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THE VALUE OF EXPANSION OPTION IN THE SELECTION OF THE OPTIMAL OIL EXPLOITATION STRATEGY

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Abstract

This paper presents a case study of selection of a production strategy using the real options approach to expand the production of an offshore oil field by drilling additional wells. This oilfield is located in deep waters containing oil with 28 ºAPI and the real options may be exercised at any time during the first three years of production. This flexibility adds value to the project that cannot be captured properly by the traditional method of NPV; therefore the real options theory can be applied. In this paper, the dynamics of present value of cash flows of the project is modeled using binomial model, which is common in financial option pricing. In addition, the methodology takes into account the operational constraints in the capacity of liquid production, water injection capacity and water treatment to make the optimal decision to develop the field. In this oilfield studied, the optimization of the production strategy was carried out taking into account the parameters such as type and configuration of wells, layers of completion and wells opening scheduling. The results show that the value of flexibility to expand production may increase the NPV, if the option is exercised in year 1 and 2 after the start up of the production, but it becomes meaningless if exercised in the year 3 after beginning of production.

1. Introduction

The development of a field can be a complex activity due to the several variables involved and the multiple objectives that must be optimized simultaneously such as oil production, recovery factor, water production, investments restrictions etc. The selection of an exploitation strategy is usually more important, when few data are available, that is, an uncertain scenario of technical and market parameters, among others. As it is known, the price of a barrel of oil is volatile and fluctuates according to supply and demand, economic crisis, wars, etc. Considering the volatile behavior of the oil price it should be taken as the objective function no longer the static NPV (without flexibility), but the dynamic NPV (with flexibility), which is considered as the sum of the static NPV plus the value of flexibility embedded in projects (option value). This flexibility allows decision makers to meet the uncertainties of the business. Thus, this flexibility has a value and it should be considered in the economic evaluation. In fact, the NPV (static) implicitly assumes that there is no flexibility in decision making. An alternative would be the method of decision trees, which considers the flexibility, but it does in an inappropriate way, assuming a constant discount rate, even when uncertainty is clearly changing as a result of variation of returns in several parts of the decision tree. On the other hand, the Real Options Analysis (ROA) corrects both deficiencies, and assesses the projects with flexibility properly (Copeland, 2001). Among the flexibilities considered by ROA, there are the values of the options to defer, abandon, expand, and contract the project, among several others.

The objective of this paper is to show a study where the process of choice of an exploitation strategy within a simplified scenario of uncertainties in oil price and costs are considered. The case study comprehends a deep reservoir containing 28 ºAPI oil. In this paper it is discussed the problem of development of the best alternative of exploitation strategy considering the real options approach for expanding or not, the production capacity, and in affirmative case, the results are also presented for 3 alternatives of exploitation strategy, regarding the time to expand the production capacity.

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2. Methodology

2.1. Exploitation Strategy and Operational Conditions

The exploitation strategy is optimized based on the structure proposed by Mezzomo (2005) and Ravagnani et al. (2009) where the following variables are defined: (1) the parameters of the project of development of the field, (2) the recovery method, (3) the geometry of the wells and (4) the production/ injection schemes. Based on previous studies, in this work it is considered a *five-spot* configuration of horizontal wells for the recovery method through injection water with spacing of 500 meters between wells with producers completed in the last layer and injectors completed in the first layer. The liquid production and water injection flow rates per well are 2000 m^3/d, respectively. It is assumed some constraints of liquid production capacity, water injection capacity and water treatment. It is assumed that there are two alternative platforms: small and large. The small platform has the following capacities:

- liquid production: 10,000 m^3/day.
- water treatment: 9,500 m^3/day.
- water injection: 10,000 m^3/day.

The large platform has the following capacities:

- liquid production: 14,000 m^3/day.
- water treatment: 13,300 m^3/day
- water injection: 14,000 m^3/day.

For the economic analysis of each alternative, assumptions regarding values of the fiscal and market variables are shown in Table 1.

