A PRACTICAL COMPREHENSIVE GEOLOGICAL AND ENGINEERING STUDY OF A CARBONATE RESERVOIR: NORTH McELROY UNIT—CRANE COUNTY, TEXAS

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INTRODUCTION

The North McElroy Unit is located in crane and Upton Counties in West Texas. The Unit operates the northern 40 percent of the McElroy Field (Fig. 1). The field was discovered in 1926 by the Church and Fields No. 1 University, which is currently the North McElroy Unit No. 3455. The primary production mechanism was essentially a solution gas drive. There was, however, a limited water drive on the steeply dipping eastern flank of the field.

Wells were originally completed open hole through the pay zone. If the initial production was low or the production fell off, the wells were stimulated with 30 to 1300 quarts of nitroglycerine. The wells potentialed from 100 to 9000 barrels per day per well. By the mid 1960's, production from the unit area incorporating numerous pilot waterflood operations was down to 3000 BPD.

In 1966, a decision was reached to coordinate several of the various waterflood operations in the northern portion of the field. The North McElroy Unit was formed and started operations on January 1, 1967, with Getty Oil Co. as operator.

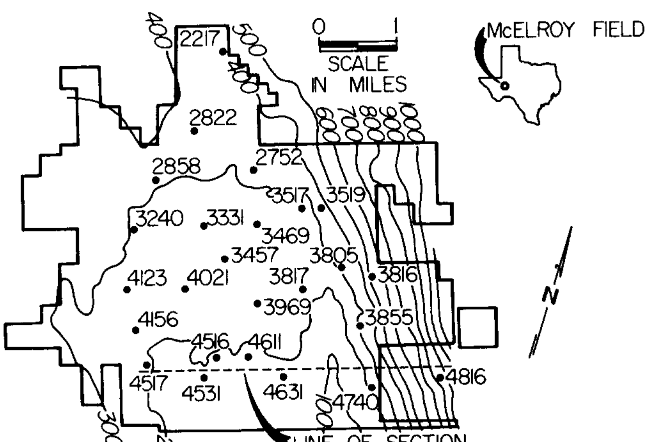

FIGURE 1

Injection was started on a 40-acre 5-spot and a 40-acre inverted 9-spot pattern in the western portion of the field. The major part of the field used the 80-acre inverted 9-spot pattern. The results were quite disappointing. The reservoir was apparently too tight for this size spacing. As a result of an engineering study made in 1974, the pattern was changed to a 20-acre 5-spot. This necessitated the infill drilling of 80± new wells. The flush production from these new wells substantially increased the unit production immediately. In 6 to 9 months response from the waterflood was apparent. The dwindling flush production was not only offset, but increased; production has maintained a steady increase ever since.

A major problem confronting the operator was the lack of information on the wells. There were few Gamma Ray logs and even fewer open-hole surveys. The well histories were, for the most part, incomplete, if there were any at all. Sample and core descriptions were very inconsistent, infrequent, and unreliable. Core analysis was useless unless run by the low temperature or gyp-free method and no cores were available for study. Attempts were made to evaluate the geology but the limited data available at that time was of little assistance to the waterflood operations.

In 1973, a decision was reached to make a comprehensive joint geological and engineering study of the North McElroy Unit. It was hoped that the combined efforts would result in a more practical study to assist in the current waterflood operations. The objectives of this study were to (1) determine the different lithologies within the unitized interval and their associated physical properties; (2) establish reliable correlations and construct meaningful structure maps; (3) define the most efficient completion and production techniques; and (4) incorporate a more efficient water-injection program.

PROCEDURES

In the early 1970's several wells had been cored and the routine gyp-free analysis was run. The cores had been stored and were still available for detailed geological study. Several more cores were proposed over the unit area which gave a density of at least one core in each section in the major portion of the field. A total of 25 wells would be cored, yielding 8100 feet of core for analysis. Portions of the cores from 4 wells were set aside for special analysis of the rock porperties.

After the routine low temperature gyp-free analysis was completed, the cores were shipped to the operator's research lab in Houston for detailed geological study and analysis. This included a microscopic examination of 8100 feet of continuous polished slabs of core material. Where appropriate, samples were chosen for X-ray diffraction, atomic absorption, and thin-section analyses. Petrographic study of thin sections provided details of composition and texture so that the separate facies could be constructed and depositional environments could be envisioned. It was found that some of the environments were uniform and continued over the entire unit area. The boundaries of these environments had distinctive Gamma Ray Log character, becoming reliable correlation points for building meaningful structure maps. Most of the maps reflect actual rock units of particular environments and lithologies.

