Long-term fiscal, contractual stability proves elusive

In the first of a two-part feature, David Wood* *sets out to review the current upstream contractual frameworks, °establish their objectives, explore the reasons why they sometimes fail to deliver, and consider approaches that improve flexibility and stability.*

History has shown that during sustained periods of demand outstripping supply and resulting high oil and gas prices, governments frequently attempt to extract a larger fiscal share. Conversely, during periods of widespread recession when supply outstrips demand, associated with low prices and limited flow of capital into the industry, governments are often forced to offer fiscal incentives to attract and compete for investment. Nevertheless, even the most stoical of observers have been surprised by the pernicious and innovative nature of recent attempts by several governments to challenge and erode either contractual or fiscal value of international oil and gas projects.

Some examples of recent government-induced erosion of petroleum project value include:

- ***Kazakhstan*** – increase in taxes by amending the tax code; impounding of equipment; claiming pre-emptive rights on assignment (giant Kashagan field).[1]
- ***Russia*** – further rises in production tax (August 2004) and export tax (January 2005) add to a recent history of fiscal instability; systematic dismantling of Yukos; procurement constraints in Sakhalin projects.[2]
- ***Nigeria*** – NNPC claiming substantial back-in rights to some large deepwater discoveries (eg Agbami).[3]
- ***Bolivia*** – the introduction of a new hydrocarbon law following a referendum in 2004; government seeking to increase royalties (from 18% to 50% muted) and taxes on existing licencees.[4]
- ***Angola*** – assignment disputes with Sonangol seeking greater contractual participation; ongoing procurement constraints.
- ***Trinidad & Tobago*** – upward revision of fiscal take secured for older tax/royalty contracts (BP/RepsolYPF). Renegotiations are ongoing to impose harsher terms for existing PSAs following investment in four LNG trains.
- ***UK*** – the introduction of a 10% supplementary charge on corporation tax in 2002 illustrates that fiscal instability is not the preserve of developing nations. Historical windfall profits taxes in the US could also be cited in this regard.
- ***India*** – attempts in December 2004 by the Indian government to levy a fixed rate CESS (production tax) of some $3/b on Cairn Energy's future production from its Rajasthan production sharing contract. Cairn is disputing who should pay the CESS based upon the contract terms, which it interprets to indicate that state-owned ONGC holds that liability.[5]
- ***Venezuela*** – an increase in royalties (October 2004) on the four heavy crude upgrading projects (ChevronTexaco, ExxonMobil, ConocoPhillips, BP, Total and Statoil) in the Orinoco Belt to 16.6% from 1%.[6]

The basic principles

Figure 1 outlines a basic approach to achieving long-term contractual stability between international oil companies (IOCs) and governments (represented by their national oil companies (NOCs) and various ministries and other government agencies). It seems a matter of straightforward common sense as expressed, but all too often the reality of contract negotiations ignores these basic principles. IOCs commonly fail to integrate all the issues and risks when negotiating contracts, relying too heavily on legal, financial and economic assessments performed by groups with limited on-the-ground exposure in the country where the agreement is to operate, without taking in the bigger picture.

Governments and IOCs frequently fail to empathise with each other's objectives and look instead for ways to exploit opportunities independently and build on their individual strengths. This competitive approach works well in extracting value for the consumer in most corporate activity and is part of the rough-and-tumble of capitalism. However, it does not enhance the stability of long-term relationships in which the balance of power and value can oscillate dramatically between one party and the other.

The pendulum of power in upstream contracts swings from the government during contract negotiations towards the contractor as it invests and discovers petroleum, back towards the government as investment and technology is sunk into field and facilities development. The contractor is most exposed to contractual changes just before a field comes onstream (all investment spent, no revenue yet received) and governments have most power. During the production phase the volatility of market conditions cause value to oscillate back and forth between the parties and governments are able to use their power to claw back value, but frequently slow down investment and development as a consequence.

