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**Update of the Handbook on Selected Issues for Taxation of the Extractive Industries by  
Developing Countries**

**Chapter XX: Production Sharing Contracts**

**Note by the Secretariat**

*Summary*

**Production Sharing Contracts** is among the new topics for the update of the Handbook on Selected Issues for the Taxation of the Extractive Industries by Developing Countries. It is presented to the Committee FOR DISCUSSION and APPROVAL its 21st Session.

The chapter examines the concept and some of the mechanisms of Production Sharing Contracts or Agreements (PSC or PSA) in detail. PSCs are among the most common types of contractual arrangements for petroleum Exploration and Production (E&P).

PSCs typically relate to the petroleum industry and are rarely seen in the mining industry. This is largely related to the fact that direct participation of government bodies in mining is not as common as in the oil and gas industry. However, some countries, have recently explored the possibility of PSCs in the mining sector. PSCs are used worldwide, and most common in African and Asian countries, as well as in certain countries of South America.

This chapter intends to improve understanding as to what PSCs are, including relevant terminology, what the tax mechanisms of the contracts are and what areas need attention in a PSC. It intends to discuss aspects of interest to tax administration, investors and other stakeholders.

Although the content of the current version and that of the version presented at the 20<sup>th</sup> Session are somewhat similar, this new draft is an improvement in readability and the overall flow of the text. Moreover, the chapter now contains more country examples.

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## 1. Executive summary

The aim of this chapter is to describe the main tax and tax-related issues arising from upstream production sharing contracts.

For this purpose, this chapter examines the concept and some of the mechanisms of Production Sharing Contracts or Agreements (PSC or PSA) in detail. PSCs are among the most common types of contractual arrangements for petroleum Exploration and Production (E&P). Under a PSC, the state as the owner of mineral resources, engages an oil company or a group of oil companies as a contractor to invest their technical and financial capabilities to explore and develop the country's hydrocarbon resources. The state is traditionally represented by the host government or one of its entities such as the national oil company (NOC).

A PSC is, therefore, a type of contract signed between a government entity or entities and a company or companies involved in natural resource exploration and production, intended to establish the rights and obligations of the parties, including how the costs incurred for and revenue generated by the project will be allocated among the parties. PSCs are widely used worldwide, and most common in African and Asian countries, as well as in certain countries of South America. PSCs typically relate to the petroleum industry and are rarely seen in the mining industry, where there is often less direct participation of government bodies. There is nevertheless great interest in the implementation of PSCs in the mining sector among developing countries, for example in Senegal, Gabon, Uganda, or Papua New Guinea.

There is no uniform approach or standard model to a PSC. Features from other petroleum fiscal regimes like the concessionary system<sup>1</sup> (also known as tax-royalty) can generally be found in PSCs. PSCs may also cater for how the contract terms interact with general tax or other legislation. It is also common for different versions of a PSC to be used for different areas of production within the same jurisdiction.

To provide a general overview of PSCs, the chapter starts by considering how a PSC differs from other types of fiscal regimes; it explores some of the reasons why a country would choose a PSC as well as provide an overview of the general terms and common tax clauses. When discussing terms, the chapter goes into practical tax problems that are often encountered in PSCs and finally describes a few current PSC systems around the world.

This chapter intends to improve understanding as to what PSCs are, including relevant terminology, what the tax mechanisms of the contracts are and what areas need attention in a PSC. It intends to discuss aspects of interest to tax administration, investors and other stakeholders.

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<sup>1</sup> See Chapter 7: The Government's Fiscal Take.

## 2. Acronyms and terms used

**DD&A:** Depreciation, depletion, and amortization.

**FDP:** Field Development Plan include activities and processes required to optimally develop a natural resources field.

**Government Share:** The total amount of direct revenue that a host government receives from the project. This amount can include taxes, royalties, bonuses, share of profit hydrocarbons and government participation, and is generally expressed as a percentage of divisible income generated by the project.

**Netback:** benchmark used in the oil and gas industry to assess the profitability and efficiency of a project based on the price, production, transportation, and selling of the hydrocarbon volumes produced. Netback is calculated by taking the revenues from the oil, less all costs associated with getting the oil to a market, including transportation, royalties, and production costs.

**Relinquishment:** The return of part or all of a lease or concession geographical area to a lessor, farmor or host government. The return may be voluntary or compelled contractually or by law.

**Surface fee:** Regular fee paid to the host government from the use of a piece of land or surface (e.g. area of a block or field).

**Sliding scales:** A mechanism with a more flexible share scale of fees, taxes, wages, etc. that varies in accordance with the variation of a particular standard or parameters.

### 3. Introduction: Production Sharing Contracts

Chapter 7 - The Government's Fiscal Take - provides a general overview of fiscal instruments – including PSC -, their features and their characteristics. Whereas chapter 7 covers fundamentals of PSCs, this Chapter provides a more in-depth review of PSC related features and issues.

Fiscal arrangements between governments and Oil & Gas (O&G) companies normally fall in one of two main systems: concessionary and contractual. The main difference between them generally lies in their approach towards ownership of the resources<sup>2</sup> and how the revenues generated by the project are shared.

Prior to the development of production sharing contracts, exploration and production of oil and gas was typically granted to investors by way of concessions, which is still widely used in many countries. Nowadays, PSCs are a very common means by which developing countries award investors the right to participate in the hydrocarbon industry within their jurisdictions.

According to most countries' Constitutions, natural resources belong to the government, on behalf of the people. They generally remain so at least until resources are extracted. In general, under the concessionary system, the investor has title to the hydrocarbon produced while in the contractual system, the government retains title to the resources<sup>3</sup>, however mixed systems (systems that share features of both systems) may apply<sup>4</sup>.

Contractual arrangements are divided into services contracts and PSCs. Under service contracts, the investor(s) typically receive a fixed financial compensation from the government, while under PSCs they receive a share of production<sup>5</sup>. Therefore, PSCs usually allocate more risk (and a higher reward in case of success) to the investing parties, whereas service agreements allocate less risk (and a lower reward) to the investing parties.



<sup>2</sup> Daniel Johnston, *International Exploration Economics, Risk, and Contract Analysis*, PennWell, 2003, pp. 12-13.

<sup>3</sup> Another aspect regarding ownership relates to equipment, as typically under contractual systems, once production equipment or facilities are landed in the host country, title to the equipment passes to the host government. Nevertheless, this does not apply to leased equipment or equipment brought in by service companies. Daniel Johnston, *International Exploration Economics, Risk, and Contract Analysis*, PennWell, 2003, pp. 12-13.

<sup>4</sup> For example, in Brazil, under both systems the ownership of natural resources belongs to the government until sometime after production.

<sup>5</sup> *Ib.* P. 13. See also Carole Nakhle *Mining and Petroleum Taxation: Principles and Practices, Revenue mobilization and Development* IMF, DC, 2011.

In some jurisdictions that still adopt a concessionary regime, investors may sign contracts, also called concession agreements. These agreements in general are less detailed and less flexible than pure contractual arrangements like PSCs and service contracts, at least in the oil and gas sector.

PSC enables the government to maintain formal ownership of the natural resources, while permitting a private or public company to exploit them. Under a PSC, a State contracts with an investor or a group of investors to invest their financial and technical capabilities to explore, develop and produce oil and gas within the PSC's contract area. The investor bears the entire risk of the project and will be entitled to a portion of production to repay its costs, and from the remainder, a share of production to enable a return on its investments. The State will usually be represented by the Ministry in charge of hydrocarbons or the NOC, and the extent to which the NOC is involved with the investment and operations varies from country to country.

PSCs were introduced in Indonesia in 1966. The first PSC ever signed was by IIAPCO and Permina, the Indonesian National Oil Company at the time (now Pertamina)<sup>6</sup>.

|                                                  |
|--------------------------------------------------|
| <b>Basic features of the first PSC contract:</b> |
|--------------------------------------------------|

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|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <ul style="list-style-type: none"><li>• Title to the hydrocarbons remained with the state.</li><li>• The National Oil Company maintained management control, and the contractor was responsible for execution of petroleum operations in accordance with the terms of the contract.</li><li>• The contractor was required to submit annual work programs and budgets for scrutiny and approval by NOC</li><li>• The contract was based on production sharing and not a profit-sharing basis.</li><li>• The contractor provided all financing and technology required for the operations and bore the risks.</li><li>• During the term of contract, after allowance for up to a maximum % of annual oil production for recovery of costs, the remaining production was shared x/x % with the National Oil Company [NOC]. The contractor's taxes were paid out of NOC's share of profit oil.</li><li>• A notable simplification feature was that tax was calculated using audited Profit Oil as taxable income, with only minor adjustments; the ordinary rules for calculating taxable income did not apply.</li><li>• All equipment purchased and imported into the country by the contractor became the property of NOC. Service company equipment and leased equipment were exempt.</li><li>• There was no royalty payment.</li></ul> |
|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|

#### 4. PSCs: design considerations

In theory, governments can achieve similar profiles of revenue through the different types of O&G regimes, with different instruments, because the fiscal terms of a tax/royalty regime can be replicated in a PSC regime, and vice versa. So there is no intrinsic tax reason to prefer a concessionary or tax/royalty regime over a PSC regime.

