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

Annual Report

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**Prepared for
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Abstract

This annual report describes the progress during the first 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 fluvial-dominated deltaic deposits. The project involves an integrated approach to characterize the reservoir followed by drilling of horizontal injection wells to improve production performance. The type of data we intend to integrate includes cross bore hole seismic surveys, geological interpretation based on logs and cores, and engineering information.

This report covers the first phase of the project which includes a detailed reservoir description of the field based on the available information, followed by flow simulation of the Self Unit to compare the simulated result with the historical performance. Based on the simulated results, a vertical test well was drilled to validate our reservoir description. The well will also be used as a source well for a cross bore hole seismic survey. This report discusses the related geophysical, geological and engineering activities leading to the drilling of the vertical test well. The validation phase and the collection of the cross bore hole survey has just begun, and the results will be presented in the next annual report.

Executive Summary

The annual report discusses the approach taken in generating an integrated reservoir description of a mature oil field. Phase I of the project focuses on the Self Unit, a 160-acre tract of Glenn Pool field operated by Uplands Resources, Inc. The present data available from the field are wireline logs and core reports, and historical production records. Using log and core data, the reservoir was first divided into seven DGI's, each composed of contiguous facies deposited during a limited, discrete increment of time. Based on the analysis of log patterns, five facies have been distinguished: channel fill, splay, channel-mouth bar, levee, and interdistributary mudstones.

Using the geological information, a reservoir description was created using a conditional simulation method. The DGI's were defined in terms of categorical variables, and using the information at the well locations, descriptions of all the DGI were created and compared with the geological interpretation. The match between the two was judged to be reasonable. Using the geological interpretation, petrophysical properties for each individual DGI were described using the conditional simulation method. With the help of this description, a flow simulation was conducted and the simulated flow performance was compared with the historical flow performance. The match between the two is good. Using the resulting simulated values, saturation maps were constructed and a vertical test well location was proposed for further validation. The drilling of the vertical test well and the collection of logs and core is complete. Further analysis is in progress and will be reported later.

In addition to geological and engineering information, we will also collect geophysical information through cross bore hole seismic data. To test the validity of this method in the present application, a successful test was conducted between two existing Self Unit wells. The results of that test are presented in this report. Based on that test, it was determined that the distance between the newly drilled well and the surrounding four wells is adequate for collecting the cross bore hole data. The collection of the seismic data is in progress. The results and the analysis of the cross bore hole data will be reported subsequently.

Annual Report

Introduction

The overall report is divided into four sections. In this section, we provide the background of the field which is the subject of investigation. In the second section, we discuss the development of the geological description based on the wireline log data and the available core reports. In the third section, we discuss the process of quantifying the geological and petrophysical information through geostatistical methods, and we discuss the flow simulation of the developed reservoir description which was used to finally decide the vertical test well location. The final section describes the geophysical testing which will lead to acquisition design for the cross bore hole survey.

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. The field is near the center of the Northeast Oklahoma platform which is situated between the Ozark uplift to the east, the Nemaha ridge to the west, and the Arkoma basin to the south (Figure 1). 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 (Figure 1). The well was 1458 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.

Initial wells were drilled by cable tools. Surface casing of 8-5/8 inch size was set at 275 ft. and open hole drilling was carried out to the top of Bartlesville reservoir. The hole size was

reduced to 6 inches through the pay zone interval. The producing interval was shot with 250-300 quarts of nitroglycerine, casing set to the top of the sandstone, and the shot hole cleaned out. By 1906, well drilling averaged at the rate of 3 wells per day and in this process orderly spacing of the wells was neglected. Subsequently, the completion was on a ten-acre pattern. Earthen lakes were used for storage on many leases, and oil was shipped to the Texas Gulf Coast by railroad. In 1908, 100 companies were operating in the field. By 1912, several BCF of natural gas is estimated to have been flared, vented or used as fuel for lighting field operations. The field limits had been defined by 1920. A pipeline through Coffeyville, Kansas connected the field to Chicago and Great Lakes markets. By 1926, 22 refineries served the area.

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.

Reservoir

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 1500 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 1100 psi.¹

From regional studies, the Bartlesville Sandstone is regarded as having been deposited by a fluvial-dominated delta system.² In the Glenn Pool field area, the Glenn Sand is predominantly the deposits of delta plain depositional environments. The lower Glenn sandstones are subangular to subrounded, moderately sorted, silty fine- to medium-grained sandstone, with abundant sand-size rock fragments, and thin beds of shale and siltstone.¹ The

lower non-porous break consists of interbedded, laminated silty sandstone and shale with localized thin beds of shale, sideritic clay pebbles and with intervals of carbonate-cemented sandstone.¹ The middle Glenn is subangular to subrounded, and well sorted fine- to very-fine-grained sandstone.¹ It is primarily massively bedded, with portions containing medium-scale crossbedding.¹ The middle Glenn forms the major part of the reservoir.

The upper non-porous break consists of thin silty shale or interbedded laminated, silty sandstone and silty shale.¹ It is an effective permeability barrier but limited lateral extent may result in localized contacts between the upper and middle Glenn. The upper Glenn is in part massively bedded and in part medium-scale crossbedded. It is a angular to subangular, moderately sorted very-fine to medium-grained sandstones,¹ and contains abundant carbonaceous fragments and a few sand-sized rock fragments. The upper portion of the upper Glenn contains poorly sorted very-fine- to medium-grained sandstones with silty interlaminations, sparse carbonate or silica cement, and visible porosity.

