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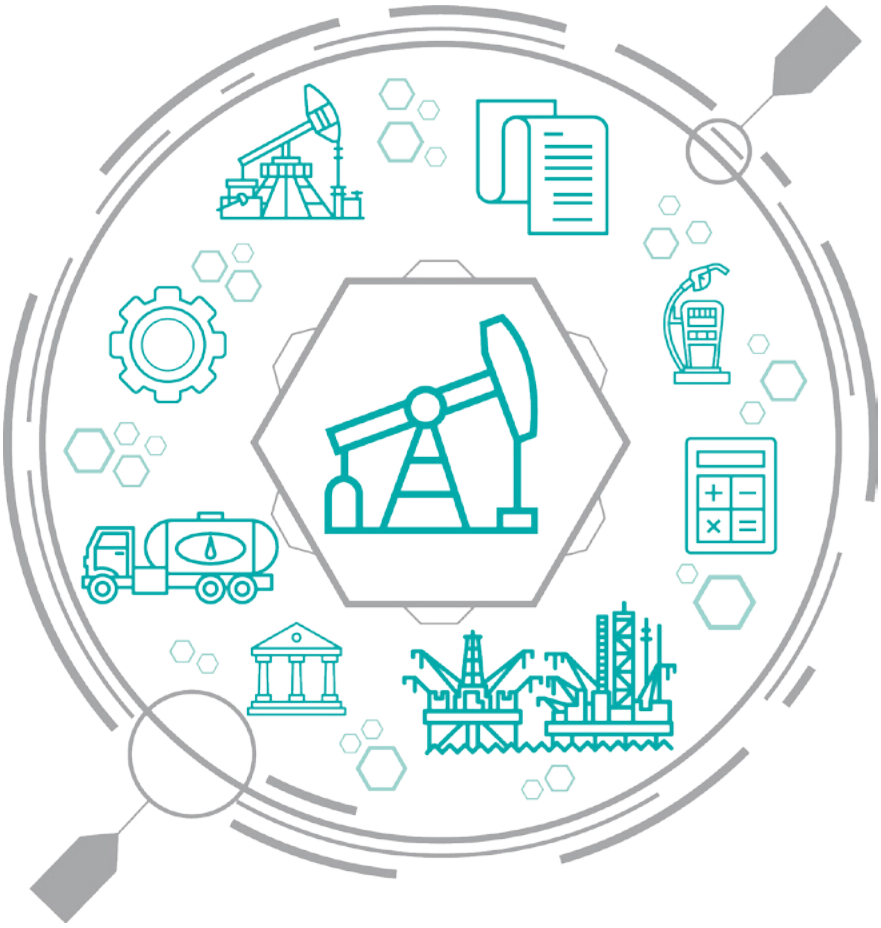

In this issue

Global oil & gas tax newsletter

Views from around the world

July 2017

Editor's introduction

Bill Page, Deloitte UK

In our second edition of 2017, our focus continues to be on two issues with important implications for the taxation of the oil and gas industry. Firstly, the potential impact of the Organization for Economic Co-operation and Development (OECD) Base Erosion and Profit Shifting (BEPS) actions and secondly, the changes in the fiscal environment reflecting the reaction of governments to lower oil prices.

Our first article considers value chain analysis in light of the recent BEPS developments, particularly, the key role that BEPS plays in determining where profits are taxed. This will have consequences to companies in the industry. Our authors have highlighted two potential areas of concern for upstream companies. The first is the tension between requirements to attribute profits to procurement activities and requirements to recharge goods and services at cost to upstream joint ventures (which are often found in joint operating agreements and production sharing contracts). The second arises as a result of the need to determine how profits are split between locations where hydrocarbon deposits are located and those locations where management and technical services are provided. Unfortunately, there are no apparent simple solutions and we expect significant controversy.

The other articles focus on changes reflecting the new reality of lower oil and gas prices. In Canada, two western Canadian provinces, Alberta and Saskatchewan, recently made significant changes to the application of indirect taxes in their jurisdictions that will significantly impact the oil and gas industry. Furthermore, Mexico and Nigeria are implementing significant legislative changes to encourage investment in maturing industries and also hoping to increase tax revenues at the same time. In this edition, our Mexican team provides an overview of the new upstream fiscal regime following liberalization of the sector, and our Nigerian team offers updates to the latest proposals to amend the taxation of oil and gas activities in Nigeria.

Finally, we are rounding out this edition with our UK indirect tax specialists studying the way that value added tax (VAT) rules and administration are being tightened to restrict the recovery of input tax. A potential cost at a difficult time for producers.

As always, we are happy to hear from readers with comments, questions and suggestions for future articles.

Transfer pricing value chain analysis in the oil and gas industry

Axelle Brière and Aengus Barry, Deloitte UK

Value chain is a term that has different meanings to different people. Economists and transfer pricing practitioners view it as a mechanism for observing where value is created in a business. Recent developments are making this even more important in determining where and how multinational businesses are taxed. The unique characteristics of the extractive industry can make this a challenge for oil and gas companies.

The concept of a value chain used in a transfer pricing context has been developed by the OECD as part of its strategy on development, adopted in May 2012 and most recently, in the final report on actions 8-10 of the BEPS project, published in October 2015. Building on the existing guidance in the OECD Transfer Pricing Guidelines, as well as comments received on the July 2016 draft, on 22 June 2017 the OECD published a revised draft to clarify the application of the transactional profit split method, the identification of indicators for its use as the most appropriate transfer pricing method, and providing additional guidance on determining the profits to be split. Public comments are to be provided by 15 September 2017 and the outcome will be discussed in a future article.

