OPTIMIZATION OF WELL FLOW RATE, HA FIELD- SUDAN

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Received Oct 2012, accepted after revision April 2013

ABSTRACT

The reservoir simulation study includes a number of steps to be conducted. These steps include – but not always all – data gathering, initialization and quality control, history matching, prediction cases and finally the optimum reservoir management plan. The objective of this study is to determine the optimum production rate for the wells in HA field - Sudan. The field has four wells producing from Ben and Arad formations. The result of this study showed that the optimum production rate for well HA-01 is 350 STB/D which is lower than the current base case rate. For well HA-02 and HA-04 the optimum liquid rate are 1000 STB/D and 2000 STB/D respectively which are higher than the base case. Well HA-03 is better to continue with the current liquid rate. The total cumulative oil is 10.1 MMSTB which is 5.87% increment compared with that produced from the current case. Finally, the study recommended that the optimization of production rate the early reservoir life time will lead well longer life and oil best recovery.

Keywords: optimum production rate, HA field – Sudan, oil best recovery.
1. Introduction and Literature Review

HA field is located in Block 2A Sudan. The area forms part of the Cretaceous-Tertiary Muglad Basin. Ben Formation is the main reservoir in this field. The study area is characterized by stacked successions of thick, amalgamated cross-bedded sandstones and intervening laterally extensive, thinner mudrock intervals. Sandstones of the overlying Arad Formation are characteristically isolated within an otherwise mudrock-dominated succession (GNPOC, 2009). Figure 1 shows the depth structure map for Ben formation including the location of the four existing wells in HA field where the average well spacing is around 600 m. Figure 2 shows the correlation between the wells among Arad and Ben formations.

2. Material and Methods
2.1 3D Model and Reservoir Data: the model has been divided into four different regions representing Arad E, Arad F, Ben1A and Ben1B reservoirs. The reservoirs are highly heterogeneous. Permeability distribution for Ben formation varied from 841 to 25%. For Arad formation the permeability varied from 10.7 to 4930.7 md and porosity between 16 to 23%.

The area is around 2.59 Km2. Each of Arad and Ben regions has its own PVT table, Special Core Analysis Laboratory (SCAL) data and Fluid in place. Cells dimensions are: i, j, k (29, 32, 61= 56,608 cells). The cells size 100*100 m. In Z direction, the thickness is 1 to 2 m. oil within the two formation has the same properties (API = 29, Oil formation volume factor = 1.05 RB/STB, Reservoir Temperature = 176° F, Gas Oil Ratio = 2 SCF/STB, bubble point pressure = 47 PSIG, Oil viscosity = 19 cp and Gas Gravity = 1.048). Eclipse 100 version 2009 was used as the numerical simulator to achieve the results of this work.
2.2 History Matching:
History matching in numerical simulation is the process of adjusting the simulator input in such a way as to achieve a better fit to the actual reservoir performance. Ideally, the changes in the simulation model should most closely reflect change in the knowledge of the field geology e.g. the permeability of a high permeability streak, the presence of sealing faults, ... etc. (Wen, et al. 1998). In this study; the error of the original oil in place for the four reservoirs from static model and dynamic model is less than 1%. Good global history matching has been achieved in production and pressure performance. The aquifer and global permeability were modified. For the wells individually; good matching achieved, and the permeability around some wells has been modified with reference to the wells test available data.

3. Results and Discussions
The production history period is from June 1999 to January 2010. One of the important objectives for any simulation run; is to predict the future performance. The prediction term refers to any process following the history matching, which includes all the available scenarios such as base case or do nothing case, stimulation activities, adding new wells ...etc. For this study, the prediction scenario is to find the optimum well production rate to be implemented for the future plan. However, the prediction cases include three cases: Case 1 which represent the base case “do nothing case”, Case 2 where the production rate is higher than what in Case 1, and Case 3 where the production rate is lower than what in Case 1 (the base case). The results were compared for the three cases in the field and in the wells individually. The prediction run will end in December, 2030 and the control mode of the prediction was used as liquid control mode. Table 1 shows the liquid production rate for all cases. Simulation was run for every case with liquid production rate as control. Oil production rate and cumulative oil produced were plotted for every well to compare between the cases; while three different samples were used to differentiate between the three cases.

