

**2/24/10
OIL & GAS
PRODUCTION
TAX
(FILE 3)**

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TAX (FILE 3)</subject><comm>SFIN26</comm></target>

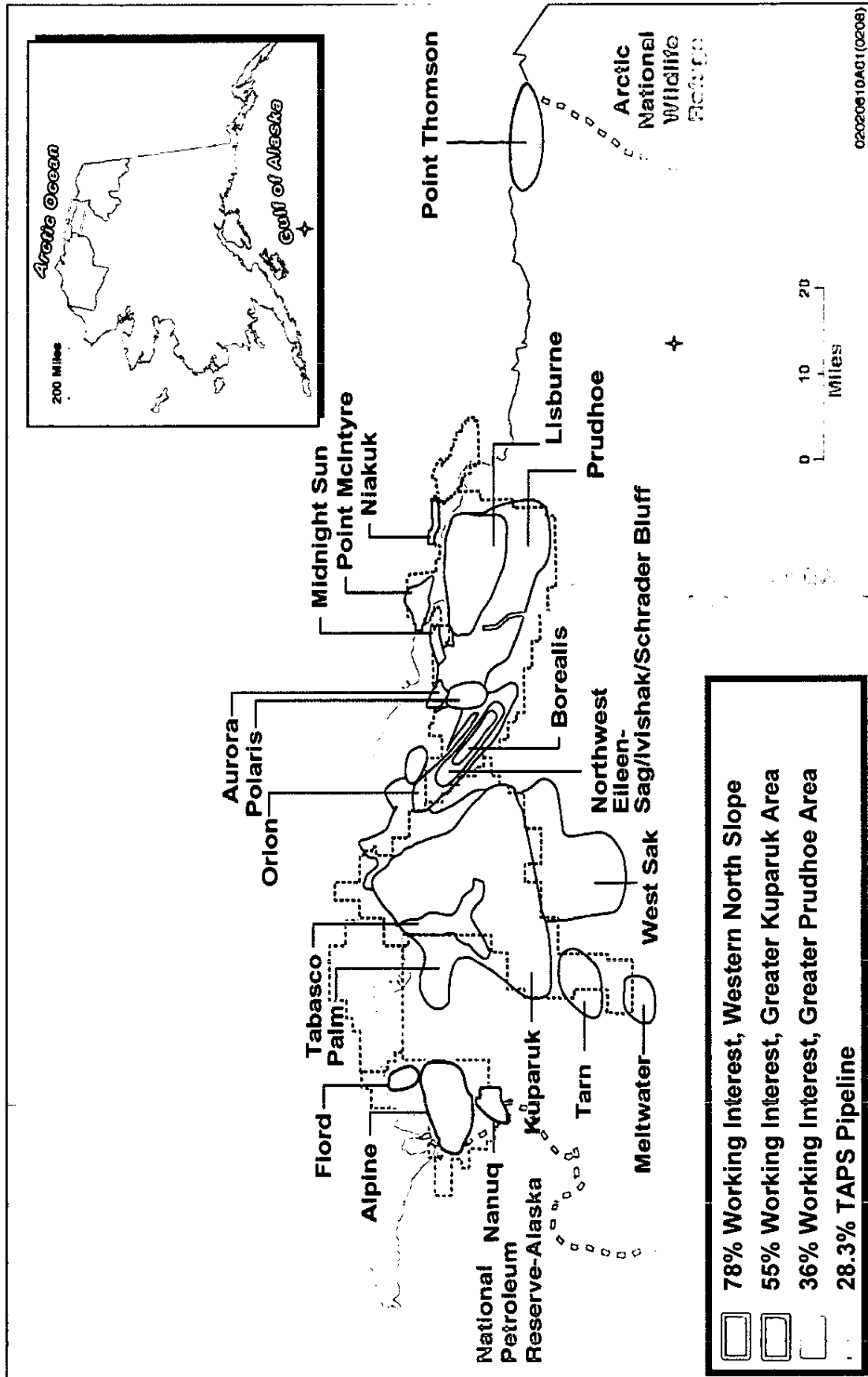
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Senate Finance Committee

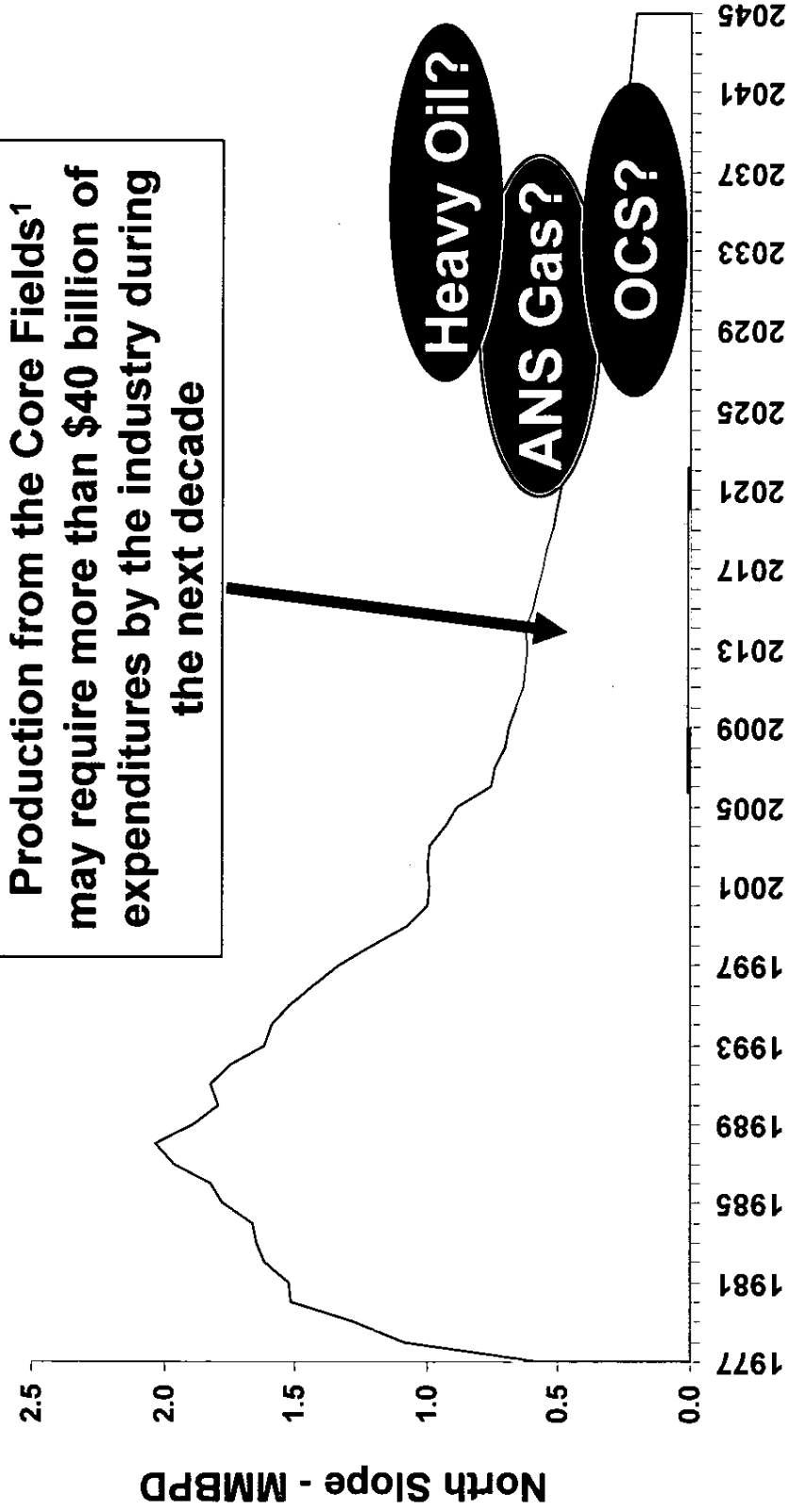
February 23, 2010

Wendy King Vice President – External Affairs
ConocoPhillips Alaska

ConocoPhillips North Slope Fields



Investment in Core Fields

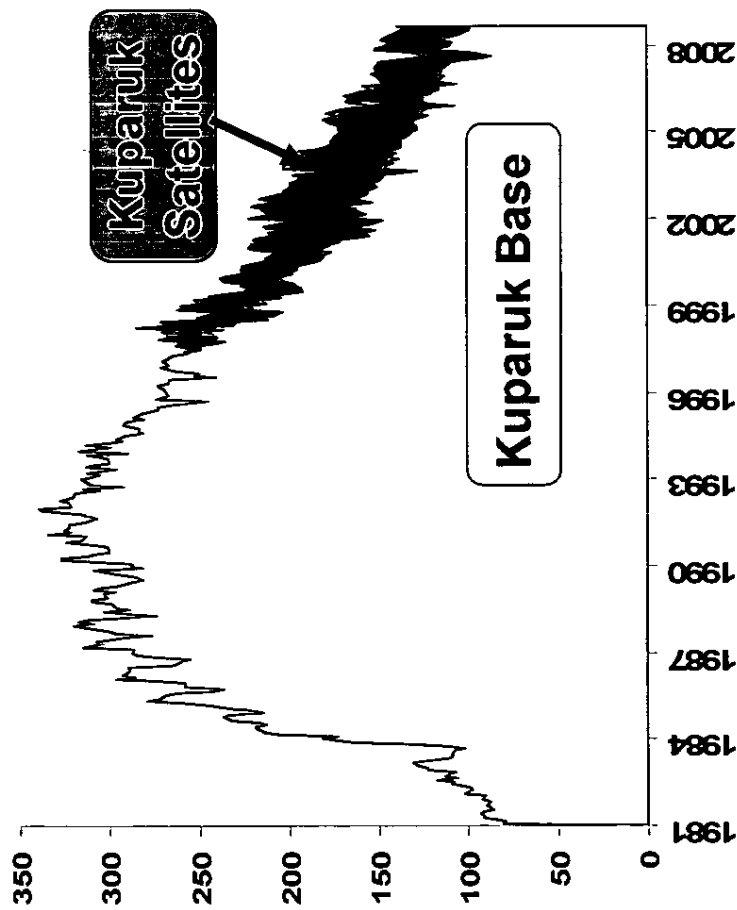


Core fields are the bridge to the future

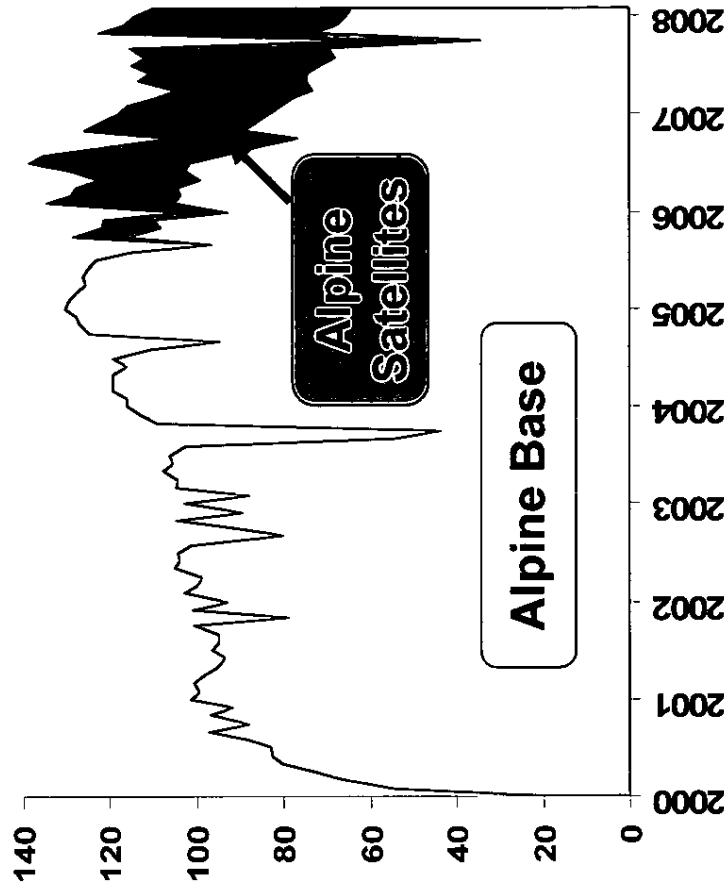
1 - ConocoPhillips core fields are Prudhoe, Kuparuk, Alpine
 Source: DOR data (forecast is for currently producing fields only)
 Slide 3

Impact of Satellite Developments

Kuparuk Production - MBD

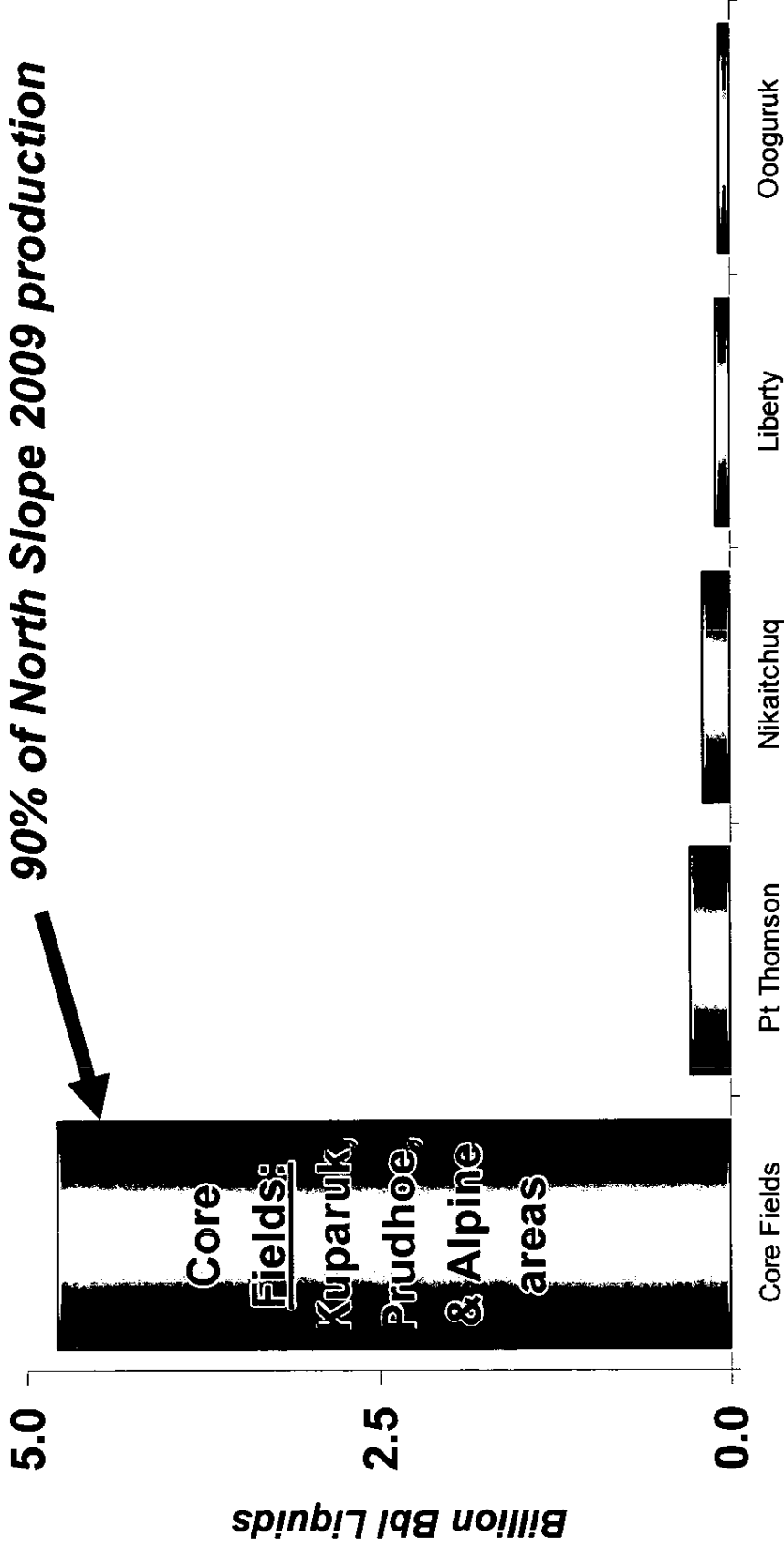


Alpine Production - MBD



Investment reduces decline

North Slope Remaining Barrels

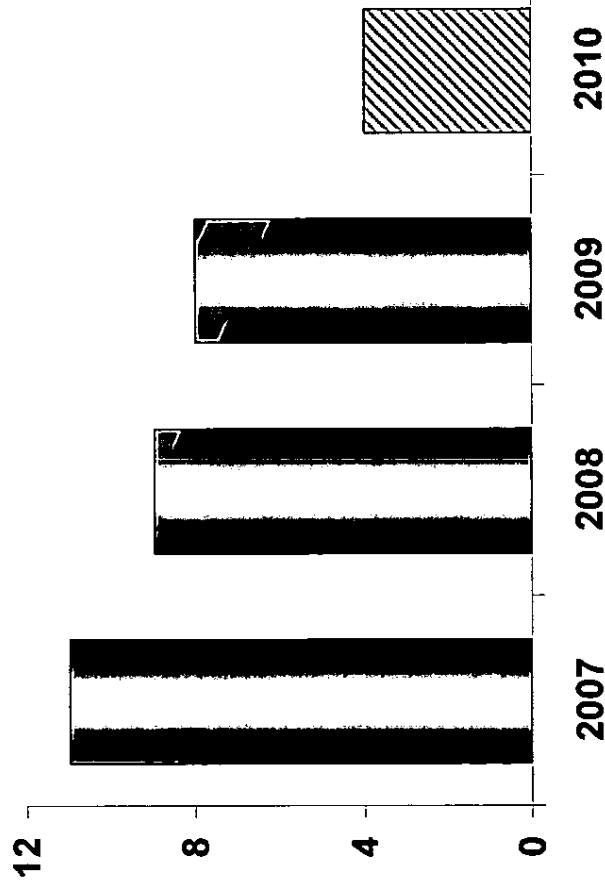


Core fields are dominant source of state production

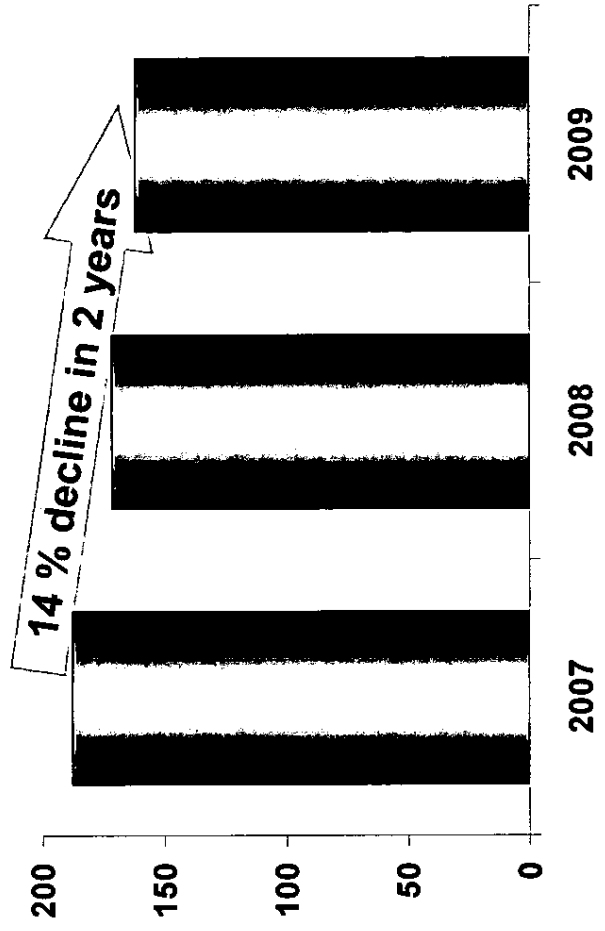
Source: DOR production forecast 2010 -- 2050 volumes
Slide 5

Industry Drilling Activity Down

Industry Exploration Wells



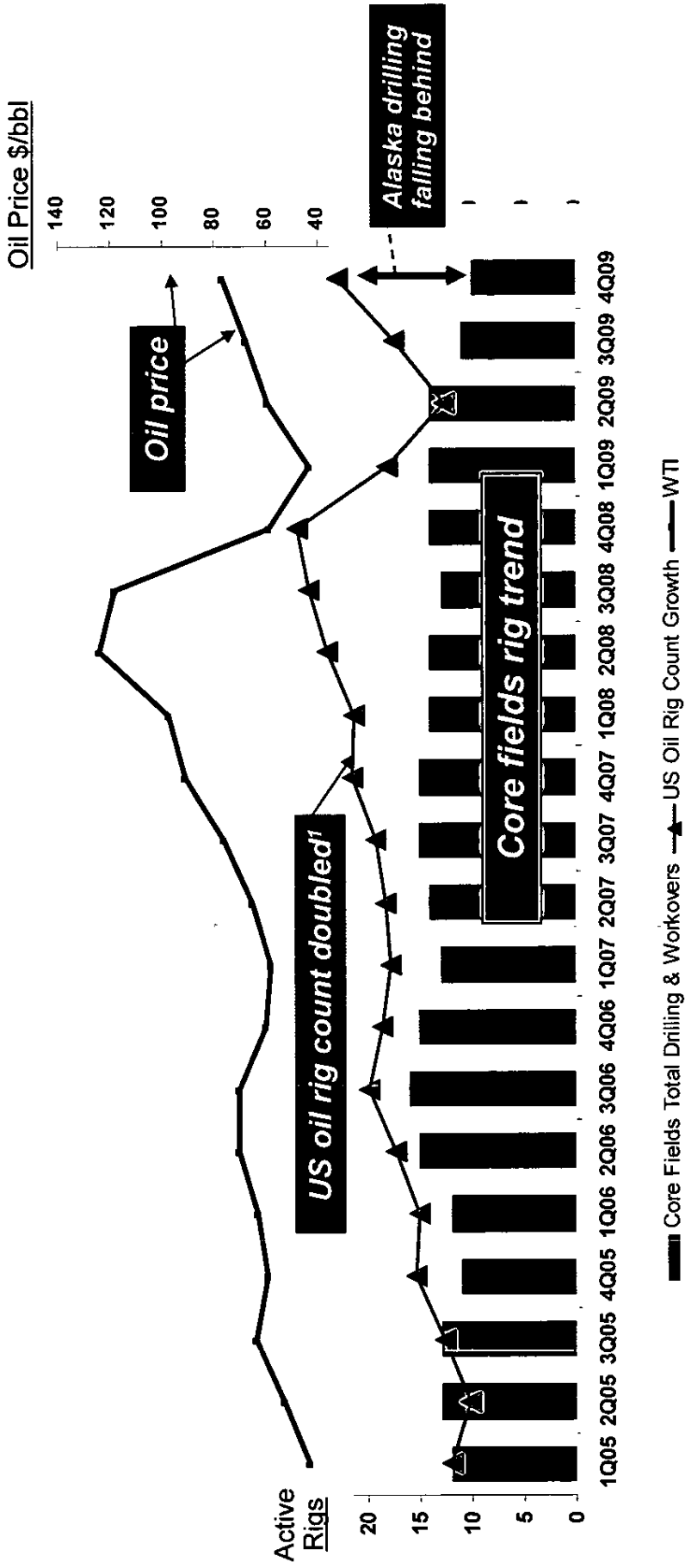
Industry Well Completions



Drilling indicators are down

Source: AOGCC for drilling and exploration wells (exploration wells are North Slope only)

Active Drilling Rigs in Core Fields 2005-2009

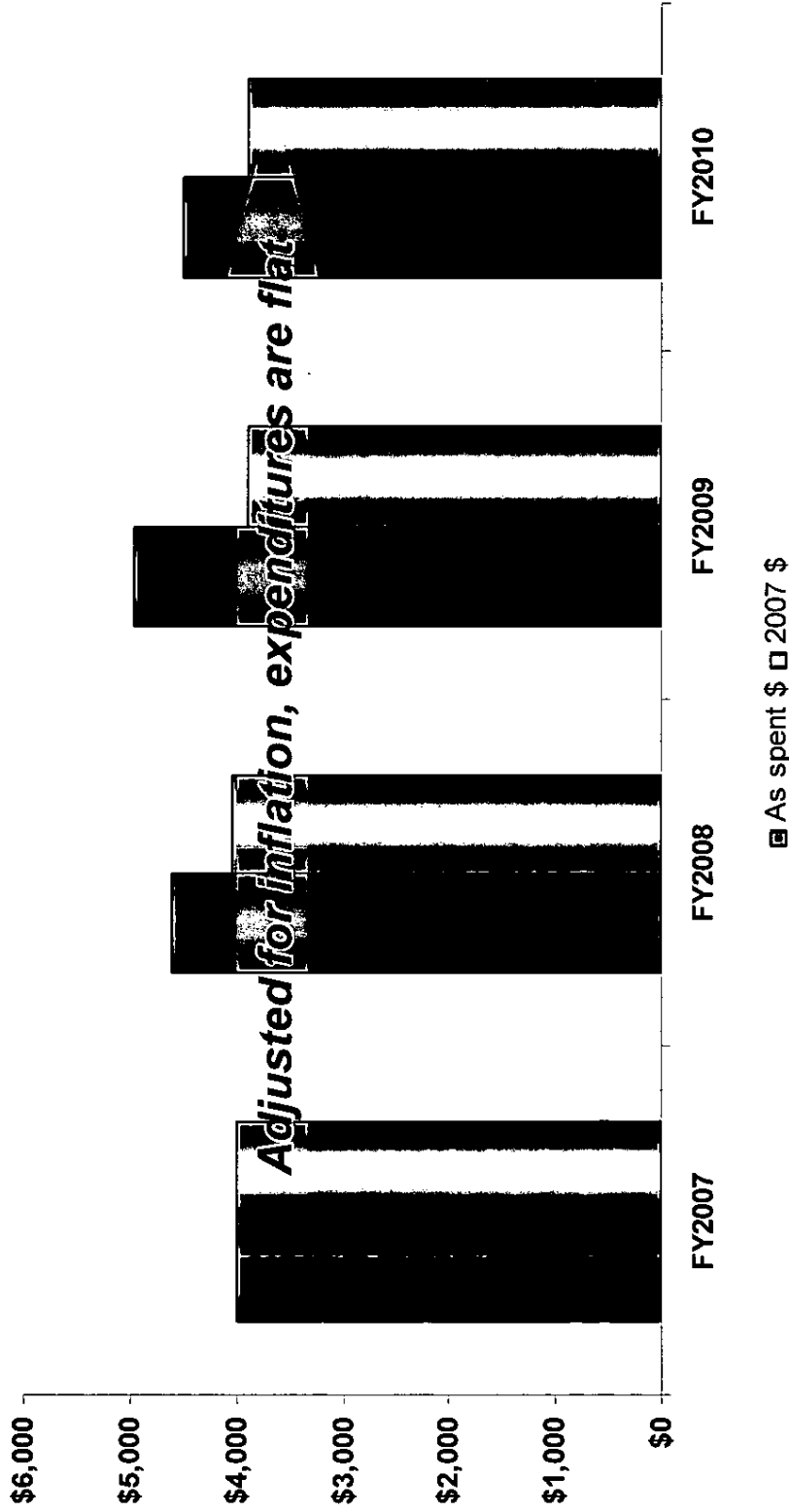


Core field drilling not tracking oil price

1 - US oil rig count normalized to 1Q05 Alaska rig count
 Sources: ConocoPhillips internal for core fields rig count, Baker Hughes for US oil rig count, DOR for oil price
 Slide 7

Inflation Impact on Expenditures

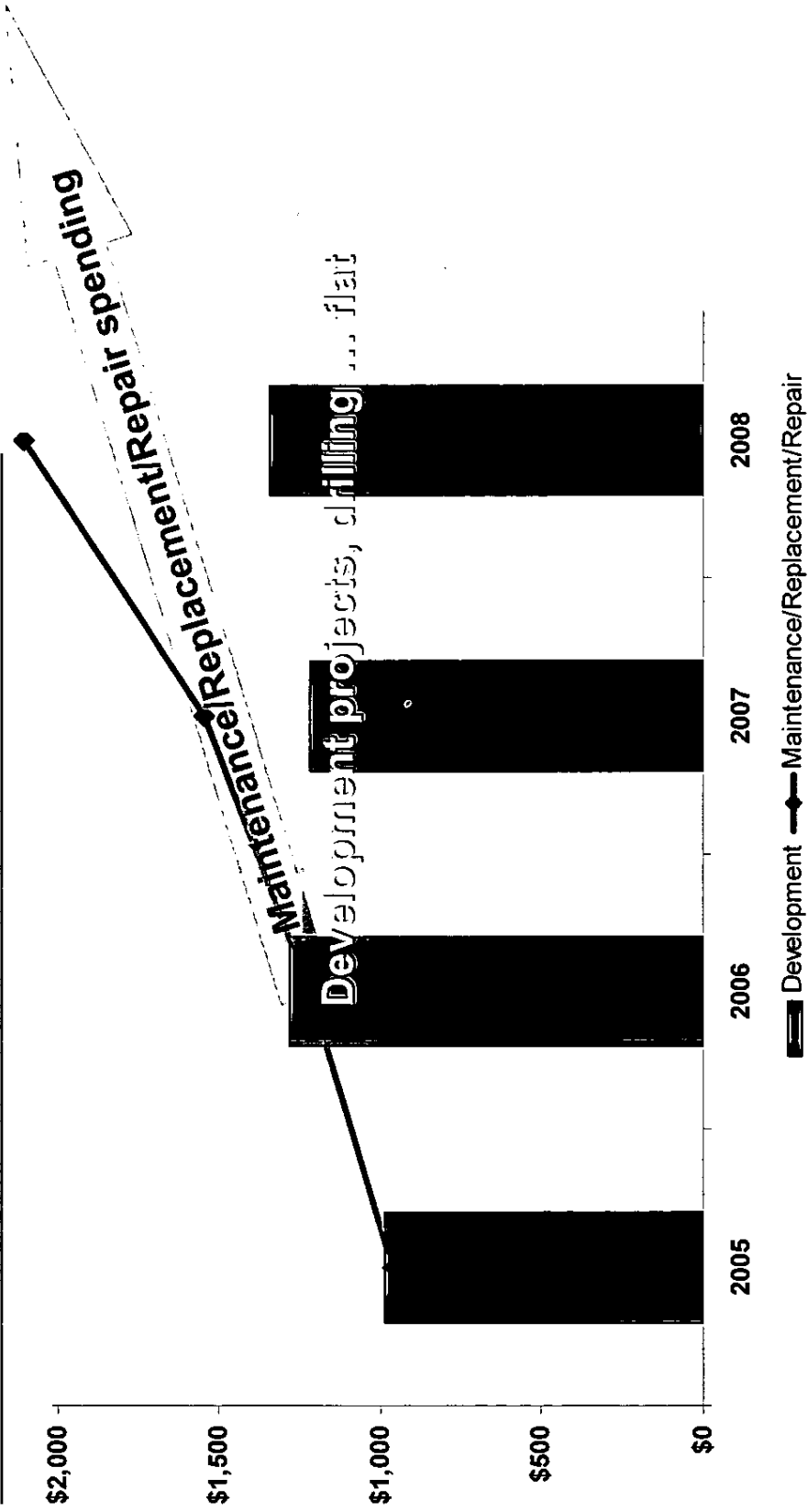
North Slope Industry spending on capital and operating expense, \$MM



Inflation is significant factor in spending increase

Extending Core Field Lives

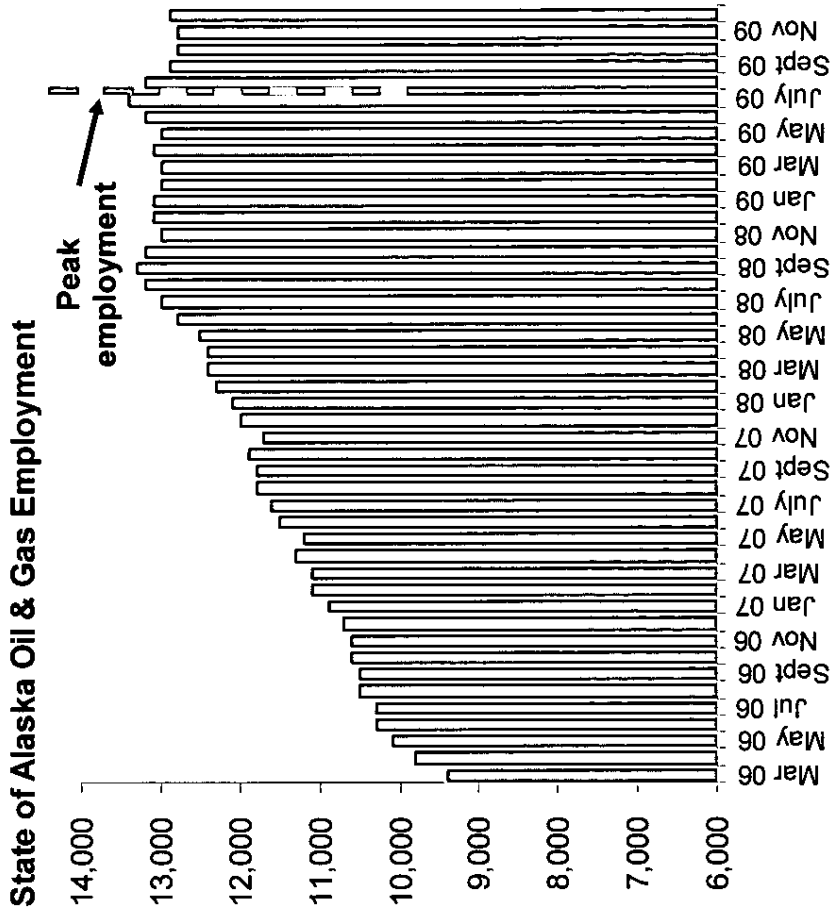
Core field gross spending on capital and operating expense, \$MM



Extending field life is cause of spending increase

Oil & Gas Employment

- Data since July-09 indicate downward trend in oil and gas jobs
- Employment levels driven primarily by maintenance and inspection activity
- Alaska state unemployment rising in oil and gas support sector
- Leading indicators: Kuparuk camp usage down 20%



Rise in employment began in 2006

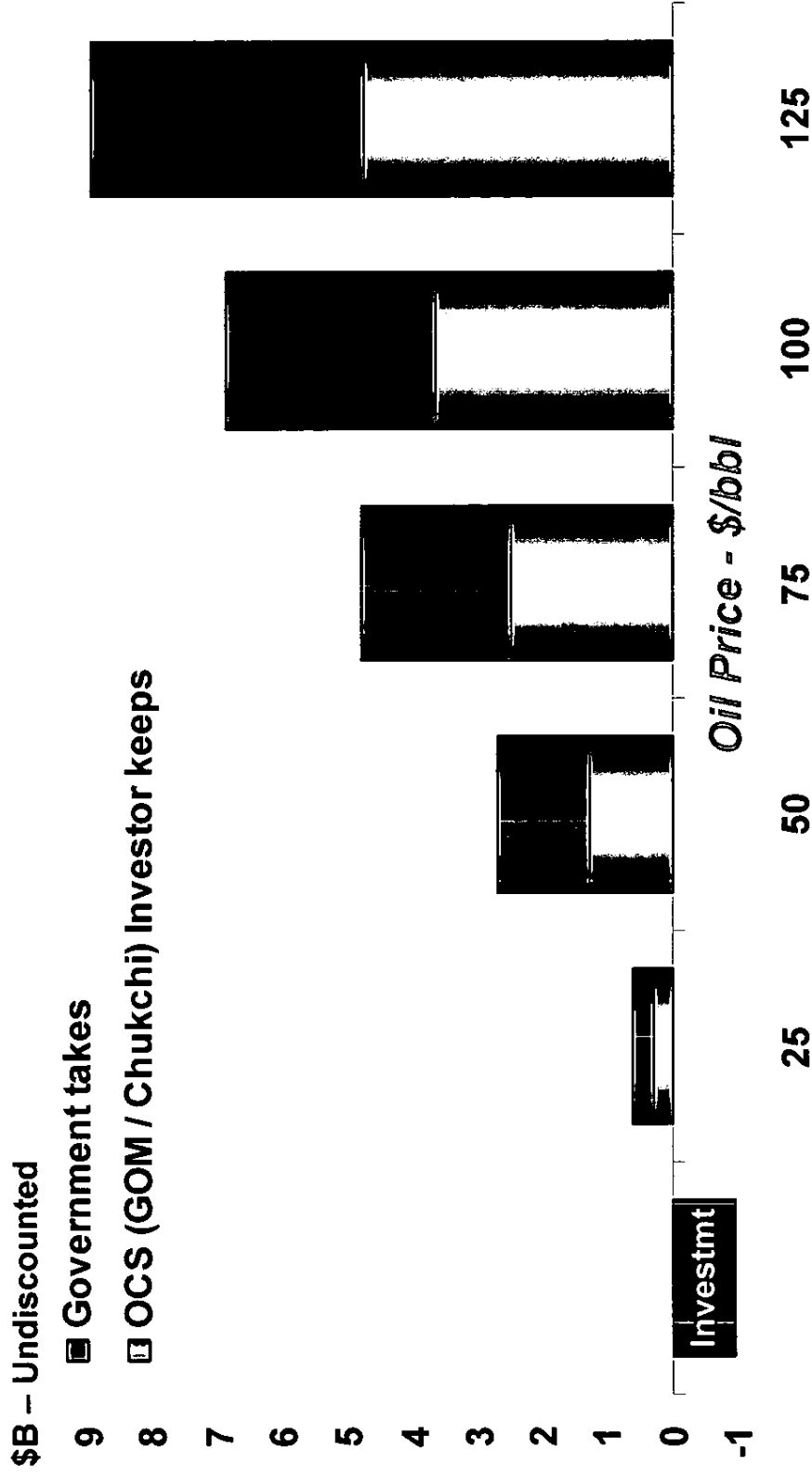
ACES Impacting Projects

- Recent project activity
 - Oooguruk – pre-ACES, royalty relief
 - Nikaitchuq – royalty relief
 - Liberty – not subject to ACES
- Over \$2 Billion in projects deferred since ACES
 - Prudhoe I-Pad and Gas Partial Processing (GPP)
 - West Sak 1N and 1P
 - ULSD topping plant (*opportunity foregone*)

Project deferrals impact industry and state revenue

OCS Fiscal – Risk/Reward is Balanced

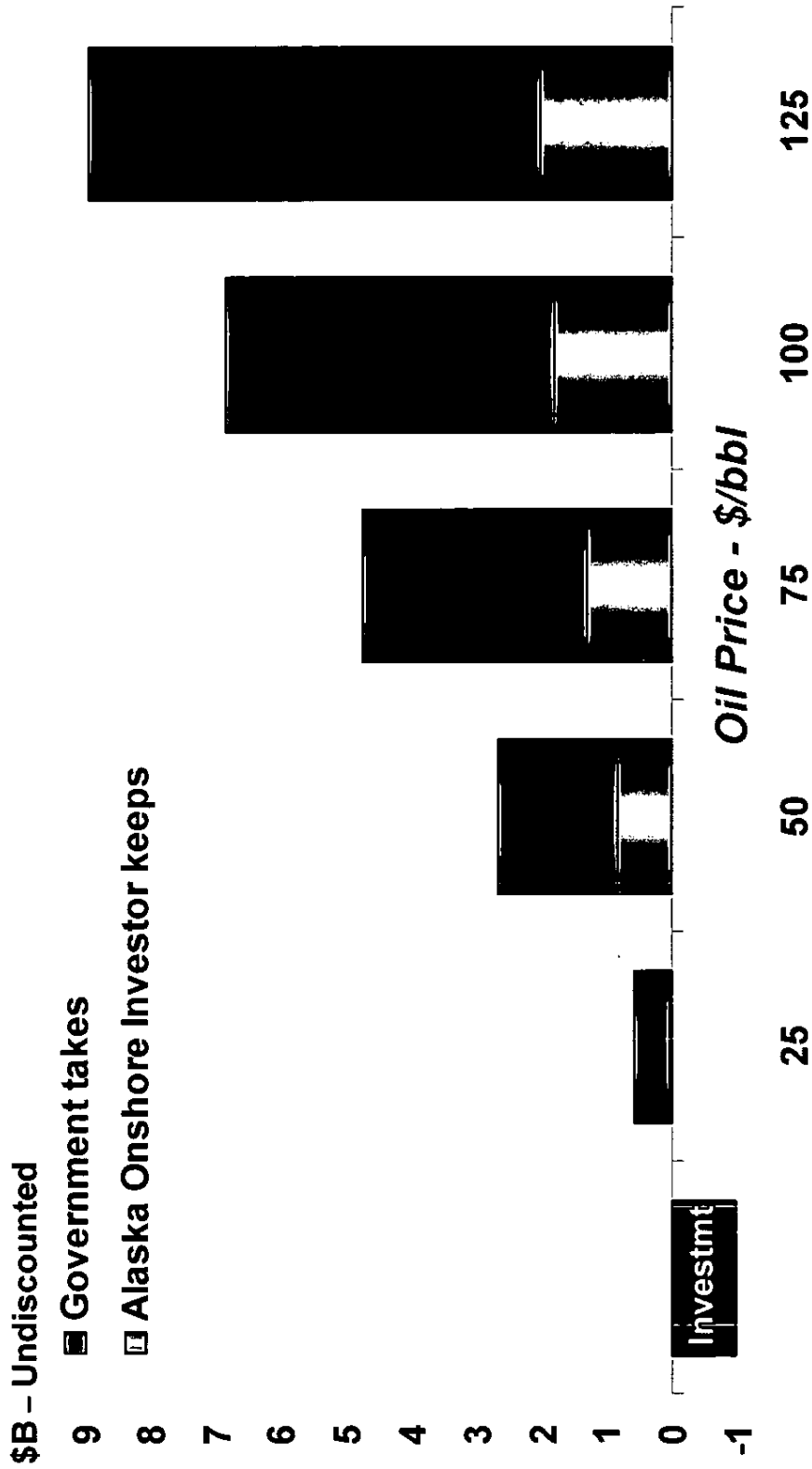
Example - \$1 Billion Investment (success case)



Adequate success case returns justify taking up front risks

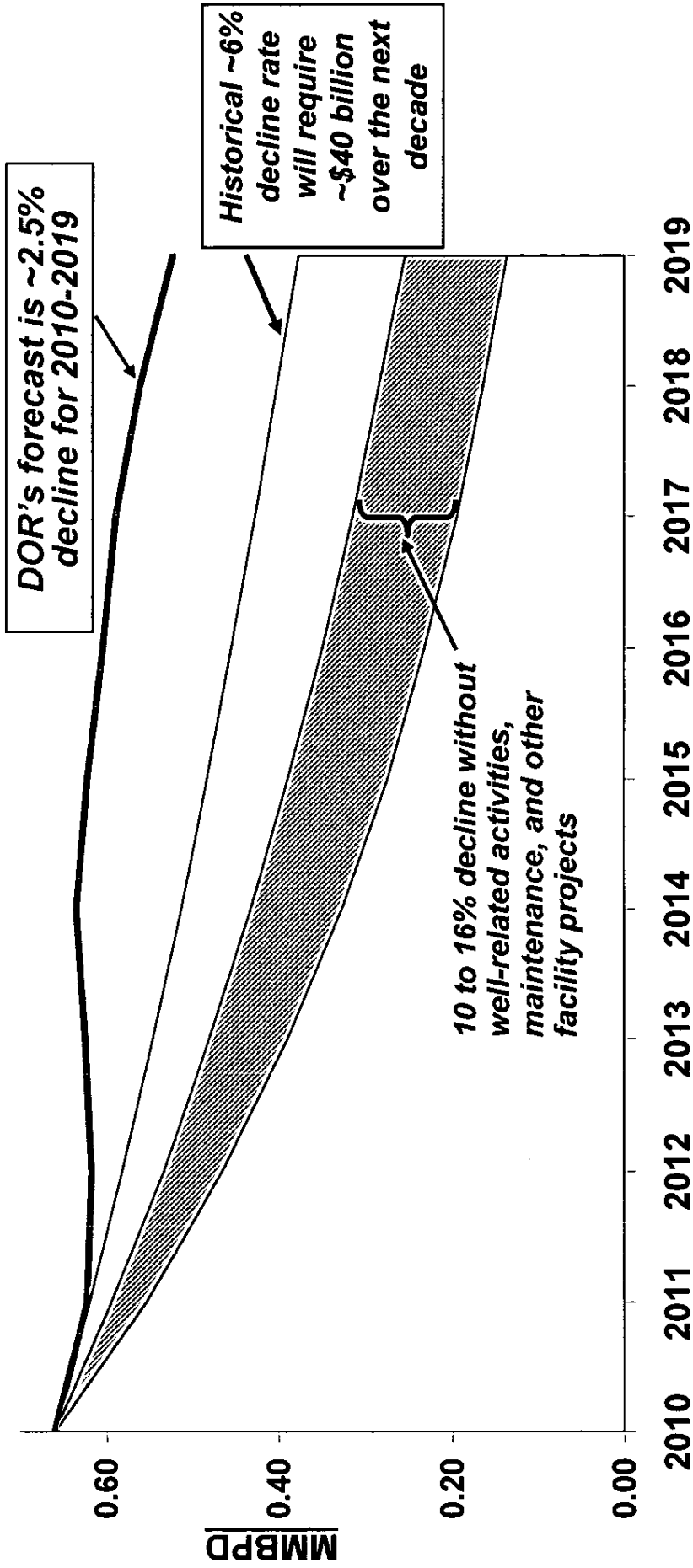
Alaska Fiscal – Risk/Reward is Broken

Example - \$1 Billion Investment (success case)



Alaska onshore fiscal terms not competitive

2010-2019 North Slope Production



Future production dependent upon investment

Sources: DOR production forecast and extrapolation of DOR expenditures forecast
ConocoPhillips estimates for base decline rate



PROGRESSIVITY
PROFITABILITY
PARITY
GAS

Senate Finance Committee

February 24, 2010

Alaska State Department of Revenue

Agenda

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- How Does the Production Tax Calculation Change when Gas is Produced?
- Brief historical background on the philosophy behind the current system
- How does “Parity” affect the production tax calculation?
- What is being potentially “locked in” with the AGIA open season?
- Forecasting oil and gas prices 2020 to 2030
- Policy Issues Associated with the Gas Tax

2/24/2010

Basic Oil Tax Calculation

Now What if
We Added 4.5
Bcf of Gas
Production?

