#0091

Modelling permeability in diagenetically layered reservoirs. East Irish Sea Basin U.K. The failure of geological models ?

Greig Cowan, Mick Wannel and Nick Colley

British Gas E&P Ltd,
100 Thames Valley Park,
Reading,
Berkshire, RG6 1PT
United Kingdom.

The North and South Morecambe Fields of the East Irish Sea Basin U.K. are affected by authigenic platy illite which precipitated below the palaeo/water-conatct of low relief precursors of the present structure. The illite reduces the horizontal permeability by 2-3 orders of magnitude and the divides the reservoirs vertically into a high permeability illite free layer, and a low permeability illite affected layer. This diagenetic permeability reduction is superimposed upon the primary, depositional permeability heterogeneity. PLT logs show that less than 5% of the flow into the wellbore comes from the illite affected layer although this layer contains 60% of the gas. Production of gas from this layer is thought to occur by vertical migration into the illite free layer. The rate and efficiency of this process depend to a large extent on the vertical permeability (Kv) of the illite affected layer.

The pre-development sedimentological model suggested that the reservoir was not depositionally layered, and that high permeability fluvial channel sandstones were deposited throughout a background of lower permeability sheetflood sandstones. Thin, permeable aeolian sandstones and shale barriers were thought to be of limited areal extent. Stochastic modelling of shale barrier distribution combined with vertical core plug data suggested a fieldwide Kv of 0.04mD. Development drilling showed that the reservoir was, in fact, highly layered. Attempts were made to measure the aquifer Kv using the RFT to test the pore pressure response to tidal cycles. This suggested a much lower Kv was appropriate. Finally, RFT data collected after significant production shows vertical pressure gradients consistent with a local Kv of 0.0004 Md.

The pre-production reservoir models failed to predict accurately the Kv. This study shows that modelling of Kv is much more complex than Kh and that special data collection and modelling techniques are required to predict Kv where authigenic illite is present.

pg 472

Reservoir Management in the Means San Andres Unit

L.H. Stiles, SPE, and **J.B. Magruder,** SPE, Exxon Co. U.S.A.

Summary. The Means field provides an opportunity to observe the evolution of reservoir management to meet ever-changing economic and technical challenges as the field has been produced by primary, secondary, and tertiary methods. 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. Current operations are an integrated program of CO_2 injection, infill drilling, and waterflooding. To date, the tertiary project has performed above expectations.

Introduction

The Means field in Andrews County, TX was discovered in 1934 and developed on 40-acre spacing. Reservoir management techniques began within 1 year of discovery and have become increasingly complex 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). Several papers[1-5] described specific programs for the field. This paper describes the evolution of reservoir management at Means.

This paper concentrates on the reservoir description, infill drilling with pattern modification, and reservoir surveillance portions of reservoir management. Reservoir description methods have evolved from the relatively simple techniques used 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 always been an integral part of reservoir management in the Means field, 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 about 50 miles northwest of Midland, along the eastern edge of the Central Basin platform (**Fig. 1**), and lies in a trend of San Andres production that extends for more than 100 miles in a northwest-southeast direction. The field was discovered in 1934 and by the early 1950's was developed on 40-acre spacing with approximately 300 wells in the MSAU area. **Table 1** lists the reservoir and fluid properties.

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 (**Fig. 2**). Production is from the Grayburg and San Andres formations at depths ranging from 4,200 to 4,800 ft. **Fig. 3**, a type log, shows the zonation of the vertical interval. The Grayburg is about 400 ft thick with the basal 100 to 200 ft considered gross pay. Production from the Grayburg was by solution-gas drive with the bubblepoint at the original reservoir pressure of 1,850 psi. The Grayburg reservoir is of much poorer quality, and its production has been minor compared with the San Andres. The San Andres is more than 1,400 ft thick, with the upper 200 to 300 ft being productive. The primary producing mechanism in the San Andres was a combination of fluid expansion and a weak waterdrive. Production was generally limited by state allowables during the primary producing phase.

Reservoir Management During Primary Operations

The first reservoir study* was completed in 1935, little more than 1 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 remains the same.

Three technical areas were explored in the 1935 report: (1) drilling under pressure to allow lighter-weight mud, (2) comparison of electric logs with core analysis, and (3) comparison of acid stimulation with nitroglycerine shot holes. At that time, only 10 wells had been drilled. Drilling was difficult and expensive for that time because of a high-pressure zone in the Yates formation at about 3,000 ft. A 15-lbm/gal mud was required to attain this high-pressure zone. Average time to drill the 4,500-ft wells was 69 days, with 6 days to rig-up. This study recommended drilling under pressure with lighter mud, and the cost of drilling was reduced by almost 50%.

Copyright 1992 Society of Petroleum Engineers

*"Report on Means Field, Andrews County, Texas," internal report, Humble Oil & Refining Co., Midland, TX (1935).

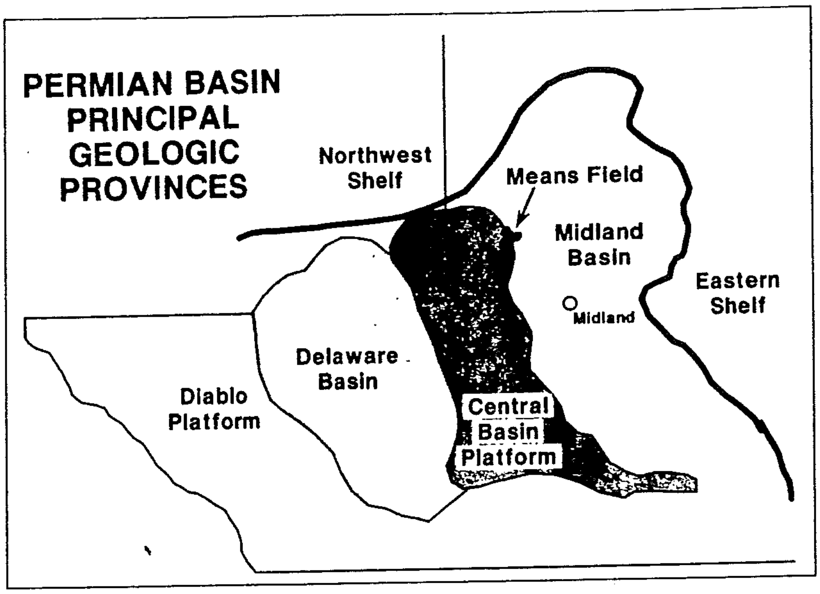


Fig. 1—Permian Basin geologic provinces.

"Reservoir description methods have evolved from the relatively simple techniques used in the 1930's to the recent use of high-resolution seismic to improve pay correlation between wells."

Of the 10 wells, 2 were logged with electric logs and 1 was cored. The implication was that only cuttings were available to evaluate productive zones in 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, which indicated that acid might be detrimental to the oil-bearing strata in the Means field. Laboratory investigations indicated that no damage should result from acidizing, and in all other cases, similar production increases had been obtained by both methods. Acidizing was recommended for future wells because of less danger to personnel and cheaper treatments.

Reservoir Management During Secondary Operations

1959 Reservoir Study With 1963 Modifications.* In the late 1950's, the portion of the field that is now the MSAU 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 Humble's first full-field computer simulations. For this study, additional data had to be accumulated, including additional logging, fluid sampling, and core data for special core analyses (e.g., capillary pressures and relative permeabilities). By this time, enough wells had been logged that cross sectoins could be prepared. Because the logs were limited in number and generally of poor quality, only gross intervals were correlated in these cross sections. **Fig. 4**, one of these cross sections, shows the major formations: Queen, Grayburg, and Upper 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 MSAU. It also recommended 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 flooded adequately by the peripheral pattern, so provisions were made for a five-spot pattern to be implemented later when needed. For the Grayburg, a cooperative lease-line 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 (**Fig. 5**). For clarity, only injection wells are shown in Fig. 5. Because 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 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.

1969 Reservoir Study. Barbe[1] reported the results of a detailed engineering and geologic study conducted during 1968–69 to determine a new depletion plan more consistent with capacity production. The geologic study included a facies study from the limited core data available. In the North

*Kempe, J.L. and Wald, 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, Humble Oil & Refining Co., Midland, TX (May 1962).

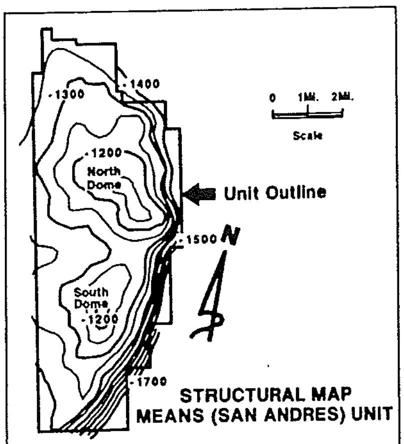


Fig. 2—Structural map.

TABLE 1—RESERVOIR AND FLUID PROPERTIES, MEANS SAN ANDRES UNIT

Formation name	San Andres
Lithology	Dolomite
Area, acres	14,328
Depth, ft	4,400
Gross thickness, ft	300
Average net pay, ft	54
Average porosity, %	9.0 (up to 25)
Average permeability, md	20.0 (up to 1,000)
Average connate water, %	29
Primary drive	Weak waterdrive
Average pressure (original), psig	1,850
Stock-tank gravity, °API	29
Oil viscosity, cp	6
FVF, RB/STB	1.04
Saturation pressure, psi	310

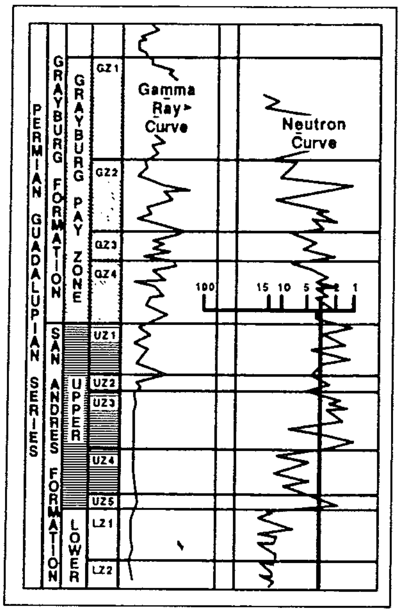


Fig. 3—Type log.

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 thick was identified between the Upper and Lower San Andres. With the low allowables before 1967, a semipermeable barrier had allowed the peripheral injection pattern to support the Lower San Andres oil zone. With increased allowables, however, the peripheral pattern would no longer adequately support either the Lower San Andres oil zone or the Upper San Andres. 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 (**Fig. 6**). Following implementation of this program, unit production increased from 13,000 B/D in 1970 to >18,000 B/D in 1972.

1975 Reservoir Study.* After peaking in 1972, production again began to decline. An in-depth reservoir study indicated that all the pay was not being flooded effectively by the three-to-one linedrive pattern. Specific objectives of the study were (1) to obtain a better reservoir description, (2) to determine remaining reserves under current operations, (3) to recommend changes to improve waterflood under current operations, (4) to evaluate alternative injection patterns, and (5) to evaluate infill drilling.

In previous studies, unit total original oil in place (OOIP) was determined from a combination of gross-pay and core data, but the lateral and vertical distributions of pay had never been calculated. Techniques were developed to correlate the old gamma-ray/neutron logs with core data so that porosity-feet could be determined. OOIP was calculated for up to six zones in each well in the field. This geologic study provided the basis for a secondary surveillance program and later 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 this concept of continuous and floodable pay, 20-acre spacing with an 80-acre inverted nine-spot pattern was recommended in 1976. This modified pattern is shown in **Fig. 7.**

Barber, *et al.*[3] reported that the 141 infill wells drilled through 1981 would recover 15.4 million STB of incremental oil. **Fig. 8** shows oil production with and without the infill program.

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 that included (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 programs, (5) injection profiles to ensure injection into all pay, (6) specific production profiles, and (7) fluid level checks to ensure pump-off of producing wells.

Tertiary Operations

Reservoir Management—1981-82 Reservoir Study.* In 1980, a tertiary screening committee recommended that the MSAU be considered for a CO_2 tertiary project. At that time, several major CO_2 projects had been proposed for San Andres reservoirs, but none had been implemented. Because laboratory data and field tests from other San Andres reservoirs 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, some properties appeared to be unique, or at least substantially different. These specific properties or problems included 6-cp oil viscosity, relatively high minimum miscibility pressure (MMP), low formation parting pressure, potential low injectivity, and possible CO_2 override.

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

Fortunately, a detailed reservoir description had preceded the infill program of the middle and late 1970's. This reservoir

*George, C.J. and Stiles, L.H.: "Reservoir Study and Depletion Plan for the Means (San Andres) Unit," internal report, Exxon Co. U.S.A., Midland, TX (Jan. 1976).

*"CO_2 Tertiary Recovery Project, Means San Andres Unit," report to working-interest owners, Exxon Co. U.S.A., Midland, TX (Jan. 1983).

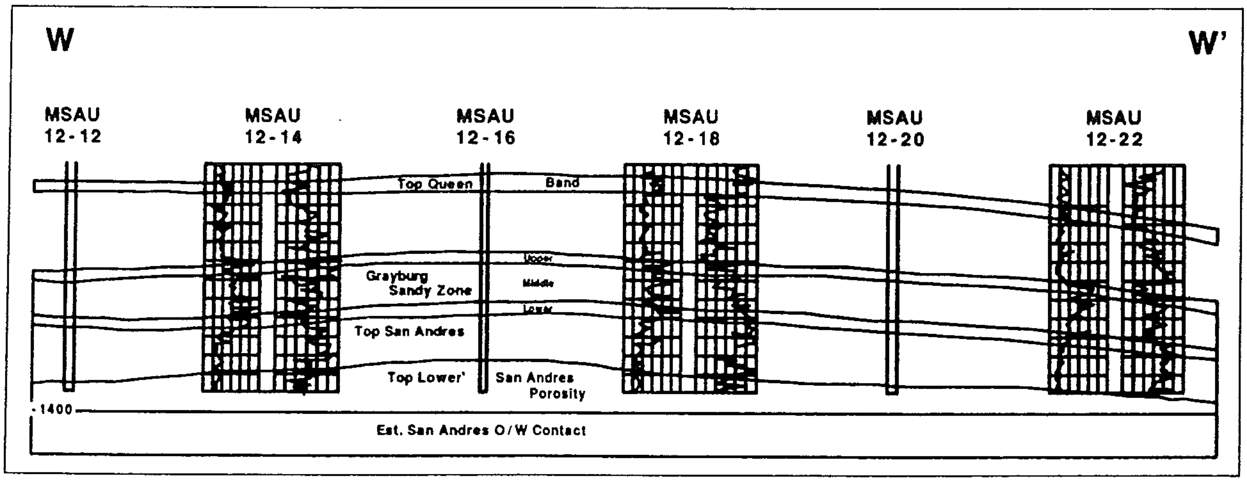


Fig. 4—MSAU west-east cross section.

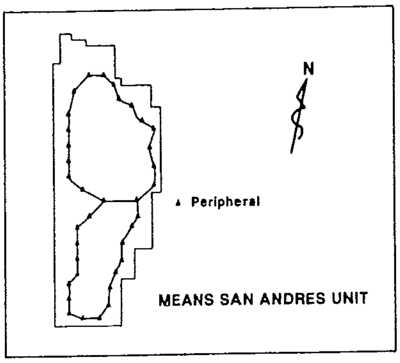


Fig. 5—Peripheral injection pattern.

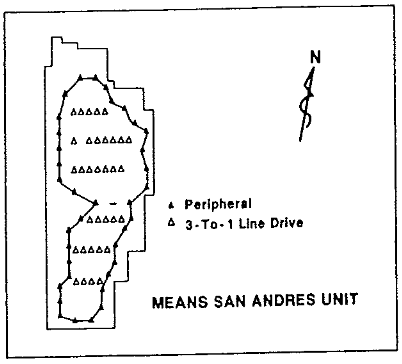


Fig. 6—Three-to-one linedrive pattern.

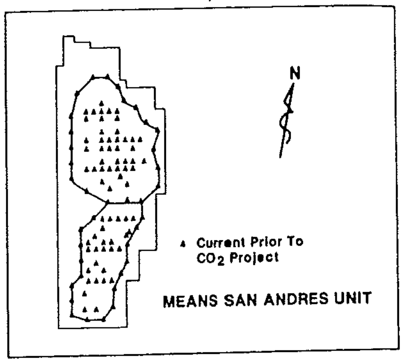


Fig. 7—Waterflood injection pattern.

description was the basis for planning 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.

During planning of the CO_2 project, optimum wellbore utility was a prime concern. Existing wells included the original 40-acre and the 20-acre infill wells, and infill drilling to 10-acre spacing was to be an integral part of the CO_2 project. The 40-acre wells were 30 to 50 years old. Many were completed open hole, did not fully penetrate the pay, and in some cases were shot with nitroglycerine. All the 20-acre wells had been drilled since 1976 and were in relatively good condition. Throughout the waterflood history, all the injectors were original 40-acre wells. The 1975 study recommended 20-acre spacing with an 80-acre inverted nine-spot pattern. As the infill program progressed, additional conversions were made, and the pattern was approaching a 40-acre five-spot. The 40-acre five-spot waterflood pattern is shown on the left side of **Fig. 9**, and the CO_2 project pattern is shown on the right. In the project pattern, the water-alternating-gas (WAG) injectors were shifted 660 ft in an east-west direction. The project pattern was to be a 40-acre inverted nine-spot in which all the WAG injectors and center producers would be new 10-acre wells. If only the 10-acre wells were considered, the pattern would be a 40-acre five-spot, which would be an excellent pattern. The 20-acre wells would be located north and south of the injectors in the best location considering possible east-west directional permeability. The 40-acre 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 6,700 acres. The project area was determined on the perceived economics of each individual pattern. It included 60% of the productive acres and 82% of the OOIP in the unit.

Project implementation began in Nov. 1983. In less than 2 years, 205 infill producers and 158 infill injectors were drilled. Constant re-evaluation 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 8,500 acres. Fig. 2 shows the outline of the CO_2 project area.

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. Before an improved and more comprehensive surveillance program was developed, an operating philosophy was created by personnel from engineering, geology, and operations and submitted to management for approval and support. Although the operation of this CO_2 project has many facets, the major operating objectives are (1) to complete injectors and producers in all floodable pay, (2) to maintain reservoir pressure near the MMP of 2,000 psi, (3) to maximize injection below fracture pressure, (4) to pump off producers, (5) to obtain good vertical distribution of injected fluids, and (6) to maintain balanced injection/withdrawals by pattern.

To achieve and maintain these objectives, a companion surveillance program was developed. Engineers, geologists, and operations personnel contributed to this program, with full support of management. Major areas of surveillance included (1) areal flood balancing, (2) vertical conformance monitoring, (3) production monitoring, (4) injection monitoring, (5) data acquisition and management, (6) pattern performance monitoring, and (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 2,000-psi MMP. 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 is used to schedule switching of CO_2 and water injection cycles.

Vertical Conformance Monitoring. The objective of vertical conformance monitoring is to optimize vertical sweep efficiency while minimizing out-of-zone injection by evaluating and monitoring the profile dis-

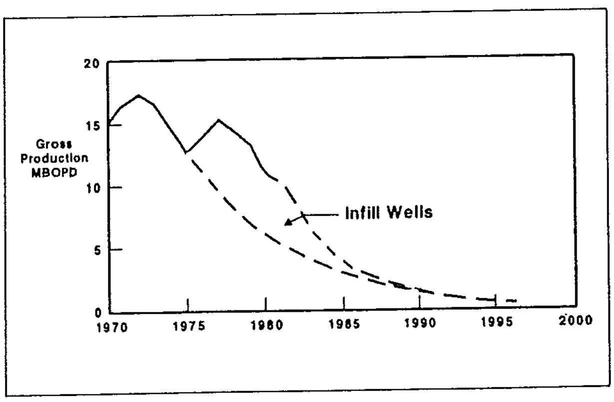


Fig. 8—20-acre infill drilling.

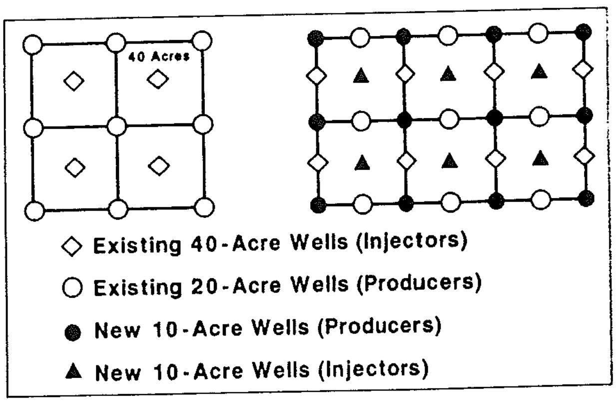


Fig. 9—Tertiary injection pattern.

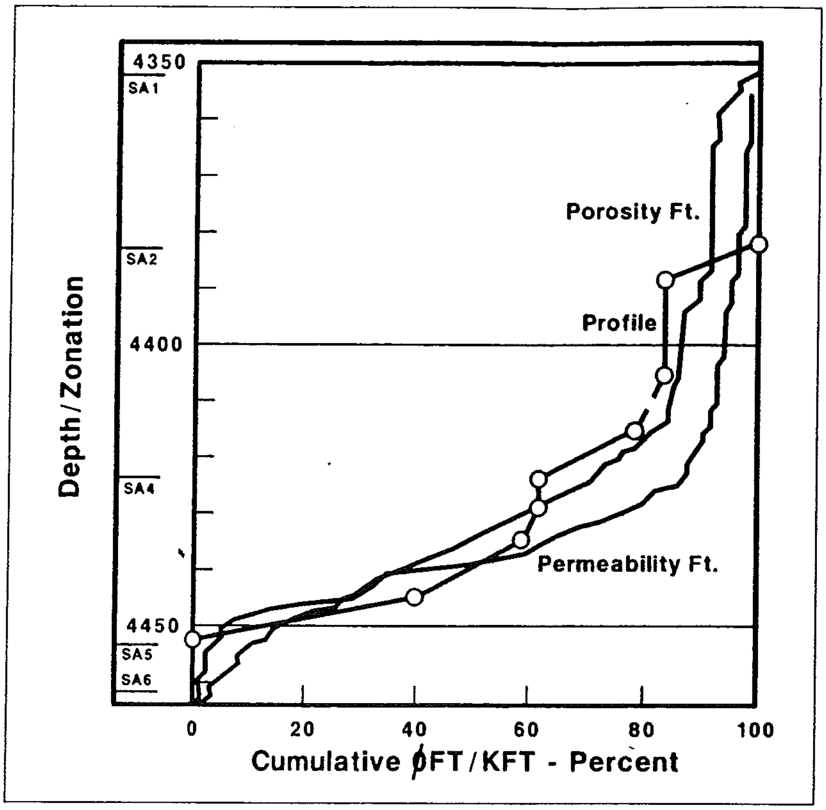


Fig. 10—Injection profile comparison.

