SCOMM
148:12

ALASKA STATE LEGISLATURE

HOUSE SPECIAL COMMITTEE ON OIL AND GAS

Representative Kurt Olson, Chair
State Capitol, Room 408
Juneau, AK 99801-1182
Phone 907-465-2693 Fax 907-465-3835

Official Business

HB 2001 Bill Packet Information
October 21, 2007

Enclosed Documents:

- No documents or document labels available at time of printing

ALASKA STATE LEGISLATURE

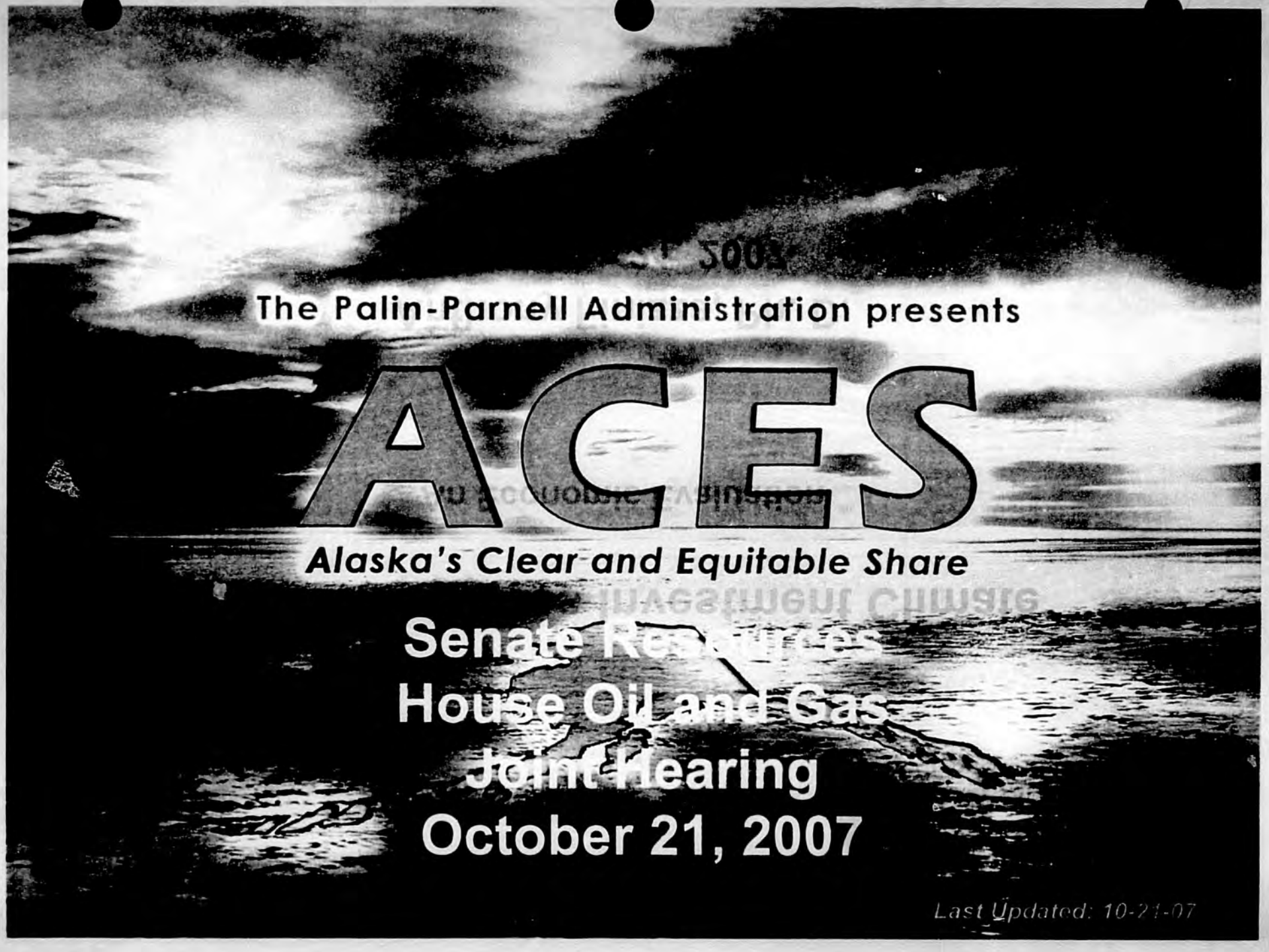
Joint Meeting
Senate Resources and
House Oil and Gas
House Finance Room 519
Sunday, October 21, 2007
1:00 p.m. - 6:00 p.m.

AGENDA

SB 2001/HB 2001 - Oil and Gas Production Tax
Presentation by: Governor's Production Tax Team

III - ACES Preserves Investment Climate
and
Sectional Analysis of SB 2001/HB 2001

Patrick Galvin, Commissioner, Dept. of Revenue
Tony Finizza, Consulting Economist
Cherie Nienhuis, Petroleum Economist, Dept. of Revenue
Kevin Banks, Acting Director, Division of Oil & Gas
Robert Mintz, Preston Gates
Marcia Davis, Deputy Commissioner, Dept. of Revenue


The Palin-Parnell Administration presents
ACES
Alaska's Clear and Equitable Share
Senate
House Oil and Gas
Joint Hearing
October 21, 2007
Last Updated: 10-21-07

ACES

Alaska's Clear and Equitable Share

ACES Preserves Investment Climate

An Economic Evaluation

Anthony Finizza, Ph. D.

October 21, 2007

ACES
Alaska's Clear and Equitable Share

Framework and Methodology for Analysis

Financial Metrics

ACES
Alaska's Clear and Equitable Share

Producer Economic Metrics

- NPV – Net Present Value ("Value today of Project Cash Flows")

Metrics Used

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	Legacy Fields	New Fields	
Producer Point-of-View	**"Reinvestment Economics"**	**"Investment Economics"**	
Financial Evaluation	**Net Cash Flow NPV10**	**Net Cash Flow NPV10**	**Does the project have NPV>0 at stress price?**
Alaska Point-of-View			
"Fairness"	**Marginal Government Take**	**Life Cycle Discounted (10%) Government Take**	**Does the SOA receive a fair share of the economic profit?**

Financial Criterion
Net Present Value (NPV)

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- **Present value of future cash flows including capital investment**

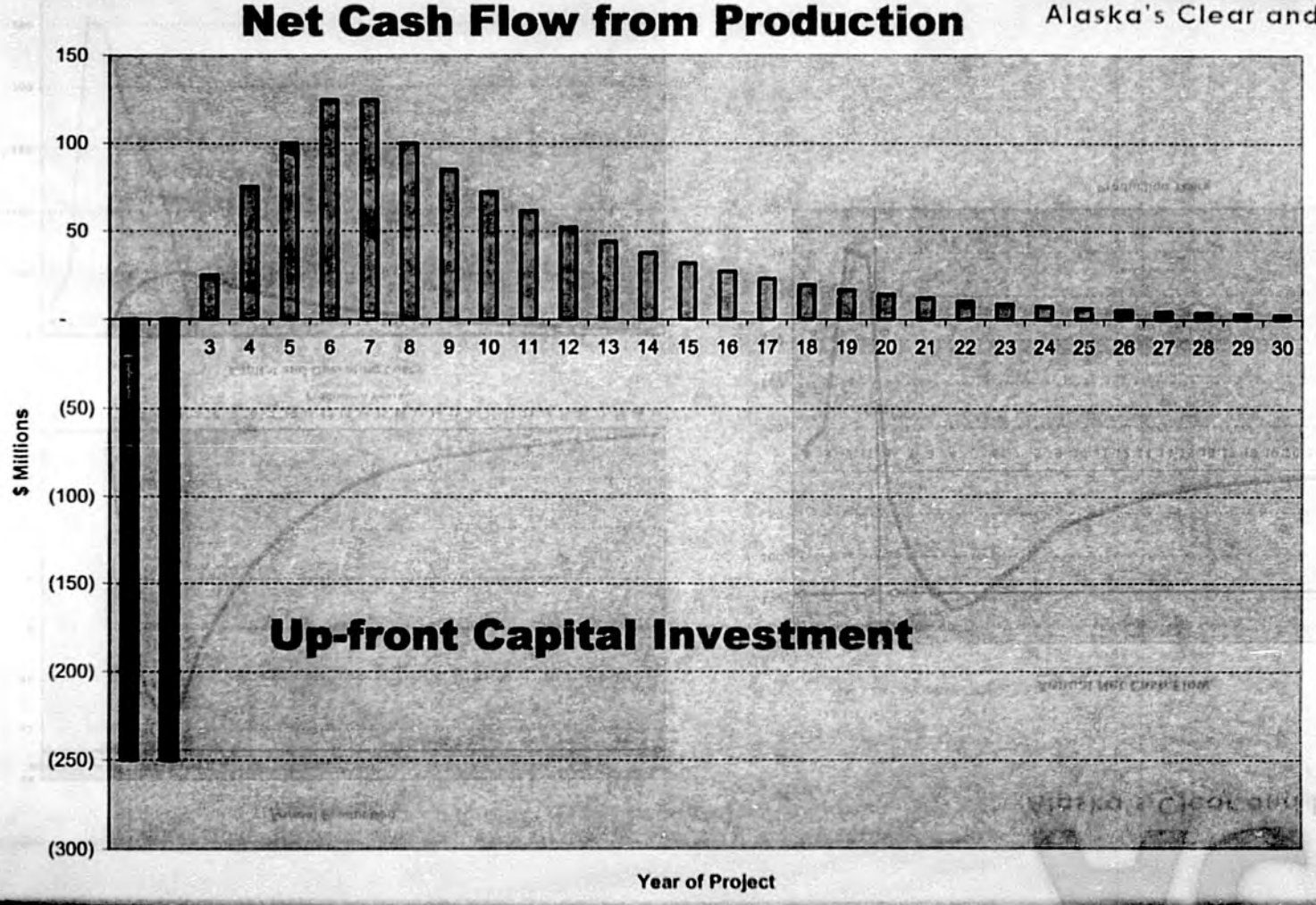
- **This is the "supreme" financial metric since a project with a positive NPV adds value to the firm**
  - **Value of the firm = PV of all future cash flows**
    = PV of cash flows from assets in place
    + PV of cash flows from future investments

- **Future cash flows discounted at rate that represents uncertainty of cash flows and when they are expected**

- **If a project generates cash in excess of that to compensate for the risk taken, the value of the firm increases**

Stylized Project Cash Flow

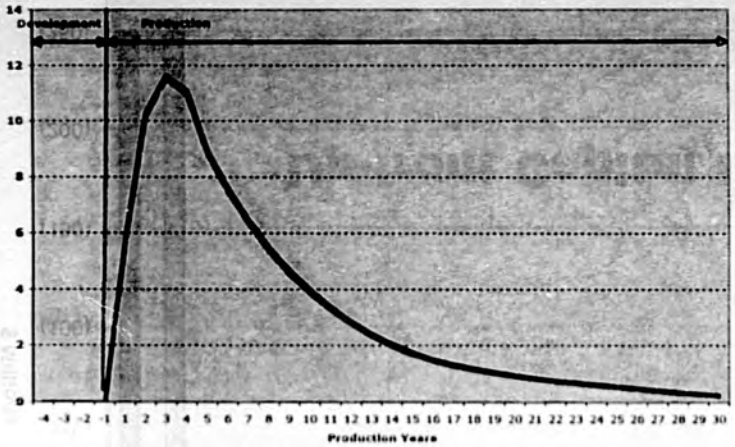
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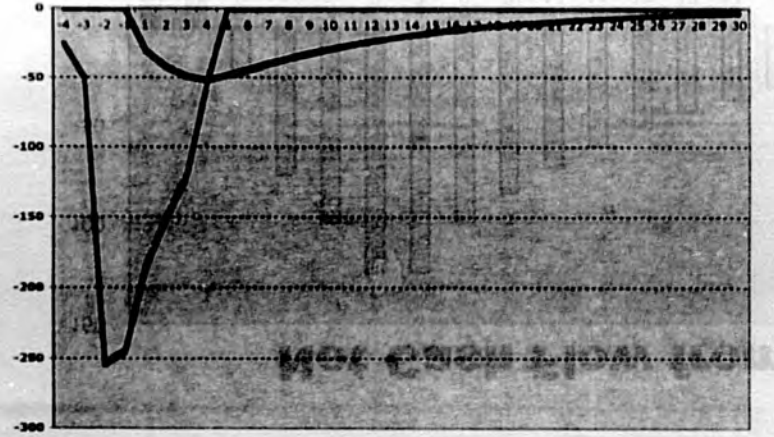
Cash Flows for New Fields

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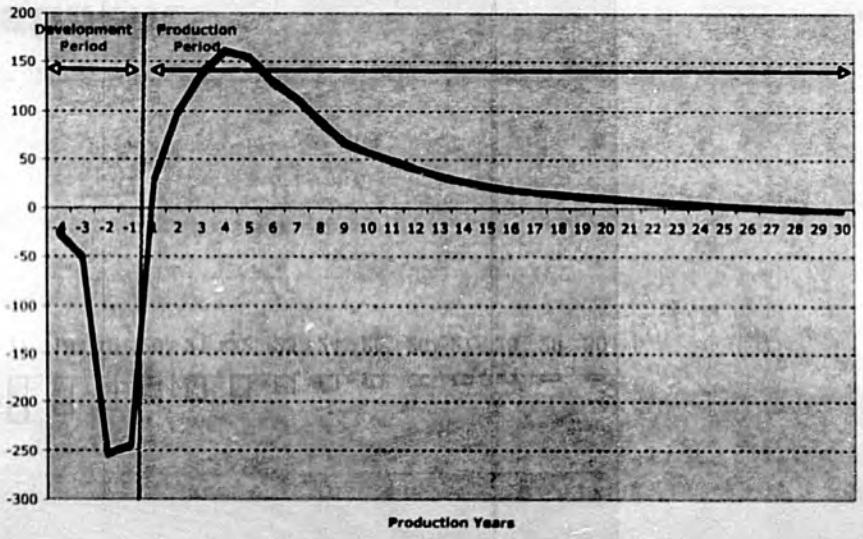
Annual Production



Capital and Operating Costs



Annual Net Cash Flow



Producer View of Future Oil Prices

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- Producers have been "burned" by forecasts of high oil prices in the past
- The consequences of error are not symmetrical
- Producers will test their projects against a price path that is below their "Most Likely" view
  - They use the "official price view" as a speed limit to signal caution
  - By "high-grading," they will have a suite of projects resilient to price risk
  - Their price view lags the current market price by as much as 5-7 years as prices rise, and by 2 years as prices fall.
  - Current "best guess" view might be: $50/barrel
  - Producers will also "stress" test their projects at $40/barrel

