statoil

Den norske stats oljeselskap a.s

050-PS. 15. DST - ~~evaluering~~

WELL TEST REPORT

PL 050

WELL NO. 34/10-8

NOVEMBER 1980

CONTENTS: PAGE

WELL DATA

Operator	:	Den norske stats oljeselskap
Well name	:	34/10-8
Location	:	61° 09' 59.53"N 01° 12' 3.40"E
Classification	:	Exploration well
Drilling rig	:	Deep Sea Saga
Spudded	:	8. March 1980
Completed	:	26. May 1980
RKB elevation	:	25 m
Water depth	:	158 m
Total depth	:	2215 m RKB
Objective	:	Jurassic sandstone
Status	:	Plugged and abandoned

2. OBJECTIVES

The objectives of testing well 34/10-8 were:

1. To test the Ness member of the Brent formation for productivity, pressure and temperature.

2. To obtain representative samples of the reservoir fluid.

3. To run the RFT to obtain a pressure profile in the Brent formation.

4. To get an estimate of the fracture pressure in the Brent formation.

3. CONCLUSIONS

1. RFT and DST data in the Brent formation indicate that well 34/10-8 represent the same pressure system as in wells 34/10-1, 3, 4, 5 and 6.

2. The drill stem test indicate a permeability thickness of 4363 md x ft in the tested part of the Brent formation.

3. The calculated permeability (78 md) is uncertain due to poor cement bond around the tested interval.

4. The DST analysis indicate no formation damage.

5. The samples taken indicate the same hydrocarbon system as in wells 34/10-1, 3, 4 and 5 in the Brent formation.

6. The gradient in the oil zone is estimated to 0.074 bar/m. In the water zone the gradient is estimated to 0.105 bar/m.

7. The maximum temperature recorded during the drill stem test was 73.2^{O}C or 163.8^{O}F at -1820 m MSL.

8. The fracture test indicate a fracturing pressure of approximate 5500 psig at -1820 m MSL (i.e. equivalent mudweight 2.07 g/cc).

9. No water was produced.

10. Sandslugs was observed at chokechanges.

4. DISCUSSION

4.1 DST analysis

One drill stem test was run in well 34/10-8. The Ness member of the Brent formation was perforated from 1869 m RKB to 1873 m RKB.
The DST analysis indicate a permeability thickness of 4363 md ft and a permeability of 78 md. However the cement bond log indicate poor formation bond in the tested interval. Therefore the formation thickness used in the calculations is not well defined. The calculated permeability is therefore uncertain. The calculated skin factor indicate the same. A negative skin factor is not realistic in these formation.
During the PBU the APR-N valve was leaking in 4 - 5 minutes. The data taken after the leak was therefore not used in the analysis. The staight line observed after the leak is assumed to be affected by the leaking valve.

The reservoir pressure calculated from the PBU compare perfectly with the RFT data. Both tools indicate a pressure of 4461 psia at -1820 m MSL. In appendix A2 is the reservoir pressure calculated from the PBU plotted and compared with the RFT data.

An actual productivity index of 7.52 M3PD/bar is estimated from the DST. As discussed previously the formation height which is contributing to this index is uncertain. Therefore the value calculated should be used with care.

The drill stem test was analysed by using the Horner methode. No quantitative type curve analysis was possible. The type curve technique was only used to identify the semilog straight line. The analysis of the DST can be found in appendix A1.

A thickness of 17 m, and average porosity of 15% and a water saturation of 40% was used in the analysis. These values are estimated from the CPI log in appendix A5. PVT properties were taken from the Core lab. report no RFLA 79192 based on a sample taken during DST no. 2 in well 34/10-4.

4.2 RFT analysis

The repeat formation tester was run in the Brent formation and good data was obtained from -1798.5 m MSL to -1981 m MSL.

The data are listed and plotted versus depth in appendix A2, and compared with the DST analysis and RFT measurements in previous drilled wells. A gradient of 0.074 bar/m is estimated down to approximate -1940 m MSL. A gradient of 0.105 bar/m is estimated below -1940 m MSL. The RFT and DST data compare well with data from previous drilled wells in the Brent formation.

4.3 Reservoir temperature

The maximum temperature recorded during the drill stem test was 73.2^{o}C or 163.8^{o}F at -1820 m MSL. This temperature is compared with the maximum recorded temperatures in the Brent formation in previous drilled wells on the Delta structure in appendix A3. The data indicate a temperature gradient of 3.5^{o}C/100 m.

4.4 Sampling

Surface samples, bottom hole samples and a RFT sample were taken in the Brent formation. In appendix A4 the samples taken are listed.

The samples taken indicate a similar hydrocarbon system as in wells 34/10-1, 3, 4 and 5. c)

4.5 Fracture test

A fracture test was performed by injecting water at five different injection rates. The rate, wellhead pressure and bottom hole pressure was recorded. The data collected indicate that the formation was fractured during the test. A fracturing pressure of approximated 5500 psig is estimated. (i.e. equivalent mudweight 2.07).

The data collected can be found in appendix A6.

APPENDIX 1 PAGE

BOTTOM HOLE PRESSURE REPORT

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Well 34/10-8

Test no. DST No. 1

Test Date 17.5 - 18.5.80

Date of analysis 17.11.80

Gauge no. LY-DMR314, 1206

SUMMARY OF THE RESULTS

Kh md·ft	4363	
K md	78	
S	-0.8	
$\bar{P}$ (psia) at- 1820 ss	4461	

Max recorded Temp. 73.2°C

Remarks

The cement bond log indicate poor formation bond around the tested interval. Therefore the formation thickness used in the calculations is uncertain.
A formation thickness of 17 m (55.8ft) was used in the analysis.
See CPI log page A5-2

Signature

Well 34/10-B

Test date 17.5-18.5, 1980

Reservoir Parameters

Perforations 1869 - 1873 m RKB

Zone(s) Ness

Wellbore radius 0.11m

RKB Elev 25m

Midpoint Production – 1846m ss   Bomb at 1845m RKB   – 1820 m ss

Pressure Functions Evaluated at – ______ ss   Datum Depth – ______ ss

Delta P required to correct to datum ______   Gradient ______ psi/ft

Estimated Average Pressure ______

Formation Volume Factor 1.253 vol/vol   Viscosity 1.21 cp

Thickness 17m   Porosity 15 %   Drainage Area – acres

Oil Saturation 60 %   Oil Compressibility 8.37 × $10^{-6} psi^{-1}$

Water Saturation 40 %   Water Compressibility 3.0 × $10^{-6} psi^{-1}$

Gas Saturation – %   Gas Compressibility – $10^{-6} psi^{-1}$

Formation Compressibility 3.0 × $10^{-6} psi^{-1}$

System Compressibility $C_t = S_O C_O + S_w C_w + S_g C_g + C_f$

$C_t = 0.6 \times 8.37 \times 10^{-6} + 0.4 \times 3.0 \times 10^{-6} + - \times - 10^{-6} + 3.0 \times 10^{-6}$

$C_t = 9.2 \times 10^{-6} psi^{-1}$

Rates Reported on Test.

Choke 32/64 inches   Oil Rate 3135 STBPD   Gas Rate 1.196 MMSCFD

FTP ______   Water Rate 0 BWD   GOR 381 SCF/STB

^{0}API 29.5   Gas Spec. Grav. 0.622

Cumulative Production   Oil 785.5 STB   Gas ______

Water ______

Well 34/10-8 Test Date 17.5-18.5, 1980

Horner Analysis

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

$tp = 785.5 / (3135)\times(24)\times(60) = 361 \text{ min}$

Straight line starts at ______ hrs Slope = 177.126 psi/cycle

$P_{wf's}$ = 3497.7 psia

P_{1hr} = 4311.1 psia

P^* = 4461.0 psia

Calculated Values

$$Kh = \frac{162.6\ Q\ B\mu}{M} = \frac{162.6\,(3135)(1.263)(1.21)}{177.126} = 4363 \text{ md.ft}$$

$$K = Kh/h = 4363 / ((17)(3.28)) = 78.3 \text{ md.}$$

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

$$S = 1.1513\left[\left[\frac{4311-3498}{177.126}\right] + \text{Log}\left[\frac{361+60}{361}\right] - \text{Log}\left[\frac{78.3}{(.15)(1.21)(9.2\times10^{-6})(.35)^2}\right] + 3.2275\right]$$

