3/26/09 PRESENTATION: NATURAL GAS FISCAL DESIGNS

Combined Oil and Gas Progressivity in Alaska's Production Tax II

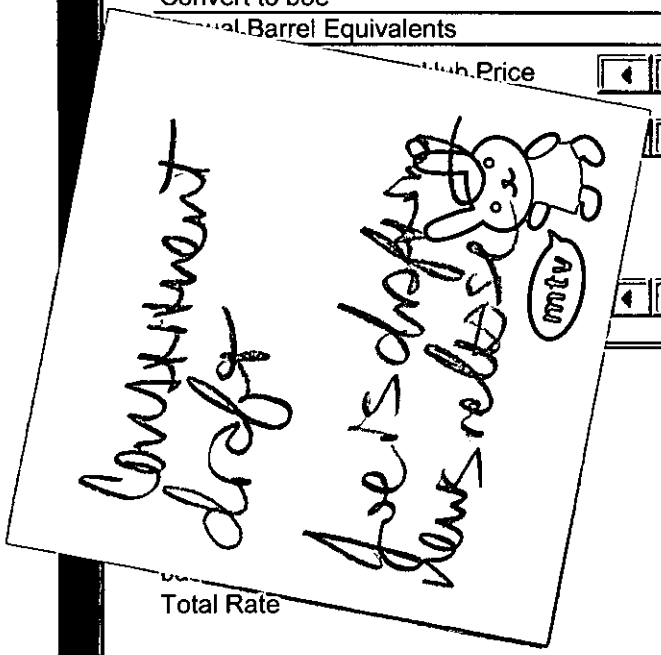
Dan E. Dickinson, CPA

Joint Hearing
Senate Resources Committee
Senate Finance Committee
Alaska State Legislature

March 26, 2009

Feb 2 Model Screen Shot - $135 oil and $6 gas - Tax Falls

	Oil Only		Incremental Gas		Combined	
Daily Vol	0.350	mmbbls/day	4.2	bcf/day		
days per year	365		365			
Annual Volume	127.8	mmbbls/yr	1533	bcf/yr		
Convert to boe	1		6			
Barrel Equivalents	127.8	boe/yr	255.5	boe/yr	383.3	boe/yr
Price	$ 135.00		$ 6.00			
			(0.75)			
	(6.00)		(2.75)			
	129.00		2.50			
	$ 16,480		$ 3,833			
	87.5%		87.5%			
	$ 14,420		$ 3,353			
	3,300		-			
	$ 11,120		3,353		$ 14,473	
	87.5%		87.5%		87.5%	
	111.8		223.6		335.3	
	$ 99.48		$ 15.00		$ 43.16	
	30.00		30.00		30.00	
	$ 69.48		$ -		$ 13.16	
	25.70%		0.00%		5.26%	
	25.00%		25.00%		25.00%	
Total Rate	50.70%		25.00%		30.26%	
	Stand Alone Oil		Stand Alone Gas		Combined	
Total Tax (Tax Rate * PTV)	$ 5,637		838.4		$ 4,380	



Sum of stand alone oil & gas: 6,475.84

Gain (loss) in production tax from using current law vs stand alone: (2,095.7)

Gain (loss) in production tax from adding gas stream under current law: (1,257.3)

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Ruggerio and Dickinson Agree I

- Dan Dickinson's testimony before LB&A on January 12, 2009 and Senate Finance February 2, 2009
- Rich Ruggerio's testimony before Senate Finance on February 2, 2009, March 11, 2009
- Rich and I agree
  - Could happen that production tax revenues fall, not rise if 4.3 bcf a day of gas added to a 700,000 bbl a day stream of oil at certain set up prices
  - I illustrated the volume effect – Rich focused on the effect of smaller oil volumes generally require great price disparity
  - I focused on price spike such as the 2008 spike; Rich confirmed that that kind of relationship between oil and gas prices only occurred in roughly 7 months out of prior 14 years: rare but not impossible
    - Price above 92.5+25=117.5 in only 3 months – but special rules

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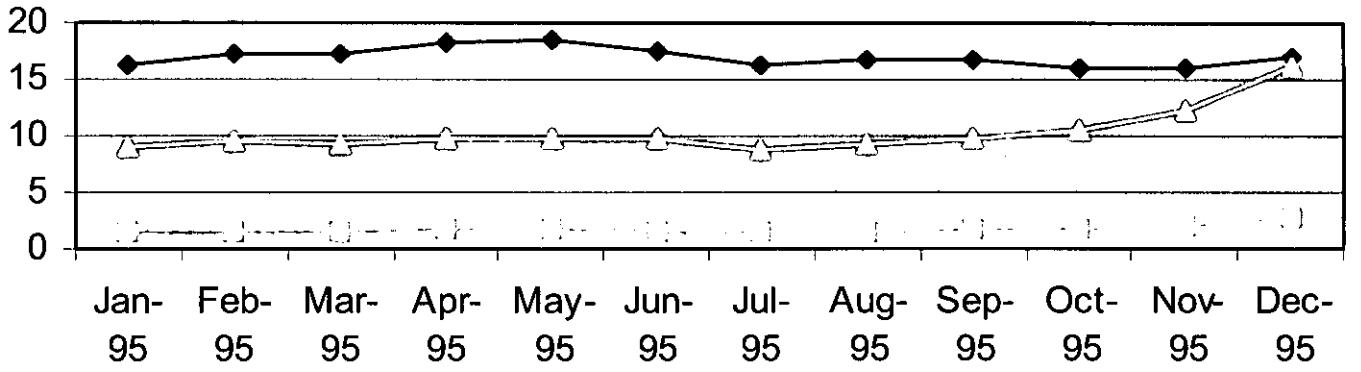
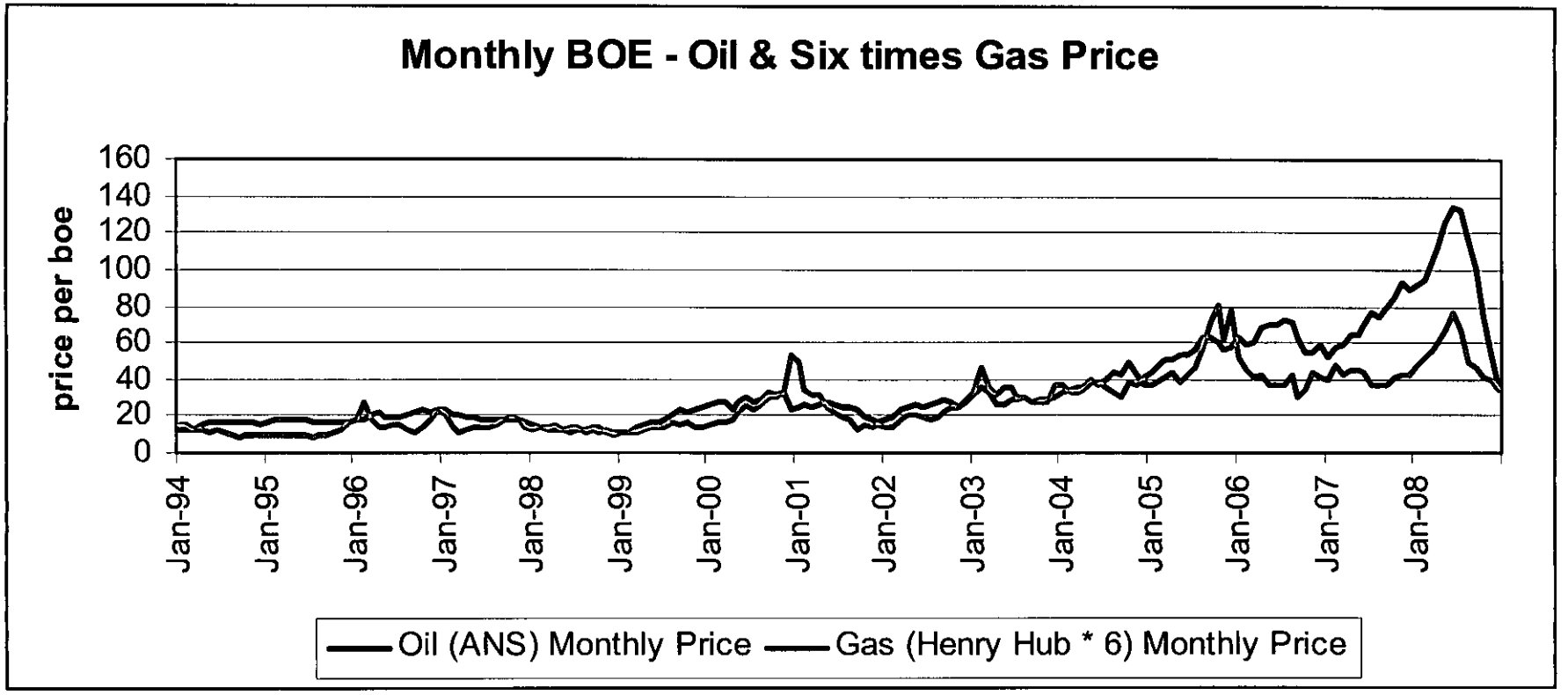
Oil Valued way above 6:1 gas btu parity: 1995