Self Unit

The Self Unit, area of investigation of project Phase I, is a 160 acre tract located in south-east portion of Glenn Pool oil field in section 21-17N 12E (Figure 2). 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. ARCO's report by Welch³ on the Glenn Sand Unit gives a brief history about the performance of 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 2000 barrels of water per day. Current oil production is 25 barrels of oil per day with 95% water cut.

Data Collection

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 lease-wide production records are not available before the year 1935. Well chronology has been established by analyzing two well maps, well map as of 8/12/55, well map as of 5/15/81 and the other sparsely available well records. Information pertaining to the number of producing wells each year is available from production documents but information regarding the location or respective number had to be estimated based on the documents mentioned above. The chronological development of the Self Unit on a well by well basis is included in Table 1. The well map depicting all the wells drilled in the Self Unit is shown in Figure 3. Initial development occurred along the periphery of the unit; subsequently, development occurred in the interior.

As already mentioned, the unit was put to production in 1906, though no exact date could be found. Welch's report³ lists the cumulative production through 1946 as 1.809 MMBO. Yearly production information from 1935-1906 has been extrapolated based upon the number of wells operating in the respective years and the production information for the years 1935-1946. From 1936-1972, the yearly estimation has been carried out on the basis of production information available for one month, three months, or in some cases six months. 1972 onwards production data availability are complete and detailed. Annual water injection and production rates are available for Self Unit and the adjoining Burrows lease combined. Data for individual leases

has been obtained based upon their respective oil production fraction. The overall production history based on the above information is summarized in Figure 4.

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.

Well schedule, water injection and production data have been summarized based on 1002-A forms, production reports, PI forms and other miscellaneous documents available with Uplands Resources and Oklahoma Well Log Library.

The first step in the development of reservoir description by using all the available information is to construct the geologic description. This step is discussed in the next section.

Geologic Description

(by Dennis Kerr and Liangmiao Ye)

Introduction

Geologic analysis goals for project year one were two fold: (1) develop a geologic description of the Glenn Sand for the Self Unit using existing data, which for the most part consists of well logs, and (2) assist in the selection of the vertical test well location, where whole core and microresistivity borehole imaging will assist in further analysis. Both goals were achieved, and working results from the geological analysis were used in the engineering analysis and design of the crosswell tomographic survey.

Stratigraphic framework of the Glenn Sand reservoir in the Self Unit has been established through a series of northeast to southwest stratigraphic cross sections. Some cross sections extend on southwestward into the adjacent Burrows Unit. The Inola marker is a thin interval (1-2 ft.), expressed as high gamma ray and conductivity log response, and occurs about 12 ft. above the Glenn Sand (Figure 5). In addition, two thin intervals, expressed as high conductivity log response, are also used as markers in those wells that penetrate to 50 ft. below the Glenn Sand. The marker beds are used as a horizontal reference, and all correlations are considered as elevations relative to the Inola marker. The Glenn Sand in the vicinity of the Self Unit is divided into 7 stratigraphic units; each unit is a DGI (see below).

Shallow stratigraphic correlations were completed in the vicinity of the cross well tomography test in order to evaluate possible acoustic reflections observed in the test results. Wells included in the cross section are Self Nos. 72, 62, 55, 66, and 57. Stratigraphic zones identified between top of Glenn Sand (about 1,470 ft. drill depth) up to the top of the logged interval (about 500 ft.) include, in ascending order: upper Boggy Formation to top of the Inola Lime (at 1,370 ft.); Red Fork to top of Pink Lime (at 1,210 ft.); Senora Formation, including Skinner Sands to top of Verdigris Lime (at 930 ft.); lower Marmaton Formation, including Pure Sands to top of the Big Lime (at 750 ft.); and Nowata Shale up to the top of the logged interval. All stratigraphic units are continuous between the test source well (No. 72) and receiver well (No. 62), except the Skinner Sands which clearly terminate between these two wells.

Architectural Elements

A number of approaches have been suggested in the literature for the definition and delineation of the hierarchy of architectural elements that make up reservoirs⁴⁻⁷. One difficulty with these approaches, as well as others, is that undue attention is given to the element-defining surfaces as reservoir barriers or baffles. Although such surfaces may provide valuable information about the geometry of the associated architectural element, they are themselves not permeability barriers or baffles. Such surfaces are two dimensional entities possessing zero thickness; from the general conductance equation, as thickness approaches zero, the rate of flow approaches infinity. The emphasis should be placed on the rock properties of immediately underlying or overlying rock volume associated with such surfaces. Another difficulty arises from the limitations of technology and data available for subsurface analysis -- particularly from mature fields developed decades ago. To fully utilize many of the proposed approaches would require cores or high-resolution borehole images from every well in a field. Such information generally is not available, or it is too costly for independent operators.

The approach used in this study to develop the reservoir architecture for the Glenn Sand of Glenn Pool field differs somewhat from the approach of others. The fundamental subsurface mapping unit is a DGI.⁸ A DGI is defined as contiguous facies deposited during a limited, discrete increment of time. In the case of the Glenn Sand, a DGI likely corresponds to distributary channel avulsion on the delta plain of a fluvial-dominated delta. Each DGI, in this depositional setting, is delineated using the stratigraphic elevation of the top of the channel-fill facies and attendant splay and channel-mouth bar facies relative to the Inola marker bed (Figure 5). The Glenn Sand itself is a collection of seven DGI's in the vicinity of the Self Unit. The hierarchy of architectural elements considered here ranges from facies to DGI to set of DGI's, each element encompassing larger rock volumes, respectively.

