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

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ABSTRACT

This paper discusses the various approaches used in attempting to improve the performance of mature oil field. The results of the implementation and the lessons learned from the implementation are also included in the paper. The field selected for the implementation is Glenn Pool oil field, a field, which has been producing for more than 90 years. Overall, the technologies that proved to be effective include: integrated approach to describe reservoirs, geological description using Discrete Genetic Intervals (DGI's), use of productivity index to rank various parts of the reservoir, geostatistics and flow simulation. The technologies which proved to be only marginal effective or ineffective include: use of micro-resistivity logs for detailed geological description, cross bore hole tomography and drilling of deviated hole using surface steered drilling assembly.

The overall project was divided into two phases. In the first budget period, we collected modern data sets to evaluate the cost effectiveness of new data in improving the reservoir description. In contrast, in the second budget period, we used conventional data to describe the reservoir. In both the budget periods, based on our detailed evaluation of the data, we developed reservoir description, and based on various reservoir management strategies, recommended the optimal reservoir management plan to improve the performance of the reservoir. In the first budget period, the recommended plan was to re-complete the existing wells. Implementation of the plan resulted in significant additional oil recovery in part of the field. Further, the predicted performance matched with the observed performance. In the second budget period, the recommended plan was to drill a

deviated well to selectively complete certain intervals of the field. Unfortunately, due to various drilling problems, the well could not be completed and had to be abandoned. As a result, the observed performance could not be compared with the predicted performance during the second budget period. Based on our experience in the first budget period, we are confident that if the recommended plan as indicated in the second budget period is implemented, it will result in significant additional oil recovery. In addition, several other potential locations within the Glenn Pool field exist where similar approach can be used to recover additional oil.

BACKGROUND

The DOE Class I Program is targeted towards improvement of production performance of existing mature oil fields located in fluvial-dominated deltaic sandstone reservoirs. This project is selected under the near-term program which requires that existing new technologies be applied in these fields to prevent any premature abandonment of these mature fields. The Glenn Pool field selected for this project fits the desired characteristics under this program.

The Glenn Pool field is located in portions of Tulsa and Creek Counties of Oklahoma. The field was discovered in 1905, and it is estimated as having produced 330 MM barrels of oil from the Middle Pennsylvanian (Desmoinesian) age Bartlesville sandstone. Glenn Pool field, like other fields developed in the Bartlesville sandstone, is located on the Northeastern Oklahoma Platform, a paleotopographic and structural depression of mid-Mississippian-Pennsylvanian age lying between the Ozark Uplift to the east and the Nemaha Ridge on the west (**Figure 1**). The figure also shows the area of study for this project. The Self-unit indicated in the figure was the subject of first budget period investigation, whereas the gray area surrounding the Self-unit was the subject of the second budget period.