Common Assumptions Used In Analyses

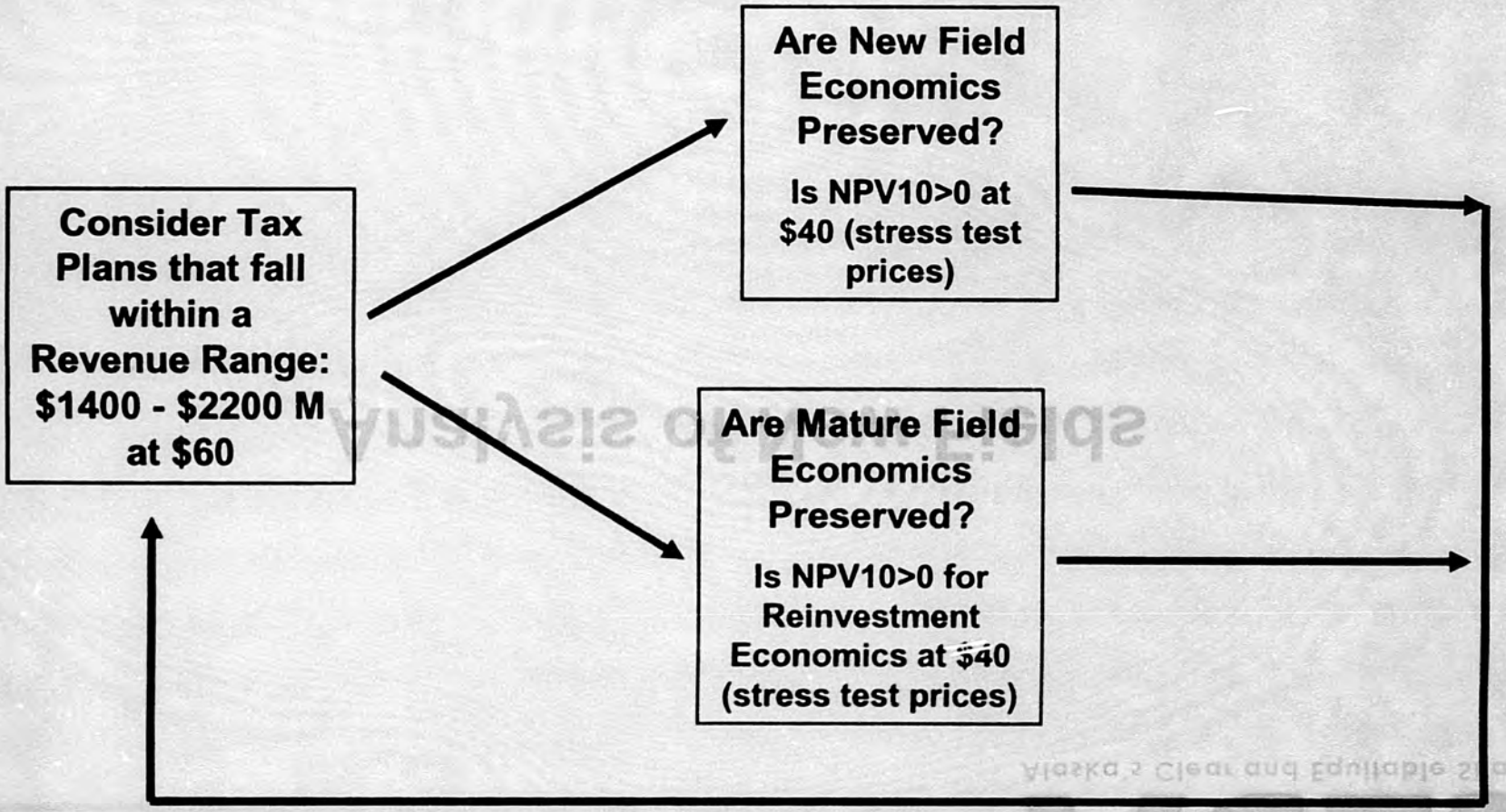
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For comparing results, we have used a common set of assumptions:

- **Oil prices:**
  - **Base case price; $60**
  - **Stress test price: $40**
  - **Analysis done at price continuum from $20 to $100**
- **Inflation: 3% per year**
- **Producer discount rate: 10% and 15% (results shown at 10%)**
- **State discount rate: 5% and 8% (results shown at 5%)**

Tax Plan Evaluation Process

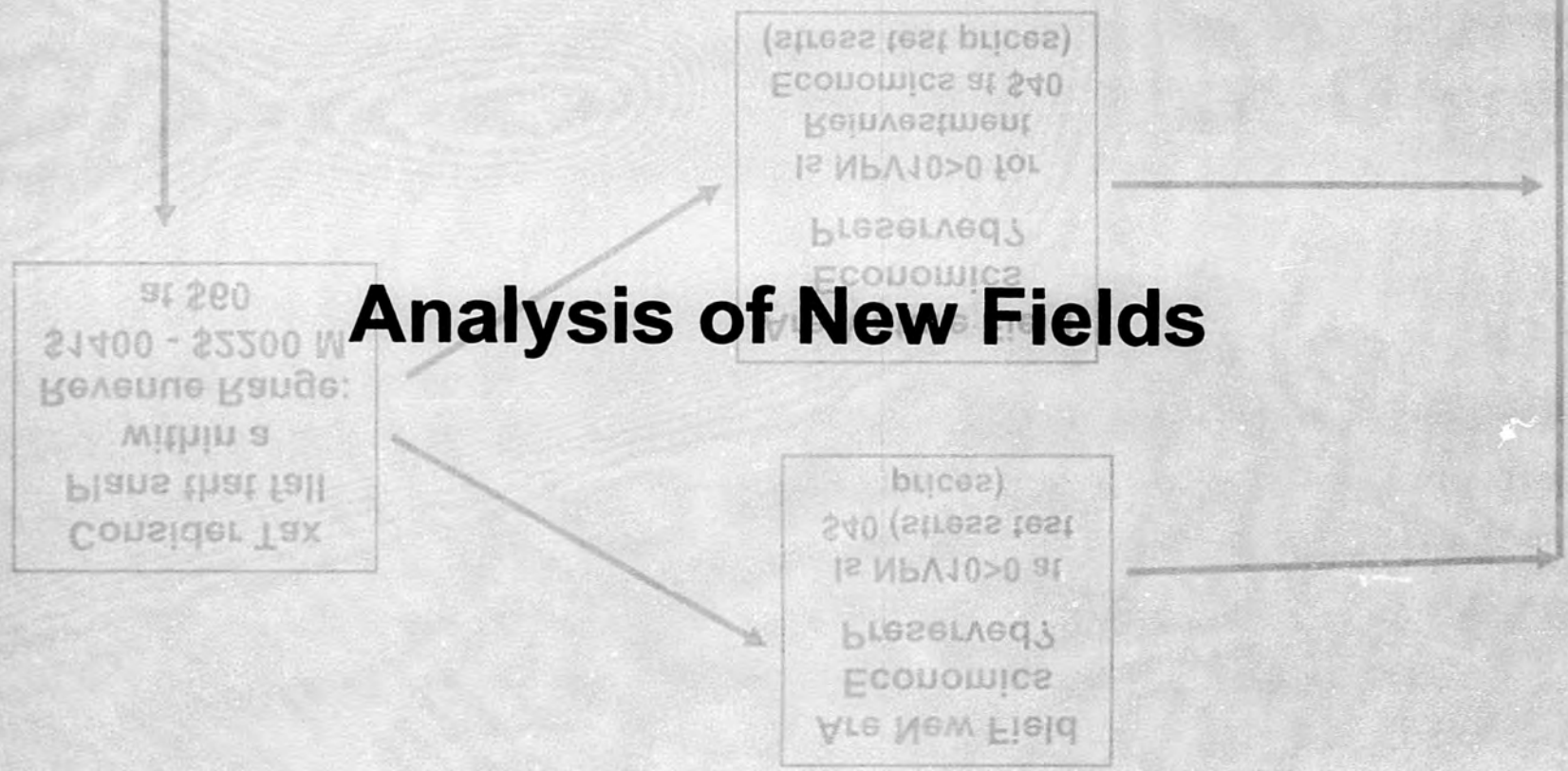
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Analysis of New Fields



Seven New-Fields Analysis

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- Hypothetical fields based on operating and capital costs, and production profiles of known field types
- Source of information derived from publicly available data, and industry information supplied in state agency interactions

Characteristics of Seven Fields

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A: Medium heavy oil satellite in existing mature unit
B: Offshore small reserves
C: Satellite in existing unit
D: Remote field
E: New unit with very heavy oil
F: Offshore medium reserves
G: New unit with large reserves

- Reserves range from 40 to 300 MB
- Various combinations of ownerships among incumbents, small producers, new entrants

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Characteristics of the Seven Fields

	Field A	Field B	Field C	Field D	Field E	Field F	Field G
Legacy Field	●						
Satellite	●	●	●		●		
Stand Alone				●		●	●
Heavy Oil	●				●		
Reserves (MMB)	80	60	40	200	100	120	320
Ownership	Existing	New	Existing	New	Existing	New	Existing
Capital ($ / B)	$11	$10	$11	$13	$16	$8	$5
Expense ($ / B)	$7	$9	$8	$12	$8	$5	$6

Tax Scenarios

(A small sample of scenarios considered)

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- Net
  - ACES: 10% Floor
  - ACES: No Floor
  - PPT (Status Quo)
  - 35% Mature Fields / 22.5% Other
- Gross
  - 13% / No credits
  - 16% / With 20% credits
  - 16% / No credits
  - 19% / With 20% credits
  - Back-end loaded progressive tax table / With 20% Credits

<u> All Models use a progressivity factor</u>**

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DESCRIPTION OF NEW FIELD MODEL

CASH FLOW SCHEMATIC FOR SINGLE YEAR

TOTAL REVENUES: (VOLUME X ANS WEST COAST PRICE)

Less:

Shipping
TAPS Tariff =

GROSS VALUE (AT THE POINT OF PRODUCTION)

Less:

Upstream Capital Costs
Upstream Operating Costs =

DIVISIBLE INCOME

Less:

Royalties =

TAXABLE INCOME FOR PRODUCTION TAX

Less:

Production Tax =

TAXABLE INCOME FOR INCOME TAX

Less:

State Corporate Income Tax
Federal Corporate Income Tax =

NET CASH FLOW FOR A SINGLE YEAR

NET PRESENT VALUE

DISCOUNTED NET CASH FLOW YEAR 1
+ DISCOUNTED NET CASH FLOW YEAR 2
+ DISCOUNTED NET CASH FLOW YEAR 3
+ DISCOUNTED NET CASH FLOW YEAR 4
+ DISCOUNTED NET CASH FLOW YEAR 5
+ DISCOUNTED NET CASH FLOW YEAR 6
+ DISCOUNTED NET CASH FLOW YEAR 7
+ DISCOUNTED NET CASH FLOW YEAR 8
+ DISCOUNTED NET CASH FLOW YEAR 9
+ DISCOUNTED NET CASH FLOW YEAR 10
+ DISCOUNTED NET CASH FLOW YEAR ...
+ DISCOUNTED NET CASH FLOW YEAR ...
+ DISCOUNTED NET CASH FLOW YEAR ...
+ DISCOUNTED NET CASH FLOW YEAR Last Year =

NET PRESENT VALUE

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New Field Tax Analysis - NPV Impact

NET PRODUCTION TAX SCENARIOS

Scenario	Rate		Progressivity		Capital	Industry NPV @ 10% at $40/bbl real ANS WC (mm$)						
	Mature Fields	Other Fields	Trigger	Rate	Investment Credit	Field A	Field B	Field C	Field D	Field E	Field F	Field G
ACES - 10% Floor	25.0%	25.0%	$30	0.0020	20%	10	60	40	40	(500)	210	1,000
ACES - NO Floor	25.0%	25.0%	$30	0.0020	20%	120	60	40	40	(300)	210	1,000
PPT Status Quo	22.5%	22.5%	$40	0.0025	20%	180	50	60	10	(200)	220	1,100
High Net Tax	35.0%	22.5%	$30	0.0030	20%	150	50	50	0	(200)	140	1,100

GROSS PRODUCTION TAX SCENARIOS

Scenario	Rate	Other Incentives	Progressivity		Capital	Industry NPV @ 10% at $40/bbl real ANS WC (mm$)						
	(All Fields)		Trigger	Rate	Investment Credit	Field A	Field B	Field C	Field D	Field E	Field F	Field G
Low Rate - No Credits	13%		$40	0.0020	None	(30)	(40)	(30)	(500)	(600)	80	700
Medium rate	16%		$40	0.0020	20%	30	0	0	(300)	(500)	130	800
Former Tax no ELF	16%		NA	NA	none	(40)	(50)	(30)	(400)	(600)	80	800
High Rate Flat Tax	19%		NA	NA	20%	20	(10)	0	(300)	(500)	130	900
Sliding Scale	Tax Table	5 Yr Holiday	NA	NA	20%	130	40	40	20	(400)	180	1,100

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New Field Tax Analysis - NPV Impact

NET PROFIT TAX SCENARIOS

Case	Tax Rate		Progressivity		Capital Investment Credit
	Mature Fields	Other Fields	Trigger	Rate	
ACES - 10% Floor	25%	25%	$30	0%	20%
ACES - NO Floor	25%	25%	$30	0%	20%
PPT Status Quo	23%	23%	$40	0%	20%
High Net Tax	35%	23%	$30	0%	20%

State NPV at 5% at $60/bbl ANS WC (mm$)

Field A	Field B	Field C	Field D	Field E	Field F	Field G
1,000	530	610	2,000	1,000	1,800	5,700
1,000	530	610	2,000	740	1,800	5,700
850	500	550	1,800	480	1,700	5,300
1,100	550	580	2,000	590	1,800	5,700

"Cradle to Grave" Government Share of Pre-Tax Income Discounted at 10% @ $60 (Applicable to New Fields)

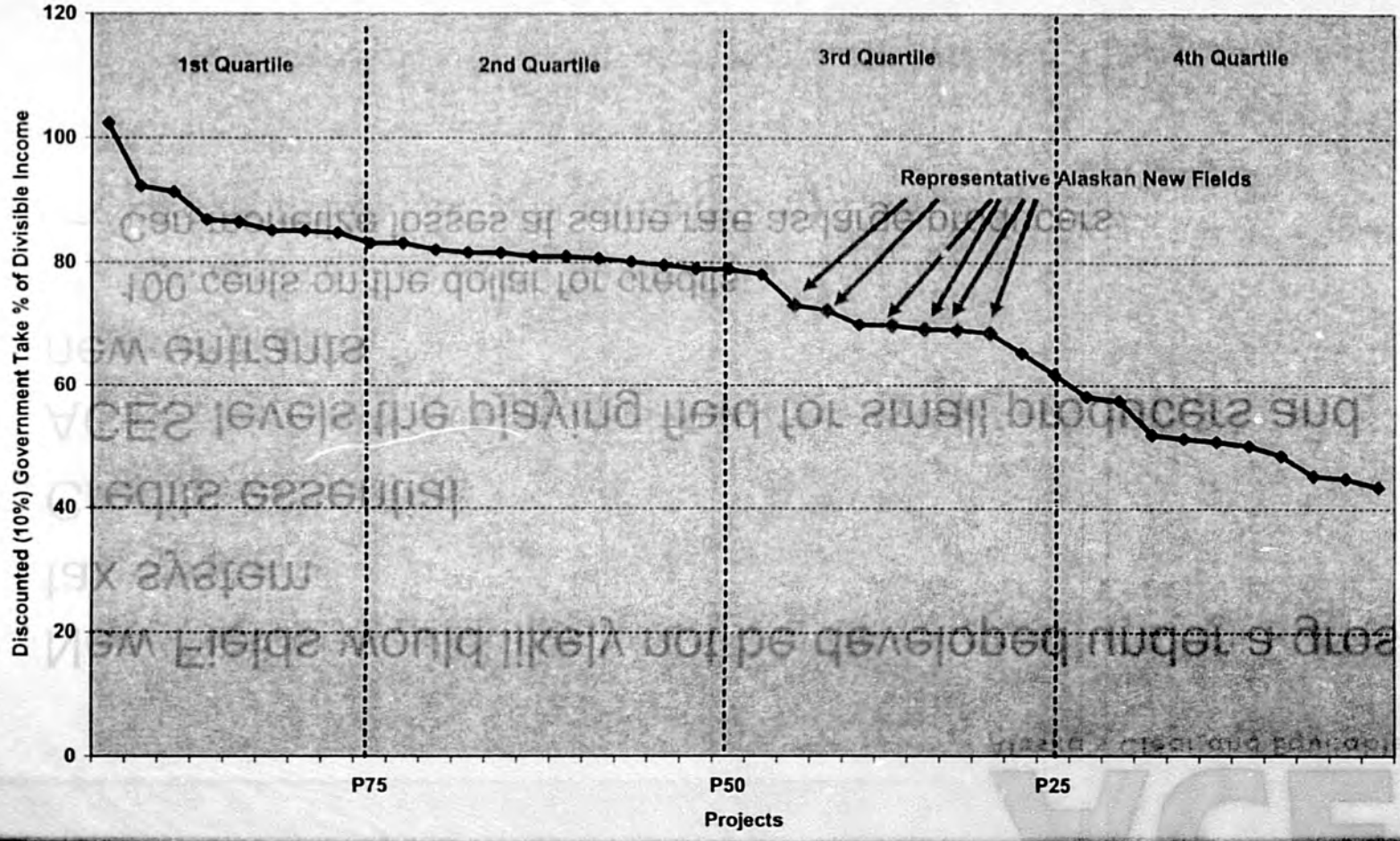
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Median Government Take By Tax Structures	
	Median (Mid-Point)
All Governments	48%
Profit Sharing Governments	76%
Tax Royalty Governments	50%
Norway	81%
Alaska - ACES Six Potential New Fields	**68% to 74% (Median 70%)**
Alaska - PPT Six Potential New Fields	65% to 72% (Median 68%)
UK	51%
Gulf of Mexico	48%

