DOE/BC/14951-25
(OSTI ID: 5313)

FOSSIL ENERGY

INTEGRATED APPROACH TOWARDS THE APPLICATION OF HORIZONTAL WELLS TO IMPROVE WATERFLOODING PERFORMANCE

Annual Report
January 1 – December 31, 1998

By
Mohan Kelkar
Dennis Kerr

April 1999

Work Performed Under Contract No. DE-FC22-93BC14951

The University of Tulsa
Tulsa, Oklahoma

National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

Available to DOE and DOE contractors from the Office of Scientific and Technical Information, P.O. Box 62, Oak Ridge, TN 37831; prices available from (615) 576-8401.

Available to the public from the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Rd., Springfield, VA 22161

DOE/BC/14951-25
Distribution Category UC-122

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

By
Mohan Kelkar
Dennis Kerr

April 1999

Work Performed Under Contract DE-FC22-93BC14951

Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Dan Ferguson, Project Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by
The University of Tulsa
600 South College Avenue
Tulsa, OK 74104

TABLE OF CONTENTS

ILLUSTRATIONS

Figures

ACKNOWLEDGMENT

The research effort described in this report was supported by the U.S. Department of Energy under Contract DE-FC22-93BC14951. Additional support is provided by Uplands Resources, Inc. The computer facilities were provided by The University of Tulsa.

We would like to thank Dan Richmond from Uplands Resources, Inc. for his valuable contribution and insight to our work. Our special thanks go to Dan Ferguson, representative of the contracting officer of the project, for his enthusiasm and valuable suggestions.

Mohan Kelkar

January, 1999

ABSTRACT

This annual report describes the progress during the sixth year of the project on "Integrated Approach Towards the Application of Horizontal Wells to Improve Waterflooding Performance." This project is funded under the Department of Energy's Class I program which is targeted towards improving the reservoir performance of mature oil fields located in fluvially dominated deltaic geological environments. The project involves using an integrated approach to characterize the reservoir followed by proposing an appropriate reservoir management strategy to improve the field performance. In the first stage of the project, the type of data we integrated includes cross bore hole seismic surveys, geological interpretation based on the logs and the cores, and the engineering information. In contrast, during the second stage of the project, we intend to use only conventional data to construct the reservoir description.

This report covers the results of the implementation from the first stage of the project. It also discusses the work accomplished so far for the second stage of the project. The production from the Self Unit (location of Stage I) has sustained a significant increase over more than three years. Based on our reservoir characterization study,[1] we identified Tract 9 as a possible location for drilling an inclined well. The details of the selection process are described in the previous annual report.[1] After fine tuning some additional reservoir studies, we initiated a well in December 1998. Unfortunately, the drilling encountered several unanticipated problems. Because of these problems, we abandoned the drilling. At present, we are searching for alternatives to drill and complete the inclined well.

EXECUTIVE SUMMARY

During the last year, we have continued to monitor the reservoir management plan in the Self Unit. Over the last year, the production from the unit has remained constant averaging about 30 bbls/day (over 100% increase in the production). In addition, we initiated the implementation of the reservoir management plan in Tract 9. Part of this implementation included completing well 9-60 in the upper zones to ensure that we do not have any free gas in the upper zones of the reservoir. Further, we needed to ensure that the oil cut in the upper zones is better than lower zones. Both these observations were validated through re-completion of Well 9-60.

Armed with this information, we designed a deviated well to be completed in the upper zone of the reservoir. We hired Integrated Directional Resources, Inc. (IDR) to complete the deviated portion of the well. In addition, according to our plan, one well would be converted into an injector, and two injectors will be selectively completed in the upper zones of the reservoir. Unfortunately, the drilling of deviated hole encountered several unanticipated problems. The bottom hole tool assembly did not perform as per expectations, the gyro tool broke once due to severity of the dog leg, and the bottom hole assembly twisted off twice in the hole. We were successful in fishing the bottom hole assembly once; however, when the assembly twisted the second time, we could not fish it out after three days of various attempts. After eight days of drilling operations, the actual costs have substantially exceeded the projected costs for the well. The well was, therefore, abandoned and plugged back.

We have decided to re-group and re-evaluate the well to determine if it is feasible to complete the deviated hole using a slightly modified technique. We will make this decision by the end of the first quarter of 1999.

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 was implemented and the performance is being monitored.