The overall objective of BEPS actions 8-10 is to ensure that transfer pricing outcomes are in line with economic value creation. What does this mean in practice? The OECD's view is that there sometimes may be a disparity between where profits are taxed and where people creating these profits are located. Therefore, the purpose of actions 8-10 is to align taxable profits with the location of the value-generating activities. One of the key pillars through which this will be achieved is a value chain analysis.

To ensure appropriate pricing and determine the transfer pricing method applicable to intercompany transactions, the objective of a value chain analysis will be to determine the nature of the contributions of each asset, function and risk to the key value drivers. This includes considering which contributions are unique and how all contributions add value. Crucially, the new approach puts more emphasis on the contribution made by people than on the assets, in analyzing where value is added.

It generally is understood that comprehensive value chain analysis should address the following questions:

- What are the key value drivers in relation to the transaction?
- How do associated companies differentiate themselves from others in the market?
- Which parties can protect and retain value through the performance of important functions relating to the development, enhancement, maintenance, protection and exploitation of intangibles?
- Which parties assume economically significant risks or perform control functions relating to the economically significant risks associated with value creation?
- How do parties operate in combination in the value chain and share functions and assets?

How does this approach apply to the oil and gas industry?

If we look at the upstream sector, an immediate potential conflict becomes apparent. While people are instrumental to the success of operations at all stages, from appraisal to decommission, this industry would not exist without the hydrocarbons produced by the geology of a specific geographic region. Therefore, immovable assets are important in the overall oil and gas value chain, which is arguably unique to the extractive industry. Indeed, in many other industries, people at some point in time create the goods or services that are core to their business. In such industries, it is easier to quantify the contribution of each individual/business unit and to follow the evolution of a product or an idea from research to production. In the case of oil and gas companies, the geological evolution of the earth has determined where, when and for how long mankind will extract and exploit the assets at the core of their business. Therefore, while in general the difference between two players in the same industry will depend substantially on the talent of their management and employees, in the oil and gas industry, assets, more specifically hydrocarbon accumulations, are key. Herein are the seeds of potential future tax disputes, as producing countries may embrace the concept that the resources themselves are the key element of the value chain, but the jurisdictions where the technical and supporting teams are located may very well focus on the value that their expertise generates.

To address this, each oil and gas company will have to undertake a value chain analysis, understanding the key functions and core business profit drivers, and assessing the relative contributions by function, by country, and the overall alignment between these findings and the financial records. The role of the assets in this value chain will need to be factored in and explained to support the transfer pricing methods used to price associated enterprises' transactions.

A further concern is that the BEPS guidance does not say how this new approach will coexist with industry practice and the requirements of production sharing or other types of contractual fiscal regimes for upstream projects. It is not unusual for operators' affiliates to be required, by joint operating agreements, to charge joint venture partners at cost (which may be determined in different ways) for goods and services provided. This is often a formal requirement of the contract entered into with the state as the resource owner. Hence, there seems to be a risk that tax authorities will compete to attribute higher values to the activities in their jurisdiction, whether these are the provision of goods and services or the production of hydrocarbons. Under the framework of the new country-by-country (CbC) reporting obligation, taxpayers will include analyses to support their transfer pricing position in the master file.

Considering that over 100 jurisdictions have collaborated to implement the BEPS actions, it seems that the issue will be identifiable for most tax authorities. Some jurisdictions, such as China and Germany, have published guidance stipulating the obligation for the taxpayer to include in its transfer pricing files (local/master) a description of its value chain and relevant analysis.

Deloitte recently launched the Value Chain Analyzer Tool (VCAT), which is a methodology, underpinned by proprietary analytics technology, to help companies quickly review the value chain from a business perspective. This process, along with Deloitte advisory services, facilitate the assessment of the consistency between oil and gas multinationals' transfer pricing strategy and the way that it is implemented in their business. The VCAT provides the foundation for a more focused approach to address transfer pricing requirements globally, including, in particular, the development of a framework for the master file. Please contact your local oil and gas transfer pricing specialist if you would like a demonstration of VCAT.

Canada: Consumption tax changes to the oil and gas industry

Andrew Azmudeh and Simon Roy-Douville, Deloitte Canada

Two western Canadian provinces, Alberta and Saskatchewan, recently made changes to the application of indirect taxes in their respective jurisdictions that will significantly impact the oil and gas industry.

First, effective 1 January 2017, Alberta introduced a carbon levy on most types of fossil fuels. On 22 March 2017, as part of the 2017-2018 provincial budget, Saskatchewan increased the rate of the provincial retail sales tax (PST) from 5percent to 6percent and expanded the tax base to apply to property and services that were not previously taxable. These policy changes in Alberta and Saskatchewan will materially increase the cost of doing business in the provinces for the oil and gas industry.

Alberta carbon levy

Alberta has developed a new Climate Leadership Plan based on the recommendations put forward by the Climate Change Advisory Panel. The plan has four main components:

- Ending coal emissions and developing more renewable energy;
- Implementing a new carbon price on greenhouse gas emissions (GHG);
- Legislating a cap on oil sands emissions; and
- Implementing a new methane emission reduction plan for the oil and gas sector.

The Alberta carbon levy will impact the oil and gas industry in the following ways:

Carbon pricing

To reduce GHG in Alberta, the government imposes a price on carbon through two different mechanisms.

Large final emitters' carbon emissions will continue to be subject to the Specified Gas Emitters Regulation (SGER) framework until the end of 2017. Under the SGER program, facilities emitting 100,000 tons or more of GHG are required to reduce their site-specific emissions intensity by 15 percent annually. In 2017, this reduction rate was increased to 20 percent. At the end of 2017, Alberta will transition this program to product and sector-based performance standards.