Source: PFC Study September 2007, Alaska data by DOR

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Discounted Government Take @ $60
Tax & Royalty Fiscal Regimes (excluding GOM)



Conclusions

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- New Fields would likely not be developed under a gross tax system
- Credits essential
- ACES levels the playing field for small producers and new entrants
  - 100 cents on the dollar for credits
  - Can monetize losses at same rate as large producers

Analysis of Mature Fields

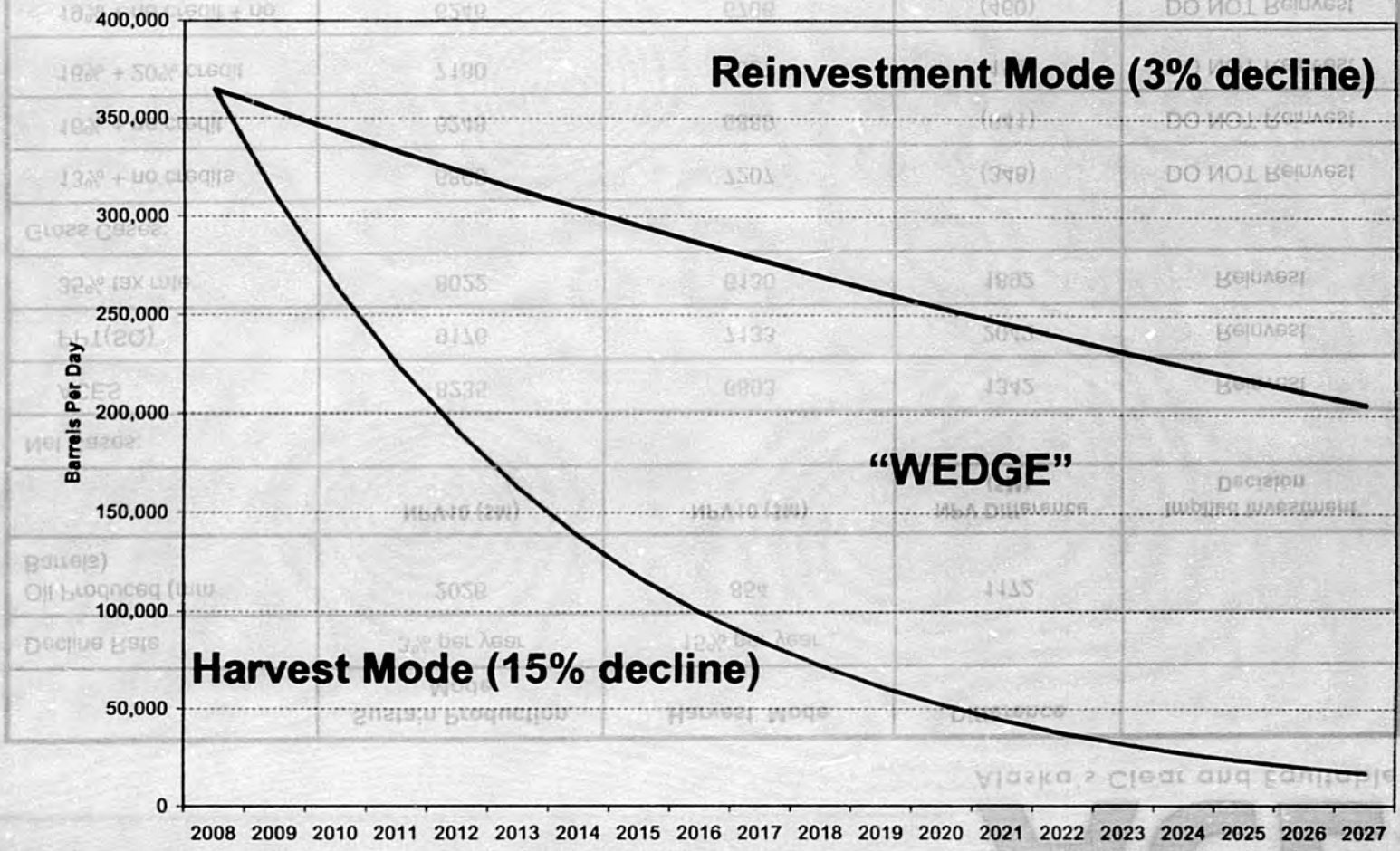
Economic Evaluation of Mature Fields

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- Hampered by lack of specific knowledge
- Recognize that reinvestment requires substantial capital
- Consider two modes:
  - Harvest: allow field to decline naturally (15% decline)
  - Reinvestment: invest to stem decline (3% decline)
- Treat each mode as a separate (mutually exclusive) project
- Compare the NPV of Reinvestment with the NPV of Harvest

Legacy Field Scenarios

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Legacy Field Reinvestment Comparison @ $40

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	Sustain Production Mode	Harvest Mode	Difference	
Decline Rate	3% per year	15% per year		
Oil Produced (mm Barrels)	2026	854	1172	
	NPV10 ($M)	NPV10 ($M)	NPV Difference ($M)	Implied Investment Decision
Net Cases:				
ACES	8235	6893	1342	Reinvest
PPT(SQ)	9176	7133	2042	Reinvest
35% tax rate	8022	6130	1892	Reinvest
Gross Cases:				
13% + no credits	6860	7207	(348)	DO NOT Reinvest
16% + no credit	6248	6889	(641)	DO NOT Reinvest
16% + 20% credit	7180	7027	152	DO NOT Reinvest
19% + no credit + no progressivity	6246	6706	(460)	DO NOT Reinvest

Assumes: 20 year horizon, OPEX+CAPEX=$5/BOE for Harvest, $15/BOE for Reinvestment. All cases assume 26 progressivity unless noted.

How Much of a $1.00 Oil Price Increase is Captured by Producer

(Mature fields - In production > 10 years)

ACES

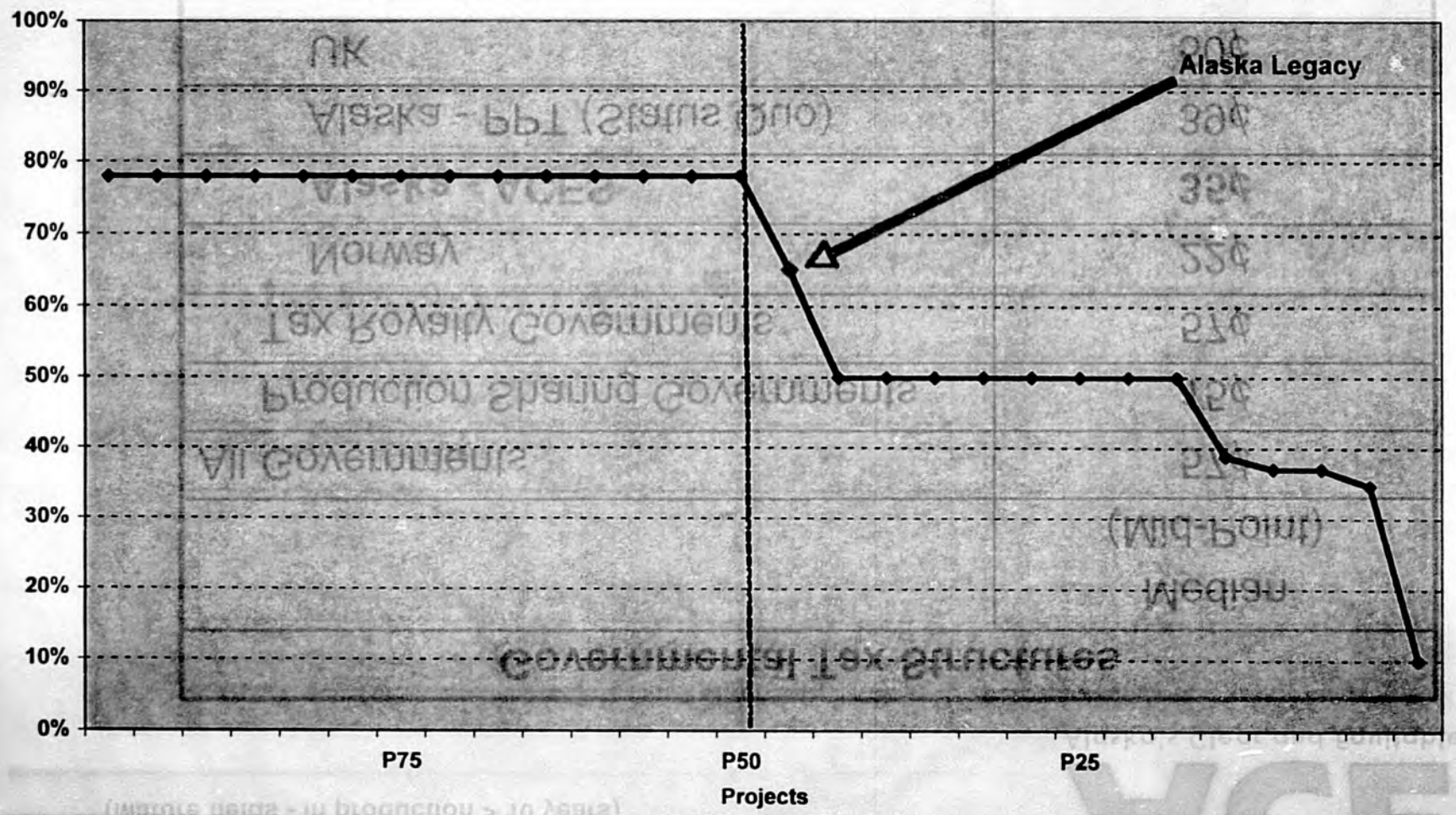
Alaska's Clear and Equitable Share

Governmental Tax Structures	
	Median (Mid-Point)
All Governments	57¢
Production Sharing Governments	15¢
Tax Royalty Governments	57¢
Norway	22¢
Alaska - ACES	**35¢**
Alaska - PPT (Status Quo)	39¢
UK	50¢
Gulf of Mexico	57¢

Source: PFC Study, September 2007. Alaska data by DOR using FY 2008 estimates

Marginal Government Take @ $60
Tax & Royalty Tax Regimes (excluding GOM)
Mature Fields

ACES



ACES

Alaska's Clear and Equitable Share

Sensitivities

Sensitivity to Alternative Assumptions

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ACES at $60

North Slope Production Tax Revenues in Millions of Dollars

					Relative to ACES		
	FY 2008	FY 2009	FY 2010		FY 2008	FY 2009	FY 2010
ACES	1421	1977	2170		-	-	-
ACES w/ 22.5% rate	1320	1748	1928		-102	-229	-242
ACES w/ PPT Progressivity	1356	1826	2011		-65	-151	-159
ACES w/ TIE Credits in	1315	1789	1972		-107	-188	-198
ACES w/ credits all in first year	1324	2003	2160		-97	26	-9
ACES w/ 27% rate	1503	2160	2363		81	183	194
ACES w/ 30% rate	1625	2435	2653		203	458	484

The Cost Story

Alaska Department of Revenue
October 21, 2007

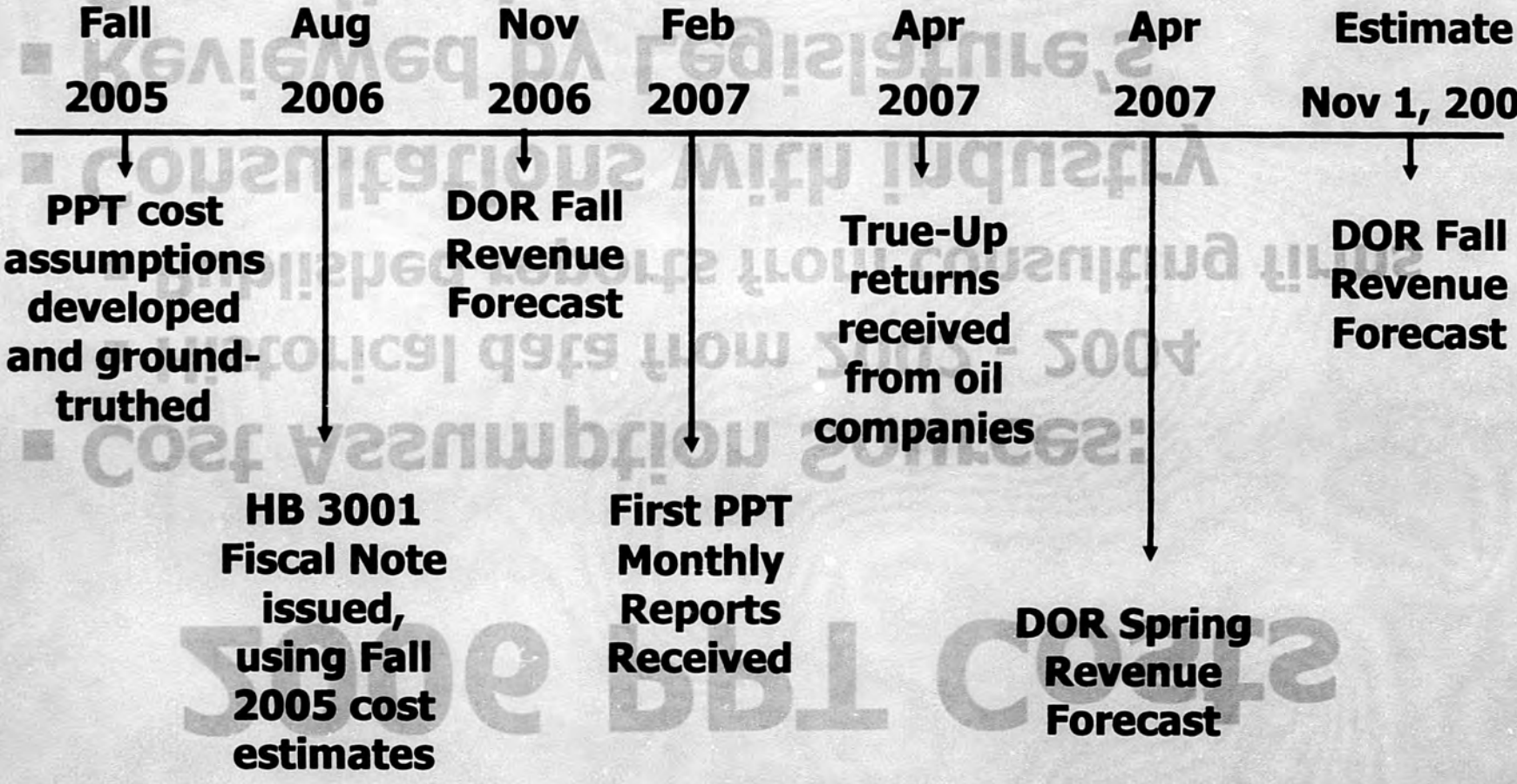
Production Tax Revenue Involves Three Unknowns

- Production
- Price
- Costs – Operating and Capital

2006 PPT Costs

- **Cost Assumption Sources:**
  - **Historical data from 2002 - 2004**
  - **Published reports from consulting firms**
- **Consultations with industry**
- **Reviewed by Legislature's Consultants**

PPT Forecast Timeline

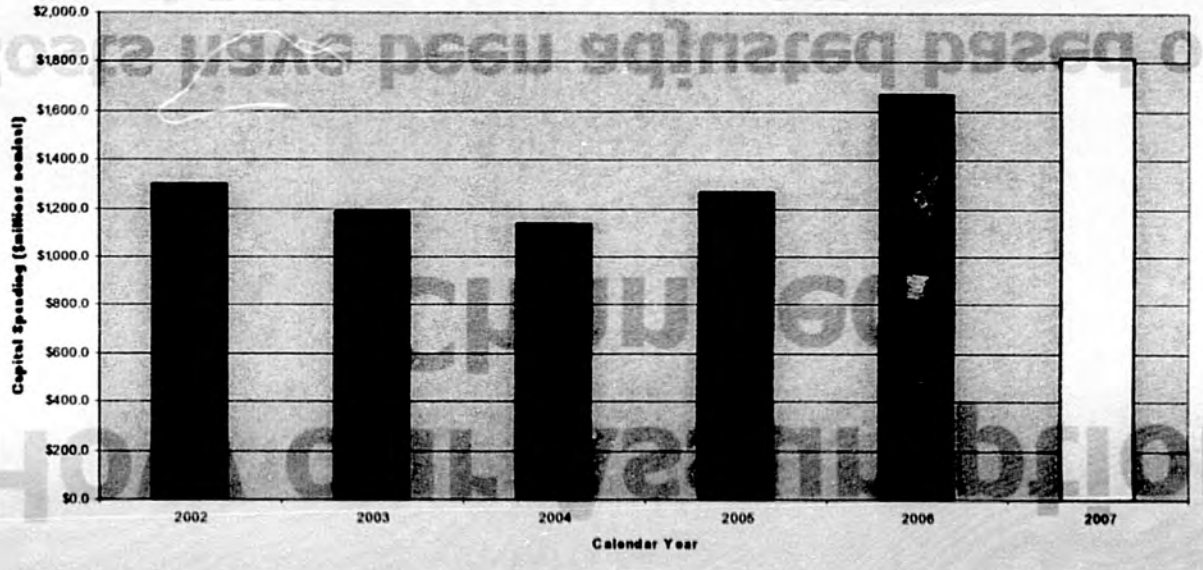


How our Assumptions Changed

- Costs have been adjusted based on actual PPT tax return filings
- Costs are now expressed in nominal dollars (have inflation component)
- Additional data has become available on which to base future costs

