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Development of Improved Methods for Locating Large
Areas of Bypassed Oil in Louisiana

Final Report
by

Adam T. Bourgoyne, Jr.
Clay Kimbrell

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

Gene Pauling, Project Manager
Metairie Site Office
900 Commerce Road, East
New Orleans, LA 70123

Chandra Nautiyal, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
Louisiana State University
Baton Rouge, LA 70803-6417

MASTER

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1.0 INTRODUCTION

If Louisiana is to move out of its current weak economic situation to a prosperous future, the state must build on existing strengths and better utilize our available resources as well as attract new industry. Oil and gas production is clearly an area of existing strength which must not be neglected.

A large fraction of Louisiana's oil reservoirs are produced through either a natural or artificial water drive mechanism, in which oil is pushed to the producing wells by the invasion of water into the reservoir. The shape of the leading edge of the invading water can become unstable on a large (macroscopic) scale due to viscous forces, gravitational forces, and reservoir inhomogeneities. The frontal instability can lead to large lateral and vertical protrusions of water into the oil region. Viscous fingering, gravity tongues, coning, and cresting are all common manifestations of unstable flood fronts. Large volumes of oil are often thought to be bypassed as these irregular flood fronts break through to the producing wells. It has been hypothesized that large areas of oil at near virgin oil saturations may exist in a number of old reservoirs nearing abandonment. If the bypassed pocket is large enough, it could be produced economically in the near term simply by drilling a new well without the need for more complex and costly enhanced oil recovery processes. Unfortunately, locating such bypassed oil has been extremely difficult because of the presence of inhomogeneities in the reservoir and because of difficulties in calculating the behavior of frontal instabilities in the reservoir. The high cost of the detailed engineering and geologic studies required and the uncertainty associated with the final predictions has prevented widespread bypassed oil prospecting. These complex studies are generally performed only by the major oil companies on their larger reservoirs. Unfortunately, Louisiana has a large number of small reservoirs, with no giant fields such as those found in the middle east, the North Sea, Alaska, and Texas. Less costly bypassed oil prediction methods are needed to permit more widespread application of this technology.

In recent years, it has become increasingly difficult to economically produce many of the older reservoirs in the state because of declining well productivity and more stringent environmental regulations. Major oil companies have been steadily decreasing their activities in Louisiana and increasingly concentrating their oil and gas exploration investments into more profitable international opportunities. Smaller independent operators are playing an increasingly

important role in producing the state's remaining oil and gas and it is anticipated that this trend will continue in the future. The small independent operators do not maintain a research and development laboratory, nor do they have the large technical support staff generally found in the major oil companies. They seek to maintain profitability in mature fields with declining productivity primarily through reduced overhead. These companies depend on oil and gas technology available in the public domain instead of developing technology and sophisticated software through their own research and development activities. Thus, it is becoming more important for the state to maintain strong university components capable of supporting the oil and gas producing industry.

The primary objective of the project was to develop a predictive method for locating pockets of bypassed mobile oil and estimating the volume of this resource. A secondary objective of the project was to transfer the learned technology to small independent operators who drill a majority of the domestic wells but lack access to a research staff. Another objective was to develop a format for compiling data on Louisiana reservoirs in a form that can be used by government and industry to evaluate the resource and plan future activities. The format developed will be demonstrated using data compiled in the bypassed oil study for selected reservoirs. The project was being funded over a three-year period and was jointly funded by the DOE and the state of Louisiana.

The objectives of the project were accomplished using an interdisciplinary approach which included the disciplines of engineering, geology, and computer science. The work was organized into the following major tasks:

1. Selection of reservoirs for study of bypassed oil potential
2. Development of improved reservoir simulator for bypassed oil prospecting
3. An interdisciplinary reservoir characterization study of three Louisiana reservoirs
4. Predictive modelling of bypassed oil for three Louisiana reservoirs
5. Technology transfer activities

2.0 RESERVOIR SELECTION

The reservoir selection task was broken into three subtasks. In the first subtask, fifteen example reservoirs were selected and information on these reservoirs was compiled. In the second subtask, a pilot atlas was developed which presented the available public domain reservoir data in a form suitable for bypassed oil studies. The third subtask involved selecting three reservoirs for more detailed study.

2.1 Example Reservoirs

The example reservoirs included in the study were selected from three fields located as shown in Figure 2.1. The Corney Bayou field is located in north Louisiana, just south of the Arkansas border, in Union Parish. Reservoirs in this field are in deep carbonate formations of the North Smackover Trend on the edge of the Monroe Uplift. They tend to have a very limited water-drive production mechanism. The Fordoche field is located in Pointe Coupee Parish in central Louisiana about 40 miles north of Baton Rouge. Reservoirs in this field are deep, relatively shaley sandstone formations of the Eocene and Oligocene Trends that form as a result of growth faults in a deltaic environment. They tend to have a limited water-drive production mechanism. The Lafitte field is located in the wetlands of south Louisiana in Jefferson Parish, about 25 miles south of New Orleans. Reservoirs in this field are miocene-aged fluvial deposits of the South Louisiana Salt Dome Basin. These reservoirs are relatively shallow and tend to have a strong water-drive mechanism.

Figure 2.1 - Location of Fields Including Selected Reservoirs

A list of the example reservoirs included in the study is given in Table 2.1. The age of the reservoirs studied ranges from Miocene to Jurassic. API oil gravity ranges from 25.0 to 53.5, and the depth of the reservoirs ranges from 4,000 ft. to 14,000 ft. The fields were selected on the basis of potential for bypassed oil, quality of available data, representation of a different production mechanism, representation of different depositional environments, and willingness of the operators to cooperate with LSU in the study. Extremely deep reservoirs were not considered because the relatively high cost of drilling made justification of additional wells more difficult.

2.2 Pilot Oil Atlas for Louisiana

The primary source of public data on oil and gas fields in Louisiana is the public files of the Office of Conservation of the Louisiana Department of Natural Resources. In 1975, a computer database was installed, and much of the data routinely collected by the state has been entered into this database. Beginning in 1976, some reports were computerized, while other forms were not entered until 1979. Older data are maintained on file for manual access. The computer database system is called the Production Audit Reporting System (PARS).

Oil and gas companies operating in Louisiana are required by law to submit a number of forms to the Department of Natural Resources. Some forms are required to obtain the necessary permits to drill or perform remedial work on a well or to transport oil and gas. Other forms either provide information on well completions or well tests, or report produced or injected volumes. These forms are processed by the staff of the Department of Natural Resources and are the source of information for the PARS database.

The primary purpose of PARS is to allow audits of oil and gas production in the state to be easily accomplished. The system also permits annual state income from taxes and royalties on oil and gas production to be determined and future income to be projected. Information on the location and status of both active and abandoned wells is also made available to agencies concerned with public health or safety problems that could be related to leaking wells. PARS also supports the Office of Conservation in its activities to prevent waste, conserve the natural resources of the state, and promote equitable allocation of production in competitive situations.

A secondary purpose of PARS is to provide information to companies, landowners, and other individuals interested in oil and gas exploration activities. Computer terminals are

Table 2.1 - List of Reservoirs Studied								
Field Name	Reservoir Name	Geologic Age	Depth (ft subsea)	API Gravity	Original Oil in Place (MMBBL)	Original Displaceable Mobil Oil (MMBBL)	Anticipated Total Oil Produced (MMBBL)	Potential Bypassed Mobile Oil (MMBBL)
Fordoche	Wilcox 8	Eocene	13,175	44.0	33.8	15.3	12.6	2.7
	Wilcox 12	Eocene	13,630	45.0	34.7	13.2	11.6	1.6
	Wilcox 15	Eocene	13,850	47.5	1.6	0.8	0.3	0.5
	*Sparta A, RA	Eocene	11,300	47.0	6.8	3.6	3.4	0.2
	Sparta A, RB	Eocene	11,490	44.8	0.5	0.28	0.26	0.02
	Sparta A, RC	Eocene	11,443	53.5	0.2	0.10	0.07	0.03
	*Sparta B, RA	Eocene	11,565	42.0	3.0	1.6	1.10	0.5
	Sparta B, RB	Eocene	11,380	42.0	6.2	3.4	2.0	1.4
	*Sparta B, RC	Eocene	11,585	42.0	0.36	0.19	0.08	0.11
Corney Bayou	*Smackover A	Jurassic	10,115	49.9	9.8	6.4	4.1	2.3
	Smackover B	Jurassic	10,095	53.2	1.8	1.2	0.2	1.0
Lafitte	*S 3900 ft	Miocene	4,070	25.0	3.1	2.3	2.2	0.1
	*4300 ft	Miocene	4,470	25.0	4.4	2.8	1.6	1.2
	*4400 ft	Miocene	4,580	25.0	4.0	2.9	1.3	1.6
	*N 3900 ft	Miocene	4,070	25.0	3.1	2.2	2.1	0.1
* Identified for Detailed Study			TOTAL		113.4	56.3	42.9	13.36

maintained at the Department of Natural Resources building to allow public access to the PARS database. Another terminal is maintained in the offices of the Louisiana Geological Survey at LSU. Computer tapes containing the database can also be purchased by interested operators or service companies. Information users must generally write their own software to readily extract the desired information from the tape. Commercial oil and gas information service companies obtain much of their data for Louisiana in this manner.

Although extensive public information is available concerning Louisiana's oil and gas activities, data is not compiled for easy retrieval. In this study, available information on 15 example reservoirs was compiled in a form that would allow the potential for commercial quantities of bypassed oil to be estimated. The new database structure would also support more detailed studies of reservoir recovery efficiency using reservoir-simulation software. This pilot atlas reservoir database is currently being studied as a potential system for routinely reporting on active Louisiana reservoirs that were considered at reservoir wide hearings of the Office of Conservation during the year.

The pilot atlas database was set up completely separate from the PARS database to avoid any possible impact on the routine operations of the Department of Natural Resources by the LSU students and staff working on the bypassed oil study. Thus it was necessary to duplicate much of the data already available in the PARS system. It is envisioned that eventually the reservoir analysis features of the pilot atlas can be linked with the existing PARS system so that duplication of data is not required.

The pilot atlas database was stored in a form that could be used easily on a personal computer or workstation. DBASE IV operating in a Microsoft DOS 5.0 environment and DBFAST operating in a Microsoft Windows 3.0 environment were used to access the data during the pilot study. However, DBASE file format (*.dbf) can be read by many other database software packages as well as by most spreadsheet programs.

The details of the pilot oil atlas for Louisiana are presented in a separate report [Bourgoyne, Kimbrell, and Gao, 1993].

2.3 Selection of Reservoirs for Detailed Study

The sample reservoirs included in the pilot atlas are thought to illustrate a number of problems associated with prospecting for bypassed oil in old Louisiana reservoirs. These problems include:

- The bypassed mobile oil is thought to be less than a third of the produced oil;
- Many of the reservoirs are very small, making any attempt at additional recovery through additional drilling economically unattractive;
- Little core data are available, making reservoir characterization studies more difficult, and
- The larger reservoirs have already been extensively studied by the operators, and the remaining bypassed mobile oil is thought to be dispersed over a large area.

The data compiled for the pilot oil atlas was used to select three promising reservoirs for further study. These included:

1. Sparta B, Reservoir A of Fordoche Field
2. Smackover A Reservoir of Corney Bayou Field
3. 3900 ft. Reservoir of Lafitte Field

A major factor in the selection process was the willingness of the operator to cooperate in the study. Also, it had been agreed that one of the reservoirs selected for detailed study would be a carbonate reservoir. The Smackover A Reservoir of the Corney Bayou Field met this criteria. The Sparta B Reservoir of Fordoche Field was representative of reservoirs occurring in very shaly sands. The 3900 ft. Reservoir of Lafitte Field was representative of reservoirs with a strong bottom water drive and coning problems.

After the detailed reservoir study was initiated, it was decided to include the study of additional reservoirs above or below the selected reservoirs. The availability of multiple targets could not be neglected in determining the economic feasibility of an additional well or well segment.

3.0 IMPROVED RESERVOIR SIMULATION

One major goal of the project was the development of improved reservoir simulation software available in the public domain for prospecting for bypassed oil. The work done was divided into two major areas which included:

1. Physical model studies to provide data for testing new algorithms, and
2. Developing software improvements for an existing reservoir simulator available in the public domain.

3.1 Physical Model Studies

Two studies using models were undertaken to provide data for testing improved reservoir simulation algorithms for more accurately modelling water front advancements in a reservoir. The first study considered vertical sweep in a horizontal well near the top of a reservoir having a bottom water drive. The second study considered areal sweep near a well having short radius horizontal extensions.

3.1.1. Coning Study in Horizontal Wells

The coning study was conducted in porous plates made of artificial sandstone. The porous plate represented a greatly scaled-down model representing half a slice through a reservoir containing a horizontal well as shown in Figure 3.1. Within this study, two physical models were constructed: One by Hebert [1990] had a permeability of 12 darcies; Another by Abels [1990] had two permeabilities.