	Oil
ANS Price	\$75.00 \$/bbl
Daily Production	500,000 Bbl/d
Annual Production	182,500,000 bbl
Total Annual Gross Sales Value	\$13,687,500,000
Marine and TAPS Tariff on Oil Gas Pipeline and Gas Treatment Plant	(\$6.50) \$/bbl
Transportation Costs	(\$1,186,250,000.00)
Value at Point Of Production	\$12,501,250,000
Royalty and Federal	(\$1,562,656,250.00)
Taxable Point of Production Value	\$10,938,593,750
<u>Lease Expenditures</u>	
Opex	(\$2,000,000,000)
Capex	(\$2,000,000,000)
Total Lease Expenditures	(\$4,000,000,000)
Production Tax Value (PTV)	\$6,938,593,750
PTV on BOE basis	\$43.45
Base Tax (25%* PTV)	\$1,734,648,438
Progressive Tax Rate	5.38%
Progressive Tax	\$373,326,216
Total Tax Due before credits	\$2,107,974,654
Credits Applied Against Taxes	(\$400,000,000)
Total Tax after credits	\$1,707,974,654

	Oil	Gas	Com
ANS Price	\$75.00\$/bbl	\$8.00\$/mmbtu	
Daily Production	500,000Bbl/d	4.5Bdf/d	
Annual Production	182,500,000 bbl	1,643Bcf/year	
Total Annual Gross Sales Value	\$13,687,500,000	\$13,140,000,000	\$26,827,500,000
Marine and TAPS Tariff on Oil	(\$6.50) \$/bbl		
Gas Pipeline and Gas Treatment Plant		(\$4.50) \$/mmbtu	
Transportation Costs	(\$1,186,250,000.00)	(\$7,391,250,000)	(\$8,577,500,000)
Value at Point Of Production	\$12,501,250,000	\$5,748,750,000	\$18,250,000,000
Royalty and Federal	(\$1,562,656,250.00)	(\$718,593,750.00)	(\$2,281,250,000)
Taxable Point of Production Value	\$10,938,593,750	\$5,030,156,250.00	\$15,968,750,000
<u>Lease Expenditures</u>			
Opex	(\$2,000,000,000)	(\$200,000,000)	(\$2,200,000,000)
Capex	(\$2,000,000,000)	(\$200,000,000)	(\$2,200,000,000)
Total Lease Expenditures	(\$4,000,000,000)	(\$400,000,000)	(\$4,400,000,000)
Production Tax Value (PTV)	\$6,938,593,750	\$4,630,156,250	\$11,568,750,000
PTV on BOE basis	\$43.45	\$19.33	\$29
Base Tax (25%*PTV)	\$1,734,648,438	\$1,157,539,063	\$2,892,187,500
Progressive Tax Rate	5.38%	0.00%	0.00%
Progressive Tax	\$373,326,216	\$0	\$0
Total Tax Due before credits	\$2,107,974,654	\$1,157,539,063	\$2,892,187,500
Credits Applied Against Taxes	(\$400,000,000)	(\$40,000,000)	(\$440,000,000)
Total Tax after credits	\$1,707,974,654	\$1,117,539,063	\$2,452,187,500

	Oil	Gas	Combined
ANS Price	\$75.00\$/bbl	\$8.00\$/mmbtu	
Daily Production	500,000Bbl/d	4.5Bdf/d	
Annual Production	182,500,000 bbl	1,643Bcf/year	
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● Was This Expected When ACES was Crafted? ●

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- Same Dynamic for Gas that creates Uplift for Heavy Oil and Marginal Field Development
- Intended to be a positive incentive for Producers to commit to the gasoline project

THE HISTORICAL PERSPECTIVE

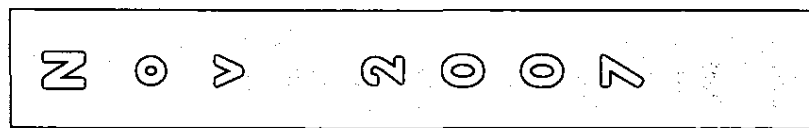
SENATE FINANCE COMMITTEE

NOVEMBER 9, 2007

Goals for Fiscal Design

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Based on [hearing dialog] we see the State trying to achieve the following in this special session:



1. Fields with larger profitability should be paying more taxes
2. Encourage investment in existing units
 - Reinvestment in producing assets
 - Investment in new developments
 - Conventional
 - Unconventional (i.e. heavy oil)
 - Gas
3. Encourage new investment outside legacy units
 - Level playing field for incumbents and new entrants
4. Durability
 - Don't want to be back 'fixing' things
5. Build on prior tax dialogue

The Fiscal Design Challenge

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- At the same time the State must address "The Take"**
 - (Goal 1) Capture the State's equitable share when margins are very high
 - (Goal 4) Include a form of progressive structure to adapt to the inevitable changes in the three main variables of the business:
 - Price
 - Production
 - Cost
- ...as well as "The Give Back"**
 - (Goal 2) Encouragement to reinvest profits for more development inside legacy units

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Goal 3: Encourage New Investment

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The [now current] legislation appears to provide the right incentives to encourage investment in new fields

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Investment credits

Net Operating Loss credits

Aid to new entrants with no existing tax base

Net based system that by design lowers the applicable production tax rate for fields with higher cost structure

More distant from core infrastructure

Heavy Oil

Gas

Beyond the individual project, the State and industry benefit from new developments as they provide additional barrels down TAPS thus extending the productive life of existing reservoirs

What was expected (in 2007)?

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- Highly likely that any new oil or gas development will cost more per barrel to find, develop and operate than current NS production
- Therefore, the addition of any new hydrocarbons to an existing portfolio will result in production taxes payable on the whole being less than the sum of the production taxes payable on the individual parts
 - Not just a gas/oil issue
 - Also an oil/oil issue, particularly a heavy oil/oil issue
- The more aggressive the progressivity the greater the impact on the effective rate or stand alone rate, and the greater the impact of oil-gas price parity

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How Parity Affects Tax Calculation

	Oil	Gas	Con
ANS Price	\$75.00\$/bbl	\$8.00\$/mmbtu	
Daily Production	500,000 bbl/d	4.5 Bdf/d	
Annual Production	182,500,000 bbl	1,643 Bcf/year	
Total Annual Gross Sales Value	\$13,687,500,000	\$13,140,000,000	\$26,827,500,000
Marine and TAPS Tariff on Oil Gas Pipeline and Gas Treatment Plant	(\$6.50) \$/bbl	(\$4.50) \$/mmbtu	
Transportation Costs	(\$1,186,250,000.00)	(\$7,391,250,000)	(\$8,577,500,000)
Value at Point Of Production	\$12,501,250,000	\$5,748,750,000	\$18,250,000,000
Royalty and Federal	(\$1,562,656,250.00)	(\$718,593,750.00)	(\$2,281,250,000)
Taxable Point of Production Value	\$10,938,593,750	\$5,030,156,250.00	\$15,968,750,000
<u>Lease Expenditures</u>			
Opex	(\$2,000,000,000)	(\$200,000,000)	(\$2,200,000,000)
Capex	(\$2,000,000,000)	(\$200,000,000)	(\$2,200,000,000)
Total Lease Expenditures	(\$4,000,000,000)	(\$400,000,000)	(\$4,400,000,000)
Production Tax Value (PTV)	\$6,938,593,750	\$4,630,156,250	\$11,568,750,000
PTV on BOE basis	\$43.45	\$19.33	\$29
Base Tax (25%*PTV)	\$1,734,648,438	\$1,157,539,063	\$2,892,187,500
Progressive Tax Rate	5.38%	0.00%	0.00%
Progressive Tax	\$373,326,216	\$0	\$0
Total Tax Due before credits	\$2,107,974,654	\$1,157,539,063	\$2,892,187,500
Credits Applied Against Taxes	(\$400,000,000)	(\$40,000,000)	(\$440,000,000)
Total Tax after credits	\$1,707,974,654	\$1,117,539,063	\$2,452,187,500

	Oil	Gas	Com
ANS Price	\$100.00\$/bbl	\$8.00\$/mmbtu	
Daily Production	500,000 bbl/d	4.5 Bdf/d	
Annual Production	182,500,000 bbl	1,643 Bcf/year	
Total Annual Gross Sales Value	\$18,250,000,000	\$13,140,000,000	\$31,390,000,000
Marine and TAPS Tariff on Oil Gas Pipeline and Gas Treatment Plant	(\$6.50) \$/bbl	(\$4.50) \$/mmbtu	
Transportation Costs	(\$1,186,250,000.00)	(\$7,391,250,000)	(\$8,577,500,000)
Value at Point Of Production	\$17,063,750,000	\$5,748,750,000	\$22,812,500,000
Royalty and Federal	(\$2,132,968,750.00)	(\$718,593,750.00)	(\$2,851,562,500)
Taxable Point of Production Value	\$14,930,781,250	\$5,030,156,250.00	\$19,960,937,500
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Total Lease Expenditures	(\$4,000,000,000)	(\$400,000,000)	(\$4,400,000,000)
Production Tax Value (PTV)	\$10,930,781,250	\$4,630,156,250	\$15,560,937,500
PTV on BOE basis	\$68.45	\$19.33	\$39
Base Tax (25%*PTV)	\$2,732,695,313	\$1,157,539,063	\$3,890,234,375
Progressive Tax Rate	15.38%	0.00%	3.59%
Progressive Tax	\$1,681,201,216	\$0	\$558,853,865
Total Tax Due before credits	\$4,413,896,529	\$1,157,539,063	\$4,449,088,240
Credits Applied Against Taxes	(\$400,000,000)	(\$40,000,000)	(\$440,000,000)
Total Tax after credits	\$4,013,896,529	\$1,117,539,063	\$4,009,088,240

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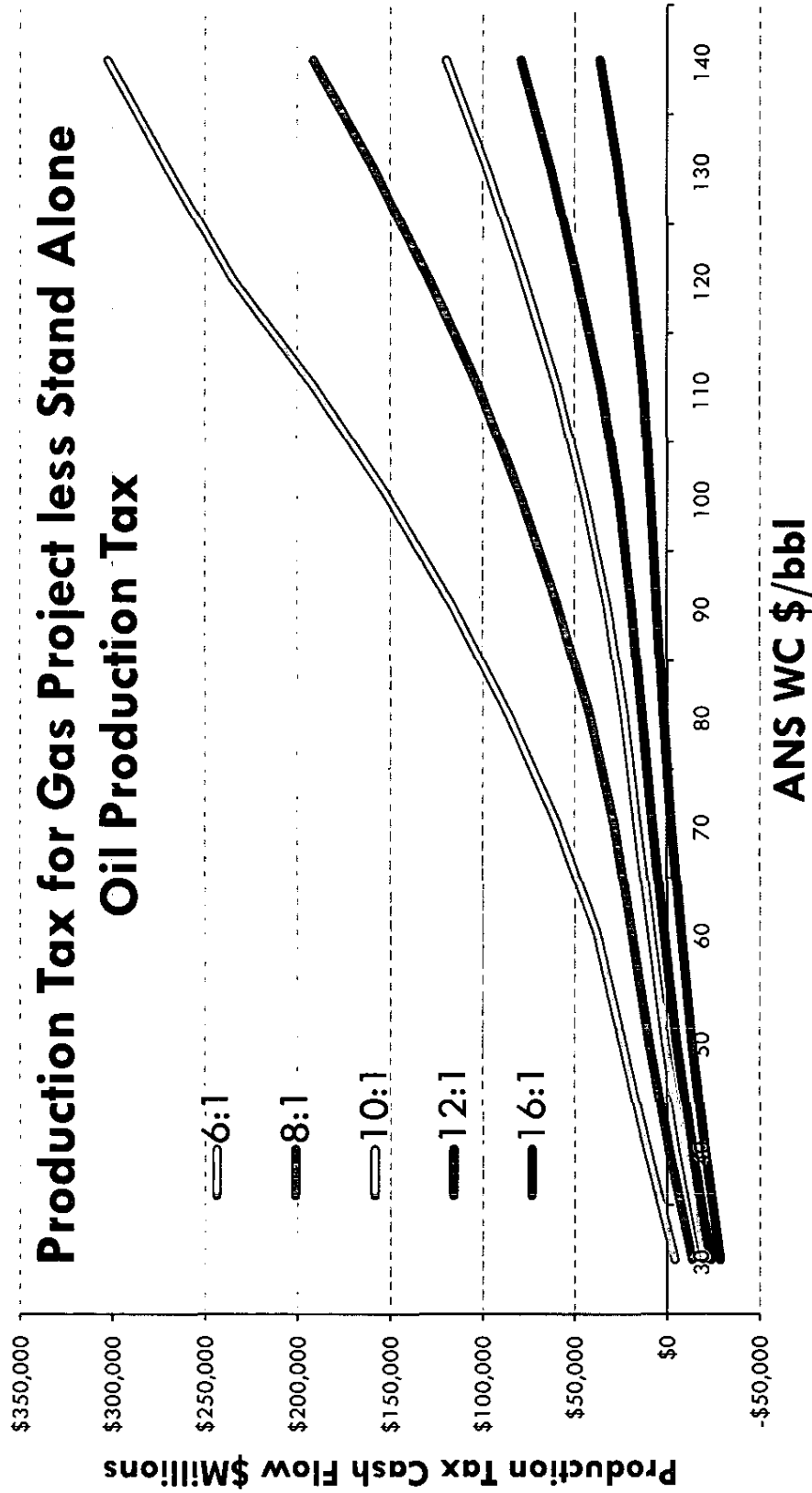
	Oil	Gas	Combined
ANS Price	\$120.00\$/bbl	\$8.00\$/mmbtu	
Daily Production	500,000Bbl/d	4.5Bdf/d	
Annual Production	182,500,000 bbl	1,643Bcf/year	
Total Annual Gross Sales Value	\$21,900,000,000	\$13,140,000,000	\$35,040,000,000
Marine and TAPS Tariff on Oil	(\$6.50) \$/bbl		
Gas Pipeline and Gas Treatment Plant		(\$4.50) \$/mmbtu	
Transportation Costs	(\$1,186,250,000.00)	(\$7,391,250,000)	(\$8,577,500,000)
Value at Point Of Production	\$20,713,750,000	\$5,748,750,000	\$26,462,500,000
Royalty and Federal	(\$2,589,218,750.00)	(\$718,593,750.00)	(\$3,307,812,500)
Taxable Point of Production Value	\$18,124,531,250	\$5,030,156,250.00	\$23,154,687,500
<u>Lease Expenditures</u>			
Opex	(\$2,000,000,000)	(\$200,000,000)	(\$2,200,000,000)
Capex	(\$2,000,000,000)	(\$200,000,000)	(\$2,200,000,000)
Total Lease Expenditures	(\$4,000,000,000)	(\$400,000,000)	(\$4,400,000,000)
Production Tax Value (PTV)	\$14,124,531,250	\$4,630,156,250	\$18,754,687,500
PTV on BOE basis	\$88.45	\$19.33	\$47
Base Tax (25%*PTV)	\$3,531,132,813	\$1,157,539,063	\$4,688,671,875
Progressive Tax Rate	23.38%	0.00%	6.79%
Progressive Tax	\$3,302,376,216	\$0	\$1,273,703,865
Total Tax Due before credits	\$6,833,509,029	\$1,157,539,063	\$5,962,375,740
Credits Applied Against Taxes	(\$400,000,000)	(\$40,000,000)	(\$440,000,000)
Total Tax after credits	\$6,433,509,029	\$1,117,539,063	\$5,522,375,740

	Oil	Gas	Combined
ANS Price	\$120.00\$/bbl	\$8.00\$/mmbtu	
Daily Production	500,000Bbl/d	4.5Bdf/d	
Annual Production	182,500,000 bbl	1,643Bcf/year	
Total Annual Gross Sales Value	\$21,900,000,000	\$13,140,000,000	\$35,040,000,000
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Gas Pipeline and Gas Treatment Plant		(\$4.50) \$/mmbtu	
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How does Parity affect State Revenues coming from an AGIA gasline?

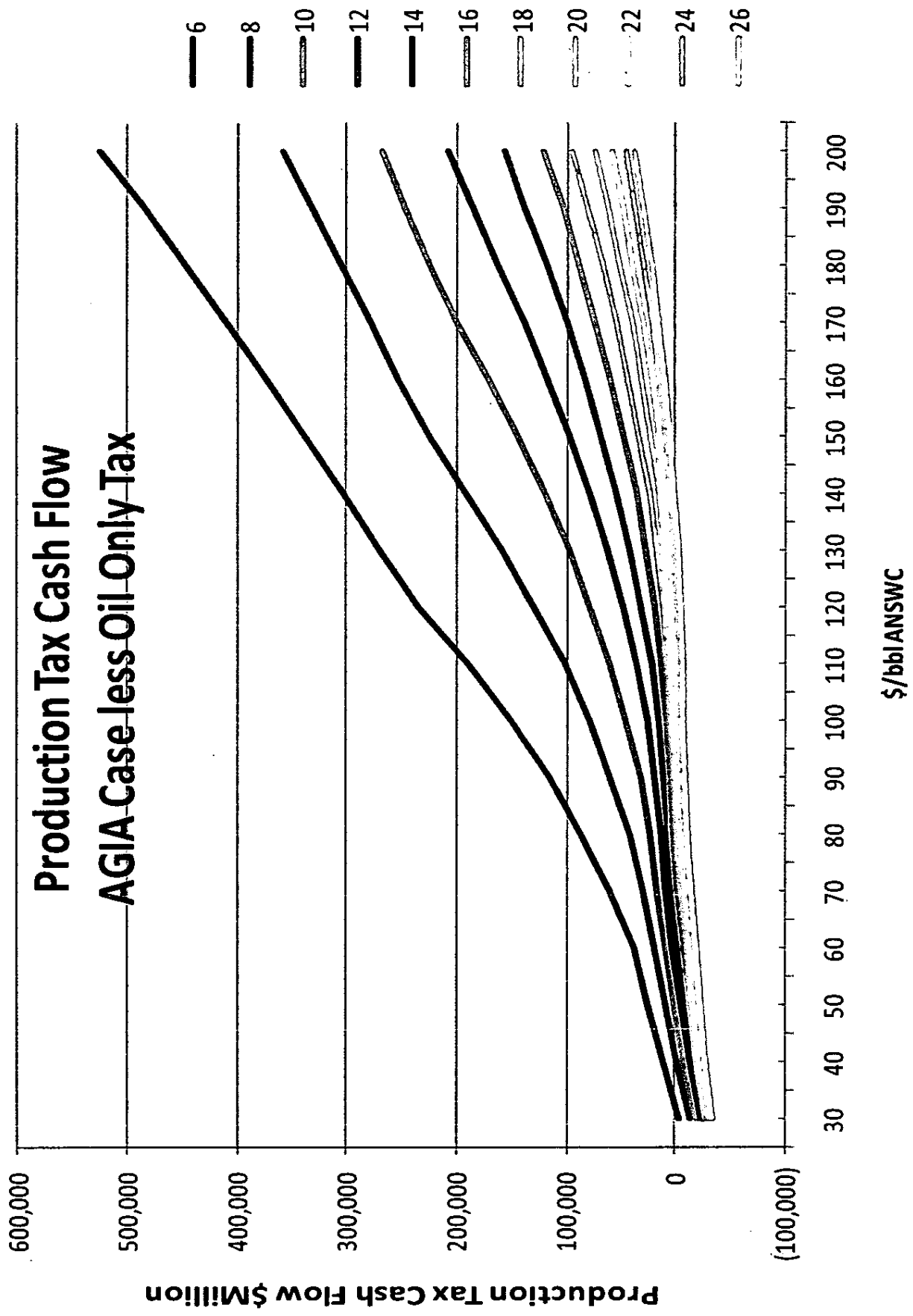
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Showing the difference between Combined Oil and Gas Tax Revenue and Oil Tax Revenue with No Gasline Project*



* Based on 25 year undiscounted cash flows to the State, using AGIA oil and gas production profile

Production Tax Cash Flow AGIA Case less Oil Only Tax



\$/bbl ANSWC

Gas Tax Policy Issues

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- What cash flow does the state expect from the gasoline?
- What price risk is the state willing to accept?
- Is the state willing to accept the risk of periods where the oil + gas tax revenue is less than oil tax alone?
- What is the cash flow sharing and risk sharing between the Producers and the State?

● Issues Surrounding Gas Tax Discussion ●

At this Time

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- Entering two open seasons for the gas pipeline
 - Likely to result in Producers continuing to claim changes in the fiscal system are necessary
- Full commitments to ship gas (i.e. project sanction) not expected until 2014
- Stakeholders will continue to discuss:
 - Necessary Producer cash flow from gas development,
 - Relative risks borne by the Producers and the State,
 - Amount of Fiscal Predictability the Producers need

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What is being potentially "locked in" with the AGIA open season?

- ●
- **What kind of shipping commitments qualify shippers for AGIA Tax and Royalty Inducements?**

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For gas to qualify for the tax and royalty inducements, “producer-shippers” and “shippers buying from producers” must meet this requirement under AS 43.90.300:

“Must commit to acquire firm transportation capacity in the first binding open season”

Definition of Key Terms

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- **Precedent Agreement (PA):** Establishes general terms of transportation service the conditions under which shipper will be obligated to acquire transportation capacity on the project (via TSA). Also specifies when the shipper and transporter are relieved of those obligations (i.e. conditions).
- **Transportation Services Agreement (TSA):** Entered when conditions of the PA are met; shipper is then unconditionally obligated to pay for transportation and the transporter to construct the project.

Qualifications for AGIA Inducements

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“Must commit to acquire firm transportation capacity in the first binding open season” means:**

1. Submit a bid for firm transportation capacity during the initial open season;
2. Execute a Precedent Agreement (PA) w/in 180 days of close of initial open season;
3. Execute Transportation Services Agreement (TSA) w/in 5 years of open season, or two years following FERC Certification, whichever is later; **and**
4. File with the DOR-DNR Commissioners:
 - Copies of documents listed above; and
 - Copy of rolled-in rate agreements governing pipeline expansions

**Summary only – does not include all terms
Proposed Regulations 15 AAC 90.200 - 230

The Gas Production Tax Exemption

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- Annual exemption from “gas production tax”
- Value Equal to:

Gas production tax value of volume of production	<u>minus</u>	Gas production tax under law at open season
--	--------------	---
- Good for 10 years following start of gas sales
- Applies only to volume of gas identified in the Commissioners’ determination of qualification or voucher.

Identifying “gas production tax”

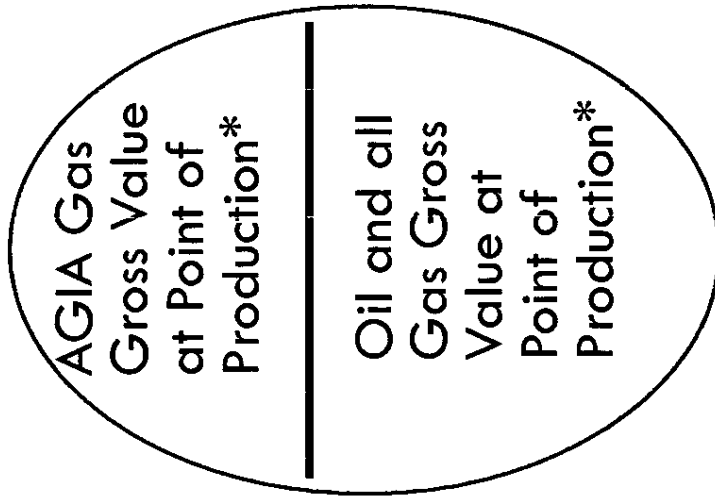
24

- Current Production Tax is calculated on combined oil and gas production, with combined oil and gas lease expenditures, so we need to attribute a “gas production tax” value.
- Under proposed 15 AAC 90.220, to attribute “gas production tax”, we use the ratio of the gross value of AGIA gas at the point of production divided by the combined gross value of the oil and all gas at the point of production. This ratio is multiplied by the combined oil and all gas production tax liability.

Gas Tax Exemption Mathematics

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$$\frac{A}{V} \times T = G$$



$$\frac{A}{V}$$

times

T

Oil and Gas
Production Tax
Liability under
system in effect
May 1, 2010

equals

G

"Production Tax
on Gas" as of
May 1, 2010

*Gross value at point of production is the value at point of production without deduction of costs upstream of that point. (See AS 43.55.900(12) and AS 43.55.150)

	Oil	Gas	Combined
ANS Price	\$120.00\$/bbl	\$8.00\$/mmbtu	
Daily Production	500,000Bbl/d	4.5Bdf/d	
Annual Production	182,500,000 bbl	1,643Bcf/year	
Total Annual Gross Sales Value	\$21,900,000,000	\$13,140,000,000	\$35,040,000,000
Marine and TAPS Tariff on Oil	(\$6.50) \$/bbl		
Gas Pipeline and Gas Treatment Plant		(\$4.50) \$/mmbtu	
Transportation Costs	(\$1,186,250,000)	(\$7,391,250,000)	(\$8,577,500,000)
Value at Point Of Production	\$20,713,750,000	\$5,748,750,000	\$26,462,500,000
Royalty and Federal	(\$2,589,218,750)	(\$718,593,750)	(\$3,307,812,500)
Taxable Point of Production Value	\$18,124,531,250	\$5,030,156,250.00	\$23,154,687,500
<u>Lease Expenditures</u>			
Opex	(\$2,000,000,000)	(\$200,000,000)	(\$2,200,000,000)
Capex	(\$2,000,000,000)	(\$200,000,000)	(\$2,200,000,000)
Total Lease Expenditures	(\$4,000,000,000)	(\$400,000,000)	(\$4,400,000,000)
Production Tax Value (PTV)	\$14,124,531,250	\$4,630,156,250	\$18,754,687,500
PTV on BOE basis	\$88.45	\$19.33	\$47
Base Tax (25%*PTV)	\$3,531,132,813	\$1,157,539,063	\$4,688,671,875
Progressive Tax Rate	23.38%	0.00%	6.79%
Progressive Tax	\$3,302,376,216	\$0	\$1,273,703,865
Total Tax Due before credits	\$6,833,509,029	\$1,157,539,063	\$5,962,375,740
Credits Applied Against Taxes	(\$400,000,000)	(\$40,000,000)	(\$440,000,000)
Total Tax after credits	\$6,433,509,029	\$1,117,539,063	\$5,522,375,740

2B

	Oil	Gas	Combined
ANS Price			
Daily Production	\$120.00\$/bbl	\$8.00\$/mmbtu	
Annual Production	500,000Bbl/d 182,500,000 bbl	4.5Bdf/d 1,643Bcf/year	
Total Annual Gross Sales Value	\$21,900,000,000	\$13,140,000,000	\$35,040,000,000
Marine and TAPS Tariff on Oil Gas Pipeline and Gas Treatment Plant	(\$6.50) \$/bbl		
Transportation Costs	(\$1,186,250,000)	(\$4.50) \$/mmbtu (\$7,391,250,000)	(\$8,577,500,000)
Value at Point Of Production Royalty and Federal	\$20,713,750,000 (\$2,589,218,750)	\$5,748,750,000 (\$718,593,750)	\$26,462,500,000 (\$3,307,812,500)
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Total Tax after credits	\$6,433,509,029	\$1,117,539,063	\$5,522,375,740

Assuming all the gas is shipped via capacity that qualifies for the AGIA inducement...

	Oil	Gas	Combined
ANS Price	\$120.00 \$/bbl	\$8.00 \$/mmbtu	
Daily Production	500,000 bbl/d	4.5 mcf/d	
Annual Production	182,500,000 bbl	1,643 mcf/year	
Total Annual Gross Sales Value	\$21,900,000,000	\$13,140,000,000	\$35,040,000,000
Marine and TAPS Tariff on Oil			
Gas Pipeline and Gas Treatment Plant	(\$6.50) \$/bbl	(\$4.50) \$/mmbtu	
Transportation Costs	(\$1,186,250,000)	(\$7,391,250,000)	(\$8,577,500,000)
Value at Point Of Production	\$20,713,750,000	\$5,748,750,000	\$26,462,500,000
Royalty and Federal Taxable Point of Production Value	(\$2,589,218,750)	(\$7,167,500,000)	(\$9,756,718,750)
Lease Expenditures	\$18,124,531,250	\$5,030,156,250.00	\$23,154,687,500
Opex	(\$2,000,000,000)	(\$200,000,000)	(\$2,200,000,000)
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$$\frac{\$5,748,750,000}{\$26,462,500,000} = 21.7\%$$

$$\$5,522,375,740 \times 21.7\% = \$1,199,688,523$$

Production Tax Attributed to Gas under proposed 15 AAC 90.220



Assuming all the gas is shipped via capacity that qualifies for the AGIA inducement...

$$\frac{\$5,748,750,000}{\$26,462,500,000} = 21.7\%$$

$$\$5,522,375,740 \times 21.7\% =$$

\$1,199,688,523

Close Approx.

Production Tax Attributed to Gas under proposed 15 AAC 90.220

	Oil:	Gas:	Combined
ANS Price	\$120.00 \$/bbl	\$8.00 \$/mmbtu	
Daily Production	500,000 bbl/d	4.5 bbl/d	
Annual Production	182,500,000 bbl	1,643 bbl/year	
Total Annual Gross Sales Value	\$21,900,000,000	\$13,140,000,000	\$35,040,000,000
Marine and TAPS Tariff on Oil	(\$6.50) \$/bbl		
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Value at Point Of Production	\$20,713,750,000	\$5,748,750,000	\$26,462,500,000
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Taxable Point of Production Value	\$18,124,531,250	\$5,030,156,250.00	\$23,154,687,500
<u>Lease Expenditures</u>			
Opex	(\$2,000,000,000)	(\$200,000,000)	(\$2,200,000,000)
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● Given that Example – ●

What is the AGIA Tax Exemption?

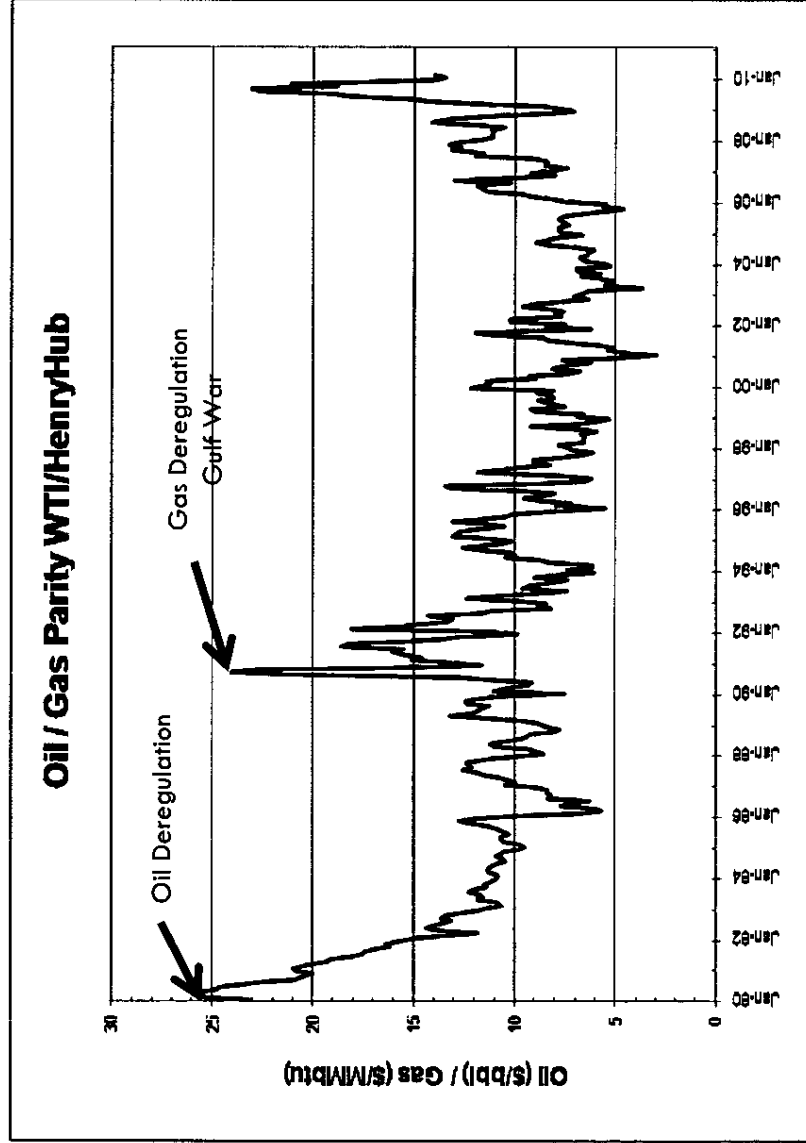
32

1. Calculate Gas Production Tax under system in place in the Year of Production:
 - Assume the Gas Production Tax then is = \$1.5B
2. Calculate Gas Production Tax under system in effect on May 1, 2010:
 - Previous slide shows gas tax attribution of: \$1.2B
3. The taxpayer can claim an exemption for the difference:
 - AGIA Gas Tax Exemption = \$300M

33	Oil and Gas Price Expectations and Forecasting Challenges
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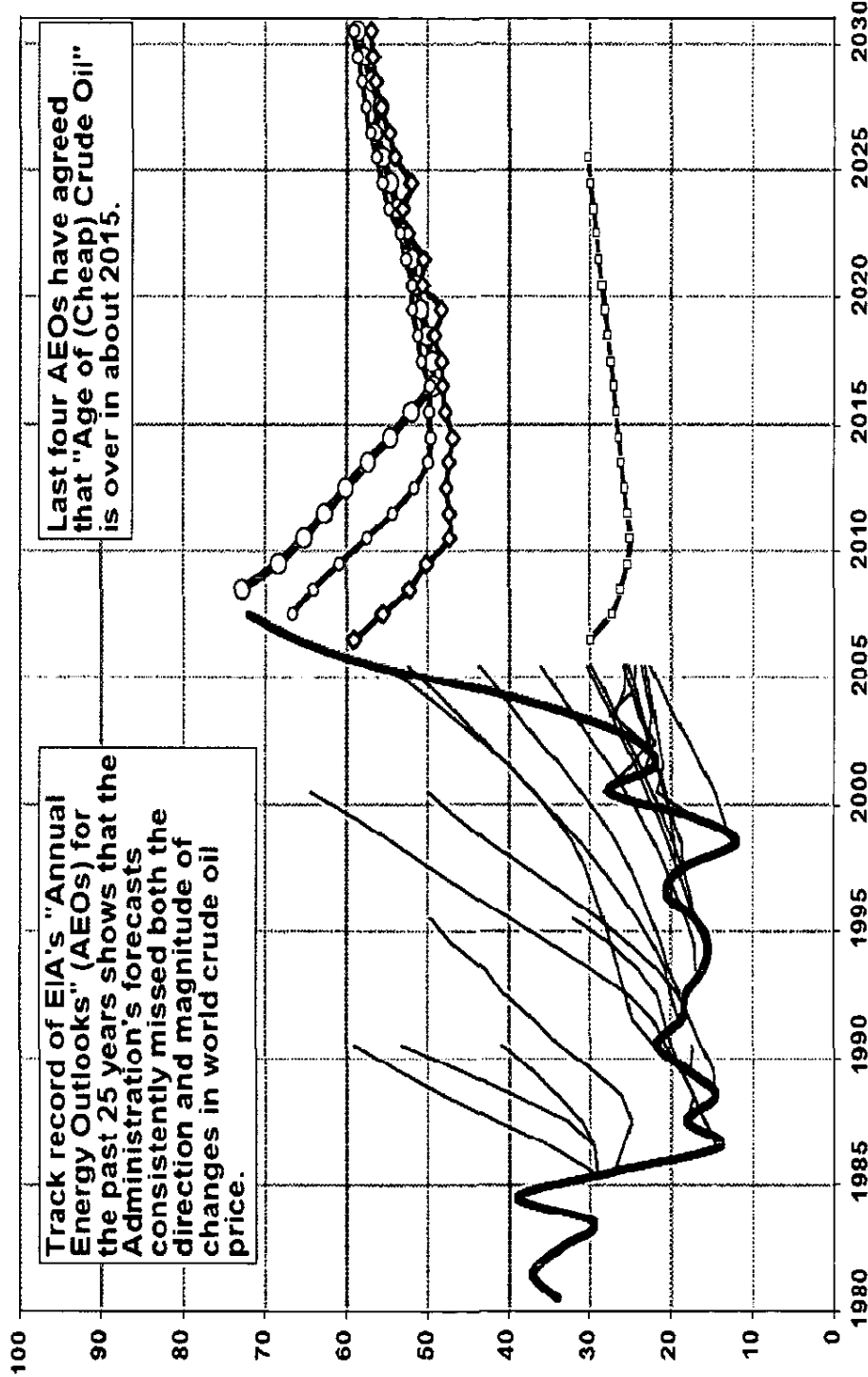
The Oil/Gas Price Parity....

34



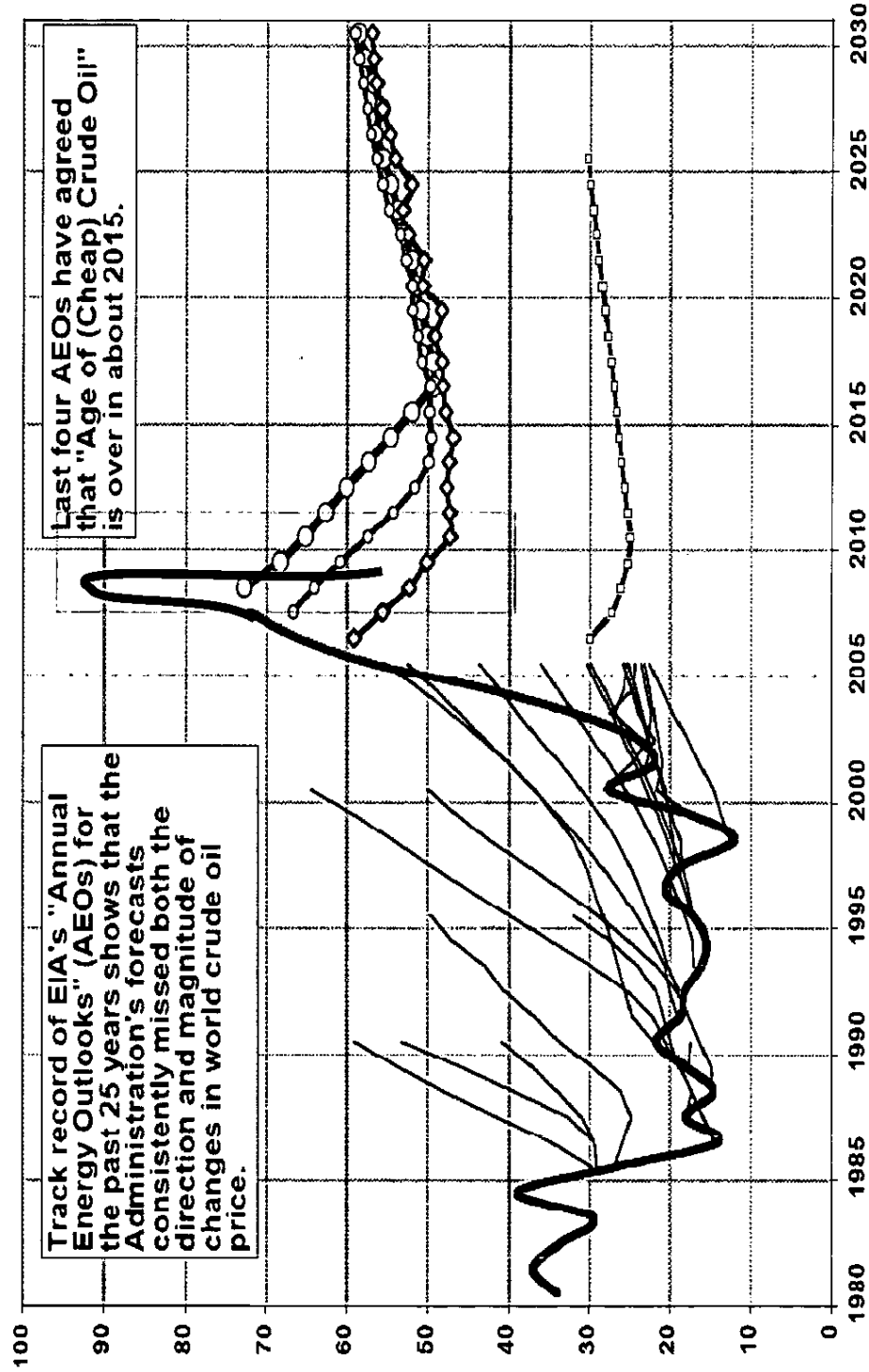
....Has Been Higher than Expected....

