The expectations of oil companies on future oil prices: an empirical analysis of reserves trading

Abstract: *This paper develops a methodology to assess the expectations of oil companies managers regarding future oil prices implied in the acquisition of reserves. The method is applied to a sample of farm-ins and farm-outs of developed onshore oil fields in the US and Canada from 1979 to 2004. The main findings point out that the determinants of the purchase price of reserves have not changed significantly over these 25 years and that oil companies (or their managers) generally believe in a mean-reverting process for the price of oil in the process of bidding and accepting offers for reserves. This means that they expect the price of oil to increase when it is below historical average and to decrease when it is above average.*

Keywords*: valuation; oil price forecasting; petroleum reserves*

1 – Introduction

In the period from 1979 to 2004, more than 6 thousand transactions involving in-the-ground[1] petroleum reserves took place in the US and Canada, amounting to approximately US$ 646 billion, accounting for a total traded volume of 40 billion barrels. These acquisitions were made by major and independent companies and traded reserves were situated in both mature oil and gas fields or undeveloped discoveries. The volume of reserves traded per year increased from 1979 to 1990, reaching a peak of nearly 3 billion barrels (which is roughly equivalent to annual US oil consumption at the time) in 1990, and then decreased. This volume of reserve trading in the late 80s and early 90s was the result of market deregulation in the US accompanied by high market liquidity, as discussed in Harford (2005), intensifying the market for farm-ins[2] and farm-outs.

One of the key issues in the process of assessing the value of an oil reserve is associated to the expectations on how oil prices will behave in the future. There are a number of methods that can be used to derive expectations from the prices of financial derivatives, such as option contracts. We focus, however, on the expectations for future oil prices from the perspective of oil companies. In this paper, we develop a method to investigate how oil companies involved in reserves trading perceive oil prices to behave over time. We believe that his methodology has two major distinctions over the estimation of expectations derived from the prices of securities: first, oil company managers involved in an acquisition of reserves may have a better perception of the dynamics of their industry and be more informed than other players regarding future supply and demand for oil; second, we are able to assess how a specific group of players (i.e., oil company managers), form their expectations, instead of looking at aggregated equilibrium expected market prices.

This is the first study, to the best of our knowledge, to assess the expectations on future prices of oil from actual trades of oil reserves. A methodology is developed to estimate what is the break-even price for oil implied by the value of bids made for acquisition of mature onshore oil fields. This method allows the estimation of premiums (or discounts) paid by acquirers relative to the spot oil price at the time of acquisition. We also estimate how field-specific factors, such as the existence of gas reserves, current oil price and firm-specific characteristics, such as being a major or an independent company, affect this premium or discount. Our evidence indicates that companies use some type of mean-reversion model for the dynamics of oil price and that the presence of marginal gas reserves is also a factor that positively affects the premium paid by the acquirer of the reserve.

The rationale of sellers and buyers, as well as the determinants of the decision to buy or sell oil and gas reserves, are complex, with arguments ranging from financial to strategic considerations. This points out that the valuation process is of paramount importance. Smith (2003) argues that when both seller and buyer who enter into a deal are rational, the methodology of valuation must be acceptable to both sides. After all, the return on investing (or divesting) in oil reserves depends on future cash flows from operations and acquisition cost. Therefore, the value paid (or received) by the firm for an oil reserve depends on the company's expectations about future oil production, oil price, capital and operational expenditures and taxation. These expectations may be different for each firm and the risk of paying too much for the oil in the ground, or selling it for too little (i.e. destroying value for the company) is ubiquitous.

Transacting petroleum reserves, however, can create value for both the buyer and the seller, depending on the specific competencies of each firm. Each of two oil companies may be able to produce oil from a single reserve using different technologies that allow production at distinct costs and flow profiles. In this process, although the reserves valuation methodology may be identical for buyer and seller, the reserve may be worth more if owned by one firm instead of another.

This paper is structured as follows: section 2 presents the model to estimate the break-even price in acquisitions of oil reserves and develops our hypotheses. Section 3 presents the database, describes the sample and the main variables. In section 4, we run Ordinary Least Squares (OLS) regressions to test our hypotheses and discuss the results obtained. Section 5 presents a robustness analysis of the results and section 6 brings the main findings and conclusions.

2 – The break-even oil price in oil reserve transactions

The valuation of in-the-ground oil reserves has been studied by Gruy, Garb and Wood (1982), who, after analysis of reserves transaction data, find that the value of each undeveloped barrel of oil is approximately 1/3 of its spot price. Hence, this is often referred to as the *one-third rule*. The relation between the market price of a barrel of oil and the value of a barrel in-the-ground is also discussed by Cairns and Davis (2001), who developed a methodology based on historical trends of oil prices, finding that the value of an in-the-ground barrel of oil is a fraction (the *r-percent* rule) of spot price.

