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Changing times: transfer pricing issues in the oil and gas industry

By Randell G. (Randy) Price and John M. Wells, national transfer pricing leaders – **Deloitte** oil and gas industry

On behalf of our Deloitte Touche Tohmatsu Limited tax colleagues who focus on transfer pricing issues within the oil and gas (O&G) industry, we are pleased to present this collection of papers on industry developments and issues.

The O&G industry's global transfer pricing landscape is in a state of change. From a macroeconomic perspective, oil prices have fallen by approximately $45/barrel over the last year, active drilling rig count is near a five-year low, thousands of industry jobs have been lost, and the capital budgets of E&P companies have scaled back significantly.

With that list as a challenging backdrop, the O&G industry (as well as the global tax community) was greeted with what may be considered the most comprehensive changes to the transfer pricing framework in nearly two decades as the G20 and the OECD issued proposed new transfer pricing guidelines under the base erosion and profit shifting (BEPS) initiative. The BEPS documentation guidance fundamentally changes transfer pricing considerations for the globally-reaching O&G community and ushers in a new paradigm regarding transparency. In addition, the BEPS Action Plan states that key changes may be needed in how companies approach the valuation of intangibles, price risk allocations, and acknowledge or respect intercompany agreements.

Our approach to this guide is to bring some order to this change. Therefore, we begin with a primer on transfer pricing challenges posed to the O&G industry by the BEPS transfer pricing deliverables. Next, we turn our attention to transfer pricing challenges given the current (and potentially protracted) economic downturn. Two articles focus on specific industries that are facing challenging environments due to commodity price deterioration: (i) transfer pricing issues in the contract drilling sector; and (ii) transfer pricing issues in the liquefied natural gas (LNG) space. The final industry article addresses the challenges and opportunities for the O&G industry regarding intellectual property migration. We have also included an overview of recent transfer pricing developments for Australia and the UK, because they appear to be at the forefront of BEPS-responsive initiatives.

More information on transfer pricing issues in specific countries and Deloitte Tax contacts locally are contained in Deloitte's Global Transfer Pricing Desktop Reference (www.deloitte.com/tax/strategymatrix). We hope you find our publication interesting and, more importantly, of practical use, and we invite you to contact our leading team of professionals if you have any questions.

Relevant BEPS developments and implications for oil and gas industry

Nadim Rahman and Vitaliy Voytovych discuss how developments with the the OECD BEPS project can impact the oil and gas industry.

The OECD's base erosion and profit shifting (BEPS) initiative is a response to the growing perception that governments lose substantial corporate tax revenue due to alleged BEPS activities by many multinationals. In 2013, the OECD developed an Action Plan with 15 key actions to address BEPS. The OECD then moved promptly to identify the resources needed, propose the methodologies to address the actions, and set deadlines to implement the actions. The key areas of focus of the OECD BEPS Action Plan include transfer pricing transparency and documentation, supply chain structures, financing structures, intellectual property structures, and common tax-efficient cross-border structures. Since the OECD is on target to complete addressing the Action Plan by the end of 2015, tax has become an increasingly significant political issue, and several tax authorities are already moving forward on the BEPS agenda independent of the agreement and finalisation of the OECD proposals.

While taxation in the oil and gas (O&G) industry is inherently complex and challenging for both the tax authorities and the taxpayer, the new, evolving landscape of BEPS poses more considerations and added nuances for cross-border tax issues. The BEPS Action Plan addresses several key areas of significance to O&G companies in the field of transfer pricing, including reporting, risk, services, and intangible property, which are discussed below.

New guidance on transfer pricing documentation requirements

Transfer pricing documentation is poised for the biggest change since the introduction of US penalty protection documentation rules in the mid-1990s. Under its BEPS initiative, the OECD issued revisions to Chapter V of the OECD transfer pricing guidelines that will significantly increase the type, amount, and transparency of information to be disclosed to tax authorities, resulting in an increased compliance burden on multinational companies engaged in cross-border transfers of goods, services, or intangible property.

Under the new guidance – issued through discussion drafts in 2014 as well as additional guidance in 2015 – taxpayers will be required to prepare three types of reports:

- Master file
- Local file
- Country-by-country (CbC) report

Master file

The master file is designed to serve as a "blueprint" of the taxpayer group as a whole to allow local tax authorities to understand the context in which local transactions take place. The master file will provide key information about the group's global operations, including a high-level overview of the taxpayer's business operations along with important information on its IP activities, financing activities, supply chain, and overall value drivers.

Local file

The local file is meant to provide information and support of the intercompany transactions that the local entity engages in with related affiliates. In addition to the information traditionally found in transfer pricing documentation (such as the description of business, description of intercompany transactions, functional analysis, and economic analysis), the local file should contain details on the taxpayer's local management structure and reporting structure, a copy of advance pricing agreements and rulings related to the transaction (even if obtained in a different jurisdiction), and reconciliation of the financial data used in the analysis to the financial statements.

Notably, the new guidelines support the use of local comparable companies over regional or global comparables, provided local comparables are reasonably available. This requirement may increase the number of sets of comparable companies global O&G companies need to prepare. On the other hand, the new guidelines allow taxpayers to perform searches for comparable companies every three years – rather than every year – if the facts and circumstances of the intercompany transaction have not changed significantly. Taxpayers will still need to update financial information of the selected comparable companies on an annual basis.

Country-by-country report

One of the most significant changes came with the introduction of the CbC report. The CbC report is designed to serve as a risk assessment tool for the tax authorities by presenting key financial information on all group members on an aggregate country basis. Specifically, the CbC report, which provides a heightened level of transparency, is to contain information on revenues, profit/loss, tax paid and accrued, tangible assets, and number of employees, among other things.

In February 2016, the OECD released implementation guidance regarding CbC reporting that stated that the CbC report will be required for years beginning on or after January 1 2016, and only for groups with global revenues greater than €750 million ($827 million). The report is to be filed annually within 12 months of the fiscal year end. Usually, the ultimate parent company of the group will have the responsibility to submit the CbC report to its tax authority; however, a "surrogate" parent could be selected instead in certain circumstances for purposes of filing. The information would then be exchanged among the tax authorities using certain multilateral or bilateral mechanisms.

The amount and type of information required to be disclosed would lead to an unprecedented level of global transparency. Such transparency may highlight inconsistencies in the company's transfer pricing policies or the actual results among similar types of entities, or a disconnect between the locations of revenue recognition/profit generation and "value creation". These changes will call for tax departments to have a better handle on global transfer pricing outcomes through regular monitoring of results and developing more in-depth support for their global transfer pricing structure.

In addition to greater scrutiny of existing transactions, tax authorities will be in a position to focus on broader aspects of taxpayers' structures beyond the intercompany transactions applicable to their jurisdiction. For example, Tax Authority in Country A may argue that the local entity providing what the taxpayer believes to be contract R&D activities may in fact be creating significant value in Country A, and therefore be entitled to a portion of the return currently earned by the IP owner in Country B.

For multinational O&G companies operating in multiple jurisdictions, the data gathering exercise required to prepare the CbC report may pose a significant challenge as tax departments are already stretched thin in the current cost-cutting environment. Taxpayers are advised to perform a "test run" of CbC report preparation to identify and address any potential issues related to systems, data accuracy, or accessibility. Also, such an exercise may uncover potential issues with transfer pricing policies or results, so performing it well ahead of the filing deadline will give taxpayers a chance to address the issues before the data is "broadcast" to tax authorities around the world.

With regard to the master file, taxpayers that took a decentralised approach to preparing transfer pricing documentation will likely require a significant change in their transfer pricing compliance processes to control the preparation of the master file. Taxpayers are advised to perform a risk assessment of current intercompany transactions (as well as activities that are not being documented at present) and a review of current transfer pricing documentation scope to ensure they develop in-depth and globally consistent support for all material intercompany transfers.

Risk allocation and recharacterisation of transactions

In December 2014, the OECD issued a "Discussion Draft on Revisions to Chapter I of the Transfer Pricing Guidelines (Including Risk, Recharacterisation, and Special Measures)" proposing changes to Chapter I of the OECD transfer pricing guidelines. Subsequent to the release, the OECD received more than 850 pages of public comments and also held a public consultation. The significant interest was caused by some of the proposals outlined in the risk discussion draft that may impact many taxpayers.

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The following is an overview of the main points in the risk discussion draft and their potential impact on the O&G industry, keeping in mind that the final guidance may differ from the proposal outlined in the discussion draft.

Identifying commercial and financial relations

The risk discussion draft expands the concept of a "transaction" to include situations in which value is transferred although no actual transaction is recorded. An example relevant to the O&G industry includes the transfer of know-how through seconded employees. Such a revision could lead to increased controversy as tax authorities may start identifying transactions where they don't necessarily take place. It may be prudent for taxpayers to develop an in-depth analysis of functions, risks, and contributions of each party to preempt such conclusions.

Identification and allocation of risk

The risk discussion draft emphasises that identifying risks is a critical part of a transfer pricing analysis, along with identifying functions and assets. But the allocation of risk between related parties can be based only on the actual conduct of the parties, and specifically, on their capability to manage and control risk.

Under the proposed revisions, risk management includes both the capability and the decision-making function in the following three areas:

- Ability to make or decline risk-bearing opportunities;
- Ability to respond to risks as they arise; and
- Ability to employ risk mitigation strategies.

As a result, merely contractually allocating risk, or providing a certain entity a "limited risk" return, may not necessarily be respected unless it follows the allocation of risk based on the actual risk management activities.

The risk discussion draft states that trading a more certain, or lower risk, return for a less certain, or higher risk, return(the "risk-return trade-off) is not a sufficient justification for the risk transfer. Instead, the document argues that such a transfer should take place only if the transferee is better placed to manage the risk than the transferor. The OECD invited the public to comment whether such risk-return trade-off is appropriate under the arm's-length principle, and received feedback that such trade-offs are based on fundamental economic theory.

Nonrecognition and recharacterisation

The risk discussion draft proposes a new approach to determining whether actual intercompany transactions may be disregarded by tax authorities for transfer pricing purposes. Under the new guidance, a transaction should be respected for transfer pricing purposes only if it has the "fundamental economic attributes of arrangements between unrelated parties and commercial rationality". The risk discussion draft suggests that each affiliate involved in a transaction should have a reasonable expectation to enhance or protect its own commercial or financial positions, compared to other options realistically available to them. A litmus test would be whether the group would be better off on an overall pre-tax basis.

The proposed approach is likely to increase uncertainty and tax controversy, and potentially lead to double tax. Tax authorities would have more precedent for recharacterising a nonrecognised transaction, which could lead to potential documentation penalties.

Activities that may be affected by the changes proposed in the risk discussion draft may include commissionaire or limited-risk distributor entities, contract R&D services, and centralised asset ownership/leasing structures, which are common in the O&G industry. For example, a number of contract drilling services providers submitted comment papers expressing concern that the OECD proposals, including under the discussion draft, do not take into account some of the unique characteristics of the sector, such as the critical importance of an asset and its specifications, the need for asset mobility that's realised through centralised asset ownership, and the significant utilisation risks associated with owning such assets.

Overall, companies may want to consider "stress-testing" their existing structures to identify any potential gaps, and addressing them through ensuring sufficient local substance, maintaining consistency between the letter of the intercompany agreements and actual activities of the parties, and enhancing the support for the current pricing approach.

Services

Cost contribution arrangements

The OECD on April 29 2015, released a discussion draft on cost contribution arrangements (CCAs) under Action 8 that contains proposed revisions to Chapter VIII of the OECD's transfer pricing guidelines. Consistent with the current guidance, the CCA discussion draft applies to both service CCAs, in which participants share the cost of services, and development CCAs, in which participants share the costs and risk of developing property. The CCA discussion draft takes the position that the outcome of operating within the context of a CCA should be the same as if the CCA had not existed. Therefore, both initial contributions to the CCA and ongoing contributions must be measured by value rather than cost (with an exception for low-value services). The value of each participant's contribution is determined by reference to the other chapters of the OECD's transfer pricing guidelines, in particular Chapter VI for intangible development CCAs. The requirement that contributions be based on value rather than costs is more limiting than the current guidance, but aligns with the BEPS Action Plan and the increased emphasis on value splits. Nonetheless, the requirement to use value rather than cost is the change likely to have the greatest impact on existing service CCAs.

