The Influence of the Production Lines Pressure Drainage Drop in the Definition of the Oilfield Drainage Strategy
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Abstract
The success of an oil field drainage project depends on the production strategy, defined by an optimization process that maximizes the project Net Present Value (NPV). Considering the complexity of the process, the industry tends to simplify the numerical simulations used, mainly by separating the behavior analysis of the reservoir and production facilities. The pressure drop in the production facilities, for instance, is not generally considered in the selection of the number and position of the wells. The main objective of this work is to verify if these simplifications have significant influence on the final result of the production strategy selection process. For this purpose, three studies have been done, with different operational conditions and fluid types. For each case, two production optimization processes of an oil field drainage project have been made, considering a simplified and a dynamic pressure drop calculation. The simplified pressure drop analysis consists in a bottom-hole pressure definition that allows the fluid to rise to the platform. In the dynamic option, it is necessary to define the production line geometry and the fluid conditions to calculate the bottom-hole pressure for each configuration, and the pressure drop is calculated dynamically, at each time step. With the result of both processes, the number and position of wells and performance of the optimized production strategies were compared. Significant differences were observed in the two cases tested, showing that the pressure drop influences the definition of the production strategy, although this influence should be minimized by operational conditions. It was also observed that the greater influence occurs on the heavy oil reservoir and that the locations are more influenced by the reservoir particularities.

Introduction
One of the most important factors for the economic viability of an oil field exploitation project is an appropriate choice of the reservoir production strategy, defining principally the number and location of producer and injector wells. That selection, in general, is carried out through an optimization process that has a tendency to be complex, because it depends on many parameters. Therefore, the industry tends to simplify the numerical simulations used, mainly by separating the behavior analysis of the reservoir and production facilities.

It is known that an integrated simulation, considering reservoir and production facilities, brings benefits in production strategy definition. However, there are not studies that show this integrated simulation compensates the computational effort and time demanded. The principal objective of this work is to quantify the collected value of the simulations coupled in the processes of production strategy definition.

Literature Review
The optimization of a production strategy is an iterative method that searches, through the maximization of an objective-function, to obtain the best production alternative. The optimization methods most used do not automatically carry out successive parameter modifications, requiring more time. Mezzomo (2001) produced a methodology of optimization applicable in development and in production phase fields. Nakajima (2003) developed a methodology of strategy optimization with horizontal wells using quality maps. Cruz et al. (1999) introduced the concept of quality maps that consists of a 2D map able to summarize the production potential of each reservoir region through all of the integration variables that influence production. The first publication about multiple reservoirs that coupled a common production system was done by Dempsey et al. (1971) in a gas field. Startzman et al. (1977) spread the model for oil reservoirs. Since then, the use of the integrated simulations of reservoir and production system has been increasing.
However, there are few studies about the impact of the constraints in the production strategy definition. In this topic, Magalhães (2005) valued the influence of two operational constraints at the production strategy optimization: limitation of produced liquids flow and limitation of gas-lift flow.

Methodology
A flowchart of the methodology is shown in Figure 1. The steps are as follows:
1. Selection of the Simulations Models: selection of geological and flow models. In this step, the premises of the field development project and the economical scenario are defined.
2. Preparation of the Simulation Models for Optimization: two models are prepared for flow simulation. In the first, it is estimated a bottom hole pressure (BHP) that guarantees the fluid production flows to the platform. The BHP is fixed for all wells, representing in the simplified way the pressure drop in the production lines. In the second, it is made a table for each well, considering the geometry of well and production lines, the property of produced fluids and the artificial lift method. In this table, it is estimated BHP according to the variations of water cut, gas oil ratio and the pressure in platform (THP- top hole pressure). This table is an input in reservoir simulation, making it possible to consider the pressure drop dynamically in the reservoir simulation.
3. Optimization of the Production Strategy: the models defined in Step 2 are optimized separately in accordance with the specifications of Item 3.1 (described below).
4. Preparation for comparison: Step 3 supplies two production strategies, one optimized with simplified pressure drop and other with dynamic pressure drop. To compare both production strategies, it is necessary to apply the dynamic pressure drop to the production strategy defined with simplified pressure drop.
5. Comparison and analysis: with the results of the Step 4, the number and location of wells resulting from each of the production strategies and their performances are compared. If both production strategies are similar in terms of number and location of wells and their performances, the pressure drop does not have an influence in the production strategy definition. But, if the production strategies are different, it is possible to measure the influence of the pressure drop in the production definition with the NPV difference.

