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The Value of Flexibility to Expand Production Capacity for Oil Projects: Is it Really Important in Practice?

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Abstract

The selection of the best oil production strategy consists of finding the optimal number of wells and their locations, well flow-rates, well opening schedule, platform production size, water treatment capacity, etc to maximize NPV, RF, among others. But, there is always uncertainty in the determinants of these variables and also there will be risk. An increase in oil price may change the optimal number of wells. Similarly, with an oil price decrease, it may be necessary to shut-in some wells. The problem becomes more complicated because the production strategy must be defined at the early stage of the development. Then, management may find it suitable to pay for some flexibility that could be useful in the future and improve the project profitability. These flexibilities have two benefits. First, they reduce the risk of the NPV of the project. Second, they add value to the entire project. To estimate the value of flexibility in the management of an oil project towards profit maximization, we consider an offshore oil field with 28 °API and 98 million cubic meters of OOIP. Because oil price fluctuates, management finds suitable to start production with 16 wells and a platform with liquid production capacity of 17,700 cubic meters per day. This platform has extra-capacity that can be used in case management needs an increase in oil production, which, is strongly dependent on oil price. This extra-capacity adds value to the project since it allows management, the option to increase production in case of an increase in oil price. To evaluate this flexibility, NPV method is not the right tool, but real options models. We analyze the possibility to exercise the flexibility to increase production by drilling more wells in years 1, 2 or 3 after the opening of 16th well. In this study, we conclude that the value of the flexibility to expand production is not very high. This is unexpected, since in most cases in literature, the value of flexibility is above 25% of the static NPV. The reason, in this case, is due to the high investment in drilling wells and the low impact on the production curve.

1 - INTRODUCTION

The selection of exploitation strategies of oil fields may be a complex activity due to the great amount of variables involved. It is still a problem that may contain multiple objectives that should be optimized simultaneously. The choice of the exploitation strategy more suitable for a certain field may improve the development of the reservoir during its productive life, maximizing the recovery of hydrocarbons, taking into account the limitations of the field. The strategy depends mainly on the geological characteristics of the reservoir and the operational program that will be used during its execution. For the planning of the exploitation scheme, the different variations in the external environment must be considered, besides a constant review of the project's activities, because the planning may change with the acquisition of new information, as for example, modification in the geological model, the match of the production profile or the changes in the economic scenario.

In this work an exploitation strategy is optimized for the reservoir development phase for an offshore oil field aiming to maximize the Net Present Value (NPV). 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 present for 3 alternatives of exploitation strategy regarding the time to expand the capacity of production. Two different platforms taking into account a small and a large capacity are analyzed. The larger platform has extra-capacity that can be used in case management needs an increase in oil production, which, is strongly dependent on oil price. This extra-capacity adds value to the project since it allows management, the option to increase production in case of an increase in oil price.

In this paper, we evaluate the possibility to exercise the flexibility to drill additional wells and its value of increasing production by drilling additional wells in the first, second or third year after the 16th well is opened, through the Real Options Theory (ROT), since the traditional NPV method is not the appropriate tool.

2 – FLEXIBILITIES IN THE OILFIELD PRODUCTION SYSTEMS

In oil production systems, there are various types of flexibilities, such as the use of a large platform where there is the possibility of increasing production, through the addition of new wells, the flexibility to close wells with high water production, the flexibility of injecting the water that is being produced in order to enhance oil recovery from the field or by using a smart completion instead of conventional one. There are other real options such as adding capacity in sequential stages, dimension of equipments, among others. These are called operational flexibilities and if exercised properly they can add value to projects and increase return.

Although these real options are present in production systems, the traditional methods of economic evaluation often used cannot capture the value of each of these flexibilities, making it difficult for decision makers choose to invest in such flexibility to accommodate future uncertainty of the business. This work evaluates the first flexibility mentioned, where there is the possibility of expanding production capacity through drilling of new wells. This flexibility will only have value if the revenues from oil production overcome the amount spent on a larger platform and the drilling of new wells.