	Jan-95	Feb-95	Mar-95	Apr-95	May-95	Jun-95	Jul-95	Aug-95	Sep-95	Oct-95	Nov-95	Dec-95
Oil (ANS)	16.16	17.14	17.31	18.36	18.43	17.43	16.23	16.72	16.65	15.96	15.88	16.94
Gas (Henry Hub)	1.52	1.59	1.54	1.63	1.64	1.62	1.44	1.56	1.64	1.77	2.04	2.71
Gas ((Henry Hub * 6)	9.12	9.54	9.24	9.78	9.84	9.72	8.64	9.36	9.84	10.62	12.24	16.26

Source: Oil prices from DOR website, Gas prices from St Louis Federal Reserve website

Oil versus Gas 6:1 thermal parity



Source: Oil prices from DOR website, Gas prices from St Louis Federal Reserve website

Ruggerio and Dickinson Agree II

- Rich and I agree
- Single month or year snapshots only tell part of the story. Full cycle economics also important
  - Progressivity example better illustrated with monthly snapshot

Monthly Progressivity Example

	Oil Only		Incremental Gas		Combined	
Daily Vol	0.350	mmbbls/day	4.2	bcf/day		
days per year	30		30			
Annual Volume	10.5	mmbbls/mo	126	bcf/mcf		
Convert to boe	1		6			
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%	
	Stand Alone Oil		Stand Alone Gas		Combined	
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)**

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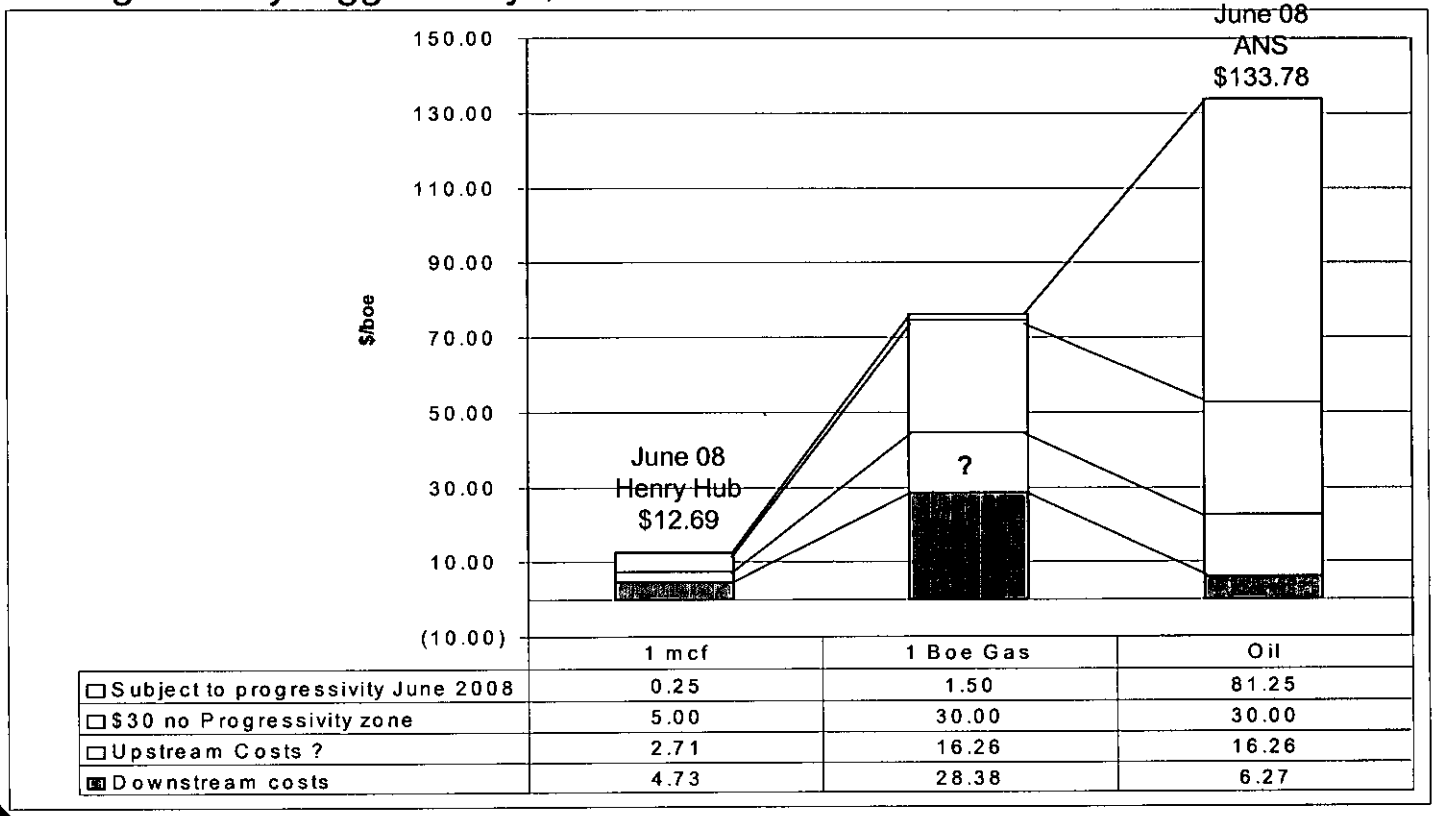
Ruggerio and Dickinson Agree III

- Rich and I agree
  - In material presented by Administration and Gaffney & Cline in 2007-2008 when focus was primarily on current oil production.
  - Under current law taxpayer can lower taxes on production from mature high "cash flow" projects by investing in beginning of other "low cash" projects
  - Works same way for ownership of
    - heavy oil deposits and 40 degree API Prudhoe Bay crude
    - High value oil and generally lower value gas
- Where Rich and I disagree – Further investigation of distinct gas tax warranted?

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



	1 mcf	1 Boe Gas	Oil
Subject to progressivity June 2008	0.25	1.50	81.25
$30 no Progressivity zone	5.00	30.00	30.00
Upstream Costs ?	2.71	16.26	16.26
Downstream costs	4.73	28.38	6.27

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

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Potential Dimensions of a Distinct Gas Tax

- If main issue is cross subsidy between oil and gas - may only need look at distinct oil and gas progressivity rather than (CPT) combined progressivity
  - Distinct mechanisms for oil and gas taxes would require allocation of costs between oil and gas. Like the 6:1 ratio embedded in current law, a simplifying compromise with side complications, though not impossible
- If main issue is difference in cost structure, may need to look at break points, "progressivity trigger" and rates in GPT (gas progressivity).
- If main issue is competitiveness in government-take as that fits into cost structure, may need to look at other aspects of gas tax.

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Looking Forward: TransCanada's AGIA application suggestion:

- "TransCanada would rely on the State of Alaska to take all feasible actions exclusively within its authority as a sovereign power to ensure a favorable economic environment for potential Shippers on the Project. Those actions include:
  - engaging with the ANS producers to reach agreement on a commercially reasonable and predictable upstream fiscal regime that balances the needs of the state and the ANS producers;
  - and encouraging robust exploration for and development of new natural gas resources and the commitment of such resources to the Project."

Source: TransCanada, Application for License, Alaska Gasline Inducement Act (November 30, 2007) page 2.5-52

Looking Forward: ConocoPhillips' Proposal

- ConocoPhillips' Proposal (ConocoPhillips current owner with BP of Denali Project)

  "The predominant lessee risk that should be the focus of discussion with the State is the risk of unclear, unpredictable State taxes and royalties. In order to enable shippers to make long term shipping commitments, prospective shippers need clearly defined natural gas fiscal terms and an understanding of the period during which these terms will apply. Addressing these issues remains a critical component necessary to develop ANS natural gas resources and make this Project a reality."

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Source: ConocoPhillips, ANS Natural Gas Pipeline Proposal to the State of Alaska, (November 30, 2007) section IV page 5

Thank You

Dan E. Dickinson CPA
Anchorage, AK
ddickinsoncpa@gci.net
907 301 1565

Senate Finance Committee and Senate Resources Committee Joint Hearing

David Wood
26th March 2009

Preliminary Report on a Fiscal Design for the Development of Alaska's Natural Gas

Presentation Structure

This presentation focuses on the key findings of the report: *"Preliminary Report on a Fiscal Design for the Development of Alaska's Natural Gas"*.

