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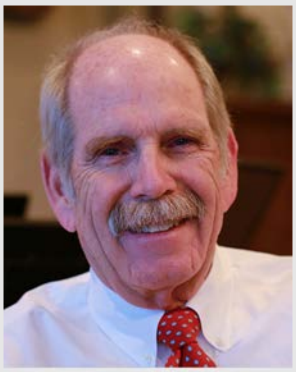

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In this article, the authors discuss the unique characteristics of the upstream oil and gas industry and explain why and how those characteristics limit the local country's revenue risk regarding transfer pricing.

Countries that impose taxes on net income are rightfully concerned about how a taxpayer calculates that income. In its simplest form, net income is the difference between the prices charged by a taxpayer for what it sells — that is, its revenue — and the prices it pays to others on what it purchases — that is, its costs. When a taxpayer sells to, or purchases from, an unrelated (or third) party at a market price, the simple revenue minus cost formula works fine. But when those sales or purchases are with a related company, there is inherent suspicion that the prices might be different from transactions with unrelated parties and that net income might be shifted to reduce taxes. If a company undercharges a related party for what it sells or overpays a related party for what it purchases, its net income and taxes will be lower than had the transactions been between unrelated parties. Transfer pricing refers to prices charged for goods and services between related entities, and when those prices deviate from a fair market value, or the price that would have occurred had the parties been unrelated (also referred to as parties dealing at arm's length), the tax authority is generally permitted to adjust the prices to that arm's-length amount and recompute taxes due.

Transfer pricing can be a significant revenue risk for any country, but especially for a developing country that might have limited sources of industries generating tax or other revenue. A tax administration's ability to challenge and adjust transfer prices depends on its human and financial resources, as well as on the availability of comparable data to apply the arm's-length standard. That concern receives much attention from commentators, policymakers, and tax authorities.

However, for international oil companies engaged in oil and gas exploration and production activities in both developing and developed countries, there are several unique characteristics that significantly reduce the risks of transfer pricing or mispricing.[1] Although some

[1]While those characteristics apply equally to developed and developing countries, this article focuses mostly on developing countries, given the attention commentators and international organizations have paid to natural resource activities in those countries.

commentators have recognized those factors,[2] they can be overlooked or unrecognized by those who may lack an understanding of the industry. Without a full understanding of the oil and gas industry, tax authorities could end up spending more time on some transfer pricing questions than is commensurate with the level of risk, and commentators could, with the best of intentions, end up creating misconceptions that might be counterproductive to creating value from the natural resources of developing countries.[3]

This article highlights and describes the unique characteristics of the upstream oil and gas industry and explains why and how they limit the local country's revenue risk stemming from transfer pricing. That there is widely and publicly available pricing information for oil operates on the revenue side to enable governments to assure themselves that transfer pricing associated with sales of crude oil to related parties is in fact arm's length. The combination of the fact that most large-scale oil and gas projects are conducted in joint ventures among several companies (often including a national oil company) and that any related-party costs charged to the joint venture are at cost, with no profit element, lets governments verify transfer pricing for most costs incurred. That is not to say that there are no transfer pricing risks for international oil companies, and this article attempts to identify areas of most potential concern. However, because of the characteristics discussed, the areas (and in most cases, even the amounts) involved in transfer pricing risks are more limited than for many other industries.

I. Background

The upstream oil and gas sector refers to the exploration, development, and production of crude oil and natural gas. The transportation, processing, refining, and marketing of petroleum is generally referred to as the downstream sector. In many developing countries, the oil and gas industry consists almost entirely of the upstream sector, with most or all of the production being exported.

The initial upstream activity — oil and gas exploration — is an exceptionally risky activity that frequently is granted to companies that have outbid others for the right to explore. That bidding process often provides the developing country with a substantial upfront payment and further work commitments by the investing company. Because of the large upfront payments and high additional investment risks, international oil companies typically form a partnership or joint venture to develop and complete the project. Through those partnerships

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[2] *See, e.g.*, Stephen Shay, "An Overview of Transfer Pricing in Extractive Industries," in *International Taxation and the Extractive Industries* (2016); Jack Calder, "Transfer Pricing — Special Extractive Industry Issues," in *International Taxation and the Extractive Industries* (2016); Calder, *Administering Fiscal Regimes for Extractive Industries: A Handbook* (2014); Maya Forstater, "Making Sense of International Tax 'Big Numbers': Billions and Trillions," Hiya Maya (blog) (undated); Forstater and Alexandra Readhead, "Inflated Expectations About Mineral Export Misinvoicing Are Having Real Consequences in Tanzania" (June 26, 2017); and Readhead, "What Mining Can Learn From Oil: A Study of Special Transfer Pricing Practices in the Oil Sector, and Their Potential Application to Hard Rock Minerals," CGD Policy Paper 128 (July 2018) (which provides an insightful description, analysis, and discussion of the extent to which oil industry characteristics reduce transfer pricing risks for that industry, and whether those practices might be adopted or adapted to similarly reduce transfer pricing risks for parts of the mining industry).

