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How to Evaluate the Fiscal Terms of Oil Contracts
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Resource Curse

Chapter 3. How to evaluate the fiscal terms of oil contracts?

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Abstract

This chapter addresses the dual issues of how country governments, national oil companies and international oil companies work together to negotiate oil contracts; and what types of contractual relations are likely to lead to better outcomes than witnessed in the past.

In particular, this chapter provides guidelines for evaluating the fiscal terms of oil contracts. While different families of oil contracts exist, I show that, contrary to popular believe, the *type* of system matters less than other design elements in determining the overall nature of the contract. In other words, governments can achieve their fiscal objectives with whichever fiscal system they choose as long as the system is designed properly. This chapter first discusses the different types of fiscal terms in oil contracts and then identifies the few substantial differences among them. I next consider the different ways to study the design of a deal in order to evaluate its merits. I assess the strengths and weaknesses of the commonly used 'Government Take' statistic and discuss how it can be supplemented by the 'Effective Royalty Rate' measure, which better captures crucial issues of timing. Finally, I consider five additional features of importance to governments and companies during the oil contracting process: the degree of government participation (which can benefit governments but cost companies); the "savings index" which accounts for the incentives facing companies to keep costs down; the responsiveness of the deal to changing economic conditions; provisions for minimizing risk; and provisions that allow companies to 'book barrels.'

Introduction

Oil is the world's number one strategic commodity. It is of vital interest to developed and developing nations that rely on imported oil and gas. It is also vitally important to exporting nations, many of them among the poorest countries in the world—the Middle East aside. For countries with petroleum resources, the contribution from the petroleum sector to the nation's budget is often dramatically greater than the contribution to the country's gross national product (GNP). For example, if the petroleum sector were to represent say 10% of GNP it would likely represent from 30 to 40% of the nation's budget. Not only is petroleum very profitable relative to most other industries, but the effective tax rate for the petroleum industry is also especially high.

Numerous dynamics influence today's industry. Oil demand continues to grow, and at a faster rate than anticipated. Consumption went from 79 million barrels of oil per day (BOPD) in 2002 to 84.5 million in 2004, leaping by 2 to 3 million BOPD each year for a period in which expectations had been on the order of 1 to 1.5 million BOPD growth per year. Much of the new demand comes from the Asian giants India and China. Supply of oil and gas, however, is a function of exploration and production. There is now every indication that exploration and the resultant discoveries have peaked (although it remains uncertain when production will peak since production lags behind exploration, sometimes by as much as 30 years). Gas is becoming increasingly important, even if, because of the higher transportation and management costs, gas discoveries in many regions of the world are still often characterized as being 'worse than a dry hole'.[2]

As these features change there are also changes in relations between the main players in the industry. On one side stand the country governments and national oil companies (NOCs) that control the bulk of the available oil and gas reserves; and, on the other side, stand the international oil companies (IOCs) that meet the majority of the financial, technical, organizational, and marketing needs of exporting and importing countries. On the side of the producing countries, numerous economic and political complexities associated with managing oil and gas exist. These issues are important not only to domestic affairs in any given country but also to the relationship between national actors and private oil companies. Many of the problems associated with oil and gas exploration and production, particularly in low-income countries, can be associated with corruption. But in some cases the problems stem from misunderstandings and poor communication in the course of negotiating and implementing an oil contract. In these cases, the government, the NOC, and the IOC can fall suspect to accusations of theft of a nation's oil wealth. Moreover, as Chapter 10 discusses, the publics in these countries often no longer sit idly by. The results are usually not healthy to a country's economic and political development.

While relations between major actors may be fraught with political difficulties, they are also important from a practical point of view. There is increasing competition among countries for the limited resources of the IOCs. The ability of countries to attract IOC investment depends on their prospectivity and stability, as well as on their marketing skills. When they succeed in attracting investment, they want the best terms they can get. Oil companies, meanwhile, want to explore in regions where there is a reasonable chance of finding oil and gas. They want to deal with stable governments, and prefer contract terms that will provide a potential return-on-investment that is commensurate with the associated risks. They are also interested in (or rather obsessive about) "booking barrels" -- adding reserves as assets to their balance sheets. Overall, the contract is the best indicator of how well the different goals of country governments and IOCs have been met. There is, however, no single clause or number contained in a contract that can tell you whether the country or the company (or neither or both) got a good deal. Rather, evaluating the contract requires examining a series of conditions.

This is the subject of this chapter: How do governments, NOCs, and IOCs work together in the process of negotiating an oil contract, and what types of contractual relations are likely to lead to better outcomes for country governments?

This question is often examined by focusing more on the broad differences between the *families* of systems that exist (Johnston 2001). Indeed, there are myriad ways to structure business relationships in the petroleum sector. Yet, the first observation elaborated here is that, for all practical purposes, only two main families of petroleum fiscal regimes exist:

'concessionary' systems and 'contractual based' systems. Although differences exist between them, as will be discussed, the differences are not great from either a mechanical or a financial point of view. Instead, working out the merits of a particular agreement requires a deeper understanding of how the different systems operate and, in particular, of the core fiscal elements. These issues are discussed in Section II.

In Section III I provide a framework for analyzing the properties of different agreements, identifying what is at stake with different provisions in an oil contract, regardless of which family an agreement comes from. I examine two measures, beginning with the most commonly cited— 'Government Take'. Government Take is the government's share of economic profits from almost all income sources, including bonuses, royalties, profit oil, taxes and government working interest. While an important statistic and widely used, it is nonetheless flawed because it does not take into account factors such as the timeframe for payouts to government and the level of government participation. In response to the issue of the timeframe, I discuss and show how to calculate a companion statistic known as the 'Effective Royalty Rate' which measures the degree to which a contract 'front-end-loads' payments to governments. Finally, I consider five additional features of importance to governments and companies: the degree of government participation, which comes at some benefit to governments but at a cost to companies; the "savings index," which gives a sense of the incentives facing companies to keep costs down; responsiveness of the deal to changing economic conditions; provisions for minimizing risk; and provisions that allow companies to "book barrels." I conclude with some observations on the options available to governments deciding how to allocate acreage.

II Fiscal System

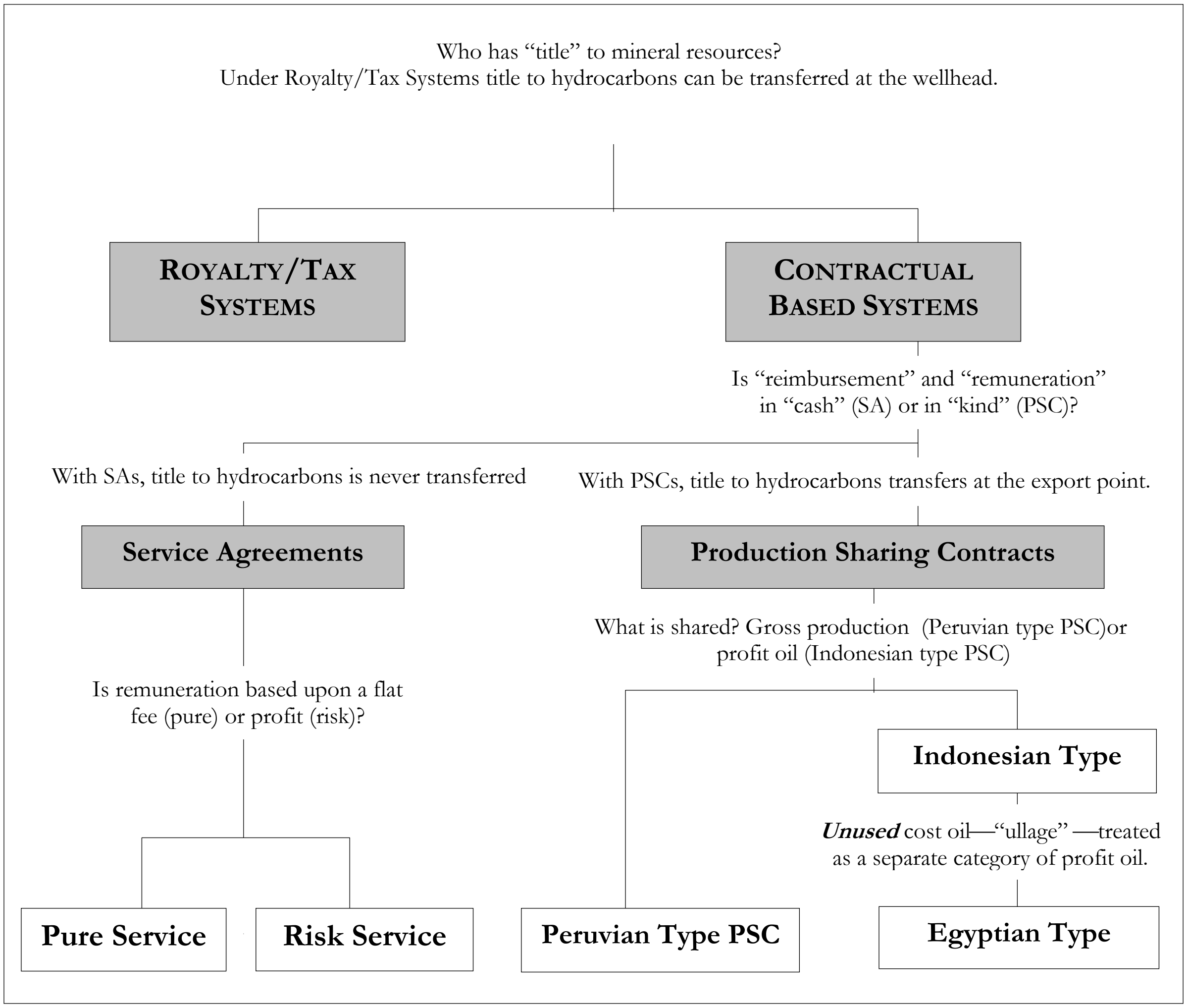
In the universe of oil contracts, two main families of fiscal system exist. The first family includes 'concessionary' systems, so-called because the government grants the company the right to take control of the entire process – from exploration to marketing – within a fixed area for a specific amount of time. Since production and sale of the oil is then subject to royalties, taxes and other concessions, contracts in this family are commonly known as Royalty/Tax Systems (abbreviated here as R/T systems). 'Contractual-based' systems comprise the second family. Agreements in this family belong to two predominant groups: production sharing contracts (PSCs) and service agreements (SAs) (Johnston 1994).

