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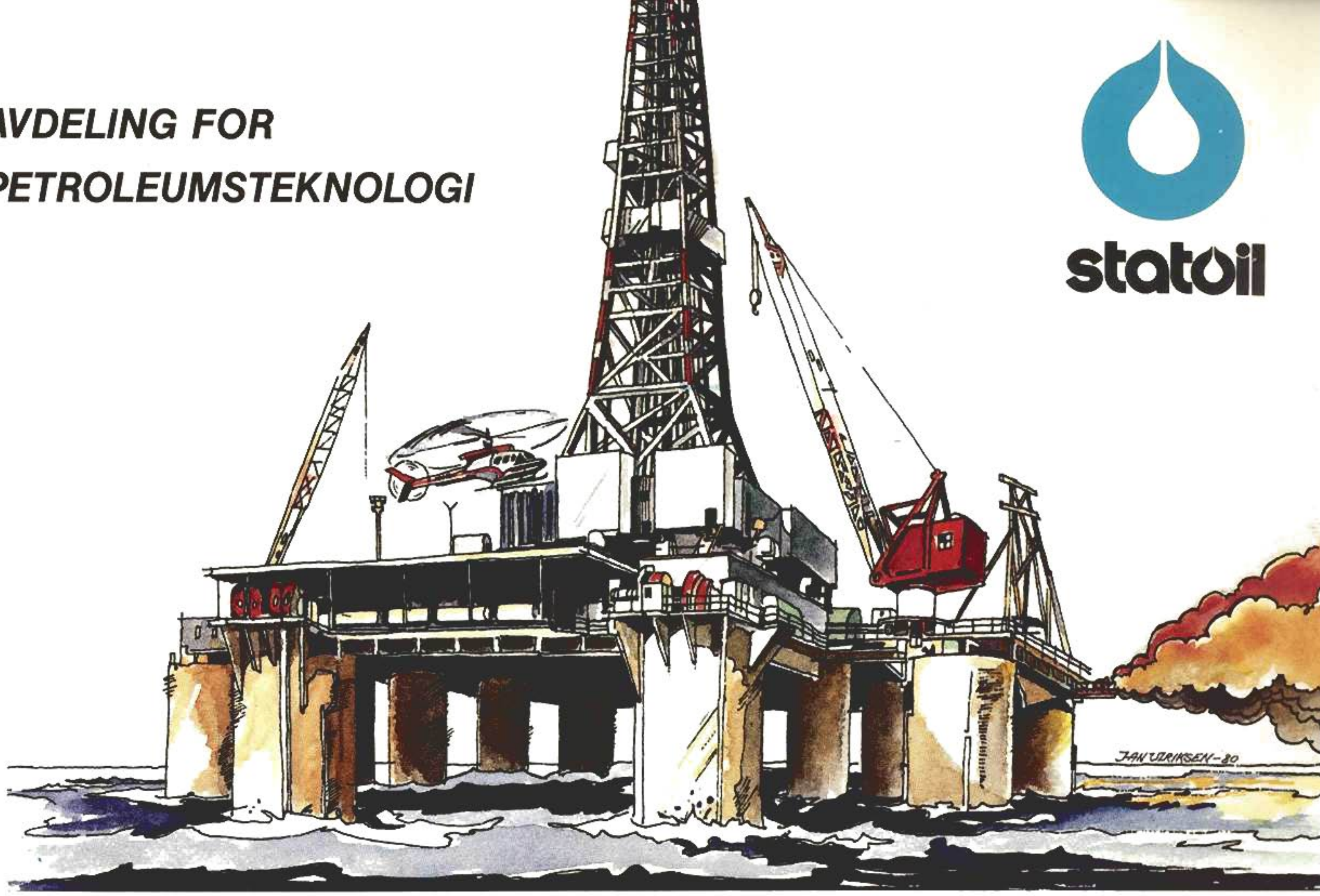

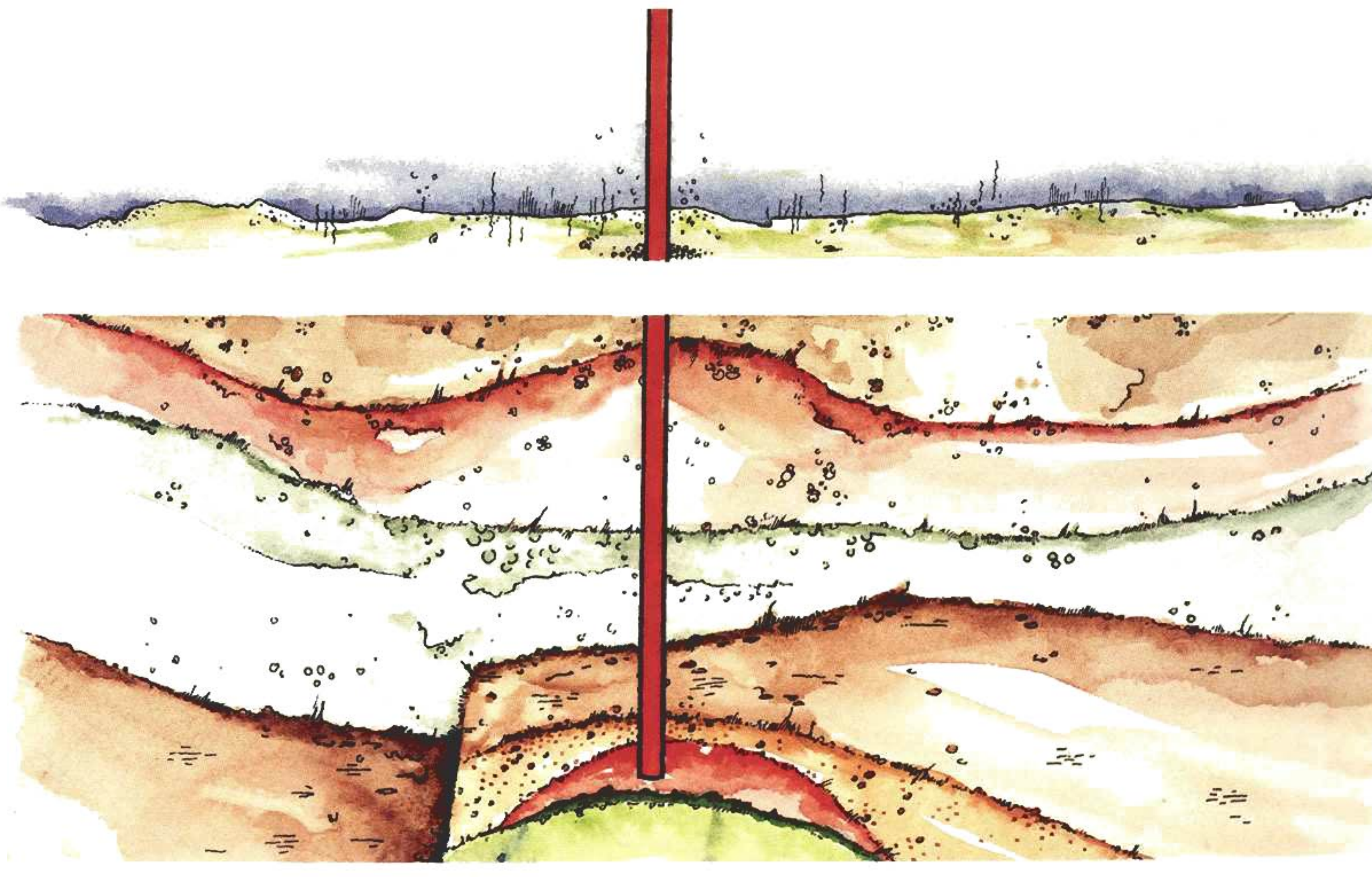

WELL TEST REPORT 34/10-14

statoil
Den norske stats oljeselskap a.s

Gradering

Confidential

Avdeling for Reservoarevaluering
Seksjon for Reservoarteknikk

Oppdragsgiver

Gullfaks Produksjon

Undertittel

Interpretation of the data cellected during the drill stem test in well 34/10-14

Tittel

WELL TEST REPORT

PL 050

WELL NO. 34/10-14

Utarbeidet	
24/9-82	Ole Nygaard

Godkjent	
24/9-82	Arne Ulle

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1. INTRODUCTION

34/10-14 is the 13th Exploration well drilled on the delta east structure of block 34/10, (the GULLFAKS field).

The well was drilled in the north-east corner of the field to investigate the extent and distribution of sandstones of middle jurassic age. Extensive testing took place with both a production test followed by a build-up period, and a water injection test followed by a fall-off period. This was performed in the same interval with the same downhole equipment.
The objective of the injection test was to gain information about injectivity and reservoir characteristics with the injection of cold seawater into a hot oil reservoir.

The GULLFAKS field will be developed in two phases (Fig. 1-1). Phase I will have two platforms, one central process-platform and one "satellite". The production philosophy calls for water-injection to keep the reservoir pressure above the bubble-point. Approximately 70000 m^3 (400.000 bbls) water will be injected per day when the production reaches plateau. The success of depletion of the field depends greatly on the efficiency of the waterdrive. Large simulator models have been run to investigate the performance of the field, but the results are dependent on the validity of the input. One special concern in that respect is the relative permeability to water and especially the endpoint at residual oil saturation. Experience from similar fields in the UK-sector indicates that the water-production might be far greater than anticipated by the reservoir models.

The reservoir simulation models must necessarily have rather large blocks, so the water encroachment cannot be properly defined. A mathematical model based on Dietz work (ref. 10), but for a radial system has been developed in appendix A1. This is a simple model describing the movement of the leading edge of the water.
The analysis of the 34/10-14 test results confirms this theory and have resulted in a much better understanding of the water-injection and the encroachment of the water front.

Fig. 1-2 shows the main faults and a cross-section through well 34/10-3 and 34/10-9 which exhibits clearly the complexity of the field. Fig. 1-3 shows a structural map of the Top Brent formation, and Fig. 1-4 shows the same map underlain by a 3 dimensional map of the field.

Fig. 1-5 shows the lithology for this well.

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GULLFAKS

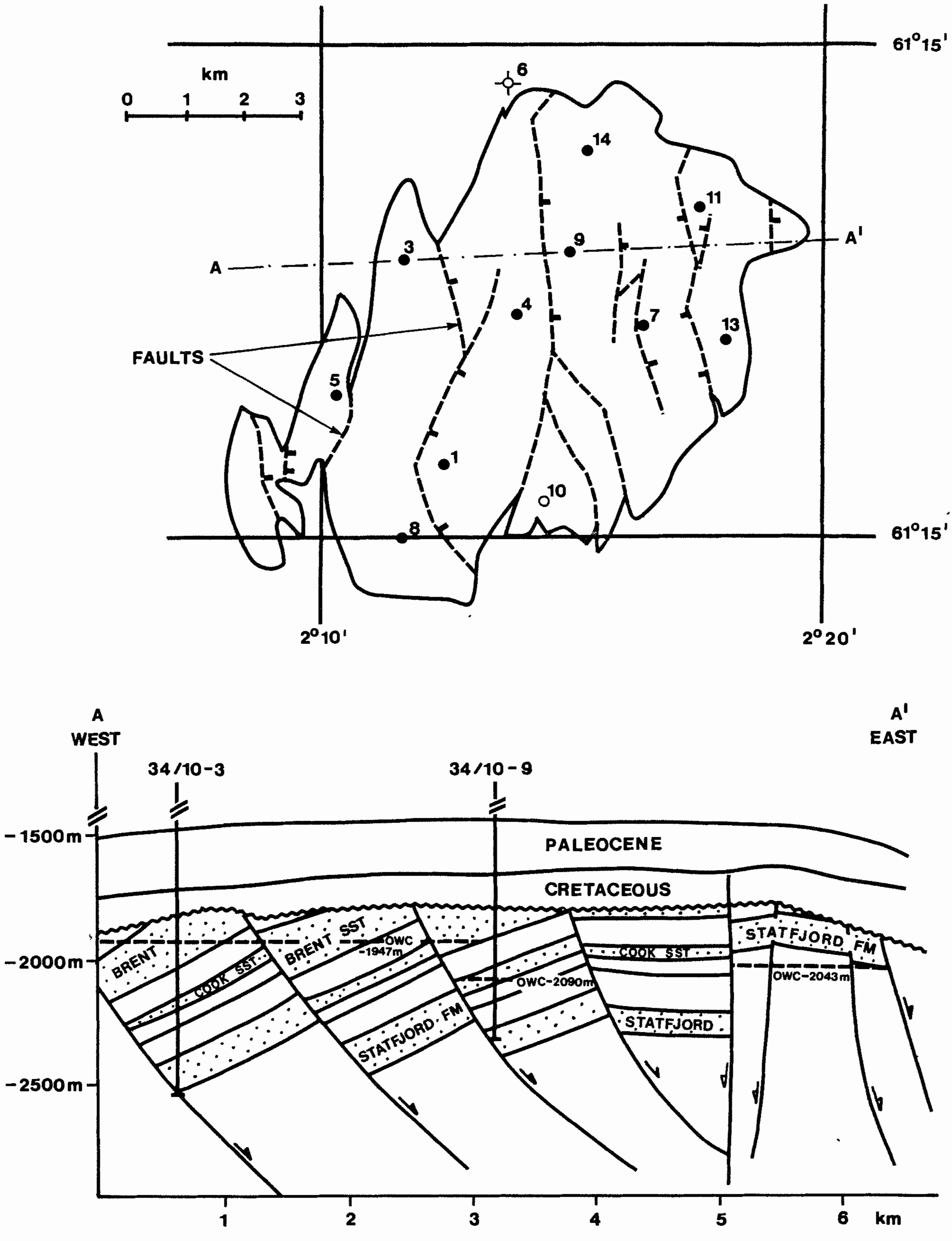
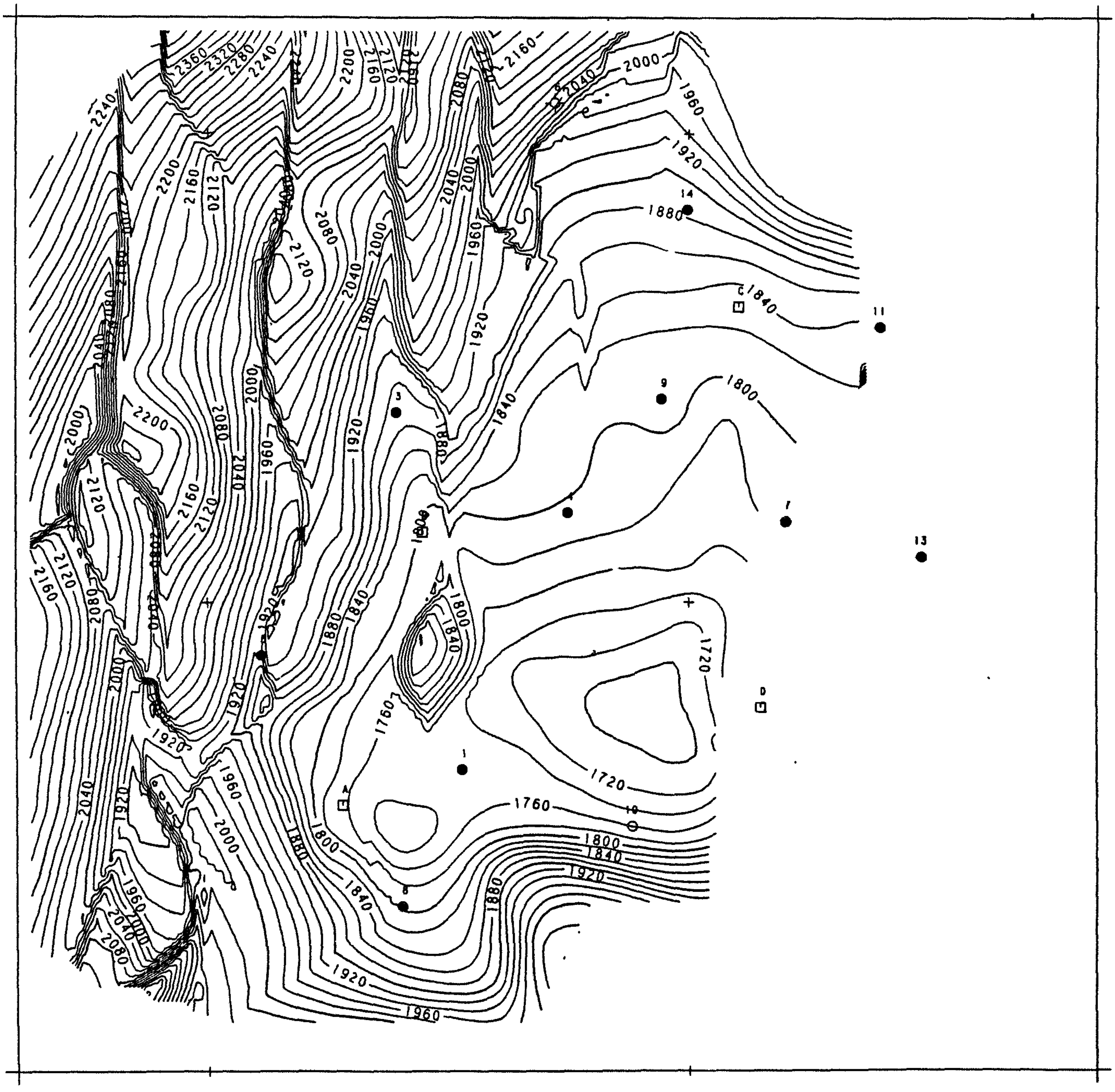


Fig.1-2

TOP BRENT



34/10 BRENT FRM * TOPP B5B *

Fig. 1-3

GULLFAKS

TOPP BRENT

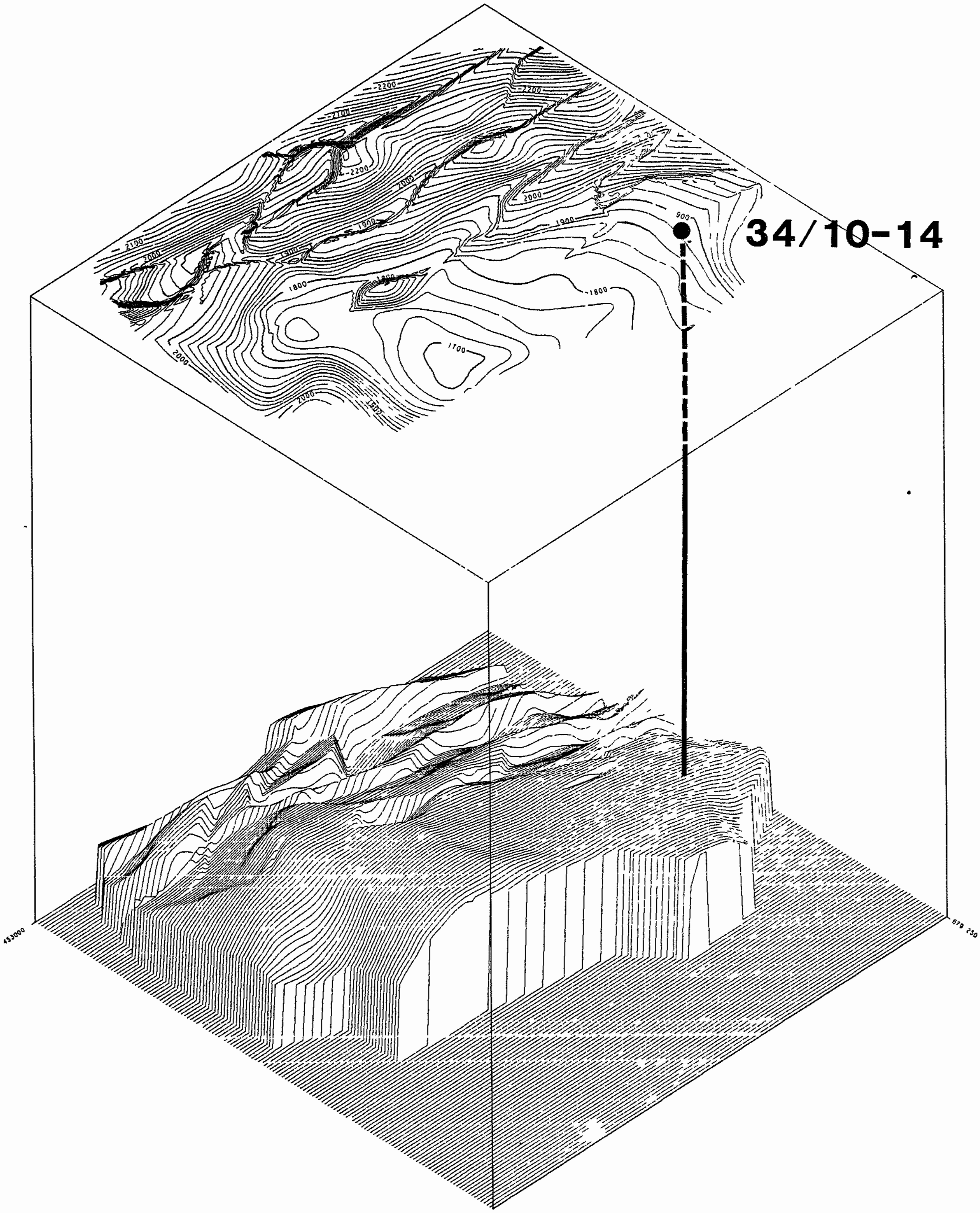


Fig.1-4

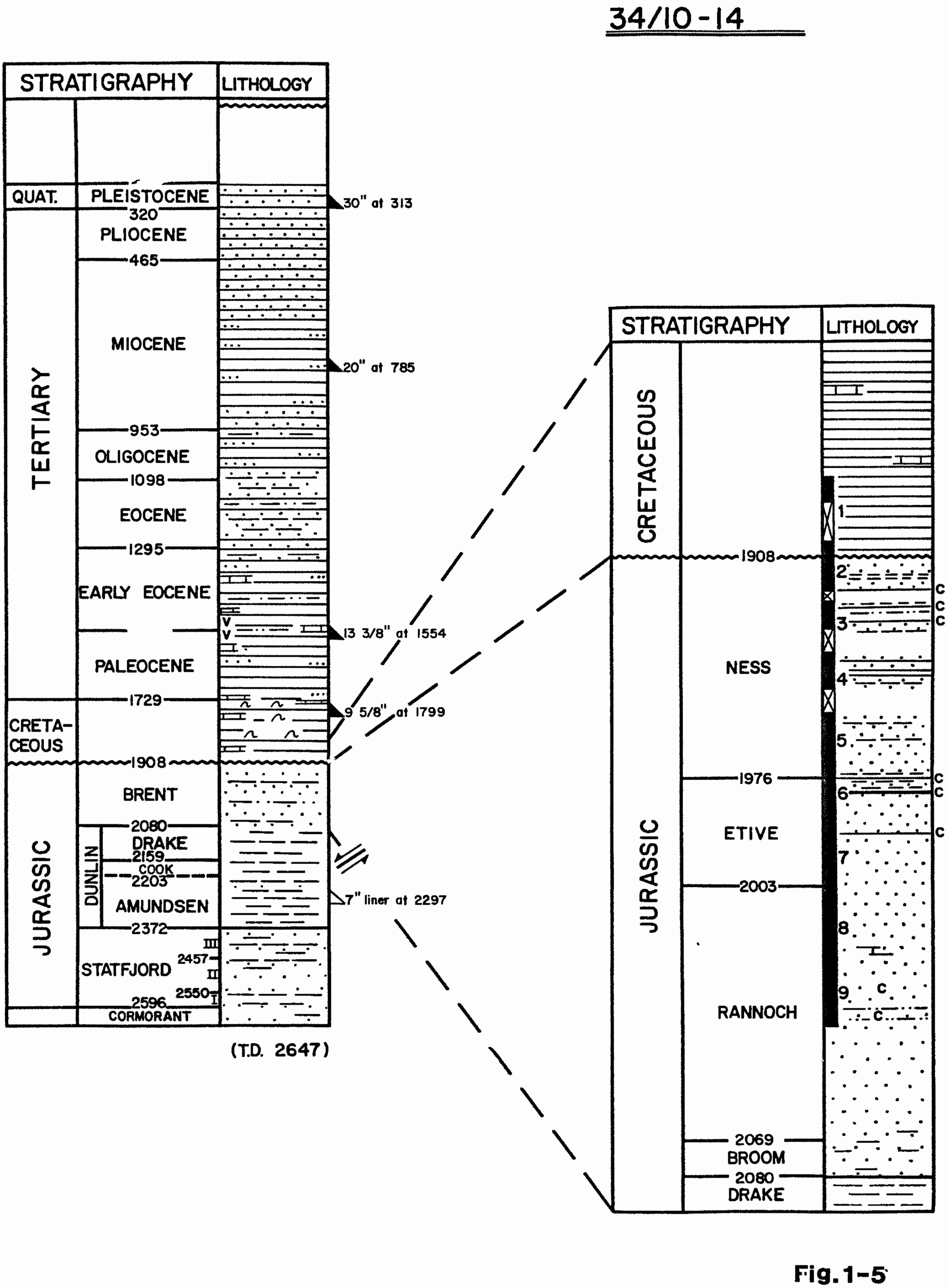

34/10-14
STRATIGRAPHY
LITHOLOGY
QUAT.
PLEISTOCENE
320
PLIOCENE
465
MIOCENE
953
OLIGOCENE
1098
EOCENE
1295
EARLY EOCENE
PALEOCENE
1729
TERTIARY
CRETA-CEOUS
1908
BRENT
2080
DRAKE
2159
COOK
2203
AMUNDSEN
DUNLIN
2372
STATFJORD
2457
2550
2596
CORMORANT
JURASSIC
III
II
I
30" at 313
20" at 785
13 3/8" at 1554
9 5/8" at 1799
7" liner at 2297
(T.D. 2647)
STRATIGRAPHY
LITHOLOGY
CRETACEOUS
1908
NESS
1976
ETIVE
2003
RANNOCH
2069
BROOM
2080
DRAKE
JURASSIC
1
2
3
4
5
6
7
8
9
c

Fig.1-5

2. OBJECTIVES

The objectives of the testing of this well were:

1. Find the average reservoir pressure and temperature
2. Calculate the productivity of the Ness-sand
3. Obtain representative fluid samples
4. Detect reservoir pressure barriers
5. Calculate the effective water permeability; Kw
6. Estimate S_{or} by TDT-logging
7. Verify the effective oil permeability; Ko
8. Calculate the relative permeability at residual oil saturation
9. Measure injection temperature and temperature effects on the injectivity
10. Gain overall experience concerning injection of cold water into a hot reservoir
11. Develop new methods of transient testing

Most of the objectives were met by the test and the results are given in the appendices.

3. CONCLUSIONS AND RECOMMENDATIONS

Conclusions

The tested interval of the Ness member shows extremely good reservoir characteristics.

- Analysis of the DST shows a permeability of 4.6 darcy and a productivity index of 95 $Sm^3/D/bar$

- The perforated interval (4 m) produced 713 Sm^3/D through a 13.5 mm choke, and a GOR of 67 Sm^3/m^3 measured on the seperator. (GOR = 88 Sm^3/m^3 from PVT analysis)

- The reservoir characteristics are the same as for well from 34/10-9

- The reservoir temperature is 75°C, gradient: 3.5°C/ 100 m

- The initial pressure is 313 barg at datum depth (- 1850 m ss).

- No sand production was experienced even though the cores from this interval were very unconsolidated.

- The formation showed good injectivity J = 35 $m^3/D/Bar$

- The water under-ride is severe and the water reaches approximately 12 meter at the top and 72 meters at the bottom after 46 hrs injection with a total of 2150 m^3 water injected

- The response time from the waterflooded zone was too short to be measured

- A pressure barrier was detected 170 m from the wellbore

- The leading edge of the water might have formed an ellipse rather than circle, due to this pressure barrier.

- The mobility ratio is enfavourable, $M \approx 3$

- During the injection a high skin value occurs, probably around + 10

- Maximum injection rate was 0.8 m^3/min

- A microannulus has probably formed during injection, thus creating a thiefzone.

Recommendations

The GULLFAKS field has a very complex geology and is therefore complicated to develop. The objectives of testing the wells have changed from the first pure exploration wells, to wells which are drilled and tested to gain information about areas of uncertainty with respect to the production phase. The results of the analysis of these wells will help in designing equipment properly and upgrade the input to the reservoir models.

It is strongly recommended to perform a special designed test now, to investigate the problems that will arise during the completion of the wells and production of the field.

The well should be placed in the area designated for the first producers and should be tested in the summertime with a reasonable weather window. This well could later be used as a production or injection well, either subsea or from the platform and as such contribute to an early production. The well should be extensively tested and enough time should be allowed for necessary work on the well.

The Ness sand contains 22% of the reserves in phase I and will be difficult to complete. The reason being the sandlenses with high permeability. In a production situation these will be depleted first and cross-flow might occur. This can be tested for and provide help in designing a completion program. During a test, using a full-bore string, the lower Ness can be perforated and production logs (PCT or PLT) be run, then these sands can be isolated and the upper Ness be tested in the same way. (The lower being isolated with a temporary bridge plug), finally the whole sequence can be tested. This will give invaluable information for the completion of the Ness-sand, and generation of suitable pseudo functions for modelling purposes.

- A fullbore string will also give information to update the wellbore hydraulic models that are currently used.

- The same procedure can be applied for water-injection to investigate where the water flowes. A water treatment filter is then recommended to minimize the skin.

- The possibility of sand production is of great concern of gravel packing of the production wells because of the cost. It is therefore important to investigate this closely. The unconsolidated sand will start to flow when the pressure drop over the perforations is too high. The probability of sandflow is further increased by the event of water breakthrough.

- A gravel pack test should also be performed to test unconsolidated sand and to aid the design of a gravel pack and a completion fluid that will work well in the production phase.

- Therefore it is recommended to flow an injection well back to see if it will produce sand.

- The pressure readings have always been a problem on semi-submercible rigs. The recording frequency is too low. This is clearly demonstrated in this test where the response from the waterflooded zone takes only 8 seconds. A surface readout is necessary and every effort should be made to arrange this within the safety regulations that apply. On the Horner plot, the t for the first readings are very important however it is very difficult to be absolutely sure of the correspondence between the downhole clocks and the surface clocks. Only a few seconds difference can change a curve to a straight line on the Horner plot.

- Such tests must be planned carefully and a lot of work must be done on beforehand to ensure proper data and when testing: <u>Take the time necessary to obtain the information needed.</u>
  This includes reservoir simulators and topside facilities, such as water filter, injection pumps, gauge arrangements etc. To simulate the temperature effect a thermal simulator is a must.

4. DISCUSSION

Geology

The location of 34/10-14 was chosen in an area where dips below the Kimmerian unconformity are rather horizontal.
The faultpattern is rather complex and the fault-throws are small.
The oil bearing zone in this well was completely within the Ness member. This zone is interpreted as a delta top deposit with interbedded sands, shales and coals. The zone can be subdivided into a shaly/coaly sequence at the top, a sand sequence at the bottom. It is believed that the shale at the top and the bottom of Ness is continuous over the entire field and that it acts as a vertical flow barrier.

