Petroleum Fiscal Regime

GeoIndia 2022

October 12, 2022

Agenda of the session

S. No.	Session	Schedule
1	Let's know each other	10 am to 10:30 am
2	Fundamentals: Petroleum Fiscal Systems	10:30 am to 11:30 am
3	**Break**	11:30 am to 11:45 am
4	Major fiscal regimes - deep dive	11:45 am to 12:45 pm
5	Group Activity – Case Study on PSC	12:45 pm to 1:30 pm
6	**Lunch**	1:30 pm to 2:30 pm
7	Group Activity – Case Study on PSC …contd	2:30 pm to 3:30 pm
8	**Break**	3:30 pm to 3:45 pm
9	Policy and Fiscal Regime for Indian E&P Industry	3:45 pm to 4:30 pm

Introduction

KPMG in India, a professional services firm, is the Indian member firm of KPMG International Cooperative.

Globally, we are present in **155 countries** around the world with a combined strength of over **162,000 people.**

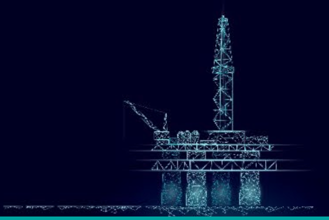
Established in September 1993, KPMG in India today operates from 20 offices in 10 cities **around the country**.

KPMG in India today combines 8400**+ professionals led by over** 470 P**artners and Directors**

Offering 100+ products that are tailored to meet client and market demand

Provide services to 2700+ clients in India, spanning multinationals, domestic, public and private sector companies

Our extensive service offerings across Audit, Tax and Advisory tailored to meet client needs and market demand



Audit

- U.S. GAAP (including SOX attestation)
- International Financial Reporting Standards (IFRS)

Tax

- International Tax and Regulatory
- Litigation Services
- Indirect Tax
- International Executive Services
- M&A Tax
- Regulatory
- Transfer Pricing

Advisory

Management Consulting

- Business Excellence
- Financial Management Advisory Services
- Strategy and Operations
- IT Advisory
- People and Change Advisory
- Shared Services and Outsourcing Advisory

Risk Consulting

- Accounting Advisory Services
- Climate Change and Sustainability Services
- Financial Risk Management
- Forensic
- Governance, Risk and Compliance Services
- IT Advisory

Transactions and Restructuring

- Corporate Finance
- Restructuring
- Transaction Services

Infrastructure and Government Services

- Business Performance Services
- Corporate Finance
- Development Sector Advisory
- e-Governance
- Major Projects Advisory
- Transaction Services, Strategic and Commercial Intelligence

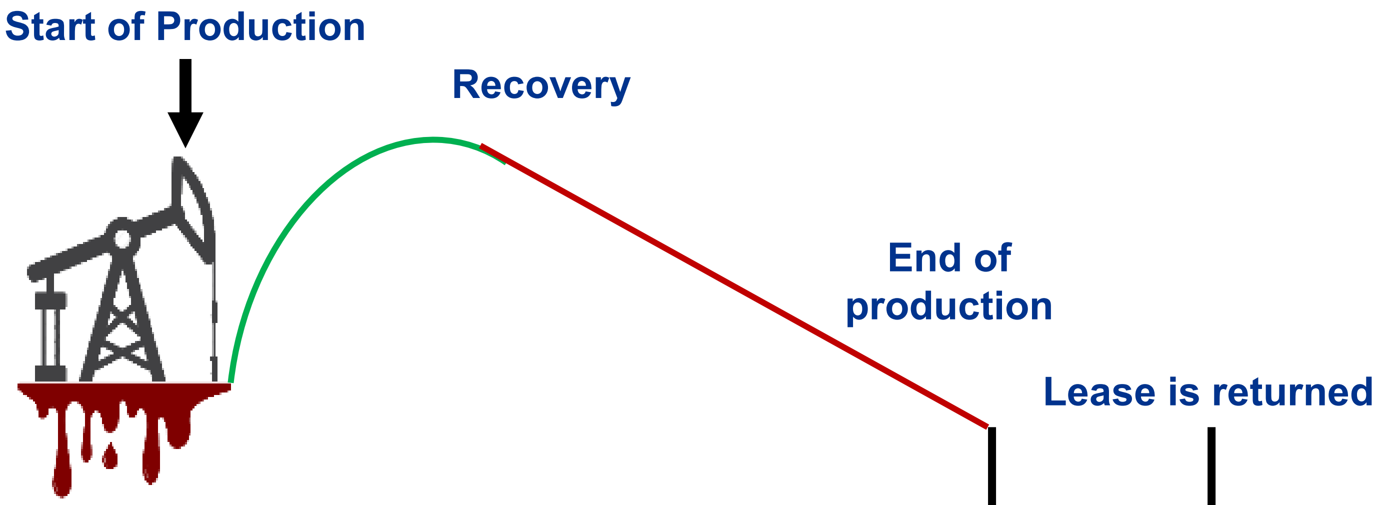
Let's know each other

Introduction should not be boring!!!

- **Two truth and one lie**
- **Most Unique**

The Life Cycle of a Petroleum Project

Lifecycle of an oil and gas field



Lease → Exploration → Development → Production → Closure → Post Closure

Lease

Host government grants a license or enters into a contractual arrangement with an oil company **without transferring the ownership of the mineral resources**

Exploration

- Geological and geophysical surveys such as seismic surveys and core borings are carried out.
- **The data acquired is processed and interpreted**

Development

If the appraisal wells are favorable and the decision is made to proceed, then the next stage of development planning commences

Production

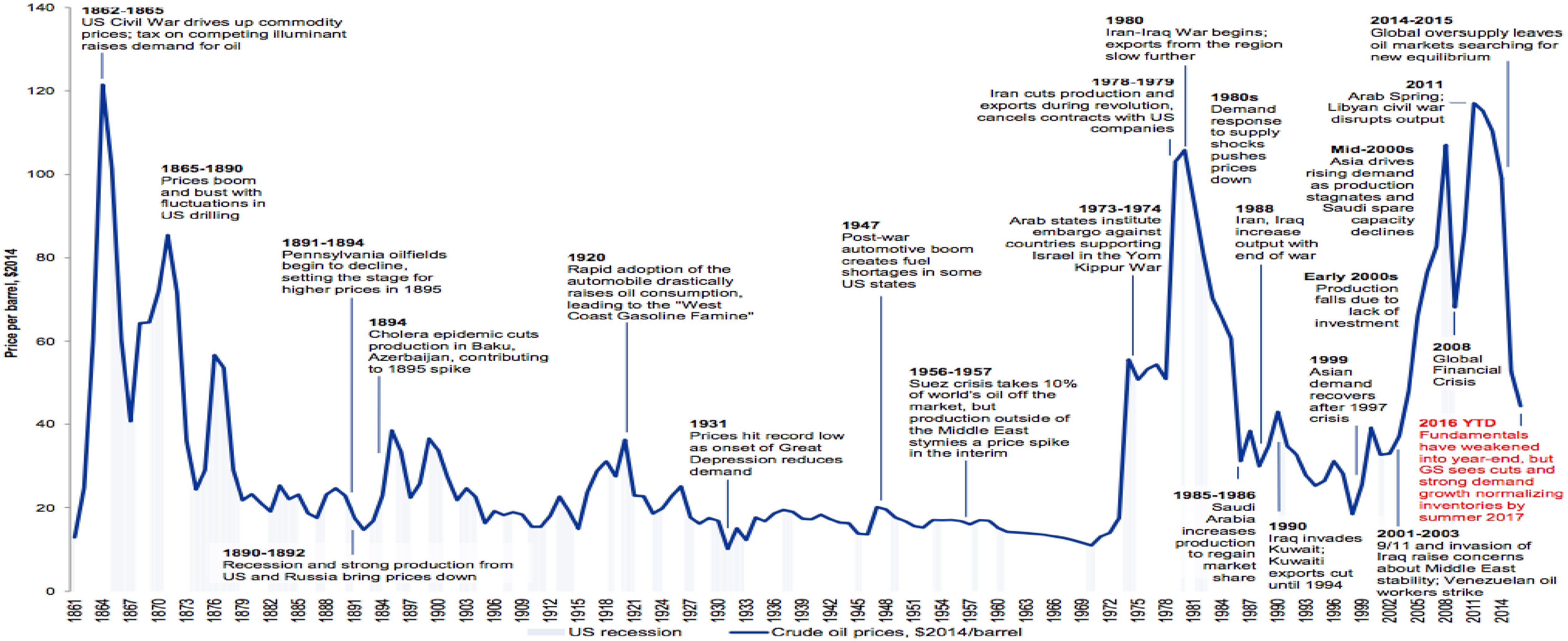
- Once the wells are completed and the facilities are commissioned, production starts.
- **Secondary and/or tertiary recovery** is used to enhance productivity later
- **Workovers** is carried out periodically to ensure the continued productivity of the wells

Closure

At the end of the useful life of the field, which for most structures occurs when the production cost of the facility is equal to the production revenue (the so-called "**economic limit**"), a decision is made to abandon.

Post Closure

The tumultuous 155-year history of oil prices



An earlier version of this chart appeared on pg. 16 of Top of Mind Issue #52: OPEC and Oil Opportunities.
Note: 2016 price shown is YTD average as of Dec. 19, 2016.
Source for data: BP, NBER/Federal Reserve Bank of St. Louis, Haver Analytics.
Source for annotations: ©James Hamilton, "Historical Oil Shocks," University of California, San Diego, February 2011; various news sources; Goldman Sachs Global Investment Research.

Extractive industry - Distinctive features

- Large upfront capital requirements and long lead times between initial investment and first revenues generated
- Geological uncertainty
- Wide range of technical, commercial and political risks
- Environmental concerns such as CO2 emissions, disruptions to land, wastes and pollutant
- Potential for surplus profits
- In general, government ownership of natural resources

Basic terminologies of petroleum fiscal system

What is Petroleum Fiscal System

There are more petroleum fiscal systems in the world than there are countries

The term *fiscal* is used to encompass all the legislative, tax, contractual, and fiscal aspects that govern petroleum operations within a sovereign nation/state and its provinces.

Referring to a country's petroleum taxation/ contractual arrangement simply as the *fiscal system* **is not correct.**

Government Objective

The objective of a host government is to maximize wealth from its natural resources by encouraging appropriate levels of exploration and development activity. For the government to meet its objectives it is required to design fiscal systems in the following way:

1. **Provide a fair return to the state and to the industry**
2. **Avoid undue speculation**
3. **Limit undue administrative burden**
4. **Provide flexibility**
5. **Create healthy competition and market efficiency**
6. **Consideration of potential political and geological risks along with potential rewards**

E&P company Objective

The objectives of E&P companies are to build equity and maximize wealth by finding and producing oil and gas reserves at the lowest possible cost and highest possible profit margin.

For higher profits they must search for huge fields but unfortunately, the regions where huge fields are likely to be found are often accompanied by tight fiscal terms

The companies are also comfortable with these terms if they are justified by sufficient geological potential.

The primary economic aspects of contract/license negotiations are the work commitment and the fiscal terms. These are sometimes collectively referred to as the commercial terms

The work commitment represents hard *risk dollars* while fiscal terms *govern the allocation of revenues* that may result from successful exploration efforts

Access to **material opportunities**

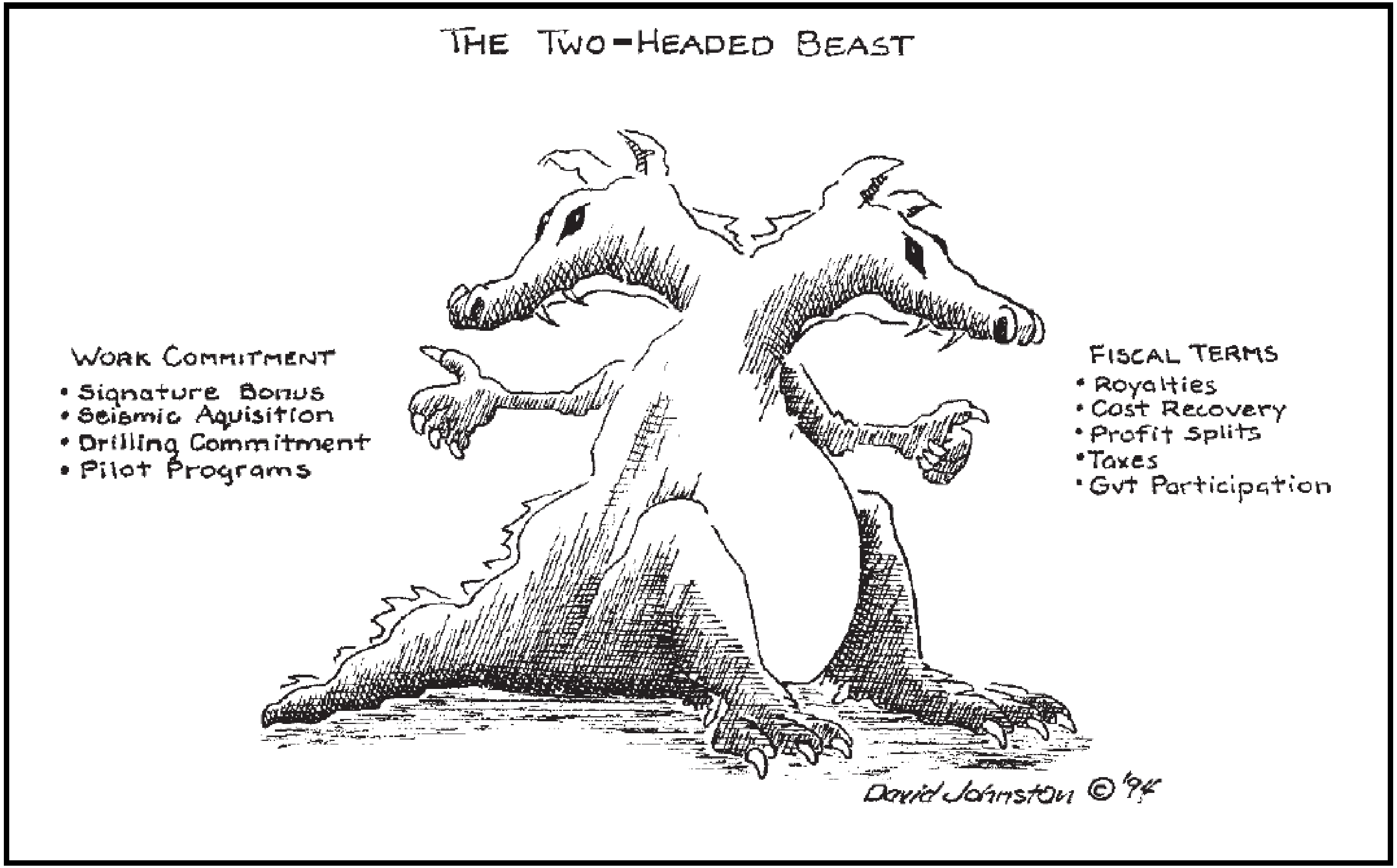
Competitive, Stable and simple fiscal regimes

Political stability and low regulatory burden

And what does commitment and fiscal terms represent?

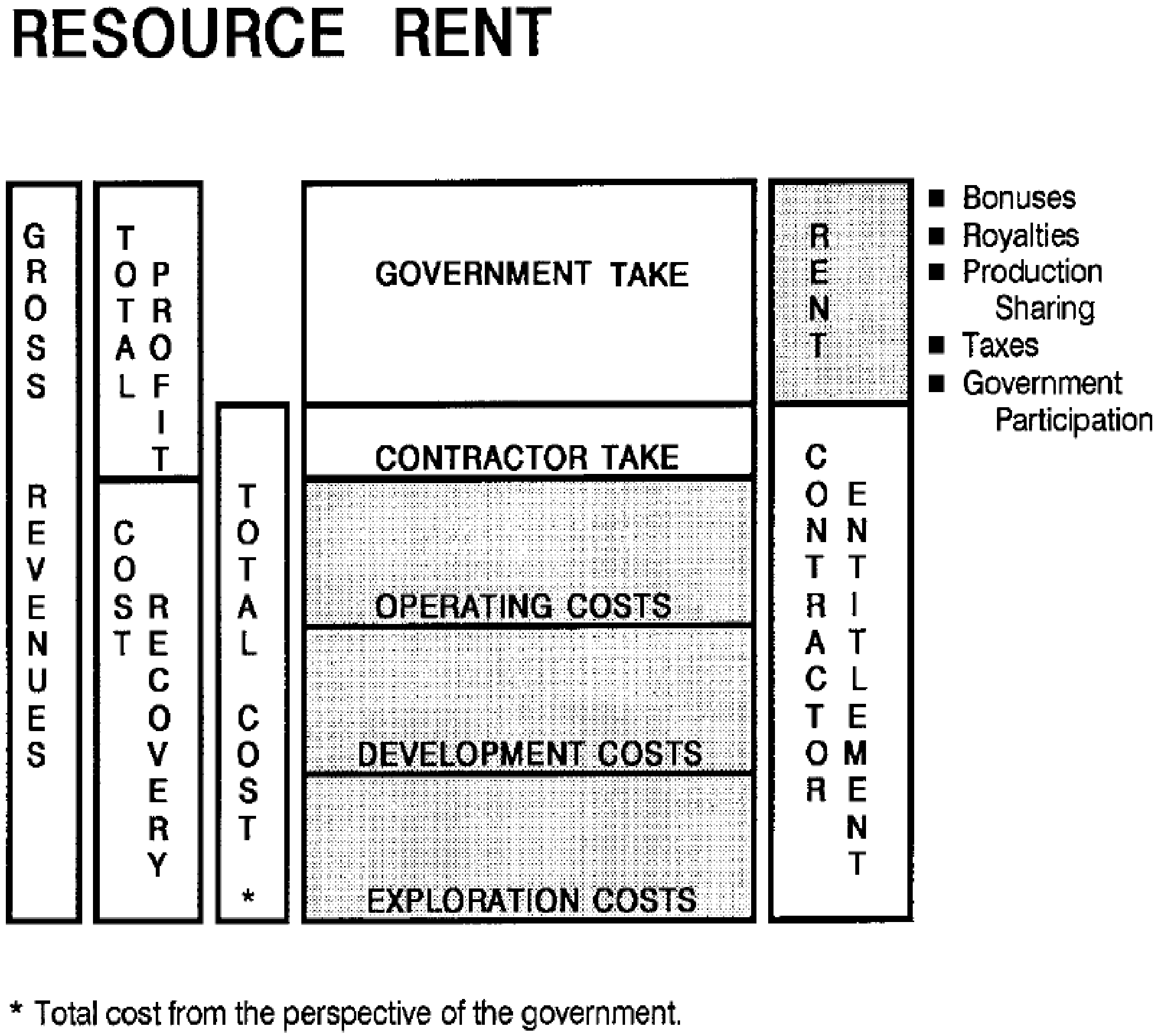
Interesting! They together can be a **two-headed beast** for negotiations

Risk - Reward Balance (easy said then done)



What is Economic Rent

- Economic Rent is the synonym of excess profit or surplus
- The theory focuses on produce from the earth derived by labor and capital
- Economic rent in the petroleum industry is the difference between the value of production and the costs to extract it
- The cost consists of normal exploration, development, operating costs and profit share for petroleum industry
- Government extracts economic rent through various levies, taxes, royalties and bonuses
- Oil companies are risk-takers and can limit risk through diversification whereas government on the other hand are not diversified
- From the government viewpoint there is a tradeoff between risk aversion, where bonuses and royalties are used, and risk sharing where taxation or production-sharing schemes are used.