Figure 3.1 - Vertical Slice of Actual System Represented by Artificial Model

In both models, it was assumed that the reservoir was strongly water-wet and of high permeability so that the transition zone would be very short as compared to the reservoir thickness. This permitted the oil/water system to be studied in the analog model with two miscible oils. One of the oils was dyed to permit the interface between the two fluids to be visually traced. The model was thin enough (0.375 in.) so that a light placed behind the model would allow the regions containing the clear oil and the dyed oil to be easily identified photographically.

Hebert's model was constructed to permit study of the case in which the permeabilities to water in the swept and unswept regions of the reservoir do not differ greatly. This was done using a model having the same permeability throughout. Abel's model was designed to give data for the more complex situation in which there is a significant difference in the permeabilities to water in the swept and unswept regions. This could be accomplished in the analog by constructing the model with a lower permeability above the original oil/water contact.

The porous plate models were made of artificial sandstone produced by mixing sand with enough epoxy to coat the grains but not significantly fill the pore space. The first phase of the study was the development of a model construction procedure for obtaining regions of varying relative permeability. Seven epoxy resins and five sand grain size distributions were experimentally studied. The resulting porous plates were evaluated as to their strengths, porosity, permeability, and chemical resistance to six different solvents. The solvents were candidates for selection as analog fluids for the displacement experiments. Typical porosities and permeabilities from these tests are shown in Table 3.1. More details on this study were published by Hebert [1980].

Table 3.1 - Permeability and Porosity Data for Artificial Sandstone

<u>Sand Size</u>	<u>Average Permeabilities (darcies)</u>	<u>Average Porosity</u>
Coarse	40 - 50	.2968
Fine	10 - 12	.2807
Sugar	5 - 6	.2911
50% Sugar, 50% Fine	3 - 4	.2246

Hebert [1990] made ten experimental runs in a model in which the permeability to water above the original oil-water contact was equal to the permeability below the original oil-water contact. This would be representative for very high permeability reservoirs in which the permeability to water at residual oil saturation is nearly the same as the permeability at 100% water saturation. The model had an overall length of 20 in., an overall height of 13.25 in., and a thickness of 0.375 in. The porosity was 28% and the permeability was 12 darcies. Fluid was produced from the model horizontal wellbore placed at one of the top corners of the model and the bottom edge of the model was maintained at a constant pressure. All other surfaces of the model were sealed. The model represented half of a vertical slice through the reservoir as shown in Figure 3.1.

The fluid used in all runs was a mixture of Soltrol and Naphtha. The viscosity of a 57% Naphtha, 43% Soltrol by volume solution was approximately equal to one centipoise. Properties of all fluids are listed in Table 3.2. All of these fluids are totally miscible which allowed for easy mixing and the neglecting of capillarity. The water analog fluid was dyed red with Sudan IV^{*} red dye to allow tracing of the cone fronts.

Table 3.2 - Properties of Fluids Used in Experiment

<u>Fluid</u>	<u>Density (g/cc)*</u>	<u>Viscosity (cp)*</u>
Carbon Tetrachloride	1.590	1.02
Soltrol 170 ¹	0.776	2.80
Naptha	0.742	0.62

*Properties measured at 70° F.

1. Soltrol 170, Phillips Petroleum Company, Bartlesville, OK

The model set-up is shown in Figure 3.2. When readying the model for a displacement run, the top fittings and the leveling bulb with the clear fluid were opened to saturate the model with clear fluid (oil). Approximately two the three pore volumes of fluid were displaced to assure uniform fluid properties. Next, the valve below the leveling bulb containing clear fluid

was closed, as was the top manifold, and the valve below the leveling bulb containing the dyed fluid was opened. The bottom fitting was opened next, flushing all of the clear fluid out of the milled channel in the end butt, and then it was closed. The top fittings were reopened and the fluid rise was controlled with the valve connected to the top fittings, allowing a very slow rise to ensure an even front. Once the desired oil-water contact level was attained, the top fittings were shut off and plugged, the piston pump hooked to the horizontal well was switched on, and a timer was started. The system was flowed until approximately two to three times the pore volume of the oil zone was produced or all the clear fluid was produced, whichever occurred first.

While flowing, a piece of transparent plastic (Mylar) film was placed over the model, and cone fronts were traced at various times with a grease pencil. The times, read from the timer, were also noted. After completion of the run, the cone fronts were traced onto tracing paper and planimetered to determine area swept and water cut.

After a run was completed, two to three pore volumes of clear fluid were displaced through the model to remove all of the dyed fluid, readying the model for another run.

The test matrix for the ten runs made by Hebert [1990] are shown in Table 3.3. All of these runs are for a mobility ratio of 1.0. The first set of displacements used an oil/water density ratio of 0.836. This was the density ratio as determined by Cooke [1989] in his study of the Lafitte Field. The oil column was kept about 3.5 in. thick for this set of displacements. The variable parameter was the flowrate which was changed from 5.028 cc/min. to 0.365 cc/min. Six total runs were made each with a different flowrate. The water-analog fluid was weighted up by adding 17.75% carbon tetrachloride by total mixture.

Table 3.3 - List of Experimental Runs and Variable Parameters [Hebert,1990]

<u>Run Number</u>	<u>Oil Analog Density (g/cc)</u>	<u>Water Analog Density (g/cc)</u>	<u>Flowrate (cc/min)</u>	<u>Oil Zone Pore Volume</u>	<u>Oil Column Ht (in)</u>
1	0.756	0.904	5.028	119.48	3.5
2	0.756	0.904	2.873	123.63	3.5
3	0.756	0.904	1.676	139.22	3.5
4	0.765	0.904	1.463	127.95	3.5
5	0.756	0.904	0.716	124.95	3.5
6	0.756	0.904	0.365	121.48	3.5
7	0.756	0.904	1.676	171.26	5.0
8	0.756	0.904	1.676	82.64	2.0
9	0.765	1.052	1.676	121.25	3.5
10	0.756	0.830	1.676	119.17	3.5

The second set of displacements consisted of two runs with the variable parameter being the oil column thickness. The oil column was 5 in. thick for the first run, and 2 in. thick for the second run. The flowrate used for these displacements, 1.676 cc/min., was selected because, at this fairly low rate, a cone was produced when run with a 3.5 in. thick oil column in the previous set of displacements. It also reduced the time required for a full run, which could approach ten hours for some of the very low rates, while not being too fast such that tracing fronts was difficult as with higher rates. The density ratio was also kept constant during these displacements at 0.836.

The third set of displacements consisted of two runs with the density ratio being the variable parameter. Once again, the flowrate was kept constant at 1.676 cc/min., while the oil column thickness remained at 3.5 in. for both runs. The density ratios used were 0.719, which was achieved by adding 35.50% carbon tetrachloride by volume to the water fluid and 0.911, which was achieved by adding 8.88% carbon tetrachloride by volume to the water fluid.

Typical tracings of the oil-water interface at different times are shown in Figure 3.3 for two different production rates. Tracings for different initial oil column thickness are shown in Figure 3.4 and for different density ratios in Figure 3.5. The fraction of oil and water in the model at different times could be determined by planimetry the area of the model above and below the interface.

LOW flowrate
(0.365 cc/min)

high flowrate
(5.028 cc/min)

Figure 3.3 - Cone Front Tracings Showing the Effects of Flowrate on Cone Shape (Times shown are in minutes) [Hebert, 1990]

Thin Oil Column
($h_o = 2.0$ inches)

Thick Oil Column
($h_o = 5.0$ inches)

Figure 3.4 - Cone Front Tracings Showing the Effects of Oil Column Height on Cone Shape (Times are shown in minutes) [After Hebert, 1990]

After all the experimental runs were completed, the total volume swept was first calculated using the thickness and porosity of the planimetered areas. Next, the unit volumes swept were calculated, dividing first by the total volume swept and then by the total oil zone pore volume. These normalized values allowed meaningful comparisons among the runs. An example run is shown in Figure 3.6. Visual breakthrough was noted on each plot as was the unit-slope straight line that ideal data should follow until breakthrough. Due to diffusion and other experimental errors, the data did not always follow this line exactly before breakthrough. One of the more important experimental errors was related to the difficulty in measuring the effective thickness of the model after coating with epoxy. A loss in model thickness due to epoxy invasion would tend to make the data fall below the unit-slope straight line before breakthrough.

Figure 3.6 - Plot of Normalized Volume Swept Versus Normalized Volume Produced for Run No.6 [After Hebert, 1990]

Instantaneous water cuts were calculated by taking the plot of unit volumes swept versus unit volumes produced for each run and curve fitting them, and then taking the slopes at each point. Figure 3.7 shows example plots of water cut versus unit volumes produced for three different production rates.

Figure 3.7 - Plot of Instantaneous Water Cut Versus Normalized Volume Produced Showing the Effects of Flowrates [After Hebert, 1990]

Abels [1990] performed a study similar to that done by Hebert [1990], except that the model was constructed to have a lower permeability (9 darcies) above the original oil-water contact rather than below the original oil-water contact (12 darcies). This was done to simulate the effect of a residual oil saturation in the flooded region above the original oil-water contact while using miscible fluids. Miscible fluids were used to model the case in which the transition

zone is small compared to the total formation thickness. The model dimensions and properties used by Abels were the same original as used by Hebert except that the original oil zone thickness was always 3.5 in. The permeability above the original oil-water contact was 9 darcies, and the porosity above the original oil-water contact was 22.5%.

Abels made an additional 10 experimental runs in the two permeability model (Table 3.4). Six of the runs were made with a mobility ratio of 5.6 and an oil-to-water density ratio of 0.84, which corresponded closely to the conditions of Lafitte field. Flow rate was varied in these runs from 0.0418 cc/min to 7.16 cc/min. Four of the runs were made at a viscosity ratio of 1.0 to allow more direct comparisons of the results with those of Hebert [1990]. Frontal tracings for Abels' experimental runs are shown in Figures 3.8 - 3.10.

Table 3.4 - Parameters Used in Two-Permeability Model
[After Hebert, 1990]

<u>Run Number</u>	<u>Oil Analog Viscosity (cp)</u>	<u>Oil Analog Density (g/cc)</u>	<u>Water Analog Viscosity (cp)</u>	<u>Water Analog Density (g/cc)</u>	<u>Flowrate (cc/min)</u>
1	2.83	0.776	0.675	0.925	0.716
2	2.83	0.776	0.675	0.925	0.418
3	2.83	0.776	0.675	0.925	0.365
4	2.83	0.776	0.675	0.925	0.334
5	2.83	0.776	0.675	0.925	0.1671
6	2.83	0.776	0.675	0.925	0.0418
7	1.02	0.756	1.02	0.904	0.716
8	1.02	0.756	1.02	0.904	0.418
9	1.02	0.756	1.02	0.904	0.334
10	1.02	0.756	1.02	0.904	0.2005

Oil Zone Thickness = 3.5 in. for all runs

RUN # 1
 $M = 4.2$
 $q = 0.716 \text{ cc/min}$
 $h_0 = 3.5 \text{ in}$
 $\rho_0 = 0.776 \text{ g/cc}$
 $\rho_1 = 0.925 \text{ g/cc}$
 $\mu_0 = 2.83 \text{ cp}$
 $\mu_1 = 0.675 \text{ cp}$

RUN # 2
 $M = 4.2$
 $q = 0.418 \text{ cc/min}$
 $h_0 = 3.5 \text{ in}$
 $\rho_0 = 0.776 \text{ g/cc}$
 $\rho_1 = 0.925 \text{ g/cc}$
 $\mu_0 = 2.83 \text{ cp}$
 $\mu_1 = 0.675 \text{ cp}$

RUN # 3
 $M = 4.2$
 $q = 0.365 \text{ cc/min}$
 $h_0 = 3.5 \text{ in}$
 $\rho_0 = 0.776 \text{ g/cc}$
 $\rho_1 = 0.925 \text{ g/cc}$
 $\mu_0 = 2.83 \text{ cp}$
 $\mu_1 = 0.675 \text{ cp}$

**Figure 3.8 - Frontal Tracings for Two-Permeability Model:
Runs 1, 2, and 3 [After Abels, 1990]**

**Figure 3.9 - Frontal Tracings for Two-Permeability Model:
Runs 4, 5, and 6 [After Abels, 1990]**

**Figure 3.10 - Frontal Tracings for Two-Permeability Model:
Runs 7, 8, and 10 [After Abels, 1990]**

After a cone develops in a bottom water-drive reservoir, the reservoir can be divided into three regions of differing mobility. Region 1 corresponds to the water zone below the original oil-water contact, Region 2 corresponds to the water in the flooded zone above the original oil-water contact, and Region 3 corresponds to the oil zone above the cone. Hebert's data corresponds to a mobility ratio of 1.0 between Regions 1 and 3, Regions 1 and 2, and Regions 2 and 3. The first six runs of Abels correspond to a mobility ratio of 5.6 between Regions 1 and 3, 1.33 between Regions 1 and 2, and 4.2 between Regions 2 and 3. These conditions approximate those found in the 3900 ft. reservoir of Lafitte field [Cooke, 1989]. The last four runs of Abels correspond to a mobility ratio of 1.3 between Regions 1 and 3, 1.3 between Regions 1 and 2, and 1.0 between Regions 2 and 3. Figure 3.11 shows the effect of flow rate on oil recovery at breakthrough for these three sets of mobility ratios.