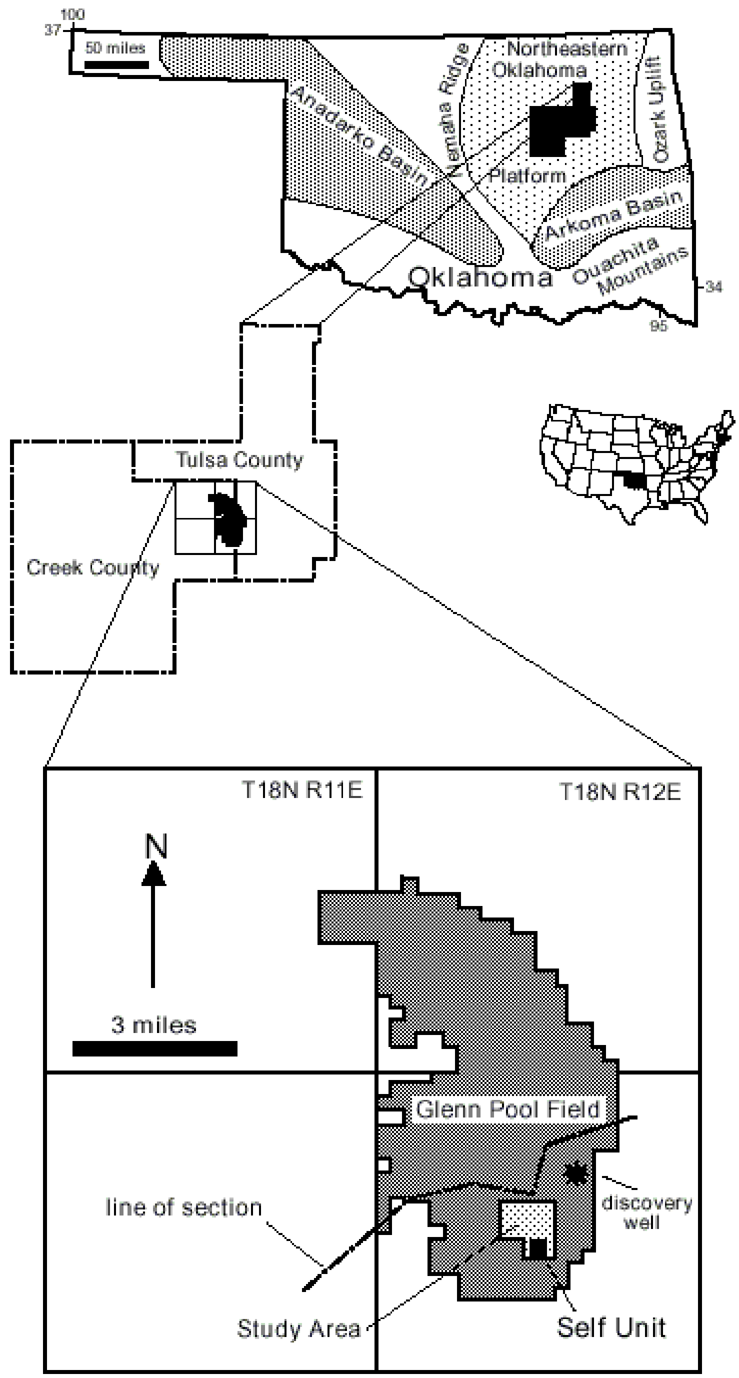

Figure 1 – Location of Glenn Pool field

The field encompasses 27,440 acres. Initial production from the wells ranged from 75-500 BOPD to 4,000 BOPD. After discovery in 1905, the field reached peak production in 1907. The first well in the field was drilled in fall of 1905. The well was located on the Ida Glenn farm near the center of the SE/4 of section 10, T17N, R12E, in Tulsa County (see Figure 1). The well was 1,458 ft. deep and produced at a flowing rate of 75 BOPD. The producing interval was called "Glenn sandstone" and in the subsequent years became the target pay zone. The average producing span was estimated to be close to 240 ft. and was the most productive compared to the other nearby fields.

With depletion of production, gas injection was introduced in 1940, and gas collected at producing wells was recycled to injection wells. Water flooding operations began in 1944. Cumulative oil production records prior to field-wide water flooding are incomplete. By 1943, it was estimated that the production throughout the field was between 222 and 236 MMBO. Over 100 MMBO had been produced up to 1990 by secondary gas repressuring, water flooding, and tertiary recovery methods bringing total production to 330 MMBO. The field is being depleted at present. Several large production units are under water flood, and a few units have undergone testing and implementation of micellar-polymer enhanced recovery methods. Results have shown the possibility for significant additional volumes of recoverable oil.

The Glenn sand has been conventionally divided into 3 units: upper, middle and lower Glenn.[1] Each is separated by apparent permeability barriers consisting of interbedded siltstones and shales. In the central portion of the Glenn Pool field the Glenn sand is present at a depth of approximately 1,500-ft, and the thickness varies from 100 to 185-ft. The upper and middle Glenn are the producing intervals in the central portion of the field and the lower Glenn is below the oil-water contact.

Oil from the Glenn sand has a gravity of 35.8° to 41.3°. It contains 3.12 to 11.46% paraffin and a sulfur content of 0.3%. Initial reservoir pressure has been estimated in the range of 600 to 700 psi. Current water flooding injection pressure ranges from 100 to 1,100 psi.[1]

BUDGET PERIOD I

Introduction

In the first budget period, our effort concentrated on Self-unit located in the southeast portion of the Glenn Pool field (see Figure 1). During this period, we applied several new technologies to improve the reservoir description. These technologies include integrated reservoir description, geological description using DGI's (discrete genetic intervals), modern logs, cross borehole tomography, geostatistics and reservoir flow simulation. The description and success of each of these technologies is discussed in this section.

Self Unit

The Self-unit, area of investigation of project during budget period one is a 160-acre tract located in southeast portion of Glenn Pool oil field in section 21-17N-12E (**Figure 1**). Currently the unit is operated by Uplands Resources, Inc. The first well on the lease was put on production November 6, 1906. In all, 5 wells were put on production in 1906. Out of the three Glenn Sand intervals, the upper and middle are present while lower Glenn is absent in the Self-unit.

The original oil in place (OOIP) for the unit has been estimated to be 13.009 MMBO. Primary production during 1906-1945 resulted in the production of 1.809 MMBO representing 13.91% of OOIP. In 1945, gas repressuring began in the unit. This resulted in a recovery of 0.231 MMBO representing 1.8% of OOIP. During 1954-1966 the unit was put on a pilot water flood resulting in production of 0.169 MMBO (1.3% of OOIP). The recoveries were higher in the areas surrounding the pilot and the gas injectors. In 1966, water flooding was extended to the majority of the field. In the initial period of water flooding, the production increased across the entire Self-unit. The total production during 1966-1978 resulted in production of 0.235 MMBO representing 1.8% of OOIP. The unit was redrilled in 1978 on a ten-acre 5-spot pattern. During 1978-1983, 0.146 MMBO production representing 1.12% of OOIP was obtained. From 1984-1992, production was 0.157 MMBO representing 1.2% of OOIP. Total production obtained to date from the unit is around 20% of the OOIP.