Capital Spending as Reported in PPT Tax Returns, March 2007 and 2007 Forecast

Calendar Year	Capital Spending in Alaska in $millions nominal
2002	$1,296.7
2003	$1,186.8
2004	$1,136.9
2005	$1,268.0
2006	$1,665.3
2007	$1,817.0



Cost Forecasts

North Slope Production and Costs FY 2008, per HB 3001 Fiscal Note and Spring 2007 Forecast	HB 3001 Fiscal Note	Spring 2007 Forecast
FY 2008		
Production (barrels per day)	802,000	764,000
Operating costs ($millions)	$1,076	$2,160
Capital costs ($millions)	$1,052	$1,900
Total Costs	**$2,128**	**$4,060**
Total Costs per Barrel	$7.27	$14.56
Operating costs per barrel	$3.68	$7.75
Capital costs per barrel	$3.59	$6.81

Current Revenue Forecasts

Actual

Estimated Production Tax Payments (in $millions)	
July 2007	$184.5
Aug 2007	$213.5
Sep 2007	$166.7
Total Payments - Quarter	$564.7
less estimated credits & refunds	$50.0
Total Quarter	**$514.7**

Production	mmBbls/day
July 2007	0.724636
Aug 2007	0.724564
Sep 2007	0.658021
Average	0.702407

Price	$/bbl ANS WC
July 2007	$69.11
Aug 2007	$75.93
Sep 2007	$73.83
Average	$72.96

DOR Forecast

Three Month Tax Calculation	
Average Price	$72.96
Less Transport	-$6.44
Wellhead Value	$66.52
Times production	0.702407
Times days in Qtr	92
Total prod value	$4,298.4
Less Royalty	-$537.3
Total value at Pt. of Prod.	$3,761.1
Capex/bbl	$7.80
Opex/bbl	$8.35
Total Capex	$513.0
Total Opex	$525.0
Production Tax Value	$2,723.1
Tax Rate	22.5%
Tax b/f credits & progressivity	$612.7
Progressivity tax rate	2.0%
Progressivity Surcharge	$54.5
Tax before credits	$667.2
Capex credits	$153.9
Total after credits	**$513.3**
Percent Error	0.3%

Tools for Forecasting Costs

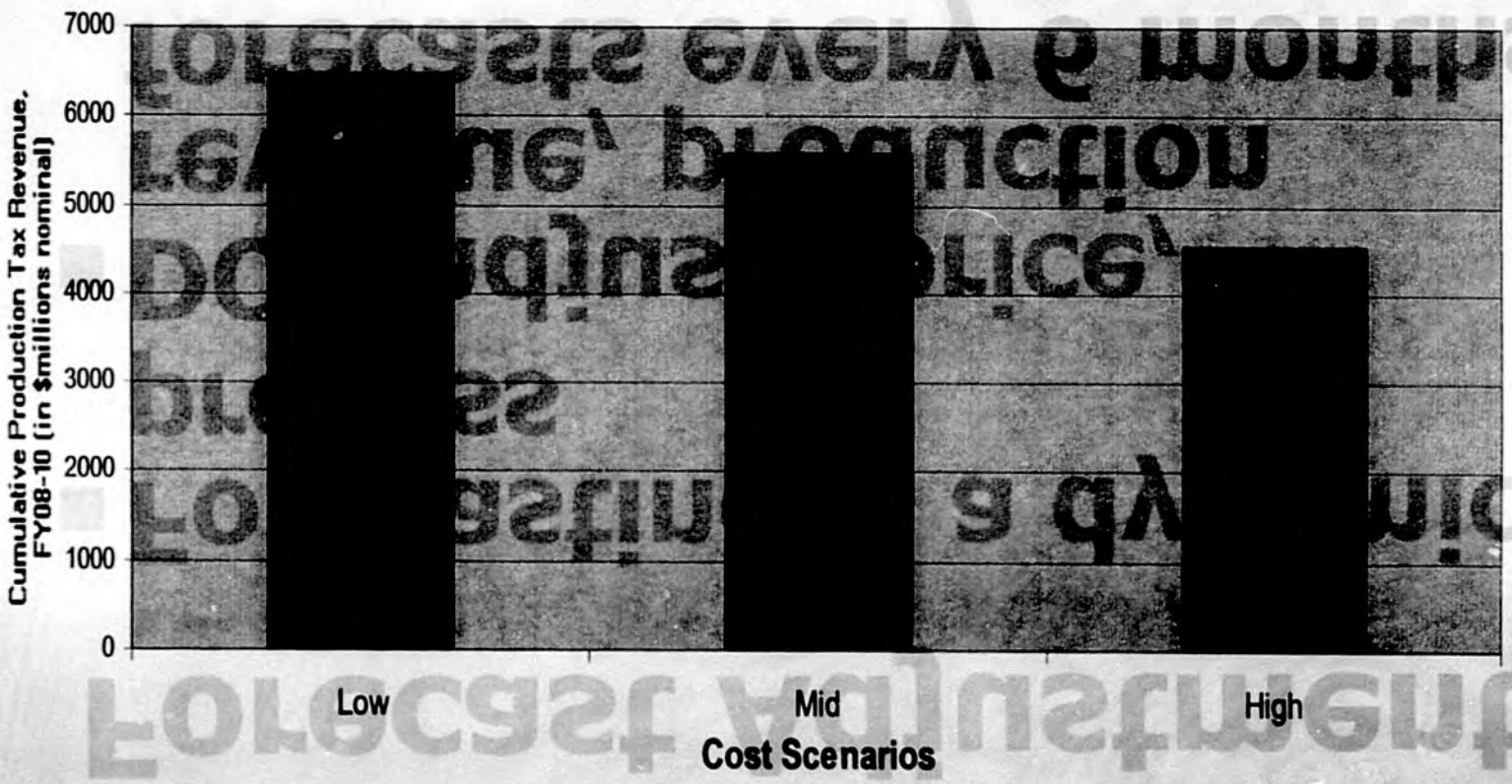
- *Require cost reporting (current and forecast)
- *Monitor data submitted to DOR
- *Monitor data submitted to other agencies (e.g. plans of development)
- Monitor publicly available information (e.g. economic indicators, labor and material costs)

*New Enhanced Tool Under ACES

Three Cost Forecasts

- Mid, Low, and High
- All Costs in Nominal Dollars
- Forecasts reflect different assumptions about unplanned maintenance costs, spending behavior; not simply a +/- 20%
- Costs and investments reflect oil price changes

Impact of Low, Mid, and High Forecasts on Tax Revenues



Forecast Adjustments

- Forecasting is a dynamic process
- DOR adjusts price, revenue, production forecasts every 6 months
- Cost forecasts to be reviewed quarterly and adjusted as necessary

Forecasting Improved Through ACES

- ACES requires more complete cost reporting, both monthly and annually
- ACES requires forward-looking cost information
- ACES provides clearer rules for defining lease expenditures
- ACES improves audit function

Costs Policy Implications

- Costs of production should not be ignored in tax policy
- Understanding industry costs benefits the state
- Cost sharing through credits puts state in "partnership" with industry

North Slope Oil and Gas Activity 2006 - 2007

FEX:
South Puviak 3D and Harrison Bay 3D Completed in 2006.

ConocoPhillips:
Fiord Production Startup Aug. 2006.

ConocoPhillips:
Qannik Development Under Way.

ConocoPhillips:
Nanuk Production Startup Nov. 2006.

Anadarko:
Nikaitchuq Delineation Wells Spudded 2006 - 07.

AVCG/Brooks:
3D Seismic Proposed 2007.

AVCG/Brooks:
3D Seismic Proposed 2007.

Shell:
Beaufort Sea OCS On-Ice 2007 Seismic Program Planned.

Shell:
Beaufort Sea OCS Summer 2006 Seismic Programs Completed.

BP:
Evaluating Liberty Prospect for Extended-Reach Development from Onshore Facilities.

Teck Cominco AK, Inc.:
Sakkan Unit Approved for Shallow Natural Gas Production for the Red Dog Mine.

Beaufort Sea

Harrison Bay

Teshekpuk Lake

National Petroleum Reserve - Alaska

Arctic National Wildlife Refuge

Dalton Highway

Trans-Alaska Pipeline

NOATAK 1

KRU QANNIK CD2-04

Colville River

Nikaitchuq

OLIKTOK POINT I-1

OLIKTOK POINT I-2

Oooguruk

Milne Point

MT. ELBERT 1

Mortheastar

SAK RIVER 1

KRU WSAK 1H-NORTH

NORTH SHORE 1E

KRU WSAK 1R-EAST

KRU WSAK 1H-SOUTH

Kuparuk River

ROCK FLOUR 2

Prudhoe Bay

Duck Island

Liberty

Prudhoe Bay

Seadhorse

KUPARUK RIVER

SAVIAK

Rock Flour

ROCK FLOUR 2

ANTIGUA

Aurora Formation

HAILSTORM 1

Badami

CRONUS 1

Cronus

Jacob's Ladder

JACOB'S LADDER C

Dinictis

Glyptodon

MAGGORE-1

Muskoxen

Ekko

Smilodon

Panthera

Indrico

Megaceros

Mammoth

Smilodon

Creodont

Wooly

Mastodon

Megatherium

Titanothere

Sakkan Unit

Sakkan Unit Location

1:300,000

0 0.9 1.8 2.7 3.6 4.5

Miles

2005 - 06 3D Seismic Programs

2007 3D Seismic Programs

2007 Unit Activity

2006 - 07 Development Activity

EXPLORATION WELLS DRILLED 2005 - 06

EXPLORATION WELLS DRILLED 2007

WELLS PERMITTED/PLANNED FOR 2007 - 08

Unit Boundaries

3-Mile Limit

Major Roads

Trans Alaska Pipeline

Gas Accumulation

Oil Accumulation

N

W E

S

Albers Equal Area, CM -150
NAD 1927

1:750,000

Miles

01.53 6 9 12

October 2007

Alternative Tax Credits for Oil and Gas Exploration

ACES Amendments to AS 43.55.025

Kevin Banks
Acting Director
Division of Oil and Gas

October 21, 2007

Alaska Department of
Natural
Resources

www.dog.dnr.state.ak.us/oil/

- Before PPT, DOR offered credits for exploration wells and seismic surveys
- ACES broadens this program to grant 20% credits for more exploration wells by defining "distinctly separate" targets and extending the time allowed to drill wells from 50 days to 540 days. [AS 43.55.025(k)]
- ACES maintains 40% credits for wells
  - North Slope: drilled more than 25 miles from an existing unit
  - Cook Inlet: drilled more than 10 miles from an existing unit

- ACES maintains 40% credits for seismic surveys conducted outside of existing units
- ACES creates new 5% credits for old seismic surveys if the DNR commissioner determines that the acquisition is in the best interest of the state [AS 43.55.025(l)]
- ACES requires pre-approval of exploration well or seismic survey plans and subsequent confirmation that the well or seismic data collected are within the intent of the plans [AS 43.55.025(c)]

- **Information Requirements**

  - ACES requires more information (i.e., core, test fluids, seismic data) from the activities that generate credits to be provided to the state [AS 43.55.025(f)]

- **Timing Requirements**
  - Limits credits to completed or abandoned wells
    - Extends confidentiality not available for these wells
  - Confidentiality for new seismic surveys receiving credits limited to 10 years
  - ACES extends time to submit requested data [AS 43.55.025(f)]
  - Credits are to be remitted only after the state has received the data [AS 43.55.025(f)]

- **Wrap-up**
- North Slope Activity Update
- Observations

A Topica[illegible] the



[illegible] K & L Gates
[illegible]21, 2007

A Few Background Basics:

The oil and gas production tax . . .

- is in AS 43.55
- is in addition to royalties, property tax, and income tax
- has existed since before statehood
- generally applies a percentage tax rate to the *value* of oil and gas produced
- unlike royalties, applies to production from private and federal leases as well as state leases

Core Provisions of HB 3001 (enacted in 2006)

- AS 43.55.011(e) – (i): tax levied on value of oil and gas produced
- AS 43.55.160: calculation of taxable value of oil and gas
- AS 43.55.165 & .170: determination of upstream costs that may be deducted in calculating taxable value of oil and gas

(cont.)

Core Provisions (continued)

- AS 43.55.023 & 43.55.024: new tax credits
- AS 43.55.020(a): monthly estimated tax payments and final payment on March 31 of year following production (because this is now an annual, not a monthly, tax)
- AS 43.55.030(a): just one annual return

AS 43.55.011(e) (current)

- There is levied on the producer . . . a tax for all oil and gas produced . . . equal to 22.5 percent of the production tax value of the taxable oil and gas as calculated under AS 43.55.160 . . .

- *Note*: "production tax value" is net value

AS 43.55.011(e) (continued)

Exceptions:

- **Tax does *not* apply to**
  - **state or federal share**
  - **landowner's royalty share (which is subject to a different tax provision)**
- **Cook Inlet production subject to ceilings based on past taxes (AS 43.55.011(j) & (k))**
- **North Slope production subject to a minimum tax depending on price of ANS (AS 43.55.011(f))**

AS 43.55.011(g) (current)

- For each month when the net value of a producer's oil and gas exceeds $40 per barrel, the tax rate under subsec. (e) is in effect increased by ¼ of a percentage point for each dollar per barrel over $40
- Informally known as "progressivity tax"
- Gas and oil are added together by treating 6 million Btu of gas as equivalent to one barrel of oil (see AS 43.55.011(h), 43.55.900(17), (18) & (24))

AS 43.55.011(e) (new)
Bill sec. 15

- **There is levied on the producer . . . a tax for all oil and gas produced . . . equal to the production tax value of the taxable oil and gas as calculated under AS 43.55.160 multiplied by the tax rate determined under (g) of this section.**

AS 43.55.011(g) and (h) (new)
Bill secs. 17 and 18

- "The tax rate . . . is 25 percent plus" the progressivity tax rate
- The progressivity tax rate is 1/5 of a percentage point for each dollar per barrel over $30 net value
- Progressivity is calculated on an annual, not monthly, basis

North Slope Tax Floor
Bill sec. 16

- New AS 43.55.011(f): minimum tax is 10 percent of gross value at the point of production of oil and gas from a unit (or nonunitized reservoir) that
- (1) has produced a cumulative total of 1 billion barrels; and
- (2) is producing over 100,000 barrels a day (average during the most recent calendar year)

Cook Inlet Tax Ceilings
Bill secs. 19 and 20

- Tax ceilings are not changed (conforming amendments only)
- Note: sec. 21 of the bill adds language dealing with Cook Inlet tax credits to be consistent with sec. 55, which clarifies how excess lease expenditures are treated

AS 43.55.160 (bill secs. 52-55)

- The basic principle is unchanged: taxable value = gross value at the point of production minus lease expenditures
- Wording has been changed:
- (1) monthly values are no longer needed (progressivity is now annual)

AS 43.55.160 (cont.)

- (2) bill is clearer and more specific on when a producer may or may not use lease expenditures for operations at one location as deductions for oil and gas produced at another location
- These rules are necessary to implement the different tax treatments of different areas and fields (Cook Inlet ceilings, North Slope floor, tax credit under AS 43.55.024(a))

AS 43.55.160 (cont.)

