



In this issue

Editor's introduction	2
Base erosion and profit shifting: Implications of the BEPS actions for commodity trading activities	3
BEPS action 2: Branch mismatch structure	7
Brazil: RD&I tax incentives	12
Gabon: Overview of the 2014 hydrocarbon regime	14
Malaysia: Application of the GST/VAT concept of transfer of a going concern to farm-out transactions	17
Russia: Potential changes to upstream taxation	20

Global oil & gas tax newsletter

Views from around the world

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Editor's introduction

Bill Page, Deloitte UK



Welcome to the final edition of the Global oil and gas tax newsletter for 2016. As many are preparing for holidays, some probably can't forget that year-ends will have to be dealt with soon after.

This edition continues our in-depth examination of the base erosion and profit shifting (BEPS) initiative where we consider some of the impacts that the BEPS actions are likely to have on commodity traders. In our second BEPS article we analyze the OECD's proposals on hybrids, including a discussion of the UK's legislation, which is the first to be enacted addressing the proposals and which comes into force on 1 January 2017.

Other articles include overviews of tax deductions available in Brazil for research and development expenditure and Russia's proposal to change its tax system for upstream taxation to link the tax burden more closely to the profitability of projects. We also have an in-depth examination of the application of indirect tax to transfers of oil and gas projects in Malaysia, and a review of the impact of Gabon's 2014 Hydrocarbon Code. We had hoped to include an update on the introduction of VAT in the Gulf, but delays in finalizing the Gulf Cooperation Council's framework document mean we will postpone this to our 2017 editions.

This edition is being issued as the world begins to address the potential implications of President-elect Donald Trump's victory in the US presidential election. Many commentators expect this to result in the most far-reaching US tax changes in a generation. We do not cover this topic in the current edition, but Deloitte's US team are preparing an article for March 2017, which will review what is known about the incoming administration's fiscal program, and the implications that it might have for the US oil and gas industry and US multinationals.

I wish all our readers a happy, prosperous and safe 2017.

Base erosion and profit shifting: Implications of the BEPS actions for commodity trading activities

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One of the main success factors for global commodity traders is having the capacity to engage in processes and transactions that connect commodity supply with demand across many different jurisdictions. Due to the cross-border nature of the business, this can lead to challenges in managing tax, including transfer pricing and permanent establishment (PE), issues. In the current environment, maintaining competitive advantages in the commodity trading industry may become more complicated in the face of international tax reform.

There have been a number of developments in recent years that have significantly changed the global tax landscape and placed pressure on commodity traders' existing business models.

As we move into the post-BEPS world, global commodity trading companies should assess their current corporate structures and business and be ready to take action to adapt to the new international tax environment.

This article analyzes the specific BEPS actions which we believe will create more significant challenges for international commodity trading structures, as well as providing some comments on the management of these challenges.

Action 7: Preventing the artificial avoidance of PE status

Action 7 focuses on updating the definition of a PE in article 5 of the OECD model tax treaty. The main objective is to prevent the artificial avoidance of PEs where there is significant activity in a country. The OECD recommends changes to the framework of international tax treaties and changes to bilateral tax treaties to reflect the new conditions that are included as part of the recently finalized multilateral instrument that is scheduled to be signed by more than 100 jurisdictions in June 2017.

Action 7 recommends a wider definition of PE, which is likely to increase the number of activities that could give rise to a PE, and increase the ability of tax authorities to tax multinationals within their jurisdiction with respect to activities that previously were not taxable.

The basic principles remain unchanged, and a PE still can be created in one of two ways: an agency PE or a fixed place of business PE. The first arises when an agent concludes contracts on behalf of its principal. Under the proposed changes, this concept will be broadened so that a PE will exist where a person is acting on behalf of an enterprise and, "...habitually concludes contracts, or habitually plays the principal role leading to the conclusion of contracts that are routinely concluded without material modification by the enterprise..."

In addition to broadening the scope of the main agency PE definition, the proposed changes add greater precision to the independent agent exemption so that it will not be available to agents who act exclusively for a single group of companies.



The second way a PE can be created under the model treaty is where a foreign entity maintains a fixed place of business in another country. Currently, there is an exemption for specific activities, such as the storage or display of goods, or any other activity that is preparatory or auxiliary in nature. Under the new framework, the exemption will be restricted to activities that are solely considered preparatory or auxiliary to the business as a whole. Action 7 also proposes the introduction of a new anti-fragmentation rule, whereby the preparatory or auxiliary exemption will not apply where business activities are carried out by an enterprise across multiple locations and those activities constitute complementary functions that are part of a cohesive business operation.

Changes to both of the ways in which a PE can be created are likely to have an impact on commodity trading activities. For example, it is common to use agency arrangements in the commodity trading industry and if a group company acts as an agent, playing an active role in negotiating contracts habitually concluded by other parties, this is likely to give rise to a PE exposure once the new rules come into effect. It will be fundamentally important for groups to decide which agents will habitually conclude contracts, or habitually play the principal role leading to the conclusion of contracts. If a PE is created, consideration will need to be given to what profit likely would be attributed to the PE.

Another scenario that may lead to the creation of a PE is where a stock of goods is held in a country by an overseas entity (i.e., before sale to third parties). Under the current definition, a stock of goods would fall under the specific activities exemption and would not create a PE. However, under the new framework the nonresident entity will have to show that the stockpiling of product is of a preparatory or auxiliary nature for the entity when viewed as a whole. Holding stockpiles in a commodity trading business is often strategic in nature. An interesting consequence of the way the new rules have been drafted is that the same activity (such as holding crude oil in storage) may not create a PE for an enterprise, such as an upstream producer (where the storage of crude oil is a necessary part of the long and complex supply chain from wellhead to market, and hence auxiliary to the core business), but could create a PE for an oil trader (where the storage of crude oil could be a speculative activity based on an expectation of future price rises, and hence a core part of the business).

