



Peter Roberts

A Practical Guide to Upstream Petroleum Granting Instruments



دار نشر جامعة قطر
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**A PRACTICAL GUIDE TO
UPSTREAM PETROLEUM GRANTING
INSTRUMENTS**

Peter Roberts

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Preface

This is a guide to the various forms of granting instrument which are used worldwide for petroleum exploration and production. This guide consists of two parts:

Part A is a general review of granting instruments as they are used for petroleum exploration and production. In this Part A the term ‘granting instrument’ is deliberately used generically as a single term for ease of reference, intended to encompass all the different forms of petroleum concession, license, contract or permit.

Part A considers the logic for the award of a granting instrument by a state, the various forms of granting instrument which are used, the mechanics of how granting instruments are awarded and how evolution in certain granting instrument forms and terms has taken place.

Part B is a clause-by-clause analysis of a production sharing contract. The production sharing contract, rather than any of the other forms of granting instrument, has been selected for particular review in this guide because it is the form of granting instrument which by far is the most widely used worldwide today for petroleum exploration and production.

Despite this focus however, many of the terms of the production sharing contract which are considered in this Part B will also be very relevant to the other forms of petroleum granting instrument.

The analysis of the production sharing contract’s terms in Part B identifies and references publicly-accessible production sharing contract examples for further illustration of certain of the less-common provisions which are discussed. For obvious reasons of confidentiality the content of production sharing contracts which I have encountered but which are not publicly available can only be discussed on an anonymized basis.

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Peter Roberts

July 2020

PART A:

**GRANTING INSTRUMENTS FOR PETROLEUM
EXPLORATION AND PRODUCTION GENERALLY**

A1. The logic for a granting instrument

A1.1 Why states enter into granting instruments

In most jurisdictions, in-ground petroleum resources, both onshore and offshore, belong to the state, and it is the state which has the exclusive exploitation right in respect of that petroleum. The United States is the most-cited exception to this principle, where the private ownership of in-ground petroleum resources is a possibility (although even in the United States federal land ownership, and ownership of the associated mineral rights, is also a feature in respect of the continental shelf and certain onshore land areas).

A state which believes it possesses petroleum resources could elect to develop those resources itself. The state would assume the economic and operational risks associated with such development and the state would be entitled to enjoy the economic benefits of the resultant petroleum production for its own account. This approach is the ultimate embodiment of the state's management of its own patrimony.

A state could however lack the economic and/or technical capacity to undertake such development, and could also be reluctant to accept the risks (both economic and reputational) of miss-performance or failure which are associated with such development.

Hence, as a partial diversion from the notion of state sovereignty over mineral wealth the state could decide to award some form of a granting instrument to a person (called the 'holder' in Part A of this guide) to undertake the development of the petroleum resources on behalf of the state – critically, at the risk and at the expense of the holder. The form of the granting instrument which is used for this purpose, and the economic returns to the state which the granting instrument generates, will be as much about the political philosophy of the state as it will be about managing the economics of commercializing the state's petroleum resources.

The term 'granting instrument' is used in Part A of this guide generically as a single term intended to encompass all the different forms of absolute concession, licence, production sharing contract, revenue sharing contract, or service contract which are in use worldwide (each of which is considered in greater detail below). A granting instrument could also be described in other ways, including as a host government agreement, a host government contract, a government petroleum contract, an upstream petroleum contract, a petroleum agreement, and so on. The list of possible names is extensive but these are simply different ways of describing the same basic concept – the granting instrument (in whatever form it takes, however it is described) and at its heart is an authorization which is awarded by or on behalf of a state to an investor (whether foreign or domestic, whether acting alone or as part of a consortium) as the holder, whereby that holder is empowered to explore for and to produce petroleum within the state's territory in accordance with the terms of the granting instrument.

The vernacular of the award of a granting instrument to a holder admittedly has a somewhat seigniorial overtone, and ignores the more contemporary view that petroleum is generally explored for and produced through a balanced documentary relationship between the state and the holder which has the elements of a reciprocal contractual relationship, but nevertheless it is used in this guide as a convenient way of describing a number of interchangeable terms for how the various petroleum exploration and production permits and permissions and the relationships which they create between the state and the holder can come into existence.

A1.2 Managing competing interests

In awarding a granting instrument, the state will expose itself to the need to manage several competing interests:

State -v- holder

The granting instrument which is awarded by the state to the holder, in whatever form it takes (A2.2), represents the award by the state of a right and an obligation to the holder to undertake an activity which the state is unable or unwilling to undertake itself, and it also represents a permission to perform an activity which the holder would not be permitted to undertake without the award of the granting instrument by the state. The essence of the granting instrument from the holder's perspective is an assumption of certain rights and obligations and the exposure to potential risks and rewards. From the state's perspective the key aspect of the granting instrument is an abrogation of some of the state's sovereign rights, done with the concomitant transfer by the state to the holder of certain rights and obligations, but also done with the prospect of various returns (both fiscal and non-fiscal) accruing to the state as a consequence of doing so.

'Economic rent' is a term that is used (but not universally) to describe the surplus of the revenues which accrue from petroleum production over the costs which were incurred by the holder in realizing that production. The difference between the two measures is, essentially, the holder's profit. The holder's interest is in maximizing the economic rent through improving the revenues and keeping the costs down; the state's interest is in capturing as much of the economic rent as possible for itself, where the proportion of the rewards which would otherwise flow to the holder as economic rent if the granting instrument proves to be revenue generative through the production of petroleum is sometimes described as 'state take'. State take is an after-the-event adjustment to the balance of risk and reward which the granting instrument originally creates, which comes into play if the petroleum exploration efforts under the production sharing contract (PSC) have been successful. The holder can predict this consequence at the time of entry into the granting instrument however, through understanding the applicable fiscal terms of the granting instrument (B9).

The great paradox for a state in this nascent state/holder relationship is that offering better terms to potential holders in order to make the granting instrument more attractive and so to secure their investment will come at the expense of reducing the level of state take from the granting instrument. The parameters for the design of a successful granting instrument will therefore pull in opposite directions for the grantor. Yet, sometimes the terms (both fiscal and non-fiscal) of one state's granting instrument will be comparatively less attractive than those of another state's granting instrument to a prospective holder. In addition, within a granting instrument a state could apply certain terms that a prospective holder could regard as onerous and unattractive. Why would a state offer relatively unattractive granting instrument terms to a prospective holder which it is trying to attract?

When it comes to designing the terms of a granting instrument a state has to reconcile its desire to retain a fair measure of return from the holder's exploitation of the state's patrimony with presenting an investment opportunity which holder will find sufficiently attractive to want to pursue. But into this equation it is also necessary to add in the petroleum prospectivity of the intended granting instrument area, which will have a significant bearing on the expected state take and the appetite of a prospective holder to become involved. There are therefore three competing interests to reconcile: the state's expectations, the prospective holder's expectations and the quality of the underlying geology. The distribution of the geology, and the form which that geology takes, is a matter of chance and is an accident of nature. The form of granting instrument which is used by a state which has been lucky in the geological lottery, and the level of state take which the granting instrument effects, is entirely man-made.

The essential rendition to note from all of this is that a higher level of state take (and generally less attractive granting instrument terms) could still be acceptable to a prospective holder where the geology of the granting instrument suggests a higher chance of exploration success, of cost-effective production and of significant petroleum recoveries. Correspondingly, if the geology of the granting instrument indicates a lower degree of petroleum prospectivity then a prospective holder could require to be compensated for accepting that risk through being offered a lower level of state take and generally more attractive granting instrument terms. Prospective holders are however generally well accustomed to dealing with this inversion of the relationship between granting instrument terms and geology.¹

There is also a relationship to note between the fiscal terms of the granting instrument and the levels of petroleum production. A petroleum discovery which has (from the

¹ "The oil industry is comfortable with tough terms if they are justified by sufficient geological potential. This is the birthplace of dynamic negotiations." Daniel Johnston, *International Petroleum Fiscal Systems and Production Sharing Contracts* (PennWell Books, 1994), 18.

holder's perspective) poor fiscal terms but high production levels could give a better net return than a low-producing petroleum discovery with better fiscal terms. But at the time when the holder negotiates and accepts the fiscal terms in the granting instrument it could have relatively little insight into how a prospective petroleum discovery might actually perform over time.

Any granting instrument necessarily represents a balancing of the competing interests of the state and of the holder. Ultimately, both parties want to make what they each regard as a fair share of money from the granting instrument by the profitable production of petroleum for sale, but even that one common interest can be expressed differently. From the holder's perspective, the key objectives are that the associated exploration, appraisal, development and production costs are recouped and a satisfactory level of profit is made. The state's interest is in maximizing revenue, which could come in a number of different ways under the PSC (and at the expense of the holder). Beyond this common ambition, the aims of the parties will diverge, and the state in particular will have other strategic imperatives that it will wish to realize from the award of a granting instrument:

- (1) Reducing the state's dependency on imported energy, and establishing a new form of domestic economic activity;
- (2) Developing as much geological and geophysical data as possible (and as quickly as possible) relating to the state's petroleum prospects. Consequently, the state wants the holder to perform the agreed exploration period obligations (B6.3) promptly. The state is not interested in any other commitments or opportunities which the holder might have and which could delay the performance of those obligations. Paradoxically, the holder has resource and cash constraints and/or alternative investment opportunities, which it has to manage. Therefore the holder wants the greatest possible degree of flexibility under the granting instrument for the performance of those obligations; and
- (3) Maximizing the state's ambitions in relation to matters such as local content, the localization of employment opportunities, technology transfer and the accumulation of expertise, and capacity building generally (B13).

The granting instrument is the melting pot in which all of these competing aspirations of the state and the holder will be managed.

State -v- population

The elected government of a state usually assumes an obligation to be accountable to the state's population for what they will regard as their mineral wealth, to be reflected through how the state awards granting instruments and maintains an adequate level of state take.

For a population, which expects the advent of national and personal wealth from the exploitation of the state's petroleum resources, the key issue for the state could be the need for careful expectation management. The population is likely to be more focused on seeing immediate financial improvement, and less interested to understand longer-term issues relating to matters such as exploration risk, project timetables and ensuring satisfactory returns to the holder.

The population might also be keen to see the state exercising a visible measure of control over the exploitation of the state's patrimony by foreign investors. This could be evidenced by the design of the form of granting instrument which is used (for example, by compelling the use of a production sharing contract or a service contract (A2.2)), or by the creation of a prominent national oil company and the securing of participation rights for that company (or another state representative) in the granting instrument (B11) and by the requirement for granting instruments to be held through local companies (B1.2, B11.4). In the extreme case, this need to evidence control could see the state exercising some form of expropriation over the holder's interests, so leading to a demand by potential holders for some sort of stabilization mechanism within the terms of the granting instrument (B16).

State -v- state

The balancing act that takes place between the state and the holder also needs to take into account that there could be competition for a state to secure investment from a prospective holder from other states, which are offering granting instrument bid rounds of their own.

Thus, the design of a successful granting instrument (that is, one which balances the competing interests of the state and a holder) has to be conducted in absolute terms and also in relative terms. The terms of a granting instrument cannot be created in a vacuum, without regard to the many competing demands for the investment interest of a prospective holder.

A2. The form of the granting instrument

A2.1 Forms of granting instruments generally

There is no single form of granting instrument which is used for the activities of petroleum exploration and production worldwide. Different forms of granting instrument are used in different jurisdictions, and sometimes a state will transition the use of different forms of granting instrument over time, or will use different forms of granting instrument simultaneously. Even if a state applies an ostensibly standard form of granting instrument, individual holders might be able to negotiate certain bespoke terms for themselves in a divergence from a standard form.

The nomenclature, which is used in describing a granting instrument, is not critical. Of greater importance is the substance of the state and the holder relationship, and a recognition that in reality a form of granting instrument which is used could be a hybrid structure which amalgamates provisions from several recognized forms of granting instrument, despite professing to be a particular form of granting instrument. It might appear that a licence (see below) offers much lower levels of state control than a production sharing contract (see below) offers, but such a sweeping generalization simply cannot be made.

Much of the content of the granting instrument will also be determined by how extensive the legislative basis behind the granting instrument is. A comprehensive petroleum code or other item of supervening legislation (which could consist of primary and secondary legislation) could set out the bulk of the intended relationship between the state and the holder, such that the granting instrument itself is a relatively thin document. An example of this approach is the United Kingdom petroleum production licence (see below).

Alternatively, there could be relatively little legislation in place in a state and the granting instrument is required to set out the bulk of the intended relationship between the state and the holder. This is often the case, for example, with a production sharing contract (see below). In some instances, the granting instrument could even be enacted as a law of the state in its own right (B16.2), to give it some legislative imperative. In this instance, an issue to further consider would be the risk of inconsistency between the terms of the granting instrument and the terms of an existing or subsequent petroleum law.

The most common forms of granting instrument, which are used for petroleum exploration and production, are summarized below. A popular distinction which is sometimes applied relates to whether a particular granting instrument can be characterized as being contractual in nature between the state and the holder, such that it can only be modified by agreement between the parties in the nature of any form of contract, or whether the granting instrument might be regarded as a regulatory instrument which can be amended unilaterally by the state as an exercise of sovereign

authority. This can be a difficult distinction to make in the case of most forms of granting instrument, and it is somewhat semantic. Production sharing contracts and service contracts are the obvious example of contractual granting instruments. A licence could be regarded as a regulatory instrument in principle but it is more widely accepted as being contractual in nature between the state and the licensee.²

Another distinction to note which is popularly recited is that which exists between what are broadly called ‘concessionary systems’ (which allow private ownership of petroleum resources (whether in-ground or at the wellhead) to be effected, and ‘contractual systems’ (where the ownership of petroleum resources is retained by the state up to various points). The former group is characterized by the holder’s right to take delivery of petroleum and includes the absolute granting instrument and the licence; the latter group is characterized by the holder’s right to take a fee in cash or in kind as petroleum and includes the production sharing contract and the service contract.

A2.2 Popular forms of granting instrument

The summary of the customary forms of granting instrument which is set out below should not be taken as a rigid demarcation. Individual granting instruments could be described as one thing but could, in substance, present themselves as something quite different, and some granting instruments are hybrids of the various forms which are described below.³ Nevertheless, the summary below represents a good place to start with, appreciating what are popularly understood to be the different forms of granting instrument which are used in practice:

The absolute concession

In this model, the state gives the holder an absolute exploration entitlement over a defined area and an absolute right to take any petroleum which is found in that area. In exchange for these entitlements, the holder typically pays the state a defined royalty on the value of the produced petroleum.

Under an absolute concession the holder could retain title to the underlying petroleum at all times – including when the petroleum is in the ground and after the petroleum has been produced and delivered at the wellhead. The state would only have a limited economic interest in a share of the produced petroleum, realized at the point of sale of that petroleum.

The absolute concession is a historical throwback (what is widely regarded as the first

2 See *R. (Benjamin Dean) v The Secretary of State for Business, Energy and Industrial Strategy* [2017] EWHC, [1998] Admin, which contains some useful clarifications as to the contractual and regulatory considerations applicable to United Kingdom petroleum production licences.

3 Ghana, for example, utilizes what it calls a ‘petroleum agreement’ to regulate private sector petroleum exploration and production. This arrangement is essentially a concession-based arrangement but with a number of elements which are commonly found in a production sharing contract.

recognized example of such a granting instrument is the 1901 D’Arcy Concession in Persia).⁴ The absolute concession, in this early form, eventually proved to be untenable with states because of the almost total abrogation of state rights and state involvement which it applied in exchange for securing only relatively modest returns.

Nevertheless, the attraction of the wide freedom to explore for and to exploit petroleum, largely free from state control over the management of the state’s resource and the conduct of the petroleum operations, which this form of granting instrument afforded to holders remained evident within more modern absolute concession forms which were applied worldwide from the 1950s to the 1970s.⁵ The key changes which became apparent in these later concessions were that they were awarded for shorter periods of time, and in respect of smaller geographical areas, and that the state would retain title to the underlying petroleum in-ground, with the holder assuming a proprietary interest only after the petroleum had been produced and delivered at the wellhead.

Various forms of concession-based arrangements are currently used, for example in Brazil, Ghana, the Gambia and Gabon.

The licence

In this model, the holder (called the ‘licensee’) is the beneficiary of a regulatory permit to explore for and to produce petroleum from a defined area, subject to paying certain rental payments to the state. The licensee is usually also taxed by the state on the profits which it makes from its petroleum operations (and this liability to taxation might not be ring-fenced (B9.1) between individual licence areas).

A licence, despite its terms often being derived from published legislation⁶ and it sometimes being described as a form of administrative authorization to explore for and to produce petroleum, is generally regarded as being contractual in nature between the state and the licensee, rather than a regulatory instrument which can be amended unilaterally by the state.⁷

With a licence, the state retains title to the underlying petroleum when the petroleum is in-ground; after the petroleum has been produced and delivered at the wellhead

4 A summary of the key terms of this concession is instructive: the holder was given exclusive rights of exploration, production and sales (including the freedom to shut in production during low price periods) over an area which covered approximately 75 per cent of the land mass of Persia. The concession subsisted for 60 years, imposed no minimum work obligations or timing commitments and gave the state £40,000 in cash and shares and a 16 per cent net profits royalty payable on the profits of the holder (but not its affiliates). Between 1932 and 1933 the concession was cancelled and renegotiated, and in 1951 the concession was cancelled completely when the Iranian oil industry was nationalized.

5 In Tanzania the entry into a concession-based arrangement with Shell and BP from 1952 and well into the 1960s regulated the first phase of the country’s exploration history, and such arrangements were also used variously in Abu Dhabi, Brazil, Libya and Oman.

6 See the UK Petroleum Act 1998 (<http://www.legislation.gov.uk/ukpga/1998/17/contents>).

7 See footnote 2.

the licensee will usually take title to the petroleum (excepting any royalty interest of the state which the state elects to take in kind at the wellhead).

Industrialized countries, with relatively highly developed systems of general law, taxation and petroleum law and regulation, tend to favor the use of licenses. Licence-based arrangements (which are also known as ‘tax/royalty arrangements’) are currently used for example in Australia, Canada, Denmark, New Zealand, Norway, Russia, and the United Kingdom.

The production sharing contract

In the 1950s and the 1960s, tension built up between certain states and holders over the adequacy of the sharing of petroleum production revenues and the control of resources, which applied under concession-based arrangements (see above). This tension was exacerbated by various external factors such as growing nationalistic sentiments, the passing of certain UN resolutions in respect of state ownership of natural resources,⁸ a period of steadily rising crude oil prices which gave the holders even greater economic returns, and the foundation and the rapid emergence of OPEC in 1960 as a pan-national agency which was intended to promote state interests in respect of crude oil production.

A partial reaction to this belief of some states that they were losing out in the commercialization of their indigenous petroleum resources was the introduction of what became known as a ‘production sharing contract’ (PSC).⁹ A form of production sharing contract was first introduced in Bolivia in the 1950s, but what would more easily be recognized today as a production sharing contract was first introduced in Indonesia in the 1960s.

The production sharing contract is the most widely used granting instrument model worldwide today. Under the production sharing contract the holder (called the ‘contractor’ – reflective of the service-provider mentality of this form of granting instrument, and making it clear that the production sharing contract really is contractual in nature between the state and the contractor) has an exclusive right to explore for and to produce petroleum from a defined contract area. The contractor recovers its sunk costs from the revenues accruing from the sale of the produced petroleum and also receives a defined profit share of the produced petroleum. The contractor pays also various bonuses, rental payments, royalties and taxes to the state.

The production sharing contract sets out a relatively detailed, legally-binding framework between the state and the contractor and for this reason the production

8 Notably, Permanent Sovereignty over Natural Resources, UNGA Res 1803 (XVII) (December 1962)–<https://www.ohchr.org/EN/ProfessionalInterest/pages/NaturalResources.aspx>.

9 The PSC is sometimes called a ‘profit’ (rather than a ‘production’) sharing contract. This is incorrect. Petroleum production is shared between the grantor and the contractor, from which the contractor’s profit share is derived after cost recovery. Profit is a subset of production.

sharing contract is of attraction for use in jurisdictions which might have less-developed systems of general law, taxation and petroleum law and regulation.

Under the production sharing contract the state retains title to the underlying petroleum at all times – when the petroleum is in-ground and after the petroleum has been produced and delivered at the wellhead (but subject to a later transfer of title to the contractor). The contractor has an economic interest, which it wants to recover through cost recovery and as a share of the produced petroleum, which is then sold.

The production sharing contract's ambit could be limited to regulating the exploration function (where it is called an 'exploration and production sharing agreement' (EPSA)), whereas in some jurisdictions the production sharing contract's ambit could be limited to regulating the development and production function after the award of a separate exploration permit (where the production sharing contract is called a 'development and production sharing agreement' (DPSA)). These are definitional distinctions which are determined by the scope of the particular production sharing contract.¹⁰

The production sharing contract is the most widely used form of granting instrument worldwide today – the production sharing contract is used for example in the countries listed in the opening section of Part B of this guide and also (for further example) in Albania, China, Libya and Malaysia.

The service contract

In this model, the holder (called the 'contractor') provides certain technical services to the state to explore for and produce petroleum within a defined area. This model really is a contractual arrangement between the state and the contractor.

In what is sometimes called the 'pure service contract' model the contractor incurs the costs associated with exploration and production and is reimbursed in cash for its effort through the payment of an agreed fee, regardless of whether the petroleum exploration and/or production activity is successful. The state takes the produced petroleum for its own account.

In contrast, in what is sometimes called the 'risk service contract' model the contractor incurs the costs associated with petroleum exploration and production and is reimbursed in cash for its efforts through the payment of an agreed fee but only if the petroleum exploration and/or production activity is successful. Because of the assumption of risk by the contractor in this latter model the fee which is payable to the contractor would be higher under a risk service contract than under a pure service contract. It is typically the case that this form of granting instrument will only be of interest to the contractor where there is a high level of pre-existing knowledge about the underlying geological conditions, such that the risk element is greatly mitigated from the contractor's perspective.

10 EPSAs and DPSAs are used as distinct forms of granting instrument in Qatar where there is no state participation in a project. See https://qp.com.qa/en/QPActivities/Pages/epsa_dpsa.aspx.

Also included in the genus of service contracts is the buyback contract (A4.2).

With any form of service contract the state retains title to the underlying petroleum at all times – when the petroleum is in-ground and after the petroleum has been produced and delivered at the wellhead. The contractor has only an economic interest, determined by the fee which it is paid under the particular service contract. That said, the service contract might also apply an exchange mechanism by which the contractor can take its fee in cash and convert to in kind and can lift petroleum volumes.¹¹

The fee which is payable to the contractor under a service contract could reflect a stable income stream which can be relied upon as a hedge against the risk of low petroleum price environments and other forms of granting instrument where the contractor lifts petroleum in kind. Service contracts, because they vest the entirety of the produced petroleum in the state, are also arguably better suited to states which are overall net importers of petroleum and which need to retain the produced petroleum for their domestic needs.

Various forms of service contracts are used for example in Algeria, Kuwait, Mexico and Saudi Arabia.

Further derivations of the forms of granting instrument, which are variously noted above, include the following items:

The revenue sharing contract

The production sharing contract (see above) allows the contractor to recover its costs first and then the resultant profit petroleum is shared between the state and the contractor. Some commentators have suggested that this model gives the contractor an obvious incentive to inflate its costs (which, it has been suggested, can be done through any combination of the contractor making false claims for costs which it did not actually incur (sometimes called ‘phantom costs’), deliberately over-engineering its project to inflate its costs (sometimes called ‘goldplating’) or engaging in transfer-pricing with affiliates for the provision of goods and services at artificially high prices.¹² The production sharing contract could therefore be re-engineered to give what is called a ‘revenue sharing contract’. A revenue sharing contract could be argued to be a form of granting instrument in its right, or it could be argued to be a production sharing contract but with a different set of fiscal terms.

Under the revenue sharing contract the gross revenues which accrue from the sale of petroleum are divided between the contractor and the state in agreed shares, and from its share the contractor recovers its costs. This, it is suggested, moves the incentive to reduce costs directly onto the contractor (as the party which is best placed to do so). Another way of looking at the revenue sharing contract is to suggest that it vests

11 See footnote 16.

12 See Daniel Johnston, ‘*Changing Fiscal Landscape*’ [2017] *Journal of World Energy Law and Business* Vol. 10 Issue 5.

all of the petroleum production revenues in the contractor, but subject to the state first taking a sizeable royalty.

The suggested need for the use of the revenue sharing contract overlooks the reality that a contractor is in business to do more than simply recover its costs, and could have the same economic incentive as the state to keep the costs down.

Sometimes called the ‘Peruvian model’, reflective of a certain form of granting instrument used in Peru in the 1970s which made no allowance for the recovery of costs before implementing a gross profit split, revenue sharing contracts are presently in use in India and in Indonesia, where the model is known as the ‘gross split contract’, and have been considered for use in Mexico.

The co-operative joint venture

The state’s representative could enter into an incorporated contractual joint venture with an investor to undertake petroleum exploration and production activities through a company that they both own. That company would then be the holder of a particular form of granting instrument (such as a production sharing contract or a service contract). The benefits which result from the activities conducted under the granting instrument pass to the joint venture company and back through to the shareholders. There is also a suggestion that having the involvement of a state’s representative in a petroleum project could protect the investor from the risk of adverse interference with the investor’s economic interests.¹³

In the 1970s the Indonesian Government introduced a particular form of granting instrument, known as the ‘joint operating body/ joint operating agreement’, wherein the state oil company and an investor would participate on a 50/50 joint venture basis to develop a particular petroleum deposit, with fiscal terms similar to those of a production sharing contract to apply between the parties.

A version of the co-operative joint venture model is used today for example in Qatar, where state participation in a particular petroleum project is a requirement.¹⁴ To facilitate field development, Qatar Petroleum awards a long term ‘development and fiscal agreement’ to a joint venture company (to be incorporated between Qatar Petroleum and a foreign investor, with equity held typically in the ratio of 70:30), giving that company the right to develop and operate a defined field.

Finally, for completeness a number of other state/investor relationship agreements which are sometimes encountered might also be mentioned. These are not necessarily granting instruments in the sense of the commercial relationship which typifies the

13 See Kirsten Bindemann, ‘*Production-Sharing Agreements: an Economic Analysis*’ [1999] Oxford Institute for Energy Studies, Oct. 1999.

14 See Dr. Talal Abdulla Al-Emadi, *Joint Venture Agreements in the Qatari Gas Industry, A Theoretical and an Empirical Analysis* (Springer, 2020).

arrangements referenced above, but they do have at least some of the hallmarks of a granting instrument:

The reconnaissance permit

A reconnaissance permit is a short term agreement which permits an investor to carry out (at its own expense) certain exploration works, possibly as a precursor to the award of a more formal, longer term granting instrument for continued exploration. Reconnaissance permits are found for example in India and Morocco.

The contract of work

A contract of work was used in Indonesia as a predecessor to the production sharing contract, and was essentially a form of service contract wherein a contractor recovered its costs and a specified fee in exchange for performing certain works.

The technical assistance contract

A technical assistance contract (TAC) is a contractual arrangement by which a state-owned entity that holds the contract for a particular area will request assistance from an investor (acting as a contractor) to better develop the area. This could be for the provision of assistance with enhanced oil recovery rates or in the re-opening of a shut-in petroleum deposit. The appointed contractor can recover its costs, and is also paid a fee for the services which it renders, which could be payable in cash or in kind.

A technical assistance contract could share many of the same characteristics as a production sharing contract or a service contract, typifying the overlap which occurs in practice between what are regarded at least nominally as different forms of granting instrument. Technical assistance contracts are used for example in Indonesia, where they can be relatively long-term arrangements.

The host government agreement

What is commonly called a ‘host government agreement’ (HGA) is a specific agreement between a foreign investor and a state, governing the rights and obligations of the investor and the state in relation to the development and operation of a particular project by the investor.¹⁵

Host government agreements are common in the development of a project in a country which does not afford protection to an investor through a bilateral investment treaty. Most host government agreements are essentially founded around a stabilization provision (B16) to protect the investor. The host government agreement is not a granting instrument in its own right, but it is sometimes equated to a granting instrument. Paradoxically though, where a granting instrument contains a comprehensive stabilization provision, the granting instrument effectively becomes a host government agreement in its own right.

15 A model form HGA is published by the Energy Charter Secretariat. See <<https://www.energycharter.org/what-we-do/trade-and-transit/model-agreements/>> accessed 3 June 2020.

A3. Key granting instrument issues

A3.1 Negotiation options for granting instruments

There is no single way in which the terms of a granting instrument will come into existence between the state and a prospective holder. A state is free to select whichever structure for procuring the entry into a granting instrument that best reflects its perceived regulatory and commercial requirements, but at the outset the principal distinction to note in the options for the award of a granting instrument to a prospective holder is that which exists between what are called the ‘competitive bidding’ and the ‘direct negotiation’ models:

Competitive bidding: in this model (sometimes called the ‘fixed content system’) the state will conduct a public bid round, in which the key commercial terms of the granting instrument are made transparent by the state and prospective holders will submit their bids to be awarded a granting instrument (with only a limited number of contestable items for a prospective holder to address).

Within this model, there are two further options for how the terms of a granting instrument can be arrived at:

- **Mandated terms, no negotiation** – the terms of the granting instrument are mandated in detail by the state within the terms of the bid round and there is little or no room for negotiation by a prospective holder of the terms of the granting instrument (other than the completion of outstanding issues such as the definition of the granting instrument’s area, the provision of collateral support in respect of the holder’s obligations and the size of the signature bonus, if applicable).
- **Contestable terms, limited negotiation** – the terms of the granting instrument are outlined by the state within the terms of the bid round but there is some room for negotiation by a prospective holder of the final terms of the granting instrument. This could relate to the completion of the outstanding issues outlined above but also to the finalization of issues such as the nature of the exploration period obligations which the prospective holder is willing to undertake, and the key fiscal terms of the granting instrument, which could be made contestable items.

Direct negotiation: in this model (sometimes called the ‘agreement system’) the terms of a granting instrument are arrived at by bilateral negotiation and agreement between the state and the prospective holder. This could take place outside the framework of a public bid round, where there could be extensive negotiation between the parties before the granting instrument is finalized.

Direct negotiation has become less common over the years because of the increasing demand for states (and holders) to embrace greater transparency in the process of how granting instruments are awarded and managed. This has increased reliance on the competitive bidding model.

A3.2 Resources booking

For most prospective holders a critical issue is the ability to record (or to ‘book’, to use the customary phrase) the petroleum resources which are associated with a particular granting instrument as an asset in the holder’s accounts. The rules around the booking of petroleum resources will depend upon the accounting conventions which the holder is subject to. Where the holder is listed on a public stock exchange the listing rules of that exchange could also condition the holder’s ability to book the resources. In all cases the form of the granting instrument which the holder holds will have a major bearing on whether resources can be booked. A form of granting instrument which allows the holder to book the associated petroleum resources could be more attractive than one which does not.

