WELL 7/8-3 NORWAY

DRILL STEM TEST REPORT
DECEMBER 1983

J. S. MacDonald
PES Houston

CONOCO INC.
PRODUCTION ENGINEERING SERVICES
BOX 2197
HOUSTON, TEXAS 77001

FROM: J. S. MacDonald DATE: March 29, 1984

SUBJECT: WELL 7/8-3 NORWAY DRILL STEM TEST REPORT

INTRODUCTION

Two drill stem tests were performed in separate intervals of the Upper Jurassic Sandstone section of Well 7/8-3 in the Norwegian sector of the North Sea. The purpose of this report is to document the test data and results, and give an analysis and interpretation of these results.

CONCLUSIONS

1. The moveable formation fluid from the interval 12342-12359 ft. (3762-3767m) is 29° API oil.

2. The tested interval from 12342-12359 ft contained a higher permeability layer, of limited extent, within a tight matrix rock. The zone will not give up sustained commercial oil flowrates.

3. The moveable formation fluid from the interval 12252-12272 ft (3734.5 - 3740.6m) was proven to be 30° API oil. The interval will not give up commercial oil flowrates.

4. The Upper Jurassic Sandstone has a formation pressure gradient of 0.701 psi/ft ± 0.001 psi/ft with an equivalent mud weight of 13.48 ppg through the tested interval.

J. S. MacDonald

Jeffery S. MacDonald
Senior Production Engineer
Production Engineering Services

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WELL 7/8-3
SUMMARY OF TEST RESULTS

1. Drill Stem Test No. 1

Date of Test	1st - 3rd December 1983
Formation Type	Upper Jurassic
Perforated Interval	12342 - 12359 ft. (3762-3767m)
Initial Flow Period	7 mins.
Initial Buildup	60 mins.
Final Flow Period	10 hrs 10 mins (610 mins)
Final Buildup	13 hrs 24 mins (804 mins)

Flow Period

Oil Flowrate (final 5 hours)	1340 declining to 1275 BOPD
Gas Flowrate	230 M SCF/D
Gas-Oil-Ratio (separator conditions)	177 SCF/BBL
B.S.W.	1%
Flowing BHP (final 5 hours)	3788 psig declining to 3736 psig
Flowing WHP (final 5 hours)	57 psig
Flowing Pressure Gradient	0.299 psi/ft.
Oil Gravity - specific	0.882
°API	29°
Gas Gravity	0.880
H_2S Content	0
CO_2 Content	4.5%

Pressure Buildup Analysis

Initial Formation Pressure (mid-perfs)	8602 psig ± 5 psi.
Formation Pressure Gradient	0.701 psi/ft ± 0.001 psi/ft. → 13.5 PPG
Mud Weight Equivalent	13.48 ppg ± 0.02 ppg.
Formation Temperature (mid-perfs.)	312°F.
Temperature Gradient (ref. mudline)	2.314°F/100 ft.
Permeability-Thickness (as tested)	120 md-ft.
Permeability (average)	7 md.
Permeability thickness (high perm layer)	355 md-ft.
Permeability (high perm layer)	120 md.
Skin Effect	- 3.2.
Productivity Index (actual)	0.27 bbl/d/psi.
Radius of Investigation	±250 ft.

COMMENTS

This is a valid test. The well produced 29° API gravity oil with a separator gas-oil-ratio of 177 SCF/BBL. Log data indicated high water saturations through this interval with a possible oil-water contact. The test was undertaken to try and determine the existence of the potential contact. However as the zone produced clean oil with no formation water, it is not possible to prove an oil-water contact, or that the interval is or is not in the start of a transition zone.

Based on the log, core and test data it is concluded that the zone of interest contained a high permeability layer, of limited areal extent, within a tight matrix. Depletion of this limited high permeability layer was the reason for the slowly declining flowrates during the test. This does not imply depletion of a limited reservoir, only of this particular high permeability layer.

2. Drill Stem Test No. 2

Date of Test	4th - 6th December 1983
Formation Type	Upper Jurassic Sandstone
Peforated Interval	12252 - 12272 ft (3734.5-3740.6m)
Initial Flow Period	5 mins
Initial Buildup Period	40 mins
Final Flow Period	9 hrs 17 mins (557 mins)
Final Buildup Period	10 hrs 10 mins (610 mins)

Flow Period Results

Average Oil Flowrate	415 BOPD
Gas Flowrate	Unable to measure
Gas - Oil Ratio	Unable to measure
Flowing BHP final	4446 psig
Flowing WHP	20 psig
Flowing Pressure Gradient (final)	0.362 psi/ft.
Oil Gravity - Specific	± 0.876
- °API	30° API
Gas Gravity	0.880
H_2S	0
CO_2	4.5%

Pressure Buildup Analysis

Initial Formation Pressure (mid-perfs)	8586 psig ± 5 psi	
Formation Pressure Gradient	0.700 psi/ft ± 0.001 psi/ft	→ 13.5 PPG
Mud Weight Equivalent	13.46 ppg ± 0.02 ppg	
Formation Temperature (mid-perfs)	310°F	
Temperature Gradient (ref mudline)	2.313 °F/100 ft	
Permeability - thickness	260 md-ft	$\frac{260}{3.2808}$
Permeability	18 md.	
Skin Factor	+8.1	
Drawdown Due to Skin	2001 psi	
% DD Due to Skin	55%	
Radius of Investigation	±200 ft	
Lateral extent of shale barrier	±100 ft	
P.I. (actual)	0.12 bbl/d/psi	
P.I. (S = 0)	0.24 bbl/d/psi	

COMMENTS

This was a valid test of the interval. The moveable formation fluid was proven to be 30° API gravity oil. The pressure buildup analysis indicates that the shale barrier separating the perforated interval from additional oil bearing pay extends approximately 100 ft. from the wellbore. Beyond this the pressure transients were expanding in a vertical as well as horizontal direction.

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DRILL STEM TEST NO. 1

DATE: 1st - 3rd December 1983

WELL 7/8-3

WELL DATA
DST NO. 1

Well Location	57° 15' 31.2" N. 2° 32' 45.8" E.
Depth RKB (to MSL)	82 ft (25m).
Water Depth	266 ft (81m).
Total Depth	14174 ft (4320m).
Plugback Depth	12457 ft (3797m).
Perforated Intervals	12342 - 12359 ft (3762-3767m). 4" casing guns. 4 SPF. 90° phasing.
Mid-perforation Depth	12350 ft (3764.3m).
Casing Size	7" 32# C95 liner. Hanger at 11348 ft. Shoe at 12557ft. 3827m
Test String	5" 19.5# Class 'G' drill pipe.
Test Packer	Dowell Positest Packer at 12284 ft (3744.2m).
Test Valve	Dowell 'Sleeve Type' PCT Valve at 12254 ft (3735m).
Cushion	Full seawater cushion.
Test String Volume	205 bbls.
Rathole Volume	1.0 bbls to top perforation; 1.4 bbls to bottom perforations.

Mud	MW	FV	PV	YP	pH	% Oil	CL-
1. When drilled	14.5	58	28	17	10.1	4	12K
2. When perforated	14.2	55	27	9	11.3	1	17K

WELL 7/8-3

DIARY OF EVENTS
D.S.T. NO 1

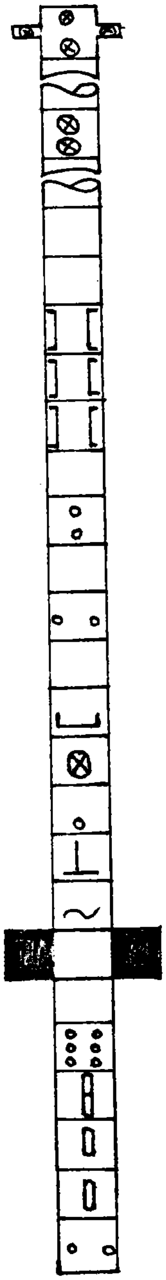
DATE	TIME	EVENT
12/1/83	05-00	Perforate test interval from 12342-12359 ft (3762-3767m) with 4" casing guns, 4SPF, 90° phasing.
	06-57	Start Sperry Sun gauge No. 0346 (20000 psi element) with a 70hr clock and a 17 hour start delay.
	06-58	Start Sperry Sun gauge No. 0120 (10000 psi element) with a 70 hr clock and a 17 hour start delay.
	07-10	Start Dowell gauge No. J-755 (14000 psi element) with a 96 hour clock.
	07-12	Start Dowell gauage No. J-756 (14000 psi element) with a 48 hour clock.
	08-00	Start picking up test tools.
	11-30	Pressure test tool string to 5000 psi. Run in hole. Fill test string with a seawater cushion whilst running in the hole.
	20-00	Function test EZ tree.
	21-56	Set packer at 12284 ft (3744.2m).
	23-30	Rig up surface flowlines.
12/2/83	06-30	Pressure test surface equipment and test string. a) Test string, flohead and choke manifold to 7500 psi. b) Separator to 1000 psi . c) Burner flowlines to 500 psi .
	06-54	Pressure up annulus to 1600 psi to open downhole test valve for the initial flow period.
	06-55	Open well at surface on a 2" fixed choke size. Flowing seawater cushion. WHP = 0 psig.
	07-01	Bleed off annulus pressure to shut in well for the initial buildup period.
	07-04	Shutin at surface. ISIWHP = 0 psig.
	08-01	FSIWHP = 0 psig.