Two additional recent developments also affect how MNEs share and allocate services cost. On November 3 2014, the OECD issued a draft pursuant to Action 10 of the BEPS Action Plan that reduces the scope for erosion of the tax base through excessive management fees and head office expenses by proposing an approach that identifies a wide category of common intragroup services commanding a very limited profit mark-up on costs (low value-adding intragroup services). Second, the US Tax Court on July 27 2015, struck down the requirement in the 2003 US cost sharing regulations that participants in a qualified cost sharing arrangement share stock-based compensation costs (SBC). This also affects the allocation of SBC under services regulations, and will have an impact on how US-based MNEs share costs under service CCAs as well as development CCAs.

Services in O&G industry and BEPS considerations

The O&G industry has certain practices of its own when it comes to allocating intragroup services, which makes it important to examine intragroup services in light of these discussion drafts.

There is a plethora of intragroup services provided within the O&G industry that range from engineering and technical services to management, administrative, and other operations-related services provided by the corporate headquarters of industry participants. The types of arrangements under which intragroup services are provided within the O&G industry are not only unique but significant in terms of value. Industry participants often provide the same types of services at cost (or cost plus a small markup) to their related parties and third-party joint venture partners in the context of a joint operating agreement or a production sharing contract. The pricing to third parties has often been treated as comparable uncontrolled service prices (CUSPs) to determine related-party pricing. However, in the US, the use of CUSP in analysing such transactions has been challenged in some cases, as the IRS has relied on the services regulations promulgated under Treas. Reg. §1.482-9 to compel O&G companies to include both stock option expenses and a profit element in their charges to affiliates, irrespective of whether foreign tax authorities, joint venture partners, or national oil companies will accept such charges. At times, the markups required on audit have been very large.

With the proposed modifications for service CCAs still in discussion form, and any future change expected to conform to final decisions in other chapters, as well as the release on low-value adding services, taxpayers should keep an open eye on the evolving landscape. Players in the O&G industry with service CCAs governed by various local regulations should review the existing terms and conditions to identify potential differences with the CCA discussion draft, in particular regarding sharing "value" instead of "costs", and also watch out for the consequences of the recent US Tax Court ruling on charging out SBCs in the *Altera* decision.

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Vitaliy specialises in the oil and gas industry (oilfield services and equipment, exploration and production, drilling, marketing, LNG) but has considerable experience in a number of other industries as well, including engineering services, semiconductors, and chemicals. He has extensive experience managing large transfer pricing engagements, including US and global documentation and planning studies, advance pricing agreement (APA) negotiations, and audit defence work.

Intangible property

Intangibles

The OECD on September 16 2014, issued revisions to Chapter VI of the transfer pricing guidelines, Special Considerations for Intangibles, as part of the BEPS deliverables. The OECD has adopted a broad definition of intangibles in the revised guidance that defines an intangible as something (1) that is not a physical asset or a financial asset; (2) is capable of being owned or controlled for use in commercial activities; and (3) whose use or transfer would be compensated had it occurred in a transaction between independent parties in comparable circumstances. Intangibles for transfer pricing purposes include know-how and trade secrets; trademarks, trade names, and brands; rights under contracts and government licenses, including contractual commitment to make a workforce available; licenses and similar limited rights in intangibles; and goodwill and ongoing concern value. The following are not considered intangibles under this release: market-specific characteristics (for example, local consumer purchasing power and location savings), and assembled workforce.

The guidance recognises that payment for use of an intangible should be made to the party with legal ownership of that intangible. However, when another party has participated in activity leading to the development, enhancement, maintenance, protection, or exploitation of an intangible, a separate transaction dealing with that activity must also be considered, in that, the legal owner has a transfer pricing obligation to pay for those activities it does not perform. The release further states that compensation for intangibles must be determined on the basis of *ex ante* information. In selecting a transfer pricing method to value intangibles, the guidance makes it increasingly likely that the method to be applied as the most appropriate will be the transactional profit split, the use of discounted cash flow techniques by requiring consideration of both parties' realistic alternatives, or other valuation techniques. Further, the pricing should be based on a functional analysis that provides a clear understanding of the MNE's global business processes and how the transferred intangibles interact with other functions, assets, and risks that comprise the global business and factors that contribute to value creation, including specific market characteristics, location, business strategies, and MNE group synergies, among others. The risk discussion draft provides additional draft guidance on risk and value creation as it relates to any intragroup transaction, including intangibles.

Hard-to-value intangibles

The OECD on June 4 2015, released a non-consensus discussion draft on Action 8 regarding hard-to-value intangibles (HTVI). Intangibles that fall within this category may exhibit one or more of the following features: intangibles that are only partially developed at the time of the transfer; intangibles that are not anticipated to be exploited commercially until several years following the transaction; intangibles that separately are not HTVI but that are connected with the development or enhancement of other intangibles that fall within the category of HTVI; and intangibles that are anticipated to be exploited in a manner that is novel at the time of the transfer. The discussion draft states that, when valuation of an intangible or rights in an intangible at the time of the transaction is highly uncertain, and questions arise as to how arm's-length pricing should be determined, the questions should be answered by reference to what independent enterprises would have done "to take account of the valuation uncertainty." For example, independent parties may agree upon: use of *ex ante* pricing, adopt shorter-term agreements; include price adjustment clauses in the agreement; adopt payment structures involving periodic milestone payments; adopt a royalty rate set to increase as the licensee's sales increase; or agree to renegotiate the pricing arrangement if major unforeseen developments occur, changing the fundamental assumptions on which the pricing was determined.

Intangible development CCAs

Besides the considerations required for service CCAs, MNEs that have existing intangible development CCAs in place – in particular cost sharing arrangements (CSAs) that comply with the US cost sharing rules – should be alert and watch for the final CCA rules to determine to what extent the final CCA guidance is inconsistent with existing local regulations, and to what extent additional actions may be required to address those inconsistencies. MNEs that have an entity that is a participant in a CSA governed by the US cost sharing regulations should be aware that the CCA draft takes a very different approach to the taxation of CCAs than the US regulations in several ways.

Intangibles in O&G industry and BEPS considerations

The O&G industry has unique practices of its own when it comes to developing and sharing intangibles, which makes it critical to examine the transfer pricing-related to intangibles under the light of the above-noted discussion drafts. There is an added complexity in this industry because of the gray area that lies between services and intangibles, as noted below.

O&G companies employ processes, know-how, and technologies to find and produce hydrocarbons. The distinction between the provision of a service and the provision of a service bundled with an intangible is somewhat nebulous, especially in the O&G industry. To break this conundrum, it is important to consider whether there is anything proprietary associated with the service, whether the recipient is obligated to employ the results of such services, and if the services are accompanied by a manual or any other device that "has substantial value independent of the services of any individual." The IRS's position in this regard appears to suggest that US-based engineers and scientists working for exploration and production (E&P) companies produce value at well sites in remote places such as the North Sea and West Africa by combining their expertise with US-developed intangibles. Currently, the US and OECD transfer pricing regimes accommodate a range of approaches for dealing with the issue. Depending on the characterisation of the transaction, a taxpayer can elect to classify it as a complex engineering service, or a service bundled with intangible property. Under the evolving BEPS landscape and expanded definition of intangibles, O&G companies will have to perform a detailed functional analysis and determine risk characterisation to distinguish between high-value services versus intangibles.

A nuance of intangibles used by E&P companies is that these have often been developed in tandem with petroleum engineers and geoscientists at major universities, industry consortia, and oilfield services firms. These non-proprietary assets are shared freely, in certain cases, with joint venture partners and NOCs in the quest for hydrocarbons, typically on a royalty-free basis. Due to this ambiguity of ownership and the openness by the industry to share knowhow, leading practices and technology, allocating a price to this expertise may remain convoluted. Further complicating intragroup intangible valuations is the fact that there are so many different services, processes and intangible assets coming together at the well site to produce hydrocarbons. Few of these assets are significant on a standalone basis; it is therefore difficult to value their separate contributions. In other industries, a royalty payment for the value of the intangibles would be paid in an effort to appropriately compensate the intangibles owner; in the O&G sector, bifurcating the revenue stream from the sale of the resulting hydrocarbons between the amount resulting from the use of the IP (be it a tool, technique, process, or patent) and that associated with more routine contributions is very difficult because of the complexity of activities at the wellhead. To avoid these complications, and when the delivery of certain services involves an IP component, some E&P companies and oilfield services companies have chosen to pursue expansive, multiparty CSAs whereby all legal entities share in the cost of intangible development and are allowed the use of the resulting IP on a royalty-free basis. O&G companies will have to examine the intangibles licensed and shared under the expansive definition of intangibles under Action 8 and take into consideration a detailed functional analysis and risk characterisation that includes value creation and risk, determine HTVI as well as consider intangible development CCAs and the associated releases under the evolving BEPS landscape.

Oil and gas industry downturn and transfer pricing considerations

Randy Price, Sam Fletcher and Mayank Gautam explain how a downturn in production for the oil and gas industry and a reduction in the price of oil will impact an energy company's transfer pricing arrangements.

After a four-year period of relative price stability, oil prices fell sharply in the second half of 2014. While volatility has been a common theme for oil prices in the last several decades, last year's fall in oil prices differs from those of the past, stemming from changes in supply conditions, expansion of oil output in the US, receding supply disruptions and OPEC's switch to a policy to defend its existing market share. With supply conditions and price not expected to substantially change in the near term, the oil & gas (O&G) industry will be required to adapt to new market dynamics.

Often, the impact of the decline in oil price is heavily dependent on the segment in which the companies operate in the O&G industry value chain. The upstream segment, dominated by oil majors and large integrated O&G companies, tends to reduce capital investment in this environment. Depressed prices often decrease a project's expected returns from future production, which results in lowering the project's potential rate of return and thus diminishes incentives for investment spending.

Decisions made by the upstream segment to decrease capital spending have put downward pressure on other sectors of the O&G industry, with the most acute impact on the oil field services (OFS) sector. As oil prices and upstream investment spending fall, reduced demand for rigs and other oil field services may be severe. In a March 2015 report, Forbes calculated that the worldwide O&G industry, including OFS companies, parts manufacturers, and steel pipe makers, have laid off at least 75,000 personnel during the current downturn. The service companies have borne the brunt of these dismissals, with nearly 59,000 layoffs, because their activity and revenue streams are directly related to drilling activity. According to a Moody's report, OFS companies may experience deep, protracted, cyclical downturn conditions for the foreseeable future, given that even with a moderate oil price increase, integrated oil majors will likely remain cautious about capital and investments.

A topic that has attracted considerable attention in recent months as the O&G industry continues to experience downturn has been how tax departments within O&G companies should address the serious challenges posed to related-party transaction policies and results dictated by the current economic crisis. The challenge may exceed the limits of what can be managed within the transfer pricing systems currently applied by many O&G companies, and may require a changed approach to transfer pricing systems currently adopted. The following sections discuss transfer pricing challenges and practical ways to overcome such challenges, and highlight long-term tax planning opportunities that may be available based on the current environment.

Challenges and practical solutions

Transfer pricing methods assume stable conditions for variables such as revenue, costs, and overall profitability. However, during an economic downturn, these steady conditions may be severely tested. During normal economic times, transfer pricing policies often lead to operating profits for transacting parties that are consistent with profits at comparable companies, and thus acceptable to tax authorities.

The current O&G contraction is idiosyncratic and countercyclical to the trend in the broader economy. That is, while the O&G industry is in a downturn, the broader economy may be improving or on a longer-term trend-line. Because transfer pricing benchmarking for O&G companies often relies on functional comparables from other industries, the benchmarking that was reliable in normal economic times may not be realistic in the downturn, because these comparables may not experience the severity of the specific downturn to the O&G industry. Thus, companies may find it appropriate to adjust transfer pricing approaches developed during normal economic times to approaches that are more appropriate for these downturn conditions.

Such adjustments for recessionary periods in a specific industry are consistent with the guidance in the US transfer pricing regulations. This section aims at providing a framework for addressing transfer pricing issues that O&G companies may potentially encounter during the current downturn.