Testinterval

In order to obtain maximum information from the reservoir it was decided to run one drill-stem test and one water injection test over the same interval. A radial simulator was set up before logs and core-data were available to calculate the fall-off time with various input data-sets. These calculations showed that a relatively thin zone of approximately 5 meters with a permeability of 1 darcy would yield the best information. At the same time a computer-program which calculates the strength of the formation was run in order to detect possible sand-producing layers.

With these restrictions 1933.5 m to 1937.5 m (RKB) was chosen (see fig. A3-3 and A5-4).
The interval has a coal layer at the top and a shale layer at the bottom. This together with a good cement job gives good control over the producing height, even though the areal extent of these layers are uncertain.

WELL DATA

Operator	:	Den norske stats oljeselskap a.s
Well name	:	34/10-14
Location	:	61^{o} 14' 0.50"N 2^{0} 15' 18.87" E
Classification	:	Exploration well
Drilling rig	:	Ross Rig
Spudded	:	24.12.81
Completed	:	15.03.82
RKB elevation	:	25 m
Water depth	:	227 m
Total depth	:	2647 m RKB
Perforated interval	:	1933.5 - 1937.5 m RKB
Objective	:	Jurassic sandstone
Status	:	Plugged and abandoned

4.1 DST analysis

A conventional DST was performed in order to obtain the productivity of the zone and reservoir parameters. At the same time this information could act as a reference for the water injection test.

Objectives:

- Reservoir pressure and temperature

- Estimate productivity

- Obtain fluid samples

- Detect reservoir/pressure barriers

Sequence:

1. Initial Flow : Well opened 23.06 hrs 01.03.82
   Well closed 08.31 hrs 02.03.82

2. Initial Build-up : 6.5 hrs

3. Bottomhole sampling : Two bottomhole samplers run in tandem

No sandproduction was experienced during the test.

SUMMARY OF RESULTS FROM DST TEST

34/10-14

	SI Units	Oil field units
Kh	18452 md · m	60539 md ft
K	4621 md	4621 md
K/μ	3851 md/cp	3851 md/cp
S	- 0.85	- 0.85
P*	310.9 bara	4509 psia
PI	95 Sm^3/D/Bar	41.2 STB/D/psi
Q_o	713 Sm^3/D	4484 BBl
GOR	66.8 Sm^3/m^3	375 ft^3/BBl
Distance to fault	167 m	547 ft
BHT max.	75°C	167°F
Choke	13.5 mm	34/64"

A more detailed analysis are found in Appendix A2.

4.2 Water injection

A water injection programme was conducted immediately after the BH sampling.

Objectives:

1. Calculate effective waterpermeability Kw

2. Estimate S_{OR} by TDT-log

3. Verify the effective oil permeability Ko

4. Calculate Krw (S_{or})

5. Calculate injectivity

6. Measure injection temperature

7. Gain overall information concerning injection of cold water into hot reservoir

8. Develop new methods of transient testing

Sequence:

Start injection of seawater 05.02 hrs 03.03.82
Rate gradually increased to 5 bbl/min

Leakage on surface : 20.49 hrs 03.03.82
Start injection : 22.45 hrs 03.03.82

Stop injection : 05.00 hrs 05.03.82

Shut-in for fall off : 7 hrs

The injection was carried out using the mud-pumps, the maximum possible rate was 0.8 m^3/min. When increasing the injection rate beyond this, the wellhead pressure increased drastically, and to avoid fracturing of the formation 0.8 m^3/min was kept throughout the test.

The analysis given in appendix A3 has led to the theory of a microannulus and a thief zone occuring. This is one of the many theories investigated and is the most probable.
The reason being the high Mobility value for the undisturbed zone from the fall off analysis and thus a longer distance to the fault.

Obviously the fault is at the same place and the undisturbed zone has the same properties. This leads to the conclusion of microannulus occuring. During the injection of water a temperature decrease of 60^oC is exerted on the tubing and makes this contract, and the same happens with the cement. At the same time 30 bar extra pressure is exerted from inside the tubing, which may have caused the cement to lose the bond. Backcalculating from the DST yields that 40% of the water is lost to another formation i.e. only 4000 bbls/D has gone into the perforated interval. The theory is supported by the fact that in the beginning of the waterinjection test the bottomhole pressure showed a steady increase, as the skin increased, but after the shut-down due to leak age on surface the bottomhole pressure is stable throughout the test (see fig. A3-1). The Mobility calculated from fall-off no. 1 is in agreement with the DST test, so the microannulus might have been created during this shut-in.

Applying the model in appendix A1 to the fall-off test yields a mobility ratio of 3 which in turn means that Krw = 0.35 at S_{or}.

This will in turn mean that the leading water edge is even more ellipse shaped since the last response comes 80 m from the wellbore, this can also underline the fact that the Ness-sand has individual sandbodies with extremely high permeability where the water will channel through to the producer. The matter is more severe than discussed in appendix A1 because the producers will have a pressure decline around them and as such act as a "magnet" for the water.

The response from the water flooded zone is too short to measure, which means that some of the objectives for the test can not be met. The information about the relative permeability to water can not be found directly.

4.3 RFT analysis

A detailed analysis is given in appendix A5. Fig. A5-1 shows the pressure points taken. They confirm the oil water contact at 1947 m MSL, found in the other wells on the field. Two samples were taken during the RFT runs and both were ussuccessful. One contained water and one had a leaking valve.

4.4 Reservoir Temperature

The maximum temperature measured during flow was 75°C (167°F) which should reflect the reservoir temperature. During injection the water had a temperature of 9°C on surface and the downhole temperature was 16°C at the same time. In other words the friction and heat transfer causes 7°C temperature rise in 1935 m of 3 1/2" tubing.

During the fall off period the temperature in the bottom of the well rose from 16°C to 37°C in 7 hrs. The temperature after shut-in can be described by a logarithmic function

$$T = 17.54 + 10.02 \ln \Delta t \qquad \text{....Eq 4-1}$$

where Δt is the shut-in time in hours and the T is the temperature in °C.

4.5 Sampling

One of the objectives of this test was to obtain a representative reservoir sample. In spite of 4 attempts to catch a bottomhole sample (2 RFT's and 2 BHS) the recombined seperator sample proved to be the best. This raises the question of whether it is necessary to run BHS under DST, taking the limiting factor: The frequency (or number of readings) of the bottomhole clocks into consideration, this sampling might be a waste of time. It is perhaps better to run one or two more RFT's.

4.6 PVT analysis

The recombined sample from the separator is used to represent the reservoir fluid. This confirms the composition from well 34/10-9 which lies on the same side of the main fault. The pertinent data are given in Appendix A5.

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* All corrrelations applied are from HP-41C reservoir fluid pac.

Appendix A1

WATER MOVEMENT THEORY

by Svein Skjæveland, Rogaland Regional College

This theory of movement of a waterfront for a radial flow is an extension of Dietz's theory for linear flow.

Fig. A1-1 can be conceived as a cross-section of a sylinder, y = height, x = r, α = 0.

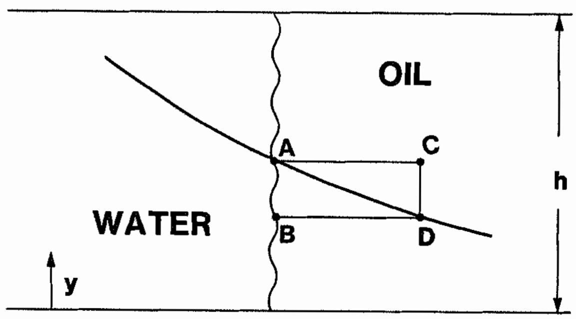


Fig.A 1-1

The water forms a cone

$$P_o\ (A) = P_w\ (A) = P(A)$$

$P\ (B) = P\ (A) - \rho_w\ dy$, consitent units P, ρ

$$P\ (C) = P\ (A) + \frac{\partial P_o}{\partial r}\ dr$$

$P\ (D) = P\ (B) + \frac{\partial P_w}{\partial r}\ dr$, Assumed vertical gravitational equilibrium

$$P\ (D) = P\ (C) - \rho_o\ dy$$

At D: $P(A) + \frac{\partial P_o}{\partial r}\ dr - \rho_o\ dy = P\ (A) - \rho_w\ dy + \frac{\partial P_w}{\partial r}\ dr$

$$(\rho_w - \rho_o)dy = \left(\frac{\partial P_w}{\partial r} - \frac{\partial P_o}{\partial r}\right)\ dr \qquad .....(1)$$

(This is at const. t)

(y, r) are the coordinates of the oil-water interphase.

Darcy's law : $q_w = -\ 2\pi\ yr\ \lambda_w \frac{\partial P_w}{\partial r}\ ,\ \lambda_w = \frac{K_w}{\mu_w}$ .....(2)

$$q_o = -\ 2\pi\ (h-y)r\ \lambda_o \frac{\partial P_o}{\partial r}$$

q : vol/time

Continuity : $q_w + q_o = q$

total

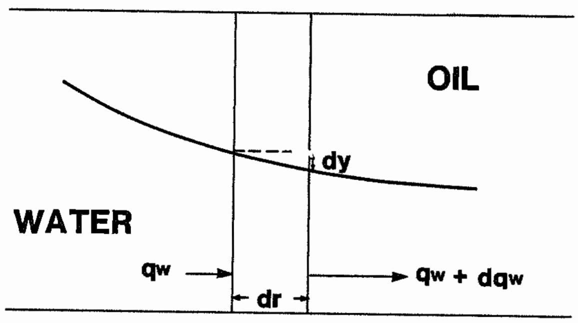


FIG. A1-2

Continuity of water: Change in flow rate per distance equal to change in volume of water per time.

$$\frac{\partial q_w}{\partial r} = -2\pi\ r\ \emptyset S\ \frac{\partial y}{\partial t} \qquad \ldots\ldots(4)$$

$S : S_{oi} - S_{or}$

From (1), (2), (3)

$$\frac{\partial y}{\partial r} = -\frac{1}{\Delta\rho}\ \frac{1}{2\pi r}\left(\frac{q_w}{\lambda_w y} - \frac{q - q_w}{\lambda_o\ (h-y)}\right)$$

$$= \frac{1}{\Delta\rho}\ \frac{1}{2\pi r\ \lambda_o}\left(\frac{a\ q_w}{y} - \frac{q - q_w}{h-y}\right)$$

$$a = \frac{\lambda_o}{\lambda_w} = \frac{1}{M}$$

$$\frac{\partial y}{\partial r} = \frac{1}{\Delta\rho}\ \frac{1}{2\pi r\ \lambda_o}\left[\frac{q}{h-y} - \left(\frac{a}{y} + \frac{1}{h-y}\right) q_w\right] \qquad \ldots\ldots(5)$$

In order to introduce time derivatives, and continuity of water, eq. (4), (5) is differentiated with respect to r:

$$2\pi \ \Delta\rho \ \lambda_o \frac{\partial^2 y}{\partial r^2} = -\frac{1}{r^2}\left[\frac{q}{h-y} - \left(\frac{a}{y} + \frac{1}{h-y}\right) q_w\right]$$

$$+ \frac{1}{r}\left[\frac{q}{(h-y)^2}\frac{\partial y}{\partial r} + \left(\frac{a}{y^2} - \frac{1}{(h-y)^2}\right) q_w \frac{\partial y}{\partial r}\right.$$

$$\left. - \left(\frac{a}{y} + \frac{1}{h-y}\right)\frac{\partial q_w}{\partial r}\right] \qquad .....(6)$$

$$\partial r = - 2\pi \ r\emptyset s \ \frac{\partial y}{\partial t}$$

From (2), (3), if we assume $\frac{\partial P_w}{\partial r} = \frac{\partial P_o}{\partial r} = \frac{\partial P}{\partial r}$

$$q = - 2\pi \ r \frac{\partial P}{\partial r} (y\lambda_w + (h-y) \ \lambda_o)$$

$$q_w = - 2\pi r \frac{\partial P}{\partial r} \ y \ \lambda_w$$

$$): \quad q_w = q \ \frac{y \ \lambda_w}{y\lambda_w + (h-y)\lambda_o} = q \ \frac{y}{a(h-y)+y}$$

In this case, the first term on the right hand side cancels. But, as stated by Dietz p.88, this expression is not absolutely accurate, but can be used after differentiation he claims

A more correct expression:

(See book by Dake (ref. 4)) for linear system sec. 10.6)

$$\frac{\partial P_o}{\partial r} = \frac{\partial P_w}{\partial r} - \frac{\partial P_c}{\partial r}$$

$$Pc = \Delta\rho \cdot y \quad , \quad \frac{\partial P_c}{\partial r} = \Delta\rho \, \frac{\partial y}{\partial r}$$

$$q = -2\pi r \left(y\lambda_w \frac{\partial P_w}{\partial r} + (h-y)\lambda_o \frac{\partial P_w}{\partial r} - (h-y)\lambda_o \Delta\rho \frac{\partial y}{\partial r} \right)$$

$$q_w = -2\pi r \; y \; \lambda_w \frac{\partial P_w}{\partial r}$$

$$): \; -2\pi r \frac{\partial P_w}{\partial r} = \frac{q_w}{y \cdot \lambda_w}$$

$$q = \frac{q_w}{y\lambda_w} \cdot y\lambda_w + \frac{q_w}{y\lambda_w} (h-y)\lambda_o + 2\pi r (h-y)\lambda_o \, \Delta\rho \, \frac{\partial y}{\partial r}$$

$$q = q_w \left(\frac{y\lambda_w + (h-y)\lambda_o}{y\lambda_w} \right) + 2\pi r \; (h-y)\lambda_o \; \Delta\rho \; \frac{\partial y}{\partial r}$$

$$q_w = \frac{y\lambda_w}{y\lambda_w + (h-y)\lambda_o} \cdot q - \frac{2\pi r (h-y) y\lambda_o \; \lambda_w}{y\lambda_w + (h-y)\lambda_o} \; \Delta\rho \; \frac{\partial y}{\partial r}$$

$$= \frac{y}{a(h-y)+y} \, q - \frac{2\pi r (h-y)\lambda_o y}{a(h-y)+y} \; \Delta\rho \; \frac{\partial y}{\partial r}$$

The first term on RHS:

$$+ \frac{1}{r} \quad \frac{2\pi \cancel{(h-y)} \lambda_o \cancel{y}}{\cancel{(a(h-y)+y)}} \Delta\rho \frac{\partial y}{\partial r} \cancel{\frac{a(h-y)+y}{y(h-y)}}$$

$$= \frac{1}{r} \; 2\pi\lambda_o \Delta\rho \frac{\partial y}{\partial r}$$

From (6)

$$\begin{aligned} 2\pi\Delta\rho\lambda_o \frac{\partial^2 y}{\partial r^2} &= \frac{1}{r} \; 2\pi\lambda_o \Delta\rho \frac{\partial y}{\partial r} \\ &+ \frac{1}{r} \cdot \frac{q}{(h-y)^2} \cdot \frac{\partial y}{\partial r} \\ &+ \frac{1}{r} \left(\frac{a}{y^2} - \frac{1}{(h-y)^2} \right) \frac{y}{a(h-y)+y} \; q \cdot \frac{\partial y}{\partial r} \qquad \text{.....(7)} \\ &+ \left(\frac{a}{y^2} - \frac{1}{(h-y)^2} \right) \frac{2\pi\Delta\rho(h-y)\lambda_o y}{a(h-y)+y} \quad \frac{\partial y}{\partial r} \\ &+ \left(\frac{a}{y} + \frac{1}{h-y} \right) \cdot \; 2\pi\phi \; s \frac{\partial y}{\partial t} \end{aligned}$$

We have : $y = y(r, t)$

Then $\frac{\partial r}{\partial t} = - \frac{\frac{\partial y}{\partial t}}{\frac{\partial y}{\partial r}}$

or $\left(\frac{\partial r}{\partial t}\right)_y = - \left(\frac{\partial y}{\partial t}\right)_r \Big/ \left(\frac{\partial y}{\partial r}\right)_t$

): $\frac{\partial y}{\partial t} = - \frac{\partial y}{\partial r} \; \frac{\partial r}{\partial t}$

As a first approximation we neglect the 2. order term on the LHS (Dietz p. 88) and later estimate the correction term.

Assume that $\frac{\partial y}{\partial r} \neq 0$

$$\frac{a}{y} + \frac{1}{h-y} = \frac{a(h-y)+y}{y(h-y)}$$

$$\frac{1}{(h-y)^2} + \left(\frac{a}{y^2} - \frac{1}{(h-y)^2}\right) \frac{y}{(a(h-y)+y)}$$

$$): \quad \frac{ah}{(h-y)y(a(h-y)+y)}$$

From eq. 7 :

$$2\pi\phi s \frac{\partial r}{\partial r} \doteq \frac{1}{r} \frac{ah}{(a(h-y)+y)}^2 \cdot q$$

$$+ \frac{1}{r} 2\pi\lambda_o \Delta\rho \frac{y(h-y)}{a(h-y)+y}$$

$$+\underbrace{\left(\frac{a}{y^2} - \frac{1}{(h-y)^2}\right)}_{\frac{a(h-y)^2-y^2}{y^2(h-y)^2}} \left(\frac{(h-y)y}{a(h-y)+y}\right) \frac{y(h-y)}{(a(h-y)+y)} 2\pi\lambda_o\Delta\rho$$

Last part of equation : $\frac{a(h-y)^2 -y^2}{(a(h-y)+y)^2} \; 2\pi\lambda_o\Delta\rho$

$$2\pi\phi s \frac{\partial r}{\partial t} \doteq \frac{1}{r} \cdot F_1(y) + \frac{1}{r} 2\pi\lambda_o \Delta\rho \cdot F_2(y) + F_3(y) 2\pi\lambda_o \Delta\rho \qquad \ldots\ldots(8)$$

The equation (8) can generally be written :

$$\frac{\partial r}{\partial t} = \frac{C_1}{r} + C_2 \quad , \quad y \text{ const.}$$

or $\frac{dr}{dt} = \frac{C_1}{r} + C_2$

$$\int \frac{r\,dr}{C_1 + C_2 r} = \int dt \qquad\qquad uv' = uv - u'v$$

$$\left(\frac{r}{C_2} \ln (C_1 + C_2 r)\right)\Bigg|_{rw}^{r} - \frac{1}{C_2} \int_{rw}^{r} \ln (C_1 + C_2 r) dr$$

$$x = C_1 + C_2 r$$

$$dx = C_2\, dr$$

$$\frac{1}{C_2^{\,2}} \int_{C_1 + C_2 rw}^{C_1 + C_2 r} \ln x dx = \left[\frac{1}{C_2^{\,2}} (x \ln x - x)\right]\Bigg|_{C_1 + C_2 rw}^{C_1 + C_2 r}$$

$$\frac{r}{C_2} \ln (C_1 + C_2 r) - \frac{r_w}{C_2} \ln (C_1 + C_2 r_w)$$

$$- \frac{1}{C_2{}^2} ((C_1 + C_2 r) \ln (C_1 + C_2 r) - C_1 - C_2 r$$

$$- (C_1 + C_2 r_w) \ln (C_1 + C_2 r_w) + C_1 + C_2 r_w)$$

$$\boxed{= \frac{1}{C_2} (r - r_w) + \frac{C_1}{C_2{}^2} \ln \frac{C_1 + C_2 r_w}{C_1 + C_2 r} = t} \quad .....(9)$$

Conversion factors:

Changing from Darcy units to SI units.

From eq. (8) :

$$2\pi\lambda_o \Delta\rho + \frac{q}{r_o h}$$

$$2\pi\lambda_o \cdot \Delta\rho \left[{}^{g}/{cm^3} \cdot 97 \cdot 10^{-4} \frac{{}^{Atm}/{cm}}{{}^{g}/{cm^3}} \right] + \frac{q}{rh} \left[\frac{m}{t} \; \frac{100 \frac{cm}{m}}{60 \cdot 60 \frac{s}{t}} \right] = 0.22 \; \lambda_o \Delta\rho$$

From eq. (8)

$$\frac{\partial r}{\partial t} = \frac{ah}{(a(h-y)+y)^2} \quad \frac{q}{2\pi r\phi s}$$

$$+ \frac{y(h-y)}{a(h-y)+y} \cdot \frac{0.22\lambda\Delta\rho}{2\pi r\phi s}$$

$$+ \frac{a(h-y)^2-y^2}{(a(h-y)+y)^2} \cdot \frac{0.035\lambda\Delta\rho}{\phi s}$$

r, h, y	:	meter
t	:	hours
q	:	m^3/hour
$\Delta\rho$	:	g/cm^3
λ	:	Darcy/cp
a	:	1/M
M	:	λ_w/λ_o

Example : 34/10-14

M	=	2.0
a	=	0.5
h	=	4 m
Q	=	47 m^3/hour
ϕ	=	0.307
$\Delta\rho$	=	0.256
S	=	0.60
λ	=	4.0 Darcy/cp

Calculation of velocity in top layer y = h

$$\frac{\partial r}{\partial t} \doteq \frac{a}{h} \; \frac{q}{2\pi r \phi s} - \frac{0.035\ \lambda_o \Delta\rho}{\phi s}$$

$$= \frac{0.5 \cdot 47}{4 \cdot 2 \cdot \pi \cdot r \cdot 0.307 \cdot 0.6} - \frac{0.035 \cdot 4.0 \cdot 0.256}{0.307 \cdot 0.6}$$

$$= 5.08 \cdot \frac{1}{r} - 0.19$$

): The front stops at 26 meters on the top (y = h) and is kept stable there.

Assuming the perforated sand has homogeneous rock and PVT properties the water encroachment of the injection test would be as shown on fig. A1-3 and listed in table A1-1.
If the water injection had continoued for 1 year the encroachment would be as shown on fig. A1-4 and listed in table A1-2.

This is and idealized case and the water encroachment in 34/10-14 behaves differently due to inhomogenities. This is discussed in detail in appendix A3.

The waterfront movement is heavily dependant on the mobility ratio. The examples shown here are for M = 2. In appendix A3 a discussion of the value of the mobility-ratio is found.

GULL FAKS

WATER INJECTION TEST 34/10-14

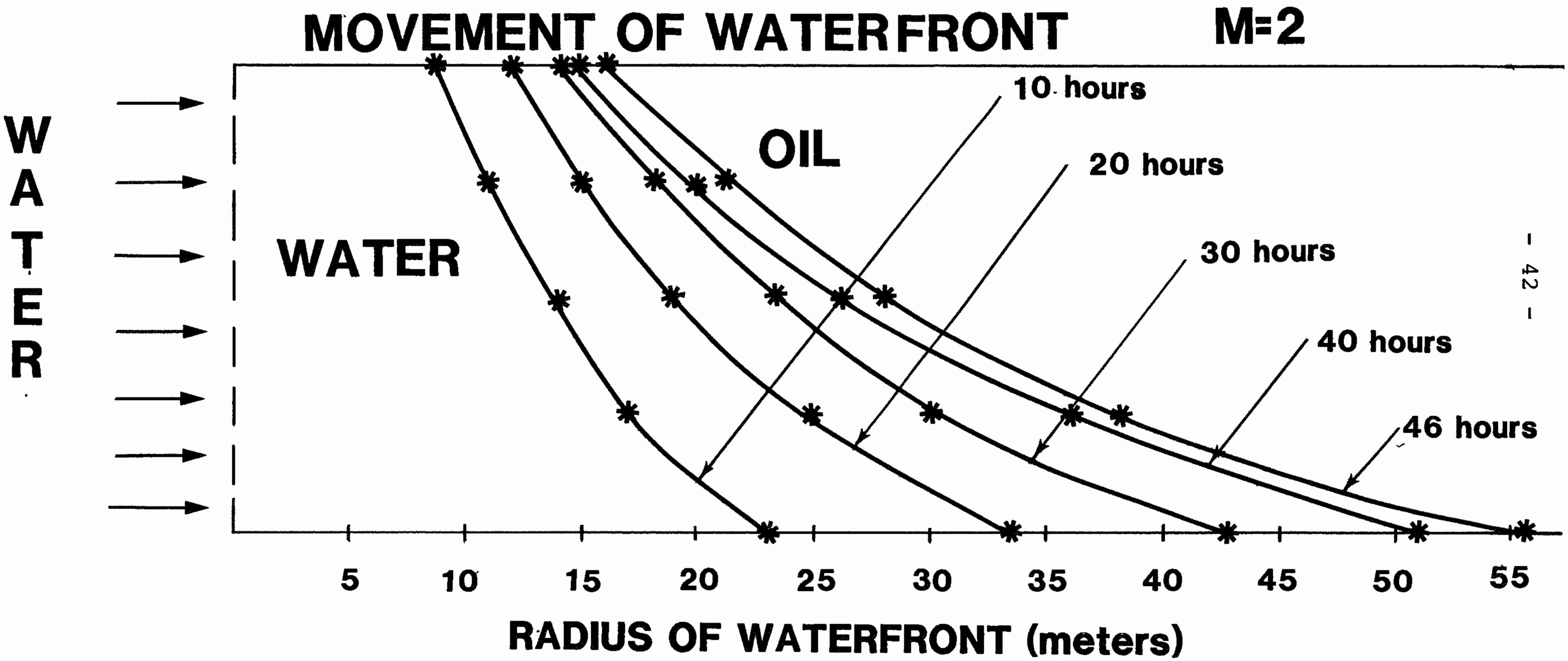


Fig.A1-3

Water Injection Test

34/10—14

Time Hours	Radius of Waterfront (meters)				
	y = 0	y = 1	y = 2	y = 3	y = 4
10	23	17	14	11	9
20	34	25	19	15	12
30	43	30	23	18	14
40	51	36	26	20	15
46	56	38	28	21	16

TableA1-1

GULL FAKS

WATER ENCROACHMENT

M=2

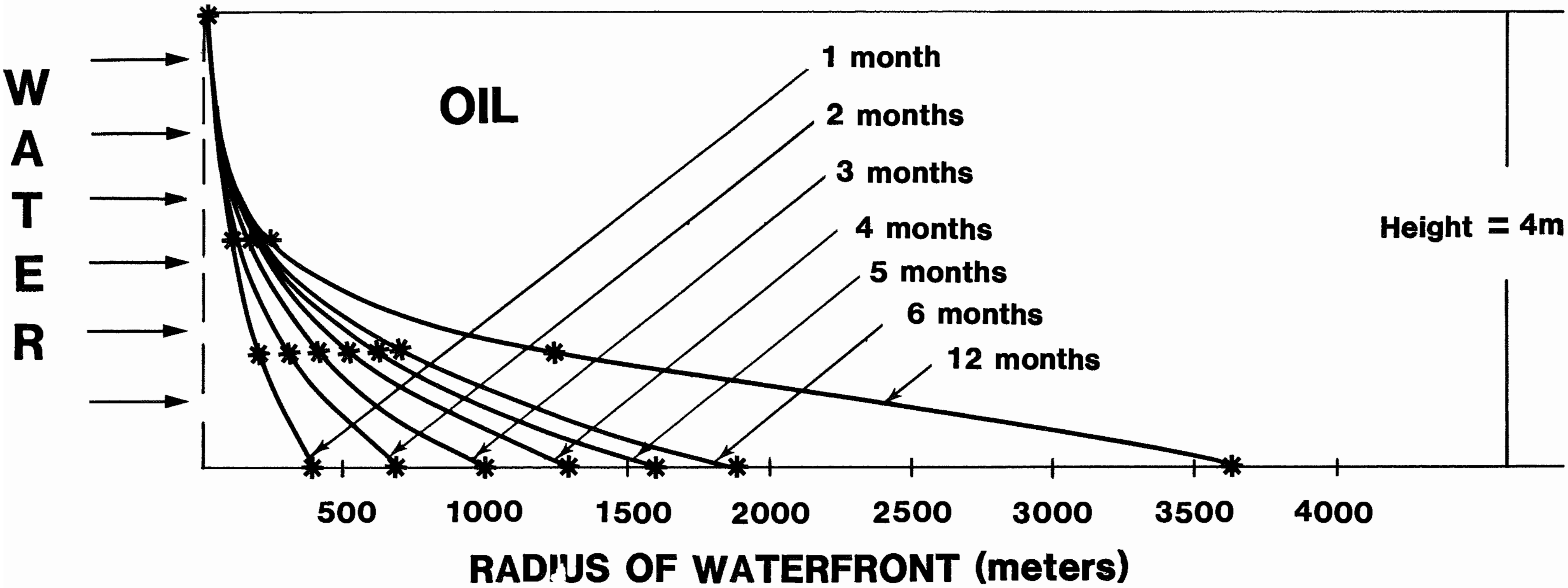


Fig.A1-4

GULLFAKS

Time Months	Radius of Waterfront (meters)				
	y = 0	y = 1	y = 2	y = 3	y = 4
1	396	196	96	48	26
2	708	314	125	50	26
3	1000	420	144	50	26
4	1308	520	157	50	26
5	1600	617	167	50	26
6	1893	711	173	50	26
12	3630	1248	200	50	26
Maximum:			214	50	26

TableA1-2

APPENDIX A2

Drill stem test analysis

A conventional drill stem test was performed in order to meet the objectives of testing this zone.

Objectives:

- Estimate average reservoir pressure and temperature
- Estimate the productivity of this zone
- Obtain fluid samples
- Detect reservoir barriers

The test would also act as a reference for the water injection test being performed in the same interval with exactly the same bottomhole arrangement.

The Horner plot for this test is shown on Fig. A2-1 and the pressure, temperature, choke and flow diagrams of the test are shown on Fig. A2-2. The results of the analysis are given in table A2-1.

DATA SUMMARY

34/10—14

Well 34/10–14 Test date 1 - 5/3 - 82

Reservoir Parameters

Perforations 1933.5 - 1937.5 mrkb

Zone Ness Brent

Wellbore radius 0.11 m

RKB Elev 25 m

Midpoint Production 1935.5 mrkb Bomb at 1911.3 mrkb RKB −1886 mss

Pressure Functions Evaluated at −1886 mss Datum Depth −1850 ss

Delta p required to correct to datum 2.8 bar Gradient 0.079 bar/m

Estimated Average Pressure 310.9 bar

Formation Volume Factor 1.299 vol/vol Viscosity 1.20 cp

Thickness 4.0 m Porosity 30.7 %

Oil Saturation 0.721 % Oil Compressibility $11.0 \cdot 10^{-7}$ kpa-1

Water Saturation 0.279 % Water Compressibility $4.3 \cdot 10^{-7}$ kpa-1

Gas Saturation 0 % Gas Compressibility —

Formation Compressibility $4.4 \cdot 10^{-7}$ kpa-1

System Compressibility $c_t = s_o c_o + s_w s_w + s_g c_g + c_f$

$C_t = 0.721 \times 11.0 \cdot 10^{-7} + 0279 \times 4.3 \cdot 10^{-7} + 4.4 \cdot 10^{-7}$

$C_t = 1.4 \cdot 10^{6}$ kpā1

Rates Reporeted on Test.

