The Impact of Fiscal Systems in World Gas Reserves

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1. Background

In a world with increasing demand for energy, three fossil fuels (oil, coal and natural gas) represent 87% of world primary energy consumption (BP, 2011). Among these three sources, natural gas is the more environment-friendly one, and, hence, the one that can bridge the gap to renewable energy sources as an answer to global warming concerns. Today, world conventional gas reserves are estimated around 7,000 trillion cubic feet (TCF) (BP, 2011).

According to International Energy Agency (IEA), natural gas consumption will grow 44% from 2010 to 2035, increasing its share in the world primary energy demand by 10% while the other two fossil sources (oil and coal) consumption will decrease 13% in the same period (IEA, 2011). This effect is stronger in the countries outside Organisation for Economic Co-operation and Development (OECD), but happens in the whole world on an overall basis. Therefore, natural gas has a very important part to play in satisfying the global need for an environment-friendly energy source. It will replace oil and coal consumption, with the benefit of being a cleaner energy source.

Although there is not a consensus over statistics of CO_2 emissions per fuel type, a commonly accepted number shows that emissions from natural gas power plant is around 450 g CO_2/kWh (combined cycle gas-fired plants) generated, while a heavy oil or diesel plant is around 800 g CO_2/kWh and a coal plant is over 1,000 g CO_2/kWh (Gagnon et al., 2002).

In the past decades natural gas was treated as a by-product of oil production, given its transportation barriers due to its gaseous state and market application limitations. Lately, the possibility of liquefying gas and the need to reduce CO_2 emissions due to global warming boosted the relevance of natural gas. In fact, by replacing other fossil fuels, natural gas adoption lead to lower emissions of greenhouse gas and local pollutants (except NO_x, which will depend on the properties of the combustion), as well as help to diversify energy supply. In sum, natural gas is a flexible fuel that can be used in power generation as well as in other end-use sectors, it offers environmental benefits compared to other fossil fuels and its resources are better spread across world regions than oil and coal, making many authors and energy experts consider we are entering the “golden age of natural gas” (IEA, 2011b).

This paper will focus on the upstream segment of the natural gas value chain, i.e. the exploration and production of conventional (non-associated) natural gas from the reservoir, and its economic implications. The activities of exploring and producing natural gas in a given country are ruled by its regulatory framework, mainly based on its fiscal system. Fiscal systems in the oil & gas industry play a key role in the relationship among oil & gas companies and countries’ governments, since it establishes rights and duties for the companies engaged in such production projects. One of the purposes of the fiscal systems is to define how the resource rent will be shared among producers and governments. Some countries have equal terms for natural gas and oil, while others have specific orientations, rules and taxation for the natural gas production and ownership.

After a hydrocarbon (oil or gas) accumulation is discovered, the operator company has to evaluate the technical and economic feasibility to produce such resources and decide whether it will declare or not the commerciality of such discovery. In case the company decides to declare commerciality, only a portion of the total hydrocarbon volume (the recoverable portion) will be considered as reserves.

A key benefit for an oil or gas producing country is the government revenue that is generated from the resource production. It is, therefore, critical that the fiscal system be designed to secure the government maximum revenue, while still providing investors with sufficient incentive to undertake exploration and development in the country. There are two main fiscal systems in use in the petroleum industry: tax/royalty system and production sharing contract (PSC).

In the tax/royalty regime, the government grants the investor a license to operate a concession for a specific period. The investor takes all the responsibility and the risks to explore for hydrocarbons. If a discovery is made, it has title to the oil/gas discovered and, in return, pays taxes and royalties set by law. In contrast, under a PSC, the company, after exploring and discovering hydrocarbons, agrees to produce oil or gas for the government in exchange for recovering its investments in kind and receiving a share of the remaining production. In theory, there should be no intrinsic reason to prefer one over the other since the two can be designed to be fiscally equivalent. However, some governments do prefer PSC over tax/royalty system, thanks to the idea that they will be able to better control the pace of production under this fiscal regime, relying on a state owned company supervision of the project.

2. Aims

This study aims to analyze the impact of fiscal systems in the economic feasibility of non-associated natural gas development projects and, consequently, in the gas reserves owned by companies and governments. It particularly focuses on the scenarios that might generate business cases with high government take or low return for the private investors, thus discouraging gas discoveries from becoming commercial and, therefore, from being incorporated as reserves.

