Global oil & gas tax newsletter
Views from around the world

In this issue

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Foreword

Welcome to this new edition of Deloitte's *Global oil & gas tax newsletter*.

The articles in this issue reflect the rapid changes to the tax landscape affecting the oil and gas industry. The first change explored in this edition has arisen following the G20/Organisation for Economic Cooperation and Development's (OECDs) base erosion and profit shifting (BEPS) agenda announcements. In particular, changes in approaches to transfer pricing could have important implications to long-standing industry practice regarding the charging of operator costs to upstream joint ventures. BEPS is a complex issue and one that we will likely explore further in future editions as the agenda develops.

The second broad theme of our articles is the recent steep fall in oil prices and the significant impact this has had on oil and gas companies, and the decrease this has made in the tax revenues of oil exporting countries. We see the result of this not only in increased audit activity by tax authorities, but also in changes in laws and practice designed to increase tax revenues. Indirect taxes are an important focus and readers will see that the introduction of value added tax (VAT) is high on the agenda in the Gulf. Indirect taxes are also an important issue for the industry in China and Malaysia where recent changes in law and practice are causing additional costs for the industry. In Nigeria we see a range of developments designed to improve the efficiency of the tax authorities: pressure on taxpayers is likely to continue when the contribution of oil revenues to government has more than halved since 2014. Whilst in Kenya, the focus is on balancing fiscal stability during oil price volatility to ensure continued investments are made in a developing oil and gas industry.

I'd like to thank all of our contributors from around the global network of Deloitte member firms and also Bill Page for taking on the role of editor. I look forward to future editions.

Julian Small
Global Oil & Gas Tax Leader, Deloitte Touche Tohmatsu Limited

Editor's note
The purpose of this publication is to address tax issues of current interest to companies operating in the oil and gas industry, whether upstream or downstream, and businesses in the oilfield services, engineering and construction industries. Feedback is always appreciated, so if you have any comments on the contents or suggestions for articles to be included in future editions, I would be very interested to hear from you. I may be contacted at bpage@deloitte.co.uk.

Bill Page
Editor, Deloitte UK

The articles in this issue reflect the rapid changes to the tax landscape affecting the oil and gas industry.

Spotlight on: Assessing the mechanism for charging for intellectual property in the upstream oil and gas industry in light of some of the recent base erosion and profit shifting developments

Written by Aengus Barry, Deloitte UK

In no other sector does engineering brilliance, politics and risk taking combine with the random geology of plate tectonics as it does in upstream oil and gas. Value is, and always has been, created by a coming together of the entrepreneurial drive of mankind and natural endowments. This has been so from the dawn of upstream oil and gas when advancements in drilling technology combined with geological good fortune produced the Spindletop gusher, and has continued through the age of sub-sea exploration to the current pre-salt drilling and arctic exploration.

Many oil and gas multinationals will have people making key decisions on everything from where to drill to how to exploit a reservoir, as well as designing cutting edge extractive technology as part of a research and development (R&D) team. It is relatively common in the industry for the costs associated with such R&D activities to be recharged across many operating entities in the group on a common basis, such as turnover, and often with no mark-up or profit element. The logic of this approach is that any intellectual property (IP) created by the engineers is owned by those same entities paying for the R&D. Often this is formalized in a cost sharing arrangement or cost contribution arrangement (CCA) whereby all group IP is effectively shared between the participants paying for the R&D.

This approach is industry standard and has manifested itself over many decades, driven by the reluctance of joint venture (JV) partners to allow a value-based charge for IP by an operator. In addition, in regimes which employ production sharing arrangements it is frequently not possible to obtain corporate income tax deductions or cost recovery for the profit element of IP royalties, or value-based, charges.

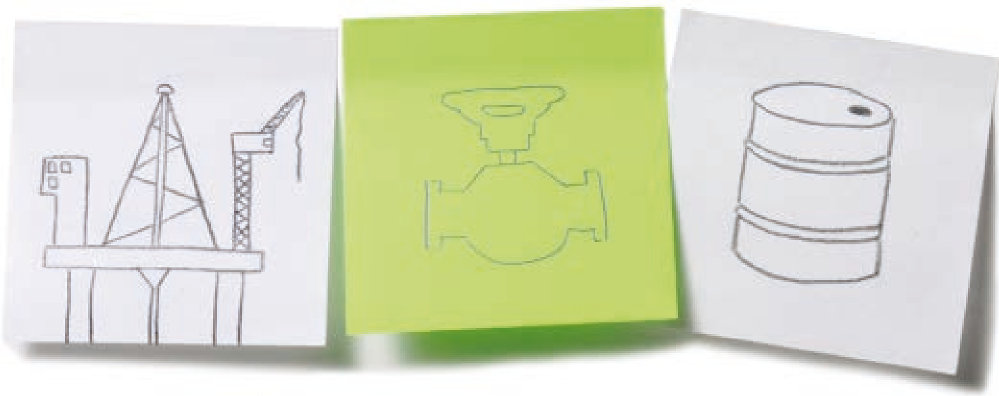
While there are variations on the standard CCA model, and while the extent to which recharges are made into an incorporated or unincorporated JV can impact the ease of a charge, much of the underlying economic logic is the same. However, many of the core objectives of the Organisation for Economic Cooperation and Development's (OECDs) base erosion and profit shifting (BEPS) agenda, in particular those related to Action 8 on the transfer pricing of intangibles, will put pressure on the current IP charging mechanisms in the upstream oil and gas industry. This article looks at how the OECD's direction of travel may affect widespread practices in this industry.

