BENCHMARKING REPORT

The Boston Consulting Group

September 2012
## Contents

1 **INTRODUCTION AND CONTEXT** .................................................................................................................................................. 3

1.1 Current E&P structure in India.............................................................................................................................................. 3

1.2 Objectives and approach of the study.................................................................................................................................. 6

1.2.1 Objectives............................................................................................................................................................... 6

1.2.2 Approach............................................................................................................................................................. 7

2 **Detailed approach for country selection and benchmarking** ................................................................................................. 8

2.1 Country selection approach .............................................................................................................................................. 8

2.2 Topics covered in the study of regimes in selected countries ................................................................................................. 10

3 **Insights from benchmarking exercise** .................................................................................................................................. 12

3.1 Insights on the level of government take .................................................................................................................................. 12

3.2 Choice of petroleum regime .................................................................................................................................................. 18

3.2.1 Petroleum regimes in a legal context.......................................................................................................................... 18

3.2.2 Description of four types of petroleum regimes .............................................................................................................. 19

3.2.3 Comparison between the four contractual structures – synthesized from country benchmarking .............................................................................................................................. 25

3.2.4 Implications for India .................................................................................................................................................. 27

4 **Appendix 1: Country selection criteria** .................................................................................................................................. 29

5 **Appendix 2: Detailed Country Profiles** .................................................................................................................................. 32
1 INTRODUCTION AND CONTEXT

1.1 Current E&P structure in India

India is an attractive Exploration and Production (E&P) location with significant yet-to-find reserve potential (approximately 56 billion BOE\(^1\)), as shown in Exhibit 1.1. Further, a large proportion of the yet-to-find potential is expected to be onshore which, due to its relative ease of extraction, adds to the country’s prospectivity.

Exhibit 1.1: India’s yet-to-find reserve potential places it in the top 15 of the world

At the same time, the issue of energy security has never been more important as India’s dependence on crude imports to meet the rising domestic demand has been increasing steadily over the past decade (Exhibit 1.2).

---

1 Barrel of Oil equivalent
India adopted the currently prevailing Production Sharing Contract (PSC) structure in 1991-92, and moved to New Exploration Licensing Policy (NELP) in 1999-2000. The move toward PSC was driven by the need to create an attractive regulatory regime which would attract private investments into the sector.

While 28 blocks were awarded in the pre-NELP era, licenses for 248 blocks have been given to more than 70 companies since the onset of the NELP era in 1999. Of the total 3.14 million square kilometers of sedimentary basin area, 2.15 million square kilometers have already been licensed out (10 out of 26 producing basins in total). Significant progress has been made since 1999 in adding reserves as well as production, as shown below in Exhibit 1.3.
Despite all the progress, there are also many reasons for concern. Well-explored basinal area has increased marginally from 16 percent to 22 percent of total area in the last 15 years. In contrast, over the past nine years, the exploration area in Colombia has increased eight-fold (125,000 square kilometer in 2003 to 1,000,000 square kilometer in 2011). Additionally, there is declining interest in NELP rounds – in NELP IX, only 23 out of the 34 blocks on offer were awarded (refer to Exhibit 1.4 below). Participation by international players remains low, with only 12 percent of the total acreage and nearly 7 percent of total contracts awarded to foreign players till date.

In addition to low and declining interest in bidding, the current regime has come under criticism on several fronts. Operating companies are complaining of long delays (in clearances and operational decision making), and the resultant cost and time overruns. From the government’s point of view, the current structure has resulted in a huge administrative burden of conducting cost audits and budget approvals due the fact that government’s take is dependent on cost recovery claimed by operating companies. The source of concern has been disputes arising between the government and operating companies on matters of cost recovery, especially for big investments which ultimately impact the profit pie to be split. The key drivers of the dispute are information asymmetry between the two parties (with the operator having much more technical information about the field), and the potentially misaligned incentives to manipulate the profit pie to be split. These disputes can be managed and addressed with adequate technical capacity and capability in the government, which is also constrained with limited technical staff in the Directorate General of Hydrocarbons (DGH).

The above concerns have led to the government re-evaluating the upstream fiscal regime for future rounds of licensing, to minimize the challenges going forward and incentivize expeditious exploration and production activities.

---

2 [http://www.investorplace.com/2012/01/ecopetrol-colombias-quiet-energy-giant/]
1.2 Objectives and approach of the study

1.2.1 Objectives

While re-evaluating options for the future, the Ministry of Petroleum and Natural Gas (MoPNG) considered it helpful to develop a clear understanding of the global context and practices associated with commercial agreements between governments and operators for the exploration of a country’s/region’s natural resources; and to draw insights, implications and best practices relevant to the Indian context. Accordingly, MoPNG has asked the Boston Consulting Group (BCG) to conduct a study to understand the practices followed in upstream regimes around the world and draw implications for India. Specifically, the project scope includes the following:

- Understand the context of the upstream E&P regime and the government’s objectives in India.
- Review the existing commercial agreements present globally, namely, PSCs, concessions/royalty-tax structures, service agreements and joint ventures.
- Draw insights from international practices and specific implications for the Indian context.
- Develop options for suitable commercial structure for future agreements between the government and interested operators.
- Identify the key foundational enablers for a successful upstream regulatory regime in India.
1.2.2 **Approach**

The engagement was conducted over a 9-week period and consisted of two modules:

**Module 1 - A global benchmarking exercise:**
The BCG team conducted a detailed study to understand key aspects of upstream commercial agreements globally. Based on an objective selection approach (refer to Appendix 4.1 for details), 10 countries were shortlisted for in-depth study and benchmarking. These countries include Colombia, Malaysia, Angola, Brazil, Norway, Nigeria, China, Egypt, Indonesia and U.S. (specifically Gulf of Mexico). For the selected countries, primary research (interviewing BCG’s global upstream experts and other external specialists and selected international regulators) was carried out. Extensive secondary research was also conducted, with respect to studying key terms and conditions of existing commercial agreements (refer to Exhibit 1.5 for details).

<table>
<thead>
<tr>
<th>Ministry</th>
<th>Indian Private Industry</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Mr. Jaipal Reddy, Minister, MoPNG</td>
<td>• Mr. Sashi Mukundan, Country Head, BP India</td>
</tr>
<tr>
<td>• Mr. GC Chaturvedi, Secretary, MoPNG</td>
<td>• Mr. PMS Prasad, Executive Director, RIL</td>
</tr>
<tr>
<td>• Mr Giridhar Aramane, Joint Secretary, MoPNG</td>
<td>• Mr Rahul Dhir, CEO, Cairn India</td>
</tr>
<tr>
<td>• Mr. Atul Patne, Deputy Secretary, MoPNG</td>
<td>• Mr. Ajay Khandelwal, CEO, Jubilant Energy</td>
</tr>
<tr>
<td>• Ms. Rashmi Aggarwal, Director, MoPNG</td>
<td>• Mr. Ashu Sagar, Secretary General, AOGO</td>
</tr>
<tr>
<td>• Mr. R. N. Choubey, Director General, DGH</td>
<td>• Mr. Swagat Bam, SVP-E&amp;P, RIL</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Indian Public Sector Undertakings (PSUs)</th>
<th>Other Experts</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Mr. DJ Pandian, Principal Secretary (Energy), Gujarat</td>
<td>• Dr. Vijay Kelkar</td>
</tr>
<tr>
<td>• Mr. Umesh Srivastava, PSC Advisor, GSPC</td>
<td>• Mr. Aramando Zamaro , Ex-Director General, ANH, Colombia</td>
</tr>
<tr>
<td>• Mr. Sunil Srivastava, Chairman, OIL</td>
<td>• Mr. Harald Ibrekk, Statoil</td>
</tr>
<tr>
<td>• R. S. Sharma, ex-Chairman, ONGC</td>
<td>• Ms. Marina Taib, Petronas</td>
</tr>
<tr>
<td>• Mr. Sudhir Vasudeva, Chairman, ONGC</td>
<td>• Mr. Jefferson Edwards, Shell</td>
</tr>
<tr>
<td>• Mr. Sudhir Vasudeva, Chairman, ONGC</td>
<td>• Mr. Jay Park, Partner, Norton Rose law firm, Canada</td>
</tr>
<tr>
<td>• Mr. DK Sarraf, Chairman OVL</td>
<td>• Mr. Jatin Aneja, Partner, Amarchand Mangaldas &amp; Co</td>
</tr>
<tr>
<td>• Mr. Dulal Haldar, VP, OVL</td>
<td>• Mr. Sunjay Joshi, Former JS (E), IAS</td>
</tr>
</tbody>
</table>

**Exhibit 1.5: Primary interviews with experts and important stakeholders**

**Module 2 – Synthesis of benchmarking exercise to develop implications for India**
In addition to studying the regimes of other countries, it was very important to understand in detail the current Indian context and to ensure that the learnings and insights from global case studies were adapted to the Indian context. Accordingly, primary interviews were conducted with all the key stakeholders in India including the Ministry, Indian PSUs, upstream private sector
companies and international oil companies. These interviews helped understand the current context, key stakeholder objectives and concerns. Finally, the insights from the benchmarking exercise were combined with interview findings to synthesize a set of recommendations for the future of upstream oil and gas sector in India.

2 Detailed approach for country selection and benchmarking

2.1 Country selection approach

In order to come up with a set of best practices around the world, we have studied countries that have been successful in achieving their respective governments’ objectives. The evaluation is based on the following three criteria:

- Extent to which the country has been able to attract investments, relative to the size of its prospective resources.
- Extent to which the country has had exploration success.
- Extent to which the country has been able to increase production.

For each criterion, a distinct metric has been identified that could measure the extent of success, as relevant to the goals and purposes. These metrics are described in Exhibit 1.1 below.

<table>
<thead>
<tr>
<th>Countries will be selected based on the following factors …</th>
<th>Countries were ranked based on three distinct measures of success …</th>
</tr>
</thead>
<tbody>
<tr>
<td>A Relative success in achieving government objectives with policy and fiscal regime</td>
<td>Criterium</td>
</tr>
<tr>
<td></td>
<td>Attacting investments</td>
</tr>
<tr>
<td></td>
<td>Increase reserves</td>
</tr>
<tr>
<td></td>
<td>Increase production</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Special cases that are particularly interesting to study</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>• Countries that have a “classical” system, representative of a particular regime</td>
<td></td>
</tr>
<tr>
<td>• Countries that have an innovative policy structure and process, with elements of potential interest for India</td>
<td></td>
</tr>
<tr>
<td>• Cases of failure, where the lessons to learn are paramount</td>
<td></td>
</tr>
</tbody>
</table>

*Exhibit 1.1: Criteria and metrics for selection of relevant countries*
Based on these metrics, all oil- and gas-producing countries have been assessed and scored depending on their relative performance (score of 1 for the highest-ranked country)—the analysis for each of these metrics can be found in Appendix 1 of this report.

We have aggregated all the scores across these three criteria to arrive at an overall ranking of the countries. The top 5 countries that emerged were selected for a comparative exercise; these were Angola, Egypt, Nigeria, Brazil and China.

### Exhibit 1.2: Ranking of countries on the selected parameters

<table>
<thead>
<tr>
<th>Country</th>
<th>Attraction of capex</th>
<th>Addition of reserves</th>
<th>Increase in production</th>
<th>Total score</th>
</tr>
</thead>
<tbody>
<tr>
<td>Angola</td>
<td>4</td>
<td>18</td>
<td>7</td>
<td>29</td>
</tr>
<tr>
<td>Egypt</td>
<td>2</td>
<td>20</td>
<td>12</td>
<td>34</td>
</tr>
<tr>
<td>Nigeria</td>
<td>8</td>
<td>9</td>
<td>17</td>
<td>34</td>
</tr>
<tr>
<td>Brazil</td>
<td>17</td>
<td>15</td>
<td>10</td>
<td>42</td>
</tr>
<tr>
<td>China</td>
<td>20</td>
<td>10</td>
<td>13</td>
<td>43</td>
</tr>
<tr>
<td>Kazakhstan</td>
<td>28</td>
<td>12</td>
<td>5</td>
<td>43</td>
</tr>
<tr>
<td>Canada</td>
<td>10</td>
<td>7</td>
<td>28</td>
<td>45</td>
</tr>
<tr>
<td>India</td>
<td>13</td>
<td>17</td>
<td>15</td>
<td>45</td>
</tr>
<tr>
<td>Libya</td>
<td>12</td>
<td>11</td>
<td>22</td>
<td>45</td>
</tr>
<tr>
<td>USA</td>
<td>5</td>
<td>9</td>
<td>34</td>
<td>48</td>
</tr>
<tr>
<td>Azerbaijan</td>
<td>24</td>
<td>24</td>
<td>1</td>
<td>49</td>
</tr>
<tr>
<td>Norway</td>
<td>6</td>
<td>13</td>
<td>35</td>
<td>54</td>
</tr>
<tr>
<td>Malaysia</td>
<td>7</td>
<td>26</td>
<td>21</td>
<td>54</td>
</tr>
<tr>
<td>Australia</td>
<td>9</td>
<td>23</td>
<td>24</td>
<td>56</td>
</tr>
<tr>
<td>Oman</td>
<td>14</td>
<td>33</td>
<td>19</td>
<td>66</td>
</tr>
<tr>
<td>Colombia</td>
<td>3</td>
<td>38</td>
<td>29</td>
<td>70</td>
</tr>
<tr>
<td>Algeria</td>
<td>23</td>
<td>19</td>
<td>30</td>
<td>72</td>
</tr>
<tr>
<td>UK</td>
<td>1</td>
<td>28</td>
<td>48</td>
<td>77</td>
</tr>
<tr>
<td>Indonesia</td>
<td>15</td>
<td>21</td>
<td>41</td>
<td>77</td>
</tr>
<tr>
<td>Argentina</td>
<td>19</td>
<td>34</td>
<td>39</td>
<td>92</td>
</tr>
</tbody>
</table>

Additionally, a select few countries were added to the list that are either internationally recognized as being “classical” examples of particular policy regimes (e.g. Indonesia and Malaysia for PSCs, and U.S. and Norway for “Concessions”), or those that are recognized for their unique policy regimes and innovative policy structures (e.g. Colombia). Some cases of policy implementation failures were also studied, in order to learn from the mistakes of policy design.
2.2 Topics covered in the study of regimes in selected countries

An in-depth study was conducted on the regimes prevalent in the afore-mentioned countries to understand the context of their oil and gas sectors, the objectives of respective governments, and the policy frameworks. Detailed country profiles are available in Appendix 2.

Context

The level of macroeconomic data and the prospectivity and dependence of a country on hydrocarbon imports were among the elements examined with regard to the country’s oil and gas sector, since these influence the fiscal terms and the policy regime, as well as the strength of oil and gas industry (especially the National Oil Company).

Exhibit 1.3 outlines an overview of the contextual factors for the selected countries (PSC- and Concession-regime based). The next chapters will describe the learnings from a comparison of these countries’ individual characteristics and local contexts, leading into the adopted policies. The discussion will focus on two important policy choices that each country has had to make—the level of government take and the chosen oil policy regime.
<table>
<thead>
<tr>
<th>Characteristics</th>
<th>Colombia</th>
<th>Norway</th>
<th>Brazil</th>
<th>US-GoM</th>
<th>Angola</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fiscal Regime</td>
<td>Concession</td>
<td>Concession</td>
<td>Concession and PSC</td>
<td>Concession</td>
<td>Concession, PSC and JV</td>
</tr>
<tr>
<td>Government Take²</td>
<td>82%</td>
<td>79%</td>
<td>72%</td>
<td>64%¹</td>
<td>78%</td>
</tr>
<tr>
<td>Exploration Capex² (bn USD)</td>
<td>12</td>
<td>21</td>
<td>37</td>
<td>177</td>
<td>21</td>
</tr>
<tr>
<td>Production Rate, 2010 (mm BOE/d)</td>
<td>1.0</td>
<td>3.9</td>
<td>2.4</td>
<td>2.7</td>
<td>1.8</td>
</tr>
<tr>
<td>Change in Production, 2000-2010</td>
<td>0.00</td>
<td>-0.05</td>
<td>1.12</td>
<td>-0.94</td>
<td>1.1</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Energy Landscape</th>
<th>Success Parameters</th>
<th>Characteristics</th>
<th>India</th>
<th>China</th>
<th>Malaysia</th>
<th>Indonesia</th>
<th>Nigeria</th>
</tr>
</thead>
<tbody>
<tr>
<td>Actual prospectivity</td>
<td>Total resource base (Bln BOE)</td>
<td>7</td>
<td>35</td>
<td>60</td>
<td>54</td>
<td>18</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total yet-to-find potential</td>
<td>12</td>
<td>17</td>
<td>160</td>
<td>12</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Share of offshore resources</td>
<td>7%</td>
<td>100%</td>
<td>94%</td>
<td>100%</td>
<td>90%</td>
<td></td>
</tr>
<tr>
<td>Energy landscape</td>
<td>NOC activity</td>
<td>Ecosoil</td>
<td>Statoil</td>
<td>Petrobras</td>
<td>-</td>
<td>Sonangol</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Name of NOC</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Share of NOCs in investments</td>
<td>27%</td>
<td>55%</td>
<td>65%</td>
<td>-</td>
<td>31%</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Technical and financial strength</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Self-sufficiency</td>
<td>Exporter</td>
<td>Exporter</td>
<td>Gas: Importer</td>
<td>Oil: Exporter</td>
<td>Importer</td>
<td>Exporter</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Regulatory structure</th>
<th>HC ownership state retained</th>
<th>Freedom to monetize by OC</th>
<th>Freedom of international sales</th>
<th>Free market price</th>
</tr>
</thead>
<tbody>
<tr>
<td>India</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>China</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Malaysia</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Indonesia</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Nigeria</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
</tbody>
</table>

Exhibit 1.3: Contextual Background of Countries Selected for Benchmarking
Government objectives

With this contextual background, the objectives of the government in each of the countries were identified. For example, in the case of Colombia, official goals include building national wealth, minimizing government involvement in operations, maximizing acreage utilization, and ensuring self-sufficiency. On the other hand, the objectives for the Malaysian government include ensuring fair investor return, retaining control over production, maximizing production, and encouraging the development of local industry.

Policies adopted

We studied in detail the fiscal regime and specific fiscal terms adopted in contractual agreements across different countries—incuding the level of royalties, whether sliding-scale or not, the amount of taxation, cost recovery ceiling, investment credit, profit sharing, excess profit payments, cess etc. In addition to understanding fiscal terms, we looked at other policies intended to incentivize E&P activities—e.g. special incentives for small and marginal fields, standards for meeting health and safety requirements, measures to build local industry capabilities (training requirements, mandatory participation of National Oil Company and so on), and means and processes for government involvement in operational E&P activities (role of government, level of involvement).

Detailed country profiles have been included in Appendix 2, which provides elaborate descriptions of the context in which each these countries operate, the government objectives and their adopted policy regimes. A short overview of such context is described below for the selected countries.

3 Insights from benchmarking exercise

3.1 Insights on the level of government take

Within their preferred regulatory framework, countries try to adopt policies that balance two distinct and sometimes conflicting goals: maximizing share of government take from oil and gas activity, as well as the objective of attracting private sector investments into the industry. Hence, the targeted level of government take is ultimately a choice made by the concerned country, driven by its own perception of what it can afford to retain from oil and gas profits, while still attracting oil companies for investments.

The following section lays out the factors that determine the level of government take for different countries, India’s performance on those factors, and the recommendation for government take for India.

3 Government take is a standard international term defined as the share of NPV of a specific project that the Host State receives.
The three primary factors which determine the level of government take are as follows:

- **Geology** – Level of prospectivity and resource base of the country, as well the ease of extracting these resources.
- **Fiscal terms** – Returns offered to the oil company as compared to the risks.
- **Ease of doing business in a country** (regulatory environment) – Fiscal stability, degree of operational freedom for the investor and support in contract execution.

**1. Geology:** This is the primary driver of investor’s decision with regard to making risky exploration-related investments. Countries with a higher level of endowment are able to demand a higher level of government take. This is also supported by empirical observations laid out in the Exhibit 2.1 below.

**Exhibit 2.1: Countries with attractive hydrocarbon basins impose a higher government take**

Based on geological surveys and mathematical probabilistic models, India’s yet-to-find potential (YTF) is estimated to be around 56 billion Barrel Of Oil Equivalent (BOE), placing in the 15th rank as far as YTF is concerned (Exhibit 2.2). Additionally, India is attractive as large areas are still relatively unexplored – the proportion of moderately- to well-explored areas is at a mere 22 percent of the size of total sedimentary basins.
Exhibit 2.2: India ranks among top 15 in terms of absolute YTF potential

2. Contractual structure: It is found that there is no correlation between the level of government take and the type of contractual structure adopted (Exhibit 2.2).

No correlation between government take and the types of legal regime

1. Share of pre-take NPV (10%) for a standard representative field of 500M bbl and a base price of $75 per barrel of oil and $6 per Mcf in North America and $8 per Mcf in Europe

Source: IHS CERA
Exhibit 2.2: Government take in countries globally is independent of the fiscal regime adopted

3. Ease of doing business: To attract and retain investments into the country, it is imperative to foster a conducive business environment that provides a stable and supportive regulatory regime, an efficient governance mechanism and a strong enabling infrastructural ecosystem.

The following exhibit underscores the fact that the level of exploration investment, corrected for the prospectivity outlook of a country, tends to follow the relative level of business friendliness of countries.