3. Methods

To perform this analysis, a typical non-associated conventional gas field development project was assessed through a business case study, in order to calculate government take, contractor take, net present value, and return rate for the operator.

Such business case considers that the operator company has just discovered a conventional gas field and such field’s development is under assessment. Therefore, past expenses regarding exploration phase (for example licensing bonus, seismic acquisition, wildcat drilling) are not considered, being this a point-forward analysis.

Eighteen different scenarios were evaluated, considering different premises for natural gas recoverable volumes, natural gas prices and fiscal systems.

For the gas price, we have considered the forecast for natural gas import price by IEA for United States, Europe and Japan markets. The three prices evaluated in this study reflect the price forecast for these three markets in 2015: US$5.6, US$9.0 and US$ 11.5 per million british thermal unit (mmbtu), respectively (IEA, 2011b).

For the recoverable volumes, it was used three volumes that can be considered for average gas fields, being neither a small field nor a giant field: 500 billion cubic feet (BCF), 1.5 trillion cubic feet (TCF) and 5 TCF.

The two fiscal systems used in this paper are real fiscal systems chosen from two of the main natural gas producing countries, and its terms are defined in the table below:

	Fiscal system 1 Tax/royalty	Fiscal system 2 PSC
Royalties	12.5%	N/A
Cost recovery ceiling	N/A	40-50%
Profit Sharing	N/A	35%
Corporate Tax	35%	35%

Table 1 – Fiscal Systems terms (IHS, 2011)

The eighteen scenarios are a result of the combination of the different premises, as shown below:

Fiscal System 1: Tax/Royalty

Price \ Volume	500 BCFs	1.5 TCFs	5 TCFs
US$ 5.6 / mmbtu	scenario 1	scenario 2	scenario 3
US$ 9.0 / mmbtu	scenario 4	scenario 5	scenario 6
US$ 11.5 / mmbtu	scenario 7	scenario 8	scenario 9

Fiscal System 2: PSC

Price \ Volume	500 BCFs	1.5 TCFs	5 TCFs
US$ 5.6 / mmbtu	scenario 10	scenario 11	scenario 12
US$ 9.0 / mmbtu	scenario 13	scenario 14	scenario 15
US$ 11.5 / mmbtu	scenario 16	scenario 17	scenario 18

Table 2 – Scenarios evaluated

Operational premises like capital expenditure (capex), operational expenditure (opex) and production curve were based on real market values of a typical conventional non-associated gas field development project in deep waters. The production curve considered is described in the graph below, showing the percentage of total recoverable volume that is produced each year of the project. As the graph shows, it was considered a period of 5 years for development of the project (construction and installation of facilities) before the start of production, which lasts for 15 years.