Is the arrangement really a CCA?

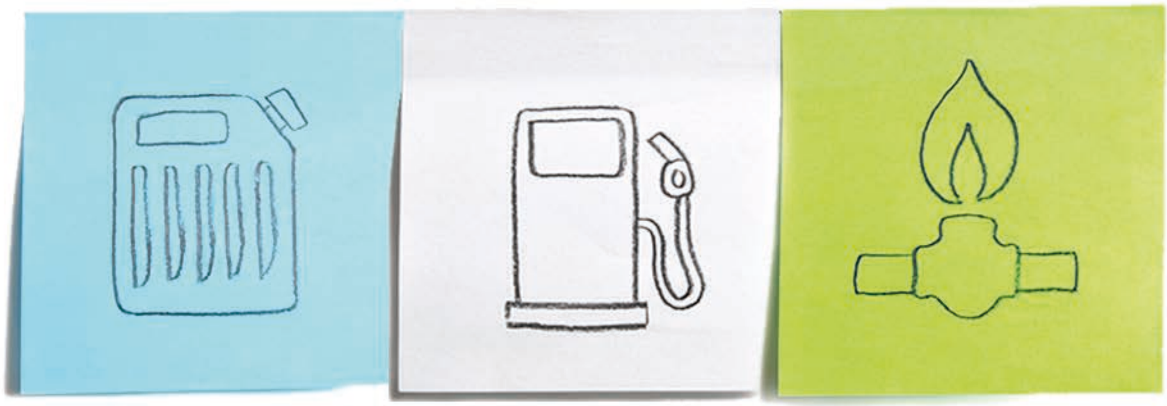
The first interesting question BEPS raises is whether this arrangement can be characterized as cost sharing for transfer pricing purposes in the future. One of the central themes of the proposed amendments to the OECD *Transfer Pricing Guidelines for Multinational Enterprises and Tax Administrations*[1] released on 5 October 2015, is that to be a member of such an arrangement it is necessary for an entity to have the functional capacity to input to the R&D exercise. The document makes clear that any participant in a cost sharing arrangement would have to have the capability and authority to control the risks associated with the risk-bearing opportunity under the CCA. The guidance further notes that:

"An enterprise that solely performs the subject activity, for example performing research functions, but does not receive an interest in the output of the CCA, would not be considered a participant in the CCA but rather a service provider to the CCA."[2]

Many oil and gas multinationals will have people making key decisions on everything from where to drill to how to exploit a reservoir.



1 http://www.oecd.org/ctp/transfer-pricing/transfer-pricing-guidelines.htm
2 Paragraph 8.14, of the amended OECD Guidelines



However, in many instances the profits derived from incremental production will be a mix of the oil price, good fortune and of course the baseline technology.

The examples at the end of the document suggest that any entity not in possession of the requisite people skills (such as R&D risk oversight) should not be characterized as a participant in the cost sharing program. Instead, an entity simply paying for R&D would be characterized as a capital provider, and would therefore be entitled to a risk adjusted reward on their capital invested and, crucially, would be expected to pay an arm's length fee for access to the intangibles they use.

While a detailed functional and risk analysis would be required to verify the basis of the facts for every group, it is probable that in the eyes of the G20/OECD, upstream asset owning companies may be users of IP, not co-generators.

In short, these revisions suggest that a transfer price specifically for IP or high value-add services is warranted, which is a departure from current industry practices.

How to price the use of IP?

On 4 June 2015 the OECD released a further BEPS transfer pricing paper, on *Hard to value intangibles*[3] and these changes were enshrined in Chapter VI of the OECD *Transfer Pricing Guidelines for Multinational Enterprises and Tax Administrations* on 5 October 2015. The revised text puts forward a number of proposals. At the outset it implies that pricing IP with respect to direct "comparables" (licences between, say, two independent third-parties for similar IP) are often not reliable. It also suggests other methods such as profit split, which seek to analyze the value added by the IP in question with reference to the end profits realized from the venture, may be more appropriate.

There is also a link to the cost contribution arrangements paper noted above which suggests that, if a CCA is in place, payments for R&D should be on the basis of value not cost (which has normally been the case).

In some instances this could be relatively straightforward for the oil and gas industry – if technology allows well production to be increased by a measurable figure (10 percent, say), or taps an entirely new reservoir, it may be possible to measure the benefit provided, and therefore, the profits to be split. However, in many instances the profits derived from incremental production will be a mix of the oil price, good fortune and of course the baseline technology. Setting aside the occasional straightforward example, it is likely that determining the value-add of IP generated by a group is likely to be very much easier said than done.

In this industry, however, key to determining the profits attributable to the IP in question will be determining how to split profits between the two fundamental drivers of value touched on at the beginning of this article – the asset (such as molecules of oil or gas under the ground which are very valuable but at present inaccessible), and the people that extract the molecules in question and take them to market.

What next?

Charging for R&D, IP or highly skilled services on the basis of the value provided would in some cases be a change from the current modus operandi. It is a long-standing practice in upstream JVs and fiscal arrangements with host governments for charges to be based on the recovery of the operator's costs, constraining its ability to generate a profit via such intra-group charges.

Taxpayers should consider that any group introducing a value-based IP charge may be laying itself open to challenge. However, the current situation, if continued, could just as easily be challenged by the tax authorities in countries which are home to the key people functions noted above.