[3] *See, e.g.*, "Illicit Financial Flows: Report of the High Level Panel on Illicit Financial Flows From Africa" (undated), report commissioned by the AU/ECA Conference of Ministers of Finance, Planning and Economic Development and chaired by former South Africa President Thabo Mbeki, asserting that the African continent is losing over $50 billion per year from illicit financial flows. The definition adopted by the Mbeki Commission for the term "illicit financial flows" was "money illegally earned, transferred or used." This paper focuses on traditional transfer pricing practices involving activities that are not illegal but are required under most countries' tax laws when transactions between related parties are involved. Taxpayers' transfer pricing determinations, generally required to be based on the arm's-length principle, are sometimes challenged by tax authorities as being outside a range believed appropriate. Governments and nongovernmental organizations often assert that taxpayers use aggressive or even abusive approaches to transfer pricing motivated by minimizing tax. Illegal transfer pricing practices have no place in proper management of natural resource (or other) tax and financial practices, and any alleged illegal practices should be vigorously prosecuted. The issue of illegal activities (which would include falsifying invoices regarding transfer pricing) is often confused and conflated with legal but disputed transfer pricing positions taken by taxpayers in estimating the FMV of an item at a particular point in time. The Mbeki Commission itself demonstrates that confusion by defining trade misinvoicing as misrepresenting the price or quantity of goods or services, which it notes can lead to tax evasion — itself an illegal activity. It distinguishes tax evasion from tax avoidance, which it defines as:

(Footnote 3 continued)

> The legal practice of seeking to minimize a tax bill by taking advantage of a loophole or exception to tax regulations or adopting an unintended interpretation of the tax code. Such practices can be prevented through statutory anti-avoidance rules; where such rules do not exist or are not effective, tax avoidance can be a major component of IFFs.

Thus, the commission equates a legal practice with "money illegally earned, transferred or used." Commentators also often fail to make the distinction of legal versus illegal, but it is a crucial one.

See also Sebastian Beer and Jan Loeprick, "Profit Shifting: Drivers of Transfer (Mis)Pricing and the Potential of Countermeasures," 22(3) *Int. Tax & Pub. Fin.* 426 (2015); and Léonce Ndikumana, "Trade Misinvoicing in Primary Commodities in Developing Countries: The Cases of Chile, Cote d'Ivore, Nigeria, South Africa and Zambia," UNCTAD (Dec. 23, 2016).

or joint ventures, companies diversify and reduce their risks on any particular project. In many joint ventures, the national oil company is a joint venture participant, either as a full equity partner or on a carried interest basis (with the other partners funding its investment share).

The joint venture or partnership is formal and governed by a joint operating agreement. After the exploration and development stages of the project are complete and the value of the reserves in the developing country has been established, the balance of power somewhat shifts to the developing country. According to one commentator:

> While geological risks begin to diminish after discovery, political and financial risks intensify . . . Once a resource project becomes commercial, bargaining power really begins to shift. The large investments for the development phase of petroleum operations start out as a source of strength for the contractor. By the time production commences, capital investment is a sunk cost, and facilities installed in a foreign country can represent a significant source of vulnerability to the contractor.[4]

Given that projects are expected to last decades, and that the nature of risks shifts over project phases, investors benefit from trying to develop and maintain a long-term relationship with the country. Ideally, the contract or fiscal terms that govern the project are flexible enough so that as conditions change, the terms adjust, or as differences arise, investors and the government parties work to resolve them in a mutually supportive way.[5]

Arguably, because of the shift in power noted above, international oil companies have a strong incentive to maintain a positive relationship with the developing country, including its tax authority. Those companies worry that the developing country might try to alter the financial terms of the arrangement by, for example, changing tax or royalty rates or adopting new oil taxes. Can those concerns lessen the likelihood of those companies taking aggressive pricing positions or implementing base erosion techniques that could create hostilities with the developing country? Perhaps, but countries cannot simply assume that to be the case and must exercise their own due diligence in verifying transfer prices.

Before turning to characteristics of the oil and gas industry that can assist tax authorities in performing their obligations regarding transfer pricing, a brief comment on fiscal structures is needed.