3 – THE VALUATION MODEL OF THE EXPANSION REAL OPTION IN OIL PRODUCTION SYSTEMS

The traditional analysis employed in the economic evaluation of projects through NPV requires predicting the expected cash flows adjusted to risk level via discount rate (cost of capital) and subtracting the investments. As can be seen, this method does not consider the possibility of exercising options inherent in the project, such as to expand, defer, contract, among others, considering the existing flexibilities in projects that take into account the uncertainties of the business, because the presence of option changes the risk profile, but there is no clear methodology to quantify that.

There are many uncertainties at the beginning of a project of oil exploitation and those could determine the viability to invest or not in the business. An alternative to NPV is to try estimating the flexibilities of the project through analyzing the decision tree, which allows the decision maker wait until the end of one period to decide whether to invest or not, after resolution of an uncertainty of the project, either price/cost or production. However, this method of assessment does not consider the changes in discount rates over the tree, once changes in risk over time of the project can occur. A solution for this problem is to use the real options theory, which correctly estimates the discount rates along the tree on the basis of a risk-neutral probability (Trigeorgis, 1998; Copeland, 2001). For this reason, this work uses a discrete model of real options that could evaluate correctly the flexibility to expand production capacity by drilling new wells in some of the strategies defined.

The model used in this paper was presented by Cox, Ross and Rubinstein (1979). This model is nothing more than the decision tree analysis with the correct discount rates at each node, estimated by the risk-neutral probability (p). It can be calculated by:

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

where u is called the upward movement, d the downward movement and r_f is the risk-free rate. These values are obtained as follows:

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

where $\sigma_{project}$ is the volatility of the project. The value of the volatility of the project considered in this study is twice the volatility of oil prices (Costa Lima et al., 2006). Thus for the project, we may have:

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

Thus, the model uses the upward and downward movements to estimate the ups and downs in the values of the projects (V) along the tree, according to the volatility of the project and that is correlated with the volatility of the oil price. The tree, thus, constructed, will be the tree with the values of the underlying assets at risk, as shown in Figure 1. In this work it is considered the possibility to expand the production by up to three years, i.e., the life of the option.

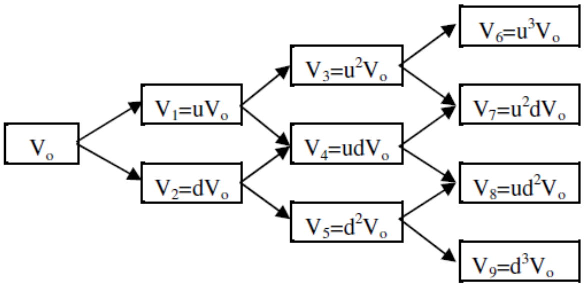

Figure 1: Tree of underlying assets subject to risk.

The next step of the analysis is to construct the tree of the values of the returns of the project. As this work considers the expansion of the project through the drilling of new wells, in each point of the tree is chosen as the maximum return in every situation. This value is equal to the previous tree or the value increased by the expansion of the project minus the investment paid for the expansion, i.e., the choice for expansion or not is the option that maximizes the project value at each node of the tree. Mathematically, it can be written as:

$$R_n = MAX\ [\ V_n\ ;\ V_n*(1+i) - I\ ]$$

where V_n are the values of the tree, i is the increment in value of the project due to expansion and I is the investment necessary to add more wells to increase oil production. The tree of the returns (R) of the project is shown in Figure 2.