● EIA Forecasting Is Widely Quoted ● ● But Usually Not Even Close ●



Source: US DOE Energy Information Administration Mar 2008

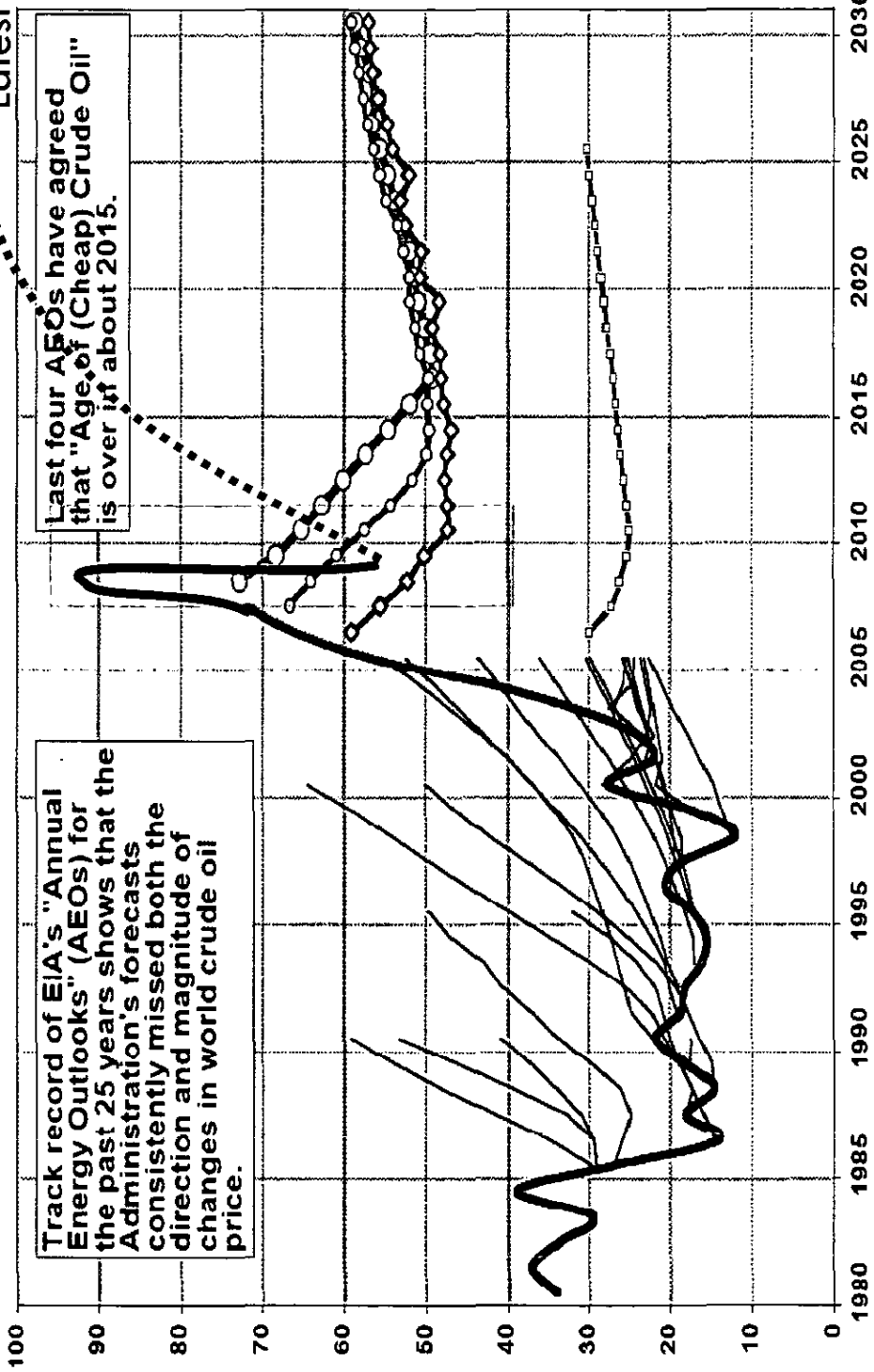
EIA Forecasting Not Even Close



Source: US DOE Energy Information Administration Mar 2008

EIA Forecasting Not Even Close

Latest EIA Forecast



Track record of EIA's "Annual Energy Outlooks" (AEOs) for the past 25 years shows that the Administration's forecasts consistently missed both the direction and magnitude of changes in world crude oil price.

Source: US DOE Energy Information Administration Mar 2008

In the past 5 years, We've gone from an expected major gas shortfall...

20

- 2005
 - ▣ US to suffer significant gas shortage predicted by 2010 to 2012
 - ▣ About 5-8 bcfd of new imports projected to be needed
- 2006
 - ▣ Over a dozen new LNG projects sanctioned
 - ▣ 48 proposed NA regasification facilities
- 2007
 - ▣ Gas prices strengthening, gas rig count up
- 2008
 - ▣ Spot LNG cargos selling for > \$24/MMBtu
 - ▣ US Henry Hub > \$14/MMBtu

...to awash in gas!

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- 2009
 - Unconventional gas exceeding all predictions
 - Storage overflowing due to warm winter
 - Global economic slowdown, demand way off
 - Gas trading at lowest parity to oil since deregulation of the US gas industry
- 2020 to 2030 ???
 - If past is an indicator, very hard to predict what will happen with any accuracy
 - Need an approach that adapts to any number of possible future states.

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Policy Issues Associate with the Gas Tax

Gas Tax Policy Options By 2014

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- Leave the Current System**
 - Accept the gas price risk as an incentive for Producer participation in the gasoline
- Eliminate the Risk of Oil+Gas Tax < Oil Tax**
 - Set a minimum tax equal to the tax that would have been paid for the oil alone
- Reduce the Oil Tax Reducing Effect of Price Parity**
 - Establish a "collar" around the parity ratio, if the collar ratio is exceeded the equivalence of oil to gas is adjusted
- Separate or Ringfence gas production for State production tax purposes**
 - Need to develop a way to allocate costs between oil and gas that does not require an army of auditors
 - Changes the current cash flow balance between the State and Producers

The End

17

Oil and Gas in Alaska's Production Tax

Dan E. Dickinson CPA

Senate Finance Committee

February 24, 2010

DAN E.
DICKINSON CPA

Why are we going through all these numbers?

Questions:

Is this system stable or robust and likely to be viable over a wide range of conditions (including a good environment for a gas project)?

Are the cross subsidies clear and rational?

How will the state react if there are large drops in tax revenue? To whom will it look for revenue?

Two ways of measuring the issue:

How much does gas “drag down” or “compensate” oil progressivity?

How much will tax revenues fall because a gas project is added?

From Dec 10 2008 Presentation to LB&A

	Oil Only	Incremental Gas	Combined
Daily Vol	0.7 mmbbls/day	4.2 bcf/day	
days per year	365	365	
Annual Volume	255.5 mmbbls/yr	1533 bcf/yr	
Convert to boe	1	6	
Annual Barrel Equivalents	255.5 boe/yr	255.5 boe/yr	511.00 boe/yr
ANS WC Price/ Henry Hub Price	\$ 79.72	6.08	
Adj to Alberta		(0.75)	
Transportation to Market	(6.34)	(2.88)	
Gross Value at Point of Production	73.38	2.45	
Value times Volume	\$ 18,749	3,756	
Non Royalty %	87.5%	87.5%	
Taxable Wellhead	\$ 16,405	3,286	
US Costs (millions \$)	4,337	-	
Taxable Value or PTV (millions \$)	\$ 12,068	3,286	\$ 15,354.4
Non Royalty Fraction	87.5%	87.5%	87.5%
Taxable volumes boe	223.6	223.6	447.1
Prog Base (taxable value/volume)	\$ 53.98	\$ 14.70	34.34
Less \$30	30.00	30.00	30.00
Starting Point	\$ 23.98	NO PROG	4.34
Prog rate (.4% or .1% per dollar)	9.59%		1.74%
base rate	25.00%		25.00%
Total Rate	34.59%		26.74%
Total Tax (Tax Rate * PTV)	Stand Alone Oil	Stand Alone Gas	Combined
	\$ 4,174.6	821.6	\$ 4,105.16
	Sum of stand alone oil & gas	4,996.18	
	Gain (loss) in production tax from using current law vs stand alone analysis	(891.0)	
	Gain (loss) in production tax from adding gas stream under current law:	(69.4)	

Note:
Prior to
Credits

Source: Oil & Gas prices from 1/26/08, equal volumes, US from DOR 2008 Revenue Sources Book. Gas tariff and adj to Alberta from TC 2007 AGIA Proposal. Tariff is "normalized leveled toll including fuel"

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January 2010 example:

	Oil Only	Incremental Gas	Combined
Daily Vol	0.700 mmbbls/day	4.2 bcf/day	
days per year	365	365	
Annual Volume	255.5 mmbbls/yr	1533 bcf/yr	
Convert to boe	1	6	
Annual Barrel Equivalents	255.5 boe/yr	255.5 boe/yr	511.0 boe/yr
ANS WC Price/ Henry Hub Price	\$ 78.22	\$ 5.81	
Adj to Alberta	(5.90)	(0.75)	
Transportation to Market	72.32	(2.80)	
Gross Value at Point of Production	\$ 18,478	\$ 3,465	
Value times Volume	87.5%	87.5%	
Non Royalty %	16,168	3,032	
Taxable Wellhead	4,000	-	
US Costs (millions \$)	\$ 12,168	\$ 3,032	\$ 15,200
Taxable Value or PTV (millions \$)	87.5%	87.5%	87.5%
Non Royalty Fraction	223.6	223.6	447.1
Taxable volumes boe	\$ 54.43	\$ 13.56	\$ 33.99
Prog Base (taxable value/volume)	30.00	30.00	30.00
Less \$30	\$ 24.43	\$ -	\$ 3.99
Starting Point	9.77%	0.00%	1.60%
Prog rate (.4% or .1% per dollar)	25.00%	25.00%	25.00%
base rate	34.77%	25.00%	26.60%
Total Rate	Stand Alone Oil	Stand Alone Gas	Combined
Total Tax (Tax Rate * PTV)	\$ 4,231	\$ 757.9	\$ 4,043
Sum of stand alone oil & gas	4,988.85		
Gain (loss) in production tax from using current law vs stand alone	(946.1)		
Gain (loss) in production tax from adding gas stream under current law:	(188.3)		

Note:
Prior to Credits

Source: HH and ANS are January 2010, Gas transportation low end of TC range from Feb 7 presentation, oil trans from Fall 2009 RSB

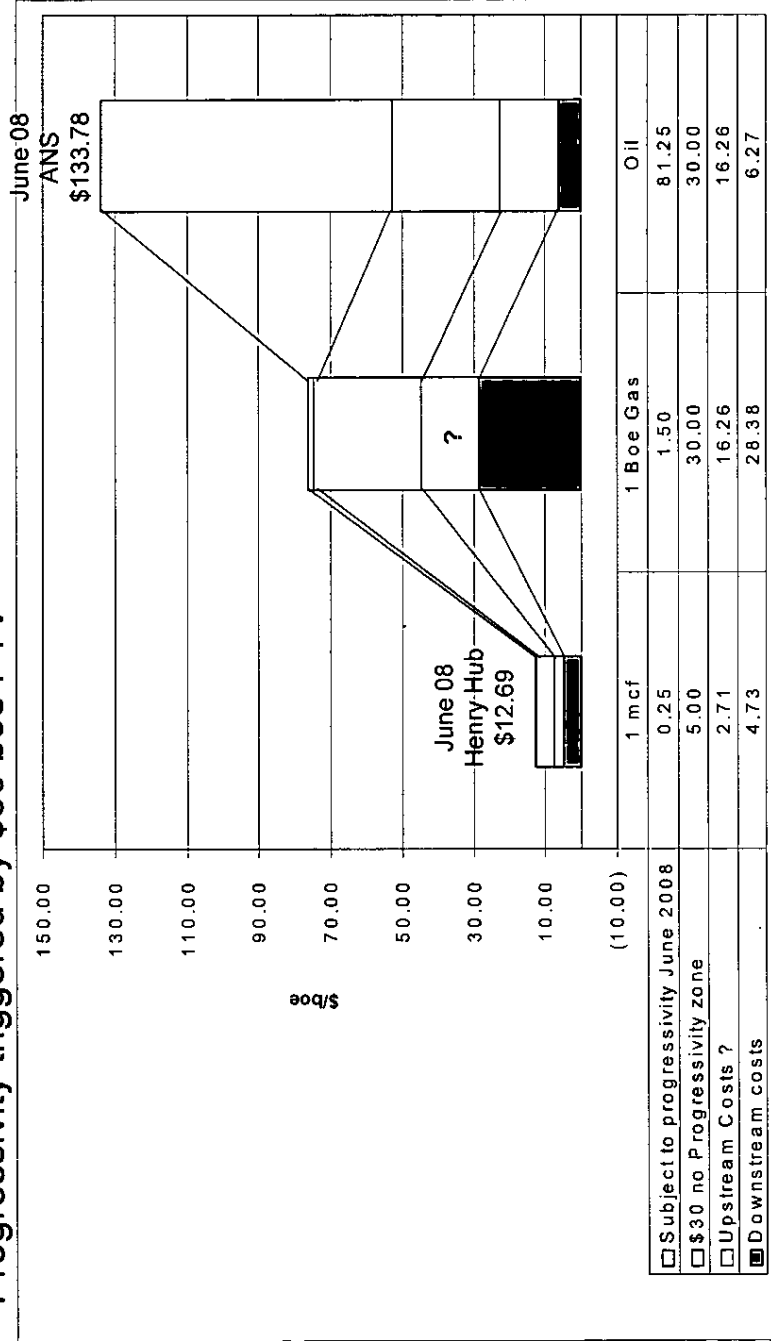
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Looking Forward: Combined Progressivity Tax (CPT)

Gas exported from state and oil taxed at same rate – both part of combined progressivity calculation.

- Prices swings in one can effect tax on the other
- Gas converted to oil on Btu basis (roughly 6:1)
- Progressivity triggered by \$30 boe PTV



Sources: Oil data from Spring 2008 RSB, Upstream Gas Cost is oil data on boe basis, Gas Downstream cost is Black & Veatch Estimate from Appendix G Alaska Gasline Determination, Oil price from DOR website, Gas Price from St. Louis Fed Reserve website

Gaffney Cline slide:

Response to Mr. Dickinson

Gaffney, Cline & Associates

DAN E.
DICKINSON CPA

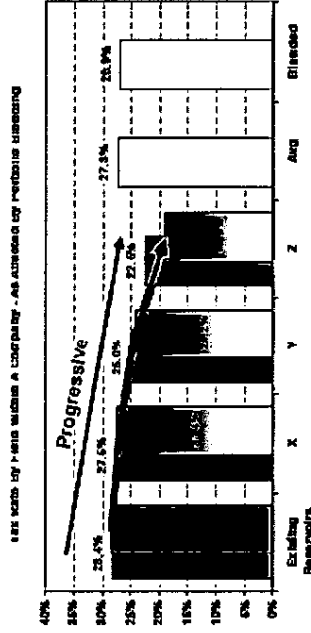
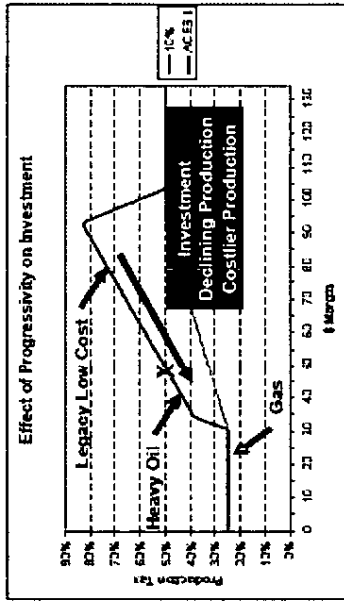
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- The basic elements were introduced in the 2006 tax changes.
- Focus was on oil.
- Gas was “on hold” waiting for the release of the “Stranded Gas Development Act” contract (May 2006)

Gaffney Cline Slide:

Cross Subsidies and "Less Tax"

- The cross subsidy issue caused by progressivity was also discussed at great length and it was shown how under certain circumstances the "effective" rate of tax on a higher cost / lower profitability development (such as gas or heavy oil) could be lower than the base rate



- It was also noted that any evaluation involved many commercial and economic parameters that would need to be evaluated across a range of expected values

Gaffney, Cline & Associates

02 February 2009

DAN E. DICKINSON CPA

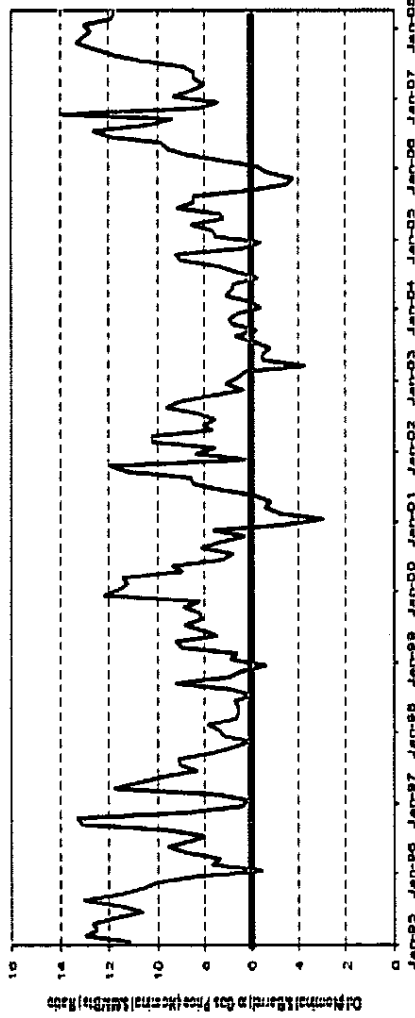
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Gaffney Cline Slide:

Pricing Parity is Key

- One way to predict the future is to look at the past
- Plot of oil price divided by gas price with "6" representing thermal and, therefore, price parity

Figure 4-5. Historical Oil to Gas Price Ratio



Source: Black and Veatch 2008, Appendix G1, Section 7.15.4.3

Gaffney, Cline & Associates

02 February 2009

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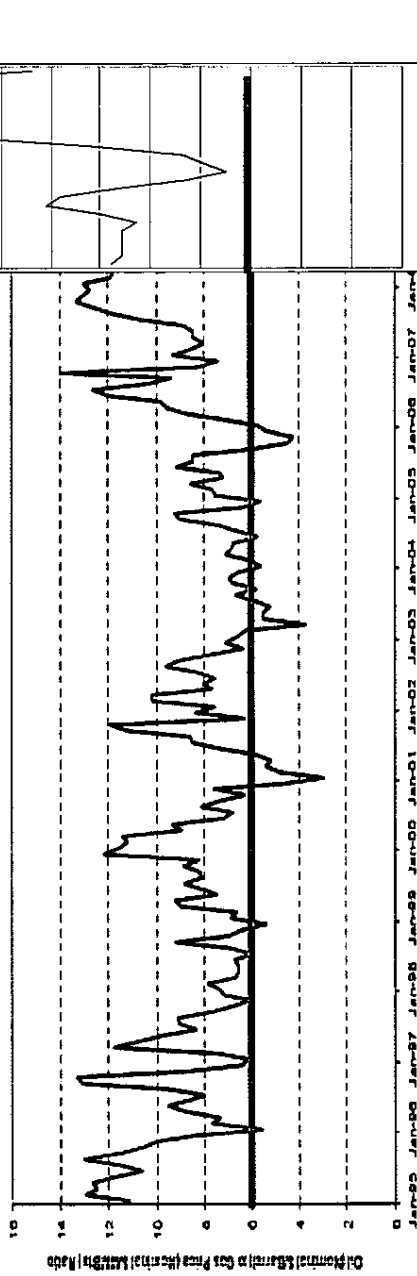
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Updated Gaffney Cline Slide:

Pricing Parity is Key

- One way to predict the future is to look at the pa
- Plot of oil price divided by gas price with "6" representing thermal and, therefore, price parity

Figure 4-5. Historical Oil to Gas Price Ratio



Source: Black and Veatch 2008, Appendix G1, Section 7.15.4.3

Gaffney, Cline & Associates

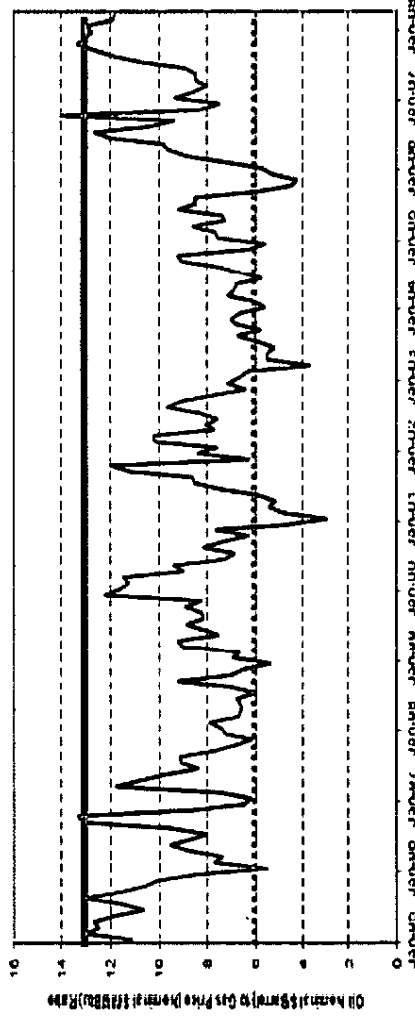
02 February 2009

Gaffney Cline Slide:

Pricing Parity is Key

- Mr. Dickinson chose roughly 13:1 price parity
- This occurred <4% of the time in the last 14 years

Figure 4-5. Historical Oil to Gas Price Ratio



Source: Block and Veatch 2008, Appendix G1, Section 7.15.4.3

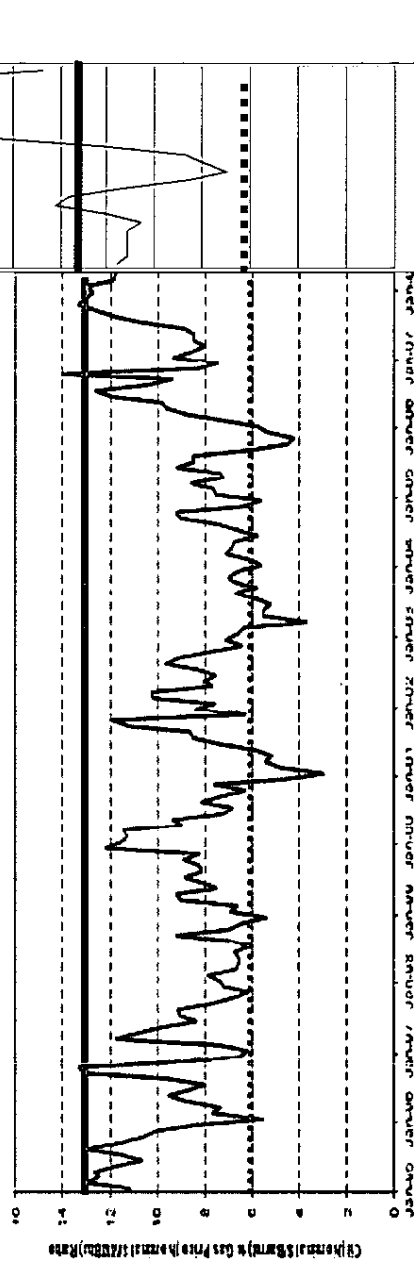
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02 February 2009

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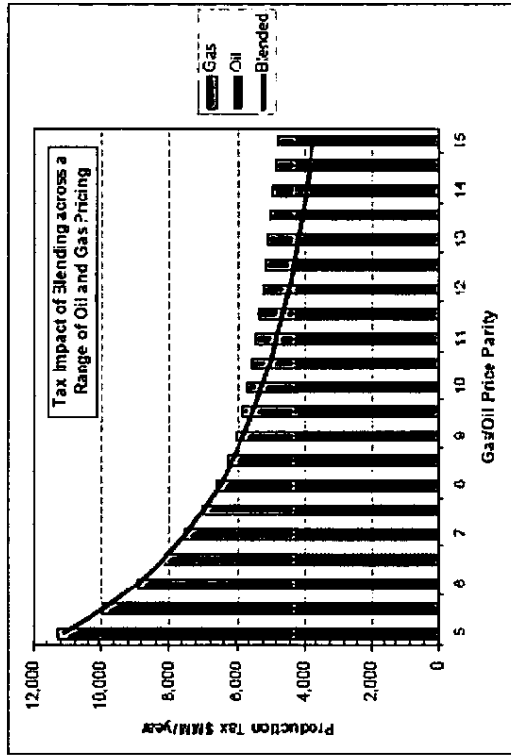
Gaffney, Cline & Associates

02 February 2009

Gaffney Cline Slide:

Collecting "less" combined tax

- Just modifying the oil/gas price parity in Mr. Dickinson's model is revealing



Gaffney, Cline & Associates

02 February 2009

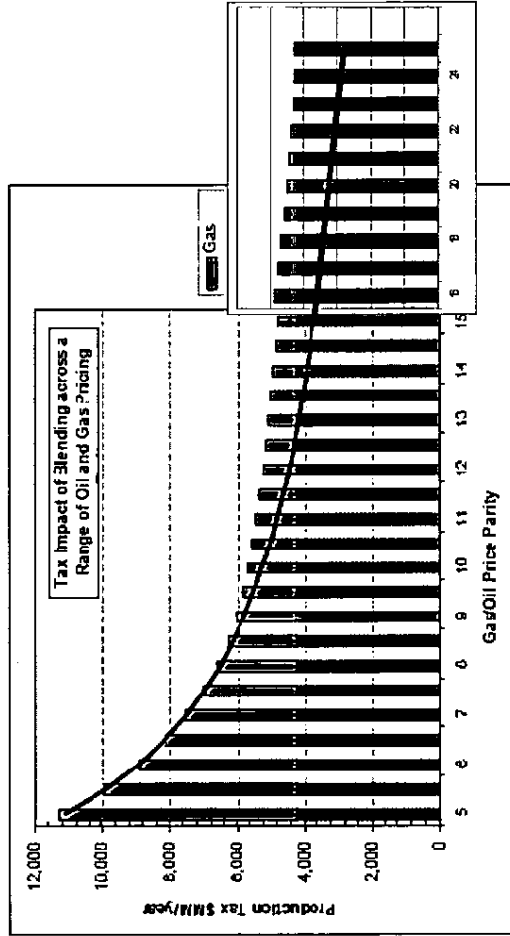
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Updated Gaffney Cline Slide:

Collecting "less" combined tax

- Just modifying the oil/gas price parity in Mr. Dickinson's model is revealing



Gaffney, Cline & Associates

02 February 2009

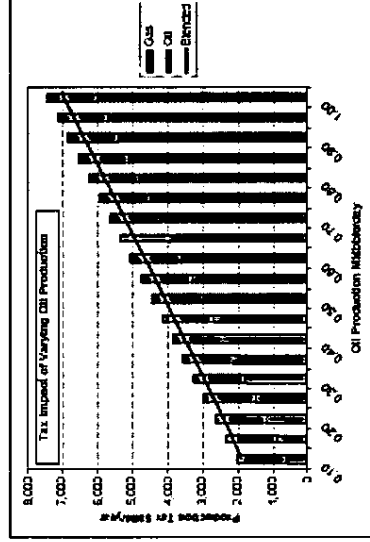
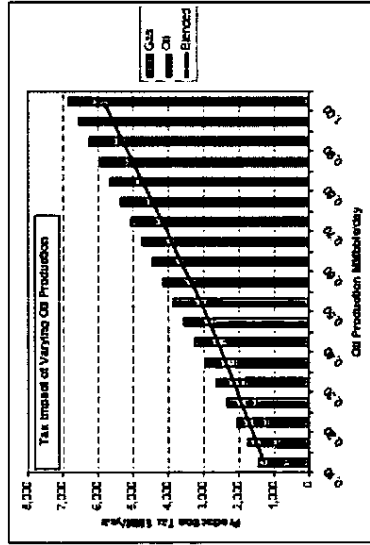
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Gaffney Cline Slide:

Impact of Varying both Oil/Gas Production and Price Ratios

- Gas at 4.2 bcf/d and Oil at \$80/bbl
- Left prices 13:1 and on the right prices 10:1



- At 10:1, the issue of pay less overall taxes goes away. At the long-range expectation of prices at 8:1, paying “less” taxes is a non-issue

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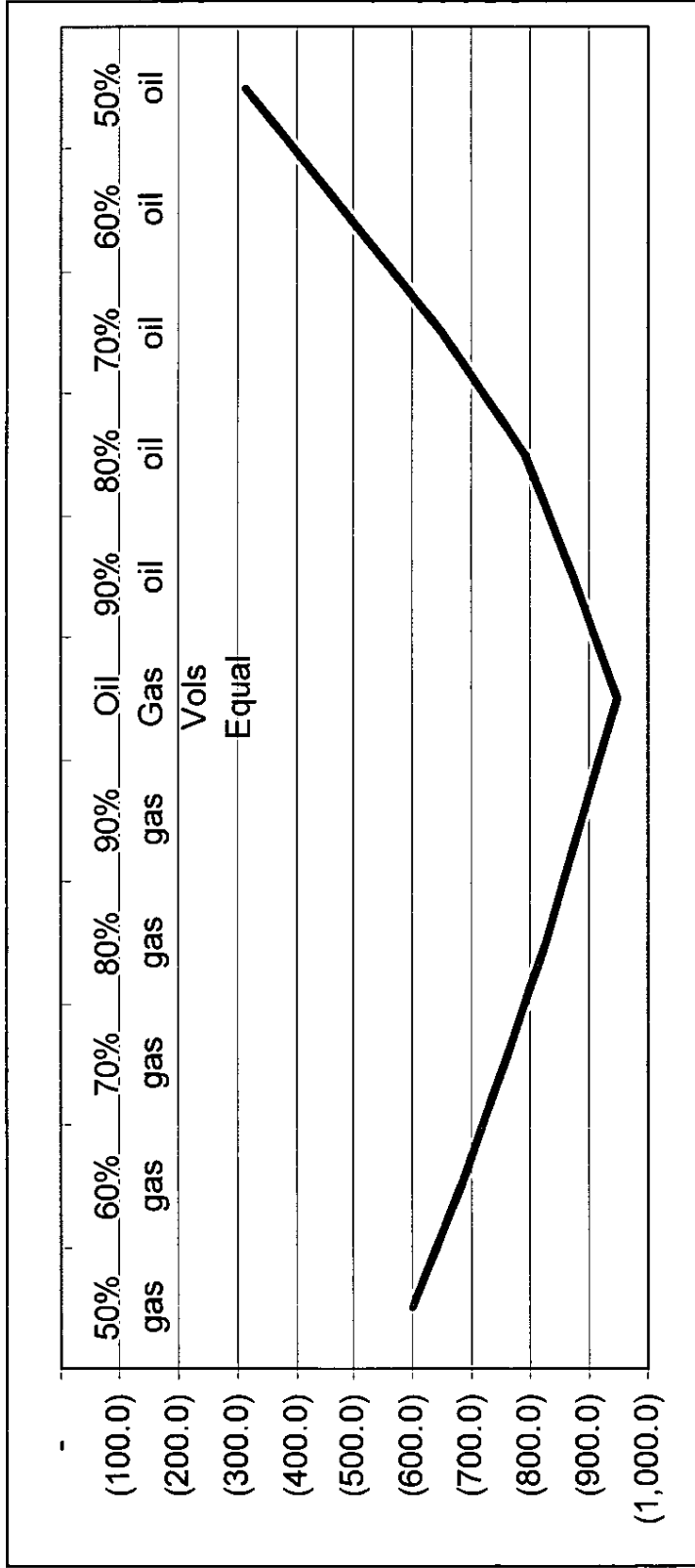
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Effects of Volume

- Size of effect is directly related to gas:oil volumes (at a given price)



Note: Difference between stand alone oil tax + stand alone gas tax and combined tax

Source: HH and ANS are January 2010, Gas transportation low end of TC range from Feb 7 presentation, oil trans from Fall 2009 RSB

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Gaffney Cline Slide with questions:

Summary

- A range of possible outcomes “caused” by ACES’ structure was identified, reviewed and built into the final design of ACES to provide incentives to both existing SOA producers as well as new entrants
 - Are these well targeted incentives?
- When evaluating ACES and a possible gas line reasonable results are obtained when real world input values are used
 - “Reasonable results” include material potential tax revenue losses from a gas line
- Nobody has brought forth expected, sustainable scenarios to show that ACES needs to be modified

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Solutions

How can this be fixed?

1. Change AS 43.55 before the open season
2. When revenues are actually impacted, add a recoupment factor outside of AS 43.55 - for example in Income Tax or in a new section.

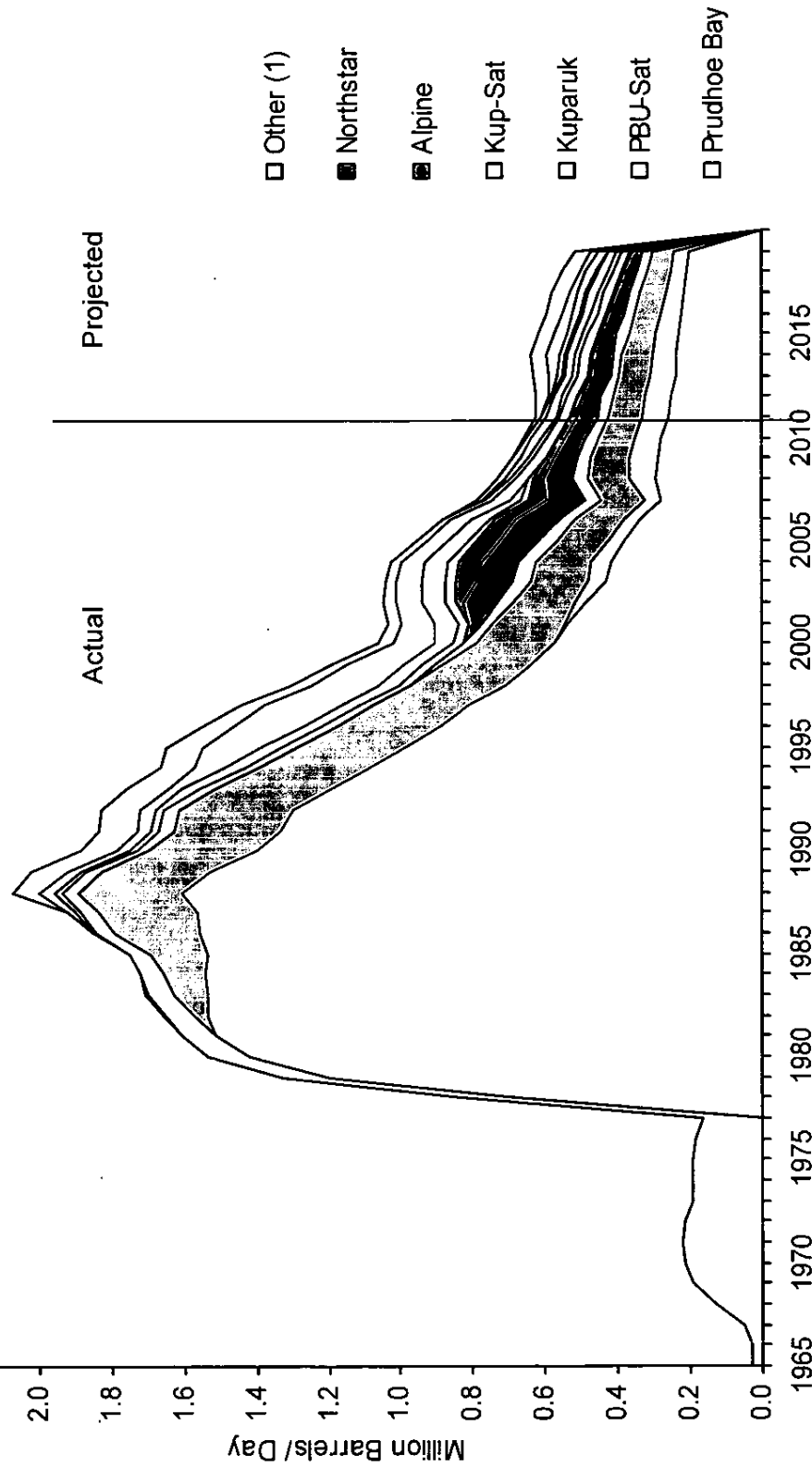
Note: Existing "AGIA" law AS 43.90.320 (d):

In this section "gas production tax" means the tax levied on the production of gas under AS 43.55

"Locking down" current production taxes under AS 43.55 is not prohibiting any additional "revenue enhancements" in relation to a gas project.

Fundamentals

Alaska Oil Production, 1965 - 2019



Source: Alaska Department of Revenue, Fall 2009 Revenue Sources Book. Extrapolated
 (1) Cook Inlet, Duck Island, Milne Point, Greater Point McIntyre, Liberty, Known On & Offshore, Fiord and NPRA.

Thank You

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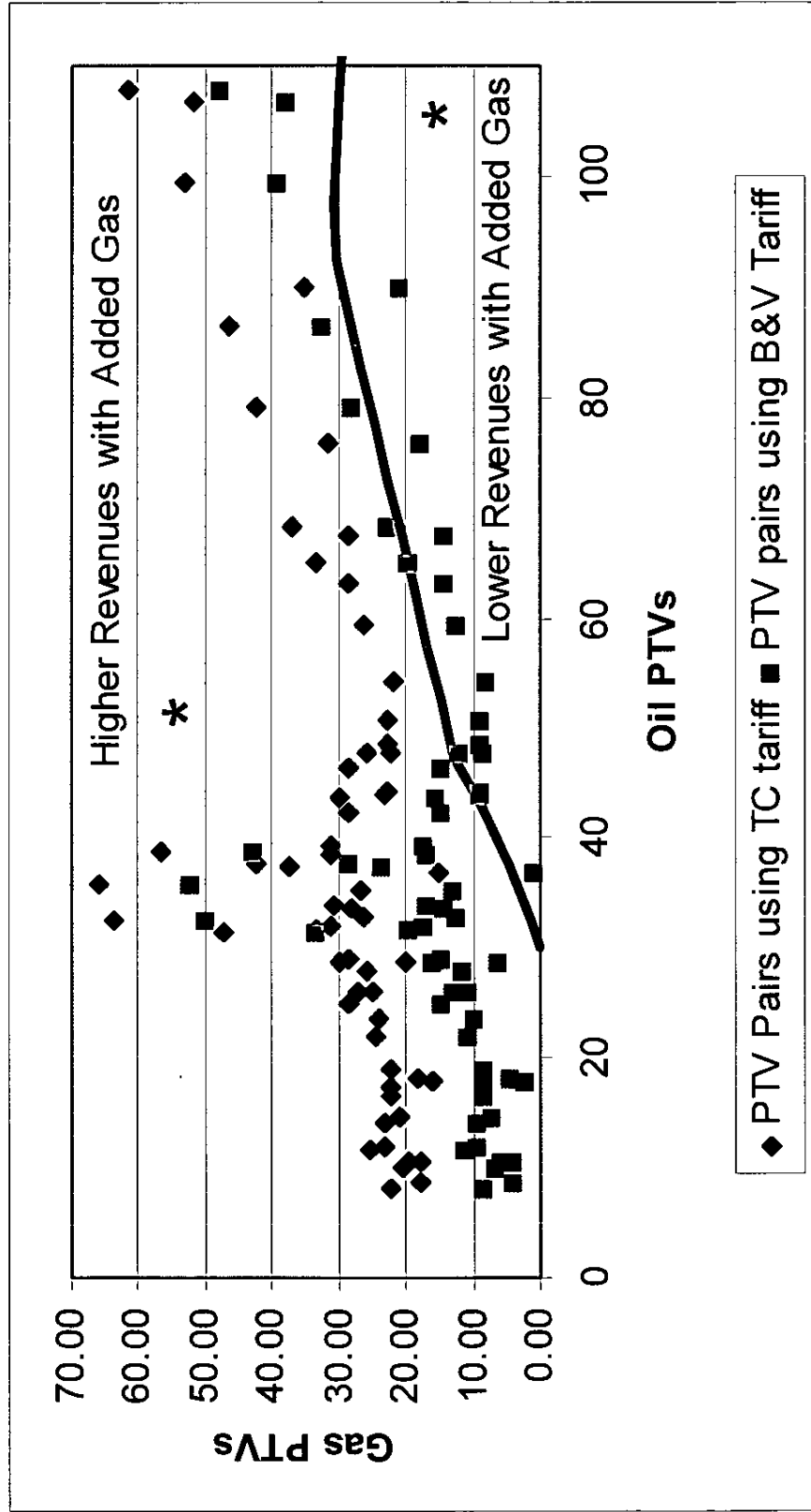
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Monthly Progressivity Example From March 26 2009

	Oil Only	Incremental Gas	Combined
Daily Vol days per year	0.350	4.2 bcf/day	
Annual Volume	30	30	
Convert to boe	10.5 mmbbls/mo	126 bcf/mcf	
Annual Barrel Equivalents	10.5 boe/mo	21.0 boe/mo	31.5 boe/mo
ANS WC Price/ Henry Hub Price	\$ 135.00	\$ 6.00	
Adj to Alberta		(0.75)	
Transportation to Market	(6.00)	(2.75)	
Gross Value at Point of Production	129.00	2.50	
Value times Volume	\$ 1,355	\$ 315.0	
Non Royalty %	87.5%	87.5%	
Taxable Wellhead	\$ 1,185	\$ 276	
US Costs (millions \$)	275	-	
Taxable Value or PTV (millions \$)	\$ 910	\$ 276	\$ 1,186
Non Royalty Fraction	87.5%	87.5%	87.5%
Taxable volumes boe	9.2	18.4	27.6
Prog Base (taxable value/volume)	\$ 99.07	\$ 15.00	\$ 43.02
Less \$30	30.00	30.00	30.00
Starting Point	69.07	\$ -	\$ 13.02
Prog rate (.4% or .1% per dollar)	25.66%	0.00%	5.21%
base rate	25.00%	25.00%	25.00%
Total Rate	50.66%	25.00%	30.21%
Total Tax (Tax Rate * PTV)	\$ 461	\$ 68.9	\$ 358
Sum of stand alone oil & gas		529.98	
Gain (loss) in production tax from using current law vs stand alone		(171.8)	
Gain (loss) in production tax from adding gas stream under current law:		(102.8)	

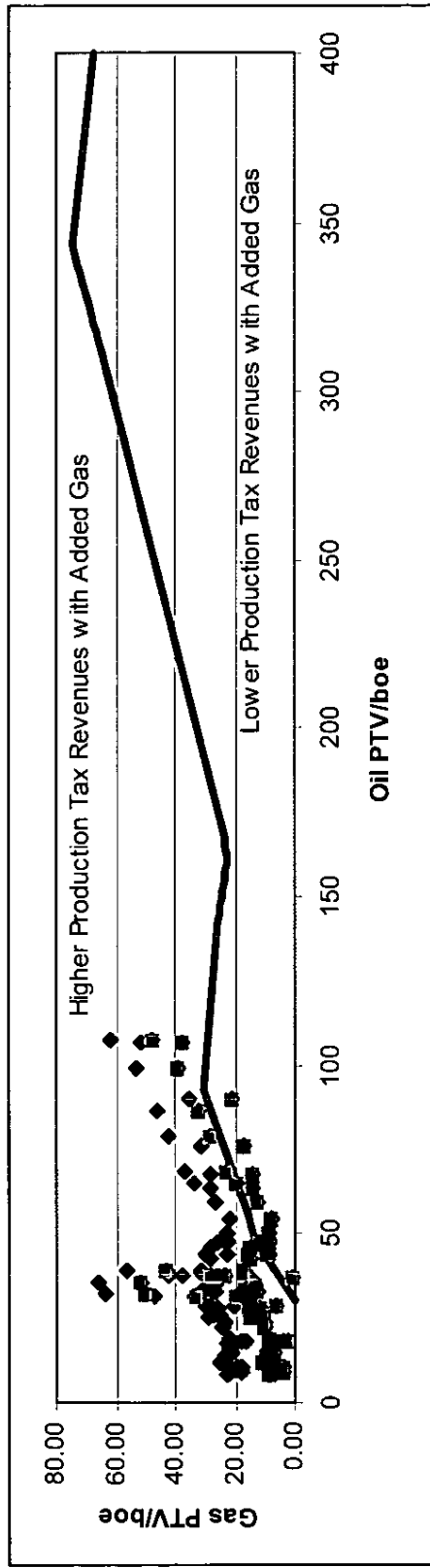
Note:
Prior to
Credits

Oil and Gas PTVs 2004 - 2008



2 24 2010

Oil and Gas PTVs 2004 - 2008



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- Other Oil Gas Issues
- Under distinct oil and gas taxes the joint costs of running the legislature must be divided between oil and gas
 - Gross margin method?
- Gas liquids – “in between”

October 2009 Market Values:

	Oil Only	Incremental Gas	Combined
Daily Vol	0.700 mmbbls/day	4.2 bcf/day	
days per year	365	365	
Annual Volume	255.5 mmbbls/yr	1533 bcf/yr	
Convert to boe	1	6	
Annual Barrel Equivalents	255.5 boe/yr	255.5 boe/yr	511.0 boe/yr
ANS WC Price/ Henry Hub Price	\$ 74.28	\$ 4.02	
Adj to Alberta	(5.90)	(0.75)	
Transportation to Market	(2.80)	(2.80)	
Gross Value at Point of Production	68.38	0.47	
Value times Volume	\$ 17,471	\$ 721	ROYALTIES 90
Non Royalty %	87.5%	87.5%	
Taxable Wellhead	\$ 15,287	\$ 630	
US Costs (millions \$)	4,000	-	
Taxable Value or PTV (millions \$)	\$ 11,287	630	\$ 11,918
Non Royalty Fraction	87.5%	87.5%	87.5%
Taxable volumes boe	223.6	223.6	447.1
Prog Base (taxable value/volume)	\$ 50.49	\$ 2.82	\$ 26.65
Less \$30	30.00	30.00	30.00
Starting Point	\$ 20.49	\$ -	\$ -
Prog rate (.4% or .1% per dollar)	8.20%	0.00%	0.00%
base rate	25.00%	25.00%	25.00%
Total Rate	33.20%	25.00%	25.00%
Total Tax (Tax Rate * PTV)	\$ 3,747	Stand Alone Gas 157.6	Stand Alone Oil 3,904.42
Sum of stand alone oil & gas			
Gain (loss) in production tax from using current law vs stand alone			(925.0)
Gain (loss) in production tax from adding gas stream under current law:			(767.4)

Sum of stand alone oil & gas
 Gain (loss) in production tax from using current law vs stand alone
 Gain (loss) in production tax from adding gas stream under current law:

Oct 2009 + 1 Dollar higher Gas Value

	Oil Only	Incremental Gas	Combined
Daily Vol	0.700 mmbbls/day	4.2 bcf/day	
days per year	365	365	
Annual Volume	255.5 mmbbls/yr	1533 bcf/yr	
Convert to boe	1	6	
Annual Barrel Equivalents	255.5 boe/yr	255.5 boe/yr	511.0 boe/yr
ANS WC Price/ Henry Hub Price	\$ 74.28	\$ 6.00	
Adj to Alberta	(5.90)	(0.75)	
Transportation to Market	(2.80)		
Gross Value at Point of Production	68.38	1.45	
Value times Volume	\$ 17,471	\$ 2,223	ROYALTIES 278
Non Royalty %	87.5%	87.5%	
Taxable Wellhead	\$ 15,287	\$ 1,945	
US Costs (millions \$)	4,000	-	
Taxable Value or PTV (millions \$)	\$ 11,287	1,945	\$ 13,232
Non Royalty Fraction	87.5%	87.5%	87.5%
Taxable volumes boe	223.6	223.6	447.1
Prog Base (taxable value/volume)	\$ 50.49	\$ 8.70	\$ 29.59
Less \$30	30.00	30.00	30.00
Starting Point	\$ 20.49	\$ -	\$ -
Prog rate (.4% or .1% per dollar)	8.20%	0.00%	0.00%
base rate	25.00%	25.00%	25.00%
Total Rate	33.20%	25.00%	25.00%
Total Tax (Tax Rate * PTV)	Stand Alone Oil	Stand Alone Gas	Combined
	\$ 3,747	486.2	\$ 3,308
Sum of stand alone oil & gas	4,233.05		
Gain (loss) in production tax from using current law vs stand alone			(925.0)
Gain (loss) in production tax from adding gas stream under current law:			(438.8)

DAN E. DICKINSON CPA

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Dan E. Dickinson, CPA, CMA

Dan E. Dickinson is a certified public accountant in private practice in Anchorage. He also holds the certified management accountant designation.