At one end of the scale, under an absolute concession (A2.2) the in-ground petroleum resources belong to the holder and would be bookable. This is clearly a physical measure of petroleum volumes to which the holder is entitled.

Moving further along the scale, under a licence (A2.2), the licensee can typically book its petroleum entitlements as they are produced at the wellhead. This is also a physical measure of petroleum volumes to which the licensee is entitled.

At the other end of the scale, the underlying petroleum resources which are associated with any form of service contract (A2.2), which only gives the holder (as a contractor) an entitlement to a monetary fee for the services that it provides and gives the holder no direct petroleum entitlements, would not be bookable, but this can be a grey area.

Sometimes the phrase ‘working interest barrels’ is used by a holder in its public statements to indicate the barrels of oil equivalent which the holder is entitled to recover under its arrangements with the grantor but which might not actually constitute bookable resources. A holder could recite its working interest barrels in its annual report and accounts, to give a fair value measure of the entitlements which it has. The monetary fee which is payable to the holder could also be paid in kind and translated into physical volumes of petroleum which are available for lifting by the holder at a defined export point.¹⁶ At this point, under some accounting conventions it might become possible to book the associated resources.

The production sharing contract (A2.2) is the trickiest proposition to analyze from

16 See <<https://www.bhp.com/-/media/bhp/documents/investors/news/ohanetdevelopment.pdf?la=en>> accessed 3 June 2020: “Under the terms of the [risk service contract] the total production from the fields is the property of SONATRACH. The foreign participants in the venture bear the total cost of developing the Ohanet reservoirs, and in return, we will recover our investment, together with an agreed fixed profit margin, from hydrocarbon liquids production over a target eight-year period (from the start of production). The monetary entitlement will be translated into volumes of condensate butane and propane that will be lifted from export ports on the Algerian coast.”

a resources booking perspective because the holder (as a contractor) does not hold title to the underlying petroleum resources. Under the production sharing contract the associated petroleum resources could be booked by the holder, through reliance on what is known as the ‘entitlement method’.¹⁷ This approach considers the holder’s right of access to produced petroleum volume entitlements under the production sharing contract, rather than the holder’s legal title to those entitlements, and translates them to a certain number of barrels of oil equivalent at prevailing petroleum prices, which could then become bookable by the holder.

¹⁷ See < <https://www.spe.org/en/industry/petroleum-resources-management-system-2018/>> accessed 3 June 2020.

A4. Evolution in granting instrument forms and terms

A4.1 Changes to granting instruments

The form of the granting instrument which is used by a state to regulate petroleum exploration and production activities, and the fiscal and non-fiscal terms which that granting instrument contains, will be a reflection of what the state perceives is best suited to enable the state to develop its petroleum interests with the assistance of an investor as the holder at the point in time at which the granting instrument is entered into.

Over time there is always a risk (which is evidenced by demonstrable behavior in some instances) that a state with desirable petroleum resources can take the decision to impose a series of revised fiscal terms upon its existing holders. In such circumstances the reputational consequences of being an unreliable business partner could seem less significant for the state than the risk of missing out on making a better return, regardless of the need for a stable investment regime for current and prospective holders. This could be a matter to be addressed by a stabilization provision (B16) in the granting instrument.

Over time, it also possible that a state's perceptions of what it wants from its granting instruments could change. A growing dissatisfaction with the economic balance of the state/holder relationship, or the increased confidence which results from increasing levels of technical and financial capability within the state as a consequence of successful petroleum production experiences, or most likely a combination of these factors, could cause the state to seek to change the granting instrument basis going forward.

Such a change could see a revision to the fiscal and non-fiscal terms of future granting instruments, or even a wholesale move away from one particular form of granting instrument to another. As examples of this, Brazil has transitioned from concession-based arrangements to production sharing contracts for certain petroleum discoveries, and Guyana has done the same. India and Indonesia have explored moving from production sharing contracts to revenue sharing contracts. Russia has moved away from production sharing contracts in favor of license-based arrangements. Change, it seems, is the only constant. Some country examples to illustrate this are considered below:

A4.2 Country examples

Brazil

Petrobras, the state oil and gas company, had a monopoly on petroleum exploration and production activities until the mid-1990s. In 1997, petroleum exploration and production by foreign and domestic private sector participants in Brazil became possible through the award of a federally regulated modern-form concession agreement.

Following the significant offshore pre-salt discoveries made in 2007 the Brazilian

Government made a case for moving from concession-based arrangements to a production sharing contract system, to apply to the lucrative pre-salt coastal shelf and other defined areas which were perceived to have lower exploration risk and greater production potential. The concession agreements, it was argued, had worked well enough for the state when the extent of the prospective petroleum resources was not clear, but given the belief that the pre-salt discoveries had largely removed that risk then the move to a production sharing contract regime would be a better option to provide increased state take.

In 2010, the Brazilian Government introduced its production sharing contract regime for pre-salt coastal shelf and designated other strategic areas, all of which were perceived to have lower exploration risk and greater production potential. Consequently, two granting instrument regimes now operate side-by-side in Brazil, with the geographic location of the petroleum deposit being the determining factor for which one will apply.

Guyana

Offshore petroleum exploration in Guyana first started in the 1950s, but it has only been since the turn of the present century that the country's upstream prospects have come to prominence. A form of concession agreement which recites a tax and royalty system had been the model used to manage private sector participation but this was replaced by production sharing contracts. In 2015 a consortium of Exxon-Mobil, Hess and Nexen announced what would be the first of a number of major discoveries in the Stabroek contract area, with the capacity to transform Guyana into a major oil-producing province and to completely revolutionize the nation's economy.

Concerns about the overly investor-friendly nature of the fiscal terms in the current production sharing contracts¹⁸ has caused the Guyanese Government to conclude that a move towards a new form of production sharing contract will be necessary in future bid rounds.¹⁹

India

Production sharing contracts had been used in India to govern the participation of foreign and domestic private sector participants in petroleum exploration and production since 1997, but a major change of direction came following a dispute over the terms of a particular production sharing contract in 2011.

In 2000, Reliance Industries was awarded a production sharing contract to develop the KG-D6 offshore block. Commercial gas production commenced in April 2009. In 2011, the Indian Government sought to disallow certain cost recoveries under

18 Global Witness, 'Exxon's exploitative oil deal in Guyana will deprive the country of up to \$US55 billion' <www.globalwitness.org/en/press-releases/exxons-exploitative-oil-deal-in-guyana/> accessed 3 June 2020.

19 DPI, 'Department of Energy designing new model PSA' <<https://dpi.gov.gy/departement-of-energy-designing-new-model-psa/>> accessed 3 June 2020.

the production sharing contract on the grounds that Reliance was in breach of its obligation to comply with an approved development plan. In response Reliance commenced arbitration proceedings. At the heart of the dispute was an accusation by the Indian Government that Reliance had been incurring excessive levels of costs in the performance of the petroleum operations which it was seeking to cost recover.

In 2012, the Indian Government constituted the Rangarajan Committee, to look into the existing production sharing contracts' cost recovery and profit shares mechanisms. In its eventual report the Rangarajan Committee recommended shifting to a revenue sharing contract model (A2.2), with the revenue sharing ratios to be a contestable item and subject to competitive bidding in future bid rounds. The Rangarajan Committee's recommendations were the subject of some criticism, centered on the fact that a revenue sharing contract model was not suitable for India as the country's sedimentary basins were poorly explored and their prospects were uncertain. Consequently, it was suggested, because of the uncertainty over the possible geology which was on offer, a party bidding to participate would likely only put in a bid with a low level of state take. The better solution for India, it was suggested, was not a shift to a revenue sharing contract mechanism but to engage in the better management of the production sharing contract regime, particularly in relation to auditing recoverable petroleum costs.

In 2016, the Indian Government introduced the Hydrocarbon Exploration and Licensing Policy (HELP). The key feature of this policy was the introduction of a revenue sharing contract model, rather than to continue the country's reliance on production sharing contracts, in the interests of reducing the need for state oversight of the day-to-day operations and the scrutiny of costs incurred by a production sharing contractor. The first bidding round under HELP was launched in 2017; revenue sharing contracts for 55 blocks were awarded but all were awarded to Indian companies, without interest from foreign investors.

Indonesia

Indonesia is credited with first introducing the production sharing contract as a workable form of granting instrument in the mid-1960s, replacing the concession agreements which had previously regulated petroleum operations in the country and which had increasingly become regarded as too generous to their holders.

The Indonesian production sharing contract is widely regarded as a holder-friendly form of granting instrument, intended to attract inward investment but also as one which was always capable of being fine-tuned by the state to respond to changing economic circumstances. For example, the fiscal terms of the production sharing contract were reworked in favor of the state following a rapid increase in global crude oil prices in 1973, when the Indonesian Government realized that its production sharing contractors were earning higher than expected profits under their contracts, and throughout the 1980s and the 1990s the Indonesian Government promulgated a series of exploration incentives packages designed to encourage new exploration in high-risk areas by offering amendments to the fiscal terms of existing production sharing contracts.

In 2017, concerned by suggestions that production sharing contractors were exaggerating their project costs to the detriment of the state, Indonesia began eradicating the cost recovery regime for upstream petroleum contracts. Regulation 8/2017 on Gross Split Production Sharing Contracts set out a new economic structure for future production sharing contracts, based on dividing gross production between the state and the contractor but without a mechanism for the contractor to recover its sunk costs as a priority (although operating costs incurred by the contractor could be taken into account as a deduction against the contractor's income tax liability – in essence the classification of costs as permitted recoverable costs would still exist but in the context of calculating income tax liability rather than the allocation of petroleum production volumes).

The new gross production split structure became mandatory for all new production sharing contracts awarded after January 2017, additionally with provision for its application to production sharing contracts that had expired and were being replaced and also to existing production sharing contracts which were being extended. Production sharing contracts signed before the Gross Split regulations came into force could also be converted into a gross split production sharing contract at any time, on the application of the contractor.²⁰

Iran

Iran was home to the original D'Arcy Concession of 1901 (A2.2), and concession agreements remained the norm for private sector participation in Iran petroleum developments throughout the twentieth century. The 1979 Revolution sparked a wave of resource nationalism in Iran, resulting in the emergence of strongly autarkic policies. Lacking the necessary capital and technological skills, Iranian petroleum production levels dropped and it was suggested that a new approach was needed – one which applied a form of granting instrument which drew in foreign capital and know-how, but which did not give a proprietary petroleum interest to a foreign investor.

In the early 1990s a new upstream regulatory model was applied whereby the participation of foreign investors in the development of Iranian petroleum resources was undertaken through an arrangement known as a 'buyback contract'. Despite the exotic nomenclature, this was effectively a form of service contract (A2.2). The holder would incur all of the associated exploration risk and expense, and if a petroleum discovery was made and moved into production then the National Iranian Oil Company (NIOC) would take over the project from the holder and would manage the project exclusively from that point on. The term 'buyback' was intended to reflect the nature of the arrangement whereby NIOC acquired the project which the holder had developed, with the consideration payable by NIOC to the holder for this notional acquisition being the fiscal amounts which would thereafter be payable to the holder under the terms of the buyback contract.

20 See Brad Roach, Alastair Dunstan, 'The Indonesian PSC: The End of an Era' [2018] Journal of World Energy Law and Business Vol. 11 Issue 2.

Under this buyback contract the holder would be reimbursed its costs (which were fixed according to an agreed development plan and budget) and an agreed element of profit at a fixed rate, paid out of a maximum (usually 60 per cent) of the gross proceeds of the petroleum sales, but the holder's recovery would be subject to: (i) the realization of a defined minimum level of international petroleum prices (where the holder's recovery would be suspended for as long as international petroleum prices remained below that minimum level); and (ii) the continued production of petroleum from the contract area at agreed production levels.

The risk profile assumed by the holder through the exploration and development phases, the imposition on the holder of the incidence of development cost overruns, and the absence of compensation to the holder when payments were suspended, all combined to impact the holder's rate of return on a project. Some holders also feared that NIOC's assumption of responsibility for the management of the project at the point of production, without any assistance from the holder, could lead to poor management of the petroleum deposit over the long term, damaging the continued production of petroleum and the prospects for the holder to recover its sunk costs and profit entitlements in full. The term of the buyback contract (typically between 7 and 10 years) was also regarded as too short to permit full recovery by the holder.

In 2015, the Iranian Government announced the introduction of a new form of granting instrument - the Iran Petroleum Contract (IPC) – intended to stimulate new levels of investment in the country's upstream sector. The IPC is essentially a long term service contract (A2.2) but one which also contains several features found typically in a production sharing contract (notably, the cost recovery and profit petroleum mechanisms), intended to improve the overall economic picture for the investor. The intention of the IPC is also that under certain circumstances, the associated petroleum resources can be booked by the holder, but without the holder owning the underlying acreage because NIOC still maintains exclusive ownership rights over the state's resources. The holder is paid a progressively indexed fee per barrel of produced petroleum, with amounts due to the holder payable in cash or in kind.

Russia

The Law on Subsoil Resources (1992) set out the legislative regime for foreign and domestic private sector participants in Russia's upstream through the use of a licensing system, with the provision of licenses for exploration and production, supplemented by a series of laws and regulations.

In the early 1990s, the Russian Government desperately needed foreign investment to revitalize Russia's petroleum sector (particularly for geographically isolated, technologically complex projects), to stimulate domestic petroleum production levels and to generate foreign currency earnings from exports. The Federal Law on Production Sharing Agreements (1995) was passed to set out a framework for foreign and domestic private sector participants through the use of production sharing

contracts, which was closely followed by the signature of new production sharing contracts for the Sakhalin 1, Sakhalin 2 and Kharyaga projects.

In 2003, the 1995 Law was amended substantially, increasing the difficulty of securing a production sharing contract, and adjustments were also made to the federal tax code to make future production sharing contracts less attractive to foreign investors. Since then no new production sharing contracts have been awarded in Russia. The Sakhalin and Kharyaga production sharing contracts were unaffected by these reforms, but the Russian Government's actions made it clear that production sharing contracts would no longer be an option for foreign investment in the Russian petroleum sector. Consequently, a system of licensing has remained the principal option for granting instruments in Russia.

Tanzania

The entry into concession agreements in the 1950s and 1960s regulated the first phase of the country's petroleum exploration history. Tanzania eventually moved away from concession-based arrangements to a production sharing contract system, which was established in 1969.

In later years, the Petroleum (Exploration and Production) Act 1980, vested ownership and control of Tanzania's petroleum resources to the state, with provision for the Ministry of Energy and Minerals to award exploration licences and development licences. These licenses are granted to the Tanzania Petroleum Development Corporation (TPDC), a state-owned company through which the Tanzanian Government implements upstream petroleum policy. TPDC then enters into production sharing contracts with investors to conduct petroleum operations on its behalf. Model form production sharing contracts have been issued by TPDC in 1989, 1995, 2000, 2004, 2008 and 2013.

In 2014, Tanzania ran its fourth offshore bid round, which took place against a backdrop of growing exploration success in Tanzania and across the east African region, making the area an investment hotspot. The 2013 model form production sharing contract offered holders fiscal and non-fiscal terms which were much less attractive than its predecessor, and was regarded by industry observers as being relatively tough (with a new signature bonus and production bonus structure, increased rental payments, increased state shares of profit petroleum, increased royalty rates and training budgets, greater domestic market obligations, reduced cost recovery limits, and increased levels of state control over transfers by the holder).

The response to the 2014 bid round was underwhelming - for the eight blocks on offer, only five bids were made, and only for four of the blocks. Exploration and production companies that were already active in Tanzania did not submit bids. A fresh bid round (with a new model form production sharing contract) that was planned for 2019 failed to materialize.

PART B:

THE CONTENT OF A PRODUCTION SHARING CONTRACT

Introduction

This is a guide to the terms of a typical production sharing contract (PSC).

The PSC is popular with a host state as a vehicle for encouraging petroleum exploration and production because it shifts the risk of wasted expenditure from an unsuccessful petroleum exploration campaign onto the holder, the contractor, which has undertaken the exploration activity entirely at its own expense, whilst also allowing the state to assume a long term share of the produced petroleum which results if the contractor's exploration campaign proves to be successful.

The PSC enables the state to benefit from the application of the contractor's technological expertise in petroleum exploration and production and project management, being capabilities which the state might not have access to indigenously. The PSC also enables the state to maintain formal ownership of its petroleum resources in-ground, giving the contractor an economic rather than a proprietary interest in the state's petroleum. This can be an important matter for the state (and the state's population) for socio-political reasons (A1.2). Consequently, the PSC has become the preferred form of granting instrument for a number of states with petroleum prospects or production.

There is no standard form PSC, and the terms of the PSC will vary between different states, although there is a fair degree of standardization in PSC terms. PSCs could also be awarded for onshore or offshore petroleum operations.

The following list is a selection of publicly available PSC forms, both model forms and executed agreements.

The PSC forms listed below (which are listed alphabetically by state, without any particular preference or recommendation) cannot be taken to be representative of the current thinking of a particular state, nor as a binding precedent, fixed and irrefutable. They can only be regarded as indicative examples which illustrate the position taken by a particular state at a particular point in time. Neither is this an exhaustive list of all available PSCs.²¹

Afghanistan

<https://www.resourcecontracts.org/contract/ocds-591adf-1045801310/view#/pdf>

Angola

http://www.sonangol.co.ao/English/AreasOfActivity/Concessionary/Documents/Licitacoes/modeloCPPonshore_en.pdf

Bangladesh

<file:///C:/Users/proberts/Downloads/2161-model-contract-bangladesh-oil-gas-and-mineral-corporation-psa-2008.pdf>

21 See <https://www.extractiveshub.org/resource/list/?IndexSearchGUID=D0E09694-0DA1-49B0-ACD5-0C3AAB706782&Page=1&TextString=production+sharing+contract&IndexString=> for more examples.

Belize

<http://med.gov.bz/wp-content/uploads/2017/01/Belize-Model-Production-Sharing-Agreement.pdf>

Brazil

<http://rodadas.anp.gov.br/en/transfer-of-rights-surplus-production-sharing-bidding-round/draft-of-the-tender-protocol-and-draft-of-production-sharing-agreements>

Cameroon

<http://www.snh.cm/images/reglementation/EN/Model%20Production%20Sharing%20Contract.pdf>

Cyprus

<https://www.pwc.com.cy/en/energy-utilities-mining/assets/energy-model-production-sharing-contract.pdf>

Egypt

<https://apexintl.com/wp-content/uploads/2018/04/7-2016-EGPC-Model-Agreement.pdf>

Equatorial Guinea

<https://www.extractiveshub.org/servefile/getFile/id/5621>

Ethiopia

<file:///C:/Users/proberts/Downloads/2165-model-contract-psa-2011.pdf>

Gabon

https://www.sec.gov/Archives/edgar/data/1471261/000104746909009334/a2195051zex-10_5.htm

Guyana

<https://gyeiti.org/wp-content/uploads/Petroleum-Agreement-Oct-7-2016.pdf>

India

<http://petroleum.nic.in/sites/default/files/MPSC%20NELP-V.pdf>

Indonesia

https://www.sec.gov/Archives/edgar/data/1116927/000091205701536472/a2060296zex-10_4.htm

Ivory Coast

<https://www.sec.gov/Archives/edgar/data/1509991/000150999118000014/kos-12312017xex1045.htm>

Kenya

<file:///C:/Users/proberts/Downloads/810-camac-energy-kenya-limited-block-l1b-psa-2012.pdf>

Liberia

<https://www.extractiveshub.org/servefile/getFile/id/123>

Mauritania

<https://www.sec.gov/Archives/edgar/data/1509991/000155837017001056/kos-20161231ex10412a5b5.htm>

Mozambique

<https://www.resourcecontracts.org/contract/ocds-591adf-0648943319/view#/pdf>

Nigeria

<https://shellandenitrial.org/wp-content/uploads/2018/09/Annex2.pdf>

Pakistan

<http://www.ppisonline.com/gov-policy/@dm!n/uploadImage/58/Model-Production-Sharing-Agreement--2003.pdf>

Qatar

<file:///C:/Users/proberts/Downloads/2132-model-contract-qatar-petroleum-psa-2002.pdf>

Senegal

https://www.sec.gov/Archives/edgar/data/1509991/000110465914075847/a14-19714_1ex10d1.htm

Somalia

<http://somalialicensinground.com/wp-content/uploads/Final-PSA-Model-Somalia.pdf>

Tanzania

<http://intosaicommunity.net/wgei/wp-content/uploads/2019/09/Tanzania-Model-Production-Sharing-Agreement-2013.pdf>

Timor-Leste

[file:///C:/Users/proberts/Downloads/2306-model-contract-psa-2014-001%20\(1\).pdf](file:///C:/Users/proberts/Downloads/2306-model-contract-psa-2014-001%20(1).pdf)

Trinidad & Tobago

http://www.energy.gov.tt/wp-content/uploads/2013/11/Deepwater_Model_PSC_CBO_2013.pdf

Turkmenistan

[file:///C:/Users/proberts/Downloads/2187-model-contract-psa-1997-001%20\(2\).pdf](file:///C:/Users/proberts/Downloads/2187-model-contract-psa-1997-001%20(2).pdf)

Uganda

file:///C:/Users/proberts/Downloads/contract_kanwatanya.pdf

For completeness of comparison the following concession-based arrangements and licence terms can also be accessed:

Australia

<https://www.nopta.gov.au/application-processes/development/petroleum-production-licence.html>

Gambia

file:///C:/Users/proberts/Downloads/791-camac-energy-a5-gambia-ltd-block-a5-petroleum-license-2012.pdf

Ghana

https://www.petrocom.gov.gh/wp-content/uploads/2018/12/ghana_model_petroleum_agreement1.pdf

Norway

<https://www.norskpetroleum.no/en/framework/the-petroleum-act-and-the-licensing-system/>

United Kingdom

<https://www.ogauthority.co.uk/licensing-consents/types-of-licence/>

B1 The parties

The PSC is principally entered into between two parties, which in this guide are referred to as the ‘grantor’ and the ‘contractor’ and together as the ‘parties’. The contractor as an entity could be made up of one person or several persons.

B1.1 The grantor

‘The grantor’ is used in this guide as a generic term to describe the representative of the interests of the state, holding the legislative authority to award, perform and regulate the PSC on behalf of the state.²² In practice the grantor could be any of a state ministry, a state agency or the state’s national oil company, and the responsibilities for awarding, performing and regulating the PSC could be held by different state entities.

There could also be different state agencies, other than the grantor, with responsibility for giving various approvals or conducting various activities in connection with the business of the PSC but for convenience (except where otherwise indicated) this guide assumes that the grantor is the sole representative of the state for all of these purposes.

B1.2 The contractor

‘The contractor’ under the PSC is a single entity which could be made up of one person or which could represent the interests of several persons acting in joint venture (where those persons are referred to in this guide as ‘the contractor parties’). The notion of a contractor party is particularly relevant to where the grantor wishes to terminate the PSC because of a breach of its terms by one of the contractor parties (B2.5), in respect of the several liabilities of the contractor parties (B17.4), and in respect of a transfer of interests by a contractor party (B21.1).

The contractor could be declared by the PSC to be an independent contractor²³ and, notwithstanding the contractor’s obligation to perform the PSC and to be subject to a measure of control by the grantor, the contractor could also be declared by the PSC not to be an agent of the grantor. The substance of this relationship will be more important than the form which the PSC recites however.

Where there are several contractor parties they will further regulate their internal relationship through some form of joint venture.

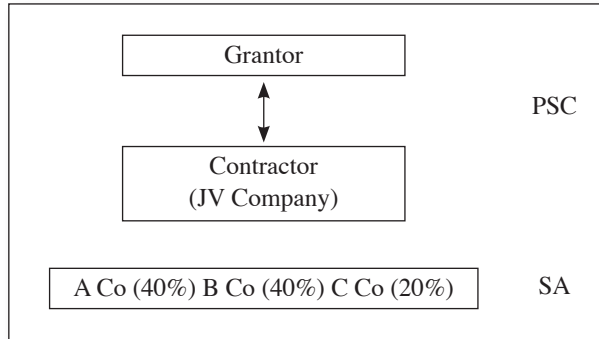
The PSC could be held by a single incorporated entity (sometimes called the ‘joint venture company’) in which the contractor parties are each shareholders, with their

22 The Nigerian upstream regime adds an additional layer to this proposition. A Nigerian state-owned entity holds the initial granting instrument for petroleum exploration (an Oil Prospecting Licence (OPL)) and/or for petroleum production (an Oil Mining Lease (OML), which is derived from the OPL), and that entity then enters into a PSC with a contractor (where the contract area for the PSC will be derived from the area of the OML or OPL as appropriate). A similar construction is also applied in Tanzania (A4.2).

23 See the Afghanistan PSC.

interests being regulated by the terms of a shareholders' agreement (a model which is sometimes called the 'incorporated joint venture') as indicated in Figure 1:

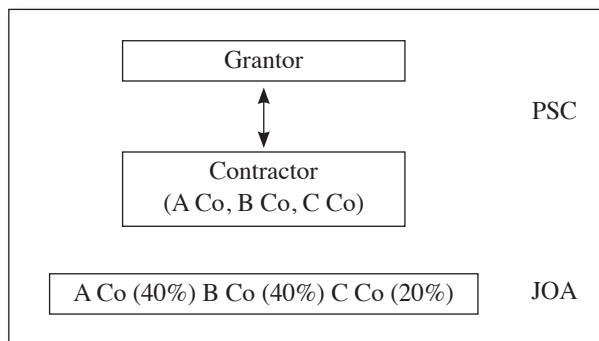
Figure 1



It could also be a jurisdictional requirement of the host state that the entity which is the contractor under the PSC (or even each contractor party²⁴) must be a company incorporated in the state (in which the contractor parties would each be shareholders). Such a local company would be subject to the tax, accounting, audit and reporting requirements of the state. Adopting such a local company requirement could also be a helpful perception in the popular demand for the greater localization of petroleum operations under the PSC (A1.2). A further variation on this theme is where a local company is required to be incorporated for a particular phase of the petroleum operations.²⁵

Alternatively, in an unincorporated joint venture model the contractor parties will each be a direct party to the PSC and they will regulate their internal relationship through a joint operating agreement (JOA – B23) as indicated in Figure 2:

Figure 2



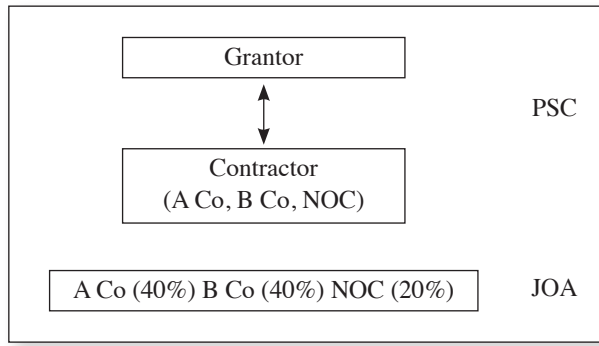
24 See the Equatorial Guinea PSC.

25 See the Egypt PSC, where a local company is required to be incorporated to act as the operator when a commercial discovery has been made.

In either of the incorporated or unincorporated joint venture models the PSC represents the vertical relationship between the grantor and the contractor, and the shareholders' agreement or the JOA (as appropriate) represents the horizontal relationship between the contractor parties.

It is also possible that a representative of the state (such as the national oil company) could (possibly being the beneficiary of the exercise of the rights created in respect of state participation under the PSC – B11.1) be a part of the contractor consortium as indicated in Figure 3:

Figure 3



The contractor parties as they exist at the outset of the PSC will be identified in the preamble to the PSC. The definition of the contractor in the PSC will also usually include a reference to that party's successors in title and lawful assignees, although in practice this provision more logically applies in respect of the successors and assignees of the contractor parties themselves. The PSC will also regulate changes in the identity of the contractor parties over time (see below).

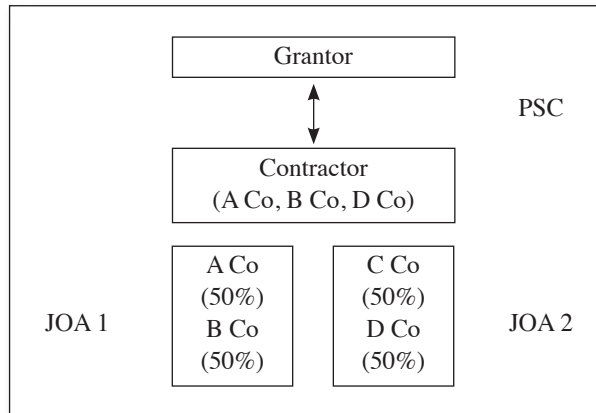
Some PSCs recite several percentage participating interest shares in the PSC, which are allocated to each of the contractor parties and which together will add up to 100 per cent.²⁶ This can be helpful in identifying a contractor party's several liability to the grantor (B17.4), effecting the possibility of termination of the PSC in respect of an individual contractor party and the subsequent reallocation of that contractor party's interests in the PSC (B2.5) and identifying a contractor party's interests in the PSC which will be the subject of a transfer (B21). From the grantor's perspective, care should be taken that this provision does not weaken the potential for the joint liability of the contractor parties to the grantor (B17.4).

These percentage participating interest shares should also be replicated in the corresponding provision in the JOA, and changes over time to the interests should be tracked to ensure a continuing symmetry of interests between the two agreements.

26 See the Afghanistan, Angola, Equatorial Guinea and Pakistan PSCs.

There is also a possibility that a contractor party is not party to the JOA however. This would apply, for example, where the PSC which has been awarded, covers multiple operating areas, but individual JOAs are put in place for different development areas (B7.2), each with different parties as indicated in Figure 4:

Figure 4



A single contractor party could hold a number of different PSCs within a particular host state but the grantor could be concerned that such a contractor party could have too many different PSC interests to be able to perform them all properly, or that the contractor party might thereby come to assume an undue degree of influence over the grantor. The PSC could state that a contractor party cannot hold more than one PSC in the host state,²⁷ although this solution overlooks the possibility that a parent company entity could hold multiple PSC interests through different affiliated entities.

B1.3 Changes to the parties

Over time, the contractor parties are likely to change (for example, as they transfer their interests under the PSC to third parties) but the grantor is probably less likely to change (apart from as a consequence of a wider sectoral regulatory reform programme).

A change of contractor party under the PSC (which applies only where the contractor party is a direct party to the PSC, rather than where a joint venture company (see above) is the contractor for the purposes of the PSC) will usually be mirrored by a change of the same person under an underlying JOA, in pursuit of the continuing symmetry of interests between the two agreements.