A logging program was set up consisting of the Dual Laterolog, Compensated Neutron, Compensated Density, and Acoustic-type logs for all of the newly cored wells. With data from the core analysis and petrographic studies, values for the rock properties were determined and put into the log analysis formulas. After some trial and error, a procedure was developed which resulted in a reasonable log interpretation. The proof of the interpretation is a successful completion which has a high oil recovery and relatively low water recovery.

Tests were run on the cores with different injection waters to determine what effects it would have on the reservoir rock, and how these changes would effect the flood efficiency.

GEOLOGY

The development of the reservoir in the North McElroy Unit is a complex history of original-sediment deposition, structural movement, and post-depositional rock-altering process or diagenesis. These will be discussed briefly below.

The North McElroy Unit is located on the eastern margin of the Permian Central Basin Platform. To the east lay the deeper waters of the Midland Basin, while coastal and continental sediments were deposited on the higher area to the west. The field occupies part of a north plunging anticline. The east flank dips steeply into the Midland Basin and is associated with fractures and possible faults which locally influence production.

Fracturing occurs throughout the entire reservoir. These usually trend northeast-southwest and northwest-southeast. In most of the field the fractures are healed and are of little consequence. Where open fractures do occur, they have a definite channelling effect on the injection waters. Usually only two wells are affected by a channel, but occasionally three may be affected.

Production is from the Permian Grayburg Formation, an anhydritic dolomite. It is separated from the underlying non-productive San Andres Formation by a distinct unconformity. This Grayburg reservoir is capped by tight dolomites and anhydritic sandstones of the Basal Queen Formation.

Far from being homogeneous, the Grayburg reservoir can be divided into seven distinct rock units or facies which are identified by mineralogy, fossil content, and other internal characteristics. These units represent different types of original deposition, such as open shelf, shelf margin, exposed mud flats, oolite shoals, and shallow lagoon. For a more detailed description, the reader is referred to Longacre (1976) and Baria (1976).

The basal Grayburg facies has poor reservoir characteristics and is referred to as the Open Shelf facies. The top of this unit corresponds to the "C" marker log horizon, as identified on the cross section Figure 2 and type log Figure 3. The best reservoir is

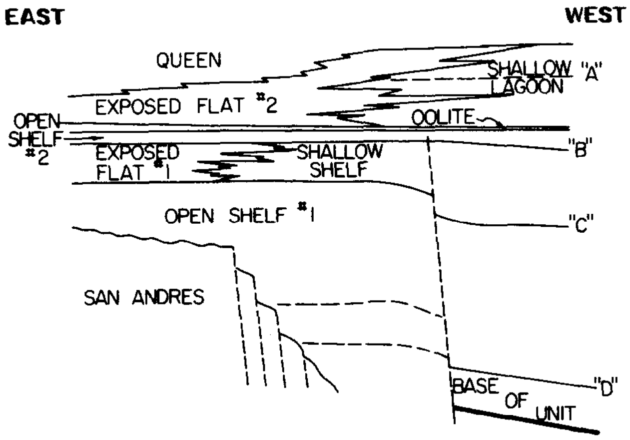

FIGURE 2

located in the upper 20 to 30 feet. Porosity within this facies consists of moldic, vugular, and intercrystalline voids.

Above this "C" horizon are two closely associated rock units which split the field into east and west parts (Fig. 2). These units lie just beneath the "B" log marker horizon. The shelf margin facies lies to the east and has good reservoir characteristics. Reservoir continuity is best developed here because of the homogeneity of the original sediment and the lack of bedding. The western member or exposed mud-flat facies is generally a poorer reservoir. Here, anhydrite has sealed up much of the porosity and has formed a permeability barrier further west. Lateral continuity is generally restricted but good vertical continuity is present. Stratigraphic sections across the field illustrate that these rock units interfinger, but as a whole they form a uniform, thick tabular body which extends across the entire unit area.

Directly above the "B" horizon is another thick, uniform rock unit (Open Shelf No. 2) whose reservoir characteristics vary from poor to fair. The productive interval here is controlled largely by structure.

Above the Open Shelf No. 2 facies unit is a non-reservoir unit called the Datum Oolite, which forms a thin blanket (3 feet to 20 feet) extending across the entire unit area (Fig. 2). Along with oolites, it contains a high percent of quartz sand and is completely cemented with anhydrite. It serves as a vertical barrier to fluid migration.

