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WELL TEST REPORT
RE-ENTRY OF WELL 34/10-7
DST No. 2 and 3

January 1984

STATOIL
Gullfaks Produksjon
BERGEN

Den norske stats oljeselskap a.s

statoil
Den norske stats oljeselskap a.s

Classification

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Subtitle

Title

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Completed		Approved	
28.1.84	Hans Ivar Berge / Knut Gjerde	28.1.84	Ole Nygaard.

WELL DATA

Operator	:	Den norske stats oljeselskap a.s
Well	:	34/10-7
Location	:	61° 12' 13.44" N 02° 16' 28.56" E
Classification	:	Exploration Well
Spudded	:	January, 7th 1980
Completed	:	March, 24th 1980
Water depth	:	204 m
Total depth	:	2250 m
Re-entry	:	June, 30th 1983
Objective	:	Re-test, DST-2 and DST-3
Re-entry completed	:	July, 8th 1983
Rig	:	Ross Isle
RKB elevation	:	22 m (log reference: RKB = 25 m)
Status	:	Plugged and abandoned

34/10-7

TEST REPORT

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1. INTRODUCTION

Well 34/10-7 is located in the east of the Gullfaks Field, in the area scheduled for Phase II development. During February 1980, DST-1 was performed over a 7 meter interval in the oil bearing Cook sand, unit 2. Reservoir log fig. 6. The well was suspended in April 1980.

The well was re-entered in June 1983 for two additional drill stem tests, DST-2 and -3. The test sequence comprised:

In Cook unit 2, DST-2:

i an 11 hour flow period
ii a 27 hour pressure buildup
iii a 15 hour seawater injection test followed by a 1,5 hour fall-off
iv a 27 hour surfactant seawater injection
v HRT-survey run across unit 2 and 3

In Cook unit 3, DST-3:

i an 8 hour flow period
ii a 9 hour pressure buildup

2. OBJECTIVES

The objectives of the re-entry test sequence in 34/10-7 were to:

- Determine representative productivity indices for units 2 and 3 of the Cook sand, and for the former, determine representative indices of the water injectivity.

- Establish whether it would be feasible from a large scale water-flooding point of view to inject water into unit 2 in isolation.

- Determine whether surfactant injection would lead to any noticeable improvement in injectivity into unit 2.

- Try and establish whether there is communication between unit 2 and 3.

- Collect representative bottom hole (unit 3) and surface (unit 2 and 3) PVT samples.

3. CONCLUSIONS

Concerning Cook unit 2:

1. The interpretation of DST-2 performed in unit 2 indicate a permeability thickness of 1439 mdm and a formation permeability of 40 md.

2. During the flow period a 6 meter zone above the perforated interval has contributed to flow.

3. The formation productivity index is under ideal conditions calculated to PI = 13 sm^3/D/bar

4. The drill stem test analysis indicate no vertical communication between Cook unit 2 and 3.

5. The rising curvature observed on the Horner plot, DST-2, is not clearly understood but is believed to reflect a local formation barrier within unit 2.

6. The drill stem test analysis indicate no formation damage.

7. The analysis of the injection sequence is restricted to a qualitative interpretation due to fracturing of the reservoir during the early phase of injection. These conditions preclude any certain conclusions concerning the effects resulting from the injection of seawater added surfactant.

8. Injection rates of up to 1600 m^3/D (approx. 10000 bbl/D) of seawater were recorded during the final stages of the injection sequence. The result is regarded as acceptable from a water-flooding point of view.

Concerning Cook unit 3

9. From the interpretation of DST-3 carried out in unit 3, the permeability thickness is calculated to 34158 mdm, giving a formation permeability of 2440 md.

10. The drill stem test indicates a skin factor of S_t = 8 caused by overbalanced perforation.

11. Recovered PVT-samples support the previous most confide PVT-sample recovered during DST-1, 1980.

12. The formation productivity index is under ideal conditions calculated to PI = 277 sm^3/D/bar.

4. DISCUSSION

4.1 DST-2, buildup analysis

The drill stem test is analysed by using the Horner method, detailed in appendix A. No initial flow period was performed. This was not required due to underbalanced perforation giving good initial pressure data. From the pressure recordings the initial static reservoir pressure is calculated to 315,5 bara at midpoint of production 1851 m RKB.

From the Horner straight line analysis, pressure buildup curve shown in figure 2 (data presented in table 1), the following parameters are calculated.

Kh = 1439 mdm
K = 40 md
S_t = 0

The calculated permeability is somewhat higher compared to the result from DST-1 (1980), K = 25 md, which tested the less permeable basal section of unit 2. Comparing the results from DST-2 to data from recovered core-samples from the same interval, ref.1, show a reasonable good agreement. The sample permeabilities varies from 21-71 md giving an average sample permeability of K = 53 md.

The low total skin factor of S_t = 0 is attributed perforating the well under underbalanced conditions preventing formation damage and plugging of perforations. Low skin factors were also reported during DST-1.

The interpretation of the HRT survey performed after finishing the injection sequence, clearly show that not only the perforated part of unit 2 has been affect during the injection sequence, fig. 5. It is evident that a 6 meter interval above the perforations has been flooded during the injection. It should be mentioned that the interpretation of the cement bond log, CBL, in the same interval is uncertain, fig. 8 and 9, but it is believed that fluid from this part of the formation has been drained during the flowing period. This gives a vertical extention of 36 meter for the oil bearing formation tested in DST-2.

Both the permeability and the total skin factor is calculated under the conditions of h = 36 m. This in turn implies that the well has been partially penetrated. A partial penetration skin factor has been calculated giving $S_p = 1,6$. This indicates a negative formation skin factor, $S_f = S_t - S_p = -1.6$. Due to the perforation method chosen, the anticipated formation skin factor should be close to zero, and the deviation is regarded as neglegible.

The slope of the straight line part of the pressure buildup in the Horner plot, fig. 2, is 8,57 bar/cycle (m = 8,57 bar/cycle = 124 psi/cycle). Compared to the infinite acting case, this part of the curve has been drawn down some 4-5 bars, i.e. p* = 310.0 bar from the straight line interception with the ordinate in fig. 2, which for the infinite acting case would give $p^* = p_i = 314.4$ bar at 1834 m RKB. As can be seen also a marked upward curvature is shown at the end of the buildup.

Several reasons are sought to explain the phenomenon:

1) The presence of a sealing fault

Assuming the fault is pressure tight and seals off both unit 2 and 3 the upward curvature of the graph in figure 2 should have a double slope m* compared to the part of the buildup curve representing the formation, i.e. m* = 2 x m = 2 x 8,57 bar/cycle.

Attempting to fit a line with a slope m* to upward part of the pressure buildup, demonstrates that the buildup curve deviates above this double slope line. The observed deviation does not preclude the presence of the anticipated fault but is not understood.

On the other hand, if the fault seals off both unit 2 and 3 a similar pressure buildup effect should be detected in DST-3 as in DST-2. Assuming the fault is located in the same distance from the well in both units, the fault pressure response should show up within 13-15 minutes after shutting the well in during DST-3, which corresponds to log ((t+ t)/ t) 1,55 in figure 22 (Horner plot DST-3). As can be seen, the DST-3 buildup curve does not show the same pressure buildup behaviour.

However, interpreting the pressure buildup graph in DST-3 as a fault pressure response would imply that the slope calculated, m = 0.369 bar/cycle, is twice the one representing the formation. The permeability in unit 3 would under these conditions be equal to some 5000 md, twice the permeability calculated in appendix B.

This permeability value (5000 md) is considered as too high and unrealistic, and tied up with the pressure buildup curves of DST-2 and 3 a greater sealing fault sealing off both units is not believed being present, causing the abnormal pressure respons in DST-2.

2) Communication with unit 3

As pointed out it is concluded that fluid from a 6 meter high zone above the perforated interval has been drained during the flow period.

Whether fluid from unit 3 has been affected is questionable. The unit 3 formation consists of high permeable sands interbedded with layers of low permeable/tight carbonate rocks at the unit boundary between unit 2 and 3. This is clearly viewed on the well's reservoir log of Cook formation, unit 2 and 3, presented in fig. 6. This layering causes a dramatic lowering of the vertical permeability. Therefore, whether the great pressure drop created during the drawdown period enables fluid from unit 3 to flow into unit 2 is uncertain.

However, assuming a slight degree of vertical communication, unit 2 and 3 might be analysed as a two permeability system. A two permeability system represents the phenomenon of two formations with different formation properties produced through one of the two. It is claimed, ref. 2 and 3, that producing a well under these conditions the Horner plot graph from the buildup period has a continuously decreasing slope.

In figure 2 showing the DST-2 buildup this is obviously not the case. As can be seen, the final part of the buildup graph has a slope of continuous increase.

Based on this contradiction in graph curvature the vertical communication between unit 2 and 3 is doubted.

3) Local barrier

As pointed out, the presence of a fault sealing off the entire Cook reservoir is not believed causing the abnormal pressure buildup behaviour. However, the pressure response indicates the presence of a barrier within unit 2.

Currently the phenomenon is not fully understood, but it is believed that a local barrier within unit 2 is present. This barrier could be in the form of changes in formation properties or in the form of a minor fault where the latter is emphasized as the most realistic.

An average porosity of 26% and a water saturation 37% are used in the DST analysis, ref. 5. PVT properties are picked from the PVT analysis of the bottom hole fluid samples recovered during DST-3 in unit 3, ref.6. During DST-2 separator samples were collected.

4.2 Dimensionless pressure function

Both injection tests (ref. section 1) have been analytically analysed using a dimensionless pressure function which is characteristic of the drained formation. The dimensionless function is obtained from the pressure-time data recorded during the flow period, DST-2. The mathematical expression of the function is not tried evaluated and is not known, consequently only the function behaviour from the recorded pressure-time data.

The flowing period can be described as:

$$p_D(t_D) + S = \alpha(p_i - p_{wf}) \qquad (1)$$

where

$$\alpha = 5.36 \times 10^{-2} \times \frac{K\ k_{ro}\ h}{q_o\ \mu_o\ B_o} \qquad (2)$$

t_D = dimensionless time

$$= 0.000264 \times \frac{K\ k_{ro}\ t}{\Phi\ \mu_o\ c_t\ r_w^2} \qquad (3)$$

In the two later equations the permeability K is from Horner pressure buildup analysis DST-2. Pressure time data from the flow period is presented in table 7 together with corresponding calculated values of $p_D(t_D)+S$ and t_D. Calculations are detailed in appendix A-2.2. Plotting the determined values of $p_D(t_D)+S$ versus t_D gives the dimensionless pressure function presented in fig. 12.

In the same figure the transient Odeh-Jones p_D function is plotted, i.e.

$$p_D(t_D) = 1/2\ \ln(4\ t_D/\gamma) \qquad (4)$$

γ = Euler's constant

As can be seen, fig. 12, the transient function, equation (4) show a smooth downward curvature while the obtained p_D function show a contrary graph curvature, demonstrating lack of transience as the pressure response (DST-2) sees formation barriers.

This is further investigated and to approve the applicablity of the function it is utilized to calculate the theoretical buildup. The pressure buildup can be described as:

$$(P_i - P_{ws}) = p_D(t_D + \Delta t_D) - p_D(\Delta t_D) \qquad (5)$$

Δt_D - dimensionless close-in time

Reorganizing equation (5) the shut-in bottomhole pressure p_{ws} (bara) can be calculated. A comparison of the theoretical calculated and the observed pressure buildup is shown in fig. 13. For small values of the closed-in time (t<40 minutes) the match between the two is poor, as may be expected with the fluctuating rates at the start of the flow period. For larger values of the time argument, however, the match indicates that the $p_D(t_D)+S$ function is reliable. The function is therefore considered as being convenient for the analytical interpretation of the injection sequence.

The most useful application of this function is subsequent analysis i.e. for log $t_D>4.0$, and the function has been plotted on an enlarged scale for this time range in figure 14. The trend of this plot has been extrapolated linearly for log $t_D>5.8$ for use in the subsequent injection analysis.

4.3 Seawater injection

Due to the rate variations during the injection, the test has been analysed using the superposed rate-time expression of the determined dimensionless pressure function:

$$\alpha' \left(\frac{p_{inj_n} - p_i}{q_n} \right) = \sum_{j=1}^{j=n} \frac{q_j - q_{j-1}}{q_n} p_D(t_{D_n} - t_{D_{j-1}}) + S \quad (6)$$

in which $p_{inj.n}$ is the injection pressure at the end of the n'th period. The dimensionless pressure function p_D is in equation (6) evaluated for the time argument $t_{Dn} - t_{Dj-1}$. (See appendix A-22)

The coefficient:

$$\alpha' = 5.36 \times 10^{-2} \times \frac{K \, k_{rw} \, h}{\mu_w \, B_w} \quad (7)$$

in which the parameters B_w and μ_w are evaluated for seawater, and k_{rw} is the relative permeability to water being injected into the oil column.

A plot has been made of

$$\frac{(p_{inj_n} - p_i)}{q_n} \quad \text{vs} \quad \sum_{j=1}^{j=n} \frac{q_j - q_{j-1}}{q_n} p_D(t_{D_n} - t_{D_{j-1}})$$

in fig. 15 and in table 9 the two plotted parameters and source data are presented. Instead of resulting in a single linear function the plot (fig. 15) demonstrates an apparent random scatter of points, precluding a sensible determination of reservoir parameters by analysis.

A similar scatter of plotted points is obtained using the transient Odeh-Jones p_D function, equation (4).

It is believed that the observed scatter of points is influenced by fracturing the reservoir during the injection.

However, the slope of any linear trend through the points in fig. 15 should be:

$$m = \frac{1}{\alpha'} \qquad (8)$$

$$= 18.66 \times \frac{\mu_w B_w}{K k_{rw} h}$$

using (approximate values):

μ_w = 1.0 cp - estimate for the cold injection water

B_w = 1.0 rm^3/stm^3

K = 40 md

k_{ro} = 0.2 - relative permeability for the injection of water into the oil-zone. ($S_w < 1 - S_{or}$)

h = 36 metre

Then the slope m = 0.065 bar/stm^3

Using this slope in figure 15, a series of lines can be drawn through the data points (only points 1 and 2 appear to be exceptions). The trend in these lines indicates that as the rates increase, the lines move to the right. The intercept of these lines with the ordinate, intercept = m x S, indicate increasing values of negative skin.

This trend is interpreted as fracturing of the reservoir which increases the observed negative skinfactor.

4.4 Surfactant seawater injection

Through this injection sequence, surfactant was added to the seawater at a 9% concentration. The surfactant composition is shown in table 10, ref. 4.

The results from the injection test have been analysed as described in section 4.3. The data is listed in table 11 and a plot of the two parameter

$$\frac{(p_{inj_n} - p_i)}{q_n} \quad \text{vs} \quad \sum_{j=1}^{j=n} \frac{q_j - q_{j-1}}{q_n} \, p_D(t_{D_n} - t_{D_{j-1}})$$

are presented in fig. 16. As can be seen, a scatter of points is obtained rather than a single linear trend. Utilizing seawater properties in equation (8), a series of lines with slope m = 0.065 bar/stm^3 can be drawn. The lines move to the right on the plot as the injection rates increase, indicating an increasing negative skin. This is interpreted as fracturing of the reservoir and conclusively no separate effect of the surfactant injection can be distinguished by analysis.

The recorded bottom hole pressure ($p_{bh} = p_{inj}$ in table 9 and 11) from both the seawater injection and the surfactant seawater injection has been plotted versus the measured injection rate, q_{inj}, in figure 17. From this plot the relationship between the two parameters show a marked discontinuity as the bottom hole pressure approaches 345 bara, p_{bh} 345 bara. The apparent pressure discontinuity defines the approximate formation fracturing pressure, and as can be seen most of the pressure information from both injection tests is gathered in this pressure region.

From the bottom hole pressures recorded during the seawater injection, the fracturing pressure is reached within the third or fourth pressure reading, which corresponds to four or five hours after the startup of the injection. These conditions should support the previous statement of reservoir fracturing both during the seawater and the surfactant seawater injection which does undermine any certain conclusions respecting the surfactant effects.

It should also be mentioned that the data collected through the injection tests in general are poor, which masks the informatin and complicates interpretation of the obtained data. This is caused by influence of several factors:

i Fluctuating pressure and flow from the cement pump used as injection pump

ii Contamination from cement pumps and fixed lines in spite of a four hour system pre-flush, table 12

iii Poor filtration efficiency of the injection fluid, table 13 and 14

Lay-out of injection surface equipment appendix A-2.1 and fig. 11.

4.5 DST-3, buildup analysis

DST-3 was performed in the upper part of the Cook sands, Cook unit 3. The perforated interval was located at 1810-1824 m RKB, perforated under overbalanced conditions. The unit 3 formation consists of a high porosity, medium grain-sized sand. At the bottom, close to the unit boundary between unit 3 and 2 the sand is laminated with 1,5-2,0 meter thick low permeable/tight carbonates. Reservoir log of the Cook unit 2 and 3 in well 34/10-7 is shown in figure 6.

From the Horner straight line analysis the permeability thickness is calculated to 34158 mdm, giving a permeability of k = 2440 md. These figures are believed being representative for the total unit 3. From recovered core samples in the same interval, ref. 1, sample permeability measurements reported a liquid permeability of k = 2420 md.

The moderate positive skin factor of S_t = +8,2 is caused by the methods of perforating (conventional casing gun, 4 sh/ft), under which both formation and perforations are polluted by mud-flow and filtrate.

The pressure calculated from the second buildup do compare perfectly to the initial pressure data, and no depletion is observed. Both pressures are calculated being $p_{ws} = p_i$ = 314,3 bar at midpoint of production. A comparison of the initial static pressure data from DST-3 to previous RFT-data (DST-1) is shown in figure 25. No noticeable separation is observed.

The actual productivity index calculated gives a PI = 153,6 sm^3/D/bar and under ideal conditions, S_t = 0, PI = 277 sm^3/D/bar.

Through the DST-3 analysis an average porosity of 31,6% is used and a water saturation of 16,1%, ref. 5.

PVT properties were taken from the PVT report based on the recovered fluid samples during the test, ref. 6.

The recovered sample does support the previous most confied PVT properties and both sampling and sample measurements have been successful.

Drill stem test calculations and analysis are presented in appendix B-1.1 together with pressure buildup data, table 16, and Horner plot, figure 22.

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   "Determination of skin factors and flow capacities of individual layers in two layered reservoirs."
   SPE 11138

3. Prijambodo, R., Raghavan, R. and Reynolds, A.C.:
   "Well Test Analysis for Wells Producing Layered Reservoirs with Crossflow."
   SPE 10262

4. Eimund Gilje
   LAB 83-44
   "34/10-7 (Cook) surfactant stimulation fluid study"
   Statoil exploration and production laboratory

5. "Data summary Well 34/10-7."
   Table 1
   "Results of petrophysical parameters in Cook."

6. 34/10-7, DST-3
   LAB 83-67
   "Composition, single flash and bubble point of reservoir fluid."
   Statoil exploration and production laboratory

APPENDIX A

A-1.1

BOTTOM HOLE PRESSURE REPORT

Well 34/10-7

Test no. DST-2

Test Date 30.06.-04.07.83

Date of analysis Nov. 83

Gauge no. SDP no. 82016

SUMMARY OF THE RESULTS

	Horner analysis	
Kh md·m	1439	
K md	40.0	
S	0	
$\bar{P}$ at -1826 m ss	313.9 bar	

Max recorded Temp. 75.8°C

Remarks

Signature

Well 34/10-7

Test date 30.06.-04.07.83

Reservoir Parameters

Perforations 1836-1866 m RKB

Zone(s) Cook unit 2

ss

Wellbore radius 0.11 m

RKB Elev 25 m

Midpoint Production — 1826 m ss

Bomb at 1834 m RKB — 1809 m ss

Pressure Functions Evaluated at — 1809,5 m ss

Datum Depth — ____ m ss

Delta P required to correct to datum ____ bar

Gradient 0.0673 bar/m

Estimated Average Pressure ____ bar

Formation Volume Factor 1.434 vol/vol

Viscosity 0.493 cp

Thickness 36 m

Porosity 26 %

Drainage Area ____ m^2

Oil Saturation 63 %

Oil Compressibility 168 10^{-6} bar^{-1}

Water Saturation 37 %

Water Compressibility 43,5 10^{-6} bar^{-1}

Gas Saturation – %

Gas Compressibility ____ 10^{-6} bar^{-1}

Formation Compressibility 43,5 10^{-6} bar^{-1}

System Compressibility $C_t = S_0C_0 + S_wC_w + S_gC_g + C_f$

$C_t = 0.63 \times 168 \cdot 10^{-6} + 0,37 \times 43,5 \cdot 10^{-6} + \_\_\_ \times \_\_\_ \cdot 10^{-6} + 43,5 \cdot 10^{-6}$

$C_t = 165,4 \cdot 10^{-6}\ bar^{-1}$

Rates Reported on Test.

Choke 40/64 inches

Oil Rate 810 Sm^3/D

Gas Rate $98,9 \cdot 10^3$ Sm^3/D

FTP ____ bar

Water Rate 0 Sm^3/D

GOR 122 Sm^3/Sm^3

^0API 39,7

Gas Spec. Grav. 0,68

Cumulative Production

Oil 485 Sm^3

Gas $52,4 \times 10^3$ Sm^3

Water –

Well 34/10-7 Test Date 30.06.-04.07.83

Horner Analysis

Effective Production Time tp ≐ Cumulative Production / Rate Reported on Test.