- For instance:
- (i) To avoid undercutting the tax floor, deductions may not be "exported" from units subject to the tax floor (AS 43.55.160(f)(2))
- (ii) To avoid double-dipping re: Cook Inlet tax ceilings, deductions must first be used up in Cook Inlet and may not be shielded by the ceilings (AS 43.55.160(h) and (i))

AS 43.55.165 (bill secs. 56-59, 64)
Lease Expenditures

AS 43.55.165(a) and (b) are rewritten and reorganized:

- **(1) for more clarity**
- **(2) to limit lease expenditures to only what the Department of Revenue allows by regulation**

Lease Expenditures (continued)

- AS 43.55.165(c) and (d) are repealed.
- Those provisions allowed the Department to substitute cost billings under unit operating agreements in place of the general standards for determining lease expenditures.

Lease Expenditures (continued)

- AS 43.55.165(e): the list of *excluded* costs is expanded:
- par. (6) – costs arising from violation of law or noncompliance with lease or permit obligation
- par. (15) – all dismantlement, removal, & restoration costs (costs are prorated for past production under current law)

Lease Expenditures Exclusions (cont.)

- par. (19) - repair or replacement of facilities or equipment associated with an unscheduled drop in production or an oil spill or unpermitted release

- par. (20) – crude oil topping plant (but deduction is allowed for value added of product used in lease operations)

Tax Credits under AS 43.55.023
Bill secs. 26-31, 65

Changes to .023(a) – qualified capital investment expenditure credits :

- **Only 50% of a credit may be used the first year**
- **For exploration, requirements are conformed to changes in .025 credits (see below)**

Tax Credits under AS 43.55.023 (continued)

Changes to .023(a) (continued)

- Credits for capital expenditures in a unit subject to the tax floor may be applied only against tax on oil and gas production from that or another unit subject to the tax floor

Tax Credits under AS 43.55.023 (continued)

- **Change to .023(b) – carried-forward annual loss credit :**
  - **No carry-forward for unused lease expenditures for units subject to the tax floor**

Tax Credits under AS 43.55.023 (continued)

Change to .023(d) – transferable tax credit certificates:

- **Two certificates will be issued, each for half of the credit**
- **One certificate cannot be used until the next year**

Tax Credits under AS 43.55.023 (continued)

New subsection .023*(l)* :

- **Makes clear that a tax-exempt entity may not obtain a transferable tax credit certificate**

Tax Credits under AS 43.55.023 (continued)

AS 43.55.023(i) is repealed:

- **This eliminates the transitional investment expenditure credits for investments that were made during the five years before April 1, 2006.**

Tax Credits under AS 43.55.025
Bill secs. 36-44

- **Sec. 36 - Existing 2016 sunset is uniformly applied**
- **Secs. 37 & 43 - Exploration well credit expanded to delineation wells within 2 drilling seasons (rather than being limited to discovery well or dry hole)**
- **Sec. 37 - Well must be completed or abandoned, not just suspended, before credit may be claimed**

Tax Credits under AS 43.55.025 (continued)

- Sec. 37 - Costs excluded if due to gross negligence or health/safety/ environmental violation
- Sec. 38 – Clearer definition of requirement for new exploration target; 3-mile requirement deleted for Cook Inlet; DNR evaluation required in advance and after drilling

Tax Credits under AS 43.55.025 (continued)

- Sec. 39 – Data submission requirements are more specific
- Sec. 39 – Well data confidentiality limited to 24 months
- Sec. 39 - Two certificates will be issued, each for half of the credit; one certificate cannot be used until the next year

Tax Credits under AS 43.55.025 (continued)

- Sec. 39 - Makes clear that basic information about tax credit is public
- Sec. 40 - Makes clear that a tax-exempt entity may not transfer a tax credit certificate
- Sec. 44 - New five percent tax credit available for old seismic data if DNR determines that acquiring the data for public distribution is in state's interest

State Purchase of Tax Credits Certificates – Bill secs. 45 & 63

- New AS 43.55.028 establishes oil and gas tax credit fund to purchase credit certificates from explorers or small producers that have no tax liability to apply credits against
- Funded by appropriation of a percentage of production tax revenues
- Replaces existing cash refund authority under AS 43.55.023(f) (repealed by bill)

State Purchase of Tax Credits Certificates (continued)

- **Retains existing criteria for refunds except eliminates $25 million maximum**

Payment of the Tax
Bill secs. 22-25, 51

- Current system of monthly installment payments and final payment on March 31 is retained
- Installment payments now take account of the tax floor for units subject to the tax floor and also take account of Cook Inlet tax ceilings
- Installment payments do not take account of progressivity rate

Payment of the Tax (continued)

- **AS 43.55.110(f), Bill sec. 51 – Gives express authority to Department to require tax payments to be made electronically**

Reporting Requirements AS 43.55.030, 43.55.040

- Bill sec. 46 – Makes clear that every oil or gas producer must file an annual return, whether or not tax is due
- Bill sec. 46 - Expands the list of specific information requirements for returns (note: Department retains general authority to require more information)

Reporting Requirements (continued)

- Bill secs. 47 & 49 – Additional penalty of up to $1,000 per day for late filing or nonfiling of required returns or reports
- Bill sec. 48 – Requires explorers or producers to file an annual statement on expenditures (or adjustments) even if no oil or gas is produced during the year

Reporting Requirements (continued)

- **Bill sec. 48 – Makes clear that the Department may also require monthly reports from producers, explorers, and operators**
- **Bill sec. 49 – Adds express authority for the Department to require reporting of forward-looking information for revenue forecasting purposes**

Reporting Requirements (continued): Bill sec. 51

- AS 43.55.110(e) – Gives express authority to Department to require returns and reports to be filed electronically

Confidential and Public Information

- AS 38.05.035, Bill sec. 2 – broad authority for DNR to share oil and gas lease related information with DOR for purposes of administering the production tax
- AS 43.05.230, Bill sec. 13 – broad authority for DOR to share production tax related information with DNR

Confidential and Public Information (continued)

- Under both provisions, confidential information is still confidential
- AS 43.55.890, Bill sec. 61 – Makes clear that Department of Revenue may publish extensive production tax information aggregated among at least three producers or explorers

Additional Administrative Improvements

- AS 39.25.110, Bill sec. 10 – oil and gas auditors placed in exempt service
- Transition provision, Bill sec. 67 – current employees may opt to stay in classified service
- AS 43.05.260, 43.55.075, Bill secs. 14, 50 – statute of limitations for production tax is six years, not three years

Additional Administrative Improvements (continued)

- **AS 43.55.075(b), Bill secs. 1, 50 - Legislative confirmation of Department of Revenue's interpretation of statute of limitations as applied to events that retroactively change amount of production tax or credit: period of limitations begins to run when a return is filed reflecting the change**

Additional Administrative Improvements (continued)

- **AS 43.55.110(g), Bill sec. 51 – Gives express authority to the Department of Revenue to issue advisory bulletins interpreting production tax statute and regulations for guidance of taxpayers and others; non-binding unless Department provides otherwise**

Transition, Applicability, and Effective Dates

- **Bill secs. 66, 72 – Most substantive changes in the production tax are prospective beginning Jan. 1, 2008**
- **Bill secs. 66, 71 – Changes to lease expenditure exclusions and use of unit operating agreements for lease expenditures are retroactive to April 1, 2006**

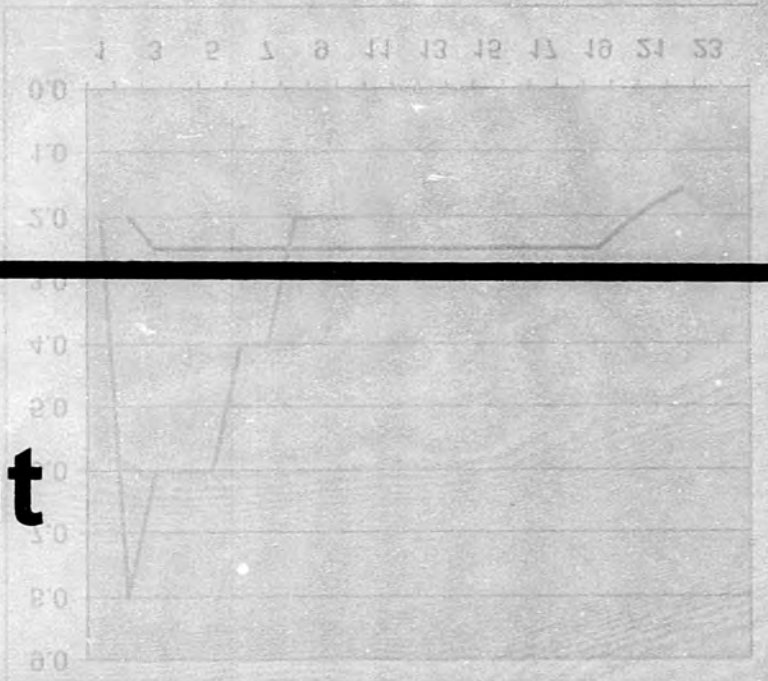
Transition, Applicability, and Effective Dates (continued)

- Bill secs. 66, 71 – Statute of limitations extension applies to still-open periods and retroactive to April 1, 2006
- Bill sec. 71 – Clarification that tax-exempt entities may not transfer tax credits applies back to beginning of the respective tax credit provisions

Transition, Applicability, and Effective Dates (continued)

- Bill sec. 73 – Most other provisions of the bill take effect immediately
- Bill secs. 68, 70 – DOR and DNR may start developing regulations immediately, and regulations may be retroactive to applicability date of the statutory provisions they implement

Payout

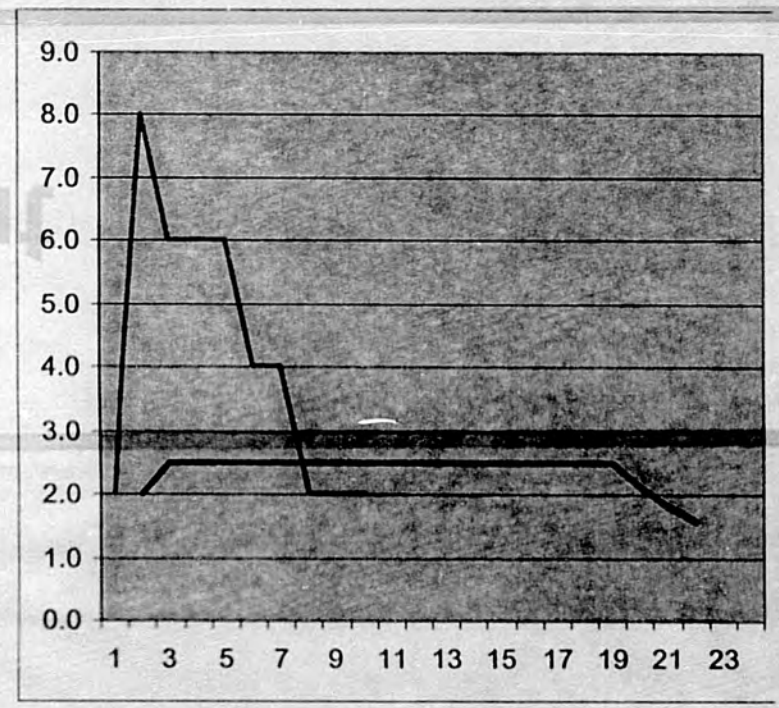


10-21-07

What is expectation as to the time to recover initial investment?

- **Simple answer – As soon as possible!**

- **Rule of thumb – from date of first production plus:**
  - Oil – 3 to 6 years
  - Gas – 5 to 9 years (combination of higher costs and lower BOE)



Other Countries - PSC

- **Production Sharing Contracts**
  - Recovery of costs is commonly known as "Cost Oil"
  - Range of annual cost recovery varies
    - Some put no cap on cost recovery
    - Others may cap cost recovery at say, 40% of revenue
  - To compensate for particular situations the recovery may be 'tweaked'
    - Uplift
    - Share of First Tranche Petroleum (aka Royalty)
    - The "tweaks" are to provide some compensation for the time value 'loss' of longer recovery times

Other Countries – Tax & Royalty

- **Basically speed of deduction and credits**
  - Depreciation period
    - 1,3,10 years
  - Depreciation method
    - Straight line
    - Declining balance
    - Depletion (based on production to remaining reserves)
  - Credits
    - An additional deductions equal to a percentage of qualifying investment

Another key impact

- **The "Ring Fence" can provide very different value to the oil company**
  - Consolidated by taxing district (e.g. the entire State of Alaska)
    - Immediately write off aqainst other income streams
    - Progressive systems provide possible increased benefit
  - Ring Fenced say by individual field or reservoir
    - Usually have to wait until a discovery is turned into a development and revenue starts before the oil company can begin to recover their costs

Attractiveness of Exploration Credits

Alaska Exploration Investment Credits

- **One of the stated goals is to attract new exploration, new investment**
- **How does Alaska compare to other regimes?**
  - Compares very favorably on a global basis
  - State / Feds effectively becomes a major 'investor'
- **Comes close to leveling the playing field between incumbents and new entrants**
  - A feature that is not available in most countries
  - Usually there is a high barrier to entry

Alaska is offering…

- **Depending on parameters such as start date and distance from other existing oil and gas units and wells, investors can:**
  - ➢ Earn credits of 20% up to 40% of qualifying expenditures
  - ➢ Deduct money spent against current state and/or federal income tax liability
    - If no current PPT/ACES income can request and receive loss carry forward credits
  - ➢ Achieve favorable potential outcome after State/Federal Income Tax impact is considered
    - Contractor share – 21 to 36%
    - State/Federal share – 64 to 79%

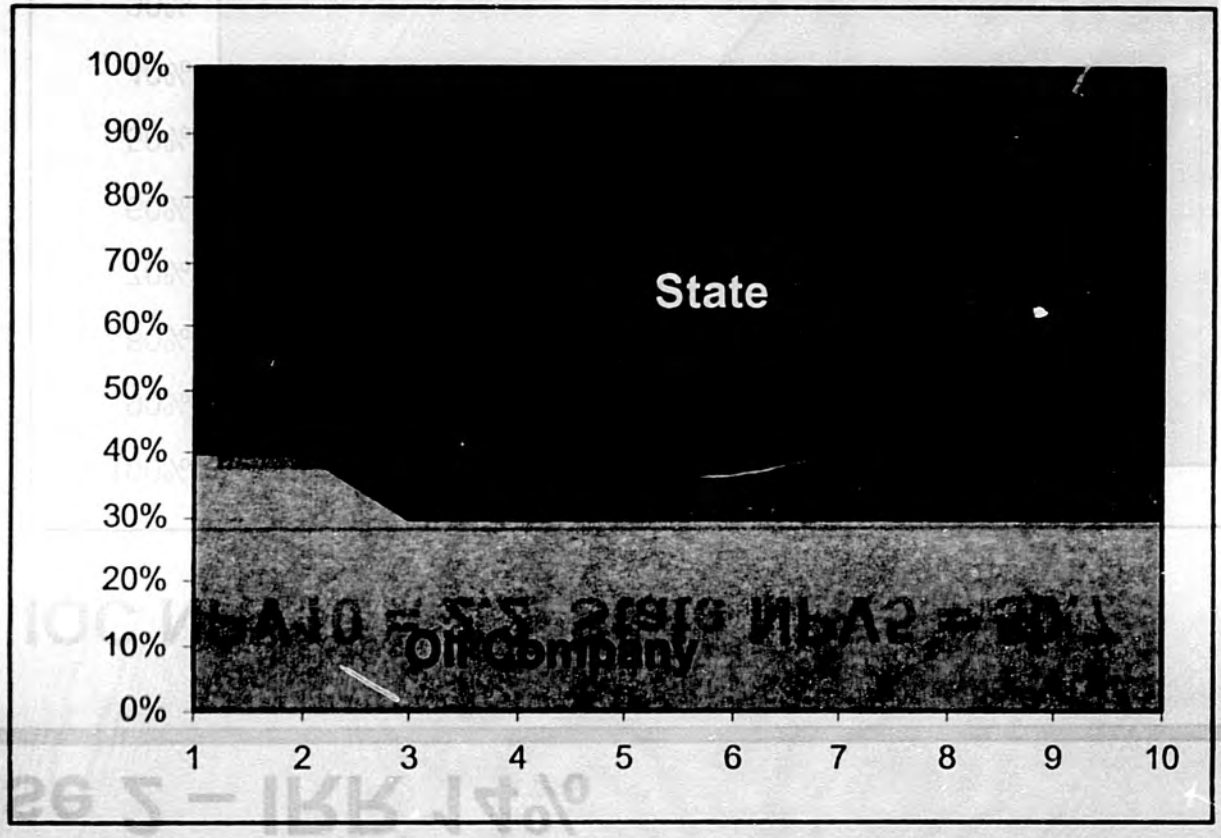
Example

Example of timing of take

- **Assumptions**
  - Investment of 20
  - 10 years of flat cash flow = 100
    - 10 per year
    - Overall State gets 68, Oil Co gets 32
- **How does timing impact IRR (Internal rate of return), IOC NPV and State NPV?**