Choke 13.5 millimeter Oil Rate 713 m3/D Gas Rate $47.6 \cdot 10^{3}$ sm3/D

Water Rate — m^3/D Gor 66.8 sm3/sm3

^{0}API 30 Gas Spec. Grav 0.61

Cumulative Production Oil 269.6 m3

Water —

HORNER ANALYSIS

Well 34/10–14 Test Date 1 - 5/3 - 82

Effective Production Time tp = Cumulative Production / Rate Reported on Test

tp = 228 / 713·24·60 = 460 MINS

Straight line starts at 30 mins Slope = 1.3 bar/cycle

P_{wfs} = 300.6 Bara

P_{1hr} = 308.5 Bara

P^* = 310.9 Bara

Calcuated Values

$$kh = \frac{162.6\ Q\ B\mu}{M} = \frac{162.6 \cdot 4500 \cdot 1.3 \cdot 1.2}{1.3 \cdot 14.50377} = 60539 \text{ md.ft}$$

k = kh/h = 60539 / 131 = 4621 md.

$$s = 1.1513 \cdot \left[\left[\frac{P1hr - Pwf\ s}{M} \right] - \text{Log} \left[\frac{K}{\text{Ø} u c_t Rw2} \right] + 3.2275 \right]$$

$$s = 1.1513 \left[\left[\frac{7.9}{1.3} \right] - \text{Log} \left[\frac{4621}{0.307 \cdot 1.2 \cdot 9.3 \cdot 10^{-6} \cdot (0.35)^2} \right] + 3.2275 \right]$$

s = – 0.85

Productivity Index

$$PI = \frac{Q}{\Delta p} = \frac{713}{(307.1 - 299.6)} = \frac{713}{7.5} = 95 \text{ Sm}^3\text{/D/Bar}$$

Distance to boundary

$$L = 0.01217 \sqrt{\frac{K \cdot tx}{\phi \ \mu \ C_t}}$$

$K = 4621$ md

$t_x = 90$ min (1.5 hrs)

$\phi = 0.307$

$\mu = 1.2$ cp

$C_t = 9.3 \cdot 10^{-6}$ psi^{-1}

$$L = 0.01217 \cdot \sqrt{\frac{4621 \cdot 1.5}{0.307 \cdot 1.2 \cdot 9.3 \cdot 10^{-6}}} = 547 \text{ ft} \ ; \ 167 \text{ m}$$

SUMMARY OF RESULTS FROM DST TEST

34/10-14

	SI UNITS		OILFIELD UNITS	
K* h	18452	md-m	60539	md·ft
K	4621	md	4621	md
K/μ	3851	md/cp	3851	md/cp
S	-0.85		-0.85	
P*	310.9	Bara	4509	Psia
$\bar{P}$ at - 1850 m ss	307.1	Barg	4454	Psig
PI	95	Sm^3/D/Bar	41.2	STB/D/Psi
Qo	713	Sm^3/D	4484	BBI/D
GOR	66.8	Sm^3/m^3	375	ScF/BBI
DISTANCE TO FAULT	167	m	547	ft
B.H. TEMPERATURE	75	°C	167	°F

TableA2-1

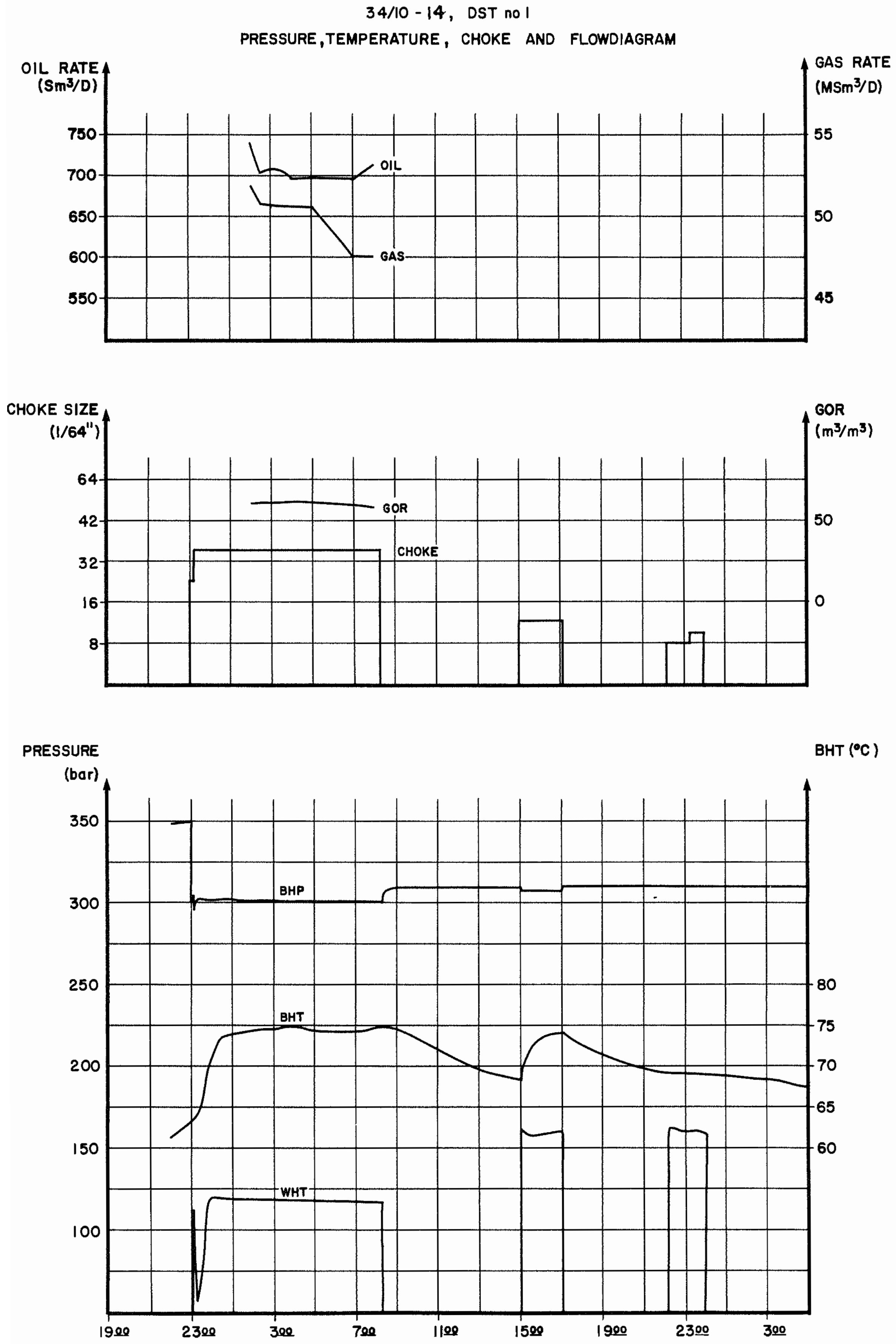

34/10 - 14, DST no I
PRESSURE, TEMPERATURE, CHOKE AND FLOWDIAGRAM
OIL RATE (Sm³/D)
GAS RATE (MSm³/D)
750
700
650
600
550
55
50
45
OIL
GAS
CHOKE SIZE (1/64")
GOR (m³/m³)
64
42
32
16
8
50
0
GOR
CHOKE
PRESSURE (bar)
BHT (°C)
350
300
250
200
150
100
80
75
70
65
60
BHP
BHT
WHT
19⁰⁰
23⁰⁰
3⁰⁰
7⁰⁰
11⁰⁰
15⁰⁰
19⁰⁰
23⁰⁰
3⁰⁰

Fig.A2-2

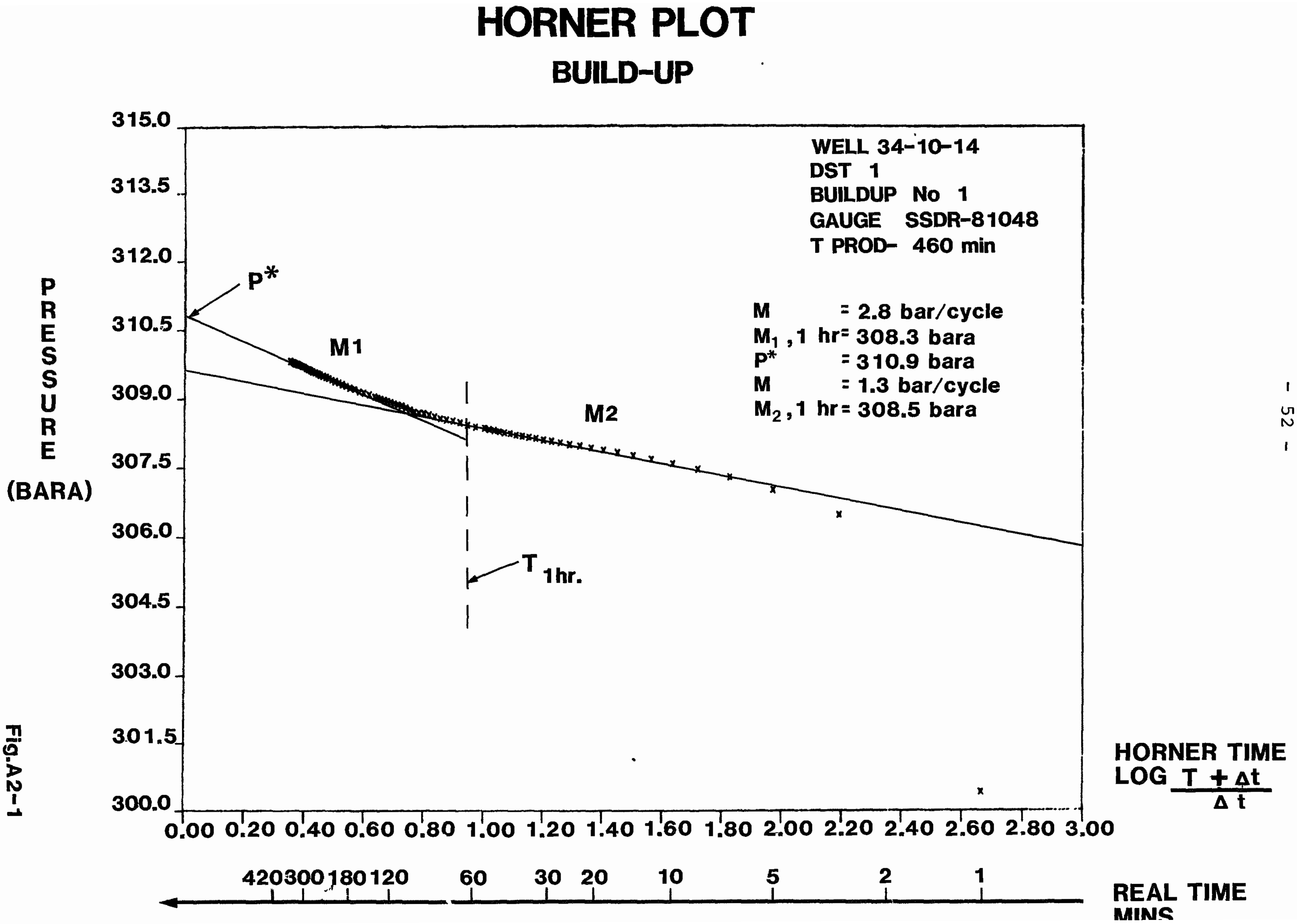

HORNER PLOT
BUILD-UP
WELL 34-10-14
DST 1
BUILDUP No 1
GAUGE SSDR-81048
T PROD- 460 min
M = 2.8 bar/cycle
M1 ,1 hr= 308.3 bara
P* = 310.9 bara
M = 1.3 bar/cycle
M2 ,1 hr = 308.5 bara
P*
M1
M2
T 1hr.
PRESSURE
(BARA)
315.0
313.5
312.0
310.5
309.0
307.5
306.0
304.5
303.0
301.5
300.0
0.00 0.20 0.40 0.60 0.80 1.00 1.20 1.40 1.60 1.80 2.00 2.20 2.40 2.60 2.80 3.00
HORNER TIME
LOG T + Δt / Δ t
420 300 180 120 60 30 20 10 5 2 1
REAL TIME
MINS

Fig.A2-1

APPENDIX A3

Water Injection Analysis

The GULLFAKS field will be developed with pressure maintenance. Water will be injected to keep the pressure above the bubble point throughout the life of the field.

The production strategy calls for water-injection in the water-zone, however this will not give enough pressure support to producers far from the oil-water contact. This means that some water injectors must be placed in the oil-zone in the middle of the field where the thickest oil-zone occurs. Fig A3-1 shows the planned producers and water injection wells.

In order to study the injectivity and gain reservoir information a water injection test was performed in the same interval as the DST, and with the same downhole equipment. The test was carried out on the semi-submersible rig "Ross Rig" using existing equipment on board. The injection water was taken from approximately -30m using the rig water hook-up.

The mud-pumps were used for injection through the floor manifolds, and no filtering of the injected water took place. 0.01% Biocide was added to the water to avoid bacteria growth in the reservoir.

To avoid fracturing, a plot of maximum allowable wellhead injection pressure vs. rate was made from a wellbore hydraulic model, and the wellhead injection pressure was monitored continously on the rig floor with high accuracy pressure reading instruments. The rate was increased in steps and the pressure response monitored for each step. The rate was increased to 0.86 m^3/min (5.4 bbl/min) where the pressure suddenly increased several hundred psi, it was then decided to choke back to 0.80 m^3/min (5 bbl/min) to avoid fracturing the formation. This rate was kept stable throughout the test.

After 16 hours injection a leak in the chicksans on surface, caused a shut-down of injection for 2 hours. Thereafter the injection continued for 30 hours. The wellhead pressure, bottomhole pressure, rate and cumulative injection are shown on Fig. A3-2.

Following the injection period a shut-in period of 6 1/2 hours took place. Fig. A3-3 illustrates the water-injection radially and vertically.

A radial simulation model was set up on beforehand to calculate the various fall off responses with different datasets. They all showed that the response from the flooded zone would be very short (1-10 mins), depending especially on the permeability. The test-interval was chosen because it was assumed to have the lowest permeability of the oil bearing Ness sands, plus a relatively good natural sealing at the top and bottom. Fig. A3-4 shows the rock properties from logs. However the formation turned out to have 3-5 times higher permeability than anticipated.

The bottomhole gauges could only read every 2. minutes and the well was therefore shut in at surface and the pressure monitored continously at wellhead. This was done to have early data and to abandon the test when enough information was gained. The pressure relationship during and after injection is shown on Fig. A3-5.

Foreword to fall-off test analysis

The Ness member of the Brent formation is difficult to interpret geologically. It is an interbedded sand deposit with coarsening upwards sequences, this means highest permeability towards the top of each sand-body. However the sand-bodies are not continous and the communication vertically is also questionable. This will make the Ness member difficult to complete in a production well because the various sand bodies can be depleted differently and cross flow might occur due to pressure differences.

During the injection test 2150 m^3 sea water was injected, this is 7 times the oil produced during the drill stem test.
From the drill-stem test a pressure barrier (fault) was observed 170 m from the wellbore. In the course of the injection this will act as a pressure barrier for the pressure transients caused by the injected water. Accordingly the pressure transients will rather form ellipses than circles.

In appendix A1 the theoretical background for water encroachment is described. An example is also given with data from this test. However, the radius to the front-end heavily depends on the mobility ratio.
The mobility ratio is given as:

$$M = \frac{\lambda_w}{\lambda_o} = \frac{\dfrac{K \cdot K_{rw}}{\mu_w}}{\dfrac{K \cdot K_{ro}}{\mu_o}}$$

The permeability is defined as a rock property and can be assumed constant, (neglecting the cooling effect on the rock from the injection water).

The relative permeability curve for well 34/10-3 (Ness) measured under reservoir conditions is shown on Fig. A3-6.

From this

K_{ro} = 0.4 at Sw = 28%

K_{rw} = 0.2 at S_{or}

and

μ_o = 1.2 cp

μ_w = 0.4 cp, for hot water

this gives

$$M = \frac{\frac{0.2}{0.4}}{\frac{0.4}{1.2}} = 1.5$$

The endpoint for the relative permeability to water is the most uncertain parameter. This is likely to be higher, which also proves to be the case from the fall-off analysis.

In appendix A1 the example shows the water front with M = 2. The viscous fingering of water causes the water to move faster as the oil-water viscosity ratio increases. (Ref. 2 page 34). The maximum oil-water ratio possible in this case is 3. Applying the same theory with M = 3 gives a waterfront as shown on Fig. A3-7.

Including the relative permeability will thus reduce this mobility, this means that $1.5 < M < 3$ is reasonable. The fractional flow curve for the relative permeability curve on fig. A3-5 are shown on fig. A3-8. The curve is calculated both for cold water (μ_w 1.5 cp) and hot water ($\mu_w = 0.5$ cp).. The point of tangency to this curve (from $S_w = S_{wi}$) gives a water saturation at the flood front of $S_w = 0.56$. Therefore, according to the classical Buckley-Leverett theory, water saturations cannot exist in the range $S_w < S_w < 0.56$. The watercut criterium on GULLFAKS is $f_w = 0.95$, this in turn means that the S_{or} value is not so important, the interesting value is S_w at $f_w = 0.95$ which is below S_w at S_{or}.

Fall-off analysis

Fall of number 1 is a 2 hrs shut in due to leakage and repair on surface. This occured after 16 hrs injection. The Horner plot for this shut-in is shown on Fig. A3-9. Only 735 m^3 (4595 bbls) water was injected at this time. This means that any response from the water zone has died out before the first bottomhole pressure reading. (At this stage of the test one pressure gauge on 1 min mode was still active).
The Horner plot gives a perfect straight line with m_3 (oil zone) = 1.43 bar/cycle.

This gives :

$$K/\mu = \frac{162.6 \cdot Q_{WI} \cdot B_W}{m_3 \cdot h} = \frac{162.6 \cdot 6750 \cdot 1.0}{21 \cdot 13.1} = 3990 \text{ md/cp}$$

Q_W = 6750 bbl/day

h = 13.1 ft

B_W = 1.0 RB/STB

m_3 = 21 psi/cycle

Extrapolation of the last points on the Horner plot gives P* = 313 Barg.

The final shut-in after 46 hrs injection is shown on Fig. A3-10 and 11.

Fig A3-9 is surface data read every 5. seconds of the first 30 mins of the fall-off period, and thereafter with increasing interval throughout the test.
Unfortunately these early data are influenced by the movement of the mud-pump pistons before the line between the mud-pump and data header was blocked off. This lasts approximately 3 minutes, but is severe for the first minute only.
Fig. A3-11 shows the bottomhole data plotted on Horner graph for the fall off test.

From Fig. A3-7 it can be seen that the water flooded region has a radius of 12 meters. This assumes homogeneous properties around the wellbore which is not absolutely correct, but will give a very good estimate of the response time from this region.

The formula for depth of investigation:

$$L = 0.01217 \cdot \sqrt{\frac{k \cdot tx}{\phi \ \mu \ C_t}} \qquad \text{.....eq. A3-1}$$

solved for tx:

$$t_x = \frac{L^2 \cdot \phi \cdot \mu \cdot C_t}{0.01217^2 \cdot k} = 0.002 \text{ hrs.} = \underline{7.6 \text{ sec}}$$

where:

L = 39 ft

C_t = 7.6×10^{-6} psi^{-1}

ϕ = 0.307

K = 4621 md (From build-up test)

μ_w = 0.4 cp (Hot water)

The viscosity represents the leading edge of the water front which is assumed to have reached the reservoir temperature.

This shows that the response from the waterzone cannot be measured by existing equipment. Even bottomhole gauges with surface readout will have problems with such short time responses.

The transition zone has combined properties of oil and water and will thus give a curved line on the Horner plot. This can be seen both on the surface and the bottomhole graphs, however the curve approaches a straight line towards the end of the transition period. This is due to the relatively small amount of water present at this distance from the well.

To calculate the time for the end of the tranzition zone equation A3-1 is used with L = 72 meters from Fig. A3-7. This gives t_x = 14 minutes.

From Fig. A3-7 it can be seen that the transition period ends at approximately 19 minutes, this may confirm the assumption of $M = 3$ and accordingly $K_{rw} = 0.4$, and that the water forms an ellipse rather than a circle.

The line m_3 reflects the oil zone and the mobility calculation yields,

$K/\mu =$ 6560 md/cp for this zone. This is higher than expected as it should be in the same range as calculated from the build-up test (3851 md/cp).

As described under "temperature effects" a microannulus has developed most probably. This is a wellknown phenomen and the thiefzone created causes the wrong mobility ratio calculated for the undisturbed oil zone. The mobility ratio is known to be 3850 md/cp from the DST. Backcalculating yields an effective injection rate of 650 m^3/Day (4100 bbls/Day) versus 1075 m^3/Day actually injected. This also implies that the distance to the pressure barrier will be the same as calculated from the DST.

Extrapolation of the last pressure points yields P* = 317 bara.

The mobility for the various segments are calculated applying equation A3-1.

$$\frac{K \cdot kr}{\mu} = \frac{162.6 \cdot Q \cdot B}{m \cdot h} \qquad \text{....Eq. A3-2}$$

where:

Q = - 6750 BBl/day

B_w = 1.0 RB/STB

h = 13.1 ft

m = slope of straight line

The results are listed in Fig. A3-10 and this figure also illustrates the fall-off test schematically.

The specific storage ratio $\frac{(\emptyset \cdot C_t)\ \text{water}}{(\emptyset \cdot C_t)\ \text{oil}}$

is approximately 1. The slope ratio $\frac{m_{oil}}{m_{water}}$ is inversely proportional with mobility ratio $\left(\frac{\lambda_{water}}{\lambda_{oil}}\right)$. This can be seen from the figure. (ref. 1, page 83)

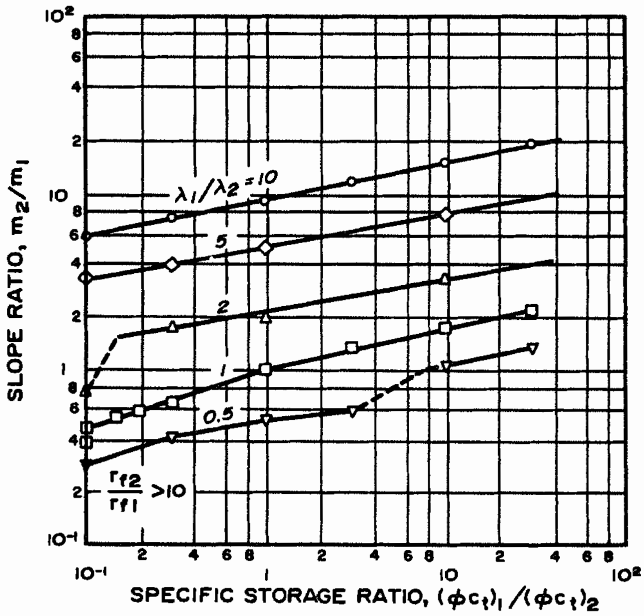


Fig. 7.16 Effect of specific storage ratio and mobility ratio on the slope ratio for falloff testing in a two-zone reservoir. After Merrill, Kazemi, and Gogarty.[18]

From this the slope of the waterflood zone can be found.

If M = 3 and M_{oil} = 0.88 the waterflooded zone has a slope of 2.6.

Skin

Due to the bad quality of the early data no skin-factor can be calculated. However a large positive skin occurs in this test.

This can be seen from the first part of the formula for skin:

$$S = 1.1513 \frac{P_{Ihr} - P_{wf}\ (\Delta t = 0)}{-m}$$

This value is high due to the extreme pressure drop after shut-in, although no exact value can be calculated.

The reason may be that the water is not filtered and that mud from the rate hole might be forced into the formation by turbulence.

Different methods of calculating the skin yields an estimated value around + 10.

Wellbore storage

Wellbore storage occurs, but only for a short time. The exact value cannot be calculated due to bad early time data. An estimate can be made applying eq. 2.22b of ref. 1

$$t > \frac{170.000\ C\ e^{0.14S}}{kh/\mu}$$

where:

$C = V \times Cw$

$V = 50$ bbls

$Cw = 3 \times 10^{-6}$ psi^{-1}

$k = 4621$ md

$h = 13.1$ ft

$\mu = 1.0$ cp (cold water)

$S = +\ 10$ (assumption)

This gives t > 6 sec.

Injectivity

$$J = \frac{-Q}{(P_i - P_{wf})}$$

where:

$Q = 1073\ m^3/D$

$P_i = 316$ Barg

$P_{wf} = 347$ Barg

This yields $J = 35\ m^3/D/bar$

Temperature profile

Fig A3-13 shows the temperature increase after shut-in. This represents the temperature in the last volume of water injected. The front-end water will be heated by the rock very efficiently and will thus be at reservoir temperature.

Initial Pressure

The initial pressure is calculated from the build-up, first fall off and final fall off. They all give different results. The reason for this is the complex nature of the Ness sand with pressure barriers close to the well. However, the most reliable pressure is the final fall off pressure which gives
Pi = 317 Bara.

This is due to the fact that this fall off sees furthest into the formation, and as such will extrapolate to the most reliable initial pressure.

Temperature effects

Injection of cold water into a hot oil reservoir complicates the interpretation as especially the viscosity changes with temperature. The cold water has a viscosity of 1.2 cp and heated to reservoir temperature it decreases to 0.4 cp.

The oil will also get more viscous as it cools down. The oil viscosity vs. temperature from correlations are shown on fig.

A3-14. If the oil are cooled down from 75^{o}C to 60^{o}C the oil viscosity increases from 1.2 cp to 1.6 cp which is 33% increase.

In these calculations it is assumed that the front-end water has reached the reservoir temperature after a short period of time due to heat-convection and heat transfer. Accordingly the low viscosity will apply in the equations.

It is also assumed that the oil viscosity does not change because the water tongue is long and narrow, so the heat transfer from oil to water is negligible.

To avoid this problems the mobility is calculated and compared with the drill stem test. Fig. A3-13 shows the temperature increase for the last volume of water injected, after shut in. Another temperature effect is the cooling of the liner and the cement around it, this will cause the liner to subtract and microannulus might occur between the liner and the cement.

Discussion of the fall-off test results

The analysis reflects the extremely good quality of the individual sand-bodies in the Ness. This caused the pressure to drop almost 1000 psi in 5 seconds after shut-in of which 600 is due to friction in the tubing, and this time is also approximately the response time for the waterflooded zone and the time where wellbore storage occurs. Therefore the objective of measuring the relative permeability to water could not be met.
The transition zone can clearly be identified and applying the theory described in Appendix A1 yields the radius of the waterfront.

The most probable explanation to the high mobility value for the oil zone might be a microannulus formed due to a rather large temperature decrease in the wellbore as described under temperature effects. Allthough an extreme good bond was achieved on the squeeze cement job the temperature decrease could lead to microannulus and thief-zone. Back-calculating shows that this zone then would have gained 40% of the injected water.

Recommendations

One of the objectives of the test was to gain experience in order to design future tests which could obtain maximum information. From the analysis it is clear that early reliable data are needed.

This can only be met by downhole gauges with surface readouts. Therefore it is strongly recommended that this possibility be very carefully investigated.
To avoid too much skin the water should be cleaned before injection

- The amount of water injected must be large enough to ensure a proper response time, the procedure given in Appendix A1 is recommended for this purpose.

- The test-interval must be chosen very carefully with regard to homogenity.

- A CBL log should be run before and after the test to detect possible microannuli.

- If the test is to be properly analysed a reservoir simulation model capable of handling changes of properties with temperature should be used.