What is Contractor Take....(1/2)

Contractor Take: The Common Denominator

- Division of profits boils down to what is called contractor and government take which are expressed in terms of percentages
- Contractor take is the percentage of profits to which the contractor is entitled whereas, Government take is the complement of that
- Contractor take focuses exclusively on the division of profits and correlates directly with reserve values, field size thresholds, and other measures of relative economics
- Under a system such as Indonesian production sharing contract the split of government vs contractor is 85% vs 15% but the contractor may still end up taking 35%-50% of share because of reimbursement of costs which is also known as *cost recovery*
- The main limitation of estimating take is that it is not always easy to account for other aspects of a given fiscal system, such as cost recovery limits, investment credits, royalty or tax holidays, and domestic market obligations (DMOs).

Contractor Take: Synonyms

- Company take
- Contractor marginal take
- Contractor share of profits
- Contractor after-tax equity split

Government Take: Synonyms

- State take
- Government marginal take
- Government share of profits
- Government after-tax equity split

What is Contractor Take….(2/2)

Contractor Take: The Common Denominator

The formula for calculating take is as follows:

Operating Income ($) = Cumulative gross revenues - cumulative gross costs over life of the project

Government Income ($) = All government receipts from royalties, taxes, bonuses, production, or profit sharing, etc.

Government Take (%) = Government income / operating income

Contractor Take (%) = 1 – Government take

Example of Calculation of Government and Contractor take

The values mentioned in the adjacent calculation are assumed to be retrieved from a cash flow projections

- Gross revenues are assumed to be $1000
- Cost over the life of the project is estimated to be $400

Gross revenues	$1,000	
Total costs	–400	Capital and operating
Operating income	600	Total profits
Royalties and taxes	$350	Government share
Net after-tax income	$250	Contractor share
Contractor take	42%	($250/$600)
Government take	58%	($350/$600)

Comparison of Terms—Selected Countries

Country	Contractor Take, % *	Cost Recovery Limit, %	Maximum Government Participation, %
Abu Dhabi (OPEC Terms)	9–12	100	0
Albania	20–25	45	0
Angola	20	50	50
Australia	40–50	100	0
Brunei	28–30	100	50
Cameroon	14–16	?	50
China	38–41	50–60	51
Colombia	30–37	100	51
Congo	30–35	100	50
Egypt	24–28	30–40	50
Gabon	20–25	40–55	10
India	30–42	100	30
Spain	60	100	0
Syria	18–22	25–35	0
Thailand	30–44	100	?
Indonesia	11–13	80	15[1]
Indonesia E.	30–33	80	15[1]
Ireland	75	100	0
Korea	36–40	100	0
Malaysia	14–19	50–60	15
Morocco	40–44	100	0
Myanmar	21–23[2]	40	0
New Zealand	47–51	100	0
Nigeria	10–18	40	?
Norway	18	100	?
Papua New Guinea	30–35	100	22.5
Philippines	44–47	70	0
Timor Gap	26	90	0
United States	42–53	AMT[3]	0
Vietnam	30	40	0

[1]Indonesia seldom exercises its right to participate.
[2]Tax holiday on first three years' production
[3]Alternative Minimum Tax
* Excludes Government participation — usually a carried interest.

Petroleum Fiscal Systems- Expected Monetary Value (EVM)

The equation of EMV effectively yields a weighted average. It is composed of the value of a possible discovery multiplied by the chance of making that discovery minus the risk capital times the probability that there will be no discovery.

$$\textbf{EMV} = (\textbf{Reward} \times SP) - [\textbf{Risk capital} \times (1 - SP)]$$

where

$$\begin{aligned}
EMV &= \text{Expected monetary value} \\
\textbf{Risk capital} &= \text{Bonuses, dry hole costs, G\&G, etc.} \\
SP &= \text{Success probability} \\
\textbf{Reward} &= \text{Present value of a discovery based on discounted cash flow analysis discounted at corporate cost of capital.}
\end{aligned}$$

Example of Calculation of EMV

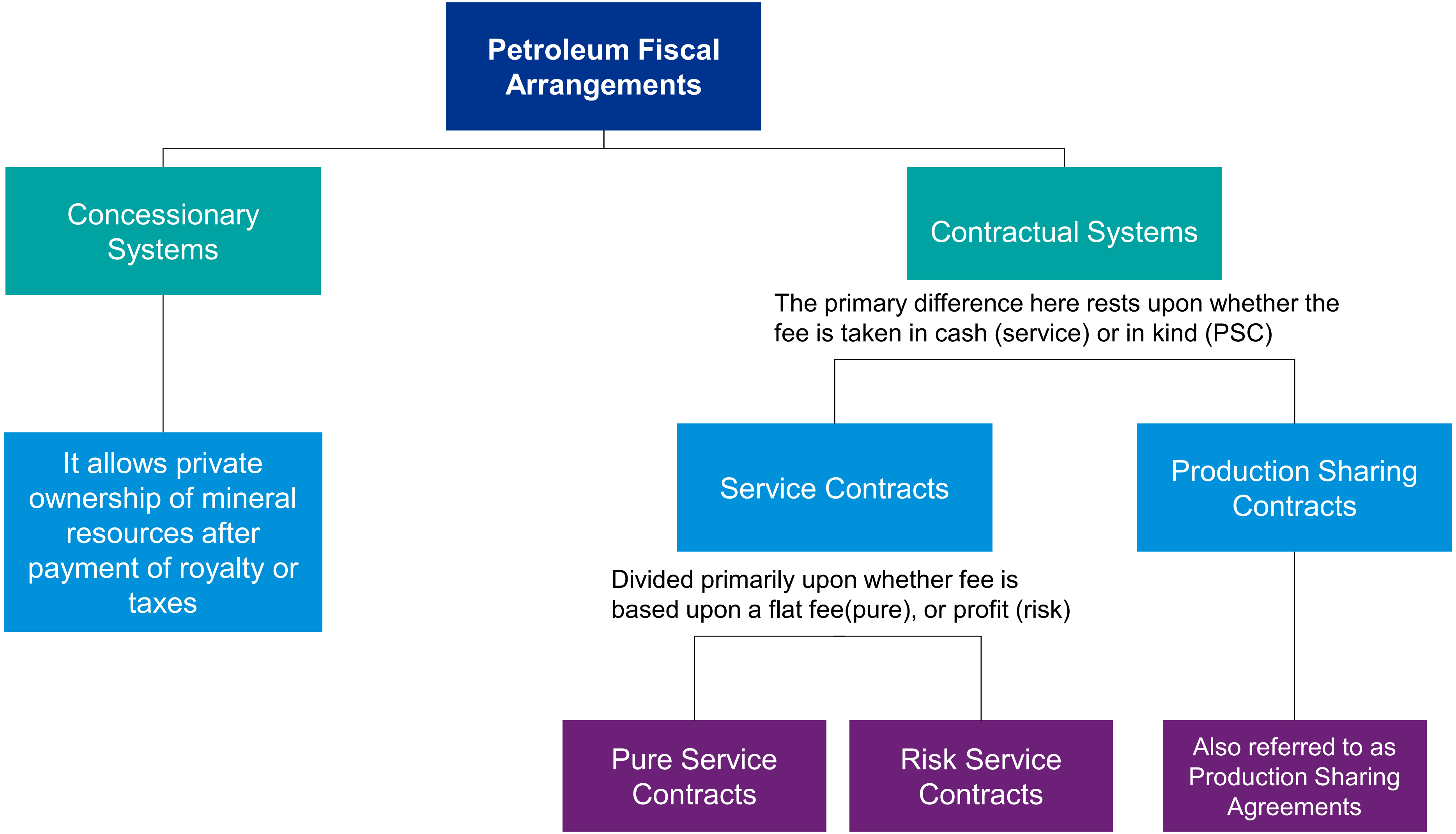
In order to calculate EMV, lets consider the following assumps:

- the discounted present value of a prospect is $120 million
- the dry-hole costs are $15 million
- the company believed this prospect had a 20% chance of success

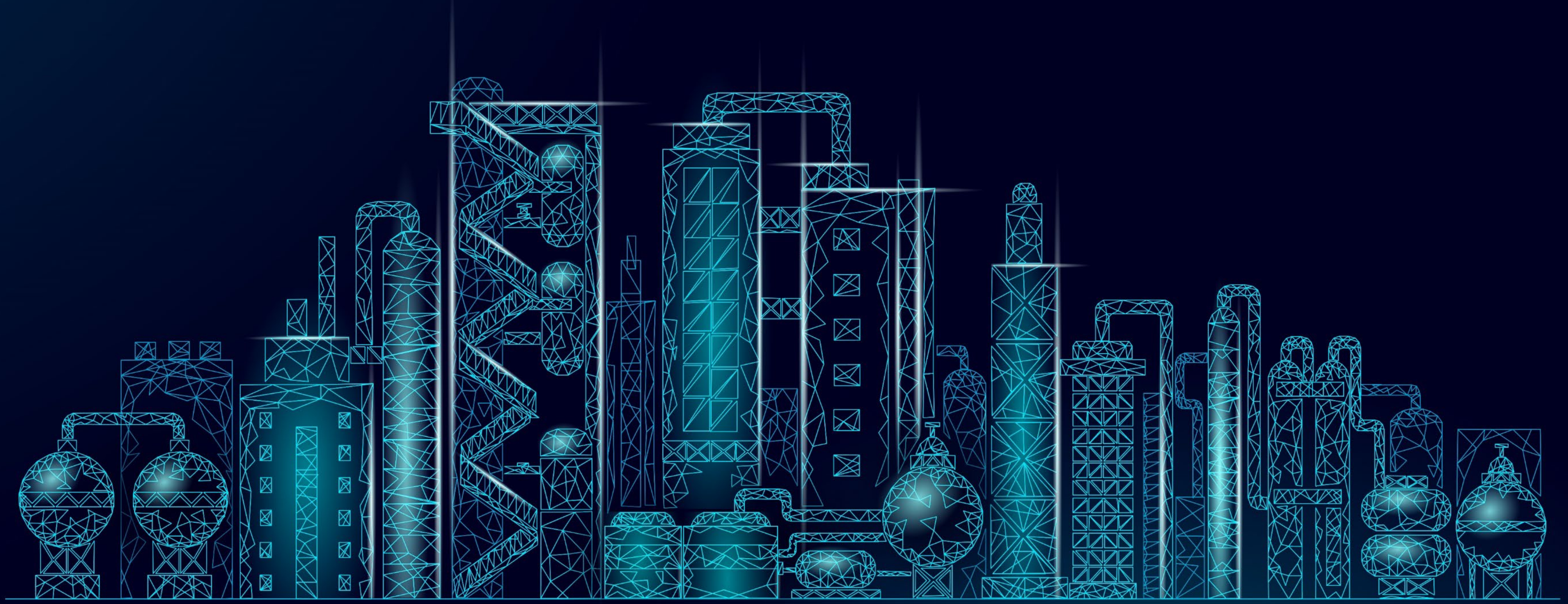
The expected value would be $12 million

$$\begin{aligned}
EMV &= (\textbf{Reward} \times SP) - [\textbf{Risk capital} \times (1 - SP)] \\
&= (\$120\ \text{MM} \times .20) - [\$15\ \text{MM} \times (1 - .20)] \\
&= \$12\ \text{MM}
\end{aligned}$$

Petroleum Fiscal Systems- Family Systems



Petroleum fiscal system 1 : Concessionary Systems



Concessionary Systems

Concessionary arrangements predominated through the early 1960s. The earliest agreements consisted of only a royalty payment to the state. The simple royalty arrangements were followed by larger royalties. Taxes were added once governments gained more bargaining power. In the late 1970s and early 1980s, a number of governments created additional taxes to capture excess profits from unexpectedly high oil prices.

The Concessionary system flows in the following way:

First: Royalties - The royalty comes right off the top. Gross revenues less royalty equals net revenue.

Second: Deductions - Operating costs; depreciation, depletion, and amortization (DD&A); and intangible drilling costs (IDCs) are deducted from net revenue to arrive at taxable income

Third: Taxation - Revenue remaining after royalty and deductions is called taxable income. With tax deductions the contractor share of gross revenues is obtained.

One Barrel of Oil
$20.00

Contractor Share		Royalties & Taxes
	20% Royalty →	$4.00
	$16.00	(Net revenue)
$9.00 ←	Deductions (Operating costs, DD&A, IDCs, etc.)	
	$ 7.00 (Taxable income)	
	Provincial Taxes (Ad valorem, severance, income) 10% →	$ .70
	$6.30	
	Federal income tax 40% →	$2.52
$3.78 ←	Net income after tax	
$12.78		$7.22
64%		36%

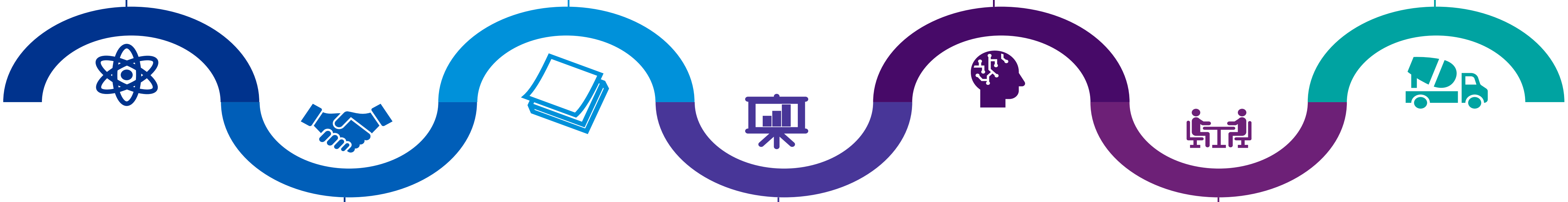
Basic Equations, Royalty/Tax Systems

Gross revenues	=	Total oil and gas revenues
Net revenues	=	Gross revenues
	–	royalties
Net revenue (%)	=	100% – Royalty rate (%)
Taxable income	=	Gross revenues
	–	Royalties
Deductions	–	Operating costs
	–	Intangible capital costs[1]
	–	DD&A (including abandonment costs)
	–	Investment credits (if allowed)
	–	Interest on financing (if allowed)
	–	Tax loss carry forward
	–	Bonuses[2]
Net cash flow (aftertax)	=	Gross revenues
	–	Royalties
	–	Tangible capital costs
	–	Intangible capital costs[1]
	–	Operating costs
	–	Bonuses
	–	Taxes

Petroleum fiscal system 2 : Production Sharing Contracts

Production Sharing Contracts

The 1st PSC was signed by IIAPCO in August 1966 with Permina (Indonesian National Oil Company). The features of the contract are:



- Title to the hydrocarbons remained with the state
- Permina maintained management control, and the contractor was responsible to Permina for execution of petroleum operations in accordance with the terms of the contract
- The contractor was required to submit annual work programs and budgets for scrutiny and approval by Permina
- The contract was based on production sharing and not a profit-sharing basis
- The contractor provided all financing and technology required for the operations and bore the risks
- During the term of the contract, after allowance for up to a maximum of 40% of annual oil production for recovery of costs, the remaining production was shared 65%/35% in favor of Permina. The contractor's taxes were paid out of Permina's share of profit oil
- All equipment purchased and imported into Indonesia by the contractor became the property of Permina. Service company and leased equipment were exempt

Production Sharing Contracts

The arithmetic hierarchy of a typical PSC system flows in the following way:

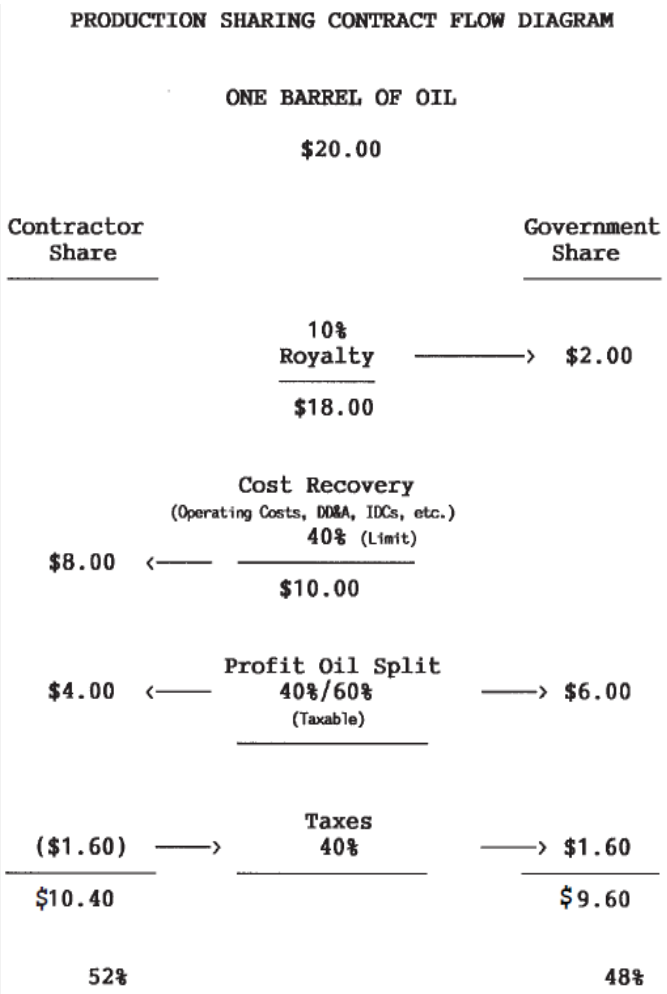
For illustration one barrel of oil is used

First: Royalties - The royalty comes right off the top just as it would in a concessionary system

Second: Cost Recovery - Before sharing of production, the contractor is allowed to recover costs out of net revenues. However, most PSCs will place a limit on cost recovery. From a mechanical point of view, the cost recovery limit is the only true distinction between concessionary systems and PSCs

Third: Profit Oil Split - Revenues remaining after royalty and cost recovery are referred to as profit oil or profit gas. The terminology is precise because of the ownership issue. The term *taxable income* implies ownership that does not exist yet under a PSC

Fourth: Taxes - The contractor's share of profit oil is then taxed at the applicable tax rates



Basic Equations, Contractual Systems

Gross revenues	= Total oil and gas revenues
Net revenues	= Gross revenues – Royalties
Net revenue (%)	= 100% – Royalty rate (%)
Cost recovery "Cost oil"	= Operating costs + Intangible capital costs[1] + DD&A (including abandonment costs) + Investment credits (if allowed) + Interest on financing (if allowed) + Unrecovered costs carried forward
Profit oil	= Net revenue – Cost recovery
Contractor profit oil	= Profit oil × Contractor percentage share
Government profit oil	= Profit oil × Government percentage share
Net cash flow (aftertax)	= Gross revenues – Royalties – Tangible capital costs – Intangible capital costs[1] – Operating costs + Investment credits – Bonuses – Government profit oil – Taxes
Taxable income	= Gross revenues – Royalties – Intangible capital costs[1] – Operating costs + Investment credits – Government profit oil – DD&A (including abandonment costs) – Bonuses[2]

Basic Elements of a PSC

The basic elements of a production sharing system are:

- many aspects of the government/contractor relationship may be negotiated but some are normally determined by legislation
- elements that are not legislated must be negotiated as more aspects that are subject to negotiation, the better it is
- Flexibility is required to offset differences between basins, regions, and license areas within a country
- The legislative body ordinarily has more authority than the national oil company or oil ministry empowered to negotiate contracts
- fiscal elements such as taxes are normally legislated, others are subject to negotiation and are defined in the PSC

Production Sharing Fiscal/Contractual Structure

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

*Those features most commonly associated with contractor take.

Basic Elements of a PSC

Work Commitment

- Work commitments are generally measured in kilometers of seismic data and number of wells
- Some instances where the work commitment may consist only of seismic data acquisition with an option to drill are referred to as seismic options
- The terms of the work commitment outline penalties for nonperformance
- The work commitment is a critical aspect of international exploration and embodies most of the risk of petroleum exploration
- There is only a 10%–15% chance of ever getting beyond the work commitment as many wells are dry

Bonus Payments

- Cash bonuses are sometimes paid upon finalization of negotiations and contract signing, hence the term signature bonus
- Apart from cash payments the bonus may also consist of equipment or technology
- Contracts that have bonus provisions can have many variations as not all PSC's have bonus requirement
- Production bonuses are paid when production from a given contract area or field reaches a specified level - usually some multiple of 1,000 BOPD
- A specified time period such as a month or quarter during which the average production rate must exceed the benchmark level to trigger the bonus payment

Sliding Scales

- A feature found in many petroleum fiscal systems is the sliding scale used for royalties, taxes, and various other items
- The most common approach is an incremental sliding scale based on average daily production
- Sometimes misconceptions arise when it is assumed that once production exceeds a particular threshold all production is subject to the higher royalty rate but sliding scale do not work that way unless specified
- Production levels in sliding scale systems must be chosen carefully in order to have a flexible sliding scale

Basic Elements of a PSC

Cost Recovery

- Cost recovery is the means by which the contractor recoups costs of exploration, development, and operations out of gross revenues
- Most PSCs have a limit to the amount of revenues the contractor may claim for cost recovery but will allow unrecovered costs to be carried forward and recovered in succeeding years
- Cost recovery limits or cost recovery ceilings, as they are also known, if they exist, typically range from 30%–60%
- The cost recovery mechanism is one of the most common features of a PSC and may only slightly differ from what used in concessionary systems
- A contractor under a PSC does not own the production, and therefore at the point of cost recovery has no taxable revenues against which to apply deductions
- government reimburses the contractor for costs through the cost recovery mechanism and then shares the remaining revenues with the contractor

Exceptions

- While the cost recovery treatment is common in the universe of PSCs and service agreements, there are exceptions to every rule
- Some contracts have no limit on cost recovery like the 2nd generation Indonesian PSC
- One exception is of few PSCs having no cost recovery
- Another exception is where excess cost oil goes directly to the government though its quite a rare feature
- Example of no cost recovery PSC was Peruvian model contract between the time period of 1971 to 1978
- Example of excess cost oil was by the Egypt during the Nile Delta licensing round in 1989

Tangible vs. Intangible Capital Costs

- Sometimes a distinction is made between depreciation of fixed capital assets and amortization of intangible capital costs
- Under some concession agreements, intangible exploration and development costs are not amortized
- Rare cases where intangible capital costs are written off immediately can be an important financial incentive
- Most systems will force intangible costs to be amortized leading to longer time for cost recovery with revenues being subjected to taxation at the early production stage
- Depreciation rates are the other primary limitation to the rate of recovery of capital costs and true for all fiscal systems that require capitalization of costs

Basic Elements of a PSC

Interest Cost Recovery

- Sometimes interest expense is allowed as a deduction
- It can include interest during construction, or a rate based on cumulative unrecovered capital
- Under a PSC this is referred to as interest cost recovery whereas, Some systems limit the amount of interest expense by using a theoretical capitalization structure such as a maximum 70% debt
- In Papua New Guinea, the government limits the interest deduction with a capitalization restriction based on a 2/1 debt/equity ratio
- China allows recovery of a 9% annual deemed interest rate on development costs which is compounded annually and recovered through cost recovery

General & Administrative Costs

- Many systems allow the contractor to recover some home office administrative and overhead expenses
- Nonoperators are normally not allowed to recover such costs
- Contractors in Indonesia are limited to 2% of gross revenues for G&A cost recovery
- The 1989 Myanmar model contract had a sliding scale allowance for G&A based on total petroleum costs each year
- In China an annual overhead charge is allowed for offshore exploration at a rate of 5% on the first $5 million per year, dropping down to 1% for costs above $25 million

UNRECOVERED COSTS CARRIED FORWARD

- Most unrecovered costs are carried forward and are available for recovery in subsequent periods which is also true for unused deductions
- The term sunk cost is applied to past costs that have not been recovered
- Many PSCs do not allow preproduction costs to begin depreciation or amortization prior to the beginning of production, so there is no TLCF
- The importance of sunk costs and development feasibility centers on an important concept called commerciality
- The financial impact of a sunk cost position on the development decision can be easily determined with discounted cash flow analysis

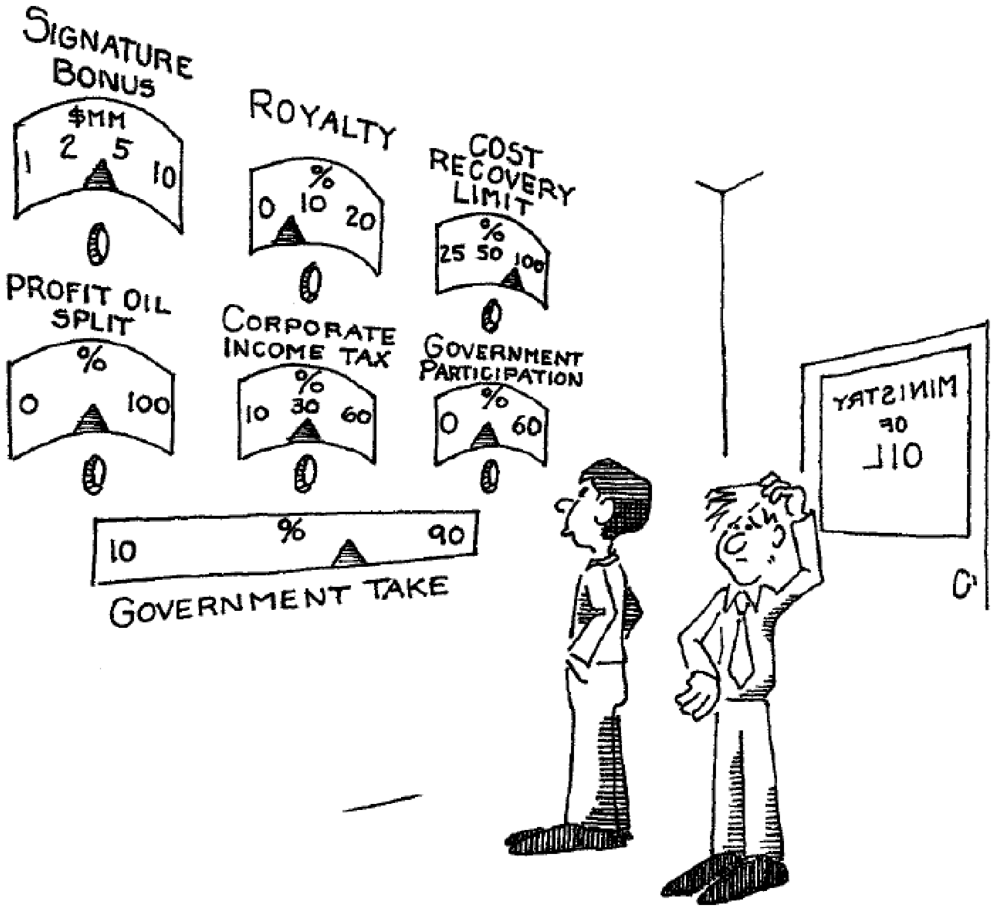
Basic Elements of a PSC

- The issue of ownership adds an interesting flavor to the concept of abandonment liability
- Under most PSCs the contractor cedes ownership rights to the government for equipment, platforms, pipelines, and facilities upon commissioning or startup
- The government as owner is theoretically responsible for the cost of abandonment and end up paying abandonment costs though indirectly
- Abandonment costs are recovered through cost recovery just as the costs of exploration, development, .and operations
- Anticipated cost of abandonment is accumulated through a sinking fund that matures at the time of abandonment

Abandonment Costs

- Profit oil is split between the contractor and the government, according to the terms of the PSC which are sometimes negotiable
- Published government or contractor take figures refer to the after-tax split
- When evaluating fiscal terms, the focus is on division of profits - the government / contractor take
- Geopotential, costs, infrastructure, political stability, and other key factors that influence business decisions are weighed against contractor take
- Governments are not totally responsible for determining the appropriate division of profits and contract terms as oil companies help define what the market can bear

Profit Oil Split and Taxation



Basic Elements of a PSC

Royalties

- Royalties are a fundamental concept, and the treatment is similar under almost all fiscal systems- though there are some exotic variations they are rare.
- Some systems will allow a netback of transportation costs. This occurs when there is a difference between the point of valuation for royalty calculation purposes and the point of sale
- The concept of a royalty should be foreign to a PSC because of the ownership issue. Many PSCs do not have a royalty and the ones that do have a range as high as 15%.
- Payment of a royalty implies ownership on the part of the royalty payer but in a PSC, the contractor has no ownership at this stage.
- In the Philippines, given sufficient level of Filipino ownership the government pays the contractor group 7.5% of gross revenues. This part of the contractor fee is equal to or viewed as a *negative royalty.*
- In New Zealand a hybrid royalty scheme has been proposed. Either a 20% Accounting Profits Royalty (APR) is levied or a 5% Ad Valorem Royalty (AVR), whichever is higher.
- A specific rate royalty is a fixed amount charged per barrel or per ton. This kind of royalty is relatively rare, but it may also go by another name, such as “export tariff,” like that found in the former Soviet Union (FSU)
- Another aspect of royalties that contributes to their lack of popularity with industry is that they can cause production to become uneconomic prematurely. This works to the disadvantage of both industry and government

Basic Elements of a PSC

Commerciality

- An important aspect of international exploration is the issue of *commerciality* as it deals with who determines whether or not a discovery is economically feasible and should be developed
- There are often situations where accumulated exploration expenditures are so substantial that by the time a discovery is made, the sunk costs have a huge economic impact on the development decision
- From the contractor's perspective the sunk costs will flow through the cost recovery and they can represent a considerable value. The government is also concerned as if the cost recovery it too great then the government might end up with a small percentage of gross production
- Some regimes will simply allow the contractor to decide whether or not to commence development operations whereas other systems have a *commerciality requirement*
- Commerciality requirement essentially places the burden of proof on the contractor as to whether or not development of a discovery is economically beneficial for both the contractor and the government
- The benchmark for obtaining commercial status for a discovery is usually a predetermined percentage of gross take for the government
- Under many commerciality clauses, a discovery cannot be developed unless it is granted commercial status by the host government. The grant of commercial status marks the end of the exploration phase and the beginning of the development phase of a contract

Basic Elements of a PSC

Government Participation

Many systems provide an option for the national oil company to participate in development projects. Under most government participation arrangements, the contractor bears the cost and risk of exploration. If there is a discovery, the government backs-in for a percentage. In other words, the government is *carried through exploration.* Both the Indonesian and Malaysian PSCs have government participation clauses, but Indonesia rarely exercises its option to participate.

The key aspects of government participation are:

• What percentage participation? (Most range from 10%–51%)

• When does the government back in? (Usually once a discovery has been made)

• How much participation in management? (Large range of degree of participation)

• What costs will the government bear? (Usually only their prorated share of development costs)

• How does government fund its portion of costs? (Often out of production)

Basic Elements of a PSC

Investment Credits and Uplifts

Some systems have incentives, such as investment credits or uplifts. Uplifts and investment credits are two names for the same basic concept. An uplift allows the contractor to recover an additional percentage of capital costs through cost recovery. It works the same way in a concessionary system.

For example, an uplift of 20% on capital expenditures of $100 million would allow the contractor to recover $120 million.

Domestic Obligation

Many contracts have provisions that address the domestic crude oil or natural gas requirements of the host nation. These provisions are often referred to as the domestic supply requirement or domestic market obligation (DMO)

Usually, they specify that a certain percentage of the contractor's profit oil be sold to the government. The sales price to the government is usually at a discount to world prices. The government may also pay for the domestic crude in local currency at a predetermined exchange rate. Revenues from sale of domestic crude are normally taxable

RINGFENCING

Ordinarily all costs associated with a given block or license must be recovered from revenues generated within that block. The block is *ringfenced*. This element of a system can have a huge impact on the recovery of costs of exploration and development. Indonesia requires each contract to be administered by a separate new company. This restricts consolidation and effectively erects a ringfence around each license area.

India allows exploration costs from one area to be recovered out of revenues from another, but development costs must be recovered from the license in which those costs were incurred.

From government perspective any cost that crosses the ringfence means unsuccessful operation. However, allowing exploration costs to cross the fence can be a strong financial incentive for the industry.

Basic Elements of a PSC

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

In France the level of taxation was effectively reduced when the company reinvested a certain portion of income. This approach is not as harsh as a firm obligation. The objective, of course, is to get companies to spend more in-country and repatriate less of their profits. Reinvestment obligations or reinvestment incentives are fairly rare.

REINVESTMENT OBLIGATIONS

Governments can enact legislation or issue decrees that are designed to attract additional investment. Tax or royalty holidays are often used for this purpose. These specify that for a given holiday period, royalty or taxes are not payable.

When reviewing fiscal terms that have time limitations, the starting point is as important as the time period. In some instances, the holiday begins on the effective date of the contract, or on a specific calendar date. In other cases, the holiday may begin with production startup.

There are some basic rules of a tax holiday has no impact if no discovery is made or if there is no production. A reduction in levies, taxes, or royalties will always be beneficial to the petroleum industry, and the holiday almost always comes at the early stage of production when it does the best in terms of present value.

TAX AND ROYALTY HOLIDAYS

THE INDONESIAN PSC

Evolution of Indonesian Contract

The Mining Law of 1960, Law No. 44 Concerning Oil and Gas Mining, clarified the status of foreign oil companies as contractors.

This was founded on the 1945 Constitution Article 33, which placed the nation's natural wealth within the jurisdiction of the state.

This set the stage for development of the Indonesian PSC in all its variations.

