

RESULTS OF DRILLSTEM TESTS

WELL 16/7-4

"A" - PROSPECT

## Results of Drillstem Tests

### Well 16/7-4

### "A" - prospect

#### Summary

Two successful drill stem tests have been conducted on the exploration well 16/7-4 in the Norwegian North Sea. The tests produced gas and condensate at medium rates from the Hugin formation. The test intervals were from 2590.5 m to 2597 m RKB for DST no 1. (2565.5 to 2572 m ss) and from 2525 m to 2535 m for DST no 2. (2500 to 2510 m ss). The well was tested using the standard dual flow, dual shutin procedure. During the major flow period of DST no. 1 the well production rate was 13.6 MSCF/D\* of gas and 1450 STB/D of condensate on a 42/64" choke. The condensate/gas ratio was 106.6 STB/MSCF. Test no 2 produced 16.7 MSCF/D of gas and 1730 STB/D of condensate on a 42/64" choke. The condensate/gas ratio on this test was 103.4 STB/MSCF.

Table I and II summarize the test results.

$$* 1 \text{ MSCF/D} = 10^6 \text{ SCF/D}$$

Table I : DST - 1 result summary

	Field units	Metric units (SI)
Interval (RKB)	8499 - 8520 ft	2590.5 - 2597 m
Choke size	42/64"	16.67 mm
Gas rate	13.6 MSCF/D	385 $\text{KSm}^3/\text{D}$
Liquid rate	1490 STB/D	231 $\text{Sm}^3/\text{D}$
Liquid-Gas ratio	106.6 STB/MSCF	600 $\text{Sm}^3/\text{MSm}^3$
Permeability	37.2 md	37.2 md (36.7 $\text{nm}^2$ )
Total skin factor	7.67	7.67
Flow efficiency	50%	50%
Initial pressure	4278 psia	295 bara

Table II : DST - 2 result summary

	Field units	Metric units (SI)
Interval (RKB)	8284 - 8317 ft	2525 - 2535 m
Choke size	42/64"	16.67 mm
Gas rate	16.7 MSCF/D	473 $\text{KSm}^3/\text{D}$
Liquid rate	1730 STB/D	275 $\text{Sm}^3/\text{D}$
Liquid-Gas ratio	106.6 STB/MSCF	600 $\text{Sm}^3/\text{MSm}^3$
Permeability	145 md	145 md (143 $\text{nm}^2$ )
Total skin factor	9.61	9.61
Flow efficiency	46%	46%
Initial pressure	4246 psia	293 bara

Introduction.

The Exploration well 16/7-4 was drilled to test potential Jurassic/Triassic sands on a structure in the south-west corner of the 16/7 block. The structure is so far called the "A" - prospect. The well was production tested from the 28th of November through 3rd December 1982. Two zones were tested in the Hugin formation (Jurassic/Triassic Age) through casing perforations. Drilling and testing was conducted from the semi-submersible drilling rig Glomar Biscay II.

The objectives of these tests were to determine the original reservoir pressure and temperature, to evaluate the formation productivity and permeability, and to obtain good samples of reservoir fluid.

Details on test events and data are recorded on EPRCo's standard well testing forms which are included in the appendices to this report.

Test interval for DST no 1: 2590.5 to 2597 m RKB (IEL)

Test interval for DST no 2: 2525 to 2535 m RKB (IEL)

Open hole logs of the test intervals are shown in Fig 1 (DST - 1) and Fig 2 (DST - 2).

### Test equipment.

The bottom-hole shut-in technique was utilized in these tests to limit surface pressure and minimize afterflow. The Halliburton LPR tester valve was used for this purpose. The LPR valve is operated by casing pressure manipulation.

Figure 3 is a schematic drawing of the downhole test assembly. The assembly was the same for both tests.

Four Sperry-Sun high precision gauges (MRPG) were used for downhole pressure recording. The gauges were suspended from an Otis XN nipple below the perforated joint inside the 2-7/8 inch tubing (See fig 3). The gauge assembly was equal for both tests. Two of the gauges were given 34 hours delay in case the operations should be hampered by bad weather or other problems. The other two gauges were put on 17 hours delay. The distance from the gauges down to the perforations was approximately 20 m.

Surface test equipment is shown schematically in Figure 4. The pressure and temperature upstream of the choke was monitored by a data acquisition system (MR-6) supplied by Sperry-Sun. A dead-weight tester, a Barton pen recorder and a dial pressure gauge was used as back up. The pressure downstream of the choke was recorded by the MR-6 system with a dial pressure gauge as back up. A glycol injection pump was connected to the flow line upstream of the choke to allow for glycol injection in case of hydrate formation due to the cooling effect through the choke. The well stream could also be passed through a steam heater in the event that the temperature got to low for adequate separation.

The gas stream from the separator outlet was measured by a orifice meter and the liquid stream by a positive displacement meter. Sampling ports for gas and liquid were located on the separator outlets. Gas and liquid were burned separately on a gas flare and a liquid burner mounted on the same boom.

Summary of events

DST - 1  
-----

The test interval was perforated on the November 26, 1982, using a 4 inch Kone Shot gun with 124 shots in 120° phasing. All shots were fired and the perforations were subsequently successfully logged by the CCL tool.

At 0120 hours on November 27 the gauge clocks were started and the test assembly run into the hole. To prevent rust and scale from plugging the valves, a viscous gel pill was placed in the test assembly and the first joint of tubing. The rest of the tubing was filled with seawater.

After the test string had been run into the hole and pressure tested and the surface equipment had been hooked up the RTTS packer was set at 0240 hours on November 28. At 0304 the LPR valve was opened and wellhead pressure stabilized at 388 psig. Three minutes later the choke manifold was opened on 24/64" variable choke. The well was flowing for 2 minutes and produced 2 bbls of seawater into the stock tank. At 0309 hours the choke manifold and the LPR valve were simultaneously closed for initial buildup. The well was left shut in for 1 hour.

The LPR valve was reopened at 0412 hours and the wellhead pressure stabilized at 439 psig. The well was opened for the major flow period on a 32/64" choke at 0415. Gas reached the surface in 40 minutes. The gas stream was routed through the heater.

After the viscous gel and the rat hole mud had been flushed out of the tubing the wellstream got very clean and dry. Not enough liquid could be sampled at the choke manifold to make a BSW test. A paper test indicated that the gas stream did not carry any sediments or sand particles.

After 2 hours a 42/64" fixed choke was installed. The well was kept on this choke size for the rest of the major flow period.

On inspection of the 32/64" fixed choke after it had been removed from the choke manifold it turned out that a piece of metal was stucked in the choke, partly plugging it. This was probably the reason for the relatively high wellhead pressure observed during the last hour before the choke was changed. The rate was most likely lower then what could be estimated from the choke equation.

Glycol was injected at the choke manifold for about one hour starting at 0620. When the well was put on a 42/64" choke, glycol injection was no longer necessary.

At 0750 the well stream was switched into the seperator. Due to stabilization problems production counting could not begin until 0930. The separator was run at 345 psig and 120°F.

Figure 5 shows plots of wellhead pressure and separator gas and liquid rates during the last six hours of the major flow period. The measurements are reasonably stable with variations in the order of 5%.

During the stable flow period, two sets of pressurized samples were taken at the separator. Each set consisted of two 20 liter gas bottles and one 500 cc condensate bottle. In addition one 250 cc gas bottle was sampled for fingerprint studies. Two 10 l jerry cans were filled with condensate and four 1 l plastic bottles were filled with water from the separator after shutin.

After the well had been flowing for 12 hours it was shut in through the following procedure:

- The choke manifold was closed and the well head pressure allowed to build up to approximately 500 psi above its flowing pressure.
- Casing pressure was released to close the LPR valve.

- The choke was reopened and the tubing gas bleed off through the flare. This was done to minimize risk of hydrate formation in the tubing.
- When the wellhead pressure had fallen to less than 800 psi the choke was closed. The wellhead pressure stabilized at 790 psi indicating that the LPR valve was properly closed.

The well was kept shut in for 18 hours (1.5 times the flow period). At 1107 hours on 29 November, the LPR valve was reopened and the well killed by bullheading.

See data form 5 for further details.

DST - 2

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DST - 2 was done equally to DST - 1 with the following exceptions:

- Fresh water was used as well loading fluid instead of sea water.
- The initial stabilized wellhead pressure was 540 psig (Higher than for DST - 1 due to lighter well loading fluid).
- Gas reached surface in 10 minutes.
- The separator was run on 425 psig and 103°F.
- One extra high pressure liquid bottle (600 cc) was sampled from the separator.
- The well was given a 9.5 hours major flow periode with the intention to shut it in for 10 hours. Due to problems with reopening the LPR valve, the well could not be bullheaded. The circulation and release of packer before killing the well gave an extra 4 hours buildup.

Figure 6 shows plot of rates and wellhead pressure during the last 6 hours of the major flow period. The well exhibited a slightly better stability on this test than on DST - 1.

See data form 5 for more details.

### Analysis of bottom hole data

DST - 1

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The Sperry Sun gauges 0184 and 0253 (2 min and 4 min sampling interval) worked perfectly throughout the whole test. The two other gauges which had 34 hours delay gave also reasonable readings, but gauge 0149 seems to suffer from a time error at least through the final buildup.

Data from gauges 0184 and 0253 have been used in the analysis.

Buildup data from gauges 0149 and 0161 are plotted in Figure 11 for completeness.

Figure 7 shows the pressure and temperature recorded by gauge 0184 during the entire test and Figure 8 details the same data for the main flow period.

### Buildup analysis

The buildup data is analyzed by a conventional Horner plot giving bulk permeability, static pressure and skin factors. Figures 9 and 10 shows the plot of buildup data for the two gauges used in the calculations.

The Horner time has been calculated by dividing the cumulative production by the last rate. The cumulative production includes an estimate of the gas produced directly to flare during well cleanup and stabilization. Buildup time has been calculated from the time of shut-in on the LPR valve.

The middle time region straight line extends from approximately 2 hours after shut in up to the end of the test. As can be seen from the plots the line is easy to define and the interpretation should be unquestionable. Table III gives the main results from the buildup analysis.

Table III

Gauge	Depth (m RKB)	P* (Psig)	MTR-Slope (Psi/Cycle)	Permeability (md)
0184	2579.8	4257.9	53.9	37.0
0253	2577.2	4254.1	53.3	37.4
Average	2594.0	4262.9	53.6	37.2

2594

The average data (P\*) are adjusted to mid perforation depth using a gas gradient of 0.137 psi/ft (correlated from wellstream properties).

Both gauges were reading approximately 16 psi lower than P\* on the initial buildup. An explanation for this is given in Appendix III.

Data form 14 gives the details on buildup analysis. Average data are used where absolute values are required, otherwise the data from gauge 0184 are used.

Analysis of the early time pressure data indicates that afterflow is negligible. Inflow rate during the first 2 minutes of shutin is approximately 1% of the final flowrate.

Calculations of afterflow and other data pertinent to the buildup analysis are shown in Appendix II.

### Skin and Turbulence

As shown by Figure 8 the well continuously cleaned up during the main flow period causing the flowing bottom hole pressure to stay constant or increase rather than decrease. The theoretical bottom hole pressure, calculated from the permeability determined from the buildup analysis, is also plotted in this figure. The difference between these two curves constitutes the pressure drop due to skin and turbulence.

This pressure drop consists of two parts, the wellbore damage skin and the turbulence effect. Since the whole zone is perforated, partial penetration skin is neglected. The wellbore damage skin which results from invasion by mud, cement, filtrates and perforating debris is assumed to be the only varying part of the total (or apparent) skin, and that it will approach zero as the well cleans up completely.

Figure 17 is a plot of the total skin pressure drop versus inverse time. The plot yields a reasonably straight line which when extrapolated to infinite time gives a skin pressure drop of 338 psi. At this point, the well should be clean, and the skin pressure drop should be due to turbulence effects only. This data point has been used to calculate a turbulence term coefficient and construct a theoretical backpressure test plot.

The plot with pertinent data are shown in Figure 19. The absolute open flow potential is estimated at 34 Million SCF/Day. Details on turbulence calculations are given in Appendix IV.

DST - 2  
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Again the two pressure gauges with 17 hours delay, gauges 0184 and 0190, gave good results. The two other gauges, which were given 34 hours delay, seem to have time errors at least through the final buildup.

Data from gauges 0184 and 0190 have been used in the analysis.

Buildup data from gauges 0161 and 0246 are plotted in Figure 16 for completeness.

Figure 12 shows the pressure and temperature recorded by gauge 0184 during the entire test, and Figure 13 details the same data for the main flow period.

#### Buildup analysis.

Figure 14 and 15 shows the plot of buildup data for the two gauges used in the analysis.

Horner time has been calculated the same way as for DST No. 1. The middle time region extends from approximately 1 hour after shutin up to the end of the test. Table IV gives the main results from the buildup analysis.

Table IV.

Gauge	Depth (m RKB)	P* (Psig)	MTR-Slope (Psi/Cycle)	Permeability (md)
0184	2509.8	4221.9	10.8	144
0190	2504.7	4218.4	11.4	146
Average	2530.0	4231.3	11.1	145

The average data (P\*) are adjusted to mid perforation depth using a gas gradient of 0.137 psi/ft (correlated from wellstream properties).

Both gauges were reading approximately 16 psi lower than P\* on the initial buildup. An explanation for this is given in Appendix III.

Data form 14 gives the details on buildup analysis. Average data are used where absolute values are required, otherwise the data from gauge 0184 are used.

Analysis of the early time pressure data indicates that afterflow is negligible. Inflow rate during the first 2 minutes of shutin is approximately 1% of the final flowrate.

Calculations of afterflow and other pertinent to the buildup analysis are shown in Appendix II.

### Skin and Turbulence

Figure 18 shows the apparent skin pressure drop versus inverse time for the last seven hours of the final flow. The straight line correlation is not very good for this test except for the last two hours. Extrapolation may therefore be questionable. Assuming complete cleanup at infinite time the extrapolation gives a turbulence pressure drop of 61 psi (partial penetration skin can be neglected). This data point has been used to construct the theoretical backpressure plot shown in Figure 20.

The D-factors (turbulence coefficient) calculated from welltest data and from reservoir properties may look significantly different (0.43 - 1.2 for DST No. 1 and 0.33 - 0.17 for DST no. 2). But bearing in mind that this factor (proportional to D) may vary by a factor of 10 to 20 in the same reservoir due to relatively small variations in porosity and liquid saturations, the comparisons are fairly reasonable.

Details on calculations are given in appendix IV.

### Gas Compositions

The composition of the separator gas was measured by the mudlogger every half hour from the time when the separator was stabilized.

The analysis includes hydrocarbons, CO<sub>2</sub> and H<sub>2</sub>S.

### CO<sub>2</sub> (A.D.C. Type ss1 CARbon Dioxide Analyser)

The mud logger measured CO<sub>2</sub> content of the separator gas to 0.35% on DST No. 1 and 0.38% on DST No. 2. The measurements are by volume and were taken during the stabilized flow period. The Draeger tube sniffer gave readings between 0.2% and 0.5% at the wellhead during the same period.

H<sub>2</sub>S (General Monitors Model 2170 H<sub>2</sub>S Monitor)

The H<sub>2</sub>S measuring equipment used by the mud logger was of the same type that is used for detecting H<sub>2</sub>S in the mud during drilling operations.

Neither the mud logger nor the Draeger tube sniffer at the wellhead detected any H<sub>2</sub>S during the two tests.

Hydrocarbons

The hydrocarbon composition of the separator gas was very stable throughout the tests. Data form D-10 shows the composition in Volume percent recalculated from the chromatograph readings.

Fluid properties

The liquid gravity measured was 58° API on both tests, (temperature corrected) (793 kg/m<sup>3</sup>). The gas gravity measurement was 0.792 (0.969 kg/m<sup>3</sup>) on DST No. 1 and 0.80 (0.978 kg/m<sup>3</sup>) on DST No. 2. The difference may be due to slightly different separator conditions.

The gas gravity measurements compared favourably with the gravity calculated from the chromatograph compositions.

