THE ADVANCED DIPLOMA IN INTERNATIONAL TAXATION

June 2025

MODULE 3.04 – ENERGY RESOURCES OPTION

SUGGESTED SOLUTIONS

PART A

Question 1

Part 1

A concession is a grant by a country to a foreign company to develop its oil and gas reserves on an exclusive basis in a defined area during the duration of the agreement. According to concession regimes, title to oil and gas is transferred to the international oil and gas company. Title is given to the extracted oil and gas but not to the total oil and gas exist in situ. Companies acquire rights to control large areas of land/sea to carry out their operations over a relatively long period of time (up to 75 years in some cases). The contractor pays all the costs associated with exploration, development and production activities without any guarantee from the host government to recover any of these costs.

According to PSA the government retains titles to oil and gas reserves but gives the contractor a share to production, known as profit oil. The international oil and gas company bears all the pre-production risks and costs and when commercial reserves are discovered the contractor is entitled to recover its costs via cost oil. The remaining oil and gas (the profit oil) is split between the international oil and gas company and the host government according to a pre-agreed formula, this can be fixed percentage or on a sliding scale basis. The company still has to pay taxes on its share of the profit oil; in some cases company's taxes is paid by host government from their profit oil share.

Part 2

In general, PSA allows higher revenues and tax takes for host government. However, since the table above does not indicate certain rules and conditions that allows different payments according to the different types of oil agreements, revenues will be the same for both contracts. ABC country can enhance its revenues and takes by implementing conditions and rules that allow extracting more revenues such as signature bonuses and taxes on sliding scale.

Part 3

ABC Country may introduce a number of measures that increases its revenues from its potential oil resources, such as:

- Signature bonuses;
- Production bonuses;
- Production-base bonuses on a sliding scale;
- A share of production; and
- Windfall profit taxes.

The country could also request Lucky Oil Plc to provide non-financial services, such as free training for national employees, and contributions to social services.

Additionally, ABC Country could include a clause that requests Lucky Oil Plc to leave all the production facilities and assets in place at the end of the agreement, while holding the company responsible for decommissioning the assets upon oil expiry.

Question 2

Transfer pricing refers to the pricing of transactions between related entities within a multinational enterprise (MNE). In the oil and gas industry, transfer pricing is particularly complex due to cross-border trade in crude oil, gas, refined products, and services. Improper transfer pricing can shift taxable profits to low-tax jurisdictions, reducing government revenues and increasing tax disputes. Tax authorities are highly concerned about these practices as they can lead to significant revenue losses, prompting stricter regulations and enhanced scrutiny.

Governments aim to ensure fair taxation of oil and gas profits, but MNEs may manipulate transfer prices to minimise tax liabilities. Concerns arise when companies sell crude oil or gas to affiliates at non-market rates, shifting profits offshore. Service and financing transactions can also be structured to inflate costs in high-tax jurisdictions. Furthermore, oilfield services, intellectual property (IP), and trademarks may be priced below or above fair market value to exploit tax differences between jurisdictions, creating risks of tax avoidance.

In the upstream sector, transfer pricing risks emerge from crude oil sales between subsidiaries, where companies may sell at discounted prices to offshore affiliates. Exploration and production cost allocation also poses a risk, as mispricing technical services can shift profits to tax havens. Additionally, license fees and royalties paid for IP and drilling technology may be artificially high, allowing MNEs to transfer profits out of resource-rich countries. Tax authorities monitor these transactions to ensure appropriate taxation based on the economic activities taking place in their jurisdictions.

Downstream operations involve refining, distribution, and retail activities, which create additional transfer pricing risks. Intercompany sales of refined products may be priced manipulatively between group entities. Management fees and shared services between parent companies and subsidiaries can also be structured to shift profits. Cost-sharing arrangements for oil storage, transportation, and distribution must be carefully analysed, as excessive deductions or artificially high charges could reduce taxable profits in high-tax locations. Governments increasingly enforce substance-over-form rules to prevent these practices and ensure fair taxation.

The Comparable Uncontrolled Price (CUP) method is a key approach used in transfer pricing for oil and gas transactions. This method compares intercompany prices to those charged in unrelated transactions. It is widely used for crude oil and liquefied natural gas (LNG) pricing, particularly where market benchmarks such as Brent, WTI, and Henry Hub are available. However, pricing adjustments for quality differences, transportation costs, and long-term contracts make direct comparability challenging. Despite these limitations, CUP remains the preferred method where reliable public price data exists.

