Introduction and Overview on Upstream Petroleum Contracts

Upstream petroleum agreements and the associated fiscal regimes are the cornerstone of the relationships between petroleum countries (the host countries) or their national oil companies (NOCs) and foreign investors (the international oil and gas companies, IOCs). They are indeed the instruments implementing the specific petroleum policy decided by each sovereign country. Their terms directly reflect the conditions under which IOCs accept to invest in an upstream venture.

Upstream petroleum agreements are often called petroleum exploration and production contracts (E&P contracts). They govern, under the law of the country and in particular the petroleum law, the obligations and rights of the petroleum investors. These are quite long-term contracts concerning a specific contractual area awarded to the investor on an exclusive basis by the host country, based on the applicable legislation and taxation. In particular, they define, in case commercial petroleum discoveries are developed and exploited, how the production, incomes, and risks will be allocated between the government and the investor over the field’s producing life as a direct consequence of the fiscal regime associated with E&P contracts.

E&P contracts and the associated fiscal regimes may be of several types depending on the legal system used in the country and its selected petroleum policy. While the main types of E&P contracts and fiscal regimes have been established a long time ago, the terms of each type of upstream petroleum contracts and fiscal systems have considerably changed in the last decades. The objectives of this chapter are to review the features of each main type of upstream petroleum agreements and their associated fiscal systems, and to outline their major trends and evolution. In particular the chapter seeks to answer the following questions. How are a country’s petroleum policy and E&P contracts interrelated? What are the main differences between each type of E&P contract and fiscal regimes? What main changes in E&P contracts have recently occurred? How to define “a fair government take” under a fiscal system? When may a fiscal stabilization clause be justified? What adjustments are required to account for unconventional oil and gas?
Evolution of Upstream Petroleum Policies and Their Impact on E&P Contracts

In most countries the state is the sole owner of the underground resources (ownership of which is generally distinct from the rights vested in surface landowners) and exercises sovereign rights over their exploration and exploitation. It decides on the petroleum policy it wishes to apply in the long term and in particular on the role it selects to grant to private investors, mostly foreign companies, in the exploration and production of petroleum in the country. The sovereign state may decide to open or not selected areas within the country and its exclusive economic zone for further upstream activities by foreign companies; when to award E&P contracts and how to select the winning companies among qualified applicants for a given area; or whether to encourage, and at what extent, direct investments by foreign companies in its territory.

An upstream petroleum policy represents a balance between the interests of the country and those of investors. This balance depends on many factors and varies over time. Today, only some countries remain closed to IOCs (see Box 8.1), considerably less than

Box 8.1 Countries open or closed to foreign direct investment in petroleum exploration and production.

Since the opening of E&P to foreign investors in the former Soviet Union in the early 1990s, most countries are now largely open to direct investments by foreign petroleum companies, with the exception of the following:

- **Mexico**, since the nationalization of the oil industry in 1938. However, risk services contracts (RSCs) are now authorized in selected areas. Several contracts of this type were signed since 2005, mostly related to mature fields to be redeveloped.
- **Kuwait**, since the entire nationalization of the oil industry in 1976. However, technical assistance contracts were entered into with IOCs. Other types of contracts were considered, such as RSCs, but the law enacting them is not yet promulgated.
- **Saudi Arabia**, since full nationalization of the industry in 1976. Four concession contracts were however signed with IOCs since 2003 but only for non-associated gas exploration and exploitation, excluding oil.

In some other exporting countries where the petroleum industry was previously nationalized selected areas are now open to foreign direct petroleum investment, while the national or local companies continue to carry out a significant share of the petroleum activity, in particular from the petroleum fields producing before the reopening to foreign investors. This is the case in many OPEC countries, Russia, and China. Today over 50% of world petroleum production continues to be directly carried out by national or local oil companies without any involvement of IOCs. Globally NOCs have access to over 80% of worldwide discovered reserves.

Access to new exploration and production areas has become a key priority for IOCs in the last decade in order to renew their reserves. Technological progress and higher prices now allow exploration in new zones or deeper horizons for unconventional oil and gas resources.
TRENDS IN UPSTREAM PETROLEUM AGREEMENTS

two decades ago. In all other countries which desire foreign investments the pace for the awards of E&P contracts and the location of the contract areas remain at the sole prerogative of the state, which often associate companies in the pre-selection of the areas of interest to the industry.

To implement its upstream petroleum policy, each country promulgates an *upstream petroleum law* which defines in particular how to authorize IOCs to carry out exploration and exploitation operations and how to define the terms and conditions to be met by specific E&P agreements. The applicable petroleum tax regime is often governed by a special chapter added at the same time to the general tax law. The petroleum law deals with the E&P provisions regarding exploration for both oil and natural gas, and in case of a commercial discovery, its development and production until field decommissioning and site restoration operations at the end of the exploitation. Exploration of a specific contractual area may exceed 10 years and is performed in phases with distinct work commitments. Petroleum exploration remains a quite risky activity because no commercial discovery may be found. When a commercial discovery is demonstrated and approved by the state, the contract-holder will develop and then produce it during a period which may exceed 30 years, subject to the applicable petroleum tax regime.

The terms of new upstream petroleum contracts and tax systems have considerably changed throughout the last decades, following closely the respective political evolution in developed and developing countries and the many changes in the international oil and gas markets. Undoubtedly the role and policy of the Organization of Petroleum Exporting Countries (OPEC) since 1960 was a catalyst in the evolution of the relationships between petroleum host countries and investors, resulting today mainly in higher government take in upstream profits and higher state control and participation in upstream activities, especially in the most promising producing countries in terms of reserves. Meanwhile, other countries not yet at this stage of petroleum maturity have adopted, or were induced to adopt, more attractive policies and fiscal incentives designed to encourage companies to search for and exploit petroleum in their territory.

