BAKKEN A POOL
DALY AREA, MANITOBA
RESERVOIR DEVELOPMENT STUDY

SEPTEMBER 1988

PREPARED FOR

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CALGARY, ALBERTA

Prepared by

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INTERA-ECL

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I. SUMMARY

ECL Petroleum Technologies Ltd. (ECL) was retained by Newscope Resources Ltd. (Newscope) to conduct a reservoir development study of the Daly Bakken A Oil Pool. The objective of the study was to analyze the past performance of the pool, construct and calibrate a numerical model to reasonably duplicate that performance and then use the model to evaluate the feasibility of implementing a water injection scheme.

Following a review of the pool's performance, the ECLIPSE 100 black oil reservoir simulator was used to construct a model of the reservoir. The model was successfully calibrated to the observed performance of the pool. The calibration relied mainly on adjusting horizontal permeabilities, to reflect the pool's low degree of inter-well communication. A recent fluid analysis showed that the recombined laboratory oil sample exhibited a saturation pressure of 2 000 kPa. During the model calibration, the saturation pressure was increased to 8 750 kPa so that the oil was saturated at initial conditions. This was required to provide the reservoir system with sufficient energy to produce the observed volumes. The central area of the model, which has sufficient permeability to be productive, has an initial oil-in-place (IOIP) of 542.3 10^3m^3 (3.4 MMSTB).

major change in input data (why not increase kh !?

The calibrated model was used to predict the performance of the pool for the next twenty years. Assuming that the present operating practices are continued, the model predicts an oil recovery of 94.7 10^3m^3 by January 1, 2009. This is equivalent to 17.5% of IOIP. As of June 30, 1988, 24.2 10^3m^3 of oil (4.5% of IOIP) had been produced.

Two water injection cases were considered. In the first (Case 2), water was injected into well 13-21 beginning January 1, 1989, subject to a limiting bottom hole injection pressure of

15 200 kPa (2 200 psia). As water injection rates in the pool are likely to be quite low given the low level of rock permeability and injection pressure constraints, the water injection rate could be quite sensitive to water relative permeability. The second water injection run (Case 3) was run similar to Case 2 except the relative permeability to water, at residual oil saturation, was doubled. This effectively covers the range of endpoint water relative permeability values which might be expected for this reservoir.

The model predicts that implementing a water injection scheme will result in the recovery of 112.4 - 119.5 $10^3 m^3$ of oil (20.7 - 22.0% of IOIP) by January 1, 2009. This corresponds to an incremental recovery, over continuation of the present operations, of 17.7 - 24.8 $10^3 m^3$ (3.3 - 4.6% of IOIP).

On the basis of these prediction runs and our experience gained during model calibration, ECL recommends that water not be injected in this pool. The combination of low inter-well communication and low injection pressures, resulting from the pool's relatively shallow depth, severely limits the amount of water which can be injected. In our opinion, continuing the present operating practices will maximize recovery (and value) in this pool.

→ only have to replace voidage - increase # of injectors?

II. CONCLUSIONS

1. The study area is currently producing 37 m^3/d of oil at an average watercut of 40% (June, 1988). The cumulative oil and water recovery, to June 30, 1988, are 24.2 10^3m^3 (4.5% of IOIP) and 13.0 10^3m^3, respectively. The water is not contributing to voidage in the reservoir under study as it is interpreted to be flowing behind pipe from the Lodgepole Formation, up-hole.

2. The initial reservoir pressure in the study area was approximately 8 750 kPa at a datum depth of 340 mss. Although the current average reservoir pressure is approximately 8 000 kPa, regions of the pool are probably at much lower pressure due to the lack of reservoir communication. what press. ?

3. A numerical model of the reservoir was constructed and successfully calibrated to the pool's historical performance. The model calibration relied on reducing horizontal permeabilities to reflect the low degree of inter-well communication in the pool.

4. A recent recombined fluid analysis showed that the oil in the pool has saturation pressure of 2 000 kPa. During model calibration, the saturation pressure was increased to 8 750 kPa so that the oil was saturated at initial conditions. This was required to provide the reservoir system with sufficient energy to produce the observed volumes. The solution gas-oil ratio, at 2 000 kPa, is 27.3 m^3/m^3. The extrapolated solution gas-oil ratio, at 8 750 kPa, is 40.5 m^3/m^3. Both of these ratios are small so it is conceivable that the fluid analysis study was performed with incorrect volumes of gas and oil.

5. For Prediction Case 1, which assumed that the present operating practices are continued, the model predicts that 94.7 10^3m^3 of oil will be recovered by January 1, 2009. This is equivalent to 17.5% IOIP.

6. Prediction Case 2 and 3 assumed that water would be injected into well 13-21, subject to a maximum bottom hole injection pressure of 15 200 kPa (2 200 psia), starting January 1, 1989. The model predicts that this will result in the recovery of 112.4 - 119.5 10^3m^3 of oil (20.7 - 22.0% of IOIP) by January 1, 2009. This corresponds to an incremental oil recovery, over continued present operations, of 17.7 - 24.8 10^3m^3 (3.3 - 4.6% of IOIP).

III. RECOMMENDATIONS

1. ECL recommends that a water injection scheme not be implemented in this pool. The combination of the low interwell communication and low injection pressures, resulting from the pool's relatively shallow depth, severely limits the amount of water which can be injected. In our opinion, continuing the present operating practices will maximize recovery (and value) in this pool.

2. Continued pool performance surveillance by transient pressure analysis on key wells should be given strong consideration. new only – otherwise shut in period is too long.

3. Attempts to measure the producing gas-oil ratio should be persued to ensure the GOR does not become excessive.

IV. INTRODUCTION

Newscope operates and has varied interests in approximately twenty oil wells in the Bakken A Pool (the Pool) located in the Daly area of southwest Manitoba. Development is concentrated in Sections 20, 21, 28 and 29 of Township 10, Range 29 WPM. The Pool was discovered in September, 1985 by the drilling of 13-21-10-29 WPM. Subsequent step-out wells, drilled on 16.2 ha (40 acres) spacing have delineated the oil accumulation.

The reservoir consists of the lower unit of the Bakken Sand, locally referred to as the "Kola". The Kola is a thin (1-3 m), relatively clean sandstone with an average porosity of 17%. Reservoir permeability is extremely variable and may range from less than one mD to 100 mD across the pool. This variation in permeability has a dramatic effect on productivity and it is this factor, rather than the presence of hydro-carbon bearing pore volume which determines whether a well may be economically produced. hardly

The study area is currently producing 37 m^3/d of oil from 16 wells (June 1987). Cumulative oil recovery, to June 30, 1987, is 24 240 m^3. Although 25 m^3/d of water is currently being produced, the origin of this water is believed to be from the up-hole Lodgepole Formation. The water is being produced via fissures through the Bakken shale, developed during fracture stimulations of some of the wells. Gas production, although not continuously measured, is believed to be very low.

Oil production in the pool is currently declining at a rate of 40 - 50% per year. Newscope retained ECL to evaluate the feasibility of enhancing recovery by implementing a waterflood pressure maintenance scheme. This was accomplished by constructing a numerical model which simulates the observed performance of the reservoir and then using this calibrated model to predict recoveries which might be achieved with and without water injection. The following documents our approach and results.

V. RESERVOIR CHARACTERIZATION

The study area reservoir consists of the lower unit of the Bakken Sand, locally referred to as the Kola. The Kola is overlain by the upper unit of the Bakken, the A Sand. Although the A Sand is oil-bearing, it is non-productive. The A Sand is capped by 4-5 m of shale. These Bakken shales form a seal between the underlying hydro-carbon bearing sand and the ?? Lodgepole Formation, a thick, areally extensive, locally water bearing sandstone. The Kola unconformably overlies the Torquay Sand, another oil-bearing but locally non-productive horizon.
??

The whole sequence described above dips to the southwest. no map? The top of the Kola structure varies from 325.0 to 370.0 mss in the study area. No oil-water or gas-oil fluid contacts are present in the study area and the reservoir is saturated with connate water (35% of pore volume) and oil.

The average Kola porosity is approximately 17%. It may range as high as 22%. Regions of the sand with less than 13.5% porosity are considered too tight to be productive. The Kola porosity-thickness map provided by Newscope is shown in Figure 1. The productive interval of the Kola Sand averages 1.5 m in thickness.

The Kola sand permeability is extremely variable. It ranges from 0.1 mD on the fringe to as much as 100mD in the heart of the productive area of the reservoir. Additionally, the thin sand body may actually be a series of individual lenses. This lack of continuity, coupled with rapidly varying permeabilities, means that there may be limited inter-well communication. DST pressure study?

- inferred or confirmed?

VI. RESERVOIR MODEL DESCRIPTION

VI.1 Introduction

The reservoir model describes the porous interval of the Kola Sand within the study area. The model was designed to adequately represent the significant properties of the reservoir. The basis for the model was the geological description provided by Newscope. This was supplemented with information from other sources, as documented below. Table 1 summarizes the major reservoir and fluid properties in the model.

VI.2 Simulator

The ECLIPSE 100 simulator, developed by Exploration Consultants Ltd., was used to construct the numerical model of the pool. ECLIPSE 100 consists of a fully implicit, three phase, three dimensional black oil simulator and several pre and post-processing ancillary programs. The simulator uses a fully implicit solution technique to guarantee stability for all problems. The linear equations arising at each Newton iteration are solved using Nested Factorization, accelerated by Orthomin. This method is fast and ensures that material is precisely conserved at each iteration.

VI.3 Grid System

The model grid system consists of 31 cells in the x-direction, 33 cells in the y-direction and a single vertical layer (Figure 2). The grid was oriented so that its y-axis is approximately parallel to the strike of the reservoir structure. The major direction of sand deposition was across the structure, which may have resulted in some directional permeability, so this grid orientation succeeded in aligning the grid cell faces approximately parallel and perpendicular to the postulated principal flow directions. The areal grid cell density is constant throughout the model. Each cell describes an area of 1.7 ha (4.3 acres).

The top surface of the model, representing the top of the Kola Sand, was defined by interpolating wellbore structure values. The model is 1.5 m thick, which is approximately the average thickness of the productive zone.

VI.4 Rock Properties

The pore volume in each cell was defined by digitizing the Kola porosity thickness map supplied by Newscope (Figure 1). Porosity values were assigned to each cell by sampling this map and dividing by the 1.5 m thickness of the model. Once cells with a porosity-thickness of less than 10.0 porosity-m were discarded, the model contained 790 active grid cells. This cut off is well below the porosity at which the sand is permeable.

Permeabilities were assigned to each cell by reviewing the nine core analyses available in the study area. Table 2 lists the permeability-thickness of each location with core. The equivalent model permeabilities, calculated by dividing each permeability-thickness value by the 1.5 m thickness of the model, are also listed. A permeability-thickness value of "very tight" was arbitrarily equated to a model permeability of 2 mD.

Well locations without core were assigned permeabilities by analogy to cored locations on the basis of initial productivity and log signature. The base permeability array, before modification during model calibration, is shown in Table 3. This array covers the center of the study area, as identified in Figure 3. The remainder of the model was assigned a permeability of 2 mD.

Rock compressibility, at initial reservoir conditions, was established to be 5.8×10^{-7} kPa^{-1}, using Hall's correlation (1).

VI.5 Fluid Flow Properties

Capillary pressure and relative permeability functions define the initial saturation distribution and control fluid flow in the model. Since neither gas-oil or oil-water fluid contacts are encountered in the study area, and no laboratory data is available, capillary effects were ignored.

Initially, oil is the only mobile phase in the model. Water, estimated to saturate 35% of the pore volume, was assumed to be at critical (immoveable) conditions. Although some water has been produced in the field, it is interpreted that its origin is the Lodgepole FOrmation, up-hole. No laboratory relative permeability data is available so it was assumed that residual oil saturation, resulting from displacement by gas or water, is 25% of the pore volume. Oil relative permeability was assumed to be unity at connate water saturation. Critical gas saturation was assumed to 5.0% of pore volume. Gas and water relative permeabilities were assumed to be 0.3 at residual oil saturation. The resulting relative permeability functions, assumed to vary linearly between these endpoints, are shown in Figure 4.

- very important to production
- arbitrarily assumed!

VI.6 Fluid Properties

Oil, gas and water analyses from wells within the study area were reviewed to characterize the reservoir fluids. Recorded oil gravities vary from 38.0 - 43.0 degrees API. Gas gravity was reported to be 1.105. Recorded water analyses show that the formation water has an average specific gravity of 1.110 and approximately 140 000 ppm TDS.

A fluid analysis of separator oil and gas collected from well 03-28 in January, 1988 was referenced to define the oil and gas properties as a function of pressure (2). This analysis reported an oil gravity of 41.0 degrees API, within the range noted above. When the well was sampled, the gas-oil ratio was measured to be 10.0 m^3/m^3. Once the collected gas and oil samples were recombined, the saturation pressure of the mixture was found to be approximately 2 000 kPa at the assumed reservoir temperature of 31 degrees C. If this saturation pressure is correct, then this oil was highly under-saturated at discovery conditions, as reservoir pressure was initially measured to be approximately 8 750 kPa. During the course of model calibration it was necessary to increase the saturation pressure of the oil to discovery conditions. The oil properties were extrapolated accordingly. Table 4 and Figure 5 show both the laboratory and extrapolated oil properties.

The dry gas properties used in the model are listed in Table 5 and shown in Figure 6. These were derived from the 03-28 fluid analysis, supplemented by standard correlations (3,4).

The water formation volume factor, viscosity and compressibility were specified to be 1.003 m^3/m^3, 0.85 mPa-s and 4.5×10^{-7} kPa^{-1}, respectively. These volumes were calculated using industry accepted correlations assuming the water properties noted above (5).

VII. MODEL CALIBRATION

VII.1 Introduction

The geological, rock and fluid properties described previously formed the initial description of the reservoir for the model calibration. The objective of model calibration was to refine this description to obtain a reasonable agreement between the simulated and historical performance of the reservoir.

The model calibration period extends from October 1, 1985 to June 30, 1988. Table 6 lists the wells in the study area, indicating the date of their initial production and current status.

VII.2 Historical Performance

The historical performance of the study area is illustrated in Figure 7. Total oil production increased steadily from October, 1985 to a peak of 45 m^3/d in February, 1988. This two and one-half year sustained increase in production was achieved through continuous development drilling, as individual well production rates decline at 40 - 50% per year. Currently, 16 wells are producing a total of 37 m^3/d (June, 1988). The cumulative oil recovery, to June 30, 1988 is 24 240 m^3 (4.5 % of IOIP).

except for year 13-21 Prior to interfere

Field watercut's are currently 40%. Cumulative water production, to June 30, 1988 is approximately 13 000 m^3. As noted previously, the source of this water is believed to be the Lodgepole Formation, located 8 m up-hole. Seven wells in the study area have been fracture stimulated to improve productivity. Unfortunately, most of these workovers have opened vertical fissures through the overlying A Sand and Bakken shales. Water from the Lodgepole flows through these fissures and is produced. Well's 11-21 and 08-29 were suspended due to excessive water production.

Gas production in the field is vented to the atmosphere and has not been continuously measured. A portable separator, located at 03-28 in January, 1988 measured a gas-oil ratio of 10 m^3/m^3. Attempts to quantify gas production rates at 13-21 and 04-28 were unsuccessful as the volumes produced were too small to measure.

Recorded reservoir pressures are documented in Table 7. The measurements indicate that the initial reservoir pressure was approximately 8 750 kPa. The pressures recorded at 05-21 and 09-29 in late 1987, are significant in that they show that those locations in the reservoir have undergone no pressure depletion. This indicates the degree (or lack of) communication that must exist in the reservoir. There are no successive measurements at any one location to quantify how reservoir pressure has changed with time.

sepa. pool 5-21 — very tight 9-29 ...

no! on the edges, on outside only!
Inner well pressures indicate continuity!!

VII.3 Model Calibration Procedure

or to characterize reservoir?

The model calibration procedure was to schedule the wells to produce their historical oil production rates. The models' rock and fluid properties were then selectively changed with the objective of achieving a reasonable agreement between the simulated and historical performance of the study area. The rock and fluid properties in the model at that time formed the final description of the reservoir.

Since the water produced in the field is interpreted to be from the Lodgepole Formation, this production was ignored during model calibration. In fact, since the water in the model is assumed to be initially at critical conditions, only very small amounts (resulting from water expansion during pressure depletion) can be produced.

As there are effectively no watercuts or gas-oil ratios to match, the model calibration relied on matching simulated producing bottom hole pressures (BHP's) and reservoir pressures with their respective historical values. All wells, with the exception of 13-21, were assumed to have flowing BHP's of 345 kPa (50 psia) throughout their producing histories. Well 13-21 was probably not pumped off during October, 1985 - September, 1986 as it exhibited no decline in production rate during that period.

left in the [illegible] effect either!

The initial model calibration runs used the base permeability array shown in Table 3, and assumed an oil saturation pressure of 2 000 kPa. They showed that the base permeability array permitted too much communication within the heart of the pool. This resulted in a general decline in reservoir pressure throughout the model rather than preserving reservoir pressure at specific locations, as indicated by the observed data. Lowering the level of permeability certainly reduced communication but it resulted in too much pressure drawdown at producing well locations. This was manifested in several wells being unable to produce their observed oil volumes. These results pointed to an inconsistency in the input data. On the one hand, reservoir permeability had to be reduced to prevent pressure interference, while on the other hand it had to be increased to permit sufficient pore volume communication to provide the required pressure support. Essentially, the results of these runs indicated that the model contained insufficient energy to support the observed production.

out [illegible] edges [illegible] low [illegible]

The energy available to any reservoir system is determined by its volume; the presence of external energy sources such as aquifers or gas caps; and the compressibility of the rock and fluids in place. In this pool, the well density is sufficient to accurately define the local pore volume and the presence of any external energy sources can be effectively ruled out. In any event, if they are located at some distance, the reservoir permeability is too low to permit effective communication.

As initially modelled, with an oil saturation pressure of 2 000 kPa, the total compressibility of this reservoir system is very low, in the order of 1.2×10^{-6} kPa^{-1} (8.0×10^{-6} $psia^{-1}$). Some simple single well radial model runs were made to quantify how much pore volume would be required to support the production of one well, given these oil properties.

Figure 8 compares well 04-28's actual oil production with the simulated production rate for four scenarios. The runs simulate drainage areas of 40, 360 and 640 acres. The well was scheduled to produce at a flowing BHP of 345 kPa (50 psia) and the resulting oil production was recorded.

