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

Annual Report
1996

By
Mohan Kelkar
Chris Liner
Dennis Kerr

Performed Under Contract No. DE-FC22-93BC14951

The University of Tulsa
Tulsa, Oklahoma 74104

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

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Mohan Kelkar
January 1997

ABSTRACT

This annual report describes the progress during the fourth 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 include cross borehole 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 an increase of 30 bbls/day over a year with an additional increase anticipated with further implementation. We have collected available core, log and production data from Section 16 in the Berryhill Glenn Unit and have finished the geological description. Based on the geological description and the associated petrophysical properties, we have developed a new indexing procedure for identifying the areas with the most potential. We are also investigating an adjoining tract formerly operated by Chevron where successful miceller-polymer flood was conducted. This will help us in evaluating the reasons for the success of the flood.

Armed with this information, we will conduct a detailed geostatistical and flow simulation study and recommend the best reservoir management plan to improve the recovery of the field.

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 up to 45 bbls/day (over 200% increase in the production). For Stage II of the project, we have expanded the scope of the project. Instead of concentrating only on Tract 7, we are evaluating all the areas currently operated by Uplands Resources. In addition, we have also included an adjoining tract which was operated by Chevron Production Company. On this tract, a successful miceller-polymer flood was conducted which resulted in significant oil recovery. We intend to compare the performance of this tract with other tracts to understand the success of the miceller-polymer flood. Based on our detailed evaluation, we will be able to propose the optimal reservoir management plan. Part of this plan is to determine the best location for either multilateral or a horizontal well.

The geological mapping of all the tracts is complete, and we have established a new indexing procedure to determine the area of the highest potential. The geostatistical description and the flow simulation should begin soon.

1. OBJECTIVES

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

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

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

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

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

2. STAGE I PROJECT MONITORING

During the summer of 1995, we started implementing the reservoir management plan in the Self Unit. Last quarter, after evaluating each individual well, we decided to install electrical submersible pumps to produce three wells. The other three wells required the use of rod pumps. Production from the field improved significantly once the pumps were installed. Over the last twelve months, an average daily production has been approximately 45 bbls/day. Compared to a base line production of 13 bbls/day before the implementation, this is more than a 200% increase in production. Based on our current evaluation of the flow simulation results, we expect that the production from the unit should reach between 80 to 100 bbls/day once the implementation is complete.

Part of the reservoir management plan is to increase the water injection rate. We have installed the injection pump and have completed the piping to bring the water from the Arkansas River.

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

In 1996, geology activities of the Glenn Pool project included field scale evaluation, refinement of Tract 7 and adjacent area study; inclusion of Tract 9, Tract 16, and Chevron Miceller-Polymer Flooding acreage into detailed study, and technology transfer.

3.1 Field Scale Evaluation

Field scale study was done for the purpose of broadening our understanding of larger scale variations of Glenn Sandstone, and the relationship between Tract 7 and other production units. Results of this study will be helpful in selecting an area for Phase II horizontal drilling.

The area for field scale study includes the southern half of the Glenn Pool Field with an area of about 25 square miles (**Figure 1**), covering Glenn Pool acreage of several independent oil companies including Uplands Resources, Producers, ELS, Hyperion, Reddy and part of Bazneet.

320 logs were available in public domain within the area; 280 of them cover through the whole Bartlesville interval. Correlation has been completed to the DGI level for all these logs, with reference to the Pink Lime, Inola Lime, and Brown Lime markers. Six cross sections, showing a interval from Pink Lime to Brown Lime, were constructed (see **Figure 1** for cross section locations, designated as A-A' to F-F'). Based on correlation results, sandstone distribution maps were constructed for each DGI (**Figure 2**, as one example). Structure maps were developed for

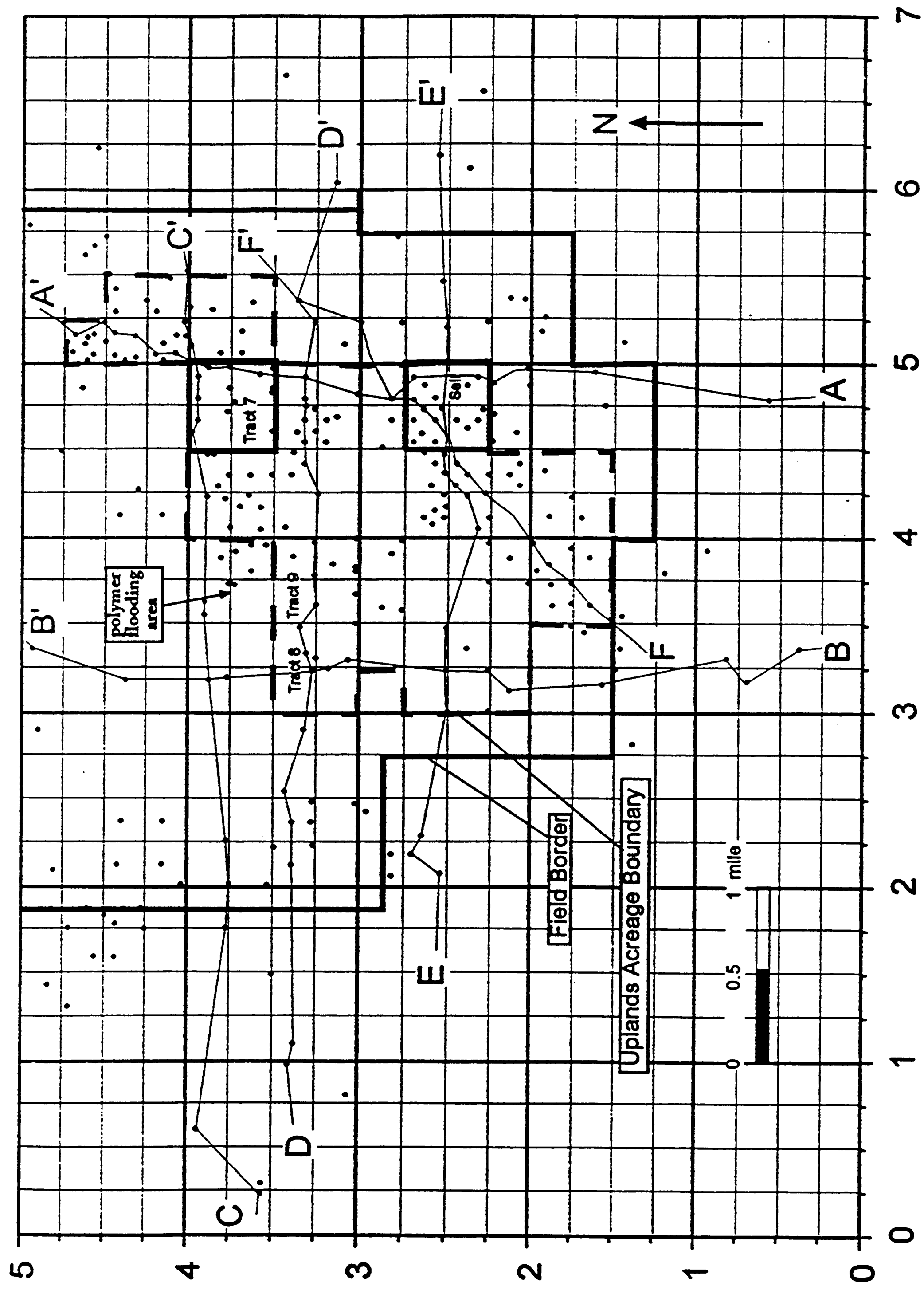


FIGURE 1: INDEX MAP, SOUTHERN GLENN POOL FIELD AND ADJACENT AREA.