In short, the distinguishing characteristic of each family of contract is where, when, and if ownership of the hydrocarbons transfers to the international oil company. While numerous variations and twists are found in both concessionary and contract-based systems,[3] from a mechanical and financial point of view *there are practically no differences between the various systems*. As will be shown in the following sections, where the components of each system are discussed in detail, the key calculations in both families follow the same hierarchy. Any oil agreement takes into account, in the following order: (1) the generation of production and revenue; (2) the royalty or royalty equivalent elements for the government; (3) the cost recovery, tax deductions or reimbursement for the corporation; and (4) the way profits are divided (such as profit-oil sharing and/or taxes). While some interesting exceptions to this general rule exist, they are most likely to be found only among the SAs of this world.

The taxonomy of petroleum fiscal systems is outlined in Figure 3.1.

Figure 3.1

Classification of Petroleum Fiscal Regimes



In fact, preferences for one system over another and certain elements or conventions generally tend to be regional.[4]

Some of the geographic influences can be seen in Table 3.1.

Table 3.1

Regions of the World and the most prominent Types of Agreement

Region	**Type of Agreement**
Latin America and Middle East	Service Agreements
Africa and the Former Soviet Union	Royalty/Tax systems with rate-of-return (ROR) features, in which the government collects a share of a company's cash flow in excess of the specified ROR.
Africa	PSCs with Cost Recovery Limits (limits to the amount of deductions that can be taken for cost recovery purposes) based on net production.
Former British Colonies	Competition for blocks not based on a bonus payment but rather on 'work program bidding', meaning the competitiveness of a plan for profit maximization of a particular block.
Former Soviet Union	PSA Terminology (vs. PSC)
West Africa	PSCs with 'cost stop' terminology (rather than the 'cost recovery limit' terminology used in Africa)
Middle East	PSCs with taxes paid 'in lieu' ("for and on behalf of the contractor") out of the NOC's share of profit oil.

The belief that systems are somehow fundamentally different from a financial point of view has led to a number of common misconceptions. For instance, one common claim in discussions of the oil industry is that R/T systems and PSC systems each allocate different amounts of risk to either the NOC or IOC. In actuality, neither R/T systems nor PSCs are *inherently* more likely to allocate greater risk either to the NOC or the IOC. Similarly, it is not the case that PSC's allow the IOCs to get their costs back faster, or even that they allow IOCs to get them back at all. Nor is it necessarily true that PSC's are more or less stable than R/T systems.

There are differences, however. I discuss these below, but first I consider the different systems in more detail in turn.

II.1 Royalty Tax Systems (R/T)

Prior to the late 1960s, R/T Systems—or 'concessionary systems'—were for all practical purposes, the only arrangements available. R/T systems are characterized by a number of features:

- Oil companies are contracted for the right to explore for hydrocarbons;
- If a discovery is deemed commercially viable, the international oil company has the right to develop and produce the hydrocarbons;
- When hydrocarbons are produced, the international oil company will take title to its share at the wellhead (this "entitlement" equals gross production less royalty). If the royalty is 10% the international oil company can 'lift' (take physical and legal possession of its entitlement of crude oil) 90% of production. If the royalty is paid in cash from another source of funds, then the IOC can 'lift' 100% of production;
- Exploration and production equipment is owned by the IOC;
- The IOCs pay taxes on profits from the sale of the oil.

Sample Calculation

The following example demonstrates the arithmetic performed to calculate Contractor and Government Take, and entitlement. Even though this analysis is "full cycle" the hierarchy of arithmetic that would be expected in any given accounting period is the same. In this particular case $20/barrel (BBL) is assumed to represent average gross revenue per barrel over the life of the field (full cycle).

Table 3.2

Royalty/Tax System Flow Diagram

One Barrel of Oil (Full Cycle)

10% Royalty	Oil Price $20/BBL
No Cost Recovery Limit	Costs $5.65/BBL
60% Tax (1st Layer)	
30% Tax (2nd Layer)	

Company Share	Cumulative Gross Revenues $20.00	Government Share
	Royalty 10%	→ **$2.00**
	$18.00	
$5.65 ← Assumed Costs	**Deductions**	
	$12.35	**Taxable Income**
$4.94 ←	**Special Oil Tax** 60%	→ **$7.41**
($1.48) →	**Income Tax** 30%	→ **$1.48**
$3.46		
$9.11	Division of Gross Revenues	**$10.89**
$3.46	Division of Cash Flow	**$10.89**
24% $3.46/($20.00-5.65)	**Take**	**76%** $10.89/($20.00-5.65)
90% ($20-$2)/$20.00	**Lifting Entitlement**	**10%** $2.00/$20.00

In this example of an R/T system, I calculate Government Take over the full cycle of the project, which includes exploration and early development through to field decline and abandonment. Here I use a simplified form of the Government Take measure for the purposes of illustration. I use one barrel of oil at $20 to represent average full cycle revenues (per barrel) and show how that barrel of oil is divided between the government and the contractor.

Of the $20, the government gets a 10% royalty equal to $2. Assumed costs are deducted from the $18 left after the royalty is taken, leaving a taxable income of $12.35. Two layers of taxes are levied against the taxable income; first a 60% tax on the $12.35 gives the government $7.41, leaving $4.94. The second layer of tax, 30%, is levied against the $4.94, giving the government an additional $1.48 and leaving the contractor with $3.46.

Take statistics are a function of cash flow (gross revenue – costs). In this particular example, Government Take equals government cash flow divided by total cash flow, or $10.89/($20 - $5.65) = 76%.

II.2 Production Sharing Contracts (PSCs)

The concept of production sharing is ancient and widespread. Farmers in the USA have been familiar with the concept for decades. The concept of the PSC, as far as the oil and gas industry is concerned, was conceived in Venezuela in the mid 1960s.[5] The first modern Production Sharing Contract was signed in 1966 between the Independent Indonesia American Petroleum Company (IIAPCO) and Permina, Indonesia's National Oil Company at the time. The characteristic features of this pioneering agreement, which can still be found in most PSC arrangements worldwide, included:

- Title to the hydrocarbons remained with the state (Indonesia);
- Permina maintained management control (Indeed, putting management control in the hands of Permina is what really distinguished the PSC from the Indonesian predecessors);

- Contractor submitted work programs and budgets for government approval;
- Profit Oil (P/O) split—the amount of oil remaining after allocation of royalty oil and cost oil— was 65%/35% in favor of Permina;
- Contractor bore the risk;
- Cost Recovery Limit (the limit to the amount of deductions that can be taken for cost recovery purposes) was 40%;
- Taxes paid 'in lieu' (i.e. taxes paid for and on behalf of the IOC by Permina);
- Purchased equipment became property of Permina;
- Company entitlement equals cost oil (oil or revenue used to reimburse the contractor for exploration and development) plus profit oil.

Sample Calculation

The following example demonstrates the arithmetic performed to calculate contractor and Government Take, and Entitlement. In this case, like the example R/T system above, I use the revenue from one barrel of oil -- $20 to represent average (per barrel) gross revenue over the life of the field (full cycle).

Figure 3.2

Typical PSC – Flow Diagram
One Barrel of Oil (Full Cycle)

10% Royalty
50% Cost Recovery Limit
60% Government P/O Share
30% Corporate Income Tax (CIT)

Oil Price $20/BBL
Costs $5.65/BBL

Contractor Share	**Cumulative Gross Revenues** **$20.00**	**Government Share**
	Royalty 10%	**$2.00**
	$18.00	
$5.65 Assumed Costs	**Cost Recovery** 50% Limit	
	$12.35 Profit Oil	
$4.94	**Profit Oil Split** 40/60%	**$7.41**
($1.48)	**Tax Rate** 30%	**$1.48**
$3.46		
$9.11	Division of Gross Revenues	**$10.89**
$3.46	Division of Cash Flow	**$10.89**
24% $3.46/($20.00-5.65)	**Take**	**76%** $10.89/($20.00-5.65)
53% ($5.65+4.94)/$20.00	**Lifting Entitlement**	**47%** ($2.00+7.41)/$20.00

This example is mathematically identical to the previous R/T system example -- with the obvious exception of lifting entitlement – the share of production to which the various parties are allowed to take physical and legal possession– here the company cannot claim to book as many barrels. The terminology, however, is different. The R/T System employs the term 'deductions' whereas with PSCs the term 'cost recovery' is used. Also, instead of a 60% tax, there is a 60/40 Profit Oil Split in favor of the government. Aside from these differences, the mathematics is the same and government and contractor take calculations are identical to the R/T system take calculations. This illustrates that from a mathematical/mechanical point of view the differences between R/T systems and PSCs are by far outweighed by the similarities.