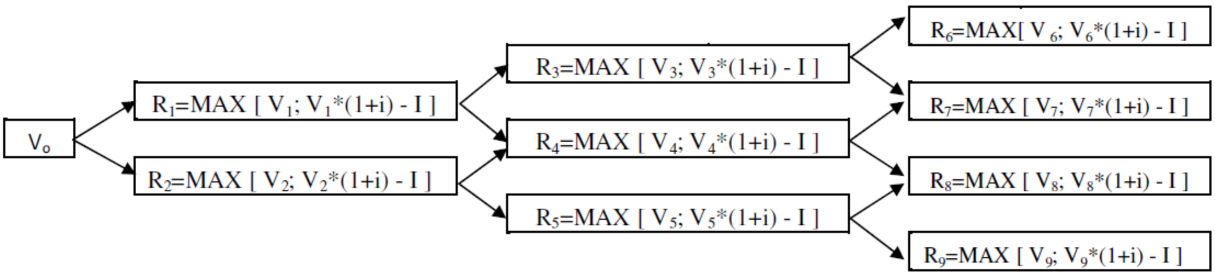

Figure 2: Tree of values of the returns of the project with expansion option.

With the tree returns of the project, the next step is to construct the decision tree for the option of expansion as follows: if the first term within the brackets of the maximum function is higher, the decision is not exercise the option for expansion and if the second term is larger, the decision is to expand, because the incremented value of the project less the investment by the expansion of this project is greater than the value of the project without the expansion. The options analysis maximizes the returns at each stage of the tree shown in Figure 2. The values of the expansion option on each node of the tree are shown in Figure 3.

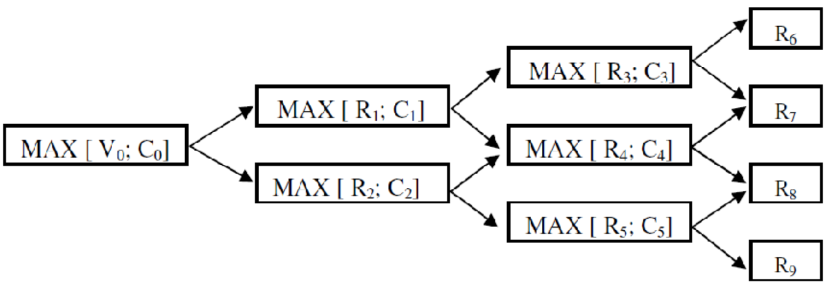

Figure 3: Tree of values of the expansion options.

where C_i are the values of the expansion option on each node of the tree. These values are given by:

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

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

If in the starting tree $V_0 \geq C_0$, the expansion option will have no value at that time because the initial value of the project is greater or equal than the expansion option. And if $V_0 < C_0$, the value of the expansion will be equal to $C_0 - V_0$. The value found at the beginning of the tree is the expanded present value (strategic). After discounting the investment, the value found is the expanded NPV (or strategic).

4 – APLICATION

The simulation model corresponds to a turbiditic reservoir with 28 °API oil volume in place of 98 millions of m^3. The simulation grid is constituted by 51x28x6 blocks, given that, each block presents dimensions of 150x150 m² in the horizontal axis and variable thickness. A production history for the first 1500 days for 4 vertical wells is included in the model, and none of the parameters of these wells can be modified, before this period of time. After 1500 days, the 4 wells cannot be excluded, but just be closed in case of low performance. The main parameters considered for the definition of the oil exploitation strategy is: number, localization and type of wells, injection and production well flow rates, water cut and bottom hole pressures limits. Table 1 presents the operational conditions for the wells. Horizontal producers and injectors are added to the simulation model and optimized according to their best locations and completion layers taking into account the liquid (oil and water) production, water treating and injection capacities of the Platform 1. An operation schedule is defined for opening injectors and producers, given that, after 1500 days, 16 wells are opening every 30 days.

Table 1: Wells operational conditions

Producers		
Operational condition	Value	Unity
Maximum liquid flow rate – Vertical well	1500	m³/day
Maximum liquid flow rate – Horizontal well	2500	m³/day
Water cut limit (%)	90	
Minimum oil flow rate for shut-in wells	50	m³/day
Minimum bottom hole pressure	100	kgf/cm²
Injectors		
Operational condition	Value	Unity
Maximum water injection flow rate	2200	m³/day
Maximum bottom hole pressure	300	kgf/cm²

Subsequently, it is analyzed the possibility to drill 10 additional wells after 1, 2 or 3 years from the drilling of the 16th well. For the drilling of these 10 additional wells, it is necessary a larger platform (Platform 2). Table 2 shows the two different capacities of platforms and their respective investments.