The Self-unit experienced good primary recovery, but response to the subsequent secondary recovery efforts has not been encouraging. Study of the available well logs and core reports indicate that lithologic heterogeneities and permeability vary throughout the lease. Well logs taken in the 1980's indicate higher water saturations in middle Glenn portions rather than in the upper Glenn. Upper Glenn portions could not be swept by water flooding because of, perhaps, lower permeabilities in these portions and inadequate perforation coverage.

Despite subsequent water flooding, water injection could not be contained on the lease and water possibly migrated to other parts of the field. Large permeability variations in upper and middle Glenn also contributed to this inefficient use of water injection. Injection pressures and rates vary throughout the lease; pressures range from 50 to 700 psi, and the rates range from 40 to 2,000 barrels of water per day. At the start of budget period one, oil production from the lease was less than 18 bbls/d with water cut of 99%.

In total, 81 wells have been drilled on the Self-lease. The study required the availability of all well records. Though starting production and abandonment data for most of the wells are available, information with regards to the production history for individual wells could not be traced. The well map depicting all the wells drilled in the Self-unit is shown in **Figure 2**. Initial development occurred along the periphery of the unit; subsequently, development occurred in the interior.

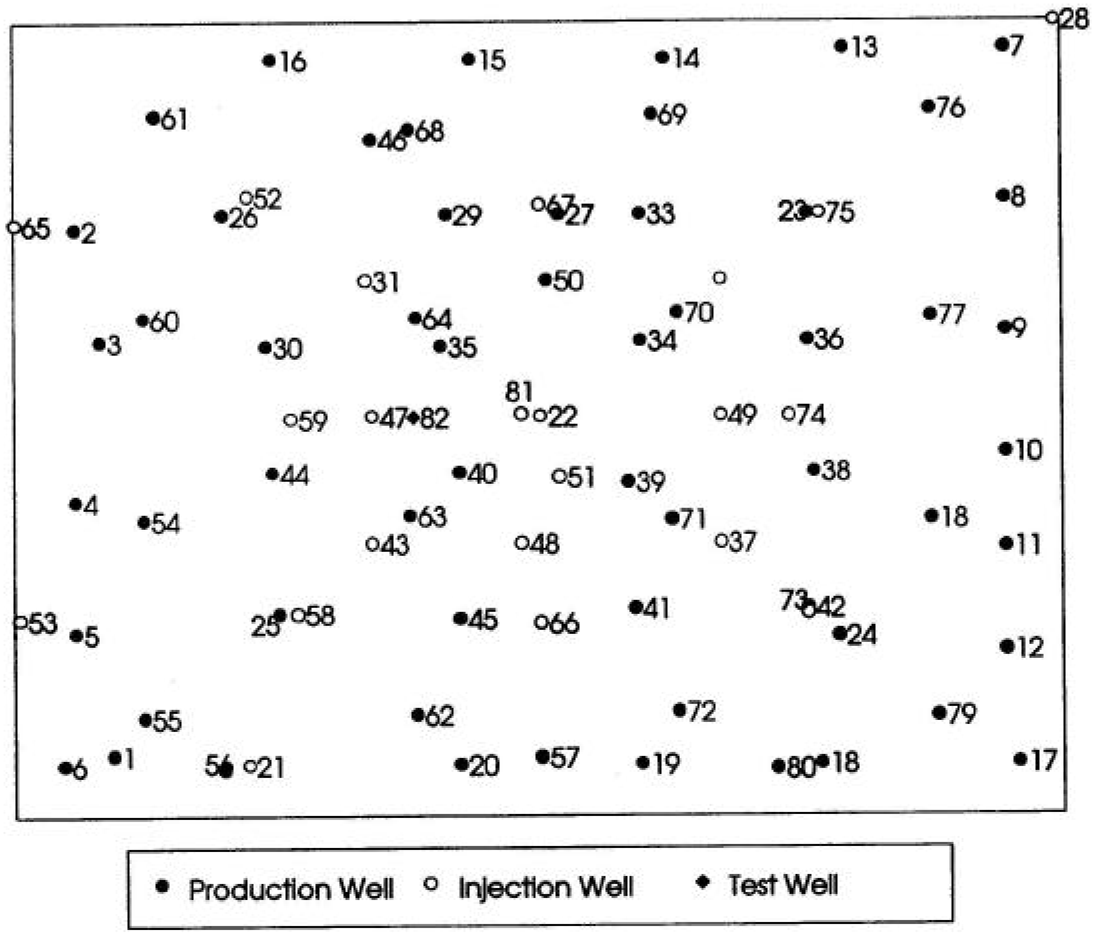

Figure 2 – Well locations

The overall production history based on the above information is summarized in Figure 3. As evident from this figure, every time new technology was implemented in Self-unit the field responded with substantial increase in production. This is evident in 1946, 1965 and 1978. This also gives an indication that if new technology is properly used and a good reservoir management plan is implemented, the Self-unit will respond with an increase in oil production.