"During planning of the CO_2 project, optimum wellbore utility was a prime concern."

tribution 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 the floodable pay. Annual profiles are run on all injection wells. Analyses are completed for each of the profiles to identify casing or packer leaks, to identify out-of-zone injection, and to compare zonal injection from profiles with porosity-feet and permeability-feet profiles for that well. From these 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 insurance. **Fig. 10** compares the injection profile with porosity-feet and permeability-feet profiles.

Production Monitoring. The objective of this 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, especially wells indicating abnormal declines. These anomalies may be caused by

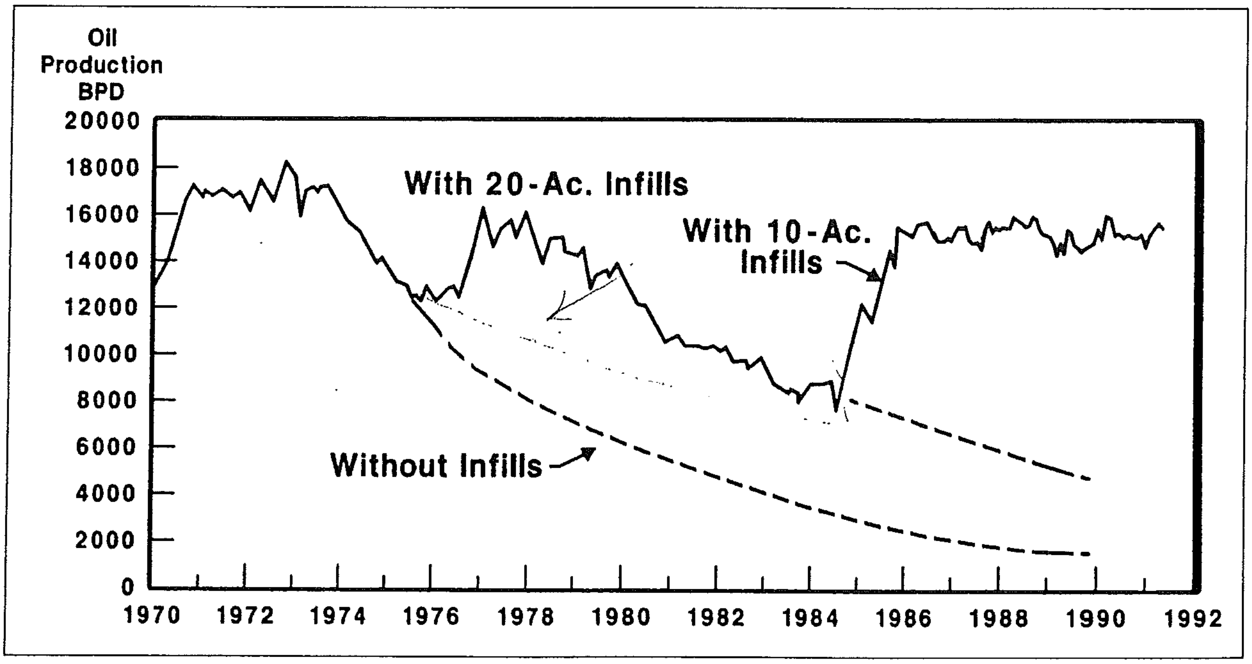


Fig. 11—Oil production—1970-90.

mechanical problems, scale or paraffin, reservoir pressure changes, and thief zones in offset injection wells. This program features monthly meetings with field operators to discuss any problems.

Injection Monitoring. The objective of injection monitoring is to ensure that injection rates and pressures are optimized while maintaining injection pressure below formation parting pressure. CO_2 and water-injection quality are monitored to identify the possible impact on MMP 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 because 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 that accurate data are collected, allocated, and entered into the appropriate data bases. It is equally important that these data be transmitted to users in a timely and efficient manner. 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 to better understand the reservoir processes, one of the current programs is the use of high-resolution seismic to improve pay correlation between wells.

The application of seismic sequence stratigraphic concepts recently has yielded significant insights into our reservoir's complexities. At the Means field, geoscientists have completed a major reinterpretation of the San Andres and Grayburg reservoirs. Seismic sequence stratigraphic interpretation provides the geometric "template" to constrain basic well-log correlations properly 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.

"Reservoir management programs in today's environment must include team effort from several groups and have management's support."

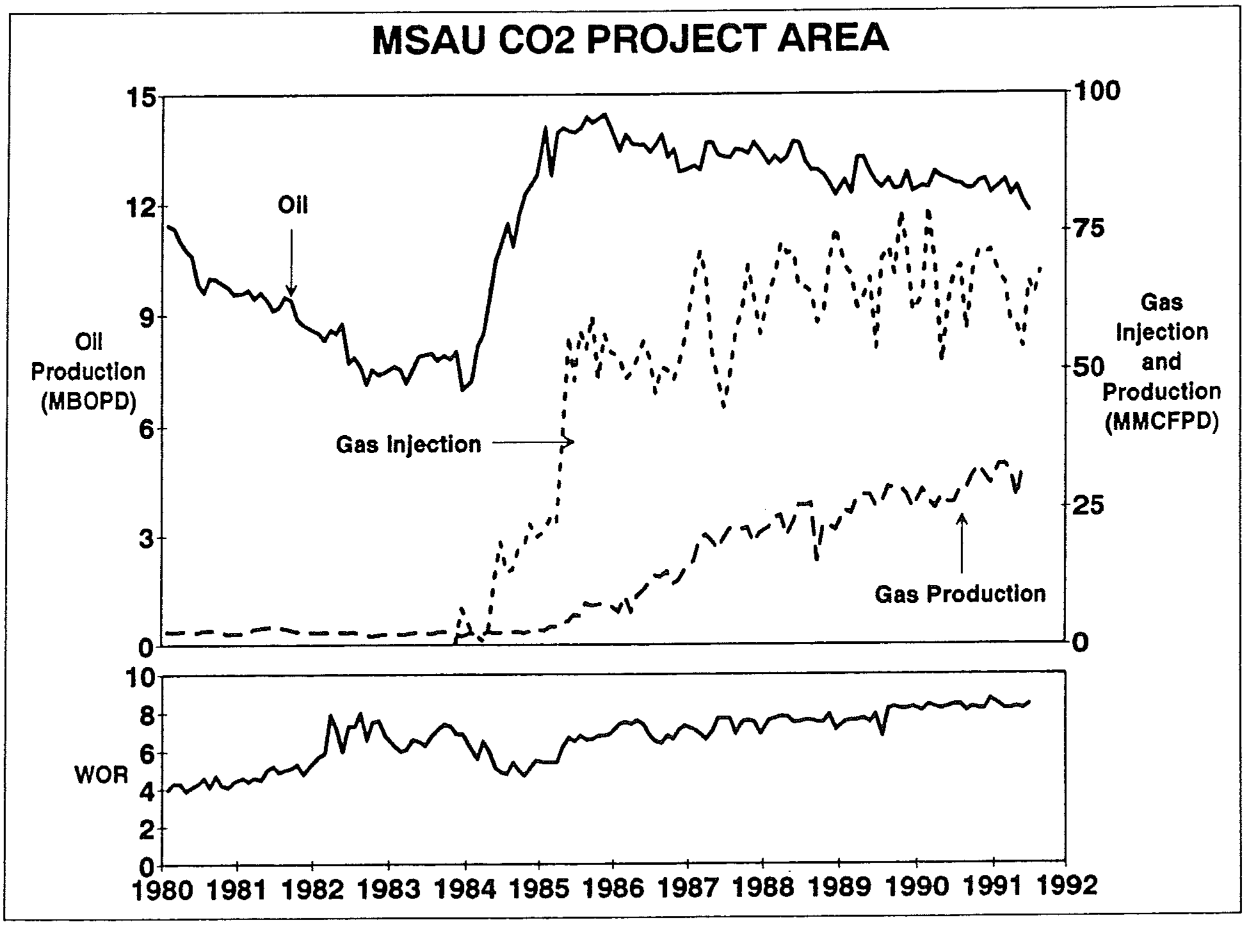


Fig. 12—Performance of tertiary project area.

At Means, an extensive 2D seismic data set 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 proved 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 producers and injectors based on correlative stratigraphic zones.

Performance. The CO_2 tertiary project was implemented as part of an integrated reservoir management plan that included, in addition to CO_2 injection, infill drilling, pattern changes, and expansion of the Grayburg waterflood outside the project area. Total unit oil production is shown in **Fig. 11** with and without the tertiary project. Current incremental project production is about 10,000 BOPD. **Fig. 12** shows the performance of the tertiary project area only. CO_2 injection first began in Nov. 1983. Between late 1983 and mid-1985 infill drilling and pattern modifications were completed, including the drilling of new CO_2 injectors. CO_2 injection was initiated as injectors were completed. Initial buildup to 14,000 BOPD in the project area in 1985 is associated primarily with infill drilling and pattern modifications. Sustained production at current levels of 12,000 BOPD is the result of tertiary response from CO_2 injection. Tertiary response continues to be difficult to quantify because the CO_2 project was implemented simultaneously with infill drilling and pattern modification programs.

CO_2 breakthrough was slightly earlier and of slightly larger magnitude than predicted. Producers east-west of CO_2 injectors and pattern differences are thought to be the causes of most of the early breakthrough. One measure of CO_2 production performance is CO_2 retention. After 0.2 HCPV of CO_2 injection, CO_2 retention is 72%. Considering the high oil viscosity of 6 cp, retention is well within expectations.

Original estimated reserves total 38 million STB of additional recovery for the project. Of this, 16.6 million STB were associated with CO_2 injection and 21.4 million STB was the result of infill and pattern modification programs. Because performance to date has exceeded original expectations, it is anticipated that recovery levels will be substantially greater than originally forecast.

Conclusions

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

Acknowledgments

We thank Exxon Co. U.S.A. and the other working-interest owners of the Means (San Andres) Unit for permission to publish this paper. In addition to the authors cited in the references, we specifically thank R.M. Stuart for his contribution to the seismic discussion and Jon Penny for his contribution to the Tertiary Surveillance Program section.

References

1. Barbe, J.A.: "Evaluation and Modification of the Means San Andres Unit Waterflood," *JPT* (Dec. 1971) 1421-27.
2. George, C.J. and Stiles, L. H.: "Improved Techniques for Evaluating Carbonate Waterfloods in West Texas," *JPT* (Nov. 1978) 1547-54.
3. Barber, A.H. Jr. *et al.*: "Infill Drilling To Increase Reserves—Actual Experience in Nine Fields in Texas, Oklahoma, and Illinois," *JPT* (Aug. 1983) 1530-38.
4. Stiles, L.H. *et al.*: "Design and Operation of a CO_2 Tertiary Pilot: Means (San Andres) Unit," paper SPE 11987 presented at the 1983 SPE Annual Technical Conference and Exhibition, San Francisco, Oct. 5-8.
5. Magruder, J.B., Stiles, L.H., and Yelverton, T.D.: "Review of the Means San Andres Unit Full-Scale CO_2 Tertiary Project," *JPT* (May 1990) 638-44; *Trans.*, AIME **289.**

SI Metric Conversion Factors

acres	× 4.046 873	E−01	=	ha
°API	141.5/(131.5+°API)		=	g/cm³
bbl	× 1.589 873	E−01	=	m³
cp	× 1.0*	E+00	=	mPa·s
ft	× 3.048*	E−01	=	m
ft³	× 2.831 685	E−02	=	m³
gal	× 3.785 412	E−03	=	m³
lbm	× 4.535 924	E−01	=	kg
md	× 9.869 233	E−04	=	μm²
miles	× 1.609 344*	E+00	=	km
psi	× 6.894 757	E+00	=	kPa

*Conversion factor is exact.

Provenance

Original SPE manuscript, **Reservoir Management in the Means San Andres Unit,** received for review Sept. 2, 1990. Revised manuscript received Sept. 30, 1991. Paper accepted for publication Oct. 25, 1991. Paper (SPE 20751) first presented at the 1990 SPE Annual Technical Conference and Exhibition in New Orleans, Sept. 23-26.

JPT

Authors

Magruder

Stiles

Loren H. Stiles is a senior technical adviser in the Southwestern Div. of Exxon Co. U.S.A. Since 1960, he has been developing techniques to improve waterflood and EOR projects. A 1986–87 Distinguished Lecturer, Stiles has held section offices and served on the Reservoir Engineering Award Committee and the Program Committee for the SPE Permian Basin Oil and Gas Recovery Conference. He holds a BS degree in civil engineering from Texas A&M U. J. Brian Magruder is a staff engineer in the Reservoir Technology Group of Exxon's Southwestern Div. in Midland. He is involved in CO_2 tertiary project design, implementation, and surveillance. Previously, he held positions in reservoir and facility surveillance in Exxon's operations groups. He holds BS degrees in civil and geological engineering from New Mexico State U.

mjb copy
for highlights

Infill Drilling To Increase Reserves—Actual Experience in Nine Fields in Texas, Oklahoma, and Illinois

A.H. Barber Jr., SPE, Exxon Co. U.S.A.
C.J. George, SPE, Exxon Co. U.S.A.
L.H. Stiles, SPE, Exxon Co. U.S.A.
B.B. Thompson, SPE, Exxon Co. U.S.A.

Summary

Evaluation of reservoir discontinuity has been used by industry to estimate potential oil recovery to be realized from infill drilling. That this method may underestimate the additional recovery potential is shown by continuity evaluation in a west Texas carbonate reservoir, as infill drilling progressed from 40-acre (162×10^3-m^2) wells to 20-acre (81×10^3-m^2) wells and eventually to 10-acre (40.5×10^3-m^2) wells.

Actual production history from infill drilling in nine fields, including carbonate and sandstone reservoirs, shows that additional oil recovery was realized by improving reservoir continuity with increased well density.

Introduction

One objective of an orderly field-development program is to determine the maximum well spacing that will effectively drain oil and gas reserves. While wide spacing has proved effective in many oilfield applications, there are a growing number of examples where infill drilling, combined with water-injection pattern modifications, has provided substantial additional oil reserves. This paper deals with such fields: Means, Fullerton, Robertson, IAB (Menielle Penn), Howard Glasscock, Dorward, and Sand Hills fields in west Texas, Hewitt field in southern Oklahoma, and Loudon field in Illinois. The paper will quantify the contribution to current production and the additional reserves attributable to this action, using data available through Oct. 1981. Infill drilling has continued in most of these fields. Also revealed by infill drilling is the fact that the west Texas carbonate reservoirs are more stratified, and porous stringers are more discontinuous than revealed by initial studies.

0149-2136/83/0081-1023$00.25
Copyright 1983 Society of Petroleum Engineers of AIME

Background

The theoretical concepts indicating that infill drilling will increase reservoir continuity and improve waterflood pattern conformance in heterogeneous west Texas carbonate reservoirs were researched and published in the early 1970's by Ghauri,[1] Ghauri *et al.*,[2] Stiles,[3] George,[4] and Driscoll.[5]

Detailed field studies recommending infill-drilling and waterflood-pattern modifications were made for the Means, Fullerton, and Robertson fields by Stiles and George.[3,4] Unpublished studies were made for the other reservoirs prior to infill drilling.

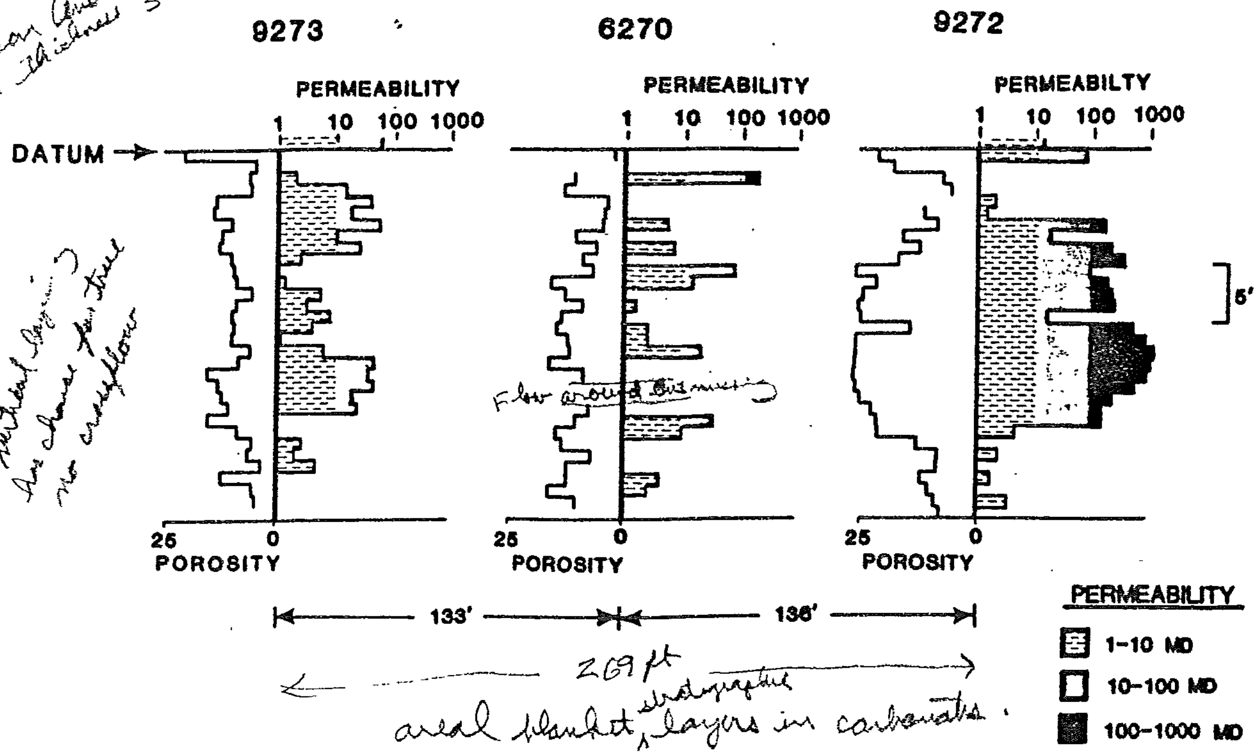
Borrowed from a previous work by George and Stiles,[4] Fig. 1 is a type cross section in the Fullerton Clearfork reservoir that illustrates the concept of "continuity," the percentage of pay in a well that is continuous to another well. The two original Wells A and B are 40-acre (162×10^3-m^2) locations, and the center well is an infill location 660 ft (201.2 m) from either original well. Note the discontinuous nature of the porosity stringers and that correlation before the infill well was drilled would have been considerably different than it is after the infill well was drilled. The increase in net pay in the infill well, especially in the upper part of the Clearfork formation, illustrates the fact that the more wells that are drilled, the more highly stratified, discontinuous, and complex a given west Texas carbonate reservoir is found to be. This fact leads to a conservative evaluation of the potential increased recovery from an infill well.

Considerations in Infill Drilling

A progression of continuity improvement was revealed by infill drilling in the Means San Andres field. Fig. 2 is a statistical plot of continuous pay vs. horizontal distance

San Andres gross thickness 300 to 500 ft

vertical layering? has chance for free no crossflow



Flow around thinness

269 ft

areal blanket, stratigraphic layers in carbonate.

Fig. 3—Porosity and permeability variations—Means tertiary pilot.

layering effect does not exist in the areal direction.

through three wells in a tertiary pilot in the Means San Andres reservoir. The wells are located approximately 150 ft (45.7 m) apart, and core porosity and permeability have been correlated over the same stratigraphic interval. Porosity is plotted to the left and permeability is plotted on a log scale to the right. The pay intervals are relatively continuous between wells, but the porosity variations are significant in an individual stringer between wells. Permeability variations are even more severe. With injected fluids taking the path of least resistance, this plot serves to illustrate why, even in stringers that are continuous between wells, recovery may be lower than anticipated.

high permeable stringer take fluid would be wasted

In a previous paper,[3] it was stated that a pay interval must meet the following three requirements for waterflooding.

1. It must be continuous and reasonably homogeneous between an injection well and the offset producing wells.
2. It must be injection supported.
3. It must be effectively completed in the offset producing well.

In many west Texas Permian carbonate reservoirs there may be 50 or more individual pay stringers. Only rarely will all the stringers be effectively completed in a specific well. When a pay stringer is not effectively completed in a given well, a partial pattern exists for that stringer, and recovery will be less than for a complete pattern. These considerations were used to evaluate infill drilling and pattern modifications in several fields.

Infill Drilling Results

Major infill drilling programs were implemented in nine fields in west Texas, Oklahoma, and Illinois. These fields include dolomite, limestone, and sandstone reservoirs with porosities varying from 4 to 21% and with average permeabilities varying from 0.65 to about 184 md. Two of the fields are still on primary production; the other seven are waterflood fields. A detailed discussion of each of these fields follows.

Means San Andres Unit

One of the first fields studied was the Means San Andres reservoir in Andrews County, TX. Production is from a depth of 4,400 ft (1341 m). The San Andres is over 1,400 ft (427 m) thick, but only the upper 200 to 300 ft (61 to 91 m) is productive at Means. It is predominantly dolomite with minor shale and anhydrite. Average porosity and permeability are 9% and 20 md, respectively. Oil viscosity was 6 cp (6 mPa·s) at initial reservoir conditions. The reservoir was discovered in 1934 and drilled to 40-acre (162×10^3-m^2) spacing. Waterflooding began in 1963 with a peripheral pattern, which was expanded to a three-to-one line drive in 1970. Following a detailed reservoir study in 1975, a large-scale infill-drilling and pattern-modification program was begun. By the 1981 study cutoff date, 141 twenty-acre (81×10^3-m^2) and 16 ten-acre (40.5×10^3-m^2) infill wells had been drilled. During this period the pattern was gradually changed, generally to an 80-acre (324×10^3-m^2) inverted nine-spot.

Actual production from the 40-acre (162×10^3-m^2) wells is shown by the lower line in Fig. 4. Production from the total unit is shown by the upper line. The area between these lines is wellbore oil production from the infill wells. The area between the dashed line and actual 40-acre (162×10^3-m^2) well production is interference oil. Increased recovery resulting from infill drilling is that production represented by the area between the

how determined?