The two most common fiscal structures used by countries in the development of oil and gas resources are tax or royalty regimes and production sharing contracts or arrangements.[6] Under each, there is likely to be a joint venture of multiple international oil companies, and possibly the inclusion of a government entity, such as a national oil company. Production by the joint venture partners is usually taken in kind and separately sold by each participant, and in the tax or royalty regime, royalty production by the government may also be taken in kind and then sold by the government. The same is true under production sharing contracts. In most developing countries — particularly for oil and, to a growing extent, for natural gas via liquefied natural gas — the production is exported. In most cases, the joint venture might not be a taxpayer, but the individual participants in the joint venture are. Finally, even if the joint venture is a taxpayer, the individual participants might also be taxpayers for activities and costs not included in the joint venture. That is a particularly important feature of the oil and gas industry that will be discussed in more detail.[7]

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[4] Daniel Johnston, *International Petroleum Fiscal Systems and Production Sharing Contracts* 142 (1994).

[5] *See, e.g.*, *United Nations Handbook on Selected Issues for Taxation of the Extractive Industries by Developing Countries* 260-289 (2017).

[6] For additional information about fiscal instruments in the extractives sector, see *The Taxation of Petroleum and Minerals: Principles, Problems and Practice* (2010), particularly chapter 4, Carole Nakhle, "Petroleum Fiscal Regimes: Evolution and Challenges," at 89-121.

[7] The joint venture structure provides an additional layer of review beyond that already applicable to the individual members of the venture. Internal and external audits, including government audits, occur at the joint venture level, in addition to those at the individual member level. Further, publicly traded international oil and gas companies are subject to scrutiny, both publicly and legally, arguably helping to lower risks of aggressive behaviors. For example, U.S. publicly traded companies are subject to SEC requirements, the Foreign Corrupt Practices Act, independent auditor reviews, and their own internal audit practices and policies.

II. The Revenue Side of Transfer Pricing

A. Transparency of Product Prices

Almost uniformly, commentators accept that product pricing poses the greatest transfer pricing risk for developing countries. In many sectors, the value of an exported item, transferred to a related party, is subject to large variation because of the product's special features. For example, in trying to discern the wholesale value of designer textiles or athletic footwear, the quality, brand, demand, location of markets, and many other factors come into the analysis. And the unique characteristics of particular products make comparisons with other products whose third-party prices might be known a subjective and difficult exercise.

1. Oil Pricing

In the past, that was also the case in the oil industry. In fact, there were numerous major transfer pricing disputes between international oil companies and tax authorities both in the producing country (claiming the price was too low) and in the importing country (claiming the price was too high). Those disputes were based principally on the lack of transparency in market pricing. However, it is now almost uniformly accepted that oil pricing is based on market indices widely used in the industry and in available publications, such as Platts and Argos. Most countries use realized prices as reported by a company and then check those prices against available published reference prices to audit consistency with their transfer pricing legislation. Given the level of published price information and accepted differentials for location and crude characteristics, transfer pricing disputes over the value of oil have all but disappeared.

To illustrate, an entire IRS group (the Petroleum Industry Program, or PIP, group) focused principally on transfer pricing of crude oil. PIP was responsible for and had control of crude oil transfer pricing for all U.S. taxpayers. Annually, PIP would analyze prices and develop a range of acceptable transfer prices by month and year for all crude oil imported into the United States. If a company imported non-U.S. crude oil in an intercompany transaction at a price above the range published by PIP, the IRS would propose a transfer pricing adjustment based on the difference between the transfer price and the low end of the PIP price range. It would then be the company's responsibility to document that its price was in fact an arm's-length value. As the use of index pricing became more prevalent and the volume of crude oil sales based on index pricing increased, the volume of transfer pricing disputes diminished and the need for PIP diminished; the IRS ultimately eliminated the group.

Further, in many projects, the developing country or its national oil company markets its own share of the production taken as a royalty in kind under a concession agreement or its share of the production under a production sharing contract. That firsthand knowledge of third-party market pricing provides additional information to tax authorities in developing countries. However, that practice could also create some concerns about whether the government actually receives the full value when it sells its own share of production. While the government may well be aware of third-party market pricing, there is a concern that it might choose to deviate from that on some of its own sales — suggesting an area of potential corruption. Ironically, it seems government sales of its own royalty or other take-in-kind production might be where most transfer pricing risk exists, while the investor share of production poses the least amount of risk.[8]

2. Natural Gas Pricing

Pricing domestic natural gas and exports of liquefied natural gas (LNG) is a bit more complex. Historically, natural gas markets have not been international, but rather limited to local — or at most, regional — markets, with pricing characteristics varying by location. Thus, that pricing has not developed the same level of international benchmarks, including quality and location differentials, and the noted revenue protections available for oil are not as advanced or available. However, when sold into domestic markets, natural gas is often subject to government price regulation, and when that is the

[8] *See, e.g.*, Alexandra Gillies, Marc Guéniat, and Lorenz Kummer, "Big Spenders — Swiss Trading Companies, African Oil and the Risks of Opacity," Natural Resource Governance Institute Report (July 2014), particularly at 18-20; and OECD Policy Dialogue on Natural Resource-Based Development, "Summary Report of Ninth Meeting of the Policy Dialogue" (Jan.-Feb. 2018), particularly at 12-15.

case, there is significant valuation or revenue protection.