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Last Historical Data (The Base Case)</th>
<th>Case 2 (Higher Value)</th>
<th>Case 3 (Lower Value)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Liquid Rate (STB/D)</td>
<td>Oil Rate (STB/D)</td>
<td>Water Cut (%)</td>
</tr>
<tr>
<td>HA-01</td>
<td>418</td>
<td>340</td>
<td>19</td>
</tr>
<tr>
<td>HA-02</td>
<td>8347</td>
<td>259</td>
<td>96</td>
</tr>
<tr>
<td>HA-03</td>
<td>6622</td>
<td>233</td>
<td>96</td>
</tr>
<tr>
<td>HA-04</td>
<td>1257</td>
<td>52</td>
<td>95</td>
</tr>
</tbody>
</table>
Well HA-01: There is no large difference between the do-nothing case (418 STB/D) and lower case (350 STB/D), both will give almost the same oil rate at 2018 after this time the lower case seems to give more oil rate than the other cases (figure 3). The cumulative oil produced is 0.98, 0.94, and 0.90 MMSTB for the higher case, lower case and the base case respectively. From figure 4; it is clear that the lower case and the base case will give the same results in year 2023 while the lower case is better in year 2030. The lower case flow rate of 350 STB/D is recommended for this well.

Well HA-02: In this well, lower case (5,000 STB/D) will give less oil than do-nothing case (8,347 STB/D). The oil rate from lower case will be always lower than the do-nothing case. The higher case (10,000 STB/D) will give more oil rate for the first two years only, after that the oil rate will be almost the same till year 2021(Figure 5). Higher case cumulative oil is 0.3 MMSTB more than do-nothing case. Lower case cumulative oil is 0.8 MMSTB less than do-nothing case (Figure 6). So, higher liquid value is recommended for this well (1000 STB/D Liquid rate).
Well HA-03: In this well, lower case (4,000 STB/D) will result in less oil than do-nothing case (6,622 STB/D). The oil rate from lower case will be always lower than the do-nothing case. The higher case (8,000 STB/D) will be almost the same as do-nothing case for oil rate term (Figure 7). Higher case cumulative oil is 0.025 MMSTB more than do-nothing case while the lower case cumulative oil is 0.237 MMSTB less than do-nothing case (Figure 8). The current case is recommended for this well (6622 STB/D Liquid rate).

Well HA-04: In this well, lower and higher case will be varied almost the same difference to the do-nothing case. Lower case (800 STB/D) will give less oil than do-nothing (1,257 STB/D) (Figure 9). Higher case cumulative oil is 0.18 MMSTB more than do-nothing case. Lower case cumulative oil is 0.1 MMSTB lower than do-nothing case (Figure 10). Higher case is recommended for this well (2000 STB/D Liquid rate).

Field Pressure: the reservoir has strong aquifer support; so the reservoir pressure trend will be maintained in the following years. The field pressure was compared for the three cases, the plot showed that the average field pressure for the lower case, base case, and higher case are 2010, 1820, and 1715 PSIA respectively (Figure 11).
4. Conclusions and Recommendations
From simulation results, the total OOIP in HA field is 34.39 MMSTB.

The field has four wells producing from commingled perforations (multilayer production). No clear decline in the reservoir pressure with the production which indicates a strong aquifer support (the reservoir is producing under steady state conditions).

The study showed that; the optimum liquid flow rate for Well HA-01 is 350 STB/D which is less than the current liquid rate (418 STB/D). While, the current liquid rate (6622 STB/D) is suitable for Well HA-03. For well HA-02 and Well HA-04 is better to increase the current rate to 1000 STB/D and 2000 STB/D instead of 8347 STB/D and 1257 STB/D respectively.

The total oil production rate at year 2030 will be 9.54 MMSTB with recovery factor equal to 27.7% if the wells continue production with the current case (the base case). Although, the total cumulative oil will be 10.1 MM STB which represent 5.87% incremental increase comparing with the base case with 29.37% recovery factor.

The optimization of production rate in the early time of the reservoir life is highly recommended which will lead to longer well life and best oil recovery.

References