Global oil & gas tax newsletter
Views from around the world

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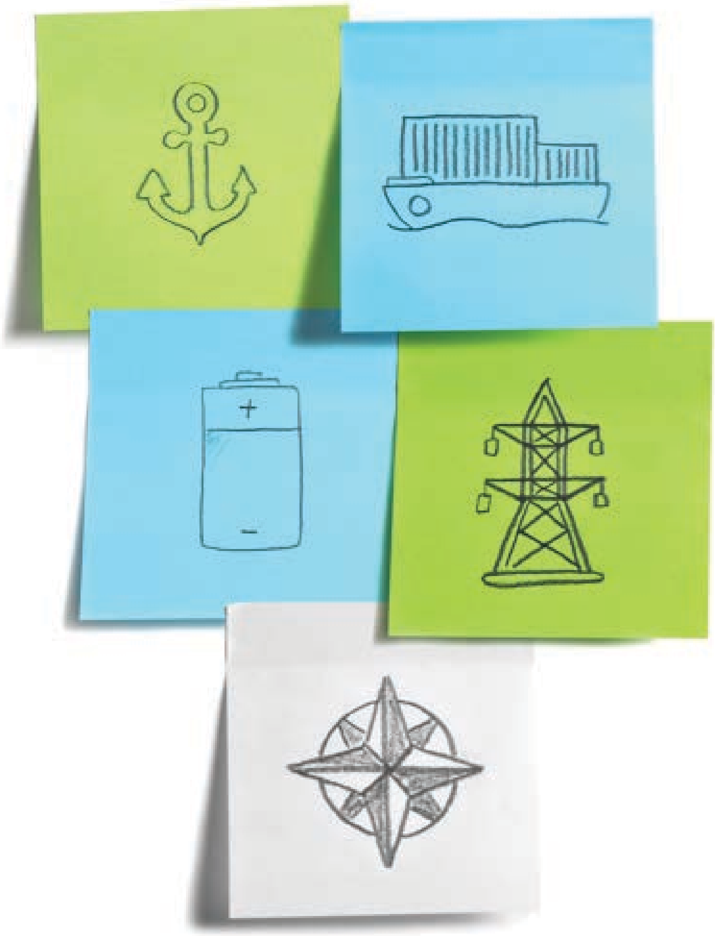


January 2014

Spotlight on PIS and COFINS: Brazilian consortium activities and tax credits

New business reality

In Brazil, the oil and gas industry is characterized by the presence of several companies acting both independently and through consortium agreements in order to carry out exploration, development, and production activities. As oil and gas activities demand high pre-operating investments, most of the oil and gas companies constitute consortium agreements in which costs and risks are shared between the parties. In this case, the leader of the consortium (named as consortium operator) will carry out the operations on behalf of the other consortium members and it will be responsible for keeping all the main documents related to costs and expenses. This information is conveyed to the consortium parties through the "cash call and billing statement" process. A cash call happens when the operator asks consortium parties for funds in advance to support future capital-based expenditures and a billing statement lists the charges that the operator has accumulated over a period of time when performing oil and gas activities on behalf of the consortium. Neither document is provided by the legislation for tax computation purposes. In general, the issuance of such documents is regulated by the Joint Operating Agreement (JOA).

As oil and gas activities demand high pre-operating investments, most of the oil and gas companies constitute consortium agreements in which costs and risks are shared between the parties.

Because each consortium party is responsible for producing its own information and submitting it before Brazilian tax authorities, they have to rely on the operator for such information. As the international oil and gas practices do not include this detailed information on documents, as required by the tax authorities in Brazil, it creates a challenge to obtain the necessary comprehensive information as detailed below.

Depending on the type of consortium, the cost allocation may vary: in a Joint Venture, parties hold joint control of the business and have rights to the net assets of the business; in a Joint Operation, the parties hold joint control of assets, rights, and obligations to the liabilities related to the business. Most oil and gas companies elect to be Joint Operations, regulated under JOAs.

PIS (the program for social integration contribution) and Cofins (the contribution for the financing of social security) are federal taxes charged on gross revenues earned by a legal entity and are due on a monthly basis. PIS/Cofins are calculated at 1.65 percent and 7.6 percent tax rates, respectively, under the noncumulative system, where the taxpayer can claim credits upon inputs for its operations (as detailed below). Accordingly, these related tax credits are based on certain costs and expenses incurred by the legal entity. Tax credits can offset the liabilities derived from the revenues accrued. If there are surplus credits derived from exempt transactions (export of oil, for instance), this amount might be used to offset against other federal taxes due by the legal entity. This tax system is managed and regulated by an advanced electronic system that includes specific files and returns that must be sent by the taxpayer to the tax authorities.

PIS/Cofins legislation provides a list of tax credits. For example: goods and services used as inputs in performing services and manufacturing goods, electric power consumed by the establishment, depreciation of machinery and other assets, among others. Most of the oil and gas companies classify inputs as tubes, pipes, valves, hoses, chemicals, as well as drilling, completion, and seismic services, as they are directly or indirectly employed on the exploration and production of oil and gas and consumed on usual and recurrent basis; however, PIS/Cofins legislation does not clearly provide the concept of input for credit purposes for oil and gas activities, which presents a challenge for oil and gas companies.

In addition, the moment when expenses related to exploration and development phases are registered may impact the calculation of PIS/Cofins credits. While the full cost method establishes that all the costs of exploration are capitalized regardless of whether those costs relate to a specific discovery of reserves, the successful efforts method establishes that only the exploration costs that result in a producing well are capitalized; exploration costs that result in dry holes are immediately expensed. Each oil and gas company may elect either of the methods. Tax authorities have challenged the application of the successful efforts method, as they understand the exploration costs could solely be expensed when production activities start or when the block is returned to the Brazilian government.

The consortium leader that acquires goods and services for oil and gas activities on behalf of the consortium can identify tax credits that fit the concept of inputs for oil and gas purposes due to the fact that goods and services tax invoices are issued by the suppliers to the leader. In this case, PIS/Cofins credits will be supported by the respective tax documents and balance sheets, which may properly feed PIS/Cofins tax returns. Other consortium parties will face difficulties to identify tax credits on goods and services purchased by the leader due to the lack of proper and detailed information in billing statements that are necessary for tax purposes. Thus, PIS/Cofins tax returns of consortium parties are prepared based on billing statements, authorization for expenditure (AFE), and accruals registered in their accounting statements.

A PIS/Cofins tax return with insufficient information and documents to support the right to use PIS/Cofins credits may expose consortium parties to potential tax contingencies.

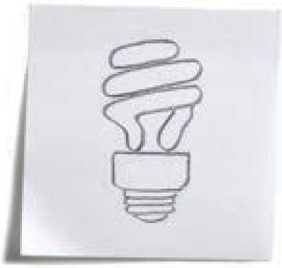
With the purpose of ensuring that the process followed by the operator complies with PIS/Cofins legislation, the consortium members should request the consortium's tax and accounting documentation prepared by the operator, such as tax invoices, balance sheets, and tax returns. This request has grounds on the consortium agreement and on the joint liability provided by tax legislation; therefore, it should be executed accordingly. Eventually JOAs might also allow nonoperators to enforce such request with the consortium operator.

Also, this process can be optimized by using the PIS/Cofins tax files (SPED Contributions), as a vehicle to inform tax credits calculated by the leader that can be used by consortium parties based on their interest held. SPED Contributions is an advanced electronic tax return to report PIS/Cofins calculated, as per parameters established by the Brazilian government, and it should be submitted by the 5th day of the second month following the month that the PIS/Cofins were calculated.

