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HOW DO MANAGERS ASSESS FUTURE OIL PRICES?

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Abstract.
This paper develops a methodology to assess oil companies managers' expectations about future oil prices implied in the acquisition of reserves. The method is applied to a sample of farm-ins and farm-outs of onshore developed oil fields in the US from 1979 to 2004, where we make assumptions on expectations on oil production and decline over time. The main findings pointed out that the determinants of the purchase price of reserves has not changed significantly over these 25 years, and that oil companies (or their managers) generally believe in a mean-reverting stochastic process for oil price in the process of bidding and accepting offers for reserves, which means that they expect oil price to increase when it is below historical average, and to decrease when it is above average. We also find that major oil companies are either more conservative than independent firms in estimating future oil prices or strategically decide to focus mainly or large capital-intensive oil prospects.

1. Introduction

Over the period from 1979 to 2004, more than 6 thousand transactions involving in-the-ground petroleum reserves took place in USA and Canada, amounting around US$ 646 billion, accounting for a total traded volume of 40 billion barrels. These acquisitions have been made by major and independent companies and traded reserves may be situated in both mature oil and gas fields or undeveloped discoveries. The volume of reserves traded per year has increased from 1979 to 1990, reaching a peak of 319 million bbl (which is roughly equivalent to 60-days US oil consumption at the time) in 1990, and then has decreased. This wave of reserves trading in the late 80s and early 90s has resulted from deregulation in USA, as discussed in Harford (2005), intensifying the market for farm-ins and outs.

The rationale of sellers and buyers as well as determinants of decision to acquire or sell oil and gas reserves are complex, with arguments ranging from financial up to strategic considerations. This points out that the valuation process is of paramount importance. Smith (2003) argues that, when rational seller and buyer go into a deal, the methodology of valuation must be acceptable by both sides and the risk of paying too much for the oil in the ground, or selling it for too little, is always ubiquitous. Transacting petroleum reserves, however, can create value for both the buyer and the seller, depending on the specific competencies of each firm. A single oil reserve may be exploited using many different technologies, which allow production at distinct costs and flow profiles. In this process, the valuation of each in-the-ground barrel of oil plays a key role. 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 cost and taxation. After all, the return of investing in acquisition of reserves depends on future cash flows from operations and acquisition cost.

In this paper a methodology is developed to estimate what is the expected break-even price for oil implied by the value of bids made for acquisition of mature onshore oil fields. This allows us to estimate the premiums (or discounts) being 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 (major or independent) 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 independent oil companies are generally able to produce oil at a lower cost than their major

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counterparts. In addition, we find that the presence of marginal gas reserves is also a factor that affects positively the premium paid by the acquirer of the reserve.

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 expose our proposed methodology, used to test our hypotheses, showing the results of the tests. Section 5 presents 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 data of reserve's transactions found that the value of each undeveloped barrel is approximately 1/3 of market oil price. Hence this is often referred to as the *one-third rule*.
The market value of a barrel of oil in the ground, *H*, is found by simply dividing the price *K* paid for a reserve of *Q* barrels, that is:

$$H = \frac{K}{Q} \tag{1}$$

Considering the case of a very large reserve, assuming that production decreases exponentially at a rate α (not enough to deplete the full reserve at a fixed time), we have:

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

where *P* is the spot oil price, the cost per barrel is *C*, the discount rate is μ and tax rate on operational profit is *R* , all of them constant along the project's life, we find:
From equation (2), the one-third rule of Gruy, Garb and Wood (1982) is achieved, for example, if we assume a discount rate of 10%, a production cost of 15% of oil price, a decline rate of 10% and a tax rate of 30%. The relation between market price of a barrel of oil and the value of a barrel in-the-ground is also discussed by Cairns and Davis (2001), that develop a methodology based on historical trends of oil price, finding that the value of an in-the-ground of oil is a fraction (the *r-percent* rule) of spot price. This fraction would range from 15 to 40% for the periods of our study.

Equation (2) sheds some light on the impact of decline rate, capital cost, price and taxation in the value of reserves. An increase in decline rate from 10 to 15%, *ceteris paribus*, would increase the per-barrel price of reserve to 40% of the expected oil price. Thus, companies will pay more for reserves that allow a more rapid production, what 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 or the level of taxation increases, per barrel price of reserves goes down. In addition, if the discount rate is numerically equal to the decline rate, the value of an in-the-ground barrel of oil is a constant fraction of oil price (which is assumed to be constant over time).

