Maximizing the value of government revenues from upstream petroleum arrangements under high oil prices

A discussion document

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EXECUTIVE SUMMARY

The current high oil prices of about $ 130 per barrel create a new challenge for governments to design upstream government petroleum fiscal regimes. Most regimes in existence today were designed before 2003 when $ 25 per barrel was the typical long term oil price forecast and costs were typically between $ 2 and $ 10 per barrel.

Today, no one seems to be able to forecast with any confidence the long term oil price. Prices may continue to move up well beyond $ 130 per barrel or prices may crash as they did in the mid 1980's to levels lower than most analysts expect. It is clear that oil market analysts have been consistently and dramatically wrong about forecasting oil prices ever since 1973.

Yet, governments are faced with the task to design fiscal terms for leases, licenses or concessions (jointly referred to here as "concessions"), production sharing contracts ("PSC's") or risk service contracts ("RSC's") that may last for as long as 20 or 40 years. In fact, investors sometimes demand fiscal stability on these terms, requiring governments to commit for decades to a particular deal.

The terms of concessions and PSC's could have fiscal systems with a wide variety of elements such as bonuses, royalties, corporate income tax, cost oil and profit oil (PSC's only), windfall profits taxes, special taxes, property taxes, export duties, etc.

For RSC's there is a wide variety of fiscal systems with elements in the form of cost recovery, payments per barrel or Mcf, profit based remuneration schemes and other concepts.

Governments usually design their fiscal systems to maximize the value of the revenues from their oil and gas resources. The new economic framework creates the need to review these systems. Many of the elements that worked well prior to 2003 are now out of date and need to be re-designed. The overall fiscal balance in upstream government petroleum regimes has to be changed if governments want to continue to maximize the value of government revenues under the current high oil and gas prices.

This report is a review of these matters. Following is a summary of five specific issues.

In order to achieve the highest possible government take, is there any inherent advantage to any of the three major petroleum regimes: concessions, production sharing contracts or risk service contracts?

There are three main models in this world. From a fiscal perspective, these government petroleum regimes have the following characteristics:

- **Concessions. Concessions usually have royalties, corporate income tax and special taxes as their main components. Examples of these regimes are in the USA, Canada, Norway, UK, Brazil, Algeria, South Africa, Thailand and Australia.**
- **Production Sharing Contracts ("PSC's). Under PSC's, contractors receive an amount of oil or gas for the recovery of their costs as well as a share of profit oil or profit gas. Sometimes, PSC's also have royalties and taxes. Examples of these regimes are in Indonesia, Malaysia, Egypt, Gabon, Cote d'Ivoire, Syria, Yemen and Trinidad and Tobago.**
- **Risk Service Contracts ("RSC's"). Under RSC's the contractor is paid in cash or in oil or gas for his services in addition to arrangements to recover all or part of the costs. Currently, risk service contracts exist in Mexico and Iran, while Iraq and Kuwait are considering these concepts.**

Concessions, PSC's and RSC's may also have carried interest provisions for national oil companies ("NOC's"). These are joint ventures with the international oil companies ("IOC's) after a commercial discovery has been made.

There are no inherent differences in the level of government take and government revenues that can be obtained through the three types of upstream government petroleum regimes. It is possible for any petroleum project to create fiscal terms that result in exactly the same government take, under particular assumptions of prices, costs and the time value of money, for each of the three regimes.

What are the factors that determine the level of government take and is there justification for increasing government take under higher oil and gas prices if costs increase as well?

In terms of the level of government take it is necessary to distinguish between:

- **the mega-trends that have caused a low or high government take during the last few decades, and**
- **the micro-environment for each project whereby detailed technical, economic and risk conditions determine the maximum government take that can be achieved.**

Mega-trends. The government take is really the "price" that investors are willing to pay for exclusive access to concession or contract areas for petroleum exploration, development and production. The "price" is determined by the market forces through:

- **The supply of concession and contract areas by governments, and**
- **The demand for concession and contract areas by IOC's.**

With about 150 governments (federal, provincial, state) regularly or occasionally offering acreage and about 200 active IOC's looking for new opportunities there is a very strong world market in petroleum contract and concession areas.

Since 1973 there have been three major movements in government take:

- **From 1973-1984 the government take increased strongly due to increasing oil prices and the fact that nationalizations took acreage off the market,**
- **From 1984 – 2003 the government take decreased because many countries opened up for exploration and production and much new deep water acreage became available, while oil prices declined,**
- **Since 2003 the government take is going up again because oil and gas prices are increasing strongly and new acreage availability is now limited.**

Micro-factors. Within this overall framework, the level of government take that can be achieved for any particular project is determined by economic and other conditions, such as:

- **Whether the project relates to the development of an discovered oil or gas field, or whether it is an exploration project,**
- **If exploration is required, the geological risk of drilling dry holes and possible attractiveness of possible discoveries,**
- **The logistical and cost conditions of the area,**
- **The nature of the project, such as whether it relates to light oil, heavy oil, enhanced recovery or LNG development,**
- **Whether the area is close or far from markets,**
- **The anticipated fiscal stability of the concession or contract, and**
- **The political, regulatory, environmental and other risks.**

The maximum level of government take and government revenues that can be obtained is competitive with comparable other international opportunities.

Higher prices and higher costs. The higher prices make it possible for governments to achieve a higher government take.

International competitive conditions create an environment whereby IOC's make higher profits under higher oil and gas prices. This is because many governments leave much "on the table" under higher oil prices. This creates favorable competitive conditions for IOC's and results in excessively increased profit expectations under higher prices.

At the same time, costs have increased as well since 2003, however, not as much as the five fold increase in oil prices. The CERA Upstream Capital Cost Index indicates that on a world wide average basis capital costs have increased by about 100%. Operating costs have increased by less than 50% in most areas.

Despite the higher profit expectations by IOC's and the higher costs, there is considerable scope for higher government takes as well.

What are the policies and fiscal structures that lead to the maximum value of government revenues from oil and gas resources and what changes are required to deal with high oil and gas prices?

Policies. An important step in achieving the highest value of government revenues is to achieve the highest possible level of production. Also the timing of the government revenues is important, which means early production is beneficial.

Countries constrained by OPEC quota are limited in their options in this respect. Nevertheless, even OPEC countries have set objectives to achieve higher levels of production. For instance, Kuwait is to achieve 4 million barrels per day by 2020.

Countries that can freely pursue the highest possible level of oil and gas production, should follow the following two policies to achieve the maximum value of government revenues:

- **Policy 1. Maximize production by creating profitable conditions for the widest possible range of petroleum exploration and development projects and extract the maximum value of government revenues from each project.**
- **Policy 2. Ensure that investors are encouraged to achieve the maximum level of production at the lowest possible costs at the optimal possible pace of development that is consistent with good conservation practices in order to achieve the highest possible value.**

Comprehensive fiscal stability. The increased unpredictability of the oil and gas markets makes 30 or 40 year fixed deals no longer a reasonable concept for governments. It can no longer be recommended for governments to provide comprehensive fiscal stability.

If fiscal stability is to be provided at all, it should be done within a certain economic framework. Within the boundaries of the economic framework fiscal stability could be provided, outside these boundaries governments should have the right to adjust the deal depending on the circumstances.

Higher government take with higher prices. **In order to benefit from the current high oil and gas prices it can be recommended to create fiscal systems whereby the percentage government take goes up if oil and gas prices are higher. The increases in government take can be much stronger over price levels that guarantee an ample supply of petroleum from diverse sources in the host nation, such as $ 80 per barrel or more. Nevertheless, it is a good policy to always leave a small gain with the investors in case of higher prices, in order to ensure that IOC's have an interest in selling their oil or gas for the highest possible prices.**

Examples of fiscal features that could lead to maximum government revenues under concessions and production sharing contracts are:

- **Taxes or profit oil shares that increase the rate with higher price levels, or**
- **Windfall profits taxes that are aimed at taxing excess gross revenues under high prices**

Most of these price sensitive features have been designed so far for price levels that are less than today and therefore it necessary to update these systems for the new environment.

Different cost environments. **Governments over the last few decades have often designed separate fiscal terms for different cost environments, such as deep water, onshore wells, heavy oils, LNG projects, enhanced oil recovery projects, etc. This is a good policy from the view of maximizing the value of government revenues and it can therefore be recommended to continue and refine such policies.**

Encouragement of IOC efficiency. **Fiscal systems should encourage efficiency on the part of IOC's within each cost environment. This means that fiscal systems should provide higher profits to IOC's when they are more efficient. This permits governments to obtain higher revenues. The IOC's and the government, should both benefit from increased efficiency.**

This is important because under the current high oil prices IOC's may be induced to squander resources in order to capture new opportunities. Governments should therefore increase their attention to fiscal structures that reward efficiency and provide a strong disincentive for squandering capital and operating costs. In order to encourage efficiency the government take should stay approximately at the same level with lower costs.

R-factors and IRR profit shares. Traditionally, governments have been trying to achieve a higher government take under lower costs conditions with features that have sliding scales based on profitability, such as profit related ratios ("R-factors") or the IRR. These sliding scales have to be carefully balanced. They have to achieve a higher government take, while they should also encourage efficiency. These features only work well over a relatively narrow range.

Under current high oil and gas prices these R-factor and IRR based scales cannot be "stretched" to accommodate the much wide economic framework. As a result governments will have to introduce additional fiscal elements to complement profit based features. This can be done by removing much of the revenues to the IOC's under high prices with sliding scale royalties or price based windfall profits taxes.

Higher government take with higher production. Fiscal systems for petroleum exploration or development projects, or for individual well drilling as in North America, should create a higher government take with the level of daily production or cumulative production.

However, at the same time fiscal terms should encourage IOC's to achieve the highest possible rate of production and recovery from the reservoirs that is consistent with good conservation practices. This means that fiscal systems should result in more profits for the IOC's if they recover more oil and gas and produce it earlier.

PSC cost oil and cost gas limits. High fixed cost oil or cost gas percentage limits in PSC's, such as 40% or 50%, are no longer effective from a government perspective and need to be replaced with cost oil limits that vary with price, in order to ensure that under higher prices cost oil limits are lower and governments are well protected in case of poor administration.

Corruption problems. The high oil and gas prices exacerbate problems with corruption in some jurisdictions. In this case it is important to emphasize fiscal elements that are transparent and easy to administer, such as:

- **royalties, simple severance taxes, price based windfall profits taxes in concessions and production sharing contracts, and**
- **per barrel or per Mcf fees in service contracts.**

Transparent bid processes. The current strong demand for petroleum contract or concession areas under high oil prices, permits governments to use competitive and transparent bid processes with significant beneficial effect for the host nations.

What are the relative benefits of developing the national petroleum resources with IOC's compared to NOC's under the current high oil prices?

The current high oil prices make it much more attractive to involve IOC's in the operations rather than relying exclusively on NOC's.

A high government take under high oil prices corresponds to a low corporate take. The low corporate take means that the "price of hiring an IOC" is now comparatively low. This creates a situation where IOC involvement is typically highly beneficial based on a comparative analysis of IOC and NOC performance.

NOC's have to be unusually efficient in order to create value for their host governments compared to IOC's. The high oil and gas prices mean that any delays in production caused by NOC inefficiencies results in considerable losses in value of government revenues. If NOC's recover less petroleum from the reservoirs than IOC's would do, the losses in government revenues are very important under high oil and gas prices.

The fact that the government retains 100% of the profits of the NOC's no longer makes up for the fact that NOC's typically recover and produce less oil over a certain period than IOC's.

What is the status of upstream government petroleum regimes in the world in the current environment of high oil and gas prices?

Most fiscal systems designed before 2003 were already sub-optimal in terms of maximizing government revenues. These deficient systems now create very significant losses in value from government revenues to their host governments, since the high oil and gas prices increases the relative losses.

A variety of nations have concessions and production sharing contracts that result in a higher government take under higher prices, however, most of these regimes are no longer optimal under the current economic framework.

The current high oil and gas prices make it therefore necessary to redesign most existing contracts and concessions.

The currently existing models for risk service contracts are deficient in their detailed fiscal structure and conception because they do not align well profit objectives of IOC's and government goals and they are not price sensitive. Therefore, the current models do not result in maximum government revenues.

However, in principle, it is possible to create more advanced service contracts that are equally advantageous to governments as possible well designed concessions and production sharing contracts.

Maximizing the value of government revenues from upstream petroleum arrangements under high oil prices

1. INTRODUCTION

Host governments seek to maximize the value of the government revenues from their oil and gas resources through fiscal systems[1].

Ever since the price increases in 1974, governments included features and formula's in their fiscal systems that would automatically provide for much higher government revenues under more profitable conditions. In other words, many government oil and gas revenue systems are designed to be flexible and capture the best possible share for government under each situation.

In order to ensure that governments get their fair share, such fiscal systems are typically tested on oil and gas field conditions under a wide range of prices and a wide range of costs. The government should receive a fair share under a wide range of circumstances.

Until about 2003 economic work on government oil and gas revenues usually considered a range of prices from US $ 10 per barrel to US $ 50 per barrel and a cost range from $ 2 per barrel to $ 14 per barrel. Typical average long term price predictions were about $ 25 per barrel. The design of most government oil and gas revenue systems was based on these ranges.

The rapid increases in oil prices since 2003, and in particular in the last year, have created an environment where many government oil and gas revenue systems have become outdated.

The current oil price increases to over $ 130 per barrel create the possibility that prices may go up to much higher levels in the future. Therefore a reasonable price range for government oil and gas revenue evaluation is now from $ 20 to $ 200 per barrel.

Fiscal systems are sometimes designed for contractual relationships that may last 40 years or more. Between now and the year 2050 rather different scenarios for future oil and gas prices are possible.

[1] The concept of "fiscal systems" is used in this report in a broad sense. It includes all payments to governments, such as bonuses, royalties, corporate income tax, special taxes, cost oil, profit oil shares, carried interest provisions for governments, etc. It also includes, features of risk service contracts, such as service fees and cost recovery.

Oil and gas prices could reach very high levels if:

- The world economic growth continues strongly,
- There are no strong increases in oil and gas production in major oil producing countries, such as Mexico, Venezuela, Nigeria, Saudi Arabia, Kuwait, Iran and Iraq, due to negative political developments and lack of progress in creating more efficient national oil companies
- The world governments are unsuccessful in achieving climate change objectives and oil and gas demand continues to grow strongly,
- No major new technological developments occur that would significantly lower the costs of oil and gas exploration and production, and
- Production of renewable energy sources would continue to be relatively expensive compared to the costs of oil and gas production.