- Report & presentation objectives
- What are the issues for Alaska's fiscal regime when applied to gas?
- What are the fiscal designs applied by other countries?
- Fiscal elements commonly combined to optimize government take
- Alaska's Prevailing Fiscal design
- Complications of combined oil and gas progressivity tax (CPT)
- Multi-year and multi-scenario fiscal performance cash flow models
- Fiscal designs go beyond upstream issues and influences
- Conclusions and recommendations of preliminary study

Report and Presentation Objectives

Report & Presentation Objectives

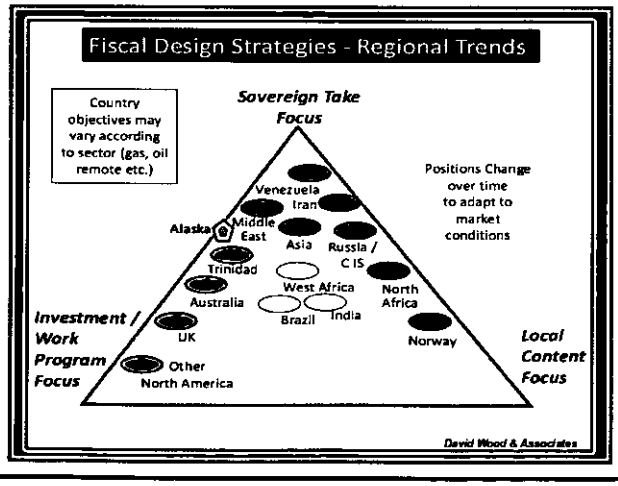
Review findings of this 8 months of study into Alaska's fiscal design for natural gas in the context of the international natural gas industry.

- Issues for Alaska's upstream fiscal design for natural gas
- Structure and interplay of regressive and progressive fiscal elements
- Fiscal designs of major natural gas producing nations
- Multi-year cash flow models to evaluate performance of fiscal designs
- Fiscal instability, credibility and certainty
- Complications associated with combined oil & gas progressivity tax
- Further models that would help make future fiscal design decisions

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

Fiscal Designs are Best Driven by Clear Fiscal Objectives & Strategies

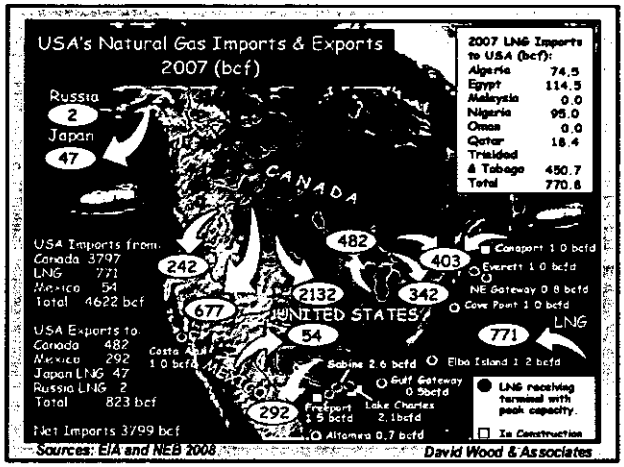
Upstream fiscal designs should reflect the broader strategies and objectives that governments are striving to achieve.



A clear statement of fiscal design strategy by a government can help to enhance its fiscal credibility. Perceptions of the fiscal strategy are important in the persuasion of large investors to sanction projects

Providing a Fiscal Regime that Accelerates Monetization of Gas

Alaska has substantial natural gas reserves that have remained stranded for decades. Lower 48 states have a thirsty and growing market for gas.

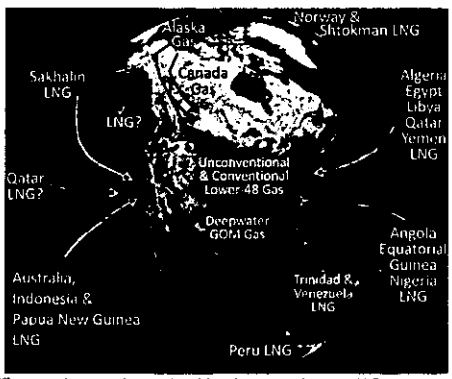


Alaska's aspirations for "the Gas Line" span more than three decades.

However, market drivers and competition have significantly in recent years.

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

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.

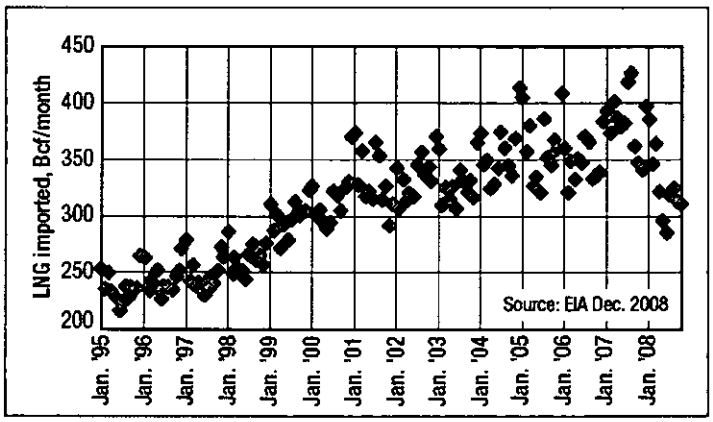
David Wood & Associates

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.

Gas Imports to US Decline in 2008 For First Time in More than a Decade

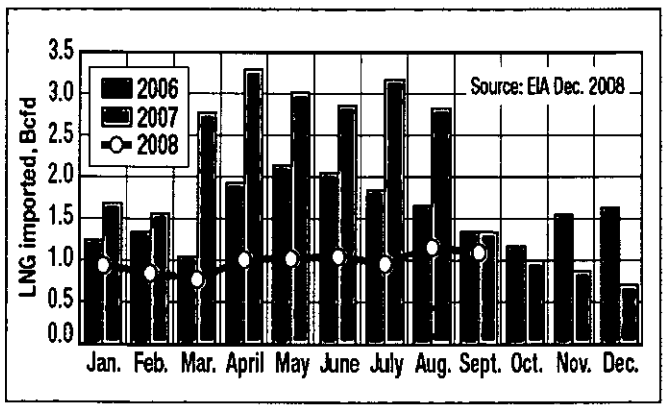
A consequence of greater Lower-48 gas production in 2008 was a reduction in US gas imports.



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

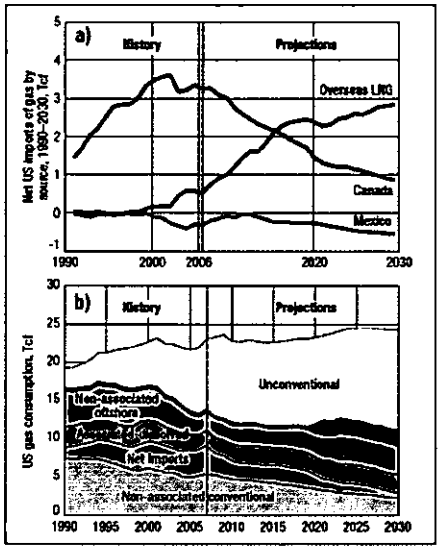
Lower LNG Imports to U.S. in 2008

Monthly LNG imports to the US, 2006–2008 show significant decline for 2008.



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

U.S. Long-term Views on Gas Supply Changed Dramatically During 2008

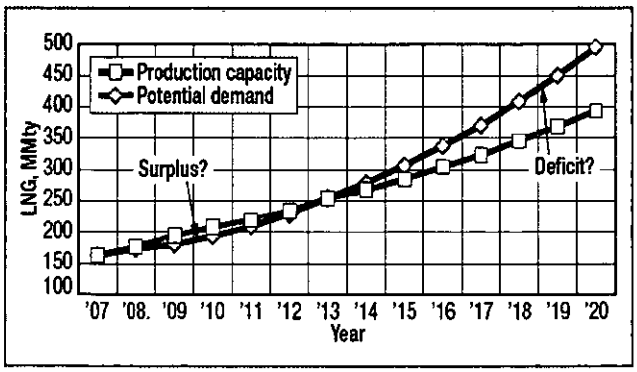


EIA Annual Energy Outlook June 2008 (top) and December 2008 (bottom) show quite different views with unconvenental lower-48 gas and Alaska gas replacing imported LNG.

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

Global LNG supply demand forecast to 2020

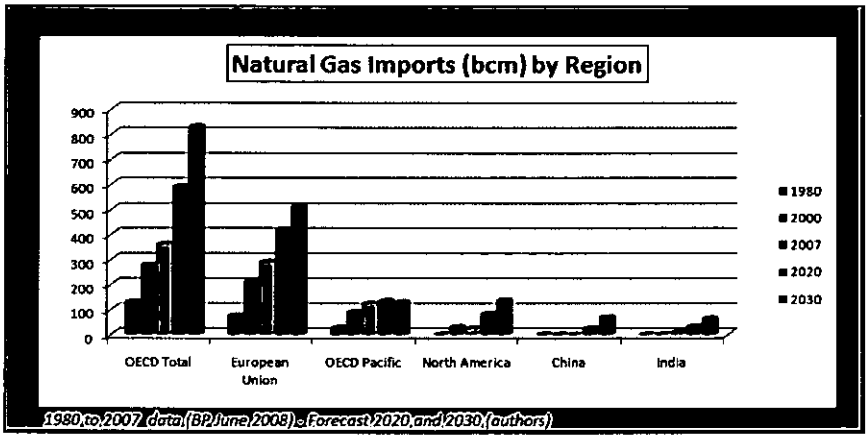
Natural gas surplus due to economic downturn and development of competing supplies is leading to over-supply and lower prices forecast to last perhaps to 2012 for internationally traded LNG. This surplus may itself fuel supply shortfalls globally beyond 2013 and higher prices 2015 to 2020.