Table 2: Platform Capacities and Investments

Capacity	Platform 1 (small)	Platform 2 (large)
Liquid Production (m³/day)	10,700	17,700
Water Treating (m³/day)	9,630	15,930
Water Injection (m³/day)	10,700	17,700
Investment (US$ millions)	515.93	643.43

The main assumptions about market, financial and operational variables employed in the construction of cash flow model for the economic analysis are shown in Table 3

Table 3: 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
Discount rate (% per year)	8
Initial investment (US$ millions)	150
Platform investment (US$ millions)	515.93 – 643.43
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 since it is a common distribution used to model prices, and besides it does not generate negative values. The price series generated during the useful life of the field is not purely randomly generated and it may respect the following criterion: the oil price in the period t should be greater than its half in the time t-1 and lesser than its double, in the same period of 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 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 these authors present modeling and correlations similar to the ones used here.

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, to obtain a probability distribution of the NPV and in this way, to obtain more information besides the base case to make a decision.

5– ANALYSIS OF EXPANSION REAL OPTIONS IN OIL PRODUCTION SYSTEMS

Here we consider an oil reserve with a volume of around 98 million m^3 located in an offshore area of Campos Basin in Brazil. Using reservoir simulation, the engineering department has found different alternatives for production: 1) produce with 16 injection and production wells, 2) start production with 16 wells and after 1 year add more 10 wells, 3) start with 16 wells and after 2 years add more 10 wells, 3) start with 16 wells and after 3 years add more 10 wells. The corresponding producing curves of these alternatives are shown in Figure 4.