The proposed changes to article 7 are far-reaching and, if adopted, will significantly increase the range of situations in which a PE could be created by commodity traders. In the case of the creation of a local PE of an overseas principal, both countries will need to sign the multilateral instrument (and then ratify in national legislative bodies) for it to have effect. It is intended that the multilateral instrument will be signed in 2017, but the timing of ratification and the introduction of local legislation will vary. Groups with commodity trading activities, therefore, should start to consider the potential impact of these proposals on their current business models to determine whether any additional tax will be due. It also will be important to monitor the activities of group companies in overseas jurisdictions to determine if they could represent a cohesive business operation.

Actions 9 and 10: Aligning transfer pricing outcomes with value creation

These actions represent the work on the transfer pricing of risk and capital (action 9) and commodities transfer pricing (part of action 10). The objective of both actions is to ensure that transfer pricing outcomes are in line with value creation, which is to be aligned with significant people functions.

The revisions can be seen as shared interpretations of how article 9(1) of the OECD and UN model tax treaties should be applied. This provision can be found in almost all tax treaties around the world. Therefore, these shared interpretations between countries will have immediate application through the existing treaties.

Action 9 looks specifically at risks and has developed rules to prevent profit shifting by transferring risks among or allocating excessive capital to group members. It is open to interpretation what excessive means in this context. The intention of this action is to update and expand guidance on the allocation and transfer pricing of risk within a multinational group.

The amendments to the OECD transfer pricing guidelines (in October 2015) highlight the importance of determining where, in a group, the capability and functionality exists to manage risks associated with business opportunities. The revisions provide an analytical framework to determine which associated enterprise should be allocated risk for transfer pricing purposes. It requires a review of overall value chain profitability in determining entity based profitability. A group company that does not both control risk

and have the financial capacity to bear the risk, will not assume the risk and will not be entitled to the profits/losses associated with it. Rewards that would previously have flowed to value drivers, such as financial or physical assets, are more likely to flow to significant people functions in the post-BEPS world to ensure value is attributed to the individuals managing key assets and/or making key decisions.

These changes are far-reaching. For commodity traders, much of the substance that creates value lies in its people—the trading personnel and the individuals making key decisions, such as establishing overall trading strategy, making key operational decisions, agreeing customer contracts and managing significant risks. Many commodity trading groups rely on global traders who operate across several locations.

The result of these changes will be that business models used in the pre-BEPS world may no longer be appropriate post-BEPS. For example, it may no longer be viable to have a centralized trading model with a single entity providing trading support and capital, earning the majority of group profit, with service providers in key locations earning relatively low returns, especially where there are key decision-makers in those service-providing entities.

The actions place focus on people and value creation rather than contractual allocations of risk and capital. Going forward, it will be critical for groups to review significant people functions across the entire group value chain and consider carefully the implications of where these are located.

The immediate lesson for commodity traders to take from action 9 is that they need to change their approach to transfer pricing, as there will be much more focus on the location of people as opposed to contractual allocations of physical and financial assets.

Action 10, which is entitled “the transfer pricing aspects of cross-border commodity transactions,” is in reality one of the BEPS actions least likely to impact commodity traders. The final report on action 10 considers additional guidance for determining the arm’s length price for commodity transactions and has been driven by concerns that the tax base may be eroded in relation to:

- The difference between the price charged and publicly quoted commodity prices;
- Variable dates for pricing the commodity transaction prior to shipping; and

- Adjustments made to publicly quoted prices in relation to services performed by other group companies.

The report is primarily directed at the mining and upstream oil and gas industries, though any commodity traders that have related party offtake agreements will be impacted. While it is relatively rare for commodity traders to pass title to products amongst many members of the same group, where this does occur, this report will be of particular interest.

The OECD proposes the use of quoted commodity prices as a starting point for transfer pricing, where the quoted prices are used in commercial transactions between third parties. This will lead to difficulties if an adjustment is needed where the quoted price is not the same as the market price at the location where title transfers.

These amendments to the OECD transfer pricing guidelines will be of relevance to any entity trading commodities between related parties. Any group selling using an internal comparable, or non-index linked price would clearly be open to challenge under the new framework (assuming the commodity in question is index-traded).

Action 4: Limiting base erosion involving interest deductions and other financial payments

The G20 and OECD perceive that interest flows (and, in particular, interest flows between related parties) are a technique frequently used in international tax planning. A particular concern is that multinational groups seek to concentrate interest deductions in high-tax entities or jurisdictions, even where this may be disproportionate to the level of economic activity in that jurisdiction and/or the group’s overall external interest burden.

The OECD’s final report on action 4 recommends that the net interest expense deductible for tax purposes should not exceed a set proportion of earnings in the relevant entity or jurisdiction. The suggestion is a range of 10 percent – 30 percent of earnings before interest, tax, depreciation and amortization (EBITDA) should be adopted, with discretion for countries to fix a limit within this range. Net interest expense exceeding the limit would not be deductible, although countries potentially could allow excess deductions or capacity to be available for carryforward (or carryback) if there are future (or past) periods where deductions could be utilized. Certain relieving provisions are suggested that would permit entities to deduct a higher level of interest expense to the extent it does not exceed the worldwide group’s net interest EBITDA ratio. To have an effect, these recommendations need to be embedded in domestic

law and, therefore, the timing of implementation will vary across jurisdictions. All work on BEPS action 4 needs to be completed in 2016, with countries likely to introduce the new rules in tax year 2017-18.

The UK's rules are set to come into effect on 1 April 2017. In line with the OECD recommendations, the UK will introduce a group override (the group ratio rule) allowing additional interest deductions where the UK group's fixed ratio (whilst exceeding 30% of EBITDA) does not exceed the worldwide group's fixed ratio.

The changes arising from action 4 are likely to have a particularly significant impact on commodity traders as they typically finance their overseas operations through debt.

An interest cap based on EBITDA is likely to be troublesome for commodity traders because of market volatility. This can result in companies experiencing high EBITDA one year, followed by very low EBITDA the next, which does not fit well with a cap based on a fixed ratio of interest to EBITDA. This could lead to unpredictable outcomes from the implementation of action 4 recommendations if these are not adapted to the industry's specific circumstances, and if there are variations in the approaches taken by different countries (i.e., in relation to excess deductions or capacity to be available for carryforward or carryback).

Action 4 should not be viewed in isolation. Any consideration of changes in financing structures to address the implementation of the action 4 recommendations must also consider the implications of, and interaction with, the other BEPS recommendations and how these might be implemented.