DATE	TIME	EVENT
12/2/83	08-01	Pressure up annulus to open downhole test valve for final flow period. Open for flow at surface on a 2" fixed choke.
	10-25	Traces of gas at surface. FWHP = 1 psig.
	10-30	Traces of oil at surface FWHP = 1 psig.
	11-15	Increasing oil content in produced fluid. Flowing 45% seawater cushion and 55% oil. FWHP = 90 psig.
	12-03	Change to 1" adjustable choke.
	12-09	Change to 16/64" adjustable choke.
	12-24	FWHP = 170 psig.
	12-24	Change back to a 2" fixed choke. The wellhead pressure did not increase dramatically on the 16/64" choke size. The well is largely formation capacity limited. The flow will be through a 2" fixed choke and the separator will be used to control the back pressure to the well.
	12-45	Switch flow through the separator.
	16-00	Take one set of separator oil and gas PVT samples for laboratory recombination.
	16-40	Take second set of separator PVT samples.
	18-00	By-pass separator.
	18-03	Pressure up annulus to 3200 psi to try and shear closed the downhole test valve. The well was left open at surface to try and determine whether the downhole valve had indeed closed.
	18-11	It was unclear whether or not the downhole valve had closed. Information upon retreiving the test tools indicate that the valve did not shear closed. The annulus pressure was however released at 18-11 to close the tool for the final buildup.
	18-20	Shutin at surface. ISWHP = 20 psig.
12/3/83	06-30	FSIWHP = 139 psig.
	07-19	Drop bar to shear impact sub.
	07-35	Impact sub did not shear. There was no communication between the annulus and the drill pipe at this stage. It was therefore necessary to use annulus pressure to

DATE	TIME	EVENT
12/3/83		open the S.S.A.R.V. reverse sub. However at 1900 psi the annulus pressure dropped. It was later discovered, upon inspection of the downhole tools, that the bar had not sheared the impact sub reverse pins when it landed but it had weakened them sufficiently such that the annulus pressure sheared them. The test string was then reversed out, recovering a full string of oil. Because the downhole test valve did not shear closed permanently, the annulus pressure required to reverse out the test string caused the valve to open during the reverse out. This prevented a representative bottomhole PVT sample being caught in the tool.
	09-55	Unseat packer and pull out of the hole.
		END OF TEST

D.S.T. NO. 1

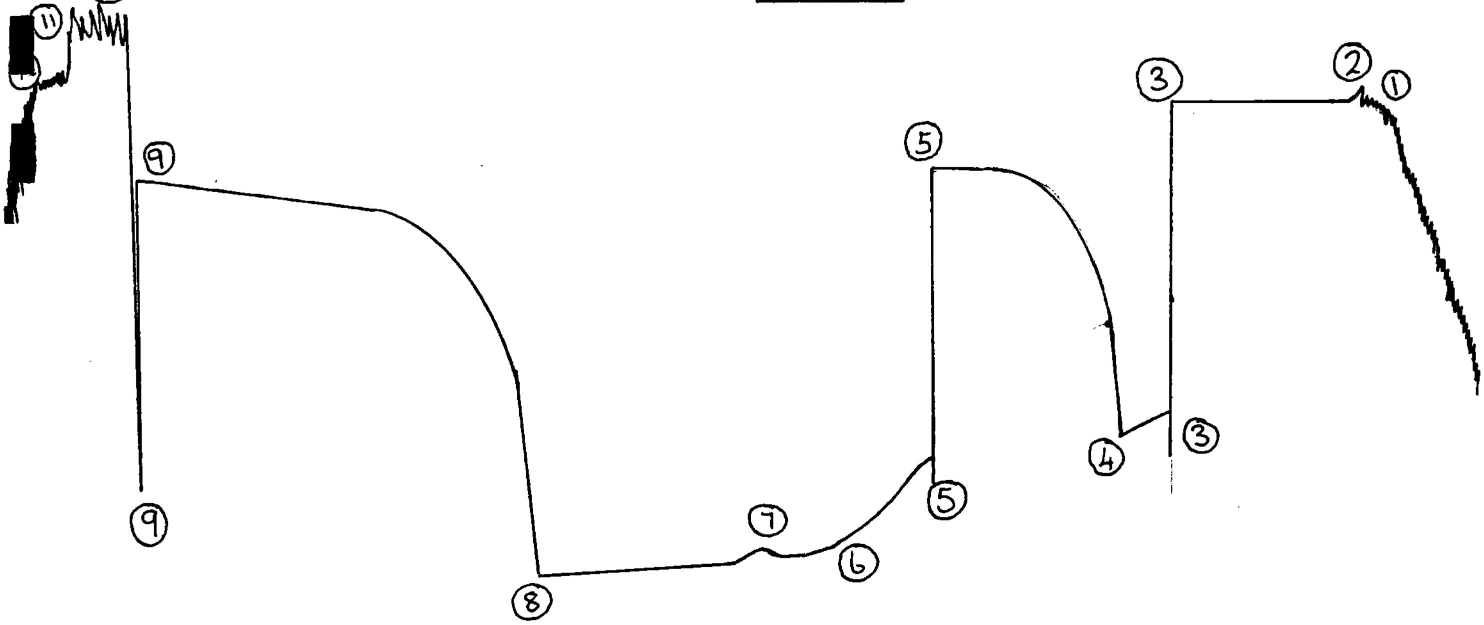
TEST TOOLS LISTING



Description	O.D. (inches)	I.D. (inches)	Length (feet)	Depth (feet)	
Flohead	–	3.00	10.00	-30.31	
5" Drill Pipe	5.00	4.28	20.31 317.63	-20.31 0.00	Rotary
Sub-sea-test-tree	5.00	3.00	22.17 1.25	317.63 339.80	Wellhead
5" Drill Pipe	5.00	4.28	10720.51	341.05	
X-over	6.25	2.85	1.78	11061.56	
3½" Drill Pipe	3.50	2.76	276.27	11063.34	
Slip Joint (open)	5.00	2.25	28.18	11339.61	
Slip Joint (½-open)	5.00	2.25	25.68	11367.79	
Slip Joint (closed)	5.00	2.25	23.18	11393.47	
7 Stds Drill Collars	4.75	2.78	641.34	11416.65	
S.S.A.R.V.	5.00	2.25	8.46	12057.99	
1 Std Drill Collars	4.75	2.78	91.62	12066.45	
Impact Reverse Sub	4.75	2.25 (equiv.)	1.08	12158.07	
1 Std Drill Collars	4.75	2.78	91.62	12159.15	
Bar Catcher Sub	4.75	2.25 (equiv)	1.02	12250.77	
P.C.T. Valve	4.75	1.50 (equiv)	18.57	12251.79	
H.R.T.	4.75	1.50	4.27	12270.36	
Hydraulic Jars	5.00	2.25	6.50	12274.63	
Safety Joint	5.00	2.25	1.71	12281.13	
Positest Packer	5.75	2.25	1.15 2.95	12282.84 12284.00	Packer Rubber.
X-over	4.75	2.25	0.82	12286.94	
Perforated Anchor	4.75	–	9.94	12287.76	
Sperry Sun Gauge Carrier	3.50	–	30.70	12297.70	
J-200 Gauge Carrier	5.00	–	6.96	12328.40	
J-200 Gauge Carrier	5.00	–	6.96	12335.36	
Ported Bullnose.	4.75	–	1.90	12342.32	

Notes: 1. All depths are to top of tool joints. (drillers depths)
2. Loggers depths (perforated intervals) are 14ft deeper than drillers depths.

SCHEMATIC OF DOWNHOLE TEST CHART
DST NO. 1



NOT TO SCALE

1. Initial hydrostatic.
2. Set packer at 12284 ft.
3. Open downhole test valve for initial flow period.
4. Shutin downhole test valve for initial buildup period.
5. Open downhole test valve for final flow period.
6. Produced the full water cushion at surface. Now flowing clean oil.
7. Change to smaller choke size at surface. Decide to change back to a fully open 2" line.
8. Shutin downhole test valve for final buildup period.
9. Opened downhole test valve whilst trying to open reversing subs.
10. Downhole test valve opened during reverse out.
11. Unseat packer.
12. Final hydrostatic.

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RECORD OF SAMPLES
D.S.T. NO. 1

A suite of separator PVT recombination samples and weathered oil samples were collected during the test. The downhole sample was not caught due to the test valve failing to shear closed after the final flow period. This resulted in the sample being replaced by mud.