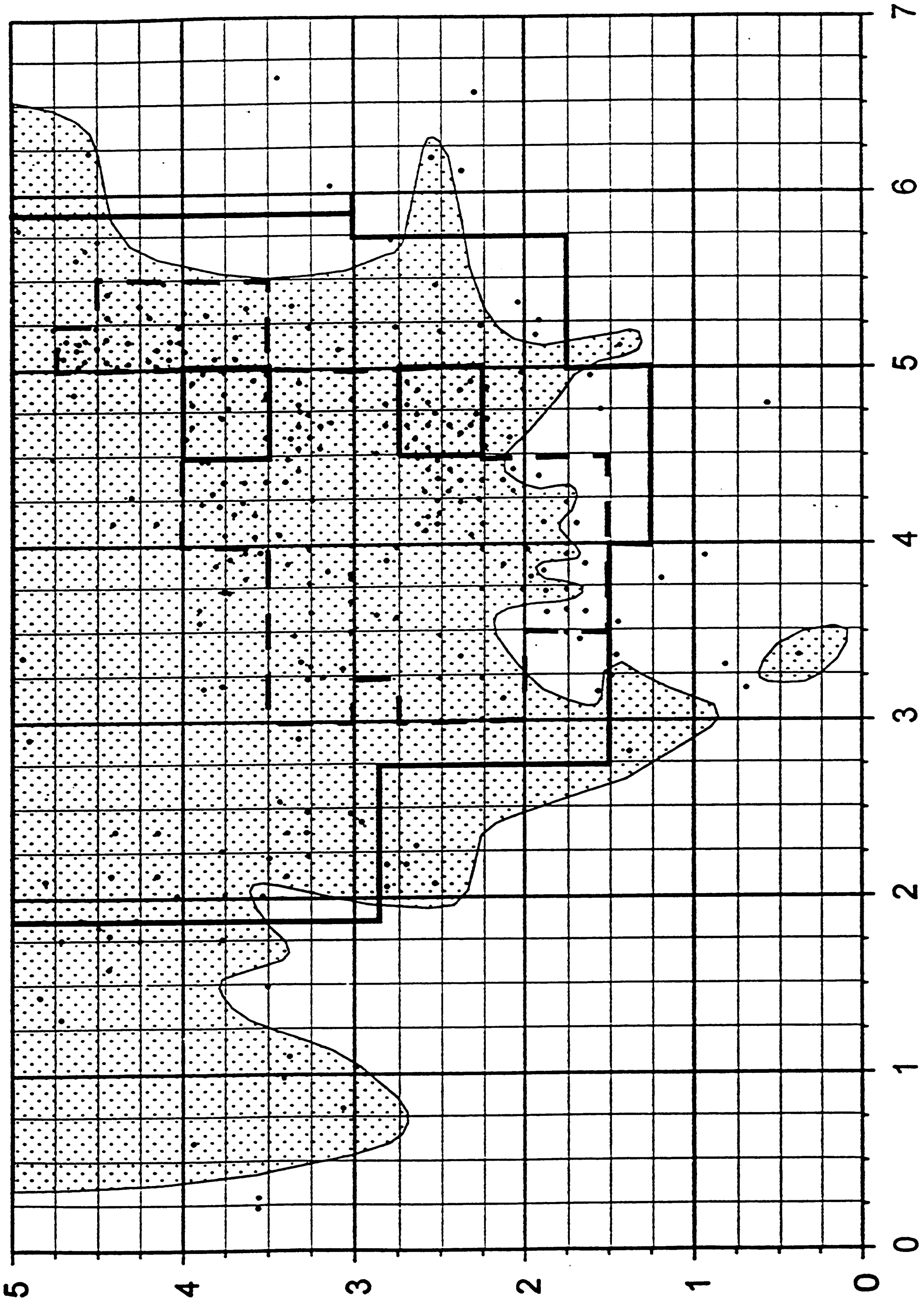


FIGURE 2: DISTRIBUTION OF DGI C SANDSTONE, SOUTH GLENN POOL FIELD.

top of Inola Lime, top of Bartlesville sandstone, top of DGI E sandstone, top of DGI F sandstone, and top of Brown Lime (see **Figure 3**, as one example).

As a result of this field scale study, it is concluded that the Red Fork Sandstone interval (between Pink Lime and Inola Lime) was deposited in a generally flat area as indicated by the fairly constant gross thickness throughout the area, which implies the chance that cutting of Bartlesville Sandstone by Red Fork sandstone is minimum. Early interpretation of Bartlesville Sandstone as incised valley fill is supported by the evidence that in the east side of Glenn Pool Field the Bartlesville Sandstone onlaps eastward onto the incised valley wall cut into the Savanna Shale (**Figure 4**). Within the valley, the successions of Bartlesville Sandstone in different parts of the Glenn Pool Field are quite comparable in terms of profile characteristics, except that the basal part of the Bartlesville Sandstone, which fills the basal unevenness of the incised valley, may not be that persistent throughout the area, dependent on the paleotopographic relief. Seven (7) DGIs (A to G in descending order) are recognized. Usually DGI A to F are present everywhere within the valley. However, DGI G may be absent where there was an ancient high, resulting in DGI F directly overlying the Savanna Shale (**Figure 4**).

A sandstone distribution map constructed for each DGI shows that the reservoir sandstones are back-stepping and getting more discontinuous upwards. This is consistent with what we have discovered in Self Unit study, Tract 7 study and outcrop observations. This also supports the earlier interpretation that Bartlesville Sandstone was deposited in a retrogradational manner.

Figure 3 is the structure map of top Inola Lime marker, showing that Tract 7 and adjacent area is in a obvious structure high. This also is the case for other levels of structure maps.

Perforation and initial production information were added to the six cross sections constructed. The cross sections include an interval from Pink Lime marker to Brown Lime marker. A copy of these completed cross sections were made and submitted to Uplands Resources, Inc.

3.2 Continuation Of Tract 7 And Adjacent Area Study

Continuation of Tract 7 study includes shale mapping, petrophysical property evaluation, acquisition of additional cased-hole logs, and revision of facies mapping.

3.2.1 Shale Mapping

As has been done for the Self Unit study, several maps showing the shale thickness between DGIs were constructed for investigating the vertical separation of the reservoirs. As one example,

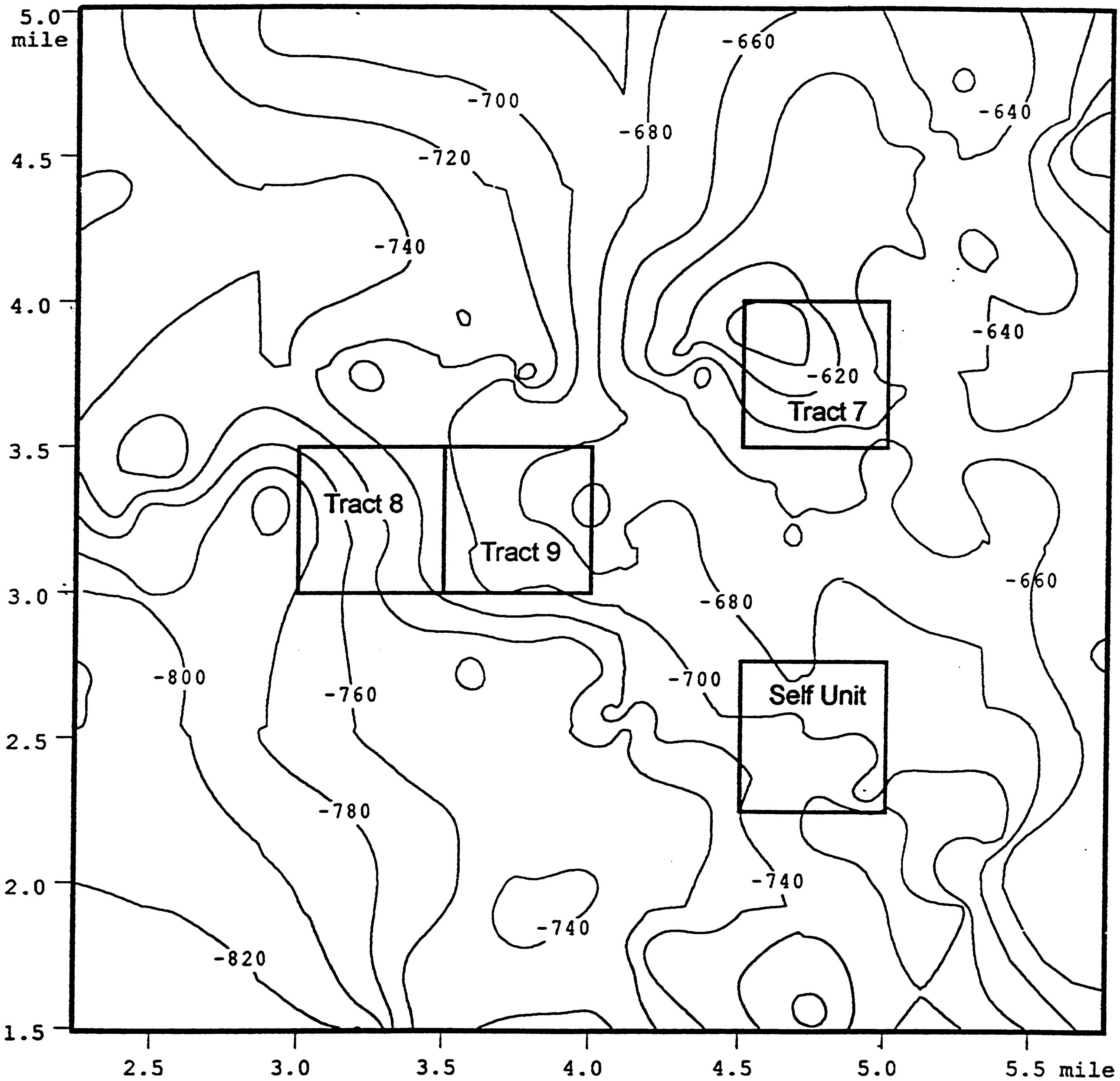


FIGURE 3: STRUCTURE MAP (TOP OF INOLA LIME, FEET IN SSE).

