Figure 1

Reservoir/Compartment Categories

- ***New infield reservoirs***

- ***Untapped reservoir/compartments***

  or

  Incompletely drained reservoir compartments

- ***Bypassed reservoirs***

Figure 2

Reservoir/Compartment Terminology

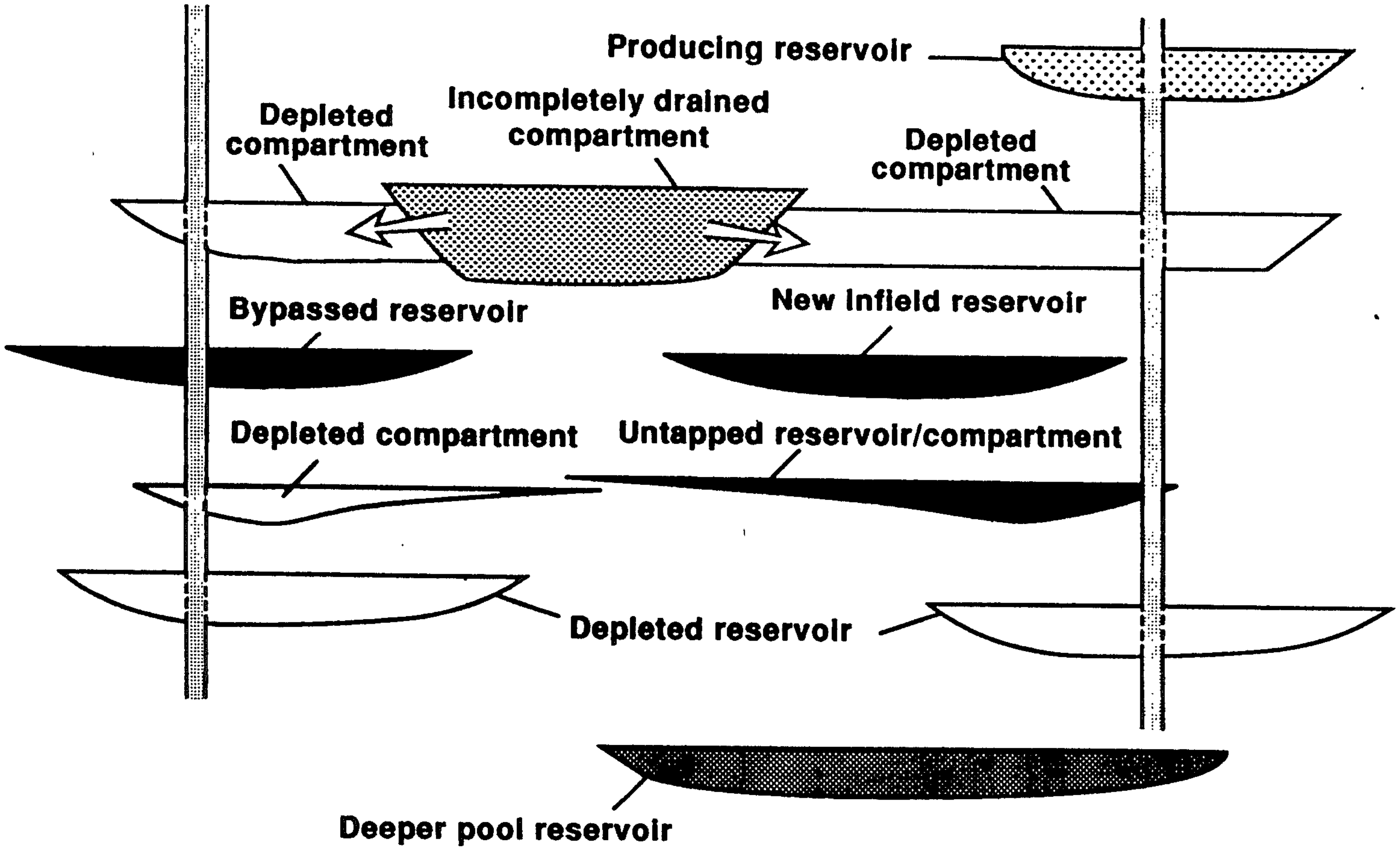


Figure 3

IS THERE MACRO-SCALE EVIDENCE FOR RESERVE GROWTH?

- Net reserve revisions for the Lower 48 states became positive in 1984 and have remained so.

- Total reserve growth has exceeded production by 10 percent in 1986–89 in seven key onshore producing states.*

Not related to wells drilled / No wells drilled ⇒ still + recomp.

- Reserves added per reserve growth completion (onshore, 7 states) have increased from 0.87 Bcf to 2.18 Bcf between 1979–85 and 1986–89.

fewer wells

*Colorado, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming

Figure 4

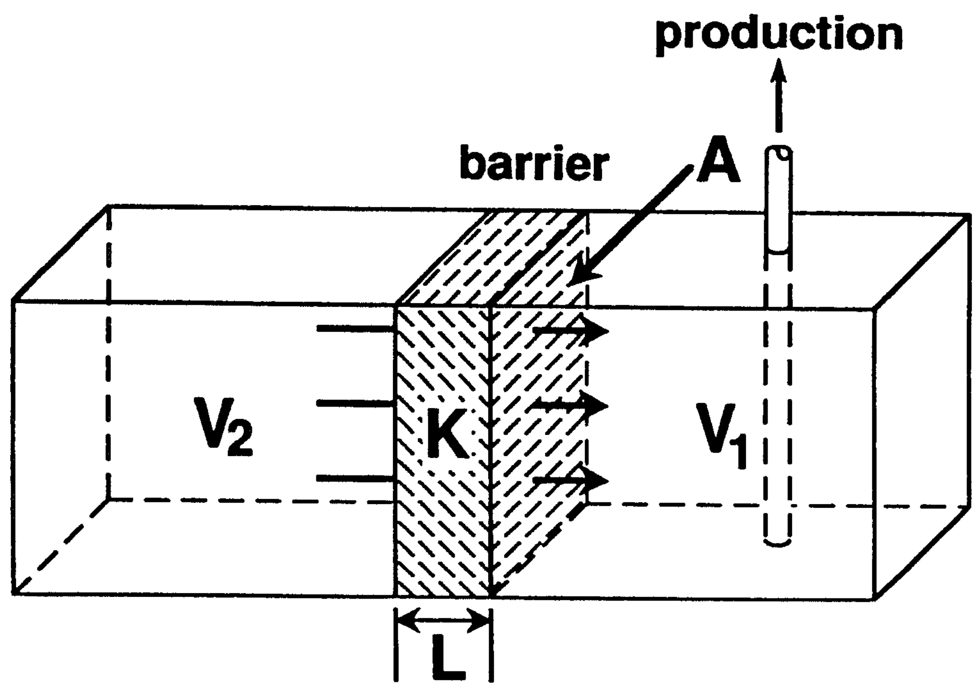
Key Point

Totally Missed The Key Point

The decline of producing rate and depletion of reserves has been dramatically slowed by continued drilling and completion activities No

Figure 5

Idealized two-compartment tank model with permeability barrier

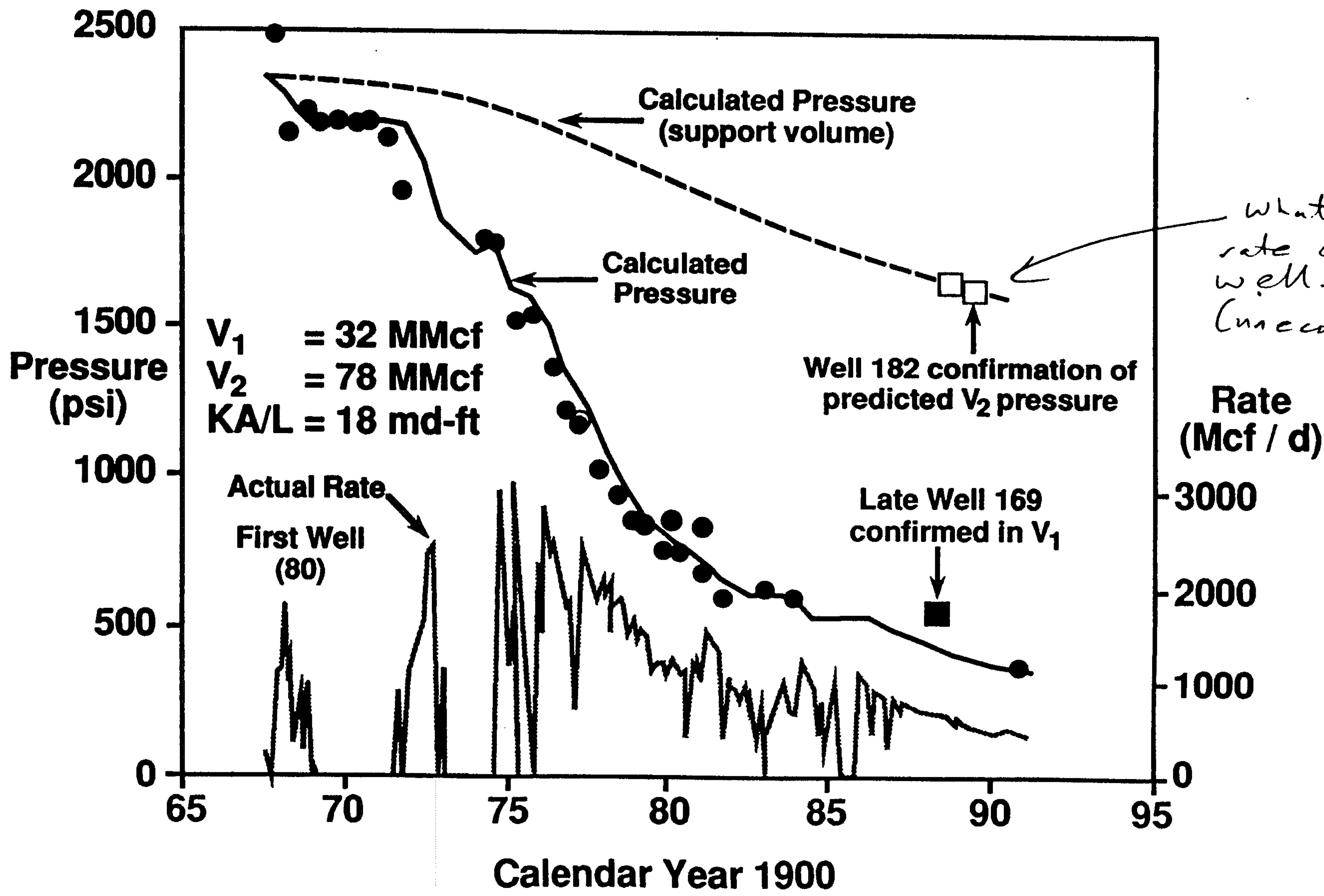


Only Three Adjustable Parameters:

V_1, V_2 and $\frac{KA}{L}$ = Transmissibility

Figure 6

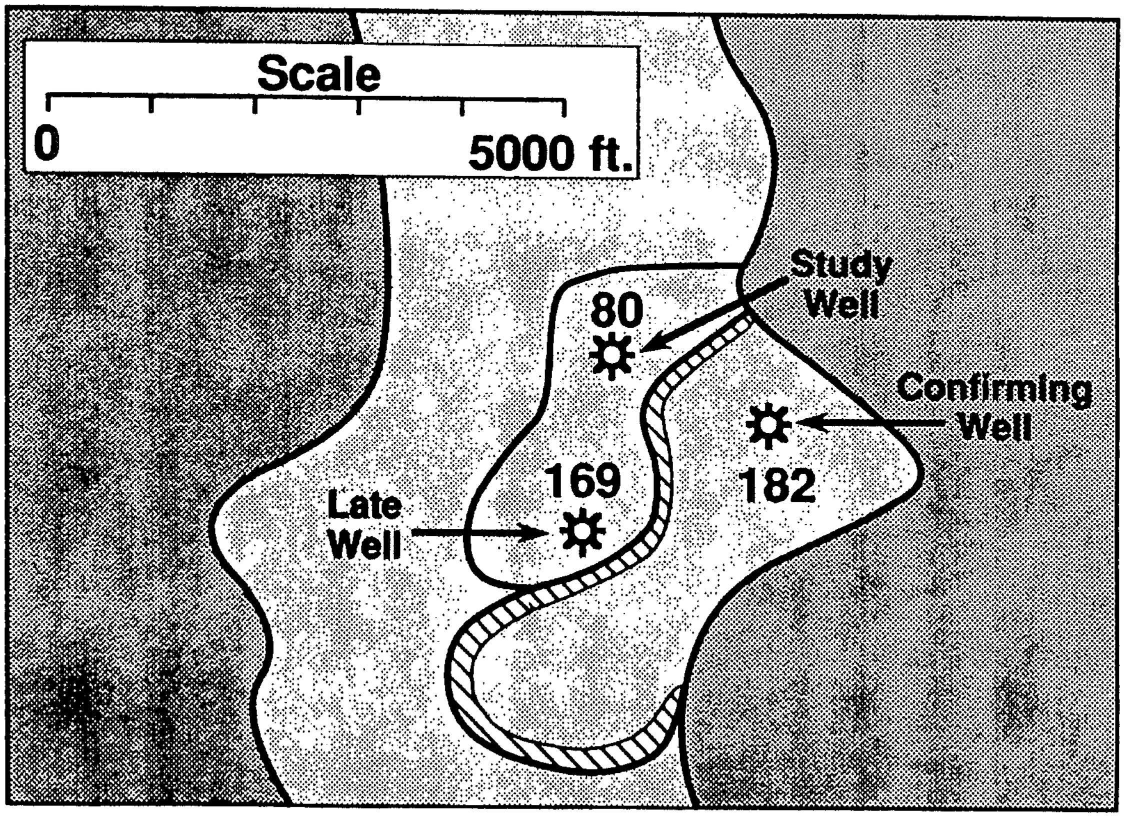
Pressure history match for the Wardner 80 well by a two-compartment model



What was rate of this well. (uneconomic?)

Figure 7

Reservoir geometry and well locations in the Wardner Lease, Stratton field



High Pressure
sat low rate

he only mentioned
this after my question

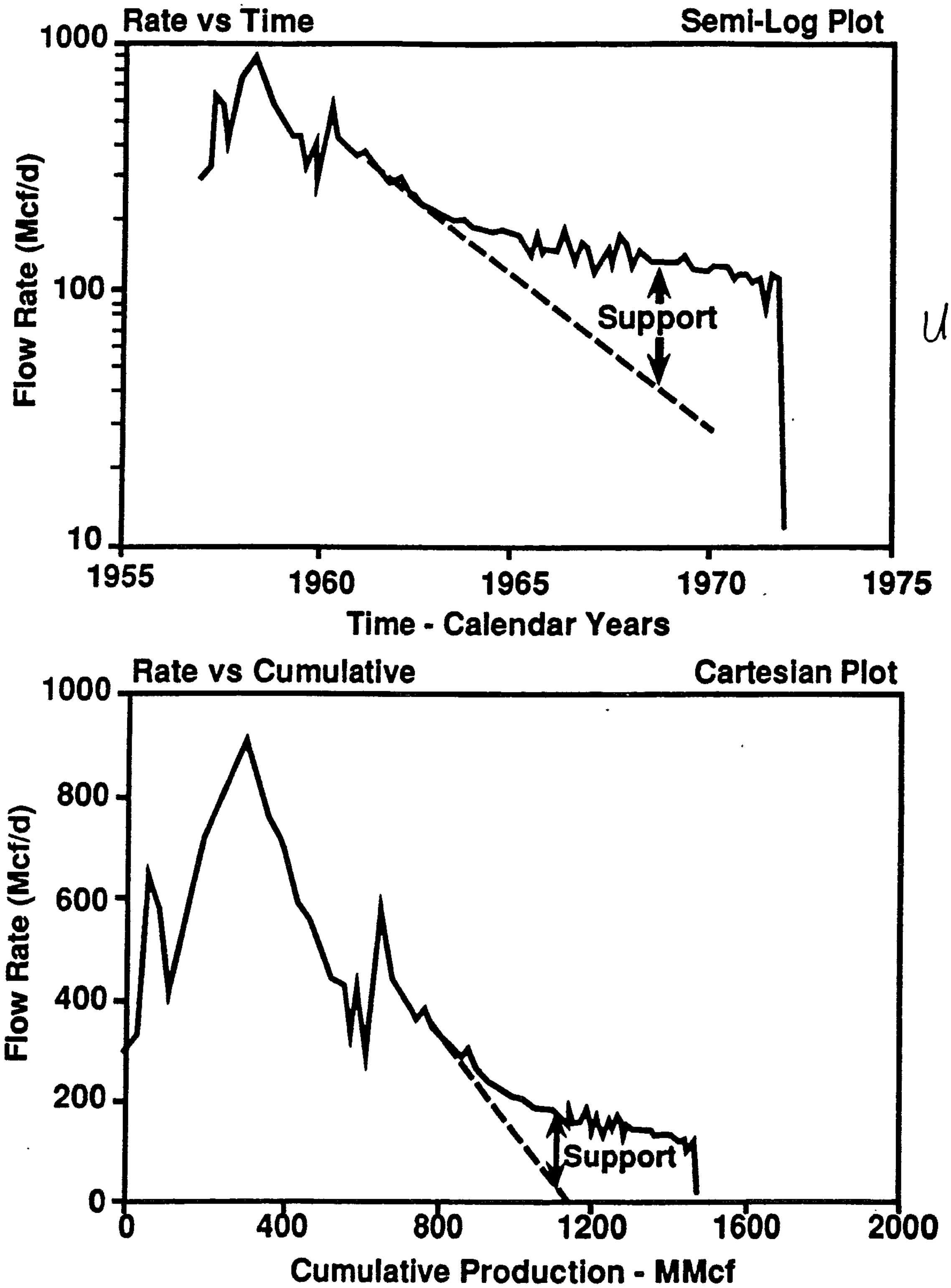
Shale

Sand

Figure 8

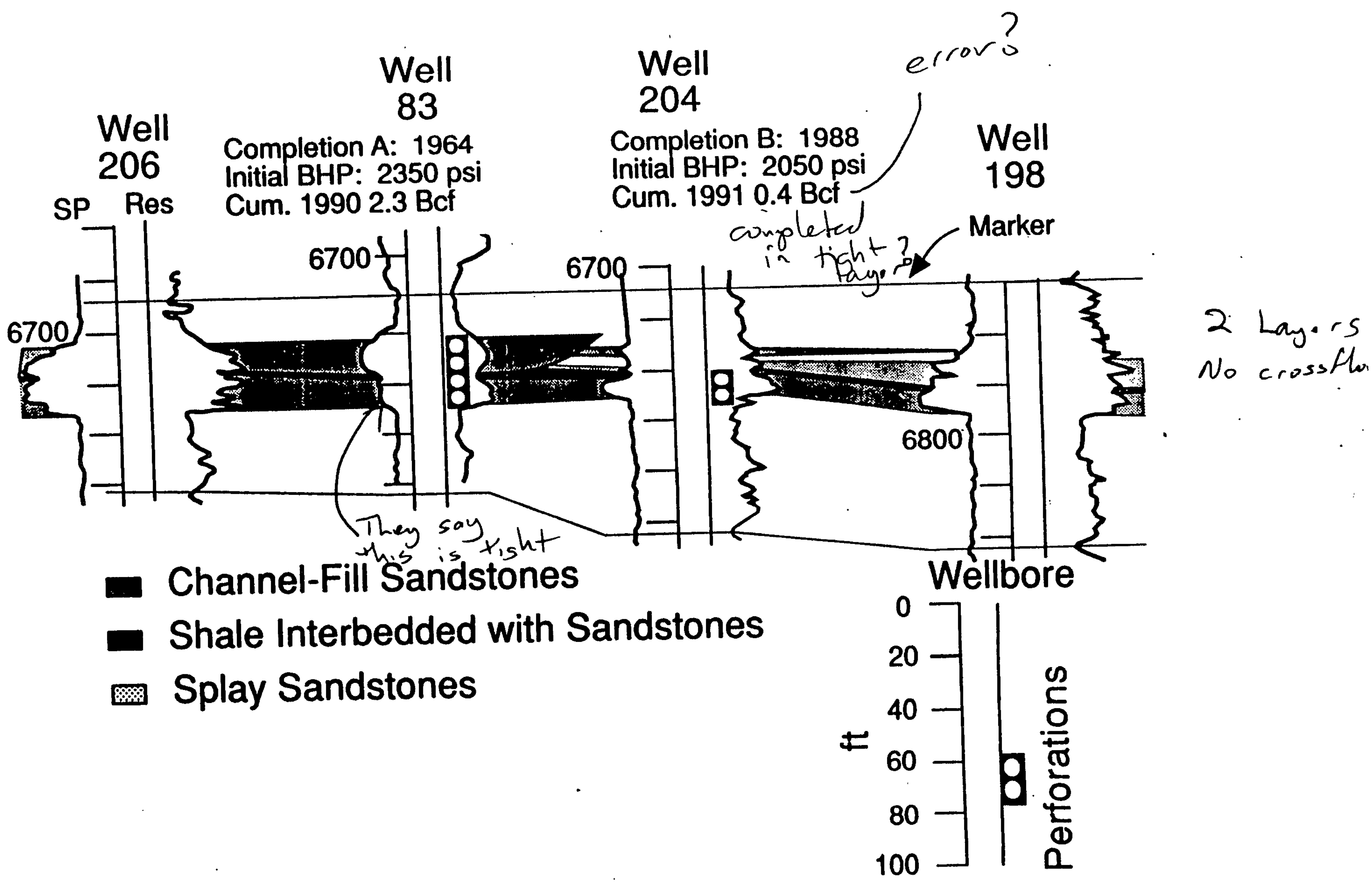
Example 2

Production History - Well 77
Completion A



Unbelievable

Figure 9


Well
206
SP
Res
6700
Well
83
Completion A: 1964
Initial BHP: 2350 psi
Cum. 1990 2.3 Bcf
6700
They say this is tight
Well
204
Completion B: 1988
Initial BHP: 2050 psi
Cum. 1991 0.4 Bcf
errors?
6700
completed in tight layer?
Well
198
Marker
6800
Wellbore
0
20
40
60
80
100
ft
Perforations
Channel-Fill Sandstones
Shale Interbedded with Sandstones
Splay Sandstones
2 Layers
No crossflow

VERY--VERY GOOD EXAMPLE M.J. Fetkovich

Series of well tests helps determine remedial action

Raj K. Prasad
Petroleum Consulting
& Engineering Inc.
Sugarland, Tex.