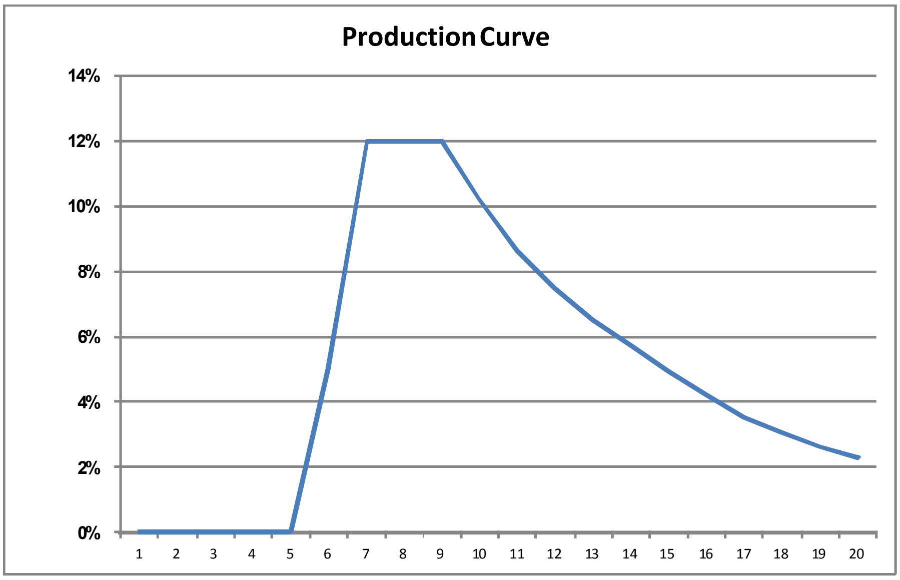

Figure 1 – Typical production curve for a gas field development

Capex was estimated at US$ 10 per barrel of oil equivalent (boe) for the 500 BCF field, US$ 9/boe for the 1.5 TCF field and US$8/boe for the 5 TCF field, whereas opex is fixed at US$ 5/boe (WoodMackenzie, 2011). During the first 5 years, the project capex is spent according to the distribution below:

Year	year 1	year 2	year 3	year 4	year 5
% of total Capex	6.6%	9.0%	39.3%	37.8%	7.2%

Table 3 – Capex distribution in the project lifetime (IHS, 2011)

For the sake of simplification, this study considers that the company operating such project is a private international oil company (IOC), with a profit-driven corporate strategy, and a cost of capital estimated at 10% per annum (Szklo et al., 2008, Maia; 2007). That means that the project will only be developed if its economic valuation presents a positive value for the IOC, or a return rate higher than its capital cost. Otherwise, it will be considered non feasible and the gas field discovered will be returned to the government.

4. Results

For each scenario, four indicators were calculated:

a) Internal Rate of Return (IRR) for the private investor
b) Net Present Value (NPV) of the project at a 10% discount rate
c) Government Take – the percentage of the total revenue generated that is paid to the government (whether through royalties, taxes or profit oil split)
d) Contractor Take – the percentage of the total revenue that belongs to the oil company

After the business case assessment, the eighteen scenarios results are summarized:

Scenario	Price (U$/Mmbtu)	Field Volume	Fiscal System	IRR	NPV @10% (US$ MM)	Govt. Take	Contractor Take
1	5.6	500 BCF	T/R	8.9%	-39.37	50.7%	49.3%
2	5.6	1,5 TCF	T/R	10.4%	37.35	49.8%	50.2%
3	5.6	5 TCF	T/R	12.0%	639.42	49.0%	51.0%
4	9.0	500 BCF	T/R	17.1%	314.89	46.6%	53.4%
5	9.0	1,5 TCF	T/R	18.9%	1,098.48	46.3%	53.7%
6	9.0	5 TCF	T/R	20.9%	4,173.30	46.0%	54.0%
7	11.5	500 BCF	T/R	21.8%	574.26	45.6%	54.4%
8	11.5	1,5 TCF	T/R	23.7%	1,876.27	45.4%	54.6%
9	11.5	5 TCF	T/R	26.0%	6,765.93	45.2%	54.8%
10	5.6	500 BCF	PSC	5.1%	-178.54	72.0%	28.0%
11	5.6	1,5 TCF	PSC	6.8%	-329.91	67.6%	32.4%
12	5.6	5 TCF	PSC	8.5%	-462.36	65.0%	35.0%
13	9.0	500 BCF	PSC	12.9%	116.23	65.2%	34.8%
14	9.0	1,5 TCF	PSC	14.5%	493.95	65.1%	34.9%
15	9.0	5 TCF	PSC	16.4%	2,099.68	65.0%	35.0%
16	11.5	500 BCF	PSC	17.0%	293.67	65.1%	34.9%
17	11.5	1,5 TCF	PSC	18.6%	1,001.89	65.0%	35.0%
18	11.5	5 TCF	PSC	20.6%	3,766.23	65.0%	35.0%

Table 4 – Scenarios results after business case assessment

As expected, return rates and net present value improve for the IOC as prices and volumes increase. Analyzing the IRR of each scenario, it is possible to see the evolution on the project profitability in the table below. IRR's below 10% were marked in red, IRR's between 10% and 15% were marked in yellow and IRR's above 15% were marked in green.