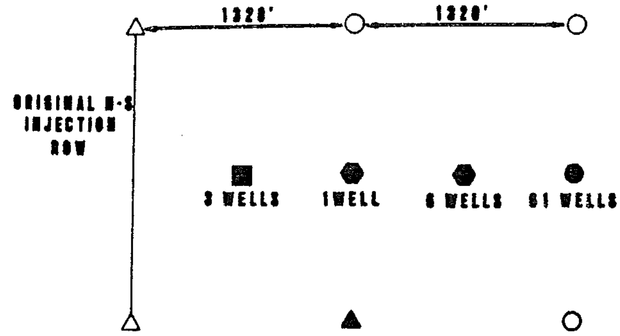


Fig. 7—Pilot infill drilling—Fullerton Clearfork Unit.

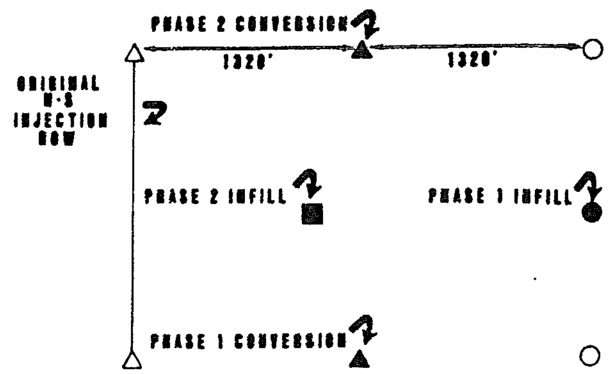


Fig. 8—Phase 2 infill drilling—Fullerton Clearfork Unit.

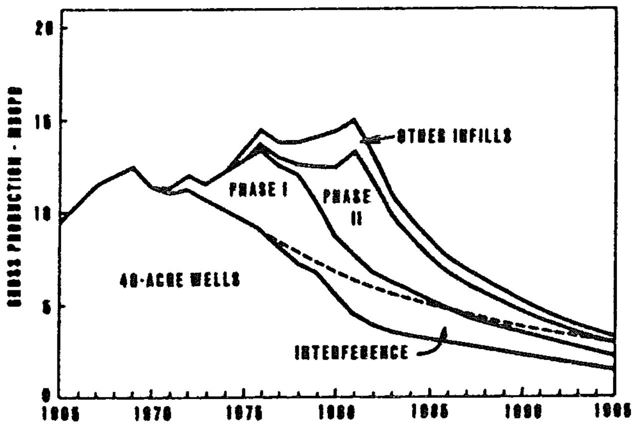


Fig. 9—Production datagraph—Fullerton Clearfork Unit.

solid triangle shows the location of the Phase I injection conversion. Prior to the Phase I program, seven wells had been drilled between 1970 and 1972 in the positions shown by the hexagons. These wells had average initial potentials of 221 B/D (35.1 m^3/d) oil, and in July 1976 they were producing an average of 92 B/D (14.6 m^3/d) oil and 70% water. Their offset wells were producing an average of 26 B/D (4.1 m^3/d) oil. The performance of the Phase I wells and the seven earlier wells suggested that additional recovery might be obtained if wells were drilled anywhere within the pattern. In 1976, three wells were drilled in the position shown by the square. They produced an average of 115 B/D (18.3 m^3/d) oil with a 74% water cut. Four of the six direct offsets to these wells had been shut in from 4 to 9 years earlier as uneconomical to produce. One was a producer testing 1 B/D (0.16 m^3/d) oil and 500 B/D (79.5 m^3/d) water. The sixth was an injector that had been converted in 1975 while producing 38 B/D (6 m^3/d) oil.

As a result of these 10 pilot wells, a 151-well Phase II infill drilling program at Fullerton was undertaken. Phase II wells have been drilled in the position shown by the square in Fig. 8. Wells in the position captioned "Phase II Conversion" are being converted to injection as part of the Phase II program. Of the 171 wells in this conversion location, 111 were watered out by 1976. Most others were producing at very low rates. It can be concluded that Phase II wells are mostly additional recovery. The production contribution from these infill drilling programs can be seen in Fig. 9. This datagraph shows the impact of the Phase I, Phase II, and other infill wells. These wells account for 71% of the unit's current production and will result in additional recovery of 24.6 million bbl (3.9×10^6 m^3) oil. Fifty-six percent of the wellbore reserves are increased recovery and will average about 97,000 bbl (15.4×10^3 m^3) per infill well.

Robertson Field

The Robertson Clearfork Unit in Gaines County, TX, produces from the Permian Glorieta, Upper Clearfork, and Lower Clearfork formations, at an average depth of 6,500 ft (1981 m). The reservoir is about 1,400 ft (427 m) thick with actual net pay of about 200 to 300 ft (61 to 91 m), broken vertically into as many as 50 to 60 separate porosity stringers in any given well: Fig. 10, a cross section between two 40-acre (162×10^3-m^2) wells, better illustrates the extreme stringerization. The reservoir rock is predominantly dolomite with anhydrite and shale. Porosity averages 6.3% and permeability averages 0.65 md. Oil viscosity at reservoir conditions is 1.2 cp (1.2 mPa·s). Beginning in 1942, the area was drilled on 40-acre (162×10^3-m^2) locations. In 1969, the unit was formed for waterflooding. From 1976 through 1980, 107 infill wells were drilled on 20-acre (81×10^3-m^2) spacing. A 10-acre (40.5×10^3-m^2) drilling program has begun with 31 wells completed through Oct. 1981.

The contribution of the 20-acre (81×10^3-m^2) and 10-acre (40.5×10^3-m^2) wells is shown in Fig. 11. The dashed line represents the expected production from the 40-acre (162×10^3-m^2) wells had there been no infills. Infill wells provide 73% of the current production. They are expected to add additional reserves of 10.7 million

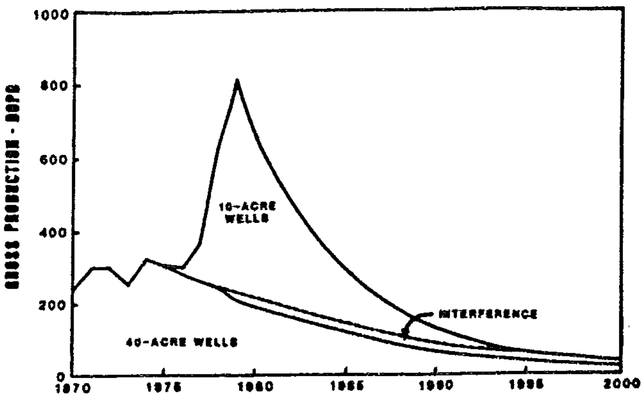


Fig. 13—Production datagraph—Douthit Unit, Howard-Glasscock field.

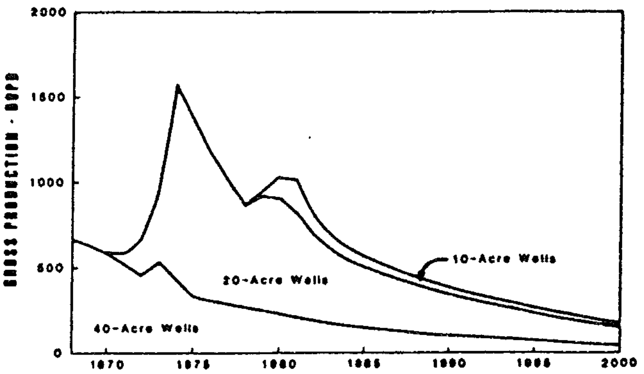


Fig. 14—Production datagraph—Dorward field.

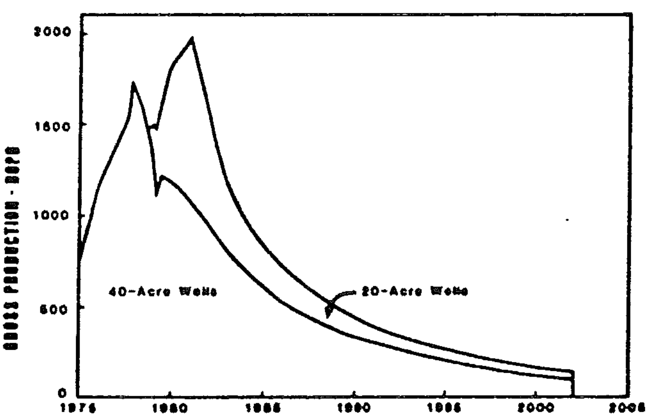


Fig. 15—Production datagraph—Sand Hills area.

The field was discovered in 1950 and drilled on 40-acre (162×10^3-m^2) spacing. Although waterflooding began in 1958 in a portion of the field, most of the field has been and is currently producing primary oil by dissolved-gas drive. Peripheral and 80-acre (324×10^3-m^2) five-spot patterns were tried. Early water breakthrough, caused by directional permeability and severe stratification, discouraged expansion of waterflooding to other areas.

Infill drilling began in 1971. At that time, 149 wells on 40-acre (162×10^3-m^2) spacing had been drilled. An average of 49,400 bbl (7850 m^3) oil per well had been accumulated, and production had declined to an average of 4.8 B/D (0.76 m^3/d) oil per well for the 107 wells still producing at that time. From 1971 through 1980, there were 123 twenty-acre (81×10^3-m^2) infill wells drilled. Ten-acre (40.5×10^3-m^2) drilling began in 1979, and 17 wells had been drilled by the end of 1980. Fig. 14 shows the results.

Because production was nearing the economic limit when infill drilling began, essentially all production from the infill wells is considered increased recovery. The infill wells will provide additional recovery of 4.6 million bbl (7.3×10^5 m^3) of oil or 33,000 bbl (5244 m^3) per well. The field is now being studied for further 10-acre (40.5×10^3-m^2) development and to determine if waterflooding is feasible with increased well density.

Sand Hills

Infill drilling in the Sand Hills area of Crane County, TX has been concentrated in the Sand Hills (Tubb and McKnight) fields. The Tubb reservoir produces from the Permian Lower Clearfork formation at a depth of 4,250 ft (1295 m) and is anhydritic dolomite with a minor amount of limestone. Average porosity and permeability are 4% and 12 md, respectively. Oil viscosity in the Tubb is 1.5 cp (1.5 mPa·s) at initial reservoir conditions. The McKnight reservoir produces from the Permian Lower San Andres at a depth of 3,200 ft (975 m) and is also mostly anhydritic dolomite. In this reservoir, average porosity and permeability are 5% and 1.3 md, respectively. In the McKnight reservoir, the oil viscosity is 1.0 cp (1.0 mPa·s). Gross productive interval is approximately 400 ft (122 m) in the Tubb and 350 ft (107 m) in the McKnight. Both reservoirs are highly stringerized with indications of poor reservoir continuity. They are both productive throughout the area of interest.

The Sand Hills (Tubb) field was discovered in 1931 and was generally developed on 40-acre (162×10^3-m^2) spacing. In the area of interest, most of the Tubb 40-acre (162×10^3-m^2) drilling was between 1936 and 1941. Development of the McKnight reservoir did not begin until 1955. McKnight development was erratic, depending largely on recompletions from the depleting Tubb reservoir; however, there was some drilling along with the workovers. Most of the 40-acre (162×10^3-m^2) McKnight activity was from 1955 to 1965 and later during the 1970's.

A 20-acre (81×10^3-m^2) infill program was begun in 1979. By the 1981 cutoff date, 56 infill wells had been drilled, with most of them being dually completed in both reservoirs. As expected, these wells found stringers that were pressure depleted but also found stringers that

Because of their location and the stage of depletion of the field, essentially all production from these wells is considered increased recovery. These infills are expected to increase oil reserves by 970,000 bbl (1.5×10^5 m^3).

Conclusions

The conclusions formulated from this infill drilling study are as follows.

1. Infill drilling in nine fields has resulted in per-well-recovery improvements that are attractive under current economic conditions.
2. Increased oil recovery from the drilling of 870 infill wells in 9 fields ranges from 56% to 100% of their wellbore production.
3. Total additional reserves from these wells will be 60.8 million bbl (9.7×10^6 m^3) oil.
4. Continuity calculations made after infill drilling indicated the pay zones to be more discontinuous than when calculations were made before infill drilling.
5. The experience in these nine fields indicates that the ultimate well density in any given field can be determined only after several years of field performance provide sufficient information on reservoir continuity and recovery efficiencies.

Acknowledgments

We thank the many persons who made this paper possible by supplying data, preparing graphics, and typing the manuscript.

References

1. Ghauri, W.K.: "Production Technology Experience in a Large Carbonate Waterflood, Denver Unit, Wasson San Andres Field," *J. Pet. Tech.* (Sept. 1980) 1493-1502.
2. Ghauri, W.K., Osborne, A.F., and Magnuson, W.L.: "Changing Concepts in Carbonate Waterflooding—West Texas Denver Unit Project—An Illustrative Example," *J. Pet. Tech.* (June 1974) 595-606.
3. Stiles, L.H.: "Optimizing Waterflood Recovery in a Mature Waterflood—The Fullerton Clearfork Unit," paper SPE 6198 presented at the 1976 SPE Annual Fall Technical Conference and Exhibition, New Orleans, Oct. 3-6.
4. George, C.J. and Stiles, L.H.: "Improved Techniques for Evaluating Carbonate Waterfloods in West Texas," *J. Pet. Tech.* (Nov. 1978) 1547-54.
5. Driscoll, V.J.: "Recovery Optimization Through Infill Drilling—Concepts, Analysis, and Field Results," paper SPE 4977 presented at the 1974 SPE Annual Technical Conference and Exhibition, Houston, Oct. 6-9.
6. "Application for Waterflood Response Allowable for Wasson Denver Unit," hearing testimony before Texas Railroad Commission by Shell Oil Co., March 21, 1972, Docket 8-A-61677.
7. Ruble, David B.: "Case Study of a Multiple Sand Waterflood, Hewitt Unit, OK," *J. Pet. Tech.* (March 1982) 621-27.

SI Metric Conversion Factors

acre	× 4.046 873	E+03	=	m^2
bbl	× 1.589 873	E−01	=	m^3
ft	× 3.048*	E−01	=	m

*Conversion factor is exact.

JPT

Original manuscript received in Society of Petroleum Engineers office July 20, 1982. Paper accepted for publication Jan. 26, 1983. Revised manuscript received May 5, 1983. Paper (SPE 11023) first presented at the 1982 SPE Annual Technical Conference and Exhibition held in New Orleans, Sept. 26-29.

Effect of Permeability on Recovery Efficiency by Gas Displacement†

W. O. KELLER,[#] G. W. TRACY,* AND R. P. ROE*

ABSTRACT

The effect of permeability on recovery efficiency by solution-gas displacement is analyzed by theoretical calculations of well-production histories. Two general hypothetical situations are considered. The first situation is evaluated on the basis of 11 specific cases involving hypothetical wells completed in a single zone of uniform permeability and thickness. The second situation is analyzed for 7 specific situations in which 4 segregated uniform zones are simultaneously depleted through a common well bore.

The analysis of cases involving a single uniform zone indicates that the recovery efficiency is a unique function of capacity (expressed in millidarcy-feet) wherein all other variables affecting recovery efficiency are held constant. In general, the recovery efficiency increases with capacity; however, for the specific conditions analyzed, the recovery efficiency does not vary appreciably for capacity values in excess of 500 millidarcy-feet.

The calculated data involving the simultaneous depletion of four zones indicate that the recovery efficiency is not a unique function of capacity, but is influenced by the permeability-thickness distribution. Simultaneous production of several zones of different permeability results in unequal rates of depletion of the various zones, the more permeable and thicker zones being depleted at much higher rates. In general, the recovery efficiency for zones of low permeability is increased for the same capacity because of the existence of other producing zones.

Calculations presented herein for simultaneous production of several zones are based upon the limiting assumption that there is no communication between the various zones except through the producing well bore. Even under this extreme assumption, for permeability values in excess of 5 millidarcys, the results (for the situations analyzed) indicate only a slight variation in recovery efficiency with permeability for the individual zones.

The calculated depletion histories for both single- and multiple-zone completions indicate that appreciable oil can be recovered from reservoir rocks having permeabilities as low as 0.1 millidarcy.

Stratification of zones of different permeability, separated by an impervious strata, can cause a serious deviation in the calculated performance history from the performance which would be predicted using the material-balance steady-state method, and assuming uniform permeability distribution. Predictions of the reservoir performance for solution gas-drive reservoirs, using the material-balance method, should take into consideration spatial variations in saturation conditions caused either by the existence of zones of different permeability or variations in the stage of depletion already in the reservoir.

The results and conclusions are quantitatively limited to the specific conditions evaluated and assumptions employed in the analysis; however, it is believed that the data are of a sufficient scope to permit generalization as to the effect of permeability, thickness, and permeability-thickness distribution upon the recovery efficiency of a depletion-type reservoir.

INTRODUCTION

The effect of permeability upon the ultimate recoveries from solution gas-drive oil reservoirs is a subject of considerable interest to the industry, yet little has been published to clarify this relation. The significance of the effect of permeability upon ultimate recovery, especially in reservoirs characterized by low permeabilities, has often been sub-

* Stanolind Oil and Gas Co., Tulsa.

† Presented by G. W. Tracy.

[#] Stanolind Oil and Gas Co., Tulsa; since removed to Keller and Peterson, Midland, Texas.

ject to differences in opinion among petroleum engineers and geologists. It has become customary, in estimating oil reserves in many fields, to disregard portions of the producing interval on the basis that the permeability, as indicated by core analyses, is too low to produce at commercial rates. This practice is especially prevalent in dealing with tight dolomitic and sandstone fields where the minimum permeability value used in estimating reserves may range from 0.1 to 5 millidarcys.

Permeability affects the recovery efficiency of a solution-gas depletion-type reservoir through operation of the economic limiting rate of production. If wells could be produced to vanishingly small rates, the recovery from zones of any permeability, however small, would be the same—all other factors remaining constant. However, if wells are to be abandoned at a finite production rate, the abandonment pressure and, consequently, the recovery efficiency will be a function of the fluid-transmitting capacity of the reservoir rock. It is, therefore, possible to arrive at the recovery efficiency of a depletion-type reservoir by calculating the abandonment pressure required to just support an economic rate of production as a function of the pay thickness and permeability. The purpose of this paper is to present such an analysis showing, under a variety of specific conditions, the calculated effect of permeability, thickness, and permeability-thickness distribution on recovery efficiency by solution-gas displacement.

The results and conclusions arrived at are quantitative only, within the limits of the conditions evaluated and the assumptions employed. However, the general relations shown are believed to be qualitatively correct. It would be impossible to take into account the effect of all variables and conditions which might or might not affect the relation between permeability and recovery efficiency. Nevertheless, it is hoped that the data presented will serve to some extent to clarify the fundamental relations involved and to stimulate additional thought and consideration of the effect of permeability on recovery efficiency.

Scope of Analysis

In order to evaluate the effect of permeability on recovery by solution-gas displacement, the recovery efficiency for hypothetical wells with pay thicknesses ranging from 10 to 200 ft, and permeability ranging from 0.1 to 100 millidarcys were calculated.

Production histories and oil recoveries were calculated for a group of 11 single-zone wells completed in 1 zone of uniform thickness and permeability, and also for a group of 7 multiple-zone wells penetrating 4 uniform zones having different thicknesses and permeabilities.

Pay thicknesses of 10, 50, and 90 ft, and permeabilities of 0.1, 1, 10, and 100 millidarcys were used in calculating the performance of the 11 single-zone wells. Recovery efficiencies for individual zones and for the entire well were calculated for the 7 multiple-zone wells which had a uniform total pay thickness of 200 ft, with individual zone thicknesses varying as shown in Fig. 1. Permeability values of 0.1, 1, 10, and 100 millidarcys were assigned the individual zones, using 7 different combinations as shown in Table 1. It was assumed that the zones of different permeabilities in the multiple-zone wells were separated by impervious barriers, and that communication between pay zones existed only at the well bores. This assumption

Table 1

Recovery Efficiency for Multiple-zone Wells to an Economic Limit of 3 Bbl of Oil per Day per Well

(Permeability, Millidarcys)

Well No.	Recovery Efficiency (Percent of Original Oil in Place) Zone A	Zone B	Zone C	Zone D	Weighted Average
	Zone Thickness (Feet)				
	50	50	10	90	200
1	(100)	(0.1)	(10)	(1)	
	20.74	7.22	20.74	17.83	16.05
2	(0.1)	(10)	(1)	(100)	
	4.96	20.31	16.22	20.74	16.46
3	(10)	(1)	(100)	(0.1)	
	20.74	18.46	20.74	8.40	14.62
4	(1)	(100)	(0.1)	(10)	
	16.12	20.74	5.16	20.47	18.68
5	(10)	(0.1)	(100)	(1)	
	20.74	7.29	20.74	17.83	16.07
6	(100)	(10)	(1)	(0.1)	
	20.74	20.67	18.00	7.32	14.55
7	(1)	(10)	(0.1)	(100)	
	16.00	20.53	5.04	20.74	18.72

yields an extreme condition resulting in maximum variation in recovery efficiency with permeability for the individual zones in multiple-zone wells.

The recovery efficiency is defined as the cumulative oil production, expressed in percent of original oil in place, to an assumed economic limit of three barrels of oil per day per well. The performance predictions of the individual zones in terms of the reservoir pressure and producing gas-oil ratio as a function of cumulative oil production were calculated by the material-balance method.[1,2,3,4,5] A steady-state solution of Darcy's law was employed in order to calculate individual zone producing rates and pressure conditions as a function of time. From these two fundamental physical principles it was then possible to calculate the entire performance histories of the hypothetical wells and the individual pay zones within the multiple-zone wells as a function of cumulative oil production, as described in the appendix.

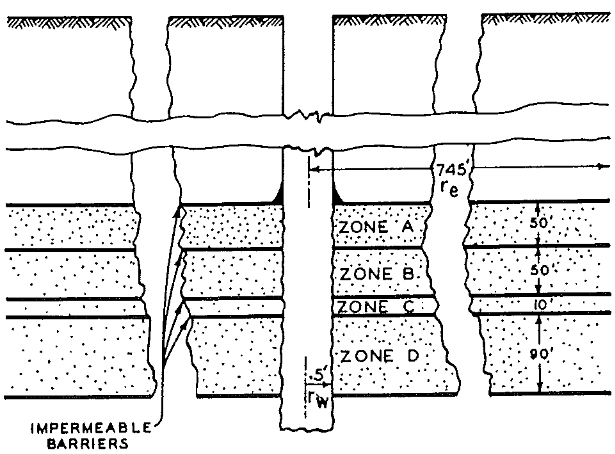


Fig. 1 – Schematic Diagram of Hypothetical Multiple-zone Well

Assumptions and Qualifications

1. The material-balance method of predicting the performance histories of solution gas-drive reservoirs permits a reasonable approximation of reservoir pressure and gas-oil ratio as a function of cumulative oil production.