Fig. 1

Performance history

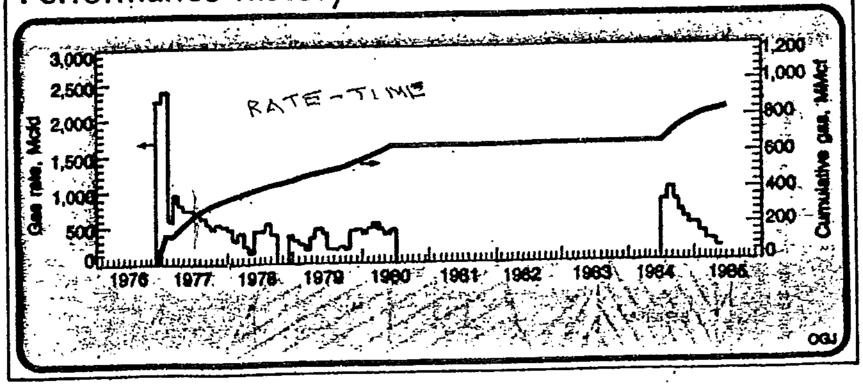
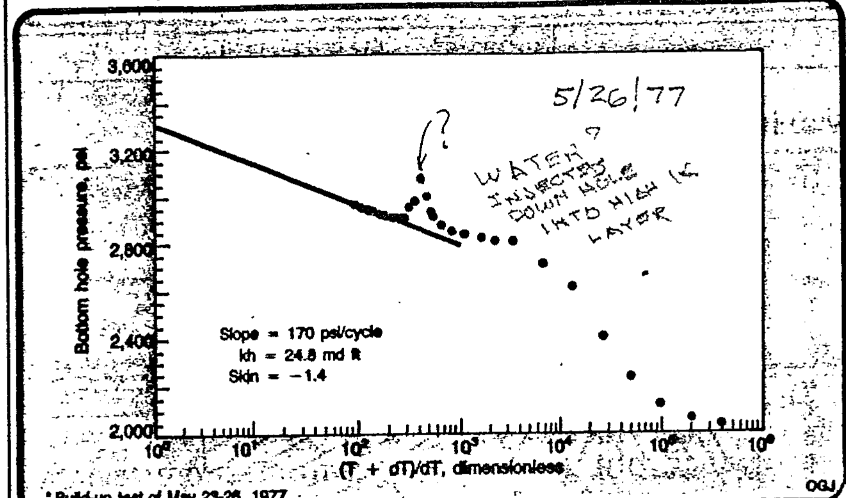


Fig. 2

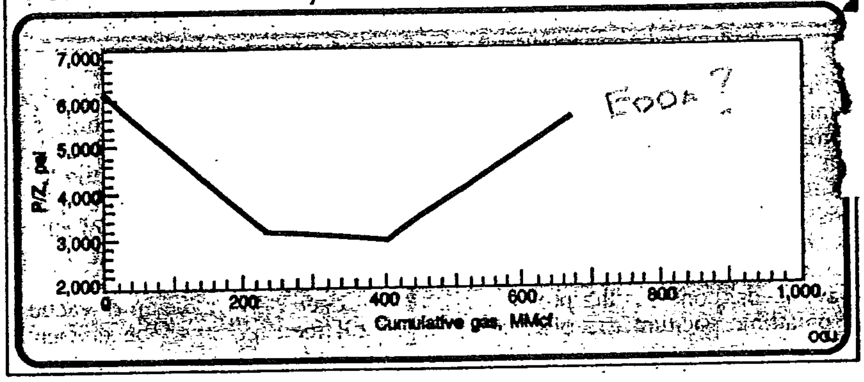
Horner plot*



* Build-up test of May 23-26, 1977

Fig. 3

Performance analysis



Short duration well tests, conducted at various states of depletion, when analyzed together can provide excellent reservoir characterization. Such may not be possible from conventional analysis of the individual tests.

This observation can be demonstrated by the analysis of two build-up tests and one shut-in pressure survey conducted at various stages of depletion in Well X.

This well was completed in the Wilcox (Lobo) trend, a series of geopressured, low permeability sands. Fracture stimulation resulted in improved deliverability which deteriorated with time.

TK SANDS

A study was undertaken to evaluate remedial procedures for improved deliverability; therefore, it was important to identify the reservoir system.

P/Z vs. cumulative gas production data indicated the following possibilities:

1. Water drive gas reservoir
2. Donut-shaped composite reservoir with deteriorating permeability
3. Layered reservoir.

If the reservoir is a water drive gas reservoir with limited reserves, possibly no workover is needed. If, on the other hand, it is a donut-shaped composite reservoir with deteriorating permeabilities and sufficient reserves, refrac is necessary. Last, if the reservoir is found to be layered with most reserves present in the damaged layer(s), then cleaning the damaged perforations is all that is required.

Data analysis, with the aid of a well test model, showed that the layered reservoir system (most reserves in the damaged layers) resulted in the best match of the performance data.

Such a conclusion was not evident from the individual build-up tests as they were not run long enough. ?

Similar results can be obtained by a single long-term well test; however, it is usually uneconomical to run such a test. Based on the above conclusions, the well was simply cleaned, which resulted in a four-fold increase in production rate from 200 Mcfd to 800 Mcfd.

Well X. Well X was completed in October 1976 in the Wilcox (Lobo) trend. Pertinent well data are presented in Table 1.

Initial well tests indicated an absolute open flow potential (AOFP) of 2,200 Mcfd. After a frac job, the well was tested at a rate of 8,156 Mcfd on a 16/64-in. choke with a calculated AOFP of 32,500 Mcfd.

Postfrac gamma-ray log indicated only the top two sets of perforations (9,756-68 and 9,808-20 ft) were ef-

12 FT 12 FT
∴ K ≅ 1 MD.

Fig. 8

Production profile

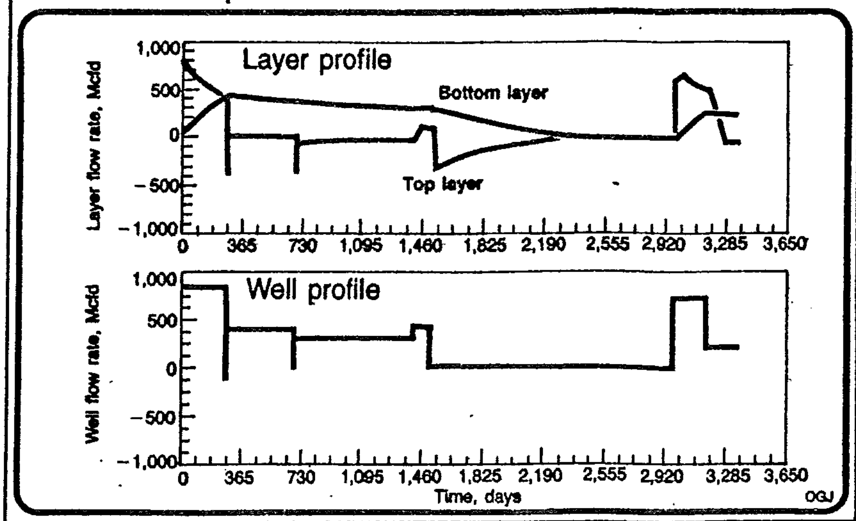
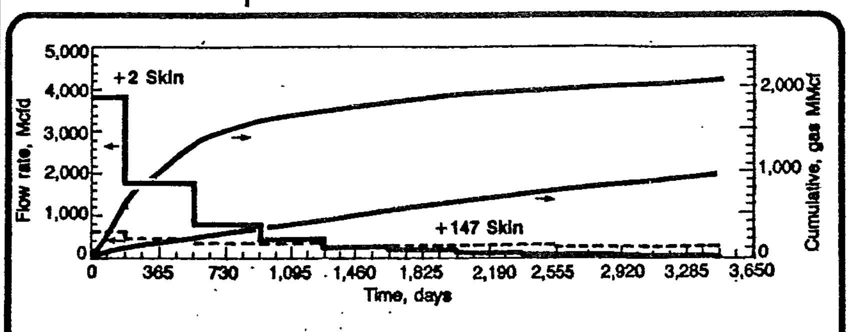


Fig. 9

Performance prediction*



* Prediction begins July 1, 1985

OGJ

dimensions. In addition to the standard features, the model includes well bore storage and skin damage, hydraulic fractures, and implicit distribution of flow between layers (cross flow between layers can be handled).

Donut-shaped composite. A donut-shaped composite reservoir with deteriorating permeability rings (Fig. 4) was considered.

Permeability of 0.95 md calculated from the 1977 build-up test was used for Segment 1 (near the well bore); permeabilities within other segments were varied to match the calculated pressures with the measured pressures. Model pressures do not match the measured pressures (Fig. 5). In fact, in the model the well is unable to produce after 3 years of production, which precludes the possibility of a donut-shaped reservoir.

Layered reservoir. Postfrac gammaray log indicated that only the top two sets of perforations (9,756-68 and 9,808-20 ft) were effectively fractured, and the bottom four sets of perforations (9,849-55, 9,880-86, 9,904-10, and 9,926-32 ft) were damaged. A two-layer model was considered with top layer representing the top two sets of perforations and the bottom layer the bottom foursets of perforations.

Size and skin of the layers were varied to match the performance data.

The model (Fig. 6) that resulted in best match indicates only 187 MMcf of OGIP in the high deliverabilty (skin = +2) layer; and 3,397 MMcf of OGIP in the highly damaged (skin = +147) bottom layer. Model pressures are in excellent agreement with the measured pressures (Fig. 7).

Well and layer production rates are shown in Fig. 8. From this figure, the following observations are made:

- Initially, the bulk of the well production is from the top layer because of its high productivity. After the top layer is depleted, the well produces mostly from the bottom layer at a lower rate.
- During the shut-in periods, the top layer is charged by the bottom layer through the well bore.
- The charging of the top layer is completed in about 3 years of shut-in.

The author...

Prasad

Raj Prasad is a reservoir engineering consultant with over 20 years of industry experience specializing in reservoir simulation, well test analysis, and enhanced oil recovery technologies. He has published several technical papers.

Prior to becoming independent, Prasad was a vicepresident with H. J. Gruy & Associates in Dallas. He holds an MS degree in petroleum engineering from the University of Tulsa. He is a registered professional engineer in Texas and a member of SPE.

Performance match was obtained by considering the bottom layer to be severely damaged. A similar match is possible if the bottom layer is partially damaged and/or has lower permeability. If the bottom layer is severely damaged but has permeability comparable to the top layer, only well bore cleaning is required to improve productivity. However, if the bottom layer is partially damaged and/or has lower permeability, well cleaning followed by fracturing through the bottom sets of perforations will be necessary to improve productivity.

Performance predictions. To evaluate effects of well conditions on well performance, two forecast runs were made: under current well conditions with severely damaged bottom layer (skin = +147), and under normal well condition (skin = +2).

These runs were made for a minimum wellhead flowing pressure of 1,000 psia.

Predicted well performance (Fig. 9) indicates that about 2,000 MMcf of remaining gas can be recovered in 6 years if the well is properly cleaned (skin = +2); whereas, under the current condition (severely damaged bottom layer) only 700 MMcf will be recovered in the same period.

Summary. Results of this study indicate:

1. Well X is communicating to a layered reservoir with no flow between layers other than through the well bore.
2. Very little gas (less than 100 MMcf) is contained in the high productivity layer(s). Bulk (about 2,660 MMcf) of remaining gas is in layer(s) with low productivity.
3. About 2,000 MMcf of remaining gas can be recovered in 6 years if the well is properly cleaned and fractured; otherwise, only 700 MMcf will be recovered in the same period. ■

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FOR HIGH LIGHTING.

Changing Concepts in Carbonate Waterflooding—West Texas Denver Unit Project—An Illustrative Example

W. K. Ghauri, SPE-AIME, Shell Oil Co.
A. F. Osborne, SPE-AIME, Shell Oil Co.
W. L. Magnuson, SPE-AIME, Shell Oil Co.

Introduction

Carbonate reservoirs demand special attention, particularly for drive projects, because of the gross nonuniformities that normally exist. Often numerous, thin pay intervals of varying quality are distributed over thick vertical sections of several hundred feet. Differing environmental conditions at the time of deposition insure that the rock encountered in a single wellbore will have markedly varying porosity, permeability, and fluid-flow characteristics and relationships. These same variations occur between wellbores. The use of simple assumptions or averages of rock properties in the design and execution of the projects can lead to economic failures.

Carbonate waterflooding in the Permian Basin has a relatively short history. The major impetus of project initiations did not occur until the late 1950's and during the 1960's. This long delay can be attributed primarily to the lack of economic incentives — specifically, low oil allowables and depressed crude oil prices. Other contributing factors included skepticism over success, difficulties in arriving at acceptable unitization agreements among the usually numerous operators, a dearth of injection water, and the sheer magnitude of the engineering task because of the large size of the fields.

A narrowly focused look at current waterflooding in carbonates would likely miss the significant evolution that has taken place in the engineering design and field operation of these projects. Major changes continue to occur in our concepts of the geologic, reservoir, injection, and production aspects. Because of our greater experience there, much of the information for this paper is derived from the Permian San Andres (dolomite) Denver Unit project operated by Shell in the Wasson field of West Texas (Fig. 1). It should be emphasized that most of the material presented here is based on Shell's experience; widely divergent philosophies still exist among operators of carbonate waterfloods in the region.

Geologic Concepts

A significant development of recent years has been the better understanding of the geology of carbonate reservoirs. Geologists now investigate in detail, using both surface and subsurface information, the environmental conditions that controlled deposition. Terminology routinely includes such depositional terms as supratidal, intertidal, subtidal, and marine. Such investigation depends not only on re-evaluating older available data, but also on obtaining new data in the form of cores (including detailed special analyses), and open-hole and cased-hole logs. The attitude toward acquiring new data has changed from reluctance to a recognition of necessity.

The Denver Unit waterflood project was begun in 1964 on the basis of a gross correlation of basically two markers—the First Porosity and the Main Pay—in the San Andres productive interval, whose gross thickness is some 300 to 500 ft at an average well depth of 5,100 ft. Later in the waterflood operation,

Greatly improved carbonate reservoir definition with detailed geology and reservoir simulation has led to confident, full-scale waterflooding. Projects now use closely spaced patterns and very selective means of well completion to improve flood efficiency and increase ultimate supplemental recovery. Producing 133,000 BOPD, the Denver Unit shows the benefits of improved waterflooding concepts.

detailed subsurface geologic and petrophysical correlation work showed that the pay interval could be subdivided into 10 individual pay members that were mappable laterally and vertically within distances of several well locations (Fig. 2). Additionally, it became apparent from this work that several individual pay members were discontinuous and would not be flooded at the 40-acre well spacing then existent in the project. It was further recognized that there were lateral impermeable barriers that would be instrumental in containing the injected fluids within individual pay members and that there would be a minimum of cross-flow from one pay member in the reservoir to another. This gave rise to the concept of "continuous" and "noncontinuous" pay (Fig. 3) and prompted infill drilling on 20-acre spacing — a plan that was instituted on a major scale in 1969. Detailed correlations of new log and core data began to highlight the discontinuity of the pay, which indicated that infill wells would exploit a substantial percentage of pay not floodable with the existing 40-acre-spaced wells.

*

?

VERTICAL WOULD RESULT IN SAME ING.

A novel approach to further delineating the permeability distribution and reservoir continuity of the Permian San Andres carbonate shelf environment of the Denver Unit consisted of studying outcrops in the Guadalupe Mountains of New Mexico. These mountains are situated some 120 miles southwest of the Wasson field (Fig. 1). Normal well spacing control cannot supply the data that can be acquired from a continuous outcrop exposure, and it is this between-well information that is critical in accurately reconstructing the subsurface reservoir for optimizing flooding operations. Our investigation was focused on the continuity that can be expected between an injector and a producer — a distance which, for Permian Basin waterfloods, is generally about 1,320 ft; i.e., 40-acre spacing. The exposed rocks closely resemble subsurface producing strata, both in their regional setting on a broad carbonate shelf, and in their detailed petrographic and petrophysical properties. Field work consisted primarily of defining laterally continuous beds and then sampling these beds at

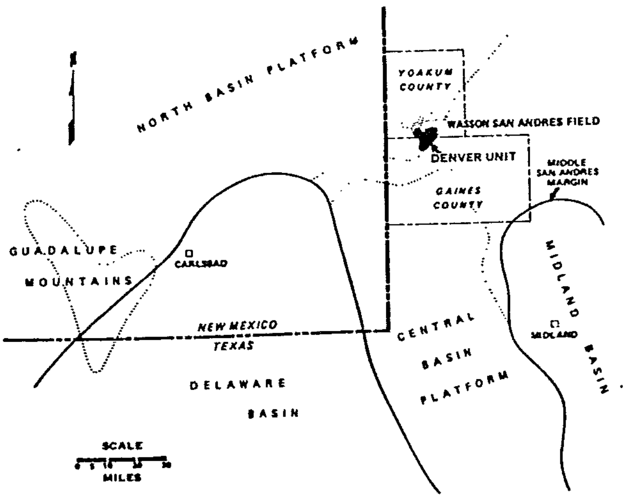


Fig. 1—Location map, Denver Unit, Wasson San Andres field.