Figure 3.11 - Effect of Flow Rate on Oil Recovery at Breakthrough as a Function of Mobility Ratio [After Abels, 1990]

3.1.2 Sweep Efficiency Study in Horizontal Extensions

Recently, there has been considerable interest and enthusiasm concerning the use of horizontal wells to exploit some reservoirs that previously were only marginally economical. Long radius horizontal wells, which are drilled using more conventional drilling methods, are being extended several thousand feet through fractured formations in an effort to increase well productivity by intersecting multiple fractures. With conventional drilling methods a sharp bend, or "dog-leg", is not possible, and as a result, the turn from horizontal to vertical typically occurs over more than a thousand feet. Novel drilling techniques are currently being developed to drill horizontally out of existing wellbores and make the turn from vertical to horizontal over a much shorter depth interval. The "short radius" horizontal wells have a more limited reach and usually extend into the formation only a few hundred feet. A recent paper by Babu and Odeh [1989] discussed a number of well situations in which the use of horizontal wells may not result in an increase in the flow rate obtained per well. These authors suggest caution in choosing applications for horizontal drilling methods.

In this study the feasibility of drilling multiple short radius horizontal well extensions from an existing vertical well is explored as a method to improve the sweep efficiency of a waterflood. The study included a literature search to evaluate the effects of various injection patterns and mobility ratios on waterflood sweep efficiency. Upon completion of the literature search, the injection pattern for a model study was selected. The five-spot injection well pattern was chosen for the model study primarily because it has been more commonly used, and therefore, model results would be applicable to a great number of existing fields. The model results can also be used to test improvements in reservoir simulation software.

The model was constructed using a square porous plate to represent a quarter of a five-spot. The vertical producing well was modified by drilling horizontal extensions along each edge to a distance of 26.3% of the interwell spacing. Analog fluids of different colors represented the water and oil. The analog fluids were varied in such a way as to produce several viscosity combinations, and thereby provide for the effects of mobility ratio of sweep efficiency.

The five-spot is the most popular pattern for a variety of reasons. Primarily, it is easily adapted to the regular well spacing commonly used in developing a reservoir during primary recovery; therefore, a minimal investment is needed to convert select producers to injectors

(Figure 3.12). Secondly, if the reservoir is evaluated on the basis of (1) injectivity per well, (2) the mobility ratio, and (3) the degree of heterogeneity, as mentioned by Rose, Buckwalter, and Woodhall [1989], and if the reservoir in question exhibits a low injectivity or a large heterogeneity, then a five-spot has frequently proven to yield good results.

Figure 3.12 - Regular Spacing and Conversion to Five-spot Pattern

One basis for comparison of the flood patterns which does not take into consideration well costs or reservoir characteristics but is chiefly a function of pattern geometry and/or dimension (assuming a mobility ratio of unity) is sweep efficiency. Sweep efficiency, defined as that fraction of the reservoir contacted by water [Craig, 1971], ideally -- that is without economic considerations -- would be the sole basis for evaluation, and that pattern which provided the greatest sweep efficiency would be chosen. In the cases of the five-spot and inverted nine-spot patterns, electrolytic model studies by Muskat [1946] with a mobility ratio of 1.0 indicate that sweep efficiency is only a function of pattern geometry. The line-drive pattern's efficiency however is not only a function of geometry, but is also a function of the dimensions involved. Changes in the efficiency can be affected by altering the injector to injector distance, denoted as

"a", or the producer to injector distance, denoted as "d", or by staggering the wells. Therefore, in this respect, the line-drive is more flexible than either the five-spot or the nine-spot. Table 3.5 displays the sweep efficiencies at breakthrough determined experimentally for a mobility ratio of unity.

The model consists of a consolidated sandstone plate composed of sand grains and epoxy resin. The sandstone plate was constructed by packing a mold with a mixture of sand and epoxy resin. The mixture was first hand-packed in the mold and then further packed and leveled with a massive stainless steel roller. The epoxy was then hardened by placing the fabricated sandstone plate into an oven for several hours. All faces and edges of the sandstone plate were then sealed with several layers of epoxy. The first layers must be very thin and allowed to completely harden before additional coats of epoxy are applied. The objective was to plug as little of the pore space around the edges as possible while insuring an adequate seal.

After sealing the sandstone completely, plastic end pieces were placed on opposite corners along a diagonal of the square plate to allow swagelok fittings to be mounted on the corners. The fittings provide a connection for plastic tubing which will function as a means of transport for the flooding fluid from its container to the model. Next, a total of four holes were drilled into the model to simulate one vertical injector and one vertical producer with short radius horizontal well extensions. To simulate the vertical injection well, an 1/8 in. hole was drilled vertically in one corner. To simulate the production well, an 1/8 in. hole was drilled vertically in the opposite corner along the diagonal to represent the vertical component of the well, and two more 1/8 in. holes were drilled perpendicular to each other along the edges and intersecting in the vertical hole drilled in the corner (Figure 3.13).

Figure 3.13 - Schematic Showing Unit Area Selected for Model Study

A vacuum was placed on the model with a vacuum pump in an effort to evacuate all of the air present in the sandstone plate. The sandstone plate was then flooded with Naphtha to completely saturate the sandstone. Naphtha is a refined oil similar to gasoline and has a density of 0.75 gm/cc and a viscosity of 0.57 cp.

Once the model was sufficiently saturated with clear Naphtha, it was flooded with dyed Naphtha by connecting the injection well to a leveling bulb elevated about 7-ft above the model. Fluid produced from the production well was recovered in a graduated cylinder. During the flooding operation, the model was placed on a light table, and was translucent enough for the flood front to be visually observed. Every so often the flood front was traced, and the time and the volume displaced were recorded for each trace. The time and volume displaced at breakthrough were also noted, and the flood was allowed to continue until 100% displacement had been achieved. The model was now completely saturated with dyed Naphtha and ready for the next run using clear Soltrol as the displacing fluid. Soltrol is a light mineral oil having a density of 0.75 gm/cc and a viscosity of 2.5 cp. In the third and final run, dyed Naphtha was the displacing fluid, and clear Soltrol was the displaced fluid.

The traces of the flood front advance for each run were planimetered to determine the area displaced at each interval recorded. Since sweep efficiency is simply the area contacted by the displacing fluid divided by the total area, the sweep efficiency as a function of time and volume displaced was easily computed. The three runs made with three different fluid combinations yielded results for mobility ratios of 1.0, 0.23, and 4.3.

The experimental results for a mobility ratio of 1.0 are given in Figure 3.14. The data for a five-spot with vertical injectors and producers correspond to the solid diamonds while the data for the modified five-spot having the horizontal extensions correspond to the solid squares. The breakthrough sweep efficiency given previously by Aronofsky [1952] is shown as a solid triangle. Note that the breakthrough sweep efficiency obtained in this study was increased from 69.7% to 80.5% by the addition of the horizontal well extensions. However, the additional area swept tended to diminish as the injected volume after breakthrough increased. For injected volumes greater than about 1.25, the increase in sweep efficiency due to the horizontal extensions approached zero.

Figure 3.14 - Experimental Results Obtained for $M = 1$

The experimental results for a favorable mobility ratio of 0.23 are given in Figure 3.15. Again, the data for a five-spot with vertical injectors and producers correspond to the solid diamonds, the data for the modified five-spot having the horizontal extensions correspond to the solid squares, and the breakthrough/sweep efficiency given previously by Aronofsky [1952] is shown as a solid triangle. Note that the breakthrough sweep efficiency obtained in this study was increased from 82.7% to 92.2% by the addition of the horizontal well extensions. However, the sweep efficiency obtained for the unaltered five-spot (82.7%) was significantly less than the value of 95.3% reported by Aronofsky [1952], and the small differences in areal sweep efficiency seen in this study may have been due to experimental error. No addition in area swept was observed in this study for injection volumes above about 1.1 displaceable pore volumes.

Figure 3.15 - Experimental Results Obtained for $M = 0.23$

The experimental results for an unfavorable mobility ratio of 4.3 are given in Figure 3.16. Again, the data for a five-spot with vertical injectors and producers correspond to the solid diamonds, the data for the modified five-spot having the horizontal extensions correspond to the solid squares, and the breakthrough sweep efficiency given previously by Aronofsky [1952] is shown as a solid triangle. Note that the breakthrough sweep efficiency obtained in this study was increased from 59.75% to 67.4% by the addition of the horizontal well extensions. The beneficial effect of the horizontal extensions was again observed to decrease with increasing volumes injected, but remained about 3% better after three displaceable pore volumes injected. Thus, the beneficial effects of the horizontal extensions tend to become greater as the mobility ratio is increased.

Figure 3.16 - Experimental Results Obtained for $M = 4.3$

The experimental data shows that the use of Short Radius Horizontal Extensions (SRHE) on the production well would allow a given amount of oil to be recovered with less water production. This can be important where environmental concerns make water disposal difficult and expensive. Shown in Figure 3.17 is a comparison of the water produced as a fraction of the

displaceable pore volume to the five-spot pattern for vertical producers and for a producer with four SRHEs. Note that for a mobility ratio, M , of 4.3, 0.7 displaceable pore volumes of water must be produced to recover 90% of the oil when using four SRHEs having a length, L_e , of 18.6% of the spacing, S , between the producer and the injector. For a vertical producer, 1.1 displaceable pore volumes must be produced to recover 90% of the displaceable oil.

Figure 3.17 - Water Production Versus Oil Production as a Fraction of Displaceable Pore Volume for Vertical Producers (VP) and Producers with Four SRHEs

3.2 Improvements To Boast II

The BOAST II computer simulator released by DOE in 1988 was selected as the starting point in the development of an improved public domain reservoir simulator code to be enhanced for by-passed oil prospecting. Dr. John Tyler of the Computer Science Department and his students have taken the available code from DOE and prepared two new versions of BOAST II. Both versions were developed to run on the IBM 3090 with vector facilities. One version was restructured and modified to exploit the facility using IBM/FORTRAN. The second version was further modified to execute in parallel using IBM parallel FORTRAN. Test runs made to date using up to six CPU's in parallel on the IBM 3090 Model 6008 yielded an effective speed-up of about 20 due to both vector and parallel-processing improvements. A vectorized code was also prepared that can run on the IBM RISC 6000 workstation. Preprocessing and post processing programs were also written to assist in data preparation and output analysis. This work is described in detail in a publication by Tyler, Logan, Baron, Li, and Schneider [1990] and in a separate DOE report by Hebert, Bourgoyne, and Tyler [1993].

4 RESERVOIR CHARACTERIZATION AND PREDICTIVE MODELLING STUDIES

The goals of the characterization and modelling studies were to:

1. Estimate the magnitude of bypassed mobile oil in mature reservoirs nearing abandonment,
2. Provide actual examples to facilitate the development of LSU's interdisciplinary team,
3. Assist in the development of a closer working relationship between industry and academia, and
4. Test concepts aimed at increasing recovery from Louisiana's oil and gas reservoirs.

Analysis of studied reservoirs were performed by using an interdisciplinary approach which included the disciplines of engineering, geology, and computer science. Geologists on the team assisted in defining and mapping the various layers within each reservoir and in defining the depositional environment. Engineers assisted in modelling the fluid properties and in coordinating the reservoir simulation study. Computer science personnel assisted in improving the needed computer software. The systematic approach used for each reservoir studied included

the following steps:

1. Collect all available data from both public and operator sources, compare for consistency, and enter the data into the database.
2. Obtain oil and water data for geochemical analysis.
3. Reinterpret all available well log and core data and prepare cross sections.
4. Determine the most probable depositional environment and attempt to correlate core data and well logging data to establish permeability trends and depositional trends,
5. Reinterpret basic data to develop structure maps, isopach maps, porosity maps, permeability maps, initial saturation maps, and relative permeability curves with input from geologists, geochemists, and engineers on the team,
6. Using a public domain reservoir simulation package, input the physical description of the reservoir and associated aquifers using the various maps constructed, the initial reservoir pressure, the rock and fluid properties, and the observed well production rate history. Calculate the oil, gas, and water production history and the pressure history of each well by running the reservoir simulation software,
7. Compare the calculated production and pressure histories of each well and the overall reservoir to the actual historical production and pressure data in the database. If a satisfactory match is not observed, repeat steps 5 and 6 until one is achieved. This may require several team meetings to go over simulation software,
8. Map the remaining oil volume and distribution computed by the reservoir simulator,
9. Investigate economics of various schemes for recovering mobile oil using reservoir simulation software, and
10. Develop recommendations for operator. Recommendations should include possible production logs that could be run to verify simulation results in a few key areas.

The reservoirs initially selected for detailed study included the Sparta B Reservoir A of Fordoche Field, the Smackover A Reservoir of Corney Bayou Field, and the 3900-ft Reservoir of Lafitte Field. The study was later extended to include additional reservoirs in Fordoche Field

and Lafitte Field so that the possibility of multiple completion horizons for a single well could be considered.