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

International Gas Markets are Growing - Competition for Gas is Increasing

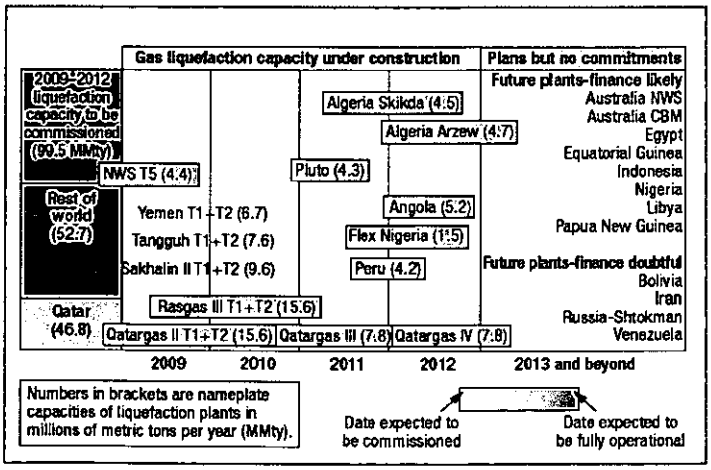
How key gas import markets compare and are forecast to grow in absolute terms (bcm = billions cubic metres; 35.3 bcf = 1 bcm).



In Press 2009, Journal of Natural Gas Science & Engineering

Worldwide New Gas Liquefaction Developments to 2013 and Beyond

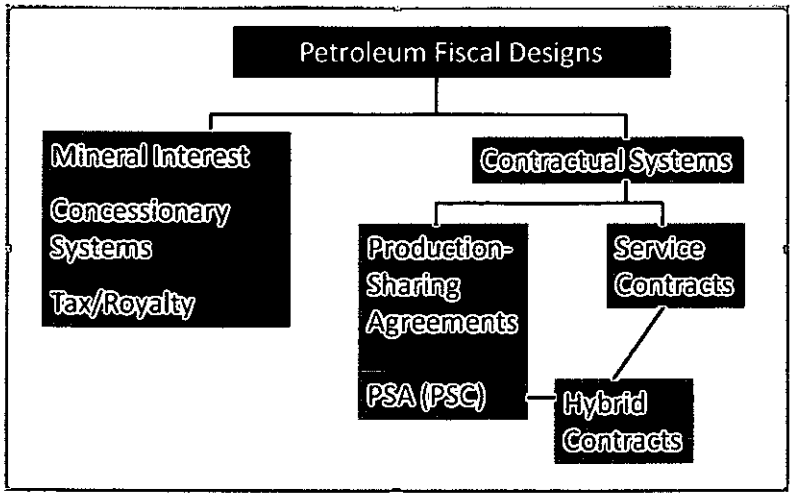
Large new capacity of LNG coming into the market with new plants under construction.



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

What are the fiscal designs applied by other countries?

Summary of Upstream Oil & Gas Fiscal Designs



Fiscal Terms of 23 Countries and Regions Reviewed

Those countries that could compete for large gas developments (e.g. $20 billion plus) over the next decade are marked with a star.

Alaska ☆	Algeria ☆
Angola ☆	Australia ☆
Azerbaijan	Bolivia ☆
Brazil ☆	Canada - Alberta ☆
Canada – Other Provinces ☆	Egypt ☆
Indonesia ☆	Libya ☆
Malaysia ☆	Nigeria ☆
Norway ☆	Papua New Guinea ☆
Peru ☆	Philippines
Qatar ☆	Russia – Sakhalin II ☆
Trinidad & Tobago ☆	Tunisia
United Kingdom	Other USA ☆

Algeria: Gas Fiscal Terms Summary

Algeria operates both mineral interest and production sharing systems. Since the new hydrocarbon law of 2005 mineral interest favored.

- Tax on revenues (TRP) with transport and NGL processing deductible
- Tax on income (ICR) 30% (or 15% if earnings reinvested)
- State participation 51% fixed (huge reduction to IOC revenues)
- Tax on extraordinary income (TPE) Sliding scale windfall tax on oil (5% to 50%) – starts at $30 / barrel (Brent) and is not deductible.
- Alnaft (gas agency) monitors long-term gas contracts
- Minimum 85% take or pay required
- Property taxes, water use and carbon credit transfer costs may apply
- Farmout assignments charged at 1% of transaction value
- Government take some 75% of revenues (depending on project and

Angola: Gas Fiscal Terms Summary

Production sharing agreements now dominate fields under development. Many of the new fields are large deepwater oil fields with associated gas.

- Large signature bonuses
- Up to 50% revenue allocation available each year for cost recovery
- Capital costs uplifted by some 20% to 50% (negotiable)
- Profit sharing on sliding scale driven by post-tax IRR rising to 80% to government at high IRRs. Scale is negotiable.
- Petroleum Income tax 50% of producers' profits
- Gas negotiations linked to no flaring rules
- Producers offered low prices to supply LNG plant under construction.
- High-cost deepwater gas gathering infrastructure as well as LNG plant to finance and build.

Norway: Gas Fiscal Terms Summary

Norway operates a mineral interest system. There are no bonuses or royalty 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 CO_2 emissions at 0.79 NOK (~10 US cents)/ m^3 CO_2
- Gas taxed on bases of actual realised prices.
- Rules 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.*

Papua New Guinea (PNG): Gas 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% (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 FEED study of PNG LNG ongoing

Qatar: Gas Fiscal Terms Summary

Qatar operates a development and production sharing agreement (DPSA) system providing access for IOCs to some of world's largest gas reserves.

- Qatar Petroleum (QP) NOC usually holds 65% to 70% equity
- Integrated upstream and downstream projects (gas and NGL production linked with LNG, GTL and petrochemicals) are typical.
- Up to 50% revenue allocation available each year for cost recovery
- Upstream gas price fixed at low value (feedstock to downstream)
- Profit gas shared on volume (e.g. <130 mmscf/d 65% goes to QP; >520 mmscf/d 90% goes to QP). Scales are negotiable.
- Value mainly in LNG etc. where producer share is typically 30% subject to 35% corporate income tax. Upstream income exempt CIT.
- NGL and condensate profit split is on a negotiable sliding scale driven by an R-factor (e.g. R <1 QP share is 65%, R>2.5 QP share 90%).

Trinidad & Tobago (T&T): Gas Fiscal Terms Summary

T&T operates mineral interest and PSA systems, but prefers the latter.

- Mineral Interest :
  - Royalty 10% (increased in 2005)
  - Petroleum profits Tax (PPT) 50% (+5% unemployment levy)
  - Supplemental Petroleum Tax (SPT) on oil sliding scale on prices
  - Green fund levy 0.1% of gross revenue
  - Petroleum production levy 3% of total income
- Midstream /downstream projects 35% special corporate tax
- Withholding tax 15% (US no tax treaty so paid by US companies)
- PSC:
  - Cost gas allocation negotiable – typically 40% to 50%
  - Profit share driven by production rate and gas price scales (e.g. at low rates prices producer gets ~45% at high rates/prices producer gets ~15%).
  - Ring fence around PSC area
  - Fiscal stability clause and exemption from other taxes

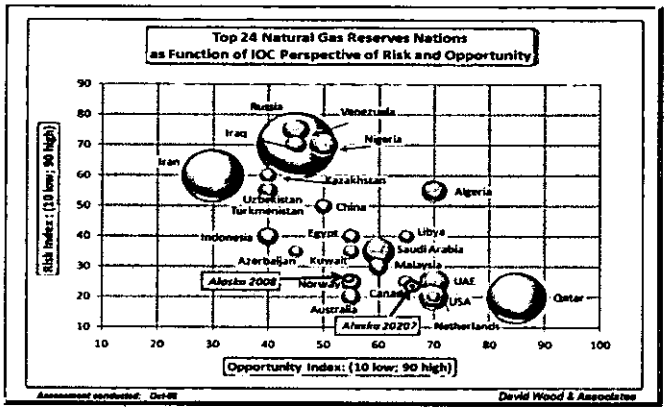
Factors Used to Assess Gas Producer Regional Risk and Opportunity

In addition to identifying projects with positive discounted cash flow potential and offering competitive producer post-tax takes superficial risk and opportunity analysis evaluates the following:

- The five attributes used to evaluate for scoping ***risk*** analysis are focused mainly on political, business and fiscal risks:
  - Expropriation / overall political instability (RL & NI components)
  - Corruption
  - High administrative burden (cost & time)
  - Community/ labor disputes
  - Regressive and inflexible fiscal terms
- The five attributes used to evaluate for scoping ***opportunity*** analysis are focused mainly on technical, operational and financial risks:
  - Access to large reserves
  - Low finding and development costs
  - Ease of operation
  - Access to equity /debt funding
  - Access to infrastructure / markets