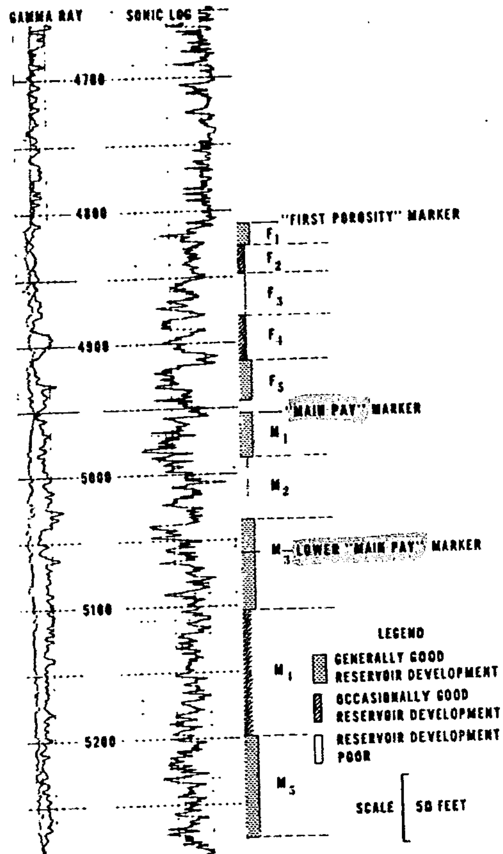
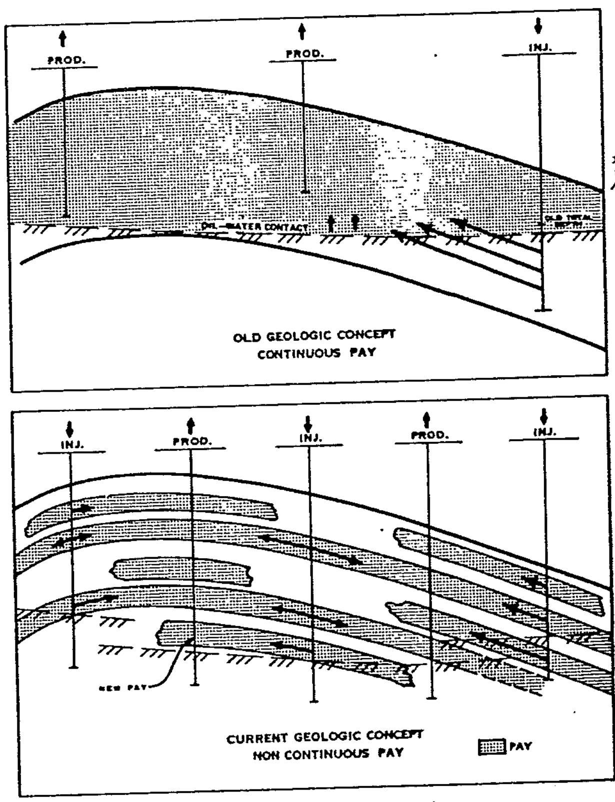


Fig. 2—Example log showing zonal subdivision of San Andres reservoir.



same as below but w/ cross

Fig. 3—Geologic concepts.

ever-decreasing intervals. The study indicated that the rock sequences are well bedded and that impermeable mudstone layers have relatively wide areal extent. The permeable layers exhibited the highly varying permeability commonly associated with carbonates, and no ordered anisotropy was detected. These facts suggest that waterflooding in the Denver Unit should be extremely efficient, but that, with the vertical barriers, unflooded oil lenses could result if all correlative intervals were not perforated in both injectors and producers. ???

*

Reservoir Engineering Concepts

Associated with improved geologic understanding came more detailed reservoir engineering work and new methods of predicting reservoir performance. The numerical simulator has played a major role in the development of infill drilling programs in the Denver Unit, where it has been employed to study various well patterns in specific regions of the Unit. Large field size, heterogeneity, and parameter adjustments made a full field study unwieldy. Therefore, models of field elements were utilized to determine the basic information required for expansion or alteration of flood design. Fig. 4 shows the outline of the Denver Unit, an area of prime infill interest, a two-dimensional (2-D) horizontal simulation area, and a three-dimensional (3-D) simulation area. As stated earlier, the Denver Unit San Andres reservoir is composed of 10 correlatable pay members. In view of this layering and the unique characteristics of each layer, a 2-D horizontal simulation (one layer) by itself would have been inadequate. At the same time, a 3-D (layered) simulation covering an areal extent necessary to incorporate the irregular well pattern within the area of interest would have been extremely costly. A way out of this dilemma was to use pseudo relative permeability curves, which allowed a one-layer model to "simulate" multilayer performance. The multilayer, 405-grid-block, 3-D simulation modeled a four-well element of symmetry, and was used to study production performance sensitivity to (1) relative permeability relationships (core curves and pseudo curves), (2) interlayer communication, and (3) injection profile conformance. Significant adjustments to core-determined relative permeability data were necessary to match actual waterflood performance.

no backflow on shut-ins

With the knowledge gained from the 3-D simulation study, a 487-grid-block, 2-D horizontal model was constructed to simulate an area covering 2,160 acres, 107 well locations, and layering effects. The main objective of this model was to optimize any infill drilling that might be carried out in the area. In this sense, the model was a "typical element." Fig. 5 shows the model grid and the well locations. The irregular well pattern exhibited by the Base Case is rather typical of small lease drilling before unitization. A material balance within the area over a 6-year period was used as a history match to set initial conditions. Six different modes of operation were investigated with this model: (1) Base Case — continuation of existing operations (40-acre spacing). (2) Case 1 — infilling with production wells only to a regular 20-acre spacing, no expansion of existing injection. (3)

Layer pressures?

Skins on all layers ??

Case 2 — infilling with mostly production wells to a regular 20-acre spacing, moderate expansion of existing injection. (4) Case 3 — predominantly a staggered line drive with 20-acre spacing. (5) Case 4 — predominantly a direct line drive with 20-acre spacing. (6) Case 5 — an inverted nine-spot pattern (studied with areal permeability anisotropy ratios of 2 and 4) with 20-acre spacing.

Analyses of the production functions and related profitability data indicated that the inverted nine-spot pattern (Case 5, Fig. 5) was preferable to the others studied. This is the basic pattern strived for in our infill development program in the Denver Unit; the program to date has added 148 new producers and 24 new injectors, and has converted 30 existing producers to injectors. With this infill program, the production behavior of the Unit has been satisfactory, with decreasing GOR, increasing reservoir pressure, and higher daily Unit oil rate. The curves of Fig. 6 display the Unit performance. At present, the infill wells are producing more than 40 percent of the total Unit production. At the same time, as shown by a composite production history of 115 wells in the area of initial infilling (Fig. 7), the original production wells have experienced no adverse effects from infilling operations. No indications of interference

open hole non-stimul

The original 2-D study was completed in early 1971, and actual production since then has matched the simulation prediction quite well (Fig. 6). The model has been recently updated and used in developing our latest infill program — a 1973-74 program that will add 106 new production wells and 15 new injectors, and convert 27 existing production wells to injection. The positive aspects of the results to date suggest that our infill predictions are valid.

In our analysis of additional supplemental oil recovery for the 1973 infill program, we have viewed the total Unit as comprising three main segments: (1) the pre-1973 infill area, (2) the 1973 infill area, and (3) the Western area. Production functions have been constructed for each of these main areas, with the Unit total being the sum of the three functions. With the completion of the 1973 infill program, infill

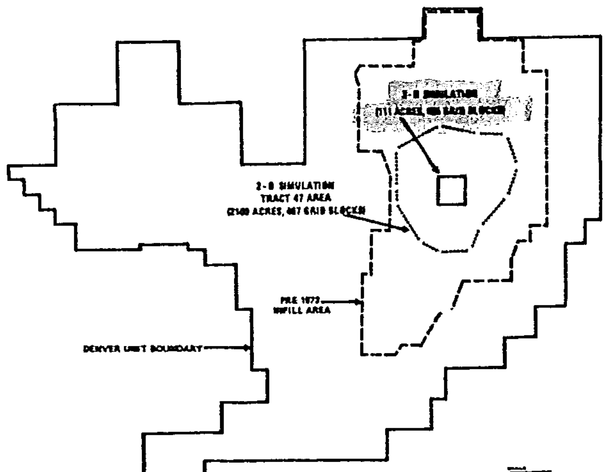


Fig. 4—Pre-1973 infill and reservoir simulation areas, Denver Unit.

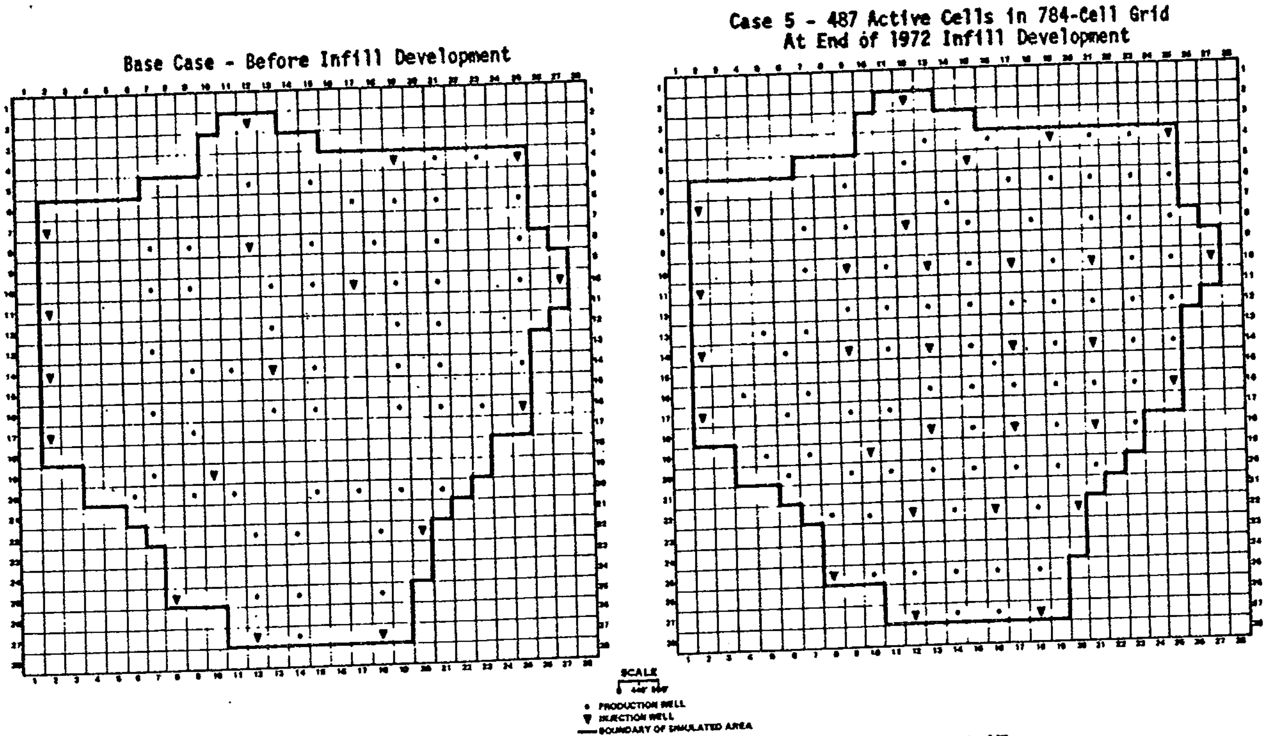


Fig. 5—Two-dimensional reservoir simulation grid and well locations, Tract 47 area.

drilling will add an estimated 51 million bbl of oil to the Unit's ultimate recovery. This represents approximately 200,000 bbl of oil per infill production well. Predicted Unit ultimate recovery efficiencies expressed as a percent of the original oil in place have increased accordingly:

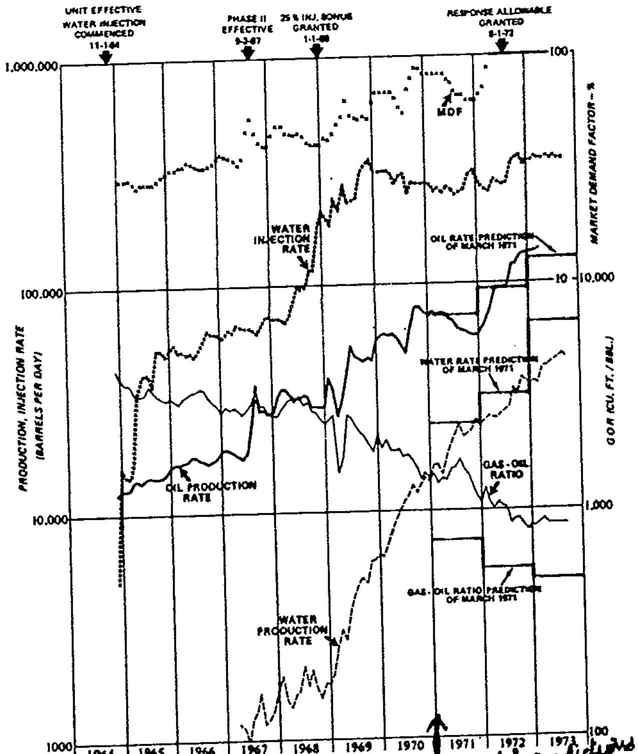


Fig. 6—Production and injection performance curves, Denver Unit, Wasson San Andres field.

model predictions start line

Before infilling	29 percent
With pre-1973 infilling	31 percent
With 1973 infilling	32 percent

The Unit recovery factor in terms of stock-tank barrels per net acre-foot of pay will be about 160. The average production well rate in the Unit is currently 230 BOPD and 70 BWPD, and the average injection rate is 1,500 BWPD per injection well at 1,050 psig surface pressure. The current monthly produced-oil/injected-water ratio stands at 0.4, the produced-water/injected-water ratio is 0.1, and the injected-volume/produced-volume is slightly more than 1. Ultimate supplemental recovery will be about 0.9 of primary recovery.

Future plans include (1) a simulation model of the Western area of the Unit to analyze its infill potential, (2) a simulation model of the original gas cap region to optimize the blow-down of this asset, and (3) a surveillance model of the entire Unit.

Thus, the Denver Unit has undergone a great change in reservoir management. Progress has been made from recovery predictions based on generalized sweep relationships to predictions based directly on models of the subject reservoir. Such sophistication is warranted, however, only when the control of rock and fluid properties is adequate and the profitability potential is sufficient to justify the detailed study.

Injection Concepts

The effects of changes in geologic and reservoir concepts may be seen most clearly when one compares the injection scheme used initially with the modified scheme of recent years. The grossly generalized reservoir models existing at the time this project was started encouraged the use of peripheral injection.

Performance, however, soon indicated that for several reasons peripheral flooding would be inadequate. Edge wells, often located in poor quality reservoir rock, became the water input wells; hence, injectivity was poor and the drive nominal. If the zone being flooded had multilayer pay or noncontinuous zones, peripheral injection failed to influence significant volumes of the reservoir. Additionally, the distance from an edge injector to an interior producer was often excessive. Interior producers were as much as 3 to 4 miles from the initial injectors along the periphery. Response was slow and restricted in volume because of the lack of drive backup, with the flood fronts tending to stall at the first row of producers.

no vertical component

As the need for pattern flooding evolved, it also became apparent that more vertical control and selectivity was required. Early injectors were simply conversions of existing producers — generally open-hole completions. Obviously, little profile control could be exercised in this type of well. The original generalized concept of the reservoir model led to the theory in several projects that if water were injected below the oil-water contact or along the flanks, it would create a bottom- or edge-water drive, or both (Fig. 3). Presumably, this drive would provide a flood front vertically and laterally through the productive zone. This did not happen. We now believe injection *must* be directed into correlative, continuous pay members, and that profile control at the injection wellbore is essential.

Our experience is that currently the simplest and most positive means of controlling injection profiles is mechanical, provided the reservoir rock has impermeable barriers to crossflow among the productive layers. Mechanical design began to improve when formation packers were used in open-hole completions to direct the water to specific pay intervals. The packers were limited in usefulness by a lack of good packer seats and by frequent tool failures. The next step was to cement fiber glass liners and selectively perforate and stimulate the pay interval. The profile at the wellbore has been significantly improved (Fig. 8).

Alteration of stimulation techniques has improved injection profile conformance. In the Denver Unit we have attempted to maintain separation between pay intervals and across impermeable barriers in all wells in the infill drilling program. The goals are good profiles in the injectors, individual zonal stimulation in the producers, and continued flexibility to apply corrective measures to both. Zonal segregation was initially poor when perforations were acidized using ball sealers for diversion, but segregation improved after treating pressures were reduced and separate pay intervals were acidized between straddle packers (30- to 60-ft spacing). Most recently, our technique includes treating more widely spaced, selective perforations individually or in pairs between closely spaced (6 to 10 ft) straddle packers and holding treating pressures below fracturing pressure (Fig. 9). The success ratio on zonal separation in the Denver Unit is now approximately 60 percent. Other measures that have contributed to success are (1) using rough-coated pipe with centralizers and scratchers across the pay zones, (2) circulating a low-water-loss preflush ahead of low-

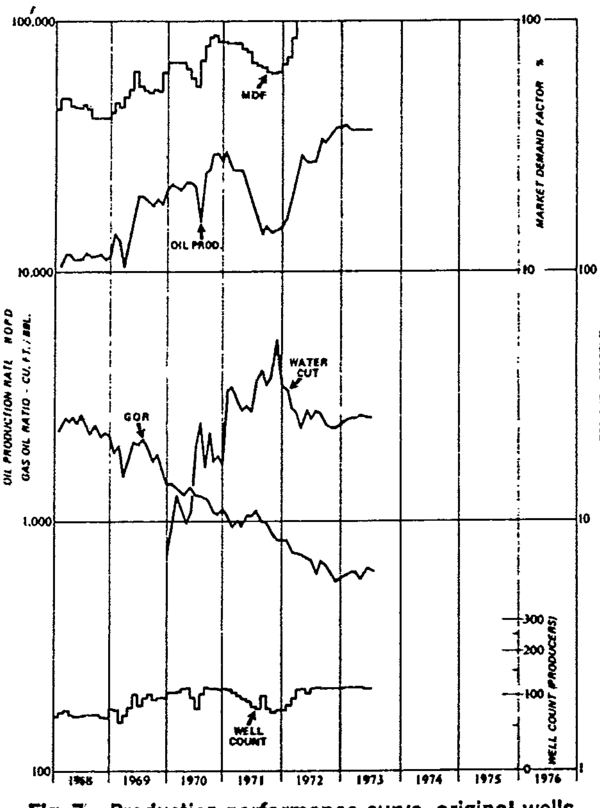


Fig. 7—Production performance curve, original wells in 1969, 1970, and 1971 infill area—Denver Unit, Wasson San Andres field.

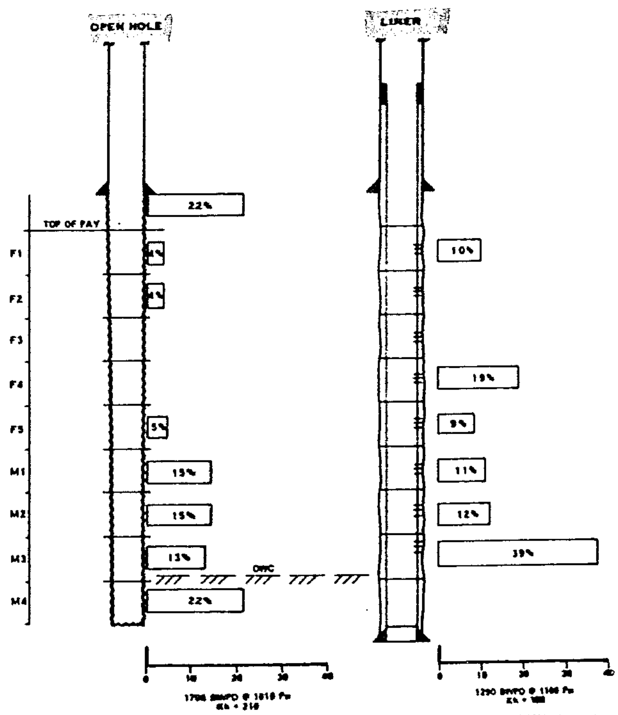


Fig. 8—Effect of liner and selective stimulation on injection profile of a Denver unit injection well.