<table>
<tr><th rowspan="2">Price (US$/ Mmbtu)</th><th rowspan="2">Fiscal System</th><th colspan="3">Field volume</th></tr>
<tr><th>500 BCF</th><th>1.5 TCF</th><th>5 TCF</th></tr>
<tr><td rowspan="2">5.6</td><td>PSC</td><td>5.1%</td><td>6.8%</td><td>8.5%</td></tr>
<tr><td>T/R</td><td>8.9%</td><td>10.4%</td><td>12.0%</td></tr>
<tr><td rowspan="2">9.0</td><td>PSC</td><td>12.9%</td><td>14.5%</td><td>16.4%</td></tr>
<tr><td>T/R</td><td>17.1%</td><td>18.9%</td><td>20.9%</td></tr>
<tr><td rowspan="2">11.5</td><td>PSC</td><td>17.0%</td><td>18.6%</td><td>20.6%</td></tr>
<tr><td>T/R</td><td>21.8%</td><td>23.7%</td><td>26.0%</td></tr>
</table>

Table 5 - IRR for each scenario

The table above shows that, from the eighteen scenarios, four of them present a return rate for the IOC lower than 10%, being three out of four in the PSC system. In such cases, considering that the company demands a 10% return, the gas discovery would be considered non economical and the block could be returned or sold to other companies. Other four scenarios have a return rate between 10% and 15%, which indicates a low but acceptable rate of return and such projects. The remaining ten scenarios present a higher return, being considered, thus, profitable projects for the IOC.

The results indicate that, at a price of US$ 5.6/mmbtu, projects under the PSC system considered here (or any other fiscal system with similar taxation level) should not be economically feasible, even a large field of 5 TCF of natural gas. It would take higher prices (or tax reliefs from the government) to enable such projects to be approved by the IOC.

It is interesting to notice that a given project based on a fix combination of gas volume and price may have very different returns for the IOC when evaluated under the two fiscal systems. For example a 5 TCF gas field being sold at a price of US$5.6/mmbtu, generates a return rate of 12% and a NPV of US$ 639.42 million under the Tax/Royalty system, whereas the same physical project has a return of 8.5% and a NPV of – US$462.36 in the PSC. This means that if two similar gas fields under the same geological and technical conditions are discovered in two different countries, it can happen that one will be considered commercial (and accounted as reserves for the IOC) and the other will be returned to the government because its development is not economically feasible.

The graph below shows the return rate and government take for each scenario, from the lowest to the highest return rate. We can see that government take, which is a statistic widely used to evaluate the fiscal systems, not always indicate the best projects. In fact, as the graph shows, several scenarios with IRR above 10% (scenarios 13, 14, 15 and 16 highlighted below) have a higher government take than one of the scenarios with IRR below 10% (scenario 1 highlighted below).