Conclusion

The immediate lesson that can be taken from the BEPS action plan is that commodity traders, like other multinational businesses, may need to change their approach to transfer pricing, particularly as many tax authorities already are applying BEPS principles in practice. It is important for groups to keep abreast of developments as they occur, both locally and internationally, particularly the progress of the multilateral instrument, in order to evaluate the impact on the group's tax position and take action where necessary.

Importantly, in the case of action 7, many OECD countries will amend their current treaty network through ratification of the multilateral instrument. As noted above, it is planned that the multilateral instrument will be signed in June 2017, but the ratification and tailoring of local legislation will vary on a country-by-country basis. Despite this, many European tax authorities already are seeking to apply current PE provisions in line with the proposed changes.

It also should be noted that OECD recommendations on Action 4 do not, of themselves, have direct effect. Another key priority for international commodity traders is to monitor developments concerning new rules in the territories in which they operate. It would be worthwhile performing some sensitivity analysis i.e., using current and forecast financial information to compare net interest expense with EBITDA in the various jurisdictions in which a group operates, to identify territories where there is a likelihood of a tax impact if action 4 recommendations, or other changes intended to have a similar impact, are implemented.



BEPS action 2: Branch mismatch structure

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The October 2015 OECD output included a paper on action 2, "Neutralizing the effects of hybrid mismatch arrangements." Action 2 sets out recommendations for rules to address mismatches in tax outcomes where they arise in respect of payments made under a hybrid financial instrument or payments made to or by a hybrid entity. On 22 August 2016, the OECD produced a public discussion document on one particular aspect of action 2: branch mismatch structures. The discussion document identifies tax mismatches that can result from certain branch structures and sets out preliminary recommendations for domestic rules. The deadline for commenting on the discussion document was 19 September 2016.

Oil and gas groups will need to consider the full scope of the BEPS action 2 hybrid mismatch proposals. Given the widespread use of branch structures in the oil and gas sector, the focus of this article is the discussion document.

The UK has been an early mover in responding to BEPS action 2: hybrid and other mismatches legislation has been finalized and will be effective from 1 January 2017, and Australia has announced its intention to introduce anti-hybrid rules in 2018 (see the [September 2016 edition](#)). At the time of writing, we are not aware of any other jurisdictions with concrete plans to introduce anti-hybrid rules. The full potential impact on multinational groups will depend on how and when other jurisdictions choose to implement the action 2 recommendations.

It is also worth noting that, in June 2016, the 28 EU member states approved an Anti-Tax Avoidance Directive (ATAD), which sets out certain minimum standards for various BEPS-related issues, including hybrid mismatches.

Based on UK experience to date, groups are likely to require a detailed review of commercial arrangements to assess the potential impact of these rules, with ongoing assessment required as other jurisdictions adopt these or similar proposals.

Branch mismatch structures

The OECD recommendations in action 2 target hybrid mismatches that are broadly attributable to the difference in the legal characterization of instruments and/or entities. Branch mismatch arrangements are not hybrid in that they more typically result from differences in the way in which jurisdictions treat payments made by or to a branch or head office (HO) and differing approaches to determine whether a permanent establishment (PE) exists, and if so, how to allocate profits to the PE. It should be noted that there is a separate OECD work stream focused on attribution of profits to PEs, i.e., action 7.

It is not uncommon for oil and gas groups to structure international investment through foreign branches. The use of branch structures in a multinational oil and gas group is often driven by non-tax commercial requirements. Historically, oil and gas groups may have been unable or reluctant to structure their international investment through companies incorporated in the territory where the assets are located because of, for example, local company law restrictions. Where there is a high risk of abortive exploration costs, and exploration is carried out by a local branch, this may enable a group to include abortive exploration costs in the calculation of the group's taxable profits, which may not be possible with a local subsidiary company. Funding of activities and repatriation of cash also may be more straightforward using a branch structure.

Five branch mismatch scenarios

The discussion document identifies five types of branch mismatches. These are set out below, together with the OECD recommendation to neutralize the effect in each case. This article also sets out the proposed measures under the UK's hybrid and other mismatches legislation, for two of those branch structures (scenarios one and four). The way in which the UK legislation addresses the perceived abuse is not entirely consistent with the OECD approach. It remains to be seen how other jurisdictions will approach this.





The five scenarios set out in the OECD's August 2016 branch mismatch discussion draft are:

01. Disregarded branch structures - where the branch does not give rise to a PE or other taxable presence in the branch jurisdiction.
02. Diverted branch payments - where the branch jurisdiction does recognize the existence of the branch and amounts payable to the branch are regarded by the branch jurisdiction as attributable to the HO, whereas the HO jurisdiction exempts these amounts.
03. Deemed branch payments - where the branch is treated as making deductible notional payments to the HO, set against locally taxable branch income, but these are treated as exempt from tax in the HO jurisdiction and HO jurisdiction does not tax the branch.
04. Double deduction branch payments - where the same item of expenditure gives rise to a deduction under the laws of both the HO and the branch jurisdictions.
05. Imported branch mismatches - the example given is similar to the branch mismatch in scenario 3, except that the branch income receivable is from a connected company, so there is a tax deduction in that connected company which relates to the branch mismatch.

Each of the five scenarios, together with the proposed OECD counteraction in each case, are summarized below, together with a summary of the UK's approach to scenarios one and four.

The proposed new UK legislation can be found in Finance Act 2016 Schedule 10. Her Majesties Revenue and Customs (HMRC) guidance on this new legislation is expected to be published in December 2016, which should assist taxpayers to better understand how HMRC intend the new legislation to operate in practice.

1. Disregarded branch structures

In this scenario, it is assumed that the taxpayer is an entity with a foreign branch. The mismatch arises due to the fact that a deductible payment receivable by the taxpayer is treated by the HO jurisdiction as receivable by the branch, which is exempt from tax in the HO location; the branch jurisdiction does not tax the amount, for instance, because the branch does not give rise to a taxable presence in that location for domestic purposes.

In the oil and gas sector, it is not unusual for a multinational group to provide assets or services from a foreign branch of a company. If the income earned by the foreign branch is exempt from tax in the HO location and the foreign branch location does not tax the income, then this is a disregarded branch structure.