Facies that make up the Glenn Sand are at this stage largely based on well log character and to a lesser extent on whole core description (see below). Five facies have been distinguished thus far: channel-fill, splay, channel-mouth bar, levee, and interdistributary mudstones. Channel-fill, splay and channel-mouth bar facies have reservoir quality porosity and permeability values. Interdistributary mudstones and levee facies are barrier or baffle rock.

Channel-fill facies is recognized by a bell-shaped log profile of combined spontaneous potential, gamma ray and resistivity logs. The basal 0.5 ft. commonly includes mudstone intraclasts that give way upward to a 5- to 10-ft.-thick interval of medium-scale through cross-stratified, medium-grained sandstone. Continuing upward for the successive 10 to 15 ft., the channel-fill facies is composed of ripple or parallel stratified, fine- to very-fine-grained sandstone interstratified with siltstone and claystone. The proportion of mud plus carbonaceous debris in the sandstones and interstratified mudrocks increases upward. Mud drapes are abundant throughout the channel-fill facies. This results in a serrated wireline log pattern. With additional core studies, the channel-fill facies may be divided into subfacies, which in turn, may be correlated to well log character and variations in reservoir properties. Within the channel-fill facies, localized isopach closures of the 10-ft. isogram typically encompasses 15 acres, and the centers of these closures are separated by 1,000 ft. along a channel-fill facies trend (Figure 6). The channel-fill facies sandstone obtains a maximum thickness of about 30 ft.

The splay facies is recognized from well logs by a funnel-shaped or symmetrical log profile. The splay facies is comprised of lower medium-grained sandstone containing a variety of physical sedimentary structures including fluid-escape structures. These sandstones are interstratified with siltstones and silty sandstones. In DGI A, the splay facies reaches a maximum thickness of 15 ft. in locations proximal to the channel-fill facies and pinches out zero up to 2,200 ft. away (Figure 6A). In other DGI's, the splay facies is more restricted in thickness and lateral extent (Figure 6).

The channel-mouth bar facies has a blocky well log profile that can be highly serrated. This facies is characterized by lower coarse- to upper-medium-grained sandstones containing carbonaceous debris throughout. Physical sedimentary structures, largely parallel stratification, are poorly developed in 1 to 2 ft. thick strata. Interstratified mudstones and mudstone ripup clast beds occur throughout. The channel-mouth-bar facies acquires a maximum thickness of 40 ft. at a channel terminus, and extends laterally beyond the limits of the Self Unit.

DGI's are delineated from the stratigraphic cross sections using the Inola marker as a datum. The Glenn Sand has been subdivided into 7 units (A descending through G; Figure 5),

each of which is a DGI. The superpositional relationship among DGI's is established by the elevation of the top of channel-fill deposits relative to the marker beds. As a working hypothesis, each DGI is a potential reservoir compartment.

A set of DGI's makes up the complete thickness of the Glenn Sand. Combination facies and facies-biased, net-sand isopach maps have been constructed for each of the seven DGI's. Units A through E are characterized by channel-fill and splay facies (Figure 6). Units F and G include a channel-mouth-bar facies (Figure 5). Thus, in the vicinity of the Self Unit, the Glenn Sand is represented by a retrogradational set of DGI's -- the vertical progression of DGIs recording the basinward advance of the fluvial-dominated delta system.

Summary

Geologic analysis goals, for this project term, were: (1) provide a geological description of the Glenn Sand in the Self Unit using the conventional data available, and (2) assist in the selection of the vertical test well location, and analyze the core and microresistivity image collected in the vertical test well. The first goal was achieved through construction and analysis of a stratigraphic cross section network followed by construction of combined facies and facies-biased, net-sand isopach maps. The second goal was completed by collaboration with the other project disciplines to identify an optimum vertical test well location. Data collected from the vertical test well are presently being processed and evaluated.

The fluvial-dominated deltaic deposits of the Glenn Sand comprise at least seven DGI's in the vicinity of the Self Unit. Reservoir facies include channel-fill, splay, and channel-mouth bar. Nonreservoir facies include levee and interdistributary mudstones. Each DGI is mapped separately with facies combined with net-sand isopach thickness. The lower two DGI's include channel-mouth bar facies at the terminus of the adjoining channel-fill facies; these two DGI's were the focus of early exploitation and are today largely depleted. The potential reservoir compartments in the upper five DGI's are made up of channel-fill and splay facies within a DGI, and the DGI's themselves. These upper DGI's have experienced more limited depletion, as evidenced by the well-site inspection of core from the vertical test well where oil was actively bleeding from distinct narrow stratal intervals. Thus, the project attention is focused on these upper DGI's.

Integration of Geological and Engineering Information

(by Bhupinder Ahuja, Asnul Bahar and Mohan Kelkar)

Integration of geological and engineering information was carried out in two stages. In the first stage, the geological information was established. In the second stage, the petrophysical description was constructed such that it honored the underlying geological information.

To establish the geological information, we treated individual DGI's as categorical variables. These variables are described in terms of indicator variables. In this approach, the data are not used in its actual form. The data are coded in the form of an indicator variable which can be written as,

$$\begin{aligned} I(x, v_i) &= 1 \text{ if } V(x) \leq v_i, \\ &= 0 \text{ if } V(x) > v_i \end{aligned} \quad (1)$$

where v_i is a threshold value. The indicator function is a binary function and takes a value as 1 or 0. An indicator variable is defined in terms of threshold value. There is one indicator function defined at each threshold. Selection of number of thresholds will determine the number of indicator values.

