RESERVOIR MANAGEMENT IN THE MEANS SAN ANDRES UNIT

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ABSTRACT

The Means field, located in Andrews County, Texas provides an excellent opportunity to observe the evolution of reservoir management to meet changing economic and technical challenges. The Means field was discovered in 1934 and developed on 40-acre [16-ha] spacing. Reservoir management techniques began within one year of discovery and have continued with increasing complexity as operations have changed from primary to secondary to tertiary. In 1963, a major portion of the field was unitized as the Means (San Andres) Unit (MSAU), which will be the subject of this discussion. Several papers have been published describing specific programs for the field.[1,2,3,4,5] This paper describes the evolution of reservoir management at Means on an orderly basis. Reservoir management at Means has consisted of an ongoing but changing surveillance program supplemented with periodic major reservoir studies to evaluate and make changes to the depletion plan. This paper concentrates on reservoir description, infill drilling with pattern modification, and reservoir surveillance. The role of reservoir description is followed from relatively simple techniques in the 1930's to the recent use of high resolution seismic to improve pay correlation between wells. The importance of reservoir continuity in determining well spacing and injection patterns is discussed for both secondary and tertiary operations. Although surveillance has been an integral part of reservoir management in the Means field since discovery, a much more detailed plan was developed for surveillance of the CO_2 tertiary project.

FIELD DISCOVERY AND DEVELOPMENT

The Means (San Andres) Field is located in Andrews County, Texas, about 50 miles [80 km] northwest of the city of Midland. Geologically, the field is located along the eastern edge of the Central Basin Platform, as shown on Figure 1, and lies in a trend of San Andres production which extends for over 100 miles [160 km] in a northwest-southeast direction. The field was discovered in 1934, and by the early 1950's was developed on 40-acre [16-ha] spacing with approximately 300 wells in the Means (San Andres) Unit area. Reservoir and fluid properties are shown in Table 1.

Structurally, the field is a north-south trending anticline separated into a North Dome and a South Dome by a dense structural saddle running east and west near the center of the field (Figure 2). Production is from the Grayburg and San Andres formations at depths ranging from 4200-4800 ft [1280-1460 m]. Figure 3, a type log, shows the zonation of the vertical interval. The Grayburg is about 400 ft [120 m] thick with the basal 100 to 200 ft [30-60 m] considered gross pay. Production from the Grayburg was by solution gas drive with the bubble point at the original reservoir pressure of 1850 psi [12.76 MPa]. The Grayburg reservoir is much poorer quality, and production has been minor compared to the San Andres. The San Andres is over 1400 ft [430 m] thick with the upper 200-300 ft [60-90 m] being productive. The primary producing mechanism in the San Andres was a combination of fluid expansion and a weak water drive. Production was generally limited by state allowables during the primary producing phase.

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PRIMARY OPERATIONS

RESERVOIR MANAGEMENT DURING PRIMARY

1935 Reservoir Study*

The first reservoir study was completed in 1935, little more than one year after discovery. The introduction to that report states, "The following report on the Means Pool, Andrews County, has for its aim the collection, study and presentation of available data to furnish a fuller understanding of the geology, drilling difficulties and current practices in the Means area, as well as to set forth certain comparisons on equipment used and tests made on the various wells in the past, thereby permitting a better control of future development in this area." As reservoir management has evolved at Means, the details have changed and the techniques have become more sophisticated, but the objective is still the same.

Three technical areas were explored in this report.

1. Drilling under pressure to allow lighter mud weight.
2. Comparison of electric logs with core analysis.
3. Comparison of acid stimulation with nitroglycerine shotholes.

At the time of this study, only ten wells had been drilled. Drilling was difficult and expensive for that time because of a high pressure zone in the Yates formation at a depth of about 3000 ft [900 m]. Fifteen pound [1800 kg/m^3] mud that was both expensive and slowed drilling was required. Average time to drill the 4500 ft [1370 m] wells was 69 days with 6 days to rig-up. When the wells were drilled under pressure with lighter mud, the cost of drilling was reduced by almost 50 percent.

Two of the ten wells had been logged with electric logs and one well had been cored. Implied was that only cuttings were available to evaluate productive zones in the other eight wells. Although by today's standards, these electric logs may have been qualitative, they did correlate well with subsequent productivity after completion. At the time of the study, some of the wells had been acidized and some had been shot with nitroglycerine. In one of the wells, production declined after acidizing, and this caused a belief that acid might be detrimental to the oil-bearing strata in the Means Field; however, laboratory investigations indicated there should be no damage because of acidizing. Since with this one exception, similar production increases had been obtained by both methods, acidizing was recommended for future wells because of less danger and cheaper treatments.