Note that from a mechanical point of view the Cost Recovery Limit is the only difference between R/Ts and PSCs. In this case this difference did not matter because the cost recovery limit was not reached. Note also, as signaled above, the difference between the entitlements in the two systems is dramatic.

II.3 Service Agreements (SA)

Service contracts or service agreements generally use a simple formula: the contractor is paid a cash fee for performing the service of producing mineral resources. All production belongs to the state. The contractor is usually responsible for providing all capital associated with exploration and development (just like with R/T systems and PSCs). In return, if exploration efforts are successful, the contractor recovers costs through the sale of oil or gas plus a fee. The fee is often taxable. These agreements can be quite similar to PSCs or R/T systems except for the issue of entitlement (entitlements are not granted and fees are paid instead). Thus, for example, except on the issue of entitlement, the 1996 round of oil negotiations in Venezuela contain the features of an R/T system because it has royalties and taxes. The Philippine SA, however, uses the terminology and structure of a PSC with a cost recovery limit and profit oil split.

Following are examples of various Service Agreement fee structures.

II.3.1 Fixed Fee - $/BBL

'Fixed fee' formulas that take revenue as a fixed ratio to BBL are used in joint ventures in Nigeria, a few contracts in Abu Dhabi, and as part of Kuwait's proposed Operating Service Agreement (OSA). A simplified example is as follows. First, the IOC conducts operations in much the same way it would in virtually any fiscal system. For performing these services (in this example) the IOC is able to recover its costs (assumed to average $4/BBL) out of revenues and is also paid a $2/BBL fee for conducting operations. The example in Table 3.3 below shows how this simple arrangement looks at $20/BBL and $60/BBL oil prices.

Table 3.3

Government Take and Company Take Under $/BBL Fixed Fee Systems

		Scenario 1 ($20 / BBL)		Scenario 2 ($60 / BBL)
A	Gross Revenues ($/BBL)	$20		$60
B	Fee $2/BBL	$2		$2
C	Net Revenue	$18		$58
D	Assumed Costs	$4		$4
E	Government Profit (Cash Flow)	$14		$54
	Company Cash Flow [B]	$2		$2
	Government Take [E/(A-D)]	87.5%		96.4%
	Company Take [B/(A-D)]	12.5%		3.6%

Notice with this structure the system is progressive—as oil prices go up (or as profitability goes up) Government Take also goes up.

II.3.2 Fixed Fee as a Percentage of Costs (Uplift)

Another type of fee-based approach—like that found in Iran under the "buy-backs" and proposed in Iraq under what is called a "squeeze PSC"—provides the IOC a means of recovering costs plus a fixed fee that is a function of the anticipated costs. The example here assumes the IOC will be reimbursed for costs of $4/BBL plus an 'uplift' of 50% of those costs, an 'uplift' being a fiscal incentive for the company where the government allows the contractor to recover an additional percentage of capital expenditure costs. This is a simple example but it serves our purposes. The IOC would conduct operations in much the same way as with other petroleum operations. The example here shows how this arrangement would look with oil prices of $20/BBL and $60/BBL. A difference is that for a given percentage, higher costs translate into a higher percentage for the oil company.

Table 3.4

Government Take and Company Take For Systems with Fixed Fees as a Percentage of Costs

		Scenario 1 ($20 / BBL)		Scenario 2 ($60 / BBL)
A	Gross Revenues ($/BBL)	$20		$60
B	IOC cost recovery (Reimbursement)	$4		$4
C	IOC Fee 50% of costs (Remuneration)	$2		$2
D	Government Profit (Cash Flow)	$14		$54
	Company Cash Flow	$2		$2
	Government Take [D/(A-B)]	87.5%		96.4%
	Company Take [C/(A-B)]	12.5%		3.6%

Notice this system is also progressive—as oil prices go up (or as profitability goes up), Government Take goes up.

II.3.3 Variable Fee – Percentage of Gross Revenues

Another type of fee-based approach (used very rarely) provides the IOC with a direct share of revenues from which, hopefully, it would be able to recover its costs and make a profit. This type of arrangement in its classic form is referred to as the "Peruvian model." Another variation is the Filipino Participation Incentive Allowance (FPIA) (Clad 1988). This form allows the contractor group a 7.5% "incentive" if there is sufficient participation (discussed more in III.3 below) by the Filipino government. This 7.5% allowance is based on gross revenues. A simple example here assumes the IOC will receive 25% of gross revenues. The IOC conducts operations in much the same way it would under almost all petroleum systems. The example below shows how this simple arrangement looks at $20/BBL and $60/BBL oil prices.

Table 3.5
Government Take and Company Take For Service Agreements with Variable Fees

		Scenario 1 ($20 / BBL)		Scenario 2 ($60 / BBL)
A	Gross Revenues ($/BBL)	$20		$60
B	IOC Fee 25% of Gross Revenues	$5		$15
C	Government Profit (Cash Flow)	$15		$45
D	Assumed Costs	$4		$4
	Company Cash Flow (B-D)	$1		$11
	Government Take [C/(A-D)]	93.75%		80.4%
	Company Take [(B-D)/(A-D)]	6.25%		19.6%

Notice with this structure the system is regressive. As oil price or profitability goes up, Government Take goes down. This is because, while the IOC is guaranteed 25% of gross revenues (almost like a negative royalty), the government is guaranteed 75% (like a large royalty). Royalties, especially large ones, are notoriously regressive.

II.4 Comparing Systems

There are numerous sources that make little distinction between the families of oil contract systems other than differences regarding the transfer of title to hydrocarbons that distinguish R/T systems from PSC and SA systems. This **difference in ownership structure**—where, when, and if ownership of the hydrocarbons is transferred to the IOC—is one of the distinguishing characteristics of petroleum fiscal systems. With an R/T system, title transfers to the IOC at the wellhead; the IOC takes title to gross production less royalty oil. For a PSC, title transfers at the export point or *fiscalization* point. The IOC takes title to cost oil and profit oil. With Service Agreements (by definition) there is no transfer of title to hydrocarbons and so this has direct implications for the IOC's ability to book barrels.

While these systems are not fundamentally fiscally different for reasons discussed earlier, some other notable variations exist that merit mention.

Title to facilities remains with the oil company under R/T Systems, but, under PSCs and Service Agreements, title to facilities transfers to the NOC or government. There is some variation to *when* title to facilities (including production facilities, pipelines and other associated facilities) transfers to the NOC or government but usually it transfers at the time of commissioning them. For example, in Nigeria, title to facilities transfers to the Nigerian National Oil Corporation (NNPC) when the equipment lands in-country. Some countries will wait until the facilities have achieved 'payout,' at which point title transfers to the NOC. From a financial point of view, as far as normal production operations are concerned, there is little difference to the IOC whether they or the government owns the facilities. The significant difference involves who is responsible for managing and restoring the site after production has concluded (the abandonment/site-restoration liability). In other words, the important legal implication is that the obligation for site restoration, abandonment, and cleanup is held by the *owner* in the absence of clear and well-crafted abandonment provisions.

Another, less evident, difference between the systems is with respect to how they handle **entitlement**. In the above examples we saw how a PSC and an R/T system over the full cycle can be financially identical, yet contractor entitlement in the PSC system may be about half that of the R/T system and, of course, is absent in the SA agreements. Below I describe in more detail the role entitlement plays in contract negotiation.

Finally, there may be difference based on **project costs**. Government Take is likely to be much higher for a PSC for low profitability projects. To see this, consider Graph 3.3. The graph shows how the PSC's payoff in this particular case is more front-end-loaded than the example R/T system. It is the cost recovery limit that makes the PSC more front-end-loaded (or regressive) than the R/T system. In early years, government revenue is guaranteed for both systems because of the royalty. The PSC, however, also has the cost recovery limit, which guarantees the government additional revenue. In fact, the Government Take for sub-marginal fields can be extremely high.[6] Note that once the costs are lower the two systems are the same.

Graph 3.3

Government Take vs. Project Profitability

Typical PSC:	**Typical R/T System:**
10% Royalty	10% Royalty
50% Cost Recovery Limit	No Cost Recovery Limit
60% Government P/O Share	60% Tax (1st Layer)
30% Corporate Income Tax (CIT)	30% Tax (2nd Layer)

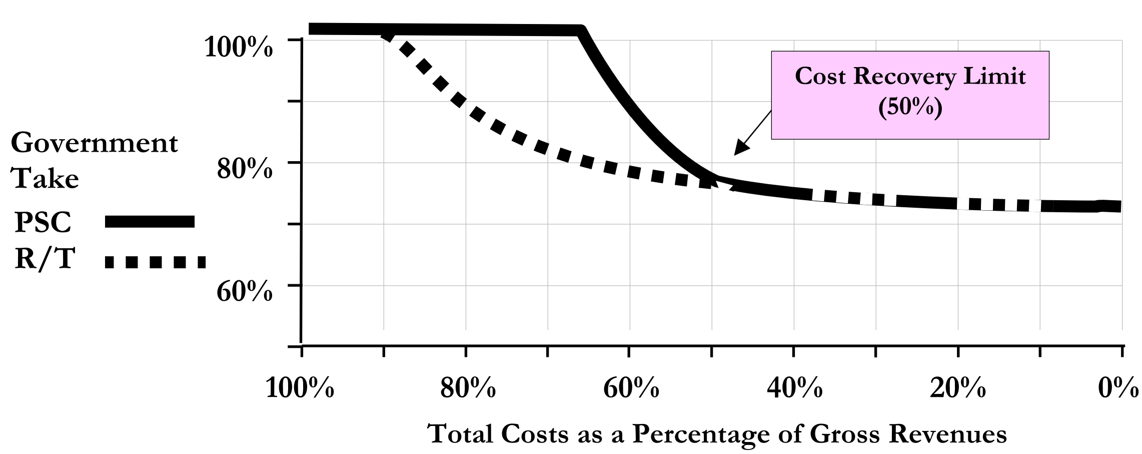


Table 3.6 summarizes the differences between systems while the statistics in Table 3.7 summarize the fiscal terms associated with these different systems. Features such as government participation, the Effective Royalty Rate and ringfencing in Table 3.7 will be discussed in Section III. Data was collected in 2001 and therefore does not take into consideration the recent oil price increases. Keep in mind, however, that most fiscal systems in the world are moderately regressive. The revenue the governments receive will go up, but Government Take will go down on average (discussed more below). Finally, it is important to remember that the differences in fiscal terms across systems is not necessarily due to the different families being used—as already discussed, similar terms can be achieved across all of these systems. Rather, differences reflect varying conditions in the diverse environments in which these systems are employed.