In a reserve transaction, the market value of each barrel of oil in the ground, H, is found by simply dividing the price K paid for a reserve of Q barrels, that is:

$$H = \frac{K}{Q} \qquad (1)$$

If the Discounted Cash Flow (DCF) method is used to assess the value of a very large oil reserve, assuming that production decreases exponentially at a rate α (not enough to deplete the full reserve at a fixed time), we have:

$$H = \frac{\alpha}{\alpha + \mu}(P - C)(1 - R) \qquad (2)$$

where P is the spot oil price, C *is* the extraction cost per barrel, μ is the discount rate (opportunity cost of capital) and R is the tax rate on operational earnings[3]. Equation 2 is analogous to the famous Gordon model[4] for valuing stocks from expected dividends (the fact to be noted is that the "growth rate" from the Gordon model is, in our case, negative – and that is why α appears added to μ in the denominator) . The value V of a reserve containing Q barrels of oil is thus given by $V=QH$.

Equation (2) sheds some light on the impact of decline rate, capital cost, price and taxation in the value of reserves. An increase in the decline rate from 10 to 15%, *ceteris paribus*, would increase the per-barrel price of a reserve from 33% to 40% of the expected oil price. Thus, companies will pay more for reserves that allow a more rapid production, which is an obvious consequence of the time value of money (i.e., earlier cash flows are more valuable than later cash flows). If the discount rate μ or the level of taxation R increases, per barrel price of reserves goes down. In addition, if the discount rate is numerically equal to the decline rate, and oil price and extraction costs are assumed to be constant over time, the value of an in-the-ground barrel of oil is a fraction of the spot price of oil.

If the decline rate is enough to fully deplete reserves at a fixed time T, at a constant decline rate α (as in Arps (1940), Gray (1960) and Mian (2002)), the instant oil production rate at time t is given by $q(t+\Delta t) = q(t)e^{-\alpha \Delta t}$. The total volume of oil extracted during time T is:

$$Q = \int_{t=0}^{t=T} q(0)e^{-\alpha t}\,dt \qquad (3), \quad \text{or}$$

$$Q = \frac{q(0)}{\alpha}\left(1 - \frac{1}{e^{\alpha T}}\right) \qquad (4)$$

The result of equation (4) is the basis of Adelman and Watkins' (2005) definition of reserves (2005): "*reserve is the estimated cumulative production from capacity already in place, as calculated by engineers and accepted by investors*". Thus, the term *reserve* refers to the end product of investments in one or more oil and gas fields.

Given a constant decline rate of oil production, α, the production flow at $t=0$, $q(0)$, and the total number of barrels of reserves, Q, from equation (4) we are able to estimate the operational life of the reserve, which is given by:

$$T = -\frac{1}{\alpha}\ln\left(1 - \frac{\alpha Q}{q(0)}\right). \qquad (5)$$

It is important to note that Equation 5 is defined and T is positive whenever $0<(\alpha Q/q(0))<1$. The first inequality holds simply because all terms α, Q and $q(0)$ are all, by definition, strictly positive. The second inequality holds whenever $\alpha<q(0)/Q$, which means that α is small enough to deplete the reserve Q at a fixed time T. As α approaches $q(0)/Q$, T tends to infinity. In the extreme cases where $\alpha>q(0)/Q$, the reserve will produce oil infinitely.

Thus there are 3 inputs needed in order to estimate T using equation (5): the oil reserve Q, current oil production $q(0)$ and the constant decline rate α. They depend on geological characteristics of the reservoir (permeability, porosity, oil quality, etc.) and the technology used in the extraction process (number of producing and injection wells in place, reservoir pressure, etc.). Assuming that these inputs are known, we can estimate the operational cash flow yielded by the reserve at time *t*, *F(t)*, as:

$$F(t) = q(t)[P(t) - C(t)](1 - R) \qquad (6)$$

where $q(t) = q(0)\, e^{-\alpha t}$ is the production flow rate at time *t*, *P(t)* is the oil price per barrel[5] at time *t*, *C(t)* is the production cost per barrel at time *t* and *R* is the total corporate and petroleum-specific taxes charged over the gross margin of sales (understood here as the difference between total sales and costs). We assume that all investment has already been depreciated.

