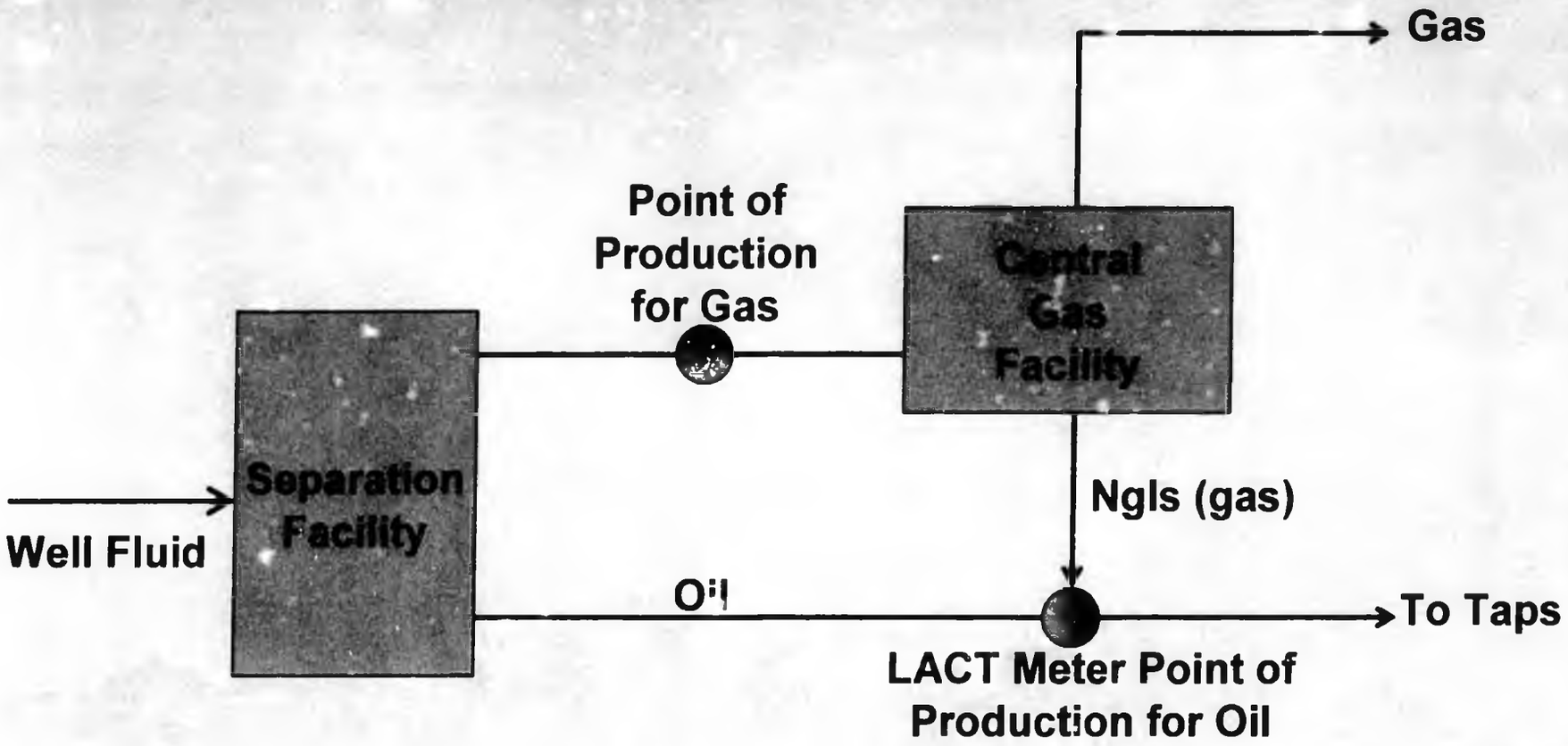
12016 SENATE RESOURCES

Combining Gas Processing and Gas Treatment

- Current Rules
  - Both post production activities – no allocation of costs necessary
- Proposed Rules
  - may require allocation of costs.
  - Choice – could move gas treatment to upstream of point of production.

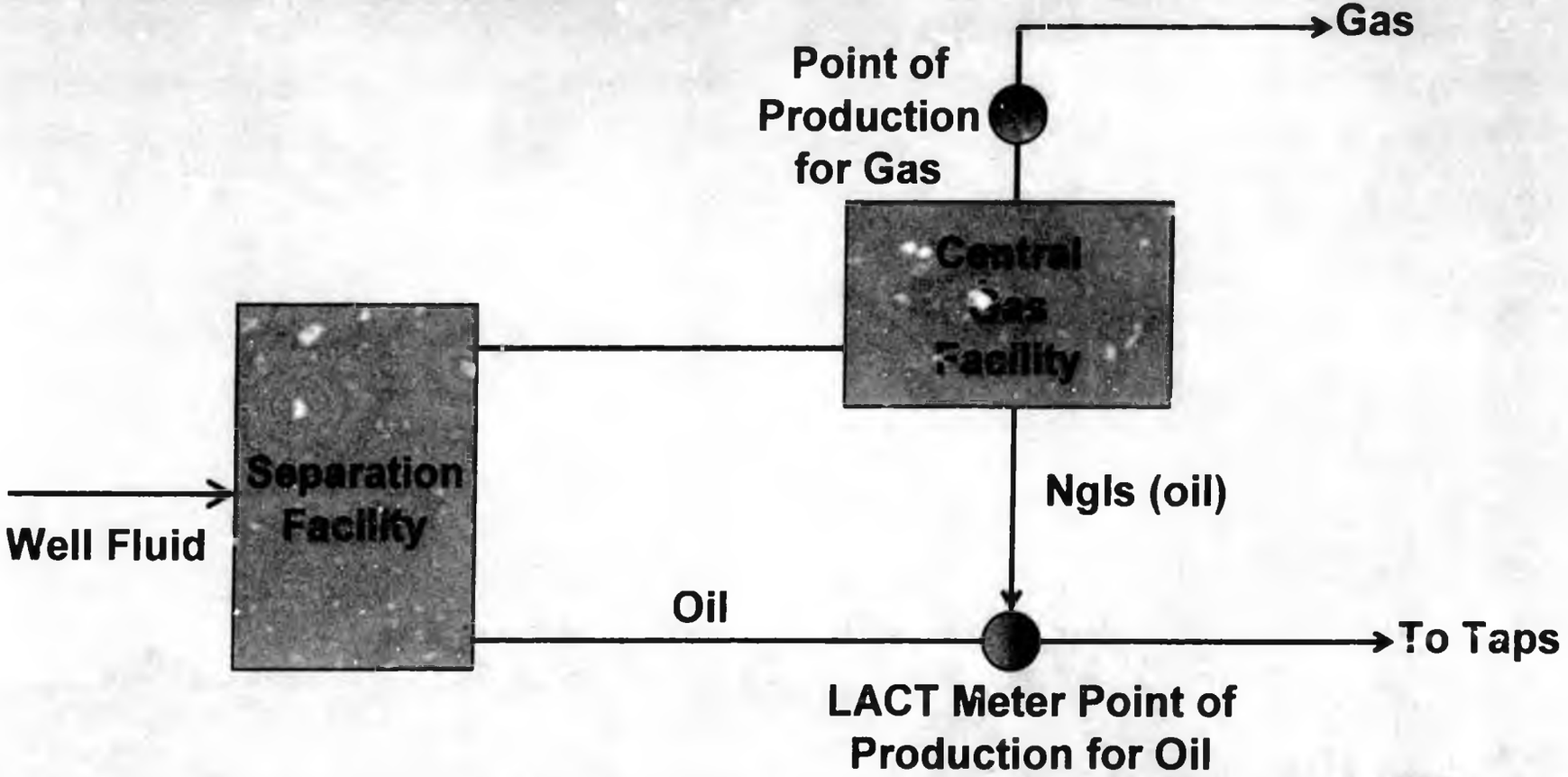
Prudhoe Bay: Point of Production

- Current



Prudhoe Bay: Point of Production

- Proposed



Goal:

- Simplified definitions that will not lead to low value-added conflicts
- Incentivize all production activity

SB

305

(FILE 12)

PRESENTATION ON ALASKA PPT

to House Resources Committee
March 13, 2006

Analysis of PPT

Barry Pulliam

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econ ONE

Econ One Research, Inc.

- An economic research and consulting firm with offices in California (Los Angeles and Sacramento) and Texas (Houston and Austin)
- We provide consulting services in various industries, including petroleum and natural gas, regulated utilities, electricity, telecommunications, and computer software
- We have worked for:
  - A number of state governments on energy-related matters, including the States of Alaska, California, Hawaii, Louisiana, New Mexico, New York, and Texas
  - Federal government agencies, including the Department of Justice, the Federal Trade Commission, the Department of the Interior, and the President's Council of Economic Advisors
  - A number of foreign countries and international agencies, including the World Bank, Mexico, Nigeria, Turkey, and Tanzania on matters related to economic development and privatization of state-owned utilities
  - A number of companies in the petroleum and natural gas industries, including BP, Occidental Petroleum, ANR Pipeline, Koch Gateway Pipeline, Sempra Energy, KN Energy Corp., Lyondell-CITGO Refining, Total Petrochemicals U.S.A., Panhandle Eastern Corp., and ONEOK, Inc.

econ ONE

Barry Pulliam

- Senior Economist with Econ One Research, Inc.
- Masters Degree in Economics from the Claremont Graduate School, with 17 years of experience consulting in the petroleum and natural gas industries
- Has consulted with or served as an economic expert for the State of Alaska on a number of occasions, including:
  - Several severance tax matters involving the valuation of crude oil
  - Operation of the TAPS Quality Bank in proceedings before the FERC and Alaska PUC
  - Merger and antitrust investigations
  - Recent arbitration between State and ExxonMobil involving crude oil royalties
- Consulted with the States of California, New Mexico, Texas, and Louisiana on economic issues related to the petroleum industry
- Consulted with federal government agencies, including the Department of the Interior and the Federal Trade Commission
- Co-author of two recent studies prepared for the Alaska Department of Natural Resources related to natural gas markets and royalty valuation issues

Dr. Anthony Finizza

- Economist working in conjunction with Econ One Research, Inc.
- Ph.D. in Economics and Finance from the University of Chicago with over 30 years of experience working in the petroleum industry
- Chief Economist for ARCO from 1975 to 1998
- At ARCO, Dr. Finizza was in charge of petroleum price forecasting for the company's Long Range Planning Process and conducted scenario-planning exercises with senior management responsible for investment decisions
- Consulted with the California Energy Commission, the State of Hawaii, and the International Hydrogen Infrastructure Group (a consortium of private companies and the U.S. Department of Energy) on energy-related matters
- Currently teaches forecasting and modeling at the University of California, Irvine
- Published articles in *Business Economics*, *The Journal of Corporate Renewal*, and *The International Journal of Forecasting*
- Senior Fellow with the U.S. Association for Energy Economics
- Former President of the International Association for Energy Economics

Oil Price Issues

Conclusions/Observations Regarding Oil Price Forecasts

- Producers are using $40 as a planning base case with $30 as a stress price case. Majors may be using a slightly lower price range than independents, but are moving their views up.
  - This range may actually be lower than their best estimate, but is consistent with their "prudent" planning approach
  - This range is consistent with recent observed oil asset purchases
- This range is consistent with publicly available forecasts although the recent EIA AEO 2006 is above this range. (~$54)
- What really matters is what forecasts are the 'risk takers" using?
- Forecasters have been humbled (and will continue to be humbled) by their forecasts

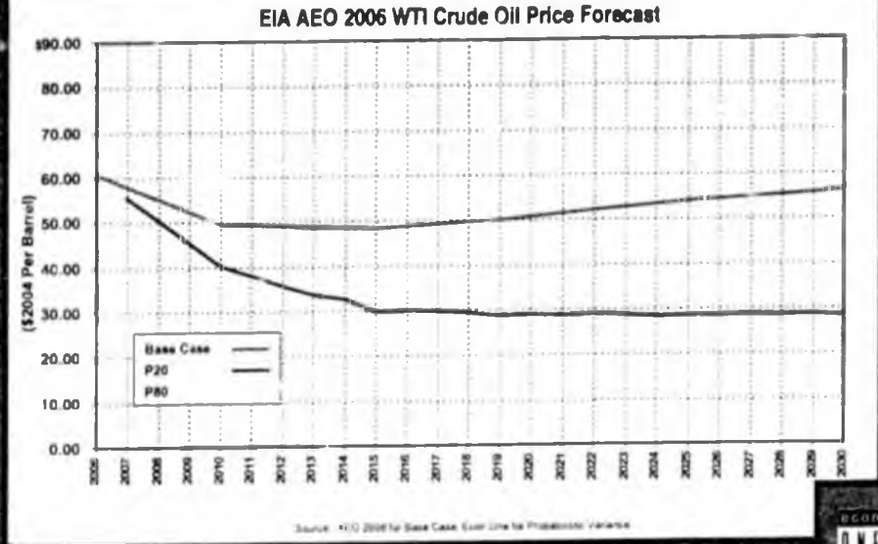
Oil Price Outlook

- Factors Suggesting Continued Higher Prices (short-term)
  - Strong oil demand, especially in China and rest of Asia
  - Growing Gap Between Global Demand and Global Non-OPEC Supply
    - Non-OPEC oil supply cannot keep up with growing world demand permitting increase in OPEC's market power
- Factors Opposing Higher Oil Prices (long-term)
  - Conventional oil faces threat from alternative sources of liquids when prices are high
    - Tar Sands: economic at ~$20-30 oil
    - Coal Liquids: economic above $30/bbl
    - Shale Oil: economic above $45-50/bbl
  - Penetration of Alternative Transportation Vehicles
    - Oil's key position in the transportation market will be eroded by Hybrid vehicles, Grid-Connected Hybrid vehicles, Fuel Cell Vehicles
  - A $10/bbl difference in oil prices is an $73B additional consumer costs per year

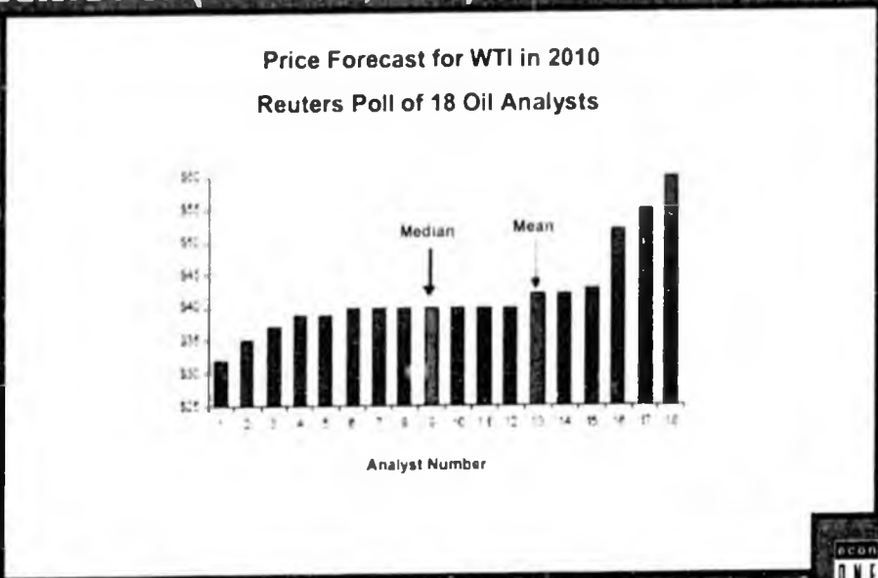
Oil Price Forecasts

- EIA's Annual Energy Outlook (AEO) - January 2006
  - Forecast of oil prices (through 2030, converted to WTI by Econ One)
  - Include Alternative scenarios, probabilistic forecasts developed by Econ One
- International Energy Agency (Paris) – 2005
- Reuters Poll of 18 Oil Analysts for WTI in 2010 (March 2006)
- NYMEX Futures market
  - WTI oil contract traded since early 1980s

Oil Price Outlook – EIA Annual Energy Outlook 2006

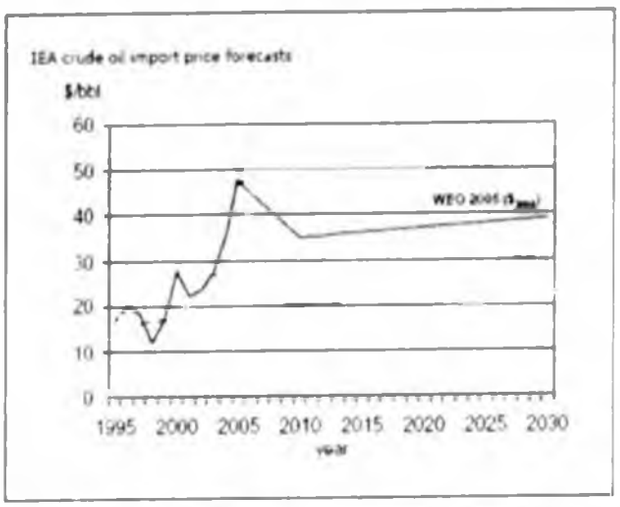


Alternative Oil Price Forecasts – Reuters Poll (March 10, 2006)

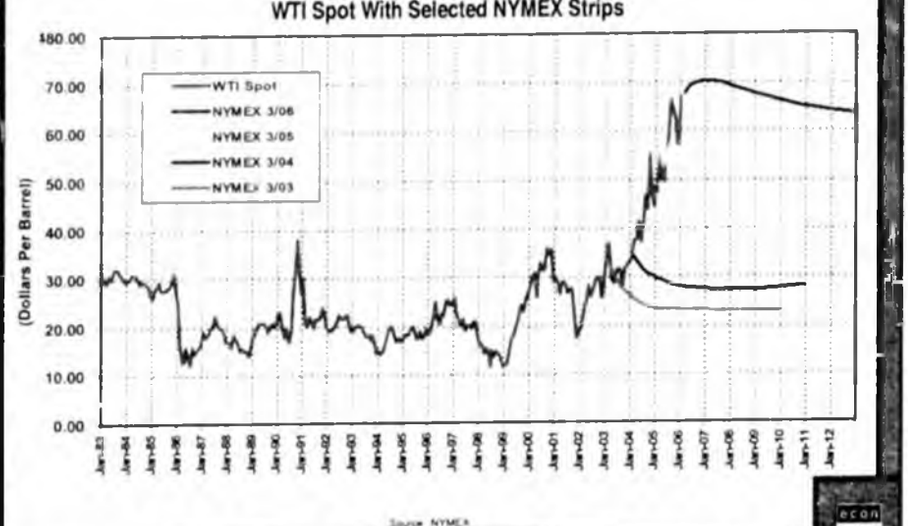


Source: Commodities Weekly, Deutsche Bank, 10 March 2006

IEA (2005) Oil Price Forecasts



WTI Prices: History and Market Forecast



Producer View of Future Oil Prices

- Producers have been "burned" by forecasts of high oil prices in the past
- 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," the 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 view might be: $35-40/barrel
  - Producers will also "stress" test their projects at $30/barrel
- The consequences of error are not symmetrical
  - If a producer underestimates the future path of prices, they will not undertake high risk projects and their returns will skyrocket (the current situation relative to a few years ago)
  - If a producer overestimates the future path of prices, they will be scorned by Wall Street and investors (their position in the late 1990s)
  - They will "miss" opportunities, but these misses will not be fully "penalized" by the market

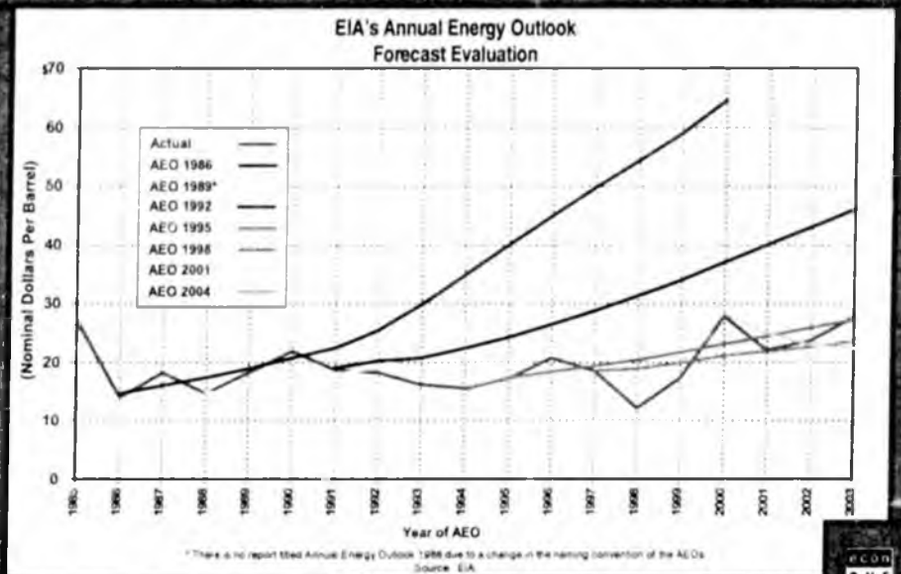
Imputed Oil Company Price Views

- Marubeni acquisition (2/23/06) of Pioneer GOM assets: ~ $40
- Norsk Hydro acquisition (9/19/05) of Spinnaker Exploration: ~$35
- Statoil acquisition (4/28/05) of EnCana's Deepwater GOM: ~ $30