Cost Recovery

Cost recovery limit has changed dramatically through the years in Indonesia. The first gen contract in 1960 had 40% limit compared to second generation in 1976 having no limit. Cost is recovered normally on first-in first-out basis

No Royalty $

The Indonesian PSCs are characterized in part by the lack of a royalty. However, some people refer to the first tranche petroleum (FTP) as the equivalent of a royalty

INDONESIAN DMO ADJUSTMENT

The Indonesian DMO requires the contractor to sell 25% of the contractor's share oil to Pertamina. After 60 months of production from a given field, the price the contractor receives for the DMO crude is 10% of the realized price. The obligation is referred to as the *DMO adjustment.* The DMO adjustment could theoretically exceed the contractor's share of profit oil.

First Trache Petroleum (FTP)

The fourth-generation contracts in 1988–89 incentive packages, a new contract feature called as FTP. The 1st element requires that 20% of production be shared in 71.14%/28.84% in favor of government before cost recovery. The contractor share of first tranche petroleum is taxed at the effective rate of 48%. The result is that 3% of gross production goes to the contractor and 17% goes to the government. The remaining 80% of production is available for cost recovery.

Hence the FTP works exactly like a cost recovery limit.

INVESTMENT CREDITS AND UPLIFTS

The Indonesian contracts have allowances for investment credits (ICs) and uplifts. The difference between the two is that the uplift applies to all capital costs, and the IC does not. The IC and the uplift are otherwise similar. The IC applies only to facilities such as platforms, pipelines, and processing equipment. This excludes drilling costs and completion costs. In Indonesia the investment credit is immediately recoverable and need not be depreciated like the costs.

IC also reduces the ultimate profit oil split for both the contractor and the host.

THE INDONESIAN PSC

NEW OIL VS. OLD OIL

In Indonesia, when discussing the domestic market obligation (DMO), the terms new oil and old oil are used. The first 60 months of production from a field is new production, and the contractor receives market price for the DMO crude. After that the production is referred to as old oil, and the DMO crude sells to the government for 10% of market price.

Older contracts pegged the DMO price at **20¢/bbl**.

Some old PSC in Indonesia are either expiring or renegotiated as the earlier PSC are till date receiving 20¢/bbl for the old DMO crude. The new fields discovered after a certain date will now receive 10% of the Market Price for DMO post 60 months of production.

INDONESIAN CRUDE PRICES

Production is shared in kind (barrels), and it is necessary to determine a price to convert oil to dollars in order to calculate cost recovery, taxes, and internal transfers. Terminology and methodology have changed over the years, but the current method uses the Indonesian Crude Price (ICP), which has been in effect since April 1989.

The ICP is determined by the government monthly, based on a moving average spot price of a basket of five internationally traded crudes:

- Indonesian (Minas)
- Malaysian (Tapis)
- Australian (Gippsland)
- UAE (Dubai)
- Oman

Tax calculations are based on ICP, and cash flow is based upon actual realized prices.

In the long run, ICP and realized prices will average out any differences.

Bonuses

Bonuses are negotiated for each contract and consist of signature or signing bonuses as well as production bonuses. In the past the Indonesian bonuses payments have been relatively modest. Bonuses are not recoverable through cost recovery, but they are deductible against income and withholding taxes.

THE INDONESIAN PSC - CONTRACTS OF WORK

The predecessors of the PSC are the early contracts of work, a fairly outmoded term that is nearly synonymous with PSC. The early contracts in Indonesia were referred to as such but had virtually all the elements of a PSC or a risk service agreement. The modern PSC in Indonesia is much more complex, but this is where it began.

1954

Original model of future contracts signed with Stanvac

1963

Contracts of work signed by Stanvac, Shell, and CalTex

- 60%/40% Split after Cost Recovery

1966

First Generation PSC—Basic PSC Signed with IIAPCO

- 40% Cost recovery limit
- 65%/35% Split inclusive of taxes in favor of government 67.5%/32.5% Above 75,000 BOPD
- 25% Domestic Market Obligation (DMO) full price for first 5 years of production, 20¢/bbl thereafter

1976

Second Generation PSC

- 100% Cost recovery (no limit)
  - 10-year amortization of noncapital costs (SLD)
  - 14-year depreciation of capital costs (DDB)
- 85%/15% Split inclusive of taxes in favor of government
- 20% Investment credit
- 25% DMO 20¢/bbl after 60 months

1978

Changes: Decree 267

- Taxes became payable:

  Effective 56% tax
  - 45% Tax on net income
  - 20% Tax on distributable income after-tax (withholding)
- 85%/15% Split (Oil) determined on after-tax basis

  Oil 65.9091%/34.0909% in favor of the government
- 70%/30% Split (Gas) determined on after-tax basis

  Gas 31.8181%/68.1818% in favor of the contractor

THE INDONESIAN PSC - CONTRACTS OF WORK

1984

Third Generation PSC—New Tax Laws—Decree 458

- 17% Investment Credit
- **Effective 48% tax**
  - 35% Tax on net income
  - 20% Tax on distributable income after-tax (withholding)
- Depreciation: Oil 7-year DDB (switching to SLD in year 5) Gas 14-yr DDB (switching to SLD)
- 85%/15% Equity split (Oil) Oil 71.1538%/28.8462% in favor of the government
- 70%/30%–65%/35% Equity split (Gas) Gas 57.6923%–67.3077% Contractor pretax share

1988-1989

Changes—Fourth Generation PSC—Incentive Packages

- First Tranche Petroleum 20%
- Depreciation: Oil, 5-year DB; Gas, 8-year DB
- Commerciality requirement excluded
- 17% Investment credit
- DMO priced at 10% of export price
- Equity split in frontier areas 80%/20% up to 50,000 BOPD also for marginal fields with less than 10,000 BOPD
- Deepwater investment uplift 110% for Oil, 55% for Gas

1994

Eastern Frontier Incentive Package

- Equity split in Eastern Indonesia 65%/35%

THE INDONESIAN PSC

JOINT OPERATING AGREEMENTS/JOINT OPERATING BODY (JOA/JOB)

In the 1970s Pertamina introduced a joint venture arrangement where the contractor participates as a 50%/50% partner with the government in areas previously under Pertamina's control. The first such contract was signed in 1977, and many have been signed since then.

Typically the contractor matches previous expenditures for the area or funds 100% of future operations for a given period such as two to three years, whichever is greater. After that, the contractor and Pertamina split exploration, development, and operating costs 50%/50%. Oil production is also shared on a 50%/50% basis. The contractor's 50% share of the production then is subject to the standard PSC terms, i.e., the 85%/15% split, and the FTP, DMO, ICs, etc.

The JOA type of joint venture is administered by a Joint Operating Body (JOB) comprised of three representatives each from the contractor and Pertamina.

SENSITIVITY ANALYSIS OF THE INDONESIAN PSC

The complexity of the Indonesian PSC provides a good example for evaluating the economic sensitivity of various contract elements. Cash flow analysis was performed on a 50-MMBBL field development scenario. The basic assumptions are outlined in
Table.

In order to gauge the effect of the DMO and the investment credit, hypothetical scenarios were developed. Three cash flow projections excluded the DMO and the IC. These scenarios yielded pure splits between the government and the contractor of 84%/16%, 85%/15%, and 87%/13% respectively. The resulting present values from the cash flow projections provided the basis of comparison. This is shown in the table ahead.

THE INDONESIAN PSC

Indonesian PSC Sensitivity Analysis Model Input Parameters

INPUT	
Field size	50/MMBBLS
Peak production rate	19,000 BOPD
Lambda (% of reserves produced in peak year)	14%
Decline rate	12%
Field life	15+ Years
Initial oil price	$18.00/bbl 4% Escalation
Development capital costs	$108 MM * $2.15/bbl
Operating costs	
Fixed	$6 million/year
Variable	$1/bbl
Total	First year $1.85/bbl

RESULTS based upon standard contract terms	
Net present value (15% DCF)	$27 million $0.52/bbl
Internal rate of return	28%
Return on investment	152%
Payout	5 Years

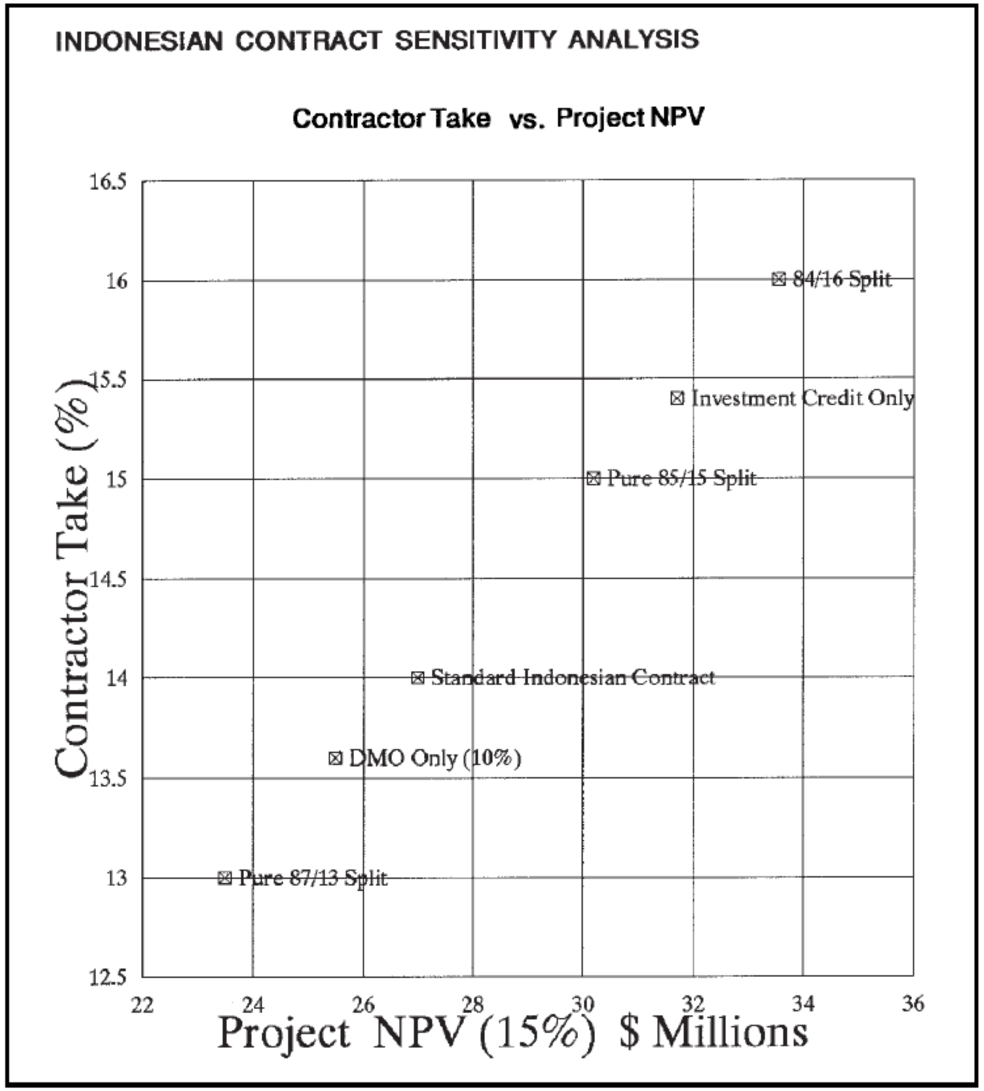
*50% of capital costs are assumed to be eligible for the 17% investment credit.

Indonesian PSC Sensitivity Analysis Results

	NPV 15% ($M)	Equivalent Contractor After-tax Take (%)	
Pure 84/16 Split Contractor 30.7692%* No DMO No investment credit	33,543	16.0%	Pure Split
Investment Credit Only Contractor 28.8462%* 17% investment credit No DMO	32,900	15.3%	Effective
Pure 85/15 Split Contractor 28.8462%* No DMO No investment credit	30,192	15.0%	Pure Split
STANDARD CONTRACT Contractor 28.8462%* DMO = 10% of wellhead price 17% investment credit	26,996	14.0%	Effective
DMO Only Contractor 28.8462%* 10% of wellhead price No investment credit	25,492	13.6%	Effective
Pure 87/13 Split Nonstandard terms Contractor 25.00%* No DMO No investment credit	23,490	13.0%	Pure Split

Indonesian effective tax rate of 48% assumed in all cases.
* Contractor pre-tax profit oil share

THE INDONESIAN PSC



The project present value of the standard Indonesian contract terms (which included the DMO and the IC) fell about halfway between the results of the pure 85%/15% split and the 87%/13% split. The present value of the standard contract terms discounted at 15% is $26.9 million. The pure 85%/15% split had a present value of $30.2 million. The effect of the DMO alone pulled the effective split down to an equivalent 86.4%/13.6% split.

The DMO is nearly invisible from the exploration perspective. Because of the present value effect, the DMO also has little influence on development feasibility economics. However, after five years of production, the DMO exerts a stronger influence

Petroleum Fiscal Systems

Valuation Rule of Thumb

The valuation rule of thumb should be used with caution for the contractors take

- Proved, developed, producing (PDP) reserves are worth from one-half to two-thirds of the wellhead price times the contractor’s take
- The valuation rule of thumb is used to make a quick estimate of the present value of a contractor’s working-interest share of PDP reserves, assuming there are no major sunk costs available for cost recovery
- Proved, undeveloped (PUD) reserves will be worth much less as the value of undeveloped reserves is usually less than half of the value of PDP reserves

Most of the science of fiscal-system analysis deals with exploration economics and, to a lesser extent, development and production economics. Therefore, the changing perspectives are a key consideration

Negotiations

Governments have devised numerous frameworks for extracting economic rent from the petroleum sector. Some are well balanced, efficient, and cleverly designed. Some will not work

The result of government efforts are sometimes referred to *as fiscal marksmanship* - either poor or good

The purpose of fiscal structuring and taxation is to capture all economic rent which is consistent with giving the industry a reasonable share of profit or take

Thus, the issue of the division of profits lies at the heart of contract / license negotiations

THE INDONESIAN 85% / 15% SPLIT

The most famous government/contractor take statistic is the Indonesian 85% / 15% split. The reason behind it being so important is that Indonesia has no royalty.

The calculation is based on two mechanism:

- A profit oil split of 71.1538% / 28.8462% in favor of the government
- An effective tax rate of 48%

This is the result of a double layer of taxation: 35% income tax and 20% withholding tax levied after income tax.

The effect of this production sharing/tax arrangement in Indonesia is that of an aggregate 85% tax rate. The government share of profit oil could simply be viewed as another layer of taxation.

Because there is no royalty, the division of production is the same regardless of the amount of costs as long as the contractor is able to recover all costs. This is why the 85% / 15% split in Indonesia is so well known.

Example of Calculation of Indonesian PSC Entitlement

Gross production = 100 MMBBLS

Royalty = 0%

Costs oil for recovery of costs = 35 MMBBLS

100.00 MM	Gross production
–35.00	Cost recovery
65.00	Total share oil
–46.25	Government share 71.1538%
18.75	**Contractor share 28.8462%**
– 9.00	Aggregate tax rate 48%
9.75	Contractor after-tax share
+35.00	Cost recovery
44.75 MM	**Contractor total financial entitlement**
53.75 MM	**Contractor legal entitlement = (35 + 18.75)**
15.00%	**Contractor take**
	(Contractor after-tax share ÷ Total share oil)

Petroleum fiscal system 3 : Risk Service Contracts

Risk Service Contracts

Service contracts are based on a simple formula: The contractor provides all capital associated with exploration and development of petroleum resources. In return, if exploration efforts are successful, the government allows the contractor to recover those costs through sale of the oil or gas and pays the contractor a fee based on a percentage of the remaining revenues.
By 1994 service agreements were being used in Argentina, Brazil, Chile, Ecuador, Peru, Venezuela, and the Philippines. In Peru either the service contract or a concession could be used.

When the term service contract is used it is normally understood to be a risk service contract. The term risk contract is also used. The term risk service is widely accepted but rather inappropriate. The added term risk is clearly an improvement. Because the contractor does not get a share of production, such terms as production sharing and profit oil are not appropriate even though the arithmetic will often carve out a share of revenues in the same fashion that a PSC shares production.

The distinction between PSCs and risk service contracts is minute. The nature of the payment for the contractor's services is the point of distinction. Other than that, the arithmetic and terminology are quite similar. This is why many service agreements are commonly referred to as PSCs. The Philippine risk service contract is a perfect example.

Risk Service Contracts- PHILIPPINE RISK SERVICE CONTRACT

The language of the Philippine contract is identical to that of most PSCs with the exception of the Filipino Participation Incentive Allowance (FPIA). The FPIA is part of the service fee, and it is based on gross revenues just like a royalty except that it goes to the contractor group. The FPIA, based on a sliding scale, can get as high as 7.5% if Filipino participation is 30% or more onshore. Offshore, 15% Filipino participation will qualify for the FPIA.

The Philippine contract has a 70% cost recovery limit, and profit sharing is 60%/40% in favor of the government. The contractor 40% share of profits is not subject to taxation. The contractor's taxes are paid out of the government share of profit oil.

Calculation of the contractor entitlement under the Philippine contract is based on the following assumptions:

Gross revenues = $100 million
Assume Contractor Group eligible for full 7.5% FPIA
Costs eligible for cost recovery =
$50 million – high cost case
$20 million – low cost case

Low Cost Case	High Cost Case	
$100.0 MM	$100.0 MM	Gross revenues
–7.5	–7.5	FPIA service fee
92.5	92.5	Net revenues
–20.0	–50.0	Costs recovery
72.5	42.5	Revenues available for sharing
–43.5	–25.5	**Government 60% share**
29.0	17.0	Contractor 40% share
+7.5	+7.5	FPIA
$36.5	$24.5	Total contractor service fee
+20.0	+50.0	Costs recovery
$56.5 MM	$74.5 MM	**Total contractor entitlement**
45.6%	**49.0%**	**Contractor take**

Risk Service Contracts- ECUADOR RISK SERVICE CONTRACT

Ecuador uses an R factor calculation for its service contract. The contractor's entitlement is based on costs recovery and a service fee that is taxed at a rate of 40%. Part of the fee calculation is based on a formula consisting of a sliding scale R factor. An unusual aspect of the Ecuador service fee is that it is calculated before the normal cost recovery arithmetic found in most PSCs and service agreements. It is not as progressive as the Philippine FPIA, but it is a step in the same direction.