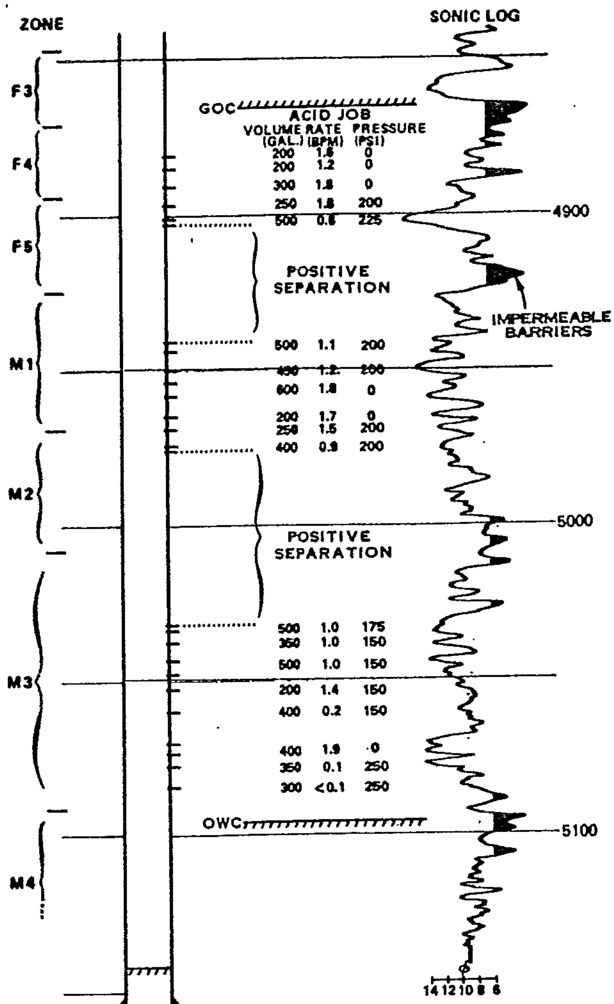


Fig. 9—Completion detail, Denver Unit well.

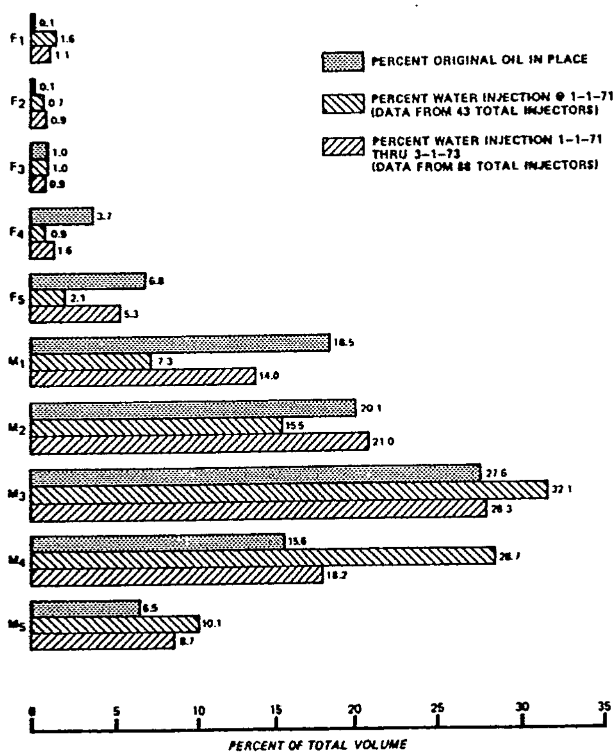


Fig. 10—Wasson Denver Unit injection profile status.

water-loss cement, and (3) reciprocating the casing during cementing.

In injection wells, initial pressures are kept below the reservoir's natural parting pressure. As fillup occurs, higher pressures can be applied without fracturing the formation. Increased rates and pressures after fillup have often improved the profiles in wells that have been selectively perforated and stimulated. It is estimated that in the pre-1973 infill area of the Denver Unit the attainment of an "ideal" injection profile (a profile that matches the porosity-feet profile) should increase oil recovery by some 20 to 30 million bbl. The profile improvement realized in the past 2 years in the Denver Unit is illustrated by Fig. 10.

Water channeling between wells has been experienced in many carbonate waterfloods. As a rule, the poorer the rock quality, the more likely it is that channeling will occur. The presence or absence of natural fractures, however, is unproved in many cases, and the evidence of induced fractures is also inconclusive. The most practical way to combat channeling is to design an injection pattern that takes advantage of the in-situ directional conductivity. This concept is becoming common in the poorer quality carbonates of the Permian Basin (for instance, the Permian Clearfork reservoirs). An inverted nine-spot pattern provides channeling protection since it can be easily altered to a line drive. In the Denver Unit project, flood performance to date suggests that horizontal permeability anisotropy is considerably less severe than had been assumed originally — say, an east-west/north-south permeability ratio of 1.3/1.0 in the individual pay members as contrasted with a ratio of 2.0/1.0.

Production Concepts

With the geologic, reservoir, and injection concepts previously discussed as a basis, specific techniques have evolved for well completions and workovers in the Denver Unit. These methods have given the Unit the ability to produce oil at high, sustained rates. The extensive infill program and a continuing workover program involving the expenditure of $160,000/month has provided an opportunity to evaluate different techniques.

Well Completions and Workovers

Items of specific interest include drilling procedures, well depth, zonal separation, perforating, stimulation, scale treatments, and water shutoffs.

The drilling of new San Andres wells presents no mechanical problems, but increased efforts are being made to use mud systems that will yield improved hole rugosity, better logging conditions, better cement jobs, and less formation damage. The desired over-all result is improved completions and wells with a longer mechanical life. The basic system has been to use a simple native mud and to control the water loss to less than 20 cc while drilling the pay interval. Chalk emulsion mud has demonstrated some improvements but has economical limitations. It is planned that for wells drilled in the immediate future salt-saturated brine or oil-base mud will be used.

no vertical communication

A general principle being followed is to be certain that wells are deep enough to exploit all potential pay. New wells have been drilled and cased to a depth about 50 ft below the oil/water contact. Existing open-hole wells have been deepened to a dense section below the contact. A gamma ray-acoustic log combination has been quite useful for correlation.

BACKFLOW admits differential depletion oppty.

Because the reservoir is layered, considerable effort has been made to keep zones separated for proper stimulation and, in the case of new wells, for prevention of "behind the pipe" crossflow for future production control. As explained under "Injection Concepts," separation in new wells is attempted by cementing rough-coated casing through the pay interval, selectively perforating with 20 to 25 widely spaced shots, and stimulating each perforation (or pairs of perforations) between straddle packers at low pressures. In existing open-hole wells, separation is effected by using inflatable straddle packers with a maximum spacing of about 30 ft and stimulating at low pressures. ?? If hole conditions will not permit packer seats (if the hole is washed out or there are many perforations) stimulation is chemically diverted — normally with benzoic acid (in 200- to 300-lb stages, mixed at 1 to 2 lb/gal in gelled carrying fluid).

Perforating is done in acid with casing-carrier select-fire guns using deep-penetrating charges. Perforations are located in correlative porous streaks. The fluid medium is either crude oil or fresh water and there is a pressure overbalance on the formation. (Underbalanced perforating has effected no noticeable improvement.) Most perforations will not take (or give up) fluid before stimulation. It is likely that "breaking down" these perforations, even though cautiously, causes communication behind casing. Statistics indicate that the spacing between sets of perforations must exceed 30 ft to maintain separation.

The basic stimulation fluid in the Denver Unit is 15 percent HCl, containing corrosion inhibitor and a nonemulsifying agent. Higher-strength acid has been used, but results have been no better. Enough acid is used to theoretically stimulate a radius of 5 to 7 ft of porous rock. The amount of acid to inject through each perforation or between open-hole straddle packers is calculated by using porosity and net pay data. Normally, 100 to 150 gal per foot of porosity has given optimum results. All acid is pumped at pressures less than fracture pressure.

If the presence of $CaSO_4$ scale (gyp) is known or suspected, the wellbore is prepared for acidizing by circulating a scale solvent (500 to 1,000 gal) and a hydrocarbon solvent (1,000 to 2,000 gal) by swabbing or by using artificial-lift equipment for 6 to 24 hours. The solutions are then squeezed into the formation and swabbed back before selectively acidizing. Another effective use of the solvents is as a preflush to each acid stage, taking care to separate the scale solvent and acid with water or hydrocarbon pads. Such treatments have proved effective and normally have led to sustained production increases.

Because water is just beginning to break through in certain response producers, our experience with water-location devices as well as with water shutoff is limited. Most Denver Unit production logging has been done with temperature and radioactive-tracer tools to "see" water entry and with tools having electrical circuits to locate oil entry. We recognize that this type of information is open to question because of the well equipment changes required (removal of tubing anchors, raising of the tubing, and perhaps the use of smaller tubing), and because of the difficulty in log interpretation. Nevertheless, it is essential to know where water enters if corrective action on problem wells is to be effective.

Another method being used to help determine probable sources of water breakthrough has been to monitor injection volumes into each zone. A theoretical water-bank radius for each zone in each injector is calculated from profile survey data, cumulative injection, and net pay information. Bubble maps have been constructed by individual zones, thus identifying potential problems. This technique has proved quite useful.

Assuming that the point of water entry has been correctly ascertained, the next step is to shut the water off. Cased and cemented wells allow the use of mechanical devices, individual zone squeezes with cement or chemicals, or, if necessary, complete well shutoff and reopening of the proper zones. The primary problem with any of this type of work is communication behind pipe.

Shutting off water from an open-hole breakthrough presents great problems. To date, only seven attempts have been made in the Denver Unit, and only two have been successful. Fortunately, breakthrough has been in the lower, more permeable zones. Thus far, all shutoff attempts in open hole have been for bottom breakthrough water. Methods used have included: (1) setting an open-hole retainer and pumping small volumes of cement across the offending interval at pressures less than fracture pressure (four tries, two successes), (2) setting an open-hole retainer and capping with Calseal (one try, no success), (3) covering the bottom of the hole with sand (one try, no success), and (4) setting an open-hole retainer and pumping polymer into the suspect zone (one try, no success). Likely causes for failure include the occurrence of down-hole crossflow during the job, excessive selectivity in picking retainer seats or zones to be shut off, and perhaps incorrect log information or interpretation.

Bad would harm well

Artificial Lift

Of salient interest in the production aspects of a waterflood is the lift efficiency of the response producers in the project. It is imperative that the production wells be pumped down to minimize bottom-hole producing pressure and, accordingly, to minimize backflow in the producing wellbore. ** diff deplet. Fig. 11 is an idealized concept of backflow occurring in a Denver Unit producer, with loss or deferral of response oil production as the water fronts continue to advance at varying rates and at different pressures in the individual pay members. To coincide with the major infill drilling program, a study was undertaken to determine the economics of 7-in. vs 5½-in. casing strings as related to lift efficiency. A *kh* (md-ft) contour map was constructed on the basis of pressure falloff tests

in injection wells to delineate areas of high productive capacity; i.e., areas with *kh* values in excess of, say, 500 md-ft. The objectives of the study were to determine (1) gas separation efficiency in the 7-in. and the 5½-in. casing strings, (2) the producing capabilities of the two casing strings in wells of different capacities, and (3) present-value economics of the two strings in high-capacity wells. Data on a number of high-volume pumping wells were analyzed. These data consisted of producing bottom-hole pressures, producing liquid rates, tubing and casing gas rates, dynamometer runs to determine pump fillage, and a statistical correlation of *kh* and producing capacity.

Separation of dispersed gas bubbles is known to be controlled by the downflow liquid velocity in the tubing-casing annulus. With the larger casing size, the downflow liquid velocity can be decreased to assure adequate gas separation for good pump fillage. It was estimated that the average annular downflow liquid velocity had to be approximately 0.3 ft/sec to obtain a bottom-hole producing pressure of about 200 psi. A 5½-in. cased well with production rates in excess of 400 B/D cannot be produced at bottom-hole pressures lower than some 200 psi. From outflow performance curves for 7-in. and 5½-in. casing strings, oil production is accelerated by using 7-in. casing. On the basis of this analysis, most of the new infill producers are being cased with 7-in. strings. A statistical analysis of lift performance indicated that approximately 70 percent of all wells in the Unit that have 5½-in. production casing strings and that are currently pumping in excess of 300 B/D of gross fluid have fluid levels of 2,000 ft or more above the pump. (It is recognized that some of the fluid at these levels may be foamy.) By contrast, some 65 percent of all wells cased with 7-in. strings have pumped-down fluid levels at pumping rates of 400 to 500 lb of gross fluid per day. Gas/liquid ratios in excess of 500 cu ft/bbl have tended to reduce pumping capacity in the 5½-in. cased holes, whereas the 7-in. cased holes do not show this detrimental effect at GLR's up to 1,000 cu ft/bbl.

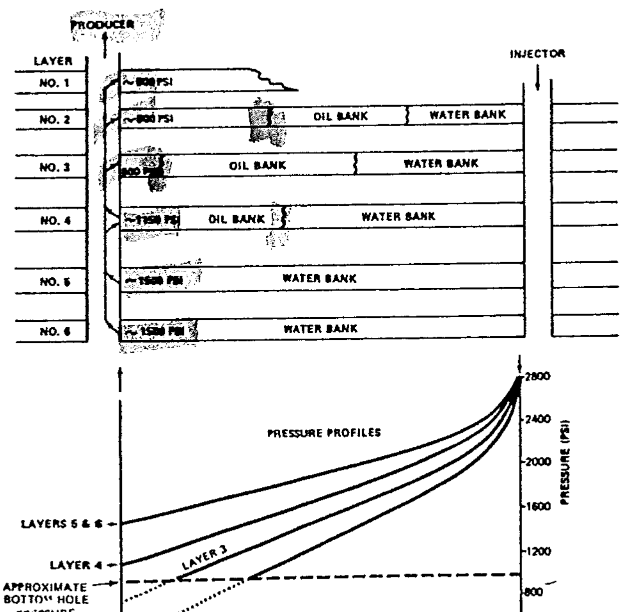


Fig. 11—Idealized concept of backflow at producing wellbore with high backpressure.

Another new approach that has permitted better natural down-hole gas separation is to drill and case infill producers to a depth below the oil/water contact, thus providing a sump in which to place the pump (Fig. 9). Extensive deepening of existing open-hole producers has accomplished the same purpose while insuring that all oil-bearing pay is open to production.

Poorman gas anchors (a 30-ft-long, 4-in. slotted pipe with a 20-ft-long, 2-in. dip tube or 3-in. slotted pipe with a 1½-in. dip tube) have been used extensively. Their utility, however, is still open to question. Scale buildup in certain wells would imply that an additional pressure drop can occur at the anchor. Also, diagnostic sucker-rod techniques and equipment changes have indicated that as the GOR decreases and fluid production increases, this type of anchor can restrict the flow of liquid to the pump. As wells respond, a general policy now is to replace the Poorman anchor with a simple 4-ft mud anchor and place the pump very near bottom. Production has increased significantly.

Because waterflood production varies widely with time, from well to well, in volume, and in type of fluid produced, and because average per-well productivity was estimated to be 500 to 600 BFPD at an average well depth of 5,100 ft, the decision to use beam pumping equipment was straightforward. It was recognized that higher-volume wells and Denver City townsite wells would require submersible pumping for efficiency and safety, and for ecological soundness.

The sucker-rod pumping installations were designed in conformance with techniques developed by Shell Development Co. and later published in API Bulletin 11L3. By mathematically simulating pumping conditions, load and stress ranges and torques could be calculated for any point in the system for a given set of producing conditions if a conventional prime mover was used. This design method, modified by considering the calculated inertial torque available by using high-slip electric motors as prime movers (discussed below), resulted in the following size recommendations:

Liquid Rate (B/D)	Beam Size	Pump Size (in.)	Strokes Per Minute	Stroke Length (in.)
300	228-246-76	2	14	74
400	320-246-86	2	15	86
500	456-304-120	2	13	120
600	640-304-144	2¼	11	144

Gradient = 0.45 psi/ft
Life depth = 5,000 ft
Efficiency = 65 percent
Rod string = 3 taper (1-in. to ⅞ in. to ¾ in.)

More than 60 percent of the beam units in operation now are API 456 or 640 units. Most of the units purchased in 1972 and to be purchased in the future are 640's.

High-slip electric motors are extensively used as

prime movers in the Denver Unit; 460 are currently in service. Field tests indicated that these motors allow, for specific designs, the use of a gear box one API size smaller than would normally be required. This reduces capital costs of new installations. Another advantage is less severe rod loading and hence longer rod life because of reduced acceleration of the rod string. Inasmuch as the use of the high-slip motors is relatively new, a detailed discussion of operating principles and experience follows.

A properly designed beam pumping system equipped with a high-slip motor can yield a 20- to 35-percent motor speed change (slip), as torque loads on the motor and gear reducer increase. This change in speed allows the rotating counterbalance masses (cranks and weights) to decelerate. As these masses decelerate, they yield kinetic energy and torque, helping to drive the rod string. The torque derived from the decelerating counterbalance masses is not transmitted through the gear reducer. Thus, the gear reducer needs to be large enough only to transmit the torque from the motor (passing through the reducer) to the rod string.

Maximum reduction of gear box torque is achieved by (1) increasing the inertial torque of all rotating masses on the polished rod side of the reducer, (2) decreasing the inertial torque of all rotating masses on the prime mover side of the reducer, and (3) using a prime mover that allows maximum slip. Item 1 is accomplished by using the longest practical crank arms and counterbalance weights, and locating them as near the end of the arms as possible. Because rotating inertia is proportional to the radius squared, maximum crank-counterbalance inertia may be obtained by always placing one counterbalance weight at the end of the crank arm and adjusting the other weight to attain balance. Item 2 is accomplished by using the smallest possible motor and unit sheaves.

As mentioned previously, the torque characteristics of a high-slip motor-beam system results in less severe rod loading. Peak rod stress and peak torque often occur nearly simultaneously. Because the high-slip motor decelerates during peak torque periods, the upward as well as the downward acceleration and velocity of the rod string are reduced. This results in lower peak rod stress and higher minimum rod stress; a 10 to 15 percent reduction of rod stress range has been measured in many installations. This reduction should prolong rod life and reduce repair costs.

Experience with high-slip motor-beam installations in the Denver Unit has revealed evidence of some gear-box overloading. A study of beam unit torsional loading suggests that these conditions are due largely to a lack of accurate surveillance tools to determine the actual gear-reducer torque. Used in this study to evaluate torque were (1) direct measurements with strain gauges, (2) torque factor calculations including inertial torque, and (3) the sucker-rod diagnostic analysis.

The Shell Development torque measurement technique (Method 2 above) utilizes strain gauges mounted on the gear box output shaft. A small FM transmitter (mounted on and rotating with the shaft) sends the strain gauge signal through a loop antenna (attached to the gear-box housing) to a strip recorder. Precise, recorded measurements of gear-reducer torque can be made from start-up, continuing throughout the pumping cycle. It was interesting to observe in the Denver Unit measurements that the maximum gear-reducer torque during the starting cycle was not significantly different from that during the normal cycle. The practice of pumping in short cycles (stopping the pumping unit once every 15 minutes) did not impose any significant overload torque on the gear reducer. It was also learned that under stabilized operating conditions the pumping units should be counterbalanced in such a way that the downstroke motor current is equal to or as much as 5 percent greater than the upstroke motor current. The purpose of this is to prevent unnecessarily overloading the gear reducer.