He has been providing analysis to the legislature on various tax and oil and gas and issues since 2007, including during the 2007 special session that passed the "ACES" reforms.

For much of 2007 he staffed the Municipality of Anchorage's Property Tax Relief Task Force. He also served on the Municipality's Budget Advisory Commission from 2007 through 2009.

In 2006 he worked for the Murkowski administration during the many attempts -- including special sessions -- which finally resulted in a net profits tax or "PPT" replacing Alaska's gross production tax based on the economic limit factor (ELF).

From 1999 through 2006 Dan worked in the Alaska Department of Revenue (ADOR). He was first appointed director of Oil and Gas Audit by Governor Knowles, and then director of Tax. He continued as director of Tax in the Murkowski administration, and in that role he signed the controversial 2005 "ELF aggregation order" for Prudhoe Bay. During his last year with the ADOR, a position was created so he could focus on state efforts to monetize North Slope gas through a Stranded Gas Development Act contract. That effort did not meet with success.

In the eighties and nineties he was involved as a consultant and expert witness in a number of oil and gas royalty and tax cases both outside and here in Alaska. A 29-year resident of Anchorage, Dan was a presenter at the Conference of Alaskans convened by Gov. Murkowski in Fairbanks in 2004. He has served on the boards of several not-for-profits as treasurer. He holds a BA in lunar geology from Brown University.

February 2010

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Senate Finance Committee



David Wood
24th February 2010

Gas Issues & Alaska's Fiscal Design

Presentation Structure



This presentation focuses the key issues pertaining to natural gas in Alaska in the context of establishing a long-term and enduring fiscal design.

- What are the issues for Alaska's fiscal regime when applied to gas?
- What are the fiscal designs applied by other countries?
- What are the risks and opportunities for international gas suppliers?
- Alaska's Prevailing Fiscal design
- Complications of combined oil and gas progressivity tax (CPT)
- Multi-year and multi-scenario fiscal performance cash flow models
- Conclusions and recommendations



What are the issues for Alaska's fiscal regime when applied to gas?

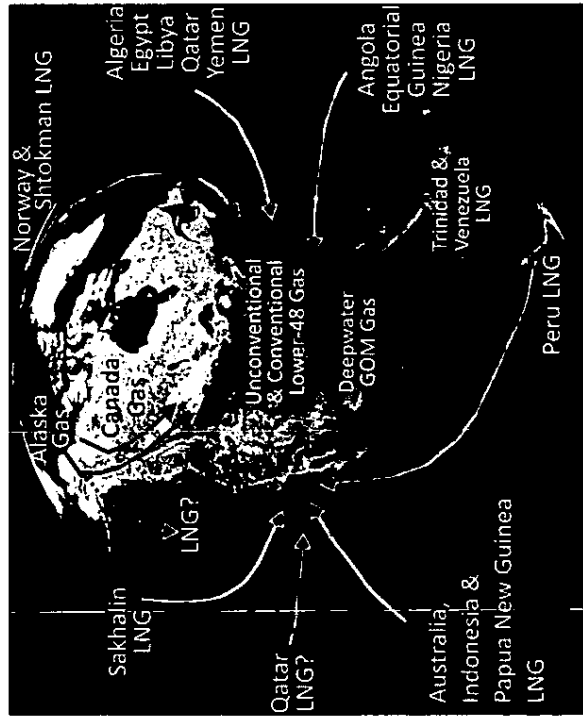
24th February 2010

David Wood

Alaska is One of Several Potential Long-term Suppliers of Natural Gas to Lower-48 U.S.



The Long-term Competition to Deliver Natural Gas to the Lower-48 US Markets is Intense



Differences between international fiscal terms and among U.S. state terms, will play a key role in that competition by influencing producers' costs of supply.

David Wood & Associates

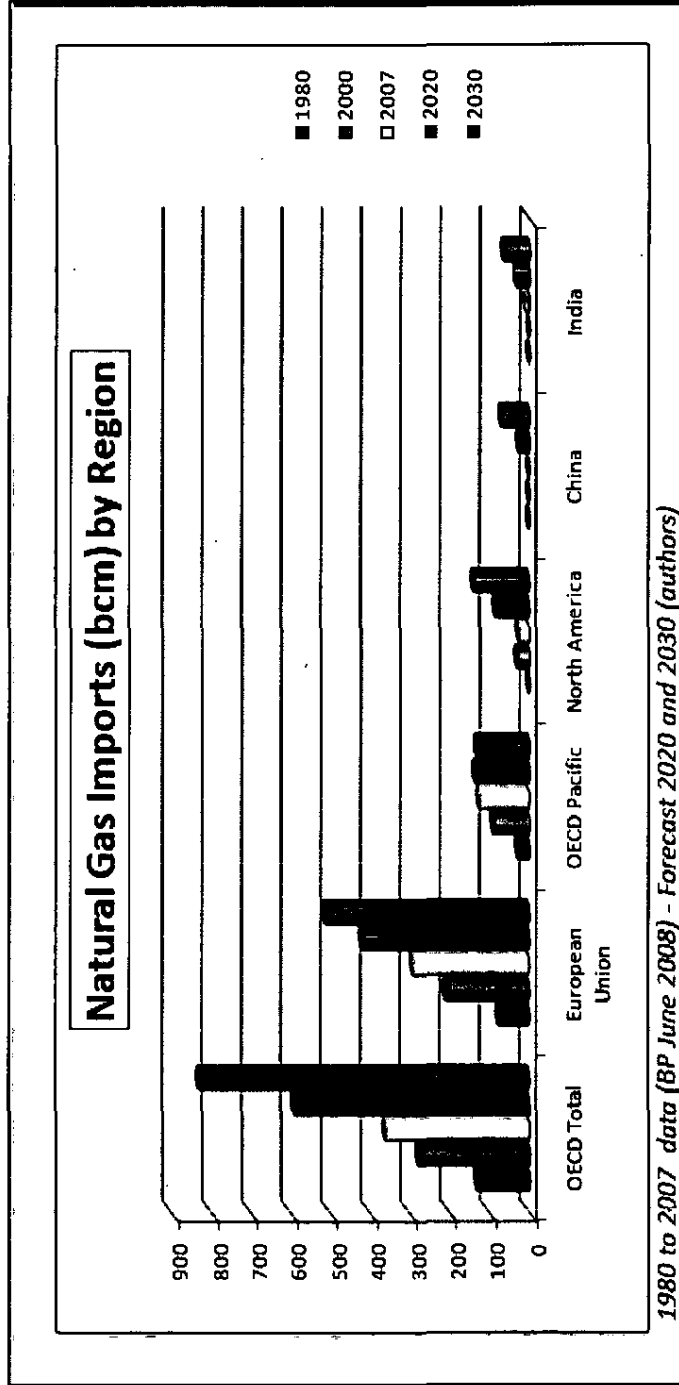
Fiscal terms are one of several factors that influence the delivered price of gas into a market and it is important to understand differences among competing sources.

The differences usually go far beyond a simple percentage sovereign take comparison.

International Gas Markets are Growing - Competition for Gas is Increasing



How key global gas import markets compare and are forecast to grow in absolute terms (bcm = billions cubic metres; 35.3 bcf = 1 bcm).



Michael Economides & David Wood, *Journal of Natural Gas Science & Engineering*, May 2009

24th February 2010

David Wood

Major IOC's are Signing Long-term Binding International Gas Agreements



Some of the large LNG sale and purchase agreements struck in 2009

Liquefaction Project	Supplier	Offtaker	Duration, Years	Volume, mtpa	Status	Date Agreed	First Delivery Expected
Gorgon (Australia)	Chevron	Osaka Gas (Japan)	25	1.375	binding	Sept. 2009	2014
Gorgon (Australia)	Chevron	Tokyo Gas (Japan)	25	1.1	binding	Sept. 2009	2014
Gorgon (Australia)	Chevron	Kogas (S.Korea)	15	1.5	HOA	Sept. 2009	2014
Gorgon (Australia)	ExxonMobil	PetroChina (China)	20	2.25	binding	Feb. 2009	2014
Gorgon (Australia)	ExxonMobil	Petronet (India)	20	1.5	binding	May 2009	2014
Wheatstone (Australia)	Chevron	Tepco (Japan)	20	4.1	HOA	Dec. 2009	2016
PNG LNG (Papua New Guinea)	ExxonMobil	Tokyo Gas (Japan)	20	1.8	binding	Dec. 2009	2014
PNG LNG (Papua New Guinea)	ExxonMobil	Osaka Gas (Japan)	20	1.5	binding	Dec. 2009	2014
PNG LNG (Papua New Guinea)	ExxonMobil	Taiwan CPC (Taiwan)	20	.5	HOA	June 2009	2014
PNG LNG (Papua New Guinea)	ExxonMobil	Sinopec (China)	20	2	binding	Dec. 2009	2014
Gladstone (Queensland, Australia)	Santos	Petronas (Malaysia)	20	2	HOA	June 2009	2015
Curtis (Queensland, Australia)	BG	CNOOC (China)	20	3.6	HOA	May 2009	2015
Kitimat (Western Canada)	Kitimat LNG	Gas Natural (Spain)	20	1.6	MOU	July 2009	2013?
Kitimat (Western Canada)	Kitimat LNG	Kogas (S.Korea)	20	2	MOU	June 2009	2013?
Qatargas (Qatar)	Qatargas	CNOOC (China)	Long-term	3	MOU	Nov. 2009	2015?
Qatargas (Qatar)	Qatargas	PetroChina (China)	Long-term	2	MOU	Nov. 2009	2015?

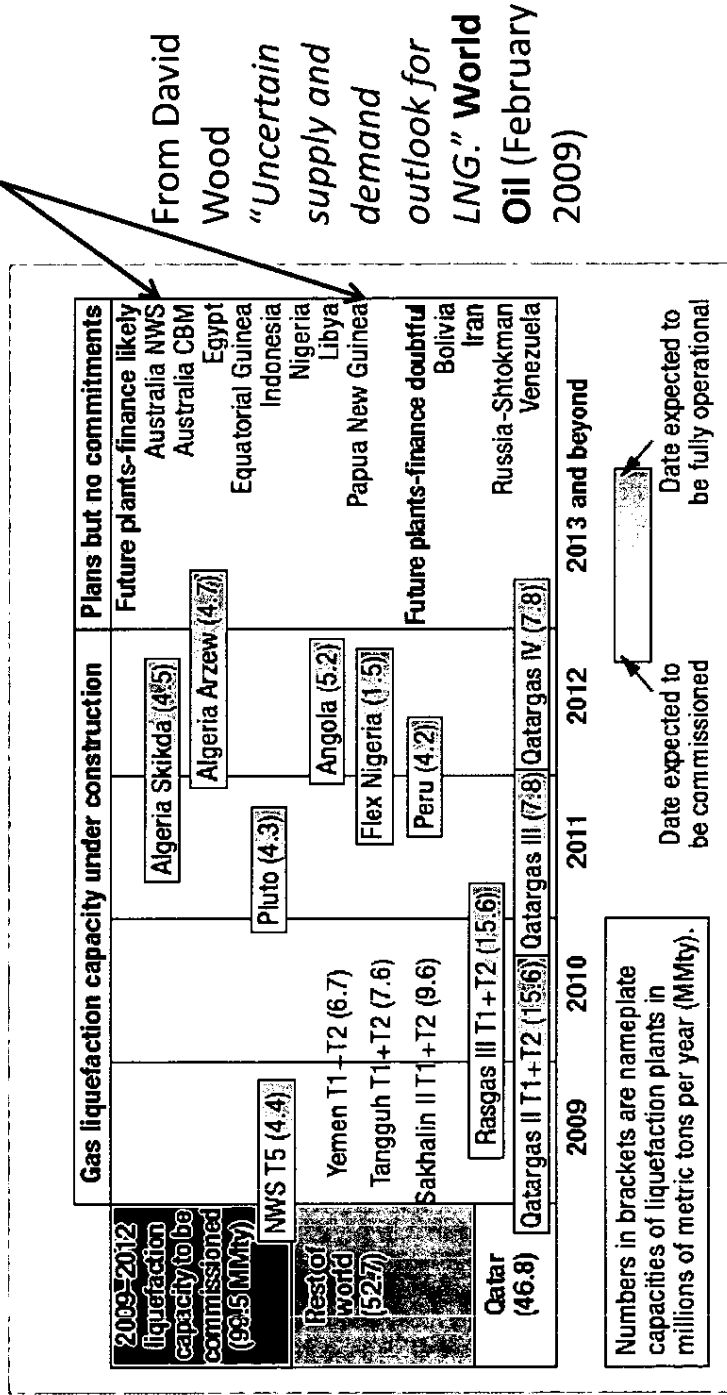
Source: Various media reports

Published by David Wood, World Oil, Feb 2010

Worldwide New Gas Liquefaction Developments to 2013 and Beyond



Large new capacity of LNG coming into the market with new plants under construction. Big commitments for new plants in Australasia made progress in 2009.



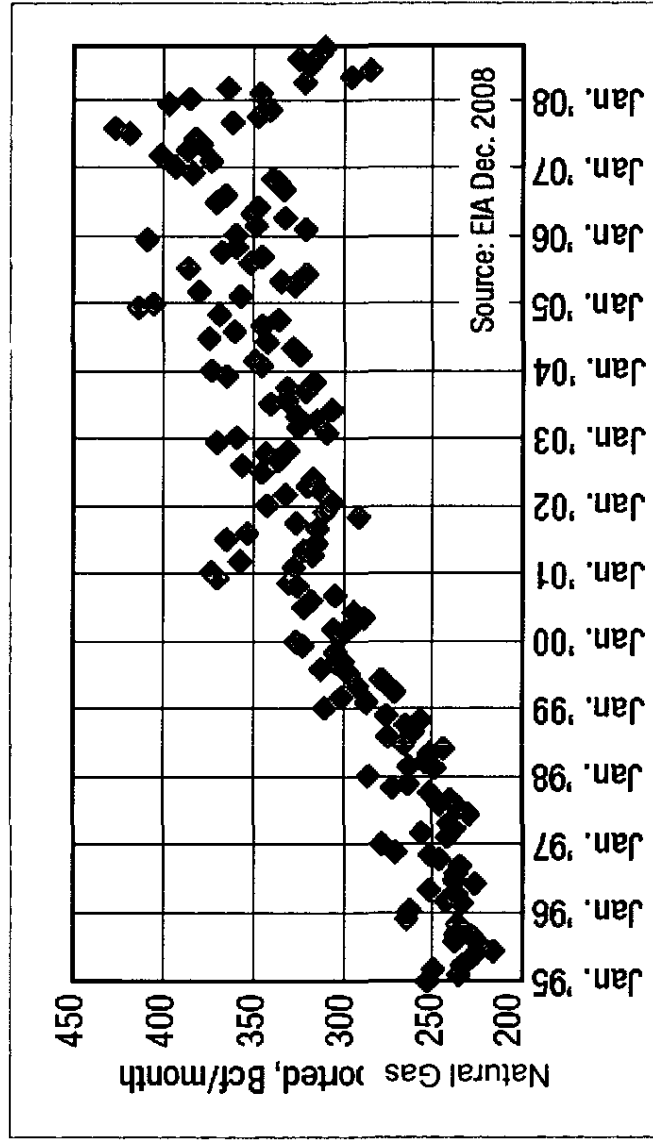
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Gas Imports to U.S. Decline in 2008 For First Time in More than a Decade

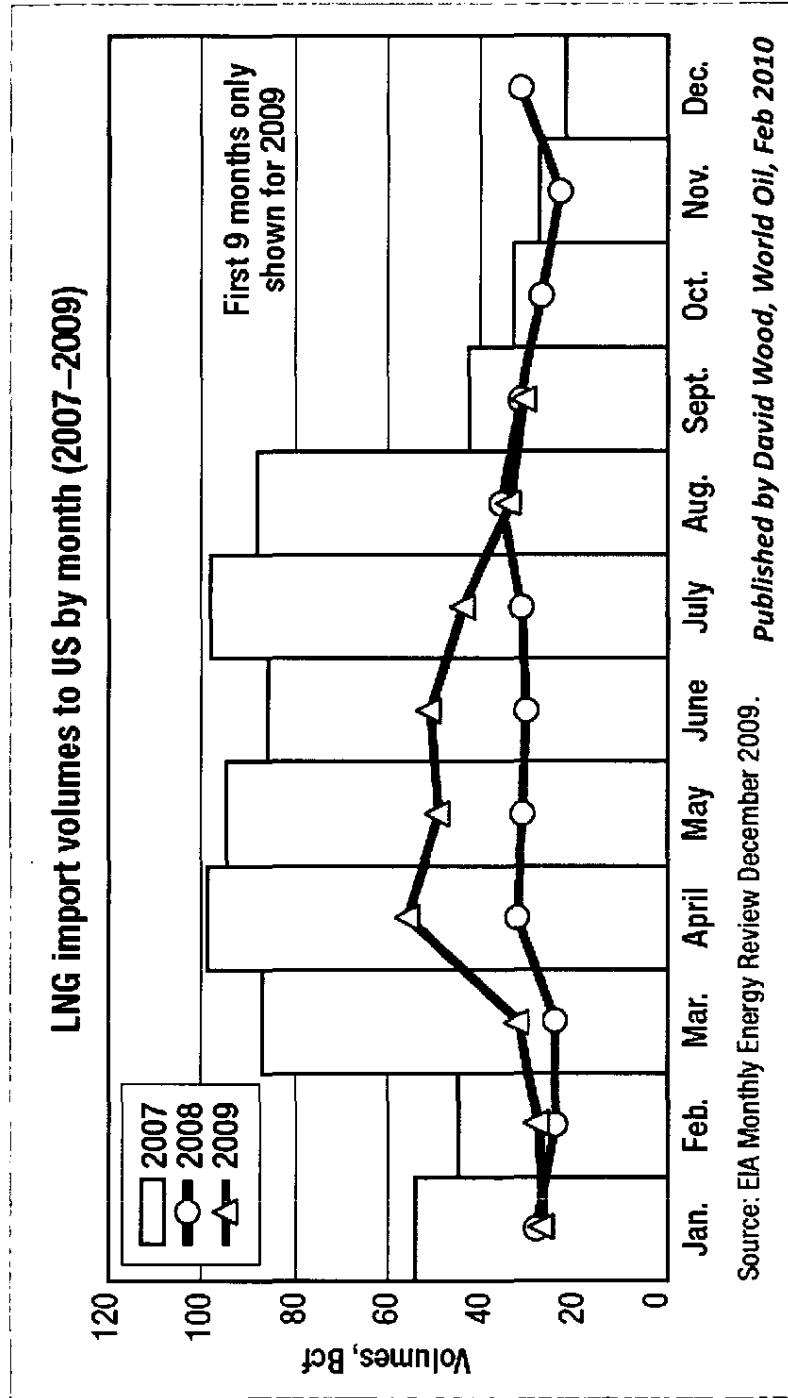


Greater Lower-48 gas production in 2008, particularly shale gas, led to a reduction in US gas imports which has persisted. Alaska gas will be competing with shale gas for lower-48 which has a different resource and cost base and fiscal structure.



From David Wood
 "Uncertain supply and demand outlook for LNG." World Oil (February 2009)

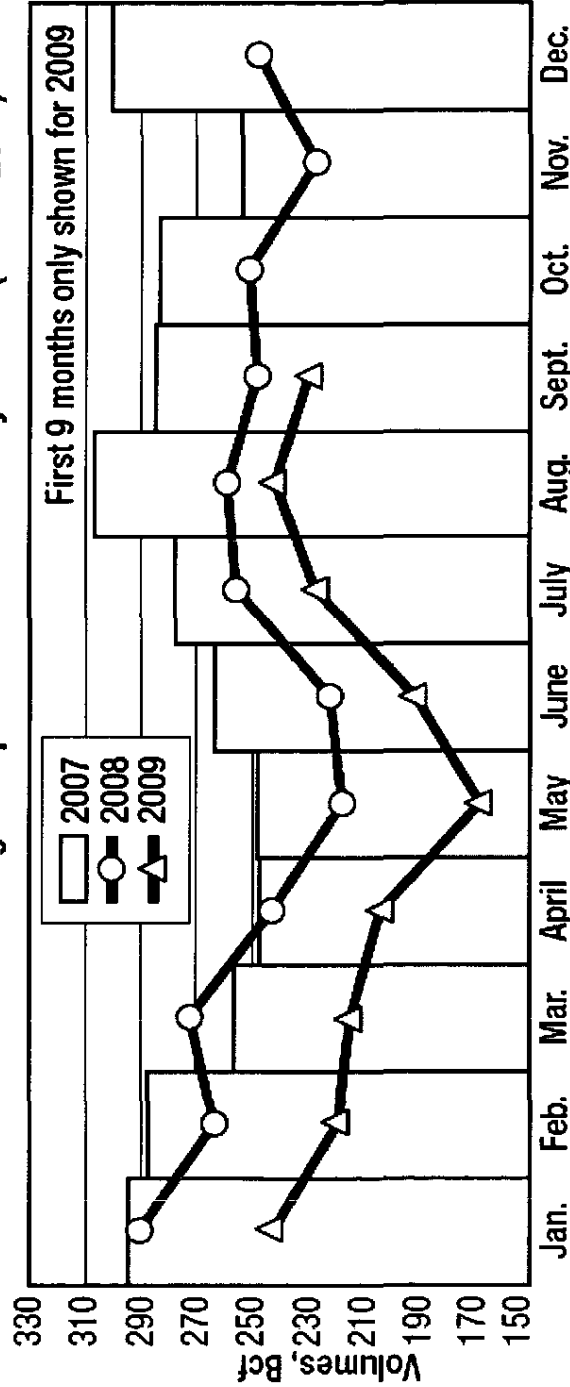
LNG Imports to U.S. are Down Is that Permanent? Shale Gas Effect?



Canadian Gas Imports to U.S. are Down Is that Permanent? Shale Gas Effect?



Net Canadian natural gas import volumes to US by month (2007-2009)



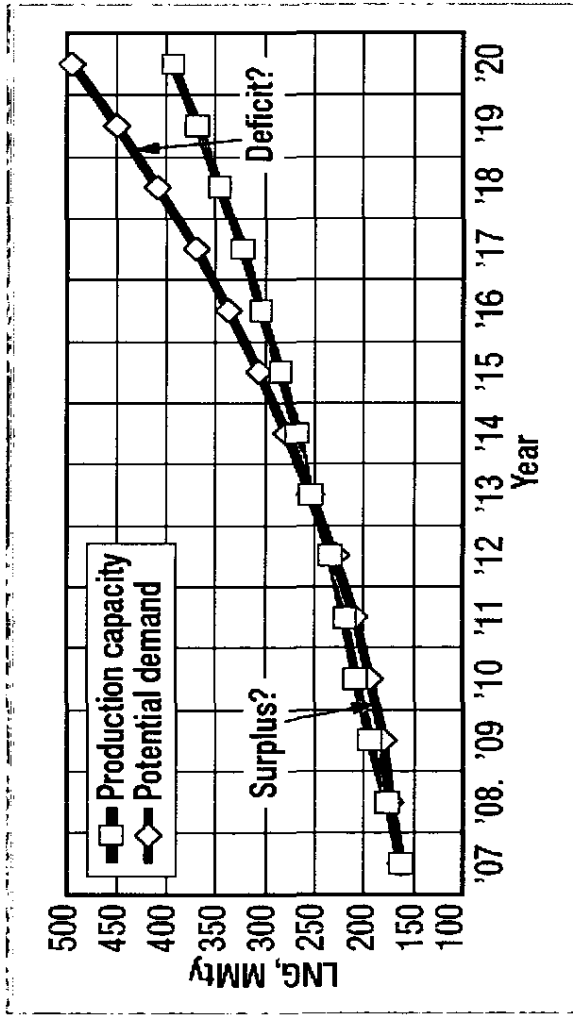
Source: EIA Monthly Energy Review December 2009.

Published by David Wood, World Oil, Feb 2010

Global LNG Supply Demand Forecast to 2020

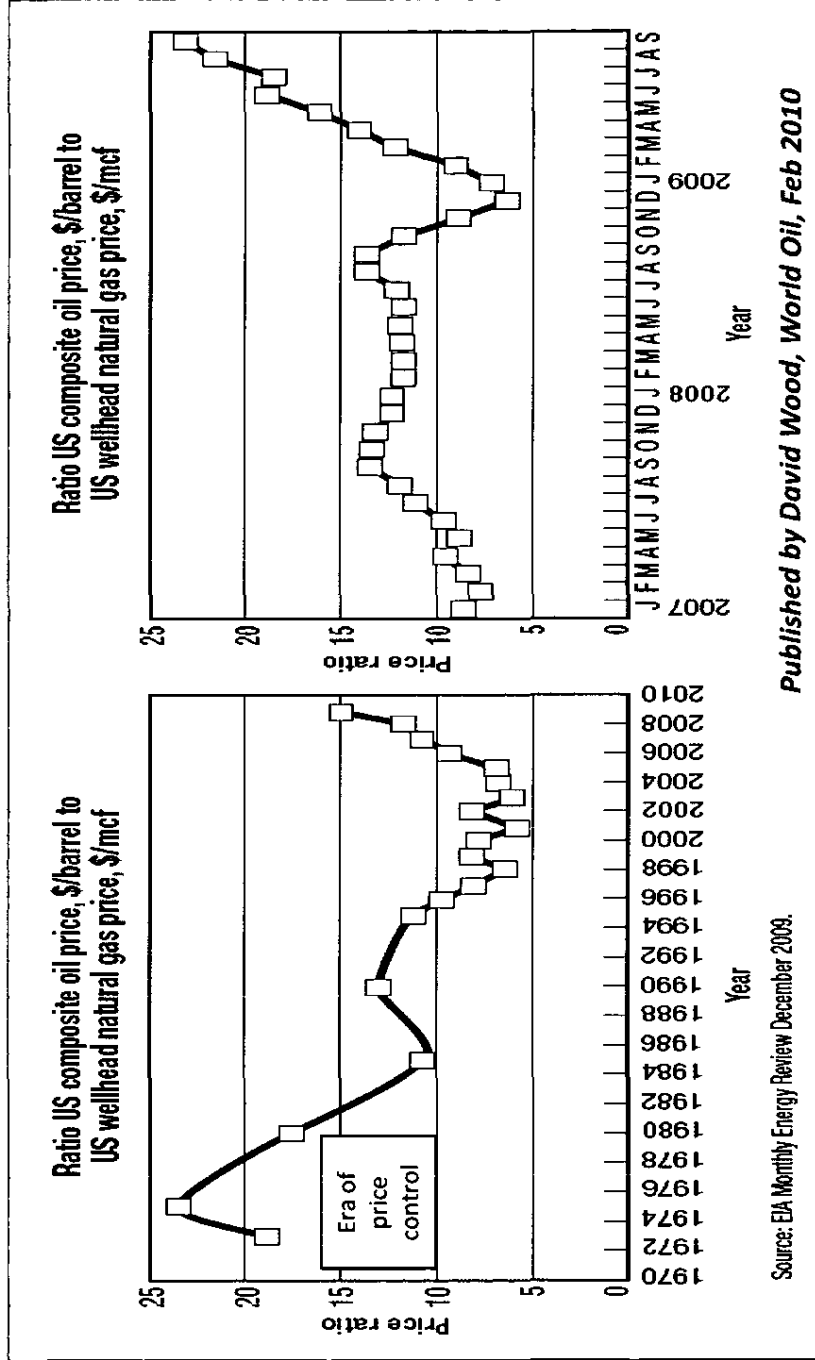


Natural gas surplus due to economic downturn and development of competing supplies is leading to over-supply and lower prices forecast to last perhaps to 2012 for internationally traded LNG. This surplus may itself fuel supply shortfalls globally beyond 2013 and higher prices 2015 to 2020.



From David Wood
"Uncertain supply
and demand
outlook for LNG."
World Oil
(February 2009).

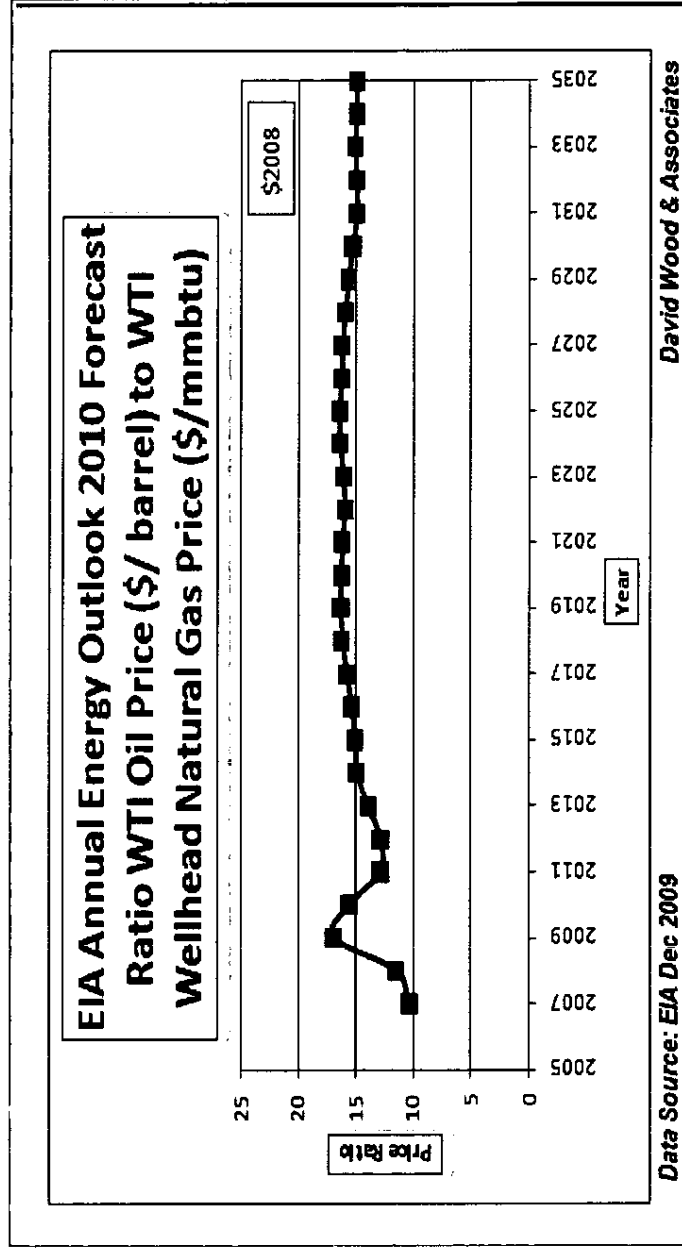
U.S. Oil to Gas Price Ratio What Range Should Fiscal Designs Consider?



Latest U.S. Government Forecast Shows High Oil to Gas Price Ratios Through to 2035



Fiscal designs should be stable under a wide range of oil: gas price ratios (e.g. stress test them with ratios of 2 to 30).



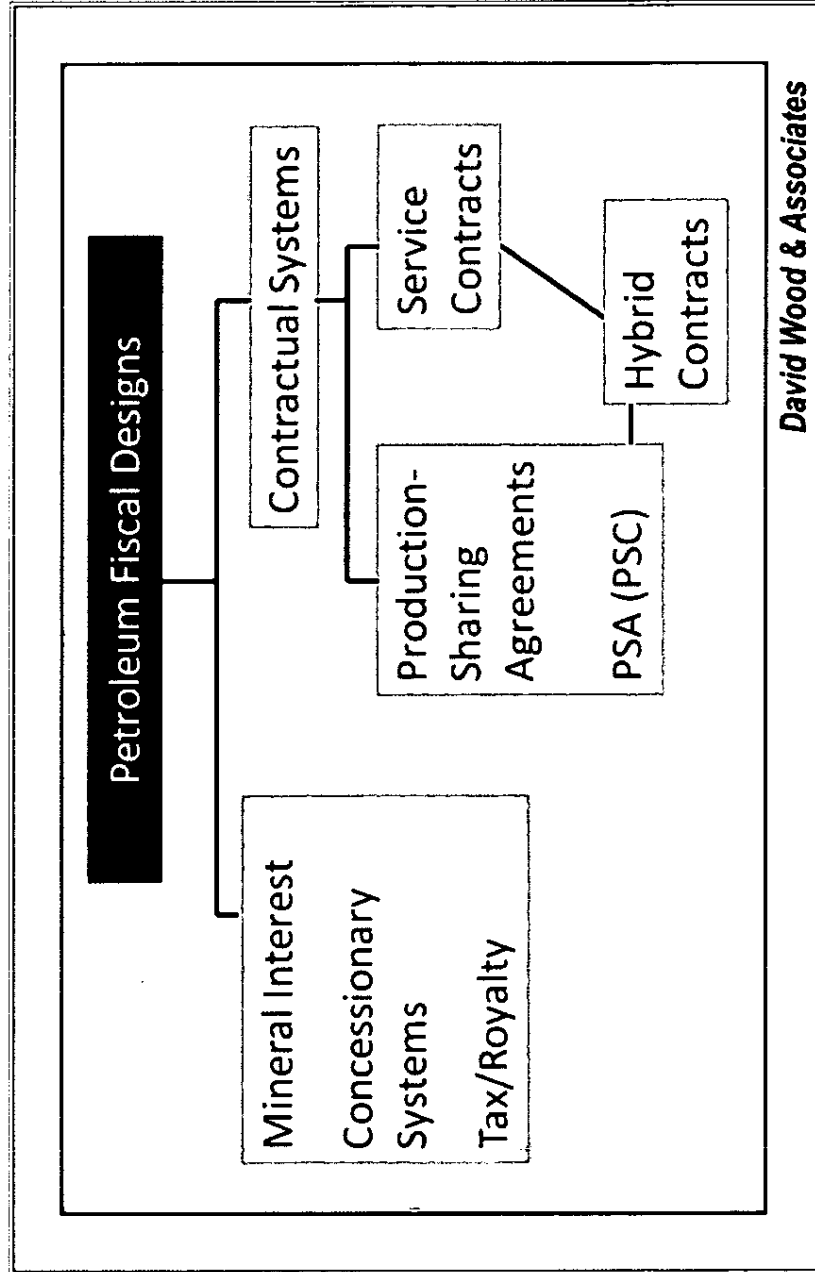
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What are the fiscal designs applied by
other countries? and what are the
risks and opportunities?

Summary of International Upstream Oil & Gas Fiscal Designs



David Wood & Associates

Norway:



Fiscal Terms Summary

Norway operates a mineral interest system. There are no bonuses or royalties and the fiscal take comes from *progressive* instruments.

- Royalty 0% and no bonuses but marginal tax burden is some 78%
- Corporate Tax (CT) 28% of taxable income
- No ring fences with CT base established at the company Level.
- Special tax rate 50% with investment uplift of 7.5% for 4 years deducted from CT base. Uplift shelters marginal fields.
- Tax of CO₂ emissions at 0.79 NOK (~10 US cents)/ m³ CO₂
- Gas taxed on bases of actual realised prices.
- Strict rules applied concerning prices of gas transfer between affiliates.
- Stated fiscal strategy is *that the tax system should act as a sleeping partner providing producers with technical control and ensuring that any investment decision that is commercially viable before tax should remain viable after tax.*
- This system secures high fiscal takes for the government (close to 80%), but has still attracted large and small international investors.
- State is actively involved as an equity participant through its NOC (Statoil).

Papua New Guinea (PNG): Fiscal Terms Summary



Papua New Guinea (PNG) operates a mineral interest system. It has relaxed fiscal terms since 1990's as fields under development have declined. Upsurge in interest in large LNG projects led to legislative changes offering progressivity and stability.

- Royalty 2%
- Income tax (IT) 30% for gas (50% for oil)
- Additional Profits Tax (APT) 7.5% after 17.5% post-IT IRR reached for project and 10% after 20% post-IT IRR reached for project.
- State equity participation 22.5% (2% of which goes to landowners)
- Partial carry for the state
- Past exploration costs recoverable through 20-year carry-forwards
- Marginal field incentives: e.g. accelerated depreciation
- ExxonMobil (41.6%) and partners completing FEED studies and a final investment decision for PNG LNG is expected in 2010
- Long-term gas buyers in China and Japan now secured.

Australia:

Gas Fiscal Terms Summary



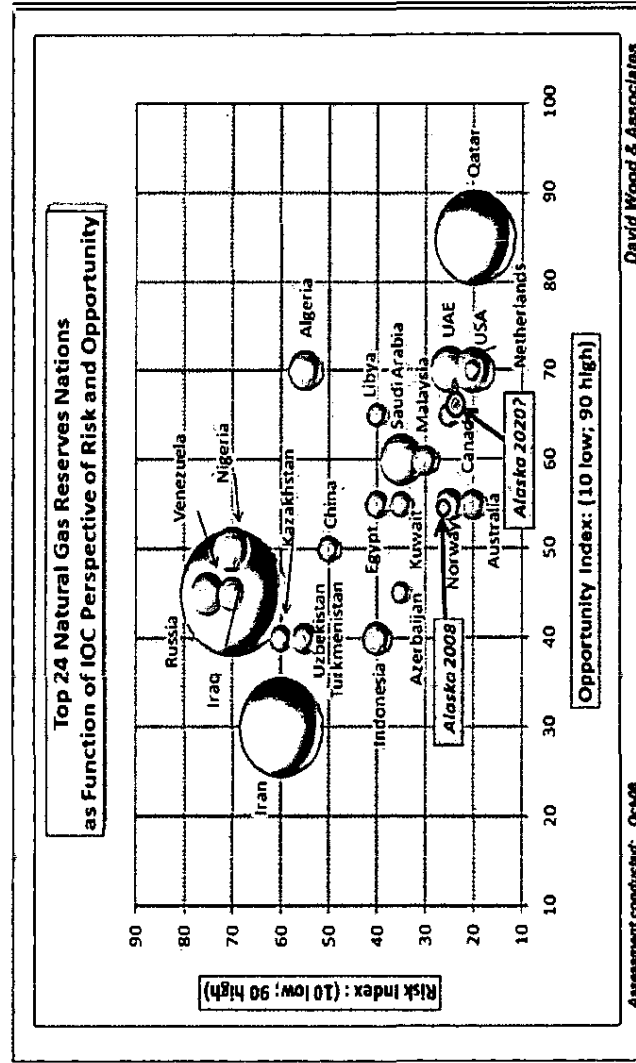
Australia operates a mineral interest system. Its fiscal take is above 70% and comparable to that of Alaska, but it is much more successful at securing investment and buyers for its high cost isolated gas resources.

- Australia has progressively shifted from traditional volume based royalty arrangements to the more progressive petroleum resource rent tax (PRRT)
- PRRT is levied at a rate of 40% of a project's taxable profit.
- PRRT payments are deductible for company income tax rate of 30%.
- PRRT is only payable once project cash flow basis achieves a rate of return of 5% over the long term bond rate on the development investments and 15% rate of return over the long term bond rate on exploration or risk capital investment. [This limit and cost uplift prevent PRRT becoming regressive]
- Explorations costs are uplifted at 15% (other costs uplifted at 5%) above long-term bond rate to partially compensate for time-value issues as there is a long lead time from discovery to positive cash flow.
- IOC majors committed in excess of \$20 bn investment in LNG projects in 2009.
- Long-term gas buyers in China and Japan now secured.

Alaska Gas Compared on International Scale of Risk versus Opportunity



The diameters of the bubbles are proportional to proved natural gas reserve holdings as reported by BP Statistical Review (June 2008).



Alaska marked on the framework from David Wood "Global perspectives required for risk, opportunity analyses." Oil & Gas Journal (9Feb, 2009).



Alaska's Prevailing Fiscal design

Schematic of Alaska's Prevailing Oil & Gas Fiscal Design

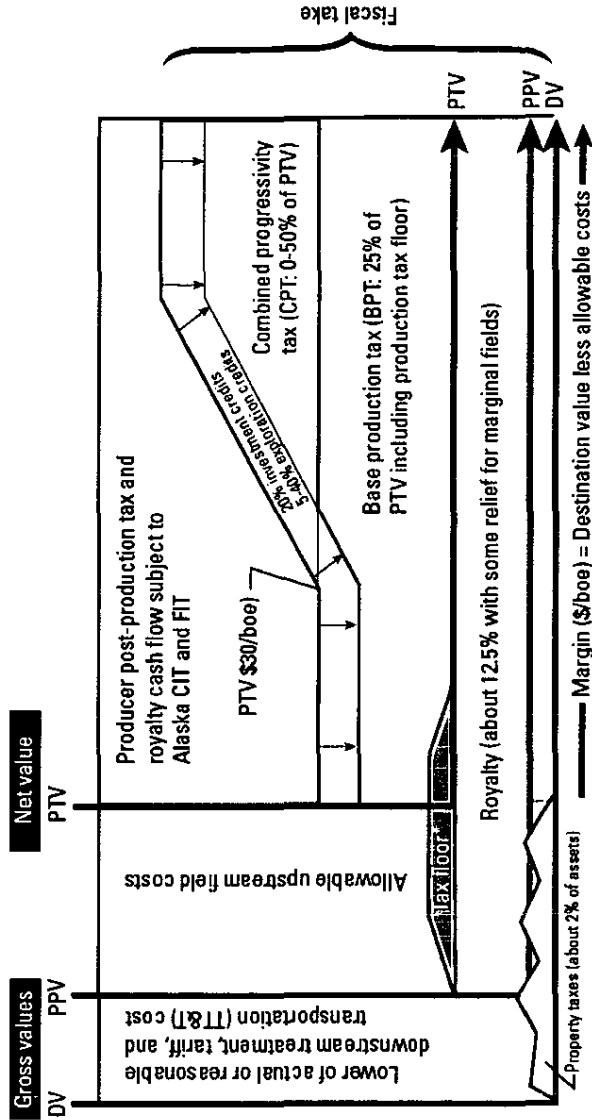


Dan Dickinson & David Wood, Oil & Gas Journal, May 2009

Destination value (DV) = volume x higher of price sold or market value

Point of production value (PPV) = DV - lower of actual or reasonable int. & T

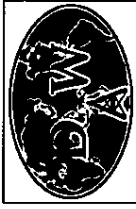
Production tax value (PTV) = PPV - allowable upstream field costs



24th February 2010

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Regressive & Progressive Elements of Alaska's Prevailing Oil & Gas Fiscal Design



Regressive fiscal elements	Progressive fiscal elements
<ul style="list-style-type: none"> • Property taxes are levied on assets in the upstream or TT&T services and shared between the state and local governments • Royalty is levied at point of production value (PPV) • *Tax floor refers to a production floor levied at 0-4% of PPV in place of BPT when that floor value is higher than the BPT value 	<ul style="list-style-type: none"> • Production taxes (BPT and CPT) are taxes paid on net value or margin • Progressivity component of production tax (CPT) commences at PTV of \$30/boe • Alaska corporate income tax (CIT) of 9.4% is levied on producer's worldwide income apportioned to Alaska. CIT is deductible from federal income tax (FIT)

Dan Dickinson & David Wood, Oil & Gas Journal, May 2009

Key Regressive Elements in Alaska's Prevailing Fiscal Design



There are three elements that make Alaska's prevailing fiscal design regressive.