Adjusting for economic conditions

To ensure the potential comparable data are indeed comparable and do reflect the economic reality for controlled parties, an adjustment for transfer pricing methods, such as the comparable profits method or the transactional net margin method, may be considered appropriate.

Revise existing comparable sets

To account for the current industry-specific economic conditions and improve the reliability of the CPM analysis, the existing comparables set can be screened based on quantitative criteria to identify comparables whose growth rates differed significantly from the tested party. Additional screening criteria such as SG&A to sales and amounts of fixed costs relative to total costs might also be explored. While there is a sound theoretical basis for applying quantitative screening, actual implementation may lead to the selection of only a few comparables. As a practical matter, certain restrictive screening criteria can be relaxed to obtain enough comparables to which additional qualitative or quantitative adjustments can be applied.

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Before joining Deloitte, Randy spent more than 10 years as an international tax/transfer pricing executive for a Fortune 500 multinational company where he developed, implemented and ultimately defended multiple transfer pricing transactions from the IRS exam phase through appeals. In addition, he has experience with transfer pricing planning and controversy matters in multiple jurisdictions outside of the US. Given Randy's experiences both within the industry and at Deloitte Tax, he provides the practical and technical transfer pricing skill set that clients desire in today's complex transfer pricing environment.

Revise comparable companies' financial data

Adjusting profit ranges of comparable companies to mimic the reality in the O&G industry can also be explored. Depending on the particular facts and circumstances of the tested party, the financials may be adjusted for differences related to volume, cost structure, inventory, and excess capacity. Further, adjustments can be made using established statistical and econometric techniques, such as regression analysis, to establish an underlying relationship between sales and profitability. Additionally, for certain categories such as cost structure or excess capacity, when comparable companies may not have enough publicly available data, an economic indicator or industry statistic specific to the O&G industry could be used as a guideline to quantify the relative magnitude of such adjustments. For instance, a correlation can be computed for average comparable company profitability against the economic indicator specific to the O&G industry, which may be used as a basis to make adjustments.

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Sam has also consulted on cross-border supply chain transfer pricing for clients in the recreational vehicle and software industries.

Revise tested parties' financial data

Another set of adjustments that can be performed to tested-party financial results relate to specific variables that lag during the economic downturn. For example, short-term profitability may be impacted by a significant sales decline as reductions in the cost of goods sold or SG&A cannot be accomplished as quickly. During this intermediate time period, it may be reasonable to use benchmarks derived from the company's operations in periods during which it experienced normal growth conditions to perform comparability adjustments.

Revise time period for averaging

Using average profit ratios over multiple years is also a common practice based on the rationale of smoothing the effect of business cycles. However, in the case of a severe downturn, relying on a three-year average including data from two preceding years may not be appropriate. Taxpayers have the ability to use a longer period for comparable company profitability, including financial data from a previous downturn (for example, extending the multiple-year period to include the last O&G recession during 2008 and 2009). Such an approach would increase the likelihood of finding observations on comparable companies that are similar to the current downturn in the O&G industry and may provide a better estimate of the time period used for calculating an average.

Pooling comparable results

Because different comparable companies may have experienced downturns in different years, pooling, rather than averaging the comparable data may provide another approach to the analysis. Pooling the results takes each available year of comparable data as a separate observation to establish a range of benchmarking. Under this approach, an appropriate range might be created from a relatively small number of comparable companies. Additionally, because it treats each comparable data set as a separate observation, pooling tends to yield a wider interquartile range, which might appeal to tested parties impacted by the O&G industry downturn.

Preempting challenges

During a downturn, taxpayers in the O&G industry may face losses unrelated to transfer pricing, and the transfer pricing method suggested for normal operating years may no longer be a reliable or supportable method. For example, the CPM may no longer be the best method when all related parties participating in certain transactions generate losses. In that case, a transactional method or profit or loss split method may be more appropriate.

Further, the current downturn in the O&G industry is an economic event felt comprehensively across geographies, lowering profit margins of multinational O&G companies. In such circumstances, tax authorities are likely to scrutinise closely the deductibility of outbound payments when local entities incur losses, presenting practical challenges in defending such deductions. Therefore, certain outbound costs related to recharge of headquarters and back-office support, payment for trademark or tradenames, franchise fees and other payments related to the use of intangibles (centralised costs) should be carefully analysed and a strong defence position should be prepared contemporaneously to anticipate future audits and potential denials of deductibility of such costs.

A more favourable development in recent years has been the increased willingness of tax authorities to accept some inbound centralised costs as deductible business expenses. However, the economic downturn poses a threat to their continued deductibility, because it may be difficult to substantiate that the centralised costs were of benefit to the recipient when the local entity suffers losses. In these cases, businesses could face an increased risk of double taxation when centralised costs are partially or fully denied as deductible business expenses in the local country.

Furthermore, tax authorities may invoke, commensurate with income standards, to put pressure on local loss-making affiliates' ability to pay for centralised costs. In addition to the nature of payment, risk with respect to such transactions may be increased depending on the identity and likely tax attributes of the recipient of the payment. Accordingly, such payments may be scrutinised closely if they are paid to intermediate affiliates in low-tax jurisdictions.

Given the prevailing economic environment and potential transfer pricing risk, the defence of transfer pricing arrangements for O&G companies is clearly important. The transfer pricing approach undertaken will need to be supported through appropriate documentation, including relevant intercompany agreements and economic analyses. The need for such documentation is critical, because tax audits may occur several years after the events at issue; therefore, it is important to memorialise the relevant facts on a contemporaneous basis.

Finally, the transfer pricing documentation report can be used to tell the company's story of economic hardship as it relates to intercompany pricing for the past fiscal year. It may be informative to provide a narrative that leads up to, and helps explain, the results of the economic analysis. Ideally, taxpayers should support and explain any low, or negative, operating results by explaining the broader economic conditions in a contemporaneous manner, rather than being reactive to alternate narratives put forth by the tax authorities. Once the tax authorities have put forward their position, rebuttal may be a difficult task, which reaffirms the need for appropriate documentation.

Opportunities

While the current downturn creates challenges for the O&G industry, it also presents opportunities for tax departments to revisit assumptions and estimates of asset values and supply chains that may need to be enhanced or rationalised to create more value in the future should an O&G industry recovery take hold.

For example, the current downturn may enable the better alignment of intellectual property (IP) within the supply chain where local geographic management and exploitation is occurring (for instance, an Asia Pacific manufacturing facility) because it is no longer cost prohibitive from a tax perspective to transfer the IP out of the developer's tax jurisdiction. Specifically, economic downturns provide a rationale to reevaluate assumptions such as growth rates, profitability, and discount/hurdle rates that are critical to assessing the true value of IP that may be transferred in a related-party context.

Another potential opportunity presented by the economic downturn is for O&G companies to reduce their transfer pricing risk by entering into an advance pricing agreement (APA) with tax authorities. APAs offer certainty that the tax authorities will accept the selected transfer pricing method to be used for related-party transactions over a fixed period of time. APAs can be beneficial in a downturn because they can provide an O&G company an opportunity to discuss the impact of the current downturn on its transfer pricing policy with the tax authorities as it unfolds, and to propose a mechanism to seek relief. If the taxpayer is taking advantage of certain non-traditional adjustments for the tested party/comparable companies (as discussed earlier in this article), APAs may be the right vehicle to discuss the need for and application of such adjustments.

Just as the current downturn is disrupting traditional business models for struggling O&G companies, the current wave of international tax reform is creating uncertainty over the ongoing effectiveness of tax outcomes under existing business structures. As the G20-OECD Action Plan on base erosion and profit shifting (BEPS) unfolds, O&G companies are expected to enter the BEPS era with unique economic circumstances in light of depressed oil prices. BEPS particularly targets situations in which risks, and the resulting rewards, are not aligned with value-creating functions, such as location of key employees. Profits that previously would have flowed contractually to entities providing access to at-risk capital may be repositioned to key people functions and, to some extent, asset-holding locations post-BEPS. This change is significant for O&G companies, especially OFS companies where much of the substance that creates value lies in its people and assets. O&G companies considering short-term operational changes to mitigate the impact of a downturn should look ahead and assess whether such

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changes – either in the supply chain or the company structure – would be appropriate in the post-BEPS time period.

Conclusion

The current downturn in the O&G industry has significantly affected companies, especially those that continue to operate in the OFS sector, potentially rendering existing transfer pricing methods vulnerable. This, coupled with increased compliance requirements and enforcement activities, has heightened the transfer pricing risk for O&G companies. As a practical matter, taxpayers dealing with transfer pricing challenges can take advantage of specific provisions within regulations and make valid adjustments. It is important to prepare appropriate transfer pricing documentation to memorialise which approach the taxpayer takes to modify existing transfer pricing to address downturn-driven challenges.

The current downturn is also an opportune time to consider whether the overall transfer pricing policy meets the needs of the company in the long run. The current downturn is forcing O&G companies to reassess operations and quickly adapt their tax policies. It is likely that companies may engage in a number of business-driven changes that may impact their transfer pricing. If companies execute changes at this time, the changes can be explained as a reaction to the downturn, and the profit impact of those changes will have the proper context of the overall economic downturn.

Transfer pricing for bareboat charters in the offshore drilling industry

Firas Zebian, Linda Lin, and Joe Wood explain the transfer pricing specifics involved in bareboat charter related to the offshore drilling industry.

The offshore oil and gas drilling industry is made up of drilling contractors (the owners and operators of drilling rigs) that provide services for drilling oil and gas wells. The industry is subject to intense price competition and volatility, and periods of high demand and higher day rates are often followed by periods of low demand and lower day rates. The market for drilling services is substantially affected by global hydrocarbon demand and changes in actual or anticipated oil and gas prices. Furthermore, sustained high energy prices may translate into increased exploration and production spending by oil and gas companies, which can in turn lead to increased drilling activity and demand for rigs. However, weakening oil prices through 2015 have slowed new investment in offshore drilling projects.

Customers in the industry have been demanding higher efficiency rigs, which requires newer rigs be built to greater specifications. Evidence of this trend is demonstrated by higher utilisation of rigs with increased specifications, and lower utilisation rates for conventional drilling rigs. In particular, the demand for high-specification rigs has led to an increased demand for drillships that operate in deep water and ultra-deep water, and are equipped with the latest dynamic positioning systems.

Overview of bareboat charters

As part of the competitive and legal environment in which offshore drilling contractors operate, one approach taxpayers have taken is to separate ownership and the operations of drilling vessels in different tax jurisdictions. Under this structure, a rig owner in one jurisdiction receives payment for use of the vessel by local operating companies in the customer's tax jurisdiction. The local operating companies may have employees who operate the drilling vessels that are provided by foreign related-party rig owners. The term for this payment by the local operating company to the rig owner for use of the drilling vessel is a bareboat charter (BBC).

The price of the BBC given the terms and conditions of the related-party transaction, is a transfer pricing question that continues to generate significant global debate between taxpayers and tax authorities. The amount of capital required to construct drilling vessels is one of the most significant burdens placed on the consolidated drilling company. The asset owner bears (either directly or indirectly) the cost of that capital, and economic principles provide that the return on those costs should be commensurate with the amount of risk incurred. Taken together, these facts argue for a significant return being earned by the asset-owning company. Conversely, most if not all of the employees are located in the operating companies that (either directly or indirectly) contract with the customer, utilise operational skills, and ultimately execute projects for customers. Tax authorities may argue these contributions by the local operating companies constitute valuable intangibles, or alternatively, are valuable services that deserve a much higher return than that paid by the local operating company.

The repercussions of the Deepwater Horizon event of April 2010 still linger, raising questions about how significant a role uninsurable liability risk plays in the offshore drilling industry, which of the related parties bears the risk of those liabilities, and how those liabilities should be accounted for in the transfer pricing analysis. Furthermore, in addition to the observable economic contributions of the related parties (such as drilling vessel, employees, etcetera), taxpayers may structure intercompany arrangements that shift market or other types of risk to certain related parties. Accurately accounting for this array of risks, and quantifying them in addition to other observable contributions in the transfer pricing analysis can present great challenges for taxpayers.