The formula for the service fee is as follows:

TS = PR(INA) + R(P-C)Q

Where:

TS = Annual Service Fee payment in U.S. dollars

PR = Average Prime Rate (decimal fraction)

INA = Development and Production Costs less reimbursements

P = Average International Crude Price ($/bbl)

C = Production Costs ($/bbl)

Q = Annual Production (MMBBLS), for *R* factor calculation (BOPD)

R = Average Profit Factor (decimal fraction)
= (R1(Q1) + R2(Q2)) / (Q1 + Q2), etc.

A sample calculation of contractor entitlement is shown next. It starts with the contractor service fee calculation. The assumptions are outlined as follows:

TS = PR(INA) + R(P – C)Q

Where:

PR = 10% (.10)

INA = $25 million (assumed)

Q = 6 MMBBLS (assumed) = average 16,438 BOPD

R = (.30 × 10,000 + .25 × 6,438)/16,438 = .2804

P = $16.00/bbl (assumed)

C = $10 MM (assumed) = $1.67/bbl

TS = .10 × $25 MM + .2804($16.00 – $1.667) × 6MM

= $2.5 MM + $24.114 MM

= $26.61 MM

Risk Service Contracts- ECUADOR RISK SERVICE CONTRACT

The contractor entitlement is based upon the after-tax service fee and cost recovery. The step-by-step calculation of the entitlement is shown as follows:

$26.61 MM	-Service fee
-2.50	-Incentive deduction (PR × INA)
$24.11 MM	-Taxable income
-9.64	-Income tax (40%)
+2.50	-(PR × INA)
$16.97 MM	-Service fee after-tax
+20.00	-Assumed cost recovery
$36.97 MM	-Total contractor entitlement

The contractor's share came to $16.97 million, and contractor take therefore is 22.3% ($16.97/$76 MM, considering $76 MM as revenue available for sharing)

Because of the way the service fee is calculated, the system is fairly progressive. Had the capital costs been higher, the contractor take would also have been higher. This is because of the hierarchy of the calculation and the nontaxable element of the service fee based upon PR × INA. The sliding scale R factor is modestly progressive, but the way the service fee is calculated, the government share flexes upward and downward to accommodate variations in profitability.

Risk Service Contracts- RATE OF RETURN CONTRACTS

Contracts with flexible terms are becoming standard. There are many advantages for both the host government and the contractor with contracts that encompass a range of economic conditions. This is the acid test.

The most common method used for creating a flexible system is with sliding scale terms. Most sliding-scale systems trigger on production rates. As production rates increase, government take, in one fashion or another, increases. This theoretically allows equitable terms for development of both large and small fields.

Some contracts will provide flexibility through a progressive tax rate. Others will tie more than one variable to a sliding scale such as cost recovery, profit oil split, and royalty. There are many sliding scales. One of the more unusual is the Guatemala contract of the late 1980s with a sliding scale royalty based on variations in crude quality. The royalty rate increases or decreases one percentage point every degree above or below 30º API crude gravity.

Flexible Contract Terms and Conditions

Contract Terms Subject to Sliding Scales	Factors and Conditions That Trigger Sliding Scales
■ Profit Oil Split	■ Production Rates
■ Royalty	▲ Water Depth
■ Bonuses	▲ Cumulative Production
▲ Cost Recovery Limits	▲ Oil Prices
▲ Tax Rates	▲ Age or Depth of Reservoirs
♦ Uplifts	▲ Onshore vs. Offshore
	▲ *R* Factors*
	▲ Remote Locations
	♦ Oil vs. Gas
	♦ Crude Quality (Gravity)
	♦ Time Period (History)
	♦ Distance from shore
	♦ Rate of Return*
■ Most Common	*Rate of Return Contracts
▲ Less Common	
♦ Rare	

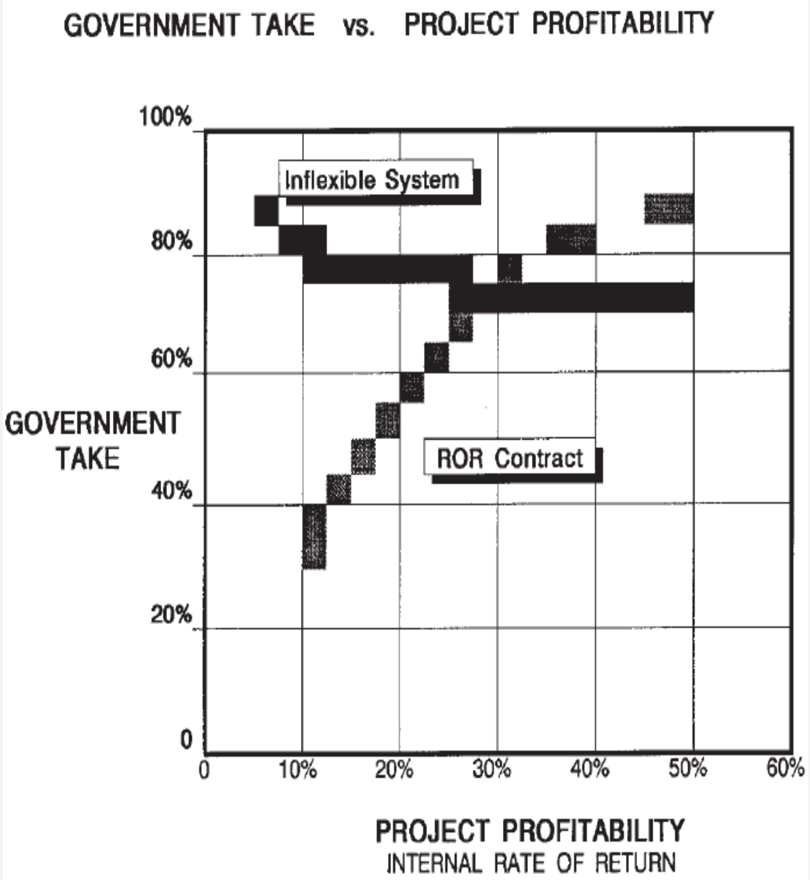
Risk Service Contracts- RATE OF RETURN CONTRACTS

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

Inflexible systems with high royalty rates can work in just the opposite way. A stiff nonnegotiable royalty is the antithesis of flexibility. Even a progressive sliding-scale royalty scheme can be regressive

Just because the royalty rate becomes progressively larger with some pseudomeasure of profitability, such as production rates, royalties are so strongly regressive that with most marginal discoveries, government take is invariably higher. There are many systems that exhibit this characteristic of reverse *flexibility*.

Some countries have developed progressive taxes or sharing arrangements based on project rate of return (ROR). The effective government take increases as the project ROR increases.



The ROR approach is characterized by a modest royalty and tax. The state receives no other funds until the oil company has recovered the initial financial investment plus a predetermined threshold rate of return. Theoretically, this rate of return would represent a minimum rate to encourage investment. The government share is calculated by accumulating the negative net cash flows and compounding them at the threshold rate until the cumulative value becomes positive. When that happens, additional taxes are levied, but the contractor still receives some of the profits in excess of the threshold rate of return. These additional taxes are often referred to as resource rent taxes (RRT).

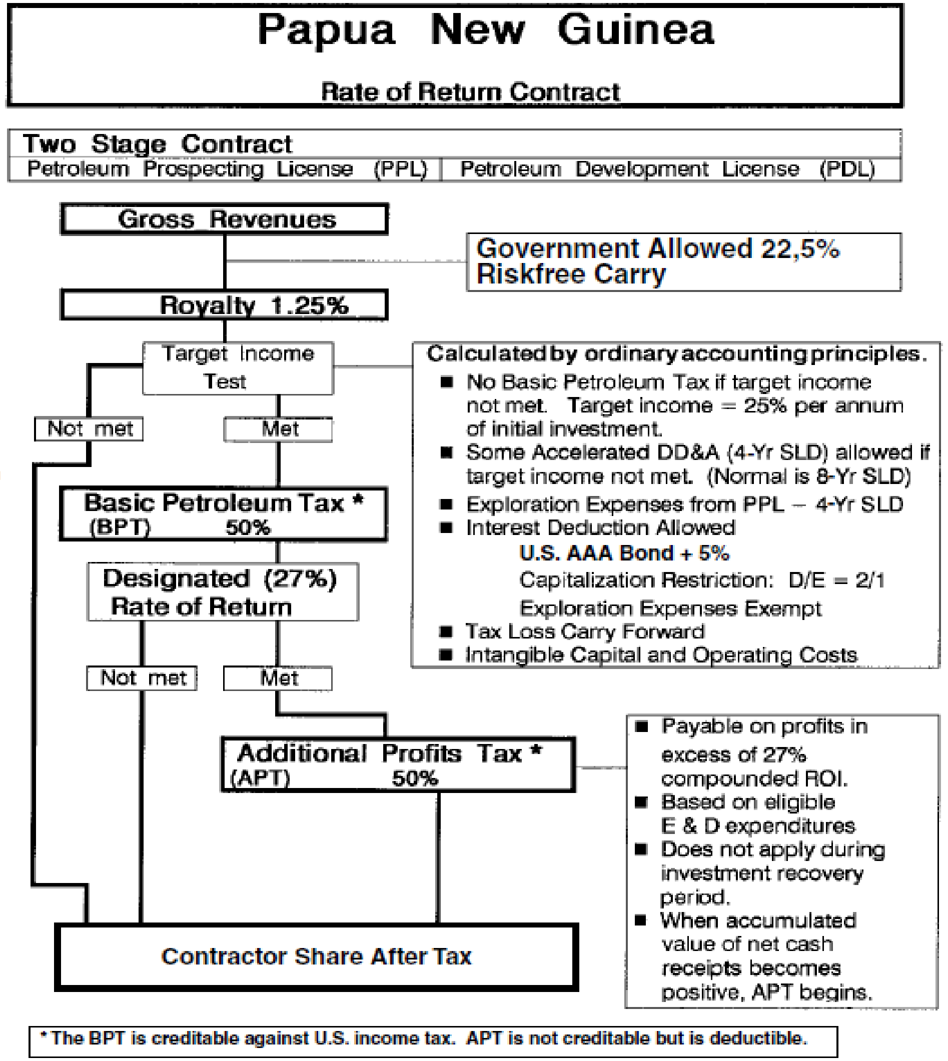
Risk Service Contracts- PAPUA NEW GUINEA ROR SYSTEM

The PNG system is typical of the classic ROR formula. Under this system the government receives a 1.25% royalty and a 22.5% carried interest (carried through exploration). A basic petroleum tax (BPT) of 50% is levied only if the contractor's income meets or exceeds 25% of the initial investment.

There is an additional tax levied if the contractor's rate of return exceeds 27%. This is done by compounding the negative net cash flows at a rate of 27%. Once the cumulative net uplifted cash flow becomes positive the additional 50% resource rent tax kicks in. It is called the Additional Profits Tax (APT). This is the hallmark of a ROR system. It is also called a trigger tax. Reaching a minimum rate of return triggers the tax.

Critics of the ROR concept complain that these contracts are too restrictive, that the uplift (rate-of-return) places an unreasonably low ceiling on upside potential.

The resource rent tax concept was first employed in Papua New Guinea (PNG). Other countries that use this kind of tax are Australia, Liberia, Equatorial Guinea, and Tanzania.



Risk Service Contracts- TUNISIAN CONTRACT WITH R FACTOR

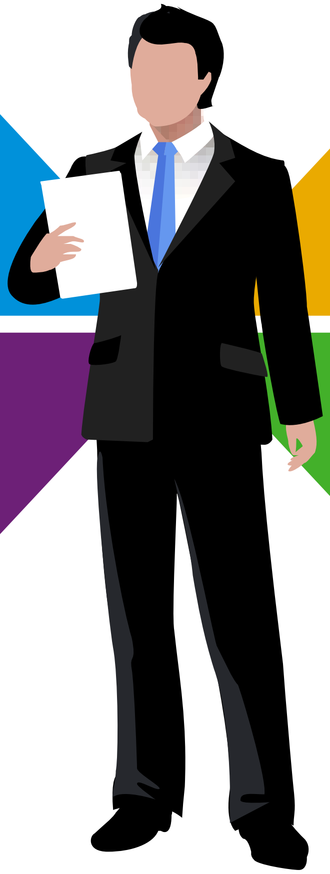
Some contracts use what is called an R factor. The most common use of such a factor is found in the Tunisian and Peruvian contracts. In these contracts the definitions are virtually identical: R factor = Accrued Net Earnings/Accrued Total Expenditures. In Tunisia oil and gas royalties, taxes, and government participation are all based upon the R factor.

TUNISIAN R FACTOR: R = X / Y

where:

X = Cumulative net revenue actually received by the contractor equals turnover (gross revenues) for all tax years less taxes paid

Y = Total cumulative expenditure, exploration, and appraisal expenses and operating costs actually incurred by contractor from date contract is signed



In this contract the R factor is based on a return on investment (ROI). Once the contractor has received his costs plus 50%, or a ROI of 150%, the tax rate increases from 50% to 55%. In some respects it is similar to a rate-of-return contract. The typical rate of return contracts trigger on internal rate of return (IRR). These concepts are discussed later.

Example: **Tunisian R Factor/Sliding Scale Taxation**

R Factor	Income Tax Rate %
< 1.5	50%
1.5–2.0	55
2.0–2.5	60
2.5–3.0	65
3.0–3.5	70
3.5 +	75

Risk Service Contracts- Joint Ventures

Joint ventures are common in the international oil industry. Most companies are willing to take on partners for large-scale or high-risk ventures in order to diversify—this is good risk management. These joint operations between industry partners differ from the government-contractor relationships that are also joint ventures but are normally referred to as *government participation.*

Some of the proposed Russian joint ventures are characterized by a 100% carry for the production association partner through development including operating costs. This is an extreme example of government participation. The opening up of the former Soviet Union and other countries dominated by centrally planned economies has added dimension to the joint venture concept. These countries, particularly republics of the former Soviet Union and Eastern Europe, prefer joint ventures because they have personnel and organizations in place that need to be integrated into future operations.

Joint Venture/Government Participation Spectrum

BURDEN: Light → Heavy

— **Pure Joint Venture**
All costs/risks shared
Very rare

— **Mauritania Type Participation**
Government carried through exploration
Contractor recovers exploration costs
plus 50% uplift on government share

— **Typical Joint Venture**
Government carried through exploration
Most common
Contractor can recover exploration costs

— **Colombian Type Joint Venture**
Government carried through exploration
and delineation

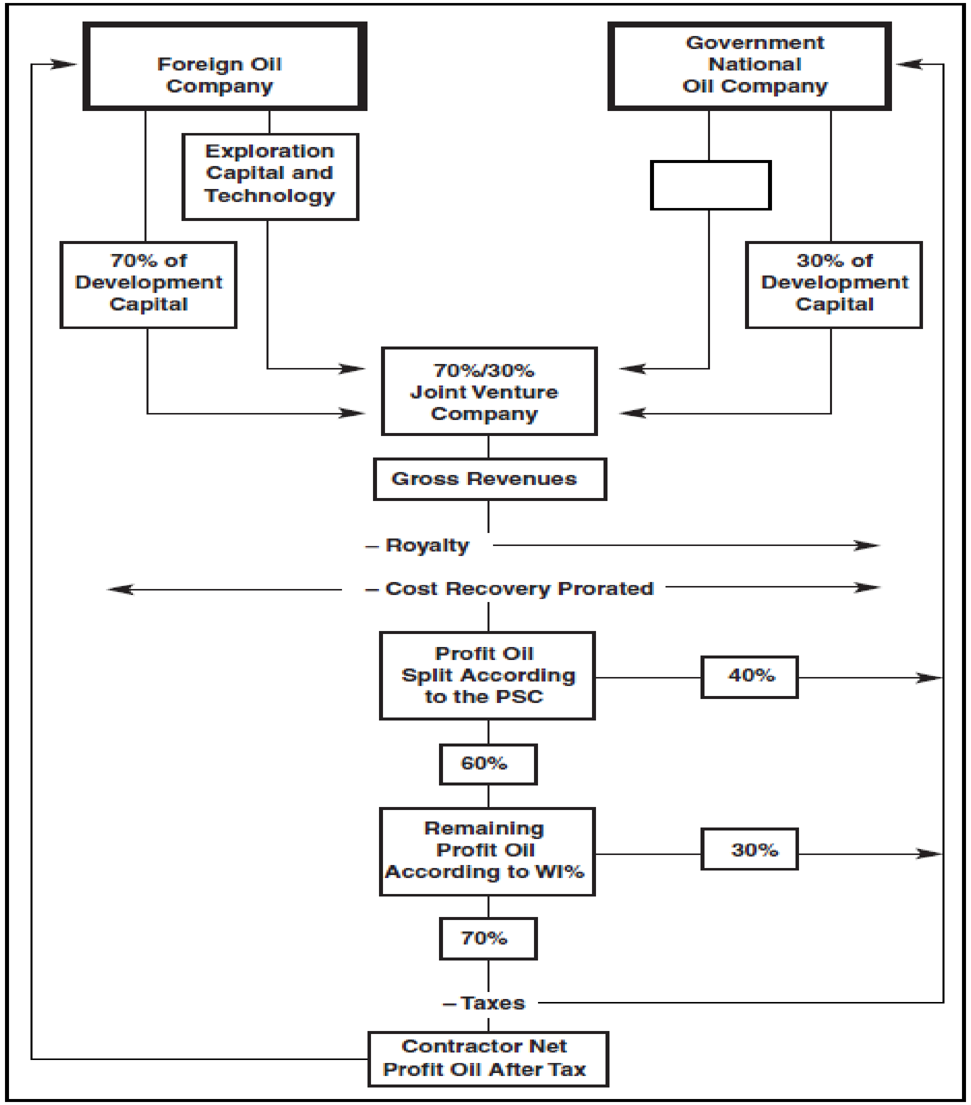
— **Full Carry**
Government carried through exploration
and development
Not common