However, this cycle is now well established and companies and governments should be able to overcome their urges for short-term gains. A cooperative approach is usually in the interest of all parties. It involves empathy, shared vision, flexible fiscal mechanisms and agreed long-term objectives. It is unlikely to be achieved by lawyers, economists and financiers drafting and interpreting contracts remotely or dealing with issues in isolation.

Figure 1 also highlights the fact that it is not just two parties involved. Many assume that all key issues and agreements are polarised between IOCs and NOCs. This is far from reality – on the side of the state exists the NOC, ministries, agencies, local community bodies and NGOs; on the side of the IOC are joint venture partners, suppliers, engineering contractors, debt financiers, export credit agencies and, in some cases, corporate divisions with conflicting strategies. Conflicting issues amongst these parties frequently lead to minor disputes (minor, that is, in terms of the overall long-term objectives). Clearly defined and workable timeframes and principles for dispute resolution are therefore essential.

E&P agreement framework

There is a plethora of upstream fiscal and agreement structures operated worldwide, each designed to extract economic rent to suit sovereign needs. To get to the root of the instability issues it is necessary to explore and understand how these agreements work and influence the returns achieved by the parties involved. They can, in broad terms, be classified into three main groups (see **Figure 2**).

Concessions (tax –royalty) – The earliest systems originating and maintained in OECD countries where governments hold mineral rights (US excepted) and title to reserves discovered is vested in concessionaires through licences with no contract involved. Fiscal instruments include royalties, special petroleum taxes (eg the defunct petroleum revenue tax (PRT) in the UK) and corporation tax. The rates of royalties and taxes are frequently linked to other metrics that trigger specific rates and increase flexibility (see below).

Production sharing agreements (PSAs) – Since the first one was signed by US independent IIAPCO in 1966 with the government of Indonesia these have become popular with developing nations because they retain title to reserves and are able to share in the revenues from risk investments without taking the financial risks. Disputes are dealt with under contract law. The IOC receives its reward for taking E&P risks and making investments in terms of a fee made up from shares of field production. Fiscal mechanisms that determine how production is shared vary significantly from country to country, but usually involve distinctive elements relating to profit and to cost recovery (see below). Most PSAs involve exploration and production phases (EPSAs), but some (eg Qatar) are signed to cover development of already discovered reserves (DPSAs). Some PSAs attempt to achieve fiscal stability by either allocating tax and royalty payments to be made only from the government's share of production, or, including a fiscal stability clause.

Service contracts – The least favoured by the IOCs because they are engaged to perform development work on a financial fee basis (cost plus an agreed rate of return) without the opportunity to share in the upside revenues from long-term field production. There are some hybrid contracts between PSA and service types that link the IOC's fee to production performance and revenues.

These tend to place more technical and financial risk on the IOC than straight service contracts, but severely limit their long-term participation in successful ventures (eg Iran's buy-back contracts).