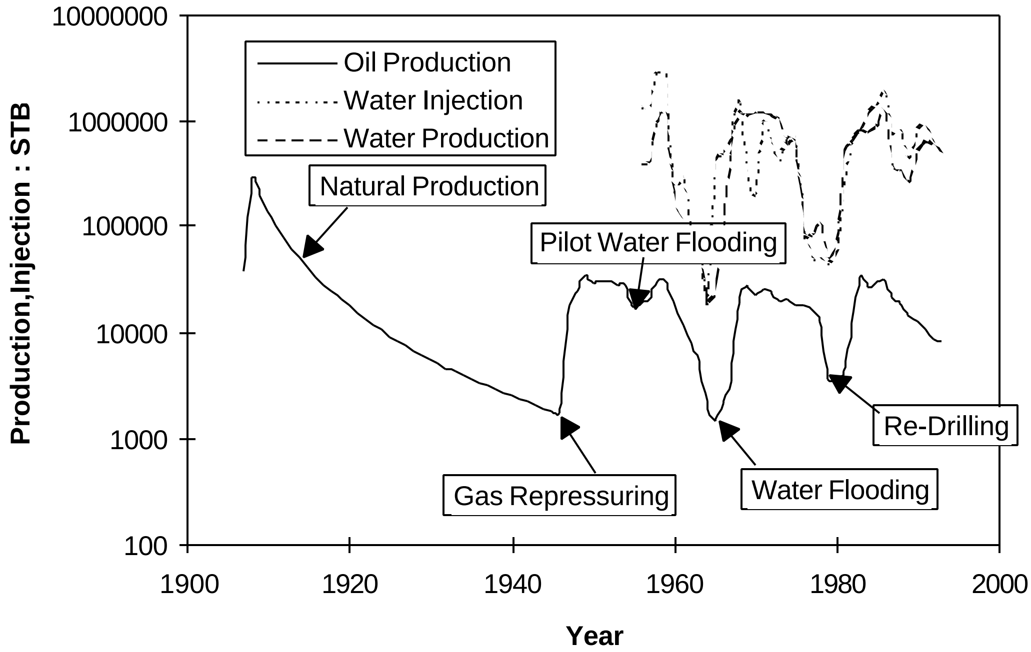

Figure 3 – Production history of Self-unit

For information related to the petrophysical properties, well logs for the drilled wells after 1978 are available. Permeability data availability for the Self-unit are not that abundant. Though eight core reports are available from the wells operating during 1940's and 1950's, the logs for those wells could not be traced and as a result no relation between the core and well log of the same well could be established. Furthermore, the existing wells have only been logged and there is no core report relevant to these wells.

Although significant production data were available, the project team believed that an additional well needs to be drilled for the following reasons.

- We did not have a single core from the Self-unit. The only core available to us was from northern part of the Glenn Pool field. We did not believe that it would be representative of Self-unit.

- We intended to run micro-imaging log to obtain detailed geological architecture. To run the micro-imaging log, we needed an open hole. With the existing wells, no open hole was available.

- We wanted to use cross borehole tomography to generate cross section information between two wells. To properly obtain the image of the reservoir, the well needs to be drilled deeper than the formation. All the existing wells were drilled to the total depth of Glenn Sand. To properly obtain the cross borehole imaging information, we needed to have at least one well 400-ft deeper than the bottom of the Glenn sand.

In view of the above considerations, a vertical well was drilled in the Self-unit at the end of 1993. The location of the well, Self-82 is shown in Figure 2. The location was decided based on preliminary geological mapping, as well as distance considerations from the surrounding wells. The well was drilled 400-ft deeper than the Glenn sand. It was cored, a suite of modern logs, including micro-imaging log, was run successfully. The well was completed in January 1994.

Using this well as a source well, three cross bore hole tomography surveys were conducted between Self-82 and the surrounding three wells. With the help of a modified geological description as well as geophysical and engineering data, a detailed reservoir description was constructed using geostatistical methodology. After validating the description by comparing the simulated flow performance with the historical data, several operating scenarios were simulated to optimize the flow performance under modified conditions. A combination of recompletion and stimulation of most wells followed by increasing the water injection rate in the field was observed to be the most optimal change to improve the flow performance of the Self-unit.

The proposed reservoir management plan was implemented, and the unit performance was monitored for over three years. At the base level, the Self-unit was producing between 15 to 17 bbls/day. The initial increase in the incremental oil production was predicted to be in the range of 15 to 32 bbls/day (see **Figure 4**). The cases in Figure 4 represent the use of different relative permeability curves. The actual increase was 24 bbls/day (see **Figure 5**). After 3 years, the incremental increase was predicted to be about 10 to 12 bbls/day. Currently, the field is producing

10 incremental bbls of oil per day over its base rate. In short, we were able to correctly predict the performance of the reservoir. Although in terms of actual production, this increase is not much, note that it still represents about 150% increase in the production. Further, the field is more than 90 years old, and has been subjected to many technologies in the past. If we can cost effectively increase production from such a mature field, we would be able to do better in other, relatively younger, fields. The economic evaluation indicated finding cost of oil is in the range of $4.80 to $6.00 per barrel. This cost can be reduced substantially (to about $2 to $3 per barrel) if we only use the cost-effective technologies and eliminate the use of other technologies.