The results of these runs show that a single well would require as much as one section of reservoir to provide the energy required to produced the observed volumes. Clearly this is impossible given the fact that only this amount of productive reservoir has been delineated and that there are 16 wells currently producing from it. A second run was made for the 40 acre drainage area case in which the oil was assumed to be initially saturated. Now, as the pressure decreased, gas came out of solution and was available to provide pressure support. The total compressibility of the system was increased by an order of magnitude and, as is evident in Figure 8, the energy contained within a 40 acre area is sufficient to support the observed production of a single well. yes, but observed GOR's are still low! how about increasing negative skin on wells

Whether or not the oil in this pool actually has a saturation pressure of 8 750 kPa could be the subject of much further discussion. These runs only illustrate that the saturation pressure must be greater than that determined by the fluid no! Make the reservoir better!

analysis, if sufficient energy is to be found. Assuming that the slope of the solution gas-oil ratio curve defined by the fluid analysis can be extrapolated, oil having a saturation pressure of 8 750 kPa would require about 50% more gas in solution than oil with a saturation pressure of 2 000 kPa. Given the low volumes of gas involved, it is quite conceivable that a non-representative volume of gas was captured for the fluid analysis study. Additionally, if there is a critical gas saturation in the reservoir (5.0% of pore volume is assumed in the model) then 03-28 would likely have been producing at a gas-oil ratio of less than solution when the sample was caught.

It was decided to continue the model calibration assuming that the oil was initially fully saturated. Further modifications to the permeability array, in most cases to reduce inter-well communication, were required to calibrate the model. It was found that the level of permeability immediately surrounding the well bore controls initial productivity, and the continuity of this permeability further away determines the amount of pore volume in communication with the well and thus the magnitude of the production decline rate.

The permeability array considered sufficient to reasonably calibrate the model is shown in Table 8 (The model area covered is shown in Figure 3). Comparison of this array with the base permeability array shown in Table 3, shows that inter-well communication in the reservoir has been drastically reduced. The area of the model not covered by the array now has a permeability of 0.5 mD.

Close inspection of the permeability array will show that cells in which wells are located (the decimal point has been replaced by an asterisk) have a higher permeability than surrounding cells. This does not suggest that only the highest permeability areas of the reservoir have been drilled. Rather, it that wasn't our first clue!

illustrates our lack of knowledge about the reservoir. Likely, a well drilled anywhere within the heart of the pool would encounter productive reservoir and would produce some volume of oil. What can be concluded from the model is that inter-well communication in this reservoir is, in most cases, poor and that any infill well would probably not recover more than the average volume of oil which can be expected from any of the existing wells.

The results of the model calibration exercise are shown in Figures 9-19. For most wells, the observed oil volume has been produced while respecting the flowing BHP target of 345 kPa (50 psia). At some wells, such as 09-20, 13-21, 03-28 and 04-28, the producing BHP's are increasing towards the end of the calibration period (Figures 11, 13 and 15). This indicates that there is still too much pore volume in communication with these wells. This reservoir is sufficiently complex that many runs could have been made with slight changes in permeability and pore volume to further refine the match. This was considered unproductive as the purpose of this work was simply to develop a concept of what is occurring in this reservoir and this has been accomplished.

only the pay (ie [illegible]) not the reservoir should have been characterized better!

The model contains an IOIP of 2 054.5 $10^3 m^3$ (12.9 MMSTB). The heart of the pool, in which the permeability is greater than 0.5 mD (Table 8), contains an IOIP of 542.3 $10^3 m^3$ (3.4 MMSTB). Only the reserves in the heart of the pool should be given full credit as potentially producible. This volume was used for calculating the recovery factors quoted in this report.

VIII. PERFORMANCE PREDICTIONS

VIII.1 Introduction

With the model calibrated as described previously, the following three prediction cases were run:

Case 1: Base Case - Continue primary depletion.

Case 2: Water Injection - Inject water into 13-21 starting January 1, 1989.

Case 3: Water Injection - As in Case 2 but increase krw at Socr from 0.3 to 0.6.

The results of these runs are most valuable when used to compare overall performance between cases. Not too much emphasis should be placed on individual well forecasts as they are very sensitive to the state of the model calibration. As noted previously, for some wells, the model is predicting increasing flowing BHP's towards the end of the model calibration. These wells future oil production will probably be over-estimated.

The following includes an overview of the major operating assumptions, a detailed description of each case and a discussion of the results as a whole.

VIII.2 Major Operating Assumptions

For consistency, several major operating assumptions were defined and adhered to in all of the prediction runs. Case specific assumptions are noted later as necessary.

1. The prediction runs extend from the end of the modelled history, July 1, 1988 to January 1, 2009.

2. The wells were scheduled to produce at a flowing BHP of 345 kPa (50 psia). They were not constrained by any maximum fluid or gas rate limitations.

3. The wells were operated for 100% of the time. They were shut-in when their oil production rate fell below the estimated economic limit of 0.5 m^3/d.

VIII.3 Case Descriptions

Case 1

This case was designed to simulate continued primary depletion. All of the wells were operated as previously described.

Case 2

This case was designed to evaluate the effect of converting 13-21 into a water injector, effective January 1, 1989. This well was chosen for conversion because it had the highest initial productivity in the pool, indicating the highest local permeability. Additionally, it is centrally located and the observed production behaviour indicates that it has some communication with 16-20 and 04-28. Well 13-21 was scheduled to inject at a flowing BHP of 15 200 kPa (2 200 psia). This is considered to be the maximum flowing BHP which will not exceed the parting pressure of the formation.

Case 3

The objective of Case 3 was to sensitize water injection to water relative permeability. As injection rates in this pool are likely to be low due to the low rock permeability and injection pressure constraints, water injection could be quite sensitive to water relative permeability. As no laboratory data is available, it was decided to re-run Case 2 with a krw of 0.6 at Socr, rather than 0.3. This would cover the range of endpoint krw values which might be reasonably expected.

VIII.4 Discussion of Results

Tables 9-11 imbued Figures 20-22 summarize the performance of the model during each of the prediction runs. Table 12 and Figures 23 - 26 compare various aspects of performance between the cases.

The current study area recovery is 24.2 10^3m^3 (4.5% of IOIP). Assuming that the current operating practices in the field are continued, the model predicts that 94.7 10^3m^3 of oil (17.5% of IOIP) will be recovered by January 1, 2009. The average study area production rate during the year 2008 will be approximately 3 m^3/d.

The results of Cases 2 and 3 indicate that injection water into 13-21 will result in the recovery of 112.4 - 119.5 10^3m^3 of oil (20.7 - 22.0% of IOIP) by January 1, 2009. This corresponds to an incremental recovery of 17.7 - 24.8 10^3m^3 of oil (3.3 - 4.6% of IOIP) by that date.

Not surprisingly, Case 3, in which the water relative permeability is higher, has a higher predicted recovery. This is because greater volumes of water can be injected while respecting well 13-21's maximum flowing ? injecting? BHP of 15 200 kPa (2 000 psia). In fact, the stabilized injection rate in either case is low. For Case 2 and Case 3 it is approximately 5 and 9 m^3/d, respectively. The low reservoir permeability in this pool and its relatively shallow depth which results in low injection pressures, are not conducive to injecting large volumes of water. why not use more than one injector!?

On the basis of these prediction runs and our experience gained during the model calibration runs, it is ECL's opinion that water not be injected in this pool. If anything, the degree of reservoir continuity described by the model is optimistic. If this is the case, then the actual recovery resulting from water injection may be even lower than the very modest recoveries reported here. In our opinion, continuing the present operating practices will maximize recovery (and value) in this pool.

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it wouldn't have hurt to have read this one.

X. REPORT PREPARATION

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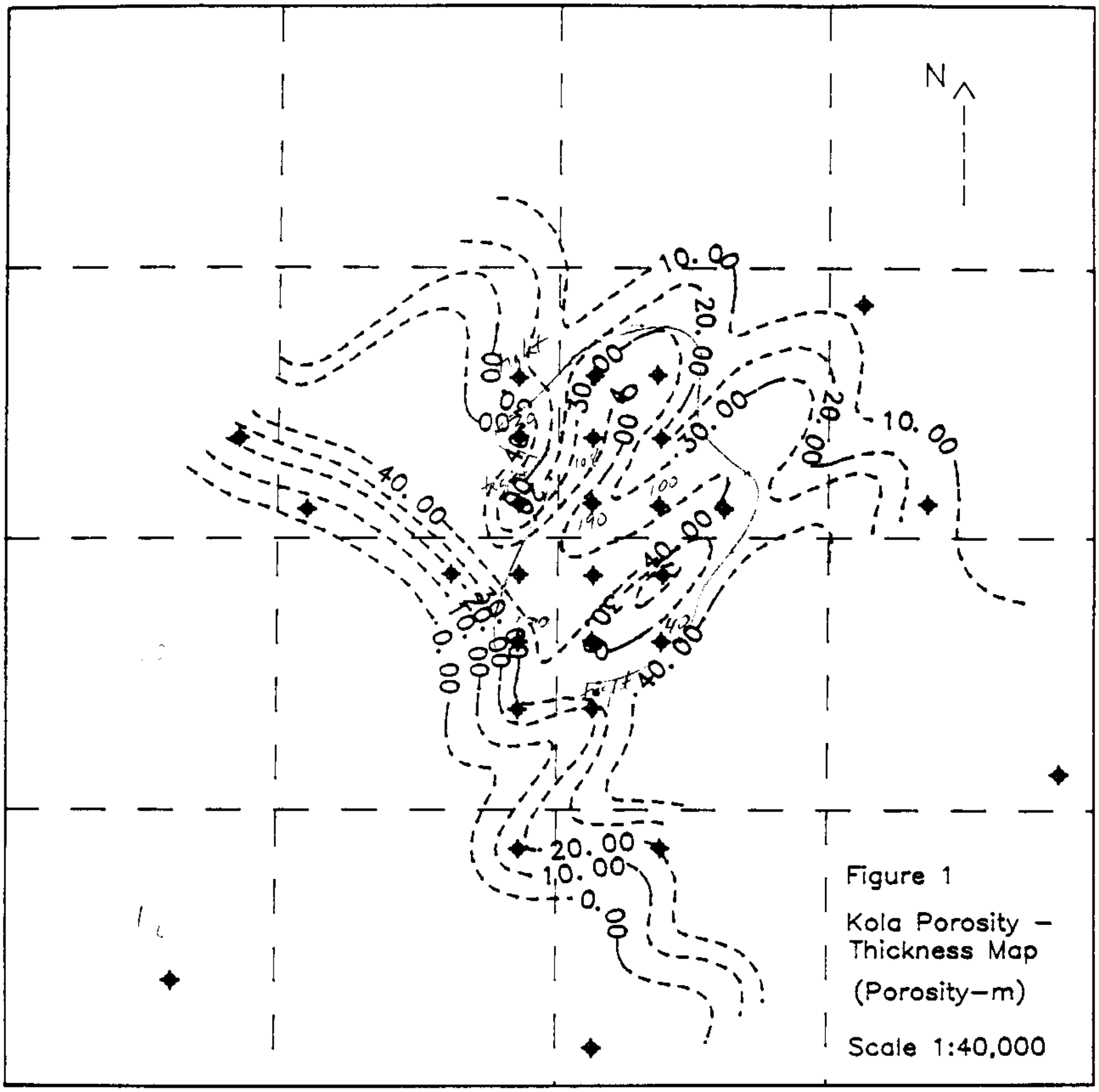
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Figure 1
Kola Porosity – Thickness Map
(Porosity–m)
Scale 1:40,000