Table 1: Fiscal and market assumptions

Variable	Value
Oil Price (US$/$m^3$)	Lognormal (314.5, 62.9)
Oil production cost (US$/$m^3$)	20% of oil price
Water production cost (US$/$m^3$)	3.145 (1+1.5% per year)
Water injection cost (US$/$m^3$)	3.145 (1+1.5% per year)
Corporate Tax (%)	34
Other Corporate Taxes (%)	9.25
Royalties (%)	10
Linear depreciation (years)	10
Interest rate (% per year)	10
Initial investment (US$ millions)	150
Platform investment (US$ millions)	503 (small), 576 (large)
Investment in each well (US$ millions)	40
Abandonment cost (US$ millions)	15

The uncertainty in the oil price is modeled assuming a lognormal distribution with a mean value of 314.5 US$/$m^3$ and a standard deviation of 62.9 US$/$m^3$, - this choice is because this distribution has been extensively used to model prices and other economic variables such as income, interest rate, exchange rate, and many others, apart from the fact that only positive values can be generated which is coherent with the nature of oil price. In this price model, the trajectory over the oil production life will be according to the following rule: if the oil price in t-1 is P(t-1), than in time t it must be: $P(t-1) / 2 < P(t) < 2P(t-1)$. That is, the simulated values of oil price in time t must be between half of the previous time and no more than twice, the price of the very same previous time.

The oil production cost is considered as 20% of the oil price, that is, it is admitted that it occurs a positive correlation between oil price and the production cost. It is also assumed that, this relation is delayed in one year, that is, the cost is influenced by the mean oil price, up to one last year. The correlation between price and cost used in this work is according to Schiozer et al. (2008), where the authors present modeling and correlations similar to the ones used here.

It is considered that the water injection and production costs increase 1.5% per year. The investments in platforms used are function of their liquid production capacities. The smaller platform costs 503 US$ millions and a larger one costs 576 US$ millions.

After the modeling phase of the uncertainty present in the cash flow variables, it is carried out a Monte Carlo simulation, generating 1000 trajectories of the cash flow in order to obtain the probability distribution of the NPV, and in this way, to reveal more information besides the base, case to make a decision.

2.2. Real Options Model

To perform the real options analysis, a discrete model of real options was used (Cox, Ross e Rubinstein, 1979). In this model, the option to expand new wells was considered up to three years, depending on the strategy considered in the analysis.

The evaluation using Real Options can be made as follows:

- Estimative of the NPV without flexibility.
- Modeling the uncertainties that determine the value of the investment. In the case studies, it was considered only the uncertainty in the value of the project.
- Placement of nodes in decision trees constructed to reflect the decision uncertainty.
- Evaluation of real options through the risk-neutral probabilistic approach.

The model of Cox, Ross and Rubinstein starts from the initial value of the project (present value in t=0) and consists in constructing a binomial tree with all possible values for the project over the life of the option, in the cases studied, discretized in three years. The tree starts from the initial value and generates for the second time, two possible values (uV e dV), three possible values (u^2V, udV, d^2V) for the third time, four values (u^3V, u^2dV, ud^2V, d^3V) for the fourth time, in a total of three time intervals (life of the option). Figure 1 shows a representation of a binomial tree model with three periods.

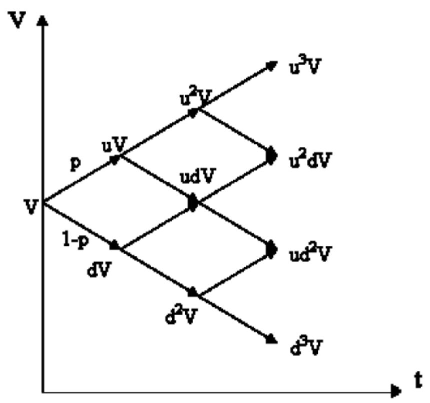

Figure 1. Binomial tree model with three periods.