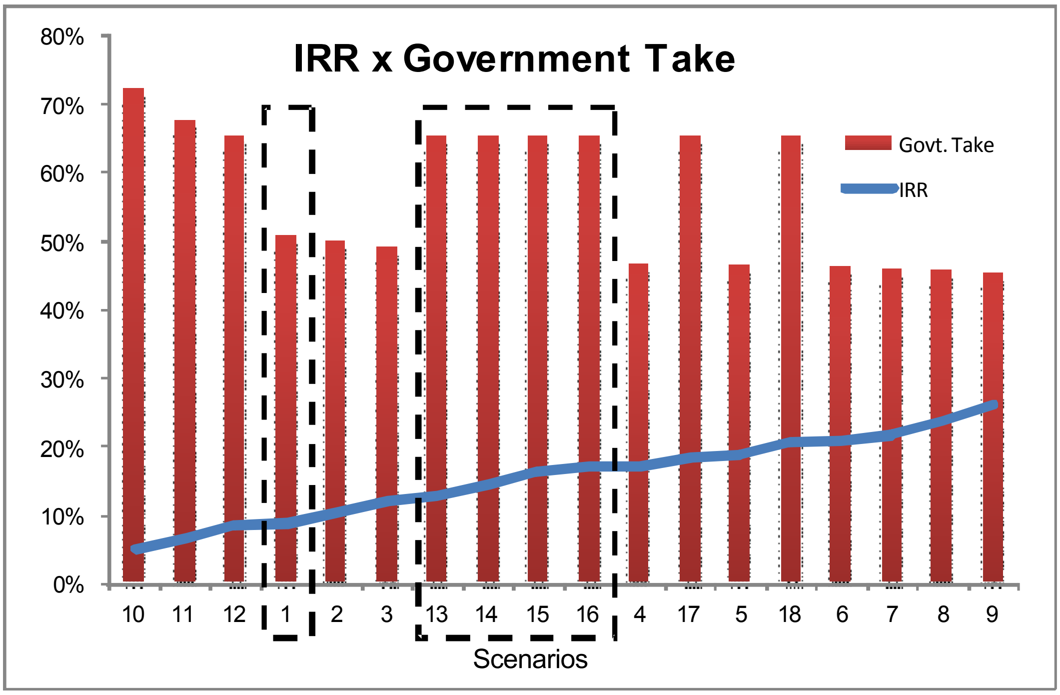

Figure 2 – IRR vs Government Take for each scenario

5. Summary / Conclusions

In a summary, the results presented herein indicate that fiscal systems for E&P activities can have a significant influence in the decision of whether to develop or not a given discovered field. As shown, the same gas field discovery can be economical in some countries and not in others. In the countries where the volume is not economical, the company will probably decide not to declare commerciality of such discovery, return the block or area containing such gas discoveries and, therefore, no new gas reserves will be booked by the company and the country. On the other hand, if the fiscal system was more favourable to the operator, it would decide to develop such reserves.

In some countries, the development of natural gas production faces yet another barrier: the gas discovered and produced in these countries does not belong to the IOC's, but to the government. So, when there is production of associated gas in an oil field in such countries, the gas produced is delivered to the government, usually through the National Oil Company (NOC), for free. This gas is not declared as reserves by the operator, since it does not belong to it. One can assume, then, that a non-associated gas discovery in these countries, regardless its size, would have no value for an IOC and, thus, would be returned to the government or the NOC which, depending on the country, may not have the required skills and technical know-how to develop such reserves.

Such results, taken in a global scale, suggest that fiscal systems can inhibit new gas discoveries from becoming commercial and, therefore, from adding new reserves to the global gas market. The world conventional gas reserves, actually estimated at 7,000 trillion cubic feet, could be much higher if several small or medium gas discoveries worldwide were not discarded by the operators due to its negative economical value influenced by the local fiscal system.

According to several authors such as Morehouse (1997) and Drew (1997), oil and gas fields' size distribution is such that a very small portion of fields contains most of the petroleum in the world. Such distribution can be represented in the log-geometric curve below:

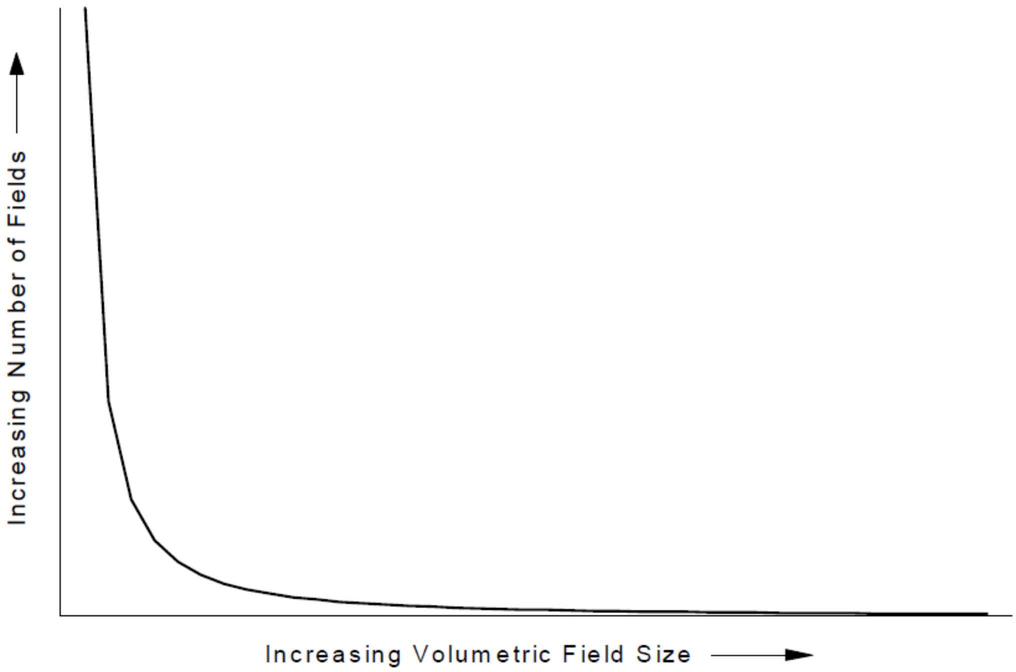

Figure 3 - Field Size Distribution (MOREHOUSE, 1997)