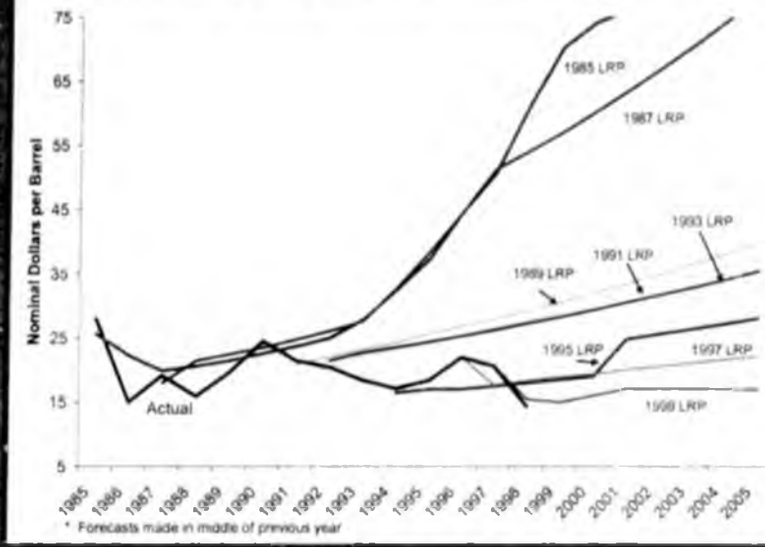
Some Examples of Humbling Oil Price Forecasting

- Energy Administration Administration (US DOE)
- A Private Oil Company
- Polls of "experts" – Society of Petroleum Evaluation Engineers

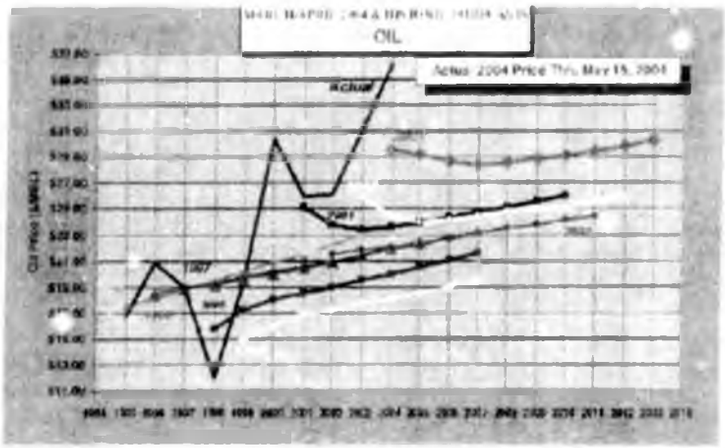
EIA's Annual Price Outlooks



Outlooks From An Oil Company

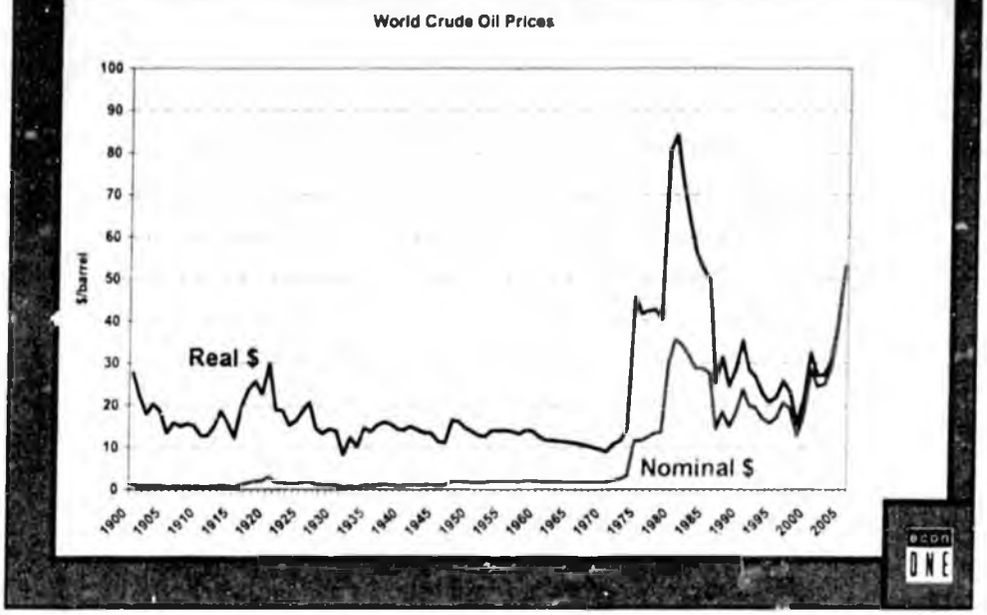


SPEE Annual Delphi Poll



Source: Society of Petroleum Evaluation Engineers (SPEE)

Historical Crude Oil Prices



Investment Decision-Making by Oil and Gas Companies

Financial Criteria
Net Present Value (NPV)

- Present value of future cash flows including capital investment
- A project with a positive NPV is a candidate for acceptance

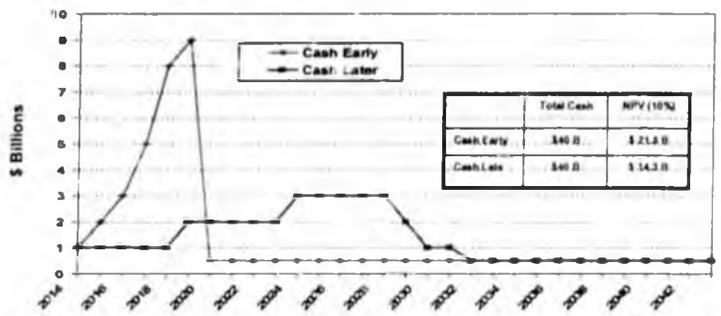
Financial Criteria
Internal Rate of Return (IRR)

- The discount rate at which the NPV of a project equals zero.
- All projects with an IRR greater than the risk-adjusted cost of capital should be accepted when there are no capital budget restraints. Choose higher IRR projects when there are capital budget restraints. Although the "market" would fund projects with IRR above cost of capital, project can be postponed.
- IRR of 12-15% currently indicates threshold rate of return without significant risk factors.

Financial Criteria
Cash (Undiscounted)

- Not used as key investment metric
- Often used to view size of project in presentations to sovereign governments
- Antithetical to discounted cash flow analysis
  - Suffers from failure to reward cash early
  - E.g. Cash flows below are equivalent, but not in discounted terms

Undiscounted Project Cash Flows



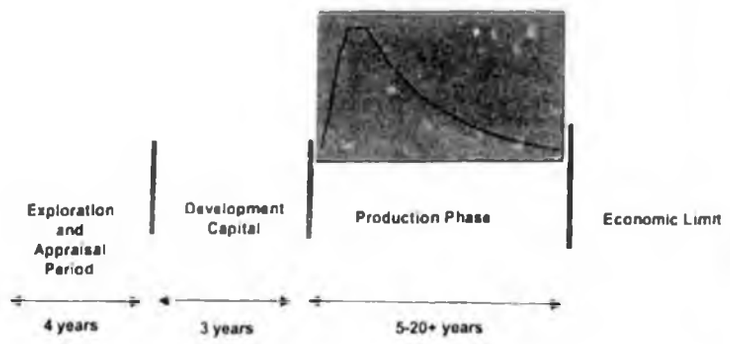
Economics of New Fields

Prudhoe Bay Discovery Well - 1967

Conclusions/Observations Regarding Exploration Impacts

- Without ANWR opening, expectation of large oil discoveries are unlikely, due to the Field Size Distribution of remaining economic reserves
- At low prices, 25/20 helps explorer more than 20/20
- Incentives are required at low prices (say, $73 M, although alternative approaches could work as well)
- At low prices, 20/20 and 25/20 preferred over SQ, in order to incent exploration
- Under either a 20/20 or 25/20 program, remaining reserves are economic, except for low prices (<$30?)

Stylized Lifecycle of New Field



Comparison of Reserves – Central North Slope vs. ANWR

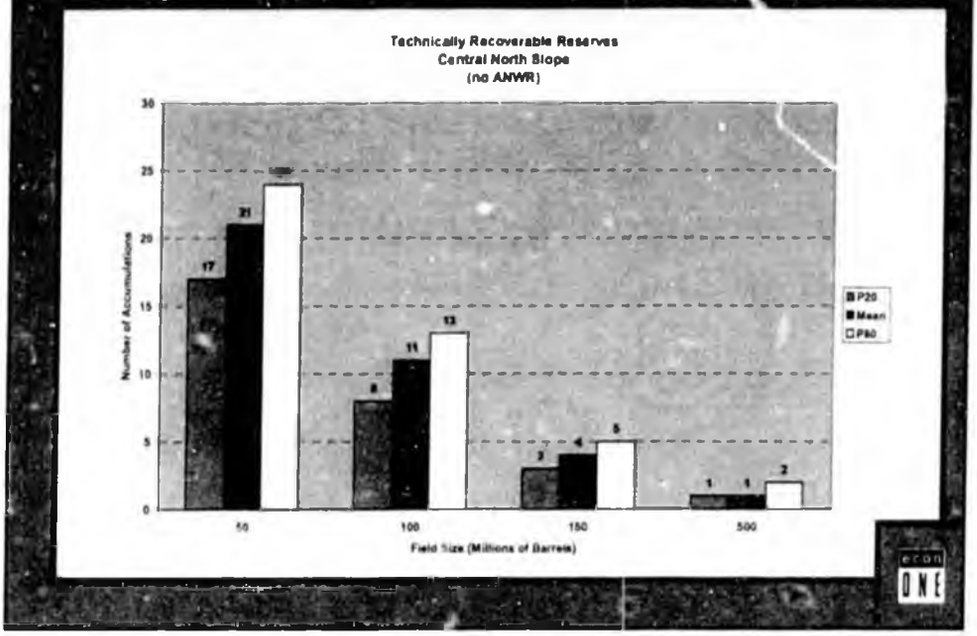
Undiscovered Technically Recoverable Oil Reserves

	Central North Slope	ANWR
Mean Estimate of Reserves (Billions of barrels)	4.0	10.4
Amount in Fields Over 1 B Barrels	0%	22%
Amount in Fields Over 500 M Barrels	2%	43%
Amount in Fields Smaller than 64 M Barrels	51%	1%

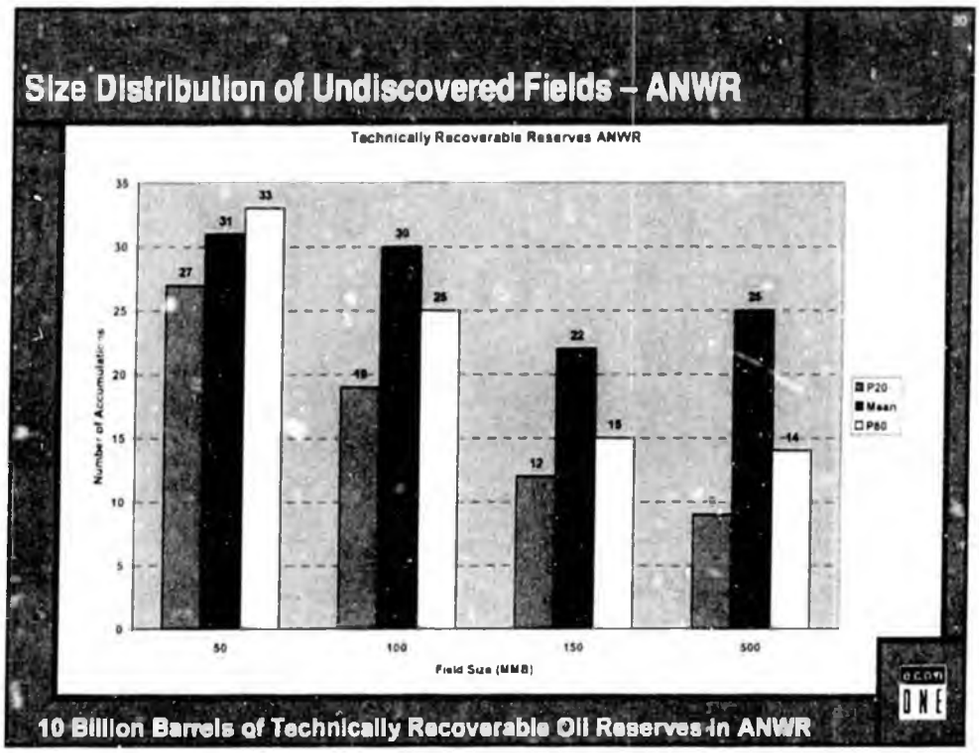
Note: Not all these reserves are economic

Source: USGS

Size Distribution of Undiscovered Fields in Central North Slope

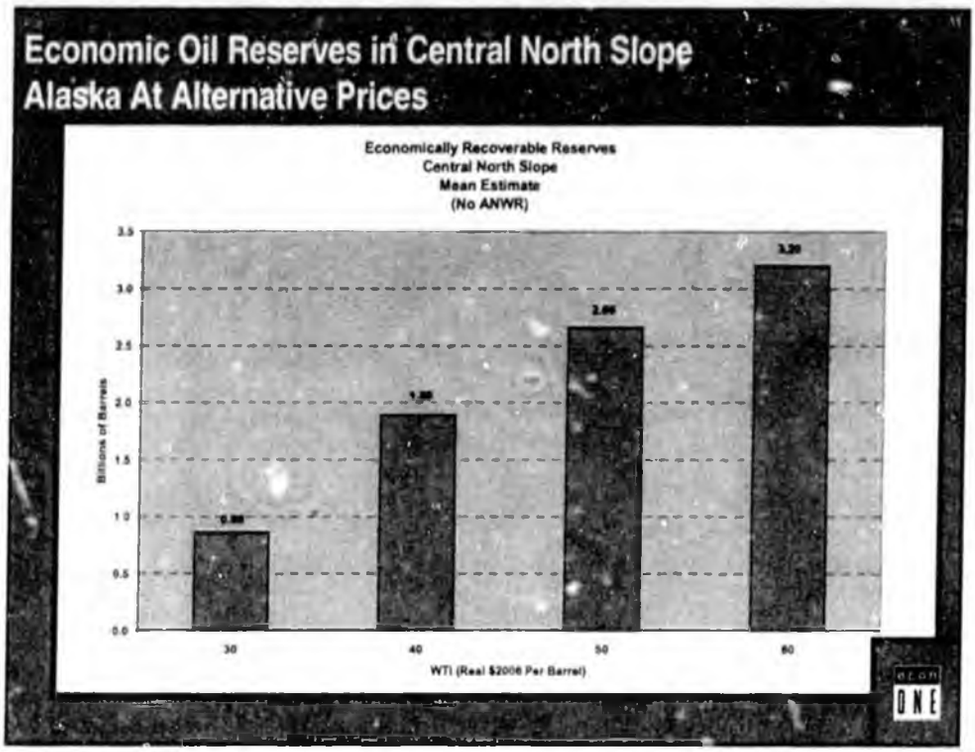


Size Distribution of Undiscovered Fields – ANWR

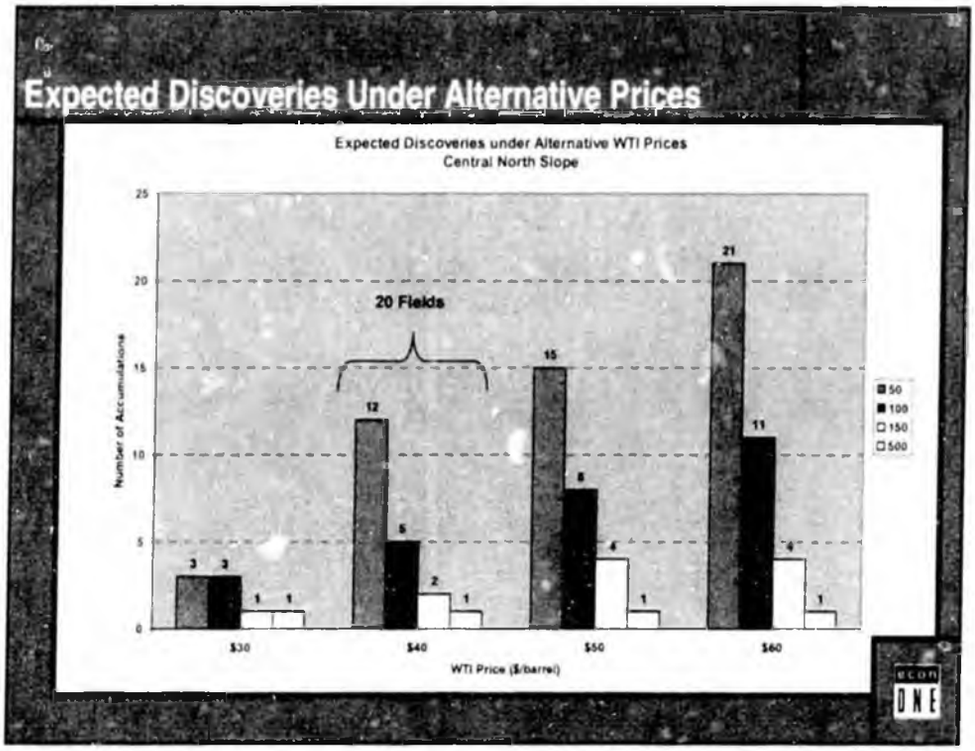


10 Billion Barrels of Technically Recoverable Oil Reserves in ANWR

Economic Oil Reserves in Central North Slope Alaska At Alternative Prices



Expected Discoveries Under Alternative Prices

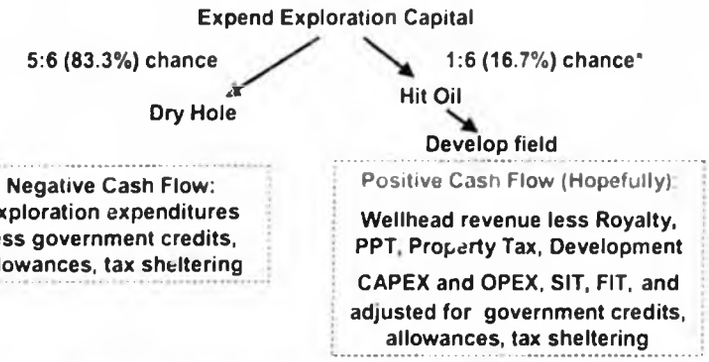


Likely Distribution of New Field Discoveries

Size of Field	Percent
50 MMB	60%
100 MMB	25%
150 MMB	10%
500 MMB	5%

How An Explorer Will Look At The Exploration Proposition

- Calculate the Net Present Value of all outcomes, weighted by the expectation of the outcome
- EMV= NPV (a successful development project) x (Chance of hitting oil) less NPV (cash flow from undertaking exploration)



*The experience in Alaska from 1994-2003 is 17.9% according to Wood Mac GOGRR 2004

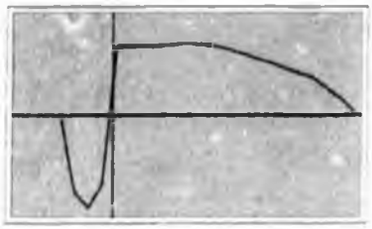
Schematic of Cash Flows For This Example

Cash Flow From Exploration

100% of Time

Cash Flow From Development and Production

16.7% of Time



Avoiding Gambler's Ruin

- Say the chance of drilling a successful well is 1-in-6, or .167
- An explorer will want to mitigate the risk of failure by drilling more wells. (Possibly shared.)
- The chance of failure with one well is .833 (=1-.167). The chance of failure with a 6 well program is .334 (=.833^6)
- An explorer can drill six wells with an expected number of successful wells = 1.0