A contractor party could also undergo a change of control (whether directly or indirectly with respect to the superior levels of its corporate structure). The PSC could make provision for how this should be addressed (B21.4).

²⁷ See the Indonesia PSC.

B2 Duration

The PSC will include provisions relating to when it comes into effect between the parties, how long it subsists for and how it can be terminated. Termination of the PSC could arise by the natural expiry of its scheduled duration, or in certain circumstances the PSC could be terminated prematurely.

B2.1 The start date

The PSC will be executed between the grantor and the contractor (on what is often called the ‘execution date’) but the PSC might only become fully legally effective between the parties, when a number of defined conditions precedent have been satisfied (where the date upon which the last of those conditions precedent is satisfied, or is waived by the party entitled to do so, will often be called the ‘effective date’).²⁸

These conditions precedent could, for example, relate to the following matters:

- (1) the provision of collateral support in respect of the contractor’s exploration period obligations under the PSC (B22.1);
- (2) board approval of entry into the PSC by each of the contractor parties (although this is rare – this decision is usually made by the contractor parties prior to execution of the PSC);
- (3) the procurement of any necessary regulatory approvals in respect of the PSC, or any other activity of state ratification which may be necessary in respect of the PSC, or even the enactment of the PSC as a law of the state if this is necessary (B16.2);
- (4) a baseline environmental impact study (B12.3) and/or a social impact assessment (B22.4) for the initial exploration operations has been approved by the grantor;
- (5) the contractor’s payment of a signature bonus which is due under the PSC (B10.1); and
- (6) the entry by the contractor parties into a JOA (B23.1).

Where the PSC applies conditions precedent the PSC usually also provides for a longstop date by which the conditions precedent must be satisfied or waived (failing which the PSC could be terminable – see below).

As an alternative to the conditions precedent formulation the PSC could be expressed to be live and effective from the date of its execution between the parties, and the conditional items noted above (apart from state ratification or the enactment of the PSC as a law of the state which may be necessary) would each be dealt with prior to the PSC’s execution.

28 See the Cyprus, Egypt and Somalia PSCs.

B2.2 Duration

The duration of the PSC will be from the PSC's execution date until whatever the eventual date of termination of the PSC is. In the longest case the PSC will terminate upon the expiry of a defined time period after the production of petroleum has taken place and decommissioning (B7.4) has been completed (although the reality of depletion by production and the permanent cessation of the production of petroleum means that the PSC could come to an end before the scheduled end of the production period).

The intended duration of the PSC could also be further defined by a series of internal time periods, such as the exploration period (B6.2) and the production period (B7.3). The PSC could also apply defined periods of time for the conduct of appraisal activities (B6.5) and development activities (B7.3) by the contractor. All of these internal time periods (many of which are themselves capable of further extension under the terms of the PSC) will together add up to define the overall duration of the PSC.

A natural gas discovery could bring its own durational requirements to the PSC (B15.2).

Whilst the different phases of activity envisaged by the PSC in the performance of the petroleum obligations (B3.1) are sequential, they are not exclusive of each other. Depending upon how the PSC is operated (and unless the PSC governs a single asset development) the activities of exploration, appraisal, development, production and even decommissioning could all be occurring at the same time in different parts of the contract area (B4.1) during the term of the PSC.²⁹ This means that the end of the production period and the completion of the associated decommissioning in one part of the contract area will not signal the end of the PSC if petroleum operations are continuing in another part of the contract area.

B2.3 Extension

The overall term of the PSC could be extended on a day-for-day basis because of the occurrence of a force majeure event (B18.1). The PSC could also be extended towards the end of its term (to allow for continued petroleum production by the contractor) but this will typically be a matter for further agreement between the grantor and the contractor (B7.3).

B2.4 Surrender

The PSC could contain a right for the contractor to surrender the PSC at any time. Although described as a surrender, such a provision is effectively a unilateral termination right for the contractor. Surrender in this context means the giving of a notice from the contractor to the grantor, stating that the contractor wishes to withdraw

²⁹ A point recognized in the Ethiopia PSC.

from the PSC and to bring to an end all of the arrangements between the grantor and the contractor in relation to the PSC. The contractor could elect to surrender the PSC for economic reasons (principally, because the exploration activities have failed to make a discovery) or for strategic reasons (for example, where the imposition of sanctions makes it untenable for the contractor to maintain the PSC).

The PSC could provide that the contractor has no right to terminate or otherwise relinquish the PSC for a defined period (such as the exploration period (B6.2)), where the grantor wishes to lock in the contractor for a defined period of time. This provision might also apply to a transfer of interests by a particular contractor party (B21.1).

The contractor's right to surrender the PSC will typically be effected without prejudice to any accrued or contingent liabilities of the contractor and without prejudice to the contractor's obligation to procure and to maintain collateral support (B22.1) for certain of its ongoing obligations (such as the anticipated costs of decommissioning).

The relinquishment by the contractor of the entirety of the contract area (B5.2) would also lead to the effective termination of the PSC by a form of surrender, subject to the ongoing legacy issues which arise as a consequence of relinquishment.

B2.5 Termination

The PSC could be terminated before its intended end date by mutual agreement between the parties, or by the act of one of the parties which is entitled to terminate the PSC because of the occurrence of a defined event. Such termination events could include the following:

- (1) termination by one party because of the other party's unremedied breach of a term of the PSC (including the failure of a party to make a monetary payment when due). This right typically applies only in favor of the grantor in respect of a contractor default (B17.2), and will often also be expressed to include the contractor's breach of any petroleum code or other item of supervening legislation to which the PSC is subject (B3.1);
- (2) the PSC could require the contractor to warrant that the information which was provided in the bid round which led to the award of the PSC to the contractor was accurate; if subsequently this is proved not to be the case this could also be a termination event in favor of the grantor (unless this is expressed to a direct termination event in its own right, without the added encumbrance of proving an actionable breach of warranty);
- (3) the contractor's insolvency (or, more likely the insolvency of an individual contractor party – see below) according to a defined statutory test could give the grantor a right to terminate the PSC;
- (4) termination by the grantor because of a change of control of a contractor party which was not notified to or approved by the grantor (B21.4);

- (5) termination by either party because of a failure to discover petroleum within a defined period from the effective date (although this event could also be the subject of a surrender – see above) or because of a prolonged period of non-production of petroleum for any reason;
- (6) termination by either party because of a prolonged period of force majeure (B18.2) affecting the PSC;
- (7) termination by one party because of the other party’s failure to comply with the terms of an arbitral award or a court judgment which has been made in respect of the PSC; and
- (8) termination by either party because a condition precedent has not been satisfied or waived by an agreed longstop date (see above).

The PSC could also reserve in favor of the grantor a right to suspend the operation of the PSC for a defined period of time, to apply where the contractor has committed any of the acts which would otherwise amount to a termination event against the contractor. The grantor could then proceed to terminate the PSC if the termination event is still continuing after the end of the defined suspension period.

Termination of the PSC by the grantor against the contractor will require careful consideration where the termination event complained of (such as an unremedied material breach or an insolvency event) can apply only in respect of one of the contractor parties and not in respect of the contractor as a single entity (B1.2). Termination of the PSC would be unwelcome to those contractor parties who were innocent of the breach in question, where the termination event complained of applies only in respect of one of the contractor parties. This could be addressed by a provision in the PSC that termination applies only in respect of a particular contractor party and not in respect of the contractor (nor in respect of the PSC) as a whole.³⁰

This will necessitate the consideration of a further issue – what happens to the interests of the terminated contractor party? The PSC could be silent on this, or it could provide that the interests revert to the grantor, or it could provide that the interests are distributed between the other contractor parties pro rata to their existing interests.³¹

The termination provisions of the PSC will usually provide that the fact of termination is without prejudice to any accrued or contingent liabilities of the parties. It will be a matter for negotiation as to whether the contractor, particularly where it has the ability to surrender the PSC for its own convenience (see above), should be obliged to pay to the grantor the unexpended exploration period obligations costs (B6.3). Termination of the PSC should also trigger the automatic termination of any ancillary exploration license or production license (B12.7).

³⁰ See the Tanzania and Uganda PSCs.

³¹ See the Afghanistan and Uganda PSCs.

The PSC might also provide that, despite its termination by the grantor, the contractor is obliged to continue to perform the PSC for a defined further period until alternative provision has been made for the continuation of the petroleum operations (by the grantor or by another entity).³²

An issue to consider is what happens where there is still viable petroleum production taking place from the contract area at the point when the PSC is due to end naturally at the end of the appointed production period (B7.3). If the production period has not been extended (B7.3) either the grantor could take over the continued production of petroleum, or the contract area could be re-let through the award of a fresh PSC. This would essentially be a PSC for production only, with the additional possibility of amending the scope (B3) and the fiscal terms (B9) to allow for enhanced oil recovery (B3.1).

It should be evident that if the PSC is terminated at a time when the contractor has accrued but unrecovered petroleum costs (B9.1) then those costs will be lost to the contractor but this point might be spelled out in the PSC³³. This position is understandable where the PSC has been terminated for the contractor's default, but could be difficult for the contractor to accept where the PSC has been terminated against the grantor by the contractor.

32 See the Afghanistan and Ethiopia PSCs.

33 See the Gabon PSC.

B3 The scope

The PSC will describe the scope of the activities which are to be undertaken by the contractor, and the rights which the contractor has and the obligations which the contractor is subject to, in performing those activities. The PSC will also describe certain obligations of the grantor which will have a part to play in enabling the contractor to perform those activities.

B3.1 Permitted activities

The intended activities, rights and obligations of the contractor are reflected in a provision in the PSC which is described as the ‘scope’ or the ‘purpose’ clause but this is not always so. Some PSCs go straight into the operational mechanics of the contractor/grantor relationship, with the provisions which are detailed below being located in various different places within the PSC. In this situation a bare statement of the intended scope of the PSC might only be discerned from the PSC’s recitals.

The scope of the PSC relates principally to the award to the contractor of the exclusive right (but see below for a partial qualification of this principle) to conduct what are sometimes called ‘petroleum operations’ in the contract area and for the term of the PSC.³⁴ The meaning of this phrase differs between various PSCs but it relates principally to the activities of petroleum exploration and appraisal, development, production, processing, transportation, and the eventual decommissioning of the associated infrastructure. What might be included within the scope of the PSC should also be determined by what is necessary in practice for the contractor to be able to produce commercial quantities of petroleum. For this reason, the scope of the PSC could also expressly include the contractor’s construction of roads, pipelines, storage facilities and port facilities if such infrastructure items might be required.³⁵

At the other end of the scale the PSC could be expressed to have a limited ambit, such as where a PSC is confined to the contractor’s engagement to work over existing petroleum producing deposits as part of an enhanced oil recovery programme, with the PSC’s fiscal terms (B9) to apply only to those levels of petroleum production which exist beyond a baseline (pre-workover) element.³⁶

Because a breach of the scope provision could lead variously to a liability of the contractor to pay damages to the grantor for breach of contract (B17.2), the irrecoverability of costs which have been incurred by the contractor (B9.1) or even the suspension and/or termination of the PSC against the contractor (B2.5), the agreed scope of the petroleum operations (including any specifically excluded activities) should be made clear in the PSC. This is a particular issue where the grantor and

34 The award of this exclusive right to the contractor does not equate to the transfer of title to petroleum (whether in-ground or at the wellhead) to the contractor under the PSC.

35 See the Senegal PSC.

36 See also the Qatar PSC, which is focused on gas production for a gas to liquids project.

the contractor might previously have been complicit in informally extending this or another's PSC's scope over time (to include, for example, the conduct of petroleum marketing and processing, midstream activities and the development of midstream infrastructure), but without formally documenting these changes to the ambit of the PSC. Modifying the PSC in this way would give a constitutional basis for the contractor's activities which could be called into question in the future.

'Petroleum', which of course is an inherent part of petroleum operations, will be defined in the PSC, either expressly by reference to various forms of crude oil, natural gas and liquids or indirectly by reference to the terms of a petroleum code or other item of supervening legislation (see below) which defines petroleum.

The PSC often expresses the notion that the performance of the petroleum operations will take place at the contractor's risk and expense. This means that the contractor will finance the entirety of each stage of the petroleum operations, and that the contractor will assume the risk of failure by not being reimbursed the costs of doing so by the grantor (or any other state entity) if the operations fail to discover petroleum.³⁷

Further detail in relation to the scope of the PSC comes in the form of provisions relating to the right of the contractor to recover its costs (B9.1) and to take a share of the produced petroleum (B9.2) and to the obligations of the contractor to perform the exploration period obligations (B6.3) and to comply with applicable laws, regulations and standards (B19.1) and with the PSC's anti-bribery and corruption (B24.1), corporate and social responsibility (B24.3), environmental (B12.3), local content (B13.3) and capacity-building (B13) requirements.

The scope of the PSC could also be defined by the various obligations of the grantor, including the award of permits and other assistances (B3.4) and the offering of stabilization protection to the contractor (B16.1).

The PSC could oblige the contractor to perform its obligations in accordance with some variant of a broad theme of 'good and prudent oil and gas field practice' (which is rarely actually defined in the PSC). This requirement, in whatever form it takes,³⁸ will set out an objective standard of behavior which would be expected from a person similar to the contractor which is operating in circumstances similar

37 In contrast, a licence (A2.2) represents something of a departure from this principle - the licensee can offset its exploration and appraisal costs from one licence area against the taxation liability which the licensee is exposed to from profits generated in another licence area.

38 In certain versions of the Indonesian PSC, for example, the contractor is required to perform its obligations "in a workmanlike manner and by appropriate scientific methods." In the Bangladesh PSC the contractor is subject to various different formulations: to produce petroleum "consistent with sound international petroleum industry...practices"; to conduct petroleum operations "in a diligent, conscientious and workmanlike manner...in accordance with...generally accepted standards of the international petroleum industry..."; to be "consistent with good and modern petroleum industry practice."

to those of the PSC, and is intended to guarantee certain minimum standards of operational behavior, health and safety management and environmental compliance by the contractor. Such a provision is necessarily generalized and reference in the PSC to specific rights and obligations might be preferable.

The scope of the PSC could also be defined (in part or substantially so) by reference to the incorporation of the terms of a petroleum code or other item of supervening legislation by which the contractor (and the grantor) are bound, which contains certain provisions which might otherwise be set out at length in the PSC. This approach could provide a series of standards which would at least be consistent across all the PSCs which incorporate such a reference.

B3.2 Excluded activities

It is arguable that a fully defined scope of permitted activities in the PSC, allied to a statement that any other activities are therefore excluded, would make it unnecessary for the PSC to then go on to describe any activities which are excluded from the scope. Despite that, the PSC could also list certain activities which are expressly excluded from the scope.

These excluded activities would relate to the contractor's conduct of anything other than the defined petroleum operations in the contract area and to the contractor's exploration for or the production of mineral interests other than petroleum from the contract area. The excluded activities could also reference the conduct of activities by the contractor outside the contract area and activities beyond a defined point in the PSC (such as petroleum refining, marketing and transportation which is not a direct part of the petroleum operations).

The scope of the PSC, established by the permitted activities and possibly also qualified by the excluded activities, could need to be modified in certain circumstances as a result of the performance of the petroleum operations (such as the development of a gas project - B15.2).

B3.3 Exclusive access

The exclusive right which is given to the contractor to conduct the petroleum operations within the contract area (see above) is almost always qualified in the PSC by the right of the grantor (or its nominee or any third party) to intervene in order to conduct its own activities (such as seismic surveys or wider exploration activity, or the development of mineral interests other than petroleum) within the contract area. This exception is made typically on the condition that the grantor's activities do not interfere with the contractor's rights or obligations.

B3.4 The grantor's obligations

The PSC will also recite certain obligations of the grantor, which will contribute towards defining the scope of the PSC. These obligations could relate to a general

commitment by the grantor to offer assistance to the contractor in managing the business of the PSC (including in the contractor's dealings with other state entities) or to more specific expectations such as the grantor's obligation to issue or to procure certain permits which are necessary for the performance of the petroleum operations, to procure access and egress rights to the contractor in respect of land belonging to third parties, and to make land available to the contractor for the development of any necessary onshore facilities.

It is a basic expectation of the PSC that the grantor will review and approve the various submissions made by the contractor in accordance with the requirements of the PSC. The PSC could also provide for the grantor to charge certain administrative fees to the contractor for doing so,³⁹ (which might be, or might not be cost recoverable by the contractor – B9.1). This proposition could be defended by the grantor on the basis that the state has a nascent petroleum economy which simply lacks the funds to apply a competent administrative function without the application of such an imposition, but this proposition will not have the capacity for infinite application.

Beyond such assistance the grantor will be reluctant to expose its own capital to the risky business of petroleum exploration. A limited exception to this could be where the grantor will fund the preparation of a multi-client seismic survey, which can then be purchased by potential bidders (sometimes also as part of a wider data package – B14.2) as a condition of being considered in a public bid round (A3.1).

B3.5 Expectations and failure

The scope provision in the PSC, related particularly to the definition of the obligations which the contractor has and the rights which the contractor enjoys, establishes a series of expectations for the grantor which, if they are unmet by the contractor, could lead variously to a liability of the contractor to pay damages to the grantor for breach of contract (B17.2), the irrecoverability of costs which have been incurred by the contractor (B9.1) or even the suspension and/or termination of the PSC against the contractor (B2.5).

The obligations which must be performed by the contractor will not be established as absolute however – certain of those obligations will be qualified by, for example, the provisions in the PSC relating to the discretion around the declaration of commerciality (B7.1), the ability of the contractor to modify the performance of the exploration period activities (B6.3) or to relinquish its interests (B5.2), and the availability of force majeure relief (B18.1).

It is less obviously the case that the PSC establishes a series of expectations for the contractor which, if they are unmet by the grantor, could lead to a liability of the grantor to compensate or to otherwise be liable to the contractor.

³⁹ See the Somalia PSC.

B4 The contract area

What is described in the PSC as the ‘contract area’ (or sometimes as the ‘area’ or as the ‘license area’) is a geographical expression of the defined location (whether onshore, or offshore, or both) in which the contractor’s rights and obligations which together make up the scope are respectively to be exercised and performed.

B4.1 The contract area

The contract area is a positive delineation, in that it defines an area of exclusivity (B3.3) for the performance of the petroleum operations by the contractor. The contract area will typically be part of a wider award of contiguous contract areas in other adjacent PSCs by the grantor. Consequently, the contract area is also a negative delineation, in that it defines the adjacent and subjacent areas into which the performance of the contractor’s activities cannot stray.

The PSC might say something particular about the consequences of directional drilling from within the contract area which strays into adjacent acreage, or from adjacent acreage which strays into the contract area (such as, for example,⁴⁰ by provision that such drilling is prohibited from within the contract area, and that drilling from adjacent acreage which strays into the contract area will be deemed to belong to the contractor and so will not benefit the person in the adjacent acreage which undertook such drilling). A further development of this theme is the possibility of provision in the PSC that petroleum which is drawn from the contract area through the contract area of an adjacent PSC will lead to the consolidation of production from the two contract areas.⁴¹

The identification of the contract area in the PSC might also be expressed not to create any direct property rights in favor of the contractor in respect of any surface, seabed or subsoil areas.

The contract area as it is defined in the PSC at the outset should be sized to be large enough to allow the contractor to undertake the required petroleum operations within the timings of the PSC, but it should not be so large that it gives the contractor an impossible task of meaningful exploration and appraisal. Neither should the contract area be so large that it reduces the grantor’s ability to award a number of other contiguous PSCs with their own adequate contract areas to other contractors. Also, the larger contract area the larger the surface area rental payments which will be due from the contractor to the grantor (B10.3).

It would be sensible in the PSC to clarify the relationship which exists between the contract area and any other area (whether at the surface or subsurface) in respect of which a permit has been issued by the grantor for the conduct of other operational

40 See the Equatorial Guinea PSC.

41 See the Egypt PSC.

activities (B3.3) where the contract area and that other area could overlap or could come into contact, but this is rarely addressed comprehensively in most PSCs.

Apart from explicit definition as such in the PSC, the extent of the contract area will also be determined by the PSC's relinquishment provisions (B5), which will have a bearing on how the contract area is redetermined on an ongoing basis. It is common to find in the definition of the contract area in most PSCs that it is the area which exists from time to time subject to the effect of periodic relinquishments.

The contractor might require a warranty from the grantor in the PSC that no other persons have interests in respect of contract area, or that the boundaries of the contract area are not subject to disputes from neighboring states which might otherwise impede the performance of the petroleum operations, but such undertakings by the grantor are rarely encountered in the PSC.⁴²

The grantor could be concerned that the contractor will have contiguous acreage in neighboring states which it could use the exploration data generated under the PSC (B14.2) to better define (and which that contractor might ultimately prefer for the implementation of a petroleum production project). To manage this concern the PSC could provide for an undertaking from the contractor that it will not hold contiguous acreage in neighboring states (which, if breached by the contractor, could be a termination event (B2.5) in respect of the PSC).

B4.2 Initial description

The PSC will recite a description of the contract area as it exists at the outset of the PSC, usually by the use of a narrative such as surface area coordinates and also with the addition of a map to the PSC. The PSC might also legislate for what will prevail in the event of a discrepancy between the narrative and the map (although there should be no excuse for the existence of such a discrepancy at the outset of the PSC).

The contract area could be described two-dimensionally by the use of surface area coordinates (to give a total number of square kilometers), or three-dimensionally, with surface coordinates and further provision that the contract area extends downwards from a defined reference point to a defined stratigraphic layer as indicated in Figure 5:

Figure 5

The contract area means the offshore area allocated for the conduct of the Petroleum Operations: (i) shown by the two-dimensional surface coordinates in and as further illustrated by the map in Appendix A; and (ii) all stratigraphic layers subjacent thereto to a maximum depth of • meters measured vertically from the mean sea level

42 Although see the Guyana and Liberia PSCs for a partial provision in this respect.

The PSC might seek to impose some form of depth limitation in the definition of the contract area. The contract area could be described such that it starts at a defined stratigraphic layer and then extends downwards to a further defined stratigraphic layer (all within the same set of surface area coordinates) as indicated in Figure 6:

Figure 6

The contract area means the offshore area allocated for the conduct of the Petroleum Operations: (i) shown by the two-dimensional surface coordinates in and as further illustrated by the map in Appendix A; and (ii) representing the stratigraphic layers subjacent thereto commencing at the depth of • meters measured vertically from the mean sea level to a maximum depth of • meters measured vertically from the mean sea level

The PSC might also provide that the contract area starts at a defined stratigraphic layer and then extends downwards but only to the point where a basement (that is, an igneous or metamorphic rock layer which suggests that a viable petroleum system might not be found below it) is proven to exist.

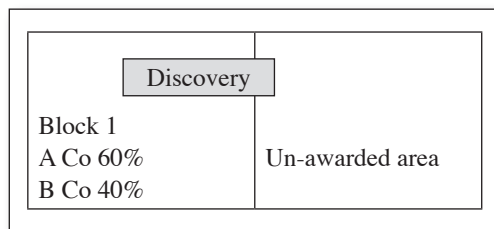
The limitation of the contract area to a particular stratigraphic layer, or to an area between particular stratigraphic layers, is suited to where layers of petroleum exist at different depths within a single set of surface area coordinates, in respect of which separate PSCs could be awarded.

The PSC might also provide that once a discovery has been made and a development area has been identified (B7.2) the base of the development area will be limited to the lowest vertical point of the discovery, thereby freeing up the stratigraphic layers which lie below that point for relinquishment (B5) and the possible future award of a separate PSC.

B4.3 Extension

The contract area could be extended to include an un-awarded adjacent or subjacent area into which extends a discovery that has been made by the contractor in the contract area during the exploration period as indicated in Figure 7:

Figure 7



The un-awarded adjacent or subjacent area could also be a part of the original contract area which has previously been relinquished by the contractor (B5).

Such an extension will typically be undertaken at the request of the contractor, which should also expect to make an additional rental payment to the grantor (B10.3) in respect of the extension area if the contractor's request is accepted by the grantor.

The grantor's preference however could be that where a discovery extends into an un-awarded adjacent or subjacent area then the contractor should apply for the award of a separate PSC in respect of the extension area (for which a further signature bonus (B10.1) could be payable by the contractor), rather than to see the existing PSC's contract area automatically enlarged to accommodate the discovery. This could then lead to a pooling or a unitization of the two PSCs (see below). If a discovery extends into an adjacent or subjacent area in respect of which another PSC has already been awarded then pooling or a unitization of the two PSCs could be required.

A related issue to consider is where the contractor wishes to build infrastructure which would be located outside of the contract area (such as an export pipeline or a storage facility) in order to effect the petroleum operations. The definition of the contract area could be extended to include the location of this infrastructure (and changes would also need to be made to the scope of the PSC (B3.1)) to facilitate this, or the contractor could enter into an ancillary arrangement with the grantor in relation to the provision of such infrastructure.⁴³

B4.4 Consolidation

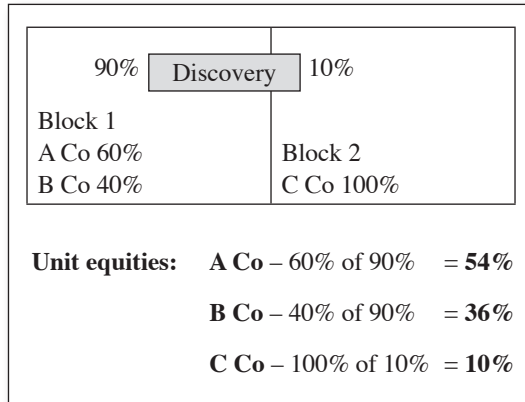
It could be that a petroleum discovery which has been made is proven to underlie more than one PSC's contract area (with those PSCs being held by different contractors). This notion could apply in the purely domestic context (that is, within the host state) but it could also apply internationally across contiguous acreage which underlies more than one state.

Rather than allow competitive drilling between the contractors in their respective contract areas, which could lead to a suboptimal development of the discovery and the unnecessary duplication of costs, some sort of consolidation of the interests of the involved contractors could be required.

One option for effecting such consolidation is that the grantor will implement a programme of unitization. The discovery would be developed as a single unit by all of the involved contractors, each holding agreed percentage interests according to a pre-agreed ratio which reflects their understanding of the extent to which the discovery underlies their respective contract areas, and the contractors would express their interests through a unitization and unit operating agreement (UUOA) with an agreed single operator of the unit as indicated in Figure 8:

43 See the Turkmenistan and Uganda PSCs.

Figure 8



Another, and much simpler, option for such consolidation is pooling, whereby the involved contractors would agree to work together under a contractually based joint venture to develop the discovery, contributing development costs and taking produced petroleum revenues according to a pre-agreed ratio which reflects their understanding of the extent to which the discovery underlies their respective contract areas. Pooling does not necessitate the creation of a single unit in the manner of a unitization.

The activities of unitization or pooling could be a mandatory requirement of the contractor at the request of the grantor as a reserved term of the PSC (or under any applicable petroleum code or other item of supervening legislation), or these activities could be voluntary at the contractor's option (but subject to the grantor's approval of the terms of the proposed activity). In either case, the PSC will usually apply a unitization provision which offers some guidance to the process to be followed.⁴⁴

44 See the Afghanistan, Bangladesh and Ethiopia PSCs.

B5 Relinquishment

The contract area as it is defined at the outset of the PSC is ordinarily sized such that it represents a geographical scope which is well beyond what the contractor could conceivably expect to explore and appraise in its entirety within the defined exploration period. This is reflective of the likelihood that the application for the award of the PSC could have been made by the contractor on the basis of relatively little existing geological and geophysical data, and so the PSC purposefully reflects a sizeable contract area at the outset so that the contractor has plenty of opportunity to select what it thinks will be the best area for exploration.

B5.1 The logic for relinquishment

As the results of the contractor's exploration (B6.1) and appraisal (B6.5) activities become available during the lifetime of the PSC the contractor will focus its ongoing attentions only on certain parts of the contract area. As a consequence dormant, unexplored parts of the contract area will become inevitable. To counter the risk of the sterilization of certain parts of the contract area which are neither being explored nor developed, a provision in the PSC known as 'relinquishment' (sometimes also called a 're-sizing' or a 'surrender' provision) provides a mechanism whereby the dormant parts of the contract area are removed from the contractor's control and are returned to the grantor.

Relinquishment benefits the grantor, which can re-award a relinquished part of the contract area to another contractor for exploration under a fresh PSC – so that relinquishment facilitates the maintenance of a higher level of ongoing exploration and appraisal than would otherwise be the case. Relinquishment also benefits the contractor, since it will be relieved of the obligation to make rental payments (B10.3) to the grantor in respect of the relinquished area.

The PSC might not contain a relinquishment provision. If this is so the contractor could be required to commit to much greater exploration period obligations as a condition of being awarded the PSC, to give comfort to the grantor that the amount of dormant, unexplored acreage will thereby be minimized.

The ultimate intention of the PSC is that, as a consequence of the relinquishment provisions, the final iteration of the contract area will be re-sized to one where only development and production activities are being undertaken by the contractor, with no fallow areas being denied to the grantor. The key to a successful relinquishment provision is that it achieves a balance between the grantor's aversion to dormancy and the contractor's need for sufficient time and space to carry out the required petroleum operations.

B5.2 Relinquishment models

Relinquishment applies ostensibly to a dormant part of the contract area, but it could also apply to a part of the contract area in respect of which the contractor has conducted exploration and appraisal activities but without success. Relinquishment within the PSC could be expressed to be mandatory, or voluntary, or a combination of both.

Where relinquishment is mandatory under the PSC the contractor is compelled to relinquish a defined percentage part of the contract area at periodic time intervals. The PSC could provide that the percentage of the contract area to be relinquished will be according to its original and then its residual contract area definitions,⁴⁵ or the PSC could provide that the percentage of the contract area to be relinquished will be according only to its original contract area definition.⁴⁶

The first proposition is illustrated by the example indicated in Figure 9:

Figure 9

<p>At the end of the First Exploration Period the Contractor will relinquish an area equivalent to 25% <u>of the original</u> Contract Area</p> <p>- <i>First relinquishment = 100 % × 25% - net 75%</i></p> <p>At the end of the Second Exploration Period the Contractor will relinquish an area equivalent to 25% <u>of the remaining</u> Contract Area</p> <p>- <i>Second relinquishment = 75% × 25% - net 56.25%</i></p> <p>At the end of the Third Exploration Period the Contractor will relinquish an area equivalent to 25% <u>of the remaining</u> Contract Area</p> <p>- <i>Third relinquishment = 56.25% × 25% - net 42.18%</i></p>

The second proposition is illustrated by the example indicated in Figure 10:

Figure 10

<p>At the end of the First Exploration Period the Contractor will relinquish an area equivalent to 25% <u>of the original</u> Contract Area</p> <p>- <i>First relinquishment = 100% × 25% - net 75%</i></p> <p>At the end of the Second Exploration Period the Contractor will relinquish an area equivalent to 25% <u>of the original</u> Contract Area</p> <p>- <i>Second relinquishment = 100% × 25% from 75% - net 50%</i></p> <p>At the end of the Third Exploration Period the Contractor will relinquish an area equivalent to 25% <u>of the original</u> Contract Area</p> <p>- <i>Third relinquishment = 100% × 25% from 50% - net 25%</i></p>

The second proposition results in relatively greater relinquished areas. If this approach is adopted in the PSC the percentages specified for the area to be relinquished could be slightly lower, to offset the extent of the relinquishment in the contractor's favor.

