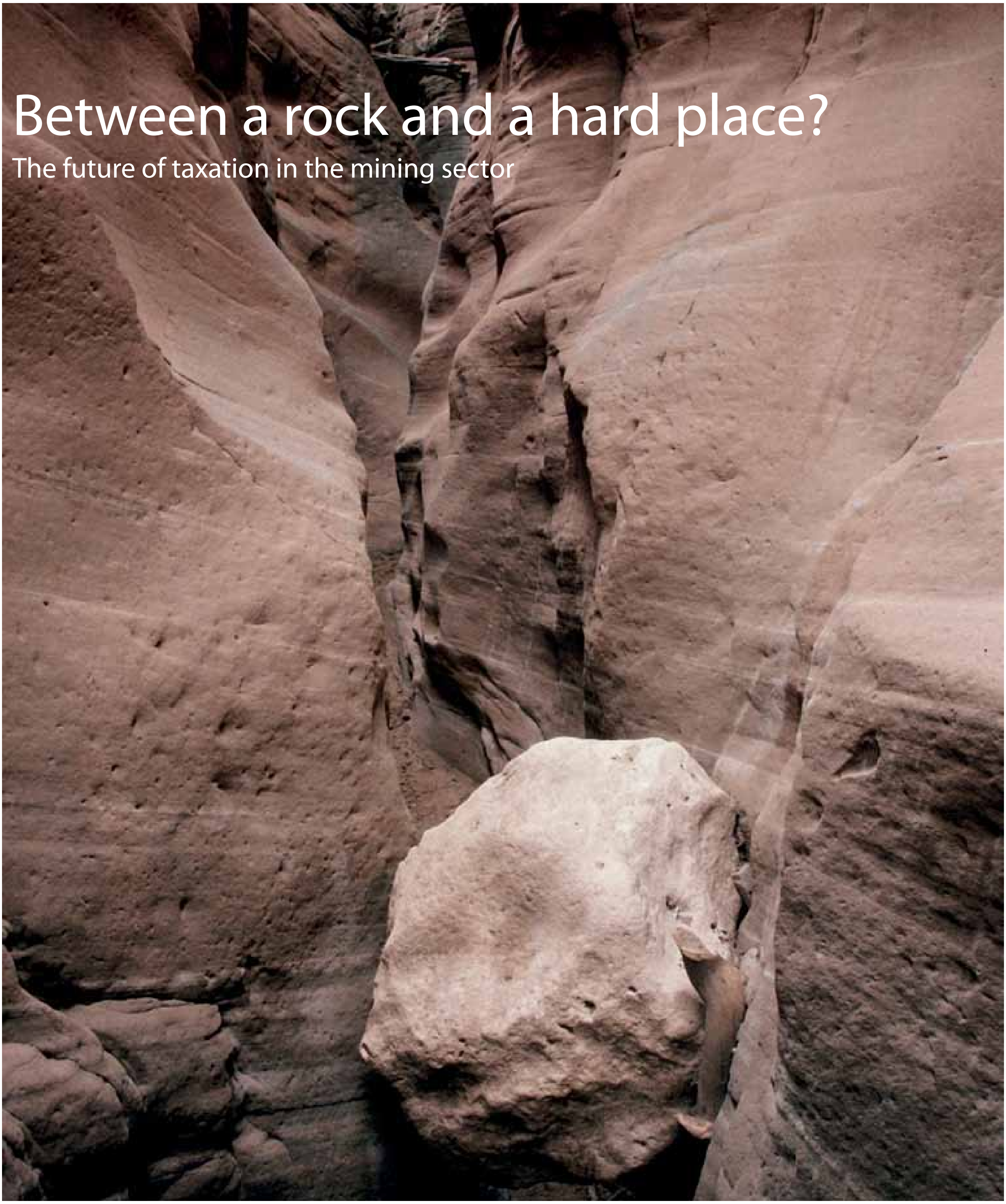
Between a rock and a hard place?

The future of taxation in the mining sector



A Perspective from Wood Mackenzie Consulting

Wood Mackenzie

Strategy with substance

Introduction

Ever since the steep rise in oil and gas prices began in 2003, the petroleum sector has experienced an increase in resource nationalism and a series of changes in tax and contract terms[1]. Investors in the sector have been on a rollercoaster ride in their relationship with host countries[2]. In many countries, there has been a significant re-distribution of the remaining value of petroleum assets from private companies to government.