GULLFAKS

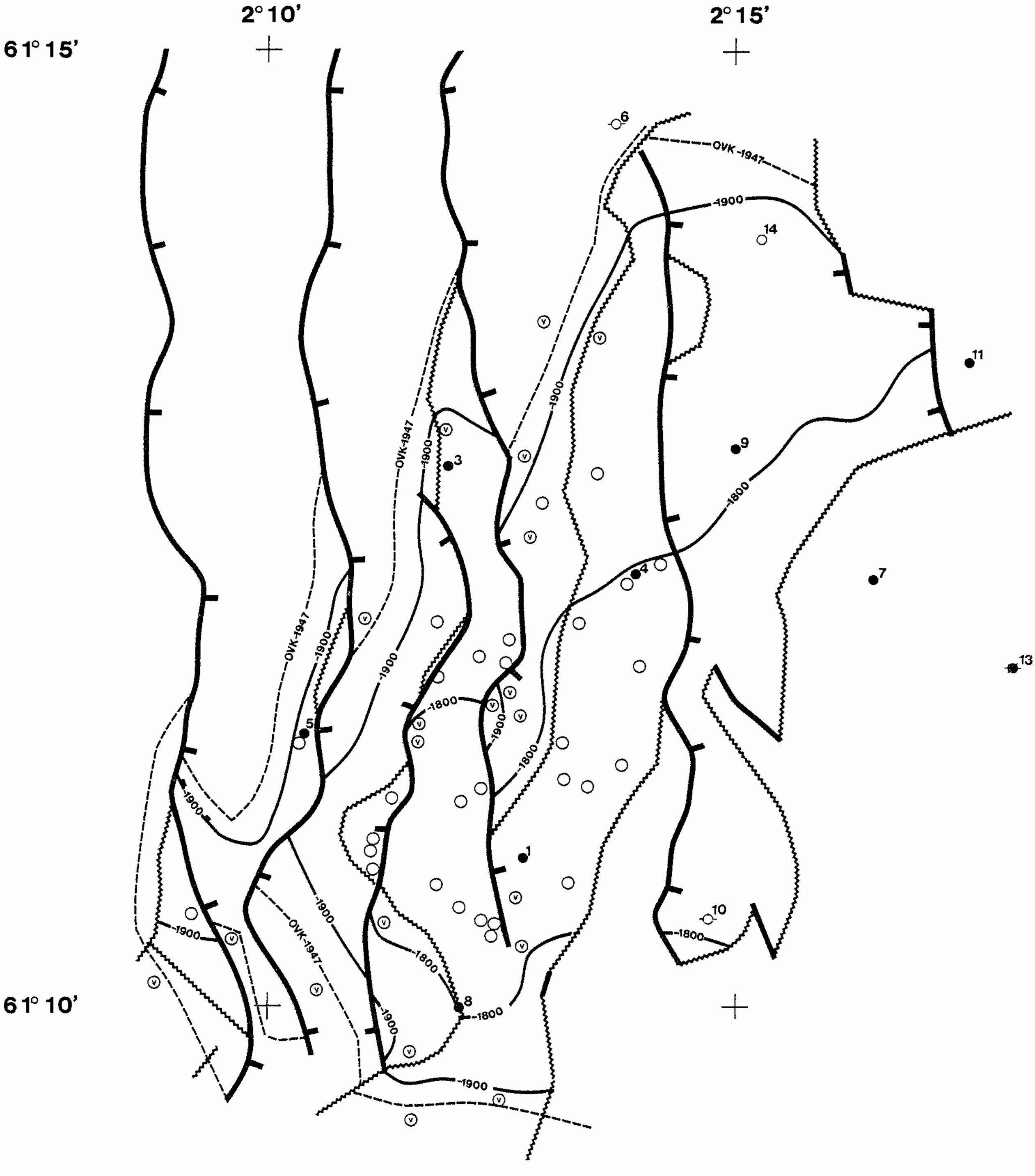


Fig.A3-1

WATER INJECTION 34/10-14

-WELLHEAD AND BOTTOMHOLE PRESSURE
-WATER INJECTION RATE AND CUMULATIVE INJECTION

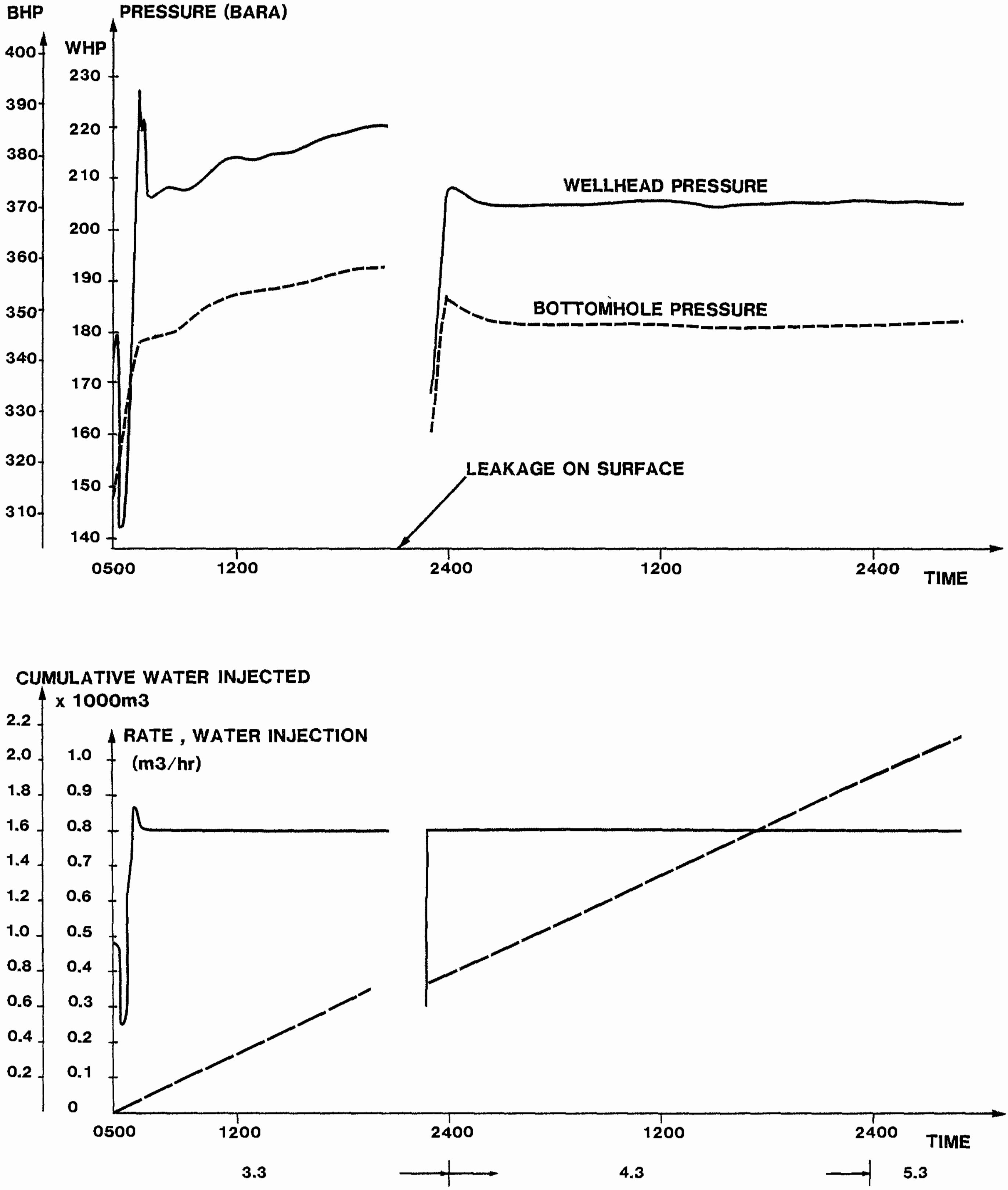


Fig.A3-2

WATER INJECTION

Idealization of the flooding process

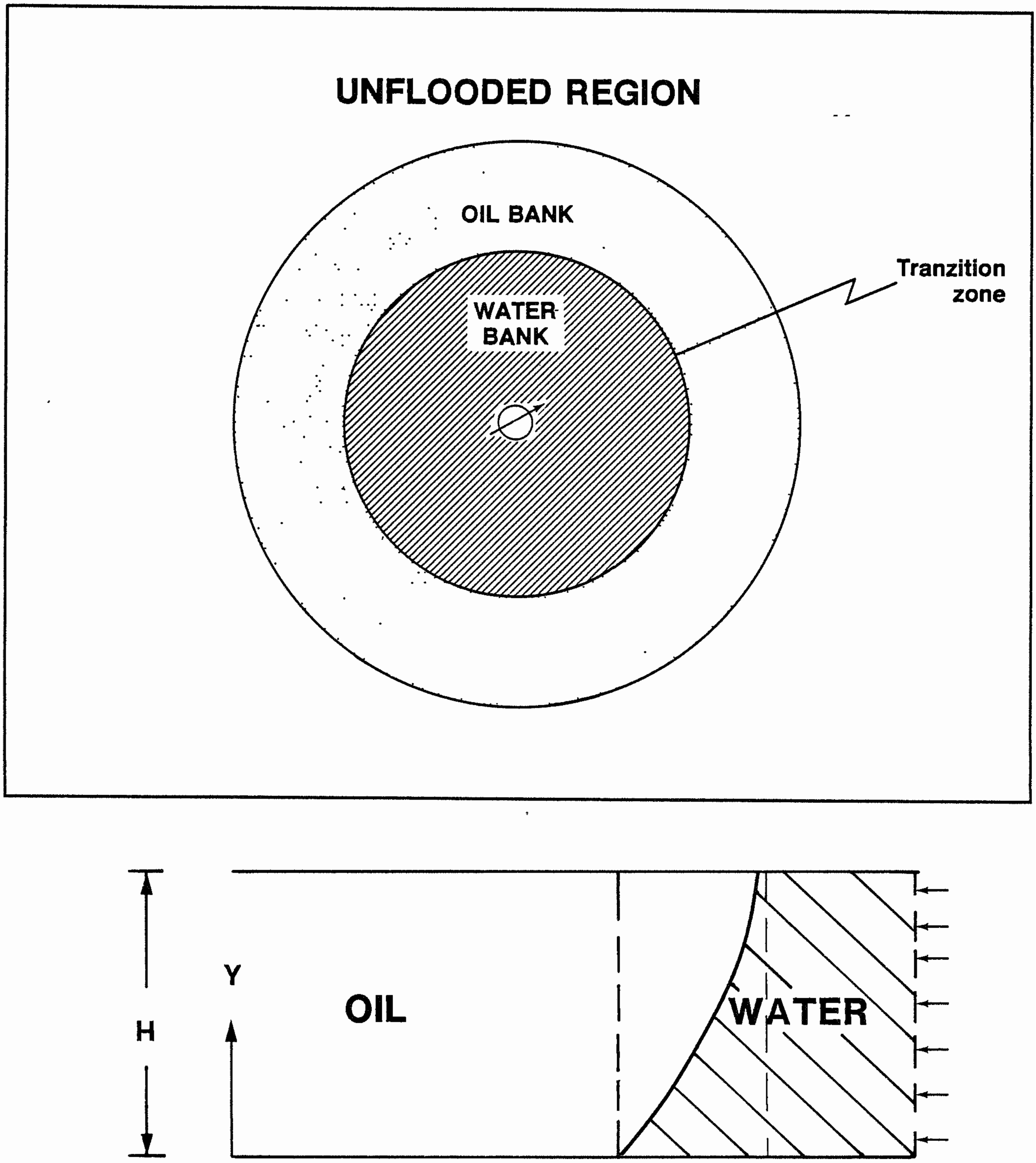


Fig.A3-3

34/10-14

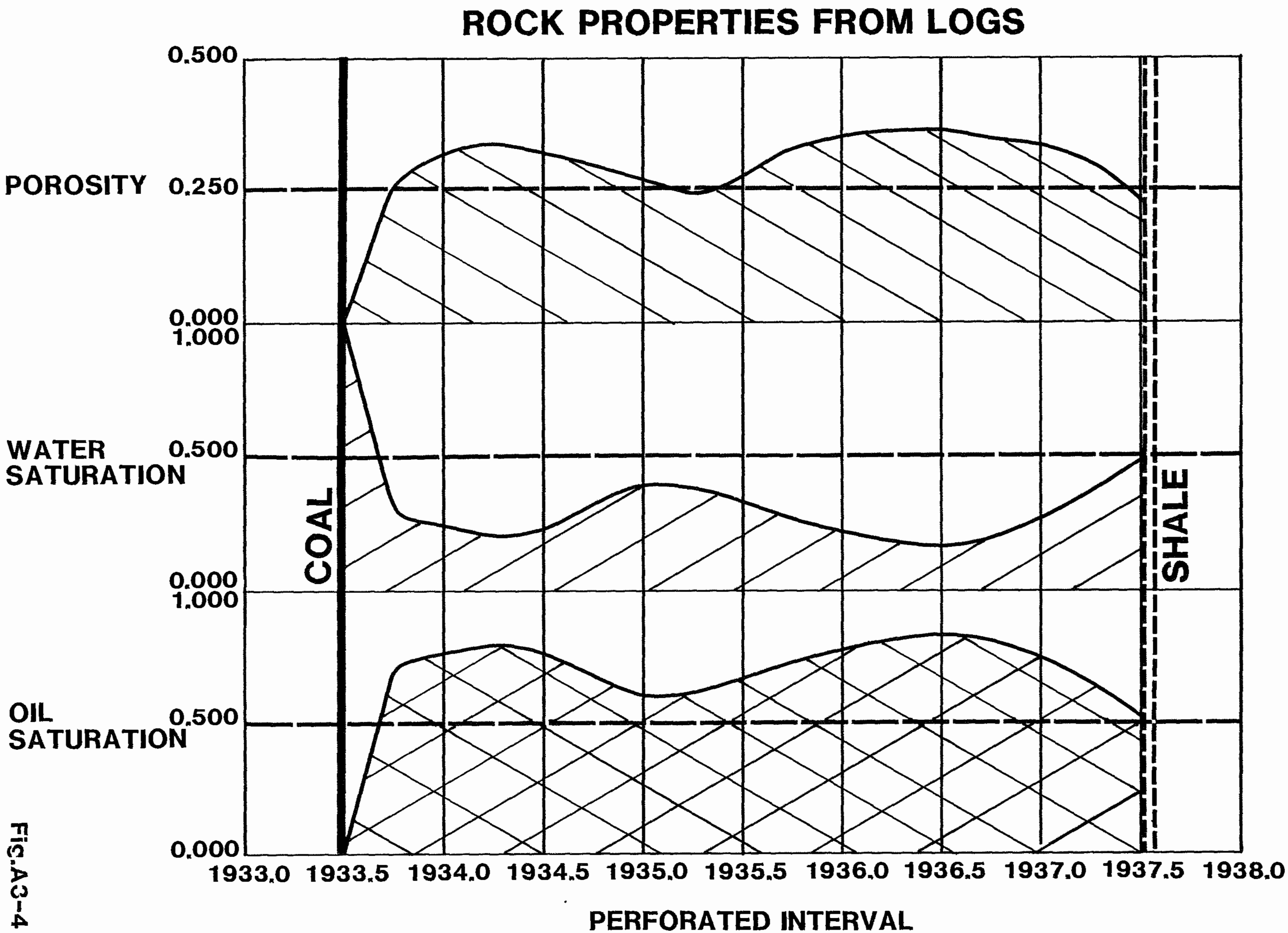
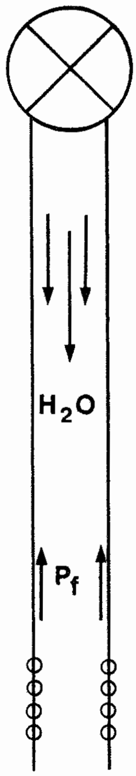


Fig.A3-4

WATER INJECTION

PRESSURE RELATIONSHIP

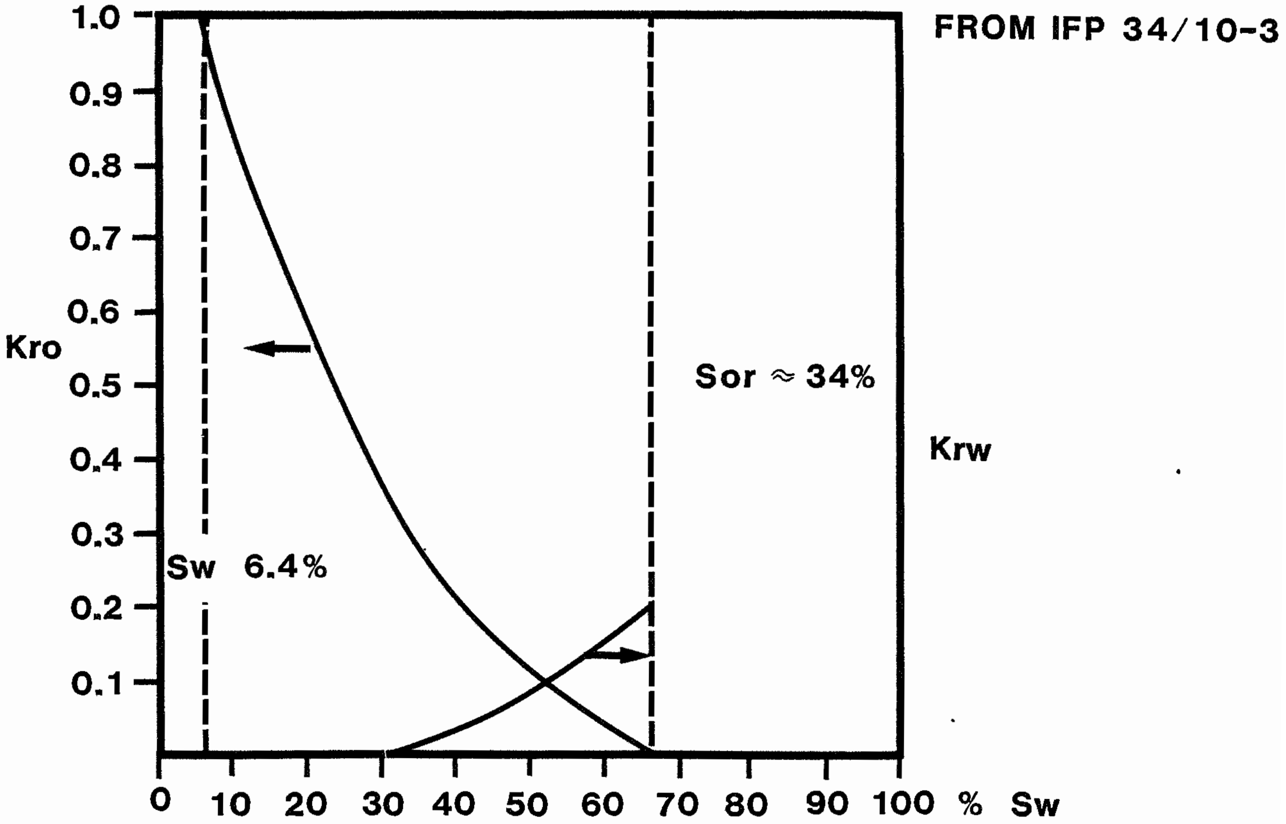


	DURING INJECTION	AFTER SHUT-IN (7Hrs.)
P_{WH}	= 203.1 Bara	= 126.8 Bara
P_{H_2O}	= 192.9 Bar	= 192.9 Bar
$P_{Friction}$	= 47.5 Bar	= 0
P_{BH}	= 348.5 Bara	= 319.7 Bara

Fig.A3-5

— RELATIVE PERMEABILITY
— CAPILLARY PRESSURE

NESS FORMATION



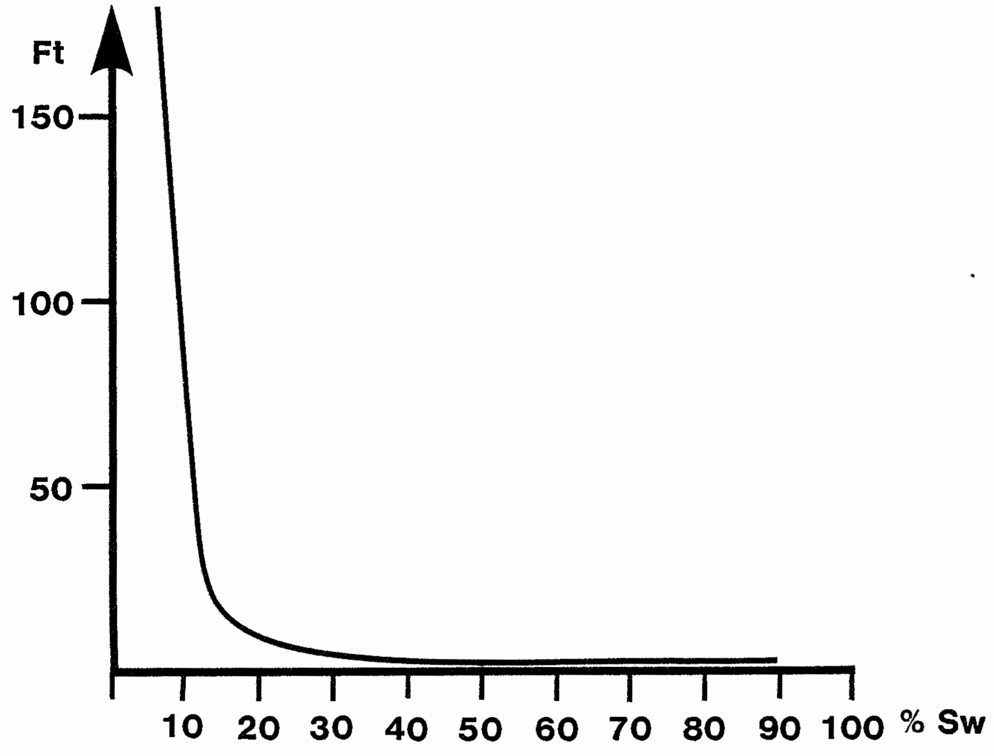


Fig.A3-6

WATER INJECTION 34/10-14

WATERFRONT BEFORE SHUT-IN

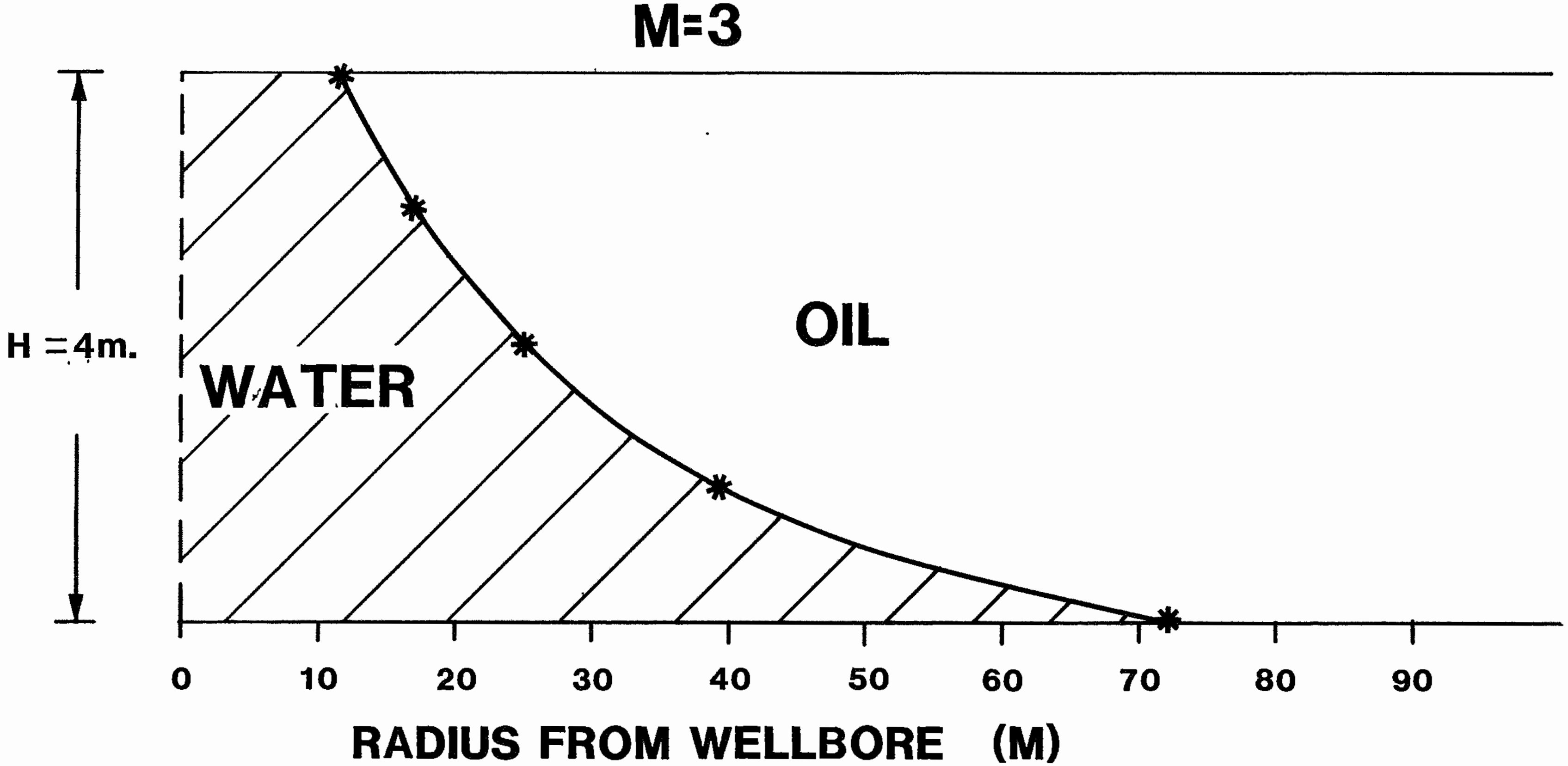


Fig.A3-7

BUCKLEY — LEVERETT

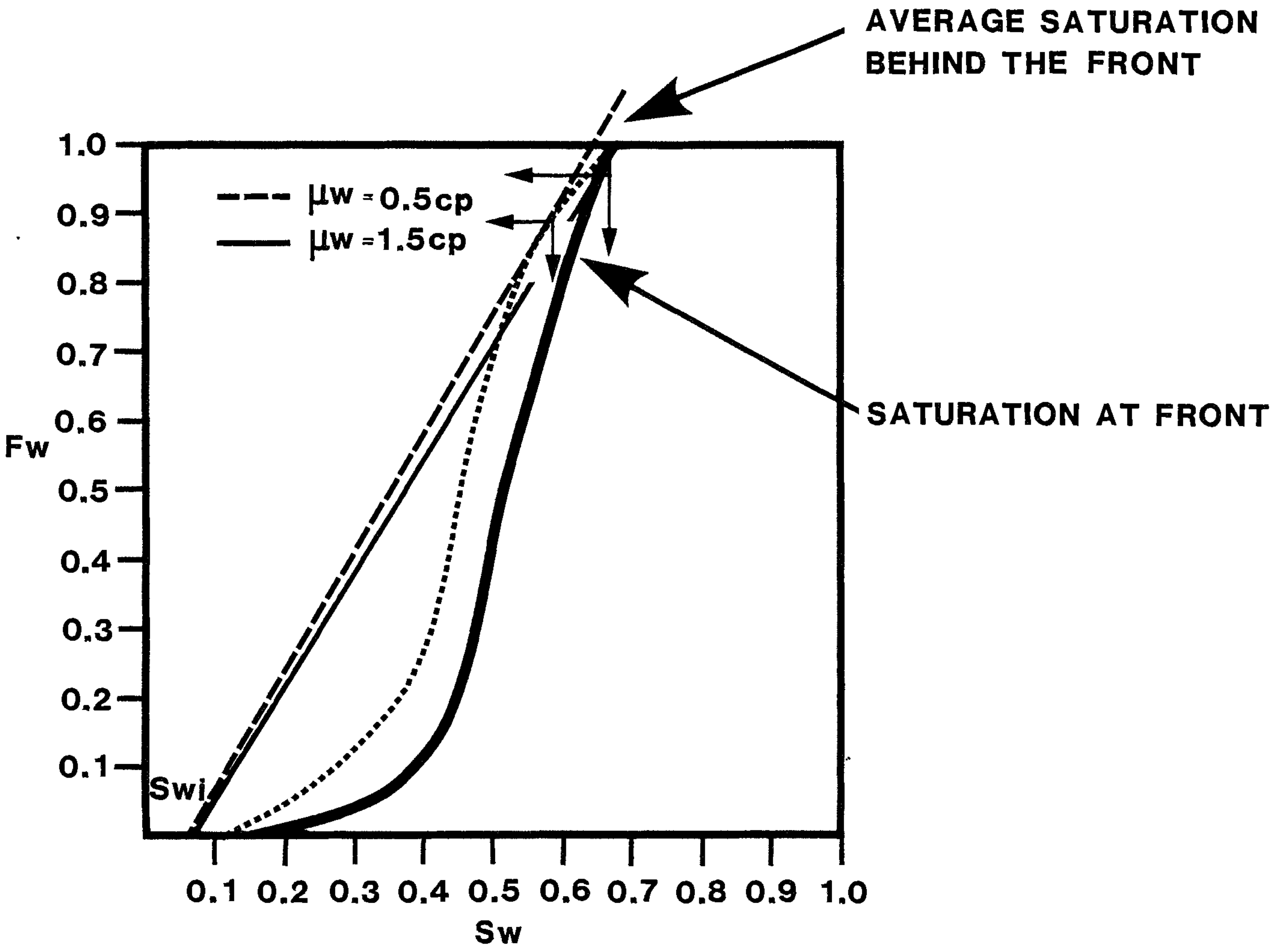


Fig.A3-8

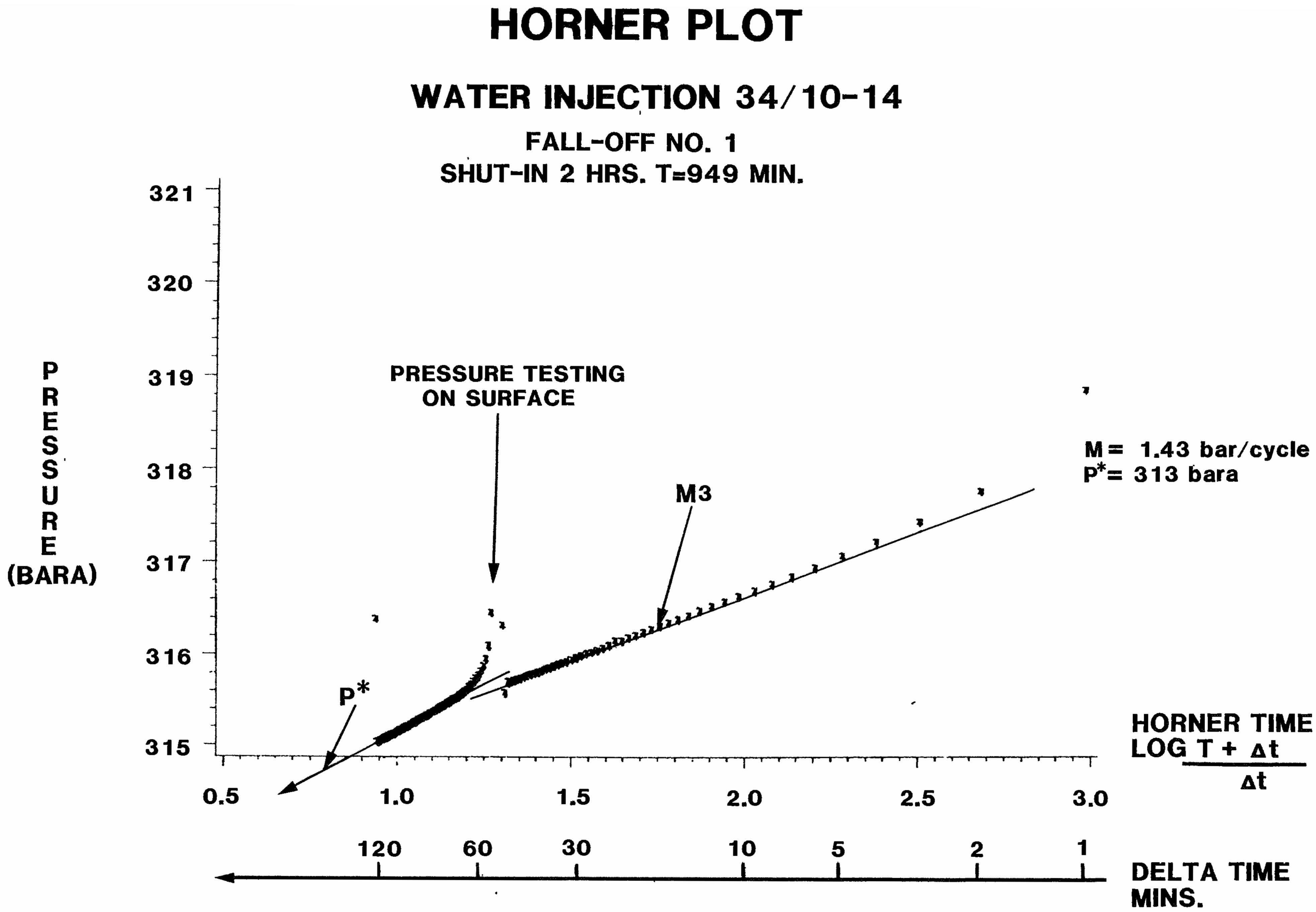
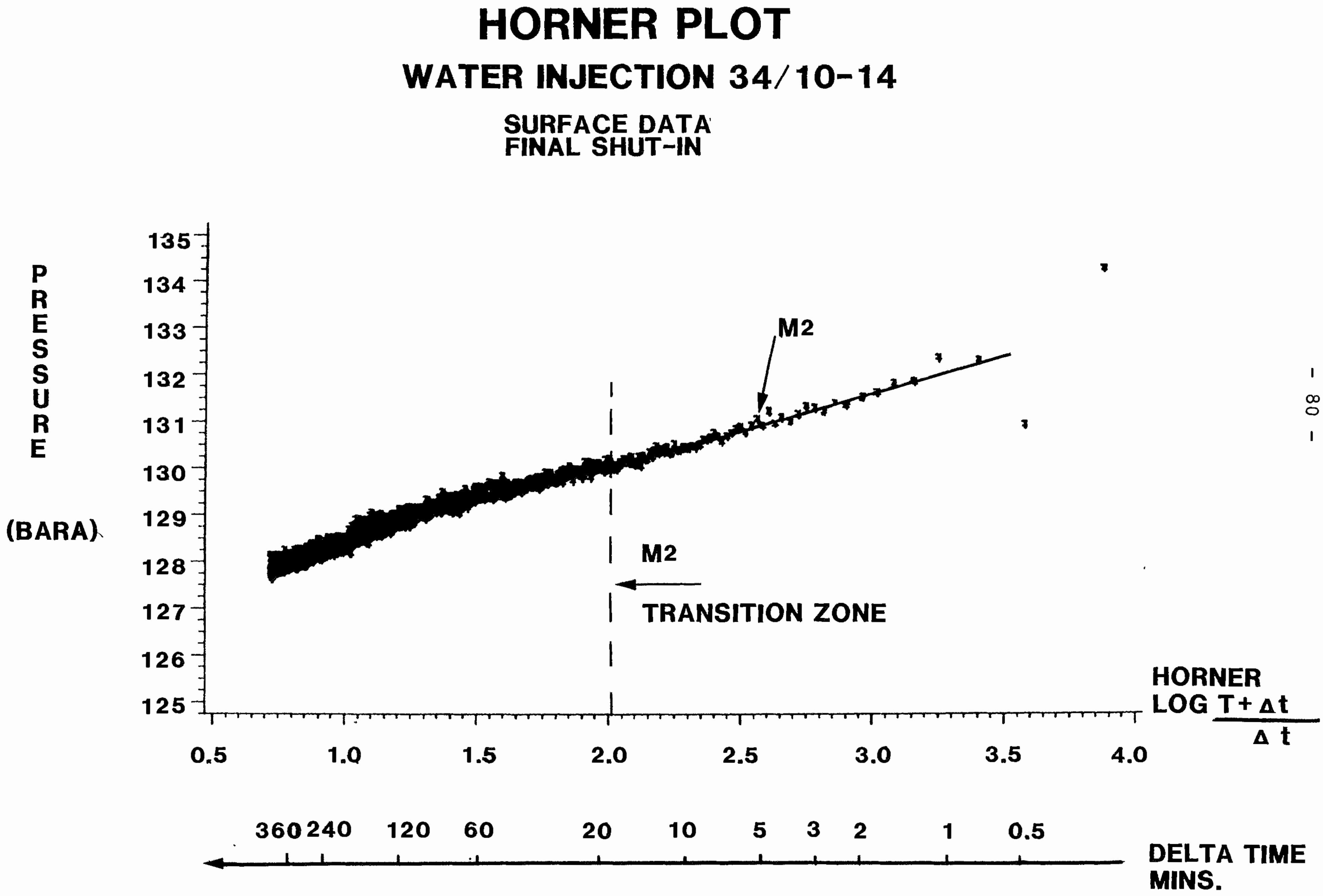

HORNER PLOT
WATER INJECTION 34/10-14
FALL-OFF NO. 1
SHUT-IN 2 HRS. T=949 MIN.
PRESSURE (BARA)
321
320
319
318
317
316
315
PRESSURE TESTING ON SURFACE
M3
P*
M= 1.43 bar/cycle
P*= 313 bara
HORNER TIME
LOG T + Δt / Δt
0.5
1.0
1.5
2.0
2.5
3.0
120
60
30
10
5
2
1
DELTA TIME MINS.