— **Russian Type of Joint Venture**
Government carried through rehabilitation
and development, until it has cash flow
from operations

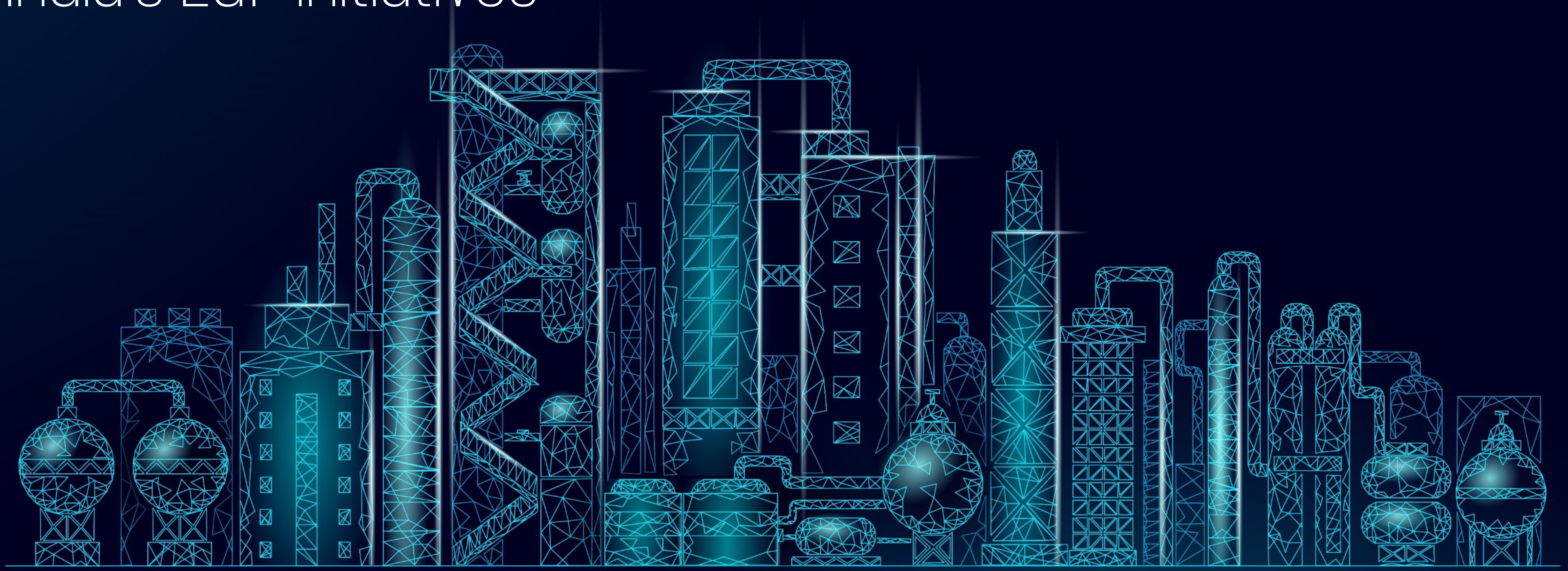
Risk Service Contracts- Joint Ventures

The figure illustrates the general nature of a contractor/government joint venture. Here the government (through the national oil company) is a 30% working-interest partner. The proceeds in this example are subject to the terms of a PSC with a 60%/40% profit oil split in favor of the contractor group. However, the contractor group includes the government as partner. Both partners receive their prorated share of cost oil. Profit oil is split according to the working interest shares. This example shows the profit oil split according to the PSC and the additional split dictated by the joint venture arrangement. This is why many people treat government participation as though it were an added layer of taxation. However, when the government backs in after discovery, it is effectively cashing in on the value added at that point. That element of government take occurs long before production begins.

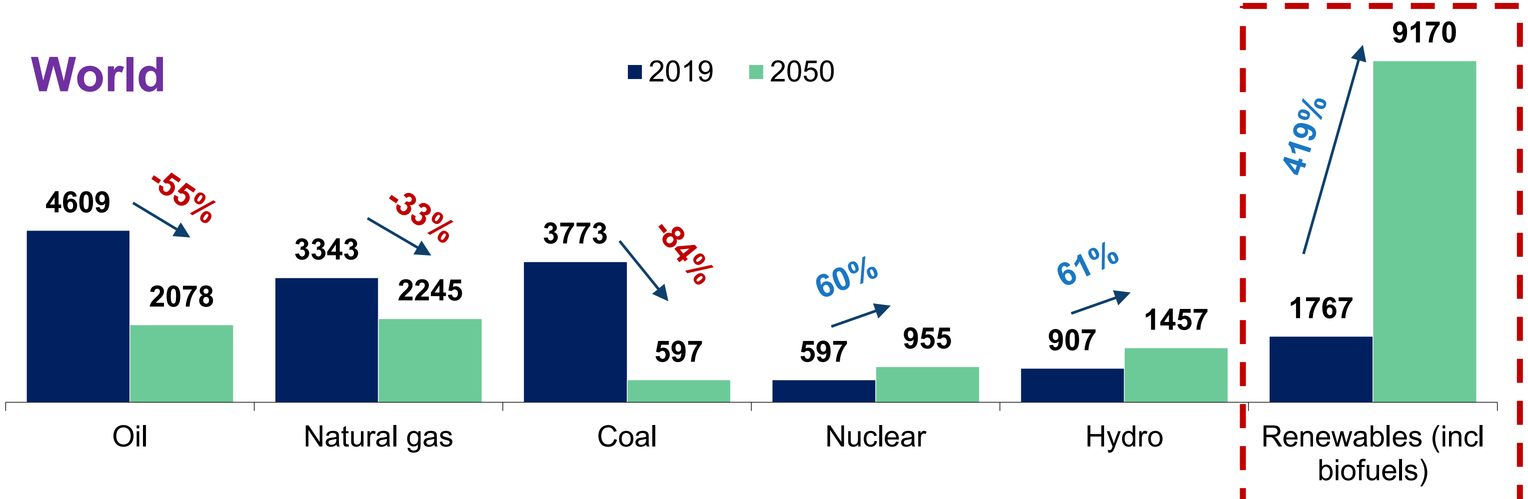
In a pure joint venture, the host government and the contractor share equally in costs and risks. This would have little practical application. However, there is a broad range from pure joint ventures to some of the least pure joint enterprises found in the former Soviet Union. The key ingredient is the amount of carry.

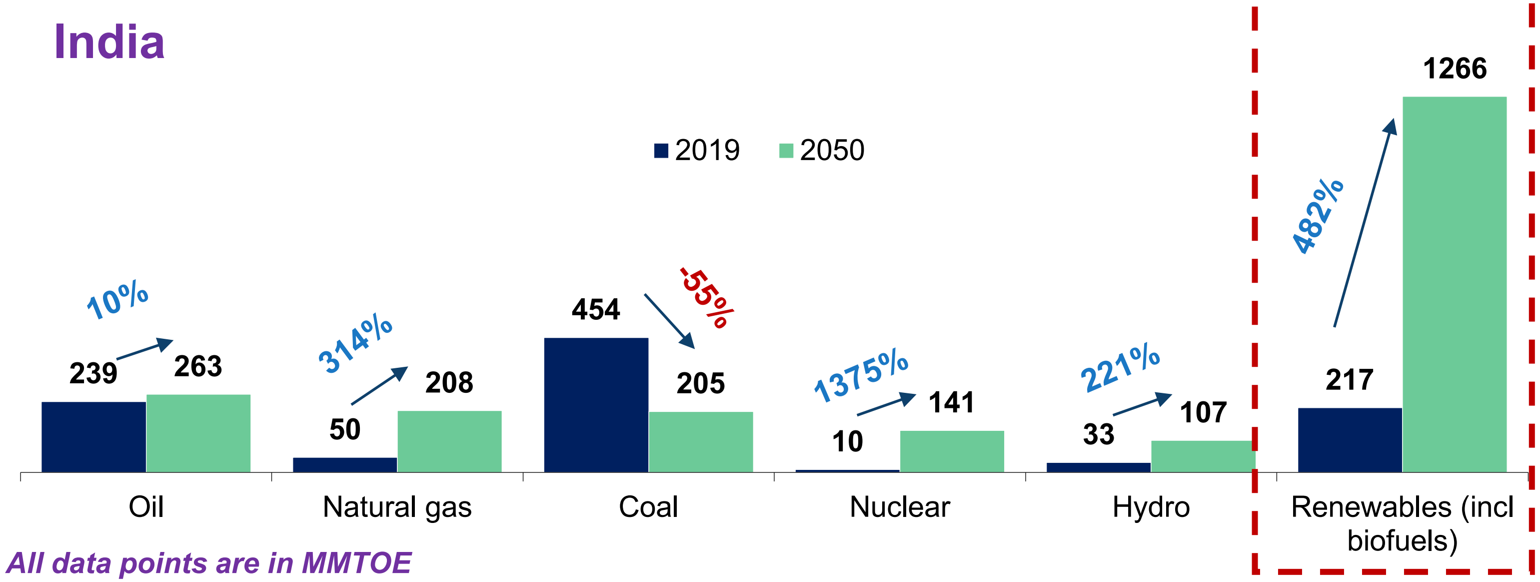


India's E&P initiatives



Global vs India: Decarbonization is transforming energy landscape. However, Oil and Gas in India is likely to have a longer run





- While the world oil and gas consumption will reduce but, India will grow till 2050
- Renewables is one of the fastest growing fuel for the world and as well as for India
- Globally, renewables will grow at a CAGR of 5% and for India it is 6%.
- For India, consumption of all fuels is increasing except coal owing to significant increase in renewables

All data points are in MMTOE

Source- BP Energy outlook 2022 (accelerated scenario)

Evolution & Development of Indian E&P sector

Data Initiatives
Policy Reforms
Bid Rounds

Focus of todays session

2015-Discovered Small Field (DSF) Policy
2016-Hydrocarbon Exploration and Licensing Policy (HELP)
2016-National Seismic Program (NSP)
2016-DSF Bid Round I (2016)
2017-National Data Repository (NDR)
2017-Open Acreage Licensing (OALP) bid round I
2017-Hydrocarbon Resource Reassessment Study

1947

State Monopoly Public sector Upstream companies

1980-1995

Beginning of deregulation 28 producing fields and 28 exploratory blocks offered including private players

1997 - 2010

Liberalization of E&P Sector-
9 NELP and 4 CBM Rounds *(254 exploratory and 30 CBM Blocks through competitive bidding and 3 Nomination CBM Blocks)*

2015-2017

2018-2020

2018-Enhanced Recovery Policy to maximize recovery
2018-Open Acreage Licensing (OALP) bid round II, III
2018- DSF Bid Round II
2019-Reforms in Exploration and Licensing Policy for enhancing domestic exploration and production of oil and gas
2019-Open Acreage Licensing (OALP) bid round IV
2019-Production Enhancement Scheme
2020-Open Acreage Licensing (OALP) bid round V
2020-Natural Gas Marketing Reforms
2020-Approvals on Self-certification basis under Production Sharing Contract

2021-22

Open Acreage Licensing (OALP) bid round VI,VII and VIII

Hydrocarbon Exploration and Licensing Policy (HELP)

Policy Features

- Open Acreage Licensing
- Revenue Sharing Model
- Full Marketing and Pricing Freedom for sale of Hydrocarbons
- Single license for Conventional & Unconventional hydrocarbons
- Increased exploration phase
- Continuous exploration permitted during contract period
- Equal weightage of work program & fiscal package
- No carried interest by NOCs
- Graded Royalties for different block types
- Up to 100% FDI allowed
- Low regulatory burden
- Transparent bidding model
- Defined mechanism for developing common reserve
- Defined timelines for PI transfer
- Flexibility to use infrastructure in adjacent blocks
- Other fiscal incentives

HELP: Open Acreage Licensing

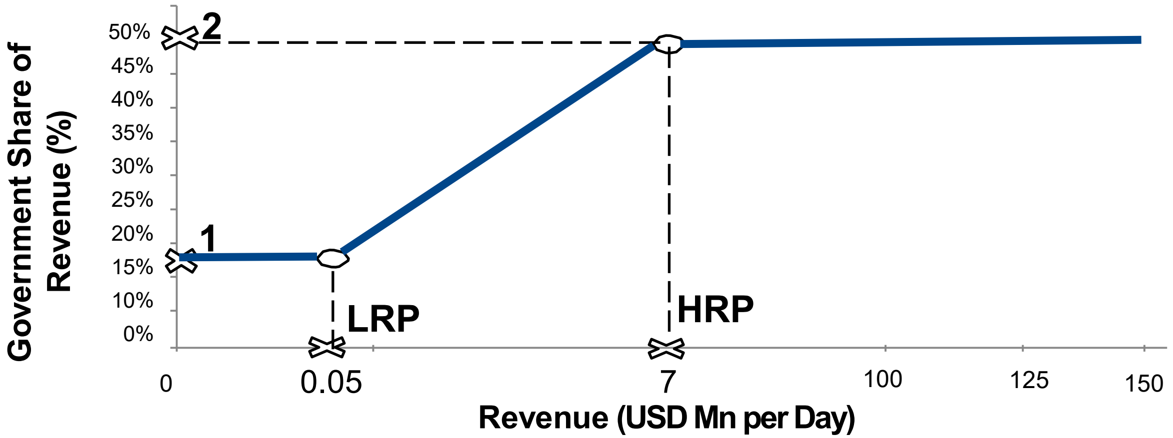
- Flexibility to choose between Petroleum Operations Contract & Reconnaissance Contract
- Incentive mechanism for originators.
- Environmental and Site Restoration obligations.
- Time bound actions and activities with disincentives for non-performance
- Time-Bound FDP preparation and provision for Direct FDP submission.
- Exploration rights on all retained area for full contract life.
- EoIs can be made round the year at 6 monthly cycles.
- Allows bidders to carve out their own blocks by studying data as per gridding structure at National Data Repository.

HELP: Revenue sharing model

Revenue sharing pattern

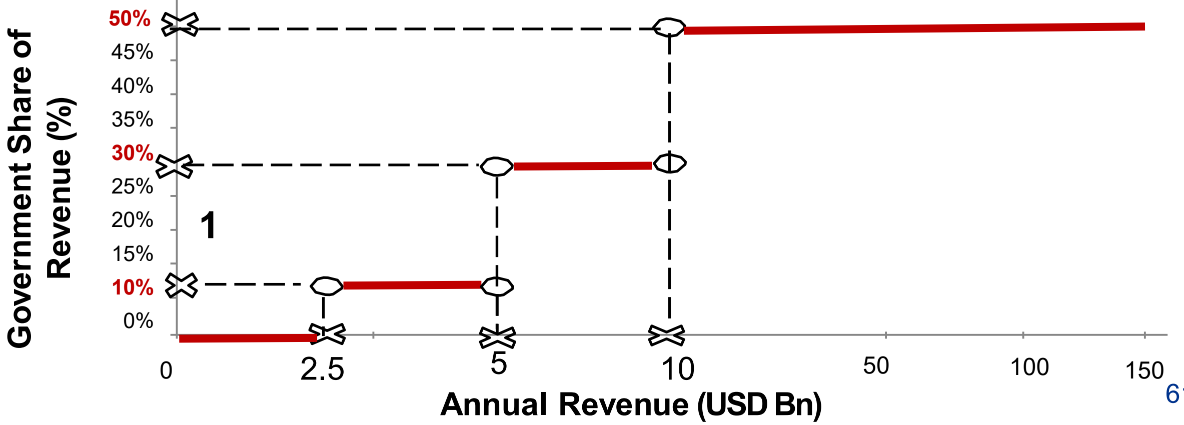
Category I Basins

- Revenue share (%) to be bid at two levels: "Lower Revenue Point (LRP)" and "Higher Revenue Point (HRP)"
- LRP set at revenue of USD 0.05 million per day; HRP set at USD 7 million per day
- Revenue share for **intermediate revenue points** will be calculated by **linear interpolation**
- Bidder offering **highest net present value of the Revenue Share** to Government will score maximum on this parameter
- HRP Rate at **HRP revenue point can not exceed 50%**



Category II & III Basins

- **No revenue share** is to be quoted at the time of bidding
- Revenue sharing at predetermined rates if **annual revenue crosses USD 2.5 billion i.e. "Windfall Gain"**
- Revenue (Net of Royalty & taxes on sales) to be considered in Financial year (April to March)



HELP: Liberalized Bidding Pattern

Category-I Basins

Previous terms

- ✓ 50% Weightage to Work Programme
- ✓ No Capping on revenue share quotes at Higher Revenue Point

Liberalized terms

- ✓ More Weightage to Work Programme (70%)
- ✓ Revenue share quote at HRP capped at 50%

Category-II & III Basins

Previous terms

- ✓ Revenue share to Government had 50% weightage in biddable parameters
- ✓ No Capping on revenue share quotes at Higher Revenue Point

Liberalized terms

- ✓ Incremental revenue share applicable on windfall gains:-

Yearly Revenue (Billion USD)	GoI Share (%)
Up to 2.5	Nil
>2.5 <=5.00	10%
>5.00 <=10.00	30%
>10	50%