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*"Report on Means Field, Andrews County, Texas," Humble Oil & Refining Co. Internal Report, 1935.

SECONDARY OPERATIONS

RESERVOIR MANAGEMENT DURING SECONDARY

1959 Reservoir Study with 1963 Modifications* **

In the late 1950's, the portion of the field which is now the Means (San Andres) Unit was still allowable limited, but the reservoir pressure was declining because of increased allowables. Recognizing the potential for additional recovery processes, operators in the area authorized a major reservoir study to evaluate secondary recovery. Highlights of this study included one of the first full field computer simulations by Humble. For this study, additional data had to be accumulated. These data included additional logging, fluid sampling and core data for special core analyses such as capillary pressures and relative permeabilities. By this time, enough wells had been logged so that cross sections could be prepared. Since the logs were limited in number and generally of poor quality, only gross intervals were correlated in these cross sections. Figure 4 is one of these cross sections and shows the major formations, Queen, Grayburg, Upper San Andres and Lower San Andres. Although relatively simple, these cross sections allowed sufficient zonation to design an initial waterflood pattern. This study recommended unitization of the major portion of the field as the Means (San Andres) Unit, and that waterflooding be initiated on a peripheral pattern that would encompass the more prolific Lower San Andres. It was recognized that the more stringerized Upper San Andres would not be adequately flooded by the peripheral pattern, and provision was made for a five-spot pattern to be implemented at some later date when needed. For the Grayburg, a cooperative leaseline pilot with the portion of the field west of the Unit was recommended.

In 1963, the field was unitized; and water injection began into 36 wells forming a peripheral pattern as shown in Figure 5. For clarity, only injection wells are shown on Figure 5. Since the Unit was at top allowable, production response could not be demonstrated. Twenty four wells, distributed throughout the Unit, were permanently shut-in and maintained as pressure response wells to monitor the reservoir pressure. Pressure response was indicated in only a few months, and the Unit was granted a waterflood allowable by the Texas Railroad Commission. Production remained at top allowable until 1967; when with increasing allowables, the Unit became capacity limited. The peripheral injection pattern could no longer provide sufficient pressure support for the increased allowables.

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*Kempe, J. L., and Waid, J. B.: "A Reservoir Study of the Means Field," Report to Working Interest Owners, Sept., 1959.

**Hackney, J. L., and Stiles, L. H.: "Proposed Plan of Operation, Means (San Andres) Unit," Report to Working Interest Owners, May, 1962.

1969 Reservoir Study

Barbe[1] reported the results of a detailed engineering and geologic study that was conducted during 1968 and 1969 to determine a new depletion plan more consistent with capacity production. The geologic study included a facies study from the limited core data that were available. In the North Dome, pressure data were correlated with the geological data to identify three major San Andres intervals; Upper San Andres, Lower San Andres Oil Zone and Lower San Andres Aquifer. A correlatable barrier from 10 to 15 ft [3-5 m] thick was identified between the Upper and Lower San Andres. With the low allowables prior to 1967, a semi-permeable barrier had allowed the peripheral injection pattern to support the Lower San Andres Oil Zone; however, with increased allowables, the peripheral pattern would no longer support either the Lower San Andres Oil Zone or the Upper San Andres adequately. Analysis of pressure data from the pressure observation wells indicated that parts of the South Dome also were not receiving adequate pressure support from the peripheral injectors. This study recommended interior injection with a three-to-one line drive (Figure 6). Following implementation of this program, Unit production increased from 13,000 BPD in 1970 to over 18000 BPD in 1972.

1975 Reservoir Study*

After peaking in 1972, production again began to decline. A detailed engineering and geologic study indicated that all of the pay was not being effectively flooded by the three-to-one line drive pattern. Specific objectives of the study were as follows:

1. Obtain a better reservoir description.
2. Determine remaining reserves under current operations.
3. Recommend changes to improve waterflood under current operations.
4. Evaluate alternate injection patterns.
5. Evaluate infill drilling.