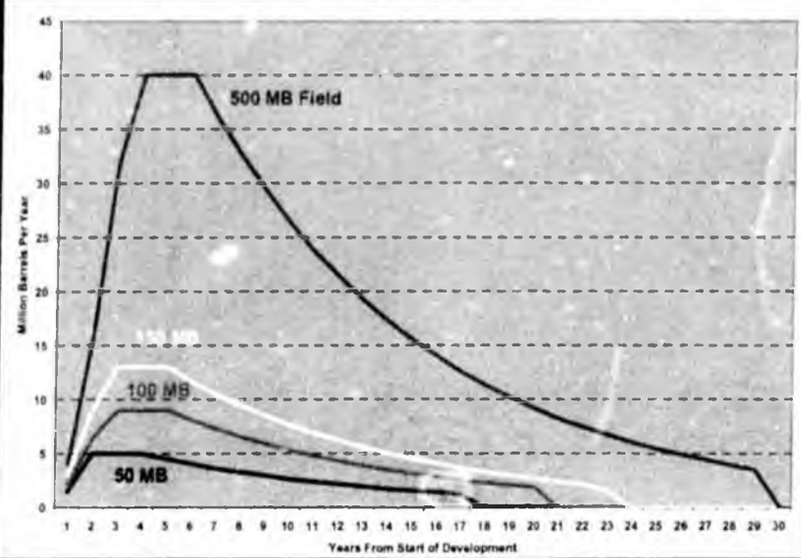
No. of Successes	Chance	Expected Value
0	.3341	0
1	.4019	.4019
2	.2015	.4030
3	.0538	.1614
4	.0081	.0324
5	.0007	.0033
6	.0001	.0078
	Total	1.000

Illustration of A Failed Exploration Program – 1 Well

A One Well Dry Hole Program at $20 Million

	20/20	25/20	SQ
Year			
1	-2.4	-2.3	-3.1
2	-2.3	-2.2	-3.1
3	-2.3	-2.2	-3.2
4	-7.8	-7.4	-10.3
Total Producer Cash Flow	-14.8	-14.2	-19.8
Producer NCF NPV10	-11.1	-10.7	-14.9

Oil Production Profiles



Economics of an 6-Well Exploration Program
50 MM Field (High Cost, Low Productivity)

Without $73 M Allowance

	Explorer NCF NPV10		
Price (Real $2006)	20/20	25/20	SQ
$ 30	-37.0	-35.7	-79.2
$ 40	44.9	41.1	23.1
$ 50	120.9	110.5	125.5
	State Revenues ($M) NPV10		
$ 30	0.0	-2.1	69.0
$ 40	64.8	71.1	100.4
$ 50	139.2	156.2	131.8

Economics of an 6-Well Exploration Program
50 MM Field (High Cost, Low Productivity)

With $73 M Allowance

	Explorer NCF NPV10		
Price (Real $2006)	20/20	25/20	SQ
$ 30	-13.2	-6.0	-79.2
$ 40	78.3	82.8	23.1
$ 50	158.8	157.9	125.5
	State Revenues ($M) NPV10		
$ 30	-38.8	-50.6	69.0
$ 40	10.3	2.9	100.4
$ 50	77.3	78.8	131.8

Economics of an 6-Well Exploration Program

Without $73 M Allowance

	Explorer NCF NPV10		
Price (Real $2006)	20/20	25/20	SQ
$ 30			-34.9
$ 40			148.3
$ 50			331.6
	Explorer IRR		
$ 30			9.9
$ 40			14.9
$ 50			21.1
	State Revenues ($M) NPV10		
$ 30			139.2
$ 40			200.6
$ 50			261.9

Economics of an 6-Well Exploration Program

Without $73 M Allowance

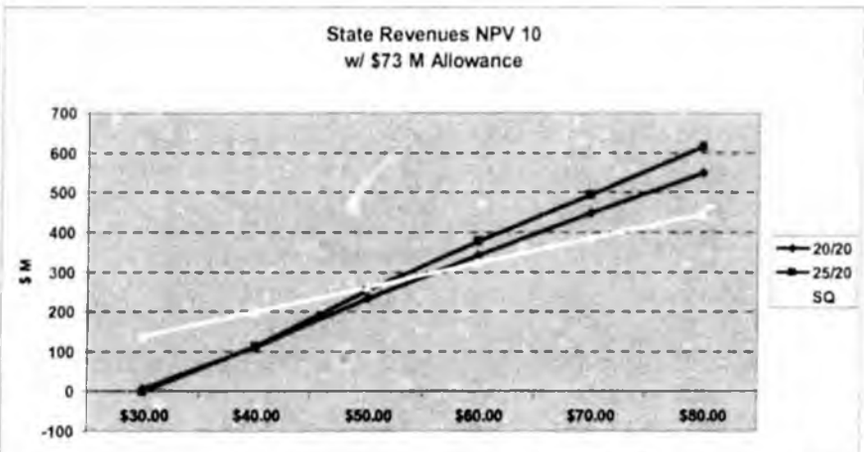
	Explorer NCF NPV10		
Price (Real $2006)	20/20	25/20	SQ
$ 30	5.1	3.3	-34.9
$ 40	149.7	138.9	148.3
$ 50	284.1	261.7	331.6
	Explorer IRR		
$ 30	10.3	10.2	9.9
$ 40	17.1	16.9	14.9
$ 50	22.8	22.5	21.1
	State Revenues ($M) NPV10		
$ 30	51.2	54.1	139.2
$ 40	165.7	183.4	200.6
$ 50	296.9	337.5	261.9

Economics of an 6-Well Exploration Program

With $73 M Allowance

	Explorer NCF NPV10		
Price (Real $2006)	20/20	25/20	SQ
$ 30	32.6	37.7	-34.9
$ 40	184.5	182.4	148.3
$ 50	323.5	311.0	331.6
	Explorer IRR		
$ 30	11.7	12.0	9.9
$ 40	18.5	18.7	14.9
$ 50	23.9	24.0	21.1
	State Revenues ($M) NPV10		
$ 30	6.2	-2.2	139.2
$ 40	108.9	112.3	200.6
$ 50	232.6	253.0	261.9

State Revenues (NPV10) From Example Exploration Program



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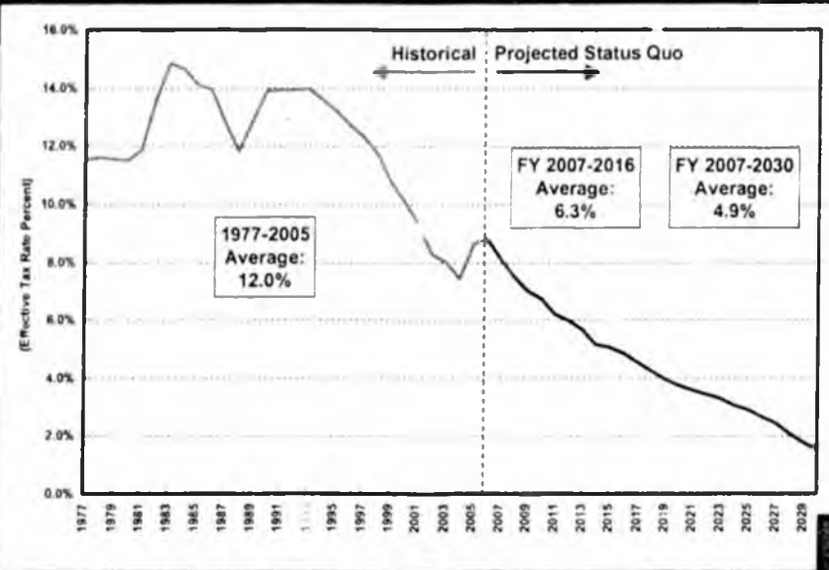
Effective Severance Tax Rates Over Time



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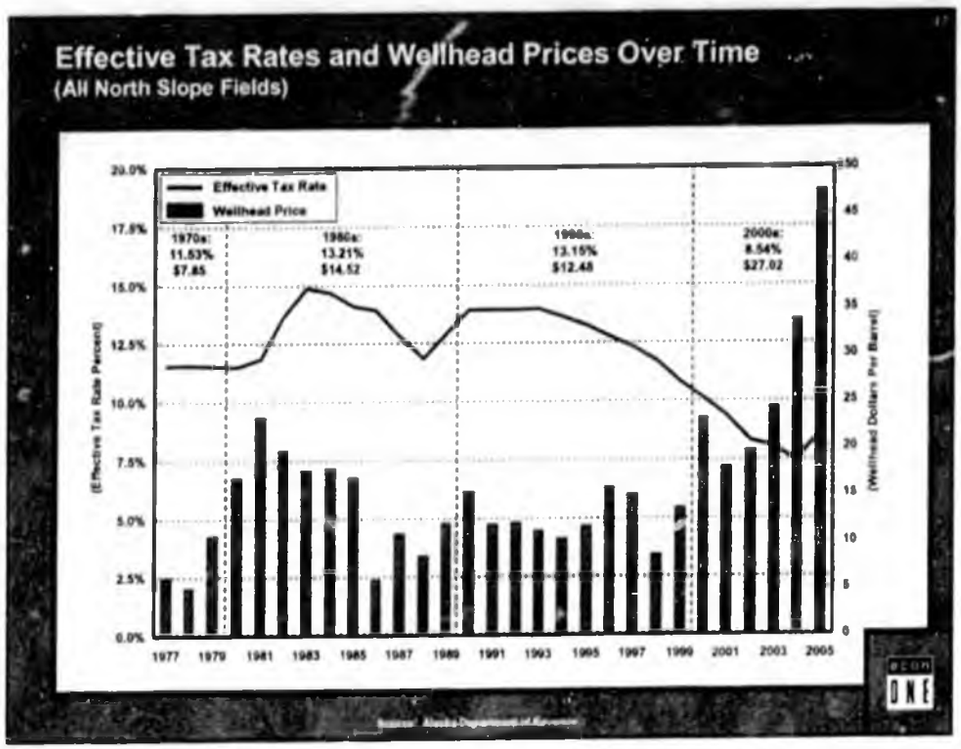
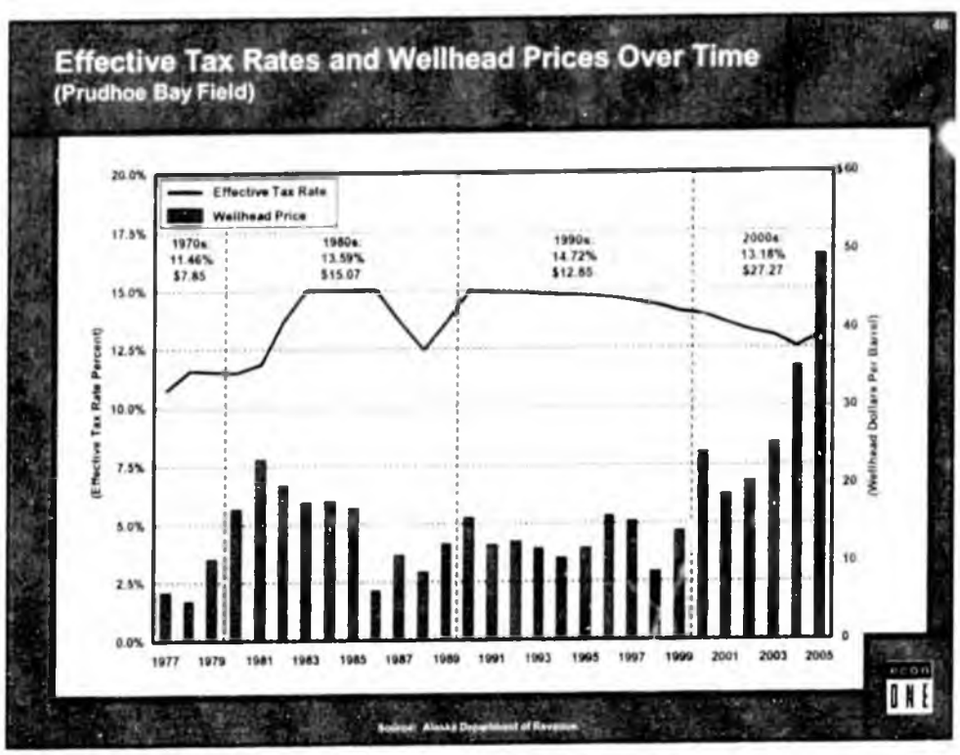
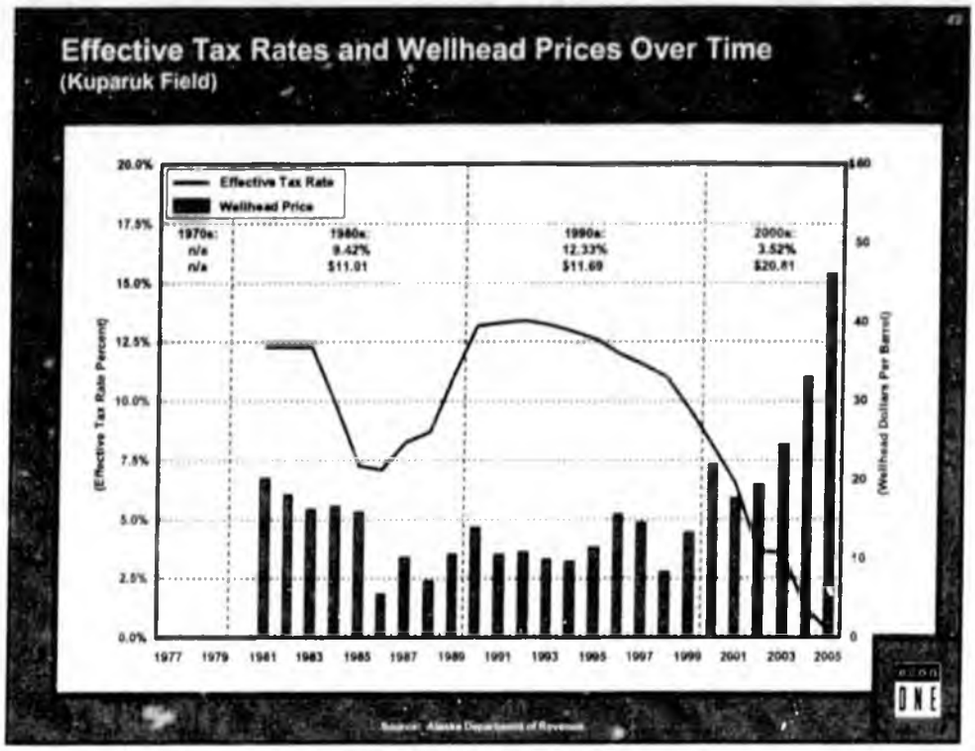
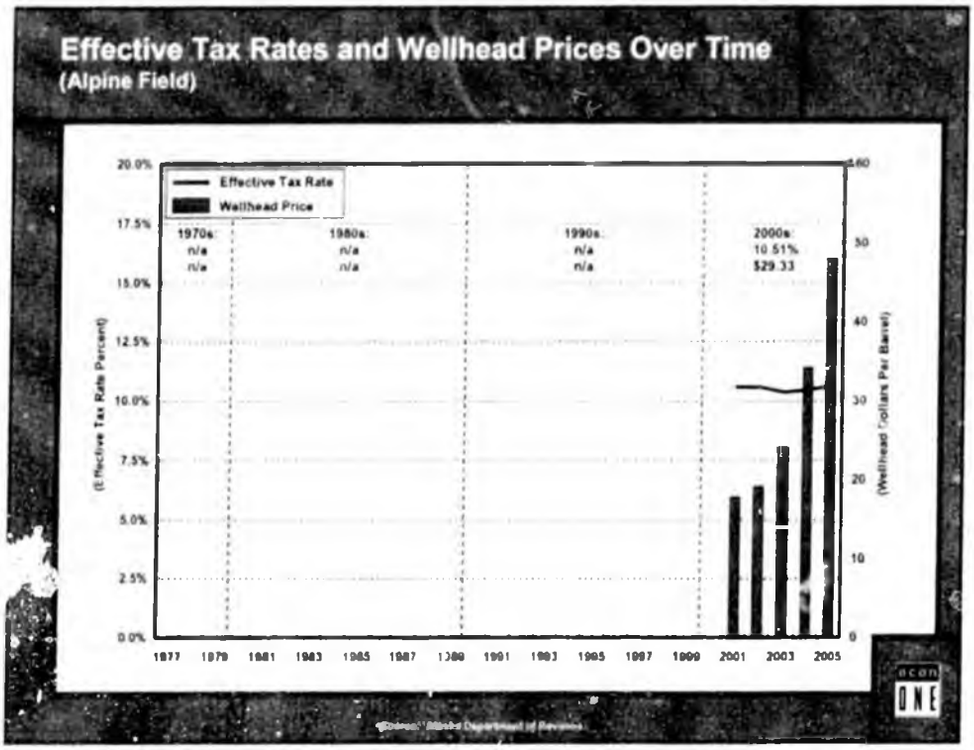

Effective Tax Rates and Wellhead Prices Over Time
(All North Slope Fields)
Effective Tax Rate
Wellhead Price
1970s:
11.53%
$7.85
1980s:
13.21%
$14.52
1990s:
13.15%
$12.48
2000s:
8.54%
$27.02
(Effective Tax Rate Percent)
(Wellhead Dollars Per Barrel)
20.0%
17.5%
15.0%
12.5%
10.0%
7.5%
5.0%
2.5%
0.0%
50
45
40
35
30
25
20
15
10
5
0
1977 1979 1981 1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
ECON ONE


Effective Tax Rates and Wellhead Prices Over Time
(Prudhoe Bay Field)
Effective Tax Rate
Wellhead Price
1970s
11.46%
$7.85
1980s
13.59%
$15.07
1990s
14.72%
$12.85
2000s
13.18%
$27.27
(Effective Tax Rate Percent)
(Wellhead Dollars Per Barrel)
20.0%
17.5%
15.0%
12.5%
10.0%
7.5%
5.0%
2.5%
0.0%
60
50
40
30
20
10
0
1977 1979 1981 1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
ECON ONE

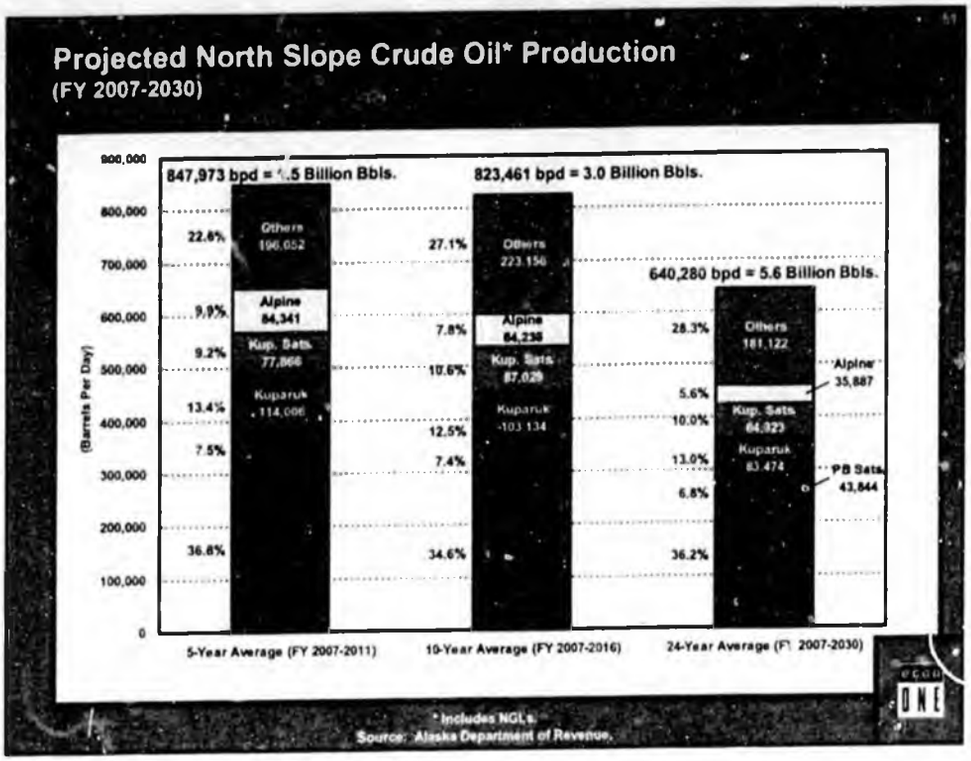
Effective Tax Rates and Wellhead Prices Over Time
(Kuparuk Field)