4.1 Fordoche Reservoirs

The middle Eocene Sparta Formation is one of several Cenozoic regressive clastic-wedge sequences which comprise the Gulf Coast Basin fill. It varies in a dip direction from a sandstone-rich continental and deltaic plain depositional system into interbedded delta front and transitional marine sandstones and shales, and finally into a shale-rich prodelta and marine shelf depositional system. In south-central Louisiana, the Sparta Formation ranges in thickness from less than 750 ft. along the updip border of the study area to greater than 2,300 ft. along the downdip border. Within Fordoche Field, the Sparta Formation is associated with the delta front and transitional marine depositional system.

4.1.1 Depositional Environment

Fine-scale correlation of sixty-two well penetrations of Sparta B sandstones (Middle Eocene) in Fordoche Field, Pointe Coupee Parish, Louisiana, shows the unit is compartmentalized into an upper and lower sandstone by a thin "shale" body that is resolvable on standard (1"=100 ft) E-logs. Sedimentary structures and trace fossils preserved in conventional core of this thin "shale" indicate that it consists of interbedded fine to medium-grained sandstones and carbonaceous mudstones deposited as storm washover lobes, and tidal-inlet channels associated with a barrier island complex. The bulk of Sparta B production (estimated at ~5.6 MM STB OIP and 2.90 BCF GIP) is from upper shoreface and storm-washover sandstones whose pore spaces contain diagenetic chlorite, kaolinite, and calcite. EOR techniques involving SHF (sequential hydrofluoric acid stimulation) have eliminated declining production rates caused by these diagenetic minerals. Sparta mudstone samples bear a pyrolysis signature confirming a barrier island depositional regime. Iman values indicate Sparta rocks are immature to marginally mature in south-central Louisiana. The depositional environment was studied in detail by Krutac and Kimbrell [1991].

4.1.2 Geochemical Analysis

Oil samples were taken from the separator from seven wells in Fordoche Field. There

are currently four producing intervals in Fordoche Field, two in the Wilcox Formation and two in the Sparta Formation. Current production is from the Wilcox W-8 and W-12 sands, and the Sparta A and B sands. All production from the Wilcox 5 sand was shut-in approximately three months before samples were collected from this field. Two samples were collected from the W-8 sand, three samples from the W-12 sand, and one each from the Sparta A and B sands. The oils from the Wilcox sands and the Sparta sands differ considerably in appearance. The Sparta oils are very dark with a significant amount of asphaltenes present, and the Wilcox oils are a yellow color with very little asphaltene present. The API gravities of the Wilcox and Sparta oils are similar, with Wilcox gravities ranging from 44° to 50° API and Sparta gravities from 40° to 53.5°. The gas chromatograms of whole oil samples from both the Wilcox and the Sparta wells are very similar. The kerosine fraction chromatograms of these oils are also similar. The chromatograms show no evidence of biodegradation or of water washing. All the straight chain hydrocarbons from C₄ to C₃₆ are present in all these samples.

The difference in appearance may result from deasphalting of the Wilcox oils either by producing light hydrocarbons through thermal cracking or by the injected gas (nitrogen) used to maintain pressure in the reservoir. The preliminary results suggest the oils may have a common source, with the oils in the Sparta reservoirs migrating upward from a source rock in the Wilcox Formation. This is consistent with the earlier work of Roger Sassen, Liz Chinn, and Rowdy Lemoine which showed the Sparta formation in this area has a high enough total organic carbon content to function as a source rock, but is thermally immature for the generation of liquid hydrocarbons.

Chromatograms of oil samples from the Sparta A and Sparta B formations are shown in Figure 4.1. Note that they are very similar.

Sparta A

Sparta B

Figure 4.1 - C₈-C₁₄ Chromatograms of Separation Oils from Sparta A (Andrews Estate No.2) and Sparta B (Smith No.9)

4.1.3 Modelling Study

The modelling work for the Sparta Reservoirs has been described in detail by Halford [1992]. The Sparta B Reservoirs A and C are formed by an anticline and are composed of two laterally continuous sands separated by a thin shale. The reservoir was simulated as a three layer model with a 19 column by 12 row grid (Figure 4.2).

Figure 4.2 - Grid Selection for Sparta B Reservoirs A and C Modelling Study

The initial oil in place is 3.36 MMSTB, with most of this (2.92 MMSTB) being present in the upper Reservoir A sand. No free gas was initially in place. Table 4.1 summarizes the reservoir characteristics.

Table 4.1 - Reservoir Properties used in Modelling Study for Sparta B, Reservoirs A & C

Discovery well	N. Smith Jr. #7D, Sm-7		
Initial oil in place	3.36 MMSTB		
Initial solution gas in place	2.6 BCF		
Average net sand thickness	16 ft		
Average permeability: Initial	135 md, overall	160 md, near wells	
Average permeability: Matched	600 md, overall	235 md, near wells	
Average porosity	0.24		
Irreducible water saturation	0.48, Residual oil saturation 0.24		
Reservoir temperature	228°F		
Initial reservoir pressure	7,800 psia		
Bubble point pressure	2,075 psia		
Initial oil/water contact	11,588 ft subsea		
Formation Compressibility	15 μ sips		
Fluid properties @ 7,800 psia and 228°F			
	Oil	Gas	Water
FVF	1.28	0.0034	1.03
Viscosity, cp	0.36	0.012	0.41
Gas in Solution SCF/BBL	650	--	18
Density, lb/ft ³	51.7	0.05	62.7
Radial aquifer characteristics*			
$t_D = 0.01$ t, from:	Aquifer contact, B, = 7130 ft ² ,		
Compressibility	8 μ sips	from:	
Viscosity	0.40 cp	Oil/water interface**	404,000 ft ²
Permeability	80 md	Fraction connected	0.0177
Porosity	0.25		
Reservoir radius	8,000 ft		
r_e/r_w	∞		

* Modified Van Everdingen and Hurst radial aquifer model where,

$$\text{Aquifer influx} = B \sum_0^t (P_{t_e} - P_t) Q(t_D)$$

** The oil/water interface is the vertical area open to flow along the oil/water contact.

Production began in March 1973 from the Sun (Oryx) - J. Blanchard No. 4 well. Five wells were eventually completed in the reservoir. Total production through May, 1989 when all wells had been shut-in, was 1.089 MMSTB of oil, 755 MMCF of natural gas, and 2.785 MMSTB of formation water. Production from the reservoir has been summarized in Table 4.2.

Table 4.2 - Cumulative Production by Well for Sparta B, Reservoirs A and C						
	Well Comp.	Date Shut-In	Oil MSTB	Gas MMCF	Water MSTB	Sand
Sm-4	1/74	1/86	75.1	53.0	368.7	Upper
Sm-7	1/74	10/84	291.3	163.6	457.3	Upper & Lower
Sm-9	1/74	9/89	378.5	265.6	1,047.7	Upper
Sm-10	3/85	5/85	0.4	0.0	3.0	Upper
B1-4	3/73	5/89	341.0	273.1	908.7	Upper
Total			1,086.0	755.3	2,785.3	

The BOAST II simulator was used to model both the Sparta A and B reservoirs. Aquifer contact, horizontal and vertical permeabilities and oil and water relative-permeability curves were the five reservoir properties modified and estimated. Figure 4.3 summarizes the history match for the Sparta B reservoir. Most of the by-passed oil is located in a low permeability region near the shale-out as illustrated in Figure 4.4. One well currently is located very near the shale-out that is producing from a lower completion. It is estimated that this well could recover an additional 0.1 to 0.2 MM BBL of oil when it is recompleted in the Sparta B, Reservoir C.

Figure 4.3 - History Match for Sparta B, Reservoir A and C

Figure 4.4 - Location of Remaining Displaceable Oil in Sparta B, Reservoir A and C

The Sparta A, Reservoir A is formed by an anticline and is composed of three laterally continuous sands separated by thin shales. The reservoir was simulated as a three layer model with a 29 column by 25 row grid (Figure 4.5).

Figure 4.5 - Grid selection for modelling study of Sparta A, Reservoir A

The initial oil in place is 7.16 MMSTB. No free gas was initially in place. Table 4.3 summarizes the reservoir characteristics.

Table 4.3 - Reservoir Properties Used in Modelling Study for Sparta B, Reservoir A

Discovery well	N. Smith Jr. #7D, Sm-7		
Initial oil in place	7.16 MMSTB		
Initial solution gas in place	4.4 BCF		
Average net sand thickness	27 ft		
Average permeability:	370 md		
Average porosity	0.24		
Irreducible water saturation	0.44, Residual oil saturation 0.23		
Reservoir temperature	226°F		
Initial reservoir pressure	8,200 psia		
Bubble point pressure	2,450 psia		
Initial oil/water contact	11,350 ft subsea		
Formation Compressibility	15 μ sips		
Fluid properties @ 8,200 psia and 226°F			
	Oil	Gas	Water
FVF	1.38	0.0035	1.03
Viscosity, cp	0.36	0.011	0.41
Gas in Solution SCF/BBL	610	--	18
Density, lb/ft ³	51.7	0.05	62.7
Radial aquifer characteristics*			
$t_D = 0.01$ t, from:	Aquifer contact, B, = ft ² ,		
Compressibility	8 μ sips	from:	
Viscosity	0.40 cp	Oil/water interface**	ft ²
Permeability	80 md	Fraction connected	
Porosity	0.25		
Reservoir radius	12,000 ft		
re/rw	∞		

* Modified Van Everdingen and Hurst radial aquifer model where,

$$\text{Aquifer influx} = B \sum_0^t (P_{t_0} - P_t) Q(t_D)$$

** The oil/water interface is the vertical area open to flow along the oil/water contact.

Production began in May 1968 from the Sun (Oryx) - N. Smith #6 well. Four wells were eventually completed in the reservoir. Total production through September, 1989 when all wells had been shut-in, was 2,932 MMSTB of oil, 1,994 MMCF of natural gas, and 4,807 MMSTB of formation water. Production from the reservoir has been summarized in Table 4.4.

Table 4.4 - Cumulative Production by Well for Sparta A, Reservoir A							
Well	Date			Oil MSTB	Gas MMCF	Water MSTB	Sand
	Comp.	Start	Shut-in				
Sm-5	6/68	1/70	9/89	997	861	2,742	Upper, Middle
Sm-6	5/68	1/70	12/74	217	113	175	Upper, Middle
Sm-7	5/69	1/70	9/89	848	520	812	Upper, Middle
An-2	11/68	1/70	5/89	870	500	1,079	Upper, Middle
TOTAL				2,932	1,994	4,807	

Figure 4.6 summarizes the history match for the Sparta A, Reservoir A. Most of the remaining oil is located in the western portion of the reservoir as illustrated in Figure 4.7. Four wells are continuing to produce and it is expected that the remaining reserves from these completions will total 0.5 MM BBL. Sufficient bypassed oil may be present to justify a directional segment out of Sm-7 to the North-East. A directional extension from this well could also recover some additional reserves from Sparta B, Reservoir C.

Figure 4.6 - History Match for Sparta A, Reservoir A

Figure 4.7 - Location of Remaining Displaceable Oil in Sparta A, Reservoir A

4.1.4 Shaly Sand Study

The model study for the Sparta A and B Reservoirs reported in the previous section used conventional log analysis procedures done by the well operators. The high shale content of the sparta sands also led to uncertainty in computing the initial oil saturations, and may have resulted in productive zones being bypassed due to log interpretation problems. Combariza [1990] undertook a study of possible bypassed oil in the Sparta reservoirs due to misinterpretation of well logs. This work was based on a newly developed shaly-sand model.

The Sparta formation is composed, from top to bottom, of the sands Sparta Stray, Sparta A and Sparta B (Fig. 4.8). The Sparta Stray is a thin sand located approximately 250 feet above the Sparta A. This sand has never been tested for possible production; however, log analyses and core data indicate that the Sparta Stray could possibly be productive.

Figure 4.8 - Type Log Sparta Sands in Fordoche Field

To locate possible bypassed oil in the shaly Sparta sands, a comparison between well log interpretation performed by the operator and the application of the LSU shaly sand models was performed. Three input data are needed in the LSU model: formation factor, formation resistivity and spontaneous potential. All three variables can be determined from well logs. Formation resistivity and spontaneous potential were read directly from the deep resistivity curve and SP curve, respectively.

Porosity in shaly sands is best determined from neutron-density crossplots. However, neither neutron nor density logs were run in the Sparta sand. Therefore, sonic-porosity was used. Porosity and formation factor are calculated as:

$$\phi_{sonic} = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}$$

and

$$F = \frac{0.81}{\phi^2}$$

Values of 189 and 55.5 μ sec/ft were used for the fluid and matrix travel time. In those cases in which sonic logs were not available but core data were, core porosities were used.