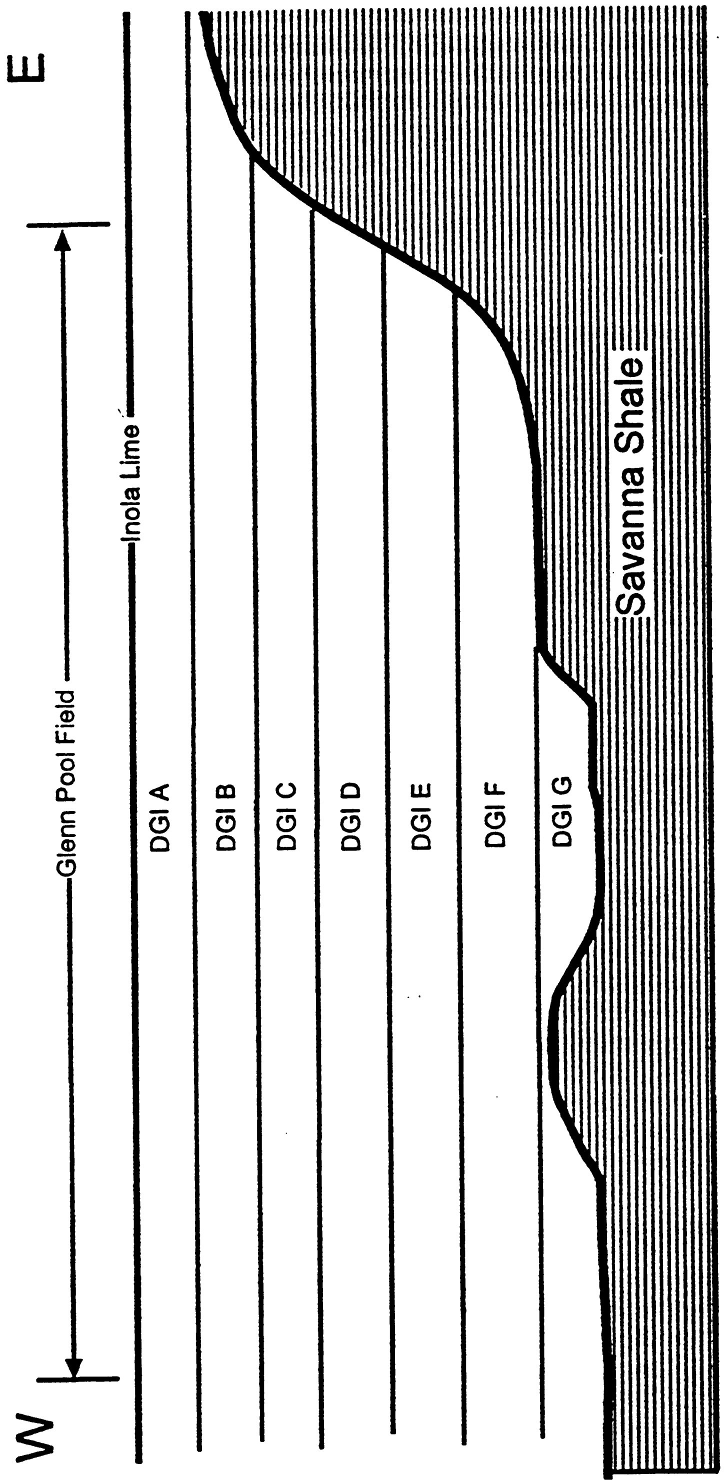


FIGURE 4: A SKETCH SHOWING THE STRATAL PATTERN OF BARTLESVILLE SANDSTONE IN GLENN POOL FIELD: THE BARTLESVILLE INTERVAL ONLAPS THE EAST WALL OF THE INCISED VALLEY.

Figure 5 shows the shale thickness between DGI D and E. Generally speaking, Bartlesville Sandstone has a pretty good vertical separation between DGIs. **Table 1** compiles separation between different DGIs in terms of shale thickness and the number of wells which show no shale break, indicating that the reservoirs of upper part of Bartlesville Sandstone (DGI A to C) has a worse vertical separation than those of lower part (DGI D to G).

TABLE 1

VERTICAL SEPARATION CONDITION, TRACT 7 AND ADJACENT AREA

Shale Break	Typical Thickness Range (Ft)	NWI*	NWWNS*	PWWNS*
A vs. B	1 to 3	89	27	30
B vs. C	2 to 4	89	19	21
C vs. D	2 to 6	89	7	8
D vs. E	2 to 6	89	7	8
E vs. F	2 to 6	89	9	10
F vs. G	3 to 8	116	4	3

Note: NWI* = number of wells investigated
NWWNS* = number of wells which shows no shale break
PWWNS* = percentage of wells which shows no shale break

3.2.2 Petrophysical Property Evaluation

It is difficult to evaluate the petrophysical property for reservoirs in Tract 7, because all cores (20 in total) were cut for DGI F and G only. Fortunately, there are three longer cores cut in nearby Tract 7 (i.e., well 6-F8, 10-49, 4-24), data of which can be used as a reference for Tract 7. **Table 2** shows core porosity and permeability data for these three wells, as well as some core data for DGI F and G in Tract 7, in comparison to the data of Self 82 core.

Table 2 indicates that for DGI E to F (or G if present), Tract 7 area and Self Unit have comparable porosity and permeability. However, for DGI B to D, Tract 7 area has a much higher porosity and permeability than that of Self Unit. There is no core sample for DGI A in Tract 7 area, however well logs show good reservoir quality DGI A sandstone in the tract. This implies that the upper part of Bartlesville Sandstone in Tract 7 area could be very good potential for further development. In addition, the engineering studies have shown that the upper part in this area is underdeveloped.

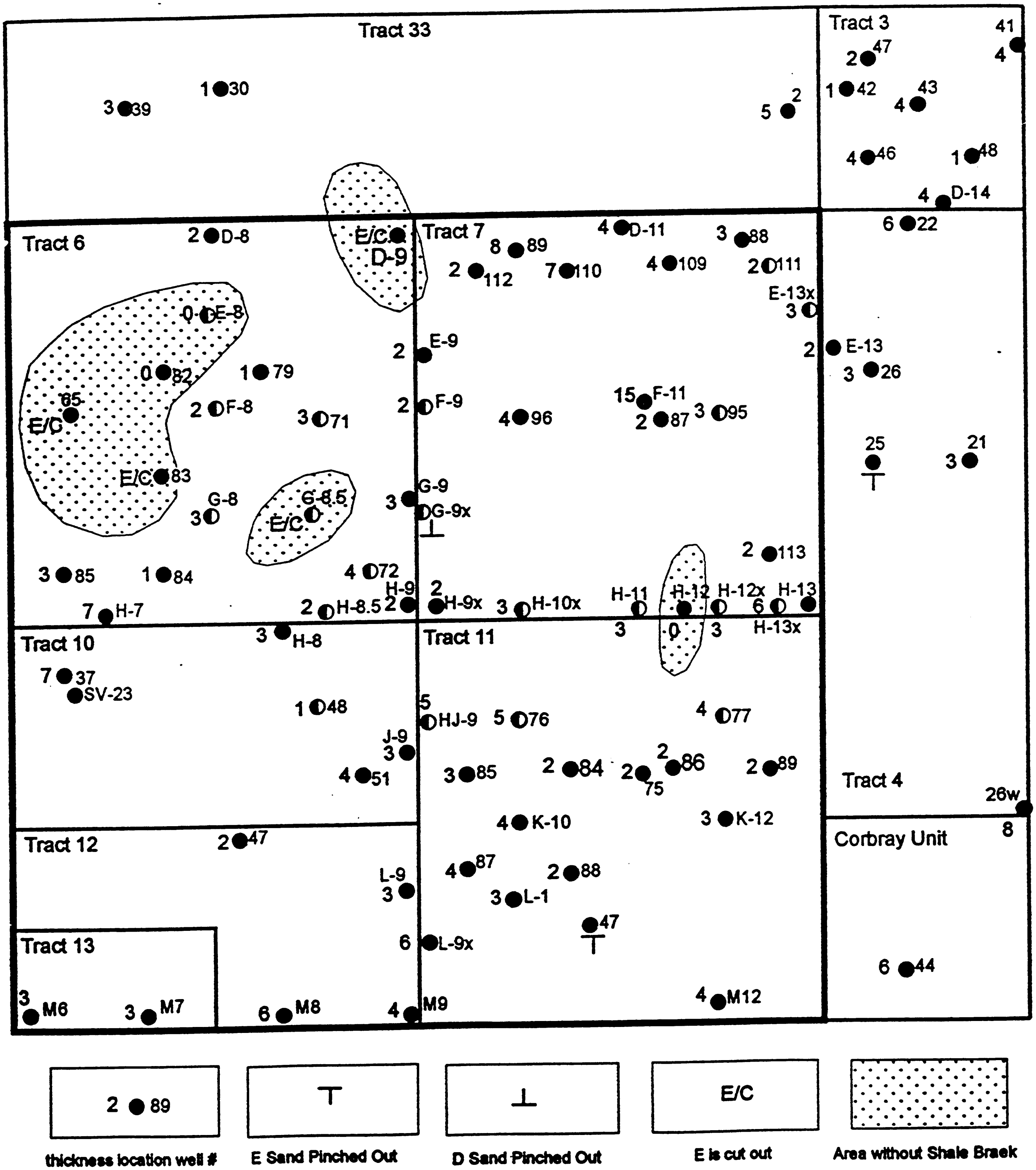


FIGURE 5: SHALE THICKNESS BETWEEN DGI D AND E.