Gear-reducer torque was also calculated from torque factors, applying the inertia of the rotating cranks and counterbalances to the API torque formula. Data used were manufacturer's polished-rod position and torque factor data, a continuous strip chart of polished-rod load and displacement, and a strip chart of motor speed. Peak torque could not be calculated precisely by this method because the manufacturer's data are published for only each 15 degrees of crank rotation. A few degrees of error in crank position in the peak torque portion of the stroke can result in a significant error because the torque factor and counterbalance effect change rapidly. This method would be more accurate if manufacturer's data were published for each degree of crank position. Additional work is being done to include the rotating inertia of the pumping unit gears and the articulating inertia of the pitmans, beam, etc., in the gear-reducer torque calculations. Articulating inertia might counteract as much as 25 percent of the rotating inertia.

The gear-reducer peak torque calculations of the standard Shell diagnostic technique have been found unreliable when the unit is equipped with a high-slip motor. Torque factors calculated by the program are disparate because of the variations in polished-rod velocity as the motor changes speed during the stroke and because the polished rod and counterbalance get out of phase when the upstroke and downstroke times are unequal. Mathematics for high-slip motors is being incorporated into this diagnostic technique.

The results of our torsional loading study show that we currently have no practical, reliable torsional analysis method for the routine surveillance of pumping units equipped with high-slip motors. The Shell Development strain gauge method is precise, but is too time consuming for frequent use. Therefore, for routine pumping unit torque surveillance, the Permissible Load concept as proposed by Bethlehem Supply has been adopted. Permissible Load is defined as the difference between the maximum and minimum polished-rod load (PRL) before the torque capability of the gear box is exceeded. Table 1, which gives permissible loads for Denver Unit pumps equipped with high-slip motors, is currently in use.

Rod strings are designed using the same mathematics mentioned above. A 5,000-ft Denver Unit string might include 1,350 ft of 1-in. rods, 1,550 ft

of ⅞-in. rods, and 2,100 ft of ¾-in. rods. Class KD rods (1.5 to 2.0 percent nickel for corrosion protection) are used. Industry-established proper rod handling techniques are employed, and rod problems to date have been minimal. (One continuous rod string is being field-tested now.)

Because of the large number of beam pump installations, the increasing amount of fluid being lifted (current average: 300 BFPD/well), gas interference, and pump corrosion, down-hole pump changes are numerous. Early pump seating problems were corrected by exclusively using API seating nipples. Redesign of the collet adapter also overcame a failure problem experienced in initial installations. Corrosion is being counteracted by coating pumps with paint-on inhibitor. A seemingly undue number of cases of pump sticking and bent barrels have occurred. These problems occur most frequently in newly stimulated wells — possibly as a result of an initial inflow of formation fines and solids from wellbore buildups of scale and hydrocarbons. Remedies being tried include increasing pump clearances to 0.004 to 0.005 in., using chrome-lined barrels, and using plunger shields.

Large volumes of fluid inflow from waterflood response producers can exceed the lift capacity of beam pumping systems. Advances in well surveillance methods and equipment innovations have led to the increased use of submersible (down-hole electric centrifugal) pumping systems. Submersible pumping is best suited to high-volume, low-GLR wells at relatively shallow depths under moderate temperature, pressure, and corrosion conditions. Initial capital cost for a submersible installation is usually less than for a long-stroke (144-in. or greater) beam pumping unit with a high-torque-rated (640,000 in.-lb or greater) gearbox. In environmentally sensitive areas, submersible installations have been preferred over beam installations for safety and aesthetic reasons.

Currently there are 14 submersible pump installations in the Denver Unit. Nine of the units were installed originally in 1970. An additional five units were installed in late 1972. The over-all performance and especially the recent performance of these units has been good. The average run time between failures (for six of the original nine units that have failed at least once) has been 388 days (1.1 years). This average includes several unduly short runs in three of these wells caused either by continued operation of oversized units or by inferior power cables — problems that are discussed below and are being corrected. For the three units that have not had sizing or cable problems, average run time between failures has been 680 days (1.9 years). The longest pump run to date has been 1,202 days (3.3 years).

Several problems have hampered or limited the use of submersible pumps in the Denver Unit. Perhaps the most important problem is that submersible systems are designed to pump efficiently only in relatively narrow ranges of fluid volume and pressure gradient. For continued successful operation, therefore, a submersible outflow system must be designed to closely match the well inflow. This inflexibility presents problems under waterflood conditions because inflow performance parameters such as reservoir pressure, GLR, and water cut are continually changing. If inflow performance is miscalculated or if it changes significantly with time, the submersible system should be replaced by one of more suitable capacity to prevent early and expensive failure. Our experience indicates that a straight-line PI (productivity index) adequately describes inflow performance above bubble-point pressure. The Vogel IPR equation best describes inflow performance below the bubble point.

Another significant submersible pumping problem has been that of inadequate gas separation in high-GLR wells (greater than 1,000 cu ft/bbl). As currently designed, submersible pumps are susceptible to "gas locking." This causes the unit to shut down and then restart after a programmable time has elapsed. Cycling causes undue wear on motor and pump, thus is a common cause of low fluid production and early unit failure.

The best solution to gas separation problems in most artificial-lift systems has been to locate the pump intake a practical distance below the producing interval. This is not easy to achieve with a submersible pump. For proper operation, the unit requires the cooling effect of continuous down-hole fluid movement past the motor. To move the unit below the producing interval, a "shroud" must be placed around the unit to divert fluid past the motor before it reaches the pump intake. Wellbore diameters less than 7 in. will not permit adding this shroud. In open-hole completions below 7-in. or smaller casing, a unit of suitable lift capacity is usually too large for the wellbore. Because of the motor cooling requirement and wellbore size restrictions, submersible units have been placed above the producing interval. In this position, any gas separation attained must be mostly mechanical. Suppliers of submersible pumps have developed mechanical, generally cup-type gas separators. Under producing conditions in high-GLR wells, these separators have failed to eliminate the gas locking problem.

TABLE 1—PERMISSIBLE LOADS FOR DENVER UNIT BEAM UNITS
(Operating with high-slip motor)

Unit	Stroke Length (in.)	Permissible Load (lb)	Maximum Allowable PRL (lb)
640-304-144*	144	17,500	22,000
456-304-144*	144	12,000	17,500
456-304-144	124, 122½,	15,000	20,500
456-304-120	or 120		
320-256-100	100	13,000	19,000
320-256-100	89, 86, 85	16,000	20,000
320-246-86			
228-246-86	74	14,000	19,000
228-200-74			
160-200-74	64	13,000	17,000
160-200-64			

NOTE: Torque on the unit should be checked if the difference between the maximum PRL and the minimum PRL exceeds the permissible load. Torque should also be checked if maximum PRL exceeds maximum allowable PRL value, even though Permissible Load may be in limits.

*For American 640-304-144 and 456-304-144 units with the TF-143, TF-143H, or TF-143J cranks and Lufkin units.

Good submersible pump operation requires efficient down-hole gas separation, a condition difficult to achieve. Recently, a centrifugal gas separator has been developed. The separator section takes the gas-liquid mixture in and centrifugally separates it into a gas column and a liquid column by means of an impeller connected to the main pump drive shaft. The impeller then directs the gas column through ports to the pump-casing annulus and feeds the liquid to the first pump stage. This separator was successfully field tested in a 1,500-GLR Denver Unit well with a history of submersible gas lock and cycling problems. The centrifugal separator eliminated the gas-locking and cycling problem and allowed a 30 percent increase in oil production. Submersible units in several more Denver Unit producers are being equipped with this gas separator for further field testing. Successful development and testing of this separator may extend submersible capabilities to higher-GLR wells.

The unreliability of the submersible power cable has been a problem. Early power cables, constructed with low-density rubber or polyethylene insulation, could be invaded by gas or well fluids, causing electrical shortouts and motor failures. Low-density polyethylene insulated cable in three 1970 Denver Unit installations failed within 6 months, apparently as a result of gas invasion. Currently used electrical power cables for submersible pumps incorporate copper conductors with either polypropylene-ethylene or polynitrile insulation protected by galvanized steel tape-interlock armor. Cables of this type normally withstand temperatures up to 180°F and pressures up to 2,500 psi in moderate corrosion environments. We have had no significant problems or failures with these newer cables.

Chemical Concepts

Chemically oriented problems that require attention in the Denver Unit include corrosion, scale, and poor water quality.

Corrosion is being effectively controlled without large expenditures for continuing chemical inhibition programs because effort was concentrated early on coatings and metallurgy. Flow lines and valves are protected with epoxies, polyester-modified epoxies, epoxy-modified phenolics, or polyurethane coatings. Injection tubing is coated with polyvinyl chloride plastic and injection lines have cement lining. Interiors of tanks and treatment vessels are coated with zinc-filled epoxy paint. In production wells, corrosion-resistant Class KD rods are used, and down-hole rod pumps are protected with a commercial paint-on inhibitor. The degree of corrosion experienced to date does not warrant an extensive program of pumping chemicals down the tubing-casing annulus.

Cathodic protection has had limited use. Wellheads and casing strings have not been cathodically protected, mainly because of poor experience elsewhere in Shell's operations. Spurious potentials have caused deleterious corrosion effects on other lines and equipment in the vicinity of the cathodically protected wells.

External corrosion of new casing strings in both injection and production wells is now being prevented by cementing to the surface. More than 100 casing failures have occurred in the existing wells unprotected by a cement sheath. Repair consists of cement squeezes in 5½-in. casing and squeezes or 5-in. liner installations in 7-in. casing (depending on over-all casing condition as determined by inspection logs). A few wells have been irreparably damaged and will need replacement.

Internal corrosion of casing above the packer in injection wells is guarded against by placing inhibited fluids in the tubing-casing annulus. However, the problem of insuring long life of the casing across the injection interval (a necessity if attempting to maintain segregated zones) has required other solutions because the makeup injection water is oxygen saturated. A recent, significant development introduced in the Denver Unit has been the use of fiber glass liners and casing strings (3½, 4½, 5½, and 7 in. in diameter) cemented across the pay interval to provide zonal separation and to control both corrosion and fill. Handled very similarly to steel, fiber glass strings are being installed in both new wells and existing open-hole injection wells; to date, 122 of 238 injectors have been so equipped. Completion techniques differ little from those in steel-cased wells except that cup straddle packers instead of slip-type packers are used during stimulation. The injection packers set in fiber glass are cup type and inflatable type.

The formation of scale is seemingly inevitable in a waterflood, and the Denver Unit is no exception. Comparatively, the problem is not severe, although significant reductions in production have occurred in localized areas, and the presence of scale is increasing as more of the Unit responds. In passing through the San Andres formation, the injection water becomes saturated with $CaSO_4$ (gyp), and the drop in pressure and temperature at wellbores in which the pressure is being drawn down for efficient production is often sufficient to cause precipitation. Calcium carbonate and iron sulfide scales usually occur simultaneously, although in lesser amounts. As discussed under "Production Concepts," chemicals designed to remove the gyp, followed by acid, will restore production. Recently, water samples were collected from every producer making measurable water. This survey has (1) located the wells with scaling tendencies, (2) provided a basis for preventive measure studies and more effective remedies, and (3) given base data for monitoring water breakthrough. Scale inhibitors thus far have been used only experimentally. Introduction of chemicals into the annulus of all production wells is not economically warranted in this flood, particularly since many wells cannot be pumped down enough for the inhibitor to effectively contact the producing interval and equipment. The squeeze technique, by experience and laboratory test, has not yet proved suitable. The inhibitors return to the wellbore too rapidly to give lasting protection and, even more significant, form precipitates that may seriously damage formation permeability. Prevention of scale is foremost in our minds, and experimentation will continue.

Injection water quality has always been of interest, but it has assumed a much greater importance with an increased need for larger volumes of water. Water

quality becomes more critical as reservoirs of poorer quality are placed under flood because such reservoirs are more susceptible to plugging both with precipitates and with carried solids. Denver Unit makeup injection water is excellent quality Ogalalla water that is chlorinated and passed through desanders; accordingly, few problems have been encountered to date. However, as a protective measure, all fresh-water injectors in the Unit are equipped with a 50-micron mesh filter at the wellhead.

Surveillance Concepts

Waterfloods require constant, detailed surveillance. The need is compounded in a project as large as the Denver Unit. Therefore, computer programs are advantageously used for a wide range of surveillance applications to pinpoint significant changes. Individual well production tests are computer-arranged in sequences of ascending or descending oil rates, water cut, and GOR. Individual well performance curves are generated by a computer-controlled drum plotter from data stored in computer history files. Prepared periodically are bubble maps of injection water bank radii based on computer calculations from injection and profile history data stored in these files. Reservoir voidage resulting from production is computer-calculated by well, pattern, and project, and compared with injection volumes. The GOR's of all production wells are checked monthly with those of wells having GOR's exceeding 3,000 cu ft/bbl or having increasing GOR trends shut in to await either remedial action or drive response.

Surveillance of the sucker-rod pumping installations is carried out by keeping accurate production records, by regularly checking sonic fluid levels, by studying well-pulling records, and by using the sucker-rod diagnostic technique. Each month, 20 to 25 of these diagnostic surveys are run, and at least 75 percent result in profitable equipment change recommendations. Continuous motor-amp charts, fluid levels, and bottom-hole pressure device readings taken in conjunction with production tests are used for routine surveillance of submersible pump installations. These data are used to monitor the inflow performance of the well and its effect on the submersible pump outflow performance.

Summary

The evolution of carbonate waterflooding in engineering design and execution has been presented, using the West Texas Denver Unit waterflood (one of the largest supplemental projects currently operating in the U.S.) as an example. If the reader can glean from this paper innovations or procedures applicable to his own supplemental recovery operations, the purpose of the paper will have been served.

Acknowledgments

We wish to thank the management of Shell Oil Co. for permission to publish this paper. Acknowledgment is also due our many engineering colleagues who have been or are currently associated with the project. Among them are G. W. Keys, K. S. Lee, J. H. Bowers, P. D. Hinrichs, L. Batchelor, G. B. Mayfield, R. J. Savoie, and J. W. Hughes. Additionally, we have drawn extensively from the petroleum literature, and are likewise indebted to the many contributors to the art of waterflooding. **JPT**

Original manuscript received in Society of Petroleum Engineers office July 30, 1973. Revised manuscript received March 11, 1974. Paper (SPE 4683) was presented at SPE-AIME 48th Annual Fall Meeting, held in Las Vegas, Nev., Sept. 30-Oct. 3, 1973.

J. F. Griggs
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Team redevelopment a success at Illinois' Tilden reef reservoir

Steven E. Baker Philip H. Carlisle *Deminex U.S. Oil Co. Dallas*

The purpose of this paper is to demonstrate a successful redevelopment of a mature oil field.

The subject field, originally developed in the 1950s, is a heterogeneous reef reservoir that has been re-evaluated using a team approach.

The reservoir management team combines the geological and engineering disciplines to understand the complexities of the reef, and to apply new technical thinking to drilling location selection, completion design, and remedial activity.

Recent activity, using this technique, has resulted in a substantial field production increase.

Regional setting

Some of the most intriguing yet elusive targets in the Illinois basin are the reefs of mostly Silurian age found in what is often thought of as the basin's hingeline trend.

Studies of reefs in the basin indicate growth originated during deposition of the St. Clair (Niagaran) and continued during deposition of the Moccasin Springs (Niagaran) and into the Upper Silurian Bailey (Cayugan) and possibly into Lower Devonian. Regressive Devonian seas ended reef growth along the rim of the basin.

A number of younger sediments produce from structural closure caused by drape over Silurian reefs. About 92 million bbl of oil has been produced from the Silurian and associated drape structures of Mississippian and Pennsylvanian age. Many reefs have multiple producing zones associated with them.

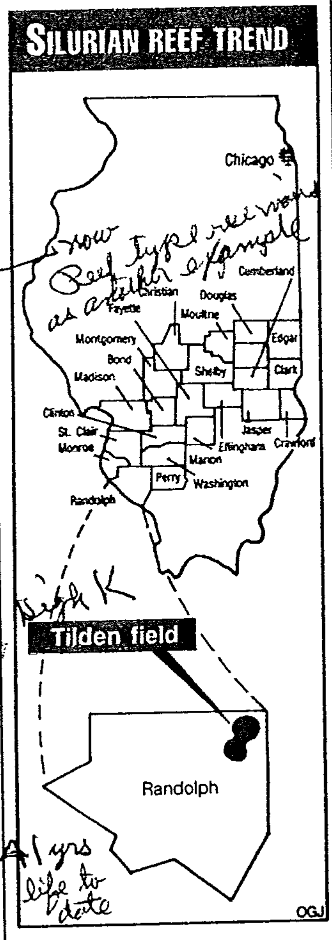
Tilden field is in 4s-5w in Randolph County, Ill., near the updip limits of producing reefs, on the westernmost edge of the Illinois basin (Fig. 1).

Tilden is one of Illinois' most prolific Silurian fields, largely due to its geographical position while post depositional forces acted upon the reef causing secondary porosity that has enhanced productivity. Sixty wells have produced oil from the Silurian age reservoirs associated with the Tilden reef, and more than 5 million bbl of oil have been produced since its discovery in 1951 by Jet Oil Co., predecessor to Deminex U.S. Oil Co.

41 yrs life to date

The exploration method leading to the discovery of Tilden field was the subsurface mapping and subsequent evaluation by drilling a structural high on the No. 6 coal. Jet used this method to evaluate as many as 60 anomalously high coal structures before the Tilden discovery.

Fig. 1



Show Reef type reservoir as another example

High K

Tilden field's development history can be divided into two periods. The first is the original development of the field by Jet, and the second period is the modern redevelopment initiated by Deminex in 1984.

Earlier development

The discovery well, the Jet 1 Carl Easdale, was completed pumping oil at the rate of 65 b/d in October 1951 after a 250 gal acid treatment.

By the end of 1953, 26 producing wells drilled on 20 acre spacing had been completed. Initial potentials ranged from a low of 7 b/d in an edge well to a high of 600 b/d in a reef core well.

Development drilling continued, consisting mainly of step-out drilling and the deepening of existing wells. Seven additional producing wells were completed. Initial potentials of these new wells, with one exception, were less than 50 b/d. Most of the new wells were in flank positions, and due to their relatively disappointing results the field was considered fully developed.

Additional production was later discovered within the existing wells. The step-out flank position wells were drilled deeper than the reef

core wells due to their structural position.

Hydrocarbon shows were noted to depths of nearly 2,300 ft (approximately −1,800 ft subsea). A subsea of -1,800 ft was assumed as the fieldwide oil-water contact.

In the late 1950s a deepening program was commenced that continued for about 10 years. During this period, 13 wells [redacted] Before being placed on pump, the wells were [redacted]

Through the 1970s and early 1980s the operator directed its attention to other areas, and Tilden field production followed a normal decline. By mid 1984, field production had declined below 90 b/d.

1980s redevelopment

[redacted]

Reservoir evaluations indicated that [redacted] that the field had been developed on. Three 10 acre wells were drilled in late 1984 with encouraging results.