Also, given that among the intervals under study there is no clean water-bearing formation, R_w could not be obtained directly from the SP. Therefore, R_w was obtained separately for each interval using the LSU model [Combariza, 1990]:

$$R_w = 0.065 \text{ ohm-m for Sparta Stray.}$$

$$R_w = 0.068 \text{ ohm-m for Sparta A.}$$

$$R_w = 0.072 \text{ ohm-m for Sparta B.}$$

The value of water resistivity used customarily by the operator is 0.07 ohm-m. Because of the similarity among R_w values, good agreement in the calculated water saturations in the cleanest intervals is sometimes observed. A membrane efficiency of 0.8 was used in every case. With the aforementioned considerations, water saturation profiles were determined for all those wells for which enough information was available.

The El Plant No. 4 was completed as an oil producer in Sparta A (referred to as the one-well reservoir Sparta A-RB) in the interval 11499/510 ft. (Fig. 4.9) and produced initially 310 BOPD and 842 MCFGPD with 0.2% BS&W. Three years later the well was producing 41

BOPD and 273 MCFGPD with 7.0% BS&W. After performing Claysol acid stimulation the production was raised to 59 BOPD and 140 MCFGPD with 1.0% BS&W. Eight years after initiating production, the well was producing 7 BOPD and 45 MCFGPD with 88% BS&W. Since this interval is a clean sand, evaluation of hydrocarbon potential is not questioned. In fact, both water saturations are the same.

However, in the interval 11510/584 ft. a very shaly sand is present. Water saturations averaging 52% were found using the LSU shaly sand models described in Chapter 4; Q_v avg. = 0.46 in the same interval. Since at 11590 ft. there appears a zone with a resistivity of 0.9 ohm-m, which is the same resistivity of the shales at 11490 ft., it is believed that this is the value of resistivity for shales associated to this formation. Any increase in resistivity may be caused by the presence of either hydrocarbons or tight intervals, the last of these two being easy to identify by observing porosity logs.

In order to remove this uncertainty, a Pickett crossplot was done (Fig. 4.10). As it can be seen in Fig. 4.10, the zones labeled as j, k, l, and o have different lithology from the remaining zones in the interval. The intent is not to give a complete interpretation of the crossplot in terms of water saturations. Instead, the crossplot helps to identify the different zones within the interval, i.e. shale, shaly sands, clean sand and tight zones.

Given the values of S_w calculated using LSU models, the interval 11510/584 ft. was overlooked. This is confirmed by the fact that sidewall cores or tests were not taken below 11507 ft., which indicates that the interval was not taken into account. This interval may be of low permeability but, given the good results of Claysol treatments both in this well and in others, this fact should not disqualify the zone from function consolidation as a potential producer.

A water saturation profile was obtained for this well in Sparta B, also. This formation was tested in the interval 11720/737 ft. and no flow was obtained. From core data, it can be seen that the permeability in the tested interval is quite low; k avg - 6.5 md. However, if it is considered that the potential interval goes down to 11794 ft. (based on similar features for Sparta A), this interval should be considered a possible hydrocarbon producer. Average water saturation in the upper portion of the zone, i.e. 11718/734 ft. is 47% and $Q_v = 0.09$. As shaliness increases downwell, Q_v increases to an average of 0.5 and S_w goes up to 53%. Water saturation calculated by the operator in this interval was not available.

Figure 4.9 - Electric Logs and S_w 's. El Plant No. 4

Figure 4.10 - Pickett Crossplot. El Plant No. 4, Sparta A

It appears that the oil/water contact in these shaly intervals of both Sparta A and Sparta B is found at high resistivities of approximately 1.3 ohm.m instead of 2.0 ohm.m. This was assumed to be true unless there was other evidence, as is the case of Sparta B in the No. Smith Jr. No. 4.

Figure 4.11 - Electric logs and S_w 's. N. Smith Jr. No. 4

The N. Smith Jr. No. 4 well was completed in the small Sparta B-RB reservoir with an initial production of 340 BOPD and 109 MCF6PD with 0.1% BS&W in the interval 11583/59s ft. (Fig. 4.11). Only one year later, oil production decreased to 27 BOPD and the gas production to 20 MDFGPD; water cut went up to 89.8%. In this formation it is clear that the oil/water contact is at 11598 ft. Given the small size of this one-well reservoir (25 acres), water encroachment was the result of the high rates of production and the driving forces of the aquifer. LSU shaly models were applied only where core data were available because no sonic log was obtained. Average water saturation values of 50% are in near agreement with those reported by the operator.

At 11326 ft. (Sparta A) there is a water saturation of 50% calculated by applying the LSU models. The operator reported 55%. However, this layered interval (11310/338 ft.) is yet to be completed in this well. Because the permeability is reported to be 110 md at 11326 ft. and because of the calculated water saturation of this interval should be considered as a potential hydrocarbon producer.

The N. Smith Jr. No. 5 well was initially completed in the interval 11301/309 ft. (Sparta A) with 864 BOPD, 435 MCFGPD and 0.3% BS&W. Three years later the well no longer produced water-free oil and began to produce with a water cut of 13%. Since then, the percentage of water increased constantly and 14 years after the initial completion, the rate of production was 55 BOPD, 55 MCFGPD and 87.5% BS&W. From the resistivity logs (Fig. 4.12), it can be inferred that the whole zone is hydrocarbon (from 11301 to 11338 ft.); water saturations using the LSU models average 45% between 11316 ft. and 11338 ft. and Q_v avg. = 0.3. The operator does not have water saturations reported in the same interval. However, the oil/water contact should have moved upwards given the initial rates of production, the latest water cut reported, and the strong water drive mechanism. Sidewall cores were taken but none of them between 11316 ft. and 11338 ft., indicating that this interval was not taken into consideration.

On the other hand, the Sparta B sand was not completed in this well despite the cleanness of the sands. The oil/water contact is at 11577 ft. Water saturation from 11571 ft. to 11577 ft. average 48%; high resistivity at 11560/566 ft. is due to a tight zone. Core data shows that the interval 11571/577 ft. might produce oil of 37° API.

There is another interval, from 11543' to 11558' associated with the Sparta B. In this interval, the sand is very shaly ($Q_v=0.5$) and the calculated water saturation is 48% using the LSU shaly sand models. This interval was also rejected from further consideration by the operator.

Figure 4.12 - Electric logs and S_w 's. No. Smith Jr. No. 5

The N. Smith Jr. No. 9 (Fig. 4.13) was completed in Sparta B from 11570 ft. to 11580 ft. The initial completion production was 179 BOPD, 36 MCFGPD and 0.1% BS&W. Four years later the production had declined to 35 BOPD, 12 MCFGPD and 6% BS&W. Then, Claysol stimulation was performed and the results were very good as production increased to 307 BOPD, 50 MCFGPD and 15% BS&W. Within a five-year period, production subsequently decreased to 40 BOPD, 20 MCFGPD and 73.2% BS&W. Water saturations reported by the operator in this sand are 11550/572 ft., $S_w = 81\%$ and 11572/596 ft., $S_w = 65-56\%$. LSU models give 11554/556 ft., $S_w = 39\%$ ($Q_v = 0.53$), 11566/578 ft., $S_w = 59\%$ ($Q_v = 0.16$), 11578/588 ft., $S_w = 30\%$ ($Q_v = 0.08$) and 11590/594 ft., $S_w = 58\%$ ($Q_v = 0.16$) (See Fig. 4.18). As it is seen, two potential crude producer intervals were possibly missed in the Sparta B: 11554/570 ft. and 11580/594 ft. In fact, examining the Gamma-ray log (Fig. 4.13), it can be seen that shaliness decreases downwell from 11550 ft. to 11570 ft. until the clean sand portion is reached. This feature is not shown by the SP log probably due to low permeabilities in the zone.

Since the whole Sparta B sand in the N. Smith Jr. No. 9 is quite shaly (Q_v avg. = 0.24) and the stimulation response was good, it is possible that the same should happen if stimulations are performed to improve permeability in all those potential intervals having very low permeabilities. The permeability at 11572 ft. (within the interval stimulated) is 3.4 md.

In Sparta A, two tight zones rest on a small sand that contains oil; water saturation in 11310/320' is 40% and in 11320/326 ft. is 56%. The oil/water contact is at 11327 ft. This sand, regardless of its clean appearance, has not been completed and a significant amount of oil remains there. Also, at the level of 11400 ft., there may exist another hydrocarbons zone: LSU models give $S_w = 37\%$, $Q_v = 0.34$ at 11386/392 ft. and $S_w = 43\%$, $Q_v = 0.57$ at 11400/430 ft.

The N. Smith Jr. No. 7 well was completed in both Sparta A and Sparta B (Fig. 4.14). It was originally completed only in the top of Sparta A (11293/310 ft.) with 360 BOPD, 53 MCFGPD and 0.1% BS&W. Three years later, Sparta B was completed in the interval 11570/578 ft. and perforations from 11310 ft. to 11320 ft. were added to the original completion of Sparta A. Production then went up to 437 BOPD, 163 MCFGPD and 1.0% BS&W. Claysol stimulation in the Sparta A eleven years after the initial completion improved production from 70 BOPD, 23 MCFGPD and 60% BS&W to 107 BOPD, 62 MCFGPD and 60% BS&W.

In the Sparta B, which is clearly dirtier than Sparta A (Q_v avg. = 0.2), only a small section of the whole interval was perforated and put on production. Water saturations calculated using the LSU shaly models give an average of 37% water from 11558 ft. to 11590 ft.

Figure 4.13 - Electric logs and S_w 's. N. Smith Jr. No. 9

Figure 4.14 - Electric logs and S_w 's. N. Smith Jr. No. 7

Again in this well, as in N. Smith Jr. No. 9, the very top of the Sparta B is shalier than the rest of the interval and from 11550 ft. to 11560 ft., there is an average S_w of 49% ($Q_v = 0.48$). Unfortunately the S_w 's calculated by the operator for this well were not available and comparisons could not be made.

As a means of illustrating the possibility of having by-passed oil in those wells not completed in the Sparta Sands, water saturation profiles were calculated using the LSU shaly sand models. This data is provided to be used by the operator in order to perform a complete study of the reservoir as a whole. It is hoped that this information will be valuable in achieving this task in order to increase reserves in the Fordoche Field. In this section, some notes for several wells not completed in either of the Sparta sands follow. Such wells are C. F. Long No. 1, J. Blanchard No. 1 and J. Blanchard No. 2.

Sparta A in the C. F. Long No. 1 well is very shaly; in fact, $Q_v = 0.41$. This sand has two intervals, 11370/392 ft. and 11460/468 ft., whose water saturations are 38% and 46%, respectively (Figure 4.15). The operator reports $S_w = 80\%$ for the latest interval mentioned. Low permeabilities are expected in Sparta A but no cores were taken.

Sparta B, however, is somehow more promising. At the top, a tight interval is present. Underneath this tight zone, i.e. in the interval 11640/673 ft., S_w 's reported from conventional interpretation average 68% while using LSU models, $S_w = 58\%$ and $Q_v = 0.1$. Shaliness increases downwell and no S_w is reported by the operator; however, water saturation of 46% and Q_v 's of 0.26 were calculated in the interval 11673/706 ft.

The Sparta A in the J. Blanchard No. 1 well is composed of a sequence of tight zones and shaly sands (Figure 4.16). Average water saturation in the interval 11318/398 ft. is 52% and $Q_v = 0.38$. Below 11400 ft. deep resistivity value is very low so that this is already a transition zone. No S_w 's were reported from the operator of the Sparta A.

In this case the Pickett crossplot is again useful to identify different zones along the interval. Fig. 4.17 shows the patterns that identify shales, shaly sands containing hydrocarbons, and tight zones.

In the Sparta B, a clean portion appears close to the top of the sand. At the very top of the interval, i.e. between 11552 ft. and 11562 ft., $S_w = 51\%$ and $Q_v = 0.45$. The interval 11564/584 ft. contains about 32% water so that a considerable amount of oil is present in this 20-foot thick sand. The o/w contact could be either at 11588 ft. or at 11640 ft. LSU models give S_w of 56% in this region; the operator reports 67-88% water for the same interval, i.e.

11588/640 ft. In this case, as in many others, testing is needed for conclusive results.

Figure 4.15 - Electric logs and S_w 's. C. f. Long No. 1

Figure 4.16 - Electric logs and S_w 's. J. Blanchard No. 1

Regardless of the cleanness of Sparta A, this sand was not yet completed in the J. Blanchard No. 2 (Figures 4.18 and 5.18). $S_w = 26\%$ from 11308 ft. to 11320 ft. and, as shaliness increases from $Q_v = 0.06$ at 11327 ft. to $Q_v = 0.32$ at 11340 ft., S_w remains at 43%. In the interval 11356/380 ft. S_w 's of 42% and Q_v 's of 0.42 were found. Below this depth there are tight zones of no interest.

On the other hand, the whole Sparta B is shaly in this well. The operator reports an average water saturation of 80% along the interval. However, considering the degree of shaliness, water saturations may be approximately 55% as given by the LSU shaly sand models. No other parameters confirm this assertion but, given the similarity to the same sand in the completed wells, it is believed that the complete sand likely contains hydrocarbons of commercial value.