The following is a list of the samples caught and the conditions under which they were taken.

a. Separator Samples

TYPE	BOTTLE SIZE	BOTTLE NO.	TIME TAKEN	SEPERATOR Pressure psig	SAMPLING Temperature °F	DATA Gas/Oil Ratio Scf/Bbl.
OIL	700cc	83081909	12/2/83 16-00	45	56	175
GAS	20Ltr	A14761	16-00	45	56	175
OIL	700cc	8207321	12/2/83 16-40	45	56	178
GAS	20Ltr	A14716	16-40	45	56	178

b. Weathered Oil Samples

1. 5 x 5 gallon weathered oil samples.
2. 1 x 55 gallon weathered oil sample.

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FLOW PERIOD DATA
D.S.T. NO. 1

SUMMARY

The well was flowed for a 7 minute initial flow period followed by an initial buildup of 60 minutes. A final flow period of 10hours 10 mins was then taken prior to a 13 hour 24 min final buildup. First traces of oil were seen at surface after 2.5 hours and the well was flowing 98% oil after 3.5 hours. Once clean oil was flowing at surface the surface choke size was decreased in an attempt to increase the wellhead pressure in order to allow a critical flowpath to the separator. However a reduction from 2" to 16/64" only resulted in a wellhead pressure increase of about 100 psi. It was therefore decided to flow the well wide open (2" choke) at the wellhead and use the separator as the back pressure control to the well. The well was then flowed through the separator for 5.25 hours before shutting in downhole for the final buildup. A detailed tabulation of the flow data is provided.

Fluid Properties

The following is a summary of the fluids recovered and their properties.

a. Oil

The produced oil is dark, black and sweet with no traces of H_2S. There did not appear to be any significant wax content to the oil. Laboratory analysis indicates that the oil has a specific gravity of 0.882 at 60°F which is equivalent to a 29° API gravity.

b. Gas

The gas has a specific gravity of 0.880 at 60°F with 4.5% CO_2 and no measurable H2S. Laboratory analysis indicates the following gas component analysis.

Component	Mol. Percent
Methane	58.3
Ethane	19.0
Propane	10.5
Iso-Butane	1.0
n-Butane	2.7
Pentanes plus	1.0
Carbon Dioxide	4.5
Nitrogen	3.0
Hydrogen Sulphide	0

c. Water

No indication of formation water production was detected during the test.

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FLOW PERIOD DATA
D.S.T. NO. 1

TIME	BOTTOMHOLE PRESSURE PSIG	WELLHEAD PRESSURE PSIG	WELLHEAD TEMPERATURE °F	SEPARATOR PRESSURE PSIG	SEPARATOR TEMPERATURE °F	OIL FLOWRATE BOPD	GAS FLOWRATE MSCF/D	GAS-OIL RATIO SCF/BBL	BSW %	REMARKS
12/2/83										
08-01	Open downhole test valve for final flow period. Open at surface on 2" choke									Flowing cushion
08-30	5185	2	52	-	-	1322	-	-	100	Flowing cushion
09-00	5028	2	56	-	-	1318	-	-	100	Flowing cushion
09-30	4877	2	61	-	-	1280	-	-	100	Flowing cushion
10-00	4721	1	65	-	-	1293	-	-	100	Flowing cushion
10-30	4561	1	70	-	-	1343	-	-	99	Trace of oil
11-30	4000	42	74	-	-	-	-	-	2	Clean Oil
12-00	12-30 Changing surface choke sizes. Decide remain with a 2" fixed choke and control well with the separator well with the separator pressure. This will allow maximum flowrates.									
12-45	Switch flow through separator									Flowing oil
13-30	3788	55	67	40	57	1417	232	164	2	
14-00	3782	56	67	40	59	1346	232	173	2	
14-30	3776	57	67	45	60	1340	229	171	2	
15-00	3769	57	67	45	62	1285	229	178	1	
15-30	3753	57	67	45	62	1358	229	169	1	
16-00	3755	57	67	45	62	1308	228	175	0	
16-30	3746	57	67	45	62	1294	228	176	1	
17-00	3740	57	67	45	62	1277	228	179	1	
17-30	3738	59	67	50	62	1288	230	179	1	
18-00	3736	59	67	50	62	1252	226	180	1	
18-00	By-pass separator.									
18-11	Shutin downhole test valve for final buildup.									

Recovered a full string of oil upon reverse out.

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COMPARISON OF BOTTOM HOLE PRESSURE GAUGES
D.S.T. NO. 1

Gauge No.	SS 0346	SS 0120	J-755	J-756
Gauge Element	20000 psi.	10000 psi	14000 psi	14000psi
Clock (hrs)	70	70	96	48
Depth (ft RKB)	12308	12317	12330	12337
Initial Hydrostatic	* 1	* 1	9190	9266
Initial Flow	5656-5382	5499-5416	5585-5456	5575-5446
Initial Buildup	8551	8550	8613	8620
Final Flow *2	3792-3677	3790-3669 *3	3819-3747	3821-3758
Final Buildup	8135	*3	8147	8152
Final Hydrostatic	9035	*3	9115	9082
Temperature	312°F	310°F	310°F	302°F

Notes:

1. The delay time set in the Sperry Sun gauges prevented the initial hydrostatic from being recorded.

2. The pressures recorded here are for the final 5 hours of the flow period.

3. The Sperry Sun gauge No. 0120 started to malfunction during the final flow period and stopped during the final buildup. This was due to the excessive bottomhole temperatures experienced.

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PRESSURE BUILDUP ANALYSIS
D.S.T. NO. 1

The following are the parameters used for the pressure buildup analysis of drill stem test No. 1. The pressure data is taken from the Sperry Sun gauge No. 0346 at 12308 ft.

P*	=	8586 psig ± 5 psi	(from Horner Buildup Plot - Fig. 1)
P 1hr	=	6660 psig.	(from Horner Buildup Plot - Fig. 2)
Pwf	=	3750 psig.	(from pressure data)
μo	=	0.9 cp	(from laboratory analysis)
Bo	=	1.15 res bbls/bbl.	(from laboratory analysis)
Co	=	7.4×10^{-6} vol/vol/psi	(from laboratory analysis)
Cw	=	4.6×10^{-6} vol/vol/psi	(from correlation charts)
Cf	=	4×10^{-6} vol/vol/psi	(from correlation charts)
Ct	=	1.03×10^{-5} vol/vol/psi	
Ø	=	0.12	(from electric logs)
Sw	=	0.40	(from electric logs)
rw	=	0.35 ft	
qoil	=	1300 BOPD	
m_1	=	1842 psi/cycle	(from Horner Buildup Plot - Fig 2)
m_2	=	459 psi/cycle	(from Horner Plot - Fig 2)

1. Initial Formation Pressure

P*	= 8586 psig ± 5psi
Gauge depth	= 12308 ft
Mid-perforation depth	= 12350 ft

Assume fluid beneath test valve is 100% oil after the initial flow.

Liquid gradient (29° API oil)	= 0.382 psi/ft
Initial Formation Pressure (at mid-perfs)	= 8586 + (12350 - 12308) 0.382 = 8602 psig ± 5 psig

Formation Pressure Gradient $= \frac{8602}{12350 - 82}$

(reference MSL) = 0.701 psi/ft ± 0.001 psi/ft

Mud Weight Equivalent = 13.48 ppg ± 0.02 ppg.

2. Formation Temperature

Maximum recorded temperature	= 311°F (average of 3 readings)
Gauge depth	= 12318 ft (average of 3 readings)
Mid-perforation depth	= 12350 ft

a. Assume average seafloor temperature is 34°F

Temperature Gradient $= \frac{311 - 34}{12318 - 348}$

(reference mudline) = 2.314°F/100 ft

b. Assume mean annual surface temperature is 50°F

Temperature Gradient $= \frac{311-50}{12318 - 82}$

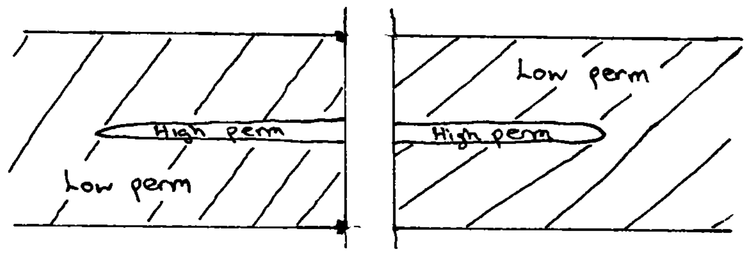
(reference MSL) = 2.133°F/100 ft

Assuming case a

Formation Temperature = 312 °F

3. Final Buildup Interpretation - Comments

Based on core and log data the perforated interval contains a 2-3 ft. layer of moderate permeability, with a very low permeability section above and below. The shape of the final buildup Horner plot (Fig 2) supports this theory. The increasing curvature of the plot indicates that the higher permeability layer does not extend any great distance from the wellbore. In addition there are indications of a decreasing flowrate during the test, which indicates some depletion of a relatively small higher permeability layer. This does not however, indicate depletion of the total reservoir. For the purposes of the buildup analysis the reservoir model assumes the zone of interest contains a thin relatively high permeability layer, limited in areal extent, within a low permeability matrix, as depicted graphically below.