The OECD recommendation to neutralize this is to restrict the scope of the branch exemption in the HO location so that it does not cover amounts that have not been brought into account for tax purposes by the branch. Specifically, payments that are disregarded, exempt or excluded from taxation under the laws of the branch jurisdiction are treated as if they had been received directly by the HO and, therefore, outside the HO exemption for branch income. In other words, the HO should be taxable on the relevant income in the HO jurisdiction.

The OECD proposes that this should only apply to payments made under a structured arrangement or between members of the same control group. The relevant definitions are the same as those included in the BEPS action 2 report. A person will be a party to a structured arrangement when that person has a sufficient level of involvement in the arrangement to understand how it has been structured and what its tax effects might be.

Under the UK hybrid and other mismatches rules, it is Chapter 8 of the legislation that potentially would apply. Chapter 8 can apply whether there is a UK HO with a foreign branch or a non-UK HO with a UK branch. It is the former scenario that is perhaps more typical in this sector, i.e., a UK HO with an exempt foreign branch. However, Chapter 8 applies only where the person making the relevant payment (i.e., the amount receivable by the branch payee) is within the charge of UK corporation tax. In other words, Chapter 8 applies only where the amount receivable by the branch is an amount for which a UK corporation tax deduction (the relevant deduction) could be taken by the payer.

Where all of the relevant conditions at Chapter 8 are fulfilled and the relevant deduction for UK tax purposes for the payer exceeds the amount of ordinary income for the payee, then the proposed counteraction under Chapter 8 is that the amount of the excess is denied as a UK deduction for the payer. The definition of ordinary income is complex but in broad terms it tests whether the amount has been treated as taxable income by the payee.

Provided the deduction for the payer for UK tax purposes is not more than the amount of ordinary income for the payee, (regardless of the rate of tax which is applied to that income), Chapter 8 should not apply and there is no adjustment for UK tax purposes.

With effect from 1 January 2017, it therefore still will be possible, for example, for a UK company to earn exempt income in an exempt foreign branch (payee). Where the income is from a payer within the charge to UK corporation tax, a deduction should not be denied for the payer provided the branch has taxable ordinary income in the branch location. Even if the branch does not have taxable ordinary income, provided this is because the law of the branch jurisdiction makes no provision for charging tax on any companies, then a UK deduction may not be denied.

Similar to the OECD recommendation, Chapter 8 of the UK legislation may apply where the relevant arrangements are between group entities or the arrangement is a structured arrangement. This latter definition, however, seems to be a lower threshold than the analogous OECD definition of a structured arrangement as it merely requires that the arrangement is designed to secure the mismatch, or that the terms of the arrangement share the benefit of the mismatch between the parties to the arrangement, or otherwise reflect the fact that the mismatch is expected to arise; the OECD definition tests a person's level of involvement and understanding of the structure and its tax effects.

In summary, the OECD recommendation in this scenario is that the HO should display the branch exemption and tax the income of the branch in the HO jurisdiction. Interestingly, this approach would seem to be inconsistent with a territorial tax regime. Under the proposed UK legislation, however, which applies only where the relevant payer is within the charge to UK corporation tax, the proposed counteraction is to disallow a UK deduction for the payment. The UK rules do not prevent a UK company from earning profits in an exempt foreign branch.

2. Diverted branch payments

In this scenario, the branch jurisdiction recognizes the existence of the branch but a deductible payment made to the branch is treated by the branch jurisdiction as attributable to the HO while the HO jurisdiction exempts the income.

The OECD recommendation to neutralize this branch mismatch is as for scenarios one above i.e., to restrict the scope of the branch exemption in the HO location

for deductible payments that have not been brought into account as income by the branch. In other words, the HO should be taxable in the HO jurisdiction on the relevant income.

As for structures at scenario 1 above, the OECD proposes that this should apply only to payments made under a structured arrangement or between members of the same control group.

3. Deemed branch payments

In this scenario, the branch is treated as making a notional payment to the HO where the branch claims a deduction with no corresponding adjustment to the net income in the payee (HO) jurisdiction. For instance, the branch provides services to a customer which produce taxable income for the branch that are reduced by the notional payment to HO; the HO location does not tax the notional payment nor does it tax the results of the branch.

The OECD's primary response is to deny the deduction for the deemed branch payment to the extent it exceeds dual inclusion income i.e., income that is taxable in both the branch and HO. However, if the branch jurisdiction does not introduce a rule of this type, the OECD recommendation is that the HO location should include such amounts as income of the HO to the extent necessary to eliminate the mismatch.

4. Double deduction branch payments

In this scenario, the same item of expenditure gives rise to a deduction under the laws of both the HO and branch jurisdictions. The OECD considers that this type of mismatch gives rise to tax policy concerns where the laws of both jurisdictions permit the deduction to be offset against income that is not taxable under the law of both jurisdictions.

This branch mismatch scenario is potentially on point in relation to expenditure incurred by a branch where branch income is not taxable in the HO jurisdiction. It also is potentially on point if there is branch expenditure and no branch income, for instance, where the branch is involved in early stage exploration or development activity perhaps incurring significant expenditure over several years before branch income is generated.

The OECD's primary response is that the HO jurisdiction should deny the HO duplicate deductions, although the denied deduction should be available for carryforward in accordance with domestic rules and available to set off against future dual inclusion income (i.e., income that is taxable in both the HO and branch jurisdictions).

However, if the HO location does not introduce such a rule, the OECD recommendation is that the branch location should deny a deduction for the payment to the extent necessary to prevent the deduction from being set off against income that is not taxable in both jurisdictions.

Under the UK hybrid and other mismatches rules, it is Chapter 10 that is potentially on point. Chapter 10 may apply whether there is a UK HO with a foreign branch operation or a non-UK HO with a UK branch operation. For example, assume there is a UK HO with a branch operation outside of the UK. Chapter 10 applies where a deduction is claimed against income in the foreign branch location if that foreign income is not also brought in as UK taxable income. The proposed counteraction to neutralize the effect is that the amount deductible for UK tax purposes is reduced to the extent a foreign deduction has been claimed.