In its rapidly growing market, however, LNG is becoming an internationally traded commodity and reference pricing is becoming more available:

> Domestic gas prices are in any case often subject to government regulation, so that (just as in the case of sales to LNG plants) transfer pricing is not a factor: all sales are priced on the same regulated basis, whether to an associate or not. International prices are potentially more relevant to LNG exports, but, whereas the huge growth in LNG international trade is likely to lead to more standardized spot pricing in future, for now there is considerable regional variation based on local supply and demand . . . . LNG is usually sold under long-term contracts rather than at spot prices. . . . If an LNG plant sells gas to an associate, for example, a related marketing company, it is usually under a similar long-term contract. . . . Because long-term contracts determine prices for years to come, there is a good case for governments to require terms to be approved or agreed in advance if an associate is involved. They should also carry out checks later to ensure that those terms are applied in practice (or modified only with agreement).[9]

However, unlike oil, natural gas frequently does not have widely available comparables, so its transfer pricing can become highly fact-specific and require significant attention.[10]

B. Value Determined by the Local Government

In some countries, the government's take is determined based on a government-determined and published price. That price can apply to all sales, to related-party sales only, or to sales with values less than the stipulated government price (whether to a related or third party) only. Obviously, if the government stipulates the price to be used for calculating its take, there is no risk of transfer pricing problems for the government for product sales. The government position of stipulating a price for oil, if done appropriately, provides certainty for the government and avoids future litigation on pricing disputes. When some countries implemented that policy, there was much less transparency in pricing, but with the current level of publicly available index pricing, the administrative burden of implementing government-stipulated pricing likely outweighs any benefit.

In Angola, for example, detailed pricing requirements based on arm's-length sales principles are incorporated into the tax law. Prices are set quarterly. The national oil company and private oil companies producing oil in Angola are required to submit market demand and price estimates at least 15 days before the start of each quarter to the Ministry of Petroleum. Private oil companies are also required to submit actual arm's-length sales data within 15 days following the end of each quarter or other agreed date. Required data includes term and spot sales, sales volumes, buyers, prices received, credit terms, and density information. Companies also must calculate volumetrically weighted average prices on a comparable density basis. The ministries of Finance and Petroleum jointly consider the data submitted, as well as data from other sources they deem relevant, and jointly determine market price by reference to free on-board sales to third parties. The quarterly market price is used for tax reporting (and cost recovery under the production sharing contract).

In practice, tax is reported on a calendar-year basis, with installments paid monthly. Payments are due by the last day of the month following lifting and are initially reported based on actual sales prices. Once a quarterly reference price is determined, tax obligations are trued up to the reference price. That occurs four times a year. Revenue reported in the annual tax return ties to the quarterly reference prices for the year. The prices are determined at or near the point of export, and thus what occurs beyond that point does not affect tax reporting in Angola.

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[9] Calder 2014, *supra* note 2, at 75-76. On LNG, see also *U.N. Handbook*, *supra* note 5, at 17. For an emerging spot market in LNG, see Henning Gloystein and Jessica Jaganathan, "Oil Like Gas: S&P Global Platts Bags Asian LNG Price Benchmark," Reuters (Feb. 25, 2018). For a long-term contract approach involving customers in a joint procurement arrangement, see Oleg Vukmanovic, "Centrica, Tokyo Gas Break Mould in Mozambique LNG Deal," Reuters (June 16, 2018).

[10] *See, e.g.*, Readhead 2018, *supra* note 2, at 17 (showing some 70 ongoing natural gas transfer pricing disputes in Norway as of November 2017).

Norway determines and publishes a norm price used for all sales of oil regardless of whether sold to a related or third party. The Norwegian norm price is a daily price set for each different crude oil produced, based on a government analysis of pricing information gathered both from producing companies and third parties. Once stated provisionally, the norm prices are subject to appeal by the producing companies, but once published as final, they must be used for the tax value of all sales.

The Norwegian system of pricing crude oil is a highly developed, formal approach, designed to establish a true arm's-length price for oil. Separate government authorities were established to manage that process. The Petroleum Price Board gathers and evaluates the pricing information and issues the proposed norm prices quarterly, covering the previous quarter. Once proposed, producing companies have an opportunity to review the prices and file a protest if there are prices the producer disagrees with. The protest is filed with the Minister of Energy and Petroleum.

The Norwegian regime could be considered a best-practices model for how a government system for setting prices should be designed and operated. While it was not uncommon for companies to contest prices in the early years of the system, continued refinements, along with much improved publicly available index pricing, have resulted in there being virtually no legal challenges to the Norwegian norm prices.

