Abstract

Smart wells are being used recently to add operational flexibility to petroleum production. Considering offshore fields with water injection, smart wells can be very useful to control water production and to improve oil production. The advantages of smart wells are that they have devices like valves and sensors are able to monitor and control production, in real time, adding flexibility to the operation.

However, the effect of smart wells on the net present value (NPV) of the project has to be carefully quantified because of the additional investments. The expected gain is a function of several parameters, especially operational controls and economic parameters. Therefore, a fair comparison between these two wells requires a methodology of production strategy optimization especially designed to capture the details in the performance of these wells. The differences are even more complicated to be quantified in the presence of uncertainties.

Therefore, the objective of this work is to present an example with a comparison between smart and conventional wells, considering uncertainties in the geological and economic models.

A methodology of production strategy optimization, presented in a previous work (Silva and Schiozer, 2009), considering the availability of different production capacities, is used in this work. The main parameters altered are: position and number of wells, water cut and schedule of well's drilling.

The results showed small differences between the two alternatives. Smart wells were able to improve oil production and reduce water production but, in most cases, the NPV indicated that the use of conventional wells was slightly more advantageous. Also, the operational conditions, such as platform capacities, have a high impact on the results. The results are also very dependent on the economic model and additional investments required to use smart wells.

Introduction

The main objective of a petroleum reservoir study is to predict production based on geological, fluid dynamics, and technical and economic parameters. This task is strongly influenced by uncertainties in the geological and economic models, introducing risk to the process. Two common risk mitigation procedures are acquisition of information and operational flexibility (Ligero et al, 2007).

Smart wells are able to improve the field production. These wells have sensors and valves that can be controlled independently. Therefore, they can be employed in projects involving different objectives, such as production control of gas and water, production by different zones in stratified reservoirs, and margin fields, among others. They can also add flexibility to the operation of petroleum fields by allowing operation of valves to control production. This flexibility can be used according to the objectives of the companies, for instance, to maximize NPV, to mitigate risk, to improve oil production, to control water production or a combination of these objectives. The operation of smart wells can be proactive, trying to anticipate problems, or reactive according to a control parameter, in general, related to water production. Proactive control is normally based on the production prediction and it is more complex to evaluate. Reactive control was used in this work based on maximum water cut.

Performance of smart wells can be predicted based on reservoir simulation by the operation of completions according to the rules established by the company. An initial additional investment is required and the benefits are obtained in the fluid production, in an attempt to minimize water production and maximize oil production.

A comparison with conventional wells is not simple because, in order to be fair with both types of wells, a detailed methodology to optimize production strategy must be applied to both cases separately. Production operational restrictions
such as platform capacity may have a strong influence on the results, as shown by Silva and Schiozer (2009). The objectives of the optimization procedure also have an impact on the decision because operation of wells and valves must be done according to a pre-established objective. Therefore, it is important to study in detail the advantages and disadvantages of this relatively new technology.

The objective of this work is to use the methodology presented by Silva and Schiozer (2009) to compare the differences between smart and conventional well performances, adding geological and economic uncertainties in order to observe the differences between each type of well. The methodology was applied to a heterogeneous reservoir, considering initially a deterministic case and then adding geological and economic uncertainties.

**Literature Review**

Initial studies involving smart wells started around 1994 and in 1997, in Saga Snorre TLP, North Sea (Norway), the first well with intelligent completion was installed. As technology improves, use of smart wells is becoming more common. Some of the smart well installation examples around the world are: South Furious Field, Malaysia; Gullfaks South Statfjord, in the North Sea; Champion West Field – Brunei and some installations in Brazil.

Yeten and Halali (2001) considered the reactive control, in the optimum allocation method in a field limited by aquifer and gas cap. They compared the performance of smart and conventional wells, showing advantages of intelligent completions in horizontal wells with high pressure drop. They also demonstrated the benefits of smart wells to prevent the unwanted fluid production and, consequently, increase the oil production. Finally, the authors concluded that the smart wells have the capacity to add flexibility to the project.