$S = -0.8$ $\Delta P_s = 0.87\,mS = -82$ psi

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

P_{DMBH} = 0

$\bar{P} = P^* - P_{DMBH}\left[\frac{M}{2.303}\right]$ = 4461 psia @ – 1820 m ss

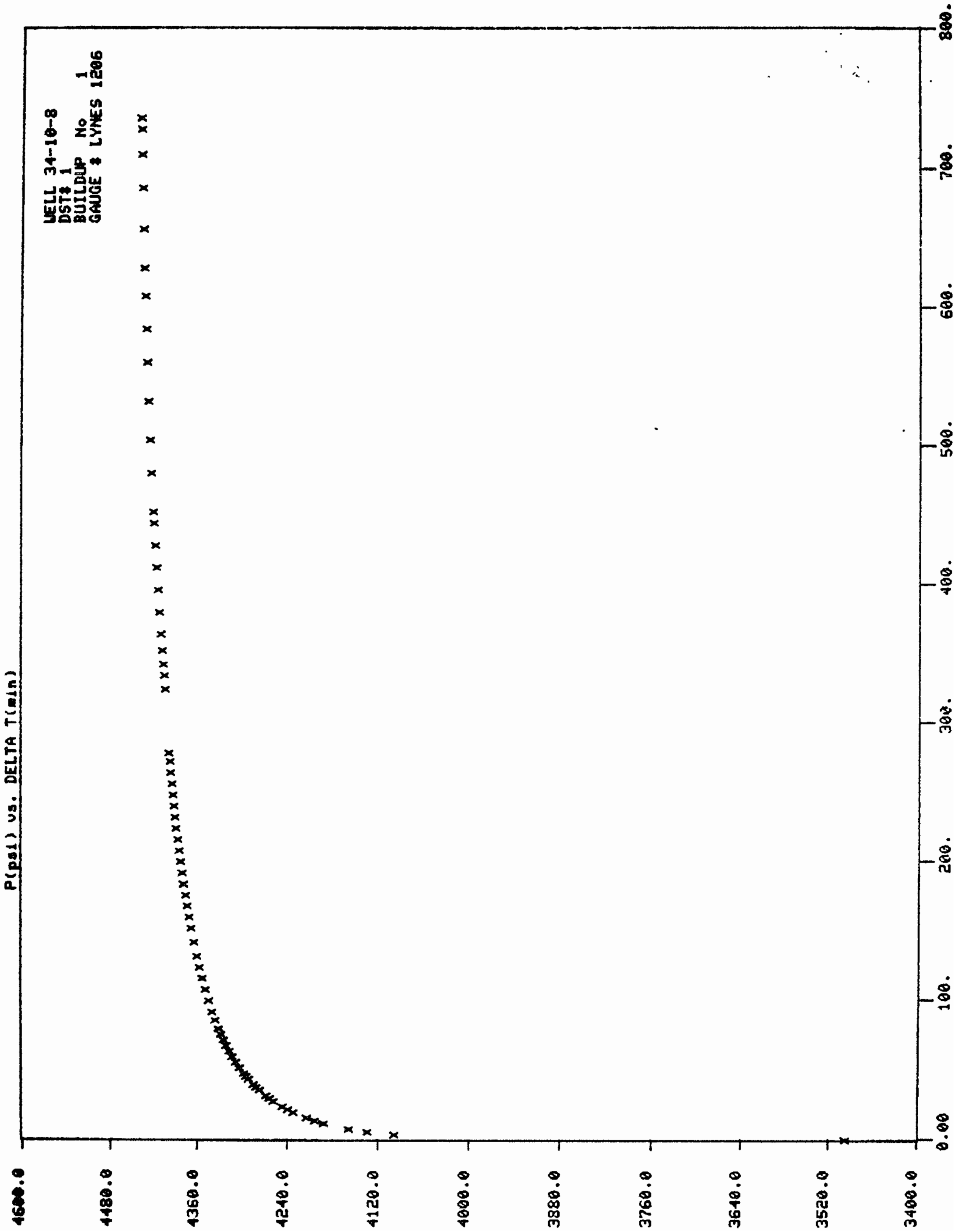
= ______ @ – ______ ss Datum

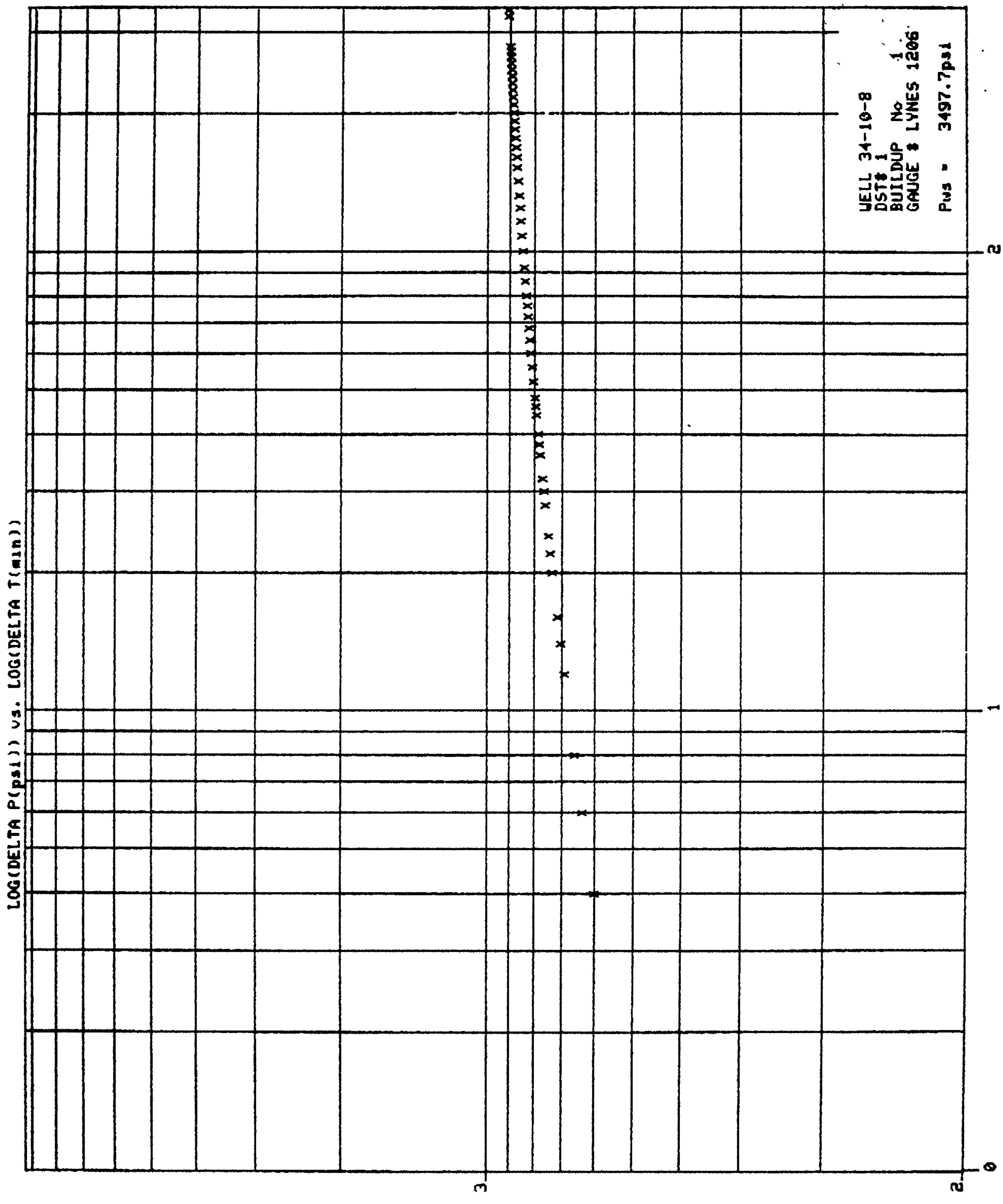
$$PI_a = \frac{Q}{P^* - P_{wf}} = \frac{3135}{4461-3498} = 3.26 \text{ STBPD/psi} = 7.52 \text{ M}^3\text{PD/bar}$$

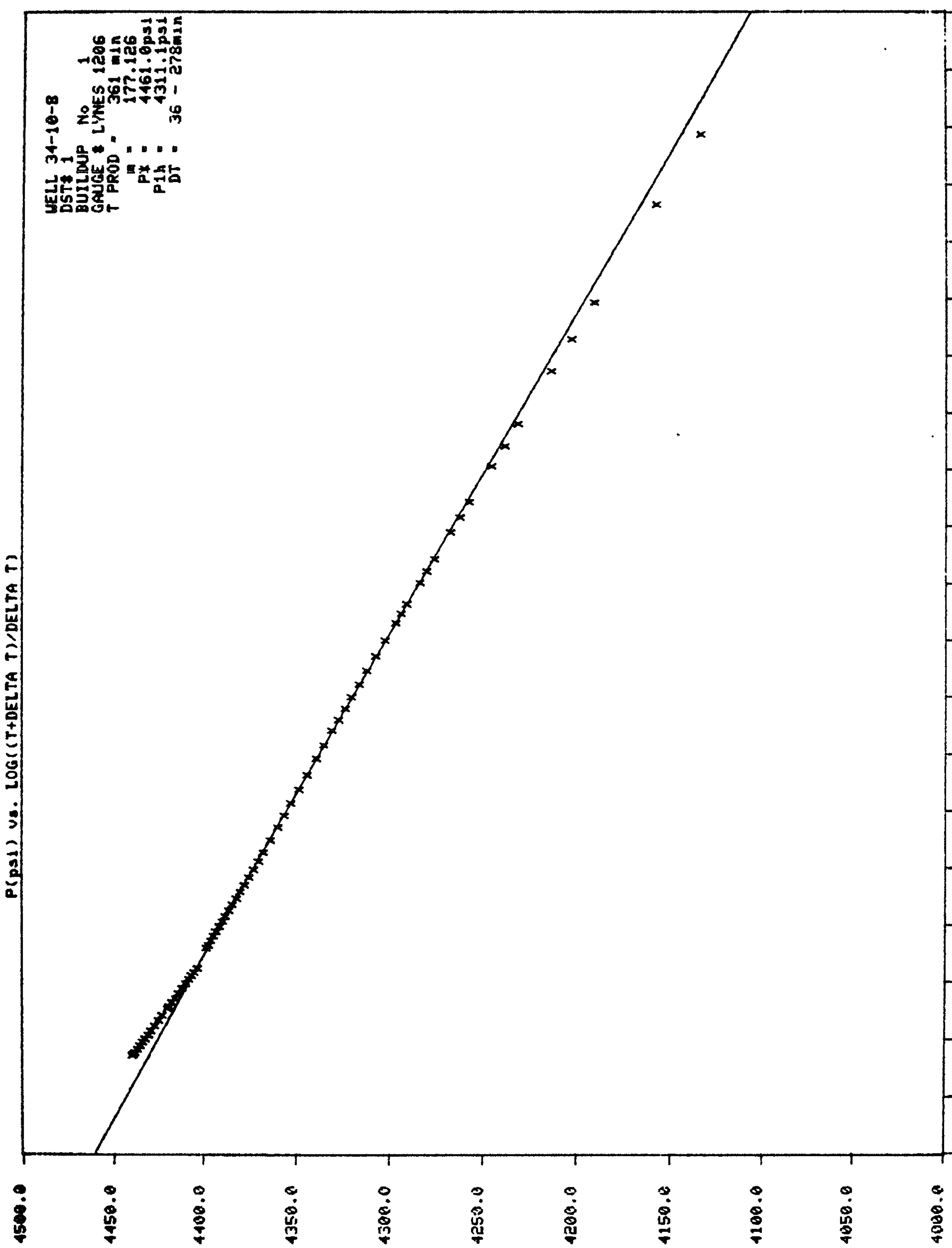
$$PI_{s=0} = \frac{Q_o}{P^* - P_{wf} - \Delta P_s} = \frac{3135}{4461-3498+82} = 3.0 \text{ STBPD/psi} = 6.92 \text{ M}^3\text{PD/bar}$$

