BENSON-MONTIN-GREER DRILLING CORP.

221 PETROLEUM CENTER BUILDING, FARMINGTON, NM. 87401 505-325-8874

June 30, 1988

Mr. William J. LeMay, Director
Oil Conservation Division
New Mexico Energy & Minerals Department
State Land office Building
Santa Fe, NM 87501

Mr. Erling Brostuen, Director
Mining and Minerals Division
State of New Mexico
525 Camino de Los Marquez
Santa Fe, NM 87501

Mr. William Humphries
Commissioner of Public Lands
State of New Mexico
State Land Office Building
Santa Fe, NM 87501

Re: REQUEST FOR NAMES OF FRACTURED RESERVOIRS UNDER PRESSURE MAINTENANCE BY GAS INJECTION

Gentlemen:

In the hearing of Cases 7980, 8946, 8950 and 9111 held June 13, 1988, the Chairman requested identification of fractured reservoirs which have undergone pressure maintenance by gas injection. This was in connection with the Canada Ojitos Unit, which produces from a fractured reservoir by gravity drainage depletion under pressure maintenance by gas injection. Transmitted here is some information on such reservoirs.

Most naturally fractured reservoirs are of the dual porosity type; and as such can be expected to be less efficient from the standpoint of pressure maintenance than single porosity reservoirs. Despite this pressure maintenance by gas injection has been carried on successfully in such reservoirs - some of them exceptionally large reservoirs.

Clearly, the most definitive factor in success or failure of pressure maintenance by gas injection is not whether the reservoir is of the single porosity or dual porosity type, but whether gravity drainage is allowed to operate.

Of these pressure maintenance reservoirs, the most noteable in New Mexico is the Empire Abo field, which produces under gravity draingae depletion with pressure maintenance by gas injection. This reservoir comprises corraline reef material in which vugs, fractures and fissures have been observed in cores throughout the main reef.

The Bahrain pool, referred to in NMOCC Case 7075 and again in the June hearings, is remarkable in that recoveries under pressure maintenance by gas injection have followed waterflooding with substantial increases in ultimate recovery resulting from the more efficient depletion process of gravity drainage when supported by pressure maintenance. Although limited, this reservoir has fractures and vugs and might be classed as a dual porosity reservoir.

Information has been released on only a few of the large fractured reservoirs undergoing pressure maintenance by gas injection in the Persian Gulf area. We have, however, found three papers with respect to these reservoirs which are enclosed with this letter:

1. Article from the Oil and Gas Journal October 21, 1974, indicating increased recovery from Iran's gravity drainage fields by gas injection.

2. A follow-up paper with respect to the particular Haft Kel field in Iran.

3. A recent paper (May 1988) covering the Fahud field in Oman; in which they apparently have experienced the same as the Bahrain field with increased recovery through pressure maintenance by gas injection over that by water drive.

Yours truly,

BENSON-MONTIN-GREER DRILLING CORP.

BY: Albert R. Greer
Albert R. Greer, President

ARG/tlp

Enclosures

cc: Vic Lyon
Frank Chavez
Bill Weiss

Gas injection will hike recovery in Iran's gravity-drainage fields

A. M. SAIDI
Coordinator of Special Projects
National Iranian Oil Co.
Tehran, Iran

OIL RECOVERY in some Iranian fields can be doubled through controlled gas-injection programs.

The high productive wells of the Iranian fractured limestone reservoirs indicate an extensive fracturing system. This can be confirmed by flowmeter surveys in most wells.[1] By this method the fluid entries can be directly measured, and the distance between fractures determined.

Detailed analyses of the logs made on watered wells in the Haft Kel field show sharp changes in water saturations with depths at intervals between 5-15 ft. This can be interpreted as capillary discontinuities as shown in Fig. 1. These and other evidences lead one to believe that these reservoirs are composed mainly of several million separate blocks with either fully open boundaries being partially surrounded by impermeable materials such as shale, calcite, etc.

The history of these reservoirs also indicate rather uniform movements of gas-oil and water-oil contacts in all or a large portion of the reservoirs. The recovery mechanisms in these reservoirs, therefore, is essentially due to gravity drainage. When gas-oil (or water-oil) contact passes blocks of given height, the oil drains out from the bottom of the blocks (top of the blocks in the case of water). The controlling factor in this type of gravity-drainage process is basically capillary pressures and block height and the speed of the drainage process is controlled by the vertical permeability of the blocks and their respective relative permeabilities.

Basic concept. Capillary pressure is a function of interfacial tension[2,3] and that in the case of a gas-oil system is a function of pressure and temperature. In fact at constant temperature, interfacial tension between oil and gas increases when pressure decreases. This means that the capillary pressure increases as the pressure decreases.

Let us consider a stack of similar blocks, as an example, each one being 30 ft tall, and let us visualize that the gas-oil contact passes these blocks at a velocity of 0.1 ft/day, while the reservoir pressure drops at a rate of 0.1 psi/day. Then, a block at the top of the reservoir, located at the original gas-oil contact, undergoes a drainage process at near bubble-point pressure, while a block located 1,000 ft below undergoes the same process 10,000 days later when the reservoir pressure drops by about 1,000 psi. If the magnitude of the interfacial tension at this new pressure level is twice as much as that of 100 psi higher, the value of capillary pressure for the same gas saturations are twice as much. Under this environment, a lower recovery will be made from the lower blocks. Therefore, during the depletion history of a reservoir, the displacement efficiency of gas in similar blocks at different periods varies from a value corresponding to the capillary pressure at the bubble-point pressure to smaller values corresponding to higher capillary pressures at lower pressure levels.

If the reservoir is pressurized by injection of equilibrium gas, then extra oil can be recovered by this process assuming that the variation of interfacial tension with pressure is fully reversible.

In a reservoir with a lower bubble-point pressure (below 2,500 psi), if the reservoir conditions allow the reservoir to be pressurized to a level higher than its original bubble point, even higher recovery can be made due to further decrease of interfacial tension. Gas composition on this process can also have similar effect since the interfacial tension between oil and a richer gas is definitely lower than that of dry gas.

This process of oil recovery, which has not been recognized earlier, is a major breakthrough to increase the oil recovery process from the Iranian fractured reservoirs. In some cases, up to 100% excess recovery by injecting gas at the original gas-oil contact pressure has been calculated in these reservoirs over the recovery calculated by the natural depletion.

Variation of capillary pressure with pressure. Capillary pressure may be defined by $P_c = J\Psi\,(\Phi/K)^{1/2}$, where J, Ψ, Φ, K, are, respectively, a correlating term which is a function of saturation, interfacial tension, porosity, and permeability. All these parameters, except for the J term, are functions of pressure in different degrees. However, the square root of the effect of pressure on the ratio of porosity over permeability is relatively small and can be ignored with respect to the variation of interfacial tension. Therefore, at a constant temperature, capillary pressure at any pressure can be written as $(P_c)_p = (P_c)_{pb}\,(\delta)_p/(\delta)_{pb}$, where, the indecies of P, and pb are, respectively, any pressure, and the bubble point pressure.

The interfacial tension between water and oil does not vary appreciably with pressure and it increases slightly as the pressure increases.

Interfacial tensions of several gas-oil systems from different Iranian fractured limestone reservoirs were measured in the laboratory under reservoir conditions. The results of these measurements are presented on Fig. 2.

The laboratory measurements were checked against gas-oil interfacial tension calculated by the Paracor method,[3] using the same composition. It was found that except for the pressure near bubble-point pressure (when the bubble-point pressure is below 2,500 psi), they match each other perfectly. The difference between the two measured and calculated interfacial tensions can be attributed to the technical problems of collecting representative gas near bubble-point pressure. The calculated interfacial tension of Gachsaran field (solid line) is also given on Fig. 2.

Producing mechanisms. A fractured reservoir may be divided vertically into several distinct zones some time in its depletion period. These segments are mainly: gas cap, gas-invaded, gassing, undersaturated, water invaded, and water zone.

Gas and water-invaded zones are those portions of the reservoir whose blocks within those intervals are surrounded by gas or water, and oil is draining out of these blocks essentially because of the gravity drainage.

The gravity force is essentially the density differences between oil and gas, or water and oil, acting against the rentention capillary forces. The absolute and relative permeability to oil with respect to gas, or water, is the index of the rate of oil transfer from these blocks.

Gassing zone consists of the portion of the reservoir where the pressure of the matrix is below the prevailing bubble-point pressure at the time. In

Fig. 1

Discontinuities

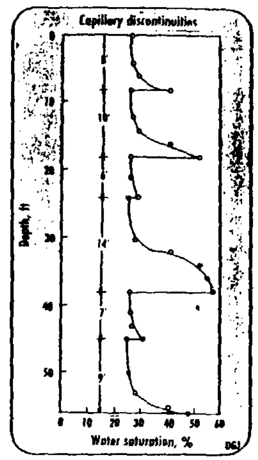


Fig. 2

Interfacial tension

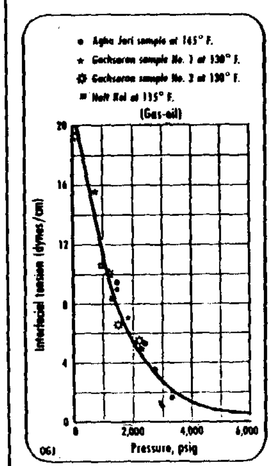
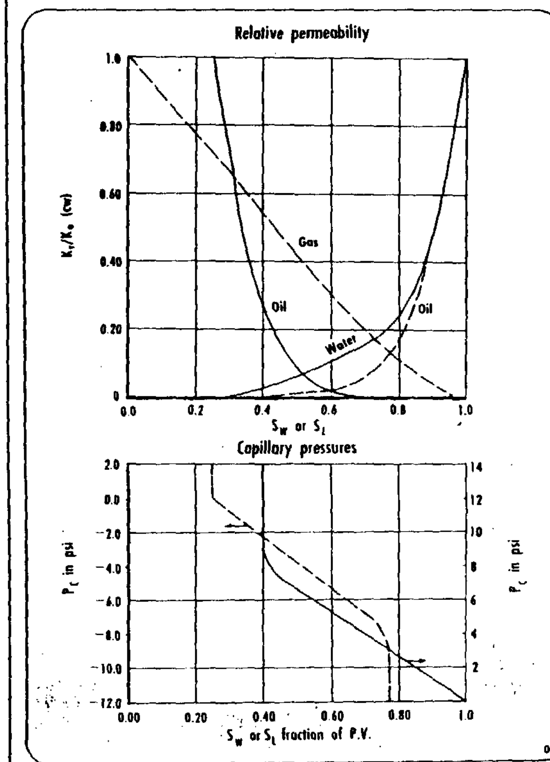


Fig. 3

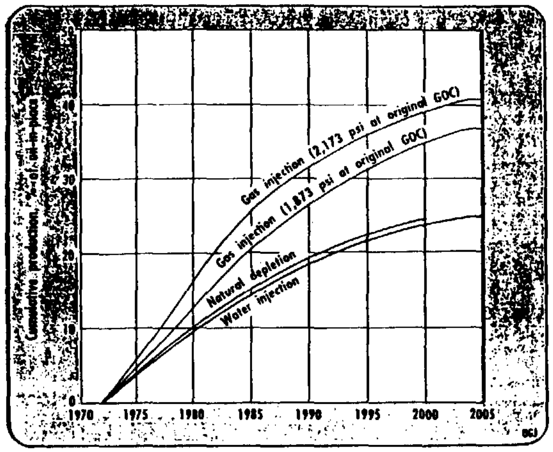
Gachsaran reservoir



Presented at World Energy Conference, Detroit.

Fig. 4

How recovery results vary



this portion of the reservoir, solution-gas drive mechanism takes place in the known sense of it, except for the volume of gas transfer due to the diffusion. When free gas reaches its critical saturation, in addition to the already mentioned processes, gas moves upward due to its lower density with respect to oil. Therefore, the *recovery due to the solution-gas drive* mechanism is mainly a function of the rate of pressure drop and the resultant effect *determines the final* fluid saturations in the blocks.

In the undersaturated portion of the reservoir two processes take place: (1) expansion of the liquids and (2) diffusion of gas through oil from matrix to the fracture. This latter process causes the oil in the matrix *to lose its gas and therefore*, oil from the fracture replaces the equivalent volume of the lost gas.

Model description. A compositional mathematical model was developed to simulate the flow mechanisms that take place in this type of fractured reservoirs mentioned here.

In this model, a reservoir can be described as a stack of blocks both vertically and horizontally with open or partially closed boundaries. These blocks are two dimensional R, Z to reduce computer time. It is also necessary to define the radius and height of each block and their horizontal and vertical permeabilities as well as porosity and their locations in the reservoir. In addition, it is required to define the number of grids within each block.

A *set of differential equations with* the necessary boundary conditions describing the fluid flow through porous media are solved for each block. As the gas-oil contact moves *down (or water-oil contact moves* up) the blocks become surrounded by gas (or water) one after the other and gravity drainage takes place. During this period, if the reservoir *pressure* is dropping, the capillary pressure is adjusted accordingly as was described in the previous section.

In addition, a two-dimensional R, Z differential equation describing Fick's Law diffusion was solved to calculate the gas transfer from matrix to fracture due to the difference in their gas concentrations.

Reservoir description. To demonstrate the effect of gas pressurizing on the oil recovery from a typical Iranian fractured *limestone reservoir*, Asmari formation of Gachsaran field was considered for this study.

However, because of the huge size of this reservoir (600 sq km) and having pressure, water-oil contact and gas-oil contact variations from one end to the other end of the field, the reservoir was divided into four segments. The results of only one segment are presented here. This segment of Gachsaran, which has over 6,000 ft of closure, is the largest segment and has very uniform pressure throughout. This segment was simulated by blocks of 20 ft in radius by 40 ft in height with vertical permeability equal to horizontal permeability of 0.6 md, and an average porosity of 4.5% was used. The relative permeability of gas oil and water oil and their related capillary pressures are given in Fig. 3.

The black oil PVT properties used in this study are also given in Table 1.

The reservoir hydrocarbon was divided into two component systems of C_1 and C_2^+ and the effective diffusion *coefficient of gas through liquid phase* between the oils in the matrix and fracture was assumed to be 0.0002 sq ft/day. The capillary pressure correction for pressure variation in the reservoir was set to be equal to the corresponding ratio of interfacial tension at any pressure over interfacial *tension at the bubble-point pressure*, which is given on Fig. 2.

Results. After matching the past history of the entire reservoir by varying the oil-in-place, permeability, etc., several prediction cases were made, namely, natural depletion, water injection, and two gas-injection cases on the segment described in this paper.

The average displacement efficiencies for water and gas were calculated to be about 21% of their respective pore volumes at the end of the prediction period.

In the prediction case of natural depletion, the reservoir was produced at a given rate while pressure and fluid contacts were calculated by the model. In the water-injection case, water was injected to the reservoir at a rate in which the reservoir pressure remained constant at the top of the oil column, at the *time of injection* (1973), while producing the reservoir.

Two gas-injection cases were made (starting from 1973): one having 300 psi lower final pressure than the other at the original gas-oil contact of the reservoir. In all these studies a final 200 ft of the oil column and a rate of *50,000 bo/d were used as the* termination point for the cases.

The results of oil recovery are given on Fig. 4. The ultimate recovery under natural depletion would be 25.3% of the original oil-in-place. Recoveries under injection schemes would be 25.7% for water injection, 38% for gas injection at the lower pressure level, and 43% for gas injection at the higher pressure level. The increment of ultimate recovery in the case of gas injection at the higher pressure is due to the further reduction of interfacial tension.

In the higher-pressure case, when the oil column is reduced below 4,300 ft, the gas-invaded blocks immedi-aL ft, the gas-invaded blocks immediately above the gas-oil contact reach pressures higher than their original bubble-point pressure. In this case, when the oil column reaches the 200 ft limit, the entire gas column below the original gas-oil contact has pressure from 0-300 psi higher than the original bubble-point pressure of 2,173 psi. In this portion of the reservoir, the gas-oil system has even lower interfacial tension than the bubble-point pressure. The extrapolated interfacial-tension curve given on *Fig. 2 was used for the pressures* above bubble-point pressure.

Table 1

Gachsaran field PVT data

Pressure, psia	Oil FVF RB/st-tk bbl	Gas FVF RB/Mcf	Solution GOR Mcf/st-tk bbl	Viscosity Oil	Viscosity Gas
400	1.110	6.818	0.140	3.11	0.0115
1,200	1.176	2.051	0.316	2.02	0.0133
2,000	1.243	1.148	0.492	1.48	0.0163
2,173	1.257	1.052	0.530	1.41	0.0169
2,300	1.256	0.987	0.530	1.44	
3,000	1.248	0.777	0.530	1.53	
4,000	1.237	0.630	0.530	1.68	

Acknowledgment

The author is thankful to the management of National Iranian Oil Co. for permission to publish this paper.

References

1. Saidi, M. A., Van golfracht T., "Sonsideration sur les Mechanismes DE BASE DAN LES RESERVOIRS Fractures," Revue de L'Institut Francais du Petrole (1971), 1?.

2. Leverett, M. C., "Capillary Behavior in Porous Solids," Trans AIME (1941), 42.

3. Katz, D. L., et al., "Hand Book of Natural Gas Engineering," McGraw-Hill Book Co., (1959).

MATHEMATICAL SIMULATION MODEL DESCRIBING IRANIAN FRACTURED RESERVOIRS AND ITS APPLICATION TO HAFT KEL FIELD

Abstract

Iranian fractured limestone reservoirs are composed essentially of millions of small blocks with sharp discontinuities formed by fractured or impermeable barriers between the blocks. Because of this unique feature the recovery mechanism of oil is essentially based on gravity drainage.