However, many governments favor PSC regimes because: the State retains ownership reserves, the government can consume or sell its share of production, and retains ownership of oil and gas infrastructure upon expiration of the contract. PSCs are also typically comprehensive contracts that provide a degree of flexibility not found in concessionary regimes, even when they include concession agreements. Governments need, however, to consider the trade-offs of such a level of flexibility, and invest resources in designing and negotiating PSC terms.

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<sup>6</sup> Daniel Johnston, International Petroleum Fiscal Systems and Production Sharing Contracts, (PennWell Books, Tulsa, Oklahoma, 1994). Page 40.

## A. Contract and license allocation

Governments sign PSCs following either a competitive allocation system, through bidding rounds, or based on bilateral negotiations with investors interested in a particular area.

If there is sufficient competition from investors to develop a particular area, it is always in the government's interest to allocate contractual rights through a transparent, competitive bidding round. This ensures the government allocates its resources to the most capable companies. When there is not sufficient competition, in particular when governments lack geological data on the areas to be allocated, it may be necessary to engage into PSCs through bilateral negotiations.

PSCs can be entered into under different levels of geological information. In some cases, contractors are responsible to undertake exploration in an area with no prior evidence of commercially viable deposits. If no discovery is made, funds invested in exploration are not recoverable. The historical economic success rate in frontier areas is approximately 5%. In other cases, sufficient information exists to limit the exploration risks taken by investors. PSC fiscal terms typically account for such different situations, providing more generous terms to governments when there is more certainty on the commercial viability of hydrocarbons in PSC contract areas.

Regardless of the allocation process, it is good practice for governments to provide a model PSC, which improves the predictability and legal certainty of the allocation process. A model PSC contains the basic provisions that the government expects to be followed by any contractors, and leave certain provisions that are more specific to the development of a particular geological field blank. The more prior information the government has on a particular area, the more specific the model PSC can be. For instance, Tanzania's 2013 model PSC applies to any area to be allocated to a contractor,<sup>7</sup> whereas in Mexico, for each area allocated in the bidding rounds organized between 2015 and 2018, the regulatory agency provided a tailed model contract, many of them PSCs.<sup>8</sup> The blank areas in a model PSCs are then finalized based on either the proposal of the winning company in a bidding round, or bilateral negotiations between the government and the company. In some cases, minimal bilateral negotiations are necessary to finalize a PSC following a successful bidding round.

## B. The status of PSCs in the legal framework

Agreeing on detailed contractual terms can be helpful in situations where the local legal and fiscal framework for oil and gas development is absent, insufficient, or inappropriate. Countries where no oil and gas development has taken place may have no or limited legislation or regulations for hydrocarbon including a tax law adapted to oil and gas. This has been an important factor in many countries for adopting a PSC regime. Countries where the legislative system is well established often prefer to set hydrocarbon taxation through general legislation or adjust the existing fiscal system through a concessionary system.

A PSC system can be clearer on how differences in accessibility, nature, quality and/or extent of resources will be considered in a particular area. For example, countries with mining legislation but no oil and gas legislation may want to allow prospecting for oil and gas. In the long run, governments should develop a detailed legal and regulatory framework for hydrocarbons, including model PSC. While adapting mining legislation or introducing new comprehensive oil and gas legislation, parties can still achieve agreement on their rights and obligations for specific prospective areas in a contractual form, like a PSC.

Some countries enact PSCs into laws to provide a stronger legal standing, others do not. If they do, such contracts may need to be passed or confirmed by the Parliament to be enacted into law. It is often easier to confirm contracts containing specific conditions for specific areas and activities than to pass general legislation that could impact the whole oil and gas sector.\

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<sup>7</sup> <http://www.wgei.org/wp-content/uploads/2015/10/Tanzania-Model-Production-Sharing-Agreement-2013.pdf>

<sup>8</sup> <https://rondasmexico.gob.mx/esp/rondas/ronda-1/cnh-r01-1022015/documentos-de-la-licitaci%C3%B3n/contratos/>



### C. The high level of flexibility

A PSC can be easily adapted for different types of geological sites or other circumstances. They allow contracting parties to fine-tune the risk-reward allocation, adapt to geological or other geographical conditions of an area, and over a long period of time. This may be used by certain countries to attract investments by providing more favorable fiscal terms to less developed areas (i.e. frontier areas) where there is a low chance of a successful O&G discovery and risks are high, and less favorable fiscal terms where the chance of a successful discovery is higher. In this respect, countries with both on-shore and offshore O&G developments commonly have PSCs with different fiscal and contractual terms between on-shore and off-shore regimes, to reflect the different levels of costs and risks involved.

### D. Transparency

In the past, many petroleum agreements were kept confidential. Governments around the world have chosen to respond to citizen demands for transparency by publishing or requiring the publication of petroleum agreements. Governments, companies and civil society organizations have agreed to adopt contract transparency as a requirement of the Extractive Industries Transparency Initiative (EITI)<sup>9</sup>. Allocation processes, government regulation and oversight of PSCs are all improved by adoption of open contracting principle.<sup>11</sup>

Transparency can be achieved through publishing all individual resource contracts, which many countries do.<sup>12</sup> It can also be achieved by designing detailed model PSCs linked to the generally applicable legal framework, where overarching legislation sets the general conditions and terms within which individual PSCs should be adopted. For countries that require Parliament to ratify PSCs, this also tends to imply a process with a certain level of transparency.

### E. Tax administration

PSCs are often implemented and administered by Ministries, other than Finance, that are responsible for energy and mining. Tax authorities in charge of collecting corporate taxation may not be equipped to assess, implement and review the fiscal implications of a PSC, and may consider them complex and difficult to administer. It is therefore important to:

- i. achieve a government consensus on how hydrocarbons should be taxed,
- ii. build the capacity of the tax administration to understand PSC terms,
- iii. give authority to the Ministry of Finance and its internal tax experts to review and validate the fiscal terms in all PSC design and allocation,
- iv. foster a strong interagency collaboration to ensure a smooth implementation of PSC tax provisions such as the pay-on-behalf system.

At the extraction phase, oil and gas tend to be subject to a variety of fiscal terms that can include bonuses, royalties, production sharing and various taxes, including corporate income tax. Tax administration is easier when there is a high degree of standardization across PSCs in a given country, and when model contracts include tax provisions. This helps facilitate consistency, fairness, transparency and reduce tax administration cost.

It is important to regulate the interaction between the tax clauses in PSCs and the domestic general tax system, specifying, if necessary, in the contract or in the domestic law, the relation between both systems.

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<sup>9</sup> <https://eiti.org/contract-transparency/>

<sup>10</sup> Oxfam. Contract disclosure survey 2018. A review of the contract disclosure policies of 40 oil, gas and mining companies: <https://oxfamlibrary.openrepository.com/bitstream/handle/10546/620465/bp-contract-disclosure-extractives-2018-030518-en.pdf;jsessionid=85ED532E904F3E7780333E8BD76EF700?sequence=4>

<sup>11</sup> <https://resourcegovernance.org/analysis-tools/publications/open-contracting-oil-gas-and-mineral-rights>

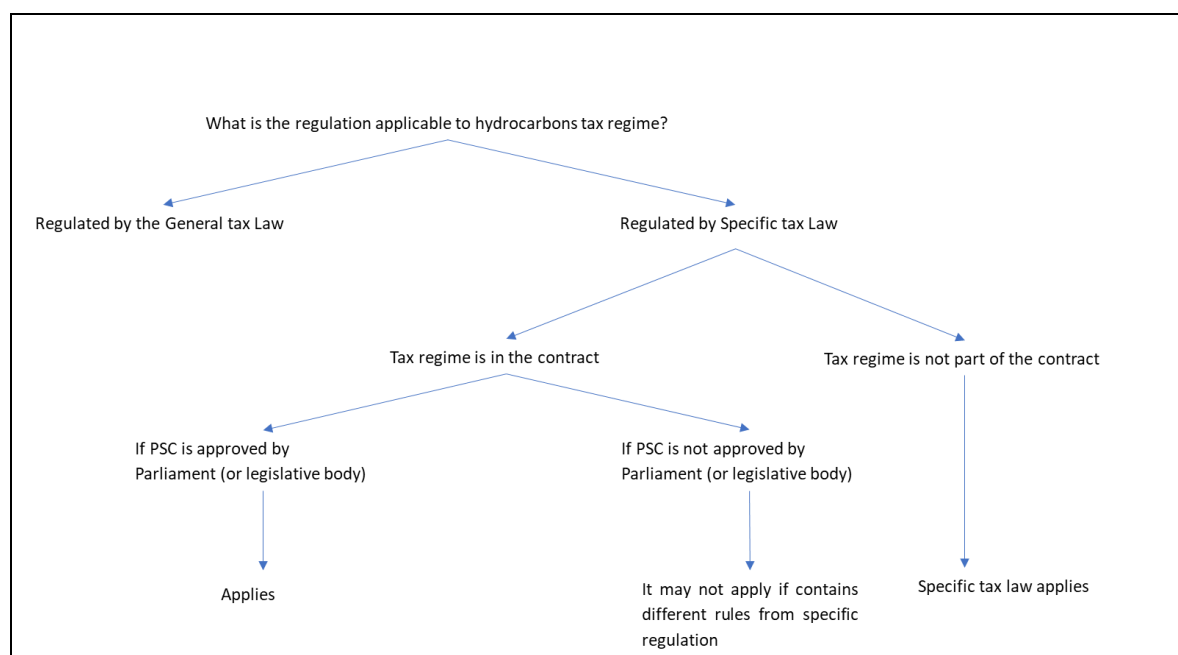
<sup>12</sup> <https://resourcecontracts.org/countries>

Using a PSC may require more alignment and more rules to provide clarity and certainty of the oil and gas tax regime with regular corporate and other taxes.