The Cost Plus method and Resale Price method are also commonly used in the oil and gas industry. The Cost Plus method is applied for intra-group oilfield services by adding a markup to costs incurred. Meanwhile, the Resale Price method ensures that when a related entity resells crude oil or refined products, it does so at a fair gross margin. These methods help establish arm’s length pricing but are challenging when dealing with highly volatile commodity prices, where margins fluctuate due to external market conditions.

The Transactional Net Margin Method (TNMM) and Profit Split Method provide alternative approaches for pricing intercompany transactions. The TNMM compares net profit margins of controlled transactions with those of independent transactions. The Profit Split Method allocates profits between related entities based on their economic contributions, making it particularly useful for joint ventures and integrated operations. Although these methods offer flexibility, they are complex and require detailed financial and operational data to justify pricing decisions. It is important to note that while methods like CUP, Cost Plus, TNMM, and Profit Split are widely accepted, their application and the scrutiny applied by tax authorities can vary significantly across jurisdictions, often leading to uncertainty and litigation.

Tax authorities challenge transfer pricing methods in the oil and gas industry by examining whether intercompany transactions reflect true economic substance and align with the arm’s length principle. Given the industry's reliance on cross-border dealings in crude oil, services, and intangibles, tax authorities are especially alert to arrangements that shift profits to low-tax jurisdictions without corresponding business activity.

Authorities often require detailed transfer pricing documentation, including Country-by-Country Reports (CbCR) and functional analyses. Inconsistencies—such as high margins in low-substance entities—may prompt adjustments. Tools like Advance Pricing Agreements (APAs), while reducing uncertainty, also allow tax authorities to pre-approve or later challenge pricing if actual transactions diverge from agreed terms. Additionally, aggressive use of royalties, management fees, or intra-group services without substantiation is likely to face recharacterisation or denial of deductions.

In challenging non-compliant pricing, tax authorities may impose profit reallocations, interest charges, and penalties, asserting taxation rights based on effective control, decision-making, or asset use in their jurisdiction. As scrutiny increases, oil and gas multinationals must ensure robust, transparent pricing models and maintain defensible documentation to support the commercial rationale of their intercompany dealings.

PART B

Question 3

Part 1

A carbon tax is a tax on greenhouse gas emissions, typically set by the government on the carbon content of fossil fuels.

Carbon taxes can have the following effects:

- Creating a price signal: Carbon taxes set a price on carbon emissions, which encourages businesses and consumers to reduce their emissions to avoid paying the tax.

- Shifting consumption and investment patterns: Carbon taxes can change how people and businesses consume and invest, making economic development compatible with climate protection.

- Incentivising lower-carbon fuels and renewable energy: Carbon taxes can encourage people and businesses to use lower-carbon fuels or renewable energy sources.

- Generating revenue: Carbon taxes can raise revenue for governments, which can be used to fund investments or lower other taxes.

Part 2

Emissions trading, also known as ‘cap and trade’, is a cost-effective way of reducing greenhouse gas emissions. To incentivise firms to reduce their emissions, a government sets a cap on the maximum level of emissions and creates permits, or allowances, for each unit of emissions allowed under the cap.

Emission trading schemes (ETS) play a key role in reducing emissions by:

- Setting a price on carbon. ETSs put a price on carbon emissions, which aligns economic incentives with environmental goals.

- Creating an economic incentive. ETSs create an economic incentive for reducing emissions in the most cost-effective way.

- Limiting the total amount of carbon emitted. ETSs limit the total amount of carbon that can be emitted by setting a cap on emissions.

- Reducing the cap over time. The cap is reduced over time, so that total emissions must fall.

- Creating a revenue source for governments. ETSs can be a revenue source for governments, creating funds for public projects including cleaner technologies.

Question 4

Capital Gains Tax (CGT) applies when a company sells oil and gas assets or transfers ownership in projects. The taxation of such gains depends on domestic tax laws, international tax treaties, and whether the transfer is direct or indirect. In resource-rich countries, CGT ensures that governments collect a fair share of profits from the sale of valuable energy assets.

A direct transfer occurs when a company sells tangible oil and gas assets, such as drilling rigs, pipelines, or production rights. Most countries impose CGT on these transactions, treating them as local-source income. For example, In Australia, capital gains on direct transfers of oil and gas assets are generally taxable in the country where the assets are located. However, for indirect transfers (e.g., sale of shares in a resource company), tax treaties may override domestic taxation, depending on whether the entity derives most of its value from immovable property. Investors should assess treaty provisions to determine potential CGT exposure.

An indirect transfer happens when a company sells shares in an entity that holds oil and gas assets, rather than selling the assets themselves. Many countries impose CGT on such transactions if more than 50% of the company’s value comes from immovable property (e.g., mineral rights). This prevents tax avoidance through offshore holding structures.