Rodriguez and Schiozer (2006) studied water production control using a smart-well model. Three models with distinct permeability were simulated, considering homogeneous and heterogeneous reservoirs. The three smart-well models presented better results compared to the conventional well, presenting a satisfactory performance, especially in the reduction of water production, which is a desirable characteristic in offshore operations, where the excess of water is a critical factor. In both cases, with high permeability channels, the smart well was better than the conventional one. This work shows gains by the use of smart wells.

Yeten (2003) compared optimized strategies using proactive and reactive control using an optimization method, taking into account the location, type and trajectory of wells. The results showed that smart wells have capacity to improve oil recovery. The proactive control presented better results than reactive one. However, the author explains that the proactive control is not appropriate for a real application, but it can be a good tool to guide the project of well location and trajectory, or to study the use of an influx control device. Similar conclusions were made by Kraaijevanger et al. (2007).

Silva and Schiozer (2009) presented a methodology to compare both types of wells. For the example tested, smart wells were very useful to control water production. The effect on oil production was variable considering two effects of the valves control: less production of fluids with more water cut and smaller productivity. Conventional wells presented better NPV for the economic model presented in the paper.

This work uses the same example presented by Silva and Schiozer (2009), showing details of the comparison considering geological and economic uncertainties.

**Methodology**

This methodology was basically divided into two parts; the first part was presented in Silva and Schiozer (2009), focused on production strategy optimization and the second part is presented here, including geological and economic uncertainties.

The main steps of the methodology are: (1) definition of the simulation and basic economic model; (2) selection of platforms’ production capacities; (3) development of an optimization methodology for production strategy; (4) optimization of the available strategies; (5) combination of the strategies: simulation of each optimized strategy on all available platforms and also cross-validation (to test smart wells using the conventional strategies and vice versa); (6) comparison of the optimized strategies and selection of the best alternative for each well and for each platform capacity; (7) comparison of the strategies with geological uncertainties; and (8) comparison of the strategies with economic uncertainties.

Some premises of this study are: (1) fixed parameters: time interval between well opening; maximum producer flow; minimum BHP of the producers and maximum BHP of the injectors; (2) the main objective-function is NPV (oil and water production are used only for result interpretation); (4) strategy optimization is based on reactive control; and (5) there is no possibility of failure in the operation of valves.

The following steps describe the optimization process of the production strategy: (1) use of an initial platform capacity; (2) definition of an initial strategy to be optimized; (3) test with a schedule for the wells’ perforations, based on their individual NPV; (4) optimization of the maximum water cut to close the well (if a conventional well is used) or valve (if a smart well is used); (5) optimization of the number and position of the wells based on oil saturation maps and quality maps; (6) rescheduling of the wells’ perforation, based on their individual NPV (i.e., back to item 3); (7) re-optimization of the water cut (i.e., back to Item 4); (8) return to the first item and restart the optimization process with another available platform, until all platforms have been optimized. More details on the optimization procedure are described in Silva and Schiozer (2009).
Application

The reservoir used here has as its main characteristics: volume in place of 55 million m$^3$ *in situ*; light oil (28 API), based on the oil from Namorado Field, in Brazil; reservoir depth (top) 3160m, water/oil contact 3265 m, 10 layers, permeability varying from 75 to 1610 mD, porosity varying from 15 to 30%.

Four platforms with different liquid production capacity were available, P1, P2, P3 and P4, in decreasing capacity and CAPEX order, as presented in Table 1. Operational constraints are presented in Table 2 and economic parameters are presented in Table 3.

| Table 1 – Platforms used in this work |
|---------------------------------------|--------------------------|
| Platform name | Liquid production capacity (Millions of bbl/day) | Platforms costs (Millions of US$) |
| P1 | 133 | 1043 |
| P2 | 111 | 929 |
| P3 | 89 | 807 |
| P4 | 67 | 673 |

| Table 2 – Well constraints |
|-----------------------------|-----------------------------|
| Producers wells | Injectors wells |
| Control Mode | Liquid production | Control Mode | Surface rate |
| Maximum rate | 3500 m³/day | Maximum rate | 5500 m³/day |
| Minimum BHP | 210 bar | Maximum BHP | 400 bar |

| Table 3 – Economic parameters |
|-----------------------------|-----------------------------|
| Parameter | Value |
| Base Oil Price | 45.00 US$/bbl |
| Oil production costs | 6.00 US$/bbl |
| Water production costs | 0.64 US$/bbl |
| Water injection costs | 0.64 US$/bbl |
| Conventional well | 40 MM US$ |
| Intelligent well | 47 MM US$ |