2. The steady-state solution of Darcy's radial-flow equation adequately describes the flow of fluids through a reservoir into a well bore, to the extent that a reasonable approximation of the pressure gradients and flow rates which would be obtained under unsteady state conditions results.

3. That capillary-pressure gradients may be neglected and the same pressure differential can be assumed to exist in the oil and gas phases.

4. Each zone is considered as a uniform homogeneous porous rock.

5. Gravitational segregation of the oil and gas phases is negligible during the producing life of the reservoir.

6. Individual zones are separated by impermeable strata so that communication between zones exists only at the well bore.

Permeability–Recovery Efficiency Relations

The analytical procedure described in the appendix enabled the determination of the effect of permeability on recovery efficiency for 4 values of permeability, ranging from 0.1 to 100 millidarcys for hypothetical wells having one zone of uniform permeability and with thicknesses of 10, 50, and 90 ft. The calculated recovery efficiency to an economic producing rate of 3 bbl per day per well, under these conditions, is shown in Fig. 2 and Table 2.

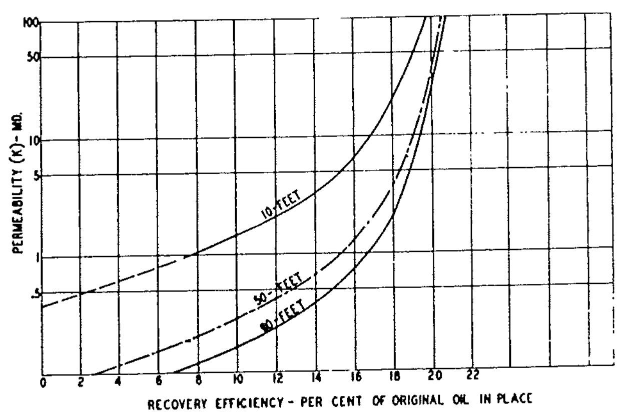


Fig. 2 – Relation Between Permeability and Recovery Efficiency For Wells with One Uniform Zone

As illustrated by Fig. 2, the effect of permeability on recovery, within the range of permeabilities and pay thicknesses considered, diminishes as the magnitude of the permeability increases. Also, for thick pay sections, permeability has less influence

[1] References are at the end of the paper.

Table 2

Recovery Efficiency for Single-zone Wells to an Economic Limit of 3 Bbl of Oil per Day per Well

Zone Thickness (Feet)	Recovery Efficiency (Percent of Original Oil in Place) Permeability 0.1 Md	Permeability 1 Md	Permeability 10 Md	Permeability 100 Md
10	0	7.58	16.89	19.75
50	2.80	15.38	19.10	20.50
90	6.80	16.67	19.65	20.56

on recovery efficiency than for thin pay sections. For example, for a uniform permeability of 100 millidarcys a difference in recovery efficiency of only 0.81 percent of the oil in place is noted for pay thicknesses ranging from 10 to 90 ft. However, for a permeability of 1 millidarcy, the recovery efficiency for the same pay-thickness range varies by as much as 9.09 percent of the oil in place. It is apparent from Fig. 2 that, for permeability values in excess of 100 millidarcys and pay thicknesses in excess of 10 ft, the recovery efficiency is influenced only to a slight degree by the magnitude of the permeability.

The general relations between permeability, pay thicknesses, and recovery efficiency for hypothetical wells which have one pay zone of uniform thickness and permeability (Fig. 2) are the direct result of the calculated abandonment reservoir pressure which will support a minimum economic producing rate of 3 bbl per day per well. This is apparent when it is realized that the steady-state solution employed implies that the oil recovery from a zone of uniform permeability and thickness is a unique function of the average pressure existing in that zone.

In order to investigate the effect of systematic variations in permeability upon the relation between permeability, pay thickness, and recovery efficiency, calculations were made for 7 hypothetical wells penetrating 4 zones having uniform thicknesses of 10, 50, 50, and 90 ft. The result of these calculations are shown in Table 1. Fig. 3 illustrates the effect of the existence of several uniform zones upon the relation between capacity and recovery efficiency. The solid curve in Fig. 3 demonstrates that, for the individual wells with one uniform zone,

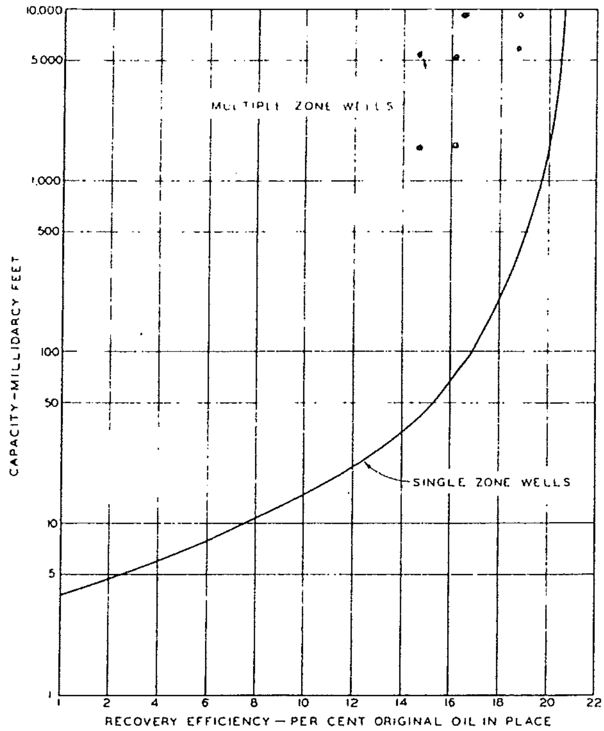


Fig. 3 – Relation Between Capacity and Recovery Efficiency

the calculated recovery efficiency is a unique function of the capacity. The recovery-efficiency capacity relationship for the 7 multiple-zone wells, as shown by the points on Fig. 3, indicates that the recovery efficiency is not a unique function of the capacity, but is influenced by the permeability-thickness distribution.

The effect of thickness-permeability distribution upon the recovery efficiency from the individual zones making up the 200-ft section is illustrated by Fig. 4, which shows the relation between pay thickness and recovery efficiency of individual zones for both single- and multiple-zone wells. The thickness-recovery efficiency relation for zones in multiple-zone wells is not unique, but is influenced by the pay thickness-permeability distribution. The dashed curves on Fig. 4 represent the approximate average relationship for zones in multiple-zone wells for the permeability thickness distributions calculated. It will be noted that the divergence in the thickness-recovery efficiency relationship between zones in single- and multiple-zone wells diminishes with increasing permeability and zone

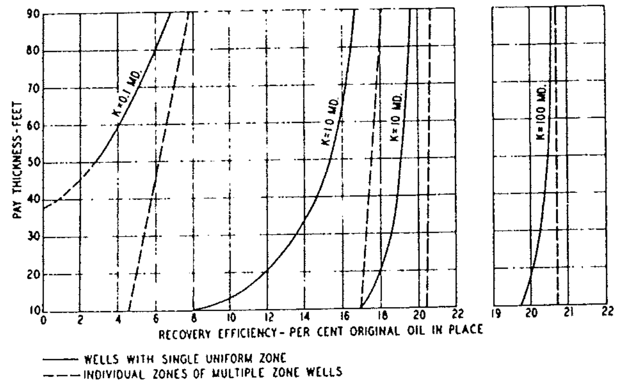


Fig. 4 – Effect of Permeability Variations on Recovery Efficiency

thickness. For example, the variation in recovery efficiency with zone thickness for a permeability of 100 millidarcys is very slight for zones in single-zone wells, and no variation is shown for a single zone in a multiple-zone well. However, for a permeability of 0.1 millidarcy, there is an appreciable variation in recovery efficiency with thickness for zones in both single- and multiple-zone wells.

From the calculated recoveries of individual zones in multiple-zone wells, it is apparent that the recovery efficiency is not a unique function of thickness and permeability, as is illustrated for single-zone wells by Fig. 2. As shown by Fig. 5,

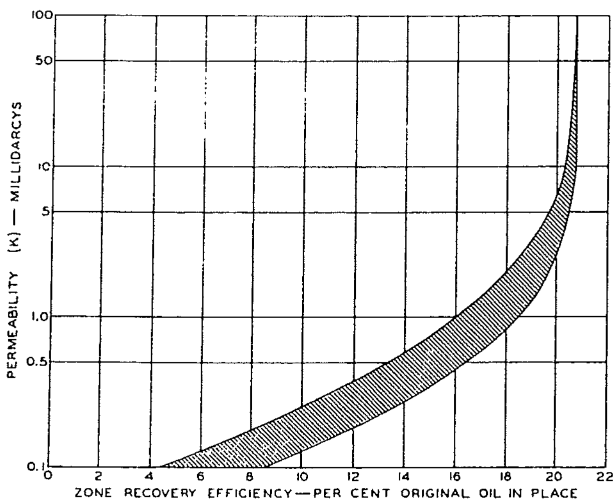


Fig. 5 – Range of Zone Recovery Efficiencies for Multiple-zone Wells

the permeability-recovery efficiency relationship for the individual zones in the multiple-zone wells is multi-valued within a limited range for a given permeability. This is a result of the effect of variations in permeability-thickness distribution. The approximate locus of the permeability-thickness distributions calculated is shown by the cross-hatched area in Fig. 5. A comparison of this plot to Fig. 2 indicates that it is apparent that the existence of zones of different permeability materially increases the recovery efficiency for low permeability values, even under the assumption that communication between zones exists only at the well bore.

It is significant that the reduction in recovery efficiency with decreasing permeability, as illustrated in Fig. 5, is greatly magnified by the assumption that the zones of different permeability are separated by impermeable barriers. Had the assumption been made that the individual zones were not separated by impermeable strata, the recovery efficiency variations with permeability shown in Fig. 5 would have been slight, and the recovery efficiency for the entire range of permeability values evaluated would approach the recovery efficiency shown for 100-millidarcy permeability. *Thus, the assumed lack of communication between zones results in absolute minimum relative recovery efficiencies for the lower ranges of permeability values.*

In order to relate the effect of permeability on recovery efficiency of individual zones in the multiple-zone wells, the producing rates of the 7 wells shown in Table 1 were calculated, assuming a maximum well rate of 100 bbl per day. An example of the results of these calculations is shown in Fig. 6 for well No. 2. As shown in Fig. 6, although the differences in recovery efficiency for the 3 zones of 1-millidarcy permeability or greater are small, the more permeable zones are depleted at a much faster rate, and the recoveries are obtained at higher rates, during the flush-production period. Considering zone C, with a permeability of 1 millidarcy, it can be seen from Fig. 6 that, although the ultimate recovery efficiency for zone C is 78 percent of the recovery efficiency for zone D with a permeability of 100 millidarcys, approximately 34 percent of the ultimate recovery from zone C is obtained at producing rates of less than 10 bbl of oil per day during the stripper stage of production. From this it can be seen that, for the lower ranges

of permeability values, the magnitude of the permeability materially affects the rate of recovery.

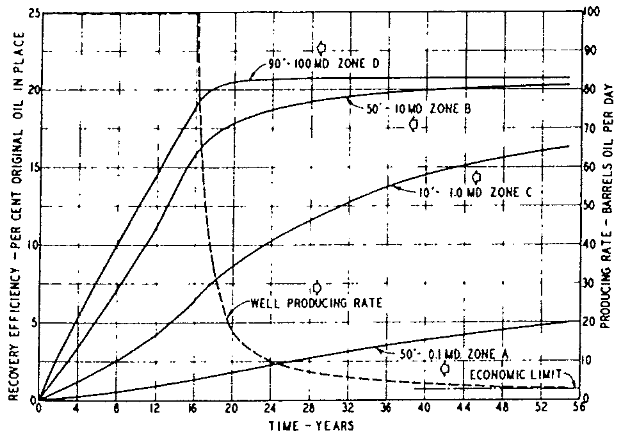


Fig. 6 – Effect of Time on Recovery Efficiency Multiple-zone Well No. 2

The depletion histories for multiple-zone wells No. 1, 2, 3, and 4 were calculated under two assumed maximum well rates of 1,000 and 100 bbl of oil per day, in order to ascertain whether or not the rate of production would influence the effect of the permeability-thickness distribution on the recovery efficiency. The results of these calculations are shown in Table 3.

The variation in recovery efficiency shown above for the two assumed maximum rates is within the limits of accuracy involved in calculations, and it is concluded the rate of production does not affect the recovery efficiency under the assumptions outlined in making these calculations. This being the case, it would follow that the overall gas-oil ratio of a multiple-zone well would not be affected by rate of production, inasmuch as a change in the overall gas-oil ratio would result in a difference in recovery efficiency.

The calculated gas-oil ratio history for multiple-zone well No. 3, for both a 100 bbl and 1,000 bbl of oil per day maximum rate, is shown in Fig. 7. Although the cumulative gas-oil ratio at depletion was the same for both rates of production, it can be seen from Fig. 7 that rate of production does affect the gas-oil ratio history of multiple-zone wells.

Also plotted in Fig. 7 is the calculated gas-oil ratio history for a single-zone well. It will be noted that the existence of several zones, with varying thickness and permeability, in multiple-zone well

Table 3

Recovery Efficiency to an Economic Limit of 3 Bbl of Oil per Day per Well

Well No.	Recovery Efficiency (Percent of Original Oil in Place) Maximum Rate 1,000 Bbl of Oil per Day	Maximum Rate 100 Bbl of Oil per Day
1	15.99	16.05
2	16.40	16.46
3	14.50	14.62
4	18.66	18.68

No. 3 results in a substantial difference in gas-oil ratio vs. well-depletion history. This is a direct result of variations in liquid saturation and gas-oil ratio of the individual zones which are at substantially different stages of depletion at any given stage in the depletion history of the well itself. It is significant that the gas-oil ratio history, for the multiple-zone well shown in Fig. 7, is entirely different than would be arrived at in predicting the gas-oil ratio history of a well if the assumption of one uniform zone had been utilized. Inasmuch as it was assumed in the calculations that the individual zones in the multiple-zone wells are not in communication except at the well bore, the divergence in the gas-oil ratio history (shown in Fig. 7) between the multiple-zone and single-zone well represents a maximum. As there is usually some degree of communication between zones of varying permeability, it would be expected that the actual gas-oil ratio history of wells would follow a trend between the two extremes represented in Fig. 7.

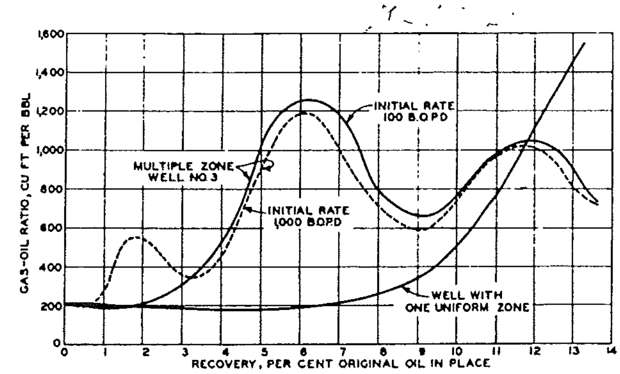


Fig. 7 – Effect of Initial Rate and Permeability Distribution on Gas-oil Ratio History

Fig. 8 shows a plot of $\frac{K_g}{K_o}$ vs. total liquid saturation for the laboratory data used in these calculations, and also for the gas-oil ratio history at a maximum rate of 100 bbl of oil per day per well for well No. 3, shown in Fig. 7. In calculating the apparent $\frac{K_g}{K_o}$ for well No. 3, it was arbitrarily assumed that the measured bottom-hole pressure

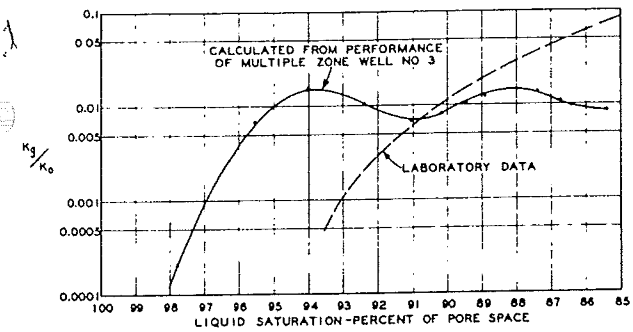


Fig. 8 – Relation Between Relative Permeability Ratios and Liquid Saturation

would be 90 percent of the equilibrium pressure in the tightest zone, and the calculated $\frac{K_g}{K_o}$ points were plotted vs. the weighted average liquid saturation of all 4 zones. It will be noted that there is considerable divergence between the apparent $\frac{K_g}{K_o}$ curve calculated from the production history of well No. 3 and the laboratory-data curve. This divergence is the direct result of variations in saturation and pressure conditions, and in relative rates of production of the individual zones. The point of significance is that the effect of the permeability-thickness distribution in a multiple-zone well upon the gas-oil ratio history and $\frac{K_g}{K_o}$ trend can cause a marked difference between the indicated actual reservoir performance and the calculated performance when the steady-state material-balance approach and the assumption of uniform permeability are utilized. This does not invalidate this type of analysis nor destroy the validity of the concepts and principles upon which the method of reservoir analysis is based. It does, however, indicate that, in applying these principles to the problem of predicting the performance of solution gas-drive reservoirs, the effect of spatial variations in saturation conditions, as between either zones or areas within the reservoir, should be taken into account.

APPENDIX

Analytical Procedure

The basic theory for the prediction of production histories by solution gas displacement have already been presented in the literature. The fundamental equations utilized by the material-balance method of predicting reservoir performance of solution gas-drive reservoirs are as follows:

$$n = \frac{\Delta n \left[U + (R - r_1) v \right]}{U - U_1} \tag{1}$$

$$S = \frac{\dfrac{(n - \Delta n)\,\beta}{n\,\beta_1}}{1 - S_w} + S_w \tag{2}$$

$$GOR = \frac{K_g}{K_o} \; \frac{\mu_o}{\mu_g} \; \frac{\beta}{v} + r \tag{3}$$

wherein:

- n = original oil in place, stock-tank barrels at 60 F. and 14.65 psia.
- Δn = cumulative oil production.
- U = reservoir volume of one stock-tank barrel of oil and its original solution gas (differential vaporization).
- R = cumulative gas-oil ratio, cubic feet per barrel.
- r = solution gas-oil ratio, cubic feet per barrel.
- v = free gas conversion factor, barrels of reservoir space per cubic foot of gas at standard conditions.
- S = total liquid saturation, percent pore volume.
- β = reservoir volume factor, barrels of reservoir oil per barrel of stock-tank oil (differential vaporization).
- GOR = instantaneous producing gas-oil ratio.
- K = permeability, millidarcys.
- μ = viscosity, centipoises.

Subscript $_1$ refers to original reservoir pressure.
Subscripts $_o$, $_w$, and $_g$ refer to oil, water, and gas phases, respectively.

The simultaneous solution to equations (1), (2), and (3) enables the calculation of the reservoir-performance history in terms of pressure and gas-oil ratio as a function of cumulative oil production, as shown by Fig. 9. The data utilized in these performance predictions, viz., shrinkage, solubility, and viscosity of the reservoir oil, as well as gas viscosity and compressibility as a function of pressure, and relative permeability to gas and oil as a function of total liquid saturation are shown by Fig. 10 through 12.

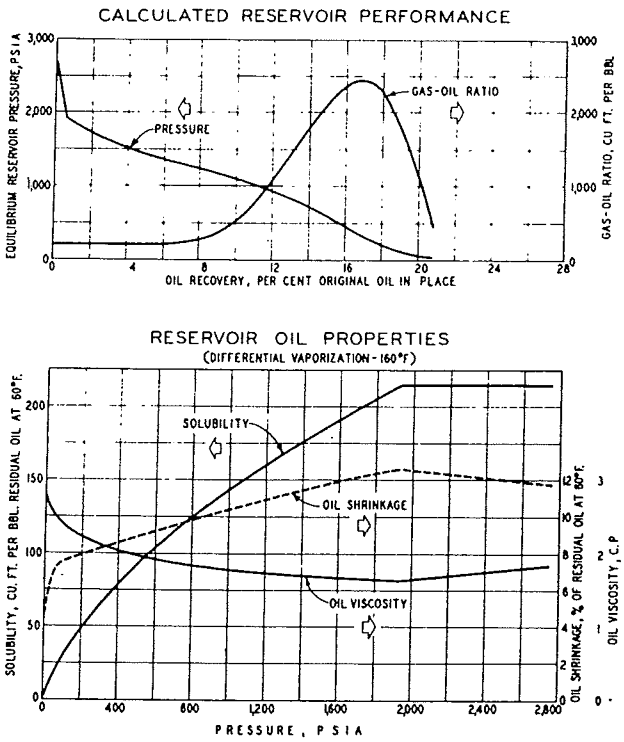


Fig. 9 and 10 – Calculated Reservoir Performance; and Reservoir Oil Properties

In order to calculate the producing histories of the hypothetical wells and of the individual zones in each well, it is then only necessary to employ Darcy's radial flow formula, as shown by equation (4), to relate P_w, P_e, and Q for the individual zones as a function of time and cumulative oil production.

$$Q = \frac{7.073\ Kt\ \frac{K_o}{K}(P_e - P_w)}{\mu_o\ \beta\ \ln \frac{r_e}{r_w}} \qquad (4)$$

wherein:

Q = flow rate, barrels of oil per day.
t = pay thickness, feet.
P_w = pressure at well bore, pounds per square inch (absolute).
P_e = pressure at r_e, pounds per square inch (absolute).
r_w = radius of well bore = 6 in.
r_e = radius of drainage = 745 ft.