$tp = 24 \times 485\ Sm^3 \,/\, 810\ Sm^3/D = 14.4$ hrs

Straight line starts at 04.25 hrs Slope = 8.57 psi/cycle

$P_{wf's}$ = 251.8 psig

P_{1hr} = 294.6 psig

P^* = ______ psig

Calculated Values

$Kh = \frac{162.6\ Q\ B\mu}{M} = \frac{162.6 \cdot 810 \cdot 1.434 \cdot 0.493}{0.159 \cdot 124} = 4723$ md.ft

= 1439 md.m

$K = Kh/h = 1439 \,/\, 36 = 40$ md.

$$S = 1.1513 \left[\left[\frac{P_{1hr} - P_{wf\,s}}{M}\right] + \text{Log}\left[\frac{tp\ \ 1}{tp}\right] - \text{Log}\left[\frac{K}{\emptyset \mu C_t\ rw^2}\right] + 3.2275\right]$$

$$S = 1.1513 \left[\left[\_\_\_\_\right] + \text{Log}\left[\_\_\_\_\right] - \text{Log}\left[\_\_\_\_\right] + 3.2275\right]$$

S = 0

$t_{DA} = \frac{0.000264\ Kt}{\emptyset \mu C_t A} = 0.000264$ ______ = ______

P_{DMBH} = ______

$\bar{P} = P^* - P_{DMBH}\left[\frac{M}{2.303}\right] =$ 312,8 bar @ – 1810 m ss

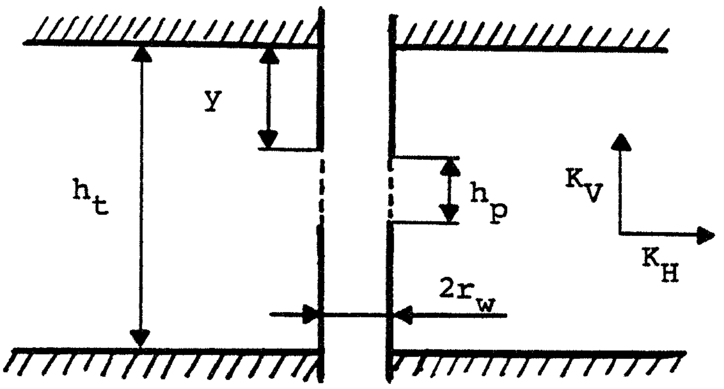
= ______ bar @ – ______ m ss Datum

$PI_a = q_o/\Delta p = 810/(315,5 - 252,9) = 12,9\ Sm^3/D/bar$

$PI_{s=0} = PI_a$

Well 34/10-7 Test date 30.06-04.07.83

PARTIAL PENETRATION SKIN FACTOR



h_t = 36 m (118 ft)

h_p = 30 m (98.4 ft)

y = 6 m (17.7 ft)

r_w = 0.11m (0.35 ft)

K_H/K_V = 10

$$z_m = y + h_p/2$$

$$r_{wc} = r_w e^{0.2126(z_m/h_t+2.753)}$$

$$S_p = 1.35((h_t/h_p - 1)^{0.825}(\ln(h_t(K_H/K_V)^{0.5}+7) - (0.49+0.1\ln(h_t(K_H/K_V)^{0.5}))\ln r_{wc} - 1.95))$$

S_p = 1.6

BRØNN 34-10-7 DST# 2
BUILDUP NUMMER 1
GAUGE SDP82016

TABLE 1

NR.	TID	TRYKK	NR.	TID	TRYKK	NR.	TID	TRYKK
1	4.14	282.650	35	7.21	304.680	67	23.26	311.590
2	4.15	286.910	36	7.59	305.380	68	23.27	311.590
3	4.16	288.970	37	8.51	306.190	69	0.31	311.810
4	4.17	290.280	38	10.01	307.040	70	1.03	311.910
5	4.18	291.260	39	11.33	307.980	71	1.19	311.940
6	4.19	292.010	40	12.29	308.440	72	2.23	312.130
7	4.20	292.670	41	12.39	308.540	73	2.55	312.230
8	4.21	293.190	42	13.03	308.730	74	3.27	312.290
9	4.23	294.080	43	13.19	308.850	75	3.59	312.320
10	4.24	294.470	44	13.39	308.980	76	5.03	312.490
11	4.25	294.810	45	13.47	309.040	77	5.07	312.480
12	4.26	295.110	46	14.07	309.160	78	6.11	312.630
13	4.27	295.370	47	14.39	309.400	79	6.43	312.690
14	4.28	295.670	48	15.19	309.640	80	6.47	312.700
15	4.30	296.120	49	15.43	309.740	81	6.49	312.700
16	4.32	296.520	50	16.31	310.000	82	6.50	312.700
17	4.34	296.900	51	17.03	310.170	83	6.52	312.720
18	4.36	297.240	52	17.19	310.270	84	6.54	312.740
19	4.38	297.540	53	17.35	310.300	85	6.58	312.740
20	4.42	298.100	54	18.07	310.460	86	7.02	312.760
21	4.45	298.440	55	18.23	310.550	87	7.03	312.760
22	4.51	299.010	56	18.47	310.620			
23	4.57	299.550	57	19.51	310.910			
24	5.02	299.940	58	20.07	310.910			
25	5.11	300.530	59	21.27	311.260			
26	5.20	301.020	60	21.35	311.270			
27	5.31	301.500	61	21.51	311.300			
28	5.40	301.930	62	21.59	311.320			
29	5.48	302.200	63	22.31	311.450			
30	6.00	302.650	64	23.03	311.560			
31	6.14	303.100	65	23.19	311.580			
32	6.30	303.560	66	23.23	311.580			
33	6.46	303.970						
34	7.06	304.420						

Figure 1

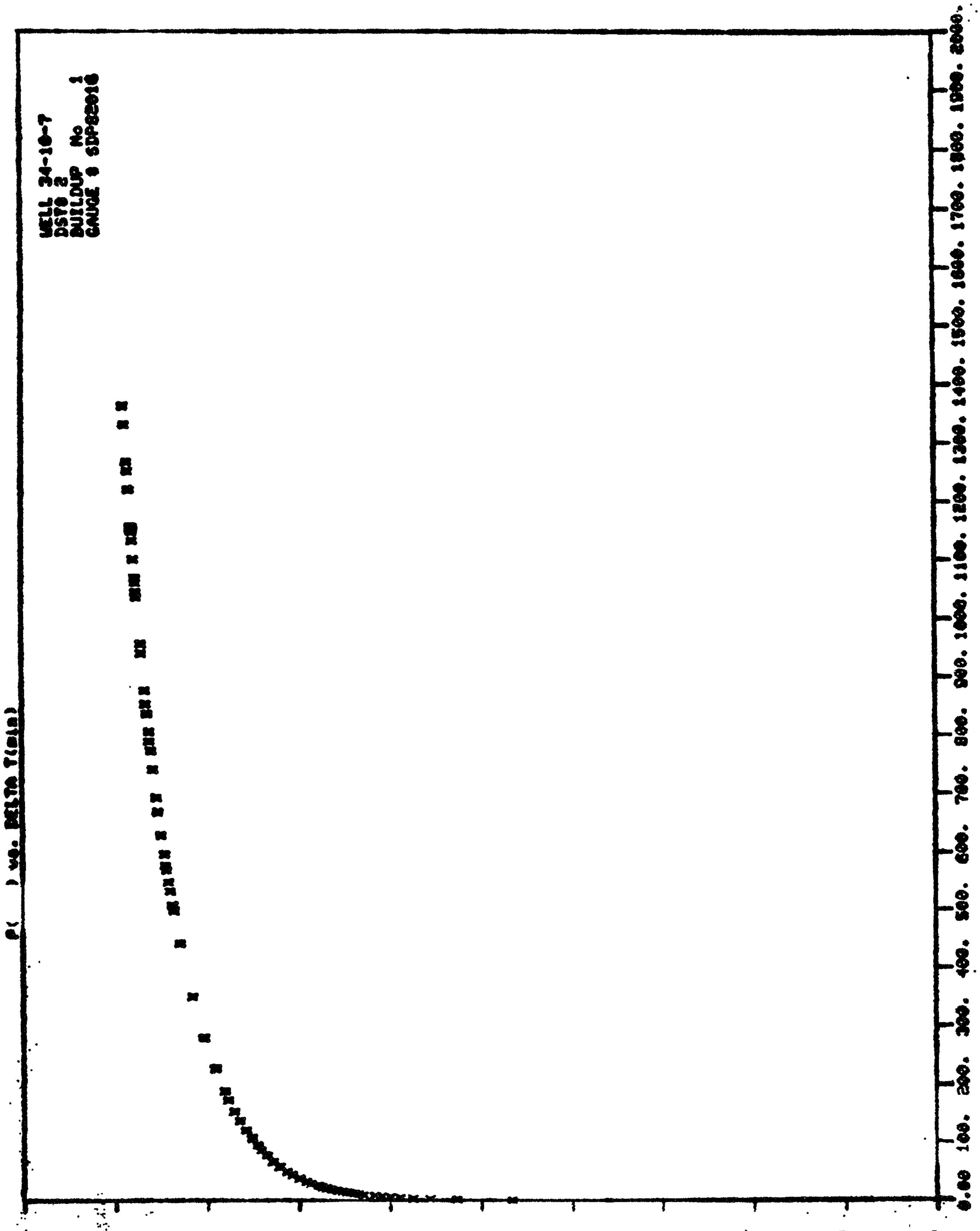
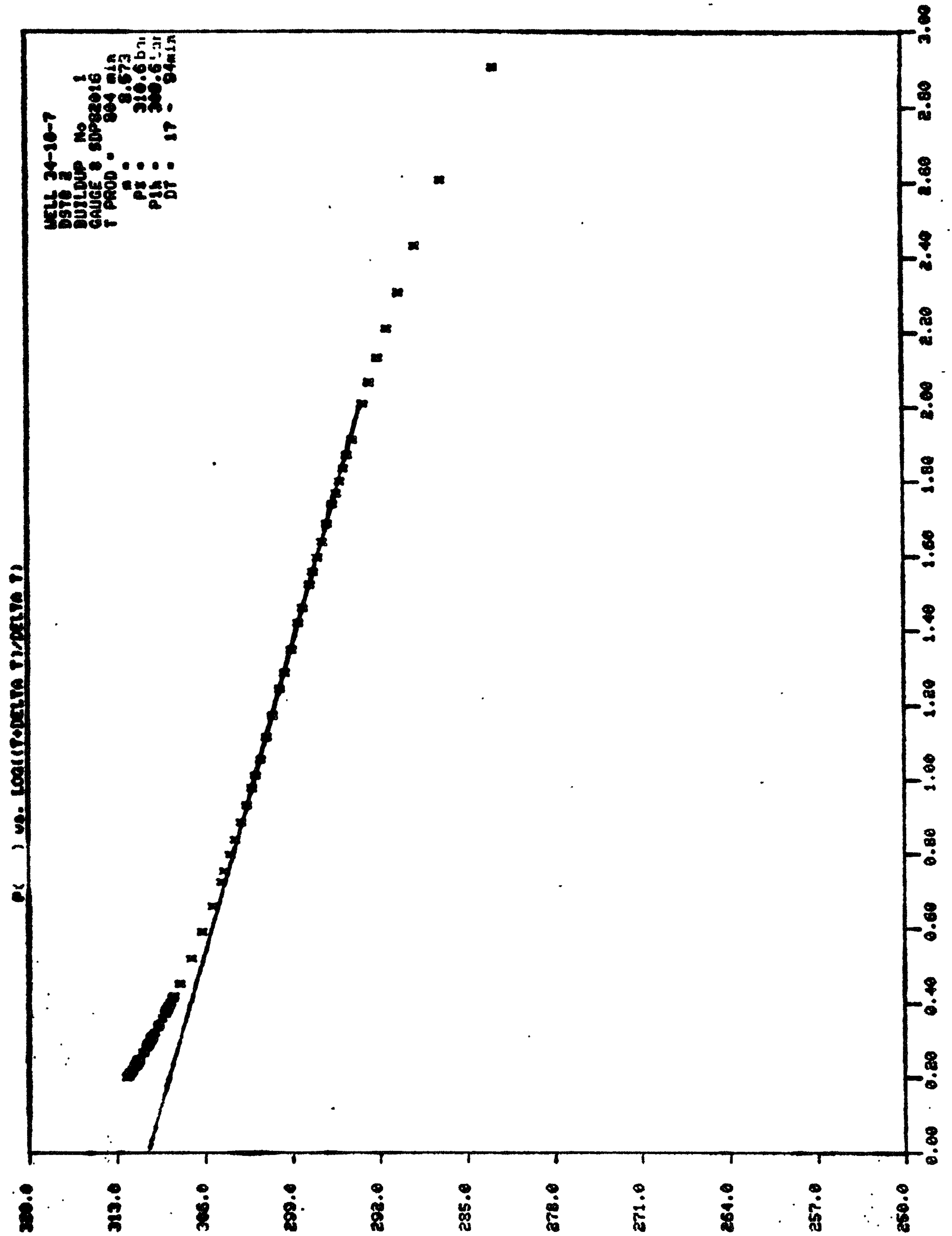
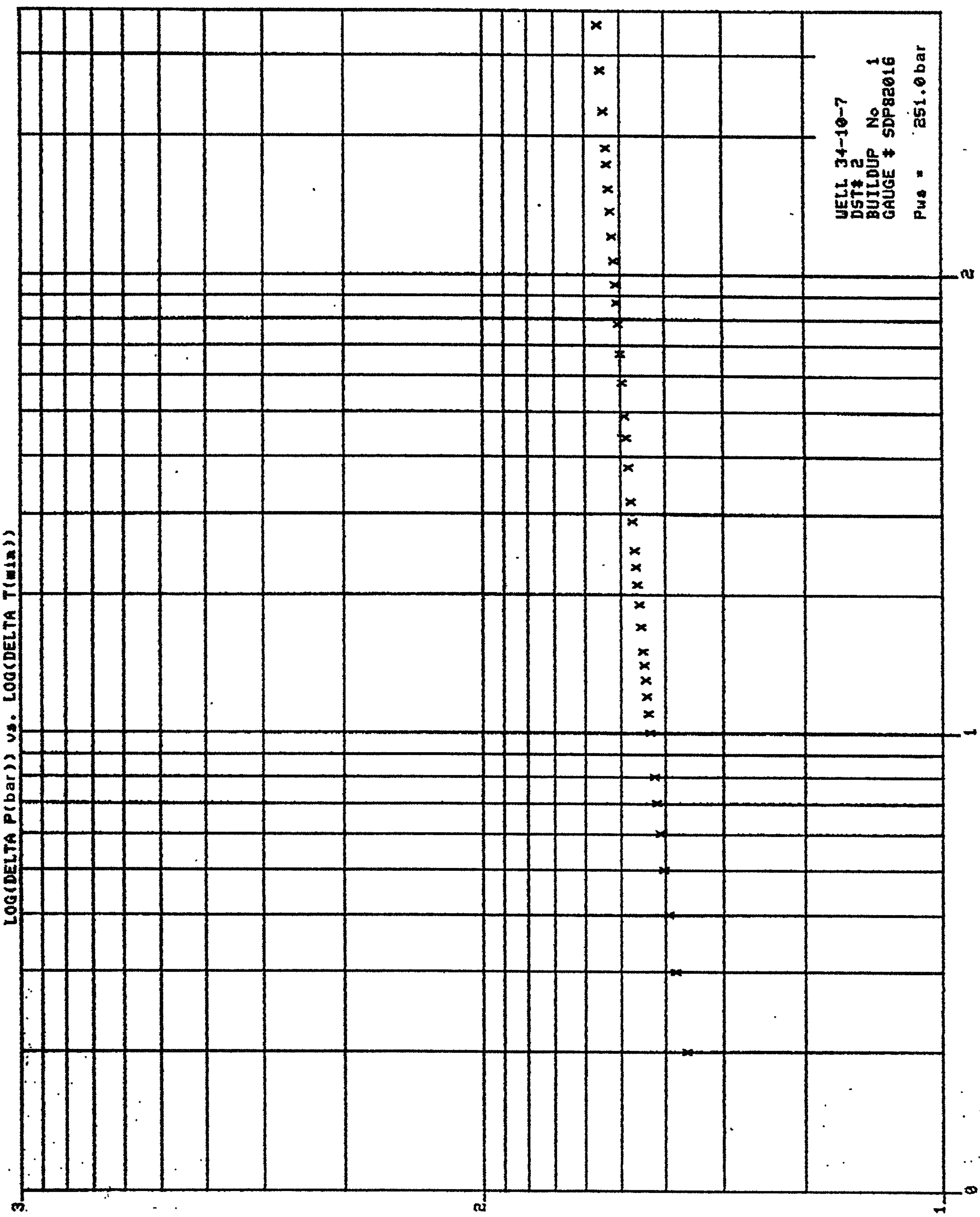

WELL 34-10-7
BUILDUP No 1
DELTA T(min)
330.0
313.0
306.0
299.0
292.0
285.0
278.0
271.0
264.0
257.0
0.00
100.
200.
300.
400.
500.
600.
700.
800.
900.
1000.
1100.
1200.
1300.
1400.
1500.
1600.
1700.
1800.
1900.
2000.

Figure 2


P( ) vs. LOG((T+DELTA T)/DELTA T)
WELL 34-10-7
DSTB 2
BUILDUP No 1
GAUGE 8 SDP82016
T PROD = 904 min
m = 8.573
Pi = 310.6 bar
DT = 17 - 94min
320.0
313.0
306.0
299.0
292.0
285.0
278.0
271.0
264.0
257.0
250.0
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

A-1.2

Figure 3



WELL 34-10-7
DST# 2
BUILDUP No 1
GAUGE # SDP82016
Pws = 251.0bar
LOG(DELTA P(bar)) vs. LOG(DELTA T(min))
3
2
1
2
1
0

FLOW DATA

Well 34/10- 7

DST no. 2

CHP/PG

Perfs.: 1836-66 m RKB

Zone tested: Cook Sand

Date/ time	Bottom hole		Well head		Chokes 1/64"		Separator data							Liq. and gas analysis					
	press. bar	temp °C	press bar	temp. °C	mani-fold	heat.	press. bar	temp. °C	gas rate $10^3 Sm^3/D$	oil rate Sm^3/D	GOR Sm^3/Sm^3	sp.gr.oil	sp.gr.gas (Air=1)	Water %	Sedim. %	CO_2 %	H_2S ppm		
30/6																			
1730	259	75	113	47	40	–	26.9	25.2	138.0	561.2	246	0.832	0.69	0	0				
1800	258	75	113	48	40	–	26.2	26.3	143.3	822.9	174	0.832	0.69	0	0	0.5	0		
1830	258	75	113	48	40	–	26.2	26.3	135.7	817.3	166	0.832	0.69	0	0				
1900	257	75	113	49	40	–	26.9	26.9	149.1	799.1	187	0.832	0.69	0	0	0.5	0		
1930	257	75	112	49	40	–	28.9	27.4	150.6	775.4	194	0.832	0.69	0	0				
2000	256	76	113	50	40	–	27.9	45.4	144.6	800.5	181	0.832	0.69	0	0	0.5	0		
2030	256	75	112	50	40	–	27.9	45.4	145.9	818.0	178	0.832	0.68	0	0				
2100	256	75	112	50	40	–	27.9	46.5	144.3	810.3	178	0.833	0.68	0	0	0.5	0		
2130	255	75	112	50	40	–	26.2	48.2	102.5	807.4	127	0.833	0.68	0	0				
2200	255	76	112	51	40	–	26.2	48.2	102.4	801.2	128	0.831	0.68	0	0	0.5	0		
2230	255	76	112	52	40	–	26.2	48.2	102.3	800.5	128	0.831	0.68	0	0				
2300	254	76	112	52	40	–	26.2	49.3	102.2	794.2	129	0.832	0.68	0	0				
2330	254	76	111	52	40	–	26.2	48.2	102.2	792.1	129	0.832	0.68	0	0				
2400	254	76	111	53	40	–	26.2	48.2	102.2	824.5	124	0.832	0.68	0	0	0.5	0		

Remarks

The gas readings before 21.00 hours are too high. These flow data are effected by carry-over due to plugging of the burners.

Table 2 continued

Well 34/10- 7	FLOW DATA	CHP/PG
DST no. 2		Perfs.: 1836-66 m RKB
		Zone tested Cook Sand

Date/ time	Bottom hole		Well head		Chokes 1/64"		Separator data							Liq. and gas analysis					
	press. bar	temp °C	press bar	temp. °C	mani-fold	heat.	press. bar	temp. °C	gas rate $10^3 Sm^3/D$	oil rate Sm^3/D	GOR Sm^3/Sm^3	sp.gr.oil	sp.gr.gas (Air=1)	Water %	Sedim. %	CO_2 %	H_2S ppm		
1/7																			
0030	253	76	111	53	40	–	26.2	48.2	102.2	820.9	124	0.832	0.68	0	0				
0100	253	76	111	53	40	–	26.2	49.3	102.2	817.2	125	0.833	0.68	0	0				
0200	253	76	111	53	40	–	26.2	51.0	101.1	816.5	124	0.834	0.68	Trace	0	0.5	0		
0230	252	76	111	53	40	–	26.2	51.5	101.1	812.9	124	0.834	0.68	Trace	0				
0300	252	76	110	53	40	–	25.9	51.5	99.0	812.0	122	0.826	0.68	Trace	0				
0330	252	76	110	53	40	–	26.2	51.5	99.7	809.8	123	0.826	0.68	Trace	0				
0400	252	76	110	53	40	–	25.9	51.5	98.9	810.5	122	0.826	0.68	Trace	0	0.5	0		

Remarks

Figure 4

34/10-7, DST no. 2
PRESSURE, TEMPERATURE, CHOKE & FLOWDIAGRAM

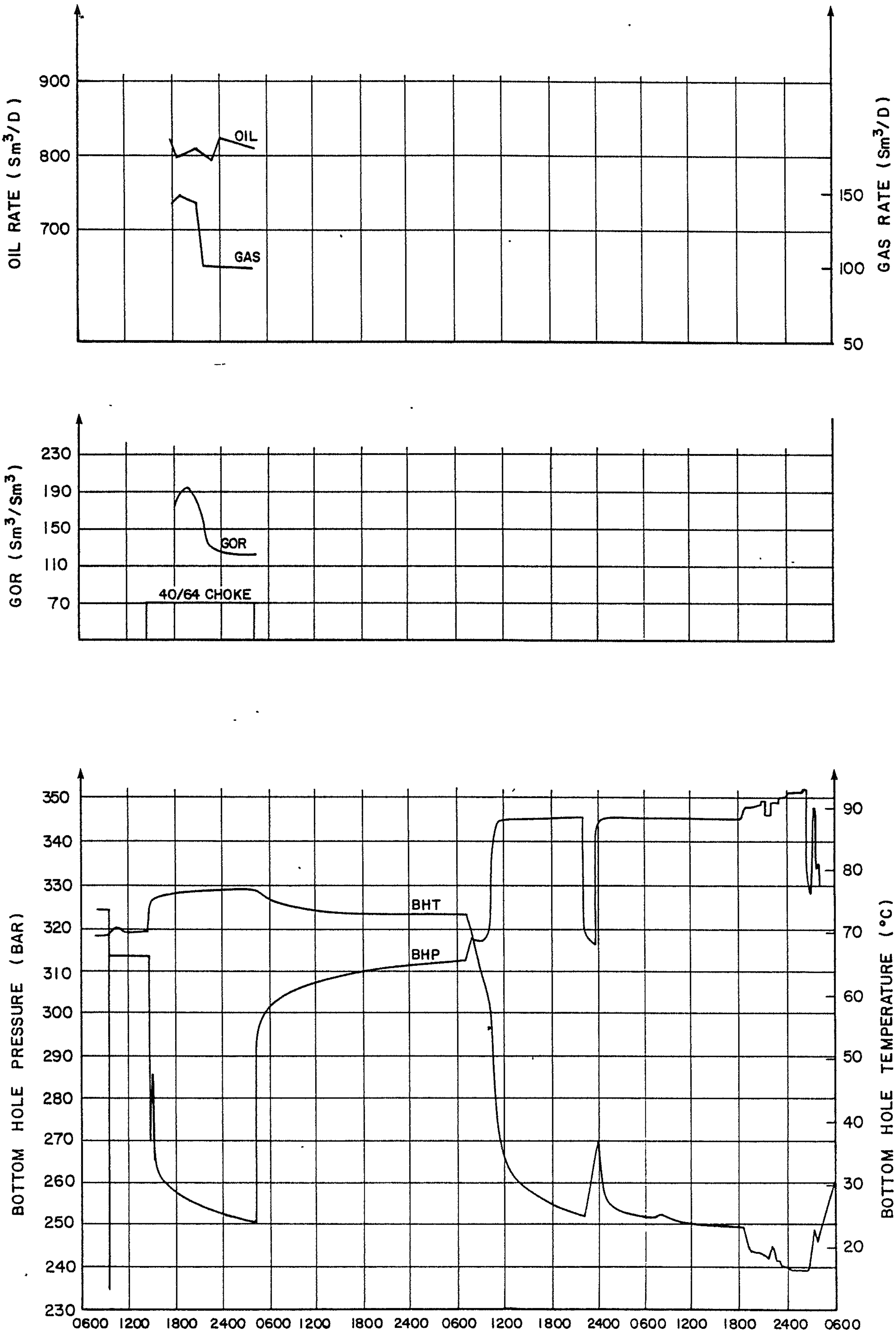


Table 3

Well 34/10- 7	SAMPLING	CHP/PG
DST no 2		Perfs.: 1836-66 m RKB
		Zone tested Cook sand

SEPARATOR SAMPLES

Time/date	Sample no.	Type of sample	Transfer time	Bottle no
1/7-83				
0252	1A	Oil	29 min.	1509
0252	1B	Gas	29 min.	A 14747
0348	2A	Oil	21 min.	1422
0348	2B	Gas	21 min.	A 14748

BOTTOM HOLE SAMPLES

Time/date	Sample depth mRKB	Estimated PB bar/°C	Transfering pressure(bar)	Bottle no

DEAD FLUID SAMPLES

Time/date	Sampling point	Sampling equipment	Remarks
1/7-83			
0345	Separator	6 x 1 l Glass Jars	Oil
0530	Separator	3 x 10 l Jerry cans	Oil
0600	Separator	2 x 200 l Drums	Oil

A-1.5 THE TEMPERATURE LOG

A squeeze job between the test intervals for DST no. 2 and no. 3 was done to prevent a possible production from the highly permeable zone above while performing DST no. 2.