While governments have been quick to react to the rise in oil prices, they have been much slower to respond to similar increases in the prices of other extracted resources, some of which have grown even faster than oil, as illustrated in Figure 1.

The increase in oil prices has resulted in substantial growth in the profitability of the largest non-state owned petroleum producers such as Chevron, Shell and ExxonMobil. Nevertheless, the increase in prices for other natural resources has also transformed the fortunes of the largest mining companies, as illustrated in Figure 2. As prices started to increase in 2003, those mining companies' profits were significantly lower than their counterparts in the petroleum sector. By the start of this decade, however, profits had grown at such a pace that they are now comparable with the upstream profits generated by the largest petroleum companies.

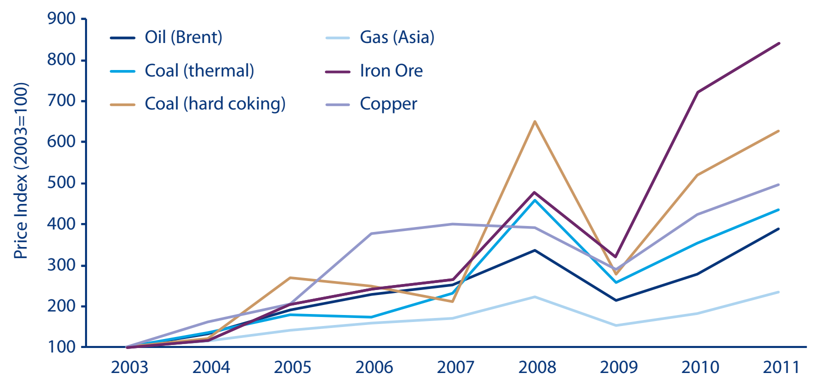
The relationship between governments and investors in the petroleum sector now appears to be stabilising, with prices, costs and taxes at a higher level than a decade ago. On the other hand, in the mining sector, there is a growing unrest in the relationship, mirroring the petroleum sector's experience of the last decade.

Generally, fiscal systems in mining are far simpler than in the petroleum sector. Many have not changed in decades, but this convention is being reviewed around the world. As a result, resource nationalism has been identified as the top business risk currently facing mining investors[3].

These brewing fiscal storms are forcing mining investors to re-evaluate their terms, and relationship, with host governments.

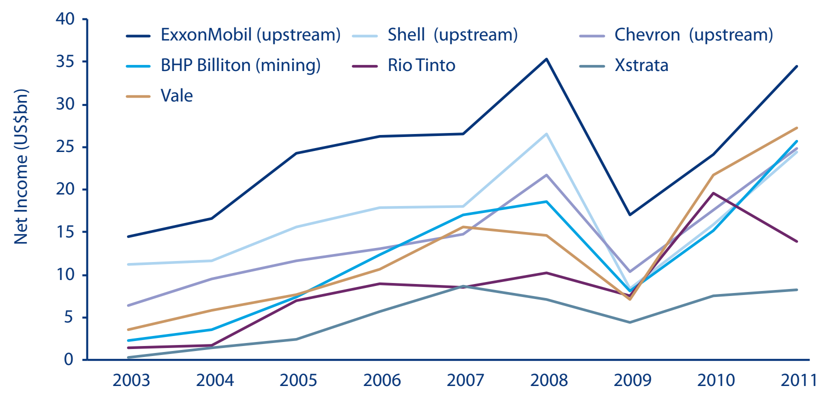
This Wood Mackenzie Perspective considers the similarities and differences between the mining and petroleum sectors, recent developments in mining taxation, and considers how the relationship between mining investors and governments may evolve.

Figure 1 Price indices of selected natural resources 2003-2011



Source: Wood Mackenzie

Figure 2 Profitability of selected extractive industry companies 2003-2011



Source: Wood Mackenzie, company accounts

[1] *"Fiscal Storms", Wood Mackenzie Perspective, May 2008*
[2] *"Twists on the Fiscal Rollercoaster", Wood Mackenzie Perspective, May 2009*
[3] *"Business risks facing mines and metals 2011-12", Ernst & Young, 2011*

Mining and petroleum: the same, but different

Project life cycle

Petroleum and mining companies search for commercial deposits of minerals, develop the facilities to extract and transport the discovered minerals to market and, when the deposit has been exhausted, remove the facilities and restore the site. While their activities are similar, there are significant differences between them at each step of the process, as summarised in Table 1.