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Kh

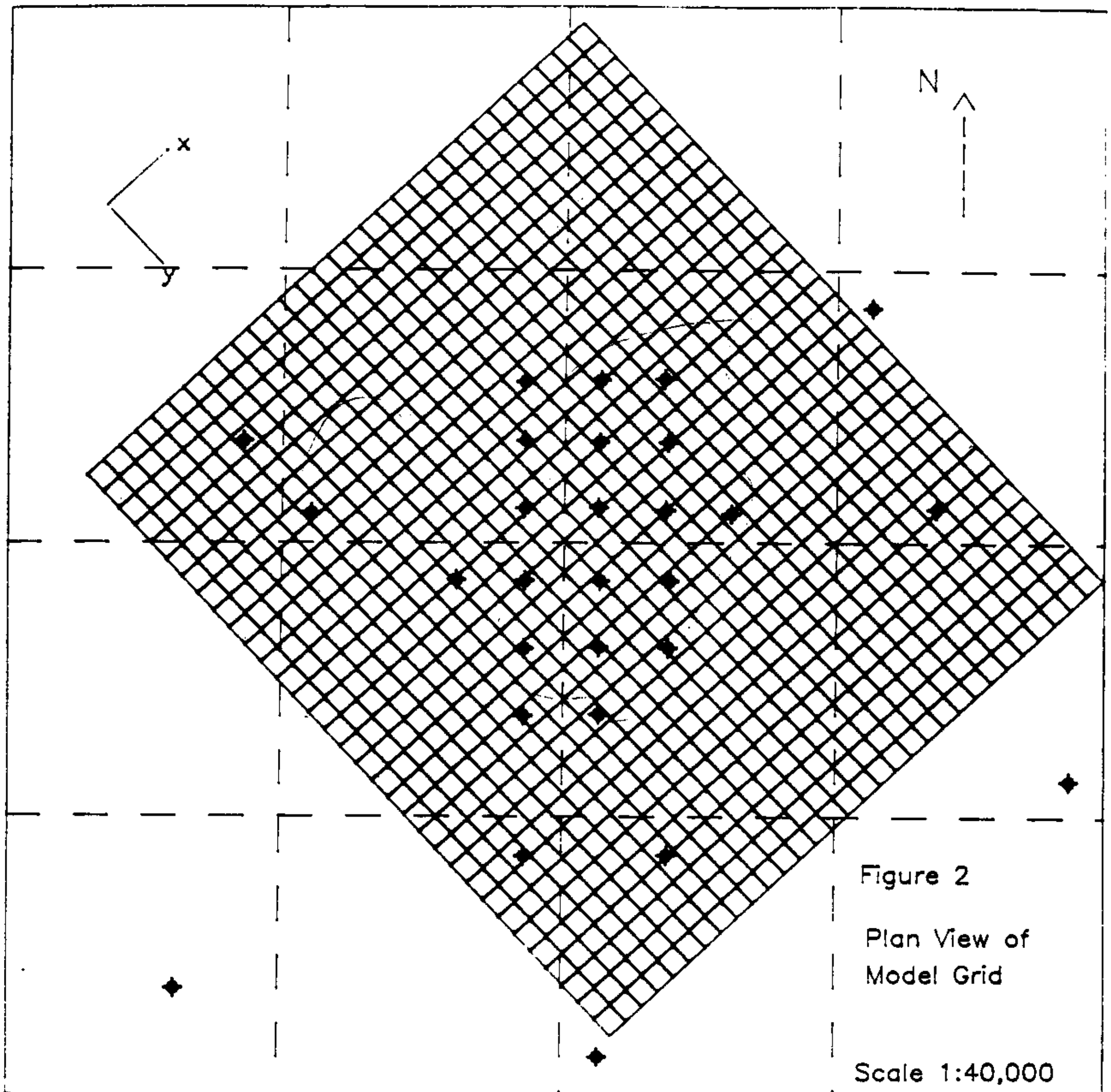


Figure 2

Plan View of Model Grid

Scale 1:40,000

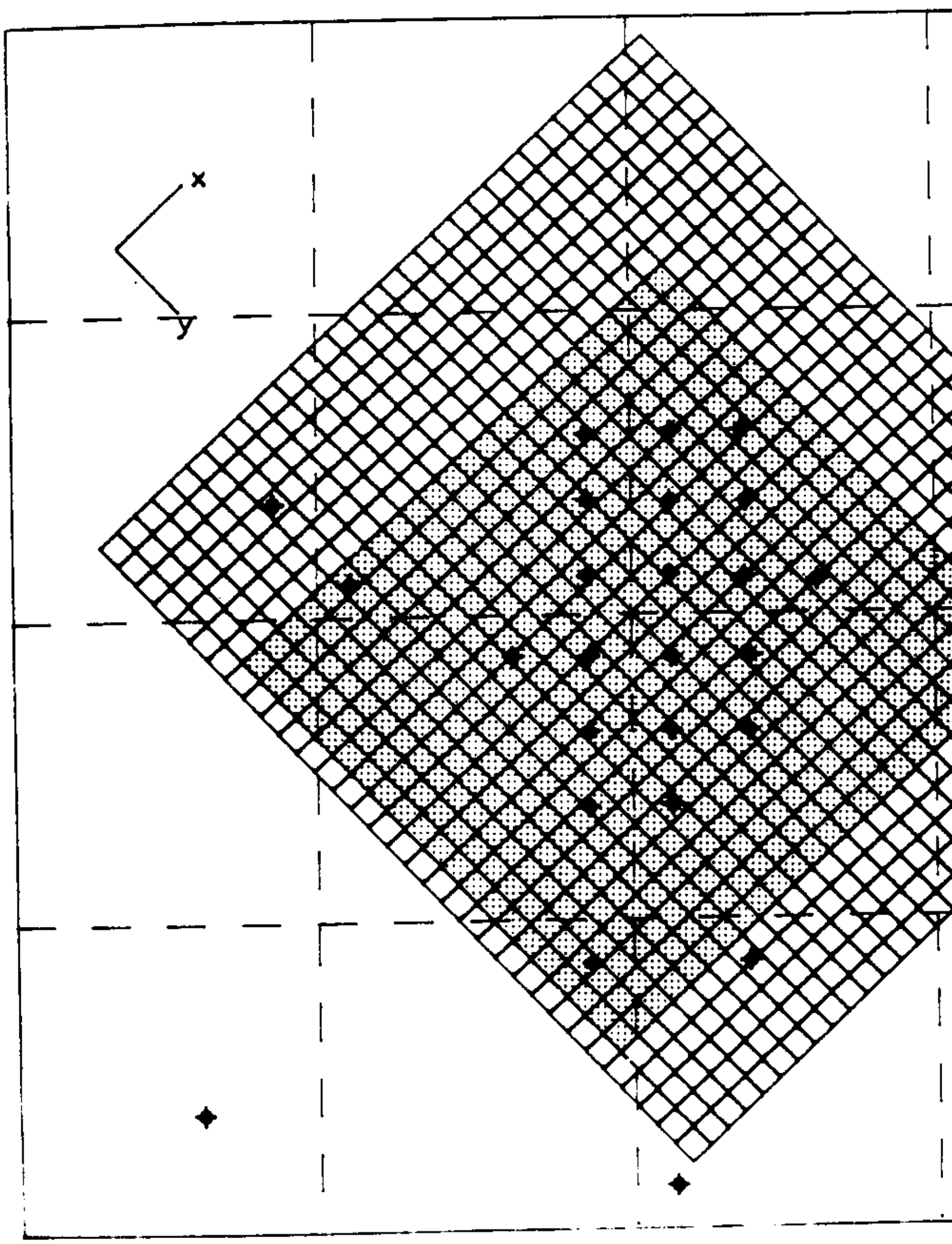


Figure 3

Location of Permeability Array

Scale 1:40,000

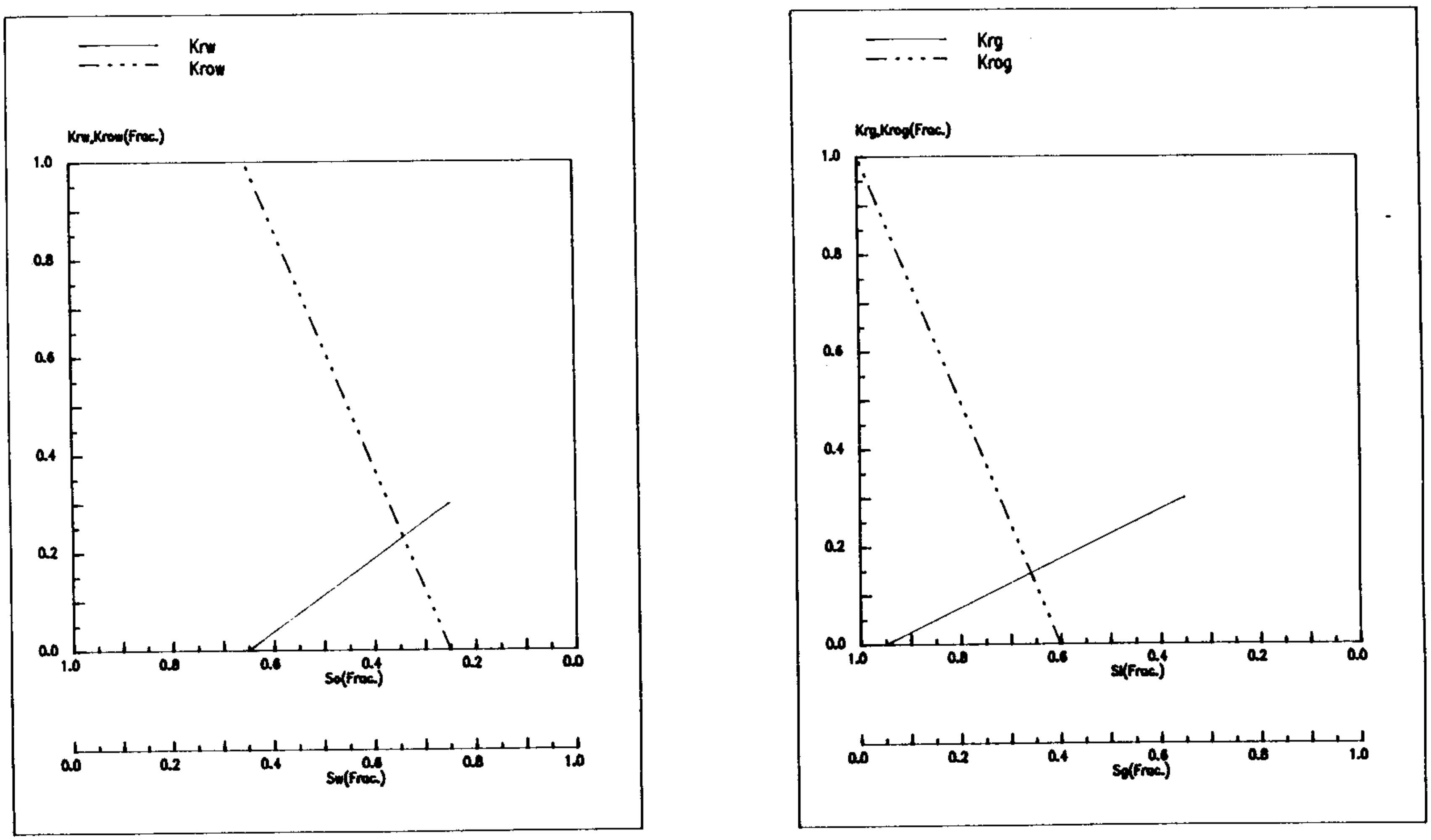


Figure 4: Relative Permeability Functions.

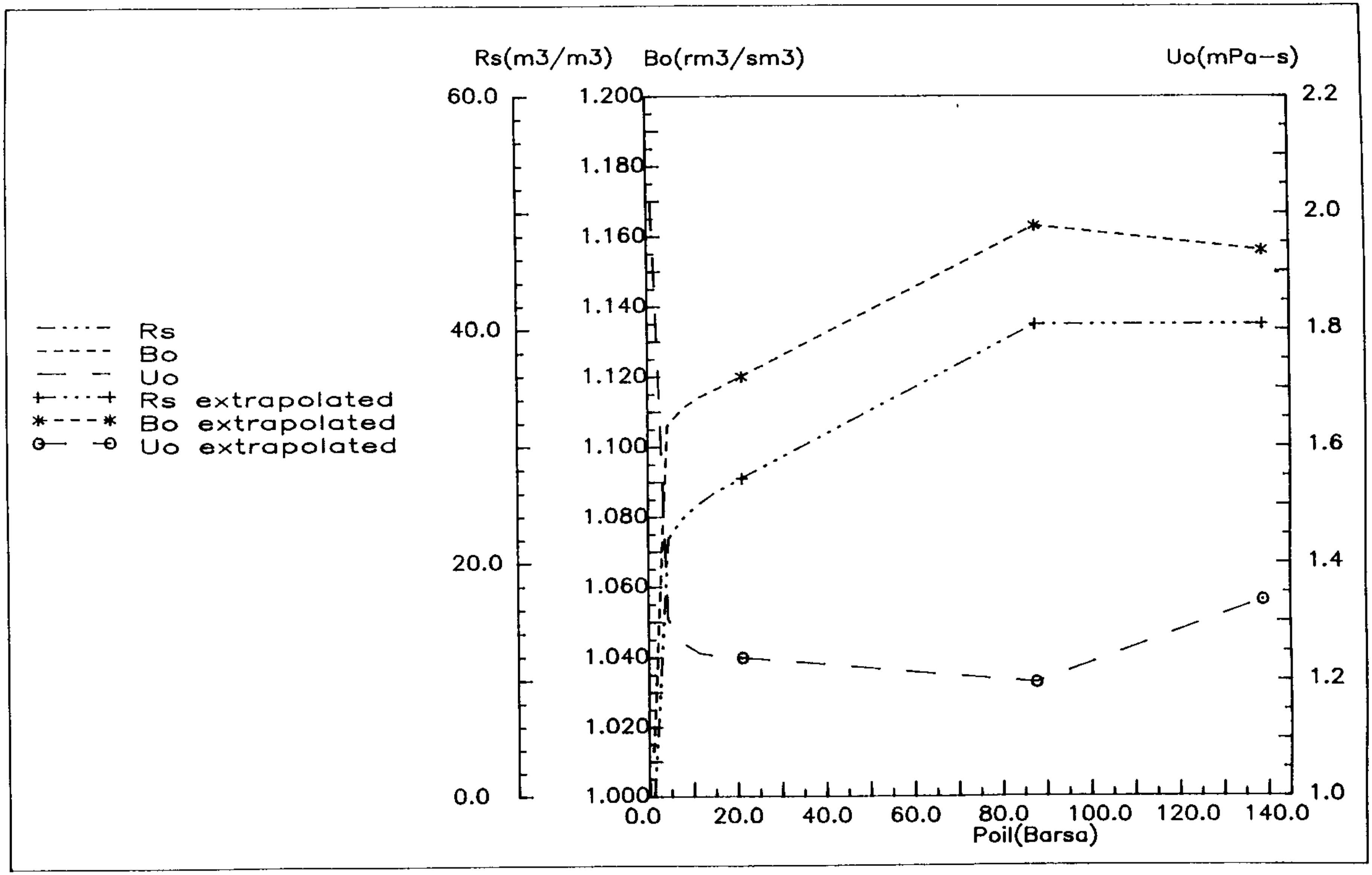


Figure 5: Oil PVT Functions.

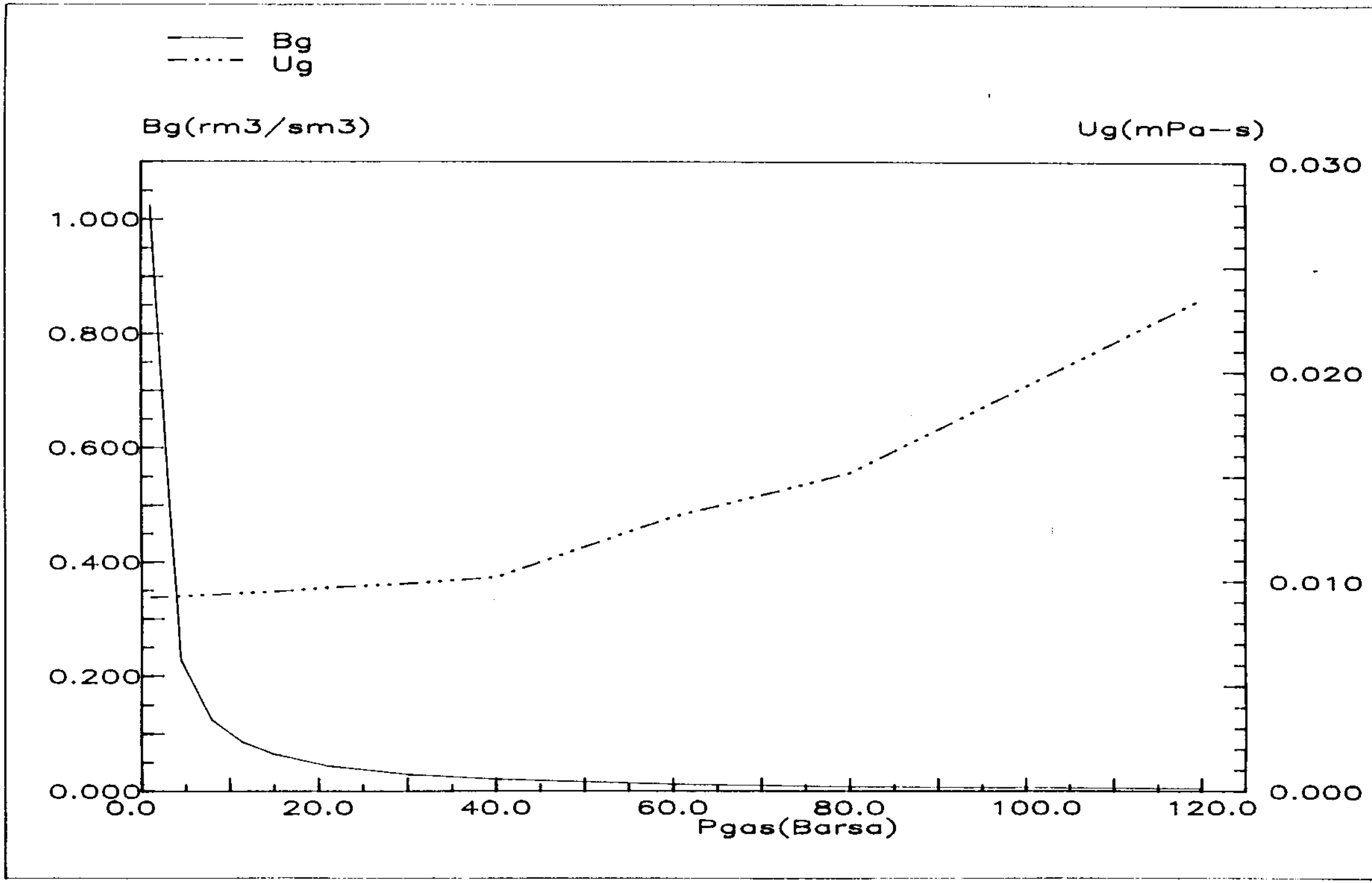


Figure 6: Gas PVT Functions.

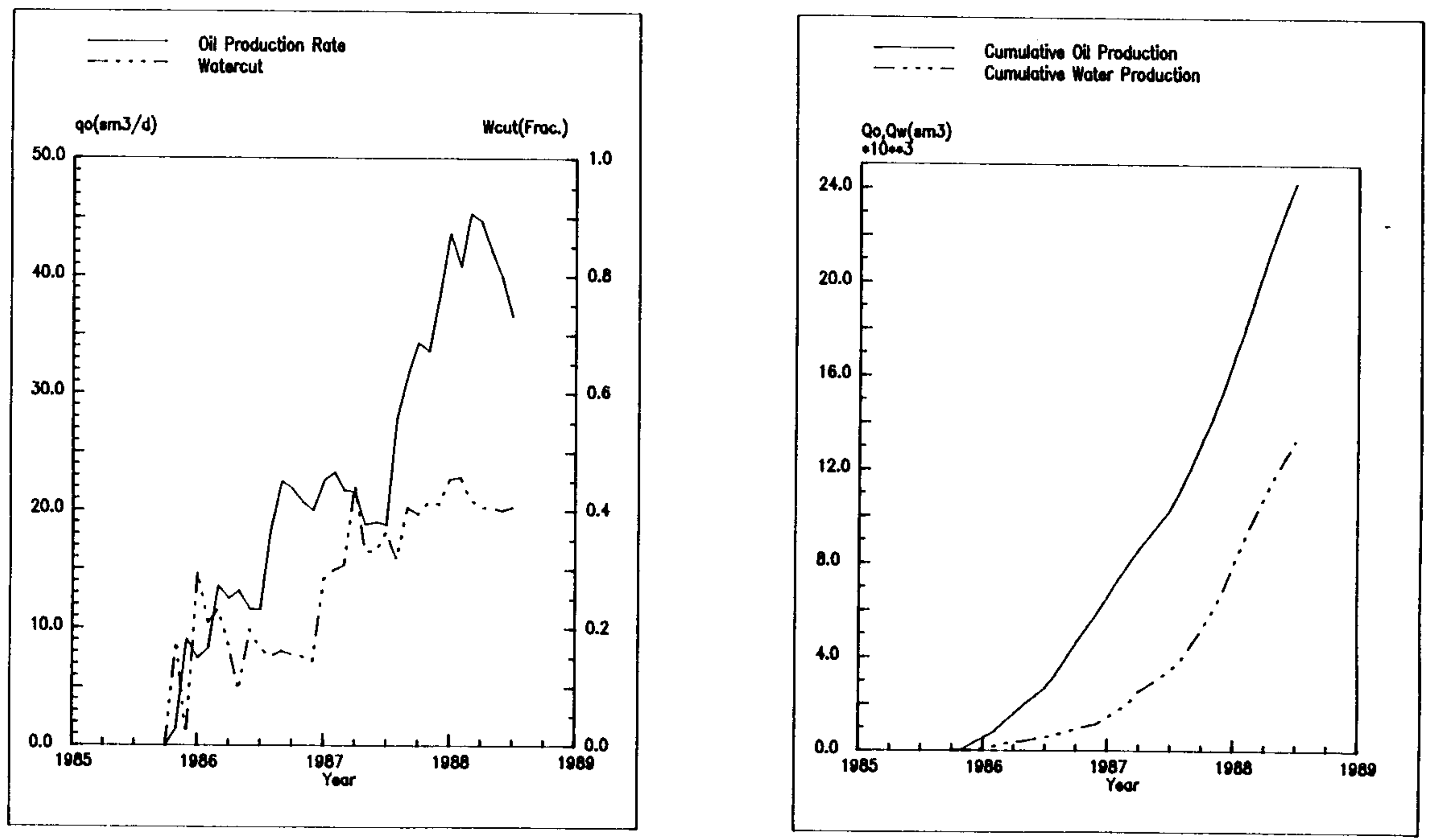


Figure 7: Study Area Historical Performance.

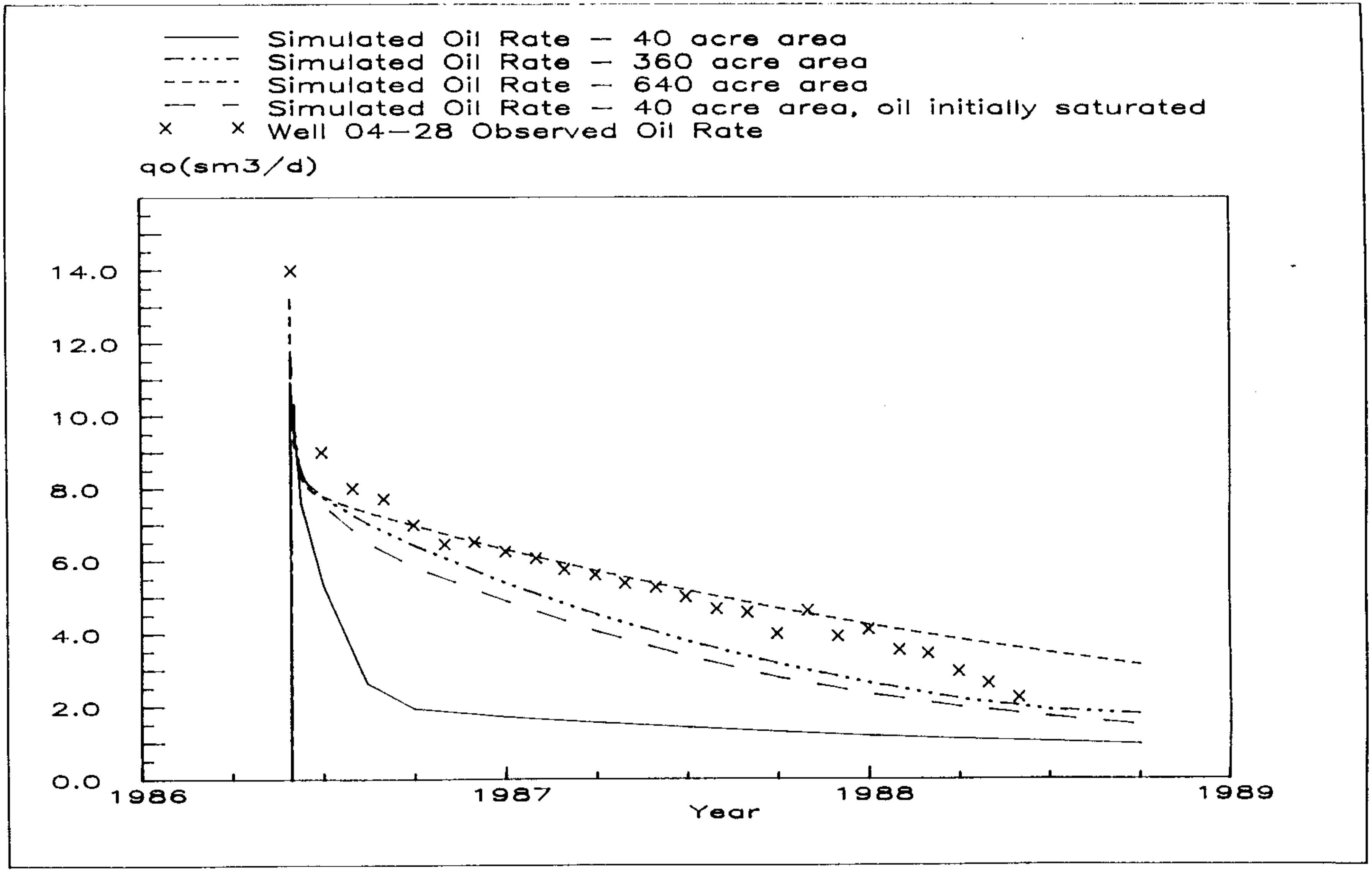


Figure 8: Single Well Radial Model Run Results.