Alaska Gas Compared on International Scale of Risk versus Opportunity

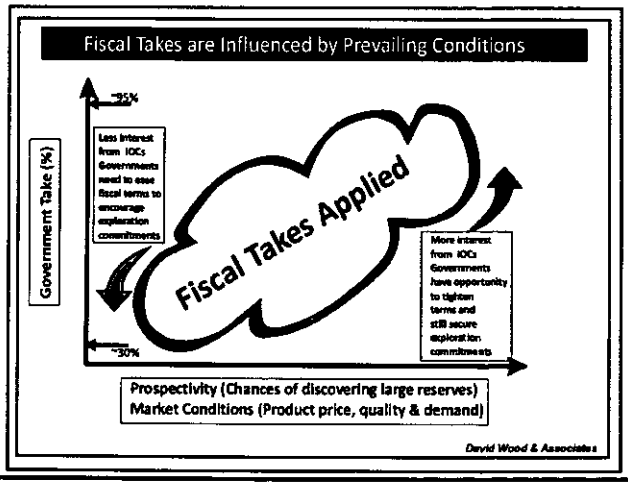
The diameters of the bubbles are proportional to proved natural gas reserve holdings as reported by BP Statistical Review (June 2008).



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

Overall Government Takes from Gas Production Varies Substantially

Governments need to retain the ability to adjust fiscal designs to meet changing conditions.



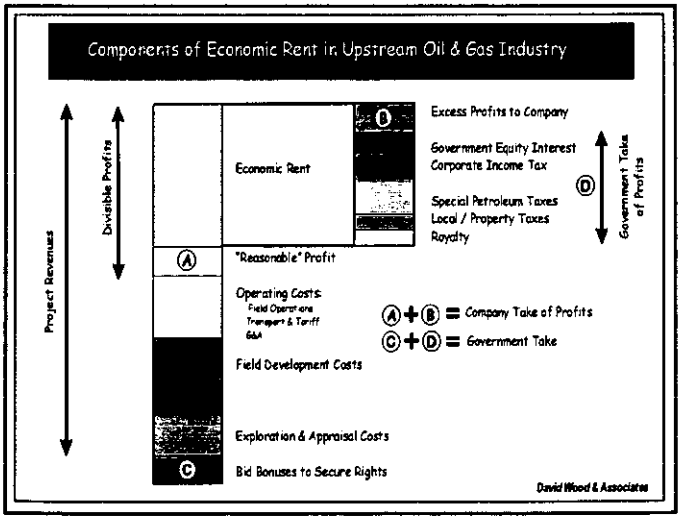
Most governments open new areas for licensing, re-licensing, or for contract by IOCs in stages over time.

Often such activity is linked to bidding rounds. It is useful for the governments to retain rights to adjust fiscal terms associated with new licensing.

Fiscal elements commonly combined to

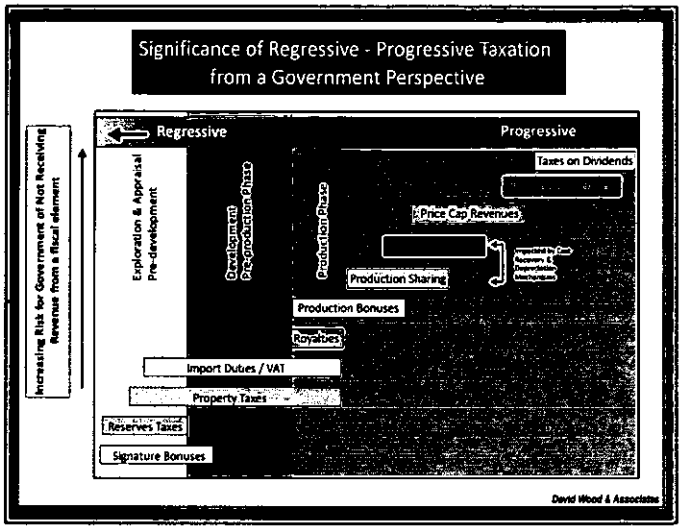
optimize government take

Fiscal Designs Focus on the Division of Economic Rent



Government take comes mainly from the revenue stream but bonuses and pre-production taxes also contribute.

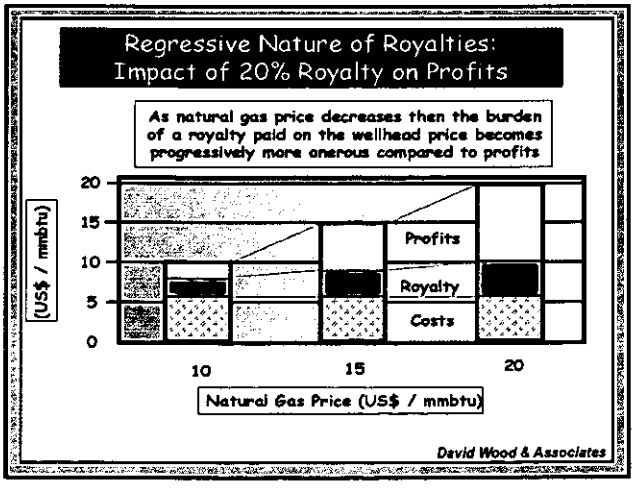
Progressive & Flexible Fiscal Designs Help to Promote Investment



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.

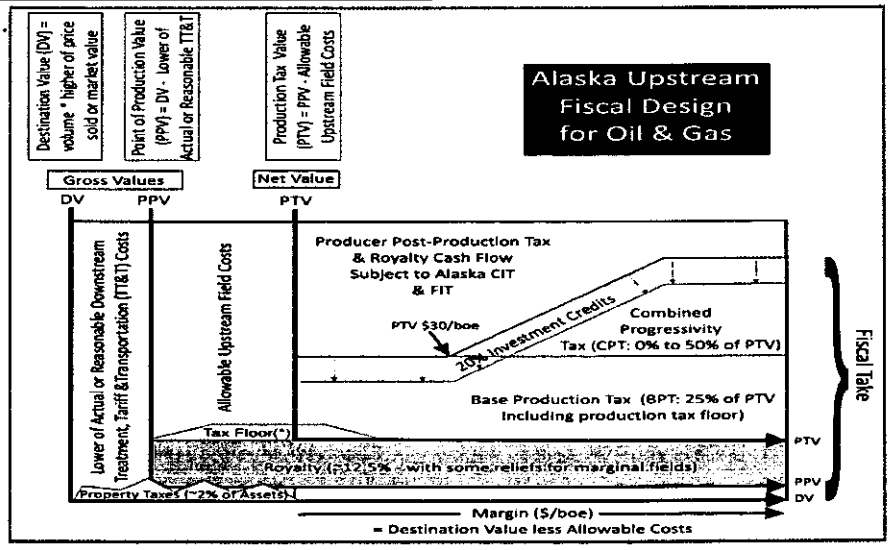
Regressive Impact of Royalty

Royalty takes a higher percentage share of profits at lower prices.



Alaska's Prevailing Fiscal design

Schematic of Alaska's Prevailing Oil & Gas Fiscal Design



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

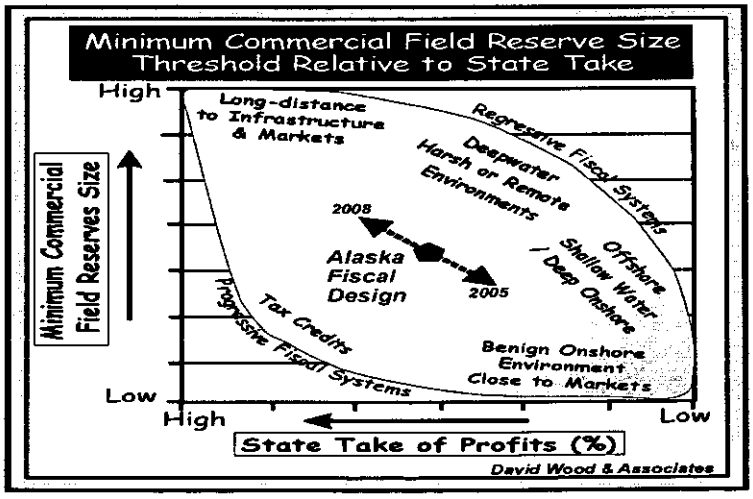
These regressive elements are partially offset by:

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

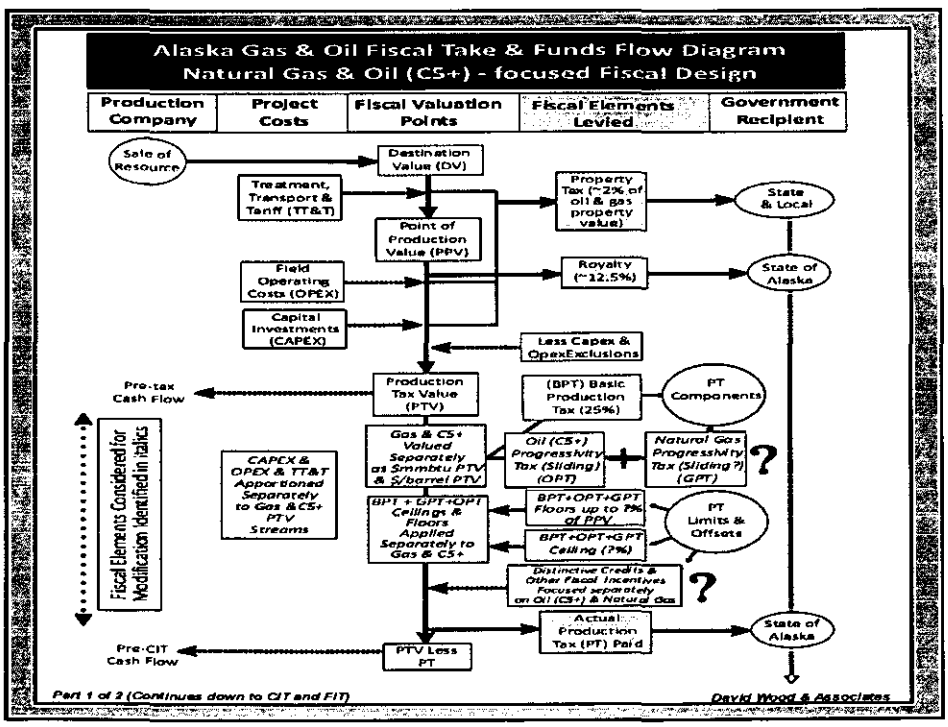
Other allowances / credits for producers should be considered to offset impacts of regressive elements coupled with tougher progressivity terms.

Regressive Fiscal Designs Increase Minimum Commercial Field Sizes

Tax credits can help offset some regressive fiscal elements.



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

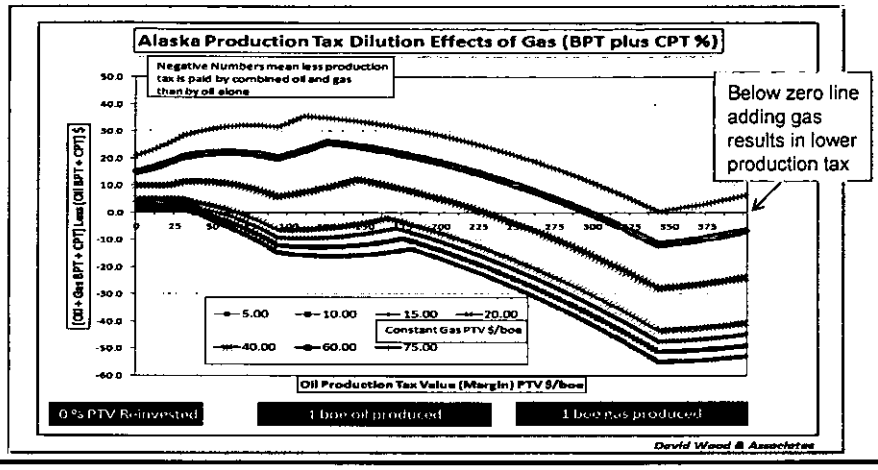
Analysis has identified that three factors are relevant to the dilution effects under prevailing production tax paid by an existing oil- only case with the addition of gas production (and vice versa – i.e. oil added to a gas-only case). These factors are:

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.

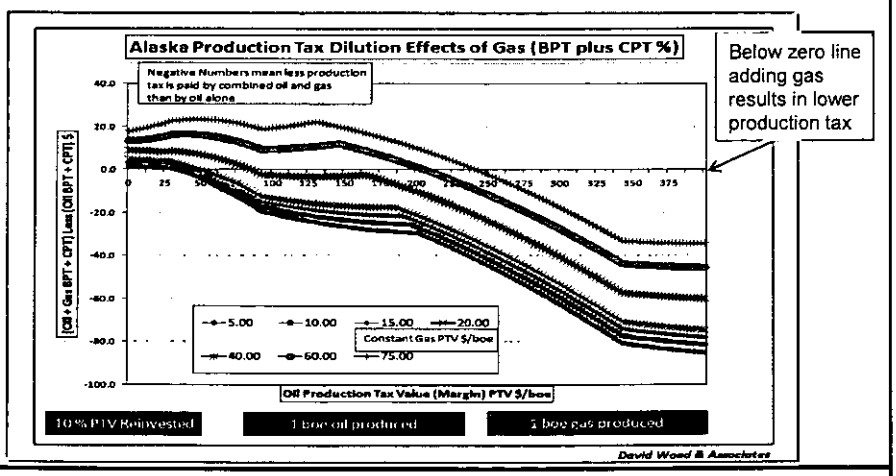
Natural Gas Dilution Effects on Combined Oil & Gas Production Tax

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.



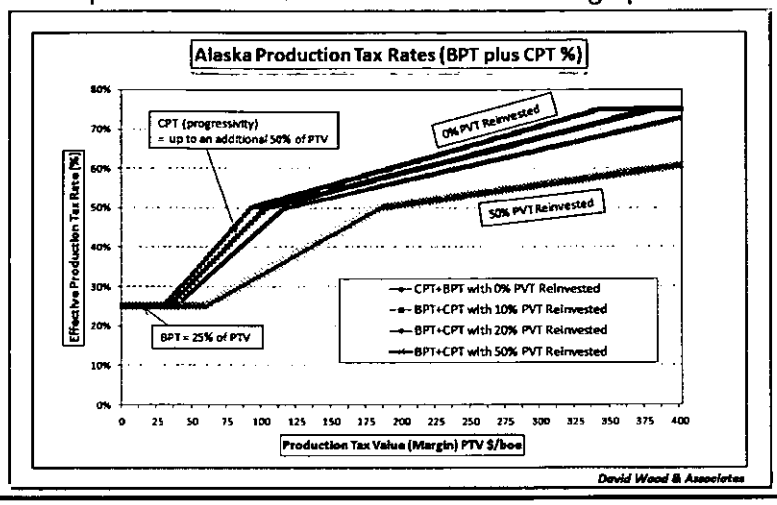
Natural Gas Production Tax Dilution Effects Impacted by Reinvestment

If some of the PTV is reinvested the reduction in production tax paid is significantly greater. This graph shows the impact of 10% reinvestment.



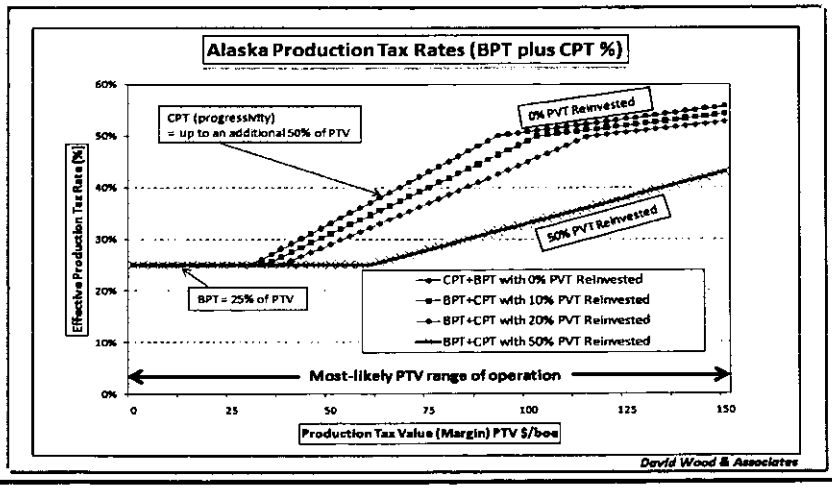
Natural Gas Production Tax Dilution Different Reinvestment Scenarios

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



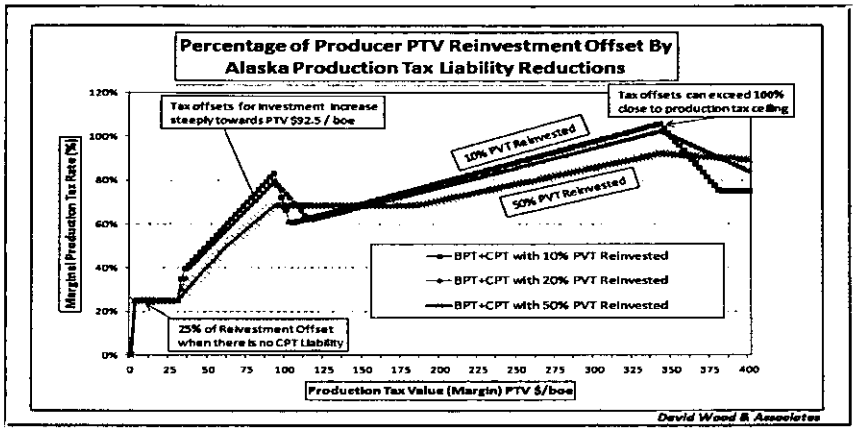
Reinvestment Scenarios For PTV Range $30/boe to $150/boe

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.