The accelerated volatility in international oil and gas market prices in the last decades, reflecting the changing world oil supply and demand balance, had a major impact on the terms of E&P contracts and fiscal regimes, requiring for example the introduction of more progressive fiscal systems, robust enough to maintain a fair government take in case of large price fluctuations. In addition, both petroleum producing countries and IOCs are giving more and more priority to the environmental and socio-economic issues, because petroleum resources, being non-renewable riches, should benefit during their relatively limited exploitation life all the stakeholders and foster a sustainable development for the country and the local communities concerned by the activity. To that end, new clauses are now included in E&P contracts.

**The Main Forms of Upstream Agreements and Licenses and the Related Fiscal Regimes**

E&P contracts concluded between host countries and qualified investors may take different forms in relation to the legal system used by the country and more specifically to the policy selected for enacting the applicable petroleum law. Box 8.2 summarizes the different forms of E&P contracts or licenses awarded by states. These may consist in the award of *oil and gas licenses* (e.g., an exploration license followed by, in case of commercial development, a production license), without the signing of a distinct agreement, when the country’s petroleum law and its regulations define in great detail the conduct...
Box 8.2 Differences between E&P petroleum contracts and licenses.

The term “E&P contract” in this chapter refers to any agreement or legal instrument authorized under the applicable law between a host country (or its NOC) and an oil or gas company (or more frequently a consortium of companies) selected by the country to conduct exploration within a specific area, on an exclusive basis and at its own risk, and in the event of commercial discovery, the development and production of the discovered oil and natural gas fields.

The petroleum law enacted in a country may provide for different legal instruments, generally known as E&P contracts, depending on the petroleum policy decided by the country. Two main approaches are followed.

1. The award of specific petroleum licenses under terms entirely defined in the national legislation and regulation. The license may be (1) an exploration license (or permit) over an exploration area authorizing exploration, or (2) a production license (or lease or concession) over a restricted development area authorizing the development and production of a commercial field. In this case, no E&P contract per se is signed because all the terms are fixed by the law and detailed regulations, as in the US, Canada, or Australia, etc. Even if such licenses are not governed by a distinct concession contract they are categorized from a legal point as pure concession agreements. Sometimes, the award of a license under the country legislation is subject to the execution of a short license (or concession) agreement providing for a few specific terms regarding exploration work obligations (such as in the UK, Norway, and Denmark) and sometimes selected tax terms (e.g., related to an additional profits tax).

2. In countries which do not have yet issued comprehensive legislation and regulation, as currently in many developing countries, there is the conclusion of a detailed E&P contract under the national law, which provides for the terms and conditions applied to exploration and production not covered under the legislation and regulation, including for certain tax aspects when the law does not fix them. In most cases, the contract deals with the subsequent award of administrative exploration and exploitation licenses or authorizations as an automatic consequence of its signing and satisfactory performance of each period of the contract.

In this chapter any reference to “E&P contracts” covers the two above situations.

of petroleum activities and the related fiscal regime. Alternatively, when the petroleum law only provides for the main principles and when the fiscal system is not fully defined by national law, the award of E&P rights may result from the effective signing of a quite detailed E&P contract, which corresponds to the ad hoc investment agreement for petroleum. The contract deals both with exploration and exploitation provisions consistent with the petroleum law and defines the elements of the fiscal regime not fully fixed under the law. The requirement for signing a detailed contract is often the situation in developing countries or in countries without a long petroleum history. The law generally states that as a consequence of the signing of contracts, petroleum licenses or specific exclusive authorizations, which are quite short administrative documents, will
then be issued for authorizing exploration and exploitation pursuant to the procedure set forth in the law or its regulation.

Each E&P contract is associated with a fiscal regime (also called system or package) which consists of the set of economic and tax provisions applicable to the contract-holder. That fiscal regime is defined by the tax and petroleum laws of the country. It is however often supplemented by a few specific terms provided for in the E&P contract when so authorized by the country law. Nevertheless, there is a new tendency to apply in a country, at a given time for new contracts, the same tax regime to all newcomers (except for one or two fiscal terms) in order to facilitate the implementation of many contracts and develop transparency between investors. The fiscal regime has a paramount importance both for the government and the company because it directly governs the allocation of the production and revenues between the country and the contract-holder. It determines the aggregate of the share of production and the different taxes payable to the country, referred to as the government revenues and often expressed in percentage as the government take in the petroleum profits derived from a given contract area or project. In any country, the petroleum fiscal system consists of several sources of government revenues. Their nature directly depends on the type of E&P contracts, as explained below. This is the reason why in this chapter both the evolution of E&P contracts and fiscal regimes are highlighted when presenting each type of upstream contract.

The award of E&P licenses or contracts more often results today from competitive biddings organized by the country pursuant to a transparent tender procedure. In some cases however a contract may be awarded following direct negotiations when the petroleum law so provides and the conditions justify it, for example when the competition would be insufficient for the concerned area. In both systems of awarding E&P licenses, only a few numbers of terms, including for the fiscal regime, are today subject to bidding or negotiation. The contract has also to be established on the basis of the model E&P contract or license elaborated by the country before the tender or the negotiation.

Evolution of the Main Types of Upstream Agreements and Associated Fiscal Regimes

When a country wishes to attract new investors, the types of E&P petroleum contracts and related fiscal regimes available today in the world are so-called modern concession agreements and the production sharing agreements; risk services agreements are sometimes also used but less frequently. Indeed, in the last decades no new types of upstream agreements were introduced, but the terms of each type of agreement and their related fiscal systems changed significantly, adapting to the new volatile environment of international oil and gas markets. Depending on its petroleum policy and the characteristics of the acreage to be tendered, the country selects the type of E&P contracts that it considers the most appropriate for the tender or negotiation.

In all these arrangements, the state remains owner of the petroleum resources when in the ground and the contract-holder is obliged to undertake and fund, at its sole risk, all the petroleum operations, only being remunerated if the exploration is successful and leads to the exploitation of commercial fields. The main differences between the main types of upstream petroleum contracts arise indeed from the remuneration scheme for the contract-holder, namely (1) its share in the production extracted from the fields, varying from 100% under concessions to significantly lesser percentages under the other types of contracts, and (2) its specific tax obligations under the national law. The total government take under a contract integrates the different sources of revenues for
the state or its NOC, both the tax payments made in cash and the revenues derived from the access to a share of production, if any, directly taken by the country. The main characteristics of each type of E&P contracts and associated fiscal regimes are summarized below.