LK3/kmd

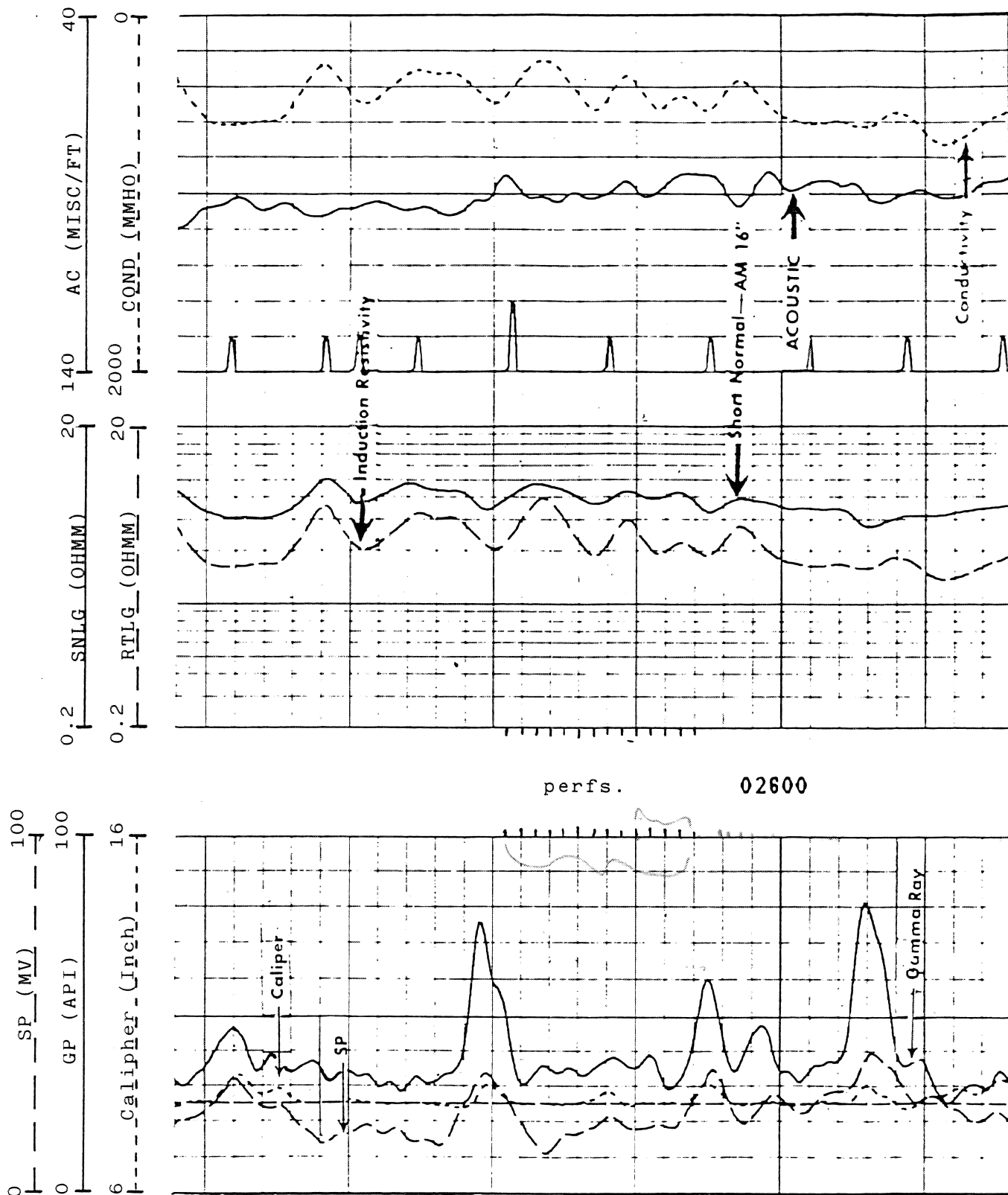


Figure 1: Open hole logs DST no 1

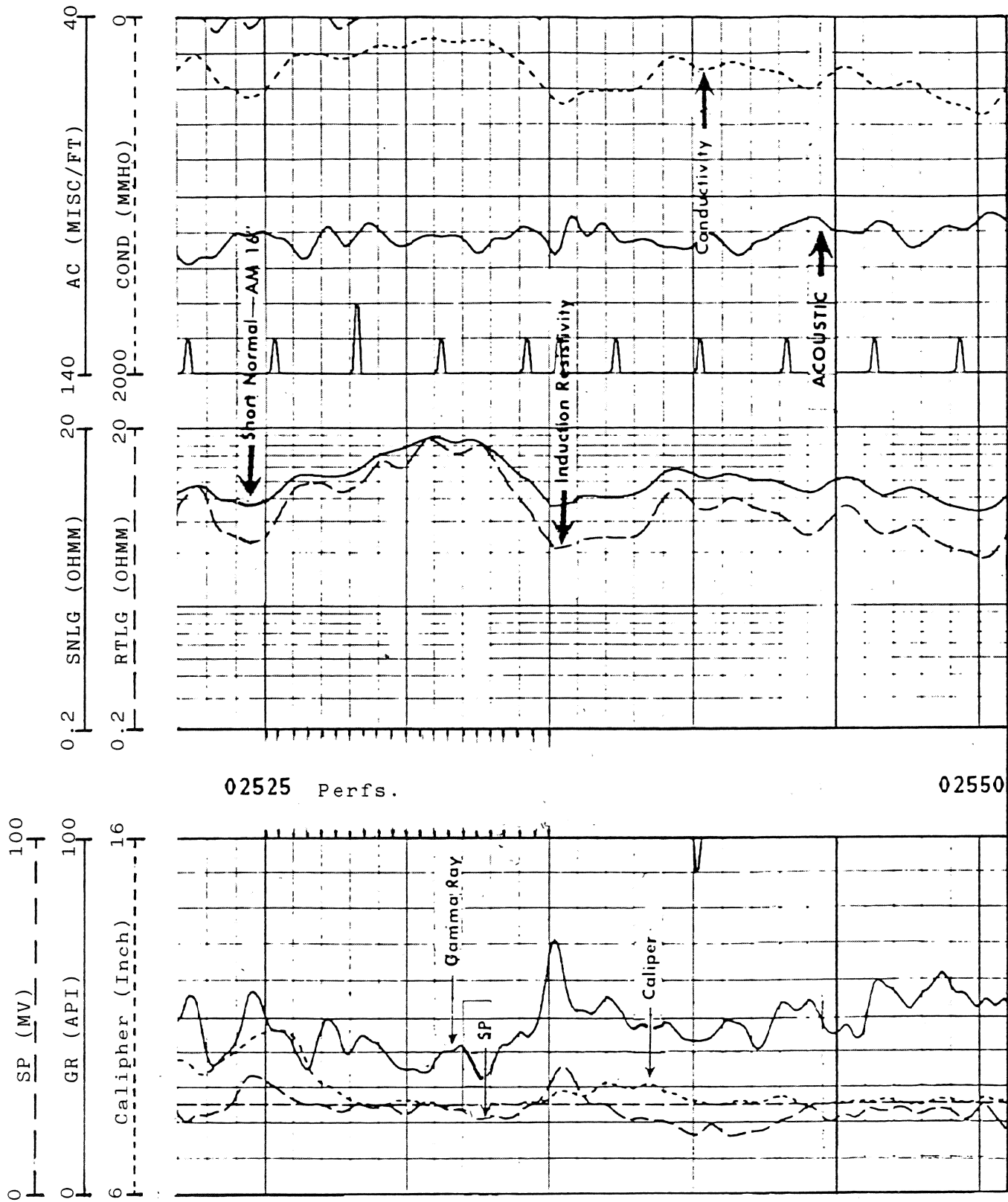
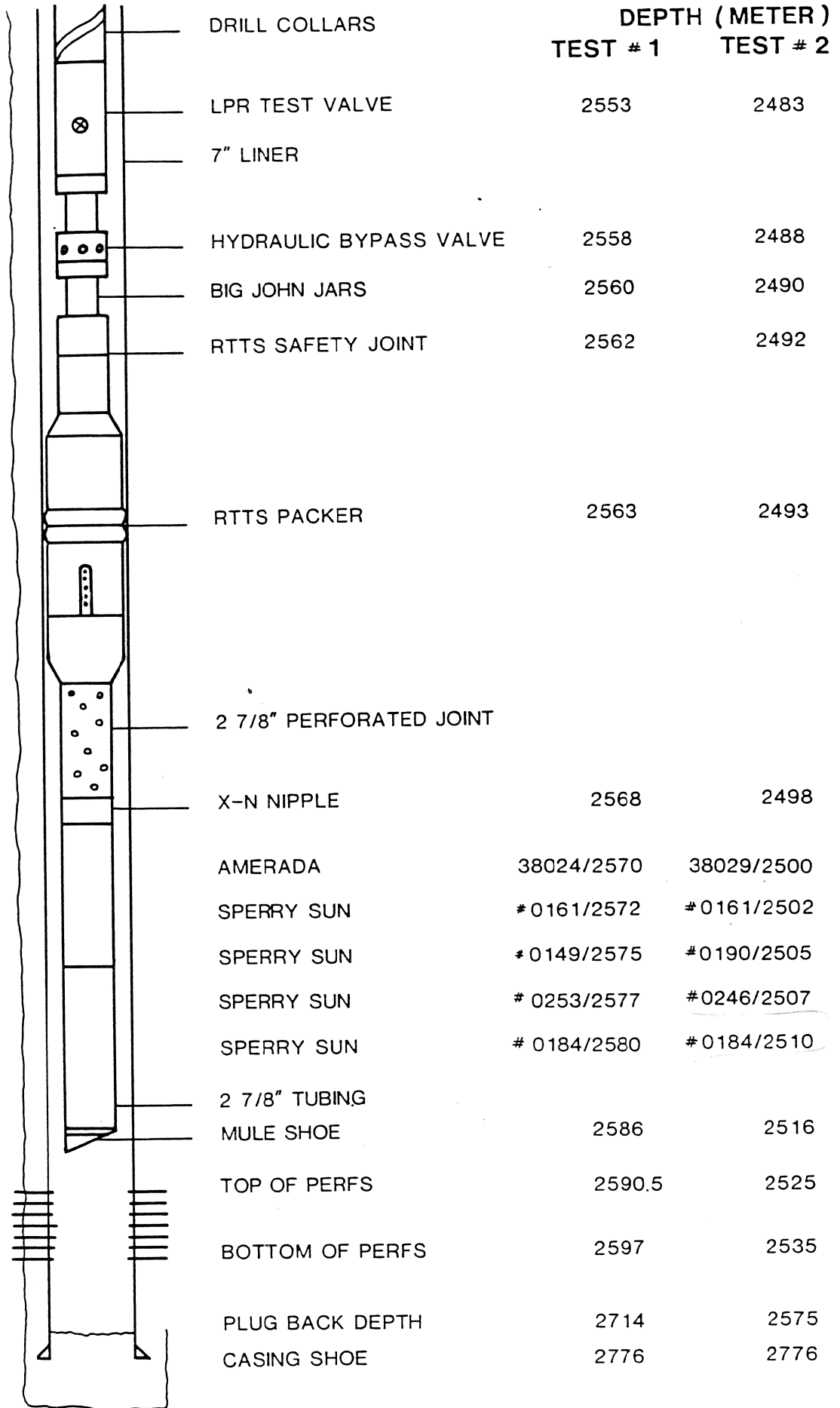


Figure 2: Open hole logs DST no 2

# FIGURE 3 BOTTOM HOLE TEST ASSEMBLY



**FIGURE 4 SURFACE TEST EQUIPMENT**

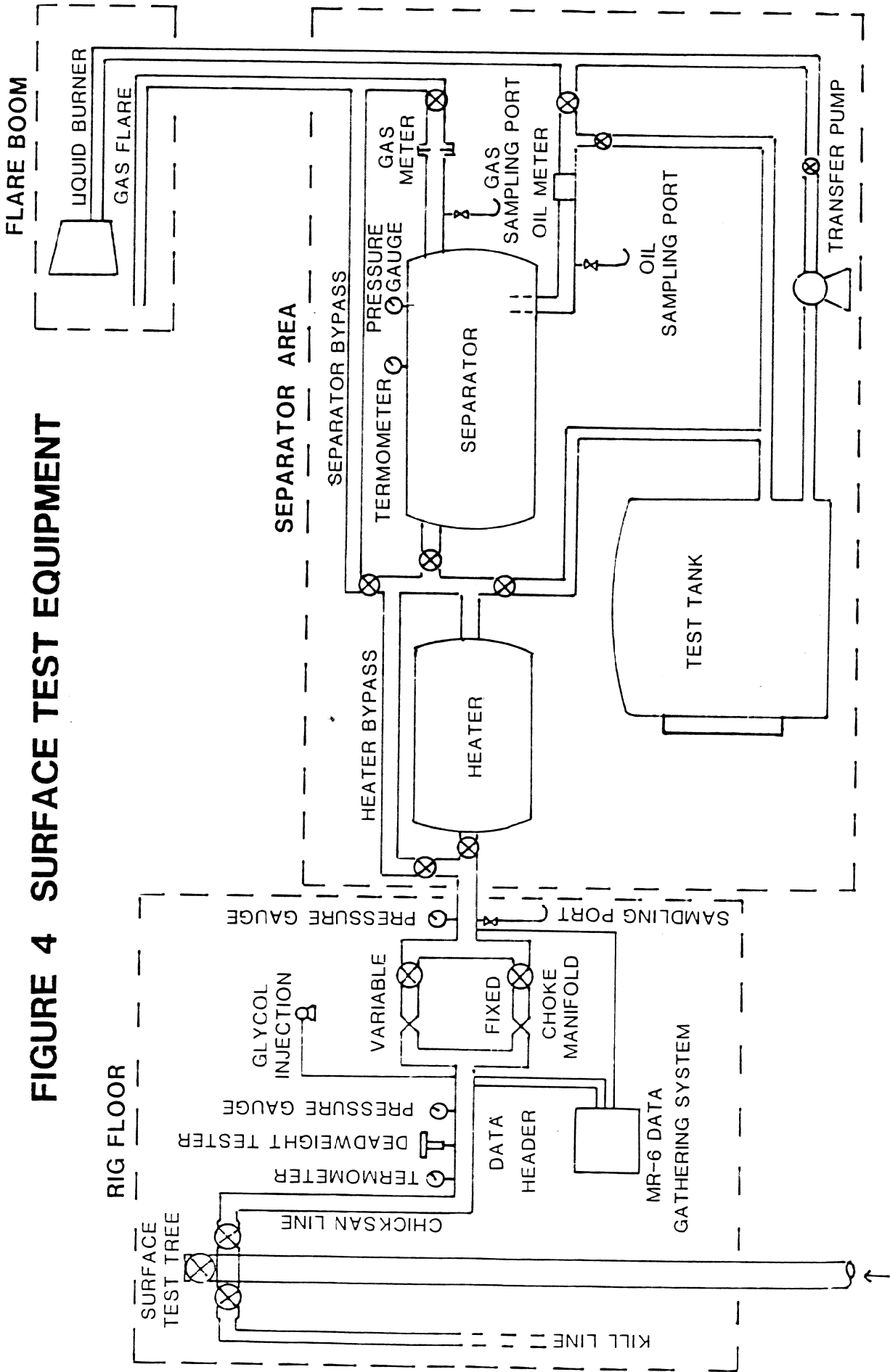


FIGURE 5  
RATES AND WHP VS. TIME - TEST #1

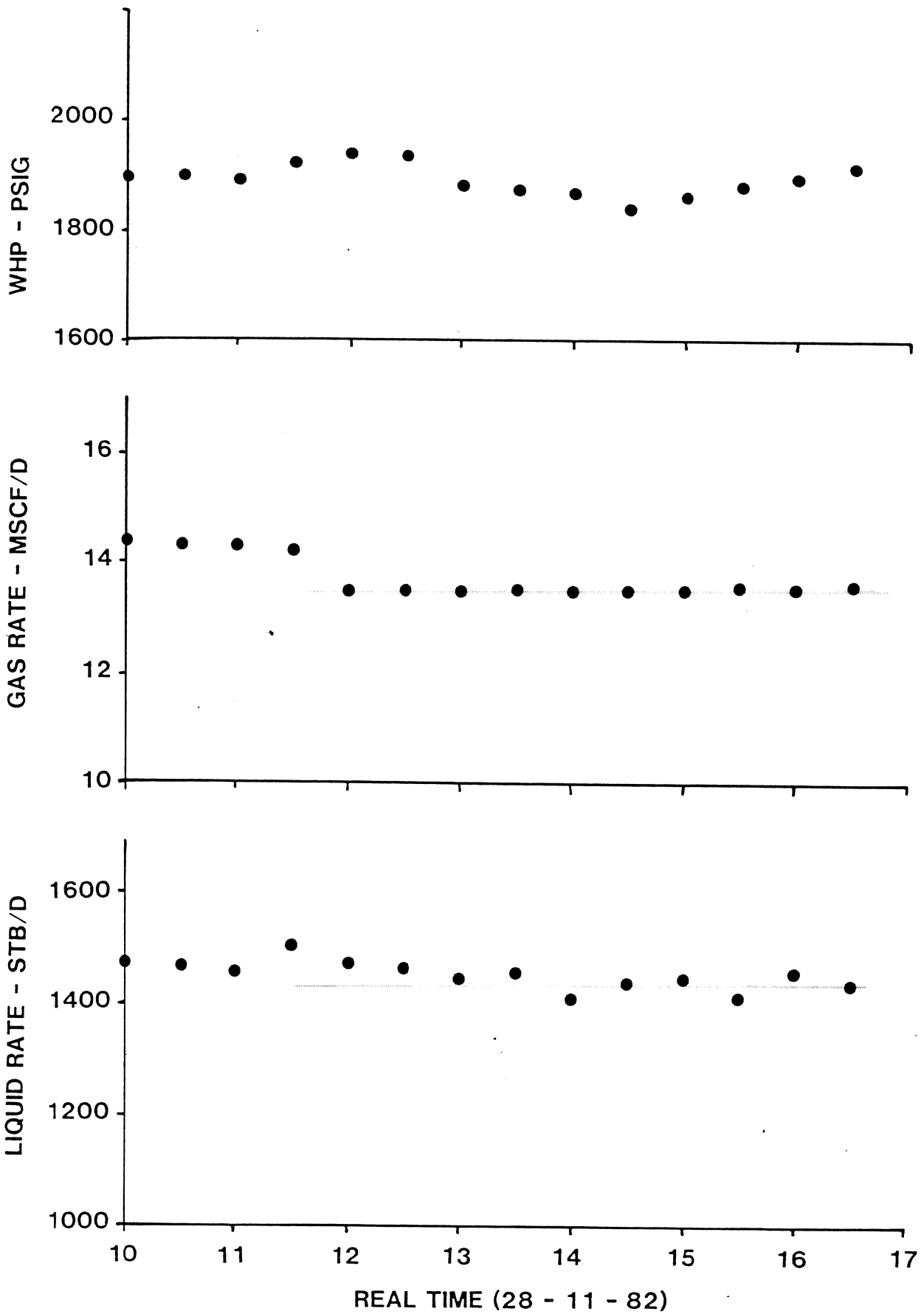


FIGURE 6  
 RATES AND WHP VS. TIME - TEST #2

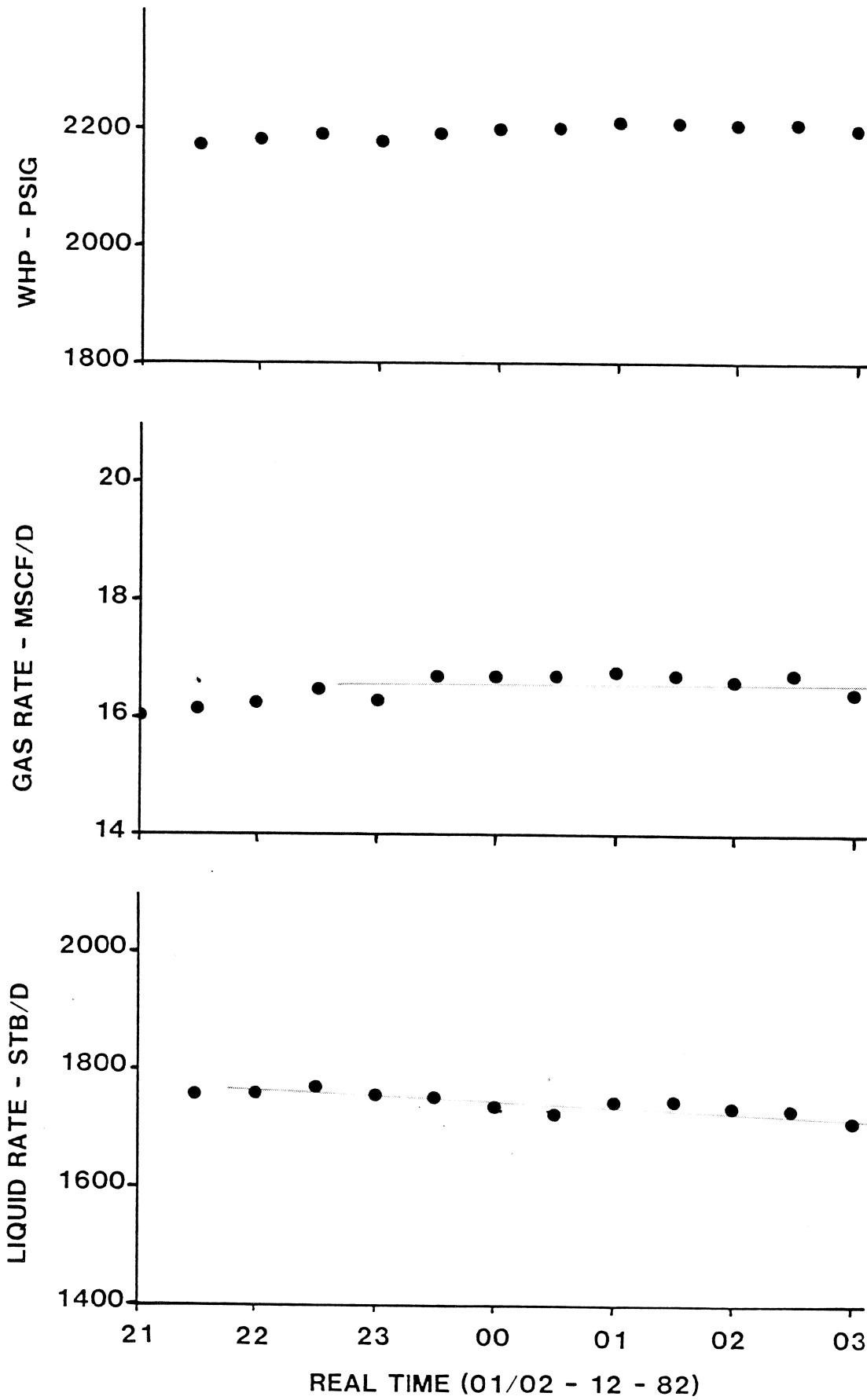
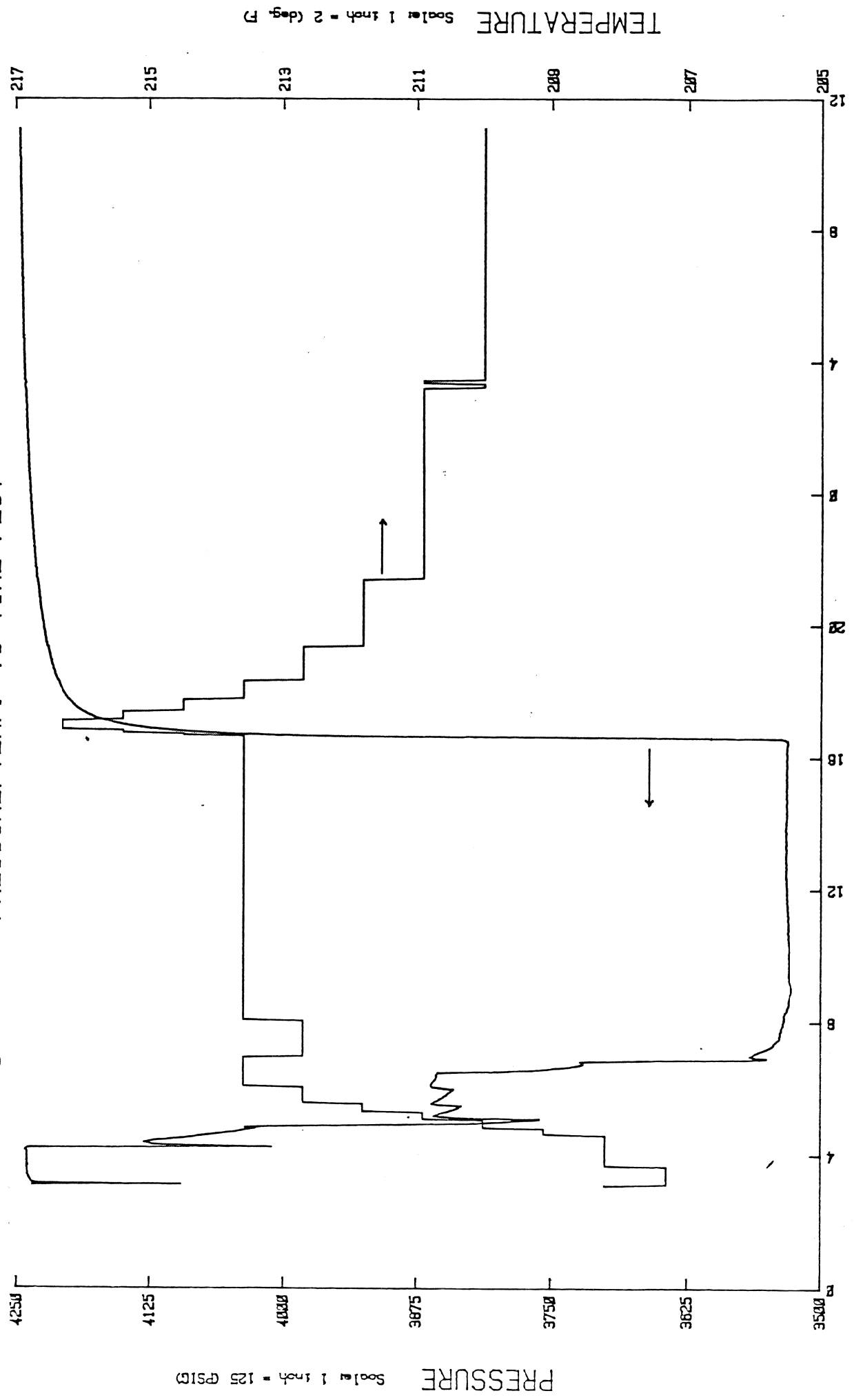


Figure 7 : PRESSURE/TEMP. Vs TIME PLOT DST no 1



28-11-82  
REAL TIME  
29-11-82  
Scale: 1 inch = 4 hours

PRESSURE Scale: 1 inch = 125 PSIG

TEMPERATURE Scale: 1 inch = 2 (deg F)