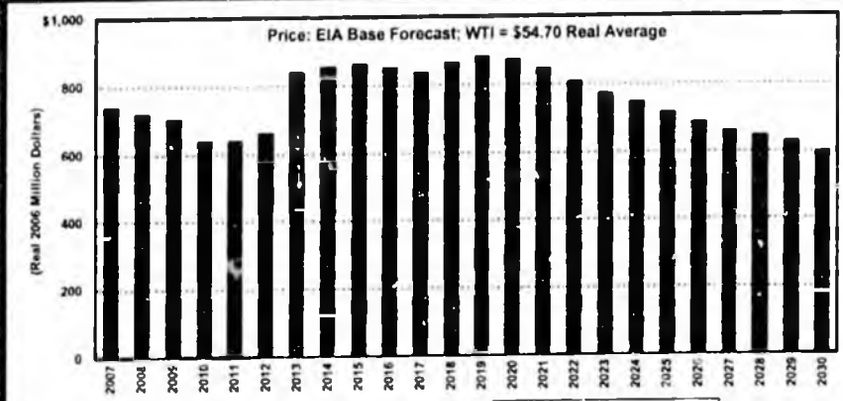
Effective Tax Rates and Wellhead Prices Over Time
(Alpine Field)



Projected North Slope Crude Oil* Production
(FY 2007-2030)



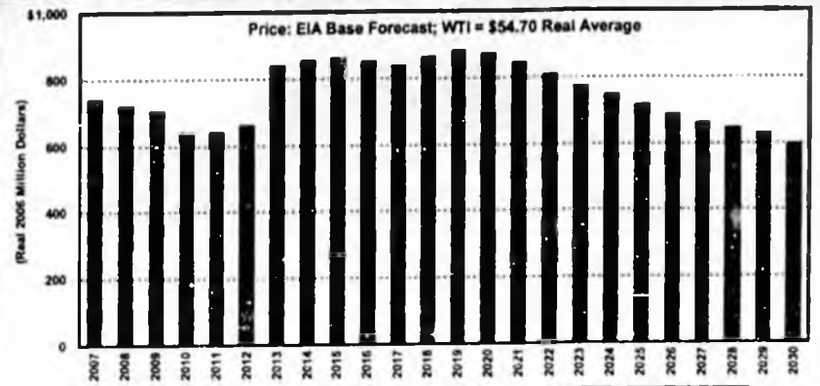
Change in Projected Taxes Under a 20/20 Tax
DOR Forecast Production (FY 2007-2030)*



	FY 2007-2016	FY 2007-2030
Total PPT Tax ($Million)	$15,272	$29,255
Total Difference from SQ ($Million)	$7,471	$17,971
Annual Average Difference from SQ ($Million)	$747	$749
PPT Effective Tax Rate (Percent)	12.4%	12.6%
SQ Effective Tax Rate (Percent)	6.3%	4.9%

* Calculated from July 2006; includes 6-year transition and $73 Million exemption; volumes per DOR Fall 2006 Forecast with Ooguruk projection.

Change in Projected Taxes Under a 20/20 Tax
DOR Forecast Production (FY 2007-2030)*



	FY 2007-2016	FY 2007-2030	1H 2006
Total PPT Tax ($Million)	$15,272	$29,255	$1,127
Total Difference from SQ ($Million)	$7,471	$17,971	$476
Annual Average Difference from SQ ($Million)	$747	$749	n/a
PPT Effective Tax Rate (Percent)	12.4%	12.6%	15.2%
SQ Effective Tax Rate (Percent)	6.3%	4.9%	8.8%

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* Calculated from July 2006; includes 5-year transition and $73 Million exemption; volumes per DOR Fall 2006 Forecast with Ongorak projection.

Change in Projected Taxes Under a 20/20 Tax
DOR Forecast Production (FY 2007-2030)*

	Eia WTI Price Forecast			Fixed $40 Price	FY 2007-2016 Base-over	FY 2007-2030 Base-over
	Base	Low	High			
Average WTI Price in Real 2006 Dollars	$54.70	$38.40	$72.00	$40.00	$30.00	$29.00
FY 2007-2016						
Total PPT Tax (Million 2006$)	$15,272	$8,786	$21,158	$8,666	$3,925	
Total Difference from Status Quo (Million 2006$)	$7,471	$3,614	$11,868	$2,434	$0	
Annual Average Difference from Status Quo (Million 2006$)	$747	$361	$1,186	$243	$0	
PPT Effective Tax Rate (Percent)	12.4%	10.3%	13.8%	10.2%	7.1%	
Status Quo Effective Tax Rate (Percent)	6.3%	6.5%	6.2%	6.3%	6.3%	
FY 2007-2030						
Total PPT Tax (Million 2006$)	$29,255	$12,785	$44,736	$18,230		$5,293
Total Difference from Status Quo (Million 2006$)	$17,971	$4,824	$30,262	$8,317		$0
Annual Average Difference from Status Quo (Million 2006$)	$749	$201	$1,261	$347		$0
PPT Effective Tax Rate (Percent)	12.6%	8.7%	14.5%	10.0%		5.0%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%		5.0%

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* Calculated from July 2006; includes 5-year transition and $73 Million exemption; volumes per DOR Fall 2006 Forecast with Ongorak projection.

Change in Projected Taxes Under a 20/20 Tax with Costs Increased by 20% DOR Forecast Production (FY 2007-2030)*

	EIA WTI Price Forecast: Base	Low	High	Fixed $40 Price	FY2007-2016 Breakeven	FY2007-2030 Breakeven
Average WTI Price in Real 2006 Dollars	$54.70	$35.40	$72.00	$40.00	$34.80	$32.50
FY 2007-2016						
Total PPT Tax (Million 2006$)	$13,083	$6 320	$18 688	$7 418	$4 578	
Total Difference from Status Quo (Million 2006$)	$4,082	$2 146	$10 218	$1 986	$0	
Annual Average Difference from Status Quo (Million 2006$)	$408	$214	$1 022	$197	$0	
PPT Effective Tax Rate (Percent)	11.2%	8.0%	12.9%	8.5%	6.3%	
Status Quo Effective Tax Rate (Percent)	6.3%	6.5%	6.2%	6.3%	6.3%	
FY 2007-2030						
Total PPT Tax (Million 2006$)	$26 [illegible]	$10 870	$41 [illegible]	$13 480		$8 158
Total Difference from Status Quo (Million 2006$)	$15,221	$2 120	$27 511	$4 580		$0
Annual Average Difference from Status Quo (Million 2006$)	$634	$89	$1 148	$232		$0
PPT Effective Tax Rate (Percent)	11.9%	6.8%	13.0%	6.3%		4.9%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%		4.9%

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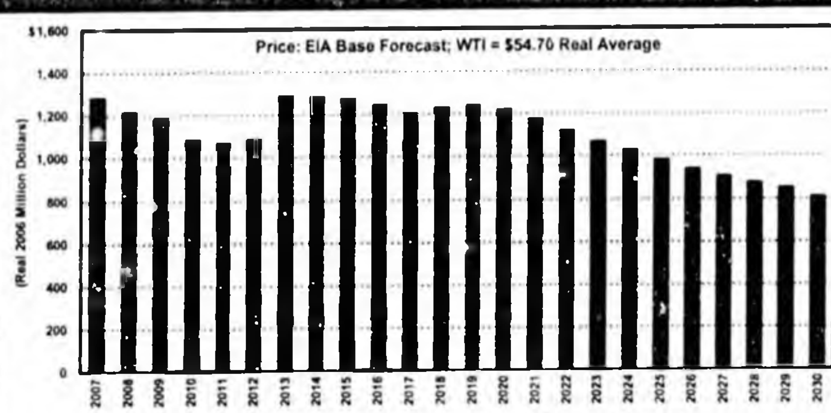
Change in Projected Taxes Under a 25/20 Tax DOR Forecast Production (FY 2007-2030)*



	FY 2007-2016	FY 2007-2030
Total PPT Tax ($Million)	$19,769	$37,840
Total Difference from SQ ($Million)	$11,968	$26,555
Annual Average Difference from SQ ($Million)	$1,197	$1,106
PPT Effective Tax Rate (Percent)	16.0%	16.4%
SQ Effective Tax Rate (Percent)	6.3%	4.9%

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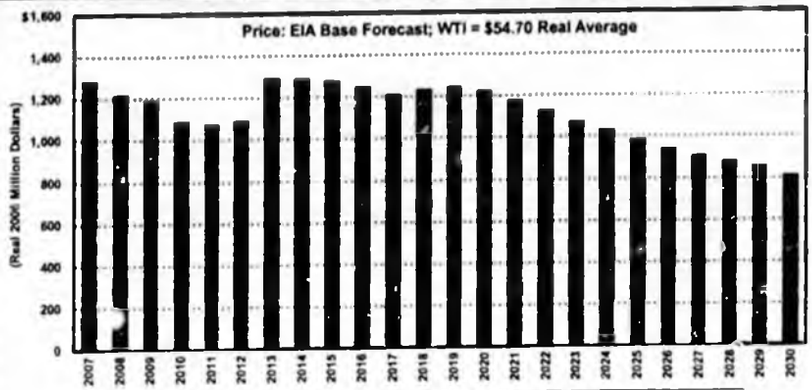
Change in Projected Taxes Under a 25/20 Tax
DOR Forecast Production (FY 2007-2030)*



	FY 2007-2016	FY 2007-2030	1H 2006
Total PPT Tax ($Million)	$19,769	$37,840	$1,432
Total Difference from SQ ($Million)	$11,968	$26,555	$782
Annual Average Difference from SQ ($Million)	$1,197	$1,106	n/a
PPT Effective Tax Rate (Percent)	16.0%	16.4%	19.4%
SQ Effective Tax Rate (Percent)	6.3%	4.9%	8.8%

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* Calculated from July 2006, includes Point transition and $70 Million exemption, volumes per DOR Fall 2006 Forecast with Original projection

Change in Projected Taxes Under a 25/20 Tax
DOR Forecast Production (FY 2007-2030)*

	EIA WTI Price Forecast: Base	Low	High	Fixed $40 Price	FY 2007-2016 Breakeven	FY 2007-2030 Breakeven
Average WTI Price in Real 2006 Dollars	$54.70	$35.40	$72.10	$40.00	$27.10	$26.10
FY 2007-2016						
Total PPT Tax ($Million)	$19,769	$12,915	$27,126	$11,798	$1,382	
Total Difference from Status Quo ($Million)	$11,968	$6,740	$17,650	$4,335	$0	
Annual Average Difference from Status Quo ($Million)	$1,197	$674	$1,765	$433	$0	
PPT Effective Tax Rate (Percent)	16.0%	13.6%	17.7%	13.6%	6.3%	
Status Quo Effective Tax Rate (Percent)	6.3%	6.5%	6.2%	6.3%	6.3%	
FY 2007-2030						
Total PPT Tax ($Million)	$37,840	$17,226	$57,183	$21,568		$4,671
Total Difference from Status Quo ($Million)	$26,555	$6,268	$42,717	$13,845		$0
Annual Average Difference from Status Quo ($Million)	$1,106	$261	$1,780	$577		$0
PPT Effective Tax Rate (Percent)	16.4%	11.7%	18.5%	13.3%		5.0%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%		5.0%

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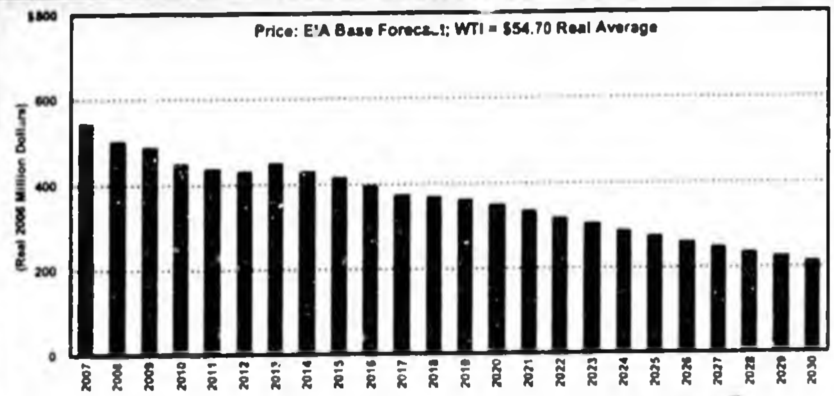
* Calculated from July 2006, includes Point transition and $70 Million exemption, volumes per DOR Fall 2006 Forecast with Original projection

Difference in Projected Taxes Between a 25/20 and a 20/20 Tax DOR Forecast Production (FY 2007-2030)*



	FY 2007-2016	FY 2007-2030
Total 25/20 PPT Tax ($Million)	$19,769	$37,840
Total Difference from 20/20 PPT Tax ($Million)	$4,497	$8,584
Annual Average Difference from 20/20 PPT Tax ($Million)	$450	$358
20/20 PPT Effective Tax Rate (Percent)	16.0%	16.4%
25/20 PPT Effective Tax Rate (Percent)	12.4%	12.6%

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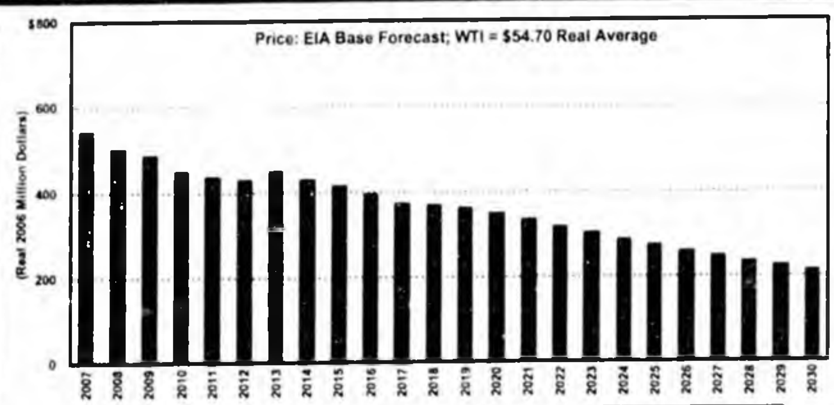
* Calculated from July 2006; includes 6-year transition and $73 Million exemption; volumes per DOR Fall 2005 Forecast with [illegible] projection

Difference in Projected Taxes Between a 25/20 and a 20/20 Tax DOR Forecast Production (FY 2007-2030)*



	FY 2007-2016	FY 2007-2030	1H 2006
Total 25/20 PPT Tax ($Million)	$19,769	$37,840	$1,432
Total Difference from 20/20 PPT Tax ($Million)	$4,497	$8,584	$305
Annual Average Difference from 20/20 PPT Tax ($Million)	$450	$358	n/a
20/20 PPT Effective Tax Rate (Percent)	16.0%	16.4%	19.4%
25/20 PPT Effective Tax Rate (Percent)	12.4%	12.6%	15.2%

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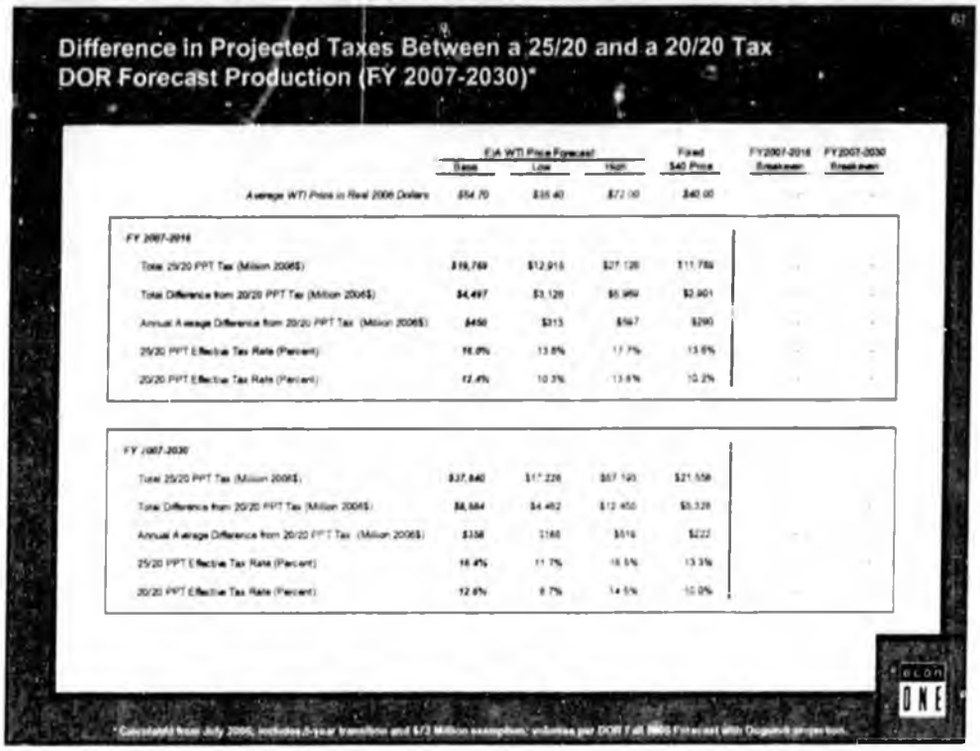
* Calculated from July 2006; includes 6-year transition and $73 Million exemption; volumes per DOR Fall 2005 Forecast with [illegible] projection


Difference in Projected Taxes Between a 25/20 and a 20/20 Tax
DOR Forecast Production (FY 2007-2030)*
E/A WTI Price Forecast
Base
Low
High
Fixed $40 Price
FY2007-2016 Breakeven
FY2007-2030 Breakeven
Average WTI Price in Real 2006 Dollars
$54.70
$35.40
$72.00
$40.00
FY 2007-2016
Total 25/20 PPT Tax (Million 2006$)
$19,769
$12,915
$27,128
$11,788
Total Difference from 20/20 PPT Tax (Million 2006$)
$4,497
$3,129
$6,969
$2,901
Annual Average Difference from 20/20 PPT Tax (Million 2006$)
$450
$313
$697
$290
25/20 PPT Effective Tax Rate (Percent)
16.0%
13.8%
17.7%
13.6%
20/20 PPT Effective Tax Rate (Percent)
12.4%
10.3%
13.6%
10.2%
FY 2007-2030
Total 25/20 PPT Tax (Million 2006$)
$37,840
$17,228
$67,193
$21,558
Total Difference from 20/20 PPT Tax (Million 2006$)
$8,584
$4,462
$12,450
$5,328
Annual Average Difference from 20/20 PPT Tax (Million 2006$)
$358
$186
$519
$222
25/20 PPT Effective Tax Rate (Percent)
16.4%
11.7%
18.5%
13.3%
20/20 PPT Effective Tax Rate (Percent)
12.6%
8.7%
14.5%
10.0%
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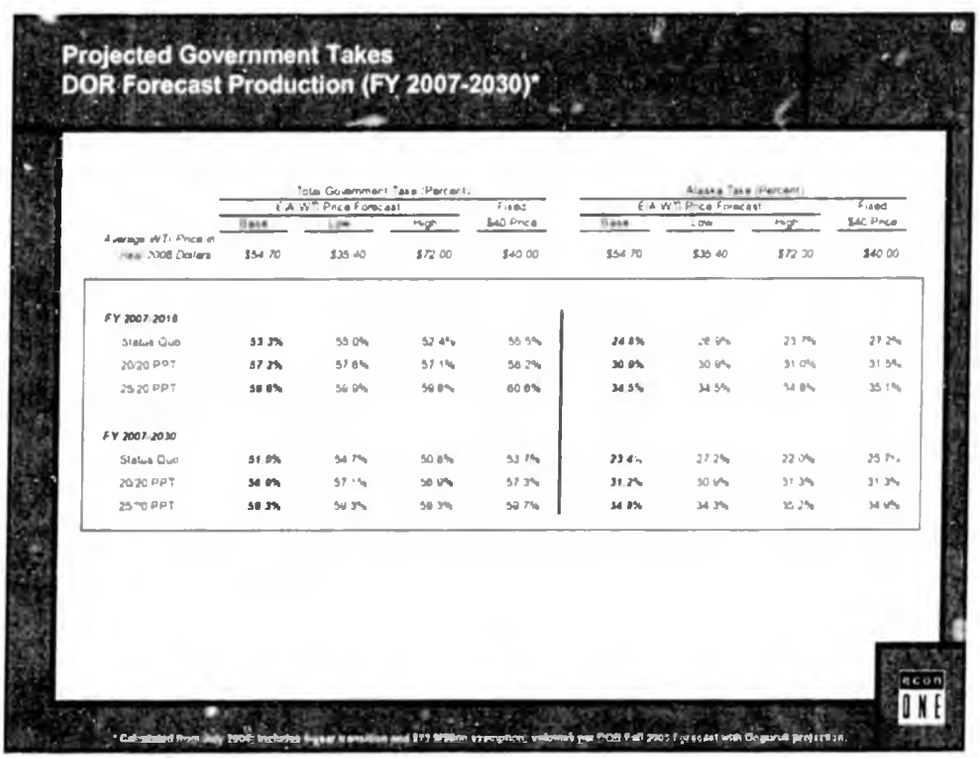
Projected Government Takes
DOR Forecast Production (FY 2007-2030)*
Total Government Take (Percent)
Alaska Take (Percent)
E/A WTI Price Forecast
Base
Low
High
Fixed $40 Price
Average WTI Price in Real 2006 Dollars
$54.70
$35.40
$72.00
$40.00
FY 2007-2016
Status Quo
53.3%
55.0%
52.4%
56.5%
24.8%
20/20 PPT
57.2%
57.6%
57.1%
58.2%
30.9%
30.9%
31.0%
31.5%
25/20 PPT
58.6%
56.9%
56.8%
60.6%
34.5%
34.5%
34.8%
35.1%
FY 2007-2030
Status Quo
51.9%
54.7%
50.8%
53.7%
23.4%
27.2%
22.0%
25.7%
20/20 PPT
56.0%
57.1%
56.0%
57.3%
31.2%
30.9%
31.3%
31.3%
25/20 PPT
58.3%
56.3%
58.3%
59.7%
34.8%
34.3%
35.2%
34.9%
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Projected Annual Average Taxes at Various Tax Rates and Prices DOR Forecast Production (FY 2007-2030)*