Table 3.6

Comparison of Fiscal Systems

	R/T Systems	PSCs	SAs
Global Frequency (% of Systems)	44%	48%	8%
Type of Projects	All types: Exploration, Development, Enhanced Oil Recovery (EOR)	All types: Exploration, Development, Enhanced Oil Recovery (EOR)	All types but often non-exploration
Ownership of Facilities	International Oil Company	Government NOC	Government NOC
Facilities Title Transfer	No transfer	"When landed" or upon commissioning	"When landed" or upon commissioning
IOC Ownership of Hydrocarbons (Lifting entitlement)	Gross production less royalty oil	Cost oil + profit oil	None
Hydrocarbon Title Transfer	At the wellhead	Delivery Point, Fiscalization Point or Export Point	None
Financial Obligation	Contractor 100%	Contractor 100%	Contractor 100%
Government Participation	Yes but not common	Yes, common	Yes, very common
Cost Recovery Limit	No	Usually	Sometimes
Government Control	Low Typically	High	High
IOC Lifting Entitlement	Typically around 90%	Usually from 50-60%	None (by definition)
IOC Control	High	Low to Moderate	Low

Source: International Petroleum Fiscal Systems Data Base, © Daniel Johnston, PennWell 2001

Table 3.7

World Average Fiscal Terms

	Global Sample		Sample of top 20th Percentile (Based on Prospectivity)	
	PSC	R/T	PSC	R/T
Number of Systems	72	64	19	6
Government Take	70%	59%	78%	80%
Government. Participation	36 countries	29 countries	12 countries	5 countries
Royalty Rate	5%	8%	5%	11%
Effective Royalty Rate	23%	8%	29%	11%
Ringfenced Systems	75%	30%	90%	33%
Lifting Entitlement	63%	92%	55%	89%
Savings Index	39%	56%	30%	37%
Cost Recovery Limit	65%	N/A	62%	N/A
Systems with ROR or "R" factors	17%	25%	26%	16%

Source: International Petroleum Fiscal Systems Data Base, © Daniel Johnston, PennWell 2001

III Beneath the surface: Evaluating key elements of an oil contract

With the exception of the United States, Canada, and a very few old Spanish land grants in Colombia, mineral rights belong to the state. Indeed in many countries, managing a country's mineral wealth is seen as a sacred trust (even though, in practice, a nation's mineral wealth often benefits only a few people).

Countries with limited proven mineral wealth seek exploration activity and have limited leeway attracting it. Still, they want the best contract terms they can get. All countries have their own unique boundary conditions, concerns, and objectives. Needs, traditions, perspectives, perceptions, and politics differ as well. Now that we have already discussed the general families of oil contracts, we turn our attention to the key elements of an oil contract. In particular, the major concerns facing a country government are:

1. Getting a large (and fair) share of the profits (Take) while keeping costs down;
2. Guaranteeing a certain share *each accounting period* (Effective Royalty Rate and/or Minimum Government Take);
3. Obtaining, but not exceeding the Maximum Efficient Production Rate (MEPR)—the rate at which oil from an oil field can optimally be extracted;
4. Maintaining a high degree of control over the country's resources;
5. Attracting investment and the right *kind* of company even if the financial conditions appear not as good.

Oil companies meanwhile want to explore in regions where there is a reasonable chance of finding oil and gas. They want to deal with stable governments, and prefer contract terms that will provide a potential return-on-investment that is commensurate with the associated risks. As already mentioned, companies are also interested in booking barrels. Indeed, in the eyes of Wall Street, oil companies are measured by their ability to replace the barrels pumped as well as by their finding and lifting costs. If they can book more barrels their 'reserve-replacement-ratio' – a key measure of successful performance in the oil industry - benefits and their finding costs go down. This can be confusing and frustrating since the ability to book barrels and the amount of barrels a company can book strongly depends on the type of system and various other peripheral elements. I look at some determinants of a company's ability to book barrels towards the end of this section.

As mentioned earlier, there is no single clause or number in an oil contract that conveys whether the country or company (or neither or both) got a good deal. Evaluating the contract requires examining a series of conditions, the most important of which are summarized in Table 3.8 (many of these conditions will be discussed in Section III.) Despite the multiplicity of goals on the part of governments and contractors, and the range of issues to be negotiated, a number of attempts have been made to create single measures to summarize the value of a contract. Chief among these is the "Government Take" statistic. I discuss this next.

Table 3.8

What's in an oil contract? Typical Contract Conditions

Condition	Description
Area	Block sizes range from extremely small for development/EOR projects to very large blocks for exploration. Typical exploration block sizes are on the order of 250,000 acres (1,000 km2) to over a million acres (>4,000 km2).
Duration	Exploration - Typically 3 Phases totaling 6 to 8 years. Production - 20 to 30 years, (typically at least 25 years)
Relinquishment	Exploration 25% after 1st Phase, 25% of "original" area after 2nd phase. This is most common but there is wide variation.
Exploration Obligations	Includes seismic data acquisition and drilling. Sometimes contract requirements can be very aggressive in terms of money and timing, depending on the situation.
Royalty	World average is around 7%. Most systems either have a royalty or an effective royalty (ERR) due to the effect of a cost recovery limit.
Profit Oil Split	Unique to PSCs and some Service Agreements. Most profit oil splits (approximately 55-60%) are based upon a production-based sliding scale. Others (around 20-25%) are based upon an "R" factor or ROR system.
Cost Recovery Limit	Unique to PSCs and some Service Agreements. Average 65%. Typically PSCs have a limit and most are based on gross revenues. Some (perhaps around 20%) are based on net production or net revenues (net of royalty). Over 20% have no limit (i.e. 100%). Approximately half of the worlds PSCs have no depreciation for cost recovery purposes (but almost all do for tax calculation purposes).
Taxation	World average corporate income tax (CIT) is probably between 30-35%. However, many PSCs have taxes paid 'in lieu' by the NOC.
Depreciation	World average is 5 year Straight Line Decline (SLD)--a constant percent decrease--for capital costs. Usually depreciation begins when equipment is placed in service or when production begins, whichever occurs later..
Ringfencing	Most countries (55%) erect a "ringfence" or a modified ringfence (13%) around the contract area and do not allow costs from one block to be recovered from another, nor do they allow costs to "cross the fence" for tax calculation purposes.
Government Participation	Typically the national oil company (or equivalent) is "carried" through exploration. Approximately half of the countries with the option to

	participate do not reimburse past costs.
Crypto Taxes	Crypto taxes are those costs and obligations the contractor must take on that are not readily captured in the Take calculations

Source: "International Petroleum Fiscal Systems", PennWell Books (2001), Daniel Johnston

III.1 The "Government Take" statistic

As mentioned earlier, the most common statistic used for evaluating contracts is the Government Take: the government's share of economic profits including almost all income sources, namely: bonuses, royalties, profit oil, taxes and government working interest (See Table 3.9). While the Government Take statistic includes most revenues accruing to government it does not include "crypto taxes" or benefits such as employment benefits and skills transfers, items which are collectively included under 'gross benefits'.

While a widely used measure, Government Take as commonly calculated has numerous shortcomings that can undermine its usefulness (Johnston 2002). It is often calculated based on unrealistic assumptions; it cannot adequately capture risk; it does not take timing of payments into account; and it leaves out other key elements altogether. Each of these shortcomings will be discussed in turn below.

Government Take is calculated using a number of assumptions about oil prices, costs, escalation rates, production rates, cumulative production, etc. Variations in these assumptions can affect the anticipated profitability of a field or project. Moreover, as can be seen from Graph 3.3, Government Take can vary quite dramatically with the profitability of a project. Government Take also does not adequately capture risk.

Table 3.9

Government Take: Key Definitions

Economic profit ($)	=	Cumulative gross revenues less cumulative gross costs over life of the project (full cycle). [Also referred to as 'cash flow'.]
Government Take (%)	=	Government receipts from royalties, taxes, bonuses, production or profit sharing and government participation, divided by total Economic

		profit
Contractor take (%)	=	1 - Government Take
	=	Contractor net cash flow divided by economic profit
Company take (%)	=	1 - Government Take (excluding government participation)
	=	Company net cash flow divided by economic profit

Note: In the past most Take statistics were based upon undiscounted cash flow. More recently Take statistics are being quoted from a present value point of view (i.e. the division of discounted cash flow).

In principle the Government Take statistic represents the division of profits "full cycle" — over the full life of a field or fields. In other words, Government Take represents the government's share of total net profits. This includes years when profits are low (sometimes zero) and years when profits are high— assuming there even are profits to begin with. In principle, however, at the beginning of a project, multiple Take statistics can be calculated, each conditional upon different possible outcomes.

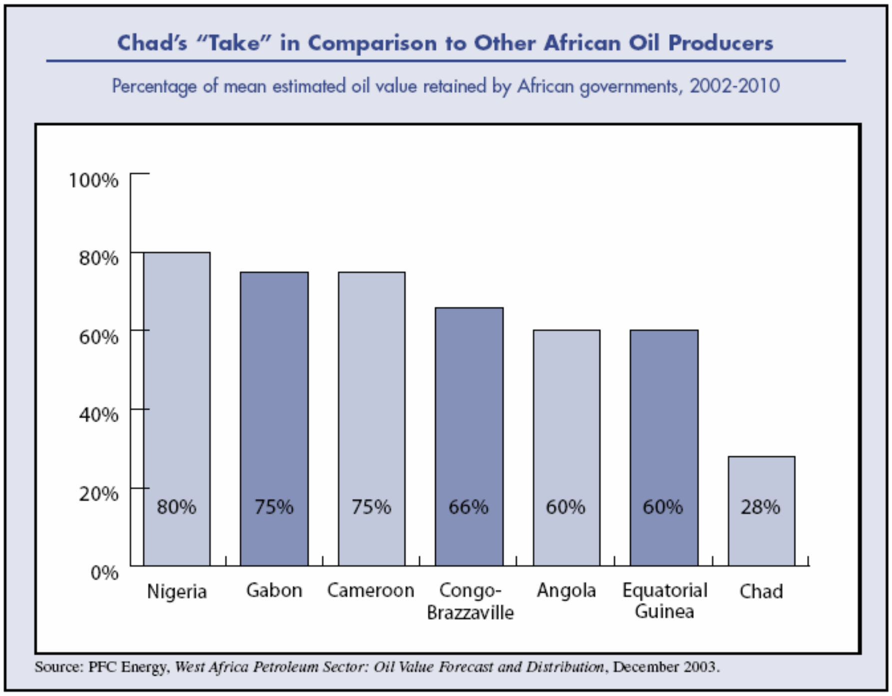
The Government Take statistic fails to provide information about the *timing* of payments. Yet, timing can be an issue of central concern to governments. For example, after Bolivia's first Gas War in 2003, a new fiscal system was proposed (Chávez 2004). The new system was intended to increase the share of revenue accruing to the Bolivian government in the early years of production from their newly discovered gas fields. Bolivia needed money sooner rather than later. The proposed system attempted to keep the revolutionaries happy without completely alienating the oil companies that risked capital exploring for and finding Bolivia's vast gas reservoirs. While a notable change to the timing of payments, the proposed system left the calculation of Government Take virtually unchanged because a comparison of the proposed system with the previously designed systems using undiscounted Government Take would not have shown a difference.

Few developing countries are able or willing to wait for profits to be generated from a developing field before they get a share. That is why we see signature bonuses and other front-end-loaded elements, like royalties and cost recovery limits. As discussed in other Chapters 2 and 5, the decision to front-end-load payments may or may not be wise in different circumstances. Regardless of the wisdom of the decision, the Government Take statistic does not provide guidance on how front-end-loaded a payment schedule is. In fact, unless it incorporates discounting, it may not say anything at all about the time value of money. Taking timing into account requires companion statistics, such as the "Effective Royalty Rate" (discussed below).

The Government Take measure excludes other key elements altogether. For example, the Take statistic says nothing about ringfencing—the practice of disallowing companies to consolidate their operations among more than one license area. Additionally, it does not measure contract or system stability; remains silent on reserve/lifting entitlements; and does not account for ownership.

Overall, what the Government Take statistic does and does not include makes cross-national comparisons based on Take statistics especially difficult. All the more so since a country's fiscal system is often compared to those of neighboring countries. In one example, Chad's Government Take is often compared to those of other West African countries. Consider for example Figure 3.4. The graph appears to indicate that the government of Chad got a raw deal, due (according to some industry accounts) to its lack of experience in negotiation. This comparison is misleading, however. Low rates in the Chad case are likely to be due at least in part to other factors, such as the quality of the oil or transportation costs.[7]

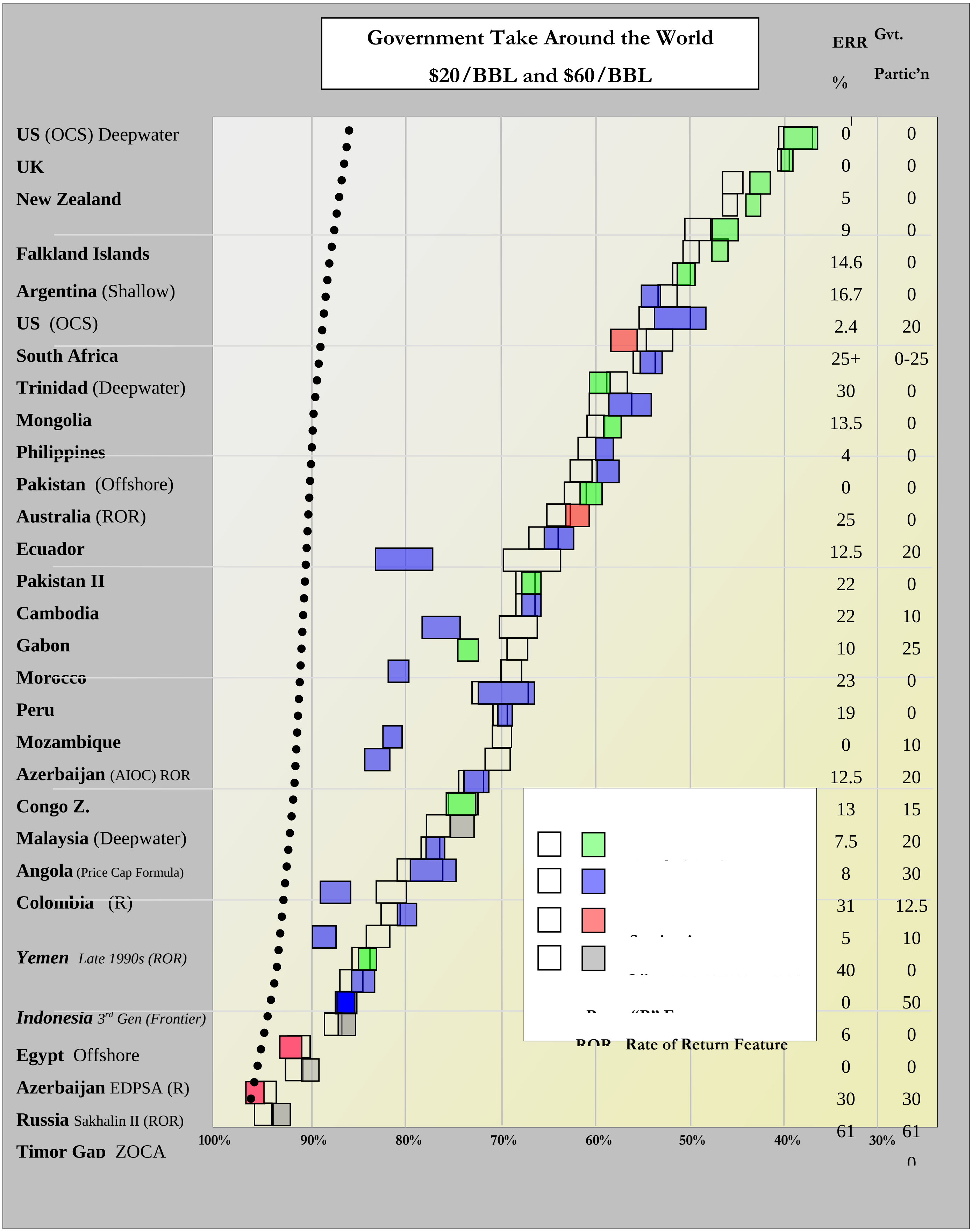
Figure 3.4



Source: "Chad's Oil: Miracle or Mirage" CRS

In Figure 3.5 I give another indication of Take rates around the world. This figure, however, shows how the Take figure depends on the price of oil. The figure represents fairly well the universe of systems that existed during the late 1990s and also includes the results of the recent feeding frenzy in the January 2005 EPSA IV license round in Libya, which featured a new generation of PSC contract (Johnston 2005). For each country the white bar indicates the Take statistic when oil prices are at $20 a barrel. Some of the bars on the graph are wider than others because some countries have fixed terms (narrow bars) but many countries have either terms that were bid or negotiated, and there is more variation and diversity found in the country's agreements. Also systems with "R" factors (tax rates based on predetermined payout thresholds, where the 'R' is typically the ratio of the company's cumulative receipts divided by its cumulative expenditures factor); or a "rate-of-return" (ROR) feature (where the higher is the rate of return the greater is the tax rate facing corporations) can have a greater range of financial outcomes than more conventional systems. The universe of systems represented in the figure were forged in an era when oil prices averaged a little over $18/BBL and around 90% of the time ranged between $16 to $20/BBL.

The natural question is: "How do terms change with $60/BBL oil?" The answer is given by the colored bars that are marked for each country. Note that in some cases the colored bars are to the right of the white bars, indicating that the systems are regressive—Government Take decreases. Notice that with most of these systems the Take only changes by a few points (2% to 3%). Cases in which the colored bars are to the left of the white bars, such as in Azerbaijan or Malaysia, are progressive. In these countries, Government Take goes up and typically by more than just a few points. The progressive systems are typically those with either an "R" feature; an ROR feature, or a price-cap formula. Many countries around the world right now wish they had structured their systems to adjust their Take upward. In fact, the scope for increasing the take as prices go up is dramatic. The dotted line on the left hand side gives an indication of the Take, at $60/BBL that would in fact yield the same economic benefits to oil companies as the terms original $20/BBL take would. The figure shows that, for an international oil company to achieve the same economic benefits or values Government Take can be quite high. For example, from an international oil company point of view an average Government Take of 67% during the late 1990s at $20/BBL is roughly equivalent to a Government Take of 92% at $60/BBL.



Government Take Around the World
$20/BBL and $60/BBL
ERR %
Gvt. Partic'n
US (OCS) Deepwater
UK
New Zealand
Falkland Islands
Argentina (Shallow)
US (OCS)
South Africa
Trinidad (Deepwater)
Mongolia
Philippines
Pakistan (Offshore)
Australia (ROR)
Ecuador
Pakistan II
Cambodia
Gabon
Morocco
Peru
Mozambique
Azerbaijan (AIOC) ROR
Congo Z.
Malaysia (Deepwater)
Angola (Price Cap Formula)
Colombia (R)
Yemen Late 1990s (ROR)
Indonesia 3rd Gen (Frontier)
Egypt Offshore
Azerbaijan EDPSA (R)
Russia Sakhalin II (ROR)
Timor Gap ZOCA
0 0
0 0
5 0
9 0
14.6 0
16.7 0
2.4 20
25+ 0-25
30 0
13.5 0
4 0
0 0
25 0
12.5 20
22 0
22 10
10 25
23 0
19 0
0 10
12.5 20
13 15
7.5 20
8 30
31 12.5
5 10
40 0
0 50
6 0
0 0
30 30
61 61
100%
90%
80%
70%
60%
50%
40%
30%
Rate of Return Feature

Source: Based on figures in Oil & Gas Journal 18 April, 2005 / Daniel Johnston and Co. Inc.

III.2 Effective Royalty Rate (ERR)

The Effective Royalty Rate (ERR) is a companion statistic to Government Take that helps to show how front-end-loaded the system is (although, as we will see, it does not measure *all* aspects of "front-end-loadedness"). It gives a feel for how quickly a contractor can get its money back.

ERR is the *minimum* share of gross revenues a government will receive in any given accounting period for a field. It typically does not include the National Oil Company (NOC) or oil minister's working interest share of production. This index, developed by Daniel Johnston in the mid 1990s, has become a standard metric in the industry (and is sometimes referred to in the industry as 'Minimum Government Take'). It is an important index that adds dimension to the Take statistics.

A complement to ERR – Access to Gross Revenues (AGR) - provides an important international oil company perspective. AGR is the *maximum* share of revenue a company or consortium can receive relative to their working interest in any given accounting period. It is limited by government royalties, and/or cost recovery limits and profit oil split (i.e. the ERR).

In a Royalty/Tax system with no cost recovery limit, the royalty is the only government guarantee. The ERR *is* the royalty rate. AGR is limited only by the royalty. In most Royalty/Tax systems in any given accounting period there is no limit to the amount of deductions a company may take and companies can be in a no-tax-paying position (although this can occur with a PSC as well).

Production sharing contracts with cost recovery limits guarantee the NOC a share of profit oil because a certain percentage of production is always forced through the profit oil split.

Thus both royalties and cost recovery limits guarantee the government a share of production or revenues regardless of whether or not true economic profits are generated.

The ERR/AGR calculations require a simple assumption—that expenditures and/or deductions in a given accounting period, relative to gross revenues, are unlimited. Therefore cost recovery is at its maximum (saturation) and deductions for tax calculation purposes yield zero taxable income. Situations like this can occur in the early stages of production, with marginal or sub-marginal fields, or at the end of the life of a field. The object of the exercise is to test the limits of the system. This provides the ERR/AGR indices.

One key weakness of the ERR index is that it does not measure the effects of depreciation or amortization. It also does not include the effects of the guarantee provided by government participation if and where it exists.

Huge problems can arise if the Effective Royalty Rate is not taken into consideration when designing a fiscal system. Depending on costs and production, contractors could be in a no-tax-paying position for years. This can cause cash flow problems for governments as well as lopsided misperceptions. This was the case in Ecuador in the mid 1990s because the ERR under their service agreement was zero (0%). In fact, although it may seem surprising, it is not hard to create a situation where contractors do not pay taxes for many years. Consider the example shown in Figure 3.6. The example shows an accounting period early in the development phase of a project where costs are high. As a result of tax deductions on operating expenses, exploration costs and depreciation, the contractor pays no taxes in the fourth and possibly also in the fifth years.[8]

Figure 3.6

No Taxes ?

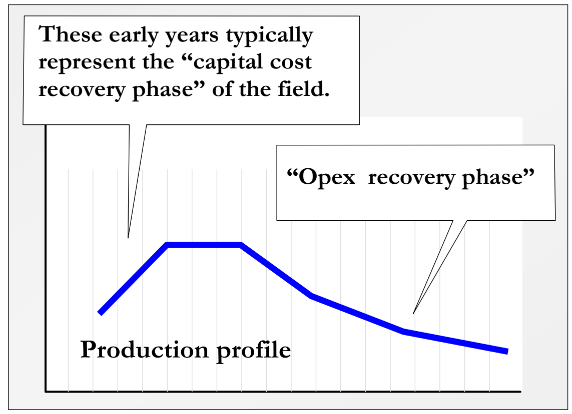
Assumptions:

Discovery size	**100 MMBBLs**	(Recoverable)
Exploration costs	**$50 MM**	(Expensed)
Development costs	**$400 MM**	
Depreciation	**25%/year**	
OPEX	**$3.50/BBL**	

Production

Year 4	**4 MMBBLs**	(Start-up)
Year 5	**6 MMBBLs**	(Ramp-up)
Year 6	**11 MMBBLs**	(Plateau)

Decline rate **10%**



Calculation of Tax Deductions, Year 4

Exploration costs	$50 MM (Expensed)
Depreciation	$100 MM (25%/year SLD)
OPEX	$14 MM ($3.5 * 4 MMBBLS)
Total	$164 MM

Year 4 Tax Calculation

$80.00	**Gross Revenues ($MM)**
- 8.00	**10% Royalty**
72.00	Net Revenues
- 19.20	**Gvt. P/O Share 60%**
52.80	Contractor Revenues
- 52.80	Tax deductions (no limit)
0	Contractor Tax Base

TLCF into Year 5 = $164-52.8 MM
= $111.2 MM

Year 4 Revenue Distribution

$80.00	**Gross Revenues ($MM)**
- 8.00	**10% Royalty**
72.00	Net Revenues
- 40.00	**Cost Oil** (Saturated - 50% limit)
32.00	Total Profit Oil
- 19.20	**Gvt. P/O Share 60%**
12.80	Contractor Profit Oil
-0.00	**Income Tax 30%**
12.80	Contractor P/O
+ 40.00	Contractor C/O
$52.80	66% of Gross Revenues

Tax Deductions for Year 5

Tax Loss C/F	$111.2 MM	($164 - $52.8 MM)
Depreciation	$100 MM	(25%/year SLD)
OPEX	$21 MM	($3.5/BBL * 6 MMBBLS)
Total	$232.2 MM	

Kazakhstan's Kashagan PSA has a Government Take of around 83% or more (depending on various factors), but only a 2% ERR. The contract is said to be extremely complex and back-end-loaded. So even though the Take is high, in fact the government does not receive the bulk of it until the later years. It is estimated that in the first 5 to 7 years of production, the government will only receive 2% of gross revenues. In many places such a deal could cause major problems. Imagine being the government or NOC official of a democratic country that has to paint the merits of back-end-loaded contracts for legislatures, the press, or the citizens?

How is the Effective Royalty Rate calculated? The following figure calculates the Effective Royalty Rate of an Indonesian-type PSC. Again, one barrel of oil is used to represent revenues for a single accounting period. Typically this would be an early accounting period following production start-up when accumulated costs are high and production is relatively low.

In this example the contractor is in a no-tax paying position, as in the example discussed above, still the government receives a 10% royalty, and because of the Cost Recovery Limit, the government is also guaranteed a percentage of the profit oil. The 34% ERR in this example is high by world standards.

Table 3.10

Sample Calculation of ERR

10%	Royalty	Oil Price	$20/BBL
50%	Cost Recovery Limit	Costs	Assumed to be unlimited
60%	Government P/O Share		
30%	Corporate Income Tax (CIT)		

	Gross Revenues	
Character Share	**$20.00**	**Government Share**

		Royalty 10%	→	**$2.00**
		$18.00		
$10.00	←	**Cost Recovery** 50% Limit		
		$8.00	**Profit Oil**	
$3.20	←	**Profit Oil Split** 40/60%	→	**$4.80**
($0.00)	→	**Tax Rate** 30%	→	**$0.00**
$3.20				
$13.20	←	Division of Gross Revenues	→	**$6.80**
		Effective Royalty Rate	**34%**	
			$6.80/$20.00	

III.3 The Government Participation Figure

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. The government then 'backs-in' for a percentage upon discovery. Government participation typically is the result of a government option (through the National Oil Company) to take up a working interest in the event of a commercial discovery. In other words the government is 'carried' through the exploration and appraisal phase in that the government as a working interest partner plays a disproportionately lower share of costs and expenses in the exploration phase than its working interest share. Technically the government through the NOC is carried up to the commerciality point— usually downstream by a well or two from the actual discovery well. The contract clause that deals with the requirement for delineation/appraisal wells following a discovery is referred to as the "commerciality clause." The government agent, usually the NOC, must decide whether to exercise their right to back-in once the commerciality point has been reached. Once the government exercises the option it then 'pays-its-way' for development and operating costs from the commerciality point forward just like any other working interest partner.

Over half of the countries worldwide have this option. Contractors prefer no government participation. This is in part due to efficiency considerations: Joint operations of any sort, especially between actors from different cultures, can have a negative impact on operational efficiency. On the other hand, if done right, such joint operations can be beneficial for governments, both because of the financial benefits (more on this below) and for building capacity.

Government participation clauses vary in terms of how they are structured. The key aspects of government participation are:

- What percentage participation? Most range from 10% to 50%. In Colombia the government has the right to take up to 50% working interest and will reimburse the contractor up to 50% of any successful exploratory wells. In China, the government participation is 51%. This usually defines the upper limit of direct government working interest involvement. The average is around 30%.
- *When* does the government back in? This normally happens at commerciality.
- How much does the Government participate? This varies considerably from case to case.
- What costs will the government bear? Usually they bear their pro rata share of costs. However there is variation in whether governments reimburse 'past costs' – those costs incurred by the IOC after the effective date of the contract up to the commerciality date when the NOC backs in. About half of the contracts have a 'past costs' clause.
- How does government fund its share of costs? Often out of up to a certain percentage of the government's share of production.

The financial effect of a government partner is similar to that of any working interest partner, with a few important exceptions. First, as noted above, the government is usually *carried* through the exploration phase and may or may not reimburse the contractor for past exploration costs. Second, the government contribution to capital and operating costs is often paid out of production. Finally, the government is seldom a silent partner.

A key question surrounding the calculation of government benefits from a contract is whether or not government participation should be included in the Take calculation. That is, is this process truly a way by which governments extract rents?

Some analysts believe it is not appropriate to view this element of a system as a rent extraction mechanism on the grounds that such returns are just standard economic returns on investments made. However this approach contradicts some basic economic laws. And, it is easy to check by asking a simple question: "Does the 'back-in' cause the foreign investor financial pain?" The answer is a certainly "Yes." And the pain is multidimensional. First of all, the value of a discovery to an explorer will be reduced by almost exactly the amount of the 'carry' and secondly, the companies will not be able to book as many barrels.

A back-in option of 50% is not as costly to the company as a 50% tax on profits (both of which will guarantee the government an added 50% share of profits); but just *how* different the financial impact depends on profitability and timing. As profitability increases the back-in or participation element takes on more of the characteristics of a pure tax or a royalty, depending on the point at which the government takes its share of production. While it is conceptually a bit abstract, as costs relative to gross revenues approach zero (the ultimate in profitability) the back-in begins to take on all of the characteristics of a tax. Thus, the less profitable a venture is, the less painful the government participation element is. Either way, both taxes and/or participation options cause the contractor financial pain to various degrees.[9]

As we saw, comparing two fiscal systems on the basis of Government Take alone is not a perfect comparison if one system has participation and the other does not. To simply ignore the participation element, however, would be a greater misrepresentation. When comparing fiscal terms for exploration rights it is not appropriate to exclude or ignore the participation element. Participation should be considered as a part of the Take for governments.

III.4 The Savings Index: A measure of contractor incentive to save

The savings index is a measure (from an undiscounted point of view) of how much a company gets to keep if it saves $1. Because of the great concern on the part of both governments and companies about reducing costs, this statistic can be used to quantify to some extent the incentives companies have to keep costs down. Only the profits-based fiscal elements influence this statistic. Royalties (based on production not profits) have no influence.

The example given above of an R/T system has two profits-based mechanisms: a 60% special petroleum tax and a 30% income tax. Therefore, if the company saves one dollar there will be an added dollar of taxable income. The government gets 60% of that. The company therefore has 40¢ on the dollar saved prior to collecting the income tax. With a 30% income tax the company only gets to keep 70% of the 40¢. The savings index then is 28¢ on the dollar (saved), or 28%.

Under a PSC a dollar saved means an extra dollar of profit oil and hence a saving that corresponds to the contractors share of profit oil.

Note that the savings index described above does not take into account present value discounting. The present value effect can be interesting and it often magnifies the IOC's incentive to keep costs down.

III.5 Responsiveness to Changing Conditions: Regressive Systems and Sliding Scales

A regressive system is one where Government Take goes down as profitability goes up. For a system to be regressive it must have at least one regressive fiscal element. Conversely, for a system to be progressive it must have at least one progressive element. Today, oil prices are more than double what they were when most of the existing fiscal systems were designed or negotiated. With the higher oil prices comes higher profitability, but with most systems, a lower Government Take. In other words, governments are benefiting from higher oil prices as total revenue does increase; it's their percentage share of net profit that decreases (as seen earlier in Figure 3.5). This is simply a function of system design.

Many systems have sliding scales built into them to take advantage of the possibility of increased production ("production based sliding scales") but few systems were designed to take advantage of the increased oil prices. The elements of a fiscal system that determine whether the system will be regressive or progressive are described in Table 3.11:

Table 3.11

The Progressiveness of Different Provisions of an Oil Contract

Element	**Effect**
Bonuses	Extremely Regressive
Royalties	Very Regressive
Taxes	Neutral
Government Participation	Neutral
"R" Factors	Progressive
ROR systems	Progressive
Depletion Allowances	Very Progressive
Uplifts & Investment Credits	Slightly Progressive

Given the great volatility of oil prices it would be wise for countries negotiating contracts to estimate the returns to them (and to private sector partners) under a range of different price scenarios.

III.6 Factors that Affect Exposure to Exploration Risk (Block Size, Relinquishment and Ringfencing)

Most governments go to a lot of effort to distance themselves as much as possible from exploration risk. This can be done through management of block sizes, relinquishment, and ringfencing, discussed in turn below.

Block size and configurations

Block size refers to the size of the territory demarcated for exploration. Block sizes can range dramatically. Typically, block sizes will be smaller in proven geological provinces and much larger in frontier regions. The choice of block size and configuration is an important consideration. A challenge is to configure the blocks or licenses in order to provide interesting tracts instead of having just a few highly prospective blocks and others that will attract little interest. The larger regions can require considerable exploration expense. The IOC, however, may be able to recover dry hole and other exploration costs in one part of a block against a production in another part of the block.

From the government's perspective, with larger blocks there is the likelihood of a greater accumulation of exploration sunk costs prior to discovery. These expenses are typically cost recoverable and/or tax deductible, leading to larger accumulations of sunk costs and resulting in less income in taxes for governments. With smaller blocks governments can minimize or mitigate their exposure.

Relinquishment provisions

Relinquishment refers to a contract term that requires a certain percentage of the original contract area to be returned to the government at the end of the first phase of the exploration period. Relinquishment options are diverse and there is a full spectrum of methods employed, ranging from almost no relinquishment (in the ordinary sense) to very aggressive relinquishment requirements like we see in the Middle East. For example, in some of these countries only a discovery will be retained and all other acreage will be surrendered at the end of the final exploration stage. In Indonesia for many years oil companies could keep more than just development areas (discoveries) at the end of the final official stage of exploration. This meant that if a company made an economic discovery it could enjoy the opportunity to continue exploration in their *remaining* acreage while they pursued development of their discovery.

Ringfencing

Ringfencing is the practice of disallowing companies to "consolidate" their operations from one license area to another. It means that each license (typically) is treated as a separate cost center for cost recovery and tax calculation purposes. Thus, ringfencing limits cost recovery or deductions that can be taken against production to the activity inside the ringfence. A number of countries will automatically ringfence a discovery once a discovery is made. This would disallow deductions for exploration activity outside the initial discovery area. This kind of treatment is becoming more and more common.

Ringfencing can protect a government from what might otherwise be a marginal or sub-marginal discovery, by limiting the costs that can be cost recovered and/or deducted against revenues generated by the discovery. However, it can be a negative incentive to the exploration companies.

III.7 Booking Barrels: Lifting Entitlement and Reserves Reporting

As described above, 'booking barrels' is the practice of counting oil among the assets of a company. As a general rule oil companies will book barrels according primarily to their working interest and to their lifting entitlement. However there are some less obvious ways in which barrels are often booked.

Under Royalty/Tax systems, entitlement equals gross production less royalty oil. However, many governments take their royalty 'in cash' instead of 'in kind.' In this case many companies are booking those barrels as well.

In PSCs, entitlement equals profit oil plus cost oil. However, in systems where taxes are 'in lieu' companies calculate what their profit oil share would have been (dividing their share by 1 minus the tax rate) and book the barrels they would have been entitled to lift had they paid taxes directly in cash (also called 'grossing-up'). This is common with Egyptian-type PSCs. R/T systems would be much preferred by an IOC wanting to book barrels because they can typically book about twice as many barrels as they would with a PSC.

Finally, some companies book gas or oil consumed on-site as well as fuel for operations; and, even though, by definition, there is no entitlement under a service agreement, companies do sometimes book barrels in these cases also.