Figure 4.17 - Pickett Crossplot. J. Blanchard No. 1, Sparta A

The Sparta Stray is a thin sand located approximately 250 ft. above the Sparta A and has not been tested for possible production. Well log interpretation performed by the operator gives very pessimistic results. However, considering the degree of shaliness that this interval presents in some wells, the use of the LSU shaly sand models supports the possibility that the Sparta Stray is a potential hydrocarbon producer. As a means of example, here are some comments that illustrate such possibility.

- i) The N. Smith Jr. No. 7 well (Figure 4.19) has an average water saturation of 56% and $Q_v = 0.17$ in the interval 11070/086 ft. Sidewall cores at 11078 ft. showed a permeability of 16 md. The same cores contained enough oil saturation to consider the interval as producer of hydrocarbons. Interpretation by the operator was not available for this well.
- ii) The N. Smith Jr. No. 9 well (Figure 4.20) presents a very shaly Sparta Stray. The water saturation averages 47% along the interval 11061/080 ft. $Q_v = 0.38$. From sidewall cores taken in this interval, permeability of 215 md was reported at 11069 ft.
- iii) In the case of El Plant No. 1 well (Figure 4.21), the operator reports 97% water at 11202/200 ft. and 64% at 11206/212 ft. Using the LSU shaly sand models it was found that at 11190 ft., $S_w = 51\%$ and $Q_v = 0.53$, and that in the interval 11206/216 ft., $S_w = 59\%$ and $Q_v = 0.15$.

Unfortunately in most cases the operator does not report water saturations in the Sparta Stray and not much can be done in terms of comparisons. However, given the values obtained using the LSU shaly models, it is believed that this sand should be considered for perforating and testing for possible production.

Figure 4.18 - Electric Logs and S_w 's. J. Blanchard No. 2

Fig. 4.19 Electric and Sonic logs. N. Smith, Jr. #7, Sparta Stray

Fig. 4.20 Electric and Sonic logs. N. Smith, Jr. #9, Sparta Stray.

Fig. 4.21 Electric and Sonic logs. El Plant #1, Sparta Stray

Therefore, as a consequence of the reinterpretation of the well logs data in the Sparta sands in the Fordoche Field some possibilities of by-passed oil were found. Such possible locations of by-passed oil can be summarized as:

- i) An isolated zone that has never been tested for possible production: Sparta Stray. This sand should be tested given the data obtained from sidewall cores and the water saturations calculated.
- ii) Shaly sections not included in the completions of the Sparta A. Although this reservoir is being drained by some wells, there are places to look for pockets of by-passed oil due to uneven advance of water. The same goes for the Sparta B, where the sand was tested and no flow was obtained.
- iii) The top of the Sparta B appears to be an ideal place to look for by-passed oil. Saturations calculated in this 15-20 ft. shaly section give offers potential reserves from Sparta B reservoirs in the Fordoche Field. Since this portion is on top of a tested and produced hydrocarbons interval, it does not have the danger of having water underneath. This portion has not been tested for possible production.

The previously mentioned possible locations of by-passed oil are illustrated on the schematical cross-section on Fig. 4.22. Fig 4.22.A is a base map showing the same cross-section. The only way to confirm the existence of this oil is by testing the individual sections proposed here. Of course, this depends upon the status and configuration of each one of the wells.

Fig. 4.22 Cross-section showing possible by-passed oil zones.

Fig 4.22.A Base Map of the cross-section of Fig. 4-22

4.2 Corney Bayou Reservoir

The Corney Bayou Field is located in Union Parish in North-Central Louisiana. The field is approximately 1 mile wide and 4 miles long (about 2680 acres), and has been producing oil and gas since March 1980. Primary production was accomplished with either water or gas drive. Gas injection was initiated in July 1984 for pressure maintenance. By then the field had produced approximately 1 million bbls of oil, 3,400 mscf of gas and 198,000 bbls of water. The

field is penetrated by 32 wells, 15 of them are producing or at least had produced at some time. The field is a structural-stratigraphic trap formed by the pinchout of an East-West striking oolitic shoal that traverses a broad South plunging nose. Later structural movement along a hingeline influenced the reservoir by initiating an updip hydrocarbon migration. The reservoir is limited down-dip by an oil-water contact at -9,954 ft.

4.2.1 Depositional Environment

The upper Jurassic stratigraphic sequence in the northern Louisiana-southern Arkansas region has been described in detail in the past [Bishop, 1968, 1969; Dickinson, 1968; Moore, 1984, 1986, 1990]. The sandstone and shales of the Norphlet Formation conformably underlies the Smackover Formation, which is divided into two members in this area, lower carbonate mudstones and shales [Russell, 1979] and upper, generally porous, carbonates [Bishop, 1969]. The Smackover Formation is overlain conformably by the Buckner Formation which is primarily shale and siltstone with minor anhydrite [Dickinson, 1968]. Carbonate grainstone interbeds [Moore, 1984] occur within the Buckner, one of which is the Smackover "A" zone.

The Smackover "A" within Corney Bayou Field is a structural-stratigraphic hydrocarbon trap. The Smackover "A" is lithologically similar to the upper Smackover Formation. However, the upper Smackover occurs as a regional thick blanket-like ooid sand, whereas the Smackover "A" occurs as strike-parallel individual carbonate sand bodies. The Corney Bayou Smackover "A" reservoir follows this trend as an isolated carbonate sand-body wedged within the less porous and permeable siliciclastics of the Buckner Formation and forms an east-west trending deep-seated anticline which dips to the south. The reservoir is an textbook stratigraphic trap; the sand pinches out to form the northern boundary of the reservoir, while an oil-water contact of -9,954 fbsl forms the east, west and south reservoir boundaries. A structure map is shown in Figure 4.23.

Extensive coring was performed by the operator and subsequent detailed analysis was performed by LSU on the sand. From this analysis a vertical section illustrates an early increase in energy as the sand body evolved from an ooid-bearing fossiliferous packstone-boundstone to an oolitic grainstone. Later, energy decreased and the oolitic grainstone was overlain by a muddy oolitic wackestone to packstone. The uppermost muddy oolitic wackestone attests to gradual dilution deposited in a lagoonal environment. Porosity is primarily intergranular and is greatest in the higher energy lithofacies as is the hydrocarbon production [Moore, et al, 1986].

Figure 4.23 - Structure Map of Smackover "A" Reservoir, Corney Bayou Field

4.2.2 Geochemical Analysis

The geochemist on the team took oil samples from all wells that were producing during the study. An example chromatogram is shown in Figure 4.24. The analysis indicated similar compositions for all wells. This evidence supported the interpretation of hydraulic connection among these wells.

4.2.3 Production History

Subsequently after the discovery and confirmation of Corney Bayou Field in 1980, 31 additional wells were drilled within the field. 15 of these wells produced or are presently producing the Smackover "A" reservoir. The others defined the limits of production and also encountered a smaller reservoir, Smackover "B", within the main Smackover Formation. Primary recovery of the volatile hydrocarbons was driven by formation solution gas and a very small amount of aquifer influx until July 1984 when gas injection began. Primary recovery to the beginning of gas injection was 1.1 MMSTB of oil and 3.5 MMCF of natural gas. The initial injection rate was 2852 MCFD at 3300 psi into the Woods and Deas - R.L. Lee No. 1 well. The reported injection rate on October, 1990, was 5371 MCFD at 3000 psi into the same well. To

date, the reservoir has produced 2.76 MMSTB of oil in-place. This equates to 18.2% of the in-place oil or 32 STB/acre-ft. The initial producing GOR is 1142 SCF/STB, while the present producing GOR is 18,756 SCF/STB. The reservoir has produced 18.4 BCF of natural gas, of which 10.0 BCF has been re-injected. Table 4.5 presents cumulative production per well for oil, gas, and water from the Smackover "A".

Figure 4.24 - C10+ saturate chromatogram for Corney Bayou Liquid Sample

<u>WELL API</u>	<u>STB</u>	<u>MCF</u>	<u>BBL H₂O</u>
17111221320000	27927	46540	6536
17111223070000	300000	2858800	25229
17111224890000	256634	1503716	321731
17111225010000	162080	377335	340319
17111225950000	181031	816775	221505
17111226960000	200507	1850624	19764
17111228020000	5420	14255	4300
17111230430000	36561	231177	31473
17111232410000	132452	485310	302223
17111232420000	99243	298888	466130
17111234170000	212609	1815667	57152
17111235140000	127524	1243132	1824
17111235390000	862560	6008905	16416
17111236050000	67515	117889	29250
17111238130000	91742	738068	6361

Table 4.5- Cumulative Fluids Produced by Well from Smackover "A" Reservoir, Corney Bayou Field

Figure 4.25 shows the total annual oil production, producing gas-oil ratio, and water-oil ratio for the reservoir as a function of time. A decline curve extrapolation performed prior to the reservoir modelling study indicated future recovery from existing completions to be about 1.3 MMSTB.

4.2.4 Reservoir characteristics

Contained in Table 4.6 is a compilation of average reservoir characteristics. The reservoir fluids exhibit volatile oil characteristics. Its initial GOR was 1142 SCF/STB, and API gravity of 50.7 and the formation temperature was 212 F. There was no PVT data for this particular reservoir. However, an analysis was available on an offsetting Smackover Formation Field and LSU's study incorporated this data into their study.

4.2.5 Reservoir Modelling

The Smackover "A" reservoir was simulated with the modified Boast II simulator. The grid boundaries were selected to be North-South and East-West in direction. The grid was designed with 500 ft. by 500 ft. blocks throughout. The grids were arranged with 42 columns, 12 rows and 3 layers for a total of 1,512 blocks. Only the reservoir facies of the Smackover "A"

zone was considered in the simulation. Initially, layer 1 (top) had an average porosity of 10%, while layers 2 and 3 had average porosities of 9%. Permeability variations between layers was very low with an estimated Dykstra-Parsons Coefficient of 0.75. Therefore, initially all three layers had horizontal permeabilities of 43 md and vertical permeabilities of 4.2 md. These were modified later, in varying degrees, in order to obtain a simulation history match. Initial average oil saturation was set 72%, with connate water saturation occupying the remaining 27% of the pore space. There was no initial gas cap. The initial reservoir pressure was 4976 psi which was slightly above the initial bubble point pressure of 4831 psi at the reservoir temperature of 212 F.

Figure 4.25 - Production History for Smackover "A" Reservoir

Table 4.6 Properties of Smackover A Reservoir, Corney Bayou Field

TYPE HYDROCARBON-----	VOLATILE OIL
AGE-----	JURASSIC
AVG DEPTH-----	-9124 FBSL
INITIAL SIBHP-----	4875 PSI
PRIMARY DRIVE-----	PRESSURE
INITIAL GOR-----	1142 SCF/STB
AVG POROSITY-----	11.0 %
INITIAL Sw-----	28.0 %
AVG PERMEABILITY-----	40.0 MD
AVG NET PAY-----	24 FT
AVG GROSS PAY-----	30 FT
AVG OIL/WATER-----	9954 FBSL
BOTTOM HOLE TEMP-----	212 DEGREES F
BUBBLE POINT PRESSURE-----	4831 PSI
INITIAL Bo-----	2.11 RES BLS/STB
Sg OF GAS-----	0.600 RATIO
API-----	49.9 DEGREES
OIL VISCOSITY-----	0.079 CP
EST OIL IN PLACE-----	9800 MMSTB
EST GAS IN PLACE-----	65268 MMCF

The results of the simulation confirmed that there was a small, almost negligible, amount of aquifer influx into the reservoir with the majority of reservoir energy originating from solution and, later, injected gas. The best history match of the reservoir indicates a smaller reservoir than originally thought. Simulation estimates were about 8.9 MMSTB originally in place. Volumetrically, the estimate was 9.8 MMSTB. The Smackover "A" sandstone is a fairly homogenous reservoir rock, therefore a consistent porosity is expected. Based on the simulation, porosity probably averages 10% which is slightly lower than 11% estimated from core analysis.

Based on these estimates, the reservoir has produced about 31% of the oil in place. The simulator indicated a consistently swept reservoir rock without any substantial pockets of highly saturated mobile oil. The one injection well is found almost dead center in the reservoir and seems to have had fairly good response throughout the reservoir. However, oil saturations at the end of the simulation average higher in the western half of the reservoir. Upon further investigation, it was evident that production from the eastern half of the reservoir has been more efficient than the western half. The eastern half of the reservoir has produced 1.45 MMSTB from 6 wells giving an average of 0.242 MMSTB/well, while the western half of the reservoir has produced 1.31 MMSTB from 9 wells giving a 0.145 MMSTB/well average. Reservoir

quality does not appear to be drastically different between the east and west (with the exception of the Holloway No. 1 well, which is above average), yet an obvious production discrepancy exists.

The reservoir is presently producing and it is expected to recover an additional 1.3 MMSTB. This would leave approximately 1.7 MMSTB bypassed mobile oil. A large portion of this bypassed oil is located in the western portion of the reservoir. A recommendation to the operator is to locate an additional gas injector in a well to the west in order to obtain better sweepage of this portion of the reservoir. Additional simulation studies could be run using present day PVT values to assist in location a second injection well as a pilot. This would be the most economical and easiest manner in which to attempt producing this otherwise bypassed oil.

