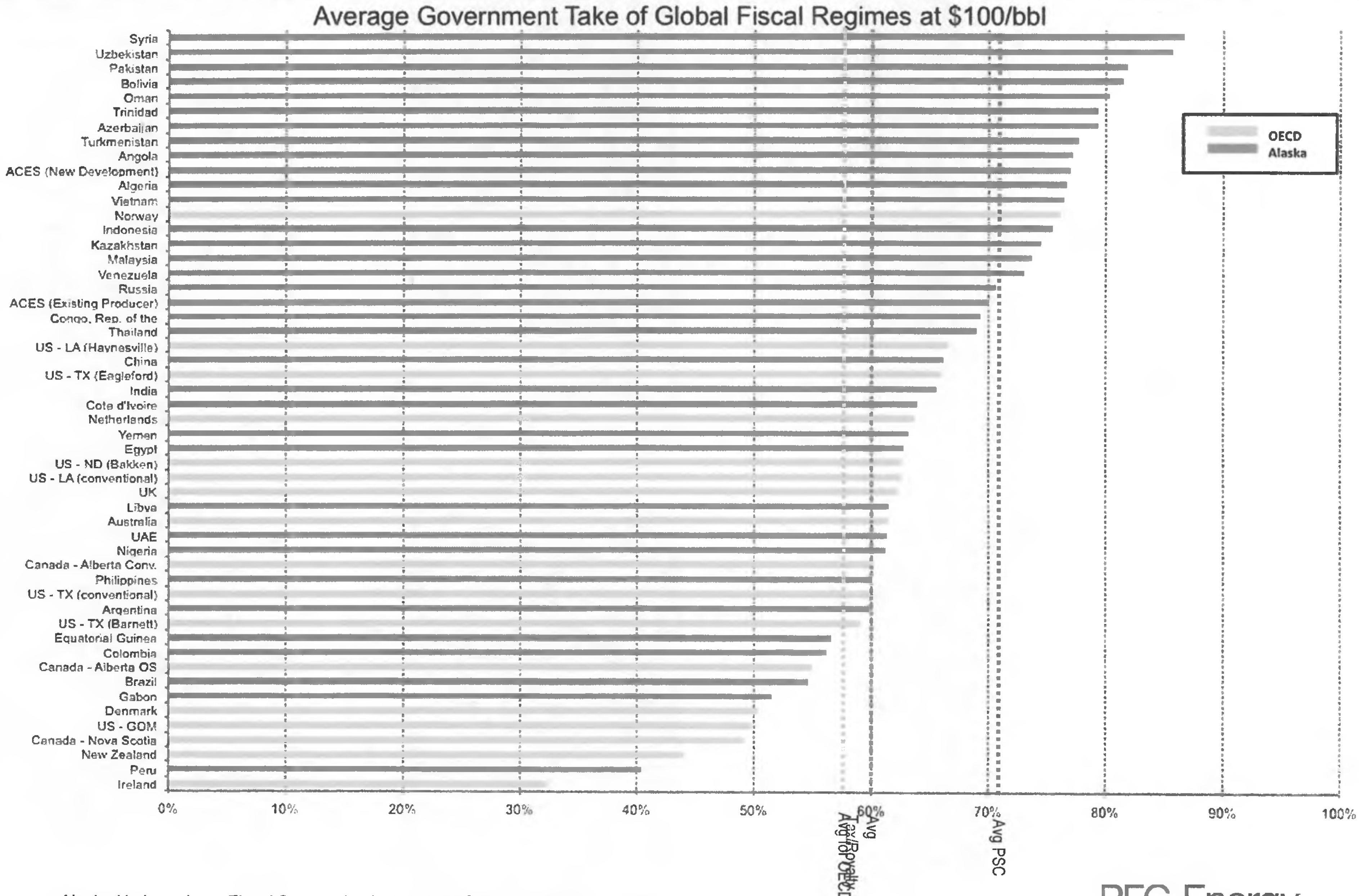
ACES: 5 key problems

- **High levels of Government Take reduce competitiveness for capital, especially at high prices**
- High marginal tax rates reduce incentives for spending control
- Complexity makes meaningful economic analysis and comparison difficult
- Significant state exposure in low price environments, and for high-cost developments
- Impact of large-scale gas sales on tax rates

Regime Competitiveness: Average Government Take at $80/bbl



Regime Competitiveness: Average Government Take at $100/bbl



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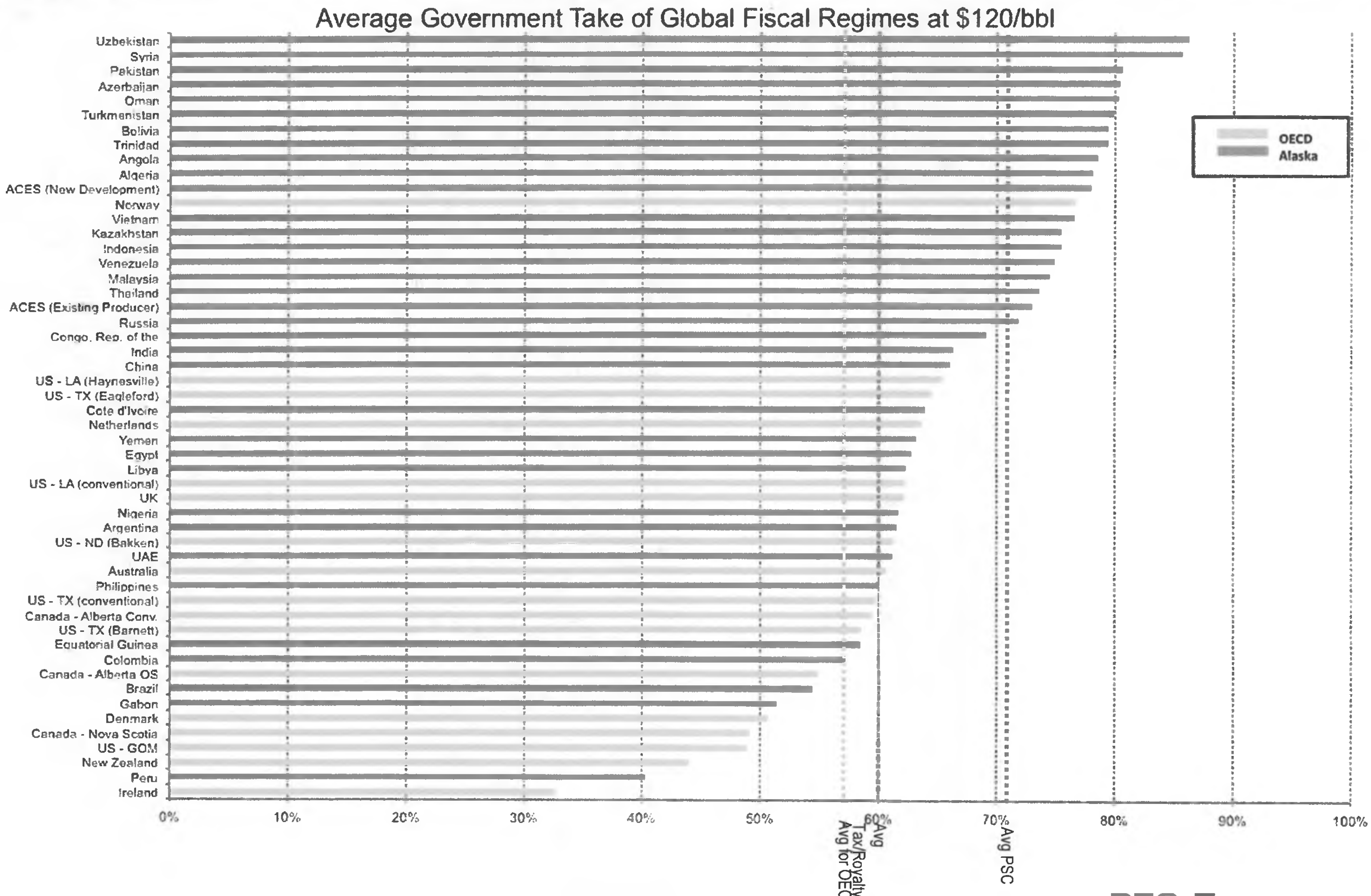
Regime Competitiveness: Average Government Take at $120/bbl