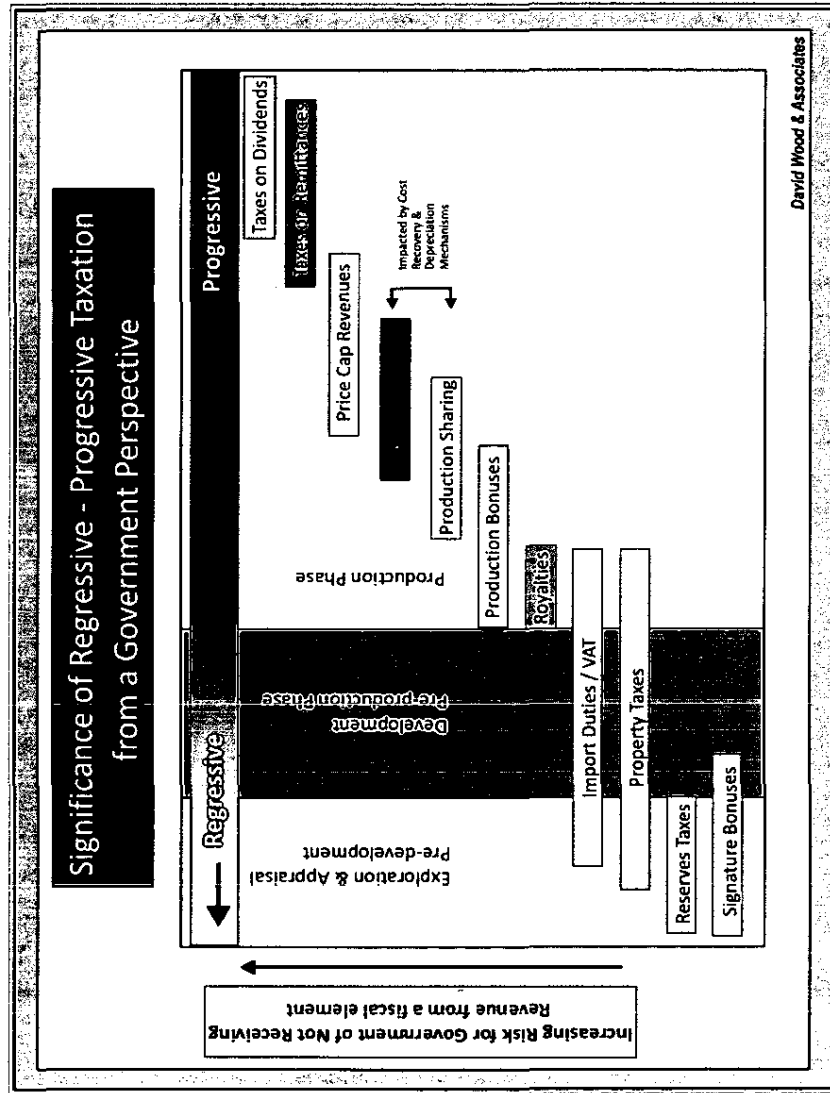
- Royalty
- Property Taxes
- Production Tax Floor

These regressive elements are partially offset by:

- Investment credits (exploration and development)
- Production taxes (levied after deduction of all allowable costs)
- Progressivity tax (only levied on high value streams)

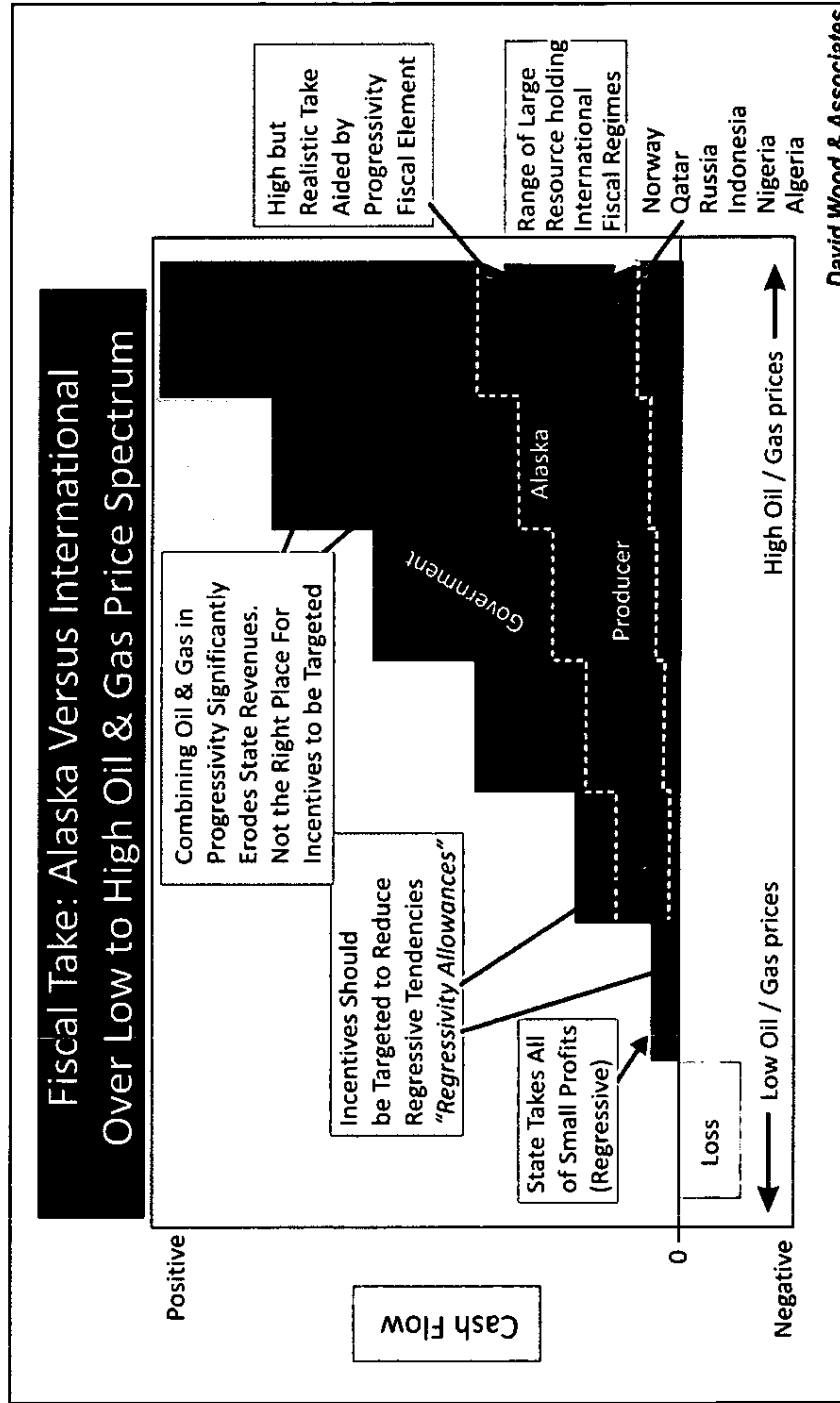
Other allowances / credits for producers should be considered to offset impacts of regressive elements coupled with tougher progressivity terms.

Progressive & Flexible Fiscal Designs Help to Promote Investment

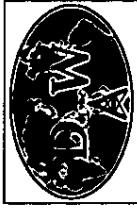


The stronger the commitment made by governments to promote a commercially attractive environment, the more likely investors are to commit investments without guarantees of fiscal stability.

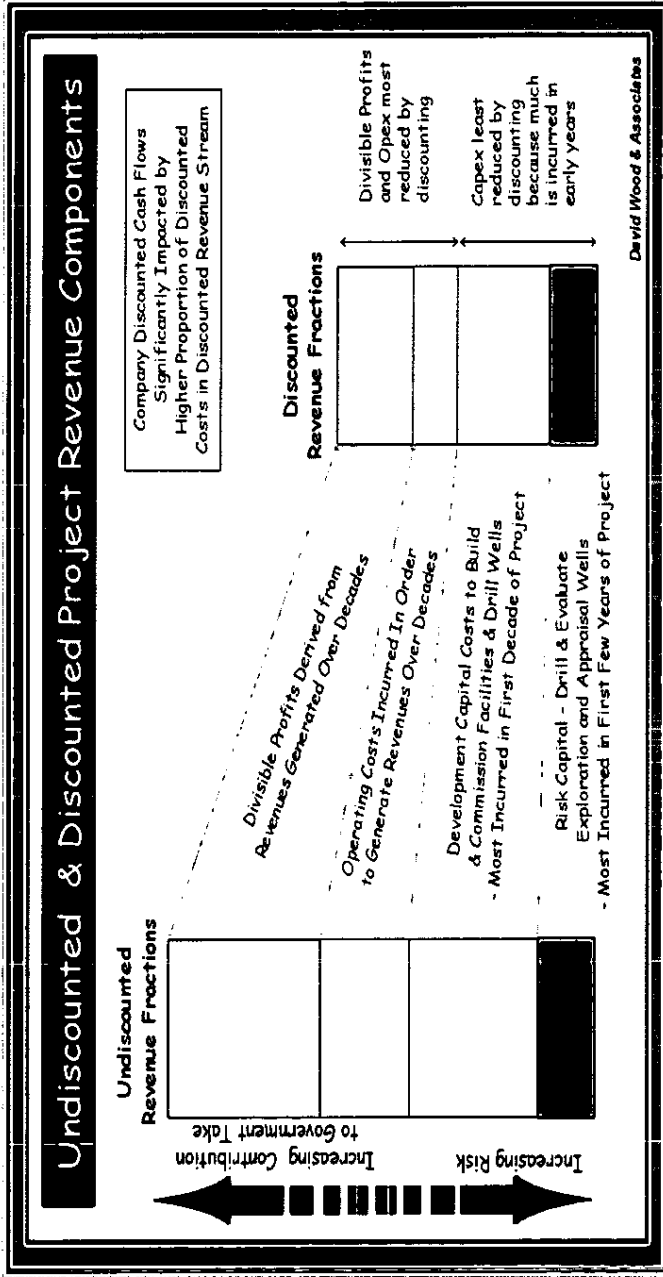
Progressivity Should Work Well For Alaska: It's the Regressive Elements that Need Relief



High Discount Rates Suggest Higher Government Take of Revenues



It is appropriate for governments to use lower discount rates than producers. However, high discount rates impact *long-term* divisible profits and operating costs more than upfront capital costs so diminish producer take.





Complications of combined oil and gas progressivity tax (CPT)

Problems with Alaska's Current Progressivity Tax from the Natural Gas Perspective



The models of a wide range of gas field sizes suggest three issues associated with calculating production tax values using a combined oil and gas (boe) revenue stream.

- Large gas production volumes contributing low value to high value oil production can dilute the PTV/boe and progressivity of the combined stream.
- The PTV / boe threshold (i.e., trigger point) at which progressivity tax becomes initially payable are set too high for natural gas.
- Tying the production tax floor to PPV can lead to regressive consequences for gas producers in high cost / low value conditions.

Impact of Natural Gas on Combined Oil & Gas Production Tax



Analysis has identified that three factors are relevant to the dilution effects under prevailing production tax paid by an existing oil- only case with the addition of gas production (and vice versa – i.e. oil added to a gas-only case). These factors are:

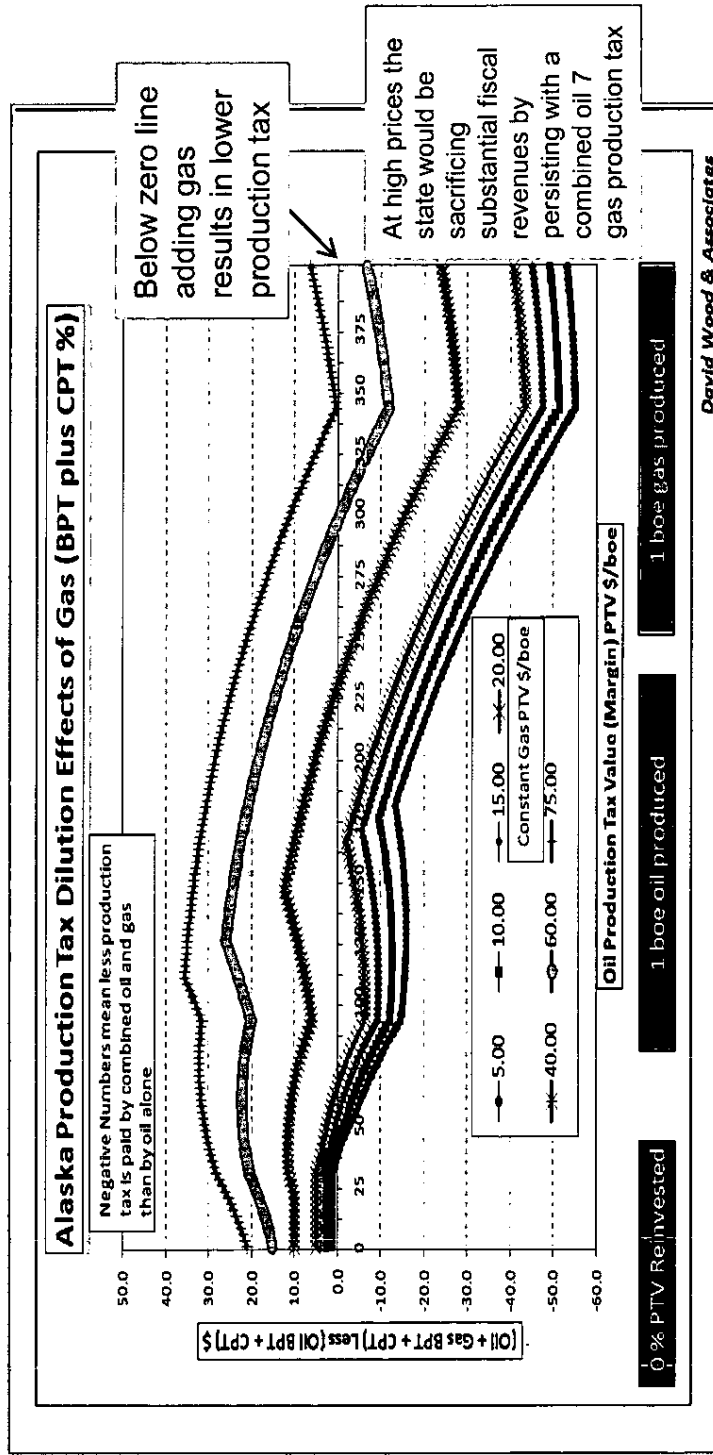
1. Magnitude of value differential between oil and gas streams (high oil value minus low gas value, or high gas value minus low oil value);
2. Relative volumes of oil and gas produced contributing to combined production tax boe stream.
3. Amount of PTV reinvested, which depending on the PTVs of each stream can have a significant impact

An Excel computer model has been developed to test these three factors.

Natural Gas Dilution Effects on Combined Oil & Gas Production Tax



The trends are non-linear with slope changes because of the changing gradients of the production tax progressivity mechanism (i.e. 0.4/boe to 0.1/boe) and the threshold values at which those changes occur.



Modifications Made to DOR Model to Calculate BOE



- (A) Oil: Gas Price Parity (Cell C3) and used that to calculate a gas price (\$ mmbtu) (cell A3)
- (B) Gas: Oil fraction per boe of production (cell A5)
- (C) Gas transportation cost (Cell A6)
- (D) The defined 6 mmbtu per boe from ACES (Cell F5)
These inputs are then used to recalculate:
- A boe destination price in cells C10 and D10 (rather than just oil price in DOR version)
- A boe transportation cost in cells C11 and D11 (rather than just oil price in DOR version)

Note: By setting A = 6 and B=0 the rest of the workbook calculates as it was presented by DOR (with corrections mentioned above). I have not reformatted the sheet but left it as per DOR's layout.

Case Combinations Evaluated with Modified DOR High-level Model



Variables			
Oil Price \$/barrel	Oil: Gas		Fraction Gas: Oil (0 to 1)
	Price Parity (X:1)	Price Parity (X:1)	
20	2		0.0
40	4		0.1
60	6		0.2
80	8		0.3
100	10		0.4
120	12		0.5
140	14		0.6
160	16		0.7
180	18		0.8
200	20		0.9
300	30		1.0
Base Case			
85	6		0.5

In this modified form the workbook can be used to model the impacts of oil and gas streams of various proportions and price parities using DOR's high-level Alaska tax methodology.

The input data for the three key variables used can be varied by changing the values in the new table located in cell range C46:E60, which can be set to a user's preference.

A macro then evaluates and records selected outputs for all oil and gas scenarios.

Macro Calculates Large Number of Price Parity and Gas Fraction Cases Rapidly



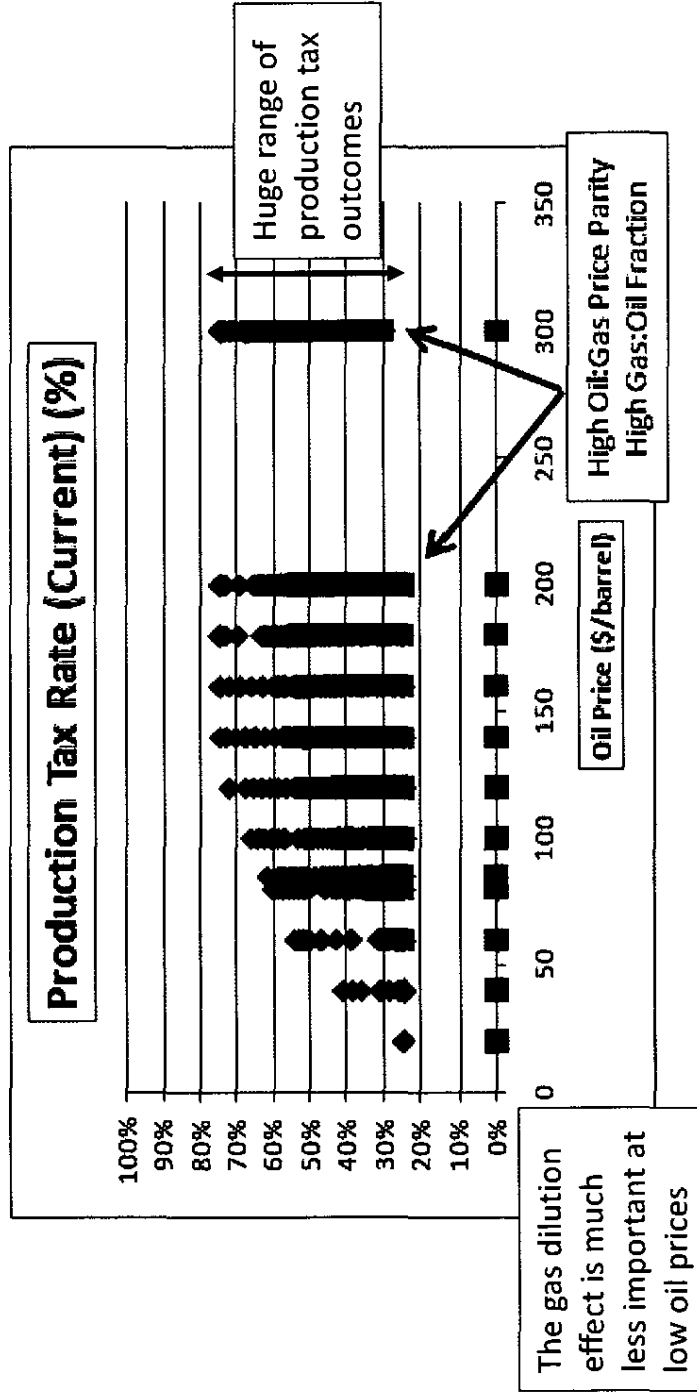
For the 12 X 12 X 12 input matrix the macro calculates 1728 values for each output variable recorded (more than 20000 values for 12 variables recorded). The macro places the recorded data into a table for analysis.

- For current and modified terms the macro records:
 - Production Tax Rate % from cell C25 on sheet Calc
 - Production Tax Value \$/boe from cell C29 on sheet Calc
 - Producer's Take Rate from cell C42 on sheet Calc
 - Producer's Total Value \$/boe from cell C37 on sheet Calc
 - State Take Rate % from cell C39 on sheet Calc
 - State Total Value \$/boe from cell C33 on sheet Calc

Production Tax Rate Analysis for 1728 Macro Scenarios for Combining Oil and Gas



The red squares are the cases in which oil:gas price parity is >10 and gas:oil fraction of production mix is >0.5 on a boe basis.



Conclusions from Combined Oil & Gas Production Tax Model



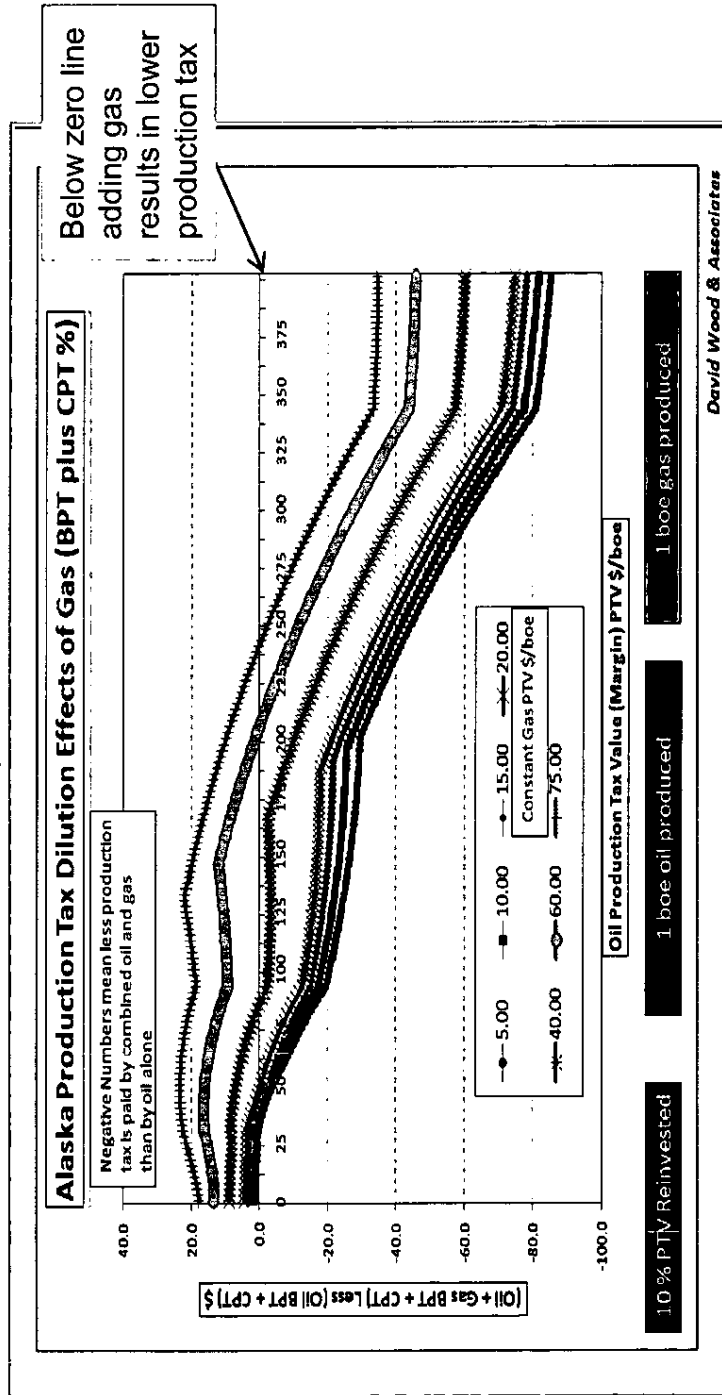
For the 12 X 12 X 12 input matrix the macro calculates 1728 values for each output variable recorded (more than 20000 values for 12 variables recorded). The macro places the recorded data into a table for analysis.

- It would be more stable to calculate Alaska's oil and gas production taxes separately and avoid boe complications particularly as oil : gas price ratio is unpredictable
- The dilution effect of gas should not be treated as a fiscal incentive as it is unpredictable in its impact
- Significant fiscal benefits of occasional price spikes on high production tax for gas or oil could be lost by persisting with a boe basis or combined calculation of the production tax value.

Natural Gas Production Tax Dilution Effects Impacted by Reinvestment



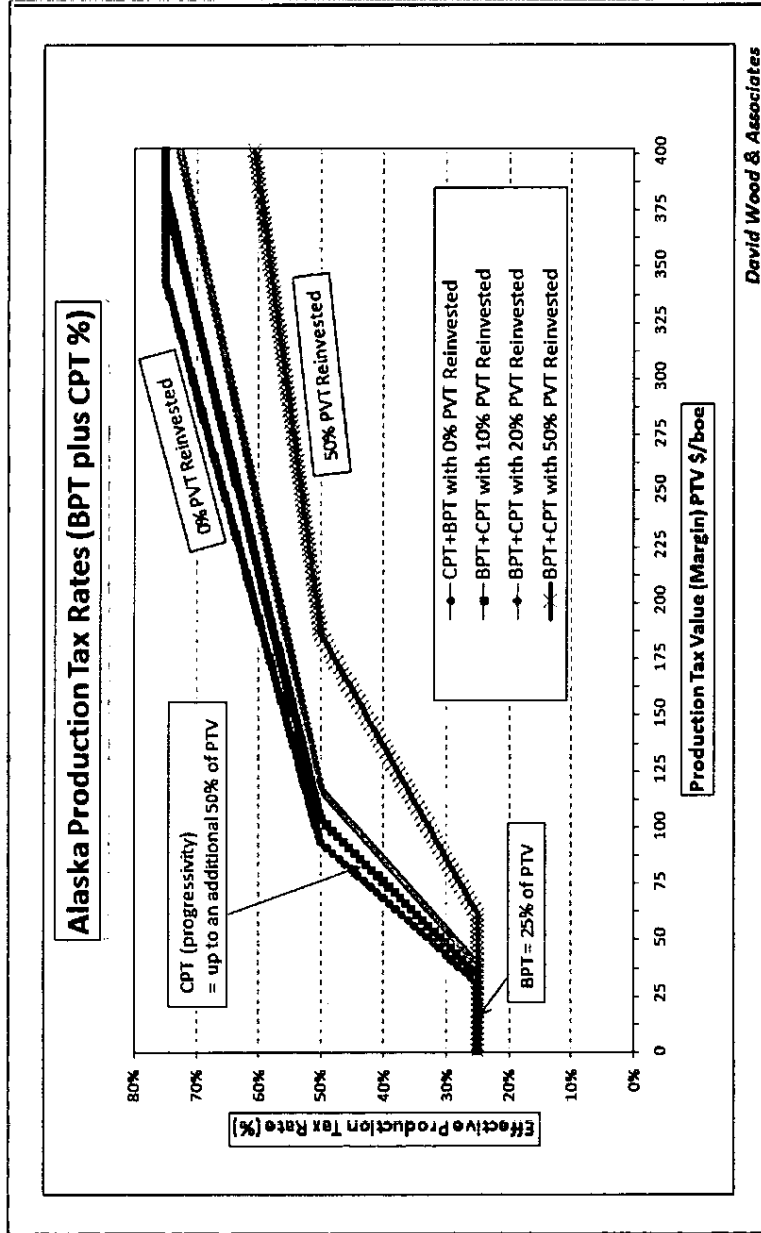
If some of the PTV is reinvested the reduction in production tax paid is significantly greater. This graph shows the impact of 10% reinvestment. [Model results presented in January 2009].



Natural Gas Production Tax Dilution Different Reinvestment Scenarios



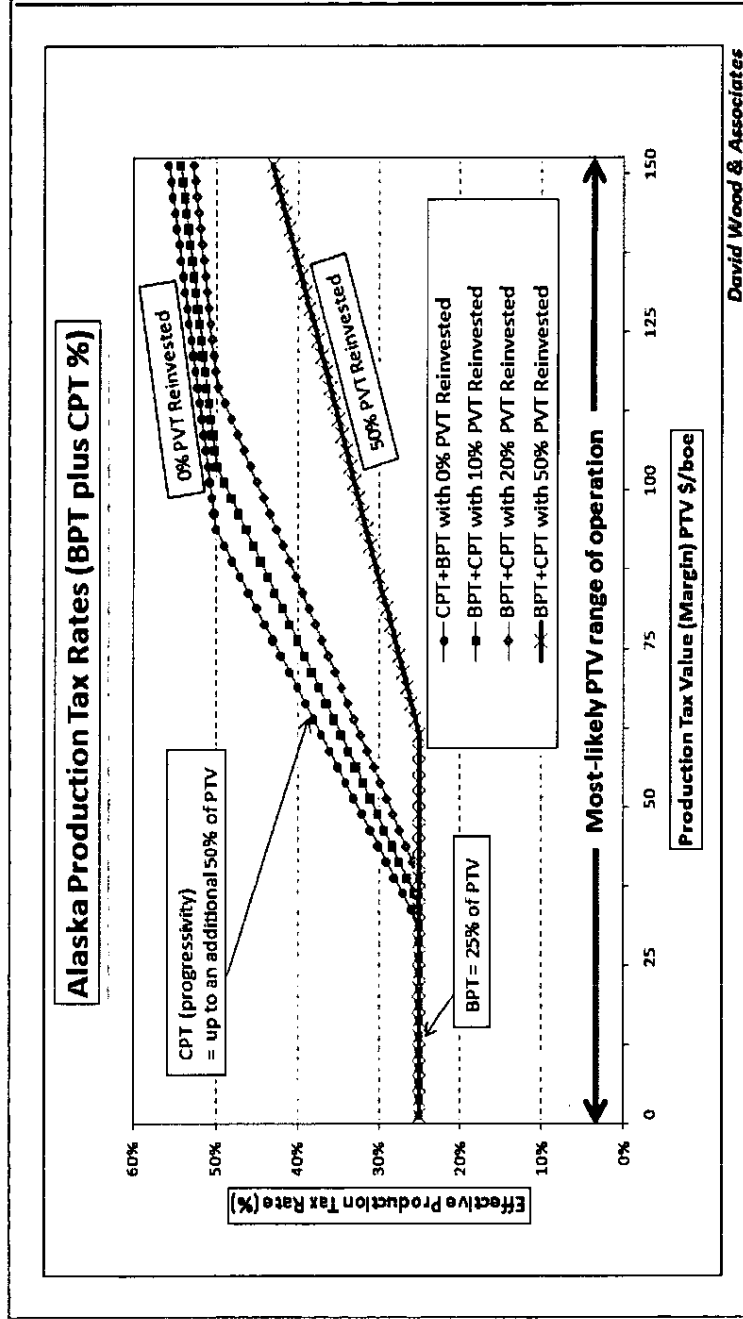
The impact of several reinvestment scenarios – 0%, 10%, 20% and 50% of PTV - on production tax rates are illustrated in this graphic.



Reinvestment Scenarios For PTV Range \$30/boe to \$150/boe



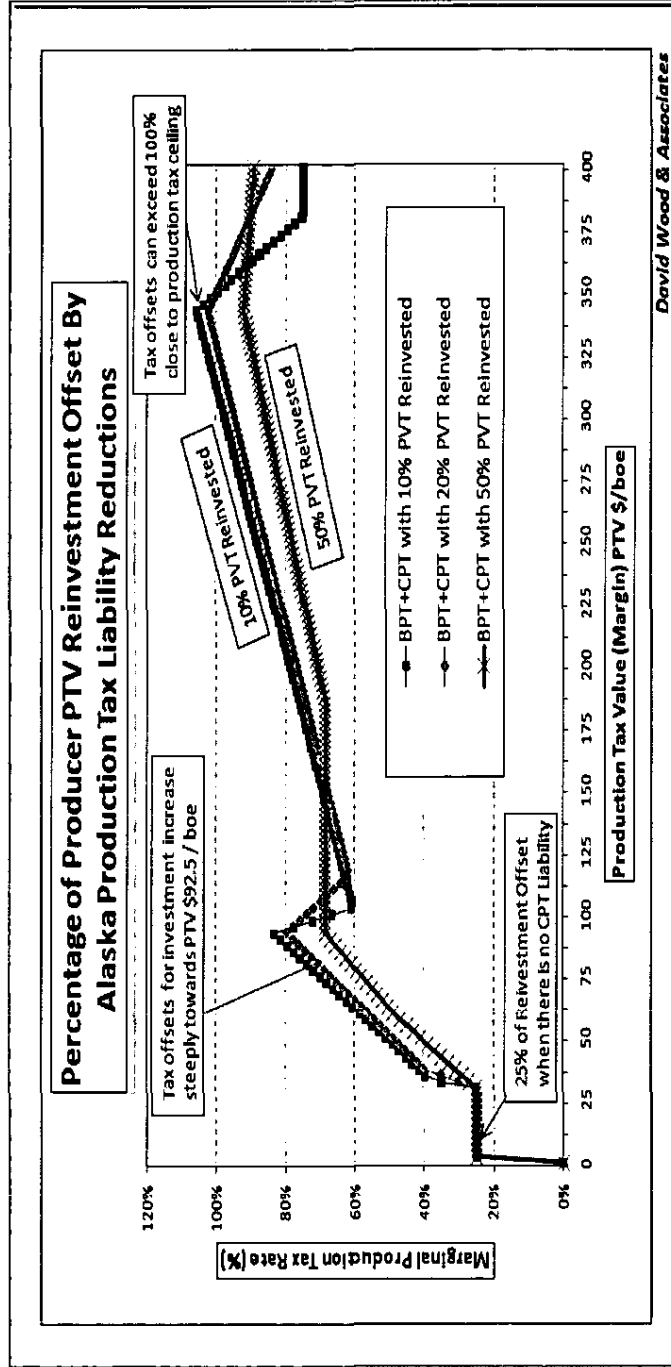
For example production tax rate can be reduced from 49% to 42% at PTV \$90/boe by reinvesting 20% of the PTV.



Marginal Production Tax Rates Seen by a Producer for Reinvestment Dollars



The vertical axis shows the percentage tax reduction associated with the incremental re-investment (or the marginal tax rate offset by the producer by its reinvestment). Note the peak around PTV\$90/boe and values above 100% at PTV \$350/boe plus multiple crossover points.



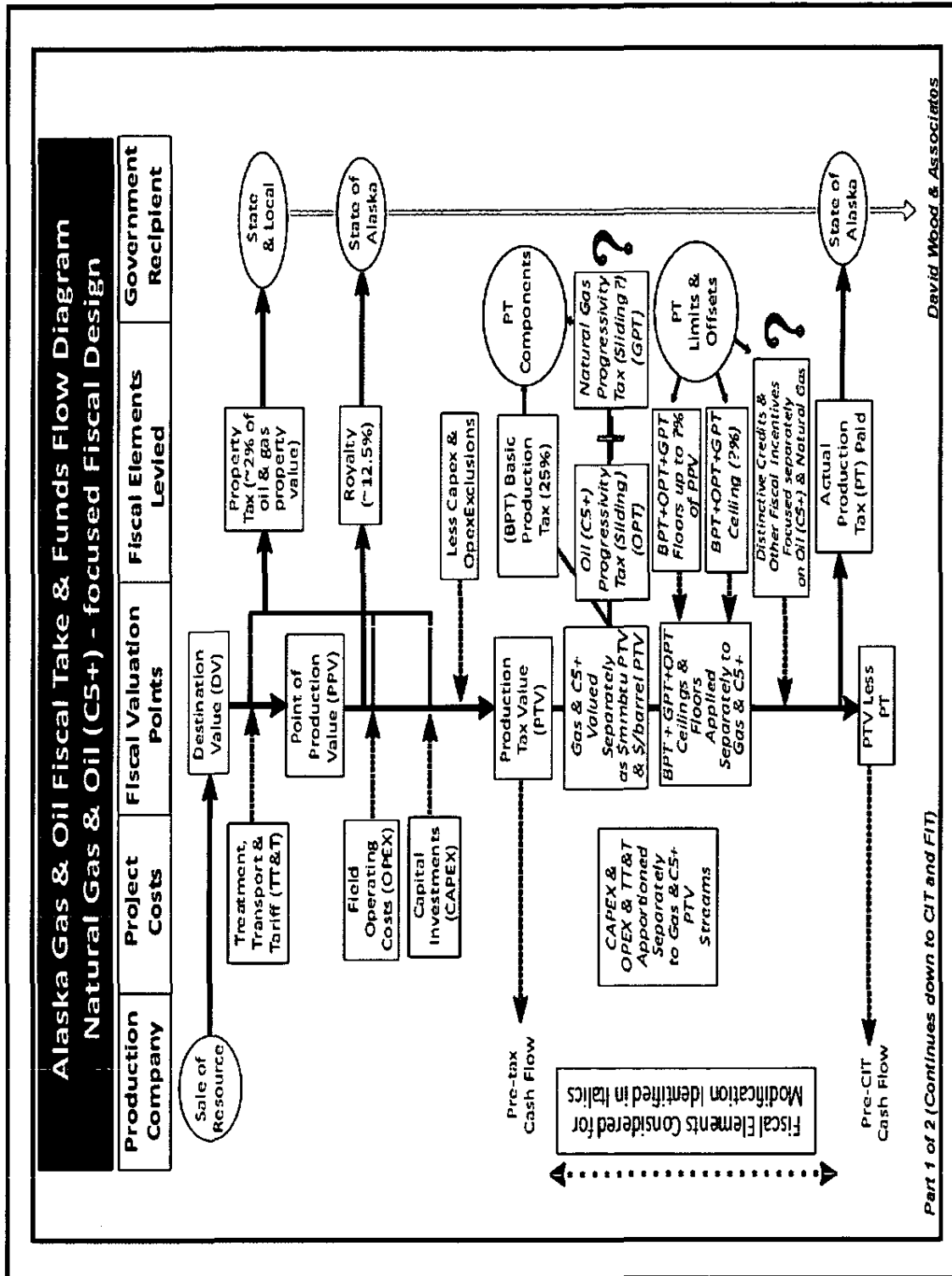
David Wood & Associates

Implications of Combined Oil & Gas Production Tax Analysis



The analysis suggests that the prevailing production tax system has the following complications to address:

1. It is difficult to predict (from tax authority & producer perspectives) and relationships between oil and gas tax liabilities are non-linear;
2. The magnitude of combined production tax impact caused by adding a gas production stream varies with relative oil and gas PTVs, oil and gas volumes and percentage of PTV re-invested;
3. Without detailed analysis (and speculative forecasting of oil and gas prices and boe contributions) Alaska's production tax outcomes can be counterintuitive (e.g. higher prices can lead to lower tax revenues collected by the State in some scenarios).



Alternative Drivers of Gas Progressivity Tax Evaluated by Fiscal Model



Ten different mechanisms are evaluated. No.1 represents the status quo evaluating gas progressivity as a combined revenue stream with oil (boe) were reviewed in December 2008 report to legislature.

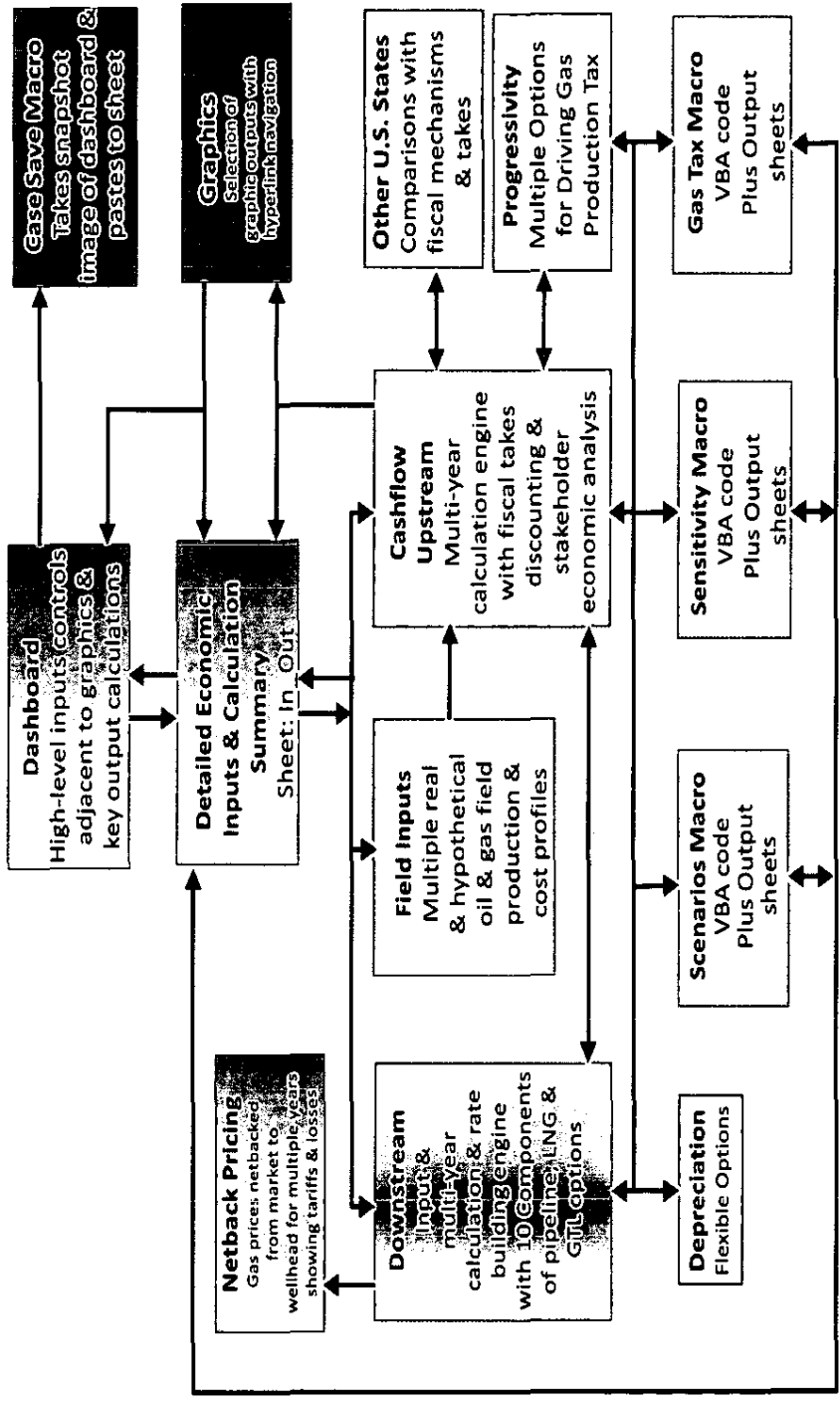
1. CPT: 2008 Rules (combined PTV/boe)
2. GPT / OPT: separates gas and oil on PTV/boe scale ← The easiest first step
3. GPT / OPT: progressivity applied to only 33% of gas PTV
4. GPT: Gas PTV (based on Gas PTV / mmbtu)
5. GPT: R-Factor (cumulative PPV less royalty/cumulative gas costs)
6. GPT: IRR (Investor's Rate of Return of cumulative PTV)
7. GPT: Cumulative gas reserves produced
8. GPT: Annual gas production volumes
9. GPT: Cumulative gas PTV
10. GPT: Mechanism #9 plus allowances to counter regressive elements



Multi-year and multi-scenario fiscal
Integrated upstream & downstream
performance cash flow model

AGFM – Alaska Gas Fiscal Model

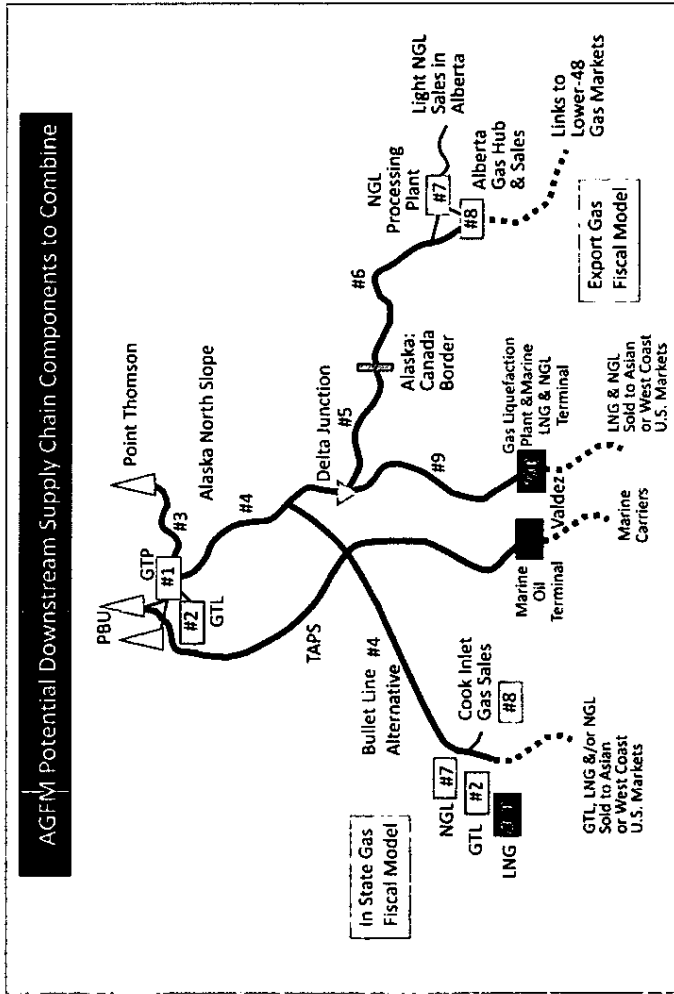
**Alaska Gas Fiscal Model (AGFM) -
Excel Workbook Structure
David Wood & Dan Dickinson -2009**



AGFM Now Extended to Evaluate In-state Gas Scenarios



The ten components are selected by entering "1" and de-selected by entering "0" on AGFM's dashboard.