In this model, *u* is called the upward movement, *d* the downward movement and *p* is called the risk-neutral probability. These values are obtained as follows:

$$u = \exp(\sigma_{project}) \qquad d = \exp(-\sigma_{project})$$

The value of the volatility of the project considered in this study was twice the volatility of oil prices (Costa Lima et al., 2006). Thus:

$$u = \exp(2 * \sigma_{oil\ price}) \qquad d = \exp(-2 * \sigma_{oil\ price})$$

The risk-neutral probability is given by:

$$p = \frac{(1 + r_f) - d}{u - d}$$

where r_f is the risk-free rate. In this study, it is assumed a risk-free rate of 10 %.

The first step of the analysis is to construct the tree with the values of the underlying assets at risk (values of the project), as shown in Figure 1.

The second step is to build the tree of the values of the returns of the project. As this is an expansion project, at each point of the tree it will be chosen the maximum return on each situation, which may be equal to those without the expansion of the project or the value increased by the expansion of the project less its investment. Mathematically, it can be written as:

$$R_{ij} = \text{MAX} [\ V_{ij} ; V_{ij}*(1+i) - I\ ]$$

where V_{ij} are the values of tree (Figure 1), *i* is the increment in value of the project due to expansion and *I* is its investment.

In the third step, from the tree of returns of the project, a decision tree can be built to the expansion option. Each node is given by the maximum value from the return of the previous tree and the option value, where C_{ij} are the expansion option values in each node. These values are given by:

$$C_{ij} = \frac{[pC_u + (1-p)C_d]}{(1+r_f)}$$

where C_u is the option value in the upward position and C_d is the option value in the downward position, both in the next time.

Therefore, real options analysis works backwards in time along the points of the decision tree, taking the maximizing decision at each node, when the choice is actually available, depending on the situation of the underlying variable. The result is a value with this added flexibility, which is used to decide if the project can be started today (Copeland, 2001).

3. Results

3.1. Analysis of the Cash Flow of Different Production Profiles

The project value estimated using the appropriated cash flow model is US$ 1,409.00, which is actually the mean value of the distribution of net present value of operational cash flow (excluding investment). It was estimated considering that the company will produce oil employing 10 production wells and 10 injections wells. This strategy was chosen based on the information the engineers had at the time of production planning phase, that is, long before the production happens.

It occurs that, in practice, real world is much more complex and has a random behavior. For example, in case of an increase in oil price, management may find it suitable to increase production (if there is enough platform capacity) by adding more production wells and, on the other hand, it can shut in some wells because of a decline in oil price.

One possibility that is analyzed here is the case of an increase in oil price in year 1 after the beginning of production. Then, management may decide to drill more 10 wells and increase oil production, as shown in Figure 1.

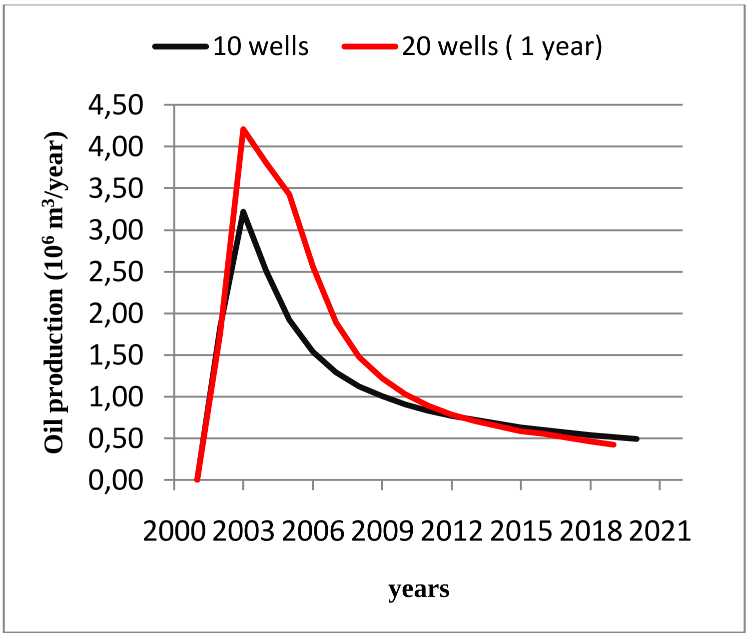

Figure 2. Production profile for the decision to produce oil reserve with 10 and 20 wells.