Production Strategy Optimization
The methodology of the production strategy optimization process is based on the proposals of Mezzomo (2003) and Magalhães (2005), which are specified as follows:
1. Definition of the Premises: the objective function is selected, in this case, NPV of the cluster production project was chosen. Also, the variable optimization parameters are defined such as exclusion, inclusion, location, and redirection of the producer and injector wells in addition to alteration of the completion layer.
2. Determination of the Initial Production Strategy: an initial configuration is defined with a large number of wells which locations are based on an evaluation of the quality map. The intention is to guarantee that all the reservoir areas contain wells because the next step involves the removing of the wells that have the worst performance.
3. Optimization: the initial strategy is studied and the parameters that increase NPV are identified and used to modify the initial strategy. Each modification results in a new simulation. The NPV from each simulation is compared and ranked in order of decreasing value, composing an optimization round. The modified parameters that result in the best NPV are used to begin the next optimization round. In this manner, optimizations round are done sequentially until reaching the stop criterion.
4. Stop Criterion: the optimization is finished if ten modifications do not result in an increase in the NPV or if the increase of the NPV in consecutive rounds is less than 1%.

Application
It was chosen three different cases, considering different fluids and operational conditions, for study the influence of pressure drop in the production strategy definition. These cases are specified in the Table 1. According to the methodology, it was made two optimizations for each case (A, B e C), considering the pressure drop simplified and dynamic. To compare both optimizations, it is necessary to apply the dynamic pressure drop in the production strategy optimized with simplified pressure drop, creating the production strategies identified, as specified in Table 2.
The simplified pressure drop states that a bottom hole pressure (BHP) is defined in an initial model that allows the produced fluid to flow, while the dynamic pressure drop is calculated considering the variations of production conditions for each time step.
The Case A is different from the others because in this study it was considered to preserve the reservoir pressure over the bubble point pressure as a production condition. The objective is to avoid creating gas in the reservoir. This condition was considered in both optimizations (simplified and dynamic), since it is a limitation of reservoir and does not refer to the operational constraint. Then, it was fixed a minimum limit to BHP for simplified and dynamic optimizations to avoid the reservoir pressure to come down below the bubble point pressure. The Case B did not consider this limitation, allowing the free variation of BHP. In this case, just the simplified optimization has a minimum limit for BHP to guarantee the flow of produced fluid to platform. The Cases A and B studied the light oil and the Case C studied heavy oil. The Case C did not consider the bubble point pressure limitation as well.

### Geological Model

It was used the Namorado Field, situated in the Campos Basin in Brazil. It is a sandstone turbidity field. It was not considered the field faults, turned it to a reasonably heterogeneous reservoir.

The software used for simulation was Eclipse 100. The Volume in place of Namorado field is written in the Table 3. The Initial Average Pressure is 320 x 10^5 Pa and the average temperature is 88°C.

### Fluid Property

Two fluids were studied to verify if there is an increase of pressure drop influence for heavy oil. The light oil (28.2°API) analyzed in the Cases A and B is identified as Fluid 1. The heavy oil (19°API) analyzed in the Case C is identified as Fluid 2.

### Simulation Model

The model used for simulation in the Eclipse is composed by 79,200 blocks of 100m per 100m considering a corner point grid with 22 layers. The average time for run is 8min.

### Pressure Drop in production lines

The pressure drop in production lines was considered in two ways: simplified and dynamic.

For the simplified it is defined a minimum pressure required to guarantee the flow and lift of the produced fluid. As the pressure of reservoir is larger than the minimum pressure required, wells produce with high rates. In this case, the well is restricted just for the maximum produced rate. When the reservoir pressure begins to decrease, the bottom hole pressure is fixed at the minimum pressure required and the produced rate is reduced. At the moment the reservoir does not have capacity to maintain this minimum pressure, the produced wells are closed.