This process would enable the leader to inform consortium parties of all tax information related to the acquisition of goods and services that can generate PIS/Cofins credits segregated by the nature of credits and by taxed and exempt transactions. This may help consortium members elaborate their SPED Contribution files based on their interest held. In addition to the compliance with legislation, this procedure can bring a positive effect on cash flow, considering that PIS/Cofins tax credits derived from exempt transactions can be offset against other federal taxes, such as income tax and social contributions.

A PIS/Cofins tax return with insufficient information and documents to support the right to use PIS/Cofins credits may expose consortium parties to potential tax contingencies.

Australia: Clarity on backlog of unlegislated tax measures and other recent developments



Clarity on backlog of announced but unlegislated tax measures

On 7 September 2013, the Liberal/National Coalition Party (Coalition) was elected to form Australia's new federal government.

One of the first orders of business for the newly elected Coalition government was to review and confirm the status of the close to 100 unlegislated tax announcements made by predecessor governments.

Following stakeholder consultations conducted over the course of November and December 2013, the government has now announced its final position on this backlog of unlegislated tax-related measures, paving the way to restoring certainty, stability, and integrity in the Australian tax system. Some measures will proceed as previously announced, subject to normal parliamentary votes and procedures, others are expected to proceed with amendment and a number will be abandoned. For those measures which would proceed, the government will now move towards enacting the bulk of the legislation during 2014.

The various tax-related measures in question cover a range of diverse taxation aspects affecting a broad spectrum of taxpayers. Some of the key government positions which may be relevant to multinational oil and gas and oilfield services companies investing in Australia are noted as follows:

Measures which would proceed as announced include:

- Replacing the immediate deductibility for the cost of acquiring mining rights and mining information, with a tax amortization allowance
- Debt/equity tax rules – limiting the scope of the 'equity-override' integrity rule
- Lowering the thin capitalization (statutory gearing ratio) safe harbor threshold from 75 percent to 60 percent of net assets
- Introducing a revised arm's length debt test as an alternative to satisfying the thin capitalization requirements
- Introduction of a withholding tax for foreign residents who dispose of certain taxable Australian property
- Clarification to the operation of Australia's taxing rights over the disposal by foreign residents of Australian real property interests held indirectly through interposed entities
- Improvements to the Managed Investment Trust (MIT) regime for property and infrastructure investments
- Amendments to certain tax-hedging rules
- A simplified look-through treatment for earn-out arrangements involving business acquisitions and disposals
- Technical and compliance savings improvements to the foreign currency translation regulations
- Removing the Research and Development (R&D) tax incentive for companies with an Australian turnover of A$20 billion or more
- Goods and Services Tax (GST) reverse charge mechanism for supplies of going concern enterprises

Measures which would proceed with amendment include the following:

- The removal of interest deductibility on debt financing obtained to fund investments in foreign subsidiaries will not proceed as originally announced, but a more targeted integrity provision would be introduced to counter certain conduit arrangements.

Measures which will not proceed include:

- Changes to the Fringe Benefits Tax treatment of cars
- Reforms to, and modernization of, the controlled foreign company (CFC) provisions
- Quarterly credits for the R&D tax incentive

. . . the government has now announced its final position on this backlog of unlegislated tax-related measures, paving the way to restoring certainty, stability, and integrity in the Australian tax system.

The timely clarification by the government on the status of the outstanding tax measures is much welcomed and it is hoped that those pieces of legislation which will be progressed will be efficiently enacted over the coming months. The abandonment of certain key measures to improve Australia's standing as an investment platform and the competitiveness of Australian businesses operating abroad (such as the CFC reforms) is, however, disappointing. It is expected that this aspect will be further reviewed as part of the ongoing global Base Erosion and Profit Shifting initiative led by the Organisation for Economic Co-operation and Development.

For affected taxpayers, it will be important to monitor the development and progress of the forthcoming pieces of legislation as well as the precise details of how and when they would apply to taxpayers' specific circumstances, if enacted.

Discussion paper on the proposed new arm's length debt test (ALDT)

On 16 December 2013, the Board of Taxation (BOT) released a discussion paper (**http://www.taxboard.gov.au/content/publications_and_media/media_releases/downloads/045.pdf**) on its review of the operation of the ALDT as an alternative to the safe harbor debt-to-net asset ratio for satisfying the thin capitalization limits on deductible debt financing. As noted above, given that the reduction in the safe harbor threshold (from 75 percent to 60 percent of net assets) is set to proceed (from fiscal years commencing on or after 1 July 2014), the ALDT may become increasingly important for taxpayers to avoid being denied debt deductions under the thin capitalization rules.

The discussion paper:

- Provides background on recent developments regarding the thin capitalization rules
- Summarizes the structure of the thin capitalization rules and outlines the key features of the ALDT
- Provides some summary statistics on the recent use of the ALDT and brief references to international experiences with thin capitalization
- Outlines some issues associated with the compliance and administrability of the ALDT
- Discusses some issues associated with the eligibility for the ALDT

Submissions on the discussion paper are due by 14 March 2014. Stakeholder comments will be considered by the BOT in developing its advice and recommendations to the government, which are due by December 2014.

Notably in an oil and gas context, the discussion paper acknowledges the following:

- Access to the ALDT is particularly important for large-scale projects undertaken by capital-intensive industries, such as integrated Liquefied Natural Gas (LNG) projects which are funded through project-financing arrangements. Project financing is typically highly leveraged, with substantial levels of financing in the form of senior debt.
- There may be practical difficulties in applying the ALDT to such large-scale projects. Due to the significant size of the projects and unique financing arrangements, which may involve the participation of several unrelated equity sponsors and debt funding provided through syndicated project-financing arrangements with parental support provided via a parent guarantee during the construction phase (on a limited recourse basis), ascertaining comparable arm's length debt funding and meeting the requirements of the ALDT could be problematic. This is because in identifying comparable arm's length debt funding that can be used as the benchmark arm's length debt level, any guarantees or credit support from an associate of the borrower must be disregarded. Excising such credit support can result in the borrower's arm's length debt amount being less than it would otherwise be. This outcome is inconsistent with ordinary commercial practice which does not present an integrity concern, particularly where the lender and borrower in a project-financing arrangement are unrelated and dealing independently and similar practices are adopted in the market for that type of finance.

… given that the reduction in the safe harbor threshold is set to proceed … the ALDT may become increasingly important for taxpayers to avoid being denied debt deductions under the thin capitalization rules.

The discussion paper seeks to canvass stakeholders' input on how the ALDT can be better designed to cater more practically for taxpayers relying on project financing for their large-scale LNG and infrastructure projects.

Taxpayers who are, or anticipate being, affected by the thin capitalization reforms, and who may require access to the ALDT, should consider making submissions to the BOT in relation to their existing and anticipated future funding profile and arrangements.

Draft taxation determination – treatment of design expenditure for R&D tax incentive claims

The Australian Taxation Office (ATO) has released a draft Taxation Determination, TD 2013/D9 (**http://law.ato.gov.au/pdf/pbr/td2013-d009.pdf**), which sets out when design expenditure must be included in the cost of a self-constructed tangible depreciating asset.

This is critical in applying the R&D tax incentive rules, which provide an uplifted tax benefit for the cost of eligible R&D activities. If design expenditure is included in the cost of a tangible depreciating asset, the R&D tax incentive benefit may only arise in accordance with the asset's tax depreciation profile (i.e., over the period the asset is used for eligible R&D activities). If, however, the design expenditure is not included in the cost of any tangible depreciating asset, the R&D tax incentive benefit arises on the entirety of the expenditure when it is incurred.

This draft determination may affect oil and gas or oilfield services companies which are either involved in constructing, or which procure another party to construct on their behalf, assets used in their operations and activities, particularly when designing and evaluating concepts for bespoke drilling, exploration or extraction techniques or processes.