**Example: Article 17.1 Liberia Model contract**

*Unless otherwise provided for in this Contract the Contractor shall, in respect of its Petroleum Operations, be subject to the laws generally applicable and the regulations in force in Liberia concerning taxes which are or may be levied on incomes, or determined thereto.*

It is crucial (and advisable) that the law regulates all tax issues, especially when exemptions are involved, and that the tax law include a specific chapter for the O&G sector.



## 5. Roles of private and public actors in PSCs

The parties to a PSC contract will often be the NOC, or relevant Ministers on behalf of the government (e.g. Ministers in charge of Petroleum), and one or more O&G companies or investor(s) (it is common to be a consortium of investors).

PSC describe and regulate various aspects of the future relationship the O&G company will have with the government or government company entrusted with the oversight of the contract and operations and allocate the risks and rewards related to potential hydrocarbon resources to be explored and developed. Below are common features usually found in PSCs.

### A. Transfer of resource ownership

Under concessionary systems, transfer of title of the O&G to an extracting company will occur upon production (at the well head). Under contractual systems the government still retains full ownership of resources and O&G companies have the right to receive a share of production to recover their costs and make a profit at the delivery point to be mutually agreed by the parties (e.g.: the point at which petroleum reaches the outlet flange of the tanker in the oil export facility). Under a service contract, the contractor is normally paid a fixed remuneration and does not acquire the title to the resource.

**Example of definition of delivery point: PSC Iraq (Kurdistan Regional Government)**

*“Delivery Point means the place after extraction, specified in the approved Development Plan for a Petroleum Field, at which the Crude Oil, Associated Natural Gas and/or Non-Associated Natural Gas is metered for the purposes of Article \_\_, valued for the purposes of Article \_\_ and ready to be taken and disposed of, consistent with international practice, and at which a Party may acquire title to its share of Petroleum under this Contract or such other point which may be agreed by the Parties.”*

**B. Government participation**

A PSC does not require government participation. Even without any direct participation in the project, the government is entitled to a share of production, after cost recovery.<sup>13</sup> This has been a key reason for Nigeria’s decision to adopt PSCS.

**Example: Nigeria moving to a PSC system**

Nigeria factored in the following considerations regarding the distinction between Concessionary and Contractual Systems which led them to move to one system:

- a) **Funding:** Under the Concessionary system, all parties to the Joint Venture (JV) fund the operations of the JV in proportion to its equity ownership or economic interest. Whereas, under the Contractual system, the Contractor bears the funding obligation 100%. Funding is the major reason why the Nigerian government moved from the JV Concessionary arrangement to Production Sharing Contracts as government is unable to meet its cash call obligations under the Numerous JV owned by the Nigerian National Petroleum Corporation (NNPC).
- b) **Risk:** Under the Concessionary System, risk is shared among the parties to the JV in proportion to their equity ownership, whereas under the contractual system, based on the terms of the contract, the risk is borne 100% by the contractor.

In addition, under the contractual system, there is not compensation if exploration is unsuccessful or a dry hole is drilled. For this reason, other mechanisms, such as exemptions during the exploration phase, are set up.

However, it is common for governments to take a direct participating interest in the investments under a PSC, thereby sharing in the associated risks and rewards. Many governments have opted for state participation in petroleum joint ventures (JVs) via an option for the NOC to participate in development projects. The State would then be required to contribute to the costs of the project in proportion to its participation, and would be entitled to a share of the profits as a participant, in addition to other revenues it would receive from the project as a regulator (e.g. bonuses, royalties, taxes, etc.).

The government’s contribution to exploration costs is often paid out of subsequent production. Such structures effectively allow a government to reduce or eliminate the need to allocate cash from other sources until a discovery has been made. However, such structure will affect the risk / reward balance for investors, and the terms of such a “carried” participation, or other elements of the fiscal regime, would have to compensate other investors.

Equity or direct participation in the project for governments can take several forms, including:

<sup>13</sup> Daniel Johnston, International Exploration Economics, Risk, and Contract Analysis, (PennWell Books, Tulsa, Oklahoma, 2003). Page 197.

- A full working interest, which places the government on par with a private investor. In this case, the government is an equal partner in the PSC from the start, taking up its full obligations and rights relating to its participation in the venture in the same way other partners do;
- Paid-up equity on concessional terms (i.e., government back-in), where the government acquires its equity share, sometimes at a below-market price, especially when being able to buy into the project after a commercial discovery has been made but at a price set in advance;
- A carried interest, where government does not contribute to the investment obligations in line with its share up to an agreed project milestone, typically discovery. Government may pay for its carried equity share out of its own share of production proceeds, including an interest charge.

### C. The Joint Operating Agreement (JOA).

JOAs are relevant in any petroleum agreement, including PSCs, where multiple parties own a working interest. These parties may include the host government (directly or, more commonly, through a government-owned oil company)<sup>14</sup>. The JOA is a private agreement entered into between the investors that constitute the investor group, to govern the relation of those parties as relate to the petroleum operations under the petroleum agreement. Where an O&G company participates in more than one PSC in a country, a different JOA will be signed for each of the PSCs in which it has a working interest. Where there are more than one investor with a participating interest, each PSC is independently managed through the consortium governed by the investors under the corresponding JOA<sup>15</sup>.

The legal framework for joint ventures can have indirect taxation consequences, for instance in case the ownership of resources passes upon production or subsequently from joint ventures to eventual participants.

#### **Example: Article 2 of the Liberia PSC Model (Scope of the Contract)**

- 1 The Contract is a Production Sharing Contract and includes all the provisions of the agreement between NOCAL and the Contractor.*
- 2 NOCAL authorizes the Contractor to be the Operator pursuant to the terms set forth herein and to carry out the useful and necessary Petroleum Operations in the Delimited Area, on an exclusive basis.*
- 3 The Contractor undertakes, for all the work necessary for carrying out the Petroleum Operations provided for hereunder, to comply with good international petroleum industry practice and to be subject to the laws and regulations in force in Liberia unless otherwise provided under this Contract.*
- 4 The Contractor shall supply all financial and technical means necessary for the proper performance of the Petroleum Operations.*
- 5 The Contractor alone shall bear the financial risk associated with the performance of the Petroleum Operations. The Petroleum Costs related thereto shall be recoverable by the Contractor in accordance with the provisions or Article \_\_\_\_*
- 6 During the term hereof, in the event of production, the Total Production arising from the Petroleum Operations shall be shared between the Parties according to the terms set forth in Articles \_\_\_\_ and \_\_\_\_.*

### **The JOA accounting procedure**

JOAs include an accounting procedure, which is a critical part of the governance when multiple investors are party to the petroleum contract. However. The JOA accounting procedure does not determine the

<sup>14</sup> JOA has no relevance if the O&G company is 100% the owner of the working interest.

<sup>15</sup> See Chapter 3 (Permanent Establishments) for the treatment and consideration of PSCs as a separate permanent establishment from others PSCs.

proper treatment of cost before the State. The latter is provided for in a distinct accounting procedure provided for in the PSC itself, not the JOA.

Under the JOA, the costs incurred by the operator for the benefit of the joint operation and associated with a specific joint operation are recorded in a joint account. In this respect, each month the operator must estimate the cash that will be required to pay invoices and meet obligations for the upcoming month and will require the collection of cash from the other partners by means of cash calls (estimation of costs in advance) or billing and payment (utilization of own funds by the operator which bills to non-operators afterwards). For these purposes, the operator is commonly required to maintain an office where, amongst others, all such accounting records, receipts, invoices, etc. are kept<sup>16</sup>. Normal practice in the petroleum industry is for the US dollar to be used as the functional currency for cost accounting and budget records, with the US dollar also being used for international commodity pricing and income.

In this respect, the operator is obliged to keep the accounts and provide the other partners with the data that will allow them to prepare their tax returns. Furthermore, the responsibility for the presentation of the tax declarations corresponds to each one of the partners of the investor group.

Typically, non-operators, including the government-owned oil company, are entitled to conduct and audit at their own costs and raise any objection, but generally is not acceptable for them to deduct the disputed charge from cash-calls or payments. Most JOAs contain time-limits for audits, which would supplement any prescription periods that have effect under the applicable law or the PSC itself.

### **The PSC operating committee**

A common feature of most PSCs is the formation of an operating committee, normally composed of representatives from the contractor and the entity with responsibility for oversight of the PSC. The role of the operating committee is to permit the government and the rest of participants to get involved in the operations of the block. The operator usually prepares an annual work program and budget for review by the operating committee. The role of the operating committee is often of an advisory nature with State approval by the Ministry, whereas in some countries the operating committee can have an approval authority, e.g. for the most relevant decisions (approval of major expenditures, evaluation of results, determination of the commerciality of discoveries).

The appraisal activities attempt to determine if a discovery can be a commercial success. If the investor determines the discovery to be economically viable, the investor will typically submit a declaration of commerciality to the operating committee or the relevant Ministry for their review. The investor will subsequently develop a field development plan (FDP) which will typically need to be submitted to the suitable approval authority, e.g. Ministry of operating committee. The government approval of the FDP typically signifies the formal authorization for the investor. If no further exploration or development is intended by the investor, the investor may take the decision to relinquish parts or the entire area or transfer their participation (upon government approval) to a third party by notifying their decision to the relevant authority<sup>17</sup>.