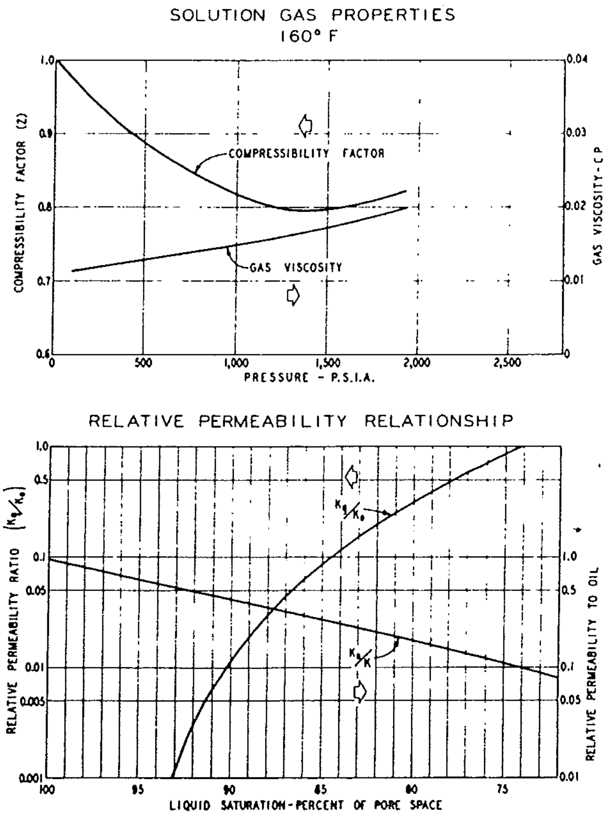


Fig. 11 and 12 – Solution Gas Properties; and Relative Permeability Relationship

This was accomplished by a series of stepwise calculations, wherein the reduction in the pressure at r_e, because of fluid withdrawals, was assumed to be negligible over short time increments. Starting at the original reservoir pressure at r_e, equation (5) was employed to evaluate the common well-bore pressure required to maintain the assumed maximum oil rate per well.

$$P_w = \frac{\left[\sum_{i=1}^{i=4} \frac{7.073}{\ln \frac{r_e}{r_w}} \left(\frac{Kt \frac{K_o}{K}}{\mu_o \beta} P_e \right)_i \right] - Q_t}{\sum_{i=1}^{i=4} \frac{7.073}{\ln \frac{r_e}{r_w}} \left(\frac{Kt \frac{K_o}{K}}{\mu_o \beta} \right)_i} \quad (5)$$

$$\text{Let } C = \frac{7.073\ Kt}{\ln \frac{r_e}{r_w}}$$

$$\text{and } f = \frac{\frac{K_o}{K}}{\mu_o \beta}$$

$$P_w = \frac{\left[\sum_{i=1}^{i=4} (CfP_e)_i\right] - Q_t}{\sum_{i=1}^{i=4} (Cf)_i}$$

wherein:

Q_t = total rate of flow of well, barrels of oil per day, and

i denotes number of zones.

Equation (5) was derived by equating the sum of the flow rates from each of the individual zones, as expressed by the right-hand member of equation (4), to the assumed maximum well-producing rate, (Q_t). In solving equation (5), values of f corresponding to the appropriate values of P_e were used, because in this radial flow system P_e very closely approximates the average reservoir pressure. The instantaneous rate of production from each individual zone, utilizing this calculated well-bore pressure (P_w), is first obtained from equation (4), where P_e equals the original reservoir pressure. These individual zone rates were then assumed to be maintained over a short time interval; and from the cumulative oil vs. pressure relationship shown in Fig. 9. a lower reservoir pressure at r_e was obtained for each zone at the end of the assumed time interval. This stepwise process was repeated, utilizing redetermined values for P_e in each zone, until an assumed minimum well-bore pressure of 25 psi was reached. The remaining production history of the well and each individual zone was then calculated for each zone in a similar manner, maintaining the minimum producing well-bore pressure of 25 psi. This procedure enabled the prediction of the oil-producing rates, gas-oil ratio, and pressure conditions for the wells and the individual zones as a function of time and cumulative oil production. The following example calculations illustrate in more detail the procedures employed.

Example calculations:

1. Basic data (well No. 4)

Q_t = 100 barrels of oil per day.

Original reservoir pressure = 2,750 psia.

Zone	Thickness (t), (Feet)	Permeability (K), (Millidarcys)	Original Oil in Place (n), (Stock-tank Barrels)
A	50	1.0	1,125,000
B	50	100.0	1,125,000
C	10	0.1	225,000
D	90	10.0	2,025,000
Total	200		4,500,000

The following tabulation shows the pressure (P_e) at r_e, and the cumulative production calculated for each of the individual zones after 9.6 years of production.

Zone	P_e Pounds per Square Inch, Absolute	Cumulative Production, (Δn), (Barrels)
A	1,598	36,000
B	934	134,300
C	1,942	1,500
D	1,179	178,700

2. Determination of the well-bore pressure at 9.6 years.

$$P_w = \frac{\left[\sum_{i=1}^{i=4} (CfP_e)_i\right] - Q_t}{\sum_{i=1}^{i=4} (Cf)_i} \quad (5)$$

Solving equation (5) for P_w, where f is a function P_e, values for P_e were assigned various zones from previous stepwise calculation, starting with P_e = original reservoir pressure of 2,750.

Zone	P_e	C	f	Cf	CfP_e
A	1,598	0.0442	0.403	0.01781	28.46
B	934	4.4200	0.190	0.83980	784.37
C	1,942	0.000884	0.524	0.00046	0.89
D	1,179	0.7956	0.248	0.19731	232.63

Total

$$\sum_{i=1}^{i=4} (Cf)_i = 1.05538 \qquad \sum_{i=1}^{i=4} (CfP_e)_i = 1{,}046.35$$

$$P_w = \frac{1{,}046.35 - 100}{1.05538} = 897 \text{ psia}$$

3. Determination of instantaneous oil-producing rates of individual zones.

$$Q = \frac{7.073\ Kt\ \frac{K_o}{K}\ (P_e - P_w)}{\ln \frac{r_e}{r_w}\ \mu_o \beta} = (C)(f)(P_e - P_w) \qquad (4)$$

Solving equation (4) for Q for each zone:

Zone	P_e	P_w	$P_e - P_w$	Cf	Q
A	1,598	897	701	0.01781	12.49
B	934	897	37	0.83980	31.33
C	1,942	897	1,045	0.00046	0.48
D	1,179	897	282	0.19731	55.70
					Q_t = 100.00

4. Determination of percent recovery in each zone at end of an assumed short time increment of 0.12 years, with each zone producing at the instantaneous rate determined above.

Zone	Q	$\Delta\Delta n$	Δn	Percent Recovery
A	12.49	625	36,625	3.25
B	31.33	1,555	135,855	12.08
C	0.48	24	9,524	6.77
D	55.70	2,780	181,980	8.99

wherein: percent recovery $= \left(\frac{\Delta n}{n}\right)$ (100)

5. Determination of P_e after 9.72 years of production, or at the percent recovery calculated previously. This was accomplished by reading from Fig. 9 the value of the pressure at the percent recovery of each of the individual zones.

Zone	Percent Recovery	P_e
A	3.25	1,590
B	12.08	916
C	6.77	1,929
D	8.99	1,168

The foregoing stepwise procedure was continued until the calculated P_w reached an assumed minimum value of 25 psi. The calculations were then continued in the same manner, except that a constant value for P_w of 25 psi was employed, thus eliminating the calculation of P_w as shown in step 2 above.

This procedure enabled the determination and inter-correlation of all of the basic factors, such as oil-producing rate, pressure conditions, gas-oil ratios, cumulative recovery, and time, for the entire multiple-zone well, and the individual zones down to an economic limit of 3 bbl of oil per day per well.

REFERENCES

[1] Schilthuis, R. J: Active Oil and Reservoir Energy, *Trans. Am. Inst. Mining Met. Engrs.* **118**, 33 (1936).

[2] Muskat, M: The Production Histories of Oil-Producing Gas-Drive Reservoirs, *J. of Applied Phys.* **16**, 147-152, (1945).

[3] Muskat, M; Taylor, M. O: Production History Gas-Drive Reservoirs, *Trans. Am. Inst. Mining Met. Engrs.* **165**, 78 (1946).

[4] Loper, R. G; Calhoun, J. C: The Effect of Well Spacing and Drawdown on Recovery from Internal Gas-Drive Reservoirs, (unpublished paper presented at the meeting of the Mid-Continent Section Am. Inst. Mining Met. Engrs., Dallas, Texas, October 1948).

[5] Tarner, J: How Different Size Gas Caps and Pressure Maintenance Programs Affect Amount of Recoverable Oil, *Oil Weekly*, **114** [2], 32-44, June 12 (1944).

DISCUSSION

A. W. Walker (University of Tulsa, Tulsa): I think this paper is one of those that certainly deserves a great deal of discussion and comment.

The authors have covered the water front as far as material-balance calculations and application of relative permeability effects on recovery efficiency

are concerned. At least they have touched on all the phases of it, and we could go on discussing the various ramifications at great length. As perhaps some of you know, this question of $\frac{K_g}{K_o}$ relationship and so-called material-balance calculations has been one of my pet hobbies for several years; therefore, some of these comments will go back and refer to past events.

I do not wish to cover too many phases of it, but there were two points of particular interest that I think are extremely important. The first is in regard to multiple-zone well completion. Several years ago the American Institute of Mining and Metallurgical Engineers circularized the industry with a questionnaire in regard to the opinion of petroleum engineers on dual and multiple-zone completions, such as covered by these calculations, and it seemed to be the general opinion that there was no harm in producing several zones together, if the energy was purely by gas expansion.

The calculations contained in this paper bear out this opinion very well, and show that the advantages were all on the side of multiple-zone well completion, rather than single-zone completions.

The second point is in $\frac{K_g}{K_o}$ relation, on which I think a little more work needs to be done. As a matter of fact, I am quite proud of the fact that some of my former associates are bringing out the first realistic approach to the handling of the $\frac{K_g}{K_o}$ relationship. We know from past experience that, using the $\frac{K_g}{K_o}$ relationship curves from cores ½ in. in diameter and ¾ in. long, we have obtained results which certainly have not stood up too well in regard to actual field experience. Quite frequently they are off as much as 30, 40, or 50 percent. What we are actually doing, it appears to me, is putting in an experience factor, or correction factor, whereby this $\frac{K_g}{K_o}$ relationship is reduced to something like a weighted average. In this particular case, all we have done is weighted the average in one direction. There is another direction which will have to be taken into consideration,,and that is from the well to the drainage boundary.

This paper has demonstrated a very definite improvement on the present technique. Experience and actual field data, in almost every case, verify the results shown by the authors. In other words, this marked peak on a gas-oil ratio curve is very seldom seen in field data, and it is smoothed out, as this paper has indicated. I am very grateful to see this type of approach to the problem.

Case Study of a Multiple Sand Waterflood, Hewitt Unit, OK

David B. Ruble, SPE, Exxon Co. U.S.A.

Summary

Twenty-two sands in the Hewitt field have been flooded simultaneously by Exxon Co. U.S.A.'s Hewitt Unit, and a case history of the operations is detailed in this paper. A multiple sand waterflood project requires special optimization methods to improve oil recovery. Injection and production surveillance programs and optimization methods used are highlighted. These include injection wellbore design, injection distribution, production stimulation, polymer augmented injection, and infill drilling. Successful application of these techniques has increased ultimate recovery from this waterflood operation.

Introduction

Hewitt Unit is located 20 miles (32.2 km) west of Ardmore in south central Oklahoma and covers approximately 2,600 acres (10.52 km^2) (Fig. 1). The Unit became effective March 1, 1968, for the purpose of conducting a waterflood in 22 separate Pennsylvanian-age sands.

Currently the unit has 147 active producing wells and 142 active injectors on a 20-acre (80 937-m^2) five-spot pattern with each productive sand open in the wellbore. All zones are commingled in the producers, and a total of 419 individual injection strings provide waterflood support. The unitized production peaked at 14,000 BOPD (2226 m^3/d oil) in Jan. 1973 and has declined to a current level of 4,500 BOPD (715 m^3/d oil). Injection rates were as high as 200,000 BWPD (31 797 m^3/d water) but have been reduced to a current level of 160,000 BWPD (25 438 m^3/d water).

Primary Production

Hewitt, one of the oldest fields in Oklahoma, was discovered in 1919. Development was rapid during the 1920's, with primary production peaking at 27,000 BOPD (4293 m^3/d oil) in 1921. The spacing was erratic, with approximately 1,000 wells drilled for an average of 2.5 acres (10 117 m^2) per well.

0149-2136/82/0003-9478$00.25
Copyright 1982 Society of Petroleum Engineers of AIME

In the early days completion was accomplished by drilling through the first major producing zone and running slotted production casing across the producing interval. Cemented casing was the exception rather than the rule. After production had declined, the well was deepened through the next major interval and smaller slotted casing was run to total depth. This procedure was repeated in many instances. Initially all casing was hung from the surface and, later, upper portions of the multistrings were salvaged, leaving uncemented slotted liners.

Hewitt was a prolific field producing 98.5 MMbbl (15.6×10^6 m^3) before unitization, or an average of 37,800 bbl/acre (1.485 m^3/m^2). After 49 years of life, operations had declined to the stripper stage and several hundred wells had been shut down or abandoned. Production before unitization was 2,700 BOPD (429 m^3/d oil) from 600 active wells, or 4.5 BOPD (0.7 m^3/d oil) per well. The average decline in production was 4% per year, and some leases had a projected life beyond the year 2000.

Only 2 1/2 K in high could be gravity dr

Recovery was principally by solution-gas drive augmented by gravity drainage on downstructure leases. Water/oil contacts were to the south, southeast, and west of the field, but no active water drive was present. Gas caps were present initially in some sands, but no effective gas drive was realized because the gas caps were dissipated rapidly during early development.

Geology

The geologic section and nomenclature adopted in identifying individual sands is shown on a type log (Fig. 2). The section is a sand/shale sequence of the Hoxbar and Deese formation of Pennsylvanian age. Gross interval between the top and lowermost sands is 1,500 to 1,600 ft (457 to 488 m). The average depth of the sands ranges from 1,200 to 2,900 ft (365 to 844 m) subsurface. The pay interval is divided into five major zones, the first Hewitt through the fifth. The sands within a zone are termed A, B, etc., with the exception of the Stearns and Chubbee at the top. Four sands comprise 73% of the

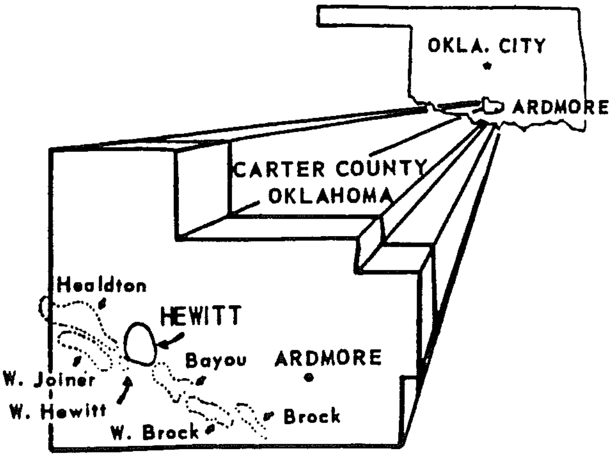


Fig. 1—Location map, Hewitt Unit.

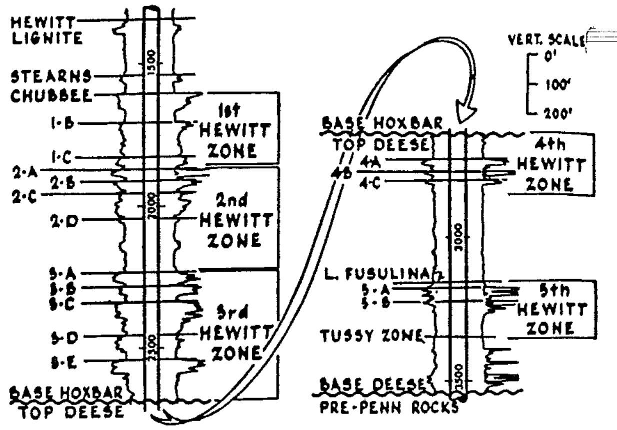


Fig. 2—Composite type log, Hewitt field.

total acre feet: the Chubbee, 2C, 3C, and 3E.

The Hewitt structure contoured on the Chubbee is shown in Fig. 3. It is a northwest-to-southeast trending anticline with a 12° dip to the west and south. The productive limits of the field are bounded by water/oil contacts to the west, south, and southeast, by a major fault to the north, and by steep dip and faulting to the east. Fig. 4 shows a plat of the unit with the water/oil contacts of the major sands. Most of the 22 sands contain water/oil contacts, and they occur at about the same subsea elevation. Moving from low to high on the structure, the number of sands within the oil column increases, and inside Zone 3E productive limit a maximum net sand thickness of up to 225 ft (68.6 m) occurs.

Waterflood Development

Exxon began evaluating Hewitt as a waterflood prospect in the mid-1950's. As the major acreage owner, Exxon did most of the geological and engineering work during negotiations with 47 other operators. A summary of the unit's reservoir data is shown in Table 1.

The waterflood was developed in three stages (Fig. 5). Initial flooding began in 1969 in the southern and southwest portions. This portion of the field was favored because of the structurally lower position of the sands and the anticipated higher oil saturations caused by gravity drainage. In addition, the south end was closer to a source water supply. By the end of 1970, the north half of Section 22, all of Section 9, and the top of Section 16 were under flood. The final expansion occurred in 1971, when 600 acres (2 428 124 m^2) were added in Sections 10 and 15, and the balance of Section 16.

The flood pattern is a 20-acre (80 937-m^2) five-spot with some irregularities. The unit drilled 53 of the 147 active producers and 86 of the 142 active injectors, with the balance being older primary wells brought into the unit. These old wells were utilized as much as possible to minimize costs. Many new wells and major workovers of old wells were necessary to provide cemented casing strings for injection wells. Flood development included the plugging of 680 wells. Plugging costs total $4,500,000 or approximately 25% of the flood development cost. The total waterflood investment of $18,500,000 was paid out in 1974.

Ninety-two of the 147 producing wells are equipped with electric submersible pumps and the other 55 are conventional rod pumps. Production is monitored through a central tank battery. Initially source water was supplied by five wells completed in a 1,200-ft (366-m) saltwater sand 8 miles (12.9 km) south of the unit. Cur-

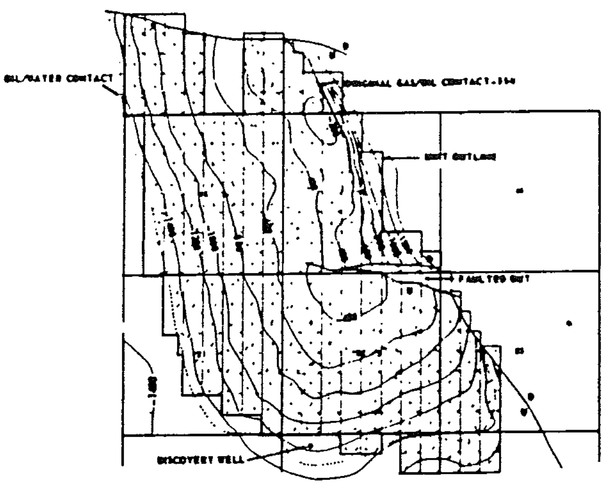


Fig. 3—Hewitt Unit, Chubbee structure.

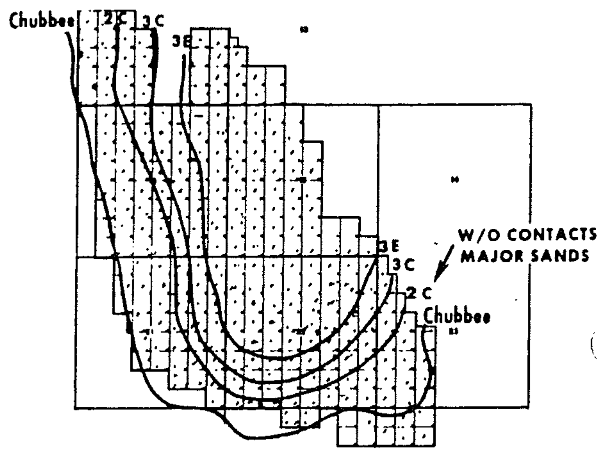


Fig. 4—Water/oil contacts of the major sands.

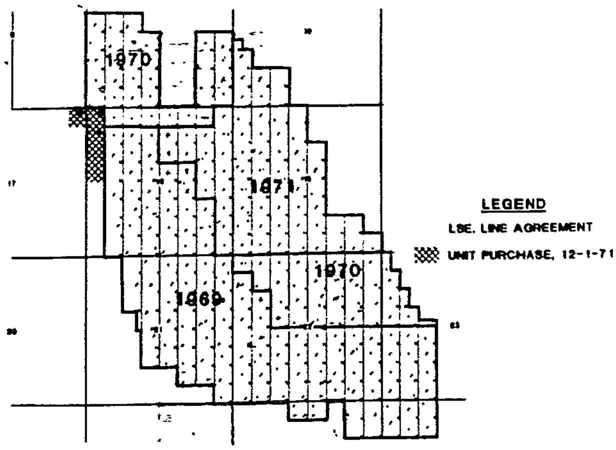


Fig. 5—Hewitt Unit flood development.

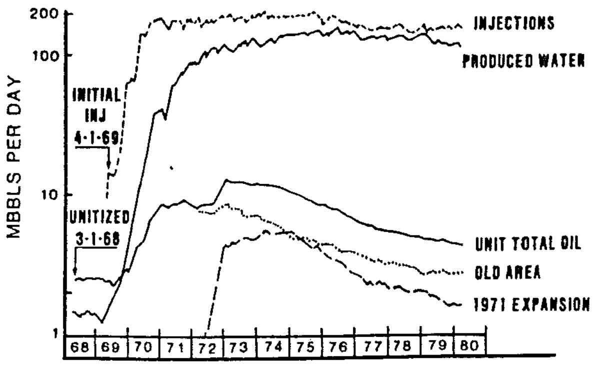


Fig. 6—Hewitt Unit operations.

TABLE 1—HEWITT UNIT RESERVOIR DATA

General	
Unit area, acre	2,610
Floodable net sand volume, acre-ft	284,700
Average composite thickness, ft (22 separate sand reservoirs)	109
OOIP, MMbbl	350.8
Rock Properties	
Permeability, md	184
Porosity, %	21.0
Connate water, %	23.0
Lorenz coefficient	0.49
Permeability variation	0.726
Fluid Properties	
Mobility ratio	4.0
Original reservoir pressure, psig	905
Reservoir temperature, °F	96
Original FVF, RB/STB	1.13
Flood start FVF, RB/STB	1.02
Oil stock-tank gravity, °API	35
Oil viscosity, cp	8.7
Original dissolved GOR, cu ft/STB	253
Primary recovery mechanism	solution-gas drive gravity drainage

rently only two of the wells are maintained for makeup requirements. Produced water is treated in coalescers and sand filters before reinjection. Source water has been commingled with produced water since 1975 without any adverse effects.

Operations

Unit operations, shown in Fig. 6, began with injection in April 1969, and approximately 6 months later oil response occurred. Production increased steadily during 1970, to 9,000 BOPD (1431 m^3/d oil), and then leveled off during the next 20 months at an average of 9,500 BOPD (1510 m^3/d oil) through Aug. 1972. Response from the 1971 expansion area combined with the remainder of the unit to peak production at 14,000 BOPD (2226 m^3/d oil) during Jan. 1973. The unit production declined at a constant rate of 24% per year from 1974 until 1977, when the decline began to shift to the current decline rate of 12% per year.

early high value

Water production rose rapidly along with early flood gains, and by 1972 exceeded 90,000 B/D (14 309 m^3/d) for a water cut of more than 90%. This high water-cut behavior was expected. Preunit engineering studies had predicted this type of behavior, caused primarily by permeability variation. Layered no-crossflow.