The key points made in the draft determination can be summarized as follows:

- Expenditure shall be included in the cost of a depreciating asset where it has been incurred "in relation to holding" that asset provided that it is "directly connected with holding the asset." As such, the necessary direct connection will exist where design expenditure is both directed to and results in the taxpayer's beginning to hold the asset in question.

This draft determination may affect oil and gas or oilfield services companies which are either involved in constructing, or which procure another party to construct on their behalf, assets used in their operations and activities, particularly when designing and evaluating concepts for bespoke drilling, exploration or extraction techniques or processes.

- Any design costs that do not result in the entity's beginning to hold the asset do not form part of the cost of the asset and may qualify for immediate R&D tax incentive benefit in the year the cost is incurred. This would include costs that have been directed to the asset as part of the R&D activities but which are not considered to be connected with bringing the final asset into existence.
- Examples of costs which do not need to be included in the cost of an asset are:
  - Creation of broad concept designs
  - Early expenditure associated with the collection and analysis of data
  - Expenditure associated with the evaluation of the performance of existing products in order to decide which new products/solutions need to be developed
  - Expenditure on rejected system options or other aspects of design that do not find their way ultimately into a finished asset

The practical outcome of the approach proposed in the draft determination is that it is likely the correct treatment for particular design expenditure can only be ascertained once the final shape, features, and performance of the end asset are known. As such, where a project extends over a number of fiscal years, this may result in a re-evaluation of the treatment and a need to amend an entity's income tax return at a later date. If this exceeds a four-year period, this may prove problematic in practice if the amendment period for the return has expired.

Changes to offshore license transfer fees

The registration fees for transfers of, and dealings in, offshore (Commonwealth) petroleum titles imposed under the Offshore Petroleum and Greenhouse Gas Storage (Registration Fees) Act 2006 have been abolished as of 1 November 2013. Those fees will continue to affect applications for the registration of transfers and dealings made up to and including 31 October 2013, but will cease to have effect for applications made on and after 1 November 2013.

Registration fees which formerly applied to the transfers of, and dealings in, Commonwealth petroleum titles could be up to 1.5 percent of the higher of the market value or the consideration provided for the title in question.

From November 2013, all applications for transfers and dealings will be subject to a fixed registration fee which will reflect the costs incurred in undertaking the regulator's relevant work. The new fixed registration fees are set out in the National Offshore Petroleum Titles Administrator's (NOPTA) Schedule of Fees and Levies (**http://www.nopta.gov.au/_documents/scheduleOfFees-20131109.pdf**).

It is expected that, in many cases, the new fixed registration fees will be lower than the ad valorem fees applicable under the former regime, which means lower transaction costs for transfers of, and dealings in, offshore petroleum titles.

Petroleum Resource Rent Tax (PRRT) developments

Release of new ATO guidance

On 19 November 2013, the ATO released two pieces of guidance to assist taxpayers in complying with their PRRT obligations.

The first guidance relates to substantiating the calculation of "look-back expenditure" (**http://www.ato.gov.au/Business/Petroleum-resource-rent-tax/In-detail/PRRT-in-detail/Starting-base/PRRT-look-back-approach-for-starting-base/**) for onshore petroleum projects which became subject to the extended PRRT regime with effect from 1 July 2012. Under the transitional rules, existing projects are able to recognize prior investments and deduct them against their PRRT profits once they enter the PRRT regime. In determining the amount of deductible prior investments made in a project, a taxpayer has the option of choosing the "look-back" approach which allows the taxpayer to recognize actual expenditure incurred on the project for up to 10 years preceding 1 July 2012 as if the PRRT rules had applied during that period.

If the expenditure was incurred between 1 July 2002 and 30 June 2010, the taxpayer must be able to reasonably substantiate the amount and nature of the expenditure sought to be recognized as look-back expenditure. Full substantiation applies to expenditure incurred from 1 July 2010 onwards.

On 19 November 2013, the ATO released two pieces of guidance to assist taxpayers in complying with their PRRT obligations.

According to the ATO guidance, taxpayers are able to rely on the following records to reasonably substantiate the amount and nature of expenditure:

- Accounting and income tax records
- Joint venture records and statements
- Other sources of information

The ATO provides that an entity may use any reasonable basis to substantiate the amount and nature of expenditure. It provides a six-step approach for determining, quantifying and classifying eligible look-back expenditure and excluding any non-deductible expenditure, including indirect administrative and accounting expenditure (which is specifically disallowed). As a concession, the ATO allows taxpayers with expenditure of A$500 million or less for its interest in a petroleum project to use a safe harbor percentage of 7.5 percent to exclude indirect administrative and accounting expenditure from the total costs charged or allocated to the project. The ATO is still considering whether the provision of a safe harbor percentage to larger projects is reasonable and what the percentage would be.

The second guidance relates to the apportionment of composite expenditure (**http://www.ato.gov.au/Business/Petroleum-resource-rent-tax/In-detail/PRRT-in-detail/Work-out-PRRT/Apportionment-of-PRRT-deductible-expenditure/**) for PRRT purposes. PRRT is a project-by-project tax on the upstream profits derived from the recovery and processing of petroleum. Expenditure can only be deductible in determining the taxable profit of a particular PRRT project to the extent the expenditure is incurred in relation to the upstream activities of that project. Therefore, composite expenditure may need to be apportioned:

- Among multiple PRRT projects
- Between upstream and downstream elements
- Between deductible and specifically non-deductible elements
- Among the different classification of PRRT expenditures

The ATO does not prescribe specific methods for apportioning payments for PRRT and requires taxpayers to choose the most relevant and reasonable basis which is supportable by appropriate records. A merely notional or arbitrary basis for apportioning a payment is not acceptable.

When choosing a reasonable basis of apportionment, the ATO provides the following principles and practices:

- Apply a methodical and consistent approach to classifying and apportioning the expenditure.
- Maintain records that describe the activities which show the extent and nature of the activities, and the connection to the project activities.
- Maintain records of calculations and the steps undertaken to support the choice of a reasonable basis.
- Use reliable data.
- Keep information to support the reasoning and justification of any estimates made.
- Consider whether there is a correlation between the basis of apportionment and the expenditure using relevant and appropriate accounting, financing and economic principles, supported by any additional records and details (such as time sheets).

Records must generally be retained for a period of seven years from the date of assessment for the year of tax in which the relevant amount is returned as an assessable receipt or claimed as deductible expenditure.

Affected taxpayers should familiarize themselves with the ATO guidance and ensure the guidance is complied with in the context of their circumstances.

Federal Court decision on calculating taxable PRRT profit

On 11 November 2013, the Federal Court held, in PTTEP Australasia (Ashmore Cartier) Pty Ltd v Commissioner of Taxation [2013] FCA 1175, that:

- The taxpayer was liable to pay PRRT at the taxing point which occurred when it sold crude oil (i.e., on the lifting of a shipment, or in other words, when the buyer takes delivery of it) from its petroleum project.
- In calculating the amount of consideration for the shipment of the crude oil which was assessable to PRRT, the consideration receivable for each shipment of crude was the invoiced price, without taking into account a credit for certain "interest value amounts."

As previously mentioned, PRRT is a tax on the upstream profits of a petroleum project, and PRRT profits are calculated as assessable receipts less deductible expenditure.

Assessable receipts arise when a marketable petroleum commodity, such as stabilized crude oil, is sold or is removed from the place of production or an adjacent storage site. Where there is a sale of an assessable commodity, assessable receipts are calculated as consideration receivable less expenses payable in relation to the sale.

Broadly, deductible expenditure refers to expenditure incurred in carrying on project activities upstream of the taxing point and must not be a specifically excluded item of expenditure. Excluded expenditure is defined to include payments of principal or interest on a loan or other borrowing costs.