Exhibit 2.3: Investments into exploration tends to follow friendliness of business environment

A comparison of oil- and gas-producing countries across the world, on parameters of regulatory risk and ease of doing business, indicates the need for strengthening of the regulatory system in India (as illustrated in Exhibit 2.4).
Exhibit 2.4: Comparison of regulatory risk and overall business environment amongst countries

The current level of government take in India is between 57 to 67 percent (for offshore fields), compared to an average of about 70 percent for oil- and gas-producing countries\(^4\), which may imply that India trails other energy-producing nations on this parameter. However, as discussed above, the level of government take that India can afford is a function of its resource attractiveness and its business friendliness. Thus, in comparing India’s government take to that of other countries, these factors need to be taken into account. Exhibit 2.5 compares the government take of different countries relative to level of estimated recoverable reserves, and shows that the current level of government take in India is in line with its prospectivity.

---

\(^4\) Based on comparative study of IHS CERA (2011)
Exhibit 2.5: India’s government take is in line with its prospectivity
3.2 Choice of petroleum regime

3.2.1 Petroleum regimes in a legal context

Petroleum regimes take many forms and exist in the context of a country's constitution and petroleum law.

Exhibit 2.8: E&P legal systems take many forms and exist in the context of the law and constitution

Constitutional provisions serve as the overarching structure under which activities of the oil and gas sector are conducted. They stipulate the role of federal, state and municipal governments, the role of a National Oil Company, private and foreign investments, and the type of host government contract that is possible in the country. The Indian constitution (Articles 294 – 297) mandates government ownership of hydrocarbon reserves. Thus, any contractual structure adopted by the Ministry of Petroleum and Natural Gas must ensure that the title of hydrocarbons is retained with the Sovereign.

Petroleum Law is the cornerstone of an effective petroleum legislative framework. It confirms state property rights to petroleum, creates a "Competent Authority" with jurisdiction over management of the state's interest (whether it be a Ministry, a regulatory body, a National Oil Company, or all of these).
Petroleum Regulations implement the policy and objectives of the Petroleum Law by contemplating host government contracts, establishing the mechanism for awarding the contracts, and creating environmental protection procedures.

Host government contracts are the result of the laws and regulations in place. In India, ORDA\(^5\) act, 1948, and PNG rules\(^6\), 1959, govern the upstream activities—including granting of E&P licenses and mining leases—in respect of Petroleum and Natural Gas which belongs to the government. In India, PNG rules allow creation of any contract whether it is concession, a production sharing contract, a joint venture or a service contract.

### 3.2.2 Description of four types of petroleum regimes

Following an empirical review of upstream regimes from countries across the world, four main legal/regulatory systems used by oil- and gas-producing countries can be distinguished: Concessions, Production Sharing Contracts, Service Agreements and Joint Ventures.

<table>
<thead>
<tr>
<th>Systems</th>
<th>Concession</th>
<th>PSC</th>
<th>Concession/PSC</th>
<th>JV</th>
<th>Services</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Geographic distribution of the different legal/regulatory systems</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

It is not uncommon for countries to use hybrid structures or a mix of regimes simultaneously.

*Exhibit 2.9: Concessions and PSCs are widely implemented*

Broadly speaking, Concessions are generally more adopted in developed countries, while Production Sharing Contracts are typically more popular in developing countries.

---

\(^5\) The Oilfields (Regulation and Development) Act, 1948

\(^6\) Petroleum and Natural Gas Rules, 1959
### 3.2.2.1 Concessions

In a Concession regime, the State transfers the right to explore and produce hydrocarbons in a certain area to the oil companies at the latter’s expense and risk. Oil companies then become the owners of the production, and may freely market the output as they see fit. Royalty and taxes paid by the oil company on its revenues constitute the receipts for the government. Royalties are paid on all production from the start of operations at a fixed or variable rate. These payments, since they are made before any kind of cost recovery, have a significant impact on the project’s Net Present Value (NPV), as it applies to total volume/revenue prior to cost recovery.

**Typical features from international cases**

Generally, two distinct types of fiscal regimes are observed in concession countries, based on the mix of fiscal instruments adopted: pure tax regimes and royalty/tax regimes. Pure tax regimes are prevalent in countries like the U.K. and Norway that have explicitly made the choice of removing royalties as a fiscal instrument, in order to maximize oil recovery in smaller and marginal fields that would otherwise have become uneconomical to exploit.

<table>
<thead>
<tr>
<th>Rate Sliding?</th>
<th>Royalty Valorem</th>
<th>Royalty Ad Valorem</th>
<th>Corporate Income Tax</th>
<th>Special Oil Tax</th>
</tr>
</thead>
<tbody>
<tr>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
</tr>
</tbody>
</table>

#### Exhibit 2.11: Two types of fiscal regimes in concession countries

Some general observations from international cases:

- In a typical OPEC agreement, the royalty rate is around 20 percent. However, elsewhere it can be as low as 5 percent, as in the case of Namibia.
- The royalty rate may vary (sliding-scale) with the level of production, as in China or Norway.
- Some recent adjustments to contracts have linked royalty payments to the financial performance of the given field or project, in order to provide incentives for marginal
developments. However, in such cases, the payments cease to be royalties in the traditional sense, and should be considered as “additional taxes”.

- Taxes are paid on net income, after the deduction of costs and royalty. The rate of taxation may be equal to the standard corporate tax rate in the country. It may also include an additional tax designed to capture “super-profits”, as in Norway, the U.K. and Australia.

**Pros and cons of Concession systems**

The pros and cons of a concession system are analysed both from the government’s and oil company’s perspective.

From government’s perspective, concession systems offer a number of advantages to:

- **Administrative and regulatory ease**: Once exploration and production licenses have been granted, the government does not get involved in the operational decision making in field development or budget approval. The regulator sets minimum working program at the time of the granting of the licenses, and oversees the E&P activity to ensure that operators adhere to certain environmental and safety standards.

- **Flexibility to adapt government take**: In concession regimes, since the governing law is based on national legislation, the state is within its rights to change the regulatory (fiscal) system, and increase or decrease taxes going forward.

There are several downsides too from the government’s perspective. The government has less operational control over the development of the field. The oil company is typically responsible for taking all operational decisions regarding field development. Also, fixed royalty arrangements deny the state the right to participate in any potential upside should production levels increase beyond initial estimates, or oil prices rise significantly.

From an oil company’s perspective, concession regimes offer a number of advantages:

- **Hydrocarbon ownership**: The fact that hydrocarbon ownership is fully passed on to oil companies means that all of discovered reserves can be booked to the company’s reserve base.

- **Operational flexibility**: Full operational freedom in E&P activities, without the need to get government approval for business activities and investment budgets.

However, from the investor’s perspective a major disadvantage of the “classical” concession system is its strong reliance on royalties as a component of government take. Royalties impose additional upfront costs on the operators, and since they are usually solely linked to revenues and unrelated to the development costs or the size of the field, it can often be uneconomical to develop smaller fields. This is not in the interest of either the oil company or the government. Therefore, a number of countries, such as Norway, the U.K., Denmark and Germany, have eliminated royalties to encourage the development of marginal fields.
3.2.2.2 Production Sharing Contracts

Production Sharing Contract is a contractual agreement signed between the host state and the Operating Company, whereby the two parties share the petroleum produced. In the event of successful commercial discovery, the Contractor is entitled to recover the amount of petroleum necessary to reimburse it for the costs incurred in exploring, developing and producing the oil and gas. The remainder of production is shared between the Contractor and the State, according to predefined percentages. The government retains ownership of hydrocarbons, and is considerably involved in the functioning and operations of the field development and production.

Typical features from international cases:

Like in concession countries, we can distinguish two types of PSC regimes, based on the mix of fiscal regimes that are adopted.

Some of the distinguishing features of a PSC are outlined herewith (based on our study of global trends):

- Production share may be fixed (e.g. Indonesia and Egypt), or variable. Variable production share can be a function of different variables:
  - Annual average production (Mozambique, China).
  - Cumulative production (Angolan shallow water).
  - Rate of return (Guinea, Angolan deep water).

Source: BCG analysis

Exhibit 2.12: Two distinct types of fiscal regime in PSC
- Ratio of cash flow to investment (India, Peru).
- Many PSCs now incorporate some of the fiscal terms of the tax and royalty system, such as royalties, taxes and additional profit taxes, too.

**Pros and cons of Production Sharing Contract**

Again, the pros and cons are analysed separately from the perspective of the government and the oil company.

PSCs offer unique advantages to the government:

- **Cost control**: Help maintain control over the cost expenditures of the oil companies. This is important, given the cost recovery provision in PSCs directly impacts the government's share of profit oil.
- **Operational control**: Provide ability to stimulate higher levels of exploration activity, by being able to apply minimum technical standards in the development of the fields.

However, the government’s participation in Management Committees and its exercising of direct control over operational investment decisions mean a high level of administrative and managerial burden for the state.

From the oil company's perspective, the concept cost recovery and profit sharing is attractive – enabling operators to recover the investments made before they share profits with the State. These contracts are preferred particularly, in countries with lower levels of data availability and large unexplored areas, as such contracts improve the risk-reward trade-off from investor's point of view. The flip side of cost recovery is the scrutiny the oil company attracts in terms of all expenditure and investment-related decisions, which may sometime slow down decision making and thus impact project IRR.

**3.2.2.3 Service Agreements**

A typical Service Agreement is a fee-for-service arrangement, where the contractor takes no risk in the exploration of fields. The contractor receives payment for his services in cash (calculated as the sum of costs and a mark-up fee), which is not subject to the discovery of reserves. The contractor does not acquire the title to the resource, and hence has no upside gain from production.

**Typical features in international cases:**

Services Agreement is usually adopted in countries where the hydrocarbon prospectivity is high, or where the constitution of the concerned nation does not allow the title to natural resources to be given to oil companies. For example, countries in the Middle East typically use service agreements for exploitation of their oil and gas resources. Service agreements can also incorporate a risk clause, under which, the oil company funds development upfront and later, recovers costs plus an agreed rate of return upon the commencement of production (but only in
In the event of successful production, the oil company is compensated for the exploration risk by in kind (part of the oil production), or an option to buy crude at a discount off market value. Known as risk service agreements (RSAs), these types of service contracts were used by Petrobras and have been adopted in Mexico (1950s) and Iran and Iraq (1960), but are not common practice anymore.

**Pros and cons of service agreements**

Service agreements would not be desirable for the Indian context, considering that they are usually not preferred by oil companies and governments alike.

<table>
<thead>
<tr>
<th>Characteristic features</th>
<th>Implications</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOC is responsible for all E&amp;P investments—may hire OCs for the execution of some operations</td>
<td>• Requires investment of large amount of financial resources&lt;br&gt;• Imposes considerable exploration risk on the state&lt;br&gt;• Requires high levels of operational experience from NOC</td>
<td>• State needs to compensate OCs for performed work at cost plus (fixed) margin&lt;br&gt;• State has to compensate OC even in case of no discovery&lt;br&gt;• NOC needs to play an active role as service provider, and offer the right level of operational remuneration</td>
</tr>
<tr>
<td>All hydrocarbons are owned and marketed by the state</td>
<td>• Limited attraction for International Oil Companies</td>
<td>• OCs cannot account the discovered reserves on their books&lt;br&gt;• Compensation is through modest fixed margins&lt;br&gt;• No potential for upside in windfall profits</td>
</tr>
<tr>
<td>OC remuneration is defined as compensation for costs plus fixed profit margin</td>
<td>• Often leads to cost over-runs&lt;br&gt;• Often leads to sub-optimal production levels</td>
<td>• OCs receive fixed return margins on incurred expenses and have hence no incentive to minimize costs&lt;br&gt;• Fixed returns do not provide an incentive for OC to invest best technology</td>
</tr>
</tbody>
</table>

**Service contracts impose high risk on government, are not attractive for IOCs, and often lead to cost-overruns**

*Note: Typical variation to pure service contracts is a risk service contract wherein the exploration risk is taken by the OC and it is rewarded back in oil. However, this variation is attractive only in high prospectivity countries and hence isn’t relevant in Indian context.*

**Exhibit 2.13: Pure service contracts not desirable option for India**

### 3.2.2.4 Joint Ventures

Joint Venture system, also known as participation or association, is typically adopted by producing countries where the National Oil Company (NOC) holds the original right to carry out E&P activities. It essentially consists of the organization of a special purpose entity, as a separate legal entity, with participation from the government (through the NOC), and the oil company in proportion to their equity stakes.

A classical example of a country with predominantly JV system is Venezuela, where it is mandatory to set up a JV (referred to as mixed company) between PDVSA (the local NOC)—and
the private oil company to undertake E&P activities. Nigeria is another country to have adopted the JV system widely, from the 1970s to the 1990s. Meanwhile, in the case of Angola, despite the JV system being allowed for in the law of the country, it is rarely used in practice.

From these international case studies, the most important reason for adopting JV legal system seems to be either a set of constitutional constraints, desire to maintain operational control over E&P activity, or desire to transfer knowledge and technical skills from international operators to the local NOC. And it essentially means equity exposure to potential risks from E&P activity.

Analyzing the features of a JV system from the international case studies, it is inferred that a JV system may not fulfill Indian government’s objectives well, due to the following reasons -

- **Shared hydrocarbon ownership with the state**: Ownership of hydrocarbon is shared with the oil company to the extent of equity participation by the oil company.
- **Need for high level of government involvement in operational matters**: In a JV system, government take is largely dependent on net profits, making it imperative for the authorities to monitor and control the project costs and expenditures. This will require a high level of administrative burden for the Indian government, similar to the current system.
- **Government is also exposed to exploration risks**: All risks (including exploration risks) and costs are shared (based on equity stake) by the government and the oil company. This may not be not desirable for the Indian government

### 3.2.3 Comparison between the four contractual structures – synthesized from country benchmarking

From the extensive case studies developed for the selected countries, it is inferred that the four contractual structures distinguish themselves along four primary criteria – hydrocarbon ownership, level of risk taken by the government, administrative burden on the government, and level of operational control exercised by the government. This is laid out in the Exhibit 2.10 below.
Exhibit 2.10: Comparison of the four prevalent fiscal systems

<table>
<thead>
<tr>
<th>Hydrocarbon Ownership</th>
<th>Hydrocarbons</th>
<th>Production Sharing Contracts</th>
<th>Service Contracts</th>
<th>Joint ventures</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Legal &amp; Contractual Instrument</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Concessions</strong></td>
<td>Concession Agreement, License Agreement and Lease</td>
<td>Production Sharing Contract</td>
<td>Services Agreement without a risk clause</td>
<td>Articles of Association, and other documents for SPE</td>
</tr>
<tr>
<td><strong>Production Sharing Contracts</strong></td>
<td>Before extraction: State</td>
<td>Before extraction: State</td>
<td>Before extraction: State</td>
<td>Production is shared between Host State and OC, proportional to their respective equity interests</td>
</tr>
<tr>
<td></td>
<td>After extraction: OC (at wellhead)</td>
<td>After extraction: State/OC, each proportional to its profit oil share</td>
<td>After extraction: State</td>
<td></td>
</tr>
<tr>
<td></td>
<td>OC can book reserves</td>
<td>OC can book reserves</td>
<td>OC paid in cash and cannot book reserves</td>
<td></td>
</tr>
<tr>
<td><strong>Company entitlement</strong></td>
<td>Gross production less royalty and taxes</td>
<td>Cost oil/gas + profit oil/gas - taxes</td>
<td>Service fee (usually fixed margin on costs / production) less taxes</td>
<td>Share of produced HC profits minus taxation</td>
</tr>
<tr>
<td><strong>Level of Control</strong></td>
<td>OC makes all upfront E&amp;P investments without guaranteed returns</td>
<td>OC takes exploration risk and makes all upfront investment. OC &amp; Government share development and production costs after commercial discovery</td>
<td>State: OC gets full compensation of costs and guaranteed margin</td>
<td>State assumes the risk related to the percentage it holds in each business</td>
</tr>
<tr>
<td><strong>Administrative and Managerial Burden</strong></td>
<td>Low: no participation in management committees. Government focuses on setting industry-wide policies</td>
<td>High: government needs to attend management meetings for all the fields and take a view on all individual operational decisions</td>
<td>Very high: government needs to plan and execute on the development of the entire oil and gas industry</td>
<td>High: government has mandatory operational involvement in the fields</td>
</tr>
<tr>
<td><strong>Level of Burden</strong></td>
<td>Government participates in operational and investment decision-making through management committees</td>
<td>High: government decides where and how much to invest in exploration and development</td>
<td>High: government has mandatory operational involvement in the fields</td>
<td></td>
</tr>
</tbody>
</table>

1. Ownership usually passes at point of export. Source: BCG analysis

Key distinguishing features
3.2.4 **Implications for India**

As discussed in the chapters above, Service Contracts and Joint Venture contracts are not desirable regimes to adopt as they can be deterrents for investment from oil companies, and also impose high burden on the government for investment of risk capital.

As described earlier (refer to Exhibit 2.10), four key parameters need to be considered while assessing the optimum fiscal regime for a country:

- Ownership of hydrocarbons
- Risk-reward trade-off for investor
- Administrative burden on the government
- Level of operational control by the government

Here is a comparison of PSC and concession regimes, based on these four parameters:

<table>
<thead>
<tr>
<th>Ownership of hydrocarbons</th>
<th>Concessions</th>
<th>Production Sharing Contracts</th>
</tr>
</thead>
<tbody>
<tr>
<td>Title to all the extracted hydrocarbons passes to the investor at the well-head</td>
<td>Hydrocarbon ownership is retained by the government</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Risk-reward trade-off for the investor</th>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>In a low prospectivity country like India, concessions are relatively less attractive as investor has to upfront pay royalty irrespective of its costs / commerciality of the field</td>
<td>• Preferred by investors where the risk is high as profit sharing is subsequent to cost recovery by the investor</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Degree of government administrative burden</th>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eliminates need to audit and scrutinize costs; cost inspection carried out mainly through national tax mechanism</td>
<td>• Significant burden of cost audit due to cost oil/profit oil split</td>
<td></td>
</tr>
<tr>
<td>• Government participates in all decision making (including technical) through Management Committee (MC) meetings</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Degree of government’s operational control</th>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Limited control on operational decisions from oil companies beyond broad powers of approval and overseeing the fulfillment of MWP</td>
<td>• Government through the MC co-decides how operations will be conducted</td>
<td></td>
</tr>
</tbody>
</table>

Both concession and PSC regimes can be inherently attractive, and the choice depends on how the government prioritizes its objectives.

There are a few essential pre-requisites in order for a concession regime to be effective and successful in attracting E&P investments:

- **Fiscal stability**: The country’s fiscal policy regime should be perceived as being stable, as this will ensure certainty in the minds of investors with regard to the returns they can expect from
their investments. Any changes in the fiscal structure that impact the overall take for the investor are a significant deterrent for inflow of private capital into the sector. For example, the U.K., which has a concession regime, raised the supplementary charges on North Sea oil and gas production from 20 percent to 32 percent in March 2011, following a rise in oil prices. This move was strongly criticized as the North Sea tax regime has undergone frequent changes over the past decade, and this persisting instability is likely to be detrimental to investments since the oil companies are unable to assess the overall returns from their investments with any degree of certainty.

- **Availability of geological data**: Oil companies look for upfront availability of geological data to bid appropriately for blocks in concession systems. In the absence of data, the oil companies will be hesitant to bid high fiscal terms for the government, (as they may build significant premium in their assessment of blocks) which may not be desirable.

Similarly, in the case of a PSC structure, a few enablers are necessary to ensure an effective petroleum regime and attract E&P investments:

- **Strong regulatory institutions**: Usually, PSC systems need strong regulatory institutions, equipped with capacity and technical expertise, to monitor and exercise operational control in order to ensure strong and efficient governance processes. For example, a strong regulatory structure underpins the PSC regime in Malaysia. The concerned regulator, Carigali, has a staff of almost 400 personnel who monitor nearly 80 PSC contracts. Also, Carigali enforces mandatory training of its employees by the oil companies on all contracts. Thus, Malaysia has built a strong regulatory capacity as well as the capability to manage the PSCs.

- **Dispute resolution mechanisms**: PSC inherently involves two stakeholders—the government and the oil company, which sometimes have conflicting objectives. Given the significant involvement of both parties in operational matters, instances of conflict between the partners cannot be ruled out. In order to ensure smooth functioning of the contract and efficient development of the field, it is critical to have strong dispute resolution mechanisms in place.

The current PSC system in India can be adapted and strengthened to address some of the inherent conflicts in the regime, as well to address concerns that have been raised by domestic and international investors. This will require some significant changes, but will continue to mean considerable involvement of the government and a high administrative burden.

On the other hand, a concession system can meet the needs of both the government and investors, although it will require making changes to address concerns pertaining to fiscal stability, and creating a conducive enabling environment to ensure government gets attractive bids.

---

7 Based on interaction with the regulatory authorities in Malaysia
Appendix 1: Country selection criteria

Criterion 1: Attracting investments

The level of exploration-related investments that a country has attracted needs to be put into perspective vis-à-vis its level of prospectivity. Moreover, it is important to keep in mind that state-owned National Oil Companies account for the bulk of the investments in a number of countries; hence the level of exploration-linked capital expenditure is not fully representative of the level of success a country has had in attracting private sector investments.

In order to arrive at a more objective measure of a country’s relative success in attracting exploration capex, we normalized the level of exploration capex from private operating companies relative to the countries level of Yet-to-Find potential, and ranked them accordingly (Exhibit 3.1).