A carbon levy on purchases and imports of fossil fuels that produce GHG was introduced as from 1 January 2017. The carbon levy applies in conjunction with the SGER and the sector-based performance standards frameworks.

Carbon levy rates

The carbon levy rate will be CAD 20 per ton of carbon dioxide-equivalent emissions for 2017 and will increase to CAD 30 per ton on 1 January 2018.

The rates on major fuels will be as follows:

Fuel	Rate (CAD) (1 January 2017 – 31 December 2017, inclusive)	Rate (CAD) (After 31 December 2017)
Gasoline	0.0449/L	0.0673/L
Diesel	0.0535/L	0.0803/L
Natural gas	1.011/GJ	1.517/GJ
Propane	0.0308/L	0.0462/L

How does the levy generally work?

For refined fuels, such as diesel and gasoline, the administration of the carbon levy generally is similar to the administration of fuel tax under the Alberta Fuel Tax Act. Entities that currently are registered for Alberta fuel tax generally are required to register for carbon levy purposes and remit the carbon levy on refined fuels to the province, together with the remittance of the fuel taxes.

For natural gas, the levy is collected and remitted by entities in the distribution system. Natural gas distribution system generally means a system, not including a transmission pipeline, by which natural gas is distributed to the purchasers.

For heating fuels, entities higher up in the distribution chain are responsible for collection and remittance, which will reduce administration and compliance costs.

For other fuels, such as natural gas liquids and coal, entities that produce and sell or import and sell will be required to collect and remit the levy as a direct remitter.

What exemptions are available?
The following exemptions are relevant to oil and gas industry:

SGER/Performance standards – Fuel used in the operations of a specified gas emitter is exempt, provided the emissions from the fuel are direct emissions as defined under the SGER.

Production process – Fuels used in an oil and gas production process are exempt from the carbon levy until 1 January 2023. Where the fuel used in the production process is gasoline or diesel, the fuel should be marked fuel to qualify for the exemption.

Flaring and venting – Fuel that is flared or vented in a production process is exempt until 1 January 2023.

Exports – Fuel purchased for export in bulk is exempt from the carbon levy.

Condensate, raw material or solvent – Fuel used as a diluent, raw material or solvent in an industrial process or oil and gas production is exempt, provided it is not used to produce heat or energy or is not flared or vented.

To benefit from the above exemptions, the consumer must register and obtain an exemption certificate and present the certificate to their fuel supplier. Vendors of fuel that sell to consumers that qualify for an exemption can obtain a license to purchase the fuel exempt.

Saskatchewan PST changes

The 2017-2018 Saskatchewan budget introduced a number of significant changes to the indirect tax landscape in the province. Not only did Saskatchewan increase the PST rate from five to six percent effective 23 March 2017, it also expanded the scope of the tax base for the oil and gas industry. Notable changes affecting the energy sector are discussed below.

Application of PST on services in relation to real property

Effective 1 April 2017, PST applies to services in relation to real property. These services previously were not subject to PST. Taxable real property services include construction, alteration, repair, erection, remodeling, improvement or any other service in relation to real property, a building or other structure on real property. Some maintenance services, such as snow removal, are exempt.

For example, the construction or development of oil and gas wells (excluding drilling the wellbore and downhole servicing and repairs), pipelines and natural gas processing plant attracts PST at a rate of six percent effective 1 April 2017. Before that date, the services were exempt and the contractor or subcontractor paid or self-assessed the PST on the cost of the materials. Now, PST applies to the final invoice to the oil and gas producer, but the contractor or service company would purchase the materials exempt.

Saskatchewan introduced transitional rules for this change to the PST. Written agreements for services to real property, other than real property master service agreements that are entered into before 1 April 2017, are subject to the rules in place for the application of PST before that date. This includes nominal change orders that take place on or after 1 April 2017, where nominal is defined as a change not exceeding 10 percent of the original contract price.

Elimination of PST remission for permanently mounted equipment (PME)

Effective 1 April 2017, the remission of PST provided under Order in Council 1436-67, for qualified PME used in exploration and development of oil, gas and potash resources was eliminated. Previously, the qualifying equipment was PST exempt and going forward it will no longer be exempt. PST will apply to this equipment whether leased or capitalized in the record of the operator.

There are special transitional rules for PME under lease and PME that is owned and located in Saskatchewan on 1 April 2017.

PST on leases

Businesses renting out equipment with an operator in Saskatchewan now are expected to collect PST on the supply of taxable rental property in circumstances where the operator supervises the use of the equipment but does not physically operate the equipment. While this has been the administrative policy in Saskatchewan, there was no legislative support for this administrative interpretation prior to the amendment in the legislation as part of the 2017-2018 Saskatchewan budget. The amended legislation has attempted to codify this policy and is retroactive to 1995.

PST on insurance premiums

Effective 1 August 2017, PST at the rate of six percent will apply to all insurance as defined in the Saskatchewan Insurance Act and includes insurance for vehicles registered under the Automobile Accident Insurance Act. PST will apply where the insured person or business is a resident of Saskatchewan or on the premiums paid in respect to property located in Saskatchewan. In addition to the insured plans, PST will apply to benefit plans and administrative services only plans.

The introduction of the carbon levy in Alberta and the changes to the PST legislation in Saskatchewan will significantly impact the oil and gas industry operating in Western Canada. Corporations that operate in these jurisdictions should review their activities to ensure that they fully comply with the new tax regime and they also should attempt to utilize applicable exemptions and concessions.