Under the arrangement in question, the taxpayer received advance payments from the buyer of its crude oil based on the estimated value (calculated by reference to a deemed or notional oil price) of the taxpayer's crude oil production. Subsequently, when the buyer actually lifted a shipment of crude, the amount actually payable for the crude was then determined based on the prevailing oil price and the actual lifted quantity. The buyer would then be credited for the amounts which it had already paid in advance based on the estimated value of crude production – this ensured that the buyer was not overcharged and that it ended up paying the correct amount for the actual shipment. In addition, the buyer was effectively credited with an interest value amount calculated based on the advance payments which the buyer had previously made.

The single judge of the Federal Court held that when calculating the consideration receivable for the sale of an assessable commodity, the focus of the calculation is on the sale of the commodity such that the amount receivable for a particular sale must be the consideration that moves the sale of the agreed quantity of the product. Accordingly, the interest value amounts could not be taken into account as negative or subtracting elements of the consideration receivable for the sale. The Federal Court also considered that the interest value amounts could not be expenses payable in relation to the sale of crude oil as such expenses were confined to those incurred by the taxpayer to achieve receivability of the sale consideration. Finally, the Federal Court held that the interest value amounts were not deducible project expenditure because the interest value amounts did not have a close and direct relationship to carrying out the upstream operations, facilities and other things comprising the petroleum project. The advance funding arrangement was considered to be a tool by which the taxpayer managed its cash flows and the interest value amounts were the cost of obtaining an advance of funds based on anticipated sales and served to compensate the buyer for the time value of the advance funding provided by the buyer.

This case continues to highlight the strict and narrow interpretation adopted by the courts in applying the PRRT rules in calculating taxable PRRT profits. The outcome of this case appears to be consistent with the findings of other recent PRRT cases. It is, however, acknowledged that it is a factual and legal matter as to what constitutes the taxpayer's true consideration for its crude oil sales, based on the precise wording of the transaction documents in question and the intent of the parties. The taxpayer has lodged an appeal to the Full Federal Court against the decision of the single judge of the Federal Court.

The status and progress of the appeal should be monitored. Meanwhile, PRRT taxpayers in similar or comparable circumstances should carefully review their selling arrangements and contracts, to ensure that their PRRT positions adopted in relation to their sales are robust and defensible.

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Brazil: Customs regime for oil and gas companies changed

The Brazilian government issued guidance on 4 December 2013 (Normative Instruction (NI) 1415/2013) that sets out new procedures for qualifying taxpayers to use the special REPETRO customs regime that applies to goods used in the exploration and production of oil and natural gas fields in Brazil. The REPETRO regime aims primarily to reduce the tax burden on companies involved in such activities and operates by granting a suspension of federal taxes incurred on the import of specific goods and assets (temporary admission regime). Taxes affected include the customs duty (II), federal excise tax (IPI), the program for social integration contribution (PIS), the contribution for the financing of social security (COFINS) and the freight tax (AFRMM).

The NI provides that the following items do not qualify for benefits under the REPETRO regime

- Machinery and equipment and parts with a customs value lower than US$25,000
- Goods whose main function is for the transport of persons or of oil, gas, and other fluid hydrocarbons
- Goods destined for personal use
- Goods that are the subject of a finance lease contract

The REPETRO regime aims primarily to reduce the tax burden on companies involved in such activities and operates by granting a suspension of federal taxes incurred on the import of specific goods and assets (temporary admission regime).

The NI also sets out the following new procedural requirements to benefit from the REPETRO regime:

- The taxpayer must enroll in the Electronic Tax Mailbox in order to request the application of the regime (or to request an extension of the regime). All communications between the taxpayer and the tax authorities will be electronic, via e-CAC.
- The taxpayer must demonstrate that it is in compliance with the tax rules by presenting a certificate that it does not have any outstanding federal tax liabilities and that it has paid its tax liability in full.
- The taxpayer must submit certain documents (including a contract summary that contains specified information) to the Brazilian tax authorities.
- The above documents must be submitted within 30 days after an application is made to use the REPETRO regime.

A REPETRO license will be granted to an applicant through an Executive Act; the license can be reviewed by a tax auditor at any time during the period the regime is in effect and can be revoked (and penalties can be imposed) for noncompliance.

The new NI applies as of 5 December 2013, the date it was published in the official gazette. Taxpayers that already have applied to benefit from the REPETRO regime have 60 days to comply with the new rules.

Russia: The law on encouraging hydrocarbon production on Russia's continental shelf

On 30 September 2013 the President of the Russian Federation signed the Law[1] on encouraging hydrocarbon production on Russia's continental shelf (the Law).

The key amendments will come into force on 1 January 2014. Due to the systemic nature of the anticipated changes, it can be said that the legislator is essentially introducing a special tax regime for oil and gas companies carrying out hydrocarbon extraction on the continental shelf.

The Law includes a number of significant amendments to tax and customs legislation and to the Law on the continental shelf. In particular, it stipulates tax treatment with respect to profits tax, Value Added Tax (VAT), and Mineral Extraction Tax (MET), the application of transfer pricing rules, and the procedure for the payment of customs clearance charges associated with extraction activities on the shelf.

Below you will find an overview of the key provisions of the Law.

Terms and definitions

The Law introduces new concepts to Russian legislation such as "commercial exploitation of hydrocarbon deposits," "new offshore hydrocarbon deposit," "operator of a new offshore deposit," "artificial islands," and "artificial structures and constructions."

In particular, an offshore hydrocarbon deposit is defined as "a hydrocarbon deposit at a subsurface site(s) located entirely within Russia's inland seas and/or territorial waters and/or on the continental shelf of the Russian Federation or in the Russian sector of the Caspian Sea shelf."

The term "new offshore deposit" refers to an offshore deposit where the commercial extraction of hydrocarbons begins no earlier than 1 January 2016[2] (New Deposit).

The Law introduces certain conditions which must all be met for an entity to be recognized as the New Deposit Operator (Operator), i.e.:

- A License Holder or an entity which is a related party of the License Holder must hold a direct or indirect interest in the entity's capital.
- An entity carries out at least one type of activity associated with hydrocarbon extraction at the New Deposit (itself or by engaging subcontractors).

> … it stipulates tax treatment with respect to profits tax, Value Added Tax (VAT), and Mineral Extraction Tax (MET), the application of transfer pricing rules, and the procedure for the payment of customs clearance charges associated with extraction activities on the shelf.

- An entity carries out activities associated with hydrocarbon extraction at the New Deposit based on the agreement with the License Holder. The agreement should also provide for reimbursement payable to the Operator, the amount of which shall depend, inter alia, on the volume of hydrocarbons extracted at the corresponding offshore hydrocarbon deposit and/or proceeds from the sale of the raw materials.

An entity is recognized as the Operator starting from the conclusion of an operation agreement. There should be no more than one Operator at the New Deposit. License Holders may engage both Russian and foreign entities as Operators.

Profits tax

The profits tax rate for New Deposits is set at 20 percent. The entire amount of the profits tax is payable to the federal budget[3] and therefore cannot be reduced by regional authorities.

The law prescribes a specific procedure for calculating income and expenses for the purposes of profits tax calculation at the New Deposits applicable to the following taxpayers engaged in activities associated with hydrocarbon extraction at the deposits:

- Organizations holding licenses to use subsurface resources of the new offshore hydrocarbon deposit (License Holders)
- Operators of a new offshore hydrocarbon deposit

The tax base for activities associated with hydrocarbon extraction at each New Deposit should be determined separately from the tax base on other taxpayer's activities. At the same time, if the taxpayer performs activities involving mineral production at two or more deposits, the tax base should be determined separately for each deposit.

> The profits tax rate for New Deposits is set at 20 percent.