### **No profit-No loss principle**

One of the foundations of all the JOAs, and that is the usual practice of the activity of the E&P, is that the operator will perform functions at cost, without adding any margin to the operation. Nevertheless, the operator has the right to charge an overhead, to reflect the costs resulting from the work carried out by the operator function. The overhead /indirect charges are normally set up according to the investments and varies from the stage of exploration and development and production.

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<sup>16</sup> See Chapter 3 (Permanent Establishments) for the treatment and consideration of the office as a separate permanent establishment.

<sup>17</sup> See Chapter 3 (Permanent Establishments) for the moment when discontinuation or transfer to a third party of an E&P related PE determines the cease of existence of the PE.

The operator will normally be part of an international cost-sharing arrangement under which it will have access to technology and services developed or provided by its foreign affiliates. Normal practice, established more than fifty years ago, in the E&P sector of the petroleum industry is that the operator is charged for its contribution to such an arrangement at cost, with no mark-up. A more detailed description of cost-sharing arrangements and documentation requirements can be found in Chapter VIII of the Guidelines on Transfer Pricing for Multinational Enterprises and Tax Administrations (OECD 2017).

The no profit – no loss principle is also found in farm-in/out transactions where the farmor seeks to share the risks of the operation rather than obtaining a gain and the farmee is not willing to pay more than past costs when proven reserves to be discovered are still uncertain, in particular at the exploration stage. A more detail description about farm-in and farm-out transactions can be found in Chapter \_\_ on Financial Transactions.

#### D. Economic Stability

Economic or fiscal stability is often granted to investors in the extractive industries through stabilization provisions, discussed in detail in chapter 8 (Tax aspects of negotiation and renegotiation of contracts ) and chapter XX (Tax incentives). In jurisdictions that offer fiscal stability to investors, such provisions are included in PSCs.

The more recent best practice on economic stability clauses in contracts can be found in the Guiding Principles for Durable Extractive Contracts, a set of principles developed by multiple stakeholders as part of the OECD policy dialogue on natural resource-based development. The 7<sup>th</sup> principle states that:

*“Durable extractive contracts are consistent with applicable laws, applicable international and regional treaties, and anticipate that host governments may introduce bona fide, non-arbitrary, and non-discriminatory changes in law and applicable regulations, covering non-fiscal regulatory areas to pursue legitimate public interest objectives. The costs attributable to compliance with such changes in law and regulations, and wholly, necessarily and exclusively related to project specific operations, should be treated as any other project costs for purposes of tax deductibility, and cost recovery in production sharing contracts.*

*If such changes in law and/or applicable regulations result in the investor’s inability to perform its material obligations under the contract or if they lead to a material adverse change that undermines the economic viability of the project, durable extractive contracts require the parties to engage in good faith discussions which might eventually lead the parties to agree to renegotiate the terms of the contract.”<sup>18</sup>*

An example of an economic stability clause in a PSC is the following:

**Qatar Economic Stabilization clause:**

*Economic Stabilization: In the event CONTRACTOR is subjected by GOVERNMENT or QP, to any additional liabilities, fees, taxes, imposts or costs of any sort or kind, other than de minimus ones, during the term of this Agreement, then CONTRACTOR shall have the right to request from QP a modification to the terms and condition of this Agreement that will restore CONTRACTOR to the economic position it was in prior to the imposition of such liabilities, fees, taxes, imposts, or costs.*

In some PSCs taxes are paid for and on behalf of the contractor out of the NOC share of profit (also known as “taxes in lieu”). This type of PSC provides an additional measure of economic stability, because if the tax law is amended, it would not affect the financial position of the IOC.

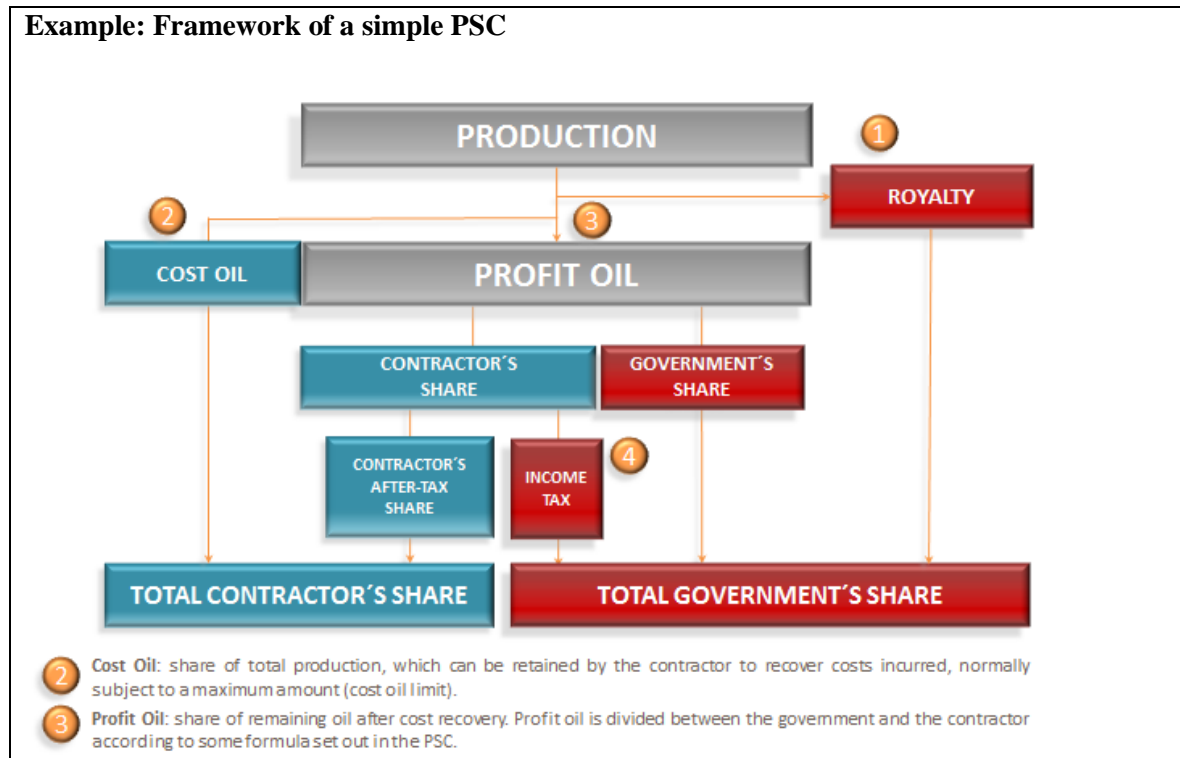
<sup>18</sup> OECD Policy Dialogue on Natural Resource-based Development, Guiding Principles for Durable Extractive Contracts, 2020 [http://www.oecd.org/dev/Guiding\\_Principles\\_for\\_durable\\_extractive\\_contracts.pdf](http://www.oecd.org/dev/Guiding_Principles_for_durable_extractive_contracts.pdf)

## 6. Production sharing framework

### A. General framework

Determining the production, how it is lifted and shared, is a main feature of the PSC. It will form a major part of the fiscal take and the contract clauses regarding production and production sharing will influence other fiscal considerations.

#### Example: Framework of a simple PSC



### B. Production Allocation

PSCs include a fiscal instrument that defines some of the production as “Cost Oil/Gas”, and the rest as “Profit Oil/Gas” which is shared between the State and Contractor.

#### a. Cost Oil

Most PSCs contain a cost recovery provision, which determine the procedure by which the contractor is able to recover its costs. The share of production that goes to the working interest partners to allow them to recover their costs is referred to as “cost oil” or “cost gas”.

Therefore, “cost oil” is the oil retained by the contractor to recover the costs of exploration, development and production. Most PSCs limit the amount of cost oil that can be retained in a given accounting period, so that the State receives a share of production as profit oil as soon as production commences, whether or not the contractor's project is profitable. The amount of hydrocarbons to be recovered through the "cost oil" is limited to a percentage of the production. Costs that are not recovered are carried forward and recovered later. Most PSCs allow virtually unlimited carry forward, with some exceptions, and if production is sufficient during the life of the contract, the working interest owners will eventually recover all their recoverable expenditures.

**EXAMPLE, ANGOLA:**  
**Model Contract, Angola, Deep Water, 1999.**

*Contractor Group shall recover all exploration, development, production and administration and services expenditures incurred under this agreement by taking and freely disposing of up to a maximum amount of 50% per year of all crude oil produced and saved from development areas and not used in petroleum operations.*

PSCs normally specify which costs are eligible for cost recovery<sup>19</sup>. Usually, these include unrecovered costs carried from previous years, operating expenditures (OPEX), capital expenditures (CAPEX) and abandonment costs. They may also specify the order of recoverability and limitations on recoverability. For example, some contracts limit recoverability by depreciating development costs, which means that only a fraction of such costs is recovered each year.

In addition, most contracts specify the order in which costs are to be recovered. This is important to contractors when they finance the whole exploration activity but share operating and development activities the government. A common order of cost recovery would be: (i) current year operating costs, (ii) unrecovered exploration and appraisal expenditures, (iii) unrecovered development expenditures, (iii) capitalized interest, if allowed, (iv) any investment credit or uplift and (iv) future abandonment cost fund<sup>20</sup>.