WELL 16/7-4 DST-1

FIGURE 08: FLOWING BOTTOM HOLE PRESSURE  
SPERRY SUN GAUGE MK-3/0184

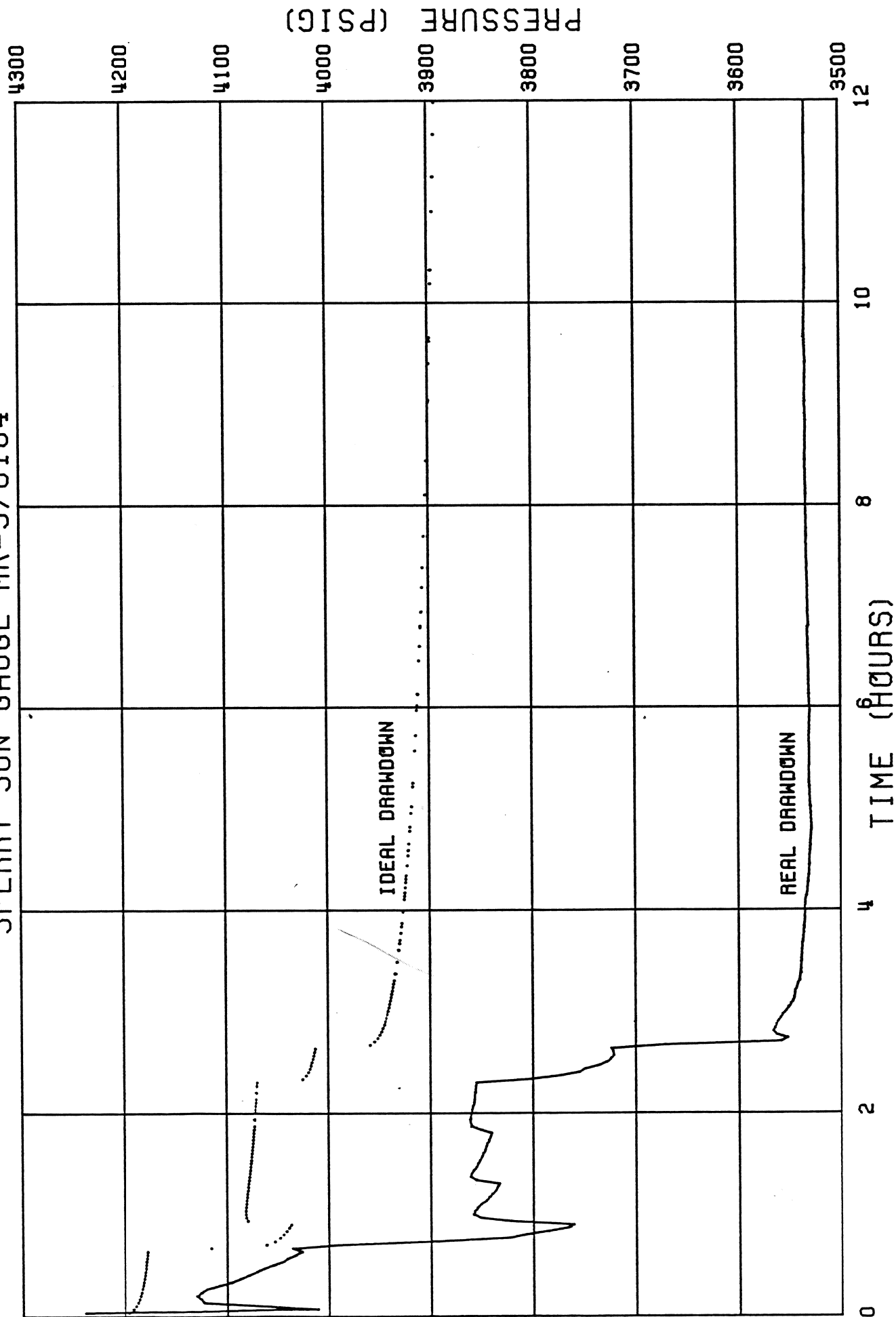


FIGURE 09: HORNER BUILDUP PLOT  
SPERRY SUN GAUGE MK-3/0184

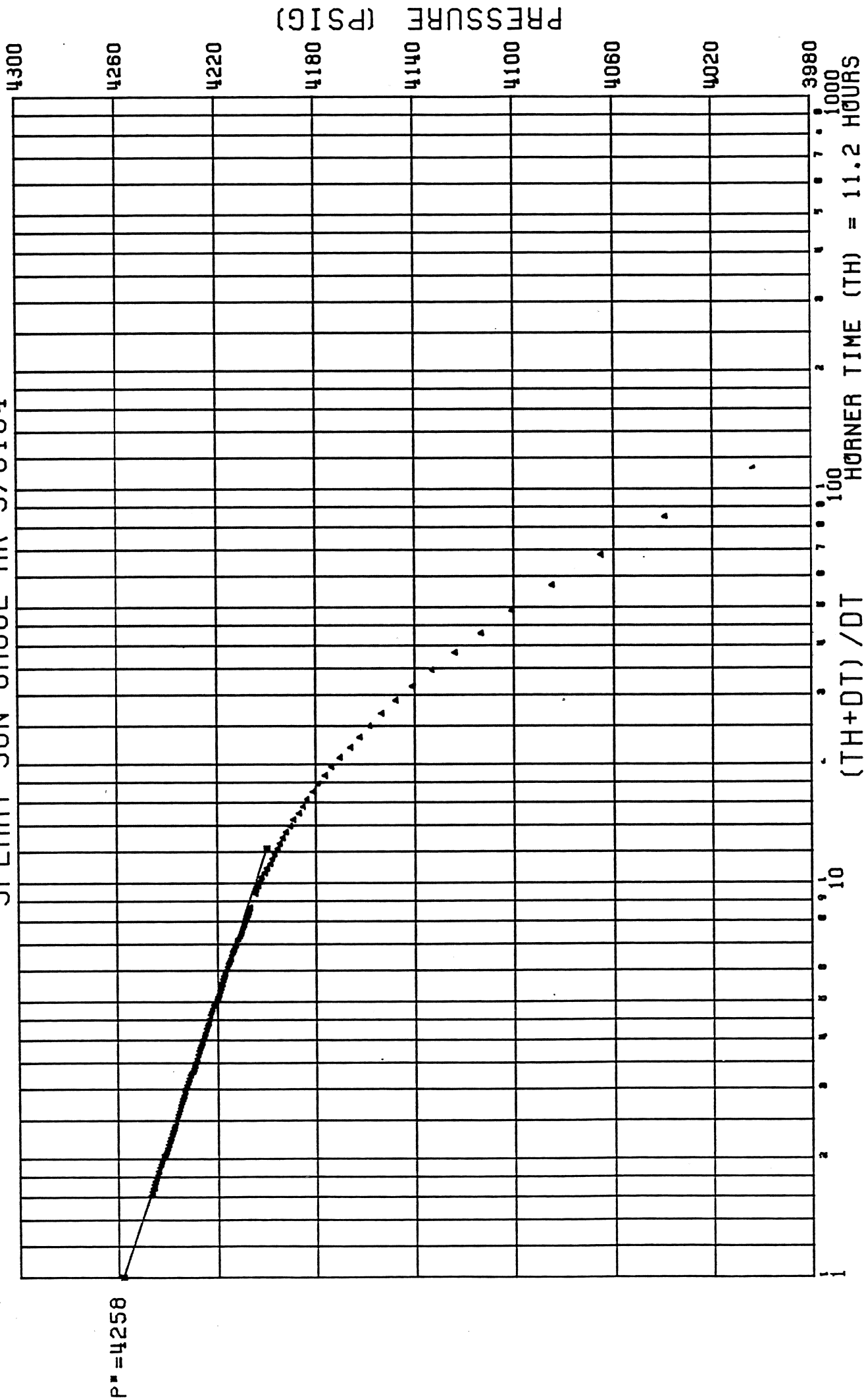


FIGURE 10: HORNER BUILDUP PLOT  
SPERRY SUN GAUGE MK-1/0253

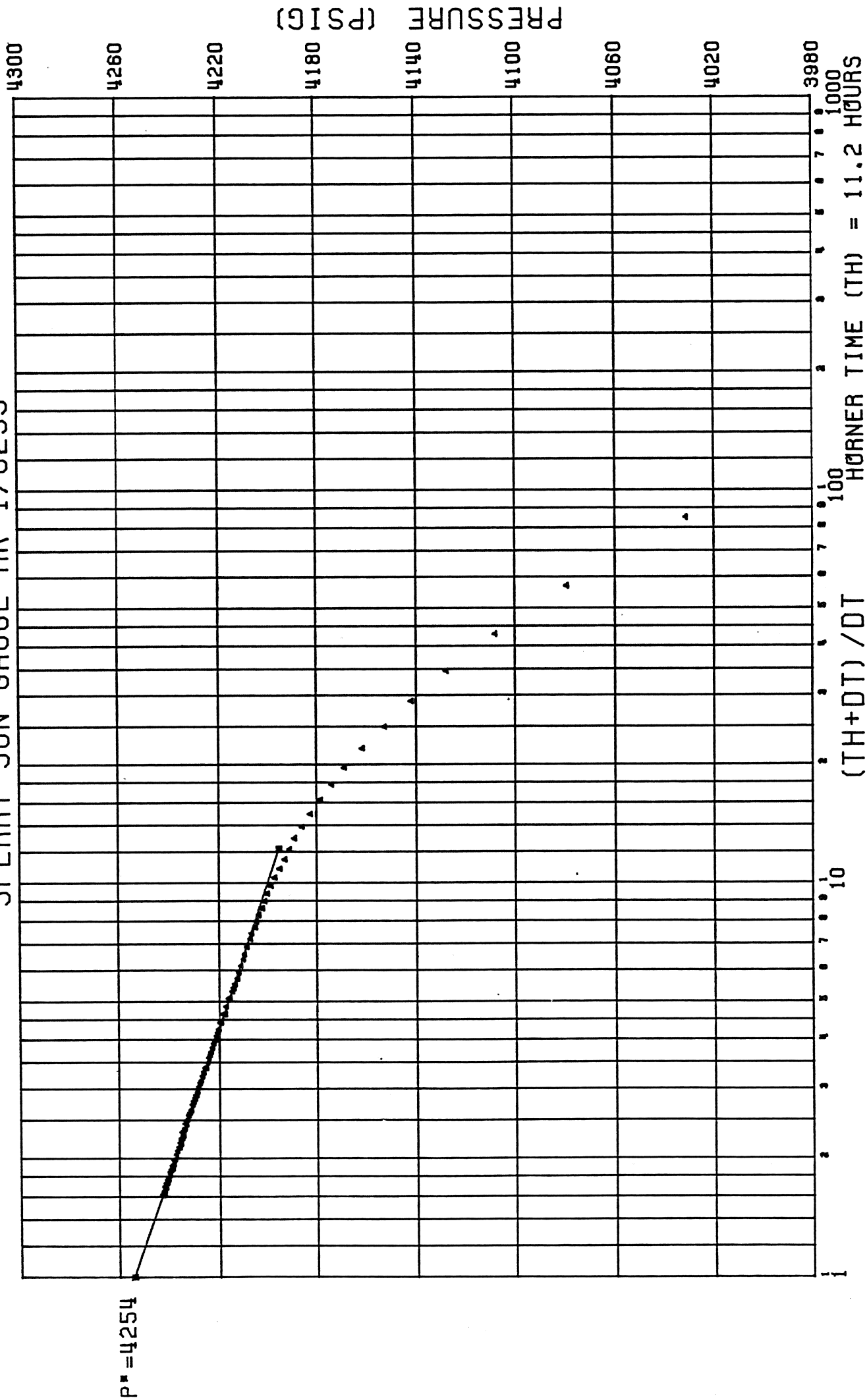
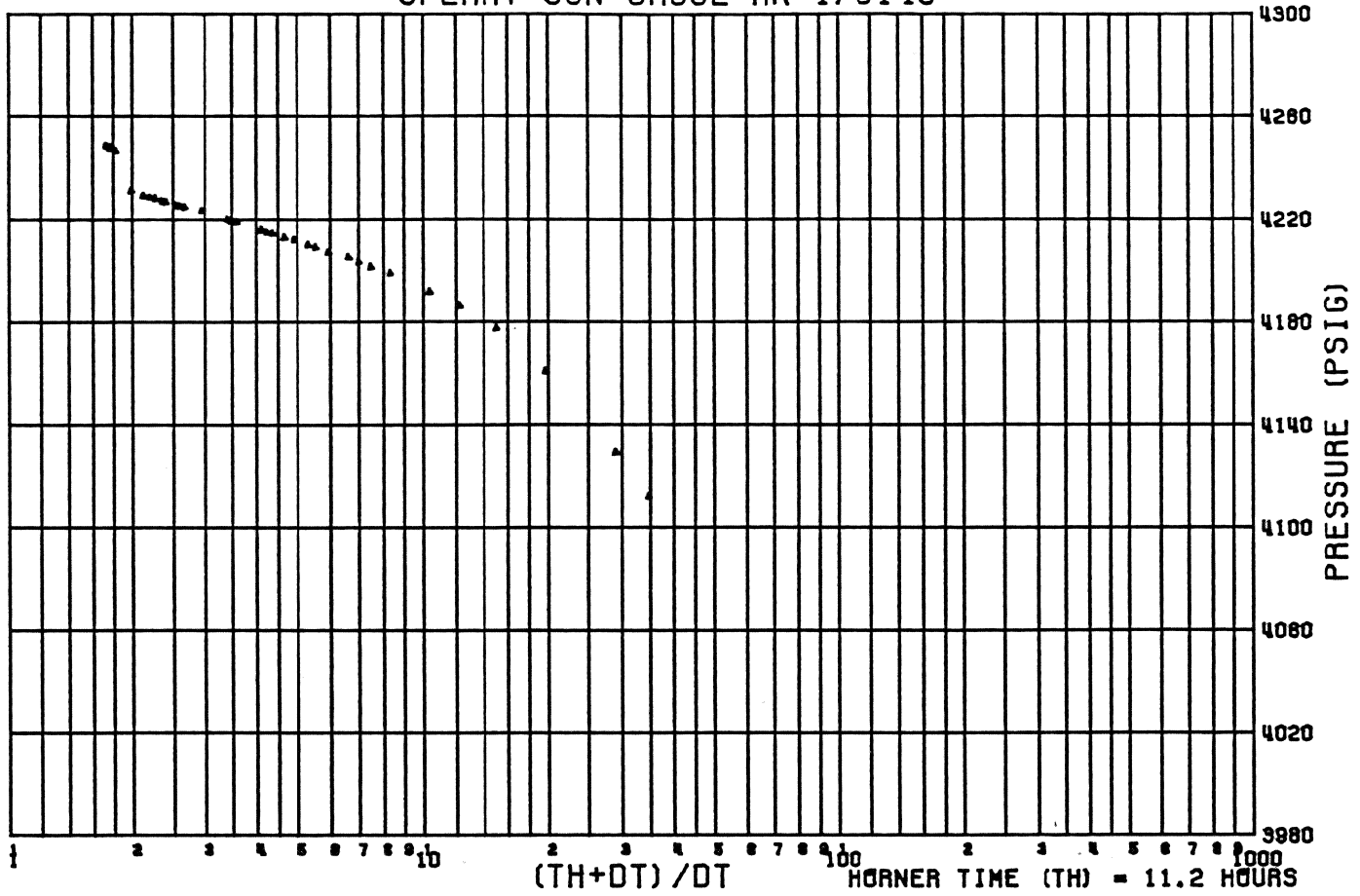


FIGURE 11: HORNER BUILDUP PLOT  
SPERRY SUN GAUGE MK-1/0149



HORNER BUILDUP PLOT  
SPERRY SUN GAUGE MK-1/0161

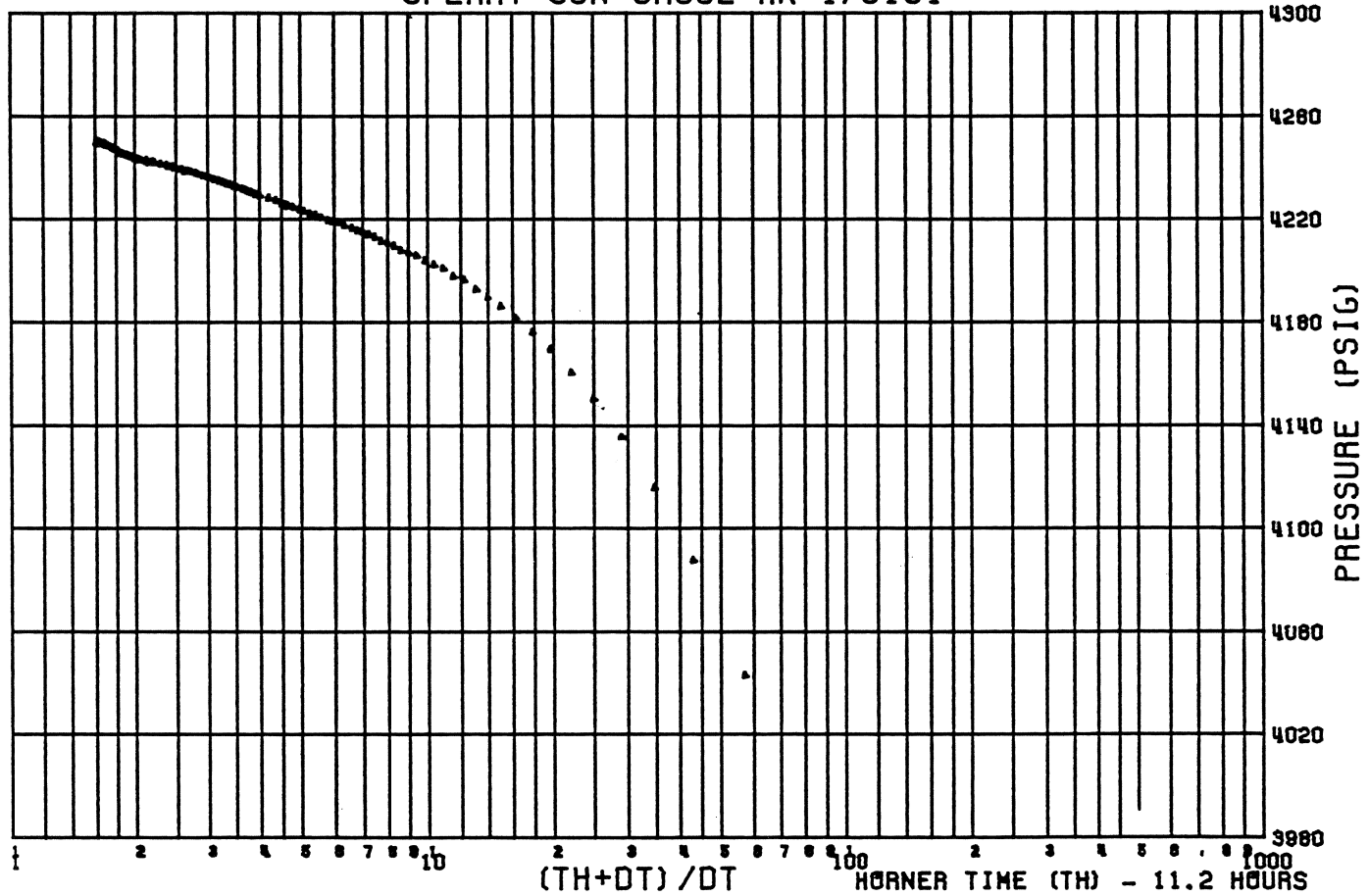
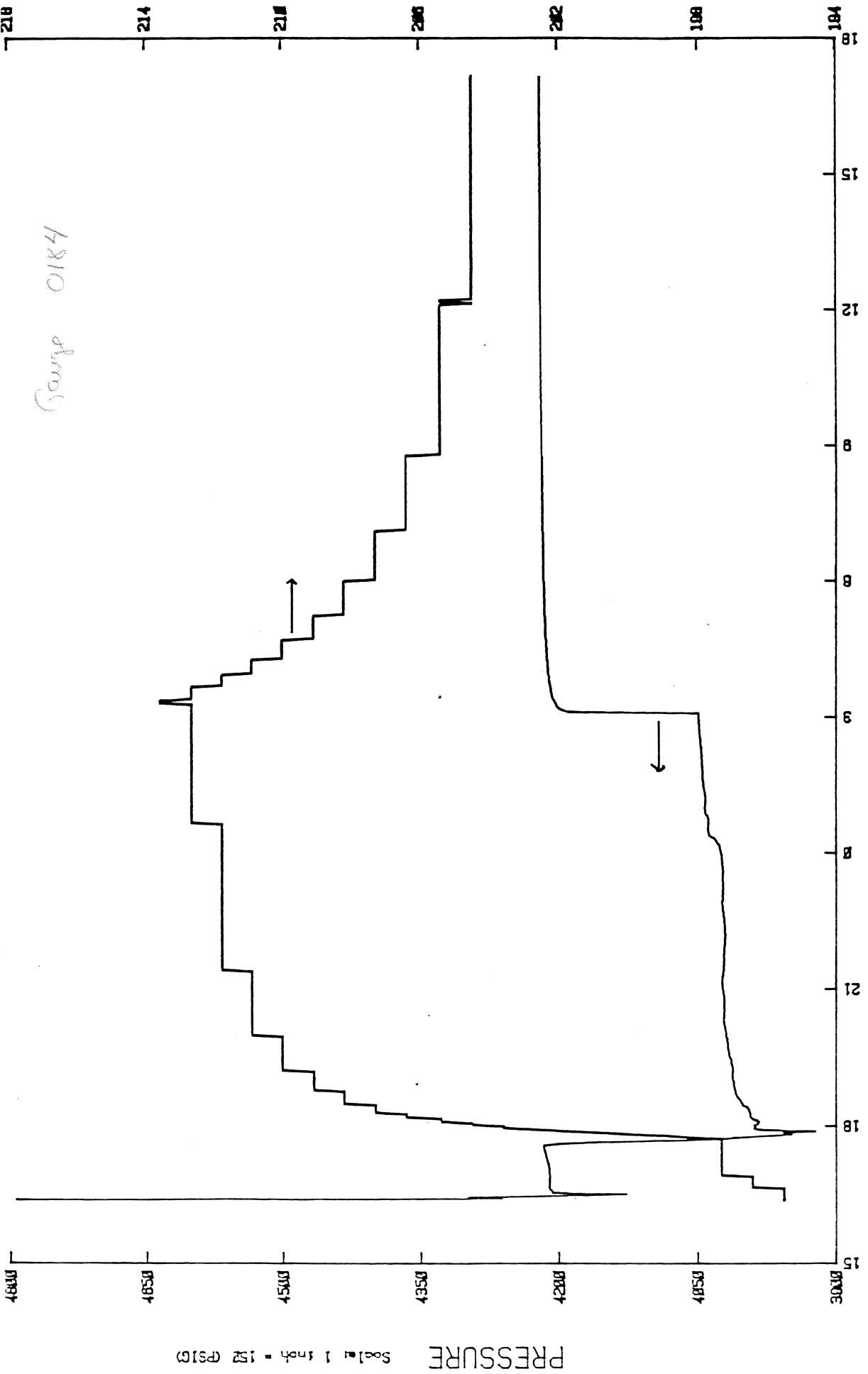