Above the datum oolite, the Grayburg reservoir

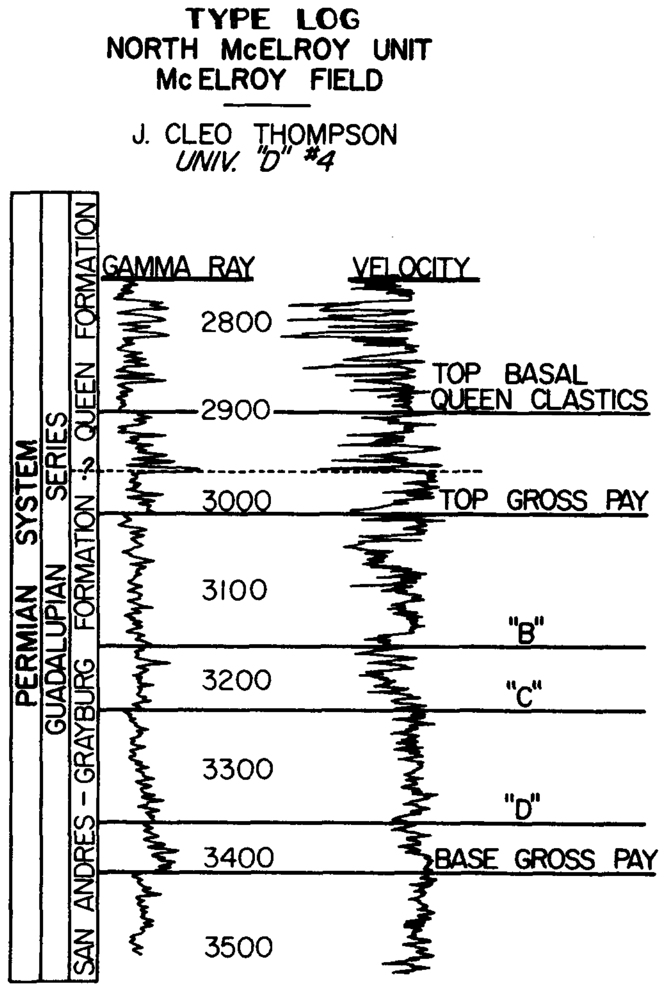

FIGURE 3

interfingers with non-reservoir sandstones and shales of the basal Queen Formation. In the central portion of the field lies the Exposed Flat No. 2 Unit. This is a distinct, fair reservoir unit. Another unit in this part of the Grayburg is the Shallow Lagoon facies. It is interbedded with numerous non-reservoir units. The structure map on the top of the unitized interval is the top of the Basal Queen Clastics.

DIAGENESIS

As Grayburg sediments accumulated, and in the time afterward, many changes took place in the sediments. These post depositional rock-altering processes or diagenesis were crucial to the creation of reservoir porosity and entrapment of hydrocarbons. A more detailed description of diagenesis may be found in Baria (1976). Originally, most of the sediments accumulated as lime muds. Original porosities were high, but permeabilities were almost nil. These widespread lime mud units with poor primary reservoir characteristics were later transformed into porous and permeable dolomites. Calcium sulfates formed cements in those units with good original porosities (sands and oolites). The transforming fluids migrated out of the Midland Basin and into the Grayburg along the fractures and possible fault systems on the eastern side of the field. A permeability barrier of anhydrite cement formed to the west. Oil migration probably followed the same path.

One important aspect of McElroy diagenesis lies in the equilibrium relationships between reservoir sulfate minerals and injection water. Whenever a given volume of anhydrite is hydrated, the volume of gypsum produced is 1 to 1-1/2 times greater by volume than the original anhydrite. This increased volume is created at the expense of pore volume. So, the character of an anhydrite rich reservoir can be altered by injection waters that differ from those waters the rock is in equilibrium with (connate waters). McElroy injection water is currently fresher than the original formation water. Where flow rates are low (as on the west side of the field) permeability and porosity may be reduced. Only monitoring of water chemistry and injection pressures can provide information on any effects to permeability.

RESERVOIR CHARACTERISTICS

The reservoir rock has matrix porosities, capable of production, ranging from 4 to 18 percent. Porosities up to 32 percent occur in a few relatively minor stringers. The "A" zone, or top of gross pay, is that interval above the "B" zone that contains porosity (See Fig. 3). This is also the most erratic zone where correlations are not continuous. The effective top of this zone is whatever the upper limit of productive porosity appears to be in each well. The Shelf Margin facies, located in the eastern half of the "B" zone, has a porosity range of 18 to 23 per cent. Vugular porosity exists in this zone, along the hinge line from the southern boundary of the Unit to the northern boundary.

This area has core porosities ranging from 2 to 32 percent, with averages up to 14 percent. The Exposed Mud Flat facies in the western portion of the "B" zone has a core porosity range of 2 to 18 percent with an average of 8.5 percent.

The Open Shelf facies or "C" zone (Fig. 3) has a core porosity range of 0.5 to 18.6 percent with an average matrix porosity range of 3 to 8 percent. This zone also includes non-connected moldic porosity.

The porosities in the non-productive "D" zone vary from 0.3 to 11 percent with an average of 3 percent. The porosities in the non-productive San Andres gray dolomite have a range of 2 to 4 percent with an average of 3 percent.