Stage II of the project involves selection of part of the same reservoir (Berryhill Unit - Tract 7 and Tract 9), 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. The plan included re-completion of many of the producers and injectors. The wells were selectively re-perforated in upper zones and were acidized. After evaluating each individual well, we decided to install electrical submersible pumps to produce three wells. The other three producers required the use of rod pumps. Production from the field improved significantly once the pumps were installed. In the first two years since the implementation, the production averaged about 40 bbls/day. Over the last twelve months, an average daily production has been approximately 30 bbls/day. Compared to a base line production of 13 bbls/day before the implementation, this is more than a 100% increase in production. The water cut in producing wells is not as low as predicted. We believe that the reason for this high water cut is our inability to control the water injection in the desired zones. We intend to run injection surveys in injection wells to determine the location of zones where most of the water is injected.

3. FIELD IMPLEMENTATION FOR STAGE II

In the previous annual report,[1] we provided detailed field implementation plans for Tracts 7 and 9. We decided to concentrate on Tract 9 because of the limited number of wells producing in that tract. The geological description of the reservoir had divided the reservoir into several discrete genetic intervals (DGI's). These intervals were classified as A,B, C, D, E, F, G and H. The lower DGI's (E, F, G and H) have better reservoir properties. Therefore, these intervals have already been flooded. We decided to concentrate on the upper zones. Initially, our plan was to re-complete the existing wells in the upper portion (DGI's A, B, C and D) of the reservoir and shut in the lower portion of the reservoir in the same wells. Unfortunately, many of these old wells were treated with nitro-glycerine. Historical records indicated that the amount of nitro-glycerine used was substantial. This may have resulted in substantial caving of the reservoir rocks near the well bore. As a result, we were not confident about the formation of caverns, which may have been left behind in these wells. After receiving several bids from various contractors, it became apparent that completing the lower portion of the existing wells is not an easy task. The amount of cement required cannot be known unless we start circulating in these wells, and it is possible that the cost would exceed the cost of drilling a new well. With this scenario in mind, we decided not to re-complete the old producing wells.

In addition to concern about the existing wells, we were also concerned with the possibility of a gas cap in Tract 9. Earlier historical reports had indicated that there is a possibility of a gas cap in other parts of the reservoir. Tract 9 sits very close to the structural high in the reservoir. Previous operators, therefore, believed that te upper intervals had developed secondary gas cap within the vicinity of structural high. Therefore, most of the wells were selectively completed in the lower zones of the reservoir. We had run several TDT (Thermal Decay Temperature) logs in Tract 7 to check the presence of gas in that tract. These TDT logs had indicated an absence of a gas cap in Tract 7;[1] however, we did not have any direct proof of presence of oil in the upper zones in Tract 9. To test the presence or absence of gas in Tract 9, we completed well 9-60. The well was selectively completed in the upper intervals (DGI's A, B, C and D), and a bridge plug was placed to separate the bottom zones (DGI's E, F and G) from the top zones. After the well was re-completed, there was no indication of the presence of gas in the upper zones– this is consistent with our model and Tract 7 observations, and the well showed a slight improvement in the oil cut – also consistent with our model. Our reservoir description assumes that the upper zones have higher oil cuts because they have not been completed as extensively as the lower zones. We were encouraged by this result which indicated that the oil saturation is higher in the upper zones, and there is no free gas present in the top zones.

Armed with all the information in the previous studies as well as the information from well 9-60, we designed a deviated production well to be selectively completed in the upper four zones (DGI's A, B, C and D). The location is shown in Figure 1. This overall implementation includes converting well no 61 into an injector, re-perforating wells M-3A and M-4A, and drilling a deviated production well between 61 and M-3A/M-4A in an east-west direction. The total length is expected to be about 500 ft, and the well would be completed in zones A through D. Figure 2 shows the well plan proposed for the deviated hole and Figure 3 shows the direction in which the well is to be drilled. With this configuration, we can take advantage of the portion of the Tract 9 which has not been drained, and also support the production through three injectors which are completed in the same zone. By locating the producer in the middle, we expected that the three injectors will create relatively unform flood front supporting the producer. As discussed in the previous report[1] we expected 75 bbls/day of additional oil production from this well. In addition to testing the concept of a deviated hole, we also decided to test the concept of drilling a vertical well using air drilling.

The drilling of the vertical portion of the well was initiated at the end of November 1998. The drilling encountered no problem, and we completed the vertical portion in the allocated time and within our budget. For drilling the deviated hole portion, we gave a contract to Integrated Directional Resources (IDR), a company specializing in drilling directional wells through use of surface rotary steering equipement . The drill bit is steered from the surface rather than using mud motors. This is a relatively new technology, and, if successful, can result in substantial savings in drilling horizontal holes in the future for marginal oil fields.