Figure 12 : PRESSURE/TEMP. Vs TIME PLOT

DST no 2

Gauge 0184



02-12-82

01-12-82

REAL TIME  
Scale 1 inch = 3 hours

WELL 16/7-4 DST-2

FIGURE 13: FLOWING BOTTOM HOLE PRESSURE  
SPERRY SUN GAUGE MK-3/0184

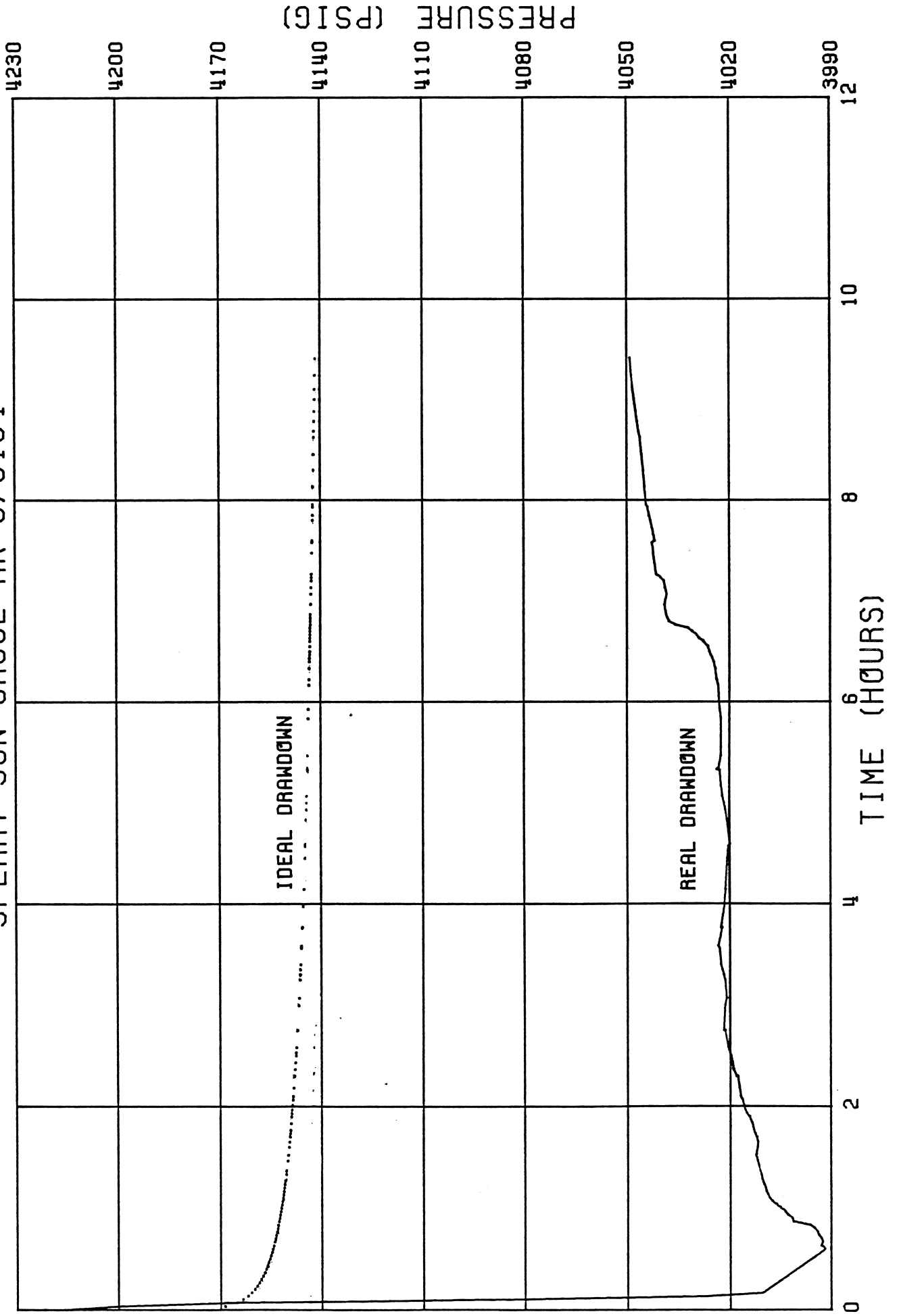


FIGURE 14: HORNER BUILDUP PLOT  
SPERRY SUN GAUGE MK-3/0184

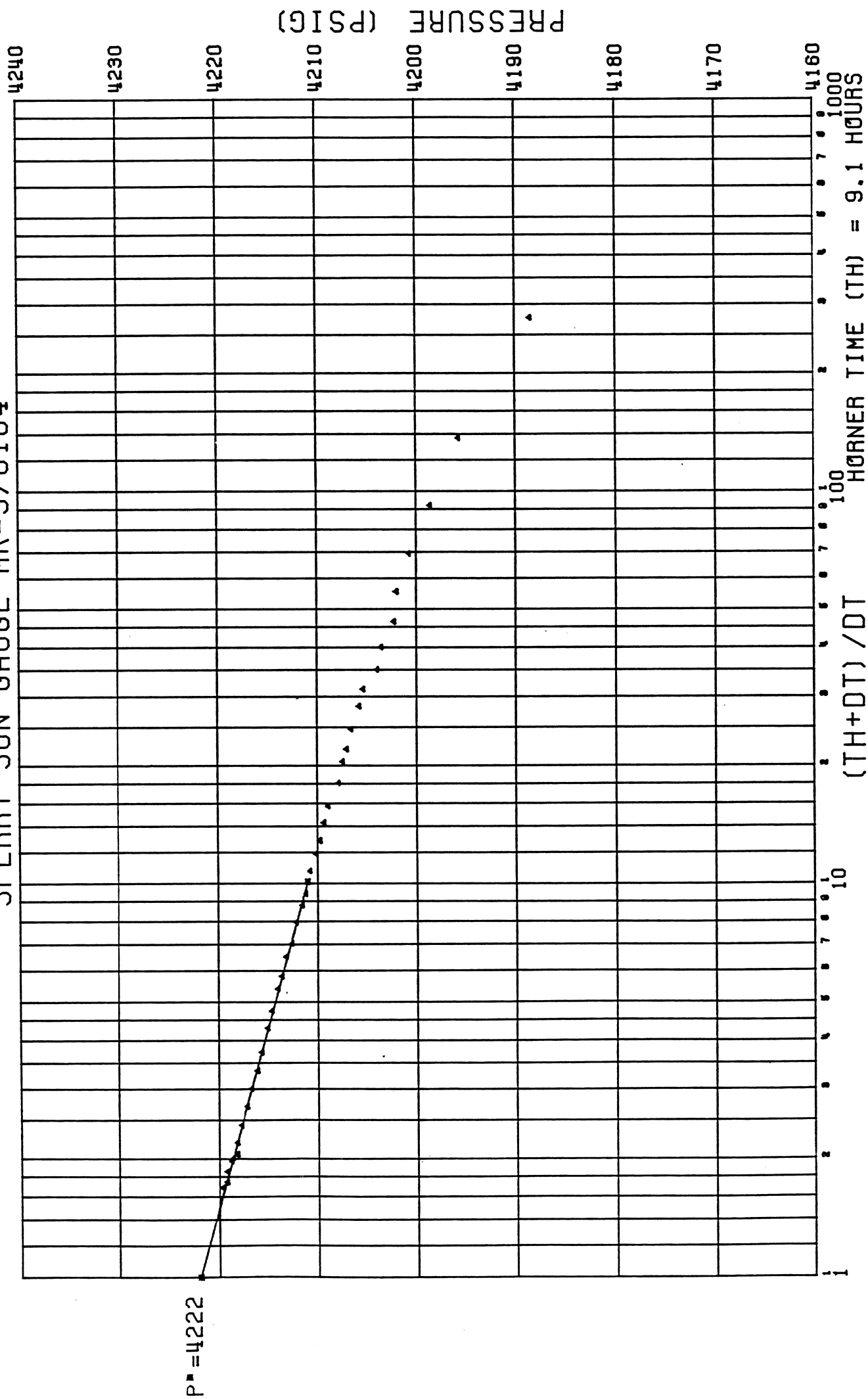


FIGURE 15: HØRNER BUILDUP PLOT  
SPERRY SUN GAUGE MK-1/0190

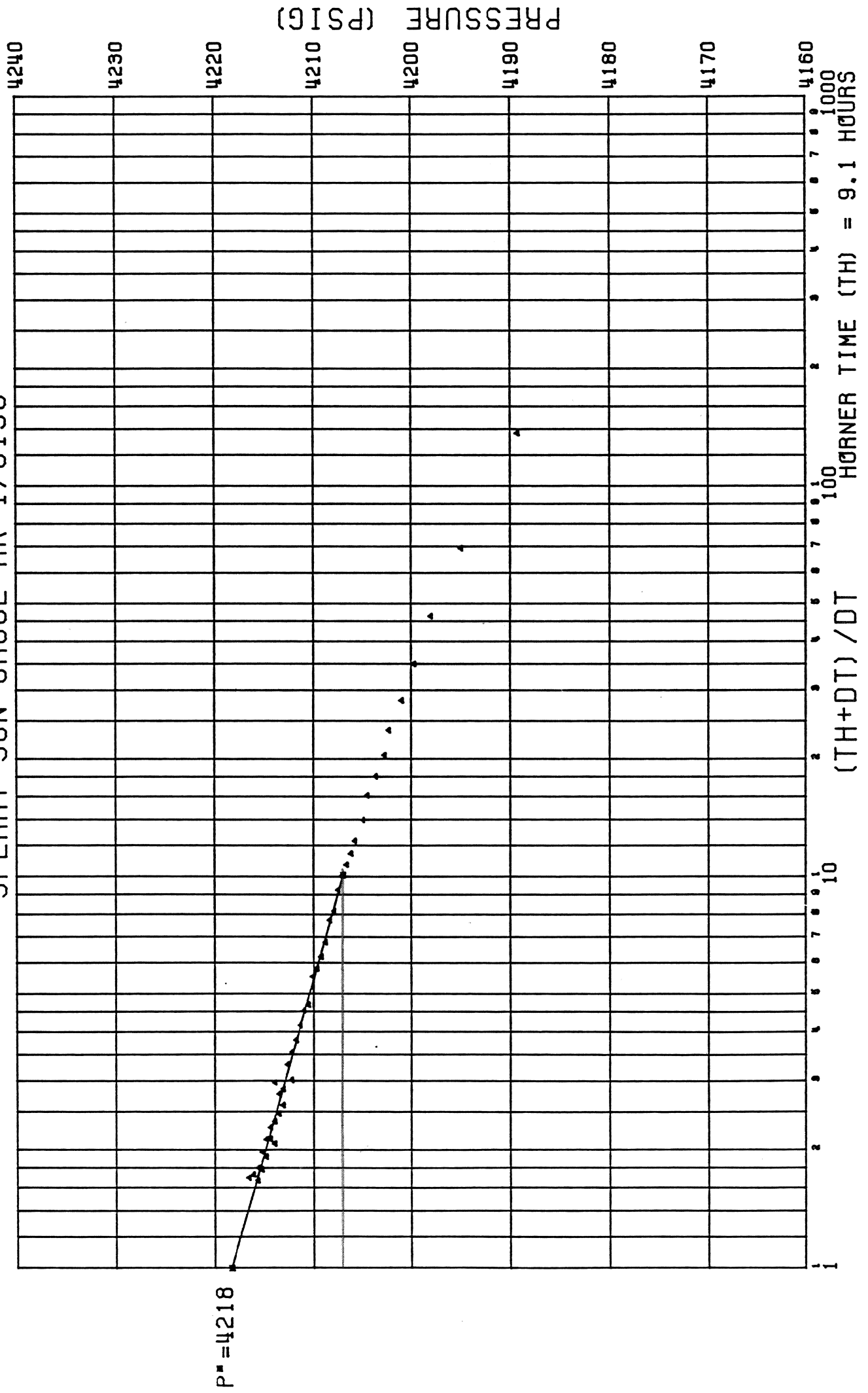
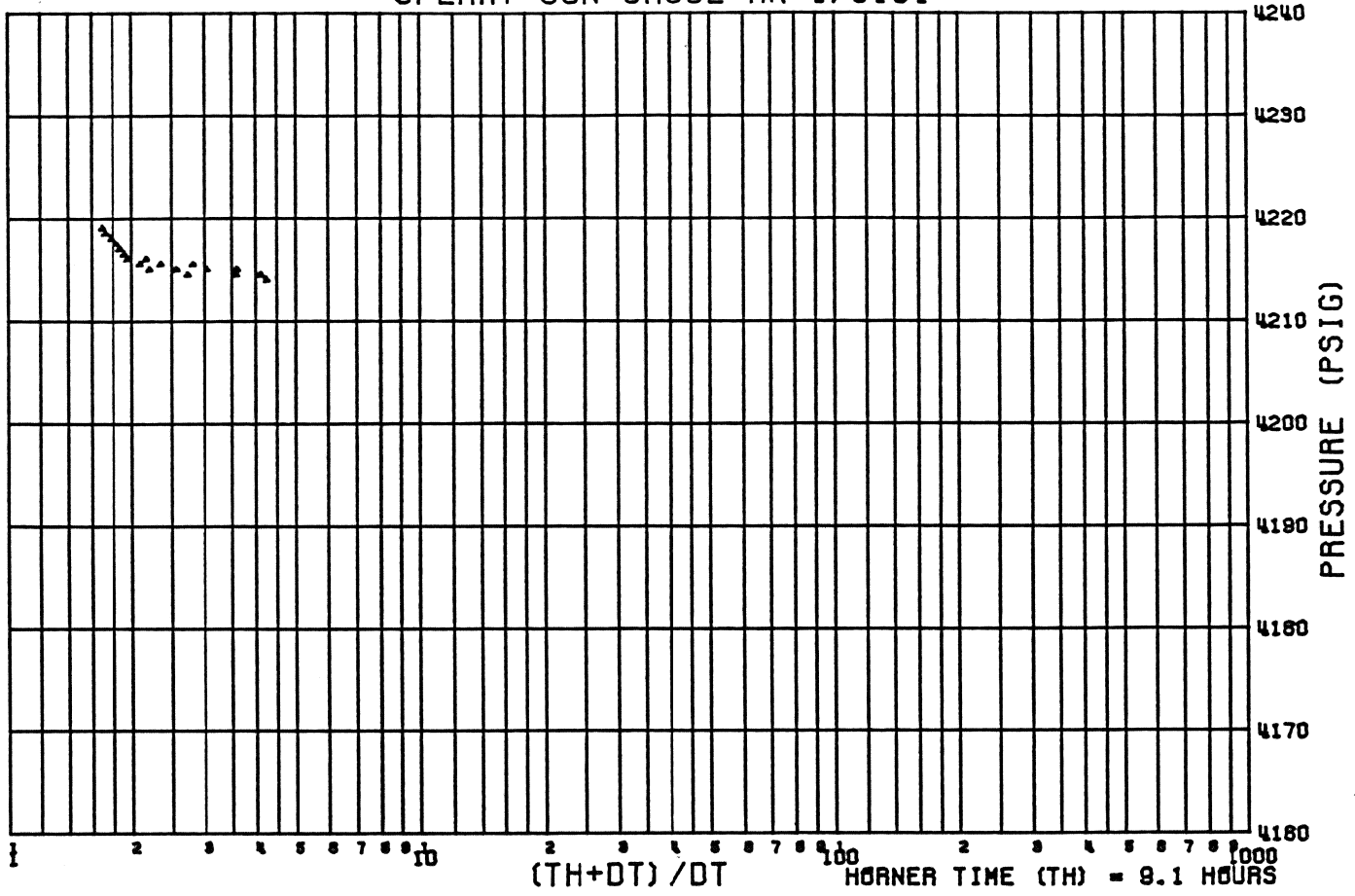


