Automated Methodology for Field Performance Optimization Developed with Horizontal Wells
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Abstract
The main task of reservoir engineering is the development and management of a petroleum field in order to improve the profitability of a reservoir by raising production rates with minimum costs or increasing ultimate reserves. The performances of many horizontal well projects around the world demonstrate their effectiveness in achieving this objective, especially in offshore fields. However, this type of well has more complicated interaction with the reservoir, since its behavior is a function of a high number of parameters. The purpose of this paper is to present an automated methodology to optimize reservoir performance with horizontal wells, by using numerical reservoir simulation to provide the production forecast.

The methodology is developed through the performance analysis for individual wells, group of wells and field. The objective of this analysis is to identify the parameters that define horizontal wells productivity, to realize a comparison between wells performances, and to investigate the causes of inadequate field and wells performance. The analysis is based on selected objective-functions: net present values, cumulative oil, gas and water productions and water injection. The methodology is developed to propose changes to optimize a strategy set previously. A concept of well neighborhood is used to allow simultaneous changes, which yield a lower number of simulation runs.

Introduction
The definition of a production strategy is one of the most important steps in reservoir management. It affects the reservoir behavior, which influences future decisions, economic analysis and, consequently, attractiveness of projects. It’s a complex process because it involves a high number of parameters and objectives. These parameters are basically related to geological characteristics, economic scenarios, number of production and injection wells, well placement, operational conditions and well scheduling. The objectives depend on the type of analysis and are usually related to profits and production maximization, costs minimization or both. Therefore, an adequate plan of recovery for petroleum reservoirs has a great economic importance in oil industry and the interest for optimum management has increased, providing several studies to develop efficient procedures for optimization problems.

In the last years, the use of horizontal wells on production strategies has increased significantly due to technological improvement and advantages that this kind of well provides compared to conventional ones, such as increase of flow rates, acceleration of reserve production, improvement of recovery and drainage area per well. For these reasons, horizontal wells have become an important tool for reservoir management, especially in offshore fields, where high productivity is necessary, production costs are higher and the optimization of reserves is required. Furthermore the difference between vertical and horizontal wells tends to decrease as the water depth increases, raising the cost-benefits for this type of well. However, horizontal wells have a different interaction with reservoir, involving a greater number of variables, thus making decision process more complex.

This paper presents an automated methodology to optimize performance of reservoirs developed with horizontal wells, by using numerical reservoir simulation to provide production forecast. The methodology is developed through the performance analysis for individual wells, group of wells and field, to propose changes to improve an acceptable strategy set previously. The analysis is based on selected objective-functions: net present values, cumulative oil, gas and water production and water injection. A concept of neighborhood and dependence between production wells is introduced to allow simultaneous changes and, consequently, reduce the number of simulation runs. However, it’s important to emphasize the methodology proposed will not lead to unique solutions, but a set of alternatives, considering the objectives of the project.

Reservoir Management Process, Developing Plan and Economics
A successful project depends on an adequate plan of reservoir recovery. The planning requires careful analysis, efforts, time-consuming, and must be developed step-by-step. The first aspect handles with development and depletion strategy,
Horizontal wells can be applied in any phase of reservoir recovery to achieve the objectives mentioned above and are effective in reservoir with heterogeneous characteristics and fluid flow problems, such as:

i. **Water and Gas Coning**: because of a long wellbore, the production rate per unit of length is small, resulting in a lower drawdown pressure near wellbore region, reducing coning problems.

ii. **Low Permeability Reservoirs**: horizonal well can be used to stimulate the reservoir as it places a flow path through the formation.

iii. **Heavy Oil Reservoirs**: with reduced coning problems and larger contact with the reservoir, horizontal wells can be economically viable in non-thermal application for heavy oil recovery.

iv. **Thin Zones**: due to a larger contact area with thin formation, horizontal wells provide higher flow rates than vertical wells.

v. **Naturally Fractured Reservoirs**: in this case, fractures provide a natural fluid flow path, increasing significantly the production of oil and gas. Horizontal wells drilled perpendicular to the natural fractures will show not only higher rates but also higher ultimate reserves.