A CBL run after the squeeze gave shows of a good cement bond, but these data were not good enough to eliminate the change of production along the well bore. The CBL before and after the squeeze is shown in figures 8 and 9, appendix A-1.9.

It was decided to run a temperature log (HRT) after the seawater injection. A cooling effect over the perforated zone and the permeable section above was seen.

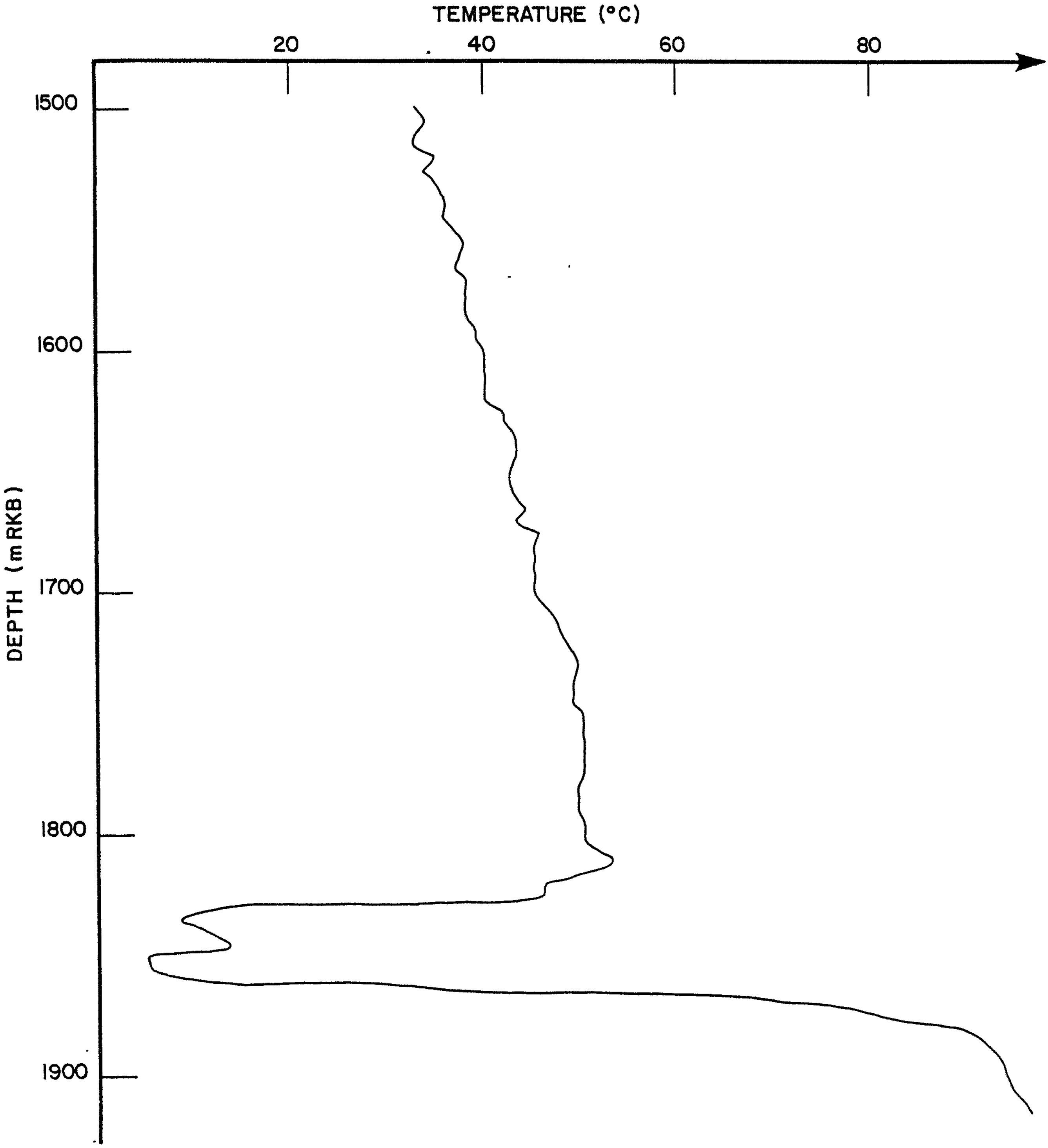
It is therefore assumed that the production has drained the formation interval from 1830 - 1866 m RKB.

The temperature profile is shown in figure 5.

Figure 5

34/10-7, DST no. 2

TEMPERÁTURE LOG



K.G. 18.10.83

Figure 6

Table 4

Well 34/10-7	LAYOUT OF TEST-STRING	CHP/PG
		Perfs 1836-66 m RKB
DST no 2		Zone tested Cook sand

TEST-STRING	ID inch	OD inch	LENGTH m	DEPTH mRKB
Flopetrol sst w/x-over				-5.55
1 jnt 3 1/2 ph-6 tbg. 12.95 lbs/ft p-105	2.75	3.5	9.21	3.66
1 pupjnt 3 1/2 ph-6 tbg.	2.75	3.5	4.50	8.16
1 jnt 3 1/2 ph-6 tbg	2.75	3.5	9.21	17.36
1 pupjnt 3 1/2 ph-6 tbg.	2.75	3.5	1.06	18.43
1 x-over 3 1/2 ph-6 box x4 1/2 sa pin	3.0	5.75	0.50	18.93
1 Flopetrol lub. valve	3.0	13.10	1.76	20.69
1 x-over 4 1/2 sa pin-3 1/2 ph-6 pin	3.0	5.75	0.56	21.25
1 pupjnt 3 1/2 ph-6	2.75	3.0	2.29	23.54
7 stds 3 1/2 ph-6 tbg.	2.75	3.5	192.59	216.13
1 pupjnt 3 1/2 ph-6 tbg.	2.75	3.5	1.68	217.81
1 x-over 3 1/2 ph-6 box x4 1/2 sa pin	3.0	5.75	0.50	218.31
1 Flopetrol ex tree	3.0	10.87	3.66	221.97
1 x-over 4 1/2 sa pin x3 1/2 bds pin	3.0	5.75	0.21	222.18
1 slick jnt 3 1/2	2.75	3.5	2.24	224.42
1 x-over 3 1/2 bds box x4 1/8 sa pin	2.75	5.30	0.20	224.62
Top 18 3/4 wellhead at 224.7 m RKB				
1 fluted hanger	3.0	9.75	0.30	224.92
1 x-over 4 1/8 sa pin x3 1/2 ph-6 pin	2.75	5.30	0.50	225.42
1 pup jnt 3 1/2 ph-6	2.75	3.5	2.74	228.16
1 pup jnt 3 1/2 ph-6	2.75	3.5	1.06	229.22
1 jnt 3 1/2" tbg ph-6	2.75	3.5	8.60	237.82

Remarks.

All measurements to bottom of each item

Well 34/10-7	LAYOUT OF TEST-STRING	CHP/PG
		Perfs 1836-66 m RKB
DST no 2		Zone tested Cook sand

TEST-STRING	ID inch	OD inch	LENGTH m	DEPTH mRKB
48 stds 3 1/2 ph-6 tbg.	2.75	3.5	1320.31	1559.13
1 x-over 3 1/2 ph-6 box x3 1/2 if pin	2.75	5	0.38	1559.51
1 slip joint (open)	2.25	5	5.54	1565.05
1 slip joint (closed)	2.25	5	4.02	1569.07
5 stds drill collars + 2 single	2.25	4 3/4	161.33	1730.40
1 rtts mech. circ. valve	2.44	4.625	1.10	1731.50
1 std drill collar	2.25	4 3/4	28.50	1760.00
1 slipjt (closed)	2.25	5	4.02	1764.02
1 slipjt (closed)	2.25	5	4.02	1768.04
1 std dill collar	2.25	4 3/4	28.49	1769.53
1 apr-m circ./safety valve	2.25	5	2.29	1798.82
1 drill pipe tester valve	2.25	5	1.35	1800.17
1 lpr tester valve	2.25	5	4.99	1805.16
1 ful flo hydraulic bypass	2.25	4.625	2.02	1807.18
1 jar	2.25	4.625	1.58	1808.76
1 rtts safety joint	2.44	5	0.88	1809.64
1 rtts packer, (above)	2.40	5	0.56	1810.20
1 rtts packer, (below)	2.40	5.75	0.83	1811.03
1 bundle carrier	2.25	4.00	5.09	1816.12
1 perforated 2 7/8 eue pup jt	2.44	2.88	3.53	1819.65
1 geovann equal sub 2 7/8 eve box xpin	2.44	2 7/8	0.52	1820.17
1 x-over 2 7/8 eve box x2 3/8 eve pin	1 7/8	3 1/4	0.24	1820.41
1 baker f-nipple 2 3/8 eve box x pin	3"	1 3/4	0.28	1820.69
1 jt geovann 2 3/8 eve box x pin	1.99	2 3/3	9.73	1830.42
1 jt geovann exstended fire head 2 3/8 eve box x pin	0	2 3/8	2.57	1832.99
1 jt geovann fire head 2 3/8 eve box x pin	0	2 3/8	0.38	1833.37
geovann perforator	0	2 3/8	30.00	1863.37
1 geovann bullplug	0	5.00	1.57	1864.94

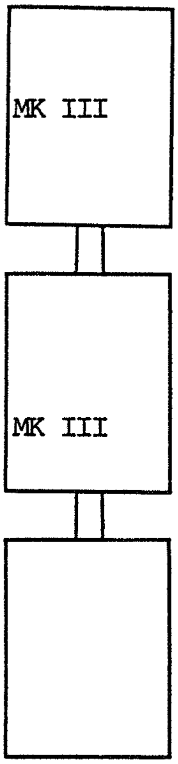
Remarks.

All measurements to bottom of each item

Table 5

Well 34/10-7	GAUGE ARRANGEMENT	CHP/PG
DST no. 2		Perfs.: 1836-66 m RKB
		Zone tested Cook sand

Bundle Carrier

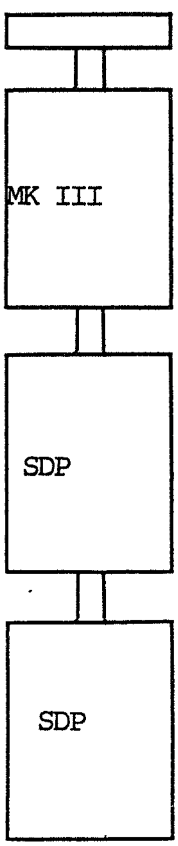


Gauge type and number : Sperry-Sun, MK III no 0239
Depth, pressure elemement : 1816 m RKB Range : 690 BAR
Mode : 8 min. Delay : 0
Actuated : time 06:02 date : 29.06.83
Will run out : time 14.02 date : 08.07.83

Gauge type and number : Sperry-Sun, MK III no 0100
Depth, pressure elemement : 1816 m RKB Range : 690 BAR
Mode : 4 min. Delay : 17 hours
Actuated : time 06.04 date : 29.06.83
Will run out : time 11.04 date : 04.07.83

Gauge type and number :
Depth, pressure elemement : Range :
Mode : Delay :
Actuated : time date :
Will run out : time date :

Wireline "F" nipple at 1820.69 mRKB



Gauge type and number : Sperry-Sun, MK III no 0242
Depth, pressure elemement : 1824.42 m RKB Range : 690 BAR
Mode : 4 min. Delay : 17 hours.
Actuated : time 11.12 date : 30.06.83
Will run out : time date :

Gauge type and number : Flopetrol, SDP no 82014
Depth, pressure elemement : 18 28.60 Range : 690 BAR
Mode : 30 sec. Delay : 0
Actuated : time 11.18 date : 30.06.83
Will run out : time – date : –

Gauge type and number : Flopetrol, SDP no 82016
Depth, pressure elemement : 1831.55 m RKB Range : 690 BAR
Mode : 1 min. Delay : 0
Actuated : time 11.02 date : 30.06.83
Will run out : time – date : –

A-1.8 PERFORATION

The perforation for DST no. 2 was performed with a tubing conveyed perforating. The tool was fabricated and operated by the company Geovann. This was the first time Statoil used tubing conveyed perforating and the job was performed as planned.

The perforated section was depth correlated with the performed test interval by using the Schlumberger CCL-GR tool. The test string had a radio-active marker at the top of the collars which was used for correlation.

The string was found to be 1 m off the planned test interval. The actual depth interval was 1836-1866 m RKB.

The 5" casing gun was equipped with 12 shots per foot and 60^{o} phasing. The gun was detonated by dropping a special bar.

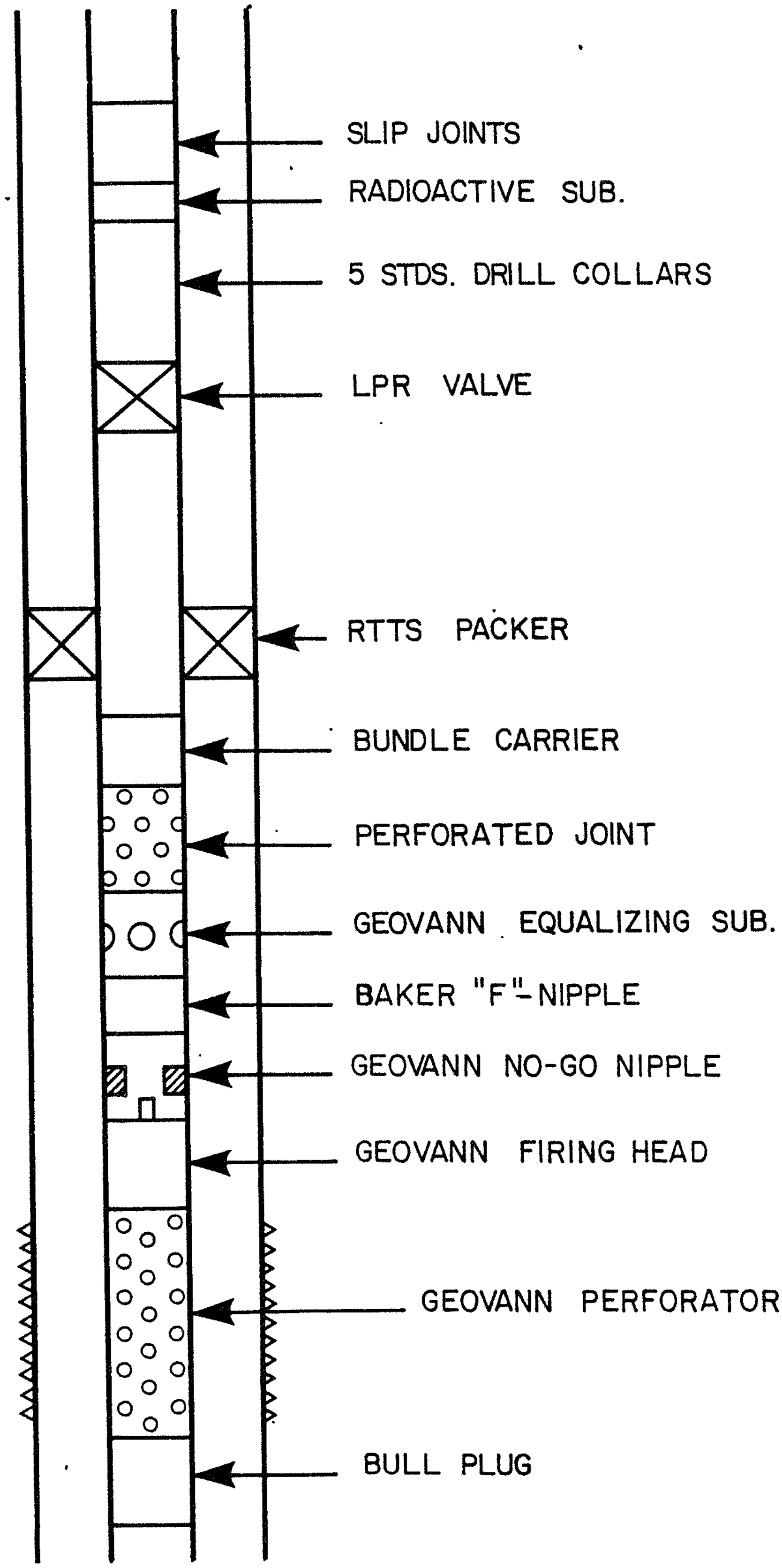
The reservoir pressure in Cook was calculated to 317 bar (RFT measurements, Feb. 1980) and the cushion used while perforating was approximately 200 bar. This gave an underbalanced differential pressure of 117 bar.

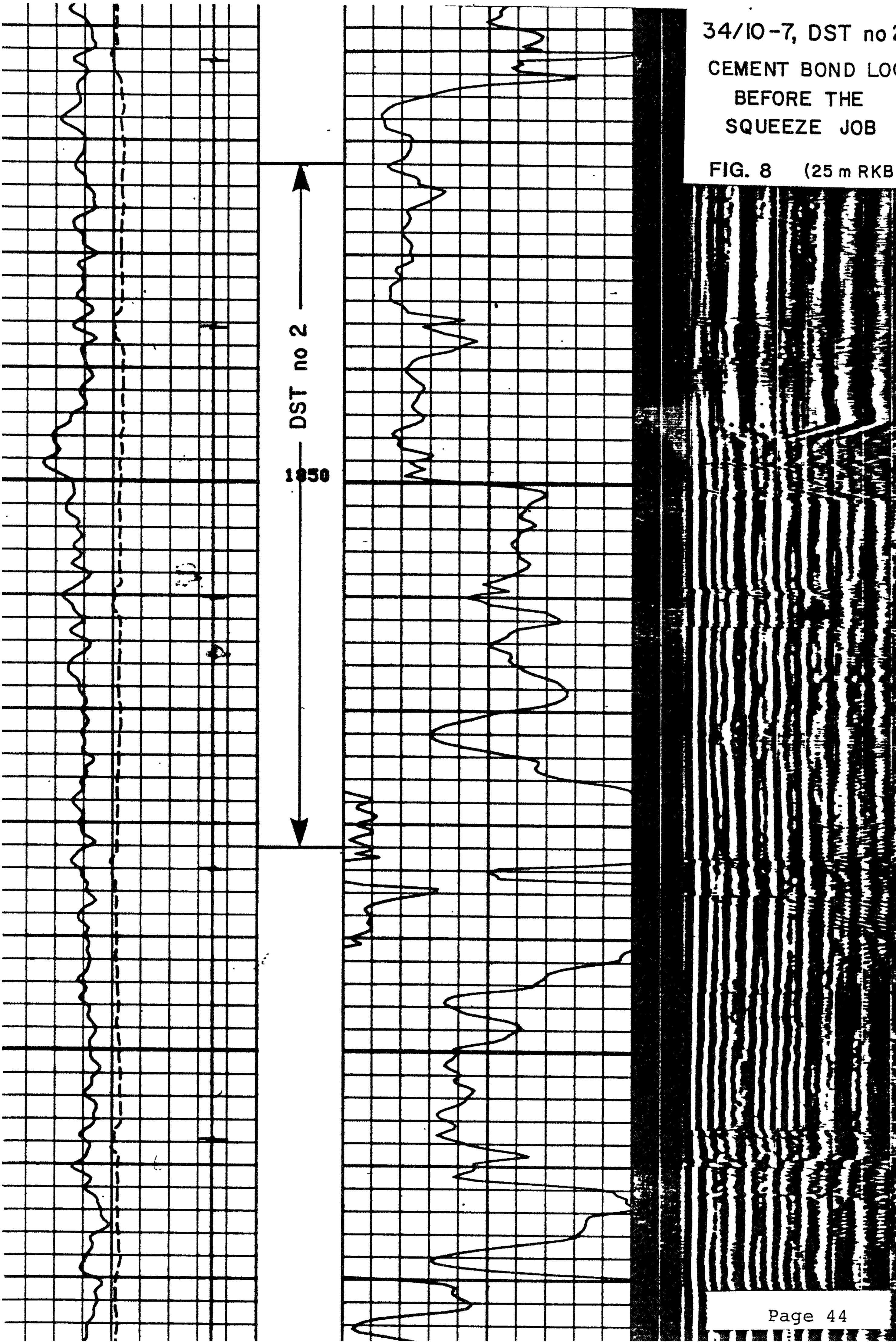
The detonating bar was inserted in the lubricator section and dropped by opening the swab valve. The bar detonated all of the shots successfully. An acoustic recorder (sensor) was connected to the tubing and gave a relatively good indication of the detonation.

The small influx of fluid (initial flow) into the rat-hole was enough to give a good estimation of the reservoir pressure, p_i = 314,4 bara at 1834 m RKB.