FIGURE 16: HORNER BUILDUP PLOT  
SPERRY SUN GAUGE MK-1/0161



HORNER BUILDUP PLOT  
SPERRY SUN GAUGE MK-1/0246

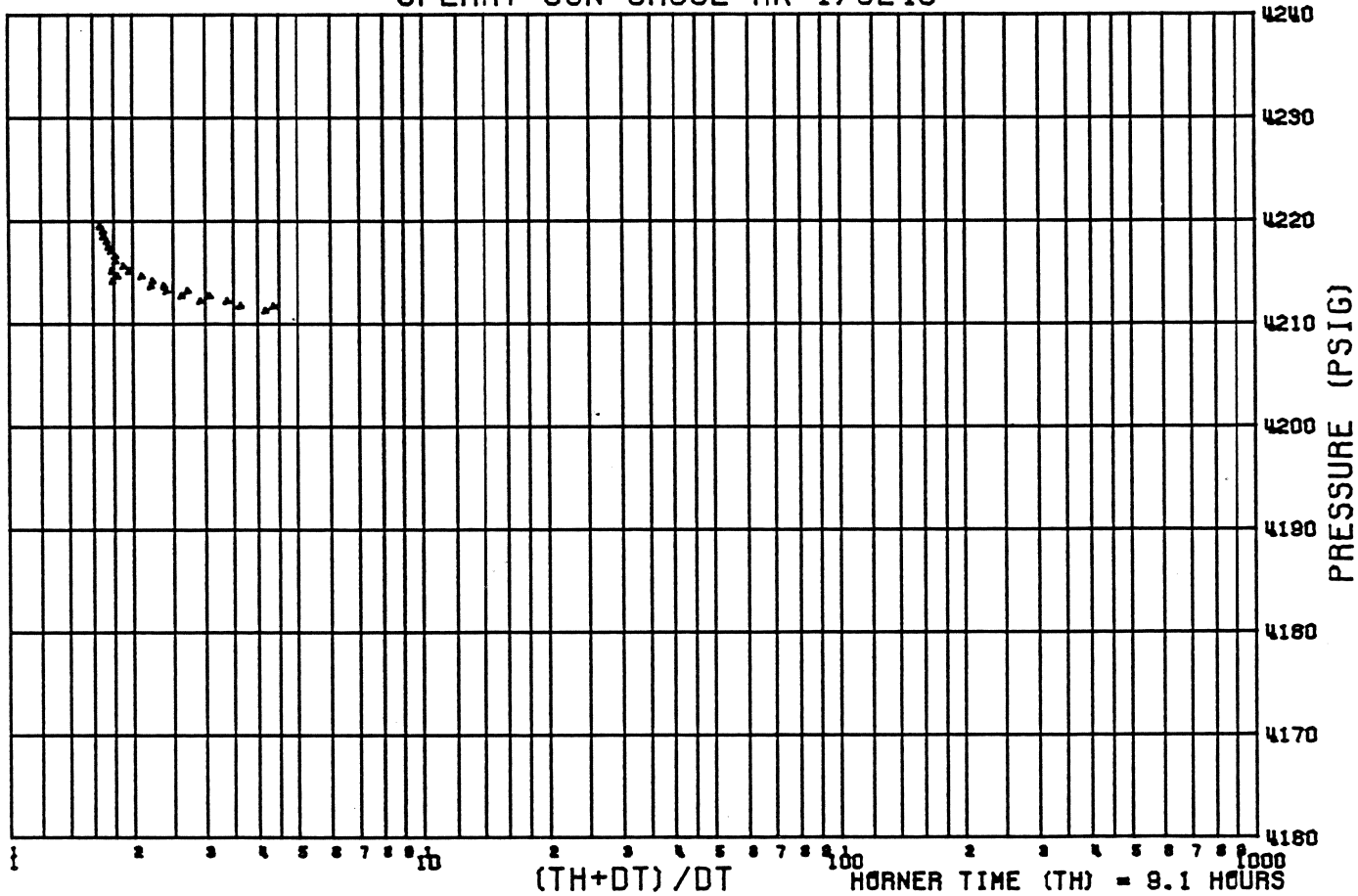


FIGURE 17: WELL CLEANUP ANALYSIS  
SPERRY SUN GAUGE MK-3/0184

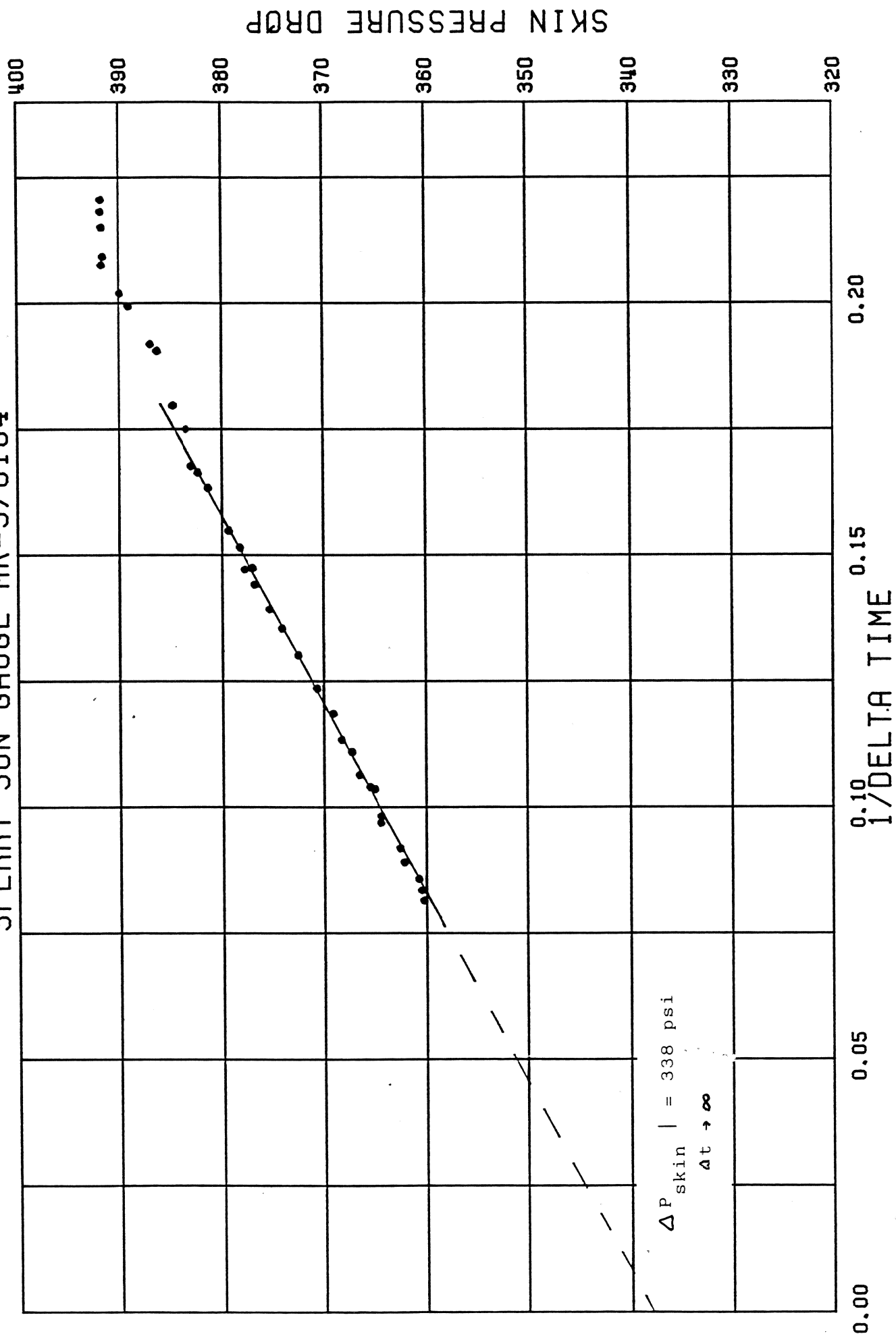


FIGURE 18: WELL CLEANUP ANALYSIS  
SPERRY SUN GAUGE MK-3/0184

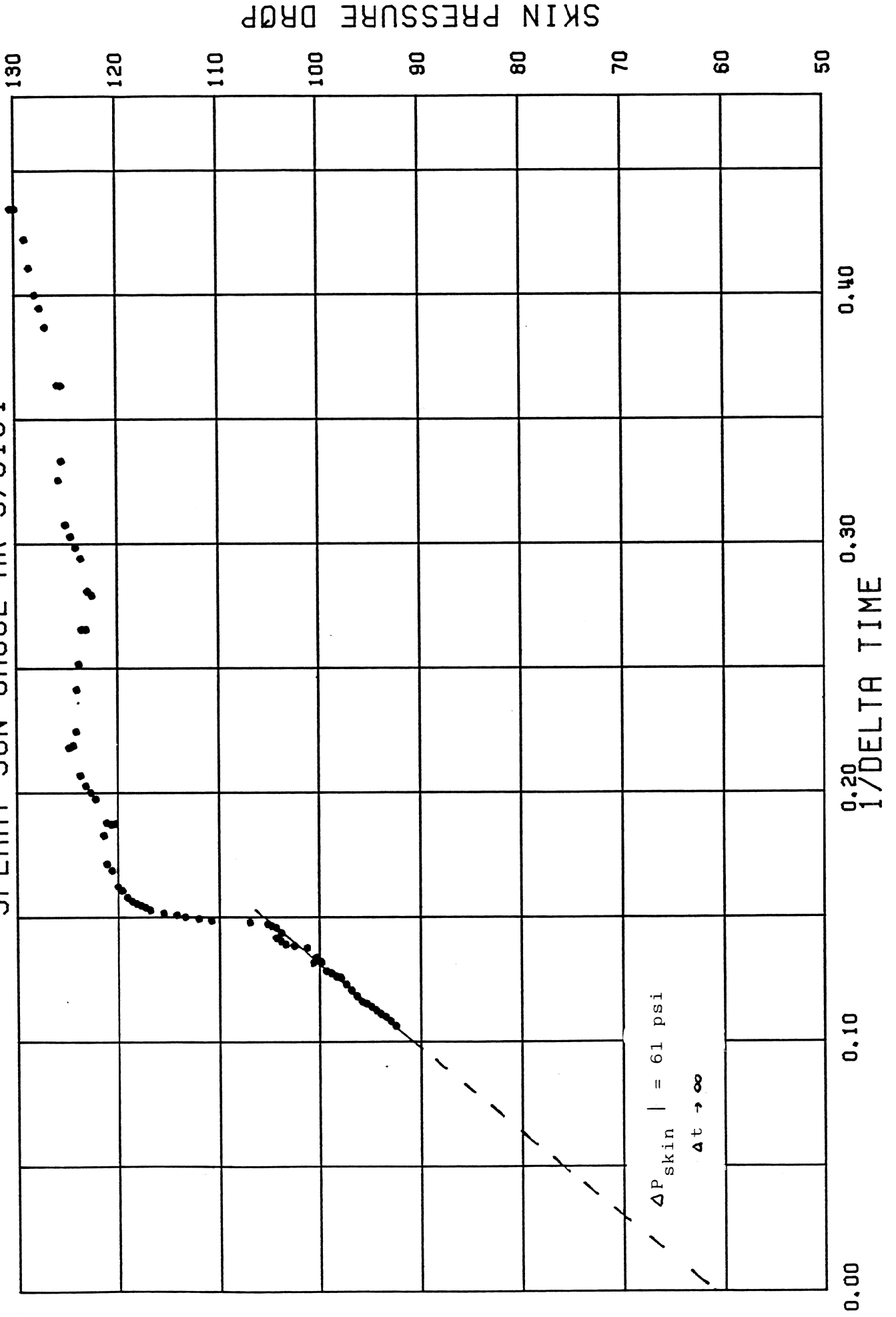


Figure 19: Theoretical Backpressure plot DST no 1

$$q = C (P_e^2 - P_{wf}^2)^n$$

AOF = 34 MSCF/D

C =  $61 \times 10^{-6}$

n = 0.791

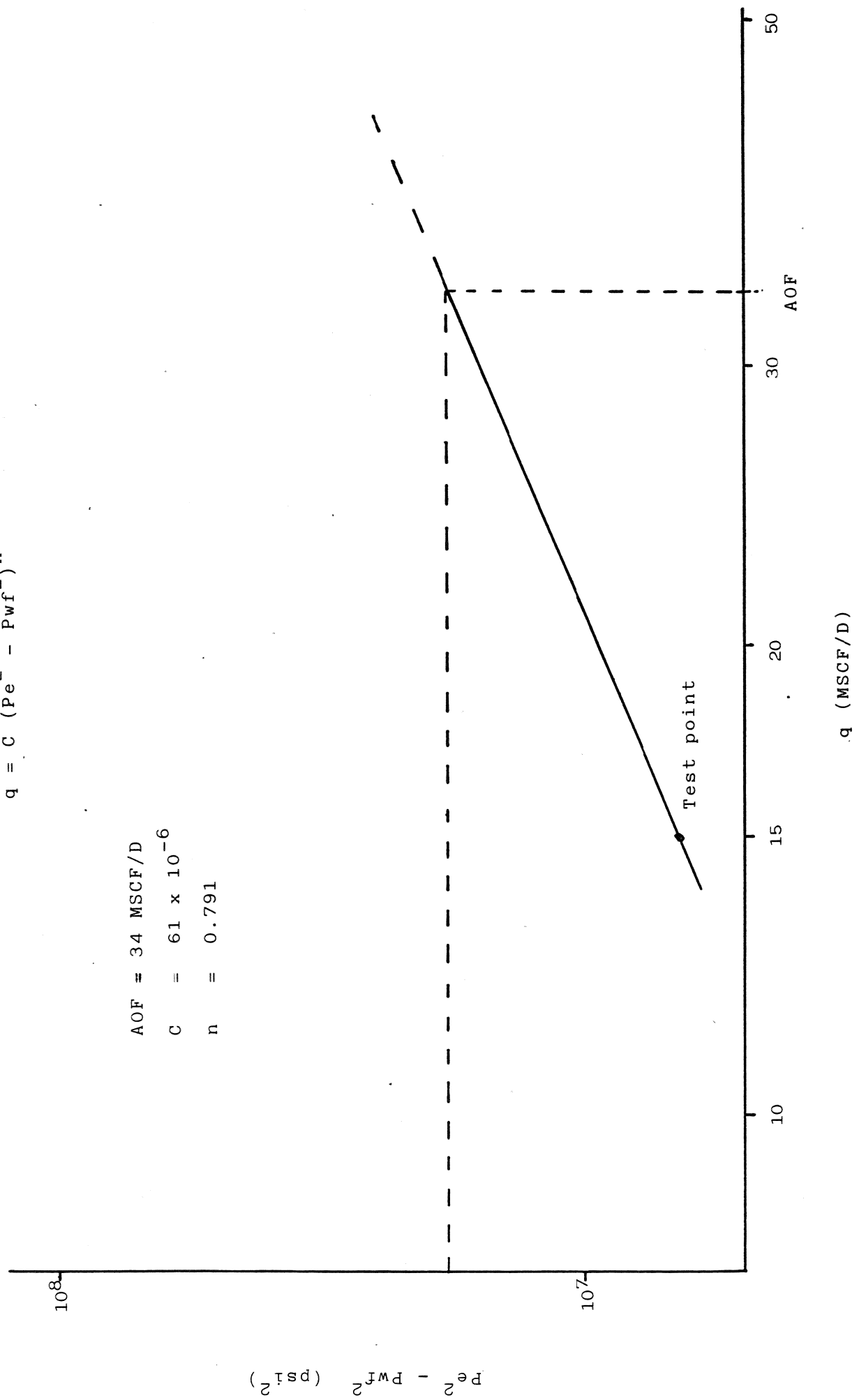
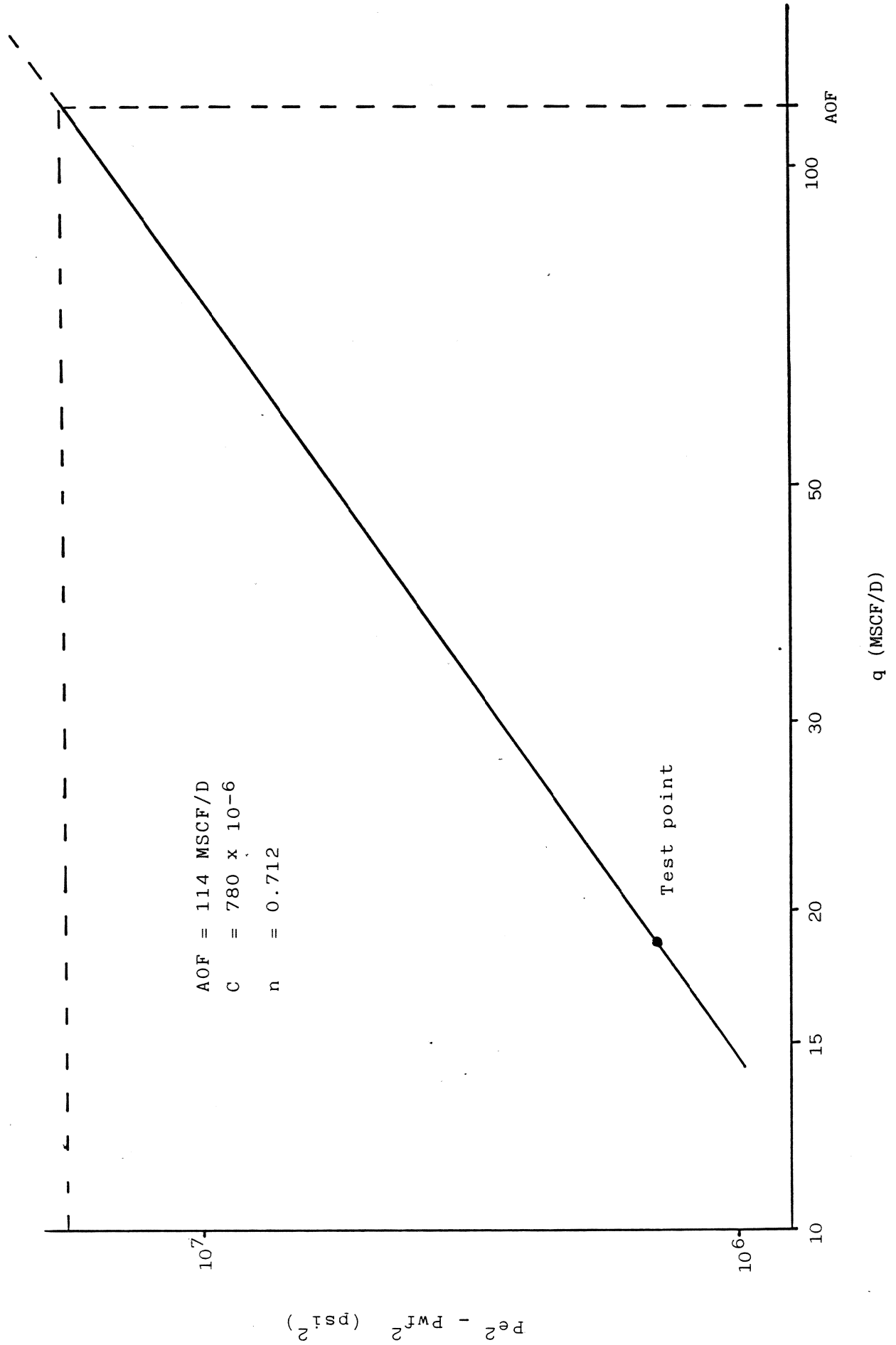


Figure 20: Theoretical Backpressure plot DST no 2



Appendix I

Test data forms



WIRELINE NIPPLE

GAUGE TYPE AND NUMBER: AMERADA RPG-3 38029  
DEPTH, PRESSURE ELEMENT: 2569.6 meter RANGE: 0-15000 psi  
MODE: 120 HR CLOCK DELAY: NONE  
ACTUATED: time 00.35 date: 27-11-82  
WILL RUN OUT: time 00.35 date: 02-12-82

GAUGE TYPE AND NUMBER: SPERRY SUN MRPG Mk-1 0161  
DEPTH, PRESSURE ELEMENT: 2572.2 meter RANGE: 10000 psi  
MODE: 4 min 112 Hrs DELAY: 34 HRS  
ACTUATED: time: 01.16 date: 27-11-82  
WILL RUN OUT: time: 03.16 date: 03-12-82

GAUGE TYPE AND NUMBER: SPERRY SUN MRPG Mk-1 0149  
DEPTH, PRESSURE ELEMENT: 2574.7 meter RANGE: 10000 psi  
MODE: 4 min 112 Hrs DELAY: 34 HRS  
ACTUATED: time: 01.18 date: 27-11-82  
WILL RUN OUT: time: 03.18 date: 03-82-82



D.S.T. HANGER

GAUGE TYPE AND NUMBER: SPERRY SUN MRPG Mk-1 0253  
DEPTH, PRESSURE ELEMENT: 2577.2 meter RANGE: 10000 psi  
MODE: 4 min 112 Hrs DELAY: 17 HRS  
ACTUATED: time: 01.20 date: 27-11-82  
WILL RUN OUT: time: 10.20 date: 02-12-82

GAUGE TYPE AND NUMBER: SPERRY SUN MRPG Mk-3 0184  
DEPTH, PRESSURE ELEMENT: 2579.8 meter RANGE: 10000  
MODE: 2 min 56 Hrs DELAY: 17 HRS  
ACTUATED: time: 01.22 date: 27-11-82  
WILL RUN OUT: time: 02.22 date: 30-11-82

GAUGE TYPE AND NUMBER: \_\_\_\_\_  
DEPTH, PRESSURE ELEMENT: \_\_\_\_\_ RANGE: \_\_\_\_\_  
MODE: \_\_\_\_\_ DELAY: \_\_\_\_\_  
ACTUATED: time: \_\_\_\_\_ date: \_\_\_\_\_  
WILL RUN OUT: time: \_\_\_\_\_ date: \_\_\_\_\_

## COMPLETION DATA

Well 16/7-4 Test 1 Date 27-11-82

Company Supervisor Sam Banks

Test Engineer Haaland/Kollbotn

1. Interval 2590.5 m - 2597 m (IEL)
2. Well loading fluid Sea water 0.45 psi/ft
3. Approximate Differential ( $p_f - p_w$ ) 470 psi
4. Type of perforating gun 4" Kone Shot 120° phasing
5. Perforation density 4 .spf
6. Mud weight 10.9 .ppg
7.  $Cl^-$  of filtrate 4000 ppm
8.  $Cl^-$  of mud filtrate at time of drilling 8500 ppm

<ol style="list-style-type: none"> <li>9. Casing:</li> <li>Size _____ in.</li> <li>Weight _____ lb/ft</li> <li>Grade _____</li> <li>Capacity _____ bbl/ft</li> <li>Shoe _____ m</li> </ol>	<ol style="list-style-type: none"> <li>10. Liner:</li> <li>Size <u>7</u> in.</li> <li>Weight <u>29</u> lb/ft</li> <li>Grade <u>P-110</u></li> <li>Capacity <u>.0371</u> bbl/ft</li> <li>Top <u>2115</u> m</li> <li>Shoe <u>2776</u> m</li> </ol>	<ol style="list-style-type: none"> <li>11. Tubing:</li> <li>Size <u>3.5</u> in.</li> <li>Inside Diameter <u>2.75</u> in.</li> <li>Weight <u>12.95</u> lb/ft</li> <li>Grade <u>C-75</u></li> <li>Capacity <u>.00735</u> bbl/ft</li> <li>Connections <u>PH-6</u></li> <li>Burst pressure <u>14060</u> psi</li> </ol>
--	--	--

12. Plugged back total depth 2714 m
13. Depth of packer 2563 m
14. Tubing volume 62 bbl
15. Volume between packer and lowest perforation 4.1 bbl
16. Rathole volume 14.2 bbl
17. Depth of tailpipe 2586 m
18. Location of pressure gauges: depth 2577.2 m gauge number 0253 Sperry Sun  
depth 2579.8 m gauge number 0184 Sperry Sun
19. Initial WHP before well open 388 psig

PERFORATION

Well 16/7-4 Test 1 Perforation 2590.5-97 Date 26/11-82

1. Geologist(s): None
2. Test Engineer(s): Haaland/Kollbotn
3. Service Company/Engineer: Dresser Atlas / N.J. Wuerzer
4. Distance between CCL and top of gun: 0.6 m
5. Number of Runs: 1
6. Wellhead pressure bled down to zero before perforating?  
 (Yes)  (No)
7. Wellhead pressure before perforating: 0 - overbalanced
8. Time of perforation: 23.40 (local time)
9. After perforating, record pressure versus time every minute for the first 10 minutes and every 5 minutes thereafter until pressure stabilizes.