Exhibit 3.1: India’s ability to attract investments into E&P

Invested exploration capex differs widely; in countries like China, Brazil and Mexico mainly driven by NOC spend

<table>
<thead>
<tr>
<th>Country</th>
<th>Total Exploration Capex (2000–2010, ($Bln))</th>
</tr>
</thead>
<tbody>
<tr>
<td>United States</td>
<td>177</td>
</tr>
<tr>
<td>China</td>
<td>72</td>
</tr>
<tr>
<td>Canada</td>
<td>52</td>
</tr>
<tr>
<td>Brazil</td>
<td>37</td>
</tr>
<tr>
<td>Australia</td>
<td>25</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>18</td>
</tr>
<tr>
<td>Norway</td>
<td>21</td>
</tr>
<tr>
<td>Angola</td>
<td>21</td>
</tr>
<tr>
<td>Russia</td>
<td>18</td>
</tr>
<tr>
<td>Mexico</td>
<td>14</td>
</tr>
<tr>
<td>India</td>
<td>12</td>
</tr>
<tr>
<td>Nigeria</td>
<td>12</td>
</tr>
</tbody>
</table>

Note: ranking is after filtering of countries with Yet-to-Find potential reserves smaller than 10 bln BOE
Source: Rystad

In terms of attracting IOC capital investments relative to size of potential reserves in place, UK, Egypt and Colombia have been most successful

| Country   | Total IOC Exploration Capex/Yet to Find Potential (US$/BOE)
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>United Kingdom</td>
<td>1.61</td>
</tr>
<tr>
<td>Egypt</td>
<td>1.01</td>
</tr>
<tr>
<td>Colombia</td>
<td>0.72</td>
</tr>
<tr>
<td>Angola</td>
<td>0.71</td>
</tr>
<tr>
<td>United States</td>
<td>0.61</td>
</tr>
<tr>
<td>Norway</td>
<td>0.53</td>
</tr>
<tr>
<td>Malaysia</td>
<td>0.51</td>
</tr>
<tr>
<td>Nigeria</td>
<td>0.39</td>
</tr>
<tr>
<td>Australia</td>
<td>0.33</td>
</tr>
<tr>
<td>Canada</td>
<td>0.30</td>
</tr>
<tr>
<td>Mauritania</td>
<td>0.14</td>
</tr>
<tr>
<td>Libya</td>
<td>0.12</td>
</tr>
<tr>
<td>India</td>
<td>0.12</td>
</tr>
<tr>
<td>Oman</td>
<td>0.11</td>
</tr>
<tr>
<td>Indonesia</td>
<td>0.10</td>
</tr>
<tr>
<td>Tunisia</td>
<td>0.08</td>
</tr>
<tr>
<td>Brazil</td>
<td>0.08</td>
</tr>
<tr>
<td>Liberia</td>
<td>0.08</td>
</tr>
<tr>
<td>Argentina</td>
<td>0.07</td>
</tr>
<tr>
<td>China</td>
<td>0.07</td>
</tr>
</tbody>
</table>

China has a lot of exploration capex investments, but ~90% is from local NOCs financed by the State

India’s exploration capex is ~65% invested by independent and integrated private oil companies

Note: ranking is after filtering of countries with Yet-to-Find potential reserves smaller than 10 bln BOE
Source: Rystad
Criterion 2: Increase in reserves

For this criterion, it is important to factor in the ease of reserve discovery in countries with high prospectivity. Hence we filtered our country selection approach, using the change in proven reserves relative to existing reserves as a ranking metric (Exhibit 3.2).

Exhibit 3.2: India’s ranking on addition to reserves

Criterion 3: Increase in production

Finally, we ranked the countries according to their relative success in expanding production over the past decade. Taking into account their starting base, the nations were rated based on percentage change in production between 2001 and 2011 (Exhibit 3.3).
Exhibit 3.3: India's ranking on production growth
5 Appendix 2: Detailed Country Profiles
Appendix 2

Upstream E&P commercial structures
Global Practices

September, 2012
Agenda

Columbia
Malaysia
US GOM
Angola
Brazil
Norway
Nigeria
China
Indonesia
Agenda

Columbia
Malaysia
US GOM
Angola
Brazil
Norway
Nigeria
China
Indonesia
# Colombia Fiscal System (1/2)

## Government Objectives

1. **Build National Wealth**
2. **Minimize Govt. Involvement in Operations**
3. **Maximize Acreage Utilization**
4. **Self-Sufficiency**

## Regulatory System

- Concession system
- Surge in E&P Investments led by Regulatory Reform

## Boundary Constraints

- Attract IOCs
- Explore the undeveloped areas
- Stability of new Policies
- Export taxes applicable

## Adopted Policy

- Sliding Royalty\(^1\), 8% - 25% (\(\alpha\) production)
- High Price Participation, 30%-50% of incremental revenue
- Exploration & Production rentals\(^2\), \$5mm
- Additional royalty to ANH\(^3\), 2%-33%
- Attracting IOCs by attractive terms, regulatory reform & improvements in security

## Benefits to Colombia

- Fair for small and large companies, independent of costs
- Maximizes Govt. revenue increase in case of increase in oil price
- Lease payments ensure that there is an efficient use of land
- Keep the national agency, ANH, self-sustainable
- New investments of \$xx.xx since 2004; increased production and overall increase in Govt revenue
- Reduce Govt. involvement in the operations of the NOC; provides pvt. capital to fund more projects.
- Allows competitive exploration of smaller fields, that may not interest the large NOC
- Reassures IOCs of the stability of the legal and fiscal policies for guarding their investments

---

1. Share of pre-take NPV (10%) for a standard field of 500M bbls.
2. Standard investor post-tax IRR for field of 500M bbls, ranging from oil price of \$25-60/bbl; 3. Varies with the fixed production rate; 4. Based on approx 5000 sq. km area; 5. Negotiable with ANH
Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; IHS CERA report, 2011; web research

---

Global E&P Regimes - Country profiles.pptx

---

Copyright © 2012 by The Boston Consulting Group, Inc. All rights reserved.
## Colombia Fiscal System (2/2)

<table>
<thead>
<tr>
<th><strong>Adopted Policy</strong></th>
<th><strong>Benefits to Colombia</strong></th>
</tr>
</thead>
</table>
| **3. Maximize Acreage Utilization** | • New licensing procedure for assignment of blocks:  
- Separate licensing for rounds & tenders, relinquished areas and free areas;  
- Selection based only technical capabilities and work proposal;  
- Established new contract schemes for technical evaluation agreement (TEA)  
• Building an advanced NDR system called EPIS with large investments to build a comprehensive and centralized data base | • Encourages E&P to maximize recovery. Allocates the fields based on company’s technical and financial capability.  
• Set process for relinquished areas ensure a thorough analysis of resource potential in the acreage  
• Selection criteria is not based on the fiscal terms but on the maximal resource extraction. Financial terms are negotiated after the selection  
• Encourages exploration and data gathering at no cost to the Govt. OC gets preferential treatment for the E&P  
• Provides transparent and quick information to all investors to ensure a healthy competition and application of best technology |
| **4. Self Sufficiency** | • Match production to meet the growing consumption needs of the country  
• Incentives for exploration in the undeveloped areas via E&P contracts or TEA | • Domestic production diminished the reliance on the petroleum imports; Colombia started to export oil in 2010  
• Accelerates the creation of database of reserves, which upon finding resources help in making Colombia an attractive destination for more investments  
• Promotes competition by encouraging participation |
Colombia: impact of policy on output

**Exploration and Development Capex (Mln US$)**

- NOCs
- IOCs

**Number of Rigs**

- Offshore
- Onshore

**Oil and Gas Production (mln boe/d)**

- Gas
- Oil

**Oil and Gas Reserves (Bln boe)**

- Gas
- Oil
Colombia Fiscal System (I)

General context

Reasons for selection

- Colombia has dramatically transformed from being a net importer of crude oil to exporting crude oil.
- Successful in reforming the regulation to attract IOCs for E&P
- Creation of ANH in 2003, an independent body to manage the E&P activities, grant contracts and
- Improved security and pro-business policies attracting new E&P companies

Macroeconomic data

- GDP (USD Billion) = 472
- Population (Million inhab.) = 46.4
- GDP per capita (USD) = 10,248

Summary of the oil industry

Oil and gas context

- Since 1999, Colombian government has taken measures to make the investment climate more attractive to IOCs.
- Oil production was flat to declining in the period from 2000 to 2005. However, since 2006, the production has steadily increased and due to a surge in investments.
- Colombia had 1.9 billion barrels of proven crude oil reserves in 2011, the fifth-largest in South America.
- ANH reported that Colombian production reached 923,000 barrels per day in May 2011.
- Colombia consumed 296,000 bbl/d in 2010, allowing the country to export most its oil production.
- United States is the largest destination for Colombia’s oil exports.
- In 2010, Colombia exported 365,000 bbl/d of crude oil and refined products to the United States.
- Upstream sector initiatives include allowing foreign oil companies to own 100 percent stakes in oil ventures and compete with Ecopetrol, the NOC, the establishment of a lower, sliding-scale royalty rate on oil projects; and longer exploration licenses.

Oil and Gas Production

- Mboe/d
- Oil and Gas Reserves (K mmboe)

Source: Rystad, IHS Cera, 2011

Global E&P Regimes - Country profiles.pptx
Colombia Fiscal System (II)

Characteristics of Fiscal System

Financial characteristics

- Property right is with State while underground; once explored property is transferred to operator at point of delivery
- Established a sliding-scale royalty rates to encourage smaller companies
- Permitted IOCs to own 100% stake in oil ventures
- Annual rent imposed in order to incentivize efficient use of awarded acreage
- Voluntary relinquishment during exploration period, mandatory before production period
- No special considerations for NOCs
- No tax on remittances by IOCs

General terms

- Exploration under the work program for 6 years, 8 years for unconventional HCs
- Longer production licenses for up to 24 years
- High Price Participation:
  - Triggers when the price exceed the base price set by ANH annually
  - Only when gross cumulative oil production exceeds 5mm barrels, or
  - Only after 5 years of gas production commencement
- Direct contracting for Free Areas (like OALP – separate bid for production)
  - Selection based on technical, legal, financial and operational capabilities
- Competitive Process for Released Areas
  - Selection based on objective point based proposed Minimum Exploration Program

Main government compensation mechanisms

Fiscal terms of concession agreement

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royalty</td>
<td></td>
<td>Sliding rate tied to fixed production rates &amp; HC type</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Oil 8% - 25%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Gas 6.4% - 20%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Heavy Oil 6% - 18.75%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Gas Offsh. 4.8% - 15%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Unconv. HC 4.8% - 15%</td>
</tr>
</tbody>
</table>

Other government compensation mechanisms

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Additional Royalty</td>
<td>2% - 33%</td>
<td>ANH production participation of production after royalty, biddable</td>
</tr>
<tr>
<td>High Price Participation</td>
<td>30% - 50%</td>
<td>Based on incremental revenue</td>
</tr>
<tr>
<td>Other Payments</td>
<td></td>
<td>Exploration Rental $3.06 per ha for first 100 ha, $4.49 per ha for additional ha</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Production Rental $0.1162 per barrel for oil, $0.0162 per Mcf for gas</td>
</tr>
</tbody>
</table>

Income Tax 33%  General corporate tax

1. Share of pre-take NPV (10%) for a standard field of 500M bls, 2. Standard investor post-tax IRR for field of 500M bls, ranging from oil price of $25-60/bbl

Source: IHS CERA report, 2011

The Boston Consulting Group

Global E&P Regimes - Country profiles.pptx
Colombia Fiscal System (III)

New policy mechanisms ...

Direct contracting for Free Areas
• Applies to E&P and TEA on Free Areas based on first come first served
• Selection criteria based on application with minimum legal, technical, financial and operational capabilities
• When a proposal is accepted direct negotiation begins
• Operator pays surface fees and own costs

Competitive Process for Released Areas
• Applies to Relinquished areas released by ANH
• A selection will be made based on the highest bid amount.
• Secondary criteria is the proposed work program for the first phase based on the table below

Contracting by a tender, round or any other special process
• Applies to E&P contracts in Special Areas.
• A public invitation for proponents to offer with a subsequent objective selection of the most favorable proposal based on legal, technical, financial and operational capabilities.
• ANH conducts road shows worldwide and conducts bidding rounds wherein they invite the IOCs for E&P

... yielding to increasing investments

• Activities such as geological study, seismic operations, and stratigraphic wells
• Nominal average surface fee of $20/sq.km for 18 months in case of onshore, 24 months in case of offshore
• 303 E&P contracts and 89 TEAs awarded from 2004 – 2011
• Contractor required to submit the report and analysis after the exploratory work is over

• Objective manner of evaluation the bidders
• Goal is to maximize the recovery factor
• Data from the operator goes into centralized database, which is made available with the new license

• Traditional means for licensing out the areas based on new proposals
• Work programs for each of the three phases: Exploration (6yrs+), Evaluation (2yrs+) and Exploitation (24yrs+)
• Extension

Source: Global E&P Regimes - Country profiles.pptx
Colombia Fiscal System (IV): Key Learning

Pro-business policy reform ...

Characteristics
- Concessionary regime (Royalty, Tax, High Price Participation)
- Significant improvements in security of infrastructure, legal stability
- Successful in reforming the regulation to attract IOCs for E&P

Positives
- Improved security and stable political environment
- Full operational control of upstream properties
- Partial privatization of the NOC, Ecopetrol, no influence on ANH
- In 2010, Colombia production exceeded the consumption allowing them to export most of its oil, primarily to US

Significant events
- 2003: Founded ANH, an independent body to manage the E&P activities, grant contracts and regulate E&P activities
- 2006: Pro-industry policies adopted by President Urebe

Key learnings
- Energy policy has to take into account international environment
- Contract terms alone are not enough
- Separation of regulator from operator pays off
- Significant success in attracting smaller E&P companies through pro-business fiscal policies and transparency
- Increased E&P activity at the expense of government take

Significance for India
- Potential to design variable fiscal terms without the need for monitoring costs
- Implicit use of rewards and penalties by means of sliding fiscal terms to exploit high oil prices

... yielding to new investments and E&P activity

Exploration Capex (US mm)

Oil and Gas Production (Mboe/d)

Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; Rystad; ANH website; web research
Colombia Fiscal System (V): Regulator, Reforms, Repository

NOC: Ecopetrol

- Ecopetrol, the NOC was removed from being responsible for licensing, monitoring, and administering agreements in 2003.
- Now Ecopetrol competes on equal basis with the other IOCs
- Ecopetrol also looks to be a preferred business partner for the IOCs, leveraging its local knowledge

Pro-Business Reforms

- Allowed 100% FDI
- Lower sliding scale of royalty
- Longer terms for exploration
- Allowed Govt. to get into stability agreements
- Improved security, reduced risk of doing business
- Lowered Govt. take to incentivize E&P activities

Regulator: ANH

- Formed in 2004, with main functions as follows:
  - Issuing Licences to OCs for E&P
  - Acquisition of geological information in frontier areas
  - Selecting acreage to be offered
  - Technical regulator to ensure best practices of E&P are being followed
  - Maintaining and providing data

- Reports to Ministry of Energy and Mines (MEM)
  - Potential of undermining the independence

Data Repository

- Exploration & Production Information Services, EPIS, created in 2000 to be the official data repository
- EPIS is an advanced system that allows acquisition, validation, and uploading of the information from the operators
- EPIS is open to use for all; ability to restrict access for selected data
- EPIS facilitates providing information to the users of exploration and investment projects
- Data acquisition and funding for EPIS is provided by ANH
Colombia Fiscal System (VI): Features

<table>
<thead>
<tr>
<th>Features</th>
<th>Possible learnings</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Regulatory System</strong></td>
<td></td>
</tr>
<tr>
<td>• Concession system</td>
<td>• Reassures the IOCs to invest despite high perception of the risk on Govt. stability</td>
</tr>
<tr>
<td>• Agreements for Stability, E&amp;P and TEA</td>
<td></td>
</tr>
<tr>
<td><strong>Government Role</strong></td>
<td></td>
</tr>
<tr>
<td>• ANH, which is an independent body to manage the E&amp;P activities, grant contracts and regulate E&amp;P activities</td>
<td>• Self sustaining agency that has no influence from the NOC</td>
</tr>
<tr>
<td>• No active state participation</td>
<td>• Low level of administrative burden on the Government</td>
</tr>
<tr>
<td>• Self sustaining agency that has no influence from the NOC</td>
<td>• Govt does not seek to have control over operations</td>
</tr>
<tr>
<td>• Govt does not seek to have control over operations</td>
<td></td>
</tr>
<tr>
<td><strong>Role of NOC</strong></td>
<td></td>
</tr>
<tr>
<td>• NOC (Ecopetrol) competes on equal terms with other oil companies</td>
<td>• No discrimination against IOCs</td>
</tr>
<tr>
<td><strong>Fiscal Terms</strong></td>
<td></td>
</tr>
<tr>
<td>• 8% to 25% Royalty based on fixed production rates; lower rates for gas, unconventional HCs &amp; offshore</td>
<td>• Non-negotiable royalty, captures government take when the production rate is high, incentivizes smaller fields</td>
</tr>
<tr>
<td>• 2% - 33% Additional Royalty to ANH, biddable</td>
<td>• Govt. shares the reward when prices rise unexpectedly</td>
</tr>
<tr>
<td>• High Price Participation, based on incremental revenue over the annually set base price</td>
<td>• Same income tax rate for all corporations</td>
</tr>
<tr>
<td>• 33% income tax</td>
<td>• Lower cost audit burden; share of audit shared with regular tax and fiscal authorities</td>
</tr>
<tr>
<td>• Rentals per ha of area used for Exploration and Production</td>
<td></td>
</tr>
<tr>
<td><strong>Licensing rounds</strong></td>
<td></td>
</tr>
<tr>
<td>• Separate licensing for rounds &amp; tenders, relinquished areas and free areas; selection based only technical capabilities and work proposal; financial terms are negotiated after the selection</td>
<td>• Clear objective for each licensing procedure, distribution of risks</td>
</tr>
<tr>
<td>• Maximization of E&amp;P for all sizes</td>
<td></td>
</tr>
<tr>
<td><strong>Innovative Terms and Solutions</strong></td>
<td></td>
</tr>
<tr>
<td>• Separate terms and licensing rounds for relinquished areas and unexplored areas</td>
<td>• Encourages exploration and data gathering at no cost to the government.</td>
</tr>
<tr>
<td></td>
<td>• Encourages participation of smaller companies into mature and less technically challenging fields</td>
</tr>
</tbody>
</table>
Agenda

Columbia
Malaysia
US GOM
Angola
Brazil
Norway
Nigeria
China
Indonesia
Malaysia Fiscal System (1/2)

Government Objectives

1. Ensure Fair Investor Return
2. Retain control over Production
3. Maximize Production
4. Local Industry Development

Regulatory System

- PSC system (R/C based)
- Complex fiscal system
- Among Highest Govt. Take in Asia

Boundary Constraints

- Attract IOCs
- Explore the undeveloped areas
- Incentivize marginal fields
- Export taxes

Government Objectives

1. Ensure Fair Investor Return
   • Fixed Royalty of 10%
   • Cost recovery ceiling from 30% - 70%
   • Income Tax, 38%
   • Profit Sharing, 10% - 90%
   • Excess Profit Payments, 70% of contractor's incremental profit share

2. Retain control over Production
   • Petronas has a right to carried interest in any exploration block
   • After discovery Carigali becomes a working partner

Adopted Policy

Benefits to Malaysia

- Low royalty rate incentivizes investments in E&P
- Govt. recovers returns faster, still allowing recovery of investor costs
- Govt. take from profit share increases with R/C and production
- Maximizes Govt. revenue in case of increase in oil or gas price
- Ensures Govt. involvement in the operations of the fields;
- Ability to perform cost audit and supervision of practices on a regular basis
- Shares production costs with the OCs, encourages production
- Carigali acts as a facilitator between the Govt. and the OC to ensure smoother process

Govt. take 1: 93%
IRR 2: 7%

Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; Wood Mackenzie; web research
Malaysia Fiscal System (2/2)

<table>
<thead>
<tr>
<th>Adopted Policy</th>
<th>Benefits to Malaysia</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Sliding scales of fiscal terms linked to revenue/cost ratio and production</td>
<td>• Encourages development of smaller fields, which form a significant part of Malaysia’s resources</td>
</tr>
<tr>
<td>• New incentives for encouraging investments in marginal fields proposed in the new petroleum act, 2011</td>
<td>• Encourages E&amp;P to the fullest extent. Allocates the fields based on company's technical and financial capability.</td>
</tr>
<tr>
<td>• Use of risk service contracts for marginal areas</td>
<td>• As oil fields are maturing, Govt. focused on enhancing output from existing fields</td>
</tr>
<tr>
<td>• Requirement to train Petronas personnel during the contract period</td>
<td>• Increase the recovery of less attractive resources</td>
</tr>
<tr>
<td>• Requirement to use local services to the extent possible</td>
<td>• Develops competence in the NOC by means of technology and knowledge transfer including latest technology adoption and builds a team of local experts</td>
</tr>
<tr>
<td></td>
<td>• Promotes local industry and creates local jobs</td>
</tr>
<tr>
<td></td>
<td>• Potential to form a cluster of competitive and innovative industry related to E&amp;P</td>
</tr>
</tbody>
</table>

Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; web research
Global E&P Regimes - Country profiles.pptx
Malaysia: Impact of policy on output

**Exploration and Development Capex (Mln US$)**

- NOCs: 20, +6%
- IOCs: 20, +15%

**Number of Rigs**

- NOCs: 6,000, +15%
- IOCs: 8,000, +6%

**Oil and Gas Production (mln boe/d)**

- Gas: 1.5 to 1.8, +2%
- Oil: 1.6 to 1.8, +2%

**Oil and Gas Reserves (Bln boe)**

- Gas: 18 to 20, +1%
- Oil: 19 to 20, +1%
Malaysia hydrocarbon profile (I)

General context

Reason for selection

- Comprehensive fiscal policy with high government take, deterred new large investments recently
- Historically successful in building strong local NOC with very deep experience while attracting IOCs
- New initiatives to explore the mature fields and to exploit the existing infrastructure

Macroeconomic data

- GDP (USD Billion) = 279
- Population (Million) = 28
- GDP per capita (USD) = 15,568

Summary of the oil industry

Oil and gas context

- Malaysia is the 26th largest producer of crude oil, and 14th largest producer of natural gas in the world.
- Most of the E&P occurs in the oil and gas fields in the shallow waters off Peninsular Malaysia since the 1960s.
- E&P dominated by NOC, Petronas, but IOCs such as Exxon, Shell, Total and Murphy have been participating in a substantial manner
- As these fields mature, the new focus is on the deep water potential
- Increasing demand of Gas has led to construction of gas pipelines from Thailand and Indonesia
- Several smaller operators have been successful by E&P in overlooked acreage within mature areas
- Petronas Carigali is planning to set up a Shale Technical Centre of Excellence in Kuala Lumpur with Halliburton
- Two risk service contracts offered recently to encourage investments in marginal fields in 2011 with a goal to increase the recovery of HCs

Oil and Gas Production

Oil and Gas Reserves (K mmboe)
### Exploration and production history

|----------|-----------------------|---------------------------------|
| • Before 1970, Malaysia imported all its oil requirements  
  • Started awarding acreage through concessions regime  
  • Petronas was formed with exclusive rights to Malaysian HCs, 1974  
  • Most E&P done by Petronas followed by Exxon and Shell  | • PSCs introduced in 1976  
  • Signature bonus was removed from PSC & const recovery was increased from 20% to 50% in 1985 resulting in a surge in the licensing activity  
  • Over time, the perception of poor prospectivity brought a slowdown in bids  
  • In 1999, deepwater PSC was created for very high cost, high risk projects targeted toward big IOC's with experience in deep water  
  • Eliminated the | • Fiscal terms of PSC changed to R/C terms in 1996.  
  • The new terms caused a new surge in the licensing activity, trebled the number of operators  
  • 11 deepwater blocks awarded since 2005 expected to be the most prospective acreage in Malaysia  
  • Range of fiscal incentives were announced in 2010 to promote investment in marginal fields to maximize recovery |

### State participation and role

#### Historically active role ...

- Petronas is the only NOC of Malaysia, wholly owned by the Government. It plays a role in upstream regulations in form of Petronas Carigali which is the E&P subsidiary of Petronas.
- Petronas Carigali has been responsible for managing the PSCs in Malaysia.
- Petronas Carigali works alongside the contractors to oversee the E&P activities for oil and gas.
- Enforce the requirement on the contractors to purchase goods and services locally to the maximum extent possible.