The relatively high cost of failed petroleum exploration programmes is of particular relevance to the distinction between fiscal terms for petroleum and mining. The risked cost of failure must be balanced by the companies against their share of risked rewards. Where exploration risks and costs are particularly high (e.g. frontier offshore areas), fiscal terms must be suitably attractive to enable the investor to achieve the right risk/reward balance. When risks are much lower and the value of the expected development is much higher – for example, large discovered fields – the fiscal terms can be extremely onerous and yet still be acceptable and even volunteered by investors[4].

Mining exploration programmes, by comparison, are far less driven by discovery of new resource deposits. Most mining exploration is what petroleum investors consider appraisal – establishing the size and productivity of a known resource and analysing the options to bring the product to market. Consequently, mining investors have many more 'break points' in the exploration/appraisal programme before committing to a full scale development. Moreover, exploratory drilling in mining is generally much less expensive than petroleum because the wells are significantly shallower. Thus, there is less need for fiscal terms to reflect the exploration risk associated with mining.

Much attention is now being paid by petroleum investors to the development of unconventional oil and gas resources (e.g. shale oil/gas, coal bed methane). The life cycles of these projects have more in common with mining than conventional oil projects, with similar implications for fiscal terms.

Project profiles

Perceptions of the risks associated with any opportunity have a strong influence on the fiscal terms, but the main focus is the distribution of revenues associated with successful developments. The problem for fiscal policy-makers is that no two projects are the same.

Any oil, gas, coal, iron ore, copper, gold or other natural resource project requires substantial investment to

Table 1 Petroleum and mining project life cycle characteristics

	Exploration	Development	Production	End of Life
Petroleum	Main objective = discovery of new resource deposit High risk – low success rates so each wildcat well is a big throw of the dice High cost (drilling deep wells)	Limited range of development types, but highly variable costs, depending on location and infrastructure > 50% field capex 'up-front' Highly capital intensive with high capex: opex ratio R&D focus = increased recovery, deep water, horizontal drilling, unconventionals	Oil production profiles skewed to 'front-end' Gas sold under contract (and 'mega-fields') produce at plateau rates for much longer periods Limited upstream processing, other than shale oil/gas and LNG Low unit transportation costs for oil; higher for gas	Low cost (onshore) High cost (offshore)
Mining	Main objective = resource monetisation, less about 'discovery' Low risk – low success rates but multiple 'walk away' options Low cost (surface surveys, shallow drilling)	Wide range of development types from panning to open-pit mines Bulk mineral developments critically dependent on infrastructure availability High level of capital replacement during field life Can be labour intensive (small scale mining) R&D focus = environmental (e.g. clean coal), deep mines, bulk infrastructure	Decades long plateau production profiles are normal Significant upstream processing High energy use / costs Variable unit transportation costs (low for precious metals, high for bulk minerals) Operating costs dominate total project costs for bulk minerals	High cost land reclamation

Source: Wood Mackenzie

[4] *For example, the winning bids for technical service contracts to re-develop federal Iraqi oil fields were as low as US$1.15/bbl. Wood Mackenzie's Global Economic Model (GEM) calculates the Government Share (i.e. government revenue as a percentage of the project's gross cash flow) from each contract to be at least 99%.*

generate an uncertain flow of revenue over many years. Although this is common to all projects, the quantities of production, the price received, and the level and timing of costs are different for each project and are likely to change frequently over time. The same fiscal terms applied to any two natural resources projects are, therefore, likely to have a different impact on the project's economics. On the other hand, a separate fiscal system for every single resources project would normally pose too many administrative problems. Hence, most countries aim to develop fiscal terms which will apply to groups of projects that share common characteristics.

Within the natural resources sector, the first differentiation is normally the type of resource to be produced. Many countries have separate terms for oil, compared to gas, for instance. The fiscal terms for petroleum projects are often further differentiated and applicable royalty, tax or government profit share rates will vary depending on project size, location, price, profitability or a combination of these measures.

This differentiation is far more rare in mining. Royalty rates applicable to different resource types normally vary within a narrow range (somewhere between 0% and 10%). Some countries differentiate royalty rates for a particular resource by linking the rate to production rates but very few systems include any kind of progressivity when it comes to taxing mining profits. Why is this?