1 The Law on Amendments to the first and second part of the Russian Federation Tax Code and Certain Legislative Acts of the Russian Federation in connection with the Implementation of Tax and Customs-Tariff Measures to Encourage Oil and Gas Production on Russia's Continental Shelf.

2 This includes offshore hydrocarbon deposits with no commercial production commencement date as of 1 January 2016.

3 As a reminder, under a general provision of the Russian Federation Tax Code, the amount of profits tax assessed at a rate of 20 percent is divided between the federal and regional budgets in the proportion of 18 percent to 2 percent.

Some peculiarities of calculating the income and expenses of Operators and License Holders

- If the Operator or the License Holder decides to discontinue work at a subsurface site due to economic or geological inexpediency or for other reasons, the Operator or the License Holder may allocate the entire amount of losses incurred on mineral resource development (or any part of them) to any new offshore development at the subsurface site.
- If the right to use subsurface resources at the subsurface site is terminated, the taxpayer may treat the entire amount of expenses incurred for mineral resources development (or any part thereof) as expenses associated with New Deposits which the taxpayer is developing at other subsurface sites lying wholly within Russia's inland seas and/or territorial waters, and/or on the continental shelf of the Russian Federation, or in the Russian sector of the Caspian Sea. In this respect, the amount of expenses for such activities, carried out in relation to each deposit at another subsurface site, may not exceed one-third of the total amount of expenses for the development of natural resources at the subsurface site, in relation to which the right to use subsurface resources has been terminated.
- In the subsequent acquisition of the rights for a subsurface site, the entire amount of expenses previously incurred for mineral resource development may be treated as expenses for activities associated with hydrocarbon production at the New Deposit carried out at this subsurface site.
- If the taxpayer transfers hydrocarbons produced at the New Deposit for processing by other structural subdivisions (or by third parties on a give-and-take basis) and such processing does not relate to hydrocarbon production at the New Deposit, the income from the sale of the processed hydrocarbons should be taxed based on general rules outlined by the Russian Federation (RF) Tax Code. Income from activities associated with hydrocarbon extraction at the New Deposit should be determined as the cost of the hydrocarbons in accordance with the new rules stated by the Law.

- Organizations engaged in activities associated with hydrocarbon production at New Deposits may carry forward losses arising from such activities. The general 10 year limitation does not apply to Operators and License Holders when calculating their profits tax base with respect to hydrocarbon extraction activities at the New Deposit in accordance with Art. 275.2 of the RF Tax Code.

Bonuses and privileges

- The License Holder may include in other expenses the amount of actual costs as reimbursement of expenses for mineral resource development previously incurred by the former license holder in order to obtain the license.
- License Holders carrying out activities in the territory of a New Deposit may create a provision for profits tax purposes with regard to the completion of hydrocarbon extraction activities at the New Deposit.
- The Operator may include in expenses the full amount of reimbursement paid to the License Holder for the previously incurred costs of obtaining the license.
- If the Operator is a foreign entity carrying out hydrocarbon extraction activities at a New Deposit in the RF through more than one division, such an entity may determine the tax base for its activities, relating to the same New Deposit, altogether for the group of these divisions. In this respect, all divisions included in the group should apply a unified accounting policy for tax purposes.

- The Operator and the License Holder may deduct as expenses for profits tax purposes the full amount of accounts receivable in respect of a loan or borrowings (including accrued interests) written off as a result of debt forgiveness or due to other reasons, if the amounts were provided to finance hydrocarbon production at the New Deposit.
- General expenses in respect of new deposits should be allocated in the proportion determined by the taxpayer. This methodology should be documented in the accounting policy and should be applied for at least five years. This methodology is applicable if:
  - The expenses may not be directly attributed to activities associated with hydrocarbon production at the New Deposit or to another taxpayer's activity
  - The expenses are directly related to activities associated with hydrocarbon extraction at the New Deposit and are incurred in respect of several deposits

Mineral Extraction Tax (MET)

The Law establishes differentiated ad valorem MET rates for shelf projects depending on their complexity. All offshore projects are divided into four categories from basic to Arctic.

Depending on the category, MET rates are established ranging from 30 percent for the basic category to 4.5 percent for the Arctic category.

MET rates are established for a certain period of time and calculated starting from the month following the month of commencement of commercial hydrocarbon extraction.

Depending on the category, MET rates are established ranging from 30 percent for the basic category to 4.5 percent for the Arctic category.

Applicable MET rates and their application conditions are shown in Table 1 below.

Table 1

MET rate	Application conditions
30 percent	Deposits lying within the Azov Sea or with 50 percent or more of their area in the Baltic Sea. The rate is established for a maximum period of 60 calendar months, no later than 31 March 2022.
15 percent	Deposits lying at least 50 percent within the Black Sea (up to 100m deep, inclusive), in the Russian part of the Caspian Sea in the Pechora and White Seas, in the southern part of the Sea of Okhotsk (south of 55 degrees north latitude), or in the Russian part of the Caspian Sea. The rate is established before the expiration of 84 calendar months but no later than 31 March 2032.
10 percent (except for natural gas)[4]	Deposits with 50 percent or more of their area in the Black Sea (below a depth of 100m), the north part of the Sea of Okhotsk (at or north of 55 degrees north latitude), or the southern part of the Barents Sea (south of 72 degrees north latitude). The rate is established before the expiration of 120 calendar months but no later than 31 March 2037.
5 percent (except for natural gas)	Deposits with 50 percent or more of their area in the Kara Sea, the northern part of the Barents Sea (at or north of 72 degrees north latitude), and the eastern Arctic (the Laptev Sea, the East Siberian Sea, the Chuckchi Sea, and the Bering Sea). The rate is established before the expiration of 180 calendar months but no later than 31 March 2042.
4.5 percent (except for natural gas)	When mineral resources are extracted by entities without the right to export LNG produced by natural gas extracted at the new deposits with 50 percent or more of their area in the Kara Sea, the northern part of the Barents Sea (at or north of 72 degrees north latitude), and the eastern Arctic (the Laptev Sea, the East Siberian Sea, the Chuckchi Sea, and the Bering Sea), the tax rate is established before the expiration of 180 calendar months but no later than 31 March 2042.

4 MET rates for natural gas and their application conditions are shown in Table 2 overleaf.

The Law stipulates that transactions between the Operator and the License Holder concluded in the course of hydrocarbon extraction with respect to the same deposit should not be subject to transfer pricing control.

At the same time, the Law expands the list of transactions subject to transfer pricing control.

Please note that the Law establishes special MET rates for natural gas produced at certain New Deposits. Table 2 below shows applicable MET rates depending on certain conditions.

Table 2

MET rates for natural gas	Rate application conditions
1 percent	For natural gas produced at deposits with 50 percent or more of their area in the Kara Sea, the northern part of the Barents Sea (at or north of 72 degrees north latitude), and the eastern Arctic (the Laptev Sea, the East Siberian Sea, the Chuckchi Sea, and the Bering Sea). The rate is established before the expiration of 180 calendar months but no later than 31 March 2042.
1.3 percent	For natural gas produced at deposits with 50 percent or more of their area in the Black Sea (below a depth of 100m), the north part of the Sea of Okhotsk (at or north of 55 degrees north latitude), or the southern part of the Barents Sea (south of 72 degrees north latitude). The rate is established before the expiration of 120 calendar months but no later than 31 March 2037.

The Law also establishes the MET rate as RUB 0 for hydrocarbon extraction, the tax base in relation to which is defined in physical terms, particularly for hydrocarbon deposits, located entirely within Russia's inland seas and/or territorial waters and/or on the continental shelf of the Russian Federation or in the Russian sector of the Caspian Sea shelf.