Components "1", "2", "4", "7", "8" and "10" can be reconfigured to model gas export routes or to model In-State "Bullet Line" gas supply to Cook Inlet with optional NGL, GTL and / or LNG plants placed there for exports.

Dashboard Control Sheet: High-level Controls: Spinners & Graphics



Ctrl#	Ctrl#
11	11
1	1
6.00	6.00
2.00%	2.00%
60.0	60.0
2.00%	2.00%
2.00%	2.00%
1.00%	1.00%
100.0%	100.0%
100.0%	100.0%
5.00%	5.00%
10.00%	10.00%
12.50%	12.50%
25.00%	25.00%
20.00%	20.00%
0	0
0	0
8	8
0.175	0.175
-0.900	-0.900
0.882	0.882
0.086	0.086
11.00	11.00
2	2
2.000	2.000

Save Dashboard Image

The model calculates money of day and real values

Key Assumptions

Analyse Field # (1 to 20)

Input Option 1=A, 2=B or 3=C (see Fields B6)

1-A is default for selecting individual fields

Gas Destination Price, Year 0 (\$/mmbtu)

Gas Price Nominal Escalator (%/yr)

Oil (C5+) Destination Price, Year 0 (\$/barrel)

Oil (C5+) Price Nominal Escalator (%/yr)

Cost Nominal Escalator (%/Yr)

Buying Power Inflation / Deflator

Capital Costs Sensitivity Adjuster (%)

TT&T Costs Sensitivity Adjuster (%)

Operating Costs Sensitivity Adjuster (%)

Government Nominal Discount Rate (%)

Producer Nominal Discount Rate (%)

Royalty (%)

Base Production Tax (%)

Investment credits (%)

CPT or Separate Mechanism used (0=CPT)

GPT & OPT Mechanisms (0 = CPT rates)

Alternative Progressivity Mechanism (3 to 10)

Entry Tariff to Alberta gas hub SCAD/btu (Year 0):

AECO to Henry Hub Differential (US\$/mmbtu)

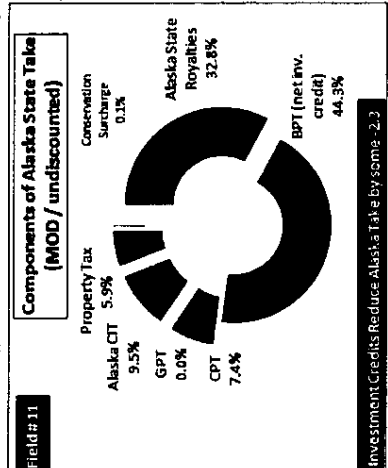
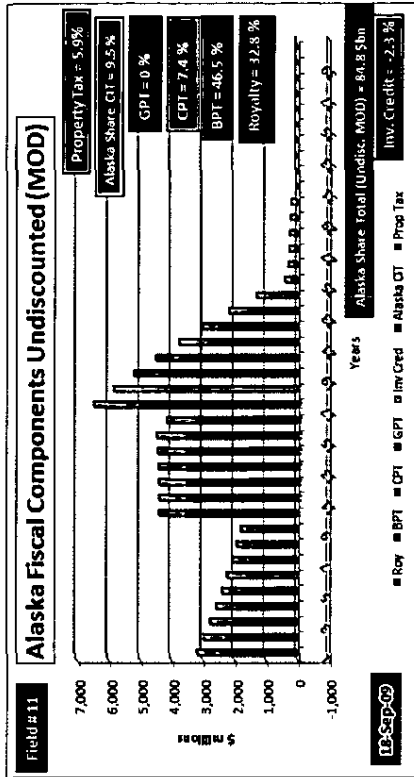
CAD per USD exchange rate

Price Premium to Rich Gas (US\$/mmbtu)

Rich gas has energy content > btu/cf

Alternative AECO Gas Pricing (1 to 4; 2=base)

ANSWC to WTI Oil Price Differential (US\$ / barrel)



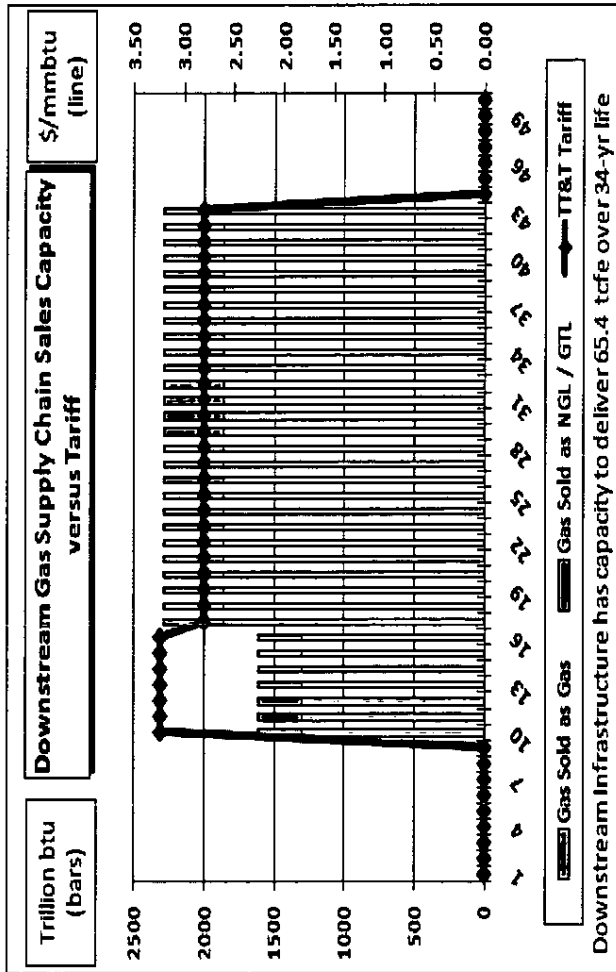
MOD	Cashflow	64.9%	35.1%
MOD NPV @ 5 %	64.8%	35.2%	
MOD NPV @ 10 %	64.9%	35.1%	

Fiscal Elements	\$ millions
Royalties	27,822
BPT (net inv. credit)	37,546
CPT	6,299
GPI	0
Alaska CIT	8,070
Property Tax	5,028
Conservation Surcharge	61
Alaska Totals	84,826
Max Oil/Gas Price Ratio Undiscounted and MOD	10.0

Dashboard Control Sheet: Dynamic Graphics & Summary Results



Avg. MOD Revenue / unit gas & NGL (\$/millions btu sold)	12.08
Avg. Tariff for T & T / unit gas & NGL (\$/millions btu sold)	2.87
Alaska Downstream Property Tax (\$/btu sold at capacity)	0.14
Alaska Income Tax Downstream (\$/btu sold at capacity)	0.07
Federal Income Tax Downstream (\$/btu sold at capacity)	0.25



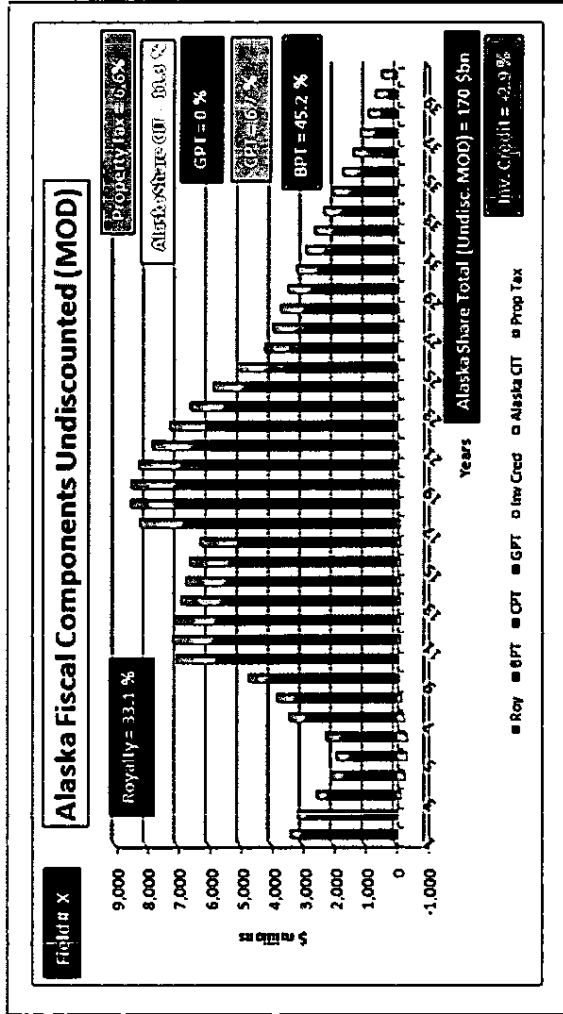
This graphic sits adjacent to the supply chain selection and definition table and responds immediately to changes.

Note the graph shown highlights the start of supply chain, its expansion, gas plus NGL capacities and the multi-year tariff calculated.

Contributions of Each Fiscal Element to Alaska's Take for Total North Slope (#11 -#14)



The relative contributions to Alaska's fiscal take for price scenario 1 and an *Pipeline* supply chain for the *proved gas reserves* combination of *North Slope fields* shows that gas production would ramp-up in stages, but proven reserves would not fill expanded capacity for more than 3 years.



There are many factors that can be varied in such combination scenarios. For example timing of each field coming on stream and capacity and timing of the gas supply chain infrastructure.

Alaska North Slope Production & Reserves are Dominated by Three Corporations



For fiscal analysis it is important to be able to model the expected fiscal returns from specific corporations. AGFM facilitates this by enabling percentage fractions of individual fields to be combined in a user definition area on sheet Fields.

Company Holdings of Major North Slope Fields			
1	2	3	Field
36.40%	26.36%	36.08%	Prudhoe Bay Field#11
52.88%	29.19%	2.82%	Point Thomson Field#12
0.98%	39.03%	55.04%	Kuparuk Field#13
Exxon Mobil	BP	ConocoPhillips	

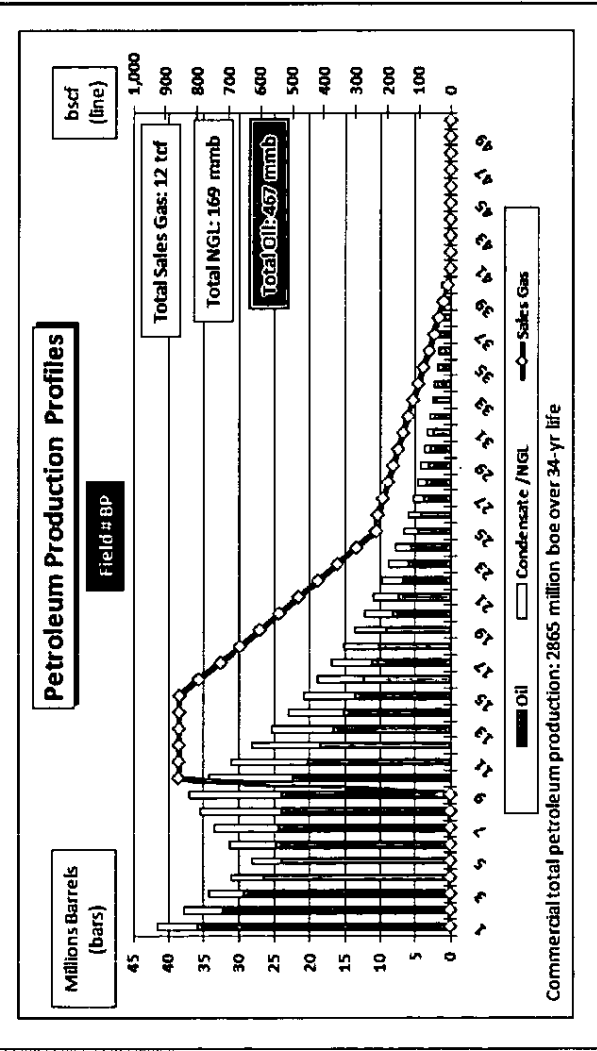
Three North Slope fields contain most of North Slope proved gas reserves.

By applying the corporate working interests to those fields a profile for each company can be approximated.

Alaska North Slope Production Profiles Forecast by AGFM for BP



AGFM can be set up to apply corporate interests to the field data to approximate the position of a specific corporation. In this case combining "BP's interests" in Fields #11, #12 and #13 the major North Slope Analogues. [Note input assumptions are based on public domain data. In evaluating appropriate fiscal designs in the absence of data assumptions will be necessary]



These corporate profiles can be analysed in a similar way by AGFM to individual fields.

These forecasts are dependent on the assumptions and input made for the individual fields and supply chains, but are useful for indicative fiscal design evaluations.

Hypothetical Field Cases Evaluated



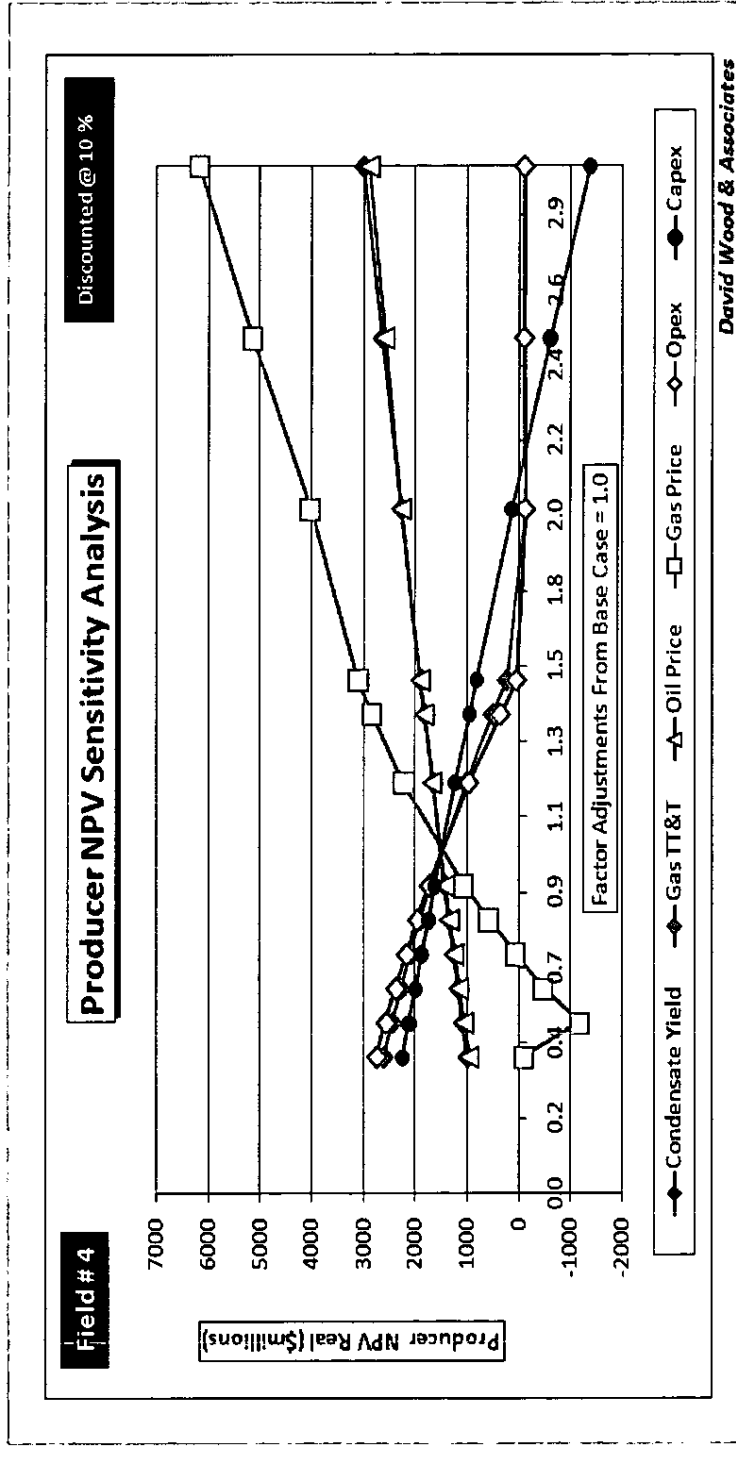
Five non-associated natural gas fields and five oil fields with associated gas were constructed to use with a multi-year fiscal model built in Excel.

- The natural gas fields (#1 to #5) range in reserve size from 500 bcf to 10tcf.
- The oil fields (#6 to #10) vary in reserve size from 28 mmb (with 20 bcf of associated gas) to 500 mmb (with 690 bcf of associated gas).
- The fields display a wide range of production and cost profiles.
- Base cases for each model field tested with wide ranging sensitivity cases.
- Base case assumptions applied: Year 0 gas price: \$7.5 / mmbtu; Year 0 oil price: \$80 / barrel; nominal inflation 2% / year. The model allows these and the sensitivities to be changed easily and quickly.

Sensitivity of Alaska Gas Field to Project & Market Variables



Economic performance of a gas field development from a producer's perspective for a large gas field under the prevailing Alaska fiscal system.



Base Case Hypothetical Field Models Reveal High-level Implications for Government Take



Government take includes Alaska state take and federal government take. The models apply the prevailing Alaska fiscal design and some base case assumptions.

- For stand-alone oil fields (with associated gas):
 - Government take of destination value (gross) is about 60%
 - Government take of destination value less costs (net) is about 75%

- For stand-alone natural gas fields (non-associated gas with NGLs):
 - Government take of destination value (gross) is about 30%
 - Government take of destination value less costs (net) is about 67%

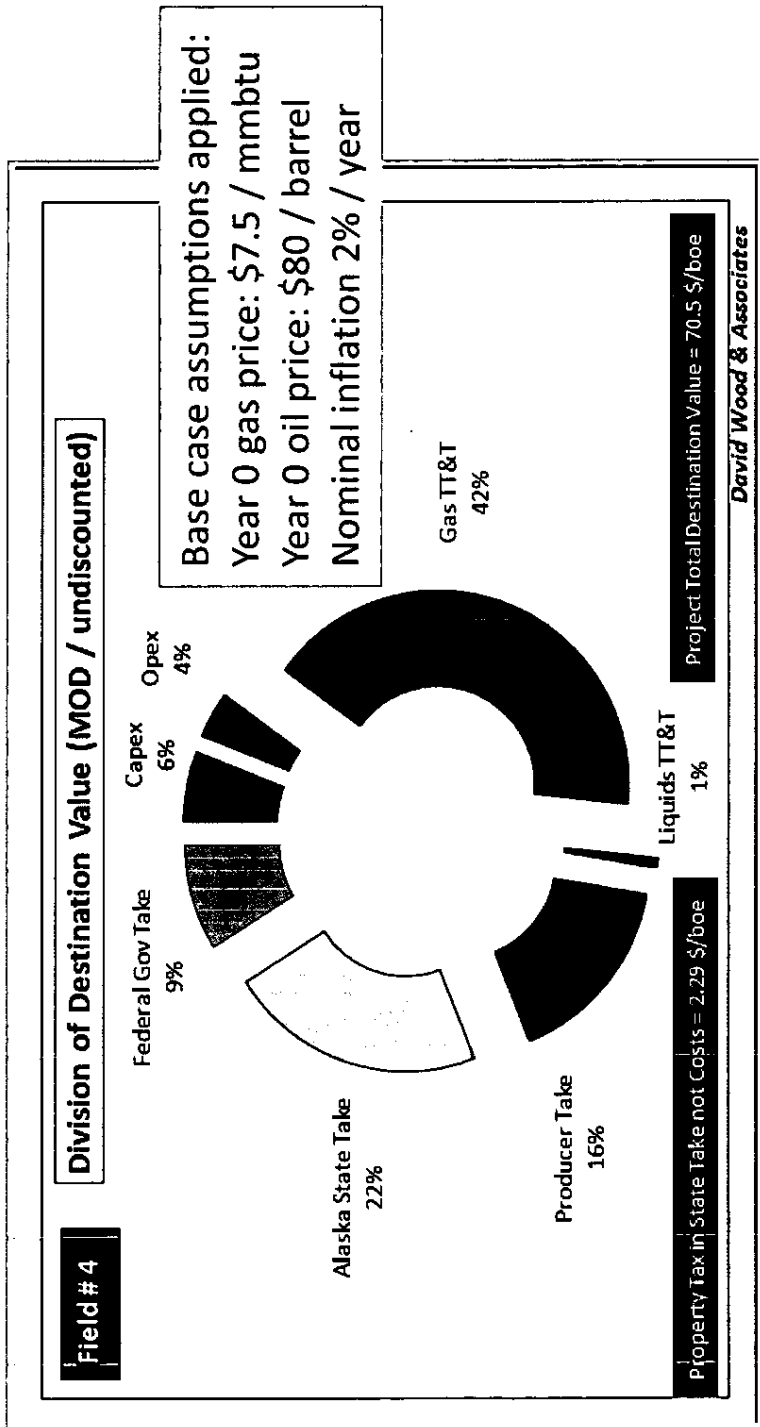
- Exact percentages vary with field sizes, prices and costs.

- Large producers with portfolios of legacy fields under the current system aggregate oil and gas and can see reduced government take.



Large Gas Field: Division of Destination Value

For gas fields of various size (5 tcf shown here) gas TT&T takes the largest share of destination value. Alaska takes some 22% of destination value.

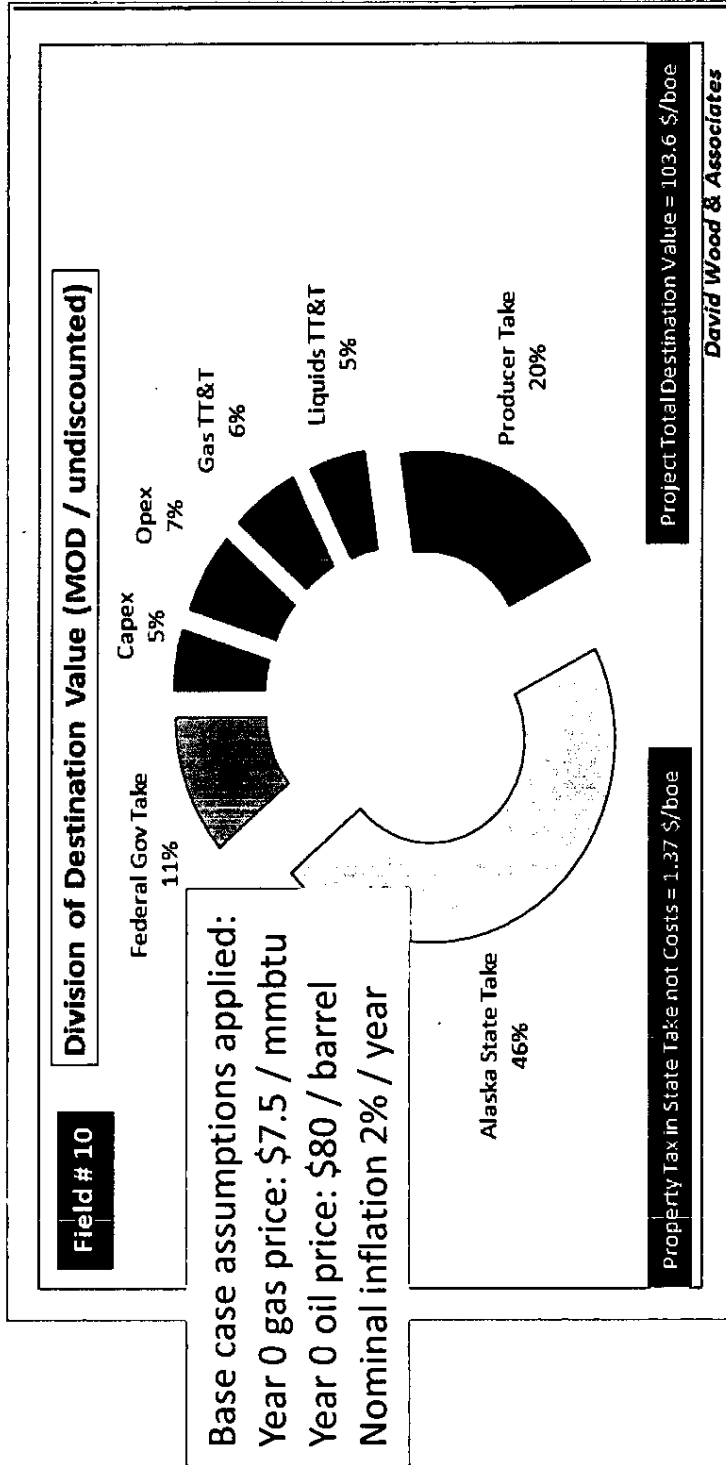


Large Oil Field:

Division of Destination Value



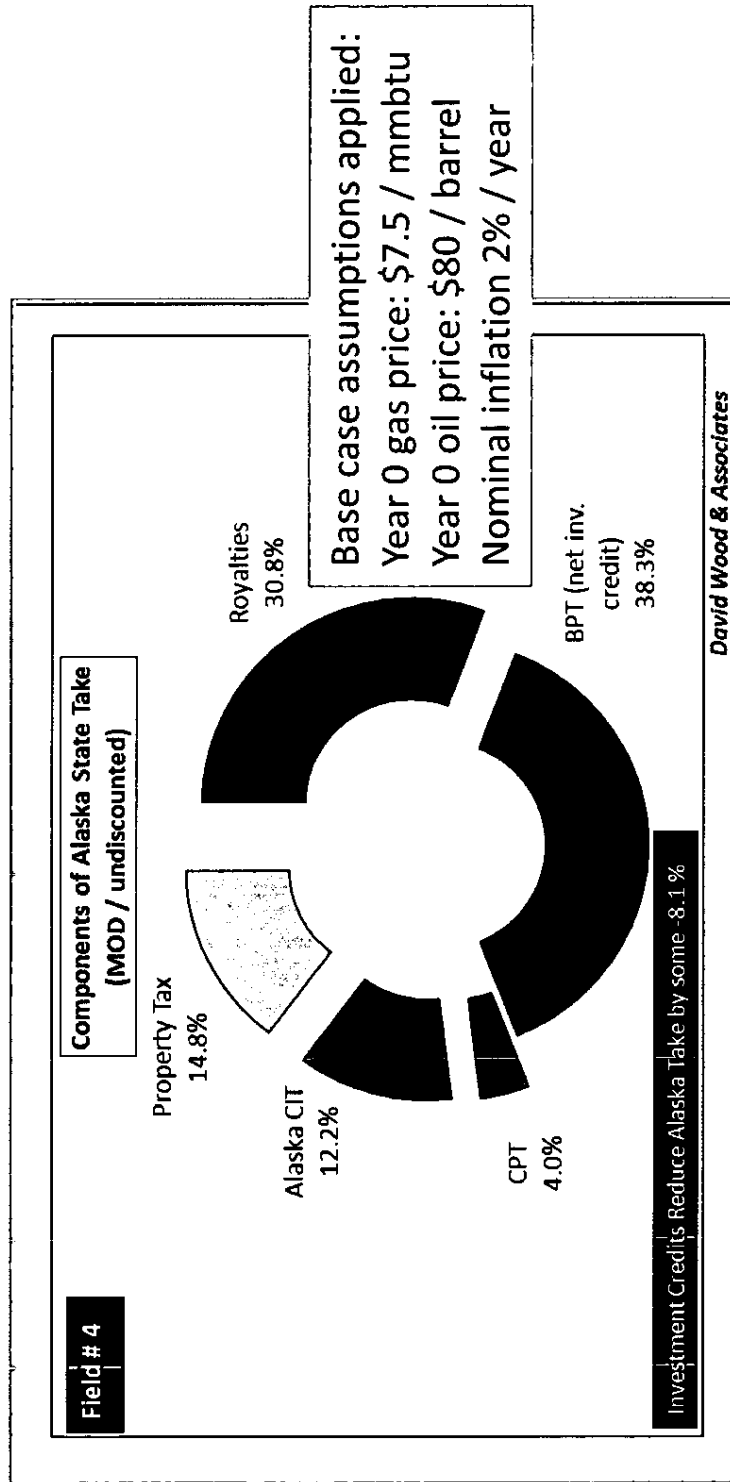
For oil fields of various size (500 mmb shown here) costs are less significant than for gas. Alaska takes some 46% of destination value.



Components of Alaska State Take for Large Gas Field



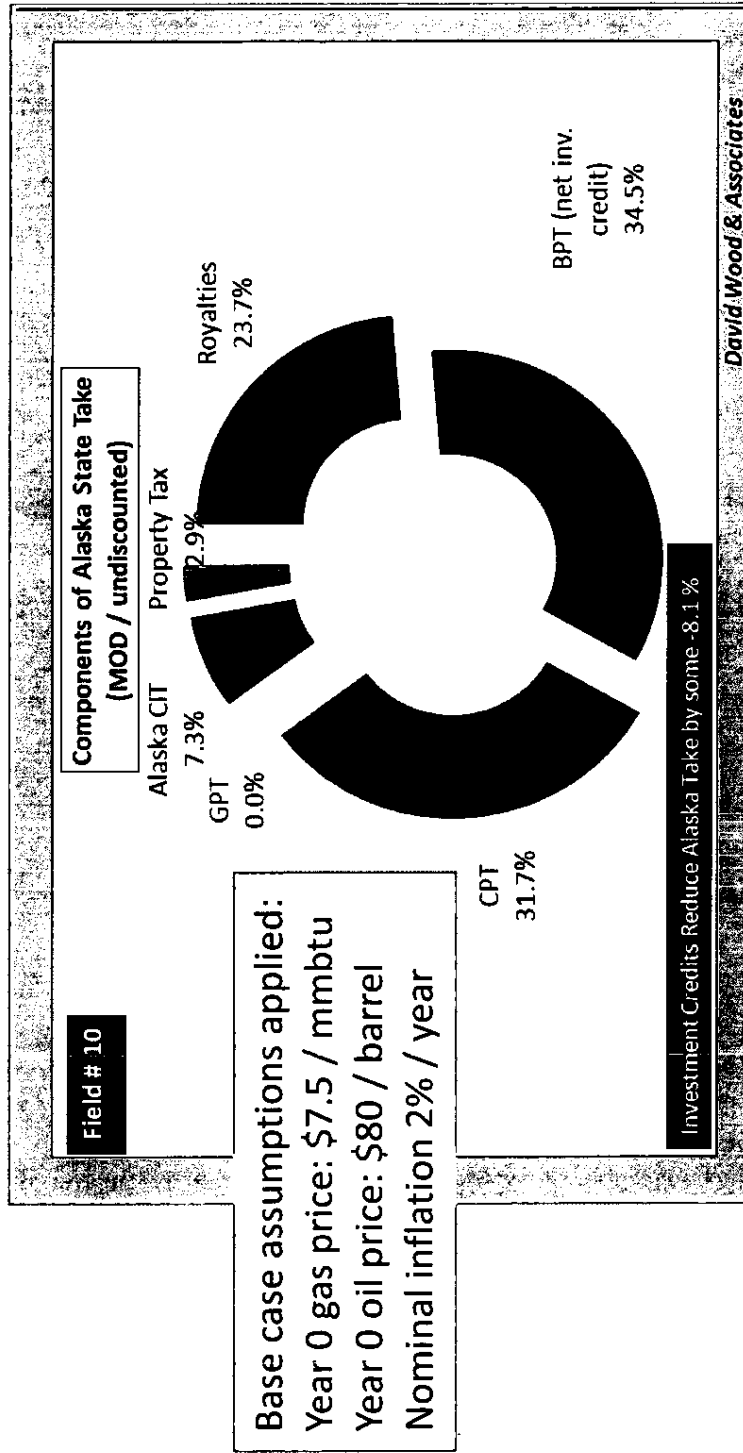
Royalties and basic production tax account for two-thirds of Alaska state take for this 5 tcf field. Base case price and cost assumptions applied.



Components of Alaska State Take for Large Oil Field



Basic production tax and combined progressive tax account for two-thirds of Alaska state take for this 500 mmb oil field.





Conclusions & Recommendations

Approaches to Fiscal Design that Can Improve Performance & Credibility



The following are selected recommendations for Alaska from my December 2008 report for the Legislature:

- Develop a clear statement of fiscal strategy and objectives
- Focus on a simple, flexible and progressive fiscal design
- Some level of fiscal stability important to secure investment
- Such designs could be more effective than contractual guarantees
- *Drive progressivity fiscal elements for gas with gas PTV (not boe)*
- Consider return on investment drivers for progressivity taxes
- Combine progressivity tax with allowances to offset regressive elements
- Aim to clarify and optimize fiscal revenue streams from NGLs
- Consider state equity involvement in strategic infrastructure projects
- Promote cost disclosure and control with some fiscal incentives
- Apply time constraints to new leases to develop resources

David Wood – Biography

Dr. David Wood has more than 30 years of international oil and gas experience spanning commercial, fiscal and technical functions within the exploration and production sector, holding senior corporate, strategic and operational management positions.

His industry experience includes working with government agencies, national oil companies, major and independent oil and gas operators in most continents, including long-term postings in the Middle East and South America. This has provided him with a broad insight to commercial and technical issues along international oil, gas and energy supply chains.

David now works as an independent international consultant and expert witness. He has published an extensive body of work on energy related topics including: performance modelling of fiscal terms, economic analysis, enterprise risk and portfolio simulation, LNG, GTL and gas supply, deepwater exploration and production techniques, corporate performance, portfolio and strategy management, mergers and acquisitions, negotiations & project management. He is actively involved in energy consulting, professional training, research and development programmes. He is a member of the Energy Institute (UK) and the Petroleum Exploration Society of Great Britain and associate editor of the Journal of Natural Gas Science & Engineering.

19

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

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FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM

February 22, 2010

SUBJECT: Gas production tax limitation in AS 43.90.320
(Work Order No. 26-LS1526)

TO: Senator Tom Wagoner

FROM: Donald M. Bullock Jr.
Legislative Counsel

You asked to what extent is the state bound by the tax exemption in AS 43.90.320.¹ The exemption in that section is offered to producers that commit to acquire firm transportation capacity in the first binding open season of the gas pipeline project license under AS 43.90 (Alaska Gasline Inducement Act, "AGIA").

The exemption in AS 43.90.320 is statutory and not contractual. Under article IX, sec. 1 of the Alaska constitution, the state may not contract away its taxing authority except as otherwise provided in article IX. Article IX, sec. 4 authorizes the legislature to grant exemptions from tax "by law." The tax exemption in AS 43.90.320 is granted by law, but as a law, is subject to amendment or repeal by the legislature.²

¹ The amount of the exemption is described in AS 43.90.320(a), which reads as follows:

(a) If a person qualified for a resource inducement under AS 43.90.300 agrees under (c) of this section, the person is entitled to *an annual exemption from the state's gas production tax in an amount equal to the difference between the amount of the person's gas production tax obligation calculated under the gas production tax in effect during that tax year and the amount of the person's gas production tax obligation calculated under the gas production tax in effect at the start of the first binding open season held under this chapter. If the difference is less than zero, the gas production tax exemption is zero.*

(Emphasis added.)

² As you are aware, the legislature has faced the issue of whether a contractual limitation on oil and gas production taxes is permissible under the state constitution. If such a contract were allowed under article IX, the legislature could not pass a law that impaired the obligations of that contract because of the prohibition in article 1, sec. 15. In

While a person offered the exemption may reasonably expect that the legislature would allow the exemption to continue during the specific 10-year period described in AS 43.90.320(b), the continuation of the exemption is subject to legislative discretion. A similar statutory tax incentive was offered in AS 43.55.011(b) (repealed, sec. 34, ch. 2, TSSLA 2006), in which new oil production was taxed at the rate of 12.25 percent of the gross value at the point of production for the first five years, and 15 percent thereafter. That tax incentive was in place from its enactment in 1981 until its repeal in 2006.

Although the exemption in AS 43.90.320 is offered to producers, a change in the law that reduces the value of the inducement may affect the license agreement with the AGIA licensee. The state and the AGIA licensee have a contract under which, in return for commitments and costs incurred by the licensee to develop the pipeline project, the state shares the costs and offers the services of the Alaska Gasline Inducement Act coordinator.³ The royalty and tax exemption inducements are offered as incentives to commit to acquire firm transportation capacity in the pipeline project. If the legislature removes or reduces the inducements and the first binding open season fails to produce sufficient commitments for the project to move forward, the licensee may claim the state reduced the value of its exclusive license, contrary to article I, sec. 15 of the state constitution.

As a practical matter, the licensee's open season is expected to begin May 1, 2010, and the inducements are only offered during this first open season. If no firm commitments are received, the inducements expire. If firm commitments are received, the inducements take effect for the 10-year period described in AS 43.90.320(b), unless amended by law.

If I may be of further assistance, please advise.

DMB:ljw
10-118.ljw

AS 43.90.320, the state offers an exemption in the amount of any increase in gas production tax liability during the designated period.

³ AS 43.90.110(a).

Information provided by the Department of Labor & Workforce Development as follow-up to the Feb 16th presentation by Jeff Hadland on Alaska's oil industry employment, unemployment and resident hire.

STATE OF ALASKA

Sean Parnell, Governor

**DEPARTMENT OF LABOR AND WORKFORCE
DEVELOPMENT**
OFFICE OF THE COMMISSIONER

P. O. Box 111149

Juneau, AK 99811-1149

PHONE: (907) 465-2700

February 18, 2010

The Honorable Lyman Hoffman
The Honorable Bert Stedman
Co-Chairs Senate Finance
State Capital Building
Juneau, AK 99801-1182

Dear Senators Hoffman and Stedman,

Thank you for the opportunity for our department to testify before your committee on February 16, 2010, regarding oil industry employment, unemployment and resident hire. You requested we provide you with supporting data and supplemental information to our presentation to further clarify oil industry employment in Alaska. The information you requested is attached and includes:

Attachment A-1: Chart showing Alaska Oil, Other Private Sector and Government Employment Average Annual Wage and Salary Employment 1980-2010.

Attachment A-2: Data table providing supporting data for chart Alaska Oil, Other Private Sector and Government Employment Average Annual Wage and Salary Employment 1980-2010.

Attachment B-1: Chart showing Resident, Nonresident and Percent Nonresident Workers in Alaska Oil and Gas Industry 1988-2008.

Attachment B-2: Data table providing supporting data for chart showing Resident, Nonresident and Percent Nonresident Workers in Alaska Oil and Gas Industry 1988-2008.

Attachment C-1: Chart showing Total Workers by Quarter-Alaska Oil Industry 2003Q1 thru 2009Q3.

Attachment C-2: Data table providing supporting data for chart showing Total Workers by Quarter-Alaska Oil Industry 2003Q1 thru 2009Q3. Additional private sector and government worker counts are also provided.

Attachment D-1: Chart Comparing US and Alaska Monthly Oil Industry Employment January 2000 thru December 2009.

Attachment D-2: Data table providing supporting data for chart Comparing US and Alaska Monthly Oil Industry Employment January 2000 thru December 2009.

The Honorable Lyman Hoffman
The Honorable Bert Stedman
February 18, 2010
Page 2

Attachment D-3: Correlation analysis of Alaska oil industry employment with US oil industry employment.

Attachment E-1: Alaska Oil Industry Percent Nonresident Workers 1993-2008. This chart was revised to be more easily reproduced in gray scale.

Attachment E-2: Supporting data for chart Alaska Oil Industry Percent Nonresident Workers 1993-2008. Additional information showing resident hire data for all private sector and all industries is also provided.

Attachment F-1: Data tables showing Alaska Oil Industry Percent Nonresident Workers by Employer 2008.

Attachment G-1: Data table providing Alaska Unemployment Insurance Claimants 2009 for all residents, nonresident, inter-state claimants and instate claimants, oil industry and all industries.

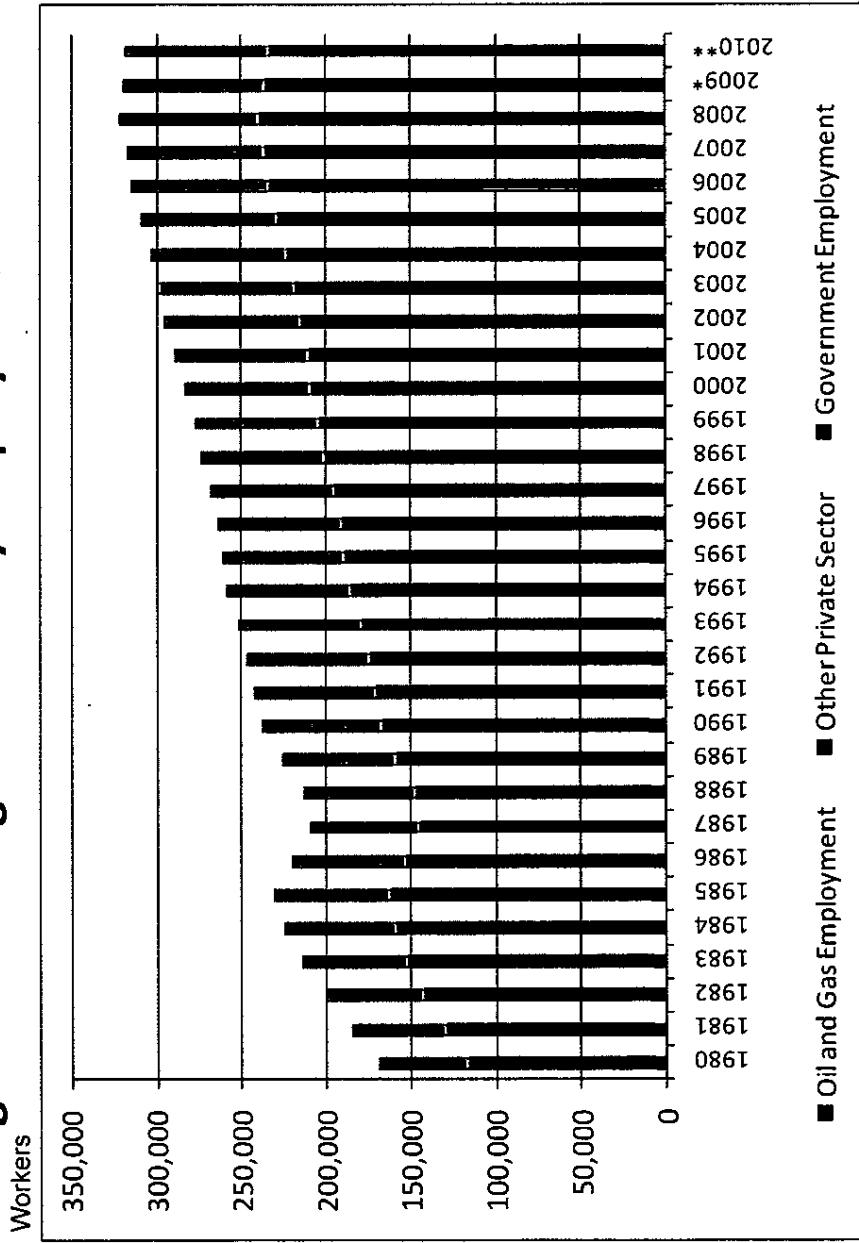
If you need further assistance, please contact Paula Scavera, Legislative Liaison at 465-2700.