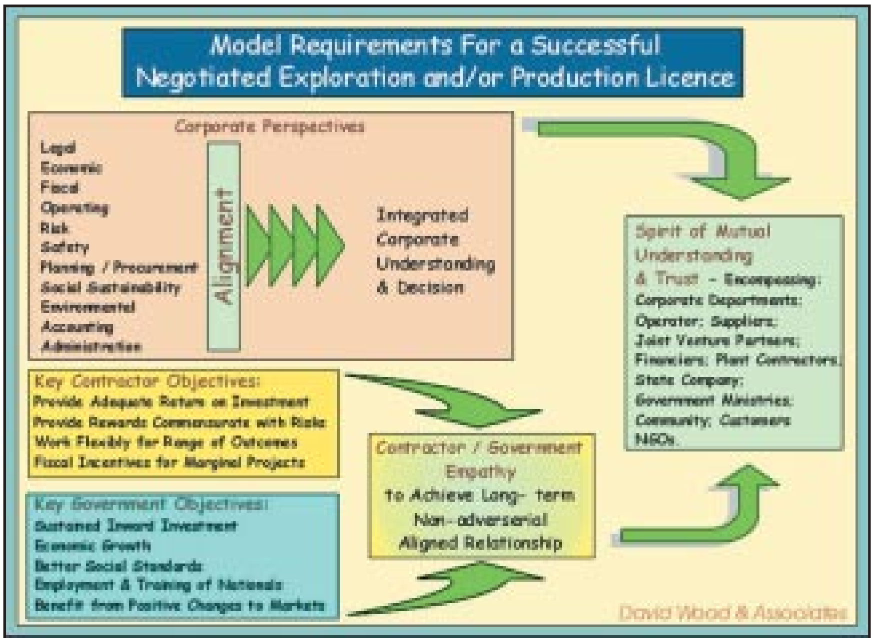

Figure 1: Basic requirements for stable long-term agreements – the word 'alignment' is the key to this approach

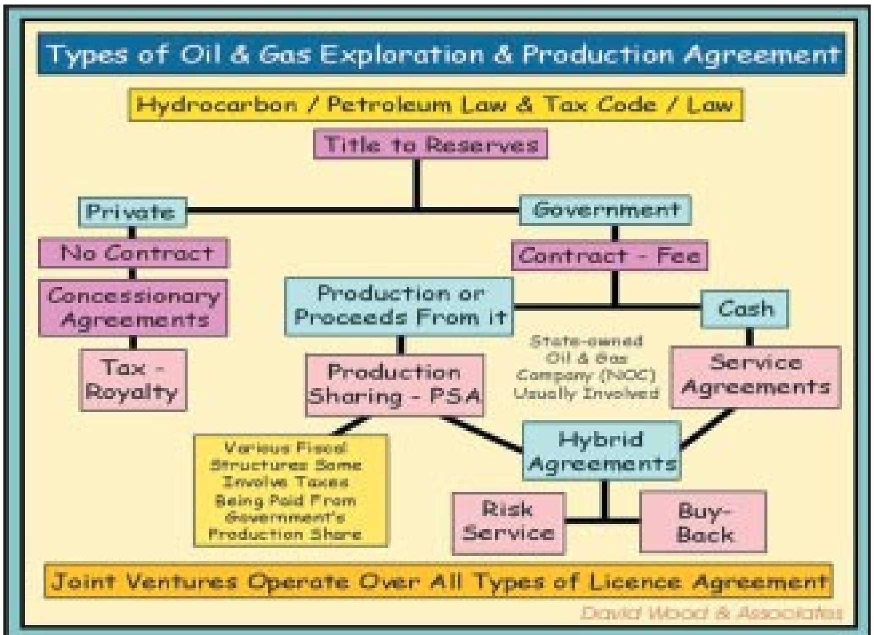

Figure 2: Classification of upstream agreement types

Not all countries operate just one or other of these types of contracts. In Nigeria, for example, projects with all three of these contract types are active. Moreover, countries may operate several contracts with different PSA mechanism for historical, geographic, variable risk or cost reasons.

Indices that attempt to rank the severity or otherwise of fiscal terms in a country should take such complexities into account, but rarely do so. This article focuses on PSAs because they are now the most common contract type employed for the exploration and development of large fields in the developing world, and are frequently associated with high political risk countries. They are not, however, embraced by all developing nations.

Several Opec countries refuse to entertain them (eg Saudi Arabia, Kuwait and Iran) and a fierce debate has ensued in Russia, which adopted a few PSAs in the 1990s (eg Sakhalin I and II) but has essentially rejected them in recent years in favour of a tax system that enables the government to more easily adjust (generally upwards) its take and control the industry in line with market conditions.