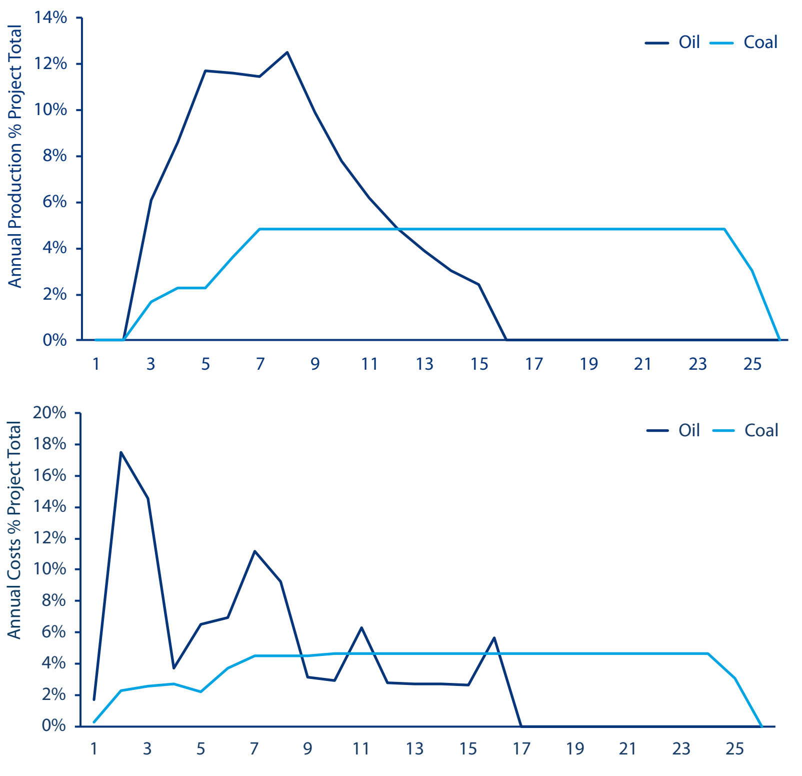
The most common response is that the sort of 'windfall' profits that are generated by many petroleum projects simply don't exist in mining, where profit margins are perceived as far less than petroleum. This reflects lower commodity prices and higher unit costs. There is also the perception that petroleum projects are more likely to generate higher rates of return because the production profile is skewed towards the early years of production, rather than a long plateau, which is common in mining.

To illustrate these 'typical' profiles, Figure 3 compares the production and cost profiles of a recent Australian oil field development (Vincent, 200 Mbbl) and coal mine development (Moolarben, 200 Mt). Annual production and costs are shown as a percentage of the project's lifetime total.

Figure 3 shows that the oil project commits a significantly higher proportion of the project's total costs in developing the field. The high productivity of the oil wells enables the field to produce more quickly, compared to the coal project. Another striking difference between the two projects is shown in Figure 4, which compares the total and annual capital and operating expenditure ('capex' and 'opex') of the two projects, expressed in terms of costs per unit of production.

Capex accounts for over two thirds of the total costs of the oil project, but only 11% of the total coal project costs. Even allowing for some likely discrepancy in how production costs are categorised in reports, there is a clear distinction between the two types of projects. With much of the oil project costs incurred (or 'sunk') by the time the field reaches peak production, annual unit costs appear relatively low (between US$5 /bbl and US$20 /bbl, depending on whether there is a capital programme that year or not). The coal project, by contrast, has an even expenditure profile across the life of the mine, with annual unit costs of c.US$45 /ton. Given that a

Figure 3 Example oil and coal production and cost profiles



Source: Wood Mackenzie

ton of thermal coal and a barrel of crude oil are currently trading for broadly the same amount (US$100-US$120), the comparison of unit costs in Figure 4 confirms the perception of significantly higher costs – and therefore lower profit margins – in coal, compared to oil.

A critical consideration in this comparison between conventional petroleum and bulk mining projects is the level of dependence on available infrastructure. This can be significant in the petroleum sector – notably for remote gas discoveries. But offshore oil projects, in particular, can export production from 'stand-alone' facilities, relatively inexpensively. Bulk mining developments, on the other hand, critically depend on available capacity in local railways and ports. If the infrastructure is not available, mining investors can either:

- develop it themselves, adding significant capex to the project
- encourage infrastructure suppliers to develop new capacity, and pay tariffs accordingly
- encourage government to invest in the infrastructure, or
- form a joint venture of all of the above to develop the infrastructure.