Nigeria is another example of a country that uses a government set price for taxing the income realized from the production and sale of oil by producing companies. However, the official selling price set by the Nigerian government is not necessarily tied to market prices and therefore can result in increasing the effective tax rate above the 85 percent statutory rate. In the 1980s, the disparity between the government-stipulated price and the market value got so large that companies were experiencing effective tax rates over 100 percent. That resulted in companies halting production and the government revamping the tax model under a memorandum of understanding designed to guarantee producing companies a margin. That memorandum expired, with valuation of crude oil reverting to the official selling price. The producing companies have no input into the value, and there is no mechanism to appeal the price stipulated.

In general, companies prefer using their actual prices (consistent with publicly available index pricing data available for auditing purposes) rather than government-established prices. Special transfer pricing rules:

> are generally unpopular with investors because of the administrative burden of substituting government-imposed transfer prices and the risk that the imposed prices will overvalue sales in practice, whether because of averaging or because they use an inappropriate benchmark or pricing date or because they are applied asymmetrically. (The "heads I win, tails you lose" application of special valuation rules is not uncommon — for example, Argentina and Nigeria apply them only where they produce a higher value than the recorded price.)[11]

C. Lack of Valuable Intangibles

A major contributor to transfer pricing disputes is the existence of valuable intangibles that affect the product value. Questions include who owns them, what jurisdiction has the right to tax them, and how they are valued. Intangibles such as trademarks, trade names, and embedded technology all contribute to disputes. For example, for a smartphone, it is critical to know how the total value of the completed product is divided among its various components: the technology embedded in the phone; the value of the manufacturing efforts; the phone's trade name; the phone's trademark; and the value of the phone's physical design.

None of those problems exists with oil and gas. There is no producer's name attached to a barrel of crude oil or an MCF of gas. A buyer does not care who produced the oil — the value is the same regardless of the producing company and is determined by the physical characteristics of the oil, such as the API (American Petroleum Institute) gravity and sulfur content, and the production location. For natural gas, while production might include some liquids and

[11] Calder 2014, *supra* note 2, at 89-90.

impurities, once processed and ready for sale, it is a consistent product.

Thus, while intangibles and technology are involved on the cost side of transfer pricing — for example, technology involved in finding, developing, and producing oil and gas — those intangibles do not translate into value of the commodity itself, unlike with the smartphone. Oil produced in the most rudimentary way is valued no differently than oil produced with the most sophisticated technology. Aside from quality and location differences, a barrel of oil produced onshore from shallow depths is not inherently of greater or lesser value than one produced in deep water, or in remote locations with severe environmental challenges.

Therefore, the risk of any intangible value affecting the sales price of oil and gas is virtually zero, leaving the value to be determined in the open market based on the physical characteristics and the production location of the oil and gas.

III. The Cost Side of Transfer Pricing

A. Joint Operating Agreements and No-Profit Rule

Commentators frequently note that in addition to questions regarding the transfer pricing of the product ultimately sold (or exported), costs incurred by the business in the developing country in earning its net or taxable profit present other opportunities for transfer pricing concerns. The suggestion is that related, affiliated companies might charge the country costs, and that by overcharging for goods or services provided, the multinational organization can artificially reduce the taxable profit of the in-country business. Again, however, a unique feature applicable to oil and gas activities effectively eliminates that concern for most of the costs involved in oil and gas projects.

"For petroleum, joint ventures are common and impose cost restrictions that give governments significant protection from transfer pricing abuse," one commentator wrote. "It may for this reason be prudent for governments to award petroleum licenses to joint ventures rather than to single companies."[12] As noted, it is common in the industry for unincorporated joint ventures among several investors, often including the country's national oil company, to be the formal structure for conducting exploration, development, and production activities. One of the parties to the joint operating agreement is appointed as the operator, with day-to-day responsibility for conducting operations and reporting to the other party.[13] The formal governance structure begins with the operations management committee, which includes representatives of all joint venture participants (often including the national oil company). Several subcommittees are typically set up to make recommendations to the operations management committee (which takes votes and makes joint venture decisions). There are often subcommittees for facilities, engineering, safety and health, environmental, and finance (plus accounting) that generally meet quarterly to review and recommend approving, modifying, or rejecting the operator's plans.

The process starts with preparing an annual planning and budget plan. The operator develops both an overall plan and specific line items. It seeks agreement from the operations management committee on an approved plan, which will then become the base line for the year, subject to ongoing review and approval of authorizations for expenditure — that is, those over a specific, agreed dollar amount. There are reviews of contracts and bid proposals, as well as confirmations that items are for the sole benefit of the joint venture.[14] Only approved costs, most of which are third-party costs, can be billed to the joint venture.

[12] Calder 2014, *supra* note 2, at 80 (especially n.21).