Oil and gas prices could reach very low levels if:

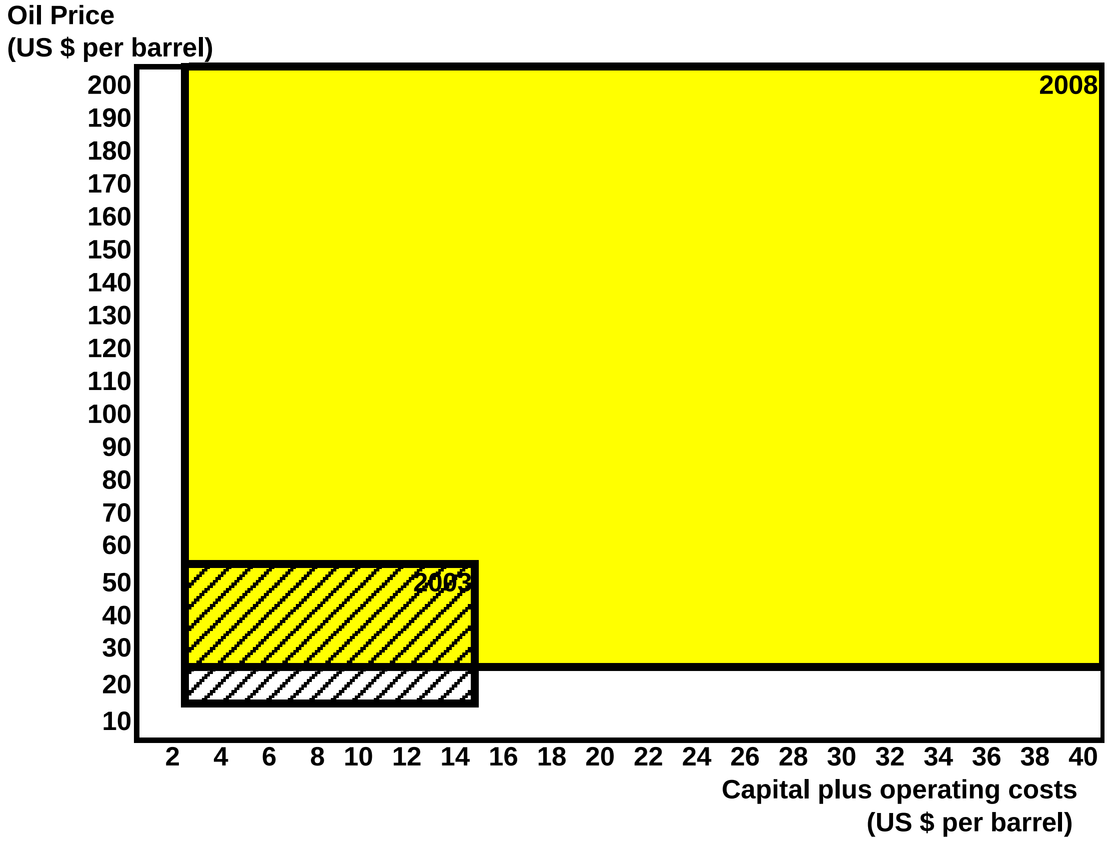
- The world economic growth slows down
- Strong increases in oil production occur in major oil producing nations due to political stability, improved efficiencies by national oil companies and enhanced involvement of international oil companies
- The world governments are achieving climate change objectives and are successful bringing CO_2 emissions down to 1990 levels by 2050 or earlier,
- Major new technological developments would significantly lower the costs of oil and gas exploration and production, and
- Production of renewable energy sources would become relatively cheap.

It is therefore necessary today to consider a price range of $ 20 to $ 200 per barrel in order to design fiscal systems that may form the basis of 40 year contracts.

The rapidly increasing oil prices from 2003 onwards resulted in the fact that many high cost oil and gas resources that were previously marginal or uneconomic have now become attractive. This includes ultra-deep water oil and gas fields, heavy oils, oil sands, gas from deep gas wells and from tight reservoir formations, coal bed methane gas and a wide variety of LNG projects. At the same time costs for many of the operations have gone up very considerably. Therefore, it is now necessary to consider oil and gas projects over a price range of $ 2 to $ 40 per barrel.

Chart 1 illustrates the very large change in the economic framework that needs to be considered for fiscal design since 2003.

Chart 1. Economic framework for upstream fiscal design



The range for "fiscal" design for oil has expanded enormously.

Fiscal systems now need to function in a much wider range of prices and costs in order to ensure that governments receive their fair share for oil and gas fields under any of these price-cost combinations.

Chart 1 appears a relatively wide range for fiscal design. Yet, governments are faced with the need to design fiscal systems with the longest possible "shelf life" in order to create a stable investment climate.

At this point in time gas prices in the main gas markets of North America and Europe are below oil prices on a Btu equivalent basis. Also much of the gas now has to be transported through long distance pipelines or as LNG. This means that the net back prices of gas at the gas fields are even less. Nevertheless, also for gas the economic range for fiscal design has expanded considerably.

The problem is that many fiscal systems designed for the 2003 range of price-cost combinations do not function well for the 2008 range. This means that many governments in the world at this point in time do not receive a fair share from the production of their oil and gas resources. Fiscal systems need to be re-designed.

It also means that host governments and international oil and gas companies ("IOC's") will be faced with a complex adjustment process.

Governments would want a higher government take under higher prices. However, the fiscal adjustment process does not only relate to the level of government take, but also to the structure of the fiscal terms. This means the concepts and formula's on which fiscal systems were based need to be changed in order to protect host governments better over a much wider range of possible circumstances.

At the same time the much higher value of oil and gas now makes the optimization of the government revenues from the production now a much stronger priority. Delays in production as a result of poor or slow implementation of exploration and development plans are now very costly to host governments. The early and highest possible recovery of oil and gas from the reservoirs is now imperative. This means efficient and technologically advanced international oil companies are now becoming far more valuable to governments than less qualified companies or inefficient national oil companies.

All these factors have now an enormous impact on the optimization of all aspects of government petroleum fiscal regimes.

In the new economic framework for oil and gas a number of issues arise:

1. Does any of the three government petroleum regimes discussed above provide a better government take?
2. What are the factors that determine the level of government take under current conditions?
3. What are the government policies and fiscal structures that lead to the maximization of the value of government revenues?
4. What is the new optimal balance between international oil companies and national oil companies?
5. What is the status of fiscal systems in the world today in the context of the new price-cost relationships and what is the anticipated future of these regimes?

This report deals with these issues.

2. GOVERNMENT TAKE FOR THREE PETROLEUM ARRANGEMENTS

Basically, there are three types of government petroleum regimes in the world:

- concessions, licenses or leases, which will be called "concessions" in this report
- Production Sharing Contracts ("PSC's")
- Risk Service Contracts ("RSC's")

From a fiscal perspective, these regimes have the following characteristics:

- **Concessions.** Concessions are fiscal systems that usually have royalties, corporate income tax and special taxes as their main components. Examples of governments that use these regimes are the USA, Canada, Norway, UK, Brazil, Algeria, South Africa, Thailand and Australia.
- **Production Sharing Contracts.** Under production sharing contracts ("PSC's") the contractors are provided with an amount of oil for the recovery of their costs as well as an amount of oil that represents a share of the profits, while the governments receive the remainder of the profit oil. Sometimes, PSC's also have royalties and taxes. Examples of governments that use these regimes are Indonesia, Malaysia, Egypt, Gabon, Ivory Coast, Syria, Yemen and Trinidad and Tobago.
- **Risk Service Contracts.** Under risk service contracts ("RSC's), the contractor receives fees for his services in addition to an arrangement to recover all or part of the costs, while the government receives the remainder of the value of the production. Currently, risk service contracts exist in Mexico and Iran, while Iraq and Kuwait are considering these concepts.

Under various of the concessions, PSC's and RSC's national oil companies have a so-called carried interest. This means that the national oil companies participate in the petroleum operations on a joint venture basis after a commercial oil or gas discovery has been made.

There is no inherent difference in the level of government take and government revenues that can be obtained through the three types of petroleum arrangements: concessions, production sharing contracts and risk service contracts.

It is possible to create an identical government take under the three different arrangements.

For instance, as an example, one could evaluate alternative petroleum arrangements for the development of an onshore oil field of one billion barrels that has already been discovered. Assume that it would require two years to establish the first production and that this production would last 23 years. The total concession or contract period would be 25 years. The evaluation is made for an oil price of US $ 100 per barrel for the duration of the production. This means that the total gross revenues over 25 years would be $ 100 billion.

The total expenditures required are assumed to be $ 8 billion in order to develop and produce the one billion barrel field over 25 years. It is assumed that the capital expenditures for development wells and processing facilities would be $ 3.2 billion. The expenditures are incurred mostly during the first two years, but also during the remainder of the 25 year period as part of constant improvements and upgrades in the technology applied to the field. The operating costs are estimated to be $ 4.80 per barrel or $ 4.8 billion for the total concession or contract period. This would leave $ 92 billion to be divided between the government and the investor, which is called the "divisible income".

This can be summarized as follows:

Gross Revenues: 1 billion barrels at $ 100/barrel		$ 100.0 billion
Capital Expenditures:	$ 3.2 billion	
Operating Expenditures:	$ 4.8 billion	
Total Costs:		$ 8.0 billion

Divisible Income		$ 92.0 billion

It is now assumed that the government objective is to achieve a 95% government take. This means that the government wants to have government revenues of 95% of the $ 92 billion, or $ 87.4 billion over 25 years. The government is prepared to leave the remainder to the investor. The investor would therefore earn a cash flow of $ 4.6 billion over 25 years. This means the corporate take is 5%.

This can be summarized as follows:

Divisible Income:	$ 92.0 billion
Government Revenues based on a 95% government take:	$ 87.4 billion
Net cash flow to IOC, or a corporate take of 5%:	$ 4.6 billion

As an example, a government take of 95% can be achieved in the following three ways under the three different types of government petroleum regimes:

- Concession: for instance, a royalty of 46% and a corporate income tax of 90%,
- PSC: a profit oil share of 95%, and
- Risk service contract: a service contract with a 100% cost recovery and a fee per barrel of $ 4.60 for a total of $ 4.6 billion.

This can be summarized as follows:

Table 1. Three ways of achieving 95% government take (all amounts in $ billion)			
	Concession	**PSC**	**Service contract**
Divisible Income	**92.0**	**92.0**	**92.0**
Royalty (46%)	46.0	--	--
Income Tax (90%)	41.4	--	--
Profit Oil	--	87.4	--
Service contract benefit			87.4
Total government revenues	**87.4**	**87.4**	**87.4**
Corporate net cash flow/ Corporate service fees	4.6	4.6	4.6

In all three cases the net cash flow to the investor will be $ 4.60 per barrel and as a consequence the total IOC cash flow is $ 4.6 billion over 25 years. In all three cases the total government revenues will be $ 87.4 billion. This means that for all three cases the government take is 95% and the corporate take is 5%.

This government take is “undiscounted” or at a 0% discount rate. This means that the time value of money is not taken into account. All costs are revenues are calculated on the basis of the money of 2008.

To facilitate understanding of the various issues, the following abbreviations will be used in this report:

GR0 - means undiscounted government revenues
NCF0 - means undiscounted net cash flow of the IOC
GT0 - means undiscounted government take
CT0 - means undiscounted corporate take.

Based on these abbreviations, Figure 2 provides the overview of the results for the three petroleum arrangements.

Table 2. Undiscounted Government Take

		Concession	PSC	RiskSC
GR0	$ billion	87.4	87.4	87.4
NCF0	$ billion	4.6	4.6	4.6
GT0	%	95.0%	95.0%	95.0%
CT0	%	5.0%	5.0%	5.0%

Although in all three cases the undiscounted government take (“GT0”) is identical, the timing of the government revenues is different.

Governments usually pay great attention to the timing of the government revenues. If government revenues are received later rather than earlier, the government may have to find other sources or revenues in order to achieve certain budget objectives. Governments may have to raise taxes, reduce expenditures or may have to increase government borrowing. For instance, governments may have to pay 5% interest in order to borrow. This means that it is costly for governments to have a delay in government revenues during a contract or concession.

In order to take these costs into account, government may evaluate the benefit taking the 5% borrowing costs into account, or stated more generally "taking the time value of money into account". In other words they may look at all government revenues on a 5% discounted basis in order to do a proper comparison of the three petroleum arrangements on this basis.

The values for the divisible income and government revenues become lower when these values are discounted. The 5% discounted divisible income is now $ 56.9 billion rather than $ 92 billion.

Following is an overview of the three petroleum arrangements on a 5% discounted basis. In calculating the year by year cash flow, it was assumed that the PSC would be subject to a 40% cost limit.

Table 3 provides the same results, but now after the application of a 5% yearly discount rate. This means that all abbreviations now end with "5".

Table 3. Government Take at a 5% discount rate

		Concession	PSC	RiskSC
GR5	$ billion	54.6	54.2	54.4
NCF5	$ billion	2.3	2.7	2.5
GT5	%	95.9%	95.2%	95.6%
CT5	%	4.1%	4.8%	4.4%

In terms of when the government revenues are being received, the concession is the most favorable in this example, the risk service contract is next and the PSC is last.

However, the PSC and the risk service contract can be made equal to the Concession, by slightly increasing the profit oil split and slightly lowering the fee per barrel. Therefore, it is very easy to calibrate the three fiscal systems in such a way that the government in all three cases receives government revenues that are of equal value to the government, taking a 5% discount rate into account.

It should be noted that a 5% discount rate for government revenues is an acceptable discount rate for relatively rich jurisdictions, such as Alaska, Alberta and Kuwait.

For governments that are urgently in need of higher government revenues from oil and gas in order to built or rebuilt their nation, such as for Bolivia, Chad, Ivory Coast, Iraq or Bangladesh, the discount rate would be higher than 5%. In some cases one might use a discount rate as high as 10%.

However, whatever discount rate one would use to evaluate government revenues from oil and gas, the fact remains that one could calibrate the same discounted government revenues for concessions, production sharing contracts and risk service contracts.

Government revenues can be equalized for any particular price-cost combination for the three petroleum arrangements using whatever yardstick the government likes to use.

It is therefore clear that the type of government petroleum regime does not determine the level of government take.

What are the main drivers for the level of government take?

3. FACTORS THAT DETERMINE THE LEVEL OF GOVERNMENT TAKE

3.1. International competitive framework and mega-trends in government take

The government take is really the “price” that investors are willing to offer for exclusive access to contract or concessions area for exploration, development and production of oil and gas. The “price” is determined by the market forces through:

- The supply of concession and contract areas by governments, and
- The demand for concession and contract areas by IOC’s.

The supply of concession and contract areas is primarily determined by government policies. Also technological progress permits to offer areas with increasingly higher costs and risk. Governments could be national governments, such as in Colombia or Libya, or it could be regional governments, such as Alberta or Alaska. More than 150 governments make occasionally or regularly acreage available for petroleum investments.

The demand for concession and contract areas is primarily determined by the oil and gas prices as well as by new companies entering the market. Higher prices induce international oil companies (“IOC’s”) to seek investment opportunities more actively. More than 200 IOC’s with world wide operations are regularly looking for petroleum investment opportunities. This is in particular true during periods of high oil and gas prices.

As a result there is a very active market in petroleum concession and contract areas.

This “market” is the main determinant of the overall level of government take that can be achieved at any particular time.

Supply of concession and contract areas

The petroleum policies of governments around the world have resulted in a significant expansion of available acreage. Over the last 30 years countries that were not available for petroleum investment before, opened up to investments by IOC’s such as Russia, Kazakhstan, Azerbaijan, China, Vietnam, India, Saudi Arabia (for gas only), Iran, Venezuela, Brazil, Peru, and Argentina. Today almost the entire world is available for investment by IOC’s.

At the same time deep water technology has evolved rapidly over the last three decades and gradually blocks with ever increasing water depth have become available. Improved pipeline technologies permitted inland basins to be connected to the coasts and such pipelines opened up new acreage. The LNG trade now makes many areas with gas worthwhile for investment.

Demand for concession and contract areas

The demand for concession and contract areas depends primarily on the oil price. The higher the oil price: the more cash flow the IOC's have available for investment in upstream ventures and the more aggressively will they pursue new opportunities.

What is also an important factor is that the number of IOC's has expanded rapidly over the last 20 years. Originally oil companies from USA, Canada, the UK, Netherlans, France, Germany, Italy, Australia and Japan dominated the world petroleum sector. Today state companies from China, India, Malaysia, Brazil and other countries have joined as investors. Also many new private companies have emerged such as from Pakistan, New Zealand, Norway, UAE, South Africa, Ireland, Hungary, Argentina and many other countries.

This has created a strong increase in demand for concession and contract areas.

Market mechanisms

Governments use three processes to determine the level of government take. These processes are:

- bidding,
- negotiation, or
- legislation.

Broad mega-trends of the last 34 years

The broad supply/demand trends over the last 34 years have been the following.

1974 - 1983

During this period the oil price went up strongly. This increased demand for new acreage strongly. However, at the same time a number of governments, such as Venezuela, Kuwait and Saudi Arabia nationalized their petroleum resources and this took acreage off the market. As a result the government take went up strongly during this period.

1983 – 2003

During this period the oil price declined. At the same time considerable new acreage came on the market. The Soviet Union broke up and Russia, Kazakhstan, Azerbaijan started to offer acreage.

However, also a number of other countries, that were closed or largely closed for international oil companies opened up, such as Venezuela, Brazil, India, Argentina, Peru and Vietnam. At the same time it was during this period that technological progress made it possible to go into much deeper water and inland basins were connected with pipelines. In general, the available acreage for investment by IOC's almost doubled.

2003-2008.

Since 2003 the oil price has increased again strongly. At the same time there is little new acreage available. Most countries have now opened up and further potential in water deeper than 3000 meter is limited. As a result government take has increased again strongly. This is taking place through four processes:

- Fiscal systems are adjusting automatically upward because governments had already designed fiscal systems whereby the government take would go up automatically in case of higher prices, such as in Angola, Malaysia, Trinidad and Tobago, Russia and India
- Governments are changing fiscal terms and increasing government take. Examples are: UK, Alaska, Alberta, Algeria, Bolivia and Kazakhstan.
- Companies are bidding up government take in bid rounds: Libya, India
- Greater state participation by NOC's or the State: (Russia (Gazprom), Venezuela, Algeria, Kazakshtan).

For gas the trends are somewhat weaker that for oil. The reason is that there are still considerable gas development opportunities around the world and therefore some nations are trying to increase gas market share rather than increasing government take.

These are the broad trends in government take. What are the main factors that determine the level of government take in more detail?

3.2 Detailed micro-economic environment that determines the level of government take for each project.

It should be noted that the concession and contract areas do not contain petroleum resources of equal value and attractiveness. Just as in the real estate market, each area is different. Some contain high value and others contain low value petroleum resources.

The value of the petroleum resource and therefore attractiveness to the investor depends on:

- **Whether the project relates to the development of an oil or gas field that has already been discovered, or whether it is an exploration project for a new area,**
- **If new exploration is required, the geological risk of drilling dry holes and possible attractiveness of possible discoveries,**
- **The logistical and cost conditions of the area,**

- **The nature of the project, such as whether it relates to light oil, heavy oil, enhanced recovery or LNG development,**
- **Whether the area is close or far from markets,**
- **The anticipated fiscal stability or lack of stability of the concession and contract, and**
- **The political, regulatory, environmental and other risks.**

In this respect technological progress is very important. Over the last four decades there has been a strong development in new technologies that make exploration, development and transportation of new petroleum resources less costly. As a result the supply of concession and contract areas now include areas containing oil and gas fields in deep water, heavy oils, oil sands, coal bed methane gas, etc.

In order to stimulate the development of low value resources, some governments are willing to accept a wide range of levels of government take within the same jurisdiction. The same governments could accept relatively modest government takes for heavy oils, deep water, etc., and would insist on higher government takes for "easy oil".

In the following sections of this chapter some of the most important factors will be reviewed in more detail.

3.3. Level of government take for development of oil and gas that has already been discovered

If a field has already been discovered important factors that determine the level of government take are the oil and/or gas prices and the costs.

In order to evaluate these two factors an example of three different onshore one billion barrel oil fields will be provided. These fields have the following characteristics:

- A field with light oil that is relatively easy to produce and for which the total costs are $ 2 per barrel
- A field with median quality oil that is difficult to produce and involves enhanced recovery practices with a total cost of $ 8 per barrel, and
- A field with extra heavy oil that is very difficult to produce with a total cost of $ 14 per barrel.

It is assumed that the capital costs are 40% of the total costs.

These fields could be analyzed under a price range from $ 20 per barrel to $ 200 per barrel (of course, light oil is more valuable than heavy oil, which means that international oil prices would be higher for the heavy oil than for the light oil).

As an example, it is assumed that it would be acceptable to an investor to obtain $ 1 net cash flow for every dollar invested over the 25 year period.

This means that the net cash flow per barrel to the investor for the three different fields would be as follows:

- $ 2 per barrel field: $ 0.80 per barrel
- $ 8 per barrel field: $ 3.20 per barrel
- $ 14 per barrel field: $ 5.60 per barrel

The total net cash flow to the IOC over the 25 years on an undiscounted basis would be:

- $ 2 per barrel field: $ 0.8 billion
- $ 8 per barrel field: $ 3.2 billion
- $ 14 per barrel field: $ 5.6 billion

This would be on an undiscounted basis. This means that the undiscounted profit to investment ratio ("PIR") would be 1.00. Since the PIR is undiscounted this can be abbreviated as that the PIR0.

Based on the assumption about the PIR0 that the investor would be willing to accept and the costs and prices, the maximum undiscounted government take ("GT0") that can be achieved becomes a simple calculation. This calculation is provided in Table 4 for a price of $ 20 per barrel.

Table 4. Maximum GT0 at $ 20 per barrel

Costs:		**$ 14/bbl**	**$ 8/bbl**	**$ 2/bbl**
Gross Revenues	**$ billion**	**20.0**	**20.0**	**20.0**
Capital Expenditures	**$ billion**	**5.6**	**3.2**	**0.8**
Operating Expenditures	**$ billion**	**8.4**	**4.8**	**1.2**
Divisible Income	**$ billion**	**6.0**	**12.0**	**18.2**
NCF0	**$ billion**	**5.6**	**3.2**	**0.8**
GR0	**$ billion**	**0.4**	**8.8**	**17.4**
GT0	**%**	**6.7%**	**73.3%**	**95.6%**
CT0	**%**	**93.3%**	**26.7%**	**4.4%**

Under $ 20 per barrel, projects costing $ 14 per barrel were uneconomic from an IOC point of view. Therefore, a 6.7% government take would not actually be applied anywhere. Typically the lowest government takes are in the range of 25% to 40%.

Of course, the levels of profit required are merely an assumption. Early in this decade when oil prices were about $ 20 per barrel investors were often willing to accept less. Nevertheless, regardless of whether somewhat lower or higher assumptions are used with respect to the PIR0, Table 4 clearly demonstrates the strong relationship between the maximum government take that is achievable and the levels of costs.

The lower the costs of a petroleum development project, the higher the government take that can be achieved for a particular level of price.

How does this relationship change with higher prices?

Most IOC's no longer bid, negotiate or evaluate the profitability of exploration or development investments on the basis of a single oil price forecast. IOC's often study the economics of the projects over a wide price range.

Unfortunately, under current high prices, many governments "leave a lot on the table". In other words many host governments do not get their fair share. This means that IOC's tend to make higher profits under higher prices, as is evidenced by the very high profits announced by oil companies during the last few years. This is true even if costs typically also go up with higher prices.

Under high oil prices IOC's have a much wider variety of attractive opportunities than under low prices since more projects become economically viable. At US $ 60 per barrel oil and higher gas prices, a much wider range of heavy oil, oil sands, deep water and LNG projects has now become economic. Much of these projects have become available under modest government takes.

This means that at this point in time, the world market for concession and contract areas creates a higher level of profitability and higher profits from petroleum resources under higher oil and gas prices.

Nevertheless, despite the higher costs created by higher oil prices and the higher profit expectations of IOC's, governments are still able to increase the government take under higher prices significantly. This is illustrated in Table 5 for a price level of $ 120.

Table 5. Maximum GT0 at $ 120 per barrel

Costs:		$ 14/bbl	$ 8/bbl	$ 2/bbl
Gross Revenues	$ billion	120.0	120.0	120.0
Capital Expenditures	$ billion	11.2	6.4	1.6
Operating Expenditures	$ billion	11.8	6.7	1.7
Divisible Income	$ billion	97.0	106.9	116.7
NCF0	$ billion	16.8	9.6	2.4
GR0	$ billion	80.2	97.3	114.3
GT0	%	82.7%	91.0%	97.9%
CT0	%	17.3%	9.0%	2.1%

In this Table 5, it is assumed that capital costs are 200% of the costs in Table 4. In other words it is assumed that capital costs have doubled since the start of this decade. This is approximately in line with the CERA Upstream Capital Cost Index. Operating costs have increased far less than capital costs. For simplicity it is assumed that in this particular case operating costs increased 40%. It is assumed that IOC's would now seek a PIR0 of 1.5 in view of better opportunities around the world. It should be noted that a higher level of profitability of a PIR0 of 1.5 is applied to double the capital costs results in a tripling of the undiscounted net cash flow ("NCF0").

Again these assumptions are merely examples. It is possible for any particular area to make higher or lower assumptions with respect to all these factors. However, regardless of such different assumptions, it can be easily seen by comparing Table 5 and Table 4, that the maximum government take that is achievable under current prices is still much higher than early this decade.

It is interesting to note that the $ 14 per barrel project that was uneconomic under $ 20 per barrel is now very economic despite the high cost increases. It is therefore, that oil sand and heavy oil development projects have now become very attractive and can deliver a relatively attractive government take.

It is for these reasons that governments are increasing their government take at this moment under higher prices. The price jump from $ 20 to $ 120 per barrel permits considerably higher government take levels despite the much higher costs, even under assumptions of higher IOC profit expectations.

It should be noted that the profitability expectations on the part of IOC's are under downward pressure. Some of the bidding rounds that were very successful from a government perspective indicate that profitability expectations (such as the PIR0) may not have gone up very much on the basis relative to costs. The important reason is that new international oil companies are now entering the scene, such as from China, India, the Middle East, that are willing to accept more modest levels of profitability in order to gain access to concession or contract areas.

The general conclusion is that the level of government take for development projects is determined by:

- **The level of oil and gas prices: higher prices permit higher government takes, and**
- **Costs: Lower costs permit governments to achieve a higher government take under any particular price level.**

3.4. Level of government take for exploration projects

For exploration projects, in addition to the factors that are important for a development project, the exploratory risk becomes of great importance for the level of government take that can be achieved.

Example calculation of maximum achievable government take

The probability of discovering one billion barrel fields is typically not very high. Therefore, it is more realistic to take a 100 million barrel discovery as an example.

In this example, it can be assumed that the oil price would be \$ 60 per barrel and the costs would be \$ 8 per barrel, of which 40% are development costs and 60% are operating costs. It can be furthermore assumed, as an example, that the exploration program would cost \$ 20 million in terms of geophysical work and the drilling of an exploration well.

In case of a success, which is a discovery of 100 million barrels, the divisible income would now be as follows:

Gross Revenues: 100 million barrels at \$ 60/barrel		\$ 6000 million
Exploration Expenditures:	\$ 20 million	
Capital Expenditures:	\$ 320 million	
Operating Expenditures:	\$ 480 million	
Total Costs:		\$ 820 million

Divisible Income		\$ 5180 million

However, there is now also a probability that the investor will only drill a dry hole and will incur the loss of a failed exploratory program. How could the minimum net cash flow and the maximum government take be determined in this case?

Assuming a PIR0 of 1.00, the minimum net cash flow for the success case would have to the \$ 340 million. What needs to be added to this cash flow to take account of geological risk?

This can be determined based on the probability of success. For instance, it can be assumed that the geologist estimates the probability of success of the venture at 20% and the probability of a dry hole at 80%.

A dry hole risk of 80% means that for every successful exploration program four dry holes have to be drilled. Four unsuccessful exploration programs cost four times \$ 20 million or \$ 80 million. However, in addition the IOC would need to make an extra profit in order to justify the exploration program and maintain a PIR0 of 1.00. This extra profit would be equal to the cost of the four unsuccessful dry holes or also \$ 80 million. This means that the IOC would need in total \$ 160 million more net cash flow. This is the minimum dry hole risk cash flow requirement.

The total net cash flow to the IOC would therefore have to be \$ 340 million plus \$ 160 million or US \$ 500 million. The calculation of the minimum corporate take is now:

$$\text{Minimum corporate take} = \frac{500}{5180} \times 100\% = 9.65\%$$

The total maximum government take would now be 90.35% at $ 60 per barrel.

As can be easily understood, the minimum dry hole risk cash flow requirement per barrel, for a particular level of PIR0, is inversely proportional on the exploration target field size. For the 100 million barrel example the minimum dry hole risk cash flow requirement was $ 160 million or $ 1.60 per barrel. Table 6 illustrates the per barrel values for other field sizes.

Table 6. Minimum dry hole risk cash flow requirement

Exploration target (millions of barrels)	Minimum cash flow ($/ barrel)
10	16.00
30	5.33
100	1.60
300	0.53
1000	0.16

Also, the minimum dry hole cash flow requirement is directly proportional to the level of dry hole risk, which is the number of dry holes required per discovery. Table 7 illustrates the relationship between the dry hole risk, the size of the exploration target and the minimum dry hole cash flow requirement per barrel.

Table 7. Minimum dry hole cash flow requirement per barrel for different targets and risks (dry hole costs: $ 20 million, PIR0 =1)

Field Sizes:		10	30	100	300	1000
Prob Success	Dry holes	($/bbl)	($/bbl)	($/bbl)	($/bbl)	($/bbl)
50%	1	4.00	1.33	0.40	0.13	0.04
33%	2	8.00	2.67	0.80	0.27	0.08
25%	3	12.00	4.00	1.20	0.40	0.12
20%	4	16.00	5.33	1.60	0.53	0.16
10%	9	36.00	12.00	3.60	1.20	0.36
5%	19	76.00	25.33	7.60	2.53	0.76

As is obvious from Table 7, it is not attractive for IOC’s to incur expensive exploration programs in order to discover small fields under high risk conditions. However, also the exploration costs per barrel of a very large discovery are very low as measured against this discovery. Therefore it is “cheap” for governments to encourage exploration for large fields under high oil prices, while the benefit of finding large fields is very important in terms of resulting government revenues.

Almost all governments have policies to permit higher levels of profitability for large fields than for small fields, while at the same time insisting on a higher government take for larger fields.

It is for this reason that many concessions and production sharing contracts, and also the original Brazilian risk service contact of the 1980's, have sliding scales that relate to the level of production. Small exploration targets require a lower government take, for the same exploration costs and PIR10, than large exploration targets. This means the government take can go up for larger fields.

This is generally achieved with sliding scales for royalties or profit oil that have higher levels with a higher level of production per day or the cumulative production for a field or contract area.

3.5.Conclusions on the level of government take

The level of government take depends on the competitive international framework.

The competitive international framework is driven by the supply and demand for acreage and the fundamentals of oil and gas field development economics and exploration economics.

Therefore, the main factors that permit governments to achieve a high government take are:

- **High oil and gas prices,**
- **Low costs,**
- **Development projects rather than exploration projects,**
- **Low geological risk for exploration targets and large possible fields as targets**
- **Low other risks: such as political, fiscal, regulatory or environmental risks.**

Governments that are faced with trying to promote investment in high cost, high risk and small exploration targets under high political and other risks, will be forced to accept a relatively low government take.

As a result of these factors the undiscounted government take for profitable projects can range anywhere from 25% to 98%. All of these levels could be the maximum government take achievable for the government under the circumstances.

Achieving 70% government take (at a particular oil or gas price level) for a high risk high cost exploration project could be a good deal for government, while achieving 95% for a low cost large oil development project could be a bad deal.

Chart 2 is an illustration of typical GT0's for the three petroleum arrangements under favorable conditions, average conditions and unfavorable conditions.

It can be seen how for conditions of large low cost onshore oil fields, the government takes could be very high, in the 95% - 99% range, as in Abu Dhabi (Concessions), Kuwait (model North Kuwait Operating Services Contract) or Libya (EPSA IV PSC's)

In the case of average conditions, such as for the Norwegian North Sea (Concession) or Egyptian deep water offshore (PSC), the government take is typically in the 60% to 85% range. This range could also apply to the Phase 1 of the Iranian petroleum arrangement which is the buy back contract. The short duration, as short as 5 years of these contracts, requires Iran to rapidly refund the private investors their capital and operating costs in a short period. Due to the short term of the contract, the government take is highly variable depending on circumstances.

Under relatively unfavorable conditions the government take could be in the range of 40% to 60%. This is now applicable to the relatively small fields in most of the British North Sea (Concession's), with respect to LNG developments offshore East Timor (PSC's) or the RSC's for marginal gas fields in Mexico, the multiple services contracts.

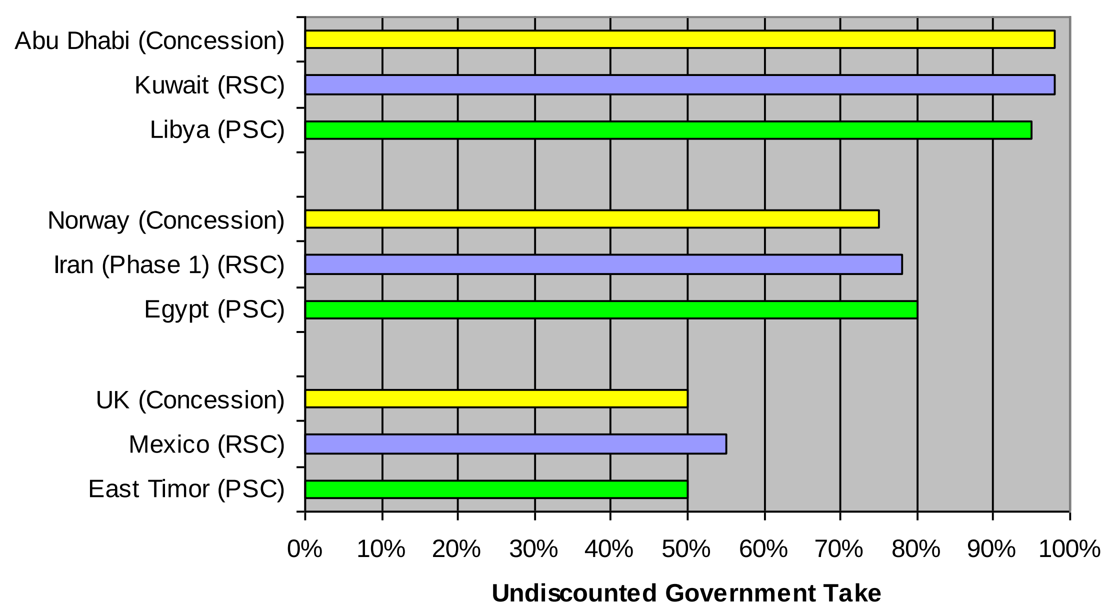


Chart 2. Typical government takes for Concessions, PSC's and risk service contracts (RSC's)

However, the government take is usually not a fixed percentage for all price-cost combinations. Whether a fiscal system is favorable or unfavorable depends on the detailed features of the petroleum arrangement.

This leads to a broader question of how fiscal structures behave and what fiscal elements lead to a framework resulting in maximum government revenues.

4. MAXIMIZING THE VALUE OF GOVERNMENT REVENUES AND THE STRUCTURE OF GOVERNMENT TAKE

Many governments seek to maximize the benefits from their petroleum resources. An important benefit is the level of government revenues derived from the production. There are, of course, many other benefits, such as employment, local business opportunities, training and technology transfer, local R&D, etc. However, in this report the focus is on government revenues.

4.1. Policies aimed at achieving maximum the value of government revenues

What are the policies that maximize the value of these government revenues?

In this discussion it is assumed that the country would not be concerned with OPEC quota. In other words it is assumed that the country can freely pursue the highest level of production at the earliest possible time. It should be noted that under current world supply demand conditions even countries that are subject to OPEC quota today still make plans for much higher production in the future. For instance, the goal of Kuwait is to achieve 4 million barrels per day in 2020.

Two policies result in achieving the objective of maximizing the value of government revenues:

Policy 1. Maximize production by creating profitable conditions for the widest possible range of petroleum exploration and development projects and extract the maximum government revenues from each project.

Obviously, in order to achieve the highest possible revenues from oil the first step is to maximize the level of production.

In Chapter 3 it was evaluated how the maximum level of government take that can be obtained can be high or low and is determined by prices, costs, development or exploration, exploratory risk and targets and other risks.

Therefore, it is obvious that a policy that flexibly adjusts the government take to different conditions in order to ensure that the maximum number of development project and exploration project is economic, will result in the highest possible overall production. This will ensure that the largest number of projects will contribute to the government revenues from oil and gas.

This means for instance:

- setting a lower government take for costly difficult and heavy oil, but a higher government take for low cost light oil developments,
- setting a lower government take for ultra deep gas fields or fields producing gas from tight formations, but a higher take on gas fields with prolific wells producing from shallow formations, and
- setting a lower government take for high risk exploration aimed at smaller and expensive oil and gas fields, but a higher government for low risk exploration for larger low cost oil and gas fields

The objective is to extract the highest possible government take for each specific condition, in such a way that the highest number of projects is economic from an investor perspective.

This can be done by:

- establishing the best fiscal conditions for government for each concession or contract area, which means each area would have different terms, or
- by creating flexible fiscal systems that adjust automatically to different conditions, or
- both.

The terms could than be further maximized for each area through a bid process or through negotiations. Under the current very strong demand for oil and gas contract and concession areas it is highly beneficial for most governments to have competitive and transparent bid processes.

Policy 2. Ensure that investors are encouraged to achieve the maximum level of production at the lowest possible costs at the optimal possible pace that is consistent with good conservation practices in order to achieve the highest possible value.

This means that the fiscal systems have to align the government objectives and the profit objectives of the investors. This alignment has to be such that investors achieve a higher level of profitability and make more profits:

- under higher levels of production and on discoveries of larger fields, and
- if they are more efficient, which means they create the lowest possible costs under optimal production scenarios.

This can be done by structuring the fiscal terms in such a way that these terms adhere to these concepts. In other words, in order to align the government objectives of maximizing the government revenues with the IOC objective of higher levels of profitability, the **structure** of the fiscal terms has to be appropriate.

In order to ensure an optimal pace of development it is important that the **level** of government take is competitive with other investment opportunities. It is the relative profitability of the operations that determines the level of investment and re-investment in further development of the reservoirs by IOC's in the various concession and contract areas.

If terms are too generous, as happened in the Alberta oil sands for the last few years, an investment boom will occur that creates massive development, but the government does not receive its fair share.

If terms are too tough, companies will slow down activities and divert capital and human resources to other parts in the world.

The best fiscal terms are terms that optimize the pace of development, and encourage companies to carry out voluntarily sustained active work programs that ensure the application of the best possible technology to the active development of the petroleum resources.

The implementation of the two policies will be discussed in more detail in this chapter.

The strategies to achieve an optimal fiscal structure for the petroleum arrangements focus on the three main components that determine the profitability of operations:

- The optimization under higher or lower oil and gas prices
- The optimization under higher or lower costs, and
- The optimization for exploration projects, under higher or lower probability of success and expectations for smaller or larger fields

These strategies can be applied to concessions, PSC's or RSC's.

The implicit assumption about designing an optimal fiscal structure is that this structure would remain unchanged for a considerable period of time. It creates a stable environment for investors if the "shelf life" of a fiscal system is as long as possible. In case of contractual arrangements, some components or all fiscal terms of the contract could be subject to fiscal stability. However, given the current uncertainties in the world about economic conditions what is the value of fiscal stability for governments? This matter needs to be reviewed prior to enter into the discussion of optimal fiscal designs.

4.2. Fiscal stability concepts

Not many governments offer comprehensive fiscal stability on the total fiscal system, but some do. Many governments provide fiscal stability on some features, such as royalties or production sharing, but not on others, such as corporate income tax. Some governments do not offer any fiscal stability.

In the current economic framework it can no longer be recommended for governments to provide comprehensive fiscal stability. The increased unpredictability of the oil and gas markets, makes 30 or 40 year fixed deals no longer a reasonable concept for governments.

Also climate change policies may dramatically impact on the future role of the petroleum industry. In the next decade or two decades information may become available that would require governments to take much stronger action than is currently contemplated to reduce CO2 emissions. New fiscal systems may be required for the upstream to deal with these issues in an effective manner.

Therefore, governments should be as free as possible to adjust fiscal terms.

If fiscal stability is provided at all, it should be done for a certain economic framework. Within the boundaries of the economic framework fiscal stability could be provided, outside these boundaries governments should have the right to adjust the deal depending on the circumstances.

As an example, governments could specifically exclude from fiscal stability provisions, windfall profits taxes or other fiscal features that take a share of the divisible income over a certain price level, for instance, $ 80 per barrel. However, other criteria than price, such as R-factors or cumulative production, could also be used.

With respect to gas, similar provisions with respect to windfall profit taxes and fiscal stability can be introduced. However, for gas the upstream net back prices are rather different around the world and therefore the detailed conditions will vary more from area to area.

4.3. Optimal structure of fiscal systems with respect to oil and gas prices.

Because oil and gas prices are unpredictable, it is of great importance to ensure that the government take is maximized under any level of oil or gas prices. As was indicated in the introduction of this report the range for fiscal design has expanded now to $ 20 to $ 200 per barrel. How can optimization of government revenues be achieved in this framework?

In Chapter 2 it was evaluated how under any of the three petroleum arrangements exactly the same government take of 95% could be obtained for the one billion barrel field at $ 100 per barrel and $ 8 per barrel total costs.

However, what would be the result in terms of government take if we make different assumptions about the oil price? For instance, what would be the government takes of the three arrangements at US $ 20 per barrel and the same costs?

Table 8 provides for this analysis.

Table 8. GT0 for the one billion barrel field at US $ 20 per barrel

			Concession	PSC	RiskSC
GrossR0	$ million	20000.0			
TC0	$ million	8000.0			
DI0	$ million	12000.0			
GR0	$ million		11720.0	11400.0	7400.0
NCF0	$ million		280.0	600.0	4600.0
GT0	%		97.67%	95.00%	61.67%
CT0	%		2.33%	5.00%	38.33%

The concession now results in a higher GT0, while the risk service contract results in a much lower GT0. The GT0 under the concession is actually higher under $ 20 per barrel than under $ 100 per barrel. This means the government would make the deal tougher when the price goes down. This does not make sense, of course.

Under the PSC the government take stays the same, but the total amount of profit is now so low that investors would not be interested to invest as much as $ 3200 million in order to receive only $ 600 million net cash flow. Investors would therefore not invest under these conditions. If the project is already under way and the price drops to $ 20 per barrel, the investors would have a bad deal.

For the risk service contract the government take is lower under tougher conditions. This makes sense in principle. However, the government take is now so much lower that the risk service contract is overly generous. This is unfavorable from a government perspective, because investors would have been willing to accept much lower fees under lower prices, rather than the same fees.

If $ 200 per barrel would have been used, the concession would have had a lower government take, which means that the deal would be a "give away". The PSC would have the same government take and result in exorbitant profits. The risk service contract a much higher government take. However, the much higher government take might be so tough compared to other investment opportunities that it would impede an active pace of development of the resource, which at $ 200 per barrels would create significant losses for the government in terms of time value of money.

This means that none of the three specific examples of fiscal systems discussed above are fiscal systems with an optimal <u>structure</u> in order to maximize government revenues when considered in the $ 20 to $ 200 per barrel price range.

In economic terms the above fiscal systems can be classified as follows based on the undiscounted government take ("GT0") in terms of behavior with respect to higher or lower oil prices:

- The specific example of the concession is a ***<u>regressive system</u>*** with respect to the oil price. Under a regressive fiscal system the GT0 goes down when the oil price goes up. Regressive systems have a strong tendency to create windfall profits under high oil prices and uneconomic conditions under low oil prices.

- The specific example of the production sharing contracts is a ***neutral system*** with respect to the oil price. Under a neutral fiscal system the GT0 stays the same regardless of the level of price. This could also lead to windfall profits under high oil prices and uneconomic conditions under low oil prices.
- The specific example of the service contract is a ***progressive system*** with respect to the oil price. Under a progressive system the GT0 increases with the level of the oil price and decreases under lower prices. If the system is too progressive, it could lead to overly generous conditions under low oil prices compared to international conditions and conditions that are too tough under high oil prices and therefore would present a disincentive for investment in the oil field.

The optimal fiscal system for the $ 20 to $ 200 per barrel price range, is a fiscal system that is progressive with price, but not so strongly progressive that it creates:

- **overly generous conditions for investors under low prices resulting in the government not receiving a fair share, or**
- **excessively tough conditions under high prices, resulting in conditions where the fiscal terms may slow the pace of exploration or development.**

Following these principles of price progressivity will result in an optimal pace of development through acceptable levels of investment at any level of international prices, while maximizing government revenues.

Examples of fiscal features that could lead to an optimal level of price progressivity under concessions and production sharing contracts are:

- profits based taxes that increase the tax rate with the price level,
- Windfall profits taxes that are solely aimed at taxing excess profits under high prices, or
- profit oil shares that increase with the level of price.

Current risk service contracts models in the world are all based on fees that are not sensitive to the oil prices or gas prices. This means that these models have an extreme price progressivity. The government takes 100% of the price increase. At the same time the government gives 100% of the price decrease as well, as was illustrated in Table 8.

This exposes governments to the risk, under the current high oil prices, that service fees are being agreed to that would be too generous if oil and gas prices would decline again. At the same time under much higher oil prices the pace of exploration and development would slow down or stop, since it would not be of interest to investors to make further follow up investments in the fields compared to other investment opportunities.

Price sensitive features. It should be noted that in the new economic framework, many of the price sensitive features that are currently employed in the world need to be reviewed. For instance, a windfall profits tax of 50% over $ 40 per barrel may make sense in a $ 40 to $ 80 price range, however it does not make sense in the $ 80 to $ 200 price range. This would continue to create windfall profits of significant proportions in this price range for no reason.

Many oil market analysts are convinced that the current high oil prices are no longer a direct result of the supply and demand of oil. It appears that oil prices are reacting to other economic forces, such as the movements in the US $ or simply as hedge for world wide economic uncertainty. In this way oil has become similar to gold.

Many oil supply analysts are of the view that vast volumes of heavy oils, enhanced recovery oil, oil sands, deep water small oil fields and other new sources of oil can be made available in the $ 40 to $ 80 per barrel range. Therefore, there is no reason to leave significant profits with investors related to oil prices that are higher than $ 80 per barrel.

For most countries, it will not bring forward supplies that are attractive to government from a government revenue maximization point of view in the next decade or decades. There is enough to invest in for the moment for price levels up to $ 80 per barrel and therefore fiscal systems should prioritize the development of these resources.

From the perspective of government revenue maximization, governments should receive therefore the vast majority of any margin over $ 80 per barrel. The actual level would depend on balancing upside price benefit with downside price risk or such other risk factors such as political, economic or regulatory risks that would justify providing some more attractive price upside. Governments should therefore redesign their fiscal systems in order to capture in a much stronger manner than before windfall profits in the $ 80 to $ 200 price range.

Of course, the $ 80 per barrel level could be reviewed from time to time by governments.

It is a good policy to always leave a small gain with the investors in case of higher oil prices, in order to ensure that investors under concessions or production sharing contracts have a vested interest in selling their crude oil for the highest possible price, which will ensure that governments receive the possible valuation of crude oil for the purposes of calculating royalties, cost oil and other fiscal features.

The economic reality in the world today is that almost all governments leave considerable windfall profits “on the table” under current fiscal systems. This means that governments that want to secure a reasonable pace of development of their oil and gas potential will be forced in the short term to offer far more beneficial terms than would be necessary under more stabilized conditions.

As was discussed in Chapter 3, many governments at this time are in a process of adjusting their government take upwards under high price conditions and as a result for the next few years the competitive framework that creates the best degree of progressivity with higher prices is a moving target.

Over time it is likely that government takes in the world will move up for fiscal terms over this price range. This means that governments may have to adjust possible windfall profits or other fiscal features upwards from time to time.

4.4. Basic structure of fiscal systems with respect to the level of costs for oil and gas development projects.

4.4.1. Fiscal design for different cost environments.

With respect to costs it is not necessary to design fiscal systems that cover the entire range between $ 2 and $ 40 per barrel in costs. The different petroleum opportunities in the world have so their own cost range. Deep water oil and gas fields are more costly that onshore large oil fields in the Middle East. Therefore, fiscal systems are typically designed for a certain cost environment.

Table 9 provides for some typical cost environments for different upstream investment opportunities around the world.

Table 9. Typical cost environments (capital costs plus operating costs) for oil and gas fields (wells) ($ per barrel of oil equivalent) ($ 2008)

	Low	**High**
Large onshore fields in Middle East and North Africa	$ 2.00	$ 8.00
Onshore oil and gas fields in other parts of the world	$ 4.00	$ 24.00
Onshore heavy oil fields (no major upgrading)	$ 8.00	$ 28.00
Shallow water oil and gas fields	$ 10.00	$ 30.00
Individual oil and gas wells in North America	$ 12.00	$ 35.00
Deep water oil and gas fields	$ 12.00	$ 40.00
Oil sands (mines, SAGD) including upgrading	$ 18.00	$ 40.00

Not only are the level of costs different for the different cost environments, the entire cash flows are different. For instance, in deep water operations it may take 10 years before first production is achieved after the award of a contract or concession. With respect to the (further) development of onshore oil fields that have already been discovered, it may take only 2 or 3 years after the award of the contract or concession to reach first production or a new target level of production. In certain cost environments, almost all capital costs may have to be incurred prior to start up of the field, such as deep offshore gas fields requiring new pipelines. In other cases, the projects can be constructed in phases, so subsequent phases benefit from the cash flow generated from previous phases.

Typically for the same field size (in terms of barrels of oil equivalent) gas fields are usually somewhat less costly than oil fields.

Most host governments would design different fiscal systems for these different cost environments. This means that the government take range on large onshore oil and gas fields in the Middle East and North Africa will be much higher than for deep water oil and gas fields around the world.

If oil and gas prices remain high, it is likely that in each cost environment, smaller and more marginal opportunities will be developed that are higher in costs and therefore the upper end of the cost range will increase with oil or gas price increases.

Each fiscal system can be optimized for the particular cost environment.

The first step in new fiscal system design under high oil prices is therefore to design different fiscal systems for each cost environment. Each system should be optimal for its cost environment, by generally insisting on a higher government take for cost environments that have lower costs and more attractive cash flows and a lower government take for cost environments that have higher costs and less attractive cash flows.

4.4.2. Fiscal design within a certain cost environment.

Within a certain cost environment costs could still vary over a considerable range.

Therefore it is important for governments to achieve a higher government revenues when costs are lower, however, at the same time it is important to encourage efficiency among IOC's by offering higher profits under lower costs.

This is a relatively difficult balance to strike.

Maximization of government take within a cost environment. Within each of the cost environments, costs are often very difficult to predict. In the short term costs are often linked to oil price movements and therefore could change very significantly. For instance, in some parts of the world, costs of certain goods and services have tripled during the last few years as a result of the oil price increases. This is because the oil price increases created significant additional demand for these goods and services.

In the long term technological progress has an enormous impact on costs per barrel and therefore costs in real terms are often over-estimated. Oil reservoirs that seem relatively difficult to produce today, may be relatively easy oil in the next decade.

This means that by necessity the fiscal terms have to flexibly adjust to a wide range of costs and secure under all conditions the best possible government revenues for the state.

In order to protect the government revenues under a wide range of cost variation, governments typically have traditionally employed two concepts:

- Profit based sliding scales based on profitability indicators, such as R-factors and the IRR, to increase government take under low cost conditions, and
- To protect governments from low government revenues under very high costs, PSC's typically include fixed cost limits.

The effectiveness of both these features is dramatically reduced in the new economic framework. Both features will be discussed in detail.

R-factor and IRR scales. The most typical method for creating flexible systems under any of the three government petroleum regimes has been to create sliding scales related to certain profitability indicators. This could be the internal rate of return (IRR) or certain ratios that indicate profitability, usually called R-factors. For instance the PIR0 would be an R-factor. Such sliding scales can be applied to:

- Certain special taxes under concession systems,
- Profit oil under PSC's, and
- Certain contractor benefits under risk service contracts.

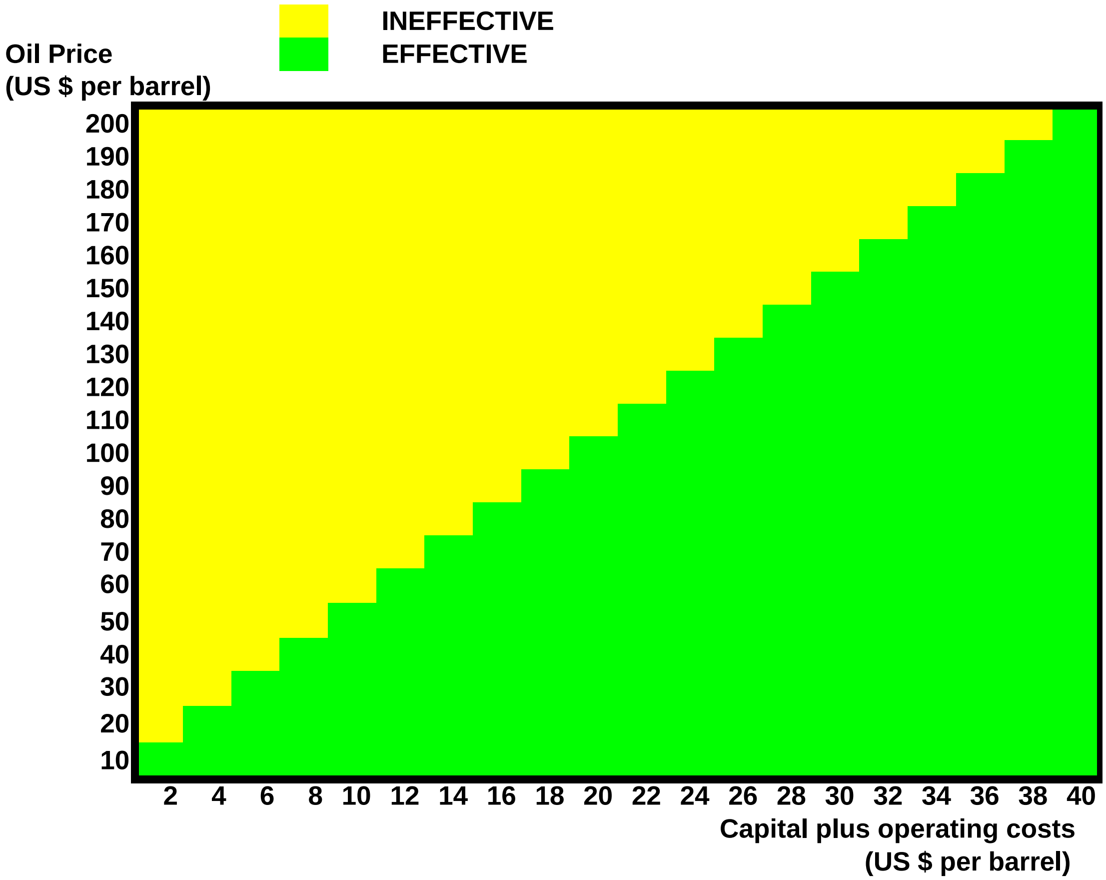
By introducing systems that were progressive based on these sliding scales, governments receive a higher government take when costs are low relatively to the oil or gas prices. For fiscal systems designed prior to 2003, R-factors often worked reasonably well for oil prices up to \$ 40 per barrel or so. However, these R-factors cannot be "stretched" to cover a much wider range.

For instance, a typical R-factor is based on the ratio between cumulative gross revenues and cumulative costs. Typically such R-factors start at 1,00 and may have as highest value 5.00, but more typically 3.00 or 4.00.

An R-factor of 5.00 means that if cumulative revenues are 5 times the cumulative costs the maximum government take should be reached. In other words, if total costs are \$ 10 per barrel the maximum government take would be reached at \$ 50 per barrel. This means that an R-factor would become ineffective over \$ 50 per barrel, if the government is determined to continue to increase government take over this level.

Chart 3 displays this issue. It illustrates the range in which the above described R-factor would be effective. Many of the R-factors in the world do not go as high as 5.00 and therefore in reality the range for most fiscal systems is even more limited. Different ratios exist, but the problem is the same for each of these types of R-factors.

Chart 3. Effectiveness of R-factors



If in a particular cost environment the average cost is estimated to be $ 8 per barrel, the highest level R-factor to cover a range up to $ 200 per barrel would have to be 25.00. This simply does not work.

A further problem with R-factors and IRR based scales is that if the scales are made too sensitive, the government take drops so significantly with higher costs, that it is actually attractive for investors to have higher costs. For instance, based on a cost increase of $ 10 million, the government revenues could drop $ 15 million. This makes these sliding scales no longer effective for governments. Also it misdirects investments in to high cost and sometimes inefficient operations. **This is called "gold plating".**

Whether gold plating occurs depend on the IRR or R-factor range, the percentage increments in the profit scale, and the absolute effect of the R-factor, in other words the drop in total profits for an increase in R-factor. However, in order to avoid gold plating R-factor scales have to have a very robust and conservative design.

IRR systems lead earlier to gold plating than R-factor systems. IRR scales create gold plating in almost all cases and can therefore not be recommended in general.

R-factor systems remain a useful component of the overall fiscal system. However, the lower the typical costs for the cost environment, the more the need arises to complement the R-factor concept with price sensitive fiscal features, as discussed in subchapter 4.2 of this report.

In this case, the first step under concessions and production sharing contracts is to reduce the revenues to the investor by applying price sensitive features. The next step is to apply the R-factor based on a sharing of the profits or profit oil. The revenues used for the R-factor should than be the gross revenues less the price sensitive feature. The effectiveness of the R-factor can be further enhanced by also deducting tax payments or profit oil deliveries made up to the end of the prior year, quarter or month.

As will be discussed in subchapter 4.4 of this report also other features, such as sliding scale royalties can be used to reduce revenues to the investor before applying the R-factor.

Using these methods the effectiveness of the R-factor can be restored under current conditions of high oil and gas prices for concessions and production sharing contracts.

R-factors applied to service contracts typically remain effective under high oil prices because the contractor only receives fees which are already less than the total gross revenues.

Cost oil limits in PSC's. Still many nations have fixed cost oil limits in PSC's. These limits are often in the range of 40% to 60%. This means petroleum costs need to be recovered and can be obtained as cost oil based on a limit of, for instance, 40% of the oil. A 40% limit on the basis of US $ 20 per barrel crude oil means that the maximum costs that can be recovered would be US $ 8 per barrel. Under an oil price of US $ 200 per barrel this would be $ 80 per barrel.

The main purpose of the cost limit was to protect the host government against poor administration by its own administrators. This meant that if excessive petroleum costs would be approved because of poor quality administrators, or even corrupt administrators, the IOC could not take more than 40% of the oil for cost recovery. At the same time the cost limit ensured that the host government would receive income as soon as production would start and provided governments with a guaranteed income under excessive cost conditions.

Of course, with oil prices of US $ 100 or US $ 200, this protection for the host government is no longer effective. Governments with a poor administration will therefore now face the possibility of significant losses. This concept needs to be reviewed in order to re-establish a proper protection for governments.

It would make much more sense to make the cost limit a function of the oil or gas price based on a sliding scale formula. For instance, at US $ 20 per barrel the cost limit could be 50% and at US $ 100 it could be 15%, while at $ 200 per barrel it could be 10%. This would ensure that the government would receive its fair share, regardless of the quality of the administration and at the same time if prices go up strongly there is space for higher costs, if costs go up as well.

Promotion of efficient operations. A fundamental principle of sound fiscal design is to ensure that under all circumstances the investor has a strong interest in being efficient. This means that the fiscal design should be such that more efficient IOC's should make higher profits than a less efficient IOC's. In other words, the fiscal design should not give the same profits to all investors regardless of whether they are efficient or not.

Governments have a very strong interest in encouraging competitive efficiency. This will ensure that the national oil and gas resources are being produced at the lowest possible costs. What are the characteristics of a good flexible fiscal design that protects the interests of the host nation and at the same time encourage efficiency on the part of the IOC's? This can best be evaluated by analyzing what would happen if the government decided not to encourage more efficient IOC's and would "cream off" all profits over a certain level?

In order to evaluate this matter, the one billion barrel field studied in Section 3.2 of this report, at $ 8 per barrel, will be used as an example. A case is evaluated where a government has decided to permit profits up to a PIR0 of 1.50, but will not permit "one penny more". In other words it "creams off" all profits over a PIR0 of 1.50.

Table 10 provides the results.

Table 10. Analysis of development project with cost variation and constant PIR0

`		$10/bbl	$ 8/bbl	$ 6/bbl
PFR0	(ratio)	1.50	1.50	1.50
NPV10	($ billion)	2.3	1.9	1.4
GT0	(%)	93.3%	94.8%	96.2%
GR0	($ billion)	84.0	87.2	90.4

This table shows that the **profitability** as measured by the PIR0 is the same for each of the three cost levels. However, this does not mean that the **profits** are the same.

What is very important to IOC's is the actual value of the cash flow. The value of this cash flow is measured by the so-called net present value of the cash flow. This means what the cash flow would be worth today. A typical discount rate to use in this case would be 10%. Therefore the net present value discounted at 10% ("NPV10") is a significant indicator of the attractiveness of the project.

As can be seen in Table 10, the NPV10 is significantly higher for the high cost project than for the low cost project. The same profitability results in rather different profits. The same level of profitability on higher costs means that the profits are automatically higher.

There is no doubt that the IOC will not have any encouragement to be efficient under such a fiscal system. In fact the IOC would seek to increase rather than decrease costs. For instance, the $ 10 per barrel cost option may represent the drilling of many horizontal wells, while the $ 6 per barrel cost option may represent drilling a much lower number of horizontal wells. The investor may select the high cost option and drill horizontal wells because the profits are higher in this case. **In this example the fiscal system misaligns the interest of the government and the investor.**

The resulting losses for the host government are staggering. The difference between the high cost and low cost case is a loss of government revenues of $ 6.4 billion loss in revenues.

Therefore, a policy aimed at "creaming off" all profits over a certain level of profitability will result in significant losses of potential government revenues, since IOC's will have an incentive to pursue high cost options.

What would be a better policy?

A better policy is to create a "win-win" situation. If the investor is more efficient:

- **the investor should benefit from a higher level of profitability (PIR0) and more total profits (NPV10), and**
- **the government should receive higher government revenues.**

Table 11 provides such an example.

Table 11. Analysis of development project
Regressive GT0 with costs and $ 100 per barrel

`		$10/bbl	$ 8/bbl	$ 6/bbl
PIR0	(ratio)	1.17	1.44	1.88
NPV10	($/billion)	1.75	1.77	1.78
GT0	(%)	94.8%	95.0%	95.2%
GR0	($/billion)	85.3	87.4	89.5

This table illustrates how both parties benefit from such a "win-win" approach.

Whether the GT0 can be improved depends sometimes on the specific circumstances of the project. In some cases the GT0 would have to be neutral or slightly regressive in order to achieve the desired incentive to encourage efficient operations. When costs are high relative to gross revenues, fiscal systems are often regressive.

As an example, this "win-win" approach can be developed for every price level and for a reasonable cost variation within a particular cost environment, using a combination of:

- a price sensitive feature that "clicks" in at a level that is reasonable compared to the average expected costs for the cost environment, and
- a modest R-factor sliding scale applied to profits (whether under a concession, PSC or service contract)

This is just an example. There are many other fiscal systems that can provide this "win-win" approach.

Therefore, government revenues can be maximized in a certain cost environment by creating a "win-win" approach whereby both the government revenues and the profits to the investor increase in case investors are more efficient and achieve lower costs.

4.5. Basic structure of fiscal systems for exploration projects.

Basic Framework

As was discussed earlier in subchapter 3.3, with exploration projects a very important issue is the level of geological risk and the size of the exploration targets.

In the case of exploration projects far less information is known about the possible costs. A 100 million barrel target, could be one attractive thick reservoirs with easy oil or many small thin reservoirs with difficult oil or even heavy oil. Costs could therefore vary over a wide range.

However, in general two concepts apply:

- smaller discoveries are typically higher costs per barrel than larger discoveries, and,
- exploration costs, including minimum dry hole cash flow requirements, drop strongly on a per barrel basis with larger discoveries.

For these reasons fiscal systems for exploration projects should preferably be progressive with field size. This means that a large field with higher levels of production should have a higher government take.

Therefore, the optimum fiscal system for exploration projects, combines a production progressive feature with the features discussed under subchapters 4.2 and 4.3.

Of course, it is possible to provide for an infinite number of combinations of fiscal systems that would all reasonable adhere to Policy 1 and 2 and the principles discussed in subchapters 4.2 and 4.3. However, an example of a single fiscal system will be provided as illustration of the principles.

Again the level of the government take will be entirely determined by the competitive conditions of the area. Therefore, this is again merely an example.

The example is an exploration project that has a $ 20 million exploration program with a probability of 20% of being a discovery of 100 million with a total cost of $ 8 per barrel. The range of discoveries is estimated to be from 30 million barrels at a cost of $ 14 per barrel to 300 million barrels at a cost of $ 4 per barrel.

The following fiscal system is applied:

- a sliding scale royalty starting at 0% for low levels of production to 30% for high levels - in order to provide progressivity with production.
- a corporate income tax of 25% with accelerated depreciation
- a windfall profit tax of 90% over $ 30 per barrel (net of the royalty) in order to provide progressivity with price, and
- an R-factor based sliding scale ranging from 50% below an R of 1 to 87% for an R of over 3.5. The R-factor is based on the data at the end of the prior year. It is the income of the investor net of royalties, windfall profit taxed and profit shares divided by the capital and operating costs cumulatively up to the end of the prior year. This provides progressivity with costs and price.

Chart 4 shows how for each of the three possible outcomes of the exploration, the undiscounted government take would increase strongly with the oil price. The windfall profit feature together with the R-factor creates therefore a system that is strongly progressive with price.

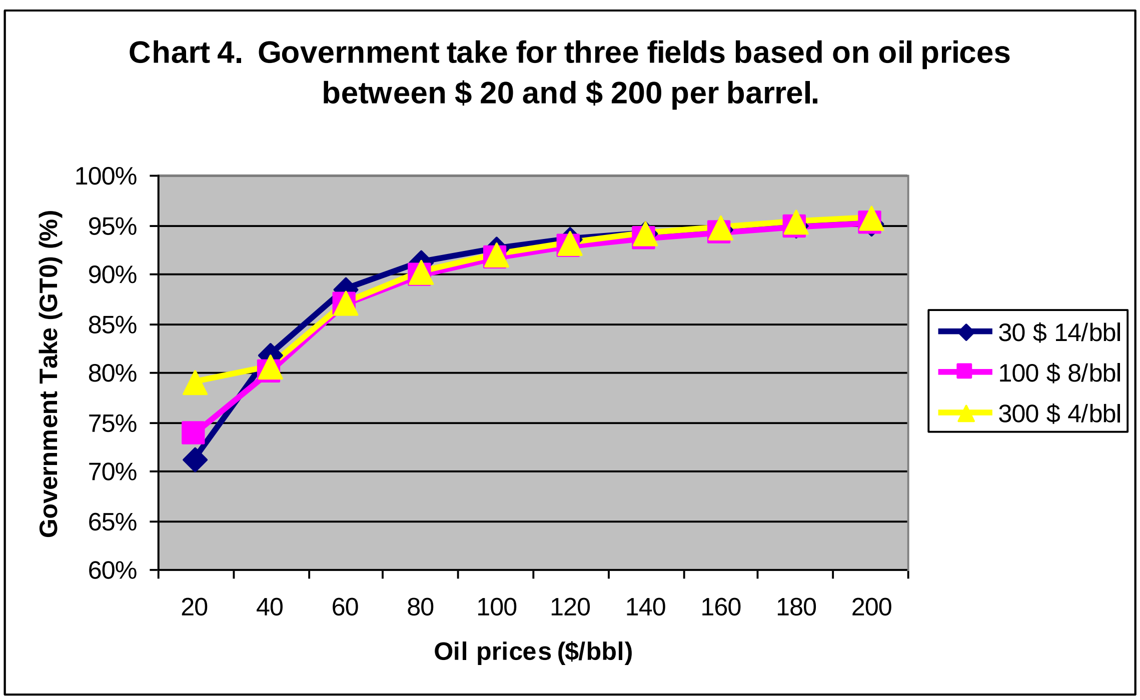


Chart 5 illustrates the relationship with costs. The R-factor system creates a system whereby the total government take is approximately flat between 150% of planned costs and 80% of planned costs and if the costs are much less than expected, the government receives a higher government take under these conditions.

Of course, how much emphasis should be given to each of the could vary considerably depending on the economic framework of the particular project or area and government policies.

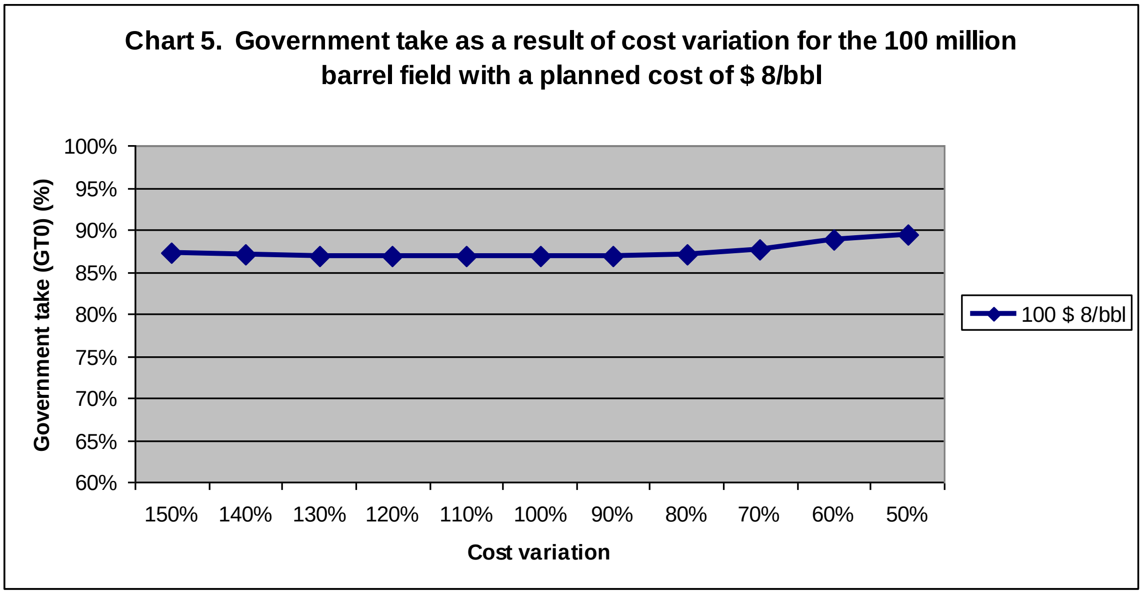


Table 12 provides and overview of how fiscal system would react to lower or higher costs. A cost variation of plus or minus 20% is analyzed.

Table 12. Analysis of exploration project at $ 60
100 million barrel field, $ 8/bbl + or - 20% costs

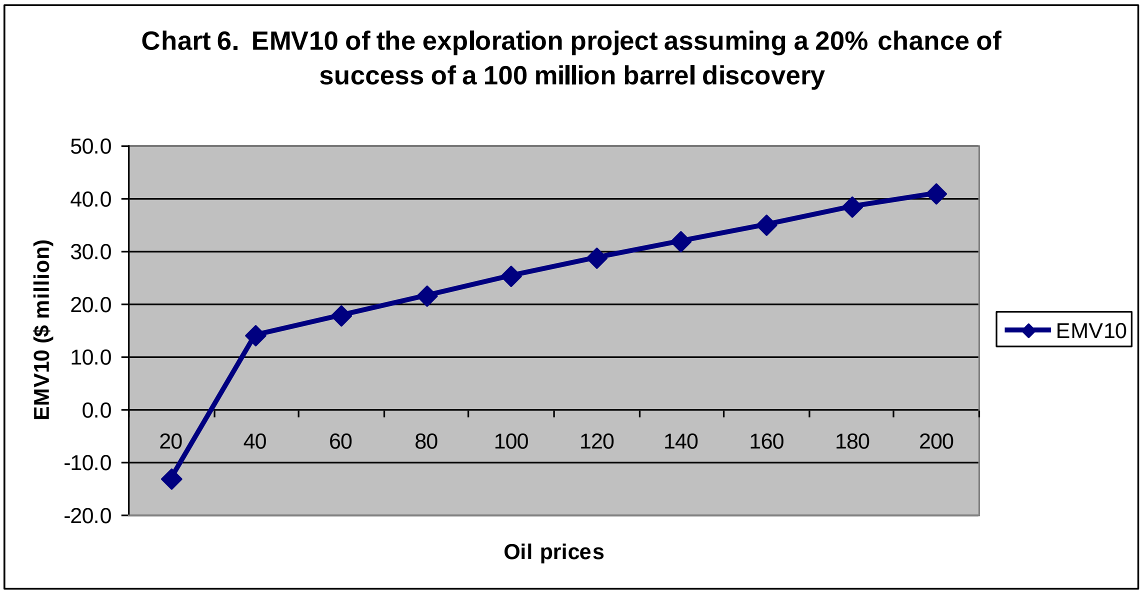
`		120%	100%	80%
PFR0	(ratio)	1.09	1.36	1.73
NPV10	($ million)	125.8	160.0	190.7
GT0	(%)	86.9%	86.9%	87.0%
GR0	($ million)	4360.0	4500.0	4650.0

As can be seen, the fiscal system is a typical win-win situation. If the IOC is more efficient and costs are lower:

- the IOC will obtain more profits, since the NPV10 is higher,
- profitability is much higher, since the PIR0 is much higher, while
- the government benefits from significantly higher government revenues if the IOC is more efficient.