Implications of Analysis

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

1. It is difficult to predict (from tax authority and 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) production tax outcomes can be counterintuitive.

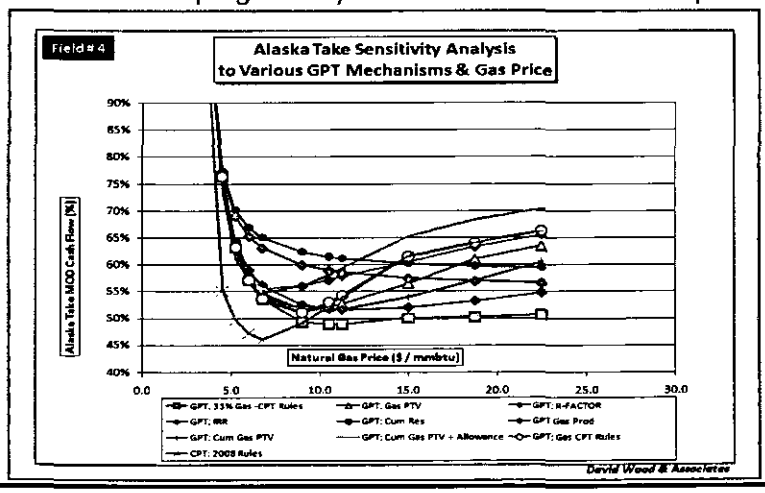
Alternative Drivers of Gas Progressivity Tax Evaluated by Fiscal Model

Ten different mechanisms are evaluated. No.1 represents the status quo evaluating gas progressivity as a combined revenue stream with oil (boe).

1. CPT: 2008 Rules (combined PTV/boe)
2. GPT / OPT: separates gas and oil on PTV/boe scale
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

Ten Progressivity Mechanisms: Sensitivity Analysis

A large gas field (5 tcf reserves) illustrates the impact on Alaska's state take of cash flow of the ten progressivity mechanisms at different oil prices.



Multi-year and multi-scenario fiscal

performance cash flow models

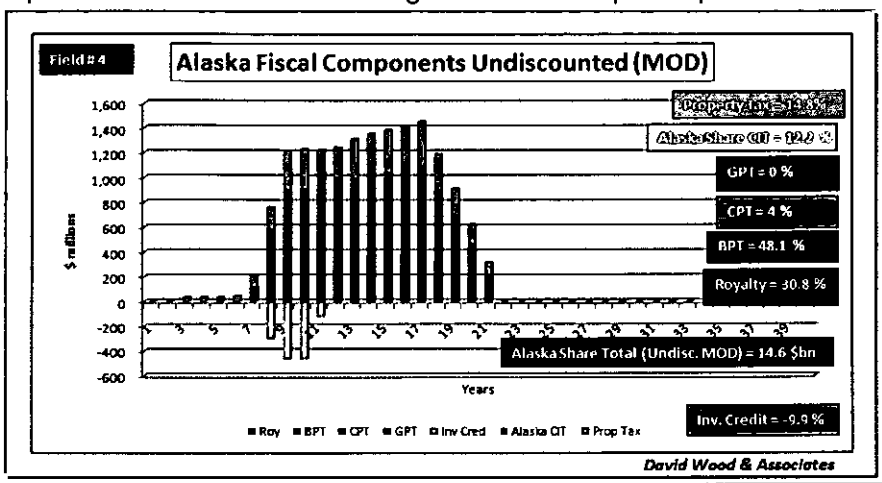
Hypothetical Field Cases Evaluated

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.

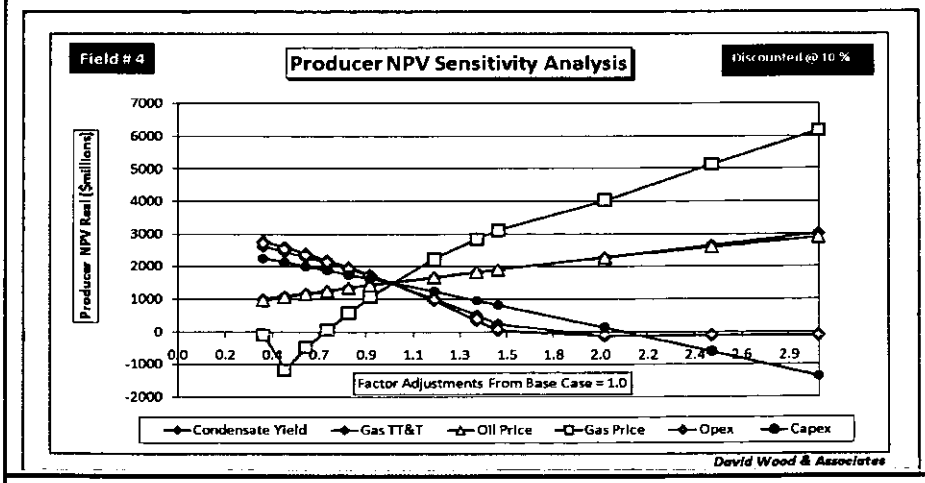
Alaska Fiscal Take Varies Over Field Life

Components of Alaska fiscal take for a large gas field (5 tcf) showing the impact of investment credits during the field development phase.



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.



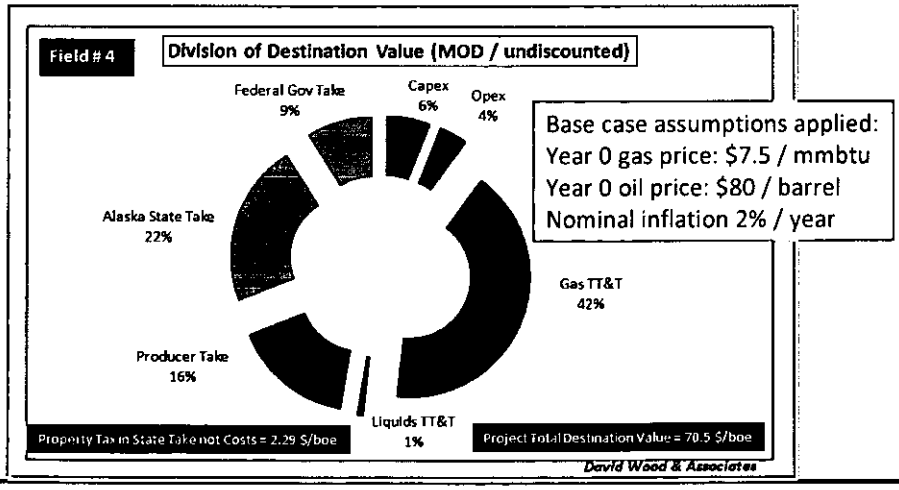
Base Case Hypothetical Field Models Reveal High-level Implications for Government Take

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

- For oil fields (with associated gas):
  - Government take of destination value (gross) is about 60%
  - Government take of destination value less costs (gross) is about 75%
- For natural gas fields (non-associated gas with NGLs):
  - Government take of destination value (gross) is about 30%
  - Government take of destination value less costs (gross) is about 67%
- Exact percentages vary with field sizes, prices and costs.

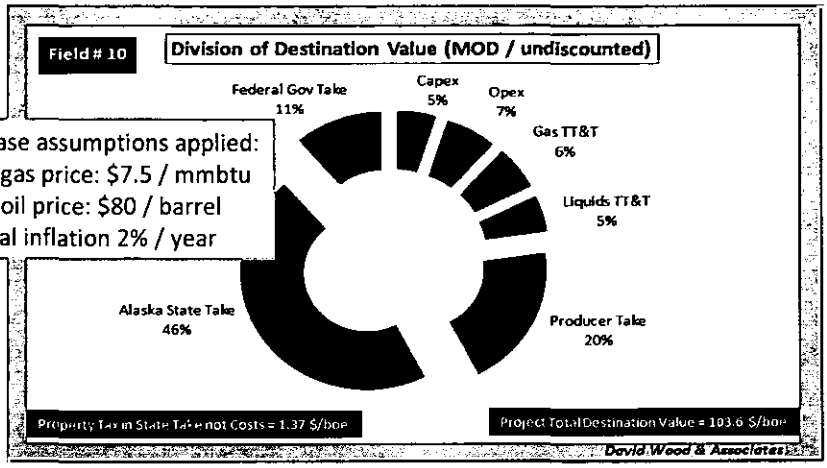
Large Gas Field: Division of Destination Value

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.