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 oil production rate at time t is $q(t + \Delta t) = q(t)e^{-\alpha \Delta t}$. The total volume of oil extracted during time T is:

$$Q = \int_{t=0}^{t=T} q(0)\, e^{-\alpha t}\, dt. \tag{3}$$

or

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

The result of equation (4) is the basis of reserve's definition of Adelman and Watkins (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.
Since we estimate the decline rate of oil production from equation (4), the operational life of reserve is:

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

In order to estimate *T* using equation (5), we need to know three inputs: 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 technology used in the extraction process (number of producing and injection wells in place, pressure of reservoir 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 at time *t*, *C(t)* is the production cost per barrel at time *t* and *R* is the total corporate tax (royalties, corporate tax etc). We also assume that all investment has already been depreciated.

The present value of cash flow from producing 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 cost per barrel is fixed, i.e. *C(t) = C*, and calling *P* a hypothetical fixed price during the operational life of the field, we have:

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

In an extreme case of a large oil reserve, the operational life is infinite and its value can be found according to:

$$V = q(0)(P - C)(1- R)\left(\frac{1}{(\alpha+\mu)}\right). \qquad (9)$$

It is important to notice the economic interpretation of the oil price *P* here. Although P may be understood as a constant oil price for the whole operational life of the reserve, i.e., 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 equations 8 or 9 is what companies expect to receive from extraction operations and sale of oil into the market, and can be seen as a standard for buying and selling of 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 actual future price is higher than *P**, and lose money in case of actual price lower than P*. After some algebra, the break-even price *P** is:

$$P^* = \frac{K}{q(0) * (1 - R) * \left(\dfrac{1 - e^{-(\alpha+\mu)T}}{(\alpha+\mu)}\right)} + C. \qquad (10)$$

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

$$\text{Premium} = P^* - P(0) \qquad (11)$$

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

Factors that affect the oil price premium

The purchase price *K* is the value for which buyer and seller agree to trade reserves. Implied in the purchase price is thus a break-even oil price *P** that, in terms of creation of value for the firm, is 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). Provided that the production schedule and quality of oil produced are given and known by both buyer and seller, firms may trade reserves for two main reasons: i) Buyer and seller have different expectations about future price of oil to be produced and/or; ii) Differences in firm-specific competencies are enough to justify a value-creating transaction; in other words, the firm that is buying the reserves is able to produce oil and commercialize production at a lower cost than the selling company.

A mean-reverting process in 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 is considered fixed. Under the rationale of reason (i), the price premium reflects the expectations of buyer and seller about future prices. For example, if the price premium is zero (i.e., the break-even price P^* is equal to the market spot oil price at the time of acquisition), this may reflect that the buyer is expecting a price increase, whereas the seller is expecting a decrease in oil price. 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 oil price to increase when it is low and to decrease when it is high.

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

H1: The implied oil price P^* is negatively related to spot oil price, i.e., managers believe in a mean reverting process for oil price;

The rationale for trading reserves under reason (ii) above is that the values of C (production costs and opportunity) and μ (cost of capital) in equation (8) may be different for buyer and seller. 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 $P_b^* < P_s^*$. We expect that independent and major companies may operate differently from each other and thus have distinct cost structures. It is well known that the focus of major oil companies is on large projects, leaving the production of low-scale fields to smaller companies, since per-unit overhead costs tend to be higher for major companies in fields with low economies of scale (i.e., projects that are less capital-intensive than giant offshore fields for example). Therefore, in mature and small fields, we expect to find, *ceteris paribus*, lower premiums when the selling company is a major than when it is an independent. In other words, the operating cost C is higher for major companies than for independents, what underestimates the break-even price for majors (relative to independent firms), causing major companies to be willing to sell small reserves at a lower premium (or at a higher discount). Thus, we expect to find smaller premiums when the seller is a major company. Our second hypothesis is thus:

H2: Major companies sell small reserves at a higher discount (or lower premium) than independent oil companies;

The existence of gas reserves is also a factor that impacts oil price premium. The presence of gas may increase the cash flow since 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 price is overestimated, and thus the premium is underestimated.

H3: The price premium is positively related to the amount of gas reserves

Summarizing, our predictions are:

1) Oil price premium and spot oil price are negatively related;
2) The size of gas reserves and price premium are positively related;
3) Oil price premium is smaller when the seller is a major oil company.