The drilling of the deviated hole was initiated on December 1, 1998. The bottom hole tool assembly included 6" PDC bit, CDA double joint, 2, 20 feet Monel collars followed by 6 joints of drill pipe (PH6). The initial attempt to drill the well failed, because after drilling the well up to a depth of 1,363 ft, it was realized that the tool was not building any curve. Instead it was drilling a straight hole. The possible cause for this was assumed to be the double joint, and the decision was made to use a single knuckle tool. The well was plugged back using cement on December 2nd. On December 3rd, the drilling resumed with a slightly different assembly. Instead of double joint, a single knuckle tool was used. To control the direction, a gyro tool was used. The gyro tool was provided by K-Jet, Inc. in Oklahoma City. From the surface, after drilling of 1 foot, the gyro was run and seated, a tool face was marked at the surface, and then gyro tool was pooled back and the rig resumed drilling. The drilling went smoothly with the angle being built according to the expectations. On December 5th, the gyro tool broke. The possible cause was determined to be high torque and high dogleg severity. After changing the tool, the drilling resumed at a very slow rate. After drilling a few more feet, the up hole Monel collar failed. The steel drill pipe failed at the pin due to high stress exerted by the Monel collar. A fishing operation was initiated and the fish was successfully brought to the surface with 3.5" basket grapple. Examination of the twist point indicated that Model collar is the stiffest part of the assembly. Although it provides better drilling control, it also accumulates the most stress. To avoid a repeat, the decision was made to drill with only one Monel collar.

After drilling another 24 feet, on December 6th, the Monel collar failed again at the connection on top of the non magnetic cross over. Unlike the first time, when the Model collar remained in the hole, this time, Model collar remained connected to the drill pipe. Instead, the collar was twisted of at the bottom where the cross over was connected. The pipe was pulled and numerous fishing attempts by Baker Tools were made over the next three days. The fish could not be caught. Because of significant cost over-runs, a decision was made to abandon the well by plugging back inside the casing.

At this point, we are formulating a way by which we can go back to the same vertical hole and try to recomplete the deviated hole. Part of the reason for the failure of the fish was determined to be inflexibility of Monel collars. We may be able to eliminate that problem by using more flexible Monel collars. In addition, how the gyro tool is attached also needs to be examined. After all the costs are paid, we will reconvene with IDR to determine how to best pursue the re-completion of the well. We should finalize the decision in the first quarter of 1999.

4. TECHNOLOGY TRANSFER

While we were working on implementation of the reservoir management plan, we are also making a concerted effort to transfer the technology. During this year, we worked on several publications. These include:

- *Glenn Pool Field, Oklahoma: A Case of Improved Production from a Mature Reservoir.*
  American Association of Petroleum Geologists Bulletin (January, 1999).

- *Facies Architecture of the Bluejacket Sandstone in the Eufaula Lake Area, Oklahoma: Implications for Reservoir Characterization of the Subsurface Bartlesville Sandstone.*
  American Association of Petroleum Geologists monograph series.
  To be published May, 1999.

- *Sequence Stratigraphy of the Middle Pennsylvanian Bartlesville Sandstone, Northeastern Oklahoma: A Case of an Underfilled Incised Valley.*
  American Association of Petroleum Geologists Bulletin.
  Submitted for peer review; decision expected November, 1998.

- Untitled Logging Technology in preparation by BDM Petroleum Technologies staff.

  Society of Professional Well Log Analysts monograph series.

  Submitted revised manuscripts, in peer review; publication date unknown.

- *Application of Borehole Imaging for Meandering Fluvial Facies Architecture Reconstruction of the Bartlesville Sandstone, Oklahoma.*

  American Association of Petroleum Geologists Bulletin, expected publiction fall, 1999.

5. REFERENCES

"Integrated Approach Towards the Application of Horizontal Wells to Improve Waterflooding Performance", 1997 Annual Report, DOE Contract Number DE-FC22-93BC14951, Washington, D.C. (1998).