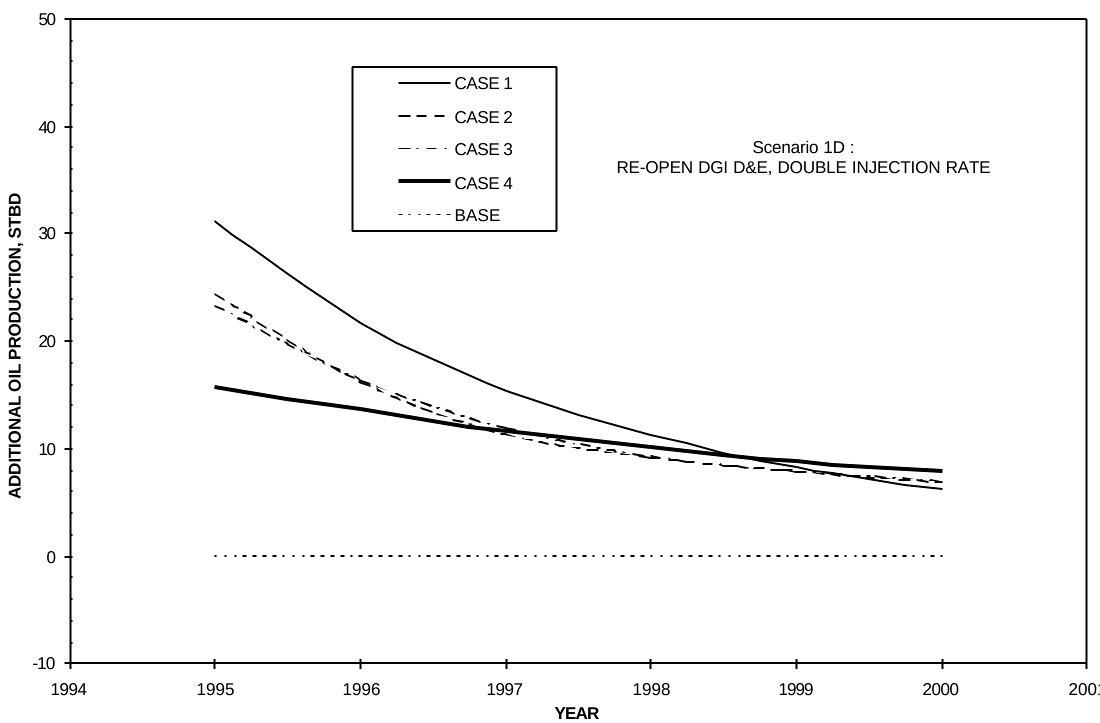

Figure 4 – Incremental production rate for the Self-unit for various cases

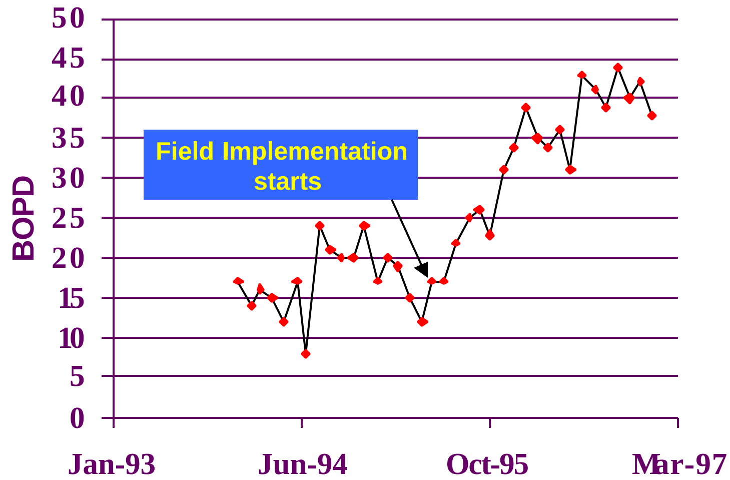

Figure 5 – Results of field implementation

In the following sections we will describe various technologies used in improving the reservoir description. Here, we only provide the summary of the technologies. The details can be found somewhere else.[2]

Evaluation of Various Technologies

In this budget period, we used several modern technologies. In this section, we briefly describe the technologies and their value to the project.