A three-phase compositional reservoir model was developed to simulate the usual features of sandstone reservoirs and the following characteristics of fractured reservoirs: variable block size, gravity drainage, imbibition, variations of capillary pressure with reservoir pressure, diffusion of gas through liquids, bubble point pressure depression.

The Haft Kel reservoir with forty-six years of producing history was successfully matched with this model.

Résumé

Les réservoirs calcaires fracturés d'Iran sont constitués de millions de petits blocs séparés par des discontinuités (fractures ou barrières imperméables). Par conséquent, le mécanisme de récuperation est essentiellement le drainage par gravité.

Un modèle compositionnel triphasique a été élaboré pour simuler, outre les caractères usuels des réservoirs gréseux, les caractéristiques propres aux réservoirs fracturés: blocs de dimensions variables, drainage par gravité, imbibition, pression capillaire fonction de la pression dans le réservoir, diffusion du gaz dans les liquides, abaissement de la pression de bulle, etc.

Les quarante-six ans de production du réservoir de Haft Kel ont été simulés avec succès.

1. INTRODUCTION

Proper simulation of the Iranian fissured reservoirs can only be made through complete understanding of the nature of the mechanisms that take place in these reservoirs. Some of these mechanisms are similar to those that occur in the classic sandstone reservoirs such as water drive, expansion drive, etc. However, some of the mechanisms do not take place in the same manner or some are often ignored in the sandstone reservoirs because of their insignificant contribution to the oil recovery. It was therefore thought appropriate to describe briefly the nature of some of the important mechanisms involved in the fractured reservoirs before going into their mathematical description.

A mathematical model describing some of these mechanisms using the tank concept was developed nearly fourteen years ago.[1] This model has been modified to its eighth version incorporating the results of single block studies.[2] However, with the present fast computer it was thought feasible to develop a model using as many blocks as necessary to describe a fractured reservoir. In this manner less manpower is needed for any study and fewer assumptions and approximations are made as compared with the above-mentioned model. It was due to the above reasons that the present model was developed.

To check the entire model, the Haft Kel reservoir with forty-six years of history was selected. The reason for this selection is that the reservoir has produced over 94% of its primary recoverable oil and the variations in the levels and pressure in this reservoir permit modelling on a one-sector basis.

by ALI M. SAIDI,
Co-ordinator of Special Projects,
National Iranian Oil Company,
Avenue Takhte Jamshid, Teheran, Iran

2. DESCRIPTION OF THE RESERVOIR MECHANISMS

The history of the Iranian well-fractured reservoirs shows very uniform pressure and fluid levels over a wide area of reservoir. The information available on pressure and levels is basically that measured in the fissures. If the variations of the pressures and levels in a reservoir are such that they cannot reasonably be grouped into one area, the reservoir is then divided into more than one sector. A vertical cross-section of pressure–depth relationship for a sector at its initial time and at different times in the depletion period of a fractured reservoir is discussed in detail in the literature.[3] In the fracture system there is only one of the three phases present and with the prevailing pressure they determine the boundary conditions of the blocks surrounded by this particular phase. Studies made on the outcrop of the Asmari and Bangestan formations, flow meter surveys, log analyses of the wells invaded by water in Haft Kel field,[3] etc., show that these reservoirs are composed essentially of several million small blocks with fully open boundaries or partially surrounded by impermeable materials. The major flow mechanisms in the oil zone are visualised as the matrix blocks feeding the fractures, and the fractures, in turn, are acting as carriers of the fluids to the producing wells with essentially no pressure drop.

Gas, water-invaded zones

These portions of the reservoir consist of the volume of the reservoir in which gas or water has surrounded the blocks. Oil drains from the blocks due to the gravity drainage process. This is the main process that causes the oil to flow from the matrix to the fractures and then to the well bores.

Capillary pressure, which is the main retaining force in holding oil in the matrix pores, is a function of interfacial tension, and the gas–oil interfacial tension measurements show a rapid decrease as pressure increases.[4,5] Therefore, the gas–oil drainage process is a strong function of reservoir pressure.

Gassing zone

This zone consists of the portion of the reservoir where the blocks are surrounded by oil and the matrix pressures are lower than the prevailing bubble point pressure.

In this portion of the reservoir, as gas percolates upwards from the matrix blocks, the fissure oil replaces the volume of gas lost to the fractures.

Oil column

In this portion of the reservoir where the blocks are surrounded by oil the following mechanisms are taking place:

1. Fluid and rock expansion.
2. Oil circulation due to convection. The thermal expansion of the oil in these reservoirs is higher than the contraction due to pressure gradient. This causes a continuous potential gradient in the vertical direction within the fractures. This force makes the oil to circulate and the oil with less gas in solution at the gas–oil level to contact the blocks at the lower depths. The uniform initial PVT properties of the oil in each fractured reservoir can easily be explained by the above process. As the reservoir pressure drops, the oil at the gas–oil contact becomes even heavier and the potential, due to the density differences of the oil, becomes larger.
3. Displacement of matrix oil by fracture oil. Because of the density difference between the oil in the matrix and fracture, due to the above process, the lighter matrix oil is displaced by the heavier fracture oil.
4. Gas diffusion. Because of the higher gas concentration between the oil in the matrix and that in the fissure, diffusion takes place between matrix and fracture and gas is transferred from matrix to the fracture according to Fick's Law. This gas is then released to the gas cap through the fracture system.

3. DESCRIPTION OF FRACTURE MODEL

The uniform pressures and levels within a sector of a reservoir and limited areas of pressure drop around the wells cause the three-dimensional problem to be reduced to a vertical two-dimensional problem. To represent the oil-in-place and the rock types, consider a horizontal layer of a sector that consists of many small blocks. If these blocks could be classified into, let us say, four groups each having its own dimensions, porosity, vertical and horizontal permeability, capillary pressures, grid divisions, location, etc., then each layer is represented by four blocks. However, each of the four blocks is multiplied by the number that it represents, so that the total oil-in-place within that layer remains the same.

From the above descriptions, each sector of the reservoir can be represented by a number of blocks stacked vertically and to a limited extent horizontally. Each block is divided into several vertical and horizontal grids. The pressure and level change in the fracture system is detected by the nodes located at the top and bottom of each grid. A schematic representation of such a sector is shown in detail in Fig. 1.

The fluid compositions within the blocks and fractures can be varied with depth. The variation of

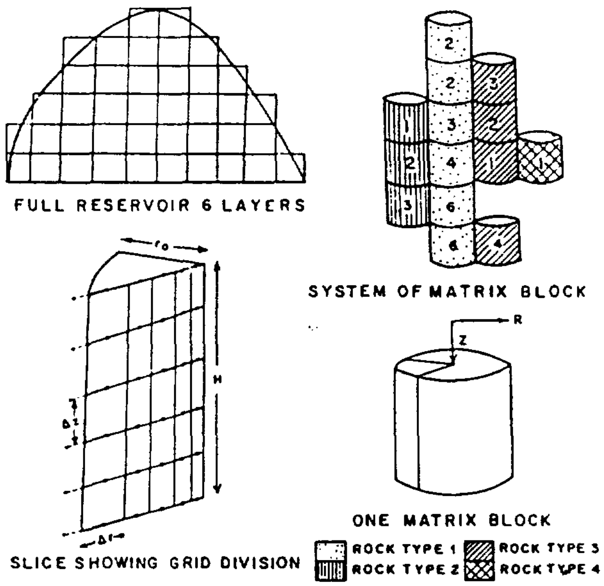


Fig. 1—*Schematic representation of a reservoir by the model.*

interfacial tension with pressure to correct the capillary pressures, and the fracture volume versus depth, are expressed in tables. In addition, a program was developed to convert the black oil PVT information into a two-component system with great accuracy.[6,7]

Assumption

The mathematical model described here represents only a sector of a reservoir. The multi-sector model and the mixed sandstone-fractured model will be discussed in a separate paper. The basic principles involved in the mathematical simulation of multi-component three-phase flow are conservation of mass, Darcy's Law and PVT behaviour of fluids. In addition the following assumptions and conditions were made in the development of this model:

1. A reservoir or each sector of a reservoir consists of a suitable number of horizontal and vertical blocks as was described earlier.
2. Two-dimensional cylindrical blocks, with no angular flow, are sufficiently accurate to describe the three-dimensional blocks.
3. Fluids leaving matrix blocks enter directly into the fracture system without being imbibed by other blocks.
4. The blocks are surrounded by fissures or impermeable boundaries.
5. The fracture system has infinite transmissibility. This is equivalent to saying that fluids within the fissure system are under hydrostatic equilibrium at all times.
6. The capillary pressure effect in the fissure system is zero.
7. At the initial condition, the capillary pressure maintains continuity vertically through different matrix blocks which are separated by horizontal fractures.
8. Fick's Law diffusion can occur between matrix blocks and fissure system due to any concentration gradient within the hydrocarbon phase.
9. The number of the components in the hydrocarbon system is limited to ten.
10. At the end of any time-step, the hydrocarbon phase is at complete equilibrium.

To verify assumption (2), several gas and water gravity drainage displacement studies were conducted on both 3-D and 2-D (R-Z) blocks. These studies indicated that there is insignificant difference between the results of the 2-D and 3-D systems. The main advantage of using the 2-D (R-Z) system over the 3-D is to reduce computer time by a factor of more than two. To explain and verify the assumption that oil leaving a matrix block would not be imbibed by other blocks while flowing to the fractures, studies were made with two blocks with known volume of fracture between the two blocks in two positions, horizontal and tilted. The result of gas–oil drainage shows that in the case of a completely horizontal fracture between two blocks the oil drainage from the upper block is imbibed by the lower block. However, if the fracture is tilted, even at a small angle, almost all the oil produced from the upper block flows into the side fractures. In addition, there is the possibility that a block partially touches a block above or below, which may have the same effect as the two blocks with the horizontal fracture in between. In all the above cases, assumption (4) would be correct if an effective longer block height than the actual were used.

General discussions on the fractured model

The developed model has been used to study over ten major Iranian fractured reservoirs with success. Most of the studies were multi-sectoral, and in some of the studies the reservoir was divided into as many as four sectors.

To check the mathematical model against some known data, a laboratory experiment made by the Shell Laboratories in Rijswijk on a consolidated core

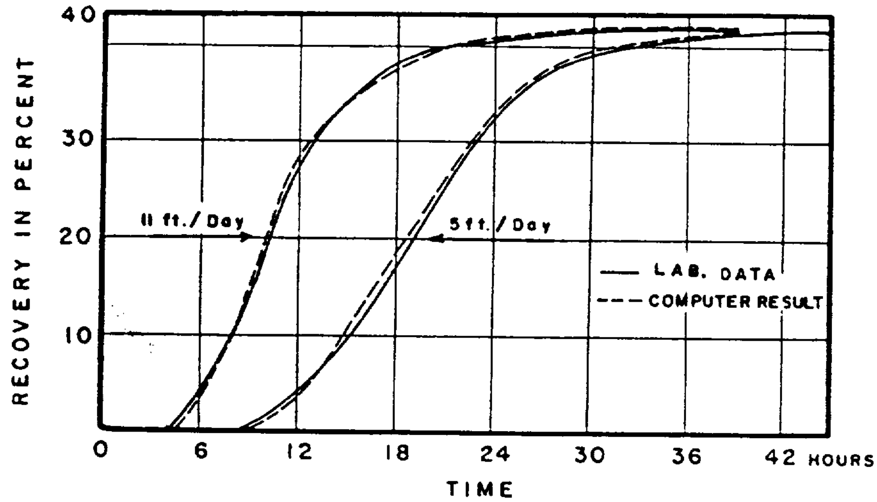


Fig. 2—Comparison between laboratory and simulated block.

was simulated. The core was about 5 ft (1·5 m) high and 5 in (125 mm) in diameter, with a permeability of about 2 D with porosity of 25 %. The capillary pressure of this very homogeneous core was measured on a sample taken from its adjacent formation. The rate of water–oil movement in the fractures around the blocks carried from a minimum of 5 ft/day to a sudden submergence of the block.

Figure 2 shows the results of the simulated and the laboratory experiment. In addition, in another transparent laboratory model experiment, a sharp gas–oil front was noticed in all the cases that were studied. Similar observations were made in the above simulated model studies.

In matching the past history of a reservoir, the fracture pressures, water–oil and gas–oil levels are fed into the model. The model calculates the oil and gas production which is compared with the actual production. The reason for choosing this method is that since the pressures and levels are known, it means that the boundary conditions are also known, and therefore the calculations are done only once.

In order to arrive at a good match, the more accurate and reliable information such as pressure, levels, capillary pressures, relative permeabilities, etc., are fixed and oil-in-place and its distribution, block size, diffusion coefficient, fracture volume with depth, and permeability of the blocks are changed within their acceptable intervals. In matching the GOR it was noticed that the distribution of oil-in-place and diffusion coefficient often has to be changed. This is because the volume of the gas necessary to replace the oil in the gas-invaded zone is first taken from the free and solution gas produced from the system, and the remaining gas is produced with the oil through the wells within the sector.

In the prediction mode, where production and/or injection are given, pressure is first calculated by material balance method and water influx equations using the previous constants. The levels are then calculated making two or three iterations until the resulting model production matches the input data.

The running time of a block with 2 × 2 grid division is nearly five times faster than a 2 × 10 grid division. It is obvious that when there are 500 blocks in a reservoir the computer time can be greatly reduced if 2 × 2 grid division can give the same results as 2 × 10 grid division. This was achieved with great accuracy by using fictitious capillary pressures, and possibly different relative permeabilities, for water–oil and gas–oil systems, so that the recovery curves of the single blocks under all possible conditions are almost exactly the same as if the blocks had 2 × 10 or finer grid divisions. After matching the history of a reservoir with 2 × 2 grid blocks, a run using 2 × 10 or finer grid blocks is also made to double-check the previous results.

Sensitivity analysis

To know the effect of variations of different reservoir and model parameters on the calculated values, the variations of the following were examined using a single book:

1. Studies on absolute and relative permeabilities indicate that the recovery curve is not very sensitive to the shape of relative permeabilities, if the end points are kept the same. The effect of absolute permeability, on the other hand, is very pronounced, for both water and gas displacement. These studies indicate that the variation of permeability has a time delay effect.

For the first approximation the change in permeability is proportional to the time necessary to recover the same volume of fluids, or $k_1/k_2 = t_1/t_2$, where t and k are, respectively, time and permeability.

The following more accurate relationship between permeability, saturation and time was derived: $1/S = 1/SU + C(t/k)^n$, where S and SU are, respectively, saturation at any time t and at final point, and C, K and n are, respectively, a constant, permeability, and another constant. The constant n is between 0·5 and 1.

2. The effect of the variation of porosity is similar but in opposite direction of permeability.

3. The effect of variation of the number of vertical grid divisions in a block on recovery due to gravity drainage is very significant. The radial number of the grid divisions has no significant effect on the recovery. For radii less than 30 ft (9 m), two radial grid divisions were found to give sufficient accuracy. But the decrease of the number of grid divisions in the vertical direction causes a large increase in the oil recovery when gas displaces oil, and a large decrease in the water saturation when water displaces oil.

The large variations in oil recovery when using a lesser number of grids is due to the approximation of capillary pressures, in different directions. In the case of gas displacing oil, the area above the capillary pressure curve represents gas displacement, while in the case of water the area below the capillary pressure curve represents water displacement.

The effect of variation of vertical grid division on saturation change for a 10 ft (3 m) block is given in Fig. 3.

4. Pressure has a negligible effect on oil displacement by water, while the effect of pressure on oil displacement by gas is very pronounced. This is mainly because the gas–oil capillary pressure is a strong function of pressure.

5. The taller the block, the lower the recovery in the early years. It crosses eventually that of the shorter block and reaches its final saturation at the later years. In the case of gas displacement the crossing time is reached sooner than the water displacement.

6. The model is very sensitive to capillary pressure.

7. The size of time step has almost no effect for a given permeability when the solution is stable.

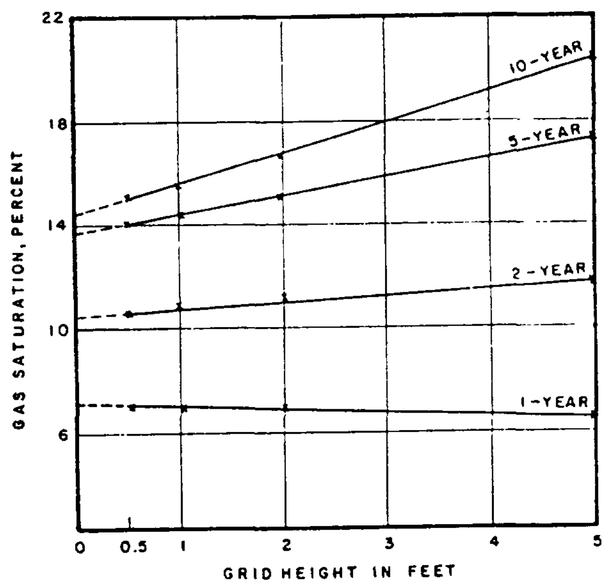


Fig. 3—Effect of grid height on gas saturation.

Special features of the model

To improve the computing efficiency, the following special features are incorporated in the model:

1. Independent time step size for each matrix block is taken depending on the variation of saturations in the blocks. To accomplish this, a target time is chosen. Calculation of all the blocks is performed up to that target time. In this fashion considerable saving on running time was achieved.

2. Since the matrix inversion routine constitutes a significant part of the computations, it is written in COMPAS (machine language). The running time due to this was reduced by about 20%.