Fig.A3-9



HORNER PLOT
WATER INJECTION 34/10-14
SURFACE DATA
FINAL SHUT-IN
PRESSURE
(BARA)
135
134
133
132
131
130
129
128
127
126
125
M2
M2
TRANSITION ZONE
HORNER
LOG T+Δt / Δt
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
360
240
120
60
20
10
5
3
2
1
0.5
DELTA TIME
MINS.

Fig.A3-10

HORNER PLOT

WATER INJECTION 34/10-14

FINAL SHUT IN
0500-1200 T-30 Hrs.

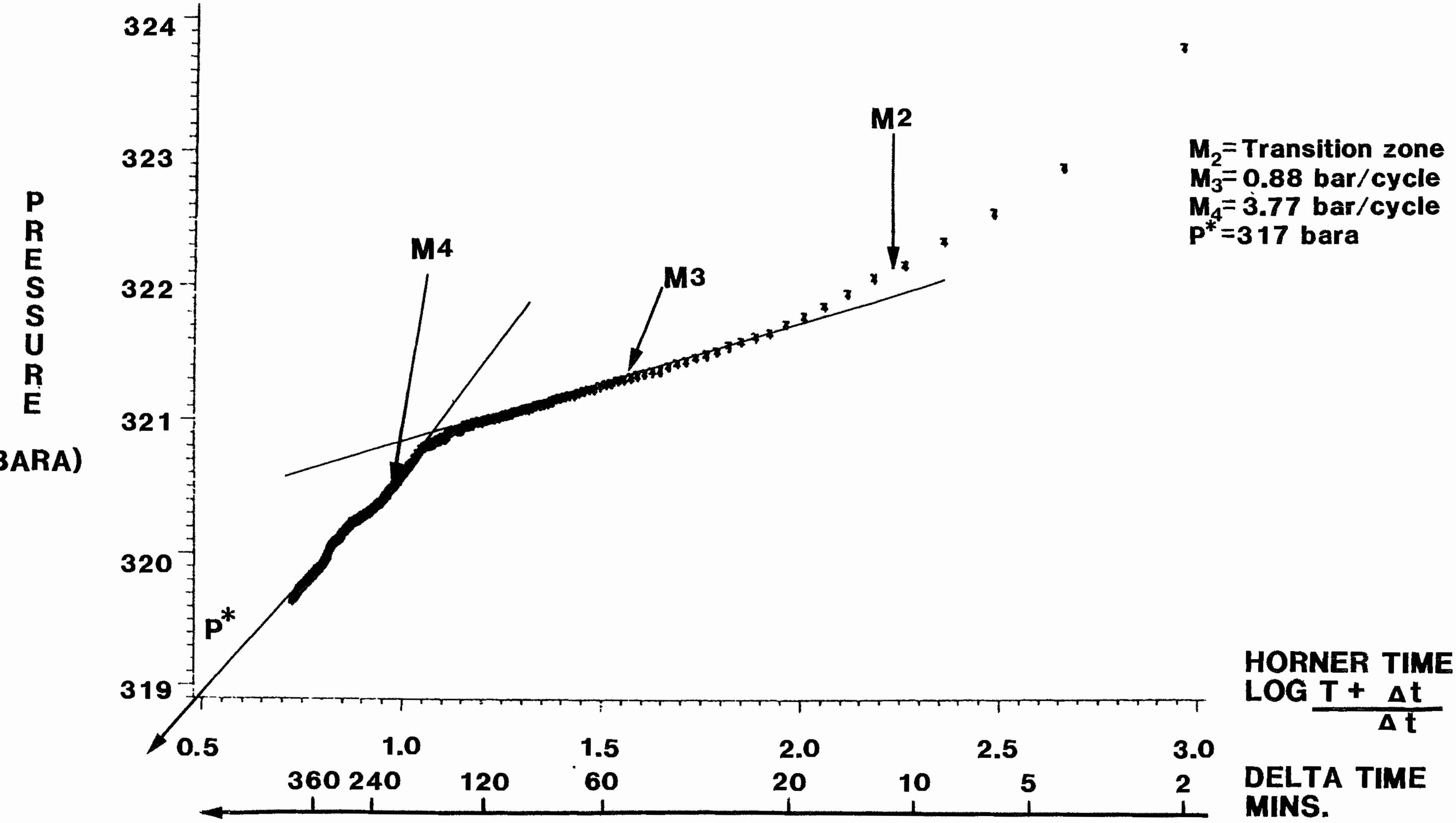
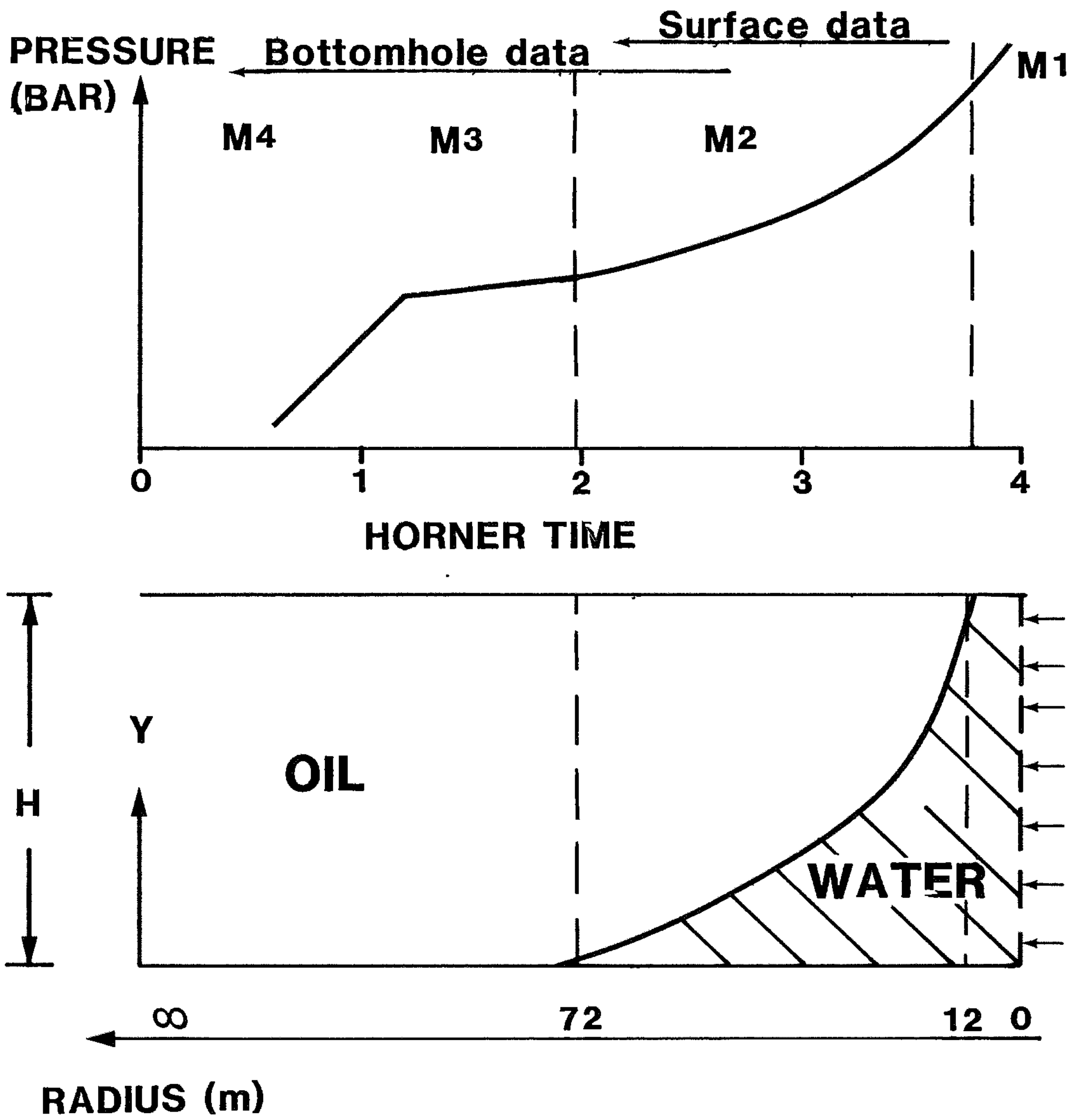


Fig.A3-11

FALL OFF DATA Well 34-10-14



	M4	M3	M2 **	M1 *
Slope bar/~	3.77	0.88	Curved	
Duration min.	260	120	~ 20	
Zone	Fault	Oil Zone	Transition	Water Flooded
$\frac{K \cdot Kr}{\mu}$ md/cp	1530	6560		

The mobility is too high due to thiefzone occuring

* No straight line here due to bad data.

** The curve is a result of combined oil and water properties.

Fig.A3-12

34/10-14

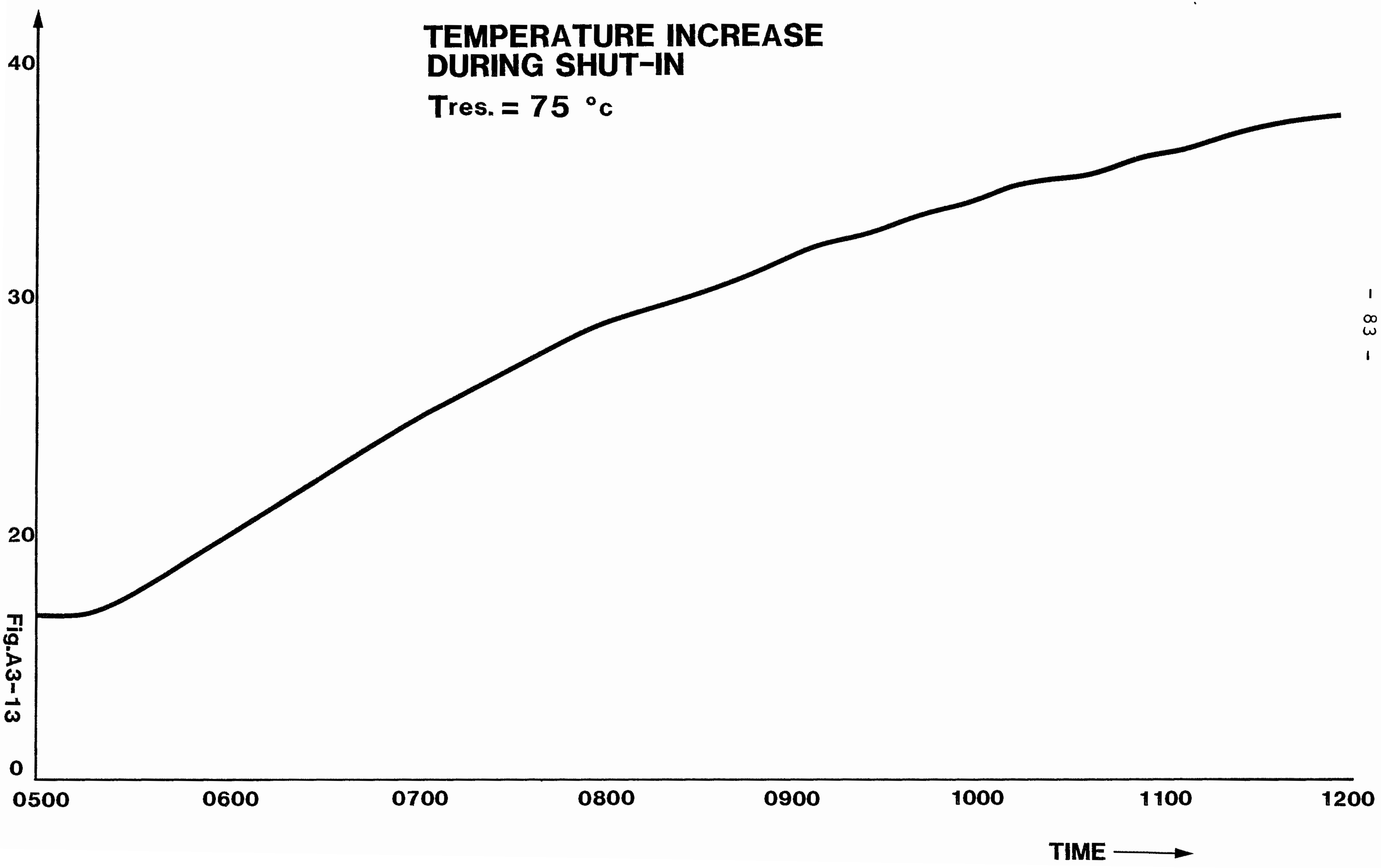


Fig.A3-13

OIL VISCOSITY VS TEMPERATURE

FROM CORRELATION

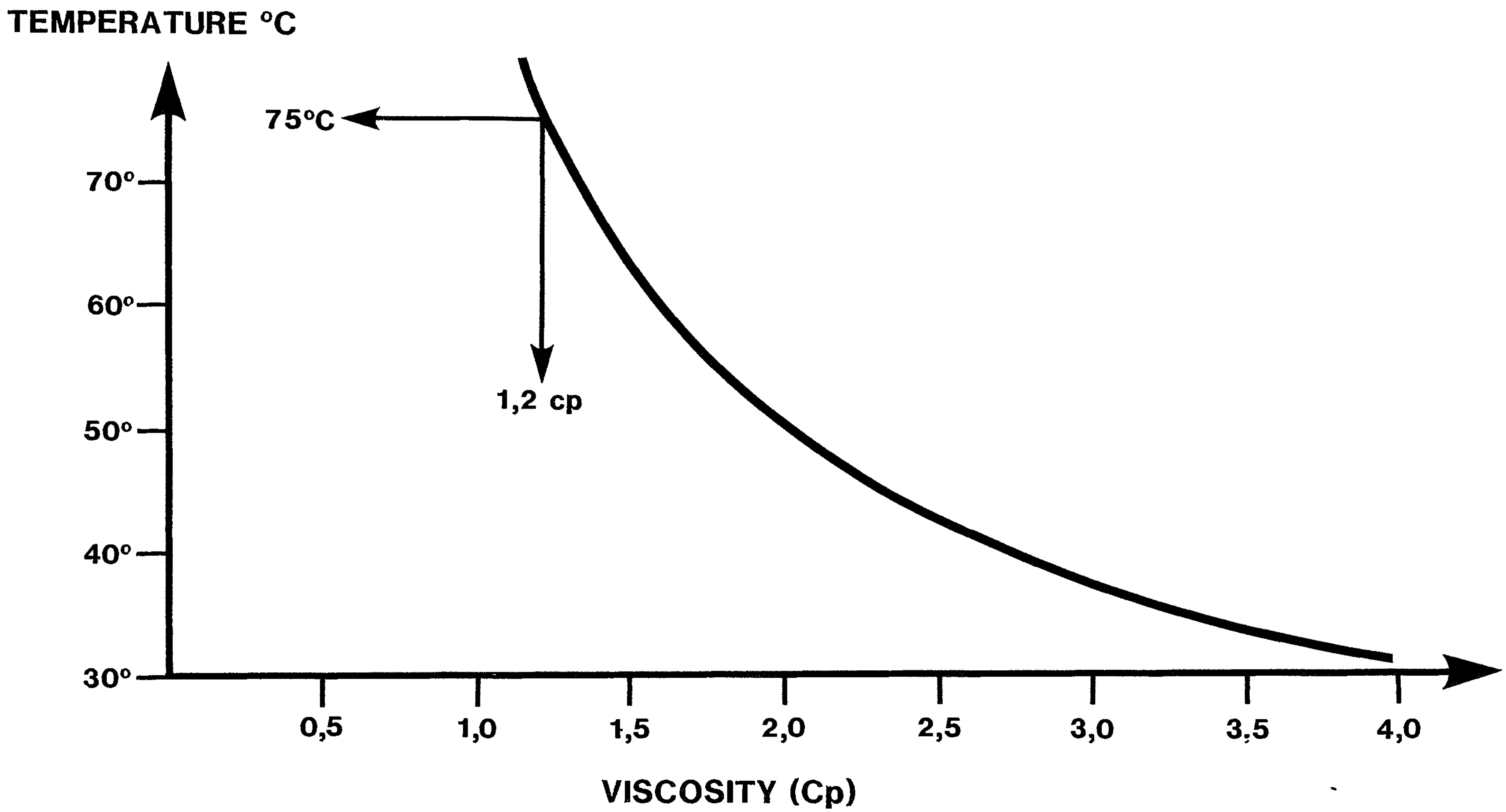


Fig.A3-14

III 4. WELLBORE SCHEMATIC 34/10-14

statoil
Den norske stats oljeselskap a.s

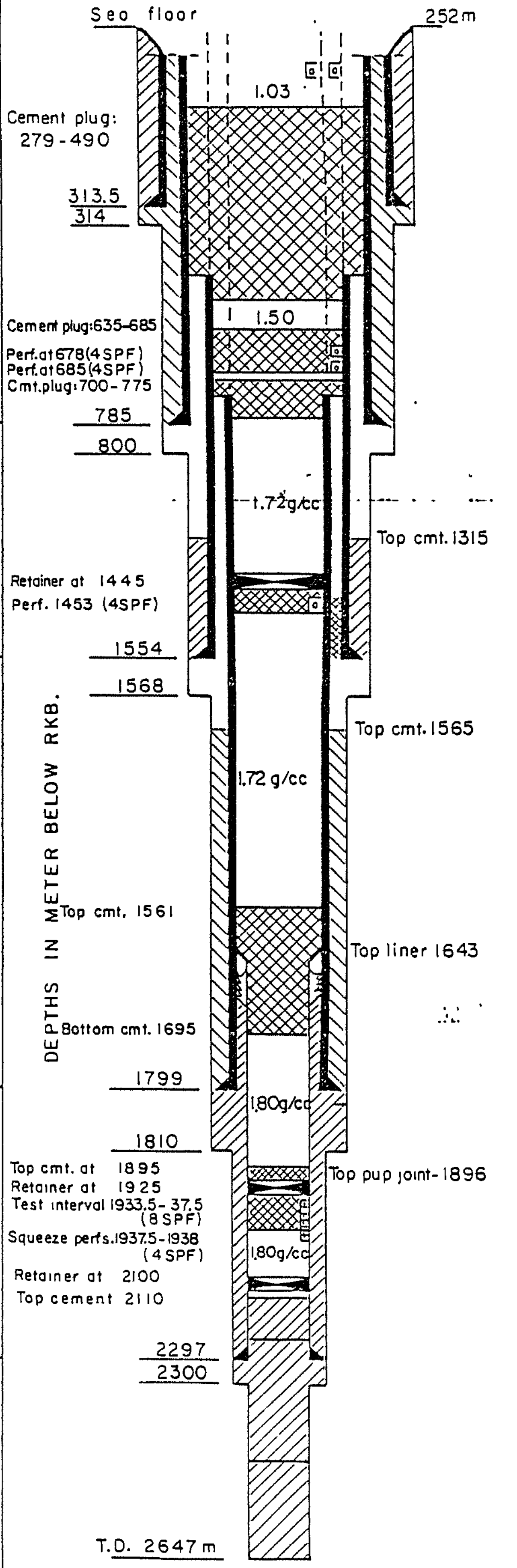
RKB - MSL: 25 m.

WATER DEPTH: 227 m.

(Not to scale)

Orginal arb. av: TJu
Tegnet av: AM
Dato: 7-5-82

Hole	Casing
36"	30" Grade B
26"	20" 94 lb/ft Vetco LS + 133 lb/ft Butt.K-55 Shoe joint float joint and X/O
17 1/2"	13 3/8" N-80 BUTT. 72 lb/ft
12 1/4"	9 5/8" N-80 BUTT 47 lb/ft 109 Joints + P-110 Butt. 47 lb/ft 20 Joints
8 1/2"	7" N-80 Butt. 29 lb/ft
6"	PLUGGED WITH CEMENT



Casing cement	Plugs/Squeeze
LEAD: 17.0 tons class "G" cement w/93.04 liter sea-water/100kg cement + 3.2 ltr. D-75/100kg cement to 1.56 g/cc. TAIL: 13.0 tons class "G" cement w/44.37 liter sea-water/100kg cement + 1kg $CaCl_2$/100kg cement to 1.91 g/cc	Cut 20" and 30" casing several times. Final cut at 256 m RKB. Perf. 9 5/8" csg. at 256m under pressure control. Perf. 13 3/8" at 265 m under pressure control. Cement plug: 490-275 m 39.4 m tons class "G" cement w/ 1% $CaCl_2$ to 1.90 g/cc. Tagged at 279m
LEAD: 106.3 tons class "G" cement w/92.8 liter sea-water/100kg cement + 4 ltr D-75/100kg to 1.56 g/cc. TAIL: 17.1 tons class "G" cement w/44.48 liter sea-water/100kg cement to 1.91 g/cc. Displaced w/1.15 g/cc mud.	Cut 13 1/8" csg. at 400.5m Tested 13 3/8"/20" csg. and perfs. at 678,685m to 110 bars. No leak off in pressure. Cement plug:685-635 m 5.1 m tons class "G" cmt. w/1% $CaCl_2$ to 1.90 g/cc. Isolation squeeze 13 3/8" x20": Perf. twice at 685m and 678m. Not able to inject w/138 bar press.
LEAD: 50.4 tons class "G" cement w/91.72 liter sea-water/100kg cement + 3.2 ltr. D-75/100kg + 1.33 ltr D-80/100kg + 0.9 ltr. D-81/100kg to 1.56 g/cc. TAIL: 20.4 tons class "G" cement w/43.18 ltr. fresh water/100kg cement + 0.09 ltr. D-81/100kg to 1.90 g/cc.	Cement plug: 775-675m 8.3 m. tons class "G" cement w/43.18 l/100kg fresh water to 1.90 g/cc Tagged cmt. at 679m. Dressed to 700 m. Cut 9 5/8" csg. at 735m. Isolation squeeze 9 5/8" x 13 3/8": 5.4 m. tons class "G" cement w/42.21 ltr.freshwater/100kg + 1.33 l D-73/100kg + 0.89 l D-80/100kg + 0.18 l D-81/100kg to 1.90 g/cc
LEAD: 9.6 tons class "G" cement w/41 liter fresh water/100kg cement + 1.78 ltr. D-73/100kg + 0.89 ltr. D-80/100kg + 0.27 ltr. D-81/100kg to 1.90 g/cc TAIL: 10.5 tons class "G" cement w/41.06 ltr. fresh water/100kg cement + 1.78 ltr. D-73/100kg + 0.89 ltr. D-80/100kg + 0.18 ltr. D-81/100kg to 1.90 g/cc. Lost circulation during mixing and displacement of cement	Cement plug, 1695-1550 m. 6.1 m. tons class "G" cement w/43.37 l/100kg fresh water + 0.09 l/100 kg D-81 to 1.90 g/cc Tagged hard cmt. at 1561 m. Tested to 69 bars diff. w/1.80 g/cc mud.
MUD SWEEP: 3.2 m^3 - 1.85 g/cc BJ-Mud Sweep. LEAD: 13.8 tons class "G" cement w/41.08 ltr. fresh water/100kg cement + 1.78 ltr. D-73/100kg + 1.78 ltr D-80/100kg + 0.27 ltr. D-81/100kg to 1.90 g/cc. TAIL: 12.3 tons class "G" cement w/41.14 ltr. fresh water/100kg cement + 1.78 ltr. D-73/100kg + 1.78 ltr D-80/100kg + 0.18 ltr. D-81/100kg to 1.90 g/cc.	Squeeze at 1933.5-1937.5m (Test interval) 6.3 m.tons class "G" cement + chemicals to 1.90 g/cc. Isolation squeeze at 1937.5-1938m (4SPF) Tested cmt. to 310 bars w/1.80 g/cc mud prior to run EZSV at 2100 m. Plug 3: 2150-2000 m. 3.8 m.tons class "G" cmt. w/43.4 l/100kg fresh wtr. + 0.89 l/100kg D-80 + 0.27 l/100kg D-81 to 1.90 g/cc. Tagged at 2054m,dressed to 2110m. Plug 2. 2407-2190m 5.5m.tons class "G" cmt. Composition as in plug no 1. 1.90g/cc. Plug 1. 2647-2437 m 5m. tons class "G" cement w/41.06 l/100kg fresh wtr + 1.78 l/100kg D-73 + 1.78 l/100kg D-80 + 0.27 l/100kg D-81 to 1.90 g/cc

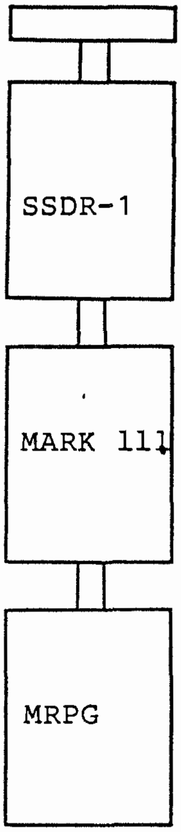
Well 34/10-14	LAYOUT OF TEST-STRING	
DST no 1		Perfs 1933.5-1937.5m RKB
		Zone tested BRENT (NESS)

TEST-STRING	ID inch	OD inch	LENGTH m	DEPTH mRKB
TUBING ABOVE RKB				- 5.54
2 JOINTS 3½" TDS 12.71bs/ft L-80 TUBING	2.75	4.25	18.59	13.05
3½" TDS BOX x 4½" OTIS ACME PIN	-	6.00	0.35	13.40
OTIS LUBRICATOR VALVE, 4½" OTIS ACME BOX xPIN	2.90	13:0/ 10.75	1.74	15.14
STATOIL x10, 4½" OTIS ACME BOX x 3½" TDS PIN	-	6.00	0.40	15.54
3½ " TDS PUP JOINT	2.75	4.25	2.55	18.09
24 JOINTS (8STDS) 3½" TDS TUBING	2.75	6.00	221.85	239.94
3½" TDS PUP JOINT	2.75	4.25	2.86	242.80
x/O 3½" TDS BOX x 4½" OTIS ACME PIN (HANDL.SUB)	-	6.00	0.61	243.41
OTIS SSTT	2.90	13.00	2.17	245.58
3½" SLICK JOINT	1.98	3.50	2.13	247.71
x/O 4½" ACME BOX x BOX	-	6.00	0.33	248.04
ADJUSTABLE HANGER SECTION	-	5.00	0.67	248.71
FLUTED HANGER- WEARBUSHING DEPTH	-	18.00	0.16	248.87
ADJUSTABLE HANGER SECTION	-	5.00	0.46	249.33
x/O 4½" OTIS ACME BOX x 3½" TDS PIN	-	6.00	0.38	249.71
3½" TDS PUP JOINT	2.75	4.25	2.52	252.23
148 JOINTS(49STDS + 1SINGLE) 3½" TDS TUBING	2.75	4.25	1377.69	1629.92
x/O 3½"TDS BOX x 3½" IF PIN (T-3)	2.25	4.50	0.40	1630.32
SLIP JOINT (OPEN) 5' STROKE	2.25	5.00	5.54	1635.86
SLIP JOINT (CLOSED)	"	"	4.02	1639.88
SLIP JOINT (CLOSED)	"	"	4.02	1643.90
DRILLCOLLARS - 6 STDS (25000 lbs)	"	4.75	171.12	1815.02
x/O 3½"IF BOX x 2 7/8" EUE PIN	2.37	"	0.23	1815.25
RTTS MECHANICAL CIRCULATING VALVE	2.44	4.62	0.92	1816.17
x/o 2 7/8"EUE BOX x 3½" IF PIN	2.62	4.50	0.20	1816.37
DRILLCOLLARS - 1 STD	2.25	"	28.52	1844.89
SLIPJOINT (CLOSED)	"	5.00	4.02	1848.91
DRILLCOLLARS - 1 STD	"	4.75	28.52	1877.43
APR-M CIRC./ SAFETY VALVE	2.00	4.62	1.85	1879.28
APR-N TESTER VALVE	"	"	3.89	1883.17
FUL FLO HYDRAULIC BYPASS	2.25	"	2.08	1885.25
BIG JOHN JAR	2.37	"	1.58	1886.83
RTTS SAFETY JOINT	2.44	4.87	0.82	1887.65
RTTS PACKER - ABOVE	"	5.75	0.51	1888.16
RTTS PACKER - BELOW (2 7/8"EUE BOX DOWN)	"	"	0.81	1888.97
2 7/8"EUE PERF. PUP JOINT	2.25	2.875	3.40	1892.37
2 7/8"EUE COLLAR	-	3.5/8	0.13	1892.50
x/O 2 7/8"EUE PIN x 2 3/8"EUE PIN (T-27)	2.00	3 1/8	0.19	1892.69
2 3/8"EUE COLLAR	-	3 1/16	0.13	1892.82
OTIS"XN" NIPPLE 2 3/8"EUE PIN x PIN	1.875	2.75	0.21	1893.03

Well 34/10-14	LAYOUT OF TEST-STRING	Perfs 1933.5-1937.5m RKB
DST no 1		Zone tested BRENT (NESS)