TABLE 2

COMPARISON OF CORE POROSITY AND PERMEABILITY BETWEEN SELF UNIT AND TRACT 7 AREA

DGI	Well Self 82 Phi (%)	Well Self 82 K (md)	Well Self 82 Facies	Well 6-F8 Phi (%)	Well 6-F8 K (md)	Well 6-F8 Facies	Well 10-49 Phi (%)	Well 10-49 K (md)	Well 10-49 Facies	Well 4-24 Phi (%)	Well 4-24 K (md)	Well 4-24 Facies
A	NS	NS	CH	NC	NC	FP	NC	NC	FP	NC	NC	FP
B	9.1 (3)	0.018 (1)	CH	11.5 (2)	1.6 (2)	CH	0.1 (1)	13.3 (1)	FP	NS	NS	FP
C	11.8 (16)	0.57 (15)	CH	22.3 (19)	397 (19)	SP	20.6 (17)	148 (17)	CH	5.1 (22)	2.3 (22)	CH
D	16.5 (20)	26.4 (19)	SP	20.7 (17)	237 (17)	SP	17.8 (12)	105 (12)	SP	11.9 (4)	18.2 (4)	SP
E	19.9 (5)	181.8 (5)	SP	19.3 (20)	151 (20)	CH	18.1 (26)	77.6 (26)	CH	15.7 (8)	66.9 (8)	SP
F	21.8 (9)	246 (9)	BS	20.5 (56)	137 (56	BS	22.2 (24)	217 (24)	BS	18.5 (43)	146 (43)	BS
G		not developed		17.9 (34)	30 (34)	BS	16.2 (49)	18.2 (49)	BS	19.4 (36)	91.4 (36)	BS

DGI	Well 7-100 Phi (%)	Well 7-100 K (md)	Well 7-100 Facies	Well 7-102 Phi (%)	Well 7-102 K (md)	Well 7-102 Facies	Well 7-103 Phi (%)	Well 7-103 K (md)	Well 7-103 Facies
A-E	NC	NC		NC	NC		NC	NC	
F	21.2 (22)	162.3 (22)	BS	15.4 (4)	32 (4)	BS	20.2 (20)	141.3 (20)	BS
G	15 (40)	35.5 (40)	BS	17.8 (50	14.9 (50)	BS	17.2 (36)	29.5 (36)	BS

Note: The number within parenthesis is the number of samples.

NC = not cored

NS - not sampled

CH = channel-fill sandstone

FP - flood plain mudstone

SP = splay sandstone

BS = braided stream sandstone

3.2.3 Acquisition Of Additional Cased-Hole Logs

As pointed out before, data coverage in Tract 7 is not good. Thus additional cased hole GR logging for 6 wells was proposed and implemented. Five of them are in Tract 7 unit (well number: 7-97, 7-99, 7-100, 7-103, and 7-107), and the other one (11-82) is in Tract 11 unit. There is a suspicion that upper part of Bartlesville Sandstone in Tract 7 area may contain a gas cap. Thus cased-hole neutron logging (TDT) was also performed for three wells (well number: 7-97, 7-103, 7-107). These TDT logs do not show any evidence of gas.

3.2.4 Revision Of Tract 7 Facies Mapping

One important aspect of Tract 7 study has focused on the revision of sand isopach and facies maps constructed for each DGI of the area (1.6 square miles) in later 1995. This revision is necessary after the acquisition of additional well data. Also insights into the reservoir architecture of Bartlesville Sandstone gained from recent outcrop studies have benefited this revision greatly. In this version of facies architecture reconstruction, Bartlesville Sandstone (especially for DGI A-C) is less layer-caked than earlier believed. As a result of this observation, a thick and blocky sandstone, if exists, within top part of Bartlesville Sandstone is more likely to be placed into one DGI rather than divided into more than one DGIs, resulting in that sandstone of DGI A to C are more channelized than earlier interpretation.

Also outcrop study has resulted in a new facies interpretation for DGI F sandstone (about 40-50 ft thick). DGI F was interpreted as channel mouth bar deposits based on the Self 82 core characteristics and persistent blocky log shapes. Similar rocks have been observed in the lower part of Bartlesville Sandstone outcrops in the Eufaula Dam area. These "massive" thick sandstones may laterally transition to cross-stratified and/or parallel-bedded thick sandstone; are highly channelized, showing unidirectional paleoflow; vary greatly in thickness according to the position relative to the channel thalwegs; and are made of many small individual channels which are stacked together and cut each other horizontally and vertically, resulting in a widespread distribution.

Thus, while the facies interpretation of DGI A to E is kept unchanged, DGI F is re-interpreted as braided-stream deposits. Facies interpretation for DGI G is being undertaken on the only available core of Crow 9-43 which is on the property of Gemini Oil Company. Initial observation indicates that DGI G sandstone is analogous to DGI F sandstone, except that DGI G is often more shaly than DGI F because of higher rip-up clast content.

As mentioned above, six additional cased-hole Gamma Ray logs were acquired. As a result of these additional well logs, the net sand isopach and facies maps developed earlier were checked and modified as necessary. Generally speaking, only very minor changes were needed. Also, interpretation of these additional logs indicates that the actual reservoir sandstone volume is a little bit higher than what was shown in original maps. For DGI E, F and G, facies boundaries in original maps don't need to be modified, only net sand contours need minor modification. For DGI A, B, C and D, both facies boundaries and net sand contours need minor modification. However, the general picture of these facies distributions holds unchanged

3.3 Inclusion Of Tract 9, Tract 16 And Miceller-Polymer Flooding Acreage

As the project progressed, potential horizontal drilling acreage outside of Tract 7 came under consideration. Thus, Tract 16 and Tract 9 were selected for study. On the other hand, Chevron's Miceller-Polymer Flooding during early 1980's in a 160 acre unit immediately west of Tract 6 has been said to be very successful in terms of oil production increase. The concern here is what we can learn from this project for reservoir management in Uplands acreage. Thus, this miceller-polymer flooding acreage is included into our study as well.

3.3.1 Tract 16 Study

Tract 16, an 80-acre unit and located immediately north of Self Unit and south of Tract 11, was evaluated for horizontal drilling. However, the available development history record is not complete. Data survey has shown that at least 28 wells (maybe more) have been drilled in this unit, of which only 3 wells were logged, 9 wells show limited completion information, and the remaining 16 wells have no data. Currently no well is active.

Initial geological analysis based on the limited data available shows that DGI G sandstone is absent in the southern two-thirds part of the unit. DGI A to C are the most likely potential for further oil recovery.

3.3.2 Tract 9 Study

Tract 9, another 160 acre unit of Uplands acreage in the Glenn Pool Field, is located in the southeast quarter of Section 17-17N-12E, i.e., west of Tract 10, 12 and 13. Data survey shows that at least 56 wells have been drilled in this unit. However, only 11 logs are available for geological description.

As what was done in other tracts, Bartlesville Sandstone is subdivided based on the correlation of these 11 logs and logs in other tracts. DGI A to DGI G are again recognized. Log facies interpretation is performed for each well and each DGI facies mapping is completed for each DGI in conjunction with other tracts (shown later). Characteristics of vertical profiles are very similar and correlatable to what was observed in Tract 7 area.

3.3.3 Miceller-Polymer Flooding Acreage

Chevron's Miceller-Polymer Flooding acreage, also a 160 acre unit, is located in the northeast quarter of Section 17-17N-12E, i.e., immediately north of Tract 9 or west of Tract 6 (**Figure 1**). The miceller-polymer flooding project was conducted during the early 1980's and is considered to be very successful in terms of oil production increase. Currently this unit is operated by Hyperion Oil Company based in Dallas, Texas.

An investigation of the real factors leading to this success was intended, in the hope of gaining insight into our proposed reservoir management planning. Fourteen logs were collected from public domain in Tulsa. Correlation to DGI level and sandstone classification for each DGI is made for each of these wells. Facies map for each DGI was constructed for this unit in conjunction with other reservoir units.

After this basic geological description, it is perceived that more details about this miceller-polymer flooding project could be valuable to identify the factors leading to oil production increase. From a geological point of view, a good question is what the oil saturation profiles look like for the unit right before the project started, in comparison to the current oil saturation profile in our target area. Other good questions include how was the Bartlesville Sandstone subdivided and how is their division compared to our DGI division?

For answering these questions, a trip to Hyperion Oil Company in Dallas was completed in December, 1996 to collect more data. Data of 23 cores (which includes oil saturation information), well logs and many other materials regarding the project were collected. Analysis of these data has begun, initial results do support that the upper part of the Bartlesville Sandstone has a higher potential for future development.

3.3.4 Unifying The Facies Map For All Tracts Studied

With inclusion of Tract 16, Tract 9, and Chevron Miceller-Polymer Flooding acreage, the area mapped for detailed facies architecture over the course of the project is about 1500 acres. It is helpful to construct a unified facies map for entire area including Self Unit, Tract 3, 4, 6, 7, 9, 10, 11, 12, 13, 16, and Chevron Miceller-Polymer Flooding acreage. The unified facies map is completed for each DGI and shows the depositional relationship among different tracts very clearly. **Figure 6**, as an example, shows the unified facies map of DGI C for the entire area.