45 See the Afghanistan PSC.

46 See the Bangladesh PSC.

The PSC might also provide that at the end of the exploration period (B6.2) the contractor is required to make a final relinquishment of all of the parts of the contract area which are not then sanctioned for development as part of a development area (B7.2). If there are none then the entirety of the PSC will effectively be surrendered. This final relinquishment could be an automatic event or one which takes place at the grantor's request. Such an approach overlooks the possibility however that the contractor might wish to consolidate discoveries which have previously been made in the contract area but not declared as commercial during the exploration period in order to make a later declaration of commerciality (B7.1), which could be a possibility under the PSC.

Additional mandatory relinquishment is sometimes also applied by the grantor as a sanction which is to be applied as a reaction to the contractor's failure to perform an obligation under the PSC (such as an exploration period obligation) or to an unjustified delay by the contractor in commencing or in carrying out production operations.

Relinquishment by the contractor could also be voluntary under the PSC, such that the contractor has the option to relinquish all or any part of the contract area at any time. Voluntarily relinquished areas should be credited against the contractor's mandatory relinquishment requirement.

The PSC could also allow the contractor to voluntarily relinquish the entirety of the contract area (subject to the contractor's compliance with the conditions set out below, and possibly also subject to certain timing restrictions (B2.4)). This would essentially be a surrender right for the contractor in respect of the PSC (B2.4).⁴⁷

The PSC could also specify a particular regime to apply in respect of a marginal discovery (B7.1) which has been made by the contractor, where the contractor can relinquish that marginal discovery and the grantor could seek to appoint another contractor, perhaps more suited to or willing to undertake the development of a marginal discovery.

The contractor could also have a preference to defer the prescribed mandatory relinquishment for a period of time, in the interests of having a greater choice over the contract area in which it elects to conduct exploration and appraisal operations. Thus, rather than to have provision for a relinquishment of 25 per cent of the contract area at the end of each of the first and the second exploration phases (see the examples above), the PSC could provide that the contractor will instead relinquish 50 per cent of the contract area at the end of the second exploration phase. The grantor could be willing to accept this flexibility (and the accompanying increased rental payments), unless the grantor is particularly keen to be re-letting relinquished parts of the contract area.

⁴⁷ See the Uganda PSC.

B5.3 Relinquishment conditions

Relinquishment by the contractor (whether mandatory or voluntary) will be subject to a number of conditions under the PSC:

- (1) relinquishment of any part of the contract area might not be possible where an exploration period obligation is still to be performed by the contractor (unless the contractor pays compensation to the grantor for a failure to perform the exploration period obligation – B6.3);
- (2) relinquishment of any part of the contract area where petroleum operations have been carried out will be subject to the contractor's completion of any decommissioning activities which are required in relation to those operations (B7.4), or at least subject to the contractor's provision of adequate collateral support for those activities (B22.1);
- (3) the timetable for mandatory relinquishment could be postponed in respect of a part of the contract area where appraisal works are, or the consideration of a development plan is, still underway;
- (4) there could be a requirement in the PSC that the relinquished area should be a three-dimensional area which is sufficiently sized to permit the conduct of petroleum operations in its own right by another person - relinquishment cannot be configured such that it would result in a relinquished area which is not readily capable of being re-awarded by the grantor under a new PSC because of its irregular size or shape (a principle which is sometimes called the 'ragged edge' rule);⁴⁸
- (5) the contractor could insist that it should still have rights of access over the relinquished area to the extent necessary to allow petroleum operations to be performed in the un-relinquished parts of the contract area (which seems sensible enough, but which could pose difficulties where the relinquished area has been awarded to another contractor as part of a fresh PSC which contains an exclusive access provision (B3.3) in favor of that contractor);
- (6) the grantor will ordinarily not compensate the contractor for the loss of the relinquished area;
- (7) the grantor's approval is ordinarily required for a proposed relinquishment (which would relate to the approval of any voluntary relinquishment or the approval of the parts of the contract area which the contractor proposes to relinquish as part of a mandatory relinquishment provision). This could also be a topic to be considered by the management committee if the PSC provides for such a body (B8.2); and
- (8) any exploration and appraisal expenditures which have been incurred by the contractor in the relinquished area should be capable of being cost recovered (B9.1) by the contractor against any future production revenues from the un-relinquished parts of the contract area.

48 See the Afghanistan, Bangladesh and Belize PSCs.

B6 Exploration and appraisal

The contractor is very likely to have imperfect knowledge regarding the level of in-ground petroleum resources at the time when the PSC is executed between the parties (apart from what the contractor has been able to learn from a purchased data package). Consequently, the first phase of activity for the contractor under the PSC is the exploration for petroleum within the contract area, followed by the appraisal of any discovery which is made as a consequence of that exploration.

B6.1 Exploration

The PSC will facilitate the performance of exploration and appraisal activity through the creation of certain exploration period obligations which will bind the contractor. These obligations are the first counterpoint to the award to the contractor of exclusive access to the contract area under the PSC (B3.3).

‘Exploration’ is a shorthand term for the operational activities of drilling wells, generating and processing seismic data and conducting technical studies. These activities are of vital importance to the grantor because they represent the creation of value – although these activities are principally intended to facilitate the discovery of commercially viable quantities of petroleum, they also generate invaluable geological and geophysical data for the grantor and this will be so for the grantor even if the exploration activity proves to be unsuccessful. The contractor has a different perspective however, and will be less focused on the generation of data. The contractor wants to make a petroleum discovery which is capable of being commercialized so that it can recover its costs of exploration and appraisal (B9.1). In pursuit of this, the contractor will want the greatest amount of flexibility in how it performs the exploration period obligations (including the ability to accelerate, delay or even avoid them).

B6.2 The exploration period

The exploration period is a period of time, defined by the PSC, in which the contractor must undertake a defined set of exploration period obligations (see below). The exploration period usually starts on a defined day which occurs shortly after the effective date of the PSC (B2.1). The exploration period activities could be preceded by the conduct of a baseline environmental impact study (B12.3) and/or a social impact assessment (B22.4) by the contractor.

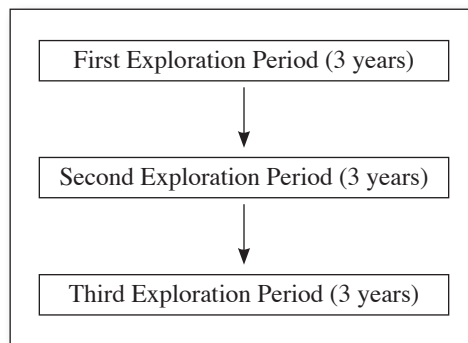
The contractor wants the longest possible exploration period, so that it can schedule its performance of the exploration period obligations at its own pace and with the greatest possible flexibility. The grantor would prefer a shorter exploration period, so that it can make an early assessment of the prospectivity of its acreage and consider the relinquishment and the re-awarding of the contract area (B5) if necessary. In between these two objectives the exploration period must at a minimum be of

sufficient duration to allow the contractor to properly perform the exploration period obligations. And in every case the contractor will require that the PSC must take account of the seasonal and weather conditions which apply to the contract area – year-round exploration and appraisal activities, year after year, might simply be impossible to achieve, depending upon the location in which the exploration activities are to be conducted.

The starting point for the overall duration of the exploration period in most PSCs is between six and twelve years but the exploration period is rarely described in the PSC as a single period of time. Rather, the exploration period typically consists of a number of sequential fixed time periods (known commonly as the ‘exploration phases’).

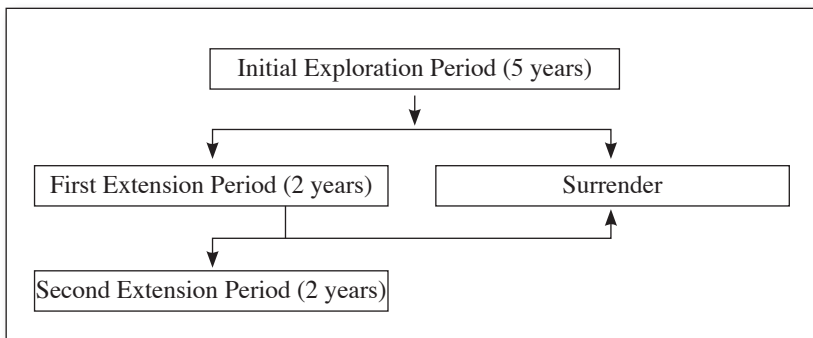
The PSC could be structured so that these exploration phases will follow on automatically from each other as indicated in Figure 11:

Figure 11



Alternatively the exploration period could be structured to consist of a slightly longer initial exploration phase, followed by a series of shorter extension periods, exercisable at the contractor’s option (and where surrender of the PSC (B2.4) could result if an extension period option is not exercised by the contractor) as indicated in Figure 12:

Figure 12



In either case an extension to the duration of an exploration phase could be allowed by the grantor to facilitate the completion of the drilling and the testing of a well which was commenced during that exploration phase but not completed by the end of the exploration phase, to allow the well to be completed and the results shared with the grantor.

A particular flexibility which might be engineered in the PSC is a right for the contractor to accelerate the commencement of the next scheduled exploration phase within an exploration period if it has completed its exploration period obligations for a particular phase and it wishes to complete all of its exploration period obligations as soon as possible. It is not typically the case that the grantor has the benefit of this acceleration right, since its exercise by the grantor could prejudice the contractor's interests.

The exploration period (and the exploration phase timings) which are set out in the PSC could be fixed and absolute or they could be capable of being extended on a day-for-day basis because of the occurrence of a force majeure event (B18.1).

Where the PSC applies an exclusive operations right in favor of the grantor, with provision that the contractor could elect to assume the exclusive operation proposal as a petroleum operation (B12.4), the exploration period could be further extended to accommodate this possibility.

The PSC typically precludes the contractor from performing any of the petroleum operations (including exploration) without first having acquired certain permits and approvals from the grantor or from other state agencies. The time taken to secure these permits and approvals will eat into the exploration period. The exploration period could be extended in the contractor's favor if these permits and approvals are not forthcoming in a timely manner. The frustration of the contractor's intent in this regard could also be a matter for a claim for force majeure relief (B18.1).

B6.3 Exploration period obligations

The PSC will recite a series of operational activities relating to the business of exploration which the contractor must undertake during the exploration period. The exploration period obligations could be derived from the commitments which were made by the contractor during a public bid round, where those obligations were contestable items (A3.1).⁴⁹

The exploration period obligations (sometimes also called 'minimum work obligations' or 'commitment wells'), which are usually allocated equally across each of the different exploration phases, are principally intended to facilitate the discovery of commercially-viable quantities of petroleum but they also serve to generate valuable data for the grantor (see above). All of these activities, and their associated costs,

⁴⁹ See the Afghanistan PSC.

should be regulated by an appropriate work programme and budget (B12.1).

Above all, the contractor has an interest in reducing the scope of the exploration period obligations to the greatest extent possible because they represent the incidence of costs which might not be recovered by the contractor if a commercial discovery is not made as a consequence (although, paradoxically, more exploration could also increase the contractor's chances of making a discovery).

The exploration period obligations typically relate to any of the activities of drilling a well (or wells) to a defined target depth or to a target distance in a location or locations to be further agreed between the grantor and the contractor, generating new seismic data, processing and/or reinterpreting existing seismic data, or preparing technical studies. Issues which typically arise for debate in the negotiation of the PSC in respect of these activities will relate to whether the requirement to drill an exploration well could include any of the activities of deepening, side-tracking or testing an exploration well which has already been drilled as an acceptable substitute activity, and whether drilling an appraisal well would equate to drilling an exploration well. These possibilities might be spelled out in the PSC, or they might be left for discussion between the parties at the appropriate time.

The exploration period obligations should be drafted with sufficient detail in the PSC. Requiring the contractor to drill an exploration well, for example, should also address clearly whether the contractor is expected to commence or to complete drilling within the relevant exploration phase (and consideration could also be given to what 'commence' would mean for these purposes, including a definition of the necessary 'spudding' activity).⁵⁰

In some PSCs the contractor's exploration phase obligation is defined by the requirement to complete what are defined as 'work units'.⁵¹ Each exploration period obligation is ascribed a number of work units (being units with an ascribed monetary value), and the contractor is required to complete a number of work units within a defined time period in order to meet its obligations. In theory, this approach gives more flexibility to the contractor, which can select the manner in which it applies the work units rather than being bound by defined exploration period obligations, although the applicable work programme and budget (B12.1) will still impose some constraint on the contractor's discretion.

The performance by the contractor of each exploration phase's obligations should not be determinative of whether the contractor can proceed to the next exploration phase. The contractor's liability for a failure to perform a particular exploration phase obligation to the extent required by the PSC should be assessed in its own

50 *Vitol E&P Limited v. Africa Oil and Gas Corporation* [2016] EWHC 1677 (Comm) shows the analysis of the English courts on the definition of 'spudding'.

51 See the Pakistan and the Trinidad and Tobago PSCs.

regard as a potential breach of contract by the contractor (B17.2), and the failure to perform such an obligation should not be used by the contractor as an excuse for not continuing with the performance of any further obligations. That said, the contractor's exploration phase obligations are also sometimes referred to as the 'unless' clause, meaning that the contractor cannot proceed unless the contractor has performed a particular exploration phase obligation.

A failure of the contractor to perform an exploration period obligation according to the PSC's requirements (which failure is not excused by force majeure or which failure is authorized by the grantor or is otherwise permitted by the PSC) could have a number of consequences:

- (1) the grantor could treat the failure as a breach of the terms of the PSC, giving the grantor a right to suspend and/or to terminate the PSC (B2.5);
- (2) whether or not the grantor terminates the PSC, the failure could also expose the contractor to a liability to pay damages (whether general damages or liquidated damages) to the grantor for its breach of contract (B17.2); and
- (3) the contractor could be obliged to pay to the grantor a monetary sum which reflects the unspent element of the exploration period obligation's costs (see below). This formulation offers no remedy to the grantor where the contractor has spent the exploration period obligation's costs but has still failed to complete the exploration period obligation and so this formulation could be revised to say that the contractor will pay to the grantor the greater of the unspent element of the exploration period obligation's costs and a defined monetary amount (as a liquidated damage).

Where the contractor becomes obliged to make a monetary payment to the grantor, the grantor could also call on any collateral support which has been provided by the contractor in respect of its obligations under the PSC (B22.1) as surety for the payment which is due.

The exploration period obligations in most PSCs are relatively inflexible, in that they are required to be performed by the contractor without regard to extraneous economic circumstances affecting the contractor (such as, for example, the impact of a low petroleum price environment). That said, experience has shown that global market conditions which adversely affect all sector participants could lead to discussions between the grantor and the contractor about the rescheduling of exploration period obligations and their associated costs, notwithstanding the absence in the PSC of a formal mechanism to facilitate this, in the interests of keeping the PSC alive between the parties. The product of such discussions should be mindful of the need for compliance with a waiver provision in the PSC (B24.10).

The willingness of the grantor to be accommodating to the contractor could be less forthcoming however where the contractor's difficulties relate to any of private

financing difficulties, problems within the contractor party consortium or disappointing results from the early part of the exploration period's activities.

From the grantor's perspective the PSC should describe a fixed set of exploration period obligations which must be performed by the contractor without fail (subject only to the availability of force majeure relief to the contractor – B18.1), up to the maximum amount of the scheduled expenditure (see below) and to schedule. The contractor will be less impressed by a requirement for rigid, absolute performance however – the contractor wants to make a petroleum discovery which is capable of being commercialized so that it can recover its exploration costs, but the contractor will also want the greatest amount of flexibility in how and when it performs the exploration period obligations so that it can maximize costs savings, and the prospect of making a return on its incurred costs. In response to the grantor's requirements, the contractor could seek to moderate the grantor's preferred positions in the PSC in several ways:

- (1) the PSC might permit the contractor to be deemed to have completed the performance of a particular exploration period obligation where circumstances beyond the contractor's control have prevented the required performance (such as a provision that the contractor could be deemed to have drilled a well to a required target depth or distance where the attempt to do so had to be abandoned because the drilling encountered an impenetrable geological layer or dangerous downhole conditions), or where in drilling an exploration well the contractor encountered a viable petroleum system before the agreed target depth or distance was reached. In the former case, the PSC could require the contractor to drill a substitute well at its own expense.⁵² In any of these circumstances it will always be an issue as to whether the contractor can unilaterally deem that the particular circumstances have arisen, or whether the grantor's approval is required;
- (2) the PSC might give the contractor an option to pay an agreed monetary amount to the grantor rather than to perform a particular exploration period obligation, so that the contractor can effectively buy out an unperformed obligation.⁵³ This buy-out option for the contractor makes particular sense if the performance of previous exploration period obligations has indicated no or a negligible chance of future success, where the contractor believes that taking the risk and the (additional) expense of drilling what would almost certainly be another dry hole would defy commercial logic;
- (3) the contractor could be entitled to carry forward an unperformed exploration period obligation, as an offset to apply in a later time period under the PSC or even under another PSC;
- (4) a commercial discovery (B7.1) could obviate the contractor's obligation to perform

52 See the Angola PSC.

53 See the Angola PSC.

the remainder of the exploration period obligations, or they could remain due for performance by the contractor. The grantor will have a preference for the latter formulation, since the continued performance of those obligations will generate more data for the grantor and could lead to another commercial discovery;

- (5) the contractor could seek to structure the performance of the exploration period obligations such that the first obligations are undertaken at the end of a defined first exploration phase and the next obligations are undertaken at the start of a defined second exploration phase. This would allow a drilling rig to drill two exploration wells consecutively across the two exploration phases but without the need for the intervening demobilization and remobilization of that drilling rig; and
- (6) where in a particular exploration phase the contractor has performed work which is in excess of the required obligation for that exploration phase then the excess work could be carried forward and credited towards satisfaction of the exploration period obligation for a future exploration phase, or even towards another PSC. This construction could be difficult to apply in practice to discrete and identifiable work products, but it could be more readily applicable where the PSC adopts a work units formulation (see above). Such a carry forward mechanism might also more readily lend itself to the contractor's obligation to fund a defined amount of exploration period obligations (see below).

B6.4 Exploration period obligations costs

The grantor could require that the contractor's performance of the exploration period obligations must be completed regardless of the cost to the contractor of doing so. The contractor could seek to moderate the grantor's position by requiring that the PSC will apply a monetary cap to the costs which the contractor is expected to incur in the performance of the exploration period obligations, to protect the contractor from being obliged to incur limitless expense. If, says the contractor, the monetary cap is reached and the exploration period obligations remain unperformed according to their definition then the exploration period obligations will be deemed to have been completed. This construction is rarely accepted by the grantor however, which has as its primary objective the successful performance of the required works rather than the expenditure of money.

Alternatively the grantor could structure the exploration period obligations so that the contractor must incur a defined minimum amount of expenditure (called the 'exploration period obligations costs') in their performance. This benefits the grantor because it establishes a minimum financial threshold for the contractor's obligation, which would ensure a certain level of quality and commitment in the performance of the exploration period obligations. The exploration period obligations costs also establish a baseline amount for the payment of liquidated damages by the contractor for a failure to perform the relevant obligation (see above). The PSC could make clear that the principal purpose of so stating the costs is to establish a liability of

the contractor for a performance failure, rather than to have them taken as a proxy for the required performance.⁵⁴

Where a minimum expenditure formulation is adopted, the PSC could state what expenditures will count, and will not count, towards satisfaction of the contractor’s expenditure obligation.⁵⁵ The grantor could, for example, wish to make it clear that the amount of the exploration period obligations costs are not offset by the contractor’s rental payment (B10.3) or training payment (B13.1) obligations under the PSC or by the contractor’s general and administrative overhead costs (B8.1).

The PSC could provide that if an exploration period obligation is performed and the exploration period obligation’s costs are not fully expended then the exploration period obligation will be deemed to have been completed, without an obligation of the contractor to account to the grantor for the unspent balance of the exploration period obligation’s costs. Alternatively, the amount of the unexpended exploration period obligation’s costs could be carried forward and credited towards the exploration period obligations costs for the next exploration period obligation, or in some circumstances they could become due for payment by the contractor to the grantor.

The combination of exploration period obligations and costs could be recited together in the PSC along the lines of the example indicated in Figure 13:

Figure 13

During the Exploration Period the Contractor will perform the following Exploration Phase Obligations and will incur not less than the following Exploration Phase Costs in doing so:	
Exploration Phase Obligation	Exploration Phase Cost
At the Grantor’s option: Acquire and process not less than • square kilometers of 3D seismic OR Spud one Exploration Well before the end of the First Exploration Period and thereafter drill expeditiously, in a location and to a depth to be agreed with the Grantor	\$• \$•
Spud one Exploration Well before the end of the Second Exploration Period and thereafter drill expeditiously, in a location and to a depth to be agreed with the Grantor	\$•
Spud one Exploration Well before the end of the Third Exploration Period and thereafter drill expeditiously, in a location and to a depth to be agreed with the Grantor	\$•

54 See the Cameroon PSC.

55 See the Uganda PSC.

B6.5 Discovery and appraisal

If a petroleum discovery is made during the exploration phase the next question to consider is whether that discovery merits appraisal. ‘Appraisal’ (sometimes also called ‘delineation’ or ‘evaluation’) is a shorthand term for the activities which are undertaken in assessing whether a petroleum discovery which has been made during the exploration period is a candidate to be declared as a commercial discovery (B7.1), which in turn could then be capable of becoming the subject of a development programme and eventual petroleum production operations.

Where the contractor notifies the grantor of the existence of a discovery the PSC could give the contractor an additional period of time in which the contractor will prepare and propose a plan for the appraisal of the discovery, for the approval of the grantor. This additional period of time, and the conduct of the appraisal plan’s activities, could overrun the end of a scheduled exploration phase or of the exploration period (which might then be extended accordingly by the grantor). Whether a discovery should qualify for appraisal could be determined by an objective test in the PSC, relating for example to the achievement of defined flowrates of petroleum over a particular period of time, or could be something for the grantor to consider in its discretion.

In some PSCs the term ‘commercial well’ is used to indicate a discovery which could go forward for appraisal.⁵⁶ This is not the same as a commercial discovery, and the risk of confusion is obvious.

If at the end of the exploration period (or at the end of the appraisal of a discovery which is made) the contractor is of the opinion that there are no commercially viable quantities of petroleum in the explored part of the contract area the contractor will take steps to plug and abandon any drilled wells and will carry out any site remediation which has become necessary as a consequence of its activities (B7.4). The part of the contract area which contains the undeclared discovery could also become the subject of relinquishment by the contractor (B5).

Completion of the activities contemplated by the appraisal plan could however indicate that a discovery could be capable of being exploited commercially. If an appraised discovery indicates the presence of commercially viable quantities of petroleum then the contractor will move to making a declaration of commerciality. If this is so then, subject to the approval of the grantor, a development programme and (eventually) planned production operations will then get underway in respect of the discovery.

⁵⁶ See the Angola and Egypt PSCs.

B7 Development, production and decommissioning

If an exploration period activity indicates a discovery which contains what could potentially be commercially viable quantities of petroleum then it could then lead to a process of appraisal and in turn to the declaration of a commercial discovery by the contractor. Thereafter will come the activities of development and production in respect of that discovery. These activities, and the development of the wells and the associated infrastructure which they will necessitate, will also lead eventually to a consideration of the necessary decommissioning activities.

B7.1 Declaration of commerciality

The contractor will make a declaration of commerciality in respect of a discovery which has been appraised when it feels that the discovery demonstrates evidence of the existence of commercially viable quantities of recoverable petroleum which is sufficient to allow for its profitable exploitation. The declaration of commerciality will then be a precursor to the development period and eventual production.

What constitutes ‘commerciality’ for the purposes of declaring a commercial discovery will initially be a matter for the subjective determination of the contractor. The contractor will take into account the costs which it incurred in making the discovery (which need to be cost recovered – B9.1) and the actual and prospective volumetric, operating and financial data relevant to the discovery. The contractor’s thinking could also be guided by the requirements of the PSC for the contractor to perform the petroleum operations in accordance with good and prudent oil and gas field practice (B3.1). The foregoing statement assumes that the contractor will analyze the economics of the discovery on a stand-alone basis, whereas in reality the contractor might also wish to realize a profit margin from a discovery which covers the contractor’s sunk costs in respect of its other unsuccessful exploration activities.

The contractor might also wish to assess commerciality by reference to any previous discoveries which have not been declared commercial in their own right but which might become so by consolidation with the addition of the latest discovery. The contractor does not want to immediately have to relinquish a marginal discovery. It would prefer to wait to do this until the end of the overall exploration period, so that it can then make a decision about combining the development of the marginal discovery with the development of another commercial discovery, in order to achieve a combined economy of scale. The grantor could however have a more aggressive ‘use it or lose it’ philosophy, compelling the swift relinquishment of a marginal discovery.

The PSC might also provide for the conduct of a pilot production programme by the contractor to give a practical assessment of potential commerciality. This should not be confused with an early oil programme (B7.3).

Once the contractor has made its determination that a declaration of commerciality

can be made, the issue of commerciality will usually be subject to approval by the grantor. The combination of these principles means that the declaration of commerciality will essentially have to be arrived at as a joint determination of the grantor and the contractor (but, usually, subject to the contractor raising the prospect of commerciality in the first instance – although even this could be procured by a resolution of the management committee, which could be subject to the grantor’s voting control (B8.2)). Even if the PSC gives the contractor the absolute right to determine whether a discovery is commercial the need for the grantor’s approval of a consequent field development plan (see below) could allow the grantor an effective veto right.

Ordinarily the grantor would have an interest in seeing a declaration of commerciality because of the hope that it will lead to petroleum production revenues and a profit element. Even if a declaration of commerciality is not made, the grantor should still be able to secure the data which was generated by the exploration works, which at least is something for the grantor. The situation is worse for the contractor, which will have no means of recovering the incurred exploration and appraisal costs.

From the grantor’s perspective, the test for whether a discovery is commercial could be triggered by a mathematical test for something which affords an acceptable level of state take (A1.1), regardless of the contractor’s ambitions. The grantor might particularly be concerned about the commerciality of a discovery from the grantor’s perspective where the PSC has relatively unattractive fiscal terms (such as unconstrained cost recovery (B9.1), low profit shares (B9.2), no provision for the payment of royalty (B10.4) or low or no taxation (B10.5)). If there is a dispute between the parties concerning the commerciality of a discovery the PSC could provide for the appointment of an independent expert to determine the matter (B20.2).

That there will not be automatic alignment between the aspirations of the contractor and the grantor in respect of the declaration of commerciality in every case is apparent therefore, and this is particularly illustrated by the case of a marginal discovery.

What ‘marginal’ means for these purposes will be a subject assessment of the contractor, which will weigh up the forecast exploration, appraisal and development costs, the forecast petroleum production volumes and prices and the application of the general economics of the PSC. It is not axiomatic that the grantor will see marginality through the same lens however – the grantor (or another contractor) could have different economic and strategic perspectives which could produce a different result.

A marginal discovery (which has no obvious meaning beyond being something which the contractor regards as not being sufficiently remunerative – which will always be a subjective decision of the contractor, based on its internal expectations as to what constitutes an acceptable rate of return on the capital which it has deployed

in the exploration activity) might generate enough income to allow the contractor to recover its costs but will thereafter leave relatively little petroleum for recovery by the grantor as profit petroleum: in such a case the contractor could be willing to proceed with a development of the discovery so that it can at least recoup its sunk costs, whereas the grantor might refuse to approve the declaration of commerciality because it wishes to access meaningful profit sharing.

On the other hand the grantor could be so desperate to see any petroleum production that it could require the contractor to propose a declaration of commerciality even in respect of a marginal discovery - which, because of its marginal economics, the contractor could be reluctant to develop because it has other exploration and development leads with better prospects which it would rather pursue (although the contractor should always be keen to develop a discovery at least to recover its exploration and appraisal costs, which would otherwise be irrecoverable).

A particular paradox to note is that if the contractor relinquishes a marginal discovery that discovery could cease to be marginal as it no longer has to bear the associated exploration and appraisal costs (since those costs were incurred by, and written off by, the relinquishing contractor). This could make the discovery no longer marginal in the hands of a successor contractor which picks it up under a re-awarded PSC.

The PSC could also provide that if a commercial discovery has not been made (or approved) by the end of the exploration period then the PSC will automatically terminate. This termination effect could also be achieved by the complete relinquishment of the contract area by the contractor (B5.2).

B7.2 Development

‘Development’ is a shorthand term for the activities which are undertaken in assembling a field development plan (FDP) for a commercial discovery after the appraisal activity has been concluded in respect of that discovery and the discovery has been approved as commercial. These activities relate to having the field development plan approved by the grantor and the contractor then implementing that field development plan in order that development can be undertaken, petroleum production operations can eventually commence and the contractor can finally begin to monetize the PSC.

In some PSCs, the term ‘exploitation period’ is applied to whatever happens after the exploration period, intended to encompass all the activities of appraisal (unless appraisal is included in the exploration period), development and production.

The PSC will usually go into some detail about the required content of the field development plan, which will include an assessment of the discovered petroleum deposit’s geological and geophysical characteristics, the estimated petroleum in place (which could also be indicated by the provision of a third party resource estimation report), petroleum production project development options and costs

and the provision of a baseline environmental impact study (B12.3) and/or a social impact assessment (B22.4).

The contractor could be required to submit a field development plan for approval by the grantor within a defined period of time after a discovery has been approved as commercial. Longer periods of time might be required for technologically complex field development plans, or for gas commercialization (B15). Even after the submission of a field development plan for approval there could be some iteration between the grantor and the contractor (relating, for example, to the grantor becoming satisfied that the field development plan makes technical and economic sense and complies with any necessary environmental standards). Revisions to the contractor's proposed field development plan which are required by the grantor are always possible, which will have an impact on the timing of a development project.

The PSC could identify a particular development period, as a defined period of time in which the contractor will undertake the development activity under the PSC, but the development period could also be part of the production period (see below).

The PSC might also prescribe the creation of a specific geographical area around the nucleus of a commercial discovery. Such a 'development area' (sometimes called an 'exclusive exploitation area') would represent the delineation of a part of the contract area in which the contractor would be deemed to have performed certain of its exploration period obligations, whilst leaving the rest of the contract area as being open to the performance by the contractor of the remainder of its exploration period obligations.