As can be seen in Figure 2, the production profile with 10 production wells over the entire life of the oilfield is less than in case of drilling additional wells. Also in this figure, it is included the production curve of the field considering that the production starts with 10 wells and after one year add more 10 production wells. It can be noted that, the alternative of adding more 10 wells shows that the production curve has moved to the right.

Other possibility is the addition of more production wells in year 2 after the beginning of production with only 10 production wells, which is shown in Figure 3.

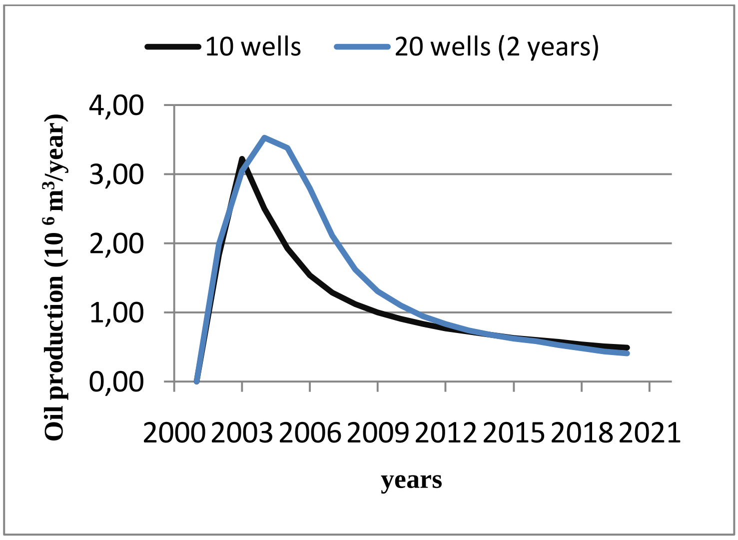

Figure 3. Production profile for the choice of 10 wells in year 1 and 10 additional wells in year 2.

The strategy of Figure 3 will be exercised, if management finds it timely to add more 10 production wells, to benefit from an increase in cash flows value – because of increase in oil price and/or decrease in operating cost. In this case, note that, production profile has moved upward and the area between the two curves is the extra volume of oil produced.

Other possibility is the case that value of cash flow increases seriously, only in year 3 and management decides to drill 10 additional wells. Now the two production curves are those shown in Figure 4.

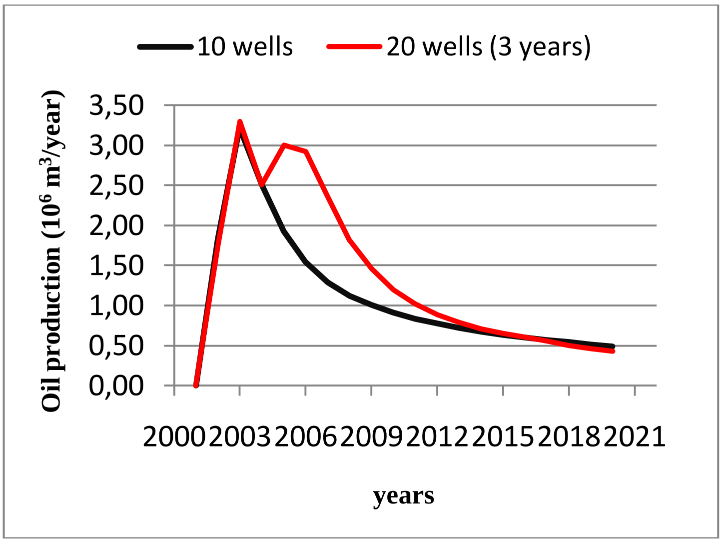

Figure 4. Production profile for the choice of 10 and 10 additional wells in year 3.