(Million 2006 Dollars)

WTI Price	20/20	21/20	22/20	23/20	24/20	25/20	Change Per % Increase in Tax Rate	Change Per % Increase in Credit Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
FY 2007-2016								
$40	$888.8	$946.8	$1,004.8	$1,062.8	$1,120.9	$1,178.9	$58.0	($13.6)
$45	$1,149.5	$1,225.1	$1,291.6	$1,362.7	$1,433.7	$1,504.8	$71.1	($13.6)
$50	$1,410.2	$1,494.7	$1,578.4	$1,662.5	$1,746.6	$1,830.7	$84.1	($13.6)
$55	$1,671.0	$1,766.1	$1,866.2	$1,962.4	$2,060.5	$2,156.6	$97.1	($13.6)
$60	$1,931.7	$2,041.9	$2,152.1	$2,262.2	$2,372.4	$2,482.6	$110.2	($13.6)
Change Per Dollar Increase in WTI Price	$52.1	$54.8	$57.4	$60.0	$62.6	$65.2		
FY 2007-2030								
$40	$676.3	$720.7	$765.1	$809.5	$853.9	$898.3	$44.4	($10.6)
$45	$879.9	$937.1	$988.0	$1,042.5	$1,097.1	$1,151.8	$54.5	($10.6)
$50	$1,081.8	$1,146.3	$1,211.0	$1,275.6	$1,340.3	$1,405.0	$64.7	($10.6)
$55	$1,284.3	$1,359.1	$1,433.9	$1,508.7	$1,583.6	$1,658.3	$74.8	($10.6)
$60	$1,487.0	$1,571.9	$1,656.8	$1,741.8	$1,826.7	$1,911.7	$84.9	($10.6)
Change Per Dollar Increase in WTI Price	$40.5	$42.6	$44.8	$46.9	$48.6	$50.7		

* Calculated from July 2006: $73 Million exemption; does not include transition; volumes per DOR Fall 2005 Forecast with Gaspack projection

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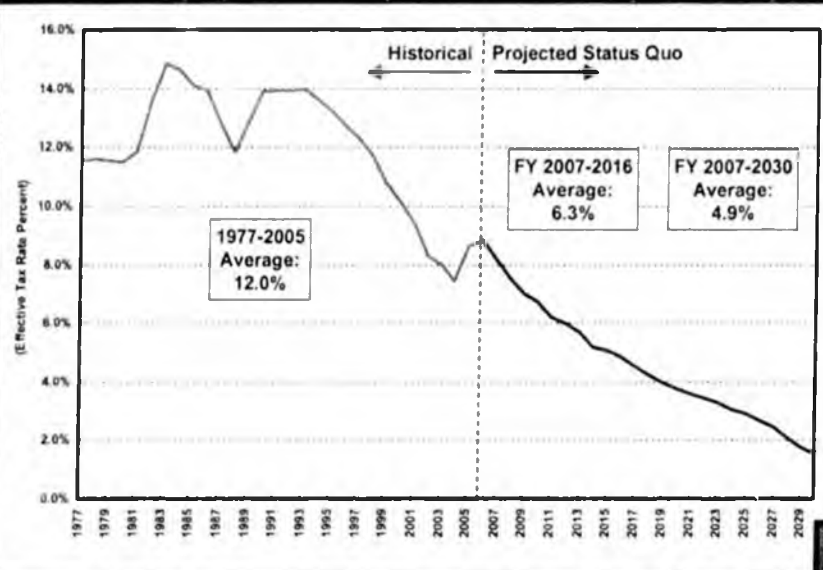
Effective Severance Tax Rates Over Time



Source: Historical: Alaska Department of Revenue.

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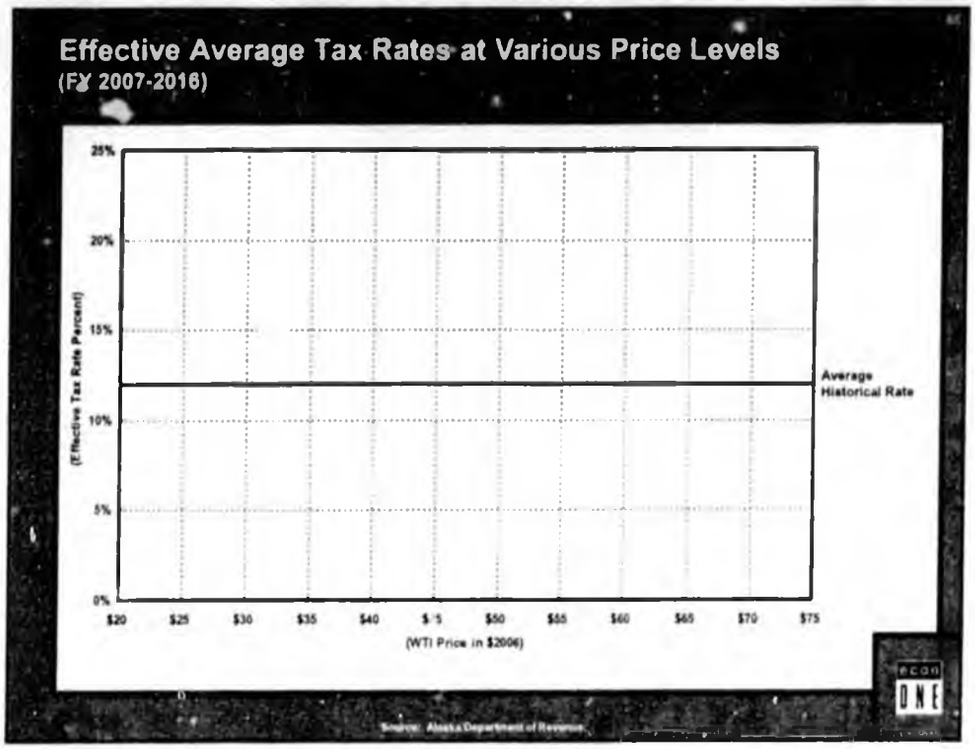
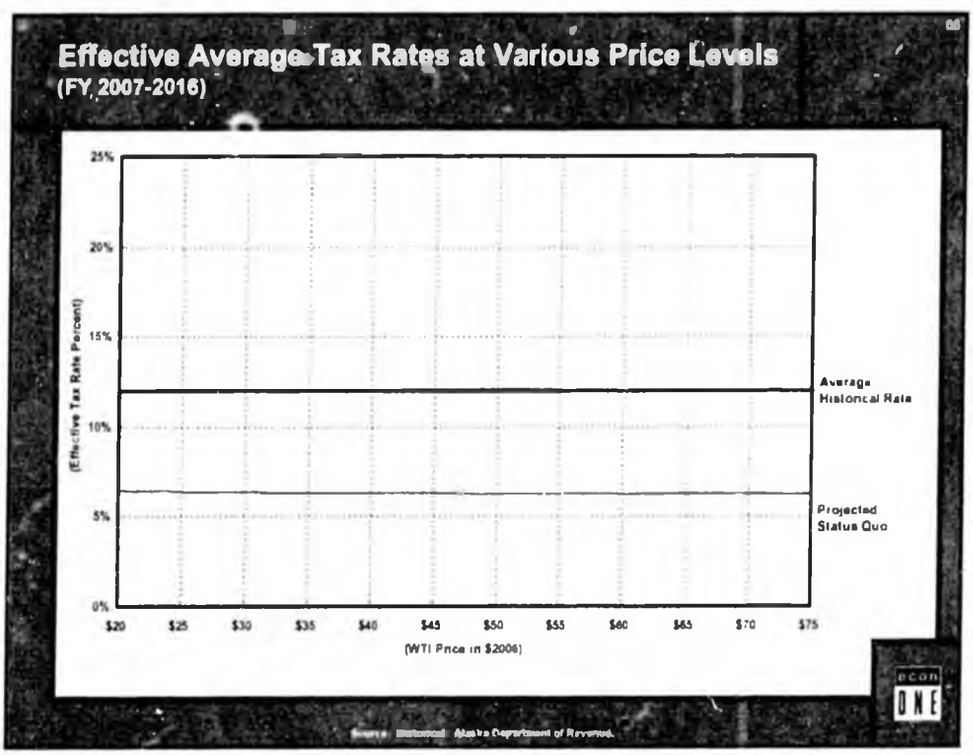
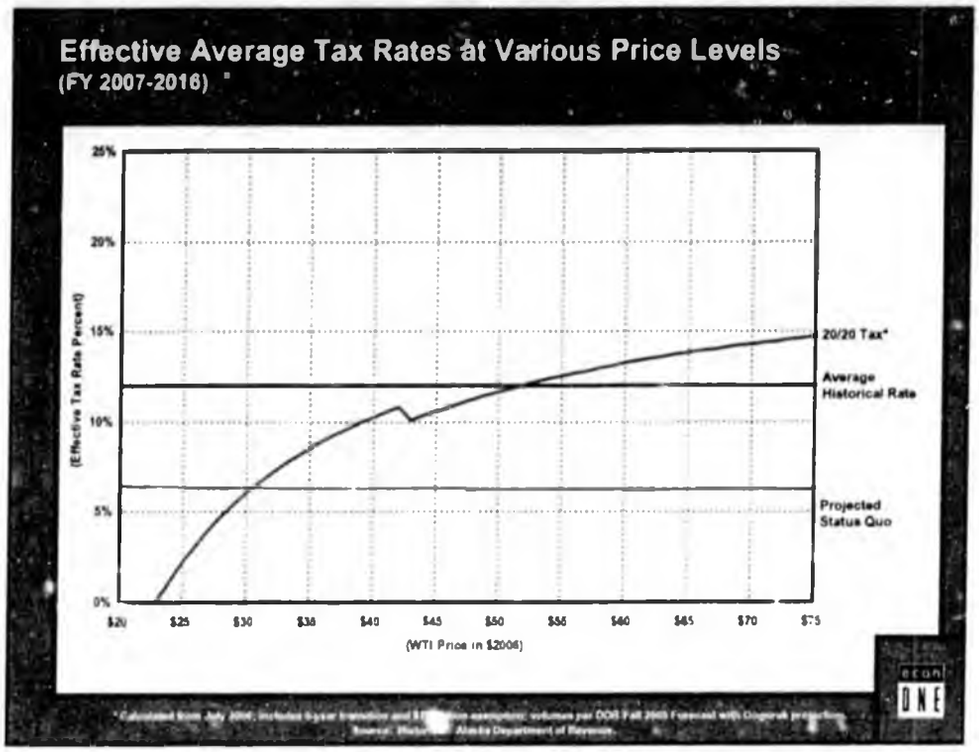

Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)
25%
20%
15%
10%
5%
0%
(Effective Tax Rate Percent)
Average
Historical Rate
$20
$25
$30
$35
$40
$45
$50
$55
$60
$65
$70
$75
(WTI Price in $2006)
econ
ONE


Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)
25%
20%
15%
10%
5%
0%
(Effective Tax Rate Percent)
Average
Historical Rate
Projected
Status Quo
$20
$25
$30
$35
$40
$45
$50
$55
$60
$65
$70
$75
(WTI Price in $2006)
econ
ONE


Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)
25%
20%
15%
10%
5%
0%
(Effective Tax Rate Percent)
20/20 Tax*
Average Historical Rate
Projected Status Quo
$20
$25
$30
$35
$40
$45
$50
$55
$60
$65
$70
$75
(WTI Price in $2006)
econ ONE


Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)
25%
20%
15%
10%
5%
0%
(Effective Tax Rate Percent)
25/20 Tax*
20/20 Tax*
Average Historical Rate
Projected Status Quo
$20
$25
$30
$35
$40
$45
$50
$55
$60
$65
$70
$75
(WTI Price in $2006)
econ ONE

Example of Tax with Sliding Scale

Assumptions: 0.25% per dollar over $45/barrel WTI (threshold);
$55/barrel WTI price;
$47/barrel ANS wellhead price;
20/20 PPT.

- Sliding Scale Tax in Addition to PPT, and Deductible Against PPT
- If WTI is <= Threshold price (e.g., $45): No Additional Tax
- If WTI is > Threshold price: Additional Tax Equals 0.25% Per Dollar Over Threshold x Gross Wellhead Value

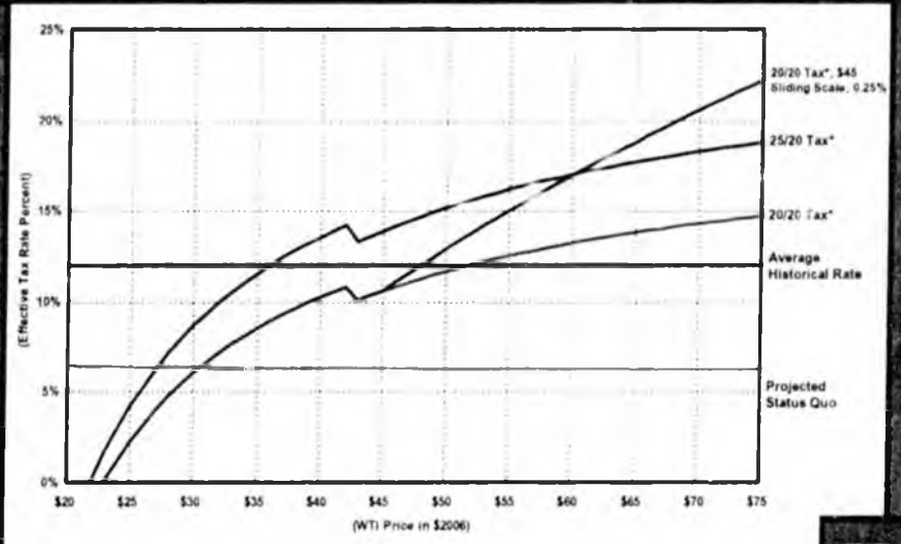
Additional Tax = (WTI Price - Threshold) x Increment Rate x ANS Wellhead Price x (1 - PPT Tax Rate)

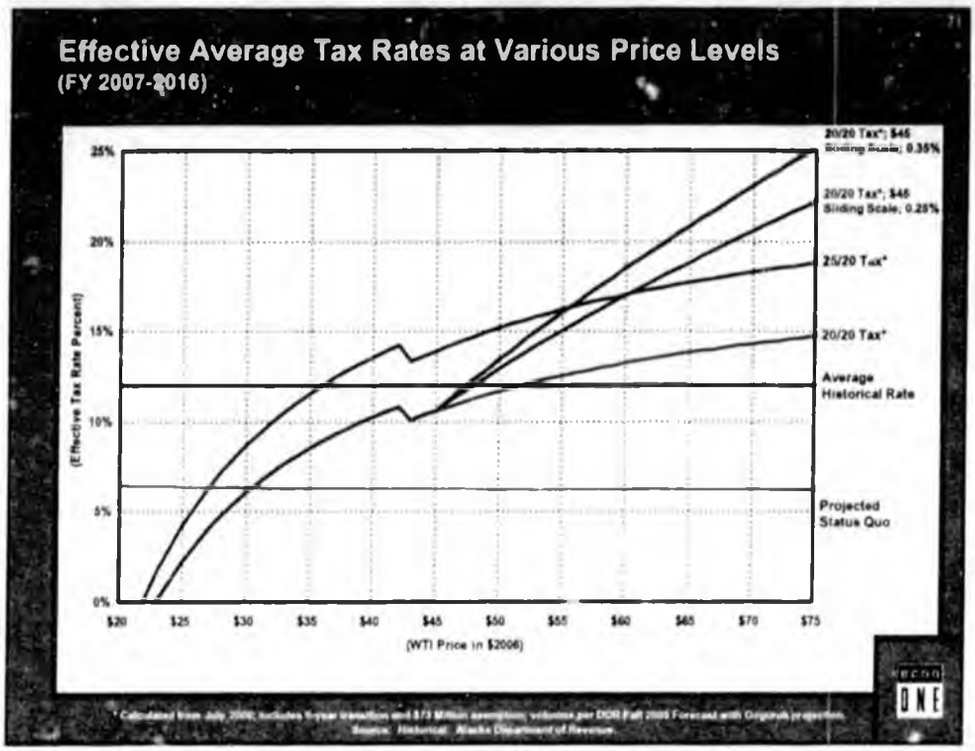
= ($55 - $45) x 0.25% x $47 x (1 - 20%)

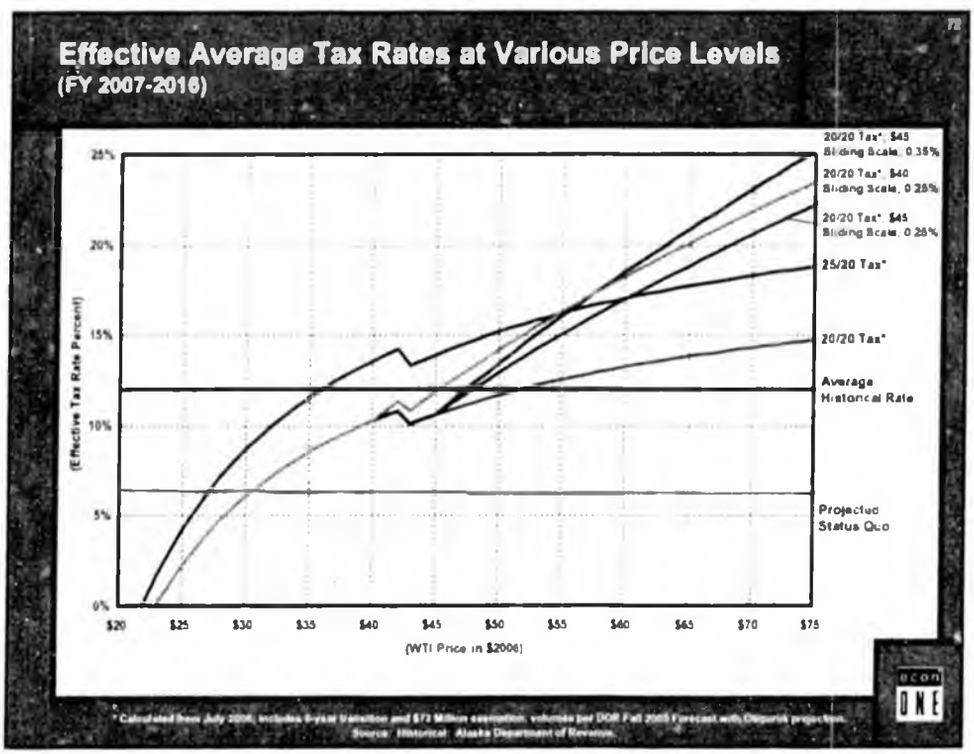
= 2.5% x $47 x 80%

= $0.94

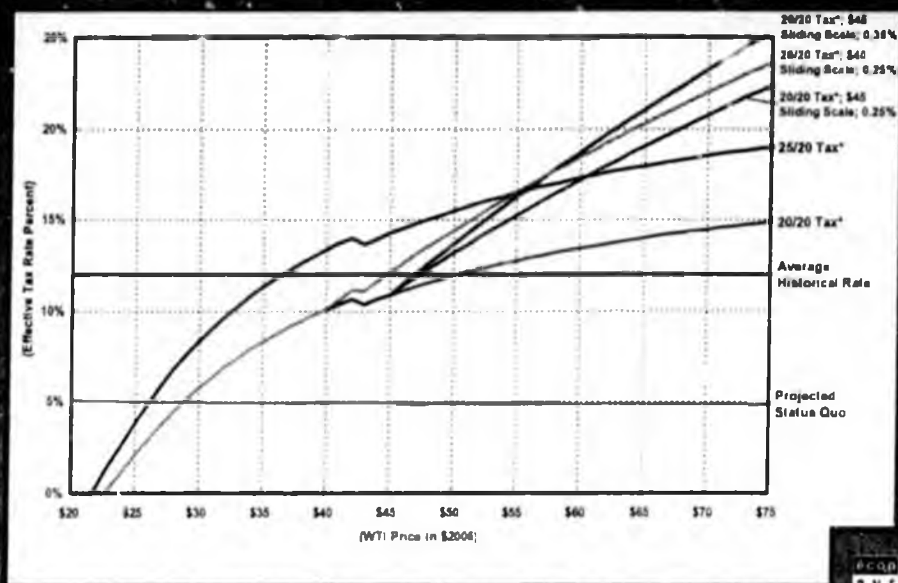
Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)




Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)
25%
20%
15%
10%
5%
0%
(Effective Tax Rate Percent)
$20
$25
$30
$35
$40
$45
$50
$55
$60
$65
$70
$75
(WTI Price in $2006)
20/20 Tax*; $45
Sliding Scale; 0.35%
20/20 Tax*; $45
Sliding Scale; 0.25%
25/20 Tax*
20/20 Tax*
Average
Historical Rate
Projected
Status Quo
econ
ONE


Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)
25%
20%
15%
10%
5%
0%
(Effective Tax Rate Percent)
$20
$25
$30
$35
$40
$45
$50
$55
$60
$65
$70
$75
(WTI Price in $2006)
20/20 Tax*; $45
Sliding Scale; 0.35%
20/20 Tax*; $40
Sliding Scale; 0.25%
20/20 Tax*; $45
Sliding Scale; 0.25%
25/20 Tax*
20/20 Tax*
Average
Historical Rate
Projected
Status Quo
econ
ONE

Effective Average Tax Rates at Various Price Levels
(FY 2007-2030)



* Calculated from July 2006; includes ... year transition and $73 Million exemption; volumes per DOR Fall 2005 Forecast with Gogorich projection.