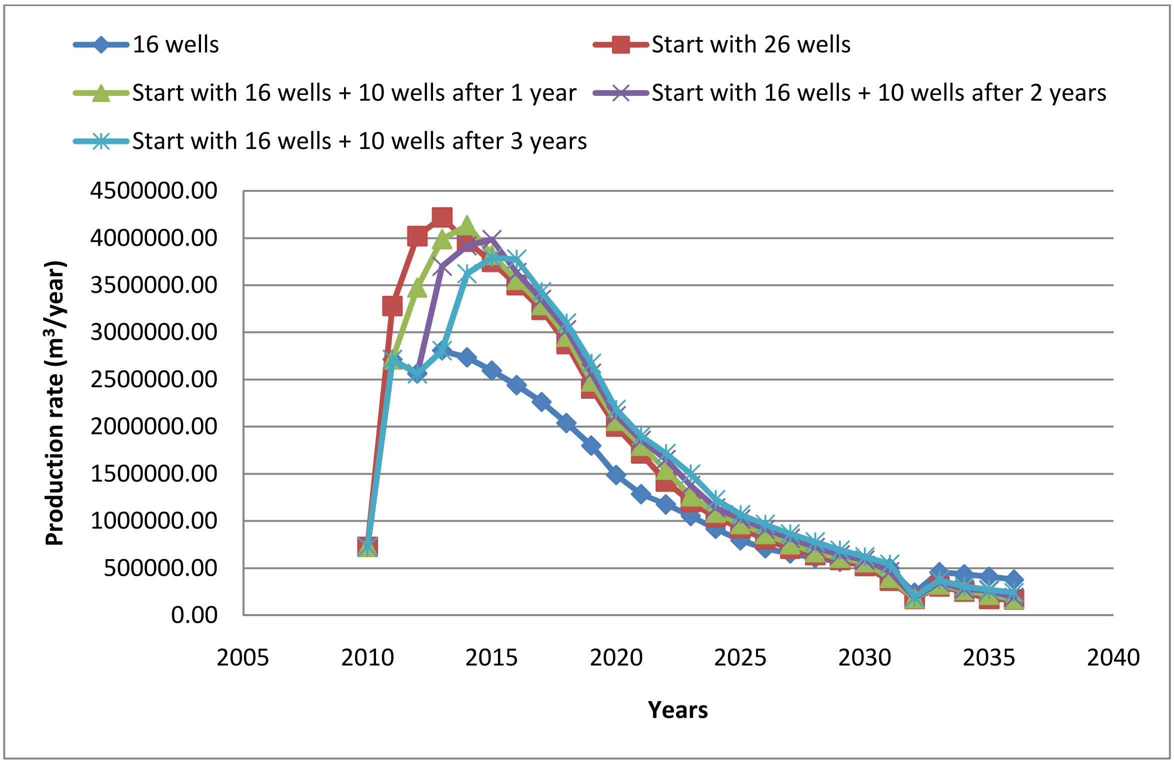

Figure 4: Cumulative oil production curve for the different alternatives of production

At the beginning of the oilfield production, all alternatives give similar results, even alternatives to produce from the beginning to end with 26 wells at once. From the second year, there are some differences among production curves where the strategy to start with 26 wells seems to allow the highest rate in years 2, 3 and 4. The strategy to produce with 26 wells at once, will give the highest cumulative oil production, but not necessarily the best NPV value. In Figure 5, there is the total oil cumulative production, for the 25 years of operation for this oil field.