**Concession Agreement**

This is an old legacy from the regime used in the mining industry in the nineteenth century, whereby the government grants oil and gas mining rights (generally named exploration license or production lease) giving exclusive rights to all the petroleum extracted by the concessionaire from the licensed area. The company becomes the owner of the entire oil and gas production when extracted at the wellhead – or at another agreed point of transfer of title – and markets it. The original concession regime was criticized by many developing countries and has gradually evolved toward what is known today as the modern concession agreement updated to better safeguard the legitimate interests of the host country. The concessionaire, also called the licensee or lessee, is subject to different tax obligations depending on the country policy implemented in national law, namely:

- **Ad valorem royalty on production**, payable in cash or in kind at the election of the country and equal to a percentage of the monthly (or quarterly) petroleum revenues. In some cases, the concessionaire is exempted from royalty, as in many European countries for the North Sea offshore operations. The royalty rate is generally fixed by the law either as a unique rate or a progressive royalty scale based on different technical or, as in Canada, economic parameters.

- **Corporate income tax** (CIT), corresponding to a percentage of the annual net incomes or profits computed after deducting eligible expenses, costs, and capital allowances. The CIT rate may be the generally applicable corporate tax rate stated in the tax code of the country or the higher tax rate specific to upstream petroleum operations fixed by law. The corporate tax is often determined on a consolidated country basis for all the upstream activities of a company, and not per contract, concession or field, unless the tax law provides explicitly for smaller tax ring-fencing, for example per concession.

- **Additional profits tax** (APT), which may have different names, is an annual tax payable, in addition to the CIT, only when some conditions of profits or petroleum price are met. That type of supplementary tax on profits was introduced by several countries since the 1970s and 1980s when the oil price was abruptly raised. The APT is assessed in many producing countries on an adjusted cumulative cash flow basis determined per company or per concession, such as in the UK, Norway, Denmark, The Netherlands, Australia, etc. APTs are now applied under different mechanisms in more and more countries with the objective of achieving a more progressive fiscal scheme when the effective profitability of projects exceeds predefined levels.

- **Miscellaneous taxes or quasi-taxes**, including bonuses, rental fees, and training fees; withholding taxes on dividends paid by the taxpayer to its shareholders, on interest paid to the lenders for loans, and on the remuneration of foreign subcontractors for services; stamp duties; and in a very few countries export and import duties.

Those tax payments constitute the total petroleum government revenues under concession contracts. The amount and the timing of payments depend on the terms of the petroleum legislation and the applicable concession contract. One of the major drawbacks
of concession contracts was their lack of flexibility, as in many countries most of the components of the fiscal package are entirely fixed by the tax law, except for some fiscal parameters.

In some countries, the state or its NOC may also benefit under a concession contract from an option to participate at a given percentage in the event of a commercial discovery, receiving a proportionate share in the production. The obligation of the participating state is generally assimilated by the investors to a tax obligation when the state is carried by the licensee during exploration and sometimes during development. This means that the state or its NOC holds as co-investor no funding obligations during those periods and therefore does not directly bear the exploration risks, being however, but only in case of production, subject to reimbursing the investor under the agreed terms its pro-rated share in the past investments.

**Production Sharing Contract (PSC)**

First introduced in 1966 by Indonesia, its use has spread rapidly in many developing countries, for political and economic reasons and above all for its fiscal flexibility. Indeed, the PSC provides in the contract itself for specific progressive production sharing percentages when the law does not fix them. Another frequent advantage of PSCs, especially when there is no efficient additional profits tax used by the country under concession agreements, is to allow the country to get a higher government take in the profits from the first years of production.

Under the terms of PSCs, the company does not directly hold the petroleum rights related to the area concerned but is legally appointed to conduct on an exclusive basis the petroleum operations as a contractor to the state or its NOC, by virtue of its contract. As any concessionaire, it is committed to undertake and finance all the work stipulated under the PSC to search for and exploit the oil and gas which may be trapped in the area. In compensation for its activity, and in the sole event of commercial production, the company is repaid in kind for the recovery at cost of its eligible expenses and capital expenditures incurred in exploration, development, and production by being allowed to market a portion of the total oil (or gas) produced, called the cost petroleum (or cost oil and cost gas), up to a maximum annual percentage of total production, called the cost petroleum stop or ceiling. As an incentive to invest, the company also receives a profit element from the portion of the remaining amount of petroleum produced after deducting the cost petroleum, which is called the profit petroleum (or profit oil and profit gas), shared between the contractor and the state according to the terms tendered or agreed upon when signing the PSC, prior to the commencement of exploration. The state’s share in the profit petroleum remains with the host country (or its NOC) and may be directly marketed and sold by the latter. This access by the state to a share of the production is the major difference with the concession contract.

The contractor under a PSC is also subject to several tax obligations dealt with in the law and, when authorized by the law, in the applicable contract. Those obligations may include the payments of royalty (if the law so provides), corporate income tax (CIT) on profits, and various taxes or quasi-taxes (such as bonuses, surface rentals, and social fees). To render the PSC simpler in its understanding and implementation, the profit petroleum sharing may be agreed on an after corporate tax basis, as it was in the original PSCs, under which the income tax is deemed included in the state’s share of profit petroleum allocated to the host country. Under that after tax sharing basis, obviously the host country receives a higher share in the profit petroleum than under a before corporate
tax sharing basis – another system used in other countries where the PSC provides that the country receives two separate revenues: first, a lower state share in profit petroleum; second, a payment in cash from the contractor for its corporate tax liability. Globally, the two petroleum sharing schemes result in similar takes for the state, but the first one grants to the country a higher access to the production as the corporate tax in this scheme is paid in kind and not in cash.