Time (Local)	WHP (PSIG)

Time (Local)	WHP (PSIG)

10. Other perforating runs:

Time                  Run                  Interval                  WHP

11. Remarks: All shots fired (80 shots)  
 \_\_\_\_\_  
 \_\_\_\_\_

INITIAL FLOW PERIOD DATA\*Well 16/7-4 Test 1 Perforations 2590.5-97 Date 28/11-82

1. Wellhead pressure prior to opening well 57 psig
2. Time well opened 0307
3. Initial choke size 24 v .64ths
4. Well response: Well (flowed, died)
  - Time gas surfaced \_\_\_\_\_
  - Time mud surfaced \_\_\_\_\_
  - Time formation fluid surfaced \_\_\_\_\_
5. Well data just prior to shut in
  - Flowing wellhead pressure 228 psig
  - Choke size 24 v .64ths
  - Pressure downstream of the choke 0 psig
  - Rate 1440 B/D, MCFD. (measured, ~~estimated~~)
6. Time of shut in 0309
7. Total length of initial flow 2 min. —
8. Cumulative production 2 bbl, MSCF (measured, ~~estimated~~)
9. Description of produced fluids: Seawater (well loading fluid)
  - Oil \_\_\_\_\_ % \_\_\_\_\_ °API
  - Water \_\_\_\_\_ % Cl<sup>-</sup> \_\_\_\_\_ ppm
  - Gas: Sp Gr \_\_\_\_\_
  - C<sub>1</sub> \_\_\_\_\_ ppm C<sub>5</sub><sup>+</sup> \_\_\_\_\_ ppm
  - C<sub>2</sub> \_\_\_\_\_ ppm CO<sub>2</sub> \_\_\_\_\_ ppm, %
  - C<sub>3</sub> \_\_\_\_\_ ppm H<sub>2</sub>S \_\_\_\_\_ ppm, %
  - C<sub>4</sub> \_\_\_\_\_ ppm

\* If extended initial flow (clean up) is run, enter production data at 30 min intervals on Production Test Data sheet (D-5).

If well is swabbed, fill out swab report (D-3).



PRODUCTION TEST DATA SHEET

WELL 16/7-4 TEST No. 1 PERFORATIONS 2590.5 - 97 DATE 28-11-82

1	2	3	4	5	6	7	8			9			12	13	14	15
							WELLHEAD PRESSURE PSI	WELLHEAD TEMPERATURE °F	CASING PRESSURE PSI	CHOKES	OIL STB	WATER BBLs				
DATE TIME	REMARKS	WELLHEAD PRESSURE PSI	WELLHEAD TEMPERATURE °F	CASING PRESSURE PSI	CHOKES	OIL STB	WATER BBLs	GAS MSCF	OIL STB/D	WATER B/D	GAS MSCF/D	CONDENSATE GOR OR	GAS RATIO	OIL °API @ 60°	GAS AIR = 1	
28-11																
0452	Gas to surface	2418	98	1530	32V		Flow through heater									
0453	Change choke	2146	92	1500	32F		Approximate rate	9 MSCF/D								
0455		2097	98	1460	32F		Burner lit									
0510		2388	89	1600	32F		Debris plugging choke									
0622	Start glycol inj.	2476	104	1540	32F											
0630	Change choke	2478	104	1460	32V											
0652	Change choke	2040	112	1600	42F											
0701	Stop glycol inj.	1861	119	1510	"		Downstream pressure	910 psi								
0750	0.2% CO <sub>2</sub> , No H <sub>2</sub> S	1873	129	1500	"		Flow through separator									
0850	BSW NIL	1888	132	1440			Approximate rate	14 MSCF/D								
0905	- " -	1892	134	1480	"		No BSW detected									
0930	Start prod. counting	1853	135	1480	"	230	2.30	Estimated from choke equation								
1000		1899	137	1520	"	260.7	2.60	1475				14.38	102.6	58	0.791	
1030		1902	138	1420	"	291.3	2.90	1469				14.33	102.5			
1100		1896	139	1490	"	321.8	3.20	1461				14.34	101.9			
1130		1924	139	1560	"	353.9	3.49	1504				14.23	105.7			

PRODUCTION TEST DATA SHEET

WELL 16/7-4 TEST No. 1 PERFORATIONS 2590.5-2597 DATE 28-11-82

1	2	3	4	5	6	7	8	9	10			11		12	13	14		15
									WELLHEAD PRESSURE PSI	WELLHEAD TEMPERATURE OF CASING PRESSURE PSI	CHOKE SIZE	CUMULATIVE PRODUCTION	OIL STB/D			GAS MSCF/D	WATER B/D	
28-11		1938	140	1460	42F	383.8		3.78	1475			13.51	109.2	58	0.791			
1200		1935	142	1510	"	414.4		4.06	1468			13.51	108.7					
1230		1886	143		"	444.6		4.35	1447			13.51	107.1					
1300		1876	142		"	475.0		4.63	1459			13.51	108.0					
1400		1871	143		"	504.4		4.91	1413			13.51	104.6					
1430		1844	143		"	534.4		5.19	1438			13.51	106.4					
1500		1861	145		"	564.5		5.47	1446			13.51	107.0					
1530		1883	150		"	593.9		5.75	1441			13.57	104.2					
1600		1889	156		"	624.3		6.04	1456			13.57	107.3					
1630		1914	143		"	654.2		6.32	1435			13.57	105.7					
1636	Close choke LPR open	1930	142		"		Average	Average	GLR	9661		SCF/STB						
1638	Close LPR	2233	145		"		Average	Average	LGR	103.5		STB/MSCF						
	Open choke				"													
1650	Bleed of tubing	2437	113		"													
1658	Choke closed	790	136		"													
1752		792																
29-11																		
1107	Open LPR valve																	

WHP indicates that LPR valve is closed  
Start bull heading. Test finished.

SEPARATOR DATA SHEET

DATE 28-11-82

TEST DST No. 1

WELL 16/7-4

1	2	3	4		5	6		7	8				11	12	13
			OIL METER			WATER METER			GAS METER DATA						
DATE TIME	SEPARATOR PRESS PSIG	TEMP °F	READING BBLs	ΔBBLs	READING BBLs	ΔBBLs	READING BBLs	ΔBBLs	STATIC PSIA	DIFF. IN. H <sub>2</sub> O	TEMP °F	PLATE IN.	GAS GRAVITY	REMARKS	
28-11															
0930	340	115	19.17						355	158	115	3.25	0.791		
1000	345	118	52.27	33.10					360	158	118	"	"		
1030	"	119	85.26	32.99					"	156	116	"	"		
1100	"	117	118.03	32.77					"	156	115	"	"		
1130	"	106	151.87	33.84					"	150	104	"	"		
1200	"	120	135.35	33.48					"	140	120	"	"		
1230	"	119	218.65	33.30					"	145	"	"	"		
1300	"	120	251.50	32.85					"	145	"	"	"		
1330	"	120	284.63	33.13					"	145	"	"	"	Start sampling	
1400	"	120	316.70	32.07					"	145	"	"	"	Set no. 1	
1430	"	120	349.35	32.65					"	145	"	"	"		
1500	"	120	382.17	32.82					"	142	120	"	"		
1530	"	120	414.26	32.09					"	140	115	"	"	Start sampling	
1600	"	120	447.32	33.06					"	140	115	"	"	Set no. 2	
1630	345	120	479.90	32.58					360	140	115	3.25	0.791		

OIL RATE CALCULATIONS

DATE 28-11-82

TEST DST No. 1

WELL 16/7-4

1	2	3	4	5	6	7	8	9	10	11	12	13	14	CORRECTED VALUES				REMARKS	
														TEMP OF	GRAVITY °API @ 60°	METER READING BBLs	Δ BBLs		METER FACTOR
28-11	MIN																		
0930	-	115	58	19.17	-		0.93	1.000											
1000	30	118	"	52.27	33.10	1.0	0.93	0.9981	0	30.72	1475	9749							
1030	30	119	"	85.26	32.99	"	"	0.9975	0	61.32	1469	9755							
1100	30	117	"	118.03	32.77	"	"	0.9988	0	91.76	1461	9815							
1130	30	106	"	151.87	33.84	"	"	1.0057	0.99	123.10	1504	9461							
1200	30	120	"	185.35	33.48	"	"	0.9968	"	153.82	1475	9160							
1230	30	119	"	218.65	33.30	"	"	0.9975	"	184.41	1468	9203							
1300	30	120	"	251.50	32.85	"	"	0.9968	"	214.55	1447	9336							start sampling
1330	30	"	"	284.63	33.13	"	"	"	"	244.96	1459	9257							set no 1
1400	30	"	"	316.70	32.07	"	"	"	"	274.39	1413	9563							
1430	30	"	"	349.35	32.65	"	"	"	"	304.36	1438	9393							
1500	30	"	"	382.17	32.82	"	"	"	"	334.48	1446	9344							
1530	30	"	"	414.26	32.09	"	"	"	"	363.93	1414	9599							start sampling
1600	30	"	"	447.32	33.06	"	"	"	"	394.27	1456	9318							set no 2
1630	30	120	58	479.90	32.58	1.0	0.93	0.9968	0.99	424.17	1435	9455							
*	Shrinkage factor includes temperature correction to 60°F																		
**	The temperature correction factor correct for the difference between oil meter temperature and 115°F.																		

WELL 16/7-4

TEST DST No. 1

## GAS RATE CALCULATIONS

DATE 28-11 82

1	DATE TIME	2	GAS METER			5	6	7	8	9	10	11	12
			STATIC (p <sub>1</sub> ) PSIA	DIFF. (h <sub>w</sub> ) IN H <sub>2</sub> O	TEMP °F								
	28-11												
	0930	355	158	115	3.25	2276.5	0.951	1.1244	1.0359	2521.7	14.33		
	1000	360	158	118	"	"	0.9481	"	1.0354	2521.8	14.38		
	1030	"	156	116	"	"	0.9501	"	1.0357	2518.8	14.33		
	1100	"	156	115	"	"	0.9510	"	1.0355	2520.7	14.34		
	1130	"	150	104	"	"	0.9602	"	1.0383	2552.0	14.23		
	1200	"	140	120	"	"	0.9469	"	1.0346	2507.6	13.51		
	1230	"	145	"	"	"	"	"	"	"	"		
	1300	"	145	"	"	"	"	"	"	"	"		
	1330	"	145	"	"	"	"	"	"	"	"	Start Sampling	
	1400	"	145	"	"	"	"	"	"	"	"	Set No. 1	
	1430	"	145	"	"	"	"	"	"	"	"		
	1500	"	142	120	"	"	0.9469	"	"	2507.6	13.51		
	1530	"	140	115	"	"	0.9510	"	"	2518.5	13.57	Start Sampling	
	1600	"	140	115	"	"	0.9510	"	"	2518.5	13.57	Set No. 2	
	1630	360	140	115	3.25	2276.5	0.9510	1.1244	1.0346	2518.5	13.57	D-8	



GAS SAMPLE FIELD ANALYSIS RECORD

WELL 16/7-4 TEST 1 DATE 28-11-82

		1	2	3	4	5	6	7	8	9	
TIME SAMPLED	SAMPLE POINT	COMPONENTS									
		C <sub>1</sub>	C <sub>2</sub>	C <sub>3</sub>	C <sub>4</sub>	C <sub>5</sub> <sup>+</sup>	H <sub>2</sub> S	CO <sub>2</sub>			
10:35	separator	.6592	.1548	.1116	.0358/ .0358	.0093	0	.0035			
11:05	"	.7070	.1458	.1180	.0082/ .0117	.0058	0	.0035			
11:35	"	.7045	.1566	.1086	.0092/ .0121	.0055	0	.0035			
		Pressure problems at separator supply									
12:15	"	.7226	.1483	.0727	.0051/ .0064	.0014	0	.0035			
12:45	"	.7380	.1698	.0763	.0046/ .0066	.0015	0	.0033			
13:00	"	.7013	.1553	.0964	.0146/ .0242	.0053	0	.0033			
13:15	"	.7189	.1636	.0895	.0092/ .0127	.0027	0	.0035			
13:30	"	.7044	.1680	.0957	.0098/ .0149	.0023	0	.0033			
13:45	"	.7117	.1693	.0914	.0090/ .0130	.0023	0	.0033			
14:15	"	.7149	.1622	.0931	.0102/ .0133	.0029	0	.0033			
14:45	"	.7110	.1616	.0947	.0104/ .0152	.0037	0	.0035			
15:15	"	.7180	.1795	.0891	.0080/ .0095	.0013	0	.0035			
		Irratic flow supply									
16:15	"	.7017	.1593	.1045	.0117/ .0166	.0023	0	.0038			
16:30	"	.7160	.1679	.0937	.0015/ .0096	.0016	0	.0038			
		Recalculated from gas units to mol fractions									
		Gas gravity based on composition: 0.771									

PRODUCTION TEST SUMMARYWell 16/7-4 Test DST no. 1 Date 28-11-82

## Test Data:

1. Interval 2590.5 - 2597 m (IEL)
2. Produced fluid Gas and Condensate
3. Cumulative production 654/6.32 STB, MSCF
4. Stabilized rate 1446/13.57 STB/D, MSCF/D
5. Length of flow period 12.4 hr
6. Choke 42 Fixed 64ths
7. Gravity of oil or condensate 58 °API @ 60°F
8. GOR or Condensate - Gas Ratio 9385 SCF/STB
9. Water cut < 1 %
10. Chlorides 4500 ppm
11. H<sub>2</sub>S NIL %, ppm
12. CO<sub>2</sub> 0.35 %
13. Stabilized flowing wellhead pressure 1900 psig
14. Stabilized flowing wellhead temperature 145 °F
15. Wellhead pressure at end of buildup N/A psig
16. Initial reservoir pressure 4264 psig @ 2594 m
17. Final flowing pressure 3238 psig @ 2594 m
18. Productivity index 0.0132  $\frac{\text{MSCF/D}}{\text{psi}}$
19. Maximum bottom-hole temperature 214 °F @ 2594 m
20. Samples taken: Two sets of separator samples (pressurized)  
consisting of 1 x 500 cc of liquid and 2 x 20000 cc of gas each.  
2 x 10 l. jerry cans of separator liquid (atmospheric). 4 x 1 l  
plastic bottles of water from separator. 1 x 250 cc of separator  
gas (pressurized).

BUILDUP ANALYSIS

1. Rate  $q = \underline{14.98}$  Gas + Condensate MSCF/D
2. Horner Time:  $\frac{\text{Cumulative production}}{\text{Last rate}} = \underline{11.2}$  hr
3. Fluid and reservoir properties  
 Viscosity:  $\mu = \underline{0.0239}$  cp at pressure of 4095 psia  
 Compressibility factor (for gas wells):  $z = \underline{0.882}$   
 Compressibility:  $c_t = \underline{10^{-4}}$  1/psi  
 Volume factor:  $B_g = \underline{730}$  RB/MSCF at pressure of 4095 psia  
 Thickness:  $h = \underline{21.3}$  ft = 6.5 m  
 Perforated thickness:  $h_p = \underline{21.3}$  ft = 6.5 m  
 Porosity:  $\phi = \underline{17.1}$  %  
 Wellbore radius:  $r_w = \underline{0.3}$  ft = 0.0091 m  
 Bottom-hole temperature:  $T = \underline{214}$  °F
4. Initial pressure:  $p_i = \underline{4241}$  psig at 2579.8 m
5. Flowing bottom-hole pressure:  $p_{wf} = \underline{3532}$  psig at 2579.8 m
6. Wellbore storage:  $\alpha = \underline{N/A}$  RB/psi
7. End of afterflow:  $\Delta t_{af} = \underline{N/A}$  min
8. Middle time region slope:  $m = \underline{53.6}$  psi/log cycle
9. Extrapolated pressure:  $p^* = \underline{4257}$  psig at 2579.8 m
10. Ideal buildup pressure at  $\Delta t = 1$  hr:  $p_{w1} = \underline{4199}$  psig at 2579.8 m
11. Permeability-thickness product:  $kh = \frac{162.6 \text{ quB}}{m}$   
 $kh = \frac{162.6 (14.98) (0.0239) (730)}{(53.6)} = \underline{793}$  md-ft
12. Permeability:  $k = \frac{kh}{h} = \frac{(793)}{(21.3)} = \underline{37.2}$  md

13. Diffusivity:  $\eta = \frac{2.637 \times 10^{-4} k}{\phi \mu c}$

$= \frac{2.637 \times 10^{-4} (37.2)}{(0.17)(0.0239)(10^{-4})} = \frac{2415 \times 9}{1} \text{ ft}^2/\text{hr}$

14. Average permeability:  $\bar{k} = \frac{141.2 q \mu B \ln(r_e/r_w)}{h(p^* - p_{wf})}$  ( $\ln r_e/r_w = 6.0-8.0$ )

$\bar{k} = \frac{141.2 (14.98)(0.0239)(730) \ln(1040/0.3)}{(21.3)((4257) - (3532))} = \frac{19.6}{1} \text{ md}$

15. Radius of investigation beginning of MTR:

$R_{ib} = \sqrt{4\eta\Delta t} = \sqrt{4(2415 \times 9)(11.2)} = \frac{1040}{1} \text{ ft} = \frac{320}{1} \text{ m}$

16. Skin factor:  $s = 1.151 \left[ \frac{p_{wl} - p_{wf}}{m} - \log \left( \frac{k}{\phi \mu c r_w^2} \right) + 3.23 \right]$

$s = 1.151 \left[ \frac{((4199) - (3532))}{(53.6)} - \log \frac{(37.2)}{(0.17)(0.0239)(10^{-4})(0.3)^2} + 3.23 \right]$

$s = \frac{7.67}{1}$

17. Pressure drop due to skin:

$\Delta p_s = 0.87 ms = 0.87 (53.6) (7.67) = \frac{358}{1} \text{ psi}$

18. Flow efficiency:  $E = \frac{p^* - p_{wf} - \Delta p_s}{p^* - p_{wf}}$

$E = \frac{(4257) - (3532) - (358)}{(4257) - (3532)} = \frac{0.5}{1}$

19. Damage ratio:  $DR = \frac{1}{E} = \frac{1}{(0.5)} = \frac{2}{1}$

20. Productivity index:  $J = \frac{q}{p^* - p_{wf}} = \frac{(10935)}{((4257) - (3532))} = \frac{15}{1} \text{ (RB/D) ps}$

21. Closest possible boundary:  $L_{cb} = \frac{460}{1} \text{ ft} = \frac{140}{1} \text{ m}$

SEPARATOR SAMPLE DATASET NO. 1

Well 16/7-4 Test DST No. 1 Date 28-11-82  
 Producing Interval 2590.5 - 97 m (IEL)  
 Initial Reservoir Pressure 4264 psig @ 2594 m  
 Reservoir Temperature 214 °F @ 2594 m

	<u>Liquid</u>		<u>Gas</u>	
	<u>Sample No. 1</u>	<u>Sample No. 2</u>	<u>Sample No. 1</u>	<u>Sample No. 2</u>
Time Sampled	<u>13.25</u>	<u></u>	<u>13.25</u>	<u>14.10</u>
Length of Time Well was Produced	<u>9.18 hrs</u>	<u></u>	<u>9.18 hrs</u>	<u>9.93 hrs</u>
Container No.	<u>O.O.I.O</u>	<u></u>	<u>O.P.C.M.2201</u>	<u>O.O.I.172</u>
Container Volume (cc)	<u>500</u>	<u></u>	<u>20 000</u>	<u>20 000</u>
Separator Pressure (psig)	<u>345</u>	<u></u>	<u>345</u>	<u>345</u>
Separator Temperature (°F)	<u>120</u>	<u></u>	<u>120</u>	<u>120</u>
Wellhead Pressure (psig)	<u>1878</u>	<u></u>	<u>1878</u>	<u>1853</u>
Wellhead Temperature (°F)	<u>141</u>	<u></u>	<u>141</u>	<u>144</u>
Flowing Bottom-hole Pressure (psig)	<u>3533</u>	<u></u>	<u>3533</u>	<u>3533</u>
Flowing Bottom-hole Temperature (°F)	<u>214</u>	<u></u>	<u>214</u>	<u>214</u>
Separator Rate (Sep. bbl/D)*	<u>1575</u>	<u></u>	<u>1575</u>	<u>1575</u>
Separator Gas Rate (MSCF/D)	<u>13.51</u>	<u></u>	<u>13.51</u>	<u>13.51</u>
Separator GOR (SCF/Sep. bbl)	<u>8578</u>	<u></u>	<u>8578</u>	<u>8578</u>
Well Rate (STB/D) <sup>+</sup>	<u>1445</u>	<u></u>	<u>1445</u>	<u>1445</u>
Well GOR (SCF/STB) <sup>+</sup>	<u>9348</u>	<u></u>	<u>9348</u>	<u>9348</u>
Full Wellstream Water Cut	<u>0</u>	<u></u>	<u>0</u>	<u>0</u>
How Outage was Taken on Liquid Samples	<u></u>			

Gas Sampling Method Evaluated container

Liquid Sampling Method Brine displacement

Special Instruction for Lab

Sampled by OTIS/Loyal Clements

\* Rates based on Meter Readings corrected for Meter Factor Only.

+ Rates corrected to Stock-Tank Conditions as per Form D-7.