Current events in US

Public disclosure of the BBC issue is largely limited to analysis of SEC filings and documents from one US court case. In that case, the Internal Revenue Service (IRS) ultimately conceded the transfer pricing adjustments, and a January 12 2012, stipulation entered by US Tax Court Judge James S. Halpern stated that "after taking into account self-initiated adjustments reported on that return, reflects arm's-length transfer prices, pursuant to Section 482…for payments made to certain of its foreign affiliates in 2004 pursuant to bareboat charters of drilling rigs owned by those foreign affiliates".

Subsequent to that case, in 2014 the IRS again issued assessments "related to transfer pricing for certain charters of drilling rigs…This item, if successfully challenged, would result in net adjustments of approximately $290 million of additional taxes…" Clearly, the issue continues to be of interest to the IRS.

There is no information in the public record as to whether any taxpayers have concluded advance pricing agreements (APAs) with the IRS in relation to BBC transactions.

Transfer pricing methods

a) Primary

A traditional method used to price BBCs involves using publicly available results for third-party service providers engaged in similar technical services as those performed by the related-party operating company.

Typically, to determine the BBC amount, a mark-up on costs is derived from third-party service providers and applied to the uncontrolled costs of the operating company. The difference between the third-party revenue and the marked-up uncontrolled costs is taken as the BBC payment.

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The term "uncontrolled" used above is deliberate as it is well established practice that controlled expenses are not part of the cost base. While US transfer pricing regulations do not specifically explain this idea, the OECD guidelines express it as follows:

> *"The denominator should be reasonably independent from controlled transactions, otherwise there would be no objective starting point. For instance, when analyzing a transaction consisting in the purchase of goods by a distributor from an associated enterprise for resale to independent customers, one could not weight the net profit indicator against the cost of goods sold because these costs are the controlled costs for which consistency with the arm's length principle is being tested. Similarly, for a controlled transaction consisting in the provision of services to an associated enterprise, one could not weight the net profit indicator against the revenue from the sale of services because these are the controlled sales for which consistency with the arm's length principle is being tested."*

Furthermore, the IRS's "APA Study Guide" states that:

> *"For technical reasons, the denominator in the PLI's definition generally should be an item that does not reflect controlled transactions. Thus, the operating margin and gross*

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Joe has extensive experience auditing transfer pricing issues involving profit split methods, IP migrations, cost-sharing arrangements, high-value services, offshore procurement, asset leasing, and other issues related to business restructurings. During his time with the IRS, he worked on large oil and gas and technology sector multinationals in the US, and he successfully argued and resolved cases at the field examination, IRS appeals, and APA programme levels. Joe also completed expert witness training at the IRS, and he understands the strategic relationships between the audit and litigation process.

> *margin PLIs (which have sales in the denominator) generally are used for tested parties (often distributors) that* ***sell to unrelated parties****, while the markup on costs PLIs (which have total costs or cost of goods sold in the denominator) generally are used for tested parties (often manufacturers) that* ***buy from unrelated parties****."*

One point that historically has been an area of contention in these transactions when under audit is the argument that different third-party comparable companies should have been used by the taxpayer to determine appropriate profit to the operating company.

The taxpayer's practice of using third-party service providers who do not own significant tangible assets stems from the fact that the operating companies in those cases do not own significant tangible assets, because the significant tangible assets of the consolidated group (the rigs themselves) are owned by the related-party rig owners. That is why the arm's-length profitability of the related-party operating companies is normally benchmarked by observing the returns of technical service providers in the marketplace who likewise do not own significant tangible assets.

In practice, there have been instances in which third-party companies that own significant tangible assets have been used to corroborate the results of applying third-party service provider mark-ups to the operating company costs. However, in those instances so-called "asset intensity" adjustments were applied to the third-party companies to control for the fact that the related-party operating company did not own significant assets, and under economic theory it would earn a different return than companies with significant assets on their balance sheets. Typically, when such asset intensity adjustments were properly applied to these types of third-party companies, the results corroborated the analysis done using the (non-asset-owning) third-party service providers.

b) Secondary

Secondary methods for pricing BBCs include using third-party asset owner results to benchmark the profitability of the related-party rig owners, use of a profit split method, and the economic return model.

When using third-party asset owner results to benchmark the profitability of related-party rig owners, practitioners have generally taken two approaches – use of third-party asset leasing companies outside the O&G industry or use of consolidated drilling companies.

Using companies outside the O&G industry may give rise to a potential problem in that their return on assets may not mirror that in the O&G industry, and their performance may not be related to the price of oil. Given the fact that the annual return of the rig owner's assets in the marketplace (namely, the drilling rigs) are closely related to the price of oil, comparability issues may surface that must be addressed when using such an approach.

Likewise, using other third-party consolidated drilling company results to benchmark the profitability of the related-party rig owner is problematic, because each company may have a very different mixture of drilling assets, and the value of the drilling assets may vary dramatically depending on the particular classes of the assets. Thus, the specifications of the rig (for example, drillship versus jack-up) typically drive the day-rate and have a direct impact on revenue and profit potential. As a result, it may be very difficult to justify a particular rig owner's profitability using the results of consolidated third-party drilling companies.

Another method for pricing BBCs is the profit split method. The two applications of the profit split method specified in the US transfer pricing regulations include the comparable profit split method and the residual profit split method. The comparable profit split method, in theory, relies on comparable third-party profit splits between drilling rig BBC participants; however, in practice this kind of data is virtually nonexistent. Therefore, in practice the residual profit split method is more practical, though it still remains a method that traditionally has not been employed.

The residual profit split method uses the "system profit" (the sum of the rig operator's and rig owner's profits), and first allocates some of that profit to "routine contributions." The US transfer pricing regulations define routine contributions as "contributions of the same or a similar kind to those made by uncontrolled taxpayers involved in similar business activities for which it is possible to identify market returns. Routine contributions ordinarily include contributions of tangible property, services and intangibles that are generally owned by uncontrolled taxpayers engaged in similar activities." The amount of system profit that is left after the allocation of income to routine contributions is defined as residual profit. The residual profit "generally should be divided among the controlled taxpayers based upon the relative value of their contributions of intangible property to the relevant business activity that was not accounted for as a routine contribution."

The basis whereby the residual profit should be allocated to the parties (for instance, capitalised cost, fair market value, etcetera) remains a topic of vigorous debate. Moreover, offshore drilling firms typically may not own valuable intangible property on which to base a traditional application of the residual profit split method. However, the IRS in some cases may argue that the operating companies own valuable marketing and know-how intangibles. Because these types of intangibles are not generally reflected on the operating company balance sheet, the IRS's task in quantifying and valuing them appears particularly onerous.

The economic return model is another method that may be used to price BBCs. The model derives BBC payments as a function of a number of factors that impact the cash flow of the asset owner eventually benchmarking the rate of return to the asset owner. One of the benefits of this method is consistency, because it charges all affiliates the same BBC rate for the same vessel. In addition, because the operator bears certain risks under this method, it may earn additional income that satisfies local tax authorities. On the other hand, it may not properly reflect higher lease rates during periods of strong demand.

c) Considerations in selecting transfer pricing method

The primary consideration when selecting a transfer pricing method is the types of data available to the analyst. BBC transactions of drilling rigs between unrelated parties are extremely rare, and the prices may not be publicly available. In addition, because such transactions are rare they may not be made in ordinary circumstances, and therefore may not satisfy the comparability standards of the US transfer pricing regulations. As a result, the comparable uncontrolled price method and the comparable profit split method are generally not applicable.

Financial statements for the rig owners and rig operators will generally be available, but there may be issues with respect to segmentation of those financial statements in relation to the related-party transactions under review. However, the financial statements generally will allow for application of the comparable profits method. Two key issues with respect to application of the comparable profits method are the selection of the tested party (the rig operator or the rig owner) and the selection of comparable third-party companies.

With respect to the question of which related party should be the "tested party," the regulations state,

> *"…the tested party will be the participant in the controlled transaction whose operating profit attributable to the controlled transactions can be verified using the most reliable data and requiring the fewest and most reliable adjustments, and for which reliable data regarding uncontrolled comparables can be located. Consequently, in most cases the tested party will be the least complex of the controlled taxpayers and will not own valuable intangible property or unique assets that distinguish it from potential uncontrolled comparables."*

The rig owners possess an asset that by all accounts is specialised and unique, and it is not generally believed that there are publicly available third-party companies that possess solely comparable assets or assume comparable risks. Therefore, traditionally the rig owner is not selected as the tested party when applying the comparable profits method to BBC transactions.

There is, however, an ample amount of publicly available data on the rates of return earned by third-party technical service providers. While the nature of the technical services rendered by the third parties may not be identical to those rendered by the related party, the level of comparability between third-party service providers and the rig operator is believed to be much greater than the level of comparability between third-party asset owners and the rig owner (due to the unique nature of the drilling asset).

The best transfer pricing method also depends on the intercompany arrangement as structured by the taxpayer. For example, through intercompany BBC agreements, a taxpayer may explicitly shift price risk to the rig owner entity, thereby insulating the rig operator from fluctuations in day rates due to fluctuations in the price of oil. As a result, the rig operator may be relieved from both capital and price risk, and therefore its arm's-length return may not be related to companies operating in the O&G industry. Consequently, selection of the transfer pricing method and its application should appropriately reflect such facts.

Conclusion

The BBC represents one of the most substantial transfer pricing issues facing the offshore drilling industry today and there are several approaches to pricing BBCs in the offshore oil and gas industry. Taxpayers often taken the traditional approach outlined above, which while being accepted by multiple tax jurisdictions, remains under some scrutiny.

All transfer pricing analysis should be based on the facts and circumstances of the particular taxpayer being considered. However, there are a host of non-transfer-pricing considerations that should also be addressed by taxpayers when structuring BBC arrangements, and taxpayers should consult with their legal, international tax, and transfer pricing advisors as tax authorities will likely continue to demonstrate great interest in this issue.

Primer on liquefied natural gas transfer pricing

Samuel Fletcher, Randy Price and Vitaliy Voytovych provide an overview of the value chain, common methodologies and considerations involved in transfer pricing for liquefied natural gas-related companies.

Recent developments in the US natural gas market, namely the surge of unconventional (shale) gas development projects, have resulted in an unprecedented market shift as a market once primed for natural gas import now explores exporting significant volumes of natural gas. In light of these developments, many players in the natural gas space have sought opportunities to capitalize on market dynamics and take advantage of the large price differential between the Asian and US natural gas markets. Due to the complexity of the natural gas value chain and number of participants, such export opportunities may present various transfer pricing implications.

In the sections below, we describe the functions provided, risks borne and assets contributed by common participants of the liquefied natural gas (LNG) value chain. This is followed by a brief commentary on the "acting in concert" principle and an overview of common transfer pricing methodologies employed in the natural gas industry. Lastly, we provide some transfer pricing considerations that should be monitored as market participants shift from import facilities to export or bi-directional facilities.

Functions, risks and assets in the LNG value chain

In general, when evaluating complex supply chains from a transfer pricing perspective, it is important to examine the functions performed, risks assumed and assets contributed by each participant to i) properly perform comparability analysis and ii) determine the economically significant contributors to the value chain (as such contributors generally attract a higher return). Specifically, we have outlined some of the common functions of LNG value chain participants below.

Exploration and production (E&P) – upstream

E&P functions generally include activities related to the identification, extraction, and production of hydrocarbons. The E&P function is often responsible for obtaining appropriate permitting, undertaking geological/geophysical studies and well testing, constructing the (on/off-shore) assets as well as obtaining appropriate production licenses, among other activities. Depending on the structure of the value chain, the E&P function may also perform entrepreneurial/marketing activities such as entering into long-term supply agreements.

As contributor of the hydrocarbon and production assets to the value chain, the E&P function also undertakes a number or risks, specifically environmental and regulatory risk, risks related to equipment failure and mechanical downtime, risks associated with large fixed costs and hydrocarbon yield risk.

Liquefaction – midstream

The liquefaction function relates to activities required to cool the hydrocarbons into a liquid state, which can either occur onshore, at a liquefaction facility, or off-shore on a floating LNG (FLNG) vessel. Before compression and cooling, the facility also processes the natural gas to remove impurities and other natural gas liquids. Capital required for a liquefaction facility or vessel is substantial and thus, similar to E&P, the liquefaction function is burdened by risks that include equipment and mechanical malfunctions/downtime as well as those risks associated with large fixed costs.