To estimate a minimum pressure required, it was studied the pressure drop for well located at a medium area, considering the characteristic of fluid and the production conditions for each Case.

It is important to emphasize that in the simplified pressure drop, the minimum pressure required is the same for all wells, independent of their distance from the platform. The minimum pressure required is also fixed during all the field production time without relation to water cut, for example. Since the water specific gravity is larger than the oil, this estimative of pressure drop is inaccurate.

The advantage of using the simplified pressure drop is the smaller computational effort and better easiness in the optimization process.

The dynamic pressure drop is result of flow chart defined for each well, considering their geometry. Since the simulator considers this flow chart, the simulator calculates the minimum pressure required for flowing and lifting of produced fluid for each well, according to the water cut, gas-lift injected, required pressure in platform (THP) and gas oil ratio for each time step. To create the flow chart, it was used the software VFPI that belongs to the software Eclipse 100.

### Results

**Case A- Light Oil and Production limit above bubble point pressure**

The Figure 2 shows an analysis of productions strategies that compose the optimization of Case A. In this, there is a NPV graphic versus accumulated oil production. The best
productions strategies are in the superior right quadrant. The production strategy located in this area has a good profit and oil production.

Production strategies with a high value of NPV and low accumulate production oil represent a high danger, since their performances are supported by a specific economic scenario. The inverse is not also adequate, because there are productions strategies with a high capital expenditure and a low profit.

Therefore, it is possible to verify that both production strategies optimized are in the superior right quadrant, representing the best result.

For \( A_{\text{OPT}} \), after applying the dynamic pressure drop, creating the \( A_{\text{DYN}} \), the good result was maintained, reducing the oil production but keeping the high NPV.

The principal difference in production strategies defined in Optimizations A1 and A2 is the number of wells, written in Table 4.

Table 4: Number of Wells defined in Optimizations A1 and A2

<table>
<thead>
<tr>
<th>Optimizations</th>
<th>Number of Wells</th>
</tr>
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<tbody>
<tr>
<td></td>
<td>Produced</td>
</tr>
<tr>
<td>A1</td>
<td>16</td>
</tr>
<tr>
<td>A2</td>
<td>19</td>
</tr>
</tbody>
</table>

Despite the difference between the numbers of wells, the well locations are similar. 10 produced wells and 5 injector wells have the same location for both productions strategies. This behaviour happens because the reservoir characteristics were more influent in well locations than the operational constraint.

The produced wells are located in central area, where is the best characteristic reservoir production. Injector wells are located near boundary, allowing a large distance from produced wells to avoid water production.

In Figure 3, it is possible to observe the production profile of both production strategies optimized. The production strategy defined in Optimization A2 has a high initial production rate greater than production strategy define in Optimization A1. However, the \( A_{2\text{OPT}} \) has a larger operational cost, due to water production and injection rates.

Case B- Light Oil and Production allowed above bubble point pressure

The Figure 4 shows an analysis of productions strategies that compose the optimization of Case B. The best productions strategies are located in superior right quadrant, as mentioned before. It is possible to verify that \( B_{1\text{OPT}} \) is in the superior right quadrant, since it is considering the simplified pressure drop. However, when the dynamic pressure drop is applied, creating \( B_{1\text{DYN}} \), the production strategy becomes a bad option; it then belongs to the inferior quadrant, while the production strategy \( B_{2\text{OPT}} \) belongs to superior quadrant.

Therefore, it is verified that the production strategy defined in Optimization B2 has a better performance. So, the optimization considering the simplified pressure drop results in worst performance, proving that there is an influence of pressure drop in production strategy definition in this case.
The principal difference between the production strategies is in number of wells, like in the Case A. The B1_opt has a smaller number of produced wells and a larger number of injector wells than B2_opt. The Table 5 summarizes the number of wells for each production strategies.

Table 5: Number of Wells defined in Optimizations B1 and B2

<table>
<thead>
<tr>
<th>Optimizations</th>
<th>Number of Wells</th>
<th>Produced</th>
<th>Injectors</th>
</tr>
</thead>
<tbody>
<tr>
<td>B1</td>
<td></td>
<td>14</td>
<td>11</td>
</tr>
<tr>
<td>B2</td>
<td></td>
<td>16</td>
<td>9</td>
</tr>
</tbody>
</table>

This behaviour is justified for reduction of produced wells performance when it is considered the dynamic pressure drop, resulting in a larger number of produced wells to drain the same volume.