The maximum injection flow rate is 5500 m³/day but the rate is an optimization parameter. A minimum of 60 days was allowed between well perforations. The field also has restrictions in the operation condition: the maximum amount of water equivalent to the fluid production volume is injected, considering reservoir conditions to avoid pressurization. All of the wells are horizontal with a length of 500 m. The producers are located in the second layer of the grid, and the injectors are in the tenth layer. Furthermore, the intelligent producers are equipped with 5 valves, equally spaced.

The final strategies resulting from the eight models are called CS (Conventional Strategy) for conventional wells and IS (Intelligent Strategy) for smart wells. The letters are added to a number corresponding to the platform. For example, CS3 is the best strategy with conventional wells optimized for platform P3. A letter I or C may appear at the end of the strategies’ names, representing a cross-validation, that is, the strategy optimized for one type of well is tested with another type. For example, IS3C is the strategy optimized for platform P3 and smart wells, but now applied to conventional wells.

Results

The details of the results of the deterministic cases are presented in Silva and Schiozer (2009). The main aspects are presented here.

Summary of the deterministic optimization procedure

The final NPV of the eight optimized models are showed in Figure 1 for conventional (a) and smart (b) wells. The final NPV plotted against Np and Wp is presented in Figure 2.

The best strategies are IS3 and IS3C, respectively, for smart and conventional wells. It was observed that for all platform capacities, the same number and position of wells was obtained for conventional and smart wells. The performance of strategies with smart-well was slightly superior. Platform P3 presented the best NPV results; platform P1 was the worst, having the best Np values but presenting the worst results for NPV.

Figure 2 shows a region of maximum NPV corresponding to platform P3. There is a tendency for platforms P3 and P4 to produce more oil with the use of smart wells. The same does not occur when platform capacity is higher (P2 and P1) where the differences are much smaller. The explanation is that, as the liquid flow rate limitation given by the platform capacity increases, the “penalty” of water production decreases; so, the conventional wells produce more water and also more oil.
The water production is always lower with smart wells, especially with higher capacity platforms. The influence of the platform capacity is higher than the type of well. The selection of the type of well to be used is, then, a function of the production restrictions.

The effect of this behavior on the NPV was a better performance for conventional wells but this is highly dependent on the additional investment and economic model; for other examples, the results may be different. The necessity to study each particular case to select best alternative is evident.

In Figure 3, the operation of the five valves of four wells for the best alternative is shown (IS3). The first valve of Well PH-7 (first valve closed in the field) is closed after 10 years of production. Wells like PH-2 are open during the whole period. This explains the small differences between the two types of wells.
Geological uncertainties

In the second phase of the study, heterogeneities (barriers and channels) were included in the reservoir model in order to simulate a case with uncertainties not predicted in the selection of the best alternative. The work is independent of the previous (strategy optimization) because the heterogeneous models are different from the model used in the optimization process. Only platforms P2, P3 and P4 were used in this step of the work. The platform P1 was excluded from this part due to the low NPV compared to the others platforms.

In Figures 4 and 5, it is possible to observe the six strategies (CS2, IS2, CS3, IS3, CS4 and IS4) simulated with nine geological models. In Figure 4, the six points with higher NPV are the six strategies simulated in the base geological model. This figure shows the NPV versus the oil production (a) and water production (b). NPV and Np are reduced when the conventional wells have higher performance with platform P2. We can conclude that the efficiency of the smart wells increases for more heterogeneous cases, with higher uncertainties and with lower production capacities.