The present value of cash flows yielded by extracting and selling oil from a reserve, *V*, can be estimated as the integral of the *F(t)* curve, discounted at a constant opportunity cost of capital μ:

$$V = \int_{t=0}^{t=T} q(t)[P(t) - C(t)](1 - R)e^{-\mu t}\, dt \qquad (7)$$

Assuming that the extraction cost per barrel is fixed, i.e. $C(t) = C$, and calling *P* a hypothetical fixed oil price during the operational life of the field, we have[6]:

$$V = q(0)(P - C)(1 - R)\left(\frac{1 - e^{-(\alpha+\mu)T}}{\alpha + \mu}\right) \qquad (8)$$

It is important to notice the economic interpretation of the oil price *P* in Equation 8. Although P may be understood as a constant oil price for the whole operational life of the reserve, i.e., the oil price is held constant from time *0* to *T*, more realistically, we can also think of *P* as a value that is equivalent to a time-varying *P(t)* in the computation of the value *V* in equation 7. Alternatively, we can also think of *P* as a *hedged oil price,* supposing that the company is able to pre-contract the sale price of all production from the reserve being acquired.

The result of equation 8 is what companies expect to receive from extraction operations and sale of oil to the market and can be seen as a standard for buying and selling in-the-ground reserves. If K is the purchase price of the reserve, the acquirer will break-even in terms of value creation (i.e., the NPV of the project is zero) when $V = K$.

The break-even oil price P^* in an acquisition of a mature petroleum reserve (i.e., a reserve with a finite operational life) is the value of P in equation 8 that satisfies $V = K$. The acquirer will create value if the actual price in the future is higher than P^* and destroy value in cases where the actual future price is lower than P^*. After some algebra, the break-even price P^* is:

$$P^* = \frac{K(\alpha + \mu)}{\mathrm{q(0)(1 - R)(1 - e}^{-(\alpha+\mu)\mathrm{T}})} + C \,. \qquad (9)$$

This value of P^* can be compared to the spot oil price to give the information on the expectations of buyer and seller on the future dynamics of oil prices. We define the premium in a reserve transaction as:

$$Premium = P^* - P(0) \qquad (10)$$

where $P(0)$ is the spot oil price at the time of acquisition.

2.1 - Factors that affect the oil price premium

Purchase price K is the value for which buyer and seller agree to trade reserves. Thus, given flow profiles $q(t)$, opportunity cost of capital μ, extraction costs C, and corporate tax rate R, there is a break-even oil price P^*, which is implied in the purchase price K. This break-even price P^* is, in terms of present value of the reserve (i.e., its value) for the firm, equivalent to a constant price from the moment that reserves are traded (i.e., $t = 0$) until the end of the operational life of the field (i.e., $t = T$, where T is given by equation 5).

A mean-reverting process for oil price is justified under the microeconomic theory of price formation: *"In competitive markets, there is no space for abnormal profits"*, provided that, in the short run, technology and capital are considered fixed. Although it is impossible to measure the expectations of **each** buyer and seller, if both assume a mean-reverting behavior in oil prices, we expect the price premium to be negatively related to the spot price, i.e., managers expect the price of oil to increase when it is low (i.e., below historical average) and to decrease when it is high (i.e., above historical average).

Based on the rationale above, we are able to state our first hypothesis:

H1: The implied break-even oil price P is negatively related to the spot oil price at the time of acquisition, i.e., managers believe in a mean-reverting process for the price of oil.*

The existence of gas reserves is also a factor that impacts oil price premiums. The presence of gas may increase the cash flow since it is used currently as an important energy source and is expected to be so over the coming years. As a result, we expect that the larger the gas reserves relative to oil reserves, the higher the premium. Since the value of gas reserves is not included in the computation of the value of the cash flows yielded by the field in equation (8), the break-even oil price is overestimated, since there may be revenues derived from gas production at little or no cost. As a result, the premium is underestimated whenever there are gas reserves associated to oil reserves. Another reason to expect that the presence of gas may increase the price premium is that the oil contained in reservoirs associated to gas tends to be lighter (and, thus, have higher commercial value) than oil found without the association of gas.

H2: The price premium in a transaction is positively related to the amount of gas reserves existent.

The rationale for trading reserves under reason (ii) above is that the values of C (production costs) and μ (opportunity cost of capital) in equation (8) may be different for buyer and seller[7]. In this case, the break-even price P^* may be different for buyer and seller. Calling P_b^* and P_s^* the value of P^* for the buyer and the seller, respectively, transaction of reserves is able to create value whenever $P_b^* < P_s^*$. Notably, integrated oil companies may differ from smaller (so called *independent*) oil companies, thus it is necessary to control for this difference, whenever a major company is involved in the transaction. However, we have no solid reasons to believe that majors will charge (pay) a higher or lower premium for selling (buying) oil reserves.

1) Oil price premium and spot oil price are negatively related;

2) The size of gas reserves and price premium are positively related.

3 – Reserves transaction data

We use a database of more than 6 thousand transactions involving the acquisition of proven petroleum reserves in the US from 1979 to 2004, organized by the Scotia Group. This database is available online at Scotia's website. Some of the transactions include the purchase of oil and gas reserves, but also of pipelines, plants, equipment, goodwill, etc. In these transactions, the value of ancillary assets is subtracted from the acquisition price; if the purchaser assumes debt, the value is added to the acquisition price. The result is named "Scotia-adjusted petroleum reserve price", or simply "adjusted price".