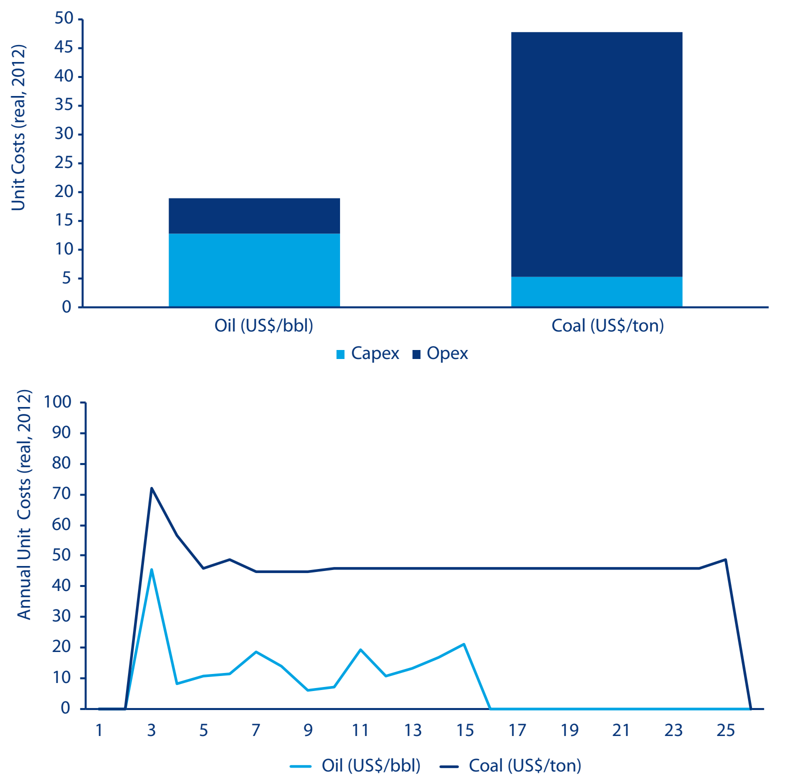
The inclusion, or not, of infrastructure costs within the mining project profile is extremely important to its economics and, therefore, to the fiscal terms developed for mining.

Implications for fiscal policy

This distinction between the different project profiles has certain significant implications for fiscal policy-makers:

- Once an oil project starts producing, its ongoing unit costs are often low relative to the price generating substantial profits from each barrel of production. The more costs that have been sunk, relative to the expected profits to come, the weaker the company's position becomes. This is often referred to as the 'obsolescing bargain'. The oil company's strongest influence on fiscal terms is prior to exploration – thereafter, it weakens significantly. This is what makes fiscal 'contracts' attractive to investors and why they are content to agree to production sharing contracts (PSCs) around the world.
- Petroleum companies have a much stronger demand for early recovery of capital costs in order to achieve acceptable rates of return. They seek accelerated depreciation schedules for tax purposes and try to ensure that the cost recovery proportion of production in a PSC is as high as possible. These are often regarded as incentives, which may then be the subject of potential revision. A current example of this is the debate in the US over depreciation schedules for drilling expenditure.
- Mining companies retain a much stronger bargaining position through the project life, with regard to possible changes in fiscal terms. The loss in value associated with shutting down production in mid-project is not of the same magnitude as it is for a typical oil project.
- Mining projects, which need to develop significant new infrastructure, need these additional costs to be reflected in the fiscal terms applicable to the resource extraction component of the business. Liquefied Natural Gas ('LNG') projects provide a parallel within the petroleum sector. The upstream business (i.e.

Figure 4 Example oil and coal unit costs



Source: Wood Mackenzie

up to the processing plant gate) will normally be liable to resource rent taxes, while the processing plant and transportation business is subject only to standard income tax. This raises several key issues: ownership in the upstream and downstream businesses, transfer pricing and tariffing. These issues need to be addressed simultaneously with developing fiscal terms for the project and, in some countries, a special fiscal system has been developed to cover the entire project[5].

- With lower expected profit margins in coal (and other mining projects), fiscal systems should be focused on the taxation of profits rather than targeting revenue. Royalty is comparable to an operating cost for producers and is, therefore, a regressive instrument which reduces the investor's profit margin more when prices are falling. Profits based taxes, on the other hand, will reduce government revenue when the profit margin falls. At the moment, however, royalty is the predominant tool used by governments to extract a share of economic rent from mining projects (other than standard corporate income tax). In the petroleum sector, terms have evolved so that many fiscal systems now employ progressive taxes as the main fiscal instrument.