The average of the NPV (expected monetary value - EMV) computed to the more heterogeneous models, indicates that the intelligent wells have better performance with platforms P3 and P4 (lower platform capacities). Otherwise, the conventional wells have higher performance with platform P2. We can conclude that the efficiency of the smart wells increases for more heterogeneous cases, with higher uncertainties and with lower production capacities.

Figure 5 shows that the heterogeneities enhance the effects observed in the deterministic model. Water production is much lower with smart wells with lower production capacity. The effect of the application of smart wells on oil production is also dependent on the production capacity. The effect on the NPV and return on investment (ROI) is presented in Figures 5c and 5d.
Economic uncertainties

The third phase of the study was to include variations in the economic model. Variations in the oil price and water costs were tested as described in Table 4. The base economic model (used in the examples so far) is also called the probable economic model. The analysis was done with the heterogeneous models studied in the previous section (geological uncertainties).

Figure 6 shows the average of each strategy, considering nine geological models for each economic model. It is possible to observe an inversion in the best combination well/platform. In the pessimistic model, platform P4 is the best, especially with the smart wells. But, for the probable and optimistic models, platform P2 is the best, with the use of conventional wells. It is observed that platform P3 is the worst considering the geological and economic uncertainties (while in the deterministic optimization process, P3 was the best platform). These results show again the importance of a detailed study for each particular case.

Table 4 – Variations in the economic model.

<table>
<thead>
<tr>
<th></th>
<th>Optimistic</th>
<th>Probable</th>
<th>Pessimistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Price (US$/bbl)</td>
<td>55</td>
<td>45</td>
<td>35</td>
</tr>
<tr>
<td>Water costs (US$/bbl)</td>
<td>0.40</td>
<td>0.64</td>
<td>0.80</td>
</tr>
<tr>
<td>Probability</td>
<td>25%</td>
<td>50%</td>
<td>25%</td>
</tr>
</tbody>
</table>
Figure 6 – Average NPV (9 models) - platforms P2, P3 and P4.

Risk Analysis

Figure 7 shows the NPV risk curve considering geological (9 models) and economic (3 models) uncertainties. Platform P4 is not a good alternative (the only advantage is the lower water production in all cases). Platform P2 has the highest expected monetary value (EMV); although P2 is not the best alternative for lower oil prices; the difference is small when compared with the benefits observed with medium and high oil prices.

The benefits of smart wells increase with heterogeneities and uncertainties but they are case dependent, as can be observed in the curves of Figure 7. The highest benefits are observed for higher heterogeneities, high uncertainty, optimistic economic model and lower production capacities.

Figure 7 – Risk curve considering 9 geological models and economic uncertainty

Conclusions

In this work, a methodology to optimize production strategy was used to compare smart and conventional wells. Relative performance of these two types of wells are dependent on several factors, such as: operational restrictions, economic model, additional initial investment, objective of the company and reservoir characteristics; heterogeneities and geological and economic uncertainties also have an important role in the process.

Smart wells for the control of water production, as used in this work, have two major effects on oil production. When production capacities have strong limitations, oil production increases due to the selective production (valves are used to close production with higher water cut). When production capacities have no limitation, oil production decreases due to the smaller total production (although water production is much smaller in these cases). Heterogeneities tend to increase this
behavior due to the higher water production and earlier breakthrough. The effect of smart wells in the NPV is case dependent, as it depends on oil and water production. As the additional investment is made at the beginning of the project and the additional revenues start only with high water cut, the differences in the NPV are difficult to predict.

Uncertainties tend to enhance the benefits of smart wells because of their operational flexibility. Additional flexibility from production capacities is also important in these cases. Smart wells are very useful in the presence of uncertainties combined with low production capacities.

Acknowledgment

The authors would like to thank the Department of Petroleum Engineering (DEP – Unicamp), UNISIM, CEPETRO and FAPESP for their financial support.

Bibliographic references


Yeten, B. and Jalali, Y., Effectiveness of Intelligent Completions in a Multiwell Development Context. SPE 68077 presented at SPE Middle East Oil Show, Bahrain, 17-20 March 2001.