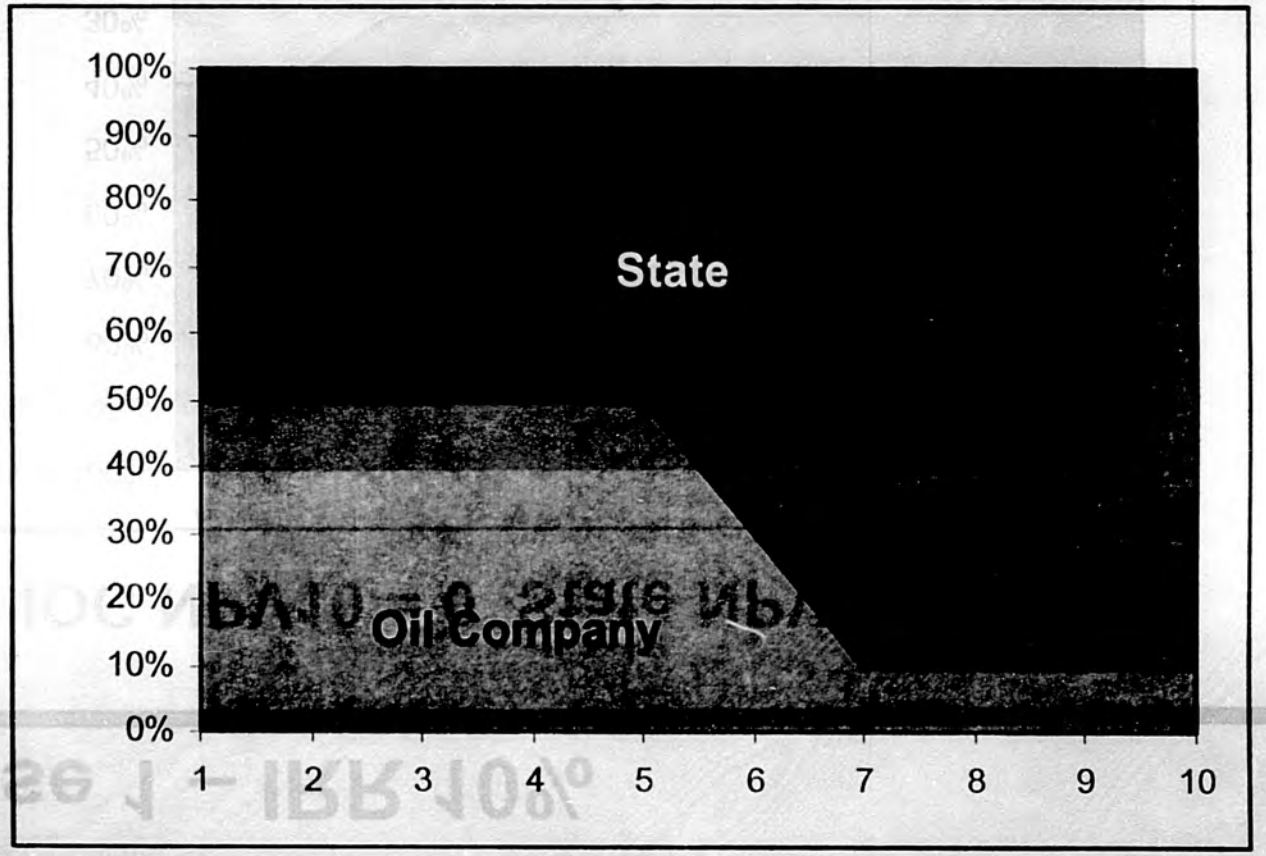
Case 1 – IRR 10%

- **IOC NPV10 = 0 State NPV5 = 52**



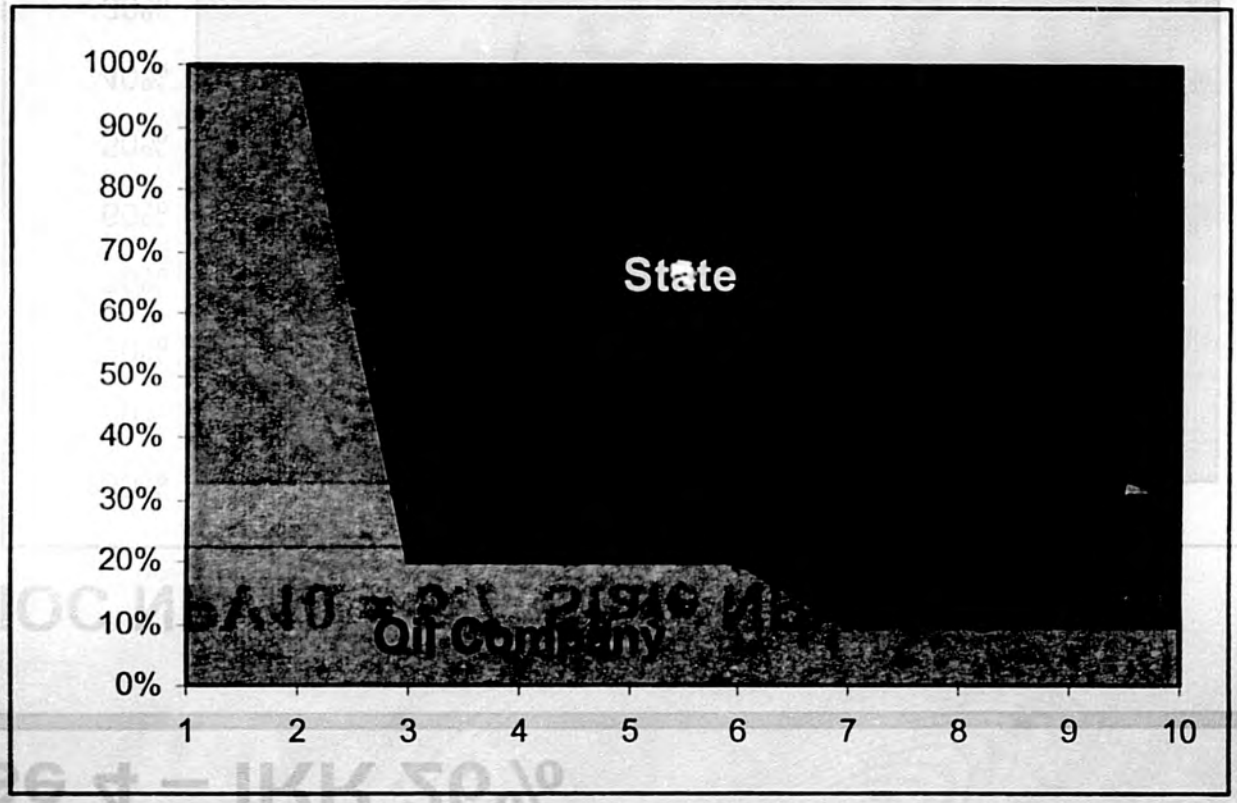
Case 2 – IRR 14%

- **IOC NPV10 = 2.2 State NPV5 = 50.7**



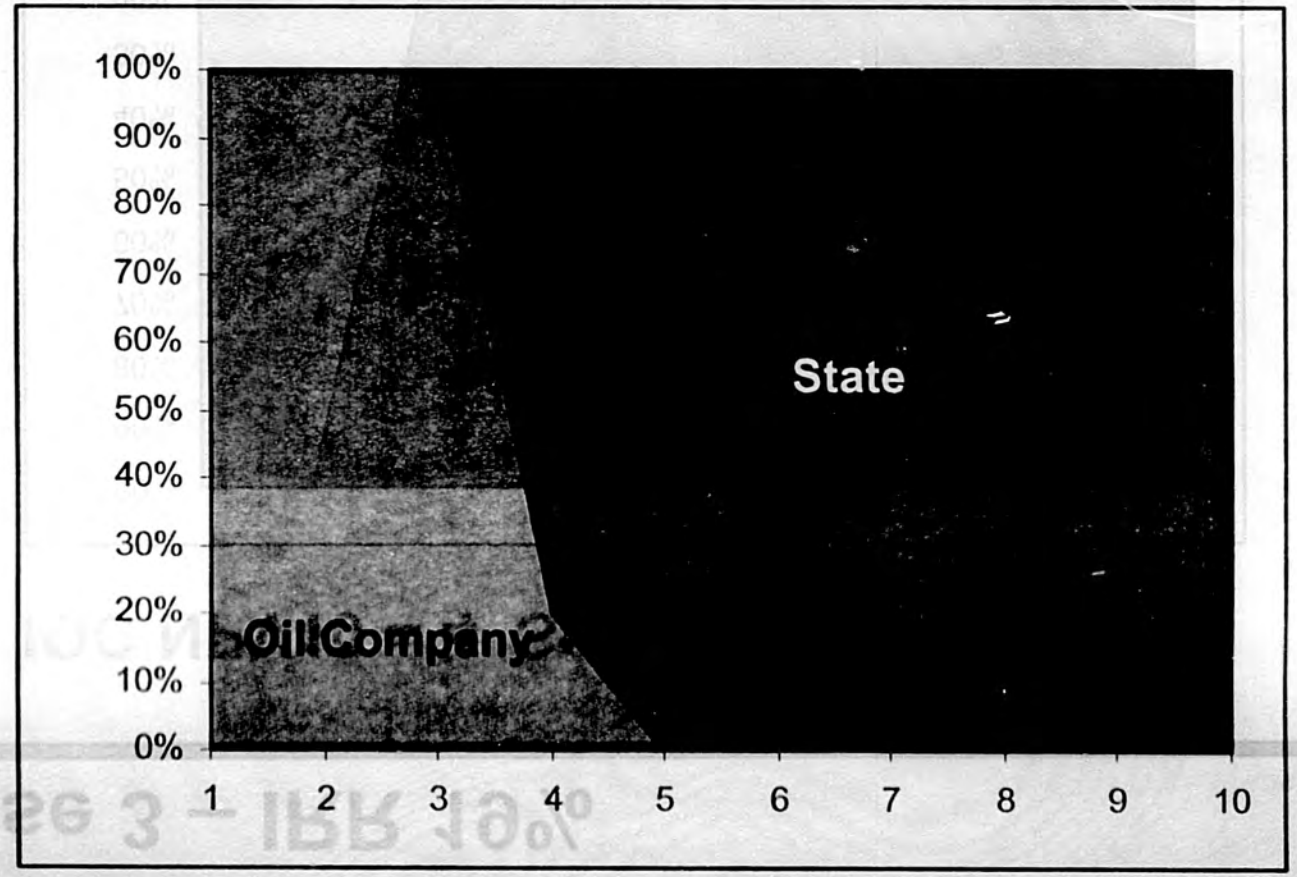
Case 3 – IRR 19%

- **IOC NPV10 = 4 State NPV5 = 49.5**



Case 4 – IRR 26%

- **IOC NPV10 = 5.7 State NPV5 = 49.3**



ACES

Alaska's Clear and Equitable Share

Joint Hearing
Investment Climate

- Comments from DNR Commissioner, Tom Irwin
- The Cost Story
- Field Models and Investment Climate
- Equal Value for Explorers
- Sectional Overview

ACES
Alaska's Clear and Equitable Share

Equal Value for Explorers

- Cash for Credits Earned by Explorers
  - Establishes a Tax Credit Fund
- Full Carry-Forward Value of Investment
- Expanded Exploration Incentive Credit Program

SB 2001/HB 2001
October 20, 2007
Supplement to the Sectional Analysis of October 1 2007
Authors: Dan Dickinson & Steve Porter

Approximately 50 sections of the bills submitted on the first day of the special session were changed from the October 1 work draft. Where those changes were only punctuation, style, word, or grammar edits that do not affect the original analysis they are merely listed as "minor changes."

Minor changes – Section 1

Section 2 – Expands "data" that must be provided by DNR to DOR to "reports, files and other information."

Section 8 – Although this section adds approximately 5 pages of text to the bill, it merely restates the entire existing text of AS 38.05.180 (j) in order the make a change to AS 38.05.180(j) (6) (B). Section 8 was originally just the text of AS 38.05.180(j) (6) (B).

Section 10 – Adds Department of Natural Resource royalty auditors to the list of exempt employees.

Minor changes – Sections 15 – 22; 24 – 26

Section 26 also incorporates two substantive changes.

1. If more than one explorer holds an interest in a well, to obtain a .023 credit for exploration, that explorer, and any others holding an interest in the exploration, have to agree in writing not to invoke their rights to have information held confidential by DNR longer than 2 years.

2. The two legacy fields – Prudhoe and Kuparuk are "combined." Credits still cannot be applied against taxes from other non-legacy fields. However, unlike the October 1 work draft of the bill, credits from one legacy field can be applied against taxes from the other.

Minor changes – Sections 27 – 29; 36 – 39

Section 39 also incorporates two substantive changes

1. If more than one explorer holds an interest in a well, to obtain a .025 credit for exploration, that explorer, and any others holding an interest in the exploration, have to agree in writing not to invoke their rights to have information held confidential by DNR longer than 2 years.

2. The 30 day period that an explorer has to provide certain data to DNR may be extended to "a period provided by the Department of Natural Resources."

Minor changes – Sections 42, 44 – 46

Section 47 - Makes clear that the $1,000 a day reporting penalty applies to both "reports" and "statements."

Minor changes – Sections 48 – 50

Section 51 – Authorizes the DOR to issue non-binding "advisory" opinions. The opinion is not binding on the DOR, meaning that if a taxpayer relies on the opinion and the department subsequently changes its mind, merely having followed the advisory opinion does not shield the taxpayer from interest and penalties.

Minor changes – Sections 42, 54, 55, 56

Section 58 – Adds any costs arising from "violations of law, or failure to comply with an obligation under a lease, permit or license issued by the federal government" to the list of costs which must be excluded from qualified lease expenditures.

Minor changes – Sections 59, 60 and 62

Section 63 (a), (b) and (c) are now section 63, 64 and 65, and subsequent sections 64 – 71 are renumbered 66 – 73.

In the new Section 67, DNR auditors are given (as DOR auditors were in the original bill) 90 days to opt to either become exempt or to retain their status in a union position.

MEMORANDUM
DEPARTMENT OF NATURAL RESOURCES

State of Alaska
DIVISION OF OIL AND GAS

TO: Senator Bert Steadman
Co-Chair Senate Finance Committee

DATE: May 18, 2007

FILE NO:

THRU:

TELEPHONE: 269-8800

FROM: Kevin Banks
Acting Director

SUBJECT: Royalty and Tax Incentives Presentation to Senate Finance 4-25-07

On Thursday, April 25, 2007, I gave a presentation to the Senate Finance Committee about the various royalty and tax incentives that are now available to the oil and gas industry in Alaska. As I indicated during my testimony, I was unable to prepare a formal slide presentation on short notice. Instead, I promised the committee that I would follow-up with a memo that would summarize my presentation. Here is the summary.

The catalogue of royalty and tax incentives now offered by the state of Alaska are available to any qualified company willing to commit to exploring and developing the state's oil and gas resources. It should be noted that, while there is a growing interest to find natural gas in anticipation of the North Slope gasline, the principal target of these incentives on the North Slope has been the exploration and development of oil. These incentives are sought after by explorers and developers who face a commercial landscape where access to regulated oil pipelines in the state is not constrained and where the oil pipeline version of rolled-in rates is available.

Explorers want incentives for marginal oil prospects even though the transportation cost, as a proportion of the market value of oil, is relatively small. Commercializing gas is challenged by the relatively higher cost of transportation as a proportion of market value. To illustrate this point, consider that the combined marine transportation and TAPS tariff is about $7.00 per barrel for ANS crude oil that sells in the U.S. West Coast for more than $60.00. Contrast this with a $2.00 - $2.50 per mmBtu tariff on ANS gas that today sells for $6.50. On an energy equivalent basis, the cost of transportation for gas is two-to-three times the cost of transportation for oil.