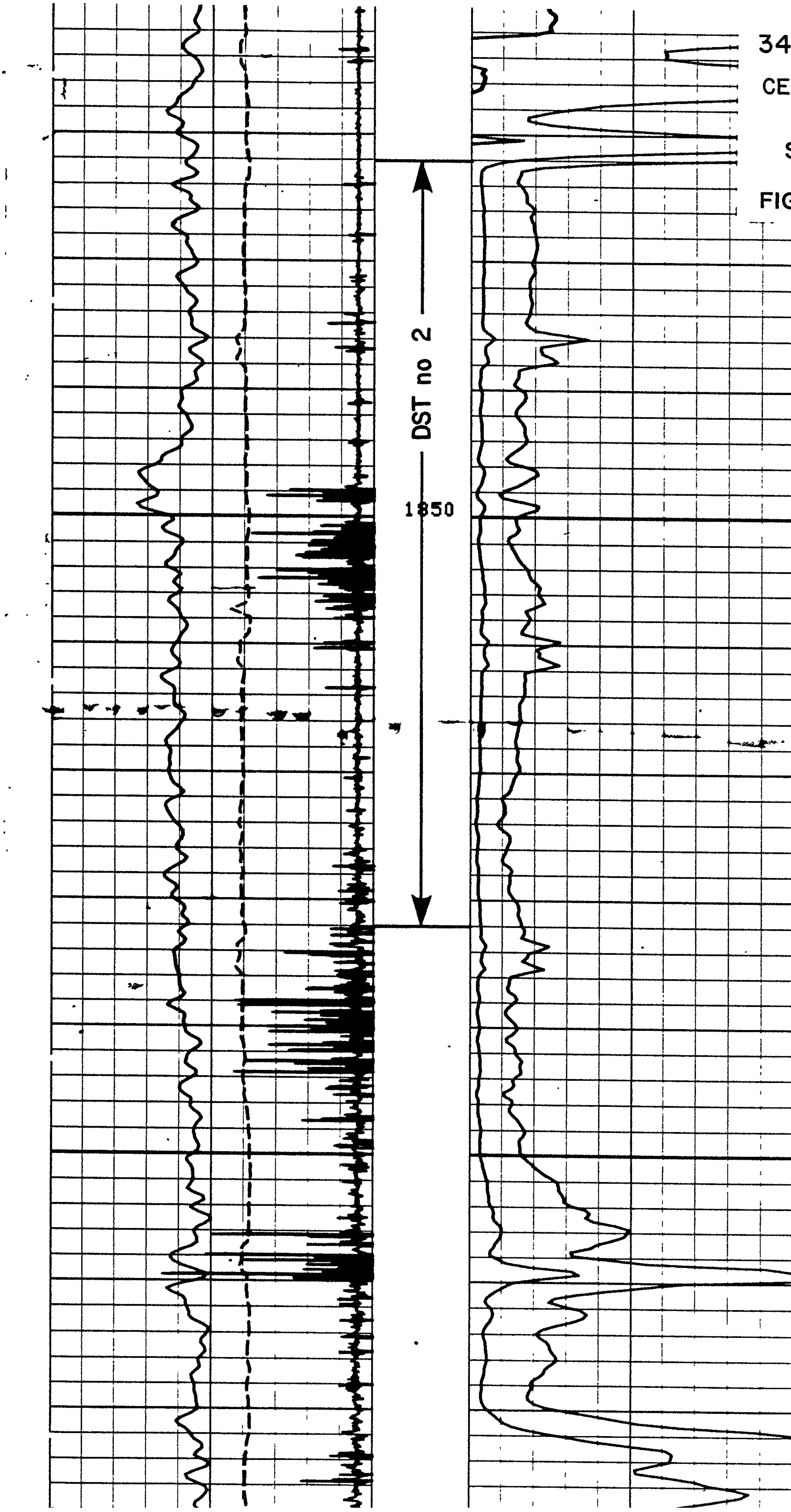
Figure 7

A SIMPLIFIED SET-UP OF THE BOTTOM HOLE ASSEMBLY FOR 34/10-7, DST no.2





34/10-7, DST no 2
CEMENT BOND LOG BEFORE THE SQUEEZE JOB
FIG. 8 (25 m RKB)



34/10-7, DST no

CEMENT BOND LO
AFTER THE
SQUEEZE JOB

FIG. 9 (25 m RKI

Table 6

Well 34/10-7 DST no. 2	DIARY OF EVENTS	CHP/PG Perfs.: 1836-66 m RKB Zone tested Cook sand

Date	Time	OPERATIONS
20/6-83	0600	Started to pick up Halliburton bottom hole assambly
	2100	Started to pressure test surface equipment
		PERFORATING
30/6-83	0115	Rigged up for Schlumberger
	0405	Rih w/ gr-ccl for positioning of perforating-gun and checking for full opening of lpr-valve
	0800	Rigged down Schlumberger
	0900	Rigged up lubricator and inserted the detonating bar
	0935	Dropped the detonating bar
	0940	Perforated
		SETTING OF BH GAUGES
	1147	Rih with 3 pressure gauges on slick-line
	1345	Attempted to set the gauges in the 'f'-nipple
		FIRST FLOW/FIRST BUILD UP
	1445	Opened well on 40/64" fixed choke
	1451	Gas at surface
	1452	Mud at surface
	1500	Oil at surface
	1637	Switched flow to starboard burner due to plugging of port burner
	1646	Switched flow through separator
	1715	Switched flow to surge tank for meterfactor
	2028	Lowered the oil level in separator, due to carry-over

Remarks :

Well 34/10-7 DST no. 2	DIARY OF EVENTS	CHP/PG Perfs.: 1836-66 m RKB Zone tested Cook sand

Date	Time	OPERATIONS
1/7	0252	Started to collect 1st set of pvt samples
	0348	Started to collect 2nd set of pvt samples
	0410	By-passed separator
	0413	Closed at choke manifold and lpr-valve
		INJECTION
2/7	0650	Opened lpr-valve
	0656	Opened kill valve
	0703	Started to inject seawater at rate of approx. 70 m3/d
	1003	Increased inj. rate to approx. 284 m3/d
	22000	Closed at cement pump and at kill valve for fall off
	2335	Started to inj. approx. 287 m3/d with 10% surfactant added to the seawater
3/7	1820	Increased inj. rate to approx. 626 m3/d
	2100	Increased inj. rate to approx. 855 m3/d
	2120	One of two cement-pumps stopped due to over-heating of engine
	2200	Increased inj. rate to approx. 900 m3/d
	2300	Increased inj. rate to approx. 1075 m3/d
4/7	0000	Increased inj. rate to approx. 1332 m3/d
	0210	Increased inj. rate to approx. 1490 m3/d
	0231	Stopped injection

Remarks :

A-2.1 INJECTION TEST EQUIPMENT

As pointed out in section 1, the injection tests consisted of the following main periods:

i a 15 hour seawater injection

ii a 1,5 hour fall-off

iii a 27 hour surfactant seawater injection including a fracturing test at the final stages

The chemicals were transported to the rig in helicopter fuel tanks. Two Dowell Schlumberger tanks of 57 m^3 were used for the chemicals on the rig.

Equipment

The lay-out on the surface equipment is shown in figure 11.

Two Wilden pumps were used to dose the surfactant into the injection fluid.

A Primary Filtration Backwash Unit was used to ensure a good quality of the injection fluid.

The Dowell Shclumberger cement pump was used for the injection.

Equipment experience

Using the rig cement pump for injection is not recommended. A separate system of pumps and pipework is required. This is important, especially if a low permeable section is present.

A-2.2 INJECTION TEST ANALYSIS

Dimensionless pressure function

The calculations of the dimensionless pressure function is based on the equations presented in section 4.2. Under the assumption of only one mobile fluid is present in the reservoir, the p_D+s function in equation (1), section 4.2 is calculated as:

$$\alpha = 5.36 \times 10^{-2} \times \frac{K\ k_{ro}\ h}{q_o\ \mu_o\ B_o} \qquad \text{I}$$

$$= 1.38 \quad 10^{-1} / \text{ bar}$$

where

k_{ro} = 1.0
p - bar
h - metre
other parameters : DST-2

giving

$$p_D(t_D) + S = 1.38 \times 10^{-1} \times (\ p_i - p_{wf}\ ) \qquad \text{II}$$

Dimensionless time is calculated using equation 3 section 4.2 giving

$$t_D = 0.000264\ \frac{K\ k_{ro}}{\phi\ \mu_o\ c_t\ r_w^2} \qquad \text{III}$$

which is reduced to

$$t_D = 5.55 \times 10^4 \times t \qquad t - \text{hours}$$

when using parameter values from DST-2, k_{ro} = 1.

Test analysis

The flow rate measurements from the injection tests are presented in table 8. Corresponding bottom hole pressure is plotted versus injection time in figure 10. Combining table 8 and figure 10, grouping the data when the measurements show a constant behavious gives q_{inj} versus p_{inj} as shown in table 9 and 11 respectively for seawater injection and surfactant seawater injection.

Throughout the superpositioning of the dimensionless pressure function in the injection analysis, the following steps have been taken to calculate the $p_D(t_{Dn} - t_{Dj-1})$ term in equation (4) in section 4.3.

1) For a casual term in the step of summation the t_n is known from the level of summation i.e. t_n = 3.45 hrs at third level in table 9.

2) From the step of summation determin the t_{j-1}, which for the second step of summation at third level gives t_{j-1} = 2,45, table 9.

3) Subtraction giv the argument of t in equation III, previous page, determining the dimensionless time argument $t_{Dn}-t_{Dj-1}$. Reading figure 6 gives $p_D(t_{Dn} - t_{Dj-1})$. For the second step at the third level of summation in table 9 gives $p_D(t_{Dn} - t_{Dj-1})$ = 6,75, from figure 6.

TABLE 7

DST 2: Determination of dimensionless pressure function from flow period

t hrs.	log t_D	p_{wf} bar	log (P_D+S)
0.05	3.406	278.7	0.705
0.075	3.582	275.8	0.738
0.116	3.774	272.9	0.768
	plugging		
0.550	4.447	274.1	0.756
0.558	4.453	272.5	0.772
0.575	4.466	271.0	0.787
0.591	4.479	270.2	0.795
0.600	4.485	270.0	0.797
0.625	4.502	269.4	0.803
0.65	4.520	269.0	0.806
0.691	4.547	268.7	0.809
0.716	4.562	268.4	0.812
0.725	4.567	268.3	0.813
0.800	4.610	268.0	0.816
0.958	4.688	267.0	0.825
1.075	4.738	266.8	0.829
1.191	4.783	266.2	0.832
1.358	4.840	265.7	0.836
1.466	4.873	265.4	0.838
1.583	4.906	265.2	0.841
1.733	4.945	214.8	0.844
1.866	4.978	264.6	0.846
2.00	5.008	264.2	0.849

TABLE 7 continued

t hrs.	log t_D	p_{wf} bar	log (P_D+S)
2.15	5.039	264.1	0.850
2.316	5.071	263.9	0.852
2.533	5.110	263.5	0.855
2.725	5.142	263.3	0.857
3.008	5.185	262.9	0.860
3.241	5.217	262.5	0.863
3.808	5.252	261.9	0.868
3.908	5.300	261.8	0.869
4.241	5.334	261.4	0.872
4.508	5.361	261.2	0.874
4.841	5.392	260.4	0.876
5.175	5.421	260.6	0.878
5.508	5.448	260.4	0.880
5.875	5.476	260.2	0.882
6.241	5.502	259.9	0.884
6.508	5.520	259.7	0.886
6.908	5.546	259.4	0.888
7.058	5.556	259.3	0.889
7.725	5.595	258.9	0.892
8.125	5.616	258.8	0.893
8.691	5.646	258.4	0.896
9.291	5.675	258.1	0.898
9.608	5.690	257.8	0.900
10.016	5.707	257.7	0.901

TABLE 8

DOWELL DATA, FLOW RATES

TID	CUM. VOL M^3	VOL M^3	RATE M^3/D	REMARKS
2/7				
0703	0	-	-	Start injection
0915	6.2	6.2	67.6	
0930	7.0	0.8	76.8	
0945	7.8	0.8	76.8	Average rate 70 M^3/D
1000	8.6	0.8	76.8	Increase at 1003
1015	10.6	2.0	192.0	
1030	13.0	2.4	230.4	
1045	16.4	3.4	326.4	
1100	19.5	3.1	297.6	
1115	22.4	2.9	278.4	
1130	25.3	2.9	278.4	
1145	28.1	2.8	268.8	
1200	30.9	2.8	268.8	
1215	33.8	2.9	278.4	
1230	36.5	2.7	259.2	
1245	39.5	3.0	288.0	
1300	42.4	2.9	278.4	
1315	45.3	2.9	278.4	
1330	48.1	2.8	268.8	
1345	51.2	3.1	297.6	
1400	54.0	2.8	268.8	
1415	57.0	3.0	288.0	
1430	59.9	2.9	278.4	
1445	62.8	2.9	278.4	
1500	65.7	2.9	278.4	
1515	68.7	3.0	288.0	
1530	71.7	3.0	288.0	
1545	74.5	2.8	268.8	
1600	77.3	2.8	268.8	
1615	80.2	2.9	278.4	
1630	83.1	2.9	278.4	

1645	86.3	3.2	307.2	
1700	89.2	2.9	278.4	
1715	91.9	2.7	259.2	
1730	95.1	3.2	307.2	
1745	98.0	2.9	287.4	
1800	101.0	3.0	288.0	
1815	103.8	2.8	268.8	
1830	106.6	2.8	268.8	
1845	109.9	3.3	316.8	
1900	112.7	2.8	268.8	
1915	116.0	3.3	316.8	
1930	119.2	3.2	307.2	
1945	122.3	3.1	297.6	
2000	125.4	3.1	297.6	
2015	128.6	3.2	307.2	
2030	131.7	3.1	297.6	
2045	134.8	3.1	297.6	
2100	138.0	3.2	307.2	
2115	141.1	3.1	297.6	
2130	144.1	3.0	288.0	
2145	147.1	3.0	288.0	
2200	150.5	3.4	326.4	

SHUT IN FOR FALL OFF.
TOT. AVERAGE RATE FOR FIRST INJ. 242.69 M^3/D
AVERAGE RATE AT MAIN FLOW RATE 283.80 M^3/D

2335	0	-	-	Start injection
SEA WATER WITH 9% SURFACTANT				
2345	1.9	1.9	273.6	
3/7				
0000	4.9	3.0	288.0	
0015	8.0	3.1	297.6	
0030	11.2	3.2	307.2	
0045	14.3	3.1	297.6	
0100	17.3	3.0	288.0	
0115	20.2	2.9	278.4	
0130	23.2	3.0	288.0	
0145	26.1	2.9	278.4	

0200	28.9	2.8	268.8
0215	31.7	2.8	268.8
0230	34.6	2.9	278.4
0245	37.4	2.8	268.8
0300	40.5	3.1	297.6
0315	43.6	3.1	297.6
0330	46.4	2.8	268.8
0345	49.3	2.9	278.4
0400	52.3	3.0	288.0
0415	55.2	2.9	278.4
0430	58.2	3.0	288.0
0445	61.2	3.0	288.0
0500	64.0	2.8	268.8
0515	67.0	3.0	288.0
0530	69.7	2.7	259.2
0545	72.7	3.0	288.0
0600	75.6	2.9	278.4
0615	78.6	3.0	288.0
0630	81.6	3.0	288.0
0645	84.6	3.0	288.0
0700	87.3	2.7	259.2
0715	89.9	2.6	249.6
0730	92.4	2.5	240.0
0745	95.0	2.6	249.6
0800	97.6	2.6	249.6
0815	100.7	3.1	297.6
0830	103.8	3.1	297.6
0845	106.9	3.1	297.6
0900	110.0	3.1	297.6
0915	113.1	3.1	297.6
0930	116.2	3.1	297.6
0945	119.2	3.0	288.0
1000	122.3	3.1	297.6
1015	125.4	3.1	297.6
1030	128.5	3.1	297.6
1045	131.6	3.1	297.6
1100	134.8	3.2	307.2
1115	137.9	3.1	297.6
1130	141.0	3.1	297.6

TABLE 8 continued

1145	144.1	3.1	297.6	
1200	147.2	3.1	297.6	
1215	150.2	3.0	288.0	
1230	153.3	3.1	297.6	
1245	156.4	3.1	297.6	
1300	159.4	3.0	288.0	
1315	162.4	3.0	288.0	
1330	165.4	3.0	288.0	
1345	168.4	3.0	288.0	
1400	171.4	3.0	288.0	
1415	174.5	3.1	297.6	
1430	177.5	3.0	288.0	
1445	180.6	3.1	297.6	
1500	183.7	3.1	297.6	
1515	186.7	3.0	288.0	
1530	189.7	3.0	288.0	
1545	192.7	3.0	288.0	
1600	195.8	3.1	297.6	
1615	198.9	3.1	297.6	
1630	202.0	3.1	297.6	
1645	205.0	3.0	288.0	
1700	208.0	3.0	288.0	
1715	211.0	3.0	288.0	
1730	214.0	3.0	288.0	
1745	217.1	3.1	297.6	
1800	220.2	3.1	297.6	
1815	223.2	3.0	288.0	Av. rate 286.97
1830	228.6	5.4	518.4	(inc. rate 1820)
1845	235.0	6.4	614.4	
1900	241.6	6.6	633.6	
1915	248.3	6.7	643.2	
1930	254.9	6.6	633.6	
1945	261.5	6.6	633.6	
2000	267.9	6.4	614.4	
2015	274.2	6.3	604.8	
2030	280.7	6.5	624.0	
2045	287.3	6.6	633.6	Av. rate 625.9 M/D
2100	293.8	6.5	624.0	Inc. rate 2100
2115	302.7	8.9	854.4	One pump stopped

TABLE 8 continued

2130	309.1	6.4	(614.4)	at 2120
2145	313.6	4.5	432.0	
2200	318.1	4.5	432.0	
2215	327.5	9.4	902.4	
2230	336.0	8.5	816.0	
2245	345.1	9.1	873.6	Av. rate 900 M^3/D
2300	355.6	10.5	1008.0	Inc. rate 2300
2315	365.7	10.1	969.6	
2330	377.5	11.8	1132.8	
2345	389.0	11.5	1104.0	Av. rate 1075.2 M^3/D
4/7				
0000	400.4	11.4	1094.4	Inc. rate 0000
0015	414.1	13.7	1315.2	
0030	428.5	14.4	1382.4	
0045	443.1	14.6	1401.6	
0100	457.2	14.1	1353.6	
0115	470.9	13.7	1315.2	
0130	484.3	13.4	1286.4	
0145	498.0	13.7	1315.2	
0200	511.4	13.4	1286.4	Av. rate 1332 M^3/D
0215	525.8	14.4	(1382.4)	Inc. rate 0210
0230	541.3	15.5	1488.0	Stopped injection

TOTAL VOLUME PUMPED: 541.3 M^3 + 150.5 M^3 = 691.8 M^3

TOTAL PUMPING TIME 2513 MIN

TOTAL AVERAGE RATE = 396.4 M^3/D

TABLE 9

Dimensionless superposition applied to seawater injection

Point No.	t hrs.	Σ( )	$p_{inj.}$ bar	$q_{inj.}$ sm^3/D	$\frac{p_{inj.}-p_i}{q_n}$
	0	0	312.3	0	0
1	2.45	7.145	317.5	70	0.07
2	2.95	7.168	318.3	77	0.08
3	3.45	6.732	340.3	230	0.12
4	3.95	6.830	346.2	298	0.11
5	4.95	7.151	346.1	274	0.12
6	5.45	7.300	345.8	259	0.13
7	7.95	7.595	346.2	275	0.12
8	8.45	7.595	345.7	288	0.11
9	9.95	7.800	346.1	275	0.12
10	10.45	7.728	346.2	307	0.11
11	10.95	7.836	345.9	288	0.12
12	11.98	7.985	346.5	302	0.11
13	13.98	7.978	346.7	267	0.13
14	14.45	8.092	346.9	290	0.12
15	14.95	7.916	347.1	326	0.11

TABLE 10

Surfactant composition

RL 3011	33.33 W%
GX-080	16.67 W%
GX-150	16.67 W%
IPA	33.33 W%

RL 3011 - Synth. petroleum sulfonate, MW 375, Essochem.

GX-080 - Genapol, isotridecylalcohol + 8 ED, Hoechst.

GX-150 - Genapol, isotridecylalcohol + 15 ED, Hoechst.