In this study, the thresholds have been related to the presence or absence of sandstone. $I(x, v_i) = 1$ if a particular DGI is represented by sandstone at a location, else, $I(x, v_i) = 0$ if that sandstone is absent at that location. Variogram and covariance, which describe the spatial relationship of a particular DGI, are calculated for each threshold.

The simulation takes place in a sequential manner. All the unsampled locations are visited in a random path and the equations are solved based upon either simple or ordinary kriging methods. The number of times the kriging method is used at a given location is equal to the number of thresholds. The results obtained for each unsampled point are in the form of a posterior distribution function which represents the probability of the value at that location being less than a given threshold. A uniform random number generator is used to convert the posterior distribution function into actual value of the variable at that location. We used the program SISIMPDF from the GSLIB software library.⁹ For details regarding how the program works, refer to reference 9.

Based on the geological description, the entire reservoir is described in terms of 7 DGI's. With the addition of shale, each well datum is described in terms of one of the eight indicator variables. Indicator eight corresponds to shale. A total of 20x20x158 grid blocks in x, y and z

directions, respectively, are used for the simulation. To ensure that the vertical stacking of DGI's is preserved as much as possible, the simulation is carried out in three parts. The first part contained DGI's A, B, C and shale. The second part contained remaining C, D and parts of E and F, and shale. The third part contained DGI's E, F, G and shale. In this way, the appearance of A below E, F or G is prevented in the simulated results (i.e., the Principle of Superposition is honored). For details regarding the simulation parameters including the variogram models, please refer to reference 10. The simulated results have been observed to honor the spatial relationships as well as the fractional contribution of each of the DGI's.

Further validation of the simulated results is done by comparing the simulated map view of DGI's with the geological maps. Figures 7 and 8 show the comparison between the simulated map views of DGI's A and C, respectively, with the maps constructed based on the geological information. The comparison is quite reasonable. In addition, the simulated results are also compared at cored well locations which were not included as conditional data. For these wells, only core reports were available. Using these core reports, the DGI descriptions at these wells were constructed. Since only partial cores were recovered, the location of markers at these wells is not precisely known. Figure 9 shows a comparison between the simulated and the actual DGI descriptions at Well #28. The comparison is reasonable except that there is some vertical shift. If the marker at Well #28 is moved by 5 ft. in the cored well, the match would be much better. Figure 10 shows a similar match for Well #37. For this well, the match is much better. Similar degrees of matches were acquired at other wells¹⁰ indicating a good replication of geological information. In addition to these data, the simulated descriptions of shales were also compared with the geological shale maps. The comparison was deemed satisfactory.¹⁰

Once the geological simulation was constructed, the next step was to describe the petrophysical properties consistent with the simulation. The conditioning data for the porosity values were the log-derived porosity values at individual well locations. As a first step, the porosity values corresponding to each DGI are isolated from each other so that the porosity description at every grid block is consistent with the underlying simulation. For each DGI, the porosity description for the entire reservoir was constructed using a simulated annealing program.¹¹ The variograms were generated based on well data for that particular DGI data only. Since we have divided the entire reservoir into 7 DGI's, the simulation has to be repeated seven times. For shale, we assumed zero porosity. With the help of seven simulations, now we had seven porosity values at each grid block. These seven values were then "filtered" through the geological simulation to accept the appropriate porosity value. For example, at a particular grid block, DGI B was present, the porosity corresponding to that DGI simulation was accepted at that grid block. Similar procedure is carried out at each of the grid blocks. This ensured that the

porosity values at individual grid blocks were consistent with the geological simulation. The generated porosity descriptions at different depths are shown in Figure 11. Although the porosity values are much higher at the bottom portion of the reservoir, these values are not shown here. This is because the logs collected in 1978 indicate that the bottom part of the reservoir has already been flooded because of its high permeability. Since the oil from the bottom part of the reservoir has already been produced, the zone of interest is predicted to be DGI's A and C. Once the porosity values are generated, permeability values are created by using a cross plot between the porosity and log permeability for individual DGI's.¹⁰

Flow Simulation

Once the geostatistical simulation was finished, the next task was to conduct the fluid flow simulation. The flow simulator ECLIPSE is used for carrying out the flow simulation. Due to hardware limitation, the number of grid blocks used in geostatistical simulation had to be reduced before the flow simulation could be run. The number of grid blocks used in geostatistical simulation was 63,200 (20 x 20 x 158) while in flow simulation it was 6400 (20 x 20 x 16). This reduction requires a process to average the petrophysical properties. A simple arithmetic averaging was used for porosity and horizontal permeability. For vertical permeability, harmonic averaging was used. The relative permeability curves used for simulation are shown in Figure 11. The capillary pressure curve is shown in Figure 12. The PVT properties are shown in Table 2.

In conducting flow simulation, several assumptions had to be made. A key assumption was the bottom hole pressures in the producing wells. No information is available in old well records. To investigate our assumption of 400 psi bottom hole pressure during early stages, the initial potential of wells based on the simulation was compared with the available initial potential data on some early wells. The comparison is shown in the Figure 13. We predicted the same order of magnitude estimates as the actual wells. Considering the uncertainties with respect to how these wells were completed, the match was deemed satisfactory.