In summary, the proposed UK counteraction is similar to the OECD's primary recommendation to deny a deduction in the HO jurisdiction unless the foreign income, against which the amount is locally deducted in the branch, also is brought in as UK taxable income as defined in the legislation.

Where the foreign branch is in the early stages of development and may not generate any local income for some years, Chapter 10 should not prevent a deduction for UK tax purposes.

5. Imported branch mismatches

The example given in the discussion document is similar to the branch mismatch in scenario 3 above. The branch earns taxable income that is reduced by a notional payment to the HO, where the HO jurisdiction exempts the notional payment and does not tax the branch profits, except that in this example the branch income is receivable from a connected company. In other words, the target is a deductible payment in the connected company, which may not itself give rise to a branch mismatch, but is part of a wider arrangement where there is a branch mismatch.

The OECD suggests that either or both the HO and the branch jurisdiction should implement rules to neutralize the mismatch, and the discussion document goes on to state that an imported mismatch rule is needed to deny the deduction for any payment that is directly or indirectly set off against any type of branch mismatch payment that is not counteracted.

As with structures at scenarios 1 and 2 above, the proposal is that an imported branch mismatch rule should apply only to payments under a structured arrangement or between members of the same control group.

This would seem to introduce additional obligations for a taxpayer to understand arrangements to which it is not a party. To determine whether there is a branch mismatch elsewhere in a group, where the taxpayer incurs an expense even if that expense would have been incurred absent of a branch mismatch elsewhere. This will require the taxpayer to have access to information regarding the taxation of other entities elsewhere in the global group.

In summary based on UK experience to date, groups are likely to require a detailed review of existing commercial arrangements to assess the potential impact of these rules with ongoing assessment and review required as other jurisdictions adopt these or similar proposals. Whether or not the UK's approach is instructive as to the direction that other jurisdictions may take, remains to be seen. With relatively low commodity prices and valuations companies should be currently reviewing these rules and making preliminary plans to reorganize their operations if required (and possible) in order to preserve the rate of return on their investments.

Brazil: RD&I tax incentives

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The oil and gas industry in Brazil requires significant investments in research, development and innovation (RD&I), especially with respect to pre-salt opportunities. The National Agency for Petroleum, Natural Gas and Biofuels (ANP) includes an RD&I clause in contracts for exploration, development and production of oil and natural gas in Brazil that requires a minimum level of investment in qualifying RD&I.

The ANP concession contracts establish that the concessionaires must invest in qualifying RD&I, in an amount corresponding to 1% of the gross revenue arising from fields that pay special participation. In the Production Sharing Agreement (PSA) created in 2010 for the giant pre-salt oil reservoirs, the amount of the RD&I obligation also corresponds to 1% of the annual gross revenue of the fields delimited in the blocks subject to the PSA regime.

The ANP is responsible for analyzing, approving, monitoring and supervising the investment by the oil and gas companies in connection with the RD&I clause.

Up until the first quarter of 2016, the total RD&I obligation amounted to USD 3.3 billion; USD 3.1 billion payable by Petrobras and the balance by other concessionaires. With the development of the fields in the pre-salt area, which possess large oil reserves and are expected to be highly productive, investment in RD&I should increase sharply in view of the requirement for 1% of gross revenue to be invested. Companies are allowed to carry forward RD&I expenses for up to five years to meet the required 1% for a given year. This enables expenditure incurred prior to commencement of production to be utilized.

In this environment, companies should bear in mind that investments in RD&I are eligible for tax incentives. Although the ANP regulations applicable to the mandatory investments in RD&I have specific rules and

definitions, for example, regarding subcontracting and cooperation, there are opportunities for the enjoyment of tax incentives. For the mandatory RD&I investments, the following categories are eligible, subject to approval by ANP:

- Programs for the development of the technical capabilities of suppliers;
- Labor infrastructure improvement;
- Study of frontier sedimentary basins involving data acquisition;
- Development of basic industrial technology;
- Human resource development;
- Non-routine basic engineering; and
- Support for RD&I labor facilities.

The tax incentives for investments in RD&I are broad and not limited to particular industries. Generally, activities undertaken to achieve technological innovation qualify for RD&I tax incentives (so most of the categories of expenditure listed above are potentially eligible). These include designing new products or processes, as well as the aggregation of new functionalities or characteristics to a product or process, resulting in improvements in quality, efficiency, or productivity. For the RD&I tax incentives, eligible expenses could include costs of internal projects that involve a technological risk and cooperation projects with universities and technical institutions, as long as the project responsibility, management and control is maintained by the company.

Companies should be in a current taxable position to enjoy the main RD&I tax incentives which take the form of the following deductions, but which cannot be included in a loss to carry forward):

- Super deduction: total deduction for income tax calculation purposes equal to 160% of the total qualifying RD&I expenditure.
- Enhanced super deduction: if the entity increases the number of researchers (which excludes administrative staff) exclusively dedicated to research projects by up to 5% in a given year, the super deduction increases to 170%; and if headcount increases more than 5% in a given year, the super deduction increases to 180% of the qualifying investments. The enhanced super deduction applies only in the calendar year in which the head count increases.
- Enhanced super deduction for patents: an extra 20% deduction is allowed for qualifying investments incurred in developing a patent, but the super deduction is available only if the patent is registered.

Companies enjoying the RD&I tax incentives must file an annual report with the Ministry of Science, Technology and Innovation (MCTI), describing the projects and investments performed in the previous calendar year. For projects lasting more than one year, submission still is required annually, describing the activities and expenses incurred in the previous year. Starting in 2015, MCTI improved the process for reviewing the projects submitted by companies claiming RD&I tax incentives. After reports are filed electronically, technical committees review them and provide an evaluation for each project on eligibility and completeness of the information. In case of queries from the relevant technical committee, companies have a 30-day period

to provide additional clarification that will be considered when the MCTI issues its final evaluation of the projects. The Brazilian tax authorities receive MCTI's evaluation and have a five-year period to audit the taxpayer with respect to the amounts invested in projects enjoying the RD&I tax incentives.