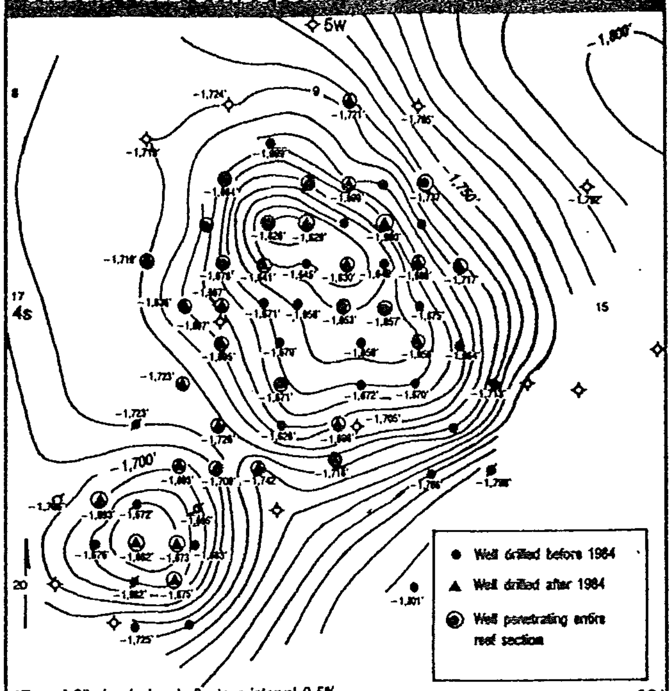
[redacted] (Fig. 2). Two of the 10 acre infill wells were successful with initial potentials in excess of 50 b/d, but the flank wells drilled had relatively poor results.

Information gained from initial redevelopment suggested 10 acre spacing was more appropriate for field development. Therefore, two additional development wells were drilled in late 1987 followed by two more in mid-1988.

During the 1988 program, a reservoir management team was assembled consisting of a geologist and a petroleum engineer. The team [redacted] to drilling location selection and completion practices.

Fig. 2

TILDEN FIELD STRUCTURE*



*Top of Silurian (subsea). Contour interval 0.5%

In early 1989, a thorough review of completion practices resulted in major changes in completion techniques.

The combination of improved drilling location selection through an understanding of the reef complexities and improved completion techniques has since led to several successful infill reef core and step-out locations with a total of eight wells being drilled.

Geologic modeling and detailed log analysis have also led to [redacted] Fig. 3 shows total field production through mid-1991.

Reef geology

The Tilden reef is more than [redacted] its core.

The productive core and its associated detrital debris extend laterally for approximately 1,200 acres, although few productive boundaries have been found. More than 100 ft of structural closure is present on top of Silurian.

The pinnacle reef is reflected as structural highs in the overlying sediments. Immediately above the Silurian age reef is a thin (less than 10 ft) interval of New Albany shale. A major source of hydrocarbons is present in this extremely organic rich shale.

Above the New Albany shale, another thin (also less than 10 ft) layer of Chouteau lime is overlain by a 350 plus ft section of Borden siltstone. This sequence of rocks provides an excellent vertical seal to trap hydrocarbons within the underlying Silurian. Lateral seals are provided by the presence of tight non-reef cherty limes.

During reef building, framebuilders adapt to sea level changes and localized areas of preferred development occur within the reef core and the flanks. As the reef core grows higher, the flanks begin to receive large amounts of reef-rubble conglomerate, especially during large storms.

Core analysis indicates that reef core organisms colonized in localized patches with varying intensities. As environmental conditions changed, adaptation occurred, resulting in diversification or possibly a reduction in the number and type of species. This has had significant effects on creating localized areas of primary porosity within the Tilden reef. [redacted]

[redacted] tant role in creating significant reservoir potential within the Tilden reef. [redacted] Cave travertine and banded calcite is evident in a number of cores.

[redacted]. Caliche zones are evident in several cores, and samples often indicate fairly major periods of weathering occurred. This led to compartmentalized reservoirs of varying lateral and [redacted]

Significant fracturing occurred as a result of subsidence and differential compaction. Fracturing created fluid migration pathways throughout the reef.

Evidence in cores suggests considerable primary and secondary porosity was destroyed by post depositional fluid migration. Vadose deposition occurred throughout the reef building process, creating large cavities where sediment infill occurred. Secondary calcite healed fractures and filled pore spaces.

The upper 100 ft of the reef has some of the best preserved primary porosity. This could largely be due to the growth of the frame building organisms during the late Silurian and into the early Devonian being truncated by the regressing Devonian seas. A period of non-deposition occurred during early to middle Devonian. The original matrix porosity was not as adversely affected and secondary porosity was enhanced during this period.

Lithologic correlations are difficult in a reef environ-

Fig. 3

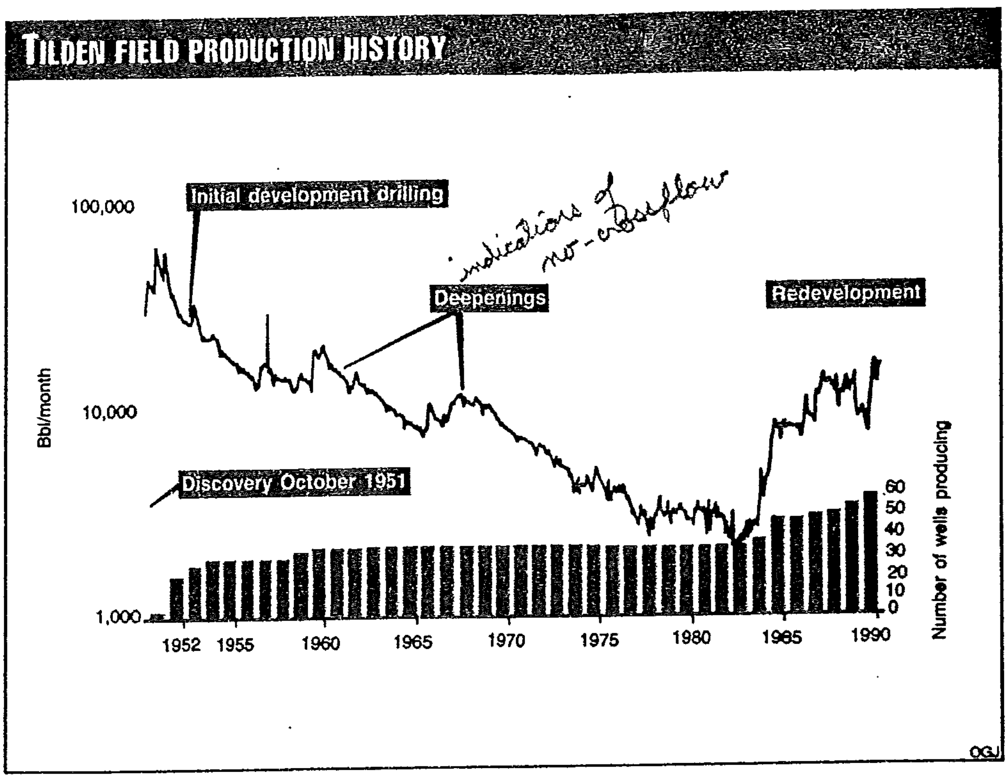
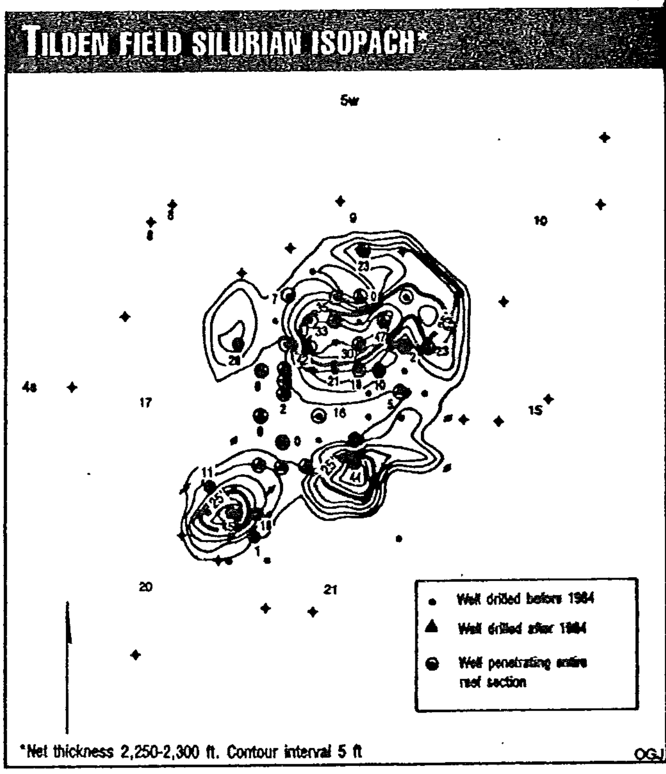


Fig. 4



*Net thickness 2,250-2,300 ft. Contour interval 5 ft

ment without the aid of detailed studies. Although core studies are helpful in understanding localized vertical stratigraphy, lateral changes occur so rapidly that the horizontal resolution is almost limited to core diameter.

Because lateral variations are so significant, production data have been used as an aid in understanding the geologic complexities. Correlations made using logs, cores, and samples are highly interpretive. When supported by well production history data, verification of expected reservoir continuity or discontinuity can often be confirmed.

Cores were taken on all pre-1984 wells. Generally, fossil assemblages were described in limited detail, so meaningful lithologic correlation is difficult using this information. The main objective in coring wells during original field development was to aid in making pipe setting decisions.

Recent development has been done without cores. Sample analysis identifies general lithologic changes, although detailed analysis can only be made from cores. Fossil assemblages are difficult to identify in samples, making recognition possible only to those highly skilled in analysis. Samples are collected and evaluated every 10 ft through the reef. A sample log is prepared indicating general lithologic descriptions, drilling time, fluorescence, and cut.

Development history

Original wells

Tilden field's original development wells were drilled to the top of the reef and cored 50-75 ft into the reef. The production casing was set at the top of the reef, and the [redacted]

The completion consisted of drilling out the shoe with cable tools and swabbing the well to allow it to clean up before placing it on pump. Some wells were capable of flowing for a short time before being placed on pump.

If the production rate was insufficient, the wells were [redacted] Wells that did not initially require stimulation were also subsequently acidized with good results.

Early Deminex work

The post-1984 wells at Tilden were drilled and [redacted]

The wells were perforated and acidized in one to three stages using a retrievable bridge plug to separate the intervals for acid breakdown treatments [redacted] as one [redacted]

The fracture treatments consisted of high rate (40 bbl/min downhole rate) foam sand fracs. An average treatment consisted of 60,000 gal of 75 quality nitrogen/gelled water foam carrying 60,000-80,000 lb. of 20/40 or 12/20 mesh sand.

The wells were flowed back, cleaned out, and put on pump. The average well had an initial potential of 20-40 b/d [redacted]

Later development

Development wells drilled more recently benefited from improved location selection and completion techniques.

New well locations based on geologic modeling [redacted]

lation techniques, namely fracture acidizing, have led to higher initial potentials and faster payout times.

Drillsite selection

Open hole analysis. One of the keys to development at Tilden has been wellsite geology.

During the original development, wellsite observations of cores were used almost exclusively for pipe setting decisions. Today, modern logs replace much of the information provided by cores, but wellsite analysis of cuttings for lithology and hydrocarbon show are still important to pipe setting and completion design decisions.

Modern logs have made a significant impact on Tilden redevelopment. Modern logs provide the ability to [redacted] provide detail [redacted] oil in place for a particular well or interval. This ability has enhanced location selection by providing the tools necessary to "model" the field.

Tilden development wells currently use four logging passes. The first pass consists of a dual induction, spontaneous potential, and gamma ray. The second pass consists of a compensated density, compensated neutron, microlog, caliper, and gamma ray. The third pass is a dielectric used to help distinguish productive intervals from water bearing intervals, while the fourth pass is a dipmeter used to help select offset locations.

(in flooded field would not perf. high K swept layer

Long-spaced acoustic logs were run during 1989 and 1990 primarily to make rock property and frac-height calculations. These logs were important to the completion practice study performed in 1989. They are no longer run because fracture property information was found to be fairly consistent throughout the field. This consistency is probably due to the homogeneous nature of the rock material itself since the frac-height calculations are unable to account for heterogeneities caused by secondary porosity.

The dipmeter has replaced the acoustic log particularly in the step-out or reef edge locations. The dipmeter information is important in these wells to assist in defining depositional environments as well as aiding completion interval selection. Offset locations, especially step-outs, are then further defined without the additional expense and risk of coring.

Reservoir evaluation. One of the major obstacles in evaluating the reservoir has been the [redacted] Therefore, being able [redacted]quately address the heterogeneity of the field has been difficult.

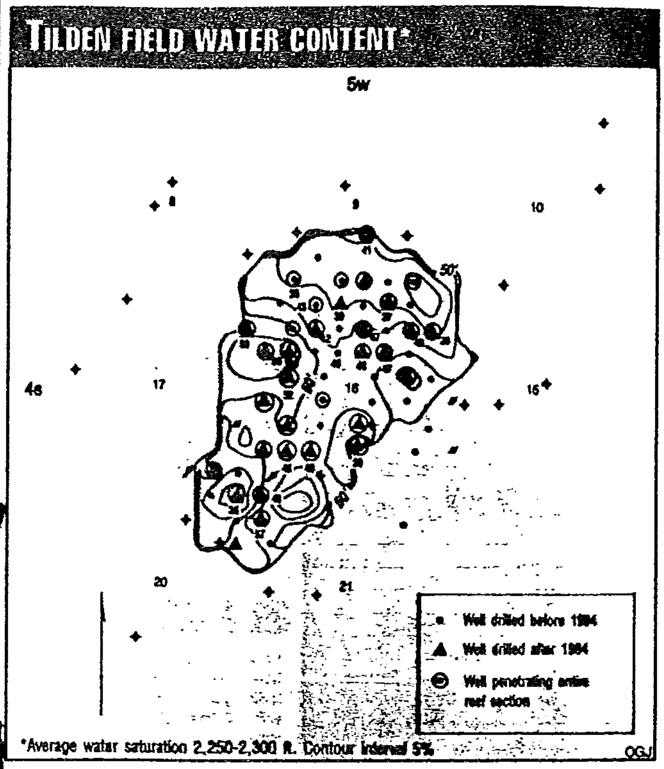
The creation of a digital database was considered to be critical in trying [redacted] Digitizing log data for a personal computer based log analysis package was the first step in creating a detailed database.

A large percentage of the development wells at Tilden are modern (post-1984) and are well dispersed throughout the field (Fig. 2). Old logs are used in a qualitative manner, i.e. to determine if a well or interval is in a reservoir identified by the isopach mapping. Core descriptions are more useful in identifying porous oil reservoirs that can be correlated to isopach mapping.

Digital land grid data was imported into a PC based mapping and software package. Well locations and basic well data were also input into the mapping package.

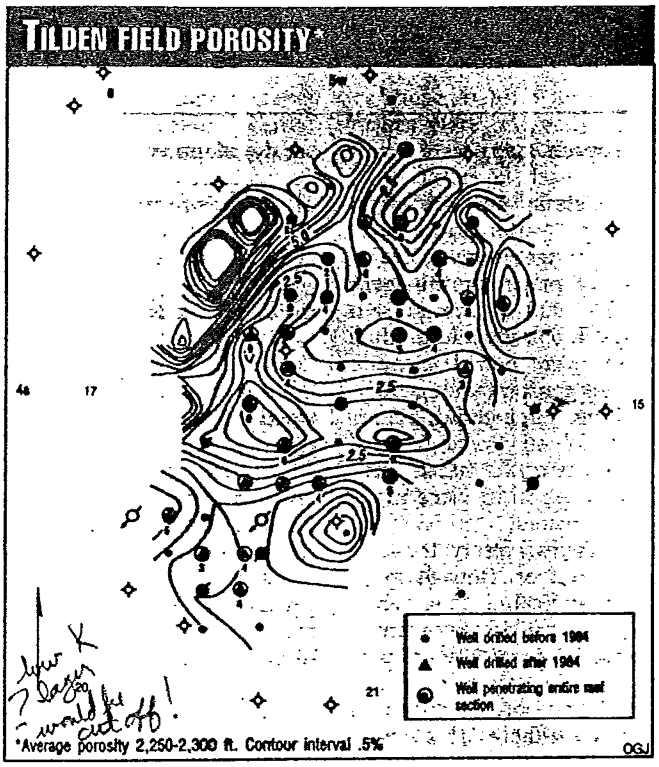
After the database had been established, base case parameters and [redacted] The cut-offs were based on observations made from recent completions, in particular, the 1989 completions that had been thoroughly production tested. Detailed log analysis was performed on each well for net pay thickness, average water saturation, and average porosity.

Fig. 5



*Average water saturation 2,250-2,300 ft. Contour interval 5%

Fig. 6



*Average porosity 2,250-2,300 ft. Contour interval .5%

The results were then imported into the mapping software.

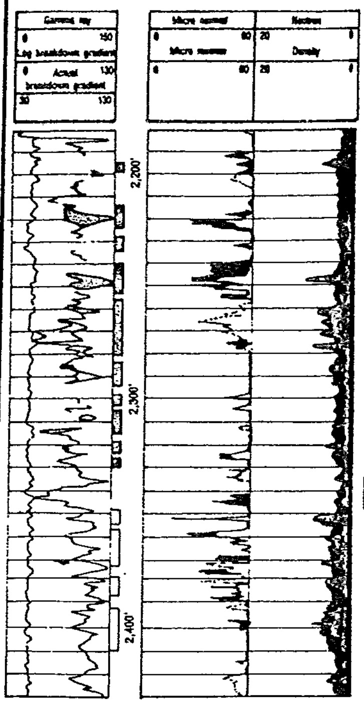
Isopach maps are used to identify individual reservoirs and [redacted]

tion at Tilden, a method had to be devised to account for the lateral discontinuity of each reservoir. The solution was to [redacted] The reef [redacted]

What up! all about.

Fig. 7

ACTUAL VS. PREDICTED BREAKDOWN PRESSURES



15 C. Easdale
NE NW NE 16-4s-5w

Upper Silurian

Perforated at 2,194-2,330' with 106 holes overall; breakdown treatment 3,500 gal 15% HCl selectively; frac with 31,000 gal crosslinked gelled water, 15,000 gal 20% & 15% HCl

Middle Silurian

Perforated at 2,349-2,409' with 53 holes overall; breakdown treatment 2,500 gal 15% HCl selectively; frac with 15,000 gal crosslinked gelled water, 8,000 gal 20% and 15% HCl

Commingled initial potential 126 b/d of oil, 189 b/d of water, and 76 Mcfd of gas

OGJ

Isopach maps were created for each layer for three parameters; net thickness, average water saturation, and average porosity. Examples of maps for the layer 2,250-2,300 ft are shown (Figs. 4, 5, and 6). Individual maps were edited to more closely conform with geological and engineering principles. When the individual layer isopach maps were complete, oil in place maps were created.

Individual reservoir analysis based on isopach mapping indicated that while some reservoirs have lateral extent, the majority are productive in only a few wells and some only produce in a single wellbore. This observation is not surprising because of the complexity of the field and randomness of reservoir distribution.

Individual reservoirs were correlated with modern open-hole logs in stratigraphic cross-sections. Once the correlation between wells is made, additional offset development drilling can be analyzed on an oil-in-place basis for the reservoirs that would not likely have been penetrated.

Completion techniques

Multiple stage completions. All phases of completions were reviewed and revised by the reservoir management team.

Because geologic input and interpretation of detailed well log analysis [redacted] The first multiple stage completions were individually tested to determine the effectiveness of the technique. [redacted] Different pressure regimes observed in the production tests within the same well indicated different reservoirs.

As a result of this completion study, modern completions are generally [redacted] Treating intervals separately helps insure proper stimulation of each interval instead of preferential treatment of the lowest pressure zone (typically the more depleted Upper Silurian).

[redacted] The pressure differential prediction is qualitatively estimated from the reservoir model and geologic analysis. Absolute values of pressure are not as important in completion design [redacted]

There are limitations to the multiple completion approach [redacted] further subdi- [redacted] it is not economically feasible to identify and separately treat each of these individual reservoirs.

Reservoirs are therefore clustered in completion intervals, and steps are taken to insure that all perforations are open and fracture treatment rates and pressure are sufficient to adequately treat the overall interval.

Perforations and breakdowns. [redacted] in [redacted]

Core observations of thin pay zones [redacted] and the obvious lack of vertical interconnection indicated additional perforations would be required. [redacted]

It is important to insure that these perforations are open. [redacted] as it was difficult to "ball-out" an acid treatment due to the large vertical intervals being treated. Increasing shot density would make this process even more difficult, so another method of breaking down perforations has been implemented.