4.3 Lafitte Field

Lafitte field is located in southeastern Louisiana and more specifically in south Jefferson Parish, approximately 21 miles south of the city of New Orleans. The field is atop a deep seated salt dome. Lafitte field contains reservoirs with water-drive production mechanisms. Four shallow reservoirs from Lafitte Field were chosen for study. These reservoirs were relatively shallow and normally pressured, permitting field tests of any prospects found at reasonable drilling costs. They were also thought to be highly developed because they were penetrated by a large number of wells. The average producing well spacing was less than 10 acres per well. These four reservoirs were stacked one on top of the other in a fairly limited geographic area. Because of this there was a significant possibility of multiple completion opportunities. The reservoirs had strong natural water drives, which is typical in many Louisiana reservoirs. The hydrocarbon production from these reservoirs had declined to a low level and they were felt to be nearing abandonment.

All of the reservoirs were already unitized and operated by a single operator; the operator making legal and regulatory problems associated with a field test minimal. The operator was also very willing to assist and cooperate with LSU in the study and had the necessary resources to test any good prospects identified.

4.3.1 Depositional Environment

Productive sediments within the field consist of Miocene aged alternating and mixed sand-shale facies. These facies are made up of delta plain deposits. The Miocene was a huge progradational megacycle with several great thick depocenters centered in different part of the Gulf Coast. Each general depocenter is made up of a complex of shifting deltas and delta lobes. During the mid to late Miocene time, deposition related to delta building had shifted to southeastern Louisiana. The integrated drainage from the ancestral Mississippi River system began to supply sediments from the entire continental North America. Mid-Miocene to Pliocene depocenters were concentrated in southeastern Louisiana.

In addition to these major depositional cycles, contemporaneous growth faulting and formation of salt domes provided numerous trapping mechanisms for hydrocarbons. Growth faults in the Gulf Coast Tertiary are listric faults that flatten with depth and become parallel with bedding plans. Salt domes within the Gulf Coast consist of many types and shapes. Some actually penetrate the overlying sediment at varying degrees and others simply push up sediment. In all cases, some degree of structural faulting occurs. Sand percent in the area of Sections 20 and 21, TWN 17S-RING 24E and between the depths of 1900 ft. and 6000 ft. subsea is between 40-50% sand content. This is typical of upper deltaic plain and fluvial environments. In this same vicinity, sand thicknesses range from 5 ft. to 200 ft.

The majority of SP curve shapes of sands display both abrupt and gradational upper and lower sand contact. They consist of both smooth and serrated bell and cylinder shapes with no obvious funnels. These are all very typical shapes for alluvial-deltaic point bars and distributary channel fills.

The normal sequence of 3900 ft. sand has a smooth bell shape with gradational upper sand contact and an abrupt lower sand contact. Its thickness ranges from 2 ft. to over 100 ft. and has been classified as an alluvial-deltaic point bar. Type Logs for the North and South 3900 ft reservoir are shown in Figure 4.26.

In general, the 4300 ft. sand has serrated bell shape with gradational upper and lower sand contacts. Its average thickness is 60 ft. -70 ft and has been classified as an alluvial point bar. A type Log for the 4300 ft sand is show in Figure 4.27.

The 4400 ft. and has a smooth bell shape with a gradational upper sand contact and an abrupt lower sand contact. Its average thickness is 130 ft. -140 ft and has been classified as an

alluvial-deltaic point bar or distributary channel fill. A type Log for the 4400 ft. reservoir is shown in Figure 4.28.

Type Log for North 3,900-ft Reservoir

Type Log for South 3,900-ft Reservoir

Figure 4.26 - Type Log for North and South 3900 ft Reservoirs

Figure 4.27 - Type Log for 4300 ft Reservoir

Figure 4.28 - Type Log for 4400 ft Reservoir

4.3.2 Geochemical Analysis

Duplicate samples were obtained from the eight currently producing wells in the field. There are three formations currently producing in Lafitte Field, the 3900 sand, the 4300 sand, and 4400 sand. There were five wells producing from 3900 ft. sand, one well producing from the 4300 sand, and two wells producing from the 4400 sand. Each of the duplicate samples was analyzed individually. The whole oil gas chromatograms of the oils from Lafitte Field all showed evidence of either biodegradation or water washing. The chromatograms show the total loss of straight-chain hydrocarbons in all samples. There are a few identifiable isoprenoid hydrocarbon peaks present in some of the whole oil chromatograms. The concentration of isoprenoids appears to be related to depth, with deeper samples showing higher concentrations of isoprenoids than the shallower samples. The oils contain approximately 51% saturated hydrocarbons, 34% aromatic hydrocarbons, and 15% NSO compounds. These data suggest the samples are biodegraded rather than water washed. Water washing tends to remove aromatics and NSO compounds more efficiently than saturated hydrocarbons. In addition, water washing removes naphthenes more efficiently than saturates. In the whole oil chromatograms of these samples, a broad naphthene envelope is clearly present. The increasing concentration of isoprenoids with depth is also consistent with biodegradation occurring in these oils. An example chromatogram from a whole oil sample taken from State Lease Well No. 1 is shown in Figure 4.29.

Figure 4.29 - Oil Chromatogram - State Lease No. 1, 3900-ft Sand, Lafitte Field

4.3.4 Reservoir Properties

The reservoir rock and fluid properties are presented in Table 4.7. Average porosity and permeability for the four reservoirs were 31% and 1215 md, respectively. Average irreducible water saturation averaged 18% for the four. API gravity of the oil was 25 degrees in all four reservoirs and the average gas-oil ratio for all four reservoirs was 300 scf/stb. Annual oil production history for the four reservoirs studied are shown in Figure 4.30. Note that the production from the 4300 ft sand and 4400 ft sand has almost ceased and that production from the 3900 ft sand north reservoir is in steep decline.

Figure 4.30 - Annual Oil Production from Shallow Lafitte Field Reservoirs

Table 4.7 - Properties of Shallow Reservoirs in Lafitte Field

RESERVOIR	POROSITY %	AVERAGE PERMEABILITY md	AVERAGE SWI %	API GRAVITY DEGREES	AVERAGE GOR SCF/STB
3900' NR	34.0	1600	17.0	25	150
3900' SR	33.0	2100	15.0	25	150
4300'	29.0	590	27.0	25	410
4400'	29.0	570	12.0	25	490

The 3900 ft sand (Figure 4.31) is located in Section 20 and 21 of Township 17 South, Range 24 East. It is Miocene age and its average depth is -4,050 ft subsea. After the reinterpretation of the basic geological information was performed, it was decided that the 3900 ft sand consisted of two reservoirs in this locale, the North and the South. Both reservoirs were undersaturated, strong edge water-driven oil pools. The north reservoir's average permeability and porosity was 1600 md and 34%, respectively. The south reservoir's average permeability and porosity was 2100 md and 33%, respectively. They both had structural-stratigraphic trapping mechanisms. The main trap consisted of a major shale-out of the sand, which limited the north reservoir to the north and both reservoirs to the east. The two reservoirs were separated by an interpreted permeability barrier running northwesterly. This formed the south limits of the north reservoir and the north limits of the south reservoir. The north reservoir was limited downdip by an average oil-water contact of -4,060 ft subsea. The south reservoir was limited downdip by an average oil-water contact of -4,085 ft subsea. In addition, the sand becomes abruptly thicker to the west. Average gross thickness of the sand jumps from an average 50 ft for both reservoirs to over 100 ft thick. The north reservoir covered 46 acres and the south reservoir covered 64 acres. Based upon volumetric calculations, the north reservoir originally contained 3.1 MMSTB of crude and the south reservoir originally contained 3.2 mmstb. Each reservoir has produced a cumulative 1.8 MMSTB of crude. This translates into a 58% recovery for the north reservoir and a 56% recovery for the south reservoir. The north reservoir has had 8 completions and the south has had 11 completions. Presently, both the north and the south 3,900 ft reservoirs have wells producing from them.

The 4300 ft sand (Figure 4.32) is located in Section 20 and 21 of Township 17 South, Range 24 East. It is Miocene age and its average depth is -4,480 ft subsea. The reservoir is an undersaturated, strong edge water-driven oil pool whose average permeability and porosity is 586 md and 29%, respectively. It has a structural-stratigraphic trapping mechanism which consists of an northeasterly trending anticlinal pin-out. Its flanks dip at 4-15 degrees. The reservoir is limited to the east, west and south by an oil-water contact of -4,538 feet subsea. To the north, it is limited by a pinch-out/permeability barrier. It encompasses roughly 150 acres and has an average net pay of 19.8 feet. Based upon volumetric calculations, it originally had 4.4 MMSTB of crude in place. It has produced a cumulative 1,443,503 STB of crude, 586,421 MCF of natural gas and 7,504,439 BBLS of water from a total of 12 wells. This translates into a

32.8% recovery.

The 4400 ft sand (Figure 4.33) is located in Section 20 and 21 of Township 17 South, Range 24 East. It is Miocene age and its average depth is -4,550 ft subsea. The reservoir is an undersaturated, strong bottom water-driven oil pool whose average permeability and porosity is 564 md and 28%, respectively. It has a structural trapping mechanism which consists of an northeasterly trending linear closure. Its flanks dip at 10-20 degrees. The reservoir is limited downdip by an oil-water contact of -4,579 ft subsea. It encompasses roughly 115 acres and has an average net pay of 19.6 feet. Based upon volumetric calculations, it originally had 4.0 MMSTB of crude in place. It has produced a cumulative 884,550 STB of crude, 430,446 MCF of natural gas and 3,265,077 BBLs of water from a total of 8 wells. This translates into a 21.8% recovery.

Figure 4.31 - Structure Maps for North and South 3900 ft Reservoir, Lafitte Field

Figure 4.32 - Structure Map for 4300 ft Reservoir, Lafitte Field

Figure 4.33 - Structure Map for 4400 ft Reservoir, Lafitte Field

4.3.5 Modelling Studies

Because the Lafitte Field reservoirs all have fairly strong water-drive systems, were initially undersaturated and had low initial gas-oil ratios, it was assumed they produced throughout their life above bubble point. Therefore, for this particular case and goal, there was not an advantage for using three phase analysis. For this reason BOAST II was modified to calculate only for two phases; oil and water. This modification greatly reduced the required computer time for a given grid size.

There was no PVT data available on the original oil and gas, so empirical calculations and PVT input from present-day fluid samples were used to arrive at all fluid properties used in the simulation. Gross and net sand values were mapped and digitized for each layer and input into the data file. Porosity values were taken from sidewall core analysis and varied by layer and by trend (use of contour maps) in the same manner as the net and gross sand values.

Estimated permeability values were available from sidewall cores. Values calculated from the sidewall samples were used as the initial values of the horizontal permeability in the first simulation run. The vertical permeability was estimated initially to be on the order of ten times less than the horizontal permeability because of the apparent stratification seen on the logs. Both the horizontal and vertical permeabilities were varied from the initial estimate as required to obtain history matches. Connate water saturation values were taken from side wall core analysis and well log analysis.

Several wells penetrated the 3900 ft sand over its life of production. One of the problems with the interpretation were the varying oil-water contacts which were noted over the life of the reservoir. It was originally thought that the reservoir was fairly homogeneous in its characteristics. Internal shale laminations and variant permeability trends were not believed to be a major factor in controlling the drainage of the reservoir. However, as new wells penetrated the sand, varying oil-water contacts were noted. East-west and north-south cross sections assisted in the interpretation of this reservoir.

The reservoir clearly shows a distinct oil-water contact trend for a northern area and a different oil-water contact trend for a southern area. By comparing these oil water contacts with trends in the sand characteristics it was deduced that sand was separated by a permeability barrier or shale out of the sand extending east-southeast through the sand.

Both the north and south reservoirs were included in one simulation model. The

reservoirs grid consisted of 100 ft. squares in the horizontal directions. In the vertical direction, the reservoir consisted of three layers. They were based on correlative zones, with an average layer thickness of 10 ft. Overall, the model consisted of 3,240 grid blocks and more specifically, in the x, y and z directions, of 34 x 32 x 3 grid blocks. Average values of 17% and 15% for the original water saturation were used throughout for the north and south, respectively. This model was used to locate areas of highest remaining oil saturation.

Because the 4300 ft. sand reservoir consists of numerous sand-shale intervals of variable characteristics, east-west and north-south cross-sections, the various sand and shale layers were correlated over the entire reservoir. Vertical layers used within the simulator were based on these correlations. Sand layers varied in gross thickness from 2 ft to 6 ft and shale layer gross thicknesses were held constant at 2 ft each. In all, there were 10 sand layers and 9 shale layers. Within each of these layers the net thickness and vertical and horizontal permeabilities were varied according to values obtained from sidewall cores and well log interpretation. Initially, maps were constructed for each layer and were used for the input into the simulator. Lateral permeability barriers and faults were handled by giving these areas zero values for their net sand thickness and permeability.