B7.3 Production

'Production' is a shorthand term for the production of petroleum in commercial quantities from a developed discovery. The production period will be a defined period of time in which the contractor will undertake the production of petroleum from the contract area. In most PSCs the production period could be set at anything between 10 and 40 years (subject also to possible renewal in the contractor's favor at its eventual expiry, particularly in the case of shorter defined production periods). From the contractor's perspective a lengthy production period will be necessary to enable the contractor to secure an adequate return on its often significant level of capital investment.

It is not axiomatic that the production period under the PSC will start only when the production of petroleum in commercial quantities commences. The production period typically starts earlier in time – which could be as far back as when the contractor's declaration of a commercial discovery is approved by the grantor or to when a field development plan is approved by the grantor (see above) – in either case these approvals will be forthcoming some time prior to the actual start of the production

of petroleum. It is from such an earlier point in time that the clock will start to run on the contractor's production period, and for this reason the contractor will want the production period to be as long as possible because it also has to encompass certain of the activities of the development period.

A confusion relating to when the production period starts could arise where the contractor agrees to start producing petroleum from a discovery as a test programme (sometimes called an 'early oil programme'), in advance of making a declaration of a commercial discovery.⁵⁷ An early oil programme can be used to test the prospectivity of a discovery and can also generate early revenue for the parties. The contractor's commitment to undertake an early oil programme should not trigger the start of the production period.

The commencement of the production period under the PSC will not necessarily bring the exploration period to an end under the PSC. The grantor and/or the contractor could still wish to continue exploration in the remainder of the contract area, notwithstanding the making of an early discovery which is capable of moving into production.

The contractor may want a right to extend the production period at the end of the scheduled production period. Particularly in the case of what was originally a relatively lengthy production period, such an extension is unlikely to be awarded automatically to the contractor by the grantor, because the grantor might at that time prefer to see the PSC come to an end and the contract area be re-awarded through a fresh PSC. Extension of the production period will therefore likely be a matter for negotiation between the grantor and the contractor towards the end of the scheduled production period, and at the point of extension certain of the fiscal and other terms of the PSC might also be the subject of renegotiation between the parties, to apply during the extension period. An extension of the production period could also be a matter which triggers a liability of the contractor to pay a further signature bonus (B10.1) to the grantor.

The PSC could have something to say about the rate of production of petroleum from the discovery which the contractor maintains over time. The PSC could simply oblige the contractor to maximize the production of petroleum from the discovery but such an obligation is usually modified to require the contractor's compliance with good and prudent oil and gas field practice (B3.1) however, rather than that it is to be construed as an absolute and unqualified obligation. This restriction would be applied to ensure that the petroleum deposit which underlies the discovery is preserved and exploited for as long as possible. Sometimes the phrase 'maximum efficient rate' is used to describe the top limit of the rate of petroleum production which the contractor should aspire to, where the phrase could be defined to require

⁵⁷ See the Uganda PSC.

the contractor not to undertake activities which might result in an excessive loss of pressure or in a decline in production, or which might result in irreversible damage to the underlying petroleum deposit.

The PSC might also specify certain commercial circumstances when the contractor is required by the grantor to reduce the rate of petroleum production from the petroleum project. This could relate, for example, to an absolute or a partial curtailment of production during periods of low petroleum prices or where the state has made a commitment to reduce petroleum production rates (where the state is an OPEC member). The contractor, when faced with this prospect under the PSC, could require a corresponding extension to the production period under the PSC in order to later recover its position. The contractor could also require that the imposition of an absolute or partial curtailment of production is made rateably across all PSCs and impacts all contractors.

Whether the contractor has a right to require a production curtailment during a low petroleum price environment will be a matter for negotiation.

B7.4 Decommissioning

The PSC could require the contractor to prepare a detailed decommissioning plan and an associated budget in respect of the wells and production facilities in the contract area which are used for the production activities. Older PSCs tend not contain decommissioning provisions however.

The decommissioning plan and budget could be submitted by the contractor to the grantor at the same time as a field development plan is submitted to the grantor, or such a submission could come later in the lifecycle of the project – for example, when a defined percentage (say 50 per cent)⁵⁸ of the estimated petroleum initially in place in the discovery has been produced from the petroleum project, and certainly well ahead of the intended date of the permanent cessation of production of petroleum from the discovery.

In order to meet the anticipated costs of decommissioning the contractor could be obliged to provide long term security for those costs, or the contractor could be required to contribute monies periodically into a segregated decommissioning sinking fund, which will (hopefully) mature to be sufficient to meet the cost obligations of the decommissioning plan at the time of the intended decommissioning activities. These payments could be required to be made from the time when the decommissioning plan and budget is approved by the grantor, from a certain time after the date of the first production of petroleum from the production project, or from a point when the production of petroleum has reached a defined percentage level of the initial

58 See the Afghanistan PSC.

assumption of petroleum in place in the project. The contractor's contributions to the decommissioning fund will be recoverable costs (B9.1).

Once the decommissioning plan and budget has been approved by the grantor it could be a requirement of the management committee (B8.2) to consider periodically whether the plan and budget remain appropriate for the ongoing production activities, taking into account any operational changes or technological evolutions which could have occurred, and the management committee could also recommend any necessary revisions to the plan and budget.

The actual decommissioning activities could be undertaken at the appropriate time under the stewardship of the contractor if the contractor remains party to the PSC, or under the stewardship of the grantor if the PSC has come to an end and the contractor's involvement has ceased.

If, at the intended time of decommissioning, the grantor has a preference not to decommission certain wells and/or production facilities (for example, because the grantor wishes to continue petroleum production from the producing part of the contract area⁵⁹ or to undertake a field enhancement programme, in either case for its own account or through the issue of a permit to do so to a third party) the grantor could release the contractor from its decommissioning obligations, with the accumulated decommissioning funds to be held over for when the intended decommissioning does eventually take place.

Care will also need to be taken where certain infrastructure which is to be decommissioned in the abstract under the PSC is also being used to support petroleum operations in respect of other PSCs. One element of decommissioning could trigger a domino effect in respect of other PSCs, which the grantor might be reluctant to see happen.

⁵⁹ See the Timor Leste PSC.

B8 Governance

The PSC will contain various governance provisions, relating to how the PSC is administered by the contractor over its lifetime and to how the grantor is involved in that administration. A paradox which appears in some PSCs is the requirement that the contractor has sole responsibility for the performance of the petroleum operations but also with provision that the grantor is responsible for the management of those operations. Distinguishing the point between the performance of the petroleum operations and their management could be difficult.

B8.1 The operator

The contractor will perform the petroleum operations as required by the PSC. As part of a public bid round analysis (A3.1) the grantor would (or should) have assured itself that the contractor has the necessary technical competence. This could form the basis of a warranty made by the contractor in the PSC (B2.5).

Where the contractor consists of a consortium of persons (B1.2) the PSC could appoint one of the contractor parties to act as a designated operator for the purposes of the PSC. This role is distinct from the role of the operator under the JOA (B23.1) but it is customary that the same entity will be the operator under both the PSC and the JOA.

The operator under the PSC will be primarily responsible for liaising between the contractor and the grantor, for incurring expenses in connection with the petroleum operations and for executing contracts and commitments.

The operator could be agreed between the contractor parties (subject to the grantor's approval) or the operator could be selected directly by the grantor. The selection and appointment of a replacement operator will also require the grantor's approval. The PSC might also contain certain grounds for the removal of the operator's status as such by the grantor, usually relating a defined operator default, although this prospect is commonly confused with the default of the contractor party which has been appointed as the operator which leads to the removal of that contractor party from the PSC (B17.2).

The operator will act as the de facto agent of the contractor parties, and acts and omissions of the operator will be deemed to be those of the contractor parties so that they cannot later be disclaimed by a contractor party. Because of the power of the operator to bind the contractor parties the role of the operator under the PSC is something which will be closely controlled under the terms of the JOA.

The operator could require provision in the accounting procedure which is appended to the PSC (B25) that its operational expenses and also a general and administrative (G&A) overhead charge (in the same manner as is customarily charged by the operator under a JOA) are reserved as cost recoverable items (B9.1). In some PSCs the general and administrative overhead charge could be expressed in the main body of the PSC.

In certain other PSCs the operator's role could be displaced by a form of state participation when a development project is underway (B11.4).

B8.2 The management committee

The PSC could make provision for the governance of the ongoing relationship between the grantor and the contractor and the management of the PSC through the constitution of a consultative committee (variously called the 'management committee', the 'joint management committee' or the 'advisory committee') to consider various matters in relation to the PSC.⁶⁰ This management committee could be made up of a defined number of representatives from both parties (and possibly also a representative of the state other than the grantor).

Where this formulation is adopted in a PSC (which it commonly is) the PSC will provide for how the management committee is constituted, where and how often it meets (which could include provision for periodic meetings by telephone rather than in person), the scope of its powers and how it makes, records and implements its decisions. The PSC might contain a deadlock provision, intended to overcome the inability of the grantor and the contractor to agree upon a certain issue at the management committee, although this is not a frequently encountered provision in practice – typically the grantor reserves a casting vote for itself, and the parties will have to do their best to arrive at some sort of solution. If agreement cannot be reached then a formal dispute under the PSC could be raised (B20.1).

The management committee will consider various matters in relation to the PSC (such as the formulation of any necessary policies and procedures, the review and approval of work programmes and budgets and later amendments thereto (B12.1), decommissioning plans (B7.4), insurance proposals submitted by the contractor (B24.7), and procurement and contract management issues (B12.5)).

It is not necessarily the case that decisions of the management committee will formally bind the grantor, despite the presence of the grantor's representatives on the management committee - and this will be so even if the grantor has voting control in respect of the decisions of the management committee. There may still be a need to forward matters requiring the grantor's approval under the PSC to the grantor outside of the management committee, and to this extent, it is not unreasonable to question the value of the management committee in respect of the business of the PSC.

If the persons appointed to the management committee as the contractor's representatives are drawn from the ranks of the JOA's operator and the non-operators then it will be necessary to reconcile this with the usual provision in the JOA that the JOA operator has the exclusive right to represent the interests of the JOA parties before the state.

⁶⁰ See the India, Tanzania and Uganda PSCs.

B9 Cost recovery and profit shares

‘Fiscal terms’ is a shorthand term which is sometimes used to describe the package of economic terms which are offered by the grantor to the contractor within the PSC. The principal elements to note under the PSC in relation to the structuring of the fiscal terms, and in relation to the realization of the state take, are the mechanisms for cost recovery and profit shares.

The PSC could also suggest an alternative fiscal regime which could apply in the contractor’s favor to encourage the development of a marginal discovery (B7.1) or for enhanced oil recovery operations (B3.1).

B9.1 Cost recovery

‘Cost recovery’ reflects a process whereby the contractor is enabled to recover the accrued costs which it has incurred in connection with the performance of the petroleum operations from the revenues which eventually result from the sale of produced petroleum, regardless of whether the underlying petroleum project is profitable. Although the recovered costs relate to petroleum operations, generally the PSC could also provide for separate cost recovery regimes for crude oil and (non-associated) natural gas development projects.

Cost recovery is essentially the reimbursement to the contractor of incurred petroleum operations expenditures, and should not be seen as some form of taxable income.

Cost recovery gives comfort to the contractor that it will be able to recover its investment once petroleum production revenues start to flow and is essentially the quid pro quo for the contractor taking exploration risk (B6.1) under the PSC. From the grantor’s perspective the facilitation of cost recovery encourages the contractor to invest properly in the performance of the petroleum operations, so maximizing the chances of success in finding and developing a petroleum deposit, and it is a catalyst for investment by the contractor, but the contractor’s view of cost recovery could be less sanguine however, as it could be conditioned by the application of certain provisions in the PSC which will condition the rights of cost recovery (see below).

In some circumstances the contractor could have incurred certain costs which are associated with the petroleum operations before the effectiveness of the PSC (such as where a reconnaissance permit was previously awarded – A2.2) and the terms of the PSC could recognize such costs and could declare them to be recoverable costs.

The cost recovery mechanism in the PSC is typically characterized by a number of features:

Irrecoverable costs: costs which have been incurred by the contractor in the performance of the petroleum operations will accrue in a costs pool but it is not the case that all of those costs will automatically be recoverable by the contractor. The PSC’s accounting procedure (B25) will (or should) describe carefully the categories of costs which are recoverable and also those costs which are ineligible for recovery

by the contractor. The grantor will usually oversee the conduct of a periodic audit process which will identify recoverable and irrecoverable costs. Where a contractor's costs are not approved for cost recovery they will be borne by the contractor, which will have the effect of diminishing the overall economic returns from the PSC from the contractor's perspective. The distinction between recoverable and irrecoverable costs is frequently an issue for contention in the negotiation of the PSC, and the poor definition of those costs classifications in the PSC could generate later disputes between the grantor and the contractor.

Common examples of irrecoverable costs include the contractor's liability to pay the various bonuses, rental payments and royalties (B10) under the PSC, costs incurred by the contractor which are not regulated by a work programme and budget (B12.1), costs incurred by the contractor prior to the effectiveness of the PSC (including data package acquisition costs – B14.2), costs incurred by the contractor which are associated with the provision of collateral support (B22.1) and with the contractor parties' JOA arrangements (B23.1), fines or penalties incurred by the contractor which relate to the contractor's mis-performance or non-performance of the PSC (B17.2), fees payable by the contractor to the grantor in consideration of any services provided by the grantor to the contractor under the PSC, liabilities of the contractor to the grantor for a breach of the terms of the PSC (B17.2), undocumented costs, and the costs associated with downstream activities and the marketing of petroleum for sale (although an exception might be made for natural gas – B15.2). The PSC might also declare as irrecoverable any costs which were (in the grantor's opinion) excessive in the light of good and prudent oil and gas field practice (B3.1).⁶¹ This could be a contentious issue.

Enhanced cost recovery: the PSC might provide⁶² that certain costs are notionally increased under the terms of the PSC in the contractor's favor (so that, for example, the contractor will cost recover \$125 for each \$100 of those costs). This 'enhanced cost recovery' is intended to give the contractor an added incentive to undertake certain activities and to incur the associated costs where those activities will also benefit the grantor. These enhanced costs might also be expressed to not be subject to a cap on their recoverability (see below). The principle of enhanced cost recovery could apply, for example, to the costs of seismic surveys or exploration drilling, where the resultant data will accrue to the grantor, or to a programme of exploration activity in particularly difficult deep-water or frontier areas in the state.

From the contractor's perspective care should be taken to ensure that the incremental element of enhanced cost recovery, which gives the contractor a monetary amount in excess of its actual incurred costs, is not then taxed in the hands of the contractor as income. The incremental element of enhanced cost recovery would also count

61 See the Tanzania PSC.

62 See the Indonesia PSC.

towards the contractor's economic returns from the PSC, which could be taken into account in any rate of return calculation which the PSC employs (see below).

Ring-fencing: PSC costs are ordinarily subject to a concept called 'ring-fencing'. This means that the costs which have been incurred by the contractor under the PSC in the performance of the petroleum operations, which might otherwise be irrecoverable by the contractor because of the lack of a commercial discovery and a development and production project under the PSC, cannot be recovered by the contractor against the petroleum revenues which are generated under another PSC where a development project has taken place. In the absence of such ring-fencing a measure of cross-subsidization between PSCs would be possible and the economic risk profile of the PSC would be significantly enhanced for the contractor - but at the expense of the grantor, which would be subsidizing unsuccessful exploration activities by allowing their costs to be offset against the contractor's other revenues. This is more akin to the taxation approach which applies in a licensing regime (A2.2).

Cost recovery limits: the more generous the cost recovery regime is from the contractor's perspective, the longer it will take for the grantor to realize revenue from the PSC. Consequently, the PSC will typically not allow the contractor to offset the entirety of its recoverable costs from the revenues which result from the sale of produced petroleum in respect of a defined accounting period, because of the risk that the grantor would see no share of those revenues until the contractor's costs were fully recovered. Indeed, in the extreme case the contractor's recovery of costs could be so extensive that the revenues eventually available to the grantor through the profit share (see below) are non-existent (apart from the recovery of the various bonuses, rental payments and royalties), if the PSC remains in the cost recovery phase for the entirety of its duration.

To overcome this risk to the grantor one option is that the PSC might apply what is called a 'first tranche petroleum' provision, wherein the revenues resulting from the sales of petroleum are applied towards reimbursement of the contractor's accrued costs but with the exception that a defined percentage of the revenues is firstly applied between the grantor and the contractor according to the agreed profit shares (see below) in order to give the grantor early access to a part of the revenues resulting from the sales of petroleum. This construction first appeared in Indonesian PSCs in the late 1980s.⁶³

The more typical protection for the grantor in this situation however is to engineer the cost recovery mechanism in the PSC such that the PSC imposes a general percentage cap on the amount of costs which are recoverable by the contractor in respect of a defined accounting period (often called a 'cost stop'), with provision for any unrecovered costs to be carried forward for recovery by the contractor in successive accounting periods. Once the cost stop has been reached in respect of the defined accounting period then the remaining revenues are distributed between the parties

63 See the Indonesia PSC.

according to the agreed profit shares for the remainder of that accounting period. The cost stop mechanism does not deny the recovery of costs by the contractor, but it does limit how much of those costs can be recovered by the contractor within a particular period. Alternatively, some costs could be capped and other costs not so capped in this manner if the PSC applies a hierarchy order of recoverable costs (see below).

The cost stop figure could be a flat percentage of all recoverable costs in respect of specified periods throughout the duration of the PSC or it could be applied on a sliding scale, whereby a higher percentage for recoverable costs could apply in the contractor's favor in the early period of petroleum production to accelerate cost recovery, before then dropping down to a percentage figure which is something nearer to equilibrium with the profit shares when a specified percentage of the overall costs have been recovered by the contractor.

The PSC might also provide that if any otherwise recoverable costs remain unrecovered by the contractor by the end of the PSC's term those costs will be lost to the contractor and the grantor will have no obligation to reimburse them.

Individual costs: each contractor party will incur its share of the overall costs associated with the performance of the petroleum operations, but the actual costs incidence could be different between certain of the contractor parties. Some contractor parties will, for example, pay for certain insurances to be put in place (B24.7) whilst others will not, and some contractor parties will have borrowed money to meet their share of the petroleum operations costs and so will have associated financing costs and interest charges which could be cost recoverable under the PSC, whilst others will not. Cost recovery should be accounted for under the PSC so that each contractor party has its own separate costs pool which is generated according to its actual costs incurrences, rather than that the contractor parties' costs are aggregated and made payable to the contractor parties according to their percentage participating interests (B1.2).

Where a contractor party has borrowed money to meet its share of the petroleum operations costs, and financing costs and interest charges are expressed to be cost recoverable under the PSC, it is possible that an affiliate of a contractor party could lend money to that contractor party with high financing costs and/or at a high rate of interest. To protect against the risk of abuse the PSC could apply a deemed rate of interest to apply to such an affiliated lender, or the consent of the grantor could be required to an affiliate lending arrangement as a condition of the financing costs and interest charges being cost recoverable by the contractor party.⁶⁴

Cost recovery hierarchy: when recoverable costs are due to be recovered the costs will be relatively generalized, but the PSC might seek to apply some form of hierarchy to the recovery of those costs. This could be applied so that (for example)

64 See the Qatar PSC's recognition that disallowing the contractor's ability to cost recover interest charges could necessitate changes to certain other of the fiscal terms to compensate the contractor.

costs will be recovered by the contractor in the order of annual production operating costs first, then accrued exploration and appraisal operating costs, and then accrued development project capital costs. In the latter two cases only a defined percentage of the costs could be recoverable, which would apply if the PSC does not apply a general cap on cost recoverability (see above). This hierarchy could be expressed in various ways, according to the grantor's preference.⁶⁵

Decommissioning costs (B7.4) could be an anomaly in this construction, since they could be incurred by the contractor as part of a sinking fund (and cost recovered as incurred) well ahead of the time when the decommissioning activity is actually performed.

The PSC could oblige the contractor to prepare a monthly or quarterly statement of expenditures and recoverable costs (reflecting the various conditions set out above) for submission to the grantor for review and approval.⁶⁶

B9.2 Profit shares

'Profit shares' in the PSC represent the division of produced petroleum between the grantor and the contractor. Each party's produced petroleum entitlements will be sold to realize a cash amount (which has a relevance to how cost recovery is applied – see below).

The PSC could give the grantor a right to take its profit share in cash or in kind. This could be the subject of an election by the grantor under the PSC (and could be the subject of periodic revisions to that election by the grantor over the lifetime of the PSC). Where the grantor elects to take in cash, the grantor could appoint the contractor to act as its agent to sell its entitlements and to account to the grantor for the resultant proceeds of sale. If the grantor wishes to take its entitlements in kind then the grantor would market and sell its entitlements directly, and this arrangement would need to be reflected in a lifting agreement (B12.2). The grantor could also require the contractor to purchase the grantor's in kind entitlements at a market price.⁶⁷

The profit shares division between the grantor and the contractor takes the form of a percentage ratio. Although the profit shares relate to petroleum operations generally the PSC could provide for different ratios to apply to for crude oil development projects and to (non-associated) natural gas development projects.

Each party has an interest in maximizing the percentage which it takes under the PSC, not surprisingly. The profit shares could be set as fixed percentages for the lifetime of the PSC (say 60 per cent to the grantor and 40 per cent to the contractor). Alternatively to make the fiscal terms 'progressive' (meaning, in essence, that the grantor enjoys progressively greater levels of return as economic circumstances evolve - progression

65 See the Bangladesh, Kenya and Tanzania PSCs.

66 See the Trinidad and Tobago PSC.

67 See the Uganda PSC.

reduces the risk of the grantor becoming unhappy with the economic bargain created by the PSC over time and seeking to reopen it) the profit shares could be represented by variable percentages. These percentages could describe a sliding scale of profit shares (on incremental (looking-forward) rather than retrospective levels) which are designed to increase the grantor's participation levels (through a corresponding reduction in the contractor's profit shares) as the underlying project attains greater levels of petroleum production. This example is indicated in Figure 14:

Figure 14

Daily production (BOE/D)	Grantor profit share	Contractor profit share
0 -12,499	60%	40%
12,500 – 24,999	65%	35%
25,000 – 49,999	70%	30%
50,000 – 99,999	75%	25%
>100,000	80%	20%

The sliding scale which is shown above accounts for increased levels of petroleum production does not account for the true economic value of that production. Production levels could be high but petroleum prices could be low, which would offset the real gain to the grantor. Thus, this structure is progressive as far as production is concerned, but is neutral in respect of real profitability. A progressive profit share scale could also be engineered to apply by reference to petroleum price movements in isolation, rather than to petroleum production levels. This is essentially a windfall tax (B10.5).

Another way of creating a sliding scale of profit shares in order to embrace progressiveness is the use of what is known as an 'R factor' (or 'ratio factor'), sometimes also defined as an 'investment multiple'. The R factor is arrived at by dividing the revenues from a petroleum production project by the costs of that project (so that $R = \text{Revenues/Costs}$) and then ascribing a particular profit share which is payable to the grantor and to the contractor in respect of each band of the resultant R factor calculation. This example is indicated in Figure 15:

Figure 15

R- factor	Grantor profit share	Contractor profit share
0 – 1.0	60%	40%
> 1.0 – 1.5	65%	35%
> 1.5 – 2.0	70%	30%
> 2.0 – 2.5	75%	25%
> 2.5	80%	20%

At the start of a petroleum production project costs inevitably outweigh revenues and so the R factor will be low (indeed, at the very outset of the project, costs are high and revenues are non-existent and so the R factor will be zero). As the R factor increases (that is, as revenues increase (and the economic gain to the contractor improves) and increasingly outweigh costs in the later stages of the project) then the profit share in favor of the grantor increases.

Finally, the PSC could apply the sliding scale which is outlined above in respect of the R factor to the contractor's rate of return from the project (where higher rate of return percentages over time will lead to increasing grantor profit shares and reducing contractor profit shares). This is sometimes described as a 'rate of return' (ROR) based system. Understanding what the contractor's internal rate of return is, particularly where the contractor is a consortium of contractor parties (B1.2), could be a challenge and so the PSC will typically set out its own deemed contractor rate of return methodology for the purposes of this mechanism.

B9.3 Cost recovery and profit shares together

The combined cost recovery and profit share mechanism could be applied on a specific basis by reference to individual development areas under the PSC (B7.2). The PSC should be careful however to make clear that this does not apply the ring-fencing principle (see above) to individual development areas within the overall contract area, unless that is the intention.

The PSC usually provides for quarterly calculations in arrears of the cost recovery and profit share elements, based on metered levels of petroleum production from the preceding quarter (net of any royalty liftings which are attributable to the grantor – B10.4) and applying a valuation methodology which exists in the PSC to manage the interface between produced petroleum, petroleum sales revenues and the interests of the grantor and the contractor.

There is an obvious disparity between the contractor's accrued petroleum costs (which are incurred and paid in cash) and the produced petroleum which is applied between the parties in their respective profit shares (which is a physical measure) to offset those petroleum costs. To reconcile these different measures, by normalizing them to a consistent cash basis, the PSC will contain a valuation mechanism, whereby crude oil is required to be sold on an arm's length basis by the contractor and according to international market prices and the actual sales proceeds are remitted through the petroleum accounting mechanisms of the PSC to create a cash value which will then be applied for the cost recovery quantification. If crude oil is sold other than on an arm's length basis, the PSC could recite a mechanism by which a proxy market price is derived.

Similar provisions will apply in the sale of natural gas (B15.2), except that gas which is sold under a bilateral contract does not have an international market price against

which the fairness of the particular contract price as part of an arm’s length transaction can be assessed. For this reason it is customary to find provision in the PSC that the terms of a proposed gas sales contract, and in particular the gas pricing provisions, must be approved by the grantor before the gas sales price from the contract can be applied to the cost recovery and profit shares methodology.

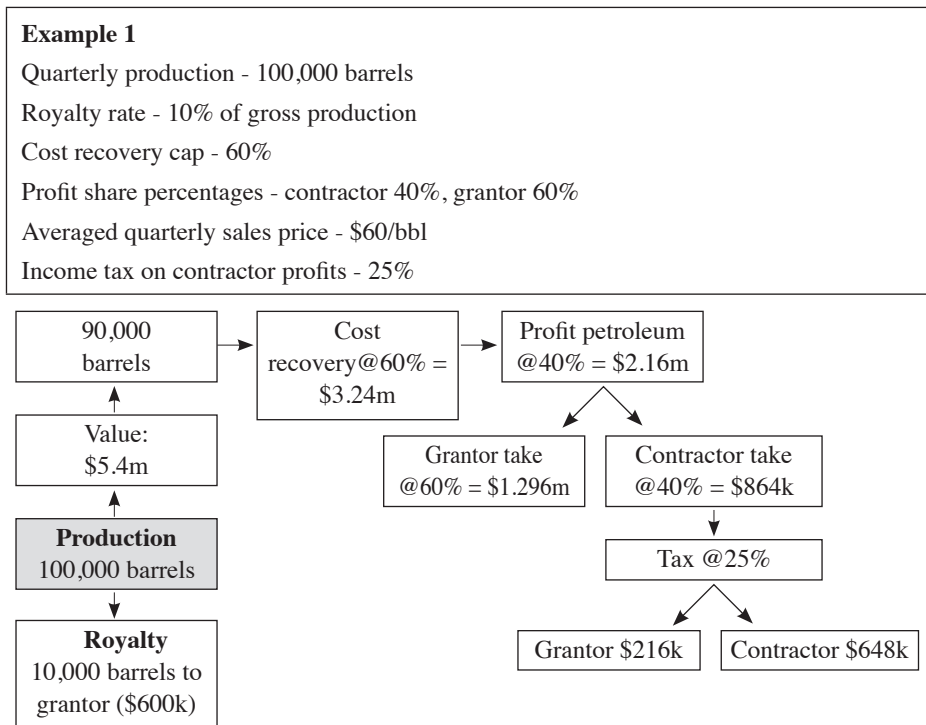
B9.4 Worked examples

The PSC could include worked examples of how the cost recovery and/or profit shares mechanisms are intended to work under the terms of the PSC.⁶⁸

The examples which are set out at the end of this section indicate how cost recovery and profit shares work together (applying a simplified model which does not apply the impact of rental payments which are payable by the contractor (B10.3) and also not accounting for the possibility of state participation (B11), both of which could improve the grantor’s position).

The first example indicated in Figure 16 illustrates the PSC’s cashflows when there is cost recovery to be made, and the second example indicated in Figure 16 illustrates the PSC’s cashflows after cost recovery has concluded:

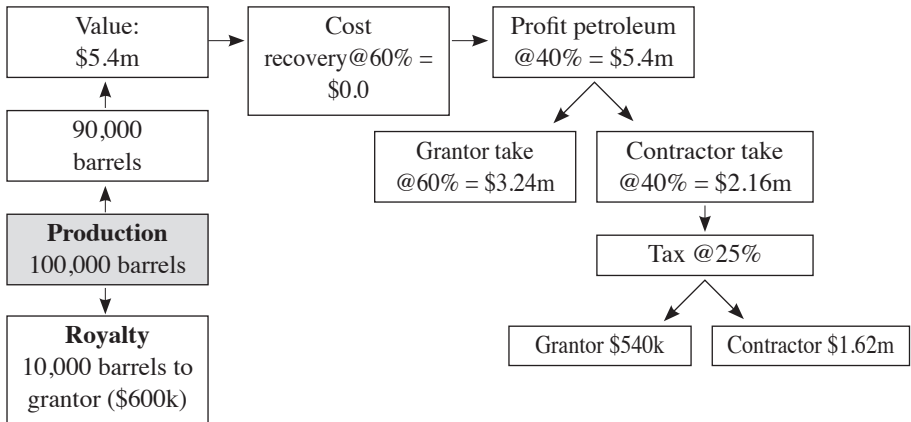
Figure 16



68 See the Ivory Coast PSC.

Example 2

Quarterly production - 100,000 barrels
 Royalty rate - 10% of gross production
 Cost recovery cap - 60%
 Profit share percentages - contractor 40%, grantor 60%
 Averaged quarterly sales price - \$60/bbl
 Income tax on contractor profits - 25%



Example 1	
Grantor take:	\$600k
	\$1.296m
	\$216k
	\$2.112m
Contractor take:	\$3.24m
	\$648k
	\$3.888m

Example 2	
Grantor take:	\$600k
	\$3.24m
	\$540k
	\$4.38m
Contractor take:	\$1.62m
	\$1.62m

B10 Other fiscal elements

There are several other ways in which the grantor could earn revenues from the PSC, all of which will be taken into account as part of a wider analysis of how the overall level of state take from the PSC is quantified.