Shipping/storage – midstream

The shipping/storage function relates to activities that include pre-liquefaction gathering activities and pipeline transportation of the natural gas as well as the transportation of LNG aboard an LNG tanker (post-liquefaction) and or natural gas pipeline. Capital required for a liquefaction facility or vessel is substantial and thus, similar to an E&P and a liquefaction facility, the shipping/storage function is burdened by risks that include equipment and mechanical malfunctions/downtime as well as those risks associated with large fixed costs.

Regasification – midstream

After the LNG has arrived at its destination and been offloaded from the vessel and stored, the LNG is re-gasified. Capital required for a regasification facility is substantial and thus, this function is burdened by risks that include equipment and mechanical malfunctions/downtime as well as those risks associated with large fixed costs.

Marketing/trading – midstream

The marketing/trading function is responsible for selling the LNG to the end market through the identification of long term sales contract opportunities as well as opportunities to sell natural gas in spot contracts and futures/forward contracts. This function may also participate in portfolio or cargo hedging and is typically responsible for administrative activities related to the long term sales contracts as well as scheduling/logistics when required. The marketing/trading function contributes assets in the form of a working capital and margin account as well as portfolio capability.

As a marketer/trader, risks are borne such as losses from poorly executed arbitrage and hedge trades, speculative trading losses, and/or misaligned contractual clauses (for example, force majeure).

The marketing/trading function typically is the most scrutinised along the value chain as it has the ability to function as a routine service provider (for example, engaging in execution-only trading, general risk management and middle/back office activities) or in an entrepreneurial role should it engage in more complex trading/hedging strategies, actively manages and places its capital at risk. In a similar manner, determining the segment where the marketing/trading function lies within the LNG value chain is difficult due to its dependency on the value chain's specific organisational/operating structure as well as functions performed/risks borne. For purposes of this article, we have noted the function's participation in the midstream segment of the value chain, however, it is possible the function can be present in each segment of the value stream (upstream, midstream or downstream).

Transmission – downstream

Transmission activities include the transportation of natural gas (after it is regasified) to end consumers (industrial or retail) through a pipeline distribution network. Capital required for a transmission network is substantial and thus, the transmission function is burdened by risks that include equipment and mechanical malfunctions/downtime as well as those risks associated with large fixed costs.

Additional general risks in the natural gas industry

Technology risk

Compared to the more established oil & gas (O&G) industry, the LNG industry is evolving. Thus, newer technologies such as Floating LNG (FLNG) are unproven and therefore impose a risk factor that may require adjustment when computing the required return.

Sovereign risk/geo-political risk

Natural resource projects are often governed by government policy, which has the ability to impact the profitability of the project. This risk is especially relevant for a number of planned export facilities in the US LNG market awaiting final approval. Although these projects have secured long-term supply commitments, the ultimate deployment and economic impact of the project remains obscure until officially sanctioned by the relevant governing bodies.

Further, natural gas resources in geographies with more political instability, are more susceptible to sabotage and may require additional resources dedicated to security.

Traditional methods for attempting to capture country risks are well understood in finance academia, practice and theory. In contrast to many types of country risks, geopolitical risk is difficult to measure as it may result in a binary effect, where the risk matures and the company faces the possibility of being unable to supply hydrocarbons due to complete political unrest or instability.

The functional and risk analysis forms the basis for the selection and application of transfer pricing method(s) when determining an arm's-length price for dealings between related parties.

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Sam has also consulted on cross-border supply chain transfer pricing for clients in the recreational vehicle and software industries.

Common control and "acting in concert"

Due to the sheer volume of investment required to construct and operate the different components along the LNG value chain, it is common that participants embrace similar ownership structures. While investors in the LNG value chain may be unrelated, it is important to consider the transfer pricing regulations promulgated under US Treas. Reg. Sec. 1.482 (§482 Regulations) which apply to transactions that occur between "controlled" parties or a "controlled" group, to determine if a transfer pricing issue exists.

Transfer pricing issues hinge on the facts and circumstances relating to the relationships between the parties and the control of the LNG value chain. The §482 Regulations, however, construe the definition of control broadly and rather subjectively; as per the §482 Regulations, "controlled" is defined as:

> "Any kind of control, direct or indirect, whether legally enforceable or not, and however exercisable or exercised, including control resulting from the actions of two or more taxpayers acting in concert or with a common goal or purpose. It is the reality of the control that is decisive, not its form or the mode of its exercise. A presumption of control arises if income or deductions have been arbitrarily shifted."

Thus, while the terms governing the overall LNG value chain might be extensively negotiated between the parties in an arm's-length manner, they may be considered controlled parties for purposes of the §482 Regulations. In our experience, US-based joint venture partners in this industry often decide to apply the §482 Regulations to their transactions to proactively address the treatment of said transactions.

Common transfer pricing methodologies to determine remuneration along the LNG value chain

It is important to note that LNG value chain economics and strategies are very dynamic. However, based on our collective O&G industry experience, we have seen the following transfer pricing models generally applied to the operations present in the LNG value chain:

Comparable uncontrolled price methodology

The comparable uncontrolled price (CUP) methodology is commonly used within the LNG industry using pricing from quotation media that is widely and routinely used by uncontrolled buyers and sellers in the commodities markets worldwide to negotiate prices.

Pricing from the following quotation media is often used in negotiations:

- British National Balancing Point (**NBP**) Index: The NBP is a virtual trading location for the exchange of natural gas in the United Kingdom (UK). It is the most liquid natural gas trading point in Europe and is commonly used in LNG purchase and supply agreements worldwide as a contractual pricing index.

  NBP prices best represent the European market price for natural gas and are considered close to end users. Belgium's *Zeebrugge* and the Netherland's Title Transfer Facility (**TTF**) gas hubs are closely linked to movements in the NBP, as are global pricing movements.

  The NBP is also the pricing point for the Intercontinental Exchange (**ICE**) natural gas futures contract. ICE is a leading operator of regulated futures exchanges and during 2009 over 2.5 million natural gas futures trades were made through ICE.

  Though the index is commonly used by traders for financial hedging purposes, physical trading contracts are for delivery of natural gas in the UK. Traders exchange a variety of contracts, including day ahead contracts and monthly futures contracts. When traders reach a consensus regarding a future commodity price, pricing data is created that may be used by other market participants to price their own (physical) purchases and sales of commodities.

  Thus, the price quotations generated by the NBP represent the collective current view of the marketplace (i.e. the indirect evidence) of where prices will be set.

Overall, application of the CUP methodology often has many advantages, including its wide acceptance and common application in OECD member countries as well as its ease of implementation. Specifically, such an approach is directly addressed in the §482 Regulations (§1.482-3(b)(5)) as well as proposed in the recently released OECD Discussion Draft on the Transfer Pricing Aspects of Cross-Border Commodity Transactions (proposed for insertion after paragraph 2.16).

However, it should be noted that application of the CUP methodology to LNG transactions has some limitations as it is likely that adjustments may need to be made for differences in terms and conditions (for example, duration, contract date, shipping terms, destination, etcetera).

Residual pricing methodology

The residual profit split methodology determines the remuneration due to the entrepreneurs by first determining appropriate returns for each of the members of the LNG value chain. Routine LNG value chain activities (such as transport, logistics, trading) are given benchmark returns for their activities based on the financial data of public companies that engage in similar routine activities. Thus, the routine entities are remunerated according to their limited risks and functions.

The residual profits (or losses) are then split between the entrepreneurs within the system based on share of relative capital or some other appropriate measure.

Profit split methodologies are accepted by OECD member countries and in fact often the outcome of bilateral negotiations between tax authorities (for example, advance pricing agreements) and are emphasised in recent OECD guidance. Taxpayers have implemented this methodology to compensate different members of their supply chain in the natural gas value chain. However, the split of residual profits can be controversial and may cause dispute amongst participating nations' tax regimes or may result in a case of double taxation. This may also prove a more difficult method to administer in cases where a fixed split is levied by a specific jurisdiction (for example, Australia) and would need further consideration.

Net-back pricing model

Another pricing model used within the industry is the net-back pricing model, which employs a number of US/OECD specified methods at the same time in order to determine intercompany pricing for each function of the value chain.

Under the net-back pricing method, a net-back price (ultimate sales price used for the natural gas entrepreneur(s)) to be used between controlled taxpayers is determined by identifying the prevailing gas prices in the market destination (such asEurope, Asia, or other location) and deducting costs and profits related to the different routine natural gas supply chain activities (liquefaction, transport, regasification, logistics, trading, etcetera). Application of this methodology involves the following steps:

- **Identification of natural gas price at market destination** – The first step (final sales price) is determined through the identification of either i) direct evidence of a CUP (for example, contract sales price with or between an uncontrolled taxpayer(s)) or ii) indirect evidence of a comparable uncontrolled price derived from data from public exchanges or quotation media.
- **Remuneration for routine natural gas value chain contributions** – The second step allocates operating income to each controlled party to the controlled transactions within the value chain to provide a market return for routine contributions. Routine contributions are contributions of the same or a similar kind to those made by uncontrolled taxpayers involved in similar business activities for which it is possible to identify market returns. Routine contributions ordinarily include contributions of tangible property, services and intangible property that are generally owned by uncontrolled taxpayers engaged in similar activities. Market returns for the routine contributions should be determined by reference to the returns achieved by uncontrolled taxpayers engaged in similar activities and may be remunerated in the form of a return on costs, return on assets or other reasonable measure. Typically this analysis is performed through

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the application of the Comparable Profits Method/ Transactional Net Margin Method (CPM/TNMM).

- **Allocation of residual profit for non-routine contributions to natural gas value chain entrepreneur(s)** – A non-routine contribution is a contribution that is not accounted for as a routine contribution. Thus, in cases where such non-routine contributions are present, there normally will be an unallocated residual profit after making the remuneration for routine functions within the natural gas value chain. The residual profit should be allocated to or divided among the principal company/entrepreneur(s) based upon the relative value of their non-routine contributions to the value chain. This can be demonstrated through evidence of the entrepreneur(s) undertaking key decisions, providing intellectual property or bearing risks commensurate with the returns.

Local tax authorities are likely to respect the structure if the markups for each function are consistent with the arm's-length principle and the principal company/entrepreneur has proper substance. Further, the net-back pricing methodology promotes transparency as all intercompany/related party pricing is a net-back off of a market driven price.

Current environment and additional considerations

In light of the North American renaissance in the production of natural gas from US shale resources, investors have seen first-hand how the natural gas market dynamics can change rapidly (and significantly) in terms of supply/demand, price volatility and economic winners and losers. A US LNG import and regasification industry that had recently invested billions of dollars has been forced into a paradigm shift within just a few years as many market participants have begun exploring opportunities to retrofit an existing import facility (brownfield) to accommodate exports.

Brownfield development projects provide a number of advantages over their greenfield development counterparts. Many brownfield projects already have a site selected and received necessary environmental and regulatory approvals (for example, maritime transport permits, Department of Energy (DOE) and Federal Energy Regulatory Commission (FERC) approvals), which reduces schedule risk as both the regulatory approval process and time to completion can be accelerated. Further, existing brownfield facilities provide some element of cost savings as more than 50% of the assets used for the import facility can be used in the liquefaction process (for example, storage tanks, pipeline transportation, etcetera) and allow for bi-directional optionality should market dynamics change.

While the advantages of a brownfield development appear clear on a macro-level, participants in such developments should remain cognizant of transfer pricing issues that may be present. In cases where changes in ownership structure are made (for example, an import partner is not interested in the export opportunity and would like to divest import interest) or operating rights are transferred between legal entities, a transfer pricing issue may exist in the valuation of the ownership interest and/or transfer of rights. This is likely to result in a complex economic analysis with considerations such as the present value of "unlocking" the export opportunity, costs of unwinding existing tolling arrangements, value of existing FERC and DOE permits and the value of progress in the FERC and DOE approvals queue (schedule risk). Such issues should be monitored as the taxation of US export structures is likely to garner more scrutiny from the IRS as more projects reach final investment decision and come on-line.