The division has incorporated all of the incentives that are currently available in the prospect modeling done in our economic analysis of AGIA. Because they are available to every company, these incentives, by themselves, do not favor the explorer/developers vis-à-vis incumbent producers. To provide pipeline access for these players, the terms in AGIA are required.

During the hearing on April 25, 2007 committee members were given a list of the royalty and tax incentives now offered by the state. Some of these incentives are particularly focused on different regions in the state. During my testimony, I focused on those that applied to the North Slope.

DIRECTED INCENTIVES

Exploration Incentive Credits (EICs)

AS 38.05.180(i) provides royalty and tax credits for up to 50 percent of drilling costs on a lease or 50 percent of seismic costs on unleased state lands. This provision allows DNR to incorporate the credit as part of a lease offered in our conventional lease sales. Since the state began offering EICs under this program, 22 exploratory wells qualifying for credit have been drilled on state leases. This has resulted in approximately $60 million in credits for exploratory drilling since 2004. There have been no applications for geophysical EICs.

AS 41.09.010 provides royalty and tax credits for up to 50 percent of drilling and seismic costs on unleased state and non-state lands. It also provides up to 50 percent of the seismic costs on lands within an exploration license area. The program is capped at $500,000 per project with a total program cost capped at $30 million. Data acquired under this program must be made public after two years. This provision expires on July 1, 2007.

Exploration Tax Credits

AS 43.55.025 provides an incentive credit for work performed between July 1, 2003 and July 1, 2016. The applicant may receive a production tax credit of 20 percent of drilling costs if the well is more than 3 miles from an existing oil and gas well or more than 25 miles from an existing unit (more than 10 miles from a unit in Cook Inlet). An applicant who meets both conditions may receive a credit of 40 percent. An applicant may also receive a credit for 40 percent of seismic costs if outside of an existing unit.

For income tax, AS 43.20.043 provides an incentive of up to 10 percent of the qualified capital investment costs for any oil and gas activity south of 68° latitude. The program applies to cost expended after the program was initiated on June 30, 2003 and is capped at 50 percent of the taxpayer's tax liability. Carry-forwards are allowed. These credits can be transferred if the entire business of the taxpayer is sold. The credit ceases to apply once production starts. The applicant cannot "double dip" other tax credits offered by the state.

Royalty Reduction/Modification

AS 38.05.180(j) provides three opportunities to modify royalty rates on a lease: to encourage development and production in a field or pool that would not otherwise be developed; to provide for a lower royalty rate where a field has shut in; or provide a lower royalty rate to extend field life. In the first instance, the royalty rate cannot go below 5 percent and must include a mechanism that accommodates for changes in price and may include a mechanism for changes in production rates, costs, etc. The royalty rate may be reduced to as low as 3 percent in the second and third instances.

Royalty modification under this statute has been approved only once, for leases at the Oooguruk Unit development project (2006). No production has occurred to-date at Oooguruk.

Royalty modification for Oooguruk reduced total state revenues by $111 million and added 8.4 percentage points to the producer's IRR (including PPT; see below.)

Cook Inlet Platform Royalty Relief

AS 38.05.180(f)(6) provides for a sliding scale royalty rate between a low of 5 percent and the lease rate depending on per-barrel production rates measured over a three month period on platforms and selected units within the Cook Inlet basin. The table below illustrates how the royalty rates are set.

Dolly, Grayling, King Salmon, Steelhead				
< 1200 Bpd = 5%	1200-1300 Bpd = 7%	1300-1400 Bpd = 8.5%	1400-1500 Bbl = 10%	>1500 Bpd = 12.5%
Baker, Dillon, "A", "C"				
<975 = 5%	975-1100 Bpd = 7%	1100-1200 Bbl = 8.5%	1200-1350 Bpd = 10%	>1350 = 12.5%
Granite Point, Anna, Bruce, and West McArthur River Unit				
<750 = 5%	750-850 Bpd = 7%	850-1000 Bbl = 8.5%	1000-1200 Bpd = 10%	>1200 = 12.5%

The Baker and "A" platforms have been shut-in. All other platforms are still in production.

Discovery Royalty

AS 38.05.180(f)(4) provides for a discovery royalty of 5 percent on leases issued before 1969. This discovery royalty is now rarely available because most of the leases where this discovery royalty may apply have expired.

AS 38.05.180(f)(5) provides for a 5 percent royalty rate in the following six fields in the Cook Inlet: Falls Creek, Nicolai Creek, Starichkof, North Fork, Redoubt Shoals, and West Foreland. In order to receive this incentive, the fields must be in production by January 1, 2004.

Lease Valuation Modification

AS 38.05.180(aa) substitutes for the lease term that requires the lessee to pay royalties based on the "higher-of" actual proceeds, market value, or the actual proceeds of other lessees in the same field. Instead, the value of royalty production sold by the lessee to a utility will be based on the contract price.

AS 38.05.180(ee) substitutes for the lease term that requires the lessee to pay royalties based on the "higher-of" actual proceeds, market value, or the actual proceeds of other lessees in the same field. Instead, the value of royalty production sold by the lessee to a chemical fertilizer plant will be based on the contract price.

PPT INCENTIVES

Tax Ceiling based on the Economic Limit Factor

AS 43.55.011(j) and (k) provides that the tax payer will pay no more than the tax it would owe under the severance tax and ELF system. Applies to production only in the Cook Inlet.

Qualified CapEx Credits

AS 43.55.023(a) provides a 20 percent transferrable tax credit under PPT for qualified capital expenditures.

Loss Carry-Forward Credits

AS 43.55.023(b) provides 20 percent transferrable tax credits under PPT for capital expenditures if the taxpayer is unable to take advantage of the qualified capex credits in any year.

Transition Investment Expenditure Credits

AS 43.55.023(i) provides a non-transferrable tax credit based on 20 percent of the capital expenditures incurred by the taxpayer between 2001 and 2006. The amount taken as a credit under this section may not exceed 10 percent of the taxpayer's qualified capital expenditures incurred during the calendar year for which the credit is taken.

Frontier Basin Production Credit

AS 43.55.023(a) provides a non-transferrable tax credit of up to $6 million for production south of 68° latitude and outside of the Cook Inlet basin. This credit will sunset in 2016.

Small Producer Credit

AS 43.55.023(c) provides for a non-transferrable tax credit of up to $12 million for small producers. The tax credit is based on a sliding scale: a producer whose statewide production is 50,000 barrels per day or less qualifies for the full $12 million tax credit, at 100,000 barrels per day the credit amount falls to zero.

As part of its evaluation of both the Oooguruk Unit and Nikaitchuq Unit royalty modification applications, DNR examined the impact of the PPT and the PPT tax incentives on new development economics. In both cases, the producer will pay more taxes on an undiscounted basis but, when discounted, the cash flows to the producer are significantly enhanced. For example, at DNR's mean price ($33) the Oooguruk the producer NPV(10) rose by nearly $90 million and 6.5 percentage points were added to the producer IRR. Similarly, the Nikaichuq producer will realize a $120 million in tax savings (discounted) with similar increases in producer IRR.

PROGRAM INCENTIVES

Exploration Licensing

AS 38.05.132 provides the authority to the DNR commissioner to award an exploration license of up to 500,000 acres in return for a work commitment from the licensee. The licensee pays no bonus bid, only a one-time $1.00 per acre fee, and no rental. The license may eventually be converted to a conventional oil and gas lease upon expiration of the license. Normal oil and gas lease obligations will apply at that point, i.e., a 12.5 percent minimum royalty rate, rent, and term. DNR has issued four licenses in three basins since the inception of this program, two in Susitna basin (both in 2003), and one each in Nenana (2002) and Copper River (2000) basins. Additionally, a license was issued but not executed by the licensee in the Bristol Bay basin (2004).

Nonconventional Gas Incentive

AS 38.05.180(n)(2) provides that the commissioner may award a lease for only gas and offer a 6.25 percent royalty and reduced rent if the lease is located in a region where gas from the lease does not compete with gas produced from conventional oil and gas leases, i.e., gas supplied to the Red Dog mine.

FEDERAL OUTER CONTINENTAL SHELF LEASES

The U.S. Department of the Interior, Minerals Management Service, has offered leases in the Beaufort Sea that provides a royalty suspension volume (RSV), the initial volume of production that is free of royalty. The RSV differs by lease size and location. Zone A is near existing infrastructure in the central part of the Beaufort Sea planning area; Zone B includes areas east and west of the existing infrastructure and the deep water. The lessee receives the benefit of the RSV only if it successfully discovers and develops oil on the lease.

Lease Size	Zone A	Zone B
< 771 Hectares (~2000 ac)	10 MMB	15 MMB
771 – 1541 ha (2000 – 3800 ac)	20 MMB	30 MMB
> 3800 ha (3800 ac)	30 MMB	45 MMB

The RSV program is subject to a price ceiling $39 per barrel, sustained for a year and adjusted for inflation (the 2004 ceiling = $41.47 per barrel). At this level, the lessee must pay royalty on all of the oil produced from the lease. If the price of oil falls below $21 per barrel through a quarter, the lessee pays no royalty and the royalty-bearing volumes suspended during this time do not count against the RSV.

There is no similar incentive program offered on federal lands within the NPRA.

cc: Tom Irwin, Commissioner DNR
Marty Rutherford, Deputy Commissioner DNR
Pat Galvin, Commissioner DOR
Jon Iverson, Director Tax Division DOR

Distributed By Rep. Keogan
10/21/07
House Oil & Gas

Annual Employment & Earnings
January - December 2003

Alaska

Industrial Classification	# of Units	Jan Emp	Feb Emp	Mar Emp	Apr Emp	May Emp	June Emp	July Emp	Aug Emp	Sept Emp	Oct Emp	Nov Emp	Dec Emp	Average Mo. Emp	Total Earnings	Avg Mo Earnings
TOTAL INDUSTRIES	20,370	278,121	284,453	287,706	289,592	303,400	311,032	308,802	310,151	313,323	298,858	289,542	287,537	296,876	$11,091,168,266	$3,113
TOTAL GOVERNMENT	1,832	80,056	82,201	83,147	83,345	83,834	78,773	66,565	68,322	82,426	82,795	82,432	82,468	79,697	$3,205,483,928	$3,352
FEDERAL GOVERNMENT	467	16,450	16,454	16,787	16,752	17,304	17,937	17,949	17,774	17,734	16,624	16,632	16,859	17,105	$933,304,127	$4,547
STATE GOVERNMENT	722	23,815	24,411	24,742	24,950	24,204	23,770	23,392	23,048	24,321	24,568	24,448	24,202	24,156	$955,173,348	$3,295
LOCAL GOVERNMENT	643	39,791	41,336	41,618	41,643	42,326	37,066	25,224	27,500	40,371	41,603	41,352	41,407	38,436	$1,317,006,453	$2,855
PRIVATE OWNERSHIP	18,538	198,065	202,252	204,559	206,247	219,566	232,259	242,237	241,829	230,897	216,063	207,110	205,069	217,179	$7,885,684,339	$3,026
GOODS-PRODUCING	3,483	31,493	35,059	35,709	34,350	37,774	43,758	51,167	49,834	44,876	40,185	34,217	31,151	39,131	$2,170,640,867	$4,623
NATURAL RESOURCE & MINING	334	10,324	10,575	10,780	10,794	11,106	10,994	11,081	11,104	10,927	10,565	10,203	10,081	10,711	$885,519,947	$6,889
Agriculture, Forestry, Fishing, Hunting	129	677	849	1,033	1,261	1,421	1,496	1,430	1,425	1,333	1,076	898	771	1,139	$45,877,471	$3,356
111 Crop Production	17	77	103	123	169	305	273	233	214	186	144	101	119	171	$3,302,553	$1,613
1112 Vegetable & Melon Farming	2	18	19	17	19	41	69	64	60	57	38	19	17	37		
1114 Greenhouse, Nursery, etc.	14	59	84	106	150	264	204	169	154	129	106	82	102	134		
1119 Other Crop Farming	1	0	0	0	0	0	0	0	0	0	0	0	0	0		
112 Animal Production	23	180	214	247	274	300	314	362	365	347	295	215	200	276	$8,909,699	$2,689
1121 Cattle Ranching, Farming	1	6	7	8	9	8	7	7	6	6	5	5	5	7		
1125 Animal Aquaculture	20	172	205	237	263	290	305	350	357	339	285	208	193	267	$8,677,904	$2,708
1129 Other Animal Production	2	2	2	2	2	2	2	5	2	2	5	2	2	3		
113 Forestry & Logging	33	336	442	562	674	681	750	661	698	648	540	478	360	569	$25,398,805	$3,719
1131 Timber Tract Operations	33	336	442	562	674	681	750	661	698	648	540	478	360	569	$25,398,805	$3,719
114 Fishing, Hunting, Trapping	39	60	73	75	73	55	57	84	76	91	66	65	64	70	$6,180,761	$7,367
1141 Fishing	39	60	73	75	73	55	57	84	76	91	66	65	64	70	$6,180,761	$7,367
115 Agriculture, Forestry Support	17	24	17	26	71	80	102	90	72	61	31	39	28	53	$2,085,653	$3,254
1151 Crop Production	1	0	0	0	7	7	9	15	7	4	0	0	0	4		
1152 Animal Production	2	5	4	4	5	5	7	7	7	6	4	5	4	5		
1153 Forestry	14	19	13	22	59	68	86	68	58	51	27	34	24	44		
Mining	205	9,647	9,726	9,747	9,533	9,685	9,498	9,651	9,679	9,594	9,489	9,305	9,310	9,572	$839,642,475	$7,310
211 Oil & Gas Extraction	35	2,584	2,591	2,564	2,530	2,538	2,573	2,566	2,554	2,517	2,535	2,523	2,525	2,550	$326,371,766	$10,666
212 Mining, Except Oil & Gas	73	1,321	1,308	1,334	1,388	1,473	1,550	1,558	1,538	1,503	1,464	1,376	1,332	1,429	$94,722,360	$5,525
2121 Coal	1	86	76	76	78	80	84	87	79	74	82	82	82	81		
2122 Metal Ore	29	1,141	1,132	1,137	1,152	1,166	1,214	1,231	1,212	1,207	1,186	1,148	1,152	1,173	$81,017,507	$5,755
2123 Nonmetallic Mineral, Quarrying	43	94	100	121	158	227	252	240	247	222	196	146	98	175		
213 Mining Support Activities	97	5,742	5,827	5,849	5,615	5,674	5,375	5,527	5,587	5,574	5,490	5,406	5,453	5,593	$418,548,349	$6,236

Data are preliminary and subject to revision
Blanks in the Total Earnings and Average Mo Earnings columns is due to confidentiality; data is suppressed
Source: Alaska Department of Labor and Workforce Development, Research & Analysis Section