SEPARATOR SAMPLE DATASET NO. 2Well 16/7-4 Test DST no. 1 Date 28-11-82Producing Interval 2290.5 - 97 m (IEL)Initial Reservoir Pressure 4264 psig @ 2594 mReservoir Temperature 214 °F @ 2594 m

	<u>Liquid</u>		<u>Gas</u>	
	<u>Sample No. 1</u>	<u>Sample No. 2</u>	<u>Sample No. 1</u>	<u>Sample No. 2</u>
Time Sampled	<u>15.30</u>		<u>15.30</u>	<u>16.00</u>
Length of Time Well was Produced	<u>11.26 hrs</u>		<u>11.26 hrs</u>	<u>11.76 hrs</u>
Container No.	<u>0.0.I.BC</u>		<u>0.0.I.191</u>	<u>0.0.I.125</u>
Container Volume (cc)	<u>500</u>		<u>20 000</u>	<u>20 000</u>
Separator Pressure (psig)	<u>345</u>		<u>345</u>	<u>345</u>
Separator Temperature (°F)	<u>120</u>		<u>120</u>	<u>120</u>
Wellhead Pressure (psig)	<u>1889</u>		<u>1889</u>	<u>1899</u>
Wellhead Temperature (°F)	<u>147</u>		<u>147</u>	<u>146</u>
Flowing Bottom-hole Pressure (psig)	<u>3533</u>		<u>3533</u>	<u>3533</u>
Flowing Bottom-hole Temperature (°F)	<u>214</u>		<u>214</u>	<u>214</u>
Separator Rate (Sep. bbl/D)*	<u>1575</u>		<u>1575</u>	<u>1575</u>
Separator Gas Rate (MSCF/D)	<u>13.57</u>		<u>13.57</u>	<u>13.57</u>
Separator GOR (SCF/Sep. bbl)	<u>8616</u>		<u>8616</u>	<u>8616</u> <i>a 116 8/2/</i>
Well Rate (STB/D) <sup>+</sup>	<u>1446</u>		<u>1446</u>	<u>1446</u>
Well GOR (SCF/STB) <sup>+</sup>	<u>9385</u>		<u>9385</u>	<u>9385</u>
Full Wellstream Water Cut	<u>0</u>		<u>0</u>	<u>0</u>
How Outage was Taken on Liquid Samples				

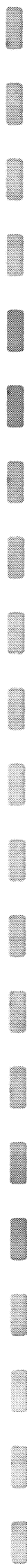
Gas Sampling Method Evacuated containerLiquid Sampling Method Brine displacement

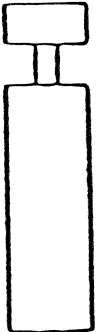
Special Instruction for Lab \_\_\_\_\_

Sampled by OTIS/Allan Black

\* Rates based on Meter Readings corrected for Meter Factor Only.

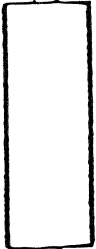
<sup>+</sup> Rates corrected to Stock-Tank Conditions as per Form D-7.



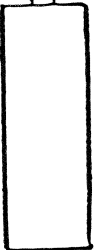


WIRELINE NIPPLE

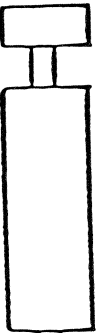
GAUGE TYPE AND NUMBER: AMERADA RPG-3 38029  
 DEPTH, PRESSURE ELEMENT: 2499.6 m RANGE: 0-15000 psi  
 MODE: 120 Hr Clock DELAY: None  
 ACTUATED: time 1901 date: 30/11-82  
 WILL RUN OUT: time 1901 date: 5/12-82



GAUGE TYPE AND NUMBER: SPERRY SUN MRPG Mk-1 0161  
 DEPTH, PRESSURE ELEMENT: 2502.2 m RANGE: 10000 psi  
 MODE: 4 min 112 HRS DELAY: 34 HRS  
 ACTUATED: time: 1904 date: 30-11-82  
 WILL RUN OUT: time: 2104 date: 06-11-82



GAUGE TYPE AND NUMBER: SPERRY SUN MRPG Mk-1 0190  
 DEPTH, PRESSURE ELEMENT: 2504.7 m RANGE: 10000 psi  
 MODE: 4 min 112 Hrs DELAY: 17 Hrs  
 ACTUATED: time: 1906 date: 30-11-82  
 WILL RUN OUT: time: 0406 date: 06-12-82

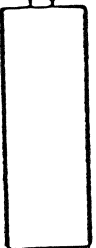


D.S.T. HANGER

GAUGE TYPE AND NUMBER: SPERRY SUN MRPG Mk-1 0246  
 DEPTH, PRESSURE ELEMENT: 2507.2 m RANGE: 10000 psi  
 MODE: 4 min 112 Hrs DELAY: 34 Hrs  
 ACTUATED: time: 1908 date: 30-11-82  
 WILL RUN OUT: time: 2108 date: 06-12-82



GAUGE TYPE AND NUMBER: SPERRY SUN MRPG Mk-3 0184  
 DEPTH, PRESSURE ELEMENT: 2509.8 m RANGE: 10000 psi  
 MODE: 2 min 56 Hrs DELAY: 17 Hrs  
 ACTUATED: time: 1901 date: 30-11-82  
 WILL RUN OUT: time: 2010 date: 03-12-82



GAUGE TYPE AND NUMBER:  
 DEPTH, PRESSURE ELEMENT: RANGE:  
 MODE: DELAY:  
 ACTUATED: time: date:  
 WILL RUN OUT: time: date:

COMPLETION DATAWell 16/7-4 Test DST No 2 Date 01-12-82Company Supervisor Sam BanksTest Engineer Kollbotn

1. Interval 2525 - 2535 meter (IEL)
2. Well loading fluid Fresh water 0.433 psi/ft
3. Approximate Differential (pf-pw) 630 (psi)
4. Type of perforating gun 4" KONE SHOT 120° PHASING
5. Perforation density 4 (spf)
6. Mud weight 10.9 (ppg)
7. Cl<sup>-</sup> of filtrate 4000 (ppm)
8. Cl<sup>-</sup> of mud filtrate at time of drilling 8500 (ppm)
9. Casing:
 

Size _____ (in.)	10. Liner: Size <u>7</u> (in.)	11. Tubing: Size <u>35</u> (in.)
Weight _____ (lb/ft)	Weight <u>29</u> (lb/ft)	Inside Diameter <u>2.75</u> (in.)
Grade _____	Grade <u>P-110</u>	Weight <u>12.95</u> (lb/ft)
Capacity _____ (bbl/ft)	Capacity <u>0.0371</u> (bbl/ft)	Grade <u>C-75</u>
Shoe _____ (ft)	Top <u>2115</u> (m)	Capacity <u>0.00735</u> (bbl/ft)
	Shoe <u>2776</u> (m)	Connections <u>PH-6</u>
		Burst pressure <u>14060</u> psi.
12. Plugged back total depth 2575 (m)
13. Depth of packer 2493 (m)
14. Tubing volume 60 (bbl)
15. Volume between packer and lowest perforation 5.1 (bbl)
16. Rathole volume 4.9 (bbl)
17. Depth of tailpipe 2516 (m)
18. Location of pressure gauges: depth 2509.8 (m) gauge number Sperry Sun 0184  
 depth 2504.7 (m) gauge number Sperry Sun 0190
19. Initial WHP before well open 568 psi

PERFORATION

Well 16/7-4 Test DST No. 2 Perforation 2525 - 35 Date 30-11-82

1. Geologist(s): None

2. Test Engineer(s): Kollbotn

3. Service Company/Engineer: Dresser Atlas / H.J. Wuerzer

4. Distance between CCL and top of gun: 0.6 m

5. Number of Runs: 1

6. Wellhead pressure bled down to zero before perforating?

       (Yes)        (No)

7. Wellhead pressure before perforating: 0 - Overballanced psi

8. Time of perforation: 17.45 (local time)

9. After perforating, record pressure versus time every minute for the first 10 minutes and every 5 minutes thereafter until pressure stabilizes.

Time (Local)	WHP (PSIG)

Time (Local)	WHP (PSIG)

10. Other perforating runs:

<u>Time</u>	<u>Run</u>	<u>Interval</u>	<u>WHP</u>
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11. Remarks: All shots fired (120 shots)

\_\_\_\_\_  
\_\_\_\_\_

INITIAL FLOW PERIOD DATA\*Well 16/7-4 Test No. 2 Perforations 2525-35 Date 01-12-82

1. Wellhead pressure prior to opening well 4 (psi)
2. Time well opened 16.27
3. Initial choke size 24V (64ths)
4. Well response: Well (flowed, died)
  - Time gas surfaced \_\_\_\_\_
  - Time mud surfaced \_\_\_\_\_
  - Time formation fluid surfaced \_\_\_\_\_
5. Well data just prior to shut in
  - Flowing wellhead pressure 355 (psi)
  - Choke size 24V (64ths)
  - Pressure downstream of the choke 15 (psi)
  - Rate 576 (B/D, MGF<sub>D</sub>) (measured, estimated)
6. Time of shut in 1632
7. Total length of initial flow 5 (min, hr)
8. Cumulative production 2 (bbl, MGF) (measured, estimated)
9. Description of produced fluids: Fresh water (well loading fluid)
 

Oil	_____ %	_____ °API
Water	_____ %	Cl <sup>-</sup> _____ (ppm)
Gas:	Sp Gr _____	
	C <sub>1</sub> _____ (ppm)	C <sub>5</sub> <sup>+</sup> _____ (ppm)
	C <sub>2</sub> _____ (ppm)	CO <sub>2</sub> _____ (ppm, %)
	C <sub>3</sub> _____ (ppm)	H <sub>2</sub> S _____ (ppm, %)
	C <sub>4</sub> _____ (ppm)	

\* If extended initial flow (clean up) is run, enter production data at 30 min intervals on Production Test Data sheet (D-5).

If well is swabbed, fill out swab report (D-3).

PRODUCTION TEST DATA SHEET

WELL 16/7-4 TEST DST No. 2 PERFORATIONS 2525-2535 m DATE 02-12-82

1	2	3	4	5	6	7	8			9			12	13	14	15
							WELLHEAD PRESSURE PSI	WELLHEAD TEMPERATURE °F	CASING PRESSURE PSI	CHOKE SIZE IN	OIL STB	WATER BBLs				
DATE TIME	REMARKS	WELLHEAD PRESSURE PSI	WELLHEAD TEMPERATURE °F	CASING PRESSURE PSI	CHOKE SIZE IN	OIL STB	WATER BBLs	GAS MSCF	OIL STB/D	WATER B/D	GAS MSCF/D	GOR OR CONDENSATE GAS RATIO	GRAVITY			
01-12																
1609	Set RTTS packer															
1624	Oper LPR	4		1480												
1627	Open Choke	568	59	"	24V				Problems with pluggin in variable choke.							
1632	Closed choke & LPR	355	59	0					Produced 2bbl in 5 min							
1736	Open LPR	234	59	1480												
1737	Open choke	538	73	"	32V											
1742	Adjust choke	611	71	"	42V											
1748	Gas to surface	1116	98	"	42F	Changed to fixed choke										
1752	Burner Lit	2072	105	"	"											
1800		2012	101	"	"	Downstream pressure: 933 psi										
1830		2116	120	"	"	CO <sub>2</sub> < 0.5% , No H <sub>2</sub> S.										
1900		2129	128	"	"											
1933	Changed flare boom	2139	133	"	"	CO <sub>2</sub> = 0.2% , No H <sub>2</sub> S										
1942	Flow through sep.	2137	133	"	"	Estimated rate 15.5 MSCF/D										
2004		2149	135	"	"	0.6 ~ 1.0% BSW.										







**OIL RATE CALCULATIONS**

WELL 16/7-4 TEST No. 2 DATE 02-12-82

1	2	3	4	5	6	7	8	9	10	CORRECTED VALUES			14
										11	12	13	
DATE TIME	Δ TIME MIN	TEMP °F	GRAVITY °API @ 60°	METER READING BBLs	Δ BBLs	METER FACTOR	SHRINKAGE *	TEMP. CORR. **	BSW 1 - %	CUM. PROD STB	RATE STB/D	GOR SCF/STB	REMARKS
01-12 2100		94	58	101.46			0.88						
2130	30	96	"	143.41	41.95	1.0	0.88	1.00	0.994	36.69	1761	9171	
2200	30	97	"	185.42	42.01	1.0	"	.9995	"	73.42	1763	9229	
2230	30	100	"	227.74	42.32	1.0	"	.9978	"	110.36	1773	9318	
2300	30	100	"	269.67	41.93	1.0	"	.9978	"	146.96	1757	9283	
2330	"	101	"	311.60	41.93	1.0	"	.9973	"	183.53	1756	9527	
2400	"	101	"	353.22	41.62	1.0	"	.9973	"	219.84	1743	9598	
02-12 0030	"	102	"	394.57	41.35	1.0	"	.9967	"	255.89	1730	9671	
0100	"	102	"	436.30	41.73	1.0	"	.9967	"	292.27	1746	9582	
0130	"	103	"	478.04	41.74	1.0	"	.9962	"	328.64	1746	9582	
0200	"	103	"	519.49	41.42	1.0	"	.9962	"	364.74	1732	9613	
0230	"	104	"	560.96	41.47	1.0	"	.9956	"	400.85	1734	9642	
0300	30	104	58	601.90	40.94	1.0	0.88	.9956	0.994	436.50	1712	9585	
*	Shrinkage factor includes temperature correction to 60°F												
**	The temperature correction factor corrects for the difference between oil meter temperature and 94°F.												







PRODUCTION TEST SUMMARYWell 16/7-4 Test DST no. 2 Date 02-12-82

## Test Data:

1. Interval 2525 - 2535 m (IEL)
2. Produced fluid Gas and Condensate
3. Cumulative production 661.5/6.24 STB, MSCF
4. Stabilized rate 1730/16.73 STB/D, MSCF/D
5. Length of flow period 9.5 hr
6. Choke 42 Fixed 64ths
7. Gravity of oil or condensate 58 °API @ 60°F
8. GOR or Condensate - Gas Ratio 9670 SCF/STB,
9. Water cut 1 %
10. Chlorides 4900 ppm
11. H<sub>2</sub>S NIL %, ppm
12. CO<sub>2</sub> 0.38 %
13. Stabilized flowing wellhead pressure 2200 psig
14. Stabilized flowing wellhead temperature 148 °F
15. Wellhead pressure at end of buildup N/A psig
16. Initial reservoir pressure 4232 psig @ 2530 m
17. Final flowing pressure 4058 psig @ 2530 m
18. Productivity index 0.096  $\frac{\text{MSCF/D}}{\text{psi}}$
19. Maximum bottom-hole temperature 213 °F @ 2530 m
20. Samples taken: Two sets of separator samples (pressurized)  
consisting of 1 x 500 cc of liquid. 2 x 20000 cc of gas each.  
1 x 600 cc pressurized liquid sample form separator. 2 x 10 l  
jerry cans of separator liquid (almospheric). 6 x 1 l plastic  
bottles of water from separator. 1 x 250 cc of separator gas  
(pressurized)

BUILDUP ANALYSIS

1. Rate  $q = 18.52$  Gas + Condensate MSCF/D
2. Horner Time:  $\frac{\text{Cumulative production}}{\text{Last rate}} = 9.1$  hr
3. Fluid and reservoir properties
 

Viscosity:  $\mu = 0.0242$  cp at pressure of 4206 psia

Compressibility factor (for gas wells):  $z = 0.900$

Compressibility:  $c = 10^{-4}$  1/psi

Volume factor:  $B = 725$  RB/MSCF at pressure of 4206 psia

Thickness:  $h = 32.8$  ft = 10 m

Perforated thickness:  $h_p = 32.8$  ft = 10 m

Porosity:  $\phi = 20$  %

Wellbore radius:  $r_w = 0.3$  ft = 0.091 m

Bottom-hole temperature:  $T = 213$  °F
4. Initial pressure:  $p_i = 4216$  psig at 2509.8 m
5. Flowing bottom-hole pressure:  $p_{wf} = 4049$  psig at 2509.8 m
6. Wellbore storage:  $\alpha = \text{N/A}$  RB/psi
7. End of afterflow:  $\Delta t_{af} = \text{N/A}$  min
8. Middle time region slope:  $m = 11.1$  psi/log cycle
9. Extrapolated pressure:  $p^* = 4222$  psig at 2509.8 m
10. Ideal buildup pressure at  $\Delta t = 1$  hr:  $p_{wl} = 4211.5$  psig at 2509.8 m
11. Permeability-thickness product:  $kh = \frac{162.6 \text{ quB}}{m}$ 

$$kh = \frac{162.6 (18.52) (0.0242) (725)}{(11.1)} = 4753 \text{ md-ft}$$
12. Permeability:  $k = \frac{kh}{h} = \frac{(4753)}{(32.8)} = 145$  md

13. Diffusivity:  $\eta = \frac{2.637 \times 10^{-4} k}{\phi \mu c}$

$$= \frac{2.637 \times 10^{-4} (145)}{(0.20)(0.0242)(10^{-4})} = \frac{78956}{1} \text{ ft}^2/\text{hr}$$

14. Average permeability:  $\bar{k} = \frac{141.2 q \mu B \ln(r_e/r_w)}{h(p^* - p_{wf})}$  ( $\ln r_e/r_w = 6.0-8.0$ )

$$\bar{k} = \frac{141.2 (18.52) (0.0242) (724) \ln(1740/0.30)}{(32.8)((4222) - (4049))} = \frac{70}{1} \text{ md}$$

15. Radius of investigation beginning of MTR:

$$R_{ib} = \sqrt{4\eta\Delta t} = \sqrt{4(78956)(9.1)} = \frac{1700}{1} \text{ ft} = \frac{520}{1} \text{ m}$$

16. Skin factor:  $s = 1.151 \left[ \frac{p_{wl} - p_{wf}}{m} - \log \left( \frac{k}{\phi \mu c r_w^2} \right) + 3.23 \right]$

$$s = 1.151 \left[ \frac{((4211.5) - (4049))}{(11.1)} - \log \frac{(145)}{(0.2)(0.0242)(10^{-4})(0.3)^2} + 3.23 \right]$$

$$s = \frac{9.61}{1}$$

17. Pressure drop due to skin:

$$\Delta p_s = 0.87 ms = 0.87 (11.1) (9.61) = \frac{93}{1} \text{ psi}$$

18. Flow efficiency:  $E = \frac{p^* - p_{wf} - \Delta p_s}{p^* - p_{wf}}$

$$E = \frac{(4222) - (4049) - (93)}{(4222) - (4049)} = \frac{0.46}{1}$$

19. Damage ratio:  $DR = \frac{1}{E} = \frac{1}{(0.46)} = \frac{2.15}{1}$

20. Productivity index:  $J = \frac{q}{p^* - p_{wf}} = \frac{(13408)}{((4222) - (4049))} = \frac{77.5}{1} \text{ (RB/D) psi}$

21. Closest possible boundary:  $L_{cb} = \frac{760}{1} \text{ ft} = \frac{230}{1} \text{ m}$

## SEPARATOR SAMPLE DATA

SET No. 1

Well 16/7-4 Test DST No. 2 Date 30-11-82  
 Producing Interval 2525 - 35 m  
 Initial Reservoir Pressure 4232 psig @ 2530 m  
 Reservoir Temperature 213 °F @ 2530 m

	Liquid		Gas	
	Sample No. 1	Sample No. 2	Sample No. 1	Sample No. 2
Time Sampled	<u>22.50</u>		<u>22.45</u>	<u>23.00</u>
Length of Time Well was Produced (hrs)	<u>5.22</u>		<u>5.13</u>	<u>5.38</u>
Container No.	<u>0.0.I.Q</u>		<u>A.14077</u>	<u>A.14051</u>
Container Volume (cc)	<u>500</u>		<u>20 000</u>	<u>20 000</u>
Separator Pressure (psig)	<u>410</u>		<u>430</u>	<u>430</u>
Separator Temperature (°F)	<u>100</u>		<u>100</u>	<u>100</u>
Wellhead Pressure (psig)	<u>2180</u>		<u>2183</u>	<u>2178</u>
Wellhead Temperature (°F)	<u>143</u>		<u>143</u>	<u>143</u>
Flowing Bottom-hole Pressure (psig)	<u>4049</u>		<u>4049</u>	<u>4049</u>
Flowing Bottom-hole Temperature (°F)	<u>213</u>		<u>213</u>	<u>213</u>
Separator Rate (Sep. bbl/D)*	<u>2018</u>		<u>2018</u>	<u>2018</u>
Separator Gas Rate (MSCF/D)	<u>16.31</u>		<u>16.31</u>	<u>16.31</u>
Separator GOR (SCF/Sep. bbl)	<u>8082</u>		<u>8082</u>	<u>8082</u> <sup>n 123 bbl</sup>
Well Rate (STB/D) <sup>+</sup>	<u>1762</u>		<u>1762</u>	<u>1762</u>
Well GOR (SCF/STB) <sup>+</sup>	<u>9256</u>		<u>9256</u>	<u>9256</u>
Full Wellstream Water Cut	<u>-</u>		<u>-</u>	<u>-</u>
How Outage was Taken on Liquid Samples	<u></u>			

Gas Sampling Method Evacuated container

Liquid Sampling Method Brine displacement

Special Instruction for Lab

Sampled by OTIS/Alan Black

\* Rates based on Meter Readings corrected for Meter Factor Only.

+ Rates corrected to Stock-Tank Conditions as per Form D-7.

SEPARATOR SAMPLE DATA

SET No. 2

Well 16/7-4 Test DST No. 2 Date 01-12-82  
 Producing Interval 2525 - 35 m (IEL)  
 Initial Reservoir Pressure 4232 psig @ 2530 m.  
 Reservoir Temperature 213 °F @ 2530 m.