Of all acquisitions, we selected those that satisfy the following conditions:

a) Data on price of purchase, volume of acquired reserves of oil and gas and current production of oil and gas are all available;

b) The purchase of reserves refers to a single onshore oil field or to a group of onshore fields;

c) The field (or group of fields) was producing oil at the time of acquisition;

d) The estimated life of production for the fields (equation (5)) is less than 10 years;

e) The gas production divided by oil production (measured in thousand cubic feet per barrel) at the time of acquisition was smaller than 10;

f) The ratio between gas reserves and oil reserves (measured in thousand cubic feet per barrel) was smaller than 10 at the time of acquisition;

g) The adjusted price is equal to the acquisition price (i.e., no assets other than oil and gas reserves were being acquired, nor debt was being assumed).

Conditions *b*, *c* and *d* ensure that there is little uncertainty regarding the size of reserves and that fields were typically producing at an irreversible declining rate, since these are assumptions made to estimate the life of the field. Restriction *e* is made to ensure that the current production of gas is responsible for a small fraction (less than 1/5) of the revenues yielded by the field and, equivalently, restriction *f* assures the same thing for potential future cash flows, indicating that the purchase was mainly driven by the value of oil (not gas) reserves[8]. We return to this issue in the next section, where we are able to estimate how the magnitude of gas reserves impacts the price premium paid by acquirers of reserves. Condition *g* also assures that the purchase price does not include the acquisition of assets other than oil and gas reserves, nor is the acquirer of reserves assuming debt from the selling company (this also guarantees that firm acquisitions and mergers are excluded from our sample).

We end up with a sample of 76 acquisitions, from January-1980 to September-2004, for which data on purchase price, volume of oil and gas reserves, current oil and gas production and the names of the companies (or group of companies) that are buying and selling the reserves are available. We are able to estimate the operational life of each field, break-even oil price and price premium, according to equations (5), (8) and (10), respectively. In order to do so, we have to estimate the decline rate α, the opportunity cost of capital μ, and the operational cost per barrel of produced oil C, for each of the 76 reserves acquired.

It is almost impossible to find the values of these input parameters associated to each individual trade, but, alternatively, we can use some aggregated estimates. Adelman and Watkins (2005) use a decline rate of 9% for US onshore oil fields. Slider (1983, chapter 8) states that the decline rate tends to be higher for large fields and lower for small fields. Since the reserves in our sample are mostly typical of small fields with a median reserve of around 1 million barrels (as shown later in Table 1), we use a decline rate of 8% to estimate the operational life and the break-even oil price for the acquisition.

According to Smith (2003), the risk-adjusted discount rate for oil projects ranges from 9% to 14%. For investment in mature petroleum fields, the opportunity cost of capital tends to be lower than that for undeveloped reserves because of: i) a lower level of informational asymmetry, since the production schedule is already well known; ii) existence of historical information on operational costs; iii) the time horizons of the projects are generally lower than for undeveloped reserves. This means that there is lower systematic and unsystematic risk in the cash flows generated by developed fields (the case of the fields in our sample), than in cash flows yielded by an undeveloped reserve. In other words, the proper opportunity cost of capital to discount the cash flows produced by the oil fields in our sample should be lower than the company's weighted-average cost of capital (WACC). We use a value of 10% for μ, which is also a rule-of-thumb value used by managers for investment in mature fields (Van Meuers, 1999). This value is slightly lower than the historical weighted-average cost of capital (WACC) for publicly traded US oil companies in the last 25 years.

The production cost estimated for fields located in onshore US basins ranges from US$2.50 to US$4.00 per barrel, according to the IHS Energy Group database. We use a production cost of US$3/bbl. Since the values of α, μ and C are chosen quite arbitrarily, we check the robustness of our results to the choice of parameters μ, α and C, via sensitivity analysis in section 5.

Table 1 describes the basic characteristics of the 76 acquisitions of reserves considered in this paper. The average traded reserve volume is 3.6 million barrels, the largest reserve has 63 million barrels of oil, and the highest bid is USD 515 million. The median and average values paid for an in-the-ground barrel of oil are both around USD 7, which is somewhat consistent with the one-third rule-of-thumb (given that the average and median spot prices for West Texas Intermediate – WTI - oil are USD 21.38 and USD 20.16, respectively, during the period of analysis). The price premium is calculated relative to the WTI average spot price in the month in which the transaction took place and ranges from a negative USD 20.48 to a positive USD 30.68. It is positive in 24 of the 76 observations. The average and median operational lives of the reserves are around 7 years, which is a typical value for a mature onshore field. It is important to notice that the standard deviations of the estimated *break-even oil price* and *oil price premium* are higher than for the standard deviation of the simple *purchase price/oil reserves* ratio and *spot oil price*, for two main reasons: first, the break-even oil price and the price premium involve the expectations about future prices for a period of up to 10 years, which may naturally increase variability due to oil price volatility; second, there are factors other than the ones considered in our model that are determinants of the oil price premium, such as the volume of gas reserves, quality of oil (viscosity, acid and sulfur content), proximity of refineries and buyer/seller firm-specific characteristics. We address these issues in the next section.