Projected Effective Tax Rates with Sliding Scale Tax DOR Forecast Production (FY 2007-2030)*

WTI Price ($ 2006)	Status Quo	20/20	20/20 with Sliding Scale Tax: $35 Threshold Price, 0.20% Increment	$35 Threshold Price, 0.25% Increment	$35 Threshold Price, 0.30% Increment	$35 Threshold Price, 0.35% Increment	$40 Threshold Price, 0.20% Increment	$40 Threshold Price, 0.25% Increment	$40 Threshold Price, 0.30% Increment	$40 Threshold Price, 0.35% Increment
	(Percent)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
$30	4.9%	5.8%	5.8%	5.8%	[illegible]	5.8%	5.8%	5.8%	5.8%	5.8%
$40	4.6%	10.0%	11.0%	11.3%	[illegible]	11.8%	10.0%	10.0%	10.0%	10.0%
$50	4.9%	11.9%	14.9%	15.7%	[illegible]	17.2%	13.9%	14.4%	14.9%	15.4%
$60	4.9%	13.4%	18.4%	19.7%	[illegible]	22.2%	17.4%	18.4%	19.4%	20.4%
$70	4.8%	14.8%	21.5%	23.2%	25.0%	26.7%	20.5%	22.0%	23.5%	25.0%
$80	4.8%	15.2%	24.2%	26.5%	28.7%	31.0%	23.2%	25.2%	27.2%	29.2%

WTI Price ($ 2006)	25/20	25/20 with Sliding Scale Tax: $40 Threshold Price, 0.20% Increment	$40 Threshold Price, 0.25% Increment	$40 Threshold Price, 0.30% Increment	$40 Threshold Price, 0.35% Increment	$50 Threshold Price, 0.20% Increment	$50 Threshold Price, 0.25% Increment	$50 Threshold Price, 0.30% Increment	$50 Threshold Price, 0.35% Increment
	(Percent)								
	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
$30	8.3%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%
$40	13.3%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
$50	15.9%	12.9%	13.2%	13.4%	13.7%	11.6%	11.9%	11.9%	[illegible]
$60	17.3%	16.4%	17.2%	17.9%	18.7%	15.4%	15.9%	16.4%	16.9%
$70	18.8%	19.5%	20.7%	22.0%	23.2%	18.5%	19.5%	20.5%	21.5%
$80	19.4%	22.2%	24.0%	25.7%	27.5%	21.2%	22.7%	24.2%	25.7%

* Calculated from July 2006; Includes ... and $73 Million exemption; volumes per DOR Fall 2005 Forecast with Gogorich projection.

Projected Government Takes with Sliding Scale Tax
DOR Forecast Production (FY 2007-2030)*

			20/20 with Sliding Scale Tax							
			$35 Threshold Price				$40 Threshold Price			
WTI Price ($ 2006)	Status Quo	20/20	0.20% Increment	0.25% Increment	0.30% Increment	0.35% Increment	0.20% Increment	0.25% Increment	0.30% Increment	0.35% Increment
	(Percent)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
$30	57.0%	**57.7%**	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%
$40	53.7%	**57.2%**	58.0%	58.2%	58.4%	58.6%	57.3%	57.3%	57.3%	57.3%
$50	52.3%	**58.0%**	58.9%	59.4%	59.9%	60.4%	58.2%	58.5%	58.9%	59.2%
$60	51.5%	**58.0%**	60.0%	60.8%	61.6%	62.4%	59.4%	60.0%	60.7%	61.3%
$70	50.9%	**58.0%**	61.2%	62.3%	63.3%	64.4%	60.6%	61.5%	62.4%	63.3%
$80	50.6%	**58.0%**	62.3%	63.7%	65.0%	66.4%	61.7%	62.9%	64.1%	65.3%

		20/20 with Sliding Scale Tax							
		$45 Threshold Price				$50 Threshold Price			
WTI Price ($ 2006)	20/20	0.20% Increment	0.25% Increment	0.30% Increment	0.35% Increment	0.20% Increment	0.25% Increment	0.30% Increment	0.35% Increment
	(Percent)								
	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
$30	**58.7%**	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%
$40	**58.7%**	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%
$50	**59.3%**	57.6%	57.7%	57.9%	58.1%	58.0%	58.0%	58.6%	58.9%
$60	**60.3%**	58.8%	59.3%	59.7%	60.2%	58.1%	58.5%	58.8%	59.1%
$70	**59.3%**	59.9%	60.7%	61.5%	62.3%	59.3%	59.9%	60.6%	61.2%
$80	**59.4%**	61.1%	62.1%	63.2%	64.3%	60.5%	61.4%	62.3%	63.2%

* [illegible]

SB

305

(FILE 13)

STATE OF ALASKA

DEPARTMENT OF REVENUE

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March 15, 2006

Senator Tom Wagoner, Chair
Senate Resources Committee
State Capitol, Room 427
Juneau, AK 99801

Rep. Ralph Samuels, Co-Chair
House Resources Committee
State Capitol, Room 126
Juneau, AK 99801

Rep. Jay Ramras, Co-Chair
House Resources Committee
State Capitol, Room 104
Juneau, AK 99801

Re: Questions on PPT Legislation (SB 305, HB 488)

Dear Senator Wagoner and Representatives Samuels and Ramras,

Thank you for the opportunity to respond to questions posed during (and following) recent committee hearings. This letter incorporates answers presented during testimony which was based on our interim draft reports dated March 2 and March 7, 2006, and provides additional information not previously available. In addition, this letter expands some of the answers in response to followup questions posed during the hearings. We have included a substantial number of attachments which are indexed to the question number. Lastly, we have included an index, by topic, which should prove helpful.

1. Identify values/amounts for the "look-back" or transitional section; per year according to the actual, by type (exploration, development, production). The Department of Revenue model uses $1 billion per year as capital costs, so for the

transitional period, there would be about $5 billion. This annual costs are based on compilations of historical data.

(millions)	Exploration	Dev. & Production*	Total
2001	152	1,636	1,788
2002	125	1,054	1,180
2003	90	970	1,060
2004	67	980	1,047

* We do not have information on the split between development and production expenditures.

Although we have not completed this work, we have some evidence about costs in 2005 and the first half of 2006 and it appears they will continue the downward trend seen in the four years presented.

2. How are mobilization, demobilization, and platform abandonment costs treated—as tax credits or deductions?

Mobilization costs are capitalized for federal tax purposes, as Intangible Drilling Costs. As such, they are a capitalized expenditure for PPT purposes, and therefore are deductible and creditable. We understand that demobilization and abandonment expenditures are both expensed as incurred. This would mean that these costs are deductible, but would not generate a credit.

3. Is there a "rating" for political stability – or one that reflects instability?

We do not have any information on a quantification of the risk of political stability.

4. What loss of revenue is incurred by moving the effective date from Jan 1, 2006 to July 1, 2006 on both 20/20 and on 25/20?

Using a combination of our spring forecast and YTD actuals, the average ANS price between January 1, 2006 and July 1, 2006 is estimated as $58.62.

- The loss of revenue using the 20/20 system would be about $480 mm in additional tax.
- The loss of revenue using the 25/20 system would be about $770 mm in additional tax.

5. Section 9 – what amount is involved in this section?
A very small amount, probably no more than 1% of total state production of oil and gas. Currently it is limited to Alpine and its satellites and Cook Inlet, though production expected soon from the NPRA will also have private leasehold interest.

6. Was there consideration of phasing out the $73 million allowance over a certain period of time?

No, it was not considered.

7. Of the current 14 producers in Alaska, which would pay a severance tax after employing the proposed $73 million standard allowance?

With the merger of Chevron and Unocal, there are now 13 producers in Alaska. Of the 13 producers, BP, ConocoPhillips and ExxonMobil will pay severance tax at most anticipated price levels after employing the $73 million standard allowance. At high oil and gas prices, and given our cost assumptions, Anadarko, Marathon, and ChevronUnocal will also pay severance tax after deducting the $73 million dollar allowance, given the production volumes reported publicly by those companies.

8. Which other tax regimes – worldwide - have a progressivity structure?

Note: this question answers progressivity generally, but see definition at Question 91.

Progressive features are relatively common around the world. Following is a list of the main fiscal regimes with such features. "Old" features are defined as features that have been in existence for more than 20 years. "New" less than 20 years.

There is a wide variety of systems that are progressive with the level of well production or field production. These systems are not included in the list.

Country	Region/Type	Feature	Oil/Gas	Old/New
Canada	NWT	IRR based profit sharing royalty	Both	Old
	Newfoundland	IRR based profit sharing royalty	Oil	Old
	Nova Scotia	Payout based profit sharing royalty	Both	New
	Alberta	Production/Price sensitive royalty	Oil	Old
	Alberta	Price Sensitive royalty	Gas	Old
	Alberta oil sands	IRR based profit sharing royalty	Oil	Old
Colombia		Price sensitive windfall profits tax	Oil	New
Venezuela	Conventional	IRR based profit share	Oil	New

	Oil			
Peru		R-factor royalty	Both	New
Bolivia		Profit sensitive Surcharge with uplifts	Both	New
Trinidad & Tobago	Conventional Oil	Supplemental Petroleum Tax, Price sensitive	Oil	New
	Deep water	Production/Price sensitive profit oil/gas shares	Both	New
Norway		Uplifts on Hydrocarbon Tax	Both	Old
UK	Old licenses	Uplifts and Oil Allowance on PRT	Both	Old
Denmark		Uplifts on Hydrocarbon Tax	Both	Old
The Netherlands		Uplifts on Special Profit share	Both	Old
Algeria		Cumulative Revenue sensitive PRT and uplifts	Both	New
Tunisia		Sliding scale taxation	Both	New
Libya		R-factor based profit oil splits	Oil	Old
Nigeria		Uplifts and tax credits	Oil	Old
Angola		IRR based profit oil shares	Oil	New
Qatar		R-factor based profit oil shares	Oil	New
Saudi Arabia		IRR based corporate income tax rates	Gas	New
Iran		Buy Back contracts	Both	New
Pakistan	Offshore	Price Sensitive Windfall profits tax	Both	New
India		R-factor based profit oil shares	Both	New
Thailand		Profit sensitive SRB	Both	New
Malaysia		Price sensitive windfall profits tax	Both	Old
Indonesia		Uplifts	Both	Old
Australia	Offshore	IRR based PR	Both	Old
PNG		IRR based API	Both	Old
Russia	Sakhalin	IRR based profit oil shares	Both	New
Kazakhstan	Tengiz	IRR based profit share	Oil	New
	General	New models with variety	Oil	New

		of progressive features		
Azerbaijan	AIOC	IRR based profit oil share	Oil	New
	Other	R-factor based profit oil shares	Oil	New

9. How many private royalty owners are there in Alaska – all areas, not just the North Slope (i.e., Nenana Basin, Kenai Peninsula, native corporation holdings, etc).

We do not have information on the number of private royalty owners in Alaska, which would include private oil and gas leases that are not in production. Homesteads staked under certain (but not all) federal homestead laws included oil and gas rights, and any of the owners of such parcels might enter into an oil and gas lease.

10. Provide a graph showing the status quo, the PPT, and the gas line contract terms.

This question appears to query the relationship between tax under the status quo, the PPT, and the gas line contract terms. At this time, gas line contract terms are not public information.

11. Provide information on the effect of previous incentives – the costs.

Claimed expenses under SB 185 (43.55.025) total $104.8 million and claimed credits total $33.6 million [see table below]. A claim was recently received by the Department of Revenue, thus the totals has been updated from the $95.5 million and $29.0 million figures previously provided.

Exploration Production Tax Credit Program Summary, AS 43.55.025
As of February 28, 2006

	No. of Projects	**Claimed Expenses**	**Claimed Credits**
FY 04, 05			
Audited & Issued:	7		
N. Slope wells		$51,050,000	$13,308,000
Cook Inlet wells		$ 3,430,000	$ 392,000
Cook Inlet seismic		$ 3,178,000	$ 1,085,000
Audits In progress:	5		
N. Slope wells		$26,615,000	$10,646,000

N. Slope seismic		$ 7,957,000	$ 3,182,000
Other - seismic		$ 3,295,000	$ 1,318,000
Other - wells		$ 9,286,000	$ 3,714,000
Total	12	$104,811,000	$ 33,646,000

12. What is the rational for offering the same amount of credits for non-state lease lands where the state receives no royalty tax benefit – was there discussion of a reduction in the credit to offset this?

The rationale is that the incentives have the potential to result in higher severance taxes, taxes that are assessed on any oil or gas production within Alaska's borders. Given the overall economic benefit of increased production of oil and gas (and particularly gas in the Cook Inlet where significant private lands occur), an incentive for exploration and development even in the event that a field would pay no taxes after incentives makes sense.

13. Why should Point Thomson be incentivised?

We believe the development of Pt. Thomson may be critical for the development of the gasline. Accordingly, incentivizing Pt. Thomson may well incentivize the gasline

Pt. Thomson is particularly problematic for two reasons. First, it is a high cost field since it is a high pressure gas condensate reservoir and second we do need the gas reserves to underpin the gas pipeline economics. By providing incentives, the goal would be two-fold. First any incentive to encourage Pt. Thomson improves the economics of the gas pipeline. Second, incentives may encourage early production of the liquids which requires expensive infrastructure to handle the high pressure production.

14. Can you provide better definitions for "point of production" and "oil" and "gas" and has the State litigated these terms?

See the answers to questions 22-24, below. Regarding past litigation, in general the point of production and the definitions of oil and gas have not been major subjects of litigation under the production tax statute. In contrast, there has been considerable litigation of related concepts, though not necessarily the phrase "point of production," in the royalty context.

In the tax context, there was at least one dispute decided at the internal DOR appeal stage relating to point of production, but most of the controversy in this area played out in the development of regulations defining "gas processing plant," rather than

litigation. The use of the term "gas processing" in the bill is consistent with existing department regulations, but under current law gas processing generally is considered an activity occurring downstream of the point of production, while under the bill it is considered an activity occurring upstream of the point of production.

15. What steps must be taken to make the tax credits refundable rather than transferable?

This would require a language change to Section 12 at AS 43.55.024(d) and (e). We are available to work with drafters on the exact wording.

16. On Page 13, line 24 of the bill, what does "payment in lieu of" tie into for oil?

AS 43.55.160(c) presents the general rule that lease expenditures are deductible. Lease expenditures would include property taxes. Section 21 AS 43.55.160(d)(1)(B)) clarifies that payments in lieu of property taxes are also deductible.

17. Does the limit on transferable tax credits in Section 12 (subsection (e)) limit the amount of tax credits that a single taxpayer can take against their own production tax in a single year?

Section 12 (AS 43.55.024(e)) limits the amount of tax that can be reduced through purchased credits. There is no limit on credits utilized by a taxpayer that were generated by that same taxpayer.

18. The State of Alaska has relied on the services and expertise of multiple outside law firms to handle disputes over oil and gas issues; have you conferred with such counsel in the drafting or review of this legislation? If so, have they assessed the impacts of the legislation on the State's legal position in past agreements, current disputes, or future disputes?

Yes, such counsel (not all of them) has been consulted and such assessments have been discussed but have not generally been generated in formal written form.

Did such advice result in any changes to the legislation?

The bills reflect discussions with counsel that took place during the drafting process, so in that sense such advice did affect the legislation.

19. Have you asked the Department of Law to review this legislation in light of the 6th Circuit Court of Appeals' decision in Cuno v DaimlerChrysler that is now pending before the United States Supreme Court?

The Department of Law has examined this matter. The court decision calls into question, under the Commerce Clause of the United States Constitution, investment tax credit provisions that are found in state tax laws throughout the country. However, the decision's applicability to tax credits under a production tax, rather than an income tax, is not clear. In any event, the decision is currently being reviewed by the United States Supreme Court, and we should learn within the next several months whether it will be sustained.

20. Please provide information regarding the expenditures that will qualify for the transition credits—including the depreciation method chosen under the federal and state income tax systems.

It appears that this question relates to the transition provision in Section 21 (AS 43.55.160(g)) which allows a deduction for capital expenditures made over the last five years, deductible over the next six years. The capital expenditures that qualify for transitional treatment are the same type of expenditures that qualify for ongoing credits. These are defined in Section 12 (AS 43.55.024(h)). These expenditures include exploration expenses and those expenditures that are capitalized for federal tax purposes. Exploration expenses include geological and geophysical exploration. Expenditures capitalized for federal tax purposes include intangible drilling costs. The capitalized expenditures are subject to a variety of useful lives under federal and state income tax rules. See Question 59 below.

21. Have any of the definitions in Sections 30-33 been the subject of disputes with tax and/or royalty payers in the past? To the extent they have, please provide the definitions the state asserted in those disputes.

See question 18 above.

22. Please provide an identification of the point of production at each unit in the state under existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

For crude oil, the point of production will not change under our proposal. It will remain the point where the oil is first metered or measured in a condition of pipeline quality. (Note that certain oil used on the lease will no longer be taxable under the proposed production tax reforms, but that is not a point of production issue.) As examples, the points of production for oil are and will be the LACT (lease automatic transfer custody) meters at the inlets to TAPS (for Prudhoe Bay) and the Kuparuk Pipeline (for Kuparuk), and at the onshore production facilities for the Cook Inlet platforms.