The MCTI review process was first implemented at the end of 2014, and it was improved in 2015 with the increase in the number of technical committees. As a result, the latest public information indicates that 75% of the projects submitted for calendar year 2014 were approved as RD&I projects for purposes of granting tax incentives (a total of 8,616 projects). In the petrochemical sector, 99 companies filed for RD&I tax incentives and 81 companies had their projects partially or completely approved.

Thus, while the enjoyment of the RD&I tax incentives depends on an entity's taxable position, it is expected that a significant number of pre-salt projects will qualify in future years. This provides an opportunity for oil and gas companies to reduce their tax burden in compliance with the ANP and tax authorities' requirements.



Gabon: Overview of the 2014 hydrocarbon regime

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Introduction

After a protracted and complex process, Gabon's legislature introduced a set of tax and legal provisions in 2014 (Law No. 011/2014, dated 28 August 2014) that now constitute the Hydrocarbon Code (as from 8 September 2014). Discussions about a potential new resources exploitation regime started in 2010 and several draft laws and ordinances were issued between then and 2014, but their adoption was subject to lengthy debate. It should be noted that the rules were prepared at a time when oil prices were much higher than they currently are.

Structurally, the law includes 260 sections, divided into eight parts:

- Part one: general provisions
- Part two: institutional framework
- Part three: upstream activities
- Part four: downstream activities
- Part five: control and sanctions
- Part six: shared provisions to all hydrocarbon activities
- Part seven: tax, customs, exchange and various contributions regime
- Part eight: miscellaneous, transition and final provisions.

Increased minimum participation of the Gabonese state

The state has the right to take a 20% stake in the share capital of all companies authorized to produce hydrocarbons in Gabon. The acquisition of this participation by the state must be made at market value. In addition to the 20% stake, contracts covering production activities must contain a provision granting the state a compulsory 20% direct participation in

the project that is carried by the contractor. A higher participation may be mutually agreed to by the state and the contractor subject to market value considerations.

Finally, the national oil company, Gabon Oil Company, has the right to acquire a maximum share of 15% in any contract covering production activities at a market price.

Range of petroleum contracts

The law introduces a specific range of contracts:

- Service contracts under which service providers carry out geological and geophysical studies or any other services aimed at the promotion of the hydrocarbon sector, on behalf of the state.
- Technical evaluation contracts that define the conditions under which service providers must, at their own technical and financial risks and on behalf of the state, carry out preliminary exploration work.
- Exploration contracts, exploitation and production sharing contracts (PSCs) and, exploration and PSCs under which the contractors commit to carry out, at their own exclusive technical and financial risk, and on behalf of the state, hydrocarbon exploration and/or development activities and receive as compensation an exclusive right to operate on a given field and a share of the hydrocarbons produced, when production is involved.

Tax regime

Downstream companies are subject to the general tax law in force in Gabon. Sections 208 to 235 of the law detail the taxes applicable to upstream companies:



Bonuses	Governed by the PSC or contract with the state.
Annual surface rent/land tax	Fixed by regulation but not less than Central African franc (XAF) 50 (USD 0.08)/ha for exploration and to XAF 5,000 (USD 8.00)/ha for production.
Proportional mining royalty	<ul style="list-style-type: none"> • Between 13% and 17% for hydrocarbons produced in a conventional exploitation zone; • Between 9% and 15% for hydrocarbons produced in deep and very deep offshore zones.
State's share of production	<ul style="list-style-type: none"> • Not less than 55% in conventional exploitation zones; • Not less than 50% in deep and very deep offshore zones.
Corporate tax	General tax rate applies (35%). Corporate tax is not deemed to be included in the state's share.
Value added tax (VAT)	<p>All hydrocarbons activities conducted by contractors are subject to VAT at a 0% rate.</p> <p>The contractor benefits from:</p> <ul style="list-style-type: none"> • A VAT exemption on imported goods for hydrocarbon activities by the contractor or accredited service providers; • A 0% VAT on local goods and services from administratively-accredited service providers; • A VAT refund in the case of the importation of goods, acquisition of local goods and services by/from non-accredited service providers, subject to the provisions of the Tax Code.

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- A 0% VAT on local goods and services from administratively-accredited service providers;
- A VAT refund in the case of the importation of goods, acquisition of local goods and services by/from non-accredited service providers, subject to the provisions of the Tax Code.

Enhanced local content and social responsibility obligations

Companies carrying on hydrocarbon activities in Gabon now are formally required to participate in social and economic development projects, such as the following:

- The promotion of projects with high social impact;
- The transfer of technology and competencies to Gabonese citizens and Gabonese companies; and
- The training of Gabonese employees in hydrocarbon industry trades.

There also is a requirement to contribute to various funds e.g., the Hydrocarbon Support Fund, Hydrocarbon Administration Equipment Fund, the Training Fund, the Local Communities' Development Fund and to make contributions to the following when production starts:

- Diversified investment reserve, set at 1% of the turnover of the contractor; and
- Hydrocarbon investment reserve, set at 2% of the turnover of the contractor.

Hydrocarbon law and stability

Existing PSCs and similar arrangements concluded or delivered by the state before the publication date of the Hydrocarbon Code (8 September 2014) remain in force until their expiry date. Although most of the PSCs signed before the new law became effective are protected by a stability clause and the provisions of the Law, it appears that in practice any request for renewal of permits, renegotiation of any provisions of a PSC, approval for transfer of assets and any similar request is likely to give the government the opportunity to impose requirements based on the 2014 law.

Latest developments

Many provisions of the Hydrocarbon Code need to be supplemented by implementation decrees and the code refers to additional regulations that need to be implemented. To date, two years after the Hydrocarbon Code came into force, only nine of these implementation decrees have been published. These decrees relate to operational aspects of the industry (e.g., the required elements of the development plan for a hydrocarbon field) or administrative aspects (e.g., a decree relating to the terms and conditions of audit and control of hydrocarbon activities, and an order relating to the time limit to declare a field commercially viable). The decrees relating to the terms and conditions of the various funds relating to local content still are awaited, as are provisions relating to the application of the tax regime governing the transfer of hydrocarbon assets.

Since the Hydrocarbon Code came into force, some companies have signed PSCs which are expressly subject to the code. Other PSCs were signed in August 2014 before the code became effective force and, although those PSCs implement some of the new provisions, they are not subject to the Code.