The flow simulation was carried out over a period of 87 years starting November 1906. The comparison between the simulated and the observed performance is shown in Figure 14. Except for the early years, the simulation shows a good match with the Self Unit data. The general trends over the various phases of production, such as gas repressurized, pilot water flooding, and water flooding after redrilling, have been closely followed. The discrepancy between the simulated and the observed performance prior to 1936 can be attributed to :

- a. Non-availability of annual production.

Prior to 1936 no annual production data were available, only cumulative production was available. The authenticity cannot be independently validated.

- b. Based on well configurations during the early period, many wells were drilled on the periphery of the Self Unit. This may have resulted in draining part of the reservoir not belonging to Self Unit.

As a further validation of the simulation results, the oil saturation map based on the 1980 logs were compared with simulated oil saturation maps at the same period. The comparison is restricted to DGI C which has the maximum potential of additional producible oil. The comparison is favorable. See Figure 15.

Based on saturation maps and simulation results, a vertical test well was drilled. The data collected include 153 ft. of core, and a suite of logs including the microresistivity log (FMI). The core is currently being analyzed and the geological description constructed. Preliminary comparison between the actual observations and the predicted description has been encouraging. This well will be further used to compare our simulated observations with the actual observations. Also, the well will be used as a source well for cross bore hole seismic data collection between the test well and the neighboring four wells. The additional data collected from this well and the analysis of the data will be presented in the next annual report.

Summary

In this section, an approach is presented to combine the geological information and petrophysical information with the help of geostatistical tools for carrying out the characterization study of the Self Unit of Glenn Pool oil field. Petrophysical properties have been allocated honoring the statistics of the individual DGI's. The resulting description has been used to carry out flow simulation. Based on the results, the following conclusions can be drawn:

Given geologic information at the sampled locations, sequential indicator simulation technique can reproduce geological sand maps.

Results, when compared to the DGI's at the cored locations, which were never a part of the conditioning data, have yielded good match with the simulated results.

The technique has also resulted in giving a reasonable match between geological shale maps.

Based on the early records, modern day well logs, and the findings of this work, it can be said that there is very low additional potential in the DGI's D through G. DGI C was found to be the best target zone for future production.

The flow simulation result obtained using this methodology of reservoir characterization indicates a reasonable match with 87 years of historical production.

The region with favorable petrophysical properties and oil saturation has been proposed for a vertical test well.

Geophysical Description **(by Chris Liner and Gokay Bozkurt)**

Introduction

The role of geophysics in this project is primarily to supply crosswell seismic tomographic images of the reservoir between the vertical test well and four surrounding wells. These will be interpreted in collaboration with the geologic and engineering teams to gain knowledge of the internal geometry of the reservoir.

Crosswell Seismic Test

From meetings and discussion with Amoco personnel, it became clear by late spring 1993 that a seismic crosswell field test was needed at Glenn Pool. The primary goal was to test operational procedures and data acquisition parameters in advance of the full crosswell test scheduled in late 1993 or early 1994.

The test was conducted on August 24 and 25, 1993 between Wells #62 and #72 of the William B. Self Unit. The well locations are shown in Figure 16. The acquisition team consisted of equipment and personnel from Amoco Production Company's Tulsa Research Center (H. Tan, L. Colethorp and J. Beck). Also represented were The University of Tulsa (C. Liner, M. Kelkar and graduate students), Uplands Resources (D. Richmond, J. Helm), and the Department of Energy (R. Lindsey).

These particular wells were chosen because they were widely spaced (about 660 ft.) and intermittently shut in. Well #62 served as the receiver well and Well #72 as the source well. The seismic source is an annular piezoelectric transducer which produces a swept signal. For Day 1 shooting the signal sweep contained frequencies from 200-2000 Hz. Other acquisition parameters are listed in Table 3. The recorded data traces were cross-correlated with the pilot

sweep to create impulse-like correlated data traces. The correlation process allows more energy to be input over a time window (0.25 seconds) than could be injected by an impulsive source. An impulsive source of similar strength would be damaging to downhole equipment and the borehole. The test operation involved two wireline trucks, one each for source and receiver well, and a control truck. Each shot generated 6 channels of time-dependent data: one channel for each of the 3 receivers, one channel for the pilot signal, and two dead channels.

The receiver apparatus consisted of three hydrophones on wireline spaced 8 ft. apart. The hydrophones return electrical signals in response to the passage of acoustic, or sound, waves. The receivers are suspended freely in the borehole while the source is continuously moved in the receiver well. Both source and receiver wells must be fluid-filled for the crosswell system to operate.

Four common receiver fans were shot on Day 1, as shown in Figure 17. Also shown are the fan numbering system, extent of fans, lithology in source and receiver wells, well separation, and starting/ending depth associated with each fan. Some formation depths are also indicated. The lithology and formation depth information was supplied by the geology team based on well-log interpretation. The deepest sand unit in each well is the Glenn Sand which is the productive interval in the field. From the acquisition geometry we did not expect to determine velocity in the Glenn Sand itself during this limited test. The fans were acquired in the order 1, 2, 3, 4.

Fans 1-3 had source spacing of 16 ft. which allowed rapid traverse of the entire section of interest. This source spacing is very large, even for a typical tomographic survey. It was used for testing purposes only, and the total interval covered by sources in fans 1-3 was approximately 700-1500 ft. High-resolution reflection surveys require smaller source intervals. To test the feasibility of reflection work at Glenn Pool, fan 4 was shot with source spacing of 4 ft. This was accomplished by moving the source up one-half of the fixed receiver interval of 8 ft.