HELP: Graded royalty rates

Details	Location	HELP Blocks*					
		Category I		Category II		Category III	
		Normal Rates	Concessional Rates	Normal Rates	Concessional Rates	Normal Rates	Concessional Rates
Royalty on Oil & Gas Production	Onland	12.5% for Oil	11.25% for Oil	12.5% for Oil	10% for Oil	12.5% for Oil	8.75% for Oil
		10% for Gas	9% for Gas	10% for Gas	8% for Gas	10% for Gas	7% for Gas
	Shallow Water	7.5% for Oil	6.75% for Oil	7.5% for Oil	6% for Oil	7.5% for Oil	5.25% for Oil
		7.5% for Gas	6.75% for Gas	7.5% for Gas	6% for Gas	7.5% for Gas	5.25% for Gas
	Deep Water (First 7 Years)	No Royalty	No Royalty	No Royalty	No Royalty	No Royalty	No Royalty
		No Royalty	No Royalty	No Royalty	No Royalty	No Royalty	No Royalty
	Deep Water (After 7 Years)	5% for Oil	4.5% for Oil	5% for Oil	4% for Oil	5% for Oil	3.5% for Oil
		5% for Gas	4.5% for Gas	5% for Gas	4% for Gas	5% for Gas	3.5% for Gas
	Ultra Deep Water (First 7 Years)	No Royalty	No Royalty	No Royalty	No Royalty	No Royalty	No Royalty
		No Royalty	No Royalty	No Royalty	No Royalty	No Royalty	No Royalty
	Ultra Deep Water (After 7 Years)	2% for Oil	1.8% for Oil	2% for Oil	1.6% for Oil	2% for Oil	1.4% for Oil
		2% for Gas	1.8% for Gas	2% for Gas	1.6% for Gas	2% for Gas	1.4% for Gas
Cess on Oil Production	All	NIL	NIL	NIL	NIL	NIL	NIL

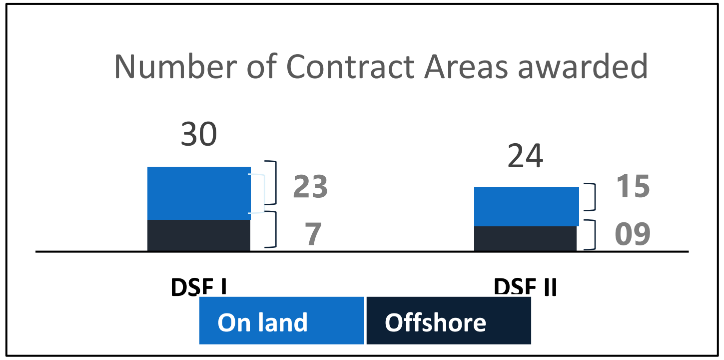
** Concessional Rates applicable in HELP blocks if Commercial Production is commenced within 4 years for Onland and Shallow Water blocks, and 5 years for Deep Water and Ultra Deep Water Blocks from the Effective Date of the Contract.*

Discovered small field round (DSF)

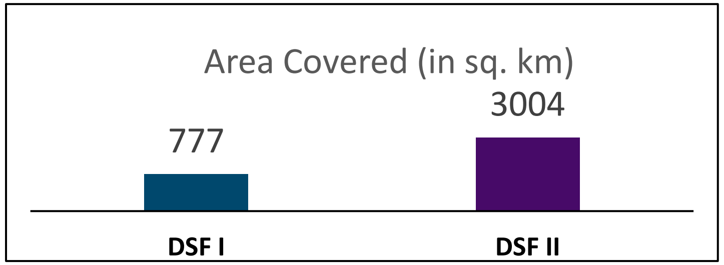
Key Features & Statistics

- Unified License for Conventional-Unconventional Hydrocarbon
- Prior Technical experience not a pre-qualification criteria
- Exploration allowed during entire contract period
- Royalty in-line with HELP and no Cess
- No Minimum Biddable Work Program
- Provision for sharing of common facilities
- Full Pricing & Marketing Freedom

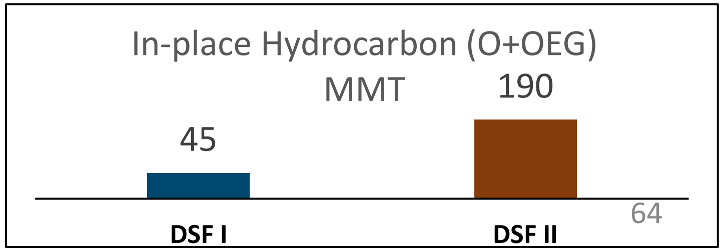
54 blocks awarded



3,781 Sq. km. awarded



~235 MMT
In place Hydrocarbon reserves in blocks awarded



Geoscientific data initiatives undertaken by GoI

Hydrocarbon Resource Reassessment Study** (2017)

49.1% increase

in Hydrocarbon resource estimate as compared to 1995

National Data Repository

Centralised repository of geoscientific data

2.603 Million LKM
2D data populated*

0.897 Million SKM
3D data populated*

National Seismic Programme (Incl. Andaman Survey)

Launched to conduct assessment of unapprised areas

Target to acquire

~63,243 LKM

of 2D Seismic Data

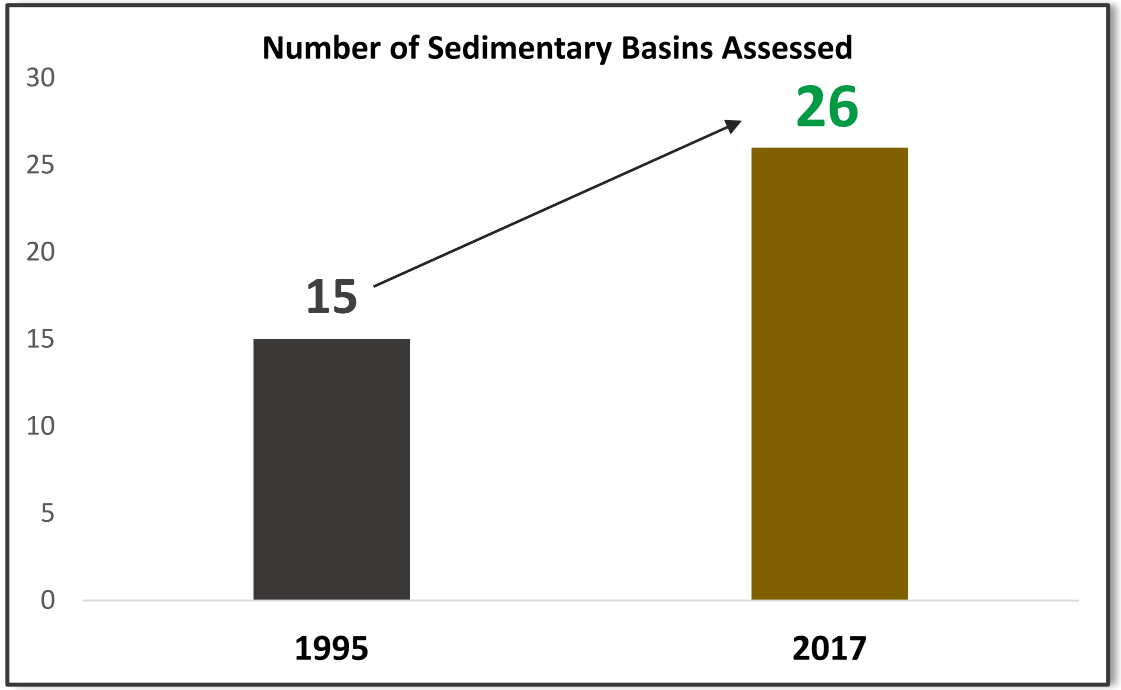
Other forward-looking changes

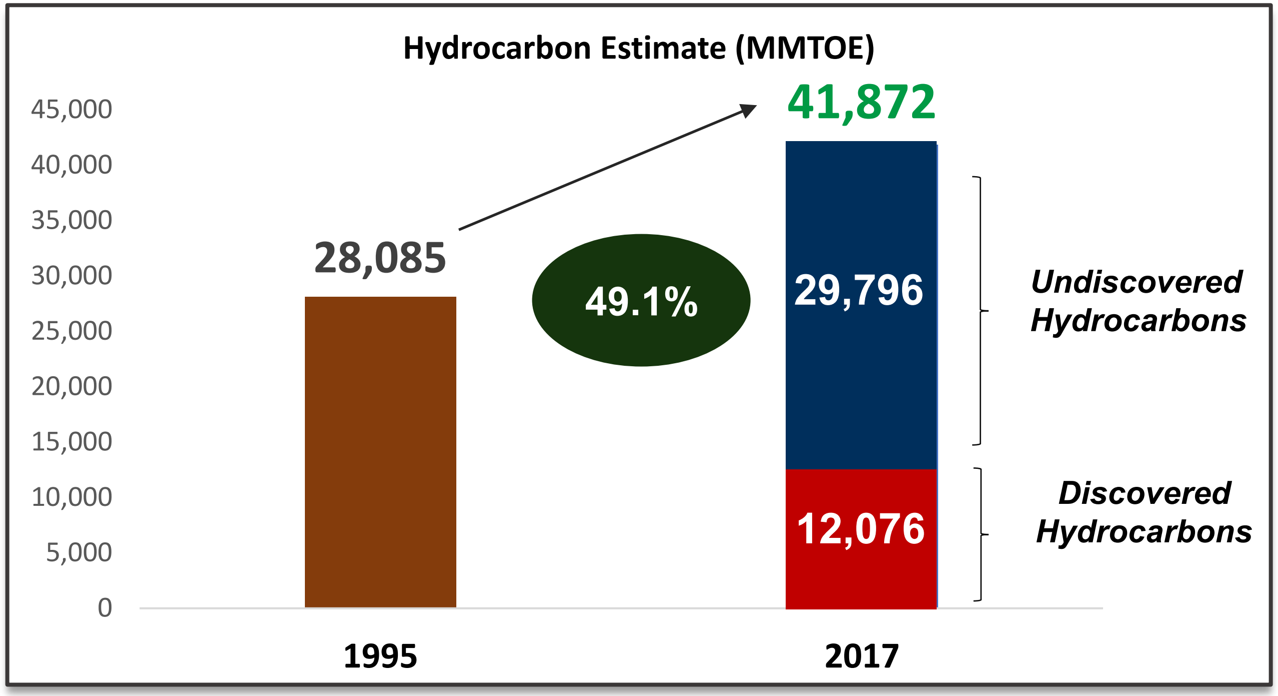
- No go areas in Andaman basin being released for E&P activities
- Govt. initiated **preclearing of blocks with different agencies** such as Defence and Environment
- Govt. taking measures to expedite PEL grant

*As on Jan 2021 **The Hydrocarbon Resource Reassessment Study was conducted in 2017 for 26 sedimentary basins

Hydrocarbon Resource Reassessment Study, 2017

Govt. conducted Hydrocarbon Resource Reassessment in 2017, resulted in increase in Hydrocarbon resource estimates by 49.1% (as compared to 1995 Study)





About **70% of undiscovered in-place under yet-to-find** category **(~230 billion barrels of oil equivalent)**

Out of total sedimentary basinal area of **3.36 million Sq. Km**, **~47% is under explored**

National Data Repository

National Data Repository (NDR): Centralised repository of geoscientific data of Indian basins

Key features	Quality Data*	Users**
Ease of Access	2D Seismic Data	More than 250 companies
Integrated with GIS browser	3D Seismic Data	More than 800 users
Virtual Data Room	Seismic Reports	
Seamless Data Exchange	Well and log data	
Cutting Edge Technology	Well Reports	
High Quality Data		

Way Forward for NDR

1. Cloud based solution and expansion of storage
2. Deriving key insights through Data analytics

India's E&P Fiscal system

Evolution India's E&P fiscal system

1947 | 1980 | 1997 | 2015

Nomination Regime

- Till the end of 1970s, Indian E&P industry was dominated by the two National Oil Companies(NOCs) ONGC and OIL to whom PELs were granted on nomination basis.
- Exploration was primarily confined to onland and shallow offshore areas.

Pre-NELP (Production Sharing Contract)

- Pre- NELP Exploration-
  - In 1980, Government started offering blocks through bidding rounds also known as Pre- NELP exploration rounds.
  - 28 Exploration blocks were awarded in four bid rounds
- Pre-NELP Discovered Field Rounds
  - Petroleum Mining Lease(PML) of small/medium sized discovered fields (proven reserves were discovered by ONGC and OIL) were offered to the private sector in 1992
  - 28 contracts for 29 discovered fields were awarded

NELP (Production Sharing Contract)

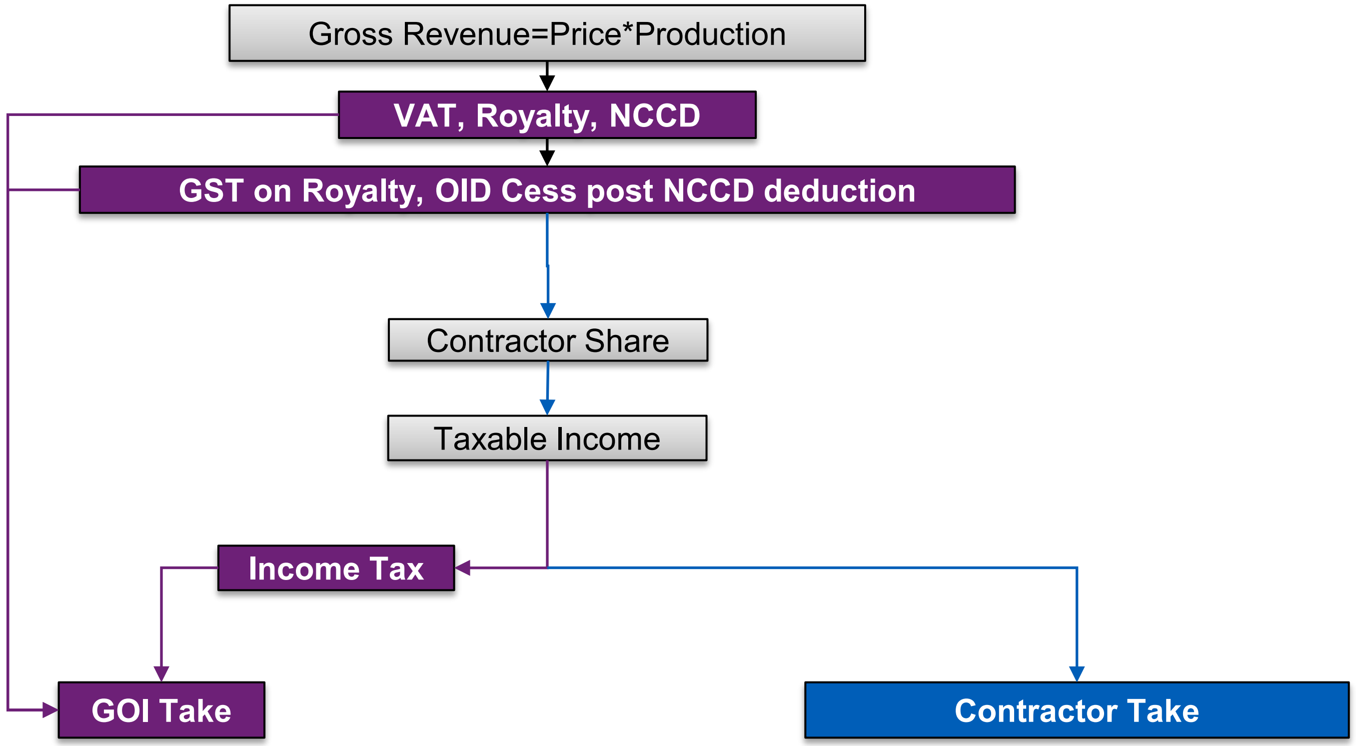
- GoI formulated a policy, called New Exploration Licensing Policy (NELP) in 1997
- Licenses for exploration were awarded through a competitive bidding system and NOCs were required to compete on an equal footing with Indian and foreign companies to secure Petroleum Exploration Licenses (PELs).
- Nine rounds of bidding were conducted under which 254 exploration blocks were awarded

DSF/HELP (Revenue Sharing Contract)

- Discovered Small Field (DSF)-
  - The Government launched policy in 2015 under revenue sharing regime wherein the terms are liberalized for providing maximum autonomy to contractor with minimum Government oversight.
  - With two DSF bidding rounds carried out till date, 53 Contract Areas have been awarded, **resulting in entry of over 12 new players in Indian E&P sector**
- Hydrocarbon Exploration and Licensing Policy (HELP)
  - Government launched HELP in 2016 under revenue sharing regime
  - The HELP is implemented through Open Acreage Licensing Programme, where the continuous bidding rounds are conducted on the investor selected blocks.
  - Till date,105 blocks are awarded under five rounds of OALP.