It is notable that production sharing contracts (PSCs) are common in petroleum but essentially non-existent in mining. Indonesia – which introduced the first petroleum PSCs in the 1960s – did employ 'Contracts of Work (CoW)' for coal and other minerals concessions until 2009. Like the petroleum PSC, the CoW provided fiscal stability for the duration of the contract and early CoWs allocated production between government and contractor, based on a fixed 13.5 : 86.5 ratio. This 'production share' was essentially a royalty and later CoWs entitled the contractor to 100% of production but imposed a 13.5% royalty, which is identical from a financial perspective.

Unlike PSCs generally employed in the petroleum sector, the CoWs did not assign a maximum percentage of production for cost recovery, nor did the government share of production (or royalty rate) vary according to any measure of project performance. Thus, the CoWs were essentially royalty/tax concessions but with fiscal stability guarantees. The standard petroleum PSC model – limited production for cost recovery with progressive production sharing and fiscal stability – has not been adopted in mining to date, although fiscal stability clauses have been included in mining licences in some countries.

Evolution of fiscal terms

In the petroleum sector, the evolution of global fiscal terms and state participation has tended to follow the oil price cycle, as illustrated in Figure 5.

The fiscal systems applicable to the mining sector have been far more stable by comparison. Most systems remain based on a simple royalty plus income tax model. In the past two years, however, there has been a spate of changes to terms around the world. The majority of these changes are incremental increases in applicable royalty rates but there have also been a number of petroleum-style windfall profits taxes proposed. For example, Australia's Mineral Resource Rent Tax (MRRT), which is based on its Petroleum Resource Rent Tax (PRRT), will apply to coal and iron ore projects from July 2012. This follows a terse debate with the mining investment community and the applicable MRRT has a much smaller impact than the government's initial proposals. A similar windfall tax was proposed in Namibia and Mongolia but was ultimately withdrawn following discussions with the mining community.

Some countries are beginning to modify royalty and tax rates for mining so they are now linked to project production, price or

Table 2 Typical petroleum and mining fiscal terms

Fiscal Terms	Petroleum	Mining
Signature bonuses	common	rare
Indirect Taxes	common; with many exemptions	common; with many exemptions
Fiscal Systems		
Royalty / Tax	common	all
Typical Royalty Rates	5% - 20%	2% - 10%
Export Duty	rare	rare
Corporate Income Tax	common, but often replaced with petroleum profit tax	all
Windfall / Additional Profit Tax	common	rare
Production Sharing	common	none
Service Fee	rare	rare
State Equity Participation	common	rare
Marginal Government Share *	50% - 95%	30% - 50%

* Government Share = (Government Revenue / Project Operating Margin) when all fiscal terms apply at maximum rates

Source: Wood Mackenzie

[5] *See "Natural Gas: experience and issues", by G. Kellas, in "The Taxation of Petroleum and Minerals: Principles, Problems and Practice", IMF / Routledge 2010*

profitability – similar to the approach that is prevalent in petroleum. An example is the 'Specific Tax on Mining Income' applicable to copper mines in Chile. The base for the tax is net operating income rather than gross revenue, and small producers are liable to a nominal tax rate, between 0% and 4.5% depending on annual production levels. Until 2010, larger producers (more than 50,000 tonnes p.a.) paid tax at 4% or 5%, depending on when their investment contract was signed. Since September 2010, mines developed under new investment contracts will pay 5% only if the annual profit margin of the mine is less than 35% of annual revenue. If the profit margin is greater than 35%, an incremental tax is payable, rising to 14% if the profit margin is 85% or more of revenue. The rates are illustrated in Figure 7.

This approach to mining taxation mirrors that in petroleum and is appropriate for those projects. Another interesting feature of the Chilean mining tax is that, instead of imposing the new tax on all projects, existing producers were asked if they would volunteer to pay it. Most mining projects in Chile are governed by investment contracts that include an 'invariability' clause, which guarantees the tax regime in place at the time of signing the contract will persist for a certain number of years (up to 12 years for small projects and 20 years for large projects). When the rate was raised in 2006 (from 4% to 5%) and then in 2010 to the new progressive scale, producers were asked to pay the tax at the new rate, in exchange for an extension of the invariability period. There are also examples of this trade-off in the petroleum sector, with existing production sharing and other contracts being replaced in mid-life to enable the government to receive a higher share of profits, in exchange for an extended contract duration (e.g. Libya, Venezuela).