3. Reserves transaction data

We use a database of more than 6 thousand transactions involving the acquisition of proven petroleum reserves in the USA from 1979 to 2004, organized by 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, equipments, goodwill, etc. In those transactions the value of ancillary assets is subtracted from 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 select 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 currently 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 price of acquisition (i.e., no assets other than oil and gas reserves was 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 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[1]. 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 price of purchase does not include the acquisition of ancillary assets other than oil and gas reserves, nor is the acquirer of reserves assuming debt from the selling company (this also guarantees 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 price of purchase, 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. We are able to estimate the operational life of each field, break-even oil price and price premium, according to equations (5), (8) and (11), 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 value of these input parameters associated to each reserve, 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 (see 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 in 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) lower level of informational asymmetry, since the production schedule is already well known; ii) existence of historical information on operational costs; iii) the time horizon 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 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 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. In section 5, we check the robustness of our results to the parameters μ, α and C, via sensitivity analysis.

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 515 million dollars. The median and average value paid for an in-the-ground barrel of oil are around $7 dollars, what is somewhat consistent with the one-third rule of thumb (given that the average and median spot prices of West Texas Intermediate – WTI - oil are $21.38 and $20.16, respectively during the period of analysis). The price premium is calculated relative to the monthly average of the WTI in which the transaction took place, and ranges from a negative USD 20.48 to a positive USD30.68. It is positive in 24 of the 76 observations. The average and median operational life 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 simple *purchase price/oil reserves* ratio and *spot oil price*, for two main reasons: first, the break-even oil price an the price premium involve the expectations about future prices for a period of up to 10 years, what naturally may 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.

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 when 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

4. The 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, gas reserves and firm characteristic 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 (10)) to the break-even price P^*. Variables that are mechanically related to P^* would result in endogeneity problems in our estimation. The following model was employed:

$$Premium = c + \beta_1\, Spot\ Price + \beta_2\, GOR + \beta_3\, Maj + \varepsilon \qquad (12)$$

where,

Premium is defined in equation (11), 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, that is how much is the premium paid per barrel of oil for each thousand cubic feet of gas

Maj is a dummy variable that assumes 1 when at least one 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 major: 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, what 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-squared 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.

Table 2: Pearson correlation coefficients

This table shows the Pearson correlation coefficients for the variables. With 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

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 result means that oil companies expect oil price to increase when it is low relative to historical levels, and to decrease when it is high, thus indicating that our first hypothesis is consistent.

The coefficient for *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 historical average price of gas from 1979 to 2004, what strengthens the hypothesis that the commercial value of gas is able to explain a price premium of up to \$20/bbl *ceteris paribus*. As expected, this suggests that our second hypothesis is empirically verified.

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**			

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, as we expected. 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 \$0.93 and \$10.93/bbl (respectively *5.93-2*(2.55)* and *5.93+2*(2.55)*). Although with a lower significance than the other two variables, we are able to conclude that independent companies are either more efficient (i.e., able to produce at lower costs than their major counterparts, or are more optimistic about future oil price), what is the verification of our third hypothesis.

Once we are dealing with acquisitions made through a period of 25 years, it is natural to raise questions on the behavior of the price premium over time. Once the data has been arranged on a chronological order in our sample, the Durbin-Watson statistic shows that there is no significant serial correlation between the 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 the time lag between 2 acquisitions being not constant, which is our case, this does not invalidate our analysis).

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 cost).
The robustness to the operational cost C is straightforward: since, from equation (10), 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 (11), 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, what implies that our conclusions are independent of the estimated cost C.

In **Figure 1,** there is a sensitivity analysis of the significance of the coefficients β in the OLS regression to the opportunity cost of capital μ.

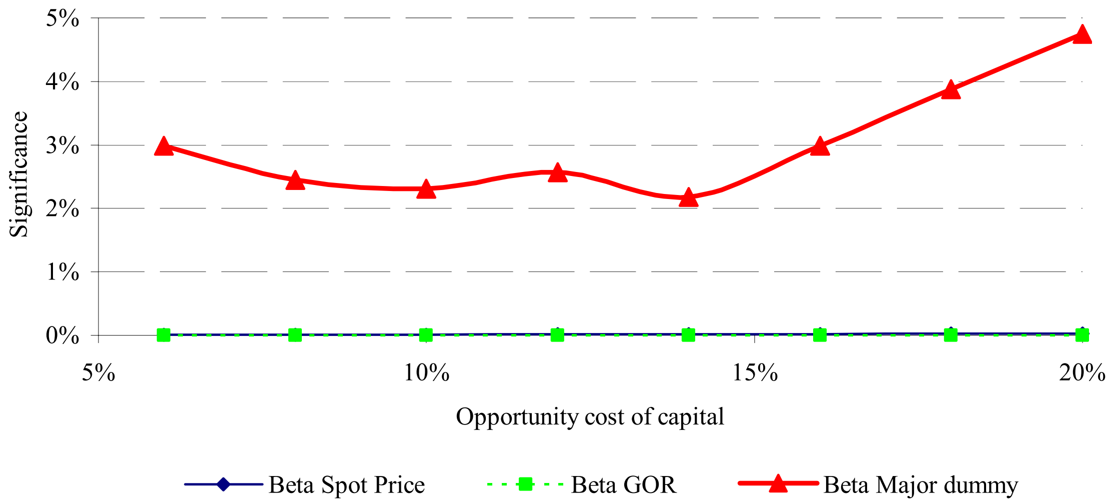

Figure 1 – Sensitivity analysis of the significance of the coefficients β in the OLS regression to the opportunity cost of capital μ.