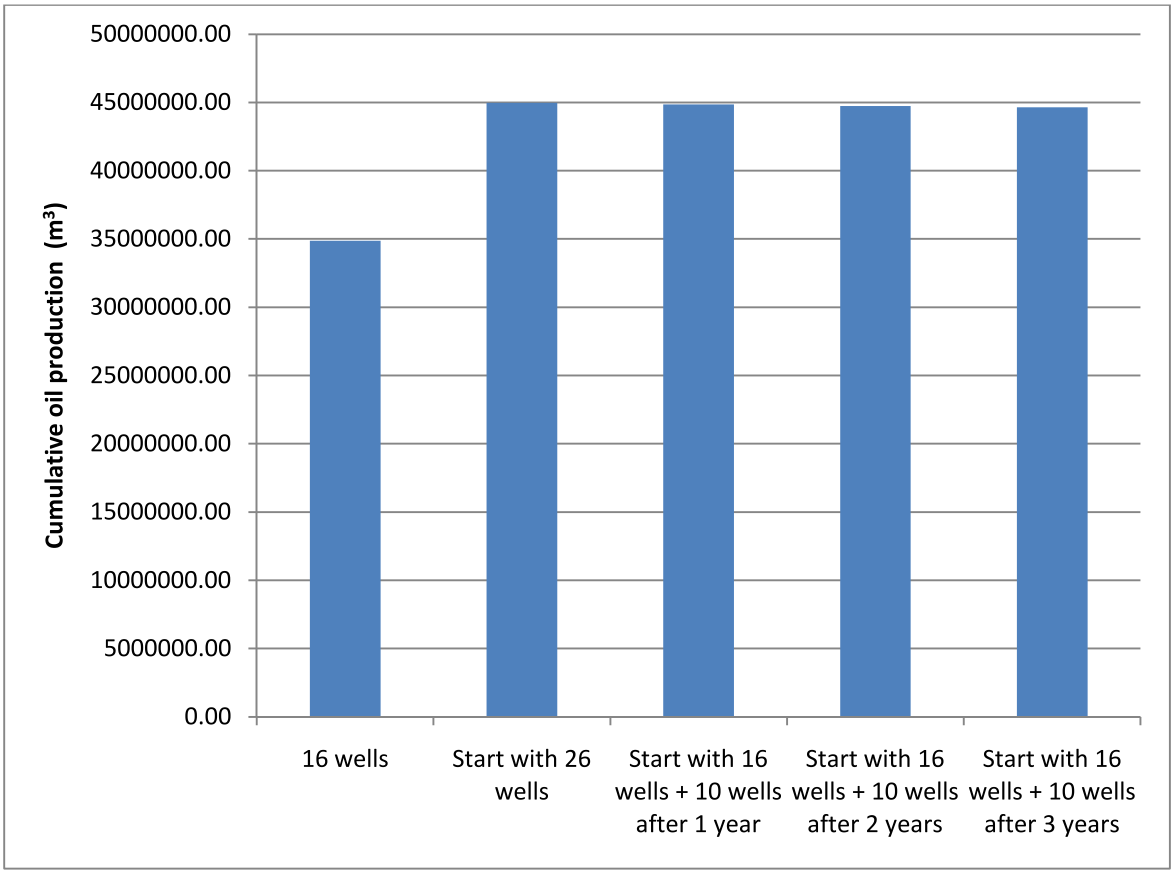

Figure 5: Cumulative oil production (m^3) for the 5 different production strategies

Note that strategies with a total of 26 wells results in the highest cumulative production, that is, around 45 million of cubic meters, whereas the decision to produce the reserve with only 16 wells would result in a production of around 35 million m^3, that is, 10 wells increases the production in 10 million m^3.

These different possible strategies can be classified in rigid and flexible. In the rigid one, the number of wells cannot be changed from the beginning to the end of production. On the other hand, the number of wells can increase over the time, because the platform has spare capacity. If the manager decides for a platform with excess capacity, he will be able to benefit from additional revenue by adding more wells and increasing production, but this implies in excess of investment at the beginning. That is, in order to benefit from the expansion option by drilling additional wells the manager must support an increment in cost.

In this context, important information is to estimate the classic NPV of the different alternatives under different discount rates under the viewpoint of valuation and decision-making, as presented in Table 4.

Table 4: NPV for all selected alternatives under different discount rates

Possible strategies	Strategy number	Opportunity cost of capital (k)			
		k = 12,00%	k = 10,00%	k = 8,00%	k = 6,00%
NPV 16 wells with flexibility up to 26	I	1,168.53	1,386.85	1,648.81	1,969.75
NPV 16 wells (no flexibility)	II	1,126.04	1,336.0	1,590.91	1,902.51
NPV 16 wells at the beginning + 10 wells after 1 year	III	1,338.07	1,613.79	1,941.93	2,339.07
NPV 16 wells at the beginning + 10 more wells after 2 years	IV	1,276.66	1,554.83	1,887.46	2,291.39
NPV 16 wells at the beginning + 10 wells after 3 years	V	1,168.60	1,441.44	1,768.58	2,168.18
NPV with 26 wells at once	VI	1,334.29	1,599.04	1,913.47	2,292.81

From Table 4, it can be noted that the best NPV is for strategy number III, that is, start production with 16 wells and after 1 year add more 10 wells. This strategy is the best even for different discount rates in the range from 6% up to 12%. These figures come from the classic NPV approach, which does not consider that, the presence of real option changes the risk level and cannot be properly captured using adjustment in the discount rate.

Then, following the case study considering the discount rate of 8%, the methodology for real options analysis may be employed to estimate the impact of the option value on valuation and decision-making associated with the problem of choosing the best alternative. The option to expand production can be understood as an American Call Option, that is, the holder has the right to exercise the option any time during which it is available (maturity time). The model for valuation and decision-making using option pricing depends on the following parameters:

- Underlying asset (V). The value of the underlying asset, that is, the present value of cash flow, is estimated using traditional cash flow and the value is U$ 2,713.06 million.
- Exercise cost (E). The exercise cost is the required investment in platform, production and injection wells and other facilities and its value is U$ 1,222.15 million.
- Time to maturity (T). The time during which the option can be exercised is 3 years after the drilling of the 16th well.
- Future volatility (σ). The volatility of the project cash flow (not the price) is estimated in 40%, that is, we estimate that volatility of project is twice that of oil price.
- Dividend yield (d). In this paper, we did not consider the dividends for simplification, but this is an important variable which must be included. In general, the increase of the dividend value tends to reduce the value of the expansion option, if exercised in the future.
- Risk-free discount rate (r). In this paper, we assume that, the rate of governmental Bonds is a good proxy for the risk-free rate and it is assumed the value of 4%.