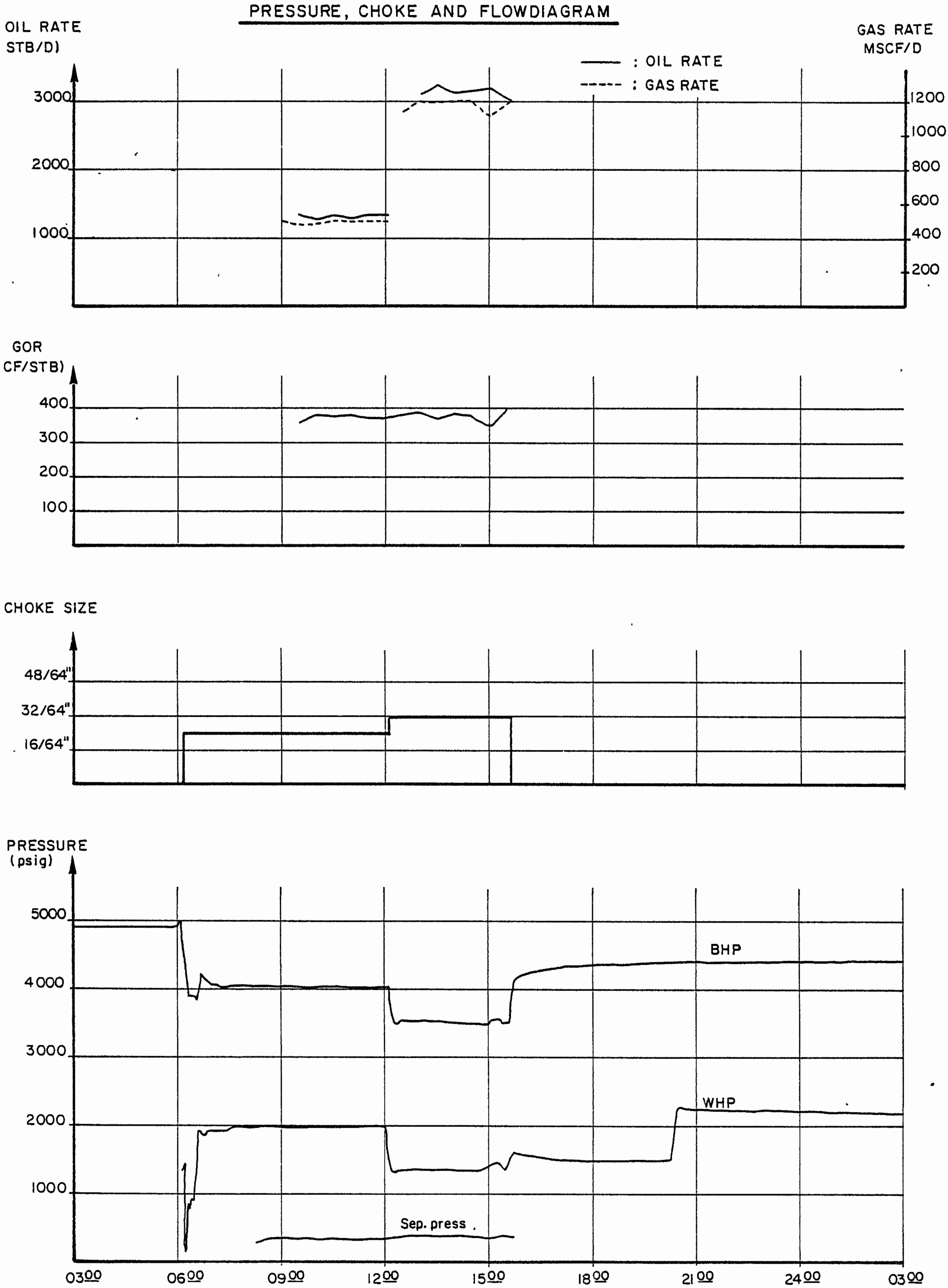
BRØNN 34-10-8   DST# 1
BUILDUP NUMMER 1
GAUGE LYNES 1206

NR.	TID	TRYKK
1	15.39	3497.700
2	15.43	4097.900
3	15.45	4133.900
4	15.47	4157.700
5	15.51	4190.700
6	15.53	4202.700
7	15.55	4213.400
8	15.59	4231.200
9	16.01	4238.300
10	16.03	4245.400
11	16.07	4257.100
12	16.09	4262.100
13	16.11	4267.000
14	16.15	4275.600
15	16.17	4279.800
16	16.19	4283.400
17	16.23	4290.300
18	16.25	4293.400
19	16.27	4296.300
20	16.31	4302.000
21	16.35	4307.000
22	16.39	4311.600
23	16.43	4315.500
24	16.47	4319.900
25	16.51	4323.100
26	16.55	4326.600
27	16.59	4330.200
28	17.05	4334.400
29	17.11	4338.400
30	17.19	4343.400
31	17.27	4347.700
32	17.35	4352.000
33	17.43	4355.600
34	17.51	4359.100
35	18.01	4363.100
36	18.11	4367.000
37	18.19	4369.500
38	18.27	4372.000
39	18.35	4374.500
40	18.43	4377.000
41	18.51	4379.200
42	18.59	4381.300
43	19.07	4383.500
44	19.15	4385.300
45	19.23	4387.400
46	19.31	4388.800
47	19.39	4390.600
48	19.47	4392.300
49	19.55	4393.800
50	20.03	4395.200
51	20.11	4396.600
52	20.17	4397.700
53	21.03	4402.700
54	21.13	4404.500
55	21.21	4406.000
56	21.31	4407.500
57	21.43	4409.300
58	21.59	4411.500
59	22.15	4413.600
60	22.31	4415.400
61	22.47	4417.200
62	23.03	4419.000
63	23.11	4419.700
64	23.39	4422.600
65	0.03	4424.700
66	0.31	4426.800
67	0.59	4428.900
68	1.23	4430.400
69	1.47	4432.200
70	2.07	4433.600
71	2.35	4435.000
72	3.05	4436.400
73	3.29	4437.800
74	3.47	4438.500
75	3.55	4439.200


P(psi) vs. DELTA T(min)
WELL 34-10-8
DST# 1
BUILDUP No 1
GAUGE # LYNES 1206
4600.0
4480.0
4360.0
4240.0
4120.0
4000.0
3880.0
3760.0
3640.0
3520.0
3400.0
0.00
100.
200.
300.
400.
500.
600.
700.
800.


LOG(DELTA P(psi)) vs. LOG(DELTA T(min))
WELL 34-10-8
DST# 1
BUILDUP No 1
GAUGE # LYNES 1206
Pws = 3497.7psi
3
2
0
1
2


P(psi) vs. LOG((T+DELTA T)/DELTA T)
WELL 34-10-8
DST# 1
BUILDUP No 1
GAUGE # LYNES 1206
T PROD = 361 min
m = 177.126
P* = 4461.0psi
P1h = 4311.1psi
DT = 36 - 278min
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00
1.10
1.20
1.30
1.40
1.50
1.60
1.70
1.80
1.90
2.00
4500.0
4450.0
4400.0
4350.0
4300.0
4250.0
4200.0
4150.0
4100.0
4050.0
4000.0



DST no. 1 DATE: 17-18 MAY 1980

FLOW DATA 34/10-8 DST no. 1.
All pressure data from Lynes

Date/Time	Bottom hole		Well head		Chokes		Separator data							Liq. and gas analysis at goos neck					
	Press. Psia	Temp. ^{O}F	Press. Psia	Temp. F	Manifold	Heater	Press. Psia	Temp. ^{O}F	Gas rat. mscf/d	Oil rate stb/d	GOR scf/stb	Oil S.G.	Gas S.G.	Water %	PH	Sedim. %	Oil S.G.	Co2	H_2S
17.5.80																			
08.11	Flowed through separator																		
09.00	4053	160.5	1992	71	24/64		355	60	505			.8807	.645			.25	.882	1.2%	neg.
09.30	4048	160.5	1990	72	"		353	64	480	1331	361	"	"			"		1.0%	neg.
10.00	4046	160.8	1992	73	"		352	68	486	1269	383	"	"			"		1.0%	neg.
10.30	4038	161.0	1985	72	"		356	68	502	1333	377	"	.622			"	.881	1.2%	neg.
11.00	4034	161.0	1983	71	"		348	70	498	1284	382	.8814	"			.15			
11.30	4032	161.3	1982	72	"		350	71	497	1330	374	"	"			0			
12.00	4030	161.3	1980	74	"		350	74	496	1335	371	"	"			0		1.0%	neg.
12.07	Changed choke to 32/64"																		
12.30	3535	162.8	1346	80	32/64		380	80	1142			.8814	.622			.25	.881		
13.00	3529	163.0	1372	94	"		397	85	1205	3110	387	"	"			0		1.2%	neg.
13.30	3533	163.0	1370	92	"		397	90	1195	3234	370	"	"			0	.883		
14.00	3519	163.3	1361	93	"		391	93	1205	3124	386	"	"			0			
14.30	3507	163.3	1356	95	"		390	96	1202	3153	381	.8793	"			0			
15.00	3509	163.3	1413	98	"		367	96	1119	3186	351	"	"			0			
15.00	Broken choke seal, WHP increased																		
15.30	3500	163.3	1364	98	32/64		401	96	1202	3000	401	"	"			0		2%	neg.
15.34	Bypassed separator.																		