The balance between the profits which are attributable to the scarcity value of the molecules in the ground and that which is allocated to the people who help to extract those very molecules, may change in the coming years as a result of the BEPS initiative. Precisely how that occurs will be one of the key transfer pricing challenges and multinationals in the industry are advised to pay close attention to this area going forward.

3 http://www.oecd.org/ctp/transfer-pricing/release-discussion-draft-beps-action-8-hard-to-value-intangibles.htm

China: Impact of VAT reform on production sharing contracts

Written by Andrew Zhu and Jocelyn Li, Deloitte China

Launch of VAT reform

China launched a VAT reform program[4] in 2012 that aims to resolve the issues of double or multiple taxation that arise under the parallel business tax (BT) and VAT systems. Before this reform, VAT was only levied on sales of goods, provisions of processing, repair or replacement services and importation of goods; while BT was imposed on activities related to intangible assets and provision of services that are not subject to VAT. Unlike the credit mechanism applicable for VAT, BT is computed by applying BT rates (five percent or three percent) to gross business turnover from the taxable activities without any ability to reduce this by the amount of BT incurred.

The VAT reform was initially launched in Shanghai and applied to transportation and certain service industries[5]. Now it has been rolled out to the whole country and expanded to most industries, excluding lending of money, construction and real estate, and consumer services.

Typical upstream oil and gas projects in China

For investment in oil and gas exploration and production in China, foreign international oil companies (IOCs) typically enter into a production sharing contract (PSC) with a Chinese national oil company (NOC) by contributing the operating funds, equipment and technology, in exchange for a share of the hydrocarbon resources. Usually annual gross oil production net of cost recovery and levies and taxes (such as special oil gain levy, resource tax and VAT on gross production) is profit oil that is shared between PSC participants. Cost recovery entails the recovery of exploration, development and production expenditures, amongst which, drilling and construction services generally account for a large percentage. As set out in most PSCs in China, exploration and development costs are funded by IOCs and can be recovered from oil production (sometimes with a limit) when a commercial discovery is made.

Taxes on drilling and construction services

Under current practice, drilling and construction services still fall within the scope of BT and are subject to BT at the rate of three percent as construction services[6], while crude oil and natural gas produced under a PSC and for domestic sales are subject to in-kind VAT at the rate of five percent[7] without input VAT credit and which is not recoverable by the customer. Consequently, when a commercial discovery is made, drilling and construction costs together with the associated BT can be recovered from oil production while the remaining oil is shared between the parties. If there is no commercial discovery, the party that finances the drilling and construction services (the IOCs in most cases) can only absorb the cost itself.

Impact of VAT reform on PSCs

As VAT reform progresses, it is widely expected that VAT may be expanded to the construction industry in the first half of 2016, and the VAT rate for the construction service may be 11 percent, increasing from three percent under the BT regime. Drilling and exploration services provided by oilfield service companies falls within the definition of construction service. If oilfield service companies pass the additional tax cost wholly or partially to their customers, because of the inability of IOCs to recover input VAT, the profit oil for PSC participants will be reduced due to the increase in drilling and construction costs for development of a commercial discovery. If there is no commercial discovery, the increased cost can only be borne by the party that finances the drilling and construction activities (which again will be the IOCs in most cases).

4 Caishui [2011] No. 110
5 Caishui [2013] No. 106
6 Decree No. 540 of the State Council
7 Guoshuifa [1994] No. 114; 5 percent in-kind VAT is only applicable to offshore oil and gas fields and Sino-foreign cooperative oil and gas fields. Sales of oil from onshore fields are subject to VAT at the normal rate of 17 percent (a lower rate of 13 percent applies for natural gas) but with input VAT credit. Where it applies, the 5 percent in-kind VAT shall be paid in-kind and the basis for computing such tax is generally the gross production after deducting the amount of oil used for operations and any wastage. The Chinese party that participates in the PSC is responsible for matters concerning the declaration of VAT or any applicable filings with the competent tax authorities.

It has also been suggested that in due course the five percent in-kind VAT on crude oil may be increased to 17 percent (with a lower rate of 13 percent for natural gas), but with input VAT becoming creditable. In this case, 11 percent VAT on drilling and construction services consumed and other input VAT can offset the 17 percent output VAT. However, the earliest window to revisit or possibly revise the tax law stipulating the five percent in-kind VAT might be 2018.

Impact in the transitional period

In light of the above, there will be a transitional period after VAT reform is officially introduced which will affect the construction industry, but this will be before VAT reform in relation to the five percent in-kind VAT which isn't expected to happen for another few years. During this period, drilling and construction costs for PSCs will be increased because these services will be subject to VAT which will not be creditable input VAT for the customer. Deloitte estimates that the total cost will increase by around four to six percent. Some IOCs are considering the option to apply for transitional treatment with the Ministry of Finance (MOF) and State Administration of Taxation (SAT). One of the proposed transitional treatments may allow oilfield service companies to adopt a simplified taxation method and apply a three percent VAT rate, but restrict the right of customers to recover input VAT, so that the system will function in the same way as the current BT system.

There will be a very short timeframe for preparation after the new VAT rules are announced. PSC participants, especially IOCs, should closely monitor VAT reform development, continue to liaise with service providers and the corresponding NOCs, and plan carefully the following aspects, ensuring a smooth transition:

- prepare an action plan with milestones;
- review or update the project financial forecast, including but not limited to impact on cash-flow and profit; and
- consider possible solutions and approaches during the transitional period in relation to the five percent in-kind VAT, including consideration of the terms of the relevant PSCs, discussion with the Chinese party with regard to any compensation or other solutions, and escalation to the competent authorities including the MOF and SAT to request transitional treatment.