This type of model acts very similar to a fracture zone in terms of the pressure buildup response and explains the upward curvature of the plot. Using the late time slope 'm_1' a kh and skin factor can be calculated which is representative of the wells performance as tested. The slope 'm_1' is the gradient between the last pressure point and P* from the initial buildup. This assumes that the buildup plot would continue in an upward curvature and eventually point to P*. The skin factor calculated from this slope will be negative. This is a pseudo skin effect related to the type of system we are dealing with.

An additional kh can be calculated using the early buildup slope 'm2'. This kh less the kh calculated from slope 'm_1' represents the transissibility of the higher permeability zone.

4. Permeability - Thickness (kh)

a. As Tested

$$(kh) = \frac{162.6\ q\ \ \mu o\ Bo}{m_1}$$

$$= \underline{120 \text{ md-ft}}$$

Assuming contributing h = 17 ft

$$\underline{k = 7 \text{ md}}$$

b. Higher Permeability Layer $(kh)_2$

$$kh = \frac{162.6\ q}{m_2}$$

$$= \underline{475\ md - ft}$$

$$(kh)_2 = kh - (kh)$$

$$= \underline{\underline{355\ md - ft}}$$

Assuming from core and log data that the thickness of the higher permeability layer is 3 ft.

$$\underline{\underline{k = 120\ md}}$$

Although different flowrates should be used for each calculation the variation between the early rates and final rate is less than 5%. Therefore the average of 1300 BOPD has been used for each calculation.

5. Skin Factor

$$S = 1.151 \left\{ \frac{(P1hr - Pwf)}{m} - \log \frac{k}{\phi\ \mu\ Ct\ rw^2} + 3.23 \right\}$$

$$\underline{\underline{S = -3.2}}$$

Effective Wellbore Radius = r_{we}-S

$$\underline{\underline{r_{we} = 8.6\ ft}}$$

6. Radius of Investigation

The radius of investigation equation is being used assuming an average permeability of 20 md.

$$rinv = \tfrac{1}{2} \sqrt{\frac{0.00105\ kt}{\phi\ \mu\ Ct}}$$

$$\underline{\underline{= \pm\ 250\ ft}}$$

7. Productivity Index

P.I. (actual) $= \dfrac{q}{Pi - Pwf}$ (at end of flow period)

$$\underline{\underline{= 0.27\ bbl/d/psi}}$$

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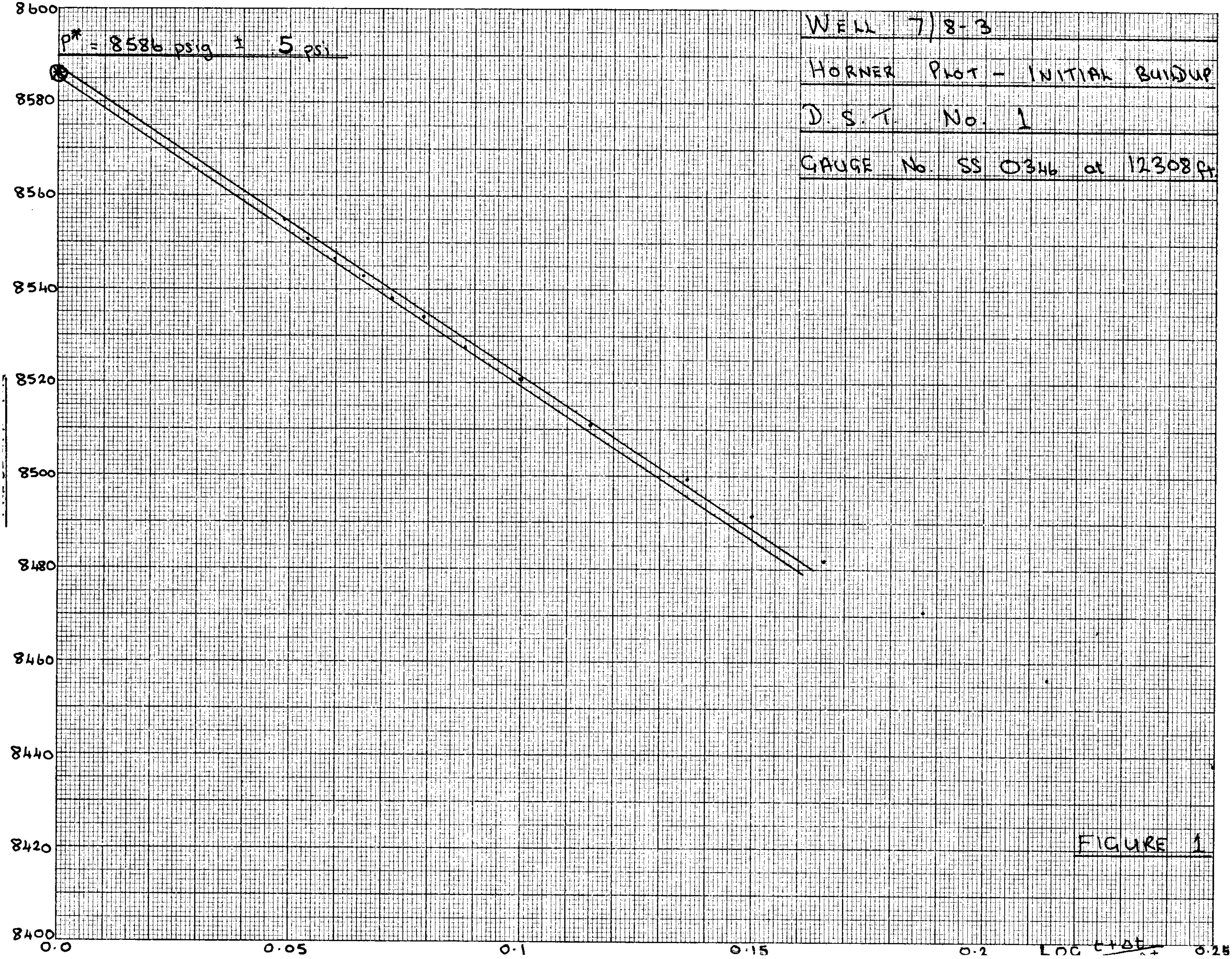
PRESSURE BUILD-UP DATA

D.S.T. No. 1

Gauge # Sperry Sun 0346 at 12308 ft.