Injection rose rapidly during the early development to 190,000 B/D (30 208 m^3/d), which is essentially plant capacity. Input remained at that level through the third quarter of 1975. The drop in injection after 1975 to the current level of 160,000 B/D (25 438 m^3/d) was due to selective injection cutbacks discussed later under Flood Optimization.

Cumulative withdrawals since unitization to Jan. 1, 1980, total 34 MMbbl (5 405 568 m^3) of oil and 425 MMbbl (67.6×10^6 m^3) of water. A total of 648 MMbbl (103×10^6 m^3) of water has been injected, which equates to a 1.4 reservoir pore volume throughput.

Injection Well Design

Initial waterflood studies indicated a large permeability variation in the sands at the Hewitt field. This, along with the large number of sands proposed to waterflood, indicated the need for injection water control to flood the field efficiently.

Fig. 7 illustrates a triple completion used to segregate injection mechanically. Surface casing was cemented below freshwater sands, and three staggered lengths of 2⅞-in. (7.3-cm) casing then were run and cemented to the surface. The short string, or Completion A, was set through the first Hewitt sand, String B through the second sand, and String C included the third, fourth, and fifth sands. Each completion string was perforated to include at least one of the four major sands (Chubbee, 2C, 3C, and 3E). This method of injection well completion enabled simultaneous flooding of most of the reserves. State regulatory approval was received to inject down cemented casing.

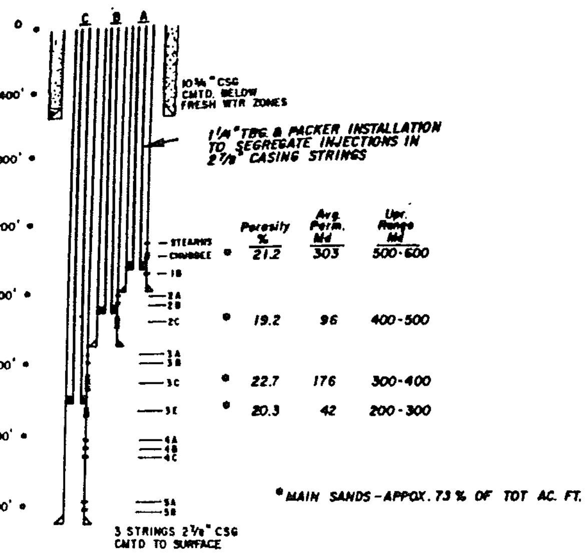


Fig. 7—Hewitt injection well, triple completion.

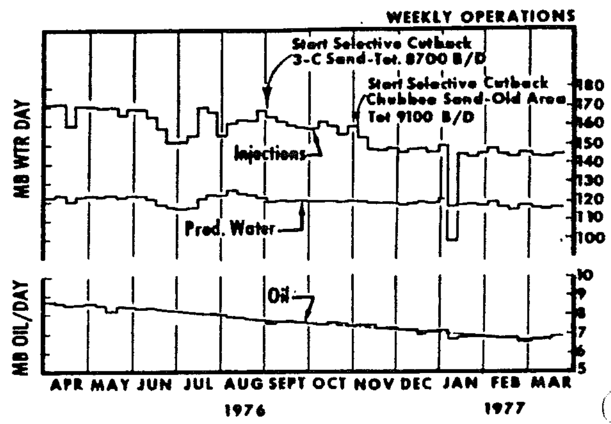


Fig. 8—Hewitt Unit selective injection cutbacks.

Injection Surveys

In a multiple sand waterflood, regularly scheduled injection profiles give information necessary to achieve control of water distribution and improve recovery efficiency. An average of 200 radioactive tracer profiles are run annually at Hewitt. Water injection is allocated to individual sands on the basis of these profiles. From the tracer surveys, injection allocations are set for each completion string. Profiles also identify thief zones, stimulation candidates, tubing and casing leaks, and channeling between zones.

Tubing and Packer Installations

When an imbalance of injection volumes is indicated between zones by well tracer profiles, tubing and packer installations can be used to improve distribution. As shown in Fig. 7, 1¼-in. (3.175-cm) tubing and packers are installed in the 2⅞-in. (7.3-cm) casing to allow injection down the tubing and tubing-casing annulus. This method is applicable only when there is sufficient pressure to inject water into the lower permeability zone. Currently there are 132 tubing and packer installations. These installations have enabled the unit to increase the number of separate injection streams to allow timely flooding of the less permeable producing sands.

Early profiling in the 1971 expansion area indicated the need for improved distribution. Of the 51 tubing and packer installations in this area, 41, or 80%, were completed by Jan. 1, 1973, before and during early flood response. Table 2 summarizes the flood results and 1971 expansion area. As shown, the 1971 area projected recovery of 174 bbl/acre-ft (22 427 $m^3/km^2 \cdot m$) is expected to exceed the old area by 19 bbl/acre-ft (2 449 $m^3/km^2 \cdot m$). The comparison of flood efficiency is of equal significance. The 1971 area has produced 1 bbl (0.16 m^3) of oil per 13.8 bbl (2.2 m^3) of injected water, compared with the old area's 1 bbl (0.16 m^3) of oil produced per 22 bbl (3.5 m^3) of water injected. This difference indicates a more efficient flood in the 1971 expansion area. We credit a major part of the increased flood efficiency in the expansion area to the early installation of the tubing and packer strings.

Waterflood Performance Predictions

Utilizing the injection profiles, an accurate account of injection into each sand is recorded to aid in predicting areas of low cumulative injection throughput and corresponding high oil saturations. A computer analysis run with the injection data models and predicts injection and production from individual producing sands. The producing wells have all the sands commingled in the wellbore. Because of the commingled status, oil recovery from any individual sand is virtually impossible to determine, and a prediction of oil recovery potential is made with injection data.

The computer analysis used at the Hewitt Unit to model waterflood performance is based on articles by Caudle.[1,2] The program provides a simplified model bridging the gap between three-dimensional reservoir simulators and rule-of-thumb prediction techniques. The program assumes steady-state flow, piston displacement, and noncommunicating layers. Within the limitations of the assumptions, the model accounts for areal sweep efficiency, vertical stratification, mobility ratio, initial gas saturation, and changing injectivity. The program output used at Hewitt is a comparison of cumulative injection to cumulative recovery and reserves. These reserve estimates are used to evaluate work programs on injection wells.

Selective Injection

Another optimization approach at the Unit has been the selective decrease or increase of injection into individual sands. The purpose of the injection changes is to allocate the injection water optimally into the sands with the highest oil saturation. These injection changes result in larger oil-cut production caused by less water cycling through depleted sands. The water injection cutbacks

TABLE 2—RECOVERY SUMMARY, OLD AREA vs. 1971 EXPANSION AREA (Jan. 1, 1980)

	Old Area	1971 Expansion	Unit Total
Floodable volume, acre-ft	190,664	94,036	284,700
Cumulative oil, MMbbl	22.7	10.8	33.5
bbl/acre-ft	119	115	118
Produced water, MMbbl	351.3	73.5	424.8
Water/oil ratio	15.5	6.8	12.7
Injections, MMbbl	499	149	648.0
bbl inj/bbl oil recovered	22	13.8	19.3
Ultimate unit oil recovery, MMbbl	29.6	16.4	46.0*
bbl/acre-ft	155	174	162*

*Does not include preunit production.

prevent a more depleted oil sand from flooding out a less depleted sand in the commingled producing well. Fluid levels are monitored on a regular basis in all producing wells in the field. The wells with a high fluid level are considered for the possibility of a decrease in offset injection. Conversely, low fluid level producers that potentially could benefit from injection increases are identified. The producing sand cumulative throughput of water and corresponding oil reserves are analyzed for the potential of injection changes.

During 1975 and 1976 several injection cutbacks were used to decrease injection into high water-cut sands. The first injection cutback, in Oct. 1975, amounted to 12,000 B/D (1908 m^3/d) in the Chubbee, and was followed by an increase in production of approximately 200 BOPD (31.8 m^3/d oil). The other two injection cutbacks were begun in Sept. and Nov. 1976 and totaled 17,800 B/D (2830 m^3/d). These injection decreases lowered injection costs while oil production remained unchanged. The decreases in injection did not alter the field decline but successfully lowered fluid levels. Fig. 8 shows production levels during 1976 following the injection cutback.

In the second half of 1977 the field decline began to change from a 24% per year rate to a 1980 decline rate of 12% per year. Selective injection increases were initiated in June 1977 and are credited as a principal reason for the gradual shift in field decline. A total increase of 12,250 BWPD (1948 m^3/d water) has been implemented to date. Fig. 9 shows an example of the effect of selective injection increases into less depleted sands during 1977–80. As shown, the injection increase in Section 15 resulted in increased oil production of as much as 350 BOPD (56 m^3/d oil).

Polymer Treatments

The Hewitt Unit has had three polymer-augmented injection projects. The projects have involved the injection of a high molecular weight, water-soluble polyacrylamide that becomes gelatinous when mixed with water. A cross-linking agent is injected, and this activates the polyacrylamide to form a viscous gel. The material will enter the most permeable section of the sand and build up yield strength to block and/or divert flow. The resulting pressure buildup diverts the injection water to less permeable flow channels that are less depleted and contain a higher oil saturation. This diversion of injection water improves the vertical sweep efficiency of the flood.

A map of three polymer project areas is shown in Fig. 10, and a summary of the three projects is presented in Table 3. Each of the projects injected polymer into the Chubbee sand, one of the four major unit sands. Treatments were sized to inject polymer at a 500-ppm concentration for 30 days. The objective was to increase injection wellhead pressure to as near plant injection pressure [1,080 psig (7445 kPa)] as possible while maintaining a constant rate of injection water. This increase in pressure indicates plugging of the most permeable

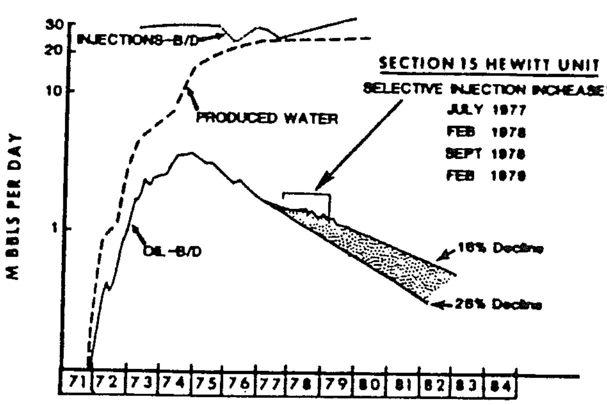


Fig. 9—Hewitt Unit selective injection increases.

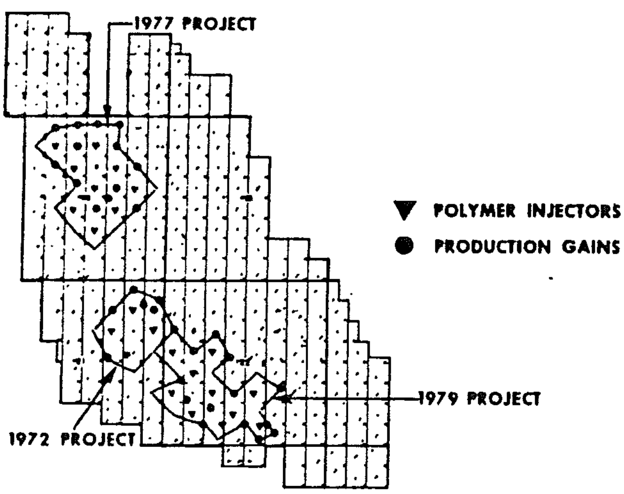


Fig. 10—Polymer project areas.

TABLE 3—HEWITT POLYMER PROJECTS

	1972	1977	1979
Injectors treated	4	9	10
Producers monitored	11	21	23
Number of producers responding	6	14	14
Average injection pressure, psig			
Before	210	240	274
After	595	650	780
Treatment size, lbm polymer	15,500	29,600	33,000
bbl water	87,000	182,000	189,000
Incremental recovery, bbl oil	115,000	130,000	33,000
bbl/acre-ft	32	16	6.5
Cost, $ thousand	37.5	135	115

streaks in the Chubbee sand and corresponding water diversion.

The polymer projects have been credited with increasing tract recovery from a 1972 project high of 32 bbl/acre-ft (4125 $m^3/km^2 \cdot m$) to a low in 1979 of 6.5 bbl/acre-ft (838 $m^3/km^2 \cdot m$). These figures correspond to 20 to 4% of the 162 bbl/acre-ft (20 881 $m^3/km^2 \cdot m$) projected unit recovery.

Producer Stimulation

Selective stimulation of producing wells has proved a successful method of improving recovery at the Hewitt Unit. Ninety-seven of the 140 active producers have cemented casing strings that permit the selective fracturing of a producing sand. The other active producing wells were drilled during primary development and have two or more uncemented liners through the pay interval, prohibiting selective stimulation. An average stimulation workover consists of six stages in four selected intervals in a producing well. The largest stimulation workover consisted of 13 stages in 10 producing intervals. A standard fracture stage consists of 5,000 gal (18.9 m^3) of emulsion-based fluid and 8,800 lbm (3992 kg) of sand.

Seventy-one stimulation jobs have been completed from 1972 to the present. Overall, the 71 stimulation jobs have yielded an average first-year gain of 64 BOPD (10.2 m^3/d oil). Thirty-five of the fracture jobs were completed by the end of 1973. Criteria for selecting zones for stimulation include: (1) individual sand quality, (2) individual flood performance in relation to other producers, (3) cumulative and current injection rates by zones in offset inputs, and (4) mechanical condition of the wellbore.

Artificial Lift Optimization and Selective Testing

Existing lift equipment does not have the capacity to pump off all the wells in the unit. Fluid levels are monitored and equipment is moved to maximize fluid production from the higher oil-cut producing sands.

Individual sands have been tested in 15 producing wells to locate watered-out zones or zones needing stimulation. Intervals are tested individually by isolation with bridge plug and packer. Producing well wireline surveys have not been used at the unit for the following reasons.

1. High water-cut production lies outside the accuracy of the tools.
2. The fluid level is below more than half of the producing zones.
3. It is difficult to run the tool past the submersible pump.

Selective testing is expensive in terms of tool rentals, well servicing, and lost production, but the results have shown it to be economical. Selective stimulation treatments of 16 producing zones in 10 wells have yielded a 450-BOPD (71.5-m^3/d) first-year buildup. Additionally, 14 uneconomical zones have been squeeze cemented or blanked off.

Drilling

In addition to the 122 wells drilled during the start of waterflood operations, nine producers and three injection replacement wells have been drilled. Seven of the producing wells were successful, one was marginal, and the ninth well gave very little buildup. Cumulative oil production as of Jan. 1, 1980, from the nine replacement wells was 2.38 MMbbl (378 390 m^3) or approximately 265,000 bbl (42 132 m^3) per well. Currently the wells produce 600 BOPD (95.4 m^3/d oil) or 67 BOPD (10.7 m^3/d oil) per well. The three injection inputs were drilled to replace wells with mechanical problems that prevented needed injection distribution. Three of the wells drilled during 1974 and 1976 resulted in an increase in producing-tract ultimate recovery. The old producing wells in these tracts were projected to recover 122 bbl/acre-ft (15 725 $m^3/km^2 \cdot m$). The three new wells resulted in an increase in projected recovery of 45 bbl/acre-ft (5800 $m^3/km^2 \cdot m$) or a total tract recovery of 167 bbl/acre-ft (21 525 $m^3/km^2 \cdot m$).

TABLE 4—MULTIPLE PRODUCING PATTERNS vs. REMAINDER OF UNIT, COMPARISON OF PATTERN RECOVERY

	Area (acres)	Number of Producing Wells	Volume (acre-ft)	Pattern Recovery MMbbl	Pattern Recovery bbl/acre-ft
Producing Patterns with multiple wells	466	47	79,009	17.6	223 Δ85
Remainder of unit	2,144	93	205,691	28.4	138
Unit total	2,610	140	284,700	46.0	162

Quantitative Analysis of Infill Performance: Robertson Clearfork Unit

J.A. Barbe, SPE, Exxon Co. U.S.A.
D.J. Schnoebelen,* Exxon Co. U.S.A.

Summary. This study analyzed the results of 218 infill wells drilled in the Robertson Clearfork Unit (RCU), Gaines County, TX. This program increased ultimate recovery by more than 23 million bbl [3.7×10^6 m^3]. The individual well performance, as a function of reservoir continuity, was analyzed quantitatively with pressure correlations, numerical analyses, and geologic study.

Introduction

Infill drilling has significantly increased the cumulative production, conventional remaining reserves, and EOR prospects in RCU. This paper documents the successful infill program and the techniques used to quantify reservoir performance under various well spacings and injection patterns.

RCU is a highly stratified, lenticular dolomite reservoir. Continuity of pay between wells is unusually poor, and the reservoir was only partially drained by wells on 40-acre [16-ha] spacing. Ultimately, 10-acre [4-ha] wells and 40-acre [16-ha] inverted nine-spot patterns were required for an effective waterflood. Expected recovery from the unit has been increased by more than 23 million bbl [3.8×10^6 m^3] by the drilling of 218 infill wells and an increase in the number of water-injection wells to form the 40-acre [16-ha] inverted nine-spot patterns. (Throughout this paper, 10-, 20-, and 40-acre [4-, 8-, and 16-ha] spacing refers to the nominal spacing of wells, although the exact areas vary.)

Three approaches were used to quantify reservoir continuity as a function of horizontal distance: geologic correlation, pressure-transient behavior, and regression analysis of infill performance. All three techniques indicate that 10-acre [4-ha] spacing can effectively drain 80 to 85% of the reservoir volume by primary production (solution gas drive). On this spacing, however, reservoir discontinuities limit the floodable volume to only 60 to 65% of the total reservoir.

These studies have permitted the operator to project the results of further infill drilling quantitatively. They also permit a realistic assessment of EOR potential based on actual floodable reservoir volume calculations.

Background

RCU became effective Jan. 1, 1970, and injection began in the first six injectors almost immediately. By mid-1971, the waterflood had been expanded throughout the unit. Full-scale injection averaged 20,000 to 30,000 BWPD [3.2×10^3 to 4.8×10^3 m^3/d water] throughout the 1970's, and by 1974, a degree of reservoir fill-up caused an oil production increase. The response peaked briefly in 1974 at 3,500 BOPD [560 m^3/d oil] and then began a rapid >25%/yr decline (see Fig. 1). This precipitous decline, and the low ultimate secondary recovery it foretold, prompted the first major reservoir performance review in 1975 and 1976. This marked the beginning of the successful infill drilling program described here.

The first RCU discovery within the unit boundary was in 1946. The field was subsequently named the Doss (Upper Clearfork) field. In 1970, after additional new zone discoveries and various field consolidations by the Texas Railroad Commission, the unitized reservoir consisted of two separate regulatory fields: the Robertson, North (Clearfork 7,100) field, which included the RCU Lower Clearfork, and the Robertson field, which included the Glorieta formation and the Upper Clearfork.

The two reservoirs were first flooded under a "confluent production" program in which dually completed injectors flooded each zone separately while production was commingled in the producers. Then in 1977, the injection wells were commingled, and the entire unitized formation has been operated as a single reservoir since. Reservoir performance studies, as well as injection profile tests, indicate that the waterflood conformance was no worse under the commingled mode than under the previous operation.

The 1976 reservoir study identified two major problems in waterflood performance: inadequate completions and poor reservoir continuity. Extrapolation of production curves forecast an ultimate recovery of only 30 million bbl [4.8×10^6 m^3], 8.3% of the original oil in place (OOIP), with the initial operating scheme. This could be improved to 42 million bbl [6.7×10^6 m^3] by an extensive workover program of perforating additional intervals and selective stimulation. The problem of poor reservoir continuity, however, could be overcome only by infill drilling on closer spacing. Detailed zone-by-zone geologic correlations of porous intervals were developed with techniques reported by George and Stiles.[1] These were used to evaluate continuity between wells and thus to estimate recovery from 20-acre [8-ha] infill wells.

Reservoir Geology

Regional Overview. Geologically, the Robertson field is located on the northeastern edge of the Central Basin platform, which separated the Delaware and Midland basins during the Permian Age (Fig. 2). Production is from Permian Leonardian carbonates of the Glorieta, Upper Clearfork, and Lower Clearfork formations.

The 13 Clearfork fields shown in Fig. 2 have many similar geologic features and demonstrate the effect the Central Basin platform had on Permian carbonate development and stratigraphy. The uplift of the Central Basin platform provided a shallow platform where prolific biological activity could occur, thereby allowing the accumulation of abundant carbonate sediments. Progressive deepening of the basin and growth of a marine bank along the margin of the basin accentuated the environmental differences between the basin and shelf areas. An idealized block diagram, shown in Fig. 3, illustrates a shelf margin complex similar to the environment that produced the Robertson carbonates. Hypersaline waters were more common shoreward of the marine bank, with several areas periodically subaerially exposed. Near-normal marine conditions prevailed farther basinward along the platform. Carbonate deposition would tend to build upward and basinward, subject to later dolomitization.

Trapping Mechanism. The Robertson field is situated on a large northwest/southeast-trending anticline, though most of the trapping of hydrocarbons is controlled by lateral and vertical limits of porosity and permeability. Most Clearfork reservoirs on the Central Basin platform exhibit a similar stratigraphic trapping mechanism.[2]

Fig. 4 is a structural map on the top of the Lower Clearfork formation. The crest of the structure is located on the west side of

*Now at Indiana U

Copyright 1987 Society of Petroleum Engineers

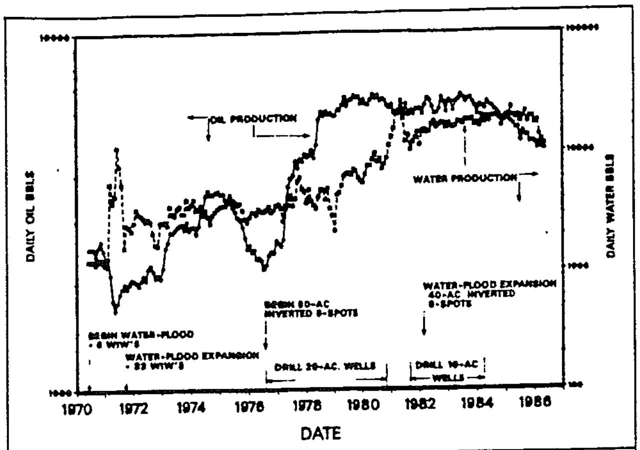


Fig. 1—Production history.