Sincerely,



Clark Bishop
Commissioner

Attachment A-1
Alaska Oil, Other Private Sector, and Government
Average Annual Wage and Salary Employment 1980-2010



•Estimate **Projection
 •Note: Government includes state, local and federal civilian employment.
 Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section, February 18, 2010.

Attachment A-2

Alaska Oil And Gas Employment Average Annual Employment ¹

Year	Oil and Gas Employment	Total Private Sector Employment	Total Employment
1980	6,200	116,100	169,400
1981	8,100	129,900	186,100
1982	8,100	141,900	200,400
1983	7,400	151,600	214,300
1984	8,000	159,200	225,700
1985	8,900	162,400	230,700
1986	8,500	152,700	220,700
1987	8,100	144,300	210,100
1988	8,600	147,200	213,700
1989	9,200	158,300	227,000
1990	10,300	167,000	238,000
1991	10,800	171,000	242,700
1992	9,200	173,800	247,100
1993	9,200	178,200	252,800
1994	9,500	185,400	259,300
1995	8,900	189,200	261,900
1996	8,500	190,500	263,500
1997	8,400	195,500	268,700
1998	9,300	201,300	274,900
1999	7,900	204,100	277,800
2000	8,800	209,300	283,800
2001	9,500	210,500	289,300
2002	8,900	214,400	295,000
2003	8,100	217,800	299,400
2004	8,200	223,000	304,300
2005	8,700	228,600	309,800
2006	10,100	233,500	315,000
2007	11,500	236,200	317,900
2008	12,900	239,500	322,400
2009*	13,000	236,200	320,000
2010**	12,700	234,000	318,600

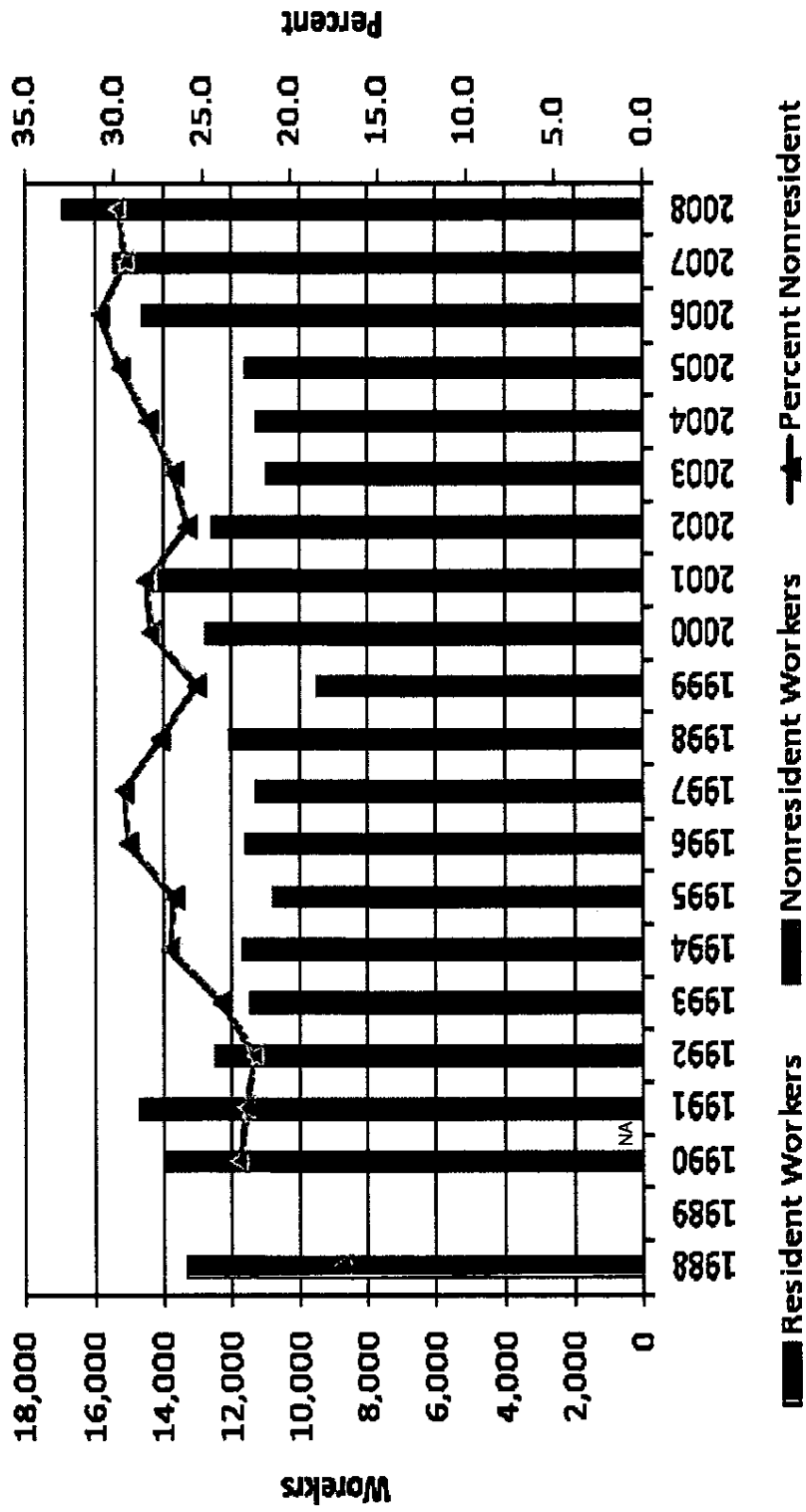
* Preliminary

** Forecast

¹ Nonagricultural wage and salary data, excludes the self-employed

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section, February 18, 2010.

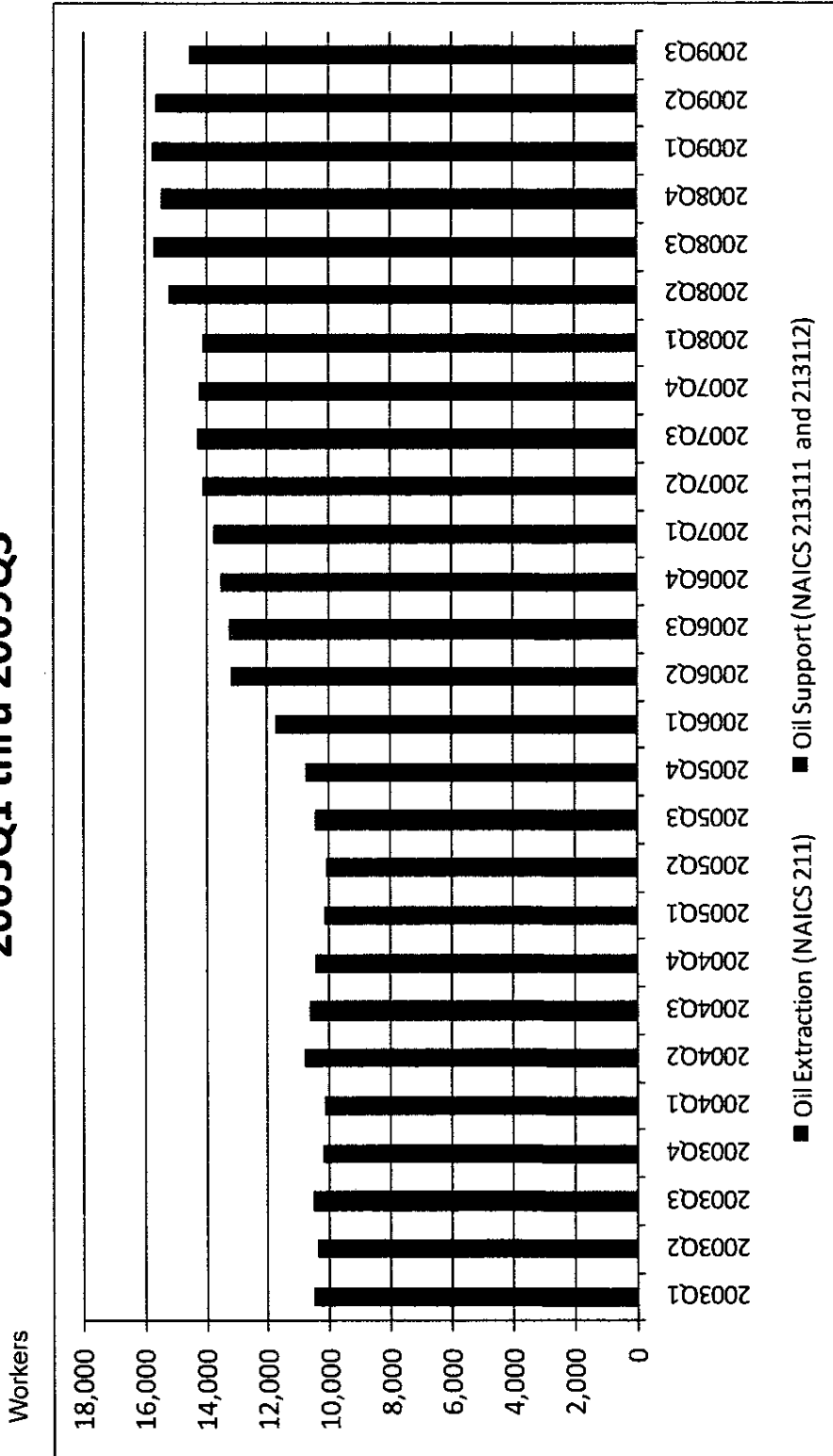
Attachment B-1 Resident, Nonresident and Percent Nonresident Workers in Alaska Oil and Gas Industry 1988-2008



Note: See *Nonresidents Working in Alaska-2008* for complete methodology and residence definition.
 Data not produced in 1989.
 Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section, February 18, 2010.

Attachment C-1

Total Workers by Quarter-Alaska Oil Industry 2003Q1 thru 2009Q3



Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section, February 18, 2010.

Attachment C-2
 Alaska Total Workers Employed At Any Time During the Quarter
 Total, Private Sector, Government and Oil Industry
 Alaska 2002Q1 Through 2009Q3
 (Excludes Federal Govt, Military and Self-Employed)

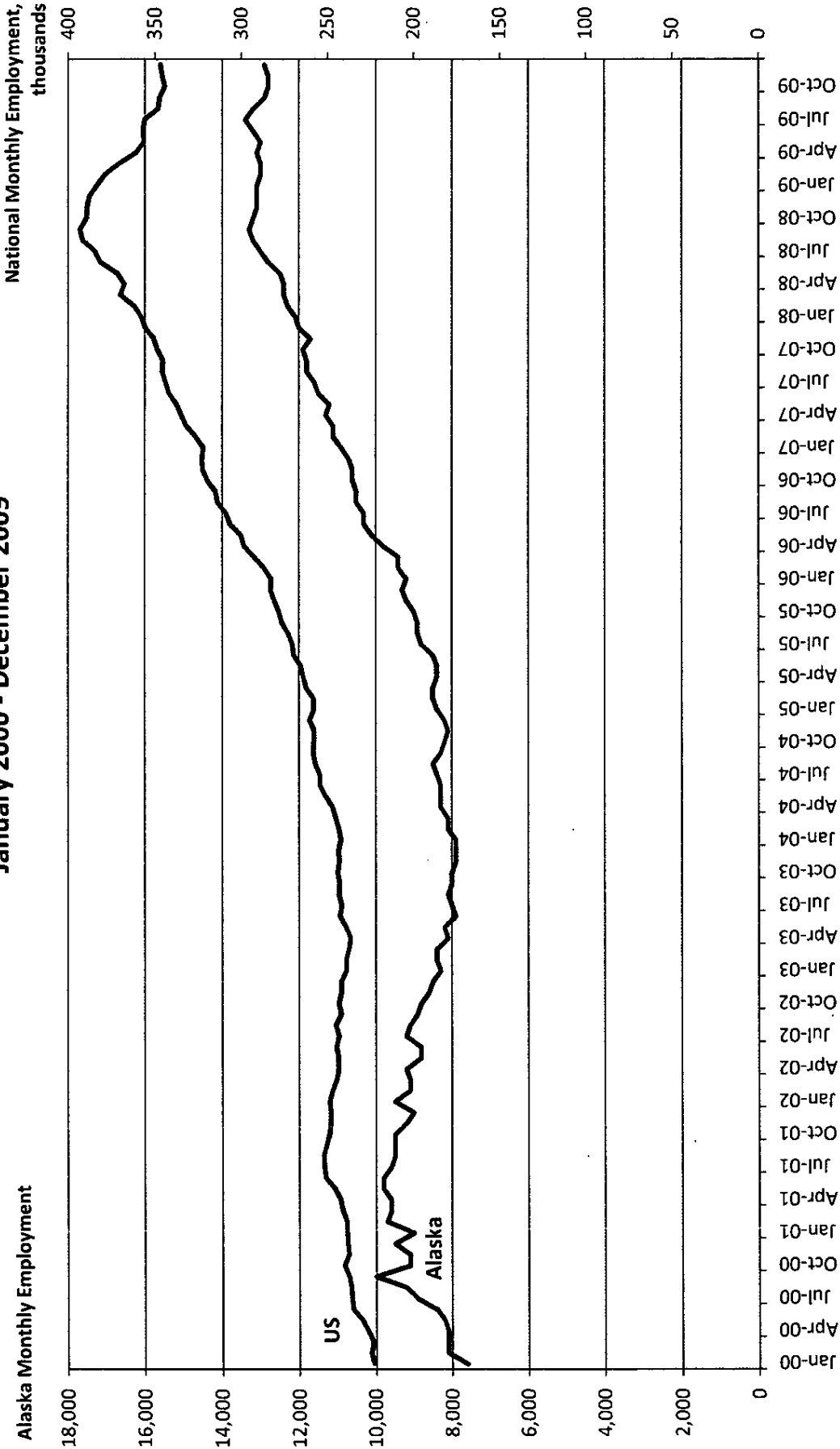
YYYY/Q	Oil extraction (NAICS 211)	Oil Support (NAICS 213111 and 213112)	Total Oil	Total Private	State Govt.	Local Govt.	Total
20021	3,195	8,483	11,678	241,357	23,430	44,129	308,916
20022	3,218	9,090	12,308	284,097	25,774	46,935	356,806
20023	3,173	8,166	11,339	298,508	26,169	45,016	369,693
20024	3,133	7,832	10,965	259,172	24,211	46,075	329,458
20031	3,017	7,520	10,537	242,747	23,995	45,137	311,879
20032	2,949	7,495	10,444	284,787	26,218	47,571	358,576
20033	3,009	7,542	10,551	302,155	26,215	44,834	373,204
20034	3,076	7,135	10,211	262,917	23,742	47,280	333,939
20041	2,945	7,236	10,181	244,343	23,278	45,668	313,289
20042	2,932	7,936	10,868	291,656	25,542	47,789	364,987
20043	2,972	7,703	10,675	309,914	25,736	45,469	381,119
20044	2,978	7,484	10,462	269,611	23,772	46,876	340,259
20051	3,039	7,108	10,147	248,614	23,567	45,142	317,323
20052	2,922	7,206	10,128	296,711	26,638	46,932	370,281
20053	2,953	7,546	10,499	316,186	26,070	45,184	387,440
20054	2,960	7,826	10,786	271,760	23,878	47,019	342,657
20061	3,013	8,716	11,729	256,917	23,760	45,810	326,487
20062	3,163	10,077	13,240	308,312	26,165	48,336	382,813
20063	3,270	10,021	13,291	321,152	27,628	46,738	395,518
20064	3,328	10,193	13,521	281,536	24,852	47,627	354,015
20071	3,438	10,348	13,786	262,758	24,476	46,011	333,245
20072	3,599	10,555	14,154	314,152	26,552	47,759	388,463
20073	3,674	10,630	14,304	324,970	26,615	46,072	397,657
20074	3,655	10,607	14,262	284,723	24,877	47,344	356,944
20081	3,705	10,407	14,112	266,679	24,539	45,981	337,199
20082	3,800	11,438	15,238	313,613	26,738	47,938	388,289
20083	3,890	11,798	15,688	327,818	29,259	46,923	404,000
20084	3,858	11,624	15,482	286,760	25,282	48,235	360,277
20091	3,824	11,957	15,781	263,263	24,820	46,468	334,551
20092	3,861	11,775	15,636	303,090	26,956	49,555	379,601
20093	3,820	10,752	14,572	313,077	27,184	47,654	387,915

Note: This is not average monthly employment, but a total count of individuals employed during the quarter with each employer. May include duplicate workers if employed by more than one employer.

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section, February 18, 2010

Attachment D-1 Comparing US and Alaska Monthly Oil Industry Employment*

January 2000 - December 2009



*Alaska monthly oil industry employment includes employment for NAICS industries 211, 213111 and 213112. Due to data constraints at the national level, US monthly oil industry employment includes employment for NAICS industries 211 and 213112 (excludes drilling employment). Since drilling is a relatively small percentage of national oil industry employment, the overall trend is the same and is considered an acceptable proxy for total national oil industry employment for this illustration.

Sources: Alaska Department of Labor and Workforce Development, Research and Analysis Section; US Bureau of Labor Statistics, February 18, 2010.

Attachment D-2
 Alaska and US Monthly Oil Employment
 2000 thru 2009

Month/Year	Alaska Oil Industry	US Oil Industry (In Thousands)
Jan-00	7,600	223.5
Feb-00	8,100	224.9
Mar-00	8,100	223.9
Apr-00	8,100	226.8
May-00	8,200	230.2
Jun-00	8,400	235.5
Jul-00	8,900	236.2
Aug-00	9,200	236.6
Sep-00	10,000	237.9
Oct-00	9,100	240.7
Nov-00	9,100	238.0
Dec-00	9,500	238.7
Jan-01	9,000	239.1
Feb-01	9,700	239.3
Mar-01	9,600	241.6
Apr-01	9,600	242.9
May-01	9,800	246.0
Jun-01	9,800	251.3
Jul-01	9,600	252.1
Aug-01	9,500	252.5
Sep-01	9,500	250.8
Oct-01	9,500	249.1
Nov-01	9,200	248.4
Dec-01	9,000	248.3
Jan-02	9,500	249.0
Feb-02	9,100	247.3
Mar-02	9,100	244.9
Apr-02	9,200	243.9
May-02	8,800	243.9
Jun-02	8,800	245.1
Jul-02	9,200	243.6
Aug-02	9,100	245.4
Sep-02	8,900	242.3
Oct-02	8,800	243.7
Nov-02	8,600	242.2
Dec-02	8,500	242.4
Jan-03	8,300	239.3

Attachment D-2
 Alaska and US Monthly Oil Employment
 2000 thru 2009

Month/Year	Alaska Oil Industry	US Oil Industry (In Thousands)
Feb-03	8,400	239.5
Mar-03	8,400	237.8
Apr-03	8,100	236.7
May-03	8,200	239.6
Jun-03	7,900	243.1
Jul-03	8,000	242.1
Aug-03	8,100	243.7
Sep-03	8,000	243.3
Oct-03	8,000	244.3
Nov-03	7,900	243.5
Dec-03	7,900	243.9
Jan-04	7,900	242.6
Feb-04	8,100	243.7
Mar-04	8,100	245.5
Apr-04	8,300	247.3
May-04	8,300	251.3
Jun-04	8,300	254.7
Jul-04	8,400	254.8
Aug-04	8,500	257.5
Sep-04	8,300	258.6
Oct-04	8,200	258.2
Nov-04	8,100	258.0
Dec-04	8,200	260.6
Jan-05	8,400	258.2
Feb-05	8,500	258.4
Mar-05	8,500	262.6
Apr-05	8,400	264.3
May-05	8,400	265.7
Jun-05	8,500	269.9
Jul-05	8,800	270.7
Aug-05	8,900	273.1
Sep-05	8,900	276.8
Oct-05	9,000	278.4
Nov-05	9,200	281.1
Dec-05	9,300	283.2
Jan-06	9,200	282.8
Feb-06	9,400	287.0
Mar-06	9,400	292.7

Attachment D-2
Alaska and US Monthly Oil Employment
2000 thru 2009

Month/Year	Alaska Oil Industry	US Oil Industry (In Thousands)
Apr-06	9,800	298.5
May-06	10,100	300.4
Jun-06	10,300	306.6
Jul-06	10,300	309.0
Aug-06	10,500	313.9
Sep-06	10,500	315.1
Oct-06	10,600	319.6
Nov-06	10,600	322.4
Dec-06	10,700	322.8
Jan-07	10,900	321.9
Feb-07	11,100	326.3
Mar-07	11,100	331.9
Apr-07	11,300	334.8
May-07	11,200	337.5
Jun-07	11,500	342.1
Jul-07	11,600	344.1
Aug-07	11,800	346.1
Sep-07	11,800	345.5
Oct-07	11,900	348.8
Nov-07	11,700	350.7
Dec-07	12,000	355.4
Jan-08	12,100	358.0
Feb-08	12,300	361.9
Mar-08	12,400	369.9
Apr-08	12,400	367.5
May-08	12,500	371.8
Jun-08	12,800	381.4
Jul-08	13,000	384.5
Aug-08	13,200	391.5
Sep-08	13,300	393.0
Oct-08	13,200	389.4
Nov-08	13,100	389.0
Dec-08	13,100	387.9
Jan-09	13,100	383.5
Feb-09	13,000	378.7
Mar-09	13,000	370.5
Apr-09	13,100	360.8
May-09	13,000	356.1

Attachment D-2
Alaska and US Monthly Oil Employment
2000 thru 2009

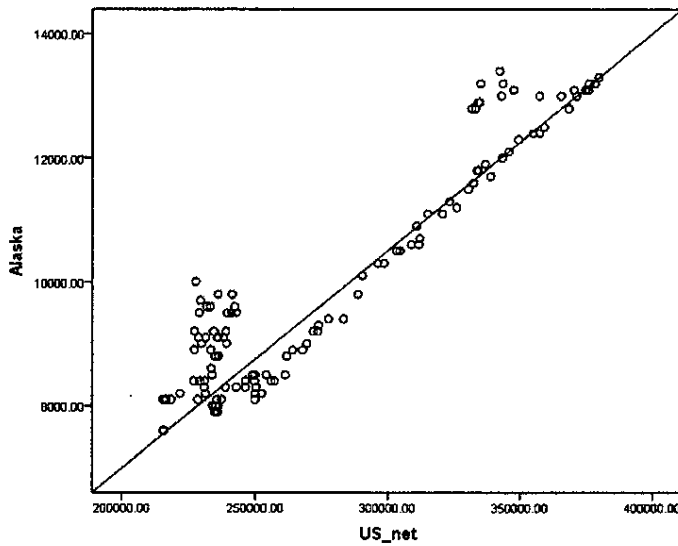
Month/Year	Alaska Oil Industry	US Oil Industry (In Thousands)
Jun-09	13,200	356.8
Jul-09	13,400	355.8
Aug-09	13,200	348.3
Sep-09	12,900	347.6
Oct-09	12,800	344.6
Nov-09	12,800	346.0
Dec-09	12,900	347.1

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section,
February 18, 2010.

Attachment D-3

Alaska and US Oil Industry Employment Correlation Analysis

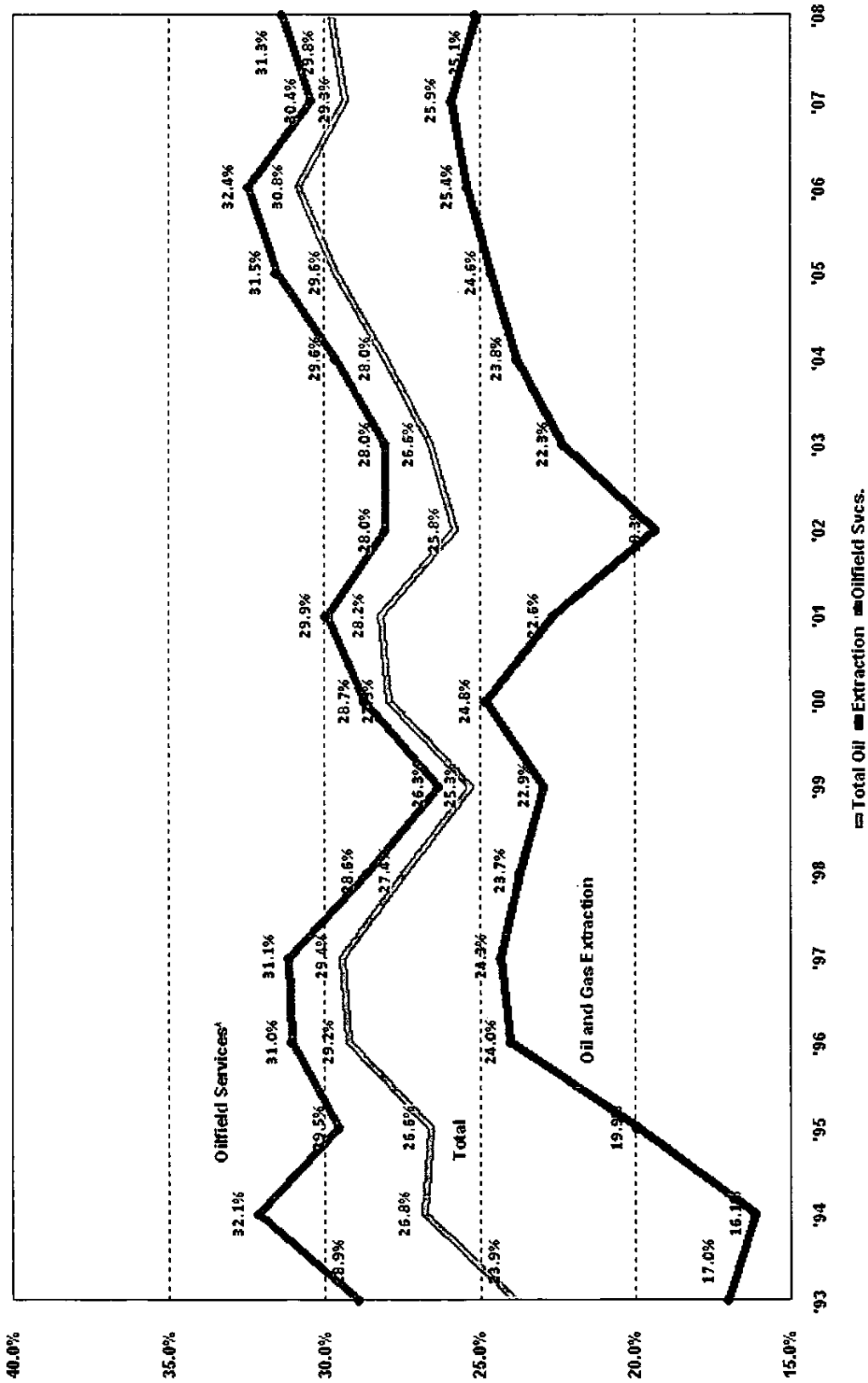
A Pearson correlation coefficient was calculated to determine the degree of correlation between Alaska and US oil and gas employment 2000 thru 2009. The correlation coefficient was calculated at 0.937. This indicates that Alaska and US oil and gas employment are very highly linearly dependent over time.



This scatterplot visually displays the high degree of linear dependence between Alaska and US oil and gas employment.

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section, February 18, 2010.

Attachment E-1 Alaska Oil Industry Percent Nonresident Workers 1993-2008



* This industry category includes support activities for oil and gas drilling and related operations (NAICS 211, 213111 and 213112).
Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section, February 18, 2010.

Attachment E-2
Oil, All Industries and Private Sector
Number and Percent Nonresident Workers
Alaska 1993 to 2008

Year	Oilfield Services*				Oil and Gas Extraction				Total Oil (NAICS 211,213111,213112)			
	Nonresident Workers	Resident Workers	Total Workers	Percent Nonresident	Nonresident Workers	Resident Workers	Total Workers	Percent Nonresident	Nonresident Workers	Resident Workers	Total Workers	Percent Nonresident
1993	1,923	4,742	6,665	28.9	817	3,984	4,801	17.0	2,740	8,726	11,466	23.9
1994	2,507	5,305	7,812	32.1	626	3,260	3,886	16.1	3,133	8,565	11,698	26.8
1995	2,221	5,307	7,528	29.5	643	2,595	3,238	19.9	2,864	7,902	10,766	26.6
1996	2,658	5,915	8,573	31.0	735	2,323	3,058	24.0	3,393	8,238	11,631	29.2
1997	2,656	5,876	8,532	31.1	675	2,105	2,780	24.3	3,331	7,981	11,312	29.4
1998	2,635	6,583	9,218	28.6	672	2,163	2,835	23.7	3,307	8,746	12,053	27.4
1999	1,784	5,009	6,793	26.3	618	2,077	2,695	22.9	2,402	7,086	9,488	25.3
2000	2,901	7,212	10,113	28.7	658	1,992	2,650	24.8	3,559	9,204	12,763	27.9
2001	3,235	7,591	10,826	29.9	759	2,597	3,356	22.6	3,994	10,188	14,182	28.2
2002	2,634	6,788	9,422	28.0	614	2,563	3,177	19.3	3,248	9,351	12,599	25.8
2003	2,289	5,881	8,170	28.0	625	2,175	2,800	22.3	2,914	8,056	10,970	26.6
2004	2,437	5,784	8,221	29.6	730	2,342	3,072	23.8	3,167	8,126	11,293	28.0
2005	2,658	5,787	8,445	31.5	784	2,399	3,183	24.6	3,442	8,186	11,628	29.6
2006	3,643	7,600	11,243	32.4	852	2,502	3,354	25.4	4,495	10,102	14,597	30.8
2007	3,544	8,119	11,663	30.4	987	2,822	3,809	25.9	4,531	10,941	15,472	29.3
2008	4,024	8,851	12,875	31.3	1,019	3,036	4,055	25.1	5,043	11,887	16,930	29.8

* This industry category includes support activities for oil and gas drilling and related operations.

Excludes federal military, civilian and self-employed.

See: *Nonresidents Working in Alaska-2008* for complete methodology.

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section, February 18, 2010.

Attachment E-2
Oil, All Industries and Private Sector
Number and Percent Nonresident Workers
Alaska 1993 to 2008

Year	All Industries			Private Sector Only			
	Nonresident Workers	Resident Workers	Total Workers	Nonresident Workers	Resident Workers	Total Workers	Percent Nonresident
1993	77,038	259,852	336,890	73,119	200,632	273,751	26.7
1994	77,530	266,013	343,543	73,691	206,298	279,989	26.3
1995	78,675	269,412	348,087	75,034	209,058	284,092	26.4
1996	74,761	273,069	347,830	71,117	211,319	282,436	25.2
1997	71,233	279,811	351,044	67,770	218,866	286,636	23.6
1998	69,551	286,707	356,258	65,910	225,075	290,985	22.7
1999	64,828	293,901	358,729	61,814	233,277	295,091	20.9
2000	64,988	297,885	362,873	62,221	238,037	300,258	20.7
2001	67,963	301,881	369,844	64,453	237,618	302,071	21.3
2002	67,972	306,521	374,493	63,517	237,517	301,034	21.1
2003	68,305	309,469	377,774	63,731	239,095	302,826	21.0
2004	70,367	312,686	383,053	65,755	242,613	308,368	21.3
2005	74,266	315,003	389,269	69,243	244,724	313,967	22.1
2006	78,840	317,968	396,808	73,789	246,376	320,165	23.0
2007	78,669	322,758	401,427	73,728	251,855	325,583	22.6
2008	79,619	327,533	407,152	74,435	255,129	329,564	22.6

* This industry category includes support activities for oil and gas drilling and related operations.

Excludes federal military, civilian and self-employed.

See: *Nonresidents Working in Alaska-2008* for complete methodology.

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section, February 18, 2010.

**Attachment F-1
Alaska Oil Industry
Percent Nonresident Workers by Employer
2008**

Employer Name	Industry (NAICS 3)	Total Worker Category	Percent Nonresident
Amoco Production Company	Oil and Gas Extraction	100 to 249	81.7
Anadarko Petroleum Corporation	Oil and Gas Extraction	0 to 49	0.0
BP Exploration Alaska Inc	Oil and Gas Extraction	2,000 to 2,249	27.7
Chevron USA Inc.	Oil and Gas Extraction	250 to 499	10.6
ConocoPhillips Company	Oil and Gas Extraction	1,250 to 1,499	20.7
Exxon Mobil Corporation	Oil and Gas Extraction	0 to 49	40.0
FEX Gp Inc.	Oil and Gas Extraction	0 to 49	50.0
Forest Oil Corporation	Oil and Gas Extraction	0 to 49	4.5
Forest Oil Corporation	Oil and Gas Extraction	0 to 49	0.0
Pacific Energy Resources Ltd	Oil and Gas Extraction	0 to 49	0.0
Pioneer Natural Resources USA Inc.	Oil and Gas Extraction	0 to 49	12.8
Renaissance Alaska LLC	Oil and Gas Extraction	0 to 49	100.0
XTO Energy Inc.	Oil and Gas Extraction	0 to 49	0.0
Amoco Corporation	Support Activities for Mining	50 to 99	37.7
Arctic Pipe Inspection Inc.	Support Activities for Mining	0 to 49	6.9
ASRC Energy Services O&M Inc.	Support Activities for Mining	3,000 to 3,249	24.1
ASRC Energy Services Response LLC	Support Activities for Mining	0 to 49	0.0
ASRC Energy Svcs-Houston Contracting Co.	Support Activities for Mining	250 to 499	14.6
Aurora Gas LLC	Support Activities for Mining	0 to 49	11.1
Aurora Well Service LLC	Support Activities for Mining	0 to 49	22.2
Baker Hughes Oilfield Operations Inc.	Support Activities for Mining	100 to 249	54.1
BJ Services Company Usa	Support Activities for Mining	50 to 99	21.1
Brooks Range Petroleum Corporation	Support Activities for Mining	0 to 49	0.0
Chevron Pipeline Company	Support Activities for Mining	0 to 49	21.7
Colville Inc.	Support Activities for Mining	100 to 249	24.1
Cooper Cameron Corporation	Support Activities for Mining	0 to 49	12.0
Dosecc Exploration Services LLC	Support Activities for Mining	0 to 49	0.0
Doyon Drilling Inc.	Support Activities for Mining	250 to 499	21.3
Enerflex Systems Inc.	Support Activities for Mining	0 to 49	0.0
ENI US Operating Co. Inc.	Support Activities for Mining	0 to 49	53.3
Expro Americas LP	Support Activities for Mining	0 to 49	21.9
Exxon Mobil Development Company	Support Activities for Mining	0 to 49	100.0
Fairweather E&P Services Inc.	Support Activities for Mining	100 to 249	33.8
Flowline Alaska Inc.	Support Activities for Mining	100 to 249	5.1
FMC Technologies Inc.	Support Activities for Mining	0 to 49	0.0
Frontier Drilling USA Inc.	Support Activities for Mining	0 to 49	0.0
Frontier Exploration LLC	Support Activities for Mining	0 to 49	40.0
G B R Equipment Inc.	Support Activities for Mining	50 to 99	44.6
Geo-Pilots Inc.	Support Activities for Mining	0 to 49	100.0
Halliburton Energy Serv Inc.	Support Activities for Mining	250 to 499	32.3
Inlet Drilling AK Inc.	Support Activities for Mining	50 to 99	16.9
Kakivik Asset Management LLC	Support Activities for Mining	100 to 249	31.6
Kuukpik Drilling LLC	Support Activities for Mining	50 to 99	12.2
Landmark Graphics Corporation	Support Activities for Mining	0 to 49	0.0
Little Red Services Inc.	Support Activities for Mining	100 to 249	35.0
Marathon Oil Co.	Support Activities for Mining	50 to 99	9.4
Mckinley Service & Equipment	Support Activities for Mining	50 to 99	32.2
M-I LLC	Support Activities for Mining	100 to 249	17.3

**Attachment F-1
Alaska Oil Industry
Percent Nonresident Workers by Employer
2008**

Employer Name	Industry (NAICS 3)	Total Worker Category	Percent Nonresident
Norcon Inc.	Support Activities for Mining	750 to 999	23.2
Nordic Well Servicing Inc.	Support Activities for Mining	0 to 49	20.0
Nordic-Calista Services No. 1	Support Activities for Mining	100 to 249	24.1
Peak Oilfield Svc Co.	Support Activities for Mining	1,000 to 1,249	26.8
Pollard Wireline Inc.	Support Activities for Mining	50 to 99	12.0
Precision Energy Services Inc.	Support Activities for Mining	0 to 49	0.0
Proactive Diagnostic Svcs Inc.	Support Activities for Mining	0 to 49	0.0
Production Testing Services Inc.	Support Activities for Mining	0 to 49	44.1
Remote Access Tech Intn'L Inc.	Support Activities for Mining	0 to 49	40.0
Rowan Drilling US	Support Activities for Mining	0 to 49	100.0
S&S Drilling	Support Activities for Mining	0 to 49	0.0
Schlumberger Technology Corp.	Support Activities for Mining	500 to 749	30.5
Seischk Inc.	Support Activities for Mining	0 to 49	0.0
Shell Exploration & Production	Support Activities for Mining	0 to 49	28.9
Shell Oil Company	Support Activities for Mining	0 to 49	20.0
Stallion Rockies Ltd	Support Activities for Mining	0 to 49	34.8
Three Mile Creek Services Inc.	Support Activities for Mining	0 to 49	4.0
Total Safety US Inc.	Support Activities for Mining	0 to 49	4.8
Tubular Solutions Alaska LLC	Support Activities for Mining	0 to 49	6.3
Udelhoven Oilfield System Svc.	Support Activities for Mining	750 to 999	30.5
VECO Alaska Inc.	Support Activities for Mining	3,250 to 3,499	35.5
Veritas Dgc Land Inc.	Support Activities for Mining	250 to 499	47.8
Weatherford Artif Lift Systems	Support Activities for Mining	0 to 49	16.7
Well Site Services Inc.	Support Activities for Mining	0 to 49	25.0
Worldwide Oilfield Consultants	Support Activities for Mining	0 to 49	66.7

AS 23.20.110 allows for the release of information showing the number of resident and nonresident workers by firm for those Alaska employers who had 20 or more workers during the year. Due to confidentiality restrictions regarding the release of individual company employment data, each company's employment is expressed as a range as opposed to the exact number of employees. In addition, the percentage of total employees that were nonresidents is provided rather than the actual number of nonresident employees.

Residency is calculated by matching workers reported by Alaska employers with the two most recent Permanent Fund Dividend files (2008 and 2009). Workers shown include all workers employed at any time during the year with that employer. If a worker applied for a Permanent Fund Dividend in 2008 or 2009, they are considered residents for purposes of this report. For complete methodological information, please see "Nonresidents Working in Alaska - 2008," available from the Alaska Department of Labor and Workforce Development, Research and Analysis Section at <http://146.63.75.50/research/reshire/nonres.pdf>.

Source: Alaska Dept. of Labor and Workforce Development, Research and Analysis Section, February 18, 2010.

Attachment G-1

Alaska Unemployment Insurance Claimants 2009

	Nonresident	Resident	Total
Total Alaska Oil Industry Claimants	575	2,269	2,844
In-State Claimants	164	2,167	2,331
Inter-State Claimants	411	102	513
Total Alaska Claimants	10,489	53,141	63,630
In-State Claimants	3,336	49,035	52,371
Inter-State Claimants	7,153	4,106	11,259

Note: Residency determined by match with 2008 and 2009 PFD file. Applicants for a 2008 or 2009 PFD are considered residents for purposes of this table.

Oil Industry UI Claimants are defined as a count of individuals that formerly worked for employers in NAICS 211, 213111 and 213112 and who collected at least one week of Unemployment Insurance during 2009. This includes both In-state as well as Inter-state claimants, and no individual is counted twice within one year. All Industries totals may not equal the sum of individual industries as unclassified claimants are not included in the industry breakouts.

Source: Alaska Dept. of Labor and Workforce Development, Research and Analysis Section, February 18, 2010.

Information provided by the Tax Division, Department of Revenue as follow-up to the Feb 16th presentation by Jennifer Duval and Frank Molli on Alaska's Oil & Gas Production Forecast. Copies of the attachment will also be added to your Oil & Tax Production Tax Review binders.

The follow-up information the committee asked the division to provide was:

- Slide #12 & #32 – Please provide a list of the development prospects that have been excluded from your forecast.
- Slide #13 - Please narrow your ANS production graph (“onion chart”) to cover the 15 year timeframe from 2000 to 2015. Provide a table of the underlying numbers supporting this timeframe – annual production by field
- Legacy Field Contribution - Please provide a pie-chart that shows total oil production from currently producing projects broken out into 4 slices - Prudhoe, Kuparuk, Alpine and everything else. Provide separate charts for three years - 2000, 2010 and 2015 - so that we can see how the production shares have changed (or are projected to change) over the 15 year period (2000-2015). Please annotate each slice with total barrels produced (and what % each slice represents of the whole).
- Heavy Oil – Please provide a link to the 2008 Department of Energy report you referenced in your testimony that estimated Alaska's heavy oil deposits at 25-30 billion barrels with a current estimate recovery rate of 2-15%. The original report is not attached, but is available http://www.netl.doe.gov/publications/press/2008/08002-DOE_Releases_Alaska_Report.html.