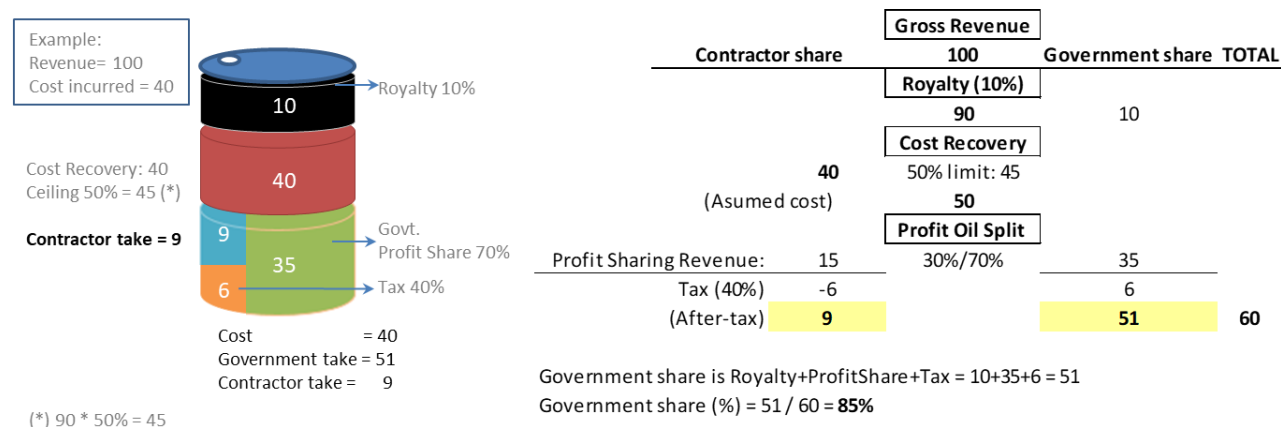
Expenses not eligible for cost recovery may include (depending on government policy) bonuses, royalties; interest or other financing related payments and overheads beyond specified limits; and costs outside the budget (unless approved by government).

#### b. Profit Oil

Profit oil is the share of production remaining after royalty (and other production taxes, if any) is paid and cost oil has been delivered to the contractor, paid in cash or in kind<sup>21</sup>.

Profit oil is shared between the parties, allocating a specified percentage of the profit oil directly to the government, with the members of the contractor group, which may include the government-owned company, sharing the remaining oil in proportion to their participation under a formula established in the PSC.

For example, if a company is a party to a contract that specifies a royalty of 10% and a cost recovery oil equal to a maximum of 50% of gross production, until all development costs are recovered, profit oil would be 40% (100% - 10% - 50%).



<sup>19</sup> In general, the financial expenses, the payment of entrance bonuses and the overhead of the parent company are not recoverable, they are usually limited with a reference to a% of the investments.

<sup>20</sup> Charlotte J. Wright and Rebecca A. Gallun, Fundamentals of Oil & Gas Accounting (PenWell Books, Tulsa, Oklahoma, 2008).

<sup>21</sup> Please Note Indonesian Government released a new O&G gross split regime in 2017, which coexists with the current cost recovery regime.



In most countries, the contractual terms of distribution of the production of liquid and gaseous hydrocarbons are different, with the terms for gas usually more beneficial for the contractor due to higher development costs, longer schedules, a need for gas market development and/or lower sale price for natural gas.

The profit sharing formula is generally specified in the contract (and often times in the government's legislation). There are many ways to distribute the Profit Oil. The most common are:

- Fixed percentages: The portion allocated to the government can vary between 40% and 85%.
- Variable scales: The percentages of distribution can vary depending on one or several variables. There are four main categories of production sharing formulae developed by host governments<sup>22</sup>:

### Production Sharing formulas

|                                           |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
|-------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Daily Rate of Production (DROP)</b>    | Government share of profit petroleum increases with the daily rate of production from the field. Its strength is simplicity. Its main weaknesses are that field size is often a poor proxy for project profitability and the mechanism is not progressive with respect to oil prices or costs. Attempts have been made to blend this with a scale of prices.                                                                                                                                                                                           |
| <b>Cumulative production from project</b> | Government share of profit petroleum increases as total cumulative production increases. Also an inaccurate proxy for project profitability. Such schemes are becoming rarer.                                                                                                                                                                                                                                                                                                                                                                          |
| <b>'R-Factor'</b>                         | Government's profit share increases with the ratio of contractor's cumulative revenues to contractor's cumulative costs (the 'R factor'). This improves on production based formulae in being a more direct measure of profitability, and is commonly used. Its weaknesses are that it does not take into account the time value of money, that current project profitability has no/low impact on the R-factor value, because it is cumulative which can make some recurring investment more challenging especially later in the life of the project. |
| <b>Rate of Return (ROR)</b>               | The government's share is set by reference to the cumulative contractor rate of return, with single or multiple tiers. It can take into account the time value of money by using discounted cash flows. Like the R-factor, this is traditionally a cumulative indicator, and will make ongoing investment more challenging unless its calculation is designed to be dynamic, e.g. to reflect the current project profitability.                                                                                                                        |

#### Example Daily Rate of Production:

| Daily Production Rate (thousands bbls/day) | Government Profit Share (%) |
|--------------------------------------------|-----------------------------|
| 0-25                                       | 30%                         |
| >25-50                                     | 35%                         |

<sup>22</sup> IMF, Fiscal Regimes for Extractive Industries: Design and Implementation (15 August 2012).

|         |     |
|---------|-----|
| >50-75  | 40% |
| >75-100 | 55% |
| >100    | 60% |

**If average daily production for the agreed time period was 45,000 bbls per day**

**Government Profit Share =  $[(30\% * 25,000) + 35\% (20,000)] / 45,000$**

**Government Profit Share = 32.2%**

Finally, in a PSC regime, the IOC is generally required to file a tax return showing the value of its share of production (both profit oil and cost oil) as income, less deductions permitted by the tax law. The tax due is then payable either directly by the IOC or, as mentioned above, by the NOC on behalf of the IOC.

## 7. Principal fiscal related clauses in PSCs

Besides sharing production, other instruments allocate production, revenues or profit. Some of these instruments include more direct allocation of production whilst others cover the revenue governments indirectly receives as part of the overall fiscal take.

PSCs includes fiscal clauses that determine the fiscal treatment of the production shared. The primary fiscal components of a PSC may include (i) bonuses, (ii) royalty, (iii) cost recovery, (iv) profit oil, and (v) taxes.

### A. Bonuses

Contractors often pay signature bonuses for acquiring the right to explore, develop and produce. Signature bonuses are a pre-payment of government take of future cash flows. Bonuses are can be negotiated, set by the host government or biddable for each contract and may be different depending on the stage of the O&G project:

| Type of Bonus     | Description                                                                                                                                                                                                                |
|-------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Signature Bonus   | Payment made by the contractor to the government at the time that the petroleum contract is granted. It may be determined through a bidding process, negotiation, or set by legislation.                                   |
| Development Bonus | A relative smaller sum of money is paid at the signing of the contract with another payment being due if and the decision is made to develop a field within the contract area.                                             |
| Discovery Bonus   | Payment made at the time that a commercial discovery is declared.                                                                                                                                                          |
| Production Bonus  | Payment made at a certain point in time during the life of the petroleum contract, typically at the time that petroleum production begins, at a defined production rate or at a defined quantity of cumulative production. |

In choosing to charge bonus payments at discovery or production, the government is assuming some risk since if O&G is not discovered no additional bonus would be received. However, bonus are typically a regressive fiscal instrument that are more commonly charged for highly prospective areas, or as part of a competitive bidding round.

**EXAMPLE FROM THE LIBYA MODEL PSA:**

*Signature bonus: as a signature bonus, a lump sum amount of ..... US Dollars (US\$ .....);*

*Production bonus: (a) an amount of XX US Dollars (US XX) to be paid in respect of each Commercial Discovery within thirty (30) days after Commercial Production Start Date of such Commercial Discovery; and (b) an amount of XX US Dollars (US XX) upon achieving cumulative production of XX (XX) Barrels of oil equivalent from each Commercial Discovery and thereafter, an amount of XX US Dollars (US XXX) upon achieving each additional thirty million (XX) barrels of oil equivalent.*

Typically, bonuses are not recoverable through cost recovery, but they could be deductible against income and withholding taxes. However, countries may adopt different approaches depending on their domestic policy, as shown in the examples below:

| Country    | Bonus Treatment                                                                                                                                                                                                                                       |
|------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Malaysia   | Signature bonuses to be paid are cost recoverable, and for tax purposes are qualifying exploration expenditure tax deductible under Initial Allowance of 10% and Annual Allowance of 15% or calculation based on a formula, whichever is the greater. |
| Vietnam:   | Non recoverable / tax deductible                                                                                                                                                                                                                      |
| Indonesia: | Non recoverable / non tax deductible                                                                                                                                                                                                                  |

## B. Rentals (land, surface fees)

Generally paid annually on the basis of the size of the acreage under lease, normally at the beginning of the calendar year or contract year. They may take on different forms: it could be a fixed amount for the contract or per square km. of operations land, the “object value” or a negotiated amount.

The basis for charging may vary between exploration/exploitation phase or onshore and offshore and may be payable depending on the territorial zone in which operations are carried out. Normally they are considered as a recoverable or deductible cost.