Vertical stacking is a method of improving data quality and suppressing random noise. The idea is to make repeat measurements without moving source or receiver and summing the repeat results to create a final trace. The signal-to-noise improvement achieved by this process is $\text{SQRT}[N]$ where N is the number of vertical stacks. Only random noise is suppressed by this technique. Source generated noise (such as tube wave energy) is not suppressed.

All fans from Day 1 used an 8-fold vertical stack. Figure 18 outlines the vertical stacking process. Each large star is a stacked source location and actual source locations are shown by small stars. Three stacked source positions are indicated. As the source is continuously moved

uphole, the source is activated 8 times in a 2 ft. zone centered on the stacked source location. The resulting traces are summed to form the stack trace at this level. The vertical stacking process is valid if the stacking interval is much less than a seismic wavelength. We estimate the P-wave wavelength in the data to be approximately 12-13 ft., and the S-wave wavelength approximately 6 ft. Therefore, the 2 ft. vertical stacking interval is valid for both P and S waves.

Data acquired on Day 1 is shown in Figure 19. Each image is a common receiver fan. The vertical scale on each plot is travel time in milliseconds ($1 \text{ ms} = 10^{-3} \text{ sec}$) and horizontal axes show source depth. In general, the data quality and signal transmission are good. First arrivals (which are the basis of tomographic processing) are well defined. Significant events beyond first arrival energy are also present. These are some combination of direct shear waves, reflected P & S waves, and tube waves. The 16 ft. source spacing on fans 1-3 give the direct arrivals large time delays as source/receiver separation increases. Fan 4 has 4 ft. source spacing and indicates reflection energy beyond the first arrival. These reflections are important as a source of high-resolution information about the rock configuration.

Figure 20 shows a detailed plot of data from fan 1 in a time window near the first arrivals. This shows good continuity of first arrivals, and first arrival amplitudes which are significantly above background noise levels. When first break amplitudes fall below background level (as on the left-hand-side of Figure 20) first breaks cannot be picked for use in tomography. This gives a constraint on the maximum operating range of the crosswell acquisition system. This operating range varies with geographic location and reservoir depth.

Figure 21 indicates how direct arrivals weaken with angular source/receiver separation. Calculations based on data from fans 1-3 indicate the maximum transmission distance for direct arrivals at the Glenn Pool site is about 735 ft. This is sketched in the upper drawings of Figure 21. The lower drawing of Figure 21 shows this limit for the case anticipated for the full crosswell test. Here we expect well separation of 450 ft., so the 735 ft. maximum range corresponds to a maximum source/receiver angle of 52° . This is in excess of the design criteria of 45° . It follows that we should have good direct arrival energy at maximum acquisition angles in the vertical test well.

A major attraction of crosswell seismic data, relative to surface data, is its higher frequency content. Figure 22 shows selected traces from fan 1 detailed around first arrival events. These data have been processed to enhance the first arrivals. The spectrum plot in Figure 22 indicates significant frequency content from 300-1300 Hz. No surface seismic data exists at Glenn Pool,

but typical surface seismic frequencies are 20-80 Hz. Thus, crosswell seismic data gives a 10-to-20 fold increase in resolution relative to surface seismic data.

Day 2 of the crosswell test followed up ideas and concerns identified on Day 1. The shooting geometry is shown in Figure 23. Four additional fans were acquired. Fans 5 and 6 have source level spacing of 16 ft. These were designed to test maximum signal range by shooting with large vertical source/receiver separation. The data from Day 2 shooting are shown in Figure 24. The longest source/receiver separation occurs in fan 6. The signal is clearly seen to fade into background noise levels on the left-hand-side of the fan 6 plot in Figure 25. At this range no useful source-generated energy was detected. This test fan reinforced the maximum range calculations derived from Day 1 data.

All of the Day 2 data were shot with a source band width of 400-2000 Hz. This change from 200-2000 Hz on Day 1 was in response to low frequency noise interpreted in the Day 1 data. Tube wave noise which can degrade the data has a typical frequency of about 200 Hz. The 400 Hz low-cut had a nominal effect on the desired data quality.

Fans 7 and 8 are reflection-quality common receiver fans with 4 ft. source spacing. These are near reservoir depth and may contain reflections from the reservoir itself. These two fans were shot with the first source in each fan vertically offset by 2 ft. That is, the source levels in fan 7 are at depth levels 1488, 1484,, 1276, while fan 8 has source levels 1490, 1486,, 1278. This acquisition geometry allows the data traces to be interleaved to an effective spacing of 2 ft. The interleaved fan is shown in Figure 26, and should be compared to the same zone covered with 4 ft. spacing by fan 8 that is shown in Figure 27. The strong linear events are tube wave energy. Clearly some advantage has been gained by the 2 ft. spacing, and further interpretation of this data is under way.

Also on Day 2, a vertical stack test was performed as part of fan 5. The source interval 800-928 (fixed receiver location) was shot once with 8-fold vertical stack and again with 32-fold vertical stack. Figure 27 shows the resulting data. The 32-fold data (lower plot) stand out slightly better from background noise level. On the amplitude spectra plots, the 32-fold data show some improvement in signal strength in the 1500-2000 Hz range. Overall, the effect is a minor improvement in data quality. Based on this result, an 8-fold vertical stack will be used in the full survey.