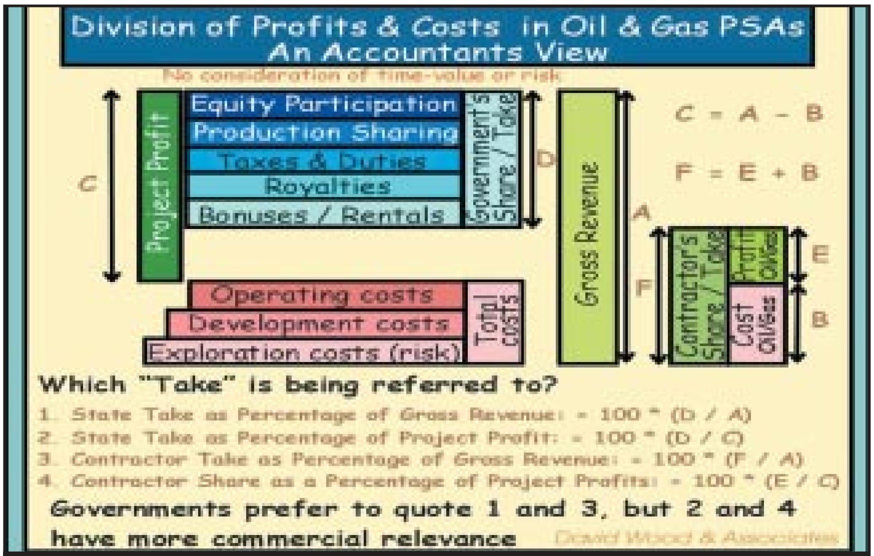

Figure 3: Make up of contractor and state takes of gross revenue and of field profits – the term 'take' requires precise qualification

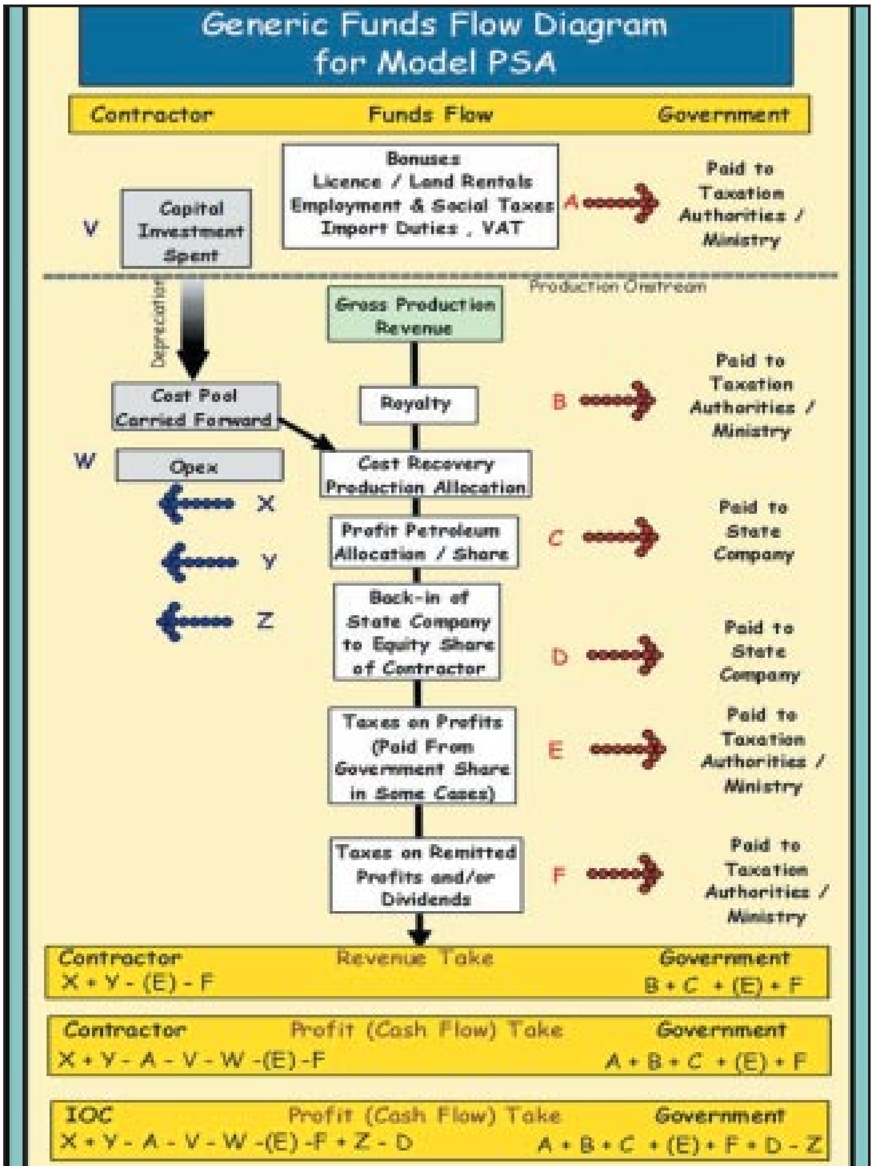

Figure 4: Flow diagram of fiscal mechanism and take components in a typical PSAs7