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The new black gold: Transfer pricing of intangibles in the oil and gas sector

John Wells, Vitaliy Voytovych, and Firas Zebian explain why intangible assets in the oil and gas industry have become so valuable and how taxpayers can manage transfer pricing compliance of intangible assets to mitigate their transfer pricing risks.

What do recent Western economic sanctions against Russia; the US' growing energy independence; and ultra-deepwater oil and gas (O&G) discoveries off the coast of Brazil and in the Gulf of Mexico have in common? Each of these events is driven by technological advancements in the O&G sector.

Innovations in the use of horizontal drilling, hydraulic fracturing, and seismic imaging in US shale formations have allowed US oil production to climb from less than 5 million barrels per day (BPD) in 2005 to over 8 million BEP in 2014. Similarly, US natural gas production has increased to almost 12 million BPD (converted from cubic feet to barrels of oil equivalent) over this same period. While this shale boom has yet to take hold internationally, countries such as Russia are dependent on Western equipment and technology to develop their new energy frontiers, in particular shale opportunities in Siberia. This makes the Western sanctions which were imposed on Russia because of actions in Ukraine especially restrictive for Russia's declining O&G production, because they prohibit the export of such technology.

Western O&G expertise and seismic imaging technology have also allowed exploration and production (E&P) companies to discover and produce hydrocarbons from deeply buried reservoirs far offshore. Other technologies in the O&G sector have helped create kit suitable for high-pressure/high-temperature deepwater environments, remote/automated drilling operations, and enhanced oil recovery from mature oil fields. New processes and down-hole measurement tools are mitigating the risk of a loss of well control, such as that which preceded the Macondo disaster and the Gulf oil spill in 2010.

Indeed, the O&G sector is replete with technology and other forms of intangible property (IP) that allow participants to access hydrocarbons from increasingly difficult environments, and more safely than ever. A stylised fact of this industry is that the research and development (R&D) expenditures that give rise to O&G IP are fairly small relative to sales, specifically when compared to R&D/sales ratios found in high-tech and pharmaceutical industries. R&D expense for "supermajor" E&P companies (the largest of the independent oil companies, or IOCs) and the largest oilfield services (OFS) providers are displayed in Table 1. Note that the supermajors have a smaller R&D/sales ratio than the OFS providers, but still spend more on R&D in absolute terms. Also, note that R&D for the whole upstream sector has increased between 2012 and 2013, a trend that has been relatively constant since 2008.

Table 1

		2013 (USD in million)			2012 (USD in million)		
		R&D Expense	**Revenue**	**R&D/Sales**	**R&D Expense**	**Revenue**	**R&D / Sales**
Supermajors	E&P Company A[1]	1,318	451,235	0.29%	1,307	467,153	0.28%
	E&P Company B	1,044	420,836	0.25%	1,042	451,509	0.23%
	E&P Company C	707	379,136	0.19%	674	375,765	0.18%
	E&P Company D	1,244	225,086	0.55%	1,103	249,855	0.44%
	E&P Company E	750	220,156	0.34%	627	230,590	0.27%
	E&P Company F	258	54,413	0.47%	221	57,967	0.38%
Service Providers	OFS Company A	1,174	45,266	2.59%	1,153	41,731	2.76%
	OFS Company B	588	29,402	2.00%	460	28,503	1.61%
	OFS Company C	556	22,364	2.49%	497	21,361	2.33%
	OFS Company D	265	15,263	1.74%	257	15,215	1.69%
	OFS Company E	83	9,838	0.84%	63	8,502	0.74%
	OFS Company F	112	7,126	1.58%	117	6,151	1.90%

[1] *Sourced from company Forms 10-k. Deloitte Tax LLP internal policies do not allow the use of company names without prior authorisation. The above table summarises the major players in the E&P and OFS segments.*

O&G companies must deploy the IP generated by this R&D across the globe so that it can be used by their local operating companies. Transfer pricing and tax regulations dictate that where there are cross border transfers of IP, appropriate compensation must be paid to the IP owner. But while transfer pricing methods for IP transactions are well developed for most industries, applying such methods in the upstream O&G sector can be complex. Intangibles used by E&P companies have often been developed in tandem with petroleum engineers and geoscientists at major universities, industry consortia, and oilfield services firms. These non-proprietary assets are typically shared freely with joint venture partners and national oil companies (NOCs) in the quest for hydrocarbons, most often on a royalty-free basis. Due to this ambiguity of ownership and the openness by the industry to share know-how, leading practices, and technology, allocating a price to this IP may remain convoluted.

Further complicating intercompany IP valuations is the fact that there are so many different services, processes, and IP coming together at the well site to produce hydrocarbons. Few of these assets and activities are significant on a stand-alone basis; it is therefore difficult to value their separate contributions. In other industries, a royalty payment for the value of the IP would be paid to appropriately compensate the IP owner; in the upstream O&G sector, bifurcating the revenue stream from the sale of the resulting hydrocarbon between the amount resulting for the use of the IP (be it a tool, technique, process, or patent) and that associated with more routine contributions is difficult because of the convolution of IP and activities at the wellhead.

The transfer pricing regimes promulgated across the globe accommodate a range of approaches for dealing with these issues. Depending on the characterisation of the transaction, a taxpayer can elect to classify these intercompany transactions as a complex engineering service or a service bundled with IP. In practice, E&P and OFS companies have addressed these issues differently.

E&P companies' approach to IP transfer pricing

In general, E&P companies employ one of two basic transfer pricing mechanisms to allow for the development and use of IP.

Global IP ownership model

A number of E&P companies, including some of the supermajors, engage in expansive, multiparty cost sharing arrangements (CSAs) whereby all operating entities share the cost of IP development and are allowed the use of the resulting IP on a royalty-free basis. In many cases, such arrangements have been in place for several decades and effectively turn each participant into a co-owner of the intangibles being developed.

Two characteristics of a global ownership model make this approach appealing to E&P companies. First and foremost, it eliminates the need for a royalty, because every legal entity is the economic owner of its share of the IP. This allows these companies to avoid the contentious issue of how to bifurcate the hydrocarbon revenue at the well site and calculate royalties on the portion attributable to IP. A second advantage of the global ownership approach is that it allows companies to avoid a markup on intercompany charges for engineering, geological, and geophysical services, as these services can be viewed as part of the intangible development costs covered by the CSA. This is no small accomplishment, given that some tax authorities have taken the position that such intercompany services should command a high markup, yet the joint venture partners and NOCs that have to pay a share of these costs are reluctant to pay the markups.

There are some downsides to the global ownership model: it forces E&P companies to calculate complicated valuation analyses as legal entities enter or exit the CSA, and the structure itself may be more tax inefficient than having a principal company own all the IP to be used offshore.

Central IP ownership model

Other E&P companies eschew the administrative structure of a CSA and allow IP to be developed and owned in one or a few R&D locations where such development naturally occurs. They may charge their operating affiliates for the R&D performed on their behalf at cost or cost plus a small markup, but no effort is made to collect royalties on the use of any resulting IP and such arrangements are not codified in a formal CSA. Those models may not produce tax efficiencies and are most prone to being criticised by the tax authorities, because IP ownership and use is difficult to ascertain and open to dispute. From an administrative standpoint, however, such arrangements are quite elegant. Arguments supporting this approach rely on the fact that much of the IP in use by E&P companies is in the public domain and developed jointly with universities, upstream partners, and oilfield services companies, and are not otherwise compensable.

Some E&P companies using this model have a "natural hedge" against tax authority adjustments in that they centralise IP ownership in two locations, each of which uses the other's IP. A tax authority's attempt to impose a transfer pricing adjustment on one of the entities by asserting royalties for the implicit IP license could be forced to consider the corresponding inbound royalty payment for what amounts to very similar IP.

In addition to the above two IP transfer pricing models, a number of E&P industry participants have historically maintained that the nature of the industry does not allow for any type of meaningful transfer pricing management of IP, and have argued against intercompany charges for intangibles.

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Before joining Deloitte, Wells was the lead economist for the global energy and natural resources sector of another Big 4 firm, and an economic adviser to the Kuwait Government. Wells also spent four years on the faculty of Auburn University, where he taught Ph.D.-level courses in time-series analysis, macroeconomics and international finance.

OFS companies' approach to IP transfer pricing

E&P companies outsource most of the heavy lifting around exploring, developing, and producing O&G to OFS companies. OFS companies also undertake a significant portion of the IP development in the industry. IP in the oilfield services business lies in the industry's ability to provide engineering services consistently across different reservoirs (deepwater, unconventional plays such as shale or coal bed methane, and mature), geologies (sandstone, carbonates, shale, coal beds) and geographies (onshore, offshore, North & South America, Europe, Asia, West Africa, the Middle East) while satisfying stringent health, safety, and environmental regulations, decreasing nonproductive time, reducing delivery and service costs, and meeting the demanding requirements of NOCs and IOCs. From a transfer pricing perspective, the OFS industry IP is viewed to be a combination of:

- Technologies that provide the science behind building the tools used in providing services;
- Local engineering knowledge, field know-how, and processes that allow for the adaptation of the tools to provide consistent services under differing conditions across differing geologies and well requirements; and
- Business development knowledge that creates marketing intangibles (trademarks, trade names, reputational integri-

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ty), develops customer relationships, provides customer satisfaction, and drives sales and customer contracts.

Technology intangibles

Technology in this industry is delivered to the client via the tools and systems that companies use in the provision of their services. Technology normally is a qualifying factor that allows a company to bid for services, as opposed to a clear-cut differentiating factor. Services contracts usually specify particular technologies needed for a given job. An OFS company that does not have the specified technologies in its repertoire would be disqualified from bidding on the contract.

The large companies operating in the oilfield industry own very similar technology portfolios. IOCs and NOCs, the customers of the oilfield services industry, have a vested interest in maintaining the competitive balance within the industry. It is common for IOCs and NOCs to diversify suppliers as well as related technology to avoid sole-sourced technology. That is one of the motivations for the consortia between E&P companies and oilfield services companies and research universities discussed above.

Technology within this industry is normally centrally designed, developed, and managed. Hence, most OFS companies employ a central IP ownership model. Even when mergers and acquisitions lead to technologies changing hands, the acquired technologies are typically also centrally owned and developed. This approach to IP development and maintenance has historically meant that most local affiliates of OFS companies pay a royalty to the technology IP owner(s).

The centralised and specific nature of the technology IP also allows OFS companies to share the risk and costs of IP developments through CSA arrangements.

Processes and local know-how

Processes and local know-how in this industry directly affect service quality and are the means by which a company's technology is provided to the customer. Processes and people have been so important in OFS after the Macondo incident that an OFS provider's process, safety, reliability, repeatability, and people have come to be viewed as more important than technology. NOCs and IOCs require consistency in service delivery, which allows them to better control their costs and enhance their production plans.

As a matter of practice, processes in the OFS industry are developed based on the experiences gained and lessons learned by engineers and field personnel operating in the various geologies and on different well sites across the globe. Such processes and standards are usually maintained in centrally controlled databases or knowledge sharing platforms.

Consequently, processes and know-how IP are developed across all jurisdictions and in some cases are jurisdiction-specific. As a matter of practice, it would be difficult to track and charge for contributions of specific affiliates to a company's combined depository of processes and know-how. However, the part of this IP that is thought to be attached to and accompanying the technology IP is normally charged through the same royalty mechanism as technology IP.

Marketing

Marketing IP in the oilfield services industry relates to trademarks, trade names, strategic customer relationships, and value-add business development activities.

Trademarks and trade names do matter, but are not a big value driver in the oilfield services industry. The discussion about the importance of consistent service quality, tender qualification processes, service provider diversification by clients, and importance of local on-the-field personnel to the oilfield services business makes it clear that trade names and trademarks do not provide a large competitive advantage.

The marketing value drivers in the OFS industry are usually the business development organisations driving sales and creating customer relationships.

The importance of business development organisations relates to the fact that sales in this industry are highly technical, so a sales person must have specific knowledge of the types of physics a tool or service uses, and the geology in which it is employed. This makes it difficult for someone outside this discipline to be an effective salesperson.