The IOC will therefore have an incentive to be more efficient. **In this example, the profit incentive of the IOC is aligned with the government objective of maximizing revenues.**

Chart 6 provides the so-called Expected Monetary Value discounted at 10%, or EMV10. This is the weighted average of the 20% chance for the positive NPV10 of the 100 million barrel discovery and the 80% chance of the negative NPV10 of the dry hole.



This chart shows that the fiscal regime would result in attractive exploration down to a price level of $ 30 per barrel.

Yet, at higher prices, all the way up to US $ 200 the government would not leave significant value “on the table”. This is illustrated by the relatively flat line between $ 40 per barrel and $ 200 per barrel.

4.6. Bid or negotiating process

It is generally possible to design a system that would adhere to the two Policies and the principles discussed in subchapters 4.2, 4.3 and 4.4.

However, it is usually not possible to design a system that would flexibly adjust to a wide range of geological risk.

It is for this reason that governments often use some type of bid system or negotiations to extract the maximum possible government take from areas with different geological risk.

For instance, this means that a low bonus bid can be expected for a high risk block that is believed to contain small fields, while a high bonus can be expected for a low risk block that is believed to contain large fields.

With respect to our examples, it should be noted that many oil companies today are willing to bid in bidding rounds for exploration blocks an EMV10 value of zero in the range of $ 55 to $ 70 per barrel. So the above example is generous from this perspective.

If the area would be up for bonus bids, the IOC would be willing to bid about $ 19 million signature bonus in a perfectly competitive environment, based on the following assumptions:

- the IOC is willing to accept an EMV10 on a price of US $ 60 per barrel
- the bonus is 100% tax deductable
- this is the first block in the country, so the bonus will be subject to tax loss carry forward.

In this way the government can “fine tune” the government revenues and account properly for the exploration risk.

The bid or negotiating process therefore plays an important role in maximizing the benefits to government.

The bid process does not have to be for signature bonuses. It could be for other fiscal variables. In the case of service contracts, it could be for discounts on the fees. It is also possible to have work program bids in order to ensure the maximum amount of exploration.

The current high oil prices are have increased the demand for oil and gas upstream opportunities considerably, while many new IOC’s have entered the scene. This means that there is a far competition among IOC’s permitting governments to extract the maximum possible benefit.

Where competitive conditions exist, transparent bid processes should now play a major role in shaping the final government take and maximizing the government revenues.

Competitive conditions would now exist in most parts of the world, except possibly for areas of very high political or other risks and for certain marginal opportunities. In these cases a negotiating process rather than a bid process can be recommended.

4.7. Corruption avoidance

The significantly higher oil and gas prices have significantly increased the effects of possible corruption. Therefore in those jurisdictions that have serious corruption problems, it becomes now of additional importance to design the fiscal system in such a manner that it corruption is mitigated as much as possible.

Fiscal features that are transparent and for which the required payments are easy to determine, collect and audit typically help in mitigating corruption. The most transparent features in this respect are:

- royalties,
- simple severance taxes, and
- simple windfall profits taxes,
- low cost limits under PSC's also help considerably, and
- in service contracts, production based service fees (per barrel or Mcf) are easy to administer and therefore mitigate corruption.

Fiscal features that facilitate corruption are features that are less transparent and for which the required payments that are more difficult to determine, collect and audit and require detailed cost administration in order to ensure a fair share for the government. The least transparent features in this respect are:

- complex corporate income taxes with a wide variety of uplifts and tax credits or other special allowances.
- complex profit oil scales and taxes with R-factor or IRR based scales,
- and service contracts that are based on guaranteed profit margins also facilitate corruption by design.

Furthermore, often income earned through carried interests or shareholdings owned by national state companies often do not enter into the government budget and therefore facilitate corruption.

Therefore under current high oil prices it is important to take increased measures in countries that struggle with corruption to strengthen fiscal concepts that assist in mitigating corruption and reduce fiscal features that facilitate corruption.

4.8. Conclusions

The highest benefit from IOC's is obtained by following two broad policies:

- **Policy 1. Maximize production by creating profitable conditions for the widest possible range of petroleum exploration and development projects and extract the maximum government revenues from each project.**
- **Policy 2. Ensure that investors are encouraged to achieve the maximum level of production at the lowest possible costs at the optimal possible pace that is consistent with good conservation practices.**

Sophisticated fiscal systems can be created that achieve these objectives with respect to concessions, production sharing contracts or risk service contracts.

However, under the current high price conditions many of the traditional features of petroleum arrangements now need review.

Governments need to take stronger measures to capture most of the divisible income over certain price levels. Given the oil and gas supply conditions in the world as a whole, divisible income sharing should be very strong for governments over $ 80 per barrel.

Governments should now avoid contracts or concessions that provide for comprehensive fiscal stability. If fiscal stability is provided, it should be given only within certain economic parameters. Outside these boundaries governments should be free to change fiscal terms and conditions depending on international competitive circumstances from time to time.

The traditional concepts that created progressivity such as R-factor or IRR based sliding scales are ineffective for the current price range, and need to be complemented with other features to extract a higher government take under high price conditions or high levels of production or cumulative production.

Fixed cost oil percentage limits in PSC's are no longer effective from a government perspective and need to be replaced with cost oil limits that vary with price, in order to ensure that under higher prices cost oil limits are lower and governments are well protected in case of poor administration.

The current high oil prices create an environment where IOC's may be induced to squander resources in order to capture new opportunities, governments should therefore pay more attention to fiscal structures that reward efficiency on the part of IOC's and provide a strong disincentive for squandering capital and operating costs. Fiscal systems that are strongly progressive with lower costs should therefore be avoided.

Fiscal systems for petroleum exploration projects, or for individual well drilling as in North America, should create more progressivity with the level of daily production or cumulative production.

The current strong demand for petroleum contract or concession areas, creates an environment in which governments can use competitive and transparent bidding processes with significant beneficial effect for the host nations.

The high oil and gas prices exacerbate problems with corruption in some jurisdictions and in this environment it is important to emphasize royalties, simple severance taxes, price based windfall profits taxes and low cost limits in concessions and production sharing contracts and per barrel or Mcf fees in service contracts.

As can be seen from the above discussion the involvement of IOC's in the national oil and gas development requires considerable planning and economic optimization of this relationship.

A simple question is therefore why involving IOC's in the first place? After all, if national oil companies would develop the same fields or do the same exploration, the state simply keeps a government take of 100%.

5. ANALYSIS OF IOC BENEFIT

5.1 Roles of national oil companies

State owned national oil companies could be involved in the exploration, development and production of oil and gas in many different ways.

Some nations see their involvement on a so-called carried interest basis, whereby national oil companies ("NOC's") participate in the operations of an IOC, after a commercial discovery has been made on the basis of a joint operating agreement. This concept is applied in more than 30 countries in the world.

Venezuela prefers to involve a subsidiary of their NOC on a joint venture basis with IOC's whereby all parties are shareholders of a joint "mixed company".

Some nations see their NOC's as entities that conclude production sharing agreements with IOC's.

In all of these cases, the national oil companies have a role in the overall structure of a fiscal system with IOC's. Therefore the fiscal concepts discussed in the previous chapters apply.

A number of nations prefers to have a preponderant role for their NOC's in carrying out **directly** petroleum exploration, development and production:

- at the exclusion of IOC's, such as Kuwait,
- for all oil operations, but not gas operations, as in Saudi Arabia
- for most oil and gas operations, but with the possibility for service contracts in some other operations, such as in Mexico, Iran and possibly Iraq (outside the KRG area).

The strong direct involvement of these NOC's is for many historical and political reasons, in particular the degree of control that the nation seeks over its oil industry.

However, often also economic arguments are being brought forward. All five countries in which these national oil companies operate have potentially significant financial resources. Therefore, an important economic argument for direct NOC involvement is that the nation can be itself investor and as a consequence make the profits associated with these operations. In this way the resource wealth can be retained for the nation, rather than facing the fact that significant profits would be repatriated to the home countries of the various IOC's.

In particular, the excessive profits that IOC's are making in the world at this time under the very high oil prices bolster this economic argument.

It is therefore important to evaluate this matter in more detail from an economic perspective under the current high oil prices.

5.2 Economic analysis of the benefit of IOC involvement compared to direct NOC operations

The possible benefit of IOC's over development by national NOC's depends entirely on the assessment of the relative efficiency of the two entities. Some NOC's maybe relatively efficient, others may be less efficient.

What matters to a government in the end, from an economic perspective, is the amount and timing of the government revenues.

If NOC's would be equally efficient as IOC's than, of course, it would be from a strict cash flow point of view more attractive to have an NOC develop the oil and gas fields and earn all government revenues than have a IOC develop it and give up corporate take.

In many cases, however, NOC's are less efficient. This is due to many factors, such as the bureaucratic nature of decision making, delays in budget approvals, shortage of capital at critical moments, inability to provide for an integrated technical management of the oil field developments, inability to attract qualified personal in a world market that currently offers premium salaries for well qualified professionals, etc.

However, a somewhat inefficient NOC could still be more advantageous to the nation than an efficient IOC, since they may still provide higher revenues after the corporate take has been deducted. Of course, these matters have to be evaluated at the appropriate discount rate, of say 5%.

What is the break even point between an inefficient NOC and an efficient IOC? This depends on the level of government take and the oil price. The higher the government take and the higher the oil price, the more efficient the NOC has to be in order to create the same benefit to the government.

As a result of the considerably higher oil prices and much higher government takes a dramatic change has now occurred in the relative efficiency that is required for an NOC in order to produce the same wealth for a nation as an IOC.

Table 13 provides an analysis based on the development of the one billion barrel field at $ 8 per barrel, which was already used in Section 3.2.

It provides a comparison whereby, all factors between an NOC and an IOC are the same except for the ability to fully produce the field. The GT0 is 70% and the oil price is $ 20.

In Table 13 it is assumed that the NOC would have the same exact capital expenditures and would have the same operating expenditures per barrel. Furthermore, the production profile of oil would be the same, so the field would start producing in the same year and would reach a maximum level of production in the same year. The only difference is that the NOC would produce 77.78% of the IOC production in every year due to less efficient reservoir and production management, resulting in a lower recovery factor.

Table 13. IOC-NOC comparison based on GR5 at $ 20

		IOC	NOC
Production	**(million bbls)**	**1000**	**777.8**
Gross Rev	**($ million)**	**20000**	**15556**
Capex	**($ million)**	**3200**	**3200**
Opex	**($ million)**	**4800**	**3733**
Divisible Inco	**($ million)**	**12000**	**8623**
GT0	**70%**		
GR0	**($ million)**	**8400**	**8623**
GR5	**($ million)**	**4847**	**4847**

Table 13 shows that a production level of 777.8 million barrels by the NOC would be the break even point compared to the IOC on the basis of the same 5% discounted government revenues ("GR5"). Both companies would create $ 4847 million dollars in 5% discounted government revenues.

This means that as long as the NOC produces 77.78% of the oil that is produced by the IOC, there is no difference to the government between the two options, assuming a reasonable time value of money for a government.

However, this is at an oil price of $ 20 per barrel, what would be the break even point if the oil price would be $ 100 per barrel and the undiscounted government take is now 95% as a result of the higher prices?

Table 14 illustrates this issue.

Table 14. IOC-NOC comparison based on GR5 at $100

		IOC	NOC
Production	(million bbls)	1000	952.3
Gross Rev	($ million)	100000	95230
Capex	($ million)	3200	3200
Opex	($ million)	4800	4571
Divisible Income	($ million)	92000	87459
GT0	95%		
GR0	($ million)	87400	87459
GR5	($ million)	54151	54151

Table 14 illustrates how under high oil prices a much higher government take could be obtained, for instance 95%. Also the oil produced is now more valuable to the host government. Therefore the NOC has to be considerably more efficient in order to match the performance of the IOC. In this example the efficiency now has to be 95.23% on a per barrel of production basis.

This illustrates how under higher oil prices NOC's have to be more efficient in order to match the performance of IOC's and provide the same revenues, undiscounted or discounted, to the host government. Due to the high oil prices, lower or later production of oil or gas on the part of NOC's is now very damaging to the nation.

Of course, if the NOC would have higher costs and would have delays in achieving peak production than the NOC can typically not match the GR5 performance on IOC's under current high oil prices, as is illustrated by Table 15 based on $ 100 oil. This table assumed 20% higher costs for the NOC and a two year delay in achieving peak production and a production level that is 80% of the IOC.

Table 15. NOC-IOC comparison at $100 and 80% efficiency

for alternative one billion barrel fields

		$ 14/bbl	$ 8/bbl	$ 2/bbl
IOC production	(million barrels)	1000	1000	1000
NOC production	(million barrels)	800	800	800
IOC GR5	($ million)	46.0	52.8	59.0
NOC GR5	($ million)	37.1	41.5	45.9
GR5 Loss	($ million)	-8.9	-11.3	-13.1

In this case the losses to the host nation are staggering, ranging from a loss of GT5 of $ 8.9 billion to $ 13.1 billion.

However, such differences in performance are not atypical between NOC's and IOC's.

During the last 40 years IOC's had to specialize in squeezing every barrel possible out of the various reservoirs, since stock markets watch carefully the booked reserves of each company. NOC's have never been under this pressure. Therefore, in particular in complex and difficult reservoirs IOC's may recover as much as 25% to 50% more than NOC's during a 20 to 40 year period.

It should be noted that achieving a higher recovery factor is a process that takes place during the entire term of the contract. In other words an IOC does not "construct" and oil field with facilities that give the highest possible recovery factor immediately.

Normally the first phase of development of a field relates to standard and traditional recovery of oil and gas. As the IOC starts to understand the reservoir in much more detail with extensive production history and testing of various wells, incremental investments are being made in order to achieve a higher level of recovery. Also new technology is being introduced and IOCs are therefore in a constant process of upgrading and improving their production methodologies and recovery of oil and gas. Most of the improved and enhanced recovery therefore takes place during the last half of a contract term.