#### Participation and Involvement has increased ...

- In the recent years, Pertronas Carigali has played a larger role in the oversight, by embedding themselves within the OCs more deeply.
- Carigali responsible for formulation of policies and guidelines of the Malaysian PSC to optimize the country's oil and gas reserves.
- Carigali has been acquiring new technologies and undergoing trainings with the IOCs for each project to build its knowledge base.
- Additionally, Petronas Carigalli also takes on E&P projects abroad as a commercial company.

Malaysia hydrocarbon profile (III)

Characteristics of Fiscal System

Financial characteristics
- PSC regime – considered to be one of the most complex and punitive in the world
- Property right is exclusively with Petronas Carigali
- Cost recovery ceiling protects government interest in case the profits are large, and protects the interest of the company when their costs are larger
- Reliance on the knowledgeable Petronas Carigali for monitoring costs and granting approvals.

General terms
- Govt share of profit oil based on R/C which favours small marginal discoveries
- Petronas has a right to carried interest in any exploration block. Interest is negotiable and varies from 15% to 25%, after discovery Carigali becomes a working partner.
- Contractor enter into a PSC with Petronas where the contractor bears all the risks of E&P for a share of the total production.
- Exploration under the work program can last up to 10 years
- No relinquishment required
- Production licenses up to 30 years (pre-2004); more recently, extension phase is tied to development and production of proven resources

Main government compensation mechanisms

Fiscal terms of concession agreement

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royalty</td>
<td>10%</td>
<td>Most contracts are at 10%, even as the maximum limit is 10%</td>
</tr>
<tr>
<td>Petroleum Income Tax</td>
<td>38%</td>
<td>Reduced in 1990s from 45%</td>
</tr>
<tr>
<td>Cost Recovery Ceiling</td>
<td>30% - 70%</td>
<td>Depends on the R/C ratio</td>
</tr>
<tr>
<td>Unused Cost Recovery</td>
<td>80% - 20% (table on next slide)</td>
<td>Depends on R/C; rewards the OCs for cost savings</td>
</tr>
</tbody>
</table>

Other government compensation mechanisms

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Profit Sharing</td>
<td>20% - 90% (table on next slide)</td>
<td>Govt. share, depends on the R/C ratio and cumulative production</td>
</tr>
<tr>
<td>Excess Profit Payments</td>
<td>70% of contractor's incremental profit</td>
<td>Triggers when oil/gas price is over the base price and R/C &gt; 1</td>
</tr>
<tr>
<td>Research Cess</td>
<td>0.5% of Cost Oil and Profit Oil</td>
<td>Payable to Petronas, Non recoverable cost, Tax deductible</td>
</tr>
<tr>
<td>Training</td>
<td>$100,000</td>
<td>Contractor required to train Petronas for a negotiated number of months. $100,000 is an estimation</td>
</tr>
</tbody>
</table>

1. Share of pre-take NPV (10%) for a standard field of 500M bls, 2. Standard investor post-tax IRR for field of 500M bls, ranging from oil price of $25-60/bbl

Source: IHS CERA
# Malaysia Fiscal System (IV): Table for Fiscal Terms & Cash Flow

## Cost recovery

<table>
<thead>
<tr>
<th>Contractor's R/C Ratio</th>
<th>Cost Recovery Ceiling (% gross production)</th>
<th>Contractor's share excess cost recovery (%) (i.e., Unused cost recovery)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Cum. Production &lt; THV¹</td>
</tr>
<tr>
<td>0&lt; R/C &lt; 1.0</td>
<td>70</td>
<td>NA</td>
</tr>
<tr>
<td>1.0 &lt; R/C &lt; 1.4</td>
<td>60</td>
<td>80</td>
</tr>
<tr>
<td>1.4 &lt; R/C &lt; 2.0</td>
<td>50</td>
<td>70</td>
</tr>
<tr>
<td>2.0 &lt; R/C &lt; 2.5</td>
<td>30</td>
<td>60</td>
</tr>
<tr>
<td>2.5 &lt; R/C &lt; 3.0</td>
<td>30</td>
<td>50</td>
</tr>
<tr>
<td>R/C &gt; 3.0</td>
<td>30</td>
<td>40</td>
</tr>
</tbody>
</table>

## Profit sharing

<table>
<thead>
<tr>
<th>Contractor's R/C ratio</th>
<th>Cum. Prod &lt; THV¹</th>
<th>Cum. Prod &gt; THV¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>0&lt; R/C &lt; 1.0</td>
<td>80</td>
<td>40</td>
</tr>
<tr>
<td>1.0 &lt; R/C &lt; 1.4</td>
<td>70</td>
<td>30</td>
</tr>
<tr>
<td>1.4 &lt; R/C &lt; 2.0</td>
<td>60</td>
<td>30</td>
</tr>
<tr>
<td>2.0 &lt; R/C &lt; 2.5</td>
<td>50</td>
<td>30</td>
</tr>
<tr>
<td>2.5 &lt; R/C &lt; 3.0</td>
<td>40</td>
<td>30</td>
</tr>
<tr>
<td>R/C &gt; 3.0</td>
<td>30</td>
<td>10</td>
</tr>
</tbody>
</table>

## Cash Flow Components from Malaysia’s PSCs

- **PS Contractor:** 26% (1976 PSC), 40% (1985 PSC), 28% (R/C PSC), 20% (Deep Water PSC)
- **Cost:** 26% (1976 PSC), 40% (1985 PSC), 38% (R/C PSC), 36% (Deep Water PSC)
- **Government:** 13% (1976 PSC), 21% (1985 PSC), 20% (R/C PSC), 10% (Deep Water PSC)
- **PETRONAS:** 16% (1976 PSC), 40% (1985 PSC), 38% (R/C PSC), 34% (Deep Water PSC)

1. THV: Threshold volume; 30 million barrels of oil (or 0.75 tcf for gas) of gross production or size of its proved ultimate recovery based on the development plan

Source: IHS CERA 2011, Wood Mackenzie
Malaysia country profile (V): Key Learning

Maturing Fields and High Govt. take discourage investments...

<table>
<thead>
<tr>
<th>Characteristics</th>
<th>Positives</th>
<th>Negatives</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PSC regime, with active participation from Petronas</td>
<td>Oversight from Petronas Carigali causes delays</td>
</tr>
<tr>
<td></td>
<td>Special focus on deepwater exploration in the recent years</td>
<td>Limited upside for OCs due to Excess Profit Payment</td>
</tr>
<tr>
<td></td>
<td>Petronas is embedded deeply within the contractor’s operations and acts as</td>
<td></td>
</tr>
<tr>
<td></td>
<td>a facilitator between the government and the contractor</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Exploration Capex (mm USD)

<table>
<thead>
<tr>
<th>Year</th>
<th>Capex (mm USD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>2,000</td>
</tr>
<tr>
<td>2001</td>
<td>1,500</td>
</tr>
<tr>
<td>2002</td>
<td>1,000</td>
</tr>
<tr>
<td>2003</td>
<td>500</td>
</tr>
<tr>
<td>2004</td>
<td>1,000</td>
</tr>
<tr>
<td>2005</td>
<td>1,500</td>
</tr>
<tr>
<td>2006</td>
<td>2,000</td>
</tr>
<tr>
<td>2007</td>
<td>2,500</td>
</tr>
<tr>
<td>2008</td>
<td>3,000</td>
</tr>
<tr>
<td>2009</td>
<td>4,000</td>
</tr>
<tr>
<td>2010</td>
<td>5,000</td>
</tr>
<tr>
<td>2011</td>
<td>6,000</td>
</tr>
</tbody>
</table>

Key learnings

- The NOC, Petronas, acts as a competent partner of the government by successfully overseeing the E&P operations
- Effective use of Cost Recovery, Cost Recovery Ceilings and Excess Profit payments based on the R/C ratio variable

Significance for India

- Malaysia has managed to attract a larger number of IOCs with the PSC regime and higher share of average government take.

Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; Rystad; web research
**Malaysia Fiscal System (VI): Regulator, Reforms, Repository**

**NOC: Petronas Carigali**

- Petronas Carigali is a subsidiary of Petronas in charge of the upstream E&P activities in Malaysia
- Petronas Carigali works alongside with IOCs to explore, develop and produce oil and gas
- Petronas manages the performance of the PSC partners
- Petronas Carigali maintains all the exploration data for Malaysia
- National Depletion Policy (NDP) in 1980 gives Petronas the right to restrict development timing and production levels for fields with in-place reserves in excess of 400 million barrels
  - In the past, the NDP applied to Shell and EPMI

**Regulator: PMU**

- The Petroleum Management Unit (PMU) of Petronas acts as resource owner and manager of Malaysia’s domestic oil and gas assets.
- PMU manages the optimal exploitation of hydrocarbon resources and enhances the prospectivity of domestic acreages to attract investment and protect the national interest.
- Reports to the EVP (of E&P) for Petronas, who also oversees Petronas contractor part.
  - Potential conflict of interest

**Reforms**

- New provisions for exploiting mature fields
- Pricing based on a Automatic Pricing Mechanism formula

**Data Repository**

- Yet to establish the full national data repository
- Interested companies may propose exploration of any open area with suitable minimum work and financial commitment for consideration


Global E&P Regimes - Country profiles.pptx
Agenda

Columbia
Malaysia
**US GOM**
Angola
Brazil
Norway
Nigeria
China
Indonesia
US – GoM Fiscal System (1/2)

**Government Objectives**

1. Receive a fair market value for leased areas
2. Expeditious and orderly development of resources
3. Minimize administration and own investment
4. Maintain high safety and environmental standards

**Regulatory System**

- Concession system
- Highest E&P activity in the world

**Boundary Constraints**

- No investment by the Govt.
- Free market to encourage competition
- Little or no government role in operations
- Strategic national interest in maintaining reserves

**Adopted Policy**

- Three components of government compensation:
  - Signature Bonus, $20mm, $100mm
  - Royalty, 18.5%
  - Lease Payments based on area; escalates after the exploration period

**Benefits to US**

- Simple and clear system
- No cost audit burden
- High motivation for development of resources when the prices are high
- Ensures there is an efficient use of land
- No preferential treatment for any company

- Royalty relief (temporary) for deep waters to encourage exploration and production
- Royalty relief for matured and special areas on a case-by-case basis

- Encourage a healthy competition and deployment of the best technology to maximize the production
- Encourages small companies to develop fields where the initial burden of capital is low, also ensures that hard to produce resources are extracted fully

Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; web research

Copyright © 2012 by The Boston Consulting Group, Inc. All rights reserved.
US – GoM Fiscal System (2/2)

Adopted Policy

2 Expeditious & Orderly Development of Resources
- Relinquishment – No mandatory clause
  - Area rentals escalate after the prescribed exploration period by 100% of the original rate annually
- Flexibility in royalty terms incase of special cases

3 Minimize Administration & Investment
- Government has very little oversight over the operations of the E&P activities
- Leases are delivered through a bidding process conducted by Mineral Management Services. Criteria for selection is technical evaluation, bonus, and royalty rate
- No material participation by the government at any stage

4 Maintain high Safety & Environmental Standards
- Bureau of Safety and Environmental Enforcement (BSEE) was formed after the temporary moratorium on exploration in response to Macando in 2010
- Contractors need to put a security deposit toward potential accident or safety

Benefits to US

- Enables the contractors to have a long term view to maximize the production
- Ensures active exploration of awarded acreage, so that potential resources are expeditiously maximized
- Ensures that all the resources are extracted rather than only the most profitable ones
- Minimal delays due to government administration
- Fair and transparent process with no discretion or preference for any company
- Promotes competition by encouraging participation
- Eliminates the need for government to invest in any project
- Independent body with the ability to enforce safety and environmental protection
- Encourages OCs to follow best practices and procedures to minimize the risk of accidents and unreasonable harm to the environment

Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; web research
General context

Reason for selection

- Successful investments and production across the lifecycle, including deep-water and unconventional HCs
- OCs get into a lease agreement with the regulating body depending on the area location, most likely Mineral Management Service (MMS)
- Most well studied country/ regime for oil and gas development

Macroeconomic data (whole US)

- GDP (USD Billion) = 15,000
- Population (Million) = 313
- GDP per capita (USD) = 48386

Summary of the oil industry

Oil and gas context

- American oil and gas industry has been closest to the free market with minimal intervention by the federal government
- In US, the natural gas prices remain near the historical low prices due to over-supply resulting from over zealous development in past
- Slow down in deep water drilling and issuance of permits following the 2008 fiscal crisis
- In 2010, over 30% of oil and 11% of gas produced in the US was from the GoM
- GoM produces about 1.6 million barrels per day of crude oil
- Production volumes from the deep water exploration in GoM have been increasing
- Regulation is different for the offshore areas depending on the Federal or State jurisdiction
- Gulf of Mexico comprise of mostly deepwater areas away from any state limit, governed by Outer Continental Shelf Land Act.
- Onshore leases are administered by Bureau of Land Management
- Declining pattern in lease development productivity over time

Oil and Gas Production

Oil and Gas Reserves (K mmboe)
US – Gulf of Mexico hydrocarbon profile (II)

Characteristics of Fiscal System

Financial characteristics

- Concession agreement
- Ownership of the hydrocarbons is with the land owner. Ownership transferred to the operator through lease.
- Area rent imposed in order to ensure that awarded acreage is explored efficiently and resources come on stream as soon as possible
- Security deposit to be paid before the start of operations to cover for the environmental damages

General terms

- Bureau of Ocean Energy Management (BOEM) responsible for managing & development of offshore resources
- Bureau of Safety and Environmental Enforcement (BSEE) was formed in 2011 to enforce safety and environmental protection, granting of permits for exploration and oil spill response.
- Lease has two phases one for Exploration and the other for Production
- Production phase will last as long as production is technically possible as opposed to being financially feasible as is the case onshore.

Main government compensation mechanisms

Fiscal terms of concession agreement

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bonus</td>
<td>$20 - $100 m</td>
<td>Bonus on Signature, varies widely, minimum of $25 per acre for offshore, $37.50 for deep water</td>
</tr>
<tr>
<td>Royalty</td>
<td>18.5%</td>
<td>Royalty relief for deep water, deep gas, end-of-life and special cases, temporary measure to attract investment</td>
</tr>
</tbody>
</table>

Other government compensation mechanisms

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Income Tax</td>
<td>35%</td>
<td>General corporate income tax.</td>
</tr>
<tr>
<td>Annual Area Rental</td>
<td>$7</td>
<td>Rents increases every year after the first five years by 100% of the original rent</td>
</tr>
<tr>
<td></td>
<td>$11 (deep)</td>
<td></td>
</tr>
</tbody>
</table>

1. Share of pre-take NPV (10%) for a standard field of 500M bls, 2. Standard investor post-tax IRR for field of 500M bls, ranging from oil price of $25-60/bbl
Source: Bureau of Ocean Energy Management, IHS CERA
### US – Gulf of Mexico (III): Outcome and Key Learnings

**Characteristics**

- U.S. Gulf of Mexico shows how open, clear rules create continued, shifting investments and maximize government revenue

**Positives**

- Very transparent rules promote investment
- IOC’s maximize fields with high RFs
- Clear transition to deep-water as different companies leverage their capabilities

**Negatives**

- Some lack of safety oversight led to incidents such as Macondo
- Increasing regulations for new licenses
- Different state and federal rules add some complexity

**Significant Events**

- 1945/58/83: Continued extending of “federally owned” offshore land
- 2010: Deepwater Horizon incident slows down new licenses, investments

**Key learnings**

- Clarity of regulations and legal infrastructure (including sanctity of contracts) attracts companies
- Open, competitive bidding process will foster significant investment (if royalty/taxes below break-even amount, at 18.75% for GoM)

**Significance for India**

- With the right environment, India can trust the open market to work, and for companies to bring in the right technologies (for deepwater, shale etc)
- The tender process should maximize revenue to the govt., as people will bid away their ‘profits’

---

*Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; Rystad; web research*
Agenda

Columbia
Malaysia
US GOM
Angola
Brazil
Norway
Nigeria
China
Indonesia
Angola country profile (1/3)

Government Objectives

1. Maximise government take
2. Maximise oil production
3. Develop local oil and gas industry

 Adoption Policy

- Signing bonuses biddable term, and additional bonuses such as exploration bonus, first oil bonus, and in some cases also annual production bonus.\(^1\)
- Taxes are generally very high under both concession and PSC.\(^2\)
- Three type of fiscal agreements, adjusted for each type of discovery area/field type:
  1. Concession system for Cabinda region (onshore/shallow waters):
     - Royalty rates between 10-20%
  2. PSC system for all other (mainly offshore areas):
     - Profit oil between 30-80%; sliding scale based on IRR levels
  3. Risk Sharing Agreements for pre-salt fields:
     - Tax free, variable % of gross production; based on rolling rate of return

Boundary Constraints

- Concession system in Cabinda region
- PSC and RSA system in all other regions

- Oil law specifies that all concessions of areas to be explored are to be made exclusively to Sonangol, which may decide to explore areas individually or select to associate with OCs, through consortium, JVs, service agreements with risk clauses or PSCs

Regulatory System

- High level of (signature) bonuses ensure government take at all stages of development; bonus payments have increased over years due to competition
- High taxation ensures high government take
- Profit oil division based on Rate of Return, ensures investor attraction while also allowing the government to take a bigger share of windfall profits:
  - Increases government take with higher oil prices/production levels
  - Eg if RoR beyond 20%, then government take is up to 80%

Benefits to Angola

1. Signing bonus have ranged between $10 mln to $1.1 bln depending on prospectively of blocks/previous rounds' exploration success; other bonuses range between $25-35 mln per year. 2. Taxes in concession regime: Oil operations tax: 70% + Oil Revenue Tax (66%). In PSC: Oil income tax: 50% Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; Norwegian Petroleum directorate; Statoil website; web research; IMF and IEA country reports

\(^{1}\) Signing bonus have ranged between $10 mln to $1.1 bln depending on prospectively of blocks/previous rounds' exploration success; other bonuses range between $25-35 mln per year. 2. Taxes in concession regime: Oil operations tax: 70% + Oil Revenue Tax (66%). In PSC: Oil income tax: 50% Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; Norwegian Petroleum directorate; Statoil website; web research; IMF and IEA country reports

The Boston Consulting Group

Global E&P Regimes - Country profiles.pptx
**Angola country profile (2/3)**

### Adopted Policy

- Focus on attracting International Oil Companies through well structured IRR regime
  - Different fiscal regimes depending on type of field (e.g., recently moved to RSA regime to attract investors)
  - Rate of Return based sliding scale under all regimes (PSC/concession/RSA)
  - Capex uplift of 50%