[Insert Table 1 here]

4 – Determinants of the price premium

In this section, we investigate whether we find empirical support for the hypotheses stated in section 2 regarding the impact of current oil price and gas reserves on the price premium paid in an acquisition. With this purpose, we run an Ordinary Least Squares (OLS) regression. In the choice of the explanatory variables that are included in our model, caution is in order, since the chosen variables cannot be mechanically related (via equations (1) to (9)) to the break-even price P^*. Variables that are mechanically related to P^* would result in problems of endogeneity in our estimation. The following model was employed:

$$Premium = c + \beta_1\, Spot\ Price + \beta_2\, GOR + \beta_3\, Maj + \varepsilon \qquad (11)$$

where,

Premium is defined in equation (10), as the difference between the estimated P^* and the spot price, which is defined as the monthly average of the WTI oil at the month of acquisition.

Spot Price is the monthly average of the WTI oil at the month of acquisition. It is important to note that the spot price, although included in the computation of the price premium, is exogenous to P^* and is, therefore, not mechanically related to the dependent variable.

GOR is the ratio between gas reserves and oil reserves at the time of acquisition, measured in thousand cubic feet of gas per barrel of oil. It is important to note that we have ruled out all observations for which the value of *GOR* is higher than 10, in order to ensure that the presence of gas reserves would not invalidate the assumptions made in the computation of the break-even price P^*. The use of a per-barrel measure of gas reserves allows us to draw a straight economic interpretation for the coefficient β_2: *how much is the premium paid per barrel of oil for each thousand cubic feet of gas in the field.*

Maj is a dummy variable that assumes 1 when at least one of the selling companies is a major, and 0 otherwise. In all the cases in which *Maj* assumes value 1, the buying firm is an independent oil company (or group of independents). The following companies are defined as majors: Exxon, Mobil, Shell, BP, Texaco, Chevron, Standard Oil and Amoco.

Table 2 shows the Pearson correlation coefficients for the variables included in the regression. The correlations between independent variables are all non-significant at usual levels. P* is significantly correlated to GOR, which was already expected from our hypotheses.

The OLS estimation of equation (12) is shown in Table 3. Standard errors and covariance are heteroskedasticity consistent, using the White method. The fit of the model, measured by the R-square of the regression, is 0.517, which means that these 3 single variables are able to explain more than half of the cross-sectional variability of the price premium.

[Insert Table 2 about here]

The coefficient for spot price has the expected negative sign and is significant at less than 1%. Although it is not possible to state that $\beta_1 > -1$ at usual levels of significance, it possibly indicates the belief in a mean-reverting process for oil price. For every dollar that spot price deviates from long-term expected value, there is an 80 cent movement in the premium in the opposite direction. For example, if current spot price is 1 dollar above its long-term expected price, the value of P^* is increased by 20 cents (i.e., \$1.00 – \$0.80). This means that for every 1 USD increase in the spot price, oil companies expect an increase of only 20 cents in the average price of the oil produced from that reserve. This result means that oil companies expect the price of oil to increase when it is low in relation to historical levels and to decrease when it is high, thus indicating that our first hypothesis is consistent.

The obtained estimate for the coefficient of the *GOR*, β_2, has a direct interpretation: for every extra thousand cubic feet of gas, the per-barrel price premium is 2 dollars. It is interesting to note that this value is close to the average sales price of gas to the industrial sector from 1979 to 2004, according to data of the Energy Information Administration (EIA, 2006), which strengthens the hypothesis that the commercial value of gas is able to explain a price premium of up to USD 20/bbl (in the case where GOR = 10) *ceteris paribus*. As expected, this suggests that our second hypothesis is empirically verified.

[Insert Table 3 about here]

It can also be seen by the regression estimates that major companies sell reserves at a higher discount (or lower premium) than their independent peers. Roughly building a

95% confidence interval over the expected value of β_3, we are able to predict that the premium charged by independent companies relative to majors is between USD 0.83 and 11.03/bbl (respectively *5.93-2*(2.55)* and *5.93+2*(2.55)*). Although the economic rationale for this result is not straightforward, it is possible to check that major and independent companies behave differently when trading reserves[9].

Once we are dealing with acquisitions made over a period of 25 years, it is natural to raise questions on the behavior of the price premium over time. Since the data in our sample has been arranged in chronological order, the Durbin-Watson statistic shows that there is no significant serial correlation among subsequent residuals (i.e., the unexplained part of the price premium). This indicates that we cannot identify a pattern of behavior (increasing or decreasing) for the price premium over time (even though the time lag between 2 subsequent acquisitions is not constant, which is standard in time series analysis, this result identifies that there is no serial correlation of residuals).

5 – Robustness analysis

In this section, we estimate the robustness of the results obtained in section 4 to the parameters μ, α and C. (i.e., the values elected for the opportunity cost of capital, flow decline rate, and per-barrel extraction cost).

The robustness of the results to any arbitrary value chosen for the extraction cost C is straightforward since, from equation (9), the break-even price P^* is directly related to C (i.e., if C increases by 1 dollar, then P^* also increases by 1 dollar). In addition, from equation (10), the same happens between the spot price $P(0)$ and P^*. Thus, the relation between the price premium and C is also direct. This means that an increase or decrease in the parameter C would only affect the intercept of the OLS-estimated equation, which implies that our conclusions are independent of the arbitrary value chosen for the extraction cost C.

[Insert Figure 1 about here]

We then let the opportunity cost of capital μ vary within the interval [6%; 20%], which contains reasonable values for the cost of capital of either major or independent US oil companies, maintaining other parameters constant. We calculate P^* and the price premium according to equations (9) and (10), respectively, for each acquisition using $\mu = 6\%, 8\%, 10\%...20\%$, and re-run the OLS regression of equation (11) for each new μ. The results are maintained unaltered in terms of coefficient signals (relative to those shown in Table 3), and altered only slightly in terms of significance, as shown in figure 1.

The same procedure is used to test for the robustness of the decline rate α, letting it vary in the interval [4%; 16%], which is a wide interval for a typical decline rate in the oil-flow rate (common-practice values are usually between 6% and 12%) . We again re-estimate P^* and the price premium for α = 4%, 5%, ….16%, estimating an OLS regression for each value of α. Again, the signals of the coefficients in the regressions are unaltered (relative to Table 3) and their significance is not materially affected, as shown in figure 2.

These sensitivity analyses show that our results are verifiable regardless of the arbitrary choice of values for the parameters μ, α and C, provided that reasonable values are used.

[Insert Figure 2 about here]

6 – Conclusions

This paper investigates the main determinants of the prices of acquisitions of proven oil reserves located in mature onshore fields. We developed a methodology to estimate the expected future oil price implied by the values of transactions of oil reserves (farm-ins and farm-outs), considering expectations of oil flow rate over time, estimated production cost and opportunity cost of capital.

We use a sample of 76 reserves acquisitions (farm-ins and farm-outs) to study how much an in-the-ground barrel of oil is worth for oil companies, according to characteristics such as proven oil and gas reserves, current production flow and spot oil price. The main findings indicate that: i) **there is a belief in a mean-reverting process for oil prices among decision-makers**, i.e., managers expect the price of oil to increase when it is below historical average, and to decrease when it is above average; the belief in a mean-reverting process for oil prices is consistent with microeconomic theory and with anecdotal evidence in the oil industry. It is important to note, however, that we are not suggesting that oil prices actually present a mean-reverting stochastic process; ii) **the presence of gas reserves, even in fields with a low gas-oil ratio, increases the value of the bid**, confirming that gas reserves are valuable in US onshore locations; iii) **Major oil companies value small mature reserves at a discount relative to independent oil companies**; iv) **The**

determinants of the in-the-ground oil prices in the acquisition of mature onshore reserves have not changed significantly over time. Although more discussion could be dedicated to this issue, one possible point to be considered is that most of the technological efforts in the petroleum industry in these last 25 years have been dedicated to exploration activities (such as 3-D seismic survey, improved interpretation of geological models etc.) or to large-scale production (such as advances in horizontal drilling, deepwater production, enhanced oil recovery (EOR) etc.), with only marginal changes in the technology used to extract oil from onshore mature fields.

The limitations of this work are mainly related to limited sample size, which makes it impossible to compare acquisitions of reserves that occurred at the same time. The concentration of acquisitions over the period of 1988 to 1993 may indicate that it is possible that, in other periods, the determinants of the valuation of mature oil reserves might be different from those found here. A possible further analysis would involve the study of a relation among firm size, size of reserves being acquired or sold and expected costs of production. However, we will leave this issue for future studies.