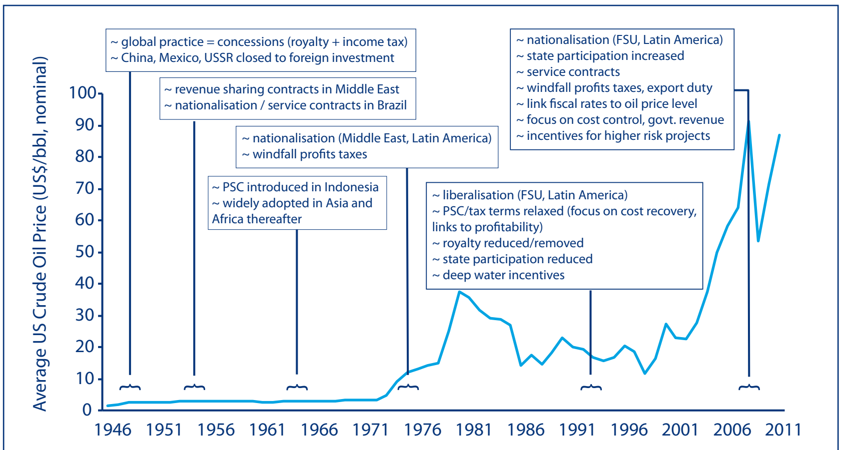
Linking progressive tax rates to annual margins, rather than project rate of return or revenue/costs multiples, is an interesting departure from the petroleum norm but one that appears sensible, given the differences in mining project profiles described earlier.

Other forms of 'resource nationalism'

As well as increased taxation, the rise of resource nationalism in the petroleum sector was characterised by increased state equity in projects – notably in South America and the FSU regions. This trend is less pronounced in mining, although several African countries have recently increased the requirement for either state or local company participation in projects. Under Zimbabwe's Indigenisation Law, 51% of mining projects must be owned by indigenous partners. Similarly, South Africa and Namibia have created new state-owned mining companies to participate in future projects.

The move toward higher state participation in Africa contrasts with developments in Asia, where increased private participation in mining is the trend. This participation is being tempered, however, by increasing regulation of the industry

Figure 5 Evolution of fiscal terms in the petroleum sector



Source: Wood Mackenzie

Figure 6 Recent changes in global mining tax terms

to maximise indigenous benefits over export-led programmes. The latter are preferred by foreign investors as they are more likely to receive full market prices for exported production than domestic sales. To counter this, some countries – for example, India and Iran – have increased export duties in order to reduce the incentive to export minerals.

In May 2012, Indonesia went further by introducing legislation (Minerals Added Value Regulation No. 7) stipulating a total ban on exports of certain raw minerals from 2014, unless the raw minerals were first processed. The regulation imposes an export tax effective immediately and requires miners to provide evidence of plans to install processing facilities from 2014 onwards. Interestingly, coal is excluded from this legislation, although existing mining legislation already bans the export of unprocessed coal[6].

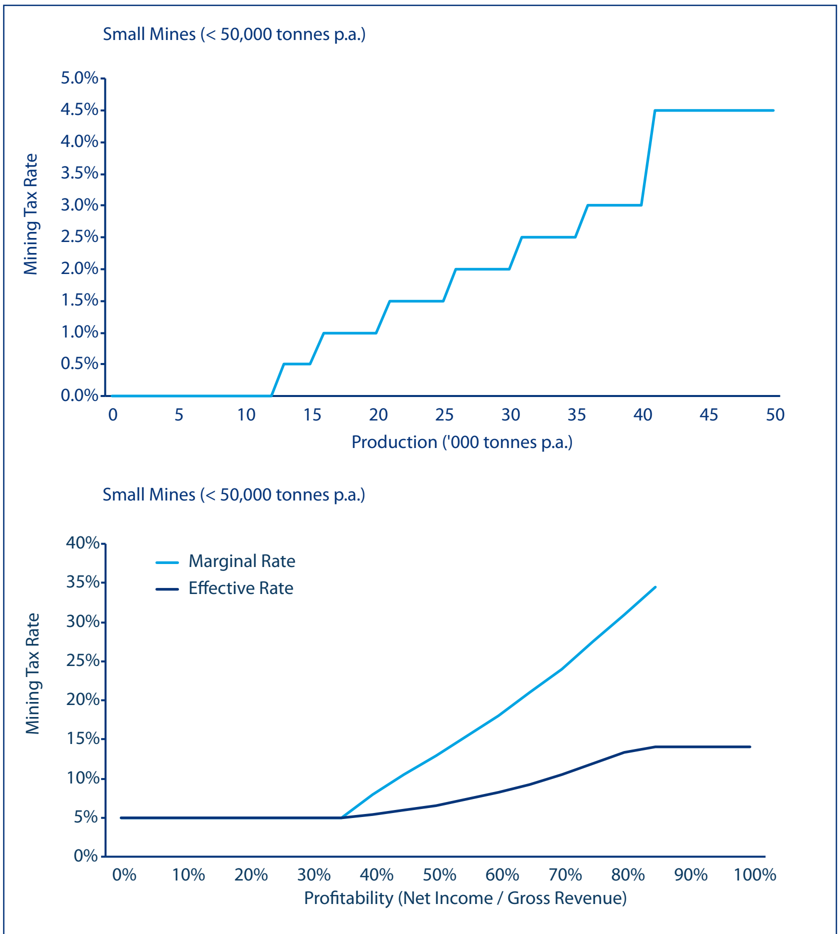
The way forward: confrontation or cooperation?