They provide the government with regular income and encourages voluntary relinquishment of acreage. However, they may raise issues regarding the delimitation of the “area”.

### **EXAMPLE. INDONESIA LAND AND BUILDING TAX (PBB):**

Tax rate: 0,5% of a “deemed” tax base (ranges from 20% up to 100% of the “object value”, being a statutory value). In 2013 it was changed to provide for post GR 79 PSCs a self-remit tax and claim it as cost recovery. This change became a concern as most post GR 79 PSCs were still in exploration phase (uncertainty of cost recovery).

The Directorate of General Taxes (DGT) issued a clarification for the “offshore” component of objects to specify that only apply to the area “utilized” (the term “utilized” was not defined).

Latter, the DGT issue new compliance and calculation procedures for PSCs, where:

- The definition of “offshore area” did not refer to “utilization”, giving rise to uncertainty.

- Introduces a “zone” concept, which could include areas outside the PSC contract area. However, there still is under clarification by tax authorities based on distinction between surface working area and subsurface reservoir area.

#### **Example: Nigeria Signature Bonuses and Lease Rental**

In Nigeria, IOCs pay a signature bonus to government for the right to an Oil Mining Lease (OML) after which a PSC contract is signed with the government or holder. The signature bonus is not recoverable.

The OML is a license granted to an IOC to extract crude oil and/or gas in commercial quantities from a defined area for sale or export. The money paid to government upon the award of this license is known as “Signature Bonus”, this is a one-off payment.

In addition to the Signature Bonus, the IOC will pay lease rental or concession rental to government on an annual basis. The lease rental is likened to rent of the land / area where the OML is granted. The difference between the Signature Bonus and Lease Rental is that: (i) Signature Bonus is a one-off payment upon award of an OML. It is capitalized and not allowed for Cost recovery. (ii) Lease Rental is an annual payment for the duration of the OML which allowed for tax deduction and Cost recovery.

In PSC an OML is granted for a duration of 30 years whereas in JV the duration is 20 years. At the expiry of the license, the government may renew it or award the license to another Company. The Signature Bonus is paid upon award of an OML irrespective of whether the IOC is renewing such license.

### **C. Royalties**

Most PSCs contain provisions whereby a royalty is paid to the government out of production, although royalties are not an essential feature of PSCs. The combination of a cost oil limitation and a minimum share of profit oil to the state actually replicates the economic features of a royalty: it guarantees that the government collects a share of the value of production, as soon as production starts.

Royalties are based on the volume or value of petroleum extracted and can be paid either in cash or in kind. Payment in kind involves delivery of physical quantities of O&G to the government (normally in some cases by the government-owned company).

Royalties based upon gross revenues can be determined at different points of valuation: e.g. wellhead, block boundary, export terminal or point of sale. The point of sale, however, may be different than the point of valuation. The statutory royalty may allow transportation costs from the point of valuation to the point of sale to be deducted (netback transportation cost).

Royalties may become obstacles to new investments in marginal fields or lead to the early abandonment of marginal producing field due to its regressive effect. To prevent these situations, contracts may include royalties paid on a sliding scale, so that royalty rate varies based on selected variables such as price, hydrocarbon type, etc. They can be lower with lower production or price and increases as production or price increases.

| TYPE OF ROYALTIES |                                            |                                                                                                 |
|-------------------|--------------------------------------------|-------------------------------------------------------------------------------------------------|
| Fixed Percentage  | Of Production (e.g. 10% of oil extracted). | Easy to administer, but do not take into account the profitability of the project (regressive). |

|                |                                                                                                                                                                                                                                                                                                                                                                                                 |                                                                                                                                    |
|----------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------|
| Sliding Scales | <ul style="list-style-type: none"> <li>• Level of field Production,</li> <li>• Level of well Production,</li> <li>• Level of well Production and Price,</li> <li>• Cumulative Production,</li> <li>• Based on payout,</li> <li>• Based on R-factor</li> <li>• Based on Internal Rate of Return,</li> <li>• Based on gravity of oil,</li> <li>• Based on elapsed time</li> <li>• Etc.</li> </ul> | More progressive than fixed royalties, depending on the mechanism adopted. Variable royalties can be more burdensome to administer |
|----------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------|

Some exclusions from royalty payment apply with respect to e.g. O&G vented or flared (with approval), reinjected, used in field operations or acceptable losses.

#### - *Sliding Scale Royalties*

Sliding scale royalties are used to escalate the royalty based on a factor or factors agreed in the contract that tends to predict the profitability of a project. Normally production levels are a poor proxy for profitability, but there are other factors that can be used (e.g. prices, costs and timing, production, IRR). Instead, price is more reliable indicator for profitability.

#### **EXAMPLE, ALGERIA:**

**The rate is determined in each contract. However, the law has fixed a minimum rate per area <sup>1</sup>**

| Production (BOE) / Area | A     | B     | C     | D     |
|-------------------------|-------|-------|-------|-------|
| 0-20,000 BOE/day        | 5.5%  | 8.0%  | 11.0% | 12.5% |
| 20,001-50,000 BOE/day   | 10.5% | 13.0% | 16.0% | 20.0% |
| 50,001-100,000 BOE/day  | 15.5% | 18.0% | 20.0% | 23.0% |
| > 100,000 BOE/day       | 12.0% | 14.5% | 17.0% | 20.0% |

#### - *R-factor*

Some countries have designed the royalty rate to depend on the “R factor” (“R” stands for “ratio”), similar to the one used to split profit oil. The R-factor model varies depending on the profitability of the project from all sources, e.g. oil prices, project costs, production profile and reserves. A common “R-factor” is the ratio of cumulative receipts from the sale of petroleum to cumulative expenditures.

$$R = \text{Cumulative Revenue}^{(1)} / \text{Cumulative expenditure}^{(2)}$$

<sup>(1)</sup> Cumulative net revenue actually received by the contractor for all tax years less taxes paid.

<sup>(2)</sup> Cumulative expenditure, exploration and appraisal expenses, development and operating costs actually incurred by the contractor from the date the contract is signed. Therefore, Cumulative expenditure is defined as the accumulated capital expenditure (Capex) and operating expenditures (Opex).

The factor R is calculated in each accounting period; and once the threshold is crossed then the new tax rate will apply in the next accounting period.

The ratio is initially zero during exploration as there is no sale of petroleum while there may be considerable expenses and gradually grows in time. An R-factor less than 1 would mean that costs have not been fully recovered yet (total expenditures exceed total receipts). At payout, the R-factor will equal to 1 and the larger the R-factor, the more profitable the operation. The royalty rate or the government's share of production may increase with increasing R-factors.

When the threshold is reached, the factor R can be applied as follow:

- Increasing the royalties.
- Increasing the Profit Oil.
- Increasing the corporate income tax.

Some advantages of applying the PSC sliding scale system using R-factor are as follows:

- Provide a progressive fiscal system that can balance interests between the government and the investors.
- Create incentives for the investor company to maintain the level of project profitability.
- Minimizes the need of changes or renegotiation of contract terms.

However, there are some challenges of implementing PSC sliding scale with R-factor:

- Creating the wrong incentives. The contractor may spend relatively unnecessary costs to keep a lower R-factor that maintains a higher company share ("*gold plating*").
- Determining the R-factor band. The band should be adapted to each field, target a reasonable rate of return for investors and fair share of profit oil to the host country.

If designed well, PSC sliding scale systems may offer a progressive system that can be attractive for marginal projects, balancing the risks in facing price surges, e.g. oil price volatility, during the field lifetime, i.e. exploration, development and production<sup>23</sup>.

#### D. Corporate Income Tax

Most PSC-based systems include a corporate income tax which may have different forms of calculation:

- Corporate income tax is calculated separately, but with the same calculation as that used for Cost Oil. In these cases, the corporate income tax is simply a percentage of Profit Oil.
- Corporate income tax is calculated separately, in accordance with the corporate income tax law which are different from the basis used to calculate Cost Oil and Profit Oil.
- Corporate income tax is included in Profit Oil/Gas paid by the state company "on behalf of" the contractor" (Gross Up/Tax Paid PSC/Taxes "in lieu") and the basis for its calculation is provided in the tax law and/or the PSC.

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<sup>23</sup> Trian Hendro Asmoro. PSC Sliding Scale as A Fiscal Model For Marginal Fields In Indonesia. IPA16-25-BC. 2016.

## a. Direct payment by the contractor:

Example of PSC with payment of direct taxes by the contractor is **Indonesia** model. In this country, the contractor must satisfy a corporate income tax at an effective rate of 45%:

- (I) Corporate tax, which rate is 25% and
- (II) Tax on the remittance of funds ("final tax on profits after tax deduction") at the rate of 20%, payable regardless of whether a dividend is distributed or there is a remittance of funds from the branch to the central house and an international CDI between the country of residence of the operator and Indonesia.

## b. Government (including National Oil Companies) payment on behalf of the contractor.

Contractor's profit share is taxable. Some host countries pay such taxes on behalf of the contractor from its own share of the production (also known as "taxes paid on behalf or "in lieu").

Examples of PSC with payment of tax by the NOC are found in Egypt, Libya, Guyana and Iraq (Kurdistan). In these countries the profit oil of the State includes a volume of hydrocarbons sufficient to satisfy the corporate income tax of the contractor (in some cases, also other additional taxes), so that in order for the contractor to calculate the tax base of his corporate income tax, it is necessary to use the gross up formula and apply the local corporate income tax rate to calculate the tax payment.