**Risk Service Contract (RSC)**

This was first implemented around 60 years ago by large producing countries. It has today a number of variations. Under RSCs, the company does not hold direct access to a share of the petroleum produced, but in compensation for its work and investments performed as contractor to the state or the NOC it receives, only in case of commercial production, a monetary remuneration which cannot exceed a portion of the market value of the petroleum production extracted from the contract area. RSCs remain today a considerably less common form of E&P contracts between host countries and IOCs. It originated in exporting countries such as Iran, Iraq, Qatar, and Venezuela that nationalized their petroleum industry and gave their NOC the monopoly of exploration and production. They gave to their NOC the right of using companies as service contractors in some specific cases for two main reasons: firstly, their technical capacity to use the most advanced technology, and, secondly, their financial capacity to obtain third-party funds and loans for investment under better terms that those to which the host country would have access. More recently it developed in other exporting countries such as Bolivia, Ecuador, and Mexico.

The main difference between the RSC and the PSC is the fact that, according to the terms of the former, the company does not benefit from direct access to a share of the petroleum produced. It receives during the contract’s duration a monthly or quarterly remuneration, generally called a **service fee**, paid in cash, which is determined under a formula designed with two objectives: (1) to reimburse over several years, sometimes with interest, the eligible investment and operating costs incurred, by allocating up to a maximum percentage of the annual production value, and (2) to provide for a profit element, such as a fee per barrel, which may be variable with parameters (for example levels of production). The service fee is generally subject to the payment of CIT on profits. The company is often entitled under the RSC to purchase at market price and lift a share of the oil produced. This **buy back clause** authorizes the contractor to buy a share of production equal in value to the payable service fee. It provides security to the contractor for receiving its remuneration in case the country would encounter problems with timely paying in dollars of the service fee.

Analyzing over time trends in the type of upstream petroleum agreements selected by countries, an increasing use of PSCs in emerging and developing countries is observed worldwide. Concessions continue however to remain largely selected, especially in most developed countries, but also in some developing countries where a concession contract is often associated with state participation rights. Meanwhile, some emerging and developing countries used to concession agreements decided to introduce PSCs, for example Brazil in 2010 considered PSCs more consistent with its petroleum policy for its new promising pre-salt province. Only a very few countries abandoned PSCs in the last decade in favor of other types of E&P contracts while keeping in force the existing PSCs already signed, namely the Russian Federation and Kazakhstan – where the change was caused by difficulties in implementing a quite specific sharing mechanism as a result of considerably
delayed development projects and Algeria. RSCs have been signed in the last decade in certain exporting countries, mainly for redeveloping producing fields, such as in Iraq (with the exception of the Kurdistan region which continues to prefer PSCs for E&P projects), Mexico, and Ecuador.

**Evolution in E&P Fiscal Regimes: What Could Be a Fair Government Take?**

The main purpose of any E&P petroleum fiscal system consists in determining how the profits are shared between the host country and the IOC, because it directly governs, first, the expected return on the future investment the company is evaluating, and consequently its decision on whether or not to make such investment, and, second, the amount and timing of government petroleum revenues for the country.

The fiscal terms for new E&P contracts awarded by countries, whatever their type, facilitate their implementation and correct any identified loopholes. These fiscal terms evolved in the last decades to reflect the changing international petroleum environment, and at any given time greatly depend both on the international oil and gas price environment at their date of design, and the petroleum attractiveness of the country and area to be licensed.

Since the turn of the twenty-first century, while OPEC countries were offering limited acreage, the combination of rising oil and gas prices with the priority for most IOCs to renew their naturally declining reserves has increased the competition between IOCs for obtaining the most promising open areas elsewhere. The direct consequence was companies offering to countries more favorable fiscal and contractual terms than before for recent upstream petroleum agreements.

The higher petroleum market price environment and the favorable fiscal terms achieved in some countries induced the other producing countries either to demand renegotiation of their fiscal terms or to impose new fiscal terms less favorable to the investors but more representative of the terms generally accepted in other places. Such requests were sometimes accepted and in other cases rejected by investors, leading to arbitrations still ongoing.

By contrast, in the two preceding decades, under the then declining oil and price environment, especially after the price drops of 1986 and 1998, the opposite trend was observed. For continuing their operations or for deciding on new development projects, a number of IOCs were asking host countries to improve the fiscal terms applied in existing contracts or to amend the petroleum taxation in order to provide better terms to investors than previously agreed. Many countries updated their petroleum policy and eventually accepted such requests when duly justified as a means to foster upstream investments and attract new E&P investors under low petroleum prices.

The huge impact of the petroleum market price on the economics of any E&P project, which by experience is highly uncertain and unpredictable, explains the importance of designing fiscal systems associated to E&P contracts with terms sufficiently progressive for maintaining a fair sharing of the profits between the state and the contract-holders when the circumstances become different from those expected, namely, when the oil or gas price significantly rises or decreases, or when the field characteristics are considerably different from those assumed when the petroleum fiscal regime was designed. Therefore, new fiscal schemes were introduced to achieve these mutually beneficial objectives.

Indeed one of the most striking constraints in designing a fiscal package for E&P activities in a country, in addition to price uncertainty, is that the profitability of upstream projects varies in quite large proportions depending on their characteristics, such as the location of the project (onshore, shallow offshore, deep offshore), the petroleum
prospectivity of the area, the chance of success, the expected reserves and production profiles, the type and quality of petroleum to be extracted, the availability of infrastructure in the region to transport the production, etc.\textsuperscript{9} As a consequence, the \textit{petroleum economic rent} for a project – equal to the difference between the realized gross incomes from the production and the total technical costs incurred for exploration, development, production, and abandonment of the field – varies widely in the world. For example, oil prices rose from less than $20 to over $125 per barrel in the last decade, and technical costs today may range from less than $10 to over $40 per barrel, depending on the field characteristics, with the result that the petroleum rent could now fluctuate between $10 and $85 per barrel. The range for rent will indeed continue to increase in the future with the anticipated price rise.