PSA contractor – state takes

The fiscal mechanisms of PSAs determine which party gets which share of production. The 'contractor' usually involves a joint venture of IOCs, but frequently also involves a NOC with a carried interest through exploration and/or with a back-in right to take an equity stake in the contractor's contractual position (commonly ranging from 10% to 40%). Hence the term 'contractor' is often not synonymous with an IOC and it is distinguished from such in this article. It should also not be confused with the contractors that undertake to engineer, procure, install, fabricate and commission facilities under EPC contracts for the contractor (licences) parties to the PSAs. Some of the fiscal elements yield shares to the NOCs, others go directly to a government's taxation authorities. **Figure 3** illustrates the key financial and fiscal elements of PSAs from an accounting perspective.

The key components of shared production are cost oil (or gas) and profit oil (or gas), but they form only part of the fiscal mechanism that usually involves bonuses, royalties and taxes of various types extracted in sequence from the revenue stream. **Figure 4** illustrates this sequence of fiscal extraction, which is contract-specific, with certain elements sometimes negotiable and others enshrined in a hydrocarbon law. Although providing a simplified accountant's view of the process, it is useful for analytical and negotiation purposes to develop this into a simple quantified spreadsheet. Such a sheet should identify how and in what sequence the actual rates for each fiscal element and contractor's share are extracted from one unit of production based upon an appropriate oil or gas price.

The contractor take of profits is more complex than revenue take because it may vary depending upon field size and the interaction of actual prices and costs on the fiscal elements. Cross-plotting contractor profit take versus contractor revenue take (Figure 5) reveals a wide spectrum of IOC, contractor and (by difference) government fiscal takes that exist worldwide for tax-royalty, PSA and service contracts.

Whilst it is possible to generalise that the toughest fiscal takes (from the contractor's perspective) are associated with PSAs and applied in the most prospective areas (highest potential for large reserves) this is by no means a universal rule. There is much overlap in the fiscal take from the various types of contract and prospectivity levels. Poor cost recovery mechanisms (see below) and large government back-ins to take equity shares the contractor position account for the lowest IOC take of profits for a given contractor take of gross revenue.

The problems with considering PSAs in such simplistic percentage 'take' terms include failure to take into account:

- non-fiscal contract terms that influence contract value,
- field size expectation and environment,
- time-value issues impacting production sharing,
- flexible scales and triggers for specific fiscal elements,
- variable market conditions (oil and gas prices) and
- country track record in respect of honouring contracts.

Yet government and contractor takes are widely quoted in isolation when comparing upstream contract performance. A detailed economic and contractual analysis is essential to evaluate economic performance of specific contracts. This involves building a detailed fiscal cash flow model and stress testing it with a range of model field sizes, cost, prices and production profiles.