3. Because of the large storage requirement, information pertaining to individual matrix blocks is put on and retrieved from the disk which causes a significant amount of input–output time. To reduce this deficiency a technique was introduced to provide simultaneous input–output and computations. This is structured in such a way that while execution is in progress on one matrix block, input is being processed for the second block and the output is being written for the third block. In this manner peripheral processors are functioning in parallel with the central processor.

4. MATHEMATICAL DESCRIPTION OF THE MODEL

The flow equations using Darcy's Law and the conservation law of mass for water and component i in both gas and oil phases may be written in the following form:

$$\nabla \cdot \frac{kk_{rw}}{B_w \mu_w} \nabla(P_w - \gamma_w h) + q_w = \frac{\delta}{\delta t}\left(\varphi \frac{S_w}{B_w}\right) \qquad (1)$$

$$\nabla \cdot \frac{kk_{ro}\rho_o}{\mu_o} X_i \nabla(P_o - \gamma_o h) + q_o X_i - q_v X_i + \nabla \cdot \frac{kk_{rg}\rho_g}{\mu_g} Y_i \nabla(P_g - \gamma_g h) + q_g Y_i + q_v Y_i + \nabla \cdot D \nabla X_i = \frac{\delta}{\delta t}[\varphi(S_o \rho_o X_i + S_g \rho_g X_i)] \qquad (2)$$

Equation (2) represents a total material balance on the components. The $\nabla \cdot D \nabla X_i$ represents diffusion in the oil phase only, where $D = D_{AB} S_o \rho_o / \varphi$. The following algebraic equations relate oil, gas and water pressures:

$$P_w = P_o - P_{cwo}, \qquad P_g = P_o + P_{cgo} \qquad (3)$$

The phase equilibrium relations are:

$$Y_i = K_i X_i \qquad (i = 1, 2, \ldots, N) \qquad (4)$$

and constraints which must be satisfied are:

$$\sum_{i=1}^{N} X_i = 1, \qquad \sum_{i=1}^{N} Y_i = 1 \qquad (5)$$

$$S_w + S_o + S_g = 1 \qquad (6)$$

Equations (1)–(6) are $2N + 6$ equations with the $2N + 6$ unknowns:

$$P_w, P_o, P_g, S_w, S_o, S_g, X_1, X_2, \ldots, X_n, Y_1, Y_2, \ldots, Y_n$$

These equations are solved for the necessary initial and boundary conditions.

As an example, the initial and boundary conditions of a block when water starts to touch the bottom of a block until it passes the top of the block are:

Initial conditions: $t = 0, 0 \le z \le H$ and $0 \le r \le r_o$, $S_w =$ constant, and $P_o = P - z \nabla \gamma_o z$.

Boundary conditions:

for

$$0 < t \le H/v$$

at $z = 0,\ 0 \le r \le r_o$
$P_w = P$

at $0 \le z \le vt,\ r = r_o$
$P_w = P - \gamma_w z$

at $vt < z \le H,\ r = r_o$
$P_o = P - [vt\gamma_w + (z - vt)\nabla\gamma_o(z - vt)]$

at $z = H,\ 0 \le r \le r_o$
$P_o = P - [vt\gamma_w + (H - vt)\nabla\gamma_o(H - vt)]$

for

$$t > H/v$$

at $z = 0,\ 0 \le r \le r_o \qquad P_w = P$

at $0 \le z \le H,\ r = r_o \qquad P_w = P - \gamma_w z$

at $z = H,\ 0 \le r \le r_o \qquad P_o = P - \gamma_w H$

where z is vertical direction and P is a reference pressure at $z = 0$.

Equations (1)–(6) have to be solved for the necessary initial and boundary conditions for each block in a sector. The basic difference between this set of equations representing a compositional system and that of a black oil system is that the gas and oil equations represent liquid and vapour and the units are mols/day, as against STB/day and MCF/day, respectively. The q_v term replaces the normal gas–oil ratio R_s and represents mass transfer between the liquid and vapour phases which is a function of both composition and pressure.

The method of evaluating q_v is to express it in the form

$$q_v = \frac{\partial q_v}{\partial P}\delta P_o + q^*_v = -(S_o\rho_o + S_g\rho_g)\frac{\partial L}{\partial P}\delta P_o + q^*_v \qquad (7)$$

where $\partial q_v/\partial P$ is the derivative of the vaporisation with respect to pressure evaluated at the start of the time step. $\partial L/\partial P$ is obtained from equilibrium flash calculations for a pressure change δP. q^*_v is the iteration on the vaporisation rate to account for compositional changes plus correction for any error. The vaporisation rate at the end of any iteration is simply calculated implicitly from the net transfer to the gas phase by using the flow equation (2).

The total accumulation of component i (ACC_i) was calculated explicitly from eqn. (2) as $(ACC_i) = V\varphi^{n+1} \times (S_o\rho_o X_i + S_g\rho_g Y_i)^{n+1}$. The total mol fraction of oil and gas of component i was calculated as:

$$Z_i = (ACC_i) \Big/ \sum_{i=1}^{N} ACC_i \qquad (8)$$

The mol fraction of each individual phase was obtained from equilibrium flash calculation by solving:

$$\sum_{i=1}^{N} Z_i(1 - K_i)/[L + K_i(1 - L)] = 0 \qquad (9)$$

and the phase mol fractions were calculated from:

$$X_i = Z_i/[L + K_i(1 - L)] \quad \text{and} \quad Y_i = K_i X_i \qquad (10)$$

At this point the new pressure and compositions are obtained.

By appropriate transformation and manipulations of the above equations, it is possible to solve them for liquid hydrocarbon pressure, p_o, using the known implicit pressure and explicit saturation methods (IMPES).[9,10] The coefficients of the pressure equations are solved by the Gaussian elimination method.

The iterative procedure for the solution used in the simulation is:

1. While holding the non-linear coefficients constant, the pressure equation is solved by the Gaussian elimination method.
2. Using the last pressure iteration, water saturation and the number of mols of each component present in each grid block were calculated.
3. The hydrocarbon is flashed to obtain the compositions and hydrocarbon saturations, oil and gas.
4. The non-linear coefficients in the pressure equation are calculated, and steps (1)–(4) are repeated until convergence is obtained.

5. HAFT KEL FIELD STUDY

Haft Kel Field is situated in the south-west of Iran at the east side of the Dezful embayment. The field was discovered in 1928 and had a cumulative oil

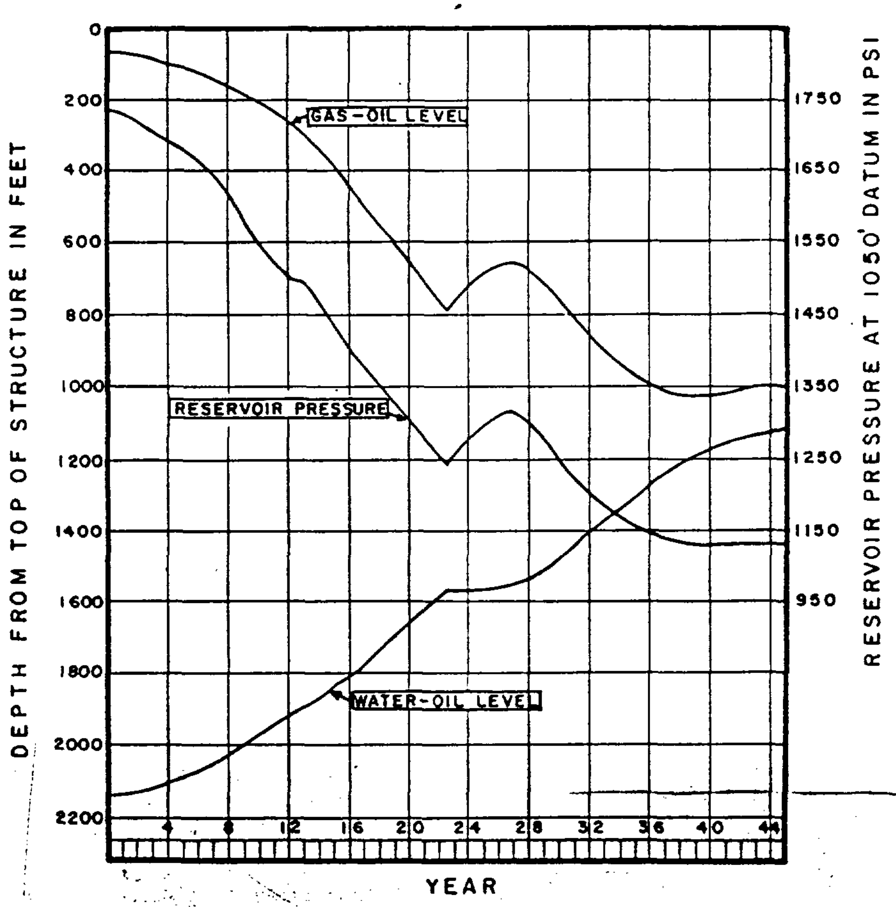


Fig. 4—Pressure, gas–oil and water–oil levels of the Haft Kel.

production of over $1{\cdot}64 \times 10^9$ STB at the end of 1973. It is approximately 20 miles (32 km) long and 3 miles (5 km) wide. The main producing formation is the Asmeri limestone of Oligo-Miocene age which is 900 ft (280 m) thick. This reservoir is also in pressure communication with the Eocene and Cretaceous rocks and with the Naft Safid Field from the north-west. These formations and reservoirs have probably contributed to oil production in Haft Kel.

The oil-in-place finally used in the mathematical model is $7{\cdot}24 \times 10^9$ STB in the matrix and 197×10^6 STB in the fissures.

Because of excellent communication in the reservoir, the pressure variations and gas–oil and water–oil levels within the field are not significant and they can reasonably be averaged. In addition, in order to simplify the study and to reduce the computer time, only one rock type was used to represent the reservoir. The porosity and permeability of the blocks varied, respectively, from 12 to 7% and from 0·8 to 0·05 md. The block dimensions are varied from 10 to 14 ft (3–4·25 m) in height with radii of 6–8 ft (1·8–2·5 m). The forty-five years of history consisting of the pressure, water–oil and gas–oil contacts are given in Fig. 4. The relative permeabilities of gas–oil and water–oil are given in Fig. 5, and their related capillary pressures at the bubble point pressure are given in Fig. 6. The cumulative fracture volume distribution versus depth which was finally used in this study is given in Table I. The black oil PVT properties are given in Table II.

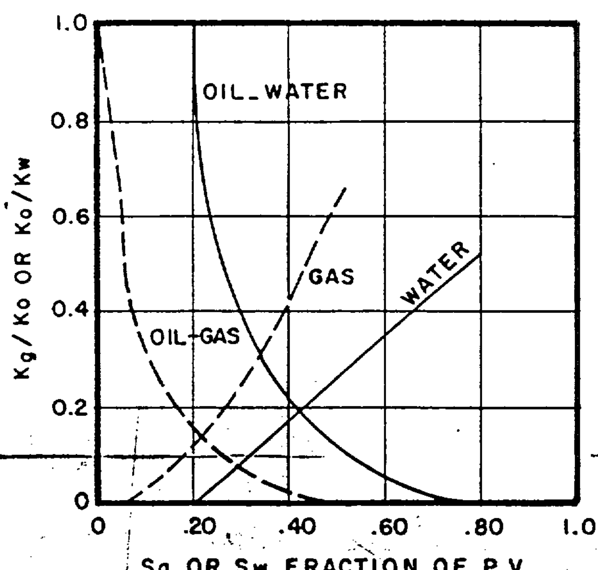


Fig. 5—Oil, water and gas relative permeability.

TABLE I

FRACTURE VOLUME DISTRIBUTION *VS.* DEPTH

Depth	*Fracture volume* (10^6 *RB*)	*Depth*	*Fracture volume* (10^6 *RB*)	*Depth*	*Fracture volume* (10^6 *RB*)
90	4·5	600	97·0	1400	165·0
200	10·0	700	107·0	1700	193·0
350	55·0	900	127·0	1850	213·0
500	85·0	1100	135·0	2136	234·0

The water formation volume and compressibility factors, rock compressibility, and diffusion coefficient of 1·002 RB/STB, 3×10^{-6} psi^{-1}, 4×10^{-6} psi^{-1}, and 0·00025 ft^2/day were respectively used in this study. The gas–oil capillary pressure was calculated from the equation:

$$P_c \text{ (at any pressure)} = P_c \text{ (at bubble point)} \times (3{\cdot}62 - 2{\cdot}76 \times 10^{-3} P + 6{\cdot}5 \times 10^{-7} P^2)$$

In matching the past history of this reservoir, almost all the parameters mentioned earlier within their possible ranges were changed to arrive at a good match.

TABLE II

PVT PROPERTIES OF THE HAFT KEL RESERVOIR

Pressure (psia)	*Oil FVF (RB/STB)*	*Gas FVF (RB/MCF)*	*Solution GOR (MCF/STB)*	*Viscosity*	
				Oil	*Gas*
212	1·065	10·6	0·09460	1·590	0·011065
612	1·1037	4·16	0·194934	1·170	0·012059
1012	1·142	2·40	0·295268	0·910	0·013049
1412	1·181	1·662	0·3956	0·785	0·014040
1812	1·1766		0·3956	0·785	0·015032
2122	1·1723		0·3956	0·785	0·016024

The reason for such detailed studies was to check and find feelings for the magnitude of certain not well-known mechanisms, such as convection and diffusion, block height, equilibrium gas saturation, fracture volume, etc. This study was very important since the histories of the other Iranian fractured reservoirs are relatively short and they are far from being near depletion. In addition, Haft Kel Field has very strong water drive so that the water–oil and gas–oil levels have advanced almost equally from their original positions, while most other Iranian fractured reservoirs have relatively weak water drive. Because of this, the calculation of water displacement efficiency in these other fields would be inaccurate. This would lead to a possible wrong decision on the type of fluid injection in these reservoirs for pressure maintenance and secondary recovery. The results of yearly oil production history match are given in Fig. 7. The solid line is

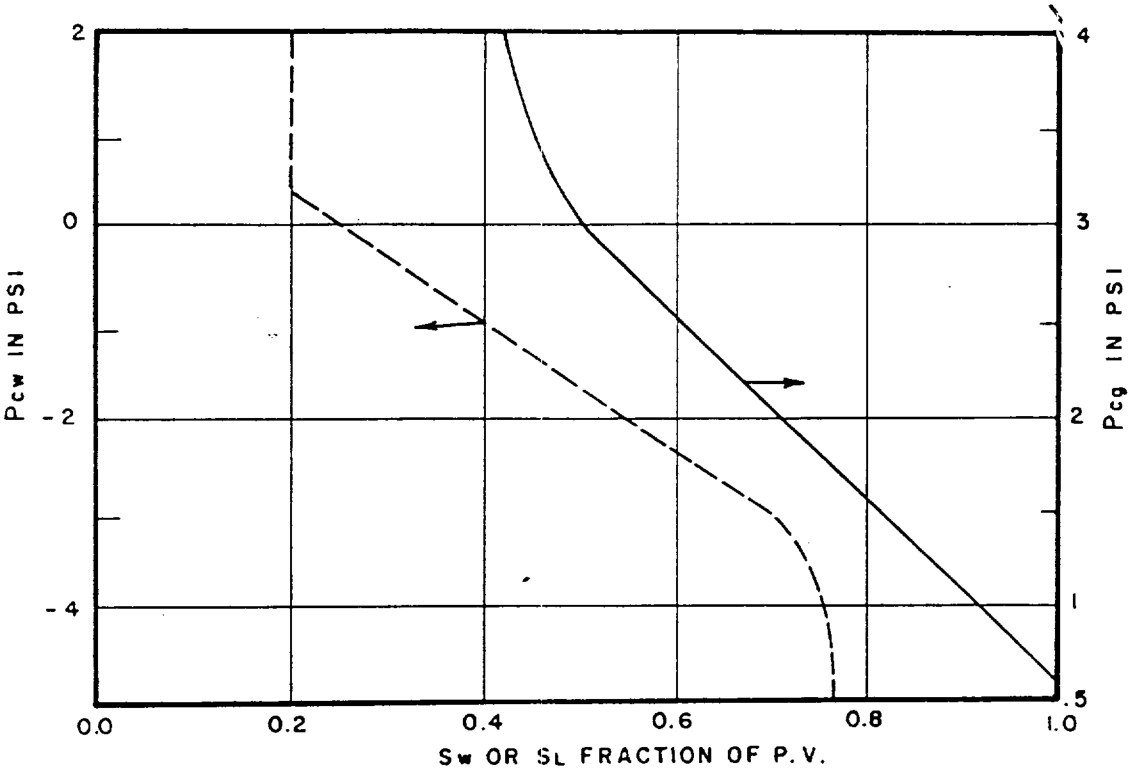


Fig. 6—Average water–oil and gas–oil capillary pressure used for Haft Kel Field.