To insure open perforations, [redacted] elements is [redacted] The 3 ft spacing typically allows treatment of two perforations per setting.

Breakdown and treatment pressures are monitored and are used in fracture treatment design. During the completion practices study, these data were compared with pressure estimates from the frac-migration logs.

During the Upper Silurian completion of the 15 C. Easdale well in 1989, perforated intervals with significant deviation between predicted and actual breakdown pressures [redacted] Actual breakdown pressures in some perforations were much higher than predicted and in some cases were much higher than the average breakdown pressure for the entire Upper Silurian interval.

The actual and predicted breakdown pressures as gradients in psi/100 ft, and their corresponding porosity log readings for the 15 C. Easdale are shown (Fig. 7).

High breakdown pressures in these porous and permeable intervals [redacted] Hydrochloric acid will readily remove this damage if sufficient pump pressure is applied; and the actual damage itself is not significant. [redacted]

Fracture acidizing. [redacted] thought to have been partially caused

Low K and good stimulation?

by the inability to create high conductivity and long length fractures from the sand/foam fracture treatments.

The size of the foam fracs was small relative to the net interval being treated. Treatment pumping equipment and fluid property limitations prevented the larger jobs with higher sand volumes and concentrations necessary to effectively stimulate the Silurian reef.

Since the Silurian is a clean limestone highly soluble in hydrochloric acid, fracture acidizing was thought to be a better alternative to sand-propped fractures. This change was also implemented in 1989 as a result of the completion practices study.

The major limitations to fracture acidizing are leak-off of the treating fluid and premature spending of the acid. An alternating phase treatment of acid and viscous gelled water pads is employed to control both.

The purpose of the cross-linked gelled water pad is to create and extend the hydraulic fracture and control leakoff. The less viscous acid phase "fingers" through the pad, contacting and etching the fracture face as it moves toward the tip of the fracture. The following gelled water pad phase extends the fracture further allowing greater acid penetration down the fracture. Low K?

[redacted] most of the significant fluid production comes from localized areas of secondary porosity (vugs and fractures) found within the individual reservoirs. The goal in fracture acidizing treatments is to reach as many areas of secondary porosity as possible in the lateral direction and connect them to the wellbore.

all BS

The major problem in reaching these cells is maintaining net hydraulic fracturing pressure throughout the treatment by overcoming leak-off. High injection rates (50-60 bbl/min) are required to insure that sufficient net fracturing pressure is maintained.

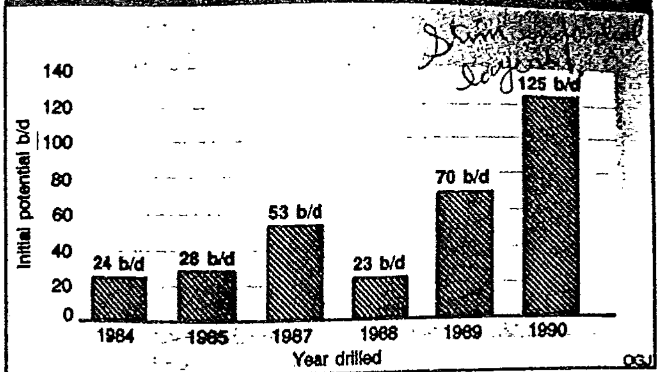
The high fluid rates choke off the secondary porosity leakoff channels allowing the fracture to continue lateral growth, and hopefully penetrate additional areas of secondary porosity.

Production characteristics. Modern completion techniques result in high volume production rates which are closely monitored during production testing to insure the wells are sufficiently pumped off. Pumping equipment is often resized based on production test and fluid level analysis during the testing phase.

Current development wells have higher initial potentials, some greater than 100 b/d, with less severe decline rates than earlier post-1984 wells. Comparing early redevelopment practices with current practices shows initial potentials have more than doubled since the reservoir management team approach was implemented (Fig. 8).

Fig. 8

TILDEN FIELD DEVELOPMENT WELL RATES*



TILDEN FIELD REMEDIAL RESULTS

Well		Remedial activity	Production increase, b/d
3	F. Easdale	Deepening	3
4	F. Easdale	Deepening	23
1	H. Edmiston	Deepening	0
1	F. Easdale	Deepening	50
3	C. Easdale	Deepening	13
3	Wilson	Pumping facility	140
12	C. Easdale	Pumping facility	145
1	Bickett	Recompletion	20
12	C. Easdale	Stimulation	15
3	M. Bingle	Recompletion	185
12	C. Easdale	Recompletion	150
16	C. Easdale	Recompletion	15

Remedial activity

While drilling has played an obvious important role in the success at Tilden, [redacted].

Remedial activity has included deepening existing wells further into the reef, and workovers within existing wellbores.

Deepenings. Deepenings in the 1960s were highly successful, adding several hundred thousand barrels of reserves. Today, every pre-1984 well is technically a deepening candidate [redacted] However only a handful of wells have been deepened since 1984 as a result of technical and economical considerations. Deepening costs are high relative to the cost of drilling a replacement well, and candidates must be thoroughly evaluated.

No-crossflow

Open hole evaluation is complicated due to limited logging tools available for slim hole applications. Completion options are also limited. Multiple zone completions usually involve only Middle and Lower Silurian since [redacted] Therefore, one-third of the wellbore is not available for completion.

A slim-hole liner, set to isolate pay zones, prevents use of the selective acidizing packer. Production tubing size is limited in high volume completions which might require larger tubing.

Workovers. Workover potential exists generally in the form of recompletion in overlooked intervals in wells drilled since 1984. Only these wells are cased completions and have sufficient log data to evaluate and effectively complete overlooked behind pipe pays.

The ability to isolate the intervals for recompletion is critical [redacted] prevent effective completions otherwise. [redacted]

high K layer.

These behind-pipe pay zones were originally overlooked for a number of reasons, which include:

1. Conventional water saturation calculations in some of the zones are high, [redacted]

2. The original redevelopment wells lacked wellsite or any kind of geologic analysis of well cuttings. [redacted] ple shows [redacted]

3 [redacted] field was originally treated as one reservoir, [redacted]

Another source of workover candidates is incomplete or inadequately completed intervals.

Early redevelopment wells may have unopened perforations because of th [redacted]

not necessary at all!

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Philip H. Carlisle is a geologist with Dusoco in Dallas. Working for Dusoco since 1985, he has been involved in exploration and production projects, primarily in Illinois, Oklahoma, and Texas. Much of his time has been committed to the design and integration of multidiscipline computer applications techniques used in the company's exploration and development activities. He has a BS in geology from Michigan State University.

[redacted] stimulation [redacted]roduction potential from this type of workover candidate is difficult to quantify because of the uncertainty of success of the original completion.

Partial depletion of the target workover interval is likely regardless of the success of the original completion, which negatively affects project economics.

One of the most effective types of workovers has been in wells with high producing bottom hole pressures. Pumping down wells with high fluid levels has had dramatically increased production. Producing fluid levels must be constantly monitored to [redacted] Results of remedial activity show the impact of remedial activity on field production and are further examples of the effectiveness of the team approach applied to the redevelopment of a mature field (Fig. 9).

Conclusions

This paper has focused on Tilden field discovery and early development, geology of the Silurian reef producing interval, development drilling, completion practices, remedial activity, and finally a brief description of how a heterogeneous reservoir has been mapped using PC based log analysis and mapping packages.

Significant conclusions are as follows:

1. [redacted] part. Later development has proven [redacted]

2. Lateral variations within the reef are extreme. By using proper geologic analysis with the integration of production data, a better understanding of the complexities and separation of reservoirs can be achieved.

3. Computer aided log analysis and geologic modeling have led to a more detailed understanding of the reservoirs involved. Large amounts of data have been used that may have otherwise been overlooked or not incorporated. Selection of development drilling locations and workover candidates has improved using the additional information gained from computer analysis.

4. A better understanding of reservoir characteristics has been beneficial to improving completion technology. [redacted] and high rate fracture acidizing treatments has led to dramatic increases in initial potentials and sustained higher production rates.

A most important conclusion is that significant new potential has been realized from an old field using advanced ideas and techniques.

A combined effort of the team geologist and engineer has permitted a better understanding of the complexities of the reservoir, resulting in the capability to more effectively produce and develop intervals within a heterogeneous reservoir.

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NORTH DAKOTA

Balcron Oil Co., Billings, said as many as seven offset wells may be possible alongside a discovery in a nonproducing township 10 miles northeast of Plaza.

Balcron's 32-22 Dyke, in 22-154n-87w, Ward County, flowed 130 b/d of oil from perforations in the Sherwood member of Mississippian Mission Canyon at about 7,000 ft, the company said. Total depth is 7,300 ft.

Based on analogy to nearby production, reserves could average 200,000-250,000 bbl/well, the company said. Balcron, a division of Equitable Resources Inc., Pittsburgh, owns an approximate 35% working interest in the prospect.

Petroleum Information noted that Texaco had completed 34-1 Paul Rau, in 34-154n-88w, Mountrail County, 6 miles southwest of Balcron's Dyke well. Unconfirmed reports have Texaco's discovery producing at rates of 20-30 b/d of oil.

Wabek field, about 8 miles south of Balcron's well, has produced about 3.8 million bbl of oil and 2.3 bcf of gas from Sherwood in 10 years, PI noted. Balcron estimated Wabek ultimate recovery at 5-6 million bbl of oil.

Two well Mandan field, 7 miles northeast of Balcron's well, produces oil from the Bluell member of Mission Canyon, PI noted.

API MONTHLY WELL COMPLETIONS*

	Oil wells	Footage	Gas wells	Footage	Dry holes	Footage	Total wells†	Footage
December 1991	958	3,509,545	664	3,651,803	611	3,075,516	2,321	10,421,643
November 1991	1,013	4,318,200	904	4,810,442	745	3,688,695	2,759	13,060,830
December 1990	809	3,786,394	795	3,496,120	557	2,779,866	2,203	10,217,829

*Total wells reported to API during December 1991. †Includes oil, gas, and dry holes plus service wells and stratigraphic and core tests.

DUMAS TEXAS
NOVEMBER ~~25~~, 1955

~~POSSIBLE EXPLANATION OF~~ SIP
VARIATIONS, EAST PANHANDLE FIELD
AND RELATION TO RECONDITIONING
STUDIES.

MR. C.W. B

1526

DEAR SIR:

CALCULATING AN ESTIMATED INCREASE IN PROD

During the preparation of ~~IN AN ATTEMPT TO PREPARE~~ A RECONDITIONING REPORT ON THE PHILLIPS CUBINE #1, WE HAVE ENCOUNTERED SOME DIFFICULTY IN EVALUATING THE SPOT DELIVERABILITIES TAKEN, AND BECAUSE OF THE LARGE VARIATIONS IN SIP FROM YEAR TO YEAR. IN CHECKING THE Data ~~FOLDERS~~ OF THE OFFSET WELLS, IT WAS DISCOVERED THAT VARIATIONS IN SHUT-IN PRESSURES WERE ALSO OCCURING IN SOME OF THEM.

SOME OF THE OFFSET OPERATORS IN THAT AREA SEEM TO THINK THAT THERE IS A HIGH PRESSURE AND A LOW PRESSURE ZONE. THIS STATEMENT SEEMS TRUE, BUT NEEDS A THOROUGH EXPLANATION BEFORE ACCEPTING SUCH A SEEMINGLY RIDICULOUS STATEMENT. FOLLOWING IS A WORKING HYPOTHESIS.

THE PAY SECTION IN THIS AREA CONSISTS OF TWO SEPARATE ZONES, BROWN DOLOMITE THE UPPER ZONE, AND GRANITE WASH THE LOWER ZONE. (FROM A SERIES OF ASSUMPTIONS AND ROUGH CALCULATIONS USING A BEFORE RECONDITIONING BP TEST ON THE CUBINE #1 IT IS ESTIMATED THAT THE BROWN DOLOMITE PRODUCES with a line pressure of 50 psig APPROXIMATELY 10% OF THE TOTAL PRODUCTION.) THE GRANITE WASH HAS A RELATIVELY HIGH PERMEABILITY, K_{GW}, WHILE THE BROWN DOLOMITE HAS A VERY LOW PERMEABILITY, K_{BD}. INITIALLY THE RESERVOIR PRESSURES IN THESE ZONES WERE EQUAL. DURING SUBSEQUENT PRODUCTION THE GRANITE WASH WAS DEPLETED RATHER RAPIDLY IN COMPARISON TO THE BROWN DOLOMITE, UNTIL THE "TRUE" PRESSURE IN EACH ZONE NOW STANDS AT APPROXIMATELY 140 psig IN THE BROWN DOLOMITE AND 50 psig IN THE GRANITE WASH. THE QUESTION OF EQUALIZATION NOW ARISES.

NEW PARAGRAPH

BUT BECAUSE OF PRODUCTION PRACTICES IN THIS AREA, 25% OF POTENTIAL, THE WELLS ARE HARDLY EVER SHUT-IN LONG ENOUGH TO BRING THIS ABOUT. CONSEQUENTLY BOTH ZONES ARE PULLED DOWN TO THE SAME WORKING PRESSURES. UPON SHUTTING IN A WELL FOR A SHORT TIME THE SIP WILL INITIALLY BE THAT OF THE GRANITE WASH DUE TO THE RAPID BUILD-UP OF THIS HIGH PERMEABILITY ZONE. DUE TO THE LOW PERMEABILITY OF THE BROWN DOLOMITE, ITS AFFECTS SHOULD TAKE A LONG TIME. ~~FR~~

FROM THIS IT WOULD BE SUPPOSED THAT GIVEN A LONG ENOUGH BUILD-UP TIME THE WELL-HEAD PRESSURE WOULD BE EQUAL TO THE BROWN DOLOMITE PRESSURE. A CAVED OR MUDDED WELLBORE SHOULD SHOW THIS TO BE TRUE, BUT ~~IN~~ A CLEAN WELLBORE THE BACKFLOW INTO THE GRANITE WASH ~~WOULD~~ NOT.

NOW WE COME TO THE EFFECT OF CAVINGS, OR MUD, UPON THE SITUATION. DUE TO SUCH A SITUATION IT WOULD SEEM THAT CLEANING OUT THIS MUD WOULD INCREASE THE SIP IF NO SUCH HIGH PRESSURE ZONE WAS PRESENT, BUT THIS HAS BEEN THE OPPOSITE, EXAMPLE, THE CUBINE #1 HAD A SIP = 126.7 psig ON A BEFORE RECONDITIONING ONE-POINT AND AFTER THE CLEAN OUT A SIP OF 73.5 psig WITH 5' OF LIQUID.

WITH MUD BUILDING UP IN A WELLBORE THE GRANITE WASH WILL BEGIN TO BE COVERED, AND AT FIRST RESTRICT THE RATE OF FLOW BY REDUCING THE EFFECTIVE THICKNESS OF PAY, h. WHEN THE WELL IS SHUT IN, THE BACK FLOWING FROM THE HIGH PRESSURE FORMATION WILL BE REDUCED AND TEND TO INCREASE THE APPARENT WELL-HEAD SIP. WHEN THE PAY IS COVERED WITH MUD THE ABILITY OF THE HIGH PRESSURE ZONES GAS TO ENTER THE GRANITE WASH WILL BECOME INCREASINGLY HARDER AND THE PRESSURE SHOULD INCREASE MORE. SHOULD THE WELL BE SHUT IN, THE HIGH PRESSURE GAS WILL FORCE SOME OF THE MUD INTO THE FORMATION, FURTHER REDUCING THE PERMEABILITY, AND AS YOU KNOW THE IMMEDIATE VICINITY OF THE WELL BORE IS THE MOST CRITICAL. THIS WILL FURTHER REDUCE THE ABILITY OF THE WELL TO PRODUCE UNTIL THE

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GRANITE WASH IS COMPLETELY MUDDED OFF. THEN ALL THE GAS WILL ORIGINATE FROM THE BROWN DOLOMITE AND UPON SHUTTING IN, WILL RECORD THE HIGHER PRESSURE OF THE BROWN DOLOMITE.

FROM THE ABOVE EXPLANATIONS THE FOLLOWING ASSUMPTIONS CAN BE MADE.

1. A HIGH SIP INDICATES THE WELL NEEDS RECONDITIONING.

GRAYSON CUBINE — 5-12-55 SIP = 140.4 psig; RECENTLY CLEANED OUT 95' CAVINGS, VERY MUDDY, NO SIP SINCE.

IT IS INTERESTING TO NOTE THE FOLLOWING SIP OF THE GRAYSON AND ITS OFFSETS FOR 1955. EVIDENTLY OFFSET WELL INTERFERENCE DOES NOT ENTER THE PICTURE.

COMPANY	LEASE	SIP psig	DATE TAKEN	
PHILLIPS	GRAYSON #1	140.4	5-12-55	
"	CUBINE #1	80.1	5-12-55	
MAMIE AXELROD	BACK MAGNOLIA A-1	54.0	5-5-55	
MAGNOLIA	CUBINE #2	40.5	5-12-55	
NEVEL BACK	MORGAN #1	46.7	5-12-55	
" "	MORGAN #2	61.4	5-12-55	
SHAMROCK	CARPENTER #1	114.0	5-6-55	*
"	BACK #1	48.4	5-6-55	

* THE SHAMROCK CARPENTER #1	69.0	5-28-53
	90.3	6-18-54
	114.0	5-6-55

2. WHEN A WELL IS RECONDITIONED, THE SIP SHOULD DECREASE.

CUBINE #1 —	126.7	8-18-52	BEFORE RECONDITIONING
	73.5	1-19-53	AFTER RECONDITIONING
BACK-MAGNOLIA "A" #1 —	136.0	2-19-53	BEFORE RECONDITIONING
	89.0	10-1-53	AFTER RECONDITIONING

3. SHUTTING IN A CAVED WELL, MUD ~~NEARLY~~ COVERING THE PAY, SHOULD CAUSE THE PRODUCTION TO DECLINE. A CLEAN WELL BORE SHOULD SHOW NO SUCH AFFECT.

CUBINE #1 PRODUCTION.

	1952	1953	1954	1955
JAN.	18,719 (1)	3293	1079	13,904
FEB.	15,934	5690	405	15,079
MAR.	14,217	5137	835	16,455
APR.	12,537	4189	20,787 (5)	12,606
MAY	10,573	5079	37,487	8,810 (7)
JUNE	5,354 (2)	8088	30,262 (6)	10,790
JULY	7,041	7556	19,113	8,916
AUG.	4,859	7683	25,104	9,236
SEPT.	2,724 (3)	6659	21,419	5,271
OCT.	1,898	4417	15,861	7,067
NOV.	0	3708	13,697	—
DEC.	0 (4)	2858	10,870	—

(1) SLM - 1-21-52 - 48' CAVINGS, MOIST MUD ON CASING TO TOP OF FC
(2) OFFICIAL SIP
(3) BFORE RECONDITIONING POINT
(4) RECONDITIONED.
(5) BOOSTER
(6) OFFICIAL SIP
(7) OFFICIAL SIP

...ible with process

any additional ~~ANATICN AS~~ in regard to th...

~~IF YOU WISH CONSIDERABLE MORE DATA BEFORE EITHER ACCEPTING OR REJECTING ITS POSSIBILITIES~~

We will be glad to conduct a complete investigation in any manner that you wish.

MJF:HBB

MHc

OK ABB

YVT

HBB

EAST PANHANDLE FIELD SHUT-IN
WELLHEAD PRESSURE ANOMALIES

#91

MR. C.W.B.

IN REGARDS TO YOUR LETTER OF JANUARY 13, 1956, FILE: 1-Bi-19-56-NG, REQUESTING PERMEABILITY VALUES FOR THE BROWN DOLOMITE AND THE GRANITE WASH, WE HAVE DISCUSED THIS WITH THE GEOLOGICAL DEPARTMENT.