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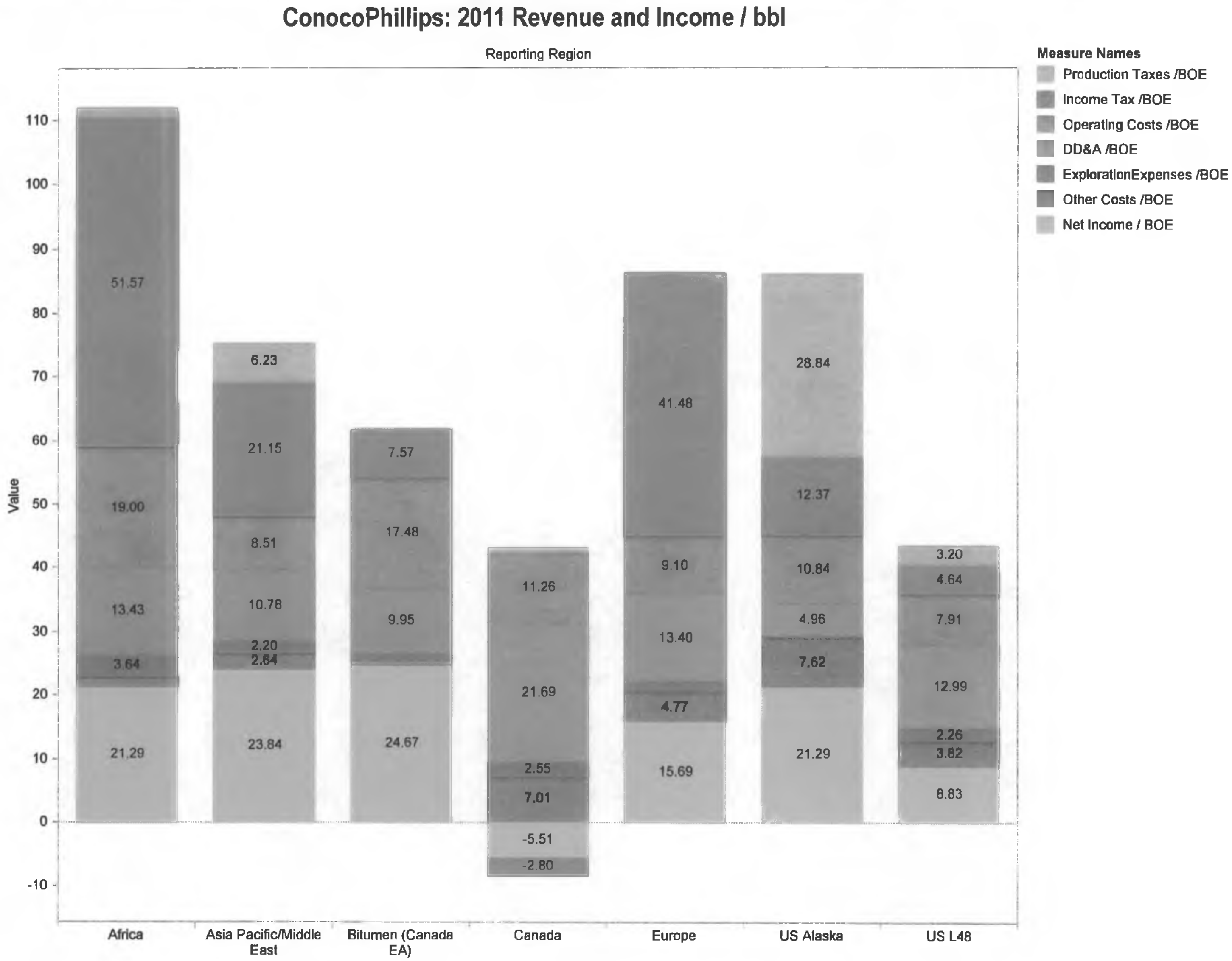
Difference Between New Investment vs Base Production is Critical