In general, PSC entitlements typically go up with falling oil prices and down with increasing oil prices. Because a company's entitlement with a PSC is based on its share of cost oil and profit oil when oil prices went from $20/BBL to $60/BBL the typical entitlement under a PSC went down by around 15%. This is because with higher prices it does not take as much cost oil to recover costs and thus entitlement goes down. This is not an issue for R/T Systems.

Conclusions

I conclude with some comments about how deals between governments and contractors should be made, issues that are taken up again in Chapters 4 and 5. Fiscal design elements discussed above are important, but so are the means by which governments choose to *allocate* acreage or projects.

As in the past, there is significant competition for a limited amount of exploration capital. At the same time, exciting acreage is hard to come by. If governments want to increase exploration activity in their countries, they have to offer terms commensurate with their geological potential, location and political situation. Acreage has begun to take on more of the characteristics of a global commodity. There is over three times as much acreage available today as there was 25 years ago. In the past two decades the Soviet Union became the former Soviet Union (FSU) and many African and the Eastern-block countries have opened up. Furthermore, with more aggressive and specific relinquishment provisions in contracts, the market for acreage or projects is more dynamic and robust.

The means by which governments determine how to award licenses are extremely varied. Some governments (approximately 30 to 40 each year) have official "block offerings" or "license rounds" where blocks are awarded on the basis of competitive bids.

In competitive systems there can be a lot of variation over what in fact is bid on (elements that become part of a contract or a system are usually either negotiated, statutory, or bid items; working out which way to do it is of huge concern to many governments). Libya for example let companies bid the terms (Johnston 2005). By allocating licenses in a competitive bid round, the IOC ultimately determines what the market could bear for the Libyan blocks. This takes the burden of fiscal design off of the NOC personnel and places it on the IOCs. This is possible—and profitable—because oil companies will suffer just about anything for highly prospective acreage or projects (referring back to Figure 3.5 we see that in the Libyan license rounds companies appear to have bid terms consistent with nearly $50/BBL expectations). Venezuela used a somewhat different approach. Venezuela launched its exploration round in 1996, putting 10 blocks up for bid. For all practical purposes, however, Venezuela had 10 separate license rounds, block-by-block. On Monday morning 22 January 1996, bids were opened for the first block only (the La Cieba block). These licenses were awarded on the basis of a single-parameter bid—a profits-based tax known as the "PEG." Companies were to bid from zero to a maximum of 50%. Royalty and other fiscal elements were "fixed" (i.e. neither bidable nor negotiable). Ties were to be broken by a subsequent bonus bid round to follow the opening of the PEG bids within a few hours. On the first block, La Ceiba, 11 companies bid and nine tied with a full 50% PEG bid. The tie was broken with a bonus of $103,999,999 from the Mobil/Veba/Nippon consortium. That afternoon the next license (Paria West) was awarded to Conoco under the same rules. This kind of approach magnified the already intense competition by awarding licenses individually—one-at-a-time. With each "round" the pool of bidders would potentially be reduced by perhaps only one group if any at all. This approach greatly reduced the chance that less-prospective blocks would receive no bid. Nonetheless, two blocks did not receive a bid. The resulting Government Takes were around 92%. Finally, on the other end of the spectrum, in the Gulf of Mexico, licenses are awarded by the United States solely on the basis of a bonus bid (in practice however, few countries worldwide extract such a large portion of rent through bonuses).

These are examples of competitive bidding systems. But other countries negotiate exploration rights one-on-one with companies. While companies typically prefer negotiated deals, these situations can be just as competitive as an official tender. It all depends, however, on the prospectivity of a block or area. When governments have good geology they are more likely able to allow companies to bid the terms. Sealed bid license rounds (auctions) can be very beneficial for a government with highly sought-after acreage or projects.

There is considerable pressure these days from the World Bank, the International Monetary Fund and bodies such as the Extractive Industry Transparency Initiative (EITI) for oil companies and governments to be more transparent. With these initiatives there is a strong push for governments to allocate acreage on the basis of public auctions similar to the highly publicized recent EPSA IV rounds in Libya. This likely makes sense for acreage where there is high potential for profit. The problem remains, however, that unless acreage is particularly interesting, the industry has been relatively unwilling to face the kind of magnified, head-on competition that a sealed bid type license round (like Libya) provokes. It is somewhat unrealistic to expect *all* governments to allocate *all* acreage and projects on the basis of sealed bids. Many countries, even Nigeria and Kazakhstan, have some acreage and some projects that are not quite as exciting as others. When it comes to attracting IOC investment, allocation of such acreage becomes much more important with less-than-exciting prospects. One of the most difficult things for IOCs to contemplate is a direct heads-on competitive sealed-bid license round for non-spectacular acreage or projects. Countries are also likely to find that with less exciting prospectivity they will likely have to design terms themselves and allocate licenses in a user-friendly way. In such cases a government may have no choice—negotiated deals may be the only option. Otherwise they are likely to be disappointed with the level of exploration activity in their country—a common complaint. In such cases allocating licenses through negotiated deals can have its own advantages. Government officials (Energy Ministry or NOC) become aware of what the market can bear as they entertain various proposals and offers. Likewise the lack of interest provides information too. There is nothing worse than a failed license round for a NOC official.

These considerations tend however to differ somewhat for different types of project. As summarized in Table 3.12, competitive bidding tends to be more viable for frontier acreage or exploration acreage than for development projects or enhanced oil recovery projects. The greater the risk the greater the range of bids possible; as risk diminishes, such as in the case of development projects, the terms tend to be fairly fixed.

Table 3.12

Different Situations — Different Considerations

	Enhanced Oil Recovery	**Development Projects**	**Exploration Acreage**	**Frontier Acreage**
Degree of Risk	Med - High	Low	High	Highest
Block Size Acres (km^2)	Field 4,000 or so (16)	Smaller 3,000 - 5,000 (12 - 20)	Large 1-2 MM+ (8,000)	Very Large 3-4 MM+ (16,000)
Work Program (s)	1) Feasibility Study 2) Pilot Program 3) Development	1) Appraisal 2) Development	Exploration Program	Exploration Program
Focus of Negotiations/ Analysis	IRR	IRR	Take	Take
Most Common Allocation Strategy	Negotiated deals	Negotiated deals	Competitive Bidding and other means	Competitive Bidding and other means

Beyond this, which method is best depends to a large extent on the bargaining power of countries and what they can expect IOCs to accept. IOCs most prefer negotiated deals (such as are employed in Colombia, Trinidad and Tobago, or Indonesia), followed by fixed term contracts with work program bidding (as in UK, Norway, Australia, or New Zealand). Fixed terms contracts with bonus bidding (as in the US, Nigeria, or Burma) cause more pain to IOCs. The least preferred form of bidding is the sealed bid round with terms bid (as in Venezuela, Libya). As described in Chapter 5, in situations in which prospects are good, competitive bidding may be optimal and much care should go into auction design. In situations in which governments are in a weak bargaining position, however, negotiated deals may be required. Negotiated deals raise special challenges for negotiators, as discussed in Chapter 4. They also risk raising political economy concerns. In the context of negotiated deals, it can be hard for governments to keep both oil companies and citizens happy simultaneously, leading to suspicions of foul play. This is where transparency can have a dramatic impact. Overall, transparency is a vital part of the education process for both states and citizens, and remains one of the best ways not only to control expectations at the outset but also to promote a healthy business environment over the life of the oil extraction relationship.

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[1] This chapter draws substantially on previously published work by David Johnston and Daniel Johnston (see references at end of chapter).

[2] Gas is simply much more difficult to transport than oil and is still 'flared' (a process by which waste gases produced in the course of processing oil are disposed of through combustion) in many parts of the world. In fact, nearly 10 billion cubic feet of gas is flared per day. Nigeria flares almost 2 billion cubic feet per day in their Niger Delta oil fields—not far from some of the poorest people in the world. And in many other parts of the world gas discoveries are simply 'shut in.'

[3] These distinctions are not always clear. Some risk service agreements (agreements where fees are paid for services rendered) appear to have more of the characteristics of a royalty/tax system (Venezuela; with royalties and taxes), while some look more like a PSC (Philippines; with a cost recovery limit and profit oil split).

[4] Region also plays an important role in determining what a contract is called. Hence, in some areas, R/T systems are often simply referred to as 'concessions.' In other parts of the world, however, the term 'concession' has a negative connotation; in other words, it lacks political correctness. Political correctness also helps to explain why Personal Service Contracts are sometimes called Personal Service Agreements (PSAs). For instance, in Russia the word 'agreement' is favored over the word 'contract' because 'contract' has a negative connotation when translated into Russia. Yet, a PSC and a PSA are virtually identical and I hereafter use the term PSC to refer to both.

[5] According to a Permina brochure from 2000 (author's personal file).

[6] Graphs like this are therefore usually capped at 101% —showing Takes beyond the 100% range is relatively meaningless.

[7] One additional noteworthy feature in Figure 3.4 is the timeframe used: 2002-2010. Since Chad did not start shipping oil until 2003, the timeframe represents only the early years of production, when taxes would be minimal. It suggests that the Take calculation has not been "full cycle." If so, then the comparison above is probably more of a representation of Chad's Effective Royalty Rate than overall Government Take, insofar as the Effective Royalty Rate measures the extent to which the system is front-end-loaded.

[8] Although, this does not mean the government is not receiving revenue as the government can still receive royalties and shares of profit oil.

[9] Note however that from a project cash flow point of view, companies will certainly prefer 50% government participation to a 50% tax because at least with participation, after the NOC backs-in, it "pays its way."