The fact that the government satisfies the tax in the name and on behalf of the contractor, does not exempt the latter from presenting a corporate income tax declaration and fulfilling the rest of the formal obligations in the country, since the contractor remains the corporate income tax taxpayer, regardless of whether the government is responsible for payment of the tax.

For double taxation relief purposes in the contractor's resident country, it is very relevant that the contract establishes the necessary documentary requirements showing that obligations derived from PSCs are equivalent to the payment of income tax (e.g. a tax paying certificate)<sup>24</sup>.

The following example illustrates the application of the gross up:

**Guyana:**

In addition to the corporate income tax, the Government undertakes to satisfy, with its share of profit oil and on behalf of the contractor, not only the corporate income tax, but also the royalties and any other similar tax that may arise

**Kurdistan:**

*"The share of the Profit Petroleum to which the GOVERNMENT is entitled in any Calendar Year in accordance with Article \_\_\_ of this Contract shall, be deemed to include a portion representing the corporate income tax imposed upon and due by each CONTRACTOR entity, and which will be paid directly by the GOVERNMENT on behalf of each such entity representing the CONTRACTOR to the appropriate tax authorities in accordance with Article \_\_\_ of this Contract. The GOVERNMENT shall provide the CONTRACTOR with all written documentation and evidence reasonably required by the CONTRACTOR to confirm that such corporate income tax has been paid by the GOVERNMENT."*

<sup>24</sup> In 1976, the Internal Revenue Service of the USA ruled that oil companies would not enjoy a tax credit on foreign income derived from PSCs as it was characterized as a royalty and concluded that this obligation did not constitute an "income tax".

*“Each CONTRACTOR entity shall be subject to corporate income tax as provided in Article \_\_\_ below, which shall be deemed to be inclusive and in full and total discharge of any corporate income tax of each such entity. Payment of the said corporate income tax shall be made for the entire duration of this Contract directly to the appropriate Kurdistan Region tax authorities by the GOVERNMENT, for the account of each CONTRACTOR entity, from the GOVERNMENT’s share of the Profit Petroleum received pursuant to...*

## 8. Non-fiscal clauses generating tax issues

To understand the full potential of the interaction between PSCs and corporate and other taxation, it is necessary to be aware of some of the other features of PSCs.

PSCs may contain **non-fiscal clauses** related to the duration of exploration and exploitation, bonuses, duties, the state participation in the operations, domestic market obligations, work program, local content (e.g. training programs), etc. It is important to be aware that non-fiscal clauses may have an impact on the ultimate fiscal take.

One is the corporate investment structure in the country of operation. Some countries require the IOCs to form an "office", branch or company. It may happen during the exploratory stage. It is possible to invest through a branch, but for the presentation of the FDP it is necessary to invest through a local company. Main issues in this regard are treated in the Permanent Establishment Chapter<sup>25</sup>, including the fact that more than one PE may actually exist within one country. This is the case as the common construct is to have one JOA for each underlying petroleum agreement. Further, other non-fiscal clauses that clearly affect tax matters are described below:

### A. Contract period.

Considerable time may elapse between investment in the extractives industry and the realization of profits. PSCs are therefore long-term in nature. Typically, they provide for a term of 20 or 25 years or longer from the commercialization of the asset and usually provide for extensions of the contract duration if continued commercial exploitation is expected. One of the differences between oil and gas due to market constraints is timing of production (typically gas discoveries usually takes longer)).

The following framework can be found in some PSCs regarding contract period:

Exploratory phase: First phase X years (minimum commitments XX MUSD with / without exploratory drilling) and second phase x years (minimum commitment XX MUSD - X exploratory drilling). Maximum extension of X years.

Development and production phase: (I) Crude: XX years, with potential extension period(s): X + X + X. If an extension is requested, the fiscal terms can be maintained or renegotiated depending on the terms of the PSC. (II) Gas: XX years, divided with potential extension periods: X + X + X.

### B. Ring fence vs. consolidation

Ring-fencing is a rule that prevents costs or losses in one activity (e.g. Oil and Gas) or area being offset against income in another activity or area. For example, all costs associated with a given area must be recovered from revenues generated within that area, which can have an impact on the recovery of exploration costs and end up in final sunk costs (i.e. if the country of residence does not allow for deduction).

<sup>25</sup> Chapter 3 of the Handbook.



Some countries allow only certain classes of costs associated with an area to be recovered from revenues from another field (e.g. only exploration, but not development costs) or allow deduction of exploration costs incurred by an abandoned area with revenues from a producing area.

Where ring fencing applies, investors having signed more than one PSC within a country will be compelled to independently manage each area through the corresponding joint venture, consortium or association (accounting and business, legal and tax obligations).

In imposing ring fencing, governments make a tradeoff between investment incentives and revenue collection. Ring fencing prevents the postponement of tax revenue. Without ring-fencing, a company undertaking a series of projects would be able to deduct exploration or development expenditures from each new project against the income of projects that were already generating taxable income, which would be an incentive to invest in new fields.

### C. Domestic market operation (DMO).

Many PSCs require the contractor to sell a portion of its share of production to the host government to help meet the local market demand. This requirement is referred to as domestic market obligation (DMO) and is based on some governments' policy to supply and satisfy domestic demand in priority. In some PSCs such obligation applies only if the government's and the NOC's share of production are not sufficient to meet the local demand. Usually, this contractor obligation is proportional to its share of production relative to the total production of the host country, and in some cases subject to a cap defined in each PSC.

In some PSCs the price the contractor can charge for the DMO oil or gas is at a discount to world market prices (occasionally the contract establishes a maximum price). This comes at a cost for the investor and will be typically incorporated in the contractor's project economics. In some PSCs the government may also pay for the domestic crude in local currency at a predetermined exchange rate. Such DMO terms may expose the investors to lower price realization and foreign exchange risks, with a negative impact on the investment terms, and investors may require a higher share of the profits as a result. Both aspects need to be carefully and clearly established in the PSC for the sake of certainty.

#### **Example of a DMO clause:**

*After commercial production commences, fulfill its obligation towards the supply of domestic market. CONTRACTOR agrees to sell and deliver to the Government of \_\_\_\_\_ a portion of the share of Crude Oil, (...), calculated for each year as follows:*

*(a) Compute [X] per cent of CONTRACTOR's entitlement (...) multiplied by total quantity of Oil produced from the Contract Area;*

*(b) The price at which such Oil be delivered and sold (...) shall be [X] per cent of the price determined under Sub-section (...), and CONTRACTOR shall not be obligated to transport such Oil beyond the Point of Export, but upon request CONTRACTOR shall assist in arranging transportation and such assistance shall be without cost or risk to CONTRACTOR.*

### D. Work Commitments program

A key issue in PSCs negotiation is the work program that outlines the contractor's commitments regarding to e.g. seismic, drilling, information disseminations, financial obligations, and employment of local workforce.

Examples of minimum work obligations in the Exploration phase:

- Specified in terms of kilometers of seismic data and number of wells to be drilled. Seismic work may constitute the only work in least explored (frontier) areas, may consist of seismic data acquisition with an option to drill exploration wells.
- Acquire and interpret certain seismic data required to decide whether to drill a well.

Sometimes a minimum expenditure level is required in the work commitment. The terms of the work commitment outline indemnities for non-performance (e.g. failure to drill a well as established in the petroleum contract). It is a sensitive aspect for exploration activity (as they embody most of the risk).

#### **EXCERPT FROM THE EQUATORIAL GUINEA MODEL PSA 1:**

##### **EXAMPLE. EXCERPT FROM THE INDIA MODEL PSA 20051:**

*During the currency of the first Exploration Phase..., the Contractor shall complete the following Work Programme:*

*(a) a seismic program consisting of the acquisition, processing and interpretation of [\_\_\_\_] line kilometres of 2D and/or [\_\_\_\_] sq. kms. of 3D seismic data in relation to the exploration objectives; and (b) [\_\_] Exploration Wells shall be drilled to at least one of the following depths : i) [\_\_] metres and [\_\_\_\_] (geological objective); ii) to Basement; and iii) that point below which further drilling becomes impracticable due to geological conditions encountered and drilling would be abandoned by a reasonable prudent operator in the same or similar circumstances. Abandonment of drilling under this provision by the Contractor, would require unanimous approval by the Management Committee.*

#### **D. Responsibility of decommissioning:**

The resource ownership may lead to the subject of decommissioning under a PSC. Under a concessionary system, the investor is typically responsible for decommissioning, whereas under PSCs, unless specific provisions have been included in the contract the government is typically legally responsible for decommissioning<sup>26</sup>. Properly structured, the abandonment cost can be estimated and anticipated through cost recovery during the producing years<sup>27</sup>.

#### **Example of abandonment responsibility of contractor: PSC Kenya.**

*“If the Government does not elect to continue using such facilities, assets or wells, **the Contractor shall be responsible for their abandonment and decommissioning** upon termination of this Contract or of the Development Area within the corresponding Development area, if earlier. Contractor may in consultation with Government defer the abandonment and decommissioning operations for a reasonable length of time if this would result in operational efficiencies, which minimize the cost for all parties.”*

<sup>26</sup> Silvana Tordo, Fiscal Systems for Hydrocarbons. Design Issues. World Bank working paper no. 123 (2007). Page 8.

