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Global oil & gas tax newsletter

Views from around the world

September 2016

Editor's introduction

Bill Page, Deloitte UK

Welcome to the September 2016 edition of our oil and gas tax newsletter.

As our last edition was being finalized in June, the UK was waking up to the news that the referendum had resulted in a narrow victory for the campaign to leave the European Union (the EU). Our first article considers some of the tax implications of this potentially very protracted process.

The past quarter has also seen some recovery in oil prices from the lows of the first half of 2016, but commentators are suggesting that the industry is preparing for oil prices that will be "lower for longer." Cash constraints continue to affect budgets for new projects, and also are having a major impact on the governments of hydrocarbon producing countries as they deal with the effect of declining tax revenues from the industry. As we have seen in the last two editions of the newsletter, tax authorities and fiscal policy makers are approaching this problem with two solutions: tightening tax rules to increase tax collections and introducing incentives to encourage new investment. Some are implementing both strategies simultaneously. In this edition, we look at examples of the two approaches. We also continue our series of articles on the OECD's base erosion and profit shifting (BEPS) project with a review of how developing countries are embracing the BEPS process, something that will become increasingly important for the oil and gas industry given the key role that developing countries play on the supply side of the industry.

Implications of Brexit

The UK referendum on 23 June 2016 resulted in a narrow victory for the campaign to leave the EU. The new Prime Minister, Theresa May, quickly confirmed that her Government would accept the verdict, but the formal legal procedure to leave (set out in article 50 of the Lisbon Treaty) has not yet been triggered and it is not yet clear when this will take place. When invoked, article 50 will trigger a negotiation period of at least two years during which time the UK will need to agree to terms for leaving the EU. These negotiations also will include agreement on the relationship with the EU following the UK's departure. Whilst the specific tax implications of Brexit are not yet clear, this article highlights some of the tax and related issues that are likely to arise.

Corporate tax considerations

Simon Lee, Deloitte UK

The vote in favor of leaving the EU will have little, if any, immediate impact on the UK's indirect or direct tax regimes. The tax consequences most likely to arise in the short term will be those generated by the economic impact, for example, the tax implications of foreign exchange fluctuations and the impact on merger and acquisition (M&A) activity. The UK will remain an EU member state until a secession agreement has been concluded. Few changes are considered likely to occur while the secession negotiations take place and the scope of future tax changes would be determined by those discussions.

Following secession, it is possible that the UK's approach to taxation could diverge from its current position, as it may have additional freedom to determine fiscal policy, separately from the EU. This said, the potential models for post-EU arrangements could require continued adherence to the EU's fiscal framework and restrictions in respect of state aid, depending on the outcome of the negotiations.

Even without the legal constraints entailed with being a member of the EU, the UK is thought to be unlikely to develop a radically different tax system in the short term.

The existing EU direct tax requirements are relatively insignificant and the territorial system of corporate tax applied in the UK is similar to that applied by many other countries. It should be noted that there have been calls for the UK corporate tax rate to be reduced to 15 percent in due course to enhance the country's attractiveness to investors, though there is no timetable in place for this.

There are, however, some areas of UK tax legislation that are intrinsically linked to the EU, principally value added tax (VAT) and customs duty, in respect of which changes should be expected.

Value added tax

Although embedded in UK law, VAT is a tax that is fully harmonized across the EU and governed by EU VAT directives and regulations and so it could be materially affected by Brexit. Following secession, the UK will have greater flexibility with respect to rates applied, the scope of exemptions and zero rating. Transactions with EU member states will no longer be intra-EU acquisition and dispatch transactions, but will become exports and imports, which could be costly in terms of cash-flow and reporting.

On secession, the jurisdiction of the Court of Justice of the European Union (CJEU) will cease, with matters decided solely by the UK courts who may be less likely to refer to, or accept precedent from, previous CJEU judgements.

Customs and excise duties
Customs duty is almost entirely governed by EU directives and regulations. Following secession, control of customs duty and its rates, as well as entitlement to all of the revenue generated will revert to the UK (75 percent of customs revenues currently go to the EU). UK legislation will be needed to replace the EU Directives, regulations and decisions that currently administer customs duty.

The most significant customs duty-related change that businesses might see would be the re-characterization of trade with EU countries as imports and exports. *Prima facie,* this would mean that duty would become payable when goods move to and from EU member states, which could be an impediment to trade. However, there are a number of options which would not entail this, including continued membership of the European Customs Union. The UK also may lose access to EU level trade agreements although it would be likely to replace these over time. Excise duty issues are similar although rates are not fully harmonized within the EU. As with customs duty, movements of excise goods between the UK and EU member states could be treated as imports or exports, depending on the arrangement reached with the remaining EU member states.

Direct taxes
Direct taxes are less likely to be affected by the vote to leave as they are not dealt with directly by EU treaties, being solely a national competency. However, the four EU treaty freedoms (free movements of goods, services, capital and people) are applied with respect to taxes in the EU and European Economic Area (EEA) and it is possible that remaining member states will see adherence to these as a key requirement if the UK seek to retain access to the single European market after secession.

A number of directives aimed at supporting intra-EU trade and administrative cooperation have been implemented by the member states. These will cease to apply to the UK, thus rendering the EU parent-subsidiary, mergers, interest and royalties, mutual assistance and recovery assistance directives inapplicable for UK purposes. In addition, the recent anti-tax avoidance directive, which seeks to implement certain BEPS actions across the EU, seems unlikely to be implemented by the UK, though the UK has in any case chosen to implement most of the BEPS actions.

EU policy on state aid is another potentially significant area. Certain direct tax incentives (such as tax credits granted for certain sectors e.g. the film industry) have required approval from the European Commission to be lawful, and similar requirements apply to members of the EEA (the EU member states, plus Iceland, Liechtenstein and Norway). *Prima facie,* this requirement would be lifted for the UK on secession, but in practice this could be another key point of negotiation. The EU also has a code of conduct for business taxation requiring member states to refrain from harmful tax competition. Although the UK would no longer be bound to this code, analogous principles have been laid out as part of the OECD's BEPS recommendations so the UK still would be required to adhere to this.

Finally, there are certain UK provisions, such as tax-neutral reorganization rules, affording relief from tax to entities of other EU member states (often with reciprocal arrangements in the domestic law of that foreign country). These may be withdrawn by the UK, and UK companies potentially cease to enjoy access to the corresponding provisions in local law without legislative changes.

International mobility and Brexit

Debra Wardle and Louise Bonnar, Deloitte UK

The oil and gas industry relies heavily on a skilled, globally agile workforce to deliver both short – and long-term projects; this is even more so today, in what appears to be a "lower for longer" business environment. In this section, we look at some of the aspects of Brexit impacting companies and their internationally mobile employees.

In a nutshell, restrictions on the ease with which oil and gas companies can hire talent from the EEA and dependence on government quotas may become more of a challenge in the future. Similarly, regulations on the movement of people between the UK and the European continent may become more cumbersome and more expensive. Currency fluctuations in the immediate aftermath of the Brexit announcement also raise issues for employee pay and reward making this another business uncertainty for the industry.

Throughout this article, we have used the broader definition of the European Economic Area (EEA comprises all EU countries together with Iceland, Liechtenstein and Norway), which is used when considering immigration and social security matters.

The following looks at some areas that affected companies should be addressing now to mitigate future restrictions and risk.