IPA - Isopropanol

Physical/chemical Data:

Density at 15°C kg/liter:		0.78
Smell	:	very characteristic
Appearance	:	clear liquid
Flashpoint °C	:	12
Acidcount ppm, max. calculated as acetic acid	:	20
Destillation area, °C	:	82

TABLE 11

Dimensionless superposition applied to surfactant seawater injection

Point No.	t hrs.	Σ( )	$p_{inj.}$ bar	$q_{inj.}$ sm^3/D	$\frac{p_{inj1}-p_i}{q_n}$
1	1.42	6.95	346.7	298	0.12
2	3.17	7.367	346.0	278	0.12
3	3.67	7.383	346.3	298	0.11
4	7.17	7.849	346.2	278	0.12
5	8.2	8.078	345.0	245	0.13
6	18.66	8.460	345.1	288	0.12
7	20.17	7.691	349.7	612	0.06
8	23.2	8.065	349.6	620	0.06
9	24.42	7.568	350.6	1075	0.04
10	26.67	7.669	352.0	1332	0.03

TABLE 12

Particle measurements during pre-flush of injection system (surface)

Date	1.7.83	2.7.83									
Time	2335	0025	0045	0045	0100	0140	0205	0230	0255	0255	0255
	(3)	(3)	(1)	(2)	(3)	(3)	(3)	(3)	(1)	(2)	(3)
Particle dia. d µ m	Number of Particles ⩾ d µm(microns) in 1.0 ml water										
2.0	1417000		20360	19300	403800				16740	16420	1024020
3.0	720600		7700	6960	109420				6440	5480	396440
4.0	295400		3320	3000	36880				2560	3640	141360
5.0	126100		1720	1360	15080				920	1640	54240
7.5	24540		460	280	3400				320	280	8720
10	8380		240	80	1000				120	40	3000
15	1760		0	0	200				20	20	640
20	500				80				0	0	220
25	160				0						80
30	40										20
Flow Rate m^3/day	65	955									
Turbidity NTU	30	7.2	0.7	0.53	6.4	15	19	14	0.37	0.31	16

(1) Filter Inlet (2) Filter Outlet (3) Rig Floor

TABLE 13

Particle measurements during seawater injection

Date	2.7.83											
Time	0735	0735	0735	0845	0845	0945	0945	1100	1100	1215	1215	
Particle dia. d μ m	(1)	(2)	(3)	(2)	(3)	(2)	(3)	(2)	(3)	(2)	(3)	
	Number of Particles ⩾ d μm(microns) in 1.0 ml water											
2.0	22280	20640	197400	33420	141080	29900	58780	9780	210720	14560	331600	
3.0	6260	4980	26040	3620	21800	13400	18780	4200	83820	4000	98040	
4.0	2400	1700	8400	1700	6940	7400	7400	1540	13880	1620	26280	
5.0	1100	760	3340	480	2380	680	2980	780	4820	1000	8600	
7.5	320	220	460	280	320	240	680	300	820	260	1300	
10	100	100	200	240	180	140	300	100	300	120	360	
15	80	40	80	80	120	80	80	60	60	120	140	
20	0	0	0	0	0	0	20	0	0	0	0	
25							0					
30												
Flow Rate m^3/day		30						460				
Turbidity NTU	0.67	1.7	3.5	0.78	1.4	0.41	1.4					
Suspended Solids	0.38				3.1							

(1) Filter Inlet (2) Filter Outlet (3) Rig Floor

TABLE 13 continued

Date	2.7.83											
Time	2000	2000	2100	2100	2100	2155	2155					
Particle dia. d µ m	(2)	(3)	(1)	(2)	(3)	(2)	(3)					
	Number of Particles ⩾ d µm(microns) in 1.0 ml water											
2.0	16560	112020	22720	18500	307040	19320	1566900					
3.0	6340	20260	8640	6920	82720	6440	775700					
4.0	2680	5120	4360	3480	23420	2800	251440					
5.0	1340	1980	1960	1960	8040	1120	87200					
7.5	220	380	460	440	1160	220	11280					
10	60	240	60	160	360	40	3240					
15	0	0	0	0	60	0	400					
20					0		80					
25							20					
30							0					
Flow Rate m^3/day		460										
Turbidity NTU	0.30	1.4	0.38	0.35	3.3	0.34	32					
Suspended Solids												

(1) Filter Inlet (2) Filter Outlet (3) Rig Floor

TABLE 14

Particle measurements during surfactant seawater injection

Date	3.7.83										
Time	0000	0000	0000	0100	0100	0100	0230	0230	0400	0400	0400
Particle dia. d μ m	(1)	(2)	(3)	(1)	(2)	(3)	(2)	(3)	(1)	(2)	(3)
	Number of Particles ⩾ d μm(microns) in 1.0 ml water										
2.0	1082400	1327400	1164300	1177280	1188060	1191040	1232760	1300360	1484440	1629960	1169180
3.0	146080	554600	148400	48620	45640	290320	73520	422760	186600	51380	136440
4.0	29700	84260	74700	12200	11420	98320	17740	177820	42000	12960	69160
5.0	12360	24840	43400	4600	4280	45740	5880	94400	12200	4720	37260
7.5	1600	2500	11420	720	600	8160	700	20040	1100	760	7880
10	300	440	2880	240	220	1840	100	4540	320	240	1920
15	40	80	280	80	40	60	40	340	60	40	120
20	20	40	20	20	20	0	0	40	20	0	20
25	0	20	0	0	0			0	0	0	
30		0									
Flow Rate m^3/day		65									
Turbidity NTU	270	270	240	250	255	220	255	230	245	250	230
Suspended Solids								4.2			

(1) Filter Inlet (2) Filter Outlet (3) Rig Floor

TABLE 14 continued

Date	3.7.83											
Time	1230	1230	1230	1400	1400	1530	1530	1530	1700	1700		
Particle dia. d μ m	(1)	(2)	(3)	(2)	(3)	(1)	(2)	(3)	(2)	(3)		
	Number of Particles $\geq$ d μm(microns) in 1.0 ml water											
2.0	1131580	1336040	1020580	1406208	1056120	1387720	1126580	1312100	1074740	193060		
3.0	95320	80500	64400	81880	191720	96900	43140	112800	63200	178460		
4.0	24540	17140	18800	16280	100120	22700	9400	50980	15700	77320		
5.0	8800	5620	6780	4960	51680	7660	4900	27880	4960	52040		
7.5	1520	880	900	460	14880	940	540	7360	640	6980		
10	540	180	220	120	3780	540	280	1880	300	1840		
15	60	80	100	80	300	80	80	140	60	120		
20	40	60	40	40	40	60	60	60	60	80		
25	20	0	0	20	0	20	40	0	0	40		
30	0			0		0	0			0		
Flow Rate m^3/day		65										
Turbidity NTU	275	270	240	265	240	250	255	230	265	270		
Suspended Solids												