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**Production Strategy Optimization**

Optimum reservoir management is an important theme in petroleum industry. Most of the studies related to reservoir performance optimization focus the well placement.

Aanonsen et al. proposed a method to optimized well locations under geological uncertainties based on response surfaces and experimental design. Multiple regression and kriging were used to reduce the number of simulation runs.

A methodology to optimize the number and location of producer well in new fields was developed by Pedroso and Bittencourt and Horne's developed a hybrid algorithm based on direct methods such as genetic algorithm, Polytipe search and Tabu search to obtain the optimal solution for problems related to reservoir development. Simulator was used as a data generator for the evaluation of the objective function, which involved an analysis of cash flow. Güyagüler and Horne have also used genetic algorithm to reduce computational burden in a well placement optimization problem upon uncertainties.

Cruz et al. introduced a concept of “quality map”, which is a bi-dimensional representation of reservoir performance. This concept can be applied to evaluate the well location and scheduling, to compare reservoirs, to classify stochastic realizations and to include uncertainties related to reservoir characteristics.

A methodology to optimize the number and location of producer well in new fields was developed by Pedroso and...
Schiozer. It was applied in primary recovery stage developed with vertical wells. The work utilizes parallel computing with intention to accelerate the process. Mezzomo and Schiozer proposed an optimization procedure based on reservoir simulation that evaluates both individual wells and field performance. The methodology helps managers to make decisions that lead to an adequate recovery for the reservoirs, maximizing profits and minimizing risks associated to the investments.

Moreno and Schiozer developed a methodology procedure to improve a previous exploitation strategy. Well performance results are classified under following parameters: net present values, cumulative oil, water and gas production, well operation time, water cumulative injection, in order to better choose well changes. It was also considered a concept of neighborhood constraints to perform simultaneous changes and, thus reducing simulation runs.

**Optimization Procedure**

This work presents a methodology to support reservoir managers to optimize a strategy developed with horizontal wells. It does not provide unique solutions, since this optimization problem depends on many factors which may lead to a set of alternatives. This methodology is based on economic optimization and the main objective is to maximize the net present value of the field. It is necessary to define how to better achieve the objective according to parameters involved. To simplify the optimization process considers that there are no changes in economic scenario along the time. The process is divided in steps described below.

**Step 1: Economic Scenario Analysis and Selection of Optimization Plan**

The investment plan of petroleum companies are normally realized by portfolio analysis. The selection of possible options is based on comparative performances and the decisions are influenced by economic scenario.

The first step of the proposed methodology consists on the selection of economic scenario and operational conditions analysis. This is an important step, because it may affect significantly the optimization plan. Depending upon economic scenario and reservoir characteristics, the process will define investments or costs reduction as priorities. Controlling variables such as cumulative oil, water and gas productions, and water injection are set in a priority order.

**Step 2: Analysis of Previous Strategy**

In this step, the strategy to be optimized must be analyzed. This study will evaluate the field and well performances according to the previous strategy by running a reservoir simulator. The productivity of each well, group of wells and field performance are observed. It is the first analysis between horizontal wells and field interaction and the strategy must yield at this point, potential to be optimized. If the strategy presents a very bad performance, the optimization procedure proposed here is probably not the best choice because major modifications may be required.

**Step 3: Well Priority and Changes**

As long as the controlling variables were set in priority order during Step 1, it is possible to determine a rank sequence for well changes based on analysis of Step 2. This sequence must consider group of wells with lower performance or potential to be improved. These information, along with horizontal wells’ characteristics, provide a list of possible actions that can be adopted to improve the well performance. The choice of the best action in the list can be based on technical experience or numerical simulation tests. Each adopted change must be evaluated by well, group of wells and field performances and the automation is extremely necessary at this point because the amount of information if very high.

**Simultaneous Changes**

In order to reduce the number of simulation runs, it is recommended to perform simultaneous changes, though with restrictions. If the wells chosen to be altered are too close, one change may affect the other, making it harder to decide if the modifications are valuable. In this case, it is necessary to introduce the neighborhood and dependence concepts. This is more useful in strategies with a great number of wells.