With these figures, we are now in a position to estimate the option to expand. Firstly, we carry out the modeling of dynamics in project value over time, as shown in Table 5.

Table 5: Dynamics of project value over time

2010	2011	2012	2013
2,898.46	4,323.99	6,450.64	9,623.22
	1,942.89	2,898.46	4,323.99
		1,302.36	1,942.89
			873.00

The figures of Table 5 are found considering that the risk-neutral probability is 45%. In 2010, the project value is U$ 2,713.06 million, but in 2011, its value cannot be known with certainty: it can increase to US$ 4,047.40 million or go down to US$ 1,818.62 million. The same occurs over the next years during which the option can be exercised.

In order to exercise the option to expand production by adding more production and injection wells, the company must incur in extra investment, as shown in Table 6.

Table 6: Information about increase in project value and need of additional investment

Possible strategies	Strategy number	Increase in project value	Increase in investment cost
NPV 16 wells at the beginning + 10 wells after 1 year	III	804,00	446,57
NPV 16 wells at the beginning + 10 more wells after 2 years	IV	719,00	417,56
NPV 16 wells at the beginning + 10 wells after 3 years	V	521,10	391,19

The value of increase in project comes from the increase in production because expansion option is exercised – this information comes from reservoir simulation in order to estimate correctly the increase in oil production. After using this information, in Table 6, about increments in cost and also value of cash flow after making use of expansion option, we find the values shown in Table 7.

Table 7: Results for NPV considering value of expansion option

Possible strategies	Strategy number	Static NPV	Strategic NPV
NPV 16 wells at the beginning + 10 wells after 1 year	III	1,941.93	2,006.24
NPV 16 wells at the beginning + 10 more wells after 2 years	IV	1,648.81	1,950.25
NPV 16 wells at the beginning + 10 wells after 3 years	V	1,648.81	1,778.62

By considering the value of option to expand, note that the value of each alternative has been correctly increased. This is because the option to expand, reduces the risk of the project and it is considered in a right way using option pricing techniques (in case of, for example, decision-trees, the problem is that the discount rate changes from node to node, it considers that this rate remains constant over the nodes, as if risk remained constant).

In terms of decision-making, the decision would not change for this case, that is, strategy number III would be selected using classic NPV or option pricing techniques. Why? This has happened for two reasons: 1) the expansion option value of other alternatives is very small; 2) the total production of oil is highest for alternative III.

But, the decision can change from strategy III to IV or V. How? If, for example, the increment in project in year 2 is above U$ 774 million, the decision may change to expand production in year 2 after the drilling of the 16th well. Similarly, a decrease in investment cost can change the decision to expand production to year 3 or even keep it on year 1.

6 - CONCLUSIONS

- The valuation of flexibilities (not only for oil production projects) requires more than a simple NPV rule and decision-tree model, since there is not a clear model that considers the discount rate properly.
- The strategy with higher number of wells has allowed higher production rate and also a better NPV. The cumulative oil production is very similar to the strategies with a total of 26 wells.
- The valuation of project's alternatives using Real Options Theory is systematically higher than the values created by classic NPV. This is not a problem with the method, but a manifestation of the correct consideration of risk in the analytical tools.
- Although the Real Options Theory suggests a higher value for all production strategies, the model does not suggest a change in the decision making according to NPV. *This must not be understood as a rule, but only a feature of this oil field in particular*.
- In this study, we conclude that the value of the flexibility to expand production is not very high. This is unexpected, since in most cases in literature, the value of flexibility is above 25% of the static NPV. The reason, in this case, is due to the high investment in drilling wells and the low impact on the production curve.

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