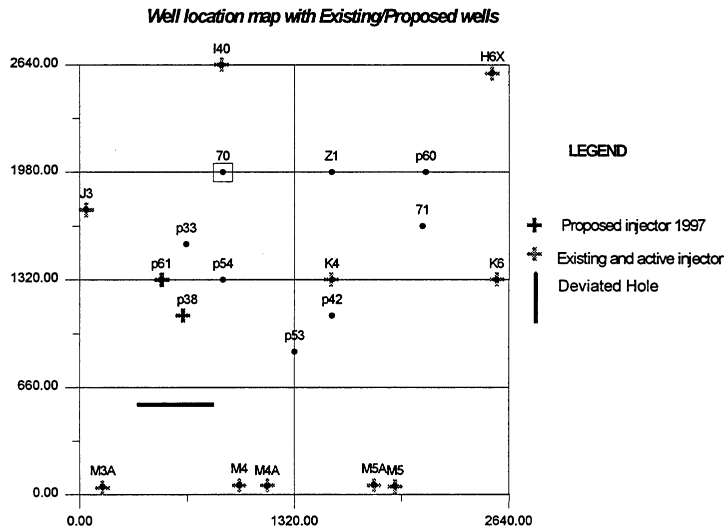

Figure 1: Proposed management plan for Tract 9.

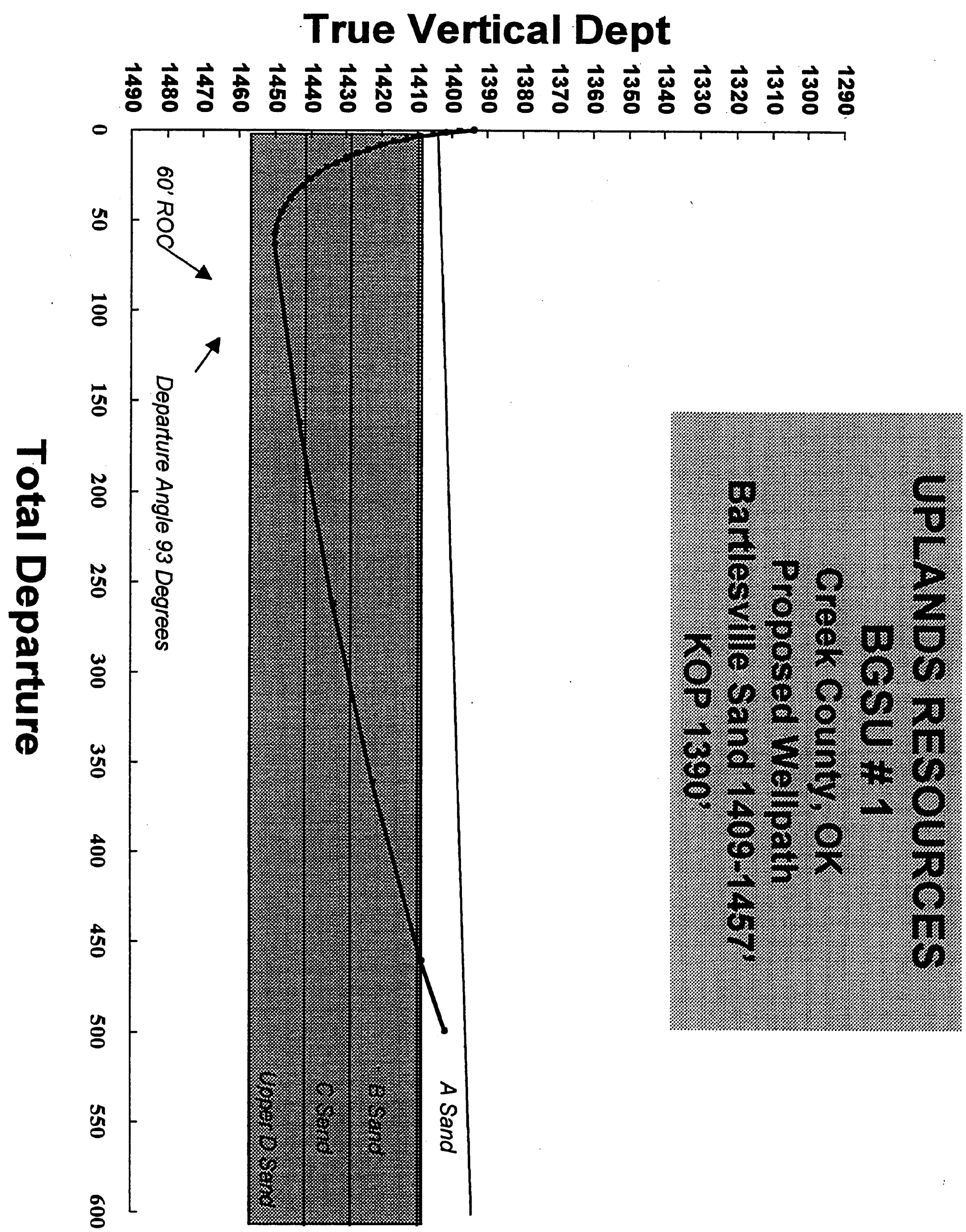

Figure 2: Profile of a deviated hole.

