Case Study From

NEW ERA IN OIL, GAS & POWER VALUE CREATION

Fiscal Terms for Upstream Projects – An Overview[1]

Fiscal terms for upstream investment refer to the agreement between a local government and an oil and gas exploration company to explore, develop and produce hydrocarbons. The objective of a host government is to maximize wealth from its natural resources by encouraging appropriate levels of exploration and development activity. In order to accomplish this, governments must design fiscal systems. The objectives of the oil companies are to build equity and maximize wealth by finding and producing oil and gas reserves at the lowest possible cost and highest possible profit margin.

In a competitive world, areas with the least favorable geology, the highest costs, and the lowest prices at the wellhead would offer the best fiscal terms, while areas with the best geology, the lowest costs, and the highest prices at the wellhead would offer the toughest fiscal terms.

The objective of the host government is to design a fiscal system where exploration and development rights are acquired by those companies who place the highest value on these rights. In an efficient market, competitive bidding can help achieve this objective. The hallmark of an efficient market is availability of information. Yet exploration is dominated by numerous unknowns and uncertainty. With sufficient competition the industry will help determine what the market can bear, and profit will be allocated accordingly. In the absence of competition, efficiency must be designed into the fiscal terms. This is not easy to do.

Introduction

Regardless of what fiscal system is used, the bottom line is the financial issue of how costs are recovered and profits divided. In order to accomplish this, governments must design fiscal systems that

- Provide a fair return to the state and to the industry.
- Avoid undue speculation.
- Limit undue administrative burden.
- Provide flexibility.
- Create healthy competition and market efficiency.

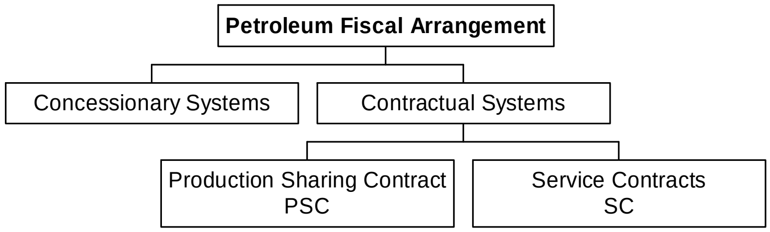
The design of an efficient fiscal system must take into consideration the political and geological risks as well as the potential rewards.

Detailed economic modeling using cash flow analysis is the best way to evaluate division of profits. Factors that limit a company's profits in a contract, such as cost recovery allowance, a government's right to back-in for an extra share of production, or an additional tax, can be modeled for the purposes of contract negotiation or project evaluation. Division of profits is commonly referred as *contractor take* and *government take*.

[1] This case study was prepared using publicly available information.

There are two main types of petroleum fiscal arrangements: concessionary systems and contractual systems (**Figure 1**). In concessionary systems private ownership is allowed whereas in contractual systems the state retains ownership. In contractual systems companies have the right to receive a share of production or revenues from the sale of oil or gas in accordance with a production sharing contract (PSC) or a service contract.

Figure 1 Petroleum Fiscal Systems



Concessionary Systems

To calculate the contractor take, the first item to be deducted from the gross revenues from oil and gas production are the royalties. Gross revenues less royalty equals net revenue. The next item are deductions, which include operating costs, depreciation, and amortization; and intangible drilling costs. These are deducted from net revenue to arrive at taxable income. The third item is taxation. Revenue remaining after royalty and deductions is called taxable income. Taxable income might be taxed in two layers: provincial and federal. The remaining revenue after taxation is the contractors take. Concessionary contracts are a relatively simple and are not as widely used as the more complex production sharing contracts.

Figure 2a A Barrel of oil in Concession Agreement – High Royalties

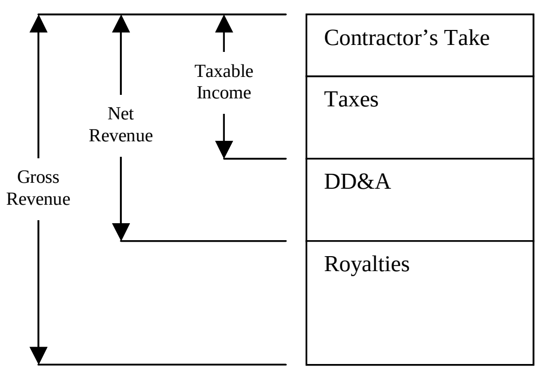
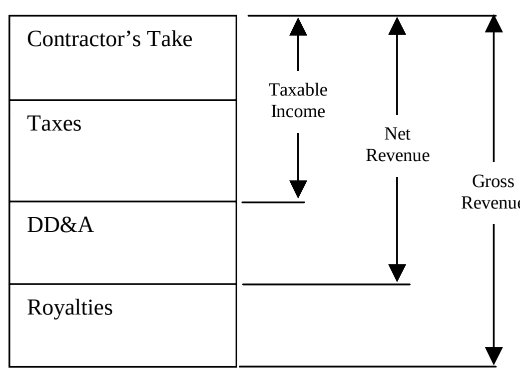


Figure 2b A Barrel of oil in Concession Agreement – Low Royalties

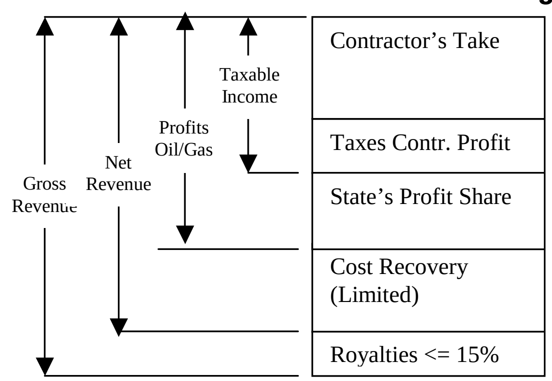


Royalties are regressive because they are levied on gross revenues. For less profitable ventures, the relative percentage of royalty increases. The further from gross revenues that taxes are levied, the more progressive the system becomes. **Figures 2a** and **2b** compare the cases of low and high royalties in concession agreements.

Production Sharing Contracts

In most contractual systems, the facilities put in place by the contractor within the host government domain become the property of the state either the moment they are landed in the country or upon startup or commissioning. Sometimes, the title to the assets or facilities does not pass to the government until the attendant costs have been recovered. Contractual systems are divided into *service contracts* and *production sharing contracts*. The difference between them depends on whether or not the contractor receives compensation in *cash* or in *kind* (crude). **Figure 3** depicts the distribution of how gross revenues are distributed from a barrel of oil under a PSC.

Figure 3 A Barrel of oil in a Production Sharing Contract



Basic features of production sharing contracts:

- The title of the hydrocarbons remains with the state.
- The State maintains management control and the contractor is responsible for the execution of petroleum operations in accordance to the terms of the contract.
- The contractor is required to submit annual work programs and budgets for scrutiny and approval the State Company.
- The contract is based on production sharing and not profit-sharing basis.
- The contractor provides all financing and technology required for the operations and bore the risks.
- During the term of the contract, after allowance for up to a specified percentage of annual production for recovery of costs, the remaining production is split between the contractor and State.
- Equipment purchased and imported by the contractor become property of the State. Service company equipment and leased equipment are exempt.

Deductions stages

1. Royalty. Royalties are the first deduction.

2. Cost Recovery. Before sharing of production, the contractor is allowed to *recover costs* out of net revenues. Most PSCs place a limit on cost recovery. If operating costs and DD&A amounts to more than the allowed limit, the balance would be carried forward and recovered later. From the mechanical point of view, the cost recovery limit is the only true distinction between concessionary systems and PSCs.

3. Profit Oil Split. Revenues remaining after royalty and cost recovery are referred to as *profit oil* or *profit gas*. The analog in a concessionary system would be taxable income. The contractor share of profit oil or gas is a specified percentage. If this were a service agreement, the contractor's share would be called service fee-not profit oil.

4. Taxes. The contractor's share of profit oil and gas is subject to taxation.

Basic Elements

The basic elements of a production sharing system are categorized in **Table 1**. These elements are also found in concessionary systems with the exception of the cost recovery limit and production sharing. Many aspects of the government/contractor relationship may be negotiated but some are normally determined by legislation. Those elements not determined by legislation must be negotiated. Usually, it is better to have more aspects that are subject to negotiation. This is true for the government agency responsible for negotiations as well as for the oil companies. Flexibility is required to offset differences between basins, regions, and license areas within a country.

Table 1 Production Sharing Fiscal/Contractual Structure

	National Legislation	**Contract Negotiation**
Operational Aspects	Government participation Ownership transfer Arbitration Insurance	Work commitment Relinquishment Commerciality
Revenue or Production Sharing Elements	Royalties Taxation Depreciation rates Investment credits Domestic obligation Ringfencing	Bonus payments Cost recovery limits Production sharing

Work Commitment. The work commitment refers to the obligations an exploration company incurs once a PSC is formalized. Work commitments are generally measured in kilometers of seismic data and the number of wells to be drilled in the exploration phase.

Bonus Payments. Cash bonuses are lump sums paid by the contractor to acquire a particular license. These cash bonuses are the main element in bidding rounds of very prospective acreage. Production bonuses are paid when production from a given contract area or field reaches a specified level.