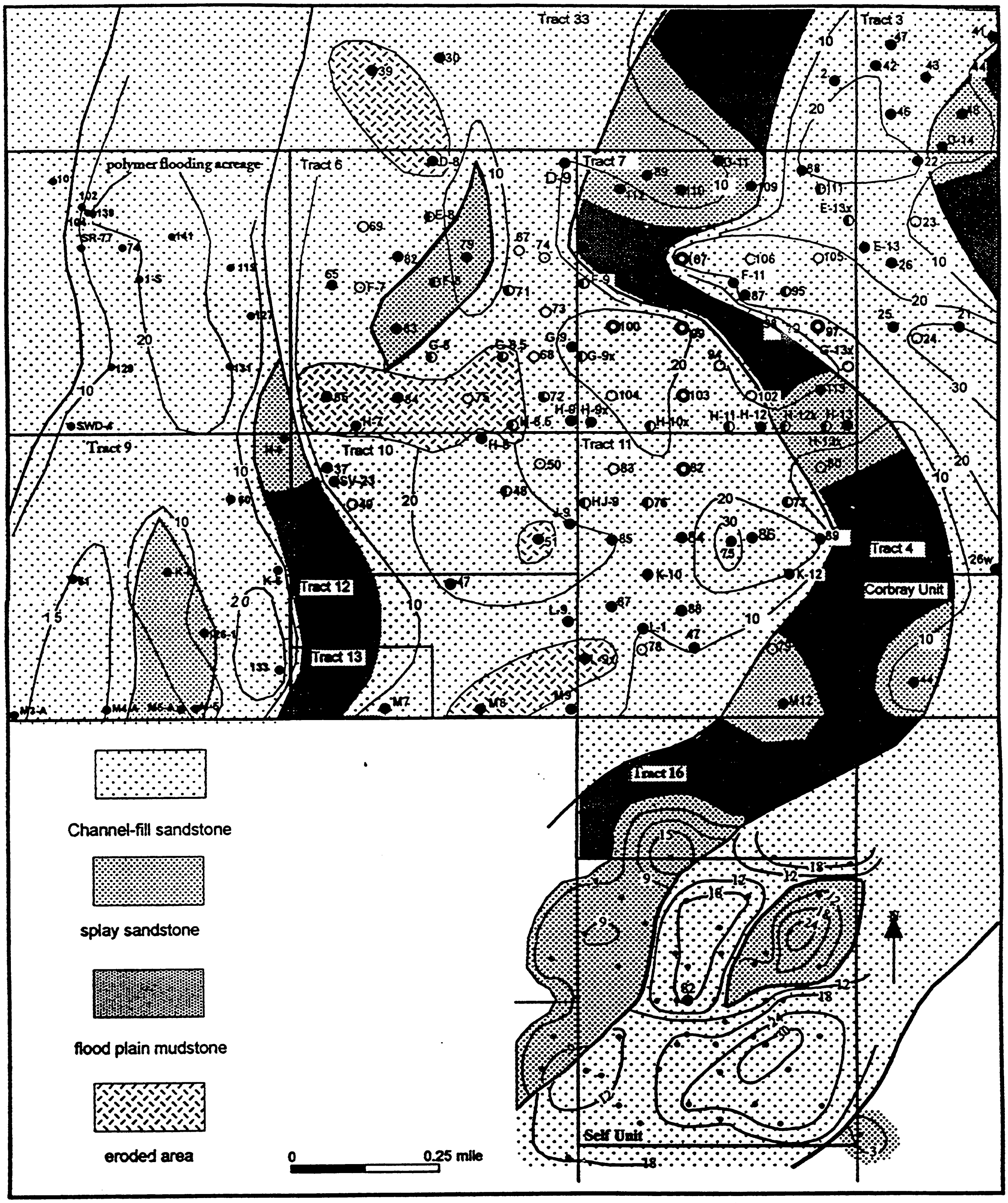


FIGURE 6: SAND ISOPACH AND FACIES MAP, DGI C.

3.4 Well-By-Well Determination Of Net Sand Thickness

To have a more accurate estimate of oil reserves in Tract 6, 7, 9, 10, 11, 12, 13, 16 and Chevron Miceller-Polymer Flooding acreage, net sand thickness is evaluated by using well logs. The "50% method" is adopted for determining the net sand thickness, which is the portion of sandstone with reservoir quality. About 120 logs were analyzed for this purpose. The net sand thickness has been provided to engineers for reserve estimate and engineering study.

Figure 7 displays the ratio of net sand thickness to gross sand thickness (i.e., the interval thickness from sandstone top to sandstone bottom within a DGI) for each DGI. The ratio displayed is the average value calculated from all 120 logs. From this figure we can see, the ratios for DGI A and DGI G are slightly smaller than those for other DGIs. This implies that at least in these tracts, DGI A and G are more muddy or shaly than other DGIs. As was mentioned earlier, Bartlesville Sandstone was deposited in a regressive manner, thus it is easy to understand why DGI A is more shaly than lower DGIs. But why for DGI G? One possible explanation is that the lower part of Bartlesville Sandstone contains more rip-up clast shale originated from the erosion of underlying Savanna Shale. This explanation is supported by the core observation conducted thus far, but needs more attention.

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

4.1 Introduction

This section presents the work completed in the last year. The area of investigation has been expanded and currently incorporates Tract 9 and Chevron William Berryhill Lease (Miceller-Polymer Flood). All the relevant data for the additional area have been collected, effecting modifications in the geological model. An attempt has been made to investigate the prospective areas for recompletion of upper zones. The area of investigation currently is as shown in **Figure 1.**

A database of all the wells that have been drilled was compiled detailing information pertaining to the location of the well and the perforation depths. A total of 280 wells are included in this database, including both producers and injectors. Perforation maps were generated for each DGI displaying only those wells that have been completed in that DGI with an estimate of the interval that has been completed out of the thickness of the DGI under consideration. The conclusion derived from these maps was that the upper zones were not perforated as densely as the lower zones. Since most of the available completion data are skewed towards the years 1942-1995 this conclusion is appropriate during the course of secondary flooding implementation in the field.

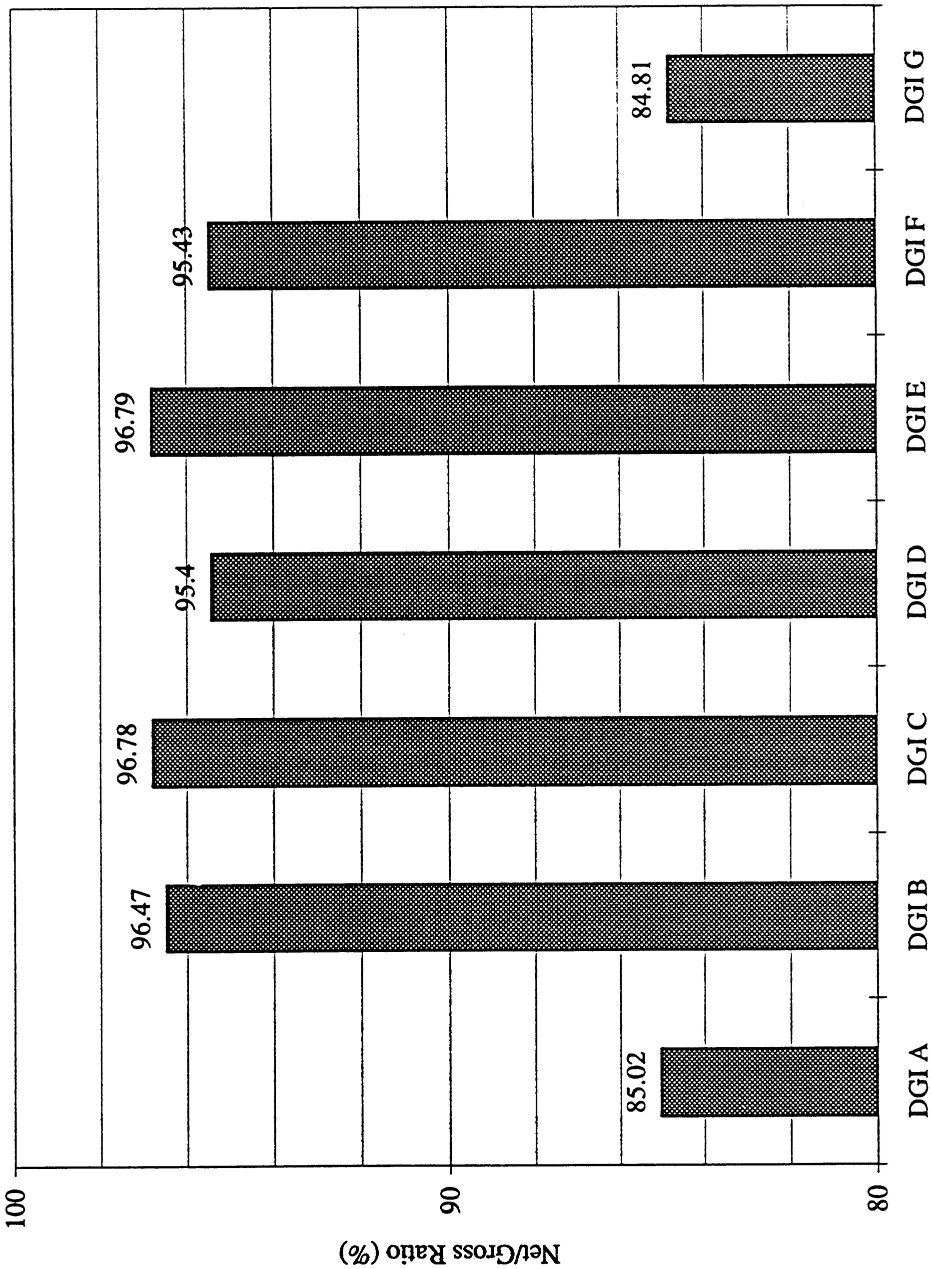


FIGURE 7: AVERAGE NET/GROSS RATIO DETERMINED FROM 120 LOGS.