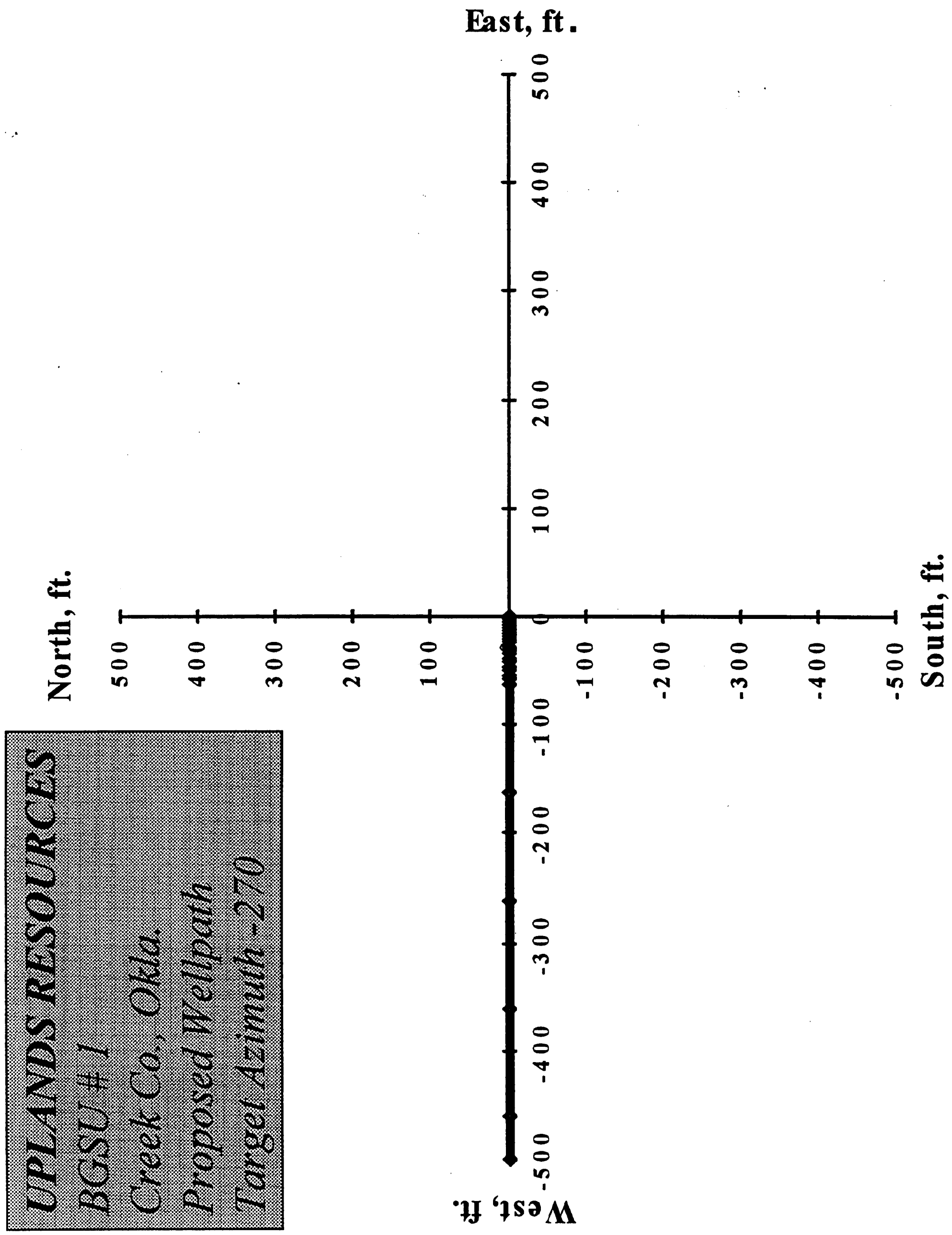

Figure 3: Direction of deviated hole.