Analyzing figure 3 and considering the results of the business cases presented herein, we may affirm that most of the current gas fields declared as reserves are located in the right side of the graph (highlighted in red in figure 4) and as we move towards the left side of the graph, a very relevant number of fields discovered may not be considered reserves depending on the fiscal system (and other technical or commercial conditions) applicable. Therefore, enhancing policies which would enable smaller fields becoming commercial would increase world gas reserves, moving the red area as shown in the graph below. Also, given the shape of the graph, the smaller the "break-even" volume gets, a higher number of fields would be considered commercial, adding significant reserves to the world gas market.

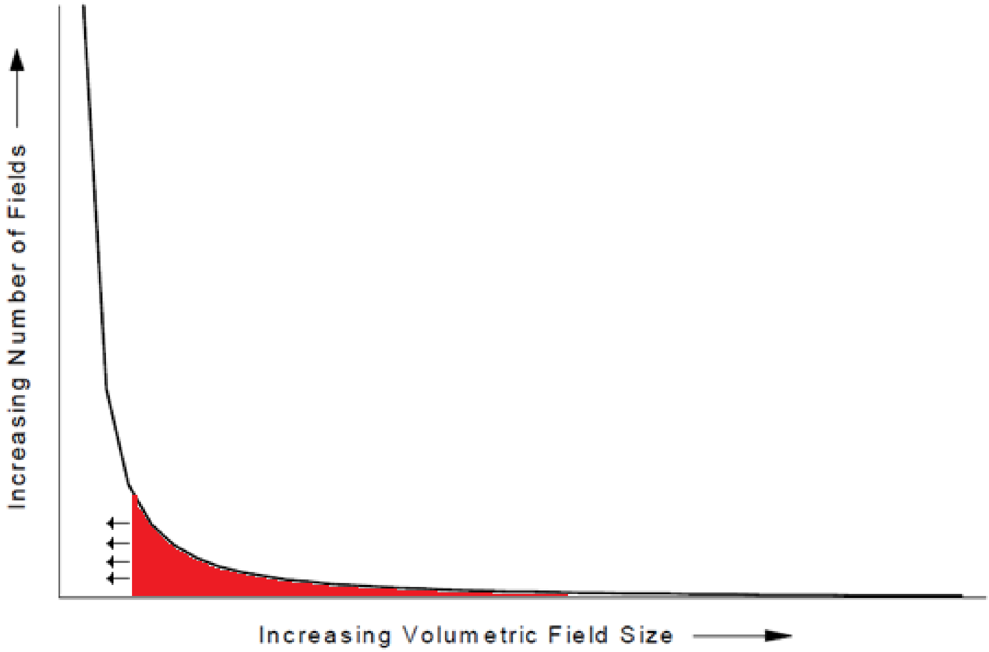

Figure 4 - Field Size Distribution (MOREHOUSE, 1997)

As a final remark, this study did not consider the issues of gas price elasticity (which is usually high, except in certain market niches) and how this would affect demand; as well as the issues of natural gas remote resources and its transportation barriers which could derail large fields at profitable fiscal regimes from becoming reserves.

It is important to mention that besides the conventional gas reserves; unconventional gas (especially shale gas) has become, in the past few years, a very important source of energy, as huge discoveries are taking place and being developed. Current estimates indicate a potential of almost 6,000 TCFs of shale gas recoverable resources in a worldwide basis (IEA, 2011b). Such numbers suggests the importance of natural gas to the global energy matrix will only increase. And, as natural gas becomes more relevant, the responsibility of governments is even greater to foster cooperation between governments and companies by adjusting policies and fiscal systems that stimulate private investment for its development.

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