The 11th Gabon deep water licensing round was formally opened on 27 October 2015 but does not seem to have elicited many bids. The Hydrocarbon Administration announced in March 2016 that it is considering a revision of the tax terms to address the challenges of lower oil prices. However, it is likely that the revision will not occur before the end of 2016. Companies considering new projects in Gabon should seek advice on the latest position before proceeding.

Malaysia: Application of the GST/VAT concept of transfer of a going concern to farm-out transactions

Chandran T. S. Ramasamy, Deloitte Malaysia

Malaysia introduced a goods and services tax (GST) in 2015. The GST is similar to value added tax (VAT) and uses many of the same concepts (see March 2016 edition of the Global Oil & Gas tax newsletter for background on Malaysia's GST).

This article focuses on how GST may become a significant tax cost in farm-out transactions.

It is typical in Malaysia, as in many other jurisdictions, for exploration and production (E&P) operations to be undertaken through an unincorporated joint venture (JV) for each particular oil and gas block. The JV would be constituted amongst participating companies, with each JV partner having a participating interest. At some point after the JV is formed, a JV partner may, for various commercial reasons, transfer some or all of its participating interest to a transferee, which could either be an existing member of the JV or an outsider. Such transactions generally are referred to as farm-outs. The GST issue arising is whether the transfer of the participating interest could be considered a transfer of a going concern (TOGC) for Malaysian GST purposes and, therefore, subject to the TOGC rules. This is particularly significant in Malaysia given that new businesses (such as transferees) have difficulty in obtaining GST voluntary registration before they commence making supplies in their own right, due to the current practise of the tax authorities. Additionally, the unregistered transferee may have difficulties recovering the GST charged to it on the transfer and during the exploration phase.

TOGC is a concept commonly found in international GST and VAT systems. Whilst there is no judicial precedent on the meaning of TOGC in Malaysian GST law, many international precedents provide useful context.

A long-standing principle of what may constitute a transfer of business as a going concern was established

in an employment law decision before the English High Court (*Kenmir Ltd v Frizzell* [1968] 1 All ER 414. In this case, the High Court laid down the following principles, which have been applied in a number of UK VAT cases:

“In deciding whether a transaction amounted to the transfer of a business [or part of a business], regard must be had to its substance rather than its form.... In the end the vital consideration is whether the effect of the transaction was to put the transferee in possession of a going concern, the activities of which he could carry on without interruption...”

Therefore, as the term implies, TOGC basically involves a transfer of the business (or part of the business) of a GST/VAT-registered person to a transferee to continue those activities as a going concern.

In an E&P context, it is common for a JV partner to be involved in more than one JV. As such, the transfer of a participating interest in one JV is likely to constitute a transfer of only a part of the transferor's business. Of course, in the less common scenario where a JV partner has a participating interest in only one JV and no other business, the transfer of that JV partner's entire participating interest could be seen as constituting a transfer of its whole business to the transferee.

In either case, it seems clear that the substance of the transaction is one involving a transfer of a part of an upstream business or its entirety as a going concern, for the transferee to carry on without interruption, in line with the meaning of TOGC based on the Kenmir case. Whilst this is the position adopted in the UK for transfers of upstream businesses, the practice of Malaysian Customs has raised doubts whether an upstream business, which has yet to produce revenue (e.g., because it is still in the exploration phase), can qualify as a TOGC.

From a technical perspective, applying the TOGC concept to an upstream transaction requires determining the applicability of two separate provisions in the TOGC rules in the GST law, as follows:

01. The transferee must be registered or liable to be registered (in this article, we have referred to this as the TOGC registration rule). This has complexities in Malaysia, given that in practice exploration businesses (before taxable supplies have started) generally are not able to obtain a voluntary registration. To determine the liability of the transferee to register mandatorily for GST (if it is not already registered), the transferee would be treated as having carried on the business of the transferor (or relevant part thereof) before, as well as after the transfer, and any supply by the transferor in relation to the business that is transferred would be treated as supplied by the transferee, i.e., included in the value of the transferee's supplies for registration threshold purposes. It should be noted that in Malaysia the GST registration threshold is MYR 500,000 (approximately USD 125 000). It is important for the transferee to be GST-registrable so that any GST charged by the transferor (in the event that the requirements for not charging GST set out in point two below are not met) would be claimable as input tax credit (ITC) by the transferee.
02. If business assets are transferred as a TOGC, GST will not be chargeable on the supply of the business assets (i.e., the supply of the assets would be out of scope), provided the following requirements are met (referred to as the "TOGC out-of-scope rule"):
 - a. The assets would be used by the transferee in carrying on the same kind of business as the transferor; or
 - b. If only part of the business is transferred under a TOGC, that part is capable of separate operation; or
 - c. The transferee is already, or immediately becomes as a result of the transfer, a taxable person.

A recent case at the UK First-Tier Tribunal (UK FTT) is *M. Young (t/a The St Helens) v Noor* [2012] UKFTT 702) considered the relationship between the two TOGC provisions described above. The UK VAT rules for TOGCs have similar provisions to the Malaysian concepts described above and UK precedents are considered likely to be helpful. The decision in the *Young* case noted, amongst other things, that:

01. The objective of the TOGC registration rule (including a transferor's past activity towards the GST/VAT registration threshold of the transferee) is to "... prevent an existing business [of the transferor] which has already been registered [for GST/VAT] benefiting from the [GST/VAT] registration threshold again simply by transferring it to a new legal entity [i.e., transferee]". Applying this to a Malaysian context, the transferee would be liable to immediately register for GST on the date of the transfer under the TOGC.
02. The objective of the TOGC out of scope rule was "... simplification and avoiding a substantial VAT liability on the commencement of a business [by the transferee]."

This case has particular relevance for Malaysian exploration businesses who are unable to register voluntarily and must instead consider whether they are mandatorily registrable under the TOGC registration rule. In this regard, the *Young* case confirmed that the TOGC registration rule and out-of-scope rule described above effectively operate independently of each other. Hence, a transfer need not satisfy the criteria for TOGC out-of-scope treatment for the transferor's past activity to be viewed as part of the transferee's taxable activities for GST/VAT registration under the TOGC registration rule.