B10.1 Signature bonus

This is a payment made by the contractor to the grantor at the time of signature of the PSC. The extent of the signature bonus tends to be modest for unexplored acreage where there is little geological data and a higher level of exploration risk; the bonus tends to increase in size where the prospectivity of the acreage improves through the availability of existing seismic data and the experience of previous drilling activity.

The signature bonus is payable by the contractor regardless of whether or not a commercial discovery of petroleum ensues (B7.1), is not repayable if the contractor subsequently surrenders the PSC (B2.4) and is typically not cost recoverable (B9.1). For these reasons the signature bonus tends to be a sensitive issue from the contractor's perspective, compared to most of the other fiscal elements (and especially those elements which are triggered by the contractor's earnings from the PSC, where the contractor will at least feel that it is finally deriving some benefit from the PSC).

A further bonus might also be payable by the contractor if an extension to the production period is agreed (B2.3), and sometimes also upon the issue of a particular permit (such as an exploitation permit – B7.2) to the contractor or upon the final approval of a field development plan (B7.2).

B10.2 Production bonus

This is a payment made by the contractor to the grantor on the occurrence of a particular event – this could be when a commercial discovery is declared (B7.1), when petroleum production begins, when rates of petroleum production over a particular period reach a defined threshold or when a defined cumulative quantity of petroleum production is achieved. The production bonus is usually paid on a barrel of oil equivalent basis, regardless of how profitable the production of petroleum is for the contractor, and is typically not cost recoverable.

Compared to a signature bonus, a production bonus tends to be a less emotive issue for the contractor, which at least could be enjoying cost recovery and profit shares from the sales of produced petroleum at the time the production bonus becomes payable.

Some thought will need to be given by the grantor to how the level of a production bonus is set. Significant bonus payments which are payable on higher petroleum production levels are obviously attractive to a grantor but there is no guarantee that the higher production levels will be reached in practice and so this could be an illusory attraction.

B10.3 Rental payments

A rental payment is a fixed payment which is made annually by the contractor to the grantor. The rental payment could be a fixed monetary amount which is payable periodically for the lifetime of the PSC or the rental payment could be fixed as a monetary amount which is payable in respect of each square kilometer within the surface area coordinates of the contract area (B4.2). The PSC should make clear whether the latter construction can be readily applied to a contract area which starts at a defined stratigraphic layer and extends downwards to a further defined stratigraphic layer, without an actual surface area but still within a particular set of surface area coordinates.

The rental payment amount could also increase during successive phases of the PSC, as the contractor moves from exploration and appraisal to the point of earning revenues from acreage when petroleum production gets underway.

The PSC usually provides that any rental payment amount which has already been paid by the contractor in respect of a part of the contract area which is relinquished (B5) will not be reimbursed by the grantor, and also that the future rental payment which is payable by the contractor will be adjusted to account for the effects of a relinquishment.

A rental payment is similar to a signature bonus in that it is payable by the contractor regardless of whether a commercial discovery of petroleum ensues, but the amounts involved in the payment of a rental payment tend to be much smaller than the amounts required as a signature bonus and so the issue tends to be less painful to the contractor.

B10.4 Royalty

A royalty is an ad valorem payment made by the contractor to the grantor, calculated by reference to the volume of petroleum which is produced from the contract area over a particular period of time. Not all PSCs oblige the contractor to pay a royalty to the grantor, ahead of the division of produced petroleum sales revenues between cost recovery and profit shares, but some do. A royalty could be payable in cash or in kind to the grantor, where (respectively) it represents a guarantee of either immediate cashflow to the grantor or the provision to the grantor of cost-free petroleum for the grantor to do with as it wishes (and in either case the royalty also represents a payment to be made by the contractor which is regardless of the realization of profits from the PSC).

Because a classic royalty assumes that it is payable by a petroleum title-holder, and under the PSC the contractor has only an economic interest in the proceeds of sale of the produced petroleum (B14.3), a royalty is a relative anomaly in the context of the PSC.

Royalty rates could be set as a fixed percentage of produced petroleum or they

could be set by reference to a sliding scale (with higher royalty rates applicable to less difficult forms of petroleum production and lower royalty rates to apply where petroleum is produced in more challenging circumstances).

Royalties payable in cash by the contractor are ostensibly payable from the value of the gross produced petroleum, rather than payable after the deduction of the associated costs of production, but there is often scope for dispute between the parties on the real value of the royalty. Royalties payable in cash are usually based on a deemed wellhead sales price for produced petroleum, but because petroleum could require processing and transportation (both of which represent negative cost consequences for the contractor) to another point for an actual sale to take place, the effective petroleum sales price will be lower. These extra costs could be deducted (or netted back – to give a ‘netback price’) from the wellhead price to determine the true royalty. How accurately these costs are defined and calculated under the PSC could lead to disputes between the parties.

The PSC could provide that the quantity of petroleum represented by the royalty amount is deemed to be sold back by the grantor to the contractor at the wellhead, at a market price which is determined under the PSC.⁶⁹

B10.5 Taxation and duties

The PSC could expose the contractor to a liability to pay local income taxes to the state on the value of the profit share of petroleum which it receives. The contractor could also be subject to various forms of local indirect taxation. Some PSCs will exempt the contractor from exposure to some or all of these taxes.

The level of taxes which are imposed upon the contractor under the PSC will largely be determined by the PSC’s other fiscal terms; significant state take for the grantor which is secured by the fiscal terms could obviate the need for the grantor to additionally tax the contractor, and the obverse could be true where the fiscal terms generate a relatively low level of state take. And in any event, regardless of the level of taxation which is applied under the PSC each contractor party will also be mindful of the taxation liability which it has in its country of origin.

Where the PSC exposes the contractor to local taxation the PSC could also go into detail regarding the deductible costs which could be allowed against the contractor’s tax liability.⁷⁰

Where the contractor is taxed under the PSC, the PSC might offer some form of ‘tax holiday’ to the contractor, to apply for a number of early years during the production period (B7.3), as an incentive to the contractor. This could however give the contractor an incentive to accelerate the rate of petroleum production under the

⁶⁹ See the Afghanistan PSC.

⁷⁰ See the Liberia PSC.

PSC during the tax holiday period (subject to any rate of production limitations (B7.3)), which could be detrimental to the underlying petroleum deposit.

The PSC might provide that the contractor's tax liability is paid by the grantor out of the grantor's profit shares, effectively as an offset.⁷¹ This would preserve the objective notion of the contractor's tax liability, whilst at the same time relieving the contractor of the incidence of that liability. Alternatively the PSC might state that the grantor will assume responsibility for paying certain of the contractor's taxes⁷² or that the contractor will deliver petroleum to the grantor as an offset against the tax which would otherwise be payable by the contractor.⁷³ In any of these situations the contractor should ensure that the grantor's assumption of the contractor's tax liability does not constitute a benefit in kind for the contractor which would itself be taxable in the hands of the contractor, unless this is the intention.⁷⁴

The PSC could also expose the contractor to a liability to pay some form of additional profits tax, sometimes called a 'windfall tax', in an attempt to increase the level of state take when petroleum prices have increased over time and the contractor is enjoying a greater economic return from the PSC⁷⁵ (although some provisions of this nature also seek to apply to an unexpectedly large discovery which the contractor has made). This might particularly be the case where the PSC's fiscal terms are not written to be progressive from the grantor's perspective.

The liability of the contractor to pay capital gains tax on a transfer of its interests in the PSC is considered elsewhere (B21.5).

The PSC could exempt the contractor from customs and import duties which would otherwise be leviable on materials and equipment which are brought into the state for the petroleum operations.

The overall taxation and duties profile which the PSC creates in favor of the contractor will also play a key part in establishing the contractor's economic expectations in respect of a stabilization provision (B16.1).

B10.6 Other components

Elements such as a state participation right (B11), the domestic market obligation (B12.6) and the satisfaction of local content requirements (B13.3) will also, indirectly, represent part of the overall state take from the PSC. These elements are less obviously quantifiable in objective monetary terms but they represent real value to the grantor.

71 See the Cyprus and Trinidad and Tobago PSCs.

72 See the Qatar PSC.

73 See the Angola PSC.

74 See the Guyana PSC.

75 See the Kenya and Tanzania PSCs.

B11 State participation

The grantor is the visible embodiment of the state on one side of the PSC. The state, acting through a nominated representative such as the grantor (or possibly the national oil company or some other nominee of the state), could seek to participate on the other side of the PSC too, as a contractor party. This is the essence of state participation.

Where the grantor (as the state representative) becomes a contractor party, under the PSC the grantor would also be party to the underlying JOA, with a defined percentage participating interest therein. This is typically set at 10 per cent but the figure could vary.

B11.1 State participation

State participation takes place ostensibly in order for the state to secure a direct share of petroleum production, but state participation also has certain other advantages as far as the grantor is concerned – it enables the grantor to secure direct access to current operational data as a contractor party with a position in the PSC and the JOA (B23.2), it offers a form of on-the-job engagement for the grantor’s personnel, and it creates a saleable interest in the PSC and the JOA for the grantor. State participation can also be a politically popular device, showing the state’s population how the state is directly involved in developing the state’s patrimony (A1.2).

There are several options for the grantor to participate in the PSC, in any of the exploration, development or production phases. These options will be indicated in the terms of the PSC. The question for the contractor is whether the various ambitions of the grantor in respect of state participation could be addressed by means other than the inclusion of a full state participation right in the PSC.

In order to facilitate state participation in the PSC, the PSC could append a pro forma agreement (often called a ‘participation agreement’) which regulates the completion of the participation process between the contractor parties and the grantor.⁷⁶ The PSC could also require that a separate joint venture agreement is entered into between the grantor and the contractor to reflect the terms of the state participation.⁷⁷

B11.2 Initial state participation

The grantor could be a contractor party from the outset of the PSC, and could participate in the exploration period as a fully paying party. This exposes the grantor to the risks of wasted expenditure on unsuccessful exploration, which the grantor could ill-afford, however. Alternatively therefore the grantor could be a contractor party from the outset of the PSC and could participate in the exploration period but subject to being fully carried for its share of the exploration period costs by the other contractor parties. The carry arrangement would be converted into a paying interest for the grantor at the point when the production of petroleum from the contract area begins.

⁷⁶ See the Kenya PSC.

⁷⁷ See the Uganda PSC.

Such a carry arrangement could be ‘hard’ (that is, the amount of the carry which has accrued in favor of the grantor during the carry period is not repayable to the other contractor parties by the grantor when production eventually begins) or the carry arrangement could be ‘soft’ (that is, the amount of the carry is repayable to the other contractor parties by the grantor when production eventually begins). Where the carry is repayable the amount of the carry could be repayable at par by the grantor or (less commonly) with the application of a premium in favor of the contractor parties. Repayment of the carry by the grantor is typically made from the grantor’s petroleum entitlements (B9.2), rather than in cash.

Participation by the grantor as a contractor party from the outset of the PSC, whether as a fully paying party or as a carried party, would give the grantor direct access to exploration data under the terms of the JOA (to which it would also be a party), in addition to whatever data the state is already entitled to receive under the PSC.

An alternative formulation by which a state participation right in the PSC could be expressed is one whereby the grantor becomes a participant in the PSC from the outset but has the right to elect to withdraw from a particular development project (but still to remain as a contractor party in the PSC).⁷⁸ This is akin to the exercise of a non-consent right under a JOA.

B11.3 Subsequent state participation

The grantor could elect not to be a contractor party from the outset of the PSC, but could elect to ‘back in’ to the PSC as a paying party at a later stage in the lifetime of the PSC. This election could be made when a commercial discovery is approved for development (B7.1), so that the grantor pays its share of the development costs only as they then accrue going forward, or alternatively the grantor could ‘back in’ to the PSC prior to the start of the production period (B7.3) so that the grantor does not pay its share of the development costs as they accrue.

The ‘back in’ right, in either of the above situations, could be free to the grantor or it could be subject to payment by the grantor of a share of the historic exploration and/or development costs (as appropriate) which have been incurred by the contractor parties. Such a payment could be made by the grantor at par or (less commonly) with the application of a premium in favor of the contractor parties.

Even where the grantor does not participate in the exploration period (or in a later development project) the grantor could still require ongoing access to exploration and development data under the JOA and the PSC so that the grantor can make an informed decision about the possibility of ‘backing in’ later. This is especially so if the grantor has to make a payment as a condition of an election to ‘back in’ to the PSC.

Where the grantor becomes a contractor party under the PSC through the exercise of a later ‘back in’ right the grantor would also need to become party to the underlying

78 See the Tanzania PSC.

JOA, with a defined percentage participating interest (B23.1). That interest would be contributed by the existing JOA parties, pro rata to their respective existing interests.

B11.4 State participation options

The model for state participation which is suggested above is one whereby the grantor holds (say) a 10 per cent percentage participating interest as contractor party with a position under the PSC and the JOA, but this is not the only option to consider. State participation could be effected in a more dramatic manner. The PSC could be structured so that the responsibility for operatorship of the ongoing petroleum operations is handed to a state representative (which could be the grantor, or more likely could be the national oil company) at an appropriate time. This would typically take place after a commercial discovery has been developed and has moved into production, unless the national oil company and the contractor parties are of the view that the national oil company is competent to undertake the development phase of the petroleum operations.

As a further refinement of this, the national oil company and the contractor parties could elect to incorporate a company (in which they will all be shareholders) which will act as the operator.⁷⁹

B11.5 The contractor's preference

The contractor's natural inclination will be not to have a state participation right in the PSC because it adds another layer of complexity to the conduct of the petroleum operations, and because it represents a form of joint venture with the grantor as a state-owned entity whose objectives are not always obviously aligned with those of the contractor parties. This could make for a fractious joint venture. A state participation right could also create a disproportionate to equity working capital impact of a carry arrangement for the contractor (where the grantor participates in the PSC at the outset and requires to be carried by the other contractor parties for its share of the necessary exploration and development costs), and is unattractive because the amount of the carry which has accrued in favor of the grantor during the carry period might not be repayable by the grantor when petroleum production begins.

A further issue for the contractor to be aware of is where the state participation right is traded for value to a third party by the grantor prior to its exercise. The grantor could in the PSC reserve the right to transfer this interest to a third party, which might (or might not) be subject to certain transfer conditions.⁸⁰ Alternatively the state participation right in the PSC could be exercised by the grantor for the benefit of an (unnamed) nominee. In either of these instances, if the grantor effects such a transfer or exercises the state participation right through such a nominee the contractor parties are faced with the possibility of an unknown or unapproved third party becoming party to the PSC and the JOA as a fellow contractor party.

⁷⁹ See the Egypt PSC.

⁸⁰ See the Gabon PSC.

B12 Petroleum operations

A number of provisions in the PSC relate variously to the mechanics of how the petroleum operations are conducted by the contractor, and are assembled here for consideration together.

B12.1 Work programmes and budgets

The PSC will require the commitment of the contractor to prepare and thereafter to perform each year an annual work programme and budget (WP&B) in respect of each aspect of the anticipated petroleum operations. This requirement will apply to each of the activities of exploration and approval, development and production, and decommissioning.

The annual work programme and budget will be subject to the grantor's approval (which could be subject to prior discussion at the management committee if the PSC imports such a possibility – B8.2). The work programme element of the annual work programme and budget will have to be approved by the grantor within a sufficient time period to allow the necessary works envisaged by the PSC to take place in accordance with the timetable demanded by the PSC for the performance of petroleum operations. Some iteration could take place between the grantor and the contractor, with possible revisions and resubmissions by the contractor. The PSC might also provide for deemed approval by the grantor if the grantor's approval (or no objection by the grantor) has been forthcoming within a defined period of time after the annual work programme and budget was submitted to the grantor for approval.

Thereafter, the performance of the annual work programme and budget is less likely to be subject to ongoing approval, except where subsequent amendment of the annual work programme and budget (which could arise as a consequence of contractor slippage in the programme or as a reaction to the results of the performance of the exploration phase work obligations) is required by the contractor.

The PSC could also reserve a right for the operator to overspend against an approved work programme and budget with approval, up to a specified percentage of the approved amount.⁸¹

The PSC could provide that any activities which are carried out by the contractor must be within the ambit of an approved annual work programme and budget (unless the management committee or the grantor otherwise authorizes, or unless the contractor's activities are in response to an emergency). The budget element will form part of the determination of the contractor's recoverable costs (B9.1). A failure of the contractor to comply with this requirement could expose the contractor to a liability for breach of the terms of the PSC (B17.2), and could disqualify the associated costs from being cost recoverable (B9.1).

81 See the Bangladesh, Cyprus and Equatorial Guinea PSCs.

B12.2 Lifting

The PSC could require the parties to put in place a lifting agreement in respect of crude oil production.⁸² Such an agreement would identify the grantor's and the contractor's produced petroleum entitlements (B9.2) at a defined point (which could be at the wellhead or at a delivery point which is further defined in the PSC). A lifting agreement will typically be put in place in respect of a specific development area (B7.2), and a PSC with several development areas would have several corresponding lifting agreements.

Because the PSC will reserve the right of the grantor to take its profit share of the produced petroleum in cash or in kind (B9.2), where the latter formulation applies the lifting agreement will be needed to identify the grantor's share of the profit petroleum which it plans to lift in kind and to dispose of for its own account.

B12.3 Environmental provisions

The contractor will be required to undertake the petroleum operations in accordance with the host state's legislative requirements for environmental protection (and/or in accordance with certain regional or international environmental standards). This requirement of the contractor could be imported through the governing law of the PSC (B19.1) but will usually be made clear by the inclusion of a specific environmental provision in the PSC. The principal aspect of this requirement relates to ongoing environmental protection and the preparation of a pollution response plan.

As part of this commitment, and particularly in relation to onshore acreage, when a field development plan has been approved and a development project is underway (B7.2) the contractor could be required to conduct a baseline environmental impact study in respect of the target area. This study could later be used to assess the contractor's satisfaction of the site remediation elements within an approved decommissioning plan (B7.4). In some circumstances such a study could also be required ahead of the performance of exploration works (B6.2).

B12.4 Exclusive operations

The PSC could reserve a right for the grantor to undertake certain petroleum operations in its own name and for its own account in certain circumstances, a right generally known as an 'exclusive operation'.⁸³ This is akin to the sole risk provision in a JOA.

The grantor could seek to do this in parts of the contract area which have not been relinquished by the contractor (B5.2) and which are not the subject of ongoing

⁸² A widely used model form lifting agreement is available at www.aipn.org.

⁸³ See the Angola PSC.

exploration and/or development activities, or as a reaction to a proposed petroleum operation which was not approved by the management committee (B8.2).

A discovery which is made as the result of an exclusive operation would belong to the grantor, but the PSC might give the contractor an option to buy back into the exclusive operation, whereupon it would effectively be reconstituted as a petroleum operation in the ordinary course of the PSC.

PSCs which contain an exclusive operations right in favor of the grantor are rarely prescriptive (compared, for example, to the corresponding terms in a JOA) about how this provision would work. Whether the grantor should also be obliged to indemnify the contractor for losses or liabilities which were caused by the exclusive operation, in the manner of a JOA's sole risk right, will be an issue to consider, as will the issue of whether such an indemnity would in practical terms be worth anything to the contractor.

B12.5 Procurement

A function of the contractor under the PSC will be to procure from third parties the goods and services which are necessary to perform the petroleum operations (including the hire of drilling rigs and the provision of drilling services). This function, which will be represented in the PSC by provisions relating to the management of contract awards and wider procurement activities, is as much of a skill which the contractor brings to the grantor/contractor relationship under the PSC as the contractor's technological capability and financial risk assumption.

The PSC could include procurement provisions which regulate the selection of third party contractors and the award of contracts by the contractor. The provisions could be recited in the main body of the PSC,⁸⁴ in the accounting procedure (B25) or in a specific procurement manual which is appended to the PSC.⁸⁵

The procurement functions in the PSC will also have close association with the PSC's provisions relating to local content (B13.3).

B12.6 Domestic market obligation

The contractor would typically prefer the freedom to export its petroleum entitlements from the host state. As a partial exception to this principle the PSC could contain a form of domestic market obligation (DMO) provision, intended to give the state a competitive advantage in respect of the petroleum which is produced from the contract area (which would be of particular appeal where the state has a need to keep produced petroleum in-country in order to meet the domestic demand). The domestic market obligation could take a number of forms:

84 See the Bangladesh PSC.

85 See the Afghanistan PSC.

Free distribution - a certain measure of petroleum could be provided by the contractor to the grantor for free, to be used as the grantor wishes. This could be subject to a restriction that the petroleum can only be used within the state and cannot be sold for export by the grantor or by another person;

Discounted sale for use - a certain measure of petroleum could be sold by the contractor to the grantor at a price which is discounted to the comparable market price; the grantor then sells that petroleum, whether for use in the local market or for export. The reduction in revenue which the contractor suffers from receiving the discounted sale price (compared to the market price) could be cost recoverable (B9.1);

Discounted sale and buyback - a certain measure of petroleum could be sold by the contractor to the grantor at a price which is discounted to the comparable market price; the grantor sells that petroleum back to the contractor at the market price and keeps the delta between the discounted sale price and the market price. The reduction in revenue which the contractor suffers from receiving the discounted sale price could be cost recoverable;

Market price sale - a certain measure of petroleum could be sold by the contractor to the grantor at the comparable market price, for use or onward sale as the grantor decides. This option could apply to a defined percentage of the total volume of petroleum which is produced under the PSC or it could apply to the entirety of such petroleum. The grantor's logic for the latter approach is that the contractor is being paid the market price and so should be agnostic as to where the petroleum is sold, but this overlooks the possibility that a particular contractor party could be a vertically integrated oil company and might want access to the petroleum for its own processing or trading purposes; or

Priority purchase and priority sale – the grantor could reserve the right to buy petroleum from the contractor to a value which equates to certain monetary sums which are otherwise due for payment from the contractor to the grantor (such as taxation payments – B10.5). This would lead to an offset of payments between the grantor and the contractor.

In all instances, the contractor will also require that the incidence of a domestic market obligation is applied rateably to all contractors holding PSCs but this might not always be the case where the state utilizes different forms of PSC over time, or where the grantor applies the domestic market obligation provisions inconsistently between different contractors and their PSCs.

The PSC might also provide that the domestic market obligation provisions will apply only until the host state has achieved a defined measure of self-sufficiency with respect to its petroleum production and consumption.⁸⁶

86 See the India PSC.

The sale of petroleum to the grantor by the contractor under a domestic market obligation could also be unattractive to the contractor where payment for the petroleum is made in the local currency.

The PSC might also reserve a right of the grantor to requisition all quantities of petroleum production during times of war or national emergency.

B12.7 Additional licences

The PSC could mandate the need for entry by the contractor into further licences specifically for certain activities, notwithstanding that the contractor has entered into the PSC and these activities are already envisaged by the PSC, if that is what the regulatory regime of the state requires.

A specific exploration licence might be required by the PSC for the conduct of the exploration works.⁸⁷ The PSC might also require a specific license for the execution of the development plan and the resultant production of petroleum (sometimes called an ‘exploitation permit’ or a ‘production license’), with a specific exploitation period duration.⁸⁸

B12.8 Measurement

The PSC will recite certain standards for the measurement of different grades of petroleum which are produced under the PSC, typically with provision for the measurement function to be performed by the contractor (using equipment provided by the contractor, but approved by the grantor, and in accordance with measurements standards which might be specified in the PSC). The PSC will also reserve a right of the grantor’s representatives to attend measurement calibration, and even to call for an audit of the veracity of the measurement process.

B12.9 Books and records

The contractor will usually be obliged to maintain certain books of account and records relating to the performance of the petroleum operations (which could also be part of the accounting requirements under the PSC’s accounting procedure (B25)). The contractor could also be required to retain cuttings, cores and samples from the petroleum operations (which could also constitute data within the grantor’s entitlements (B14.2)). These books, records, cuttings, cores and samples could be required to be kept at a location within the host state, at which they can be accessed by the grantor.

87 See the Uganda PSC.

88 See the Egypt PSC.

B13 Capacity building

‘Capacity building’ is a shorthand term for the commitment of the contractor to help develop the host state’s local economy and the petroleum sector know-how of the grantor (and of the wider state), as a condition of being awarded the PSC. Under the PSC the contractor’s commitment to capacity building could be represented through several provisions.

The PSC’s capacity building provisions (and the domestic market obligations – B12.6) could also be helpful in managing the concerns of objectors to the state’s award of granting instruments in respect of its patrimony (A1.2) of the value of the PSC.

B13.1 Training payments

The contractor could be required by the PSC to commit a defined sum of money to be spent annually on training the personnel of the grantor (or of the wider state) on technical, legal, commercial and financial aspects of the petroleum industry, and also to be spent on acquiring certain office hardware (such as books, computers and seismic analysis equipment) for use by the grantor.

The grantor will wish to ensure that the training payments can be spent on service providers of the grantor’s choosing, so that the grantor can select what it believes is the most appropriate form of training and from service providers which the grantor does not regard as being unduly connected with the contractor.

The contractor’s concern in relation to making training payments relates to handing over cash for training and not knowing where it goes after that. This could be addressed in the PSC by the contractor procuring the provision of suitable training courses which are agreed with the grantor and which the contractor will pay for directly.

The amount to be expended by the contractor in providing training could be a fixed amount or it could be expressed as a percentage of the contractor’s actual annual expenditure under the PSC (although in this latter formulation the grantor takes the risk of zero training payments by the contractor if there is zero expenditure under the PSC). The extent of the contractor’s obligation could also be reset to a higher rate when petroleum production commences, as the contractor earns revenues from the production of petroleum from the contract area.

To account for the situation where the grantor cannot spend the entirety of the training payment budget in a particular year, the PSC could provide that the monetary amounts which are due as the training payments are deposited by the contractor into a separate bank account, against which the grantor can draw down at any time with the prior agreement of the contractor.

Training payments which are made by the contractor are typically cost recoverable under the PSC but there could be variations on this theme. Such training payments could be expressed to be cost recoverable where they are paid during the exploration

period, but not so when they are incurred during the production period (as a provision which is intended to reflect the improved economic circumstances over the lifetime of the PSC for the contractor).

The contractor might also be required to make defined payments to certain development funds which are specified by the grantor, which could relate to the promotion of the wider petroleum industry in the host state (and also to the promotion of diversified (non-petroleum) industries in the state) and for environmental reparations.

B13.2 Employment and secondments

The contractor could be required to offer on-the-job training and temporary employment to a number of personnel of the grantor or of the wider state. This requirement could be represented by a general request in the PSC that the contractor will employ local citizens to the greatest possible extent, or it could be represented by a formal arrangement for the periodic secondment of defined numbers of grantor/state personnel into some of the businesses of certain of the contractor parties.

This requirement is a form of technology transfer which (in the long run) is intended to enable the nationals of the grantor or of the wider state to understand and operate the PSC's underlying petroleum projects on their own behalf, thereby removing the need for the assistance of expatriate personnel which are provided by the contractor under the terms of the PSC. This is part of a process which is sometimes called 'localization'.

B13.3 Local content

The PSC could contain a local content provision, by which the contractor is obliged to procure certain goods and/or services which are needed for the performance of the petroleum operations from within the state rather than from the international market.

The purpose of a local content provision is to stimulate the local economy of the state, but the contractor may have a concern that the goods and/or services which are on offer locally (if they even exist) simply do not match the requisite standard for the performance of the petroleum operations, or that locally sourced goods and services (if they do exist) are available only at greater cost than internationally-sourced goods and services. The PSC could provide for a certain degree of cost overrun in the provision of locally-sourced goods and services as a permissible measure of costs which are 'comparable' with prices for internationally-sourced goods and services (meaning that the local content's costs are not really comparable).⁸⁹

'Hard local content' is a term which is sometimes used to describe the position where the grantor specifies a minimum value or percentage requirement for local

⁸⁹ See the Angola PSC.

content provision in the PSC.⁹⁰ Correspondingly, ‘soft local content’ describes the position where the contractor is required to do whatever it reasonably can to promote local content in the performance of the petroleum operations but without the imposition of a fixed target.

As the state’s petroleum economy matures over time and the necessary goods and/or services which are on offer locally are increasingly able to meet the requisite standard for the performance of the petroleum operations there could be movement from soft local content to hard local content. A measure of hard local content could also be secured by a provision in the PSC that goods and services which are valued below a certain monetary threshold must also be procured locally.

⁹⁰ See the Bangladesh, Kenya and Pakistan PSCs.

B14 Assets, data rights and petroleum title

Under the PSC the costs of acquiring or developing assets which are used in the performance of the petroleum operations, and the costs of generating petroleum deposit and production data, will fall ultimately to be borne by the grantor, through the PSC's cost recovery mechanism. The PSC will therefore provide for how the ownership of such assets and data will come to be assumed by the grantor.

The PSC should also make clear how title to produced petroleum is intended to transfer between the parties.

B14.1 Assets

The PSC will provide that title to all fixed and moveable assets which are acquired or developed by the contractor for use in the performance of the petroleum operations will pass to the grantor at some point in time. This is logical because the grantor will effectively have paid for the acquisition or the development of these assets through the cost recovery mechanism (B9.1). Paradoxically however, although title to these assets passes to the grantor it is the contractor which has responsibility for the decommissioning of those assets (B7.4), although the grantor could also have an interest in doing something with certain of the assets which are not decommissioned and removed at the end of the term of the PSC.

The asset title transfer provision applies principally in respect of assets which have been acquired or developed by the contractor during the development period (B7.2) and the production period (B7.3). Assets used during the exploration period (B6.2) and the appraisal period (B6.5) are typically leased by the contractor from a third party, to which the asset title transfer provision will not apply (see below).

The PSC could provide for title to an asset which has been purchased by the contractor to transfer to the grantor at any of the following times (these options have been selected from the terms of various PSCs): when the asset is purchased by the contractor; when the asset is first imported into the host state; when the asset is first used for the performance of the petroleum operations; when the costs associated with the asset have been fully cost recovered by the contractor; when the tax depreciation of the asset has concluded; or when the PSC expires or is earlier terminated. When title to an asset has transferred from the contractor to the grantor but the petroleum operations are still continuing the PSC could give the contractor a continuing right to use the asset for the petroleum operations, and an obligation to maintain the asset.

Because of the grantor's interest in assets where title is due to transfer to the contractor the PSC could provide that the contractor will not sell or otherwise dispose of an asset without the grantor's consent, that if an asset is disposed of by

the contractor then the sales proceeds will either be accounted for to the grantor or will be applied to reduce the cost recovery pool, and that the contractor will insure an asset in a manner which reflects the grantor's interest (B22.8). The contractor might wish to retain in the PSC the right to create a security interest over the assets which have not yet transferred to the grantor in favor of any third party lenders who have financed the contractor's project costs, but the grantor will typically be reluctant to allow the creation of such an encumbrance.