TEST-STRING	ID inch	OD inch	LENGTH m	DEPTH mRKB
2 3/8" EUE COLLAR	-	3 1/16	0.13	1893.16
x/O 2 3/8" EUE PIN x 2 7/8"EUE PIN (T-48)	2.00	3 1/8	0.10	1893.26
2 7/8" EUE TUBING	2.25	3 5/8	9.39	1902.65
2 7/8" EUE PUP JOINT W/ 2 HOLES	"	"	2.03	1904.68
2 7/8" EUE COLLAR	-	"	0.13	1904.81
2 7/8" EUE PIN x PIN, BLIND SUB (T-22)	-	3 1/8	0.25	1905.06
2 7/8" EUE PUP JOINT	2.25	3 5/8	2.39	1907.45
FLOPETROL DST HGR.	-	-	-	-
2 7/8" EUE TUBING JT.	2.25	3 5/8	9.40	1916.85
2 7/8" EUE PERF. PUP JT.	"	"	3.02	1919.87
2 7/8" EUE COLLAR	-	"	0.14	1920.01
2 7/8" EUE PIN x 2 3/8" EUE PIN	1.875	3.75	0.29	1920.30
2 3/8" EUE BOX x 3 1/8" 8N PIN	2.00	3 7/8	0.12	1920.42
HALLIBURTON GAUGE CARRIER	3.00	3.75	1.10	1921.52

Well 34/10-14	GAUGE ARRANGEMENT	
		Perfs.: 1933,5-1937,5mRKB
DST no. 1		Zone tested BRENT (NESS)

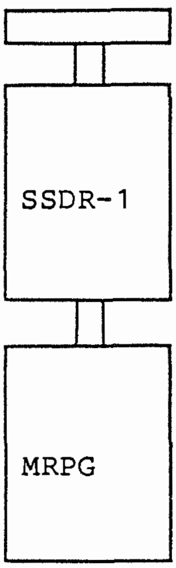


WIRELINE NIPPLE at 1892.8m mRKB

Gauge type and number : FLOPETROL SSDR-1, No. 81086
Depth, pressure elemement : 1897.3m Range : 10 000 psi
Mode : 1 min Delay : 0
Actuated : time 04:32 date : 1.3-82
Will run out : time 13:25 date : 4.3-82

Gauge type and number : SPERRY-SUN, MARK 111, No. 1576
Depth, pressure elemement : 1900.01m Range : 10 000 psi
Mode : 4 min Delay : 17 hrs
Actuated : time 04:25 date : 1.3-82
Will run out : time 13:25 date : 6.3-82

Gauge type and number SPERRY-SUN, MRPG, No. 0136
Depth, pressure elemement : 1902.64m Range : 10 000 psi
Mode : 2 min Delay : 17 hrs
Actuated : time 04:26 date : 1.3-82
Will run out : time 05:26 date : 4.3-82



D.S.T. HANGER at 1907.4m mRKB

Gauge type and number : FLOPETROL, SSDR-1, No. 81048
Depth, pressure elemement : 1911.3m Range : 10 000 psi
Mode : 2 min Delay : 0
Actuated : time 04:28 date : 1.3-82
Will run out : time 22:28 date : 6.3-82

Gauge type and number : SPERRY-SUN, MRPG, No. 0182
Depth, pressure elemement : 1914.16m Range : 10 000 psi
Mode : 4 min Delay : 17 hrs
Actuated : time 04:07 date : 1.3-82
Will run out : time 13:07 date : 6.3-82

Well 34/10-14 DST no. 1	DIARY OF EVENTS	Perfs.: 1933,5-1937,5 Zone tested BRENT (NESS)

Date	Time	OPERATIONS
		ISOLATION SQUEEZE
27.02	10.40	Rigged up Schlumberger, perforated
		1937.5-1938 m RKB (4 sh/ft)
	19.00	Squeezed cement using RTTS packer
28.02	19.10	Rigged up Schlumberger and ran CBL/VDL log
		Cement job OK
		PERFORATING
01.03	00.30	Hooked up first perforating gun, RIH and perforated
		perforated 1935,5-1937,5 m RKB. POOH
	03.00	RIH w/perf. gun no.2, perforated at same depth,
		i.e. 8 sh/ft, 90°facing, total of 208 shots.
		POOH. All shots fired
		TESTSTRING RUN
	04.37	Started to run test string
		Finished running test-string
	22.15	Sat packer at 1889 m RKB
		FIRST FLOW PERIOD
	23.03	Opened APR-N valve, annulus pressure 103 bar
		and WHP = 111.4 bar
	23.06	Opened well on 24/64" adj. choke to gas flare
	23.21	Increased to 28/64" adj. choke
	23.26	Increased to 34/64 adj. choke
	23.27	Switched to 34/64" fixed choke
	23.28	Mud to surface
	23.30	Gas to surface
02.03	00.30	Swithched flow through heater (Temp. = 52°C)

Well 34/10-14 DST no. 1	DIARY OF EVENTS	Perfs. 1933,5-1937,5m Zone tested BRENT (NESS)

Date	Time	OPERATIONS
02.03	00.53	Switched flow through separator
	03.45	Switched flow through surge tank
	04.37	Switched flow to burner
	06.25	Switched flow through surge tank
	06.58	Switched flow to burner
	06.20	Started 1. set of p.v.t. samples on separator
	07.20	Started 2. set of p.v.t. samples on separator
	08.00	Sampled 1.5 m^3 separator oil
		BUILD-UP PERIOD
02.03	08.31	Closed APR-N valve
	08.32	Closed choke manifold
	11.00	Sampled 4 x 1.5 m^3 surge tank oil
	14.59	Opened APR-N valve, annulus pressure 103 bar WHP = 160.3 bar
		BOTTOM HOLE SAMPLING
	15.06	Opened well on 12/64" adj. choke
	15.08	Plugging of 12/64" fixed choke
	15.40	Switched flow through separator
	17.12	Closed choke-manifold, WHP = 160.1 bar
	17.19	Closed lubricator valve. Leak in kill line
	17.25	Started rigging up wire-line
	22.14	Opened lubricator valve, WHP = 161.2 bar
	22.16	R.I.H w/B.H.S (150 ft/min)
	22.25	Opened up on 8/64" adj. choke. Plugging
	22.32	Opened up on 8/64" fixed choke.
	22.43	Samplers at sampling depth; 1830 m RKB
	23.25	Plugging of 8/64" fixed choke
	23.28	Opened up on 10/64" adj. choke
	23.40	Samplers closed

Well 34/10-14 DST no. 1	DIARY OF EVENTS	Perfs. :1933.5-1937.5mRKB Zone tested BRENT (NESS)

Date	Time	OPERATIONS
03.03	24.00	POOH w/B.H.S.
	00.06	Closed choke manifold, WHP = 161.3 bar
	00.29	Samplers in lubricator
	00.34	Closed lubricator valve
	01.10	Samplers out of hole. 1 sample OK
		WATER INJECTION
	04.02	Started displacing string with sea water.
	05.02	String displaced, started injection of sea water into formation, rate = 3 bbls/min
	05.45	Increased injection rate to 4 bbls/min
	06.05	Increased injection rate to 5 bbls/min
	20.49	Closed kill-valve, due to leak in kill-line
	22.51	Opened kill-valve, started to inject 2 bbls/min
	22.57	Increased injection rate to 4 bbls/min
	23.05	Increased injection rate to 5 bbls/min
05.02	05.00	Closed kill-valve
	12.00	End of "fall-off"

Well 34/10-14	FLOW DATA	Perfs.: 1933.5-1937.5m RKB
DST no. 1		Zone tested BRENT(NESS)

Date/ time	Bottom hole		Well head		Chokes 1/64"		Separator data							Liq. and gas analysis					
	press. bar	temp. °C	press bar	temp. °C	manifold	heater	press. bar	temp. °C	gas rate 10/Sm^3/d	oil rate Sm^3/d	GOR Sm^3/Sm^3	sp.gr.oil	sp.gr.gas	Water %	Sedim. %	CO_2	H_2S		
2.00			118.4	28.9	34	-	43.8	48.9	51933	740.0	70.0	0.878	0.61	0	0		0		
2.30			118.5	29.4	"	-	43.9	48.9	50885	702.1	72.5			0	0	0.01	0		
3.00			118.0	30.6	"	-	44.8	48.9	50885	707.6	71.9		0.61	0	0		0		
3.30			117.8	31.1	"	-	43.8	48.9	50885	705.1	72.2			0	0		0		
4.00			117.8	31.7	"	-	43.8	48.9	50687	700.8	72.3	0.877		0	0		0		
4.30			117.7	31.7	"	-	43.8	48.9	50687	700.8	72.3		0.61	0	0	0.01	0		
5.00			118.0	32.2	"	-	43.8	48.9	50687	697.7	72.6	0.877	0.61	0	0		0		
5.30	ADJUST CONTOLLERS FOR BETTER SEPATATION. NO READING TAKEN.																		
6.30			118.0	32.8	34	-	43.9	48.9	47601	798.2	59.6		0.61	0	0		0		
7.00			118.2	33.3	"	-	43.9	48.9	47601	695.3	68.5	0.878	0.61	0	0		0		
7.30			118.1	33.3	"	-	43.9	48.9	47601	714.3	66.6		0.61	0	0	0.01	0		
8.00			118.1	33.3	"	-	43.9	48.9	47601	713.1	66.8		0.61						
8.30			118.1	33.3	"	-	43.9	48.9	47601	713.7	66.7	0.877	0.61						

Remarks

WHP: LYNES SURFACE PROBE
BHP & BHT: FLOPETROL SSDR-1 no. 81048
REST OF DATA FROM OTIS TEST-REPORT

TableA5-1

CORES 34/10-14

CORE NO.	DEPTH (MKB)	TOT. (M)	REC. (M)	RECOVERY %
1	1889.0-1907.8	18.8	7.0	39
2	1907.8-1925.0	17.2	14	78
3	1925.0-1939.5	14.5	7.7	53
4	1939.5-1957.0	17.5	9.9	57
5	1957.0-1972.5	15.5	15.5	100
6	1972.5-1991.0	18.5	17.9	97
7	1991.0-2010.0	19.0	18.4	97
8	2010.0-2028.0	18.0	18.0	100
9	2028.0-2047.0	19.0	19.0	100
10	2210.0-2228.0	18	15	83

BRENT FORMATION

MEMBER	DEPTH; m RKB
NESS	1908-1976
ETIVE	1976-2003
RANNOCH I	2003-2062
RANNOCH II	2062-2069
BROOM	2069-2080

TableA5-2

Well 34/10-14	SAMPLING	
DST no 1		Perfs.: 1933,5-1937,5
		Zone tested BRENT (NESS).

SEPARATOR SAMPLES

Time/date	Sample no.	Type of sample	Transfer time	Bottle no
06:20/2/3	1	OIL	30 min	001 AD
06:20/2/3	1	GAS	30 min	001 124
07:20/2/3	2	OIL	30 min	001 AF
07:20/2/3	2	GAS	30 min	001 116
08:00/2/3		OIL	(1x1,5m^3 CONTAINER)	
09:00/2/3		OIL	(4x1,5m^3 CONTAINERS)	
09:00/2/3		OIL	(5x20 l JERRY CANS)	
09:00/2/3		OIL	(5x10 l JERRY CANS)	

BOTTOM HOLE SAMPLES

Time/date	Sample depth mRKB	Estimated PB bar/°C	Transfering pressure(bar)	Bottle no
23:40/2/3.	1830	262/7,2	262	80016

WELLHEAD SAMPLES

Time/date	Sampling point	Sampling equipment	Remarks
02:30/2/3	GOOSE NECK	1 l GLAS BOTTLES	
03:30/2/3	" "	" " "	
04:30/2/3	" "	" " "	
05:30/2/3	" "	" " "	
06:30/2/3	" "	" " "	
07:30/2/3	" "	" " "	

TableA5-3

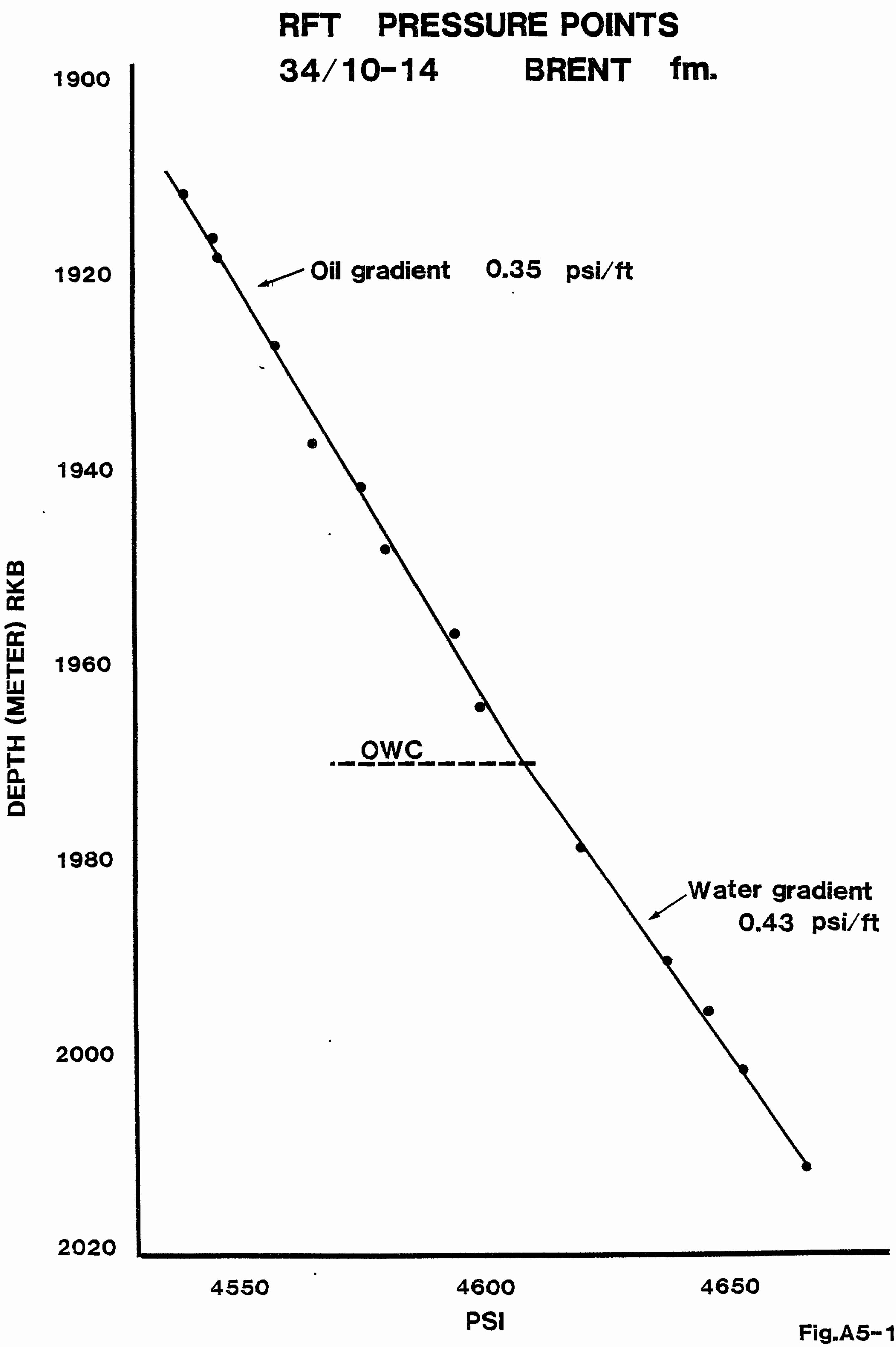

RFT PRESSURE POINTS
34/10-14 BRENT fm.
1900
1920
1940
1960
1980
2000
2020
DEPTH (METER) RKB
Oil gradient 0.35 psi/ft
OWC
Water gradient
0.43 psi/ft
4550
4600
4650
PSI

Fig.A5-1

REPEAT FORMATION TESTER

Two RFT runs were made before the liner was run. 15 pressure points and 2 segregated samples were taken.
All the pressure points were successfully taken. The pressure vs depth plot is shown on Fig. A5-1. This gives an oil water contact at 1969.5 m RKB, and an oil gradient of 0.35 psi/ft.

Table A5-4 and A5-5 shows all the pertinent data concerning the fluid samples.
Sample no. 1 only contained water and mud-filtrate, and sample no. 2 had a leaking valve, shown by the fact that the bubblepoint changed between two analysis of this bottle. It was therefore decided to use the recombined samples from the seperator to describe the reservoir fluid.

RFT - SAMPLING DATA

Well: 34/10-14

Date: 30/1-1982

Run no.: 1

Type of sample (Segregated)

Chamber size, lower 1 gal

upper 2 3/4 gal

Choke sizes: 8 * 0.020

Filter size: "

Depth	m RKB	1961.5
Log hydr. pres. bef. setting	psi	5100
Log pretest pressure	psi	4590
Cor. pretest pressure	psi (g/cc)	4580
Upper chamber		
Time opened		20^{10}
Log flowing pressure	psi	Variable due
Log shut in pressure	psi	To plugging
Time sealed		21^{10}
Cor. flowing pressure	psi	
Cor. shut in pressure	psi (g/cc)	
Lower chamber		
Time opened		21^{11}
Log flowing pressure	psi	3600
Log shut in pressure	psi	3800
Time pealed		21^{16}
Cor. flowing pressure	psi	
Cor. shut in pressure	psi (g/cc)	
Log. hydr. pres. after retracting	psi	5090
Max recorded temp.	^{o}F	160
Surf-pressure, lower ch.	psi	1700 - Flopetrol bottle
Surface pressure, upper ch.	psi	1600

TableA5-4

RFT - SAMPLING DATA

Well: 34/10-14

Date: 30/1-1982

Run no. 2

Type of sample (Segregated)

Chamber sizes, lower 1 gal

upper 2 3/4 gal

Choke sizes: 4 * 0.020 + 4 * 0.015

Filter size:

Depth Log hydr. pres. bef. setting Log pretest pressure Cor. pretest pressure	m RKB psi psi psi (g/cc)	1917.5 4987 4546 4536
Upper chamber Time opened Log flowing pressure Log shut in pressure Time sealed Cor. flowing pressure Cor. shut in pressure	 psi psi psi psi (g/cc)	 12^{35} 12^{52}
Lower chamber Time opened Log flowing pressure Log shut in pressure Time sealed Cor. flowing pressure Cor. shut in pressure	 psi psi psi psi (g/cc)	 12^{53} 01^{00}
Log. hydr. pres. after retracting Max recorded temp. Surf-pressure, lower ch. Surface pressure, upper ch.	psi ^{o}F psi psi	4981 160^{o} 1900 - Flopetrol bottle 1800

PVT analysis

The seperator samples were most representative for the reservoir fluid and a PVT-study was performed on a recombined sample.

Main results:

Bubble point 211.0 barg

	at P_B	at P_i = 316 Barg
Density (g/cm^3)	0.772	0.769
Compressibility (bar^{-1})	1.29×10^{-4}	1.14×10^{-4}
Viscosity (cp)	1.10	1.215
B_o single flash (m^3/m^3)	1.244	1.228

From single flash (300 barg, 73.3°C to atmosphere, 15°C).

GOR	:	83.3 Sm^3/m^3
Density of oil 0.88(g/cm^3)	:	29.4 °API
Density of gas	:	(air = 1.0) 0.67
B_o	:	1.228 Res m^3/m^3

Composition of reservoir liquid

	mol %
Nitrogen	0.79
Carbon dioxide	0.15
Methane	42.16
Ethane	3.67
Propane	1.24
iso-butane	0.58
n-butane	0.74
iso-pentane	0.71
n-pentane	0.44
Hexanes	1.22
Heptanes plus	48.30

The oil formation volume factor and solution gas oil ratio vs. pressure are shown on Fig. A5-2.
The viscosity vs. pressure are shown on Fig. A5-3.

The oil confirms the data from 34/10-9, which forms the basis for the reservoir fluid east of the main fault.

PVT PROPERTIES 34/10-14

RECOMBINED SAMPLE

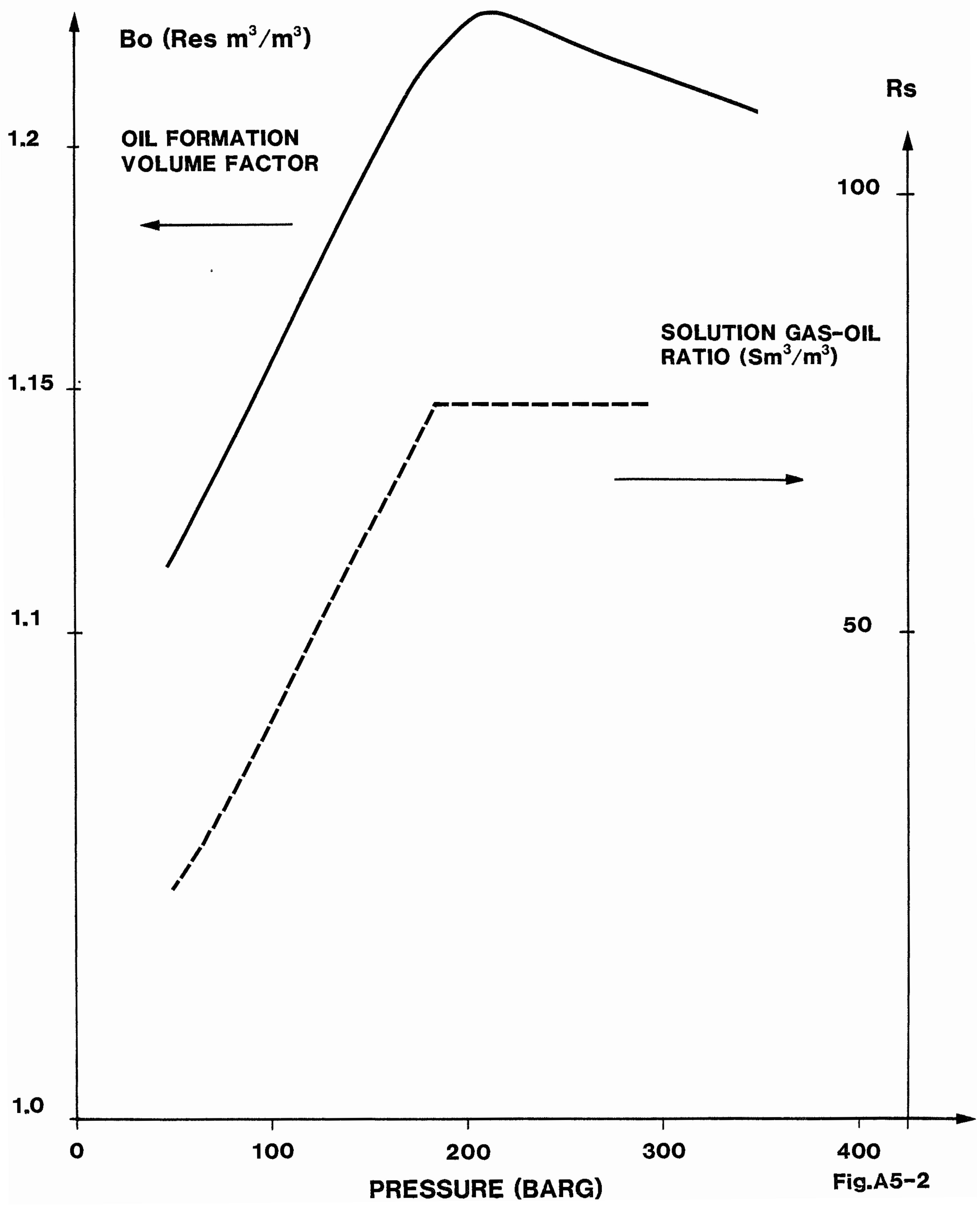


Fig.A5-2

PVT PROPERTIES 34/10-14

RECOMBINED SAMPLE

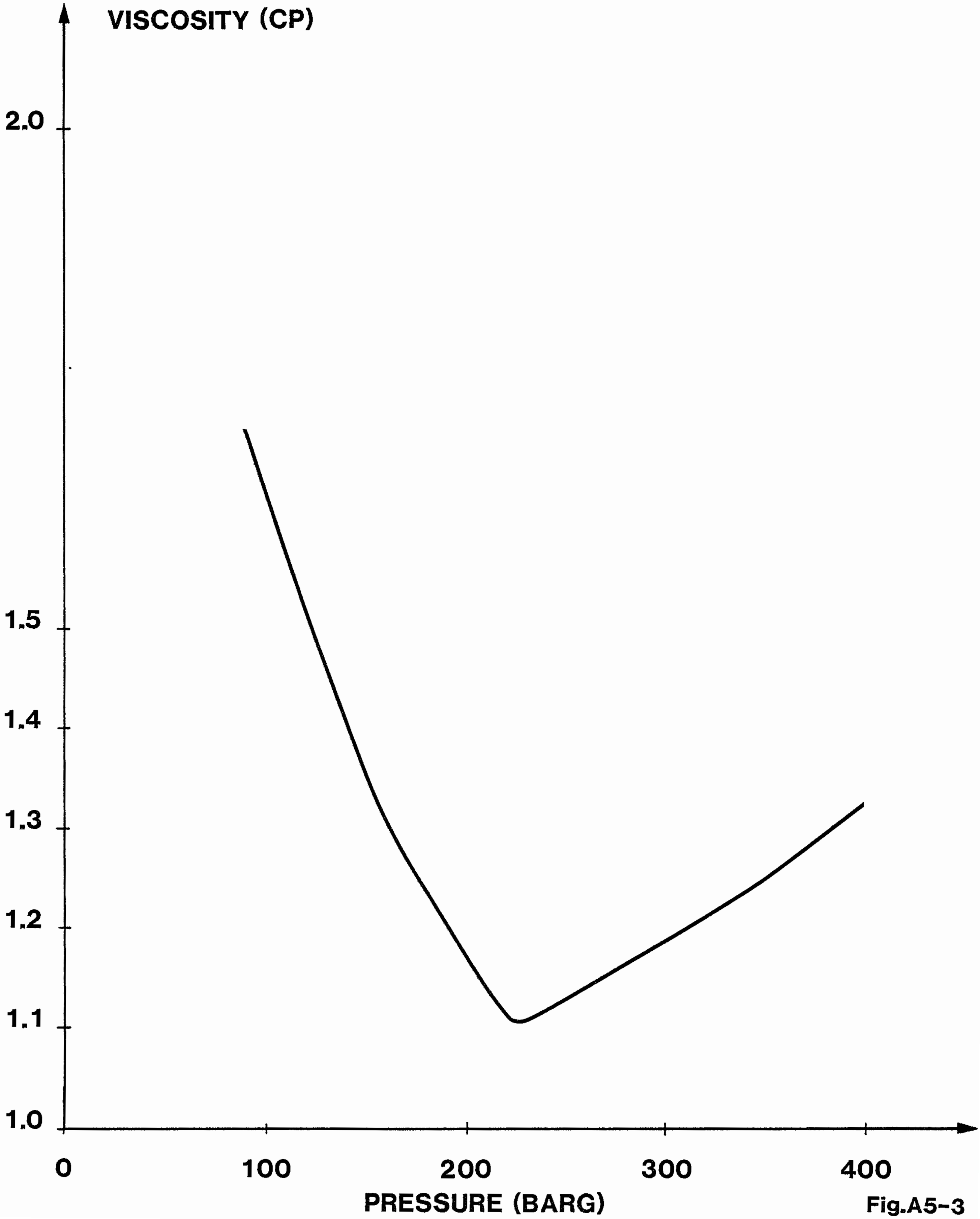


Fig.A5-3

GRAPHICAL LØG-PRESENTATIØN

WELL : 34-10-14 DEPTH INTERVALL :1908.00-2000.00 (METER)

ENGINEER :EAA SCALE 1:200

DATE: 13.08.35 12 AUGUST 1982

STATØIL

STRATIGRAPHY (REF. RKB)	ACTUAL
TØP NESS	1908 M
TØP ETIVE	1976 M
TØP RANNØCH	2003 M
TØP BRØØM	2069 M

P E T R Ø P H Y S I C A L E V A L U A T I Ø N

INPUT PARAMETERS

RW=0.073 RMF=0.10 RSH=X.XX PHINSH=X.XX RHØHC=0.8 G/(CC**3)

M=2 N=2 A=1 RHØBSH=X.XX TEMP=160 (DEG. F)

PØRØSITY

	FDC	CNL
QUARTZ	2.65	-0.035
HEAVY MINERAL	2.90	0.25
FLUID	1.0	1.0

STATISTICS

FØRMATIØN	NET-PAY	NET-SAND	AVR PHI	AVR SW	AVR VSH
NESS	26.00		32.0%	32.8%	7.6%
ETIVE		26.0	33.3%	100.0%	2.3%
RANNØCH		43.25	31.5%	100.0%	8.5%
BRØØM		2.5	21.3%	100.0%	19.6%

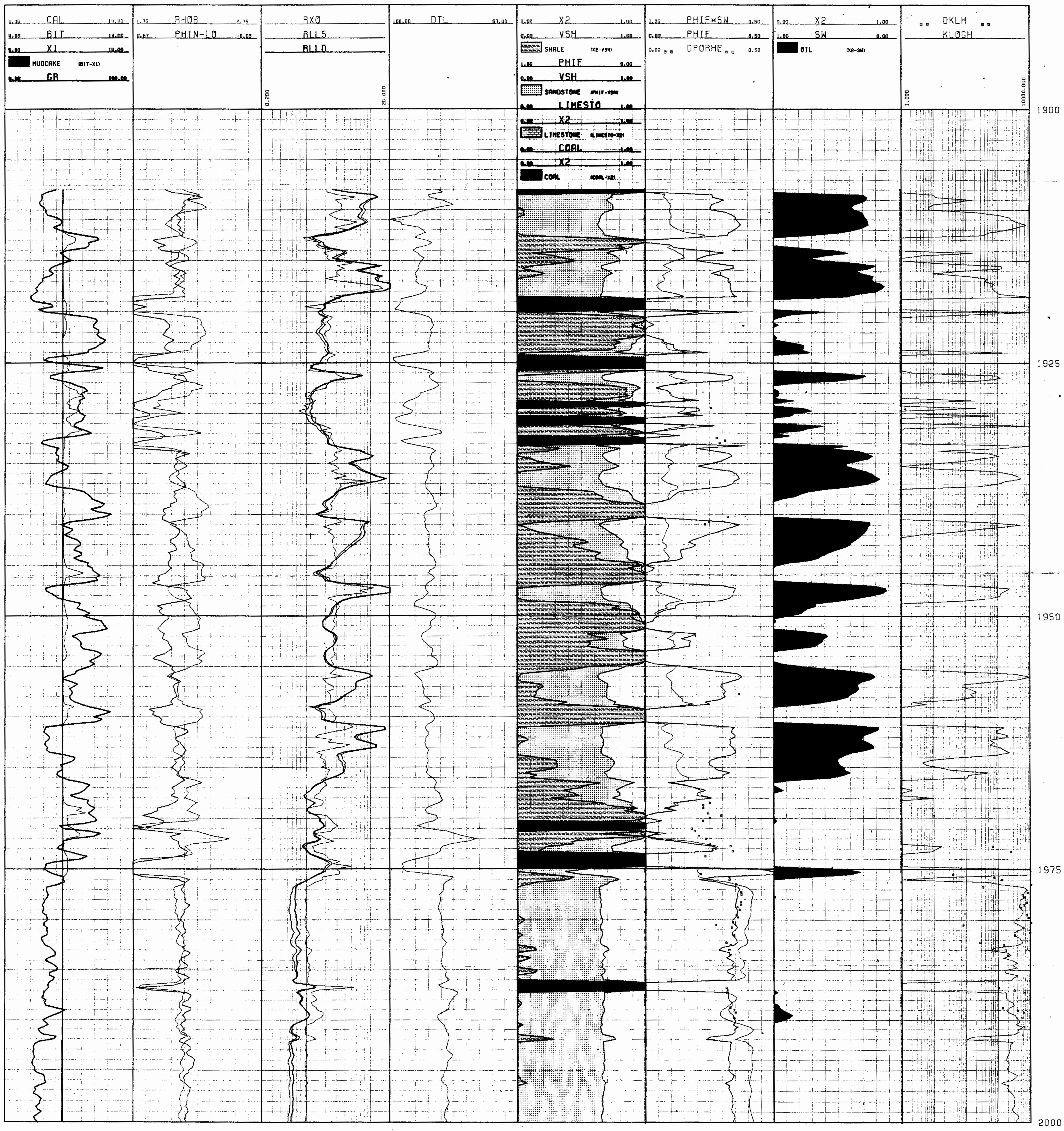
CURVE IDENTIFICATIØN

	REMARKS	LØG
CAL = CALIPER (INCH)		DLL-MSFL
BIT = BIT SIZE (INCH)		
GR = GAMMA RAY (API UNITS)		FDC/CNL
RHØB = BULK DENSITY (G/CM**3)		FDC
PHIN = NEUTRØN PØRØSITY (L.S. UNITS)		CNL
RXØ = MICRØSPHERICAL RESISTIVITY (ØHMM)		MSFL
RLLS = DUAL LATERØLØG -SHALLØW (ØHMM)		DLL
RLLD = DUAL LATERØLØG -DEEP (ØHMM)		DLL
DT = SØNIC (MICRØSEC/FEET)		BHC

VSH = SHALE VØLUME (FRACTIØNS)	CØMPUTED
PHIF = FINAL PØRØSITY (FRACTIØNS)	CØMPUTED
DPØR = CØRE PØRØSITY DEPTH SHIFTED (%)	FRØM CØRE
DRHØMA = GRAIN DENSITY DEPTH SHIFTED (G/CM**3)	NØT AVAIL
RHØMAA = APPARENT MATRIX DENSITY (G/CM**3)	NØT AVAIL
SW = WATER SATURATIØN (FRACTIØNS)	CØMPUTED
DKH = HØRIZ. PERMEAB. DEPTH SHIFETED (M-DARCY)	FRØM CØRE
KLØGH = CALCULATED PERMEABILITY (K-\ RELATIØN)	CØMPUTED

NØTE: HELIUM PØRØSITY (DPØRHE) FRØM CØRE ANALYSIS ARE DEPTH-CØRRECTED TØ MATCH FIN. PØR. (PHIF).
SAME DEPTH CØRRECTIØNS APPLIED TØ HØRISØNTAL PERMEABILITY

PREPARED BY: E.AABØE



A6 SIMULATION OF FALL-OFF TEST

A radial simulator has been set up and run with pertinent data from 34/10-14.