The reservoir was grid in the horizontal directions with each block being 200 ft square. Overall, the model consisted of 8,208 grid blocks. The final history match ran in a CPU run time of 2.5 hours on an IBM 3090.

As history matching runs were made for this reservoir several adjustments were necessary to provide an acceptable match. The primary parameter varied was the horizontal and vertical permeabilities. The sand formation consisted of a complex arrangement of alternating sand-shale layers. It was assumed that a major controlling factor for accurately depicting the sweepage within the simulator was an accurate description of the sand-shale sequences. Therefore, changes made within the model in an attempt to match the actual production history were almost always concerned with the thickness, porosity and most importantly, the permeability of these sequences. The strength and placement of the aquifer also was adjusted during history matching.

Final history matching for this reservoir were not as close as desired, however for the purpose of finding areas of high concentrations of oil saturations, it was considered to be sufficient. When nearby wells were grouped together, the history matches improved dramatically. One reason for this was the coarseness of the horizontal grid blocks used.

The 4400 ft sand reservoir was grid finer in the horizontal directions as compared to the 4300 ft reservoir with each block being 100 ft square. In the vertical direction, the reservoir was divided into 13 layers, with thicknesses varying from 2 ft to 85 ft. Overall, the model consisted of 19,188 grid blocks and more specifically, in the x, y and z directions, of 36 x 41 x 13 grid blocks. The upper three layers of the model were based on correlative sand-shale sequences which occurred throughout the reservoir. The lower 10 layers were not separated by correlative sand-shale sequences. At this point in the formation. Layers 4-12 were defined to have gross and net thicknesses of 4 ft each. This was designed to track the position of the oil-water contact more precisely. The last layer was 100% water saturated and acted as the bottom water of the reservoir. It was of varying gross and net thickness based on the actual formation thickness. One of the main keys to locating bypassed oil in this reservoir was assumed to be the severity of water coning in individual wells. An average value of 13% for the original water saturation was used throughout the reservoir.

Typical obtained history matches are shown in Figure 4.34. Since these reservoirs have strong water-drive mechanisms, the average reservoir pressure remained essentially constant over the life of each of the reservoirs.

Because it was necessary to use relatively large grid blocks for the full field study, Bourgeois [1989] simulated a portion of the 4400 ft. reservoir near one of the producers. This study investigated the shape of a typical water cone in more detail.

Table 4.8 shows original oil in place and oil produced to date for each of the reservoirs. The north 3900 ft sand reservoir, the south 3900 ft sand reservoir, the 4300 ft sand reservoir, and the 4400 ft sand reservoir originally had 3.1 MMSTB, 3.2 MMSTB, 4.4 MMSTB, and 4.0 MMSTB in place and to date have produced 1.8 MMSTB, 1.8 MMSTB, 1.5 MMSTB, and 1.0 MMSTB, respectively. In terms of recovery efficiency, the north and south 3900 ft sand reservoirs have low efficiencies of 58% and 56% respectively. The 4300 ft sand reservoir has an efficiency of 34%, and the 4400 ft sand reservoirs has an efficiency of 25%. Also shown in the same table are the estimated residual oil and remaining reserves which are expected be recovered by present production wells or existing wells. Residuals for the north 3900 north, 3900 south, 4300 and 4400 reservoirs are 0.9 MMSTB (29%), 0.9 MMSTB (28%), 1.5 MMSTB (34%), and 1.1 MMSTB (28%), respectively. The last column shows the amount of oil to be potentially bypassed under the present scenario. Potential bypassed oil for the 3900 north, 3900

Figure 4.34 - Typical History Match Results for Laffite Field

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south, 4300, and 4400 reservoirs are 0.1 MMSTB (3%), 0.2 MMSTB (6%), 1.3 MMSTB (29%) and 1.7 MMSTB (42%), respectively. A total of 3.3 MMSTB of oil will be bypassed from these four stacked reservoirs for the present operating conditions.

Well spacing seems to have played a large role in reducing the amount of bypassed oil. The spacing is 5.8 acres per well for the 3900 ft sand reservoirs and 11.5 acres per well for the 4300 ft sand 4400 ft sand reservoirs. Note that the 3900 ft sand reservoirs have very little bypassed oil as compared to the deeper sand reservoirs. The shaliness of the 4300 ft sand reservoir also is thought to have played an important role in the efficiency of its production. The combination of the placement of producing wells and the flow restrictions formed by these shales have enabled a large quantity of producible oil to remain in the reservoir as bypassed production. Water coning is a major problem limiting the recovery effectiveness of the 4400 -ft sand reservoir as well as placement of wells.

The results of the simulation runs for the 4300 ft sand and 4400 ft sand reservoirs show potential economic pockets of the recoverable oil for both of these reservoirs. Figure 4.35 shows areas of high oil saturations for the 4300 - ft sand reservoir and Figure 4.36 shows the areas of high oil saturation for the 4400 - ft sand reservoir. Bypassed areas in the 4300 - ft sand reservoir are fairly small and scattered. This again is explained by the shales forming flow restrictions of varying degrees within the reservoir. Economic recovery of these individual pockets would be marginal at best.

The high oil saturation in the 4400 ft sand reservoir are primarily contained within one area an elongated zone running along the structure axis of the reservoir. This appears to provide a very economical target for recovery of bypassed oil.

TABLE 4.8 - Estimated Bypassed Mobile Oil, Lafitte Field

RESERVOIR	ORIGINAL OIP MMSTB	OIL PRODUCED MMSTB	RESIDUAL OIL MMSTB	RESERVES MMSTB	BYPASSED OIL MMSTB
3900' NR	3.1	1.8	0.9	0.3	0.1
3900' SR	3.2	1.8	0.9	0.3	0.2
4300'	4.4	1.5	1.5	-	1.3
4400'	4.0	1.0	1.1	0.1	1.7
TOTAL	14.7	5.9	4.4	0.7	3.3

Figure 4.35 - Areas of Bypassed Mobile Oil Predicted for 4300 ft Reservoir, Lafitte Field

Figure 4.36 - Areas of Bypassed Mobile Oil Predicted for 4400 ft Reservoir, Lafitte Field

The high oil saturation area within the 4400 ft sand reservoir provides an excellent target for a horizontal wellbore. One horizontal well could recover a substantial amount of this bypassed oil while greatly reducing the water coning production. The wellbore would also penetrate the 4300 ft sand reservoir and, if properly placed, could recover some of the bypassed oil remaining in this reservoir. The north 3900 ft sand reservoir would also be penetrated but it is not believed that substantial amounts of moveable oil would be encountered within this reservoir. However, it should be considered as a secondary objective. A map view of these targeted high oil saturation zones with a proposed well having a 2100 ft horizontal departure through the 4400 ft sand is shown in Figure 4.37.

No horizontal wells have been drilled in this area for these types of reservoirs. Horizontal wells have been drilled in North Louisiana and Mississippi in similar deltaic sand reservoirs with excellent results. OXY USA Inc. drilled a horizontal well in Olla Field of Lasalle Parish, Louisiana within the Cruse sand of the Wilcox Formation. This sand is very similar to the Lafitte Field sands, being deposited as a crevasse splay in a fluvial environment. Average porosity and permeability values of 32% and 525 md, respectively, compare very well with the Lafitte values. The Cruse sand in Olla Field also had a history of water coning problems. The productivity index and actual production are approximately 500% better than vertical wells in Olla Field. The well paid out in less than 4 months. Reservoir simulation calculation indicate the similar results should be expected in Lafitte Field.

Figure 4.37 - Map View of Proposed Horizontal Well

5. TECHNOLOGY TRANSFER ACTIVITIES

The results of the work of the LSU Interdisciplinary team is being disseminated to industry using several approaches. These include:

1. Presentation and publication of technical papers
2. Discussions with a consortium of oil operators which have expressed interest in the project,
3. Conducting annual workshops, and
4. Providing technical support for operators interested in field testing of concepts and models produced by the project team.

The consortium of oil operators for this project are also industry representatives for a departmental advisory committee. Meetings are held twice a year. Several cooperative projects for future work are now pending.

During 1989, the project personnel participated in a regional IOCC/DOE Technology Transfer Seminar held in Lafayette, Louisiana. During 1990, project personnel held a Jurassic Core Workshop in Baton Rouge on the LSU Campus. During 1991, a workshop on Horizontal Drilling in Louisiana was held by project personnel in New Orleans, Louisiana, a poster session was presented at the Society of Exploration Geophysicist's (SEG) Development and Production Forum in Durango, Colorado and a presentation on prospecting for bypassed oil was given at the annual IOGCC Convention in New Orleans, Louisiana. During 1992, workshops were held on the Pilot Oil Atlas for Louisiana on the Baton Rouge Campus.

6. SUMMARY AND CONCLUSIONS

The overall objective of this project was to develop methods for extending the producing life of certain types of reservoirs by reducing the amount of oil being bypassed and abandoned. Increasing recovery from known reservoirs can significantly lengthen the life of the oil producing industry in Louisiana and have a major short term impact on the economic strength of the state. A secondary objective was to transfer the technology to Louisiana's oil producers, especially the smaller companies with little or no access to research and development staff. Another objective was to improve the national competitiveness of LSU in obtaining funding for oil and gas research.

The objectives were accomplished using an interdisciplinary approach which included the disciplines of engineering, geology, and computer science. The available public domain computer software suitable for reservoir simulation work was studied, and the BOAST II software package released by DOE in 1988 was selected as the starting point in the development of an improved public domain reservoir simulator code that has been enhanced for by-passed oil prospecting. Dr. John Tyler of the Computer Science Department has taken the available code from DOE and prepared two new versions of BOAST II. Both versions were developed to run on the IBM 3090 with vector facilities. One version was restructured and modified to exploit the facility using IBM parallel FORTRAN. Test runs made to date using up to six CPU's in parallel on the IBM 3090 Model 6068 yielded an effective speed-up of about 20 due to both vector and parallel processing improvements. LSU is currently maintaining and distributing for DOE the new IBM versions of BOAST II that were developed.

Other, software was developed to allow automatic gridding of the reservoir being studied simply by tracing contour lines on structure maps, isopach maps, permeability maps, etc. This improvement significantly reduces the time required for preparing the large data set needed for a field study. Improved algorithms for automatic correlation of well logs have also been developed and tested using example field data.

Engineering and Geologic studies of bypassed oil potential have been made on several reservoirs in three fields. These fields include the Corney Bayou Field in North Louisiana, the Fordoche Field in Central Louisiana, and the Lafitte Field in South Louisiana. Based on these studies, the following recommendations were made:

1. The operator of the Corney Bayou Field should consider converting an additional well in the Eastern half of the reservoir from a producer to an injector and allowing the reservoir pressure to rise to insure miscibility in all areas of the field.
2. The operator of the Fordoche Field should consider testing and stimulating potential bypassed shaly zones at the top of the Sparta B and in the Sparta Stray Sands.
3. The operator of the Lafitte Field should consider an additional well to allow recovery of additional oil in the 4300 ft and 4400 ft sands.

Physical model studies were conducted to provide data for testing improvements being made in the reservoir simulation software. Techniques were first developed for making slabs of artificial sandstone containing variations in permeability. Permeability variations as high as 3:1 have been achieved with only minor variations in porosity. Two of the models constructed were used to simulate a vertical slice through one of the bypassed oil zones of the Lafitte field having a horizontal well completed near the top of the oil zone. One model was used to obtain experimental data for the situation in which the permeabilities to water in the swept and unswept regions of the reservoir do not differ greatly. The second model was used to obtain data for the more complex situation in which there is a significant difference in the permeability to water in the swept and unswept regions. A third model allowed experimental data to be obtained on the improvements in area sweep efficiency that can be achieved using short radius horizontal wells drilled from an existing producer.

Technology transfer has been accomplished primarily by annual workshops for independent oil operators, through informal meetings with operators that are providing data for the field studies, and by publications in the technical literature. During 1989, project personnel participated in a regional IOCC/DOE Technology Transfer Seminar held in Lafayette, Louisiana. During 1990, project personnel held a Jurassic Core Workshop in Baton Rouge on the LSU Campus. During 1991, a Workshop on Horizontal Drilling in Louisiana was held by project personnel in New Orleans, Louisiana, a poster session was presented at the Society of Exploration Geophysicist's (SEG) Development and Production Forum in Durango, Colorado and a presentation on prospecting for bypassed oil was given at the annual IOGCC Convention in New

Orleans, Louisiana During 1992, workshops were held on the Pilot Oil Atlas of Louisiana at the Microcomputer Lab of the LSU Petroleum Engineering Department on the Baton Rouge Campus.

It is still too early to assess the impact of techniques applied in this project on Louisiana's economic development. Simple extrapolation of the computed average results of the conducted reservoir studies yields an estimated possible improvement in oil recovery equal to about 10% of the cumulative oil recovered to date. However, an extrapolation based on such a small sample would not be statistically sound. Furthermore, the computed results have not yet been verified through additional drilling.

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