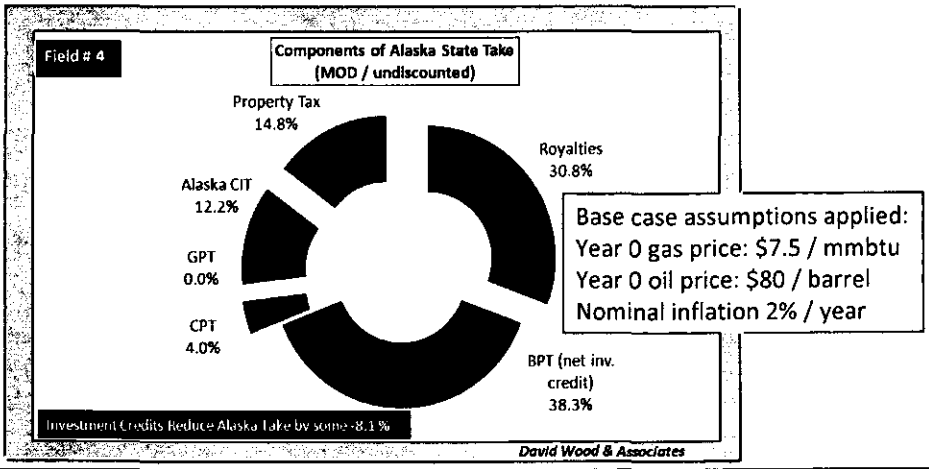
Large Oil Field: Division of Destination Value

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



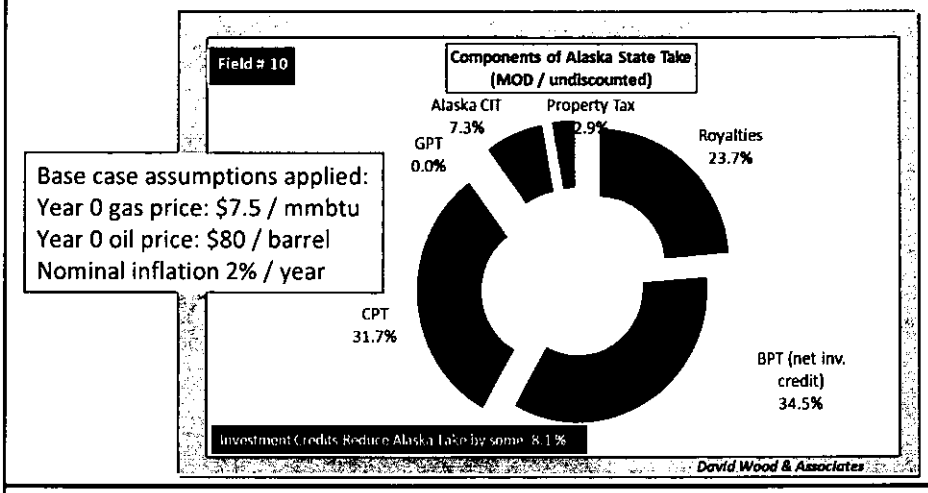
Components of Alaska State Take for Large Gas Field

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 progressivity tax account for two-thirds of Alaska state take for this 500 mmb oil field.



Fiscal designs go beyond upstream

issues and influences

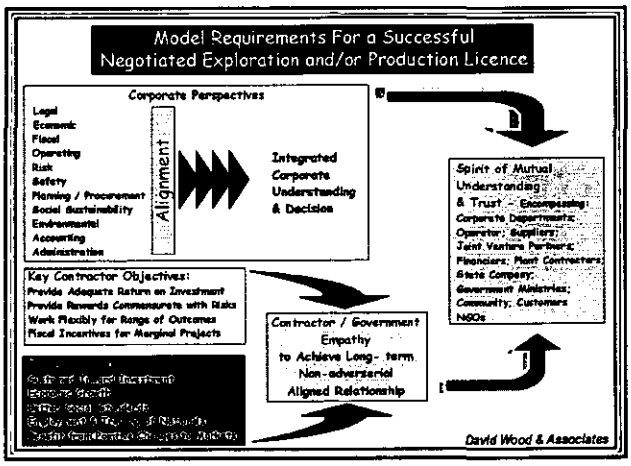
Integrated Upstream & Downstream Fiscal Designs

IOCs have demonstrated more enthusiasm around the world for downstream infrastructure project investments that are integrated with development of upstream resources (e.g. Algeria, Nigeria, Russia, Qatar etc.).

- IOCs have signed up around the world to progressive systems with high marginal government takes (with significant government equity shares) when gas values are high and with limited access to reserves.
- They have been more likely to do so when:
  - there are incentives and/or allowances available to compensate for regressive elements when gas values are low or during field development phases.
  - integrated upstream and downstream projects granting them exclusive access rights to those resources (limited TPA).
  - terms are controlled by contracts.

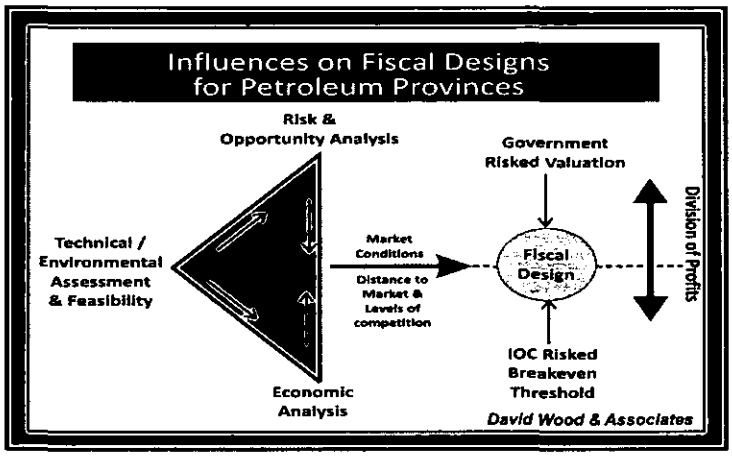
Alignment between Government and Producer Objectives

Alignment of purpose should be taken into consideration when formulating fiscal designs. Win-win outcomes take a long-term view to achieve.



Influences on Fiscal Design

Technical, economic and risk analysis will determine whether fiscal designs on offer provide acceptable levels of return to justify IOC investment.



Fiscal Instability and Fiscal Credibility

The IOCs have experienced unprecedented fiscal instability around the world in recent years, coupled with greater political uncertainty.

- There are different degrees of fiscal instability culminating in the extreme in expropriation of assets.
- Milder forms of instability involve changing fiscal terms with various degrees of retrospective impacts on existing leases and contracts.
- IOCs are facing more competition from NOCs to access large oil and gas reserves and political manipulation by governments.
- Such factors make the U.S. (and other OECD countries) more attractive regions for risk investment where large reserves exist.
- Although issues of fiscal stability and credibility remain important and take time to establish they are only one of several factors that will influence IOC investment decisions in upstream developments.

Guarantees of Fiscal Certainty

IOCs often seek fiscal certainty in exchange for committing to very large investments in strategic infrastructure and reserves development.

- Issuing such guarantees is risky for governments.
- Implement flexible and progressive fiscal designs is a better approach
- Clear, pro-commercial fiscal strategy statements improve confidence
- If guarantees are offered they should involve:
  - limited time periods
  - reciprocal commitments from IOCs to place ceilings on costs
  - more regressive fiscal elements than if no guarantees given
- Retaining the right to adjust fiscal terms enables governments to periodically change the fiscal design to respond to market conditions.

Conclusions & recommendations of

preliminary study

Conclusions Regarding Progressivity Tax Structure

Complications in CPT lead to the following general conclusions:

1. Under the current production tax rules (CPT) the impact of natural gas revenue on the magnitude of combined production taxes is difficult to predict making tax planning difficult (for both state and producers).

2. This is likely to render the production tax structure unstable in the long term and to require future adjustments by the legislature to progressivity rates and thresholds according to prevailing conditions.

3. Such adjustments would have significant impacts on investors and risk undermining fiscal stability and credibility over the long term.

4. By separating CPT into GPT and OPT these problems are removed and incentives can be structured in a transparent way. Under separate oil and gas taxation streams the combined production taxes become more predictable, stable and flexible.

Useful Analysis to Aid Natural Gas Fiscal Design Yet to be Conducted

The dilution effect of production tax is one of several issues that suggest that the natural gas fiscal design requires some adjustment. A first step is to establish a strategy for what a revised fiscal design should achieve. In order to help this process the following analysis could be conducted.

1. Establish and compare multi-year cash flow models for Prudhoe Bay and Point Thomson fields to evaluate from a natural gas perspective the taxation outcomes a range of scenarios: 1) Gas pipeline alternatives; 2) LNG plant at Valdez; GTL plant on the slope; and others.

2. Use the information from 1. together with the ten hypothetical yet-to-find fields (presented in December Report) to test alternative gas fiscal designs.

3. Evaluate the fiscal designs and specific fiscal instruments applied in the main oil and gas producing states of the Lower 48. Alaska may be competing for investment with large-scale unconventional gas projects (e.g. shale gas). It is important to understand the incentives being offered by such projects.

Approaches to Fiscal Design that Can Improve Performance & Credibility

The following are selected recommendations for Alaska from the report:

- 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 infrastructure projects
- Involve cost control components to some fiscal incentives
- Apply time constraints to new leases to develop resources

Preliminary Report on Fiscal Designs for the Development of Alaska Natural Gas

Report delivered and presented in Anchorage December 2008

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