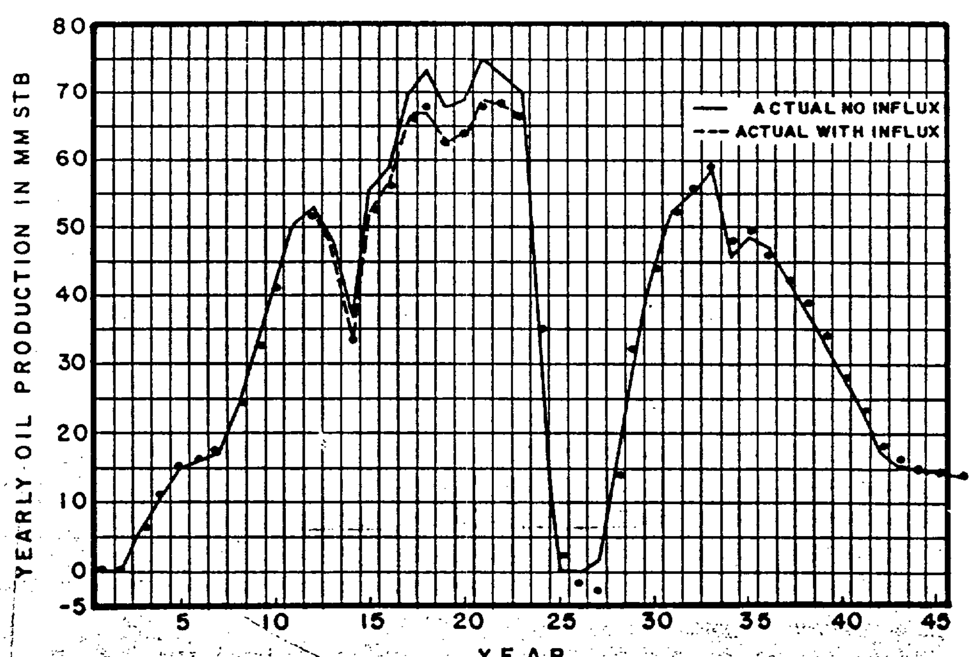


Fig. 7—Production history of the Haft Kel Field.

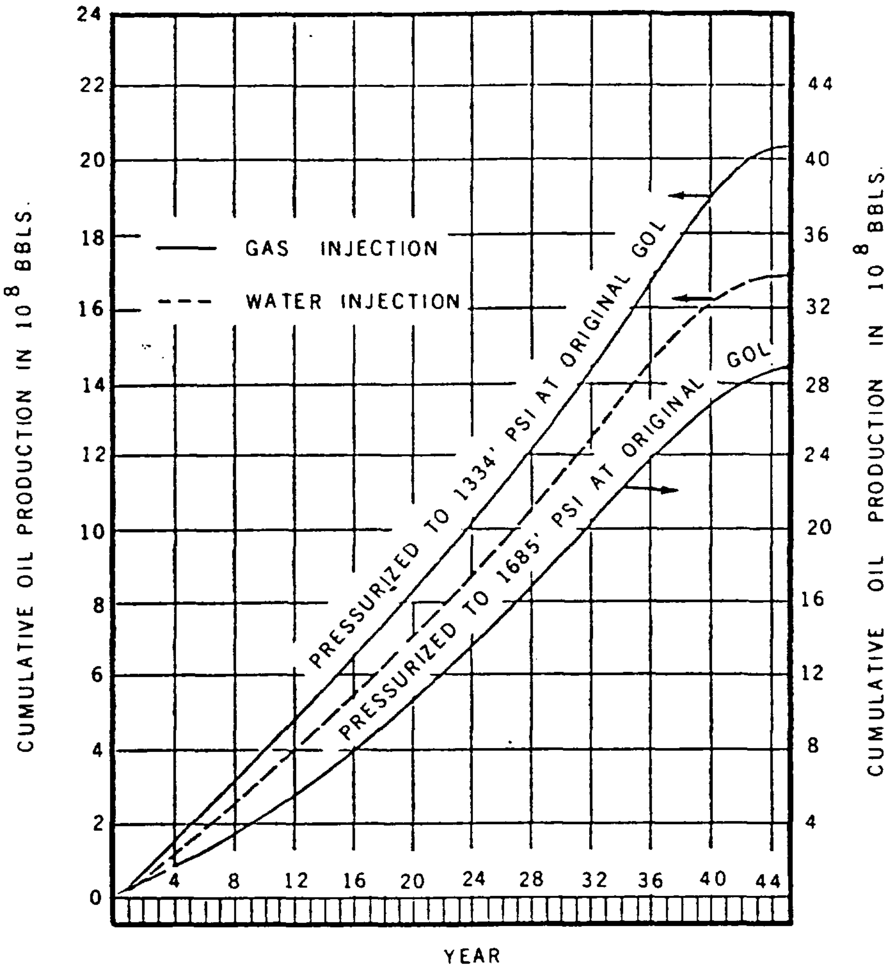


Fig. 8—Oil recovery under different fluid injection schemes.

yearly production and the dashed line is the net production minus estimated oil influx from the Naft Safid reservoir and other sources. The GOR was matched on the yearly cumulative basis. To evaluate the effect of gas and water injection on recovery, several hypothetical studies were made, using the same reservoir data under which the natural depletion history was matched. Water or gas was injected into the reservoir from the starting day of production, such that in the case of water injection the original gas–oil contact was kept the same, and in the case of gas injection the original water–oil contact was kept constant. The reason for making hypothetical studies, *i.e.* to inject gas or water at the initial situation, was that if gas is injected into the Haft Kel Field, with an air column of about 100 ft (30 m), it will contact the water-invaded zone, by pushing the oil column down to the presently water-invaded zone. To analyse and compute such systems the knowledge of three-phase capillary pressure and relative permeability is essential. Gas injection with higher final reservoir pressure (1683 psi) than the pressure at the original gas–oil contact (1412 psi) was also studied. The results of the hypothetical studies are given in Fig. 8.

6. SUMMARY AND CONCLUSIONS

The following conclusion may be made from this paper:

1. Iranian fractured reservoirs are substantially different from the classic sandstone reservoirs and to

study them special attention and a special mathematical model are required.

2. These reservoirs can be described by a stack of vertical, and to a limited extent horizontal, blocks surrounded by fractures and/or impermeable barriers.

3. A rigorous mathematical model was developed to describe such reservoirs, and some of the fundamental portions of the model were tested against some known laboratory data.

4. The Haft Kel Field was matched and several hypothetical prediction cases were studied.

5. Studies indicated that if gas had been injected into Haft Kel Field from the beginning, such that the reservoir pressure at the gas–oil contact was kept constant at 1412 psi, nearly 800 million STB of additional oil could have been recovered.

7. NOMENCLATURE

RB	Reservoir barrel
STB	Stock tank barrel
B	Formation volume factor, RB/STB
b	Reciprocal formation volume factor, STB/RB
C	Compressibility, psi^{-1}
D_{AB}	Diffusion coefficient, ft^2/day
g	Acceleration due to gravity, ft/sec^2
GOR	Gas oil ratio, ft^3/bbl
h	Depth, ft
H	Block height, ft
k	Absolute permeability, md
k_r	Relative permeability
K	Equilibrium phase constant (Y_i/X_i)
L	Moles liquid per mole hydrocarbon mixture
N	Number of components
P	Pressure, psia
P_c	Capillary pressure, psia
q	Injection rate, STB/day/ft^3 for water, mol/day/ft^3 for gas and oil
q_v	Vaporisation rate, mol/day/ft^3
q^*_v	Vaporisation rate neglecting pressure change, mol/day/ft^3
q'_v	Derivative of vaporisation rate with respect to pressure, mol/day/psi
S	Saturation
t	Time, days
v	Velocity, ft/day
X_i	Mol fraction component i in liquid phase
Y_i	Mol fraction component i in gas phase
Z_i	Mol fraction component i in total hydrocarbon
μ	Viscosity, cP
ρ	Molar density, lb mol/bbl
φ	Porosity, fraction
γ	Specific weight, psi/ft
δ	Change over time step
∇	Laplacian operator

Subscripts

g	Gas phase
i	Component number i
o	Oil phase
w	Water phase

Acknowledgements

The author wishes to thank the management of the National Iranian Oil Company for the support of this work. The assistance of INTERCOMP for developing the computer program and computing technique is also greatfully acknowledged.

References

1. K. H. ANDRESEN, R. I. BAKER and J. RAOOFI, Development of Methods for Analysis of Iranian Asmari Reservoirs, Proc. of the 6th Wld Petrol. Congr., Section II, Paper 14, 1963.
2. R. H. YAMAMOTO *et al.*, Compositional Reservoir Simulation for Fissured Systems: The Single Block Model, SPE Paper No. 2666, presented at the 44th Annual Fall Meeting of Sol. Pet. Eng., 1969.
3. A. M. SAIDI and T. VAN GOLDFRACHT, Considérations sur les méchanismes de base dans les réservoirs fracturés, Revue Inst. Fr. Pétrole, 1971, 12.
4. A. M. SAIDI, Effect of Gas Pressure Maintenance on the Recovery of the Iranian Fractured Limestone Reservoirs, presented at the 9th Wld En. Conf., 1974.
5. D. L. KATZ *et al.*, Handbook of Natural Gas Engineering, 1959, McGraw-Hill, New York.
6. G. H. ALANI and H. T. KENNEDY, Volumes of Liquid Hydrocarbons at High Temperatures and Pressures, Petrol. Trans. AIME, 1963.
7. J. E. LITTLE and H. T. KENNEDY, A Correlation of Viscosity of Hydrocarbon Systems with Pressure, Temperature and Composition, SPE J., 1963.
8. A. SOTOODENIA, private communications.
9. J. W. SHELDON *et al.*, A Method for General Reservoir Behavior Simulation on Digital Computers, 35th Annual Sec. Petrol. Engrs Meeting, Oct. 1960, Denver.
10. H. L. STONE and A. O. GARDER, Jr, Analysis of Gas Cap or Dissolved Gas Drive Reservoirs, Trans. AIME, 1961, 222, 92.

Fahud Field Review: A Switch From Water to Gas Injection

Niel O'Neill, SPE, Petroleum Development Oman

Summary. The water injection schemes implemented in the Fahud field during the early 1970's led to poor recoveries because the reservoirs were both fractured and oil-wet. On the basis of the results of a thorough performance review, it was decided in 1983 to promote gas/oil gravity drainage fully by drilling rows of downdip producers and switching completely from water to gas injection. This paper investigates the reasons behind each stage of development and reviews recent efforts to evaluate the future production potential through the use of dual-porosity simulators.

Introduction

The Fahud field (Fig. 1), which has a stock-tank oil initially in place (STOIIP) of 1000×10^6 stock-tank m^3 [$6,300 \times 10^6$ STB], is an elongated monocline with an eroded fault escarpment. The field is divided by a permeability barrier into two accumulations, Fahud North-West (NW) and South-East (SE), each of which contains three fractured Natih limestone reservoirs. The three Fahud NW reservoirs (NW-A, NW-C/D, and NW-E/F/G) are separated by continuous shales but are in communication with each other across the eroded fault escarpment (Figs. 2 and 3). The same applies to the three Fahud SE reservoirs (SE-A, SE-C/D, and SE-E). The oil has a density of 870 kg/m^3 [31°API] with initial reservoir fluid properties as presented in Table 1. The field was discovered in 1964 and started production in 1967. To date, 12% of the field's STOIIP has been produced. This paper reviews the field's performance during four distinct phases of development: initial, waterflood, reassessment, and present development.

Initial Development—1967–71. The field was initially produced under natural depletion supplemented in 1968 by gas injection. The high offtake rates led to a rapid displacement of the gas/oil contact (GOC), which resulted in the early gassing out of a number of relatively downdip completions. Simulation studies and field trials were conducted, which concluded that better recoveries would be obtained through waterflooding.

Waterflood Period—1972–80. Following the recommendations, water injection schemes were implemented in four of the six Fahud reservoirs. However, they failed to arrest either the pressure or oil production decline.

Reassessment Period—1981–83. The poor performance of the waterflood led to a thorough review during which a number of thermal decay time (TDT) logs and tracer tests were conducted. It was concluded that because the reservoir rock was both fractured and oil-wet, recovery factors from waterflooding were low and could be substantially improved by reverting to full-scale gas/oil gravity drainage.

Present Development—From 1984. The present policy is to promote gas/oil gravity drainage fully. This ongoing development requires the phasing out of water injection, the completion of downdip grids of producers, and the full replacement of voidage by gas injection. Dual-porosity simulation studies are currently being conducted to optimize the remaining development and to predict the future field performance.

Geology

The Fahud field is a 0.24- to 0.3-rad [14 to 17°] northeast-dipping monocline bounded in the southwest by a fault plane and overlain by the sealing Fiqa shales (Figs. 2 and 3). The three main oil-producing reservoirs are contained in the Natih formation, which is about 440 m [1,444 ft] thick. The Natih carbonates consist of seven regressive cycles. Reservoir division into subunits is largely based on its relative position in a depositional cycle. A fully developed cycle contains shale at the base and grain-supported limestone at the top. The reservoirs are therefore of variable quality, but usually improve upward in a cycle. Notably the rudistid grainstones of Subunits A_3 and C_1, each being at the top of a cycle, are excellent reservoirs (Table 2). These subunits are greatly improved as a result of freshwater leaching during periods of subaerial exposure terminating the respective cycles.

Very high permeability values can be explained only by fractures in the reservoirs. Fracture identification logs, tracer tests, and outcrop studies indicate a northeast/southwest directional trend in the fracture system, a fracture spacing of about 10 m [33 ft], and fracture widths up to 2 mm [0.08 in.]. This feeder fracture system is rather different from more common fracture models in carbonates, which usually have smaller spacings and widths. The matrix blocks (or slabs) are thought to be of a considerable size with continuity in both the dip direction within each subunit (>100 m [>328 ft]), and also in the vertical direction through the varying-permeability subunits (up to 80 m [262 ft]).

Initial Development

The initial development of the Fahud field, consisting of 47 producers in the six reservoirs, was drilled by the end of 1968. The majority of the wells were located relatively downdip to enable completions between 380 and 420 m subsea (ss) [1,250 and 1,380 ft ss]—100 to 140 m [330 to 460 ft] above the 50% oil/water contact (OWC). This positioning was selected to give some scope for both gas-cap expansion and natural water influx.

The initial production performance was encouraging with well offtakes of up to 2500 m^3/d [15,700 B/D] and total field production building up to more than 35 000 m^3/d [220,000 B/D] by 1969 (Figs. 4 through 7). Because of the rapid decline in reservoir pressure, however, gas injection had to be initiated in mid-1968. This arrested the pressure decline but did not stop the fall in the GOC, which in Reservoir NW-A moved from an original level of 76 to 300 m ss [250 to 980 ft ss] in early 1970 (Fig. 8). The expanding gas cap had caused two updip NW-A wells completed at 200 m ss [660 ft ss] to gas out in late 1968 and two more wells completed at 250 to 300 m ss [820 to 980 ft ss] to gas out in late 1969.

In the meantime, geologic and petrophysical studies had indicated that the reservoirs were far more heterogeneous than had been originally suspected. Core-derived permeabilities ranged from <1 to 1,000 md. In addition, there were thought to be extremely high-permeability zones in the vuggy/rudist Subunits A_3 and C_1, where core recovery was extremely poor. It was consequently concluded that the rapid advance of the GOC was caused by drainage of these high-permeability zones and that the majority of the reservoir rock was being left undrained.

To avoid premature gas breakthrough into the main rows of producers, two options were considered: reducing the offtake to a level that matched the total sustainable drainage rate of each reservoir or injecting water into the more permeable Subunits A_3

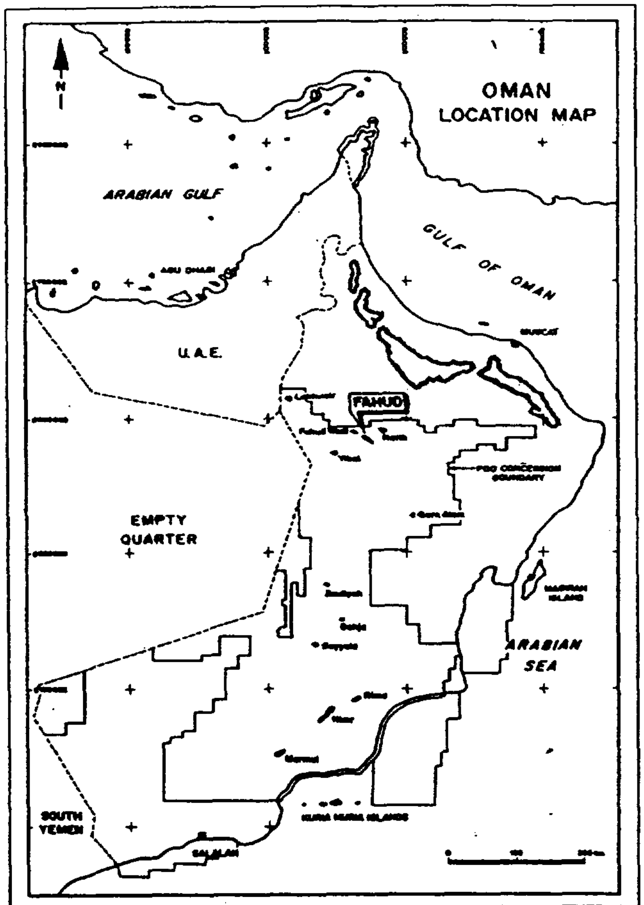


Fig. 1—Oman location map.

and C_1 and relying on gravity-induced crossflow to sweep the tighter underlying subunits.

To investigate the merits of waterflooding vs. gas/oil gravity drainage in the Fahud field, a simulation study of Subunit NW-$C_{1,2}$ was made. The model consisted of five layers with permeabilities of 1,000, 100, 100, 10, and 10×10^{-3} darcies and 15 columns. To investigate the merits of water injection, runs were made for a range of k_H/k_V (horizontal/vertical permeability) values and injection rates. Waterflooding of the lower layers could occur only through gravity-induced crossflow because capillary effects were ignored. The study showed that while gas injection gave recoveries very similar to the extrapolated field results (15 to 20% of STOIIP), water injection would increase these recoveries by between 50 and 100%. The main difference was in the sweep efficiency of the underlying lower-permeability layers.