This figure shows how the significance (measured by the p-value of a student-t test) of the beta coefficients obtained from the OLS-estimated regression of equation (12), when the opportunity cost of capital μ varies 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.

We then let the opportunity cost of capital μ vary in the interval [6%; 20%] which contains reasonable values for the cost of capital of either major or independent US oil companies, maintaining other parameter constant. We calculate P^* and the price premium according to equations (10) and (11) respectively, for each acquisition using μ = *6%, 8%, 10%...20%*, and re-run the OLS regression of equation (12) for each new μ. The results are maintained unaltered in terms of coefficient signals (relative to 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 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 a 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 seriously 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.

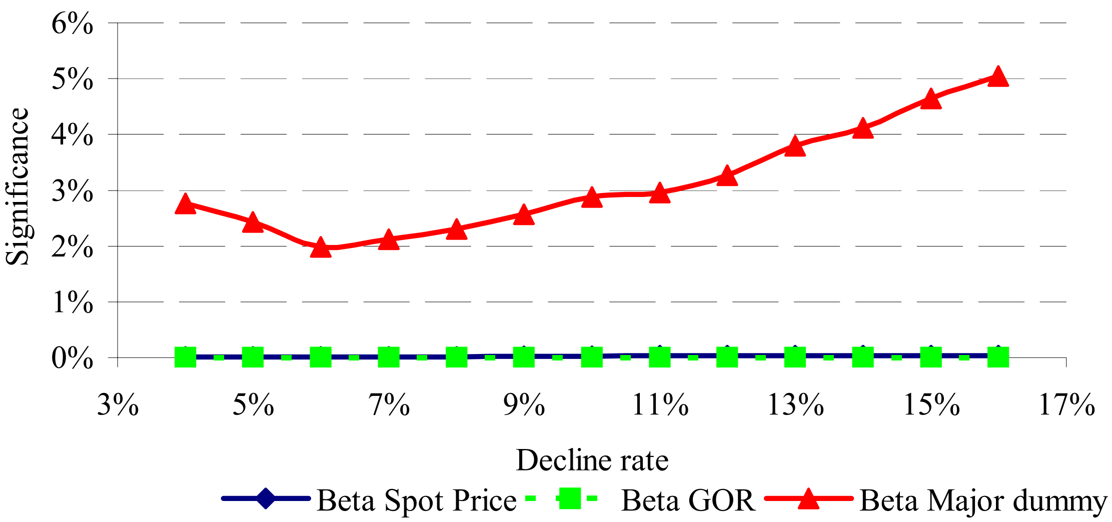

Figure 2: Sensitivity analysis of the significance of the coefficients β in the OLS regression to the decline rate α

This figure shows how the significance (measured by the p-value of 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.

6. Conclusions

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

We use a sample of 76 reserves acquisitions (farm-ins and farm-outs) to study how much is an in-the-ground barrel of oil 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 price among decision-makers**, i.e., managers expect oil price to get higher when it is low, and to decrease when it is high; a mean-reverting process for oil prices is consistent with microeconomic theory and with anecdotal evidence in the oil industry. It is important to notice, 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, specially in US onshore locations; iii) **Major oil companies valuate small mature reserves at a discount relative to independent oil companies**; it is known that major oil companies have tried to get rid of small reserves, focusing mainly in large, capital-intensive projects, such as deepwater fields in the Gulf of Mexico and the North Sea, or prospects in new exploratory regions like the Western African Coast and Eastern South America, as part of a strategic decision to abandon fields where overhead per-barrel costs are high; iv)

The determinants of the in-the-ground oil prices in acquisitions reserves of mature onshore fields 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 have been dedicated to the exploration (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.) in these last 25 years, with only marginal changes to 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 occurred at the same time. The concentration of acquisitions over the period 1988 to 1993 may indicate that the determinants of reserves valuation might be different in other periods. A possible further analysis would involve the study of a relation between firm size, size of reserves being acquired or sold and expected costs of production. However, we leave this issue for future studies.

7. References

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[1] Oil fields typically enter a mature period, with irreversible declining production, 10 to 15 years before having their reserves completely 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.