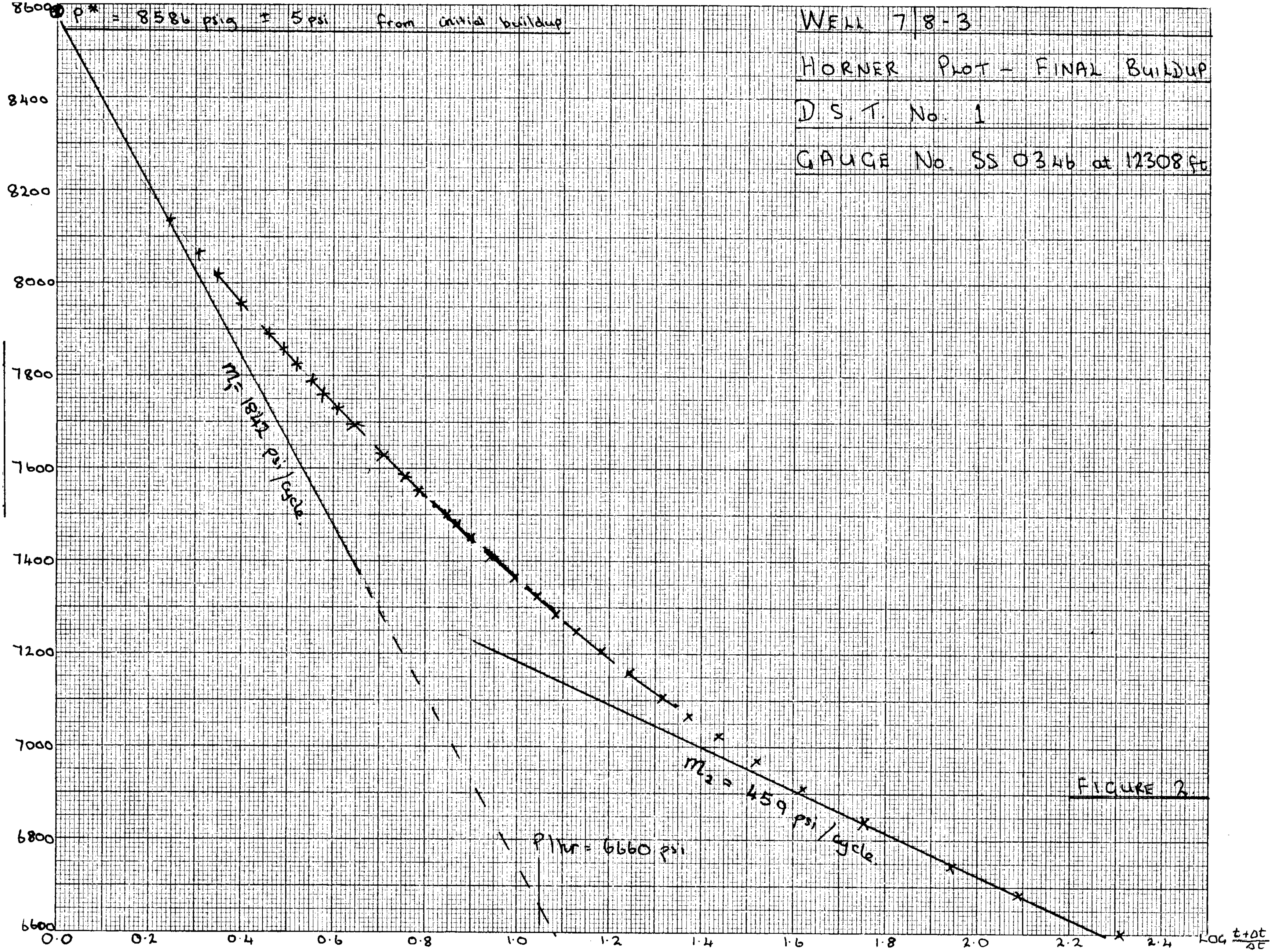
	Δt mins.	log $\frac{t^* + \Delta t}{\Delta t}$	Pressure psi
[redacted]tial Buildup	1	0·903	8192·37
t = 7mins. [redacted]	3	0·523	8306·56
	5	0·380	8384·02
	7	0·301	8415·78
	9	0·250	8438·50
	11	0·214	8456·53
	13	0·187	8470·81
	15	0·166	8482·22
	17	0·150	8491·34
	19	0·136	8499·34
	23	0·115	8511·27
	27	0·100	8520·84
	31	0·088	8527·57
	35	0·079	8534·07
	39	0·072	8538·81
	43	0·066	8542·82
	47	0·060	8546·57
	53	0·054	8550·85
	59	0·049	8555·27
[redacted]nal Buildup	1	2·786	6450·96
	3	2·310	6596·37
[redacted] 610 mins.	5	2·090	6683·49
	7	1·945	6746·21
	11	1·752	6839·28
	15	1·620	6911·44
	19	1·520	6970·16
	23	1·440	7021·41
	27	1·373	7065·72
	31	1·315	7106·53
	37	1·243	7158·40
	43	1·181	7205·77
	49	1·129	7249·19
	55	1·082	7286·27

Δt mins.	$\log \frac{t^* + \Delta t}{\Delta t}$	Pressure psi.
61	1.041	7321.28
69	0.993	7362.46
79	0.941	7408.18
89	0.895	7449.50
99	0.855	7487.13
109	0.819	7520.07
119	0.787	7550.78
129	0.758	7578.34
139	0.731	7604.62
149	0.707	7628.42
159	0.685	7651.24
179	0.644	7691.94
199	0.609	7727.79
219	0.578	7759.62
239	0.551	7788.54
269	0.514	7826.46
299	0.483	7860.44
329	0.455	7890.94
369	0.424	7924.52
409	0.396	7955.08
449	0.373	7982.66
499	0.347	8011.76
549	0.325	8037.88
599	0.305	8061.89
659	0.285	8086.03
719	0.267	8108.20
803	0.245	8134.88



WELL 7/8-3
HORNER PLOT - INITIAL BUILDUP
D. S. T. No. 1
GAUGE No. SS 0346 at 12308 ft.
P* = 8586 psig ± 5 psi
8600
8580
8560
8540
8520
8500
8480
8460
8440
8420
8400
0.0
0.05
0.1
0.15
0.2
0.25
LOG t+Δt/Δt

FIGURE 1


P* = 8586 psig ± 5 psi from initial buildup
WELL 7/8-3
HORNER PLOT - FINAL BUILDUP
D.S.T. No. 1
GAUGE No. SS 0346 at 12308 ft
m1 = 1842 psi/cycle
m2 = 459 psi/cycle
P1hr = 6660 psi
FIGURE 2
8600
8400
8200
8000
7800
7600
7400
7200
7000
6800
6600
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8
2.0
2.2
2.4
LOG (t+Δt)/Δt

WELL 7/8-3 - NORWAY

DRILL STEM TEST NO. 2

DATE: 4th - 6th December 1983

WELL 7/8-3

WELL DATA
D.S.T. NO. 2

Well Location	57° 15' 31.2" N. 2° 32' 45.8" E.
Depth RKB (to MSL)	82 ft (25m).
Water Depth	266 ft (81m).
Total Depth	14174 ft (4320m).
Plugback Depth	12278 ft (37424m).
Perforated Intervals	12252-12272 ft (3734.5-3740.6m) 4" casing guns. 4 SPF. 90° phasing.
Mid-perforation Depth	12262 ft (3737.5m).
Casing Size	7" 32# C95 linear. Hanger at 11348 ft. Shoe at 12557 ft.
Test String	5" 19.5# Class 'G' drill pipe.
Test Packer	Dowell Positest Packer at 12189 ft. (3715.3m).
Test Valve	Dowell PCT at 12159 ft. (3706.1m).
Cushion	Full seawater cushion.
Test String Volume	203 bbls.
Rathole Volume	1.5 bbls to top perforations; 2.1 bbls to bottom perforations.

Mud	MW	FV	PV	YP	pH	% Oil	CL-
1. When drilled	14.5	58	28	17	10.1	4	12K
2. When perforated	14.2	55	27	9	11.5	1	17K

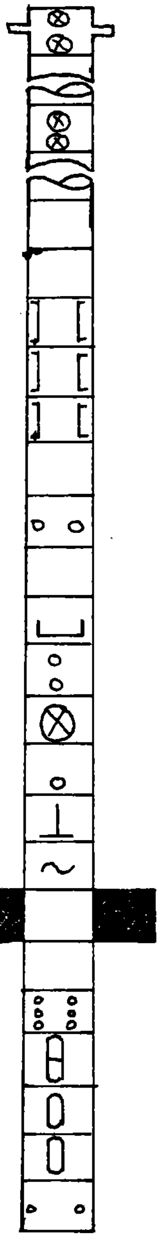
WELL 7/8-3

DIARY OF EVENTS
D.S.T. NO. 2

DATE	TIME	EVENT
12/4/83	21-30	Perforate test interval from 12252-12272 ft (3734.5-3740.5m) with 4" casing guns, 4 SPF, 90° phasing.
	22-45	Start Dowell gauge No. J-755 with a 96hr clock.
	22-46	Start Dowell gauge No. J-756 with a 48hr clock.
	22-47	Start Sperry Sun gauge No. 0346 with a 70hr clock and an 8.5hr start delay.
	22-52	Start Sperry Sun gauge No. 0341 with a 70hr clock and an 8.5hr start delay.
	23-00	Start picking up test tools.
12/5/83	01-30	Pressure test bottomhole test assembly to 5000 psi.
	11-00	Function test sub-sea-test-tree.
	12-14	Set packer at 12189 ft. (3715.3m).
	13-10	Rig up and pressure test surface flowlines. a. Test string to 7500 psi. b. Choke manifold to 7500 psi. c. Separator to 1000 psi.
	13-28	Pressure up annulus to open downhole test valve for initial flow period.
	13-33	Bleed off annulus to shutin downhole test valve for initial buildup period.
	14-13	Pressure up annulus to open downhole test valve for final flow period.
	14-14	Open well for flow on a 2" fixed choke.
12/5/83	19-10	Traces of gas at surface. FWHP = 15 psig.
	19-15	Traces of oil at surface. FWHP = 15 psig.
	23-30	Pressure up annulus to shear the downhole test valve closed.