<u>Integrated Approach</u>

We made a concerted effort to integrate information from various sources to better understand the reservoir. Geophysical, geological, and engineering data were used to better describe the reservoir properties. In addition to interdisciplinary nature of the project, this project also involved active participation from government, the university, a small oil company and a major oil company. The biggest benefit of working together among such a diverse group of people is understanding and appreciating each other's language and perspective on the issues at hand. Communication between different disciplines helped us better understand what each discipline considers to be an important part of the reservoir description. We tried to create a good balance between the form of the reservoir (architecture) and the function of the reservoir (production performance). Interaction among various entities during the project made us aware of each other's priorities and each other's objectives. Although the objectives of each organization did not always coincide, we learned to appreciate and respect each other's objectives. This helped us in proceeding in the project in an optimal way.

Cross Borehole Tomography

Cross borehole tomography is a method by which an inter well image of reservoir characteristics is constructed by using an acoustic source in one well and receivers in another well. We conducted three such surveys with the help of Amoco Production Company and Conoco. The surveys were conducted between well pairs 82-63, 82-64 and 82-81. The collected data were processed by Amoco, using a public domain software and by Memorial University in Newfoundland, Canada. In addition, data were also provided to a group of scientists from Imperial College. Depending on the assumptions involved in the software, the results obtained from the three methods were significantly different. The results are in the form of sonic velocity distribution across the well pair. We used this information by relating the velocity to the porosity and the facies at the well location. The use of these data slightly improved our reservoir description. Because of the high cost of acquisition and significant uncertainty in the interpretation, the use of cross borehole data were limited.

Formation Micro-Resistivity Borehole Imaging

We used this tool in the newly drilled well 82. Along with the resistivity imaging, we also cored the desired interval. Formation Micro-resistivity imaging tool produces a high-resolution resistivity of the wellbore. Analysis of the image provides spatial orientation of architectural elements in the vicinity of the wellbore. By combining the information from the core data and the imaging tool, we were able to describe the geological heterogeneties at higher resolution level than otherwise possible with conventional well logs. Unfortunately, we were not able to use this detailed information in an effective way in flow simulations due to computer memory limitations. For a mature, shallow, oil field with marginal oil production, the detailed knowledge of geological structure may not be important in predicting unswept reservoir and preferential flow paths. The cost benefit analysis of using micro resistivity log versus taking an oriented core needs to be evaluated further before reaching the final conclusion on the utility of these type of logs. The preliminary analysis indicates that micro-imaging log may not be very valuable in terms of adding incremental value compared to taking a core sample.

Discrete Genetic Interval (DGI) Evaluation

Using the data collected from all the wells, we were able to construct a detailed description of geologically distinct units deposited during a limited time interval. This information was extremely valuable in understanding the vertical as well as areal heterogeneties. Previously, Glenn sand was divided into three basic units - upper, middle, and lower. With the help of DGI approach, we were able to divide the sand in six geological units. This detailed geological description helped us in flow simulation as well as in our overall reservoir management planning.

Geostatistics

Geostatistics is a procedure by which inter well properties are described using all the available information. Geostatistics assumes that the reservoir properties are spatially correlated, and this correlation can be quantified by a method called variogram analysis. Geostatistics further allows us to quantify uncertainties in describing these properties. Using geostatistics as a tool, we were able to describe the spatial relationships for geological facies as well as the petrophysical properties. By using the relationship between the seismic velocity and the porosity, we were able to use the cross borehole data to improve the spatial relationship for porosity at inter well distances. Using a geostatistical technique called conditional simulation; we generated geological facies image. The comparison between the simulated image and the geologist's view of the reservoir indicated good results. This provided us the confidence that the architecture of the reservoir is preserved. Using the geological description as a starting point, alternate images of the petrophysical properties (permeability and porosity) are constructed by further integrating engineering and geophysical information. Overall, geostatistics was a valuable tool in constructing realistic reservoir descriptions.

Flow Simulation

Once the reservoir description was constructed, we used the ECLIPSE commercial simulator to simulate the reservoir performance. We used both the deterministic (conventional, "layer-cake") as well as geostatistical reservoir descriptions for simulation purposes. Typically, the number of grid blocks in the simulator is less than the number of grid blocks in geostatistical simulation. As a result, appropriate up scaling procedure is used to scale the petrophysical properties suitable for simulation purposes. Since the performance data from individual wells were not available, we could only match overall unit performance. After matching the historical oil production performance, we projected the future oil production performance under various scenarios to understand the benefits and the drawbacks of various alternatives.

With increasing speed of computers, flow simulation technology is becoming increasingly viable for small operators. Field simulations can be conducted on personal computers without much difficulty. We believe that flow simulation will be an integral part of future reservoir evaluation procedures.

BUDGET PERIOD II

Introduction

In the second budget period, we extended our efforts to other parts of the Glenn Pool field (see Figure 1). This part of the Glenn Pool was also operated by Uplands Resources, Inc. The main idea behind the second budget period is to apply conventional technology to develop reservoir management plan. Unlike the first budget period, where modern technologies such as micro-resistivity logs and cross bore hole tomography data were collected, in the second budget period, the analysis relied on more conventional data. Any use of modern technology was restricted to the analysis and interpretation of the data.