[13] While each joint operating agreement will be unique, most share many of the provisions regarding governance. There will be specific oversight, review, approval, and audit processes, including verification that all items charged into the joint venture are charged at cost. Further, specific accounting procedures that are part of petroleum agreements or applicable petroleum tax laws and regulations also contain rules defining costs eligible for recovery and tax deductibility.

[14] The national oil company is frequently a member of the contractor group (the international and national oil companies that form the joint venture to provide resources to design and implement the project, and that jointly are party to the production sharing agreement with the host government) and plays an active role in contractor selection. It will also be part of the review and approval process, which includes putting together an agreed bid slate (identifying those contractors who are technically qualified to perform the work) and evaluating them in the commercial (compensation) phase. The award of contracts may require the approval of both the national oil company and the government (in its role as resource owner and concessionaire). When approvals are not given in advance, the national oil company or government has the right to disallow cost recovery for work, which, because of the time it can take to get approvals, puts the operator in a position to move forward and take that cost recovery risk.

The operator will be empowered (on behalf of all joint venture participants and subject to the supervision noted above) to contract for goods and services to conduct operations, normally from third parties (including drilling, construction, fabrication, transportation, and all other needed items or services). The lion's share of the costs for any joint venture project consists of third-party costs, all of which are backed up with the underlying contract plus invoices (available in-country and to the government either as the resource holder or joint venture participant). When the national oil company or government seeks to have local content, the local contractors will be third parties.

A second category of costs consists of the operating personnel in the country, which may be operator employees or contractors. Costs of those personnel are again the actual and verifiable costs (salaries plus benefits, for example) — essentially as with any other third-party-related cost.

A final category of costs is headquartering or other affiliate costs. Those are the smallest part of joint venture costs but are still supported by an annual certification process audited by the operator's external auditor. Validation is of the total cost of the functions to be billed out and a certification that they consist of costs only — that is, no markup. Allocation of headquartering costs to a particular joint venture is typically supported by time-writing.[15] The operator supplies management and administrative services, usually via its own personnel or from related companies, by way of costs described in this category and the personnel category.

Under the terms of standard joint operating agreements, an operator's charges to an oil and gas joint venture are limited to costs. When the operator procures materials for the project, it cannot add a markup to the charge by the third-party provider or for overhead costs (including the procurement services in purchasing materials).

Therefore, for oil and gas projects, the developing country is not only not overcharged for the costs of the joint venture, it is in reality undercharged, resulting in additional tax revenue. That is clearly not the situation with any other industry, in which a developing country could be at risk of inflated charges for materials and services billed to the local project. The no-profit rule applies even though the country where the services are being provided might require a markup on related-party services, therefore resulting in double taxation for the taxpayer.[16]

The long-standing no-profit practice was essentially standardized in the earliest model joint operating agreement, which was developed by the American Association of Petroleum Landmen in 1956 and provided simply for cost reimbursement for direct and indirect charges by the operator of the joint venture. In 2016 the association published the latest version of the model agreement, which still allows only cost reimbursement. The Association of International Petroleum Negotiators also created a model contract, last updated in 2012, that includes an accounting procedure noting the no-profit, no-loss principle.

The no-profit rule applies to all joint venture costs, including direct (third-party contractor costs, material purchases, direct labor, transportation, and generally any expenditure of direct benefit to the joint project) and indirect costs (generally operator costs allocated to the project to compensate the operator for items not directly chargeable). However, no charge is allowed for the value of intangibles brought into the project, for example.

Thus, for experienced personnel provided by the operator, there is no markup for special skills. The charge to the joint venture is the same cost the employer has (salary and benefits).[17] That

[15] In some cases, reimbursable indirect costs may be calculated by a formula agreed on by the joint venture participants as a reasonable estimate of those costs, such as a small percentage of operating costs, keeping in mind that it is a third-party negotiated rate among competitors.

[16] One commentator has suggested that this transfer pricing method is in fact "the comparable uncontrolled price for costs between non-associated participants in petroleum joint ventures worldwide." Calder 2014, *supra* note 2, at 80. That argument has not been universally accepted, and the result is double taxation.

[17] Commentators often point out that inter-affiliate management or service costs and financing are key areas for base erosion. *See*, *e.g.*, Readhead 2018, *supra* note 2, at 20-21. An operator's inter-affiliate management or service costs are precisely the types of costs covered by the no-profit or no-markup rule. They are incurred by nonoperators, and while not covered by the no-profit rule because they are not billed to the venture, are small in relation to any joint venture and are easily identified. Financing costs are often not permitted in a joint venture, and if they are — as in a project financing case — they are either with an unrelated third party or based on unrelated third-party arm's-length arrangements. See Section IV, *infra*, for further discussion of the types of costs that may not be protected by the no-profit rule.

essentially provides the developing country free access to the value of the technology used there.