Transfer pricing

The Law stipulates that transactions between the Operator and the License Holder concluded in the course of hydrocarbon extraction with respect to the same deposit should not be subject to transfer pricing control.

At the same time, the Law expands the list of transactions subject to transfer pricing control. Controlled transactions may now also include a transaction where one of the parties is either the License Holder or the Operator of the New Deposit and takes into account income (expenses) arising from the transaction when determining the profits tax base in accordance with Art. 275.2 of the RF Tax Code.[5] At the same time, the other party to the transaction should meet the following criteria:

- The other party is neither the License Holder, nor the Operator, or
- The other party is the License Holder or the Operator, but does not take into account income (expenses) arising from the transaction when determining the profits tax base in accordance with Art. 275.2 of the RF Tax Code.

Transactions must exceed RUB 60 million in the course of one calendar year to be regarded as controlled transactions.

Indirect taxation

VAT

Under the new Law, Russia's continental shelf and exclusive economic zone are deemed to be Russian territory for the purpose of determining the place of supply of hydrocarbons extracted from an offshore deposit and the products of its technological conversion and also work (services) pertaining to geology study and exploration performed on the continental shelf and exclusively within Russia's economic zone, as well as maintenance, repair, reconstruction, upgrade or liquidation, or other capital services.

Hydrocarbons (as well as products of its technological conversion) produced and transported from a point of origin situated on Russia's continental shelf to a destination point outside Russian territory are taxable at a 0 percent rate if all supporting documentation is provided.

Services related to the carriage and/or transportation of hydrocarbons from points of origin situated on Russia's continental shelf to a destination point outside Russian territory are deemed to be international carriage. Provided supporting documents are available, such services are subject to 0 percent VAT.

Amendments to Art. 165 of the RF Tax Code allow contractors and subcontractors to apply 0 percent VAT on export sales of hydrocarbons for the purpose of using them in activities associated with hydrocarbon extraction on Russia's continental shelf.

5 Art.275.2 of the RF Tax Code.

Custom duties

Exemption from export duties for the development of new deposits

The Law establishes the effective period for the exemption from export duties for some types of goods obtained during the development of the New Deposit. Application conditions are shown in Table 3 below.

Table 3

Hydrocarbon type	Location of the new deposit	Application period
• Crude oil • Natural-gas condensate • LNG and condensed natural gas • Broad light-hydrocarbon fraction	Deposits lying wholly within the Azov Sea or with 50 percent or more of their area in the Baltic Sea.	Up to 31 March 2032
	Deposits lying at least 50 percent within the Black Sea (up to 100m deep, inclusive), in the Pechora and White Seas, in the southern part of the Sea of Okhotsk (south of 55 degrees north latitude), or in the Russian part (Russian sector) of the Caspian Sea.	Up to 31 March 2032
	Deposits with 50 percent or more of their area in the Black Sea (below 100m deep), the north part of the Sea of Okhotsk (at or north of 55 degrees north latitude), or the southern part of the Barents Sea (south of 72 degrees north latitude).	Up to 31 March 2042
	Deposits with 50 percent or more of their area in the Kara Sea, the northern part of the Barents Sea (at or north of 72 degrees north latitude), and the eastern Arctic (the Laptev Sea, the East Siberian Sea, the Chuckchi Sea, and the Bering Sea). The rate is established before the expiration of 180 calendar months but no later than 31 March 2042.	Up to 31 March 2042

Exemption from export duties for the development of other offshore deposits

The Law also includes export duty exemption for goods produced during the development of other offshore deposits. Application conditions are shown in Table 4 below.

Table 4

Hydrocarbon type	Location of the offshore deposit	Application period
• Condensed natural gas • Crude oil • LNG	Deposits with 50 percent or more of their area in the southern part of the Sea of Okhotsk (south of 55 degrees north latitude) provided that the level of depletion for each hydrocarbon type (other than associated gas) produced at such deposit is less than 5 percent at 1 January 2015.	Up to 1 January 2012

Pursuant to the Law, offshore fixed and floating platforms, offshore mobile drilling rigs, and drilling vessels are exempt from transport tax.

Other taxes

Property tax

The Law stipulates that property situated within Russia's inland seas and territorial waters, on Russia's continental shelf, in the exclusive economic zone or in the Russian sector of the Caspian Sea is exempt from property tax (including property transferred under lease agreements).

The exemption is applicable only if the property is used in the development of offshore hydrocarbon deposits, including geological study and exploration and the performance of preparatory work, for no less than 90 calendar days in the course of one calendar year.

Transport tax

Pursuant to the Law, offshore fixed and floating platforms, offshore mobile drilling rigs, and drilling vessels are exempt from transport tax.

Areas of uncertainty

In conclusion, we would like to mention a few aspects that, in our opinion, were not considered by the legislator and currently constitute disputable areas:

- Can the Operator claim expenses incurred by the License Holder prior to the conclusion of the operation agreement for the reimbursement of the License Holder's costs?
- How will the income and expenses incurred by taxpayers in respect of hydrocarbon extraction activities at the New Deposit prior to the enactment of the new Law be treated?
- What will be the technical procedure for the transfer of losses and expenses upon the decision to discontinue work at the subsurface site? If no New Deposits are established at the subsurface site, does this mean that the License Holder will lose the expenses incurred for mineral resource development?
- How will expenses incurred by the Operator for hydrocarbon extraction at the New Deposit be treated in the event that it prematurely loses its Operator status?
- Will amendments to customs legislation be regarded as a tax incentive? Will it be appropriate for companies to plan offshore hydrocarbon production, considering that, under favorable conditions, practical offshore hydrocarbon production may only commence in 10 years?
- Will Russian transfer pricing regulations apply to transactions between the License Holder and the Operator that were carried out prior to the enactment of the Law?

Tanzania: Tax updates

Application of withholding tax to services provided outside Tanzania

The long running dispute over the interpretation of Tanzania's sourcing rules took a disappointing turn recently when the Tax Revenue Appeals Tribunal (TRAT) issued their decision in the case of *Tullow Tanzania BV vs. the Commissioner General of the Tanzania Revenue Authority* (TRA). The TRAT found in favor of the TRA, supporting the earlier decision of the Tax Revenue Appeals Board. The TRAT is the second level of appeal available in Tanzania. The final appeal is to the Court of Appeal and the case is expected to be heard in 2014.

The point at issue is whether payments for services physically provided outside Tanzania are Tanzanian source income and thus subject to 15 percent withholding tax. The legislation seems clear that where the service is performed outside Tanzania, payments are not Tanzanian source. The TRA has argued that it is the location of consumption (rather than performance) that is critical. The TRAT decision supports this but, in our view, without any clear technical justification.