In previous studies, Unit total original oil in place had been determined using a combination of gross pay and core data; but the lateral and vertical distribution of pay had never been calculated. Techniques were developed to correlate the old gamma ray-neutron logs with core data such that porosity-feet could be determined. Original oil in place was calculated for up to six zones in each well in the field. This geological study provided the basis for a secondary surveillance program and later also the basis for design and implementation of the CO_2 tertiary project.

George and Stiles[2] described a technique for estimating continuous and floodable pay that indicated potential additional recovery from infill drilling with pattern densification. As a result of the application of the continuous and floodable pay concept, 20-acre [8-ha] spacing with an 80-acre [32-ha] inverted 9-spot pattern was recommended in 1976. This modified pattern is shown on Figure 7.

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*George, C. J., and Stiles, L. H.: "Reservoir Study and Depletion Plan for the Means (San Andres) Unit," Exxon Company, USA, Internal Report, Jan., 1976.

Barber, et al[3] reported that the 141 infill wells that had been drilled through 1981 would recover 15.4 million STB [2.45 Mm^3] of incremental oil. Oil production with and without the infill program is shown on Figure 8.

During the top allowable period, reservoir surveillance was generally limited to monitoring of injection, production and pressure response. During this period, particular attention was paid to mechanical efficiency and cost reduction. With the advent of capacity production and pattern waterflooding, the reservoir surveillance program became more intense. A detailed surveillance program was developed which included the following:

1. Monitoring of production- oil, water and gas,
2. Monitoring of water injection,
3. Control of injection pressures with step-rate tests,
4. Pattern balancing with computer balance program,
5. Injection profiles to ensure injection into all pay,
6. Specific production profiles,
7. Fluid levels to ensure pump-off of producing wells.

TERTIARY OPERATIONS

RESERVOIR MANAGEMENT DURING TERTIARY

1981-82 Reservoir Study*

In 1980, a tertiary screening committee recommended that the Means San Andres Unit be considered for a CO_2 tertiary project. At that time, several major CO_2 projects had been proposed for San Andres reservoirs; however, none had been implemented. Since laboratory data and field tests from other San Andres reservoirs had indicated that the CO_2 process was viable, it was reasonable to assume that CO_2 injection at Means would result in additional recovery, and that accelerated implementation was technically sound. Although Means was generally similar to other large San Andres fields in the Permian Basin, there were some properties which appeared to be unique or at least substantially different. These specific properties or problems included the following:

1. Oil viscosity, 6 cp [6 mPa·sec],
2. Relatively high minimum miscibility pressure (MMP),
3. Low formation parting pressure,
4. Potential low injectivity,
5. Possible CO_2 override.

The decision was made to initiate plans for the implementation of a fieldwide project and to investigate potential problem areas simultaneously. These evaluation programs included laboratory investigations, a field pilot and reservoir simulation. Details of the planning and implementation of the CO_2 tertiary project were reported by Magruder, et al[5].

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*"CO_2 Tertiary Recovery Project, Means San Andres Unit," Report to Working Interest Owners, Jan., 1983.

Fortunately, a detailed reservoir description had preceded the infill program of the middle and late 1970's. This reservoir description was the basis for planning of the CO_2 tertiary project. Although this reservoir description was the building block for the project, it was continuously updated during the planning and implementation phases of the CO_2 project as more data became available.

In planning for the CO_2 project, optimum wellbore utility was a prime concern. Existing wells included the original 40-acre [16-ha] and the 20-acre [8-ha] infill wells; and infill drilling to 10-acre [4-ha] spacing was to be an integral part of the CO_2 project. The 40-acre [16-ha] wells were from 30 to 50 years old; and many were completed open hole, did not fully penetrate the pay, and in some cases were shot with nitroglycerine. All of the 20-acre [8-ha] wells had been drilled since 1976 and were in relatively good condition. Throughout the waterflood history, all of the injectors were original 40-acre [16-ha] wells. The 1975 study had recommended 20-acre [8-ha] spacing with an 80-acre [32-ha] inverted 9-spot pattern. As the infill program progressed, additional conversions were made, and the pattern was approaching a 40-acre [16-ha] 5-spot. The 40-acre [16-ha] 5-spot waterflood pattern is shown on the left side of Figure 9, and the CO_2 project pattern is shown on the right. In the project pattern, the WAG injectors have been shifted 660 ft in an east-west direction. The project pattern was to be a 40-acre [16-ha] inverted 9-spot in which all of the WAG injectors and center producers would be new 10-acre [4-ha] wells. If only the 10-acre [4-ha] wells were considered, the pattern would be a 40-acre [16-ha] 5-spot that would be an excellent pattern. The 20-acre [8-ha] wells would be located north and south of the injectors in the best location considering possible east-west directional permeability. Finally, the 40-acre [16-ha] wells, which were in the poorest mechanical condition, would be located east and west of the injectors.