Under the joint operating agreement, the application of the no-profit rule is subject to audit by all co-venturers, including the government if it is a participant. That is particularly important to tax authorities because the interests of the nonoperating co-venturers that are not to be overcharged by the operator are completely aligned with their interests in not having inflated costs charged to the country.[18] For larger expenditures, the co-venturers review and approve the charges before they are billed to the venture.

Typically, there are annual audits, and the starting point for the nonoperators will be the joint interest bill. The government has audit rights, as a co-venturer and as the concessionaire, and often contracts with other companies (such as international or other local accounting firms) for assistance. Tax authorities also have separate audit rights. Given all those parties, it is not uncommon for the operator to host auditors of one type or another year-round, supplying large amounts of documents and data to support the joint venture charges. The national oil company will often focus on items for cost recovery purposes under the production sharing contract, and the tax authorities will focus on costs for the permissibility, as well as the timing, of tax deductions.

That raises an important distinction between the level of costs chargeable to the joint venture for cost sharing among venturers (and cost recovery in production sharing contracts) and what each member claims as a deductible cost for income or profit tax purposes on its tax return. Technically, costs not charged or chargeable to a joint venture may still be claimed as a tax deduction by the member incurring the cost.

Therefore, while it has generally been acknowledged that for cost sharing and cost recovery among venturers, the no-profit rule operates to protect a government (and the nonoperator participants) from cost-related transfer pricing problems, that does not necessarily carry over to the non-venture costs claimed on the separate tax returns of the participants that incurred the costs:

> Transfer pricing risks are higher in the case of profit-based taxes, which, in an unincorporated [joint venture], are paid separately by each partner on its share of profit oil. Each partner will submit a tax return, which includes its share of costs paid to the operator, as well as any expenses it incurs separately at the "partner level." Costs paid to the operator, which for major oil projects will constitute the bulk of the total costs, have undergone scrutiny by nonoperators and the government for purposes of cost recovery, and thus those same costs pose limited transfer pricing risk for profit tax purposes. However, for those costs that fall outside the scope of the JV and which are not recoverable, partners may nevertheless choose to offset them against their individual tax bill depending on the provisions of host country tax laws. The lack of oversight by JV partners means that, to the extent that such costs are incurred with related parties, transfer pricing risks remain and those costs should be scrutinized.[19]

However, protection provided by the no-profit rule does carry over to joint venture costs claimed as tax deductions, making even the income or profit tax risk much lower because of the information available to the government as a result of the rule.

Tax authorities will have all the records of what a nonoperator paid into the joint venture (anything else must be looked at, as noted above, but having the no-profit rule records clearly limits the scope of the audit) and the level of transfer pricing risks. Similarly, tax authorities will have access to detailed records of the costs the operator charges the joint venture, so anything in addition

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[18]Neither the operator nor the nonoperator benefits from overpaying third parties, which reduces profitability of the joint venture activities and each party's share. The government, as a party and as tax administrator, has the same interest in all third-party costs. For operator inter-affiliate costs, all other partners (including the government) have an interest in keeping those items at cost, per the agreements. Further, in the overall context of the joint venture project, those types of costs are small; thus, there is little risk in the inter-affiliate cost area.

[19]Readhead 2018, *supra* note 2, at 16-17.

to costs claimed for income tax purposes can easily be identified and reviewed.

Because not all costs are covered by the no-profit rule, there could be areas of transfer pricing concern. Non-covered costs include not only any the operator incurs that are disallowed as joint venture costs, but other operator-incurred costs to, for example, maintain an office to oversee other activities in the country that might not be related to one specific joint venture. Similar costs incurred by nonoperators are also relevant for the tax returns of those nonoperators. Overall, in developing countries, those types of costs are likely to be relatively small and, perhaps more importantly, clearly identified, because proper venture-related costs are covered by a joint interest bill, and all other costs will show up in the accounting records as 100 percent costs to the particular entity.

Thus, because those types of costs are limited, transparent, identifiable, and fairly easy to audit, they pose relatively low transfer pricing risks. Further, countries can adopt special rules or safe harbors that address those limited areas as a way to further reduce transfer pricing risks.

Some specific items that might not be covered by the no-profit rule follow.

B. Financing

When financing is done at the project level (nonrecourse project financing), and all partners (including a country's national oil company) have the same financing terms, the financing is clearly arm's length and will generally involve a third-party lender. But financing can also be handled by each partner outside the project itself.

For example, companies X and Y, based outside the country where the resource exists, form in-country subsidiaries (companies XX and YY, respectively) as their partners in the joint venture. To fund the subsidiaries' shares of project investment, the subsidiaries receive a mixture of equity- and debt-based funding from their parent companies. No debt is incurred at the project level, and no financing expenses are permitted for cost recovery under the applicable project agreement. The question that can arise is whether, as XX and YY complete their income tax returns, they can deduct the interest expense paid to their parents on the debt-financed portion of the funding. If so,[20] what protections are available to a country and, for example, how can it determine whether the actual interest rates charged are within an arm's-length range?