The number of injector wells is proportional to performance of produced wells, since there are produced wells with a high performance, the reservoir depletion is also high, so it is necessary a large number of injector wells to maintain the reservoir pressure. Therefore, the Optimization B1 results in a production strategy with a smaller number of produced wells and a larger number of injector wells.

For both production strategies, the produced wells are located in field center area, where is the best characteristic of reservoir. The most different locations are placed in areas far of platform. Nevertheless, there are 6 identical produced well locations. The injector wells are located near boundary in both production strategies with 5 identical locations.

Again, it is concluded that the reservoir characteristics are determinant in the definition of well locations, but the pressure drop has more influence in well locations than Case A.

The Figure 5 shows the profile of production of strategies defined in optimizations B1 and B2. B2_opt has a higher oil production and less water production and injection.

Case C- Heavy Oil and Production allowed above bubble point pressure

The Figure 6 illustrates the analysis of productions strategies that compose the optimization of Case C. It is verified that C1_opt has a high NPV, but when the dynamic pressure drop is applied, creating C1_dyn, the production strategy reduces its profit, turning less profitable than C2_opt.

About the number of wells, the standard of Case A and B happens again. For optimization that considers the simplified pressure drop, it is defined a smaller number of produced wells and a larger number of injector wells compared to production strategy optimized with dynamic pressure drop. The Table 6 summarizes the number of wells for each production strategies.

Table 6: Number of Wells defined in Optimizations C1 and C2

<table>
<thead>
<tr>
<th>Optimizations</th>
<th>Number of Wells</th>
<th>Produced</th>
<th>Injectors</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td></td>
<td>10</td>
<td>5</td>
</tr>
<tr>
<td>C2</td>
<td></td>
<td>13</td>
<td>4</td>
</tr>
</tbody>
</table>

About the well locations, it is verified that there are 5 wells with identical location in both production strategies: 4 produced wells and 1 injector well. Thus, the number of identical well location is inferior in Case C comparing to the Cases A and B, so it is possible to conclude that the pressure drop has more influence in heavy oil reservoir. However, the characteristic of reservoir is also determinant in decision of well locations.

The Figure 7 shows the profile of production of strategies defined in optimizations C1 and C2. C2_opt has a higher oil production and smaller water production and injection.
Conclusions

Case A- Light Oil and Production limit above bubble point pressure
- There is a difference between the production rate curves of dynamic and simplified pressure drop. However, this difference is minimized by the limit of production above bubble point. In this case, it is possible to consider the simplified pressure drop.

Case B- Light Oil and Production allowed above bubble point pressure
- The influence of pressure drop in the definition of production strategy becomes higher when it is allowed the production above bubble point. However the effect is higher with the start of water production, when the Net Present Value of project is already 70%.
- The principal influence of pressure drop is on the definition of the number of wells. When it is considered the simplified pressure drop, the optimization results in smaller number of produced wells and large number of injector wells, comparing to the dynamic pressure drop.
- The definition of well locations is more influenced by reservoir geological characteristic than pressure drop.

Case C- Heavy Oil and Production allowed above bubble point pressure
- The influence of pressure drop analyzed in heavy oil reservoir was more effective than in light oil reservoir. This behaviour happens because for heavy oil reservoir the pressure drop influences in the beginning of production, while for the light oil reservoir the influence starts with water production.
- Again, the principal difference between the production strategies is the number of wells.

The well locations are more influenced by the reservoir characteristics.

Comparison between influence of pressure drop in Cases A, B and C
- About Cases A and B, it is possible to conclude that the operational conditions considered in Case B propitiate a higher influence in the definition of production strategy compared to Case A.
- The difference in NPV between the production strategy optimizations considering simplified and dynamic pressure drop can be a measure of the influence of this operational constraint. Therefore, the Case C has more influence of pressure drop, followed by Cases B and A, respectively.

References