(1) Filter Inlet (2) Filter Outlet (3) Rig Floor

Figure 10

Recorded bottom hole pressure during injection

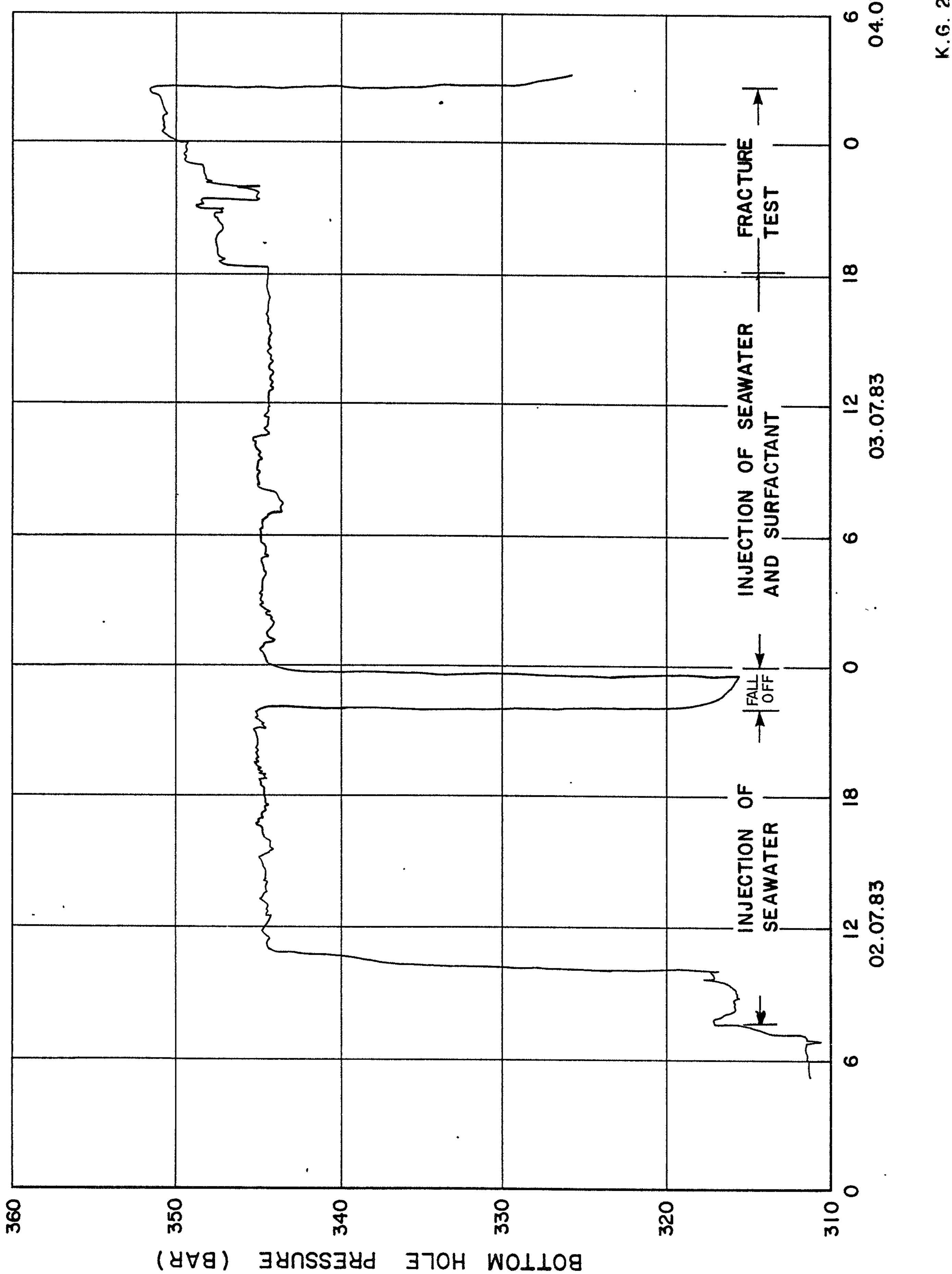


Figure 11

SURFACE INSTALLATION FOR INJECTION TESTS – 34/10-7

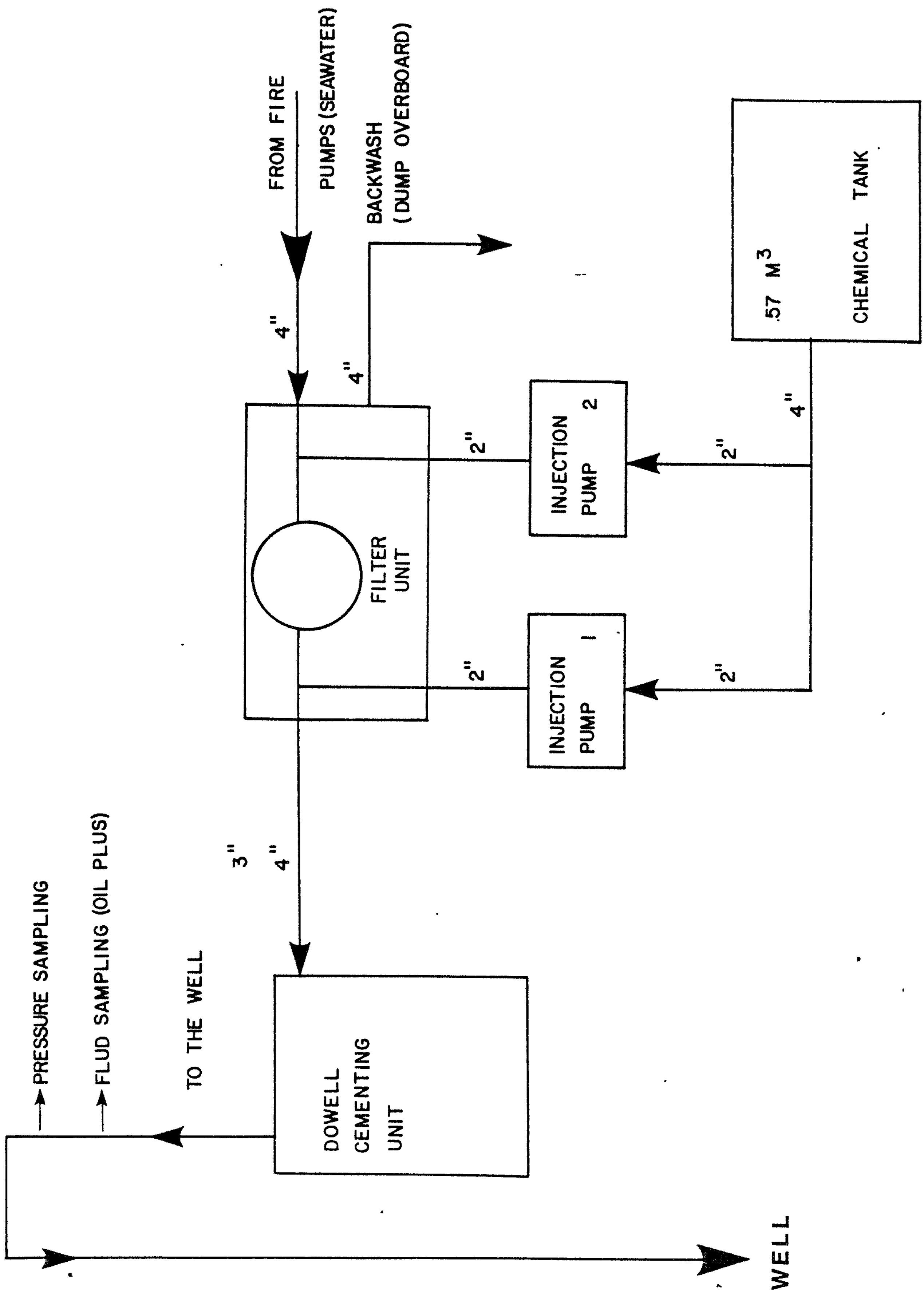


Figure 12

DST#2: Generated p_D- function from flowing period

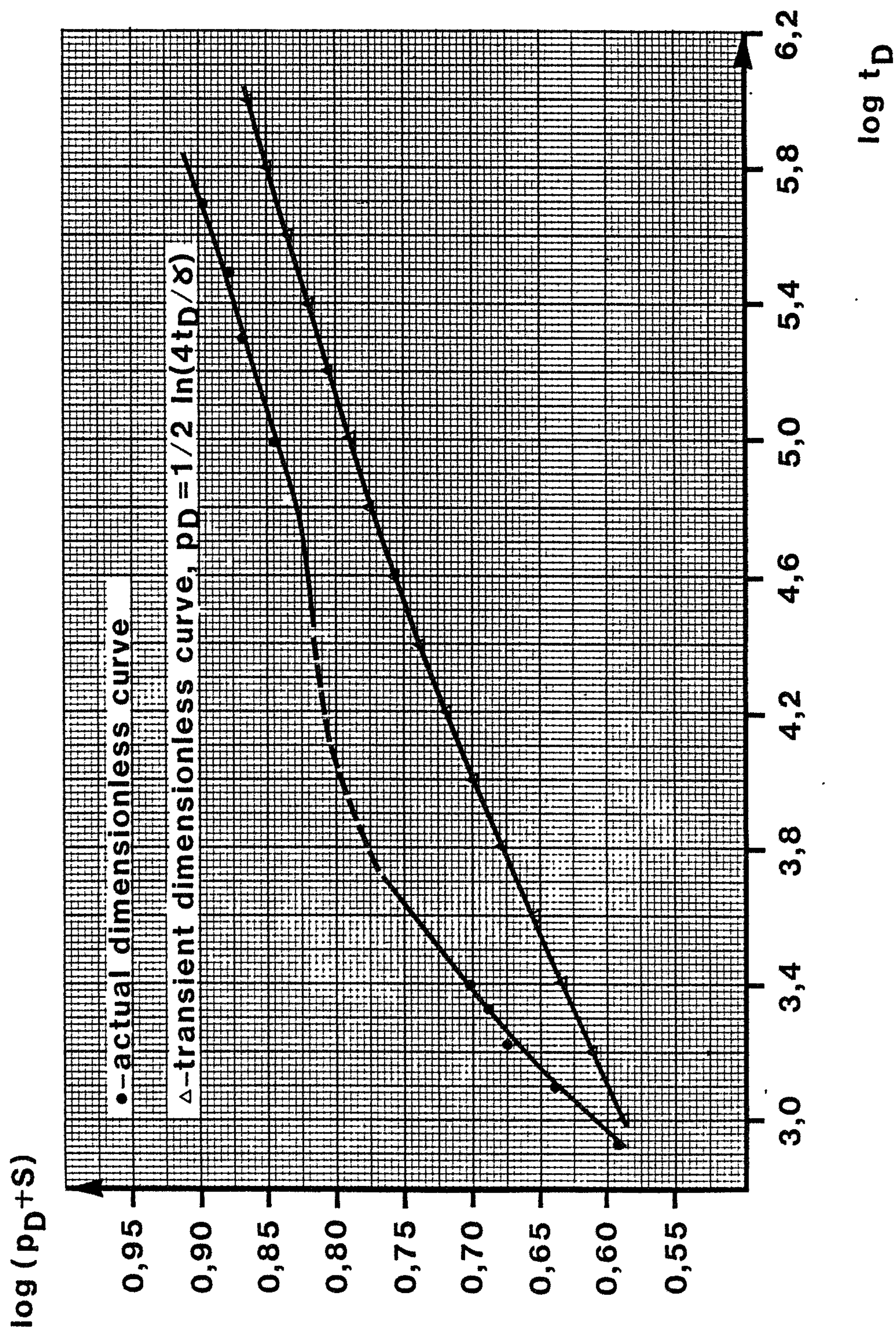


Figure 13

Comparision of theoretical to actual buildup

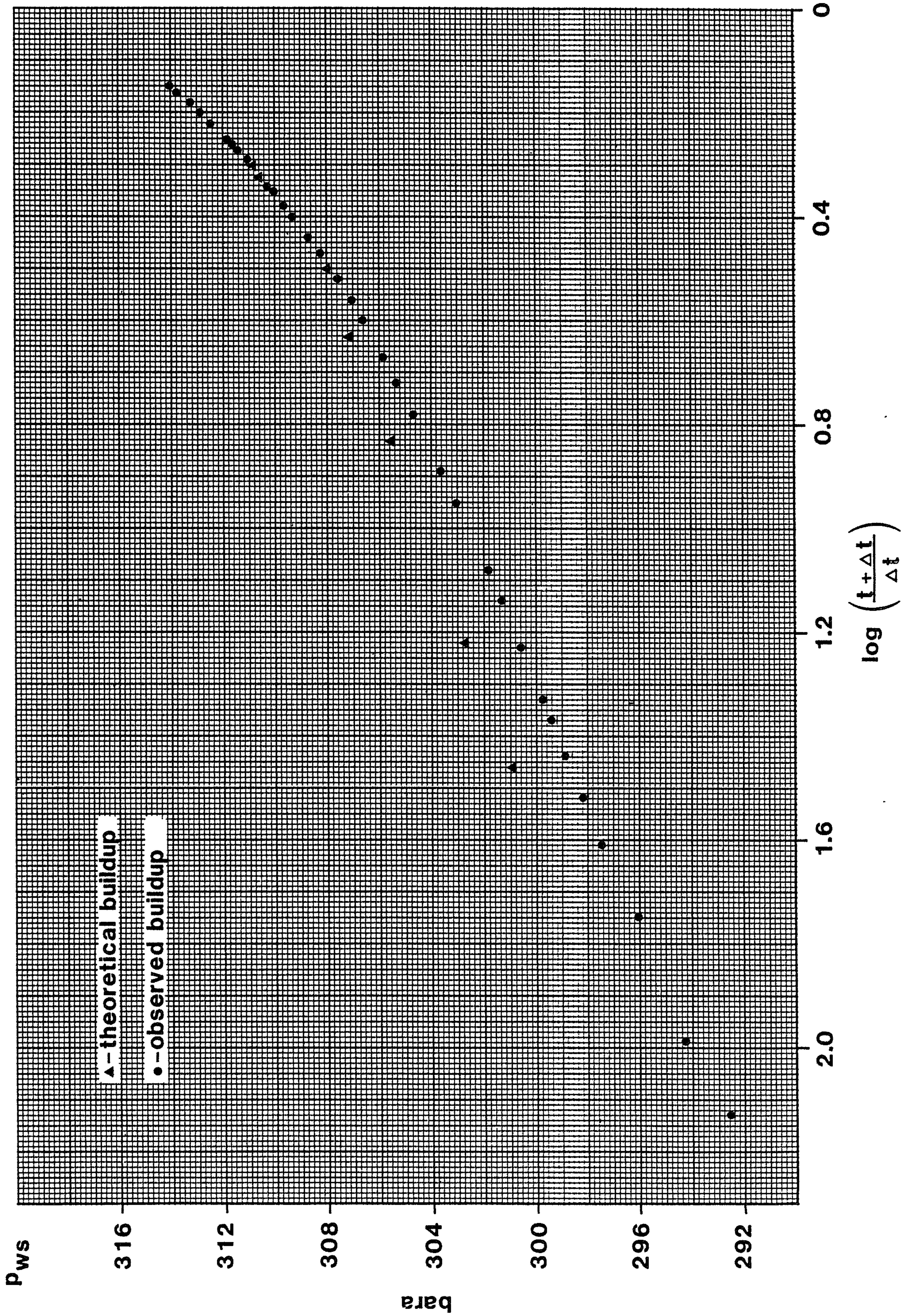


Figure 14

DST # 2 Generated p_D - function from flowing period

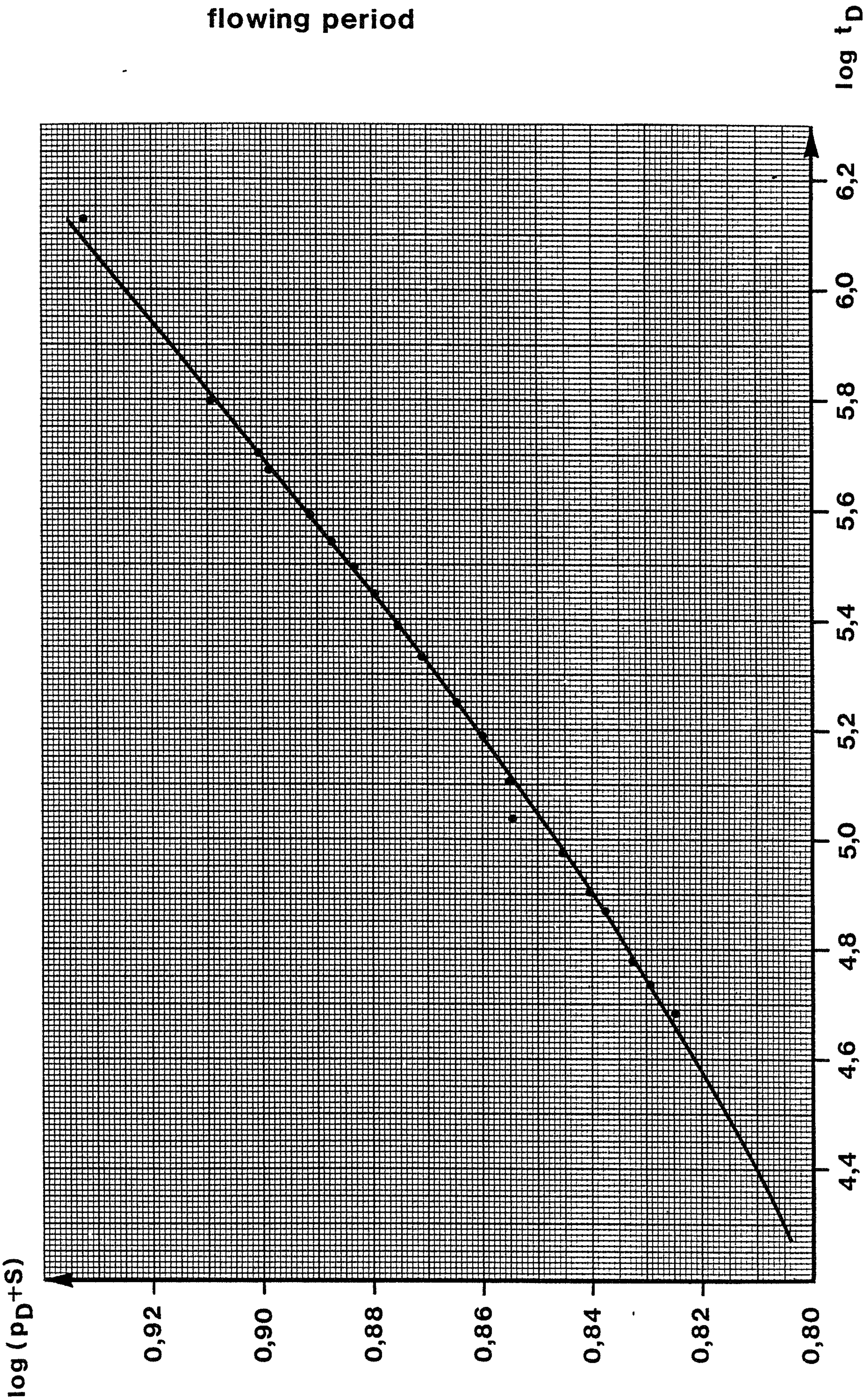
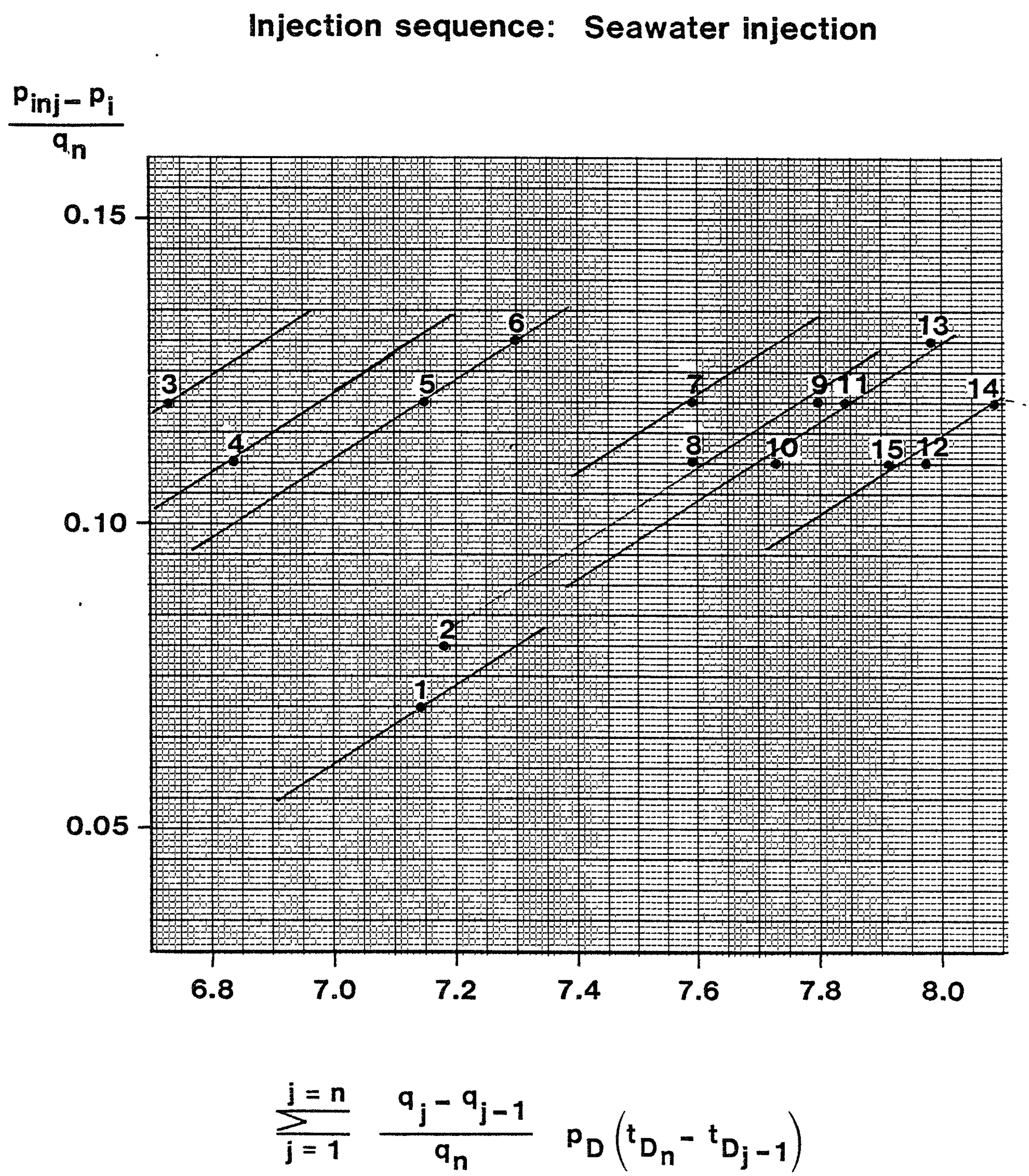


Figure 15



Injection sequence: Seawater injection
$\frac{p_{inj} - p_i}{q_n}$
0.15
0.10
0.05
6.8
7.0
7.2
7.4
7.6
7.8
8.0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
$\sum_{j=1}^{j=n} \frac{q_j - q_{j-1}}{q_n} \; p_D\left(t_{D_n} - t_{D_{j-1}}\right)$

Figure 16

Injection sequence: Surfactant seawater injection

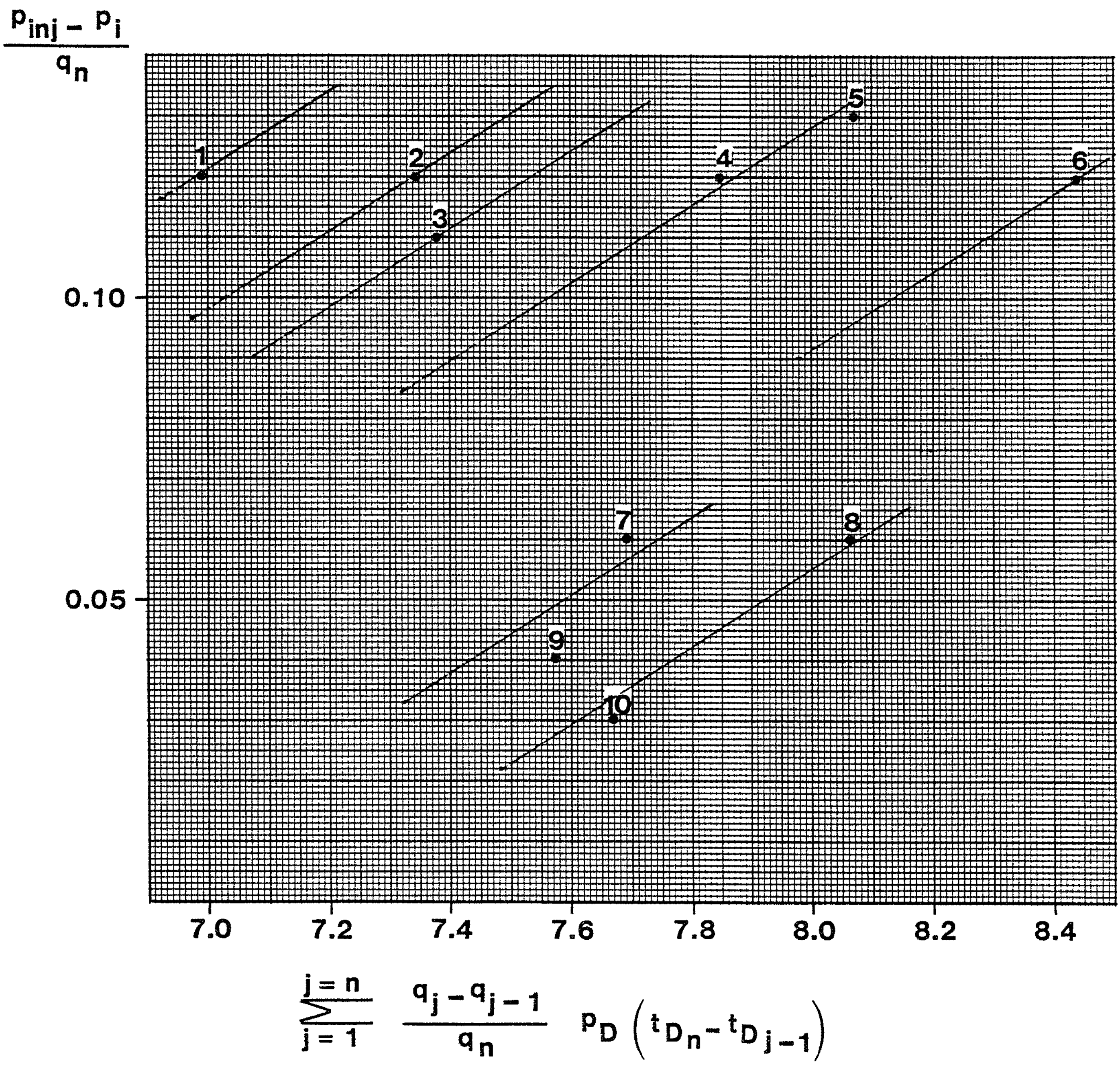
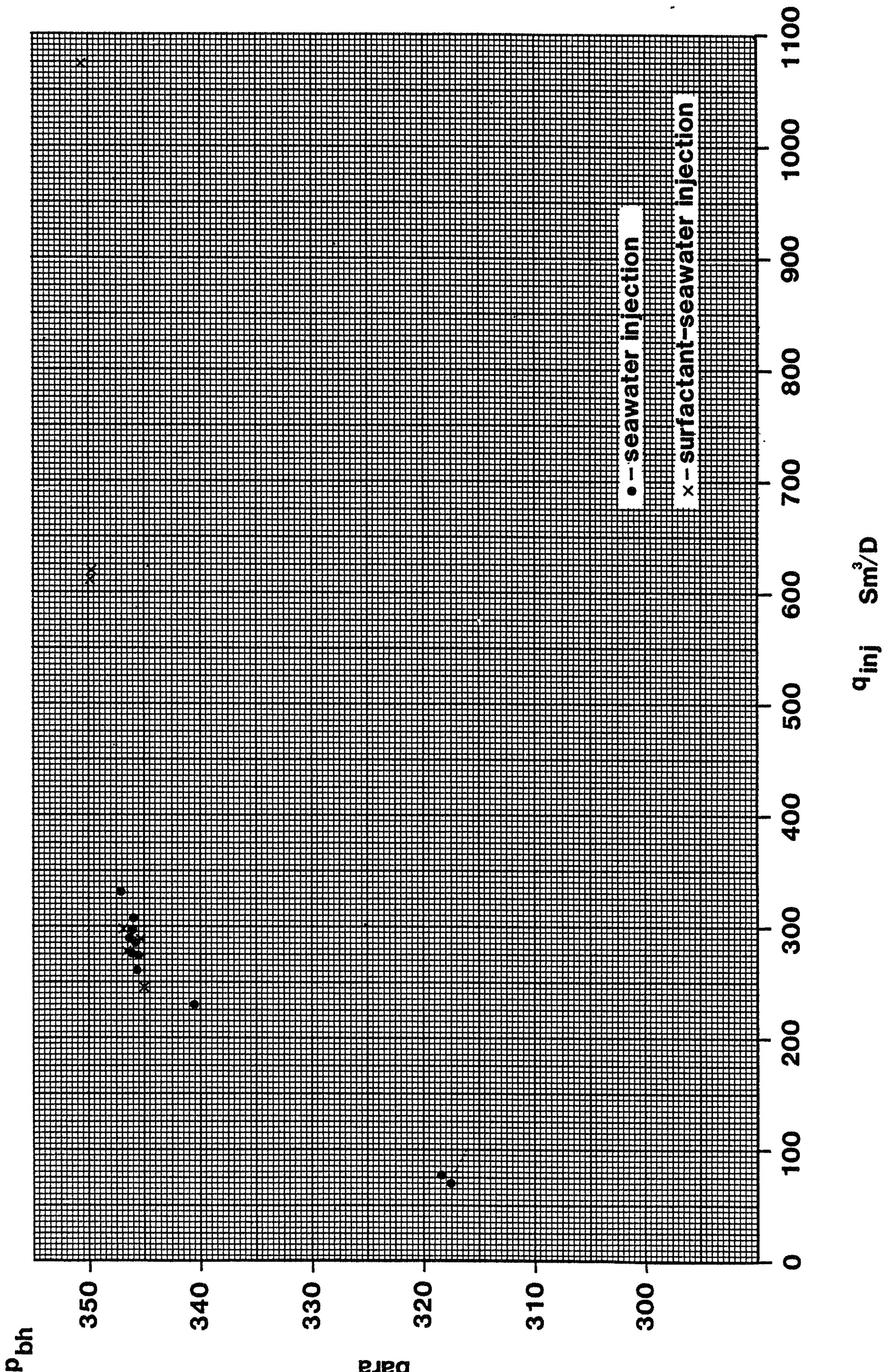


Figure 17

Bottom hole pressure versus injection rate, Cook unit 2



APPENDIX B

BOTTOM HOLE PRESSURE REPORT

Well 34/10-7

Test no. DST-3

Test Date 06.07.-09.07.83

Date of analysis Nov. 83

Gauge no. SDP-82016

SUMMARY OF THE RESULTS

	Horner analysis	
Kh md· m	34158	
K md	2440 md	
S	+8.2	
$\bar{P}$ at-1760 mss	313.2 bar	

Max recorded Temp. 72,8°C

Remarks

Signature

B-1.1

Well 34/10-7

Test date 06.07.-09.07.83

Reservoir Parameters

Perforations 1810 - 1824 m RKB

Zone(s) Cook unit 3

ss

Wellbore radius 0.11 m

RKB Elev 25 m

Midpoint Production — 1792 m ss

Bomb at 1785,3 m RKB — 1760,3 m ss

Pressure Functions Evaluated at — 1760,2 m ss

Datum Depth — ______ m ss

Delta P required to correct to datum ______ bar

Gradient 0.0673 bar/m

Estimated Average Pressure ______ bar

Formation Volume Factor 1.434 vol/vol

Viscosity 0.493 cp

Thickness 14 m

Porosity ______ %

Drainage Area ______ m^2

Oil Saturation 83.1 %

Oil Compressibility 168 $10^{-6} bar^{-1}$

Water Saturation 16.9 %

Water Compressibility 43,5 $10^{-6} bar^{-1}$

Gas Saturation ______ %

Gas Compressibility ______ $10^{-6} bar^{-1}$

Formation Compressibility 43,5 $10^{-6} bar^{-1}$

System Compressibility $C_t = S_0C_0 + S_wC_w + S_gC_g + C_f$

$C_t = 0{,}831 \times 168 \; 10^{-6} + 0.169 \times 43{,}5 \; 10^{-6} + \_\_ \times \_\_ \; 10^{-6} + 43{,}5 \; 10^{-6}$

$C_t = 190{,}5 \; 10^{-6} bar^{-1}$

Rates Reported on Test.

Choke 32/64 inches

Oil Rate 829,6 Sm^3/D

Gas Rate 110,5 Sm^3/D

FTP ______ bar

Water Rate 0 Sm^3/D

GOR 133 Sm^3/Sm^3

^{0}API 39

Gas Spec. Grav. 0.680

Cumulative Production

Oil 323 Sm^3

Gas 36,25 10^3 Sm^3

Water 0

Well 34/10-7 Test Date 06.07.-09.07.83

Horner Analysis

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

tp = 323 x 24 / 829,6 = 9,35 hrs

Straight line starts at 21,35 hrs Slope = 0.369 bar/cycle psi/cycle

$P_{wf's}$ = 307,8 bar psig

P_{1hr} = 312,9 bar psig

P^* = ______ psig

Calculated Values

$$Kh = \frac{162.6\ Q\ B\mu}{M} = \frac{162.6 \times 829{,}6 \times 1{,}434 \times 0.493}{0.369 \times 0.159 \times 14.504} = 112068 \text{ md.ft}$$

= 34158 mdm

K = Kh/h = 34158 / 14 = 2440 md.

$$S = 1.1513 \left[\left[\frac{P1hr - Pwf\ s}{M}\right] + Log\left[\frac{tp\ \ 1}{tp}\right] - Log\left[\frac{K}{\emptyset \mu C_t\ rw^2}\right] + 3.2275 \right]$$

S = 1.1513 [[______] + Log [______] − Log [______] + 3.2275]

S = +8,2 ΔP_{skin} = 2,4 bar

$$t_{DA} = \frac{0.000264\ Kt}{\emptyset \mu C_t A} = 0.000264 \text{ \_\_\_\_\_\_ } = \text{ \_\_\_\_\_\_}$$

P_{DMBH} = ______

$\bar{P} = P^* - P_{DMBH}\left[\frac{M}{2.303}\right]$ = 313,2 psig @ − 1760.3 ss

= ______ psig @ − ______ ss Datum

$PI_a = q_o/\Delta P$ = 829.6/(313.2 − 307,8) = 153,6 Sm^3/D/bar

$PI_{s=o} = q_o/\Delta P$ = 829,6/(313,2 − 307,8 − 2,5) = 276,5 Sm^3/D/bar

TABLE 15

P_{ws} versus t-shutin, first buildup DST-3

BRØNN 34-10-7 DST# 3
BUILDUP NUMMER 1
GAUGE SDP82016

NR.	TID	TRYKK
1	11.50	303.540
2	11.51	312.140
3	11.51	312.700
4	11.52	312.800
5	11.52	312.830
6	11.52	312.890
7	11.52	312.930
8	11.53	312.980
9	11.54	312.950
10	11.56	313.010
11	11.56	313.100
12	11.57	313.110
13	11.57	313.100
14	11.59	313.190
15	12.01	313.280
16	12.01	313.300
17	12.02	313.300
18	12.07	313.410
19	12.13	313.460
20	12.15	313.490
21	12.17	313.510
22	12.19	313.480
23	12.25	313.510
24	12.26	313.520
25	12.27	313.510
26	12.28	313.540
27	12.31	313.510
28	12.32	313.340
29	12.37	313.520
30	12.43	313.530
31	12.45	313.480
32	12.47	313.500
33	12.52	313.510
34	12.55	313.530
35	12.57	313.510