Three main field trials were conducted from April 1971 to test the merits of water injection. In the first, updip water injection was tested for Reservoir NW-A by injecting water into Well FN-5 and observing the water-cut development of downdip Wells FN-56 and FN-61. This scheme appeared attractive as rows of relatively downdip producers were already in place and a number of updip wells were available as injectors. In addition, scouting simulation studies suggested that a high recovery of the tighter underlying Subunit $A_{4\text{-}6}$ could be obtained through gravity-induced crossflow.

When tested, however, water breakthrough occurred in Well FN-61 (located 900 m [3,000 ft] downdip from Well FN-5) in 8 days and in Well FN-56 (located 450 m [1,500 ft] downdip from Well FN-5) in 10 days. When the water injection was stopped, the oil cut recovered faster in Well FN-56 than in Well FN-61. The rapid breakthrough during this test could be explained only by either a fissure/solution channel system or an extremely high-permeability layer. It was already suspected from the rapid decline of the GOC that a dual-permeability system existed with a leached secondary porosity system having darcy permeability imposed on the tight primary matrix. However, a review of the reservoir permeabilities derived from pressure buildups indicated average permeability values of up to 30 darcies over the 60-m [200-ft] -thick Reservoir NW-A. These high kh values found in partial completions in all subunits could not be accounted for by a single leached zone in Subunit NW A_3. This evidence, taken in conjunction with the updip injection pilot performance of Well FN-61, which had water breakthrough before Well FN-56 and afterward recovered oil production more slowly, pointed to the existence of a complex fissure system extending throughout Reservoir NW-A in addition to the leached secondary porosity zones in Subunit NW-A_3. Similar arguments, based on the high kh values from pressure buildups, could be used to support fracturing in the other five Fahud Natih reservoirs.

The two other water injection trials were conducted to test downdip injection in Reservoirs NW-A and NW-C. The water injectors were located close to the OWC while water cuts were monitored in the existing producers. In Reservoir NW-A, test water broke through after 11 months (approximately 3% breakthrough sweep efficiency) and in Reservoir NW-C within 2 to 3 months (approximately 1.5% breakthrough sweep efficiency). The difference was thought to be the result of a greater degree of fracturing and leaching in Reservoir NW-A than in Reservoir NW-C, which provides greater storage capacity and facilitates lateral spreading. Further simulation studies with a single very-high-permeability layer confirmed the early breakthrough but still indicated ultimate recoveries up to twice that from gas injection, albeit at high water cuts.

The lack of sufficient natural water influx, estimated in 1972 to have replaced only 23% of voidage and expected to decline in strength, dictated the necessity for pressure maintenance. Gas injection had been shown to maintain gas-cap pressures effectively, but would lead to low recovery efficiencies unless off-take levels were reduced to unacceptably low levels. Water injection, although resulting in early breakthrough and leading to a large degree of recycling, was expected to give substantially higher recoveries in time. This conclusion was based primarily on simulation runs that showed that the tight underlying layers would be swept by gravity-induced

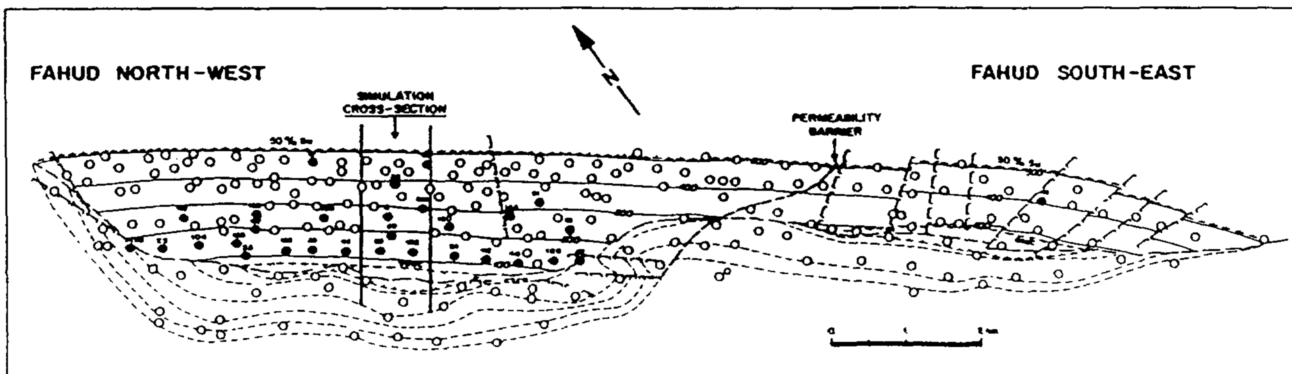


Fig. 2—Fahud field structure map.

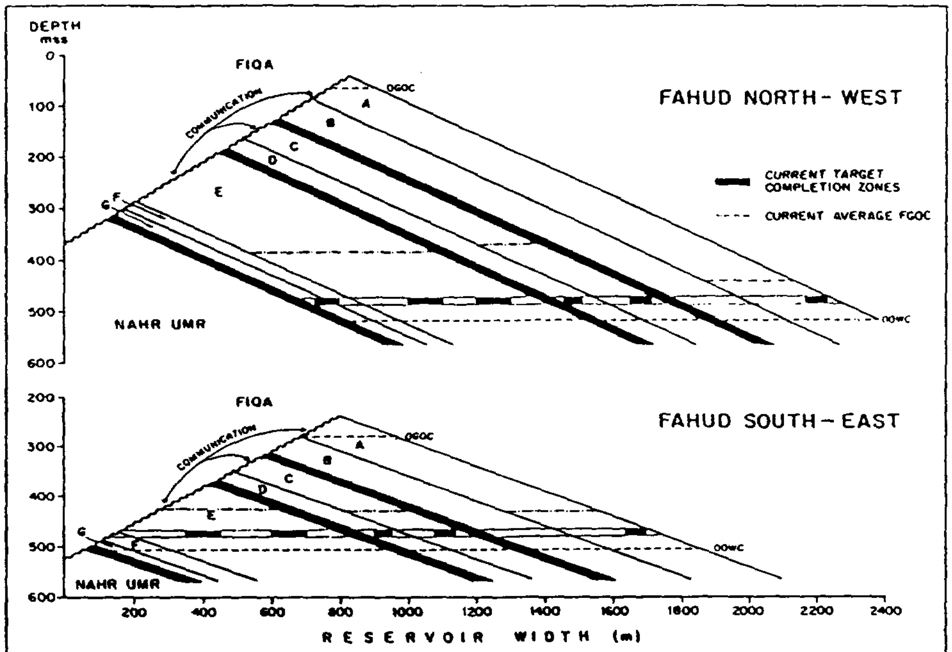


Fig. 3—Schematic cross section of Fahud NW and SE.

TABLE 1—FLUID PROPERTIES

	Fahud Northwest	Fahud Southeast
p_i, kPa	6130	6130
p_b, kPa	3800	5380
R_{si}, std m^3/m^3	23.0	29.0
B_{oi}, res m^3/stock-tank m^3	1.10	1.11
μ_{oi}, mPa·s	2.40	2.07
Oil datum, m ss	400	400
Oil density, kg/m^3	871	871

TABLE 2—FAHUD SUBUNIT CHARACTERISTICS

Subunit	Thickness (m)	Porosity (%)	Matrix Permeability (10^{-3} darcies)	Fracture Permeability* (10^{-3} darcies)
A_1	5	33	1 to 20	10,000
A_2	12	33	1 to 20	20,000
A_3	10	32	1,000	30,000
A_4	6	28	20 to 100	6,000
A_5	11	32	5 to 20	7,000
A_6	18	32	1 to 5	1,000
A_7	20	20 to 30	1	100
$B_{1\text{-}3}$	62	17 to 36	0.1 to 5	**
B_4	15	Shale	—	—
C_1	12	29	200 to 1,000	1,500
C_2	29	32	1 to 20	500
$C_{3\text{-}4}$	9	—	0 to 1	**
D_1	18	29	1 to 20	**
$D_{2\text{-}3}$	12	—	1	**
D_4	11	Shale	—	—
E_1	18	22	1 to 5	**
E_2	50	26	15	300
E_3	55	27	25	300
E_4	43	26	5	300
F	31	28	10	**
G	17	26	3	**

*Estimates of fracture permeabilities based on pressure buildups.
**Limited available data show no evidence of fracturing.

crossflow. Capillary imbibition effects, unaccounted for by the simulation runs, were expected to accelerate this process. It was therefore decided in 1972 to introduce full-scale water injection in both Reservoirs NW-A and NW-C/D and later in Reservoirs SE-A and SE-C/D. It was not considered necessary at this stage to inject water in Reservoirs NW-E/F/G and SE-E because their performance indicated a higher level of natural water influx.

Waterflood Period

The water injection pilot schemes were gradually extended, so that by 1974 there were seven injectors in Reservoir NW-A and nine injectors in Reservoir NW-C/D. Average water injection levels rose to 3200 m^3/d [20,000 B/D] during 1974 in Reservoir NW-A and to 5900 m^3/d [37,000 B/D] during 1973 in Reservoir NW-C/D (Figs. 4 and 5). Five injectors were completed in Reservoir SE-A between 1974 and 1977.

In all cases, water cuts responded rapidly to the downdip water injection. By 1976, water production equaled water injection in Reservoir NW-A and was approaching it in Reservoir NW-C. However, material-balance calculations continued to indicate that the rate of natural water influx was significant and water sweep was continuing. The reason for this is now believed to be underestimation of the STOIIP in Fahud NW. Since 1976, the STOIIP has been increased from 439×10^6 to 764×10^6 m^3 [$2,760\times10^6$ to $4,810\times10^6$ bbl] through the inclusion of Reservoir NW-A_7/B, the shift of the boundary between the northwest and southeast reservoirs 600 m [2,000 ft] to the southeast, and a favorable remapping of the main boundary fault. Subunits NW-A_7 and NW-B have a combined STOIIP of 210×10^6 m^3 [$1,320\times10^6$ bbl] and were originally considered nonreservoir because of their low permeability (< 1 md). Pressure measurements taken during a number of recent Subunit NW-B production tests, however, have indicated that they are substantially depleted and thus provide a degree of pressure maintenance. Although the omission of Reservoir NW-A_7/B had little effect on the 1972 material-balance calculations, when the majority of the reservoir was still at a pressure above the bubblepoint, by 1977 it resulted in an overestimation of the water influx of approximately 70%, or 10^7 m^3 [63×10^6 bbl]. This implied that the water sweep efficiency was 50% higher and the gas sweep efficiency 30% lower than was actually the case. Even so, the 1977 material-balance calculations indicated that gas/oil gravity drainage was more efficient in Reservoir NW/A than the waterflood, although waterflooding still appeared the more efficient recovery process in Reservoirs NW-C/D and NW-E/F/G.

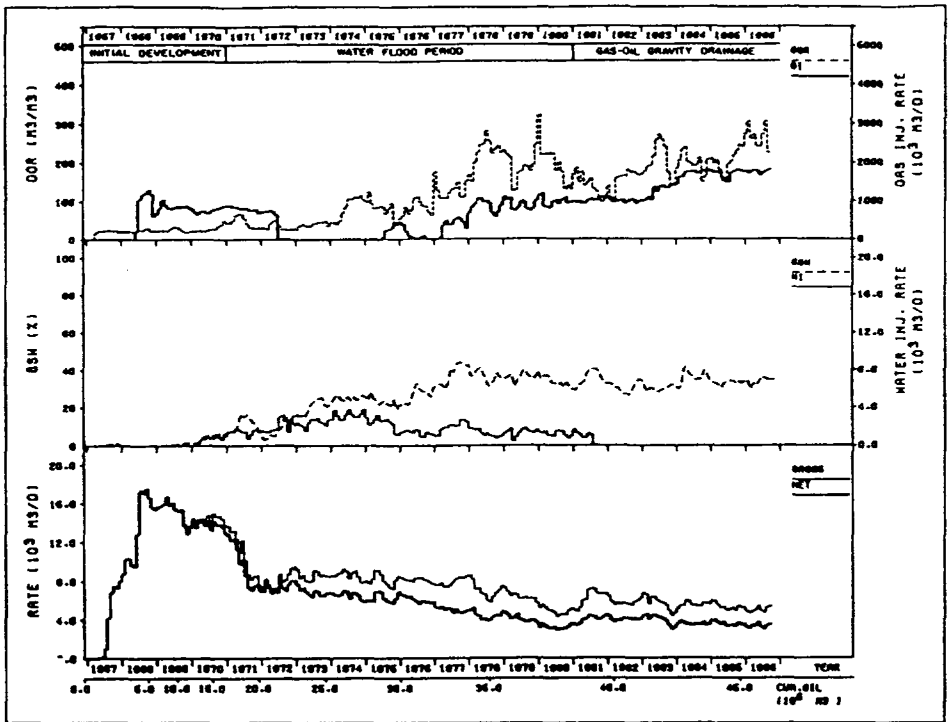


Fig. 4—Reservoir NW-A production performance (BSW = basic sediment and water, WI = water injection, and GI = gas injection).

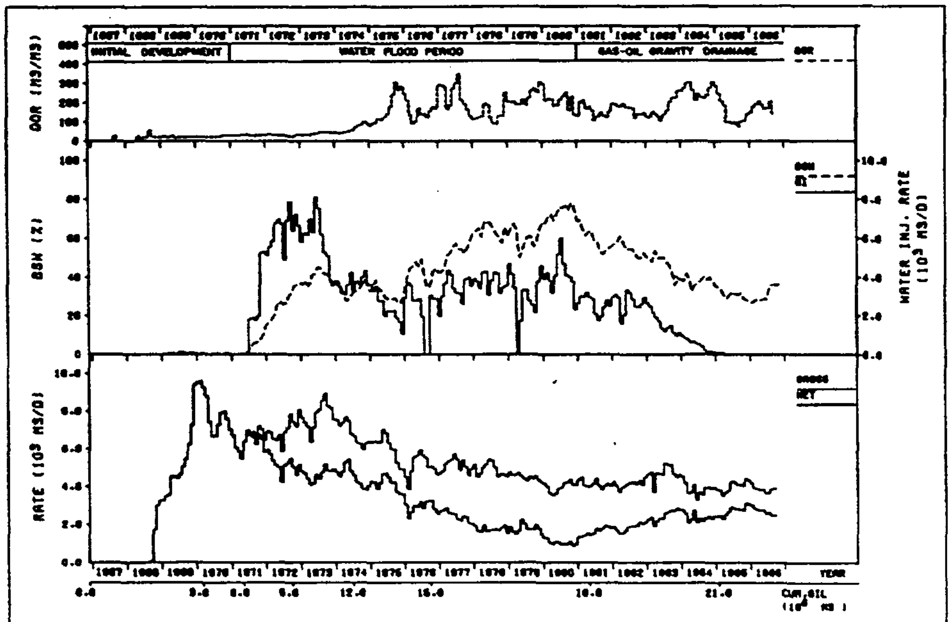


Fig. 5—Reservoir NW-C/D production performance.

Reservoir NW-A. The implementation of a line waterdrive and the phasing out of gas injection led in 1973 to a renewal of the pressure decline. The rapid response of the updip producers to water injection, caused by fracture communication, made it impossible to increase the water injection rate sufficiently to match the voidage rate. This shortfall was accentuated by the proximity of the fracture GOC to the producers, which led to increasing GOR's (Fig. 4) and voidage rates. The real problem was that the oil rim was not being charged at a sufficient rate by the combination of water sweep and gas/oil gravity drainage to match well productivities. Despite the material-balance errors described above, it was clear from the balance of water injection and production that oil recovery through waterflooding had virtually ceased.

Because the reservoir pressure was still declining rapidly (Fig. 8), it was decided in 1977 to reinitiate full voidage replacement by gas injection and to promote gas/oil gravity drainage in the better developed central part of the reservoir. Water injection would be retained only in the less fractured areas on the flanks of the reservoir.

Reservoir NW-C/D. Problems similar to those in Reservoir NW-A were encountered in Reservoir NW-C. Water cuts rose rapidly, soon causing the water injection rate to be cut back (Fig. 5), while the reservoir pressure resumed its decline. However, the cumulative water injection minus water production continued to increase and, when combined with an overestimation of the natural water influx, still gave an optimistic assessment of the waterflooding in relation

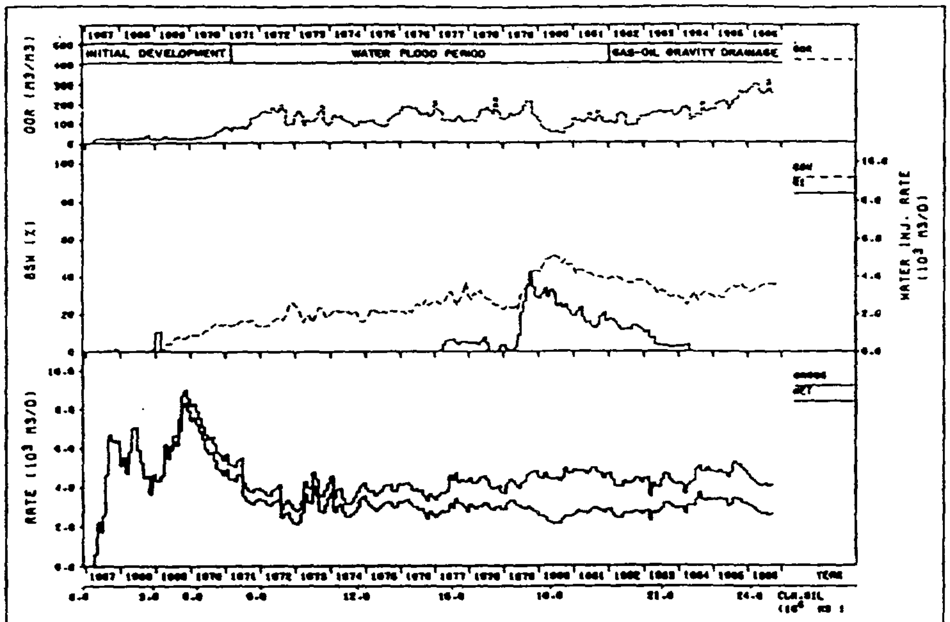


Fig. 6—Reservoir NW-E/F/G production performance.