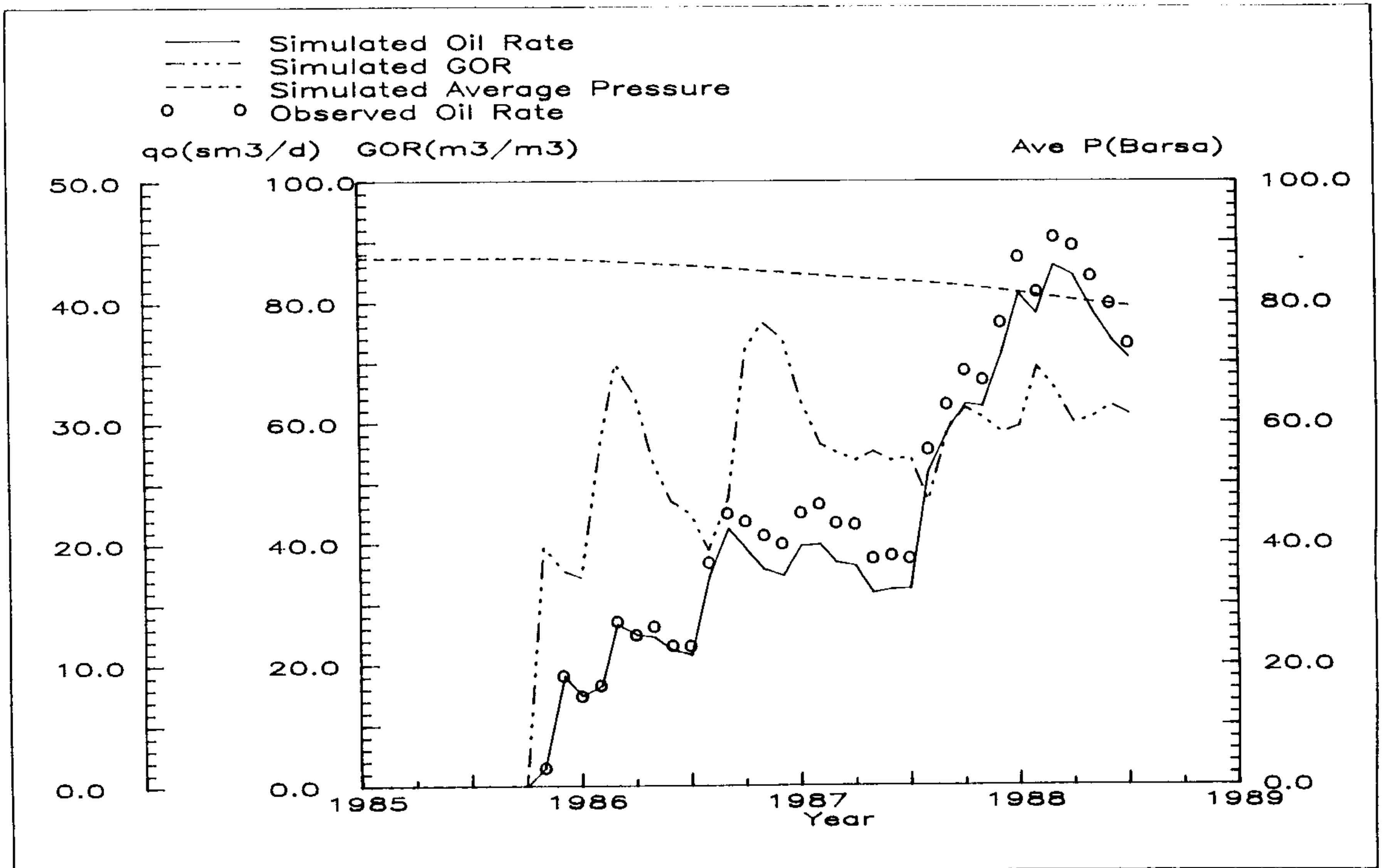
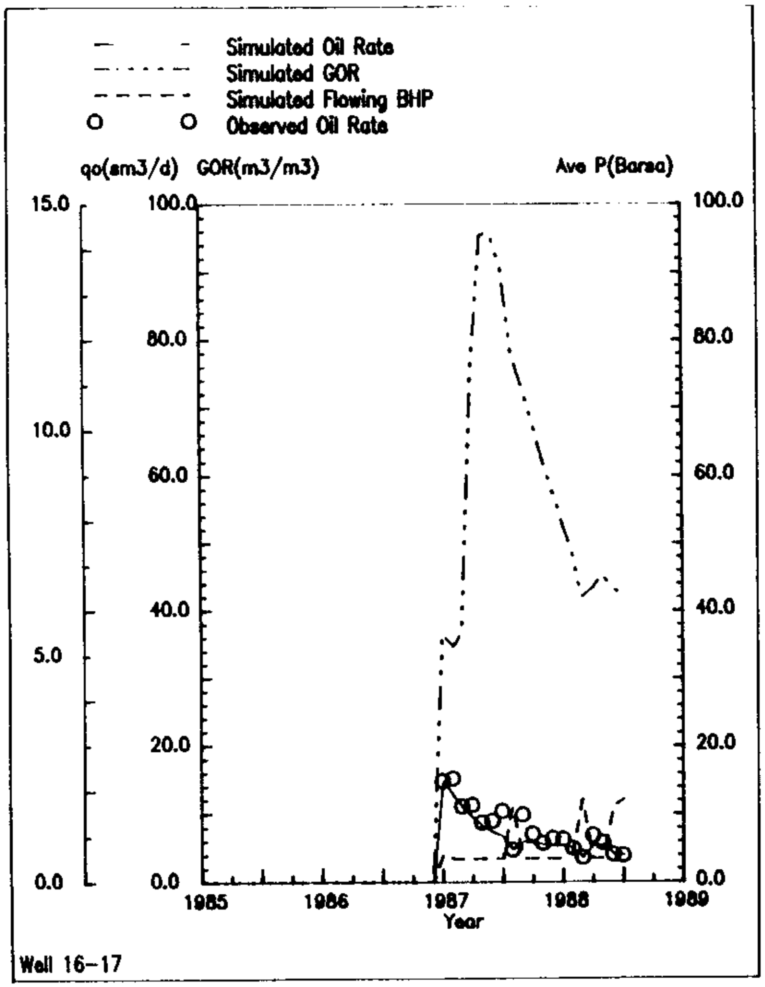


Figure 9: Study Area Model Calibration Results.



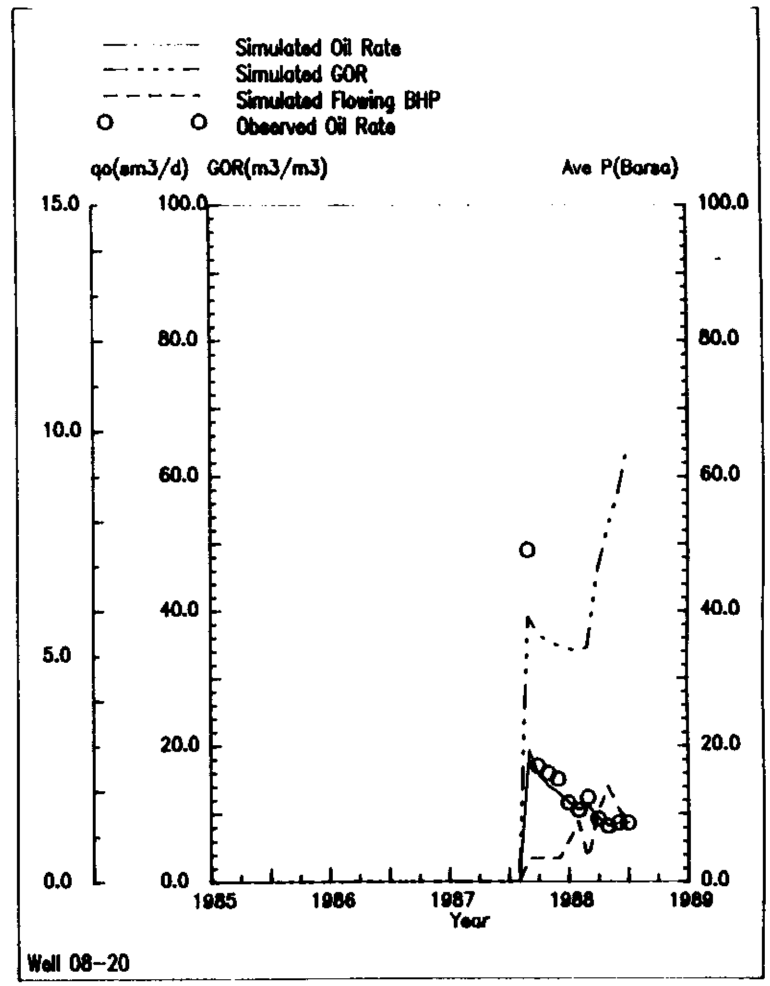
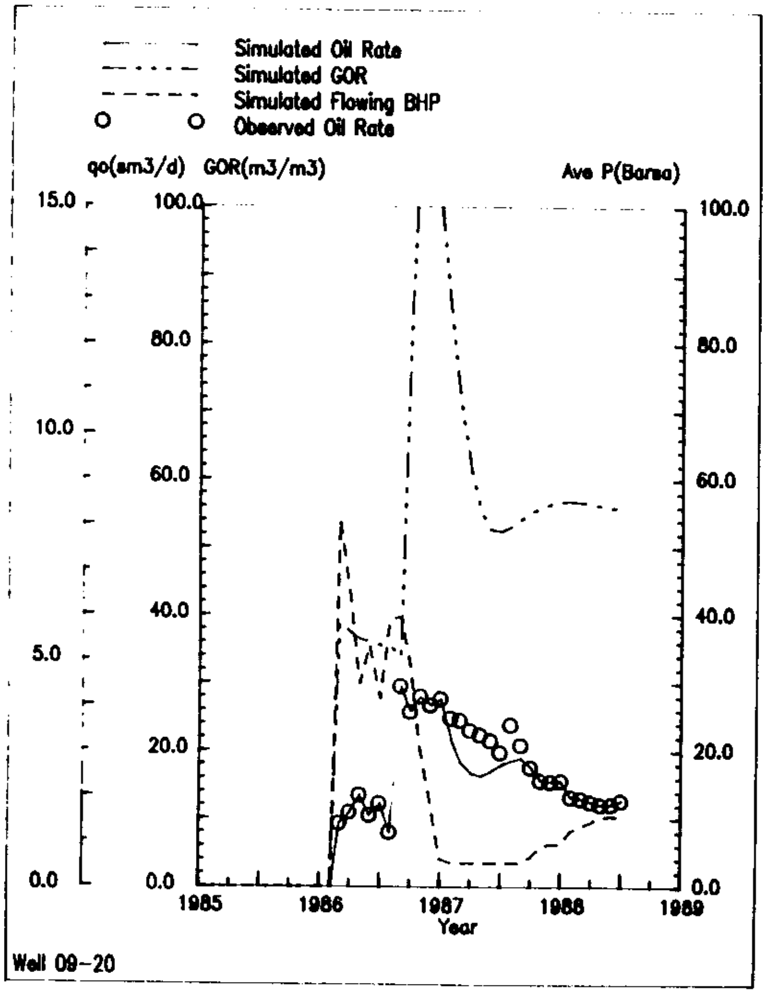


Figure 10: Well's 16–17 and 08–20 Model Calibration Results.



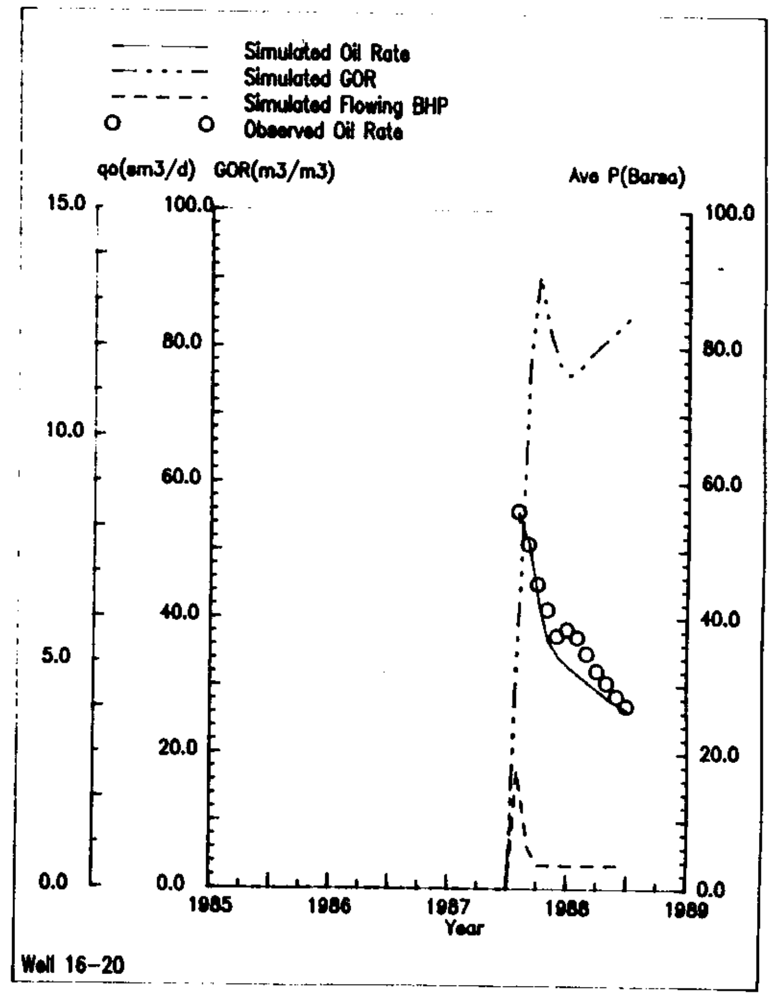


Figure 11: Well's 09–20 and 16–20 Model Calibration Results.

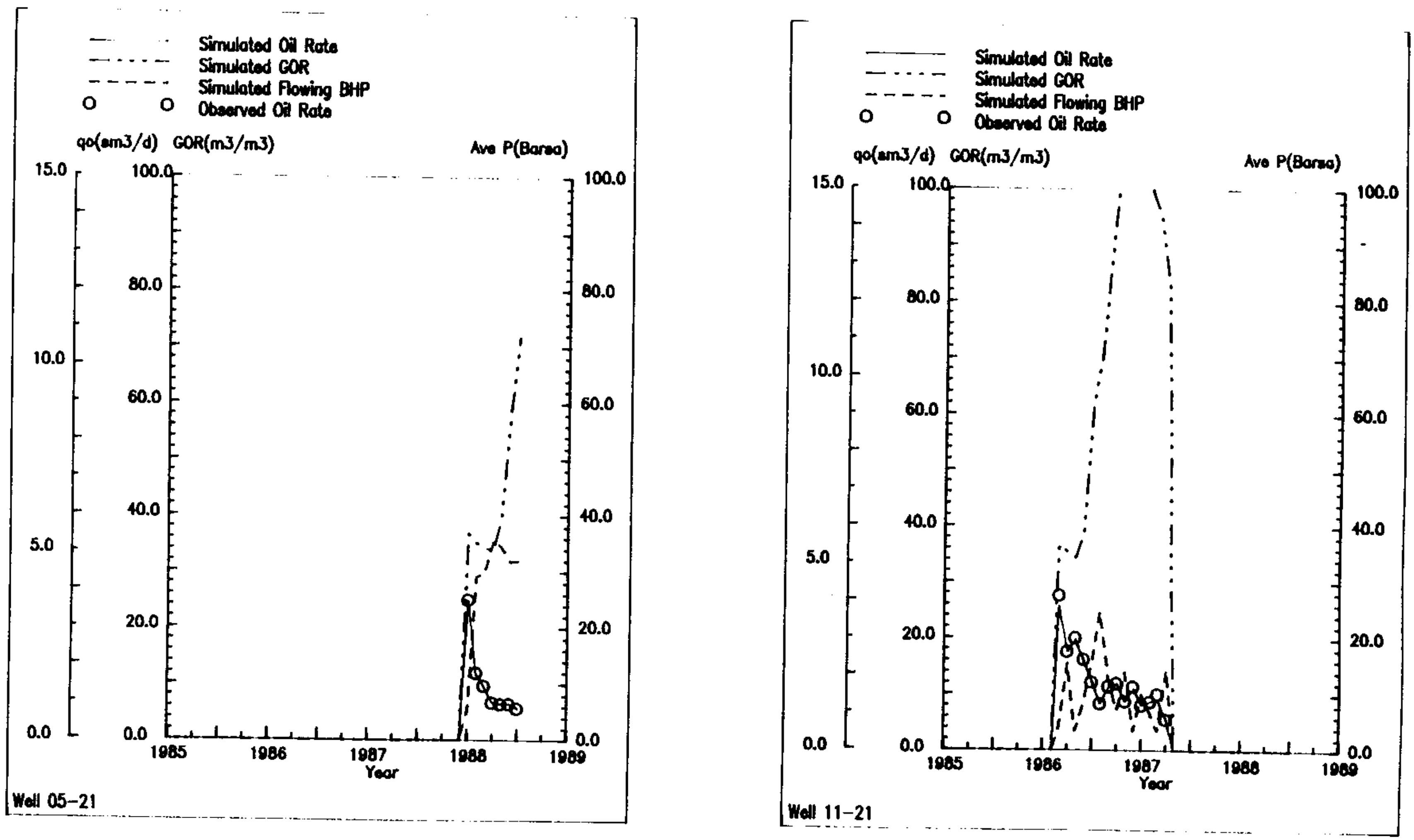


Figure 12: Well's 05—21 and 11—21 Model Calibration Results.