The big questions:

1. Immigration?

EEA nationals

During the exit process there should be no impact on EEA individuals' rights to work in the UK or UK individuals' rights to work in another EU member state since existing rules continue to apply. EEA nationals, therefore, can continue to move freely into and out of the UK, and to take up employment without restriction in the UK or other member states. Many companies have taken the opportunity to write to their employees to provide appropriate reassurance in this regard.

New legislation will confirm the treatment of EEA nationals from the official exit date, but early indications are that any EEA national working in the UK prior to the official exit date may be permitted to stay. The reverse position is not clear.

EEA nationals with five years' continuous residence in the UK or another member state can apply for permanent residence, and thus gain reassurance that they will be protected from future legislative changes. To apply for permanent residence, individuals will need to demonstrate that they have been resident in the UK or the other member state, exercising treaty rights, i.e. in employment or self-employment for at least the last five years. EEA nationals who have five years residence or who will have five years residence before the official exit date, may wish to start planning now with respect to the application process for permanent residence. Some businesses have offered individuals assistance, including providing them with travel data needed to support the application.

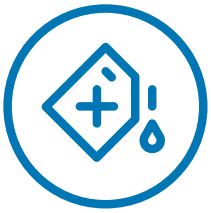
UK nationals

Many UK nationals qualify for dual nationality with another EEA member state, but have not applied for this as their UK passport allowed them free movement within the EEA. Such individuals now may wish to consider whether or not they qualify for nationality with another EEA member state.

Irish nationals and the common travel area

The common travel area allows UK and Irish citizens to move freely between and work in the UK and Ireland. Whilst it is anticipated that the common travel area will remain, this will need to be confirmed during the negotiation period.

Any individual who qualifies (or will qualify before the official exit date) for permanent residence in the other state may wish to make an application for permanent residence to protect his/her position.



2. Social security?

As a member of the EU, the UK is a signatory to its social security agreements, whereby an individual is liable to social security only in one member state where an A1 certificate (formerly known as Form E101) is obtained. Leaving the EU could mean that an individual becomes liable to social security in multiple jurisdictions. There also is a risk that individuals thereafter could lose the ability to apply credits for overseas social security contributions towards the required contributions for the UK state pension.

The status of EEA nationals currently working in the UK with a valid A1 certificates should not change until the official exit date. Such individuals will continue to pay into their home country social security system and remain exempt from UK National Insurance (NI). UK nationals working in another member state with a valid A1 certificates will continue to pay UK NI and be exempt from social security in the other member state.

EEA nationals who move to the UK or UK nationals who move to another member state before the official exit date will have their A1 applications assessed under existing rules.

The position for EEA nationals moving to the UK or UK nationals moving to another member state after the official exit date is not clear. Ultimately, new social security treaties are likely to provide solutions to questions of coverage and benefits, but this may take several years.

Potential action to take now

Whilst it is not possible to predict the future legislative landscape, there are some potential actions that employers can take now to assess the immediate impact of Brexit on their internationally mobile employees.

The position for EEA nationals moving to the UK or UK nationals moving to another member state after the official exit date is not clear.

Payroll: Exchange rate fluctuations

- Review amounts individuals are receiving where they are paid in GBP but have a contract denominated in a non-UK currency, and vice versa, to understand the impact.

- Review the current exchange rates used for payroll processes (particularly UK modified PAYE schemes used for expatriates) that may use exchange rates set at the start of the year and reconciled at year end. This could lead to unexpected amounts becoming due if not corrected at an earlier point in the year.

Policy

- Review company policies and individual assignment letters to understand if there are any specific foreign exchange limits within "exceptional circumstances" clauses that may have been triggered or any impact on cost of living allowances. Many companies have a policy to review pay if there is a significant change in foreign exchange rates (e.g., greater than 10 percent for more than three months), in which case, action may be required.

- Large mobility program managers also may wish to check with their treasury colleagues to understand if there are any particular steps that should be taken to manage the risk of having to provide salaries in multiple currencies.

- Continue to focus on cost reduction; understand the overall cost of mobility programs in the post-Brexit world and identify where further efficiencies still can be introduced as a result.

Reward

- Review the potential impact of exchange rate fluctuations on performance conditions and the cost of funding incentive programs for 2016.

- Consider any impact on how to set targets for incentives to be awarded in 2017.

- Review the impact of share price movements on outstanding equity incentive options and consider proactive communications to participants.

Program

- Consider how the current uncertainty impacts the anticipated length of assignments if at all and, where relevant, understand the tax consequences if any.

- Undertake upfront management of vendor costs by reviewing settlement terms for foreign currency invoices.

Individuals

- Provide initial reassurance (e.g., via intranet, FAQs, etc.) on immediate immigration concerns and potential options that individuals can take to mitigate the impact.

- On a cautionary note, help individual assignees understand that remitting foreign currency to the UK (to take advantage of exchange rate fluctuations) may have a tax impact to either them or the business, especially if they are filing on what is known as the UK remittance basis of taxation.

BEPS and developing countries

Bill Page, Deloitte UK

Background

The G20's BEPS initiative was launched in 2012, and readers will be aware that a significant amount of work has been done since then by the OECD to develop an action plan addressing various forms of BEPS. In July and August 2014, the OECD issued a two – part report summarizing the work requested by the G20 Development Working Group (DWG) to address the impact of BEPS on low income (i.e., developing) countries, as it is considered that BEPS presents special challenges to those economies. Many developing countries also are significant hydrocarbon producers and important emerging markets for the downstream industry, so the implementation of the BEPS agenda in those jurisdictions will be a key issue for the oil and gas industry.

The OECD report: key findings and recommendations

The first part of the report to the DWG, issued in July 2014, is based on extensive consultation with developing countries and international organizations over the course of 2013 and 2014. The report highlights the lack of appropriate legislation, inadequate information and lack of capacity in tax authorities as key challenges for developing countries. As a result, the authors felt that developing countries were potentially vulnerable to cruder and more aggressive tax avoidance than that found in developed economies. This was considered to be all the more important due to the higher proportion of tax revenues in developing countries accounted for by corporate income tax.

The critical BEPS issues for developing countries are identified in the report as:

- Excessive payments to related parties in respect of finance, services and royalties;
- Supply chain restructuring to relocate commercial risk and associated profit;
- Difficulties in obtaining information to tackle BEPS and enforce transfer pricing rules;
- Abuse of double tax treaties;
- Avoidance of tax on gains related to assets situated in-country by use of offshore structures; and
- The perceived pressure on developing countries to implement tax incentives to attract investment: such incentives are seen as eroding those countries' tax bases without often providing much benefit.

The second part of the report was issued in August 2014 and outlines recommendations on how developing countries can be helped to meet the challenges posed by BEPS. In particular, it emphasizes that the challenges faced by developing countries must be taken into account by the G20 and OECD in the BEPS actions and a structured dialogue with those countries should be promoted. This should include listening to developing countries' concerns, and encouraging the involvement of politicians in those countries. Moreover, it is recommended that G20 countries should implement their own actions to address BEPS in a way which is sensitive to "spill-over effects", i.e., the ways that changes to their domestic tax systems potentially could have the effect of reducing tax revenues in developing countries. The second part of the report also suggests the preparation of toolkits to help developing countries address specific aspects of BEPS, such as pricing of commodity exports or excessive intragroup payments, without each "reinventing the wheel." The authors also drew attention to particular challenges faced by developing countries: the lack of comparability data to enable application of transfer pricing rules and the need to reduce opportunities to avoid tax on gains arising on asset disposals through the use of offshore structures.

Whilst many developing countries only have a very limited network of tax treaties, the use of treaties to relieve tax in cases where this was not the original intention is reported as a key concern for many such countries. For this reason, the development of the multilateral instrument (action 15 of the BEPS project) is described in the report as a key future development to combat BEPS.

The second part of the report emphasizes the importance of capacity building in developing countries as a key strategy to combat BEPS. International organizations and individual G20 members already were active in this area at the time the papers were issued. The second part draws specific attention to the capacity-building role to be played by Tax Inspectors without Borders (TIWB), a joint initiative between the OECD and the United Nations Development Program (UNDP), discussed further below.

Wider engagement with developing countries

The BEPS initiative has garnered broader support than just the members of the G20. During 2015 and 2016, a number of regional network meetings have been organized by the OECD to create an opportunity for developing countries to participate in the BEPS initiative. These culminated at a meeting in Kyoto on 30 June and 1 July 2016, where representatives of 82 countries signed up to the "inclusive framework" committing to the implementation of the BEPS actions, and a further 21 countries were present as observers. A large number of developing economies were represented, e.g., 14 African countries already are full participants in the inclusive framework and a further nine were amongst the observers. The purpose of the inclusive framework, as stated on the OECD's website, is "to develop international standards related to BEPS and to review and monitor the implementation of the whole BEPS package." All signatories have committed to the minimum standard of implementation of BEPS measures, which encompass the actions on transfer pricing, treaty abuse, permanent establishments, harmful tax practices, country by country reporting and dispute resolution.

During 2015 and 2016, a number of regional network meetings have been organized by the OECD to create an opportunity for developing countries to participate in the BEPS initiative.

Whilst a number of individual developing countries, such as Gabon and Kenya, have been actively engaged with the OECD's BEPS initiative, regional bodies also are playing an important role. For example, the African Tax Administration forum (ATAF), which was founded in 2008 and has 36 members across Africa, has organized a number of regional events to encourage individual countries' tax and fiscal policy bodies to embrace the BEPS initiative. ATAF also is engaging with the African Union to enhance political support for the new legislation needed to enable individual countries in Africa to implement many of the BEPS actions.

Specific initiatives to support developing countries

As noted above, the second part of the 2014 report proposed the creation of toolkits to help developing countries with implementation of the BEPS actions. The OECD is now working on these together with the IMF, World Bank and UN. These four organizations have established the Platform for Collaboration on Tax ("Platform"), which will prepare the toolkits and reports in cooperation with regional organizations like ATAF. A concept note on the establishment of the Platform, dated April 2016, envisages that its activities could also include support for individual developing countries in implementing BEPS actions, capacity building, encouraging exchange of information and supporting measures to improve tax compliance in the informal economy.

The first tangible result of the Platform's activity is a report on the use of tax incentives published in October 2015. The report suggests that the fiscal cost of such incentives is often high and that tax incentives, in general, have only a marginal impact on investment decisions. It offers guidance on how countries can acquire data and tools for the systematic analysis of existing or proposed tax incentives. It also highlights the concern that regional competition to attract investment has promoted a "race to the bottom" and regional cooperation is important to avoiding this problem.

The OECD has indicated that further output from this initiative will comprise additional toolkits focusing on the following areas (dates in brackets are the targets for finalization according to a presentation made by the OECD to a regional networking meeting in Tbilisi in October, 2015):

- Addressing the lack of comparables for transfer pricing purposes, including supplementary work on commodity pricing (October 2016);
- Transfer pricing documentation requirements (October 2016);
- Tax treaty negotiation (December 2016);
- Base eroding payments (June 2017);
- Supply chain restructuring (March 2018); and
- Assessment of BEPS risks (March 2018).

There also will be a report on issues relating to indirect transfers of assets, which is expected to be issued in September 2016, though a concept note has been provided to the DWG which is already in the public domain. This note suggests that the report will have a particular (but not exclusive) focus on extractive industries, and that it will examine policy implications such as the possibility of economic double taxation as well as recommending concrete options for countries "to enact and administer effective rules to tax such gains."

One of the principal concerns voiced by commentators over the implementation of BEPS measures by developing countries is their limited capacity to enact and implement legislation. There are a number of initiatives to help address this, apart from the work of the Platform. For example, the Addis Tax Initiative (ATI) was launched at the third International Financing for Development conference in Addis Ababa in July 2015. ATI is funded by 40 governments and international bodies with participation of key OECD member states, several developing countries, the EU, the OECD, the World Bank and ATAF. ATI aims to significantly increase support for developing countries to improve tax administration and collection, particular revenue from natural resources, and provides a diagnostic tool to help national tax administrations to identify bottlenecks. Another source of practical help is TIWB mentioned above, which was launched by the OECD and UNDP in 2013.

This program provides assistance to tax audit teams in developing countries by the secondment of serving or recently retired tax officials with at least five years' tax audit experience. A press release issued in June 2016 indicated that more than USD 185 million of additional tax revenue has been collected by developing countries with the support of TIWB since the program began. A further 100 deployments are planned between 2016 and 2019.

Implications for the oil and gas industry

This is a developing picture, but based on the work done by the OECD and other international organizations, it is clear that some specific areas are likely to come under closer scrutiny as the BEPS actions are implemented by developing countries. For example:

- Enhanced regulation of **transfer pricing** plays a key role in several of the BEPS actions and is a recurring theme in the 2014 OECD report on the impact of BEPS on low income countries. Over the past decade, many developing countries have introduced detailed transfer pricing regulations, but tax authorities there remain concerned that intragroup pricing is being used by foreign investors to erode the tax base. It seems likely that these countries will embrace BEPS actions to combat what they see as transfer pricing abuse, particularly in the areas of commodity pricing for intragroup transactions (both exports and imports). The impact is potentially significant, given the high volumes and complex commodity trading arrangements common in the oil and gas industry. Intragroup charges are important for oil companies, as for other multinationals, but may be particularly significant for oilfield service companies when projects require multiple services and equipment leases charged from other group companies. There also will be the potential for conflicts where tax authorities compete to maximize tax take where supply chains span more than one country.

- Tax planning using **double taxation agreements** is a major concern amongst developing countries. Many are participating in the preparation of the multilateral instrument that will implement the treaty-related BEPS measures. The OECD is expected to release the text of the instrument in September 2016. The use of intermediary entities in tax treaty jurisdictions has been a common tool in international tax planning for decades, and multinational groups, including those in the oil and gas industry, will need to review the level of substance underpinning such arrangements.

- Action 7 focuses on tightening the definition of **permanent establishment** in existing tax treaties, which will be implemented via the multilateral instrument. Many developing countries have few treaties so the direct impact of this will be limited; however, there also may be some changes to existing definitions in domestic law and more focus on the possibility of unregistered permanent establishments having been created, for example, by supply chain or oil trading arrangements.

- **Country-by-country reporting** is intended to ensure greater transparency in relation to transfer pricing and other items on the BEPS agenda. Detailed information reported to the tax authorities in the jurisdiction of a parent company's tax residence will be available through various means (e.g., tax treaties, the multilateral instrument) to each of the tax authorities in countries where a group does business. These will be scrutinized in the case of all foreign investors, but with oil and gas projects often being the largest foreign investment in the relevant host country, these are likely to be subject to particularly close attention.

- **Tax incentives**, such as tax holidays, rate reductions and special regimes to mitigate VAT and import taxes are not part of the main BEPS agenda (though they may be seen as related to harmful tax practices, covered in action 5). A number of international bodies and civil society organizations have been encouraging developing countries to restrict the availability of such incentives for many years and there is already a clear trend to limit incentives and subject them to more control. This trend is likely to accelerate. Whilst few oil and gas projects enjoy tax holidays, other incentives, such as relief from VAT on inputs in the exploration and development phase, can be critical to project economics.

- **Taxation of capital gains** arising on indirect disposals of oil and gas (and other) assets is a hot topic in many developing countries and several have introduced legislation to capture tax on gains realized on transactions between nonresidents. The frequently found requirement for government consent on a change of underlying control of natural resource projects is a key lever to enforce payment, even if legislation is unclear. There is a wide variety in the approaches taken and the rules frequently give rise to a risk of double economic or juridical taxation. Though this topic is outside the main BEPS agenda, it is on the list of issues to be addressed by the Platform, and this may help to create a more uniform approach and reduce the risk of double taxation.

Oil and gas projects often have some measure of contractual protection against law changes under a concession, production sharing agreement/contract, a host government or other type of investment agreement. Occasionally these have the effect of freezing tax rules so that law changes (such as those implementing the BEPS actions) do not apply, but more frequently a mechanism is provided to enable renegotiation of aspects of the agreement to maintain the previous balance of the economic interests of the state and the investor(s) in cases where a law change adversely affects the latter. Whether this option is available will depend on the facts and circumstances of each case, but such protections often are difficult to apply in practice as they rely on the agreement of the state to enter into negotiations. It also may be difficult to argue that an investor is disadvantaged; for example, most production sharing agreements/contracts have detailed provisions affecting transfer pricing, and the introduction of refinements to the local tax law and practice in line with the BEPS actions may not be readily accepted by the state as an adverse change.

Conclusion

A great deal of attention has focused on how the BEPS actions are being implemented in the developed economies where many of the world's oil and gas companies are based and which still form the largest markets for their products. The impact on developing countries, however, should not be underestimated as most are now actively engaged with the BEPS process via the inclusive framework. Capacity issues in developing countries are beginning to be addressed with support from international initiatives such as TIWB and ATI, and the reports and toolkits being prepared under the auspices of the Platform.

It is clear that the BEPS actions will ultimately have an impact in almost every country where the oil and gas industry operates and companies will need to monitor new tax legislation and other changes in each jurisdiction where they have activities.

Australia: Game-changing tax reforms impacting oil and gas multinationals

Jonathan Schneider, Janelle O'Hare and Zubin Sadri, Deloitte Australia

Multinational oil and gas companies operating in Australia currently are facing unprecedented levels of scrutiny by the government, tax authorities and the media. Notwithstanding the tough economic climate, characterized by steeply declining commodity prices, there is a sharpened focus on large oil and gas companies paying their "fair share of tax." To achieve this, Australia is adopting significant legislative tax reforms, which are having a direct impact on how investments are structured and funded.

The Australian Tax Office (ATO), as the administrator of Australia's tax laws, continues to be active in its review of the oil and gas industry, focusing on group sales and marketing companies, equipment and vessel leasing structures into Australia, cross-border financing arrangements and other related party transactions. On 10 August 2016, the ATO released a discussion paper on offshore "hubs" that sets out the ATO's practical guide to risk assessment and compliance activity in relation to offshore marketing, procurement and distribution entities. In the courts, the ATO has been spurred on in recent times by key wins in transfer pricing and anti-avoidance tax cases.

Critical tax law changes in the last quarter

There were two critical areas of tax reform contained in the Australian Federal Budget 2016-2017, released in May 2016, namely the anti-hybrid changes and the diverted profits tax (DPT), which are discussed below.

1. Anti-hybrid changes

The government has expressed its intention to enact anti-hybrid tax law changes that follow the recommendations from the report on action 2 of the BEPS initiative.

Hybrid instruments (such as redeemable preference shares or convertible notes) are a common source of funding into Australia, as they provide the flexibility typically sought from intragroup financing arrangements, but they also have been structured to provide beneficial tax outcomes.

These tax outcomes will be negated under the proposed anti-hybrid law changes. The use of hybrid entities (such as limited liability companies and limited partnerships) also will be caught.

It is understood that the new measures will be applicable from late January 2018 or six months following the date of Royal Assent.

Key takeaways

While a draft of the anti-hybrid rules is yet to be released to the public, oil and gas groups that use hybrid instruments or entities to finance their Australian investments or activities should start to consider the potential application of the new rules to their financing structures and the associated tax, financial reporting, legal and treasury issues which may arise, including the potential need to refinance existing structures.

If adequate planning and consideration is not given to these expected changes, there could be adverse economic and tax implications, including potentially the disallowance of tax deductions for financing payments made out of Australia.

2. Diverted profits tax

Largely modelled on the UK's version of the diverted profits tax (DPT), the government states that Australia's DPT would be targeted at "uncooperative" taxpayers and would provide the ATO with greater powers to collect additional tax from taxpayers whom they consider to have transferred profits, assets or risks to foreign group entities using artificial or contrived arrangements to avoid Australian tax. The Government intends to introduce the DPT into parliament within the next few months, with the goal of having the legislation passed by the end of 2016. It is unclear whether this target is achievable; at this stage, there is only a Treasury Consultation Paper released at the time of the budget, which provides an overview of the proposed DPT framework.

If implemented, the DPT would be applicable from 1 July 2017 and would target Australian members of a global group with gross annual global income of at least AUD 1 billion. This likely would capture several foreign-headquartered oil and gas groups with investments and operations in Australia, but also could apply to Australian-headquartered oil and gas groups.

In broad terms, the DPT would apply to certain types of transactions between an Australian company and a foreign affiliate located in a perceived "low tax" jurisdiction, which includes Hong Kong, Ireland, Singapore, Switzerland, Thailand and the UK, amongst others.

For oil and gas groups, the types of transactions that could be captured include (but are not limited to):

- Payments to a sales and marketing company located offshore;
- Payments to an affiliated foreign lessor for the use of substantial equipment or vessels in Australia;
- Financing payments to a foreign group company (e.g., interest) and which also potentially could apply to hybrid financing arrangements (discussed above);
- Royalty payments to a foreign affiliate holding intellectual property; and
- Payments to a foreign affiliate that provides insurance to the global group (e.g., captive insurance arrangements).

If a DPT assessment is made, a 40 percent penalty rate of tax would be applicable on the diverted profit amount (as compared to Australia's existing corporate tax rate of 30 percent). The tax would have to be paid in cash, which is a liability the Australian taxpayer would have to fund upfront. The ATO then would have up to 12 months to finalize its tax assessment (up, down or no change). The Australian corporate taxpayer would be able to appeal the assessment only after the expiration of the 12-month period. This is very different to how Australia's tax laws currently are structured and administered (i.e., Australia operates a self-assessment system whereby the taxpayer first determines and pays its tax liability according to the tax laws, and the ATO then reviews and amends the liability if it disagrees with the taxpayer's assessment).

Key takeaways

- The proposed scope of the DPT is very broad. It may cover a broad range of transactions and the law (once drafted) is likely to be complex in design and application;
- The DPT, as proposed, may result in double taxation across two or more jurisdictions, which could result in significant unintended cash leakages; and
- Oil and gas multinationals that may be affected must closely monitor the development of the DPT legislation and consider its potential application in detail.

Recommendations

Oil and gas multinationals operating in Australia need to understand the context of Australia's changing tax landscape and be aware of the ATO's more aggressive approach towards foreign-owned oil and gas groups. The proposed anti-hybrid rules and the DPT are key measures that are likely to have far-reaching application and will require appropriate planning and detailed consideration to ensure these changes are managed without giving rise to significant and unintended cash tax costs or adverse scrutiny from the ATO, the media or key stakeholders.

Ghana: Recent tax developments in the upstream petroleum sector

George Ankomah, Deloitte Ghana

Introduction

Ghana is a relatively new player in the global oil and gas market, joining the league of oil producing countries in December 2010 when the country's first commercial oil production began from the Jubilee Field. This new status prompted strong economic growth in subsequent years, with the country recording a GDP growth rate of 14 percent (according to the World Bank World Development Indicators) in 2011. A central discussion point for the government and various stakeholders has since been the contribution of oil revenues to the socio-economic development of Ghana. Taxation plays a significant role in this discussion.

The general fiscal landscape in Ghana recently has undergone noteworthy changes, with the enactment of a new Income Tax Act (ITA) to cover taxation of all industries, including the upstream oil and gas sector, effective from January 2016.

Until 2016, upstream oil and gas taxation had been under the regime of the Petroleum Income Tax Law (PITL) and Petroleum Agreements (PAs) signed by the Government with oil companies. The PITL provides the framework for determining chargeable income from oil and gas operations for tax purposes, while PAs provide specific fiscal considerations applicable to each of the oil companies.

It should be noted that the ITA has only replaced PITL as the primary income tax legislation for upstream oil and gas in general; the Ghanaian Government and the tax authorities appear to accept that it does not affect PAs, which have fiscal stability provisions.

The following are some of the significant changes in ITA, which are applicable to the oil and gas industry in general:

- **Corporate income tax rate** – The corporate income tax rate applicable to upstream petroleum operations is reduced from 50 percent to 35 percent. Whilst the reduction is significant, almost all existing PAs already prescribe a 35 percent corporate income tax rate for oil companies despite the higher rate of 50 percent provided in the PITL. The ITA's petroleum corporate tax rate, therefore, only serves to align the legislative rate to what has become the standard corporate income tax rate in the upstream and the extractive industries in general.

- **Specific ring fencing regime** – Ring fencing has been one of the industry's most contentious tax issues. Ring fencing provisions are not explicitly provided for in the PITL. The lack of clear rules on ring fencing left ambiguities around its application and resulted in disputes between the tax authorities and oil companies. The situation also presented the government with what it considers as a risk of loss of tax revenues. The ITA has introduced clear ring fencing rules to apply to oil and gas operations (apart from those covered by pre-existing PAs with fiscal stability).

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- **Loss carry forward restriction** – The PITL allowed operating losses incurred in petroleum operations to be carried forward indefinitely for deduction against future periods' income until fully utilized. The ITA, on the other hand, imposes a limit on the deduction of prior year operating losses. Under draft regulations to the ITA (currently pending final enactment), entities in "priority sectors," which includes entities undertaking petroleum operations, are allowed to carry forward operating losses for five years. The deduction is required to be taken on a first-in-first-out basis. Unutilized losses cannot be deducted after expiration of five years from the year they accrue. Existing investors operating under PAs that incorporate fiscal stability are not affected by this provision of the ITA – they are allowed to continue deducting losses indefinitely as provided under the PITL. New investors will be expected to comply with the provisions under the ITA unless their respective PAs provide otherwise.

- **Extension of the thin capitalization rule to upstream oil and gas companies** – Thin capitalization rules, which limit the deduction for interest incurred on related party debt financing, historically have not applied to upstream oil and gas companies in Ghana. The PITL allowed for a full deduction of interest costs incurred on borrowings for financing petroleum operations to the extent the interest was at a commercial rate.

  With the consolidation of the oil and gas tax framework under the ITA, thin capitalization provisions now may apply to oil and gas companies (unless they have pre-ITA PAs with fiscal stability). The ITA restricts deduction of interest expenses incurred by a Ghanaian entity on foreign related party debt to a debt-to-equity ratio of 3:1. Interest costs in respect of debt in excess of the ratio may not be deducted for corporate tax purposes by the Ghana entity. With these restrictions, oil companies to which the thin cap rules may apply may have to review their financing structures to take the provisions into consideration. Also, given the huge investment requirement for upstream projects, there may be a case for investors to request a more generous ratio of debt to equity.

- **Oil subcontractor withholding tax** – The ITA's changes did not spare oil and gas service providers, as the Government also aims to increase tax revenue from that sector. The ITA initially provided for withholding tax at a rate of 15 percent on payments for works and services to both resident and nonresident oil subcontractors, which would be a final tax. This represented a significant increase from the 5 percent that applied under most of the existing PAs. At time of writing, the Government is in the process of amending the withholding tax rate applicable to resident subcontractors to 7.5 percent on account (i.e., to be offset against the final liability for the relevant period), while the rate for nonresident subcontractors will remain at 15 percent which will be a final tax.

  Despite the increase in the withholding tax rate under the ITA, stability clauses in existing PAs would mean that oil companies may opt to apply the 5 percent provided under their respective PAs. However, the stability provisions do not extend to the tax liability of subcontractors; thus, the subcontractor's tax obligation ultimately falls under the ITA provisions. This creates a gap between the ITA's withholding tax rate and the lower rate required by the PAs. The Ghanaian tax authorities have yet to issue guidelines to resolve this discrepancy. For resident subcontractors, this should not pose an insurmountable challenge if the current amendment is passed as any tax withheld (5 percent or 7.5 percent) ultimately will be treated as a tax payment on account and credited against their corporate tax liability in Ghana. The situation for nonresident subcontractors will be more challenging as it may not be practical to request nonresident entities that suffer only the 5 percent withholding tax to account and remit the additional 10 percent to the Ghanaian tax authorities. The authorities may have to seek an arrangement with the oil companies to withhold 15 percent upfront on nonresident subcontractor payments if the full impact of the increase is to be realized.

Suspension of VAT relief purchase order

In addition to the changes in the ITA, Ghana's Government also is seeking to revise the existing VAT relief mechanism for all VAT-exempt entities. The existing PAs exempt oil companies from payment of VAT on all local purchases for petroleum operations. The Ghanaian tax authorities, therefore, instituted the VAT Relief Purchase Order (VRPO) system to provide administrative relief from VAT for oil companies (and other exempt entities).

Under the VRPO system, oil companies are required to issue a form to the supplier to discharge their VAT liability on local purchases in place of a cash payment of the relevant VAT. However, as part of an ongoing government policy of using tax credit schemes in place of upfront exemptions, the Government announced plans to abolish the VRPO system in its 2015 and 2016 budget statements and replace it with a system that will require exempt companies, such as oil companies, to pay VAT upfront and seek subsequent refunds.

Although the plan to abolish the VRPO system has not been fully implemented, the Ghanaian tax authorities have suspended the issuance of VRPO forms to newcomers to the sector. If the credit and refund system becomes effective, oil companies are likely to face an adverse cash flow impact. The more positive aspect of the new system will be that it will afford oil service companies the benefit by having cash receipts for their VAT charges against which to offset input VAT incurred, so they will experience a cash-flow benefit.

Conclusion

The current global oil price slump is already impacting government tax revenue from the sector. In the government's 2016 mid-year budget review, the Minister of Finance noted a 6.4 percent shortfall in the government's tax revenue target, which is mainly due to low crude oil prices. It seems likely that government will continue to seek means of increasing tax revenues from all sectors of the economy.

Given that most of the existing PAs have fiscal stability provisions that serve to insulate the oil companies against changes in the underlying fiscal framework prevailing at the time of agreement, the changes introduced under the ITA should not apply to most of the oil companies already operating in Ghana, other than through negotiations. The changes, however, are likely to influence ongoing and future PA negotiations.

Overall, the Ghanaian income tax regime remains fluid as the government seeks to address stakeholder concerns, as well as amend some of the provisions in the ITA. The government and the tax authorities are expected to issue regulations and practice notes on the ITA in the near future to guide taxpayers and administrators on the application of some unclear provisions in the new ITA.

Gulf Cooperation Council: Introduction of VAT

Mathew Parkes, Deloitte UK

A significant change will soon affect businesses with operations in the Gulf Cooperation Council (GCC) states (Bahrain, Kuwait, Oman, Qatar, Saudi Arabia and the UAE): VAT will be introduced.

The intended introduction of VAT has been announced as from 1 January 2018 (in the UAE and Saudi Arabia), at an expected rate of 5 percent. The broad aspects of the VAT systems are expected to align with commonly established international VAT principles; however, at the time of writing, draft legislation has not been formally published. There also is uncertainty for businesses surrounding how tax authorities in the region – that they will face a significant VAT implementation challenges – will interpret the legislation and administer the tax in practice.

In the energy sector, businesses are taking steps to ensure their systems and processes are ready for VAT implementation, and considering the strategic and financial consequences for their operations. Whilst many in the industry expect a VAT relief to apply to the oil and gas sector, it is not certain how broadly this will apply to goods and services supplied across the sector. Even if VAT relief does apply, VAT recovery of costs – and in particular repayment of VAT credits for capital expenditure at the initial stages of a project – is a major consideration for businesses to monitor in practice.

The intended introduction of VAT has been announced as from 1 January 2018 (in the UAE and Saudi Arabia), at an expected rate of 5 percent.

Indonesia: Developments in the taxation of the upstream industry

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The Indonesian Ministry of Finance (MoF) recently introduced a new VAT reimbursement mechanism through MoF Regulation No. 218/PMK.02/2014 (MoF-218). Generally, VAT incurred by contractors is reimbursable since sales are not subject to VAT. This new mechanism has created a challenge for the upstream oil and gas industry in Indonesia. MoF-218 not only provides changes in the administrative procedure for VAT reimbursement of Production Sharing Contracts (PSCs), but also provides some provisions that may result in additional burdens for PSCs contractors. Below are the major changes in MoF-218:

- The VAT reimbursement amount should not exceed the government share excluding the First Tranche Petroleum (FTP) amount (a fixed proportion of production that is shared before cost recovery under the terms of most PSCs). It should be noted that PSCs normally stipulate that the government will reimburse the VAT out of its share without excluding FTP.

- The VAT reimbursement is subject to confirmation by the Directorate General of Taxation, which means in practice that the contractor must obtain a fiscal clearance letter from the tax office. Previously, the tax office had no role in the VAT reimbursement process as this was performed entirely by SKK Migas (the upstream oil and gas regulator). Under MoF-218, there is an additional administrative step that may create delays to VAT reimbursements if the tax office considers that the contractor has any outstanding tax liability.

- SKK Migas may offset a VAT reimbursement against over-lifting of the contractor, while previously over-lifting was settled in cash.

- The VAT claimed is not considered reimbursable in the following cases:

  – VAT paid in error on the importation and/or delivery of taxable goods and services that are formally exempted from VAT by the law and regulations; and
  – VAT on operating costs of a liquefied natural gas plant.

MoF-218 has had a detrimental economic impact by creating the potential for delays in receiving VAT reimbursements, and in some cases, VAT is no longer reimbursed. The upstream oil and gas industry has suggested an amendment of the new VAT reimbursement mechanism to be consistent with the principles embodied in Indonesian PSCs and to encourage greater efficiency in the administration process. Earlier in 2016, the government, through the Minister of Finance, promised to consider the VAT reimbursement issue further, although no specific timeline was indicated.

The government also realizes that the recent decline in oil prices has weakened the appetite for investment in Indonesia's upstream oil and gas business and is considering measures to improve the country's attractiveness to new investment by offering incentive packages as part of its fiscal regime. The issuance of Government Regulation No. 79 of 2010 (GR 79) in December 2010 created a new era for the industry, which significantly toughened the fiscal environment. The government, supported by the industry and the Indonesian Petroleum Association, is considering amendments to GR 79 to provide incentives to maintain and boost investment.

Although the changes have not been finalized, several ideas have been proposed by the industry to improve the upstream fiscal regime, including:

- **No tax for exploration activity**
  Contractors have asked the government to consider providing exemptions from certain types of taxes (e.g., land and building tax) during the exploration phase of projects on the grounds that the contractor does not generate any revenue during this phase and bears a higher risk of losses. Currently, most exploration activities are conducted in the eastern part of Indonesia, which is lacking in infrastructure, thus increasing the time required and costs.

- **Ring fencing on the block basis**
  Cost recovery currently is ring fenced on a field-by-field basis, i.e., costs incurred in respect of a specific field are available for offset only against production from that field. It is proposed by the industry to relax the ring fence to enable exploration costs incurred elsewhere within the same block to be cost recovered against production from any fields within the block.

- **Dynamic split in production sharing mechanism**
  It is proposed by the industry that, in future, production sharing will be based on a "dynamic split" mechanism, rather than fixed percentages of volume produced. This will take into account oil price fluctuations to provide a more equitable share to contractors and the government. This new mechanism could be introduced through the amendment of existing contracts. Under the current regime, the fluctuation of the oil price is not considered in the formula to calculate the sharing of production; the oil price is used only as the basis to convert the contractor's lifting to come up with the profit oil or gas to be split and the tax payable calculation.

The Government is aiming to finalize the amendment of GR 79 by the end of 2016.

Tanzania: New income tax rules for the oil and gas industry

Dmitry Logunov and Joseph Thogo, Deloitte East Africa

New income tax regimes for the extractive industries in Tanzania, covering mining, as well as oil and gas, came into effect on 1 July 2016, following the enactment of the 2016 Finance Act. The regime includes more detailed rules for taxing upstream, midstream and downstream activities.

Determining taxable operations or activities

Finance Act 2016 has tightened the application of ring-fencing to petroleum operations. In determining the taxable income of a person engaged in petroleum operations under a production sharing agreement (PSA), each petroleum operation will be treated as an independent business and a taxpayer that is engaged in multiple petroleum activities along the hydrocarbon value chain and/or multiple PSAs, will be required to prepare separate tax books for each activity and determine the tax liability of each independently, for each year of income. From the date of grant of the development license, other exploration activities conducted with respect to the same block will be treated as new separate petroleum operations. Transfer pricing rules will apply where a taxpayer is engaged in different petroleum operations, including midstream and downstream activities, with the effect that the tax authorities will treat each of these activities as if they were separate taxpayers that should be taxed on an arm's length basis with regards to their interaction with other activities of the same company.

Determining taxable income

Finance Act 2016 requires the following items to be included in determining income from petroleum operations:

- The value of petroleum disposed at the PSA's delivery point (as defined in the PSA) whether from cost oil, cost gas, profit oil or profit gas;
- The sale of data or information relating to the operations or petroleum reserves; and
- Amounts required to be included from an assignment or other disposal of an interest in the petroleum right.

Deductions allowed against income

The new rules include the following deductions against income:

- Operating costs, subject to the general rules for deducting business expenses;
- Royalties and annual fees incurred with respect to the petroleum right;
- Amounts deposited in respect of the decommissioning fund for petroleum operations; and
- Depreciation allowances.

In determining the taxable income of a person engaged in petroleum operations under a production sharing agreement (PSA), each petroleum operation will be treated as an independent business and a taxpayer that is engaged in multiple petroleum activities along the hydrocarbon value chain and/or multiple PSAs, will be required to prepare separate tax books for each activity and determine the tax liability of each independently, for each year of income.

Depreciable expenditure includes expenditure (other than financial costs) incurred wholly and exclusively in respect of petroleum operations including exploration, appraisal, development and production or in developing relevant infrastructure. The depreciation granted with respect to a particular year of income must be taken in that year and may not be deferred to later years. Depreciation allowances are given at a rate of 20 percent per annum (on a straight-line basis).

Petroleum rights (which include an exploration or development license or the data relating to petroleum operations) are to be treated as separate from other assets employed in petroleum operations, and related costs will be treated as depreciable assets when incurred, but will be deemed to be investment assets if realized before the commencement of production, implying that cost base will need to be apportioned where there is a part disposal before that point.

Operating costs incurred wholly and exclusively for the purposes of the business are deductible subject to certain exclusions:

- Environmental and research and development expenditure;
- Donations, gifts to public, charitable and religious institutions;
- Book depreciation relating to depreciable assets of a capital;
- Amounts from long-term contracts;
- Bonus payments; and
- Expenses incurred in implementing the decommissioning plan for the operation that are over and above the amount in the decommissioning fund.

Unrelieved losses brought forward may be deducted from taxable profits subject to the ring fencing rules described above. The deduction for losses may not exceed 70 percent of the taxable profits arising from the relevant ring-fenced activity before the deduction of losses.

Transition into the new regime

The new legislation does not include any transition rules so the implications for taxpayers with existing upstream activities are unclear. In particular, expenditure incurred before the 2014 Finance Act came into effect was not subject to any ring-fencing, and the 2013 ring fencing rules are less stringent. In addition, it is not clear whether the 70 percent limit on loss utilization will apply only to losses incurred after the new rules come into effect or at the point a taxpayer attempts to offset losses already incurred. Most Tanzanian PSAs include economic stabilization clauses, and parties to such agreements may have some protection against the new rules, but this will require careful analysis.

Income tax treatment of acquisition and realization of petroleum rights

Although the legislation is not clear, it appears that taxpayers will be required to pool and depreciate their petroleum rights and exploration expenditure as depreciable assets from the time the expenses are incurred. However, in the event of a farm-out before commencement of production, the character of the depreciable asset at its tax basis in the pool will change to be that of an investment asset solely for the purposes of determining the tax consequences of the farm-out. The gain or loss from such a farm-out will be capital in nature. Immediately after the farm-out, all expenditure will resume its depreciable asset character in the hands of transferor and transferee. This interpretation is under discussion with the tax authorities, but has not been formally confirmed at the time of writing.

Where a petroleum right is realized, in whole or in part, the amounts arising from the realization will be treated as follows:

- The expenditure incurred in acquiring each asset will be apportioned between the assets according to their market values at the time of acquisition;
- The amounts derived in realizing each asset will be apportioned between the assets according to their market values at the time of realization; and

- In the case of a part disposal, the net cost of the asset immediately before the realization will be apportioned between the part of the asset realized and the part retained according to their market values immediately after the realization.

The new rules also indicate that the taxable amount will include any form or payment or benefit to be derived in the future from the realization of the asset and will be the market value at the time of the realization of that future benefit or payment. In determining the market value of an obligation to pay a future amount (e.g., a carry arrangement), the transferor must apply the present value of a reasonable estimate of the amount of the future payment. Once determined, these amounts also will be included in the basis of the depreciable asset on the hands of the acquirer.

The law recognizes that as future commitments or obligations, the payments or benefits might not crystallize and, thus, will allow parties to the farm-out transaction to make adjustments in the future in this instance.

If a depreciable asset is realized and the amount realized exceeds the written down value of the relevant expenditure pool, the excess will be included in calculating the income from the year. If the amount realized from a disposal of all assets in the pool is less than the brought forward value of the pool, the pool will be dissolved and excess of the written down value may be allowed for the year.

Payment of tax on disposal of PSA interest

An amendment to the "single instalment" section in the Income Tax Act now requires payment of the entire 30 percent tax arising on any gain resulting from the disposal of petroleum or mineral rights before the change in ownership may be registered. Since approval of the Ministry of Energy is required for such a disposal, this creates the anomalous situation that tax must be paid before the disposal can actually take place. In practice, the ministry has for some years been requiring agreement of the tax authorities to the consequences of PSA disposals before granting consent, but the requirement to pay tax first will require careful consideration in drafting and implementing a sale and purchase agreement.

US: Oil and gas tax considerations in today's pricing environment

Jeffrey M Wright, Deloitte US

In the continued low commodity pricing environment, many oil and gas companies remain under increased pressure to cut costs and effectively manage cash flow. This often includes an enhanced focus on utilizing available tax-related incentives. There are a number of tax considerations to explore for US domestic projects during this tumultuous period of low commodity prices, including the key reliefs outlined below.

Enhanced oil recovery credit

The Internal Revenue Service (IRS) recently announced the return of the full 15 percent enhanced oil recovery (EOR) credit for 2016, which is available to offset corporate income tax. The EOR credit is a tax credit for qualified enhanced oil recovery costs incurred by a taxpayer in a tax year. The credit is permanent but had been phased out and unavailable for the last 10 years due to commodity prices.

Although the oil and gas industry had speculated about the potential availability of the EOR credit for 2016 earlier in the year, official confirmation in Notice 2016-44 was welcome guidance for the industry.

Enhanced oil recovery projects

A qualified EOR project generally is a project that involves increasing the amount of recoverable domestic crude oil through the use of one or more tertiary recovery methods, including:

- Steam recovery methods (e.g., steam drive injection, cyclic steam injection and in situ combustion);
- Gas flood recovery methods (e.g., miscible fluid displacement, CO2 augmented waterflooding, immiscible CO2 displacement, and immiscible nonhydrocarbon gas displacement);
- Chemical flood recovery methods (e.g., microemulsion flooding and caustic flooding); and
- Mobility control recovery method (e.g., polymer augmented waterflooding).

Simply accelerating the recovery of minerals does not qualify as an EOR project. Rather, more than an insignificant increase in the amount of crude oil that will ultimately be recovered is required. A qualified EOR project also must meet other requirements provided by the statute and regulations, which are beyond the scope of this discussion.

Enhanced oil recovery costs

The EOR credit is for 15 percent of the qualified EOR costs. Qualified costs include certain designated expenses associated with an EOR project, including:

- Amounts paid for depreciable tangible property;
- Intangible drilling and development expenses (IDC);
- Tertiary injectant expenses; and
- Construction costs for certain Alaskan natural gas treatment facilities.

To the extent the EOR credit is allowed for qualified costs, any income tax deduction otherwise allowed (i.e., IDC, injectant expenses, etc.) must be reduced by the amount of the credit. In that same respect, the increase in the basis of property that otherwise is allowable for costs for which an EOR credit is claimed (i.e., lease and well capital expenditures) must be reduced by the amount of the credit.

Costs not qualifying include those for water flooding (though these costs may qualify to the extent such costs are a part of a larger qualified project), cyclic gas injection, horizontal drilling, gravity drainage and costs related to other methods not specifically designated by the regulations. However, the rules do contemplate the qualification of costs related to other recovery methods as technological advances occur and taxpayers may request private letter rulings as new circumstances arise.

Taxpayers also must consider specific limitations with respect to qualified EOR costs depending upon the type of entity claiming the EOR credit. These include special rules for integrated oil companies and certain partnership expenditures.

Calculating the available credit amount
The EOR credit amount of 15 percent may be reduced or phased out in a given year depending upon the reference price of domestic crude oil. The full 15 percent credit is available for the 2016 tax year.

Utilization of credits
As a general business credit, the amount of the EOR credit is subject to the alternative minimum tax and is nonrefundable (i.e., it can reduce the amount of tax payable but cannot exceed the amount of that tax). Even without a federal tax liability in the current year, the credit may be carried back one year or forward 20 years. Any unused credit remaining after the expiration of the carryforward period is fully deductible at that time.

Marginal well tax credit

The marginal well tax credit (MWC) is a production-based tax credit that provides a USD 3 per barrel credit for the production of crude oil and a USD 0.50 per 1,000-cubic feet credit for the production of qualified natural gas from a qualified marginal well.

Since its enactment in 2004, the MWC has been fully phased out for both marginal oil and natural gas wells due to the relevant commodity prices. No taxpayer has ever claimed the Internal Revenue Code (IRC) section 45I MWC since its enactment, and no IRS form exists to claim the credit since the IRS has never needed to develop one.

Based upon projections of the 2015 reference price for natural gas, it appears that the MWC for natural gas may be available in 2016 for the first time (as availability depends on the prior reference price). However, it appears that the MWC for oil is fully phased out for the 2016 tax year.

Qualified marginal wells
A qualified marginal well generally includes a domestic oil well with: (1) production of not more than 15 barrels per day; (2) production of heavy oil; or (3) average production of not more than 25 barrels a day of oil and not less than 95 percent water. Marginal natural gas wells are those producing not more than 90 Mcf a day (one barrel of oil is equivalent to six Mcf). Finally, only the first 1,095 barrels or barrel-of-oil equivalent per year qualify (equivalent to 6,570 Mcf/year). This limitation is based on the number of barrels or barrel-of-oil equivalents per year, per well. There are no limits on the number of wells on which a taxpayer can claim the credit.

To claim a MWC, the taxpayer must hold an operating interest. If a well is owned by more than one owner, the credit is allocated among the owners in proportion to the share of the revenue interests of all operating interest owners. Further, the MWC is not available if the taxpayer also is claiming the IRC section 45K nonconventional sources credit.

Utilization of credits
The MWC is especially attractive to entities that have paid federal income tax within the last five years. A special carryback provision provides that unused MWCs may be carried back for five years rather than the generally applicable carryback period of one year. The credit also may be carried forward for 20 years. Utilizing the potential MWC creates the opportunity for refunds and a reduced overall income tax burden.

State marginal well – Texas franchise tax benefits

In addition to the above federal MWC, there are other potential tax considerations for marginal oil and gas properties. An example is the Texas franchise tax (also commonly referred to as the "margin tax") revenue exclusion. When companies with upstream operations pay Texas franchise tax, savings potentially exist when two requirements are met for any given month: (1) the applicable commodity price is certified by the Texas Comptroller of Public Account's ("Comptroller") office as meeting the statutory threshold, and (2) the well's average production amount over the relevant 90-day period qualifies under the statute. When these two requirements are met for a given month, taxpayers are able to exclude from both the tax base and apportionment percentage, revenue earned from the respective qualifying well(s) for that month.

With regard to gas wells, the Comptroller must certify the average closing price of gas for a given month is below USD 5 per MMBtu. As of June 2016, gas prices have regularly met this price requirement since early 2010. Therefore, effectively only one requirement has existed for gas wells since that time: whether the well's production qualifies over the relevant 90-day period under the statute. For Texas franchise tax purposes, a gas well's production qualifies in a given month if an average of less than 250 Mcf per day is produced over a period covering that month, plus the two preceding calendar months. With respect to terminology, rather than use "marginal well" or other nomenclature, the Comptroller's office generally refers to such a well simply as a "low-producing well."

For oil wells, the same concepts apply except the monthly price and monthly production amount differ: the Comptroller must certify the average closing price of West Texas Intermediate crude oil for a given month is below USD 40 per barrel and the oil well must average less than 10 barrels of crude production per day or less over the 90-day period described above. In contrast to gas prices, as of June 2016, the applicable average closing price of crude oil has met the Comptroller price certification requirement less than a handful of times (e.g., December 2015, January 2016).

Specified liability loss carrybacks

Many oil and gas companies currently are generating net operating losses (NOL) for federal income tax purposes. A tax consideration other than tax credits that may be available in the current environment is the use of specified liability losses (SLLs). Generally, taxpayers can only carry an NOL back two years. However, to the extent a portion of the NOL qualifies as a SLL, the applicable carryback period is 10 years. This may open up a pool of previously paid income taxes for refund that otherwise may not be available for recoupment.

The types of expenditures eligible are defined by statute, but generally include any amount allowable as a deduction that is attributable to product liability or expenses incurred in the investigation or settlement of, or opposition to, claims against the taxpayer on account of product liability. SLLs also generally include any amount allowable as a deduction that is in satisfaction under a federal or state law requiring the reclamation of land, the decommissioning of a nuclear power plant (or any unit thereof), the dismantlement of a drilling platform, the remediation of environmental contamination or a payment under a workers compensation act.

Pertinent to exploration and production entities, expenses related to the reclamation of land include dismantling surface facilities, contouring and grading land, placement of subsoil and topsoil or an approved substitute in graded area, reseeding native vegetation, crops, or trees and future monitoring to ensure successful reclamation.

Many oil and gas companies, particularly those with upstream operations, will routinely have significant costs that qualify as SLLs. Moreover, special procedures to request and expedite a refund of these overpayments are often available.

Other considerations

These are just a few examples of the potential opportunities for enhancing cash flow during the current economic environment. In addition to other federal and state income tax considerations, there often are important considerations in the sales and use, excise and severance tax areas. Although some opportunities may not rise to a priority level during more vibrant times, in the present pricing environment, the cumulative impact may be significant and often merits a fresh focus and review.

The types of expenditures eligible are defined by statute, but generally include any amount allowable as a deduction that is attributable to product liability or expenses incurred in the investigation or settlement of, or opposition to, claims against the taxpayer on account of product liability.

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