The objective of running this simulator was to verify the theory given in appendix A1.

Conclusion

The leading edge of the water are influenced by gravity forces and the water front moves exactly like the theory in appendix A1 describes.

This is shown on fig. A6-1 and A6-2 where the results from the reservoir simulation model are plotted together with the results from the theory in appendix A1.

The output from the model has numerical dispersion which means that a criterium for the water front saturation has to be chosen.

In these cases the saturation at the front 0,25 m from bottom, which is the senter for block 8 in the model, is used as criterium. The distance from the wellbore is taken from the theory in appendix A1 and shown on figs. A1-3 and A3-7. Two cases A and B have been run.

Case A: M=2: K_{rw} at S_{or} = 0,27
Case B: M=3: K_{rw} at S_{or} = 0,40

The relative permeability for these runs are shown on fig. A6-3.

The input from the model with M=3 are shown on the following pages together with the output. The model is run for 2760 minutes which is the total injection time for the injection test. The saturation distribution for the same model with M=2 are shown on table A6-1.

GULLFAKS

WATER INJECTION TEST 34/10-14

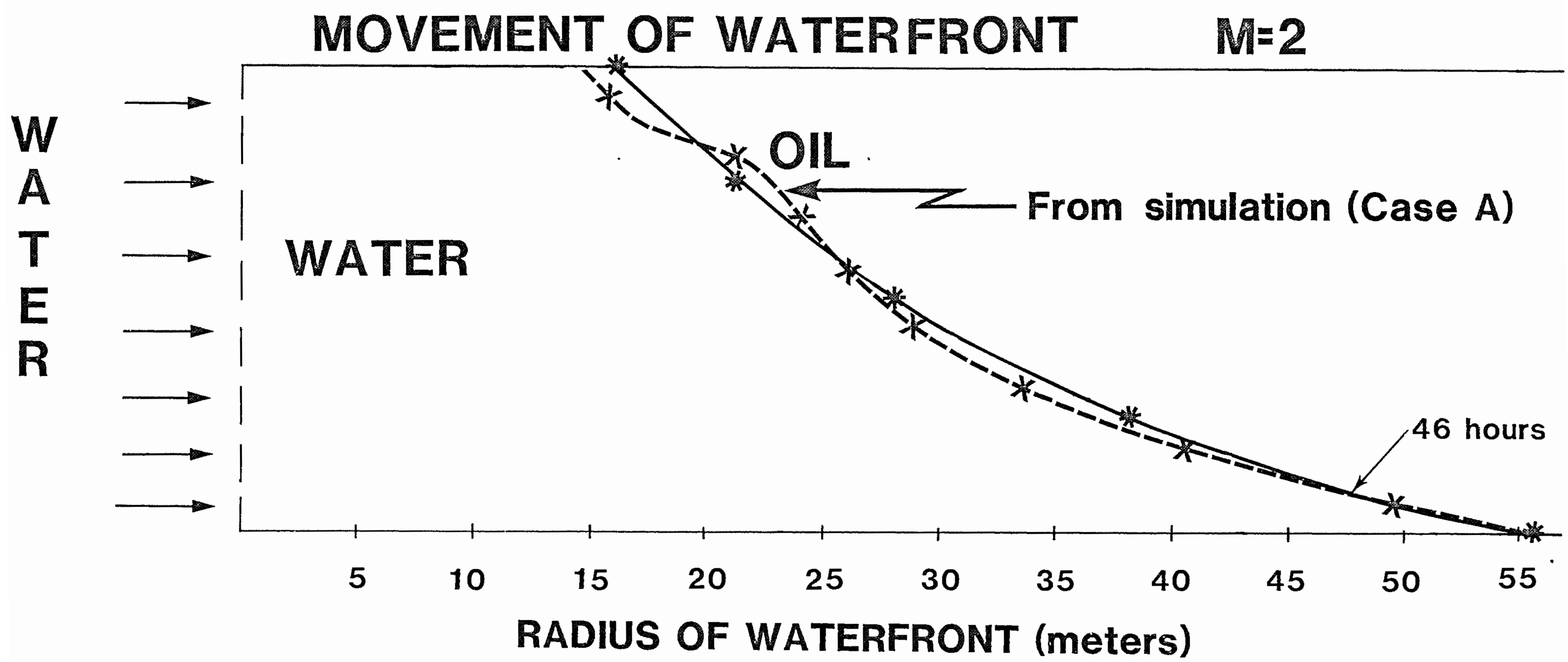


Fig.A6-1

WATER INJECTION 34/10-14

WATERFRONT BEFORE SHUT-IN

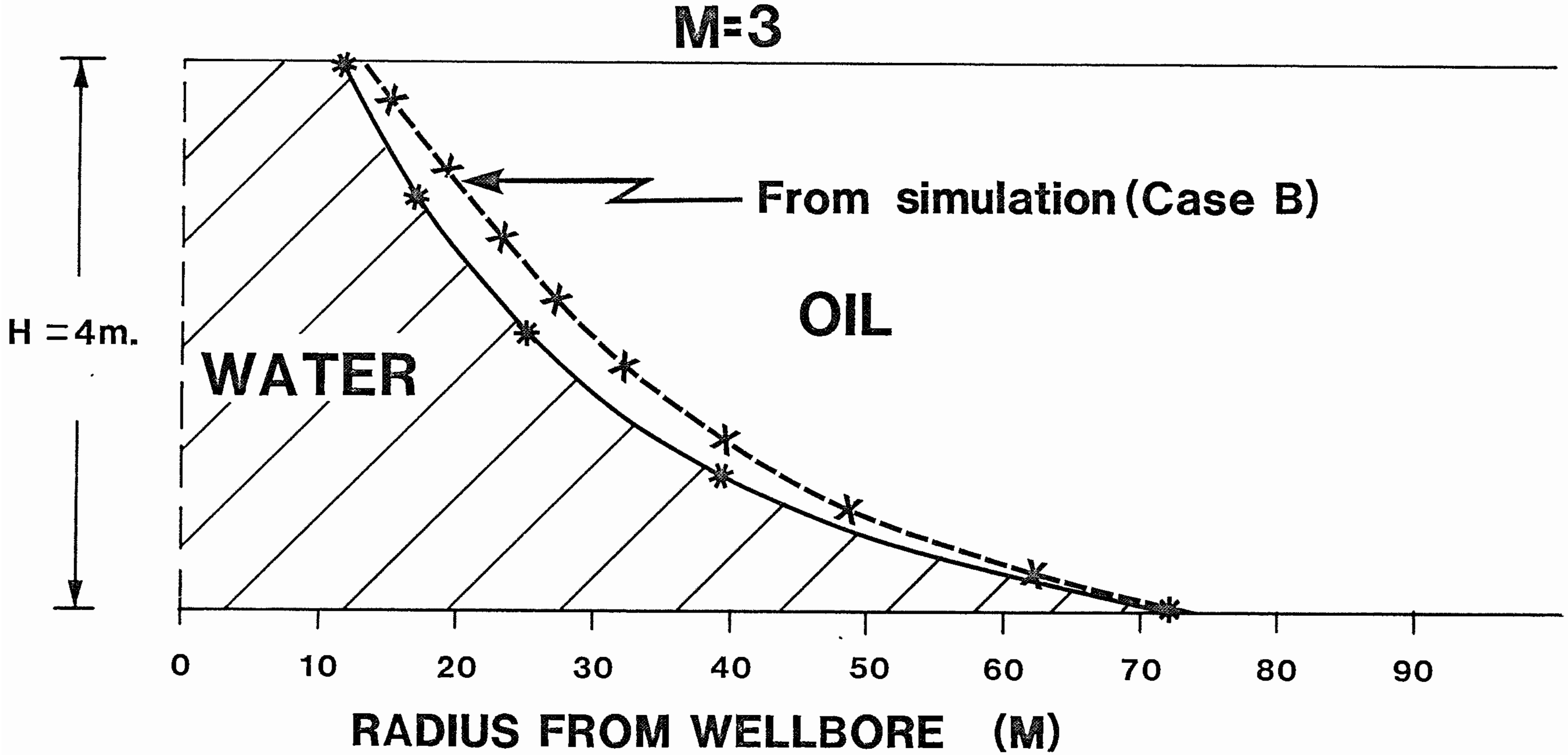


Fig. A6-2

RELATIVE PERMEABILITY

INPUT TO RESERVOIR SIMULATION MODEL

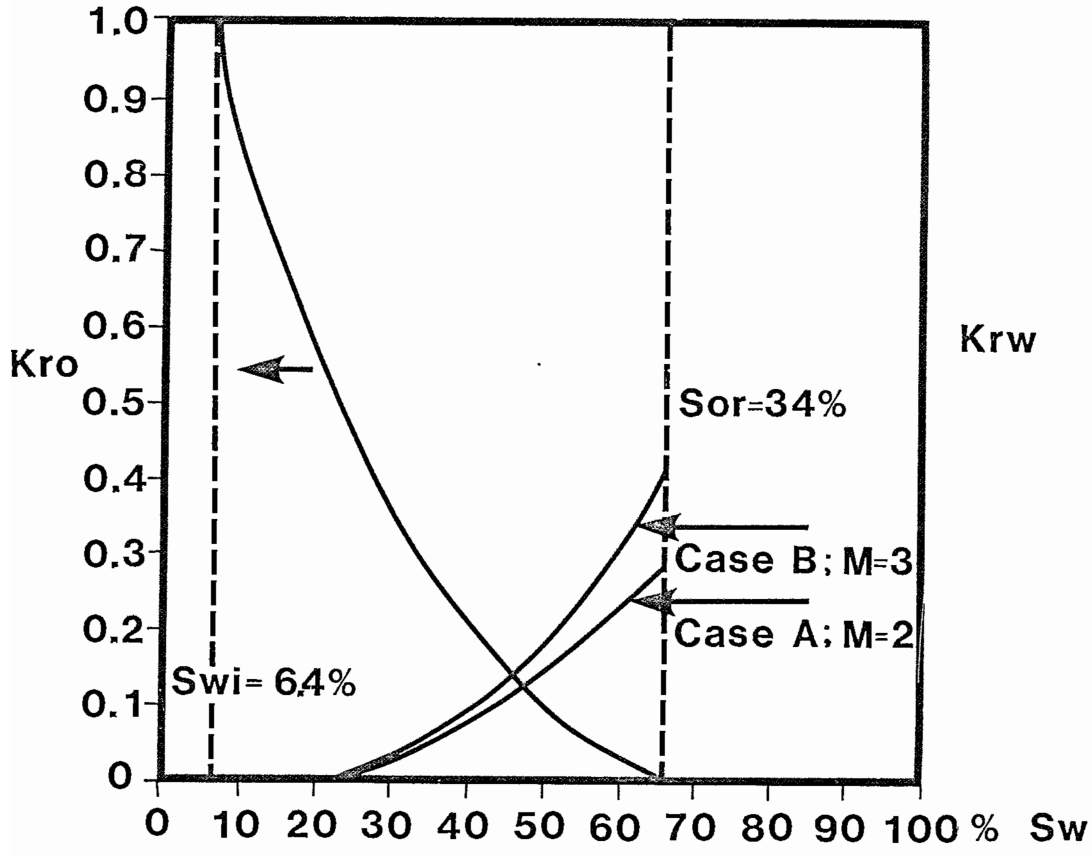


Fig. A6-3

SATURATION DISTRIBUTION

at 2760 mins.

M=2

OIL SATURATION (FRACTION)

J \ I	1	2	3	4	5	6	7	8	9	10	11	12
1	0.3400	0.3400	0.3400	0.3400	0.3400	0.3401	0.3429	0.3630	0.4201	0.5080	0.5957	0.6550
2	0.3400	0.3400	0.3400	0.3400	0.3400	0.3400	0.3405	0.3440	0.3557	0.3808	0.4238	0.4922
3	0.3400	0.3400	0.3400	0.3400	0.3400	0.3400	0.3404	0.3434	0.3530	0.3711	0.3966	0.4302
4	0.3400	0.3400	0.3400	0.3400	0.3400	0.3400	0.3403	0.3427	0.3503	0.3648	0.3852	0.4098
5	0.3400	0.3400	0.3400	0.3400	0.3400	0.3400	0.3402	0.3419	0.3470	0.3571	0.3714	0.3890
6	0.3400	0.3400	0.3400	0.3400	0.3400	0.3400	0.3401	0.3410	0.3438	0.3491	0.3568	0.3665
7	0.3400	0.3400	0.3400	0.3400	0.3400	0.3400	0.3401	0.3404	0.3414	0.3433	0.3460	0.3494
8	0.3400	0.3400	0.3400	0.3400	0.3400	0.3400	0.3400	0.3401	0.3403	0.3406	0.3410	0.3416

J \ I	13	14	15	16	17	18	19	20	21
1	0.6898	0.7364	0.7543	0.7551	0.7551	0.7551	0.7551	0.7551	0.7214
2	0.6068	0.6761	0.6978	0.7270	0.7294	0.7295	0.7295	0.7294	0.7200
3	0.5016	0.6065	0.6798	0.6990	0.7207	0.7220	0.7219	0.7219	0.7200
4	0.4525	0.5247	0.6379	0.6879	0.7099	0.7204	0.7204	0.7204	0.7200
5	0.4178	0.4648	0.5673	0.6612	0.6953	0.7198	0.7202	0.7201	0.7200
6	0.3827	0.4100	0.4756	0.5906	0.6765	0.7175	0.7202	0.7201	0.7200
7	0.3554	0.3664	0.3937	0.4577	0.5838	0.7053	0.7201	0.7200	0.7200
8	0.3427	0.3449	0.3503	0.3634	0.3982	0.6101	0.6722	0.6737	0.7186

WATER SATURATION (FRACTION)

J \ I	1	2	3	4	5	6	7	8	9	10	11	12
1	0.6603	0.6602	0.6601	0.6600	0.6600	0.6599	0.6571	0.6370	0.5799	0.4920	0.4043	0.3450
2	0.6603	0.6602	0.6601	0.6600	0.6600	0.6600	0.6595	0.6560	0.6443	0.6192	0.5762	0.5078
3	0.6603	0.6602	0.6601	0.6600	0.6600	0.6600	0.6596	0.6566	0.6470	0.6289	0.6034	0.5698
4	0.6603	0.6602	0.6601	0.6600	0.6600	0.6600	0.6597	0.6573	0.6497	0.6352	0.6148	0.5902
5	0.6603	0.6602	0.6601	0.6600	0.6600	0.6600	0.6598	0.6581	0.6530	0.6429	0.6286	0.6110
6	0.6603	0.6602	0.6601	0.6600	0.6600	0.6600	0.6599	0.6590	0.6562	0.6509	0.6432	0.6335
7	0.6603	0.6602	0.6601	0.6600	0.6600	0.6600	0.6599	0.6596	0.6586	0.6567	0.6540	0.6506
8	0.6603	0.6602	0.6601	0.6600	0.6600	0.6600	0.6600	0.6599	0.6597	0.6594	0.6590	0.6584

J \ I	13	14	15	16	17	18	19	20	21
1	0.3102	0.2636	0.2457	0.2449	0.2449	0.2449	0.2449	0.2449	0.2786
2	0.3932	0.3239	0.3022	0.2730	0.2706	0.2705	0.2705	0.2706	0.2800
3	0.4984	0.3935	0.3202	0.3010	0.2793	0.2780	0.2781	0.2781	0.2800
4	0.5475	0.4753	0.3621	0.3121	0.2901	0.2796	0.2796	0.2796	0.2900
5	0.5822	0.5352	0.4327	0.3388	0.3047	0.2802	0.2798	0.2799	0.2800
6	0.6173	0.5900	0.5244	0.4094	0.3235	0.2825	0.2799	0.2799	0.2800
7	0.6446	0.6336	0.6063	0.5423	0.4162	0.2947	0.2799	0.2800	0.2800
8	0.6573	0.6551	0.6497	0.6366	0.6018	0.3899	0.3278	0.3263	0.2914

Criterium Sw=0.57

r_{at} 0.25m=51m

Table A6-1

```
***************************************
*                                     *
*             T O O V A R S           *
*             -------------           *
*                                     *
*             VERSION 1.5             *
*                                     *
*        ROGALANDSFORSKNING'S         *
*                                     *
*   THREE-PHASE, TWO DIMENSIONAL,     *
*                                     *
*              IMPLICIT               *
*                                     *
*         RESERVOIR SIMULATOR         *
*                                     *
*                WITH                 *
*                                     *
*    VARIABLE SATURATION PRESSURE     *
*                                     *
***************************************
```

TITLE: INJECTION TEST 34/10-14

DATA WHEN SIMULATION STARTS: 20/ 8/1982

R E S E R V O I R   M O D E L   I S   U S E D

O I L   F I E L D   I N P U T   U N I T   O P T I O N   I S   U S E D

O I L   F I E L D   O U T P U T   U N I T   O P T I O N   I S   U S E D

INITIALIZATION - DATA INPUT / OUTPUT

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************************
*  INTEGER CONSTANTS  *
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    NY (=  8):  BLOCKS IN Y-DIRECTION, MAX. 93

    NX (= 21):  BLOCKS IN X-DIRECTION, MAX. 93

 STMAX (=300):  MAX. NUMBER OF TIME STEPS

  ITAB (=  1):  IF ITAB=1, COMPLETE PVT AND ROCK PROPERTIES TABLES ARE PRINTED

IWRITE (=  0):  IF IWRITE=1, BLOCK PRESSURES AND SATURATIONS ARE PRINTED FOR EVERY ITERATION IN A TIME STEP

LCYMAX (=  4):  MAX. NUMBER OF ITERATIONS PER TIME STEP

 ISTOP (=  1):  IF ISTOP EQUAL 1. THE SIMULATION TERMINATES WHEN A WELL CONSTRAINT IS REACHED

 ITIME (=  1):  TIME UNIT TRIGGER. IF ITIME=0, TIME UNIT IS DAY. OTHERWISE TIME UNIT IS MINUTE

  IDEZ (=  0):  BLOCKTHICKNESS TO EACH BLOCK WILL BE READ IF IDEZ IS NOT EQUAL TO 0. IF IDEZ=0, CONSTANT BLOCKTHICKNESS

IBLOCK (=  0):  BLOCKLENGTHS IN X-DIR. WILL BE READ IF IBLOCK IS NOT EQUAL TO 1. IF IBLOCK=1, THE PROGRAM CALCULATES THEM

 ITEXT (=  0):  TRIGGER FOR OUTPUT PRINT OF INPUT. IF ITEXT=0, OUTPUT OF INPUT. IF ITEXT=1, NO OUTPUT OF INPUT

                  IF ITEXT=2, OUTPUT OF INPUT WITHOUT COMMENTS
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  NPVT (=  1):  NUMBER OF PVT-PROPERTIES TABLES TO READ, MAX. 5. IF NPVT>1, EXCEPTION BLOCKS FROM PVT TABLE 1 WILL BE READ
 NROCK (=  1):  NUMBER OF ROCK-PROPERT.   TABLES TO READ, MAX. 10. IF NROCK>1, EXCE   ON BLOCKS FROM ROCK TYPE 1 WILL BE READ
 ISATU (=  1):  IF ISATU=0, GAS RESERVOIR. OTHERWISE OIL RESERVOIR
MOBCHK (=  1):  IF MOBCHK=1, SINGLEPOINT UPSTREAM RELATIVE PERMEABILITIES ARE USED, OTHERWISE TWOPOINT
 IUNIN (=  1):  INPUT UNIT TRIGGER. IF IUNIN=1, OIL FIELD UNITS. OTHERWISE SPE SI UNITS
IUNOUT (=  1):  OUTPUT UNIT TRIGGER. IF IUNOUT=1, OIL FIELD UNITS. OTHERWISE SPE SI UNITS
  IMAT        : TRIGGER FOR OUTPUT OF PRESSURE AND SATURATION MATRICES. IF IMAT(I) EQUAL 1, NO PRINTOUT.
                 PO      PW      PG      PS      SO      SW      SG      ISP

                  0       1       1       1       0       0       1       0

     THE TOTAL NUMBER OF BLOCKS IS 168  MAX. ALLOWED IS 240
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PIVTAB
CC PMAX,DBGUDP,DVGUDP,DBOUDP,DVOUDP,CW-BWORIG,BWORIG,RHOSTD,RHWSTD,RHGS TD
 7106.8,0,0,.0000065,0.0000896,.00000-   80,1.02,.381,.433,6.33E-5,.066
CC TP,    TBO,  TVO,  TRSO,   TBG,          TVG,      TRSG,        TVW,


2680.3 ,1.221 ,1.2  , 412.0 ,  840.0      , .0505, 0            ,.41
3132.8 ,1.250 ,1.1  , 467.0 ,  954.0      , .0551, 0            ,.41
5119.8 ,1.350 ,.900,  784.0 , 1200.0      , .0466, 0            ,.41
7106.8 ,1.450 ,.700 ,1101.0 , 1450.0      , .0381, 0            ,.41

ROCTAB
CC SWMAX,SGMAX,SOMIN,SWMIN,PCWOC,PCGOC
      1.,   1., .34 ,  .06, 0.,   0.
CC TSW,TKRW,TKROW,TPC
  0.  , 0.     ,1.     ,    0.
   .06, 0.0    ,1.0    ,    0.
   .1 , 0.0    ,0.88   ,    0.
   .20, 0.0    ,0.600  ,    0.
   .30, 0.003  ,0.360  ,    0.
   .40, 0.10   ,0.200  ,    0.
   .50, 0.18   ,0.110  ,    0.
   .60, 0.30   ,0.040  ,    0.
   .66, 0.40   ,0.0    ,    0.
   .70, 0.40   ,0.0    ,    0.
   .80, 0.40   ,0.0    ,    0.
   .90, 0.40   ,0.0    ,    0.
   1.0, 0.40   ,0.0    ,    0.
CC TSG,TKRG,TKROG,TPCOG
   0.,0.,1.,0.
   1.,1.,0.,0.

RATECA
CC TIMTOT,DELMIN,DELMAX,TQCHG
    3180.,.01,250., 2760.
CC ID,I,J,IPROD,QO,QG,QW,  QT, PCONST,WI
    1,1,1,     8, 0,0.,880,   0.,  0.,0.
    1,1,2,     8, 0,0.,880,   0.,  0.,0.
    1,1,3,     8, 0,0.,880,   0.,  0.,0.
    1,1,4,     8, 0,0.,880,   0.,  0.,0.
    1,1,5,     8, 0,0.,880,   0.,  0.,0.
    1,1,6,     8, 0,0.,880,   0.,  0.,0.
    1,1,7,     8, 0,0.,880,   0.,  0.,0.
    0,1,8,     8, 0,0 ,880,   0.,  0.,0.
CC NPRINT,TPRINT(I) ,I = 1,NPRINT
   27,60,120,180,240,480,720,960,1200,1440,1680,1920,2160,2400,2760.5
   2761,2762,2763,2764,2765,2770,2775,2780,2820,2880,2940,3000,3180
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```
WELCON
CC QGLIM,QOLIM, QWLIM,LGRLIM,GORLIM,WC   TM,PWLP,PWLI
      0.,    0.,9.E+08,1.E+08,1.E+08,     .7, 145.0377, 7541.9604


ENDCAS

RATECA
CC TIMTOT,DELMIN,DELMAX,TQCHG
   3180.   ,.002,250.,3180.
CC ID,I,J,IPROD, QO,    QG, QW,    QT,PCONST,WI
     1,1,1,     0,  0,     0,  0,     0,      0,0
     1,1,2,     0,  0,     0,  0,     0,      0,0
     1,1,3,     0,  0,     0,  0,     0,      0,0
     1,1,4,     0,  0,     0,  0,     0,      0,0
     1,1,5,     0,  0,     0,  0,     0,      0,0
     1,1,6,     0,  0,     0,  0,     0,      0,0
     1,1,7,     0,  0,     0,  0,     0,      0,0
     0,1,8,     0,  0,     0,  0,     0,      0,0

