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**Integrated Approach Towards the Application of
Horizontal Wells to Improve Waterflooding Performance**

QUARTERLY REPORT

Submitted by

Mohan Kelkar
Department of Petroleum Engineering
Chris Liner
Dennis Kerr
Department of Geosciences
The University of Tulsa
Tulsa, Oklahoma 74104

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U.S. Department of Energy
Assistant Secretary for Fossil Energy
Contracting Officer's Representative
Ms. Rhonda P. Lindsey
U.S. Department of Energy
Bartlesville Project Office
Post Office Box 1398
Bartlesville, Oklahoma 74005

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1. OBJECTIVES

The overall purpose of the proposed project is to improve secondary recovery performance of a marginal oil field through the use of an appropriate reservoir management plan. The selection of plan will be based on the detailed reservoir description using an integrated approach. We expect that 2 to 5% of the original oil in place will be recovered using this method. This should extend the life of the reservoir by at least 10 years.

The project is divided into two stages. In Stage I of the project, we selected part of the Glenn Pool Field - Self Unit. We conducted cross borehole tomography surveys and formation micro scanner logs through a newly drilled well. By combining the state-of-the-art data with conventional core and log data, we developed a detailed reservoir description based on an integrated approach. After conducting extensive reservoir simulation studies, we evaluated alternate reservoir management strategies to improve the reservoir performance including drilling of a horizontal injection well. We observed that selective completion of many wells followed by an increase in the injection rate was the most feasible option to improve the performance of the Self Unit. This management plan is currently being implemented and the performance is being monitored.

Stage II of the project will involve selection of part of the same reservoir (Berryhill Unit - Tract 7), development of reservoir description using only conventional data, simulation of flow performance using developed reservoir description, selection of an appropriate reservoir management plan, and implementation of the plan followed by monitoring of reservoir performance.

By comparing the results of two budget periods, we will be able to evaluate the utility of collecting additional data using state-of-the-art technology. In addition, we will also be able to evaluate the application of optimum reservoir management plan in improving secondary recovery performance of marginal oil fields.

Successful completion of this project will provide new means of extending the life of marginal oil fields using easily available technology. It will also present a methodology to integrate various qualities and quantities of measured data to develop a detailed reservoir description.

2. STAGE I PROJECT MONITORING

During the summer of 1995, we started implementing the reservoir management plan in the Self Unit. Last quarter, after evaluating each individual well, we decided to install electrical submersible pumps to produce three wells. The other three wells required the use of rod pumps. Production from the field improved significantly once the pumps were installed. Over the last twelve months, an average daily production has been approximately 45 bbls/day. Compared to a base line production of 13 bbls/day before the implementation, this is more than a 200% increase in production.

Part of the reservoir management plan is to increase the water injection rate. We have installed the injection pump and have started injecting water over the last four months.

3. GEOLOGICAL DESCRIPTION (By Dennis R. Kerr and Liangmiao Ye)

In the second quarter of 1997, geology activities of the Glenn Pool project focused on assisting ~~the~~ engineering component to do the reservoir simulation for Tract 9.

As part of the effort for this purpose, the relationship between porosity and Gamma Ray intensity developed earlier was further validated. In order to construct the three dimensional porosity distribution for the reservoir simulation, and given the situation that little petrophysical property data (porosity and permeability) ^{was} available within Tract 9, Gamma Ray logs were converted to porosity ^{data} based on the Gamma Ray intensity-porosity relationship developed based on Self 82 core data and Gamma Ray log (Figure 1). The relationship appears robust; leading to the belief that using this relationship in reservoir simulation is a reasonable way to overcome the paucity of porosity data. This relationship was investigated further by studying other well logs. Within the study ^y area, there are only two wells in addition to Self 82 which have both open hole Gamma Ray log and porosity logs (7-113, and Self 79). Figure 2 and Figure 3 display the plot of digitized Gamma Ray intensity ^{versus} porosity for each well. These two plots ~~do~~ show a linear relationship between Gamma Ray intensity and porosity, their relationship equations (as shown in each figure) are very close to each other. The difference between the equation shown in Figure 1 and the equations shown in Figure 2 and Figure 3 can be attributed to the different ways of measuring porosity. Core porosity is used in Figure 1, while log porosity is used in Figures 2 and ~~Figure~~ 3. Obviously, core porosity presents a very small scale (1-2 inch plugs) feature and is commonly biased toward ~~to~~ good quality reservoirs; while log porosity reflects "average" porosity for

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larger scale (a few feet) features. Thus for the same reservoir, core porosity tends to be higher than log porosity. This explains why Figure 1 shows higher slope and intercept value in the porosity-Gamma Ray relationship than Figure 2 and Figure 3.

As part of the technology transfer program, a workshop regarding this DOE Glenn Pool project was offered in Fort Worth, Texas, April 4, 1997, ^{at the} as a continuation of workshops we offered last year in Tulsa, Denver, and Houston. More than 20 geologists and engineers attended our workshop and responded with very positive comments on our works. Moreover, ^a poster presentation entitled "Reservoir characterization and improved water-flood performance in Glenn Pool field: DOE Class I project" was presented at the 1997 AAPG Annual Meeting in Dallas, April 6-9, 1997, ^{and} which received great deal of interest from members of independent and major operators.

4. ENGINEERING DESCRIPTION (by Sanjay Paranjli and Mohan Kelkar)

4.1 Introduction

Tract 9 is located south of the Chevron-William Berryhill unit and has an areal expanse of 160 acres (Figure 4). The unit is operated by Uplands Resources Incorporated and has very similar reservoir conditions to the Chevron-William Berryhill unit. The well schedule information was very difficult to reconstruct. It is known with a fair degree of certainty that ^{the} number of wells that have been drilled ^{so far} from the time of discovery ^{to present} is close to 65. The unit currently has six active producers and ten active injectors providing pressure support. Tract 9 is one of the units that rank high with respect to the original oil in place (15 MMStb). From the report compiled by Welch¹ it was observed that Tract 9 had produced cumulatively 6.058 MMStb of oil through primary depletion and secondary recovery operations as shown in Figure 5. This amounts to a recovery of 40% of the original oil in place.

4.2 Geostatistical Estimation of Petrophysical Properties

The A-G DGI model provided by the geologist was directly used as input for a thirteen layer system into the simulator with each DGI constituting one layer with shale interbedding between successive DGIs. The facies divisions used within each DGI are channel sand, splay sand and flood plain mudstone as provided by the geologist.

4.2.1 Facies Map Generation

A well base map for each DGI is constructed with the facies code assigned at the well locations. The facies type is determined by the type of SP or Gamma ray log response observed at the well. The facies code is assigned based on the following convention

- 1 - Channel sand
- 2 - Splay sand
- 3 - Flood plain mudstone, Shale

Indicator variograms are then generated for each facies, which are then input into the indicator simulation program-Sisimpdf³ for constructing the areal facies map. The Sisimpdf program honors the input proportion of each facies. In this study a multi-layered model is used which compromises the variability of the petrophysical properties to a certain degree but the depositional hierarchy is strictly honored. Unlike the Chevron-William Berryhill unit study² an attempt is made to simulate the shale layers between successive DGI layers to identify areas where the shale barrier is discontinuous, permitting sand upon sand stacking.

4.2.2 Thickness Estimation

The thickness of sand in each DGI at well locations is estimated from the data provided by the geologist. These estimates are then kriged at interwell locations using the ordinary kriging procedure to generate thickness maps for each DGI. It should be noted that the thickness of sand is explicitly forced to zero for interwell locations where the simulated facies is known to be shale.

4.2.3 Porosity Estimation

The porosity at each well location was estimated based on the Gamma ray logs due to insufficient Density-Neutron or sonic logs. A gamma ray to core porosity regression relationship was established based on data from the Self 82 well located in the Self unit (Figure 6). This is the only physical core

situated proximal to the study area. The gamma ray values were then averaged within each DGI and then kriged at interwell locations to produce gamma ray maps for all DGIs. The kriging is performed with the previously simulated facies maps as external drift³. The regression relationship is then used to translate this to a porosity map.

Gamma-ray values have a direct dependence on the shale content of the reservoir, which is inversely proportional to the porosity of section. Since gamma-ray logs show a pulsating response as opposed to the blocky response shown by SP logs feet by feet measurements of gamma ray logs may be misleading. When they are averaged over the thickness of the DGI itself the value should be representative of the shale content and in turn porosity at a particular location.

Figure 6 shows a large scatter identified by the lines A-A and B-B around the trendline for which the equation is provided. Hence it was proposed to feed the straight-line equations of A-A and B-B and use a random number generator for determining the porosity value for a given gamma ray measurement. For example a gamma ray measurement of 30 API units could be representative of a porosity value between 15% and 26% marked on the plot as Lower and Upper bounds respectively. It should be noted that ^{the} lower the gamma ray value, higher the uncertainty in the correlation.

4.2.4 Permeability Estimation

Even though the correlations between $\ln(k)$ and porosity are quite good it has not been used since the regression relationship may yield unreasonable values when extrapolated beyond the input porosity range used to construct the correlation. Once the porosity maps were generated for all DGIs the values in each DGI were transformed into a Standard normal Gaussian distribution. It is known that the porosity values are related to permeability without a large scatter. So the values in the Gaussian domain obtained from porosity are back transformed into permeability (real space) using the cumulative distribution function (cdf) from Chevron core data as input. This is done DGI by DGI with the input cdf for the corresponding DGI generated from the Chevron-William Berryhill unit.

Geostatistical Property Estimation Summary

Figure 7 presents a composite diagram of the facies, thickness, porosity and permeability map. It can be observed that the thickness and the petrophysical property maps carry the geological facies imprint.

4.3 Flow Simulation Procedure

This case study uses total liquid production as the flow constraint instead of oil production. The rationale used is that if the total liquid production were matched, discrepancies in simulated water cuts compared to the actual field values would result in acceptable errors of simulated oil production. This works in contrast to a case when oil production is used as the flow constraint which would result in gross errors in total liquid production owing to imperfections in simulated water cuts.

4.3.1 Gridblock Setup

The areal expanse of the Tract 9 is 160 acres. It was decided to divide the area into 66 ft. x 66 ft. gridblocks so that any DGI is divided in 1600 gridblocks. The thickness of each gridblock is assigned to be the thickness of the DGI itself, which was obtained by interpolating at interwell locations earlier. The system has 13 layers, which is the sum of all DGI's A through G and the intermediate shale layers between successive DGI's.

4.3.2 PVT Properties

The PVT properties input requires oil and gas properties as a function of pressure. The minimum bottom hole pressure is known to be around 20 psi and the initial pressure of the reservoir was around 900 psi. Therefore the working range of pressure is 20-900 psi. All the properties were generated using standard Black Oil model correlations for the above working range in discrete increments of pressure.

4.3.3 Input Pressure Profile

The well test data provided an estimate of the average reservoir pressure around the well. Four well tests were conducted within Tract 9. These average pressures were gridded using the kernel smoothing technique to generate an areal base map of pressure for the year 1992. Since all the DGIs are in vertical communication with the exception of DGIs A and B vertical equilibrium was assumed to calculate the areal pressure profile for each DGI. It should be noted that the base pressure map is tied to DGI E since this layer represents a median depth in the vertical structure of Glenn sand. All other DGI pressure profiles are determined based on the hydrostatic pressure difference. Figure 8 shows the base pressure map that is tied to DGI E. It can be seen that the southwestern corner pressures are lower as compared to

other areas. It is theorized that the pressure dip around p38 is created since the pressure support from injectors K4 and J3 is mostly absorbed by producers p54, p33 and p61 which are situated closer to the injectors.

4.3.4 Input saturation Profile

The saturation profile is derived from resistivity logs. It is then scaled using a multiplier to make it representative of the year 1992. The methodology used to determine the multiplier is as follows. The effective permeability is estimated from the model at all wells where well testing was carried out. The effective permeability is then compared with the true effective permeability derived from the well test. Since the effective permeability has a direct dependence on saturation the saturation is scaled so as to bring the model derived effective permeability closer to the true effective permeability at all the wells.

4.4 Flow Simulation Results

The well map presented in Figure 9. It shows only the active wells for clarity and does not include all the wells that have been drilled in this unit. Initially it was proposed to restrict the recompletion/redrilling program to the area marked by dotted lines in the well base map. In accordance the following scenarios were proposed.

4.4.1 Scenario Base

It was proposed to plug the lower DGI's (E, F, G) and then complete upper DGI's (A, B, C, D) for all existing wells within dotted area namely p33, p54, p60 and K4. Two new injectors and three new producers 70, 71 and 72 are proposed. It is intended that the injectors Z1, Z2 and K4 would form a water bank and sweep the oil east and west of the line of injectors toward the producers as shown by the green arrows in Figure 9.

4.4.2 Anisotropy Favorable/Unfavorable

It was proposed to investigate the effect of anisotropy $K_{N-S} = 3 \times K_{E-W}$ for the base case. This would be favorable for the proposed intent since the water bank formation is promoted owing to the North-South permeability being higher. It was also decided to consider the adverse case where $K_{N-S} = (1/3) \times K_{E-W}$ to get an idea of the possible downside if the truth is an exact converse to the favorable case.

The history matching for all the cases is done from the year 1992-1997. The forecasting is done from May 1997. It should be noted that the history matching was done with total liquid production as the flow constraint. Hence the oil production curve during the history matching stage would be case dependent because of variations in the oil cuts.

4.4.3 Scenario Plug/Recomplete all Wells

The Scenario base did not yield a good response. Hence it was decided not to restrict the scope of operations to the dotted area mentioned in the base scenario. It was proposed to plug all injectors and producers in the lower DGI's (E, F, G) and complete them in the upper DGI's (A, B, C, and D) without redrilling new wells.