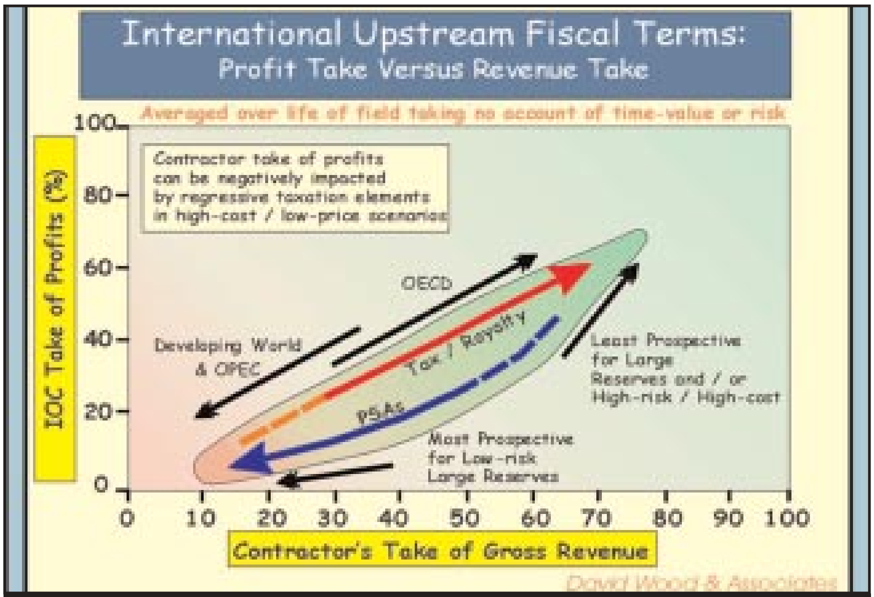

Figure 5: Take comparisons for global agreements.8 (IOC take excludes NOC back-in portion of contractor take where applicable)

Relevant commercial issues

Key commercial issues and objectives arising under PSAs from the contractor's perspective and ranked approximately in descending order of importance are:

- Maximise production split for contractor's (IOC) benefit.
- Minimise regressive taxation elements (eg royalty and bonuses).
- Strive for tax stability guarantees – taxes paid from government share.
- Minimise participation, carry or back-in by state (NOC), either by contractual entitlement or through pre-emption of assignments.
- Maximise cost oil (or gas) allocations (>50%) and accelerate cost recovery.
- Minimise or avoid domestic market obligations at subsidised prices.
- Secure access to existing infrastructure at market tariff rates.
- Link oil and gas prices to international benchmarks not posted prices.
- Accelerate depreciation of capital costs (<=5 years).
- Eliminate or minimise price caps or other windfall profit taxes.
- Avoid exclusion of expenditure items from cost recovery pool.
- Strive to include interest payments on project debt as a cost recovery item.
- Avoid ring-fencing of costs around specific fields or licences.
- Secure exemption from customs duties, local and value added taxes.
- Minimise impact of local currency obligations and interest rates.
- Accelerate approval process for field development.

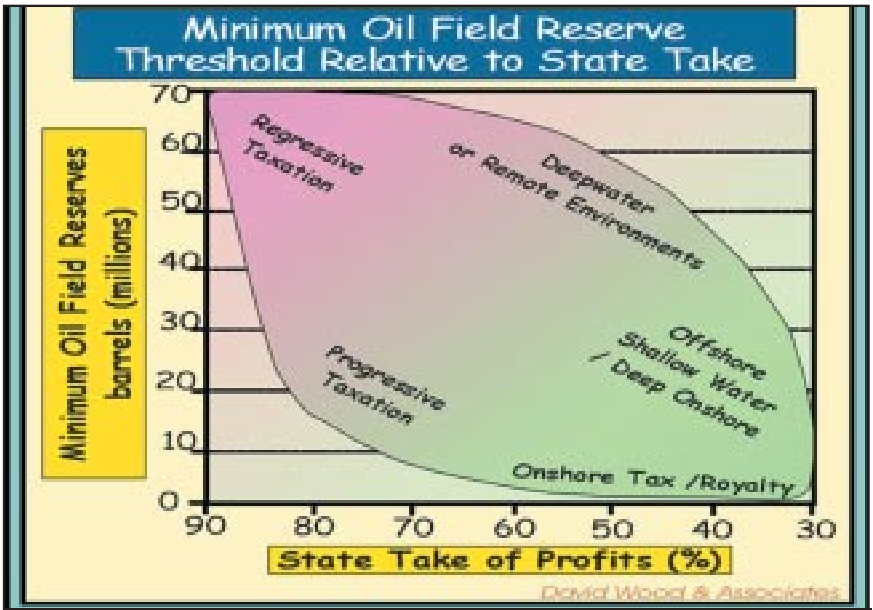

Figure 6: Minimum field size for commerciality is not simply dependent upon contractor:government take – fiscal mechanisms, technical factors and environmental issues also influence it

- Avoid procurement constraints that insist upon local contractors or substantial Government interference in procurement;
- Avoid constraints on using local staff if skill levels are inadequate.
- Involve international arbitration and clear dispute and default resolution terms (eg withering clauses) focused on the principle of time being of the essence.