Royalties. Royalties are taken right off the gross revenues. Royalties range as high as 15%, although many PSCs do not have a royalty. A specific rate royalty is relatively rare, but it may also go by another name, such as “export tariff’, like in the former Soviet Union or the War Tax levy in Colombia.

Another aspect of royalties that contributes to their lack of popularity with the industry is that they can cause production to become uneconomic prematurely. This works to the disadvantage of both the industry and government. One remedy that has become popular is to scale royalties and other fiscal elements to accommodate marginal situations.

Sliding Scales. A feature found in many petroleum fiscal systems is the sliding scale used for royalties, taxes and various other items. The most common approach is an incremental sliding scale based on average daily production. A sample sliding scale royalty is provided below.

Average	Daily Production	Royalty
First Tranche	Up to 10,000 BOPD	5%
Second Tranche	10,001-20,000 BOPD	10%
Third Tranche	Above 20,000 BOPD	15%

Cost Recovery. Cost recovery is the means by which the contractor recoups costs of exploration, development, and operations out of gross revenues. Most PSCs have a limit to the amount of revenues the contractor may claim for cost recovery but will allow unrecovered costs to be carried forward and recovered in succeeding years. Cost recovery limits or cost recovery ceilings, as they are also known, if they exist typically range from 30% to 60%.

Sometimes the hierarchy of cost recovery can make a difference in cash flow calculations. This is particularly the case if certain cost recovery items are taxable. Cost recovery of *cost oil* normally includes the following items listed in this order:

1. Unrecovered costs carried over from previous years.
2. Operating costs.
3. Expensed capital costs.
4. Current year DD&A.
5. Interest on financing (usually with limitations).
6. Investment credit (uplift).
7. Abandonment cost recovery fund.

In most respects, cost recovery is similar to deductions in calculating taxable income under a concessionary system. There are some exceptions. For example, some PSCs have no limit to cost recovery and some have no cost recovery.

Tangible vs Intangible Capital Costs. Sometimes a distinction is made between depreciation of fixed capital assets and amortization of intangible capital costs. Under some concession agreements, intangible exploration and development costs are not amortized. They are expensed in the year they are incurred and treated as ordinary operating expenses. Those rare cases where intangible capital costs are written off immediately can be an important financial incentive. Most systems will force intangible systems to be amortized. Therefore, recovery of these costs takes longer, with more revenues subject to taxation in the early stages of production.

Interest Cost Recovery. Sometimes interest expense is allowed as a deduction. Some systems limit the amount of interest expense by using a theoretical capitalization structure such as a maximum 70% debt.

General and Administrative Costs. Many systems allow the contractor to recover some office administrative and overhead expenses. Non operators are normally not allowed to recover such costs.

Unrecovered Costs Carried Forward. Most unrecovered costs are carried forward and are available for recovery in subsequent periods. The same is true for unused deductions. The term "*sunk cost"* is applied to past costs that have not been recovered. There are four classes of sunk cost: tax loss carry forward, unrecovered depreciation balance, unrecovered amortization balance and cost recovery carry forward. These items are typically held in abeyance (inactive) prior to the beginning of production. Many PSCs do not allow pre-production costs to begin depreciation or amortization prior to the beginning of production.

Exploration sunk costs can have a significant impact on field development economics and can strongly affect the development decision. The importance of sunk costs and development feasibility centers on an important concept called *commerciality*.

The financial impact of a sunk cost position on the development position can be easily determined with discounted cash flow analysis. The field development cash flow projection should be run once with sunk costs and one without.

Abandonment Costs. Under most PSCs the contractor cedes ownership rights to the government for equipment, platforms, pipelines and facilities upon commissioning or startup. The government as owner is theoretically responsible for the cost of abandonment. Anticipated cost of abandonment is accumulated through a sinking fund that matures at the time of abandonment. The costs are recovered prior to abandonment so that funds are available when needed.

Profit Oil Split Taxation. Profit oil and gas is split between the contractor and the government, according to the terms of the PSC. Sometimes it is negotiable. The contractor's share is usually subject to taxation.

<u>Commerciality.</u> Commerciality deals with who determines whether or not a discovery is economically feasible and should be developed. Some regimes allow the contractor to decide whether or not to commence development operations. Other systems have a commerciality requirement where the contractor has to prove that the development of a discovery is economically beneficial for both the contractor and the government. The benchmark for obtaining commercial status for a discovery cannot be developed unless it is granted commercial status by the host government. The grant of the commercial status marks the end of the exploration phase and the beginning of the development phase of a contract.