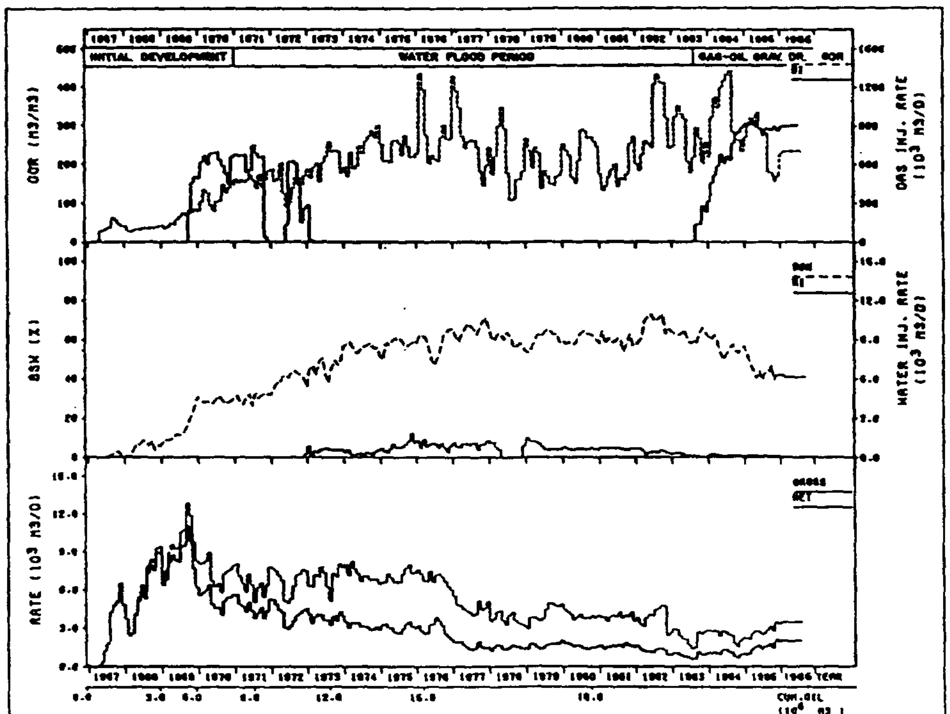


Fig. 7—Fahud SE production performance.

to the gas/oil gravity drainage performance. To improve the areal and vertical sweep efficiency, an additional injector was added and direct injection into the tighter Subunit NW-C_2 started.

Reservoir NW-E/F/G. The gradual water-cut buildup in Reservoir NW-E/F/G had initially suggested a moderately strong bottomwater aquifer in this reservoir. However, it failed to arrest both a decline in the reservoir pressure and an increase in the produced GOR during the period to 1977 (Fig. 6). The results of the material balance had again indicated that recovery by waterflooding was more efficient than by gas/oil gravity drainage. It was therefore decided to supplement the natural influx with water injection. An initial one-well pilot injector (Well FN-5) was commissioned and, although rapid water breakthrough like that in Reservoir NW-C was seen, the project was extended in 1979 to a line of seven dual Subunit NW-E_2/E_3 injectors.

Reservoirs SE-A, SE-C/D, and SE-E. The Fahud SE reservoirs, containing less than 25% of the total field STOIIP, have historically followed the same development as the Fahud NW reservoirs. Consequently, some pressure maintenance occurred through gas injection (1969–72) and through water injection in the less fractured northwestern half of Reservoir SE-A from 1973. During the period to 1980, however, the production decline was even more severe than in the Fahud NW reservoirs. This was because of a combination of reservoir geometry (the original oil column was 230 vs. 460 m [750 vs. 1,510 ft] in Fahud NW), aquifer strength, and low sweep efficiencies, which caused almost immediate water break-

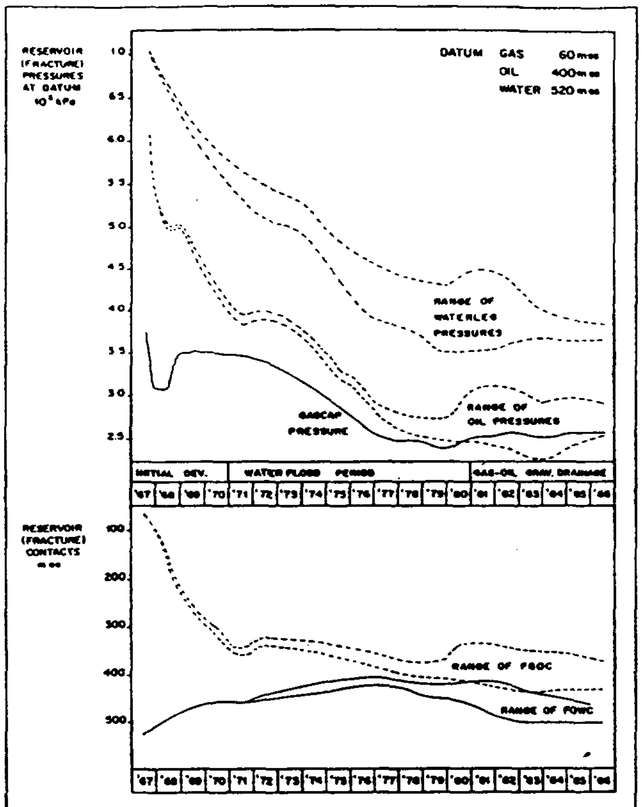


Fig. 8—Reservoir NW-A fracture pressures and contacts.

through in the fractured areas of the reservoirs (Fig. 7). By 1980, the rapid advance of the fracture OWC to a high level in the reservoirs had virtually eliminated the oil rim and cut total production from 8400 m^3/d [53,000 B/D] in 1969 to 1600 m^3/d [10,000 B/D].

Reassessment Period

The poor response of Reservoir NW-E/F/G to water injection during the second half of 1979 and 1980 and the continued decline in the net oil production from Reservoir NW-C/D (Figs. 5 and 6) brought about a radical reassessment of the Fahud production policies during 1981–83. This consisted of a thorough performance review supported by new data from a number of tracer tests and TDT logs. Subsequent results of openhole logs, which were run in downdip wells and directly measured the degree of water sweep, have been included here to complete the interpretation.

Tracer Tests. Seven radioactive tracer tests, two each in Reservoirs NW-A and NW-E/F/G and three in Reservoir NW-C/D, were conducted between 1981 and 1983. Three types of tracer with suitable half-lives (cobalt 60, cobalt 57, and tritium) were used to enable differentiation of the source of each breakthrough. The objectives of the tests were as follows.

1. To confirm the rapid breakthrough times seen in the water injection projects and to estimate breakthrough sweep efficiencies.
2. To establish the orientation of the preferential flow paths.
3. To investigate potential communication between adjacent subunits and reservoirs and to confirm suspected lateral flow barriers.

The results in all cases confirmed the rapid breakthrough from injectors to producers. The tracer front was found to move at rates between 8 and 38 m [26 and 125 ft] for 1000 m^3 [6,290 bbl] of water injected. Calculated breakthrough efficiencies were on the order of 0.3, 0.6, and 1.8% for Reservoirs NW-E/F/G, NW-A, and NW-C/D tests, respectively. Bearing in mind that the Reservoir NW-A tests were conducted in a peripheral area of nonrudist Subunit NW-A_3 development, these results confirm that the breakthrough sweep efficiencies are highest in reservoirs having vuggy/rudist

TABLE 3—SUMMARY OF WATER INJECTION RESPONSE IN RESERVOIR NW-E (1979–80)

Water Injector	Producers	Response Time (months)	Watercut Before (%)	Watercut After (%)
152	135	8	10	35
	23	3	42	77
	104	4	40	75
155	163	2	10	58
	33	2	25	82
	126	No response	—	—
150	29	4	8	78
	114	No response	—	—
5	35	1	22	60
	102	No response	—	—
160	34	4	25	60
	112	No response	—	—
164	48	1	38	78
51	128	2	18	43
	62	1	40	85

subunits such as Subunit NW-C_1. Other conclusions were as follows.

1. In six of the seven tests, tracer breakthrough was seen only in the producer located directly updip of the injector, despite continued sampling in adjacent producers. In the one exception, breakthrough was seen in two producers 350 m [1,150 ft] apart but offset from the injector. These results would imply a "plate" rather than a "matchstick" fracture model with the fractures oriented in a strike-normal direction.
2. In several cases, including both tests in Reservoir NW-E/F/G, the producer showed multiple tracer peaks, implying complex tracer paths.
3. Injection of tracer into Subunit NW-E_3 in Well FN-51W resulted in breakthrough after 6 weeks in the Subunit NW-E_2 completion in Well FN-62, confirming good vertical communication between the subunits.
4. No evidence of tracer breakthrough into adjacent reservoirs was seen.

Besides the waterflood tracer tests, the difference in composition of the Fahud West nonassociated gas from that of the Fahud associated gas (10% N_2 compared with 2% N_2) has enabled a gas tracer test to be made. The resumption of full gas injection into Reservoir NW-A in 1978 enabled the passage of the Fahud West injection gas to be traced through the field. This confirmed the communication across the boundary fault with Reservoirs NW-C/D and NW-E/F/G and established the position of the permeability barrier between the northwest and southeast reservoirs.

TDT Logging. Altogether 25 TDT logs, 11 in the Fahud NW and 14 in the Fahud SE reservoirs, were run to evaluate the performance of the waterflood. Ideally the TDT logs should have been run in wells that produced (or injected) in reservoirs different from those being monitored for water sweep. This would have ensured that any observed saturation changes were reservoir and not well effects. Unfortunately, because of a lack of appropriately positioned locations, it was possible to achieve this in only three wells. These showed a rise of 13 m [43 ft] in Reservoir NW-C OWC in Well FN-31, some sweep in Reservoir NW-C at 420 m ss [1,380 ft ss] in Well FN-155, and a 7-m [23-ft] partially swept zone in Subunit NW-E_2 at 500 m ss [1,640 ft ss] in Well FN-137. These results have been included in the overall evaluation of the water sweep described below. Although the other TDT logs run were subject to well effects, such as coning and cusping, they still give an idea of the maximum sweep that might be encountered at a particular structural position in a reservoir. The following conclusions can be made.

1. No evidence of substantial water sweep was found in the Fahud NW reservoirs. Water coning was found in Reservoirs NW-A (Well

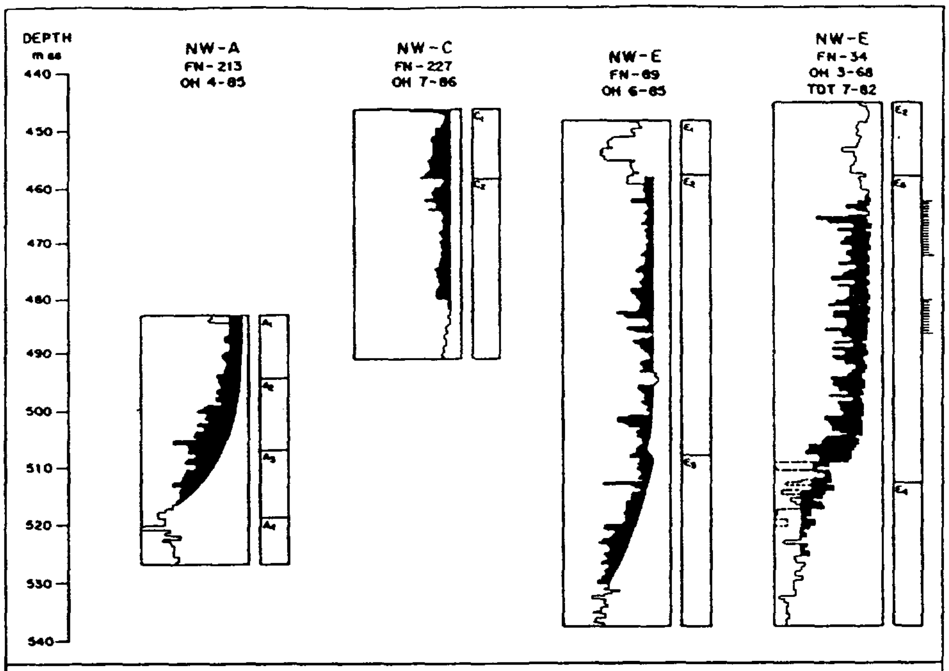


Fig. 9—Typical log-observed water sweep in the Fahud NW reservoirs.

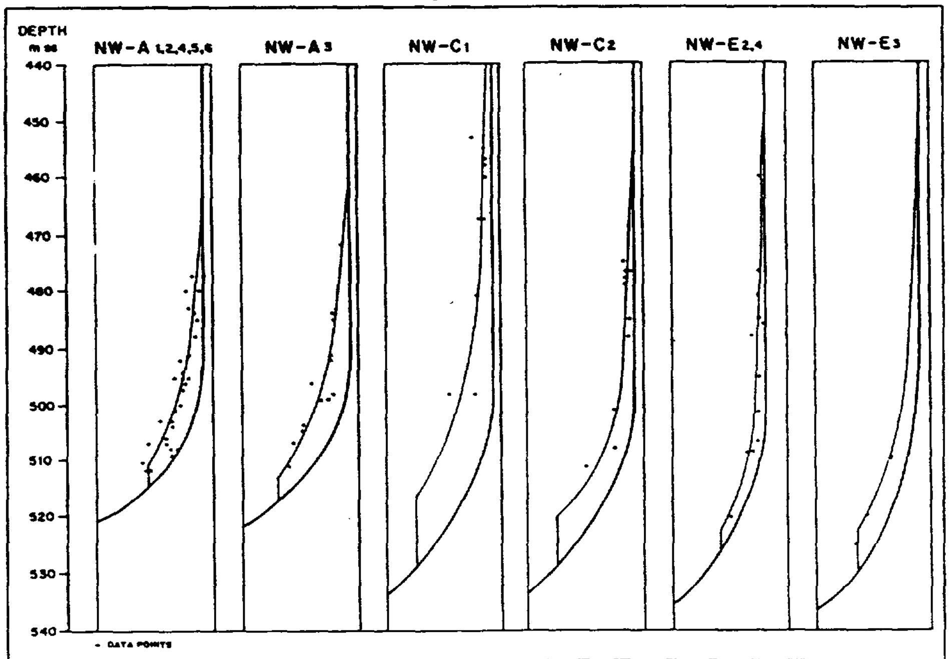


Fig. 10—Estimated water sweep profiles in Fahud NW subunits.

FN-19) and NW-E_3 (Wells FN-29, FN-34, FN-126, and FN-163) (e.g., see Fig. 9d). An apparent water sweep is found across most Subunit NW-C_1 completions, although it is not known to what extent this is caused by acid effects.

2. In two Reservoir NW-E wells (Wells FN-34 and FN-155), where TDT logs were run both before and after the period of water injection, there was no apparent additional water sweep.

3. In Fahud SE reservoirs, the only apparent evidence of water sweep is across perforations. Again it is not known to what extent this is caused by acid effects. Many logged intervals showed mud-filtrate effects despite long elapsed times between the drilling and TDT logging of these wells. This indicates tight matrix rock and, together with the water-cut performance of these wells, suggests that the water is produced through the fracture system with little or no water sweep.

Waterflood Performance. An investigation of the water-cut response to downdip injection was made as part of the performance review. Typical results for Reservoir NW-E producers are found in Table 3, which shows the breakthrough times and water-cut responses to water injection. The lack of response in Wells FN-126, FN-114, FN-102, and FN-112 and the one-to-one injector/producer relationship in the center of the reservoir confirms the plate fracture model. However, there is some lateral spreading of the waterflood toward the edges of the reservoir above Wells FN-152W and FN-51W. It is clear from such water-cut behavior and from the tracer tests that sweep efficiencies at breakthrough are very low. However, it is not clear to what extent the matrix is subsequently swept with continued water injection. The decline in oil production particularly in Reservoir NW-C/D between 1974 and 1980 and in Reservoir NW-E/F/G during 1979–80 (Figs. 5

TABLE 4—ESTIMATED WATER BALANCE FOR FAHUD NW ON JAN. 1, 1986

Fahud NW Reservoir	Water Injection (10^6 m^3)	Water Production (10^6 m^3)	Estimated Water Sweep* (10^6 m^3)	Water Influx (10^6 m^3)
A	7.3	11.2	4.1	8.0
C/D	16.2	12.2	6.3	2.3
E/F/G	3.3	7.4	5.6	9.7
Total	26.8	30.8	16.0	20.0

*Derived from data presented in Fig. 10.