In Figure 4, it can be seen that, in similar way to Figures 2 and 3, adding more wells lifts up the new production curve when compared to the one with less wells. Meanwhile, the production life of the reservoir is reduced.

The cash flow was modeling for the aforementioned production profiles, according to a simplified version of the Brazilian fiscal regime. Table 2 presents results of NPV for each of the selected production alternatives.

Table 2: Results of the Methodology

Alternative	Strategy profile	NPV
1	10 wells without flexibility	562.41
2	10 wells with flexibility	502,05
3	10 wells at the beginning plus 10 wells in year 1	632.72
4	10 wells at the beginning plus 10 wells in year 2	572.45
5	10 wells at the beginning plus 10 wells in year 3	470.78

In Table 2, the NVP of alternative 1 is higher than that of alternative 2 because in alternative 2, it is considered that management buys a larger platform, which would be used to produce oil with 20 wells, in case of favorable conditions in the future. But, at this moment, it is not yet considered the use of this excess capacity to be used to increase oil production[1].

In addition, in Table 2, it is seen that the best is alternative 3, if management intends to maximize NPV. The worst case is alternative 5, where NPV is only US$ 470.78 million. For alternative 5, management invests at the beginning in platform and drilling of 10 wells and, in year 3 invests in the drilling of more 10 production wells. Its NPV is low because the oil production of the additional 10 wells occurs far from the beginning.

3.2. Valuation of the Flexibility to Expand Oil Production Capacity

In this example, a number of managerial flexibilities can be analyzed, but only expansion by additional drilling wells will be studied. Initially, it should be recognized that, in case of good market conditions one option to increase profit is by increasing production. Similarly, in case of economic downturn, one alternative to save cost is to cut oil production. Then, for this example, it is assumed that, after discussion with a team of engineers from areas such as drilling, production planning, operations, maintenance and others, management has selected the following options that could be exercised:

- Start with only 10 wells and produce the entire reservoir with this strategy;
- Start with only 10 and additionally drill more 10 wells in year 1, *only if market conditions turns into a good one, because of increase in oil price or reduction in cost;*
- Start with only 10 and additionally drill more 10 wells in year 2, *only if market conditions turns into a good one, because of increase in oil price or reduction in cost;*
- Start with only 10 and additionally drill more 10 wells in year 3, *only if market conditions turns into a good one, because of increase in oil price or reduction in cost*;
- Start with only 10 wells but with a larger platform with capacity to produce from 20 wells at total.

For all these alternatives or managerial flexibilities, an economic evaluation according to the traditional NPV method was carried out. But, numbers of NPV do not consider the value of real option of adding more wells into the production system that can be exercised by management. In order to estimate the value of this option to expand production we need the following five variables:

1. Underlying asset. In case of projects, this refers to the *present value of the operational cash flow of project*[2]. In this value, the investment cost is not included, since it is not part of the operational cost. For example, for alternative 2, the present value of operational cash flow is U$ 1,597.41.
2. Exercise price. In case of project analysis, exercise price refers to the price management must pay to have flexibilities to be exercised. In case of alternative 2, this value is US$ 1,035.18. This value is estimated from the operational cash flow over -20 years of oil production.
3. Future volatility. This variable is hard to estimate, because it refers to variability of rate of return over the time, as analogous to volatility of time-series of price in financial markets[3]. In case of project, little is

[1] Actually, it is considered in this alternative, how much will cost to have the option to increase capacity in the future, in case of good market conditions. Then, the reduction of NPV can be understood as a cost to create the option to expand capacity in the future.