Data Collection

During the second budget period of the project, we intended to concentrate on tract 7 and surrounding areas. tract 7, another 160-acre unit in southern Glenn Pool field, is located about 1 mile north of the Self-unit. The emphasis of the second budget period is to use conventional technology and knowledge gained from advanced technology of the first budget period (FMI, cross-well tomography etc.) in developing an effective reservoir management plan.

Study of tract 7 and adjacent area involved data compilation, well log correlation of DGI's, and facies architecture reconstruction. For a better and more complete description of tract 7, its adjacent areas including tract 6, tract 10, tract 12, tract 13, tract 11, part of tract 3, tract 4, tract 33, and Corbray unit are included into the mapping area, with total area about 1.6 square miles. Subsequently, the area of coverage was expanded to include additional areas in the southern part of the Glenn Pool field including tract 9 and Chevron miceller-polymer unit which is directly north of tract 9, and is directly west of tract 6 (see **Figure 6**). Figure 6 shows the area of concentration. In addition to the existing logs, six new Gamma Ray logs were acquired to compliment the existing data. Five of them are in the tract 7 unit (well numbers: 7-97, 7-99, 7-100, 7-103, and 7-107), and the other one (11-82) is in the tract 11 unit. There is a suspicion that upper part of the Bartlesville Sandstone in tract 7 area may contain a gas cap. Thus cased-hole neutron logging (TDT) was also performed for three wells (well numbers: 7-97, 7-103, 7-107). These TDT logs do not show any evidence of gas.

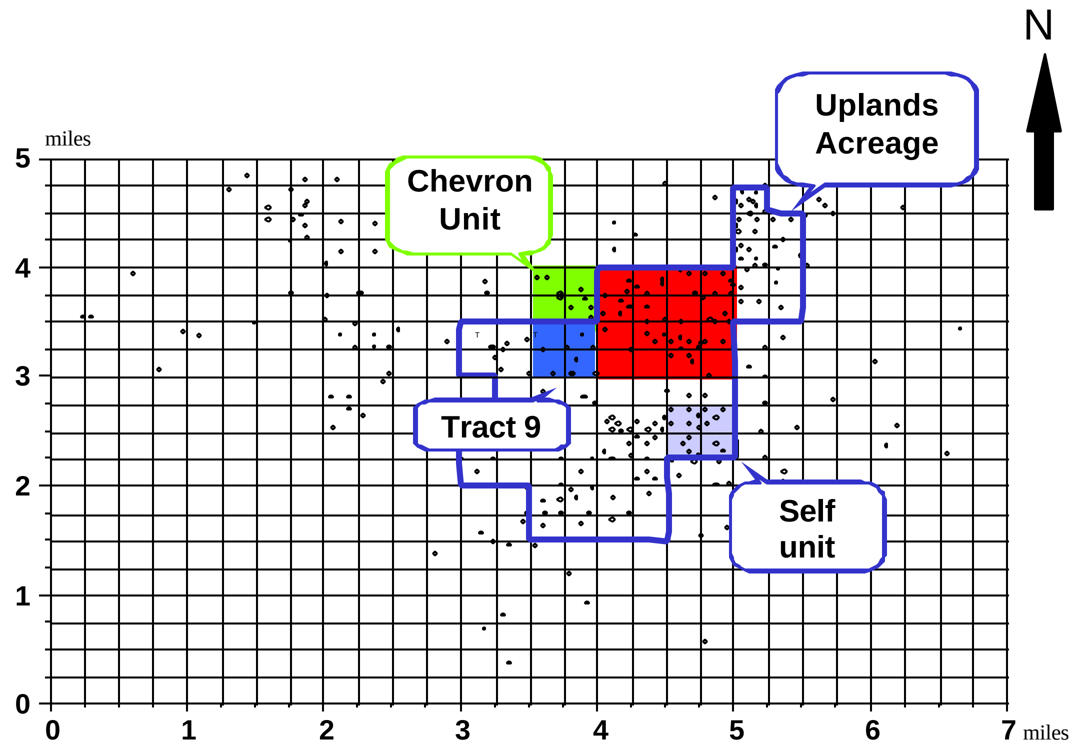

Figure 6 - Area of concentration

Reservoir Evaluation

We evaluated the entire area operated by Uplands Resources for the second budget period. In addition, we also evaluated an adjacent unit, which used to be operated by Chevron. The Chevron miceller-polymer unit was successfully flooded in early 80's using miceller-polymer flood. We wanted to understand the reasons for the success.

Since it was difficult to study all parts of the reservoir in great details, we graded the reservoir based on a method of potential index mapping. This mapping involves evaluating various areas in the reservoir based on the permeability, thickness, porosity, saturation as well as prior access to that area by already existing wells. A reservoir with high conductivity and high storativity is given higher productivity index. Depending on whether the area of interest is drained by already existing wells, potential index is calculated. A region with higher potential index is investigated further, whereas, the region with low potential index was eliminated from further consideration. In addition to potential index mapping, we also examined the primary and secondary recovery production from various units. Based on the grading of various parts of the reservoir, we decided to concentrate on tracts 7 and 9.