Mexico: The revised fiscal regime for the upstream oil and gas industry

Miguel Llovera, Valeria Vázquez and Victor Ramos, Deloitte Mexico

Constitutional amendments and legislation introduced in 2013 and 2014 heralded a seismic shift in Mexico's energy sector. The state oil monopoly ended and the sector was opened up to private foreign and local investors for the first time since 1938. The liberalization of Mexico's energy market was supported by the enactment of certain laws that set out the steps needed to transition opportunities to reality.

Hydrocarbons sector

Following the constitutional amendments, on August 2014, a number of new laws entered into force, including the Hydrocarbons Law (HL) and the Hydrocarbons Revenue Law (HRL). Together with their supporting regulations and the miscellaneous tax resolutions that continuously provide clarification on industry tax matters, these laws provide a legal framework and a special tax regime for oil and gas companies in Mexico.

The legislation on hydrocarbons in Mexico allows for free and open competition between Petróleos Mexicanos (PEMEX), the state-owned company, and private companies in the oil and gas sector, while maintaining the nation's direct, inalienable ownership of all hydrocarbons deposits.

The energy reform provides new forms under which investors can participate in the exploration and production of hydrocarbons in Mexico. The HRL provides four different types of agreements:

- License contracts;
- Production sharing agreements;
- Profit sharing agreements; and
- Service contracts.

According to the HRL, for a company to perform oil and gas exploration and extraction activities, it must (i) be a Mexican tax resident, (ii) have the exploration and production of hydrocarbons as its exclusive business purpose, and (iii) not be taxable under the optional integration tax regime for a group of companies (a limited tax consolidation regime in Mexico).

The National Hydrocarbons Commission (CNH) is the authority in charge of the bidding processes and the execution of exploration and extraction contracts. The CNH ensures that each bidding process complies with the fundamental principles in the Mexican constitution, the HL, the HRL, and the entire legal framework for the sector. Parties interested in participating in the bidding processes can participate individually, as a consortium, or as a joint venture.

The hydrocarbon consortium was incorporated into recent Mexican legislation to allow for a joint operating agreement to comply with the formalistic nature of Mexican tax law. The operator in this type of a consortium instructs the members on the rights and obligations under the exploration and extraction contracts. The operator also liaises with the Mexican Petroleum Fund (MPF), the authority that receives, administers, and distributes income resulting from exploration and extraction contracts.

In accordance with the constitutional provisions on energy matters, the principle of maximizing the state revenue from contracts is incorporated into the bidding processes. However, variables have been added to ensure that the extraction of hydrocarbons is sustainable in the long term. These variables include the amount of guaranteed investment and the least acceptable bid values. The law allows for flexibility so that the CNH can decide on the applicable parameters for the variables in each case to maximize the value to the state.

In general terms, the Mexican tax regime that applies to the oil and gas industry consists of a combination of corporate income tax, other forms of government take (depending on the type of contract), value added tax (VAT), and other local taxes.

The HRL provides that contractors will be subject to general federal taxes, including income tax and VAT. Unlike legal entities in other industries, contractors also will be subject to additional types of fees, royalties, and other payments that must be calculated in accordance with the provisions of the relevant contract.

Features of agreements to carry out exploration and extraction of hydrocarbons

License agreements

A license agreement grants contractors the exclusive right to explore, develop, produce, and market the petroleum resource at its own risk and expense, within a fixed area for a specific period of time. The contractor has the right to dispose of production to the extent that it is up to date with the payments to the Mexican state.

The fiscal obligations include the following:

- Signature bonus;
- Payment of a monthly contractual fee for the exploratory phase before production activities commence. The fee is based on the area in square kilometers of the project and is adjusted annually;
- Payment of royalties that are calculated as instructed in the HRL and the corresponding agreement; and
- Pay consideration determined by the application of a percentage to the value of the hydrocarbons, also known as an "over royalty."

The HRL provides that the state will capture the excess profits of contractors through an adjustment mechanism applicable to the royalties, known as the "R Factor," that will be included in the contract. The "R Factor" will start to apply once a certain level of daily production is reached.

Production sharing and profit sharing agreements

Production sharing and profit sharing agreements grant contractors the exclusive right to explore, develop, produce, and market the petroleum resource at their own risk and expense, within a fixed area for a specific period of time. The contractor will receive the remainder of the net operating profit in the case of profit sharing agreements or a part of the production in the case of production sharing contracts. Additionally, the contractor will have the right to cost recovery based on the provisions of the contract.

The government take under these types of agreements includes the following:

- A monthly contractual fee for the exploratory phase before production activities commence. The fee is based on the area in square kilometers of the project and is adjusted annually;
- Royalties calculated as provided in the HRL and the corresponding agreement; and
- Consideration determined by the application of a percentage to the operating profit.

The main difference between these two types of contracts is that in profit sharing agreements all of the production is delivered to the state's marketer, who delivers the proceeds of the sale of the production to the MPF. The MPF then distributes the appropriate payments to the government and the contractor. In production sharing agreements, consideration is paid to the contractor in kind, with a proportion of the production that is equivalent to the value of the cost recovery and profit entitlements.

Similar to license agreements, an adjustment mechanism is incorporated in the relevant agreements to capture the contractor's excess profits in both production sharing and profit sharing agreements.

Service contracts

Under service contracts for the exploration and extraction of hydrocarbons, contractors must deliver the entire production to the Mexican state, and the contractor's payment (as established in each contract based on industry standards) must be paid in cash. The amounts to be paid to the contractor will be made by the MPF from the proceeds generated by the sale of the hydrocarbons resulting from each service contract.