Perforation interval maps were plotted for the Chevron William Berryhill Lease to understand the completion practices before and after the miceller-polymer flood implementation in 1980. These maps showed that Chevron had concentrated its completions in the upper intervals. There was very little activity in the lower DGIs especially DGI G. We believe that the rationale used was upper zones have a lot of potential owing to ineffective flooding practices. This is supported by the TDT logs in Tract 7 which shows clean sands with high oil saturations in the upper regions. Additional work that needs to be done is to determine whether the success of Chevron Micellar-Polymer Food project was primarily due to infill drilling or effective micellar-polymer flooding.

4.2 Screening Test For High Potential Areas

A procedure was developed as a screening test to identify the areas with high potential for oil recovery in terms of the petrophysical properties. The following sections detail the method devised.

The investigation area has been divided into 60 ft. × 60 ft. gridblocks. The area of interest spans 7,920 ft. in the x direction and 5,820 ft. in the y direction and 5 DGIs (A-E) in the z direction. This results in a 3-dimensional gridblock setup of $132 \times 88 \times 5$ (x, y, z) respectively. Each DGI is represented as a slice independent of a physical magnitude associated with it. The reason for including DGI's A-E only is discussed in the following section.

4.2.1 Mapping Of Petrophysical Properties

(a) Porosity

Logs were collected and digitized wherein the combination of logs for a particular well is sufficient to make a reasonable estimation of porosity and saturation. The number of such wells is extremely small. Typically a combination of Spontaneous potential, Gamma ray, Density and Neutron logs is used to compute porosity. The computation validity is then established by comparing it with the core porosity data for the lower intervals since the upper intervals are predominantly uncored. The porosity values at the well locations are averaged for each DGI. These average values are kriged to estimate porosity values at all other gridblocks for a particular DGI. The result is seven areal slices (DGI A-G); Each slice represents a particular DGI.

(b) Permeability

Log permeability v/s porosity relationships are established for each DGI individually by combining all available core data. Permeabilities are evaluated based on the above relationships for all wells where porosity is computed. The permeability values at the well locations are averaged for each DGI. Precautions are taken to strip any unreasonable permeability value. These average values are kriged to estimate permeability values at all other gridblocks for a particular DGI.

(c) Saturation

Typically a combination of porosity, induction or resistivity logs is used to compute saturation. The saturation values at the well locations are averaged for each DGI. The computation validity is then established by,

- Comparing the log derived profile with the core profile.
- Comparing S_w averaged for each DGI with TDT saturations using compatible R_w and σ_w values.

The average values are kriged to estimate saturation values at all other gridblocks for a particular DGI.

4.2.2 Potential Index Estimation

The potential for a particular location is a cumulative effect of the production capacity, storage capacity and access to the existing wells. The potential should be directly related to the production, storage capacities and inversely proportional to the access by other wells.

(a) Conductivity Index (CI)

This index quantifies the production capacity and is related to the product of permeability and thickness $(k \times h)$. Since k and h are defined at all gridblocks in all the seven DGI slices (A-G) the productivity can be estimated at each gridblock. Since F and G have been drained considerably further indexing is done only from DGI's A-E. The productivity data for the DGI's A-E are then combined to establish quartiles X_{25}, X_{50} and X_{75}. Ranks are then assigned from 1-4 by comparing data points at each gridblock with the quartiles. For instance if the productivity for a particular gridblock is less than X_{25} then it is assigned a rank 1, if it is between X_{25} and X_{50} then the gridblock is assigned a rank 2, if it is between X_{50} and X_{75} then the grid block is assigned a rank 3 and if the value is greater than X_{75}, it is assigned a rank 4.

(b) Storativity Index (SI)

This index quantifies the storage capacity and is related to the product of porosity, oil saturation and thickness $(\phi \times S_o \times h)$. Since porosity, saturation and thickness is defined at all gridblocks in all the five DGI slices (A-E), the storativity can be estimated at each gridblock. The storativity data for the DGI's A-E are then combined to establish quartiles X_{25}, X_{50} and X_{75}. Ranks are then assigned from 1-4 by comparing data points at each gridblock with the quartiles as was done for the conductivity index.

(c) Accessibility Index (AI)

This index defines the access to a particular area by drilled wells. It is assumed that a fully penetrated well in a particular DGI contacts 10 acres. Although arbitrary, this assumption is consistent with the overall observations in the field that indicate low areal continuity. If partially penetrated, the area is proportionately reduced. The area contacted by a well is assumed to be proportional to the square of the ratio of perforated interval to the total thickness for each DGI. If a gridblock is contacted by a drilled well (i.e., it falls within the assigned drainage area), the accessibility index is assigned 0 and if gridblock is not contacted, the accessibility index is assigned 1.

(d) Potential Index (PI)

The Productivity and Storativity Indexes are combined by summing up their individual ranks at all gridblocks. The maximum value of the sum is 8 denoting that the area has the highest potential both in terms of its productivity and storativity. Conversely, the least value of the sum is 0 denoting low potential. Since the essence of the procedure is to identify areas of high potential it was decided to use a combined sum of 4 as the index of demarcation between high and low potential areas. Hence if the sum is greater than 4, the gridblock is categorized as 1 (high potential) and if sum is less than 4, the gridblock is categorized as 0 (low potential). The category value is then multiplied by accessibility index to calculate the final potential index as,

$$PI = (CI + SI) \times AI$$

Irrespective of a gridblock having a high or low potential, if the area is being contacted by a well, its accessibility is 0 which also reduces the PI value to a 0. By including the accessibility, we essentially mask all the regions that are being drained and treat them as being equivalent to areas having zero potential (see **Figure 8**).

Potential Index map (DGI C) *Cumulative Index Map (DGI A-E)*

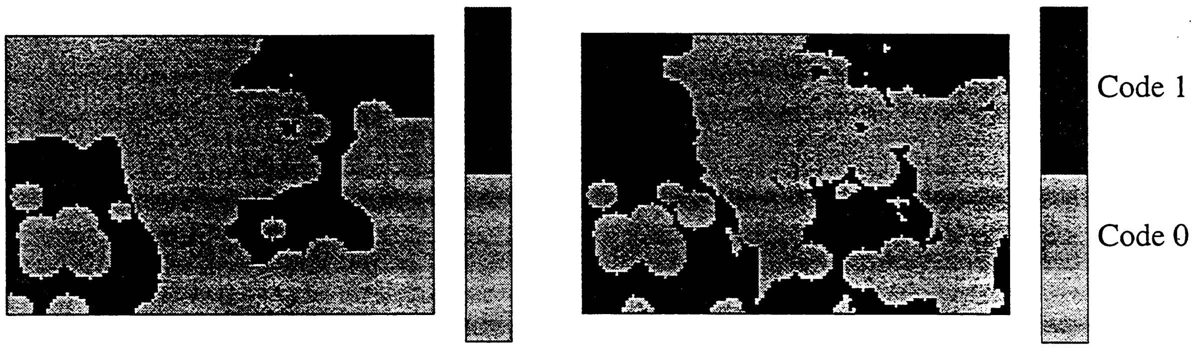


FIGURE 8: POTENTIAL INDEX MAP FOR DGI C AND CUMULATIVE INDEX MAP FOR DGI A-E.

Cumulative index is estimated by adding the PI values at corresponding gridblocks for all DGI's A-E. For each areal location, 5 indices are added corresponding to each DGI. By collapsing all the DGIs into one unit we can examine which areas have the highest potential both areally and vertically. (see **Figure 8**). In **Figure 8**, code 1 represents high potential, whereas, code 0 represents low potential.

4.3 Evaluation Of Production Information

In addition to generating the Production Index maps, the cumulative production data from the individual tracts was evaluated to assess the relative success of secondary recovery to primary recovery. The specific objectives were,

- To make a comparative analysis of the primary production and incremental secondary recovery production for Tracts numbering 1-18.
- Estimate original oil in place(OOIP) and total recovery as a percentage of the OOIP in Tracts 1-18.

Tracts 1-18 cover the areal expanse where the Berryhill Glenn Sand Unit (BGSU) has been identified. We also included Chevron Miceller-Polymer Unit for comparison purposes.

4.3.1 Analysis Of Primary Production And Secondary Recovery

Primary and secondary recovery production data were obtained from Reference 1. The report lists year wise production data from the field inception time in 1908 through 1988. It also lists the contribution from each tract provided the tract was in commercial operation in the year of question. The field wide production history can be summarized as follows,

1908 - 1955-60:	Primary Depletion
1940 - 1961-66:	Gas Injection
1965 - 1985-95:	Waterflooding

The production data for each tract is plotted as a function of time. Then the area under the curve is estimated to obtain the cumulative primary production and incremental recoveries due to 1) gas injection and 2) waterflooding.