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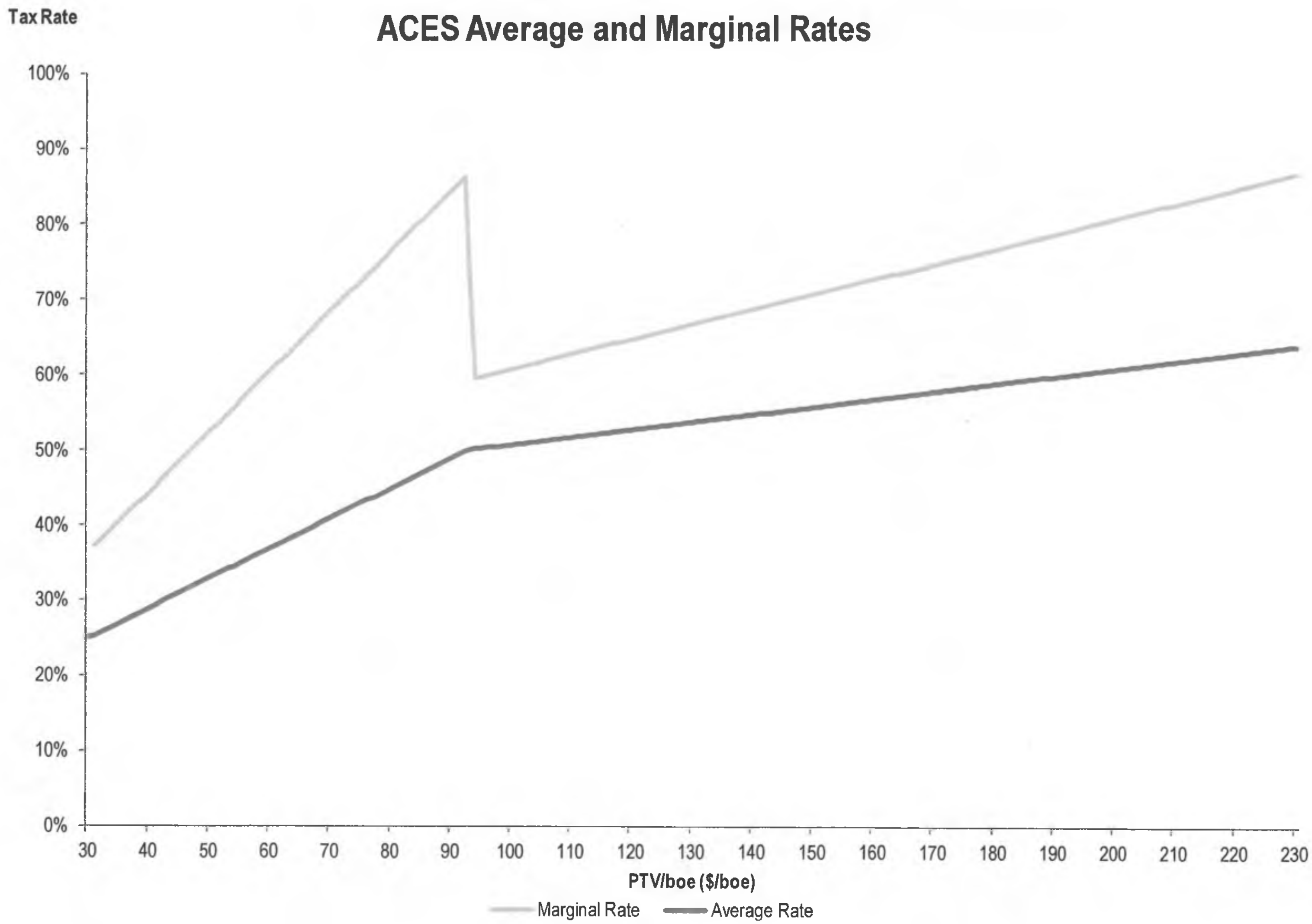
ACES: 5 key problems

- High levels of Government Take reduce competitiveness for capital, especially at high prices
- **High marginal tax rates reduce incentives for spending control**
- Complexity makes meaningful economic analysis and comparison difficult
- Significant state exposure in low price environments, and for high-cost developments
- Impact of large-scale gas sales on tax rates

ACES: Average and Marginal Production Tax Rates



Impact of Spending Under High Marginal Rates

Calculation of ACES Tax: Additional Capital Spending

Annual Taxable Production (Bbls)		50,000,000	50,000,000	50,000,000
Initial Expenditure ($)		$1,500,000,000	$1,500,000,000	$1,500,000,000
Additional Expenditure ($)	+	250,000,000	250,000,000	250,000,000
Total Lease Expenditure ($)		$1,750,000,000	$1,750,000,000	$1,750,000,000
WC ANS Price ($/Bbl)		$80.00	$100.00	$120.00
Tax Value Prior To Additional Expenditure ($/Bbl)		$40.00	$60.00	$80.00
Additional Capital Spending Per-Barrel of Existing Production ($/Bbl)	-	5.00	5.00	5.00
Tax Value After Additional Expenditure ($/Bbl)	=	$35.00	$55.00	$75.00
Taxes Before Additional Expenditure				
Tax Rate (%)		29.0%	37.0%	45.0%
Production Tax Before Credits ($)		$580,000,000	$1,110,000,000	$1,800,000,000
Capital Credits (20% x Capital Expenditures) ($)	-	300,000,000	300,000,000	300,000,000
Production Tax After Credits ($)	=	$280,000,000	$810,000,000	$1,500,000,000
Taxes After Additional Expenditure				
Tax Rate (%)		27.0%	35.0%	43.0%
Production Tax Before Credits ($)		$472,500,000	$962,500,000	$1,612,500,000
Capital Credits (20% x Capital Expenditures) ($)	-	350,000,000	350,000,000	350,000,000
Production Tax After Credits ($)	=	$122,500,000	$612,500,000	$1,262,500,000
Reduction in Taxes From Additional Expenditure				
Before Credits		$107,500,000	$147,500,000	$187,500,000
Additional Credits	+	50,000,000	50,000,000	50,000,000
Total Reduction in Taxes After Credits	=	$157,500,000	$197,500,000	$237,500,000
Reduction in Tax as % of Expenditure		63%	79%	95%
Due to Change in Taxes (Buy Down Effect)		43%	59%	75%
Due to Additional Credits		20%	20%	20%