Figure 18

p_{ws} versus t-shutin, first buildup DST-3

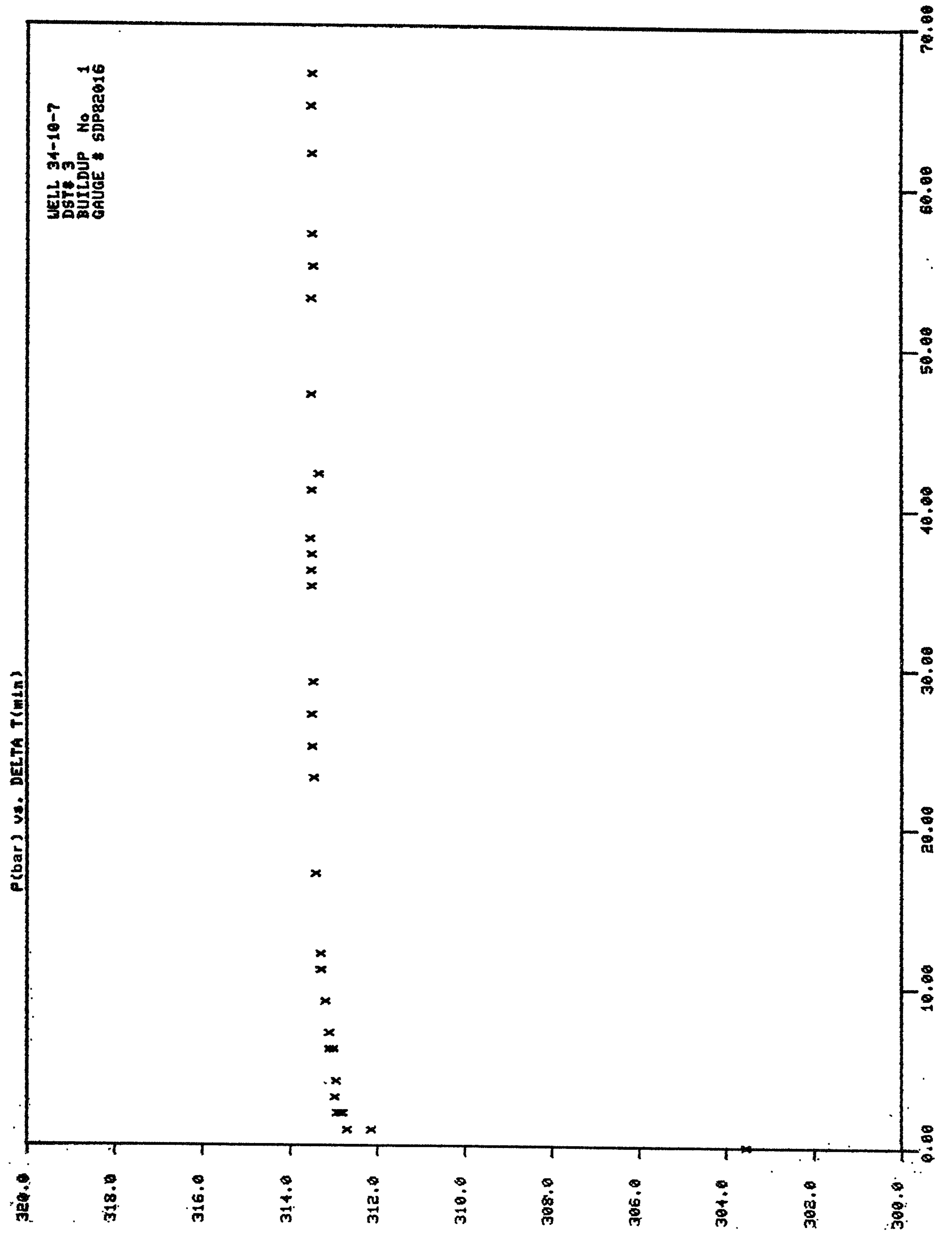


Figure 19

Horner plot first buildup DST-3

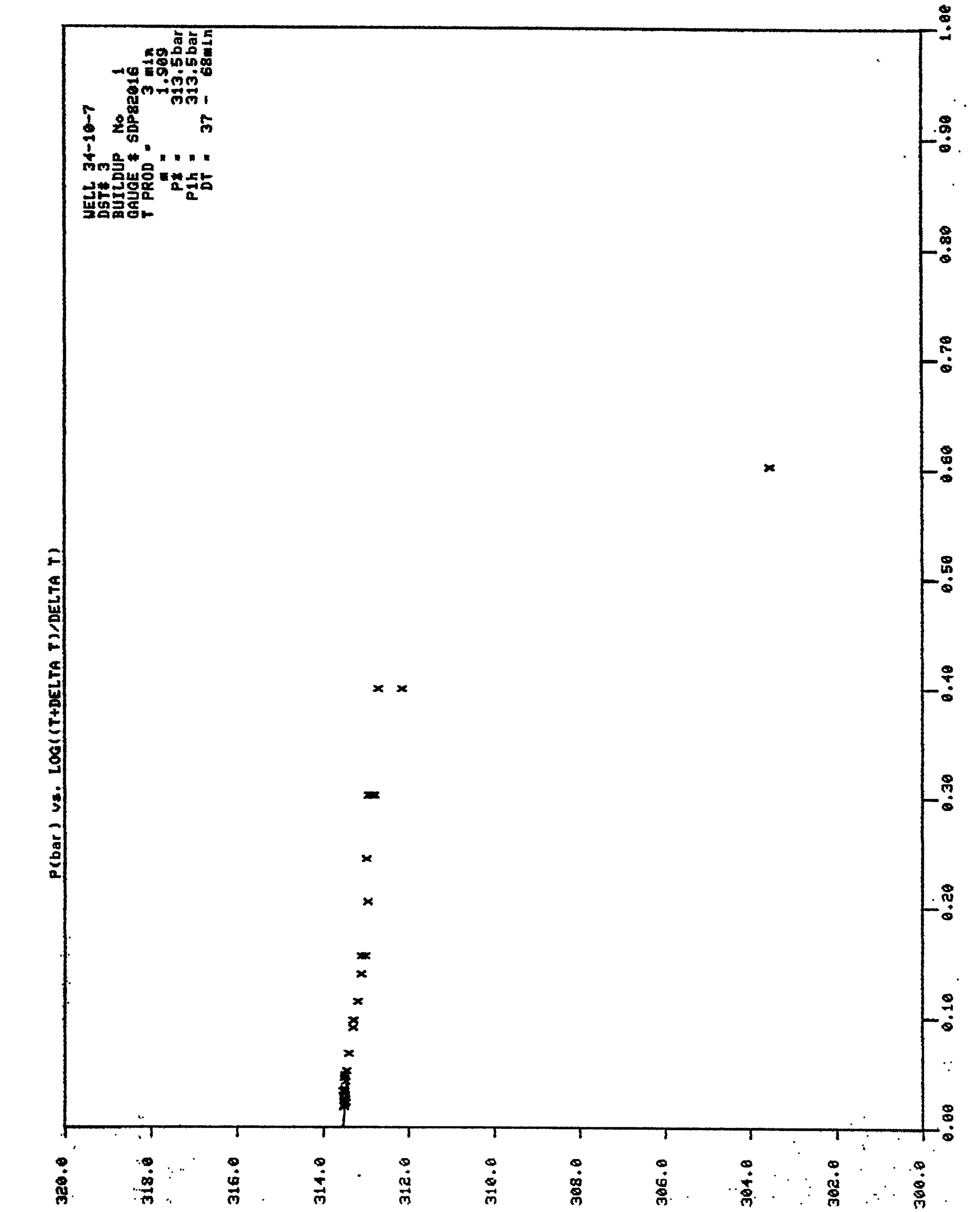
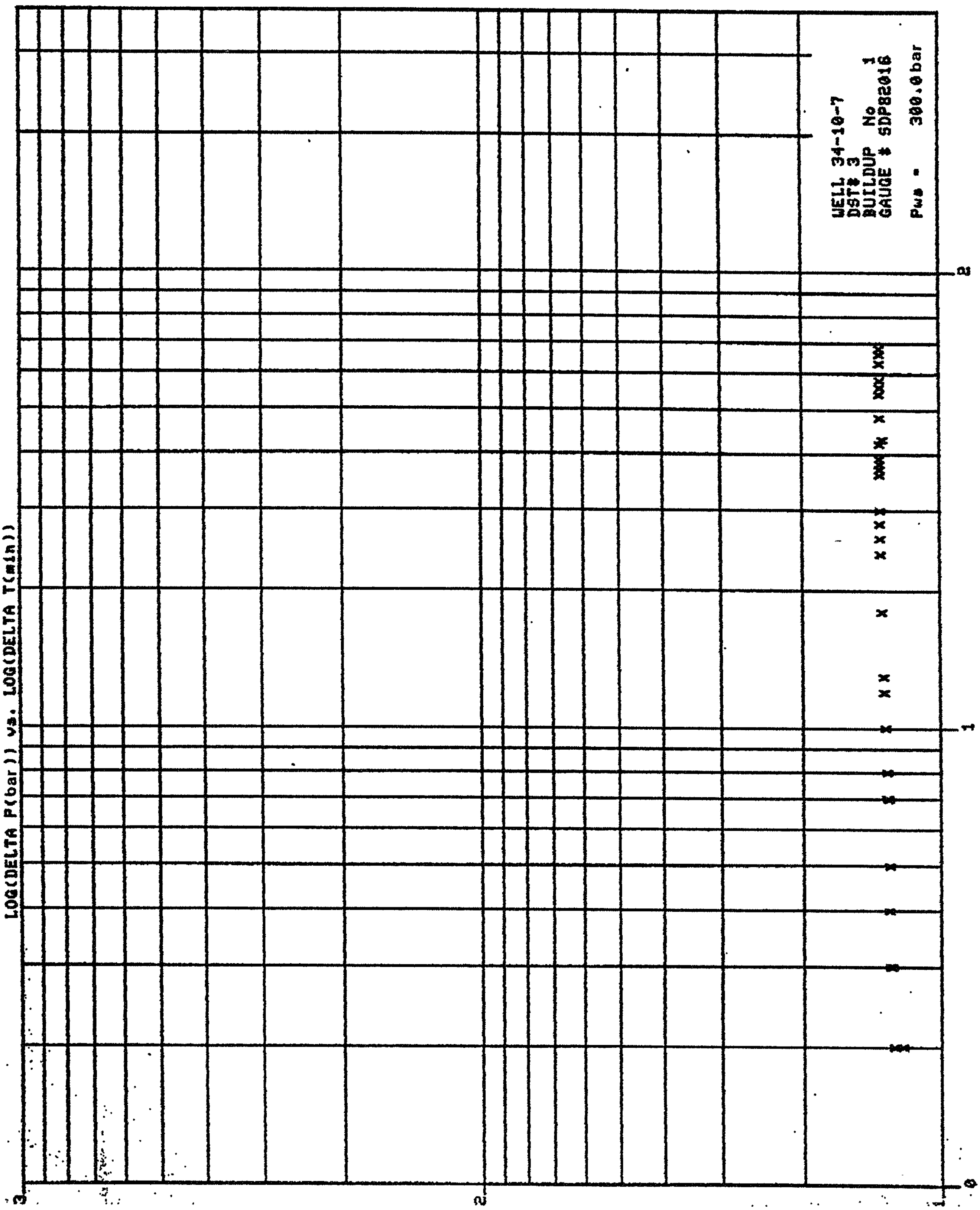


Figure 20


LOG(DELTA P(bar)) vs. LOG(DELTA T(min))
WELL 34-10-7
DST# 3
BUILDUP No 1
GAUGE # SDP82016
Pws = 300.0bar
3
2
1
0
2
1

BRØNN 34-10-7 DST# 3
BUILDUP NUMMER 2
GAUGE SDP82016

TABLE 16

P_{ws} versus t-shutin main buildup DST-3

NR.	TID	TRYKK						
1	21.09	307.790	35	22.28	312.920	69	1.56	313.020
2	21.10	311.830	36	22.34	312.970	70	2.22	313.030
3	21.10	311.900	37	22.35	312.930	71	2.26	313.030
4	21.12	311.990	38	22.36	312.910	72	2.27	313.020
5	21.14	312.100	39	22.38	312.940	73	2.27	313.030
6	21.25	312.380	40	22.39	312.940	74	2.29	313.050
7	21.26	312.430	41	22.39	312.960	75	2.30	313.040
8	21.29	312.430	42	22.50	312.960	76	2.36	313.050
9	21.34	312.590	43	22.55	312.970	77	2.38	313.060
10	21.35	312.600	44	23.00	312.950	78	2.38	313.050
11	21.35	312.620	45	23.03	312.950	79	2.39	313.050
12	21.38	312.650	46	23.08	313.010	80	2.42	313.060
13	21.39	312.680	47	23.10	313.000	81	2.45	313.070
14	21.40	312.720	48	23.12	312.950	82	2.46	313.090
15	21.42	312.750	49	23.15	312.970	83	3.18	313.090
16	21.44	312.760	50	23.20	313.000	84	3.50	313.070
17	21.44	312.790	51	23.26	312.990	85	4.11	313.060
18	21.46	312.770	52	23.28	313.010	86	4.38	313.100
19	21.47	312.740	53	23.30	313.020	87	4.41	313.100
20	21.48	312.740	54	23.33	312.990	88	4.42	313.090
21	21.54	312.820	55	23.34	312.960	89	4.52	313.080
22	21.55	312.830	56	23.45	313.010	90	5.03	313.050
23	21.56	312.810	57	23.46	312.990	91	5.46	313.100
24	22.02	312.870	58	23.54	313.030	92	5.56	313.090
25	22.03	312.890	59	0.01	312.980	93	6.18	313.110
26	22.06	312.830	60	0.17	313.010	94	6.18	313.110
27	22.11	312.890	61	0.25	313.040	95	6.18	313.100
28	22.14	312.890	62	0.32	313.000	96	6.19	313.060
29	22.16	312.920	63	0.48	313.030	97	6.20	313.110
30	22.18	312.940	64	1.01	313.050	98	6.25	313.110
31	22.18	312.940	65	1.05	313.060	99	6.28	313.110
32	22.20	312.900	66	1.21	313.040	100	6.29	313.120
33	22.20	312.870	67	1.32	313.020			
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]				

Figure 21

p_{ws} versus t-shutin, main buildup DST-3

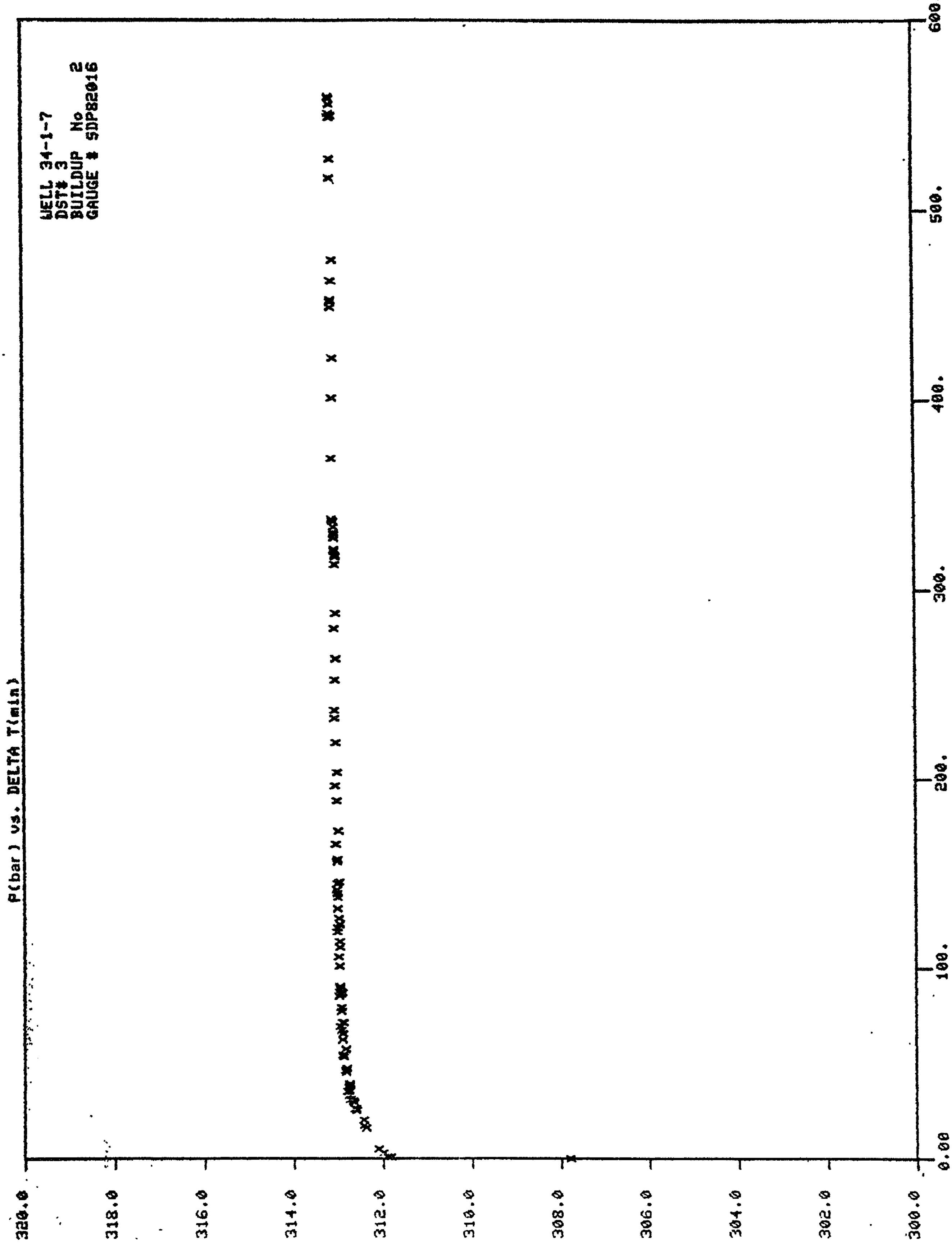


Figure 22

Horner plot main buildup DST-3

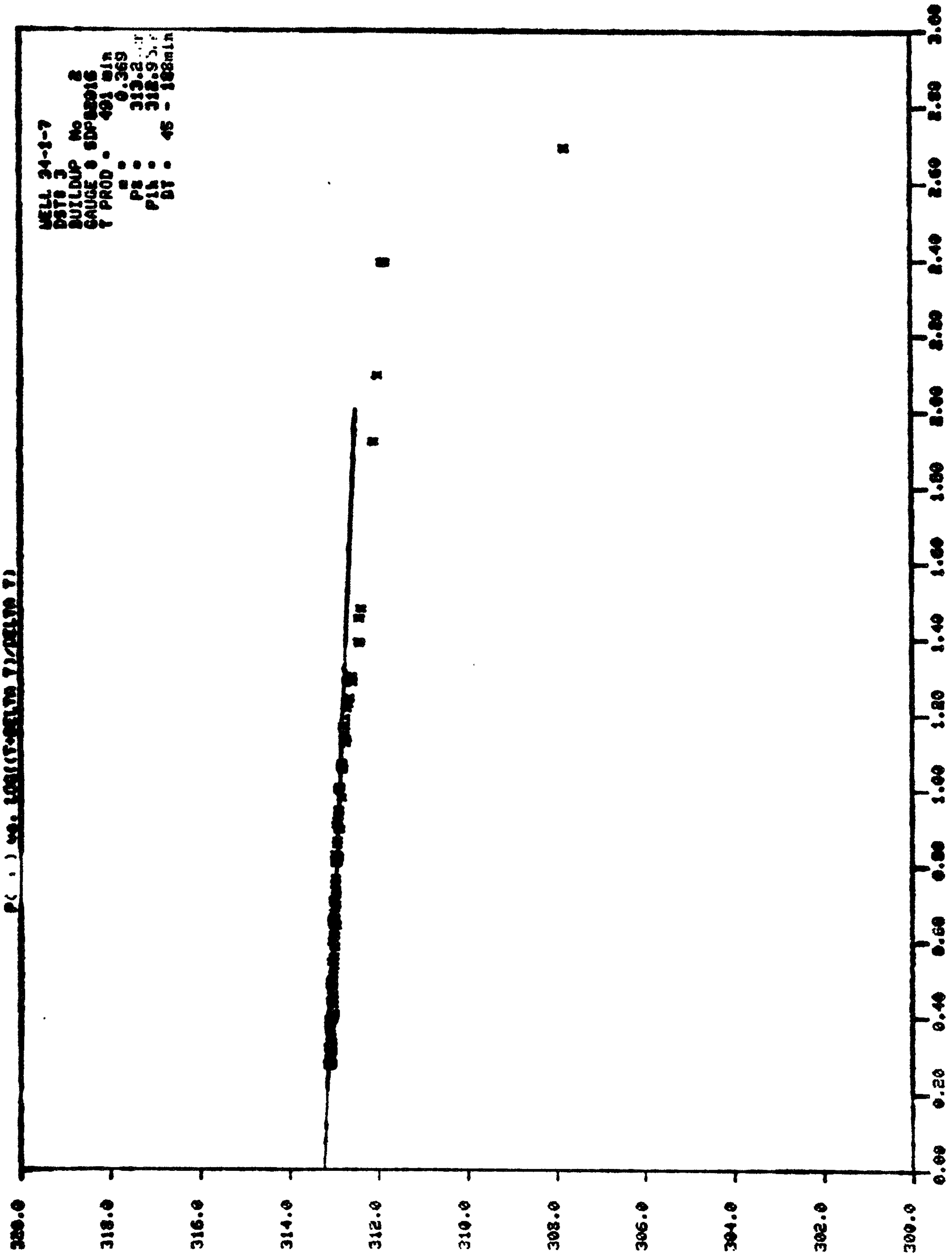


Figure 23

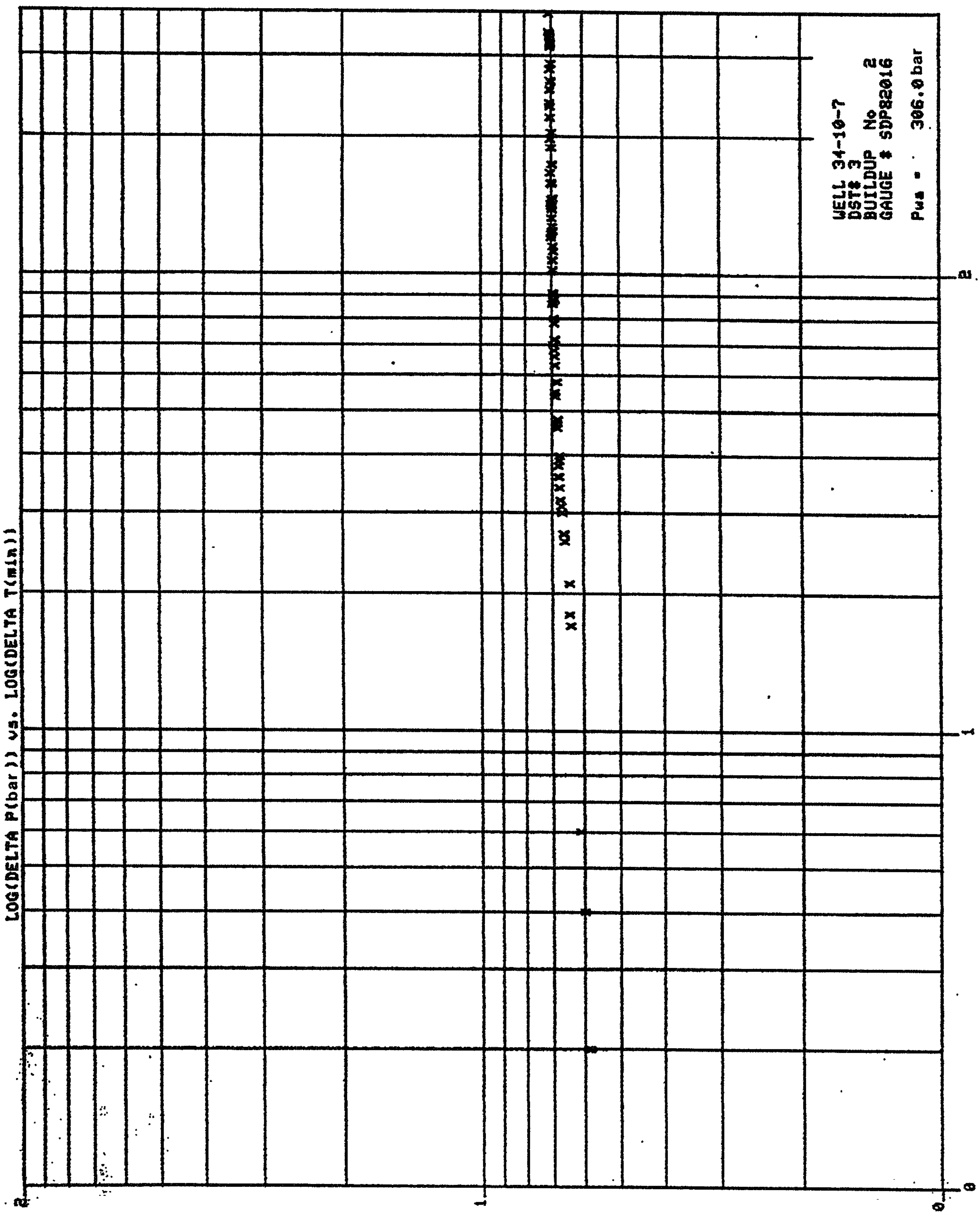

LOG(DELTA P(bar)) vs. LOG(DELTA T(min))
WELL 34-10-7
DST# 3
BUILDUP No 2
GAUGE # SDP82016
Pws = 306.0 bar
2
1
0
2
1
0

TABLE 17

Well 34/10- 7

DST no. 3

FLOW DATA

CHP/PG

Perfs.: 1810-1824 m RKB

Zone tested Cook Sand

Date/ time	Bottom hole		Well head		Chokes 1/64"		Separator data							Liq. and gas analysis			
	press. bar	temp °C	press bar	temp. °C	mani-fold	heat.	press. bar	temp. °C	gas rate $10^3 Sm^3/D$	oil rate Sm^3/D	GOR Sm^3/Sm^3	sp.gr.oil	sp.gr.gas (Air=1)	Water %	Sedim. %	CO_2 %	H_2S ppm
7.7.83																	
15.00	307.9	72	157.7	47	32	-	27.9	41	111.7	860.8	130	0.830	0.68	0	0	0	0
15.30	307.9	73	157.7	48	32	-	27.6	42	112.2	853.8	131	0.830	0.68	0	0	0	0
16.00	307.9	73	157.8	49	32	-	27.6	44	111.8	836.5	134	0.830	0.68	0	0	0	0
16.30	307.8	73	158.2	49	32	-	27.6	44	111.5	837.9	133	0.830	0.68	0	0	0	0
17.00	308.1	73	158.4	50	32	-	27.6	46	111.2	860.1	129	0.831	0.68	0	0	0	0
17.30	308.0	73	158.6	51	32	-	27.6	47	111.2	835.1	133	0.831	0.68	0	0	0	0
18.00	308.0	73	158.8	51	32	-	27.6	47	111.2	832.4	134	0.831	0.68	0	0	0	0
18.30	308.1	73	158.8	51	32	-	27.6	47	111.2	850.4	131	0.829	0.68	0	0	0	0
19.00	308.0	73	158.8	51	32	-	27.6	47	110.5	823.4	134	0.829	0.68	0	0	0	0
19.30	307.9	73	158.8	52	32	-	27.6	47	110.5	830.3	133	0.829	0.68	0	0	0	0
20.00	307.8	73	158.8	52	32	-	27.6	47	110.5	829.5	133	0.829	0.68	0	0	0	0
20.30	307.8	73	158.8	52	32	-	27.6	48	110.5	828.9	133	0.829	0.68	0	0	0	0
21.00	307.8	73	158.8	52	32	-	27.6	48	110.5	829.6	133	0.830	0.68	0	0	0	0