[2] The present value of operational cash flow of the project for different alternatives can be estimated according to: $V=\sum_{i=1}^{N}\frac{f(1)}{(1+k)^1}+\frac{f(2)}{(1+k)^2}+...+\frac{f(N)}{(1+k)^N}$, where f(i) refers to the net operational cash flow, k to the opportunity cost of capital, N is the life of cash flow.

known about this rate of return (this rate is not the internal rate of return of cash flow). Alternatively, some researchers use volatility of oil price as a proxy (Dixit and Pindyck, 1994). But, better models for estimation of project volatility can be found in Costa Lima and Suslick (2006) where they suggest that typically volatility of oil project is in the range of 2 to 4 times the oil price volatility. In this paper, it is assumed that project volatility is twice that of historical oil price, that is, 40%.

4. Risk-free interest rate. This rate refers to the rate of return of an asset with low or no risk such as government papers – bonds, saving accounts, etc. In this paper, it is used 4% as a risk-free interest rate[4].
5. Maturity. The maturity is the period of time during which management can exercise its option to expand the production by drilling additional wells.

Now, we are in a position to carry out the valuation of real options in this example available for management decisions.

It is assumed here that, the risk-free interest rate is 4% and the volatility of the project is 40%. The first step consists on the modeling of the dynamics of the present value of the net operational cash flow (underlying asset) for the base case where production is carried out with 10 wells.

Figure 4 shows the tree of underlying asset uncertainty.

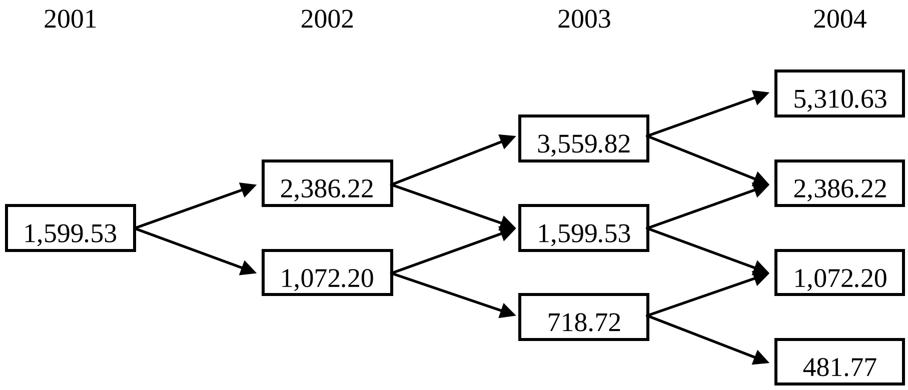

Figure 5. Tree of underlying asset uncertainty.

In year 2001, the underlying asset value is 1,599.53 million. In year 2002, its value can go up (2,386.22) or down (1,072.20), depending on, for example, oil price evolution[5] and so forth.

As the oil field is produced, reserve is reduced over time. Then, the present value of its operational cash flow is also reduced over time because it refers to the value of the remaining reserves[6]. In spite of this, for this paper it will not be considered this fact because it is assumed that management can drill additional wells in no more than 3 years after the beginning of production.

For estimating the option value of drilling additional wells in the first year of production, it is assumed that:

- The investment for drilling 10 additional wells is US$ 423.86 million;
- The increase in value of *V* because of these additional wells is US 495.35 million;
- On average, the increase in value of *V* because of these additional wells is 30.15%;

The model for estimation of the option is in Figure 6.

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[3] In the case of a time-series, the past volatility is defined as: $\sigma = \sqrt{\frac{1}{N}\sum_{i=1}^{N}(X(t) - E[X])^2}$, where X(t) refers to the rate of return of the project. Then, past volatility is estimated as standard deviation of the rate of return.

[4] It is important to note that in Brazil, the rate of return of financial instruments such governmental bonds, saving accounts, etc can be employed as a risk-free rate. This rate must be real or effective, that is, net of inflation. Currently, at the time of writing this paper, this rate is not far from 4% at yearly basis.

[5] In this example the present value of project cash flow is modeled as a binomial model. But, it is important to note that this variable is directly dependent on oil price.

[6] This case is similar to a dividend-paying asset. Because the stock of reserve is finite, the cash flow generated each year may be considered as a dividend and, consequently, the remaining value of the reserve is reduced.