Econon One Research

Source: Econ One Presentation, February 13 2013

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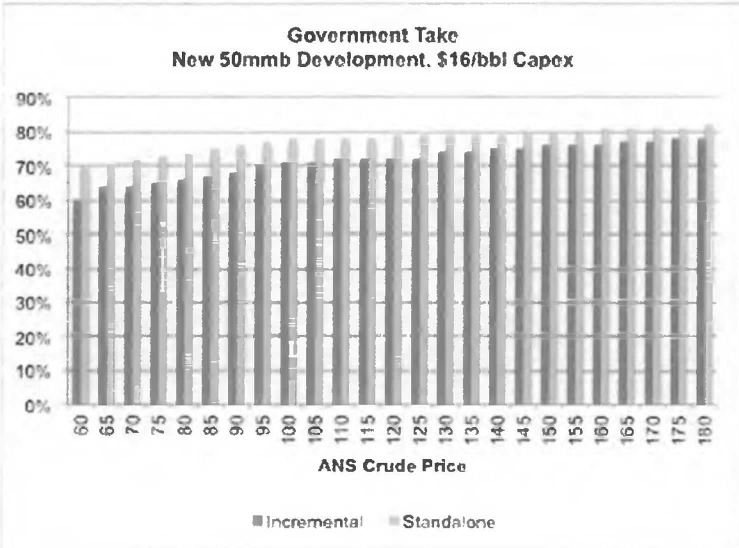
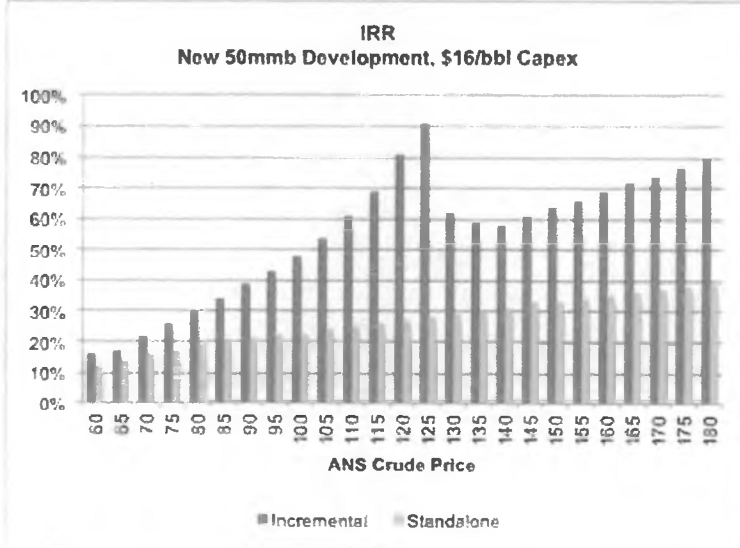
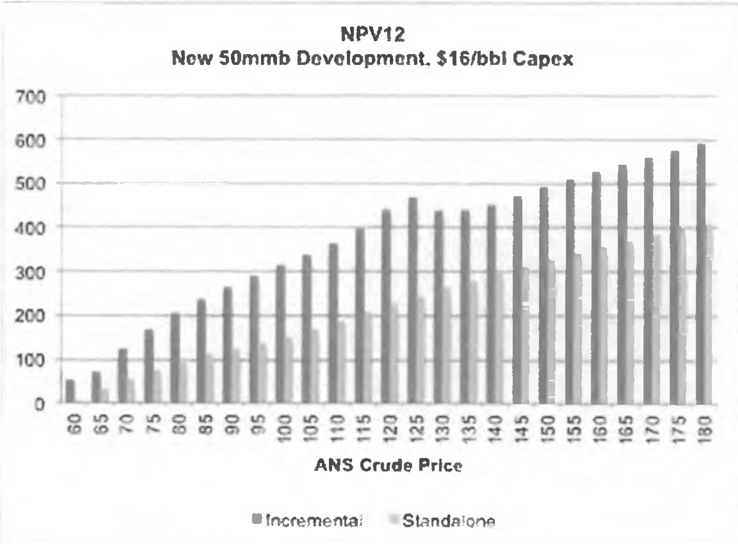
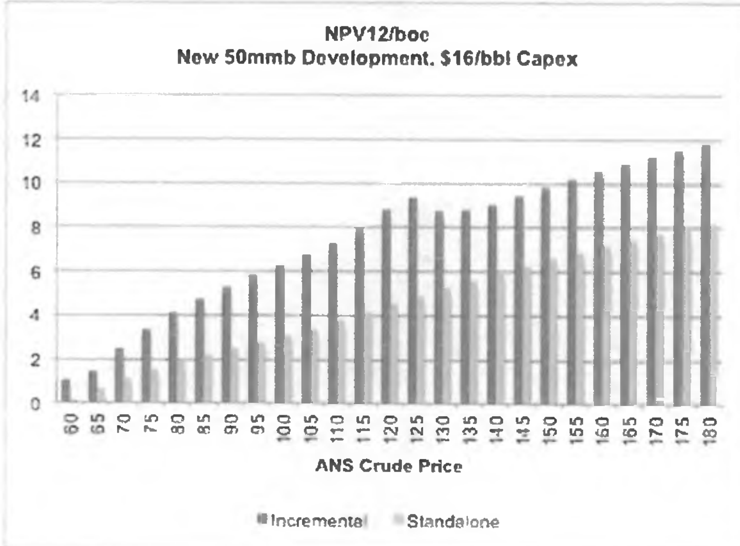
ACES: Standalone vs Incremental



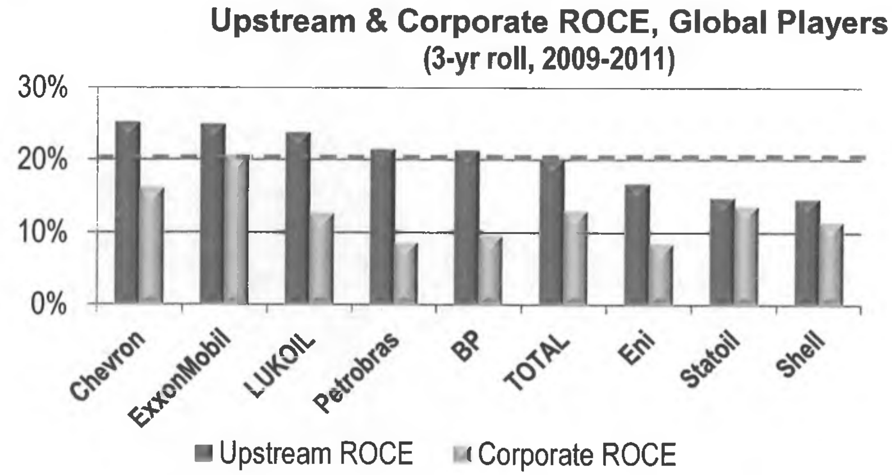


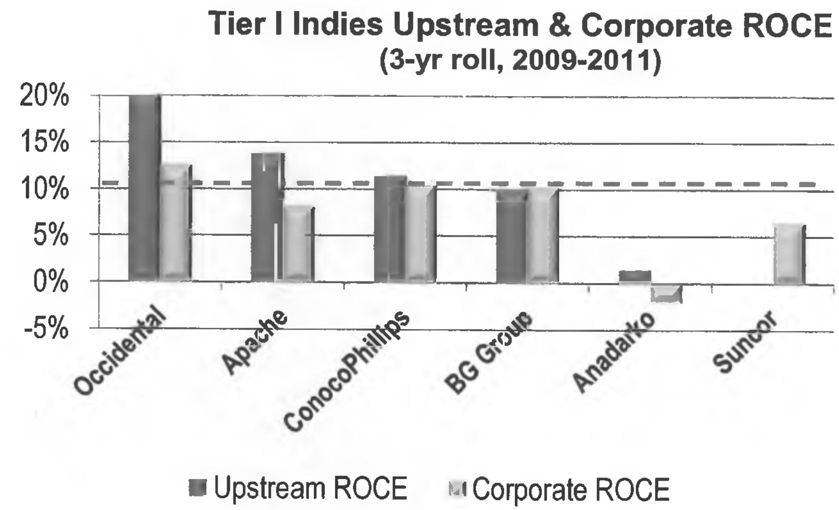




Portfolio Efficiency: Return on Capital Employed (ROCE)

- **<u>Return on Capital Employed</u>**:
  - ROCE = [(Net profit before interest and taxes) / (Gross Capital employed)] x 100
  - Where:
    - Gross capital employed = Fixed assets + Investments + Current assets *OR*
    - Gross capital employed = Share Capital + General & Capital Reserves + Long term loans
    - (+) Correlation with production, commodity prices
    - (-) Correlation with upstream spending
  - Indicates how well management has used the investment made by owners and creditors into the business.
  - The higher the return on capital employed, the more efficient the firm is in using its funds. Over time, ROCE reveals whether the profitability of the company is improving or eroding





Global Players Average Upstream ROCE: 20.4%
Tier I Independents Average Upstream ROCE: 11.4%