ENDCAS
```

PVT PROPERTIES TYPE 1

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MAXIMUM TABLE PRESSURE (PSI)	7106.800
CONSTANT SLOPE OF GAS FORMATION VOLUME FACTOR ABOVE DEW POINT (SCF/RCF/PSI)	0.000000000
CONSTANT GAS VISCOSITY SLOPE ABOVE THE DEW POINT (CP/PSI)	0.000000000
CONSTANT SLOPE OF OIL FORMATION VOLUME FACTOR ABOVE BUBBLE POINT (STB/RBL/PSI)	0.000006500
CONSTANT OIL VISCOSITY SLOPE ABOVE THE BUBBLE POINT (CP/PSI)	0.000089600
WATER COMPRESSIBILTY (1/PSI)	0.000003000
WATER FORMATION VOLUME FACTOR AT 4580.000 PSI (STB/RBL)	1.02000000
GRAVITY HEAD TO OIL AT STANDARD CONDITIONS (PSI/FEET *RBL/STB)	0.3810000
GRAVITY HEAD TO WATER AT STANDARD CONDITIONS (PSI/FEET *RBL/STB)	0.4330000
GRAVITY HEAD OF GAS AT STANDARD CONDITIONS (PSI/FEET *RBL/SCF)	0.0000633

TP	TBO	TVO	TRSO	TBG	TVG	TRSG	TVW
2680.300000	1.22100000	1.20000000	412.00000000	840.00000000	0.05050000	0.00000000	0.41000000
3132.800000	1.25000000	1.10000000	467.00000000	954.00000000	0.05510000	0.00000000	0.41000000
5119.800000	1.35000000	0.90000000	784.00000000	1200.00000000	0.04660000	0.00000000	0.41000000
7106.800000	1.45000000	0.70000000	1101.00000000	1450.00000000	0.03810000	0.00000000	0.41000000

****

TP: TABLE PRESSURE (PSI)

TBO: OIL FORMATION VOLUME FACTOR (RBL/STB)

TVO: OIL VISCOSITY (CP)

TRSO: SOLUTION GAS OIL RATIO (GAS SOLUBILITY IN OIL) (SCF/STB)

TBG: GAS FORMATION VOLUME FACTOR (SCF/RBL)

TVG: GAS VISCOSITY (CP)

TRSG: SOLUTION OIL GAS RATIO (OIL SOLUBILITY IN GAS) (STB/SCF)

TVW: WATER VISCOSITY (CP)

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ROCK TABLE TYPE 1
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MAXIMUM WATER SATURATION IN WATER-OIL TABLE (FRACTION)	1.000000000
MAXIMUM GAS SATURATION IN GAS-OIL TABLE (FRACTION)	1.000000000
IRREDUCIBLE OIL SATURATION (FRACTION)	0.340000000
IRREDUCIBLE WATER SATURATION (FRACTION)	0.060000000
WATER OIL CAPILLARY PRESSURE AT WATER/OIL CONTACT (PSI)	0.000000000
GAS/OIL CAPILLARY PRESSURE AT GAS/OIL CONTACT (PSI)	0.000000000

WATER-OIL SATURATION TABLF

TSW	TKRW	TKROW	TPCOW
0.0000000000000	0.0000000000000	1.0000000000000	0.0000000000000
0.0600000000000	0.0000000000000	1.0000000000000	0.0000000000000
0.1000000000000	0.0000000000000	0.8800000000000	0.0000000000000
0.2000000000000	0.0000000000000	0.6000000000000	0.0000000000000
0.3000000000000	0.0030000000000	0.3600000000000	0.0000000000000
0.4000000000000	0.1000000000000	0.2000000000000	0.0000000000000
0.5000000000000	0.1800000000000	0.1100000000000	0.0000000000000
0.6000000000000	0.3000000000000	0.0400000000000	0.0000000000000
0.6600000000000	0.4000000000000	0.0000000000000	0.0000000000000
0.7000000000000	0.4000000000000	0.0000000000000	0.0000000000000
0.8000000000000	0.4000000000000	0.0000000000000	0.0000000000000
0.9000000000000	0.4000000000000	0.0000000000000	0.0000000000000
1.0000000000000	0.4000000000000	0.0000000000000	0.0000000000000

GAS-OIL SATURATION TABLE

TSG	TKRG	TKROG	TPCGO
0.0000000000000	0.0000000000000	1.0000000000000	0.0000000000000
1.0000000000000	1.0000000000000	0.0000000000000	0.0000000000000

****

TSW: WATER SATURATION (FRACTION)

TKRW: RELATIVE PERMEABILITY TO WATER

TKROW: RELATIVE PERMEABILITY TO OIL IN AN OIL/WATER TWO-PHASE SYSTEM

TPCOW: OIL-WATER CAPILLARY PRESSURE (PSI)

TSG: GAS SATURATION (FRACTION)

TKRG: RELATIVE PERMEABILITY TO GAS

TKROG: RELATIVE PERMEABILITY TO OIL IN AN OIL/GAS TWO-PHASE SYSTEM

TPCGO: GAS-OIL CAPILLARY PRESSURE (PSI)

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****
* ROCK PROPERTIES *
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CFF (= 0.0000031000): ROCK COMPRESSIBILITY (1/PSI)

POROS (= 0.3070): POROSITY FOR MOST BLOCKS (FRACTION)

VERPRM (= 4621.0000): ABSOLUTE PERMEABILITY IN Y-DIRECTION FOR MOST BLOCKS (MD)

HORPRM (= 4621.0000): ABSOLUTE PERMEABILITY IN X-DIRECTION FOR MOST BLOCKS (MD)

POROSITY (FRACTION)

J I	1	2	3	4	5	6	7	8	9	10	11	12
1	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070
2	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070
3	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070
4	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070
5	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070
6	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070
7	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070
8	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070

J I	13	14	15	16	17	18	19	20	21
1	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	10.0000
2	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	10.0000
3	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	10.0000
4	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	10.0000
5	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	10.0000
6	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	10.0000
7	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	10.0000
8	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	0.3070	10.0000

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                       ************************
                       *  RESERVOIR GEOMETRY  *
                       ************************

 RW (=     0.360000000):  IF RW>0, CYLINDER COORDINATES ARE USED AND RW IS INNER WELLBORE RADIUS (FEET )
                            OTHERWISE CARTESIAN COORDINATE TRIGGER
DHDY (=     1.000000000):  SINE OF INCLINATION ANGLE IN Y-DIRECTION
DHDX (=     0.000000000):  SINE OF INCLINATION ANGLE IN X-DIRECTION
DBL1 (=     0.000000000):  DEPTH FROM DATUM TO PRESSURE POINT IN LAYER 1 (FEET )
HREF (=     0.000000000):  PRESSURE REFERENCE DEPTH (FEET )
DWOC (=    34.000000000):  DEPTH FROM DATUM TO WATER-OIL CONTACT (FEET )
DGOC (=     0.000000000):  DEPTH FROM DATUM TO GAS-OIL CONTACT (FEET )
 DZZ (=      0.00000000):  BLOCK THICKNESS FOR MOST BLOCKS (FEET )
          DZZ HAS BEEN GIVEN DEFAULT VALUE 1.0
                                       VERTICAL BLOCK LENGTH (FEET )
   1.6400    1.6400    1.6400    1.6400    1.6400    1.6400    1.6400    1.6400
                                       HORIZONTAL BLOCK LENGTH (FEET )
   0.3600    0.7700    1.7000    3.7400    8.2200    9.8000    9.8000    9.8000    9.8000    9.8000    9.8000    9.8000
  13.1000   16.4000   19.6000   19.6000   19.6000   78.7000  315.0000 1260.0000 3280.0000
                              DISTANCE FROM WELL BORE CENTER TO PRESSURE POINT (FEET )
   0.5091    1.0359    2.1802    4.7018   10.2464   19.4420   29.4451   39.3461   49.2066   59.0470   68.8759   78.6976
  90.0621  104.7295  122.6591  142.3130  161.9538  207.7054  376.6455 1016.3258 3053.1661
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                                                    ***************************************
                                                    *  TIMESTEP REGULATORS AND TOLERANCES  *
                                                    ***************************************

PCMLT (=     1.000000000):  CAPILLARY PRESSURE MULTIPLIER, NORMALLY EQUAL TO 1

DTMLT (=     3.000000000):  TIME STEP MULTIPLIER

  EPS (=     1.000000000):  MAX. PRESSURE TOLERANCE BETWEEN ITERATIONS IN ONE TIME STEP (PSI)

 SEPS (=     0.000000000):  MAX. SATURATION TOLERANCE BETWEEN ITERATIONS IN ONE TIME STEP (FRACTION)

 DSMX (=     0.050000000):  MAX. SATURATION CHANGE IN A TIME STEP (FRACTION)

 DPMX (=   150.000000000):  MAX. PRESSURE CHANGE IN A TIME STEP (PSI)

           SEPS HAS BEEN GIVEN  DEFAULT VALUE 0.0001
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**** I N I T I A L   C O N D I T I O N S ****

PORIG (= 4580.00000): ORIGINAL OIL PRESSURE AT REFERENCE DEPTH (PSI)

PSORIG (= 3060.00000): ORIGINAL SATURATION PRESSURE FOR MOST BLOCKS (PSI)

SOORIG (= 0.72000): ORIGINAL OIL SATURATION FOR MOST BLOCKS (FRACTION)

SWORIG (= 0.28000): ORIGINAL WATER SATURATION FOR MOST BLOCKS (FRACTION)

OIL SATURATION (FRACTION)

J I	1	2	3	4	5	6	7	8	9	10	11	12
1	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
2	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
3	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
4	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
5	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
6	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
7	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
8	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200

J I	13	14	15	16	17	18	19	20	21
1	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
2	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
3	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
4	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
5	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
6	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
7	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200
8	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200	0.7200

WATER SATURATION (FRACTION)

J	I	1	2	3		5	6	7	8	9	10	11	12
1		0.2800	0.2800	0.2800	0.[illegible]800	0.2800	0.2800	0.2800	0.280	0.2800	0.2800	0.2800	0.2800
2		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
3		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
4		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
5		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
6		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
7		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
8		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800

J	I	13	14	15	16	17	18	19	20	21
1		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
2		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
3		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
4		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
5		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
6		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
7		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800
8		0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800	0.2800

OIL PRESSURE (PSI)

J \ I	1	2	3	4	5	6	7	8	9	10	11	12
1	4580.00	4580.00	4580.00	4580.00	4580.00	4580.00	4580.00	4580.00	4580.00	4580.00	4580.00	4580.00
2	4580.55	4580.55	4580.55	4580.55	4580.55	4580.55	4580.55	4580.55	4580.55	4580.55	4580.55	4580.55
3	4581.09	4581.09	4581.09	4581.09	4581.09	4581.09	4581.09	4581.09	4581.09	4581.09	4581.09	4581.09
4	4581.64	4581.64	4581.64	4581.64	4581.64	4581.64	4581.64	4581.64	4581.64	4581.64	4581.64	4581.64
5	4582.19	4582.19	4582.19	4582.19	4582.19	4582.19	4582.19	4582.19	4582.19	4582.19	4582.19	4582.19
6	4582.73	4582.73	4582.73	4582.73	4582.73	4582.73	4582.73	4582.73	4582.73	4582.73	4582.73	4582.73
7	4583.28	4583.28	4583.28	4583.28	4583.28	4583.28	4583.28	4583.28	4583.28	4583.28	4583.28	4583.28
8	4583.83	4583.83	4583.83	4583.83	4583.83	4583.83	4583.83	4583.83	4583.83	4583.83	4583.83	4583.83

J \ I	13	14	15	16	17	18	19	20	21
1	4580.00	4580.00	4580.00	4580.00	4580.00	4580.00	4580.00	4580.00	4580.00
2	4580.55	4580.55	4580.55	4580.55	4580.55	4580.55	4580.55	4580.55	4580.55
3	4581.09	4581.09	4581.09	4581.09	4581.09	4581.09	4581.09	4581.09	4581.09
4	4581.64	4581.64	4581.64	4581.64	4581.64	4581.64	4581.64	4581.64	4581.64
5	4582.19	4582.19	4582.19	4582.19	4582.19	4582.19	4582.19	4582.19	4582.19
6	4582.73	4582.73	4582.73	4582.73	4582.73	4582.73	4582.73	4582.73	4582.73
7	4583.28	4583.28	4583.28	4583.28	4583.28	4583.28	4583.28	4583.28	4583.28
8	4583.83	4583.83	4583.83	4583.83	4583.83	4583.83	4583.83	4583.83	4583.83

AVERAGE PRESSURE (PSI): 4581.9132

SATURATION PRESSURE CHECK

J \ I	1	2	3	4	5	6	7	8	9	10	11	12
1	4	4	4	4	4	4	4	4	4	4	4	4
2	4	4	4	4	4	4	4	4	4	4	4	4
3	4	4	4	4	4	4	4	4	4	4	4	4
4	4	4	4	4	4	4	4	4	4	4	4	4
5	4	4	4	4	4	4	4	4	4	4	4	4
6	4	4	4	4	4	4	4	4	4	4	4	4
7	4	4	4	4	4	4	4	4	4	4	4	4
8	4	4	4	4	4	4	4	4	4	4	4	4

J \ I	13	14	15	16	17	18	19	20	21
1	4	4	4	4	4	4	4	4	4
2	4	4	4	4	4	4	4	4	4
3	4	4	4	4	4	4	4	4	4
4	4	4	4	4	4	4	4	4	4
5	4	4	4	4	4	4	4	4	4
6	4	4	4	4	4	4	4	4	4
7	4	4	4	4	4	4	4	4	4
8	4	4	4	4	4	4	4	4	4

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                    *********************
                    *  WELL CONSTRAINTS  *
                    *********************

 QGLIM (=        0.00000):  LOWER GAS RATE LIMIT FROM A PRODUCING  GAS CONDENSATE WELL (SCF/DAY). IF LOWER RATE, THE WELL IS SHUT-IN

 QOLIM (=         0.0000):  LOWER OIL RATE LIMIT FROM A PRODUCING OIL WELL (STB/DAY). IF LOWER RATE, THE WELL IS SHUT-IN

 QWLIM (= 900000000.0000):  UPPER WATER RATE LIMIT FROM A PRODUCING WELL (STB/DAY). IF HIGHER RATE, THE WELL IS SHUT-IN

LGRLIM (=  100000000.000):  UPPER OIL GAS RATIO LIMIT FOR A PRODUCING GAS CONDENSATE WELL (STB/SCF)

                              IF HIGHER RATIO, THE WELL IS SHUT-IN

GORLIM (= 100000000.0000):  UPPER GAS OIL RATIO LIMIT FOR A PRODUCING OIL WELL (SCF/STB). IF HIGHER RATIO, THE WELL IS SHUT-IN

WCFLIM (=        1.70000):  UPPER WATER CUT LIMIT FOR A PRODUCING WELL. IF HIGER WATER CUT, THE WELL IS SHUT-IN

  PWLP (=      145.03770):  LOWER WELLBORE PRESSURE LIMIT IN A PRODUCING WELL (PSI). IF LIMIT IS EXCEEDED,

                              THE WELL WILL PRODUCE AGAINST CONSTANT WELLBORE PRESSURE EQUAL TO PWLP OR BE SHUT-IN IF WI=0

  PWLI (=     7541.96040):  UPPER WELLBORE PRESSURE LIMIT IN A INJECTING WELL (PSI). IF LIMIT IS EXCEEDED,

                              THE WELL WILL INJECT AGAINST CONSTANT PRESSURE EQUAL TO PWLI OR BE SHUT-IN IF WI=0
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*************************
*  TIME AND RATE DATA  *
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TIMTOT (= 3180.000000000): TOTAL SIMULATION TIME (MINUTES)

DELMIN (=   0.010000000): MIN. LENGTH OF TIME STEPS (MINUTES)

DELMAX (= 250.000000000): MAX. LENGTH OF TIME STEPS (MINUTES)

TQCHG (= 2760.000000000): TIME WHEN NEW RATE DATA WILL BE READ (MINUTES)

PRINTOUT AT FOLLOWING TIMES (MINUTES)

60.000000	120.000000	180.000000	240.000000	480.000000	720.000000	960.000000	1200.000000
1440.000000	1680.000000	1920.000000	2160.000000	2400.000000	2760.500000	2761.000000	2762.000000
2763.000000	2764.000000	2765.000000	2770.000000	2775.000000	2780.000000	2820.000000	2880.000000
2940.000000	3000.000000	3180.000000					

BLOCK	IPROD	PROD/INJ	QO (STB/DAY)	QG (SCF/DAY)	QW (STB/DAY)	QT (STB/DAY)	PCONST (PSI)	-WELL INDEX-
1, 1	8	INJ	0.0	0.0	880.0	0.0	0.0000	0.100000D-30
1, 2	8	INJ	0.0	0.0	880.0	0.0	0.0000	0.100000D-30
1, 3	8	INJ	0.0	0.0	880.0	0.0	0.0000	0.100000D-30
1, 4	8	INJ	0.0	0.0	880.0	0.0	0.0000	0.100000D-30
1, 5	8	INJ	0.0	0.0	880.0	0.0	0.0000	0.100000D-30
1, 6	8	INJ	0.0	0.0	880.0	0.0	0.0000	0.100000D-30
1, 7	8	INJ	0.0	0.0	880.0	0.0	0.0000	0.100000D-30
1, 8	8	INJ	0.0	0.0	880.0	0.0	0.0000	0.100000D-30

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**********************************************************
*                                                        *
*     INITIAL WATER IN PLACE    =    478826611. STB      *
*                                                        *
*     INITIAL OIL IN PLACE      =    981326826. STB      *
*                                                        *
*     INITIAL FREE OIL IN PLACE =    981326826. STB      *
*                                                        *
*     INITIAL GAS IN PLACE      = 449596240677. SCF      *
*                                                        *
*     INITIAL FREE GAS IN PLACE =             0. SCF     *
*                                                        *
**********************************************************
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* T I M E S T E P : 26   S I M U L A T E D T I M E :   60.000000 (M I N U T E S) *

W E L L   S U M M A R Y

----WELL----- BLOCK NO.	STATUS IPROD	PRODUCTION RATE ----OIL---- STB/D	----GAS---- SCF/D	---WATER--- STB/D	----GOR---- SCF/STB	-WATER- CUT FRACT	-WELLBORE- PRESSURE PSI	INJECTION RATE ----OIL---- STB/D	----GAS---- SCF/D	---WATER--- STB/D
1, 1	8						4811.4094	0.	0.	880.
1, 2	8						4811.3891	0.	0.	880.
1, 3	8						4811.3571	0.	0.	880.
1, 4	8						4811.3192	0.	0.	880.
1, 5	8						4811.2796	0.	0.	880.
1, 6	8						4811.2419	0.	0.	880.
1, 7	8						4811.2102	0.	0.	880.
1, 8	8						4811.1905	0.	0.	880.
TOT FOR FIELD		0.	0.	0.	1.	0.00000		0.	0.	7040.

F L U I D   S T A T U S

CUMULATIVE PRODUCTION ----OIL---- STB	GAS ----SCF----	---WATER--- STB	CUMULATIVE INJECTION ----OIL---- STB	GAS ----SCF----	---WATER--- STB	LEFT IN PLACE -----OIL---- STB	GAS -----SCF----	----WATER--- STB	PER CENT PRODUCED OF ORIGINAL IN PLACE ---OIL--	GAS	--WATER-
0.	0.	0.	0.	0.	293.	981326826.	************	478826904.	0.0000	0.0000	0.0000

LENGTH OF TIME STEP (MINUTES):   7.220318784   NUMBER OF ITERATIONS (CUM.): 99

	CUMULATIVE ERROR- ---IN PER CENT---
OIL	0.4203734532D-10
GAS	0.4226407674D-10
WATER	-0.1344390129D-11

OIL PRESSURE (PSI)

J I	1	2	3		5	6	7	8	9	10	11	12
1	4811.41	4799.72	4787.47	4774.82	4760.08	4739.84	4722.46	4707.87	4696.54	4687.69	4680.24	4673.81
2	4812.11	4800.42	4788.17	4775.51	4760.75	4740.46	4723.04	4708.44	4697.09	4688.24	4680.79	4674.36
3	4812.81	4801.11	4788.86	4776.19	4761.42	4741.09	4723.62	4709.01	4697.64	4688.79	4681.34	4674.91
4	4813.49	4801.80	4789.54	4776.87	4762.08	4741.73	4724.21	4709.58	4698.19	4689.34	4681.89	4675.46
5	4814.18	4802.48	4790.23	4777.55	4762.75	4742.36	4724.80	4710.15	4698.74	4689.89	4682.44	4676.01
6	4814.87	4803.17	4790.91	4778.23	4763.42	4742.99	4725.39	4710.73	4699.28	4690.44	4682.99	4676.56
7	4815.56	4803.86	4791.60	4778.91	4764.09	4743.62	4725.98	4711.30	4699.83	4690.99	4683.54	4677.11
8	4816.26	4804.57	4792.31	4779.60	4764.76	4744.26	4726.57	4711.87	4700.38	4691.54	4684.09	4677.66

J I	13	14	15	16	17	18	19	20	21
1	4667.33	4660.12	4652.62	4645.65	4639.65	4628.28	4602.95	4581.05	4579.99
2	4667.88	4660.67	4653.17	4646.20	4640.20	4628.83	4603.50	4581.60	4580.54
3	4668.43	4661.22	4653.72	4646.75	4640.75	4629.38	4604.05	4582.15	4581.09
4	4668.98	4661.77	4654.27	4647.30	4641.30	4629.93	4604.60	4582.70	4581.64
5	4669.53	4662.32	4654.82	4647.85	4641.85	4630.48	4605.15	4583.25	4582.19
6	4670.08	4662.87	4655.37	4648.40	4642.40	4631.03	4605.70	4583.80	4582.74
7	4670.63	4663.42	4655.92	4648.95	4642.95	4631.58	4606.25	4584.35	4583.29
8	4671.18	4663.97	4656.47	4649.50	4643.50	4632.13	4606.80	4584.90	4583.84

AVERAGE OIL PRESSURE (PSI): 4581.93

OIL SATURATION (FRACTION)

J	I	1	2	3		5	6	7	8	9	10	11	12
1		0.3400	0.3400	0.3405	0.[illegible]794	0.5289	0.6320	0.6848	0.7164	0.7216	0.7216	0.7216	0.7216
2		0.3400	0.3400	0.3405	0.3766	0.5173	0.6209	0.6781	0.7124	0.7201	0.7202	0.7202	0.7202
3		0.3400	0.3400	0.3405	0.3766	0.5170	0.6200	0.6771	0.7120	0.7201	0.7202	0.7202	0.7201
4		0.3400	0.3400	0.3405	0.3766	0.5169	0.6199	0.6769	0.7119	0.7201	0.7202	0.7202	0.7201
5		0.3400	0.3400	0.3405	0.3765	0.5168	0.6197	0.6767	0.7118	0.7201	0.7202	0.7202	0.7201
6		0.3400	0.3400	0.3405	0.3765	0.5167	0.6196	0.6766	0.7118	0.7201	0.7202	0.7202	0.7201
7		0.3400	0.3400	0.3405	0.3764	0.5161	0.6191	0.6763	0.7117	0.7201	0.7202	0.7202	0.7201
8		0.3400	0.3400	0.3404	0.3739	0.5049	0.6071	0.6679	0.7066	0.7185	0.7187	0.7186	0.7186

J	I	13	14	15	16	17	18	19	20	21
1		0.7216	0.7216	0.7216	0.7216	0.7216	0.7216	0.7215	0.7215	0.7200
2		0.7201	0.7201	0.7201	0.7201	0.7201	0.7201	0.7201	0.7200	0.7200
3		0.7201	0.7201	0.7201	0.7201	0.7201	0.7201	0.7200	0.7200	0.7200
4		0.7201	0.7201	0.7201	0.7201	0.7201	0.7201	0.7200	0.7200	0.7200
5		0.7201	0.7201	0.7201	0.7201	0.7201	0.7201	0.7200	0.7200	0.7200
6		0.7201	0.7201	0.7201	0.7201	0.7201	0.7201	0.7200	0.7200	0.7200
7		0.7201	0.7201	0.7201	0.7201	0.7201	0.7201	0.7200	0.7200	0.7200
8		0.7186	0.7186	0.7186	0.7186	0.7186	0.7186	0.7185	0.7185	0.7200

WATER SATURATION (FRACTION)

J	I	1	2	3	4	5	6	7	8	9	10	11	12
1		0.6602	0.6601	0.6595	0.6206	0.4711	0.3680	0.3152	0.2836	0.2784	0.2784	0.2784	0.2784
2		0.6602	0.6601	0.6595	0.6234	0.4827	0.3791	0.3219	0.2876	0.2799	0.2798	0.2798	0.2798
3		0.6602	0.6601	0.6595	0.6234	0.4830	0.3800	0.3229	0.2880	0.2799	0.2798	0.2798	0.2799
4		0.6602	0.6601	0.6595	0.6234	0.4831	0.3801	0.3231	0.2881	0.2799	0.2798	0.2798	0.2799
5		0.6602	0.6601	0.6595	0.6235	0.4832	0.3803	0.3233	0.2882	0.2799	0.2798	0.2798	0.2799
6		0.6602	0.6601	0.6595	0.6235	0.4833	0.3804	0.3234	0.2882	0.2799	0.2798	0.2798	0.2799
7		0.6602	0.6601	0.6595	0.6236	0.4839	0.3809	0.3237	0.2883	0.2799	0.2798	0.2798	0.2799
8		0.6602	0.6601	0.6596	0.6261	0.4951	0.3929	0.3321	0.2934	0.2815	0.2813	0.2814	0.2814

J	I	13	14	15	16	17	18	19	20	21
1		0.2784	0.2784	0.2784	0.2784	0.2784	0.2784	0.2785	0.2785	0.2800
2		0.2799	0.2799	0.2799	0.2799	0.2799	0.2799	0.2799	0.2800	0.2800
3		0.2799	0.2799	0.2799	0.2799	0.2799	0.2799	0.2800	0.2800	0.2800
4		0.2799	0.2799	0.2799	0.2799	0.2799	0.2799	0.2800	0.2800	0.2800
5		0.2799	0.2799	0.2799	0.2799	0.2799	0.2799	0.2800	0.2800	0.2800
6		0.2799	0.2799	0.2799	0.2799	0.2799	0.2799	0.2800	0.2800	0.2800
7		0.2799	0.2799	0.2799	0.2799	0.2799	0.2799	0.2800	0.2800	0.2800
8		0.2814	0.2814	0.2814	0.2814	0.2814	0.2814	0.2815	0.2815	0.2800

* T I M E S T E P : 58 S I M U L A T E D T I M E : 2760.000000 (M I N U T E S) *

W E L L S U M M A R Y

WELL BLOCK NO.	WELL STATUS IPROD	PRODUCTION RATE OIL STB/D	PRODUCTION RATE GAS SCF/D	PRODUCTION RATE WATER STB/D	GOR SCF/STB	WATER CUT FRACT	WELLBORE PRESSURE PSI	INJECTION RATE OIL STB/D	INJECTION RATE GAS SCF/D	INJECTION RATE WATER STB/D
1, 1	8						4816.3947	0.	0.	880.
1, 2	8						4816.3946	0.	0.	880.
1, 3	8						4816.3944	0.	0.	880.
1, 4	8						4816.3942	0.	0.	880.
1, 5	8						4816.3940	0.	0.	880.
1, 6	8						4816.3937	0.	0.	880.
1, 7	8						4816.3936	0.	0.	880.
1, 8	8						4816.3935	0.	0.	880.
TOT FOR FIELD		0.	0.	0.	1.	0.00000		0.	0.	7040.

F L U I D S T A T U S

CUMULATIVE PRODUCTION OIL STB	CUMULATIVE PRODUCTION GAS SCF	CUMULATIVE PRODUCTION WATER STB	CUMULATIVE INJECTION OIL STB	CUMULATIVE INJECTION GAS SCF	CUMULATIVE INJECTION WATER STB	LEFT IN PLACE OIL STB	LEFT IN PLACE GAS SCF	LEFT IN PLACE WATER STB	PER CENT PRODUCED OF ORIGINAL IN PLACE OIL	GAS	WATER
0.	0.	0.	0.	0.	13493.	981326826.	************	478840104.	0.0000	0.0000	0.0000

LENGTH OF TIME STEP (MINUTES): 204.058321620 NUMBER OF ITERATIONS (CUM.): 221

	CUMULATIVE ERROR IN PER CENT
OIL	0.26869644300D-09
GAS	0.26880943820D-09
WATER	-0.69097258200D-10

OIL PRESSURE (PSI)

J \ I	1	2	3	4	5	6	7	8	9	10	11	12
1	4816.39	4804.70	4792.44	4779.[illegible]	4766.96	4756.42	4749.60	4744.80	[illegible]40.96	4737.59	4734.60	4731.80
2	4817.12	4805.42	4793.17	4780.51	4767.69	4757.14	4750.31	4745.50	4741.64	4738.26	4735.22	4732.37
3	4817.84	4806.15	4793.89	4781.24	4768.41	4757.86	4751.03	4746.21	4742.33	4738.96	4735.90	4733.03
4	4818.57	4806.87	4794.62	4781.96	4769.13	4758.59	4751.75	4746.91	4743.03	4739.66	4736.59	4733.71
5	4819.29	4807.60	4795.34	4782.69	4769.86	4759.31	4752.46	4747.62	4743.74	4740.36	4737.29	4734.41
6	4820.02	4808.32	4796.07	4783.41	4770.58	4760.03	4753.18	4748.33	4744.44	4741.06	4737.99	4735.11
7	4820.74	4809.05	4796.79	4784.14	4771.31	4760.76	4753.90	4749.05	4745.16	4741.77	4738.70	4735.82
8	4821.47	4809.77	4797.52	4784.86	4772.03	4761.48	4754.62	4749.77	4745.87	4742.49	4739.42	4736.54

J \ I	13	14	15	16	17	18	19	20	21
1	4728.70	4725.00	4720.72	4716.19	4711.79	4702.42	4675.55	4629.79	4580.56
2	4729.27	4725.57	4721.28	4716.74	4712.34	4702.97	4676.10	4630.34	4581.11
3	4729.88	4726.14	4721.84	4717.30	4712.90	4703.52	4676.65	4630.89	4581.66
4	4730.56	4726.76	4722.42	4717.87	4713.46	4704.08	4677.20	4631.44	4582.21
5	4731.25	4727.44	4723.03	4718.45	4714.03	4704.63	4677.75	4631.99	4582.76
6	4731.96	4728.14	4723.71	4719.06	4714.60	4705.19	4678.30	4632.54	4583.31
7	4732.67	4728.85	4724.42	4719.75	4715.23	4705.75	4678.85	4633.09	4583.86
8	4733.39	4729.57	4725.14	4720.47	4715.95	4706.33	4679.41	4633.64	4584.41

AVERAGE OIL PRESSURE (PSI): 4582.73

OIL SATURATION (FRACTION)

J \ I	1	2	3	4	5	6	7	8	9	10	11	12
1	0.3400	0.3400	0.3400	0.3[illegible]	0.3400	0.3412	0.3566	0.4117	0.5054	0.6039	0.6639	0.6912
2	0.3400	0.3400	0.3400	0.3400	0.3400	0.3402	0.3428	0.3536	0.3772	0.4164	0.4916	0.5979
3	0.3400	0.3400	0.3400	0.3400	0.3400	0.3402	0.3424	0.3511	0.3683	0.3923	0.4254	0.4732
4	0.3400	0.3400	0.3400	0.3400	0.3400	0.3401	0.3419	0.3489	0.3626	0.3815	0.4044	0.4311
5	0.3400	0.3400	0.3400	0.3400	0.3400	0.3401	0.3413	0.3460	0.3554	0.3685	0.3840	0.4009
6	0.3400	0.3400	0.3400	0.3400	0.3400	0.3401	0.3407	0.3432	0.3482	0.3551	0.3631	0.3718
7	0.3400	0.3400	0.3400	0.3400	0.3400	0.3400	0.3403	0.3412	0.3429	0.3453	0.3480	0.3509
8	0.3400	0.3400	0.3400	0.3400	0.3400	0.3400	0.3401	0.3402	0.3405	0.3409	0.3413	0.3418

J \ I	13	14	15	16	17	18	19	20	21
1	0.7319	0.7633	0.7658	0.7660	0.7660	0.7661	0.7661	0.7661	0.7221
2	0.6696	0.6957	0.7267	0.7364	0.7371	0.7373	0.7373	0.7373	0.7200
3	0.5684	0.6645	0.6950	0.7155	0.7243	0.7249	0.7249	0.7248	0.7200
4	0.4756	0.5827	0.6731	0.6963	0.7167	0.7212	0.7212	0.7211	0.7200
5	0.4255	0.4789	0.6020	0.6787	0.7004	0.7201	0.7203	0.7203	0.7200
6	0.3841	0.4080	0.4694	0.5947	0.6789	0.7169	0.7202	0.7201	0.7200
7	0.3553	0.3637	0.3829	0.4298	0.5391	0.6968	0.7199	0.7199	0.7200
8	0.3427	0.3442	0.3476	0.3548	0.3719	0.5566	0.6477	0.6510	0.7179

WATER SATURATION (FRACTION)

J \ I	1	2	3	4	5	6	7	8	9	10	11	12
1	0.6602	0.6601	0.6600	0.6600	0.6600	0.6588	0.6434	0.5883	0.4946	0.3961	0.3361	0.3088
2	0.6602	0.6601	0.6600	0.6600	0.6600	0.6598	0.6572	0.6464	0.6228	0.5836	0.5084	0.4021
3	0.6602	0.6601	0.6600	0.6600	0.6600	0.6598	0.6576	0.6489	0.6317	0.6077	0.5745	0.5268
4	0.6602	0.6601	0.6600	0.6600	0.6600	0.6599	0.6581	0.6511	0.6374	0.6185	0.5956	0.5689
5	0.6602	0.6601	0.6600	0.6600	0.6600	0.6599	0.6587	0.6540	0.6446	0.6315	0.6160	0.5991
6	0.6602	0.6601	0.6600	0.6600	0.6600	0.6599	0.6593	0.6568	0.6518	0.6449	0.6369	0.6282
7	0.6602	0.6601	0.6600	0.6600	0.6600	0.6600	0.6597	0.6588	0.6571	0.6547	0.6520	0.6491
8	0.6602	0.6601	0.6600	0.6600	0.6600	0.6600	0.6599	0.6598	0.6595	0.6591	0.6587	0.6582

J \ I	13	14	15	16	17	18	19	20	21
1	0.2681	0.2367	0.2342	0.2340	0.2340	0.2339	0.2339	0.2339	0.2779
2	0.3304	0.3043	0.2733	0.2636	0.2629	0.2627	0.2627	0.2627	0.2800
3	0.4316	0.3355	0.3050	0.2845	0.2757	0.2751	0.2751	0.2752	0.2800
4	0.5244	0.4173	0.3269	0.3037	0.2833	0.2788	0.2788	0.2789	0.2800
5	0.5745	0.5211	0.3980	0.3213	0.2996	0.2799	0.2797	0.2797	0.2800
6	0.6159	0.5920	0.5306	0.4053	0.3211	0.2831	0.2798	0.2799	0.2800
7	0.6447	0.6363	0.6171	0.5702	0.4609	0.3032	0.2801	0.2801	0.2800
8	0.6573	0.6558	0.6524	0.6452	0.6281	0.4434	0.3523	0.3490	0.2821