The proposed project was to consist of 167 patterns on approximately 6700 acres [2700 ha]. The project area was determined on the perceived economics of each individual pattern. It included 60 percent of the productive acres and 82 percent of the original oil in place in the Unit.

Implementation of the project began in November 1983, and in less than two years, 205 infill producers and 158 infill injectors were drilled. Constant reevaluation as implementation progressed caused changes in the initial plan. Additional patterns were added and some patterns were deferred. Currently, the project consists of 172 patterns on 8500 acres [3400 ha]. The outline of the CO_2 project area is shown on Figure 2, the structural map.

TERTIARY SURVEILLANCE PROGRAM

A detailed and integrated surveillance program had been in existence during the waterflood for several years. With the implementation of the CO_2 project, surveillance became even more important. Prior to developing an improved and more comprehensive surveillance program, an operating philosophy was developed by personnel from engineering, geology, and operations and submitted to management for approval and support. Although there are many facets to the operation of this CO_2 project, the major operating objectives are as follows:

1. Complete injectors and producers in all floodable pay.
2. Maintain reservoir pressure near the MMP of 2000 psi [13.8 MPa].
3. Maximize injection below fracture pressure.

4. Pump off producers.
5. Obtain good vertical distribution of injected fluids.
6. Maintain balanced injection/withdrawals by pattern.

In order to achieve and maintain the above operating objectives, a companion surveillance program was developed. Contributing to this program were engineers, geologists, and operations personnel, with full support of management. Major areas of surveillance included the following:

1. Areal Flood Balancing,
2. Vertical Conformance Monitoring,
3. Production Monitoring,
4. Injection Monitoring,
5. Data Acquisition and Management,
6. Pattern Performance Monitoring,
7. Optimization.

Areal Flood Balancing

The objective of areal flood balancing is to optimize the arrival of flood fronts (CO_2 and water) at producers while maintaining reservoir pressure above the MMP of approximately 2000 psi[13.8 MPa]. The principal tools to accomplish this objective are annual pressure falloff tests in each injector and two computer balancing programs. One of these programs is used to maintain current and cumulative injection and withdrawal balances by well and pattern. The other one is used to schedule switching of CO_2 and water injection cycles.

Vertical Conformance Monitoring

The objective in vertical conformance monitoring is to optimize vertical sweep efficiency while minimizing injection out of zone by evaluating and monitoring the profile distribution of the injected fluid and the vertical Lorenz coefficients of each pattern. Four three-well cross sections were constructed for each pattern to ensure completions in all of the floodable pay. Annual profiles are run on all injection wells. The following analysis is completed for each of the profiles.

- Identify casing or packer leaks.
- Identify injection out of zone.
- Compare zonal injection from profile with porosity feet and permeability feet profiles for that well.

Based on the above analyses, remedial action may be recommended. The desired result of this work is that the profiles are acceptable, and that no remedial action will be needed. In this case, injection profiles can be considered as insurance. An example that compares the injection profile with porosity feet and permeability feet is shown on Figure 10.

Production Monitoring

The objective of the production monitoring program is to monitor oil, gas, and water production from individual wells to identify and understand production anomalies and problem CO_2 breakthrough areas. Well tests, tank battery measurements and fluid levels are used to identify anomalies and especially wells indicating abnormal declines. These anomalies may be caused by mechanical problems, scale or paraffin, reservoir pressure changes and thief zones in offset injection wells. A significant feature of this program is monthly meetings with field operators to discuss problems that may be occurring.

Injection Monitoring

The objective of injection monitoring is to ensure injection rates and pressures are optimized while maintaining injection pressure below formation parting pressure. CO_2 and water injection quality are monitored to identify possible impact on minimum miscibility pressure and potential injectivity problems.

Pattern Performance Monitoring

The objective of this program is to maximize oil recovery and flood efficiency by evaluating and optimizing the performance of each pattern in the waterflood and CO_2 flood. Monitored items include gas-oil and water-oil performance compared with predicted or normal. A particularly important yardstick is the ratio of CO_2 produced to CO_2 injected into a pattern. Particular attention is paid to patterns that have shown little or no response. The monitoring of pattern performance is very important as each pattern matures to help determine when to change from constant WAG to the final waterflood with a tapered or increasing WAG.

Data Acquisition and Management

The objective of this program is to ensure accurate data are collected, allocated and entered into appropriate databases. It is equally important that this data be transmitted to users in a timely and efficient manner. It is obvious that regardless of how well a reservoir management program is designed, it will be of little value unless reliable data are furnished.

Optimization

This objective is to maximize oil recovery by identifying and evaluating new opportunities and technologies. If reservoir management is to be really effective, it must be dynamic and sensitive to changes in performance, technology and economics. Optimization opportunities may range from the small and simple to major breakthroughs. In the continuous goal of obtaining better reservoir descriptions so that we may better understand the reservoir processes, one of the current programs is the use of high resolution seismic to improve pay correlation between wells.

In recent years, the application of seismic sequence stratigraphic concepts has yielded significant insights into our reservoir's complexities. At Means field, Exxon geoscientists have completed a major reinterpretation of the San Andres and Grayburg reservoirs. Seismic sequence stratigraphic interpretation provides the geometric "template" to constrain properly basic well log correlations within a chronostratigraphic framework. Seismic-scale stratal geometries, combined with detailed geologic rock descriptions, define this sequence framework which is the basis for defining major reservoir flow units.

At Means, an extensive 2D seismic dataset was interpreted and integrated with core descriptions and well log cross sections. The new sequence-keyed reservoir model has already yielded substantial results. One example is the interpretation of a stratigraphic "wedge" along the east flank margin of the field which has proven productive from reservoir intervals well below the fieldwide oil-water contact. In addition, the new stratigraphic model is being used to optimize CO_2 project completions by ensuring that all pay is opened in both producer and injector based on correlative stratigraphic zones.

Performance of Tertiary Project

The CO_2 tertiary project was implemented as part of an integrated reservoir management plan which included in addition to CO_2 injection, infill drilling, pattern changes and expansion of the Grayburg waterflood outside the project area. Performance to date has exceeded expectations. Figure 11 shows Unit oil production with and without the tertiary project.

CONCLUSIONS

- Reservoir management at Means has evolved from relatively simple to elaborate techniques as the reservoir has been produced by primary, secondary and tertiary methods.
- Reservoir management at Means has met the technical and economic challenges of the time.
- Reservoir management programs in today's environment must include team effort from several groups and have the support of management.
- Reservoir management must be dynamic and sensitive to changes in performance, technology and economic conditions.

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3. Barber, A. H., Jr., George, C. J., Stiles, L. H., and Thompson, B. B.: "Infill Drilling to Increase Reserves - Actual Experience in Nine Fields in Texas, Oklahoma, and Illinois," J. Pet. Tech. (Aug. 1983), pp. 1530-1538.

4. Stiles, L. H., Chiquito, R. M., George, C. J., and Long, L. D.: "Design and Operation of a CO2 Tertiary Pilot: Means (San Andres) Unit"; Paper SPE 11987 presented at SPE 58th Annual Technical Conference and Exhibition, San Francisco, CA, Oct. 5-8, 1983.

5. Magruder, J. B., Stiles, L. H., and Yelverton, T. D.: "A Review of the Means San Andres Unit Full Scale CO2 Tertiary Project, J. Pet. Tech. (May 1990), pp. 638-644.

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Table 1
Reservoir and Fluid Properties - Means San Andres Unit

Formation Name	San Andres
Lithology	Dolomite
Area, Ac.	14,328
Depth, Ft	4,400
Thickness - Gross, Ft	300
Net Pay - Avg., Ft	54
Porosity - Avg., %	9.0 (up to 25)
Permeability - Avg., MD	20.0 (up to 1000)
Connate Wtr.-Avg., %	29
Primary Drive	Weak Wtr. Drive
Avg. Pressure - Original, PSIG	1850
Stock Tank Gravity °API	29
Oil Viscosity, CP	6
Form. Vol. Factor, RB/STB	1.04
Saturation Pressure, PSI	310