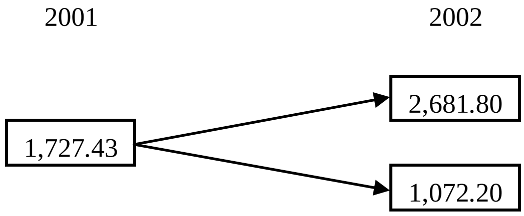

Figure 6. Tree for the estimation of drilling more 10 wells option.

From Figure 6, the value of the NPV considering drilling more 10 wells option is U$ 690.25 million. The value of the option to expand is U$ 127.90 million. That is, the value of the expansion option is 18.53% of the total strategic NPV value (U$ 690.25 millions).

For the analysis of the option to drill additional wells in year 2, there is the following information:

- The investment to drill 10 additional- wells is US$ 391.86 million;
- The increase in project value is U$ 435.08 million;
- The increase in project value because of these 10 additional wells is 26.61% on average;

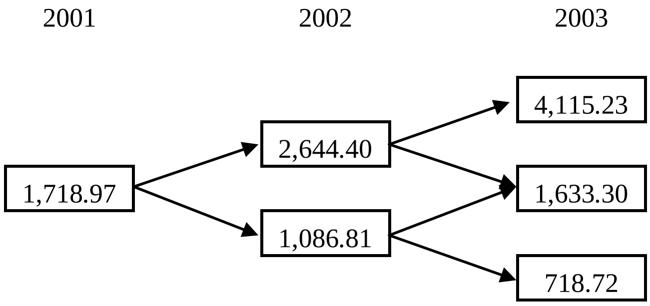

Figure 7. Tree to estimate the option value to drill 10 wells after 2 years.

As shown in Figure 7, the project increases to US$ 1,718.97 million. Then, the NPV with flexibility to drill more 10 wells in year 2 is US$ 681.79 million. The value of the option to increase production by adding more 10 wells is US$ 119.44 million, which is 17.51% of the NPV strategic.

Apart from the flexibility to drill additional wells in year 1 and 2 after the beginning of production, there is also the alternative to drill wells in year 3. But, the cost of them is estimated in US$ 362.86 million and the increment in project value is only US$ 361.86 million and this option will not be exercised.

Table 3 presents the solution of the problem by the method of decision tree and the real options approach.

Table 3: Comparison between results of decision tree and real options approach.

Year of exercise	Estimative of expansion option value using decision tree (US$ million)	Estimative of expansion option value using real options theory (US$ million)
1	106.83	127.90
2	75.55	119.44
3	0	0

As can be seen in Table 3, the method of the decision tree does not assess correctly the flexibility, considering the discount rate as being constant in the various branches of the tree. On the other hand, the real options theory evaluates the flexibility properly by considering the changes in uncertainty over time through the risk-neutral probability. For the period of one year of option exercise the difference between the methods is 19.7% and for two years to exercise the option the difference rises to 58 %[7].

[7] To make this comparison was considered that there is a 50% chance to exercise the option to expand and was assumed to be compatible with 10% discount rate used. For other values of p one should change the discount rate.

4. Conclusions

Although the selection of the best production strategy, in this work, is the same by both methods, NPV and real options approach, this paper highlights the fact that there is a significant additional value, in the case studies, around 18% of the value of the project (value of the flexibility built into the strategy), and that should be taken into account in a more accurate way, to evaluate the projects of oil fields under economic uncertainty. However, the values of options should increase substantially, when an increasing number of uncertainties and managerial flexibility is considered, which leads us to believe that, the real options analysis can indicate the selection of a production strategy different from that indicated by the traditional NPV. Option values may also have more decisive role in other case studies, for example, in reservoir models, whose strategies studied have very different behavior with respect to the addition of new wells over time. Accordingly, this work presented the differences between traditional economic evaluation methods, NPV and decision tree, and that provided by the theory of real options in a typical problem of oil exploitation.

5. Acknowledgments

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