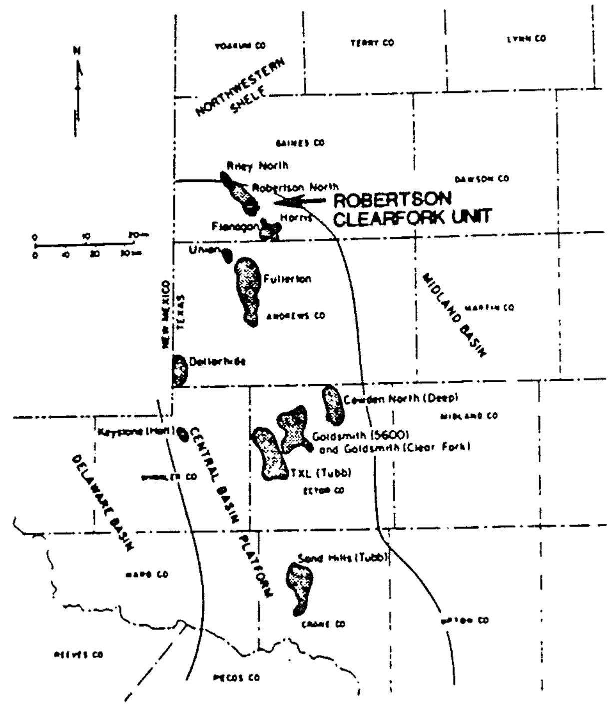


Fig. 2—Location map of RCU and other Clearfork reservoirs (adapted from Ref. 2).

the unit area, with a gentle dip to the east and a steeper dip to the southwest. The structural maps on other horizons are similar except for some shifting of the crest to the east as the formations become shallower.

Zonation and Lithology. The gross vertical interval at RCU is approximately 1,200 to 1,400 ft [370 to 430 m] thick and occurs from 5,800 to 7,200 ft [1770 to 2200 m] in depth. The net pay within this interval varies from 200 to 400 ft [60 to 120 m]. Fig. 5 is a type log (gamma ray/sidewall neutron porosity) that shows the unitized interval, which consists of the Glorieta, Upper Clearfork, Tubb (nonproductive), and Lower Clearfork formations. This section was subdivided further into 14 zones for detailed mapping (mainly on the basis of gamma ray log response).

In general, the unitized interval consists of dolomite, shale, and anhydrite, with minor beds of lignite and sandstone in the Glorieta. The Lower Clearfork is the most heavily dolomitized of all the formations and appears more massive than either the Glorieta or Upper Clearfork.

Porosity types are dominantly moldic and intergranular, though some vugular porosity is present in the Lower Clearfork. Average porosity is approximately 6.0%, and permeability averages 0.1 to 2.0 md.

Note that over the entire vertical interval of 1,200 to 1,400 ft [370 to 430 m], there may be 50 to 70 different individual pay stringers, ranging in thickness from 1 ft [0.3 m] to a few tens of feet. Fig. 5 shows that most porosity zones are usually only a few feet thick.

Depositional Environment. In general, the heterogeneity and stringerized nature of the carbonates in the Robertson reservoir are a result of their depositional environments. A complex mosaic of environments existed that ranged from supratidal (above mean high tide) to subtidal (below mean low tide). This range of environments would have coexisted while migrating laterally and vertically with time. This "shifting" of environments is probably represented best in the Upper Clearfork by the interbedded shales and dolomites. The cyclic nature of the Upper Clearfork is probably a result of slight variations in sea level or depositional rates as environments altered from subtidal (lime mud, now dolomites) and supratidal (shale and anhydrite). The Lower Clearfork generally appears to be more marine-dominated, although recognition of fossils and structure is difficult because of dolomitization. In contrast, the Glorieta appears to have been deposited more landward, consisting of supratidal-type deposits (shale, anhydrite, and lignite).

Overall, the carbonates built basinward with time, resulting in a regressive sequence. Within this regressive sequence, however, there are also minor transgressive cycles, especially in the Glorieta and Upper Clearfork formations. The regressive sequence can be seen by comparing the net-porosity-feet maps of each formation, as shown in Figs. 6 through 8. Note that the basin would have been toward the east and landward would have been to the west. These maps show a distinct west-to-east shift in the highest net porosity-feet values during the successive deposition of Lower Clearfork to Glorieta sediments as the carbonates progressively built basinward through time.

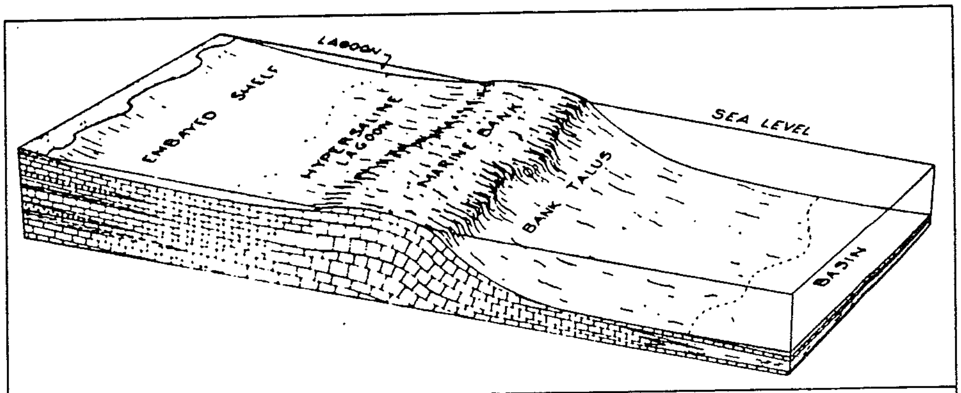


Fig. 3—Depositional environment schematic during Leonardian Age.

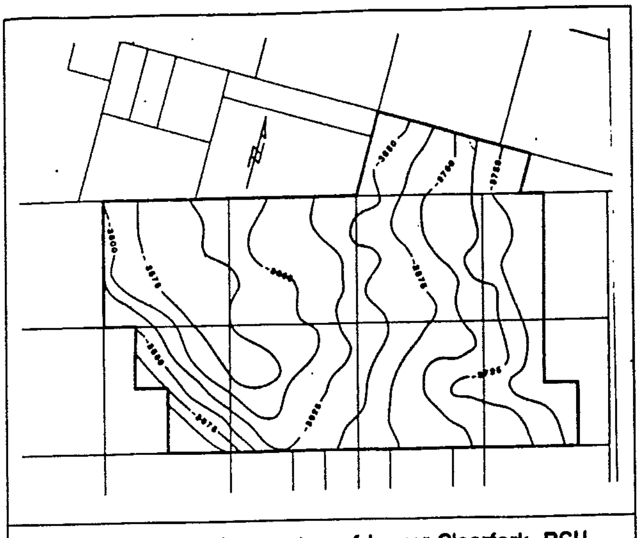


Fig. 4—Structural map—top of Lower Clearfork, RCU.

Development History

RCU was initially developed with 40 acres [16 ha] per well, with the wells generally arranged in east/west rows and north/south columns. At the time waterflooding began in 1970–71, every other well was converted to injection, thus creating 80-acre [32-ha] five-spot waterflood patterns. The first round of infill drilling involved drilling one additional well on each 40-acre [16-ha] tract, resulting in a modification of the waterflood pattern to 80-acre [32-ha] inverted nine-spots. In effect, the well density was doubled (Fig. 9). The final stage of development involved drilling one well on each undrilled 10-acre [4-ha] location; i.e., one well was drilled directly north and one well directly east/west of each of the original 40-acre [16-ha] wells. This pattern would not have had adequate injectivity to balance withdrawals; therefore, the remaining original 40-acre [16-ha] producing wells were converted to injection service in this area. Thus, the final pattern, which is still in operation, consists of 40 acres [16 ha] per inverted nine-spot pattern with roughly one injection well for each three producing wells.

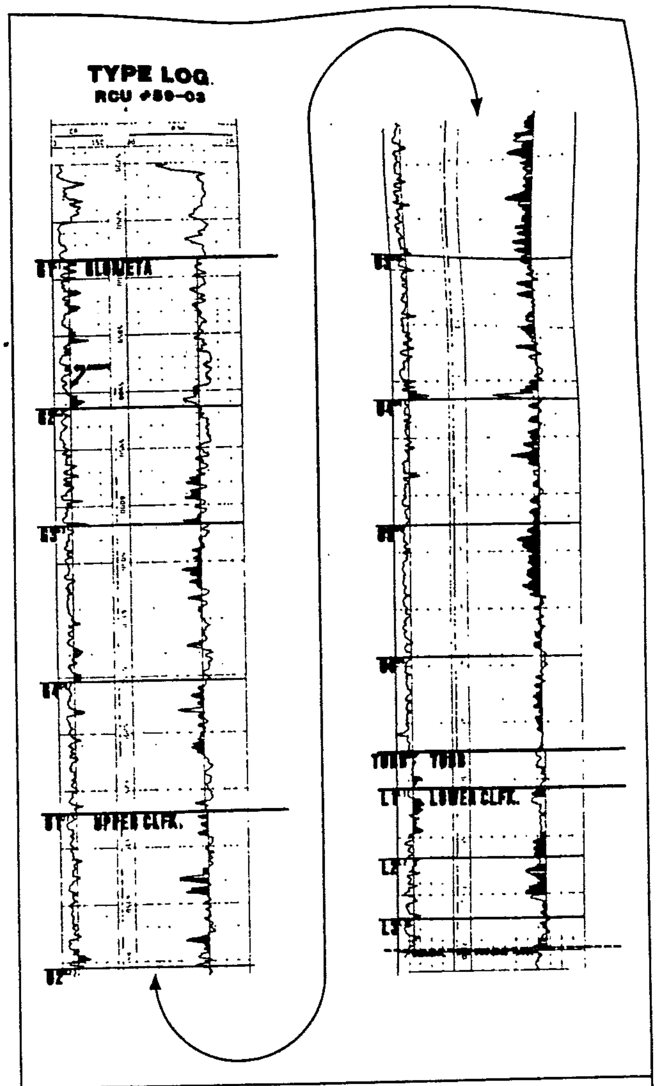


Fig. 5—Type log.

Pressure Performance

Since 1981, during the time of most of the 10-acre [4-ha] infill drilling at RCU, 197 buildup and falloff tests were run over a wide areal distribution throughout the unit. Analysis of these pressure-transient tests provides invaluable insight into the actual performance within the reservoir. For producing wells, these tests were generally analyzed with McKinley's[3] technique because the relatively low productivity and the high stratification result in very long periods of afterflow in an RCU producer. The typical producing well is affected by afterflow (or by wellbore storage effects) for more than 4 to 5 days after shut-in. The injection-well falloff tests, with short periods of afterflow, can be analyzed by conventional techniques. The fracture length for each of these wells was calculated with the techniques presented by Matthews and Russell.[4] Table 1 summarizes these tests.

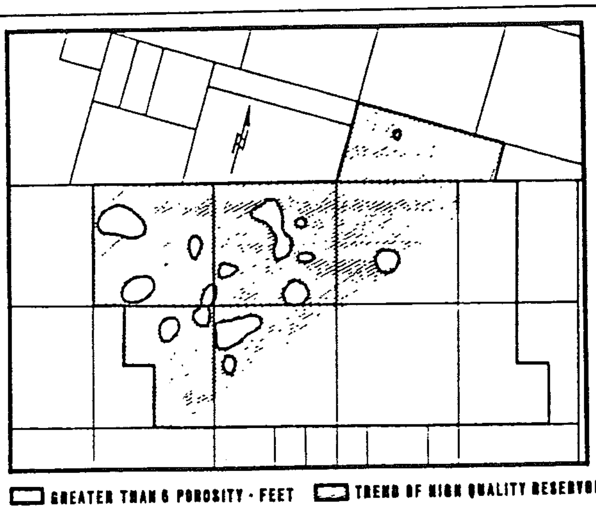


Fig. 6—Lower Clearfork—trend of high-quality reservoir.

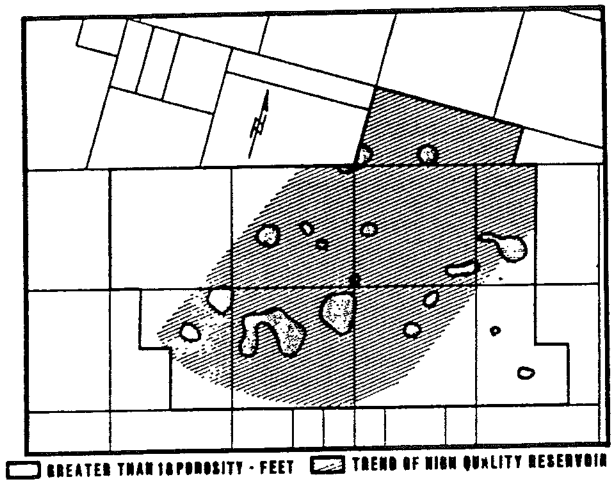


Fig. 7—Upper Clearfork—trend of high-quality reservoir.

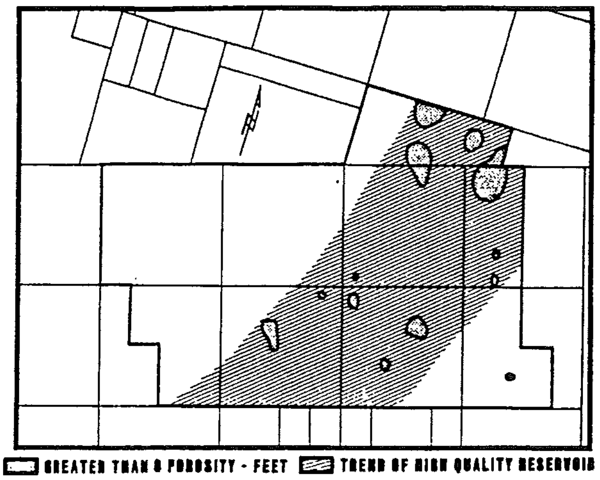


Fig. 8—Glorieta—trend of high-quality reservoir.

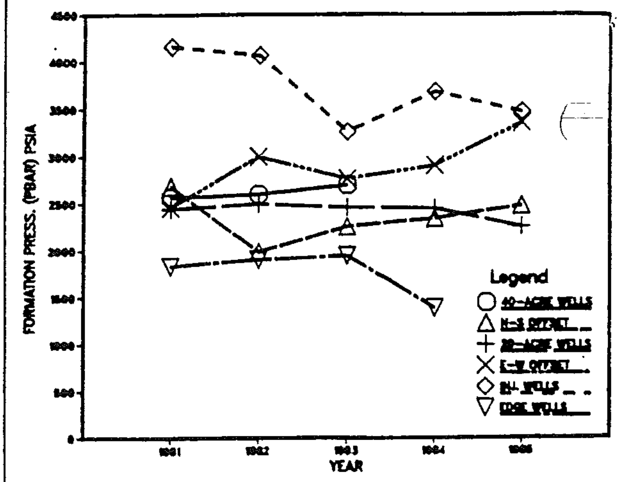


Fig. 10—Formation pressure history by well type.

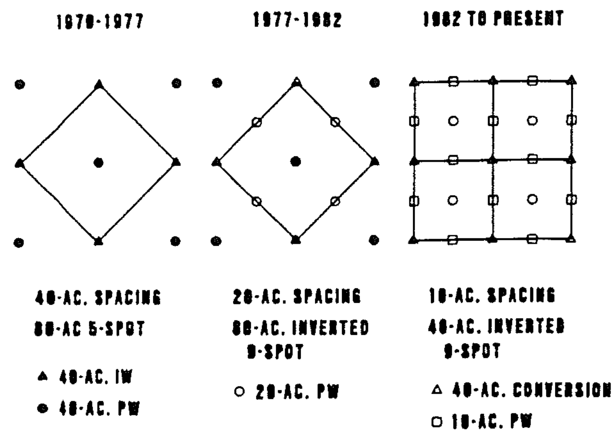


Fig. 9—Evolution of waterflood patterns.

The average reservoir pressure, $\bar{p}$, which is the extrapolated pressure for the vicinity of each well, is presented in Fig. 10. This pressure history should be analyzed and viewed in light of the major modifications occurring in reservoir operations in the 1981–85 period. During this time, the number of active producing wells increased from 140 to 229, while active injectors increased from 40 to 78. Again, one of the first conclusions from these data is that the differential pressure between the injection-well extrapolation and producing-well extrapolation has decreased during the time that the average distance between wells decreased (Fig. 10); i.e., the typical spacing at RCU decreased from 20 to 10 acres [8 to 4 ha] per well during this time. Two other pertinent reservoir performance points are shown on this graph. The first is that the producing wells in the waterflooded area have maintained pressure throughout this time. This confirmed that the decision to increase injection from the 80-acre [32-ha] inverted nine-spot pattern to the 40-acre [16-ha] inverted nine-spot pattern was sound and that pressures have been maintained. The other point to note is that the typical east/w... offs to the injectors throughout this time period has shown an... rapc lated pressure roughly 200 to 300 psi [1.3 to 2.1 MPa] higher tha either the north/south offsets or the 20-acre [8-ha] offsets. This tenc to confirm a suspected directional permeability or fracture orier tation in the east/west direction.

The continuity fraction for an injector/producer pair can be est mated by analyzing their $\bar{p}$'s in terms of a simple model. The e trapolated pressures in any given wellbore are the result of a average of pressures in the multiple zones that are open at the wel bore. In injectors, some of these zones will be relatively small, u drained, and pressured to the maximum—i.e., stabilized at th bottomhole injection pressure (BHIP). Some of the zones ...ll b continuous to producing wells and, as such, will be at a r... ...vel lower pressure because of the drainage. A similar situation exis in the producing wells, where some discontinuous zones will i deed be completely depleted to the pumping BHP. Other zones wi be effectively supported by the offsetting injection. This situatic is shown schematically in Fig. 11; there the average extrapolate formation pressure, $\bar{p}$, for all injection well tests is 3,810 psi [2 MPa], which compares to the average BHIP of 4,480 psi [30. MPa]. Similarly, in the producing wells, the average $\bar{p}$ of 2,45 psi [16.9 MPa] compares to a pumping BHP of 590 psi [4.1 MPa Although the exact relationship from one zone to another i... pr cisely quantifiable, the overall $\bar{p}$ is approximately repre... ...ati of a permeability/thickness-weighted average of pressures in all th zones open in the wellbore. This assumption permits the solutic of two equations with two unknowns, also shown in Fig. 11. Th results shown in Fig. 11 represent the averages of all tests run fro 1981 through 1985. The calculated reservoir continuity, which the percentage of zones open in both producing wells and injectic wells, is about 65%. The similar percentage of discontinuous rese voir, of course, is 35%.

The other unknown, the average pressure, which is the pressu roughly halfway between the two wells, is 3,450 psi [23.8 MPa As will be discussed, this is very similar to pressures identified b wireline formation pressure tests. Applying a similar technique t

TABLE 1—SUMMARY OF RCU PRESSURE-TRANSIENT TESTING
Average value per well

	Producing Wells					
	40-acre Original Producers	North/South Offsets	20-acre Infills	East/West Offsets	Edge Wells	Injectors
Skin factor	0.5	0	−0.6	−1	−0.1	−2.3
Calculated fracture length, ft	1	1	3	13	1	39
Flowing BHP, psi	1,033	601	517	884	667	4,480
Formation pressure, psi	2,610	2,280	2,450	2,860	1,820	3,810
Transmissibility, md-ft/cp	68	307	80	178	139	947

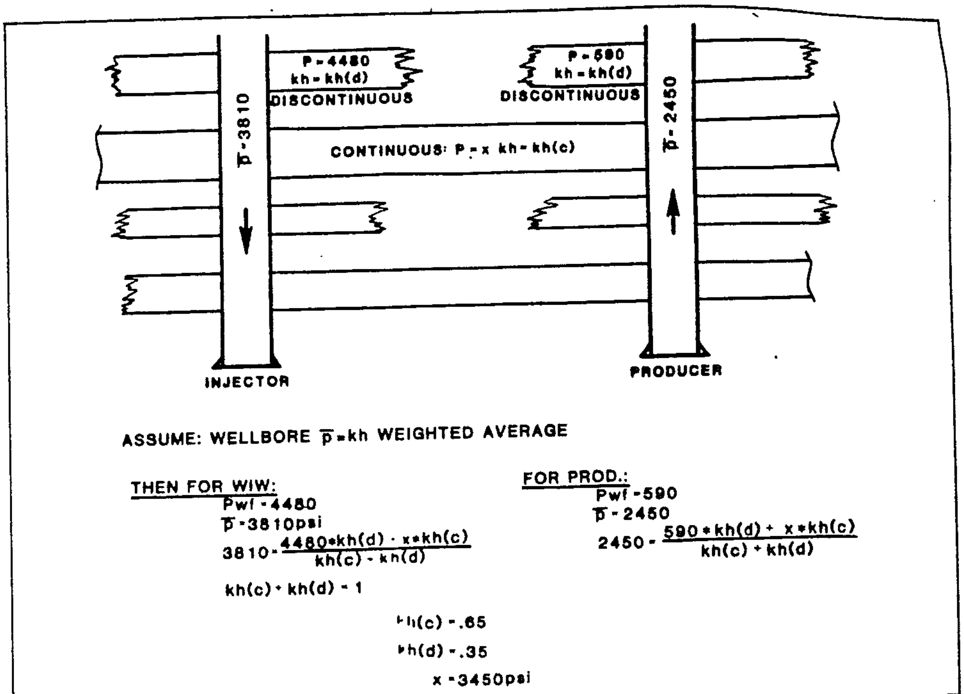


Fig. 11—Average zonal pressures—schematic cross section.

the pressure differential between injectors and producers at different spacings yields a spread from about 71% continuity at 660 ft [200 m] to less than 50% continuity at 2,000 ft [610 m]. These data are plotted in Fig. 12 and compared with estimates by other techniques.

Another interesting observation from the averages of these many pressure-transient tests is the relative lack of fractures in the producing wells even though all wells were stimulated by acid fracturing on initial completion. On the other hand, the producing wells are not damaged either, indicating mostly effective completions in the wells tested. Despite injection slightly below the fracture pressure, nearly all injectors indicate good stimulation and some fracture. It is unknown whether this results from some zones fracturing at lower-than-indicated fracture pressure or from some leaching of the carbonate by the freshwater injection, giving a fracture-like appearance on the pressure transient.

The concept of widely varying pressures in individual stringers is supported by data from wireline formation pressure tests. These tests were run in eight new infill wells from 1981 to 1984, with pressures successfully measured in more than 50 separate intervals. These pressures ranged from 644 to 4,136 psig [4.4 to 28.5 MPa]. The pressure distribution in each wellbore was random between intervals, and only rarely would two pressures fall on a hydrostatic gradient line, which would indicate that the zones were in vertical communication.