WELL 34/10-8

DST 1 1869 - 1873 m RKB

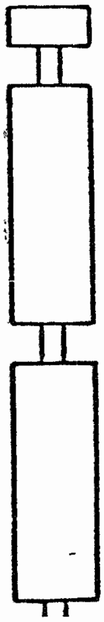
I.D.	O.D.	Description	Length (m)	Depth (m)
		Above rotary table		4.34
		SSTT String (sea bed)	158.44	154.10
		4½" Acme Pin x 3½" TDS Box	.16	154.26
		3½"TDS Pin x Pin	.38	154.64
2.712	4.20	3½" TDS Tubing	1439.91	1594.55
2.50	4.50	X-Over 3½" TDS Box x 3½" IF Pin	.29	1594.84
2.25	5.00	Slip Joint (Open)	5.53	1600.37
2.25	5.00	Slip Joint (Closed)	4.01	1604.38
2.25	4.75	Drill Collars	158.34	1762.72
2.25	4.75	X-Over 3½" IF Box x 2 7/8" EUE Pin	.21	1762.93
2.44	4.87	7" RTTS Circ.Valve	.98	1763.91
2.75	4.75	X-Over 2 7/8" EUE Box x 3½" IF Pin	.20	1764.11
2.25	4.75	1 Stand Drill Collars	28.34	1792.45
2.25	5.00	Slip Joint (Closed)	4.01	1796.46
2.25	5.00	Slip Joint (Closed)	4.01	1800.47
2.25	4.75	1 Stand Drill Collars	28.33	1828.80
2.25	5.03	5" APR-A Circ. Valve	.92	1829.72
2.25	5.00	5" APR-N Tester Valve	3.85	1833.57
2.37	4.63	4 5/8" Big John Jars	1.52	1835.09
2.44	4.87	7" RTTS Circ. Valve	.97	1836.06
2.44	5.00	7" RTTS Safety Joint	.85	1836.91
2.185	5.75	7" RTTS Packer from Top to Bottom of Rubbers	.59	1837.50
2.185	5.75	7" RTTS Packer Below Rubbers	.74	1838.24
2.25	2.875	2 7/8" EUE Pin x 2 7/8" Non upset Pin	1.05	1839.29
		2 7/8" Non upset Box x 2 3/8" Pin VAM	.15	1839.44
		2 3/8" VAM Box x 2 7/8" Non upset Box	.16	1839.60
2.25	2.875	2 7/8" Sand Screen (127 micron meter)	2.87	1842.47
3.50	2.00	X-Over 2 7/8" EUE Box x 2 3/8" EUE Pin	.16	1842.63
1.81	3.00	Baker R-Nipple w/Lynes gauges	.23	1842.86
		X-Over 2 3/8" EUE Box x 2 7/8" EUE Pin	.20	1842.06
		2 7/8 Tubing	9.28	1852.34
		Inside top of tubing joint		
		hanger for Sperry Sun gauges		
		2 7/8" EUE Tubing Joint	9.38	1861.72
		2 7/8" EUE Box x 3 1/8" 8 N Pin	.085	1861.80
		APBT Case 8000 psi Gauge	1.50	1862.30

WELL 34/10-8

DST 1 1869 - 1873 m RKB

I.D.	O.D.	Description	Length	Depth
		3 1/8" 8 N Box x 2 3/8" Pin	.29	1863.59
		2 3/8" EUE Box with a flat shoe w/a 1 1/4" hole	.10	1863.69

WELL NO.: 34/10-8 DST NO.: 1 DATE: 16.5.80



WIRELINE NIPPLE 1843 m

GAUGE TYPE AND NUMBER: DMR 314, S/N 1206

DEPTH, PRESSURE ELEMENT: 1845.1 m RKB RANGE: 5000 psi

MODE: 2 minutes DELAY: 7 hours

ACTUATED: time 14:00 date: 16.5.80

WILL RUN OUT: time 07:08 date: 18.5.80

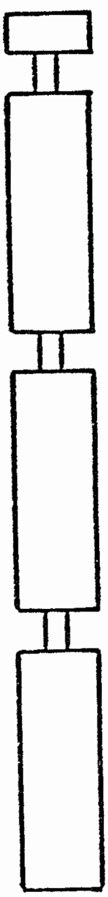
GAUGE TYPE AND NUMBER: DMR 312, S/N 1136

DEPTH, PRESSURE ELEMENT: 1847.0 m RKB RANGE: 10,000 psi

MODE: 2 minutes DELAY: 7 hours

ACTUATED: time: 14:01 date: 16.5.80

WILL RUN OUT: time: 07:08 date: 18.5.80



D.S.T. HANGER 1852 m

GAUGE TYPE AND NUMBER: MRPG 0012

DEPTH, PRESSURE ELEMENT: 1855.5 m RKB RANGE: 0 - 10,000 psi

MODE: 2 minutes DELAY: -

ACTUATED: time: 13:49 date: 16.5.80

WILL RUN OUT: time: 21:49 date: 18.5.80

GAUGE TYPE AND NUMBER: MRPG 0020

DEPTH, PRESSURE ELEMENT: 1858.4 m RKB RANGE: 0 - 10,000 psi

MODE: 4 minutes DELAY: -

ACTUATED: time: 13:47 date: 16.5.80

WILL RUN OUT: time: 05:47 date: 21.5.80

GAUGE TYPE AND NUMBER: Halliburton APBT

DEPTH, PRESSURE ELEMENT: 1863.0 m RKB RANGE: 0 - 8000 psi

MODE: DELAY:

ACTUATED: time: date:

WILL RUN OUT: time: date:

DIARY OF EVENTS	WELL No. 34/10-8	DST No. 1
	ZONE TESTED BRENT	PERFS. 1869 - 73 m RKB

DATE	TIME	OPERATIONS
		PERFORATING
16.5.	1045	Rigged up Schlumberger, ran 4" CGEL, 4 shots pr. foot.
	1240	Perforated 1869 - 73 m RKB
	1315	Rigged down Schlumberger.
		RAN TEST-STRING
	1330	Started picking up test string
17.5.	0233	Sat packer at 1837 m RKB
		FIRST FLOW PERIOD
	0610	Opened APR-N valve, annulus pressure 1500 psi
	0612	Opened on 3/4" fixed choke on manifold
	0641	Switched to 24/64" fixed on manifold
	0630	Mud to surface
	0640	Gas to surface
	0646	Lighted flare
	0815	Flowed through separator
	1000	Flowed to tank 21,6 bbl.
		Metered 22 bbl., meter factor = 0.982 *
	1110	Started taking PVT - set no. 1.
	1135	Finished taking gas sample
	1140	Finished taking oil sample
	1207	Changed choke to ½" fixed on manifold
	1245	Small sand slug to surface
	1300	Well cleaned up again, solids less than ½%
	1412	Started taking PVT set no. 2.
	1440	Finished taking gas sample
	1445	Finised taking oil sample
	1455	WHP increased due to broken ceramic choke seal
		BUILD-UP PERIOD
	1539	Shut in at choke manifold
	1540	Bled off annulus pressure, APR-N valve closed
	2018	APR-N valve leaked 4 - 5 minutes, reason unknown.

COMMENTS:

* Meter factor with water before test: 1.026

Shrikage : 3%

Factor used by Flopetrol: 1.026 x 0.97 = .995

DIARY OF EVENTS		WELL No. 34/10-8 DST No. 1 ZONE TESTED Brent PERFS. 1869 - 73 m RKB
DATE	TIME	OPERATIONS
		BOTTOM HOLE SAMPLING
18.5.	0400	Opened APR-n valve
	0401	Opened choke manifold on 10/64" choke, flowed to stock tank
	0415	Sat clocks on bottom hole samplers and picked up lubricator
	0438	Estimated flow rate 550 STB/D
	0444	Closed choke manifold
	0448	Closed master valve, bled off pressure through choke manifold and installed samplers
	0510	Tested lubricator to 5000 psi
	0516	Ran in hole with samplers
	0520	Opened choke manifold on 10/64" choke
	0610	Samplers at bottom.
	0645	Samplers closed
	0715	Closed choke manifold and pulled out of hole
	0745	Samplers on rig floor, OK!
		DISPLACE TUBING W/WATER
	0800	Displaced the tubing with water, only 35 bbls. injected.
		ATTEMPTED TO PULL GAUGES
	0900	Rigged up wireline for pulling Lynes gauges
		Unable to pass APR-n valve
	1010	Opened and closed choke to check that APR-n open..
	1013	Indication of open APR-n valve
	1020	Unable to pass 1837 m (Packer)
	1030	Wireline unit broke down
		Unit repaired
	1150	Wireline out of hole, rigged down lubricator.