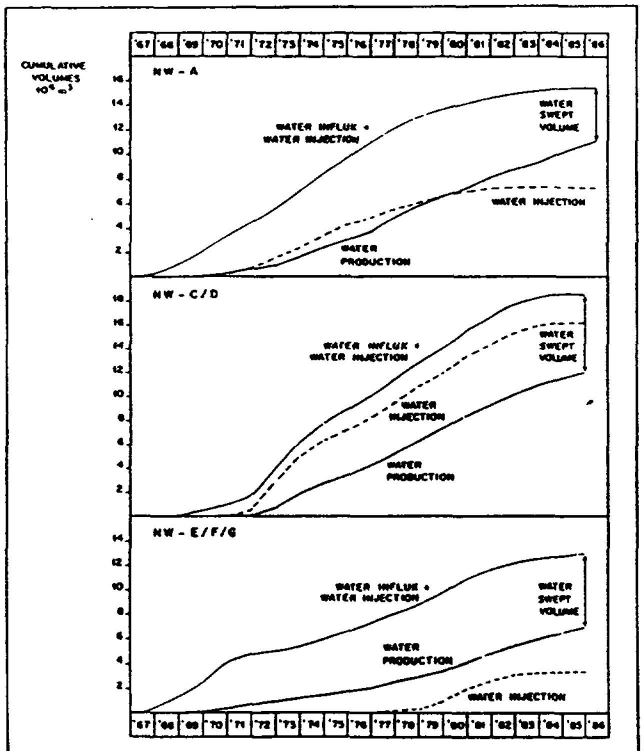


Fig. 11—Historical water balance for the Fahud NW reservoirs.

and 6) suggests that there was an almost direct exchange of oil for water production. At the same time, the efficiency of the potential gas/oil gravity drainage process was restricted by the high level of the fracture GOC's, which limited the percentage of rock exposed to gravity drainage to 65% in Reservoir NW-A, 40% in Reservoir NW-C/D, and 55% in Reservoir NW-E/F/G.

An estimate of the extent of the water sweep in the Fahud NW reservoirs has been made by combining the results of material-balance calculations with saturation profiles derived from resistivity logs run during drilling of recent downdip replacement wells. Difficulties in obtaining a unique material balance occur from uncertainties over the degree of depletion of the tighter reservoir units and uncertainties over the accuracy of the gas injection and production measurements. Estimates of the cumulative water influx range from 20×10^6 to 35×10^6 res m^3 [126×10^6 to 220×10^6 RB] compared with cumulative water injection and production totals of 27×10^6 and 31×10^6 res m^3 [170×10^6 and 195×10^6 RB], respectively. To distribute this aquifer influx between the three Fahud NW reservoirs, an estimate of the water sweep for each subunit has been made using the recently logged downdip oil saturation profiles (see Fig. 10). Good data coverage exists for Reservoir NW-A, central Reservoir NW-C, and Subunit NW-$E_{2,4}$ (see examples in Fig. 9). There is poor coverage away from the center of Reservoir NW-C, where the new grid wells have yet to be drilled, and in Subunit NW-E_3. In general, it appears that significant sweep has occurred only near the original 50% contact and only marginal changes in oil saturation are seen above 500 m ss [1,640 ft ss]. Because the fracture OWC has historically been sustained at a level

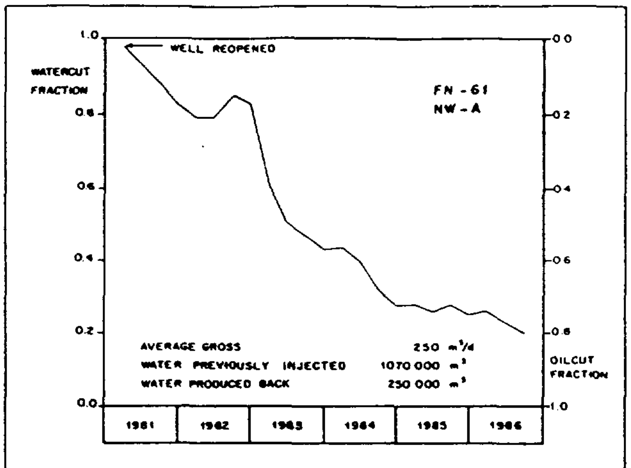


Fig. 12—Typical recent water-cut performance of a Reservoir NW-A completion.

close to the producing completions, 120 m [390 ft] above the 50% OWC at approximately 400 m ss [1,310 ft ss], the observed poor sweep would appear to be caused by oil-wet matrix rock. This production performance is considered a more reliable indication of wettability than the tests conducted on Fahud core samples, which indicated neutral to slightly water-wet properties. These tests were considered unreliable because of problems in preserving wettability while transferring from reservoir to laboratory conditions. Recently, Amott[1] wettability measurements have been conducted on native-state Natih reservoir samples from the nearby Natih field, which has rock type and performance history similar to the Fahud field. The results show a distinct oil-wet bias, particularly in the permeable subunits that have been the target for waterflooding in the past.

Extrapolating the observed saturation changes across the various subunits leads to the water balance presented in Table 4. This gives a current cumulative water swept volume of 16×10^6 res m^3 [101×10^6 RB], which, when combined with the difference between the produced and injected water, fits in well with the low estimate of aquifer influx of 20×10^6 res m^3 [126×10^6 RB].

An estimate of the historical waterflood performance for the three Fahud NW reservoirs has been made assuming that the percentage of the total aquifer influx into each reservoir has remained constant with time. Fig. 11 shows the cumulative water injection, water production, and water injection plus water influx volumes for Reservoirs NW-A, NW-C/D, and NW-E/F/G from 1967 to 1986. The difference between the curves of water injection plus water influx and water production is the cumulative water swept volume. The curves indicate that the majority of the water sweep occurred in the early stages of the waterflood (75% by the end of 1974). Since then, an increasing proportion of the water influx and water injection has been cycled straight to the producers. Recently (from 1980 in Reservoir NW-A and 1984 in Reservoirs NW-C/D and NW-E/F/G) there has been a reduction in the water swept volume as downdip producers have been opened up and water injection stopped. Fig. 12 shows the water-cut performance of one of the producers (Well FN-61), a previous Reservoir NW-A injector from 1971 to 1977 that was reopened in 1981.

Present Development

The results of the field review, which showed that water injection was giving very poor sweep efficiencies, led to a reassessment of the field's development. It was clear that even during the period of water injection, no more than 30% of the oil recovery was a result of the waterflood. Overall, only 17% of the total recovery could be accounted for by the waterflood as opposed to 80% from gas/oil gravity drainage and solution-gas drive. Gas saturation logging indicated that in the crest of the structure, gas saturations of up to 70% in Subunit NW-A_3, 50% in Subunits NW-$A_{4,5}$ and NW-C_1, and 35% in Subunit NW-$A_{1,2,6}$ had already developed. Given time, this drainage would be expected to continue downdip through the reservoirs. It was therefore decided in 1984 to phase

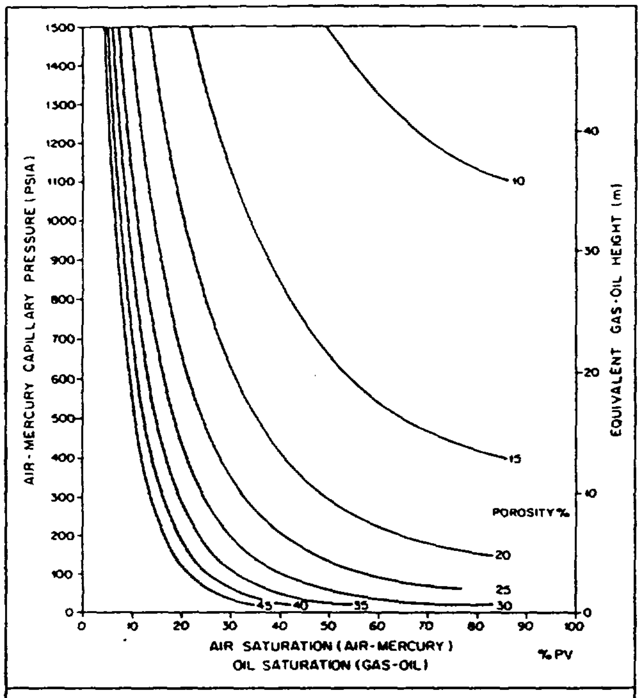


Fig. 13—Air/mercury capillary pressures and equivalent gas/oil height.

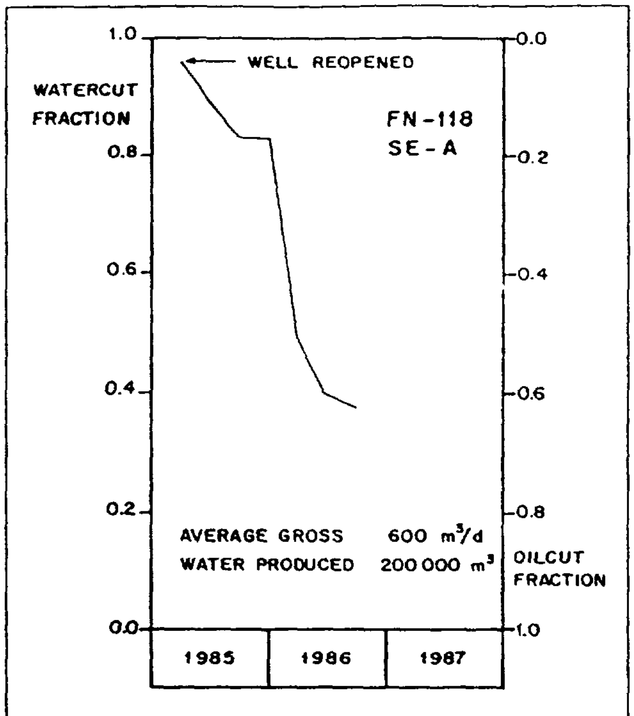


Fig. 14—Typical recent water-cut performance of a Reservoir SE-A completion.

out water injection completely, to increase gas injection to match voidage, and to shift the completions downdip gradually to maximize the rock exposed to gas/oil gravity drainage. Six downdip rows were designed on a 350- to 450-m [1,150- to 1,480-ft] spacing to give sufficient well productivity to match the estimated oil drainage rate. The structural position of the rows (Fig. 3) was set shallow enough to avoid excessive periods of water production from the resaturation of water-swept zones. The full development, expected to be completed by 1991, will consist of 166 completions, requiring a further 48 new wells and 20 workovers.

The gas injection policy in Fahud NW is to replace voidage fully and to maintain the gas-cap pressure at 2600 kPa [377 psi]. Repressurization of the reservoirs to their original gas-cap pressure of 3500 kPa [508 psi] would increase recovery by decreasing the gas/oil interfacial tension (IFT) and reducing the capillary holdup.[2] In Fahud, however, these gains are small because the reduction in IFT is slight (18.2 to 17.0 mN/m [18.2 to 17.0 dynes/cm]), the capillary pressures for 30% porosity are small (see Fig. 13), and the effective block height is large. In Fahud SE, however, gas injection has been maintained at a level approximately 500×10^3 m^3/d [17.7×10^6 ft^3/D] greater than the rate required to replace voidage to raise the reservoir pressures and to combat the moderate aquifer influx. This has resulted in a repressurization of up to 1000 kPa [145 psi] and enabled downdip watered-out wells to be reopened. Fig. 14 shows the water-cut performance of one of these wells (Well FN-118). The first three Fahud SE downdip replacement wells were drilled during 1986.

Despite the short-term successes of the current policies, which have led to a resurgence of oil production in all reservoirs, the future production potential under gas/oil gravity drainage is still uncertain. At present, the production is benefiting from primary production as the fracture GOC moves downdip. When the contact approaches the completions, the wells will have to be either beaned back or produced on a stop-cock basis. From the stop-cock production history, it will eventually be possible to establish the future production potential of all the reservoirs. To gain a better insight into the complex recovery processes in fractured reservoirs that determine these potentials and to optimize the production policies, dual-porosity simulation studies were started in 1986.

Dual-Porosity Simulation Studies. The initial studies have concentrated on a cross section of Fahud Reservoir NW-A because its geometry is simple and a wealth of performance data exists. A 30-column, 10-layer dual-porosity model was set up with a commercially available simulator[3] to represent a 930-m [3,050-ft]-wide cross section of Reservoir NW-A/B (Fig. 2). The fracture characteristics are based on transient-pressure test analysis studies, funded by the Ministry of Petroleum and Minerals, as well as outcrop, core, and wireline logging observations. Fracture relative permeabilities were assumed linear, while matrix permeabilities, relative permeabilities, and drainage capillary pressure curves were all based on core measurements. The matrix imbibition capillary pressure curves were derived from a combination of the historically observed water sweep and fracture OWC levels. Fracture pressures, fracture contacts, and observed gas and water saturations were used as matching parameters.

With a cross-sectional model, the fluid flux along strike was assumed negligible. This was considered a reasonable assumption because production from the central area of Reservoir NW-A has been uniform and the main feeder fractures are almost certainly oriented in a strike-normal direction. As the crossflow of gas to and from the cross section through the erosional edge is unknown, an artificial gas injector/producer was placed at the crest of the cross section to match the historical gas-cap pressure. The emphasis of the history match was to maintain the fracture GOC at the correct depth against time by varying the matrix/fracture exchange terms. The developed updip gas saturations and downdip water saturations could then be checked against log-derived field data. The matrix pressure in the tighter subunits, especially in the essentially unfractured Natih B, also had to be matched.

Typical updip gas saturation profiles developed by the simulator by the end of the history-matching period (1985) are plotted vs. log-derived [openhole and cased-hole compensated neutron logs (OHCNL and CHCNL)] saturations in Fig. 15. The simulator fracture pressures and contacts are in reasonable agreement with the historical data, although they tend to show too thick an oil rim throughout the production history.

A preliminary assessment of the results suggests that in the simulator, the fracture oil rim has been consistently overcharged, even though the gas/oil gravity drainage rate has been substantially restricted by reductions in the matrix/fracture exchange terms. In addition, the developed saturation profiles indicate too much drainage from both Subunit $A_{4\text{-}6}$ and the downdip areas exposed to gravity drainage (Fig. 15). It has been suggested that these differences in

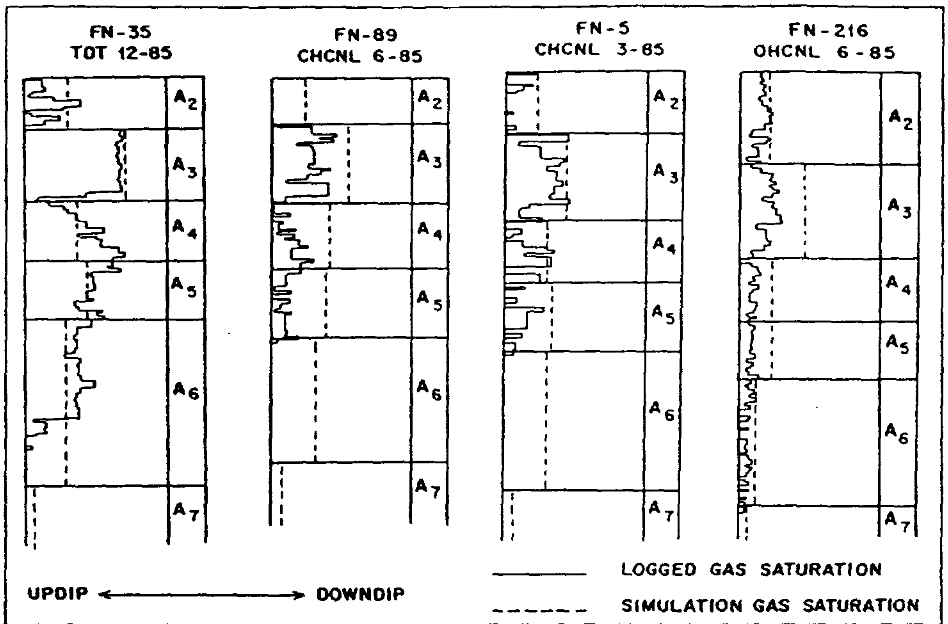


Fig. 15—Logged gas saturations vs. simulation gas saturations.

the drainage pattern are a result of reimbibition of oil draining through the fractures back into the matrix, which restricts the total drainage rate. This process has been studied in physical model experiments and simulation studies reported in Ref. 2. It is thought that in the Fahud reservoirs, oil draining from the updip more permeable reservoir rock recharges the downdip less permeable reservoir, which remains fully saturated until the reimbibition rate falls below the drainage rate. Although a reasonable history match can be obtained by restricting the matrix/fracture exchange terms, it is unlikely that a reliable prediction of performance would result. It is therefore planned to include reimbibition effects in further simulation work.

Conclusions

1. Waterflooding of the Fahud Natih reservoirs leads to poor recoveries because the reservoirs are both fractured and oil-wet. Field experience indicates low breakthrough sweep efficiencies (less than 3%) and low recoveries (less than 16%).
2. Despite the high structural level of the fracture OWC during the period of waterflooding, the sweep that has occurred is confined mainly to the bottom 30 m [98 ft] of each reservoir. New downdip wells, completed 30 to 45 m [98 to 148 ft] above the original OWC, generally show an increase in oil cut from <5 to >60% within 3 years.
3. The promotion of gas/oil gravity drainage through crestal gas injection and downdip production gives higher recoveries than waterflooding in the Fahud Natih reservoirs. Material-balance calculations show that even during the period of water injection, less than 30% of oil production was a result of the waterflood. Recovery from gas/oil gravity drainage is expected to continue at a steady rate as the high sweep efficiencies (up to 70%) seen in the best subunits in updip observation wells slowly extend downdip.
4. Reimbibition appears to affect the overall drainage rate in the Fahud reservoirs. This contention is supported by the distribution of observed secondary gas saturations in Reservoir NW-A, which shows lower gas saturations developing away from both the crest and the upper subunits when compared with predicted gas saturations from simulation studies.