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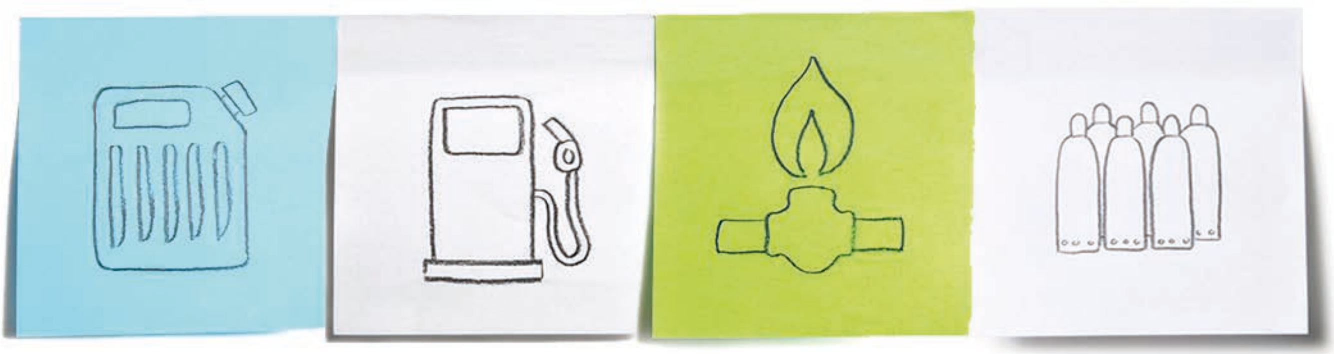


Malaysia: Impact of Budget 2016 and the introduction of changes to goods and services tax

Written by Bruce Hamilton, Deloitte Malaysia

Budget 2016[8] (the *Budget*) was delivered to the Malaysian Parliament in October 2015. One of the key measures was the introduction of changes to goods and services tax (GST) – which functions in the same way as VAT in other jurisdictions. In this article we have provided some comments on the implications for the oil and gas industry, including what it has not resolved.

2015 has been a year of contrasts – the anticipation and activity surrounding the introduction of GST and the submission of the first returns without systems collapsing were welcome outcomes. However, the extent of the fall in oil price during the year has taken some by surprise and even for those not surprised it has still negatively impacted their operations.

Looking at the *Budget,* it is clear that the Malaysian Government had some challenges to address, including replacing the revenue lost as a result of the effect of the oil price fall. GST in Malaysia, effective since 1 April 2015, has assisted in fulfilling that revenue raising need. However, it has also limited the Malaysian Government's options for addressing some of the concerns around the treatment of GST in practice when applied to industries like oil and gas.

While the *Budget* was able to give a concession around the treatment on the re-importation into Malaysia of equipment that had been exported temporarily for the purpose of rental or lease, it also provided new penalties for late GST returns, as well as late or non-payment of outstanding GST.

Since the *Budget* was announced, oil prices have at the time of writing reduced from an average of approximately USD50 per barrel to close to USD30 per barrel. This could give rise to a significant budget deficit unless additional revenue is found elsewhere. In a recent mini-*Budget,* it appears that this has been retrieved almost exclusively from the collection of GST, as since its implementation it has collected over USD12 billion in revenue, compared to a collection of USD7.8 billion in 2014 before the introduction of GST.[9]

The need to maximize sources of revenue to support the *Budget* requirements is important, as many of the actions and decisions by Malaysian Customs (the tax authority responsible for GST) on the application of GST have an impact on claims for refunds. These issues and the impact they have on the oil and gas industry are discussed in more detail below.

The first indication of the impact on the oil and gas industry was identified when a number of GST refunds were requested in the first few returns submitted. Initially this resulted in a review by Malaysian Customs and lengthy delays (often three to four months) before being paid out. In some cases, however, these claims appear to have brought issues over the treatment of certain situations to light. This is because the treatment applied was not necessarily what taxpayers had anticipated.

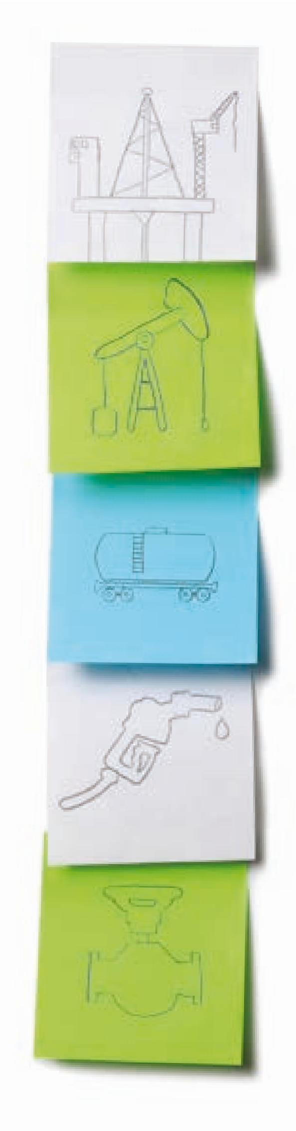
The first of these issues arose as a result of requests for refunds of the net GST paid where businesses were seeking to recover the GST on taxable supplies acquired to carry on their business functions for legitimate reasons. For some, it was simply because they were making zero rated export supplies and ultimately they received the refunds claimed. For others, however, the issue became more complex.