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[1] *Undeveloped reserve* is the term used to describe the economically recoverable amount of petroleum that is still in an untouched petroleum reservoir (see Adelman and Watkins, 2005). When the oil and gas contained in a reservoir are partially exploited, the term used to describe the remaining oil and gas to be recovered is *remaining reserves* or *in-the-ground reserves.*

[2] In the petroleum industry, the term *farm-in* is used to describe a transfer of part of an oil and gas interest under consideration for an agreement by transferee(s) to meet certain expenditures that would otherwise have to be undertaken by the licensee. In other words, it is a private agreement to purchase the rights to explore and produce petroleum in a certain area. The company that is acquiring the rights is making a farm-in, and the company that is selling the rights is making a farm-out.

[3] All of these terms being constant, we find from equation 2 that the one-third rule of Gruy, Garb and Wood (1982) is achieved, for example, by assuming a discount rate of 10%, a production cost of 15% of the oil price, a decline rate of 10% and a tax rate of 30%.

[4] See, for example, Brealey, Myers and Allen (2005) or any other Corporate Finance textbook.

[5] We do not use metric units since the standards in the oil industry for volume are the barrel (for oil) and thousands of cubic feet (for gas). One barrel is equivalent to 158.98 liters and one thousand cubic feet are equivalent to 28,32 liters.

[6] It is important to note that this value of V derives from Equation 5, that holds when $\alpha < q(0)/Q$. As α approaches $q(0)/Q$, the value V/Q tends to the per-barrel value H, as defined in Equation 2.

[7] Strictly speaking , even the oil flow function over time q(t), could be different for buyer and seller, due to differences in technology, managerial and stakeholders' objectives etc.

[8] Oil fields typically enter a mature period, with irreversible declining production, 10 to 15 years before having their reserves totally depleted. In this mature phase, the geological characteristics of the field are well known and, thus, there is little uncertainty about the size of reserves and production schedule.

[9] We could draw several possible "stories" to explain this difference. However, we leave this issue for future studies.

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Table 1: Characteristics of the acquisitions of reserves considered

This table shows the basic descriptive statistics of the variables considered. Information on oil reserves, gas reserves, oil production, gas production and price of purchase is extracted directly from the Scotia Group acquisitions database. *Gas reserves/oil reserves* and *gas production/oil production* are both calculated at the time of acquisition. Operational life of reserves and break-even oil price are calculated according to equations (5) and (11), respectively. Spot oil price is the average spot price for the WTI (West Texas Intermediate) oil in the month in which the acquisition took place and the price premium is the difference between the break-even price and spot price, as defined in equation (11).

	Mean	**Median**	**Maximum**	**Minimum**	**St. Dev.**
Oil reserves (million bbl)	3.65	1.10	63.00	0.07	8.83
Gas reserves (billion CF)	11.37	0.25	288.00	0.00	39.41
Gas reserves/oil reserves (thous. CF/bbl)	2.06	0.51	9.56	0.00	2.70
Oil production (thousand BOPD)	2.26	0.79	28.00	0.04	4.51
Gas production (million CFPD)	4.27	0.08	117.00	0.00	15.46
Purchase price (million dollars)	31.74	8.35	515.00	0.29	79.97
Purchase price/Oil reserves (dollars/bbl)	7.34	6.63	27.00	0.87	4.61
Operational life (years)	6.58	7.21	9.96	0.04	2.84
Break-even oil price (dollars/bbl)	17.99	16.92	50.80	4.85	9.26
Spot oil price at acquisition (dollars/bbl)	21.38	20.16	34.42	13.00	4.59
Oil price premium (dollars/bbl)	-3.38	-4.85	30.68	-20.48	10.37

Table 2: Pearson correlation coefficients

This table shows the Pearson correlation coefficients for the variables. With the exception of the correlation between the implied break-even price P* and the gas-oil ratio GOR, none of the correlations are significant at usual levels.

	P*	**GOR**	**Spot Price**
GOR	0.5788	1.0	
Spot Price	-0.0095	-0.1959	1.0
Maj	-0.2634	-0.0715	-0.0375

Table 3: Results of the OLS regression

This table shows the results of the OLS estimation of Equation (12). The dependent variable is the price premium , which is the difference between implied break-even oil price and current spot price, as defined in Equation (11). All independent variables included in the regression are significant at less than 5% and the adjustment measured by the R-squared is superior to 50%.

	Expected sign	Coefficient	t-Statistic	P-value.
C	**?**	10.50	2.535	0.0134
Spot Price	-	-0.805	-4.270	0.0001
GOR	+	1.998	5.026	0.0000
Maj	-	-5.932	-2.321	0.0231
R-squared	**0.5172**	**F-statistic**		**25.7088**
Adjusted R-squared	**0.4971**	**Prob(F-statistic)**		**0.000000**
Durbin-Watson stat	**2.4685**			

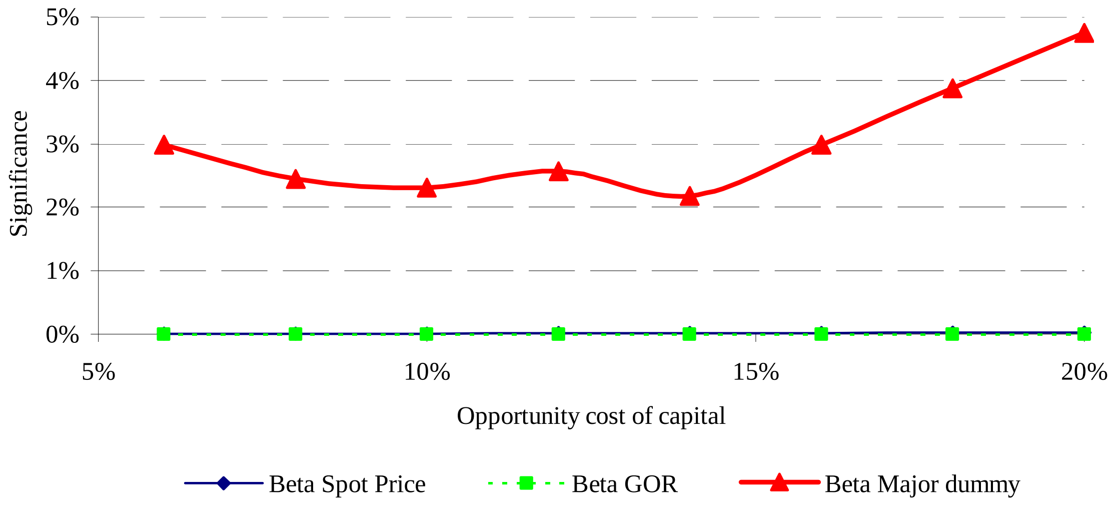

Figure 1: Sensitivity analysis of the significance of the coefficients β in the OLS regression to the opportunity cost of capital μ

This figure shows the significance (as measured by the p-value obtained from a student t-test) of the beta coefficients obtained from the OLS-estimated regression of equation (11) for different values of the opportunity cost of capital μ within the range [6%; 20%]. The red line shows the significance of the coefficient of the dummy variable for major oil companies, the green dotted line shows the significance of the coefficient of the gas-oil ratio GOR (this p-value has remained below 0.01% in all regressions), and the blue line, which lies close to the green line, shows the significance of the coefficient of the spot price.

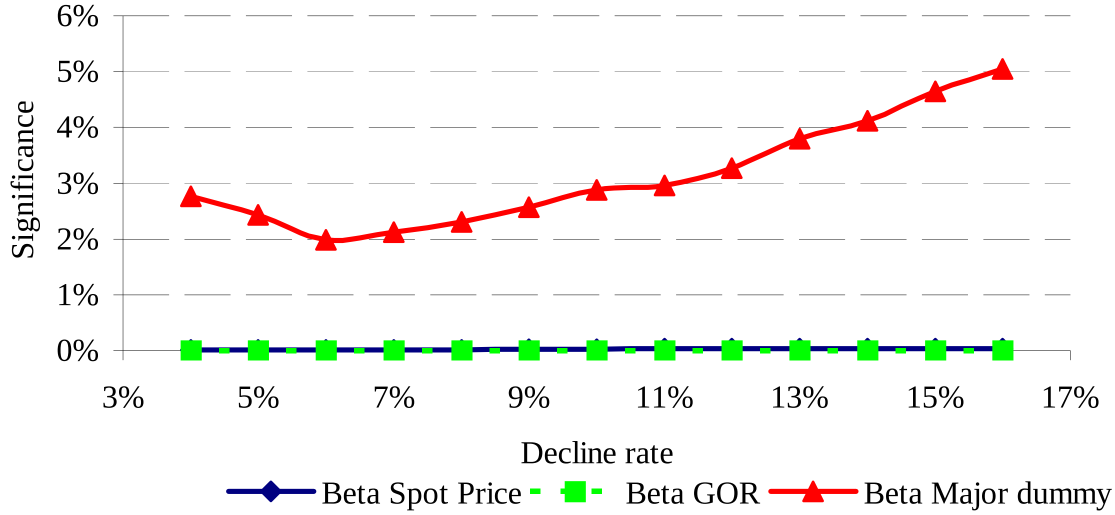

Figure 2: Sensitivity analysis of the significance of the coefficients β in the OLS regression to the decline rate α

This figure shows the significance (measured by the p-value obtained from a student-t test) of the beta coefficients obtained from the OLS-estimated regression of equation (12), when the decline rate α varies within the range [4%; 16%]. The red line shows the significance of the coefficient of the dummy variable for major oil companies, the green dotted line shows the significance of the coefficient of the gas-oil ratio GOR (this p-value has remained below 0.01% in all regressions), and the blue line, which lies close to the green line, shows the significance of the coefficient of the spot price.