Of course, the exact order of importance of the above list will depend upon local circumstances, track records and specific contract structures. In many cases such terms will not be negotiable and must be either accepted or a contract rejected. Nevertheless, their impact on contract value and risk should not be overlooked in an integrated analysis.

Field size and environmental considerations

The expected size of the oil and gas field either discovered or yet-to-be found, the depth to its reservoir, its reservoir quality and its physical location (eg remote difficult terrain, deepwater etc) and a host of other technical factors associated with specific oil and gas fields will determine, together with the fiscal mechanism, the minimum reserve size required for a commercial development. This may vary greatly from area to area and contract to contract (**Figure 6**).

Very small onshore fields under tax and (low or no) royalty concessionary systems can be commercial as costs are low and fiscal take is limited to profits. On the other hand, in deepwater or remote areas where development costs are high, the minimum commercial field size is much higher, but, irrespective of fiscal mechanisms, will vary depending upon its distance and access to existence infrastructure.

Fiscal instruments

It is possible in quite high state take systems for small or medium size fields to be commercial if progressive and flexible fiscal mechanisms are involved. As fiscal systems become more regressive the threshold field size for commerciality to be achieved increases. The more distal the point from the wellhead that a tax or levy is deducted from the revenue stream the more progressive it is (**Figure 7**).

The regressive nature of royalties is a consequence of the royalty being deducted at the wellhead from each barrel regardless of whether it is profitable or not. In times of high oil price and with large oil fields few worry about regressive taxes. In the case of high cost or marginal fields or low price environments, regressive taxes can make the difference between a project being commercial or not.

Figure 8 provides an illustration of the impact of progressive and regressive fiscal mechanisms on the same field.

Progressive Versus Regressive Fiscal Elements in Petroleum Exploration and Production Agreements

Impact on E&P Companies Returns	E&P Phase	Fiscal Instrument	Revenue or Funding Component Impacted
Most Regressive ↑	Pre-Commerciality: Exploration, Discovery, Appraisal	Signature/ Training Bonus; Land Rentals / Welfare Programs; Carried Government Interest; Value Added Taxes & Import Duties	Equity/ Risk Capital
	Post-Commerciality: Development, Commissioning, Start-up	Government Back-in; Discovery / Training Bonuses; Capital Gains on farmout or sale; Environmental Levies; Production Startup Bonus	Equity & Debt Funds
	Production	Royalty; Production Bonus; Local Taxes based on Production	Gross Production Revenue
		VAT & Import Duties; Cost Recovery & capital depreciation mechanisms; Production Sharing Profit Oil	Net Taxable Revenue
		Special Petroleum Taxes; Rate of Return or Profit Investment mechanisms to share profits; Corporate Taxes; Excess Profits or Windfall Taxes	Taxable Profits
		Repatriation / Withholding Taxes	Post-tax Profits
Most Progressive ↓		Advance Corporate Taxes	Corporate Dividends

Figure 7: Royalty is the most regressive of post-production taxes – all pre-production levies and duties are regressive