Mining investors around the world are having to engage with governments that are increasingly dissatisfied with the fiscal terms in place for their projects. The arguments for and against changes in terms mirror those that were aired in the petroleum sector during the past decade. Governments point to the steep increases in prices and company profits and acknowledge that the terms were not designed for such an environment. They argue that it is only 'fair'[7] that the terms are changed to give the resource owner a larger share of the unexpectedly high profits. The companies counter-argue that costs have risen in a similar proportion to prices and current levels of profitability are fragile. They add that changing the terms for projects in mid-life introduces a high level of 'sovereign risk' which makes opportunities in the country less attractive, resulting in investment capital being diverted to other countries.

This discussion can often be very public and has even resulted in companies and governments paying for TV advertisements to put across their point of view. 'Jobs, not taxes' is a common message from industry. This confrontational approach tends to emerge when governments unilaterally announce a change in terms. The investment community reacts – often angrily – and tries to preserve the status quo. The outcomes of these confrontations are mixed. Occasionally, the companies are successful and the proposals are abandoned (e.g. Vietnam's export duty increases in 2008/09). In other cases, the changes are made anyway (e.g. a 32% increase in the UK tax rate made in three changes in 2002, 2005 and 2011). Normally a compromise is reached and a diluted version of the original proposal gets introduced, such as the Australian MRRT. Depending on the impact of the change on company profits, investors then either accept the new deal or decrease their investment plans, as promised.

The other form of engagement takes place behind closed doors. Governments call in the investors and outline their concerns and seek possible solutions. These negotiated outcomes normally

Figure 7 Mining tax rates for copper production in Chile



Source: Wood Mackenzie

[6] *"Indonesia's Metals & Mining Legislation: Adding Value?" Wood Mackenzie Insight, June 2012*
[7] *"Fair Share", Wood Mackenzie Perspective, June 2010*

include progressive terms, designed to function in a range of future possible economic environments. The Government Share may not be stable but at least it will be predictable. It is notable in the petroleum sector that fiscal systems which have progressive terms have experienced much fewer changes than systems with flat royalty and tax rates. Moreover, as governments increasingly eschew stabilisation or non-variability clauses to protect their 'fiscal sovereignty', progressive terms will be seen as the only way for investors to minimise ad hoc fiscal shocks.

The fiscal terms for mining projects will change in many countries in the coming months and years. It remains to be seen which of these changes will be the result of reactionary battles between industry and government and which ones will emanate from pro-active negotiation.

Wood Mackenzie has considerable fiscal consulting experience and has provided advice on fiscal related issues to numerous clients, such as international oil and mining companies, including integrated and independent companies. Our experts have published several multi-client studies comparing fiscal terms around the world, with the latest being Petroleum Fiscal Systems (2010). In 2012, we launched a new Fiscal Service, which provides regularly updated, detailed benchmarking of global petroleum fiscal systems.

Wood Mackenzie's consultants provide strategic advice based on real substance to clients in the global energy, metals and mining industries. We have been helping clients understand the energy and natural resource industries for four decades with industry leading research and are now leveraging that knowledge to offer advisory services across the energy value chain. With established presence in the Americas, Europe, Asia/Pacific and the Middle East, our consultants offer a truly global view for questions that must be considered in a global context.

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