As a result of the high oil prices, governments are now insisting on a high government take. The resulting low corporate take means that the "price of hiring an IOC" is now comparatively low. This in turn creates an economic situation where IOC involvement is typically highly beneficial based on a comparative economic and technical analysis of IOC and NOC performance.

The above example was an example for a development project.

The involvement of IOC's compared to domestic NOC's is more beneficial for exploration projects. In the case of exploration the host government benefits from the introduction of various IOC's to the nation. A variety of IOC's means the creation of a framework in which different approaches and technologies are tested out. This results in the highest possible probability of discovering oil and gas.

Many production sharing and service contracts provide for the fact that in case of dry holes, the exploration costs are entirely borne by the investors. This means that the nation benefits from the discoveries being made without having to incur the geological risk. Only in case of successful exploration programs will the nation pay for the exploration indirectly through the government take that would be sufficiently attractive to encourage such exploration.

In case of discoveries, IOC's achieve often first production in a much shorter period than NOC's would. This greatly enhances the value of the eventual 5% discounted government revenues.

It is therefore that IOC's typically provide a significant cash flow benefit to host governments in exploration projects, compared to NOC's.

5.3. Conclusion

Under current high oil prices, maximum benefits to the nation in terms of maximization of higher and earlier government revenues from oil and gas are created by involving IOC's rather than NOC's in the process, unless NOC's have achieved a level of efficiency and management skills that is equal to or nearly equal to the IOC's.

Having established that it is possible to achieve these benefits through IOC's for host nations, what is actually happening the world in this respect?

Are most nations maximizing government revenues for oil and gas under their respective petroleum arrangements?

6. ANALYSIS OF EFFECTIVENESS AND ALIGNMENT

Governments typically need some time to adjust their policies to new economic circumstances. Fiscal systems are changed only now and then.

This means that most governments today are still "stuck" in fiscal systems that were designed prior to 2003. Many governments have not yet adjusted their fiscal terms to the $ 60 price level, let alone the new economic framework of $ 130 per barrel oil with possibilities for much higher prices in the future.

The fiscal systems that were designed prior to 2003 often do not adhere to the two policies to maximize government take, as described in Chapter 4. Even some of the systems designed after 2003 do not achieve this goal.

Political, historical and legal reasons have often resulted in sub-optimal fiscal systems.

Sub-optimal fiscal systems create far more significant damage to host governments under current high oil and gas prices.

As a result of the recent strong oil and gas price increases most fiscal systems in the world are now out of balance and would need review in order to re-optimize government take and government revenues.

Following is a brief review of the current status of fiscal systems in the world. The discussion is done separately for concessions, production sharing contracts and service contracts.

6.1. Concessions

Many jurisdictions still have today concession systems that do not respond to higher oil and gas prices with a higher government take or provide for higher government take in case of more profitable wells or fields or both. These jurisdictions include:

- The federal government and many states of the United States,
- The United Kingdom, and many other nations of Europe, such as France, Germany, Austria, Spain, Hungary and Italy,
- The States of the onshore of Australia,
- Several Latin American countries, such as Argentina, Bolivia, Brazil and Venezuela.
- Several other developing countries, such as Chad, Morocco, Nigeria, Pakistan, Papua New Guinea and South Africa.

There are also a variety of jurisdictions with concession systems that have implemented various degrees of price sensitivity and other features that are aimed to extract a higher government take under more profitable conditions. These systems are sometimes relatively sophisticated, while in other cases the systems are more rudimentary. Jurisdictions with such systems include Australia-offshore, the provinces of Alberta and British Columbia, Norway, Netherlands, Saudi Arabia (for gas only), Algeria, Colombia, Thailand, Russia, Trinidad and Tobago and Tunisia.

6.2. Production Sharing Contracts

Many countries still have fiscal systems based on production sharing contracts that do not respond to higher oil and gas prices with a higher government take or provide for a higher government take in case of more profitable fields or both. These are countries, such as Bangladesh, Egypt, Gabon, Indonesia, Myanmar, Philippines, Sudan, Syria, Yemen and Vietnam.

Yet there are also countries with fiscal systems based on production sharing contracts which provide for a degree of adjustment to more profitable circumstances. This include jurisdictions and countries such as Qatar, Libya, Azerbaijan, China, Equatorial Guinea, Ghana, India, Malaysia and the Kurdistan Regional Government in Iraq.

6.3. Service Contracts

It should be noted that there is a wide variety of service contracts and therefore these criteria need to be analyzed for each type of service contract separately. Following is a very brief discussion of the main style of service contracts. Service contracts can be divided in:

- **No – risk service contracts** where the host nation contributes 100% of the capital and operating costs during the delivery of the services.
- **Risk service contracts** whereby the IOC commits the initial capital requirements and runs a certain risk that the operations may be unprofitable or uneconomic.

The common characteristic of all service contacts is that the contractor does not receive a share of the oil or gas. The contractor only receives cash or sometimes oil or gas to pay for specific services.

No-risk Service Contracts

There are three types: turn key contracts for certain services, technical assistance agreements and enhanced technical service agreements.

Turn key contracts. These consist of contracts for drilling of wells and construction of certain facilities. The contracts could even include a period of initial operation by the contractor. These contracts are really not "fiscal systems". The host government or NOC simply pays for all the services it receives, regardless of the profitability of the operations.

Technical Services Agreements. Kuwait has a variety of Technical Services Agreements with major oil companies to provide management advice for certain petroleum operations in Kuwait. Under these agreements the companies receive significant payments per professional contributed to the project. The IOC's provide only management advice and do not manage the operations themselves or invest in these operations. A similar agreement was also entered into by TOTAL in India with respect to the Bombay High development. There is no relationship between the quality of the advice and the payments.

Enhanced Technical Services Agreements. Kuwait is negotiating Enhanced Technical Services Agreements with major IOC's at this point in time. However, these agreements are secret for the moment. Nevertheless, it is reported that these contracts will include a performance related bonus. Presumably the agreements involve some type of incentive for the IOC's to provide good consulting advice. There is some risk under these contracts that the government ends up paying a major share of the costs of involving IOC's without actually getting the direct benefit of their involvement.

Under the Technical Services Agreements, IOC's only provide advice. It should be noted that IOC's are not consulting companies. It is not their focus. IOC's typically operate poorly if they are not themselves in charge of the operations. They have no experience in working through state companies in order to achieve national objectives. In the end, the execution of the projects remains entirely subject to all the bureaucratic processes of the NOC. **Therefore, these type of contracts do not achieve the highest possible recovery of oil and gas and the highest possible government revenues or value of government revenues.**

Risk Service Contracts

All currently existing risk service contracts or models of service contracts suffer from the fact that fees are fixed or profit margins are fixed and need to be determined or negotiated at a certain point in time in a competitive world framework. These fees are not oil or gas price sensitive. Therefore, under the current high oil prices there is a considerable risk that contracts will be negotiated that are overly generous if low oil prices would return.

Under high international oil prices these contracts are not competitive, since alternative opportunities are more attractive to investors, and therefore there is no incentive to provide for an adequate pace of development under these circumstances.

Following is a discussion of the main types of risk service contracts. The contracts are listed from the least sophisticated to the most sophisticated in terms of alignment with respect to the criteria discussed in chapters 4 and 5. For each model there is a brief commentary on the alignment issues provided in *italics*.

Buy Back Contracts. Iran has so-called buy-back contracts. These are short term contracts of, for instance, 5 years, whereby the contractor at his own risk develops an oil or gas field and receives recovery of operating and capital costs and a negotiated fixed fee over a short period. The contractor operates the fields during the term of the contract. The contract is based on a pre-determined work program.

Under this contract the host nation will not be able to achieve maximum levels of recovery from the reservoirs and therefore maximum government revenues, due to the short duration of the contracts. Also the contracts do not provide an incentive to be efficient, other than through cost reductions, since the profit margin is fixed.

Risk service contracts in Iraq. The Ministry of Oil in Iraq has developed a model risk service contracts for the development of fields and for exploration and development of fields. Development contracts are supposed to be for 12 years and Exploration an Development contracts are designed for 16 years. Under this model the contractor receives cost recovery from a share of production. The remuneration is determined on the basis of a remuneration index which is based on the ratio between profits and capital expenditures, similar to the PIR0 ratio. For exploration contracts the remuneration index is determined during the development plan stage based on an IRR criterion. The remuneration is also paid from a predetermined share of the production. There is a cap and floor on the remuneration. Contrary to a production sharing contract, an increase in capital expenditures, does not result in an automatic reduction of the amount of profit oil.

As with the buy back contracts, under this contract models the host nation will not achieve maximum levels of recovery from the reservoirs and maximum government revenues, due to the short duration of the contracts. The remuneration index concept does not provide an incentive to be efficient.

Mexican multiple services agreement. PEMEX has concluded a number of so-called multiple services contracts. These contracts have a term of up to 20 years. Under these contracts the contractors execute flexible work program as determined from time to time. Contractor contributes all capital and operating costs. They receive recovery of their costs up to a certain limit determined by a share of the production. Work is being rewarded on the basis of a catalog with values for the work. Values include a fixed profit margin. Contractors pay corporate income tax.

Under this contract the there is some incentive to be efficient in terms of cost, but not in terms of work program definition, since the maximum work results in the highest profits regardless of the effectiveness of the work.

Kuwait Operating Services Contract. The Oil Development Corporation of Kuwait has a model Operating Services Contract for the possible development of a number of North Kuwait oil fields. These contracts permit a flexible work program as decided from time to time. The contractor contributes all capital and operating costs and receives cost recovery on only a percentage of these costs. The contractor receives also "old" oil and "new" oil fees on a per barrel basis as well as gas fees on a per MMbtu basis. In case of favorable developments in terms of low costs and high production, ODC receives a cost savings share as "claw back" from the fees paid. The contractor pays corporate income tax.

This is the most sophisticated risk service contract at this time. Under this contract there is considerable incentive to maximize recovery and be efficient. However, the contract suffers from the inherent disadvantage of having fixed fees.

Conclusion on service contracts. It can be concluded that current risk-service contracts are not structured to achieve under all circumstances the highest government revenues.

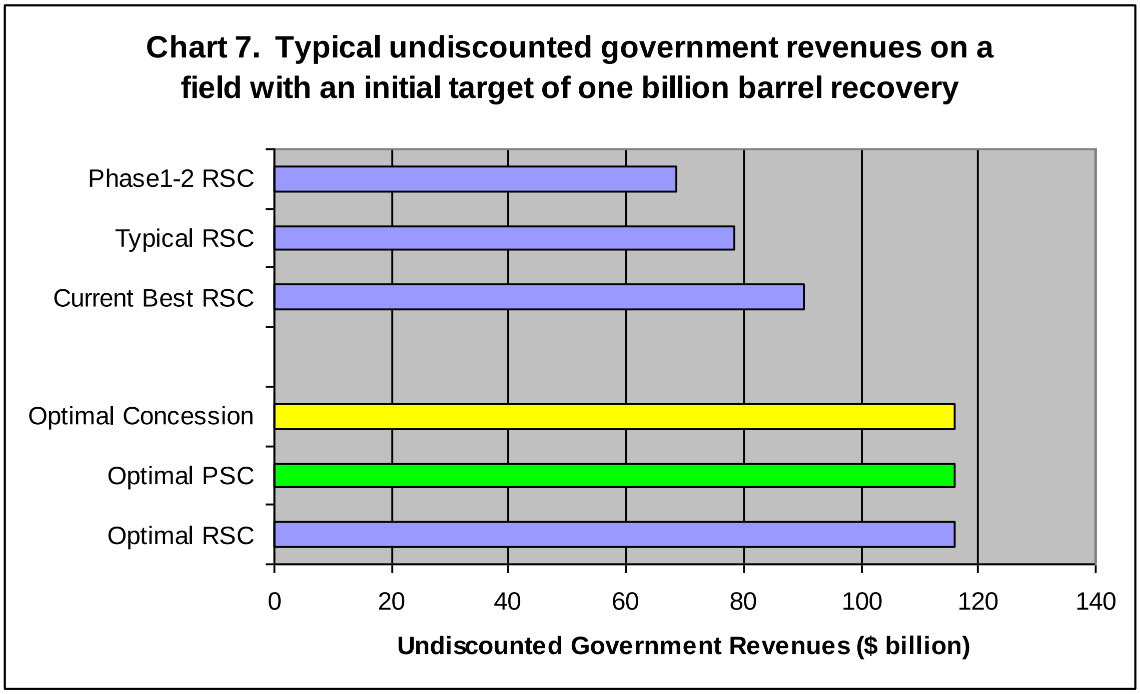
In principle it would be possible to have a fully aligned risk-service contract. For instance, this could be achieved under the Kuwait OSC with price-sensitive fees rather than constant fees per barrel of Oil.

However, such fully aligned service contracts have so far not been announced in any nation.

Therefore, the currently existing poorly structured risk service contracts are less desirable than existing relatively well structured concessions or production sharing contracts.

Losses to government are considerable based on current sub-optimal RSC's. Losses are particularly high with a Phase 1-Phase 2 approach, where the NOC takes over from the IOC shortly after the initial development phase of the field.

Chart 7 shows typical examples for the billion barrel field used earlier in this report at a price of $ 100 per barrel.



IOC's typically achieve much higher recovery than the initial plan, for instance 1.3 billion barrels, due to sophisticated reservoir management and constant application of the latest technologies during the term of the concession or contract. Based a government take of 97% the host nation receives over $ 116 billion in undiscounted government revenues. A well structured RSC, PSC or concession could all achieve these levels.

However, under the most sophisticated RSC's, currently available, it is likely that at best only the planned production of one billion will be produced, resulting in revenues of only $ 90 billion.

Under the least sophisticated RSC's, such as the Iranian RSC, the NOC will take over after 5 years based on the Phase 1-Phase 2 approach. Because of the less efficient NOC's the target production may not even be reached. Reaching 80% of the target production at higher cost over the same time period would be a good achievement for an inefficient NOC. This means that government revenues will be only $ 69 billion. In other words, such contracts could cost the nation as much as $ 47 billion in lost revenues. This is more than 40% of the maximum value of the government revenues in principle available under any of the three IOC petroleum arrangements under optimal conditions.

TSA's are comparable in result to the least sophisticated RSC's, since the NOC remains in charge.

6.4. Conclusion

There are only a limited number of countries that have reasonably optimized their fiscal systems in order to achieve maximum benefit to their nations. Many nations have sub-optimal systems.

The recent strong increases in oil and gas prices have created a further disequilibrium. As a result, at this moment the world is in a state of adjustment and many countries are reviewing their fiscal terms.

There is no evidence that any of the petroleum arrangements is inherently more successful than other arrangements. What matters is the detailed design and structure of these arrangements.