	<u>Liquid</u>		<u>Gas</u>	
	<u>Sample No. 1</u>	<u>Sample No. 2</u>	<u>Sample No. 1</u>	<u>Sample No. 2</u>
Time Sampled	<u>01.20</u>		<u>01.35</u>	<u>02.00</u>
Length of Time Well was Produced (hrs)	<u>7.72</u>		<u>7.97</u>	<u>8.38</u>
Container No.	<u>0.O.I.BJ</u>		<u>A.14059</u>	<u>A.14048</u>
Container Volume (cc)	<u>500</u>		<u>20 000</u>	<u>20 000</u>
Separator Pressure (psig)	<u>410</u>		<u>410</u>	<u>410</u>
Separator Temperature (°F)	<u>103</u>		<u>103</u>	<u>103</u>
Wellhead Pressure (psig)	<u>2219</u>		<u>2209</u>	<u>2209</u>
Wellhead Temperature (°F)	<u>147</u>		<u>147</u>	<u>147</u>
Flowing Bottom-hole Pressure (psig)	<u>4049</u>		<u>4049</u>	<u>4049</u>
Flowing Bottom-hole Temperature (°F)	<u>213</u>		<u>213</u>	<u>213</u>
Separator Rate (Sep. bbl/D)*	<u>1987</u>		<u>1987</u>	<u>1987</u>
Separator Gas Rate (MSCF/D)	<u>16.73</u>		<u>16.73</u>	<u>16.73</u>
Separator GOR (SCF/Sep. bbl)	<u>8420</u>		<u>8420</u>	<u>8420</u> <i>~ 118% per</i>
Well Rate (STB/D) <sup>+</sup>	<u>1730</u>		<u>1730</u>	<u>1730</u>
Well GOR (SCF/STB) <sup>+</sup>	<u>9671</u>		<u>9671</u>	<u>9671</u>
Full Wellstream Water Cut	<u>-</u>		<u>-</u>	<u>-</u>
How Outage was Taken on Liquid Samples	<u></u>			

Gas Sampling Method Evacuted container  
 Liquid Sampling Method Brine displacement  
 Special Instruction for Lab

Sampled by OTIS/ Allan Black

\* Rates based on Meter Readings corrected for Meter Factor Only.

<sup>+</sup> Rates corrected to Stock-Tank Conditions as per Form D-7.

SEPARATOR SAMPLE DATA

SET No. 3 (Liquid only)

Well 16/7-4 Test DST No. 2 Date 01-12-82  
 Producing Interval 2525 - 35 m  
 Initial Reservoir Pressure 4232 psig @ 2530 m  
 Reservoir Temperature 213 °F @ 2530 m.

	<u>Liquid</u>		<u>Gas</u>	
	<u>Sample No. 1</u>	<u>Sample No. 2</u>	<u>Sample No. 1</u>	<u>Sample No. 2</u>
Time Sampled	<u>02.30</u>			
Length of Time Well was Produced (hrs)	<u>8.88</u>			
Container No.	<u>80044</u>			
Container Volume (cc)	<u>675</u>			
Separator Pressure (psig)	<u>410</u>			
Separator Temperature (°F)	<u>102</u>			
Wellhead Pressure (psig)	<u>2208</u>			
Wellhead Temperature (°F)	<u>146</u>			
Flowing Bottom-hole Pressure (psig)	<u>4049</u>			
Flowing Bottom-hole Temperature (°F)	<u>213</u>			
Separator Rate (Sep. bbl/D)*	<u>1987</u>			
Separator Gas Rate (MSCF/D)	<u>16.72</u>			
Separator GOR (SCF/Sep. bbl)	<u>8420</u>			
Well Rate (STB/D) <sup>+</sup>	<u>1730</u>			
Well GOR (SCF/STB) <sup>+</sup>	<u>9671</u>			
Full Wellstream Water Cut	<u>-</u>			
How Outage was Taken on Liquid Samples	<u></u>			

Gas Sampling Method Evacuated container  
 Liquid Sampling Method Brine displacement  
 Special Instruction for Lab

Sampled by OTIS/Allan Black

\* Rates based on Meter Readings corrected for Meter Factor Only.

<sup>+</sup> Rates corrected to Stock-Tank Conditions as per Form D-7.

## Appendix II

### Reservoir rate calculation

DST no 1.  
-----

1. Average flowing pressure  $P_{av} = \frac{P_i + P_{wf}}{2} + \frac{P_s}{2}$

$$= \frac{4278 + 3553 + 358}{2} = \underline{4095} \text{ psia at } \underline{2594} \text{ m}$$

2. Full wellstream gravity (EWTM - 160 eq. 96) = 1.077 (Air = 1)

3. Z - factor (EWTM - 090, fig. 10 & 11) = 0.882

4. Reservoir temperature (measured) = 214°F = 674°R

5. Gas formation volume factor

$$B_g = \frac{5040 \times Z \times T}{P_{av}} = \frac{5040 \times 0.882 \times 674}{4095} = \underline{730} \text{ RB/MSCF}$$

6. Surface volume of combined wellstream (gas + condensate)

$$Q_t \text{ (EWTM - 090, fig 9)} = 13.51 + 1.02 \times 1.44 = \underline{14.98} \text{ MSCF/D}$$

7. Rate at average flowing condition

$$q = Q_t \times B_g = 14.98 \times 730 = \underline{10935} \text{ RB/D}$$

DST no 2.

1. Average flowing pressure  $P_{av} = \frac{P_i + P_{wf} + P_s}{2}$

$$\frac{4246 + 4073 + 93}{2} = \underline{4206 \text{ psia}} \text{ at } 2530 \text{ m}$$

2. Full wellstream gravity (EWTM - 160 eq. 96) = 1.069 (Air = 1)

3. Z - factor (EWTM - 090, fig. 10 & 11) = 0.900

4. Reservoir temperature (measured) = 213°F = 673°R

5. Gas formation volume factor

$$B_g = \frac{5040 \times Z \times T}{P_{av}} = \frac{5040 \times 0.9 \times 673}{4095} = \underline{725 \text{ RB/MSCF}}$$

6. Surface volume of combined wellstream (gas + condensate)

$$Q_t \text{ (EWTM - 090, fig 9)} = 16.68 + 1.06 \times 1.74 = \underline{18.52 \text{ MSCF/D}}$$

7. Rate at average flowing condition

$$q = Q_t \times B_g = 18.52 \times 725 = \underline{13427 \text{ RB/D}}$$

### Afterflow Calculations

$$q_{af} = \alpha_{sc} \frac{P_{w2} - P_{w1}}{\Delta t_2 - \Delta t_1}$$

$\alpha_{sc}$  = wellbore storage coefficient

$$= 54.5 \frac{A_{wb}}{M} \left[ 1 - e^{-\frac{0.00065 ML_{wb}}{Z_{wb} T_{wb}}} \right]$$

$A_{wb}$  = cross-section area of liner (ft<sup>2</sup>)<sup>b1</sup>

$M$  = Molecular weight of gas

$L_{wb}$  = distance between packer and perforations (ft)

$Z_{wb}$  = Average Z - factor

$T_{wb}$  = Bottom hole temperature (°R)

DST no 1  
-----

$$A_{wb} = 0.208 \text{ ft}^2$$

$$M = 31.2$$

$$L_{wb} = 108 \text{ ft}$$

$$Z_{wb} = 0.88$$

$$T_{wb} = 674^\circ\text{R}$$

$$\alpha_{sc} = 54.5 \frac{0.208}{31.2} \left[ 1 - e^{-\frac{0.00065 \times 31.2 \times 108}{0.88 \times 674}} \right]$$

$$= 0.0013$$

Pressure change first two min after shutin

$$P_w = P_{w2} - P_{w1} = 3711 - 3538 = \underline{173 \text{ psi}}$$

$$q_{af} = \frac{0.0013 \times 173}{2} \times 60 \times 24 = \underline{162 \times 10^3 \text{ SCF/D}}$$

$$\text{Percent afterflow} = \frac{q_{af}}{q} \times 100 = \frac{162 \times 10^3 \times 100}{15 \times 10^6} = \underline{1\%}$$

DST no 2  
-----

$$A_{wb} = 0.208 \text{ ft}^2$$

$$M = 31.0$$

$$r_{wb} = 147 \text{ ft}$$

$$z_{wb} = 0.9$$

$$T_{wb} = 673^\circ \text{R}$$

$$\alpha_{sc} = 0.0018$$

Pressure change first two minutes after shutin

$$P_w = 4189 - 4049 = \underline{140 \text{ psi}}$$

$$q_{af} = \frac{0.0018 \times 140}{2} \times 60 \times 24 = \underline{181 \times 10^3 \text{ SCF/D}}$$

$$\text{Percent afterflow} = \frac{q_{af}}{q} \times 100 = \frac{181 \times 10^3 \times 100}{18.5 \times 10^6} = \underline{1\%}$$

## Appendix III

### Estimation of volume produced during initial flow period.

On both tests the different bottom hole pressure gauges read a pressure at the end of the initial buildup consistently lower than the extrapolated static pressure. The difference was 16.5 psi on DST No. 1 and 6 psi on DST No. 2.

During the initial flow only a few barrels of gas were flowed into the wellbore. The intention of this was to avoid debris from the perforations to reach the downhole valves with the possible risk of damage and improper seal this could involve.

As the well is shut in the remaining mud and the gas in the rat-hole segregates and a gas/mud contact is formed at certain level. The gas gradient applies from gauge depth down to the gas/mud contact, and the mud gradient from thereon downward.

During the final buildup the rat-hole is filled with gas only and the gas gradient can be used to calculate pressure at any depth.

Figure III 1 and III 2 show the pressure gradients below gauge no 0184 (lowest) calculated from initial and final buildup data for DST - 1 and DST - 2, respectively.

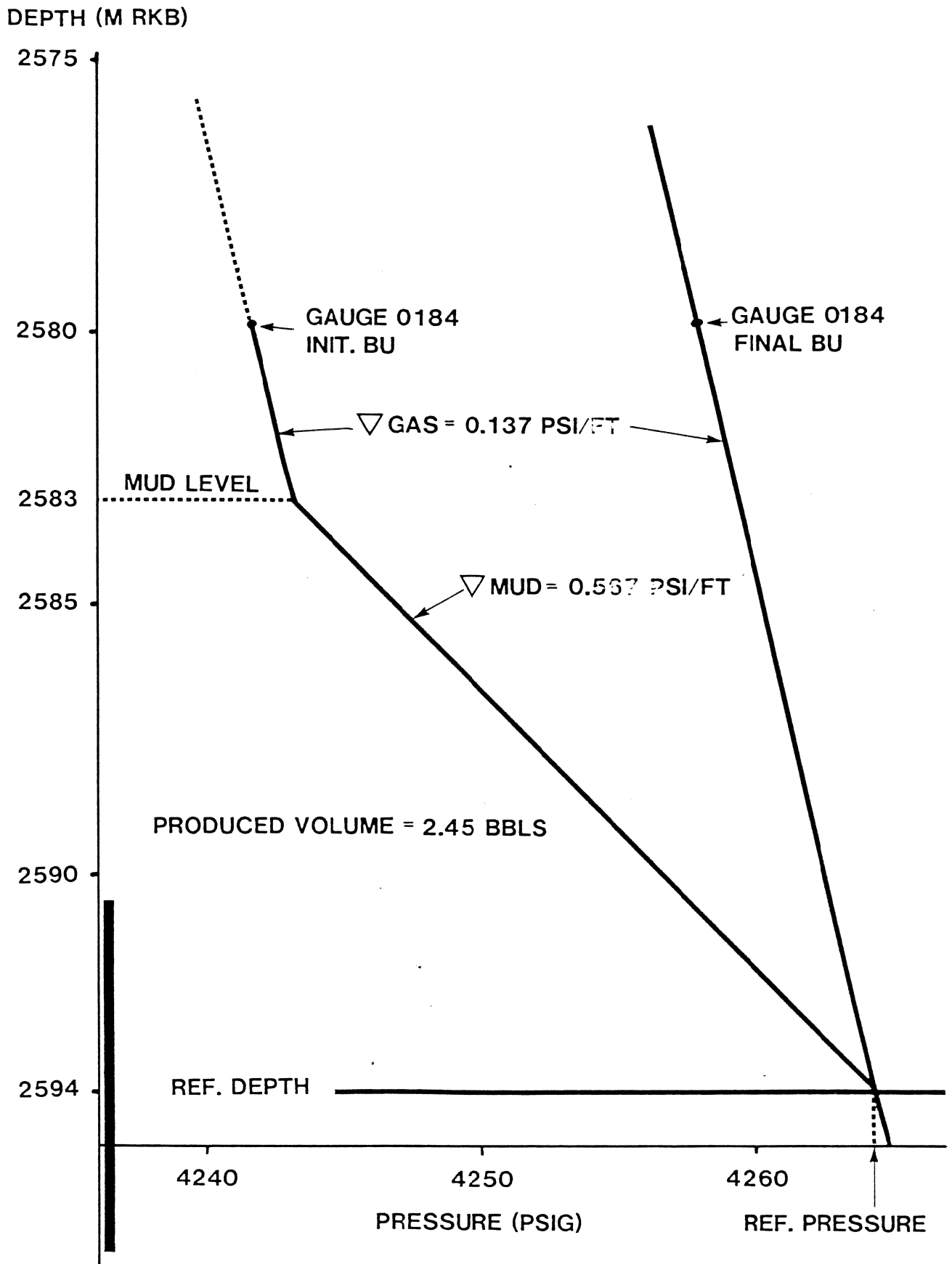
A common reference depth is selected and the mud gradient is drawn from this point upward to where it intersects with the gas gradient line from the initial buildup. The intersection depth corresponds to the mud level. The volume between the packer and the mud level is equal to the produced gas.

The reference depth is somewhat uncertain, but it has to be within the perforated interval. For this exercise, the mid perforations were selected.

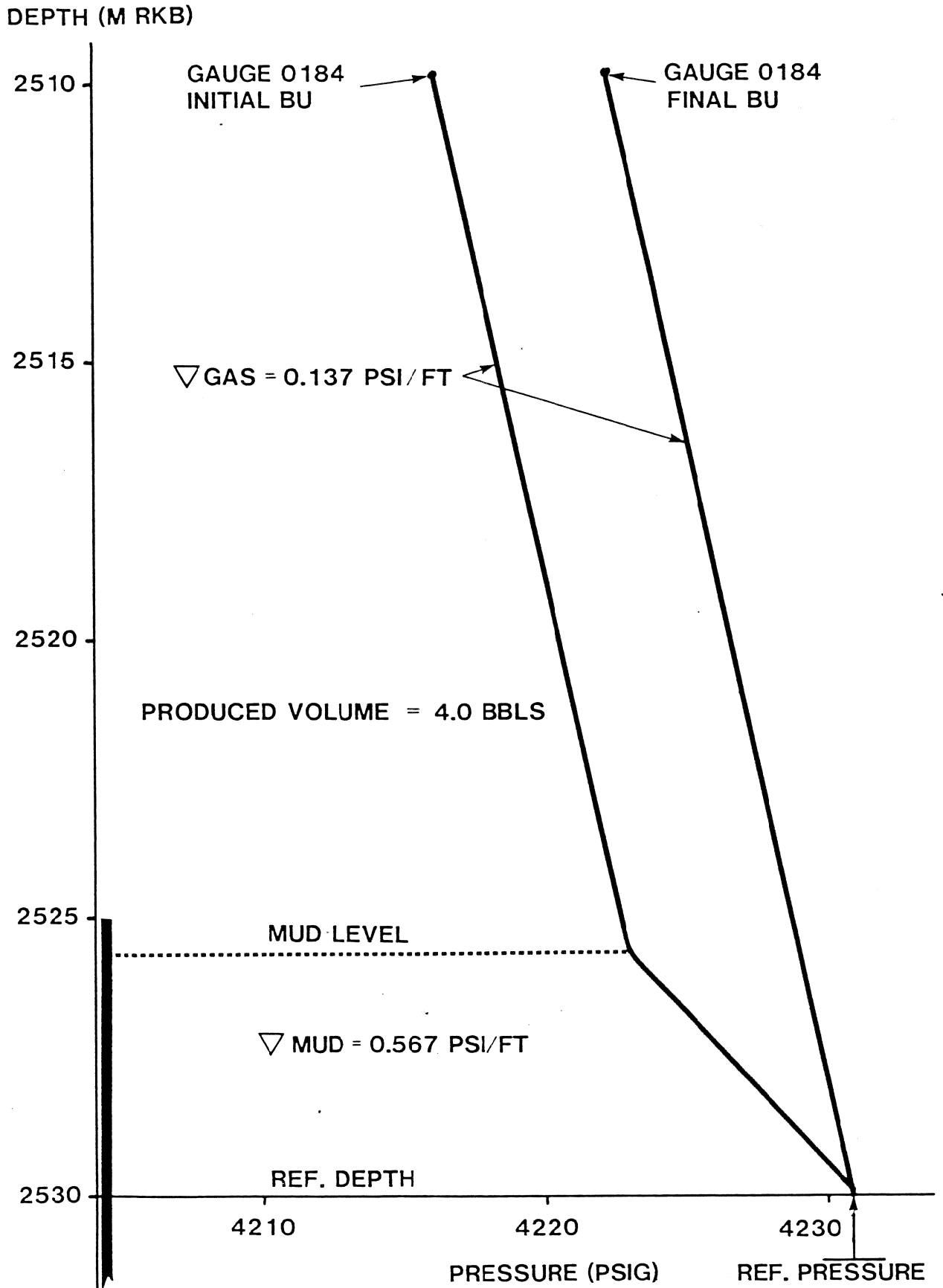
The amount of gas inflow calculated by this method is in good agreement with surface measurements on DST No. 1. The agreement is not so good on DST No. 2 but considering the relatively long flow period and the better performance this test showed later and it is likely that the surface reading is too low.

The gas gradient is calculated from gas property correlations.

FIGURE III.1



# FIGURE III.2



## Appendix IV

### Tubulence analysis

For a stabilized flow situation the pressure drawdown at the wellbore can be calculated using the Houpeurt equation\*.

$$p_e^2 - p_{wf}^2 = C (aq + Dq^2)$$

where

$$C = \frac{1.417 \times 10^6 \mu Z T}{kh}$$

$$a = \ln (0.472 r_e/r_w) + s$$

q = standard condition rate (MSCF/D)

$$D = \frac{2.216 \times 10^{-12} \beta k \gamma_g}{h \mu r_w}$$

$$\beta = \frac{4.851 \times 10^4}{[\phi (1 - S_w)]^{5.5} (\text{kg})^{0.5}}$$

$$r_e = (4 \eta t)^{0.5}$$

$$\eta = \frac{2.637 \times 10^{-4} \times \text{kg}}{\phi \mu c}$$

Calculations are based on 10000 hours flow time.

\* Ref Gas well testing, theory and practice Fourth Edition  
Energy resources conservation board Alberta Canada.

Ideal pressure drawdown

$$P_e^2 - P_{wid}^2 = C a q$$

$$\Rightarrow P_{wid} = (P_e^2 - C a q)^{0.5}$$

Real pressure drawdown

$$P_{wf} = P_{wid} - P_{turb}$$

Tubulence coefficient

$$D = \frac{P_e^2 - P_{wf}^2 - C a q}{C q}$$

Z and  $\mu$  are taken at  $P_{av}$

$$\text{where } P_{av} = \frac{P_e + P_{wid}}{2}$$

DST no 1  
-----

$$C = \frac{1.417 \times 10^6 \times 0.0239 \times 0.882 \times 674}{793} = \underline{25 \times 10^3}$$

$$r_e = \sqrt{4 \times 24159 \times 10000} = \underline{31 \times 10^3 \text{ ft}}$$

$$a = \ln \frac{0.472 \times 31 \times 10^3}{0.3} = \underline{10.8}$$

$$s = \underline{0}$$

$$q = \underline{15 \text{ MSCF/D}}$$

$$P_{wid} = \sqrt{4272^2 - 25 \times 10^3 \times 10.8 \times 15} = \underline{3768 \text{ psia}}$$

$$P_{wf} = 3768 - 338 = \underline{3430 \text{ psia}}$$

$$D = \frac{4272^2 - 3430^2 - 25 \times 10^3 \times 10.8 \times 15}{25 \times 10^3 \times (15)^2} = \underline{0.433}$$

From reservoir properties

$$\beta = \frac{4.851 \times 10^4}{[0.171 (1 - 0.389)]^{5.5} (37.2)^{0.5}} = \underline{2.144 \times 10^9}$$

$$D = \frac{2.216 \times 10^{12} \times 2.144 \times 10^9 \times 37.2 \times 1.07}{21.3 \times 0.0239 \times 0.3} = \underline{1.23}$$

DST no 2  
-----

$$C = \frac{1.417 \times 10^6 \times 0.0242 \times 0.90 \times 673}{4753} = \underline{4370} \checkmark$$

$$r_e = \sqrt{4 \times 78956 \times 10000} = 56 \times 10^3 \text{ ft}$$

$$a = 1n \frac{0.472 \times 56 \times 10^3}{0.3} = \underline{11.8}$$

$$s = \underline{0}$$

$$q = \underline{18.5} \text{ MSCF/D}$$

$$P_{wid} = \sqrt{4237^2 - 4370 \times 11.4 \times 18.5} = \underline{4127 \text{ psia}}$$

$$P_{wf} = 4127 - 61 = \underline{4066 \text{ psia}}$$

$$D = \frac{4237^2 - 4066^2 - 4370 \times 2 \frac{11.4 \times 18.5}{(18.5)}}{4370 \times (18.5)} = \underline{0.334}$$

From reservoir properties

$$\beta = \frac{4.851 \times 10^4}{0.2 (1 - 0.23)^{5.5} (145)^{0.5}} = \underline{0.118 \times 10^9}$$

$$D = \frac{2.216 \times 10^{-12} \times 0.118 \times 10^9 \times 145 \times 1.07}{32.8 \times 0.0242 \times 0.3} = \underline{0.171}$$