- Working programs, or investment obligations as an alternative (considered met if work obligations are fulfilled)
  - Each bidder must submit a financial guarantee for the bidder's proposed value of the working program

- Special bid processes:
  - Specific bids for the selection of the operator, and later, bid of the other OCs to associate
  - Bid involving only small companies
  - Bids involving companies controlled by Angolan citizen

### Benefits to Angola

- RoR-linked system geared to reward contractors first and is directed at the achievement of an acceptable rate of return
  - Higher share of revenues for contractor in early stages
  - Protective of a company's upfront capital investment (particularly at times of high cost inflation)
  - Protects investors in case of unfavorable price scenarios

- Ensure minimum level of activity on awarded blocks

- Authorities have full control and decision making power on composition in participating interests in each block, leading to 'forced marriages'
- Helps to reduce possibility of collusion among participants, and lowers entry barriers for small companies, while also promoting local participation

---

1. If quality and availability are similar to international alternatives, and prices are no more than 10% higher than international alternatives

Source: BCG analysis
## Angola country profile (3/3)

### Adopted Policy
- Sonangol usually part of the concession, though not always at majority shareholder and only selectively as operator
- Local content requirements for all operating companies
- Special bid process for companies controlled by Angolan citizens
- Mandatory hiring and training of Angolans by foreign companies

### Benefits to Angola
- Being in consortia with international oil companies provides the local NOC with opportunity to learn international best practices
- Helps to create strong local industry along the value chain
- Enable participation of local companies for fields that are less technically challenging
- Build towards training and capacity building of local staff; enforce knowledge transfer

---

1. If quality and availability are similar to international alternatives, and prices are no more than 10% higher than international alternatives

Source: BCG analysis
Angola hydrocarbon profile (I)

General context

Reason for selection

• Good case study of how a government adapted its PSCs to encourage investment whilst ensuring local participation
• Very successful in increasing production and reserves in recent years
• Strong participation of International Oil Company’s in bids for blocks
• Only big exporter using Rate of Returns as a criteria of variable scale

Macroeconomic data

• GDP : $116 bln ($5900 per capita)
• Population = 18mln
• Oil production: 2.0 mb/d
• Oil export: 1.85 mb/d
• Oil production as % of GDP: 85%

Summary of the oil industry

Oil and gas context

• Production from shallow waters started off the coast of the Province of Cabinda in 1968
• Development of shallow water fields sustained a doubling of output during the 1980s
• in the 1990s, dramatic boost in production through discovery of deep water fields after application of new techniques of deep water drilling
• Onshore fields and shallow-water fields are mature and close to peaking; future growth in output is expected to come primarily from new deep and ultra-deep water blocks
• From 2000 to 2010, its oil reserves increased from 0.7 mln b/d in 2000 to 1.9 mb/d in 2010 (+10% per year)

Production (mln BOE/day)

<table>
<thead>
<tr>
<th>Year</th>
<th>Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>0.7</td>
</tr>
<tr>
<td>2001</td>
<td>0.7</td>
</tr>
<tr>
<td>2002</td>
<td>0.9</td>
</tr>
<tr>
<td>2003</td>
<td>0.9</td>
</tr>
<tr>
<td>2004</td>
<td>1.1</td>
</tr>
<tr>
<td>2005</td>
<td>1.4</td>
</tr>
<tr>
<td>2006</td>
<td>1.4</td>
</tr>
<tr>
<td>2007</td>
<td>1.7</td>
</tr>
<tr>
<td>2008</td>
<td>1.9</td>
</tr>
<tr>
<td>2009</td>
<td>1.8</td>
</tr>
<tr>
<td>2010</td>
<td>1.9</td>
</tr>
</tbody>
</table>

Reserves (bln BOE)

<table>
<thead>
<tr>
<th>Year</th>
<th>Reserves</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>6</td>
</tr>
<tr>
<td>2001</td>
<td>7</td>
</tr>
<tr>
<td>2002</td>
<td>9</td>
</tr>
<tr>
<td>2003</td>
<td>9</td>
</tr>
<tr>
<td>2004</td>
<td>9</td>
</tr>
<tr>
<td>2005</td>
<td>9</td>
</tr>
<tr>
<td>2006</td>
<td>14</td>
</tr>
<tr>
<td>2007</td>
<td>14</td>
</tr>
<tr>
<td>2008</td>
<td>14</td>
</tr>
<tr>
<td>2009</td>
<td>14</td>
</tr>
<tr>
<td>2010</td>
<td>14</td>
</tr>
</tbody>
</table>

Source: Angolan Ministry of Petroleum, IMF, BP Statistical Review

Copyright © 2012 by The Boston Consulting Group, Inc. All rights reserved.
Angola hydrocarbon profile (II)

### Exploration and production history

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>• 1976: Establishment of Sonangol (a state-owned oil and gas company)</td>
<td>• First development of fields in deep waters; production doubled during the period; offshore fields, blocks 15 and 17</td>
<td>• Production doubles again in the period; first developments in ultradeep waters</td>
</tr>
<tr>
<td>• Concentration of exploration/production activities in the Cabinda region (onshore and shallow water)</td>
<td>• Entry of multiple international OCs: BP, ExxonMobil etc</td>
<td>• Entry of Angola into OPEC</td>
</tr>
<tr>
<td>• Main players: Sonangol, CABCOCG (current Chevron), Elf-Aquitania (current Total)</td>
<td></td>
<td>• 2004: new oil law, which is aimed to standardize future production sharing agreements and further clarify the roles of the Ministry of Petroleum</td>
</tr>
</tbody>
</table>

### State participation and role

#### Role of NOC

- In 1978, law determined that the government, through Sonangol is the sole concessionaire for exploration and extraction of Angolan oil
- Sonangol has commercial roles and regulatory tasks:
  - overseeing petroleum operations of foreign companies
  - recommending areas that should be opened for exploration
  - conducting the bidding process and negotiations for concessions
- It may decide to explore individually or to select to associate with OCs, and has large effective powers in determining which companies are awarded contracts
  - Potential conflict of interest, since Sonangol's own commercial interests may conflict with the best interests of the govt on behalf of whom it is taking decisions

#### Two distinct type of oil regimes

- Sonangol may associate to the OCs through Consortium, Joint Ventures, Service Agreements with Risk Clauses or Production Sharing Contracts
- Cabinda region and onshore blocks FS-FST: concession system
- All other (offshore) areas: PSC system in other areas
- Recently, move towards Risk Sharing Agreements in pre-salt fields, which are slightly different from PSCs
  - All production is the property of Sonangol
  - Payment is made in kind to the contractor group through a variable % of gross production – part of which is a tax free 'allowance'

Source: Angolan Ministry of Petroleum, IMF, EY Oil & Tax Guide 2011
Angola hydrocarbon profile (III)

Characteristics of Fiscal Systems

Financial characteristics

- In PSC, profit oil division based on Rate of Return, which makes fields attractive also in case of unfavorable price scenarios:
  - If RoR of the contract group is below 10%, the government only keeps 30% of profit oil. If RoR beyond 20%, then government takes up to 80%
  - However, system also generates incentive to increase costs in order to show lower RoR and hence pay lower profit oil to government

General terms

- Special bid processes:
  - Specific bids for the selection of the operator, and later, bid of the other OCs to associate
  - Bid involving only small companies, and bids involving companies controlled by Angolan citizens
  - Signing bonus is negotiable, has historically ranged between US$20 mln and $400 mln

Main government compensation mechanisms

<table>
<thead>
<tr>
<th>Mechanism terms of concession agreement (Codinda region)</th>
<th>Mechanism terms of the PSC system</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Bonus</strong></td>
<td><strong>Royalty</strong></td>
</tr>
<tr>
<td>Rate</td>
<td>Rate (for govt)</td>
</tr>
<tr>
<td>Variable</td>
<td>30-80% for govt on sliding scale</td>
</tr>
<tr>
<td>Royalty ('Petroleum Production Tax' - PPT)</td>
<td>None</td>
</tr>
<tr>
<td>10-20%</td>
<td>Based on Rate of Return of contractor group</td>
</tr>
<tr>
<td>Petroleum Transaction Tax (PTT)</td>
<td>Most commonly, between 20% when IRR is &lt;25%, to 90% when IRR &gt; 40%</td>
</tr>
<tr>
<td>70%</td>
<td>Capped</td>
</tr>
<tr>
<td>Petroleum Income Tax (PIT)</td>
<td>Capped at 50%</td>
</tr>
<tr>
<td>65,75%</td>
<td>50%</td>
</tr>
<tr>
<td>Surface rate</td>
<td>Capped</td>
</tr>
<tr>
<td>US$300 per sq km</td>
<td>Levied on taxable income. Production and transaction taxes are deductible</td>
</tr>
</tbody>
</table>

1. Share of pre-take NPV (10%) for a standard field of 500M bbls, 2. Standard investor post-tax IRR for field of 500M bbls, ranging from oil price of $25-60/bbl 3. Ownership of facilities in operation lies with the OC. Upon expiration of license, state is entitled to apply for reversion of the ownership, and King determines whether the OC will be offset for the reversion.

Source: Angolan Ministry of Petroleum, IMF, EY Oil & Tax Guide 2011
Angola (IV) – moving from PSCs towards RSAs

1. The recently awarded RSAs on Blocks 9 and 21 are an attractive contract type
   - RSAs are essentially rate-of-return based production sharing agreements
   - Cost & profit oil are replaced by high and tax-free production shares in early years
   - Work commitments are moderate: 4 wells for Block 21/09, and 3 wells for Block 9/09
   - Signature bonuses were very low by historic Angolan standards, reflecting pre-salt exploration risk
     - further bonuses are staged, and contingent upon exploration success

2. In the event of pre-salt exploration success, signature bonuses will increase rapidly
   - Contrary to its recent reputation, Angolan signature bonuses have historically been moderate
     - ~75% of blocks had signature bonuses under $70m
   - But successful discoveries in "golden blocks" dramatically inflated bonuses in the 1999 and 2005/6 rounds

Source: Angolan Ministry of Petroleum, BCG analysis
Angola (V) - Contract Structure of the new RSAs
Example from blocks 21/09 and 9/09

### Features of Block 21/09 and 9/09 RSAs

<table>
<thead>
<tr>
<th>Signatories</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>• Sonangol EP (Concessionaire) with</td>
<td></td>
</tr>
<tr>
<td>• CIE Angola Ltd.</td>
<td>40%</td>
</tr>
<tr>
<td>• Nazaki Oil &amp; Gas</td>
<td>30%</td>
</tr>
<tr>
<td>• Sonangol P&amp;P S.A.</td>
<td>20%</td>
</tr>
<tr>
<td>• Alper Oil Lda.</td>
<td>10%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Duration</th>
<th></th>
</tr>
</thead>
</table>
| • Exploration Period | 5y + optional 3y (Block 21/09)
  4y + optional 3y (Block 9/09) |
| • Appraisal Period | 12 mths following discovery |
| • Development Period¹ | Max 42 mths from Commercial Discovery |
| • Production Period¹ | 25y from Commercial Discovery |

<table>
<thead>
<tr>
<th>Contractor Payment &amp; Cost Recovery</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>• All production is the property of Sonangol</td>
<td></td>
</tr>
<tr>
<td>• Payment is made in kind to the contractor group through a variable % of gross production</td>
<td></td>
</tr>
<tr>
<td>• A variable % of this payment is a tax free &quot;allowance&quot;</td>
<td></td>
</tr>
</tbody>
</table>
  - Both allowances are based on rolling rate of return |
| • Costs are recognised within the rate of return calculations |
  - No separate cost recovery mechanism |

<table>
<thead>
<tr>
<th>Taxation &amp; Fees²</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>• Petroleum Production Tax</td>
<td>20% on full revenues²</td>
</tr>
<tr>
<td>• Petroleum transaction Tax</td>
<td>70% on revenues - costs &amp; prod. allowance²</td>
</tr>
<tr>
<td>• Petroleum income Tax</td>
<td>65.75% on revenues - costs &amp; other taxes²</td>
</tr>
<tr>
<td>• Surface levy</td>
<td>US$ 300/km² annually</td>
</tr>
<tr>
<td>• Angolan training levy</td>
<td>Variable</td>
</tr>
</tbody>
</table>

### 3 Key Differences from PSAs

1. **Cost Recovery**
   - Up to ~50% of annual gross revenues are allocated as "cost oil" in PSAs
   - Set aside as payment in kind to contractors for cost recovery
   - Costs are recovered with ~50% fixed "uplift"

2. **Contractor Payment**
   - Remaining "Profit Oil" split between Sonangol and the contractor group
   - Variable split each quarter based upon cumulative rate of return

3. **Taxation**
   - Contractor share of Profit Oil – rather than taxable income – is taxed
   - PSAs are subject to a lower rate of Petroleum Income Tax than RSAs
     - 50% vs 65.75% for RSAs

---

1. The development and production periods are defined separately for each Development Area within the Contract Area
2. Source: Cobalt SEC Form 8-K, filed 01 Mar 2010

Sources: Block 21/09 and 9/09 RSAs, Republic of Angola Law No. 13/04 Law on Taxation of Petroleum Activities
### Angola (VI) – RSA: Contractor Payment in Kind

Example from blocks 21/09 and 9/09

<table>
<thead>
<tr>
<th>Block 21/09 RSA</th>
<th>Block 9/09 RSA</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Contractor’s RoR for Contract Area</strong>¹,²</td>
<td><strong>Contractor Payment in Kind (%)</strong></td>
</tr>
<tr>
<td><strong>Contractor Payment in Kind (%)</strong></td>
<td><strong>Production Allowance (%)</strong></td>
</tr>
<tr>
<td>&lt;10%</td>
<td>96</td>
</tr>
<tr>
<td>10-20%</td>
<td>85</td>
</tr>
<tr>
<td>20-30%</td>
<td>75</td>
</tr>
<tr>
<td>30-40%</td>
<td>70</td>
</tr>
<tr>
<td>40-50%</td>
<td>65</td>
</tr>
<tr>
<td>&gt;50%</td>
<td>60</td>
</tr>
<tr>
<td>&lt;10%</td>
<td>95</td>
</tr>
<tr>
<td>10-15%</td>
<td>90</td>
</tr>
<tr>
<td>15-20%</td>
<td>85</td>
</tr>
<tr>
<td>20-30%</td>
<td>80</td>
</tr>
<tr>
<td>30-40%</td>
<td>77</td>
</tr>
<tr>
<td>&gt;40%</td>
<td>72</td>
</tr>
</tbody>
</table>

**Formal cost recovery has been replaced by high, tax-free production shares in early years**

2. Compound rates to be used in RoR calculations differ between the two blocks
3. Concept defined in Article 45.1a of Law on Taxation of Petroleum Activities, National assembly Law 13/04

Source: Block 1/09 and 9/09 RSAs
### Angola (VII) – RSA: Work Obligation and Bonuses

**Example from blocks 21/09 and 9/09**

#### Work Obligations

<table>
<thead>
<tr>
<th>RSA Block 21/09</th>
<th>RSA Block 9/09</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Initial Exploration Phase</strong></td>
<td><strong>Initial Exploration Phase</strong></td>
</tr>
<tr>
<td>• 1500km² 3D seismic (already acquired)</td>
<td>• 1000 km² 3D seismic</td>
</tr>
<tr>
<td>• 4 exploration wells</td>
<td>• 3 exploration wells</td>
</tr>
<tr>
<td>• Including at least 1 pre-salt</td>
<td>• Including at least 1 pre-salt</td>
</tr>
<tr>
<td><strong>Optional Exploration Phase</strong></td>
<td><strong>Optional Exploration Phase</strong></td>
</tr>
<tr>
<td>• 2 exploration wells</td>
<td>• 2 exploration wells</td>
</tr>
<tr>
<td>• Including at least 1 pre-salt</td>
<td>• Including at least 1 pre-salt</td>
</tr>
</tbody>
</table>

#### Investment Obligations<sup>1</sup>

<table>
<thead>
<tr>
<th>RSA Block 21/09</th>
<th>RSA Block 9/09</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Initial Exploration Phase</strong></td>
<td><strong>Initial Exploration Phase</strong></td>
</tr>
<tr>
<td>• US$ 147.5 million</td>
<td>• US$ 87.5 million</td>
</tr>
<tr>
<td>• US$ 82.5 million</td>
<td>• US$ 55 million</td>
</tr>
<tr>
<td><strong>Optional Exploration Phase</strong></td>
<td><strong>Optional Exploration Phase</strong></td>
</tr>
<tr>
<td>• N/A</td>
<td>• N/A</td>
</tr>
<tr>
<td>• Up to US$ 50 million / well</td>
<td>• Up to US$ 37.5 million / well</td>
</tr>
<tr>
<td>• Up to US$ 32.5 million / well</td>
<td>• Up to US$ 17.5 million / well</td>
</tr>
</tbody>
</table>

#### Investment Penalties<sup>2</sup>

<table>
<thead>
<tr>
<th>RSA Block 21/09</th>
<th>RSA Block 9/09</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Seismic programme</strong></td>
<td>• US$ 15,000/km² not acquired</td>
</tr>
<tr>
<td><strong>Pre-salt wells</strong></td>
<td>• Up to US$ 37.5 million / well</td>
</tr>
<tr>
<td><strong>Non-presalt wells</strong></td>
<td>• Up to US$ 17.5 million / well</td>
</tr>
</tbody>
</table>

#### Bonus Payments

<table>
<thead>
<tr>
<th>RSA Block 21/09</th>
<th>RSA Block 9/09</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Signature</strong></td>
<td><strong>Signature</strong></td>
</tr>
<tr>
<td>• US$ 10 million + $2 million after 30 days</td>
<td>• US$ 4 million + $1 million after 30 days</td>
</tr>
<tr>
<td><strong>For each Commercial Discovery</strong></td>
<td><strong>For each approved Development Plan</strong></td>
</tr>
<tr>
<td>• US$ 2 million</td>
<td>• US$ 1 million</td>
</tr>
<tr>
<td><strong>For each approved Development Plan</strong></td>
<td>• US$ 5 million</td>
</tr>
<tr>
<td>• US$ 8 million</td>
<td>• US$ 3 million per year</td>
</tr>
<tr>
<td><strong>First oil &amp; beyond</strong></td>
<td></td>
</tr>
<tr>
<td>• US$ 5 million per year</td>
<td></td>
</tr>
</tbody>
</table>

---

**Significant work commitments, but bonuses are largely staged and dependent upon success**

---

1. Considered to be met if work obligations are fulfilled
2. Applicable if work is not executed, or if technical difficulties cause abandonment before minimum expenditures have been reached

---

Source: Block 21/09 and 9/09 RSAs

---

The Boston Consulting Group
Angola (VIII) – Social Contributions and Local Content
Example from blocks 21/09 and 9/09

Social Contributions

- Funding\(^1\) for a number of 5-year overseas scholarships constitutes an element of the milestone bonus payments

Local Content Requirements

- Competitive bids are required for all work >$250k
- Operator shall contract local contractors & acquire Angolan materials providing
  - Quality and availability are similar to international alternatives
  - Prices are no more than 10% higher than international alternatives
- Operator shall comply with the "Angolan Training Decree"
  - Concerning systematic planning and delivery of training, development and succession planning
  - "Gabinete Jurídico Decree 20/82, Mandatory Hiring & Training of Angolans by Foreign companies Operating in the Angolan Oil Industry" amended May 1994

<table>
<thead>
<tr>
<th>Milestone</th>
<th>Block 21/09</th>
<th>Block 9/09</th>
</tr>
</thead>
<tbody>
<tr>
<td># Scholarships on signature</td>
<td>10</td>
<td>5</td>
</tr>
<tr>
<td>At first oil</td>
<td>15</td>
<td>10</td>
</tr>
</tbody>
</table>

- Scholarship investments are paid to, and administered by Sonangol
- Alper and Sonangol P&P are carried

Social and local content requirements are not onerous

1. Value of each scholarship is not specified in the current RSA document to which we have access
Source: BCG analysis

Global E&P Regimes - Country profiles.pptx

THE BOSTON CONSULTING GROUP
Angola (IX) - Signature bonuses
Very high bids only came in response to nearby exploration success

1993
• Very modest bonuses reflecting exploration risk
• Blocks 14, 15, 17 and 18 later proved up ~10 Bbbl of reserves

1999
• Success of "golden blocks" led to fierce competition for the ultra deep licenses

2005/6
• Exceptional bids for relinquished parts of the 1993 "golden" blocks
• Other bonuses remained moderate

2009
• Again, exploration uncertainty supports a new cycle of low bonuses

In the event of pre-salt exploration success, signature bonuses will increase rapidly

Angola country profile (X): Outcome and Key Learnings

Characteristics
- Moved from concession regime to PSC with discovery of technically challenging deepwater oil fields. Latest contracts evolved into a Risk Sharing Agreement
- Profit Share based on a Rate of Return parameter that protect investors in case of low oil prices, but also caps returns when there are windfall profits

Positives
- Predictable and transparent returns (provides robustness to oil price scenarios)
- Favorable terms for marginal and deep-water fields, promoting development
- NOC JVs set up to facilitate skills transfer, aligns state / operator interests

Negatives
- Limited upside and some uncertainty on additional bonuses/fees for companies if profit higher
- The NOC has a number of roles, including commercial, regulatory and quasi-fiscal, with many conflicts of interests

Key learnings
- Profit Share based on Rate of Return can attract investors and yet provide high govt take of windfall profits
- Special terms are needed for less economic fields (marginal fields, deep-water)

Significance for India
- Highly successful model for developing the NOC (Sonangol currently drilling in other countries)
- India needs to create separate terms for less economically attractive fields

Source: BCG experience; Rystad; web research

Annual Exploration Capex

<table>
<thead>
<tr>
<th>Year</th>
<th>Capex (mln US$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>1,000</td>
</tr>
<tr>
<td>2001</td>
<td>1,000</td>
</tr>
<tr>
<td>2002</td>
<td>1,000</td>
</tr>
<tr>
<td>2003</td>
<td>1,000</td>
</tr>
<tr>
<td>2004</td>
<td>1,000</td>
</tr>
<tr>
<td>2005</td>
<td>1,000</td>
</tr>
<tr>
<td>2006</td>
<td>1,000</td>
</tr>
<tr>
<td>2007</td>
<td>1,000</td>
</tr>
<tr>
<td>2008</td>
<td>1,000</td>
</tr>
<tr>
<td>2009</td>
<td>2,000</td>
</tr>
<tr>
<td>2010</td>
<td>3,000</td>
</tr>
<tr>
<td>2011</td>
<td>4,000</td>
</tr>
</tbody>
</table>

Total 2000-2011 = $24 bln

Copyright © 2012 by The Boston Consulting Group, Inc. All rights reserved.
Agenda

Columbia
Malaysia
US GOM
Angola
Brazil
Norway
Nigeria
China
Indonesia
Maximize government rent capture

1. Maximize government rent capture
2. Retain a level of control over production
3. Maximizing production in order to maintain self-sufficiency in oil production, and to reduce natural gas imports
4. Contribution to local industry development

Regulatory System
- Concession system
- Very active government participation

Boundary Constraints
- Desire to have a transparent, simple and cost efficient fiscal system
- Do not want to be operationally involved
- Declining fields in mature areas, in need for advanced technological methods for advanced recovery rates

Adopted Policy
- Three fiscal policy components:
  - Signature Bonus (Biddable Term, with minimum set by regulator)
  - Royalty (10%; can be reduced to 5% for marginal fields)
  - Variable Taxes: Corporate Tax (fixed 34%) and Special Petroleum Tax (max 40%, variable)

Benefits to Brazil
- Bidding on signature bonus ensures the govt receives a large portion of the expected economic rents from field. Works particularly well in areas where there is high probability of success
- Royalty ensures upfront revenue stream for government, even though regressive in high oil price scenarios
- Special tax variable based on production and profitability levels in order to make government take progressive
- State receives income through dividends of NOC Petrobras. Petrobras will have minimum 30% participation in high prospect pre-salt fields.