Those most affected included those in the upstream and oilfield services sectors involving construction, refurbishment or repair of significant plant and equipment. Most had registered for GST purposes in the expectation that they were entitled to do so as they were engaged in a business with the intention of making taxable supplies. Malaysian Customs have taken a different view. Businesses are now required to register if they make supplies in excess of USD120,000 over a 12 month period. If they do not then they may apply to register voluntarily, but if registering voluntarily the acceptance of the registration request is at the discretion of the Director General of Customs and may be subject to certain requirements.

The current position of Malaysian Customs is that if a business is not able to evidence that it will make taxable supplies within 12 months of applying for voluntary registration, it is not allowed to register. This will virtually eliminate the entity's ability to claim refunds of GST incurred prior to registration and will effectively add GST to the costs of any such projects. Exploration, appraisal and development can easily last more than five years, so this could result in significant additional cost for upstream projects, which could render some projects non-viable, particularly in the current oil price environment.

Oil prices have at the time of writing reduced from an average of approximately USD50 per barrel to close to USD30 per barrel. This could give rise to a significant budget deficit unless additional revenue is found elsewhere.

8 http://www.pmo.gov.my/bajet2016/Budget2016.pdf
9 http://www.thestar.com.my/business/business-news/2016/01/28/main-points-of-budget-2016-revision/



Where oilfield service providers are tendering internationally for fabrication and similar projects lasting longer than 12 months to be undertaken in Malaysia, they are faced with choices. If oilfield service providers use a new special purpose entity for the contract, and the contract will not allow the entity to progress bill, they face the issue of not being allowed to register for GST voluntarily in order to claim input tax credits. As a result, any GST incurred as part of the project will become an additional cost to the service provider. If, however, the contract permits them to progress bill then they may be able to register for GST, but will be required to charge GST at six percent to overseas clients. This is because the supply of the services will not fulfil the requirements to be zero rated and the time of supply for GST purposes will occur when the goods that are the subject of the services are in Malaysia. The fact that the goods may be moved overseas at the completion of the contract does not assist. For overseas recipients of the services (that may not be entitled to register themselves) this means that GST becomes an additional cost passed onto them. If the price paid is treated as GST-inclusive, it is a hardship to the profitability of the service provider.

Additionally, one other issue has emerged. When goods are imported they are subject to GST being paid by the importer of record. Under the previous sales tax regime, this was not an issue as neither import duty nor sales tax were imposed as a result of the use of a master exemption list (MEL) which applied to many items used in the oil and gas industry. However, since GST replaced sales tax, with very limited exceptions, the benefit of the MEL is no longer available. In addition, the general commercial practice required in Malaysia has always been that and although brought into the country by the importer of record, supplies of imports are made via a local agent with ownership transferred to the actual importer after the goods are in Malaysia.

As a consequence, GST is in effect levied twice. Firstly, upon importation with the local purchasing entity being the importer of record as it previously needed to be responsible for arranging the import in order to qualify for the MEL. Secondly, it would be payable on the supply made in Malaysia by the local agent to effect transfer of the final ownership of the goods to the Malaysian purchasing entity.

Where the local purchasing entity is able to register for GST purposes, there will only be a cash-flow issue, as it would be able to claim a refund of the GST incurred. However, where the purchasing entity, as importer of record, is not entitled to register voluntarily for GST, this will mean that the goods being imported will be subject to GST twice, (on importation and again on local supply) without any relief by way of input tax credits being claimable.

The additional cost, where GST is not able to be recovered, could result in these measures having a negative impact on investments and cost competitiveness. It is also to be noted that this appears to conflict with the internationally established practice (endorsed in the draft OECD VAT/GST guidelines) that VAT/GST should not be an economic burden to businesses that are making, or will make, taxable supplies.

These issues will need to be addressed for the medium- and long-term. There are options that have been raised with the Malaysian Government, but no action has been taken so far.

Kenya: Fiscal stability and oil price volatility

Written by Denis Kakembo, Deloitte Kenya

The journey to crude oil discovery in Kenya was long and winding. The search began in 1954, but a commercial discovery was first made in 2012 with additional successes thereafter. In a period where industry interest was subdued by low oil prices, Kenya enacted a new *Petroleum Act* in 1985 that set out favorable terms to boost investor interest in exploration activities. This is still the applicable law governing the industry today, but a raft of legislation will shortly be tabled before the Parliament of Kenya for enactment.

As discussions to commercialize discoveries in any new oil and gas province make progress, IOCs are at pains to remind governments about the sensitivity of projects at the appraisal or pre-development stage to the fiscal regime. If investors feel the petroleum fiscal regime is too onerous, they will not undertake a project. Petroleum fiscal regimes in general blend legal and contractual instruments that create the framework for carrying out petroleum operations. They encompass levies, taxes and related financial measures for allocating economic rent arising from the petroleum operations between governments and IOCs.

In assessing the attractiveness of a country's petroleum fiscal regime, stability is key for investors. Given that the investment is upfront and recouped over a long period of time, investors are wary that future changes in the fiscal regime may distort the economics of the project affecting their ability to recover their investment and achieve the projected return. International oil markets have in the past 16 years exhibited unprecedented volatility with crude oil prices swinging between historic highs and lows. In periods of high oil prices it has been common for governments to seek higher economic rent through revising the original terms of petroleum agreements, while oil companies request milder fiscal terms during periods of low oil prices.