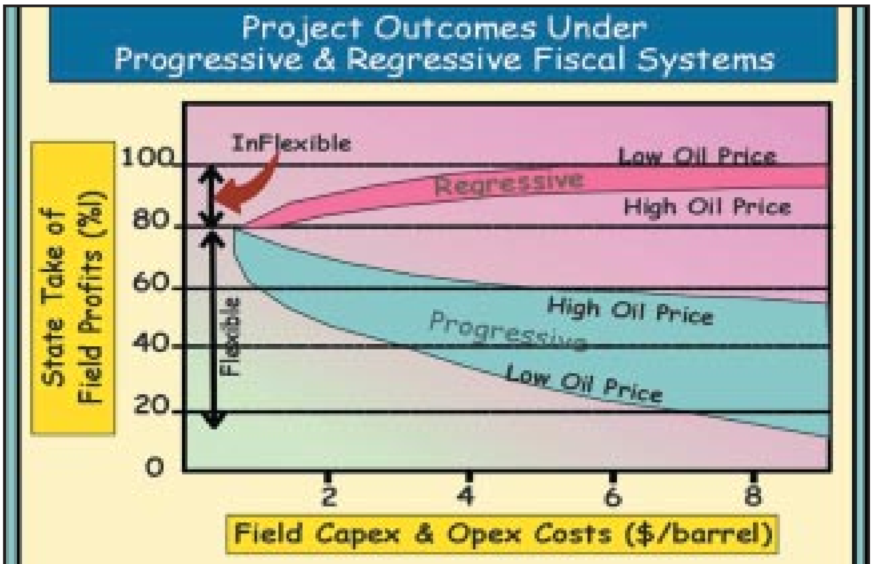

Figure 8: As unit field costs increase or oil (or gas) price decreases, progressive and regressive fiscal mechanisms operate quite differently in terms of the take of profits accruing to the state

David Wood is an international energy consultant specialising in the integration of technical, economic, risk and strategic portfolio evaluation and management. Research and training concerning risk, fiscal and contracts terms, gas and LNG are key parts of his current work. Please visit his website at www.dwasolutions.com or contact him at e: woodda@compuserve.com

Footnotes

1 Christopher Pala, 'Kazakh government discourages Caspian exploration', Petroleum Review, November 2004, p12–13. Martin Clark, 'Call the lawyers', Petroleum Economist, September 2004, p22–26.

2 On 1 January 2005, crude oil export duty rose to the record level of $9.6/b (from $5.7/b). Base mineral production tax on crude oil rose to $1.98/b of production from $1.89/b, although the effective rate will be nearly twice that as it is linked to world oil price. The tax on produced gas rose from $3.69 to $4.66/1,000 cm. The latest increases in export and mineral production taxes combined amount to some 87 US cents in every dollar of revenue above a threshold of $25/b.

3 Recent articles addressing fiscal issues and NNPC back-in in Nigeria include: David Wood, 'Evolution and economic performance of production sharing terms', Petroleum Review, January 2003, p36–40; David Wood, 'Marginal field initiative raises political tensions', Petroleum Review, March 2004, p42–47.

4 'Business Report', Times, 25 October 2004, which discusses the threat from a popular movement clamouring for nationalisation of hydrocarbon resources as well as the new hydrocarbon bill being debated.

5 Z Rashmee, Times of India, 17 December 2004.

6. Brian Ellsworth, International Herald Tribune, 12 October 2004.

7 In Figure 4 the component 'E' –tax on profits – is in brackets as it may be paid from the government or contractor's profit share depending upon the contract. If 'E' is paid by the contractor the brackets should be removed from the formulae; if 'E' is paid by the government then 'E' should be removed from the formulae. In the case of a state company back-in payment 'Z' covers its percentage share of past eligible capital costs and ongoing operating costs. The absolute values of 'E' and 'F' will be different in a situation with no state company back-in than one where a back-in occurs and IOC profits are reduced by ('D'–'Z').

8 Information compiled from various sources. Useful published accounts addressing contractor take are: David Wood, 'Appraisal of economic performance of global exploration contracts', Oil & Gas Journal, 29 October 1990, pp48–52; D Johnston, 'Global petroleum fiscal systems compared by contractor take', Oil & Gas Journal, 12 December 1994, p47–50; P Van Meurs, 'Governments cut take to compete as world acreage demand falls', Oil & Gas Journal, 24 April 1995, p78–82.

Part 2 of this article, to be published next month, will build upon the fiscal and contractual framework outlined here, to identify how flexibility and stability can be improved and how situations of potential future instability might be identified and approached.