We began our evaluation by studying Chevron unit. Our evaluation indicated that the success of the Chevron unit could be partly attributed to re-completion of the upper intervals in Glenn sand. Unlike other operators, Chevron concentrated on the upper and middle Glenn sand, and implemented the miceller-polymer flood in those sands. The increase in oil production as well as reduction in water cut was substantial. We re-simulated Chevron unit assuming that it is water flooded with same completion as Chevron had used. The response indicated that Chevron would have achieved substantial increase in the oil production with reduction with water cut just by using water flood. Although not as impressive as miceller-polymer flood, the simulation indicated to us that we can use similar approach in other parts of the field.

We studied both tracts 7 and 9, and investigated various scenarios for improving the performance of those units. For tract 9, we observed that drilling of a deviated producing well will result in the most improvement in the production. For tract 7, we observed that re-completion and stimulation of upper intervals will result in the most improvement in the production.

Based on our evaluation, we decided to drill a deviated well in tract 9, which would be completed in the upper and middle part of the Glenn sand. The location is shown in **Figure 7**. The deviated producing well will be supported by three injectors; one in the north and two in the south. To achieve the drilling in a cost-effective manner, we employed a relative new technology of surface steered drilling which is much cheaper than conventional deviated hole drilling. Unfortunately, drilling of deviated hole proved to be much more challenging than anticipated. We lost the drilling assembly twice. During the second time, we could not fish it, and the hole had to be abandoned. As a result, our reservoir management plan during the second budget period could not be validated. Because of budget constraints, another attempt at drilling the deviated hole could not be made. Hopefully, private owners would take an initiative, and with favorable oil price, drill deviated wells in the same field to validate the concept.

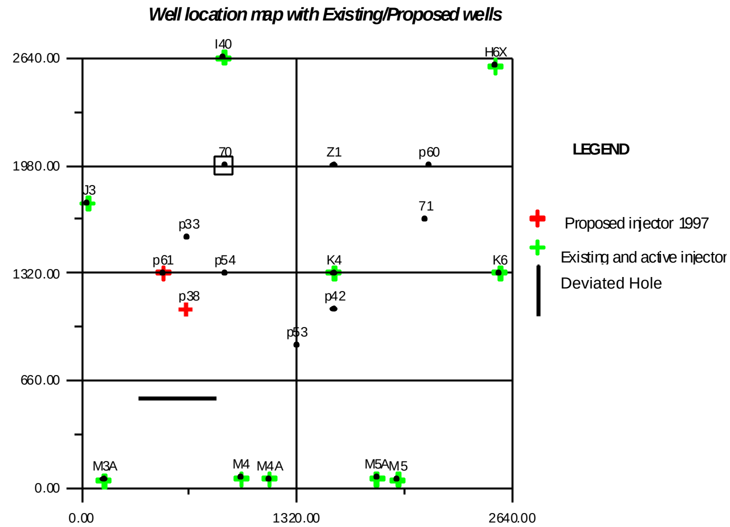

Figure 7 - Proposed management plan for tract 9

Evaluation of Technologies

The two new technologies we pursued in this budget period were the use of production index technique to grade the reservoirs, and the use of surface steered deviated hole drilling. The use of production index technique was proved to be extremely valuable in describing the reservoir in terms of quality. The reservoir was effectively divided into two regions. One with high quality with a potential to recover more oil, and one with low quality because of either poor petro-physical properties or by the fact that the area is already been drained by existing wells. This tool has lot of practical applications since the type of data required to apply the method is limited and is easily available.

In contrast, the use of surface steered tool to drill the deviated hole proved to much more difficult than anticipated. Although the technology has been used in the past in some reservoirs, this was the first time it was used in a mature reservoir such as Glenn Pool. For the technology to be cost-effective, the well had to be drilled with a reasonable cost. Our expected cost was less than $150,000, which would have three times more than a typical vertical well. In reality, the actual cost was more than $300,000, and the well was never completed. There is no question that the technology needs to be perfected to make it more reliable and cost effective.

TECHNOLOGY TRANSFER ACTIVITIES

To compliment our technical effort, we vigorously pursued various technology transfer activities. These activities resulted in 26 publications and 10 presentations. In addition, four technology transfer workshops were conducted for the benefit of small operators and independents. These workshop locations included Tulsa, Houston, Denver and Ft. Worth. We also published two news-letters and sent them to over 300 interested parties.

SUMMARY

Looking back at the project, we can conclude that, although the project ended on a sour note, we were able to demonstrate that cost-effective technologies can be used to improve the performance of marginal oil fields. We evaluated various technologies, and determined their cost effectiveness for future use. We also demonstrated the usefulness in describing the reservoir using integrated information so that we will be able to better predict the future performance of the reservoir. The success is further satisfying by the fact that Glenn Pool field is 90 years old. If we can demonstrate that the field can be rejuvenated with cost effective technologies, there are many other younger fields, where the technologies would be much more useful.

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