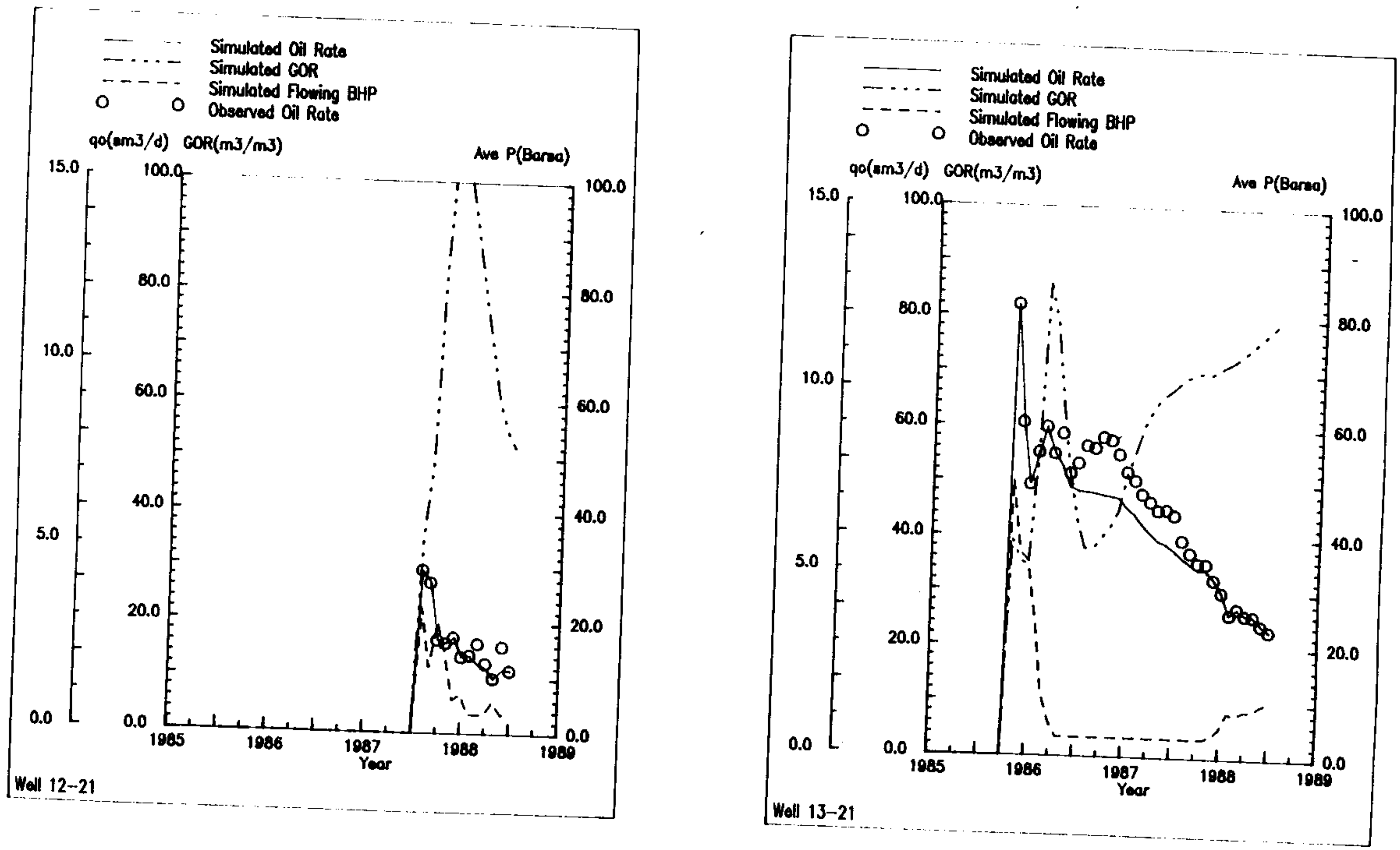


Figure 13: Well's 12–21 and 13–21 Model Calibration Results.

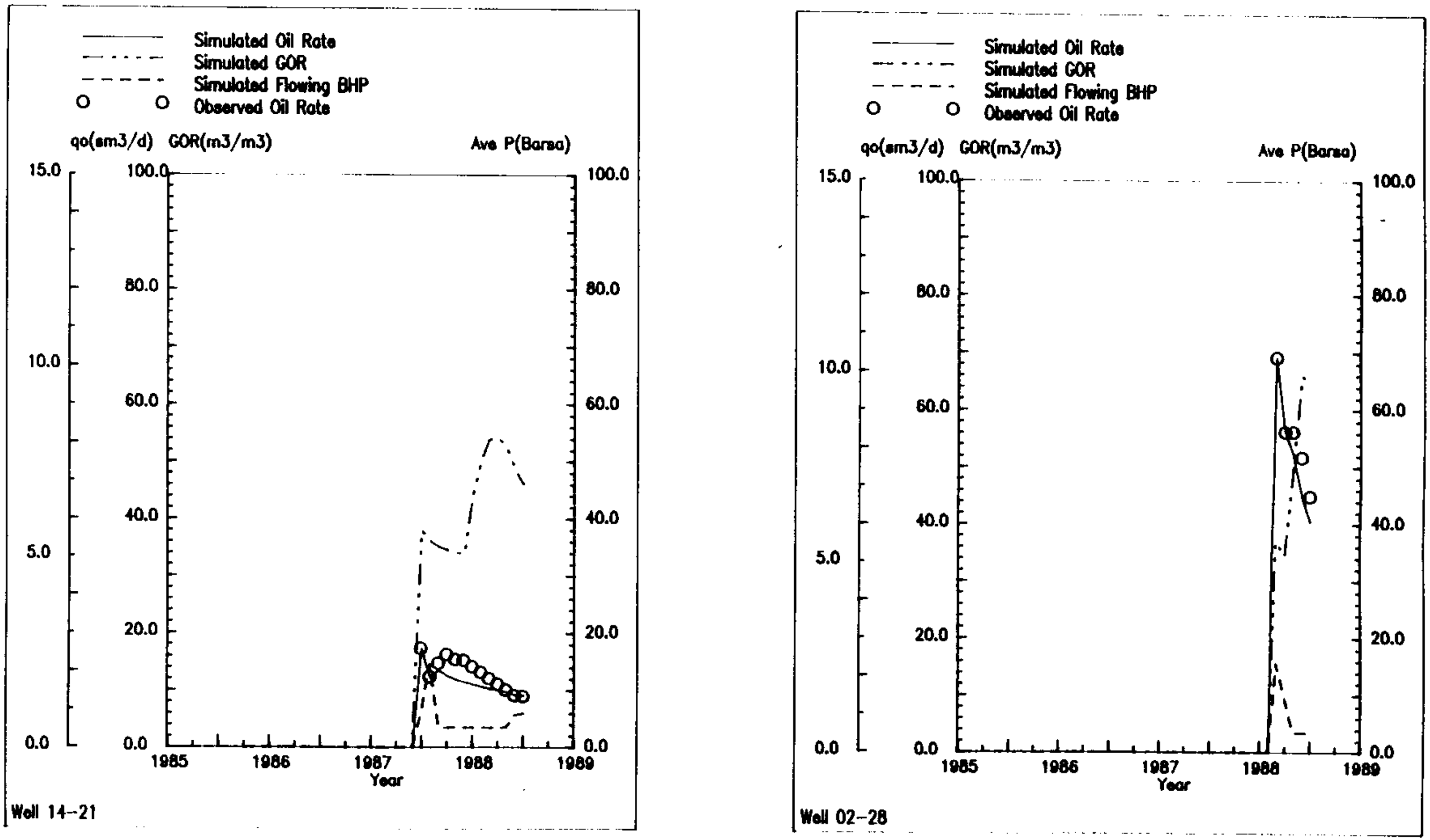


Figure 14: Well's 14—21 and 02—28 Model Calibration Results.

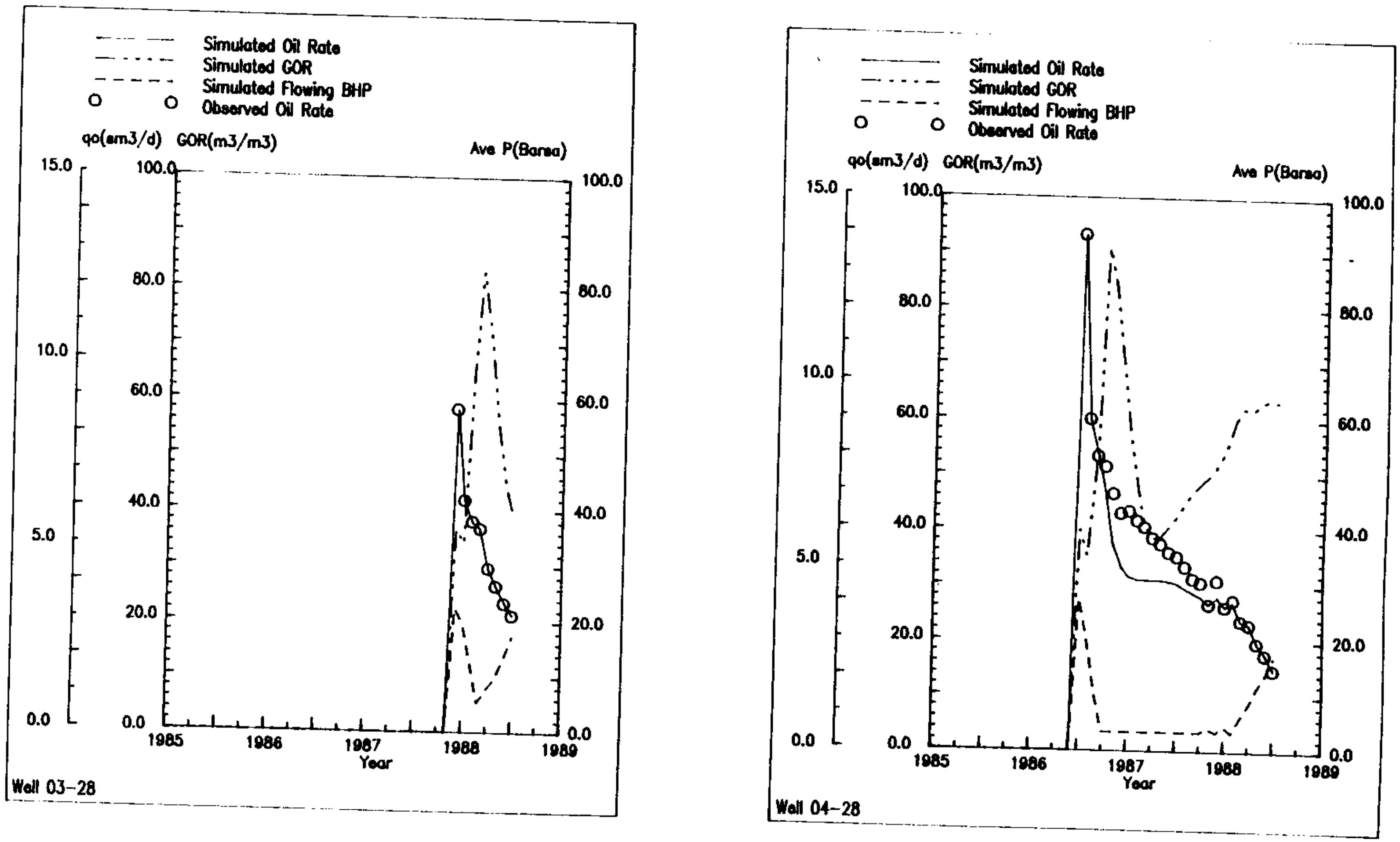


Figure 15: Well's 03–28 and 04–28 Model Calibration Results.

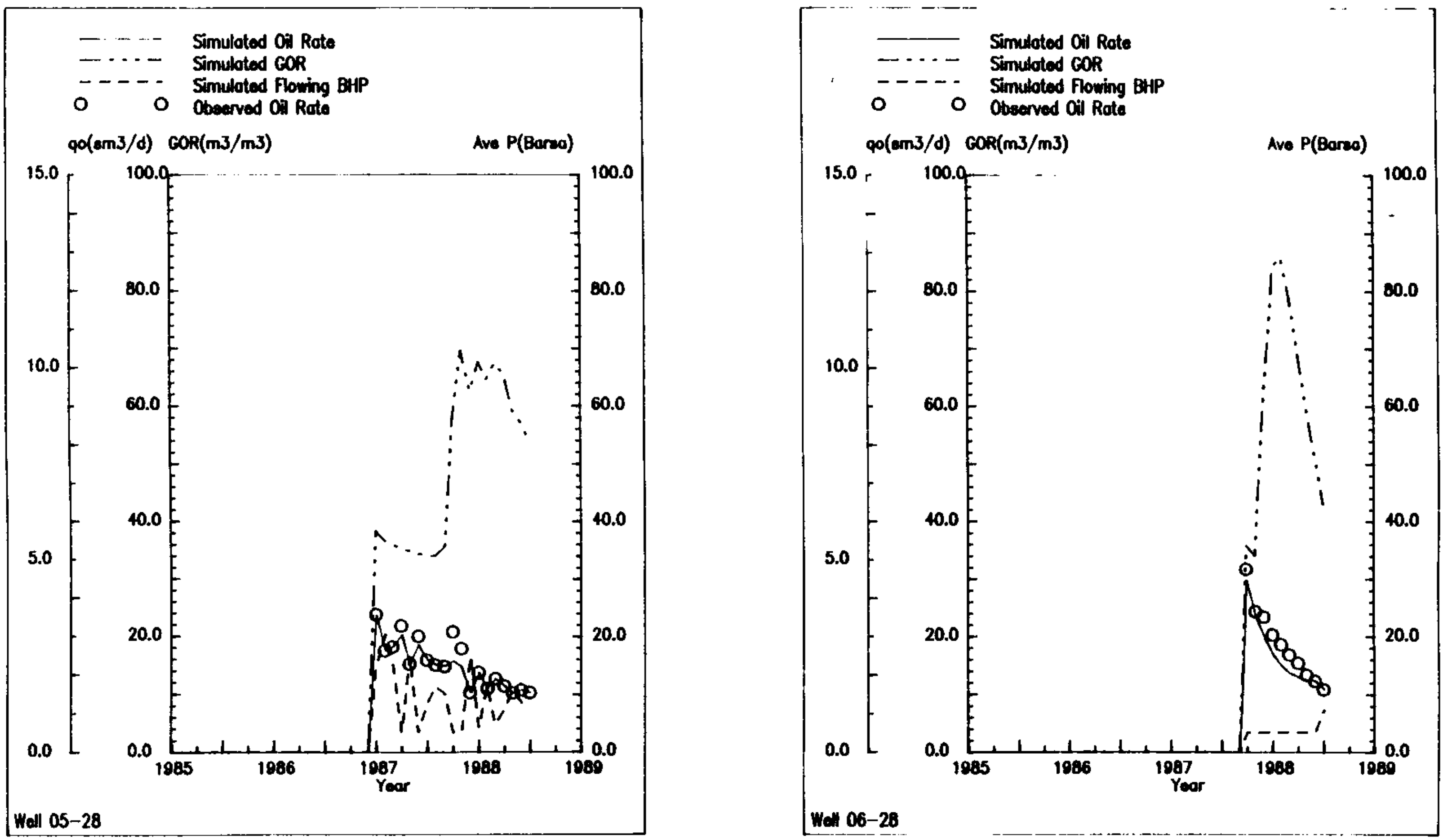
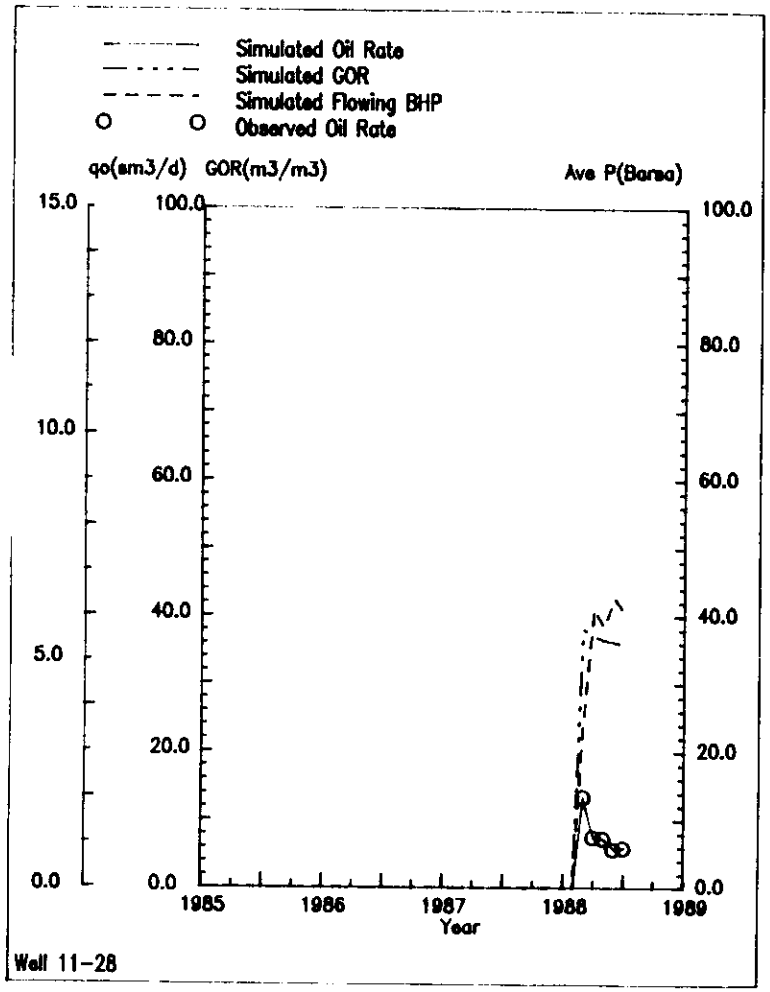


Figure 16: Well's 05—28 and 06—28 Model Calibration Results.