Crosswell tomography involves picking first arrival times on crosswell seismic data and inverting for a velocity distribution between the wells. The quality and reliability of the tomogram depends on highly redundant data. If a great number of travel times are available then the velocity field is well-constrained. With fewer travel times the solution is not unique. Crosswell data acquired during the test is insufficient for full tomographic reconstruction. However, using all Day 1 data we were able to build the partial tomogram shown in Figure 28. On the left is the lithology section from Well #72 (source well). The velocity tomogram is shown in the center. Velocities are indicated by various levels of gray as shown by the gray bar on the right. Comparing the tomogram in Figure 28 to Figure 17, we see coverage for the various fans is clearly visible. The velocities should be viewed with caution due to insufficient data for full inversion. The average velocity in well-illuminated zones is about 12,000 ft./sec. (This is in very good agreement with sonic log velocities from the Self Well #82, the vertical test well. The average sonic velocity at a depth of 1000 ft. in Self Well #82 is 11,800 ft./sec.). The tomogram in Figure 28 was constructed using about 200 travel times, or rays. We expect each tomographic image plane in the full survey to involve several thousand rays.

Vertical Test Well Location

In December, 1993 the vertical test well was drilled on the Self Unit. This well is number 82 as shown on Figure 16. The location of 82 was decided in a series of team meetings during the third and fourth quarters of 1993. From a geophysical point of view, this location was acceptable because the four surrounding wells are close (about 330 ft.) and formed perpendicular seismic image planes. This configuration seemed optimum for delineating reservoir features of interest, and we anticipate using the well 82 as source well in each of the four crosswell surveys.

Summary

A 2-Day crosswell seismic field test was conducted in late August, 1993. The test was successful in determining operational procedures and parameters for the full crosswell survey scheduled for early 1994. Based on the test results, we expect good to excellent data quality in the Self Well #82 survey. The test results were also important in deciding the vertical test well location, which was drilled in December, 1993.

References

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Figure 1: Location of Glenn Pool Oil Field (Kuykendall and Matson¹)

Figure 2: Self Unit Location (Kuyendall and Matson¹)

Figure 3: Well Locations

Figure 4: Production History of Self Unit

Wm B Self No. 59

Figure 5: Well log for part of the Self No. 59 well. Units A through G are each a DGI. Note Unit B is missing by erosional truncation prior to deposition of Unit A at this well location.

Figure 6 Combined facies and facies-biased, net-sand isopach maps for discrete genetic intervals A, B, and C. Note that DGI B is markedly truncated along its north, west, and south flanks by erosion prior to deposition of DGI A.

GEOLOGICAL

Figure 7: Comparison of Simulated Sandstone Unit A with Predicted Geological Model

GEOLOGICAL

Figure 8: Comparison of Simulated Sandstone Unit C with Predicted Geological Model

Figure 9: Simulation and Core Derived Sandstone Units for Well #28

Figure 10: Simulation and Core Derived Sandstone Units for Well #32

Figure 11: Relative Permeability Curve

Figure 12: Capillary Pressure Curve

Figure 13: Initial Potential of Self Unit

Figure 14: Simulated and Field Performance of Self Unit

Figure 15: Oil Saturation Map for Snadstone Unit C

<u>Well Pair</u>	<u>Distance (ft)</u>
62-72	660
82-81	313
82-63	294
82-64	333
82-59	333

Figure 16: Location Map

Figure 17: Glenn Pool Crosswell Test Survey Acquisition Geometry (Day 1)

Figure 18: Vertical Stacking Procedure

Figure 19: Common Receiver Fans Acquired on Day 1 of Test

Figure 20: Detail of Fan 1 Direct Arrivals

TEST SURVEY

Sketch Seismogram indicating the first arrivals and Data Quality

Crosswell coverage

PLANNED WELL SPACING

Figure 21: Predicting Data Quality for Full Crosswell Test

Fan 1

Spectrum-1248

Figure 22: Data Window and Amplitude Spectrum from Fan 1

Figure 23: Glenn Pool Crosswell Test Survey Acquisition Geometry (Day 2)

Figure 24: Common Receiving Fans Acquired on Day 2 of Test

Figure 25: Interleaved Common Receiving Fan Created from Fans 7 and 8.
Source Interval = 2 Ft.

Figure 26: Common Receiver Fan 8. Source Interval = 4 Ft.

Fan 5: 8-fold stack

Spectrum-864

Fan 5: 32-fold stack

Spectrum-864

Figure 27: Vertical Stack Test from Fan 5

Figure 28: Preliminary Velocity Tomogram Using Fans 1, 2, 3 and 4

Year	No. of Producers	Gas Injectors	Water Injectors	Water Disposal	Drilled	Plugged	Remarks
1906	5	-	-	-	5(1,2,3,4,7)	-	1,2,3,4,7
1907	27	-	-	-	22(5,6,8-27)		1-27
1911	26	-	-	-	-	1(4)	1-3,5-27
1923	24	-	-	-	-	2(3,5)	1,2,6-27
1927	20	-	-	-	-	4(11,12,17,18)	1,2,6-10,13-16,19-27
1930	18	-	-	-	-	2(19,24)	1,2,6-10,13-16,20-23 25-27
1936	18	-	-	-	-	-	1,2,6-10,13-16,20-23 25-27
1946	16	4(21,28,31,32)	-	-	5(28-32)	1(27)	1,2,6-10,13-16,20,22,23 25,26 Inactive 29,30
1947	19	5(21,28,31,32,37)	-	-	7(33-39)	-	1,2,6-10,13-16,20,22,23 25-26,29,30,33 Inactive 34-36,38-39
1948	25	6(21,28,31,32,37 43)	-	-	6(40-45)	-	1,2,6-10,13-16,20,22,23 25-26,29,30,33,34,35,36 38,39,40 Inactive 41,42,44,45