Permeabilities in the various environments vary with the porosities. In the "A" zone, the permeabilities are very erratic.

The "B" zone in the Shelf Margin facies has a permeability range of less than 0.1 to 2553.0 md with an average range of 23 to 76 md. This includes the vugular porosity. The Exposed Mud Flat facies has a permeability range of less than 0.1 to 36.0 md with an average range of 0.2 to 6 md. A permeability of 224.0 md was encountered in a single 1-foot zone. The Open Shelf facies ("C" zone) has a permeability range of less than 0.1 to 44.0 md with an average range of 0.2 to 2 md. Higher permeabilities, around 100 md occur in a few widely scattered one foot intervals. The "D" zone has a permeability range of less than 0.1 to 2 md with an average of 0.3 md. The San Andres gray dolomite has a permeability average of less than 0.1 md.

Continuity of porous and permeable stringers over the whole unit is quite erratic. In many cases, the productive stringers in one well are impervious in one or more offset wells because of gypsum and anhydrite. For this reason, it was necessary to make 2 three-well cross sections, one north-south and one east-west, for each injection pattern. These are centered on the injection well of each pattern. The injection zones are correlated and the producing wells are perforated in order to obtain the greatest benefit from the injection wells. Injection and production profiles are run periodically to monitor fluid movement and perforation effectiveness. Injection pressures are 750 psi on the east side of the field and 1350 to 1400 psi on the tighter western portion. Some injectors in the fractured areas and along the hinge line take water on vacuum. Injection rates are varied according to the needs of each pattern.

The rock property values obtained from the core analysis were used in the log analysis program. The lithology-porosity cross plot chart was modified to take into account the higher percentages of gypsum and anhydrite. With the use of porosity cut-off values of 4 or 5 percent and a water saturation of 30 to 35 percent, it has been possible to make good, realtively high, oil-rate completions. Log analysis occasionally will yield some dubious values, particularly in the eastern fractured area, where water volumes are high. The reason for this is probably an increase in porosity, a decrease in anhydrite, and a change in the gypsum content. Also, the formation waters are changing because of the influx of possible basinal water from fractures and the variable chemistry of the injection waters.

After the wells are perforated, they are acidized and fracture treated. The acidizing technique is a multistage acid job using ball sealers with water spacers. Two hundred gallons of acid is spotted opposite the perforations and the formation is broken down. The acid is displaced with water, watching for the ball or balls to hit. This is repeated until all of the perforations are acidized. Because of the irregular lithologies, the flexibility available in this method is needed. The fracturing technique, used on about 80 wells, was a modified limited-entry treatment method. The wells, being selectively perforated, generally use two stages with ball sealers. The last seven wells, however, were treated with the regular limited fracture method with little change in results. The wells were tested and put on production.

RESERVES

The cumulative production from discovery in 1926 to January 1, 1967, was 126,642,272 barrels of oil. In December of 1966, the average daily production was about 3,371 barrels of oil from 636 producing wells. This is an average of 5.3 barrels of oil per day per well. As of January 1, 1977, the cumulative production was 148,991,677 barrels with a daily average of 10,530 barrels from 504 producing wells. This is 20.9 barrels per day per well. This increase in oil production is the result of an additional 87 new wells and a more efficient waterflood pattern. In December of 1976, 105,302 barrels of water was injected through 292 injection wells.

The cumulative production of 148,991,677 barrels from the estimated 285,071,000 barrels of recoverable oil in place leaves about 136 million barrels to be produced. The total amount of oil in place is estimated between 800 million and 1.3 billion barrels. The recoverable oil figure is based on the 1 billion barrel estimate.

SUMMARY

A coordinated geological and engineering study is needed to fully develop a practical program of secondary recovery. Field consideration of geological and engineering aspects of a carbonate reservoir may help in avoiding disappointing results from water-injection pilot floods. It should be emphasized that this was accomplished by the combined efforts of the geological research and development sections, and the production department's district and area staffs. The development geologists work in the area with the people who need and use their talents. Such a coordinated program, undertaken at the North McElroy Unit, has resulted in a significant increase in oil production.

This study is not finished and will not be until all of the recoverable oil is produced. With new production techniques being developed all the time, we hope to be able to increase the recoverable oil figures several times over the next 50 or so years.

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ACKNOWLEDGMENTS

Most of the detailed core descriptions, thin section analysis, and the resulting geologic and diagenetic history were the work and conclusions of Susan Longacre and Lawrence Baria at the Getty Oil Explorătion and Production Research Lab.

Crane area engineering personnel have assimilated well histories, maintained accurate production records, and developed field analysis for practical log interpretation. They also maintain an orderly unit development and maintain the waterflood efficiency.