Government and Contractor's Take - Nomination Regime

Flow chart of calculations



Break-up of Government & Contractor Take

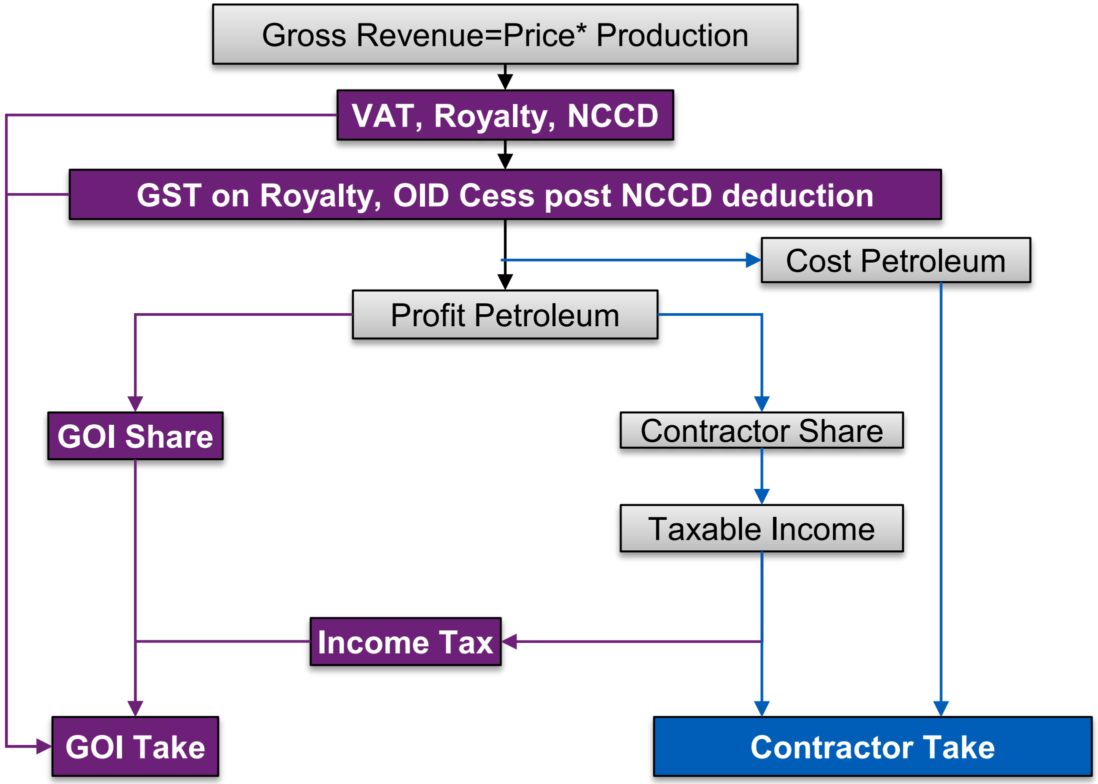
Government Take = **Statutory Levies** + **VAT** + **Corporate Tax**

Contractor Take = **Profit after Tax**

- In Nomination Regime, **Government take comprises of Statutory Levies, VAT and Corporate Tax**
- Statutory Levies include Royalty, GST on Royalty, OIDB Cess and NCCD
- After deducting all statutory levies and VAT, production and development cost are deducted from the net revenue. This becomes the taxable income.
- **Contractor take only comprises of Profit after Tax**

Government and Contractor's Take - Pre-NELP Regime

Flow chart of calculations



Break-up of Government & Contractor Take

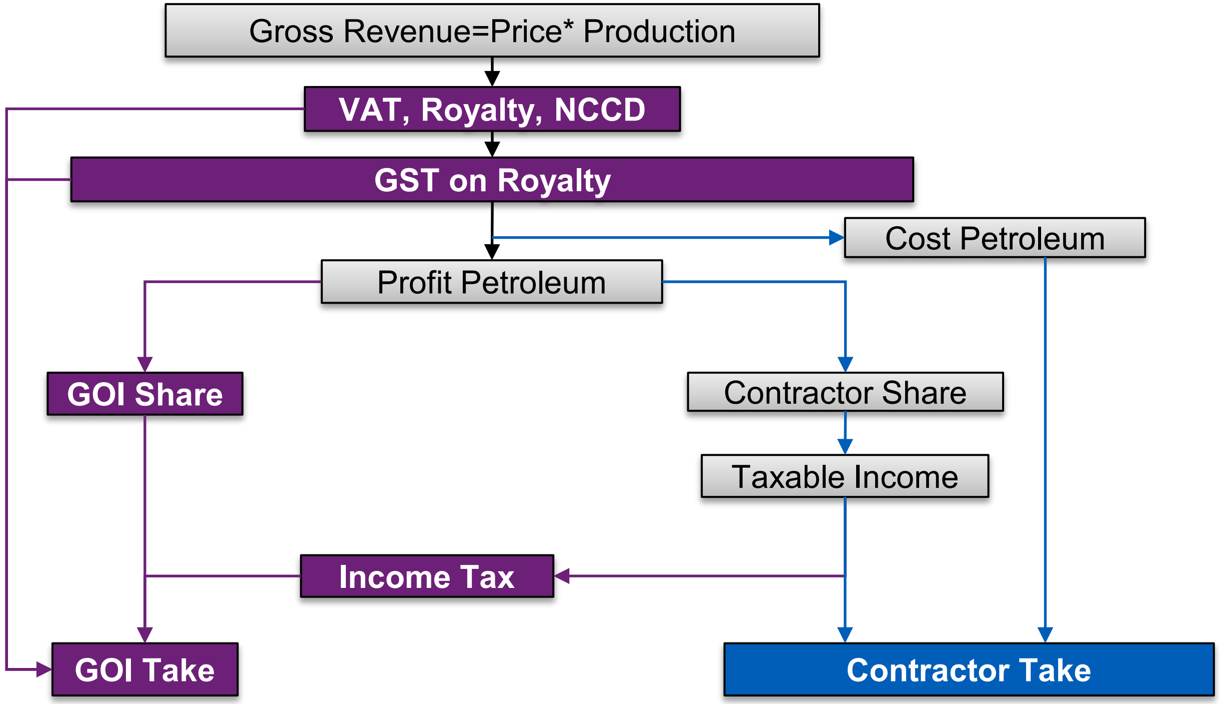
Government Take = **Statutory levies** + **VAT** + **GoI Share of Profit Petroleum** + **Corporate Tax**

Contractor Take = **Cost Petroleum** + **Contractor share of Profit Petroleum (Post Tax deduction)**

- In Pre-NELP Regime, **Government take comprises of** *Statutory Levies, VAT, GOI Share of Profit Petroleum and Corporate Tax*
- Statutory Levies include Royalty, GST on Royalty, OIDB Cess and NCCD
- After deducting all statutory levies and VAT, Cost Petroleum is deducted from the Net Revenue to get Profit Petroleum
- Profit Petroleum is split between government and contractor based on pre-decided share
- Production and development costs are deducted from the contractor share of profit petroleum to get taxable income
- **Contractor take comprises of Cost Petroleum and Profit after Tax**

Government and Contractor's Take - NELP Regime

Flow chart of calculations



Break-up of Government & Contractor Take

Government Take = **Statutory levies** + **VAT** + **GoI Share of Profit Petroleum** + **Corporate Tax**

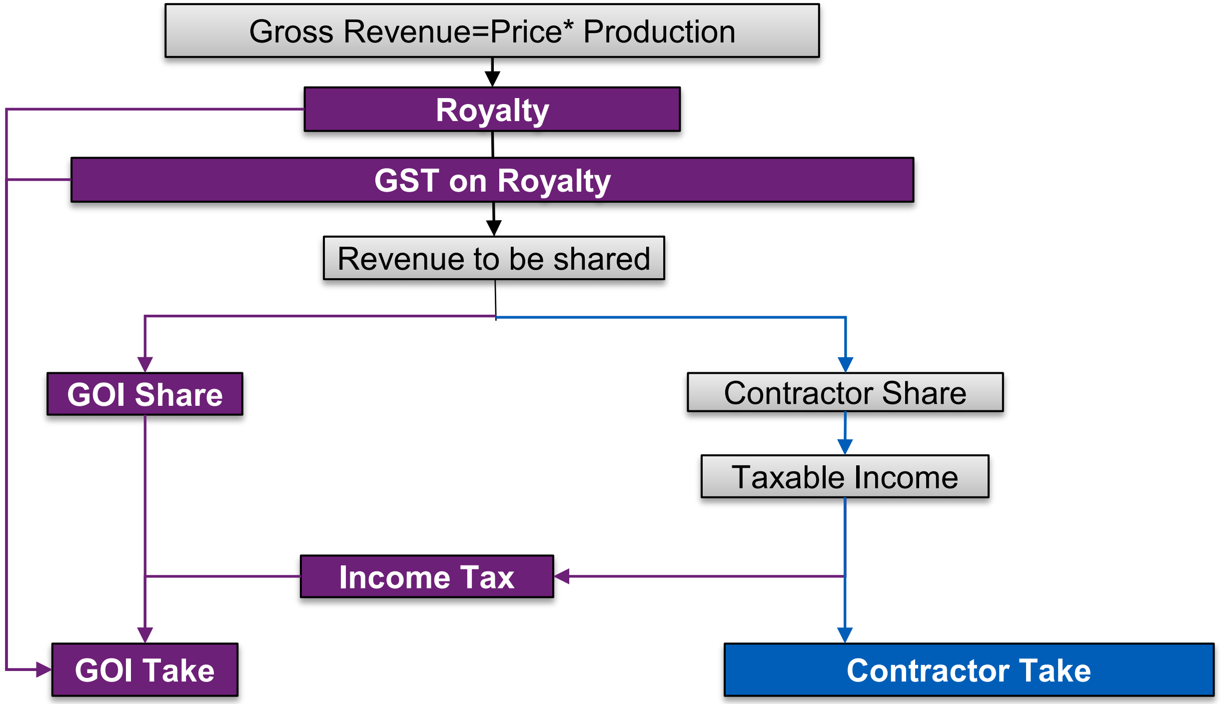
Contractor Take = **Cost Petroleum** + **Contractor share of Profit Petroleum (Post Tax deduction)**

Note – No OID Cess is applicable

- In NELP Regime, **Government take comprises of** *Statutory Levies, VAT, GOI Share of Profit Petroleum and Corporate Tax*
- Statutory Levies include Royalty, GST on Royalty and NCCD
- After deducting all statutory levies and VAT, Cost Petroleum is deducted from the Net Revenue to get Profit Petroleum
- Profit Petroleum is split between government and contractor based on pre-decided share
- Production and development costs are deducted from the contractor share of profit petroleum to get taxable income
- **Contractor take comprises of Cost Petroleum and Profit after Tax**

Government and Contractor's Take - HELP Regime

Flow chart of calculations



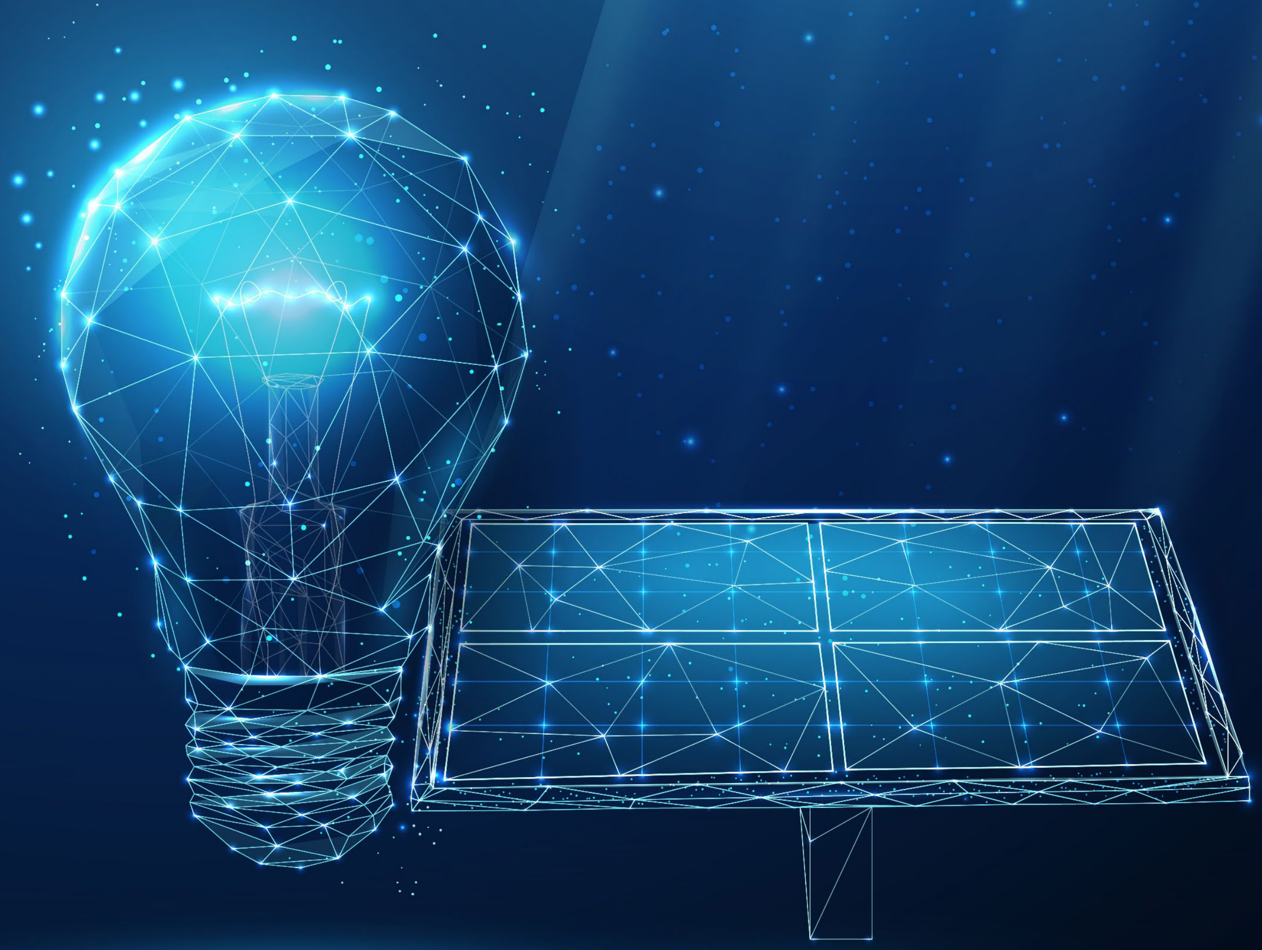
Break-up of Government & Contractor Take

Government Take = **Statutory levies** + **GoI Revenue Share** + **Corporate Tax**

Contractor Take = **Profit after Tax**

- In HELP Regime, **Government take comprises of** *Statutory Levies, GoI Revenue Share and Corporate Tax*
- Statutory Levies include Royalty and GST on Royalty
- After deducting statutory levies, Revenue is shared between government and contractor based on pre-decided LRP and HRP
- Production and development costs are deducted from the contractor revenue share to get taxable income
- **Contractor take comprises of Profit after Tax**

Summary of Major Fiscal Systems



Comparison of prevalent fiscal systems in exploration & production of oil and Gas

Primary criteria		Concessions	PSC	Service contracts	Joint Venture	RSC
Hydrocarbon ownership	**Hydrocarbons**	▪ Before extraction: State ▪ After extraction: OC (at wellhead) ▪ OC can book reserves	▪ Before extraction: State ▪ After extraction: State/OC, each proportional to its profit oil share • OC can book reserves	▪ Before extraction: State ▪ After extraction: State ▪ OC paid in cash and cannot book reserves	▪ Production is shared between Host State and OC, proportional to their respective equity interests	▪ Before extraction: State ▪ After extraction: State/OC, each proportional to its share basis LRP & HRP
Risk-Reward distribution	**Government compensation**	▪ Royalty ▪ Taxes	▪ Share of profit petroleum ▪ Taxes	▪ Mktg. of HC- Service fee ▪ Taxes	▪ Portion of profits attributable to state ▪ Taxes	▪ Revenue share basis LRP & HRP ▪ Taxes
	Company entitlement	▪ Gross production less royalty and taxes	▪ Cost oil/gas + profit oil/gas - taxes	▪ Service fee (usually fixed margin on costs / production) less taxes	▪ Share of produced HC profits minus taxation	▪ Share of revenue produced from HC minus taxation
	Risk taker	▪ OC; makes all upfront E&P investments without guaranteed returns	▪ OC takes exploration risk, makes all upfront investment. OC& Govt. share development and production costs after commercial discovery	▪ State; OC gets full compensation of costs and guaranteed margin	▪ State assumes the risk related to the percentage it holds in each business	▪ OC takes exploration risk, makes all upfront investment.
Level of Government Involvement	**Administrative and Managerial Burden**	▪ **Low**; no participation in MCs ▪ Govt. focuses on setting industry-wide policies	▪ **High**; govt. needs to attend ▪ MCs for all fields, take a view on all individual operational decisions	▪ **Very High**; govt. needs to plan and execute on the development of the entire oil and gas industry	• **High**; government has mandatory operational involvement in the fields	▪ **Low**; as recoverable cost accounting /auditing of the operator would not be focus
	Level of control	▪ **Low**; govt. regulates all activities cos' alike by setting industry standards and rules	▪ **High**: govt. participates in operational and investment decision making through management committees	▪ **Very high**: govt. decides where and how much to invest in E&P activities	• **High**; govt. has mandatory operational involvement in the fields	▪ **Low**; Govt. focuses on increasing domestic production by reducing micro-management

Source: *BCG perspectives, KPMG Perspective

Government take for major oil producing nations

Region	Countries		Indicative Govt. take*	Type of Contracts				Taxation		
				Concessional regime	Production Sharing Contract	Service contracts	Revenue Sharing Contract	Royalty	Profit based special taxes	Corporate income tax
Americas	US		~67%							
	Mexico		-**							
	Brazil		~72%							
Europe	UK		~63%							
	Russia		~66%							
	Norway		~79%							
Africa	Egypt		-**							
Asia Pacific	Australia		~59%							
	Indonesia		~82%							
	India		~61%							

- RSCs are predominant mostly in resource rich nations like US and Africa
- Service contracts are adopted mostly in countries with high geological prospectivity like **Mexico, Iran, Iraq and middle east countries**
- JVs are mostly adopted in countries with constitutional constraints
- PSCs are mostly preferred in countries with **lower levels of data availability** and **large unexplored areas like India, Indonesia, Egypt**

Source: **Information not available on public domain ; *BCG perspectives, OGA,NPD, www.trade.gov

Thank you

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