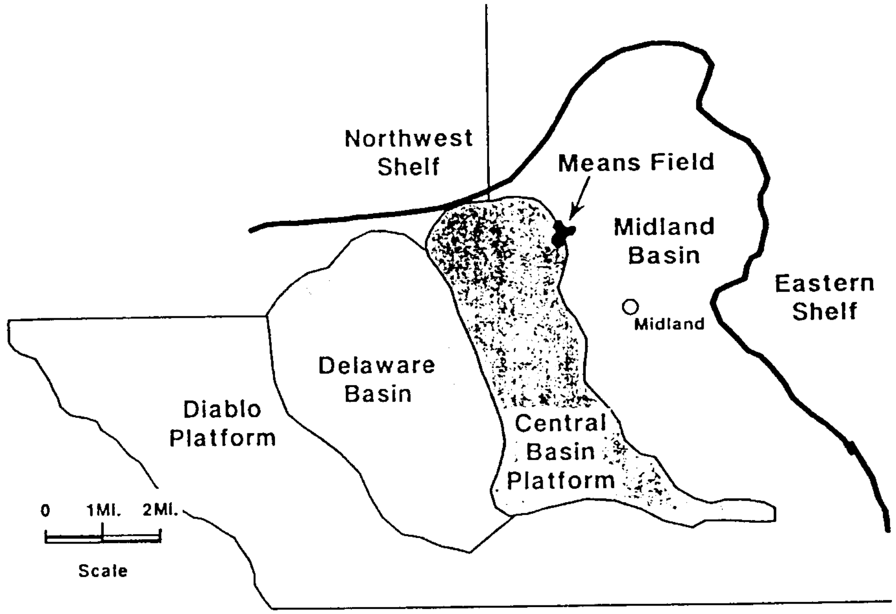

Figure 1 - Permian Basin principal geologic provinces

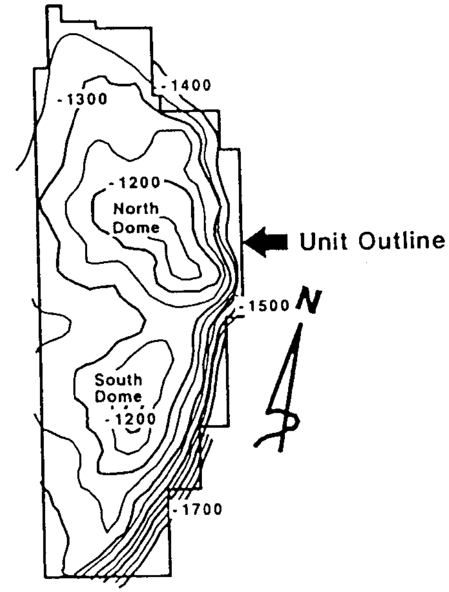

Figure 2 - Structural map - Means (San Andres) Unit

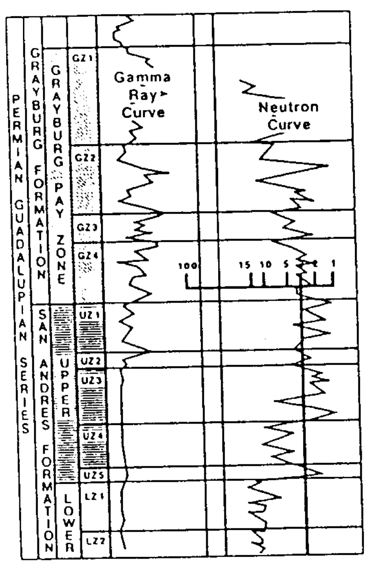

Figure 3 - Type log - Means San Andres Unit MSAU 1216

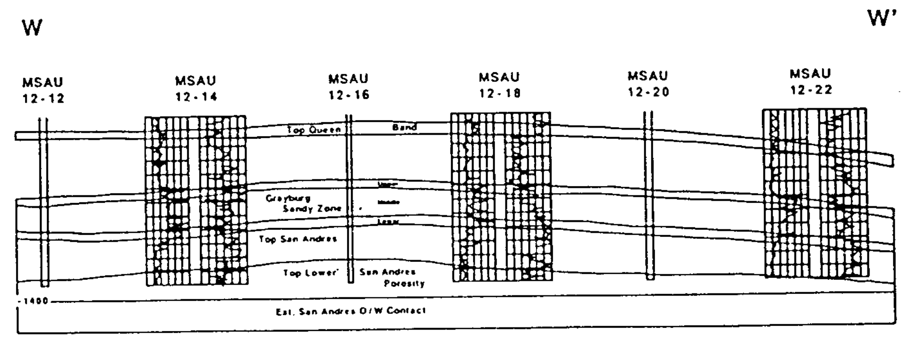

Figure 4 - West-east structural cross section (Means San Andres Unit)

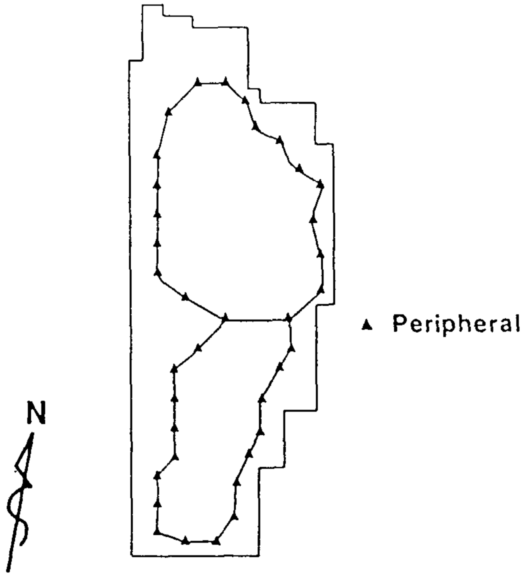

Figure 5 - Waterflood injection pattern
(Means San Andres Unit)

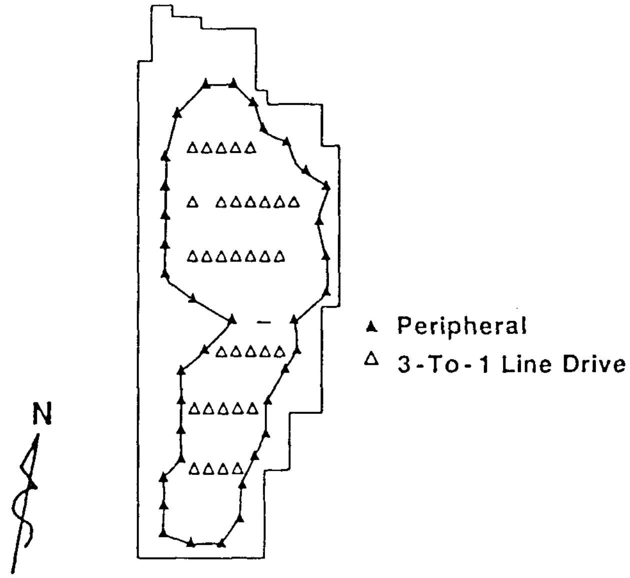

Figure 6 - Waterflood injection pattern
(Means San Andres Unit)

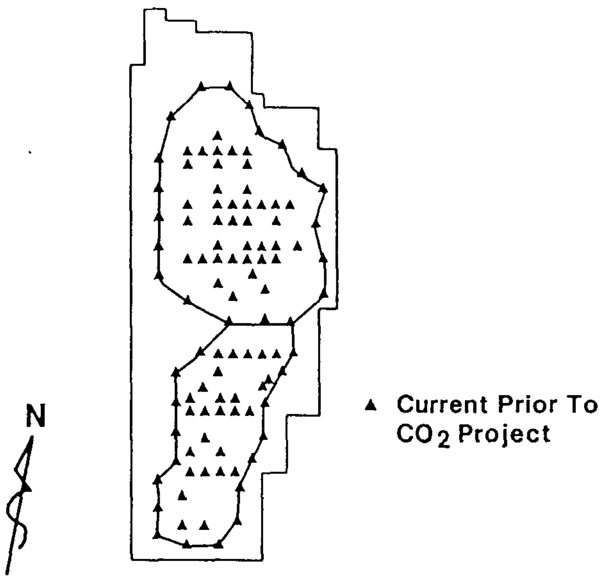

Figure 7 - Waterflood injection pattern
(Means San Andres Unit)