COMMENTS:

PE:

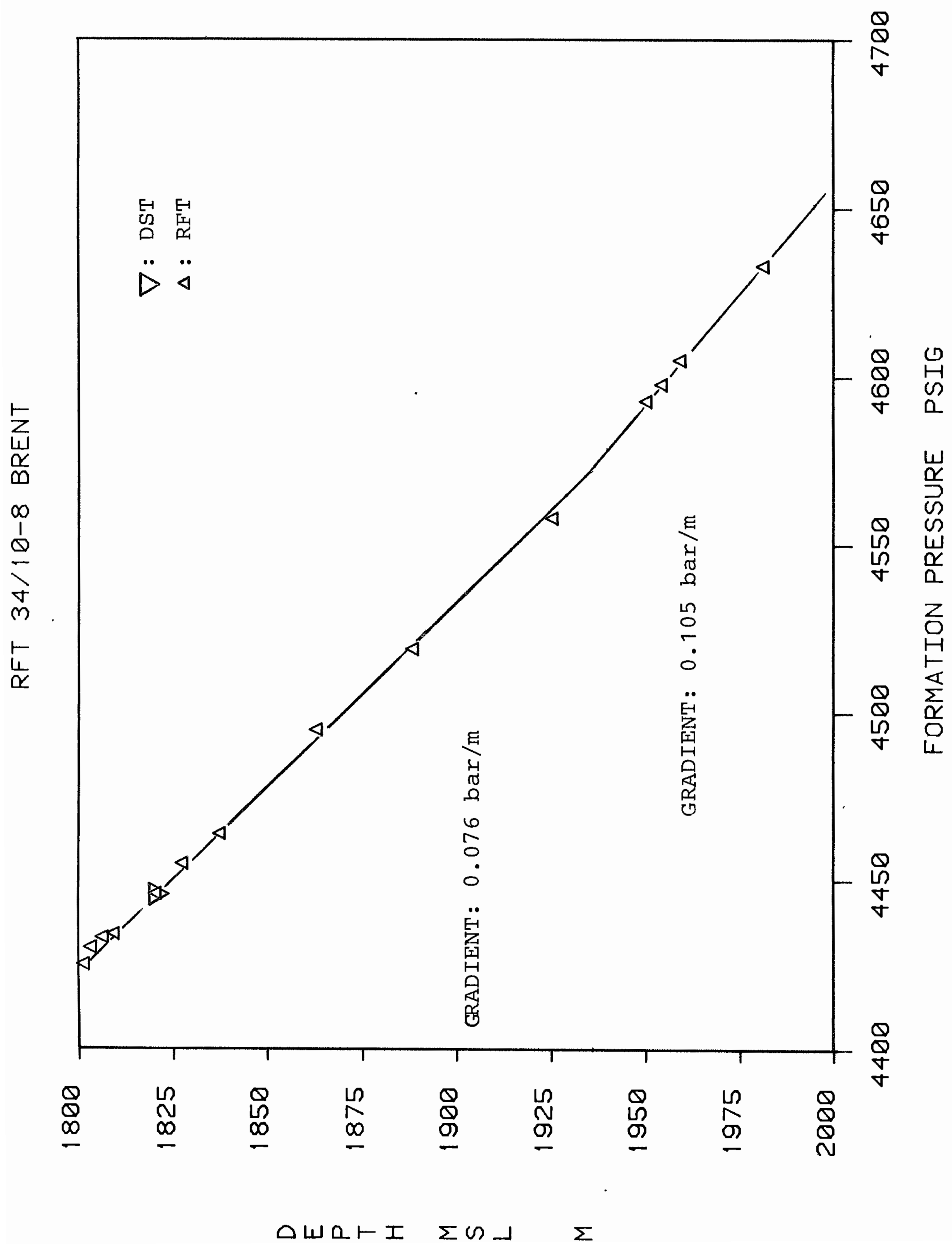
APPENDIX A2	PAGE

34/10-8 RFT data

The repeat formation tester was run in the Brent sand and good data was obtained from -1708.5 m MSL to -1981 m MSL. Seventeen tests were performed in the well and fifteen of these tests were successful. In the Ness zone fluid sample was taken at -1925 m MSL.

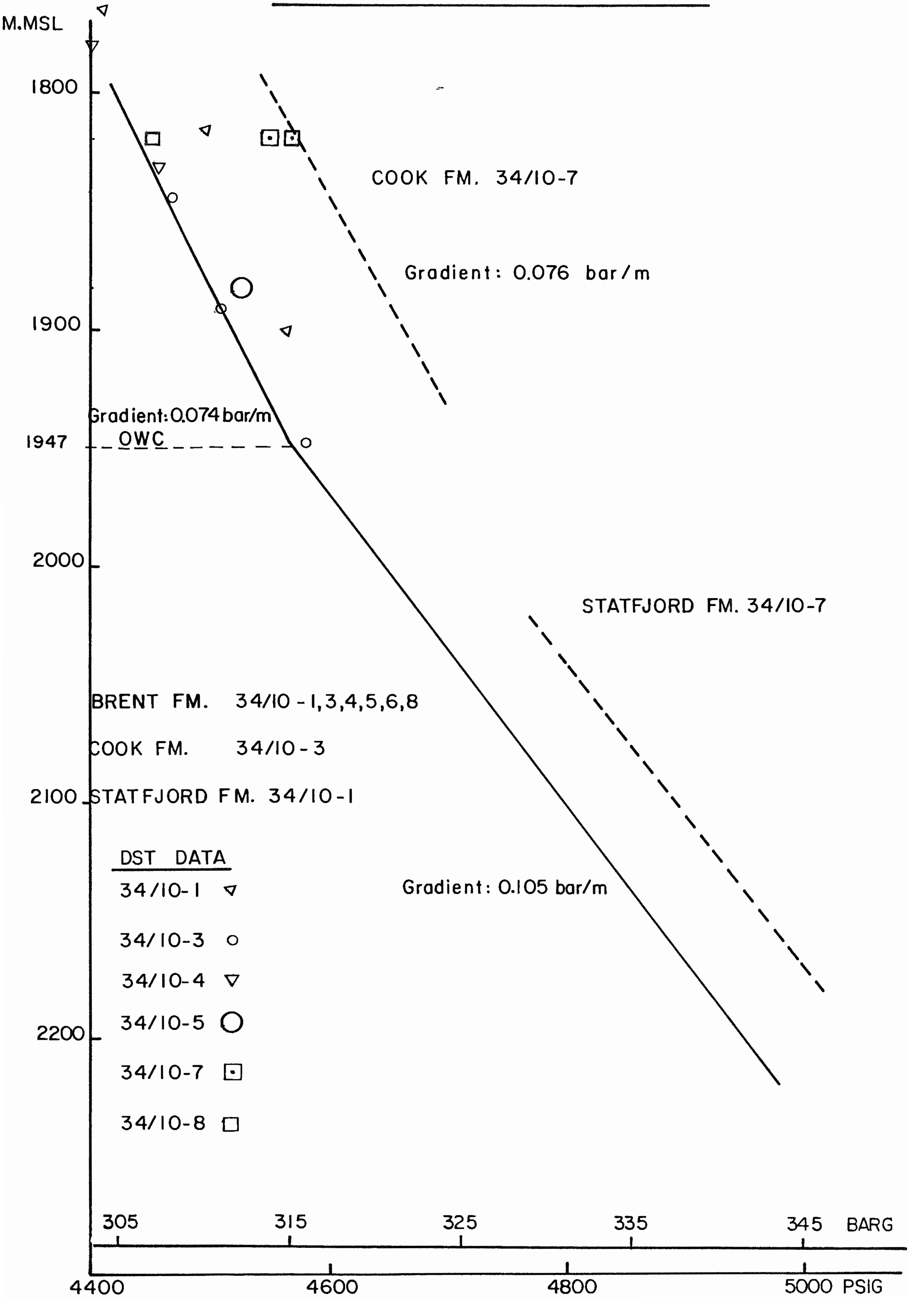
The data listed below are corrected for pressure and temperature effects.

Depth m MSL	Corr. pressure psig	Remarks
1798.5	4426	
1801	4425	
1803	4430	
1806	4433	
1809	4434	
1820	4446	
1827	4455	
1837	4464	
1862.5	4495	
1888	4519	
1925	4558	Sampling
1950	4593	
1954	4598	
1959	4605	
1981	4633	