DATE	TIME	EVENT
	23-33	Bleed of annulus pressure. S.S.A.R.V. reverse sub opened.
	23-40	Start to reverse out test string.
12/6/83	00-30	Well killed. Wait on buildup.
	09-40	Unseat packer. End of buildup.
	09-50	Circulate hole.
	12-55	Pull out of hole.
		END OF TEST

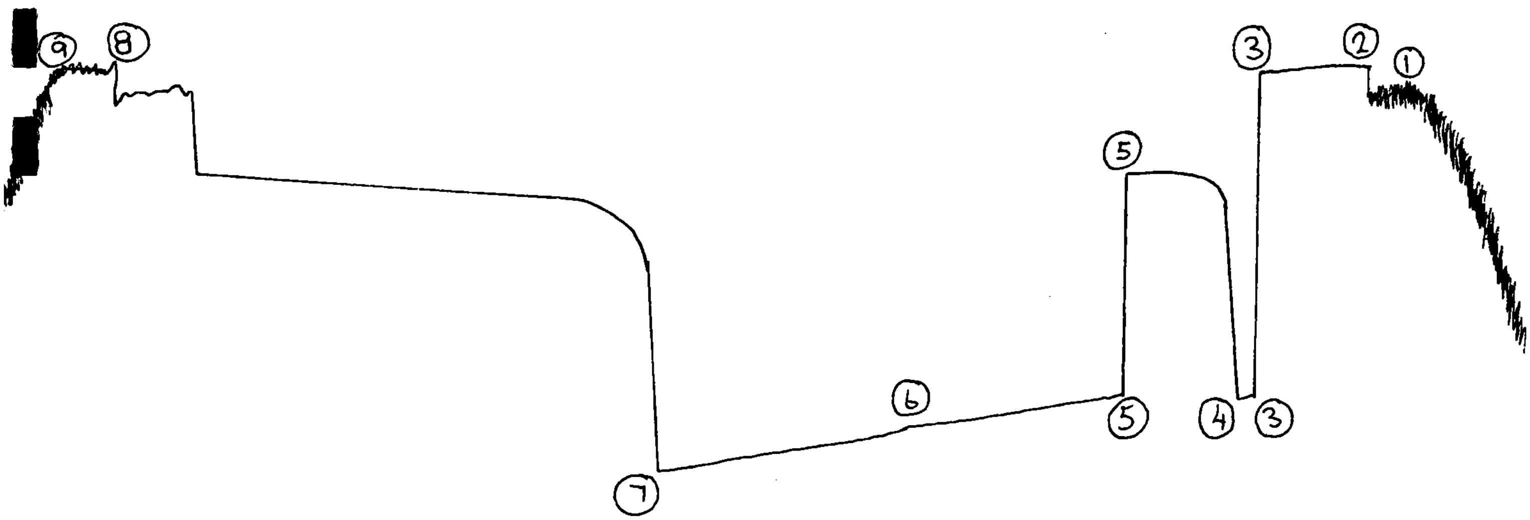
WELL 7/8-3
TEST TOOLS
DST NO 2



Description	O.D. (inches)	I.D. (inches)	Length (feet)	Depth (feet)
Flohead	—	3.00	10.00	-30.31
5" Drill Pipe	5.00	4.28	20.31 317.63	-20.31 Rotary 0.00
Sub-Sea-Test-Tree	5.00	3.00	22.17 1.25	317.63 Well 339.80
5" Drill Pipe	5.00	4.28	10625.99	341.05
X-over	6.25	2.85	1.78	10967.04
3½" Drill Pipe	3.50	2.76	276.27	10968.82
Slip Joint (open)	5.00	2.25	28.18	11245.09
Slip Joint (½ open)	5.00	2.25	25.68	11273.27
Slip Joint (closed)	5.00	2.25	23.18	11298.95
8 Stds Drill Collars	4.75	2.78	732.96	11322.13
Impact Reverse Sub	4.75	2.25 (equiv)	1.08	12055.09
1 Std Drill Collars	4.75	2.78	91.62	12056.17
Bar Catcher Sub	4.75	2.25 (equiv)	1.02	12147.79
S.S.A.R.V	5.00	2.25	8.46	12148.81
P.C.T. Valve	4.75	2.25	18.57	12157.27
H.R.T.	4.75	2.25	4.27	12175.84
Hydraulic Jars	5.00	2.25	6.50	12180.11
Safety Joint.	5.00	2.25	1.71	12186.61
Positest Packer	5.75	2.25	1.15 2.95	12188.32 Pack 12189.47 Rubb
X-over	4.75	2.25	0.82	12192.42
Perforated Anchor	4.75	-	9.94	12193.24
Sperry Sun Gauge Carrier	3.50	-	30.70	12203.18
J-200 Gauge Carrier	5.00	-	6.96	12233.88
J-200 Gauge Carrier	5.00	-	6.96	12240.84
Ported Bullnose	4.75	-	1.90	12247.80

Notes: 1. All depths are drillers depths to top of tool joints.
2. Loggers depths are ± 14 ft deeper than drillers depths.

SCHEMATIC OF DOWNHOLE TEST CHART
D. S. T. NO. 2



NOT TO SCALE

1. Initial hydrostatic
2. Set packer at 12189 ft.
3. Open downhole test valve for initial flow period
4. Shutin downhole test valve for initial buildup period
5. Open downhole test valve for final flow period
6. Oil begins to surface - mixed with water cushion
7. Shutin downhole test valve for final buildup period
8. Unseat packer
9. Final hydrostatic

WELL 7/8-3

COMPARISON OF BOTTOM HOLE PRESSURE GAUGES
D.S.T. NO. 2

Gauge No.	SS 0346	SS 0341	J-755	J-756
Gauge Element	20000 psi	20000 psi	14000psi	14000 psi
Clock (hrs)	70	70	96	48
Depth (ft RKB)	12213	12222	12235	12242
Initial Hydrostatic	9030	9032	9123	9068
Initial Flow	5473-5470	5499-5484	5511	5509
Initial Buildup	8522	8520	8555	8554
Final Flow	5442-4446	5452-4441	5525-4465	5534-4467
Final Buildup	8521	8517	8538	8527
Final Hydrostatic	8980	8977	9027	8997
Temperature	307°F	309°F	309°F	312°F

Notes:

1. All pressures are psig

WELL 7/8-3

RECORD OF SAMPLES
D.S.T. NO. 2

Due to the low flowrate produced by the well it was not possible to flow hydrocarbons through the separator during the test. Therefore no separator PVT recombination samples or gas samples were able to be taken. However a single phase bottomhole sample was collected from the downhole test tools, and several weathered oil samples were also collected from the reverse out. Based on the BSW figures recorded on the samples from the reverse out it is probable that the weathered oil samples are slightly contaminated with the seawater cushion. A record of the samples collected and an analysis of the fluid is given below.

a. Record of Samples

1. Downhole PVT Samples

Type	Bottle Size	Bottle No.	Time Taken 5.12.83	Pressure psig.	Temperature °F
OIL	550 cc.	20112/106	23-30	550	47
OIL	550 cc.	9214/182	23-30	450	47

2. Weathered Oil Samples

1 x 55 gallon weathered oil
4 x 5 gallon weathered oil

b. Analysis of Recovered Fluids

1. Oil Analysis

The produced oil is dark, black and sweet with no measureable H2S. Laboratory analysis indicates that the oil has a specific gravity of 0.876 at 60°F which is equivalent to a 30° API gravity.

2. Gas Analysis

Due to the low flowrates and the inability of the well to be flowed through the separator it was not possible to collect any gas samples. The gas is assumed to be the same as the gas from dst No. 1 with a specific gravity of 0.880 with 4.5% CO_2 and No H_2S.

3. Water Analysis

All the recovered water was seawater cushion having chlorides reading 20-25 K ppm. There was no evidence of any formation water production.

WELL 7/8-3

FLOW PERIOD DATA
D.S.T. NO. 2

TIME	BOTTOMHOLE PRESSURE PSIG	WELLHEAD PRESSURE PSIG	WELLHEAD TEMP. °F	FLOWRATE BFPD	BSW %	CUMULATIVE OIL PRODUCED Bbls.	CUMULATIVE CUSHION PRODUCED Bbls.	REMARKS
12/5/83								
14-13	Pressure up annulus to open downhole test valve for final flow period.							
14-30		15	45	520	100	0	54.4	Flowing seawater cushion (CL^- = 24K ppm)
15-00		13	45	415	100	-	14.1	
15-30		13	45	380	100	-	20.8	
16-00		16	45	380	100	-	28.8	
16-30		16	45	374	100	-	36.6	
17-00		16	45	387	100	-	44.7	
17-30		15	46	393	100	-	52.9	
18-00		16	46	399	100	-	61.2	
18-30		16	46	393	100	-	69.4	
19-00		17	47	387	100	-	77.4	
19-30		15	47	406	85	0.3	85.6	Small percent of oil at surface
20-00		15	47	425	85	1.6	93.1	
20-30		14	47	551	75	3.6	104.5	Increasing oil cut and water cushion
21-00		15	47	486	70	-	-	
21-30		16	47	372	65	7.1	112.6	
22-00		16	47	456	65	10.4	118.8	
22-30		19	47	450	52	14.9	123.7	
23-00		20	47	393	58	18.3	128.5	
23-30		20	47	418	62	21.6	133.9	
23-30	Pressure up annulus to shear downhole test valve during the initial flow period.							

Notes: 1. An additional 4 bbls of water cushion was produced during the initial flow period.