Applying the above TOGC rules to the context of a farm-out, in the common situation where a GST-registered JV partner transfers a part or whole of its business comprising a participating interest in the JV:

01. The transferee would be immediately registrable for GST on the date of the transfer assuming the business, or the part of the business transferred, exceeds the turnover threshold of MYR 500,000. Hence, the transferee should be entitled to an input tax credit on any GST charged by the transferor on the transfer of the participating interest. However, the transferee's entitlement to an input tax credit under the Malaysian GST law in respect of the GST charged by the transferor on the participating interest, would be subject to the time of supply of the participating interest occurring on or after the

transfer date. This is because the input tax credit generally would not be available under Malaysian GST law for supplies made before a person, such as the transferee, is registrable for GST. Further complexity may arise if the farm-out transaction is deemed to take place for GST purposes at an earlier time than the commercial completion date (such as in the case of early payments or specific contractual wording).

02. As to whether the out-of-scope treatment would apply to the transfer, it would depend on the fulfilment of the criteria under the TOGC out-of-scope rule, set out above. However, this should not affect whether the transferee is registrable for GST.

The above independent applicability of the TOGC rules is not reflected in Malaysian Customs practice. Malaysian Customs issued a revised GST Guide on TOGC dated 24 May 2016 which provides, inter alia, that there must be an express notification/declaration either in the agreement for the transfer or separately made, which clearly states that the transfer of the business is a TOGC and that both parties comply with the TOGC out-of-scope rule. As a matter of practice, Malaysian Customs seem to require the TOGC registration rule (even for businesses in exploration phases) to operate jointly with the TOGC out-of-scope rule. This position is arguably contrary to the TOGC rules under Malaysian GST law, international precedent and UK judicial decisions which analyzed similarly worded TOGC rules. The effect of this approach is that a transferor that is not yet registered for GST (e.g., because it is in the exploration phase) may not treat the transfer of a JV interest as outside the scope of GST.

Taxpayers adversely affected by any Malaysian Customs decision based on this practice may have the option to challenge such a decision via the review and appeal process as set out under Malaysian GST law.

Deloitte Malaysia has been advising clients in relation to the applicability of the TOGC principles to farm out transactions and is discussing the issues with Malaysian customs.



Russia: Potential changes to upstream taxation

Andrey Panin, Deloitte CIS

In response to the significant decrease in oil prices and the associated negative consequences for the oil sector, Russia's Ministry of Finance is considering options to simplify the tax burden on the industry. As part of this initiative, it has proposed to introduce a new tax on excess income (TEI). This would replace the current tax system applicable to oil and gas upstream business, which includes profit tax, export duties as well as mineral extraction tax (MET). TEI will replace profit tax and export duties, and companies applying TEI will be able to use a decreasing coefficient in the relevant MET calculation to reduce their liability. This proposed new regime would be applicable to new deposits (both onshore and offshore) and some mature fields (on the basis of criteria still to be identified). Currently, selection by the relevant government bodies of oil fields that would be allowed to participate in a trial implementation of TEI (subject to enactment of the relevant legislation) is in progress.

There is a significant difference between the current tax system for oil production and TEI, as the current system is much less sensitive to the profitability of a project. In general, MET is applied to the total volume of the oil produced and customs duties to the total volume exported—only profit tax is linked to actual profits generated by the producer. TEI would be applied to the profit generated from hydrocarbon production and is intended to capture economic rent, rather than a share of gross revenues.

It is planned to set the TEI rate at 50%. The TEI tax base would be calculated on a similar basis to profit tax, i.e., revenue from extraction of hydrocarbon resources after deduction of operational and capital expenses related to the deposit development, applied on a field-by-field basis. If the calculation generates a loss, this is expected to be available for carry forward. Thus, TEI would be imposed not on the company's revenue or volume of resources extracted, but on the financial result of the extraction activity.

Currently, MET is charged based on the volume of extracted hydrocarbons multiplied by certain rates and coefficients reflecting market conditions, field specifics, etc., at the extraction stage. This means that companies pay a fixed amount of MET for each extracted barrel of oil or cubic meter of gas, and not on the profit earned of the extracted hydrocarbon resources. Customs duties are charged in a similar way (i.e., at a fixed fee per ton of oil exported or based on the revenue from export sales in the case of gas).

One of the main goals of introducing TEI is to promote development of new deposits and efficient use of the existing deposits. The new tax system should provide for a reduction in the total amount of taxes to be paid by oil companies calculated based on gross revenues, via a decrease in MET and exemption from export duties. Therefore, it is intended to be more flexible as the amount of taxes payable would be more closely linked to the economic results of hydrocarbon resource development.

The introduction of TEI is expected to be beneficial for both new fields and mature fields that do not currently enjoy tax incentives and special exemptions. At the same time, the government is concerned that the methodology for TEI calculation could encourage companies to overstate deductible expenditures to reduce the tax burden, for example, by transferring expenses to those companies within a group that have the highest TEI liabilities. Moreover, there is a concern that it may encourage gold plating, which would have a negative impact on the operating efficiency of oil producers in general. To mitigate the risk of loss of budget revenue, the Ministry of Finance is planning to set a ceiling for deductible expenses at RUB 9520 (approximately USD 145) per ton of extracted hydrocarbons for mature fields to counteract opportunities for companies to overstate expenses. This ceiling is expected to be applied over the life of the field rather than on a period-by-period basis.

Depending on the results obtained during implementation of TEI in pilot projects, the thresholds may be adjusted and TEI may be applied more widely.

The introduction of TEI is not likely to be beneficial for those oil producers that are currently eligible for incentives with respect to MET and export duties. Such incentives apply to many fields located in new oil basins in Russia, including East Siberia and the Arctic shelf.

As of the writing of this article, no official draft law on TEI has been released. However, the introduction of TEI is contemplated in the draft Fundamental objectives of tax policy for 2017 and the planning periods of 2018 and 2019² published by the Ministry of Finance. Based on this document, the introduction of TEI is expected in 2017.

Deloitte's Moscow office has participated in discussions with the Ministry of Energy on the proposals and is helping companies working in Russia and potential investors to assess the impact. It is hoped that these changes will enhance the attractiveness of investment in upstream oil and gas projects in Russia.



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