The proposal does not look attractive on first glance (Figure 10) since the incremental oil production on implementation of recompletion/redrilling program is not significantly higher as compared to the case in which existing conditions are allowed to prevail. This is indicated by the closeness of the two curves in the oil production plot. The water cut plot shows a decrease of 98.7% to 97.3% that translates to a considerable reduction in water production. Hence despite the fact that incremental oil production is not encouraging the proposal is economically viable since the water production is cut drastically resulting in a remarkable reduction in operating costs.

4.4.4 Scenario Plug/Recomplete Old Well and Drill New Vertical Wells

This scenario is a combination of the base case and the scenario detailed in the previous section 1.4.3. The proposal for new wells is not changed. Hence in this scenario the new wells are p70, p71 and p72 as producers and Z1, Z2 as injectors. The intention is to capture the advantages of plugging the lower intervals in terms of reduction in water cut and still gain incremental oil production by virtue of the new wells drilled.

The incremental oil production after implementation of the proposal over the existing condition case is at best about 35 bbls/d. The water cut goes down from a value of 98.7% before implementation to a low of 97.8% which is a reduction of 0.9% as compared to a cut of 1.4% brought about by the plug/recomplete program.

4.4.5 Scenario Plug/Recomplete Old Wells and Drill New Multilaterals

It was proposed to drill multilateral wells (Figure 11) with lateral sections penetrating each of the upper DGI's A, B, C, D. The well will penetrate the formation in the North-South direction. Well Z1 would be a multilateral injector and well 71 would be a multilateral producer. The intention is to gain advantage of the horizontal sections of the multilateral wells. It is hoped that multilateral injector would provide good sweep and that the multilateral producer would yield more incremental oil production as compared to vertical wells.

The incremental oil production after implementation of the proposal over the existing condition case is at best about 70 bbls/d which is considerably larger than the vertical well scenario (35 bbls/d). The maximum reduction in water cut is about 1%.

The reservoir being very shallow (1,500 feet) it is not essentially advantageous to drill a multilateral well since the cost of drilling a vertical well is much lower than the cost for a multilateral well. A multilateral well would perhaps be more appropriate for deep reservoirs in which case it is more cost effective to penetrate a layered reservoir with laterals from a single vertical section as opposed to drilling multiple vertical wells.

4.4.6 Scenario Plug/Recomplete Old Wells and Drill Deviated Wells

Since the multilaterals proved to be cost ineffective it was proposed to investigate a scenario wherein the multilateral wells are substituted by deviated wells. The idea is drill at an angle of 80 degs to the vertical (almost horizontal) and penetrate all upper DGI's namely A, B, C, D with an approximate span of 80 feet in each layer. The principal direction of penetration will be North-South.

The incremental oil production after implementation of the proposal over the existing condition case is at best about 70 bbls/d, which is lower as compared to the scenario in which multilaterals were proposed. The maximum reduction in water cut is once again about 1%. Since the cost of drilling a deviated well is a cheaper proposition as compared to the cost for a multilateral well, it is economically more attractive.

4.5 Economic Evaluation

A simple economic evaluation was conducted to identify the most favorable scenarios. The rate of return histogram is presented which is a compilation of all scenarios together arranged in ascending order. It was decided to incorporate sensitivity analysis on the oil price with variations as shown in Figure 11. The ROR figures do not show a large variation for any given scenario. It can be noted that the plug upper DGIs/ recomplete lower DGIs flow scenario stands out among all the proposals.

4.6 Conclusions

The flow simulation of Tract 9 has been completed. Several scenarios have been proposed. Economic analysis shows that plug/recomplete scenario shows significant profits. With regard to proposed wells drilling deviated wells would be more advantageous as opposed to multilateral wells. Future work includes a similar investigation of Tract 7 and economic analysis for the flow unit.

References

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3. Deutsch, C.V and Journel, A.G : Geostatistical Software and Library and User's Guide, Oxford University Press, 1992

Figure 1 Gamma Ray intensity ^{versus} core porosity (well Self 82)

Figure 2 Gamma Ray intensity ^{from} verse log porosity (well 7-113)

Figure 3 ^{mean} Gamm Ray intensity verse log porosity (well Self 79)

Figure 4: Index map showing the location of Chevron unit

Figure 5: Production analysis plot for Tract 9 showing the primary, gas injection and water flooding stages of depletion

Figure 6: Gamma ray v/s core porosity correlation developed from the data compiled from Self 82.

DGI G

Figure 7: Composite diagram showing areal maps of porosity, permeability and thickness honoring the facies distribution. All dimensions are in feet/ Tract 9 study

Average reservoir pressure/Tract 9

Figure 8: Areal reservoir pressure map that is tied to DGI E in psi

Figure 9: Well base map of existing/proposed wells for Tract 9.

Figure 10: Oil production and water cut plot for scenario 1.4.3

Figure 11: Figure showing the proposed well base map with multilateral well locations

Figure 12: ROR histogram with sensitivity on oil price