A typical example is shown in **Figure 9**. It can be noted from the production response that the data compares well with the field wide history mentioned above. The production data is extrapolated as in decline curve analysis for the cumulative production estimates and the area

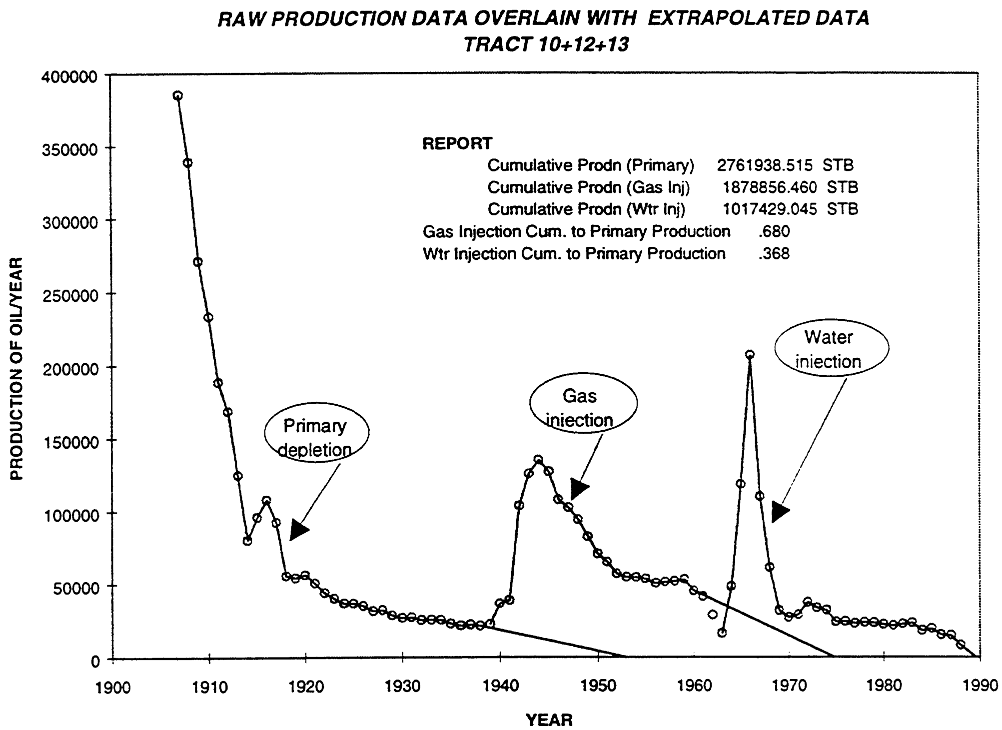


FIGURE 9: RAW PRODUCTION DATA OVERLAIN WITH EXTRAPOLATED DATA.

under the curve is adjusted accordingly during the time spans when two processes are in effect simultaneously. For instance, in **Figure 9** during 1940-52 primary depletion and production due to gas injection are occurring simultaneously. The following ratios were then estimated and the values were compared for all tracts under consideration

G/P = Incremental cumulative production due to gas injection (G) / cumulative production due to primary depletion (P)

W/P = Incremental cumulative production due to injection of water or other fluids (except gas) (W) / cumulative production due to primary depletion (P)

Figure 10 is a representation of this information. In **Figure 10,** Tract 10 represents the combined area of Tracts 10, 12 and 13. It is obvious that gas injection response is poor over the entire field with the exception of Tracts 7, 6 and 3. The most interesting feature of the plot is the W/P value for the Chevron Lease (see **Figure 4**). It stands out in comparison to other Tracts demonstrating the success of the Chevron Miceller-Polymer Flood project.

4.3.2 Original Oil In Place (OOIP) Estimations

The net sand volume figures as quoted in Reference 1 for the upper, middle and lower Glenn Sands were summed to get the total sand volume. This was then multiplied by an assumed constant field wide initial oil saturation of 0.78 and formation volume factor of 1.15 RB/STB to get the original oil in place. The calculated values are shown in **Table 3.**

TABLE 3

OIL IN PLACE ESTIMATES

Tract	OOIP MMstb	Tract	OOIP MMstb
Chevron	9.745	10	6.003
1	8.148	11	12.388
2	1.739	12	4.717
3	9.216	13	1.792
4	6.026	14	2.494
5	4.403	15	9.940
6	14.660	16	7.320
7	14.717	17	2.071
8	6.794	18	3.809
9	13.428		

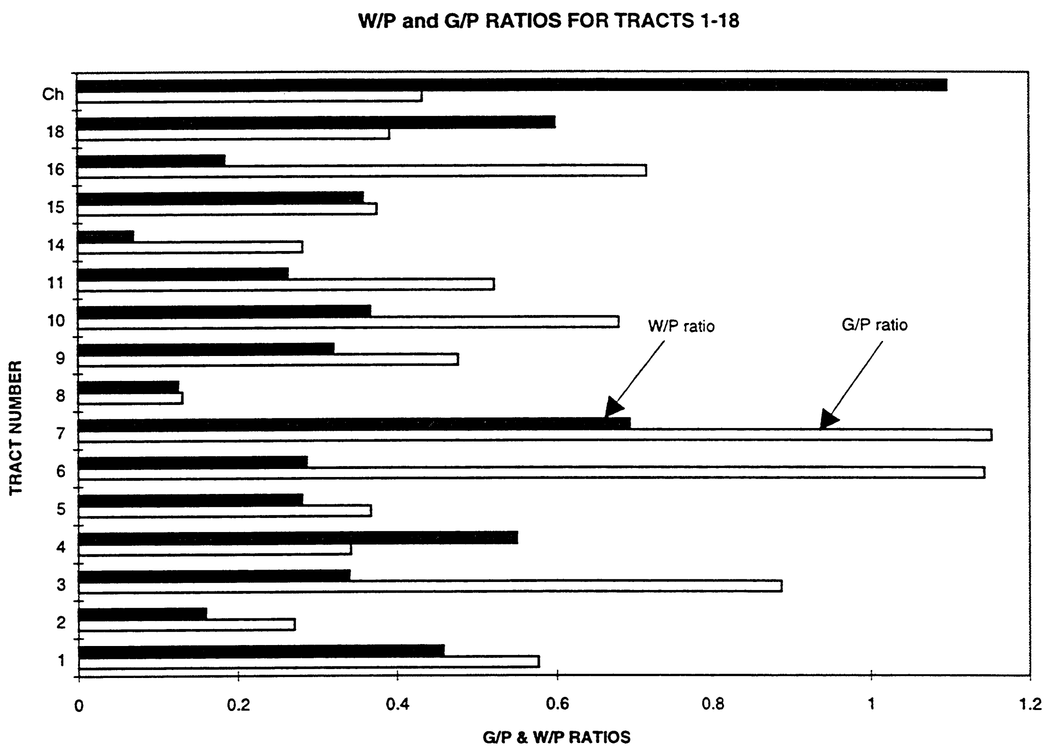


FIGURE 10: W/P AND G/P RATIOS FOR TRACTS 1-18 AND CHEVRON LEASE.

The OOIP estimates were also used to calculate the total recovery of each tract from primary and incremental production from secondary methods. **Figure 11** shows the result. It can be seen that Tract 7 has a lot of potential that can still be tapped. Tract 7 is a good candidate for secondary process implementation since the OOIP is large. Tract 9 is also attractive for the same reason coupled with the fact that it has an extremely low well density in terms of number of wells drilled.

4.4 Summary

The areas with the highest potential for additional recovery have been identified. The areas with the highest potential for recompletions have been identified as Tracts 9 and 7. Based on the current knowledge we intend to generate a detailed reservoir description followed by flow simulation studies. This would culminate in a reservoir management strategy to exploit the field effectively. These strategies may include drilling multi-lateral or horizontal wells.

5. GEOPHYSICAL DESCRIPTION (By Chris Liner)

Geophysical work in this project involved continuation of the processing of cross bore hole tomography survey. The following two sections discuss the two aspects we studied in detail.

5.1 Ray Tracing With Anisotropy

As noted in earlier reports, the Glenn Pool site is characterized by strong seismic anisotropy. This means that seismic waves traveling horizontally propagate at a different speed than vertical waves. Anisotropy leads to complications with processing crosswell seismic data. If it is not properly taken into account, the resulting tomograms exhibit artifacts which have no geological meaning. Software has been developed at the University of Tulsa to deal with this problem. The software is an extension of earlier work by Epili and McMechan[2] and is currently undergoing tests on field data.

