## Upstream

# The good, the bad and the ugly of the ANH E&P Contract

Tomás de la Calle

When it comes to assess the attractiveness of the 'Fiscal Terms' of a country to estimate the share of the oil profit that such country takes, that is, the so-called 'Government Take', the first thing one tends to look at is the Commercial Terms prevailing under the E&P Contract. This is generally okay, but there are other issues, out of the scope of the E&P Contract, that need to be considered earlier since there may be some 'details' as important and some times more important than the E&P Contract itself. We will discuss here some of such external factors first and then we will look in detail at the Colombian E&P Contract itself.

**i. Contractual Arrangement:**
Worldwide there are two E&P Contract types: concession or just R/T for Royalties and Taxes, and PSA / PSC for Production Sharing Agreement / Contract. Under a PSA a consortium of International Oil Companies (IOCs) acts as a contractor that invests all the money in the venture and when production starts, it gets paid in oil, year-by-year until it recoups the original investment. Since both the reserves and the production rights stay all the time under the jurisdiction of the host country, the PSA reserves of the IOCs cannot be registered in the books as Working Interest reserves (as is the case in a Concession type of contract), but instead as an Economic Interest. The practical implication for an oil company is that they cannot be sure of the reserves they hold since they will vary according to the oil price, as follows. If an IOC has invested, say, $1B that it expects to recoup with its share of oil production, and it assumes an oil price scenario of $50/bl, it may say it has 20mmbls of reserves (=$1000 / $50/bl). But then if the actual price turns out to be $100/bl, its reserves figure would fall by half since at such price, it would need only 10mmbls to recover the original $1B investment. This phenomena does not take place under an R/T contract because the IOC enjoys production rights and so it has certainty about its Working Interest 'barrels' whether or not they suffice to payback their investment.

As abstract as this consideration may sound, it has indeed practical repercussions; for instance, Brazil has just changed their E&P Contract that would apply for the pre-salt areas from an R/T system to a PSA type. Incidentally, Brazil was the country-model that Colombia decided to emulate in terms of oil policy back in 2003: they created the ANP, we created the ANH; they floated part of Petrobras, we floated part of Ecopetrol; they issued an R/T contract, we issued our R/T contract, and so on. In summary, the Colombian E&P Contract enjoys the features described above for this type of contractual arrangement.

**ii. Ring-fencing:**
Regardless of the contractual arrangement, there is a defined hierarchy of fiscal calculations that make oil projects within a country dependent on each other (i.e. their economics). This may apply for the calculation of the income tax or the royalties, and the sequence of such calculation may be dictated by the allowed level of aggregation of certain entities such as field, block or country. Let´s take an example for the calculation of the royalties after Law 756 of 2002 (Royalties Law): the formula for calculating the rate of royalties (RR) is dependent on the monthly average production (q) as follows:

$$RR\ [\%] = 8 + (q - 5)*0.1$$

So, if we had a field producing q=20 (thousand barrels per day), the applicable royalties would be 9.5% (= 8 + (20-5)*0.1). If we were lucky enough to have another field producing the same 20,000 b/d within the same block, the applicable royalties would again be only 9.5% because the Law defined an entity, in this case, a field as the fence for such calculation. What would it happen if the Law had defined the entity as a block (instead of a field) using the same equation? So, if the fence were a block, we would have to 'enter' into the equation with q=40, resulting in a royalty rate of 11.5%, so we would have lost 2% to the State. The same idea applies to income tax, let's also use an example: if the fence were a block and we had one producing field paying income taxes and we drilled a dry well within the same block (looking for another prospect), we would be allowed to count such well as a cost, thus reducing the payable income tax. However, if we had drilled such dry well within another block, we would not be allowed to do so (include it as a cost), since the fence is a block. In Colombia the fence is the country and the practical consequence of it is that every dry well drilled within the country is deductible from taxes.

Next month we will continue analyzing more factors affecting the Colombian Fiscal terms.

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# The good, the bad and the ugly of the ANH E&P Contract (Part Two)

Tomás de la Calle

In the past Inner Circle Monthly issue (September 2013) we discussed two topics regarding the Colombian Fiscal Terms for the oil and gas E&P sector: the Contractual arrangement and the Ring-fencing notion. We will add a third element to this discussion to complete what we referred to as the external factors affecting the economics of a potential E&P venture. We also discuss some of the key internal factors, that is, elements arising from inside the E&P contract that may affect the economics of such E&P ventures.

**iii. The Domestic Market Obligation – DMO**

DMO refers to the obligation that oil companies operating in a given country have to prioritize supplying the domestic market before the export market. In Colombia, Articles 58 and 215 of the 'Petroleum Code' set the terms of such an obligation. The key points are both the amount of production required from a given oil company and the price it will get for it. Some countries stipulate a predetermined percentage of the total production of each field to be devoted to domestic supply indicating also the price (normally not based on an international benchmark but on a lower, usually subsidized local price) and the exchange rate the State will recognize for it. Again, Colombia is very attractive regarding this issue (see articles of the Petroleum Code mentioned above). The regulation says that supplying the internal market is an obligation; it then adds that when royalties (in kind) are not enough to supply the internal market, oil companies are to supply up to 50% of their production to fill out the deficit. Regarding price, it is linked to the international one, so an export parity price is recognized and made payable in the currency the oil company is using for up to 75% of production, the remaining 25% is paid in local currency (i.e. pesos).

**Some key factors inside the Colombian E&P Contract:**

Bonuses are quite popular in many oil-producing countries since they represent an easy and quick way to monetize the oil profit. The most common are Signing and Production Bonuses. The former is used as the criteria to select the winner in a Petroleum Bidding Round: the company willing to pay the highest Signing Bonus will win a given block / area. In Colombia, we have no such bonus: the ANH have opted for a different criteria: the company willing to invest the highest amount in exploration activity. It makes the ANH's E&P contract less 'regressive' (as the economists called it) in the sense that less money is to be bet upfront, that is, the Signing Bonus plus the exploration investments. The opposite of a regressive system, 'progressive', is what the ANH E&P contract uses, that is, a scheme whereby the oil company up-front risk is left lighter, but when it discovers commercial oil it is to share part of it with ANH via the so called 'x-factor' which is a percentage (i.e. x%) of the production that the oil company has to pay to ANH. In such a way, the burden for the oil company is not up-front in the exploration stage (via a Signing Bonus) but is left for the Production stage, if there is production. The other Bonus, the Production one, is a sum of money that the oil company has to pay when 'First Oil' is produced. First Oil is a term employed when referring to a big field, one that required huge development investments along a considerable time frame. Again, the Colombian E&P contract does not have any Production bonus.

Other features of the ANH's E&P contract are far more known although no less important, including: there is no longer (as in the Association Contract) a mandatory 'back-in' for Ecopetrol which implied an automatic 'dilution' of the oil company's working interest. Also, the contract is meant to last until the economic limit of the field, so there will not be lengthy, political negotiations for a likely extension of the initial term: the contract contemplates the way to make it possible.

Finally, and probably the most important economic issue arises from the 'High prices' clause that was initially meant for prices above US$27/bl (i.e. 2005 US constant dollars for light oil). World prices are well above this level and consequently every contract is in high-prices' mode (provided the field has already produced above 5 million barrels, gross).

And probably the 'ugliest' thing about the ANH E&P contracts is the difficulty to understand and find out what parties are in a given block. When the parties have an 'official' working interest there is no problem since it becomes known and transparent for the incumbents and outsiders (like HCC!), however, when they use a different legal vehicle, like the so-called Participation Accounts the story takes a less transparent connotation: under such an arrangement there is only one partner that is 'visible', hence known, the other partners are 'hidden', hence unknown, not just to the public in general but also for the ANH, which is perverse since nobody is able to find out exactly 'What is in the box'.