1. NOC, xxx% owned by state
Source: BCG experience; ANP; Petrobras; WorldBank
**Brazil country profile (2/3)**

### Adopted Policy

- **License round includes minimum work program as part of the bidding parameters:**
  - Has 30% weight in overall score

- **Specific minimum technical requirements for participating bidders depending on type of area and type of bidder:**
  - More stringent for offshore than for onshore
  - Allowing also the mere financial participation of non-operators

- **Reduction of block sizes according to estimated exploratory risk, and area nomination possibility:**
  - Potential bidders can express interest in a particular area, which govt takes into account when selecting areas for a license round

- **Area retention fees per km² of awarded area:**
  - Doubled in case of an extension to the exploration and development period, and multiplied by nine during the production phase

- **Limit the number of basins that can be awarded to the same operator in specific basins**

- **Petrobras as default operator of all pre-salt fields**

### Benefits to Brazil

- **Helps to ensure that a minimum level of exploration will take place**
- **Investors have an incentive to bid more than they would otherwise have committed to**

- **Ensure that the participating candidates have the necessary technical and financial means to conduct operations effectively**
- **Attracts financial capital into the sector from non-oil and gas companies**

- **Has increased the level of competition, allowing smaller firms to enter by bidding on low-risk but under-explored uncontinuous blocks against lower fees**
  - Oil majors tend to bid for contiguous acreage, while small companies tend to spread their bids widely with lower fees

- **Encourages fast exploration and development of discoveries, so that potential resources come on stream as early as possible**

- **Reduce the market advantage of large oil companies (mainly Petrobras), and ensure transfer of technology and knowledge among market participants**

- **Ensure that high-potential areas are most effectively exploited in order to reach self-sufficiency in oil production**

---

1. This measure was stopped by the judiciary after being contested by oil companies that it beyond the mandate of the ANP. Source: BCG experience; ANP; Petrobras; WorldBank

---

**Maximize Production**

Copyright © 2012 by The Boston Consulting Group, Inc. All rights reserved.
## Brazil country profile (3/3)

### Control over Operations

#### Adopted Policy
- Direct control
  - State retains majority control of NOC
  - Direct equity participation in pre-salt areas through new non-operational state entity ('PetroSal')
- Technical control:
  - Ministry of Energy controls against achievement of Minimum Work Program as part of licensing round
  - Ministry of Energy needs to approve plan of Plan of Development before production may start

#### Benefits to Brazil
- State has voting rights in Petrobras. Petrobras as NOC has participation in most fields and will be the default lead operator for all pre-salt blocks
- As equity partner, government sits in the management committee of JVs and has veto and voting rights proportional to its investment interest
- Ensures that development and production plan is in line with national objectives

### Development of local oil and gas industry

#### Local Content Clause:
- Biddable term in licensing rounds
- Minimum and differentiated percentages for acquisition of goods and services, depending on the location of blocks
- Imposed preference to Brazilian suppliers for contracting, if offers are similar to internal suppliers
- In the past: Petrobras had monopoly on all oil and gas activities

#### Benefits to Brazil
- Helps country to develop its local industrial base, even though it may come at the expense of higher costs for international oil companies and may cause delays in development of fields
- As above
- Created a strong national oil company with deep and rich experience

---

1. NOC, xxx% owned by state
Source: BCG experience; ANP; Petrobras; WorldBank

---

Copyright © 2012 by The Boston Consulting Group, Inc. All rights reserved.
Brazil hydrocarbon profile (I)

General context

Reason for selection

- Policy system has resulted in lots of competitive investments; high level of IOC participation in bidding rounds and rapid growth both in oil production and reserves
- Successful encouragement of the development of a strong national oil service sector (both small and medium size oil companies, and service suppliers around it)

Macroeconomic data

- Oil & Gas sector contribution to GDP: 10%

Summary of the oil industry

Oil and gas context

- First commercial field discovery in 1941, in Candeias (BA)
- Very fast growth of both oil production and proven oil reserves since the de-monopolisation in 1997: success in stark contrast to neighboring Ecuador and Argentina
- Four of the eleven producing basins are considered the most prospective in the world from shelf to deepwater, with giant discoveries still to be found. Biggest challenge now is to bring that identified and proven potential into production in relatively difficult circumstances.
- Recent discovery of immense deep-sea fields of large 'Pre-Salt' oil and gas reserves
  - Considered to be the largest in the world since the year 2000
  - Initially, Tupi (7 bln BOE) and Iara (4 bln BOE) oil fields.
  - In Dec 2007/Jan 2008, an even bigger discovery at the Sugar Loaf field, followed by a large natural gas discovery.
- Production estimates for Tupi alone would increase current oil output by 1 mln b/d from current averages of around 1.9 mb/d
- Expectation is that the current Brazilian oil and gas industry represents only 3% of what it will be in 25 years

Called Pre-Salt due to its location about 7 Km below the sea bed, under a series of layers of rock and salt.
Source: ANP,BP Statistical Review, WorldBank
Brazil hydrocarbon profile (II)

**Exploration and production history**

<table>
<thead>
<tr>
<th>1941-1955: Rise and development of the industry</th>
</tr>
</thead>
<tbody>
<tr>
<td>• 1941: First commercial field discovery in Candeias (BA)</td>
</tr>
<tr>
<td>• In 1952, Law No 2004 established state monopoly over oil</td>
</tr>
<tr>
<td>• Creation of the National Petroleum Agency (ANP)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>1955-1995: Monopolistic period</th>
</tr>
</thead>
<tbody>
<tr>
<td>• State monopoly over petroleum sector by Petrobras, in place for more than 40 years. State monopoly over research, exploration and refining and transportation in oil and gas</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>1995-to date: De-monopolisation and growth of industry</th>
</tr>
</thead>
<tbody>
<tr>
<td>• 1997: end of exclusivity of the exercise of monopoly by Petrobras: other companies allowed to enter the market</td>
</tr>
<tr>
<td>• 2007: discovery of Pre-Salt areas, cancellation of the 9th Licensing Round</td>
</tr>
<tr>
<td>• 2008: Establishment of commission to evaluate various alternative energy policies</td>
</tr>
</tbody>
</table>

**Regulation Structure**

**Active competition in concession system**

- From 1999 onwards; annual licensing tenders organised by the ANP; Petrobras de-monopolised (but not privatised);
  - No favoring of Petrobras but company does often tend win bids due to its extensive knowledge and operating experience before deregulation
  - has removed barriers to the participation of small and medium size companies through area nomination and reduction of block sizes
- Brazil now has 68 different concessionaires active in its E&P sector, of which around half are foreign. That is up from just 1 Petrobras, in 1999. Still Petrobras holds clear leadership in both exploration and production in country

**Review of current petroleum act**

- Since the oil law of 1997, a concession-based system was put in place – still the case for the post-salt fields
- However, after discovery of the giant Tupi discovery in Nov 2007, government ordered a review of the licensing model and the entire petroleum law
  - Tupi discovery fundamentally altered the understanding of potential rewards and subsequent drilling success, and had also reduced the risk of exploring the area
  - Consequently, government wants to review rebalancing of the allocation of risk and reward
Brazil hydrocarbon profile (III)

Characteristics of Fiscal Systems – "Post-Salt Fields"

Financial characteristics
- Concession agreement
- Ownership of mineral resources in situ belongs to the State; once exploited transferred to the OC
- Facilities are owned by the OCs, but at the end of the concession, fixed assets return to the Govt
- Obligation to invest 1% of gross revenues from the field on R&D

General terms
- 3 part-bids with clear bidding criteria: contract allocation based on point system based on offered cash signature bonus (30%), work program (30%), local content (40%)
- Contracts tailored to specific fields according to difficulty of area to be licensed; technical requirements more stringent for offshore than onshore
- Local Content Clause: minimum pct (of share of Brazilian goods and services over total purchased) dictated; rest is biddable term
- Companies can form JVs to compete but operators must have at least 30% share

Main government compensation mechanisms

Fiscal terms of concession agreement

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royalty</td>
<td>10%</td>
<td></td>
</tr>
<tr>
<td>Corporate Tax</td>
<td>34%</td>
<td></td>
</tr>
<tr>
<td>Special Participation Tax</td>
<td>Variable; max 40%</td>
<td>Levied on net revenue before income tax in case of high production levels or high profitability; it is a range based on production levels per day/quarter and can reach a maximum 40 percent.</td>
</tr>
</tbody>
</table>

Other government compensation mechanisms

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Signature Bonus</td>
<td>Biddable Term</td>
<td></td>
</tr>
<tr>
<td>Area Retention Tax</td>
<td>Variable</td>
<td></td>
</tr>
</tbody>
</table>

Govt take: 50-70%
IRR: 30-75%

1. Share of pre-take NPV (10%) for a standard field of 500M bbls. 2. Standard investor post-tax IRR for field of 500M bbls, ranging from oil price of $25-60/bbl 3. Up to 50% can be spent internally, and the rest paid to universities or research institutions) 4. Must give preference to contracting Brazilian suppliers when their offers present same price, term and quality conditions

Source: Source: ANP; World Bank; 2011 Oil and Gas Tax Guide 2011; WoodMac
Brazil hydrocarbon profile (IV)

Characteristics of New Proposed Law – "Pre-Salt Fields" and "Strategic Fields"

System characteristics

**Petrobras' dominating role:**
- Petrobras will be the Operator on all blocks
- Petrobras and Petrosal will have a minimum participation of 30% in each consortium
- Petrobras might take part in the bidding rounds in order to get more participation in the consortium
- In all consortiums, Petrosal will have powers of veto and casting vote

**Direct Government Participation**
- Creation of a new state oil company (‘PetroSal’) to take up direct interest in unlicensed parts of the pre-salt areas (like Petoro in Norwegian model)
  - Not to conduct upstream activities
  - Not to engage in investments
  - Participate in operational committees, with veto powers

Financial characteristics

**Production Sharing Contract**
- Will co-exist next to concession agreement that applies to the post-salt fields

**Bidding factor:**
- Only one factor: profit oil percentage offered (minimum rate will be dictated)

**Government take:**
- Signing bonus and royalty rates are preserved
- Royalties and signature bonus not included in cost oil
- For onshore block, participation of up to 1% shall be paid to the landowner

**Specific features:**
- Length: up to 35 years
- Proportion of Minimum Exploratory Program may be fulfilled through payment of the quipvalent in money to the union

Requires investment and sharing of risk by State into exploration, production and development

---

1. in this case, there might be Transfer of Rights, by which the Brazilian government onerously transfer to Petrobras the E&P activities in areas not subject to concessions, limited to 5 Bboe.

Activities to be regulated and supervised by ANP

Source: Petrobras
### Brazil hydrocarbon profile (IV)

#### Structure of new proposed law: two forms of contracts

<table>
<thead>
<tr>
<th>Step</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. N</td>
<td>Petrobras to be hired exclusively¹</td>
</tr>
<tr>
<td>1. Y</td>
<td>CNPE to define % of profit oil to be paid</td>
</tr>
<tr>
<td>2. N</td>
<td>Petrobras should have a minimum interest of 30%</td>
</tr>
<tr>
<td>2. Y</td>
<td>Winning bid = highest % of profit oil offered</td>
</tr>
</tbody>
</table>

- **Petrobras to follow the winning bidder in the proportion of its share**
- **Partners to assume all exploratory risks – if successful, will be reimbursed in oil for the investments**

- **New state-owned company (Petro-Sal) to be created to represent Brazil’s interest in the production-sharing contracts**
- **In the case of Petro-Sal, its oil derived by the production-sharing agreement will be handle and traded by Petrobras or other company to be sub-contracted**

- **Royalties will follow the terms of Law No. 9,478 of 1997**

---

1. in this case, there might be Transfer of Rights, by which the Brazilian government onerously transfer to Petrobras the E&P activities in areas not subject to concessions, limited to 5 Bboe. Activites to be regulated and supervised by ANP. Source: Petrobras.
Brazil country profile (V): Outcome and Key Learnings

Characteristics
- Concession regime, now considering move to PSC for high prospect pre-salt fields
- De-monopolisation of NOC (Petrobras) after long period of industry protection; Petrobras very experienced and now strong enough to win in competitive bids based on technical and financial grounds
- Transparent and fair competitive bidding, clear 3-stage criteria
- Strong focus on development of national oil sector through local content requirements in bidding rounds

Positives
+ Resulted in rapid growth both in oil production and reserves
+ Openness and transparency of process and criteria bidding rounds; has attracted many new operators and high levels of investments
+ Regime supports competition and removes barriers to the participation of small and medium size companies
+ Built a very strong, technically competent National Oil Company
+ Still encouraging the development of a strong national oil service sector

Negatives
- Strong local content requirement often leads to unnecessarily high costs for operators and delays
- New PSC regime is strongly given privileged access to Petrobras; minimum 30% stake in every block and operator of all

Key learnings
- Concession regime, even if with relatively high taxes, royalty rates and signing bonuses can be highly attractive to oil companies and attract investments as long as prospectivity is shown and bidding process is shown as fair and transparent

Significance for India
- Deepwater fields and other areas with high technical challenges of operation can attract significant investments with the right policies and legal framework
- NOC can be built to be strong enough to be dominant operating partner in all fields

Source: BCG experience; Rystad; web research

Annual Exploration Capex

Copyright © 2012 by The Boston Consulting Group, Inc. All rights reserved.
Agenda

Columbia
Malaysia
US GOM
Angola
Brazil
Norway
Nigeria
China
Indonesia
**Regulatory System**
- Concession system
- Very active government participation

**Boundary Constraints**
- Desire to have a transparent, simple and cost efficient fiscal system
- Do not want to be operationally involved
- Declining fields in mature areas, in need for advanced technological methods for advanced recovery rates

### Adopted Policy

1. **Fair Revenue Share**
   - One fiscal policy component:
     - High taxation (78%): 50% special oil tax and 28% general income tax
     - No royalties
   - Two equity participation components:
     - Direct state equity participation into fields
     - Equity interest of NOC Statoil1 in concessions

2. **Maximize Oil Production**
   - Invest in industry in short & medium terms through tax reductions and investment in R&D
   - Discretionary awards of licenses and no group biddings

### Benefits to Norway

- Simple and clear tax system, reduces burden of cost audit on oil regulator
- No royalty means that incentive of government and investors are completely aligned with no distortions on investment appetite
- Direct state participation gives govt direct equity returns on oil production, while providing co-financing for the industry
- State receives income through dividends of NOC
- Investment into maximum oil recovery and long term gains for the country rather than using the oil and gas industry as a means to finance other areas of government
- Gives govt ability to choose operator with best technical skills – see ‘operational control’ factors

1. NOC, 67% owned by state 2.
2. Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; Norwegian Petroleum directorate; Statoil website; web research
### Norway country profile (2/3)

**Adopted Policy**

- **Two specific licensing rounds and qualification conditions for mature versus frontier areas**
  - Larger exploration blocks in mature areas
  - More broad-based technical expertise and financial requirements for OCs in frontier areas
- **Relinquishment - linked to development plan**
  - Mature areas: companies can only retain areas for which they have production plans
  - Frontier areas: relinquishment tied to discovered resources, not production plan
- **Area fees per km² of awarded area**
  - Only paid in case of non-activity or no submitted development plan. Increases over time.
- **Encouraging small players to enter through tax incentives**

**Benefits to Norway**

- **Encourages exploration investment in mature areas where chance of discoveries is high, but fields are often are small and less economical**
- **Promotes competition by encouraging participation of smaller companies with less technical expertise into mature areas**
- **Increase circulation of acreage in mature areas**
- **Ensures that 'time-critical' resources in mature areas are exploited in a timely matter, before existing infrastructure is shutdown**
- **Ensures activity and efficient exploration of awarded acreage, so that potential resources come on stream as soon as possible**
- **Takes away implicit barrier to entry for new and small companies and promotes competition in the sector**
- **StatoilHydro main operator of most fields (awarded through competitive bidding). Government retains 67% equity interest in Statoil Hydro**
- **As equity partner, government sits in the management committee of JVs and has voting rights proportional to its investment interest.**
  - Also, Petoro maintains veto power and power to make decisions unilaterally in matters that are assumed to be of political nature
Norway country profile (3/3)

### Adopted Policy

<table>
<thead>
<tr>
<th><strong>Control over Operations</strong></th>
<th><strong>Benefits to Norway</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td></td>
</tr>
<tr>
<td>• Discretionary licensing system:</td>
<td></td>
</tr>
<tr>
<td>– Blocks awarded based on 'technical capabilities' and 'quality' of working program</td>
<td></td>
</tr>
<tr>
<td>– No bidding on signature bonuses or financial terms</td>
<td></td>
</tr>
<tr>
<td>– No group applications allowed; OCs have to apply for a license individually; govt decides on owner shares and operatorship</td>
<td></td>
</tr>
<tr>
<td>• Ministry of Energy has broad and strong approval powers:</td>
<td></td>
</tr>
<tr>
<td>– Needs to approve plan of Plan of Development before production may start</td>
<td></td>
</tr>
<tr>
<td>– Direct production control: Oil Law authorizes the government to regulate the level of production</td>
<td></td>
</tr>
<tr>
<td>• Separate decision making between Ministry of Energy and Ministry of Environment;</td>
<td></td>
</tr>
<tr>
<td>• Charge of environmental tax (Co2 emissions tax on burned or released tax and tax on released NOx)</td>
<td></td>
</tr>
<tr>
<td>• In the past: Statoil had mandatory participation, and preference for Norwegian companies in blocks</td>
<td></td>
</tr>
<tr>
<td>• Investing heavily in R&amp;D for industry</td>
<td></td>
</tr>
</tbody>
</table>

### Benefits to Norway

<table>
<thead>
<tr>
<th><strong>Environ-mental Conversation</strong></th>
<th><strong>Development of local oil and gas industry</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>5</td>
</tr>
<tr>
<td>• Government can use own judgment to choose best operator with highest levels of technical know-how.</td>
<td></td>
</tr>
<tr>
<td>• Allows govt to introduce checks and balances and to counter market power of established alliances amongst companies</td>
<td></td>
</tr>
<tr>
<td>• Govt has power to co-develop and negotiate the working program once parties are chosen</td>
<td></td>
</tr>
<tr>
<td>• Also, ensures production plan is in line with national objectives</td>
<td></td>
</tr>
<tr>
<td>• State can curtail oil production whenever there is public interest, regardless of the production program that had been approved before by the Ministry</td>
<td></td>
</tr>
<tr>
<td>• Each check on their respective goals when awarding objectives</td>
<td></td>
</tr>
<tr>
<td>• Encourages firms to reduce emissions and to bring down levels of burned gas</td>
<td></td>
</tr>
<tr>
<td>• Created a strong national oil company with deep and rich experience; built local oil and gas (services) industry across the value chain</td>
<td></td>
</tr>
<tr>
<td>• Invest in future competitiveness, based on a comprehensive industry vision, taking into account the entire production value chain, as well as services related to it</td>
<td></td>
</tr>
</tbody>
</table>