WELL 7/8-3

REVERSED RECOVERIES
D.S.T. NO. 2

Sample No.	No Of Strokes	Volume Since Start Of Reverse Bbls.	Depth From Which Sample Recovered Ft.	BSW %	Cum. Oil From Reverse Out Bbls.		Cum. Water From Reverse Out Bbls.		Remarks
1	100	13.1	725	70	4.0	4.0	9.1	9.1	Mostly water cushion (CL^- = 25K) with traces of oil.
2	200	26.2	1450	65	4.6	8.6	8.5	17.6	
3	300	39.3	2175	56	5.8	14.4	7.3	24.9	
4	400	52.4	2900	43	7.5	21.9	5.6	30.5	Increasing oil cut with some rathole mud and seawater cushion.
5	500	65.5	3625	24	10.0	31.9	3.1	33.6	
6	600	78.6	4350	20	10.5	42.4	2.6	36.2	
7	700	91.7	5075	14	11.3	53.7	1.8	38.0	Fairly clean oil mixed with a small percentage of seawater cushion.
8	800	104.8	5800	14	11.3	65.0	1.8	39.8	
9	900	117.9	6525	14	11.3	76.3	1.8	41.6	
10	1000	131.0	7250	12	11.5	87.8	1.6	43.2	
11	1100	144.1	7975	8	12.1	99.9	1.0	44.2	
12	1200	157.2	8700	8	12.1	112.0	1.0	45.2	
13	1300	170.3	9425	10	11.9	123.9	1.2	46.4	
14	1400	183.4	10150	9	12.0	135.9	1.1	47.5	
15	1500	196.5	10875	15	11.1	147.0	2.0	49.5	
16	1570	203.0	12150	15	5.5	152.5	1.0	50.5	
17	1575	-	-	99		-		-	Reverse out is complete. Mud from annulus

WELL 7/8-3

PRESSURE BUILDUP ANALYSIS
D.S.T. NO. 2

The following are the parameters used for the pressure buildup analysis of drill stem test No. 2. The pressue data is taken from the Sperry Sun gauge No. 0346 at 12213 ft.

P*	= 8568 psig ± 5 psi	(from Horner Buildup Plot - Fig 1).
P 1hr	= 8320 psig.	(from Horner Buildup Plot - Fig 2).
Pwf (average)	= 4946 psig	(from pressure data)
μo	= 0.9 cp	(from laboratory analysis)
Bo	= 1.15 res bbls/bbl.	(from laboratory analysis)
Co	= 7.7×10^{-6} vol/vol/pi	(from laboratory analysis)
Cw	= 4.6×10^{-6} vol/vol/psi	(from correlation charts)
Cf	= 4×10^{-6} vol/vol/psi	(from correlation charts)
Ct	= 1.077×10^{-5} vol/vol/psi	
ϕ	= 13%	(from electric logs)
Sw	= 30%	(from electric logs)
rw	= 0.35 ft	
qoil	= 440 BOPD	
m	= 284 psi/cycle	(from Horner Buildup Plot - Fig 2).

1. Initial Formation Pressure

P*	= 8568 psig ± 5 psi
Gauge depth	= 12213 ft
Mid-perforation depth	= 12262 ft

Assume fluid beneath test valve is 100% oil after the initial flow

Liquid gradient (30°API oil)	= 0.375 psi/ft
Initial Formation Pressure (at mid-perfs)	= 8568 psig + (12262-12213) 0.375 = **8586 psig ± 5 psi**

Formation Pressure Gradient = $\dfrac{8586}{12350-82}$

(reference MSL) = 0.700 psi/ft ± 0.001 psi/ft

Mud Weight Equivalent = 13.46 ppg ± 0.02 ppg.

2. Formation Temperature

Maximum recorded temperature = 309°F

Gauge depth = 12235 ft

Mid-perforation depth = 12262 ft

a. Assume average seafloor temperature is 34°F

Temperature Gradient = $\dfrac{309-34}{12235-348}$

(reference mudline) = 2.313°F/100ft

b. Assume mean annual surface temperature is 50°F

Temperature Gradient = $\dfrac{309-50}{12318-82}$

(reference MSL) = 2.117°F/100 ft

Assuming case a

Formation Temperature (at mid-perfs) = 310°F

3. Final Buildup Interpretation - Comments

The shape of the final buildup plot (Fig. 2) is essentially a straight line with a turnover towards initial reservoir pressure near the end of the buildup period. The straight line portion of the plot is representative of the near wellbore permeability-thickness. The bend-over portin of the plot could be indicative of a change in viscosity (i.e gas cap, water aquifer) or an increase in kh, away from the wellbore. As this is an undersaturated reservoir and the test interval is a considerable height above any possible oil-water contact the bend-over is unlikely to be caused by viscosity changes and is probably due to an increase in kh. The logs indicate that the perforated interval is separated from additional oil-bearing pay by a shale barrier, the laterial extent of which is unknown. It is therefore concluded that the shale barrier does not extend further than ±100 ft from the wellbore and that the pressure transient is expanding in the vertical direction as well as on the horizontal direction beyond this point. It should be noted that the quoted distance from the wellbore is a very approximate number and may be as much as ± 50 ft. in error.

4. Permeability - Thickness (kh) (near wellbore)

$$Kh = \frac{162.6\ q_{oil}\ \mu o\ Bo}{m}$$

$$Kh = \underline{\underline{260\ md - ft}}$$

Assuming contributing h = 15 ft

$\underline{\underline{k = 18\ md}}$

5. Skin Factor

$$S = 1.151 \left\{ \frac{P1hr - Pwf}{M} - \log \frac{k}{\phi\ \mu\ Ct\ rw^2} + 3.23 \right\}$$

$\underline{\underline{S = +\ 8.1}}$

Drawdown due to skin

$DD = 0.87\ mS = \underline{\underline{2001\ psi}}$

Percentage of drawdown due to skin $= \dfrac{\Delta P\ skin}{DD}$

$= \underline{\underline{55\%}}$

6. Radius of Investigation

$$rinv = \tfrac{1}{2}\sqrt{\frac{0.00105\ kt}{\phi\ \mu\ Ct}}$$

$= \underline{\underline{\pm\ 200\ ft}}$

7. Distance to End of Shale Barrier

$$r_i = \tfrac{1}{2}\sqrt{\frac{.00105\ kt}{\phi\ \mu\ C_t}}$$

where t = time of first departure from straight line portion of buildup plot

$= \underline{\underline{\pm\ 100\ ft.}}$

8. Actual Productivity Index

$$\text{P.I. (act.)} = \frac{q_{avg}}{P_i - P_{wf\,avg}}$$

$$= \underline{\underline{0.12 \text{ bbl/d/psi}}}$$

9. Productivity Index (S = 0)

$$\text{P.I. } (S = 0) = \frac{0.00708\, kh}{\mu B \left(\ln \frac{r_e}{r_w} - \frac{1}{2} \right)}$$

$$= \underline{\underline{0.24 \text{ bbl/d/psi}}}$$

WELL 7/8-3

PRESSURE BUILD-UP DATA

D.S.T. No. 2.