Similar to the processes and know-how IP, marketing intangibles are often locally developed and managed, with some component of central supervision due to organisational reporting lines and centralised management of major accounts. It would be difficult to track and charge for contributions of specific affiliates to the marketing IP, especially given that most of the benefit associated with this type of intangible is realised at the local country – or even the local field – level.

Conclusion

Global politics has often played an important role in natural resource policies. Recent technological advancements in the O&G sector will make sure that this continues to be the case. As IP becomes increasingly important to the success of O&G exploration, development, and production activities, market participants will find it necessary to develop cogent IP management policies to mitigate their transfer pricing risks.

Australian CSG to LNG: A shift from construction to export and beyond

John Bland, Emily Falcke, and Geoffrey Cann, of **Deloitte Australia**, explain how the liquefied natural gas production scene is changing in Australia and what these changes mean for a company's transfer pricing and international tax operations.

Commencing in late 2014 and continuing through 2015, the three liquefied natural gas (LNG) plants in Gladstone, on Australia's east coast, began the production and export of LNG to markets in Asia and around the globe. These are the first operational coal seam gas (CSG) to LNG projects anywhere in the world. Australia now has four operating LNG projects and a further six are under construction (both CSG-sourced and conventional), with an estimated AUD 200 billion ($147 billion) worth of investment in the Australian LNG sector. Australia is already the world's third largest exporter of LNG, and when all projects are on-line Australia is likely to become the world's largest LNG exporter.

The transition from construction to production may cause major changes in the operations of Australian LNG producers as they move from focusing on construction issues, budget overruns, and delayed deadlines to the business of extraction, processing, maintenance, and supply chain management.

Given that the vast majority of the capital invested has been foreign sourced, and that Australian LNG projects generally rely on the involvement of foreign-owned participants, what are some of the immediate and future issues for this industry from a transfer pricing perspective?

Under construction

Over the past few years, the primary focus of the onshore LNG projects in Australia has been the drilling of thousands of wells and the construction of aggregation assets, transport pipelines, LNG processing plants, and related infrastructure. At the same time, the operators' global focus has been on formalising customer sales contracts and ensuring that downstream assets are well positioned.

Unlike some other countries, Australia did not have any existing infrastructure such as pipeline or processing assets that could be repurposed into gas projects. Thus, the Australian projects have required construction from the ground up. All of this has involved significant construction of plant, labour, and capital. The operators have been placed under increasing pressure as completion deadlines have passed, budgets have run over by billions of dollars, and oil prices has fallen.

One area of focus has been the sourcing of long-term financing for projects with long lead times in actual revenue, and potentially profits. Depending on the scale of the project, financing needs may range between AUD 3 billion and AUD 25 billion. A large amount of the funding is sourced from related parties of the joint venture partners or, due to the substantial capital required, via syndicated loans.

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John's recent and current engagements include, but are not limited to, leading the first Australian onshore CSG advance pricing arrangement (APA) project (currently underway), assisting clients in their development of appropriate tax-effective transfer pricing structures for high risk global mining exploration and development activities, including foreign gas exploration and development activities managed from Australia, and advising on the development of pricing models to support the arm's-length pricing for upstream and midstream funding transactions into major Australian CSG projects.

Setting the terms of this financing and the associated pricing can be different from a typical loan arrangement. For example, interest deferrals may be built into the agreements to try to match eventual interest payments to actual revenue streams. Credit rating processes may become complex procedures that use various forecasting and pricing models to determine the project's risk profile across the life of the facility and the projects' different lifecycle stages. Using simple credit rating tools, or relying only on historical audited financial information, could provide anomalous results, which would in turn result in poor credit rating estimates for the facility. However, a review of the project's forecasts over the life of the facility may show that risk profiles fluctuate depending on the project status. Similarly, some ratios may become less important; for example, interest cover in years when interest is deferred. The transfer pricing challenges associated with these financing arrangements can be considerable, and the Australian Taxation Office (ATO) has been actively undertaking reviews.

Because the east coast onshore projects are considered unconventional (the gas is sourced from trapped reserves in coal seams), there has also been a significant investment by both the project participants and the associated service providers on the sourcing of people and expertise applicable to the specific requirements of extracting CSG. Large numbers of people with experience in the oil & gas industry globally have been brought to Australia to apply and develop their knowledge in a CSG context. Similarly, processes, production designs, and other intangibles have been brought to the country and in some cases redesigned to meet the requirements of the Australian landscape and the pure methane content of CSG-based LNG produced by the east coast projects.

Project overruns and cash deficits may cause project stakeholders to try to improve their supply chain, including the potential sell-off of certain assets, such as pipelines, power assets, processing plants, or potentially in the future, storage assets. This may bring the structure of the Australian onshore LNG industry closer to that of North America, where companies focus on an area of expertise within the supply chain rather than on an end-to-end project. The transfer pricing issues associated with such restructures can be challenging, depending on the circumstances, and the ATO maintains a strong focus on business restructures and the potential tax risks associated with them.

A shift to processing

With the construction phase winding down, and the production phase not yet in full swing, at the time of writing this article, only one onshore project has successfully shipped LNG. The projects are looking at their ongoing requirements for construction and engineering staff, and planning for the staffing and asset requirements of maintenance and ongoing drilling. The many service providers to these projects are also redeploying staff to large projects on the west coast of Australia or elsewhere in the world. In some cases, this shifting of people, in particular offshore, could give rise to the exit of intangible property, or as with asset sell-offs, could be a point of interest for the ATO as a potential business restructure. Companies should be aware of the rules in Australia, which can impute an exit charge on the business changes.

With the projects beginning to book revenue and/or look toward profitable years, these companies may start making financing repayments. In some cases, financing arrangements put in place during the projects' exploration or initial development stages have reached the end of their term and require refinancing, often with a very different risk profile now that exploration and construction are largely complete.

With the commencement of production, projects also become potentially liable for payments under both the state-based royalty programme connected to their licensing arrangements and the federally applied Petroleum Resource Rent Tax (PRRT). While both these liabilities entail domestic payments, the calculation is based on the value of the commodity – the CSG – close to the point of extraction rather than on the export price. Because the projects are integrated,

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it is difficult to find a price at that point in the chain, and transfer pricing principles are applied in this domestic scenario to assess the value on which liability is based.

Export and pricing

LNG projects may be subject to increasing scrutiny from the ATO as they move into production. The energy sector is already receiving attention from the Australian Senate's Economic Reference Committee's Inquiry into Corporate Tax Avoidance, which in July 2015 sent letters to eight energy companies requesting details of their international dealings and structures, and requiring them to present evidence to the committee in August 2015. The wide ambit of Australia's transfer pricing laws means that they cover not only sales to commonly owned offshore marketing hubs but also potentially sales to customers who are upstream equity holders, even when that equity holder does not have a controlling interest. The majority of the exported product has been pre-sold in long-term contracts, say of 15 or 20 years, to the equity investors in the LNG projects and other third-party buyers.

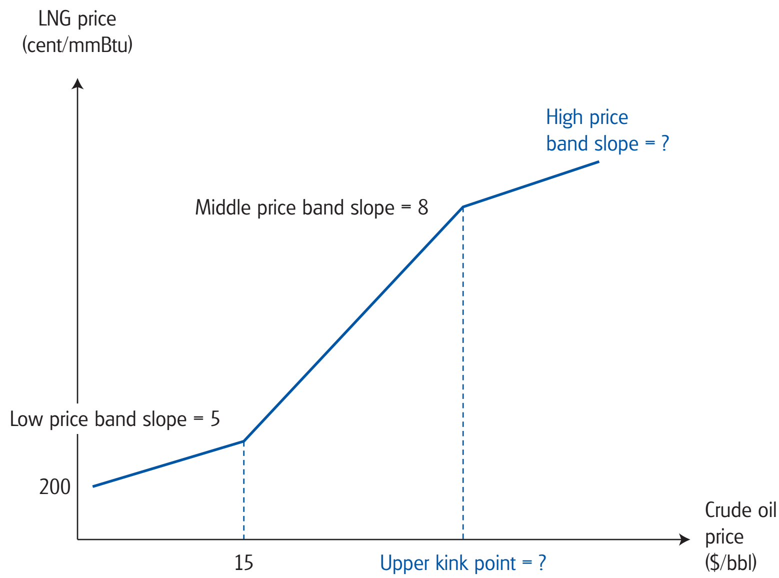
Long-term sales contracts are not uncommon. Often, committed contracts for the sale of a significant portion of LNG production are required by financiers to show the viability of a project that absorbs such large amounts of capital, with the attendant uncertainties of major long-term construction activities. This requirement to achieve funding means that many of these long-term sales contracts were agreed to five or more years ago. However, recent market changes (for example, oil price volatility, impending new supply from the US, displaced US imports now looking for customers, the emergence of buyers' clubs in Asia) are in turn driving changes to how future LNG contracts and pricing will be structured.

Basis of pricing

Export LNG is not necessarily priced like other resource commodities. First, there is the basis of the price. Export LNG is not, and has never been, a traded commodity with a publicly available list price.

For this reason, LNG contracts were often agreed with reference to LNG's "cousin", oil. For sales to Asian markets, this may have meant starting with the Japanese customs-cleared (JCC) crude, referred to as the Japanese Crude Cocktail. Sales to other markets may have been based on

Graph 1: S Curve



Source: www.osakagas.co.jp

other oil indices such as the Brent Crude price. This allowed players to use oil price forecasts to predict where the price for LNG was going to go.

Pricing in LNG contracts is often agreed based on an S curve. The curve is a stepped pricing mechanism, where each step consists of a fixed component and a proportion of the referenced oil price. An S curve, when graphed against the oil price, is in the shape of the letter S (see Graph 1).

The overall price negotiated – that is, the outcome from the S curve – likely does reflect the buyers' and sellers' views of the quality of the product and the other terms surrounding the sale. However, the fixed component is not necessarily linked to the capital spent to produce, and the proportion of the oil price may not necessarily reflect the energy content of the LNG. The pricing components actually reflect the requirements of the negotiating parties, the competitive nature of the LNG market, and are based solely on the negotiating powers of the buyer and seller. In many cases, these S curves are negotiated under long-term contracts with price renegotiation available after a period of time, say five years. This becomes important in the evolution of gas contracting.

It is very difficult to find external information for comparable purposes relating to LNG pricing, largely due to the commercially sensitive nature of the information in the contracts, and the relatively small number of contracts entered into, compared to other commodities. However, internal comparable information can often be found. This also generally removes some of the comparability issues arising from product differences. Comparability adjustments are often required. For example, many LNG contracts include DES (delivered ex-ship) transport terms, meaning the price should be considered for differences in shipping distances and port requirements. Similarly, the comparison of pricing on large-volume or long-term contracts (for example, 20 years) may need adjustment if used on mid-term contracts (for example, three years). As with most commodities, the use of a CUP requires consideration of differences in comparability, and may require making reliable adjustments to account for these differences.

The evolving market

In the period since these initial long-term contracts were signed, the global market has changed rapidly, with a significant volume of potential export gas supply available from the US shale gas reserves, most likely at a very competitive price point. This changes the global supply and demand equation.

The increasing supply has brought new intermediary players into the market; the portfolio market players. These are companies that enter into contracts to buy large amounts of production and then use this to run a portfolio of product that is sold across long-term and mid-term contracts, and the short-term spot market. This allows the portfolio player to earn a profit by enhancing the use of its product portfolio across the different contracts and to benefit from movements in pricing.

LNG storage is also becoming an important factor for portfolio players and other buyers. Storage allows a party to buy product at a low price, for example, in summer when demand is lower, store it and then resell it at a much higher price to cover its costs of storage and still make a profit. No storage assets have been constructed in Australia yet; however, new storage has come on-line in Singapore, for example.

Another change is buyers' preference to move away from long-term supply contracts to more mid-term or spot arrangements. This is consistent with changes that have also been seen in coal and iron ore sales to Asia and could be a major change in the structure of the LNG sales environment. With extra capacity coming into the market, and a volatile oil price, buyers may not wish to commit to long-term supply at a high price when there could be potentially lower-cost product on the horizon. Portfolio payers may be able to bridge the gap between producers and customers in this case, which further shows their importance in this new type of market. It is not yet clear what effect this change will have on the ability to secure financing for future greenfield projects.