<sup>27</sup> See Chapter 6: “The tax treatment of decommissioning”. Page 26 of 31

## 9. Country examples

### BRASIL

#### **Brazilian geological area subject to Production Share Contracts**

The Brazilian Production Share regime is limited to a particular geological formation, known as pre-salt. This is defined by the Law number 12.351, enacted in December, 22th 2010, Annex.

The pre-salt polygon, which has approximately 800 km in length and 200 km in width, is located in Brazil offshore, from the Santa Catarina state coast to Espírito Santo state coast, with an area around 149 thousand km<sup>2</sup>.

The Pre-salt is a geological formation where a thick salt layer holds a massive amount of oil and gas below it. Located in offshore ultra-deep waters, the pre-salt layer has until 2.000 meters of thickness.

The region has other oil and gas fields also above the pre-salt layer, which are called post-salt deposits, these deposits are the conventional oil and gas ruled by concession regimes, by the other hand, the production share regime governs the pre-salt deposits exploration and production.

The reason to have a different regime to the pre-salt deposits is that these geological formations have a very low exploratory risk and they are likely to have a high production level.

The Brazilian Fiscal Regime for the Oil and Gas industry is a mixed regime with concession and production sharing schemes. Brazil charges royalties and special participations (windfall tax) over production. The special participation is charged over fields with large production, it is a kind of profit tax. These governments interests are management by the National Agency of Petroleum, Natural Gas and Biofuel (ANP – Agência Nacional do Petróleo, Gás Natural e Biocombustíveis).

The other part of government Take directly involves the Federal Tax Administration and Tax Administrations of the subnational States'. Brazil charges income tax at a 34% nominal rate, which is a federal tax. For income tax purposes the signature bonuses, royalties and special participation are deductible.

#### **PSC consortiums Brazilian Government Representatives**

The Brazilian State is represented in all PSC for a whole state-owned company called Empresa Brasileira de Administração de Petróleo e Gás Natural S.A. – Pré-Sal S.A., or simple PPSA. This company was incorporated by the Decree number 8.063, enacted on August 1st, 2013.

Who is the consortium operator?

All PSC in Brazil will be conducted by a consortium because, whatever the bid outcome, the winner is obliged to associate with PPSA which will indicate the Operational Committee president and half of its members.

With this in mind, there will be two different situations: the first is when Petrobras chooses to participate of the exploration and production, in this case, Petrobras will be the operator with nothing less than 30% of the equity participation, the other one is when Petrobras doesn't use its right, when the operator will be a free choice of the contracted companies.

#### **Tax Issues in PSC regimes**

The Brazilian's oil and gas regulatory regime is independent of Brazilian's income tax legislation, no matter if it is a concession or a PSC regime. The regulatory regime deals with Brazilian government

interests which are: royalties and special participation (windfall tax) in concession regime, or royalties and State profit oil in PSC and signature bonus in both cases.

These government interests are charged in a ring fence base considering the field as a production unit, split from the other company's enterprises for determining the profits or the amount of royalties, and in the case of PSC, the oil and gas volume in regard of the State profit oil share.

The Brazilian oil and gas income tax legislation follows the general taxation rules. There are many laws, decrees, and instructions that rule the Corporate Income Tax, but only two norms deal with the oil and gas industry income tax in particular. These are the Law number 13.586, enacted on December 28th, 2017, and the normative instruction, number 1.778, enacted on December 29th, 2017.

This same law, this time combined with other normative instruction, with number 1.781, enacted on December 29th, 2017, and with the Decree number 9.537, enacted on October 24th, 2018, deal with the Customs regime for Oil and Gas Industry, called REPETRO.

The establishing of cost oil and the profit oil, and therefore, the State share of production, has a close relation with the accounting rules and principles, as well as with the taxation rules and principles; however, they are ruled by the contract provisions.

Many different expenses are nondeductible for cost oil determination, for instance: royalties and signature bonus, interests and financial expenditures and income tax, although these expenses are deductible to corporate income tax.

The cost oil in Brazilian PSC allows the expenses with decommissioning provisions, and annually the balance amount shall be adjusted by a contractual finance index.

None of these PSC provisions are allowable in the accounting/tax standards.

We call your attention for that transactions between related companies use transfer pricing rules, usually the same of tax legislation, regarding cost oil ascertainment.

All the expenses which are allowable to be recovered as cost oil are registered in a proper account, mixing investments and operational costs, referred to as Cost Oil account. The rate which the company is allowed to use the cost oil amount balance in each year varies from 50% to 100% of the gross production value.

The value which exceeds the cost oil recover limits can be carried forward to the next fiscal year. For taxation matters, the investment expenditures and the operational costs have different treatments. The investments have a capital allowance which consists of a rate of amortization of 2,5 times the unit product method rate, and the operational costs are deductible on an accrual basis.

### **Non-Produced resource ownership**

The non-produced oil and gas belongs to the Brazilian State. The company's production ownership arises at the production share point, after the PPSA audit the cost oil and profit oil.

There is a clause which restricts the export of production in emergency cases, and establishes, in this case that the production must be sold in the Brazilian market.

### **Risks and Equity**

All the expenditures, in all project phases, as the entire risks of project failure, or loss, and the environmental restoration in the case of an accident, or even compensation for third parts are company's liabilities.

However, there is a law provision that allows the Brazilian Government to establish a fund that would invest in selected projects, assuming part of the risks as an enterprise partner, but it hasn't set up yet.

### **Ownership of Assets**

The assets belong to the consortiums; however, they can be reverted at the end of the contract or at the relinquishment contract area's plots to the Brazilian State. The conditions which this provision is applied are determined by the need of these assets to continue the operations in that area.

There is a huge difference between this provision and the property reversal to Brazilian Government in concession contracts, since the later only is applied when the asset acquisition cost is deductible for the calc of the windfall government interest (special participation), and the National Oil Agency must consider that asset required to continue the operations in the decommissioning area.

### **Government Interests**

The government interests charged in the Brazilian Production Share Agreements are royalties at 15% rate and signature bonuses only. The Brazilian revenue arised from the Union oil share in 2018 was around US\$ 353.9 millions<sup>28</sup>.

### **Local Content**

There are local content requirements established in the contract. They vary from a global percentual of local equipment and services purchases, as well as a percentual of local content per phase with different rates for different fields.

### **Work Program**

There is a work program, and the companies must present financial guarantees for the estimated value of seismic research and drilled wells in the contract.

### **Tax Clauses**

There aren't.

### **Tax Stability Clauses**

There aren't.

### **Economic Stability Clauses**

There aren't.

### **Brazilian Government Fixed Percentages of the Profit Oil Share**

| <b>Round</b> | <b>Field</b>                  | <b>Government % Share</b> |
|--------------|-------------------------------|---------------------------|
| First        | Libra                         | 41,65                     |
| Second       | South of Gato do Mato         | 11,53                     |
|              | Around Sapinhoá               | 80                        |
|              | North of Carcará              | 67,12                     |
| Third        | Peroba                        | 76,96                     |
|              | High Cabo Frio West           | 22,87                     |
|              | High Cabo Frio Central        | 75,8                      |
| Fourth       | Três Marias                   | 49,95                     |
|              | Uirapuru                      | 75,49                     |
|              | Dois Irmãos                   | 16,43                     |
| Fifth        | Saturno                       | 70,2                      |
|              | Titã                          | 23,49                     |
|              | Pau-brasil                    | 63,79                     |
|              | South West of Tartaruga Verde | 10,01                     |

<sup>28</sup> Available in

[https://www.presalpetroleo.gov.br/ppsa/conteudo/147\\_326\\_relatorio\\_anual\\_administracao\\_2018.pdf](https://www.presalpetroleo.gov.br/ppsa/conteudo/147_326_relatorio_anual_administracao_2018.pdf)

## NIGERIA

Three categories of PSCs were executed in Nigeria;

- The 1991/1993 PSCs
- The 1998 PSCs
- The 2005 PSCs

Some of the major fiscal terms of each of these classes of PSCs were;

a. **The 1991/1993 PSCs**

- OPL Obligation – 50% of contract area to be relinquished after 10yrs
- OML/Production Period – for a renewable minimum period of 20yrs
- Production Bonus – 0.2% for Cumulative Production up to 50million barrels, 0.1% for Cum Production upto 100million barrels (this is calculated on current price at the time of attainment of target). Bonus is fiscally deductible but not recoverable from cost oil.
- Royalty rate is a graduated percentage of production volume ranging from 12% to 0% for the Deep Offshore, and 10% for the Inland Basin (Benue Block).
- Tax Rate – the DOIBA provides for the determination of the PPT payable in accordance with the provision of the PPTA with a proviso that the tax shall be at the flat rate of 50% of chargeable profit for all PSCs.
- Investment Tax Credit (ITC) – an amount equal to 50% of QCE incurred in the year to be set-off against assessable tax to arrive at chargeable tax.
- No cost recovery limits
- Profit Oil = Production – Royalty Oil – Cost Oil – Tax Oil

b. **The 1998 PSCs**

The same terms of the 1993 PSCs were maintained except for;

- Introduction of Investment Tax Allowance (ITA) which replaced ITC. ITA is amount equal to 50% of QCE incurred to be claimed as part of Capital allowance.
- Introduction of Cost recovery limits.

c. **2005 PSCs**

Same fiscal terms with the 1998 PSCs with the introduction of;

- Increased Signature Bonus
- Royalty rate no longer 0% where water depth exceeds 1000m. 1% royalty rate for water depth beyond 1000m.

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