Other important tax aspects to be considered

- Upstream companies must be residents of Mexico; such companies are taxed on their worldwide income at a rate of 30 percent. An entity will be considered resident in Mexico for tax purposes if its place of effective management is located in the country.
- Permanent establishments (PE) generally are considered to have a taxable presence in Mexico, but will be taxed only on income attributable to the PE. According to the HRL, a nonresident that carries on activities set forth in the HL in Mexico for at least 30 days in any 12 month period will be deemed to have a PE. This will be important for oilfield service companies.
- In addition to the consideration paid by a contractor to the Mexican federal government, the HRL provides for a tax on hydrocarbon exploration and production activities that must be paid by contractors to the Mexican tax authorities on a monthly basis. The tax during the exploration phase is MXP 1,583.74 (approximately USD 86) per square kilometer assigned to the contractor and MXP 6,334.98 (approximately USD 345) per square kilometer during the production phase. These amounts are adjusted annually based on Mexico's consumer price index.
- The normal 10-year carryforward period for net operating losses is extended to 15 years for taxpayers that carry out offshore activities in deep water.
- Special straight line depreciation rates apply as follows:
  - 100 percent on assets used for the exploration, secondary and enhanced recovery, and maintenance;
  - 25 percent on assets used for the development and exploitation of fields; and
  - 10 percent on investments for storage and transportation (e.g., pipelines, tanks, etc.).
- A zero percent VAT rate applies on hydrocarbon exploration and extraction activities to the extent the activities are carried out with the MPF. This basically would refer to the sale of hydrocarbons to the MPF and the payments of the MPF to the contractual parties.
- All employers in Mexico are required to distribute 10percent of their annual profits to their employees.
- Mexico's transfer pricing rules require taxpayers to provide annual information returns, including CbC reporting. Additionally, the HRL provides that in the case of transactions with related parties, the OECD transfer pricing guidelines will apply.

It is important to note that the contracts and the legislation specify extensive administrative requirements that contractors must comply with to be able to recover VAT, deduct expenses, and receive any amounts corresponding to cost recovery.

Nigeria: Implications of draft Petroleum Fiscal Policy

Femi Abegunde, Seye Arowolo and Lukman Ogunsola, Deloitte Nigeria

This article looks at the provisions of Nigeria's proposed National Petroleum Fiscal Policy (NPFP) issued in February 2017 and highlights the implications for stakeholders, especially businesses.

Steps taken by the government have aimed at rekindling efforts to create a more sustainable oil and gas industry (see Global oil and gas tax newsletter, June 2016 edition). The renewed effort by the Ministry of Petroleum Resources (MPR) to reform the oil and gas industry includes the following:

- The October 2016 launch of a roadmap called "Seven Big Wins" for the petroleum industry, which addresses specific policy and regulation issues, the business environment, investment, security, transparency and efficiency in the oil and gas sector.
- Rebranding the long-discussed Petroleum Industry Bill (PIB) as the Petroleum Industry Reform Bill (PIRB) and dealing separately with the tax aspects to eliminate some of the complexity that impeded the progress of the PIB.

The two elements of the legislative program are:

1. The Petroleum Industry Governance and Institution Framework Bill (PIGIFB), which deals with governance/institutional aspects; and
2. The NPFP deals with the fiscal aspects of the industry, and will form the basis of a subsequent bill.

The key points of the NPFP are summarized below:

All activities in the oil and gas value chain are covered

The NPFP covers all sectors of the petroleum industry, namely, upstream, midstream and downstream, and oil and gas production. However, unlike the PIB, it does not make provision for the taxation of the production of bitumen. This implies that bitumen-related activities are to be covered exclusively under the corporate income tax rules.

Nigerian Hydrocarbon Tax (NHT)

As was the case with the tax provisions in the PIB, the income of oil exploration and production (E&P) companies will be chargeable to NHT at graduated rates. However, the proposed rates are lower than the rates proposed in the PIB, as follows:

- 40 percent (reduced from 50 percent) for onshore operations;
- 30 percent (reduced from 50 percent) for shallow water operations; and
- 20 percent (reduced from 25 percent) for deep water operations.

Bitumen production will be subject to a zero percent NHT (compared to 25 percent proposed under the PIB).

E&P companies to pay corporate income tax in addition to NHT

As was proposed in the PIB, companies operating in the upstream sector will be subject to a 30 percent corporate income tax rate on taxable profits. Thus, the aggregate tax rate, taking into account both the NHT and the corporate income tax, would be 70 percent. The base for corporate income tax and NHT would be calculated using the same rules, so effectively NHT would be an additional layer of corporate income tax on profits. This is compared to 80 percent proposed under the PIB and 85 percent applicable under the current Petroleum Profit Tax (PPT); the proposal clearly is more favorable than the current system and seems intended to encourage upstream activities.

Reduction of tax-deductible items

The NPFP proposes a limitation on tax-deductible items, which may counteract the perceived benefits of a reduced tax rate. There are no provisions for the deduction of interest expense, an investment tax allowance or investment tax credits, so the proposed tax rules could result in companies paying more tax than the rate reductions might initially imply.

No provision for preferential tax rates

The PPT act allows upstream companies that have not yet fully expensed their pre-production expenditure to be taxed at a rate of 65.75 for the first five years following the commencement of commercial sales of crude oil. The policy does not provide for a preferential tax rate in this period, which suggests that the tax burden actually may increase for some upstream companies.

Gas operations subject to both corporate income tax and NHT

Gas activities are to be taxed at graduated NHT rates as follows:

- Onshore – 20 percent
- Shallow water – 15 percent
- Deep water offshore – 10 percent

Based on the above, the aggregate tax (NHT + corporate income tax) would be 50 percent per cent, 45 percent and 40 percent for onshore, shallow water and deep offshore, respectively. This rate is less favorable than the current regime, under which gas activities are subject to corporate income tax, but not PPT.

Deductions for expenses incurred outside Nigeria

Deductions for expenses incurred outside Nigeria would be limited to a maximum of 80 percent of the costs to encourage companies to invest more in Nigeria, aligning with the local content policy. Oversea cost (incurred outside of Nigeria) is inclusive of head office charges as long as it is incurred outside of the country.

Payment of royalty on same basis as taxes

It is intended to make royalty a major source of government revenue from the oil and gas industry. To achieve this, the NPFP proposes the payment of a royalty on the same basis as taxes. The current approach of levying a royalty based on water depth would be replaced with royalty payments based on volume and the price of crude oil. This would significantly increase the fraction of revenue paid as a royalty by companies operating in deep water offshore.

Volume and price-based royalty payments would be calculated separately and made based on monthly production rather than quarterly. Royalties could be paid in cash or in kind, with prior notice, especially for gas royalties in kind.

a. Volume-based royalty

The NPFP provides for a royalty in respect of oil production at graduated scales of five percent, 15 percent and 20 percent for onshore and shallow water operations, and five percent, 7.5 percent, 12.5 percent and 15 percent for deep water and frontier operations, as follows:

- Five percent minimum royalty for oil and gas production below 10,000 barrels per day (bpd) for onshore, below 20,000 bpd for shallow water, and below 50,000 bpd1 for deep water and frontier operations;
- 15 percent maximum royalty for production above 150,000 bpd for deep water and frontier operations; and
- 20 percent maximum royalty for production above 20,000 bpd for onshore and above 40,000 bpd for shallow water operations.

Royalty is a deductible cost for corporate tax (CIT or NHT) purposes, however not from both taxes at same time.

For gas operations, royalty rates would apply on a graduated scale of five percent, 7.5 percent, and 10 percent as follows:

- Five percent minimum royalty for production below 100 million standard cubic feet per day (mmscfd) for onshore, below 200 mmscfd for shallow water, and below 500 mmscfd for deep water and frontier operations; and
- 10 percent maximum royalty for production above 200 mmscfd, above 400 mmscfd, and above 500 mmscfd, for onshore, shallow water, and deep water and frontier operations, respectively.

[1] A discrepancy exists in respect of the volume bpd on which the maximum rate of 20 percent is applicable. A volume of 50,000 bpd is mentioned in the body of the NPFD without reference to any terrain, whereas in the rate table, the volume indicated is broken down into two (20,000 bpd and 40,000 bpd) for onshore and shallow water, as noted above. The policy drafters need to clarify which of these royalty-based volumes it intends to retain in the final policy.

The following table shows the tax and royalty rates under the NPFP:

Tax rates (applicable for Oil & Gas)			
	NHT		CITA
	Oil	Gas	Oil & Gas
Onshore	40%	20%	30%
Shallow water	40%	15%	30%
Deep water & frontier acreages	20%	10%	30%

Oil/condensate royalty rates based on daily production – Oil					
Oil royalty rate/PML	5%	7.5%	12.5%	15%	20%
Onshore (kb/d)	0-10			>10<=20	>20
Shallow water (kb/d)	0-20			>20<=40	>40
Deep water & frontier (kb/d)	0-50	>50<=100	>100<=150	>150	Not applicable

Gas royalty rates based on daily production			
Gas royalty rate/PML	5%	7.5%	10%
Onshore (mmscfd)	0-100	>100<=200	>200
Shallow water (mmscfd)	0-200	>200<=400	>300
Deep water & frontier(mmscfd)	0-300	>300<=500	>500

Oil royalty rates based on price			
Oil price tranch ($/bbl)	0-50	>50<=100	>100
Additional oil royalty rate/PML	0%	0.2%/$1	10%

Gas royalty rates based on price	
Gas price tranches ($/mmbtu)	Not applicable
Additional gas royalty rate/PML	

Source: Nigeria National Petroleum Fiscal Policy

b. Value-based royalty

- Zero percent royalty for crude oil price below USD 50 per barrel;
- A 0.2 percent increase for every USD 1 crude oil price increase above USD 50 per barrel;
- 25 percent maximum royalty rate for prices above USD 170 per barrel;
- Does not apply to gas production.

Increased capital gains tax (CGT) rate

The proposed new legislation also seeks to increase the CGT on asset transactions, from 10 percent to 30 percent; there currently is no plan to apply CGT to share transactions. Based on the propositions in the NPFP, the increased CGT rate would apply only to disposals of qualifying used in the petroleum industry. However, to achieve this, amendments may need to be made to the Capital Gains Tax Act (CGTA). The PIRB, however, is silent on this. Any delay in the passage of amendments to the CGTA following the enactment of the PIRB could create significant uncertainty.

Amendments to legislation

In an effort to ensure fiscal neutrality of each segment of the value chain, the policy proposes:

a. Removal of the associated gas fiscal incentive (AGFA)

The policy proposes the abolition of the incentive for investment in downstream gas utilization (sections 11 and 12 of the PPTA) where oil and gas companies can relieve both capital and operating expenditures of gas activities against oil income. Based on this proposal, gas operations would be treated similarly to oil operations with their expenses relieved exclusively from gas revenue, and would be treated as a standalone operation subject to NHT.

b. Amendment of section 39 of CITA

Section 39 of CITA would be amended to cover midstream oil utilization in addition to gas utilization projects. This move potentially would enable midstream operators (including LPG projects and LPG infrastructure) to enjoy incentives currently available only to gas projects, such as tax holidays, investments allowances, and accelerated tax depreciation.

Incentives for low cost and small field operators

The NPFP proposes a system of incentives for efficient low cost and small operators.

As part of the proposal, a 5 percent flat rate royalty would be chargeable on small field operators. It also proposes significant production allowances under the NHT that would reduce the tax rate for small fields to zero percent. However, the NPFP does not define low cost and small field operators, which creates uncertainty, nor does it explain the nature of the "significant allowances" to be provided.

Introduction of production allowances as preferred fiscal instrument

The NPFP proposes production allowances (i.e., a tax-free volume of production) as the preferred fiscal tool to improve the oil and gas sector. By basing allowances on production rather than cost, the government apparently wishes to encourage upstream operators to run cost efficient operations and focus more on improving oil and gas yield.

Production allowances would be available based on cumulative production and location as follows:

- **Onshore:** Onshore operators with cumulative production not exceeding 10 million barrels would be able to claim the lower of 30 percent of the value of oil production or USD 20 per barrel of oil produced as production allowance. For onshore cumulative production ranging between 10 million barrels and 75 million barrels, production allowance would be able to be claimed as the lower of 30 percent of the value of oil production or USD 10 per barrel of oil production.
- **Shallow water:** Shallow water operators with cumulative production not exceeding 20 million barrels would be able to claim the lower of 30 percent of the value of oil production or USD 20 per barrel of oil produced, as a production allowance. For shallow water cumulative production ranging between 20 million barrels and 150 million barrels, production allowance would be able to be claimed as the lower of the value of 30 percent of oil production value or USD 10 per barrel of oil production.
- **Deepwater:** Deepwater operators with cumulative production not exceeding 500 million barrels would be able to claim the lower of 30 percent of the value of oil produced or USD 7 per barrel of oil production, as a production allowance.

The NPFP also provides for a production allowance for gas and condensates at similar graduated rates.

Acquisition costs to be excluded from qualifying capital expenditure

The NPFP proposes to exclude acquisition costs from the definition of qualifying capital expenditure, so that they no longer would be eligible for tax relief. As a justification for this proposal, the policy drafters explained that deductibility of acquisition costs (Acquisitions cost is in respect of the signature bonus paid in acquiring the asset), combined with low capital gains tax, tax holidays and the pioneer status granted to some oil and gas companies (following the recent divestments by international oil and gas companies) have resulted in a significant reduction in government take, which is seen as unsustainable.

Tax holiday or carryforward of tax losses

Although there is some concern about government revenue leakages as a result of the incentives available under the current law, the NPFP does not categorically recommend their discontinuation.

Other fiscal reforms

Other fiscal reforms proposed by the NPFP include:

- **Removal of penalties for gas flaring from qualifying deductions.** Gas flare penalties would not be allowed as deductions from revenue in determining the total profit.
- **Improved fiscal terms for midstream oil and gas investments.** Midstream projects, such as crude oil and product transportation systems and refineries, would benefit from similar terms to those under section 39 of CITA, which would ensure that the processing of hydrocarbons and other extraction activities enjoy the same fiscal benefits, but are kept distinct from upstream activities.

Conclusion

It appears that the NPFP aims to increase the Nigerian government's revenue from the oil and gas industry, especially the deep water offshore, while limiting access to tax incentives and trying to encourage small players. The government is trying to strike a balance between the country's drive for increased oil revenue in the short term, and securing revenue from the industry through taxation in the longer term.

UK: VAT on services supplied to the oil and gas sector

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Many businesses in the oil and gas industry are fully taxable for VAT purposes, meaning that VAT generally should not represent a cost. Many transactions in the sector are not liable to VAT, for example, due to the place of supply rules or the operation of warehousing regimes. Nevertheless, the taxable nature of most transactions entitles businesses to recover input VAT on related costs (subject to the usual statutory blocks, e.g., business entertaining). Furthermore, in many European countries, the cash flow costs of VAT can be managed by streamlining the processes around claiming VAT repayments from the tax authorities, although this may be challenging in some emerging markets.

When VAT generally flows through the supply chain such that it is not a cost, why is more attention being paid to the charging of VAT by suppliers? This article considers the VAT treatment of services purchased by oil and gas businesses and draws on some recent UK experience to highlight matters that those businesses should be aware of when reviewing their VAT controls and processes around purchases.

VAT potentially overcharged by suppliers

It is not uncommon for businesses providing goods or services to the oil and gas sector to be unduly conservative by accounting for VAT on all supplies to customers based in the same country as themselves. Frequently, VAT should not be charged; for example, if the services relate to land outside the territorial waters of the country or the services are otherwise received outside the country. Although prudent VAT accounting decisions should not involve any loss of VAT to the tax authorities and may be a convenient way of protecting the supplier, the authorities are starting to take steps to ensure the rules are applied correctly.

The risk to businesses being over-charged on VAT is that they are likely to have over-recovered VAT by including amounts in their VAT returns as input tax that should not have been charged to them. This potentially exposes the businesses not only to VAT assessments but also to penalties.

In the UK, HM Revenue & Customs' (HMRC) renewed interest in the application of VAT to services supplied to the oil and gas industry may be the result of articles 13b, 31a and 31b of Implementing Regulation (EU) No 282/2011 (IR), which came into effect on 1 January 2017, as this provides more detailed guidance on the definition of immovable property and services connected with immovable property. HMRC released updated guidance in VAT Notice 741A, in place of supply of services in September 2016, which contains many examples from the IR and from the European Commission's Explanatory Notes on the EU VAT place of supply rules on services connected with immovable property that entered into force in 2017.

Since those changes have taken effect, suppliers and customers should review their processes and internal guidance for determining if supplies fall within or outside the UK VAT regime (or VAT regimes in other EU member states).

Why would suppliers charge UK VAT on sales outside the UK VAT regime?

Goods physically located outside the UK's 12 nautical mile limit at the point of sale, services related to land located outside the UK, or services supplied to an establishment outside the UK, such as a fixed production platform, generally should not attract UK VAT. However, making the decision not to charge VAT requires suppliers to review their supplies on a case-by-case basis and conclude that a particular supply is, for example, made to the fixed oil rig rather than to the customer's head office, such that it falls outside the scope of UK VAT. This can be difficult to determine for supplies of services, as it can be subjective and the VAT guidance can be relatively difficult to apply in practice.

Likewise, determining whether a service falls under the general place of supply rules (in which case the place where the customer belongs determines where the services are supplied), or alternatively is land-related (where the location of the land is determinative of whether the service falls within the UK VAT regime) has been challenging in some cases.

In the first instance, the responsibility for charging VAT on a supply is with the supplier. If in doubt, suppliers may choose to charge UK VAT, rather than risk the application of interest and penalties and/or protracted audits, if HMRC were to challenge them for not charging VAT. On the basis that the customer generally should be able to recover this VAT as a fully taxable business and any VAT charged is a cash flow matter between the parties, conservative positions (i.e., charging VAT on everything) often have been accepted by customers as reasonable.

What is in the new place of supply guidance?

HMRC's September 2016 VAT notice was released with the aim of making the guidance more readable and to reflect changes in law as a result of the introduction of the relevant articles in the IR.

Establishment of the customer

The guidance provides detailed commentary on how to determine the establishment of a customer most closely connected to a supply. This is important, for example, when deciding if a supply of services is made to a customer's offshore establishment (e.g., a production platform) or head office.

Paragraph 3.5 of the guidance specifically clarifies the position that:

> "...a UK company that acts as the operating member of a consortium for offshore exploitation of oil or gas using a fixed production platform - the rig is a fixed establishment of the operating member..."

If a supply is received for the needs of the fixed establishment (i.e., the production platform), rather than the business as a whole and the platform is outside the UK territorial waters, the supply is outside UK VAT according to HMRC guidance in Notice 741A.

Land-related supplies

In determining whether a supply is related to land (and supplied where that land is located), the IR makes it clear that only services that have a sufficiently direct connection with immovable property are included. The specific oil and gas references have been removed from the latest version of HMRC's Notice 741A. This includes the reference that "services connected with oil/gas/mineral exploration or exploitation relating to specific sites of land or the seabed" are supplied where the land is located. Also removed is the reference to scientific services, which include a recommendation or conclusion. These are services of consultancy or provision of information and, if connected with oil/gas/mineral exploration or exploitation of specific sites of land or the seabed, they are land-related.

The removal of those examples from the guidance should not necessarily be seen as a wholesale change in HMRC's approach to such supplies. Rather, it reflects the requirement to decide the VAT treatment of supplies on a case-by-case basis; in other words, it may be too much of a generalization to assume that all supplies connected with oil and gas exploration or exploitation are land related.

This view is supported in the Explanatory Notes on the EU VAT place of supply rules on services connected with immovable property that became effective in 2017. Paragraph 55 of the notes states that, although "oil or other substances contained on the soil or in the undersoil can qualify as immovable does not entail that all services involving such substances would necessarily be considered as connected with immovable property." The specific example given is the provision of a pipeline for the transport of gas, which is not a land-related service.

A footnote in the notes states that "activities such as drilling, dredging, excavation of the seabed or ocean floor and subsoil of the high seas...will relate to immovable property, even if nobody has sovereignty over this part of the earth." This should provide a strong basis for continuing to treat many supplies of services to the oil and gas industry as land related and, if involving land outside territorial waters, as outside the scope of VAT.

What do customers receiving such services need to do?

Customers, particularly those with oil and gas operations outside the jurisdiction where their head office is located, should consider the VAT treatment of purchases they make and be aware of the risk that the tax authorities could challenge the recovery of VAT that is not input tax because it should not have been charged by the supplier. This analysis should be made, in particular, if the services are likely to:

- Have a sufficient direct connection with immovable property (and that property is outside the UK); or
- Be viewed as made to a fixed platform (outside of the UK) that could be viewed as its own establishment.

A leading practice would be for the customer to have processes to revert to the supplier and challenge the charging of VAT before it seeks to recover such amounts as input tax.

Conclusion

The changes to the IR that took effect from 1 January 2017 have focused more attention on the issue of when VAT should be applied to services provided to the oil and gas sector. This, coupled with more focus on the responsibilities of customers to recover VAT only where it has been correctly charged, means that businesses receiving such supplies should be alert to situations where they may have been overcharged VAT.

In many cases, businesses will be able to resolve any overcharging of VAT by liaising with their suppliers and asking for amounts to be credited out. However, this becomes more difficult if too much time goes by and suppliers are either hard to track down or cease to exist. Customers are better protected against the risk of bearing the VAT cost plus any penalties where the VAT treatment of supplies is discussed and agreed during the procurement process and where there is a real time procedure for checking the VAT treatment of purchase invoices.

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