The asset title transfer provision will not apply to assets which are leased by the contractor for the performance of the petroleum operations and which belong to a third party (notwithstanding that the leasing costs will be cost recovered by the contractor). This provision applies principally in respect of drilling rigs and survey ships which are hired by the contractor for performing exploration and appraisal activities.

The contractor could use the leasing route to prevent the risk of confusion where the contractor owns an asset which it wishes to use in the performance of the petroleum operations, but does not want to take the risk that the grantor will assume an entitlement to own that asset. In this situation an affiliate of the contractor could own the asset and could lease it to the contractor.

The PSC could provide that wherever the contractor has an option to purchase an asset or to lease an asset for use in the petroleum operations, preference will be given by the contractor to the purchase option wherever possible.⁹¹

It might be thought that the grantor's rights to terminate the PSC in the event of a contractor's default (B2.5) could be made a more effective process because the contractor does not hold title to assets under the PSC, meaning that there will be less difficulty associated with unwinding the contractor's position. This is not an absolute truth however – a license (A2.2) could be readily terminated against a licensee, notwithstanding that the licensee would own all of the assets which it uses in the petroleum operations, and even under the PSC there could still be assets to which the contractor holds title (pending transfer to the grantor) at the point of termination.

Where during the lifetime of the PSC the contractor is able to sell certain assets which are no longer needed for the performance of the petroleum operations the contractor could be permitted to do so, subject to the grantor's approval and subject also to accounting to the grantor for the sales proceeds (whether directly or by credit as a reduction to the recoverable costs pool).

91 See the Gabon PSC, but for a contrasting view see the Somalia PSC, which recognizes that leasing could be a preferred route in certain economic circumstances.

B14.2 Data

There are two issues to note with petroleum exploration and production data which is generated in relation to the PSC.

The first issue relates to data which is generated by the grantor as a precursor to a public bid round (A3.1), such as the commissioning of a multi-client seismic survey (B14.2).

Access to this data by the contractor could be provided for free by the grantor as part of the grantor's obligations under the PSC (B3.4). Alternatively, this data may have to be purchased by a bidder as a condition of being considered as eligible for the award of the PSC (B3.4). The requirement for such a data package purchase raises cash for the grantor which could cover the costs of running a public bid round, and is useful in weeding out pure speculators from bidders with more serious intent. The data package purchase costs which are paid by the contractor are not ordinarily cost recoverable if the PSC is awarded and eventually moves into production, although in the PSC the data package purchase costs could be credited towards satisfaction of the exploration period obligations and their associated costs (B6.4). Despite the purchase of the data package however, title to the data which is contained within the package could remain with the grantor. Rather than purchasing the data outright, the bidder will only have purchased a right to access and to use the data.

The second issue relates to the ownership of the petroleum exploration and production data which is generated under the PSC (and also under any subsequent sales, transportation and processing contracts). The grantor wants to own that data because it enables the grantor to build a better picture of its entire petroleum estate, as a part of wider, cumulative exercise across all of the grantor's PSCs. From the contractor's perspective the data's relevance is limited to the boundaries of the contract area, and is useful principally in making more informed decisions regarding surrender or development (unless the contractor has, or is interested in having, contiguous acreage interests across several PSCs – which could trouble the grantor (B4.1)).

Thus, the PSC will usually provide that the data which is generated under the PSC through the activities of exploration and appraisal, and development and production, will belong to the grantor and will be something which the grantor is able to license to third parties, for a fee. This could be subject to provision in the PSC that the grantor's rights to deal with the data will be subject to control by the contractor in some circumstances⁹² (and the extent to which the contractor can exert some measure of control over the data will vary between different PSCs).

The PSC's provisions relating to ownership of the data will also need to be reconciled with the corresponding provisions of the JOA (B23.1), which typically regard such data as venture property which is owned by the JOA parties.

92 See the Uganda PSC.

B14.3 Title to petroleum

That the host state holds title to all quantities of in-ground petroleum is an essential feature of the PSC. Once petroleum has been produced and has passed through the wellhead the PSC will need to legislate for certain title transfers so that the petroleum is a readily saleable commodity, and so that the fiscal terms of the PSC (B9.3) can be realized.

The PSC will typically provide that the contractor will take title to the contractor's entitlements (B9.2) at the wellhead (which might be specified in the PSC as a defined 'delivery point'). This will then enable the contractor to sell its entitlements and to give good title to a purchaser of that petroleum.

Where the grantor elects to take its entitlements under the PSC in cash (B9.2) the grantor could appoint the contractor to act as its agent to sell its entitlements and to account to the grantor for the resultant sales proceeds. For this to happen the grantor will need to transfer title to its entitlements at the wellhead to the contractor, so that the contractor can also conclude an effective sale of those entitlements.

The PSC could also provide for the joint marketing of the grantor's and the contractor's petroleum entitlements.⁹³

93 See the Qatar PSC.

B15 Gas

The PSC is typically intended to regulate the exploration for and the discovery, development and production of all grades of petroleum (B3.1). That said, the PSC could be inclined more towards dealing with a crude oil discovery and could say comparatively little about how to account for a natural gas discovery. Whether condensate counts as a light oil or as a heavy gas could also be a grey area, which should be legislated for in the PSC.

B15.1 The problem with gas

The provisions of most PSCs afford much thinner coverage to a gas discovery than they do to an oil discovery, which could diminish the prospects for a successful gas exploitation programme.⁹⁴

Most PSCs are geared towards the production of oil and say relatively little about the applicable regime for gas commercialization. Rather, the treatment of gas is usually left to be further negotiated by the contractor with the grantor in the event of a discovery, because of a relative lack of familiarity with the techniques for commercializing gas when compared with oil. This lack of transparency could give the contractor little or no incentive to invest in exploring for and producing gas.

The reluctance of the PSC to deal with the possibility of a gas discovery in the same amount of detail as an oil discovery is attributable to the following problems which a gas discovery often presents.

The commerciality of an oil discovery can be evaluated relatively quickly because of oil's relative ease of transportation and through the existence of comprehensive global trading terms and published trading prices for the resultant commodity. The commerciality of gas on the other hand might not be capable of being established until the prospects for the gas's successful marketing (which could involve developing a comprehensive downstream marketing programme for domestic use and for exports) have been assessed. Oftentimes a firm contract for the sale and transportation of a discovered gas resource will be needed to allow the resource to be declared as commercial (B7.1). Essentially, with oil production the post-discovery sequence is a declaration of commerciality followed by a contract for sale; with gas production the reverse could be true, and this will entail a more time-consuming and less certain route towards monetizing the PSC.

Once a gas discovery has been made it might also be necessary for the contractor to develop further gas-specific provisions (including a possible revision to the fiscal terms (B9) to apply under the PSC. This could lead to a lengthy period of negotiations with the grantor. Specific infrastructure for gas processing and transportation could also need to be developed, particularly in remote areas, which

94 A point highlighted in a World Bank paper from 1995 (– Mohsen Shirazi, *The Commercialization Process in Exploration and Production Agreements* [1995] World Bank IEN Occasional Paper No. 5).

might necessitate amending the scope of the PSC (B3) to include certain midstream development activities.

The PSC might reserve a right of the contractor to use discovered gas as fuel for production operations and for gas lift. The PSC will commonly also distinguish between non-associated gas and associated gas discoveries. Both forms of discovery might be open to the prospect of a separate development plan by the contractor, or the PSC could provide that associated gas belongs to the state, so giving the contractor little or no economic incentive to develop it.⁹⁵

The PSC could also provide that any gas discovery (whether non-associated gas or associated gas) which the contractor does not develop will be relinquished to the grantor. By this route the grantor could accumulate a number of gas discoveries, to the point where they could be consolidated for the benefit of a national gas company by the host state.

B15.2 Addressing gas in the PSC

All of the above factors, whether taken alone or in any sort of combination, could give the contractor an incentive to not find gas, or not to declare commerciality if the contractor does find gas.⁹⁶ To obviate this situation a more comprehensive gas provision in the PSC could be required, particularly where it is likely that the PSC being awarded is in respect of gas-prone acreage. Such a provision might address the following topics:

- (1) more time could be required in how the PSC defines the exploration period (B6.2) to allow the contractor to explore for gas, and to appraise a gas discovery (B6.5). The PSC might also provide for the allowance of sufficient time for the contractor to assess the availability and the economic viability of domestic and export market projects for the produced gas, with consideration of the various different conceptual options which exist for the development of a gas commercialization project;
- (2) the PSC could reflect the ability of the contractor to develop (and to cost recover the costs) of midstream infrastructure necessary to take discovered gas to market, and possibly also of downstream infrastructure to realize the commercial value of the gas, notwithstanding that such infrastructure could be physically located outside of the contract area (B4.1),⁹⁷ especially after the full relinquishment process has been applied (B5), and particularly so given that the development of such infrastructure could be outside the scope of the PSC (B3.1);

95 See the Angola PSC.

96 To repeat the old (but sometimes still very relevant) piece of industry doggerel: “you get your concession and then you drill. If you are lucky you find oil; if you are unlucky you find nothing; and if you are really unlucky you find gas.”

97 See the Pakistan PSC, but for a contrasting view see the Uganda PSC.

- (3) the PSC might facilitate the establishment of a committee of representatives which is wider than the grantor and the contractor, to include midstream and downstream sector specialists, in order to assess the steps necessary to implement a successful domestic and/or export plan for a gas discovery;
- (4) the PSC could include the establishment of outline commercial terms for the sale of gas to domestic buyers (and possibly also a gas pricing methodology). Beyond this, the contractor could also require that a state gas master plan is put in place to regulate the conditions for domestic and export gas project developments; and
- (5) the contractor might be offered a combination of enhanced cost recovery (B9.1) and improved profit share percentages (B9.2) to encourage the exploration for and the development of non-associated gas, reflective of the relatively greater uncertainty of undertaking a gas development project. Whether the improved fiscal terms should also apply to associated gas, where the contractor might have the benefit of the associated crude oil production, revenues and cost recoveries, should be considered. The contractor might also require that the costs of marketing the gas are made cost recoverable, which could be a departure from the customary approach of the PSC (B9.1). These improved terms could be set out in the PSC from the outset, or they could be later agreed between the grantor and the contractor. Any modification to the PSC's fiscal terms which is made permissible under the PSC as a reaction to a gas discovery would be an exception to the otherwise standing principle of the PSC that the fiscal terms will not be modified once the exploration period has ended and better definition of the underlying petroleum deposit has been secured.

B16 Stabilization

The PSC might contain what is called a ‘stabilization’ provision, intended to protect the contractor against the risk of adverse interference by the grantor (or by the host state) with the economic bargain which the PSC originally created between the grantor and the contractor.

B16.1 The need for stabilization

The PSC is a long-term commitment which requires a significant amount of investment by the contractor, and which supposes the assumption of a significant number of risks by the contractor. The most obvious of those risks is that the business of exploration for petroleum is unsuccessful, but the success of a petroleum production project could bring its own risks too. The contractor could be concerned that over time the level of state take (A1.1) which the PSC creates proves to be insufficient to satisfy the grantor (which might particularly be the case if the PSC’s fiscal terms are not progressive – B9.2) and that as a reaction the state could make changes to the governing law of the PSC (B19.1), or to the taxation regime of the PSC insofar as it affects the contractor (B10.5) which adversely affect the contractor’s interests under the PSC. Such changes could in themselves be, or they could accumulate to the point where in the aggregate they might be, regarded as a form of expropriation of the contractor’s interests under the PSC.⁹⁸

To counter these risks the contractor (or its lenders, where the contractor is using third party financing to meet the project development costs) could require the inclusion of a stabilization provision in the PSC.

The contractor’s demand for the inclusion of a stabilization provision in a PSC tends to be resisted by a state with either or both of a well-developed petroleum economy and a proven commitment to upholding the rule of law and recognizing the sanctity of contract, but a less-developed state (and particularly a state with some previous history of direct or indirect expropriation) could accede to a contractor’s request for a stabilization provision in the PSC in order to encourage inward investment. Over time a state could also take the view that it has evolved sufficiently to no longer need to offer a stabilization provision in the terms of its next-generation PSCs where previously it had felt the need to do so.⁹⁹ But because the economic and political circumstances which are associated with the petroleum sector are in constant evolution a contractor should be reluctant to release this form of protection in its PSC.

98 Historical examples of states seeking to regain control over their national resources through more direct nationalization programmes and other interventions include Mexico (1938), Iran (1951), Libya (1971), Venezuela (1976, 2007), Saudi Arabia (1976) and Argentina (2010).

99 Such an evolution can be seen in Tanzania’s PSCs over time.

B16.2 The form of a stabilization provision

There is no standard form for a stabilization provision, and whether a provision which is offered up as such in a PSC actually constitutes stabilization will be a matter of opinion. Principally, a stabilization provision is intended to deter adverse state-level interference with the PSC, but it can also act as a state-level obligation which helps to create the legitimate expectation of the contractor to fair and equitable treatment as an investor which could form part of a claim for compensation under an investment protection agreement which might apply for the benefit of the contractor.

From the contractor's perspective the stabilization provision should be given directly by the state (that is, as a superior entity to the grantor), or by a state representative which is clearly authorized to bind the state. The stabilization provision could be recited in the PSC (with the state's representative itself as an additional signatory to the PSC to give the necessary commitments) or in a stand-alone investment protection agreement (such as a bilateral investment treaty) or a host government agreement (A1.1).

A stabilization provision could take the form of a commitment of the state to undertake any of the following commitments during the lifetime of the PSC:

- (1) to guarantee the sanctity of the contractor's investment in the PSC through enacting the PSC as a law of the state in its own right, which means that the PSC would only be capable of being changed by a new law (sometimes called a 'force-of-law' provision);
- (2) to offer equal treatment to all investors (including the contractor) in the state (sometimes called a 'non-discrimination' provision);
- (3) to exempt the contractor from current and prospective taxation liabilities relating to the PSC (sometimes called a 'tax-paid' provision);
- (4) to freeze the legal and taxation basis which applies to the contractor to that which was in force in relation to the PSC at the date when the PSC came into force (sometimes called a 'freezing' provision or an 'intangibility' provision);
- (5) to commit to renegotiate the PSC in the contractor's favor in the event of adverse changes which relate to the PSC (sometimes called an 'equilibrium' provision); and
- (6) to commit to give fair compensation to the contractor (which might be left as an undefined amount or which might be the subject of a specified compensatory formula) in the event of adverse changes which relate to the PSC and/or the contractor's position.

B16.3 Reacting to a destabilizing event

The initial reaction to an event or circumstance which, in the opinion of the contractor, necessitates a claim for protection of the contractor under a stabilization provision is that the contractor and the state would meet and seek to agree a solution to restore the contractor's position. If agreement cannot be reached then the contractor could have recourse to the dispute resolution mechanisms of the PSC (B20) or of the investment protection agreement to settle the issue – but it should be noted that the adverse events which are complained of by the contractor might not be something which the grantor can be blamed for and consequently the PSC's dispute resolution provisions in themselves might not offer a ready solution to the contractor if the state's representative is not also a signatory to the PSC.

B17 Liability

The allocation of liability between the grantor and the contractor for losses and liabilities which they are each exposed to as a consequence of the performance of the petroleum operations could be left to be determined by the governing law of the PSC or by any applicable petroleum code or other item of supervening legislation. Alternatively, and more typically, the PSC could recite an express regime for the allocation of liability between the parties. Such a liability allocation regime would reflect several elements.

B17.1 Third party claims

The PSC could require the contractor to indemnify the grantor (and possibly also a wider class of host state interests and agencies) against claims made by third parties who allege to have suffered loss or damage arising from the contractor's performance of the petroleum operations. The PSC could also oblige the contractor to manage the defense against such third party claims on behalf of the grantor (where the costs of doing so could also be expressed to be cost recoverable).¹⁰⁰

B17.2 Contractor default

The PSC could identify a number of circumstances which constitute a contractor default. These circumstances could relate to a breach of a term of the PSC or to a breach of any applicable petroleum code or other item of supervening legislation. The PSC might also apply a test of materiality to such a default.

A contractor default (whether it is a default which is capable of being remedied and has not been remedied within a defined cure period, or whether it is a default which is incapable of being remedied) could lead to grounds for the termination of the PSC by the grantor (or, more likely, to the termination of the PSC in respect of the contractor party in default – B2.5). It could also be an event which entitles the grantor to make a claim under the collateral support which has been provided by the contractor in respect of its PSC commitments (B22.1).

A contractor default could also (depending on the governing law of the PSC – B19.1) generate a liability of the contractor to pay damages to the grantor for breach of contract. The quantum of these damages will be determined by the loss which the grantor has suffered, and this might not always be an easy amount to quantify. The PSC might therefore apply liquidated damages formulation to certain aspects of the PSC. This could apply, for example, to the contractor's failure to perform an exploration period obligation (B6.3), where the liquidated damages could reflect the associated expenditure expectation or could be a further defined amount (B6.4).

To give more certainty than might be created by the circumstances of a general

100 See the Cameroon PSC.

damages claim (depending again on the governing law of the PSC) the PSC could require the contractor to indemnify the grantor (and possibly also a wider class of state interests and agencies) against any loss or damage which has been suffered arising from the contractor's mis-performance or non-performance of the petroleum operations.

The contractor's liability to the grantor for a breach of contract, and the circumstances in which the contractor is obliged to indemnify the grantor, could apply as a consequence of any standard of behavior by the contractor, or it could be expressed to apply only where the contractor's behavior falls into a particularly egregious category such as gross negligence or willful misconduct (as those terms might be specifically defined in the PSC).¹⁰¹

The contractor's default could also result in a liability of the contractor to pay certain administrative fines and penalties to the grantor or to another state agency. These fines and penalties will not be cost recoverable by the contractor (B9.1).

B17.3 Consequential loss

Whether the contractor's liability to the grantor for a breach of the terms of the PSC should include or should exclude a liability of the contractor to pay the grantor's consequential losses (as that term might be specifically defined in the PSC, or determined by the PSC's governing law (B19.1) or by any applicable petroleum code or other item of supervening legislation) should be considered.

The inclusion of a broad exclusion of liability for consequential losses in the PSC might not be effective under the governing law of the PSC, and should be careful not to limit the right of the contractor to recover the full value of compensation which might be due under a stabilization provision (B16).

B17.4 Joint and several liability

The PSC will usually prescribe that any liability of the contractor parties to the grantor is joint and several. This means that a claim which can be made by the grantor against the contractor could be brought against any one, or some, or all of the contractor parties, at the discretion of the grantor.

This will be a particular issue where the grantor has exercised a state participation right under the PSC (B11), on the basis that the grantor is unlikely to make an indemnity claim against itself or its nominee. This claim will then become a matter to be reallocated between the contractor parties under the JOA, according to the several interests created by their percentage participating interests (B23.1). The linkage between the PSC and the JOA in this regard must be made clear.

101 See the Nigeria PSC.

B17.5 Insurance protection

Any insurance which is arranged by the contractor under the PSC (B24.7) should also be structured to relate to protecting the contractor from a liability which it has under the PSC's liability provisions. This would relate principally to third party claims (see above). Insurance taken out by the contractor to cover the contractor's liability to the grantor or to the wider state under the PSC (see above) would less typically be a policy of insurance which is countenanced by the PSC.

B18 Force majeure

The PSC could contain a force majeure provision, which is intended principally to protect the contractor against incurring a liability to the grantor for a failure to perform the PSC in accordance with its requirements where the contractor's failure is caused by an event which was beyond its control.

The PSC is less likely to create a liability of the grantor for a failure to perform its obligations for which the grantor would require force majeure relief, although this could be a possibility and the force majeure provisions in the PSC will countenance the ability of the grantor to claim force majeure relief for itself.

B18.1 The concept of force majeure

The doctrine of force majeure gives a party to a contract relief from a liability which that party would otherwise have for a failure to perform the contract (in whole or in part) where the failure can be shown to have been caused by a supervening event which was beyond the control of that party.

A popular misconception is that force majeure relief absolves an affected party from the obligation to continue to perform the affected contract. This is not so. An affected party will still be obliged to perform as much of the unaffected parts of the contract as possible, and the availability of force majeure relief to an affected party is usually conditional upon the affected party taking reasonable action to overcome the force majeure event and to resume normal contractual performance.

B18.2 Force majeure relief parameters

What constitutes force majeure is defined specifically by the PSC, or the definition of force majeure could be derived from any applicable petroleum code or other item of supervening legislation to which the PSC is subject (B3.1). Force majeure protection under the PSC must also be read in light of any conditions which might be applied by the governing law of the PSC (B19). The force majeure relief which is available to an affected party is limited by the terms of the force provision and should not be read as giving a complete waiver of the need to perform the affected obligation. Such a waiver could have its own treatment under the PSC (B24.10).

From the contractor's perspective a force majeure provision could give relief for a failure to perform an exploration period obligation (B6.3) or a work programme obligation (B12.1) where the failure is attributable to a force majeure event. This could, for example, relate to unforeseen geological and geophysical conditions which are encountered during the drilling of a well, but the drilling obligations in the PSC could be absolute requirements, capable of being satisfied in the alternative by the obligation of the contractor to drill a substitute well at its own expense (B6.3) or to make a compensatory payment to the grantor (B6.3). Because it is customary that a force majeure provision will not excuse the liability which a party has to make a monetary payment when due (see below), as an exclusion which will apply

principally to the contractor as the party tasked with making various monetary payments to the grantor under the PSC, the force majeure relief on offer to the contractor in these circumstances could be somewhat emasculated.

The force majeure provision will usually include an indication of certain events which will not be eligible for force majeure relief. It is customary that a force majeure provision will not excuse the liability which a party has to make a monetary payment when due, or to provide collateral support for its obligations under the PSC when required (B22.1). This exclusion will apply principally to the contractor, as the party tasked with making payments and providing collateral support.

The force majeure provision will also be expressed not to apply to a failure which is attributable to an act or omission of the affected party (which, in respect of a force majeure claim made by the grantor, could be extended to include the wider state), and might be expressed not to apply to economic hardship or to a change in market circumstances which affects the returns which a party expects to make under the PSC (that could apply for example where a sustained period of low petroleum prices exists). A renegotiation of the requirements of the PSC between the grantor and the contractor might be possible in such circumstances (B6.3) but cannot be guaranteed to afford relief to the contractor. The better option would be to expressly legislate for this exigency in the wording of the PSC.

Periods of time which impact the performance of the PSC could be added to give an extension to the term of the PSC (B2.3). The PSC could also be subject to possible termination because of a prolonged event of force majeure (B2.5), whether automatically, by the election of one of the parties or by agreement between the parties.

B18.3 Force majeure relief for contractor parties

The contractor as an entity can claim force majeure relief under the PSC, but this could lead to difficulties where one of the contractor parties wishes to claim force majeure relief but not all of the contractor parties believe that the claim for relief should be made. This situation could apply for example where the operator under the PSC (B8.1) wishes to claim force majeure relief in respect of its obligations as the operator, but the other contractor parties do not share the operator's view. The force majeure clause in the PSC is typically not written in a way which allows an individual contractor party (including the contractor party which is appointed to act as the operator in its capacity as such under the PSC) to make a claim to protect its interests (in contrast to the way that the PSC could separate out termination rights in respect of individual contractor parties – B2.5).

This could lead to a dispute between the contractor parties, and this could be a dispute which is not readily soluble between the contractor parties under the dispute resolution mechanism in the PSC (B20.1). This could be a matter to be addressed under the JOA, relating to voting between the parties to the JOA to secure the right of the contractor to make a claim for force majeure relief under the PSC, but the linkage between the PSC and the JOA in this regard is rarely expressed in clear terms.

B19 Governing law

The PSC will (usually, but not always) recite the governing law which is intended to apply to the content and the effect of the PSC, and to the PSC's interpretation in the event of a dispute.

B19.1 Selection of the governing law

The grantor will say that because the PSC is the contractual vehicle by which the host state's mineral wealth is exploited, the governing law of the PSC must be the law of that state. This requirement is ordinarily almost impossible for the contractor to resist (and arguing that the law of the host state is insufficiently mature for the needs of the PSC will be met by a particular solution – see below).

The selection of the law of the state to be the governing law of the PSC will expose the contractor to the need to comply with all of the laws of the state, which in the context of the PSC could include environmental regulations, procurement laws, civil and criminal law compliance, taxation provisions and any supervening legislation to which the PSC is subject.

The law of the state could be relatively immature and it could lack the commercial sophistication which is necessary for the PSC to function properly. Consequently in the governing law clause there could also be a reference to international law (whatever that means) or to a chosen neutral law (such as English law), to apply in support in order to address any deficiencies which become apparent in the law of the state.¹⁰²

Such a provision could give comfort to the contractor parties (and to their lenders) that at least some sort of law will apply to the PSC, but it could also lead to the risk of confusion of interpretation as to where one body of law ends and another one begins. Even more confusion will be generated where the supporting reference in the PSC is not to another body of law but is to some variant of good and prudent oil and gas field practice (B3.1), or to the laws of unnamed other countries in which similar petroleum operations are undertaken.

102 See the Guyana, Liberia, Mauritania and Somalia PSCs.

B20 Dispute resolution

The PSC will contain some form of mechanism for the resolution of disputes which arise between the parties during the lifetime of the PSC.

B20.1 The scope for disputes

The dispute resolution provisions in the PSC are typically written with the intention that they will apply to the resolution of disputes between the grantor and the contractor relating to the content or the effect of the PSC. This could include the failure of the parties to agree in respect of an issue at the management committee, where the PSC does not apply a deadlock provision for management committee issues (B8.2), or issues relating to whether a declaration of commerciality can be made (B7.1) or whether the contractor has performed an exploration period obligation in accordance with the requirements of the PSC (B6.3).

It is normally the case that these provisions will not be readily capable of application to disputes between the contractor parties in relation to the PSC however. The popular belief is that such a dispute would fall to the JOA to be addressed, because it relates to the contractor parties, but this does not take account of the possibility of a dispute between the contractor parties which relates solely to the PSC and which has no obvious connection to the business of the JOA (see B18.3 for an example of such a dispute).

B20.2 The options for dispute resolution

As a starting point the PSC will usually require the parties to make efforts to resolve a dispute amicably, through informal consultation. Only then, if such consultation has failed, would a more formal avenue for dispute resolution apply under the PSC. The PSC might also provide for a form of facilitated consultation, through the appointment of a mutually agreed expert to assist the parties in their discussions.¹⁰³

The PSC could prescribe the courts of the host state as the venue for dispute resolution, or the PSC could provide for arbitration between the parties, ideally (from the contractor's perspective) to be held in a neutral venue and to be conducted according to the rules of a recognized arbitral institution. The governing law of the PSC (B19.1) could also apply to be the procedural governing law of the arbitration, unless an alternative is specified. A particular attraction of arbitration as a means of dispute resolution is that it is private between the parties.

A failure of a party to comply with the terms of an arbitral award or a judgment made in respect of the PSC could also give rise to grounds to terminate the PSC (B2.5).

It might seem a remote possibility that the contractor would be able to successfully enforce an arbitral award or a court judgment against the grantor but securing such

103 See the Cyprus PSC.

an award or judgment could be the precursor to a claim by the contractor in respect of an investment protection agreement (B16.2) or under a political risk insurance policy (B24.7).

As an alternative to having recourse to a court or to arbitration the PSC could also provide for the appointment of an independent expert to determine certain agreed financial and technical issues (such as the recoverability of certain petroleum costs (B9.1), the terms of a field development plan (B7.2), the calculation of royalty amounts (B10.4) or the valuation of petroleum (B9.3)).

B20.3 Dispute resolution mechanics

The PSC could include a waiver of sovereign immunity, ostensibly given by the grantor but such a provision would apply also in respect of any parastatal entity which constitutes a contractor party. The purpose of a sovereign immunity waiver is to reflect the state or the parastatal entity's release of certain rights of immunity against the enforcement of a court or arbitral award against it which it might otherwise enjoy. Such a provision would make it possible for the contractor to make a claim against the grantor for a breach of the terms of the PSC (although the political sensitivities associated with taking such a step would be a separate matter to consider).

The PSC might provide that the costs which are incurred by the grantor in respect of a dispute with the contractor must be borne by the contractor (and can be later cost recovered by the contractor). This might be expressed to apply only in respect of a dispute which arises during the exploration period, before any share of the revenues associated with the production of petroleum have begun to accrue to the grantor under the PSC, on the basis that the grantor in a nascent petroleum economy could simply lack the funds to finance an expensive dispute resolution process, but this proposition will not have the capacity for infinite application.

B21 Transfer of interests

The PSC will typically provide a mechanism to regulate the ability of the contractor (or, more specifically, the ability of a contractor party) to transfer its interests under the PSC to a third party at any time. This mechanism will necessitate the consideration of several issues.

B21.1 The grantor's approval

A transfer of interests by a contractor party will typically be conditional upon the grantor's prior approval (or disapproval) of the proposed transferee. The grantor's disapproval rights could be limited by the PSC to concerns with the financial and/or technical capability of the transferee and its suitability as a replacement for the transferring contractor party, or the grantor could have unfettered approval rights in respect of the transferee which can be applied in the grantor's absolute discretion. In the latter case the grantor could take into account any unwritten political or other reservations which it might have in respect of the transferee.

The grantor could be concerned that the contractor could have too many different PSC interests in the host state for the contractor to be able to perform them all properly (or which could give the contractor an undue degree of influence over the grantor), or that the proposed transferee has acreage in a contiguous state (B4.1). The grantor could manage these concerns by withholding its consent to proposed transfers of interests which would aggregate the contractor's position or which would expose the grantor to the neighboring acreage issue, and also by having rights in respect of a change of control of the contractor (see below) where the risks would become apparent by consolidation at the shareholder level.

It is possible to conceive of a situation where the grantor's approval to a proposed transfer by a contractor party could be withheld but for reasons relating to a desire of the grantor to make changes to the terms of the PSC, or to make changes to how the PSC is being operated by the contractor. This might be the case where the grantor feels that the contractor's historical performance of the PSC has not met expectations. Equally however, the contractor might have an interest in discussing changes to the terms of the PSC, if those changes also afford some benefit to the contractor.

The PSC might apply a less rigorous approval regime where a contractor party wishes to transfer its interests under the PSC to an affiliate (as the term 'affiliate' is defined in the PSC or by the governing law (B19.1) of the PSC). This regime would apply for as long as the affiliate-transferee remains an affiliate of the transferring contractor party. The transferring contractor party could also be required to assume continuing liability for the acts and omissions of that affiliate transferee as a condition of the transfer.

The PSC could provide that a contractor party has no right to transfer its interests in the PSC for a defined period (such as the exploration period), where the grantor wishes to lock in that contractor party for a defined period of time.