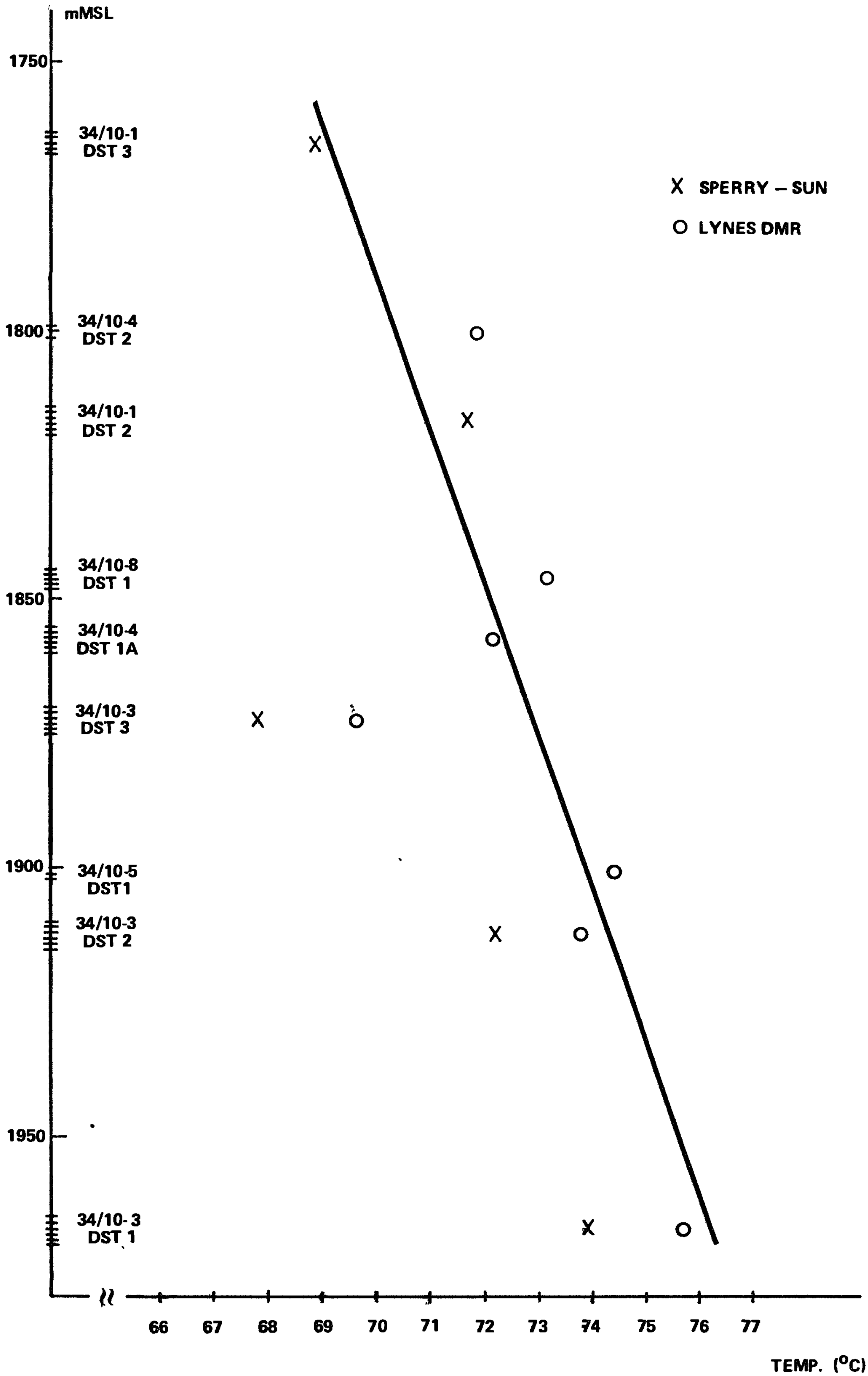


RFT 34/10-8 BRENT
▽: DST
△: RFT
GRADIENT: 0.076 bar/m
GRADIENT: 0.105 bar/m
1800
1825
1850
1875
1900
1925
1950
1975
2000
DEPTH MSL M
4400
4450
4500
4550
4600
4650
4700
FORMATION PRESSURE PSIG

RFT OG DST DATA 34/10 DELTA



RESERVOIR TEMPERATURE 34/10–DELTA



APPENDIX A4 PAGE

1. INTRODUCTION

Well 34/10-8 is the seventh well drilled on the Delta structure in block 34/10. The well penetrated the Brent and Dunlin formation and was drilled to a total depth of 2215 m RKB.

SURFACE SAMPLING ON SEPARATOR
DST no. 1 (1869 - 1873 m RKB)

DATE/TIME	SAMPLE NO.	TYPE OF SAMPLE	TRANSFER TIME	BOTTLE NO.
17. May				
11:10	1	Oil	25 min	20475-22
11:10	1	Gas	25 min	A 7697
14:12	2	Oil	28 min	2268-18
14:12	2	Gas	33 min	A 10473

BOTTOM HOLE SAMPLING

DATE/TIME	BOTTLE NO.	OPENING PRESSURE	ESTIMATED P_B AT RES. COND. (From Flopetrol on rig)
18. May			
06:45	13266/139	2210 psig	3180 psig
06:45	14068/45	2210 psig	3200 psig

Well no. 34/10-8 Test no.: 1

Interval: 1869 - 73 m RKB Date: 17.5.80

WELLHEAD SAMPLES

09:30 - 10:30	6 oil samples from goose neck	
14:30 - 15:00	6 oil samples from goose neck	
	1 bbls	from separator
	2 jerry cans	from separator

DIARY OF EVENTS	WELL No. 34/10-8	DST No. 1
	ZONE TESTED BRENT	PERFS. 1869 - 73 m RKB

DATE	TIME	OPERATIONS
		INJECTION TEST
	1200	Started injection test, WHP exceeded max allowable pressure
	1209	Opened choke manifold on 32/64" choke, flowed to tank
	1211	Changed to 10/64"
	1213	Closed choke manifold
	1220	Injected 10 bbls, WHP exceeded the allowable.
	1230	Bled back 5 - 6 bbls to cementing unit.
		Called base, decided to break formation to establish injection.
	1235	Pressure on cementing unit peaked to 3300 psi, injection established at 2500 psi
	1240	Started injection test
		DATA FROM INJECTION TEST
		Rate (bbls/min) — WHP (psi) from Lynes
		1.0 — 2600
		1.5 — 2900
		2.2 — 3150
		2.8 — 3300
		3.4 — 3420
	1330	Started bullheading w/mud
		Gauges to surface, all worked OK.
		Test ended.

COMMENTS:

PE:


OCT 1980
PE/EVALTEK
TH/AM
STATUS
SPUDDED 8/3-1980
RIG RELEASED 26/5-80
PLUGGED AN ABANDONED
KB ELEVATION = 25 m
WATER DEPTH = 158 m
LOCATION
61° 09' 5953" N
02° 12' 34" E
DST 1
INTERVAL : 1869 - 1873
CHOKE 1/2"
OIL 3135 STB/D
GAS 1.2 10^6 SCF/D
2050

Injection test

Rigged up for displacement of tubing w/water after finished bottom hole sampling. Displaced 35 bbls of water (total ca. 45 bbls in tubing)before WHP exceeded max. estimated bottom hole fracture pressure. Attemted to pull Lynes gauges on wireline, unsucceded. Tried to establish injection again without fracturing the formation, impossible.

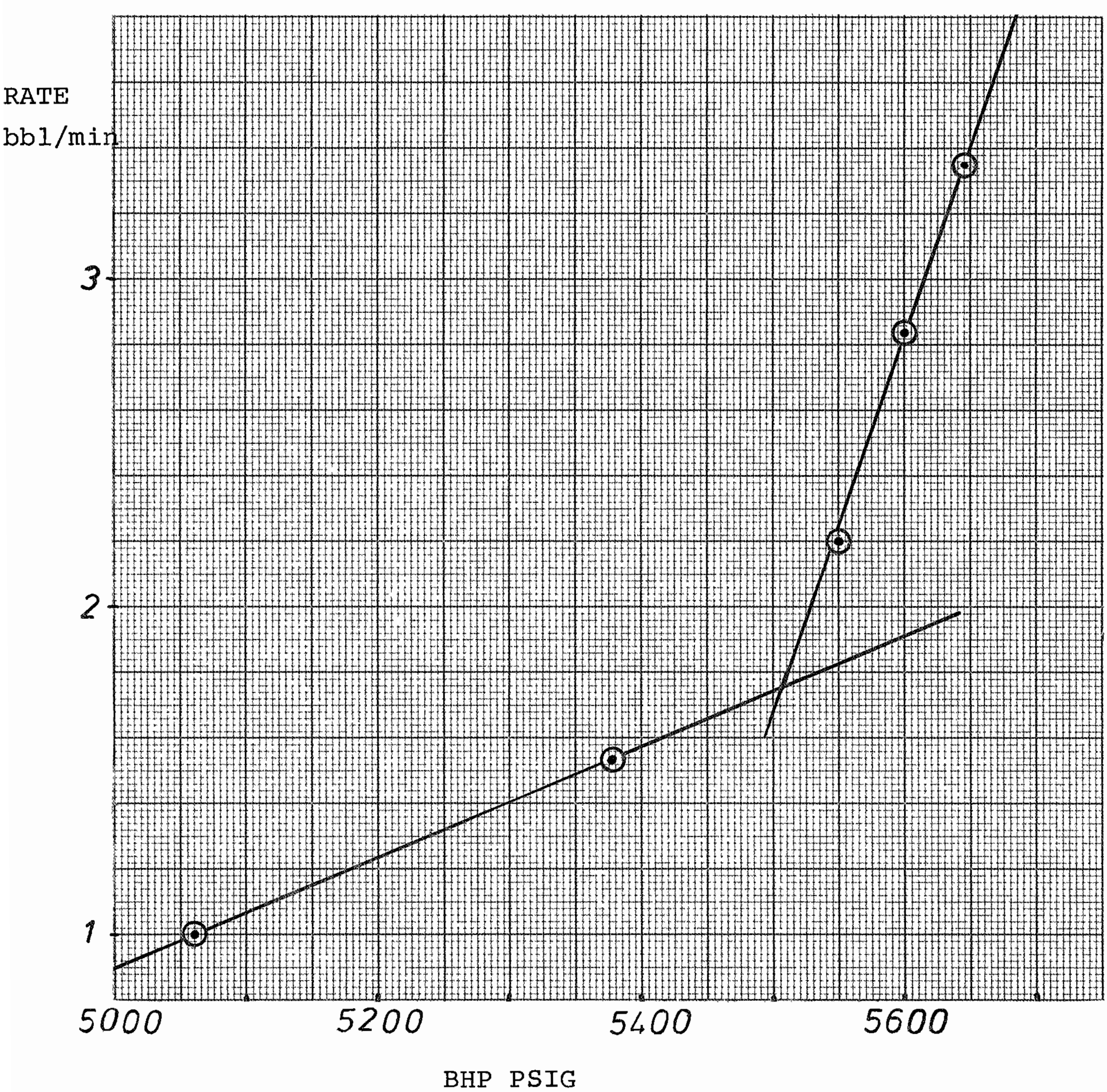
Checked that APR-n valve was open, pumped 2 - 3 bbls, stopped on max. WHP, bled back pressure again. From WHP we got positive indication of open APR-n valve (which is confirmed by BHP). Decided to fracture formation to establish injection. Pressure on cementing unit peaked to 3300 psi (Lynes surface gauge showed max. 2837 at 12.20 18. May. Injection rate was established, WHP = 2800 psi on cementing unit. Estimated volume injection/ displaced: 35 - 40 bbls.
Data from injection test:

Real time	Cum. injection (bbls)	Rate (bbls/min)	WHP (Lynes) (psia)	BHP (Sperry Sun (psig)
			P_{avg} = 2571	P_{avg} = 5061
Rate no. 1.				
12.43	0	-	2556	4962
12.45	2	1.0	2643	5117
12.47	4	1.0	2560	5007
12.49	6	1.0	2602	5072
12.51	8	1.0	2557	5057
12.53	10	1.0	2588	5095
12.55	12	1.0	2615	5130
	Stopped injection			
13.00	12.6	-	2001	
13.01	13.6	1.0	2514	5018
13.02	14.6	1.0	2538	
13.03	15.6	1.0	2539	5088

Real time	Cum. injection (bbls)	Rate (bbls/min)	WHP (Lynes) (psia)	BHP (Sperry Sun) (psig)
			P_{avg} = 2872	P_{avg} = 5377
Rate no. 2.				
13.04	16.8	-	2535	
13.05	18.3	1.5	2781	5279
13.06	19.8	1.5	2812	
13.07	21.4	1.6	2849	5351
13.08	22.9	1.5	2868	
13.09	24.5	1.6	2922	5413
13.10	26.0	1.5	2923	
13.11	27.6	1.6	2948	5466
Rate no. 3.			P_{avg} = 3138	P_{avg} = 5550
13.12	29.6	-	3141	
13.13	31.8	2.2	3129	5547
13.14	34.0	2.2	3140	
13.15	36.2	2.2	3135	5553
13.16	38.4	2.2	3147	
Rate no. 4.			P_{avg} = 3291	P_{avg} = 5600
13.17	40.4	-	3231	5575
13.18	43.2	2.8	3260	
13.19	46.0	2.8	3355	5593
13.20	48.8	2.8	3302	
13.21	51.7	2.9	3306	5633
13.22	54.6	2.9	3291	
Rate no. 5.			P_{avg} = 3422	P_{avg} = 5645
13.23	57.9	-	3420	5639
13.24	61.2	3.3	3423	
13.25	64.6	3.4	3424	5650

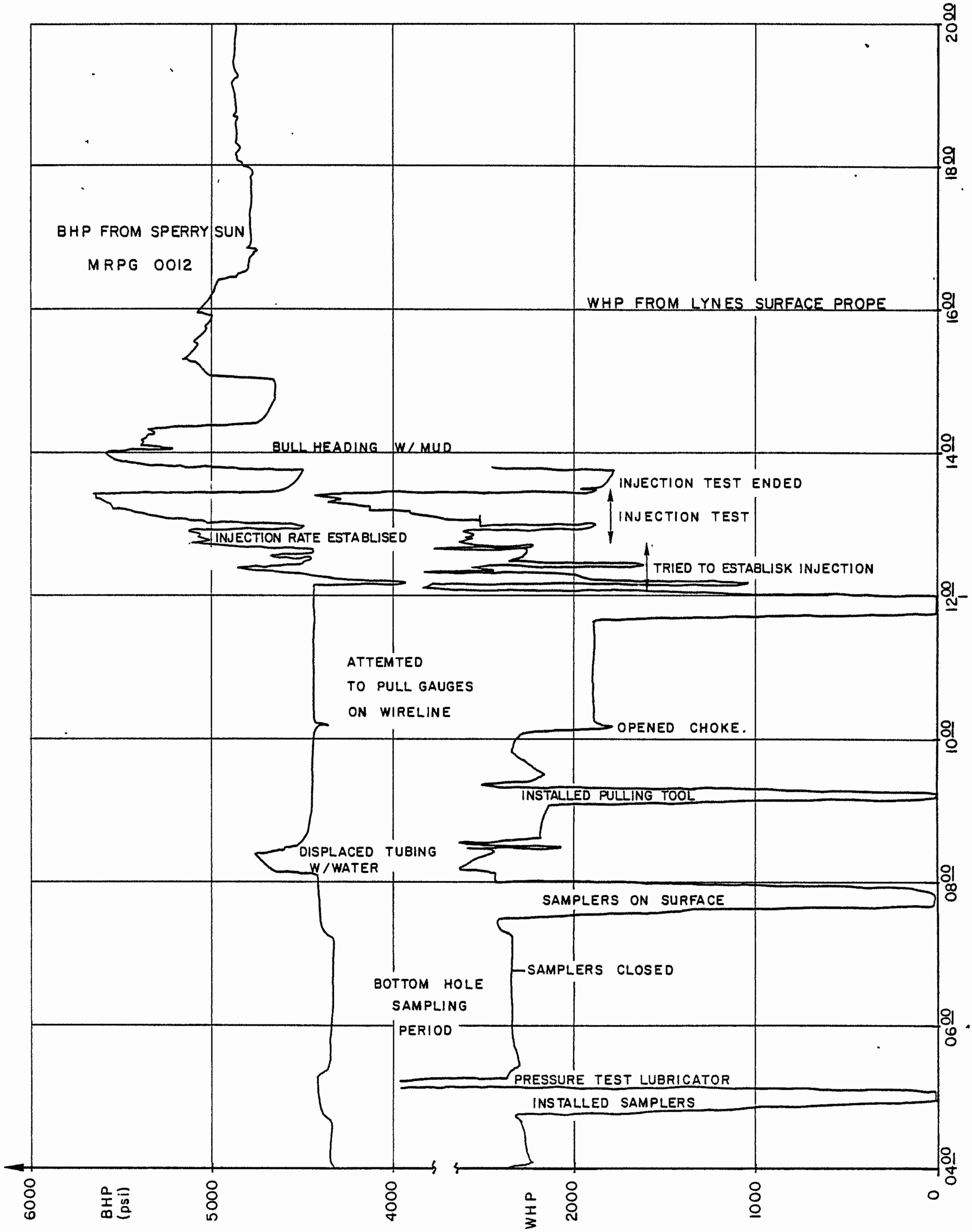
From page A6-4 , estimated fracture pressure is 5500 psi, i.e. equivalent mudweight 2.07.