Some countries have strict rules taxing both direct and indirect transfers. For example, Canada and Australia impose CGT on non-residents who sell shares in companies whose assets consist primarily of natural resources. These rules prevent foreign investors from escaping taxation by structuring sales through offshore entities.

Tax treaties are central to determining which jurisdiction has the right to tax capital gains from oil and gas transactions. Many treaties are based on the OECD Model Convention, which generally assigns taxing rights over capital gains to the residence state of the seller. However, an exception exists where more than 50% of the value of the shares arises from immovable property located in the source country. In such cases, the source country retains the right to tax the capital gain.

These treaty provisions can provide significant relief for foreign investors. For example, if an investor holds oil and gas assets through a jurisdiction like Singapore or the Netherlands, where the relevant tax treaty limits or defers CGT, the investor may legally reduce their tax exposure. Nevertheless, treaty application requires careful analysis, as different jurisdictions interpret immovable property and indirect transfer rules differently, and thresholds for triggering tax vary.

To curb abuse, anti-avoidance provisions such as the Principal Purpose Test (PPT) and Limitation on Benefits (LOB) clauses—introduced under BEPS Action 6—are now commonly included in treaties. These provisions deny treaty benefits where the main purpose of the transaction is tax avoidance, thereby limiting treaty shopping. Consequently, investors must ensure their structures have sufficient economic substance to withstand scrutiny.

Valuation disputes frequently arise in intra-group transfers of oil and gas assets, particularly where affiliated entities may assign values for tax or accounting purposes that differ from arm’s length market values. Tax authorities may challenge these valuations if they suspect that assets were sold below fair market value to reduce CGT liability or shift profits. In oil and gas, this issue is exacerbated by the inherent difficulty in valuing reserves, future production, and infrastructure under volatile price conditions.

Valuation methods like discounted cash flow (DCF), comparable transaction multiples, and cost-based approaches are all used—but each involves subjective assumptions. Disagreements may arise over projected commodity prices, cost recovery periods, or reserve volumes. Tax authorities may reject valuations they consider aggressive and make adjustments based on alternative assumptions, leading to increased CGT assessments.

A real-world example of a valuation-based dispute is the Shell Australia case, where the Australian Taxation Office (ATO) challenged a share sale involving a subsidiary that held oil and gas assets. The ATO argued that because more than 50% of the subsidiary’s value came from immovable property, the transaction should be treated as a taxable direct transfer, resulting in a $755 million tax settlement. This illustrates how disputes can arise over whether the declared transaction structure reflects the true economic substance and value of the underlying asset.

PART C

Question 5

Essential tax applying to the proposed investment, including rules for recovery of exploration expenses, treatment of capital expenditure, carry-forward losses, repatriation of profits, capital gains, transfer taxes, and indirect taxes such as VAT.

Hydrocarbon tax ring fence issues, such as restriction on interest deductions against ring fence income.

Determination of the holding structure, including election of a branch, single company or double company holding structure, consideration of taxation on income flows, withholding taxes, potential capital gains taxes on exit, and the funding structure of the investment.

The holding structure used if there are local or foreign partners.

Whether an intermediate holding country should be used for dividends, capital gains tax and related tax treaties.

Preparing a tax leakage calculation for the preferred structure, e.g. calculation from 100% of oil and gas income, reduction for taxes including any profit oil sharing under PSC regimes, calculating back to the net after tax cash to be received in the parent country.

Determining whether the seller is taxable in its own country of residence or the country where its assets are located, and estimating the amount of tax.

Reviewing transfer taxes or stamp duty applying to the sale and related asset or share transfers, including the estimated amount, and whether these amounts are payable by the seller, the buyer, or are shared.

Determining any carry-forward tax losses under a tax and concession regime, or allowable costs under a PSC regime, in the transferred company or licence asset, and reviewing whether these amounts are preserved by the transfer, and whether there is any group relief, tax consolidation, or tax loss contribution available in the new holding structure.

Reviewing what related party and external funding requirements apply for the acquisition and anticipated future expenses.

Reviewing whether any interest payments on funds to acquire the company or asset is deductible under local country rules. Some countries limit deductions based on purpose of the loan, or if related party. Reviewing whether the debt and interest deductions have been pushed down to the profitable company.

Consideration whether required loans are within this capitalisation rules in the borrowing country. These rules can generally disallow interest deductions on related party loans where a company's debt exceeds certain levels.

Reviewing whether there is an opportunity to increase the value of transferred assets to their market values to allow increased future depreciation deductions as an asset step up for tax purposes, for example by using an asset transfer rather than acquiring the company, or an asset transfer after the acquisition.