What will change, in some cases, is the point of production for some gas. At Prudhoe Bay, while the current point of production for most gas is the inlet to the Central Gas Facility (CGF), there are other potential points of production for other gas uses. For example, in the separation facilities, gas is taken right out of the flow stream and burned in that facility (however this gas is not taxable under the free use of gas rules.) For taxable gas, the *inlet* to the CGF is generally the point of production for all gas that emerges from the CGF, including the NGLs that are recovered in liquid form.

This compares to other gas plants that are or have been operating at Kuparuk, Endicott, and Lisburne. For these facilities, the point of production for gas under current law is the *outlet* where the facility is tied to a sales or other line that take the gas off the unit. Why? Because in each of these facilities, the liquid hydrocarbons extracted from the processed gaseous streamare reblended with oil and run through gas-oil separators again. Therefore, the gaseous stream entering the facility has not yet been "completed separated" from oil, and the point of production for gas must be downstream of the facility

Under the bill, all gas processing operations (as long as they do not also include gas treatment) are considered upstream of the point of production. Therefore, the point of production for gas run through the Prudhoe Bay CGF will be where the gas is metered after leaving the CGF. In this respect, the point of production for gas will change at Prudhoe Bay but remain the same – downstream of the gas processing facilities – at the other North Slope fields using gas processing.

23. Please provide an identification of 'gas treatment' and 'gas processing' facilities in the state under the existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

To date in administering the tax, there are no gas treatment facilities on the North Slope. The only "gas processing plant" currently in the state is the Central Gas Facility (CGF), because by definition in the Department's regulations, a facility is a gas processing plant only if it is located downstream of the point of production for gas. 15 AAC 55.900(b)(7). However, the Lisburne, Endicott, and Kuparuk facilities conduct "gas processing," as defined in the regulations, 15 AAC 55.900(b)(6) even though they are not "gas processing plants."

Under the definitions in the bill, it will no longer matter whether a facility is a "gas processing plant." All four of the North Slope facilities will continue to be characterized as conducting "gas processing," which will be upstream of the point of production for gas.

Under the proposed definitions, plants removing CO_2 and H_2S from gas for delivery to a sales line – which in the sponsor group proposal is assigned to a new Gas Treatment Plant (GTP)--would be a new Gas Treatment Plant.

24. What standard will be used to determine whether oil or gas is of "pipeline quality" under the definition of "gross value at the point of production"?

The current production tax statute taxes the "gross value at the point of production" of oil and gas. The quoted phrase was enacted in 1977 and replaced the previous statutory phrase "gross value at the well." This change was aimed at ensuring that costs of production operations downstream of the well would not be deductible in calculating the taxable value of oil or gas; rather, taxable value would be calculated at the point that production is complete.

In the case of oil, "gross value at the point of production" was defined as the value of oil where it is metered "in a condition of pipeline quality," and "pipeline quality" was defined as "good and merchantable condition." This definition essentially adopts commercial standards of marketability for oil. HB 488 and SB 305 would simplify and shorten the definition of gross value at the point of production for oil but do not materially change it. In addition, the definition of "oil" is broadened to include liquid hydrocarbons recovered by gas processing in the case of leases or properties whose production is subject to gas processing. The bottom line is that the point of production under these bills would still be the point where oil is metered in a condition of pipeline quality, and "pipeline quality" would mean the same thing it has always meant under the production tax statute.

In the case of gas, neither the existing statute nor the new bills use the phrase "pipeline quality" or "good and merchantable condition" with respect to gross value at the point of production. Rather, the statutory definitions of "gross value at the point of production" for gas, as interpreted and clarified by the Department's regulations, 15 AAC 55.900(a)(6)(B) and (C), focus on where gas is accurately metered after separation from oil. The new bills retain this concept but, in effect, expand "separation" to include gas processing, so that in the case of leases or properties whose production is subject to gas processing, the point of production for gas recovered by gas processing is the point where it is metered downstream of the processing.

25. Provide a historical analysis of the results of valuation methodologies adopted by the Department of Revenue, Department of Natural Resources (under all agreements), and the Department of the Interior.

a. North Slope:

While there is much that is parallel in the calculation of gross value between royalty and tax, many differences have developed. Both start with destination value in the market, and then subtract the tankering, pipeline and other costs to arrive at a royalty or tax value. The Department of Revenue's (DOR) valuation for tax comes from statute and regulation. The Department of Natural Resources' (DNR) valuation for royalty comes from lease contracts supplemented by Royalty Settlement Agreements (RSAs) which set forth different methods for each large North Slope producer.

Destination value, for DOR, is what the oil was sold for, or when the oil is not sold or is sold for a below-market price, the so called prevailing value, generally based on spot price. Destination value for DNR is a formula driven by the price of ANS or a basket of similar crudes.

From the destination value, each method subtracts marine transportation costs, TAPS costs (including tariffs, losses and quality bank changes from mid-point refineries), feeder line costs (including tariffs, losses and quality bank differences), and other miscellaneous costs. DOR deducts the costs specific to each taxpayer, while for royalty, some of the RSAs have formulaic deductions and others use the royalty payer's actual cost. In addition, DNR subtracts field costs for most DL-1 lease form leases on the North Slope whereas DOR does not.

A critical point is that DOR uses actual proceeds, and only resorts to Prevailing Value when the conditions of AS 43.55.020 (f) are met, thereby taxing on the higher of proceeds or Prevailing Value. For production covered by Royalty Settlement Agreements, DNR uses a single destination formula based on spot prices, not actual proceeds.

b. Cook Inlet

In the Cook Inlet, the Oil ELF has been at zero for quite some time so there is no developed DOR methodology. Instead, it is appropriate to compare Department of the Interior royalty methodology with DNR methodology.

26. Will abandonment costs be eligible for deductions or credits under the legislation? If so, what estimates of the timing and costs of those activities does the Department project?

See Question 2 for deductibility of abandonment costs. With regard to costs, we are aware of no field having ever been abandoned in Alaska, and so we do not have any empirical data on costs.

27. How will AS 43.55.160(j) protect the State from a proliferation of corporate entities and/or companies claiming the tax free allowance?

AS 43.55.160(j) does not establish a maximum number of companies entering the market that could utilize the standard allowance. However, this section requires that the Department of Revenue evaluate each company claiming the deduction, on an annual basis, to determine if the company qualifies for the deduction. This section goes on to require the company to show that it has not split operations or property ownership among multiple entities in order to gain usage of multiple $73M deductions, when only one deduction should have been granted.

28. Provide the number of exploration and delineation wells estimated to be drilled over the first ten years of your economic models. Include the technical and economic success rates projected in the modeling.

Five [5] exploration wells per year are included in the model. The Department of Revenue assumes $100 million is spent on exploration per year. With average costs of $20 million dollars per well, this comes out to five [5] wells per year. Delineation wells are separate and included under development expenditures. The model assumes there are four [4] finds of large oil accumulations – reserves in place that would be on the order of 500 million barrels. There are four [4] relatively small fields that are characterized as being "heavy" oil. These fields would pay no production tax under the current system because their Economic Limit Factor [ELF] would be zero [0.0]. We did not include a "success rate" in our model.

29. Provide estimates for undiscovered resources in Alaska. Include the breakdown between technically recoverable and economically recoverable resources to the extent possible.

Resources estimated are those that would enter the Trans Alaska Pipeline System [TAPS] north of the Brooks Range. These include estimates of recoverable oil from the National Petroleum Reserve – Alaska [NPRA], the Central North Slope, the Beaufort Sea and the Alaska National Wildlife Refuge [ANWR]. Estimates are presented in terms of barrels of technically and economically recoverable reserves. Technically recoverable estimates are mean estimates. Economic recovery is based upon the Department of Revenue [DOR] long term forecast of Alaska North Slope [ANS] crude oil delivered on the west coast at $25.50 per barrel in nominal terms. For purposes of analysis, all economically recoverable oil is presumed to be produced by 2046 [within 45 years]. Estimates are obtained from United State Federal government sources – the United States Geological Service [USGS], the Minerals Management Service [MMS] and the Energy Information Administration [EIA].

	Oil		
	Technically	**Economically**	**Natural Gas**
NPRA	10.6 Bbl	2.95 Bbl	59.7 Tcf
Central North Slope	3.98 Bbl	0.88 Bbl	35 Tcf
Beaufort Sea	6.94 Bbl	1.79 Bbl	Remainder plus existing PBU
ANWR	10.40 Bbl	4.21 Bbl	
Total	**32.38 Bbl**	**9.83 Bbl**	**200 Tcf +**

- **NPRA** – The entire area is estimated to contain 10.6 billion barrels of technically recoverable oil. Economically recoverable reserves consist of 2.95 billion barrels of oil.[1] (U.S. Geological Survey, 2002, Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPRA), USGS Fact Sheet 045-02, Table 3 and Figure 7)

- **Central North Slope** – The technically recoverable yet-to-be-discovered barrels of oil are estimated at 3.98 billion. Economically recoverable reserves are set at 0.88 billion barrels (USGS, 2005, Economics of Undiscovered Oil and Gas in the Central North Slope, Alaska, Open-File Rpt 2005-1276, Table 5).

- **Beaufort Sea** – There are 6.94 billion barrels of oil technically recoverable. Economically recoverable reserves during the period under consideration are set at 1.79 billion barrels, the mean estimate at lower oil prices. (Mineral Management Service, Beaufort Sea Planning Area Oil and Gas Lease Sales 186, 195, and 202 OCS FEIS, 2003, MMS 2003-001, Appendix B, Table B-1)

- **ANWR** – There are 10.4 billion barrels of technically recoverable oil. Economically recoverable reserves consist of 4.21 billion barrels. (Energy Information Administration, Analysis of Oil and Gas Production in the Arctic National Wildlife Refuge, March 2004, pg 5 and Table 1)

- **Natural Gas** – Most natural gas that is technically recoverable is considered economically recoverable provided there is a means of transmission to market. Assuming gas flow through a pipeline beginning in 2015, the period through 2046 production totals 49.6 trillion cubic feet. Best estimates of natural gas reserves on the north slope far exceed this amount and include: proven reserves – 35 trillion cubic feet within Prudhoe Bay Field, Pt. Thomson, and other fields (EIA, March 2004), NPRA - 59.7 trillion cubic feet (USGS Fact Sheet 045-02); and, together with ANWR and offshore undiscovered reserves totals above 200 trillion cubic feet (USGS, Conventional Natural Gas Resource Potential, Alaska North Slope, 2004, Rpt 2004-1440).

The studies also set ranges for technically recoverable oil with a 5% and 95% confidence interval. These wide ranges are presented below. Economically

[1] Economically recoverable estimates were based on 2001 dollars so that $23.50 equates to approximately $25.50 in 2005 dollars.

recoverable oil volumes will vary by price of oil. However, higher valued oil will also be higher cost oil to produce with each increase in price resulting in increased volume strictly related to the cost of production.

Range of Technically Recoverable Oil

	5th Percentile	Mean	95th Percentile
NPRA	5.90 Bbl	10.6 Bbl	13.20 Bbl
Central North Slope	2.87 Bbl	3.98 Bbl	5.85 Bbl
Beaufort Sea	3.56 Bbl	6.94 Bbl	11.84 Bbl
ANWR	5.70 Bbl	10.40 Bbl	16.00 Bbl

30. Provide a historical analysis of the effective tax rate on each field in production on the North Slope over the past twenty years.

See attachment section, indexed by question number. These tables contain effective production oil tax rates since 1986 for all Alaskan fields on gross value at the point of production on non-royalty volumes. The effective tax rate shown on these tables is the ELF x 12.25% for the first five years of production, and ELF x 15% thereafter. We note the effective rate varies between 15.0%, for Prudhoe Bay through 1987 (when the so-called "rounding rule" rounded the ELF up to 1), and 0.0% for a number of fields for a number of years.

31. How will Net Profit Share Leases (NPSL's) be affected by this legislation? Will the gross costs of exploration and development go into the Development Account—or those costs net of the credits and deductions?

Production taxes are currently deductible for NPSL purposes. This legislation is not intended to change the deductibility of the production tax. However, NPSL leases are administered by the Department of Natural Resources, which is better equipped to address these questions and which we understand is doing so.

Also see Question 58.

32. It's been reported that the gas line contract will propose the state take its gas production tax share in the form of gas. How does that work in this bill?

In the gasline contract the state has indeed proposed taking deliveries of gas in place of a production tax; this is not reflected in the PPT bill which will stand on its own, gasline or no. Under the PPT, if the producers sell gas, those revenues would be part of the net profit calculation. Under the gasline, they would not. Instead the state would receive a percentage of the gas, which it would monetize through marketing.

Note that the costs of developing (for example Pt Thomson) or running (for example Prudhoe Bay) a field that produces both oil and gas would go into calculating the taxable statewide value of a producer's oil and non-gasline gas under the bill.

33. Of the pre-PPT credit provisions (or claw back), what is the cost to the state for legacy fields and what is the cost to the state for frontier regimes?

See Question 20.

The assumption made for this request is that the Pre-PPT cost claw-back will be the last adjustment made to the tax. All other deductions and credits allowed under the PPT will have been exercised.

There was approximately $4.8 billion of capitalized investment made by the industry during in the period 2001 through 2006.

Using the Department of Revenue price forecast, which has prices falling and remaining below $40 after 2008:

Legacy Field Owners:	$316.6 million
Frontier Field Owners:	None. Due to no production or the inability to generate revenues sufficient to have a tax liability after other deductions or credits are taken.

Assuming a flat price of $45 for 2007-2050.

Legacy Field Owners:	$935 million
Frontier Field Owners:	15 million
Total	$950 million

Assuming a flat price of $60 for 2007-2050.

Legacy Field Owners:	$936 million
Frontier Field Owners:	15 million
Total	$951 million

34. Of the pre-PPT credit provisions (the claw back), how many investment credits were sold under SB 185 and how do we ensure the person who holds the credit, not the original recipient, gets the credit?

a. Only 2 credits that have been issued have been sold to another party.

b. The Division will first obtain a waiver of confidentiality from the seller allowing the Division to confirm the credit amount to the prospective purchaser. Once sold, the Division makes the transfer and issues a new credit certificate to the purchaser

upon receipt of documentation and confirmation of the transaction from the seller of the credit. The credit exists as an electronic entry in a Division database, therefore only the Division can make the actual transfer of the credit in that database. A new certificate is entered in the database to the purchaser and the old certificate is marked as transferred and its balance is zeroed out. The Division then notifies both the purchaser and the seller, in writing, of the completed transfer of the credit, at which time the purchaser may then apply the credit to its own production tax liability. When a credit is applied to a tax liability by a producer, the Division then verifies the holder and amount of the claimed credit against the credit certificates in the database.

35. If we have a gas pipeline in 2015, what will the ELF tax "take" be on North Slope gas and what will the "take" be under the PPT? What will the "take" be under PPT if we take gas in lieu of the production tax (the take would, I assume be the day-to-day value of the gas less the state's cut in selling the gas on the marketplace)?

Without getting into price sensitive forecast, or the confidential draft gas contract, we can make the following observations about the comparison: The upstream costs are covered in the PPT, so the difference could be as simple as;

(a) under the PPT, a taxpayer would pay 20% of the gross value at the point of production, that is sales revenues less the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale would be paid to the state. (without taking into account the effect of the $73 million dollar allowance).

(b) Under a gas contract as now contemplated, the state would receive some percentage of the gas, and then pay the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale. If the state owns part of the pipeline, then the state will also receive that portion of the tariff which is profit accruing to the owner.

36. Is current production tax deductible from corporate tax? If no, is this impact in the models presented by the Administration?

Yes, current production tax is deductible from corporate income tax.

37. Referring to Section five, what oil and gas is exempt from taxation—just what is discussed in Section 10?

The oil and gas royalty amounts paid to the state and federal government are exempt. AS 43.55.900 (13) "ownership or right to which is exempt from taxation" means any ownership interest of the federal government or the state."

Section 10 simplifies treatment of flared gas. Under current law, there are three categories of gas – gas used in production operations which is exempt from tax, gas produced in excess of that needed for safety purposes which is taxable, and gas flared beyond the amount authorized for safety which is taxed and subject to a penalty. Currently there is no "free use of oil" to produce more oil in statute. The bill exempts from tax any oil or gas used in production operations, unless the Alaska Oil and Gas Conservation Commission determines that it was waste (instead of used to produce salable hydrocarbons), in which case it is taxed.

38. Referring to Section six, will there be any impact to current state taxes or municipality taxes from this change?

No, there should be no impact to current state or municipal taxes. This language change simply makes the description of Intangible Drilling Costs consistent with Internal Revenue Code language, which is how this item is interpreted currently.

39. Why was the payment for taxes and surcharges changed from the 20th day to the last day of the month? What is the economic impact of this change?

There is no economic impact and this just clears up current language. Under AS 43.55.020, payment for the tax is "due" on the 20th, however, the tax is not "delinquent" until the last day of the month. The significance of this is that according to AS 43.05.225, interest is assessed only when a tax "becomes delinquent." Thus this bill makes the due date the end of the month and in Section 7 establishes that "an unpaid amount of tax that is not paid when due in accordance with this subsection becomes delinquent."

40. Do other nations with a net profit system have the 90 percent payment of taxes with the sure-up provision the following year? What is the economic impact of this change?

a. Net profits systems in the world typically work on the basis of three different concepts:

(a) monthly payments based on actual production, revenues and expenditures, without an annual true-up, as is the case in most production sharing agreements
(b) yearly payments based on a yearly return, filed within a few months after the year, without a need for monthly payments on account, as is the case for the Thai SRB, for instance. This means there is only a single annual payment.
(c) Yearly payments based on a yearly return, filed within a few months after a calendar year or a lease/contract year, with monthly payments on account. In this last case, the monthly payments could be based on:

a. Estimates for each month, as for instance with the Nova Scotia profit sharing royalty. These estimates can be challenged by government and different estimates may be required.
b. Payments based on a mixture of actual information from the previous month and estimates, such as in Algeria
c. Corporate income tax style procedures, whereby payments are based on taxes paid in the prior year (Norway for the Hydrocarbon Tax).

The 90% rule proposed for Alaska is unique. The overall economic impact would depend on the taxpayers' cost estimates for each month. We expect that taxpayers will experience underpayments in some months, but will experience overpayments (because of estimates used) in other months. In addition, falling production amounts or unforeseen costs will serve to likely create overpayments in later months. Overall, we do not expect any material net economic impact.

41. What are the penalties for under-payment when sure-up [true-up] is more than ten percent of the taxes owed?

If the taxpayer does not pay 90%, then interest will be due on the difference between the tax paid and the 90% amount.

42. Referring to Section 10, why does the AOGC [Alaska Oil and Gas Conservation Commission] role change from focusing on excess needed for safety reasons to whatever they determine to be waste? Does this provision provide more power to the AOGC on what is included/excluded for taxation?

Under current law, as applied by DOR regulation, the categories of flared gas recognized by DOR are different from (although related to) the categories recognized by AOGCC. The bill will simplify the categorization and harmonize it completely with AOGCC's. This simply creates one standard administered by AOGCC, in place of two standards administered by two agencies.

43. Why does it seem the credits and incentive [sic] are on production along with exploration if our focus is to provide incentives for exploration?

The bill is based on the expectation that investment, both exploration and in existing fields, will increase production.

44. Can the carryforward amount be used for a credit for more than the first year after the loss?

Yes, the credit carryforwards can be used indefinitely. There is no time limit on the credit carryforwards.

45. Is it the case that any allowable expenses for the exploration, development, or production of gas can be deducted from oil revenues in determining net value? If so, could the expenses of a gas line be included in these deductible expenses?

Expenses are allowable only if they are "upstream" costs. A gas line is "downstream" and so would not be a deductible expense.

46. Why not use GAP [sic] accounting rules versus set up or our [sic] system of defining revenues and expenses?

GAAP (Generally Accepted Accounting Principles) are useful for determining whether an item of expenditure can be classified as an "expense." GAAP does not differentiate between expenses incurred specific to a lease and those expenses that are indirect to a lease. For example, GAAP does not distinguish between wages paid to a lease-based worker, and an employee in the home office.

47. Which credits can be applied to multiple years?

There is no time limit for credit carryforwards under the bill, or for the optional credit codified in AS 43.55.025. However, any dollar of investment can only generate one credit, and that credit can only be used once.