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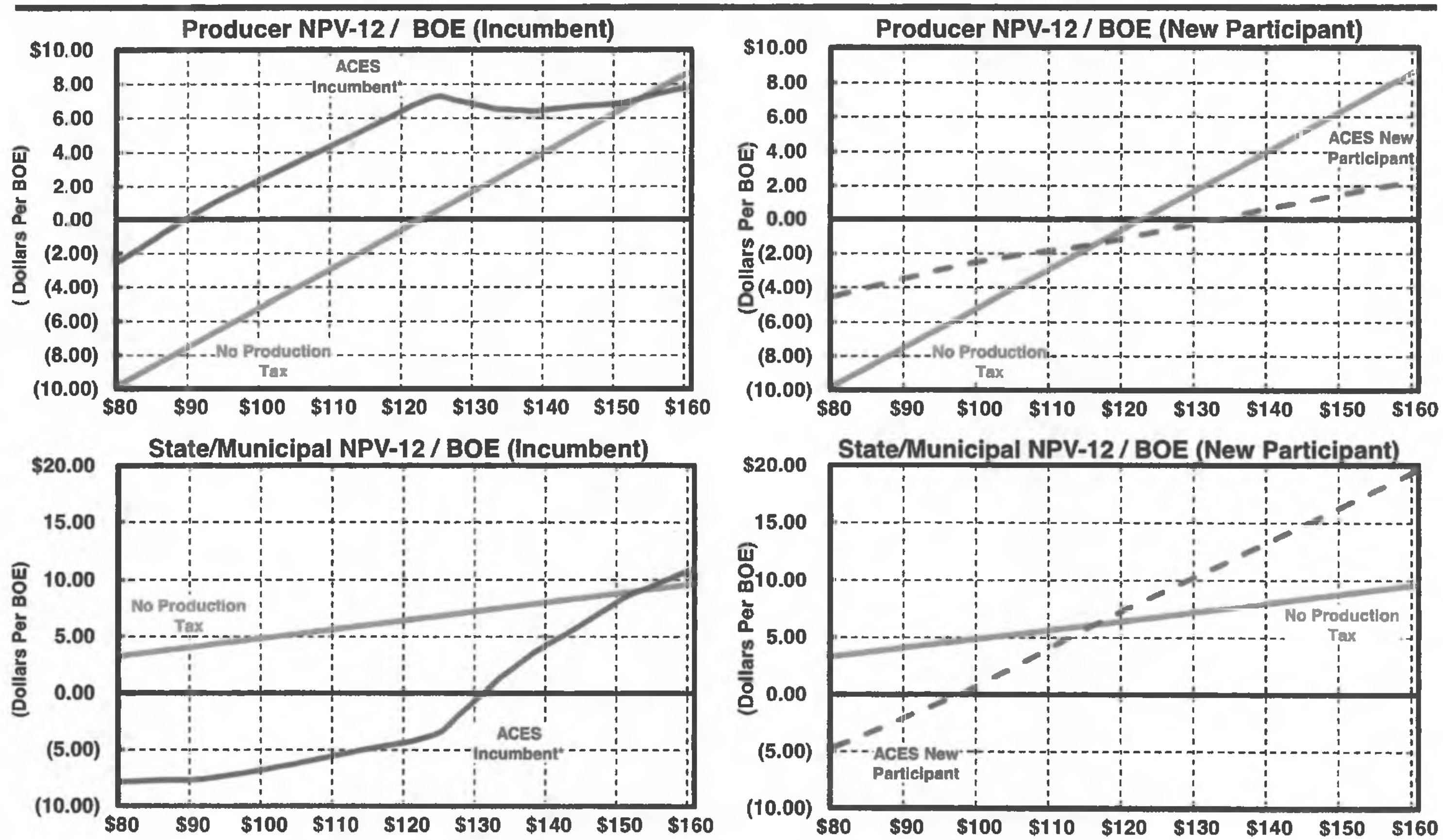
High state exposure for high-cost developments

The Economics of High Cost Heavy Oil Development



* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Econ One Research

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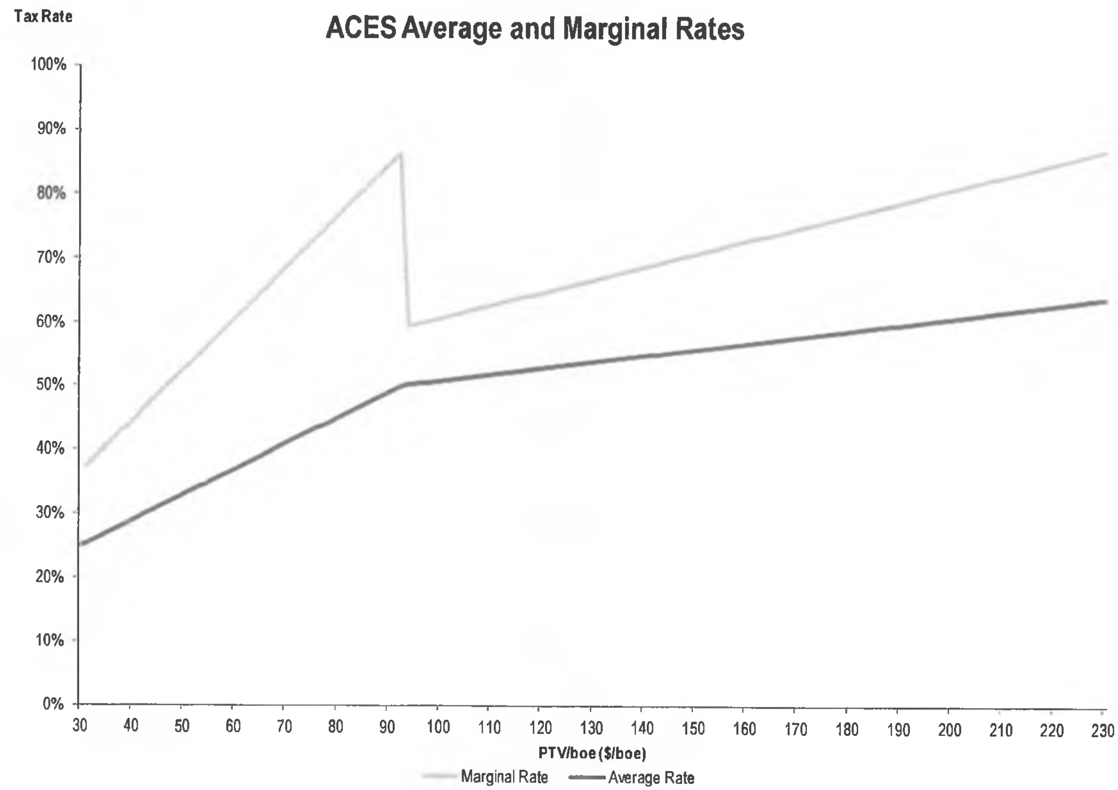
Impact of Large-Scale Gas Sales on Tax Rates

- Under ACES, production tax value is assessed on a combined BTU-equivalent basis for both oil and gas production
  - So long as no major gas export project is under development, this has no impact
  - In the event of the development of a major gas export project, however, when gas prices are significantly lower than oil prices, this could lead to significant reductions in Government Take



ACES: 5 key problems – *available solutions*

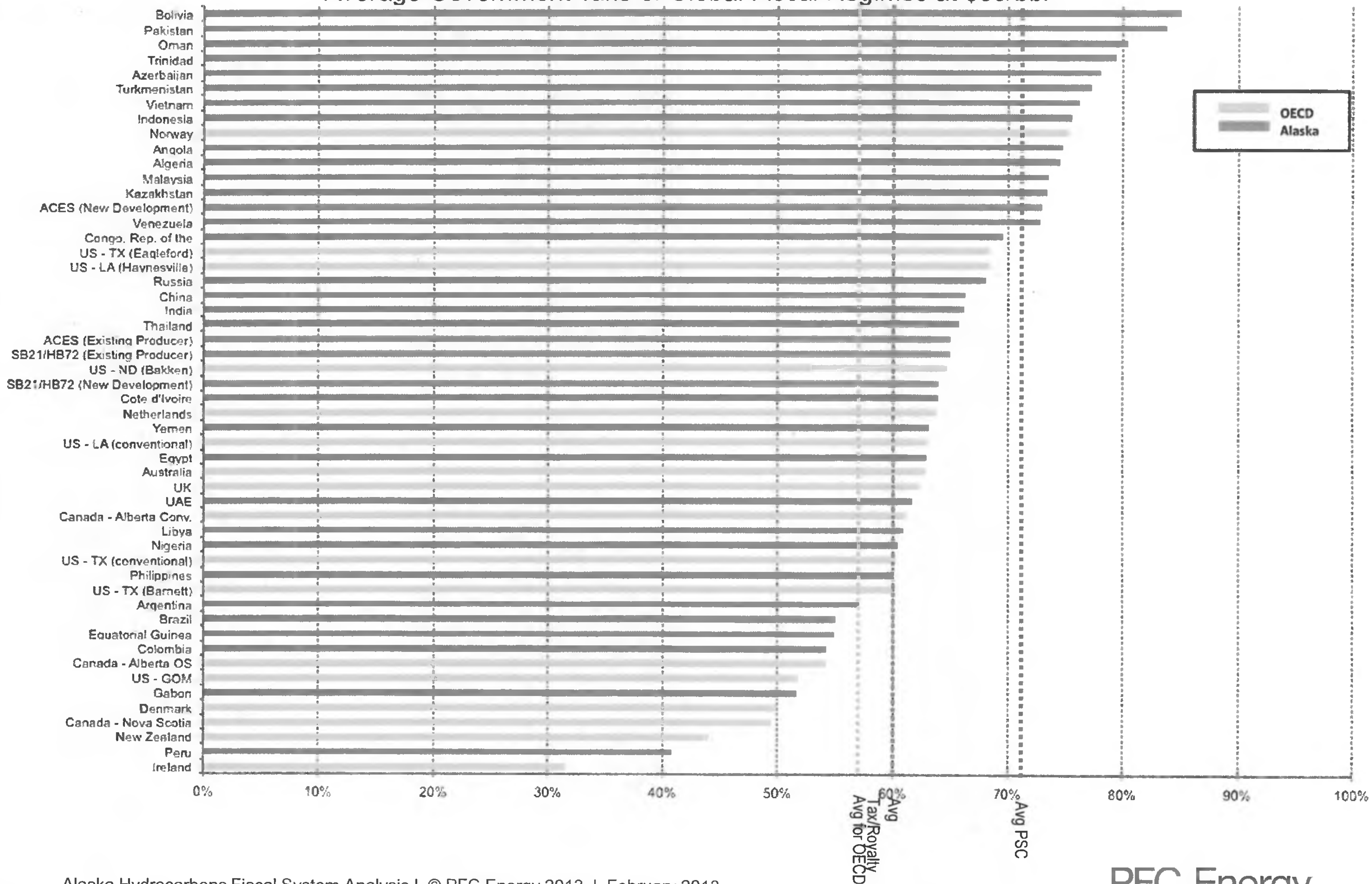
- High levels of Government Take reduce competitiveness for capital, especially at high prices
  - *Reduce, bracket or eliminate progressivity*
  - *Reduce base rate*
- High marginal tax rates reduce incentives for spending control
  - *Reduce, bracket or eliminate progressivity*
  - *Reduce, restrict or eliminate credits*
- Complexity makes meaningful economic analysis and comparison difficult
  - *Simplify overall system design, especially interaction of progressivity with credits*
  - *Improve economics for new development*
- Significant state exposure in low price environments, and for high-cost developments
  - *Reduce or eliminate some or all credits*
  - *Eliminate ability to claim credits from state treasury*
  - *Carry credits forward to production*
- Impact of large-scale gas sales on tax rates
  - *Eliminate progressivity, levy progressivity on gross basis, or use progressive Gross Revenue Exclusion*

ACES: 5 key problems – ***SB21/HB72 Solutions***

- High levels of Government Take reduce competitiveness for capital, especially at high prices
  - *Reduce, bracket or* ***eliminate progressivity***
  - *Reduce base rate*
- High marginal tax rates reduce incentives for spending control
  - *Reduce, bracket or* ***eliminate progressivity***
  - ***Reduce, restrict or eliminate credits***
- Complexity makes meaningful economic analysis and comparison difficult
  - ***Simplify overall system design, especially interaction of progressivity with credits***
  - ***Improve economics for new development***
- Significant state exposure in low price environments, and for high-cost developments
  - ***Reduce or eliminate some or all credits***
  - ***Eliminate ability to claim credits from state treasury***
  - ***Carry credits forward to production***
- Impact of large-scale gas sales on tax rates
  - ***Eliminate progressivity****, levy progressivity on gross basis, or use progressive Gross Revenue Exclusion*