Gauge # Sperry Sun 0346 at 12213 ft

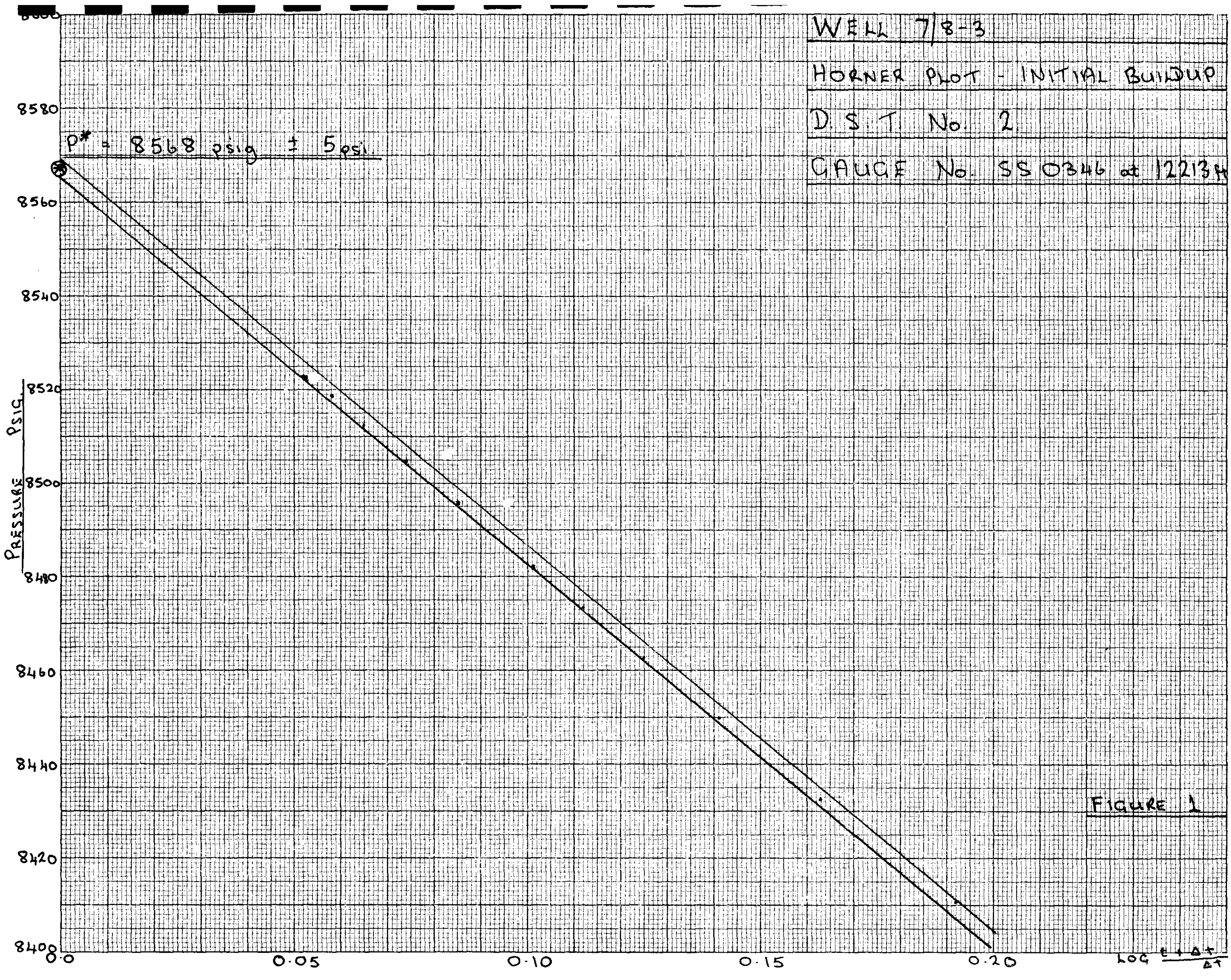
[redacted]itial Buildup.
t = 5 mins.
[redacted]

Δt mins.	$\log \frac{t^* + \Delta t}{\Delta t}$	Pressure psi
1	0.778	8096.53
3	0.426	8261.65
5	0.301	8335.01
7	0.234	8379.85
9	0.192	8410.55
11	0.163	8432.58
13	0.141	8449.76
15	0.125	8462.78
17	0.112	8473.30
19	0.101	8481.81
23	0.085	8495.83
27	0.074	8504.69
31	0.065	8512.21
35	0.058	8518.22
39	0.052	8522.09

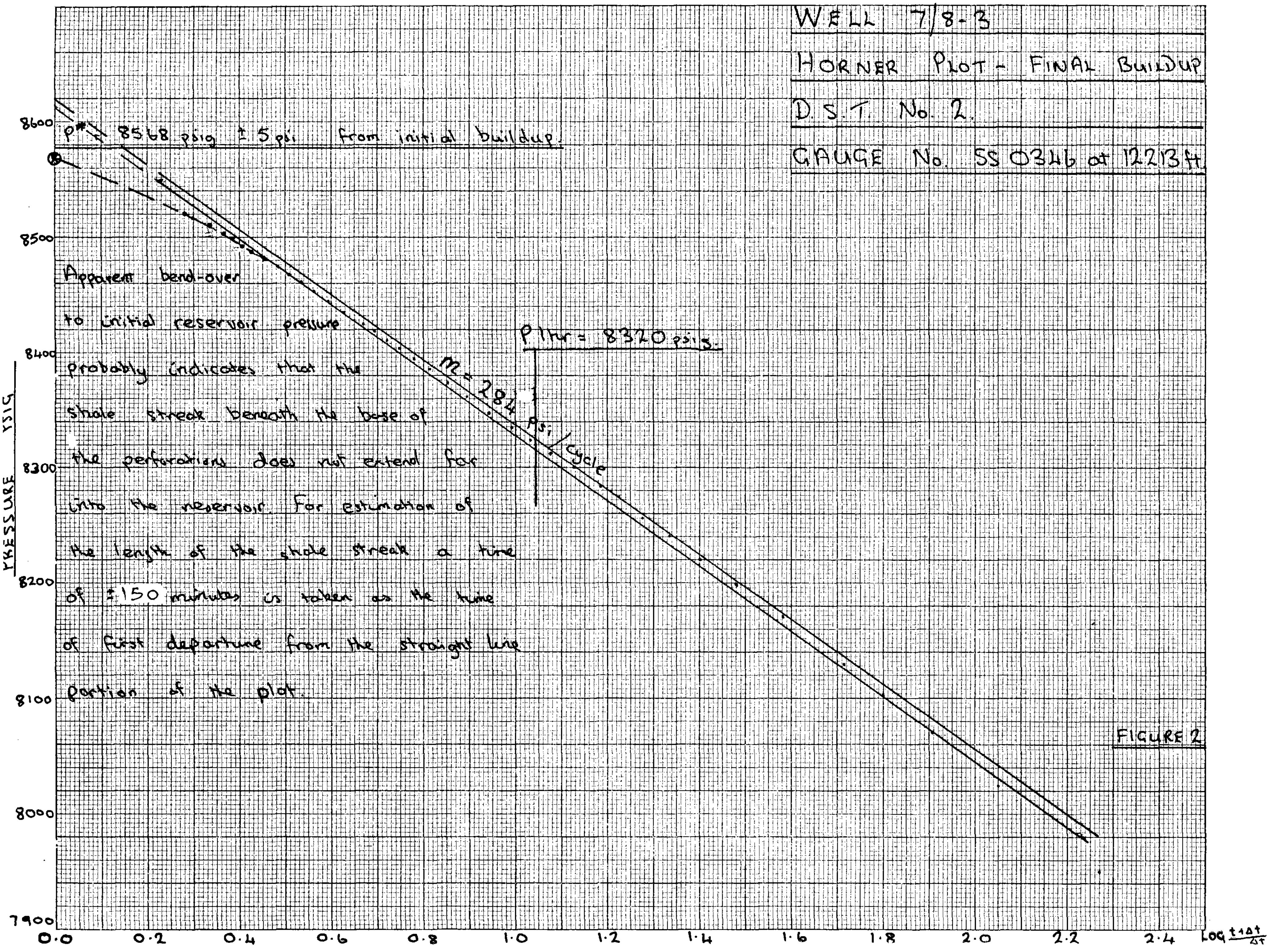
[redacted]inal Buildup
[redacted]= 556 mins

Δt mins.	$\log \frac{t^* + \Delta t}{\Delta t}$	Pressure psi
1	2.746	7773.23
3	2.270	7950.28
5	2.050	8024.74
7	1.905	8070.97
9	1.798	8102.57
11	1.712	8128.97
15	1.581	8169.04
19	1.481	8197.93
23	1.401	8220.84
27	1.334	8239.58
31	1.277	8256.02
35	1.228	8269.29
39	1.183	8282.75
45	1.126	8299.02
51	1.076	8312.19
57	1.032	8324.52
63	0.992	8335.38
71	0.946	8348.74

Δt mins.	$\log \frac{t^* + \Delta t}{\Delta t}$	Pressure psi.
81	0·896	8362.04
91	0·852	8374·94
101	0·813	8384·84
111	0·779	8394·29
121	0·748	8403·26
131	0·720	8410·75
141	0·694	8418·76
151	0·670	8424·28
171	0·628	8434·86
191	0·592	8444·99
211	0·561	8453·09
231	0·532	8461·19
251	0·507	8467·31
271	0·485	8473·45
301	0·454	8481·09
331	0·428	8487·26
361	0·405	8492·94
391	0·384	8498·94
421	0·366	8502·63
451	0·349	8506·34
481	0·334	8509·84
511	0·320	8512·56
561	0·299	8516·80
609	0·282	8520·81



WELL 7/8-3
HORNER PLOT - INITIAL BUILDUP
D.S.T. No. 2
GAUGE No. SS 0346 at 12213ft
P* = 8568 psig ± 5psi
PRESSURE PSIG
8580
8560
8540
8520
8500
8480
8460
8440
8420
8400
0.0
0.05
0.10
0.15
0.20
LOG (t + Δt)/Δt
FIGURE 1



WELL 7/8-3
HORNER PLOT - FINAL BUILDUP
D.S.T. No. 2.
GAUGE No. SS 0346 at 12213ft.
p* = 8568 psig ± 5 psi from initial buildup.
Apparent bend-over to initial reservoir pressure probably indicates that the shale streak beneath the base of the perforations does not extend far into the reservoir. For estimation of the length of the shale streak a time of ±150 minutes is taken as the time of first departure from the straight line portion of the plot.
P 1hr = 8320 psig.
m = 284 psi/cycle
PRESSURE PSIG
8600
8500
8400
8300
8200
8100
8000
7900
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8
2.0
2.2
2.4
Log (t+Δt)/Δt

FIGURE 2