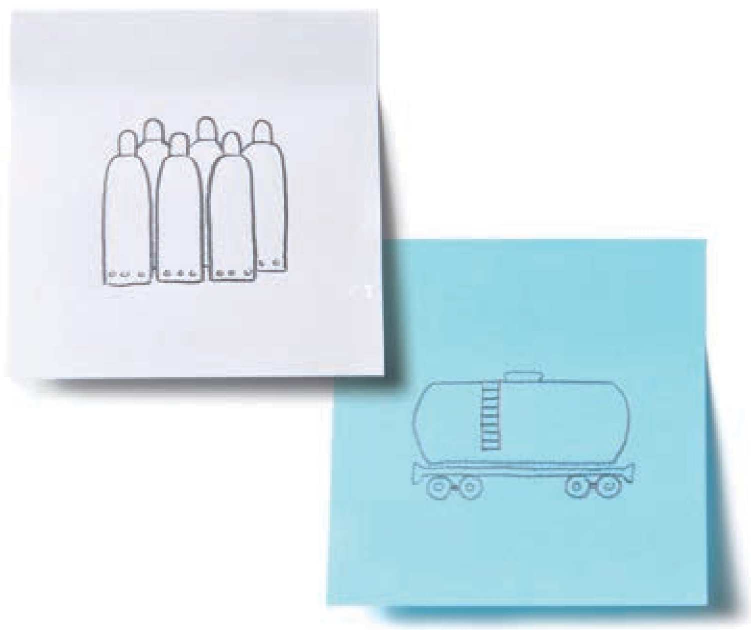
New VAT bill

In late October, the Tanzania Ministry of Finance issued a VAT Bill for comment. This includes proposals that will improve the VAT system (e.g., an explicit adoption of the destination principle); however, there are other proposals that could have a significant negative impact on the upstream industry. Specifically, the bill excludes special relief which has previously enabled companies to obtain what amounts to zero rating of services used in the exploration phase and similar relief on imports and domestic purchases of capital goods.
As exploration and production companies have no sales in the exploration phase and will have mostly zero rated export sales once in production, the resulting requirement to pay and reclaim input VAT will have serious cash flow implications as the TRA has a poor record of making VAT repayment. Representations have been made by the industry and at the time of writing there is still a chance that these proposals will be modified before the bill is presented to Parliament.

New model Production Sharing Agreement (PSA)

Tanzania launched a new licensing round at the end of October and as part of this process the government has issued a new model PSA as a basis for negotiating the fiscal and other terms for new blocks. The new model represents a significant toughening of fiscal terms with increases in royalties, state participation, state hydrocarbon share, and imposition of additional profits tax (which was previously not applied to deep water blocks). Further detailed commentary is available at: **http://www.deloitte.com/view/en_TZ/tz/services/tax/index.htm**

… the bill excludes special relief which has previously enabled companies to obtain what amounts to zero rating of services used in the exploration phase and similar relief on imports and domestic purchases of capital goods.



United Kingdom: Autumn statement

Overall the measures are welcome news.

The Autumn statement made a number of announcements affecting the UK oil and gas industry, some expected, some unexpected. Overall the measures are welcome news and reflect the UK government's continuing support of exploration for oil and gas in the UK and on the UK Continental Shelf. The key announcements were the introduction of a new onshore allowance, the extension of existing reliefs where certain conditions are met, and a potential restriction to the amount of tax relief available where certain offshore chartering arrangements are in place.

New onshore allowance

Following a consultation on a fiscal regime for shale gas, the Chancellor announced the introduction of a new UK tax regime which will apply to all onshore oil and gas projects (whether conventional or unconventional, e.g., shale) granted development consent on or after 5 December 2013. The allowance could reduce the effective tax rate from 62 percent down to around 30 percent. See **http://www.ukbudget.com/autumnstatement2013/measures/business/autumnstatement2013-business-New-onshore-allowance.cfm**

Offshore chartering

The Government announced it will consult with industry on legislation to be introduced which will cap the tax deductible amounts for certain companies. The cap will apply to intra-group leasing payments for large offshore oil and gas assets that are leased under a bareboat charter arrangement. The cap is expected to be calculated by reference to the historic capital cost of the asset which is subject to the lease.

A new ring fence to protect resulting revenue will also be introduced. See **http://www.ukbudget.com/autumnstatement2013/measures/business/autumnstatement2013-business-Oil-and-gas-offshore-chartering-and-rig-leasing.cfm**

Other measures to encourage exploration

In addition to a new regime for onshore oil and gas projects, the Chancellor announced a number of measures to stimulate exploration for both onshore and offshore exploration. Those measures include an extension of reinvestment relief where a company sells an asset used for exploration and appraisal activity and reinvests the proceeds in the UK and UK Continental Shelf, and an extension of the scope of the Substantial Shareholding Exemption where certain conditions are met. See **http://www.ukbudget.com/autumnstatement2013/measures/business/autumnstatement2013-business-Measures-to-encourage-further-exploration.cfm**

United States: Recent tax court case highlights tax considerations for landowners receiving bonus payments

Deloitte Oil & Gas Tax Alert article originally published on 27 January 2014

http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/Tax/us_tax_OG_tax_alert_011414.pdf

A recently issued Tax Court memorandum opinion *Dudek v. Commissioner*[6], addressed the tax treatment of a bonus payment received by landowners in connection with the signing of an oil and gas lease agreement. The court concluded that the lease bonus payment received by the taxpayers in this case is taxable as ordinary income and not capital gain, and that the taxpayers were not entitled to a depletion deduction. While the analysis of the court was not novel or surprising, the case does serve as a reminder of the basic tax rules surrounding the receipt of these payments by landowners. In light of the proliferation of domestic oil and gas leasing activity in recent years, this topic is of increasing relevance to many taxpayers that may not historically have received these types of payments.

The taxpayers in *Dudek* owned acreage in Pennsylvania and entered into an oil and gas lease agreement with an independent oil and gas company. Under the lease agreement, the taxpayers received an upfront payment (the lease bonus payment) to induce them to enter into the lease agreement. Additionally, the lease agreement entitled them to a royalty payment equal to 16 percent of the net profits of any oil and gas extracted from the property. The lease bonus payment was not dependent on any extraction or production of oil or gas. The taxpayers reported the lease bonus payment on their federal income tax return as a long-term capital gain, which upon examination the Internal Revenue Service (Service) re-characterized the payment as ordinary income. The Service also asserted a 20 percent accuracy related penalty because of the taxpayers' treatment of this payment. While contesting the government's character determination, the taxpayers further argued that if the bonus payment is taxable as ordinary income, that they are entitled to a deduction for depletion.

Character of bonus payments — lease v. sale

The Tax Court highlighted the long established ruling of the Supreme Court that the receipt of a lease bonus payment by a lessor pursuant to an oil and gas lease is taxable as ordinary income, not as capital gain.[7] The court then analyzed the facts to ascertain whether the transaction at issue was in fact a lease or was in substance a sale transaction, as argued by the taxpayers.

In concluding that the agreement at issue was a lease and not a sale, the court referenced a number of historical cases focused on the "sale v. lease" determination. Under these cases, the crux of the analysis is whether the owner of the land "retains an economic interest in the deposits." If so, the transaction is regarded as a lease and the proceeds are taxable as ordinary income.[8] To determine whether the taxpayers retained an economic interest, the court sought to determine whether the taxpayer retained a right to share in the oil produced, based on the economic realities of the transaction.[9]

In this situation, the court noted that the agreement entitled the taxpayers to future royalty payments equal to a percentage of the net profits of any oil or gas extracted from the property, and that it is well established that the holder of a royalty interest in natural resources possesses an economic interest in the minerals in place.[10] Moreover, the court noted that the economic realities of a sale would be evidenced by an exchange of a determinable quantity of oil and gas for a determinable price, which did not exist here.

Depletion

The court quickly discounted the taxpayers' claim that they should be entitled to a percentage depletion deduction related to the lease bonus income. I.R.C. § 613A(d)(5) specifically provides that a percentage depletion deduction for income from oil and gas wells does not apply to "any lease bonus, advance royalty, or other amount payable without regard to production from property."[11] The bonus payment at issue was paid to induce the taxpayers to enter into the lease agreement and it did not relate to any extraction or production of oil and gas.

While the analysis of the court was not novel or surprising, the case does serve as a reminder of the basic tax rules surrounding the receipt of these payments by landowners.

6 *Dudek v. Commissioner,* T.C. Memo. 2013-272 (December 2013).

7 *Burnet. Harmel,* 287 U.S. 103, 104, 112 (1932).

8 See e.g., *Laudenslager v. Commissioner,* 305 F.2d 686, 690 (3d Cir. 1962); *Cox V. United States,* 497 F.2d 348 (4th Cir. 1974).