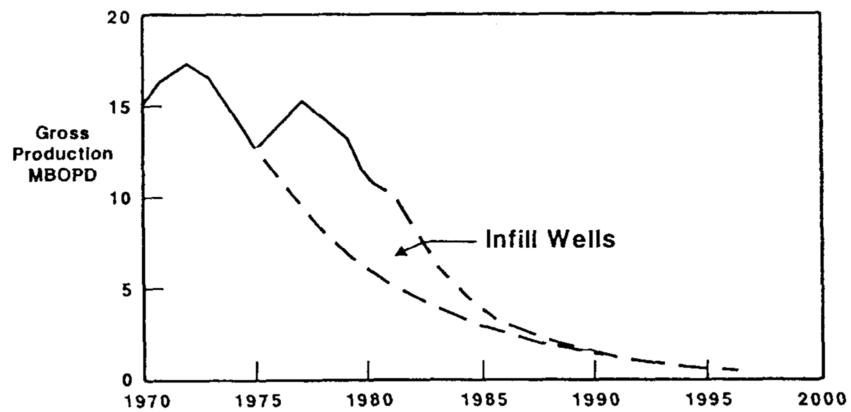

Figure 8 - MSAU infill drilling

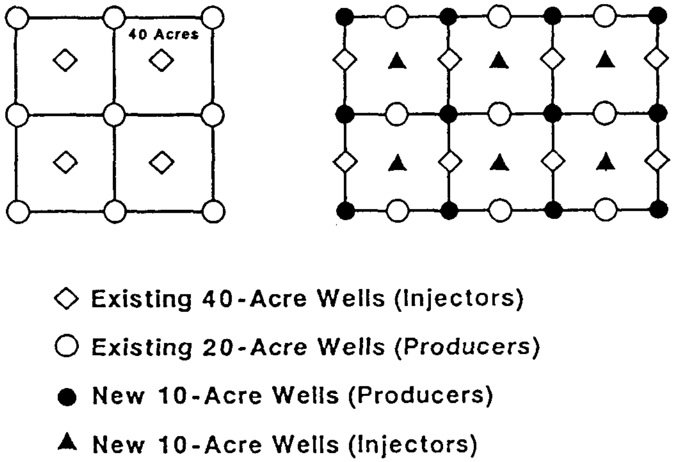

Figure 9 - MSAU flood pattern

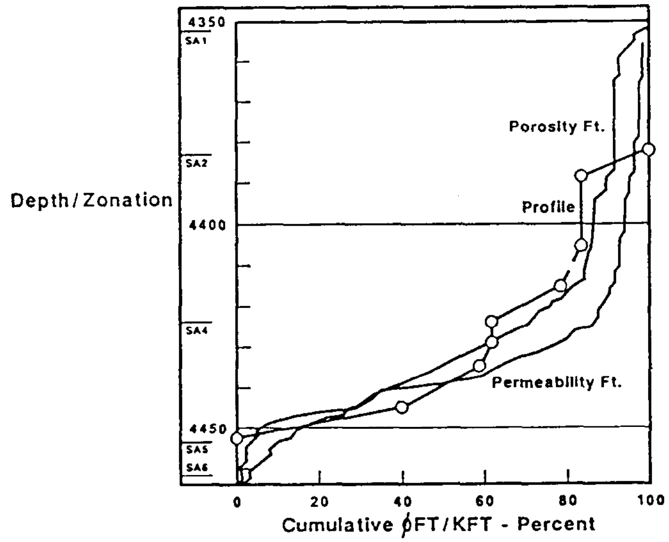

Figure 10 - Profile comparison
(Means San Andres Unit)

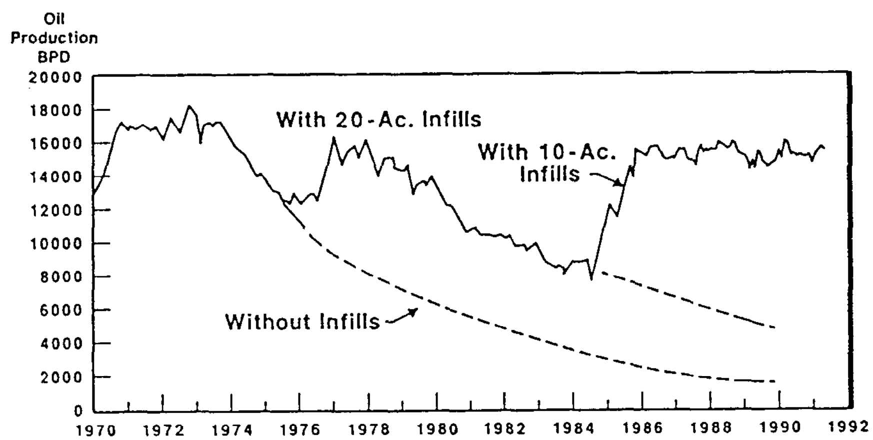

Figure 11 - Oil production - 1970 - 1990
(Means San Andres Unit)