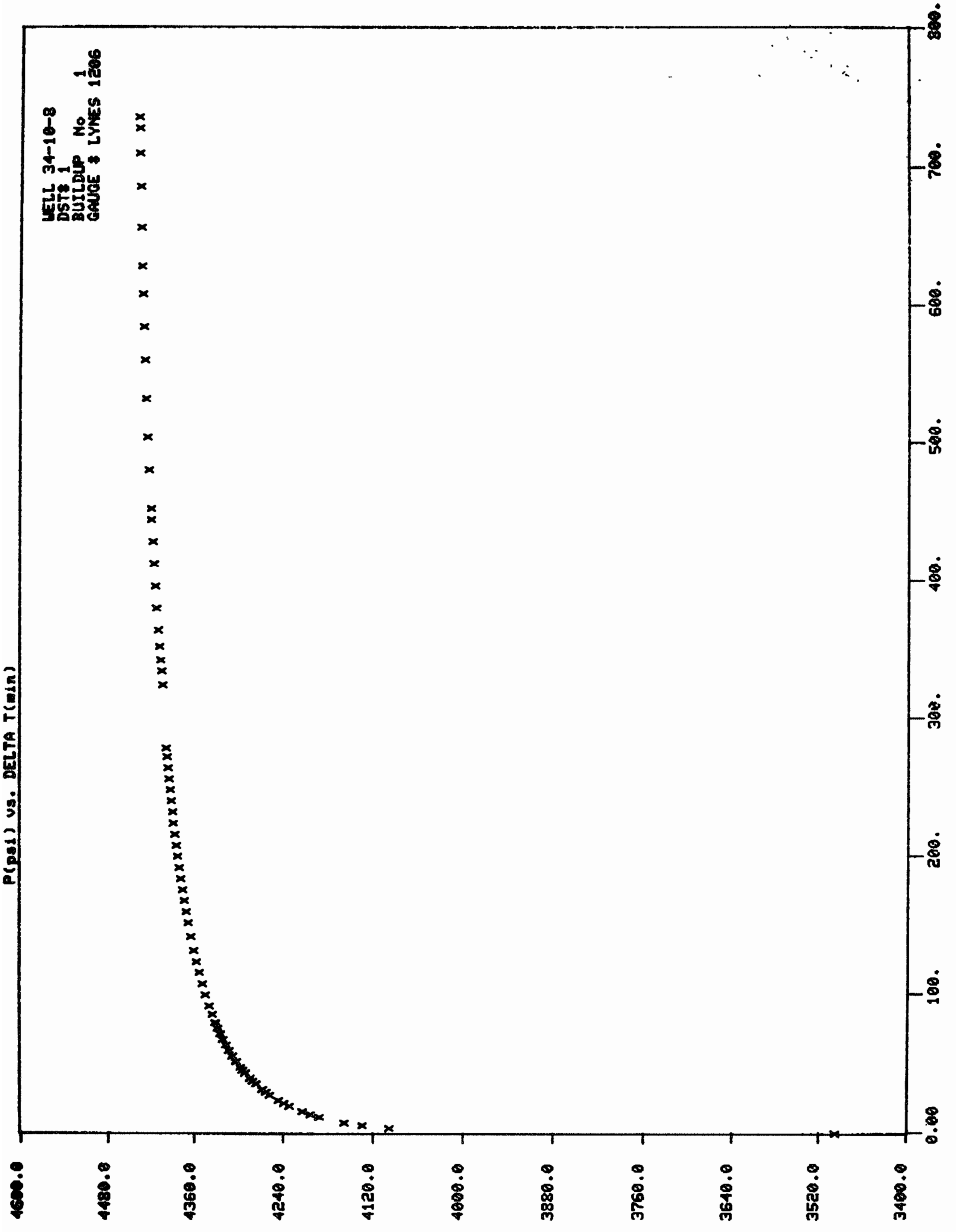
34/10-8 INJECTION TEST

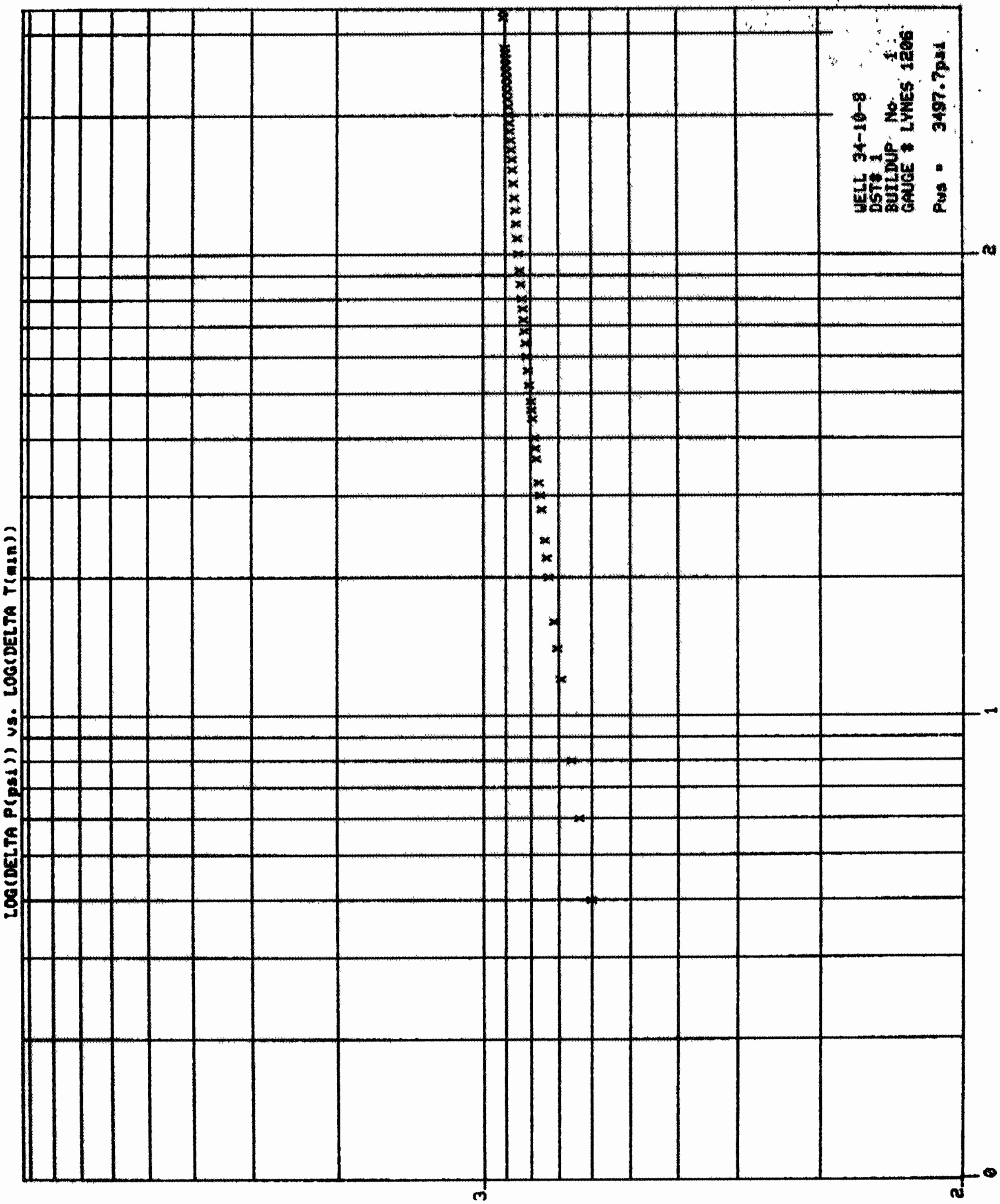


34/10-8, DST no. 1

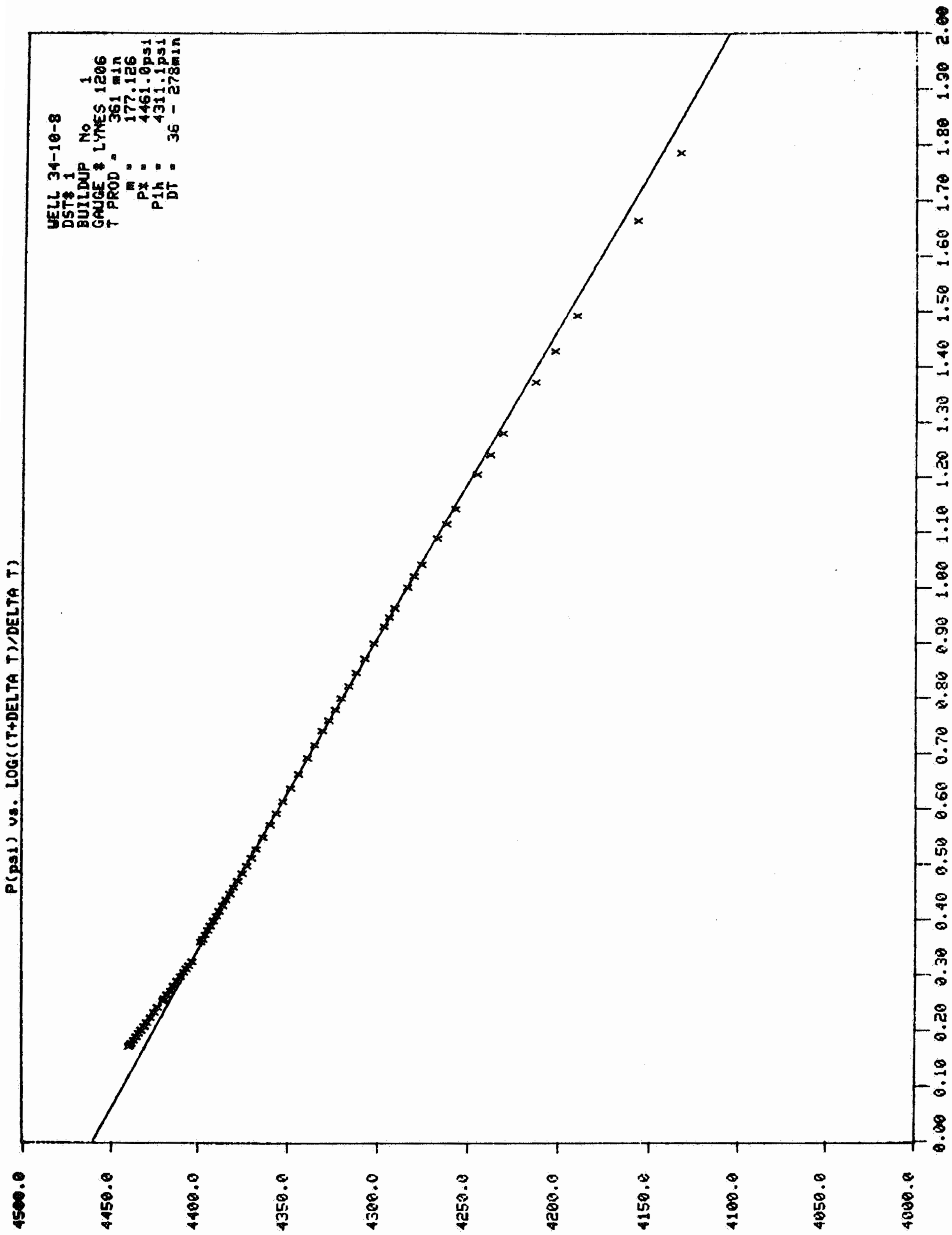
WHP and BHP from bottom hole sampling, displacement of tubing w/water and injection test.




P(psi) vs. DELTA T(min)
WELL 34-10-8
DST$ 1
BUILDUP No. 1
GAUGE $ LYNES 1206
4600.0
4480.0
4360.0
4240.0
4120.0
4000.0
3880.0
3760.0
3640.0
3520.0
3400.0
0.00
100.
200.
300.
400.
500.
600.
700.
800.



LOG(DELTA P(psi)) vs. LOG(DELTA T(min))
WELL 34-10-8
DST# 1
BUILDUP No. 1
GAUGE # LYNES 1206
Pws = 3497.7psi
0
1
2
2
3



P(psi) vs. LOG((T+DELTA T)/DELTA T)
WELL 34-10-8
DST$ 1
BUILDUP No 1
GAUGE $ LYNES 1206
T PROD = 361 min
m = 177.126
P* = 4461.0psi
P1h = 4311.1psi
DT = 36 - 278min
4500.0
4450.0
4400.0
4350.0
4300.0
4250.0
4200.0
4150.0
4100.0
4050.0
4000.0
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00
1.10
1.20
1.30
1.40
1.50
1.60
1.70
1.80
1.90
2.00

GRAPHICAL LOG-PRESENTATION

WELL : 34-10-8 DEPTH INTERVALL : 1820.00-2055.00 (METER)

ENGINEER : THY SCALE 1:

DATE: 13.15.57 : OKTOBER 1980

STATOIL

SUMMARY LOG 34/10-8

DST I
INTERVAL : 1869 - 1873
CHOKE : 1/2"
OIL : 3135 STB/D
GAS : $1.2 \cdot 10^6$ SCF/D

LOCATION :
61° 09' 59.53" N
02° 12' 3.4" E

KB ELEVATION = 25 m
WATER DEPTH = 158 m

STATUS:
SPUDDED: 8/3-1980
RIG RELEASED: 26/5-80
PLUGGED AN ABANDONED

OCT. : 1980
PE/EVALTEK
TH/AM