Fall 2009 DOR Production Forecast

Excluded North Slope Resources

ANWR

Badami restart

Beaufort Sea OCS

Beechy Point Unit

Chukchi Sea OCS

Dewline Unit

Ugnu

Umiat

96% of heavy oil from West Sak

87% of heavy oil from Schrader Bluff

NPR-A EXCEPT Rendezvous, Spark, Lookout, Moose's Tooth

Other Non-North Slope Resources Excluded

Cosmopolitan (Cook Inlet)

Kitchen Lights (Cook Inlet)

Sunrise (Cook Inlet)

Shadura (Cook Inlet)

Foothills region (south of North Slope)

Nenana Basin

Crude Oil Production-History and Forecast (million barrels / day)

Source: Fall 2009 RSB Appendix C-2 a and C-2 b

FY	HISTORY										FORECAST				
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Prudhoe Bay (1)	0.571	0.536	0.486	0.429	0.414	0.380	0.335	0.271	0.291	0.280	0.261	0.249	0.237	0.238	0.231
PBU Satellites (2)	0.005	0.007	0.030	0.045	0.052	0.043	0.041	0.043	0.034	0.037	0.036	0.043	0.043	0.042	0.040
GPI/MA (3)	0.113	0.088	0.073	0.065	0.060	0.055	0.048	0.037	0.044	0.038	0.032	0.029	0.026	0.023	0.021
Kuparuk	0.211	0.197	0.174	0.160	0.154	0.141	0.133	0.121	0.113	0.106	0.091	0.090	0.085	0.081	0.077
Kuparuk Satellites (4)	0.036	0.031	0.041	0.052	0.049	0.051	0.043	0.044	0.038	0.036	0.035	0.031	0.028	0.026	0.029
Milne Point (5)	0.053	0.052	0.052	0.051	0.051	0.049	0.041	0.033	0.033	0.031	0.029	0.029	0.029	0.029	0.028
Endicott (6)	0.043	0.037	0.033	0.029	0.028	0.020	0.021	0.016	0.014	0.014	0.012	0.011	0.013	0.015	0.017
Liberty										0.000	0.000	0.009	0.024	0.034	0.032
Alpine (7)		0.045	0.096	0.099	0.099	0.105	0.123	0.103	0.079	0.063	0.056	0.054	0.053	0.053	0.046
Fjord (8)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.011	0.018	0.021	0.029	0.025	0.022	0.019	0.018
Nanuq (9)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.010	0.019	0.022	0.009	0.007	0.008	0.008	0.007
NPR-A											0.000	0.001	0.008	0.015	0.015
Oooguruk + Nikaitichuk									0.000	0.004	0.016	0.026	0.034	0.040	0.043
Point Thomson											0.000	0.000	0.000	0.002	0.010
Northstar (10)											0.016	0.013	0.011	0.010	0.009
Total ANS	1.033	0.993	1.010	0.991	0.974	0.911	0.840	0.734	0.716	0.693	0.623	0.617	0.624	0.635	0.623
Cook Inlet	0.026	0.025	0.029	0.030	0.025	0.020	0.018	0.016	0.014	0.013	0.011	0.010	0.009	0.009	0.008
Total Alaska	1.059	1.018	1.039	1.021	0.999	0.931	0.858	0.750	0.730	0.706	0.634	0.626	0.633	0.643	0.631

(1) Includes NGLs from Central Gas Facility shipped to TAPS

(2) Aurora, Borealis, Midnight Sun, Orion and Polaris

(3) Lisburne, Niakuk, North Prudhoe Bay State, Point McIntyre, Raven, West Beach

(4) Melwater, Tabasco, Tam and West Sak

(5) Includes Sag River and Schrader Bluff

(6) Includes Badami, Eider and Sag Delta

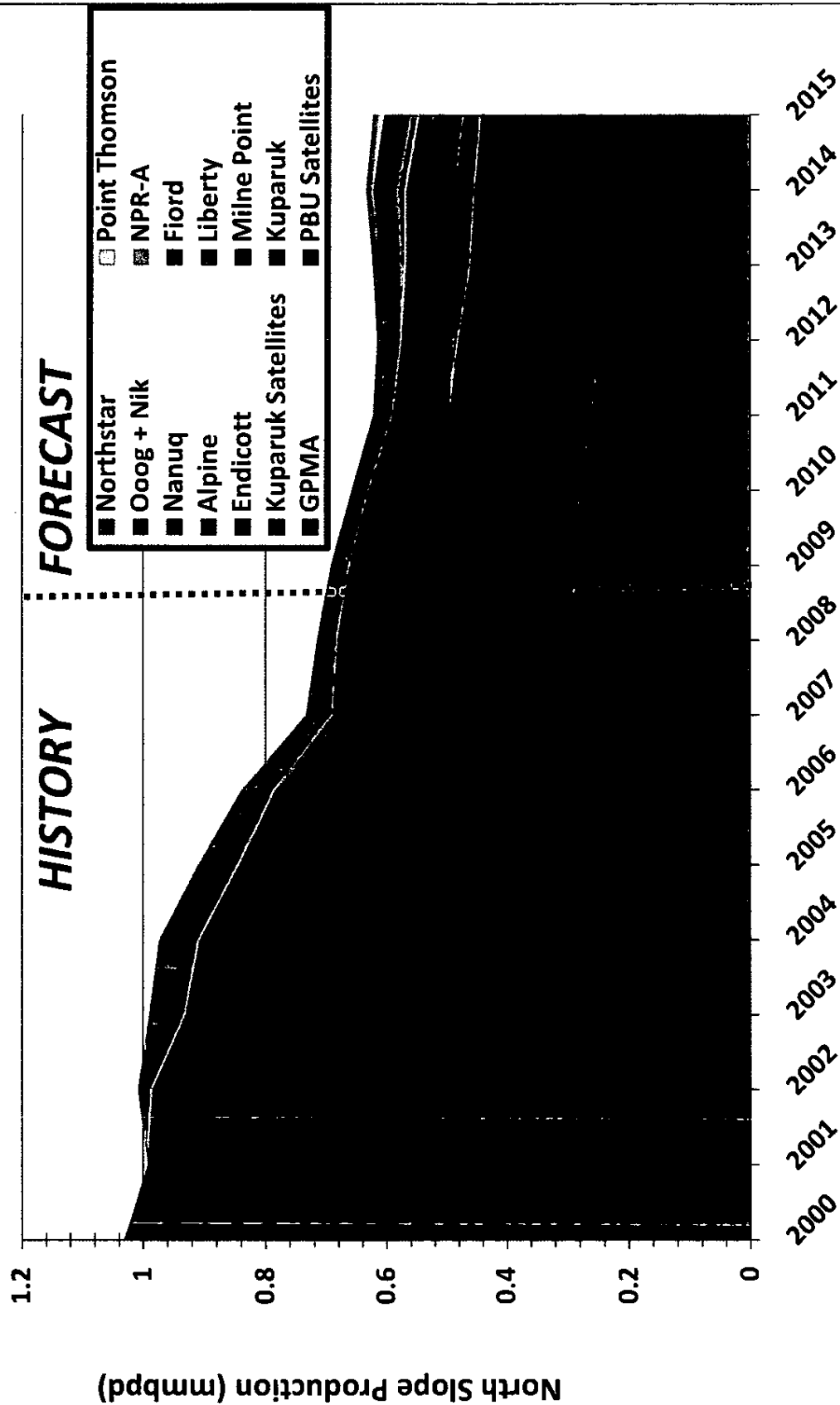
(7) Includes Alpine-West and Qannik

(8) Fjord and Fjord-Kuparuk

(9) Nanuq and Nanuq-Kuparuk

(10) Includes OCS production.

Alaska North Slope Production: History FY 2000- FY 2009, Forecast FY 2010- FY 2015

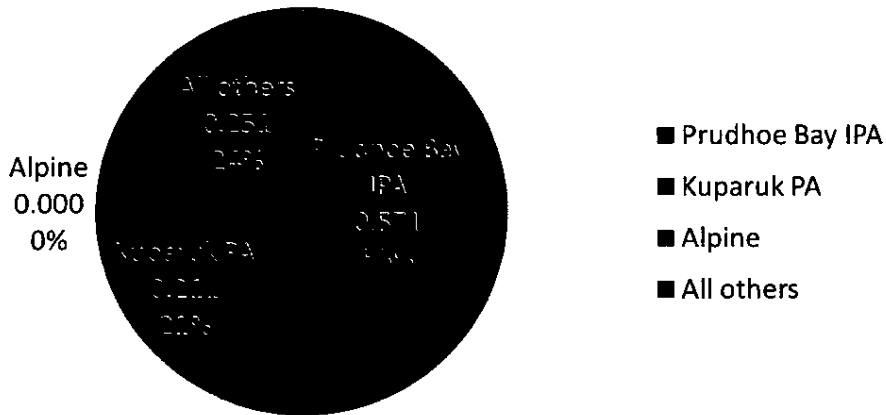


Source: Fall 2009 Revenue Sources Book

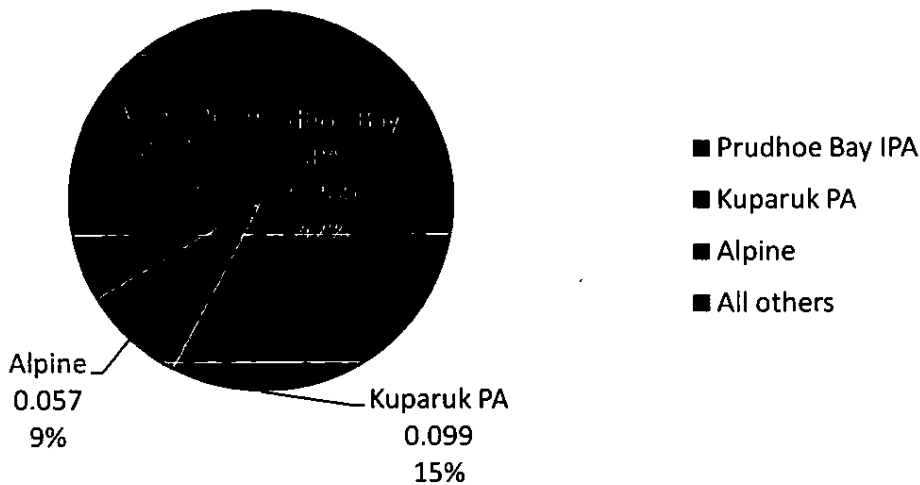
Production, Million Barrels per Day
FY 2000 actual, Fall 2009 forecast for FY 2010 and FY 2015

	FY 2000	2010	2015
Prudhoe Bay IPA	0.571	0.280	0.231
Kuparuk PA	0.211	0.099	0.077
Alpine	0.000	0.057	0.046
All others	<u>0.251</u>	<u>0.222</u>	<u>0.269</u>
TOTAL	1.033	0.659	0.623

FY 2000 Production breakdown
Million barrels per day



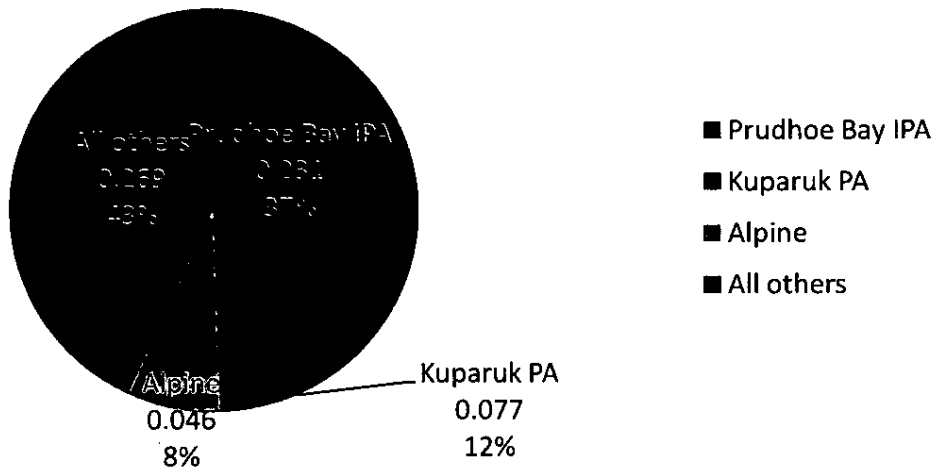
FY 2010 Forecasted Production Breakdown
Million barrels per day



Production, Million Barrels per Day
FY 2000 actual, Fall 2009 forecast for FY 2010 and FY 2015

	FY 2000	2010	2015
Prudhoe Bay IPA	0.291	0.198	0.161
Kuparuk PA	0.106	0.062	0.046
Alpine	0.063	0.029	0.017
All others	<u>0.232</u>	<u>0.235</u>	<u>0.302</u>
TOTAL	0.693	0.524	0.526

FY 2015 Forecasted Production Breakdown
Million barrels per day



Additional information provided by the Department of Revenue on O&G Production Tax Credits. This issue was discussed in committee on Feb 18th.

Oil and Gas Tax Credit Forecast

We project that approximately \$340 million in credits would be taken directly against tax liabilities in FY 2010 and that credit offsets would raise to \$390 million in FY 2011. We make the distinction between credit offsets and credit certificates only because their impact on state revenues is slightly different. Tax offsets directly reduce the amount of revenue received in the first instance by the state, while credit certificates, when subsequently purchased by the state require the state to allocate general funds for such purchases as part of the budget process. It is important to note that these projections, just like other oil and gas revenue projections are based on assumptions relating to oil prices, investment decisions, and availability of equipment and manpower to complete projects. As economic conditions change, companies continually modify their investment plans. Thus, as with every revenue projection related to oil and gas development, one should avoid assigning an undue amount of certainty to these forecasted numbers.

There are over 20 companies currently funding the development of oil and gas prospects in the state. These prospects may or may not lie within established unit boundaries, and they may or may not qualify for exploration incentive credits. One of the developments, the Ooguruk field, is now in production and another, the Nikaitchuq field, is in active development. As these and other fields come online, it becomes more difficult to project whether credits will be applied against a tax liability, or whether credit certificates will be sought.

Timing of State Payment for Tax Credits

As discussed earlier, AS 43.55.028 authorizes the state to purchase production tax credit certificates directly from companies that have earned them from oil and gas expenditures in the state. Subsections .028(e)(1) through (7) lay out additional requirements a company must meet in order to receive a payment from the state for these certificates. Among the requirements listed is a provision that companies seeking these payments spend, within 24 months of the application period, an amount equal to or exceeding the value of the payment sought. This and other requirements that must be satisfied prior to the payment for credit certificates impact the timing of the state's payment for those certificates.

Conclusions

As of February 20, 2010, the Oil and Gas Tax Credit Fund has a balance of \$90 million. This represents appropriations for FY 2007, 2008, 2009 and 2010. The dollar value of requests received for tax credit certificates to date is \$1.018 billion. Of this amount, approximately \$226 million are outstanding and potentially subject to state purchase. Applications representing an estimated \$148 million in tax credits are pending, but these will likely not be issued until FY 2011. For FY 2011, we estimate that an additional \$200 million in tax credits will be earned, and available for state purchase. These three

Department of Revenue, Tax Division
February 22, 2010

estimates total \$574 million in potential credits earned and available for state purchase through the end of FY 2011. We are not able to make any projections at this time as to when the state purchases of credits will occur, but based on history, it is likely that the timing of some of the credit purchases will be FY 2011 and beyond. Subject to audit, the information received on the annual tax filings through FY09, indicates that there is a balance of \$203 million in tax credits available to be applied against future tax liabilities.

Note about this report: This report was prepared using incomplete data from several different sources specifically for this request. The DOR does not currently have a means to capture all the relevant historical and forecast credit data in a central database available to all groups that rely upon that data. Accordingly, any users of this information should be cautioned that this forecast is subject to change as data becomes available.

Department of Revenue, Tax Division
February 22, 2010

State of Alaska
Department of Revenue

Credits Purchased by State

(\$m) Fiscal Year	\$ Million Amount
2007	54.6
2008	54.1
2009	193.1
2010	<u>98.4</u>
	<u>400.3</u>

By Fund

General fund	
2007	54.6
2008	<u>25.0</u>
	79.6

Fund 11189 Oil and Gas tax Credit fund

2008	29.1
2009	193.1
2010	<u>98.4</u>
	320.7
Total	400.3

State of Alaska
Department of Revenue

Tax Credits applied to Taxes by tax year (calendar year)

(\$m)

Type	2006	2007	2008 Totals	
.023(a)	195	194	243	632
.023(i)	98	145	0	243
.024	27	38	21	86
.025	2	92	17	111
	<u>322</u>	<u>469</u>	<u>281</u>	<u>1072</u>

Source: Tax filings
2009 tax filings true up due in March

Additional information provided by LB&A consultant Dr. David Wood in response to questions raised in committee on Feb 25th.

To: Senate Finance Committee

Attn: Senator Bert Stedman

Co-Chair, Senate Finance Committee

From: David Wood

Date: 25 February, 2010

Re: Answer to Question & Request Raised by Senator Thomas during My Testimony Given Today (25 February 2010)

The very pertinent and perceptive question asked earlier today by Senator Thomas sought information with respect to how might the gas dilution / cross subsidy effect identified in Alaska's current production tax rules have impacted the production taxes actually paid in recent periods had a gas line had been in operation at the time?

In order to provide an indicative answer to this question I have taken the data for price, volume and costs (excluding Cook Inlet Gas) for fiscal year 2008 (i.e. July 2007 to June 2008), which is available from the Alaska Department of Revenue (DOR), Fall 2008 Revenues Sources Book (RSB), (Dec 2008). That period is selected because of the wide range of oil prices that prevailed and the fact that the ACES rules were in place. The three tables attached to this document provide the necessary data and calculations to establish the impact.

Table 1 calculates the production tax for oil based on actual data showing the components of that calculation. As no gas is exported the calculations are based upon oil barrels only. This results in total production tax of **\$ 7.482 billion** which is reduced by investment credits of \$411.5 million to \$ 7.071 billion. The calculation shown essentially reproduces the figures from the RSB.

Table 2 assumes a 4.5 bcf/day gas line and calculates production tax for this hypothetical gas stream on a stand-alone basis (i.e. not combined with oil). The calculation uses the U.S. wellhead natural gas prices from the EIA's records for the months in question. There would be some small differentials between these prices and AECO prices in Alberta, but I believe they are close enough for the purpose. I have also assumed gas transportation costs of \$4.5/mcf (\$27/boe) and field costs (capital costs plus operating costs) of \$400 million (\$1.46/ boe) which are those used by Commissioner Galvin in the examples he provided from the DOR in his

testimony of 24 February 2010. This data computes a total production tax of **\$ 1.140 billion** to which no investment credits are applied.

By adding the computed production taxes in tables 1 and 2 the stand-alone oil and gas production tax for this FY 2008 (assuming 4.5 bcf /day) would be **\$8.622 billion** (reduced to \$8.211 billion by the deduction of \$411.5 million investment credits).

Table 3 calculates the production tax by combining the revenue cost and volume streams from table 2 to provide a combined oil and gas production tax calculation of **\$6.795 billion** (reduced to \$6.383 billion by the deduction of \$411.5 million investment credits).

For this period the loss to the State in production tax revenue caused by the cross subsidy effect of combining oil and gas in the production tax calculation would have amounted to:

$$\text{\$6.795 billion less \$8.622 billion} = \text{-\$1.827 billion.}$$

This calculation is in line with the figures of potential loss in fiscal revenue discussed during the testimonies.

Sincerely,

David Wood

dw@dwasolutions.com

Table 1. Oil Stand-alone Production Tax Calculation (July 2007 to June 2008)

FY 2008 Production Tax Revenues: Actual Versus Potential Under Alternative Mechanisms
 (Analysis Based on Actual US West Coast Prices and Cost Data)

Month	US West Coast Oil Price	Per Barrel Total Costs	Per Barrel Production Tax Value	Per Barrel Production Tax Value	PTV less Progressivity Threshold	PTV less Progressivity Threshold	PTV Rate per Dollar of Adjusted PTV	Incremental Progressivity Rate	Volume (Millions barrels)	Combined Progressivity Tax (CPT)	Base Production Tax (BPT)	Base Production Tax (BPT) Rate	Base Production %	K	L= (D * I * K)	M= (J + L)	N= (M - P)	CPT + BPT less Investment Credits
Monthly Analysis, \$30 PTV \$/boe threshold and 0.004% progressivity parameter under Current Law as enacted in 2007																		
Jul	75.93	-22.88	53.05	53.05	-30	23.05	0.40%	9.22%	19.5	95.2	258.3	25.00%	25.00%	258.3	353.5			
Aug	73.83	-22.88	50.95	50.95	-30	20.95	0.40%	8.38%	19.5	83.1	248.0	25.00%	25.00%	248.0	331.2			
Sep	79.92	-22.88	57.04	57.04	-30	27.04	0.40%	10.81%	18.8	116.2	268.7	25.00%	25.00%	268.7	385.0			
Oct	84.77	-22.88	61.89	61.89	-30	31.89	0.40%	12.75%	19.5	153.7	301.3	25.00%	25.00%	301.3	455.0			
Nov	92.98	-22.88	70.10	70.10	-30	40.10	0.40%	16.04%	18.8	211.9	330.2	25.00%	25.00%	330.2	542.1			
Dec	88.64	-22.88	65.76	65.76	-30	35.76	0.40%	14.30%	19.5	183.2	320.1	25.00%	25.00%	320.1	503.3			
Jan	91.16	-22.88	68.28	68.28	-30	38.28	0.40%	15.31%	19.5	203.6	332.4	25.00%	25.00%	332.4	536.0			
Feb	94.42	-22.88	71.54	71.54	-30	41.54	0.40%	16.61%	18.2	216.5	325.8	25.00%	25.00%	325.8	542.3			
Mar	105.06	-22.88	82.18	82.18	-30	52.18	0.40%	20.87%	19.5	334.0	400.1	25.00%	25.00%	400.1	734.1			
Apr	112.37	-22.88	89.49	89.49	-30	59.49	0.40%	23.79%	18.8	401.3	421.6	25.00%	25.00%	421.6	822.9			
May	125.41	-22.88	102.53	102.53	-30	72.53	0.40%	29.01%	19.5	579.2	499.1	25.00%	25.00%	499.1	1078.4			
Jun	133.78	-22.88	110.90	110.90	-30	80.90	0.40%	32.36%	18.8	676.3	522.5	25.00%	25.00%	522.5	1198.7			
Totals:										3254.2	4228.1	25.00%	25.00%	4228.1	7482.3	7070.8		

Data Source: Alaska Department of Revenue (DOR), Fall 2008 Revenues Sources Book (RSB), (Dec 2008)
 FY2008 Taxable North Slope barrels /day: 626,456
 229.3 million barrels in FY2008 Lease Expenditures (\$/bbl): 16.78
 TT&I (\$/bbl): 6.10
 Capex Credits (\$ millions): 411.5

Table 2. Gas Stand-alone Production Tax Calculation (July 2007 to June 2008) [Assuming Gas Line Operational]

FY 2008 Production Tax Revenues: 4.5 bcf/day Hypothetical Gas Sales (Standalone Production Tax Calculation) (US Gas Price Data from EIA)														
Month	EIA U.S. Wellhead Price \$/mcf	Per BOE Total Costs for Gas \$/boe	Per Barrel Production Tax Value PTV \$/boe	Progressivity Threshold \$/boe	PTV less Progressivity Threshold \$/boe	PTV Rate per Dollar of Adjusted PTV %	Incremental Progressivity Rate %	Volume (Millions boe)	Progressivity Tax (Gas Calculated Separately) \$ millions	Base Production Tax Rate %	Base Production Tax Value \$ millions	Production Tax (BPT + Progressivity) Value \$ millions	CPT + BPT less Investment Credits \$ millions	Total
Monthly Analysis, \$30 PTV \$/boe threshold and 0.004% progressivity parameter under Current Law as enacted in 2007														
Jul	6.32	-28.46	9.46	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	55.2	55.2		
Aug	5.87	-28.46	6.76	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	39.4	39.4		
Sep	5.42	-28.46	4.06	-30	0.00	0.40%	0.00%	22.6	0.0	25.00%	22.9	22.9		
Oct	5.90	-28.46	6.94	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	40.5	40.5		
Nov	6.58	-28.46	11.02	-30	0.00	0.40%	0.00%	22.6	0.0	25.00%	62.2	62.2		
Dec	6.97	-28.46	13.36	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	77.9	77.9		
Jan	6.99	-28.46	13.48	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	78.6	78.6		
Feb	7.55	-28.46	16.84	-30	0.00	0.40%	0.00%	21.8	0.0	25.00%	91.8	91.8		
Mar	8.29	-28.46	21.28	-30	0.00	0.40%	0.00%	23.3	0.0	25.00%	124.0	124.0		
Apr	8.94	-28.46	25.18	-30	0.00	0.40%	0.00%	22.6	0.0	25.00%	142.0	142.0		
May	9.81	-28.46	30.40	-30	0.40	0.40%	0.16%	23.3	1.1	25.00%	177.2	178.3		
Jun	10.82	-28.46	36.46	-30	6.46	0.40%	2.59%	22.6	21.3	25.00%	205.7	226.9		
Totals:										25.00%	1117.4	1139.8	1139.8	0.0
Data Source: EIA for gas price														
Hypothetical gas production (bcf/day): 4.5														
Lease Expenditures (\$/boe): 274.5 millions boe in FY2008														
Capex Credits (\$ millions): 27.00														
Combined Production Tax (Calculated on an oil/gas stand-alone calculation): 8210.6														

Table 3. Oil & Gas Combined Production Tax Calculation (July 2007 to June 2008)

FY 2008 Production Tax Revenues: Oil plus Gas Combined (Analysis Assumes Actual Oil Plus Hypothetical Gas)																					
Month	Oil + Gas Effective BOE					PTV less Progressivity Threshold					Incremental Progressivity Rate		Oil + Gas Volume		Combined Progressivity Tax (CPT)		Base Production Tax (BPT)		CPT + BPT less \$400 in credits		
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
	\$/boe	\$/boe	\$/boe	\$/boe	\$/boe	\$/boe	%	%	millions boe	millions boe	%	%	millions boe	millions boe	\$/ millions	\$/ millions	%	\$/ millions	\$/ millions	\$/ millions	\$/ millions
Monthly Analysis, \$30 PTV \$/boe threshold and 0.004% progressivity parameter under Current Law as enacted in 2007																					
Jul	55.22	-25.92	-25.92	29.30	-30	0.00	0.40%	0.00%	42.8	0.0	25.00%	313.4	313.4	313.4	287.4	287.4	25.00%	291.6	291.6	352.4	442.1
Aug	52.79	-25.92	-25.92	26.87	-30	0.00	0.40%	0.00%	42.8	0.0	25.00%	287.4	287.4	287.4	291.6	291.6	25.00%	341.8	341.8	392.4	442.1
Sep	54.09	-25.92	-25.92	28.17	-30	0.00	0.40%	0.00%	41.4	0.0	25.00%	291.6	291.6	291.6	352.4	352.4	25.00%	392.4	392.4	442.1	442.1
Oct	57.87	-25.92	-25.92	31.95	-30	1.95	0.40%	0.78%	42.8	10.7	25.00%	341.8	341.8	341.8	392.4	392.4	25.00%	442.1	442.1	442.1	442.1
Nov	63.83	-25.92	-25.92	37.91	-30	7.91	0.40%	3.16%	41.4	49.7	25.00%	392.4	392.4	392.4	442.1	442.1	25.00%	442.1	442.1	442.1	442.1
Dec	63.13	-25.92	-25.92	37.21	-30	7.21	0.40%	2.88%	42.8	45.9	25.00%	398.0	398.0	398.0	443.9	443.9	25.00%	443.9	443.9	443.9	443.9
Jan	64.34	-25.92	-25.92	38.42	-30	8.42	0.40%	3.37%	42.8	55.4	25.00%	411.0	411.0	411.0	466.4	466.4	25.00%	466.4	466.4	466.4	466.4
Feb	67.66	-25.92	-25.92	41.74	-30	11.74	0.40%	4.69%	40.0	78.4	25.00%	417.6	417.6	417.6	496.0	496.0	25.00%	496.0	496.0	496.0	496.0
Mar	74.92	-25.92	-25.92	49.00	-30	19.00	0.40%	7.60%	42.8	159.3	25.00%	524.1	524.1	524.1	683.4	683.4	25.00%	683.4	683.4	683.4	683.4
Apr	80.37	-25.92	-25.92	54.45	-30	24.45	0.40%	9.78%	41.4	220.5	25.00%	563.6	563.6	563.6	784.1	784.1	25.00%	784.1	784.1	784.1	784.1
May	89.15	-25.92	-25.92	63.23	-30	33.23	0.40%	13.29%	42.8	359.6	25.00%	676.3	676.3	676.3	1035.9	1035.9	25.00%	1035.9	1035.9	1035.9	1035.9
Jun	96.26	-25.92	-25.92	70.34	-30	40.34	0.40%	16.14%	41.4	470.0	25.00%	728.1	728.1	728.1	1198.1	1198.1	25.00%	1198.1	1198.1	1198.1	1198.1
Totals									505.2	1449.3	25.00%	5345.5	5345.5	5345.5	6794.9	6794.9	25.00%	6794.9	6794.9	6794.9	6794.9
Difference Between Production Tax Calculated on a combined Oil & Gas Basis Minus Standalone Oil and Gas Basis:																			P	411.5	
Capex Credits (\$ millions):																				-1827.2	

Additional follow-up information provided by Wendy King in response to questions raised during ConocoPhillips testimony before the committee on Feb 23rd.

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March 8, 2010

The Honorable Bert Stedman
State Senate
Alaska State Capitol, Room 516
Juneau, Alaska 99801-1182

Dear Senator Stedman:

Thank you for the opportunity to present to the Senate Finance Committee on February 23, 2010, regarding the State of Alaska's oil tax structure.

Questions raised during the committee discussion are answered below with additional details provided in the referenced attachments.

Question 1: Does slide number 5, "North Slope Remaining Barrels," include heavy oil?

Response: Yes, the slide is the sum of the ANS production forecast from the Department of Revenue's (DOR) fall 2008 forecast for the years 2010-2050. DOR included production from the West Sak heavy oil reservoir in this forecast. Please see Attachment 1.

Question 2: Can you provide the inflation factors used to normalize North Slope expenditures on slide number 8?

Response: Cambridge Energy Resources Associates' (CERA) inflation factors were used to normalize the hyperinflation experienced by the oil industry in concurrence with oil price changes. These are the same inflation factors used by the Department of Revenue (DOR) in their presentation to the Senate Resources Committee on February 4, 2010. The DOR presentation and the table of inflation factors used by ConocoPhillips to adjust expenditures on slide number 8 are shown on Attachments 2 through 4.

March 8, 2010

Question 3: For slide number 9, "Extending Core Field Lives," show capital split between maintenance/repair/replace and development.

Response: Please see Attachment 5, a reformatted version of slide number 9 to a stacked bar chart that shows the increasing maintenance investment focused on extending the core fields' lives. This investment is represented by the increasing gray portion of the bars. The flat to decreasing red portion of the bars shows the investment in projects and drilling.

The next chart, Attachment 6, presents a break down of the gross capital investment in the core North Slope fields. The red portion of the bars indicates that capital investment in drilling and new projects has declined in recent years. The gray portion shows that capital investment in core field maintenance, repair and replacement activities has increased. These maintenance capital investments are necessary to prolong the lives of and mitigate production decline rates of the core fields.

Please don't hesitate to contact me if the Committee has further questions or requires additional information.

Sincerely,

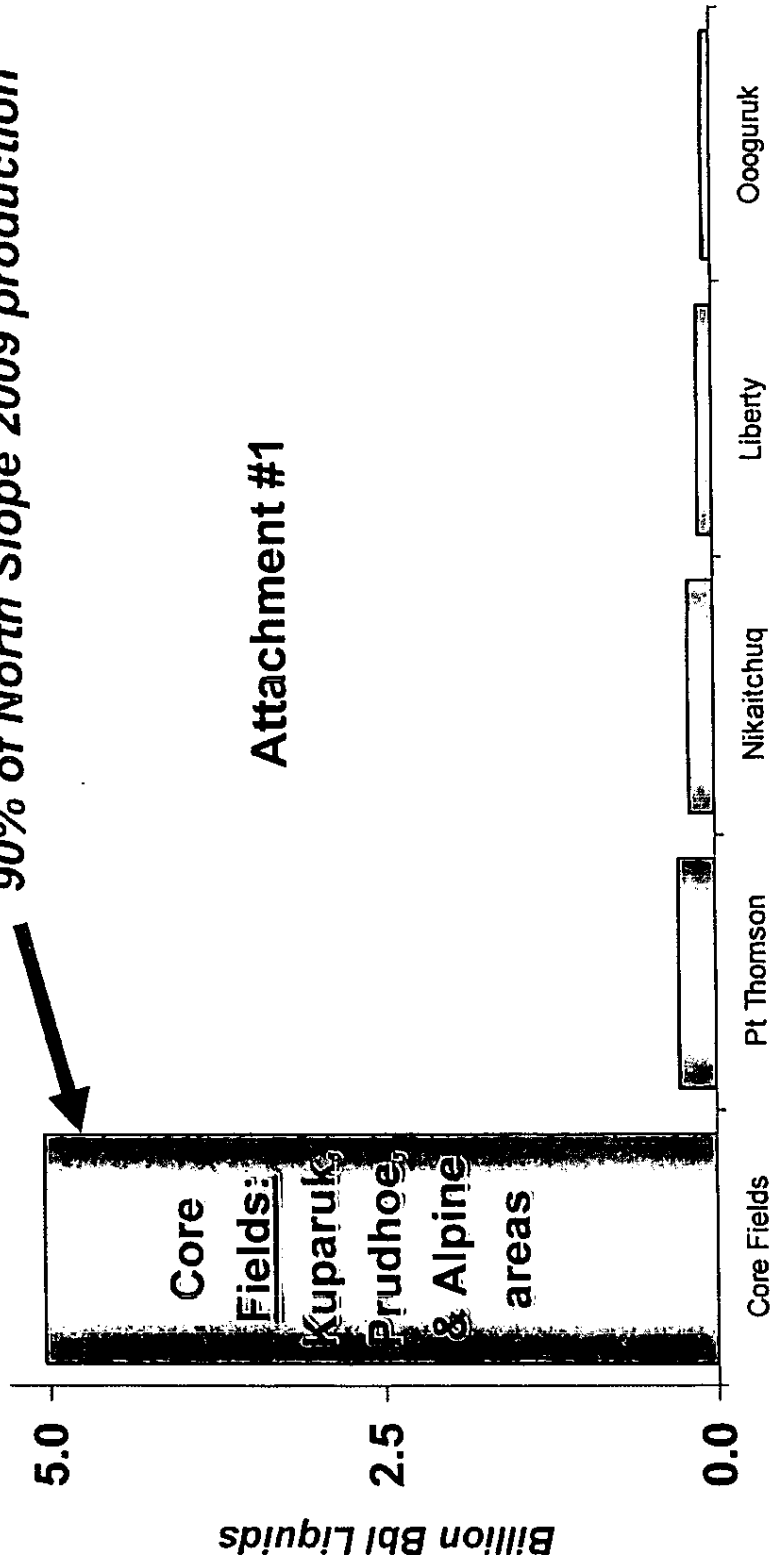

Wendy D. King

Attachments

cc: Brian Wenzel ConocoPhillips Alaska

North Slope Remaining Barrels

90% of North Slope 2009 production



Core fields are dominant source of state production

Source: DOR production forecast 2010 - 2050 volumes

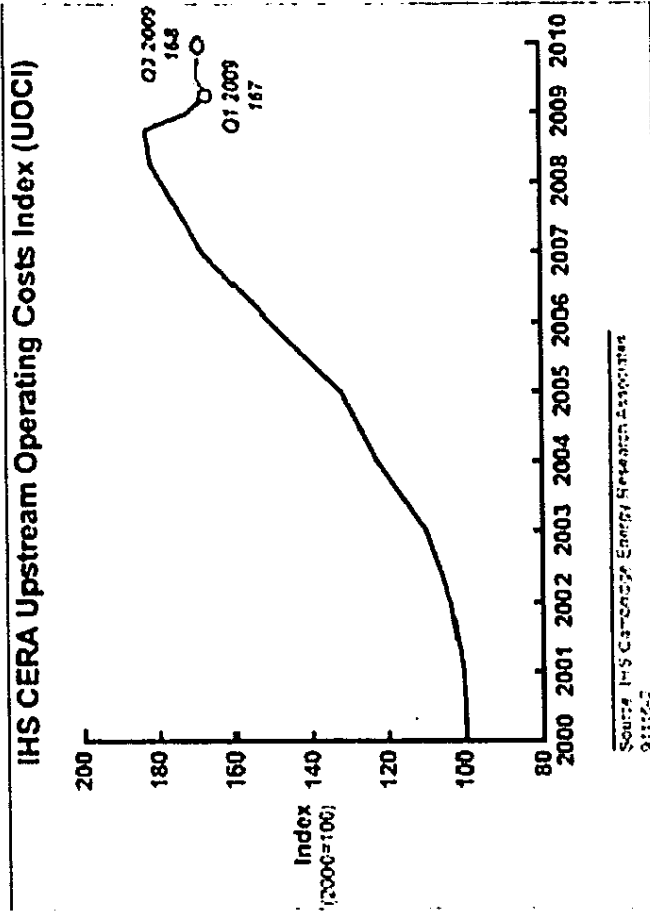
ConocoPhillips

CERA Inflation Factors

Attachment #2

Historical Trends – Worldwide Upstream Operating Costs

(B)



Alaska Department of Revenue

2/4/2010

ConocoPhillips

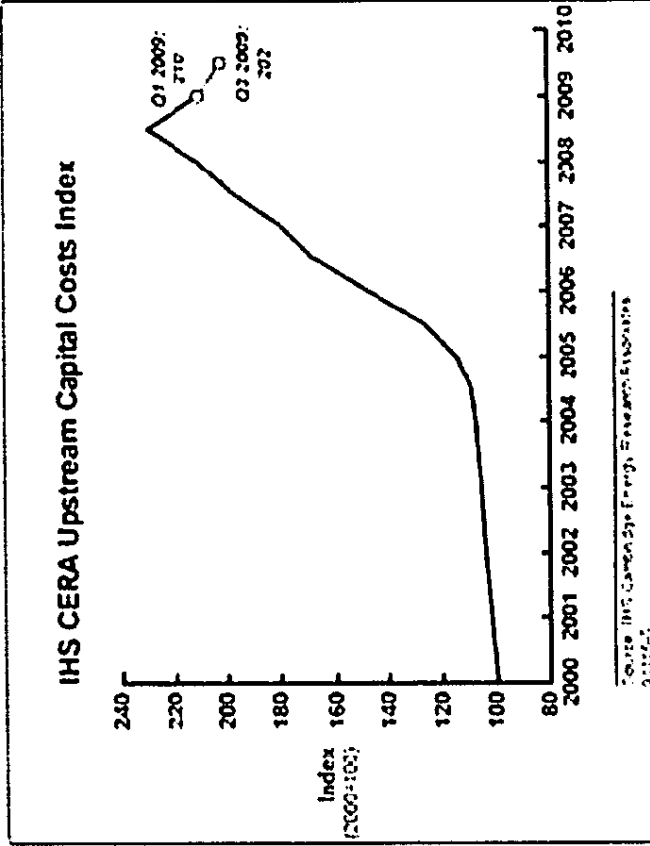


CERA Inflation Factors

Attachment #3

Historical Trend – Worldwide Upstream Capital Costs

13



Alaska Department of Revenue

2/14/2010

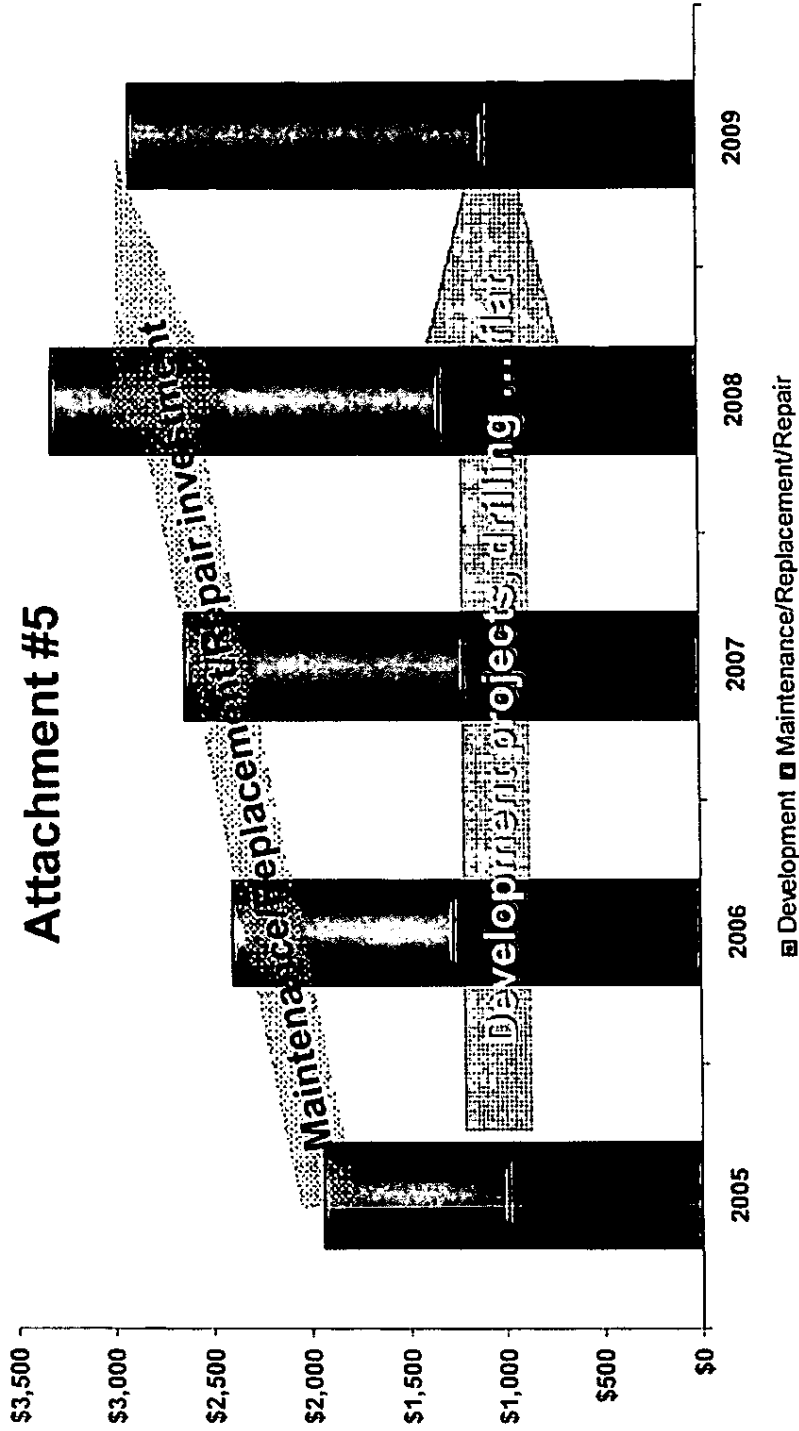
CERA Inflation Factors

Attachment #4

	CERA Upstream Capital Costs Index	CERA Upstream Operating Cost Index	CERA Upstream Inflation Adjustment	CERA Upstream Inflation Adjustment
2007	167.4	150.6	1.00	1.00
2008	197.8	168.1	1.18	1.12
2009	230.0	181.7	1.37	1.21
2010	202.0	166.6	1.21	1.11

Core Field Investments Extend Field Life

Core field gross investments include capital and operating expense, \$MM



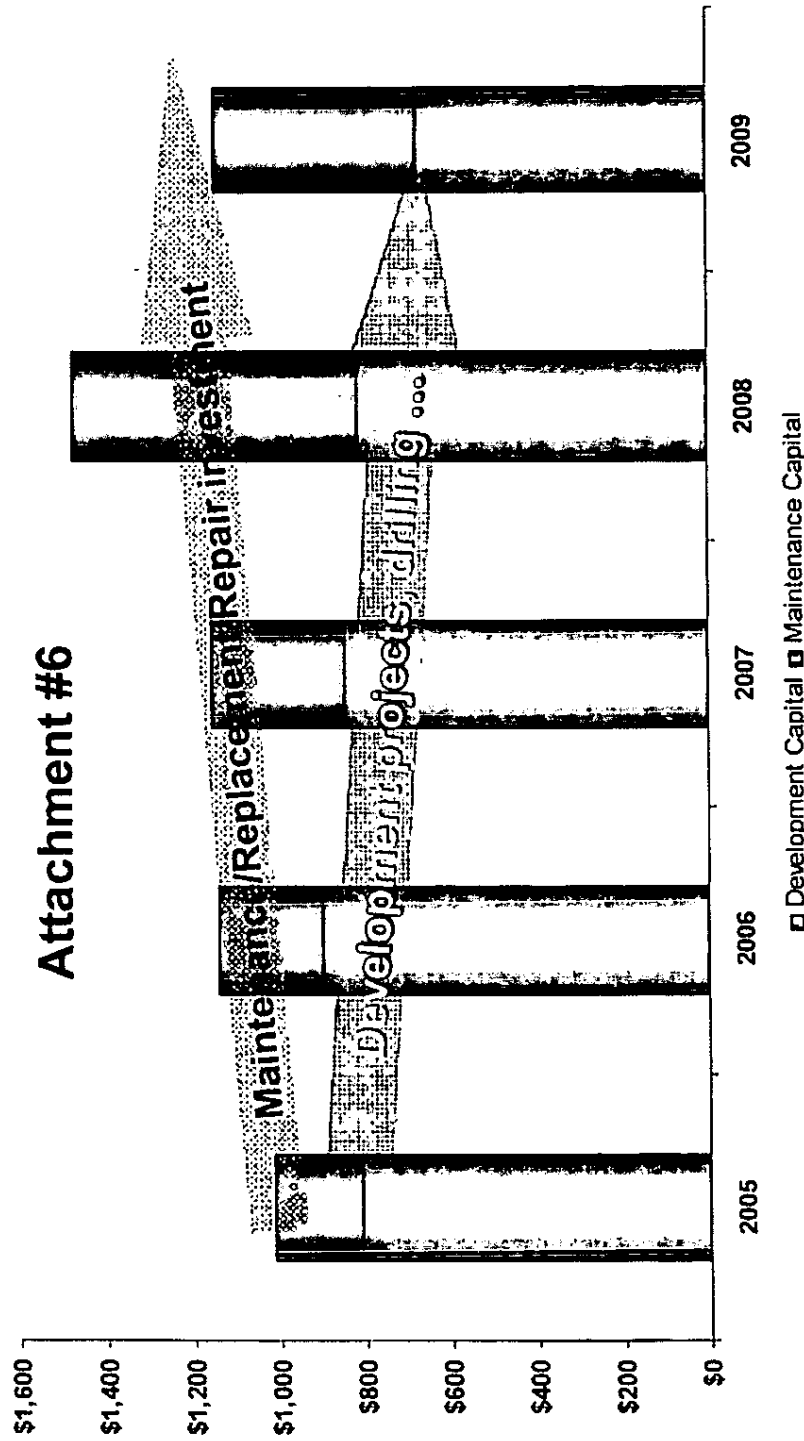
Maintenance investment essential to extending field life

Source: ConocoPhillips internal

ConocoPhillips

Capital Portion of Core Field Investment

Core field gross investment on capital, \$MM



Capital maintenance investment essential component of extending field life

Source: ConocoPhillips internal

ConocoPhillips