Consideration of any Goodwill in the transferred company, or asset such as a licence, and whether any tax relief available for the goodwill such as goodwill tax amortisation.

Consideration of transfer pricing issues in the new structure, particularly whether any intra group asset transfers or payments will be at arm's length prices.

Source: *Tolley's International Taxation of Upstream Oil and Gas, 3rd edition. Content in the above solution has been reproduced from Tolley's International Taxation of Upstream Oil and Gas, 3rd edition, with the kind permission of RELX (UK) Ltd.*

Question 6

Part 1

Interest deductions are generally allowed to a company for the purchase of assets under tax and concession regimes, as the assets will generate taxable profits. It may be more difficult to obtain interest deductions to purchase shares in a target company – there may be restrictions where the related dividends are tax exempt under participation exemption provisions.

Interest deductions may be used against profits of the acquired company if the country allows tax grouping or consolidation.

The effective use of interest deductions in PSC regimes is more difficult. The PSC itself will generally exclude financing costs as allowable costs in determining cost oil. The issue may then be whether interest deductions on debt to acquire licence interests subject to PSC regimes can be made elsewhere in the multinational group – at a parent company level.

A number of countries have thin capitalisation provisions which restrict interest deduction on related party debt.

The debt push down issue more frequently related to the placing of third party debt within a multinational group, such as borrowing from banks, and in many countries interest on this debt is not subject to thin capitalisation provisions.

Part 2

The objective here is to use a debt push down structure to utilise interest deductions in Target Company to offset that company's profit.

Tax Analysis

Purchaser Company may obtain a tax deduction in its own country. However, it may not be able to effectively use the deductions if it does not have significant taxable income. The ability to use tax deductions is generally known as 'tax capacity'.

Purchaser Companies use a new company in the target country, usually called a special purpose vehicle (SPV). The SPV then purchases Target Company, or the oil and gas assets, on behalf of the purchaser Company.

If the target company is acquired then tax consolidation is generally needed to transfer tax losses arising from interest deductions in the SPV to reduce tax in Target Company. It is necessary that the related country has some form of tax consolidation.

Consolidations

Care is needed with the timing of adding debt and related interest deductions. An upstream oil and gas target company may be in exploration or early production stages, with large carry-forward losses. There may be advantages in increasing related party debt at a later stage when the target company is profitable, and when the deductions can therefore be utilised.

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Question 7

Part 1

Thin Capitalisation Rules (TCRs) are tax regulations designed to prevent excessive interest deductions by limiting the amount of debt a company can use for tax purposes. In the oil and gas industry, where projects are capital-intensive, companies often rely on debt financing to fund exploration, development, and production. Without proper regulation, companies may use high levels of intra-group debt to shift profits to low-tax jurisdictions.

Debt financing is attractive in the oil and gas industry because interest expenses are typically tax-deductible, reducing taxable income. Compared to equity financing, where dividends are not deductible, debt financing offers an immediate tax advantage. However, excessive reliance on debt can lead to tax base erosion, prompting governments to introduce TCRs to limit excessive deductions.

One common approach to limiting excessive interest deductions is the fixed ratio method, where companies can deduct interest expenses up to a certain percentage of their Earnings Before Interest, Taxes, Depreciation, and Amortisation (EBITDA). For example, many jurisdictions cap interest deductions at 30% of EBITDA to ensure a reasonable balance between debt and equity financing.

TCRs often incorporate the arm's length principle, which requires that intra-group loans be priced as if they were between independent parties. If a related-party loan carries an unreasonably high interest rate, tax authorities may disallow the deduction of excessive interest payments. This rule is particularly relevant in oil and gas, where multinational companies structure intercompany loans across different tax jurisdictions.

Some countries apply debt-to-equity ratio caps, which limit the amount of allowable debt relative to equity. Traditionally, some jurisdictions have applied a debt-to-equity ratio cap, such as 3:1, to limit excessive interest deductions. However, many countries now follow an EBITDA-based approach, capping interest deductions at a percentage of taxable earnings (e.g., 30% of EBITDA) in line with OECD BEPS Action 4. Companies must consider both debt-to-equity limits and EBITDA-based restrictions when structuring financing arrangements. This rule prevents companies from artificially inflating debt levels to reduce taxable income.

Part 2

Apart from Thin Capitalisation Rules, tax authorities have several other tools to challenge excessive interest deductions in the oil and gas sector. One common approach is applying the arm's length principle under transfer pricing rules. Authorities assess whether the interest rates and terms of intra-group loans are consistent with those that would be agreed upon between independent third parties. If interest rates are found to be uncommercial, excessive portions of the deduction may be disallowed.