48. Can a tax credit be sold in any year or just the year after it was accrued?

Once the credit has been turned into a Credit Certificate, it can be sold at any time. A person can apply for a Credit Certificate at any time, but the bill allows the Department. of Revenue a period of time in which to issue the Credit Certificate. (See Section 12, AS 43.55.024(g))

49. What is the estimated economic impact to the state of the ability to sell tax credits?

We believe the economic impact on the state will be positive as the credits will cause additional exploration, investment and development in the state creating jobs and demands for local goods and services. We believe there will also be a positive impact on the state treasury, and that while the cost of the credits will be considerable as discussed below, a better comparison is total revenue collected with the incentive driven investment and with the incentive driven investment. Because

we don't know exactly how much investment will occur as a consequence of these credits (and because without having some certainty about that number, comparing two sets of revenues from two different sets of volumes can become an exercise in wishful thinking, the rest of this answer focuses on the narrow question of the cost to the states PPT collections from the credits

In short, the proposed twenty percent capital credit against production tax would result in total credits of between $5,369.9 and $12,506.0 million depending on whether there are additional major (Alpine like) fields discovered on the ANS and whether or not a gas line is built triggering additional discovery and development (the gas line itself will have no direct effect on the PPT credits). These will amount to between 25.0% and 37.4%, respectively, of total pre credit PPT owed. Transferable credits, presuming that 95% of production is by major three companies but only 75% of credits are generated by them, result in an overall cost to the State of financing these credits of between $1,342.5 and $3,126.5 million.

Background

Permitting transferability of tax credits provides a strong economic incentive for full use of the credits. Credits accruing to companies with insufficient offsetting revenues would be more likely to be used rather than banked or lapsed. This will result in less production tax revenue to the State.

Capital credits as proposed in the Governor's PPT are equal to 20% of capital expenditures (Section 12, AS 43.55.024(a)). They may be used in the year of expenditure, carried forward to following years, or transferred (they are fungible). If transferred, the credit can not lower a producer's production tax liability below 80% of what it would otherwise be (AS 43.55.024(e)). These credits will have market value that would not exceed their face value, and will frequently be less than face value. A company generating them but unable to use them faces a choice – use them in some following year (if they have taxable income), or sell them for a discount. The value to the purchaser is in the size of the discount they get in the purchase.

Each company that conducts exploration or development work within the State will accrue capital credits. However, only those with production tax obligations will be able to deduct a credit. In order to determine production tax obligation, each company will deduct from gross value, operating costs and capital costs. From this net amount each company will have a $73 million allowance that effectively exempt that much taxable value from the PPT. Analysis based on publicly available information indicates that at anything but high prices, only three companies will have significant production tax liabilities remaining following these deductions and exemptions.

During FY06, three oil companies (BP, ConocoPhillips, ExxonMobil) account for 95% of oil production on the ANS. Future production modeling is based on known reserves and these three companies continuing to account for this level of ownership.

The capital credit system is designed to provide incentives to invest in infrastructure and exploration. Taken with the $73 million allowance, it particularly encourages companies which do not already have a major presence in Alaska. To the extent this system is successful, the major three companies will see a decrease in their share of production. However, without modeling ownership percentages, it is not possible to accurately estimate who will be spending what and selling credits to whom. Therefore, we assume in our modeling that all capital credits will be generated generally as they would be now.

In order to estimate the capital credits, it is necessary to estimate total oil and gas development spending in Alaska. This is problematic in that a successful program will incentivize more exploration and development and therefore more spending both on the North Slope and elsewhere in the State.

Capital costs for the ANS are modeled based on the following cost assumptions: $100 million per year in exploration expenditures through either TAPS closure 2030 (without gasline); $1.00 per barrel in ongoing capital costs; and, $3.50 per barrel in capital costs for conventional oil and $8.00 per barrel in capital costs for heavy oil, both taken across 100% of barrels in new fields and 2/3s of barrels in existing fields. There are four scenarios: with and without additional large finds and with and without a gas line. The four capital cost totals are:

	Millions of Dollars	
ANS – Oil	Without Gas Line	With Gas Line
Without Finds	$23,798.6	$32,688.1
With Finds	$51,543.8	$55,462.2

Gas related capital costs in the ANS are accrued only to the scenarios that include a gas line. These total $4,701 million per scenario.

Capital costs for Cook Inlet (and by proxy, the rest of the State other than North Slope) are modeled to be $3.051 billion through 2050. This is based on capital costs of $4.00 per barrel of oil and $0.50 per Mcf of gas as forecast to be produced through 2050 in the Spring RSB.

Taking ANS oil, Cook Inlet (and the remainder of the state), and ANS gas capital expenditures together results in a range of investment until 2050 of between $26,849.4 and $62,530.0 million. The twenty percent credit would amount to between $5,369.9 and $12,506.0 million.

The total production tax owed the State prior to credits is modeled using a constant $40 per barrel ANS west coast price. Depending on the scenario, this results in total production taxes of $21,488.4 to $33,416.6 million. The total credits amount to between 25.0% (no gas line and no finds) to 37.4% (gas line with finds) of the total production tax owed.

Scenario	ANS Explore	ANS Oil Ongoing	ANS Oil Develop	ANS Gas	C.I.	Total Capital Costs	20% Credit	Production Tax	Credit % of Prod. Tax
w/Gas w/o Finds	$3,500.0	$7,096.5	$22,091.7	$4,017.0	$3,050.8	$39,755.9	$7,951.2	$22,007.6	36.1%
w/Gas w/Finds	$3,500.0	$10,468.1	$41,494.1	$4,017.0	$3,050.8	$62,530.0	$12,506.0	$33,416.6	37.4%
w/o Gas w/o Finds	$2,000.0	$5,543.5	$16,255.1		$3,050.8	$26,849.4	$5,369.9	$21,488.4	25.0%
w/o Gas w/Finds	$3,500.0	$9,674.0	$38,369.9		$3,050.8	$54,594.6	$10,919.0	$32,388.1	33.7%

Sensitivity analysis was run with 95% production by major three companies and both 95% and 75% of credits owned by majors. In both cases all credits were usable. The largest State exposure to transferability of credits is when there is this wide distribution, i.e. when 95% of the production comes from the three majors. In that case, between $1,342.5 and $3,126.5 million in credits are transferred, depending on scenario.

50. Referring to Section 16, what is current system and why do we need this change in confidentiality?

The bill codifies current practice embodied in regulations in our treatment of taxpayer information. The only change here is that the bill makes clear that any person receiving information released under current department practices is subject to the same criminal penalties that apply to a state employee.

The current confidentiality law is very general in its exception language – information must be kept confidential "except in connection with official investigations or proceedings . . . ." The Department believes that current law does allow disclosure under the circumstances specified in the bill, but there has been some question about that, and it would be desirable to clarify the meaning of the law, as the bill does. In addition, there is the new provision on penalties, referred to above.

51. In what circumstances would oil and gas taxes go straight into the CBR?

Additions to the CBRF (Constitutional Budget Reserve Fund) are made for any oil and gas taxes collected in resolution of a dispute. That means that amounts collected because of an audit assessment, or subsequent settlement, are additions to the CBRF.

52. Referring to Section 18 and 19, why change from "shall" to "is"?

This change is made in accordance with the state style manual.

53. Why does the bill offer multiple methods to determine gross value? Who will choose a methodology?

The bill does not directly allow a taxpayer to elect alternative methods; it just allows the Department to authorize use of an alternative method. The election referred to would be an election between using an alternative method and just calculating gross value according to the usual rules – NOT an election among several different alternative methods. In implementing this provision, the Department will no doubt develop criteria for when a particular alternative method would be appropriate. It is difficult to predict now whether there might be circumstances under which more than one alternative method might be appropriate and under which the Department would authorize a taxpayer to elect among several alternative methods.

54. Section 21, page 13, line 8— why is this clause constrained by Dec. 1, 2005?

This constraint is intended to avoid industry changing cost allocations in contemplation of this legislation, in order to avoid taxation.

55. Section 21, provision (h), which US CPI [Consumer Price Index] does the Administration plan on using?

This would be established by regulation. The Department has not evaluated the various CPI's at this time.

56. Are the current oil conservation surcharges deductible from any other taxation? If no, what is the policy reason to make them a credit in SB 305 and what is the economic impact?

Yes, current oil conservation surcharges are deductible for corporate income tax purposes.

57. Do any other state taxes have a "standard allowance"?

a. Seafood Marketing Assessment (ASMI) tax is imposed only on processors/exporters that process or export fisheries resources with a value of $50,000 or more in a calendar year. AS 16.51.120(g). However, note that if value exceeds $50,000, then tax is imposed on the entire amount.

b. Mining License Tax is not imposed when net income is less than $40,000 in a fiscal year. AS 43.65.010(c). However, note that if net income exceeds $40,000, then tax is imposed on the entire amount.

c. Gaming tax exempts gross receipts of less than $20,000 from paying the additional fee under AS 05.15.020(b).

d. Alaska's Estate Tax follows federal rules, but the most recent exemption (Fy05) included estates valued at under $1.5M.

58. How many NPSL's (Net Profit Share Leases) are in the state, and how much are they paying in royalties?

Out of 19 NPSL's, seven are paying net profit share payments *(in addition to royalties and production taxes in cases of a positive ELF)*. These seven include five in the Milne Point Unit, and two in the Duck Island Unit, and they began paying in 2001. The total of NPSL payments received in calendar year 2005 was $81M. Total NPS receipts from NPSL's from 2001—2005 were $254M. Net profit share payments are not deductible for PPT purposes nor for the current production tax. Royalties and production taxes are deductible for NPS purposes.

Royalties, however, are paid on net profit share leases according to each individual lease contract. For example, one NPS lease in Duck Island Unit has a twenty percent (20%) royalty rate. Other NPS leases may have the standard royalty rate of 12.5% or another, negotiated royalty rate. Royalties and production taxes are due from a net profit share lease as long as there is production, even when there is no net profit share payment from the property.

Attached is a table of producing and non-producing NPS leases showing the lease number, the net profit share rate and the royalty rate for each lease.

Also see Question 31.

59. What are the depreciable lives for Oil & Gas equipment for federal and state income tax purposes?

	Federal	Alaska
Equipment for exploration and production including drilling, gathering pipelines, pumping equipment, separation equipment, certain platforms	7	11
Offshore drilling	5	6
Pipelines, excluding gathering and transmission lines	15	17.5
Vessels, barges, other water transportation equipment	10	14.5

60. Please provide the tax calculation under the bill, with the following assumptions:

--Gross value	$60M
--Opex	15M
--Capex	10M

Gross value	$60M
Less: Opex	(15)
Capex	(10)
Tentative net profit Before standard allowance	$35M
Less: standard allowance*	(35)
Net Taxable income	$ 0
Tax	$ 0
Capital investment credit available for carryforward (20% of $10M)	$2M

* this calculation assumes that taxpayer has not reached $73M limit for the standard allowance.

61. Are net profit lease payments included as a direct cost under AS 43.55.160?

Net profit share payments under NPSL's (Net Profit Share Leases) would not be deductible lease expenditures because they are in the nature of lease acquisition costs. Lease acquisition costs are not deductible per Section 21 (AS 43.55.160(d)(2)(E)).

62. Are lease bonus payments eligible for capital credit under 43.55.024 and/or are they included as a direct cost under 43.55.160?

Lease bonus payments are neither deductible nor eligible for capital credits. Lease bonus payments are in the nature of lease acquisition costs which are specifically not deductible per Section 21 (AS 43.55.160(d)(2)(E)).

63. How are payments for "spec 3D" handled? Are they credit eligible under 43.55.024 or only allowed as deductions under 43.55.160?

We understand "spec 3D" to be certain seismic exploration costs. Exploration costs are allowed as deductions under Section 21 of the bill (AS 43.55.160(c)). Such costs are also eligible for credits under Section 12 (AS 43.55.024) by reference to definition of "qualified capital expenditure" at AS 43.55.024(h).

64. Please explain the taxation or exemption of royalties.

Public royalties (paid to federal or state jurisdictions) never enter into the base of gross value. This is so because AS 43.55.011(a) levies the tax on oil except oil the "ownership or right to which is exempt from taxation." This phrase is then defined in AS 43.55.900(13) as follows:

"any ownership interest of the federal government or the state."

These sections are not changed in the bill.

Because the bill changes the tax from a tax on gross value to a tax on net values, it is necessary to specify deductions. Royalties are specifically disallowed as a deduction under Section 21 (AS 43.55.160(d)(2)(B)). Royalties paid to state and federal jurisdictions cannot be deducted because they are not included in the starting "gross value." Private royalties cannot be deducted because the royalty share of production is subject to tax.

65. Under Section 21 (AS 43.55.160(d)), "direct costs... include..." Does the word "include" serve to restrict the list of allowable expenses to only those items included below in (A)—(C)?

No. As provided under AS 01.10.040(b), "When the words 'includes' or 'including' are used in a law, they shall be construed as though followed by the phrase 'but not limited to.'"

There are specific reasons why each of the enumerated categories of costs is set out in AS 43.55.160(d)(1). "Outlays for capital assets" is set out to avoid any doubt that the bill intends to deviate from the usual principle that capital expenditures are recovered over time through depreciation allowances. Instead, under the bill, the entire outlay for an allowable capital expenditure is potentially deductible when incurred. (Correspondingly, AS 43.55.160(d)(2)(A) makes clear that "depreciation or amortization of capital assets" is *not* deductible.)

"Payments in lieu of property taxes" is set out to clarify that when a producer makes payments that are the equivalent of property taxes; those payments are deductible just as property taxes themselves are deductible.

"A reasonable allowance . . . for overhead expenses . . . " is set out to implement a policy decision that a certain amount of overhead expenses should be deductible even though "overhead" is often not considered a "direct" cost.

Just as the enumeration in AS 43.55.160(d)(1) is not intended to be an exhaustive list of direct costs for purposes of AS 43.55.160(c), neither is the enumeration in AS 43.55.160(d)(2) intended to be an exhaustive list of costs that are *not* direct costs for purposes of AS 43.55.160(c). Some of the items listed in AS 43.55.160(d)(2) are set out to implement policy decisions that certain types of costs should not be deductible whether or not they might ordinarily be considered "direct" costs; other items are set out simply for clarity, or to avoid any potential disputes over deductibility of categories that past experience indicates may be prone to controversy.

66. The discussion of oil field needs, i.e. not to deplete the gas pressure, did not recognize the CO_2 re-injection. How will that lengthen the field life(s) and at what volumes, i.e. how will it affect taxes?

At Prudhoe Bay about 8.5 billion cubic feet of gas a day is reinjected into the field for pressure maintenance. After stripping out certain hydrocarbon liquids, CO_2 is reinjected along with the other hydrocarbons (and non-hydrocarbons). When an export line is built on the North Slope, the CO_2 will be stripped (in "gas treatment"), and there is some question about what will happen with that CO_2, whether it will be treated as waste, or whether it will be treated as a by-product.

67. What happens if the "Big Three" sell off their assets to 20 smaller companies? Will the significant gas benefits ever be realized?

Assume 20 new companies suddenly showed up on the North Slope and each qualified for the $73 million dollar allowance. A total of $1.4 billion in oil and gas value would be sheltered from taxes. If these companies had simply purchased their way in, then taxes would be lower by $280 million (20% of 1.4 billion) than they would be otherwise. At current prices, or say even at $40 oil, this could be a material portion (though not all) of the tax.

If that is the future of the North Slope and the sell off was for business purposes, the legislature may choose to act and make it less attractive to new firms coming in. If these were tax motivated sales, we hope the powers of the commissioner that are built into the bill would prevent the new entrants from using the $73 million allowance

68. How is it possible that any corporation gets triple the sale price for a commodity, having invested capital at the expected lower returns, and then maintains that they need a claw back provision? Why should we offer it?

a. The first part of this question appears to be intended to be answered by oil companies.

b. We should offer a transition deduction because we are converting from a tax on gross, to a tax on net value. When measuring net value, it is necessary to allow deductions, not only for current expenses, but also a deduction for the capital investment that is generating the value. For new assets acquired after the PPT is in effect, a full deduction for the cost the capital investment is allowed in the year acquired. Assets acquired within the last five years are currently producing taxable oil and gas, and a deduction should be allowed for, in effect, depreciation on those assets.

69. Please show us an international competitiveness rank and score for PPT under the following tax/credit scenarios, both overall and for new producers:

a. 30/15
b. 30/20
c. 25/20
d. 20/20

The following tables are a competitiveness index overview for a number of alternative fiscal options. The methodology of determining the competitiveness index has been described earlier in my February 14, 2006 report.

Four fiscal options were evaluated:

- 20% tax rate 20% tax credit rate
- 25% tax rate 20% tax credit rate
- 30% tax rate 20% tax credit rate
- 30% tax rate 15% tax credit rate

Furthermore these four scenarios were evaluated under two corporate alternatives:

- Investment is a re-investment by a large producer which has already used its corporate tax free allowance
- Investment is a first investment with full use of the $ 73 million tax free allowance

Large Producer Economics

The tax rate is an important economic factor for the large producers.

This can be studied in the following three tables. These tables display the competitiveness at a WTI price of $ 26 per barrel and at $ 36 per barrel. The two indexes are then added up to provide the total index.

$26	20-20-0	25-20-0	30-20-0	30-15-0
Alaska Current	196	193	192	191
Alaska PPT	154	158	162	177
Norway	182	181	180	175
UK	68	68	68	68
US GOM	27	27	27	26
Nigeria	80	80	80	80
Alberta-Oil Sands	80	80	80	80
Angola	151	151	150	146
Russia-Sakhalin	214	214	214	212
Azerbaijan	168	168	167	165

$36	20-20-0	25-20-0	30-20-0	30-15-0
Alaska Current	161	158	157	156
Alaska PPT	147	153	160	166
Norway	214	214	214	213
UK	63	63	63	63
US GOM	25	25	25	25
Nigeria	92	92	90	89
Alberta-Oil Sands	74	74	74	73
Angola	160	158	157	156
Russia-Sakhalin	226	226	224	224
Azerbaijan	158	157	156	155

TOTAL	20-20-0	25-20-0	30-20-0	30-15-0
Alaska Current	357	351	349	347
Alaska PPT	301	311	322	343
Norway	396	395	394	388
UK	131	131	131	131
US GOM	52	52	52	51
Nigeria	172	172	170	169
Alberta-Oil Sands	154	154	154	153
Angola	311	309	307	302
Russia-Sakhalin	440	440	438	436
Azerbaijan	326	325	323	320

The $ 26 per barrel table shows how the PPT is more attractive than the Alaska current system under any combination. This is due to the fact that the current system is very front end loaded and regressive.

Therefore at low prices the current Alaska fiscal system is rather unattractive in a world wide comparison. This is the reason for the low level of activity on the North Slope during the last two decades. It is also the reason why the PPT will provide significant encouragement for investment for companies with conservative long term price forecasts.

Many large and major companies, however, are now moving to a long term price forecast in the range of $ 30 - $ 40 per barrel. This makes the $ 36 per barrel rating an important rating.

At $ 36 per barrel the PPT is clearly more attractive than the current system under the 20-20 scenario.

Under the 25-20 scenario the PPT is only marginally better than the current system. This is consistent with the opinions expressed by Anadarko and the major oil companies that a 25-20 system would not lead to more investment. However, it is

also my opinion that 25-20 will not result in a significant drop in investment by large producers. I believe that the level of investment by large producers will stay about the same.

The 30-20 system is marginally less attractive than the current system and could therefore result in a drop in investment in my view.

The 30-15 system would be more unattractive and would under a $ 36 per barrel price forecast result in a considerably less attractive system with very likely a substantial drop in investment. It is for this reason that I did not recommend a 30% tax rate.

The Total Rating reflects the combination of the $ 26 and $ 36 per barrel ratings.

New Investor Economics

The following three tables show the same ratings but now for first investors which can fully benefit from the $ 73 million allowance.

$26	20-20-73	25-20-73	30-20-73	30-15-73
Alaska Current	198	199	196	197
Alaska PPT	130	124	126	135
Norway	185	188	189	186
UK	70	72	72	71
US GOM	27	27	27	27
Nigeria	82	83	83	82
Alberta-Oil Sands	84	84	85	84
Angola	157	156	156	153
Russia-Sakhalin	217	217	217	216
Azerbaijan	170	170	169	169

$36	20-20-73	25-20-73	30-20-73	30-15-73
Alaska Current	165	164	163	162
Alaska PPT	119	120	121	130
Norway	214	214	214	214
UK	67	67	67	66
US GOM	26	27	29	27
Nigeria	96	96	93	91
Alberta-Oil Sands	79	79	79	78
Angola	167	166	164	162
Russia-Sakhalin	228	228	228	228
Azerbaijan	159	159	159	159