Therefore, \textit{efficient taxation of upstream oil and gas projects} cannot be achieved by using only the general taxation applicable to any economic activity. Petroleum resource taxation requires sector-specific contractual and fiscal schemes. The challenges in designing an efficient fiscal package for upstream contracts, which are entered into for long periods of validity, are to meet the two following objectives at any time while remaining simple enough to be understood: (1) to encourage the company to perform further investments, and (2) to grant to the country a fair share in the rent, not fixed but progressive enough when the project economics and the price improve.

Government revenues and their timing during the production period depend directly on the type of E&P contracts and their fiscal terms. Under \textit{concession contracts}, the country only receives taxes, namely royalty on production, corporate tax on profits, more frequently an additional profits tax, and other taxes. Royalty is paid from the commencement of production on gross incomes, while corporate tax is only paid from the date profits are generated. Additional profits tax (APT) is generally paid from a later date when a predefined profitability criterion is triggered, which may be several years later. A drawback for the national fiscal system is to accurately forecast its future annual revenues, as they depend not only on future prices but also on the schedules of future expenditures and depreciation of past investments allowed as deductions for determining taxable profits. One way to limit the variability of annual corporate tax payments when the IOC holds several contracts at different stages of exploration and production in the country is to introduce a \textit{ring fence} per contract for the determination of corporate tax. This limits the amount of deductible expenditures from other contract areas in the country, with the drawback for the investor of reducing the attractiveness of doing supplementary investment outside the already producing contractual area. For the same reason, most APT mechanisms provide for a \textit{ring fence} per commercial field in order not to delay APT payments.

Under \textit{PSCs}, the country keeps from the commencement of production a share of production which can be sold at market prices, by the country or its NOC, and also receives payments of agreed taxes. The main fiscal terms governing PSCs are: (1) the cost petroleum ceiling and ring-fencing rules which control the pace for cost recovery, (2) the progressive profit petroleum sharing mechanism under which the country receives a higher percentage in production when the economics improves, and (3) taxes, such as corporate income tax and bonuses.

The original simple PSC system of a fixed percentage of profit petroleum sharing is no longer used. It was replaced by a \textit{sliding scale} based on different progressive systems, such as: \textit{increments of daily production} or \textit{cumulative production}; the \textit{R-factor} – a profitability criterion equal to the effective ratio between the accumulated revenues and the accumulated costs for the period from the contract signing date to each date of production sharing – related to a field or a contract area; or the \textit{effective rate-of-return} (ROR), another
well-known profitability criterion related to the field or the contract area achieved for the same period up to each date of production sharing. In the last decade, the R-factor became the profitability criterion most used for triggering progressive sharing mechanisms in the world. The reasons are mainly its simplicity, making it easily understood by policy-makers and investors, and its demonstrated effectiveness. Moreover, in case of cost overruns or project delays, those risks are theoretically less transferred to the country under an R-factor scheme than under ROR systems, as ROR computation integrates by definition the timing of annual cash flows whereas R-factor determines a ratio between cumulative revenues and costs at the date of assessment without any time value consideration. In Angola the ROR system with a ring-fencing per field is however used with great success for deep offshore fields, probably because they are rapidly developed and produced.

The government take (GT) in the petroleum economic rent – the average weighted share of the country’s revenues in the total profits generated by a field along its production life – varies considerably from one country to another. This depends more on the applicable fiscal and contractual terms agreed in each country or region than on the type of contract. In fact, a concession or a PSC can theoretically produce similar economic results and GT when their terms are appropriately selected, but the timing of revenues will be different due to the nature of each type of contract. Today GTs in the world may range from around 45% for the state (corresponding to 55% for the company) to 70–90% for the state (10–30% for the company), when excluding exceptional cases of lower or higher takes and the possible impact of state participation. The weighted average GT in the world is now estimated at around 65–75%, bearing in mind that this average integrates many different situations. In the last decade the general trend everywhere in the world was a continuing increase in GTs. For example in the UK, where there is no fiscal stabilization clause protecting the investors, the effective corporate income tax rate for E&P activity was increased in several steps from 30% in 2000 to 62% in 2011 in order to give a higher GT in the profits, justified by the significant rise of petroleum prices over this period.\textsuperscript{10}

Fiscal terms greatly vary in the world between countries. Globally, the most advantageous fiscal terms to governments occur in countries or basins where the petroleum geology is considered as the most promising and where technical costs and risks are deemed the lowest. Within a given country, fiscal terms may vary depending on the type of E&P projects, the exploration maturity and risks of the contract area, the field characteristics, the category of conventional and unconventional petroleum, and above all the date of award of the relevant E&P contract. This complicates the comparative analysis of petroleum fiscal systems between countries, which should be always done with sound assumptions and interpreted with great care, especially when they are only performed on a simple stand-alone field basis, a scenario which generally does not correspond to the reality as companies are generally investing in a series of projects within a country.

Indeed no magic and unique percentage exists for fixing GTs fairly. For example, fiscal terms leading to a given GT being considered too lenient for a specific field in a country may become too onerous for other less profitable fields located in the same country, explaining why there is no single fair GT. Though there is no exact science for determining the fair GT that should be applied by a country or used in a given E&P contract, there are recognized skills, expertise, and advisory capacity available in the world for recommending, after detailed analysis and rigorous economic modeling, what could be the possible range of a fair GT after taking into consideration the petroleum potential of the acreage and all the specificities of the investment, including the selected way to award the contract, the competition, and whether a fiscal stabilization clause applies under the contract.
Box 8.3  Illustrative examples of progressive fiscal schemes.

Progressive fiscal schemes in concession contracts: royalty and additional profits tax

Regarding royalty, many countries have adopted *sliding scales* based on daily production and more recently on petroleum price or one economic criterion (such as the payout time of a project, allowing a lower royalty rate up to the payout time and a higher rate thereafter; or more frequently linked to an effective profitability criterion of the project). Royalty rates are quite variable in the world, from 0% in case of exemption up to 40% in exceptional cases.