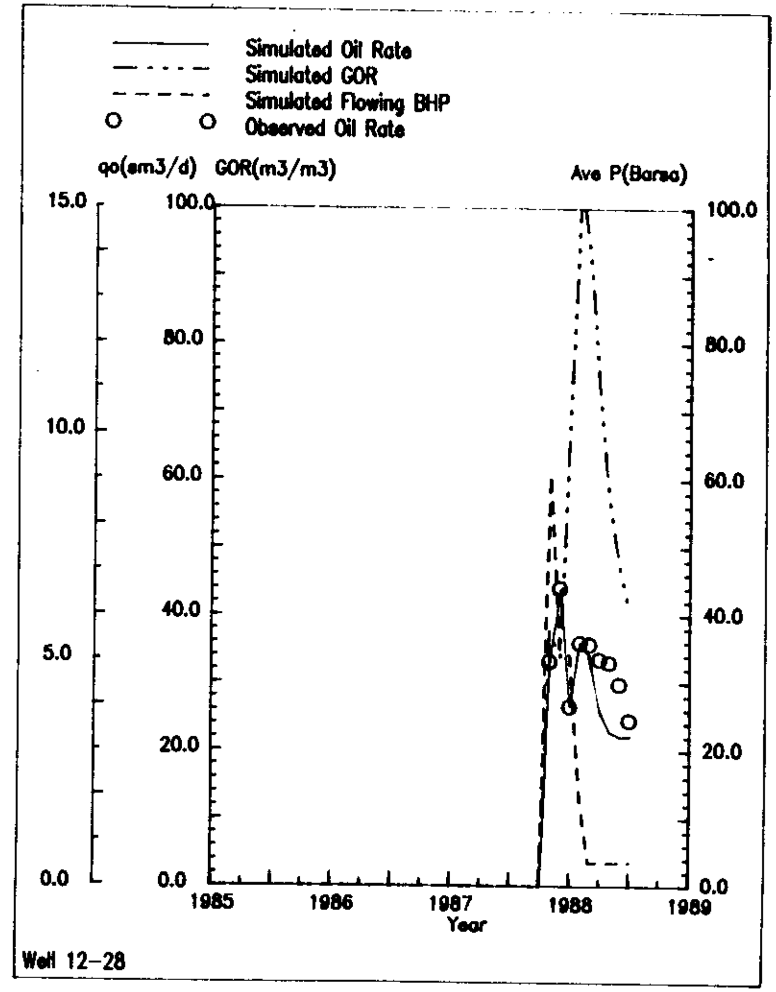


Figure 17: Well's 11–28 and 12–28 Model Calibration Results.

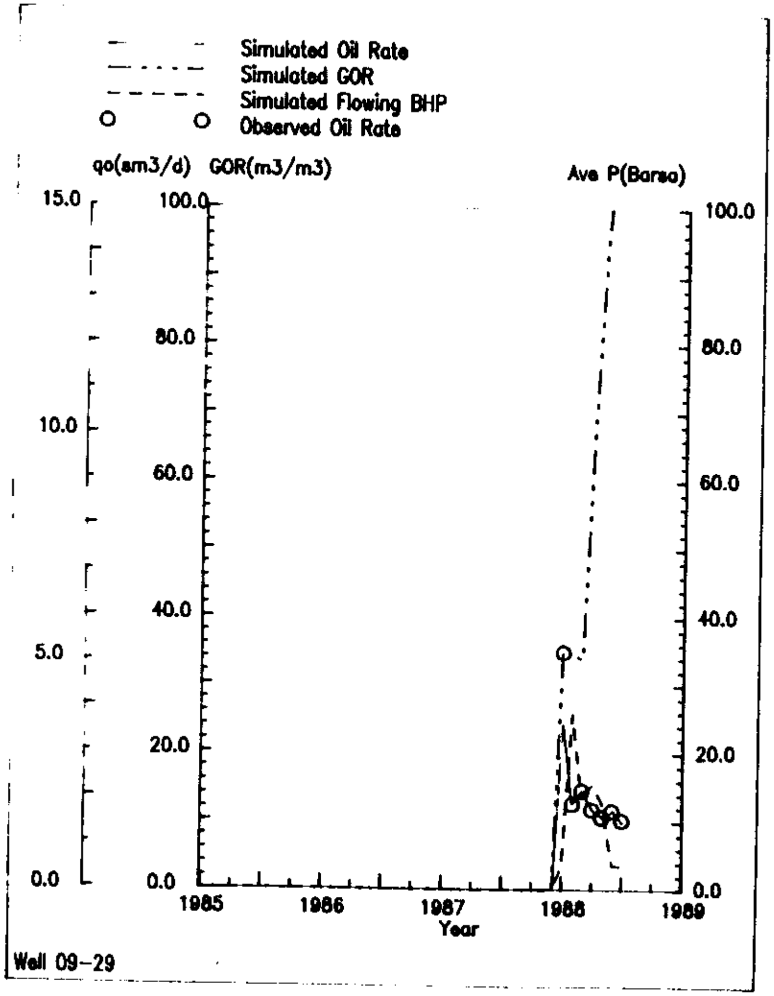


Figure 18: Well 09–29 Model Calibration Results.

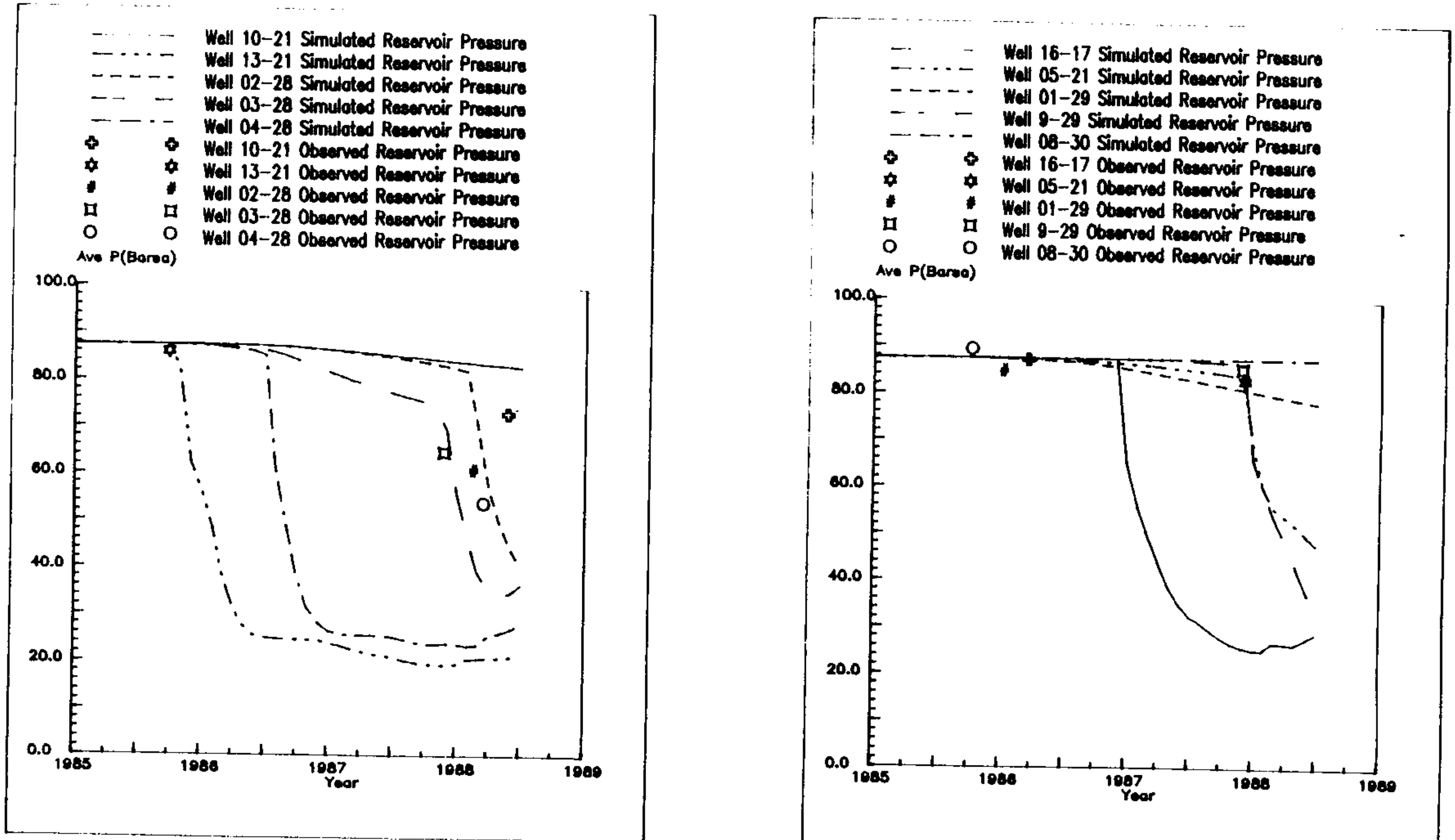


Figure 19: Simulated vs Observed Reservoir Pressures.

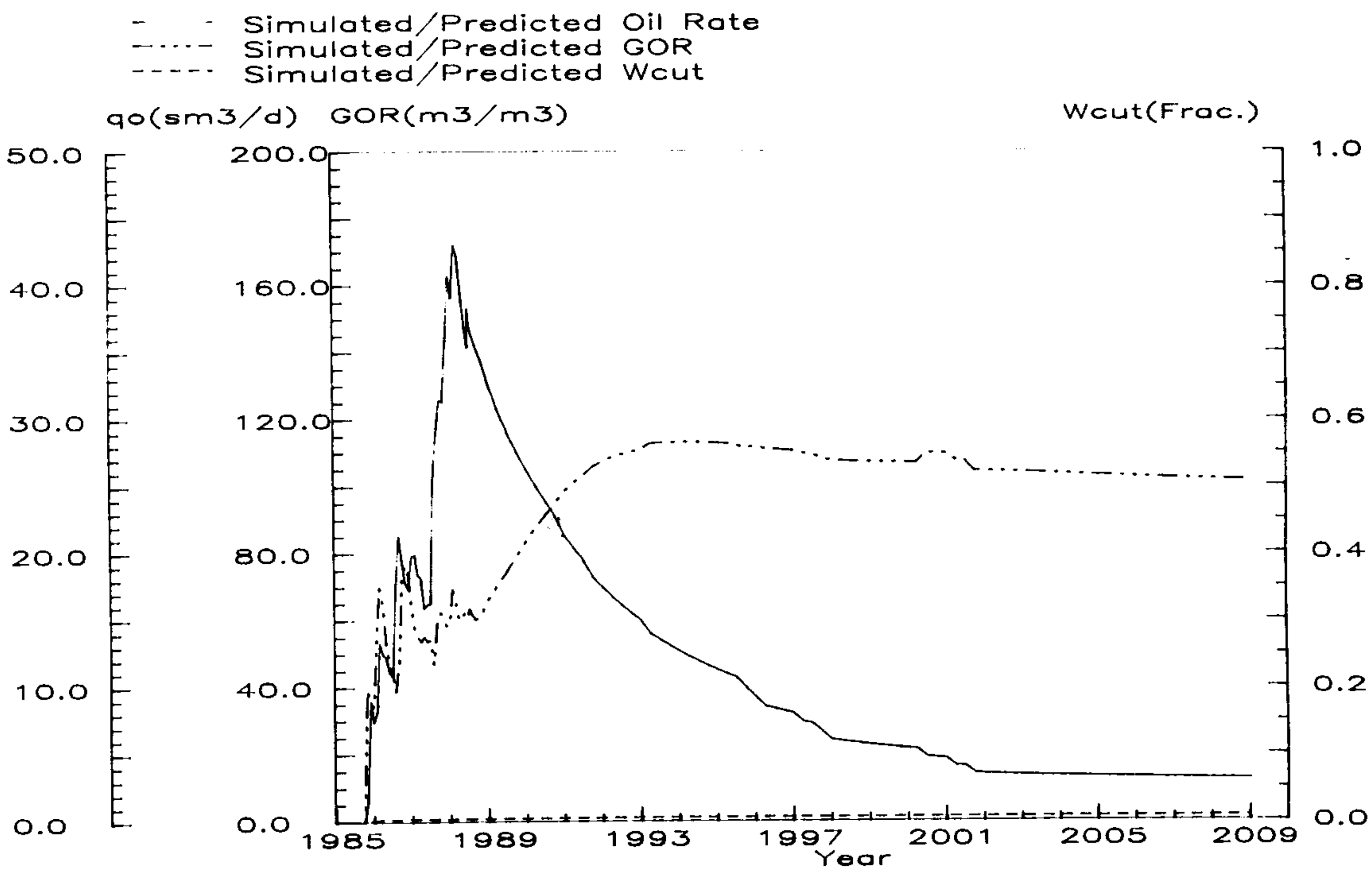


Figure 20: Case 1 (Base Case) Performance.

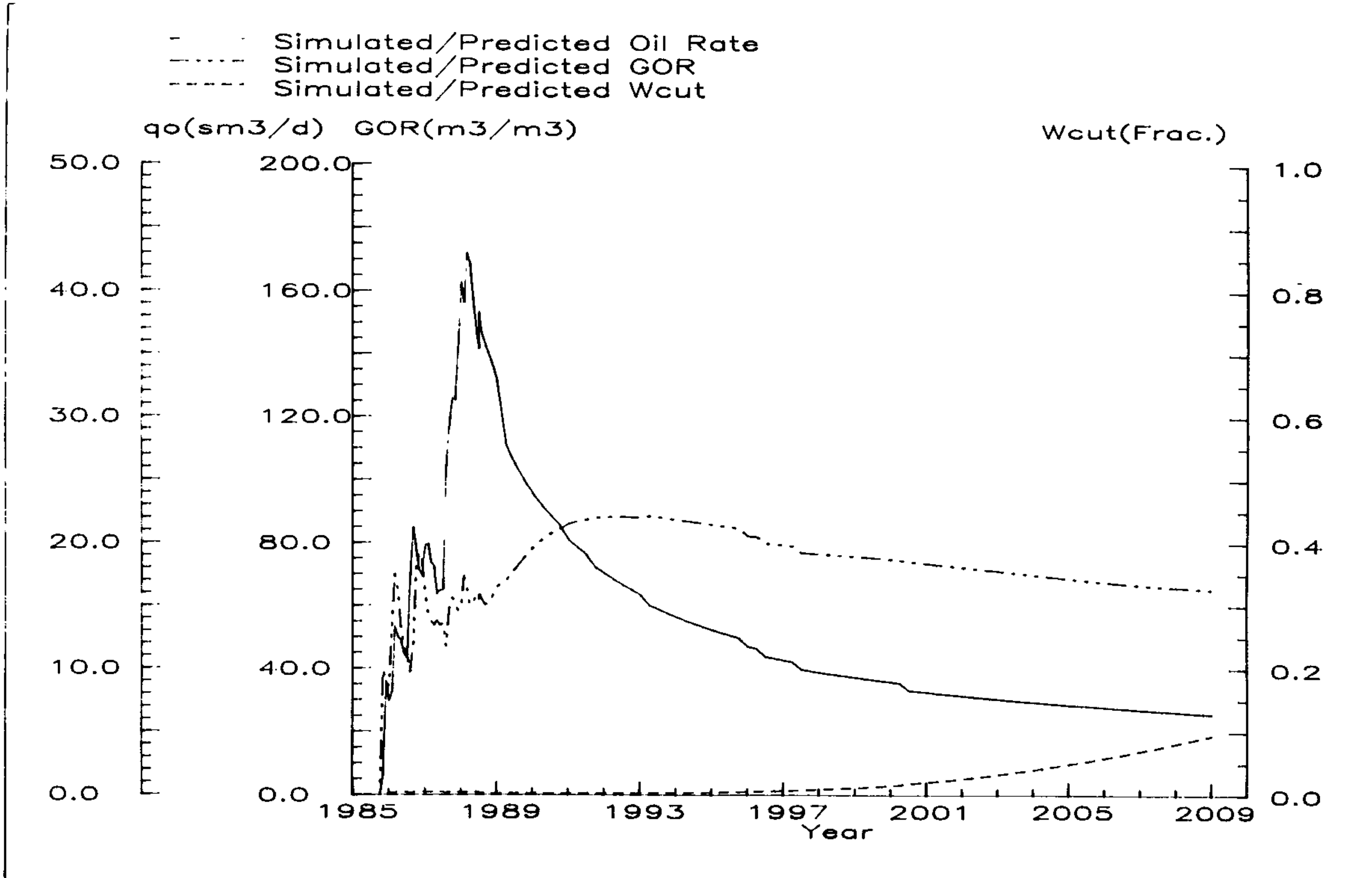


Figure 21: Case 2 (Water Injection) Performance.

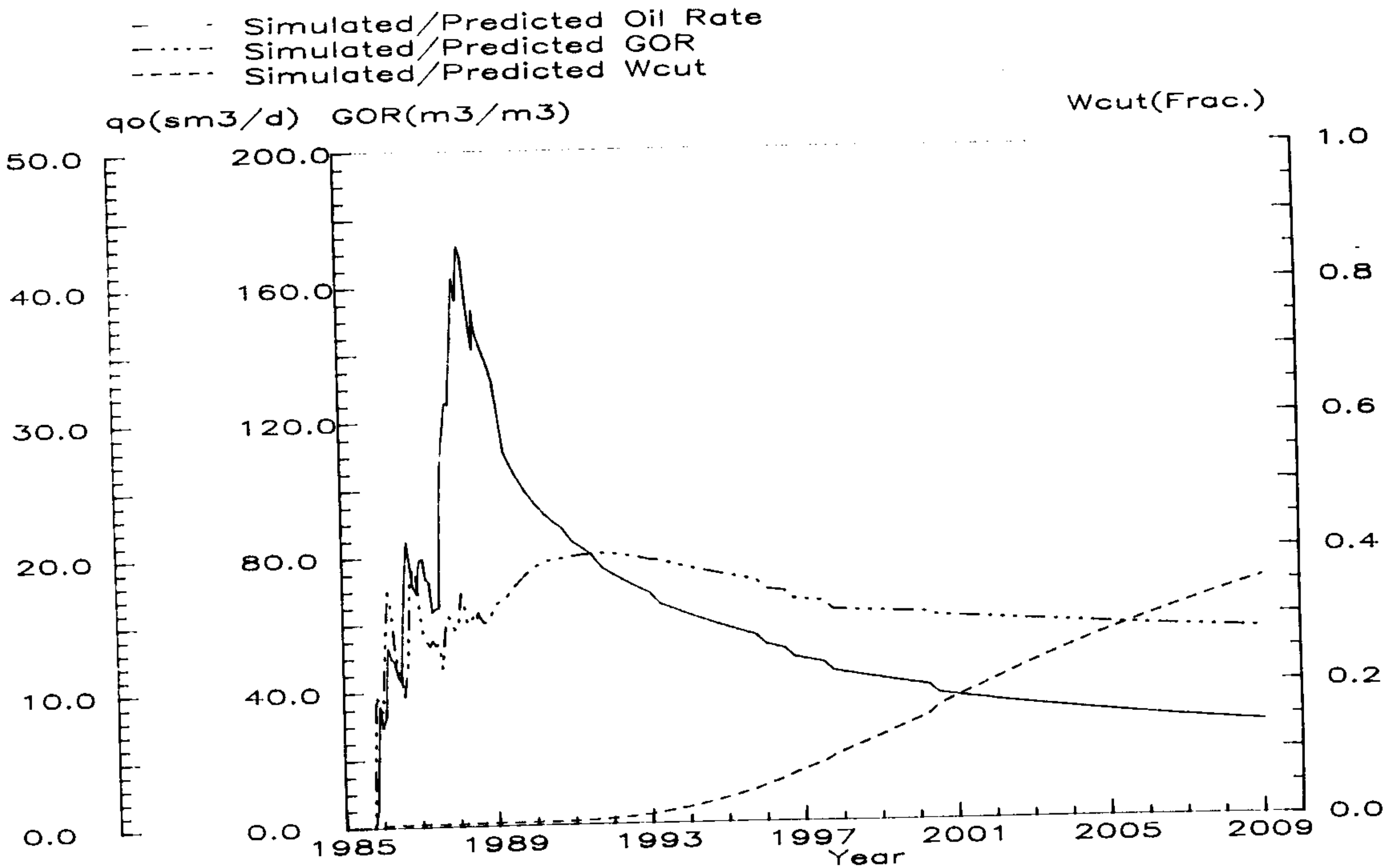


Figure 22: Case 3 (Wat. Inj. with higher Krw) Performance.