Global E&P Regimes - Country profiles.pptx
General context

Reason for selection

- Relatively simple fiscal policy with high government taxes yet attracts many investors
- Historically successful in building strong local NOC with very deep experience while also attracting IOCs
- New tax-regime very successful in stimulating O&G activity, including smaller companies to explore
- Successful in extensively exploring mature to exploit existing infrastructure in timely manner

Macroeconomic data

- GDP (USD Million) = 390.466
- Population (Million inhab.) = 4.671
- GDP per capita (USD) = 83.591

Summary of the oil industry

Oil and gas context

- World's tenth largest oil producer, and fifth largest oil exporter (2007)
- Norway contains 57% of oil reserves in the North Sea
- Large size of fields, and low exploration costs
- Despite more than 30 years of activity, still has substantial oil and gas deposits to develop
- Exploration strategy
  - Explore and exploit most promising areas first; lead to world class discoveries
  - Establishment of extensive infrastructure for large fields, that subsequent smaller fields tie into
- Oil production started to decline in 2000, but considerable potential for value creation through increased recovery rate and exploration of resources near existing infrastructure.
- The main discoveries are Statfjord, Gullfaks, Ecofisk
- Very active govt participation in industry through co-investments in JVs by state-owned entities

Production

<table>
<thead>
<tr>
<th>M Sm³ Oil equivalents / year</th>
<th>2006 R/P ratio (Years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>---</td>
<td>------</td>
</tr>
<tr>
<td>Gas (40MJ)</td>
<td>0</td>
</tr>
<tr>
<td>Condensate</td>
<td>0</td>
</tr>
<tr>
<td>NGL</td>
<td>0</td>
</tr>
<tr>
<td>Oil</td>
<td>0</td>
</tr>
</tbody>
</table>

Reserves

<table>
<thead>
<tr>
<th>Reserves (B boe)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
</tr>
</tbody>
</table>

Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy; BP Statistical Review
## Exploration and production history

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>• 1965: First Petroleum Tax Act – moderate tax level (reduced rates from normal corporate tax to make up for uncertain prospects), royalty important</td>
<td>• An initial period of concern about exploratory potential in the region, leading to a great push towards cost production</td>
<td>• 2001: Statoil goes public for private funds and focuses its growth in other international markets by using its deep-water know-how</td>
</tr>
<tr>
<td>• 1969: discovery of reserves in the North Sea by Philips PC (current ConocoPhillips);</td>
<td>• Discovery and exploration of new offshore fields (Statfjord, Gullfaks, among others)</td>
<td>• 2001: Review of petroleum tax system. Interest adjustment of loss and uplift carry over.</td>
</tr>
<tr>
<td>• 1972 - the state creates Statoil</td>
<td>• 1985: Creation of the SDFI (State’s Direct Financial Interest) to manage Government E&amp;P investment funds</td>
<td>• 2001: Creation of Petoro - state company to manage the SDFI funds</td>
</tr>
<tr>
<td>• 1975: Introduction of high level special tax; increase in 1980</td>
<td>• 1986: reduced tax level – no royalty on new devpts</td>
<td>• Merger of Statoil and Norsk Hydro, creating StatoilHydro in 2007</td>
</tr>
<tr>
<td>• Concentration of exploration and production activities in the North Sea (Offshore production)</td>
<td>• 1991: Introduction of CO2-emissions tax</td>
<td>• Reserves starting to exhaust</td>
</tr>
<tr>
<td></td>
<td>• 1992: General tax reform: reduced general tax rates, corresponding increase in special tax rate, no royalty on natural gas production</td>
<td>• Oil production fall, and gas increase</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### State participation and role

#### Historically very active role

- Originally state was very protectionist with active intervention in the sector;
  - Demanding preference for Norwegian companies in competition processes; local competition was endorsed, but not international competition
  - Investing heavily in R&D for industry, promoting elements for future competitiveness.
- In the 1990s, became more of a facilitator and a conductor, but still remained actively involved through co-investments and JVs

#### Currently, participation is mainly financial

- State retains a 67% equity interest in StatoilHydro
- State’s Direct Financial Interest (SDFI)
  - State had direct financial interests in 146 production licences, as well as interests in 14 joint ventures in pipelines and land facilities
  - Managed through state-owned companies Petoro and Gassco
  - Government pays its share of investment and costs, and receives a corresponding share of gross income from the license
  - Size of state interest depends on how promising the area is considered to be – 25% participation is common
- Actively involved in growing mature areas and bringing in new companies: providing tax breaks for investments
# Norway Hydrocarbon Profile (III)

## Characteristics of Fiscal Systems

### Financial Characteristics

- Concession agreement
- Property right is with State while underground; once explored property is transferred to operator at point of delivery^3
- No royalties, but a special oil tax does apply
- Environmental taxes on emitted CO2 and NOx
- Area fee imposed in order to ensure that awarded acreage is explored efficiently and resources come on stream as soon as possible

### General Terms

- Discretionary bid modality
  - No financial offer or signature bonus
  - Selection of operating company solely based on technical skills, financial capability and plans to explore and produce the area offered
- Yet preference for local companies in bids
- Exploration under the work program can last up to 10 years
- Relinquishment at end of exploration period
- Production licenses up to 30 years (pre-2004); more recently, extension phase is tied to development and production of proven resources

### Main Government Compensation Mechanisms

#### Fiscal Terms of Concession Agreement

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royalty</td>
<td>0%</td>
<td>Used to be 10% in 1972, then applied on a sliding scale from 8 to 16%, depending on production. Then abolished in 1986</td>
</tr>
<tr>
<td>Corporate Tax</td>
<td>28%</td>
<td>Reduced from 50.8% in 1992. General income tax that applies to all companies operating in Norway.</td>
</tr>
<tr>
<td>Special Interest - Oil Tax</td>
<td>50%</td>
<td>Not deductible for Income Tax purposes</td>
</tr>
<tr>
<td>Depreciation</td>
<td>6 yrs</td>
<td>Straight line depreciation</td>
</tr>
<tr>
<td>Uplift</td>
<td>7.5% of investment for 4 years</td>
<td>130% of development costs and capitalised interest, deductible in special tax base only</td>
</tr>
</tbody>
</table>

#### Other Government Compensation Mechanisms

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equity Interest of Statoil Hydro in the Concessions</td>
<td>% of variable interest</td>
<td>Government has currently 67% interest</td>
</tr>
<tr>
<td>Participation of Petoro in the Concessions</td>
<td>% of variable interest</td>
<td>Government shares in the cost of investment as well</td>
</tr>
<tr>
<td>Environment Taxes</td>
<td>NOK 0.49/liter of oil/cm of gas</td>
<td>Carbonic gas (CO2) emissions rate</td>
</tr>
<tr>
<td></td>
<td>NOK 16.69/kg NOx</td>
<td></td>
</tr>
<tr>
<td>Area fee</td>
<td>Variable</td>
<td></td>
</tr>
</tbody>
</table>

### Environmental Taxes

- NOK 0.49 /liter of oil/cm of gas
- NOK 16.69 /kg NOx

### Area Fee

- NOK 30K to a maximum NOK 120K per km²

---

1. Share of pre-take NPV (10%) for a standard field of 500M bbls, 2. Standard investor post-tax IRR for field of 500M bbls, ranging from oil price of $25-60/bbl 3. Ownership of facilities in operation lies with the OC. Upon exploration of license, state is entitled to apply for reversion of the ownership, and King determines whether the OC will be offset for the reversion.

Source: Norwegian Petroleum Directorate, Ministry of Petroleum and Energy, WoodMac

---

Global E&P Regimes - Country Profiles.pptx

---

The Boston Consulting Group
New focus on bringing in new players and enhance competition in the sector, through two distinct policy mechanisms ... 

... yielding clear results, both increasing the number of players in market and the wells drilled annually. 

The Issue

- Tax system implicitly favored well established companies, creating a barrier to entry for new companies and not promoting competition
  - As exploration costs are deductible, State carries 78% of the costs through deduction
  - However new entrants had to finance exploration fully themselves, and carry losses forward against future taxable income, as no other taxable income to deduct

Two distinct solutions

1. Awards in pre-defined area system (2003)
   - On top of ordinary concession rounds: for very large areas close to existing and planned infrastructure, with high probability of exploration success
   - Attracts smaller companies: high chance of making (small), exploitable discoveries. Less technically challenging and capital intensive
   - Frontier areas with more challenging geographies have separate licensing rounds with different qualifying criteria

2. Exploration reimbursement scheme (2005)
   - Companies with no taxable income can claim a refund of the tax value of the direct and indirect costs for exploration of petroleum resources.
   - Effectively means state is co-investing 78% into O&G (rather than just cost recovery)
Norway country profile (V): Outcome and Key Learnings

**Characteristics**
- Simple and clear concession system with no royalty fees, but special oil taxes instead
- Special provisions to stimulate fast area development and stimulate new company entry
- Active government participation in the system,
  - historically in a paternalistic and protectionistic manner, helping to protect and grow strong local industry, investing a lot in R&D
  - Now more neutral; supporting development through financial participation through co-investment through JVs

**Positives**
- Completely aligned incentives of the government and producers: high government take and yet increasing IRR levels for operators
- Use of tax rather than royalty protects oil company in case of low oil prices or disappointing production levels
- Co-investment into exploration encourages activity and helps smaller players finance their activities
- Deliberate company choice for the different types of resources
- Encourages fast and early development of areas with existing infrastructure through recycling of relinquished areas, while also exploring frontier areas

**Negatives**
- No clear differentiation in terms for marginal, more complex fields

**Key learnings**
- Deliberate company choice based on capability ensures production
- Industry can be a receiver of capital from Government in short and medium terms (through tax reductions, co-financing and investments in R&D), rather than a mere provider of capital for state programs

**Significance for India**
- India should ensure focus on choosing the right companies
- India should consider co-investment into exploration and development, and have a longer term outlook on the industry
- Simple concession system can reduce administrative and audit burden on regulator

**Net Govt Cashflow From Petroleum Activities**
- Direct State Equity Participation almost 40% of total govt revenues

**Annual Exploration Investments**
- Total 2000-2011 $27 bln
- +564%
Norway country profile: Features of regulatory regime and possible learnings for India

<table>
<thead>
<tr>
<th>Regulatory System</th>
<th>Features</th>
<th>Possible learnings</th>
</tr>
</thead>
</table>
|                   | • Concession system  
                   | • Very stable regulatory system with very few overturns | • Focus on maximalising production and development of fields in long run rather than maximising government take in the short run  
                   | | • Low level of govt involvement in operational day-to-day decision making; lower administrative burden |
|                   | • Government regulates activities broadly, but does not sit in management committees of individual fields  
                   | • Tries to encourage broad small company participation through tax breaks and co-investments | |
|                 | • No royalties (abolished over time)  
                   | • 50% special oil tax  
                   | • 28% corporate tax (same for all companies) | • Simple and clear system  
                   | | • Lack of royalty protects oil company in case of low oil prices or disappointing production levels  
                   | | • Lower cost audit burden; share of audit shared with regular tax and fiscal authorities |
|                 | • Licensing rounds are discretionary; only based on technical capabilities and working program; no bidding on signature bonuses or financial terms | • Deliberate company choice for the different types of resources |
| Role of NOC | NOC StatoilHydro (in which government has 67% share) competes on equal terms with other oil companies | • No discrimination against IOCs |
| State participation? | Yes, financially through Petoro – makes co-investments into exploration, taking minority (~25%) interest into fields | • Govt does not seek to have control over operations  
                   | | • Co-investment into exploration encourages activity and helps smaller players finance their activities |
| Innovative Terms and Solutions | Separate terms and licensing rounds for frontier areas and mature areas  
                   | Pre-defined area system for very large areas close to existing and planned infrastructure, with high probability of exploration success | • Encourages fast and early development of areas so as to maximise use of built infrastructure  
                   | | • Encourages participation of smaller companies into mature and less technically challenging fields while letting frontier areas being explored by large IOCs |
Agenda

Columbia
Malaysia
US GOM
Angola
Brazil
Norway

Nigeria

China
Indonesia
Nigeria hydrocarbon profile (I)

General context

Reason for selection
- Historically, country’s huge oil and gas reserves have been successful in attracting large number of foreign players.
- Uncertainty in regulations and security issues are now making the country less attractive investment destination, forcing key players to exit.

Macroeconomic data
- GDP (USD Billion) =
- Population (Million inhab.) =
- GDP per capita (USD) =

Summary of the oil industry

Oil and gas context
- Nigeria is a member of the Organization of Petroleum Exporting Countries (OPEC) and a major oil producer globally
- The country has the seventh largest gas reserves globally
- The country is the 12th largest oil producer and the largest oil exporter in Africa. The country exports approximately 2.1 million barrels per day of crude oil
- Nigeria National Petroleum Corporation (NNPC) is state owned company responsible exploration and production activities from the Nigerian government’s side
- The country has major international companies like Shell, Total, Chevron operating in its upstream segment.

Production
- Reserves (B boe)
- Million boe/ day
- 2010 R/P ratio (Years) 157 42

Source: BP Statistical Review, web search

Copyright © 2012 by The Boston Consulting Group, Inc. All rights reserved.
Nigeria hydrocarbon profile (II)

Exploration and production history

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>• Only concessions all owned by foreign players</td>
<td>• Nigeria's first joint operation agreement was signed in 1971</td>
<td>• As a result of increasing funding pressure from the JVs, the government in 1993 adopted the production sharing contract</td>
</tr>
<tr>
<td>• The oil company is granted an Oil Prospecting Licence (OPL) and on discovery of petroleum in commercial quantity, the company is granted an Oil Mining Lease (OML). The oil company conducts petroleum operations on its own, subject of course, to regulations by the appropriate authorities</td>
<td>• Under the joint venture, Nigerian Government was burdened by upstream cash commitments and had difficulty meeting its cash obligations</td>
<td>• Apart from awards restricted exclusively to indigenous companies, all awards for upstream operations are now made on the PSC basis.</td>
</tr>
<tr>
<td>• Payment of petroleum profit tax and royalty to government</td>
<td>• The Government often resorted to overdrafts from banking institutions. This resulted in under funding leading to cuts or cancellation of exploration and development projects and deferment of contractors’ payments</td>
<td></td>
</tr>
</tbody>
</table>

State participation and role

Upstream Industry Dominated by NNPC

• NNPC, on behalf of Federal Government of Nigeria is the owner of the entire oil acreages in Nigeria
• Signing of PSCs in the sole responsibility of NNPC
• The Department of Petroleum Resources Nigeria under the Ministry of Energy is responsible for upstream licenses and permits
• The new Petroleum Industry Bill calls for creating National Petroleum Directorate for overlooking policy aspects in oil and gas sector
• The National Petroleum Inspectorate (NPI) will be the upstream technical and commercial regulator

NNPC continues to play key role in sector

• NNPC holds majority stake in all the joint venture schemes while partnering IOCs are usually the operators of the ventures, but the prerogative to assume operator-ship of any joint venture scheme in Nigeria resides with NNPC.
• The company has stake in all the new PSCs signed
• The new Petroleum Industry Bill (PIB) calls for creating an incorporated National Oil Company
• The initial shares will be held by the Ministry of Finance incorporated and the Bureau of Public Enterprises on behalf of the Federal Government of Nigeria. Within three years from the date of incorporation, NNPC will divest a yet unspecified amount of shares to the public

Source: web research
## Characteristics of Fiscal Systems

### Financial characteristics
- Both licensing and contractual regime
- Property rights are exclusively with NNPC
- Joint venture agreements for most shallow water and onland blocks, PSC for deepwater blocks

### General terms
- For a PSC, initial term is 30 years, consisting of 10 years exploration period and 20 years term of OML (oil mining lease) derived from OPL (oil prospecting license)
- Under a PSC, the contractor undertakes the initial exploration risk and recovers its cost only if and when oil is discovered in commercial quantities
- Oil companies are also allocated tax oil which is the portion of production allocated for the payment of petroleum profits tax (PPT). PPT is charged at a flat rate of 50%

### Main government compensation mechanisms

#### Fiscal terms of concession agreement

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royalty</td>
<td>8%-20%</td>
<td>Royalties are based on production and are a function of water depth. They decrease as water depth increases</td>
</tr>
<tr>
<td>Signature Bonus</td>
<td>NA</td>
<td>Fixed from government for different PSCs</td>
</tr>
<tr>
<td>Capital allowances</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Petroleum Investment Allowance (PIA) and Annual allowance (AA)</td>
<td>PIA- 5-20%</td>
<td>Petroleum investment allowance (PIA) and annual allowance (AA) is provided to companies that incur &quot;qualifying capital expenditure&quot;</td>
</tr>
<tr>
<td></td>
<td>AA- 20%</td>
<td>Flat rate of 20%subject to the requirement that taxpayer retains 1% of it original cost in its books until the assets is finally disposed.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Profit Oil</td>
<td>Based on R-factor sliding scale</td>
<td>R factor essentially means the ratio of cumulative expenditure to cumulative income</td>
</tr>
<tr>
<td>Cost Recovery Ceiling</td>
<td>Capped at 80%</td>
<td></td>
</tr>
<tr>
<td>Income Tax</td>
<td>67.75%</td>
<td>First five years (newcomers)</td>
</tr>
<tr>
<td></td>
<td>85%</td>
<td>First five years (existing companies)</td>
</tr>
<tr>
<td></td>
<td>85%</td>
<td>Subsequent years (all companies)</td>
</tr>
<tr>
<td>VAT</td>
<td>5%</td>
<td></td>
</tr>
</tbody>
</table>

### Other government compensation mechanisms

#### Source: web search
The Nigerian government formulated the PIB with an intention of overhauling the oil and gas sector. The government however has not been able to pass the bill over the last five years due to which licensing rounds, contract renewals and investment have all been put on hold.

### Key Characteristics of the Initially drafted PIB

#### Key Policy Initiatives
- Vests Acreages in NPD and transfers leases held by NNPC to NNPC Ltd.
- Creates new National Grid System with 2x2 km parcels
- Institutes Transparent License Award Process
- Licenses and Leases
  - Creates exploration & prospecting licenses and mining leases.
  - Awarded to winning bidder or the NOC.
  - Petroleum Prospecting Licenses (PPL) shall be for crude oil and natural gas or for oil or gas alone.
  - Provides for size and tenure of PPL, PML (petroleum mining leases) & Exploration License
  - Sets time frame for declaration of commercial discovery and field development plan
  - Sets obligation to meet Domestic Gas requirements
  - Relinquishment provision for inactive leases with retention clauses
  - Provides for Relinquishment from Current Licenses & Leases and Marginal Fields
  - Provides for award of leases to Marginal Field Operators
  - List grounds for License revocation
  - Provides for Abandonment, Decommissioning and Disposal of facilities

#### Fiscal Provisions
- All Companies engaged in Upstream Petroleum Operation to pay Company Income Tax, Including NNPC Ltd
- Introduces a resource Tax -Nigerian Hydrocarbon Tax (NHT), a Simplified version of PPT
- Eliminates Tax Offsets and Upstream Investment Tax Allowances
- Reduction of deductible items for NHT
- Introduces volume and price based royalties
- NOC to enter PSC based on Minimum Conditions set by Act
- Signature Bonuses to be Paid to Inspectorate
- Contract areas Ring Fenced for Cost and Profit Oil Cost Recovery Limit of 80%
- Introduces Non Recoverable Cost –Fair Market Value principle
- PSC to be based on Model Contract Approved by the Minister

A number of changes have been proposed to the draft bill. The actually bill may lack transparency and provide greater benefits to foreign players.
Nigeria country profile (V): Key Learning

Characteristics
- Both JV and PSC regime with very high government take
- High oil and gas reserves and good prospects for new oil and gas discoveries attracted foreign players historically
- No new licensing rounds since 2007 due to non clarity on new regulations

Positives
+ High level of government take, minimal risks for the government
+ Operator assumes all the risk at exploration stage minimizing risk for state owned company
+ The New Petroleum Industry process a more structured and transparent framework for the sector

Negatives
- Uncertainties over regulation and security issues hurting the industry
- Huge delay is passage of the PIB
- The already high government take could go as high as 98% if the new bill is passed

Key learnings
- Governance issues, uncertainty over regulations, security concerns are limiting the growth of the sector

Significance for India
- Clarity over regulations and transparency are key to attract investment

Exploration Capex
- Total $13.8Bn

Number of Rigs (1982-2012)

Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; Rystad; web research

Global E&P Regimes - Country profiles.pptx
Agenda

Columbia
Malaysia
US GOM
Angola
Brazil
Norway
Nigeria
China
Indonesia
China country profile (1/3)

**Government Objectives**

1. High government share
2. Maximizing oil production
3. Retain high level of control over operations
4. Reduce risk for state owned companies
5. Improving domestic technological capabilities through collaboration with foreign companies

---

**Regulatory System**

- Concession system
- Very high state participation

**Boundary Constraints**

- Desire to keep a high share of resources to the state
- Increase technical capabilities in order to extract maximum resources to meet increasing domestic demand

---

**Adopted Policy**

1. **High Government Share**
   - High government take
     - Government take as high as 80% with fiscal components like royalties, profit sharing, income tax and other taxes
   - Equity participation of state owned companies
     - State owned companies have stake in all PSCs
   - Cost recovery of up to only 65%
   - Increasing exploration activities in offshore areas and encouraging foreign participation for technically difficult areas to explore

2. **Maximize Production**
   - A large share of oil and gas revenues remain with the government
   - Direct state participation gives govt direct equity returns on oil production, while providing co-financing for the industry
   - State receives income through dividends of NOC
   - Increases overall government stake from project
   - Success in exploration activities has enabled the country to maintain steady increase in production

---

1. Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; web research

Global E&P Regimes - Country profiles.pptx
### China country profile (2/3)

<table>
<thead>
<tr>
<th>Adopted Policy</th>
<th>Benefits to China</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maximize Production</strong></td>
<td></td>
</tr>
<tr>
<td>• Lower royalties on natural gas to promote natural gas production (0-3%)</td>
<td>• In line with Chinese government strategy to increase the share of natural gas in the country's energy sector</td>
</tr>
<tr>
<td><strong>Control Over Operations</strong></td>
<td></td>
</tr>
<tr>
<td>• State owned companies have a stake of 51% in all the PSC signed</td>
<td>• Majority stake of state owned companies ensures high state participation in the upstream sector</td>
</tr>
<tr>
<td>• High local content requirements</td>
<td>• Promotes employment and engagement of local people in the country's upstream sector</td>
</tr>
<tr>
<td>– the contractors are obliged to give preference to use Chinese goods, and services</td>
<td></td>
</tr>
<tr>
<td><strong>Reduce Risk for State Owned Companies</strong></td>
<td></td>
</tr>
<tr>
<td>• All exploration costs born by foreign operators; State owned companies have the right to come in the development stage</td>
<td>• Reduces exploration risk for state owned companies; provides them incentive by allowing to participate in directly in development phase</td>
</tr>
<tr>
<td>• The state owned companies continue to play a key role in development through active participation in Joint Management Committee (JMC)</td>
<td>• As equity partner, state owned players sits in the management committee of JVs and has voting rights proportional to its investment interest.</td>
</tr>
<tr>
<td>– the state oil company appoints the chairperson and the Contractor appoints the vice chairperson so that both parties are involved in the decision making process.</td>
<td></td>
</tr>
</tbody>
</table>

---

1. Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; web research

---

Copyright © 2012 by The Boston Consulting Group, Inc. All rights reserved.
# China country profile (3/3)

## Adopted Policy

- Inviting foreign companies to explore deep offshore areas and technically difficult to explore oil and gas reserves
- The country has allowed foreign players to explore shale gas through recent signed agreements with state owned players
- The Joint Study Agreements and Geophysical Survey Agreements enable the country to gather geological data to evaluate new blocks

## Benefits to China

- The foreign players are required to partner with state owned companies to develop these reserves, thus providing an opportunity for NOCs to expand their technical expertise
- Helps in creation of strong national oil companies with strong technical experience
- The technical expertise of the international players in developing shale gas in US will allow China is expediting the process of shale gas development in the country
- The agreements allow the country to build its overall geological data on exploration and enable the country to use foreign expertise to evaluate new blocks.