5.2 Geological Interpretation Of Tomograms

Since crosswell tomography is a high-resolution imaging technique, it may be expected to correlate well with detailed stratigraphy in the Glenn Pool field. Using the sequence stratigraphic model of L. Ye and D. Kerr, the 63->83 tomogram was interpreted by G. Bozkurt (see **Figure 12** and **Figure 13**). Although there are known processing artifacts in the image, the geological model can be brought very nicely into the tomogram. This level of interpretation is would not be

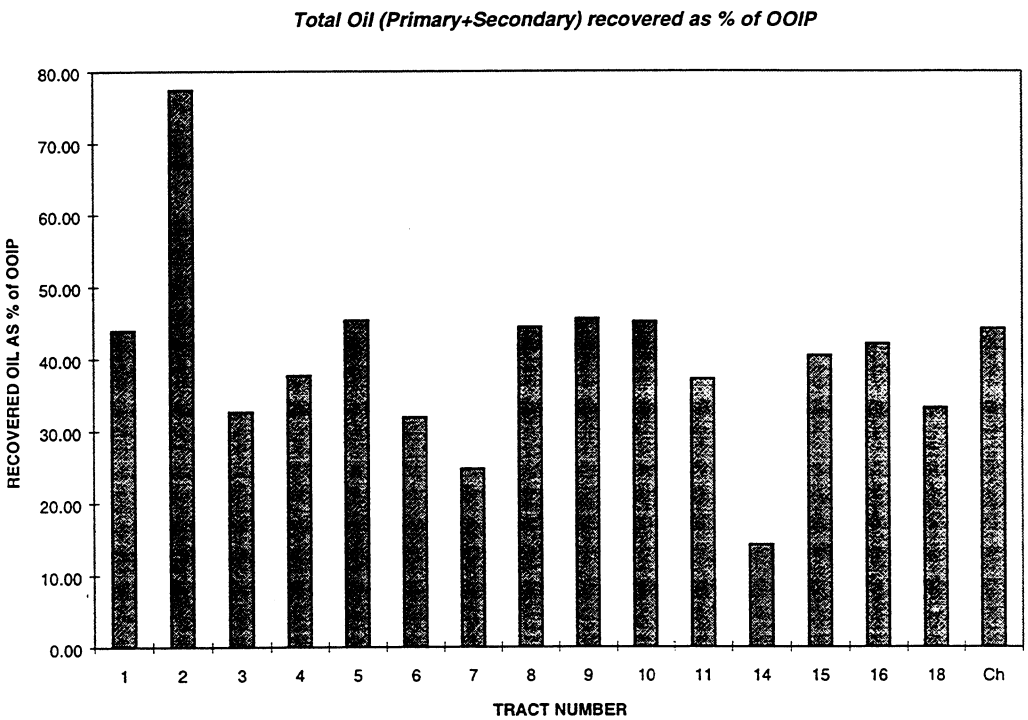
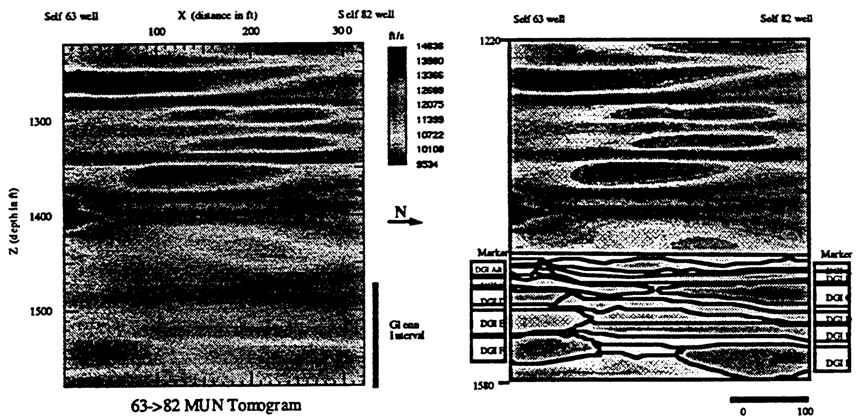


FIGURE 11: TOTAL OIL (PRIMARY-SECONDARY) RECOVERED AS % OF OOIP AND CHEVRON LEASE.



Uninterpreted Tomogram

Interpreted Tomogram

FIGURE 12: STRATIGRAPHIC INTERPRETATION OF TOMOGRAM.

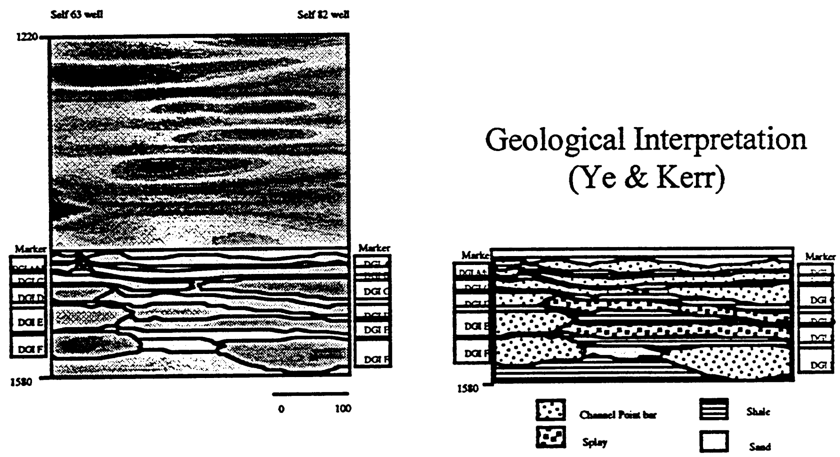


FIGURE 13: COMPARISON BETWEEN GEOLOGICAL MODEL AND TOMOGRAM INTERPRETATION.

possible from the tomogram alone, but only through the combination of tomography and geological work.

This kind of detailed interpretation for out project was long-hampered by the extreme variation in tomograms generated by different processing groups (Amoco, The University of Tulsa, Memorial University of Newfoundland and Imperial College London). Without objective evidence to judge one result superior to the others, it was unwise to forge ahead with geological interpretation. Our solution to this problem was to ultimately accept the Memorial University results on the (qualitative) basis of geological appearance. This point was emphasized in the technology transfer workshop material.

6. TECHNOLOGY TRANSFER ACTIVITIES

In 1996, technology transfer activity of the Glenn Pool project includes three aspects as described below:

6.1 Talk In Local Geological Society Meeting

A presentation regarding the progress, working methods, accomplishments of Glenn Pool project and their significance to other field management was given by Dr. Dennis Kerr in a Tulsa Geological Society meeting on April 9, 1996. Many geologists and engineers from local independent oil companies and majors attended the meeting and were very interested in and gave very positive comments to the work done in this project.

6.2 Workshops

As the most important part of the technology transfer program, one-day-workshops regarding this DOE Glenn Pool project were offered in Tulsa, Denver, and Houston in October 1996. Workshop preparation included preparing materials for the workbook, poster exhibit, and slide presentation. This effort resulted in a notebook summary and more than 250 slides and photos for the workshop. Participants were provided with workshop materials and computer software to generate the reservoir description. The response to the workshop has been good. The average attendance to the workshop was 27. The audience represented a wide cross section of small and large operators, service companies and consultants. Based on the favorable reviews received, the SPE Section at Ft. Worth requested a workshop in April, 1997 for their section.

In addition to these one-day workshops, we also participated in a Traveling Workshop series which was conducted by BDM to showcase some of the Class I projects. As part of the traveling workshop series, we visited six locations including Bartlesville, Oklahoma City, Wichita, Denver, Billings and Evansville, IL. The response from the participants has been very favorable.

6.3 Preparing Presentations For Professional Meetings

Also as part of technology transfer, two invited abstracts were submitted to professional meetings. "Reservoir Characterization And Improved Waterflood Performance In Glenn Pool Field: DOE Class I Project" was invited for the 1997 AAPG Annual Meeting to be held in Dallas, Texas in April, 1997. "Application Of Borehole Imaging For Reconstruction Of Meandering Fluvial Architecture: Examples From The Bartlesville Sandstone, Oklahoma" was invited by the Fourth International Reservoir Characterization Technical Conference to be held in Houston, Texas in March, 1997.

7. FUTURE WORK

The next goal of the project is to select the best reservoir management strategy, including the use of horizontal drilling for improving the performance of the oil field. The evaluation of Chevron Miceller-Polymer Flooding project could be of great help to our decision-making. Thus, the next immediate geological goal is to compare the Chevron Miceller-Polymer Flooding acreage and our target area in terms of: 1) oil saturation profiles; 2) reservoir architecture and 3) petrophysical properties.

In the interest of the project, observation of Crow 9-43 core is being conducted. The core was cut in Crow Unit of Gemini acreage, a couple of miles north of Uplands acreage. Goals of this core study will focus on the oil saturation profile, DGI G facies, and base contact of Bartlesville Sandstone.

The engineering goals of the project include investigating and refining the potential index maps to identify the areas for additional oil recovery. A careful investigation of the Chevron Miceller-Ppolymer Flood is underway to evaluate the reasons for the success of the project. Based on the evaluation, we have concluded that the success should be partly attributed to better access of remaining oil which was not contacted before. We want to develop a plan which does not use the miceller-polymer flooding; instead, we want to use a plan which allows us a better access to the remaining oil so that we can flood it with conventional waterflooding techniques. After identifying the areas of additional recovery, we will conduct a detailed geostatistical and simulation studies to evaluate the economic feasibility of the project before implementing the plan.

REFERENCES

1. Welch R.A, Berryhill Glenn Sand Unit Reservoir Study, Internal Report of ARCO Oil & Gas Company, 1989.

2. Epili, Duryodhan and McMechan, G.A., 1995, Parallel implementation of 3-D prestack Kirchhoff migration with application to field data: 65th Annual Internat. Mtg., Soc. Expl. Geophys., Expanded Abstracts, , 95, 168-171.