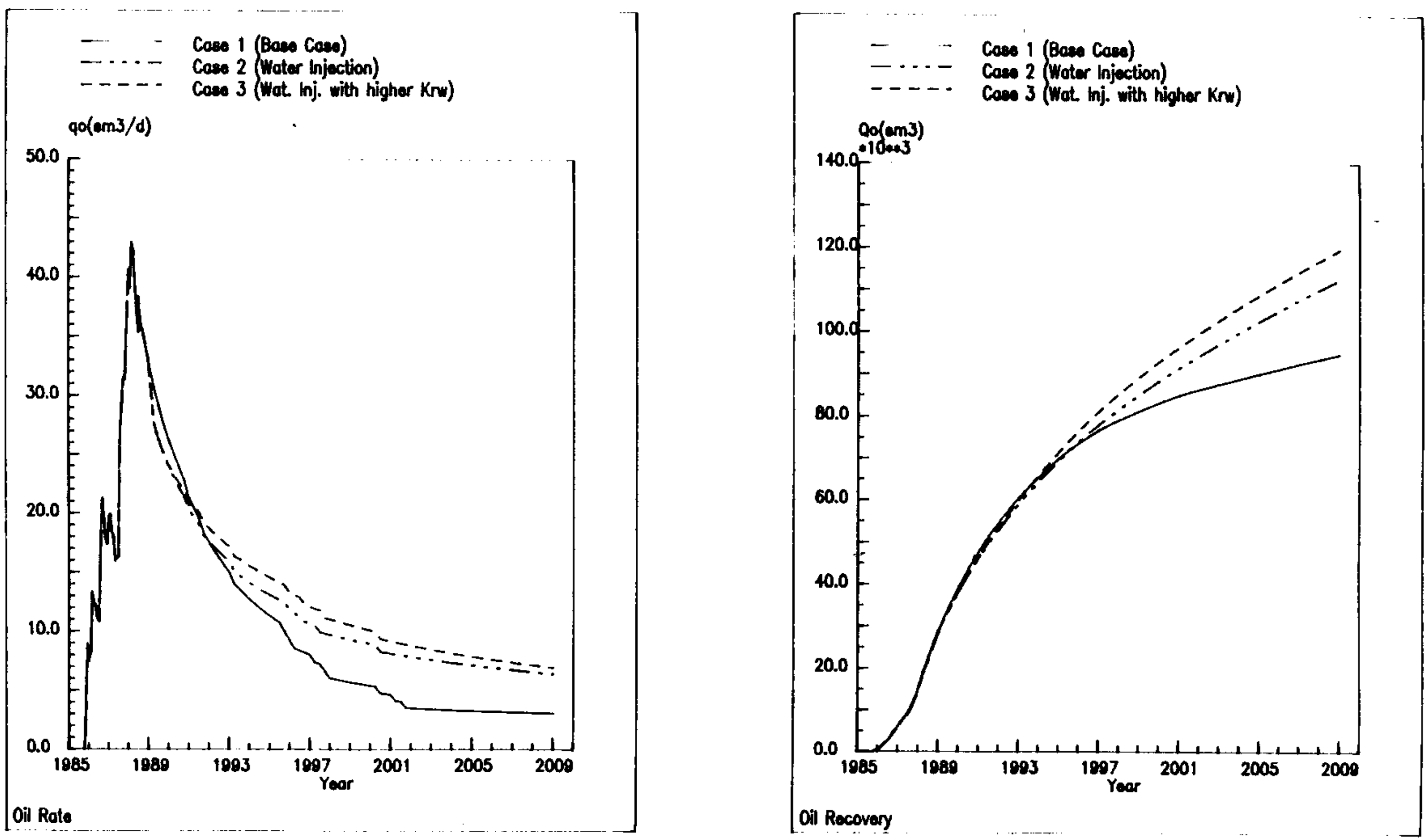


Figure 23: Cases 1—3; Comparison of Oil Rate and Recovery.

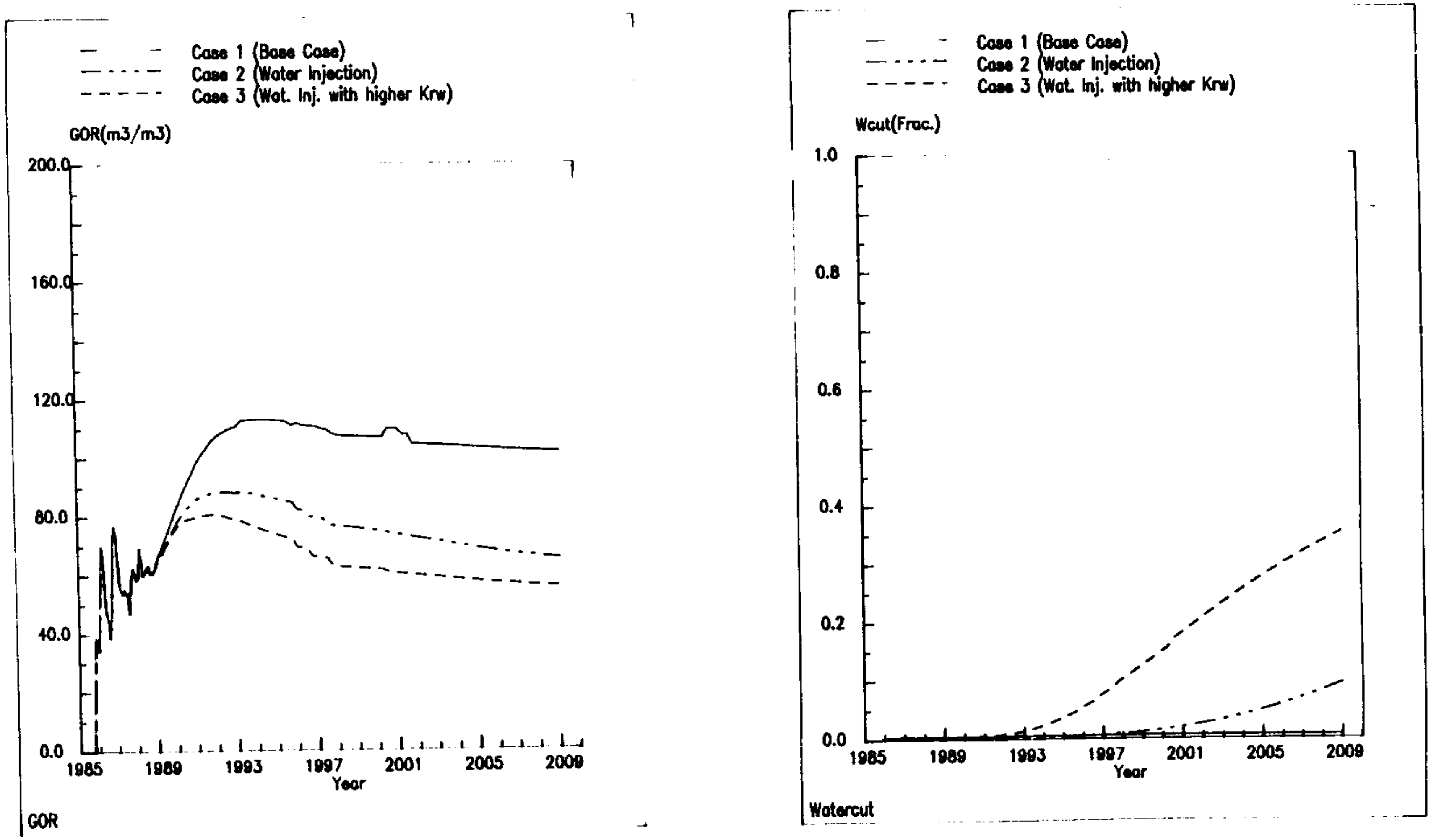
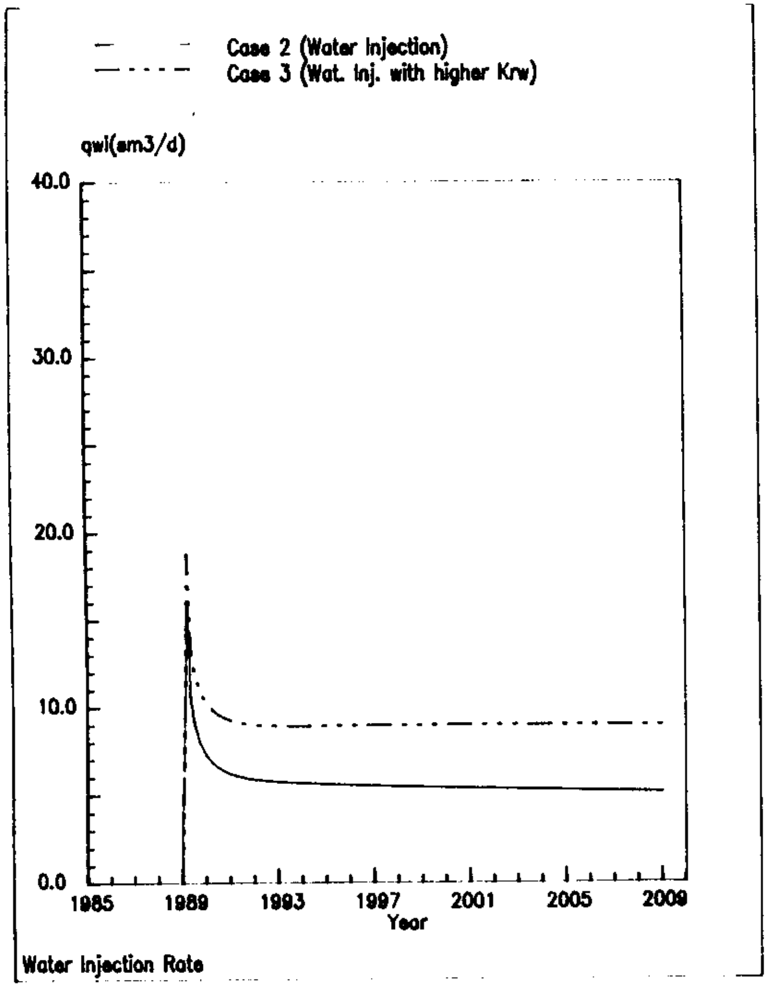


Figure 24: Cases 1—3; Comparison of GOR and Watercut.



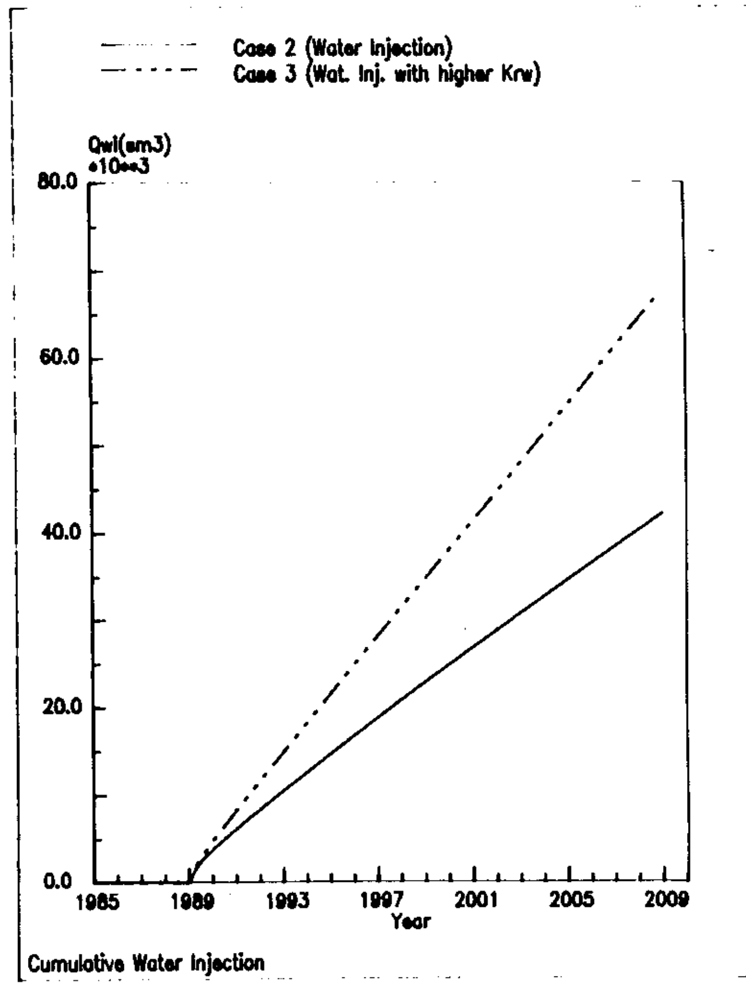


Figure 25: Cases 1—3; Comparison of Water Injection.

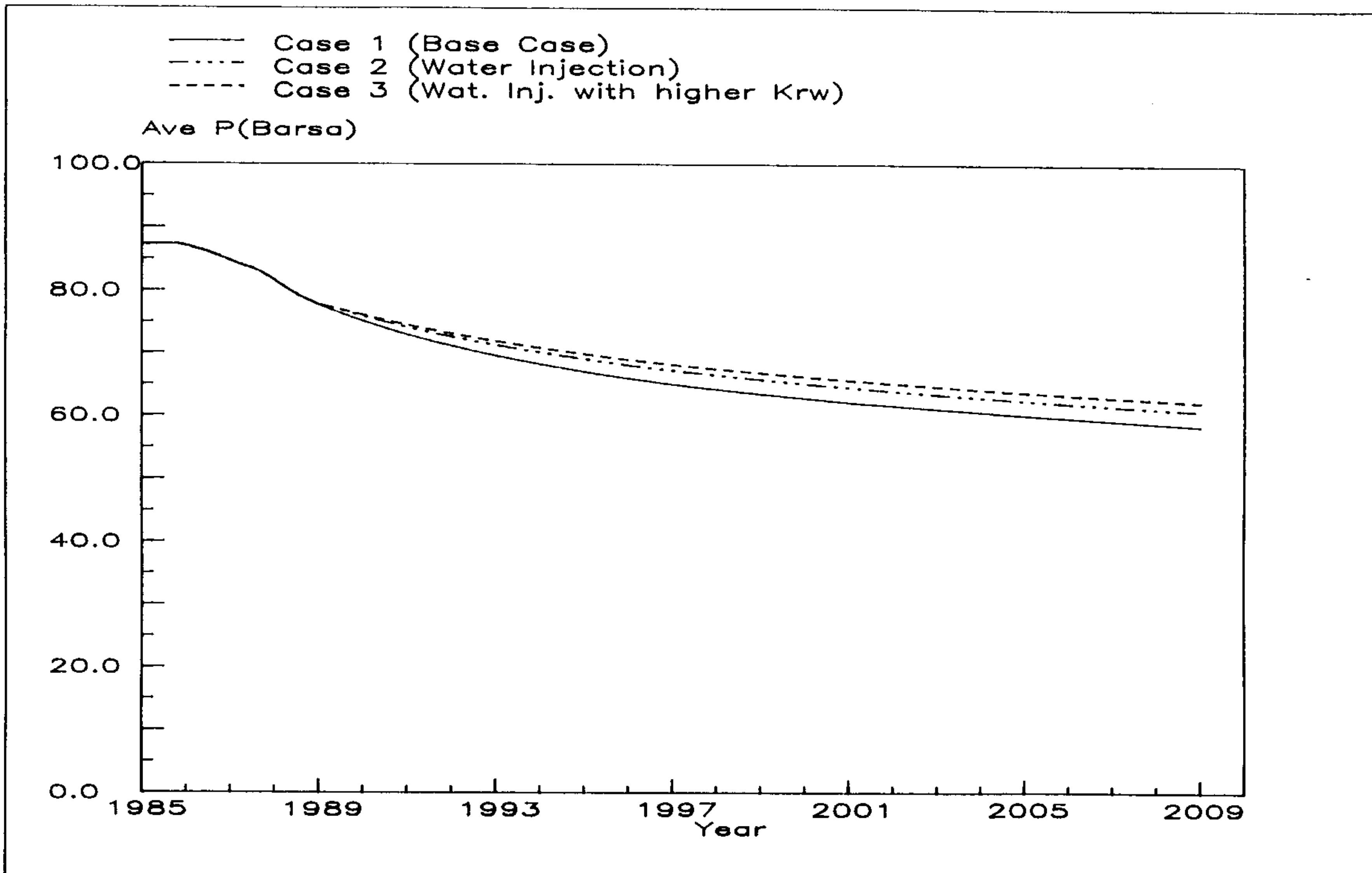


Figure 26: Cases 1−3; Comparison of Average Reservoir Pressure.