**Neighborhood and Well Dependence Concepts**

The evaluation of influence that a well has to another is not a simple task because it involves many factors related to the reservoir characteristics. In the early of optimization process, the reservoir and wells behaviors are unknown and define influences may be harder. Therefore, the first approach to be adopted is the neighborhood constraint. Wells located right next to a well that will be changed must not be altered. The proximity increases the probability of influence between wells. However, this concept does not assure independence if wells are distant from each other.

As the optimization process is performed, the neighborhood restriction must be reviewed, redefining dependence concept which can be determined by observing the changes on the net present value and cumulative oil production of a well not chosen to be altered.

**Step 4: Results Validation**

The results obtained after Step 3 must be analyzed to guarantee the success of the changes. Since the objective of the entire process is to maximize the NPV of the field, the one step backwards may be taken if it yields a decrease of the objective-function so bad actions must be identified and corrected. Depending on the objectives and especially on the time available, steps backwards can be acceptable to test different optimization solutions. The strategy proposed so far is the base to a new realization. Steps 2 to 4 can be repeated until a satisfactory solution is obtained.

**Studied Cases**

In this section, the methodology proposed will be applied in three reservoir models. The models are derived from a Brazilian offshore field, but different geological parameters were introduced in order to generate different heterogeneous characteristics.
Models Description
The three models differ from the original model on permeability parameters. In the first one, Figure 1, it was added high permeability channels. The second one, Figure 2, is a reservoir with permeability barriers and in the third, Figure 3, was included high permeability channels in Z direction. The numerical flow model has a 60x35x7 Cartesian grid, with 150x150 m each block (Figure 4).

The same economic scenario is used in the three cases which values are presented in Table 1. Optimization process starts from a five-spot scheme with 14 producers and 12 injectors, located in oil saturated zone (Figure 5). The wells both producers and injectors are 300 m long. The field is located in ultra water depth area and the oil has a lower quality related to Brent type.

Procedure Application
The optimization procedure proposed defines the Net Present Value of the field as the objective-function to be maximized. The others parameters like cumulative oil, water, gas production, and cumulative water injection are variables that will be controlled to achieve the objective.

Step 1: Defining the Optimization Plan
The economic scenario formulated for these examples presents taxes, contributions and production costs values exercised in Brazil. The oil price used is an average value performed by market.

Due to economic scenario and reservoir characteristics, it was chosen an optimization line that defines costs reduction as priority. In this case, most of actions were realized in order to decrease the cumulative water/gas production, water cumulative injection or investments. It is important to emphasize that oil production increase was not neglected and actions were proposed when a well did not present water production problem.

According to each project objective, different priorities can be selected and the order of priorities and changes will be different.

Step 2: Field and Wells Analysis
The initial strategy is a five-spot scheme focused in oil saturated zone, as described before. The reservoir is sub-saturated and the average reservoir pressure will be kept above bubble pressure to avoid gas cap formation. In this case, cumulative gas production could be discarded from priority list of controlling variables, as long as the pressure was maintained above bubble point pressure.

Step 3: Well Priority and Changes
According to previous steps, a list of priority production wells is made available in the output of the program. The critical wells are placed at top of priority change list. These wells also presented a good potential of improvement. In the examples presented here, any proposed change to reduce water production could provide a NPV increase.

Changes Realized - During the optimization process, different actions to reduce costs were considered:

i. Well direction changed;

ii. Relocation of production well;

iii. Relocation of injection well;

iv. Injection well opening delayed;

v. Production well discarded;

vi. Injection well discarded;

vii. Replacement of two producers for another one longer.

For wells with good productivity, following actions were proposed:

i. Opening anticipated;

ii. Length increased;

iii. Well direction changed;

iv. Relocation.

Simultaneous Changes – Considering the number of wells in the strategy and neighborhood constraint, simultaneous changes were restricted to three wells at a time. These numbers could increase as the optimization process was performed and dependence criterion was determined.

Step 4: Results Validation
After each optimization run, results were analyzed. Some changes provided bad results and had to be reviewed. Most of them were related to relocation. The entire process is repeated until no more changes can result in improvements.