Kenya has demonstrated this pattern and some aspects of the country's petroleum fiscal regime underwent change in the period 2012 to 2015 when crude oil prices were at their peak. Whilst some of these changes were encouraged by a desire to align the country's regime to international best practice, in other instances, the Kenyan Government sought to capture some of the windfall profits that it perceived the IOCs to be making from merger and acquisition (M&A) activity during the period.

In 2012, the Kenyan Government introduced a final withholding tax of 10 and 20 percent on the consideration earned by resident and non-resident IOCs respectively on transfers of interests in PSCs. Work obligations undertaken by the acquirer were also included in the consideration subject to tax. The imposition of tax on the value of work programs was seen by the IOCs as a tax on investment and widely criticized. In the following year, the law was revised making the withholding tax a non-final tax. This meant that taxpayers could seek an offset of the tax suffered against their future income tax. In view of the PSC provisions which deem income tax to be part of the Kenyan Government share of profit oil, it is not clear whether this amendment was actually beneficial to the IOCs.

In 2012, the Kenyan Government introduced a final withholding tax of 10 and 20 percent on the consideration earned by resident and non-resident IOCs respectively on transfers of interests in PSCs.

The *Finance Act 2014,* effective 1 January 2015, introduced wide-ranging changes to upstream petroleum industry taxation. Though the value of carried costs was excluded from the consideration earned on farm-out transactions, gains arising on the offshore disposal of shares whose value is deemed to derive from the PSC interest in Kenya are now taxable. These gains were previously not subject to tax. Net gains arising on M&A activity are now taxable albeit at higher rates of 30 and 37.5 percent for tax residents and non-residents respectively (though there remains some uncertainty around which rate applies to non-residents that are not direct parties to a PSC). Gains derived on farm-outs but reinvested in the petroleum industry in Kenya are still subject to tax, but there is pressure for the Kenyan Government to consider such gains for exemption from tax via re-investment relief.

Kenya's petroleum fiscal regime had been stable for almost 30 years from the enactment of the original rules passed in 1985 up to the introduction of withholding tax rules in 2012. The expectation of increased activity in the industry after the first crude oil discovery in 2012, led the Kenyan Government to tighten the fiscal environment as a means of increasing economic rent. With the recent crude oil price decline and the Kenyan Government's desire to produce oil, questions are being asked by some industry commentators whether fiscal incentives must be approved for the upstream petroleum sector.

Though the Kenyan Government may exercise it sovereign right to revise the country's legislation as it considers necessary, the country's petroleum fiscal regime incorporates various fiscal tools aimed at maintaining fiscal stability in the upstream petroleum sector but these do not necessarily help in relaxing fiscal terms to accommodate a much lower oil price environment. The fiscal regime incorporates an economic stabilization clause. This provides for automatic adjustments or negotiations to reinstate the initial economic balance of the PSC should legislative changes be introduced after signature. Kenya's current fiscal regime also incorporates the tax paid PSC system by which the IOCs income tax liability carves out the Kenyan Government's share of profit oil. Any increase in the income tax rates does not necessarily affect their net economic position as originally negotiated. On the other hand, a decrease in the income tax rates would not provide any benefit to oil and gas companies. It seems likely that Kenya will have to consider changes to the wider fiscal package it offers in order to encourage new investment in a period of sustained low oil prices.

Middle East: The rise of taxation, declining oil prices and fiscal balance

Written by Alex Law and Alan Onslow, Deloitte Middle East

Set against the backdrop of declining oil prices, members of the Gulf Cooperation Council (GCC), which includes UAE, Saudi Arabia, Qatar, Kuwait, Bahrain and Oman are considering the options available to them to balance their national budgets and reduce their dependency on hydrocarbon revenues.

The International Monetary Fund (IMF) estimates that for 2016 the breakeven oil price for fiscal balance in these economies ranges from USD49 a barrel for Kuwait up to USD110 a barrel for Bahrain[10]. Whilst it is widely thought that many of these countries hold sufficient cash reserves in order to weather a depressed short- to medium-term oil price, the outlook for the longer-term may be less optimistic. With the economies of China, Russia and Brazil faltering, and the lifting of sanctions against Iran offering an increase in supply of oil, there is no sign of diminishing production and low oil prices could continue at a level well below the breakeven points for most of these countries.

In December 2015, the IMF identified an overhaul of GCC tax systems as an important part of stabilizing fiscal strategy. It was recommended that such a move should be taken in conjunction with raising domestic energy prices, containing recurrent spending and enhancing efficiency in the public sector. VAT, which is currently not levied anywhere in the GCC, has been identified as a suitable revenue instrument for governments and a potential first step in the proposed overhaul.

Introduction of VAT

The introduction of VAT in the GCC has long been mooted and in light of the oil price decline may be a more attractive option. VAT is seen as simple to comply with, relatively easy to enforce, neutral to changes in trading and distribution and can be applied to a broad base of goods, services, real property and intangibles.

That is not to say there are no difficulties to implementing VAT. The fact that VAT is being considered by the GCC and not by individual member countries in isolation reflects the acknowledgement that a framework in the region would be required in order to minimize economic distortions created by VAT implementation in isolation. The simple fact that the GCC economies are not uniform and the separate governments have to address different demographic factors means a collaborative approach is considered to be beneficial to every GCC member.

The GCC has agreed to the implementation of VAT in member states, although the decision has yet to receive final approval. It is therefore widely expected that VAT will be introduced within the next two years, but the majority of the details on the implementation (rates and requirements etc) have not been disclosed. It is likely however to be a broad based VAT system with a low VAT rate (five percent potentially).