TABLE 1

BAKKEN A POOL
SUMMARY OF RESERVOIR AND FLUID DATA

Reservoir

Initial Pressure:	8 750 kPa
Current Pressure:	8 000 kPa
Datum:	340 m subsea
Average Porosity:	17%
Permeability:	0.1 - 100 mD
Rock Compressibility:	5.8×10^{-7} kPa^{-1}

measured @ 5400 in 88-0

Fluid

	Surface Density (kg/m^3)	Initial Reservoir Conditions Viscosity (mPa-s)	Initial Reservoir Conditions Compressibility (kPa^{-1})
Oil	820.0	1.20	1.15×10^{-6}
Gas	1.348	0.017	1.114×10^{-4}
Water	1111.0	0.85	4.50×10^{-7}

End Point Relative Permeability Data

Connate water saturation:	0.350
Relative permeability to oil at connate water saturation:	1.000
Residual oil-in-water saturation:	0.250
Relative Permeability to water at residual oil-in-water saturation:	0.300
Water/oil mobility ratio:	0.420
Critical gas saturation:	0.050
Residual oil-in-gas saturation:	0.250
Relative permeability to gas at residual oil-in-gas saturation:	0.300

TABLE 2

BAKKEN A POOL
CORE PERMEABILITY-THICKNESS VALUES

Well (10-29 WPM)	Core Permeability-Thickness (mD - ft)	Model Permeability (mD)
09-20	100	20
05-21	very tight	2 high!?
11-21	40	8
03-28	100	20
04-28	189	40
05-28	108	20
01-29	very tight	2
08-29	20	4
09-29	very tight	2

TABLE 3
BAKKEN A POOL

BASE PERMEABILITY ARRAY

Y\X	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
8	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
10	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2*0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
11	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
12	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2*0	2.0	2.0	2.0	2.0	2*0	2.0	2.0	2.0	2.0
13	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	8.0	8.0	8.0	8.0	8.0	8.0	2.0	2.0	2.0
14	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2*0	2.0	8.0	8.0	20.0	20*0	16.0	12.0	8.0	2*0	2.0	2.0
15	2.0	2.0	2.0	2.0	2.0	2.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	20.0	20.0	20.0	16.0	12.0	8.0	2.0	2.0	2.0
16	2.0	2.0	2.0	2.0	2.0	2.0	8.0	8.0	16.0	16.0	16.0	16.0	16.0	16.0	20.0	40*0	20.0	20.0	16.0	12*0	8.0	2.0	2.0	2.0
17	2.0	2.0	2.0	2.0	2.0	8.0	8.0	16.0	16.0	20.0	20*0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	16.0	12.0	8.0	2.0	2.0	2.0
18	2.0	2.0	2.0	2.0	2.0	8.0	16.0	16.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20*0	16.0	12.0	8.0	2.0	2.0	2.0
19	2.0	2.0	2.0	2.0	2.0	8.0	16.0	20.0	20*0	20.0	20.0	20.0	20*0	20.0	20.0	16.0	16.0	16.0	16.0	12.0	8.0	2.0	2.0	2.0
20	2.0	2.0	2.0	2.0	2.0	8.0	16.0	16.0	20.0	20.0	20.0	20.0	20.0	20.0	16.0	16.0	12.0	12.0	12.0	12.0	8.0	2.0	2.0	2.0
21	2.0	2.0	2.0	2.0	8.0	12.0	12*0	12.0	16.0	16.0	16*0	16.0	16.0	16.0	12.0	12*0	12.0	12.0	12.0	12*0	8.0	2.0	2.0	2.0
22	2.0	2.0	2.0	2.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	2.0	2.0	2.0
23	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2*0	2.0	2.0	2.0	2.0	8*0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	2.0	2.0	2.0
24	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
25	2.0	2*0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2*0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
26	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
27	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
28	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0

TABLE 4

BAKKEN A POOL
OIL PVT DATA

Oil Phase Pressure (kPa)	Oil Formation Volume Factor (rm^3/sm^3)	Solution Gas-Oil Ratio (m^3/m^3)	Oil Viscosity (mPa-s)
101	1.013	0.00	2.020
446	1.106	22.18	1.305
791	1.111	24.00	1.264
1136	1.114	25.13	1.247
1480	1.116	26.06	1.243
2101	1.120	27.29	1.239
[1] 8750	1.163	40.46	1.196

[1] Extrapolated properties.

TABLE 5

.BAKKEN A POOL
GAS PVT DATA

Gas Phase Pressure (kPa)	Gas Formation Volume Factor (rm^3/sm^3)	Gas Viscosity (mPa-s)
101	1.0238	0.00920
446	0.2284	0.00928
791	0.1255	0.00935
1 136	0.0857	0.00943
1 480	0.0648	0.00950
2 101	0.0437	0.00970
3 000	0.0288	0.00990
4 000	0.0203	0.01020
6 000	0.0113	0.01310
8 000	0.0072	0.01520
12 000	0.0044	0.02350

TABLE 6

BAKKEN A POOL
LIST OF WELLS IN STUDY AREA

Well Location (10-29 WPM)	Date of Initial Production (yr/mo)	Current Status
16-17	86/12 5	Oil Well
08-20	87/08	Oil Well
09-20	86/02 3	Oil Well
16-20	87/07	Oil Well
05-21	87/12	Oil Well
11-21	85/12 2	Suspended 87/05
12-21	87/07	Oil Well
13-21	85/10 1	Oil Well
14-21	87/06	Oil Well
02-28	88/02	Oil Well
03-28	87/11	Oil Well
04-28	86/06 4	Oil Well
05-28	86/12 6	Oil Well
06-28	87/09	Oil Well
11-28	88/02	Oil Well
12-28	87/10	Oil Well
08-29	87/12	Suspended 87/12
09-29	87/12	Oil Well

TABLE 7

BAKKEN A POOL
SUMMARY OF RESERVOIR PRESSURE MEASUREMENTS

Date (yr/mo)	Well Location (10-29 WPM)	Datum Pressure[1] (kPa)	Comments
85/09	13-21	8 604	DST-extrapolated 2cnd shut-in
85/10	08-30	8 943 outside pool	DST-extrapolated 2cnd shut-in
86/01	01-29	✓8 471	DST-extrapolated 2cnd shut-in
86/03	16-17	8 718 outside pool	DST-extrapolated 2cnd shut-in
87/11	03-28	✓6 475	Repeated fluid level shots - extrapolated build-up
87/11	09-29	8 549 outside pool?	DST-extrapolated 2cnd shut-in
87/12	05-21	8 306	DST-extrapolated 2cnd shut-in
88/02	02-28 initial completion	6 100	Bottom hole pressure survey - extrapolated build-up
88/03	04-28 ~190hr shutin after 20 mos. prod'n	5 400	Bottom hole pressure survey - extrapolated build-up
88/05	10-21	7 309 outside pool?	Fluid level shot

[1] Datum depth of 340 m ss

TABLE 8
BAKKEN A POOL

MODEL CALIBRATION PERMEABILITY ARRAY

Y\X	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
8	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.50
9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.50
10	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1*0	1.0	1.0	1.0	1.0	0.5	0.5	0.50
11	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1.0	1.0	2.0	2.0	2.0	0.5	0.5	0.50
12	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0*5	0.5	1.0	1.0	2.0	6*0	2.0	0.5	0.5	0.50
13	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1.0	1.0	1.0	2.0	2.0	2.0	0.5	0.5	0.50
14	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0*5	0.5	1.0	1.0	2.0	6*0	2.0	1.0	1.0	4*0	0.5	0.50
15	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	2.0	2.0	2.0	1.0	1.0	1.0	2.0	2.0	2.0	2.0	1.0	1.0	0.5	0.5	0.50
16	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	2.0	2.0	2.0	2.0	2.0	2.0	25*0	2.0	2.0	2.0	8*0	1.0	0.5	0.5	0.50
17	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	2.0	25*0	10.0	2.0	2.0	2.0	5.0	2.0	2.0	2.0	1.0	1.0	0.5	0.5	0.50
18	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	2.0	4.0	10.0	5.0	5.0	5.0	5.0	5.0	20*0	2.0	1.0	1.0	1.0	0.5	0.50
19	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	6*0	4.0	4.0	4.0	40*0	5.0	2.0	2.0	5.0	5.0	2.0	2.0	2.0	1.0	0.5	0.50
20	0.5	0.5	0.5	0.5	0.5	1.0	1.0	1.0	1.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	10.0	10.0	10.0	2.0	1.0	0.5	0.50
21	0.5	0.5	0.5	0.5	0.5	1.0	4*0	2.0	2.0	2.0	2*0	2.0	2.0	2.0	2.0	4*0	2.0	4.0	10.0	20*0	2.0	1.0	0.5	0.50
22	0.5	0.5	0.5	0.5	0.5	1.0	1.0	1.0	0.5	1.0	1.0	1.0	1.0	1.0	1.0	2.0	2.0	2.0	2.0	2.0	2.0	1.0	0.5	0.50
23	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1*0	0.5	0.5	1.0	1.0	1*0	1.0	2.0	2.0	2.0	1.0	1.0	1.0	1.0	0.5	0.50
24	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1.0	2.0	2.0	1.0	1.0	1.0	0.5	0.5	0.5	0.50
25	0.5	4*0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0*5	1.0	2.0	1.0	1.0	0.5	0.5	0.5	0.5	0.5	0.50
26	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1.0	1.0	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.50
27	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.50
28	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.50

TABLE 9

BAKKEN A POOL
CASE 1 PERFORMANCE SUMMARY

Period Starting	Avg. Oil Prod. Rate (m3/d)	Avg. GOR (m3/m3)	Avg. Wcut (Frac.)	Avg. Wtr Inj. Rate (m3/d)	Cum Oil Prod. (1E3m3)	Cum Gas Prod. (1E3m3)	Cum Wtr Prod. (1E3m3)	Cum Wtr Inj. (1E3m3)
Jul 1,1988	34.9	62.6	0.005	0.0	22.4	1325.7	0.1	0.0
Jan 1,1989	30.0	72.4	0.005	0.0	28.8	1727.1	0.1	0.0
Jul 1,1989	27.0	81.2	0.005	0.0	34.2	2120.9	0.1	0.0
Jan 1,1990	24.6	89.3	0.005	0.0	39.2	2524.3	0.2	0.0
Jul 1,1990	22.2	96.4	0.005	0.0	43.6	2921.4	0.2	0.0
Jan 1,1991	19.0	104.1	0.005	0.0	47.7	3314.7	0.2	0.0
Jan 1,1992	15.9	109.7	0.005	0.0	54.7	4036.0	0.2	0.0
Jan 1,1993	13.4	112.9	0.006	0.0	60.5	4675.8	0.3	0.0
Jan 1,1994	11.9	113.0	0.006	0.0	65.4	5227.9	0.3	0.0
Jan 1,1995	10.3	112.0	0.006	0.0	69.7	5717.0	0.3	0.0
Jan 1,1996	8.3	110.9	0.006	0.0	73.5	6137.9	0.4	0.0
Jan 1,1997	6.9	108.8	0.006	0.0	76.5	6476.0	0.4	0.0
Jan 1,1998	5.9	107.3	0.006	0.0	79.0	6749.3	0.4	0.0
Jan 1,1999	5.5	107.0	0.006	0.0	81.2	6978.4	0.4	0.0
Jan 1,2000	4.9	108.9	0.007	0.0	83.2	7194.4	0.4	0.0
Jan 1,2001	3.8	106.2	0.007	0.0	85.0	7389.5	0.4	0.0
Jan 1,2002	3.5	104.2	0.007	0.0	86.4	7538.1	0.4	0.0
Jan 1,2003	3.4	103.7	0.007	0.0	87.6	7669.6	0.4	0.0
Jan 1,2004	3.3	103.2	0.007	0.0	88.9	7797.2	0.5	0.0
Jan 1,2005	3.3	102.8	0.007	0.0	90.1	7922.1	0.5	0.0
Jan 1,2006	3.2	102.3	0.007	0.0	91.3	8044.0	0.5	0.0
Jan 1,2007	3.2	101.9	0.007	0.0	92.4	8163.7	0.5	0.0
Jan 1,2008	3.1	101.6	0.007	0.0	93.6	8281.3	0.5	0.0
Jan 1,2009					94.7	8397.1	0.5	0.0

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TABLE 10

BAKKEN A POOL
CASE 2 PERFORMANCE SUMMARY

Period Starting	Avg. Oil Prod. Rate (m3/d)	Avg. GOR (m3/m3)	Avg. Wcut (Frac.)	Avg. Wtr Inj. Rate (m3/d)	Cum Oil Prod. (1E3m3)	Cum Gas Prod. (1E3m3)	Cum Wtr Prod. (1E3m3)	Cum Wtr Inj. (1E3m3)
Jul 1,1988	34.9	62.5	0.002	0.0	22.4	1325.7	0.1	0.0
Jan 1,1989	27.3	69.1	0.002	13.1	28.8	1727.0	0.1	0.0
Jul 1,1989	24.5	76.7	0.003	7.7	33.7	2068.1	0.1	2.4
Jan 1,1990	22.6	81.9	0.003	6.8	38.2	2414.0	0.1	3.8
Jul 1,1990	20.9	85.3	0.003	6.3	42.3	2749.6	0.1	5.0
Jan 1,1991	18.6	87.6	0.003	6.0	46.2	3077.3	0.2	6.2
Jan 1,1992	16.5	88.3	0.003	5.8	53.0	3673.3	0.2	8.4
Jan 1,1993	14.6	88.0	0.003	5.7	59.0	4207.0	0.2	10.5
Jan 1,1994	13.5	86.5	0.004	5.7	64.4	4675.8	0.2	12.6
Jan 1,1995	12.5	84.5	0.005	5.6	69.3	5101.4	0.2	14.7
Jan 1,1996	11.0	80.3	0.006	5.6	73.8	5485.6	0.2	16.7
Jan 1,1997	10.0	77.4	0.008	5.5	77.9	5809.9	0.3	18.8
Jan 1,1998	9.5	76.1	0.011	5.5	81.5	6093.2	0.3	20.8
Jan 1,1999	9.1	75.3	0.014	5.4	85.0	6356.7	0.3	22.8
Jan 1,2000	8.4	74.1	0.019	5.4	88.3	6607.0	0.4	24.8
Jan 1,2001	8.0	72.9	0.024	5.4	91.4	6834.9	0.4	26.7
Jan 1,2002	7.7	71.7	0.030	5.3	94.3	7047.3	0.5	28.7
Jan 1,2003	7.5	70.4	0.038	5.3	97.1	7249.2	0.6	30.7
Jan 1,2004	7.3	69.2	0.046	5.3	99.9	7441.4	0.7	32.6
Jan 1,2005	7.1	68.1	0.056	5.3	102.5	7625.3	0.8	34.5
Jan 1,2006	6.9	67.1	0.066	5.2	105.1	7800.6	1.0	36.4
Jan 1,2007	6.7	66.2	0.078	5.2	107.6	7968.5	1.2	38.4
Jan 1,2008	6.5	65.5	0.090	5.2	110.0	8130.0	1.4	40.3
Jan 1,2009					112.4	8285.9	1.6	42.1

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TABLE 11

BAKKEN A POOL
CASE 3 PERFORMANCE SUMMARY

Period Starting	Avg. Oil Prod. Rate (m3/d)	Avg. GOR (m3/m3)	Avg. Wcut (Frac.)	Avg. Wtr Inj. Rate (m3/d)	Cum Oil Prod. (1E3m3)	Cum Gas Prod. (1E3m3)	Cum Wtr Prod. (1E3m3)	Cum Wtr Inj. (1E3m3)
Jul 1,1988	34.9	62.6	0.005	0.0	22.4	1325.7	0.1	0.0
Jan 1,1989	27.3	69.1	0.005	15.8	28.8	1727.1	0.1	0.0
Jul 1,1989	24.6	75.6	0.005	10.7	33.7	2068.1	0.1	2.9
Jan 1,1990	22.9	78.7	0.005	9.8	38.3	2410.1	0.2	4.8
Jul 1,1990	21.6	79.7	0.005	9.4	42.4	2736.8	0.2	6.6
Jan 1,1991	19.7	80.6	0.007	9.1	46.4	3053.2	0.2	8.3
Jan 1,1992	17.7	79.5	0.012	9.0	53.5	3631.4	0.3	11.7
Jan 1,1993	16.0	77.3	0.020	9.0	60.0	4147.4	0.3	14.9
Jan 1,1994	14.9	74.7	0.032	9.0	65.9	4597.4	0.5	18.2
Jan 1,1995	13.9	71.9	0.047	9.0	71.3	5004.4	0.6	21.5
Jan 1,1996	12.6	67.6	0.068	9.0	76.4	5370.0	0.9	24.8
Jan 1,1997	11.5	64.3	0.092	9.0	81.0	5681.1	1.2	28.1
Jan 1,1998	10.7	62.4	0.118	9.0	85.2	5950.9	1.7	31.3
Jan 1,1999	10.3	62.0	0.142	9.0	89.1	6195.6	2.2	34.6
Jan 1,2000	9.5	60.8	0.172	9.0	92.9	6428.1	2.8	37.9
Jan 1,2001	9.0	60.0	0.199	9.0	96.3	6639.2	3.5	41.2
Jan 1,2002	8.6	59.3	0.223	9.0	99.6	6835.5	4.3	44.5
Jan 1,2003	8.3	58.6	0.247	9.0	102.8	7022.0	5.2	47.8
Jan 1,2004	8.0	57.9	0.269	9.0	105.8	7199.4	6.2	51.1
Jan 1,2005	7.7	57.3	0.290	9.0	108.7	7369.1	7.3	54.4
Jan 1,2006	7.5	56.7	0.310	9.0	111.5	7531.0	8.5	57.7
Jan 1,2007	7.3	56.2	0.329	9.0	114.3	7686.2	9.7	61.0
Jan 1,2008	7.1	55.8	0.347	9.0	116.9	7835.6	11.0	64.3
Jan 1,2009					119.5	7979.9	12.4	67.6

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TABLE 12

BAKKEN A POOL
COMPARISON OF PREDICTED RESULTS AT JANUARY 1, 2009

Case	Cumulative Oil Recovery (10^3m^3)		Cumulative Gas Prod. (10^3m^3)	Cumulative Water Prod (10^3m^3)	Cumulative Water Inj. (10^3m^3)
	(10^3m^3)	(% of IOIP)			
Case 1 (Base Case)	94.7	17.5	8 397.1	0.5	-0.0
Case 2 (Water Injection)	112.4	20.7	8 285.9	1.6	42.1
Case 3 (Wat. Inj. with higher krw)	119.5	22.0	7 979.9	12.4	67.6