Results
The procedure and analysis in all three cases were equal, differing in actions decided in Step 3, due to heterogeneities. Therefore, different results like numbers of simulation runs required and optimum Net Present Values were obtained for each case. However, similar tendencies were observed. The results of these applications were also compared to an optimization process with single well change at a time. Figures 6 to 8 present the optimized strategies for each case.

Figures 9 to 29 show the results of the three cases. The evolution of Net Present Value, cumulative oil and water production along the process can be seen in Figures 9, 10, 11, 16, 17, 18, 23, 14 and 25. These figures also show the advantage of simultaneous changes, which provide optimum NPV with lower number of simulation runs related to single well change method. In this work, as the number of wells is small, the reduction in the number of simulation is not so significantly but it increases as the number of wells increase.

These results show also an interesting characteristic of this type of problem. Depending on the way the optimization procedure is conducted, the final configuration can be different. This can be seen on the difference between the final result of the procedure with multiple and single modifications. The same type of behavior is observed when the initial steps of the process are different.

In Figures 12, 13, 19, 20, 26 and 27 it is possible to observe the influence of each controlling variable in objective-function. It can be observed that the water production control yields an increase in cumulative oil production and, therefore, a greater influence in Net Present Value. This behavior was expected, since cumulative water production was defined as the main controlling variable. This tendency can also be observed in the wells performances. Figures 15, 22 and 29.
compare the water production and NPV of each well for the initial and final cases.

Conclusions
1. The methodology proposed in this paper is focused on optimization problems of fields developed with horizontal wells and the main objective is to speedup the process and to provide more reliable results.
2. The automation is reached because the important parameters for optimization process are defined in priority order, according to economic scenario, operational conditions and reservoir characteristics, determining an optimization plan. In the cases studied, the main controlling variable was cumulative water production.
3. Neighborhood and dependence concepts were introduced in order to allow simultaneous changes and reduce number of simulation runs.
4. Three models with different heterogeneous characteristics were studied in order to test the methodology for different reservoir heterogeneities.
5. The automated procedure was developed in a flexible way, allowing its application to several different cases and speeding up the process for complex reservoirs.

Nomenclature
NPV = Net Present Values
Np = Cumulative Oil Production
Wp = Cumulative Water Production
Wi = Cumulative Water Injection

References

Table 1 - Economic Scenario Values

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
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<tr>
<td>Initial Investment</td>
<td>35 MM US$</td>
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<tr>
<td>Oil Price</td>
<td>113.2 US$/m³</td>
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<tr>
<td>Oil Production Cost</td>
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<tr>
<td>Water Production Cost</td>
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<tr>
<td>Water Injection Cost</td>
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<td>Internal Rate of Return</td>
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<td>Royalty</td>
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<tr>
<td>Income Tax</td>
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Figure 1 - Case 1 - High Permeability Channel
Optimization Runs

Figure 10 - Np Evolution - Case 1

Figure 14 - NPV vs Np per Well - Case 1 (Base Run and Final Run)

Figure 11 - Wp Evolution - Case 1

Figure 15 - NPV vs Wp per Well - Case 1 (Base Run and Final Run)

Figure 12 - NPV vs Np - Case 1

Figure 16 - NPV Evolution - Case 2

Figure 13 - NPV vs Wp - Case 1

Figure 17 - Np Evolution - Case 2
Figure 18 - Wp Evolution - Case 2

Figure 19 - NPV vs Np - Case 2

Figure 20 - NPV vs Wp - Case 2

Figure 21 - NPV vs Np per Well - Case 2 (Base Run and Final Run)

Figure 22 - NPV vs Wp per Well - Case 2 (Base Run and Final Run)

Figure 23 - NPV Evolution - Case 3

Figure 24 - Np Evolution - Case 3

Figure 25 - Wp Evolution - Case 3
Figure 26 - NPV vs Np - Case 3

Figure 27 - NPV vs Wp - Case 3

Figure 28 - NPV vs NP per Well - Case 3 (Base Run and Final Run)

Figure 29 - NPV vs Wp per Well - Case 3 (Base Run and Final Run)