Authorities may also scrutinise economic substance – determining whether the lending entity in a related-party structure has sufficient operations, personnel, and risk-bearing capacity to justify the receipt of interest. If not, deductions may be denied on the basis that the arrangement is artificial or lacks commercial justification. This is particularly relevant where financing subsidiaries are located in tax-friendly jurisdictions such as Singapore or the Netherlands.

Another avenue is the recharacterisation of transactions, especially in lease-based financing arrangements. For example, where oil and gas companies lease high-value equipment from affiliated entities, tax authorities may treat lease payments as disguised interest – thereby subjecting them to TCRs or limiting their deductibility based on the underlying financing structure.

Some jurisdictions also apply Controlled Foreign Corporation (CFC) rules, taxing undistributed passive income – such as interest earned by offshore financing arms – at the parent level. These rules aim to reduce the incentive to park profits in low-tax jurisdictions by denying deferred taxation benefits.

In addition, tax authorities may use general anti-avoidance rules (GAAR) or invoke BEPS Action 4 principles to deny interest deductions that appear motivated primarily by tax avoidance. If it is demonstrated that the primary purpose of a financing structure is to secure an interest deduction without legitimate economic rationale, the deduction can be challenged under broad anti-abuse doctrines.

Question 8

A Permanent Establishment (PE) is a key concept in international taxation that determines a country's right to tax a foreign company's business profits. In the oil and gas industry, PEs often arise due to physical presence, exploration sites, drilling rigs, or long-term service contracts. Tax treaties, particularly the OECD and UN Model Conventions, define PEs and establish rules for attributing profits to them.

A PE is typically created when a company has a fixed place of business in a jurisdiction. This includes offices, branches, mines, or oil rigs. Additionally, a dependent agent PE may be formed when an entity acts on behalf of a foreign company, concluding contracts in the host country. Many tax treaties include time-based thresholds (e.g., exceeding 6 or 12 months) for triggering a PE in resource projects.

Once a PE is established, the host country gains the right to tax profits attributable to that PE. Under Article 7 of the OECD Model Tax Convention, only profits directly related to the PE's activities can be taxed. This requires separate accounting for the PE and the application of the arm's length principle to transactions with the head office.

In the oil and gas industry, PEs commonly arise when a company drills for oil, explores resources, or operates production facilities in another jurisdiction. Even if a company does not own physical assets, prolonged activity in a country – such as installing pipelines or providing long-term technical services – may create a PE. This exposes the company to local corporate tax obligations.

Many countries, particularly resource-rich developing nations, apply service PE rules for oil and gas companies providing on-site services. Under these rules, if a foreign company provides technical, consulting, or management services beyond a certain time frame (e.g., 6 months), it is considered to have a PE. This ensures the host country can tax income derived from in-country activities, even without a fixed place of business.

Oil and gas companies may structure their operations to avoid triggering PE status by splitting contracts into multiple short-term agreements to stay below PE time thresholds, using independent agents instead of dependent agents or structuring activities as preparatory or auxiliary services, which are generally exempt under tax treaties. However, anti-fragmentation rules in recent international tax reforms aim to counteract such avoidance strategies.

A company without a PE may only face withholding tax (WHT) on payments like royalties, interest, or service fees. Once a PE is created, however, the company becomes subject to corporate income tax on net profits instead of just WHT. Additionally, having a PE triggers local reporting and compliance requirements, increasing administrative costs. The oil and gas sector involves offshore drilling rigs, FPSOs (Floating Production Storage and Offloading units), and mobile drilling units, which create PE risks. Some countries claim taxing rights over floating installations if they remain in territorial waters beyond a treaty's time threshold. Companies must assess PE risks in jurisdictions with aggressive tax policies on offshore assets.

The OECD's Base Erosion and Profit Shifting (BEPS) Action Plan 7 expanded PE definitions to address tax avoidance. Key changes include narrowing the exemption for preparatory/auxiliary activities, widening the dependent agent PE definition, making commissionaire arrangements more taxable and strengthening anti-fragmentation rules, preventing artificial splitting of activities. These changes increase PE exposure for oil and gas companies operating across multiple jurisdictions.

A PE in the oil and gas sector can be triggered, for example, when a company uses a drilling rig or FPSO in a country's territorial waters for an extended period—typically over 12 months under the OECD Model or 6 months under the UN Model, which is often adopted by resource-rich countries like Nigeria or Indonesia. Additionally, service PEs may arise in countries such as India or Brazil when technical personnel provide services like installation or consultancy for more than 90 days within a 12-month period, even without a fixed place of business.