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10 http://www.imf.org/external/pubs/ft/reo/2015/mcd/eng/pdf/mreo0515st.pdf

Reform of corporate income tax

Several members of the GCC currently impose some form of tax on corporate profits and these taxes are also being targeted for reform, albeit differing strategies are being adopted by member states. Oman is seeking to increase its corporate income tax rate from 12 to 15 percent. In contrast, Kuwait is looking to reduce its corporate income tax rate from 15 to 10 percent, but broaden its base by bringing in previously untaxed entities such as Limited Liability Companies (W.L.L.s). Saudi Arabia, on the other hand, is working towards the introduction of formal transfer pricing rules to complement its current corporate income tax and zakat laws and regulations.

Looking ahead

The reforms outlined above may be only the beginning of significant tax reform in the region. Given the consensus view that low oil prices are here to stay, tax reform is a topic that is unlikely to quieten in the near future.

Deloitte considers the reforms outlined above to be only the beginning of significant tax reform in the region.

Nigeria: Recent changes in Nigeria's tax landscape

Written by Lukman Ogunsda and Tolulope Idowu, Deloitte Nigeria

The sustained slump in crude oil prices has triggered an urgent rethink of Nigeria's economic and fiscal planning approach. Presently, the price of crude oil is down by about 70 percent from USD115 per barrel in June 2014.

According to the *Q2 report* issued by the National Bureau of Statistic (NBS), there was a reduction in oil production by 7.3 percent (to 2.05 million barrels per day) in 2015 when compared with corresponding quarter in 2014 (2.21 million barrels per day). Consequently, the oil and gas industry's contribution to the country's gross domestic product (GDP) dropped by approximately 1 percent to 9.80 percent (2014: 10.76 percent).

Nigeria's challenge is not necessarily the decline in oil prices per se, but rather that the high oil prices in the past had masked Nigeria's dependence on oil to drive the economy and the relatively small tax base outside the oil and gas industry. This is the context for the paradigm shift to the era of non-oil budgeting in which only 21 percent of the budget outlay is expected to come from oil revenue compared to 53.2 percent in 2015.

Barring any significant recovery in the international price of crude oil, it is probable that the focus of the Federal Government in 2016 and beyond will likely be on non-oil revenue sources of which tax is a significant component.

In the last 18 months, the tax landscape in Nigeria has witnessed the following important developments reflecting the pressure to increase tax collections:

Appointment of new FIRS Chairman:
Mr Tunde Fowler was appointed Executive Chairman for the Federal Inland Revenue Service (FIRS). One of his first major actions was a meeting with stakeholders to discuss his administration's mandate to improve tax collection levels at FIRS significantly. He indicated that different options and strategies will be employed and deployed to actualize this mandate. Given Mr. Fowler's previous position as the Executive Chairman of Lagos State Internal Revenue Service (LIRS), there is reasonable confidence that together with his team he will deliver. However, it needs to be emphasized that the drive to ramp up the tax revenue collection capacity of FIRS should follow a proper process, based on the laws in effect.

The Nigerian tax system is still in its developmental stage with several impediments (such as outdated laws, dearth of technical skill and poor IT infrastructure) requiring much needed attention.

Non-resident company (NRC) taxation rule:
Effective from 1 January 2015, NRCs carrying on businesses in Nigeria are no longer allowed to file annual tax returns based on a deemed profit. Instead, filings must be based on actual profits derived from activities in Nigeria.

Prior to the directive, NRCs had been filing tax returns on a deemed profit basis where 20 percent of turnover attributable to the permanent establishment (PE) in Nigeria was deemed as assessable profit on which the income tax rate of 30 percent was applied to derive the tax payable. This translates to six percent of turnover.

Thus, NRCs are now required to file comprehensive income tax returns comprising audited financial statements, tax and capital allowance computations, duly completed self-assessment forms and evidence of payment of tax due, as prescribed in s.55 of the *Companies Income Tax Act* (as amended) (*CITA*).

Restriction of pioneer tax holidays to three years in the first instance:
Under the provisions of the *Industrial Development (Income Tax Relief) Act* (IDITRA), pioneer status is to be granted for an initial period of three years with a possibility of an extension for another two year period. However, the Nigeria Investment Promotion Commission (NIPC) has in practice for the last 14 years, granted pioneer status to successful applicants for a period of five years without a requirement to apply for any extension after the initial three years. The current low oil price has triggered a review of the administration of pioneer status by the NIPC. Consequently, the NIPC is no longer giving an automatic five year period and any applicant awarded pioneer status will need to apply for an extension if it wishes to extend the period.

Interim dividends tax provision: A public notice issued by FIRS requires any company paying interim dividends to its shareholders to pay companies income tax (CIT) at 30 percent to the FIRS prior to the payment of the dividend, in line with S.43(6) of the *CITA*. The tax paid will serve as a deposit against the CIT due on the profits of the company from which the dividend was paid.

As stated in the public notice, FIRS intends to carry out random compliance checks on all companies and apply penalties and interest on all erring companies from the date of default.