Table 1: Historical Information of Self Unit

1950	27	8(21,28,31,32,37 43,47)	-	-	2(46,47)	-	1,2,6-10,13-16,22,23,25,26 29,30,33-36,38-42,44 Inactive 20,45,46
1954	27	8(21,28,31,32,37 43,47)	3(22,48,49)	1(20)	2(48,49)	-	1,2,6-10,13-16,23,25,26 29,30,33-36,38-42,44-45 Inactive 46
1957	28	-	11(21,22,28,31,32 37,43,47,48,49,50)	1(20)	1(50)	-	1,2,6-10,13-16,23,25,26 29,30,33-36,38-42,44-45 46
1965	28	-	12(21,22,28,31,32 37,43,47,48,49,50,51)	1(20)	1(51)	-	1,2,6-10,13-16,23,25,26 29,30,33-36,38-42,44-45 46
1967	28	-	12(21,22,28,31,32 37,43,47,48,49,50,51)	1(20)	1(52)	-	1,2,6-10,13-15,23,25,26 29,30,33-36,38-42,44-45 46,52 Inactive 16
1970	28	-	12(21,22,28,31,32 37,43,47,48,49,50,51)	1(20)	-	1(16)	1,2,6-10,13-15,23,25,26 29,30,33-36,38-42,44-45 46,52
1971	27(1st 1/2) 23(2nd 1/2)	-	12(21,22,28,31,32 37,43,47,48,49,50,51)	1(20)	-	5(7,9,13,14 15)	1,2,6,8,10,23,25,26,29,30 33-36,38-42,44-46,52
1972	20	-	12(21,22,28,31,32 37,43,47,48,49,50,51)	1(20)	-	3(29,33,34)	1,2,6,8,10,23,25,26,30,35 36,38-42,44-46,52
1973	20(1st 1/2)	-	12(21,22,28,31,32	1(20)	-	3(10,35,36)	1,2,6,8,23,25,26,30

	17(2nd 1/2)		37,43,47,48,49,50,51)				38-42,44-46,52
1978	16	-	11(21,22,28,31,37 43,47,48,49,50,51)	1(20)	-	2(2,32)	1,6,8,23,25,26,30,38-42 44-46,52
1979	6(1st 1/2) 9(2nd 1/2)	-	10(21,22,28,31,37 43,48,49,50,51)	1(20)	3(53-55)	8(8,23-26 44-47)	1,6,30,38,42,52,53-55 Inactive 39-41
1980(June)	6	-	2(48,50)	-	-	17(1,20,21,22 28,31,37-43,49 51)	6,30,52,53,54,55
1981(Dec)	21	-	11(48,52,53,58,59 65,66,67,73-75)	-	24(56-80)	1(6)	30,50,54-57,60-64,58-72 76-80
1982	20	-	11(48,52,53,58,59 65,66,67,73-75)	-	-	1(30)	50,54-57,60-64,68-72 76-80
1984	20	-	11(52,53,58,59,65 66,67,73-75,81)	-	1(81)	1(48)	50,54-57,60-64,68-72 76-80
1992							Same status
1993							Same status

Apl Gravity=36
Producing Gas Oil Ratio=250 SCF/STB

PVTO

Rs(Mscf/STB)	Pressure (Psi)	BO(RB/STB)	VISC(Cp)
0.003593	24	1.018	3.668
0.007667	48	1.021	3.624
0.020886	120	1.027	3.487
0.039724	216	1.035	3.304
0.059391	312	1.043	3.126
0.079642	408	1.051	2.956
0.100348	504	1.059	2.795
0.12143	600	1.066	2.643
0.142831	696	1.074	2.501
0.164512	792	1.082	2.366
0.186441	888	1.09	2.241
0.208593	984	1.098	2.123
0.2194747	1032	1.102	2.067
0.242199	1128	1.11	1.96
0.25	1176	1.112	1.928

Table 2: Oil PVT Properties

<i>Number of Receivers</i>	3
<i>Receiver Interval (fixed)</i>	8 ft
<i>Vertical Stacking Interval</i>	2 ft
<i>Vertical Stack</i>	8-fold Fan 5 (Day2); 8-, 16-, 32- fold stack test
<i>Source Sweep</i>	200-2000 Hz. Day1 Acquisition 400-2000 Hz. Day2 Acquisition
<i>Sweep Time</i>	0.25 seconds
<i>Listen Time</i>	0.5 seconds
<i>Dead Time between shots</i>	1.0 seconds
<i>Total Time for a source station</i>	9.0 seconds
<i>Time Sample Rate</i>	0.125 milliseconds
<i>Uncorrelated Samples per trace</i>	4000
<i>Nominal Uphole Speed</i>	12 ft / minute
<i>Source Interval</i>	16 ft Fans 1, 2, 3, 5, 6 4 ft Fan 4 4 ft Interleaved Fans 7, 8

Table 3: Data Acquisition Parameters

DATE

FILMED

7/27/94

END