

ALASKA LEGISLATIVE COMMITTEE ON GOVERNMENT

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November 1, 2007

As this chart shows, Alaska's oil production from the North Slope could be as low as 150,000 barrels per day within 10 years without ongoing and increasing investment (assuming 15% decline, which is typical for large oil fields such as Prudhoe Bay). Based on this forecast, within 10 years, 75% of production will come from new investments.

Conservatively, we estimate that at least \$30-40 billion of new investment is required within the next 10 years to achieve the Department of Revenue forecast. This does not include the billions of dollars of additional operating expenditures that would be required to support the developments once they are producing. This is a significant level of future investment and spending.

ALASKA'S TWO LARGEST OIL FIELDS

The two largest oil fields in Alaska - Prudhoe Bay and Kuparuk, have been producing since 1977 and 1981, respectively. Today these two fields account for over 70% of the State's North Slope oil production. With continuing exploration and investment activity these fields could remain at this level of production contribution for the next decade.

These fields require continuous investment to keep the oil flowing and the facilities operating at capacity. This is the same for any oil field in the world. During production of the oil there are many changes in operating conditions; including changes in reservoir pressure, oil, gas and water production and facilities utilization. In order to keep the oil flowing, additional investments are required; such as the historical significant investments at Prudhoe Bay resulting in the installation of water and gas injection, and gas compression facilities.

Currently, the owners spend over \$2 billion dollars annually to optimize and enhance production from Prudhoe Bay and Kuparuk. These spending levels are in addition to the capital investments pursuing new wells, projects, and enhanced oil recovery opportunities. These operating expenditures are essential to mitigate production decline at these significant fields. Prudhoe Bay and Kuparuk have the potential to continue to be critical contributors to Alaska's oil production. They also have the potential to remain key hubs and enablers for the pursuit of new heavy or viscous oil, light oil and gas projects.

Many of today's exploration and development activities are occurring in and around

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Prudhoe Bay and Kuparuk. As an example, since the year 2000 there have been multiple Prudhoe Bay satellite fields developed (Aurora, Borealis, Midnight Sun, Polaris, and Orion) which are currently contributing over 40,000 B/D of oil production. These satellite developments would not have been possible without the infrastructure and facility sharing of Prudhoe Bay. By leveraging existing Prudhoe Bay and Kuparuk infrastructure, satellite development costs have been significantly reduced. If the major Prudhoe Bay and Kuparuk developments did not exist these satellite fields would not have been economic to develop. As infrastructure on the North Slope expands the economic viability of future satellite developments increases.

Development drilling in and around Prudhoe Bay and Kuparuk is another example of their critical contribution to Alaska's oil production. For the past seven years over 900 new wells have been drilled in Prudhoe Bay and Kuparuk. The drilling of these new wells has slowed the overall production decline from 12-15% to an estimated 6-9%. Almost 40% of Prudhoe Bay's production today is from these new wells. For the past two years, development drilling at Prudhoe Bay alone has achieved the equivalent development of resources as the important Oooguruk development.

Let me re-emphasize that Prudhoe Bay and Kuparuk have the potential to continue to be critical contributors to Alaska's oil production. They also have the potential to remain key hubs and enablers for the pursuit of new heavy or viscous oil, light oil and gas projects. Encouraging increasing investment at these key fields is as important as encouraging investment in exploration and development of new fields. Without these two hubs, Alaska would be severely challenged to realize the full potential of its resources.

EXXONMOBIL POSITION ON THE ENACTED PPT

I believe it is important that I clarify ExxonMobil's position on the current PPT.

ExxonMobil did not support the PPT that was enacted last year. As we testified last year, we supported the concept of a net based tax but stated that the proposed 20% tax rate, in the original PPT bill, would not encourage the full development of Alaska's resources. We agreed with the 20% tax rate in order to support the progression of a gas pipeline project.

The PPT that was ultimately enacted increased the high 20% base tax rate to 22.5% with progressivity - more than doubling industry's taxation. When combined with the gross royalties and the high cost environment, it reduces the attractiveness of Alaska's resource developments.

There has been a lot of discussion, recently on PPT revenues and forecasts, which has been used in part to support the Administration's proposal to increase taxes. PPT has only been in existence for slightly more than one year. The Department of Revenue has not completed its PPT regulations or started any PPT audit. ExxonMobil, like a number of the other producers, met with the Department of Revenue several months ago to discuss ways to help the State better forecast its expected PPT revenues and we are willing to continue those efforts. We are also willing to work with Department of Revenue auditors and our partners to improve the understanding of joint interest billings.

PROPOSED TAX INCREASE MORE COMPLICATED

I would now like to talk about the Administrations proposed tax increase. In analyzing the Administration's tax proposal, we found that virtually all of the provisions are simply tax increases or further increases in complexity. There are a few areas I would like to highlight as examples:

- 10% gross minimum tax on and ring-fencing of Prudhoe Bay and Kuparuk Fields
- Additional reporting requirements for exploration tax credits
- Elimination of requirement for joint interest billings as starting point for audits
- Information requests

10% gross minimum tax on and ring-fencing of the Prudhoe Bay & Kuparuk Fields:

The Administration is proposing a separate 10% gross minimum tax for Prudhoe Bay and Kuparuk. This gross tax would be in addition to the base royalty payments. With this minimum gross tax the State would be insulated from price and cost risks, whilst retaining the upside potential from the progressivity element.

The Administration is proposing to increase its take while shifting the development risks to the producers. Essentially, at low price, producers are penalized. Progressing a tax policy that singles out and penalizes these fields will discourage investment not only at these fields but will also impact future investment attractiveness to explore and develop other Alaska oil and gas resources.

Companies are willing to accept the risks of long-term, capital intensive investments when there is a corresponding opportunity for upside potential and a sharing of risk

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should prices fall. Under the Administration's proposed tax increase, investors' economic risk increases significantly impacting funding decisions for future investments.

The Administration has also proposed that all revenues and expenses for the Legacy Fields will have to be accounted for separately, with separate taxes paid for each unit and their satellites. This would include Alaska's heavy oil reserves produced from those Legacy Fields - a resource that already has significant economic and technical hurdles to overcome. No other fields, units or regions within the state would be subjected to these higher tax and administrative burdens.

Additional reporting requirements for exploration tax credits:

The Administration is proposing that in order to qualify for an exploration tax credit an explorer has to agree in writing to release proprietary information: such as seismic, survey and core samples.

Providing this type of proprietary information is not the norm throughout North America. Releasing key competitive and high value information would be a concern to any explorer. It often takes decades to progress from exploration to production phase. The release of proprietary and competitive information before an asset is producing is not appropriate so early in the phase of a future development. This would decrease the value of the exploration credit and may discourage an explorer from applying for the credit.

In addition, providing this type of information to the State would increase the amount of investment required of an explorer. Core samples, for example, are very costly.

Providing one-third of the core material to the State would not only add to the costs of exploring, but would be physically challenging and potentially damaging to the integrity of the entire core. Cores can always be made available upon request.

These requirements go against the basic principle that if a party is willing to take risks and collect information they should be entitled to maintain confidential and competitive information.

Elimination of requirement for joint interest billings as starting point for audits:

The Administration is proposing to remove the joint interest billings as the starting point for audits. As a non-operator for Prudhoe Bay, Kuparuk, Duck Island and Granite Point we fail to see how not using this information is to the State's advantage. The amount of a producer's deductible lease expenditures are in accordance with the monthly cost data charged by the field operator to its co-owners. In addition, in a field's joint operating agreement the working interest owners have specified what costs an operator can bill to the co-owners.

Each year the operator is subjected to very detailed audits by the other owners to ensure compliance with the limitations in those agreements. The use of these joint interest billings as the foundation of allowable business expenses would provide greater predictability and eliminate the need for the State to re-audit the same materials. Using joint interest billings will reduce disputes over appropriate deductions as well as the State's and the producers' administrative and audit costs.

Information requests:

The administration is proposing that they require additional information to improve their ability to forecast future revenues for PPT. As mentioned earlier, we met with the Department of Revenue several months ago to discuss ways to help the State better forecast its expected PPT revenues and we are willing to continue those efforts.

We believe that additional information, beyond that currently submitted with our tax filings, needs to be carefully considered. There must be some limitations and reasonableness standards established. For example, in addition to monthly cost and production information, the Department would now require a producer or explorer to file each month "other records and information the department considers necessary. . . ." While recognizing the Department's need for forward looking data we believe the current legislation is too open ended and should be amended to specify the required information. Existing data that is already submitted needs to be considered.

FISCAL PREDICTABILITY IS IMPORTANT

I would now like to address another important element of the business environment for any investor - fiscal predictability. ExxonMobil, and I believe the industry, values a predictable fiscal environment in which to make long term investment decisions. Our investments are capital intensive and typically evaluated over timeframes of decades. A change in the fiscal regime has a direct impact on how we view predictability of the Alaska fiscal environment. This directly impacts how we evaluate on a risked basis future investment decisions.

The Administration's proposed tax increase would represent the third significant change to Alaska's fiscal terms in the past three years. Changing the fiscal environment for capital intensive projects, that take many years to generate a return, can only reduce the attractiveness of future investments. Each time taxes are raised, the attractiveness of any prospective well or project diminishes and the likelihood of it not being funded increases. For every well or project not progressed, additional production and State revenues are forgone.

ExxonMobil expects to be involved in Alaska for many years to come. The policies established today, and in the future, will impact the attractiveness of potential projects and the future of Alaska.

ALASKA NEEDS A LONG-TERM RESOURCE DEVELOPMENT POLICY

As I mentioned earlier, Alaska has significant resource potential, but is in a high cost environment. It will take significant resources, technology, investment and teamwork to realize the full potential. Alaska and industry collaboratively need to create a resource development policy that encourages investment for long-term production and growth. This is a complex issue and needs significant time and effort from all parties. It is beneficial to look at what others have done.

The Canadian province of Alberta has enormous unconventional crude oil resources. Alberta's oil sands represent the potential of over 170 billion barrels of crude, and, like Alaska's resources, are located in higher cost, remote arctic regions that require significant investments to develop.

Alberta adopted a resource development policy approach, designed to increase industry investment and production. Their approach has proven successful due to a number of key factors:

- Collaborative pursuit of resource development objectives
- Development of technologies jointly with industry to reduce costs, increase oil recovery, and upgrade viscous oil to marketable products
- Creation of a level playing field for all projects
- Sharing risks with the investors by maintaining a lower gross revenue based tax, that is, lowering royalties significantly
- Providing long term fiscal predictability

Alberta's success suggests that Alaska should review what other regions are doing to encourage investment.

ExxonMobil believes a long-term sustainable resource development policy is required to enable Alaska to maximize its oil and gas resource. We believe there are many factors that need to be considered. I hope that key points addressed in my testimony are considered:

- Alaska has significant resource potential, but it is in a high cost environment
- Oil production is one third of its peak, yet we have only produced one fourth of the oil resource potential. The gas resource potential is equal to oil.
- In 10 years, 75% of Alaska's future oil production needs over \$30-40 billion of new investments - investments that are needed sooner than 10 years.
- Prudhoe Bay and Kuparuk are the "hub" of the North Slope, they
 - Represent 70% of North Slope oil production for the next 10+ years
 - Can provide significant new production in the near term
 - Can be the backbone for future exploration and economic developments, whether it is existing production, future light oil, heavy oil, or gas
 - Need increasing investments to achieve their potential

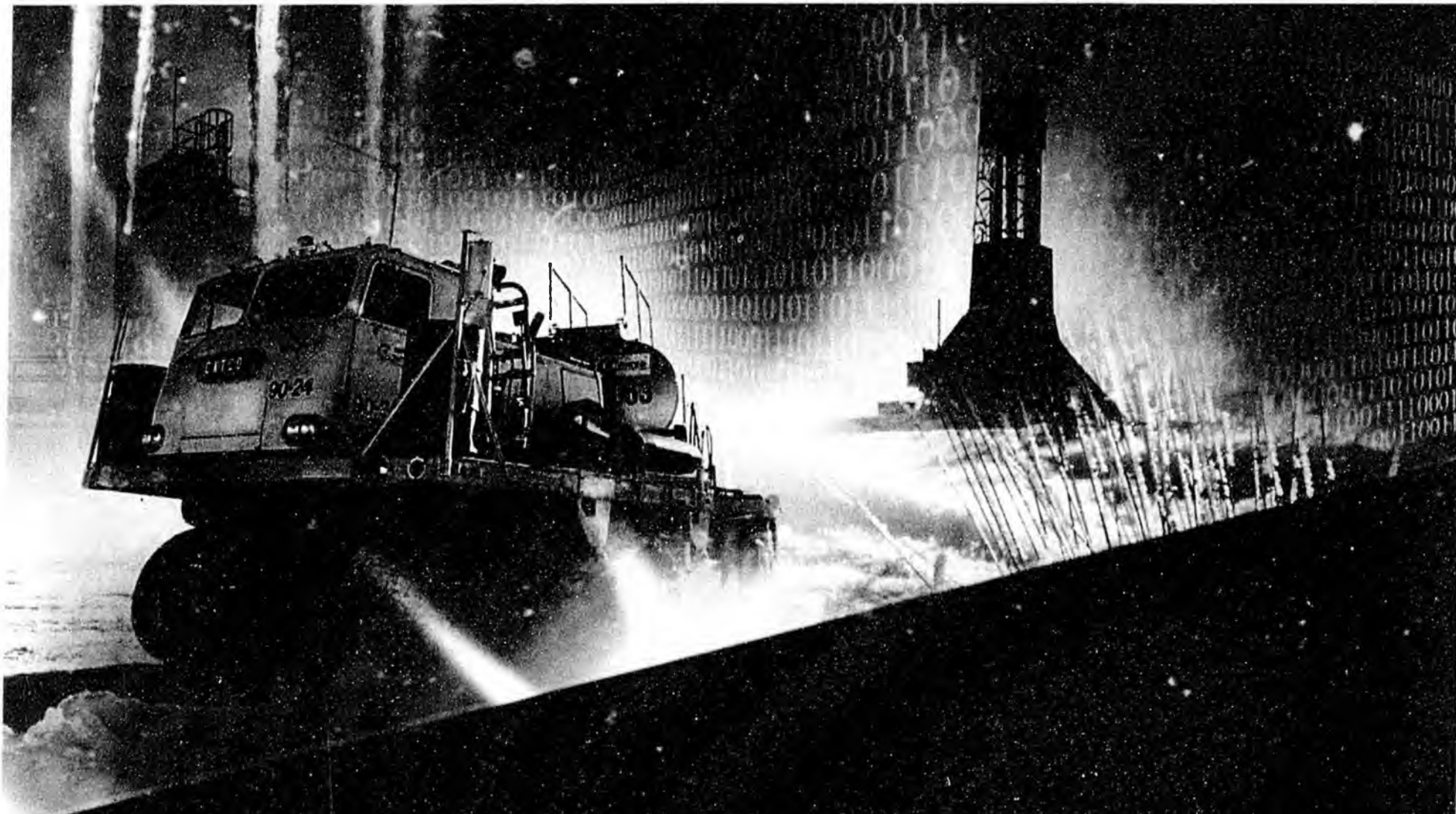
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We propose a collaborative approach to develop a sustainable long term resource policy that will encourage the needed increasing investments and build the future of Alaska for many generations to come. We believe that a long term resource policy should consider:

- Characterization of state-wide resource potential
- Identification of key issues challenging exploration and development
- Key factors that impact resource value, such as research and technology, exploration and development costs, regulatory and environmental considerations, land access
- Establishment of goals and measurement of progress
- Fiscal policy that will encourage development of remaining resources
- Regular meetings with industry and agency representatives

ExxonMobil looks forward to working with the Administration, the legislators, industry and the people of Alaska in the future pursuit and development of its oil and gas resources.

Thank you again Mister Chairman for the opportunity to testify today.



Anadarko 
Petroleum Corporation

ACES

House Resources
CS HB 2001 (O&G)
November 1, 2007

APC Operational Overview

Rockies

- Large acreage holdings

International

- World class targets
- Focused exploration

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ANADARKO HQ
Houston, Texas

Gulf of Mexico Deepwater

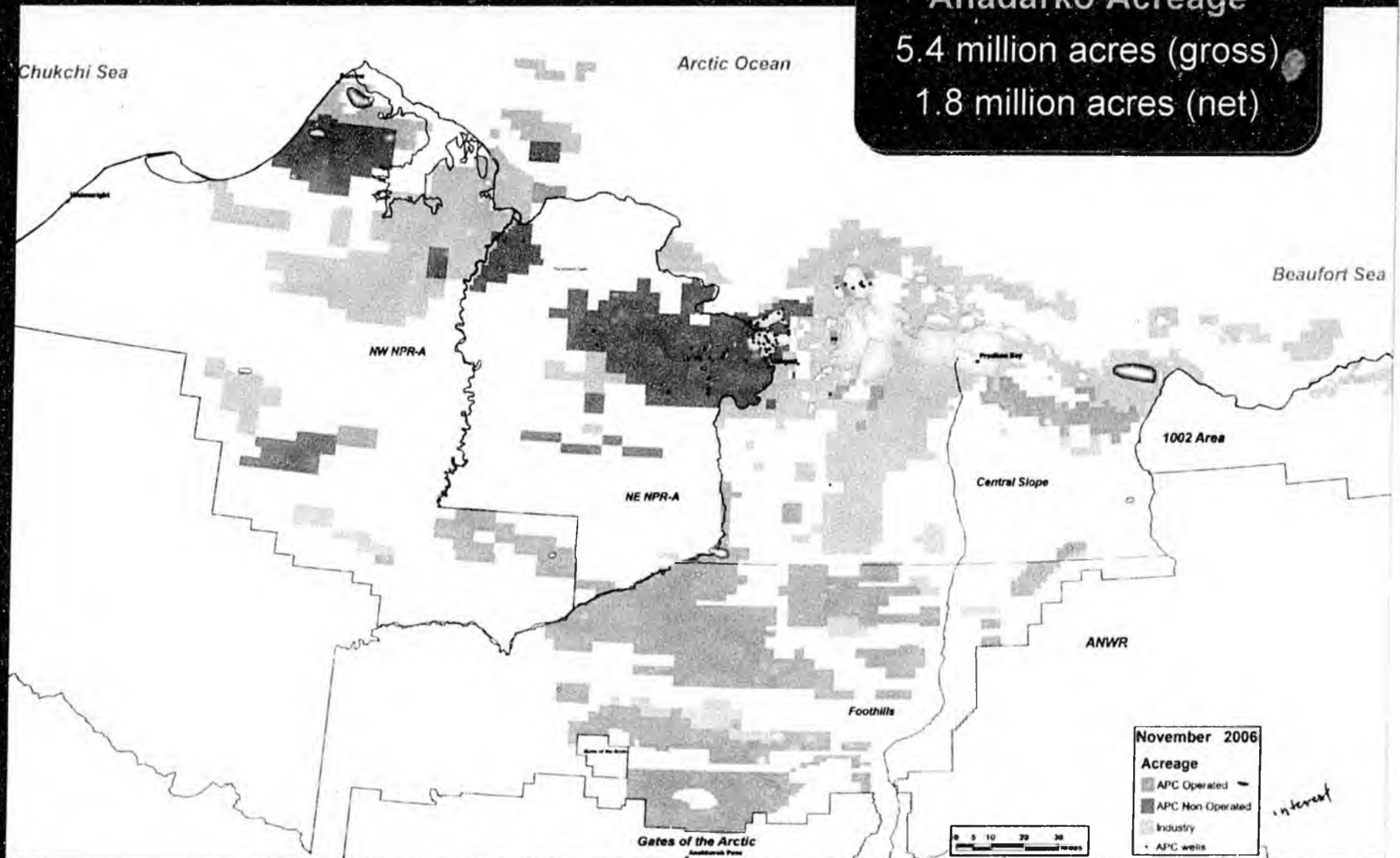
- Significant Acreage position

○ Exploration Areas
□ Producing Areas

Anadarko's Investment in Alaska-Land

Anadarko Acreage
5.4 million acres (gross)
1.8 million acres (net)

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Alaska Opportunities

- ▶ **World class petroleum basin**
- ▶ **Significant remaining resource potential**
- ▶ **Legacy type prospectivity (i.e. Anchor Fields)**
- ▶ **New entrants/partnering opportunities**
- ▶ **APC possesses tangible competitive advantages**

Alaska Challenges

- ▶ **Maturing basin/materiality/smaller prospects**
- ▶ **High costs**
- ▶ **Lack of infrastructure and competition**
- ▶ **Extremely long lead-time exploration**
- ▶ **Seasonal drilling & regulatory timing requirements**
- ▶ **Distance from market**
- ▶ **Lack of gas transportation**

Our View of PPT & Recap of 2006 Testimony

Significant tax increase at existing fields

- *Can be offset by increased exploration & development investment*

Improvement in exploration economics versus elf system encourages new investment

- *Credits help reduce high costs & improve NPV*
- *25 – 20 worse than old elf system*

On balance supportive of PPT system

Support Net Profits Approach

Appreciate Administration work to evaluate gross vs. net and conclusion to stick with net

Net considers varying economics & costs

- *Tax paid on net income after costs*
- *Accounts for costs and levels playing field*
- *Still doesn't account for risk*

Gross collects on income regardless of profit

- *Gross tax with proper incentives harder to develop equitably and still complicated to administer*

▶ Royalty acts like a gross tax

Gross versus Net Taxes Example

	<u>Field A</u>		<u>Field B</u>	
Price per barrel \$	60		60	
Cost per barrel \$	<u>10</u>		<u>20</u>	
Net Income per barrel \$	50		40	
15% Gross Tax (\$60 X 15%)	9	+	9	= \$ 18 Total Taxes
Tax Rate on Net Income	18%		22.5%	
20% Net Tax	10	+	8	= \$ 18 Total Taxes
Tax Rate on Net Income	20%		20%	

A N A D A R K O

Our View of ACES- Negatives Outweigh Positives

Support some parts of ACES

- *Expand time to qualify for Exploration Incentive Credits (offset by new exclusions and requirements)*
- *Modify Net Loss carry forward to create level playing field*
- *Goal of increased transparency & state auditor capability*

Stability

- *Concern that PPT/ACES will be revisited again in next few years to deal with gas*
 - *Gas definitely needs to be addressed, but will reopen everything again*

The significant tax increases would decrease exploration & development economics and far outweigh any positives in the bill

- *Tax rate increase*
- *Tax escalator changes increase costs*
- *Transition Investment Expenditure Credits Elimination*
 - *Fairness and Investment Impact*

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Administration Field Economics Estimates

Table below from Sept 4, 2007 Administration Presentation

Project Net Present Value of Cash Flows (10% Discount Rate)

\$40 Test Price (\$ Millions)

	Status Quo PPT	ACES Plan	16% Gross Tax <i>No Capital Credits</i>	19% Gross Tax <i>With Capital Credits</i>
Field/Project A	178	128	-35	27
Field/Project B	72	48	-22	9
Field/Project C	59	27	-53	-22
Field/Project D	-64	-90	-398	-282
<hr/>				
<i>Production Tax Revenues</i>				
<i>FY2008 @ \$60 oil price</i>	\$1.3B	\$2.0B	\$2.1B	\$2.0B

- Project Economics decrease by 33% to 54%
- What geologic & commercial risks were assigned?
- Where are dry holes & failed projects accounted for?

Comments on CS HB 2001 (O&G)

- Prefer progressive tax applied to net income
- Support maintaining Transition Investment Expenditure credits
- Support base tax rate in O & G version

A N A D A R K O



PIONEER

Pioneer's View

House Resources Committee
November 1, 2007

NYSE: PXD
www.pxd.com



Presentation Outline



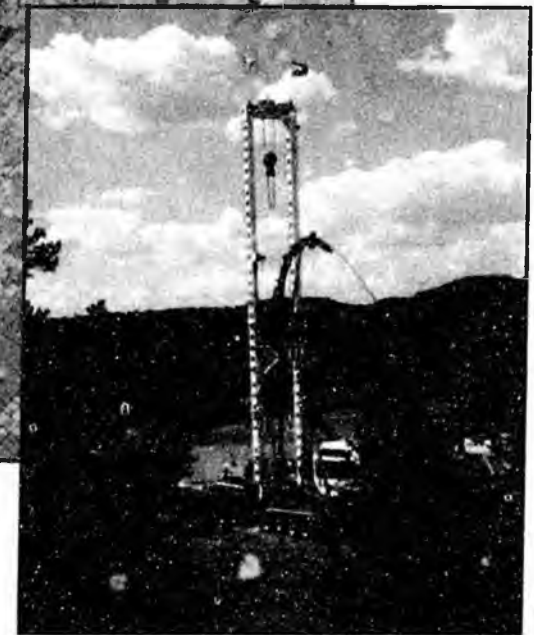
- Pioneer Profile
- Pioneer Projects & SOA Impact
- SOA “Fair Share” of Oooguruk
- Benefits of Current PPT Law
- House Oil & Gas CS
- Conclusions



Pioneer Corporate Profile



- Large U.S. independent
- Operation Areas:
 - Alaska
 - Lower 48
 - South Africa
 - Tunisia
- In 2006 Pioneer:
 - 1,600 employees
 - 36 mmboe production
 - \$1.6 billion in revenue



Pioneer Alaska Profile



PIONEER

Cosmopolitan

- Entered Alaska in late 2002
- Oooguruk Unit Operator
- Cosmopolitan Unit Operator
- ~1.5 million acre leasehold
- 11 NS exploration wells
- 35 local Alaska staff



Oooguruk Project Summary



Future Operating Statistics

Field Life Cycle	Development
Project Type	Oil, EOR
Gross Acres	58,000
Working Interest	70% (Operator)
Partner	ENI (30%)
Gross Reserve Potential	70 - 90 MMBO
First Production	2008
Gross Peak Flow Rates	15 - 20 MBOPD
Productive Life	25+ Years
Development Wells	~40



Ooguruk Project Summary



PIONEER

- Project sanction Feb 2006
- Constructed island drill site
- Fab/set ~120 modules
- Installed subsea flowline
- 3 year development drilling
- 600+ contractors at peak
- Total capex \$550+ MM
- First oil in 2008



Oooguruk Project Benefits



- First independent oil producer on the North Slope
- First third party facility access
- Other investors are watching for Pioneer success
- Royalty plus 30% net profits to SOA
- PPT revenues on Pioneer profits and KRU processing
- State income tax
- Property taxes to NSB
- Construction jobs and contractor profits
- Operating jobs and contractor profits



Government Take @ High Cost, High Burden @\$70



PIONEER

	Low Cost	High Cost	High Cost, Net Profit
Gross Revenue	\$100	\$100	\$100
Royalty	- \$12.50	- \$12.50	-\$12.50
Net Revenue	\$87.50	\$87.50	\$87.50
Cost Deductions	- \$20.00	-\$50.00	-\$50.00
Property Tax -3%	-\$2.50	-\$3.50	-\$3.50
Net Profit Share			-\$10.20
Taxable Income	\$65.00	\$34.00	\$23.80
PPT @ 28%	-\$17.00	-\$6.50	-\$3.70
State Income Tax	-\$4.50	-\$2.60	-\$1.90
Fed. Income Tax	-\$15.20	-\$8.70	-\$6.40
Net Income AFIT	\$28.30	\$16.20	\$11.90
Contractor Take	35%	32%	24%
Government Take	65%	68%	76%

Net Good

80%

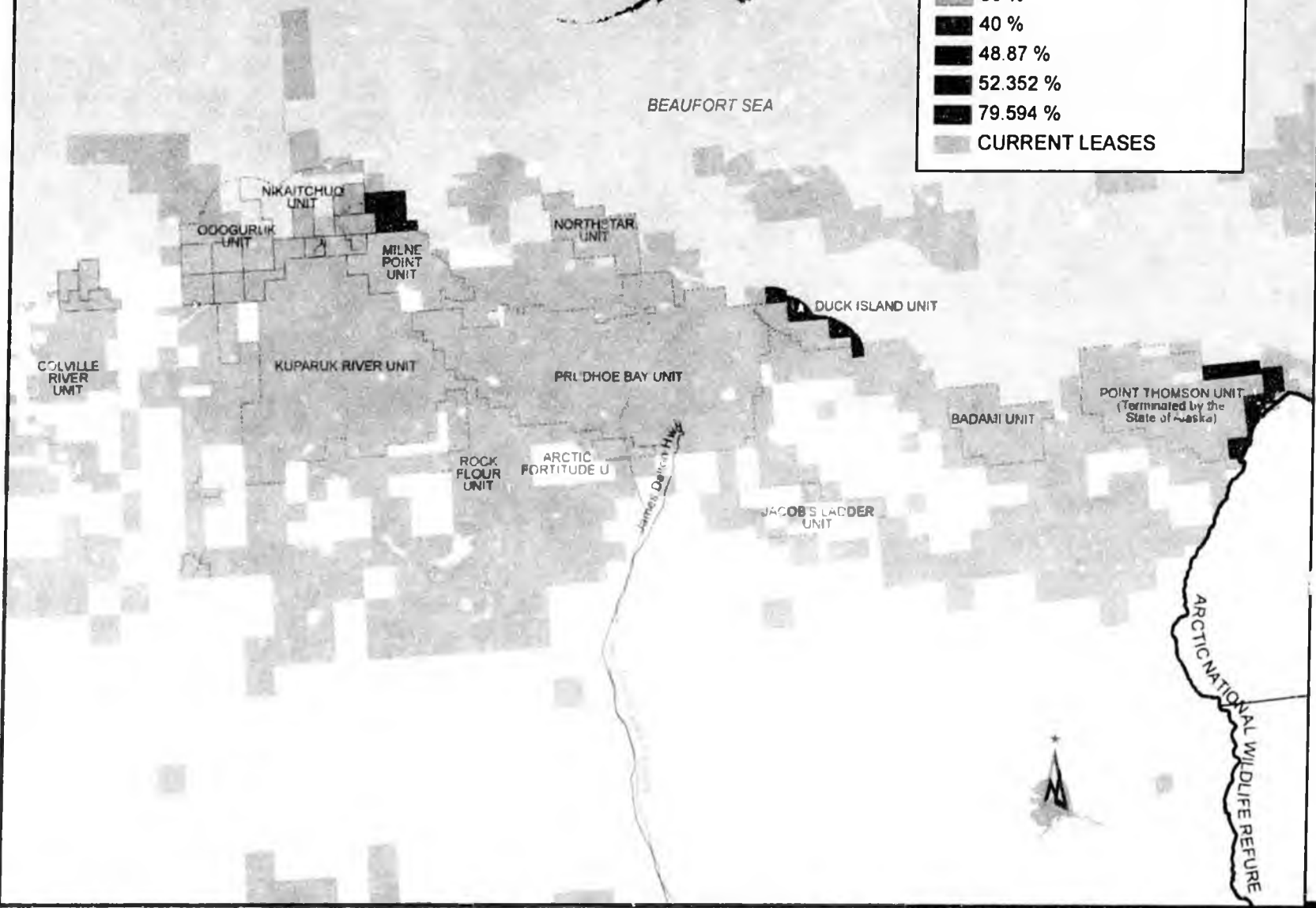
North Slope Net Profit Leases by NPS %



CURRENT NET PROFIT LEASES ARCTIC SLOPE & BEAUFORT SEA, ALASKA.



NET PROFIT ROYALTY LEASES	
[Light Gray Box]	30 %
[Medium Gray Box]	40 %
[Dark Gray Box]	48.87 %
[Black Box]	52.352 %
[Dark Gray Box]	79.594 %
[Light Gray Box]	CURRENT LEASES










North Slope Net Profit Leases by Owner

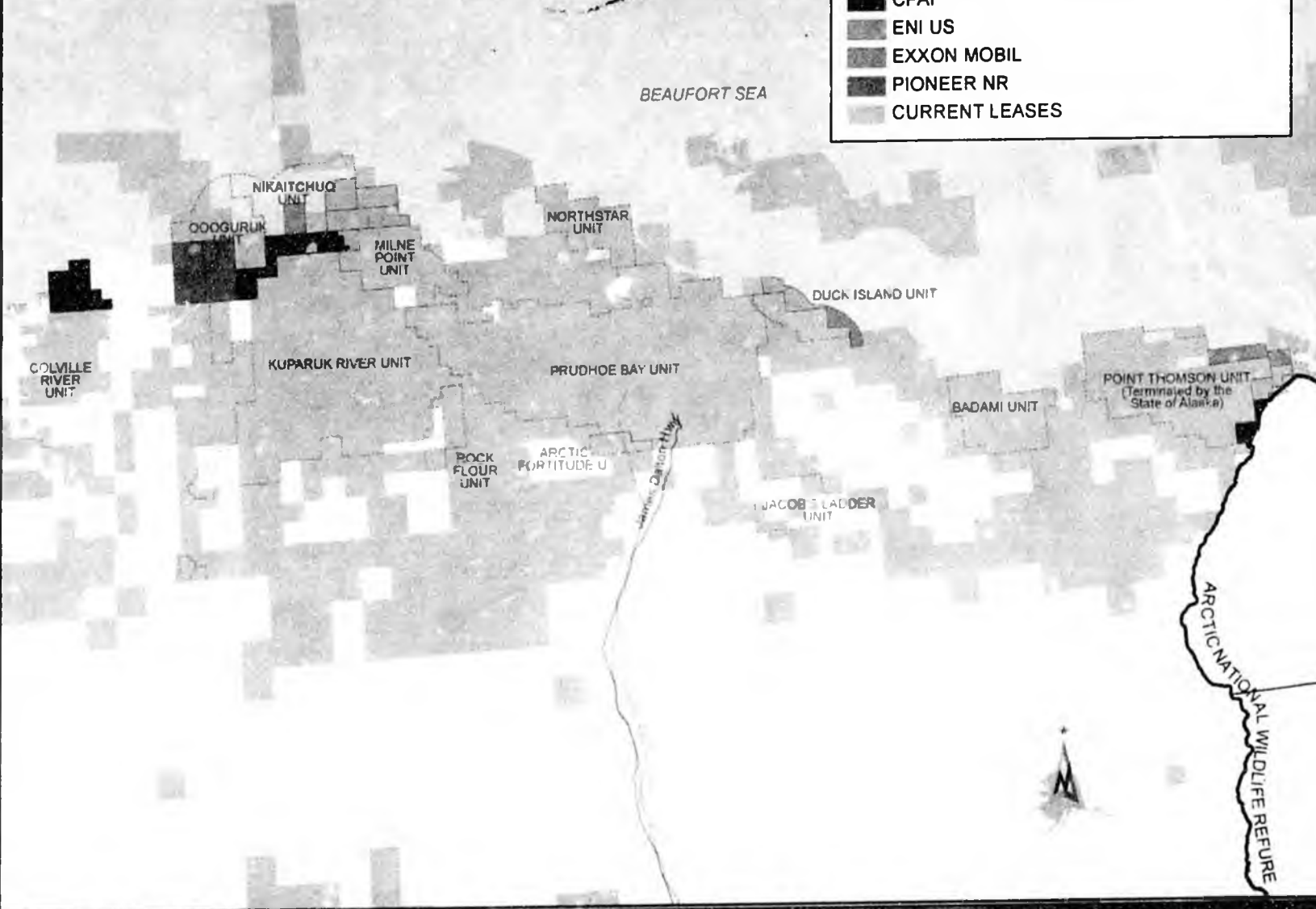


CURRENT NET PROFIT LEASES ARCTIC SLOPE & BEAUFORT SEA, ALASKA



CURRENT NET PROFIT LEASES BY OPERATOR

-  BPXA
-  CHEVRON
-  CPAI
-  ENI US
-  EXXON MOBIL
-  PIONEER NR
-  CURRENT LEASES



Pioneer's View of PPT



- **Huge Pioneer investments & Oooguruk sanction pre-PPT**
- **Balanced system - Investment credits offset high tax rate**
- **Modest incentive for investment**
 - Encourages development of abundant lower tier resources
 - Challenged by size, quality, viscosity or location
- **Sustainable and fair across a broad range of investments**
- **PPT should grow the pie and give the State a bigger slice**

Transitional Investment Expense Credits



- **TIE Credits designed to mitigate tax increase impact**
 - Fairness Issue
 - Recognition that project investment decisions were made under previous fiscal systems (ELF)
- **\$100 MM Capital Investment by Pioneer prior to PPT**
 - Earns \$20MM in credits
- **\$30 MM Spent 1Q 2003 on Oooguruk Project**
 - House CS eliminates the associated credits

Progressivity Considerations



- **A Net tax:**
 - Places a higher burden upon high profit fields
 - Rewards investment

- **A Gross Tax:**
 - Treats aggressive investors and harvesters the same
 - Disproportionately burdens marginal projects
 - Artificially truncates economic field life

Conclusions and Final Comments



- Pioneer has been an aggressive investor to date
- Fiscal stability needed to attract future Pioneer capital
- PPT provides balance/stability to grow our AK Business
- House O&G plan erodes modest PPT incentives
- Raising taxes jeopardizes lower tier project funding
 - Royalty, state income/property tax and jobs at risk
- House O&G TIE Credit effective date eliminates 1/3 of Pioneer's capital investment that led to Oonguruk
- Progressivity based on Gross disproportionately harms marginal investment opportunities
- High cost, high burden fields can least afford tax increase

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TESTIMONY OF THE
ALASKA OIL AND GAS ASSOCIATION
TO THE HOUSE RESOURCES COMMITTEE
ON ISSUES FOR HOUSE BILL 2001(O&G)

November 1, 2007

Mr. Chairman and Members of the Committee. Thank you for the opportunity to testify before you today on the Committee Substitute for House Bill 2001(O&G).

My name is Marilyn Crockett and I am the Executive Director of the Alaska Oil and Gas Association ("AOGA"). AOGA is the trade association for the oil and gas industry in Alaska. Our 17 members account for the majority of oil and gas exploration, development, production, transportation, refining and marketing activities in the state. In addition to Alaska's in-state refiners, Agrium and Alyeska Pipeline, our membership includes companies new to Alaska hoping for the opportunity to explore, companies which are exploring today but do not yet have production (but hope to in the future) and those companies which are producing today.

One of the important functions the Association performs is to provide a forum for member companies to consider regulatory and legislative proposals, and to reach agreement on an industry position on those proposals. To establish an AOGA position, a 5/6 vote of the members is required. What this means, of course, is that when AOGA voices that position, regulators and legislators can be assured that that position is the position of the overwhelming majority of Alaska's oil and gas industry.

But on tax issues, AOGA's Tax Committee has taken this approval process to the highest level. AOGA positions on tax-related issues require 100% consensus of the Committee, with no dissent. This is true for my testimony today.

With me today is the Chair of the AOGA Tax Committee, Tom Williams. He is a tax attorney here in Alaska for BP. However, for anyone who may not know his background, in 1975 - 79 Tom was the director of the division in the Department of Revenue ("DOR") known today as the Tax Division, and during Governor Hammond's second term from 1979 - 82 he was Commissioner of Revenue. In these roles he was the architect or co-architect of many aspects of Alaska's oil and gas revenues that are still in place today, from the methodology for determining "gross value at the point of production," to the methodology for determining shareable net profits under state net-profit share leases. Tom wrote the regulations that successfully implemented the State's former separate-accounting tax, as well as statutory language in the State's present income tax on oil companies enacted in 1981 to replace separate-accounting. He supervised the

first property-tax valuation of the trans-Alaska oil pipeline after it came into production, and he administered the State's temporary two-year reserves tax in 1976 and '77. He was the last Commissioner of Revenue to administer the state personal income tax, and the first to send out Permanent Fund Dividend checks to Alaskans. He was also on the original Board of Trustees of the Permanent Fund. Most notoriously, Tom became the "father of the ELF" in December 1976. He was Vice President & General Counsel for Cook Inlet Region Inc., or "CIRI", for almost four years before joining BP in 1987.

The focus of our testimony today will be on the practical impact of declining production levels on industry operations and the State of Alaska. And while we are not in a position today to provide you with a complete analysis of the many components of CSHB 2001(O&G), we will describe for you but a few of the troubling aspects of this legislation.

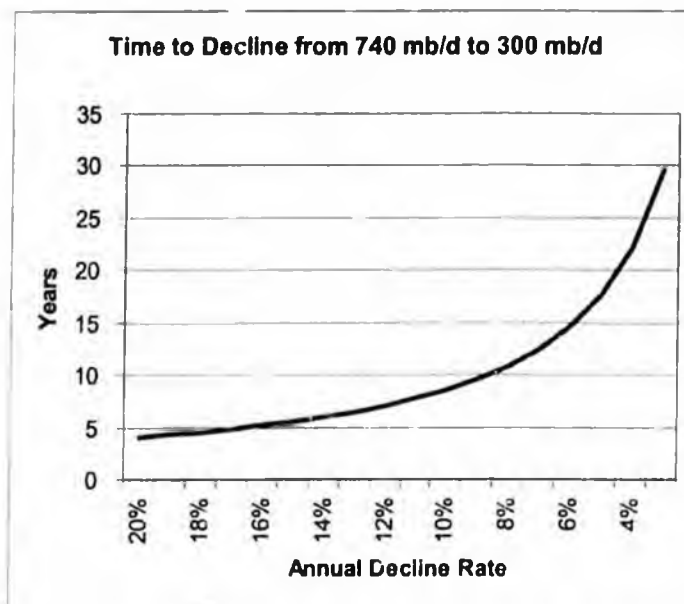
Last year the Legislature passed the Petroleum Production Tax, or PPT. Now, less than a year later, the Administration is telling you that the PPT is broken. They say it's too complicated to forecast, it isn't bringing in the revenue that was forecast last year, and they don't have enough capable auditors to enforce it.

In discussing the merits of CSHB 2001(O&G) versus PPT and the Administration's concerns, we must always keep in mind the real-world situation that Alaska faces. The greatest challenge that confronts this generation of Alaskans and the next is the ongoing decline of oil production, which has been, is today, and promises to remain the cornerstone of the finances of state government.

Production decline is eroding this cornerstone. It is a historical fact that even with the massive investments being made, North Slope production declined an average of 6.2% a year from FY 1997 to FY 2007, and Cook Inlet oil production declined at 8.0% a year.¹ Without those investments, decline would have been 15%.

With respect to the future of the North Slope, there is going to be a major challenge when ANS production gets down to about 300,000 barrels a day. According to Alyeska Pipeline Service Company, which operates the trans-Alaska oil pipeline (TAPS), the minimum mechanical capacity of the new electronic pumps that are being installed is about 300,000 barrels a day.

Here is a graph showing how long we have before ANS production reaches this 300,000 barrel-a-day mechanical threshold, depending on what the rate of decline is. If decline continues



at the historical rate of 6%, ANS will decline to 300,000 barrels a day in about 15 years, or FY 2022. On the other hand, if decline can be held to 3% or less as DOR assumes, then we would have 30 years or so before we hit the mechanical threshold.

Let me stress that this graph is not a prediction. It merely plots the results of the mathematical calculations² of how long it would take to get to 300,000 barrels a day from the level of 740,000 barrels a day in FY 2007, depending on what decline rate you choose. What it does show is how important the rate of production decline is for Alaska's future. The difference between a 6% decline rate and 3% doesn't sound like much, but as you can see from the graph, that difference determines whether the 300,000 threshold is reached around FY 2022 or FY 2037.

Investment in new production is the only way to slow the decline enough to give the children of this state a future with the North Slope similar to what we have enjoyed. There are three categories of investment that can slow the rate of decline on the North Slope, or at least keep it from getting any worse. These are, first, investment in exploration to discover new fields; second, investment in existing fields to prevent their decline from accelerating; and third, investment in innovation, technology, and new infrastructure to allow development of the vast but challenging resource of heavy and viscous oil that has already been discovered.

A great deal of the testimony to the Legislature, and a lot of the questions being asked, have focused on the fiscal terms of the "government take" for exploring in Alaska and the competitiveness of these terms relative to the terms in regimes elsewhere in the world. This kind of "who takes more" analysis is faulty for two fundamental reasons.

First, it assumes that the geologic prospects for making a commercial discovery in Alaska are comparable to those other regimes. This assumption is unsound. The North Slope has three major areas of significant oil and gas potential: the state lands in the central North Slope between the Colville and Canning rivers, the federal land in the National Petroleum Reserve – Alaska to the west of the state lands, and the coastal plain of ANWR to the east of the state lands. The exploration potential of the state lands is limited today primarily to the discovery of new satellite fields, as opposed to fields large enough to stand on their own economically. Exploration is still active in NPR-A and by no means over, but the courts have recently blocked federal leasing of the geologically promising lands around Teshekpuk Lake. And even if the Ninth Circuit decides to let that leasing go forward, the pro-leasing Bush Administration has less than 14 months left in office in which to hold the lease sale. Elsewhere in NPR-A, the relinquishment earlier this fall of some 300,000 acres of lands reflects disappointing results from leaseholder exploration efforts there. As for ANWR, despite Republican majorities in both houses of Congress and a pro-development president in the White House, the coastal plain is still closed.

And this brings me to the second reason why it is unwise to focus too much on investment in exploration as the solution to production decline. Exploration is a risky business, and there is no assurance that spending money to test a particular prospect will ever yield a dime of payback. Even when exploration succeeds in discovering a commercially viable field, it will take years from the time of its discovery until the time production from it begins. But the challenge of declining production confronts Alaska today — not eight, ten or a dozen years from now. By its nature, investing in exploration can make a significant contribution toward solving the challenge of declining production in the longer term, but not the shorter term when results are urgently needed.

Investment in heavy and viscous oil development is also a solution in the mid to long term. The first well ever drilled to test production from the Ugnu Formation was only drilled earlier this year in the Milne Point Unit, and it is still being tested and evaluated to gain a better understanding of the physical characteristics of the Ugnu oil. There are plans to use the results of these tests and evaluations to plan and develop a pilot project for producing Ugnu oil. Until then, West Sak will continue to be the only commercial heavy/viscous opportunity.

This gets us to investment in currently producing fields. Fortunately, there are investments that can be made, and are being made, in these fields to slow their decline. In the short term, this is in-fill drilling — that is, drilling new wells into the portions of a reservoir that are between the wells that have already been drilled. This accelerates the drainage of oil from the rock that currently lies in between existing wells. In-fill drilling last year contributed some 70,000 barrels a day to production from the Prudhoe Bay field. To put this into perspective, a 70,000 barrel per day field would be the 4th largest stand-alone field on the North Slope today.

There are also major investments being made, and yet to be made, in “renewal” of the surface facilities for existing fields. For instance, the gathering centers and flow stations for the

Prudhoe Bay field have been in service for over 30 years now. For them the situation is not all that different from what yours would be if you bought a minivan van years ago when your children were young, and now that the kids are all grown up and it's just you and your spouse who are driving it, it's time to replace that minivan with a new vehicle that suits your needs better. If Prudhoe Bay and the other producing fields are to continue producing in the decades to come, their original production facilities will need to be overhauled or replaced. Also, as increasing amounts of heavy and viscous oil come into production, even relatively new facilities that were designed for comparatively light "conventional" oil will probably need to be modified, refitted or replaced in order to minimize operating problems in handling that heavy/viscous oil. Regardless of the stimulus or purpose for making them, renewal investments in production infrastructure present a very similar cash-flow pattern as there is for investments in the original infrastructure to develop a field. And consequently, an incentive that is effective for the initial development infrastructure is equally effective for renewal as well.

So, this is the harsh reality in which we — government, industry, the present generation of Alaskans, and the next one — find ourselves. For all of us, decline is the great challenge that we must grapple with. It already threatens us now, and if unaddressed, will only get worse. Massive new investments for additional oil production are the only way to deal with this menace.

Turning now to the relative merits of CSHB 2001(O&G) versus PPT, AOGA submits there are several self-evident principles of taxation that should be used to test those merits. First, a tax must be "fit for purpose" — that is, it must do the things it is intended to do, and it should do them well. Second, the administration and enforcement of a tax should be as efficient as possible, consistent with ensuring compliance by taxpayers. Third, for a taxpayer who wants to calculate and pay the correct amount of tax when it comes due, it must be possible to do so.

Regarding the first test — achieving what the tax is supposed to achieve — most new taxes have as their primary or only purpose the new revenues that they will bring in for the government. In the case of PPT, however, things were not so simple. In part its purpose certainly was revenue-related, because most legislators viewed the prior ELF-based production tax as outdated and unduly generous to producers in terms of the reduction in tax rate that the ELF caused. But, as Pedro van Meurs explained repeatedly in his testimony last year and again at the beginning of this special session, the PPT was also designed to provide incentives for investing in production and in that way answering the threat of declining production.

With respect to the revenue side, no one disputes that PPT has brought the State more tax revenue since April last year than ELF would have. According to DOR, the increase was more than \$800 million in the last nine months of 2006,³ and at that rate it would have been over a billion dollars in additional production tax revenue for a full year. DOR also said at the time that the March 31st payments were about \$137 million less than the \$950 million that it had estimated, and in due course I'll come back to the questions of forecasting the PPT and higher-than-forecasted lease expenditures. For now, my point is that PPT has certainly outperformed the old ELF tax, which is just what it is supposed to do.

As a consequence of the fact that field costs are higher than DOR predicted last year, this Administration criticizes PPT for failing to generate all the tax revenues that the fiscal note for HIB 3001 predicted. It has even been suggested that Alaskans were somehow promised that PPT would generate \$800 million more this year than is now being projected, and that it is therefore necessary to raise the tax rate in order to make good on that promise.

That whole line of reasoning is flawed. First of all, DOR is complaining that they can't forecast PPT accurately because it has so many variables that affect the results. However, if they can't forecast it accurately, then why should so much reliance be placed on its current forecast that shows the prior forecast was off by \$800 million? If the first forecast was poor, what has changed to make this latest one so good?

As I explained just a while ago, the purpose of PPT was more than just the tax revenues it would generate. It was to create incentives for attracting the massive new investments that will be needed in order to meet the threat posed by declining production. The system of tax credits under PPT provides significant incentives for investing in capital assets to explore for, develop, and produce more oil and gas.

- Current capital expenditures generate a 20% tax credit in addition to being immediately deductible as lease expenditures. For the kinds of economic analysis that reflect the time-value of money, these front-end benefits have the greatest possible positive effects on the results of the analysis.
- The incentive to invest sooner rather than later is materially increased by the fact that the "transitional investment expenditure" or "TIE" credit for pre-PPT capital investments can only be taken to the extent those prior expenditures are matched two for one by new capital expenditures, and taxpayers have only until the end of 2013 to use up their "TIE" credits.⁴
- The tax credit for a carried-forward annual loss particularly benefits explorers and those who are bringing new fields into production for the first time in Alaska and don't have production yet that they can deduct their costs against.
- The "section 024(c) credit" of up to \$12 million a year for producers with less than 100,000 barrels a day of production is an incentive for independents and other smaller players to come to Alaska for oil and gas.
- The \$6 million annual credit under AS 43.55.024(c) is an incentive for exploration and development in the areas of Alaska outside the North Slope and Cook Inlet basin.

Have these incentives under PPT worked? The preliminary results so far say yes. DOR's August 3rd report on PPT states that capital investments for FY 2008 are 80% greater than previously estimated, despite the fact that operating expenditures are up by 101% over the prior projections.⁵ Of course, it will take time before companies can fully respond to these incentives, and it will take even more time to tell whether the new investments to increase oil production succeed in actually getting more production. But so far things appear to be moving in the right

direction.

Now, moving on to CSHB 2001(O&G), how well does it stack up under the standard of being fit for purpose? Certainly, it would generate even more tax revenue than the bill will, at least in the short term. But it is premised on the totally mistaken notion that increasing what the government takes from the economic "pie" will encourage greater investment, or at least not decrease it from what it would be anyway. No one has ever taxed economic growth and development into existence. CSHB 2001(O&G) will not do so, either.

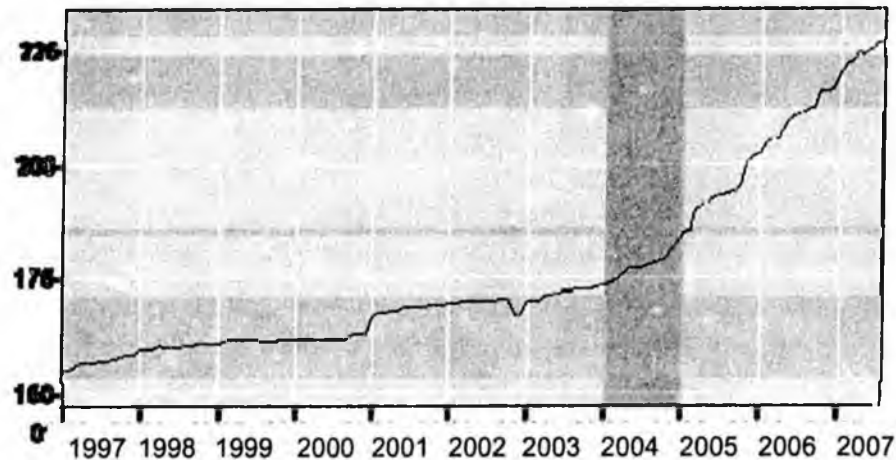
The second standard for evaluating CSHB 2001(O&G) versus PPT is that the administration and enforcement of the tax must be as efficient as possible, consistent with ensuring compliance by taxpayers. Here, the two chief objections to PPT have been, first, that it is all but impossible to forecast the revenues from it with the accuracy needed for state budget purposes, and second, that the audit challenges of PPT leave DOR's auditors hopelessly outgunned.⁶ So the questions that need to be answered are, how much merit do these criticisms have, and how would CSHB 2001(O&G) address these concerns?

Regarding forecasts for PPT, DOR cites two major concerns about the forecasts. One is that, "[w]hile costs would be expected to increase, the dramatic difference between what was predicted [in the prior Administration's fiscal note for HB 3001] and what has actually been experienced brings into question whether the legislature made its decisions based upon appropriate information."⁷ The other is that DOR needs cost information about current and planned spending from the operators, producers and explorers, and this allegedly has not been forthcoming from them.

Let us consider this "dramatic difference" between the projected expenditures behind the fiscal note last year, and what those expenditures have actually been. When the DOR staff in the prior Administration sought information about expenditures, they chose not to rely on the representations about 2006 costs that individual companies gave the Legislature in public testimony at that time.⁸ Instead, they looked at what they believed to be more reliable information contained in the most recent partnership tax returns that had been filed with the IRS for fields on the North Slope.

Federal partnership returns are not due to be filed with the IRS until October of the following year, so even as late as August 2006 when the Legislature passed HB 3001, the most recent returns available were those for 2004. Here is a chart showing the Producer Price Index

Oil and Gas Field Machinery and Equipment PPI
Source: U.S. Department of Labor



for oil and gas field machinery and equipment during the last decade. The highlighted bar in the graph marks 2004, and you can see right away why a fiscal note based on the most recently filed federal tax returns, for 2004, would be way off the mark in predicting what the field costs would be in 2006 and '07.

There was nothing sinister about what that Administration did. The companies said the 2006 costs were high, but the latest tax returns at that time indicated the costs were significantly less, with a fairly lengthy track record of gradual increases. DOR went with the reported information on the tax returns. I suspect the DOR staff in the present Administration would do the same in those circumstances. In any event, this is not a reason for casting PPT aside.

The other criticism that DOR makes of PPT is that producers and other taxpayers are not providing DOR with the information it needs in order to be able to forecast PPT revenues with sufficient accuracy. Obviously, AOGA is not privy to what these taxpayers are reporting to DOR as they make their monthly installment payments and their annual true-up payment on March 31st.

DOR's second chief objection to the administrability and enforceability of PPT is that the audit challenges of PPT leave its auditors hopelessly outgunned. It is not for us to comment about the proposal to put auditors in the "exempt" service.

But there is a dimension to PPT audits, however, that we can and should address. This has to do with what the source or starting point for determining how much a producer's deductible lease expenditures are. The PPT statutes currently allow DOR a choice between starting from the joint-interest billings and invoices that operators bill to the other participants in

an oil and gas field or venture,⁹ or starting from a comprehensive set of accounting rules and principles that DOR writes up.¹⁰ Which choice DOR chooses will determine nothing less than the very success or failure of PPT as a tax — and for CSHB 2001(O&G) as well, if it is enacted. It is like having a tax based on your federal taxable income, and choosing between your federal tax return (as audited by IRS) as the starting point, or starting with the Internal Revenue Code and leaving it up to you and DOR's auditors alike to find what the right answer is under the Code. It is like having a tax based on your financial book income, and choosing between your audited financial statements filed with the SEC as the starting point, or starting with Generally Accepted Accounting Principles and leaving it up to you and DOR's auditors alike to find what the right answer is under GAAP.

From the taxpayer's perspective, this means a near certainty of continual assessments year after year for additional tax, interest, and perhaps penalties, and depending on how litigious a company may feel, it may mean a long series of lawsuits and appeals as well.

From the State's perspective, these same troubles for the taxpayer will mean that the incentives for investment under PPT, or CSHB 2001(O&G), will be seriously eroded. The greater the uncertainty about how much tax a company owes, the greater the likelihood that the incentives will turn out be less than their face value. A taxpayer's only recourse in this situation will be to discount the face-value of those incentives significantly, perhaps completely, in running the economic analysis about making an investment or not. As a consequence, the effectiveness of those incentives will be less than it should be, and Alaska will fail to realize the full amount of new production that it needs to meet the challenge of decline.

The other choice that DOR could make is to start with what an operator bills to the other participants in an oil and gas operation. Note that I said "start" with those billings — not "end." Anything in those billings that is nondeductible under AS 43.55.165(e) would have to be backed out. The central concept of lease expenditures in AS 43.55.165(a) is that they must be "direct" and "ordinary and necessary" costs of exploration, development, or production. It would be most surprising if there are anything in those billings that goes outside this standard.

How can Alaska be sure of this? Because the participants in an oil and gas operation do not give the operator a license to waste their money. I have heard a great deal of concern expressed during these hearings about how the companies might somehow try to "game the system" in order to reduce the tax they will pay the State. While so many are so worried about efforts by the companies not to overpay the State, why would most of these same people think the companies are somehow more willing to overpay the operator than the State? Clearly they don't want to overpay either one. If anything, since the operator usually is a direct competitor they probably don't want to overpay it even more than they don't want to overpay the State. In other words, if an operator is exploring a geologic prospect, the non-operating participants don't want to pay any costs that are not for the exploration of that prospect. Similarly, if the operator is operating a producing field, they don't want to pay any costs that aren't for the operation of that field. It is reasonable to rely, in the first instance, on the non-operators' self-interests to

police and limit what the operator can spend their money on, and they will do that policing by auditing the operator's invoices to them.

In the context of PPT, DOR should "audit the audits" to verify that the non-operators do indeed audit an operator's invoices on a regular basis, and that those audits are rigorous and at arm's length. But once these things have been confirmed by DOR in its verification of the non-operators' audits, there is little point for DOR to spend the time and effort to re-plow the field that the companies' audits have already plowed.

Daniel Johnston, a consultant hired during last year's debate on PPT, gave an informal presentation to members of the Legislature on Friday, Oct. 19, 2007. During that meeting, he praised the expertise of joint interest auditors and the ability for the state to utilize unit accounting. He went on to say that it would be "extremely insightful for the state to get unit accounting". Mr. Johnston observed that state auditors can be "vicious", but that joint interest auditors are "even more vicious".

Of course, for operations where there is only one participant or where there are no audits of the operator's invoices, this approach will be inapplicable. But there are still things DOR could do to build off the billing systems where there are such audits and extend them to these other fields. However, DOR has not yet adopted the "Phase II" regulations to implement and apply its existing statutory authority to authorize or require taxpayers to follow this approach.

Unfortunately, Section 37 of CSHB 2001(O&G) would repeal DOR's explicit statutory authority under AS 43.55.165(c) and (d) to require or authorize the use of operators' joint-interest billings as the starting point for computing the amount of a producer's deductible lease expenditures for that unit or field. We believe that this repeal will mean DOR cannot authorize or require a producer to start with an operator's joint-interest billings, even when DOR wants to allow or require their use. Since these repeals are in the proposed legislation that has been introduced, we expect that DOR, in response to us, will testify that somehow they will still be able to require or authorize the use operator billings even if these present statutory provisions are repealed. However, if you enact a law specifically saying DOR may do something and later on you repeal that law, doesn't that repeal mean DOR can't do it anymore? We think so. But even if you are persuaded by DOR that we're wrong on this point, why should you repeal those statutes and take the chance that the courts won't agree?

The reason I've spent so much time about the use of joint-interest billings as the starting point for determining a producer's lease expenditures is this: Consider the situation that a non-operating participant faces. All the information it has about what's being spent for the operation is what it gets from its billings from the operator, plus whatever it may learn by auditing those invoices. But if such a non-operator cannot start from those invoices, how can it figure out what to report as the lease expenditures for that operation? All the books and records of the expenditures are with the operator, and if the non-operator hasn't yet audited the operator, it will have no idea what those books and records show. It is infeasible for a non-operator to be

auditing the operator month by month, yet the non-operator will somehow have to be reporting and paying installments month by month throughout the year. Even by the March 31 true-up the following year, it is unlikely that any audit of the operator's books and records will have been begun by that date, much less completed. The penalty for mis-estimating the installment payments is principally in the difference between the rate of interest on overpaid installments and underpaid ones. But the March 31 true-up is very serious business. Interest at an APR not less than 11% compounded quarterly begins to accrue, and penalties of up to 30% for negligence and failure-to-pay¹¹ can be assessed, on the amount of any underpayment continuing after that true-up date. If a non-operator cannot rely on its billings from the operator as the starting point for these purposes, what is it supposed to use?¹²

If, as we fear, the repeals of AS 43.55.165(c) and (d) under the proposed bill will indeed take away DOR's discretion to allow or require the use of operators' joint-interest billings, then CSHB 2001(O&G) will completely fail the third standard by which a tax is measured — that it must be possible for a taxpayer to get the tax right when it is due, when the taxpayer wants to do so. This will be impossible for non-operators under the proposed legislation. Even PPT will fail if the "Phase II" regulations do not reasonably implement DOR's present authority under AS 43.55.165(c) and (d) regarding the use of operator billings.

This issue has been addressed by us and the Administration during hearings in previous committees over the past week or so. The Administration has stated that it is their intent to allow joint interest billings to be one of the tools they will utilize, and I would encourage this committee to reconfirm that intent with the Administration during your deliberations. In any event, if these are to be utilized, then there is no reason to repeal the specific authorization to do so. Section 37 should be eliminated from the bill.

We have prepared a white paper that describes in detail the issues related to the repeal of this important discretion and have attached it to our testimony for your further reference.

Before closing today we'd like to briefly discuss progressivity. Progressivity is a feature in the present production tax. It is levied under subsection (g) of AS 43.55.011, and is a separate tax from the basic PPT tax levied by subsection (e) of that statute. It is also in addition to the basic PPT tax. Like the basic PPT tax, the present progressivity tax is based on the "net value" of production. But, unlike the basic tax, progressivity is computed monthly instead of on an annual basis. The tax rate for progressivity is zero when the "net value" per BTU equivalent barrel is \$40 or less, and it rises linearly at a 0.25 percentage points per dollar that the "net value" per BTU equivalent barrel rises above \$40, up to a maximum rate of 25 percent. The 0.25 figure which sets the rate at which the tax rate rises is known as the "slope."

I should repeat that what I've just described is progressivity under the present law, not the Committee Substitute that is before you. Frankly, we are not entirely sure how progressivity under the CS is supposed to work.

The rationale for progressivity boils down to little more than "at these prices, the oil industry can afford to pay us more." If "affording to pay" is to be the rationale for setting taxes, then who was arguing, not even nine years ago, to give industry a break when the spot price for a barrel of ANS on the West Coast — after spending some \$4.26 a barrel for transportation to get it there — crashed to \$8.16 on December 23, 1998? No one.

It is this asymmetry that makes progressivity so objectionable to the industry. We have put up all the capital and taken all the risk in making that investment. Periods of high oil prices are not only an opportunity for industry to catch up after periods of low prices, but they are also the opportunity to make up for expensive investments that proved to be unsuccessful.

Take bonus bids for oil and gas leases as an example. The industry paid \$1.013 billion in bonus bids for the Mukluk prospect in the Beaufort Sea in 1982, and then spent another \$135.6 million to put in a gravel island and drill an exploration well — it was a dry hole. Even in the State's great \$900 million lease sale in 1969, over \$525 million of those bonuses was paid for acreage that turned out to be outside the main Prudhoe Bay field. And the acreage that was in the field represented less than 2% of its oil and just over a quarter of a percent of its gas.

AOGA opposed the inclusion of progressivity in the PPT legislation that passed last year, and we do not like it any more now.

In conclusion, CSHB 2001(O&G) fails two of the three standards for evaluating a tax, while PPT passes two of them and would pass the third one as well if DOR adopts the appropriate regulations. CSHB 2001(O&G) in the short term will generate more tax revenue for the State than PPT; however, it will achieve this at the cost of reducing the incentives for new investments, and worsening the overall tax climate for making them here. CSHB 2001(O&G) fails the test of being administrable as efficiently as possible, consistent with ensuring taxpayer compliance. This failure will primarily be due to repealing DOR's existing statutory discretion to allow, as appropriate, joint-interest partners do the auditing of the operator's billings to them. Instead DOR auditors could have to re-invent the wheel for themselves in each audit. CSHB 2001(O&G) also fails the test that a taxpayer who wants to pay the correct amount of tax when it comes due must be able to do so. This will be impossible for every company that owns an interest in a lease or property that it does not operate. This in turn will effectively destroy the value of the remaining tax incentives under this bill that potential investors will perceive. If they cannot tell what they owe, they surely cannot put a reliable figure to the value of the incentives under the tax.

All of this brings us back to the fundamental issue facing Alaska today...the decline of Alaska production. Today Alaska's production has fallen from its peak of 2.1 million barrels a day down to the 700,000 range. This means that the trans Alaska pipeline is 2/3 empty. I would remind you of my chart earlier that showed the purely mathematical results about how long we have before hitting the 300,000 barrel-a-day TAPS mechanical threshold, depending on what rate of decline you assume will turn out to come true.

And it's important to remember that today's 6% decline rate would be on the order of 15-16% were it not for the substantial investments which continue to be made by operators in existing fields. Further, Alaska is fortunate to have on the nearby horizon Pioneer's Oooguruk project, scheduled to go into production in 2008.

The importance of future investment is further emphasized when one looks at the Department of Revenue's forecast of future production levels. In three short years, DOR projects that production will come from projects requiring significant new investment. Draw that timeline out to 2017—ten years from now—and you discover that half of Alaska's production will come from new production—production which will only come from investments yet to be made.

The most important policy question is whether CSHB 2001(O&G) provides a framework for encouraging this additional new investment. Committee Substitute for House Bill 2001(O&G) does not accomplish that goal.

Thank you for the opportunity to testify today.

ENDNOTES

¹ When production declines at $X\%$ a year, this means the production rate after one year (P_1) is $(1 - X\%)$ of the initial production rate (P_0), or $P_1 = P_0 \times (1 - X\%)$. After the second year the production rate (P_2) is $(1 - X\%)$ of the rate after one year of production, or $P_2 = P_1 \times (1 - X\%) = [P_0 \times (1 - X\%)] \times (1 - X\%)$, which can be simplified as $P_2 = P_0 \times (1 - X\%)^2$. After 10 years of decline, the rate P_{10} is $P_0 \times (1 - X\%)^{10}$. North Slope production was 1,404 million barrels a day in FY 1997 and 740 thousand barrels a day in FY 2007, while Cook Inlet produced 37 thousand barrels a day in '97 and 16 thousand barrels a day in '07. See DOR, *Revenue Sources Book Spring 2007*, pp. 97-98. So for North Slope production,

$$1,404,000 \times (1 - X\%)^{10} = 740,000.$$

Dividing both sides of this equation by 1,404,000 gives:

$$(1 - X\%)^{10} = 740,000/1,404,000 = 0.5271.$$

One can solve for $(1 - X\%)$ by taking the 10th root of both sides of this latter equation:

$$\sqrt[10]{(1 - X\%)^{10}} = \sqrt[10]{0.5271}, \text{ or}$$
$$(1 - X\%) = 0.9380.$$

In other words, on average the production rate each year was 93.80% of the rate for the prior year, which means the rate of decline averaged 6.20% a year. The same calculation for Cook Inlet, using 37,000 and 16,000 barrels a day instead of 1,404,000 and 740,000 respectively, yields an average annual decline rate of 8.0 percent.

² Here is the math: From the analysis in Endnote 1 above, we know that for a given decline rate R , the volume of production after N years of decline is $P \times (1 - R)^N$. So for each decline rate in the table, you use that as the value of R in the formula, and then you solve for X as the value of N that gives 300,000 barrels a day as the rate. The equation for this is:

$$740,000 \times (1 - R)^X = 300,000.$$

When you take the logarithm of both sides of this equation, you get the following equation:

$$\log[740,000 \times (1 - R)^X] = \log[300,000].$$

The reason for using logarithms is that they have the property that the logarithm of two numbers being multiplied together equals the sum of the logarithms for each of them, while the logarithm of a number raised to an exponent X equals X times the logarithm of that number. Using this gives the following restatement of the prior equation:

$$\log[740,000] + X \times \log[(1 - R)] = \log[300,000].$$

Subtracting $\log[740,000]$ from both sides of the last equation yields the following:

$$X \times \log[(1 - R)] = \log[300,000] - \log[740,000].$$

Now you can solve for X by dividing both sides of the last equation by $\log[(1 - R)]$, which yields:

$$X = \frac{\log[300,000] - \log[740,000]}{\log[(1 - R)]}.$$

By plugging the decline rate of your choice into this last equation as the value of R , the value of X can be calculated by simple arithmetic. This straightforward calculation has been done for each of the decline rates shown in the graph.

³ DOR Press Release, "New Production Tax Nets Increased Revenues For Alaska" (April 3, 2007).

⁴ For producers who begin producing in Alaska on or after April 1, 2006, they have six years from the year of that first production in which to use up their "TIE" credits. The rule still applies during those six years that it takes \$2 of new capital investment in order to get a credit for \$1 of the "TIE" investment from the years before their production begins.

⁵ See DOR, *Petroleum Profits [sic] Tax (PPT) Implementation Status Report* (August 3, 2007), p. 3.

⁶ See DOR, *Petroleum Profits [sic] Tax (PPT) Implementation Status Report* (August 3, 2007): "The Department has been severely hampered in its ability to provide the administration and the legislature with accurate revenue forecasts" *Id.*, p. 4. "The complexity of auditing production tax has increased several fold under the PPT, and the PPT increased the number of determinations an auditor must make." *Id.*, p. 5.

⁷ *Id.*, p. 5.

⁸ See, e.g., Alaska State Legislature, House Finance Committee, *Minutes* (March 29, 2006), p. 15:

Representative Holm ... asked about the rate of return at \$60 per barrel. Mr. [Angus] Walker [Commercial Vice President of BP Exploration (Alaska) Inc.] said BP is excited about current prices. BP does not make a profit until oil is above \$22.50 a barrel.

At a \$22.50 West Coast price, BP's implicit upstream field expenditures were about \$11.95 a barrel, as opposed to the \$7.27 per barrel in the fiscal note for HB 3001.

\$22.50	ANS price on West Coast
1.76	Marine transportation to West Coast
4.38	TAPS
0.67	North Slope pipelines, quality bank, etc.
\$15.69	Average North Slope wellhead value
1.96	State royalty (1/8)
\$13.73	Taxable value
1.09	Production tax (15% base rate × ELF of 0.529)
0.69	Property tax (\$/bbl average)
\$11.95	Implicit expenditures/bbl.

SOURCE: DOR, *Revenue Sources Book Fall 2006*, p. 33 Fig. 4-6 (average ANS ELF); p. 39 Fig. 4-9 (marine, TAPS, and Slope pipelines/quality bank); p. 40 Fig 4-11 (ANS production); p. 42 Fig. 4-12 (property tax; \$60 million for tax on TAPS is deducted from total for North Slope Borough, Fairbanks, Valdez and Unorganized Borough). All data are for FY 2006.

⁹ The authority for DOR to take this approach is in AS 43.55.165(c) and (d). Subsection (c) states in pertinent part: "if the department finds that the pertinent provisions of a unit operating agreement or similar operating agreement are substantially consistent with the department's ... standards under (a) of this section concerning whether costs are lease expenditures, the department may authorize or require a producer ... to treat as ... lease expenditures ... the costs, other than items listed in (e) of this section, that are incurred by the operator ... and ... billable to the producer by the operator in accordance with the terms of the [operating] agreement[.]" Subsection (d) has very similar language.

¹⁰ The authority for DOR to take this approach is in AS 43.55.165(a), which states in pertinent part: "In determining whether costs are lease expenditures, the department shall consider among other factors, (1) the typical industry practices and standards in the state that determine the costs, other than items listed in (e) of this section, that an operator is allowed to bill a working interest owner that is not the operator, under unit operating agreements or similar operating agreements ... and (2) the standards adopted by the Department of Natural Resources that determine the costs, other than items listed in (e) of this section, that a lessee is allowed to deduct from revenue in calculating net profits under [net profit share] lease[.]"

¹¹ The penalty for an underpayment due to negligence is 5% of the amount of the underpayment. AS 43.05.220(b). The failure-to-pay penalty for an underpayment is 5% of the underpayment for each month or partial month that the underpayment continues after payment was due, up to a maximum of 25 percent. AS 43.05.220(a). By regulation, DOR has adopted the policy that the imposition of a negligence penalty automatically triggers the imposition of a failure-to-pay penalty as well. 15 AAC 05.210(g).

¹² It follows that, if a non-operator can rely on the operator's joint-interest billings as the starting point for the non-operator's own lease expenditures for that operation, then the operator should similarly be able to use its proportionate share of the same total billable costs as the starting point for its lease expenditures for that operation. There is no reason to discriminate between them.

HB

2001

(1 1/2/07)

ALASKA STATE LEGISLATURE
House Resources Committee

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Friday, November 2nd
House Finance Committee Room 519
9:00 a.m.

HB 2001 Oil and Gas Tax Amendments

**Steve Porter, Contract Consultant to LB&A and Dan Dickinson,
Consultant to LB&A
Revenue Commissioner Pat Galvin**

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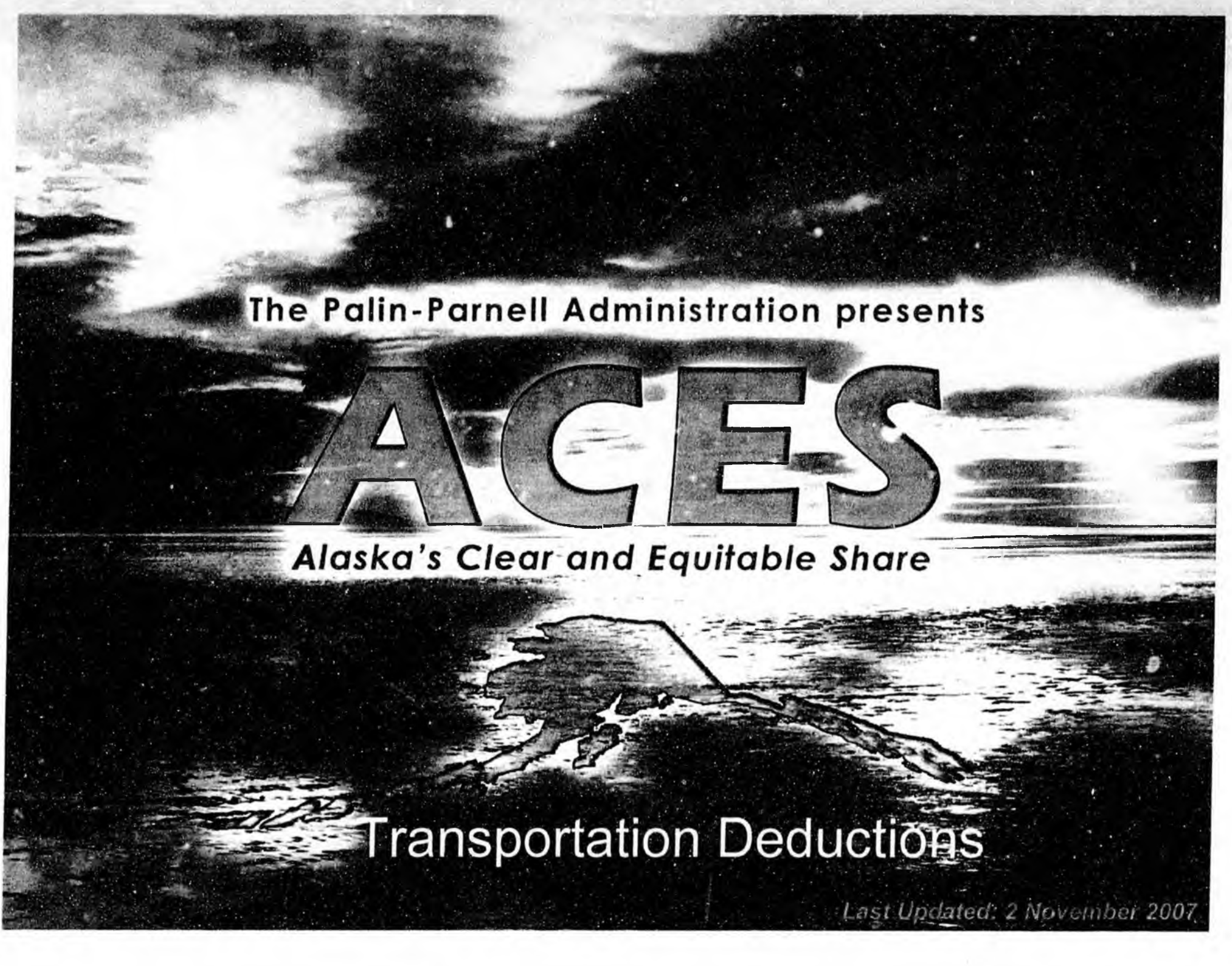
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The Palin-Parnell Administration presents

ACES

Alaska's Clear and Equitable Share

Transportation Deductions

Last Updated: 2 November 2007

Overview



- Current law
- The commercial reality
- Some problems
- Potential remedies

AS 43.55.150



- Gross value at point of production determined by subtracting “reasonable costs of transportation” from market prices
- “Reasonable costs” = “actual costs”
- “Actual costs” have historically been understood as FERC/RCA tariffs
- Exception for affiliate transactions, but only if “there are other reasonable modes of transportation” → exception is never met!

Transportation Deductions (Oil Pipelines)



- Deductions have historically relied on rates sanctioned by regulatory bodies
- Typically, this “sanction” does not reflect a regulatory determination
- Rather, the regulatory bodies have “blessed” settlement agreements between the state and the pipeline owner

Why does state base its tax policy for pipeline transportation deductions on pipeline rate litigation?

- MMS doesn't when pipeline is owned by producing affiliates.
 - They adopt a method promulgated through regulation

Pipeline Transportation Deductions



- Key reasons for state to avoid relying on regulatory process in setting tax value
 - Creates uncertainty: While litigation drags on tax value not fully known
 - Inefficient: Regulatory process unlikely to work well absent arms-length commercially sophisticated parties

TAPS Tariffs Example



Background:

- TAPS rates are currently ~\$5/bbl, set under a 1985-era settlement agreement between the State and the TAPS owners
- Rates don't appear to reflect "actual costs"
 - RCA determined that actual costs ~\$2/bbl
 - FERC Administrative Law Judge determined that actual costs ~\$2/bbl
- While litigation continues, State continues to allow a ~\$5/bbl transportation deduction

TAPS Tariffs Example



Indicative Value of “Tariffs by DOR”

- Assume:
 - TAPS tariffs are \$3/Bbl too high
 - Production tax rate of 22.5%
 - All barrels are shipped on affiliated transportation
- Then production tax value to state of setting tariffs for affiliate transactions is **~\$160 - \$200 million/year**

Transportation Deductions (Gas Pipelines)



- Gas pipelines typically built on basis of “negotiated rates” between shippers and pipelines
- FERC typically gives no scrutiny as to whether the negotiated rates are a “fair” bargain between shipper and pipeline
- If Producers end up owning the gas pipeline, then they can negotiate rates with themselves

Why would the state want to set its tax policy for transportation deductions on the basis of a non-arms length deal that state can't even litigate?

- Experience on TAPS suggests it would be unwise
- No compelling need to do so

The Key to a Remedy



- At present, state is arguably forced to live with non-arms length transactions because it is never the case that “there are other reasonable modes of transportation”
 - DOR could follow MMS’ lead and establish regulations that determine appropriate cost deductions for non arms-length transactions on pipelines
 - Cleanup language needed to ensure that the arms-length shippers – who really do have “actual costs” of the posted tariffs – are not forced to use the DOR-established tax deduction
-

DIST BY REP. Edgman.
11/2/07
10/31/2007

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSHB 2001 (U&G)	CSSB 2001 (RES)
Administration Intent		Sec. 1. Confirmation of DOR's interpretation of statute of limitations for retroactive tax changes.	Deleted.	Deleted.
Information		Sec. 2. Amends AS 38.05.035(a). Adds authority for DMR to share oil & gas info with DOR.	CS Sec. 1. ACES language	CS Sec. 1. ACES language
Technical Amendments		Secs. 3-9. Conforming technical amendments.	CS Secs. 2-8. ACES language	CS Secs. 2-8. ACES language
Administration: Auditors		Sec. 10. Amends AS 39.25.110. Adds exempt service for auditors.	CS Sec. 9. ACES language	CS Sec. 9. ACES language
Technical Amendments		Sec. 11. Amends AS 11.09.010(d). Conforming technical amendments.	CS Sec. 10. ACES language	CS Sec. 10. ACES language
Information		Sec. 12. Amends AS 43.05.230(a). Adds AS 43.55.890 (disclosure of tax info) as possible exception under AS 43.05.230(a) (unlawful disclosure).	CS Sec. 11. ACES language	CS Sec. 11. ACES language
Information		Sec. 13. Amends AS 43.05.230(h). Adds authority for DOR to share production tax info with DNR.	CS Sec. 12. ACES language	CS Sec. 12. ACES language
Administration Assessments		Sec. 14. Amends AS 43.05.260(a). Creates an exemption to allow DOR six years to conduct production tax assessments rather than three years.	CS Sec. 13. ACES language	Deleted.
Production Tax	AS 43.55.011(e). Sets the production tax rate at 22.5%	Sec. 15. Repeals & reenacts AS 43.55.011(e). Sets the production tax rate generally at 25%.	PPT	PPT
Production Tax Floor	AS 43.55.011(f). Sets a tax floor of not less than 4% of gross value when the average West Coast price is \$25 per barrel with step down factors.	Sec. 16. Repeals & reenacts AS 43.55.011(f). Sets a tax floor on legacy fields of 10% of the total gross value at the point of production; tax credits cannot reduce liability below floor.	PPT	PPT

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSHB 2001 (O&G)	CSSB 2001 (RES)
Progressivity Slope	AS 43.55.011(g). Progressivity is triggered at \$40 net value with a .25% increase per dollar; 25% tax cap on progressivity rate. (50% cap)	Sec. 17. Repeals & reenacts AS 43.55.011(g). Progressivity is triggered at \$30 net value on an annual basis with 0.2% increase per dollar; 50% maximum tax rate (including progressivity).	Repeals AS 43.55.011(g) (PPT progressivity); adds new gross progressivity provision in sec. 17 AS 43.55.011(o).	PPT
Progressivity Trigger	AS 43.55.011(h). Establishes the price index for calculating progressivity on a monthly basis.	Sec. 18. Amends AS 43.55.011(h). Establishes price index for calculating progressivity on an annual basis.	Repeals AS 43.55.011(h) (PPT progressivity calculation).	PPT
Progressivity Method	AS 43.55.011(h). Establishes the price index for calculating progressivity on a monthly basis.	Sec. 18. Amends AS 43.55.011(h). Establishes price index for calculating progressivity on an annual basis.	Repeals AS 43.55.011(h) (PPT progressivity calculation).	
Production Tax Cook Inlet	AS 43.55.011(j). Cook Inlet tax ceiling.	Sec. 19. Amends AS 43.55.011(j). Conforming technical amendment; deletes reference to AS 43.55.011(g) (progressivity) because reference is no longer applicable.	CS Sec. 14. ACES language Amends 43.55.011(j). Conforming technical amendment; deletes reference to AS 43.55.011(g) (PPT progressivity), inserts reference to 43.55.011(o) (O&G progressivity).	PPT
Production Tax Cook Inlet	AS 43.55.011(k). Cook Inlet tax ceiling.	Sec. 20. Amends AS 43.55.011(k) (Cook Inlet tax ceiling). Conforming technical amendment; deletes reference to AS 43.55.011(g) (progressivity) because reference is no longer applicable.	CS Sec. 15. ACES language Amends AS 43.55.011(k) (Cook Inlet tax ceiling). Conforming technical amendment; deletes reference to AS 43.55.011(g) (PPT progressivity), inserts reference to 43.55.011(o) (O&G progressivity).	PPT
Production Tax Cook Inlet	AS 43.55.011(l). Cook Inlet tax ceiling.	Repeals AS 43.55.011(l); conforming technical amendment.	CS Sec. 16. ACES language Amends AS 43.55.011(l). Conforming technical amendments; deletes reference to AS 43.55.011(g) (PPT progressivity), inserts reference to 43.55.011(o) (O&G progressivity).	ACES

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSHB 2001 (O&G)	CSSB 2001 (RES)
Production Tax Cook Inlet	AS 43.55.011(m). Cook Inlet tax administration.	Sec. 21. Amends AS 43.44.011(m). Adds language to be consistent with sec. 55 (lease expenditures); deletes reference to AS 43.55.011(g) (progressivity) because reference is no longer applicable.	CS Sec. 17. ACES language Amends AS 43.55.011(m). Deletes language added in ACES; deletes reference to AS 43.55.011(g) (PPT progressivity), inserts reference to 43.55.011(o) (O&G progressivity).	PPT
Production Tax Progressivity			Sec. 18. Adds AS 43.55.011(o). Replaces ACES and PPT progressivity provisions with a new a new progressivity provision.	
Production Tax Mid-Alaska Tax Ceiling			Sec. 18. Adds AS 43.55.011(p). Extends Cook Inlet tax ceilings in .011(j) to gas outside Cook Inlet and outside the North Slope.	
Tax Payment	AS 43.55.020(a). Installment payments.	Sec. 22. Repeals & reenacts AS 43.55.020(a). Makes installment payment calculations consistent with changes to the production tax.	CS Sec. 19. ACES language with conforming ammendments.	PPT
Tax Payment	AS 43.55.020(d). Royalty owner settlement deductions and installment payments.	Sec. 23. Amends AS 43.55.020(d). Conforming technical ammendments; deletes reference to AS 43.55.011(g) (progressivity) because reference is no longer applicable.	CS Sec. 20. ACES language Conforming technical ammendment; deletes r-ference to AS 43.55.011(g) (PPT progressivity), inserts reference to 43.55.011(o) (O&G progressivity).	PPT
Tax Payment	AS 43.55.020(g). Interest on unpaid installment payments.	Sec. 24. Amends AS 43.55.020(g). Conforming technical ammendment.	CS Sec. 21. ACES language Amends AS 43.55.020(g). Conforming technical ammendment.	PPT
Tax Payment	AS 43.55.020(h). Interest on overpayment of installment payments.	Sec. 25. Amends AS 43.55.020(h). Conforming technical ammendment.	CS Sec. 22. ACES language Amends AS 43.55.020(h). Conforming technical ammendment.	PPT
Tax Credits Capital Expenditures	AS 43.55.023(a). 20% tax credit for qualified capital expenditures and information requirements.	Sec. 26. Amends AS 43.55.023(a). Spreads use of tax credits over two years; moves and adds to info requirements; adds that legacy field tax credits may be applied only against legacy field taxes.	PPT	PPT

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSHB 2001 (O&G)	CSSB 2001 (RES)
Tax Credits Capital Expenditures	AS 43.55.023(b). 20% of carried-forward annual loss credit allowed against deductible lease expenditures when use of the deduction would cause the production tax in a month to be less than zero.	Sec. 27. Amends AS 43.55.023(b). Matches carried-forward annual loss to production tax rate of 25%; adds that carried-forward annual losses may not be based on lease expenditures accrued in legacy fields.	PPT	PPT
Tax Credits Capital Expenditures	AS 43.55.023(d). Transferable tax credit certificates.	Sec. 28. Amends AS 43.55.023(d). Adds no transfer of tax credits earned on legacy fields, option to obtain cash payment, and more time for agency approval; requires annual reporting requirements; spreads use of tax credits over two years.	CS Sec. 23. ACES language Amends AS 43.55.023(d). Technical amendment to PPT provision.	PPT
Tax Credits Capital Expenditures	AS 43.55.023(e). Transfer of tax credits.	Sec. 29. Amends AS 43.55.023(e). Conforming technical amendment.	PPT	PPT
Tax Credits Capital Expenditures	AS 43.55.023(f). Cash refund of up to \$25,000,000 for small producer tax credits.	Repeals AS 43.55.023(f) (replaced with oil and gas tax credit fund).	PPT	PPT
Tax Credits Capital Expenditures	AS 43.55.023(g). Tax credit audits.	Sec. 30. Amends AS 43.55.023(g). Adds language to reflect DOR authority to purchase tax credits granted in AS 45.55.028.	PPT	PPT
Tax Credits Capital Expenditures	AS 43.55.023(i). Transitional investment expenditure (TIE) tax credits for qualified capital expenditures incurred after March 31, 2001 and before April 1, 2006.	Repeals AS 43.55.023(i).	CS Sec. 24. ACES language Amends AS 43.55.023(i). Changes application of TIE credits to qualified capital expenditures incurred after March 31, 2003 and before April 1, 2006.	CS Sec. 13. ACES language Amends AS 43.55.023(i). Limits TIE credits to taxpayers that did not have commercial production before January 1, 2008, and to 1/10 of qualified capital expenditures incurred after March 31, 2006 and before January 1, 2008.

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSHB 2001 (O&G)	CSSB 2001 (RES)
Tax Credits Capital Expenditures		Sec. 31. Amends AS 43.55.023. Adds subsection (I) to make clear a tax exempt entity may not obtain a transferable tax credit.	CS Sec. 25. ACES language	Deleted.
Tax Credits Mid-Alaska	AS 43.55.024. Additional tax credit of \$6,000,000 for production from leases outside Cook Inlet and the North Slope for small producers.	Secs. 32 - 35. Amends AS 43.55.024. Subsection(a): technical correction; (b), (c), (e), (g): conforming technical amendments	PPT	PPT
Tax Credits Exploration	AS. 43.55.025. Alternative tax credits for up to 40% for oil and gas exploration.	Secs. 36 - 44. Amends AS 43.55.025 to clarify credit eligibility; extends eligibility for deliniation wells from 150 days to 540 days; requires additional information to be submitted to DOR; allows additional 5% credit for seismic exploration conducted before July 1, 2003 in exchange for seismic data.	PPT	PPT
Tax Credits Oil & Gas Tax Credit Fund		Sec. 45. Adds AS 43.55.028. Replaces PPT tax credit refund with an oil and tax credit fund funded by an appropriation of a percentage of production tax revenues.	PPT	PPT
Reporting Requirements		Sec. 46. Amends AS 43.55.030(a). Makes clear every taxpayer must file an annual return; expands info requirements.	CS Sec. 26. ACES language	CS Sec. 14. ACES language
Reporting Requirements Penalties		Sec. 47. Amends AS 43.55.030(d). Adds late filing penalty of \$1000/day for information required by the DOR.	Deleted.	CS Sec. 15. ACES language

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSHB 2001 (O&G)	CSSB 2001 (RES)
Reporting Requirements		Sec. 48. Amends AS 43.55.030. Adds new subsections (e) - requires annual expenditure statement; and (f) - authorizes DOR to require monthly filing of info.	CS Sec. 27. ACES language	CS Sec. 16. ACES language
Reporting Requirements and Penalties		Sec. 49. Amends AS 43.55.040. Clarifies DOR has authority to require filing of reports necessary to forecast state revenue; adds additional penalties.	CS Sec. 28. ACES language Amends AS 43.55.040. Retains ACES authority clarification; deletes additional penalty.	CS Sec. 17. ACES language
Administration Statute of Limitations		Sec. 50. Amends AS 43.55. Adds a new section, AS 43.55.075, that expands statute of limitations for conducting tax assessments from three years to six years.	CS Sec. 29. ACES language	Deleted.
Administration Electronic Filing & Advisory Bulletins		Sec. 51. Amends AS 43.55.110. Adds new subsections (e) & (f) that authorize DOR to require electronic filings and payments; and (g) that gives DOR authority to issue advisory bulletins.	CS Sec. 30. ACES language	CS Sec. 18. ACES language
Tax Determination	AS 43.55.160(a). Determination of production tax value of oil and gas.	Sec. 52. Repeals and reenacts AS 43.55.160(a). Retains PPT principle that the taxable value is the gross value at the point of production minus lease expenditures; the changes are necessary to implement different tax treatments.	CS Sec. 31. ACES language Amends AS 43.55.160(a). Retains PPT language with conforming amendments.	PPT
Tax Determination	AS 43.55.160(b). Production tax value may not be less than zero.	Sec. 53. Amends AS 43.55.160(b). Conforming technical amendment.	PPT	PPT
Tax Determination	AS 43.55.160(e). Carried forward annual losses established when production tax value is less than zero.	Sec. 54. Repeals & reenacts AS 43.55.160(e). Provides explicit rules for calculating production tax values for oil and gas subject to different statutory provisions.	PPT	PPT

ACES Bill Version Comparisons

10/31/2007

Subject	PPT	ACES	CSHB 2001 (O&G)	CSSB 2001 (RES)
Tax Determination		Sec. 55. Amends AS 43.55.160. Adds four new subsections related to allocations and calculations of adjusted lease expenditures.	Deleted.	Deleted.
Lease Expenditures	AS 43.55.165(a). Describes deductible lease expenditures for purposes of determining the net taxable amount; provides standards DOR shall consider for determining lease expenditures.	Sec. 56. Repeals & reenacts AS 43.55.165(a). Retains but rewords deductible lease expenditures description; adds requirement that deductible lease expenditures be affirmatively allowed through regulation; allows overhead expenses (moved from 165(b)); deletes standards (moved to 165(b)).	CS Sec. 32. ACES language PPT with conforming ammendments.	Sec. 19. ACES
Lease Expenditures	AS 43.55.165(b). Lists direct costs that may be considered deductible lease expenditures; allows overhead expenses; and specifies allowed costs need not be physically located on lease.	Sec. 57. Amends AS 43.55.165(b). Retains PPT language; adds the standards DOR shall consider for determining lease expenditures (moved from 165(a) and (c)); deletes overhead expenses (moved to 165(a)).	PPT	CS Sec. 20. ACES language
Lease Expenditures	AS 43.55.165(c) and (d). Allows DOR to substitute costs that are billable or actually billed through unit operating agreements in place of the general lease expenditures standards.	Repeals AS 43.55.165(c) and (d).	ACES	ACES
Lease Expenditures		Sec. 58. Amends AS 43.55.165(e). Adds to the list of non-deductible lease expenditures, including costs incurred for violations of law and for repair, replacement or deferred maintenance in specified circumstances.	CS Sec. 33. ACES language	CS Sec. 21. ACES language