In the intervals tested, some zones appeared to be pressure-supported. The average pressures in the supported zones were 3,430 psig [23.6 MPa] in the north/south offset wells and 3,580 psig [24.7 MPa] in the east/west wells. These agree reasonably well with the 3,450-psig [23.8 MPa] pressure calculated in Fig. 11.

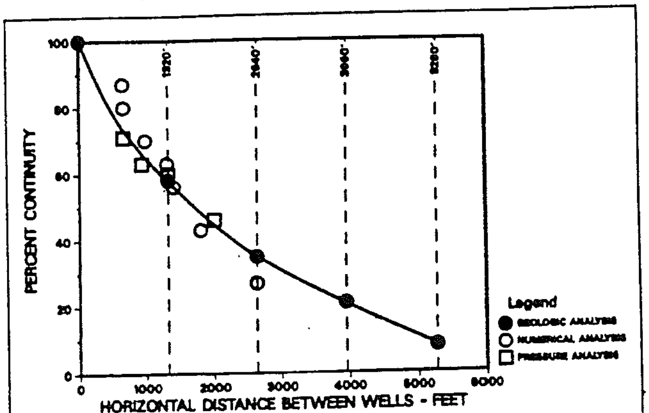


Fig. 12—Reservoir continuity vs. distance as determined by three different methods.

Infill Productivity Experience

EXPONENTIAL ??

Table 2 lists the results of a study in which the production history of each well was extrapolated to an estimated economic limit. These results were then averaged to yield the estimated ultimate recovery, called "through-the-wellbore" in Table 2, for each of the various types of infill wells. A total of 218 wells is represented in this table, and the incremental through-the-wellbore production is about 24 million bbl [3.8×10^6 m^3]. Col. 4 is the result of detailed calculations of interference, on existing wells, from production of the

TABLE 2—RCU INFILL DRILLING PROGRAM RESULTS

		Average Estimated Ultimate Recovery Per Well	
Type of Well	Number of Wells	Through Wellbore Estimated Ultimate Recovery (1,000 bbl)	Most Likely Capture Estimated Ultimate Recovery (1,000 bbl)
20-acre	83	166	158
North/south offsets	56	92	87
East/west offsets	58	70	67
Irregular or edge	21	78	74
Total for all wells	218	24,600	23,400

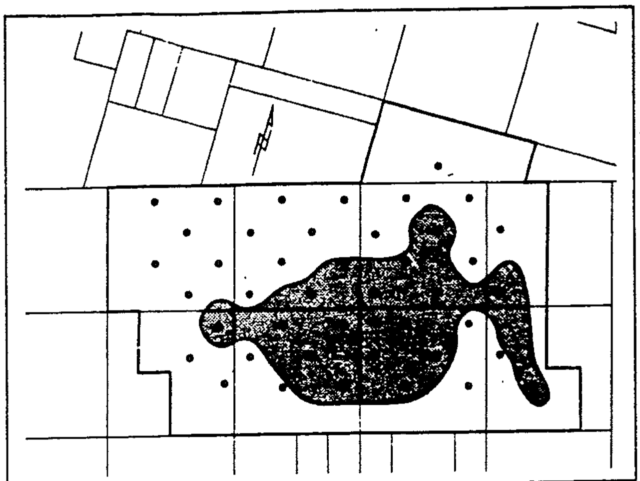


Fig. 13—Area of above-average 40-acre producers (estimated ultimate recovery>450,000 bbl/well).

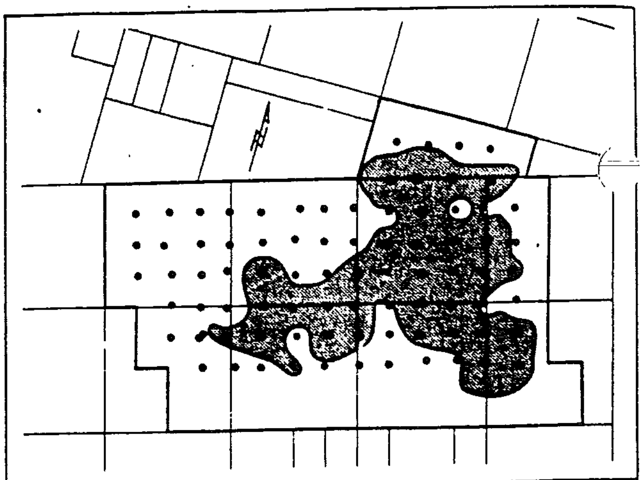


Fig. 14—Area of above-average 20-acre producers (estimated ultimate recovery>166,000 bbl/well).

new infills. This study determined that 95% of the through-the-wellbore recovery of an infill well is incremental capture or unique oil. This analysis is subjective, and at RCU it was complicated further by response from conversion of additional wells to injection service during the program. As discussed later, however, it is believed to be reasonably accurate.

Another approach to estimate the incremental capture resulting from the infill wells is to compare the total field estimated ultimate recovery to that predicted before any infill drilling, in this case by the 1975–76 RCU study. This study, which used existing wellbores, predicted an ultimate recovery of 22 million bbl [3.5×10^6 m^3] by primary and 8 million bbl [1.3×10^6 m^3] by secondary, for a total of 30 million bbl [4.8×10^6 m^3] by existing operations. The study further estimated that improvements to current operations in the existing wellbores, primarily perforating and stimulating additional intervals, could improve ultimate recovery by as much as 12 million bbl [1.9×10^6 m^3]. This would yield a total recovery of 42 million bbl [6.7×10^6 m^3] from existing 40-acre [16-ha] wells. In hindsight, this figure was probably a maximum, if not slightly optimistic. The current estimate for ultimate recovery from the total unit is between 64 and 65 million bbl [10.2×10^6 and 10.3×10^6 m^3]. This would attribute 22 to 23 million bbl [3.5×10^6 to 3.7×10^6 m^3] to the total of 218 new or infill wells plus the results of injection-well conversions. The value of 23 million bbl [3.65×10^6 m^3] is within the accuracy of the 23.4 million bbl [3.72×10^6 m^3] shown as the most likely capture in Table 2.

Barber *et al.*[5] predicted that at least 79% of the through-the-wellbore recoveries would be incremental capture. They had predicted that a total of one hundred and seven 20-acre [8-ha] wells would yield an incremental capture of 10.7 million bbl [1.7×10^6 m^3]. More recent data, as well as the results from about 10[illegible] additional infill wells, have shown that this estimate was indeed pessimistic. Incremental capture is now estimated to be between 90 and 95% of through-the-wellbore production.

Correlations of Infill Performance to Reservoir Quality

Good infill performance can result from either unusually poor reservoir continuity in a local area or better-than-average reservoir deliverability and quality. The very good infill results at RCU would be consistent with the hypothesis that the reservoir was unusually discontinuous in some areas. The technique used to test this hypothesis involved mapping the performance of various wells, as measured by the individual well estimated ultimate recoveries. Figs. 13 through 16 show areas of better-than-average well performance by well type, 40-acre [16-ha], 20-acre [8-ha], north/south, or east/west offset infill wells. These figures show that the good 20-acre [8-ha] wells were located in the same areas as good original 40-acre [16-ha] wells. Similarly, good 10-acre [4-ha] wells are found in the same area. This coincides roughly with areas of better-than-average net pay thickness. The ratio of net pay thickness inside the good area to that in the outside area is not quite as great as the ratio of well estimated ultimate recovery performance inside the good area to other areas. This indicates that in addition to thicker net pay in this area of the field, the reservoir quality and deliverability are also better.

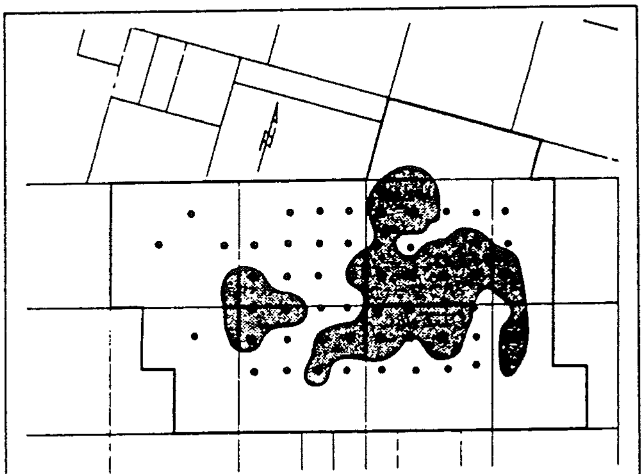


Fig. 15—Area of above-average north/south offset producers (estimated ultimate recovery>92,000 bbl/well).

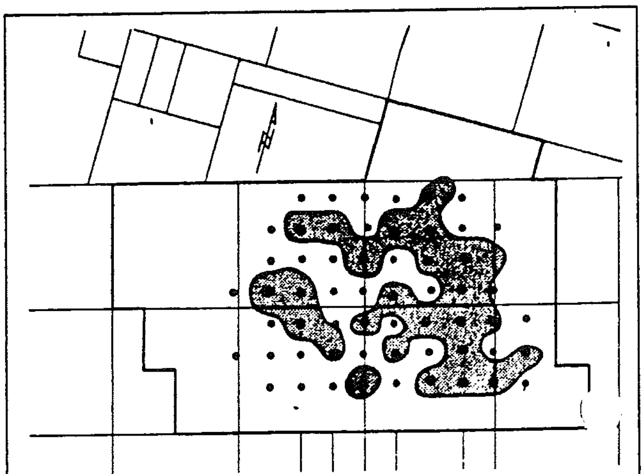


Fig. 16—Area of above-average east/west producers (estimated ultimate recovery>67,000 bbl/well).

TABLE 3—COMPARISON OF THROUGH-THE-WELLBORE ESTIMATED ULTIMATE RECOVERIES	
Type of Wellbores Compared	Average Estimated Ultimate Recovery Ratio (Infill vs. Older Wells)
20-acre well to average 40-acre direct offset	0.44
North/south 10-acre well to average 40-acre direct offset	0.23
North/south 10-acre well to average 20-acre direct offset	0.50
East/west 10-acre well to average 40-acre direct offset	0.18
East/west 10-acre well to average 20-acre direct offset	0.38

Table 3 compares the ratio of individual infill well estimated ultimate recovery performance to the estimated ultimate recoveries of its offsets. Four 40-acre [16-ha] wells surrounding each 20-acre [8-ha] infill were averaged and ratioed vs. the 20-acre [8-ha] estimated ultimate recovery. Each 10-acre [4-ha] well is offset by two 20-acre [8-ha] wells and by two 40-acre [16-ha] wells. These were averaged separately for the ratios. These ratios can be used to estimate recovery from additional locations that have not yet been drilled.

Numerical Analyses of Produced Volumes

A third approach to quantitative analysis of infill performance and reservoir continuity involved a modified nonlinear regression on the performance data. For this analysis, *drainable* describes the reservoir volume that can be drained to a wellbore by solution gas drive, and *floodable* describes the reservoir volume sufficiently continuous to be waterflooded between at least one injector/producer pair.

By use of the definitions for A, B, C, D, and F_p as shown in the Nomenclature, recoveries for wells within the area of 10-acre [4-ha] development are as follows.

1. Primary per 40-acre [16-ha] well is $A+B+C+D$.
2. Secondary per 40-acre [16-ha] well is $F_p(A)$.
3. Primary per 20-acre [8-ha] well is $C+D$.
4. Secondary per 20-acre [8-ha] well is $F_p(B)$.
5. Total per 20-acre [8-ha] well is $F_p(B)+C+D$.
6. Primary per 10-acre [4-ha] well is D.
7. Secondary per 10-acre [4-ha] well is $F_p(C)$.
8. Total per 10-acre [4-ha] well is $F_p(C)+D$.

Although continuity is really a measure of reservoir PV, for simplicity, A, B, C, and D are defined in terms of primary recovery—i.e., a constant recovery factor times the affected PV.

In the area of the field fully developed on 10-acre [4-ha] spacing, the actual well recoveries are listed in Table 4. (This area is shown in Fig. 17.) The "nominal" value represents the through-the-wellbore recoveries. The range is intended to account for drainage into or away from the well because of interference with other wells.

The most likely values are based on estimates for the following.

1. Some primary recoverable oil for 40-acre [16-ha] wells was drained to infill wells and/or misallocated to the secondary project.

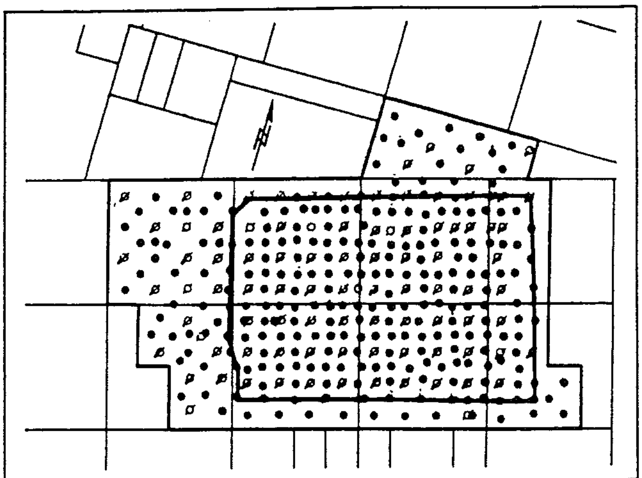


Fig. 17—RCU base map with area of 10-acre/well development highlighted.

2. Secondary production (40 acres [16 ha]) is essentially nominal because minor drainage to infill wells would more or less balance a possible misallocation of primary to secondary in allocating the well's estimated ultimate recovery.

3. The 20- and 10-acre [8- and 4-ha] wells produced oil that could eventually have been produced by the 40-acre [16-ha] wells.

Although the equations given earlier contain five unknowns, they can be solved approximately because of the requirement for all variables to be positive. If the most likely parameters are used, A, B, C, and D are positive only for a range of F_p between 1.39 and 1.43, with a most reasonable value of 1.395. Throughout the range of parameters, F_p could vary between 1.3 and 1.55, but the most reasonable value of 1.395 is stable within likely perturbations of the most likely value.

The derived values for A, B, C, D, and F_p can be related to reservoir continuity in two ways. The first involves comparison of recoveries, by well type and mode, with the volumetrically calculated OOIP for an average 40-acre [16-ha] tract. Estimates of continuity in this case range up to 80%. Continuity estimates for various spacings are listed in Table 5. The detailed calculations are in the Appendix.

The second correlation is based on the assumption that ratios of actual primary and secondary recovery factors to the theoretical factors equal the continuity fractions for the field spacing. For 10-acre [4-ha] spacing, this analysis yields values of 87 and 63% for drainable and floodable fractions, respectively (see the Appendix for details).

TABLE 4—ACTUAL WELL RECOVERIES FOR A FULLY DEVELOPED 10-ACRE SPACING

Well Type and Mode	Average Recovery (1,000 bbl) Nominal	Range	Most Likely
40-acre primary			
40-acre secondary			
20-acre total			
10-acre total			

TABLE 5—RESERVOIR CONTINUITY BY NUMERICAL ANALYSES

Spacing (acres/well)	Reservoir Drainable by Solution Gas Drive (%)	Reservoir Floodable Between at Least 2 Wells (%)
40	56	27
20	70	43
10	80	60

Conclusions

1. Infill drilling has been a successful program at RCU, both on spacings of 20 acres [8 ha] per well and further infilling to 10 acres [4 ha] per well.
2. At RCU, with 10-acre [4-ha] spacing, about 80 to 85% of the reservoir PV is drainable by solution gas drive; with 40-acre [16-ha] inverted nine-spot patterns, about 60% is floodable between at least two wells.
3. The apparent difference in extrapolated transient pressures between producing wells and injection wells is a direct and correlatable function of the discontinuity between wells.
4. Pressure correlations, numerical analysis, and finely detailed geologic correlations have all been used successfully to quantify the degree of discontinuity in the reservoir formation at RCU.
5. Discontinuity must be considered in the design, planning, and operation of any EOR project because of the relatively large volumes of pay that cannot be flooded.
6. There is a preferential water movement at RCU in the east/west direction, either as a result of fracturing in the reservoir or from an in-situ directional permeability.

Nomenclature

A = primary recovery from that fraction of reservoir that could be floodable on 40-acre [16-ha] spacing, bbl [m^3]

B = primary recovery from that fraction of reservoir that is drainable on 40-acre [16-ha] spacing but floodable only on 20-acre [8-ha] spacing, bbl [m^3]

C = primary recovery from that fraction of reservoir that is drainable on 20-acre [8-ha] spacing but floodable only with 10-acre [4-ha] spacing, bbl [m^3]

D = primary recovery from that fraction of reservoir that is drainable only on 10-acre [4-ha] spacing but not floodable on 10-acre [4-ha] spacing, bbl [m^3]

F_p = ratio of secondary to primary production from the portion of reservoir that is effectively waterflooded

References

1. George, C.J. and Stiles, L.H.: "Improved Techniques for Evaluating Carbonate Waterfloods in West Texas," *JPT* (Nov. 1978) 1547-54.
2. Galloway, W.E. *et al.*: *Atlas of Major Texas Oil Reservoirs*, Bureau of Economic Geology, U. of Texas, Austin (1983).
3. McKinley, R.M.: "Wellbore Transmissibility from Afterflow-Dominated Pressure Buildup Data," *JPT* (July 1971) 863-72; *Trans.*, AIME, 251.
4. Matthews, C.S. and Russell, D.G.: *Pressure Buildup and Flow Tests in Wells*, Monograph Series, SPE, Richardson, TX (1967) 1, 108.
5. Barber, A.H. Jr. *et al.*: "Infill Drilling to Increase Reserves—Actual Experience in Nine Fields in Texas, Oklahoma, and Illinois," *JPT* (Aug. 1983) 1530-38.
6. Staggs, H.M. Jr. and Bilhartz, H.L. Jr.: "Waterflood Correlation to Forecast Rate and Reserves," paper API 906-14-K presented at the 1969 API Southwestern District Meeting, Lubbock, March 12-14.

Appendix—Waterflood Recovery Estimate for Floodable Reservoir

Robertson reservoir parameters include the following.

Dykstra-Parsons coefficient=0.833.
Mobility ratio=0.96.
Gas saturation at flood start=0.13 (in drained areas).
Water viscosity=0.6 cp [0.6 mPa·s].
Oil viscosity at flood start=1.17 cp [1.17 mPa·s].
Initial oil saturation=0.708.
Residual oil saturation=0.34.

With these parameters, waterflood conformance can be estimated by use of Staggs and Bilhartz's technique[6] to sweep 73% of the floodable volume. Assuming that oil resaturates 50% of the "unswept" gas saturation (an approximation based on other detailed waterflood studies in west Texas carbonates), the calculated ultimate recovery from the floodable portion of the formation is 31 to 32% of the OOIP.

As discussed in the Numerical Analysis of Produced Volumes section, the ratio of secondary to primary production in the swept reservoir is 1.395. With this ratio, the primary and secondary recovery factors are estimated at 13.2 and 18.3% of OOIP, respectively.

In the 10-acre [4-ha] infill area at RCU, average OIP is 3.36 million STB [0.53×10^6 stock-tank m^3] per 40-acre [16-ha] tract. Theoretical primary and secondary recoveries, therefore, would be (3.36 million)×(13.2%)=444×10^3 bbl [71×10^3 m^3] and (3.36 million)×(18.3%)=615×10^3 bbl [98×10^3 m^3], respectively, if continuity were 100% throughout the reservoir.

The fraction of reservoir volume drainable or floodable on various spacings can then be estimated with the parameters derived by numerical analysis. The most likely parameters are

A=118,000 bbl [18.8×10^3 m^3],

B=72,000 bbl [11.4×10^3 m^3],

C=38,000 bbl [6.0×10^3 m^3],

D=22,000 bbl [3.5×10^3 m^3], and

F_p=1.395.

The following calculations show the drainable or floodable reservoir volume for the various well spacings.

The 40-acre [16-ha] drainable fraction is

$$\frac{A+B+C+D}{444}=\frac{118+72+38+22}{444}$$

$$=0.56.$$

The 40-acre [16-ha] floodable fraction is

$$\frac{F_p(A)}{615}=\frac{1.395(118)}{615}$$

$$=0.27.$$

The 20-acre [8-ha] drainable fraction is

$$\frac{A+B+2C+2D}{444}=\frac{118+72+2(38)+2(22)}{444}$$

$$=0.70.$$

The 20-acre [8-ha] floodable fraction is

$$\frac{F_p(A+B)}{615}=\frac{1.395(118+72)}{615}$$

$$=0.43.$$

The 10-acre [8-ha] drainable fraction is

$$\frac{A+B+2C+4D}{444}=\frac{118+72+2(38)+4(22)}{444}$$

$$=0.80.$$

The 10-acre [8-ha] floodable fraction is

$$\frac{F_p(A+B+2C)}{615}=\frac{1.395[118+72+2(38)]}{615}$$

$$=0.60.$$

The effective secondary-to-primary ratio for each 40-acre [16-ha] tract within the 10-acre [8-ha] infill area is

$$\frac{F_p(A+B+2C)}{A+B+2C+4D}=1.0.$$

These are the actual recoveries for this area.

Total estimated ultimate recovery=43.7 million STB [7.5×10^6 stock-tank m^3].

OOIP=206 million STB [32.7×10^6 stock-tank m^3].

Actual recovery factor $=\dfrac{47.3}{206}$

$=23\%$.

Actual primary recovery $=23\%\times\dfrac{1}{1+1}$ at 1:1 secondary/primary

$=11.5\%$.

Fraction drainable by primary $=\dfrac{11.5\%\text{ actual primary recovery}}{13.2\%\text{ theoretical primary recovery}}$

$=87\%$ drainable volume fraction.

Actual Secondary $=23\%\times\dfrac{1}{1+1}$ at 1:1 secondary/primary

$=11.5\%$.

Floodable volume $=\dfrac{11.5\%\text{ actual secondary recovery}}{18.3\%\text{ theoretical secondary recovery}}$

$=63\%$ floodable volume fraction.

SI Metric Conversion Factors

acres	×	4.046 873	E−01	=	ha
bbl	×	1.589 873	E−01	=	m^3
cp	×	1.0*	E−03	=	Pa·s
ft	×	3.048*	E−01	=	m
psi	×	6.894 757	E+00	=	kPa

*Conversion factor is exact.

JPT

Original SPE manuscript received for review Oct. 5, 1986. Paper accepted for publication July 6, 1987. Revised manuscript received Sept. 2, 1987. Paper (SPE 15568) first presented at the 1986 SPE Annual Technical Conference and Exhibition held in New Orleans, Oct. 5–8.