Demand for LNG is expected to continue to increase, particularly when prices drop as a result of increased supply. Given the number of existing and planned additional re-gas plants in China coupled with anticipated utilisation increases, countries like China will be able to grow their LNG usage at a rate that should keep up with the increase in supply. However, portfolio and marketing players will be important to match the quality of product with the right buyer.

Export contracting and pricing in the future

When looking at gas contracting in the future, portfolio players likely will continue to play an important role.

Similar to Japanese trading houses, portfolio players bridge the gap between buyers' and sellers' expectations.

Gas may well be the major energy source of the future, as technology improves its substitutability for other energy sources. Upstream players need to ensure they are carefully structuring marketing and shipping and other value-adding downstream functions. As with the movement of other commodities in the past, the LNG market is set to become a market where players with access to data and market insights will be able to enhance their use of product and see favorable profits in their supply chain.

With an increase in the liquidity of the LNG market, it is likely that at some point in the future a separate export list price will become available. This may not be a short-term outcome but, over time, as LNG players wish to be less at risk on oil price volatility, this becomes more likely. The question is, where could central trading point (and associated reference price list) be based? Shanghai may be a viable proposition, considering its access to both domestic and international markets, the volume of domestic gas consumption, and strong trading markets. Singapore is also a possible location, with its strong commodity marketing, financial and shipping industries, and new storage facilities.

When looking at the Australian industry and the global market, producers, marketers, and customers will need to understand the swiftly and likely continuously changing market realities for LNG.

The UK Government's new diverted profits tax

Aengus Barry and Brendan Burgess explain the implications for the global energy and resources sector when considering the UK's diverted profits tax.

Given the UK government's demonstrated commitment to the multilateral actions of the OECD/G20 base erosion and profit shifting (BEPS) project, the announcement in the 2014 Autumn Statement of a new diverted profits tax (DPT) came as something of a surprise to most. The global energy and resources industry, by and large, is not a primary focus of the legislation, which is far-reaching. However, it is important for groups operating in this sector to understand the implications the measures may have on extractive, trading, and service operations in this industry.

DPT came into effect on April 1 2015, imposing a tax rate 5% above the otherwise applicable UK tax rate (25% for standard, non-ring-fence UK corporate activities or 55% for oil and gas companies operating inside the UK's ring fence regime) and applies to profits of multinationals that have been "artificially diverted" from the UK.

This new tax was introduced in the lead-up to the 2015 UK general election with the overall goal of taxing UK activity in advance of the implementation of the outcome of some of the work under the G20/OECD BEPS project in relation to transfer pricing and permanent establishments. It applies in two distinct situations: (1) where a group has a UK company (or UK permanent establishment) and there is a "tax mismatch" as a result of transactions or arrangements with a related person (whether or not UK taxable) that have "insufficient economic substance" and/or (2) when a foreign company has avoided having a permanent establishment in the UK.

To fall under the purview of the new tax, there is essentially a base requirement that there is activity (read *people*) in the UK and further, for situation (1), there must be a "tax mismatch" due to the tax rate differential between the two parties. For situation (2), the conditions are more complex, although the concept of a tax mismatch is still relevant. Even if there is no tax mismatch the rules can apply to arrangements where the main purpose, or one of the main purposes, is to avoid or reduce the charge to UK corporation tax (a motive test).

There is an exemption from DPT for small and medium-sized businesses (based on the existing implementation of the European Union thresholds used in UK transfer pricing legislation, but unlikely to be of benefit to many companies in this industry). Further exemptions apply for the avoidance of UK permanent establishment cases where there are either (i) total UK sales by the group that are not within the charge to UK corporation tax of no more than £10 million ($15.7 million) per annum or (ii) UK group expenses that are no more than £1 million per annum. Given the extent of investment typically required for energy and resources projects, the exemption for those with UK costs below £1 million may be inapplicable for many. Even the threshold of £10 million of total UK sales will likely be too low to benefit most participants in this sector. The remainder of this article focuses on three areas of activity in the UK energy and resources industry where the potential impact of this new tax should be considered.

Intellectual property developed in the oilfield service industry

The generation, use, and ownership of IP is a particularly important feature of the oilfield services industry. In addition to having dissipated IP ownership, it is not uncommon for oilfield service groups to hold patents in more than one location. This may lead to the situation whereby a UK group company pays a royalty to an overseas related party for the use of IP. If the overseas related party that owns the IP is subject to a low tax rate, this could bring the transaction into the remit of DPT.

The HM Revenue & Customs (HMRC) guidance on cases of this type consist of two starkly contrasting examples, one in which the insufficient economic substance condition is clearly met and one where it quite clearly is not. These examples show that a key factor in some cases will be whether it is possible for a group to show that the non-tax benefits of the arrangement outweigh the financial benefit of the tax reduction (the tax mismatch). This is therefore a question of economic substance as well as the value of the contribution made by management in the low-tax location. However, great uncertainty remains as to what constitutes sufficient substance and how that concept will be measurable. There is no clear guidance and, understandably, no precedent as yet on how a company is expected to quantify the non-tax benefits of the arrangement. Oilfield services groups with UK companies that are paying royalties to IP holding companies with a low tax rate would therefore be well advised to consider the benefits that their people provide in this kind of arrangement.

Boat charterers

The guidance HMRC has provided on DPT specifically includes an example on the interaction between DPT and the restriction on deductions for intragroup bareboat chartering arrangements on the UK Continental Shelf (UKCS). This example points out that some service company activities that are within the scope of the bareboat charter rules could also be within the scope of DPT when the charter income is taxable at a rate that is less than 80% of the rate at which UK deductions are available (so that there is a tax mismatch) and there is also insufficient economic substance.

When the conditions are met so that DPT is on point, it is then necessary to consider whether to apply DPT to the "actual" arrangement or whether to substitute an "alternative" hypothetical provision. Depending on the facts, HMRC indicate that in certain circumstances the transaction should be recharacterised from a leasing arrangement to an outright purchase of the asset by the UK lessee. The notion of whether DPT requires the recharacterisation of the "actual" arrangement into an "alternative" hypothetical arrangement is particularly important, as it determines how the end DPT is calculated.

When considering what is a reasonable "alternative" arrangement for boat charterers, the question to ask is: What arrangements would have been made if tax was not a matter to be taken into consideration? The answer may depend on the proportion of the assets' lifetime operations that are expected to take place on the UKCS compared to the proportion of its operations expected to occur away from the UKCS.

This hypothetical forecast of future activities may be particularly difficult for some groups to apply, and then the complex commercial fact patterns are unlikely to be fully appreciated by a recharacterisation of the transaction from a leasing arrangement to an asset purchase. It will therefore be very important for groups with chartering arrangements of this sort to pay particular attention to the impact DPT may have.

Oil and gas upstream activities

The UK oil and gas ring fence regime operates at a basic corporation tax rate of 30% plus a supplementary charge of 20% applied to a similar, but not identical, base. For ring-fenced activities, the 80% tax mismatch test applies by reference to this aggregate rate of 50%. Therefore, this means that there is an applicable tax mismatch across the ring fence between activities that occur within the UK ring fence regime and other UK activities that are outside the ring fence and taxed at 20%.

One example where DPT could apply is when a UK ring fence resident company pays for the provision of services from a non-ring fence UK resident company. In that case, the group would have to conclude that the insufficient economic substance test will not be met. Importantly, if the company cannot demonstrate that there is sufficient economic substance in the arrangements, then DPT could be levied at the higher ring fence DPT rate of 55%. There is also interaction with the "actual" and "alternative" transaction requirements outlined in the example above – if it is the case that the employees providing these services were, in the past, part of the UK ring fence company and were moved to the non-ring fence company, it may be the case that the "alternative" provision would have been for them to remain in the ring fence company, and seek to calculate a DPT charge accordingly. This will depend on the commercial reasons for the move, compared to any tax considerations for doing so.

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Concluding comments

The introduction of the DPT ahead of the final BEPS announcements demonstrates the UK taxing authorities' intent to encourage multinationals that have structures potentially affected by the transfer pricing and permanent establishment elements of the BEPS project to change (at least) the UK aspects of those structures. This has the potential to adversely impact the UK's exploration and production industries, despite the fact that companies in those sectors are not necessarily the intended focus of this legislation. Given that this is a completely new tax that has never been charged or applied before, questions remain in relation to its precise scope and application.

HMRC has said that it will not be possible to obtain formal detailed guidance in respect of DPT. However, it has said that it will provide its view on the risk of being within the scope of DPT under specific fact patterns. Given the complexity of the new rules, it would be advisable for groups to fully analyse and understand how this new law may apply to their facts before deciding if discussion with HMRC is warranted before any formal requirement to notify the tax authorities of potentially being within the scope of DPT.

People power in O&G transfer pricing

Aengus Barry, Brendan Burgess and Roman Webber assess the mechanism to charge for IP in the upstream oil and gas industry in light of some of the recent base erosion and profit shifting (BEPS) developments.

In no other sector of the economy does engineering brilliance, politics and risk taking combine with the random geology of plate tectonics as it does in upstream oil and gas.

Value in the industry is, and always has been, created by a coming together of the entrepreneurial drive of mankind and natural endowments. This has been so from the dawn of the industry, when advancements in drilling technology combined with geological good fortune to produce the Spindletop gusher. It has continued through the age of sub-sea exploration to the current pre-salt drilling and artic exploration which is pushing back the frontiers of today's industry.

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

This approach is industry standard and has manifested itself over many decades, driven by the reluctance of joint venture (JV) partners to allow a value-based charge for IP, which in turn reflects the reluctance of many national oil companies (NOCs) to see IP royalties, or value-based, charges; from their perspective access to the oil and gas technology is one of the main reasons to partner with the multinational in the first place.

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

Is the arrangement really a CCA?

The first question BEPS raises is whether this arrangement will be able to be characterised as cost sharing for transfer pricing purposes in the future.

One of the central themes of the Action 8 paper on cost contribution arrangements, released on April 29 2015, is that to be a member of such an arrangement it is necessary for an entity to have the functional capacity to provide input to the research and development exercise. Although at present only a discussion draft, the document suggests that the OECD guidelines be amended to make clear that any participant in a cost sharing arrangement would have to have the "capability and authority to control the risks associated with the risk-bearing opportunity under the CCA". The examples at the end of the document suggest that any entity not in possession of the requisite people skills (such as R&D risk oversight) should not be characterised as a participant in the cost sharing programme. Instead, an entity simply paying for R&D would be characterised as a capital provider, would be entitled to a risk adjusted reward on their capital invested and, crucially, would be expected to pay an arm's-length fee for access to the intangibles they use.

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

If the OECD transfer pricing guidelines are revised in line with the current draft, it suggests that a transfer price specifically for intellectual property is warranted, a departure from current industry practices.

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How to price the use of IP?

On June 4 2015 the OECD released a further BEPS transfer pricing paper, on to hard to value intangibles and in July a public consultation was held at OECD. The paper puts forward a number of proposals. At the outset it implies that pricing IP with respect to direct comparables (licences between, two independent third parties for similar IP) often are not reliable. It also suggests other methods such as profit split, which seek to analyse the value added by the IP in question with reference to the end profits realised from the venture, may be more appropriate.

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

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

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

Concluding comments

Charging for R&D, IP or highly skilled services on the basis of the value provided would in some cases be a change from the current modus operandi.

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

There is no guarantee that OECD transfer pricing guidelines will, ultimately, move in this direction. Whilst the move towards value-based CCAs is under consideration they are not commonly found between unrelated parties, if at all. Recent court decisions that focused on adherence to the arm's-length standard of how independent parties actually price transactions may be a factor to cause the OECD to

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reconsider the value-based approach; as proposed guidance that departs from third-party behaviour cannot illustrate the application of the arm's-length principle. If so, then perhaps CCAs will continue to be cost-based. If not then there is, in short, no easy answer to the new questions that the draft guidance poses.

The balance between the profits which are attributable to the scarcity value of the molecules in the ground and that which is allocated to the people who help to extract those very molecules may well change in the coming years as a result of the BEPS initiative. Precisely how that occurs will be one of the key transfer pricing challenges in the years which follow.

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