---

**Source:** BCG experience; 2011 Oil and Gas Tax Guide 2011; web research

**Global E&P Regimes - Country profiles.pptx**

---

1. Copyright © 2012 by The Boston Consulting Group, Inc. All rights reserved.
China: Impact of policy on output

**Exploration and Development Capex (Mln US$)**

- NOCs
- IOCs

**Number of Rigs**

- Only offshore rigs data

**Oil and Gas Production (mln boe/d)**

- Gas
- Oil

**Oil and Gas Reserves (Bln boe)**

- Gas
- Oil

Copyright © 2012 by The Boston Consulting Group, Inc. All rights reserved.
China hydrocarbon profile (I)

General context

Reason for selection

• Strong increase in oil and gas production (especially from offshore areas) even with high government control over oil and gas resources
• Even with not so favorable oil and gas regime, country has been able to attract foreign players (specially for new shale gas exploration)

Macroeconomic data

• GDP (USD Billion) = 7208
• Population (Million inhab.) = 1,321
• GDP per capita (USD) = 5460

Summary of the oil industry

Oil and gas context

• World’s fifth largest oil producer, however second largest oil importer (2010)
• Oil production has increased by over 255 over the last decade (2000-20110
• State owned firms namely China National Petroleum Corporation (CNPC), Sinopec and China National Offshore Oil Corporation (CNOOC) remain the key player in the domestic upstream sector.
• Major oil and gas producing fields include Daqing, Xinjiang, Changqing, Shengli, Bohai Bay and others
• The country is actively promoting shale gas exploration and aims to reach 15-30 billion cu m/year by the end of 2020, amounting to 8-12% of Chinese total natural gas production by that time.
• A number of major foreign player like Royal Dutch shell, Total, BP have entered China’s shale gas market

Production

<table>
<thead>
<tr>
<th>Year</th>
<th>Million boe/ year</th>
</tr>
</thead>
<tbody>
<tr>
<td>1970</td>
<td>0</td>
</tr>
<tr>
<td>1975</td>
<td>0</td>
</tr>
<tr>
<td>1980</td>
<td>0</td>
</tr>
<tr>
<td>1985</td>
<td>0</td>
</tr>
<tr>
<td>1990</td>
<td>0</td>
</tr>
<tr>
<td>1995</td>
<td>0</td>
</tr>
<tr>
<td>2000</td>
<td>0</td>
</tr>
<tr>
<td>2005</td>
<td>0</td>
</tr>
<tr>
<td>2010</td>
<td>6</td>
</tr>
</tbody>
</table>

2010 R/P ratio (Years)

- Gas (40MJ): 29 years
- Oil: 10 years

Reserves

<table>
<thead>
<tr>
<th>Year</th>
<th>Reserves (B boe)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1980</td>
<td>0</td>
</tr>
<tr>
<td>1985</td>
<td>0</td>
</tr>
<tr>
<td>1990</td>
<td>0</td>
</tr>
<tr>
<td>1995</td>
<td>0</td>
</tr>
<tr>
<td>2000</td>
<td>0</td>
</tr>
<tr>
<td>2005</td>
<td>0</td>
</tr>
<tr>
<td>20110</td>
<td>45</td>
</tr>
</tbody>
</table>

Source: BP Statistical Review, web search

Global E&P Regimes - Country profiles.pptx
China hydrocarbon profile (II)

Exploration and production history

<table>
<thead>
<tr>
<th>&gt;1980: No Foreign Players Attraction</th>
<th>1980-1990s: Reformation era for Oil and Gas Industry</th>
<th>1990s-present: Increase in State Ownership</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Very limited activity and legal framework presented a blank state</td>
<td>• Bidding procedures for Sino-foreign cooperative exploration came into existence</td>
<td>• The production sharing contracts gradually became more sophisticated</td>
</tr>
<tr>
<td>• Spurred by the need of foreign capital, technology and technical know-how, China took first steps in Sino-foreign cooperative exploration</td>
<td>• In 1982 and 1983, the PRC promulgated very early regulations that lay the framework for today's oil and gas industry</td>
<td>• Entering China for exploration required partnership with Chinese State owned enterprises</td>
</tr>
<tr>
<td>• Signed five bilateral petroleum contracts in 1979</td>
<td>• The laws provided the most basic form of production sharing contracts</td>
<td>• For the right to enter the Chinese market, the foreign party must assume much greater risks, as well as the initial investment costs</td>
</tr>
<tr>
<td></td>
<td>• In late 1980s, gradual price reforms took place with the development of the market</td>
<td>• High level of state ownership, regulation and limited competition characterizes the market</td>
</tr>
</tbody>
</table>

State participation and role

Upstream Industry Dominated by State Owned Players

• CNPC, China Petrochemical Corporation (Sinopec), CNOOC have been and remain the key state owned companies governing the upstream space
• Foreign players looking to invest in upstream exploration and production activities in China will have to partner with one of the Chinese state-owned petroleum companies. This restriction is required by legislation including the Onshore Regulations, Offshore Regulations, and the other legislation governing coal-bed methane development

Continued High Level of Participation of State

• The opportunities for foreign companies to develop onshore acreage are rare, although the government's attempts to boost domestic oil and gas production have allowed selected foreign companies to carve out a niche in offshore basins and as partners to the NOCs in developing technically challenging onshore fields
• The PSC form in China establishes a considerable amount of governmental supervision of PSC matters
• The need for the Chinese NOCs to develop new technical skills has been the main driver behind recent increases in the number of PSCs signed with foreign partners.

Source: web research

Copyright © 2012 by The Boston Consulting Group, Inc. All rights reserved.

Global E&P Regimes - Country profiles.pptx
# China hydrocarbon profile (III)

## Upstream Sector Regulatory Authorities- No one regulator

<table>
<thead>
<tr>
<th>Regulatory Authority</th>
<th>Responsibilities</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>National Energy Administration (NEA)</strong></td>
<td>The NEA is responsible for the assignment and approval of blocks, the examination and approval of the development programs, the management and approval of budgets, and the management appointments for the three Chinese majors.</td>
</tr>
<tr>
<td><strong>Ministry of Land and Natural Resources</strong></td>
<td>The Ministry of Land and Natural Resources plays a role in the examination and approval of blocks open to foreign investment.</td>
</tr>
<tr>
<td><strong>Ministry of Commerce (MOFCOM)</strong></td>
<td>MOFCOM is responsible for the review and approval of all contracts for foreign investment.</td>
</tr>
<tr>
<td><strong>Other Organizations</strong></td>
<td>Ministry of Environmental Protection: sees to environmental related matters; State Maritime Administration: ensures compliance with maritime safety; China Offshore Oil Operation Safety Office: formed under CNOOC to regulate safety; State Administration of Work Safety: in charge of overall supervision and regulation of work safety.</td>
</tr>
</tbody>
</table>

## China - Joint Study Agreements and Geophysical Survey Agreements

<table>
<thead>
<tr>
<th>Agreement Type</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Joint Study Agreements (JSA)</strong></td>
<td>It is a preliminary agreement for relatively short term and are intended as precursors to full PSCs. In this the foreign party works together with the Chinese state oil company for a specified timeframe, to evaluate the block and decide if there is enough reasonable evidence to pursue a PSC.</td>
</tr>
<tr>
<td><strong>Geophysical Survey Agreements (GSA)</strong></td>
<td>In this the foreign party will conduct specified seismic survey for a short period (typically one year). A GSA is similar to a Joint Study Agreement in that after the completion of the term, the foreign investor has the option of entering into a PSC. However, a GSA is distinct in that if the parties enter into a PSC, the one-year GSA contract counts toward the PSC work commitment, and likewise, there is a one-year reduction in the PSC expiration date.</td>
</tr>
</tbody>
</table>

Source: web research
China hydrocarbon profile (IV)

Characteristics of Fiscal System

Financial characteristics

- PSC regime
- Property rights are exclusively with state owned companies
- Cost recovery ceiling protects government interest in case the profits are large, and protects the interest of the company when their costs are larger

General terms

- All bonus values are biddable
- The contract term is generally divisible into three separate periods: (i) exploration, (ii) development, and (iii) production. The exploration period is generally divided into 3 phases, usually lasting 6-7 years in aggregate. Development phase would begin at the date of approval from the government for oil/gas field
- The PSC establishes a Joint Management Committee for proper performance of operations.
- The contractor bears all exploration costs. In event of a discovery, the developments costs are born by parties in proportion of their interest

Main government compensation mechanisms

Fiscal terms of concession agreement

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royalty</td>
<td>0-12.5%</td>
<td>Incremental royalty on sliding scale from 0 to 12.5 percent for oil and from 0 to 3 percent for gas based on production levels</td>
</tr>
<tr>
<td>Signature Bonus</td>
<td>NA</td>
<td>Biddable</td>
</tr>
<tr>
<td>Local Content Requirement</td>
<td>High</td>
<td>the Contractor is obliged to give preference to the use of Chinese goods, equipment, and services</td>
</tr>
</tbody>
</table>

Other government compensation mechanisms

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Profit Sharing</td>
<td>29.40% - 49%</td>
<td>On an incremental sliding scale depending on production levels</td>
</tr>
<tr>
<td>Cost Recovery Ceiling</td>
<td>Up to 65% of gross revenue after royalties</td>
<td>Biddable</td>
</tr>
<tr>
<td>Income Tax</td>
<td>25%</td>
<td>Payable of the revenue less deduction and depreciation</td>
</tr>
</tbody>
</table>
| Other taxes        |          | Levied on contractor's income when the oil price is greater than US$40 per barrel. The SRC rate starts at 20 percent rising to a maximum of 40 percent when the price of oil is greater than US$60 per barrel.

Source: web search
China country profile (V): Key Learning

Characteristics
- PSC regime with active participation from State owned companies
- Special focus on deepwater gas exploration in the recent years
- Even with limited foreign players entering the market, the country has been able to maintain a steady growth in oil and gas production and reserves

Positives
+ High level of government take, minimal risks for the government
+ Biddable cost recovery ceiling incentivizes the contractor to reduce costs
+ Operator assumes all the risk at exploration stage minimizing risk for state owned company
+ All activities of the PSC are regulated by a JMC, reducing the government’s governance issues

Negatives
- High level of NOC-State participation
- Over skewed towards the government

Key learnings
- Effective use of Cost Recovery, Cost Recovery Ceilings and Excess Profit payments
- Use of JSA and GSA to enhance geological information on blocks

Significance for India
- Country has been successful in steadily increasing domestic reserves and production and at the same time enhance the capabilities of its NOCs
- Strong role of NOCs in upstream sector

Exploration Capex

<table>
<thead>
<tr>
<th>Year</th>
<th>Exploration Capex (mm USD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>0</td>
</tr>
<tr>
<td>2001</td>
<td>+10%</td>
</tr>
<tr>
<td>2002</td>
<td>+15%</td>
</tr>
<tr>
<td>2003</td>
<td>+10%</td>
</tr>
<tr>
<td>2004</td>
<td>+10%</td>
</tr>
<tr>
<td>2005</td>
<td>+10%</td>
</tr>
<tr>
<td>2006</td>
<td>+10%</td>
</tr>
<tr>
<td>2007</td>
<td>+10%</td>
</tr>
<tr>
<td>2008</td>
<td>+10%</td>
</tr>
<tr>
<td>2009</td>
<td>+10%</td>
</tr>
<tr>
<td>2010</td>
<td>+10%</td>
</tr>
<tr>
<td>2011</td>
<td>+10%</td>
</tr>
</tbody>
</table>

Total $80Bn

Number of Offshore Rigs (1982-2012)

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of Rigs</th>
</tr>
</thead>
<tbody>
<tr>
<td>1985</td>
<td>5</td>
</tr>
<tr>
<td>1990</td>
<td>10</td>
</tr>
<tr>
<td>1995</td>
<td>20</td>
</tr>
<tr>
<td>2000</td>
<td>30</td>
</tr>
<tr>
<td>2005</td>
<td>37</td>
</tr>
<tr>
<td>2010</td>
<td>45</td>
</tr>
</tbody>
</table>

Increase in exploration activities in offshore areas

Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; Rystad; web research
Agenda

Columbia
Malaysia
US GOM
Angola
Brazil
Norway
Nigeria
China
Indonesia
Indonesia hydrocarbon profile (I)

General context

Reason for selection

- Historically, country's rich oil and gas reserves have been successful in attracting foreign investments
- The country was the first to adopt production sharing contracts.

Macroeconomic data

- GDP (USD Billion) =
- Population (Million inhab.) =
- GDP per capita (USD) =

Summary of the oil industry

Oil and gas context

- Indonesia was a member of OPEC nations till 2008
- Declining oil production and increasing domestic consumption resulted Indonesia becoming a net oil importer in late 2004
- The country has eleventh largest gas reserves in the world and the largest in Asia-Pacific. The country was the second largest LNG exporter globally in 2010
- Most of the exploration and production is currently being carried out in the basins of Western Indonesia (major pat of country's oil reserves are located onshore and offshore of central Sumatra and East Kalimantan)
- Major foreign companies in the upstream space include Chevron, ExxonMobil, ConocoPhillips, Total, CNOOC and PetroChina. State Owned Petramina is also a key player in upstream sector

Production

Source: BP Statistical Review, web search

Global E&P Regimes - Country profiles.pptx
## Indonesia hydrocarbon profile (II)

### Exploration and production history

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>• Pertamina was responsible for management of operations</td>
<td>• Pertamina remains key stakeholder from government</td>
<td></td>
</tr>
<tr>
<td>• Cost recovery cap of 40%</td>
<td>• No Cost Recovery Cap</td>
<td></td>
</tr>
<tr>
<td>• Remaining 60% shared between Pertamina and Contractor as 65% and 35% respectively</td>
<td>• Split Sharing After Cost Recovery Is:</td>
<td></td>
</tr>
<tr>
<td>• 10% of participating interest eligible for an Indonesian company in the early commercial field development</td>
<td>Oil: 65.91% / 34.09% (Pertamina/Contractor)</td>
<td></td>
</tr>
<tr>
<td>• 25% domestic market obligation (DMO) for contractor</td>
<td>Gas: 31.80% / 68.20% (Pertamina/Contractor)</td>
<td></td>
</tr>
<tr>
<td>• Contractor Pays 56% tax to the Government</td>
<td>• Contractor Pays 56% tax to the Government</td>
<td></td>
</tr>
<tr>
<td>• Full export price for DMO over the initial 5 years of production</td>
<td>• Full export price for DMO over the initial 5 years of production</td>
<td></td>
</tr>
<tr>
<td>• Many changes made over the years</td>
<td>• Various incentive packages announced over the years</td>
<td></td>
</tr>
<tr>
<td>• First Tranch Petroleum (FTP) introduced-20% of the production to be shared first between Pertamina and Contractor. (later PSC changed the details of FTP)</td>
<td>• New oil and gas law passed in 2001</td>
<td></td>
</tr>
<tr>
<td>• Various incentive packages announced over the years</td>
<td>• BP Migas created in 2002 to regulate the upstream sector</td>
<td></td>
</tr>
</tbody>
</table>

### State participation and role

#### Initially Upstream Industry Dominated by NOC

- The state owned company Pertamina was responsible to oversee government's take in the PSCs
- The initial PSCs had Pertamina's share at approximately 65%
- The management of the operations of the PSC were also held by Pertamina

#### Over the last decade role of NOC has been reduced

- Under law No.22 passed in July 16, 2002, all of Pertamina’s rights and obligations arising from all the existing joint cooperation contracts (JCC) were transferred to BP Migas
- BP Migas is to report to the Ministry of Energy and Mineral Resources
- The main purpose of the new regulation was to end Pertamina’s monopoly position and open up all aspects of the petroleum sector to greater competition while having Pertamina remain an important company
- On June 18, 2003 Petramina was officially transformed from a state owned oil and gas company governed by its own law into a state owned limited liability company

Source: web research
Nigeria hydrocarbon profile (III)

Characteristics of Fiscal Systems

Financial characteristics
- Production sharing contracts
- BP Migas regulates the entire operations under the PSC
- FTP ensures that government starts getting returns from the start of the projects
- Ring fencing applicable. Only one PSC can be granted to one company. Separate bodies must be set for each work area

General terms
- No royalties, pure PSC regime
- Two types of bonuses namely signature and production bonuses payable to BP Migas. These bonuses are not cost recoverable
- BP Migas and contractor sign the joint cooperation contract (JCC). The JCC is valid for a maximum of 30 years from the date of approval. The exploration period is for six years extendable for further four years
- All goods and services used for upstream activities must be surrendered to the government upon termination of the JCC

Main government compensation mechanisms

Fiscal terms of agreement (new contracts)

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Signature Bonus</td>
<td>Biddable</td>
<td>Usually ranges from $1 to $15 million</td>
</tr>
<tr>
<td>Production Bonus</td>
<td>Based on production</td>
<td>Payable if the production exceeds a certain level (amount biddable)</td>
</tr>
<tr>
<td>First Tranch Petroleum (FTP)</td>
<td>20%</td>
<td>Payable to BP Migas and not to be shared with contractor</td>
</tr>
<tr>
<td>Domestic market obligation</td>
<td>25% of the contractor's share for both oil and gas</td>
<td></td>
</tr>
</tbody>
</table>

Other government compensation mechanisms

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Profit Oil</td>
<td>Oil- 80%</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Gas- 70%</td>
<td></td>
</tr>
<tr>
<td>Cost Recovery Ceiling</td>
<td>90%</td>
<td></td>
</tr>
<tr>
<td>Income Tax</td>
<td>30%</td>
<td></td>
</tr>
<tr>
<td>Withholding Tax</td>
<td>14%</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>44%</td>
<td></td>
</tr>
</tbody>
</table>

Other government compensation mechanisms

<table>
<thead>
<tr>
<th>Mechanism</th>
<th>Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>On after tax basis</td>
<td></td>
<td>Limited to cost from producing fields or POD (plan of development) approved fields</td>
</tr>
<tr>
<td>effective on net income</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: web search

Global E&P Regimes - Country profiles.pptx
Indonesia country profile (IV): Key Learning

**Key Learning**

**Characteristics**
- PSC regime with BP Migas as the regulator. State owned company remains a key player in the sector.
- All contracts have a domestic market obligation.
- First Tranche Petroleum enables country a share of revenues from the start of production.

**Positives**
- High level of government take, minimal risks for the government.
- New laws and creation of BP Migas to create for transparency.
- Recoverable costs are recovered from production remaining after the deduction of FTP allowing steady revenues to the government.

**Negatives**
- The removal of contractor’s take from FTP in new contracts reduces attractiveness for investors.

**Key learnings**
- Government owned BP Migas overseas the upstream operations, having a share in each contract.
- FTP and DMO remain key for all contracts.

**Significance for India**
- FTP may be used to assure early returns to the government.
- Clear, detailed and transparent fiscal policy.

**Exploration and Development Capex**

- Total $56.8 Bn
- +13% increase
- +11% increase

**Number of Rigs 1982-2010**

Source: BCG experience; 2011 Oil and Gas Tax Guide 2011; Rystad; web research