First, the amount of debt financing and the charges for it will be clearly identifiable. Thus, there is no concern about a hidden or hard-to-find item. Second, many countries prescribe rules for acceptable levels of debt (for example, by imposing debt-equity limits). Third, the interest rates charged can be easily scrutinized, and again, a country may limit acceptable interest rates under rules or regulations, including by providing safe harbor ranges depending on the duration of the debt and adopting rules placing the burden of proof on the taxpayer for rates outside the safe harbor range.

The point is that while in some cases financing may be an area of transfer pricing concern, it is visible and auditable and can be addressed by specific rules. Thus, the risks of inappropriate tax base erosion are discrete, limited, and manageable.

C. Management Services and Oversight

Home office management services and costs of oversight of the in-country affiliate that are not billable to the joint venture are potentially deductible and therefore must be reviewed. In the grand scheme of a major oil and gas project, those types of costs are extremely small, and thus do not pose a large transfer pricing risk. They are also easily identifiable and subject to audit. Accounting by the operator itself will separately identify those costs that are on-billed to the joint venture and those that are not (often referred to as 100 percent costs in that they are borne entirely by the operator). For nonoperator costs — again, ones associated with the project itself that are cash calls from the operator — these are clearly marked, so all others would be in their equivalent of 100 percent costs.

D. Marketing and Insurance Costs

In most cases, joint venture participants take their production and separately market it — that

[20] For example, in many cases, debt financing of exploration costs is not permitted or feasible. *See U.N. Handbook*, *supra* note 5, at 186.

is, there are generally no joint marketing activities that would be billed to the joint venture. (If there were, they would be subject to the no-profit rule.) Given that most of the product is exported and that index pricing is used to determine the export price, marketing costs would not be involved in determining the product's value, but any costs charged to the in-country affiliate would be clearly identified. If deemed necessary, a country could impose safe harbor rules.

Insurance requirements may be at the joint venture level or, more commonly, left to each partner to handle. If there is an agreement to obtain third-party insurance at the venture level, the insurance premium would be a venture charge (and thus a third-party item).

If, as is more common, the operator (and the parties) self-insure, there is no insurance premium cost at the venture level. But any losses are billed to the joint venture, and each partner would bear its own share of that cost. However, the venture member may choose to acquire insurance on its own, and while that is not a venture cost, the member may claim a deduction for any premium it pays on its income or profit tax returns. If a related party provides the insurance, that will raise transfer pricing concerns and will need to be reviewed by the tax authorities. Again, however, the existence of that type of cost will be highly visible.

IV. Conclusion

Large international upstream oil and gas projects, especially those conducted via joint ventures (and often with a developing country's national oil company as a participant), pose significantly lower transfer pricing (or mispricing) risks for investors than most international projects in other industries. Project characteristics, the transparency in market value of what is produced and sold, and unique industry structure and practices make those activities very low risk in terms of transfer pricing. In fact, developing countries may want to consider requiring some degree of international oil company joint venture participation in oil and gas projects to avail themselves of the benefits of the no-profit rule and other international constraints on those companies.

For the revenue side of transfer pricing, the availability of international benchmarks and widely published indices, coupled with the relative homogeneity of the product itself and accepted (and published) differentials for quality and location, makes it relatively easy for countries to test the transfer pricing of oil and gas to assure proper valuation. A country may also establish its own valuation rule based on knowledge it has from its own sales and available benchmarks for the product. When the government, either itself or via its national oil company, takes production in kind and resells it, it will also have firsthand knowledge of the market against which to test transfer prices. However, it may be that government sales of its own royalty or other take-in-kind production could be where significant transfer pricing and possible corruption risks exist.[21]

On the cost side, the no-profit rule provides a substantial degree of protection against transfer pricing abuse. Most of the costs of any project will be subject to that rule, and information on the actual costs will be freely accessible by the government. If outside the joint venture the taxpayer seeks to add some type of markup, that will be clearly identifiable and subject to audit for reasonableness. To maximize the transfer pricing protection available from the no-profit rule, a country's national oil company and petroleum ministry should share information with its tax administration.

There are some areas to which the no-profit rule might not apply, and costs claimed in those areas must be scrutinized. It may be, however, that special provisions could be applied as safe harbors or fixed rules to minimize transfer pricing risks. However, the types of costs not covered by the no-profit rule are not limited to the oil and gas industry. What is unique, and what provides a major benefit to countries, is the extent of the costs of oil and gas projects that are subject to the no-profit rule that can effectively be taken off the table as presenting transfer pricing risks. ■

[21] *See supra* note 7.