The province of Alberta in Canada is today the country applying the most elaborate and relatively complex royalty system, with specific regimes for *conventional oil* (with rates between 0% and 40% depending on oil price and daily production per well), *natural conventional gas* (with rates between 5% and 36% depending on gas price and daily production per well), *shale gas* and *coal bed methane* (with rates similar to conventional gas except during the first 36 months of production), *oil sands*, *horizontal oil or gas wells*, and *enhanced oil recovery projects*. In the US, the royalty rates are generally constant, but they rose in the last decade above the traditional 12.5%, up to 18.75% in federal offshore waters and around 25% in the most favorable onshore shale gas private lands.

More and more countries (such as Algeria, Denmark, Ghana, Ireland, Namibia, Israel, Kazakhstan, The Netherlands, Senegal) have adopted an *additional profits tax* (APT) of different types, payable in addition to corporate tax, taking into account the experience of supplementary tax systems gained by the UK, Norway, and Australia and based on an adjusted cumulative cash flow. In another fashion, some countries, instead of introducing a distinct APT, decided to use *variable income tax rates* schemes for E&P activity based on daily production, or more recently on an economic criterion (such as the oil price or the R-factor, or a combination of these two parameters), a solution which works efficiently when appropriately defined.

Progressive fiscal schemes in PSCs: cost petroleum and profit petroleum

First, some countries have introduced a sliding scale for determining *cost petroleum ceiling* percentage (instead of a single percentage) in relation with a parameter, such as the type of petroleum (oil, gas), daily or cumulative production, petroleum price, etc.

Second, a progressive split for *profit petroleum sharing* may be agreed, based on daily or cumulative production, and more and more frequently in the twenty-first century on the effective profitability achieved by the E&P project, measured at each date of sharing with a given profitability criterion. The retained criterion is either, in a few cases, the rate-of-return on investment, as in Angola and Kazakhstan, or in many more cases the R-factor, as in Algeria, Azerbaijan, Cameroon, India, Libya, Malaysia, Qatar, Tunisia, etc.
The differences in the appreciation of any upstream project explain why in case of competitive bidding for E&P contracts, which is becoming the customary practice, the offers submitted on the biddable contractual or fiscal terms may greatly vary. The offers made by interested companies integrate not only the uncertainties on many technical and economic factors but also the differences between the bidders regarding their long-term strategic priorities and assessment of risks. There is however a general tendency to design for upstream contracts more progressive fiscal systems when profitability changes. In terms of sound fiscal policy, the petroleum economic rent sharing in order to remain fair to all parties when circumstances change has to be progressive in relation to the effective profitability achieved by petroleum projects: the greater the profitability of the project, the higher the GT. Illustrative examples on how to introduce fiscal progressivity are summarized in Box 8.3.

Fiscal progressivity is generally more accepted today because it leads to a win-win situation encouraging investments and sanctity of contracts: granting better fiscal terms to the IOC for encouraging the development of small, costly or risky projects, while obtaining higher but still reasonable GT in case of quite profitable projects. A direct consequence of such progressive schemes is that countries increasingly bear the petroleum price and cost risks, but in exchange they benefit from a higher take when the profitability of the project rises. On the contrary, regressive fiscal systems leading to a smaller GT when profitability rises are no longer sustainable in the long run by a country.

One fiscal evolution of importance in the world is the longer experience now accumulated in implementing each type of E&P contracts and upstream fiscal regimes, leading today to more clarity on how each party interpret contracts and fiscal regimes and how to reduce identified loopholes. Nevertheless, more thoughts remain to be developed to mitigate aggressive IOC tax planning when only designed to reduce petroleum government revenues, as such an objective may be contrary to fostering the necessary long-term cooperation between the parties. Some key issues requiring the greatest care when designing upstream fiscal regimes are summarized in Box 8.4.

Why Do Some E&P Contracts Contain a Fiscal Stabilization Clause?

Any petroleum contract may include, in addition to many technical, operational, and economic clauses, a set of legal clauses, such as the applicable law, dispute resolution, force majeure, stabilization, transfer of interest, liability and indemnity, termination, etc., when those issues are not dealt with in the petroleum law itself. The reason why IOCs may request a stabilization clause in an E&P contract is explained below. Stabilization clauses have considerably evolved in the last decades and today, when they have to be accepted by countries for allowing investments, their scope has been reduced to only some fiscal issues.11

As petroleum E&P contracts are long-term agreements by nature, sometimes for terms exceeding 40 years, the overall equilibrium of the contract resulting from the agreed fiscal scheme may be deeply affected by the occurrence of unexpected circumstances and above all by the impact of petroleum price volatility. It is unusual under E&P contracts to have an adaptation provision which would automatically change the fiscal terms toward restoring the original equilibrium (except under the new progressive fiscal schemes described above which try to achieve this goal), or a provision that would oblige the parties to negotiate a change if one party suffers hardship.

To limit political risks resulting from a possible change in law by the sovereign host country, IOCs often demand the protection of a stabilization provision. While IOCs
Box 8.4 Toward more detailed E&P fiscal systems to increase clarity and mitigate aggressive tax planning.

Many issues have to be dealt with in petroleum tax laws and E&P contracts, concerning the contract-holders themselves but also their shareholders, employees, subcontractors, and lenders. Thus, a contract-holder is generally constituted by more than one entity, each one subject to tax.

The experience in producing countries demonstrated that even when the tax system is quite simple, as under royalty and corporate tax regimes, the administration of such tax clauses in the E&P sector when not properly drafted is often more complex than expected and requires a highly professional petroleum taxation office working in close cooperation with the minister or agency responsible for petroleum.12

Such difficulties should not be an excuse for rejecting additional profits tax or progressive profit petroleum sharing schemes, when their principles are properly designed to be fully understandable and not too complex and the rules are clear enough.

As in any fiscal system, loopholes may exist, and they have to be progressively eliminated to give clarity to the interpretation of the upstream fiscal regime and E&P contracts and to allow in the long run a fair application by the parties of the principles governing the selected fiscal scheme and contract.