ALTOUGH THEY HAVE NOT BEEN ABLE TO FURNISH ANY SPECIFIC VALUES OF PERMEABILITY FOR THIS AREA, THEY AGREE THAT THE BROWN DOLOMITE WOULD HAVE A MUCH LOWER PERMEABILITY THAN THE GRANITE WASH. MR. RAY MILLER, RESERVOIR ENGINEER WITH THE ECONOMICS DEPARTMENT IN THE AMARILLO OFFICE WAS ALSO CONSULTED, SINCE HE RECENTLY INVESTIGATED THIS AREA IN THE PREPARATION OF A PAPER COVERING THE ENTIRE PANHANDLE AREA. MR. MILLER WAS NOT ABLE TO GIVE ANY SPECIFIC VALUES FOR THE TWO ZONES BUT AGREED AS TO THE LARGE DIFFERENCES IN PERMEABILITY.

WHEN PRESENTED WITH THE WELLHEAD PRESSURE ANOMALIES AND THE POSSIBLE EXPLANATION MR. MILLER READILY ACCEPTED IT AS THE MOST LOGICAL EXPLANATION.

ALTHOUGH WE HAVE NOT BEEN ABLE TO OBTAIN SPECIFIC PERMEABILITIES FOR THE BROWN DOLOMITE + GRANITE WASH WE FEEL THAT OUR CONCLUSIONS ABOUT THE TWO ZONES ARE STRENGTHENED BY THE OPINIONS OF THESE QUALIFIED SOURCES.

MJF: H.BB

OK
HBB

YVT
HBB

Effect of Horizontal and Vertical Permeability Restrictions in the Beryl Reservoir

Craig A. Knutson* and **Ragnhild Erga,** SPE, Mobil North Sea Ltd.

Summary. The Beryl formation, the primary reservoir in the Beryl field, has a complicated distribution of pressures and fluids controlled by horizontal and vertical permeability restrictions. Horizontal permeability restrictions, the result of extensive faulting, divide the reservoir into eight interrelated areas as determined by careful analyses of pressure and production histories and fluid monitoring. Vertical permeability restrictions, which are the consequence of thin lithologic breaks within the massive sandstone sequence, further divide the eight reservoir areas into seven layers, as evidenced by careful review of repeat formation tester (RFT) data, pressure-transient tests, cased-hole logs, and reservoir performance data. A detailed reservoir model identified areas and intervals of unswept hydrocarbons, resulting in an aggressive workover and drilling program. The model was an essential component in the success of the subsequent reservoir simulation.

Introduction

The Beryl field[1] is located in Block 9/13 of the U.K. sector of the North Viking graben, North Sea. The field is estimated to contain 2100×10^6 STB original oil in place, and supports production from Platforms Beryl A and B. This paper discusses reservoir behavior in the Beryl A portion of the field, where a combination of a long production history, detailed data acquisition, and a concentrated reservoir management effort has given insight into complex fluid movement and reservoir behavior. The Beryl A portion of the field is a north-south-oriented horst with hydrocarbons in six reservoir horizons that range in age from Upper Triassic to Upper Jurassic. The Middle Jurassic age Beryl reservoir contains about 73% of the total estimated ultimate recovery in the area (370×10^6 bbl oil). Beryl oil production began in June 1976, gas injection in Nov. 1977, and water injection in Jan. 1979. The reservoir currently is managed by 16 producing wells, two water injectors, and three gas injectors (**Fig. 1**). By Dec. 1990, the reservoir had produced 285×10^6 bbl of oil, and 490 Bcf of gas and 170×10^6 bbl of water had been injected. Reserves are estimated to be 85×10^6 bbl oil and 535 Bcf gas.

Fluid movement within the Beryl reservoir is complicated, as evidenced by observations of (1) adjacent areas in pressure communication with apparent gas/oil contacts (GOC's) that differ by several hundred feet and (2) water overlying oil or oil overlying gas in massive sand sequences. Gas sales to begin in 1992 will have a dramatic effect on fluid distribution within the Beryl reservoir. A simulation model is being developed to predict the most efficient method to satisfy the gas contract while maximizing hydrocarbon recovery. Past efforts to simulate the Beryl reservoir have been time-consuming and of limited success because of incomplete reservoir models. In a reservoir as complicated as Beryl, a conceptual reservoir model explaining the interplay between the geologic and reservoir data must be developed before simulation begins. A simulation exercise can only support and quantify the reservoir model; it is an inefficient tool for determining the parameters that control the reservoir behavior. This paper describes a dynamic reservoir model developed by examining the reservoir pressure and fluid histories within the confines of recently recognized horizontal and vertical permeability restrictions.

*Now at Mobil New Exploration Ventures—South America.

Reservoir Description

The Beryl reservoir in the Beryl A area has an oil column of 1,950 ft, ranging from 9,600 ft subsea at the crest to 11,550 ft subsea at the oil/water contact (OWC). The variable reservoir thickness ranges from 150 ft on the crest to 600 ft on the flanks because of syndepositional faulting. East of the platform, the reservoir is eroded by the overlying base of a Cretaceous unconformity and is thus limited in extent to only the crest and west flank of the Beryl A horst. From the crest of the structure, which is near the Platform Beryl A, the reservoir dips structurally at 10° to 25° toward the west, northwest, and southwest. The structure spills to the south and appears to be filled to the mapped structural spill point. To the north, the reservoir continues with limited communication into the Beryl B area.

The Beryl formation is a Middle Jurassic (Bajocian to Callovian) transitional deltaic/marine system. Net/gross ratios range from 0.8 to 1.0, porosities from 13% to 20%, and permeabilities from 50 to 2,000 md. The formation is lithostratigraphically divided into Units 1 through 5. Unit 2 is a 50-ft shale bed that forms an effective permeability restriction, resulting in Unit 1 being produced separately from Units 3 through 5. Unit 1 development in the Beryl A area did not begin until 1989 and is not the subject of this paper.

Gravity drainage augmented by reinjection of associated gas into a secondary gas cap is the major production mechanism for the reservoir in the Beryl A area.[2] Water injection on the flanks, primarily in the south, has augmented natural aquifer support. Initial fluid-property measurements indicate that the hydrocarbons in the Beryl reservoir were undersaturated, low-sulfur

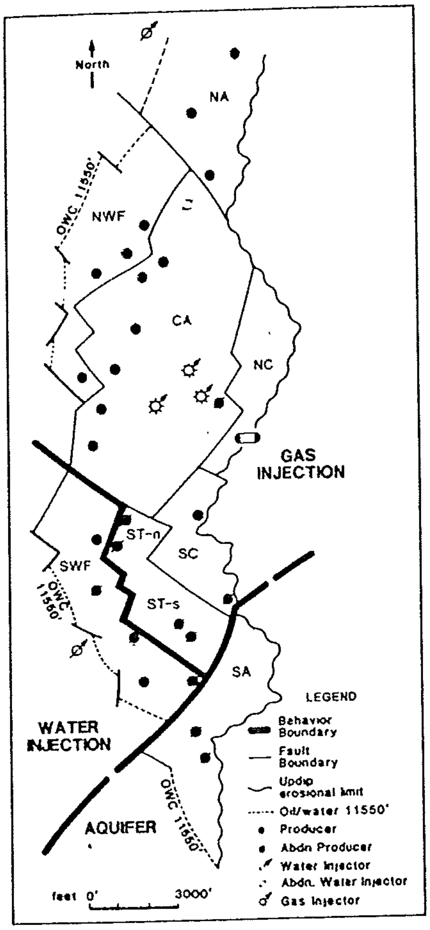

Fig. 1—Schematic of Beryl reservoir showing reservoir areas and behavioral boundaries.

"This paper describes a dynamic reservoir model developed by examining the reservoir pressure and fluid histories within the confines of recently recognized horizontal and vertical permeability restrictions."

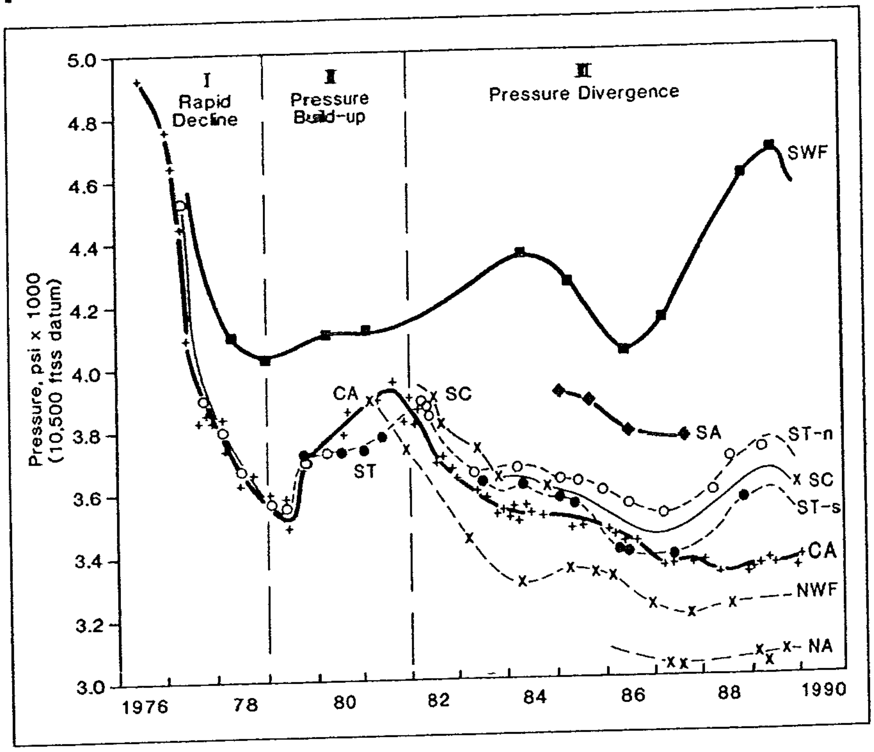

Fig. 2—Pressure profiles of eight areas within Beryl reservoir.

crudes, with bubblepoints ranging from 3,200 to 4,500 psi.

Horizontal Permeability Restrictions

The initial distribution of hydrocarbons in the Beryl reservoir has been altered by 14 years of production, 13 years of gas injection, and 11 years of water injection. The key to optimizing hydrocarbon recovery is to understand and predict the fluid distribution. This complicated distribution is governed by simple principles.

1. The voidage in a reservoir is determined by the net influx and efflux of fluids.
2. Permeability variations locally affect the voidage replacement efficiency.
3. The voidage replacement efficiency affects the pressure distribution.
4. Fluid flow in a system is always toward lower pressure.

Observations

Voidage replacement calculations compared with pressure histories indicate that fieldwide communication exists within the Beryl reservoir. Diverging pressure trends and GOC's, however, indicate that this communication is restricted. If reservoir areas show deviating pressures or GOC's, they must be separated by permeability restrictions. In the Beryl reservoir, where permeabilities are relatively high and uniform, permeability restrictions between areas are assumed to be faults. The Beryl reservoir is cut by many syn- and postdepositional faults. Pressure communication indicates that most faults leak. The larger faults with throws of 50% to 150% of the reservoir thickness tend to be the most effective permeability restrictions, but some smaller faults with throws of only 10% to 30% of the reservoir thickness are also important.

The pressure-history profiles (Fig. 2) indicate three general patterns of reservoir behavior in the Beryl reservoir related to water injection, aquifer expansion, or gas injection. The wells directly affected by water injection have relatively high reservoir pressures and a fluctuating pressure profile. The wells associated with aquifer expansion or gas injection have lower pressures and a gently declining pressure profile. Detailed interpretation of the pressure-history profiles (Fig. 2) indicates that the Beryl reservoir can be divided into several areas with varying degrees of communication to the water and gas injection wells (Fig. 1). A division into eight reservoir areas, one of which was further divided after 1982, is used to decipher the fluid movement in the reservoir.

The five areas with similar gently declining pressure profiles [central area (CA), northwest flank (NWF), southern crest (SC), and southern terrace north and south (ST-n and ST-s) in Fig. 2] are divided by relatively slight pressure differences and significant variations in present-day GOC's. GOC's have been monitored periodically with open- and cased-hole logs (Fig. 3). Initially, a single secondary gas cap developed in the central and southern terrace areas where early production was concentrated. As the reservoir was developed, differential depletion occurred and several independent gas caps were observed. In the central area, the secondary gas cap expanded continuously and its present GOC is measured at ≈10,750 ft subsea. In the northwest flank, southern crest, and southern terrace areas, where the pressures deviate from the central area, the GOC's also deviate. Relatively low-pressure areas, such as the northwest flank, have structurally deep GOC's as low as 11,200 ft subsea. Relatively high-pressure areas, such as the southern crest and southern terrace areas, have shallower GOC's (9,800 and 10,400 ft subsea, respectively).

GOC's are measured in designated wells. True GOC's must be differentiated from pseudo GOC's that result from gas cusping. This is accomplished by identifying areas of pressure communication. All wells in good pressure communication with the designated wells monitoring the GOC are interpreted to have the same GOC. Any structurally deep gas production from these wells is re-

"If reservoir areas show deviating pressures or GOC's, they must be separated by permeability restrictions. In the Beryl reservoir . . . permeability restrictions between areas are assumed to be faults."

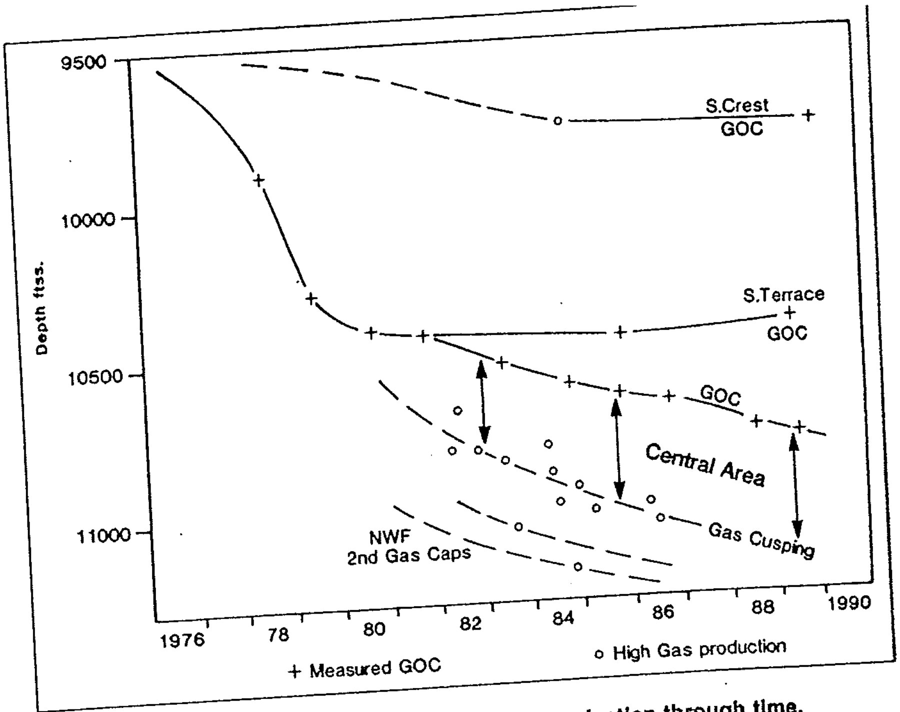

Fig. 3—Measured GOC's and depth to high gas production through time.

lated to gas cusping. In the central area, gas cusping has been observed to be as much as 300 ft vertically (Fig. 3). If wells, such as those in the northwest flank area, have a lower pressure than the monitoring wells, then structurally deep gas production can be related to a deep GOC.

Reservoir Model

The key to understanding fluid distribution within the Beryl reservoir is to recognize that the voidage replacement situation between individual fault blocks has changed through time, and consequently, pressure differentials and flow directions between areas have locally reversed. This observation of pressure-gradient reversals is critical to explain how adjacent areas can have similar pressure histories but different fluid histories. The approach to establish a conceptual reservoir model was to analyze the data in time periods during which the flow direction was consistent. Examination of field pressure profiles and the development history identified three chapters in the evolution of the reservoir: rapid pressure decline during 1976–79, repressurization during 1979–82, and pressure divergence from 1982 to 1991.

Rapid Pressure Decline, 1976–79. Production from the Beryl formation began in mid-1976 with an initial reservoir pressure of 4,950 psi at 10,500 ft subsea. This period was marked by a rapid fall in pressure as the reservoir was produced by primary depletion. In late 1977, the first gas injection in the North Sea was initiated to slow the pressure decline. Hydrocarbon production was limited to the central area, the southern terrace, and the southwest flank. By 1979, the southwest flank was depleted to a pressure of about 4,050 psi (Fig. 2), while the central area and the southern terrace were depleted to ≈3,600 psi.

A secondary gas cap was forming during this time, and by the end of 1978, the GOC was interpolated from measured data in the central area to be at 10,100 ft subsea (Fig. 3). Because the central area and the southern terrace had equal pressures, gas was assumed to be distributed in both areas. The single well in the southern terrace at this time was at 10,400 ft subsea and could not confirm the assumed GOC.

Water production during this time was minimal. A slight amount of formation water produced in the southwest flank indicated aquifer influx in the area.

In summary, fluid flow and fluid distribution within the Beryl reservoir during this early period was not yet complicated. Fluid flow was from the high-pressure area in the southwest flank toward the low-pressure central area and southern terrace (Fig. 4), where a secondary gas cap was assumed to be equally distributed at ≈10,100 ft subsea.

Repressurization, 1979–82. This period is marked by the arrest of the pressure decline and a general repressuring resulting from

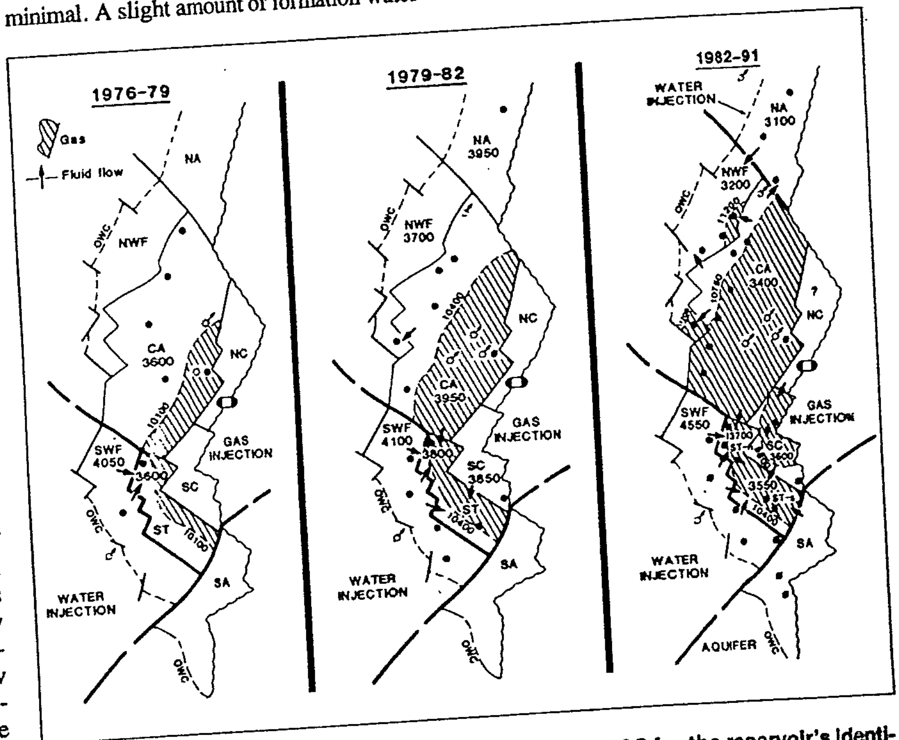

Fig. 4—Pressure distribution, fluid-flow direction, and GOC for the reservoir's identified evolutionary periods.