<u>Government Participation (Joint Ventures).</u> Many systems provide an option for the national oil company to participate in development projects. Under most government participation arrangements, the contractor bears the cost and risk of exploration. If there is a discovery, the government backs-in for a percentage, the government is *carried through exploration*. The key aspects of government participation are:

- What percentage participation? (most range from 10% to 51%)
- When does the government back in? (usually once a discoveries made)
- How much participation in management? (large range of degree of participation)
- What costs will the government bear? (usually only their prorated share of development costs)
- How does government fund its portion of costs? (often out of production)

The financial effect of a government partner is similar to that of any working-interest partner with a few exceptions:

1. The government is usually carried through the exploration phase, and may or may not reimburse the contractor for past exploration costs.
2. The government's contribution to capital and operating costs is normally paid out of production.
3. The government is seldom a silent partner.

Contractors prefer no government participation. This stems from a desire for efficiency as well as economy. Joint operations of any sort, especially between diverse cultures, can have a negative impact on operational efficiency. This is particularly true when the interests of government and an oil company can be so polarized.

Investment Credits and Uplifts. Uplift allows the contractor to recover an additional percentage of capital costs through cost recovery. For example, an uplift of 20% on capital expenditures of $100 million would allow the contractor to recover $120 million. Uplifts can create incentives for the industry. Uplifts are the key of rate of return contracts.

Domestic Obligation. Many contracts specify that a certain percentage of the contractor's profit oil be sold to the government. The sales price to the government is usually at a discount to world prices.

Ring fencing. Ordinarily all costs associated with a given block or license must be recovered from revenues generated within that block. The block is *ring fenced*. This element of a system can have a huge impact on the recovery costs of exploration and development. From the government perspective, any consideration for costs to cross a ring fence means that the government may in effect subsidize unsuccessful operations. However, allowing exploration costs to *cross the fence* can be a strong financial incentive for the industry.

Reinvestment Obligations. Some contracts require the contractor to set aside a specified percentage of income for further exploratory work within the license.

Tax and Royalty Holidays. The purpose of tax and royalty holidays is to attract additional investment.

Risk Service Contracts

In service contracts the contractor provides all capital associated with exploration and development of petroleum resources. In return, if exploration efforts are successful, the government allows the contractor to recover costs through sale of the oil or gas and pays the contractor a fee based on a percentage of the remaining revenues. The fee is often subject to taxes. The net importing countries are the ones most likely to use this approach. The distinction between PSCs and risk service contracts is minute. The nature of the payment of the contractor's services is the point of distinction

Rate of Return Contracts

Contracts with flexible terms are becoming standard. There are many advantages for both the host government and the contractor with contracts that encompass a range of economic conditions. The most common method used for creating a flexible system is with *sliding scale terms*. Most sliding-scale systems trigger on production rates. As production rates increase, government take increases. This theoretically allows equitable terms for development of both large and small fields. Some contracts will provide flexibility through a progressive tax rate, others will tie more than one variable to a sliding scale such as cost recovery, profit oil split and royalty.

The most common contract terms subject to sliding scale are profit oil split, royalty and bonuses. Less common are cost recovery limits and taxes. The most common factors and conditions used to trigger sliding scales are production rates, water depth, cumulative production, oil prices, age or depth of the reservoir, onshore vs offshore, R factors and the remoteness of locations. Less common are oil vs gas, crude quality, time period (history), distance from shore and rate of return.

The objective with sliding scale systems is to create an environment where the government take flexes upward as with increased profitability. The result of most fiscal structures is that project profitability is a function of government take. In general, it is better for both parties when government take is a function of profitability.

Some countries have developed progressive taxes or sharing arrangements based on project rate of return (ROR). The effective government take increases as the project ROR increases. In order to be truly progressive, the sliding-scale taxes and other attempts at flexibility should be based on profitability, not production rates.

Some contracts use what is called an R factor. The R factor = Accrued net earnings / Accrued total expenditures. R factors deal with all variables that affect project economics. Contractor potential upside from price increase is diminished, but the downside is also protected.

Technical Assistance Contracts (TACs)

TACs are often referred to as rehabilitation, redevelopment or enhanced oil recovery projects. They are associated with existing fields of production and sometimes, but to a lesser extent, abandoned fields. The contractor takes over operations including equipment and personnel if applicable. The assistance that includes capital provided by the contractor is principally based on special know-how such as steam or water flood expertise.

FISCAL TERMS FOR GAS

Only a few nations specifically support gas development through the fiscal system. However, most nations that provide support have seen a strong development of the natural gas sector.

Since most gas projects will typically have a relatively low rate of return compared with oil, ROR-based scales typically favor gas development. The higher the ROR benchmark, the more gas is being favored. The same applies to contracts that have R-factor sliding scales being used in production sharing, royalties or taxes. R-factor scales help gas economics because gas requires more investment and results often in lower prices at the wellhead on an energy basis. This means lower R factors. Jurisdictions that make use of uplifts or depletion allowances in calculations that apply to oil and gas usually also favor gas with a few percentage points government take (Van Meurs & Seck, 1997).

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