9 CIting, *Palmer v. Bender,* 287 U.S, 551 (1933); *Deskins v. Commissioner,* 87 T.C. 305 (1986).

10 *Kittle v. Commissioner,* 21 T.C. 79 (1953); *see also Palmer*, 287 U.S. at 557.

11 See also, Treas. Reg. Sec. 1.613A-3(j).

The court did acknowledge, however, that bonus payments are eligible for cost depletion under Treas. Reg. § 1.612-3(a)(1), such cost depletion amount being dependent upon the taxpayer's basis for depletion, the amount of the bonus payment, and the future royalties the taxpayer expects to receive. In this case, the court concluded that the taxpayer failed to meet its evidentiary burden to provide any evidence as to the amount of royalties the taxpayers expect to receive. Without this information, it was not possible for the court to compute any amount of cost depletion.

Penalties

Finally, the Tax Court upheld the Service's assertion of the 20 percent accuracy related penalty. The court noted that the taxpayer failed to establish that it acted with reasonable cause and in good faith. While not elaborating on the basis of its conclusion that the taxpayer lacked reasonable clause in detail, the court's repeated commentary throughout the opinion that the underlying tax principles were well settled provided a pretty clear view that the court viewed most of the taxpayers' arguments as meritless.

Other considerations

Establishing a separate basis for minerals

While not specifically addressed by the court, this case does implicitly raise the issue of what is necessary for a taxpayer to establish a separate "basis" for mineral rights when the land and minerals are purchased together in a single transaction. Many purchasers do not allocate cost basis to mineral rights when they are acquired in the same transaction with the underlying land.

While there is not a lot of direct authority on this topic as it relates to depletion, there is analogous authority in the context of claiming a worthless deduction for minerals.[12] This authority supports a view that unless a cost basis was established for the mineral rights at the time of purchase or at the time of receipt, if inherited or received as a gift, the mineral rights may have no separate cost basis. The Internal Revenue Manual references the Service's general view that there is no separate cost basis in the minerals unless:[13]

- The seller's cost included a stipulated amount for mineral rights,
- The seller's basis was the result of an estate tax valuation in which minerals and surface were valued separately, or
- The seller's cost basis can be properly allocated between surface and minerals because of substantive evidence of value attributable to the minerals at the date of acquisition.

While a taxpayer may be able to factually establish a separate basis for the minerals by evidence of the relative values at the time of acquisition,[14] the taxpayer generally has the burden of proving the basis allocable to the minerals.[15]

Estimated future royalties on wildcat acreage

Another potential issue highlighted but not discussed in *Dudek* is some of the historical authority potentially supportive of claiming a 100 percent cost depletion deduction in situations where a zero estimate of future royalties to be received in the future is reasonable.[16] In *Collums*, the court concluded that a zero estimate of future royalties was reasonable where the lease was in a wildcat area and where there was no evidence to indicate there would be future production during the lease term. Based on this factual determination, the court applied the cost depletion formula in the treasury regulations and concluded that the taxpayer was entitled to a cost depletion deduction in the year of the receipt of the lease bonus equal to the entire basis in the leases.

The Service, however, has published a contrary view in a subsequently issued technical advice memorandum.[17] In this ruling, the Service argued that a determination that no future production was likely was equivalent to arguing no mineral deposit exists. As such, the Service contended that a deduction for cost depletion cannot be claimed when there is no mineral deposit present.

Carving out royalty interest prior to sale

Compare the facts above to a situation where prior to entering into negotiations with the oil company the taxpayer separates an overriding royalty interest from the working interest and transfers the overriding royalty interest to a separate related party for a business reason. Later, the taxpayer negotiates a similar deal with the oil company and transfers the entire working interest to the oil company. At the end of the day, the economics are similar and the oil company has obtained the working interest "subject to" the pre-existing overriding royalty interest held by the related party.

12 See e.g., *Henley v. United States,* 396 F.2d 956 (19XX).

13 IRM 4.41.1.2.1.2 (12-03-2013).

14 *Plow Realty Company of Texas v. Commissioner,* 4 T.C. 600 (1945); *Perkins v. Thomas* 86 F.2d 954 (5th 1936).

15 Rev. Rul. 69-539, 1969-2 CB 141.

16 *Murphy Oil Co. v.* Burnet, 287 U.S. 299 (1932); *Collums v. United States,* 480 F. Supp. 864 (DC Wyo. 1979).

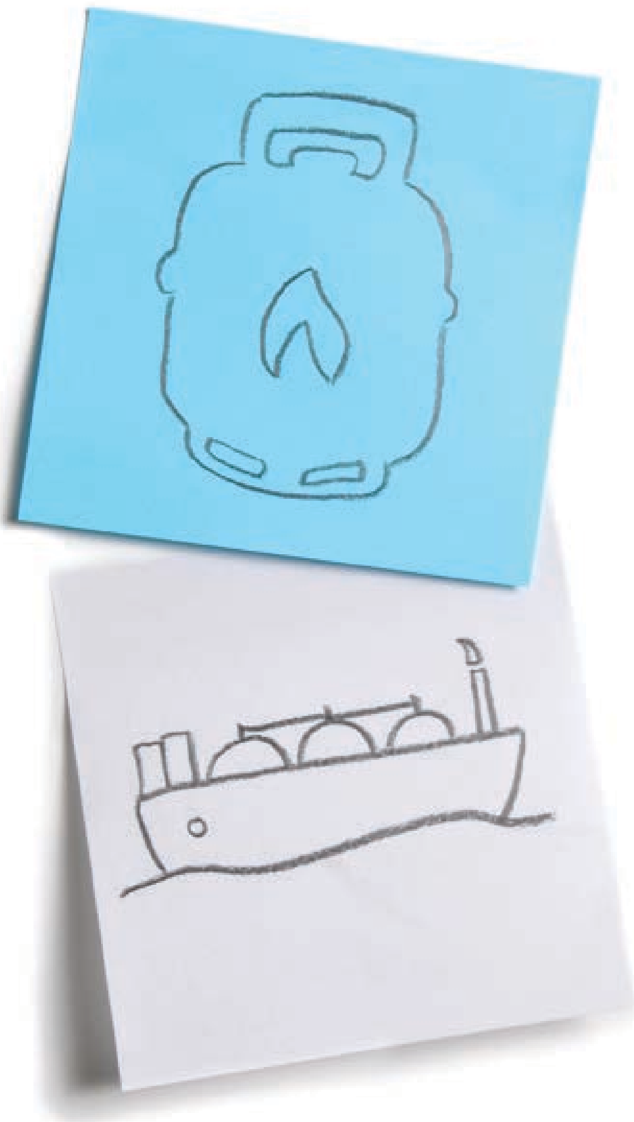
17 TAM 8532011 (May 7, 1985).

Now, under the form of the transaction the taxpayer has a stronger case that it has entered into a sale and not a lease transaction because it sold a working interest and the taxpayer did not retain an economic interest in the oil and gas deposit by retaining a royalty. Instead, the overriding royalty interest is a pre-existing interest owned by a separate taxpayer (e.g., the related party). The taxpayer has disposed of the taxpayer's entire interest in the minerals.

Query whether the Service, however, could challenge the transaction using a step-transaction or a substance over form type argument.[18]

Conclusion

With the recent proliferation of domestic drilling activity in the United States, many taxpayers and their advisors are addressing tax issues specific and unique to the oil and gas industry that were not historically relevant to them. While the Tax Court's recent opinion in *Dudek* does not contain any new or novel tax considerations of significance, it does serve to highlight a number of these unique industry issues as they relate to receipt of lease bonus payments by the owner of a mineral interest. As the above discussion illustrates, while many of these issues are considered well settled, there also remain a number of areas potentially subject to controversy between taxpayers and the government.



18 See e.g., FSA 1999-819.

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