Key petroleum fiscal issues to be addressed in sufficient detail in tax law may concern: (1) the comprehensive definition of the eligible costs and deductions for tax or cost recovery purposes, (2) the tax treatment of direct and indirect transfers of interests in E&P contracts and how to tax the resulting gains in case of cash considerations, or (3) how to mitigate the unexpected reduction in tax liabilities derived from possible tax planning and double taxation treaty shopping. For example, many countries have still not clarified their law for taxation of capital gains in case of direct or indirect transfers of interests under E&P contracts, which continues to raise great uncertainty in terms of tax liabilities resulting from such transactions, which are customary in the petroleum industry.

New producers in developing countries are in an especially asymmetrical position with IOCs in terms of resources for defining with sufficient detail their petroleum taxation and regulation, because the domain is relatively new for them and they are not yet holding sufficient experience. This is the reason why countries should prepare with the greatest care and with the help of external advice their petroleum law and model E&P contract, with the necessary amendments to their tax laws and how to administer them.

In the same way, companies should recognize this state of fact and give the highest priority to help in clarifying in a fair manner the implementation of the upstream fiscal and contractual regime, with the objective of encouraging long-term cooperation with the producing country.

accept entering into E&P contracts in developed countries without any stabilization clause, they largely require the benefit of such a clause in most developing countries. Enforceability of stabilization clauses in E&P contracts often raised difficulties in the past. Considering this experience, the wording of stabilization provisions in new upstream contracts has recently evolved under the following principles.
The applicable law in most new E&P contracts and their associated fiscal regimes is no longer the law in force at the date of its signing – the *freezing type stabilization clause* often used in the past – but the law applicable *at any time* during its term. The reason is that a sovereign state may always change its laws or regulations and can generally apply them to previously issued licenses or contracts, and therefore the enforceability of freezing type stabilization clauses may be problematic.

Stabilization is now limited to a few specific fiscal issues or rates, strictly listed in the contract, the country having the right to change non-fiscal aspects such as environmental regulations and the other fiscal rules not stabilized. With the rapid evolution of the world and techniques, a sovereign country holds the unilateral right to issue new regulations applicable to any contract-holder, for example to take into account new environment, health, labor, and safety priorities, new techniques, more advanced conservation of petroleum, or for performance of operations in more stringent conditions. Moreover, fiscal issues applicable to any industry in the country, such as labor laws and taxes, and non-discriminatory by nature are generally no longer stabilized.

In the event that a change in a fiscal term listed in the stabilization clause has a material impact on one of the parties, which may be the government or the contract-holder, such party may ask for the benefit of the so-called *economic-equilibrium stabilization provision* of the contract, designed to restore the economic benefit prevailing at the signing date of the contract by adapting the economic or fiscal terms of the contract in an appropriate way, subject to mutual agreement. There is also a trend to limit the duration of fiscal stabilization to a period shorter than the entire validity of the contract itself.

Most developed countries do not provide for fiscal stabilization clauses, keeping at any time the unilateral right to amend their petroleum taxation when they consider, under changing circumstances, that the fiscal regime leads to unfair sharing of the profits, and all their existing license-holders become automatically subject to such fiscal changes. This was the case for example in the UK, which increased its petroleum corporate tax significantly in the last decade, as mentioned above.

When a fiscal stabilization clause applies under an E&P contract, as in many developing countries, the government does not have the same flexibility to adjust its petroleum tax policy in case of changing circumstances. Therefore, it is of paramount importance that the fiscal scheme associated with E&P contracts should have to be designed in such a way to automatically protect the parties when the petroleum market price, or more generally the profitability, considerably varies over the duration of the contract. The only way to achieve this goal in such countries is by implementing a sufficiently progressive fiscal system, based ideally on a profitability criterion as presented above.

Each party to an E&P contract containing a fiscal stability clause bears a special responsibility in designing a progressive fiscal system. There is no other way in the long term to foster sanctity of contracts and minimize political risks for investors in the developing countries concerned.

**Necessary Adaptation to Upstream E&P Contracts for Unconventional Petroleum**

In the last two decades new categories of petroleum, called *unconventional petroleum*, have begun to be explored and exploited in more and more countries, in addition to what is called *conventional petroleum*. Their share in global petroleum production, relatively small today, will progressively increase both for oil and gas and may become significant, following the striking example of their successful development in North America.
Generally speaking, in most countries, the upstream petroleum legislation and contracts dealing with conventional petroleum also apply to the most recent unconventional petroleum activity, unless it is explicitly provided for under special legislation enacted by the country. Some countries have discovered with surprise that E&P contracts awarded for searching for conventional petroleum are now used by their holders for unconventional prospecting. The legal reason is that in many petroleum laws the definition of petroleum is only based on its chemical composition and as a consequence the petroleum rights granted may indeed cover both conventional and unconventional petroleum, except when the contrary was clearly intended.

Up to now, most upstream petroleum laws, regulations, contracts, and fiscal regimes were drafted having in mind only conventional petroleum activity, ignoring the specificities of unconventional petroleum, which was not of commercial interest at that time. The main categories of unconventional petroleum and their differences with conventional oil and gas are summarized in Box 8.5. The differences between conventional and unconventional petroleum activity originate mainly from the techniques used for their exploration and exploitation, their respective risks, costs, and possible impact on the environment, in particular when the extraction of unconventional petroleum requires using hydraulic fracturing, a technique known in the industry but not yet approved in some countries.

**Box 8.5 The different categories of unconventional oil and gas.**

*Unconventional petroleum* has basically the same chemical composition as *conventional petroleum* but their exploitation may result in significant differences in terms of techniques used, possible impact on the environment, costs, production profiles, and economics. The main technical differences consist both in the location of oil or gas underground, often deeper and in more compact rocks for unconventional petroleum, and in some specifications of the petroleum extracted, such as density or viscosity, leading to use of different techniques for their extraction. Unconventional petroleum includes today the following categories.