Regime Competitiveness: Average Government Take at $80/bbl

Average Government Take of Global Fiscal Regimes at $80/bbl



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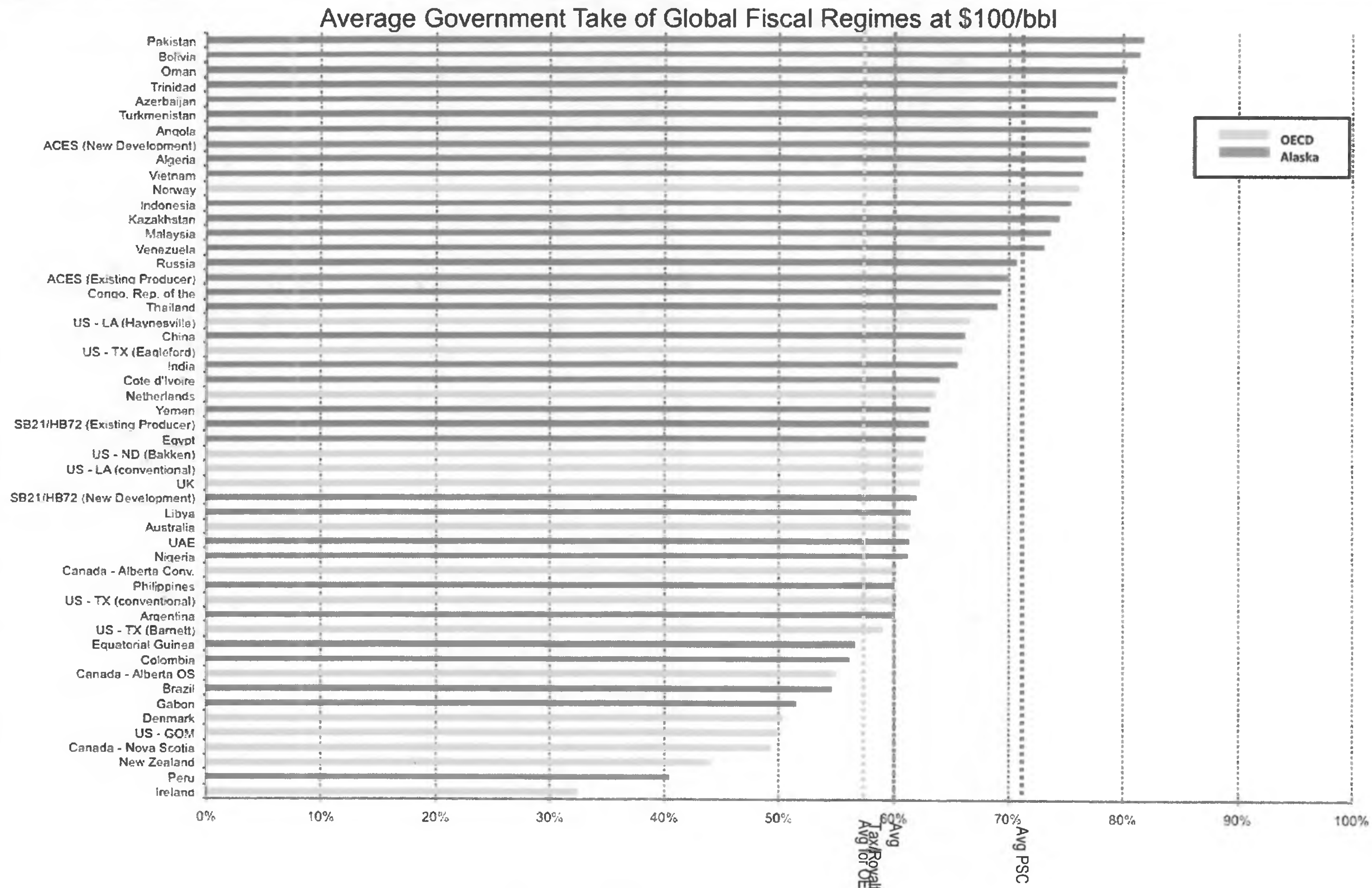
Regime Competitiveness: Average Government Take at $100/bbl



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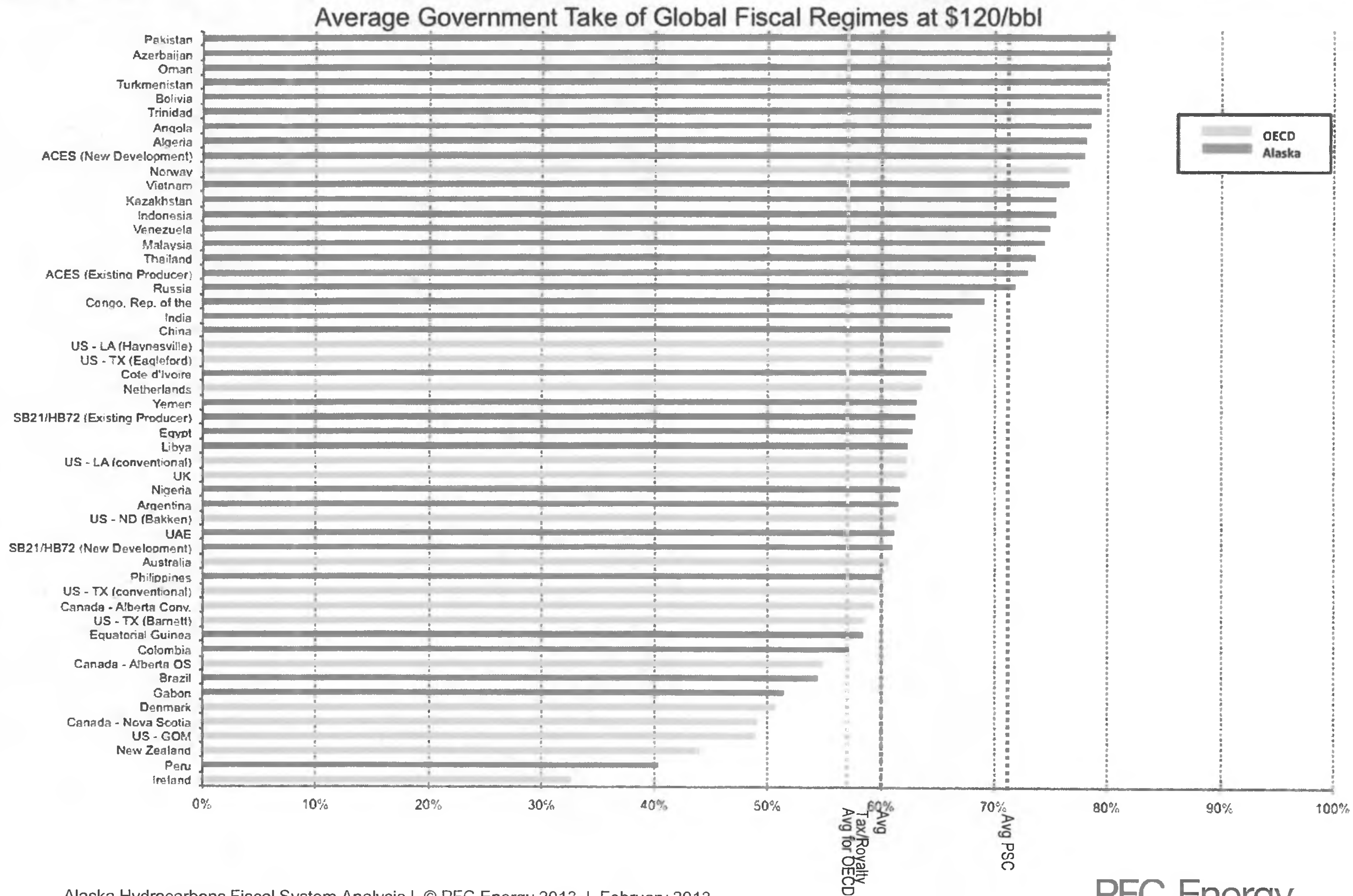
Regime Competitiveness: Average Government Take at $120/bbl