A transfer by a contractor party of its interests under the PSC does not equate to an automatic transfer of operatorship if the transferring contractor party is also the operator under the PSC (B8.1). The grantor will reserve the right to approve a replacement operator, which might not necessarily be the proposed transferee.

The PSC could give the grantor (or its nominee) a pre-emptive right to acquire the interests of a transferring contractor party. If the grantor exercises this right it will have to be reconciled with the application of any pre-emption rights under the JOA (B23.1).

B21.2 The grantor's rights

The PSC will rarely condition, or even mention, the ability of the grantor to transfer its interests as the grantor under the PSC. A possible exception to this principle is a requirement in the PSC that the grantor can only transfer its interests to another state-owned entity.¹⁰⁴

Where the grantor has a state participation right under the PSC (B11) the grantor could have a right under the PSC to transfer that right to a third party. The assignment right could be subject to the contractor's approval, and could be subject to a pre-emption right in favor of the contractor. Alternatively, the grantor could decide to transfer its state participation right as it sees fit (B11.5).

B21.3 The relationship with the JOA

The usual intention is that a contractor party's transfer of its interests under the PSC should be matched by a corresponding transfer of its interests under the JOA (and vice versa), so that there is symmetry of interests of a contractor party across the PSC and the JOA.

The grantor's prior approval (or disapproval) of a proposed transferee under the PSC could condition the approval process of the same transferee under the JOA. Although the PSC and the JOA are very different agreements, and the parties under each of those agreements will have different perspectives, in practice it could be difficult for a JOA party to approve a proposed transferee which has been rejected by the grantor, and for a JOA party to reject a proposed transferee which has been approved by the grantor.

B21.4 Change of control

The PSC might seek to legislate for what happens if one of the contractor parties undergoes a change of control during the term of the PSC. A change of control

104 See the Cameroon PSC.

could see a contractor party becoming owned by a person in respect of whom the grantor could have certain reservations.

What constitutes a change of control for these purposes could be defined in the PSC (relating, for example, to how high into the contractor party's corporate structure the change of control is intended to go and what circumstances of a purely internal contractor group reorganization would be disregarded).

The occurrence of a change of control could require any of the notification of the change of control to the grantor, the approval of the change of control by the grantor (which will not always be a tenable proposition, including for confidentiality reasons), a requirement of the contractor party which has undergone the change of control to provide collateral support in respect of its obligations under the PSC, a pre-emptive right of the grantor to acquire the interest of the contractor party which has undergone the change of control or even a right of the grantor to terminate the PSC against the contractor party which has undergone the change of control (B2.5).

B21.5 Transfer consequences

The transfer by a contractor party of its interests under the PSC will usually be without prejudice to any accrued liabilities of the contractor party to the grantor which have arisen under the PSC. The transferring contractor party will usually also be subject to a continuing liability to maintain any collateral support (B22.1) which it has procured in respect of its ongoing decommissioning liabilities, unless adequate replacement collateral support has been procured by the transferee.

The transfer by a contractor party of its interests under the PSC could trigger an exposure of that contractor party to pay capital gains or transfer taxes to the grantor if there has been some improvement in the value of the transferred interests (based on the positive difference between an assumed base cost of the transferred interests and the value of the transferred interests which is realized by the contractor party as a consequence of the transfer). These tax liabilities could be recited in any applicable petroleum code or other item of supervening legislation, or the PSC itself could contain a mechanism which levies a form of transfer tax against the transferring contractor party, which would effectively be a bespoke contractual form of a capital gains tax.¹⁰⁵ These provisions are more obviously applicable to a cash sale of its interests by a contractor party; they could be more difficult to apply to transactions involving non-cash consideration, such as an asset swap.

The grantor could say that, from its perspective, applying a liability to taxation in this circumstance is defensible because the improvement value of the transferred interests was generated by the incurrence of costs in the various stages of exploration, appraisal and development into production which are cost recoverable by the

105 See the Tanzania, Trinidad and Tobago and Uganda PSCs.

contractor and so ultimately will be borne by the grantor – so the grantor should get something back for that. This notion also explains the provision which sometimes appears in the PSC that the accrued petroleum costs pool which is available to the contractor for cost recovery (B9.1) (or, rather, to the transferring contractor party, but this is not always made clear) will be reduced by the attributed value of the improvement in the transferred interests.¹⁰⁶ This allows the grantor to apply a form of taxation to the transaction and improves the overall economics of the PSC from the grantor's perspective but it will also lead to a debate between the transferring contractor party and the proposed transferee as to how the incidence of this provision should be adjusted in their agreed purchase consideration, since the anticipated share of the costs pool is no longer available to the transferee.

The PSC could provide that only a part of the contract area can be transferred by a contractor party. This would lead to the possibility that the overall contract area could be held by different persons, with different degrees of interest. The PSC might provide that separate PSCs must be held in respect of the separated parts of the contract area, to reflect the subdivision of interests.¹⁰⁷

106 See the Gabon PSC.

107 See the Timor Leste PSC.

B22 Collateral support

‘Collateral support’ is a shorthand term used to describe the procurement by a party to the PSC of some form of additional support for the satisfactory performance by that party of its obligations under the PSC. These could be obligations of payment or of wider performance. Such collateral support is typically provided by a third party, which may or may not be related to the party which is required to procure the collateral support.

The PSC will typically oblige the contractor to procure some form of collateral support in favor of the grantor in support of the contractor’s payment and other obligations under the PSC, but not so in the favor of the contractor by the grantor in respect of its PSC obligations.

B22.1 The rationale for collateral support

From the grantor’s perspective the application of collateral support (in whatever form it takes – see below) in respect of the PSC is ostensibly intended to allow the continued performance of the PSC by the contractor, despite the existence of financial difficulties that could inhibit the originally–intended manner of performance by the contractor.

Where the PSC is awarded to a consortium of persons acting together as the contractor (B1.2) it might be the case that the grantor would make an assessment of each of the contractor parties as to their respective creditworthiness at the point when the PSC is first awarded. If the grantor has concerns as to a prospective contractor party’s creditworthiness then that contractor party might not be invited to participate in the PSC, notwithstanding the prospects for the provision of collateral support. This approach could result in some contractor parties being required to procure collateral support in respect of the PSC, and in other contractor parties not being so required.

In contrast to this piecemeal approach however, it is more typically the case that an item of collateral support is required to be procured in respect of the contractor as a single entity as a matter of course, with less focus on individual contractor party creditworthiness. This is typically an expectation which is set as a public bid round requirement (A3.1). This would apply unless the PSC is awarded to a single contractor party and the grantor has decided that the contractor party in question is sufficiently creditworthy to not need to procure collateral support.

An assessment of creditworthiness would also be made by the grantor in respect of an incoming contractor party when a contractor party transfers its interests under the PSC (B21).

The posture of the grantor on the need for the provision of collateral support by the contractor in respect of its obligations under the PSC could also vary over time. As the grantor seeks to attract new inward investment, either at the outset of the

operational lifetime of the host state's upstream sector or as the sector matures and declines, there could be a temptation on the part of the grantor to lower the bar for prospective contractors in order to attract investment or to maintain production for as long as possible. The grantor's imposition of stringent collateral support commitments could be inconsistent with such an approach.

B22.2 Forms of collateral support

The principal forms of collateral support to consider, which are customarily applicable in respect of the PSC, are bank guarantees and corporate guarantees.

A bank guarantee, which tends to be used to address shorter term liquidity concerns in respect of the contractor, is issued by a bank or other financial institution. Bank guarantees take various forms and the associated nomenclature is often applied imprecisely. A demand guarantee (also called a 'performance bond') is essentially an unconditional undertaking by a bank to pay a specified amount to a named beneficiary, sometimes with reference to an underlying obligation (such as certain commitments in the PSC) but often with no reference to the need to evidence any default under that underlying obligation. For this reason a demand guarantee can be construed as a primary obligation, and is truly abstract and not a guarantee or secondary commitment in the strictest sense. The bank will be obliged to honor a demand guarantee in accordance with its terms, making payment on demand if so stipulated, without the application of any conditions. Standby letters of credit fulfil a similar function to demand guarantees, although they employ a different vernacular in their operative provisions because they are essentially documentary credits.

A corporate guarantee is a form of guarantee which is given to the grantor (as the beneficiary) by an entity (which is usually the parent company of the contractor party which has been appointed to act as the operator (B8.1)) in respect of the contractor's commitments under the PSC. A parent company guarantee could present difficulties in enforcement by the grantor, since in practice it is unlikely to be honored on demand and without question by the guarantor and so further enforcement action by the grantor might be necessary.

There is no industry-wide standard or model form corporate guarantee and so the terms of a guarantee will need to be negotiated between the grantor and the guarantor. That said, most guarantees tend to follow a relatively formulaic structure. A corporate guarantee is a contract in its own right, and requires all the legal characteristics of a contract in order to be enforceable. A corporate guarantee is usually written so that it can only be called upon by the grantor in order to remedy a breach of an obligation in the PSC, and not so that it can be applied electively by the guarantor in order to make good a default of the contractor. The guarantor promises to be responsible for the debt or default of the contractor, and the guarantor's liability under the

terms of the guarantee will not ordinarily come into existence unless and until the contractor fails to perform the underlying obligation. Thus, the obligation of the guarantor under a corporate guarantee can be said to be secondary and not primary.

A bank guarantee could be procured by the contractor as security for certain defined payments under the PSC. The contractor's payment obligations will initially apply principally in connection with the performance of the exploration period obligations, where such payment obligations could take the form of an obligation to pay liquidated damages for a failure to perform an exploration period obligation or a right to pay a monetary amount in replacement for the need to perform an exploration period obligation (B6.3). A corporate guarantee which is issued in respect of the PSC could be applied to the entirety of the contractor's obligations under the PSC and not just those which apply during the exploration period (and, reflective of this, a corporate guarantee is sometimes described as a 'general performance guarantee').

The liability of the contractor to meet the costs of decommissioning the petroleum production, processing, storage or transportation infrastructure used in the performance of the petroleum operations (B7.4) could also be the subject of the provision of collateral support, although the costs of decommissioning could also effectively be covered by actual payments into a targeted sinking fund (B7.4).

The issue of a bank guarantee has an inevitable cost associated with it, which the contractor will seek to cost recover (B9.1). For this reason the grantor might prefer to be the recipient of a corporate guarantee. On the other hand, a bank guarantee might be more easily enforceable by the grantor than a corporate guarantee, which could become the subject of a dispute regarding compellable payment.

The required forms of the various guarantee documents could be appended to the PSC,¹⁰⁸ but this is not obviously sensible. A guarantor (whether a bank or a corporate entity) will invariably have its own preferred guarantee form which it will prefer to use. Perhaps the better option is for the PSC to spell out only the essential elements of the guarantee which would be required from the grantor's perspective.

B22.3 Collateral support terms

The contractor could seek to moderate the PSC's obligation to provide collateral support in the following ways:

- (1) where the collateral support takes the form of a bank guarantee and is given in respect of the exploration period obligations costs (B6.4), the guarantee is not procured up-front for the entirety of the exploration period obligations, but rather is procured by the contractor only in respect of the next-following period of exploration phase activity. This would be done in order to reduce the

108 See the Afghanistan, Tanzania and Uganda PSCs.

size of the guaranteed amount and so the cost to the contractor of procuring the guarantee;¹⁰⁹ and

- (2) where the collateral support takes the form of a bank guarantee for a defined monetary amount (such as the entirety of the exploration period obligations costs), the size of the guaranteed amount is reduced by defined increments against proof of work which has been done by the contractor in satisfaction of the exploration period obligations.¹¹⁰ This proposition is more realistic where the exploration period obligations relate to a lengthy period of time for their performance and/or to obvious reductions in work obligations which can be the subject of quantified translation to the amount of the guarantee (and so, for example, this proposition is less realistic for short run or limited obligations such as the drilling of a single exploration well).

Where the contractor procures collateral support in respect of its PSC obligations that collateral support will typically be provided solely by the operator in respect of all the liabilities of the contractor parties who together make up the contractor (B1.2). Arrangements would then be made under the JOA (between the contractor parties in their capacity as the JOA parties) to re-allocate that provision between themselves and to make good the provision which was made by the operator. This is more likely than a construction whereby each of the contractor parties who together make up the contractor would make individual and direct provision of their respective shares of the required collateral support in favor of the grantor.

The requirement of the contractor parties to procure collateral support in favor of the grantor under the PSC should not be conflated with the requirement of the same parties to procure collateral support in respect of their obligations under the JOA. These are separate obligations and they should not overlap (despite the concern which is sometimes felt that two sets of collateral support are seemingly being procured in respect of a single set of petroleum project commitments).

109 See the Egypt PSC.

110 See the Afghanistan PSC.

B23 The joint operating agreement

A joint operating agreement (JOA) will be employed where the contractor represents the interests of several persons acting together in an unincorporated joint venture to hold the PSC between themselves. The JOA, as the effective constitution for the unincorporated joint venture between the contractor parties for the exploration for and the production of petroleum and for the management of the PSC, will provide for how the petroleum operations that are required to be performed under the terms of the PSC will actually be performed (and financed) as between the contractor parties.

B23.1 The JOA's role

The role and the content of the JOA in upstream petroleum arrangements is a topic which has been widely considered in industry literature.¹¹¹

In the simplest case the grantor will award the PSC to a single company as the contractor. This has typically been the case for relatively modest petroleum projects, where a low level of technical complexity and/or financial exposure (found, for example, in respect of any combination of easy exploration, shallow depth drilling, onshore petroleum deposits or crude oil production) means that a single company can hold the PSC and can comfortably perform the associated work obligations. In this situation therefore it is not necessary to consider the manner in which a joint venture will be documented. However, where petroleum exploration and production projects become more complex and more expensive (such as where any combination of complex exploration, deep drilling, and offshore petroleum deposits or natural gas and liquids production exists) then the associated expense and technological risk could be spread more widely, across a group of persons that have come together for that purpose. In such a situation the PSC might be held by several parties (whether by award at the outset or subsequently by a series of farm-in arrangements), that have agreed to act together in a joint venture.

Several elements of the JOA will have a common interest with the PSC:

- (1) a key element of the JOA is the appointment by the JOA parties of a designated operator. It is customary that the same entity will be the operator under both the JOA and the PSC (B8.1), although the roles will necessarily be different;
- (2) the JOA will recite several percentage participating interest shares in the PSC, which are allocated to each of the JOA parties and which together will add up to 100 per cent. This will equate to the similar provision in the PSC where it is applied (B1.2);

111 See *Joint Operating Agreements*:

Peter Roberts and Reg Fowler, *A Practical Guide*, 4th edition (Globe Business Publishing, 2020).

- (3) the JOA will apply a mechanism for approving a proposed transferee of a JOA party's interests, which could be accompanied by a pre-emption right. These provisions could have their counterparts in the PSC (B21.1);
- (4) the importance of the PSC will be reflected in provisions in the JOA whereby the JOA's appointed operator will undertake to keep the PSC in force, and the JOA might also impose an obligation on all of the contractor parties not to do anything that might jeopardize the PSC;
- (5) data could have a particular meaning under the JOA (where it is typically described as 'joint venture data'), which could overlap with the grantor's expectation of data ownership under the PSC (B14.2); and
- (6) the JOA will have an appended accounting procedure which will have many common elements with the PSC's accounting procedure (B25).

B23.2 The grantor's interest in the JOA

The JOA which underlies the PSC represents the horizontal relationship between the contractor parties and regulates their internal arrangements regarding the operation of the PSC. The JOA is quite separate from the vertical relationship between the grantor and the contractor which is created by the PSC (B1.2) but despite that the grantor could make its influence felt in relation to the JOA in a number of ways.

The PSC could mandate the form of the JOA which the contractor parties are required to enter into, or the PSC could at least require that the JOA which the contractor parties wish to enter into has been approved beforehand by the grantor.¹¹² Subsequent amendments to the JOA could also require the grantor's approval. The JOA form could be based upon any form which the contractor parties wish to use. Internationally, the most widely used model form JOA is that which is published by the Association of International Petroleum Negotiators (AIPN).¹¹³ In certain jurisdictions, the prevailing regulatory authority mandates a form of JOA for use in that jurisdiction:

Brazil – the Brazilian upstream regulatory agency ANP mandates a particular short-form 'consortium agreement' for entry between consortium members where a PSC is granted. This is a registrable document. A more conventional full-length JOA will also be entered into separately between those persons to record the terms of their joint venture.¹¹⁴

Denmark – in Denmark the government, acting through the Danish Energy Agency (DEA), has a prescribed form of JOA for use locally. Nordsøfonden (The

112 See the Angola, Equatorial Guinea and Somalia PSCs.

113 Available at www.aipn.org.

114 The consortium agreement form is available at https://www.filesrodadas.anp.gov.br/ingles/contratos_e_editais.asp#modelos.

Danish North Sea Fund) is the mandatory state partner in licenses awarded for the exploration for and the production of petroleum in Denmark.¹¹⁵

Greenland – in Greenland the Ministry of Industry and Mineral Resources has a prescribed form of JOA for use locally. A state-owned entity, Nunaoil A/S, is a mandatory participant in the petroleum operations. Model form JOAs have been prescribed for each Greenland licensing round since 2002.¹¹⁶

Norway – in Norway, petroleum exploration and production operations can be undertaken by private sector participants, subject to the award of an appropriate license by the state. Joint licensees are required to cooperate through a form of JOA approved by the Norwegian Petroleum Directorate (NPD).¹¹⁷

The need for the grantor to become involved in the business of the JOA arises because if there is a state participation right in the PSC (B11) then the grantor (or any other state representative or nominee) will become party to that JOA at a later date and would like to know and to control what it is signing up for. The AIPN model form JOA expressly considers the prospect of the participation of a state representative, and also applies an optional formulation whereby, rather than admitting the state representative to become a new party to the existing JOA, a separate JOA is entered into between the contractor parties and the state representative solely in respect of the state representative's participation.

Also, if the JOA is a vehicle for the appointment of an operator for the purposes of the PSC (B8.1) then the grantor will have an interest in the terms of the JOA because of the bearing which it has on the PSC in this regard.

The grantor could also reserve the right to attend operating committee meetings under the JOA in the capacity of a non-voting observer, notwithstanding that a state participation right has not been exercised, so that the grantor can better understand how the petroleum operations are being conducted by the contractor. Much of what is discussed in such meetings could also overlap with what is discussed within the management committee of the PSC however (B8.2).

115 The JOA form is available at <https://ens.dk/en/our-responsibilities/oil-gas/legislation-and-guidelines>.

116 The JOA form is available at <https://www.ogel.org/legal-and-regulatory-detail.asp?key=3433>.

117 The JOA form is available at www.npd.no.

B24 Miscellaneous

A fully functioning PSC will contain a number of other provisions which do not necessarily fit within the preceding sections of this guide, but which are no less important than the preceding provisions of the PSC for that reason.

B24.1 Anti-bribery and corruption

Although this is only a relatively recent phenomenon in the context of upstream petroleum granting instruments (in contrast with most other forms of commercial contract), the PSC could contain defined anti-bribery and corruption (ABC) provisions which the parties undertake to comply with. This could include an obligation of the contractor to design and implement certain anti-bribery and corruption policies which can be audited by the grantor.¹¹⁸

The anti-bribery and corruption provisions could be drafted at length in the PSC, or they could reference an applicable item of legislation such as the United States' Foreign Corrupt Practices Act 1977, the United Kingdom's Bribery Act 2010 or any local equivalent item of legislation which applies in the host state.

B24.2 Confidentiality

The PSC will usually contain a confidentiality provision, whereby confidential information is defined by the PSC and the parties are obliged to keep that information confidential and are only permitted to disclose it under a limited number of circumstances. The principal purpose of the confidentiality provision is to protect the value of the operational data generated through the performance of the petroleum operations which is inherently valuable. This data will belong to the grantor ordinarily (B14.2), and could be released to third parties by the grantor for a fee.

The confidentiality obligation under the PSC will apply in respect of each contractor party, and will apply not only for as long as the contractor party is party to the PSC but also after it has ceased to be party to the PSC.

The grantor or the contractor might also wish to reserve in the confidentiality provision a specific right to publish the terms of the PSC as part of a commitment to extractive industries transparency initiatives.

A contractor party might be obliged to publish a (possibly redacted) version of the PSC in order to comply with the requirements of a stock exchange upon which it is listed, and so would reserve a specific disclosure right for this in the confidentiality provision.

B24.3 Corporate and social responsibility

In recent years there has been an increasing trend towards companies declaring that their commercial operations are conducted in compliance with a series of protocols

118 See the Somalia and Tanzania PSCs.

regarding ethical behavior and social responsibility, sometimes paraphrased under the headings ‘sustainable development’, ‘ethical behavior’ or ‘corporate and social responsibility’. Consequently, the PSC could contain a broad declaration by each of the parties that its performance of the PSC will be undertaken in a socially responsible manner and in compliance with certain protocols. The purpose of doing this will often be so that a contractor party can disclose the fact of this compliance to its shareholders and to its wider stakeholder community, as evidence of its commitment to being a good corporate citizen.

As for the definition of the applicable protocols, regard might be had for example to the declarations of the International Petroleum Industry Environmental Conservation Association (IPIECA),¹¹⁹ the International Union for Conservation of Nature¹²⁰ and its joint commitments with the International Association of Oil & Gas Producers,¹²¹ the Equator Principles governing social and environmental issues in project financing,¹²² and the Voluntary Principles on Security and Human Rights.¹²³ This is by no means an exhaustive list.

The corporate and social responsibility provisions which are suggested above are slowly finding their way into newer editions of JOAs, where all of the parties could have an interest in seeing them recited. In the context of the PSC however this is still a relatively unexplored area, and the grantor could be particularly reluctant to make a public statement of its intention to comply with these sorts of commitments.

As a practical example of where some form of corporate and social responsibility could manifest itself in relation to the PSC, and particularly in relation to an onshore contract area, the contractor could be required to undertake an initial, and a periodic subsequent, social impact assessment, which analyzes the effects of the contractor’s activities on any affected local communities and which outlines the contractor’s plans for local community engagement and development.¹²⁴

B24.4 Currency and remittance

The contractor could fund its petroleum operations and could operate the business of the PSC in several currencies. Costs incurred and revenues received could be reduced to a single currency (usually US dollars) for ease of reference in the cash movement provisions of the PSC’s accounting procedure (B25).

The contractor could require provision in the PSC that it can remit revenues to

119 See <https://www.ipieca.org/>.

120 See <https://www.iucn.org/>.

121 See <https://www.iogp.org/>.

122 See <https://equator-principles.com/>.

123 See <https://www.voluntaryprinciples.org/>.

124 See the Afghanistan PSC.

outside the state, and that it can retain abroad revenues earned from the sale of its petroleum entitlements. The grantor, on the other hand, may have a preference for retaining as much international currency as possible in the state. This could be an issue in less-developed states, where shortages of international currency could be a feature.

B24.5 Definitions and interpretation

The PSC will have a definitions section, where key terms used in the PSC are expressly defined. The PSC could also recite certain principles of interpretation which are intended to apply to the words of the PSC.

The PSC could utilize what are regarded as well-known industry terms without definition, but in the event of a dispute the grantor and the contractor could have very different ideas about what these undefined terms were intended to mean.¹²⁵ As an alternative to drafting definitions in the PSC, the PSC could instead refer to the terms of any applicable petroleum code or other item of supervening legislation which recites at least some of the necessary definitions, in the interests of consistency.

Where regulatory requirements preclude amendments to the form of the PSC which was advanced during a public bid round (A3.1), which could even include amendments which are obviously necessary to be made in the interests of promoting clarity or addressing any obvious mistakes in the PSC, it might be possible to produce a collateral interpretation guide to the terms of the PSC, to be agreed between the grantor and the contractor¹²⁶ (perhaps as part of a wider procedures manual relating to the operation of the PSC). Such a guide would not necessarily have legal force between the parties but it could have strong persuasive value in the event of a later dispute between them.

B24.6 Indexation

The PSC could provide that ostensibly fixed payment amounts which are due from the contractor to the grantor under the PSC (such as rental payments, bonuses and training payments) will be indexed for the lifetime of the PSC according to a specified indexation formula, so that they at least keep track with general inflationary movements.¹²⁷ This could be done in several ways - inflation could be measured according to a published index (such as the Consumer Price Index (CPI) or the Retail Price Index (RPI)).

B24.7 Insurance

The PSC could require the contractor to put in place a comprehensive policy of insurance in respect of the petroleum operations (including coverage against

125 See footnote 50.

126 See the Angola PSC.

127 See the Cameroon and Tanzania PSCs.

pollution clean-up costs, third party liability claims and to protect the value of any assets which are acquired or developed as a consequence of the petroleum operations – although if title to these assets has transferred to the grantor (B14.1) this could be an insurance obligation of the grantor, which has the insurable interest. If the contractor does take out such insurance the grantor’s interests in the insured property could be noted by making the grantor a co-insured person on the policy of insurance). The costs of procuring the insurance coverage which is required by the PSC will typically be recoverable costs under the PSC (B9.1).

Other insurances which the contractor wishes to take out in respect of its interests under the PSC, such as political risk insurance, business interruption insurance or insurance against liabilities which the contractor might have to the grantor in respect of the PSC (B17.2), will typically be for the account of the contractor.

The grantor could wish to be involved in the process of selecting the appropriate insurers, and the PSC might mandate that primary insurance must be placed by the contractor with a local entity (which will then re-insure all of the insured risks in the commercial insurance market) or that the primary insurance must be placed in the host state. The prospect of self-insurance by the contractor might not be approved by the grantor.

The grantor could also require that any policy of insurance which the contractor effects should, for completeness, contain waivers of subrogation from the insurers against the grantor and the wider state.

A further issue to consider in the PSC is provision for the reinstatement of any damaged or destroyed facilities in respect of which a successful insurance claim has been made. The contractor could require the insurance proceeds to be applied to reinstatement and the continuation of petroleum operations, whereas the grantor could have a different perspective if it is the recipient of those proceeds. Rarely is this issue addressed in detail in the PSC.

B24.8 Language

The PSC could be written in the language of the host state or in another language (typically English), or in both languages. If both languages are used the PSC should be careful to recite which version has primacy in the event of a dispute between the parties and which version is intended only for interpretation purposes.¹²⁸

B24.9 Third party access

The PSC could outline principles whereby third parties are to be afforded rights of third party access (TPA) to facilities, which are operated by the contractor for

128 The easiest way to spot the translation of a PSC into English from a native language is to look at the defined terms, which no longer appear in English alphabetical order.

the conduct of the petroleum operations, if such a notion is a feature of the host state's law.¹²⁹

B24.10 Waiver

The PSC could contain a waiver provision,¹³⁰ which in simple terms states that a party cannot claim that its requirement to perform a particular obligation under the PSC has been waived unless that waiver is evidenced by a written instrument, signed by the party in whose favor the obligation was to be performed. The waiver provision is intended to prevent alleged, oral and unproven variations to the terms of the PSC.

From the contractor's perspective the waiver provision means that any exploration programme obligations and their associated costs (B6.4), work programmes and budgets (B12.1) or field development plan commitments (B7.2) cannot safely be claimed to have been modified, deferred or avoided unless the written agreement of the grantor exists. This will be a critical issue where the grantor seeks to terminate the PSC for a material breach of a term of the PSC by the contractor (B2.5) and where in response the contractor claims that the grantor had previously acceded to the alleged breach by agreeing to waive the need for full compliance with the relevant term.

The force majeure provision in the PSC (B18.1) could offer partial relief from an affected party's performance obligation without the need for the consent of the non-affected party, but should not be taken as proxy for a waiver provision.

129 See the Tanzania PSC.

130 See the Afghanistan and Cyprus PSCs.

B25 The accounting procedure

A procedure will be appended to the PSC which sets out the accounting elements that will exist between the parties as a consequence of the performance of the petroleum operations, to be administered by the operator. The PSC's accounting procedure should be made consistent with the accounting procedure in the JOA, although they perform different functions.

B25.1 The contents of the accounting procedure

Although the content of accounting procedures will vary between different PSCs, as a general observation the PSC's accounting procedure will typically recite the following elements:

- (1) the periodic reporting (usually monthly, and also with provision for an annual statement) by the operator to the grantor of the movements on a number of items over a defined period of time: incurred petroleum operations costs; received petroleum production revenues; quantities and grades of produced petroleum; petroleum valuation and realized petroleum sales prices; payments of rental payments, royalties and other amounts due to the grantor; cost recovery statements; and decommissioning fund movements;
- (2) the definition of recoverable and irrecoverable petroleum costs (B9.1);
- (3) the operator's maintenance of accounts, records and reports relating to the petroleum operations, to be held at a defined location and to be made available for the grantor's inspection;
- (4) the maintenance of bank accounts by the operator and the specification of the contractor party and grantor bank accounts to which payments due under the PSC are to be made;
- (5) the valuation of materials which have been purchased and disposed of by the operator in the performance of the petroleum operations;
- (6) the conduct of periodic inventories by the operator, the valuation of assets and the maintenance of asset records;
- (7) the ability of the operator to charge an amount to reflect its general and administrative (overhead) costs (B8.1); and
- (8) the preparation of periodic budgets and forecasts by the operator.

The accounting procedure could also set out certain procurement provisions if they have not been addressed elsewhere (B12.5), and also the detailed definition of taxes and deductible expenses to which the contractor is subject (B10.5). Ideally, the accounting procedure would also recognize the need for separate accounting for exclusive operations undertaken by the grantor (B12.4) but this detail is not always apparent.

B25.2 The mechanics of the accounting procedure

The accounting procedure will describe the accounting standards and conventions, the languages, the currencies (and the currency conversion protocols) and the units of measurement which will apply variously to its contents. The accounting procedure will also describe whether the cash basis or the accruals basis (or even both) will apply to the operator's accounting.

The accounting procedure will reserve rights for the grantor to inspect the various accounts, records and reports, and also to commission an independent audit of the same if it so chooses.

The accounting procedure will also usually provide that it can be amended by written agreement between the parties. This could apply generally where the operational experience of the PSC suggests that changes might be needed, and also as a reaction to a claim by a party that the accounting procedure is leading to unfair or inequitable treatment of that party.

In the event of a conflict between the accounting procedure and the main body of the PSC the usual resolution is that the main body of the PSC will take precedence.

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A Practical Guide to Upstream Petroleum Granting Instruments reviews the content and the effect of the various forms of granting instrument which are used worldwide for petroleum exploration and production.

The guide begins with a general review of the use of granting instruments for the regulation of petroleum exploration and production activities (including consideration of the various forms of granting instrument and how they are awarded), and then goes into a clause-by-clause analysis of the terms of a production sharing contract (as the most widely used granting instrument worldwide, although the content of this analysis will also be relevant to the terms of other forms of granting instrument).

The analysis of the production sharing contract's terms also identifies and references a number of publicly-accessible production sharing contract examples for further illustration of the provisions which are discussed.