**Unconventional natural gas**

*Tight gas* produced from compact and deep reservoirs; *shale gas* which is natural gas directly extracted from shales where it was generated; *coal bed methane* (CBM), also called *coal seam methane* (CSM) in Australia, gas existing in coal beds which is extracted by drilling wells up to such beds. Due to the extremely low porosity and permeability of shales, the production of shale gas requires the hydraulic fracturing (“fracking”) of the rock from horizontal wells, a technique also used in tight gas reservoirs for the same reasons.\(^{13}\)

**Unconventional oil**

Oil extracted from *deep offshore* reservoirs below the sea; *heavy oil* and *oil sands* which require specific techniques for their recovery; and more recently *shale oil* extracted from compact shale formations requiring hydraulic fracturing of the rock.
Where the host country awarded a conventional license or contract, today its holder may wish to use it to conduct unconventional petroleum activity, leading to possible conflicts in the interpretation of laws or contracts when they are silent on unconventional petroleum. For example, what are the regulations applicable to unconventional petroleum activity when no specific regulation was issued? Is CBM extracted from coal seams covered by mining law or by petroleum law? In the future any petroleum legislation, regulation, and taxation will have to contain, in addition to the provisions dealing with conventional petroleum, special clauses concerning the specificities of each category of unconventional oil and gas activity.

Deep offshore activities are an exception because the existence of those zones of interest are known before awarding E&P contracts. This explains why most countries have already introduced special tax incentives under their petroleum legislation and contracts for deep offshore to take care of higher costs, such as lower royalty rates under concession agreements and a higher-cost petroleum ceiling or more favorable profit petroleum sharing under PSCs. Special regulations concerning deep offshore operations have also been issued.

For the other categories of unconventional petroleum, a few countries have already started to introduce special laws or clauses dealing with it. The most illustrative case is probably the province of Alberta in Canada regarding oil sands, gas shale, and CBM. An ad hoc legal, fiscal, and contractual regime is provided for oil sands activity under the Oil Sands Conservation Act and the Oil Sands Tenure Regulations, providing for specific oil sands permits and leases, along with the Oil Sands Royalty Regulations which define a more attractive royalty scheme in favor of companies holding oil sands leases than standard conventional petroleum leases. Regarding shale gas and CBM, the standard gas royalty framework applies in Alberta, but supplemented by a specific incentive limited to the first three years of production of unconventional gas from a well. However, most countries have still to promulgate special rules for unconventional petroleum activity and the new E&P contracts concerning such activity will be adapted accordingly.

**Conclusion and Suggestions for Fostering Future Upstream Developments**

This review of the evolution of E&P contracts shows that, while no new types of contract were introduced in the last two decades, their terms significantly changed. The main changes deal with their associated fiscal regime and concern the introduction of higher and more progressive GT, the level of which is closely related to the petroleum attractiveness of the contract area and also of the country, the degree of competition, and the expected future petroleum price.

Depending on their petroleum policy and pursuant to the law, host countries may authorize upstream concession contracts or, more and more frequently in developing countries, PSCs, while in specific cases RSCs may be selected by large exporting countries. New terms may apply to unconventional petroleum. State participation depends on the national petroleum policy and is part of the overall fiscal package.

The fiscal regime and the overall government take resulting from the applicable upstream tax law and contract terms are of paramount importance both for the country and the investor when looking to future upstream investments. Only E&P contracts which are built with a reasonably progressive fiscal scheme designed to allow in the long run, first, the host country receiving a fair GT whatever the changing circumstances and, second, the international petroleum company achieving its profitability criteria, can be sustainable, encourage fiscal stability, and foster the pursuit of new investments.
Notes

1. Petroleum means oil and natural gas.
2. For a comprehensive review on the evolution of legal, fiscal, and contractual issues, see Duval et al. (2009).
3. For country examples of licensing policies and methods, see Cameron (1984), Daintith and Willoughby (2000), and Lucas and Hunt (1990).
4. Transparency is becoming a key objective in the upstream sector for its sustainable development. For a review on how to achieve better transparency in relation with contracts, taxation and revenues, see IMF (2007).
5. For more information on upstream contracts and policy insights, see the following source book freely available on the Internet and regularly updated: The Extractive Industries Source Book for Oil, Gas and Mining at http://www.eisourcebook.org.
6. Theoretically, the economics for the investor from a decision-making point of view should be neutral whatever the type of E&P agreements. It is theoretically possible to design fiscal packages for concession contracts and PSCs giving relatively similar economic results for both the country and the investor. Nevertheless, in reality a PSC will generate under most contracts higher revenues to the host country during the first years of production because the cost petroleum ceiling mechanism indirectly allows the country to take a higher share of production under the PSC than the royalty payable under a concession contract, when the CIT is not yet payable.
7. In those two countries, due to exceptional cost overruns and delays in the carrying out of a project, the use of a production sharing scheme based on rate-of-return increments with substantially high threshold rates led from the point of view of the state to unbalanced production and cost overruns sharing. This defect could however be easily eliminated in new PSCs when the rate-of-return system contains appropriate safeguard clauses to better protect state interests.
8. For a more detailed analysis on petroleum taxation, see Daniel et al. (2010), Kemp (1987), Nackle (2008), and Tordo (2007).
9. For details on petroleum costs, see Favennec and Bret-Rouzaut (2011).
10. When the 50% supplementary petroleum tax is applicable to a field, the UK marginal GT rose from 65% in 2000 to 81% in 2011, a marginal take close to the maximum of 78% applied in Norway, excluding state participation.
11. For more information on stabilization, see Cameron (2006).
12. The most illustrative example concerns royalty in the US where after a long implementation many practical issues have still to be resolved, in particular for agreeing on the market price at the wellhead.
13. Hydraulic fracturing has been used for over 50 years by the petroleum industry. However, this technique is more massively used in shale gas wells, with the use of larger quantities of water containing a tiny percentage of associated chemicals. Local communities are voicing more and more concern against this technique. This new situation requires such communities to be given more information on the quite limited risks of the technique and for host countries to develop ad hoc regulations and contractual clauses on how to use hydraulic fracturing safely.

References