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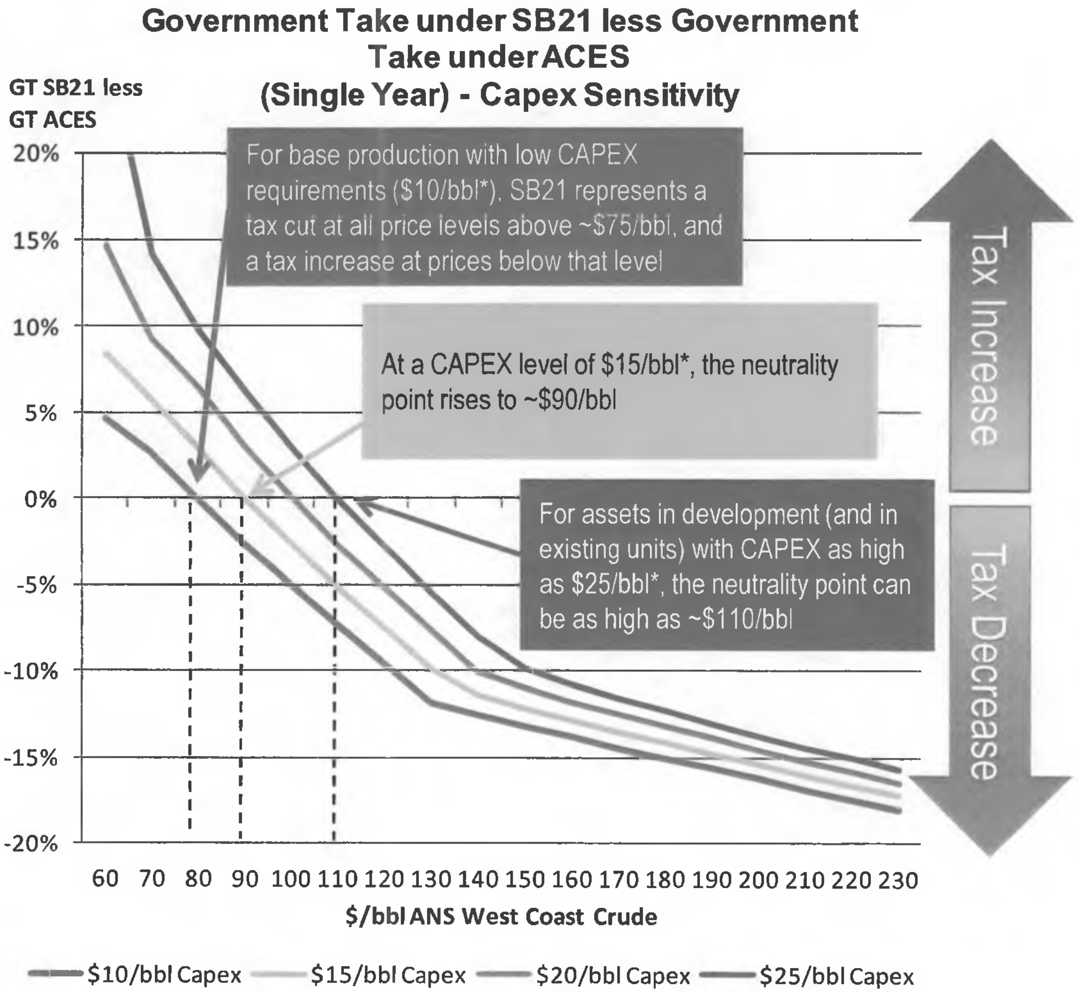
Government Take under SB21/HB72 and ACES – Capex Sensitivity



** All CAPEX figures are in gross bbl terms ($15 per gross bbl is roughly equivalent to DOR 2014 average North Slope forecast of $19.6 per bbl net of royalty, when adjusted for gross/net and for capital expenditures by non-taxable entities)*

- As noted in PFC Energy testimony on 1/31/13, at low oil prices, Relative Government Take under SB 21 is higher than under ACES, due to the impact of low or no progressivity, combined with the elimination of the 20% capital credit under SB 21
- The **oil price level** at which this occurs is highly **sensitive to annual levels of capital spending**, since CAPEX both reduces the oil price level at which progressivity kicks in under ACES, and determines the size of the available capital credit under ACES
- Looking at a **single year of production** also slightly raises this neutrality point, since over many years, inflation reduces the real price level at which progressivity starts under ACES
- For mature, producing assets with a low ongoing CAPEX requirement ($10/bbl), SB21 represents a **reduction in government take at prices above ~$75**, however for capital intensive new developments in existing units, that neutrality **point can be as high as $110/bbl**
- It is thus important to understand that one impact of the removal of the 20% capital credit under SB 21 is that for companies with high development costs relative to overall production, it **can represent a tax increase at current prices**

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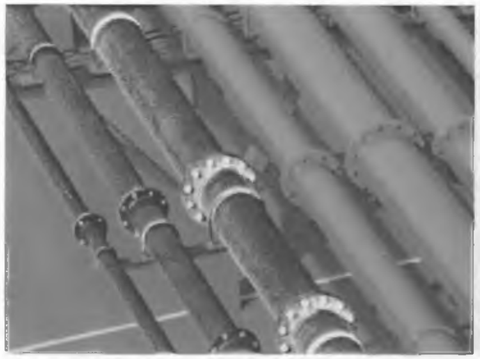

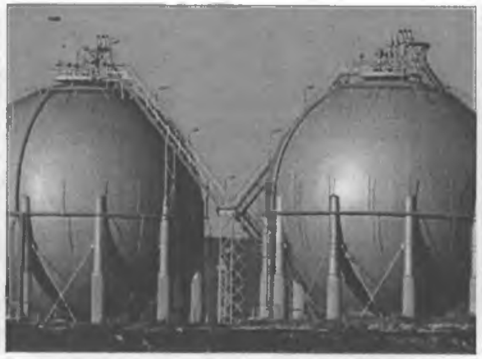

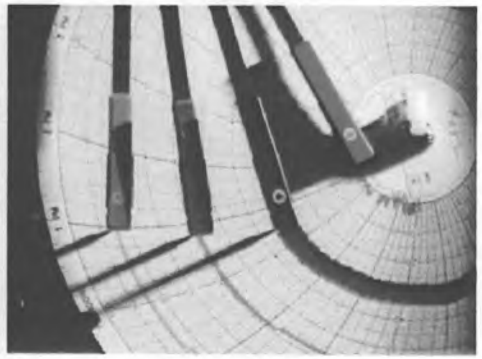

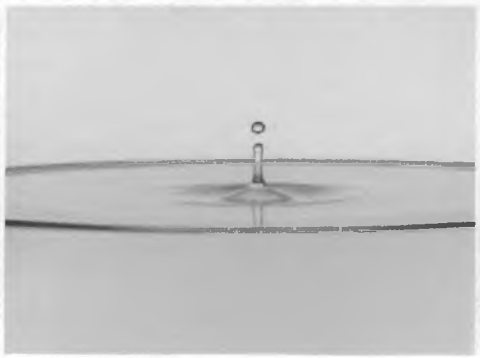

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