Nomenclature

B_{oi} = initial oil FVF, res m^3/stock-tank m^3 [RB/STB]
k_H = horizontal permeability, md
k_V = vertical permeability, md
p_b = bubblepoint pressure, kPa [psi]
p_i = initial pressure, kPa [psi]
R_{si} = initial solution GOR, std m^3/m^3 [scf/bbl]
μ_{oi} = initial oil viscosity, Pa·s [cp]

Acknowledgments

I thank the Ministry of Petroleum and Minerals of Oman and the management of Petroleum Development Oman for their permission to publish this paper.

References

1. Amott, E.: "Observations Relating to the Wettability of Porous Rock," *Trans.*, AIME (1959) **216**, 156–92.
2. Saidi, A.M., Tehrani, D.H., and Wit, K.: "Mathematical Simulation of Fractured Reservoir Performance, Based on Physical Model Experiments," *Proc.*, 10th World Pet. Cong., Bucharest (1979) 3, 255.
3. Hill, A.C. and Thomas, G.W.: "A New Approach for Simulating Complex, Fractured Reservoirs," paper SPE 13537 presented at the 1985 SPE Reservoir Simulation Symposium, Dallas, Feb. 10–13.

General References

Reiss, L.H.: *The Reservoir Engineering Aspects of Fractured Formations*, Gulf Publishing Co., Houston (1980).
Shehabi, J.A.N.: "Effective Displacement of Oil by Gas Injection in a Preferentially Oil-Wet, Low-Dip Reservoir," *JPT* (Dec. 1979) 1605–13.
Tschopp, R.H.: "Development of the Fahud Field," *Proc.*, Seventh World Pet. Cong., Mexico City (1967) 243–50.

SI Metric Conversion Factors

°API	141.5/(131.5+°API)		=	g/cm^3
bbl	× 1.589 873	E−01	=	m^3
cp	× 1.0*	E−03	=	Pa·s
ft	× 3.048*	E−01	=	m
miles	× 1.609 344*	E+00	=	km
psi	× 6.894 757	E+00	=	kPa
scf/bbl	× 1.801 175	E−01	=	std m^3/m^3

*Conversion factor is exact

JPT

Original SPE manuscript received for review March 7, 1987. Paper accepted for publication Feb. 8, 1988. Revised manuscript received Jan. 20, 1988. Paper (SPE 15691) first presented at the 1987 SPE Middle East Oil Show held in Bahrain, March 7–10.

CAMPBELL & BLACK, P.A.
LAWYERS

JACK M. CAMPBELL
BRUCE D. BLACK
MICHAEL B. CAMPBELL
WILLIAM F. CARR
BRADFORD C. BERGE
MARK F. SHERIDAN
J. SCOTT HALL
PETER N. IVES
JOHN H. BEMIS
MARTE D. LIGHTSTONE

GUADALUPE PLACE
SUITE 1 - 110 NORTH GUADALUPE
POST OFFICE BOX 2208
SANTA FE, NEW MEXICO 87504-2208
TELEPHONE: (505) 988-4421
TELECOPIER: (505) 983-6043

June 6, 1988

RECEIVED
JUN 7 1988
OIL CONSERVATION DIVISION

HAND-DELIVERED

W. Perry Pearce, Esq.
Montgomery & Andrews, P.A.
325 Paseo de Peralta
Santa Fe, New Mexico 87501

Re: Mallon Oil Company's Well Data Request

Dear Perry:

This is Benson-Montin-Greer Drilling Corporation's response to Mallon's well data request which we received on June 3rd.

If Mallon Oil Company needed the additional information it now requests it should have raised this matter at the May 19, 1988 pre-hearing conference instead of waiting until only ten days prior to hearing. As you can appreciate, we are now deeply involved in the preparation of our case for the June 13th hearing and simply do not have time to interrupt this work to assist you with Mallon's case.

We therefore decline to provide the requested information.

Very truly yours,

Bill

WILLIAM F. CARR
WFC:mlh
cc: Mr. William J. LeMay
All counsel of record

Robert D. Buettner
General Counsel and Secretary

KOCH
EXPLORATION COMPANY

May 18, 1988

Mr. William J. LeMay, Chairman
Mr. William R. Humphries
Mr. Erling A. Brostuen
New Mexico Oil Conservation Commission
State Land Office Building
Santa Fe, NM 87501

Re: Cases 7980, 8946, 8950 and 9111

Gentlemen:

As requested in the Commission's Public Notice of Prehearing Conference in the referenced cases, Koch hereby enters its appearance as follows:

(a) Koch's position on the issues set forth in the Notices is that allowables in the Gavilan Pool and the westernmost two section-wide tier of the West Puerto Chiquito-Mancos Oil Pool should be restored to statewide depth-bracket allowables and GORs.

(b) Koch has no present intention to present witnesses, except possibly in rebuttal to testimony which may be adverse to Koch's positions as hereinabove set forth. Even if such rebuttal testimony should be necessary, Koch doubts that more than one hour would be required for its presentation.

(c) Koch believes the Commission's paramount objective in these hearings should be to immediately restore allowables to stop the waste which has been engendered by the experiment with restricted production. However, Koch believes that the Commission should consider, without delaying allowable restoration, the issue of redefining the Gavilan-Mancos Pool boundary to include the "western tier" of two sections currently forming the western edge of the Canada Ojitos Unit.

(d) Koch has not reviewed the proposed statement of procedure and therefore is unable to comment upon it, however, as a non-operating working interest owner in Gavilan properties operated by Mallon Oil Company, we would adopt the position of Mallon's counsel with regard to these matters.

Please keep us advised of further developments in these cases.

Yours very truly,

Robert D. Buettner

R. D. Buettner

RDB:lra

cc: Thomas Kellahin, Esq.
William F. Carr, Esq.
Owen Lopez, Esq.
W. Perry Pearce, Esq.
Frank Douglass, Esq.
Mr. Vic Lyons
Mr. Frank Chavez
Mr. Bill Weiss

HINKLE, COX, EATON, COFFIELD & HENSLEY

ATTORNEYS AT LAW
218 MONTEZUMA
POST OFFICE BOX 2068
SANTA FE, NEW MEXICO 87504-2068
(505) 982-4554

2800 CLAYDESTA NATIONAL BANK BUILDING
POST OFFICE BOX 3580
MIDLAND, TEXAS 79702
(915) 683-4691

1700 TEXAS AMERICAN BANK BUILDING
POST OFFICE BOX 9238
AMARILLO, TEXAS 79105
(806) 372-5569

700 UNITED BANK PLAZA
POST OFFICE BOX 10
ROSWELL, NEW MEXICO 88201
(505) 622-6510

February 3, 1988

FEB

OIL CONSERVATION DIVISION

Mr. William J. LeMay, Chairman
and Secretary
Mr. William R. Humphries
Mr. Erling Brostuan
Oil Conservation Commission
State of New Mexico
Post Office Box 2088
Santa Fe, New Mexico 87504-2088

Re: Cases Nos. 7980, 8946, 9113 and 9114, Order No. R7407-E; Case No. 8950, Order No. R06469-D; Gavilan Mancos Oil Pool and West Puerto Chiquito-Mancos Pool, Rio Arriba County, New Mexico

Gentlemen:

We have received copies of correspondence dated January 28, 1988, addressed to you from Messrs. William F. Carr and W. Thomas Kellahin, counsel for Benson-Montin-Greer Drilling Corp., Sun Exploration and Production Corp. and Dugan Production Corp., and copies of correspondence dated January 19, 1988, addressed to you from Messrs. Frank Douglass and W. Perry Pearce, counsel for Mallon Oil Company, in regard to the above referenced matter.

Please be advised that Mesa Grande, Ltd. and Mesa Grande Resources, Inc. ("Mesa Grande") concur with Mallon Oil Company's statement that the field wide gas-oil ratio decreased beginning in July 1987 when standard statewide allowable rates were reinstated. This fact is documented in Mesa Grande, Ltd.'s Application for Compulsory Pooling, Case No. 9225, heard before the Commission on January 21, 1988. Total pool production rates for the period of May through November 1987 are summarized as follows:

GAVILAN MANCOS FIELD
TOTAL POOL PRODUCTION

1987

Month	Bbls.	BOPD	MCF	MCFD	Gas-Oil Ratio SCF/Bbl
May	84,507	2,726	311,957	10,063	3,691
June	94,108	3,137	329,969	10,999	3,506
July	145,654	4,699	549,485	17,725	3,773
August	162,285	5,235	542,032	17,485	3,340
September	176,449	5,882	556,083	18,536	3,152
October	167,621	5,407	556,157	17,941	3,318
November	96,848	3,228	449,751	14,992	4,644

It is important to observe that the field average gas-oil ratio actually <u>decreased</u> with an increase of field wide oil production rates. Further review of the data also evidences that the rapid increase in the field gas-oil ratio occurred in the fall of 1986 when restricted allowable rates were ordered. The restricted allowables, in fact, may have precipitated higher gas-oil ratios. This is also evidenced by the November, 1987 field production data.

It is Mesa Grande's position that the continued reduction in allowables at Gavilan is unnecessary, constitutes waste, allows for the redistribution of remaining reserves, and has caused an unnecessary economic hardship to all interest owners. The preponderance of data clearly supports this statement, all of which has been received by the Commission.

Mallon Oil Co. was only partially correct in their statement that low production rates from the Gavilan Pool commenced in the field on November 16, 1987. In fact, this unnecessary curtailment of production started on September 1, 1986. Except for the brief period commencing in July, 1987 when reinstatement of the standard statewide allowables for the pool were granted, pool production rates have been and will continue to be unnecessarily curtailed. In that regard we would concur with Mallon's position and ask that the Commission, effective February 16, 1988, immediately restore the standard statewide depth-bracket allowable for the Gavilan Pool. This situation should not continue unabated. If waste has occurred due to a rate sensitive reservoir, it has been caused by reduced allowables. This situation should not continue unabated.

We also request that all pending matters concerning the Gavilan and West Puerto Chiquito-Mancos Pools be consolidated for hearing in March 1988. In regard to Case 9111, expansion of the Canada Ojitos Unit Pressure-Maintenance project, we would remind the Commission that testimony presented by both sides in March and April, 1987, indicated that several of West Puerto Chiquito wells located along the administrative boundary separating Gavilan and West Puerto Chiquito are characteristic Gavilan A-B type producers. We have also received Mr. Carr's letter to the Commission dated February 1, 1988 regarding case 9111 where he indicated that the historic West Puerto Chiquito C zone pressure is substantially higher than Gavilan's. We are pleased to note his further confirmation of the separation of the two pools which provides additional support for our position that any expansion plans of Benson-Montin-Greer into the Gavilan area proper should be addressed when all the Gavilan-West Puerto Chiquito issues are addressed by the Commission.

We note that Benson Montin Greer's meeting for the unit now called for March, has no bearing whatsoever upon the Commission's reopening of the Gavilan Mancos and West Puerto Chiquito-Mancos Pool cases. In fact, we understand there has not been a working interest owners' meeting for the Canada Ojitos Unit in over 4 years, although requested on several occasions by various parties owning an interest in that Unit.

Mesa Grande has no sympathy for the Benson-Montin-Greer group's position that a short delay in hearing Case 9111 could result in a year's postponement of construction and attendant revenue. Mesa Grande has deferred several drilling projects in Gavilan over the past 18 months, in part due to regulatory uncertainty and reduced allowables as precipitated by the Benson-Montin-Greer group's filing their "emergency" application in mid-1986 calling for a departure from statwide rules resulting in a drastic reduction of allowables in Gavilan.

Thank you for your consideration of our requests.

Sincerely,

Owen M. Lopez

OML:tao

STATE OF NEW MEXICO

ENERGY AND MINERALS DEPARTMENT

OIL CONSERVATION DIVISION

GARREY CARRUTHERS
GOVERNOR

July 9, 1987

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501
(505) 827-5800

William O. Jordan, Esq.
28 Old Arroyo Chamiso
Santa Fe, New Mexico 87505

Re: Case Nos. 7980, 8946, 9113, 9114, and 8950

Dear Mr. Jordan:

We are in receipt of your Application for Rehearing filed in this matter on July 9, 1987. NMSA 70-2-25(A) 1978 requires that Applications for Rehearing be filed within twenty days of the entry of the order. Because the order in the referenced cases was entered on June 8, 1987, your Application for Rehearing was not timely filed and is therefore rejected.

If you have any questions, please contact either myself or Jeff Taylor at 827-5800.

Sincerely,

William J. LeMay

WILLIAM J. LEMAY
Director

WJL/fd

Memo

From
FLORENE DAVIDSON
OC Staff Specialist

To

March 2, 1987

Please substitute the enclosed Division Order No. R-6469-C and No. R-3401-A-1 for the one mailed to you on February 19, 1987.

I am sorry for any inconvenience this may cause you.

Florene Davidson

Oil Conservation Division Santa Fe, New Mexico 87504-2088
827-5802

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

CASE NO. 8950
Order No. R-6469-C
and
Order No. R-3401-A-1

APPLICATION OF BENSON-MONTIN-GREER DRILLING CORPORATION FOR THE AMENDMENT OF THE SPECIAL RULES AND REGULATIONS OF THE WEST PUERTO CHIQUITO-MANCOS OIL POOL TO ESTABLISH TEMPORARY SPECIAL PRODUCTION ALLOWABLE LIMITATIONS AND GAS-OIL RATIO LIMITATIONS, RIO ARRIBA COUNTY, NEW MEXICO.

NUNC PRO TUNC ORDER

BY THE COMMISSION:

It appearing to the Oil Conservation Commission of New Mexico (Commission) that the combined order (Order Nos. R-2565-E and R-3401-A) issued in Case No. 8950 and dated September 11, 1986 does not correctly state the intended order of the Commission,

IT IS THEREFORE ORDERED THAT:

(1) Division Order No. R-6469-B issued in Case No. 8715 and dated March 7, 1986, superseded the Special Rules promulgated for the West Puerto Chiquito-Mancos Oil Pool, as previously established by Division Orders Nos. R-2565-B, R-2565-C, and R-6469-A; and the designation of Division Order No. R-2565-E in the immediate case was in error; therefore, all references to said "Order No. R-2565-E" throughout this Order are hereby amended to read "Order No. R-6469-C."

(2) Division Order No. R-2565-E, herein redesignated Order No. R-6469-C, as described above, is hereby affirmed by this Order; similarly, all provisions pertaining to Division Order No. R-3401-A simultaneously issued in the immediate case shall remain in full force and effect except as provided in paragraph (3) herein below.

(3) The daily adjusted oil allowable formula contained in "Rule 7" of Decretory Paragraph No. (3) on page 4 of said order is hereby amended to read as follows:

$$A_{adj} = \frac{TUA \times F_a \times 600}{\frac{P_g - I_g}{P_o}}$$

(4) The corrections set forth in this order be entered nunc pro tunc as of September 11, 1986.

DONE at Santa Fe, New Mexico, on this 2nd day of March, 1987.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

WILLIAM R. HUMPHRIES, Member

ERLING A. BROSTUEN, Member

WILLIAM J. LEMAY, Chairman and Secretary

S E A L

STATE OF NEW MEXICO

ENERGY AND MINERALS DEPARTMENT

OIL CONSERVATION DIVISION

February 26, 1987

GARREY CARRUTHERS
GOVERNOR

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501
(505) 827-5800

Case 8950

William F. Carr, Esq.
W. Thomas Kellahin, Esq.
Santa Fe, New Mexico

Re: Your Letter/Application of February 13, 1987 -
Gavilan-Mancos Pool

Gentlemen:

We are in receipt of your letter referenced above seeking a hearing on overproduction by Mallon Oil Company. Insofar as you suggest that oil production by Mallon above the authorized allowable should be classified as illegal oil, it is the position of the Division that your letter/application be treated as a report of unauthorized production which should be investigated. Any hearing called to penalize or otherwise implement administrative action against Mallon should, in my opinion, be initiated by the Division.

It is my understanding that the continued production by Mallon has been authorized by the Division's Aztec District Office in order to permit the continued operation of a gasoline plant that serves these and other wells. If Mallon's wells are shut in without alternative supplies being made available, the plant will also have to be shut down, which, since it serves other producers, would necessarily penalize these third parties. Although the Division would like to see Mallon's overproduced wells shut in, I believe a solution that is equitable to all, including innocent parties, is preferable.

Although the Division will undertake to investigate and evaluate the situation reported in your letter, it would be appreciated if you would provide us with any specific information you have have regarding your allegations.

If it is determined that a willful violation of Division rules has occurred, a case will be prepared and presented at the earliest available date.

Thank you for your assistance in this matter. If you have any questions, please feel free to call or visit me.

Sincerely,

WILLIAM J. LEMAY,
Director

WJL/JT/dr

BENSON-MONTIN-GREER DRILLING CORP.

221 PETROLEUM CENTER BUILDING, FARMINGTON, NM. 87401 505-325-8874

January 15, 1987

Mr. Vic Lyon
New Mexico Oil Conservation Division
Box 2088
Santa Fe, NM 87501

Re: ORDER R-3401-A: TYPOGRAPHICAL ERROR

Dear Vic:

As we discussed briefly at the meeting yesterday, we recognize that there is a typographical error in the formula setting out the gas-oil ratio calculations under the captioned order.

The formula on page 4 should show 600 rather than 1000 as noted on the copy. The intent of the order is clear in the language of Rule 7.

The formula actually will not come into play until such time as our "net" gas-oil ratio is more than the limiting gas-oil ratio - and this will not happen until we commence selling a substantial portion of the produced gas. Throughout the operation of the pressure maintenance project we have reinjected all produced gas; and is is our intention to continue doing so until we reach the "blow-down" stage.

Yours truly,

BENSON-MONTIN-GREER DRILLING CORP.

BY: Albert R. Greer

Albert R. Greer, President

ARG/tlp

Enclosure

cc: Mr. Frank Chavez
Mr. William Carr