Establishment of a Free Zones Tax Administration (FZTA) Unit: The Oil & Gas Free Zone (OGFZ) Authority issued a general notice by which it announced the establishment of the FZTA unit, effective January 2015, to oversee tax matters relating to OGFZ entities, as well as enhance the administration of "allowable" taxes within OGFZs (i.e., taxes to which OGFZ entities are subject). The following taxes were listed as allowable in the free zones:

- pay-as-you–earn (PAYE) tax of employees of free zone enterprises;
- withholding tax (WHT) and VAT in respect of transactions entered into by free zone entities with third-parties outside the free zone; and
- industrial training fund (ITF) deductions for training of free zone employees.

It is expected that the FZTA unit will:

- interface between the free zone enterprises (FZE) and various tax agencies, in order to reduce the incidence of tax disputes;
- harmonize and coordinate the process of collecting allowable taxes in all oil and gas free zones;
- serve as a tax collection agent for all tax agencies in the collection of allowable taxes in the free zone; and
- arbitrate on any tax dispute arising between a free zone enterprise and any tax agency.

Readers may also be interested in the following recent tax rulings in Nigeria

1. According to a Federal High Court decision, execution of a split contract does not create a fixed-base for a NRC fulfilling the part of the contract outside Nigeria, nor does it imply that the NRC is doing business in Nigeria.
2. According to another recent Federal High Court decision, NRCs with a fixed-base in Nigeria are subject to income tax only on a portion of turnover attributable to operations in Nigeria.
3. Nigerian companies can now claim tax deductions for gas flaring fees provided that:
   - a gas flaring fee has been actually paid;
   - the gas flaring fee is wholly, reasonably, exclusively and necessarily incurred; and
   - the gas flaring is not considered illegal (that is no sanctions have been issued to the company for illegal gas flaring).
4. Companies engaging in both upstream and gas to liquids operations can claim a 35 percent petroleum investment allowance (PIA) for their operations, based on the provisions of *CITA* and take the relief of the same against their income.
5. Section 60 of the *Petroleum Profit Tax Act* (as amended) (PPTA) which exempts dividends paid by exploration and production companies does not extend to profit derived from gas operations. Gas income is liable to tax under *CITA* and all the provisions of *CITA* including WHT on dividends as provided under sections 80 and 9(1) (c) of *CITA* become applicable.

Talk to us

If you have questions or comments regarding the content of the *Global oil & gas tax newsletter,* please contact one of the following:

Oil & Gas Tax Leaders

Julian Small
Oil & Gas Tax Leader | Global
Partner | Deloitte UK
Tel: +44 20 7007 1853
Email: jsmall@deloitte.co.uk

Daniel Caracciolo
Partner | Deloitte Argentina
Tel: +54 11 4320 2700
Email: dcaracciolo@deloitte.com

Chris Roberge
Partner | Deloitte Asia Pacific
Tel: +852 2852 5627
Email: chrisroberge@deloitte.com

Jonathan Schneider
Partner | Deloitte Australia
Tel: +61 8 9365 7315
Email: joschneider@deloitte.com.au

Carlos Vivas
Partner | Deloitte Brazil
Tel: +55 21 3981 0482
Email: cavivas@deloitte.com

Andrew Zhu
Partner | Deloitte China
Tel: +86 10 8520 7508
Email: andzhu@deloitte.com.cn

Andrey Panin
Partner | Deloitte CIS
Tel: +74 957 870 600
Email: apanin@deloitte.ru

Dmitry Logunov
Partner | Deloitte East Africa
Tel: +25 522 216 9000
Email: dmlogunov@deloitte.co.tz

Toh Hong Pier
Executive Director, Deloitte Malaysia
Tel: +60 3 7610 8808
Email: htoh@deloitte.com

Alex Law
Partner, Deloitte Middle East
Tel: +971 4 506 4700
Email: alexlaw@deloitte.com

Frank Tak
Partner, Deloitte Netherlands
Tel: +31 8 8288 0334
Email: ftak@deloitte.nl

Oluseye Arowolo
Partner, Deloitte Nigeria
Tel: +234 1904 1723
Email: oarowolo@deloitte.com

Per Evers
Partner, Deloitte Norway
Tel: +47 2327 9636
Email: peevers@deloitte.no

Roman Webber
Partner, Deloitte UK
Tel: +44 20 7007 1806
Email: rwebber@deloitte.co.uk

Jeff Wright
Partner, Deloitte US
Tel: +1 713 982 4940
Email: jeffwright@deloitte.com

Alejandro Gomez
Partner, Deloitte Venezuela
Tel: +58 212 206 8730
Email: algomez@deloitte.com

Article contributors

Bill Page (Editor)
Senior Adviser African Projects, Deloitte UK
Tel: +44 20 7007 6937
Email: bpage@deloitte.co.uk

Aengus Barry
Director, Deloitte UK
Tel: +44 20 7007 4331
Email: aenbarry@deloitte.co.uk

Jocelyn Jia Li
Director, Deloitte China
Tel: +86 10 8520 7542
Email: joli@deloitte.com.cn

Bruce Hamilton
Director, Deloitte Malaysia
Tel: +60 3 7610 8844
Email: bruhamilton@deloitte.com

Denis Kakembo
Senior Manager, Deloitte Kenya
Tel: +250 20 423 0036
Email: dekakembo@deloitte.co.ke

Alan Onslow
Manager, Deloitte Middle East
Tel: +971 4 5064 700
Email: alonslow@deloitte.com

Lukman Ogunsola
Manager, Deloitte Nigeria
Tel: +234 1904 1894
Email: logunsola@deloitte.com

Tolulope Idowu
Senior Consultant, Deloitte Nigeria
Tel: +234 1904 2097
Email: tidowu@deloitte.com

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