Revised: 10/20/2004

Annual Employment & Earnings
January - December 2004

Alaska

Industrial Classification	# of Units	Jan Emp	Feb Emp	Mar Emp	Apr Emp	May Emp	June Emp	July Emp	Aug Emp	Sept Emp	Oct Emp	Nov Emp	Dec Emp	Average Mo. Emp	Total Earnings	Avg Mo Earnings
TOTAL INDUSTRIES	20,708	282,305	285,637	290,046	294,756	305,985	311,389	316,623	316,856	319,826	304,780	295,190	293,221	301,385	$11,637,904,696	$3,218
TOTAL GOVERNMENT	1,907	80,852	81,759	82,829	83,001	82,713	72,988	66,713	68,866	81,618	82,471	82,264	82,693	79,064	$3,298,491,072	$3,477
FEDERAL GOVERNMENT	471	16,463	16,549	16,684	16,953	17,272	18,033	18,084	17,885	17,536	16,967	16,741	16,936	17,175	$992,017,658	$4,813
STATE GOVERNMENT	787	23,913	24,188	24,611	24,704	23,945	22,994	23,503	23,046	24,651	24,365	24,405	24,383	24,059	$964,866,801	$3,342
LOCAL GOVERNMENT	649	40,476	41,022	41,534	41,344	41,496	31,961	25,126	27,935	39,431	41,139	41,118	41,374	37,830	$1,341,606,613	$2,955
PRIVATE OWNERSHIP	18,801	201,453	203,878	207,217	211,755	223,272	238,401	249,910	247,990	238,208	222,309	212,926	210,528	222,321	$8,339,413,624	$3,126
GOODS-PRODUCING	3,496	34,098	35,398	36,056	36,283	39,043	45,580	53,821	51,453	46,679	41,257	35,718	32,701	40,674	$2,285,647,330	$4,683
NATURAL RESOURCE & MINING	345	9,726	10,086	10,334	10,796	11,077	11,179	11,308	11,462	11,100	10,743	10,490	10,595	10,741	$938,124,483	$7,278
Agriculture, Forestry, Fishing, Hunting	141	525	666	863	1,113	1,329	1,356	1,346	1,327	1,249	1,058	909	851	1,049	$41,440,983	$3,291
111 Crop Production	16	78	93	117	194	295	275	249	207	188	118	91	98	167	$3,511,129	$1,753
1112 Vegetable & Melon Farming	2	16	16	16	19	43	65	73	64	59	37	25	19	38		
1114 Greenhouse, Nursery, etc.	14	62	77	101	175	252	210	176	143	129	81	66	79	129		
1119 Other Crop Farming	1	0	0	0	0	0	0	0	0	0	0	0	0	0		
112 Animal Production	25	161	208	260	301	320	329	354	363	361	271	224	184	278	$8,876,664	$2,661
1121 Cattle Ranching, Farming	2	3	3	3	6	7	6	9	8	8	8	5	5	6		
1123 Poultry, Egg Production	1	1	1	1	2	0	4	2	4	2	2	0	0	2		
1125 Animal Aquaculture	20	155	202	254	291	311	317	341	349	345	257	217	177	268	$8,671,458	$2,696
1129 Other Animal Production	2	2	2	2	2	2	2	2	2	6	4	2	2	3		
113 Forestry & Logging	30	193	284	392	503	568	576	543	538	514	510	492	453	464	$20,221,043	$3,633
1131 Timber Tract Operations	30	193	284	392	503	568	576	543	538	514	510	492	453	464	$20,221,043	$3,633
114 Fishing, Hunting, Trapping	50	66	58	60	66	67	58	89	108	90	97	50	65	73	$6,382,243	$7,302
1141 Fishing	50	66	58	60	66	67	58	89	108	90	97	50	65	73	$6,382,243	$7,302
115 Agriculture, Forestry Support	20	27	23	34	49	79	118	111	111	96	62	52	51	68	$2,449,903	$3,013
1151 Crop Production	1	0	0	0	4	4	10	7	8	9	0	0	0	4		
1152 Animal Production	3	4	4	5	5	17	17	22	22	20	11	12	13	13		
1153 Forestry	16	23	19	29	40	58	91	82	81	67	51	40	38	52	$2,251,875	$3,638
Mining	204	9,201	9,420	9,471	9,683	9,748	9,823	9,962	10,135	9,851	9,685	9,581	9,744	9,692	$896,683,500	$7,710
211 Oil & Gas Extraction	35	2,472	2,481	2,472	2,471	2,458	2,523	2,537	2,561	2,522	2,560	2,587	2,604	2,521	$351,171,332	$11,610
212 Mining, Except Oil & Gas	67	1,273	1,279	1,297	1,336	1,362	1,435	1,429	1,463	1,380	1,356	1,309	1,372	1,358	$93,762,337	$5,756
2121 Coal	1	89	89	88	90	88	93	93	95	94	94	95	95	92		
2122 Metal Ore	27	1,103	1,110	1,114	1,115	1,105	1,145	1,161	1,196	1,115	1,097	1,106	1,194	1,130	$79,962,010	$5,896
2123 Nonmetallic Mineral, Quarrying	39	81	80	95	131	169	197	175	172	171	165	108	83	136		
213 Mining Support Activities	102	5,456	5,660	5,702	5,876	5,928	5,865	5,996	6,111	5,949	5,769	5,685	5,768	5,814	$451,749,830	$6,475

Data are preliminary and subject to revision
Blanks in the Total Earnings and Average Mo Earnings columns is due to confidentiality; data is suppressed
Source: Alaska Department of Labor and Workforce Development, Research & Analysis Section

Revised: 9/14/2005

Annual Employment & Earnings
January - December 2005

Alaska

Industrial Classification	# of Units	Jan Emp	Feb Emp	Mar Emp	Apr Emp	May Emp	June Emp	July Emp	Aug Emp	Sept Emp	Oct Emp	Nov Emp	Dec Emp	Average Mo. Emp	Total Earnings	Avg Mo Earnings
TOTAL INDUSTRIES	21,275	288,078	292,486	295,849	301,133	313,460	320,392	323,269	325,194	325,645	309,082	301,273	297,228	307,757	$12,219,141,373	$3,309
TOTAL GOVERNMENT	1,984	80,303	81,938	82,594	83,344	83,353	75,227	66,138	69,279	81,835	82,919	82,746	82,507	79,349	$3,416,505,039	$3,588
FEDERAL GOVERNMENT	488	16,591	16,573	16,631	16,708	17,090	17,671	17,700	17,640	17,300	16,639	16,576	16,562	16,973	$1,016,217,424	$4,989
STATE GOVERNMENT	809	23,044	24,215	24,658	24,924	24,545	23,380	23,577	23,211	24,707	24,704	24,702	24,650	24,193	$1,023,120,221	$3,524
LOCAL GOVERNMENT	687	40,668	41,150	41,305	41,712	41,718	34,176	24,861	28,428	39,828	41,576	41,468	41,295	38,182	$1,377,167,394	$3,006
PRIVATE OWNERSHIP	19,291	207,775	210,548	213,255	217,789	230,107	245,165	257,131	255,915	243,810	226,163	218,527	214,721	228,409	$8,802,636,334	$3,212
GOODS-PRODUCING	3,528	35,706	37,080	38,008	38,283	40,547	47,071	55,670	54,430	48,893	42,950	38,335	34,855	42,652	$2,523,374,098	$4,930
NATURAL RESOURCE & MINING	350	10,291	10,745	11,022	11,306	11,416	11,739	12,101	12,224	12,192	12,026	11,906	11,909	11,573	$1,042,508,961	$7,507
Agriculture, Forestry, Fishing, Hunting	142	511	765	944	1,178	1,312	1,337	1,345	1,350	1,278	1,040	877	733	1,056	$42,492,873	$3,354
111 Crop Production	16	69	64	107	197	274	266	217	182	159	128	88	101	154	$3,249,546	$1,755
1112 Vegetable & Melon Farming	2	18	12	17	29	39	57	64	59	57	43	24	23	37		
1114 Greenhouse, Nursery, etc.	13	51	52	90	168	235	209	153	123	102	85	64	78	118		
112 Animal Production	23	173	210	242	272	299	315	340	357	365	267	215	190	270	$8,804,294	$2,713
1121 Cattle Ranching, Farming	1	4	5	5	4	4	4	4	4	1	2	5	5	4		
1123 Poultry, Egg Production	1	0	0	0	0	0	0	0	0	0	0	0	0	0		
1125 Animal Aquaculture	20	167	203	235	265	292	308	333	350	361	261	207	182	264	$8,635,271	$2,729
1129 Other Animal Production	2	2	2	2	3	3	3	3	3	3	4	3	3	3		
113 Forestry & Logging	31	179	366	494	569	580	587	581	610	580	515	458	318	486	$21,388,422	$3,664
1133 Logging	30	179	366	494	569	580	576	569	598	580	515	458	318	484		
1132 Forest Nurseries	1	0	0	0	0	0	11	12	12	0	0	0	0	3		
114 Fishing, Hunting, Trapping	51	53	93	62	82	79	72	129	136	115	70	59	73	85	$6,937,514	$6,782
1141 Fishing	51	53	93	62	82	79	72	129	136	115	70	59	73	85	$6,937,514	$6,782
115 Agriculture, Forestry Support	21	37	32	39	58	80	97	78	65	59	60	57	51	59	$2,113,097	$2,964
1151 Crop Production	1	0	0	0	4	8	10	14	7	6	0	0	0	4		
1152 Animal Production	6	14	13	13	17	18	18	15	14	13	27	29	26	18		
1153 Forestry	14	23	19	26	37	54	69	49	44	40	33	28	25	37	$1,839,060	$4,114
Mining	208	9,780	9,980	10,078	10,128	10,104	10,402	10,756	10,874	10,914	10,986	11,029	11,176	10,517	$1,000,016,089	$7,924
211 Oil & Gas Extraction	36	2,593	2,604	2,591	2,586	2,582	2,659	2,663	2,660	2,640	2,660	2,662	2,704	2,634	$382,916,222	$12,116
212 Mining, Except Oil & Gas	73	1,335	1,372	1,388	1,415	1,496	1,595	1,670	1,666	1,652	1,641	1,629	1,607	1,539	$111,013,187	$6,012
2121 Coal	4	95	99	101	99	97	105	103	102	98	97	95	106	100		
2122 Metal Ore	29	1,171	1,210	1,206	1,207	1,248	1,296	1,369	1,366	1,354	1,370	1,397	1,384	1,298	$96,403,749	$6,188
2123 Nonmetallic Mineral, Quarrying	40	69	63	81	109	151	194	198	198	200	174	137	117	141		
213 Mining Support Activities	99	5,852	6,004	6,099	6,127	6,026	6,148	6,423	6,548	6,622	6,685	6,738	6,865	6,345	$506,086,680	$6,647

Data are preliminary and subject to revision
Blanks in the Total Earnings and Average Mo Earnings columns is due to confidentiality; data is suporessed
Source: Alaska Department of Labor and Workforce Development, Research & Analysis Section

Revised: 6/6/2006

Provided by Rep. Doogan
House Oil Gas
10/21/07

Annual Employment & Wages
January - December 2006

Alaska

Industrial Classification	# of Units	Jan Emp	Feb Emp	Mar Emp	Apr Emp	May Emp	June Emp	July Emp	Aug Emp	Sept Emp	Oct Emp	Nov Emp	Dec Emp	Average Mo. Emp	Total Earnings	Avg Mo Earnings
TOTAL INDUSTRIES	21,520	292,499	298,675	303,413	308,174	320,546	333,948	329,018	330,266	331,497	312,426	306,205	303,003	314,139	$12,985,737,135	$3,445
TOTAL GOVERNMENT	1,993	78,991	81,953	82,857	83,535	83,598	78,479	66,228	69,077	82,473	82,521	82,274	82,193	79,515	$3,510,156,841	$3,679
FEDERAL GOVERNMENT	460	16,212	16,282	16,434	16,431	16,783	17,454	17,450	17,264	17,077	16,394	16,175	16,439	16,700	$1,018,636,308	$5,083
STATE GOVERNMENT	817	22,434	24,611	25,011	25,268	25,096	24,027	23,800	23,648	25,247	25,075	25,102	24,945	24,522	$1,074,883,907	$3,653
LOCAL GOVERNMENT	716	40,345	41,060	41,412	41,836	41,719	36,998	24,978	28,165	40,149	41,052	40,997	40,809	38,293	$1,416,636,626	$3,083
PRIVATE OWNERSHIP	19,527	213,508	216,722	220,556	224,639	236,948	255,469	262,790	261,189	249,024	229,905	223,931	220,810	234,624	$9,475,580,295	$3,366
GOODS-PRODUCING	3,497	36,766	38,609	39,919	40,644	42,410	51,262	57,451	55,605	50,042	44,248	39,717	36,260	44,411	$2,771,269,215	$5,200
NATURAL RESOURCES & MINING	354	11,501	11,960	12,393	13,128	13,466	13,844	13,785	13,960	13,945	13,560	13,425	13,384	13,196	$1,251,052,215	$7,900
Agriculture, Forestry, Fishing, Hunting	140	477	668	858	1,037	1,187	1,262	1,286	1,241	1,155	926	737	556	949	$36,140,390	$3,173
111 Crop Production	16	78	78	131	197	282	272	233	193	149	136	104	100	163	$3,313,839	$1,697
1112 Vegetable & Melon Farming	3	15	17	18	32	55	74	79	68	56	51	39	30	45		
1114 Greenhouse, Nursery, etc.	13	63	61	113	165	227	198	154	125	93	85	65	70	118		
112 Animal Production	24	167	197	246	293	290	302	329	341	352	256	214	175	264	$8,534,256	$2,699
1121 Cattle Ranching, Farming	1	7	6	5	2	2	3	2	2	2	1	1	2	3		
1125 Animal Aquaculture	21	157	188	238	289	286	296	324	337	348	254	212	172	258	$8,396,113	$2,708
1129 Other Animal Production	2	3	3	3	2	2	3	3	2	2	1	1	1	2		
113 Forestry & Logging	33	162	321	409	439	483	500	470	474	456	404	309	175	384	$17,738,642	$3,855
1131 Timber Tract Operations	1	2	2	2	3	8	9	10	13	12	11	8	0	7		
1132 Forest Nurseries	1	0	0	0	0	0	11	13	13	13	0	0	0	4		
1133 Logging	31	160	319	407	436	475	480	447	448	431	393	301	175	373	$17,418,684	$3,895
114 Fishing, Hunting, Trapping	48	17	18	19	38	49	86	160	147	118	60	40	48	67	$4,463,980	$5,580
1141 Fishing	48	17	18	19	38	49	86	160	147	118	60	40	48	67	$4,463,980	$5,580
115 Agriculture, Forestry Support	19	53	54	53	70	83	102	94	86	80	70	70	58	73	$2,089,673	$2,394
1151 Crop Production	2	0	0	0	5	3	9	12	13	8	0	0	1	4		
1152 Animal Production	5	32	34	29	29	32	36	38	31	36	31	34	32	33		
1153 Forestry	12	21	20	24	36	48	57	44	42	36	39	36	25	36	$1,689,103	$3,946
Mining	214	11,024	11,292	11,535	12,091	12,279	12,582	12,499	12,719	12,790	12,634	12,688	12,828	12,247	$1,214,911,825	$8,267
211 Oil & Gas Extraction	36	2,713	2,754	2,764	2,815	2,839	2,925	2,933	2,964	2,962	2,980	3,004	3,028	2,890	$419,200,313	$12,087
2111 Oil & Gas Extraction	36	2,713	2,754	2,764	2,815	2,839	2,925	2,933	2,964	2,962	2,980	3,004	3,028	2,890	$419,200,313	$12,087
212 Mining, except Oil & Gas	70	1,582	1,616	1,640	1,692	1,716	1,832	1,872	1,871	1,839	1,756	1,781	1,817	1,751	$140,181,425	$6,671
2121 Coal	4	121	121	121	119	115	126	129	129	121	125	130	124	123		
2122 Metal Ore	30	1,381	1,417	1,423	1,454	1,453	1,538	1,566	1,581	1,562	1,487	1,558	1,621	1,503	$122,714,449	$6,802
2123 Nonmetallic Mineral, Quarrying	36	80	78	96	119	148	168	177	161	156	144	93	72	124		

2006 Quarterly Census of Employment & Wages (QCEW)
Data are preliminary and subject to revision
Blanks in the Total Earnings and Average Mo Earnings columns due to confidentiality; data are suppressed
Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Revised: 8/30/2007

O+G jobs / Total jobs = 2,890 / 314,139 = [redacted]% jobs → < 1% state jobs

O+G earn / Total earn = $.419 bil / $17.985 bil = 3.2% earnings

From: Sen. Bill Wielechowski
10/21/07

Effective Average Tax Rates at Various Price Levels

(FY 2007-2016)

Average ANS West Coast Price in Real 2006 Dollars:	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00	$80.00
Total Government Take (Percent)							
22.5/20, 0.25% at $35 Net Trigger	62.6%	59.3%	58.5%	58.4%	60.8%	62.2%	63.7%
23.0/20, 0.25% at $35 Net Trigger	62.6%	59.6%	58.1%	58.7%	61.1%	62.5%	63.9%
23.5/20, 0.25% at $35 Net Trigger	62.6%	59.8%	58.4%	58.9%	61.3%	62.7%	64.2%
Annual Average Tax Difference Above/(Below) Status Quo ($2006 M)							
22.5/20, 0.25% at $35 Net Trigger	($240)	$111	$525	$1,068	$1,843	$2,760	$3,818
23.0/20, 0.25% at $35 Net Trigger	($240)	$130	$566	$1,112	$1,900	$2,829	$3,900
23.5/20, 0.25% at $35 Net Trigger	($240)	$148	$608	$1,156	$1,956	$2,898	$3,981

DNE