Remarks

Figure 24

34/10 - 7, DST no. 3

PRESSURE, TEMPERATURE, CHOKE & FLOWDIAGRAM

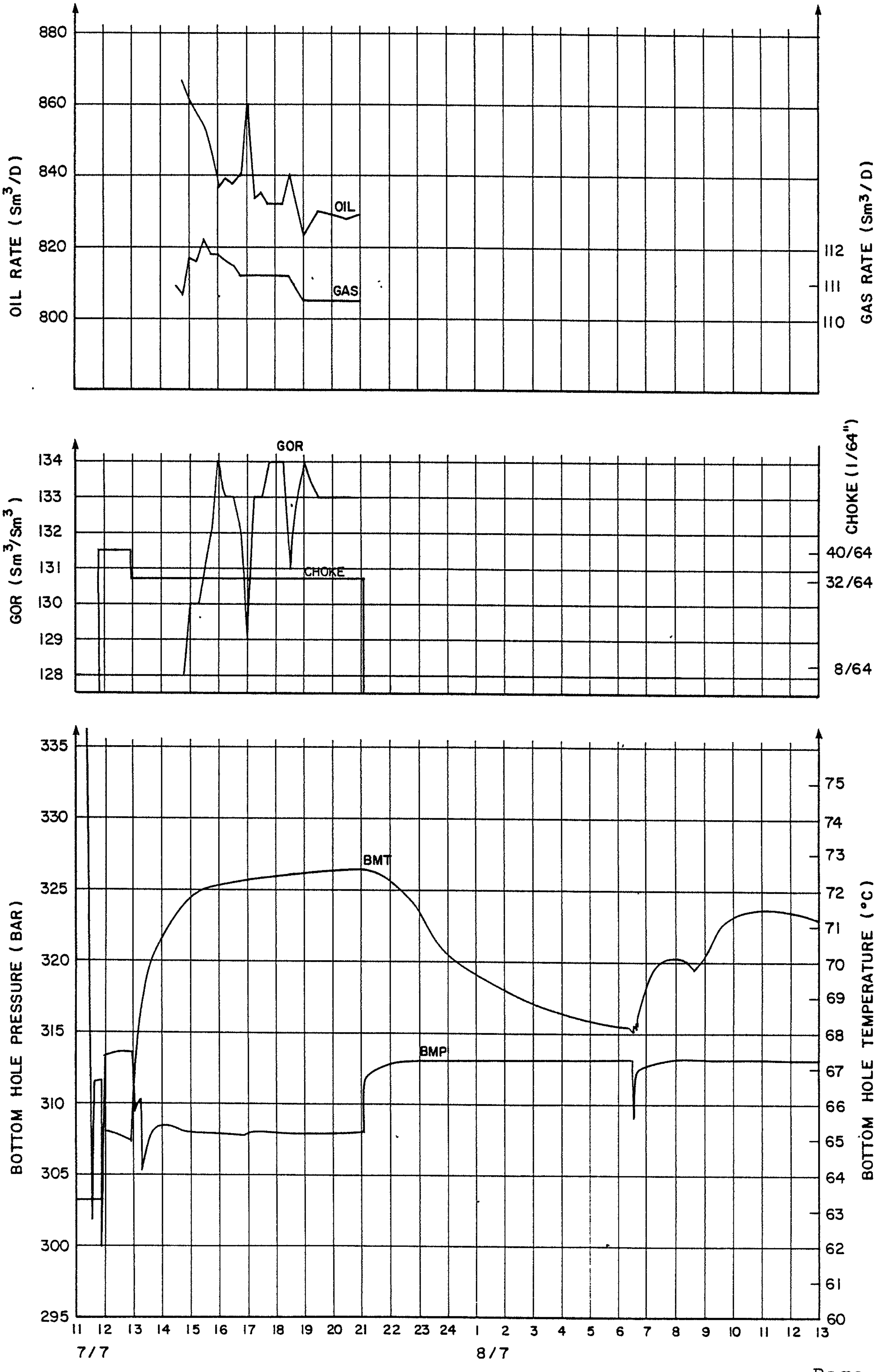


TABLE 18

Well 34/10-7	SAMPLING	CHP/PG
DST no 3		Perfs.: 1810-1824 m RKB
		Zone tested Cook Sand

SEPARATOR PVT-SAMPLES

Time/date	Sample no.	Type of sample	Transfer time	Bottle no
8.7.83				
18.28	1	Oil	35 min	82121021
18.28	2	Oil	33 min	83021216
18.28	3	Gas	35 min	A-14662
19.25	4	Oil	30 min	8212715
19.25	5	Oil	26 min	8302802
19.25	6	Gas	30 min	A-14669
20.21	7	Oil	30 min	83021222
20.21	8	Oil	30 min	83021321
20.21	9	Gas	30 min	A-14419

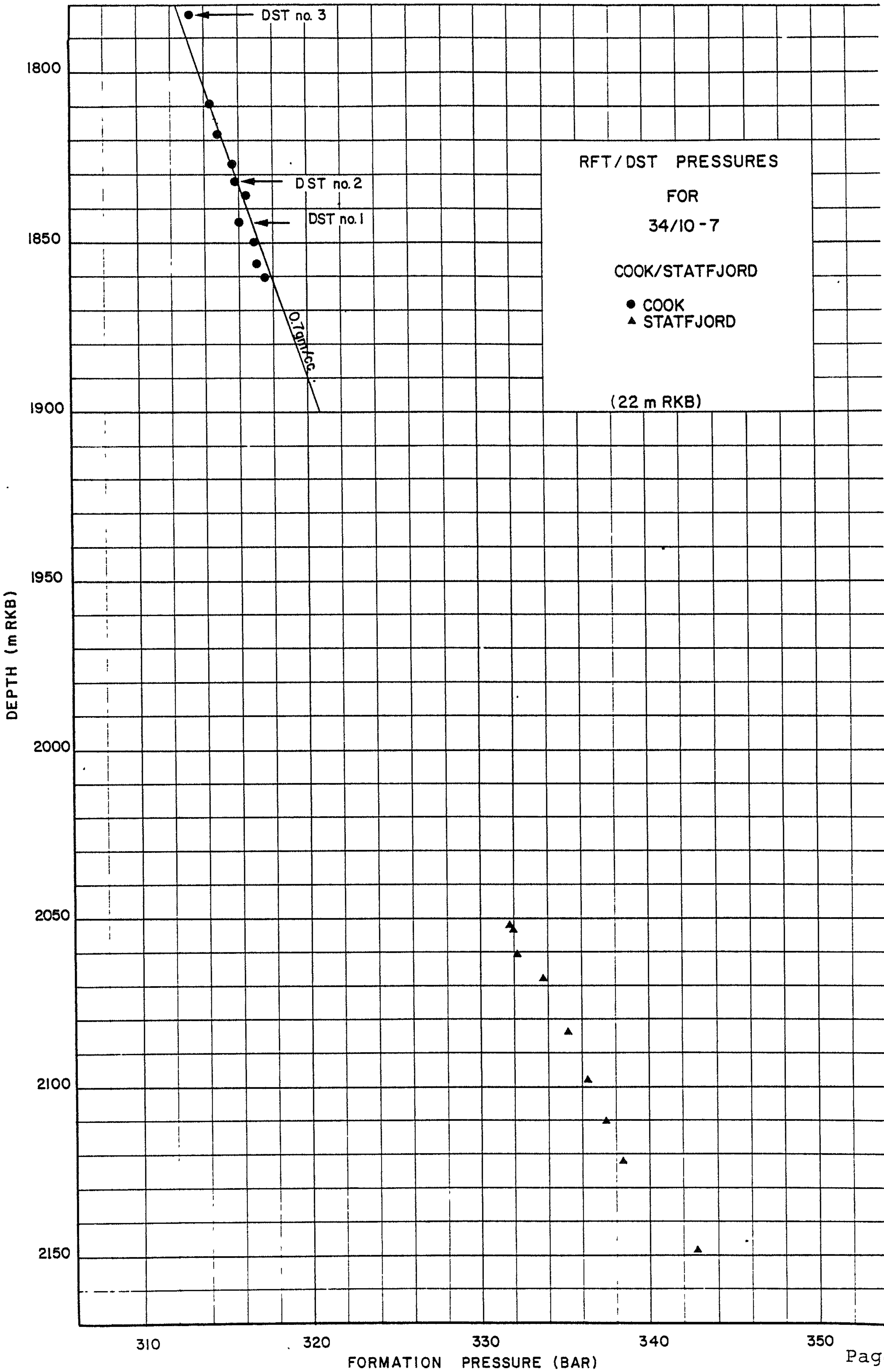
BOTTOM HOLE PVT-SAMPLES

Time/date	Sample depth mRKB	Estimated PB bar/°C	Transfering pressure(bar)	Bottle no
8.10.83				
11.10	1760	201.4/20	164.1	22024
11.13	1760	201.4/20	162.8	8151/16

DEAD FLUID SAMPLES

Time/date	Sampling point	Sampling equipment		Remarks
7.7.83				
21.15	Separator	1 x 200 L	Drum	Oil
21.15	Separator	3 x 10 L	Jerry can	Oil
21.15	Separator	6 x 1 L	Jars	Oil

Figure 25



K.G. okt. 83.

Table 19

Well 34/10-7	LAYOUT OF TEST-STRING	CHP/PG
DST no 3		Perfs 1810-1824
		Zone tested COOK UNIT 3

TEST-STRING	ID inch	OD inch	LENGTH m	DEPTH mRKB
FLOPETROL STT W/X-OVER	-	-	-	- 5.55
1 JNT 3 1/2 PH-6 TBG. 12.95 LBS/FT				
P-105	2.75	3.5	9.21	3.66
1 PUPJNT 3 1/2 PH-6 TBG.	2.75	3.5	4.50	8.16
1 JNT 3 1/2 PH-6 TBG.	2.75	3.5	9.21	17.37
1 PUPJNT 3 1/2 PH-6 TBG.	2.75	3.5	1.06	18.43
1 X-OVER 3 1/2 PH-6 BOX X4 1/2 SA PIN	3.00	5.75	0.50	18.93
1 FLOPETROL LUB. VALVE	3.00	13.10	1.76	20.69
1 X-OVER 4 1/2 SA PIN-3 1/2 PH-6 PIN	3.00	5.75	0.56	21.25
1 PUPJNT 3 1/2 PH-6	2.75	3.5	2.29	23.54
7 STDS 3 1/2 PH-6 TBG.	2.75	3.5	192.59	216.13
1 PUPJNT 3 1/2 PH-6 TBG.	2.75	3.5	1.68	217.81
1 X-OVER 3 1/2 PH-6 BOX X4 1/2 SA PIN	3.00	5.75	0.50	218.31
1 FLOPETROL EX TREE	3.00	10.87	3.66	221.97
1 X-OVER 4 1/2 SA PIN X3 1/2 BDS PIN	3.00	5.75	0.21	222.18
1 SLICK JNT 3 1/2	2.75	3.5	2.24	224.42
1 X-OVER 3 1/2 BDS BOX X4 1/8 SA PIN	2.75	5.30	0.20	224.62
TOP 18 3/4 WELLHEAD AT 224.7M RKB				
1 FLUTED HANGER	3.00	9.75	0.30	224.92
1 X-OVER 4 1/8 SA PIN X3 1/2 PH-6 PIN	2.75	5.00	0.50	225.42
1 PUPJNT 3 1/2 PH-6	2.75	3.5	2.74	228.16
1 PUPJNT 3 1/2 PH-6	2.75	3.5	1.06	229.22
1 PUPJNT 3 1/2 PH-6	2.75	3.5	4.50	233.72

Remarks.

TABLE 19 continued

Well 34/10-7	LAYOUT OF TEST-STRING	CHP/PG
DST no 3		Perfs 1810-1824
		Zone tested COOK UNIT 3

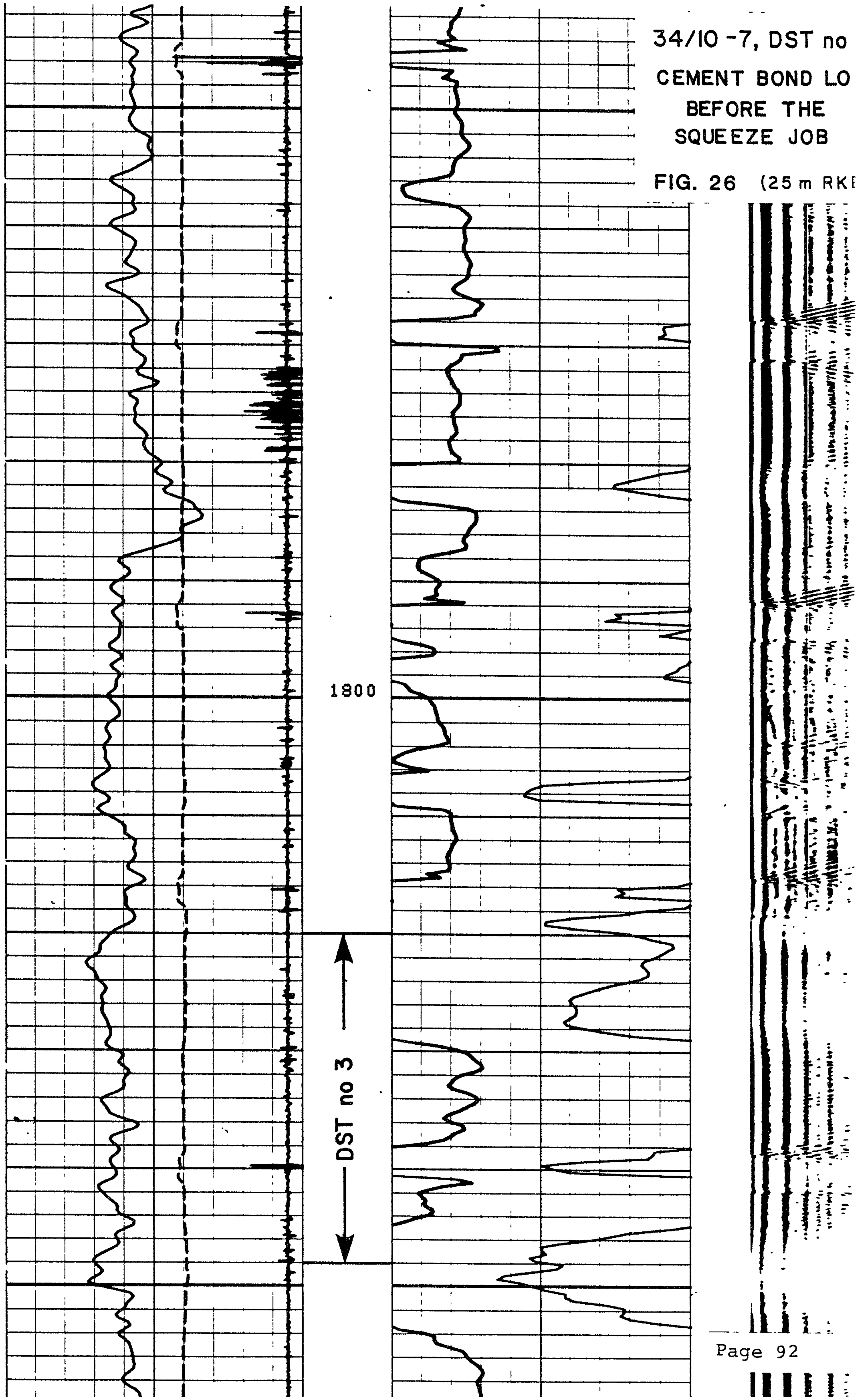
TEST-STRING	ID inch	OD inch	LENGTH m	DEPTH mRKB
4 STDS 3 1/2 PH-6 TBG.	2.75	3.5	1292.67	1526.39
1 x-OVER 3 1/2 PH-6 BOX x3 1/2 IF PIN	2.75	5.00	9.39	1526.77
1 SLIP JOINT (OPEN)	2.25	5.00	5.54	1532.31
1 SLIP JOINT (CLOSED)	2.25	5.00	4.02	1536.33
5 STDS DRILL COLLARS + " SINGLE	2.25	4 3/4	161.37	1697.66
1 RTTS MECH. CIRC. VALVE	2.44	4.625	1.10	1698.76
1 STDS DRILL COLLAR	2.25	4 3/4	28.50	1727.26
1 SLIPJT (CLOSED)	2.25	5.00	4.02	1731.28
1 SLIPJT (CLOSED)	2.25	5.00	4.02	1735.30
1 STD DRILL COLLAR	2.25	4 3/4	28.49	1763.79
1 APR-M CIRC./SAFETY VALVE	2.25	5.00	2.29	1766.08
1 DRILL PIPE TESTER VALVE	2.25	5.00	1.35	1767.43
1 LPR TESTER VALVE	2.25	5.00	4.99	1772.42
1 FUL FLO HYDRAULIC BYPASS	2.25	4.625	2.02	1774.44
1 JAR	2.25	4.625	1.58	1776.02
1 RTTS SAFETY JOINT	2.44	5.00	0.88	1776.90
1 RTTS PACKER, (ABOVE)	2.40	5.75	0.56	1777.46
1 RTTS PACKER, (BELOW)	2.40	5.75	0.83	1778.29
1 PERFORATED JNT 2 7/8 EUE BOX DOWN	2.44	2.88	3.55	1781.84
1 X-OVER 2 7/8" EUE PIN X 2 3/8" EUE PIN	2.00	3.25	0.18	1782.02
1 BAKER F-NIPPLE 2 3/8" BOX X PIN	1.75	3.00	0.28	1782.30
1 X-OVER 2 3/8" EUE BOX X 2 7/8" EUE PIN	2.00	3.25	0.24	1782.54
1 JNT 2 7/8" TBG	2.44	2.88	9.42	1791.96
1 DST HANGER	-	-	-	1791.96
1 JNT 2 7/8" TBG	2.44	2.88	9.41	1801.37
1 BULL PLUG W/CROSS	2.88	2.88	0.15	1801.52

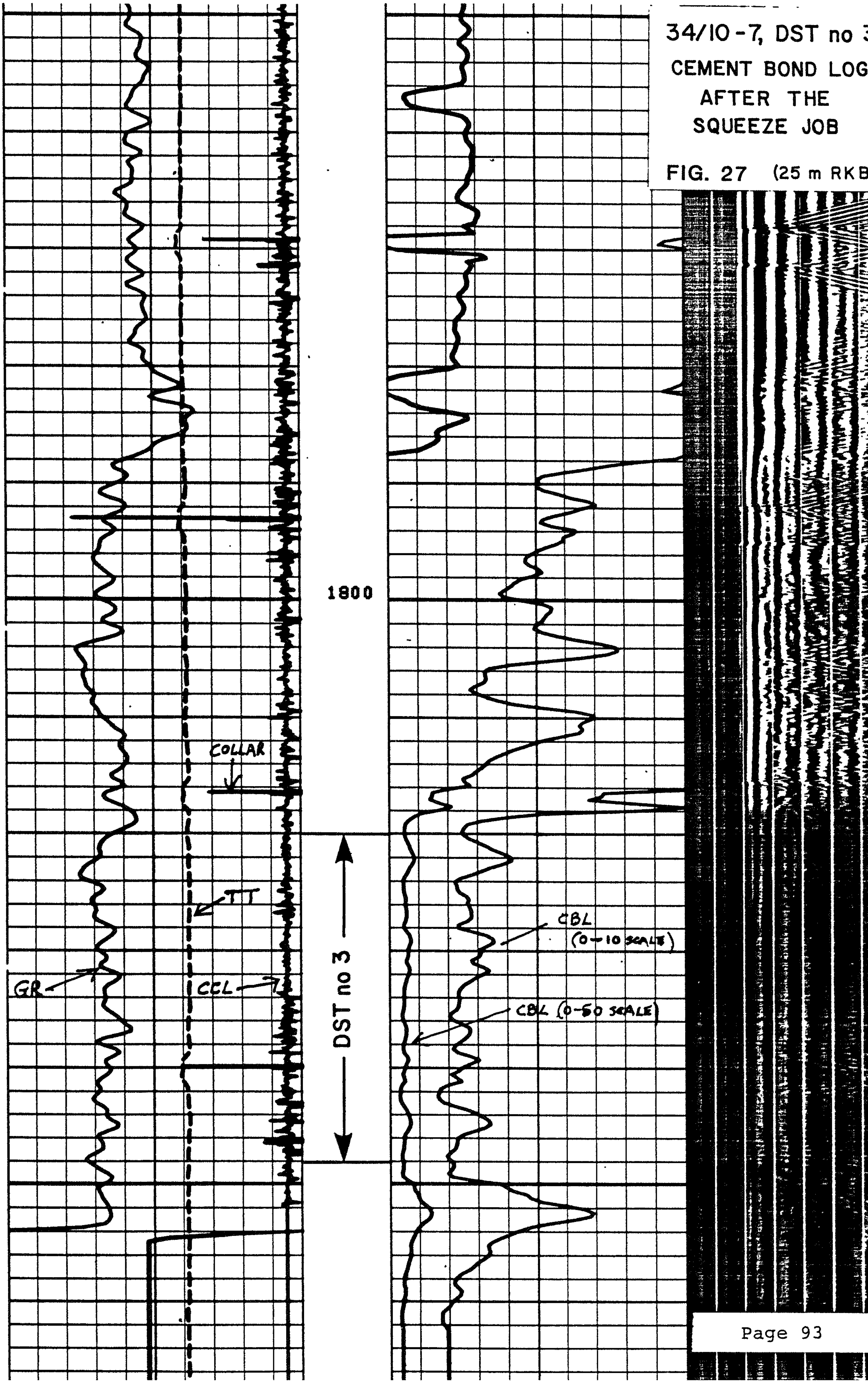
Remarks.

34/10 -7, DST no

CEMENT BOND LO
BEFORE THE
SQUEEZE JOB

FIG. 26 (25 m RKB





34/10-7, DST no 3
CEMENT BOND LOG
AFTER THE
SQUEEZE JOB
FIG. 27 (25 m RKB
1800
COLLAR
TT
GR
CCL
DST no 3
CBL (0-10 SCALE)
CBL (0-50 SCALE)

TABLE 20

Well 34/10- 7 DST no. 3	DIARY OF EVENTS	CHP/PG Perfs.: 1810-1824 m RKB Zone tested: Cook Sand

Date	Time	OPERATIONS
7.7.83		
		INITIAL FLOW/BUILD UP
	1138:30	Opened lpr-valve
	1148	Opened well on 40/64" fixed choke
	1151	Shut well in at choke manifold and lpr-valve. 2.4 m^3 produced
		SECOND FLOW/BUILD UP
	1254	Opened lpr-valve
	1258	Opened well on 32/64" fixed choke
	1303	Mud to surface
	1304	Gas to surface
	1357	Flow directed through separator
	1828	Started to take 1. set of PVT samples
	1925	Started to take 2. set of PVT samples
	2021	Started to take 3. set of PVT samples
	2111	Well shut in at lpr-valve and choke manifold for build up period.
8.7.83		
		BOTTOM HOLE SAMPLING
	0618	Opened lpr-valve
	0629	Opened well. Flow directed through heater on 8/64" choke
	0726	Closed lub valve. Rigged up for bottom hole sampling. Samplers set to close at 1100 hrs and 1113 hrs
	0811	Opened lub valve
	0812	RIH w/samplers
	0827	Opened well on 8/64" choke (heater)
	0900	Samplers on depth, 1760 m RKB
	1130	Shut well in at choke manifold
	1133	POOH with samplers
	1208	Closed lub valve. Checked samplers. OK. Prepared for Bull-heading, End test

Remarks: