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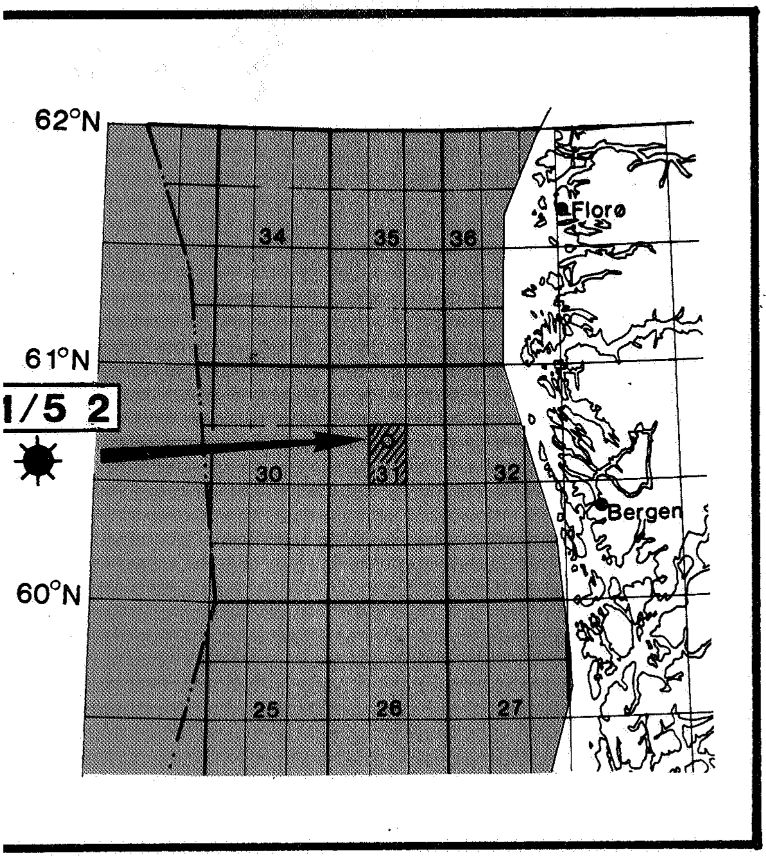
WELL TEST REPORT



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31/5-2 WELL TEST REPORT

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Abstract

Three Drill Stem Tests with gravelpacks have been carried out in the Sognefjord Formation of well 31/5-2, two in the oil zone and one in the overlaying gas zone.

A total oil and water rate of 1033 m^3/d at a wellhead pressure of 19.6 bar was obtained during DST No. 1 (1577.2 - 1581.2 m RKB). A maximum watercut of 62 percent may have been caused by a leak behind the casing.

A maximum total oil and water rate of 1295 m^3/d at a wellhead pressure of 18.1 bar was obtained during DST No. 2 (1574 - 1576 m RKB). The watercut reached 34 percent. The gas oil ratio was measured to 52.5 Sm^3/Sm^3 at 3.8 bar and 29°C.

During DST No. 3 (1546.5 - 1554.5 m RKB), 1.2 x 10^6 Sm^3/d of gas was produced at a wellhead pressure of 69 bar. A condensate gas ratio of 23.3 x 10^{-6} Sm^3/Sm^3 at 31.4 bar and 12.2°C was measured.

A reservoir pressure of 158.6 bar and a temperature of 73.9°C was measured at 1575 m RKB.

Key words

Well 31/5-2, water coning, gas test, gravelpack, gas lift

Classification

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1. SUMMARY

Three drillstem tests have been carried out in the Sognefjord formation in well 31/5-2. Two of the tests were performed in the oil zone and one in the gas zone above. The test intervals were:

1577.2 - 1581.2 m RKB, DST no 1
1574.0 - 1576.0 m RKB, DST no 2
1546.5 - 1554.5 m RKB, DST no 3

The depth refer to CNL-CDL log of 26. oct. 1983, run no. 5c (fig. 1.1).

The objectives of the tests were to:

- Sample reservoir fluids
- Estimate reservoir pressure and temperature
- Evaluate reservoir properties
- Obtain formation productivity
- Evaluate the effect of gravelpacking
- Obtain water/gas coning behaviour (DST no. 1 and 2)
- Estimate skin and turbulence effect
- Measure the actual pressure drop in straight tubing during gas flow (DST no 3)

The well was cleaned up by filtrating the CaCl-brine through a Peco and a Pall filter in series. The well was cleaned up initially, before killing of the well after perforation, before the gravel packing, and prior to stinging through the flapper valve with the teststring.

It was emphasized to obtain the lowest possible particle content in the completion fluid during those phases of the operation where completion fluid necessarily had to be lost to the formation.

The perforation was performed with a 6" Vanngun, 12 shots per foot, on a standard Dowell teststring. The assembly was run on a 3 1/2" VAM-tubing. The well was backsurged and flowed for a 4 hours period at a limited rate. All zones were gravelpacked with 12-20 mesh sand.

A standard Baker crossover tool with associated equipment for semisubmersible platforms was used. A flappervalve was used to minimize the fluid loss after the gravelpack operation.

To minimize the fluid loss while the test string was run it was placed a viscous pill on the top of the flappervalve before the gravelpack assembly was pulled out. The teststring was displaced to diesel before the flappervalve was broken and the seal assembly stinged through the packer. In that way no fluid loss occurred after the flappervalve was broken.

In DST no. 1 the watercut started at 40% and increased to 62% at the highest total rate of 1034 m^3/d. The productivity index was 87.2 m^3/day/bar. Artificial gas lift with N_2-injection through coiled tubing was used at the highest rates. No signs of gas coning was observed.

The high watercut made several problems with the separation of oil and water, and the flow had to be restricted. Injection of a radioactive tracer confirmed a leak behind the casing from the water zone. Analyses of the pressure data showed a permeability of 3200 md with a skinfactor of 7.5. The pressure at 1579.2m RKB was 158.8 bar and the maximum temperature was 68.3°C. The oil and gas spesific gravity was 0.894 and 0.625 respectively.

In DST no. 2 a maximum productionrate of 1296 m^3/day was obtained. The watercut increased and at the end the production rate stabilized at 1073 m^3/day with a watercut of 34%. The real GOR was 52.5 m^3/m^3 at 3.8 bar and 28.9°C. The productivity index was 55.6 m^3/day/bar in the beginning of the main flow period and 21.9 m^3/day/bar in the end.

N_2-injection through coiled tubing was used to stimulate the flow. No signs of gas coning was observed.

The pressure analyses were difficult due to two phase flow. However, the permeability was estimated to 5850 md and the skinfactor to 96. The skin factor increased from 40 to 96 during the main flow, probably due to relative permeability effects with the increasing water cut. The pressure at 1575m RKB was 1300 psi and the highest measured temperature was 73.9°C. The oil and gas spesific gravity were 0.894 and 0.625 respectively.

In DST no. 3 the highest flowrate was 1.23 x 10^6 Sm^3/day. The rate was restricted due to high skin, partly caused by turbulence effects. The well was cleaning up all through the test. The permeability was 5900 md and the skin factor 212. The turbulence skinfactor was 176 and the completion skin was 36. The long clean up period and the high turbulent skin effect was probably due to the first unsuccessful attempt to gravelpack the zone. This caused an excess of the acceptable fluid loss to the formation. The pressure at 1550.5m RKB was 157.9 bar and the highest measured temperature was 68.3°C. The condensate and gas gravity was 0.609 and 0.775 respectively.

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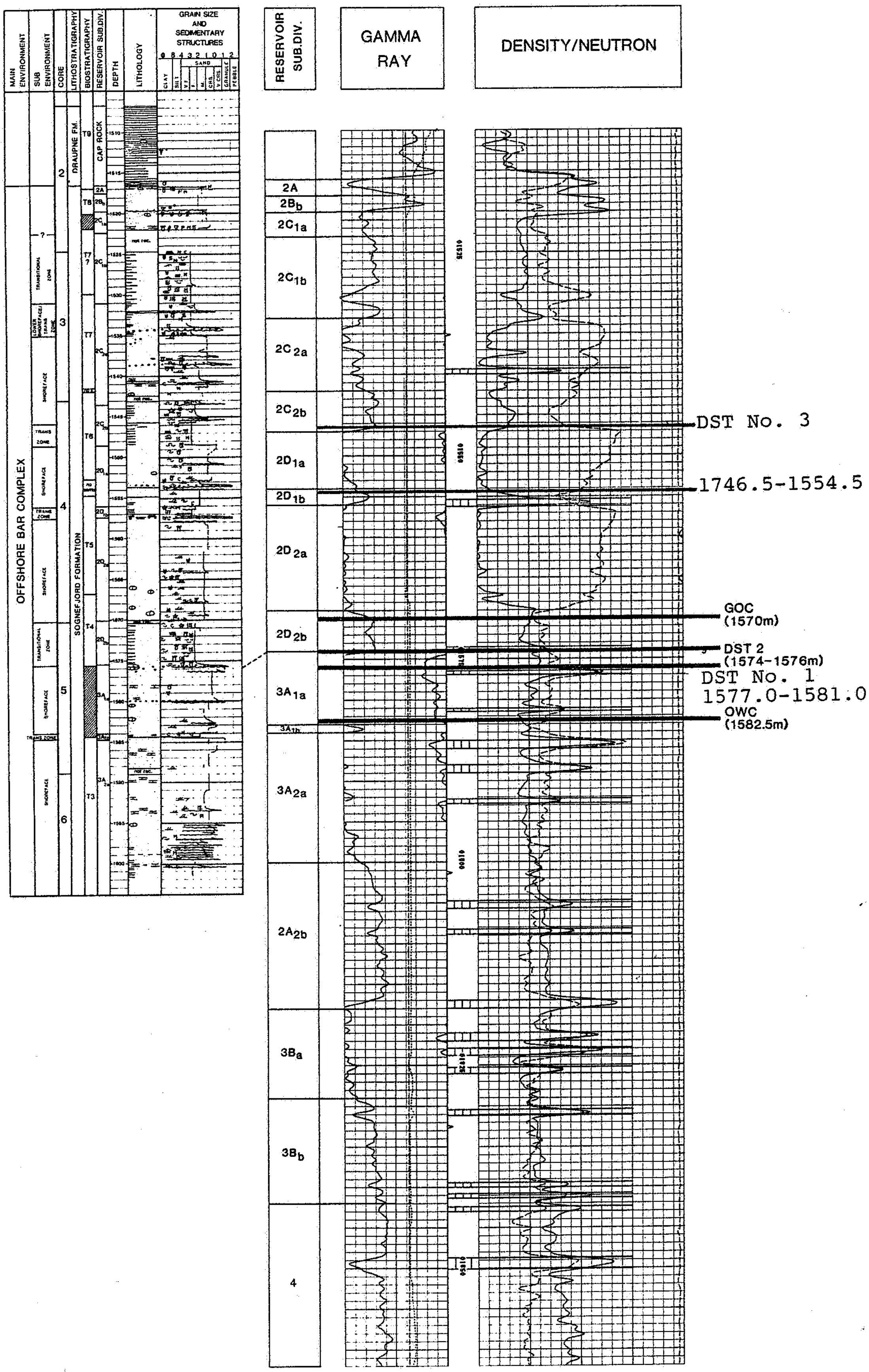
Fig. 1.1: Test intervals
Well: 31/5-2



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2. Results

The main results of the tests are shown in table 2.1.

The Oil Zone in well 31/5-2 is 12.5 m thick. The top 4 m of the oil zone consists of a low permeability micaceons sand which represents a barrier to the gas. The rest of the oil zone is and unconsolidated high permeability sandstone. 0.5 m below the oil-water contact, a thin layer of micaceons sandstone with shale laminae, is present. This layer reduces the effect of the water coning.

The gas zone consists of unconsolidated high permeability sandstone.

All the test intervals were gravel packed. The well was displaced to a filtrated CaCl bine before the first gravel pack operation. The formation was acidized before the main flow periods. N_2 injection through a coiled tubing was applied in DST No 1 and 2 to lift the produced water.

DST No 1 was perforated 1.3 m above the oil-water contact. When the well was opened, the well produced oil at an inital watercut of 40 percent. A maximum total rate of 1030 m^3/D was obtained. At the end of the test, the water cut reaced 62 percent. The gas did not brake through. After the test, water with a radioactive tracer was injected into the perforations. The GR-log, which was run over the interval afterwards, indicated that the high watercut was caused by a leak behind the casing.

DST No 2 was perforated 6.5 m above the oil water contact after squeezing off the perforations from DST No 1. A maximum total rate of 1295 m^3/D was obtained. A water brake through was observed after 30 hours of flow and the water cut increased to a maximum of 34 percent at the end of the test. The gas did not brake through.

DST No 3 was performed in the gas zone. A mulitrate flow test with rates of 0.37, 0.51, 0.87 and 1.22 $10^6 SM^3/d$ resulted in a rate dependent pressure drop of $0.67 x 10^{-3}$ $bar^2/SM^3/d$. Fluid samples were collected at the Thornton test manifold and passed through a 3-stage separation process during a separate sampling flow period.

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2. Main results

	Perforations (m RKB)	Permeability md	Skin	Max total Max. rase	Water cut (%)	Productivity index PI $Sm^3/d/bar$	Formation Pressure (o) pres (bar)	Formation temperature (oC)	Remarks
DST no. 1	1577.2-1581.2	3200	7.4	$1033m^3/d$	62	87.1	158.8	73.9	Oilzone
DST no. 2	1574-1576	5850	96 (*)	$1295m^3/day$	34	21.9 (*)	158.6	73.9	Oilzone
DST no. 3	1546.5-1554.5	5900	212(**)	$1.22x10^6 Sm^3/d$		$1.02x10^5$(***)	157.8	68.3	Gaszone

(o) The formation pressure refers for the middle of the perforations.
(*) The skinfactor and the PI in the beginning of the flow period was respectively 40 and 24.1.
(**) Completion skin of 36
(***) 10^6 $Sm^3/day/bar$

Table 2.1

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3. General Procedures

The general objectives for the program design were:

- to minimize the fluid loss to the formation
- to keep the particle content as low as possible when fluid was lost to the formation.

3.1 Clean up procedure

After conditioning the mud, the well was displaced to seawater. The seawater was circulated until the turbidity level (cloudyness) was irreducible.

The seawater was displaced with CaCl-brine with a specific gravity of 1.15. The brine was filtrated through a system of one Peco nominal and one Pall absolute filter unit in serie. The brine was filtrated until the turbidity level was irreducible. Pills of acid and viscous brine were used to accelerate the clean-up process.

The brine was circulated until the turbidity level was irreducible during the following stages of the test:

- before the perforating string was run in hole
- before the temporary killing of the well.
- before the gravelpacking
- before breaking the flappervalve and landing the teststring
- before the main acid treatment of the formation

3.2 Perforation procedure

The perforation was performed according to the following procedure:

1) Ran in hole with the sump-packer on electrical W.L. Correlated the depth with the Gammaray-CCL log. Set the packer at the prediceted depth.
2) Ran in hole with the DST/perforating-assembly on 3 1/2" tubing.

3) Set the packer.
4) Controlled the correct depth with the Gammaray-CCL.
5) Opened the multiopening circulating valve and circulated bottom up.
6) Displaced the tubing to diesel. Closed the circulating valve.
7) Perforated the well with a 20.7 bar underbalance.
8) Perforated, and the well was left flowing unrestriced for 3-4 min.
9) Choked back to 3.2 mm adj. and changed to 3.2 mm fixed choke. Ran in hole with pressure gauges, and placed them in the F-nipple.
10) Gas appeared at the surface, and the choke was changed to 4.8 mm.
11) Flowed the well at a steady rate of 2 hrs after the diesel cushion was out of the string.
12) Shut in the well at least as long as the flow period.
13) Opened the "multiopening reversing valve", MORV.
14) Cleaned up the well by circulating brine through the MORV.
15) Circulated down a viscous $CaCo_3$-pill to the MORV. The $CaCO_3$ was a mixture of two size graded $CaCo_3$,, 15μ and 40μ.
16) Closed the MORV and opened the testervalve. The $CaCO_3$ pill was pumped down to the perforations. The perforations were plugged off with an overpressure of 13.8 bar.

3.3 Gravel pack procedure

1) Ran in hole the gravelpack equipment on 3 1/2" VAM tubing The seal assembly was stinged into the sump-packer.
2) Reverse circulated one string volum around the packer.
3) Set the packer.
4) Released the crossover tool from the packer and the different circulating positions were indicated with marks on the string at the surface.
5) Functiontested the gravelpack tool in the four different positions.

6) Placed the crossover tool in position 4 and circulated acid down the string until it reached the crossover tool. The amount of acid was 1.3 m^3 per metre of perforations.
7) Lowered the crossover tool to position 2 and the acid was circulated across the perforations at the highest possible rate.
8) Closed the rig choke fully when the annulus volum across the perforations was filled with acid. The acid was pumped into the formation under limited pressure and displaced with the prepad.
9) Reduced the pump rate and opened the choke fully when the prepad was pumped.
10) Pumped the gravelslurry from the tank at a low rate. After the slurry was pumped, it was displaced with the post-pad and the rate was increased to 0.5 m^3/min. The prepad was displaced with brine.
11) Reduced the pump rate when the slurry reached the crossover tool. Placed the slurry behind the screen at low rate.
12) Reduced the rate to a minimum at the first sign of screenout. Kept this rate until initial screen-out was obtained.
13) Lowered the tool down to position 1 and packed the gravel twice.
14) Picked up the crossover tool to position 3 and packed the gravel against the screen.
15) Picked the tool up to position 4 and circulated out all excess gravel. Waited in this position until the viscosity was broken.
16) Lowered the tool down to posisiton 3 and the gravelpack was tested.
17) Pulled 1 stand of tubing to engage the flapper valve which closes the well above the gravelpack and prevents fluid loss.
18) Pulled out of hole.

3.4 Testing procedure

1) Ran in hole with the DST-string and a modified open PCT on a 5" tubing and landed the string on the indicating sub.
2) Rigged up the surface line and circulated to remove eventual sand from the flapper valve, and to clean up the well.

3) Circulated diesel into the tubing to obtain the neccessary underbalance.
4) Lowered the string into the gravelpack and broke through the indicating collet. Stinged the seal assembly through the packer. Landed the fluted hanger.
5) Closed the testervalve. Ran in hole with pressure/temperature gauges and placed then set in the F-nipple
6) Performed a pre-acid flow and build-up, pulled the gauges.
7) Performed an acid job in the following way:
   - opened MORV and circulated the well clean
   - displaced acid down to the top of the tester valve
   - closed the MORV, opened the testervalve
   - bullheaded the acid into the formation with an overpressure of approx. 34.5 bar.
8) Left the acid soaking for approximately 1/2 hour. Flowed the acid out.
9) Ran in hole with pressure gauges and placed then in the F-nipple.
10) Opened the well for clean up.
11) Performed the surface sampling program when the well fluid was clean. Shut in the well for build-up. Pulled the gauges.
12) Performed the bottom hole sampling program if required.
13) Ran in hole with gauges and performed a high rate flow with following build-up.

4. DST No. 1, OIL TEST

4.1 Operation DST No. 1

4.1.1 Perforation

The time required for this operation was extended because the first run with the perforation string was unsuccessful. See appendix A.1 in the sequence of events and Appendix A.4 for a description of the perforation string.
The packer was accidently unset and the string got stuck. It was suspected that the gun was stuck in the sump-packer, and the string had to be pulled.

In the second run everything was carried out as planned, and the procedure described in Section 3.2 was closely followed.

The average flowrate was 55.7 m^3/day during the 4 hours flow period. The stable wellhead pressure was 32.4 bar. The 4m test interval was perforated with 20.7 bar underbalance. No sandproduction was observed.

4.1.2 Gravel packing

The gravelpack procedure was followed as per Section 3.1. See the testprogram for a more detailed procedure and Appendix A.1 for the Sequence of events and Appedix A.5 for a description of the gravelpack assembly. Notice the position of the shearout safety joint. The reason for this design was that it would allow space for the gravelpack assembly in the gas zone without removing the gravelpack completion in the oil zone.

The gravel slurry was a 1.59 m^3 pill containing 12-20 mash sand. About 50% of the gravel was circulated back. The screenout pressure was 48.3 bar and the pressure used to pack the gravel was 69 bar. The pump rate used to place gravel and acid was 0.48 m^3/min.

4.1.3 Testing

The test-string is described in Appendix A.6.

During the acid clean out, the water-cut increased to 40% and formed a stabile emulsion with the oil. The burners were not able to perform the combustion of the emulsion, so the well was shut in to prevent pollution of the sea.

By injecting demulsifier the emulsion was separated and the surface sampling program could be commenced.

The bottomhole sampling program was performed as planned.

The first coning test period had to be terminated after 24 hrs. duration due to combustion problems.

Two attempts to open the well for flow failed due to separation and combustion problems.

A Penkem representative was called out to the rig and a mixture of two demulsifiers was found to separate the emulsion. The demulsifiers was deluted with diesel and injected in the flow line and at the subsea test tree.

As the total flow rate was increased to 1034.0 m^3/day and the water cut increased to 62%, the water rate capasity of the separator was exceeded. It was therefore decided to terminate the test and recomplete an interval higher up in the oil zone. For the coning test, see Appendix A.1 for a closer description of the events and Table 4.1 for the flowing rates.

4.1.4 Sampling

Five recombination samples were taken at the separator while the well was at stable flow. The water content was 40%. The separator pressure was 12.1 bar and the temperature was 55.6 °C. The total flowrate was 238.5 m^3/day.

At the same time three samples were taken at the wellhead. The wellhead pressure was 26.5 bar and the temperature was 10.6 °C.

Two sets of bottomhole samples were taken while the well was flowing on a 6.4 mm choke, see table 4.1. On of the bottomhole samplers failed. The three samples showed estimated bubble-points of 149.7 bar, 149 bar and 148.3 bar at 65.6 °C.

Samples were taken at regular intervals all through the test. The emulsion samples were taken at the wellhead. The oil and water were sampled at the separator.
See the list of the samples in Appendix. A.2.

The dead oil gravity was 0.899 and the gas gravity was 0.685.

4.2 Test interpretation and discussion DST No. 1

Figure 4.2.1 and 4.2.2 show flowrate and pressure vs. time respectively. Figure 4.2.3 - 4.2.10 show the log/log and Horner plots used for the analyses. Data for B.U 1 is recorded by Flopetrols crystal gauge No. 83866. B.U No. 2, 3 and 4 are all taken from Sperry Sun strain gauge No. 0089.

Table 4.2.1 shows the results from the interpretations.

Table 4.2.2 shows the input parameters used for the two phase flow analyses. See Table 4.2.3 for the flowrates used for the different build-up periods. Build-up No. 4 is evaluated to be the most representative and correct. This build-up has a long flowperiod of high rate. However, the results are not optimal because the build-up period lasted for only 3 hrs. 20 min. These analyses may not be respresentative for the entire system since the radius of investigation is short.

Build-up No. 1 gives approximately the same results as from build-up No. 4. The flowrate is, however, limited and unstable because this is the perforation run.

The log/log-plots from B.U. No. 2 and 3 fig. 4.2.5 and 4.2.7 shows that those data are not suitable for Horner analyses. The shape of these curves might indicate effects of cross flow. This cross flow will probably occure because of the higher mobility in the water zone than in the oil zone.

Both the flow and the build up periods No. 2 and 3 are too short to see the radial transient flow.

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DST # 1 1577.2 - 1582.2m RKB

Flowrate/shut in vs. time

Date	Time (hrs. min.)	Duration (hrs/min)	Total flowrate (m^3/day)	Chokesize (mm)
23/6-84	0905 - 1150	2.45	42.9	3.2
	1150 - 1301	1.11	65.4	
	1301 -			
29/6	0120 -			
	0120 - 0224	1.04	206.7	7.9
	0224 - 0250	0.36	79.5	6.4
	0250 - 1510	9.20	0	
	1510 - 1645	1.35	63.6	7.9
	1645 - 1915	2.30	0	7.9
	1915 - 2300	3.45	127.2	9.5
	2300 -			
30/6	0330	4.30	190.8	9.5
	0330 - 1345	10.15	0	
	1345 - 1520	1.35	71.6	4.8
	1520 - 1817	2.57	124.0	7.9
	1817 - 1950	1.33	71.6	4.8
1/7	0805	12.15	111.3	7.9
	0805 - 2245	14.40	238.5	9.5
	2245 -			
2/7	0622	7.37	0	
	0622 - 0745	1.23	111.3	7.9
	0745 - 0944	1.59	365.7	9.5
	0944 - 0955	0.11	0	
	0955 - 1438	4.43	79.5 (est)	6.4
	1438 - 1605	1.27	0	
	1605 - 1708	1.03	31.8 (est)	9.5

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Flowrate/shut in vs. time

Date	Time (hrs. min.)	Duration (hrs/min)	Total flowrate (m^3/day)	Chokesize (mm)
	1708 - 1816	1.08	0	
	1816 - 2255	4.39	254.4	9.5
	2255 -			
3/7	0224	3.34	71.6	6.4
	0229 - 1600	13.31	0	
	1600 - 1908	3.08	190.8	9.5
	1908 - 2135	2.27	270.3	11.1
	2135			
4/7	0115	3.40	333.9	12.7
	0115 - 1415	13.00	429.3	14.3
	1415 - 1830	4.15	715.5	16.7
	1830 -			
5/7	0130	7.00	874.5	19.1
	0130 - 0313	1.43	N/A	20.63
	0313 - 0433	1.20	795.0	17.5
	0433 - 0623	1.50	N/A	20.6
	0623 - 1054	4.31	1001.7	22.2
	1054 - 1610	5.16	0	
	1610 - 1707	0.57	795.0 (est)	19.1
	1707 - 1807	1.00	0	
	1807 - 1929	1.22	795.0 (est)	17.5
	1929 - 2103	1.34	969.9	19.1
	2103 -			

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DST # 1 1577.2 - 1582.2m RKB

Flowrate/shut in vs. time

Date	Time (hrs. min.)	Duration (hrs/min)	Total flowrate (m^3/day)	Chokesize (mm)
6/7	0006	3.03		
	0006 - 0058	0.52	N/A	15.9
	0058 - 0102	0.04		
	0102 - 0220	0.08	N/A	15.9
	0110 - 0225	1.15		
	0225 - 1308	10.43	135.15	9.5
	1308 -			
7/7	0215	13.07	254.4	12.7
	0215 - 0833	6.18	572.4	17.5
	0833 - 1116	2.43	826.8	22.2
	1116 - 1713	5.57	636.0	19.1
	1713 - 1901	1.48	N/A	22.2
	1901 -			
8/7	0037	5.36	954.0	25.4
	0037 - 0306	2.23	1049.4	7.1
	0306 - 0442	1.36	1033.5	25.4
	0442 - 0801	3.19		

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	K (md)	S	ri (m)	P skin (bar)	PI final m^3/bar.d	Remarks
BU 1	3608	3.3	651	.16	127.15	Pre gravel pack
BU 2	N/A	N/A			83.91	Acid clean out flow
BU 3	N/A	N/A			101.4	Surface sampling flow
BU 4	3.194	7.4	481	5.7	87.2	Coning flow

Reservoir pressure at 1579.2m : 158.8 bar

Highest measured temperature: 68.3°C

Ideal PI = 168.3 m^3/bar.d/day/psi

Table 4.2.1: Main results DST # 1 1577.2 - 1581.2m RKB, Well 31/5-2

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Input parameters

Net pay thickness, m	13
Water viscosity, cp	0.45
Oil viscosity, cp	1.98
Fluid viscosity, cp	1.563
Oil formation volume factor, bbl/bbl	1.16
Water formation volume factor, bbl/bbl	1.01
Fluid formation volume factor, bbl/bbl	1.06
Porosity, fraction	0.27
Total compressibility, psi^{-1}	10^{-5}
Well bore radius, ft	0.51

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	max rate (m^3/D)	final rate (m^3/D)	max fw (%)	WHP (bar)	GOR (m^3/m^3)	sep. press. (bar)	sep. temp. (°C)	dur. flow (hrs.min.)	dur. build-up (hrs.min.)	PI (m^3/bar/d)
Pre gravel pack flow	65.3	65.3	-	33.4	-	-	-	3.58	5.0	127.2
Pre acid post gravel pack flow	190.8	71.6	-	13.8	-	-	-	1.29	3.16	83.9
Acid clean out flow	196.0	196.0	25	24.8	-	-	-	8.35	9.52	8.3
Sampling flow	254.4	222.6	58	26.1	55.2	11.0	52.8	33.0	8.16	101.4
Coning flow	1033.5	1001.7	63	19.6	54.7	9.0	60.0	55.17	3.16	87.2

Pi ideal = 73 bbl/day/psi

Table 4.2.3. Flow results DST#1 1577.2 - 1581.2 m RKB. well 31/5-2.

DATE	AUTH.
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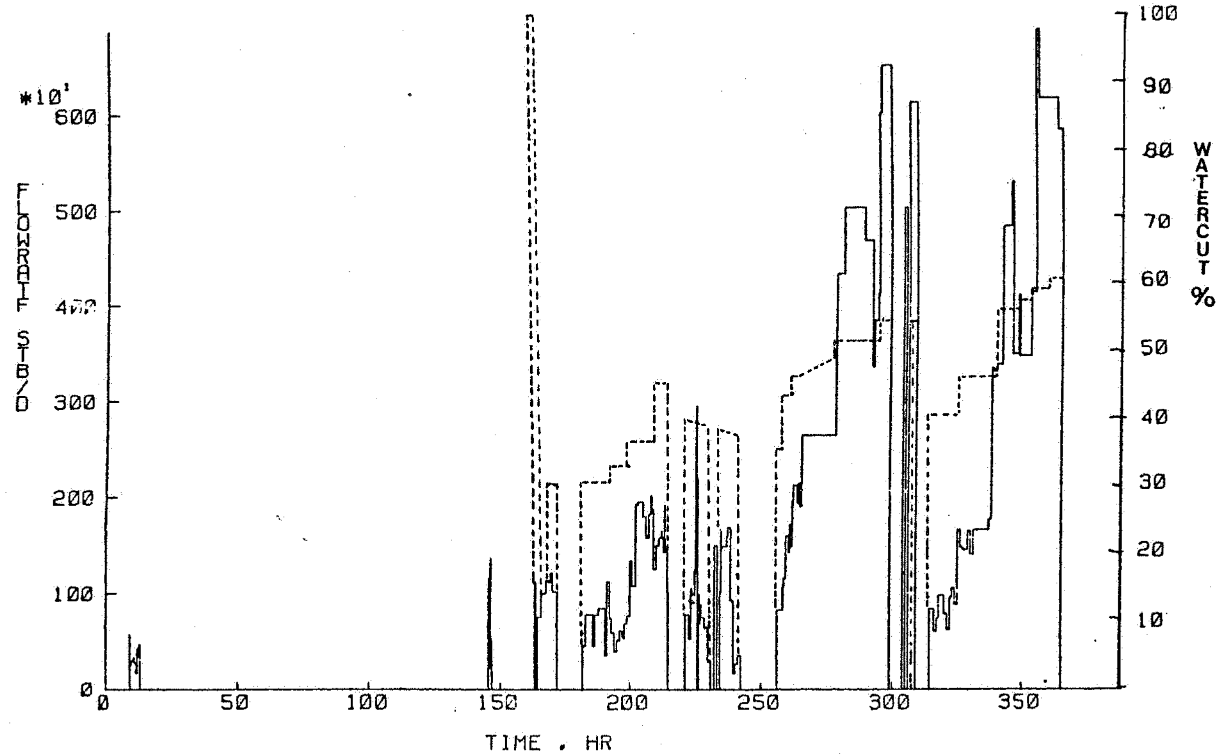
REF	

31/5-2 DST.1 RATE/TIME



------- watercut

——— total rate

Figure 4.2.1

Saga Petroleum a.s.

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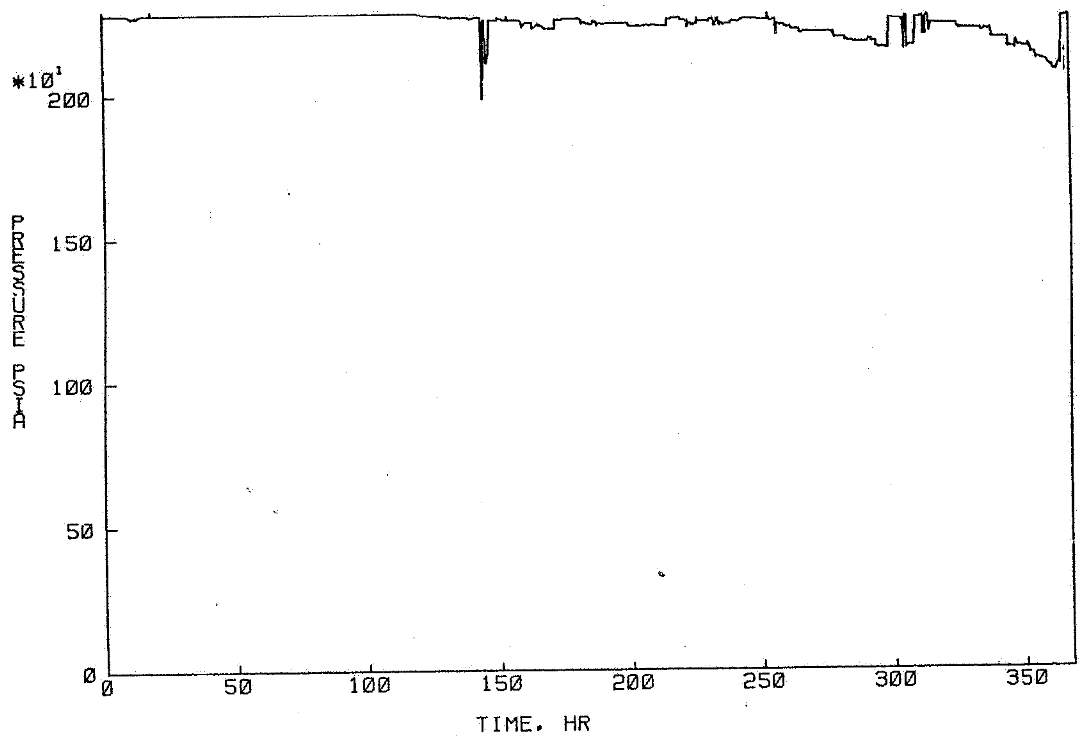
TEGN. AV IJS	GODKJ.
REF.	

31/5-2 DST.1 PRESSURE/TIME



Saga Petroleum a.s.

DATO	FORF.
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REF.	

Figure 4.2.2

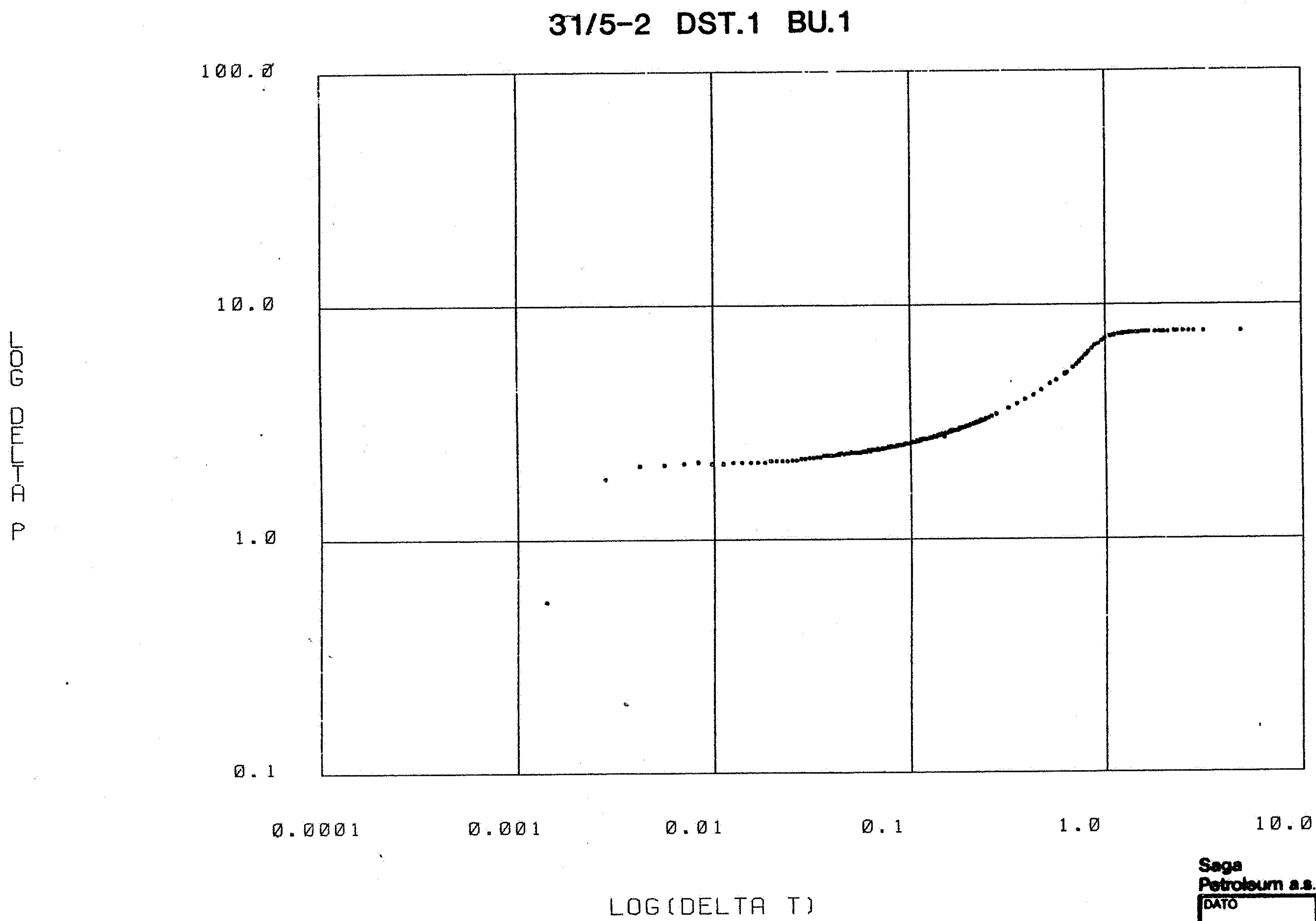


Figure 4.2.3: Log/log-plot.

DATO	FORF.
TEGN.AV	GODKJ.
REF.	

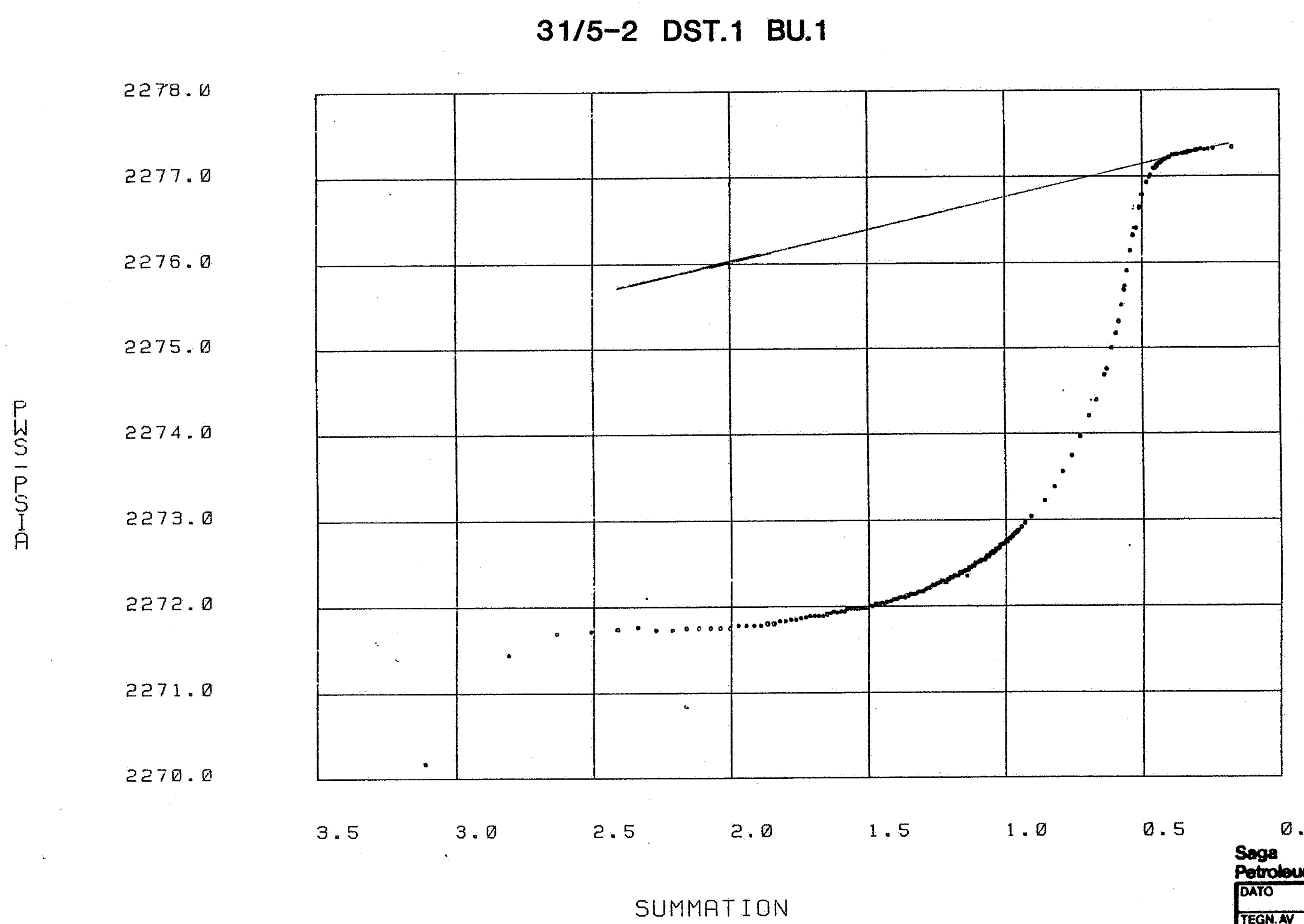


Figure 4.2.4: Horner plot.

DATO	FORF.
TEGN. AV	GODKJ.
REF.	

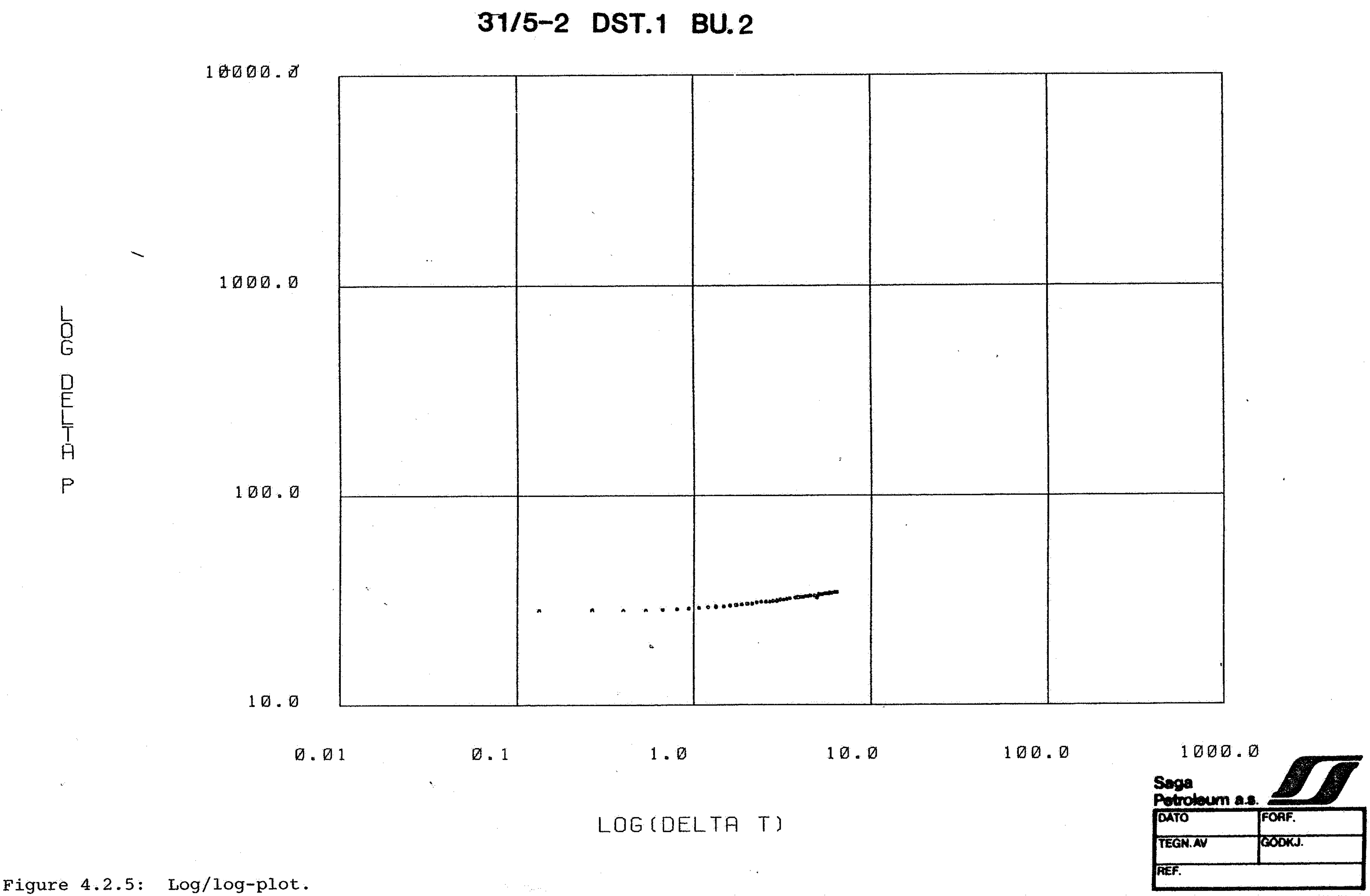


Figure 4.2.5: Log/log-plot.

31/5-2 DST.1 BU.2

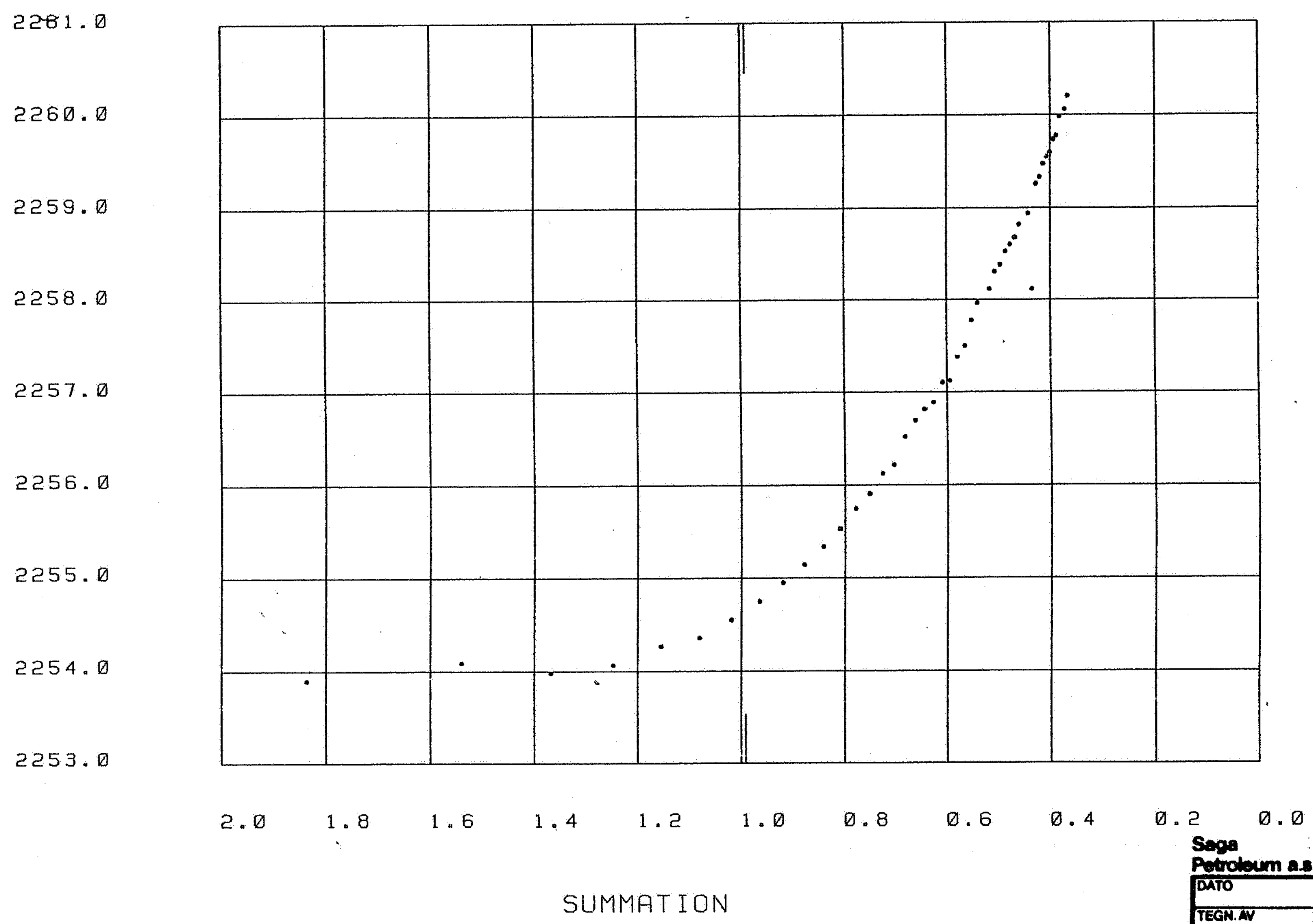
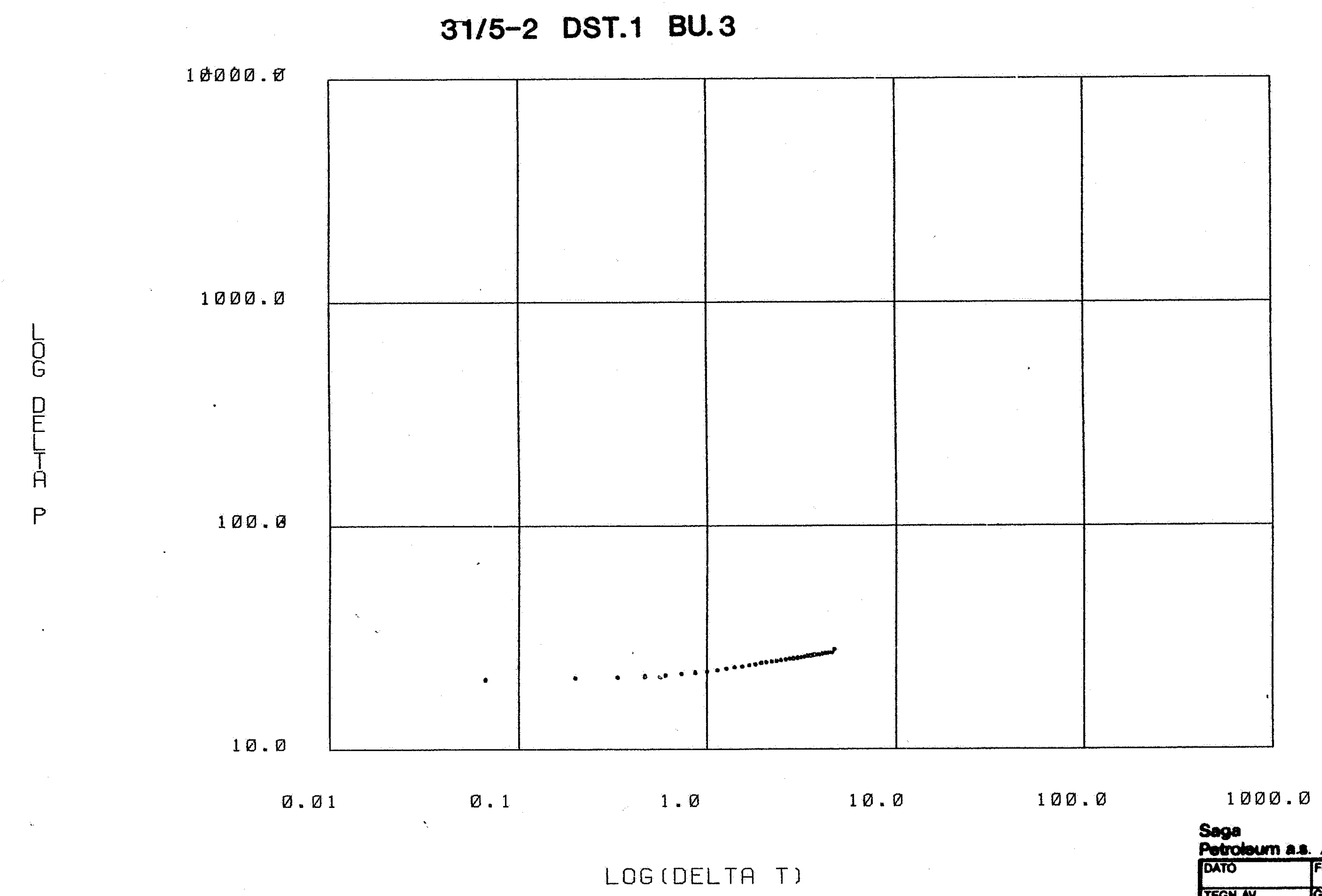


Figure 4.2.6: Horner plot.

Saga Petroleum a.s.

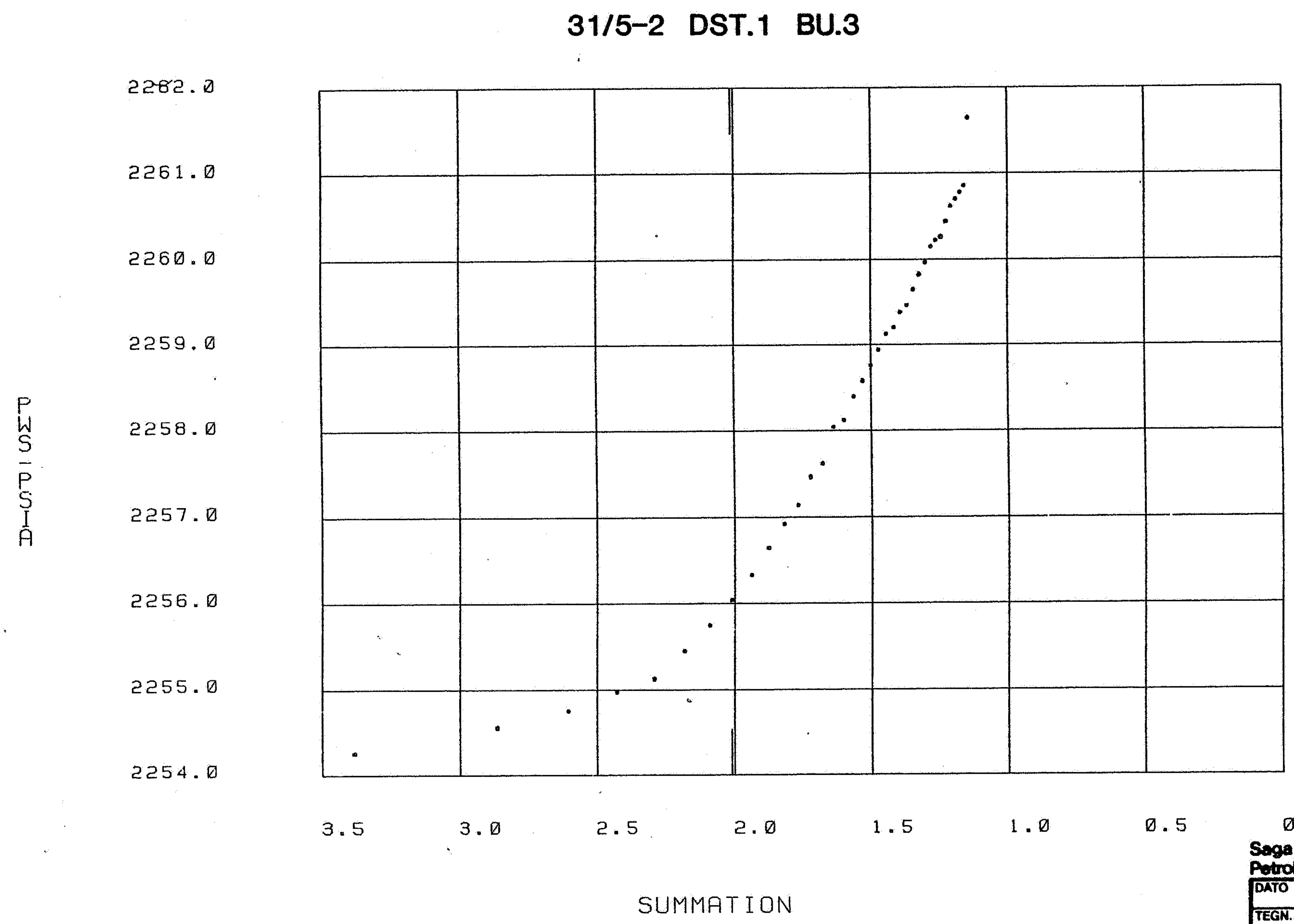
DATO	FORF.
TEGN. AV	GODKJ.
REF.	



Saga Petroleum a.s.

DATO	FORF.
TEGN. AV	GODKJ.
REF.	

Figure 4.2.7: Log/log-plot.



Saga Petroleum a.s.

DATO	FORF.
TEGN.AV	GODKJ.
REF.	

Figure 4.2.8: Horner plot.

31/5-2 DST.1 BU. 4

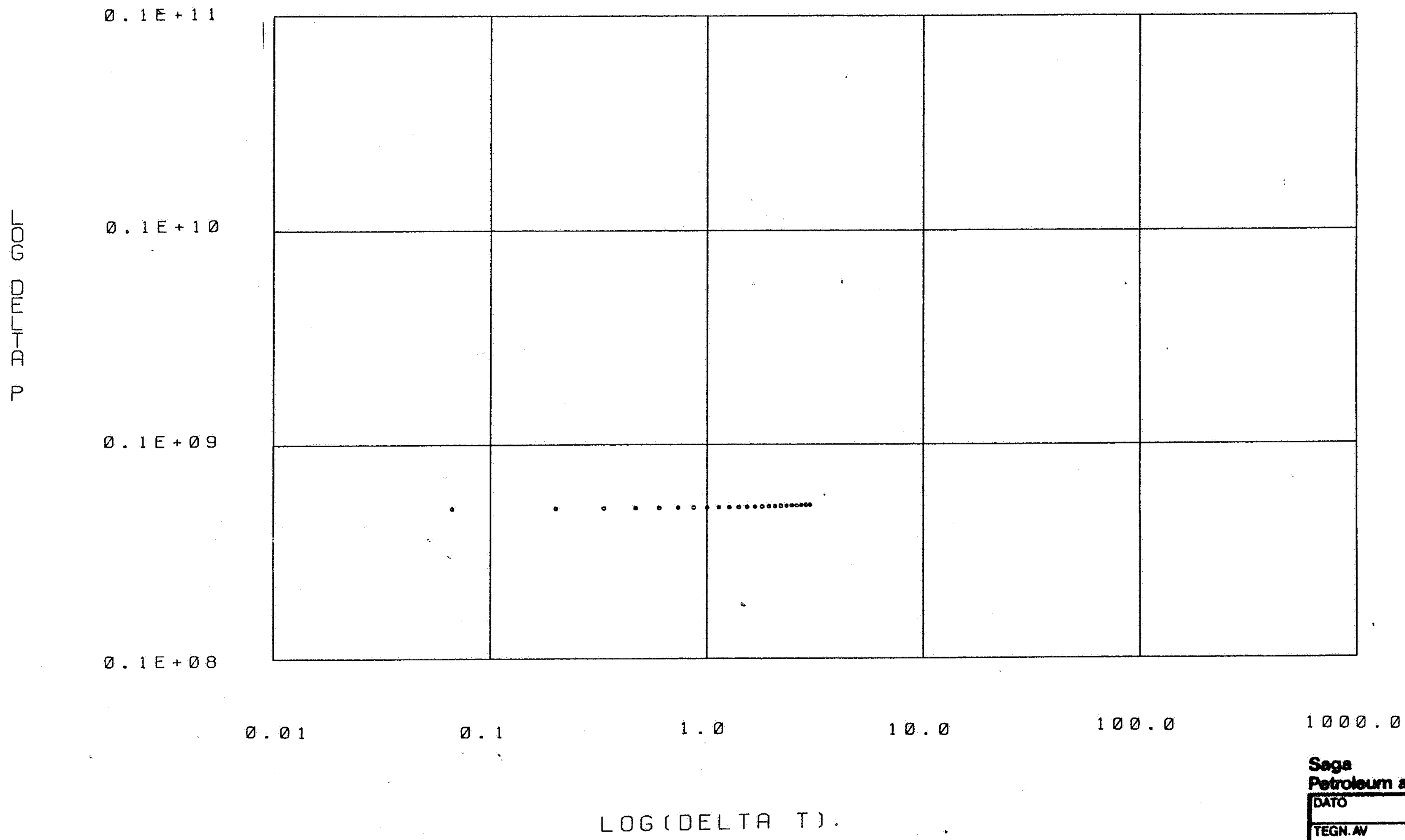
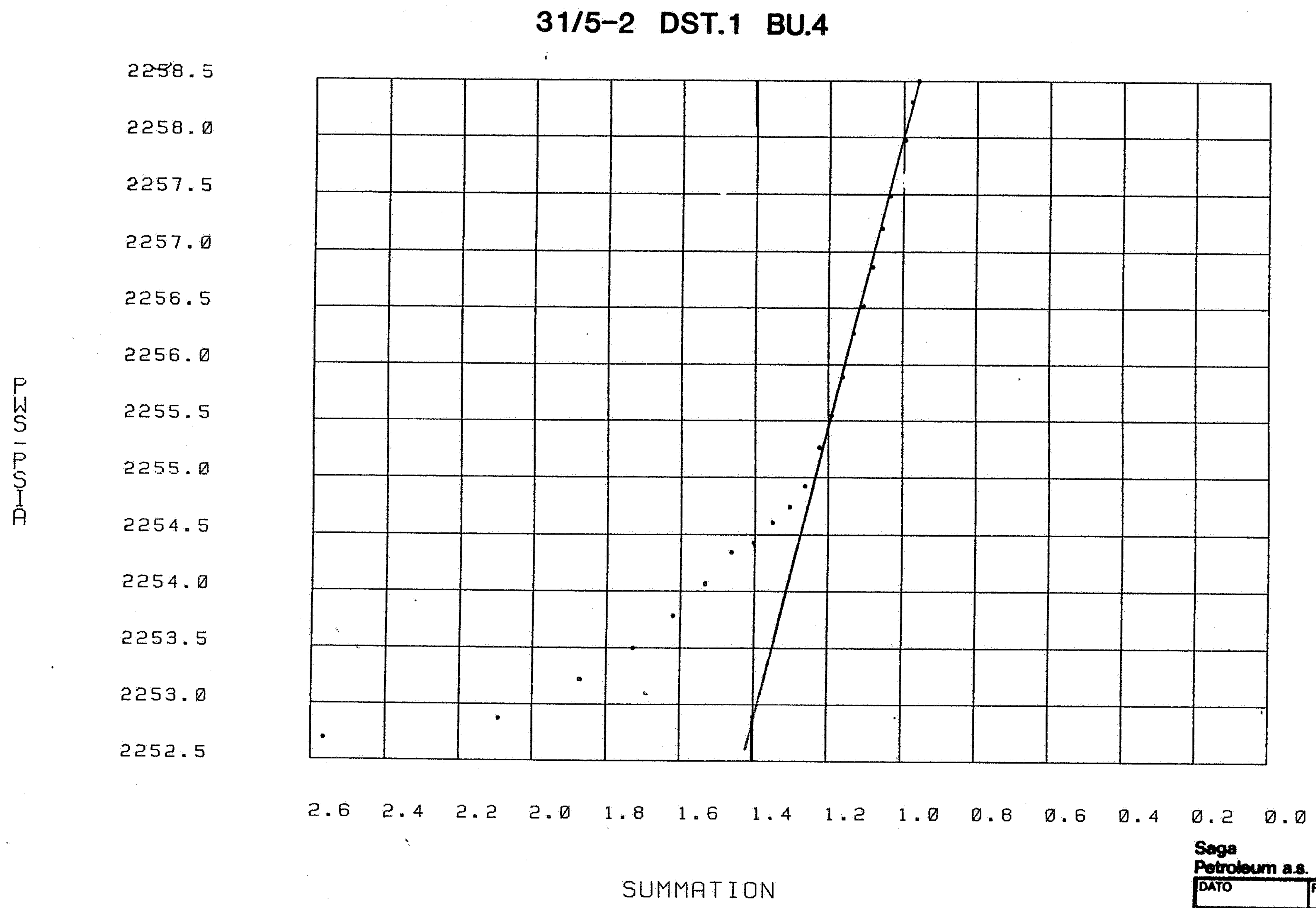


Figure 4.2.9: Log/log-plot.

Saga Petroleum a.s.

DATO	FORF.
TEGN. AV	GODKJ.
REF.	



Saga Petroleum a.s.

DATO	FORF.
TEGN. AV	GODKJ.
REF.	

Figure 4.2.10: Horner plot.

5. DST No. 2, WATER CONING TEST

5.1 Operation DST No. 2

5.1.1 Perforation

The first attempt to run the perforation string failed because the gun hung up in the wear bushing. The 2 3/8" tubing above the perforation gun broke, and the rest of the DST string was run in hole with the gun in the wellhead. This was discovered when trying to land the fluted hanger. While the string was pulled out, the packer got stuck. The string was shot off above the singleshot circulating valve and the top part of the string was pulled out.
In the first attempt to fish the rest of the string, the fish failed to pass through the BOP. The BOP was pulled and the fish was recovered, except for a piece of tubing which fell through the sump-packer.

When the BOP was in position, a new perforation string was run. The perforation procedure was carried out according to the general procedure in Section 3.2. The perforation string is described in Appendix B.4.

The two meter interval (1574-1576m RKB) was perforated with 27.6 bar underbalance. The well was flowed for 4 hrs. with a stable rate of 49.3 m^3/day and a wellhead pressure of 36.2 bar.

After a 6 hrs. build-up period the well was killed with a 2.4 m^3 graded $CaCO_3$ pill. The $CaCO_3$ was a mixture of graded 15μ and 40μ particles.

No sand production was observed and no significant fluid loss occured during the killing procedure.

See Appendix B.1 for the sequence of events.

5.1.2 Gravel packing

It was necessary to modify the gravelpack assembly due to the short perforation interval and the short distance to the gas zone. See Appendix B.5 for a description of the gravelpack assembly. Notice the position of the shear out safety joint.

5.1.3 Testing

The teststring is described in Appendix B.6.

After the gravelpack fluid was cleaned out, the formation was acidized with 3.8 m^3 15% HCL acid. The acid was bullheaded into the reservoir with 34.5 bar overpressure.

When the gauges were set in the F-nipple the wire broke and 1200m of wire was left in the hole.

The well was opened and the acid flowed out to save the gauges from expoture to acid. In the first attempt to fish the wire, the fishing tool latched on to the fish, but could not be recovered because the wire was stuck. The fishing tool could not be released.

While the rig was waiting for fishing experts and equipment, the sampling flow was carried out. The well flowed for 9.5 hrs. with a rate of 401.5 m^3/day. The wellhead pressure was 34.5 bar and no water was observed.

The well was opened to flow in an attempt to release the fish, while the tension on the wire was observed. The fish was not released. The wire was cut and pulled out of hole.

The well was opened again and flowed for 1 hr. 20 min to check the combustion of the oil. No pollution was observed at the sea. The fish was still stuck.

After further attempts some pieces of the wire was recovered, but the settingtool could not be released. The well was killed and the string pulled.

A new string was run. The well was cleaned up and the main flow was started to investigate the coning behaviour.

For the first 125 hours of the flow period the well flowed with no nitrogen lift. The choke was gradually increased for 12.7 mm to fully open. The highest rate was 1296 m^3/day with a wellhead pressure of 13.8 bar. The GOR was 51.7 Sm^3/m^3 at separator conditions of 5.4 bar and 29.4°C. The watercut was 16%.

The rate decreased to 1065.3 m^3/day and the well head pressure decreased to 10.3 bar during a 50 hours period. The watercut increased to 25% during this period. The GOR was 52.5 Sm^3/m^3 with separator conditions of 5.17 bar and 30°C.
An injection test with N_2 was done through the coiled tubing to find the optimal injection rate.

The optimal injection rate was 34.0 m^3/min, which also was the highest obtainable. The flowrate increased from 1073.3 Sm^3/day to 1192.5 Sm^3/day. The wellhead pressure increased from 8.4 bar to 12.4 bar.

During the rest of the flow-period the injection rate was kept at the same level. The injection of N_2 was stopped for a 3 hrs. period twice to check the real GOR. The GOR did not change throughout the test. The rate decreased to 1017.6 Sm^3/day during the 95 hours period the N_2-injection was used. The watercut increased to 34%.

The choke was decreased to 20.6 mm fixed and the well was flowing for a 10 hrs. period with a rate of 532.7 m^3/day and a wellhead pressure of 17.2 bar. The GOR was 44.5 Sm^3/m^3 with separator conditons of 7.9 bar/20°C. The watercut was the same, 34%.

The well was shut in after a total flow period of 133 hours. The build-up period lasted for 11 hrs. 30 min. See Appendix B.1 for the Sequence of Events and table 5.1 for the flow rates.

5.1.4 Sampling

Seven sets of recombination samples were taken at the separator during stable flow conditions. These were taken 24th of July at a separator pressure of 12.1 bar and a temperature of 35.6°C.

Three additional recombination samples were taken at the separator 31st of July. The separator pressure was 11.4 bar and the separator temperature was 21.1°C. The GOR was 46.3 Sm^3/m^3. See Table 5.1 for flowrates etc.

Some bulk samples of oil and water were taken from the separator during the end of the test.

During the entire test, samples were taken at regular intervals on the wellhead and at the separator.

See the list of the samples in Appendix B.2.

The oil gravity was 0.893 and the gas gravity was 0.618 (air = 1). The salinity of the water was 32500 ppm.

5.2 Test interpretation and discussion of DST No. 2

Figure 5.2.1 and 5.2.2 show the flowrates and pressures vs. time respectivley. The data used for the interpretation are the Flopetrol gauge SDP No. 84178 for build-up No. 1, 2, 3, 4 and 5 and the Sperry Sun strain gauge No. 0207 for build-up No. 6.

Figure 5.2.3 - 5.2.14 show the log/log-plots and the Horner plots for each build-up. The interpretation results are presented in Table 5.2.1. The parameters used in the interpretation are presented in Table 5.2.2. The flow rates of each flow-period are presented in Table 5.2.3.

Build-up No. 1 and No. 6 was interpreted by Horner analysis.

In build-up No. 2, No. 3 and No. 4 the well was shut in at the wellhead and a proper Horner line was not obtained due to afterflow. A Gringarten Type Curve analysis was used.
In build-up No. 5 the well was shut in downhole but an interpretable trasient Hornerline is still not reached.

Generally, the two phase flow in the reservoir makes DST No. 2 as well as DST No. 1, difficult to interpret.

The influence of the water might make the results of this interpretation slightly inaccurate.

The results from build-up No. 6 are evaluated to be the most reliable. This was the main flow-period and a straight transient Horner line was obtained.

The results from build-up No. 1 matches fairly good with the results from build-up No. 6.

Cross flow effects

The Horner plots and the log/log-plots have the characteristics of being affected by crossflow. The crossflow does most probably take place because of the difference in the mobilities between the oil zone and the water zone.

Saga Petroleum a.s.

2200P/ASa

DST # 2   1574 - 1576m RKB

Flowrate/shut in vs. time

Date	Time (hrs. min.)	Duration (hrs/min)	Total flowrate (m^3/d)	Chokesize (mm)
19/7-84	1303 - 1305	0.02	N/A	Unrestricted
	1305 - 1552	2.47	47.7	3.2
	1552 - 1703	1.11	48.3	6.7
	1703 - 2225	5.23	0	
22/7	2325 -	72.30		
23/7	0006	0.41	127.2	11.1
	0006 - 0218	2.12	47.7	Fully open
	0218 - 0405	1.47	127.2	25.4
	0405 - 0430	0.25	15.9	11.1
	0430 - 0515	0.45	119.25	7.9
	0515 - 0630	1.15	238.5	11.1
	0630 - 0845	2.15	270.3	
	0845 - 1915	10.30	0	Acid treatment
	1915 - 2110	1.55	262.4	12.7
	2110 -			
24/7	0140	4.30	0	
	0140 - 0530	3.50	405.5	12.7
	0615 - 0721	2.06	636.6	17.5
	0721 - 1018	2.57	0	
	1018 - 1140	1.22	636.0 (est)	17.5
	1140 -			
30/7	0455		0	
	0455 - 1150	6.55	349.8	12.7
	1150 - 1540	3.50	0	
	1540 - 2010	4.30	405.5	12.7
	2010 -			

Table 5.1

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DST # 2 1574 - 1576m RKB

Flowrate/shut in vs. time

Date	Time (hrs. min.)	Duration (hrs/min)	Total flowrate (m^3/day)	N_2-inj. rate (Sm^3/min.)	Chokesize (mm)
31/7	0436	8.21	707.6		17.5
	0436 - 0714	2.38	803.-		20.6
	2052 -				
1/8	0200	5.08	1152.8		25.4
	0220 - 0645	4.45	1160.7		25.4
	0645 - 1400	7.15	1160.7		31.8
	1400 -				
2/8	0325	13.25	1017.6		25.4
	0325 - 0415	0.50	1136.9		31.8
	0415 - 0515	1.00	1192.5		38.1
	0515 - 0645	1.30	1240.2		44.5
	0645 - 1200	5.15	1295.9		44.5
					23.8
	1200				
3/8	0100	13.00	1192.5		44.5
					23.8
	0100 - 0420	3.20	1248.2		2 x 44.5
	0420 - 1010	5.50	1240.2		Fully open
	1010 - 1210	2.0	954.0		25.4
	1210 - 2340	11.30	1192.5		Fully open
	2340 -				
4/8	1710	17.30	1144.8	5.7	" "
	1710 - 2000	2.50	1065.3	0	" "
	2000 - 2200	2.00	1081.2	7.1	
	2200 - 2340	1.40			
	2340 -				

Table 5.1 continue

DATE	AUTH.
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REF	

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2200P/ASa

DST # 2 1574 - 1576m RKB

Flowrate/shut in vs. time

Date	Time (hrs. min.)	Duration (hrs/min)	Total flowrate (m^3/day)	N_2-inj. rate (Sm^3/min.)	Chokesize (mm)
5/8	0100	1.20	1128.9	21.2	Fully Open
	0100 - 0230	1.30	1144.8	28.3	" "
	0230 - 0600	3.30	1192.5	34.0	" "
	0600 -				
6/8	0130	19.30			" "
	0130 - 0440	3.10	938.1	0	" "
	0440 - 2330	18.50	1065.3	34.0	" "
	2330 -				
7/8	0955	10.25	1017.6	22.7	" "
	0955 - 1618	6.23	1065.3	34.0	" "
	1618 - 1935	3.17	890.4	0	" "
	1935 -				
8/8	1740	22.05	1017.6	34.0	" "
	1740 - 2345	6.05	890.4	0	" "
	2345 -				
9/8	1002	10.47	532.7	0	20.6
	1002 - 2200	11.58	0	0	

Table 5.1 continue

DATE	AUTH.
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REF	

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2200P/ASa

	K (md)	S	ri (m)	P skin (bar)	PI final m^3/day/bar	Remarks
BU 1	5.346	14.5	858	.35	101.4	Pre gravel pack
BU 2	6.064	43	52.2	(5.4)	37.6	* Acid clean out
BU 3	7.470	43	1131	(6.0)	56.9	* Sampling flow
BU 4	7.450	43	570	(9.5)	58.5	* Fishing flos
BU 5						Combustion check
BU 6	5.820	96	1260	21.9	21.9	Coning flow **

* The results are obtained by Gringarten type curve interpretation

** The initial PI was 55.6 m^3/day/bar

( ) The m-factor was evaluated from the type curve interpretation
The reservoir pressure at 1585m RKB was 158.6 bar
The highest measured temperature was 73.8°C

Table 5.2.1: Main results DST # 2 1574 - 1576m RKB, Well 31/5-2

DATE	AUTH.
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REF	

2200P/ASa

Input parameters

Net pay thichness, m	13
Water viscosity, cp	0.45
Oil viscosity, cp	1.98
Fluid viscosity, cp	1.563
Oil formation volume factor m^3/m^3	1.16
Water formation volume factor m^3/m^3	1.01
Fluid fomation volume factor m^3/m^3	1.06
Porosity, fraction	0.27
Total compressibility, psi^{-1}	10^{-5}
Well bore radius, ft	0.51

Table 5.2.2

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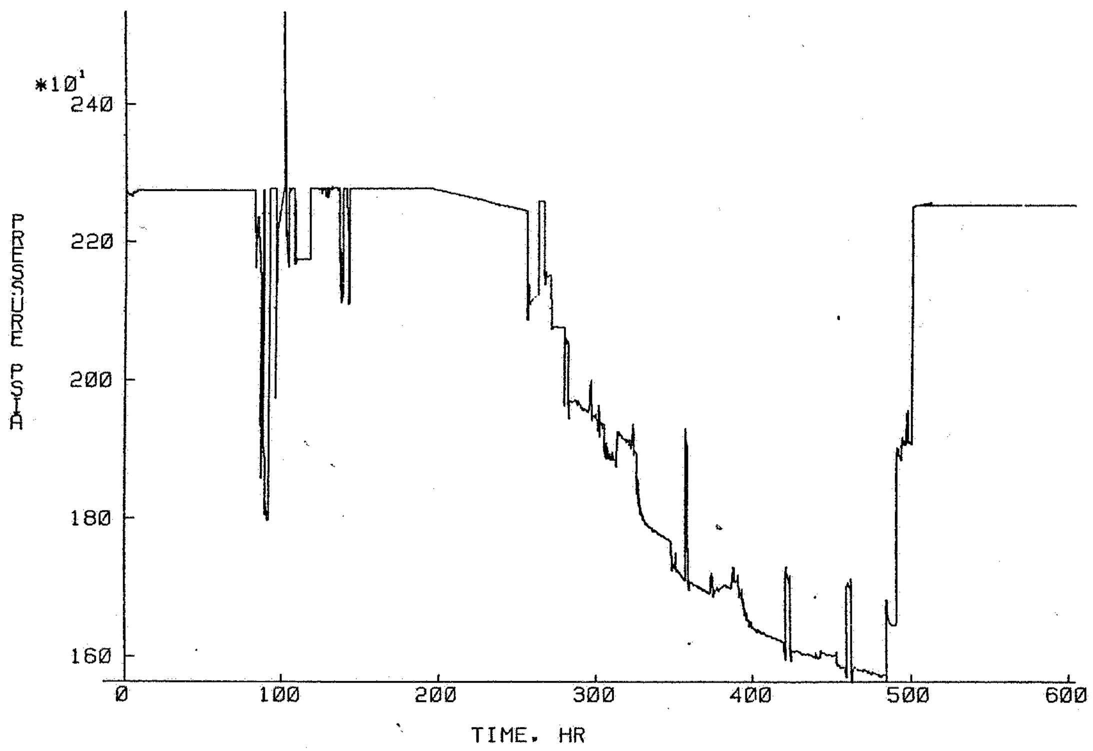
	max rate m^3/day	final rate m^3/day	max fw %	WHP bar	GOR m^3/m^3	sep. press. bar	sep. temp. (°C)	dur. flow hrs.min.	dur. build-up hrs.min.	PI m^3/day/bar
Perf. flow	60.4	49.3	-	37.2	-	-	-	4.0	6.0	101.4
Gravel pack clean out flow	433.3	278.3	-	26.5	-	-	-	9.20	4.35	8.5
Acid clean up flow	291.0	291.0	-	35.5	-	-	-	1.55	3.30	376
Sampling flow	401.5	401.5	-	41.2	46.3	10.3	21.1	9.50	10.1	56.9
Flow during fishing	644.0	644.0	-	35.5	-	-	-	1.51	12.54	58.6
Combustion check		636.0	-	35.5				1.20	4.28	-
Coning flow	1.295,9	532.7	34	18.1	52.5	2.8	28.9	233.32	11.39	22.0

* Initial productivity index of coning flow was 55.6 m^3/day/Sai.

Table 5.2.3 Flow results DST # 2 1574 - 1576 mRKB, hull 31/5-2.

DATE	AUTH.
DRAW.BY	APPR.
REF	

31/5-2 DST.2 PRESSURE/TIME



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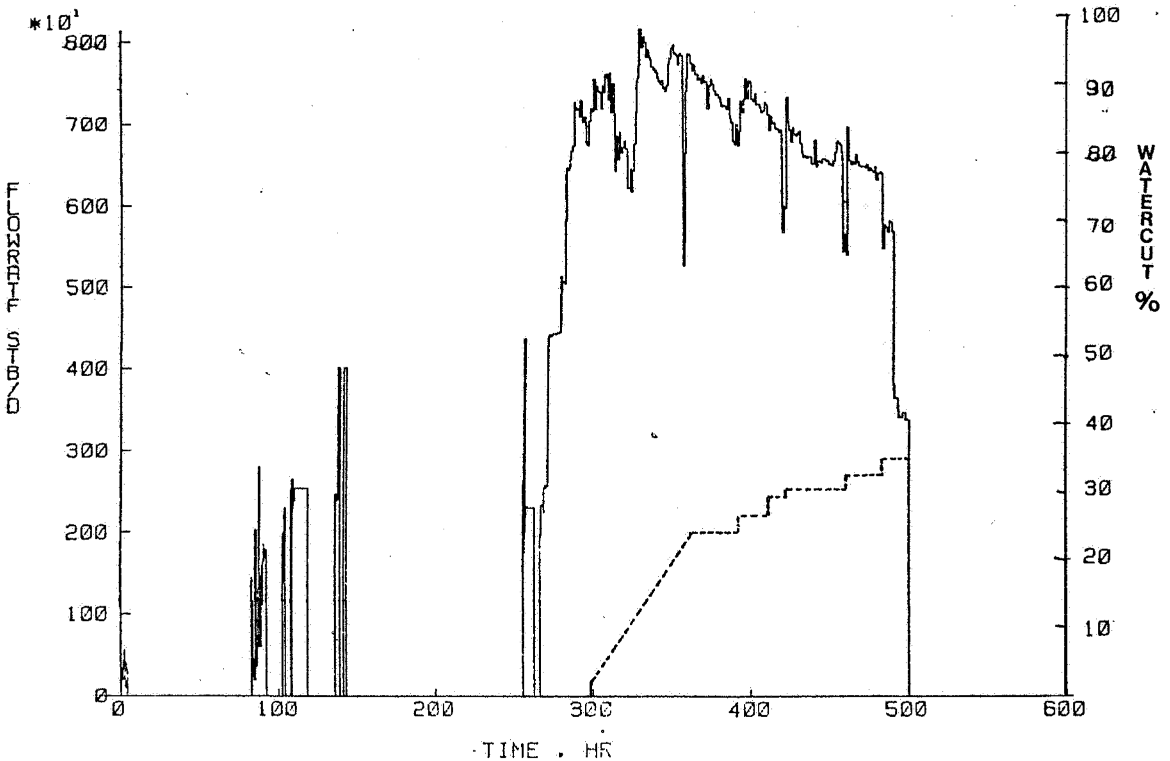
REF.	

Figure 5.2.1

31/5-2 DST.2 FLOWRATE/TIME



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TEGN. AV	GODKJ.
REF.	

Figure 5.2.2

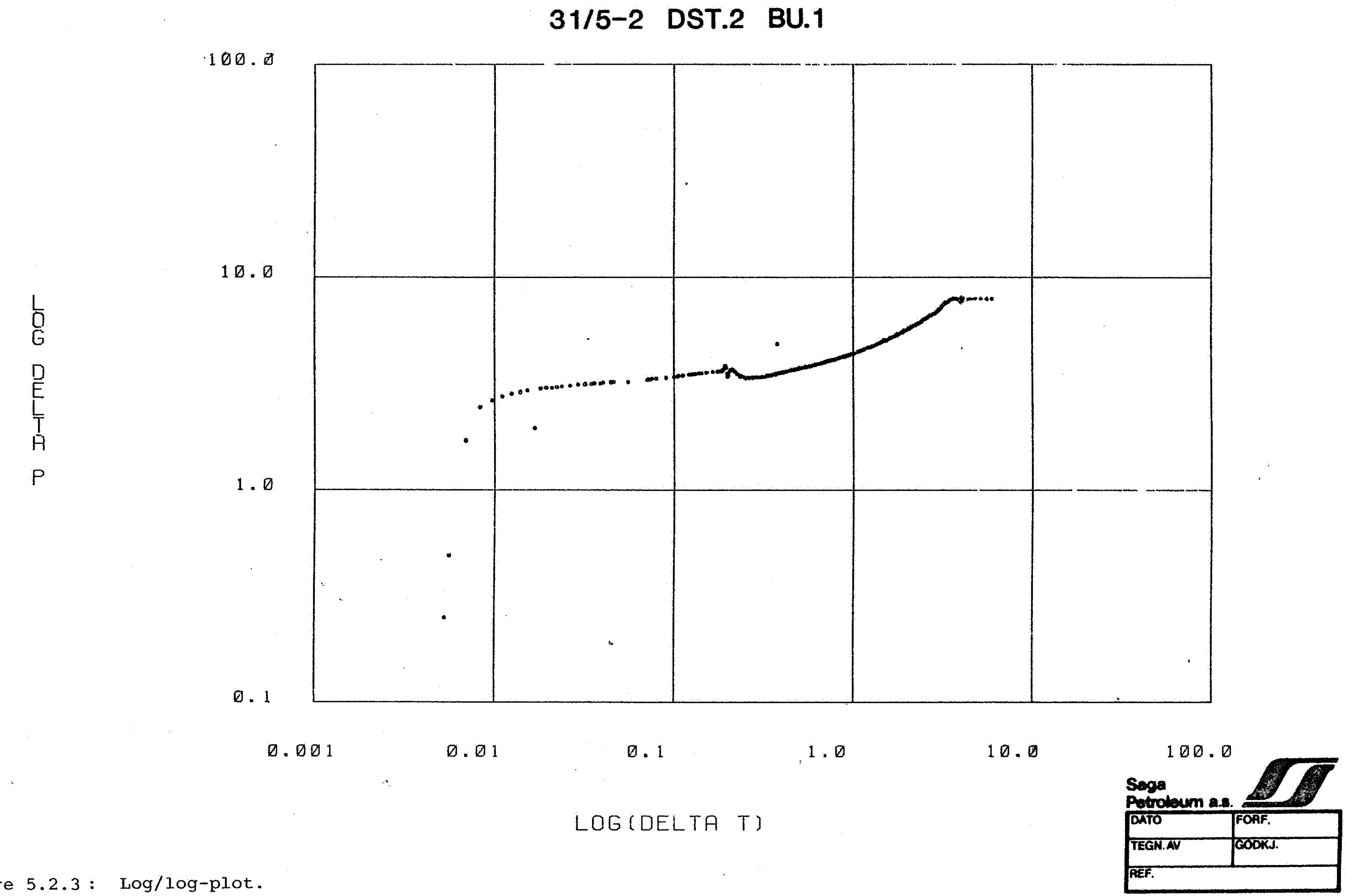
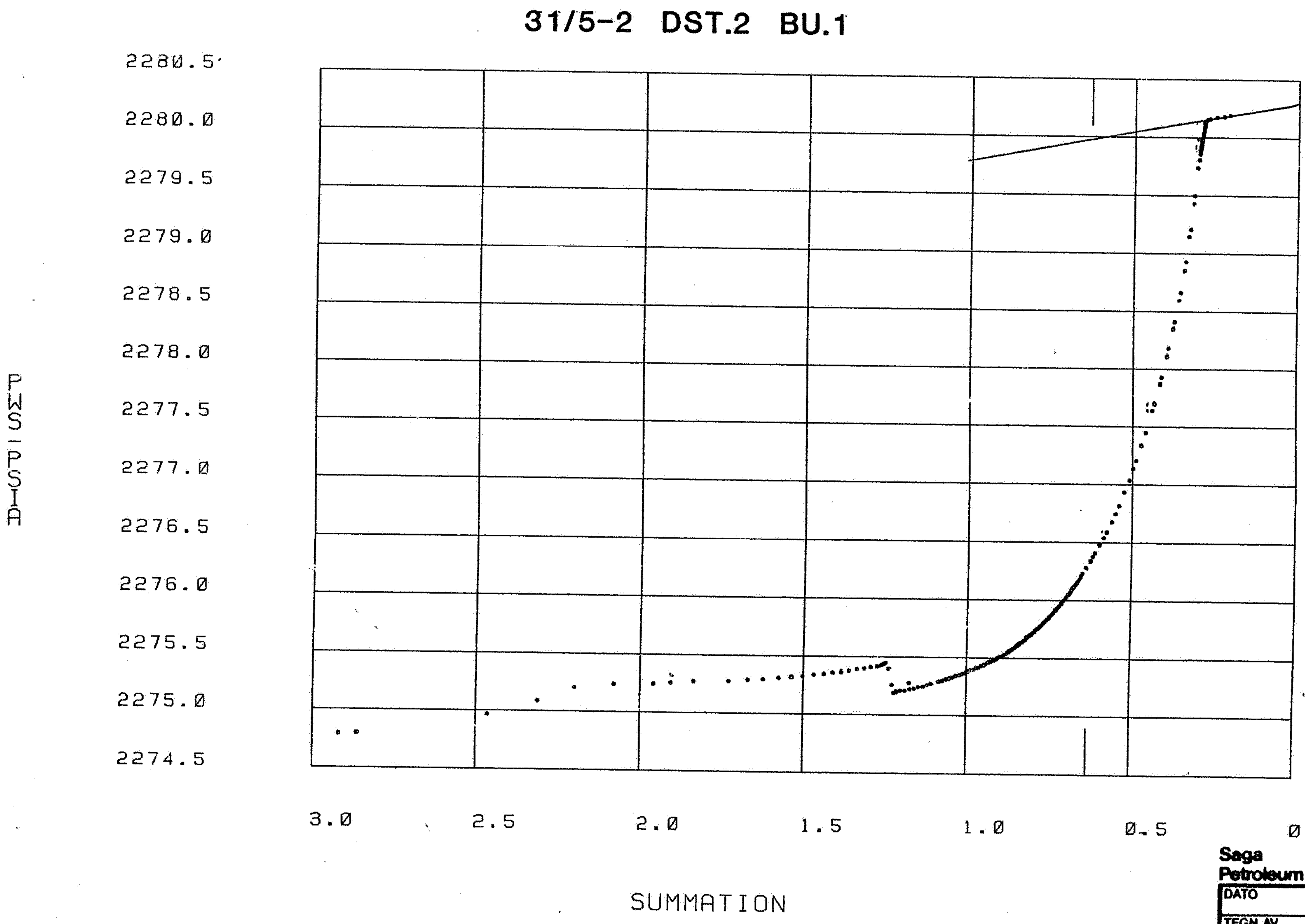


Figure 5.2.3 : Log/log-plot.



Saga Petroleum a.s.

DATO	FORF.
TEGN.AV	GODKJ.
REF.	

Figure 5.2.4: Horner plot.

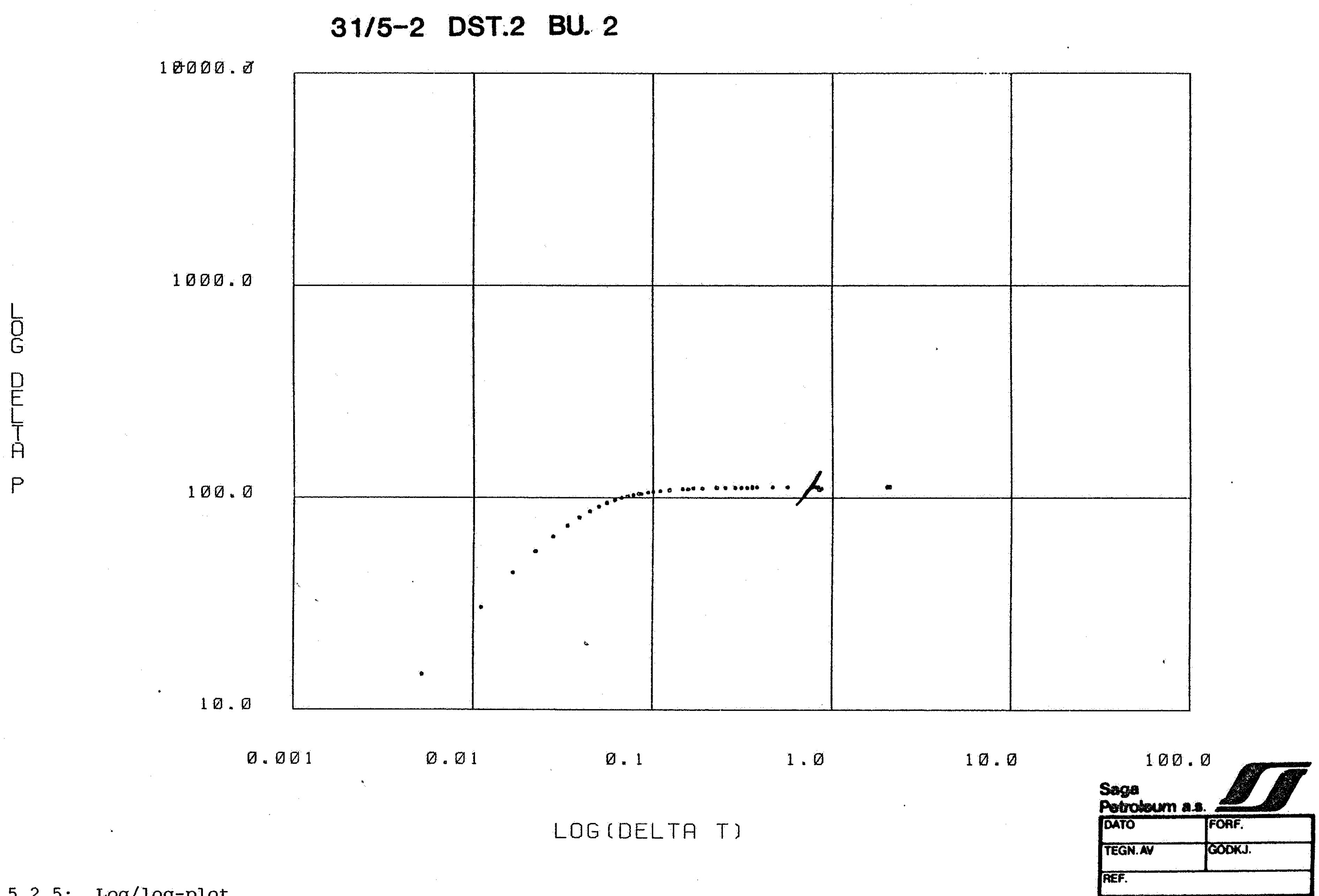


Figure 5.2.5: Log/log-plot.

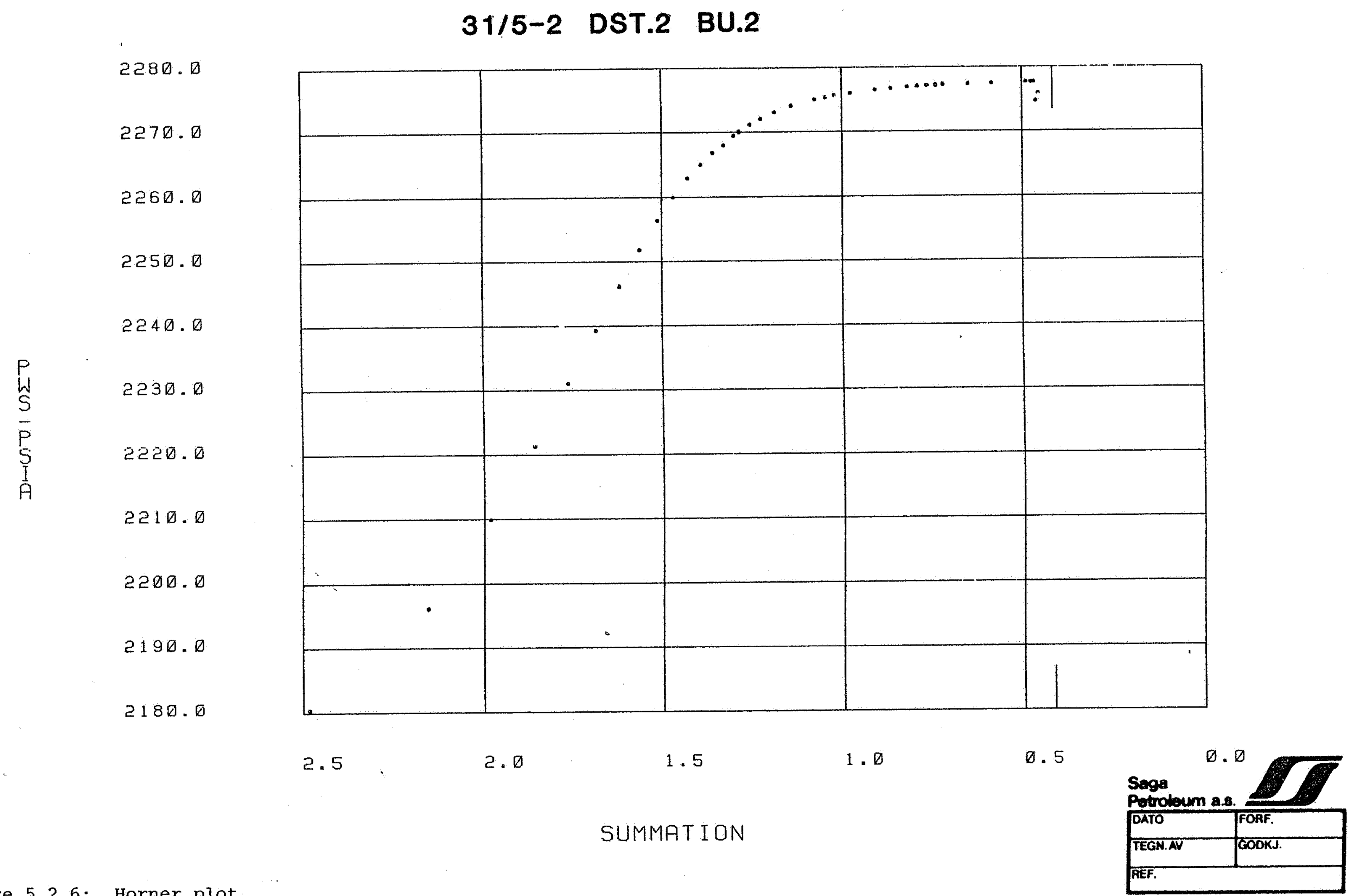


Figure 5.2.6: Horner plot.

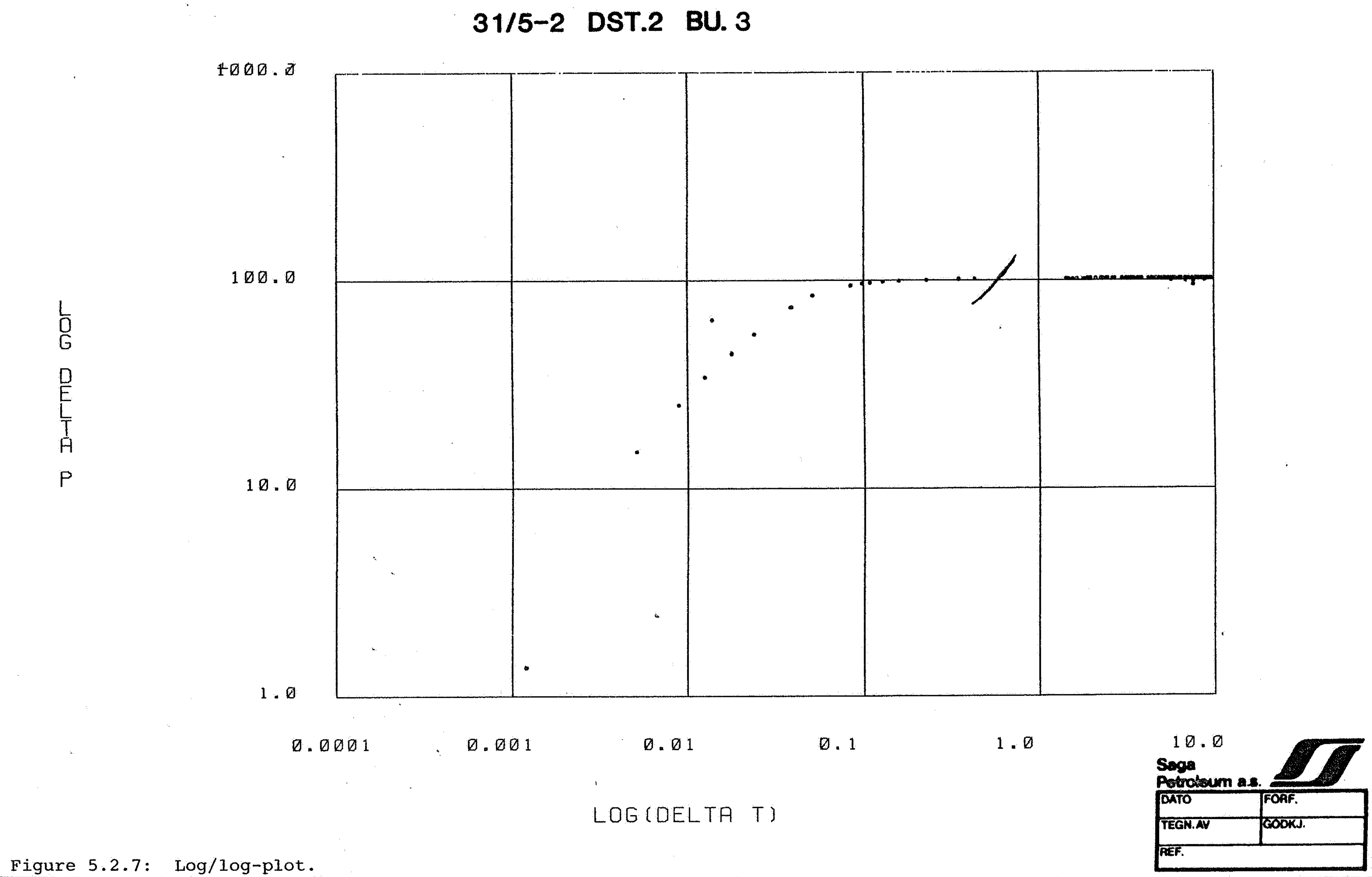


Figure 5.2.7: Log/log-plot.

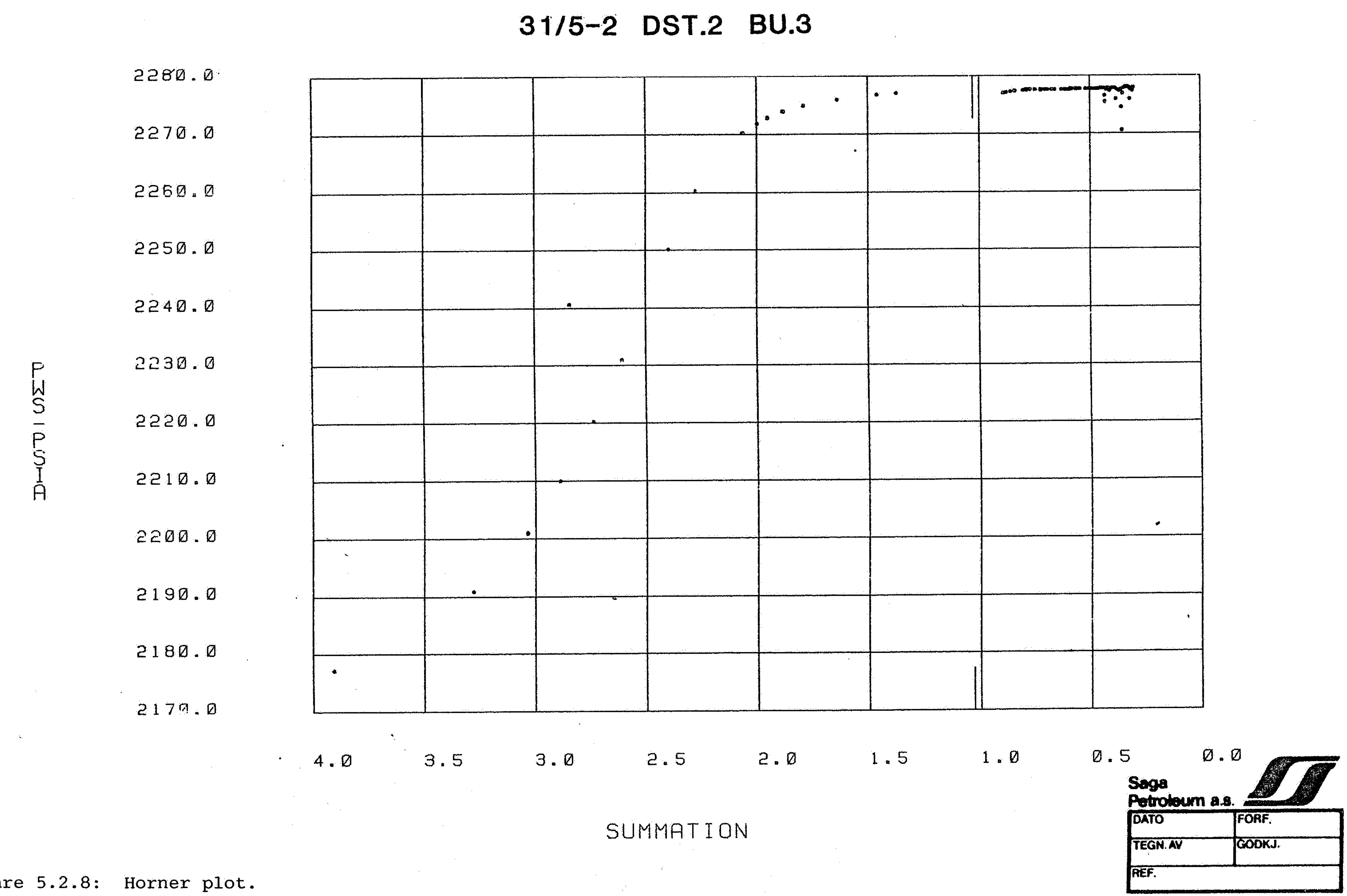


Figure 5.2.8: Horner plot.

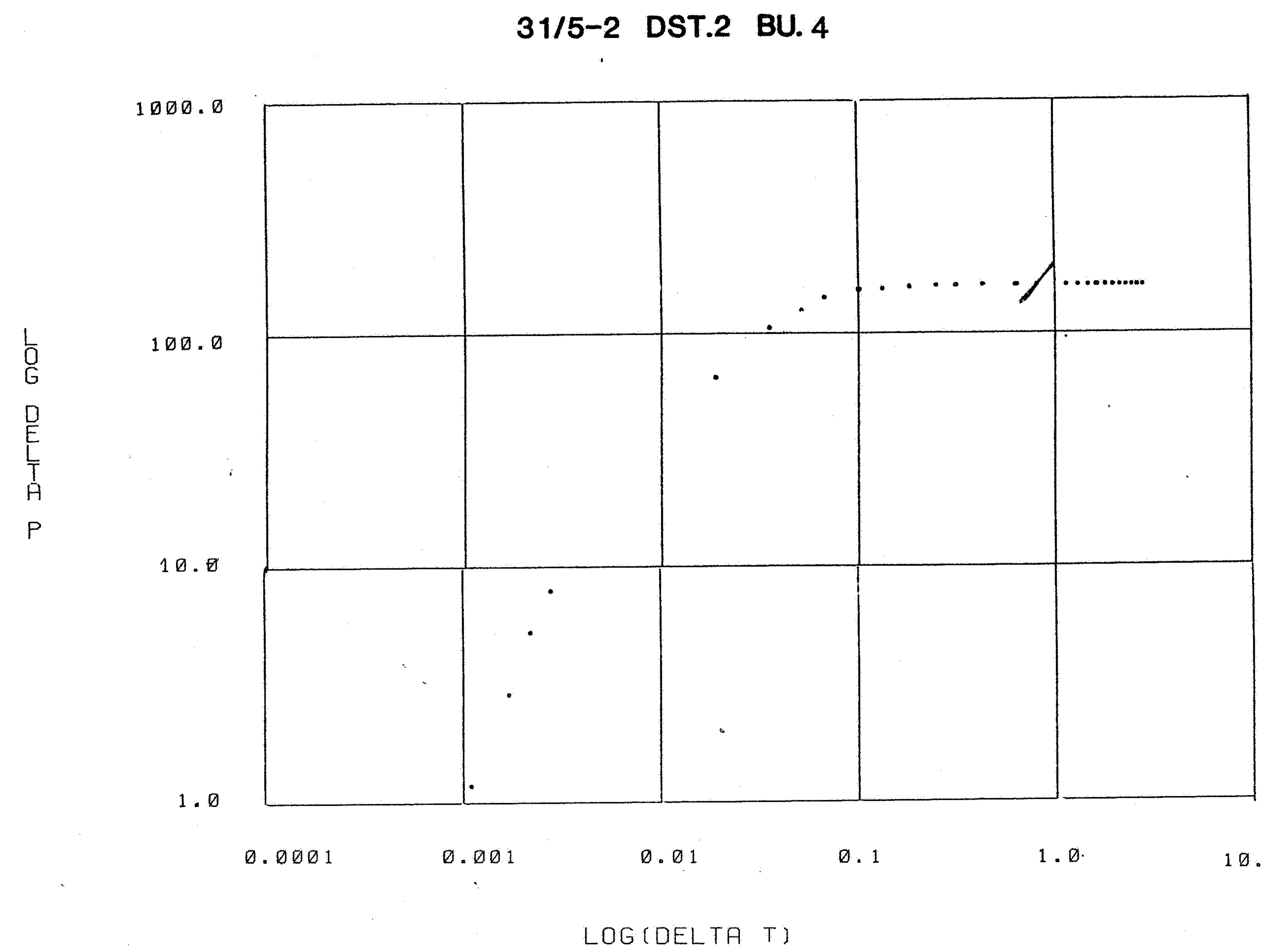


Figure 5.2.9: Log/log-plot.

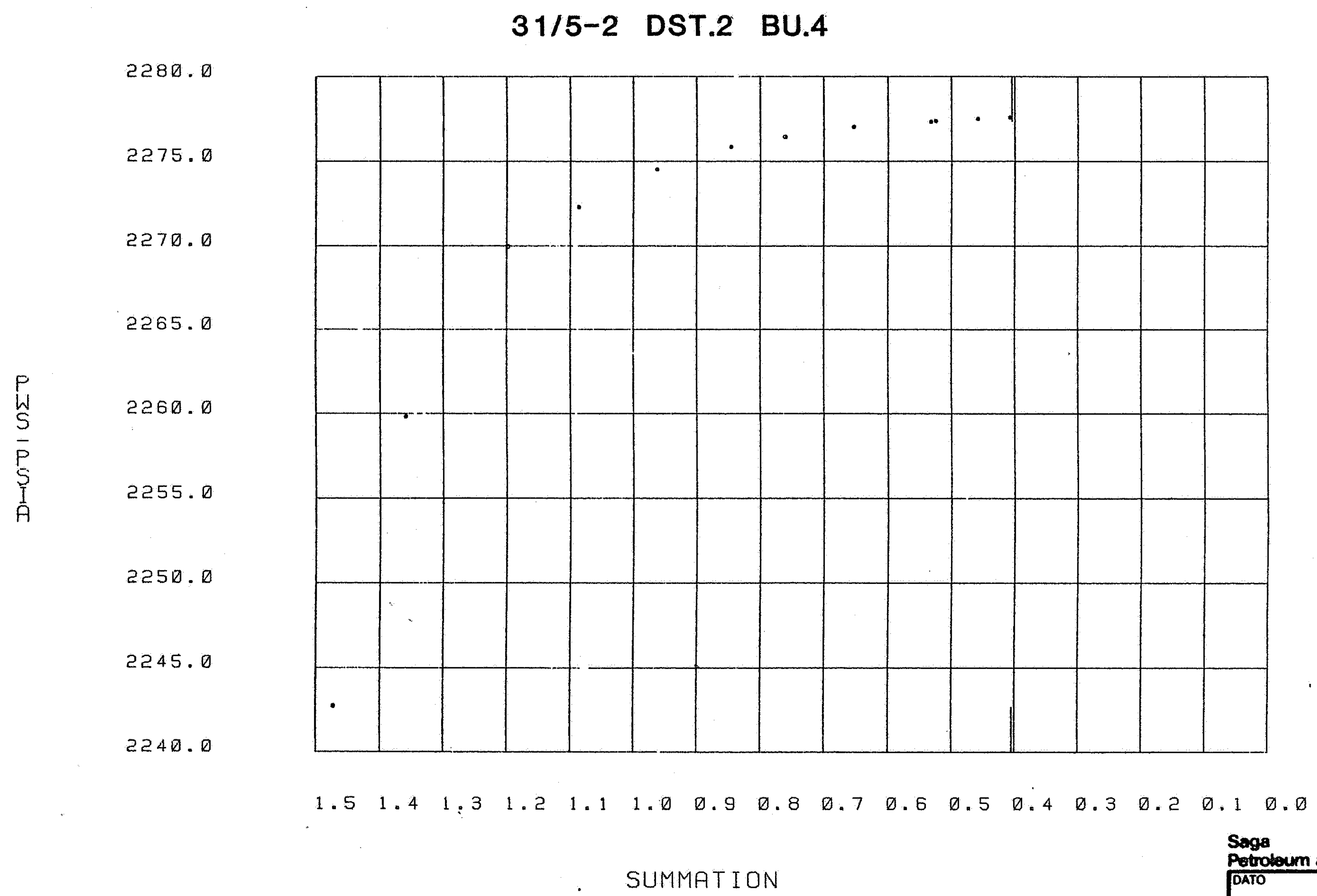
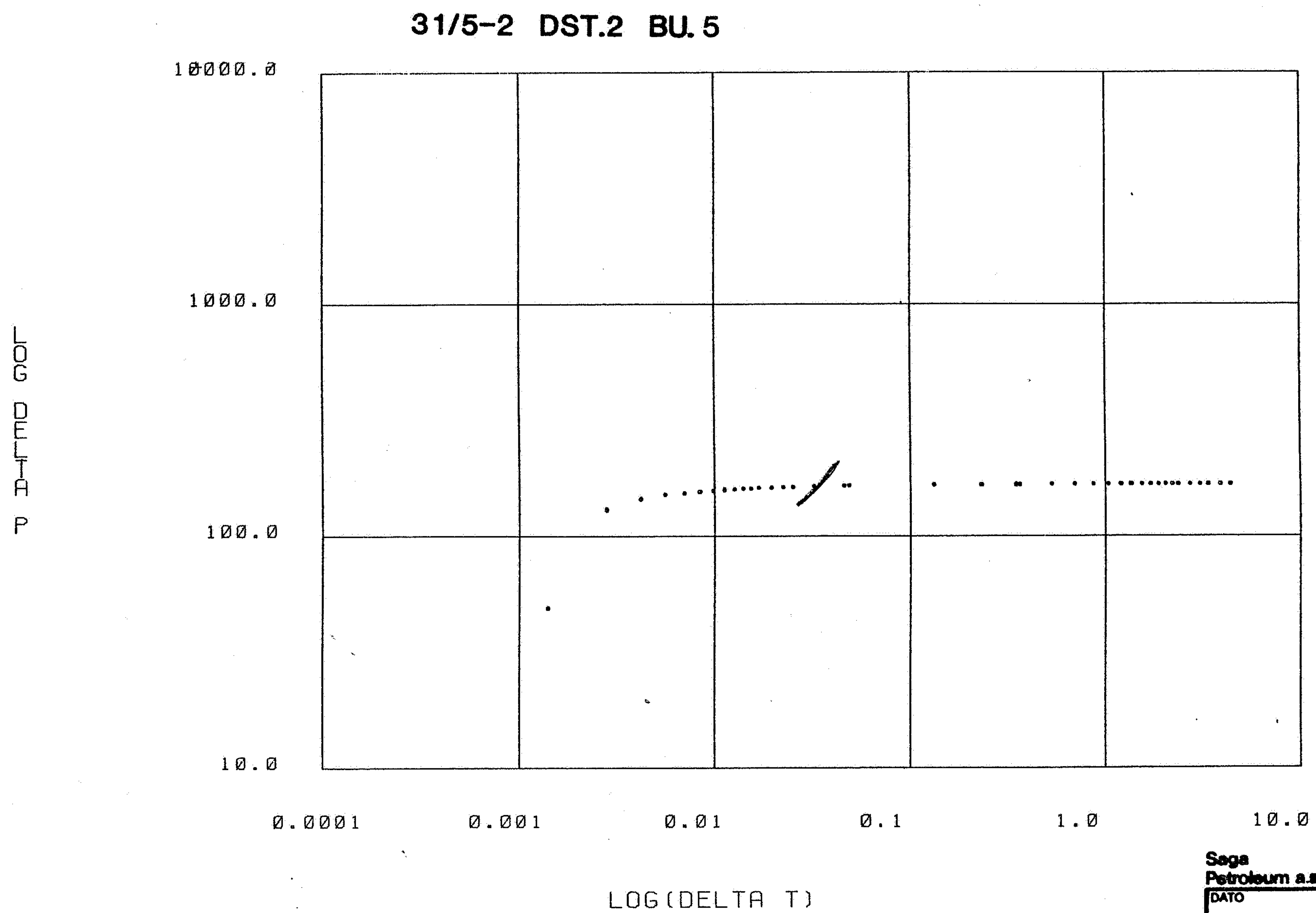


Figure 5.2.10: Horner plot.

Saga Petroleum a.s.

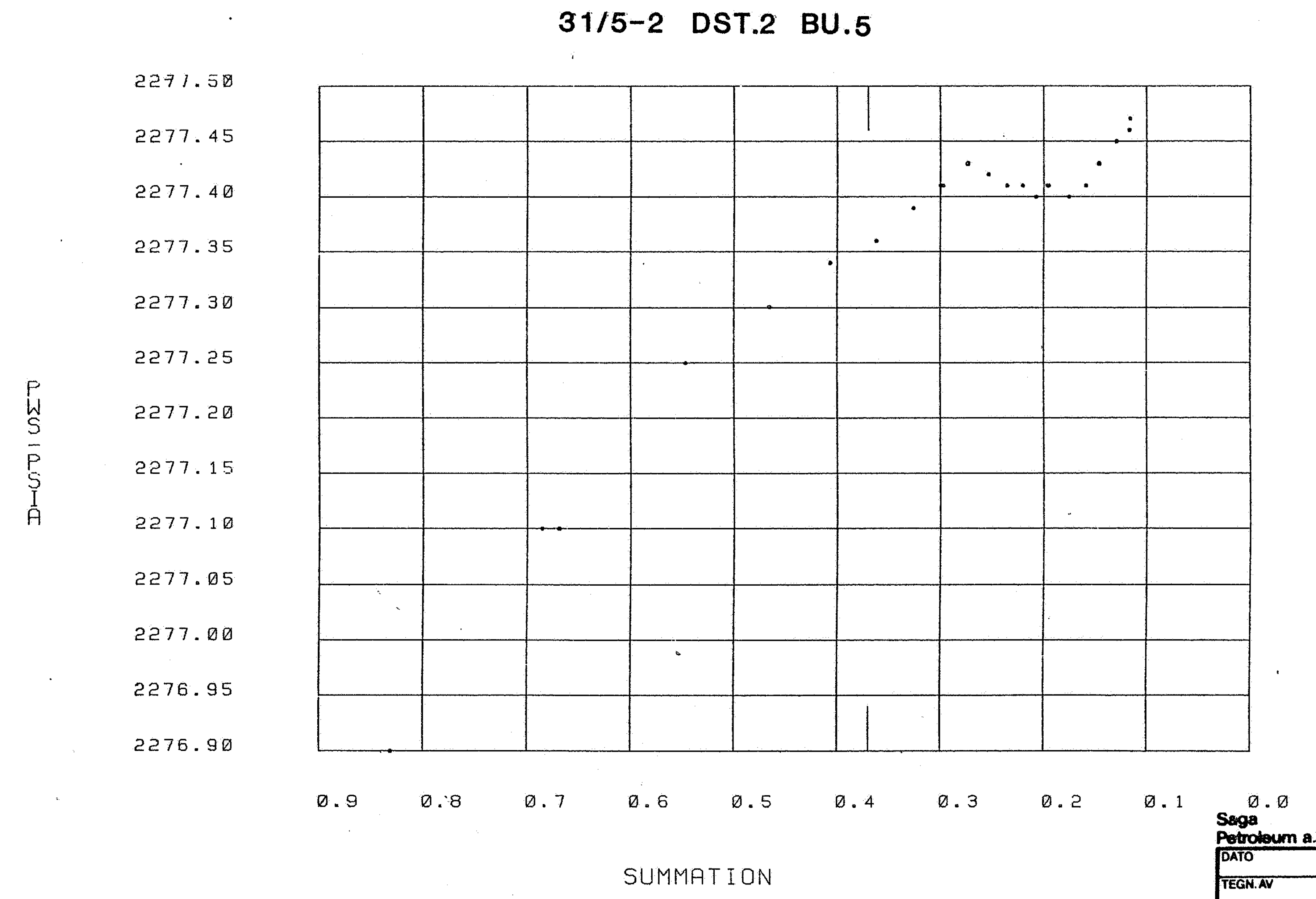
DATO	FORF.
TEGN. AV	GODKJ.
REF.	



Saga Petroleum a.s.

DATO	FORF.
TEGN. AV	GODKJ.
REF.	

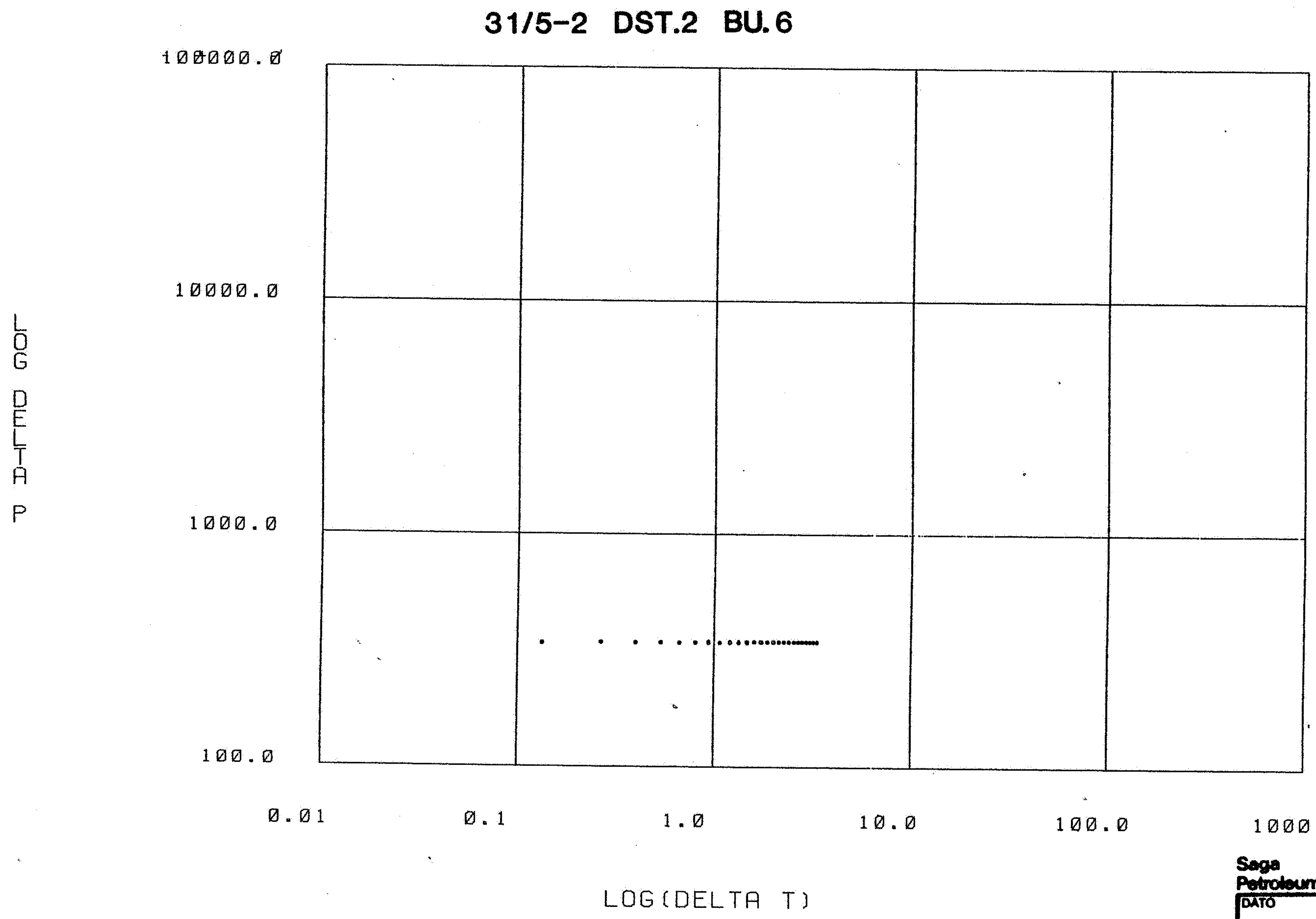
Figure 5.2.11: Log/log-plot.



Saga Petroleum a.s.

DATO	FORF.
TEGN. AV	GODKJ.
REF.	

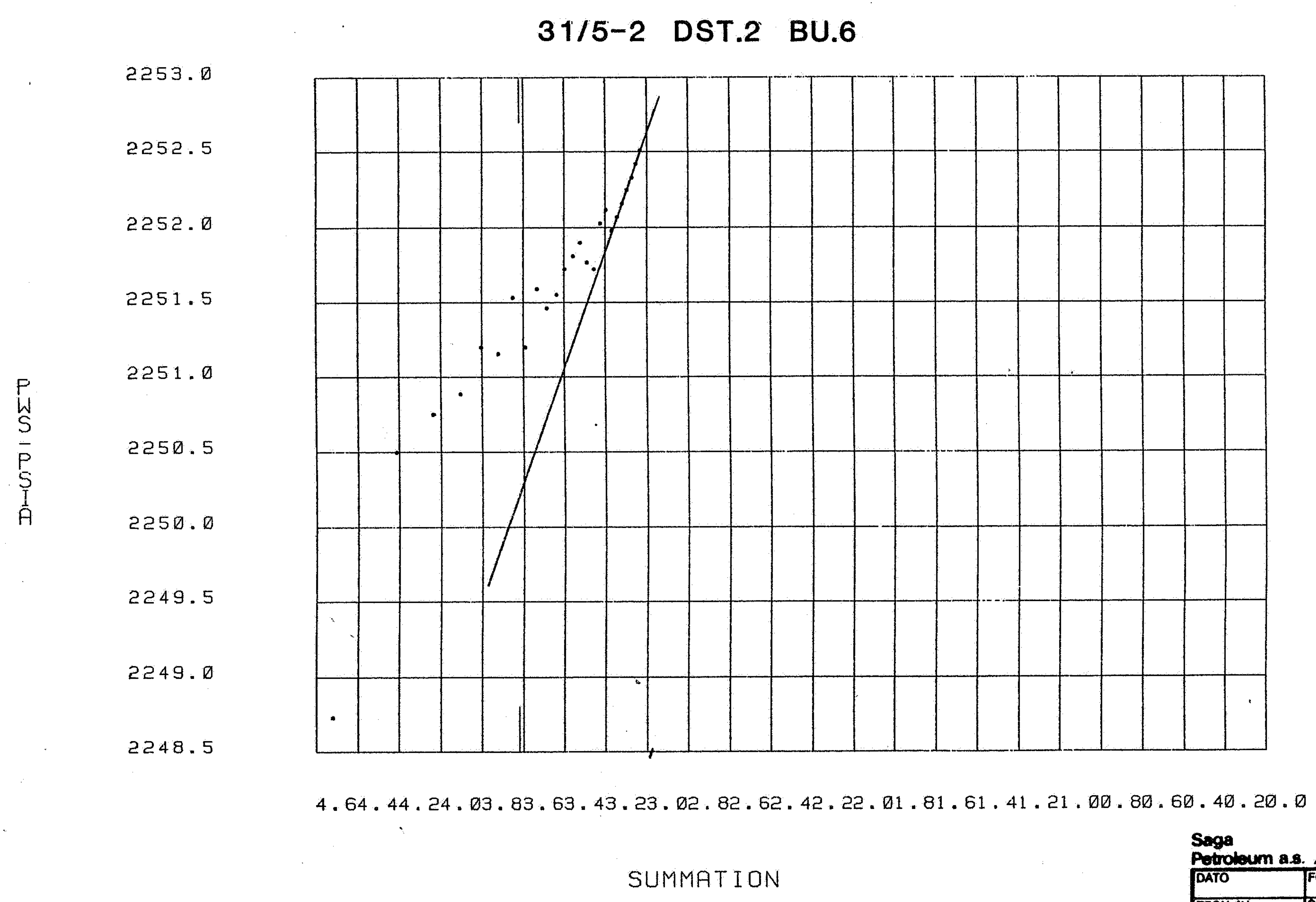
Figure 5.2.12: Horner plot.



Saga Petroleum a.s.

DATO	FORF.
TEGN. AV	GODKJ.
REF.	

Figure 5.2.13: Log/log-plot



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TEGN. AV	GODKJ.
REF.	

Figure 5.2.14: Horner plot.

6. DST # 3, GAS TEST

6.1 Operation DST No. 3

6.1.1 Perforation

The perforation run was carried out according to the general procedure in section 3.2. The perforation string is described in Appendix. C.4.

The brine was circulated and filtrated until a turbidity of 2.2 NTU was obtained. The interval, 1546.5-1554.5m RKB, was perforated with 20.7 bar underbalance. The cushion water was flowed out and the well cleaned up in 50 min. Then the gauges were run in the hole and placed in the F-nipple. The well was opened and flowed at a rate of 2.3×10^5 Sm^3/day in two hours. The wellhead pressure was 131.0 bar and no sand was observed at the surface. The initial flow-period lasted for two hours followed by a pressure build-up period of 1 hour. The tubing content was circulated out and the well killed with a 4.8 m^3 $CaCO_3$-pill with 27.6 bar overpressure. The $CaCO_3$ was a mixture of graded 15µ and 40µ$CaCO_3$.

6.1.2 Gravel packing

The first attempt to gravelpack the zone failed. See Appendix C.1 for the sequence of events. The reason was that rubber from the annular BOP was "shaved off" when the gravelpack equipment was run in hole. The rubber fell down on the sump-packer and caused a leak between the sump-packer and the seal assembly. The gravel slurry was pumped across the perforations, into the rathole, up through the wash pipe and into the annulus and therefore no screenout was obtained (see the drawing of the gravelpack assembly in Appendix C.5). The gravelpack equipment had to be pulled and a string was run in hole to wash out the rest of the gravel. A new sump-packer was run in the hole and set above the original one. A new and shorter tell tailscreen had to be used to compensate for the shorter distance to the sump-packer. See Appendix C.5 for a description of the gravelpack assembly.

The gravelpack was then carried out according to the procedure in section 3.3. The circulating pressure was higher due to the short tell tail screen.

The perforations were cleaned with 10.0 m^3 15% HCL. The well was then gravelpacked and a 3.2 m^3 viscous prepad was pumped ahead of 2.4 m^3 viscous gravelslurry containing 1.4 m^3 of 12-20 mesh sand.

The gravelslurry was followed by a 0.8 m^3 viscous postpad and displaced with brine with a cloudyness of 1.5 NTU. About 50% of the gravelslurry was reversed out again.

The gravelslurry was pumped down the string at a rate of 0.48 m^3/min. and was decreased to 0.24 m^3/min. when the screenout was expected. The initial screenout pressure was 48.3 bar. The gravelpack was packed twice to 69 bar.

6.1.3 Testing

The first attempt to run the test string failed. The reason was that the sub-sea test tree hung up in the annular BOP because the rubberpack in the BOP was splitted. The test string had to be pulled again. Then the BOP had to be pulled, a new rubber seal was installed, and the BOP was landed again.
The second attempt failed due to a wrong space out. The landing string down to the sebsea test tree was pulled again and an additional joint was added to the test string.

The test string was landed in the gravelpack assembly as described in section 3.4. The test was performed with a high rate clean up flow, a multirate test and a low rate sampling flow at the end. An attempt was made to do the sampling before the multirate test, but the well fluid contained too much acid. Traces of acid was produced throughout the entire test.

The pre-acid flow rate was maximum 9.18 x 10^5 Sm^3/day at wellhead conditions of 55.2 bar and 12.8°C. The condensate production was too small from reliable rate measurements on the separator.

On the acid clean out rate the maximum rate was $1.22x10^3$ Sm^3/day at wellhead conditions of 63.1 bar and 12.2°C.

The highest obtianed rate was 1.23 x 10^6 Sm^3 during the multirate flow. The wellhead conditons were 69.0 bar and 13.9 °C.

See Table 6.1 and Table 6.2.3 for other test results.

6.1.4 Sampling

After the first clean-up period, the flowrate was reduced to ($0.53x10^6$ Sm^3/day) to take some samples at the Thornton mixing manifold. The attempts failed because the wellstream was not clean enough. The rate was then increased to clean the well. 2 gasbottles and 4 recombination sample sets, each consisting of 3 gas and 1 oil, were taken at the separator at this high rate.

After the multirate flow and the following build-up, the well was produced at a low rate of $0.53x10^6$$Sm^3$/day. During this period, one set of PVT samples for recombination were collected from the Thornton lab. 3 sets of samples for chromotographic analyses were also collected at the Thornton minilab. 3 recombination sample sets were taken at the separator. In addition, 3 gas bottles were filled with gas for core studies.

In addition, 22 Jerry Cans of condensate were collected at the separator.

The gas gravity was 0.609 (air = 1) and the condensate density was 0.775 g/cc. The condensate gas ratio was 23.3 x 10^{-6} Sm^3/Sm^3 at separator conditions of 31.4 bar 12.2°C.

6.2 Test interpretation and discussion

Figure 6.2.1 and 6.2.2 show the flowrate and pressure vs. time respectively. The data for the analysis are recorded by Flopetrol SDP/CRG gauge no. 83871, Flopetrol gauge SDP no. 83073 and Flopetrol SDP/CRG gauge no. 83866 for the 1 st, 2nd and 3rd build-up respectively. The log/log plots and the Horner plots are presented in figur 6.2.3 thorugh 6.2.8.

Table 6.2.1 shows the results from the interpretation while Table 6.2.2 shows the input parameters used in the calculations.

See table 6.2.3 for the flowrates used in the different build-up periods. Build-up No. 2 and build-up No. 3 gives similar results. Build-up No. 1 shows too high permeability. However, the drawdown in this period is .06 bar which means that the results are very sensitive to any disturbance in the gauges, which makes it more unreliable.

The skinfactor is high even after the acid job. This is mostly due to the turbulence effect.

6.3 Calculation of completion skin and turbulence factor

6.3.1 Skinfactor vs. rate using pseudo pressure.

The skinfactors were plotted versus the flowrates to determine the completion skin.

Q mmscf/d	s
13.19	89
17.75	110
30.80	166
43.45	209

Table 6.3.1

The formula used for skincalculation is:

$$s = \frac{(\mu - \mu_{wf})k \times h}{1422\ Q\ T} \ln \frac{re}{rw}$$

The following parameters were used for the skin calculations:

k = 5900 md

h = 8m

T = 615°R

ln re/rw = 9

The plot on figure 6.2.9 shows a completion skin factor of 38.

6.3.2 Graphical solution of the steady state equiation using real pressure.

From the multirate test:

Q mmscf/d	Pwf psi	$\frac{Pe^2 - Pwf^2}{Q}$ psi^2/mscf
13.27	2258.2 x	8.1025
13.19	2259	7.884
19.0	2239.7 x	10.043
17.75	2244.2	9.613
30.47	2182.5 x	14.564
30.80	2184.9	15.068
43.84	2099.6 x	18.22
43.45	2107.2	17.64

Table 6.3.2

Pe = 2281.9 psi

x = beginning of each rate

Due to the clean up through the multirate flow the skinfactor decreased. Table 6.3.2 shows the change in the rate, and the corresponding flowing pressure, over the time the well was flowing on the same choke. To minimize the effect of this the line on the plot in fig. 6.2.10 is drawn through the point at the end of the 2. highest rate and through the point at the beginning of the higher rate.

The pressures refers to 1510.9m RKB.

The steady stat gas flow equiation is:

$$Q = \frac{703 \times 10^{-6} \quad K \quad h \; (Pi^2 - Pwf^2)}{T \; (\mu \quad z) \; [\ln \frac{re}{rw} - 0.75 + S + D \quad Q]}$$

This gives:

$$PI^2 - Pwf^2 = \frac{Q \; T \; (\mu z) \quad [\ln \frac{re}{rw} - 0.75 + S + D \; Q]}{703 \times 10^{-6} \quad K \quad h}$$

When re-arranging

$$\frac{Pi^2 - Pwf^2}{Q} = \frac{T \; (\mu \; z) \; [\ln \frac{re}{rw} - 0.75 + s + D \; Q]}{703 \times 10^{-6} \quad K \quad h} = FQ + B$$

The slope of the straight line from the plot of

$$\frac{Pi^2 - Pwf^2}{Q}$$

gives the parameter F.

The intercept between the x-axis and the straight lines give the parameter B, from which the completion skin can be balculated.

Figure 6.2.10 shows that:

$B = 4.0\ psi^2/mscf/day$

$F = 0.325 \times 10^{-3} \quad Psi^2/(mscf/d)^2$

$S = 39$

The true steady state equation is then:

$$Pi^2 - Pwf^2 = \frac{QT \times (\mu Z)\ [\ln \frac{re}{rw} + 38.25]}{703 \times 10^{-6}\ K \quad h} + 0.325 \times 10^{-3}\ Q^2$$

The parameters used for the calculations were:

$B = 4.0$

$\mu = 0.017$ cp

$z = 0.0868$

$T = 615$ °R

$\ln \frac{re}{rw} = 9.04$

$K = 5850$ md

$h = 26.3$ ft

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2200P/ASa

DST # 3 1546.5 - 1554.5m RKB

Flowrate/shut-in vs. time

Date	Time (hrs. min.)	Duration (hrs/min)	Total flowrate (Sm^3/day)	Chokesize (mm)
13/8	0401 - 0405	0.04	N/A	Fully open
	4005 - 0455	0.50	8.5×10^7 (est)	9.5
	0455 - 0600	1.05	0	
	0600 - 0800	2.00	2.29×10^5	9.5
	0800 -			
23/8	0315	235.15	0	Gravel packing
	0315 - 0415	1.00	N/A	Increasing adj. choke
	0415 - 0445	1.30	7.08×10^4	23.8 adj.
	0445 - 0630	1.45	8.35×10^5	23.8 adj.
	0630 - 0900	2.30	9.18×10^5	38.1 adj.
	0900 - 1635	7.35	0	
	1635 - 1725	0.50	5.66×10^5 (est)	12.7 adj.
	1725 - 1750	0.25	N/A	25.4 adj.
	1750 -			
24/8	0255	9.05	1.12×10^6	38.1 fix.
	0255 - 0845	5.50	5.15×10^5	15.9 fix.
	0845 - 0850	0.05	0	
	0850 - 2015	11.25	1.22×10^6	44.5 adj.
25/8	0025	3.40	0	
	0025 - 0430	4.05	3.74×10^5	12.7 fix.
	0430 - 0830	4.00	5.1×10^5	15.9 fix.
	0830 - 1231	4.01	8.72×10^5	22.2 fix.
	1231 - 1625	3.54	1.23×10^6	44.5 fix.
	2032 -			
26/8	1225	15.53	5.27×10^5	15.9 fix.

Table 6.1

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	K (md)	S total	S turbulence	ri (m)	Φ skin $psi^2/cp \times 10^6$	φ drawdown $(psi^2/cp) \times 10^6$	E %
BU 1	86776	2.34		860	0.073	0.29	74.8
BU 2	6525	1174	1135	590	195.0	196	0.5
BU 3	5854	212	173	1000	510.0	535	4.7

Completion skin: s = 39

Reservoir pressure at middle perforations, 1550.5m RKB was 157.9 bar.

Highest measusred temperature: 68.3 °C.

Table 6.2.1 Main results DST 3, 1546.5-1554.5 mRKB, well 31/5-2.

DATE	AUTH.
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Input parameters

Net pay thickness, m	8
Gas viscosity, cp	0.017
Porosity, fraction	0.27
Total compressiblility, psi^{-1}	5×10^{-4}
Well bore radius, ft	0.3556

Table 6.2.2

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2200P/ASa

	Rate gas Sm^3/day	Rate cond. m^3/day	WHT °C	WHP bar	Duration flow hrs. min.	PI Sm^3/day/bar
Pre gravel pack flow	2.29×10^5	N/A	12.8	124.8	2.0	3.36×10^6
Gravelpack clean out flow	9.18×10^5	N/A	12.8	55.2	6.45	1.93×10^4
Acid clean out flow	1.22×10^6	15.9	12.2	63.1	11.25	6.53×10^4
Multirate flow	3.74×10^5		12.2	133.4	4.05	2.37×10^5
	5.1×10^5	7.95	16.1	128.3	4.00	1.93×10^5
	8.72×10^5	14.31	13.9	109.0	4.01	1.31×10^5
	1.23×10^6	15.9	23.9	69.2	3.54	1.02×10^5
Sampling flow	5.27×10^5	13.44	12.2	128.0	15.53	1.89×10^5

The most reliable condensate rate was obtained on the sampling flow. The LGR was $23.3 \times 10^{-6} Sm^3/Sm^3$ with separator conditions at 31.4 bar/12.2°C. The glycol injection rate was .4 m^3/day.

Table 6.2.3

DATE	AUTH.
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REF	

31/5-2 DST.3 FLOWRATE/TIME

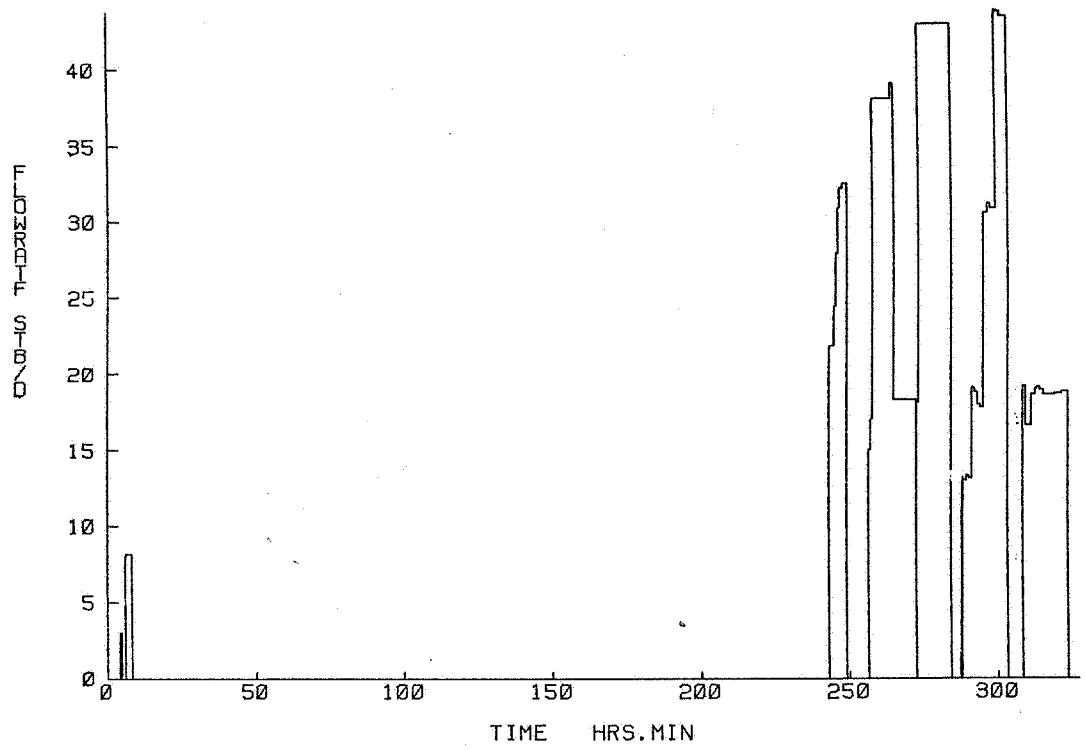

Figure 6.2.1

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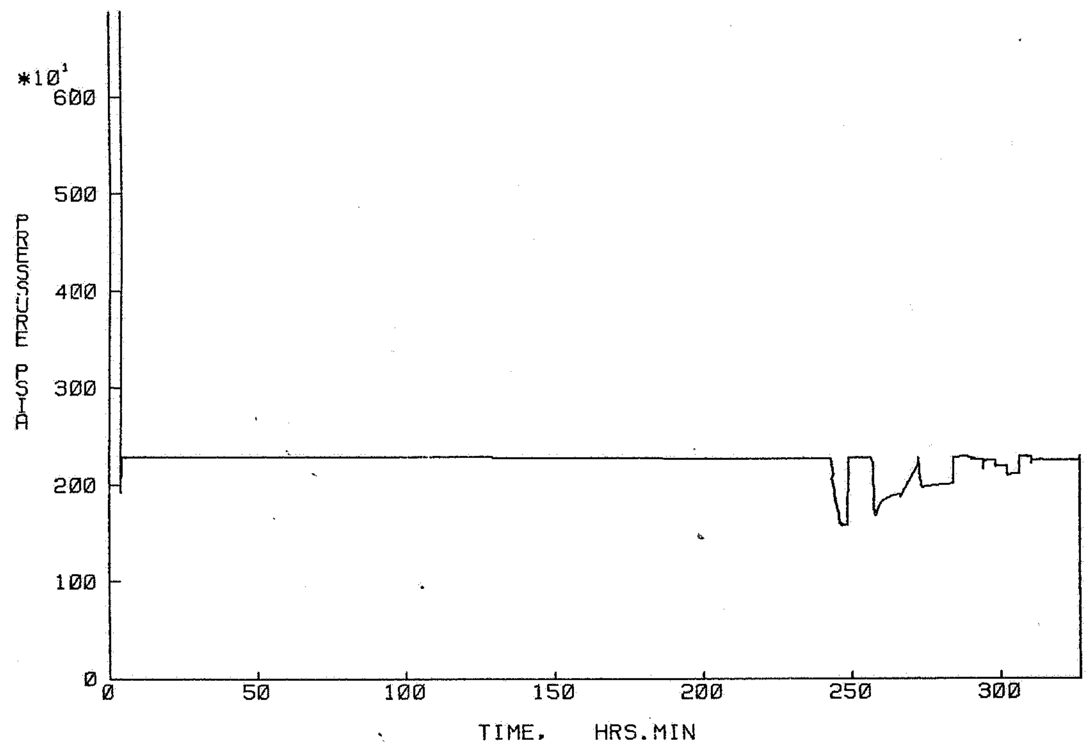
31/5-2 DST.3 PRESSURE/TIME



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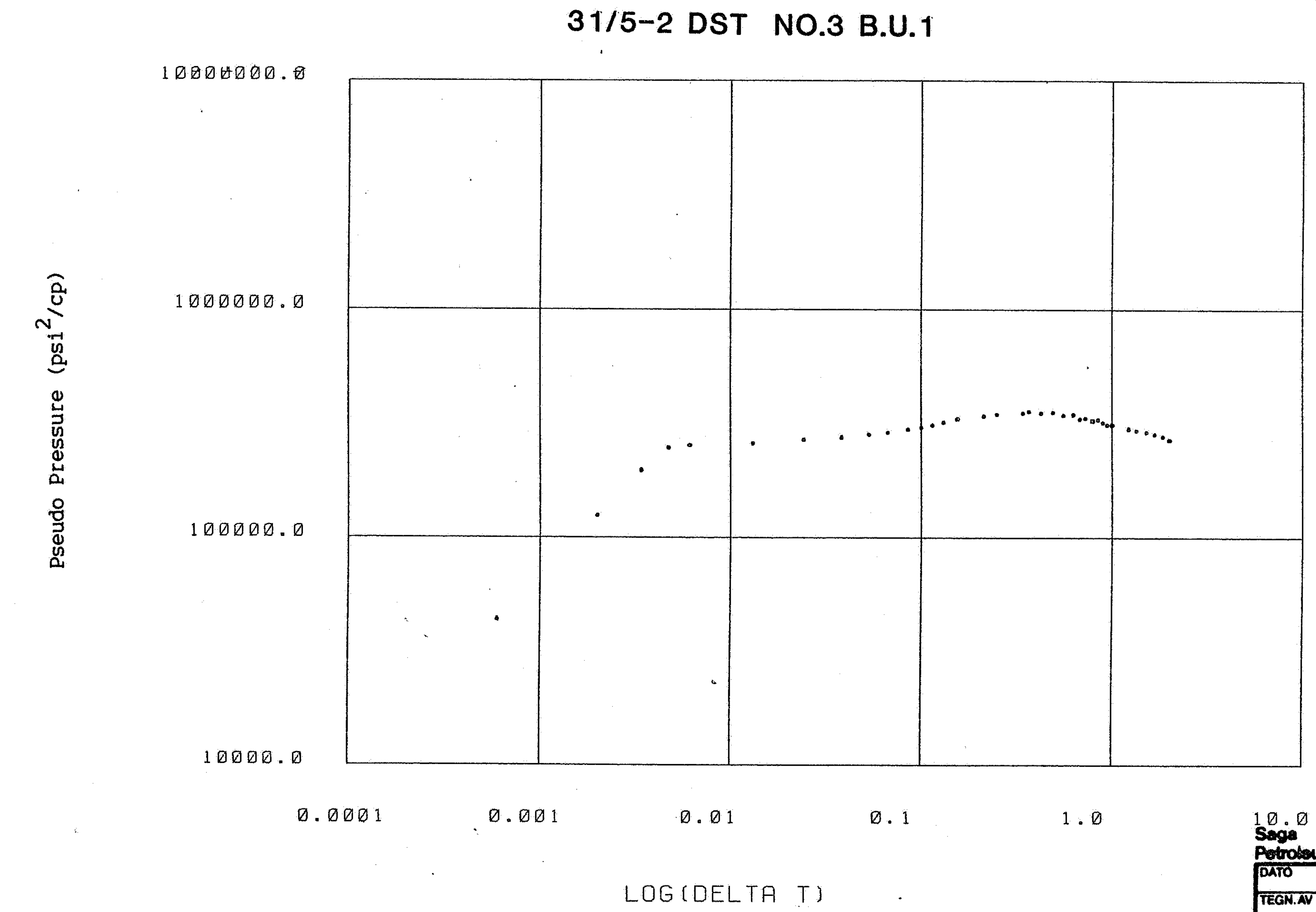
REF.	

Figure 6.2.2



Saga Petroleum a.s.

DATO	FORF.
TEGN.AV	GODKJ.
REF.	

Figure 6.2.3: Log/log-plot.

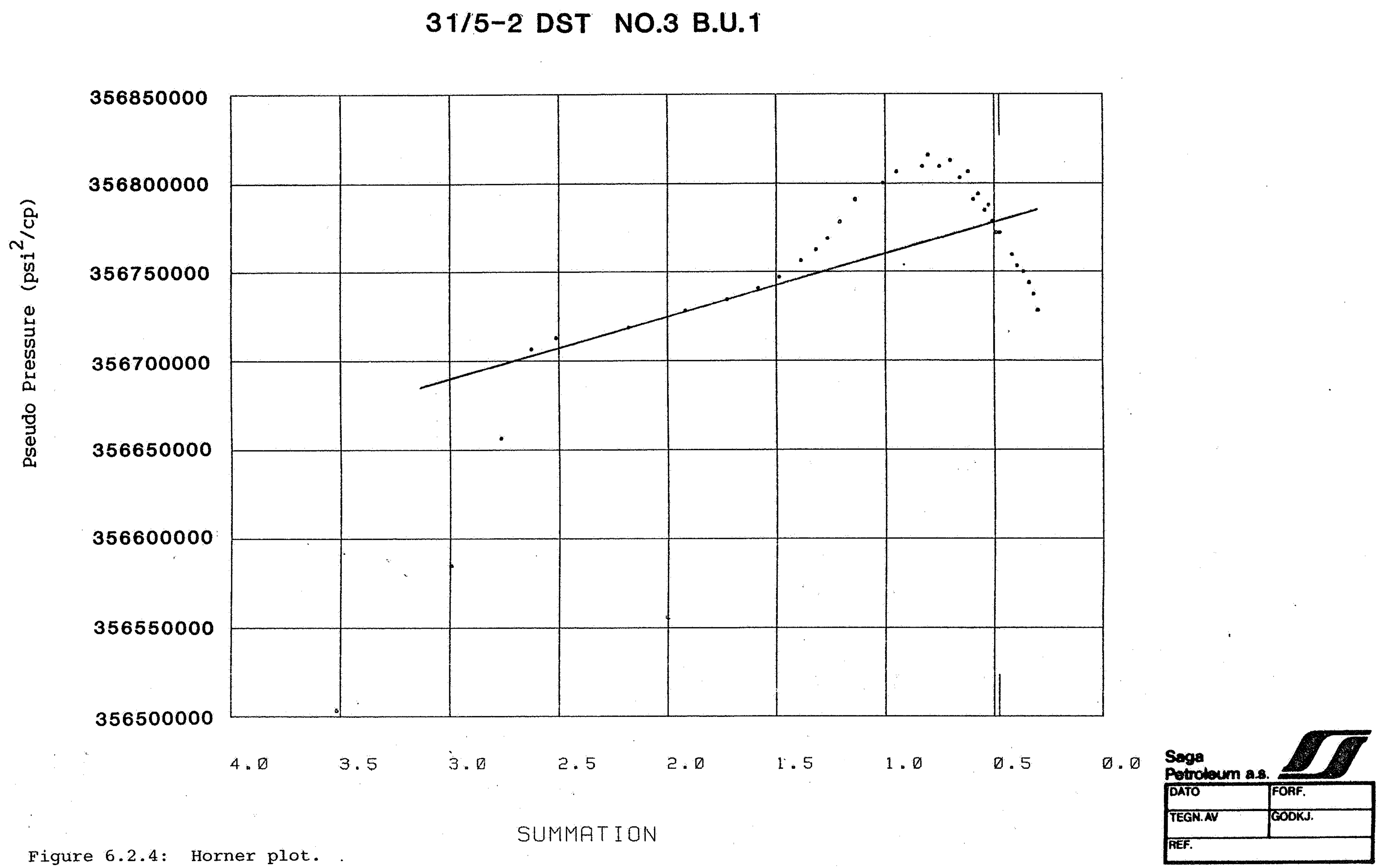


Figure 6.2.4: Horner plot.

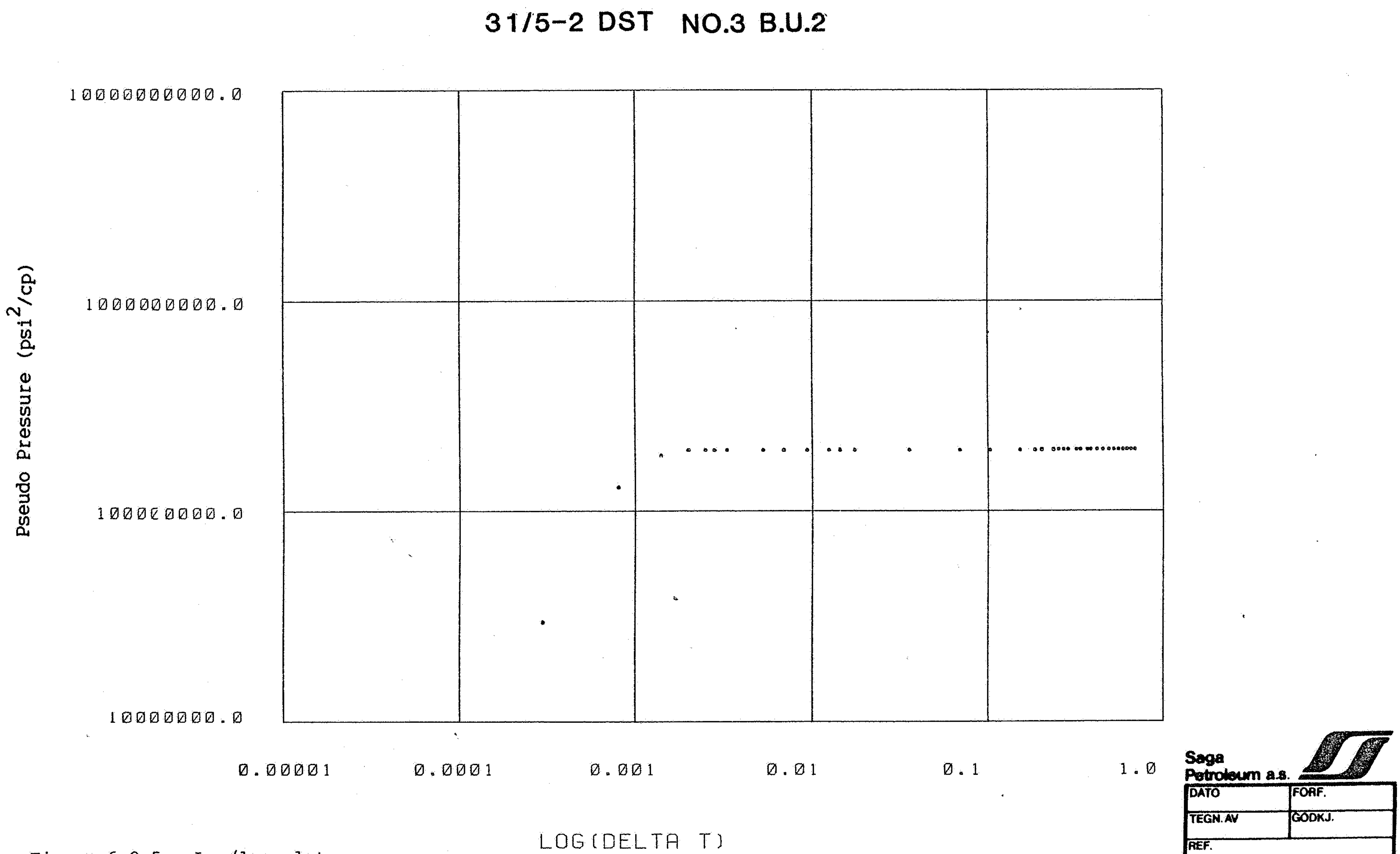


Figure 6.2.5: Log/log-plot.

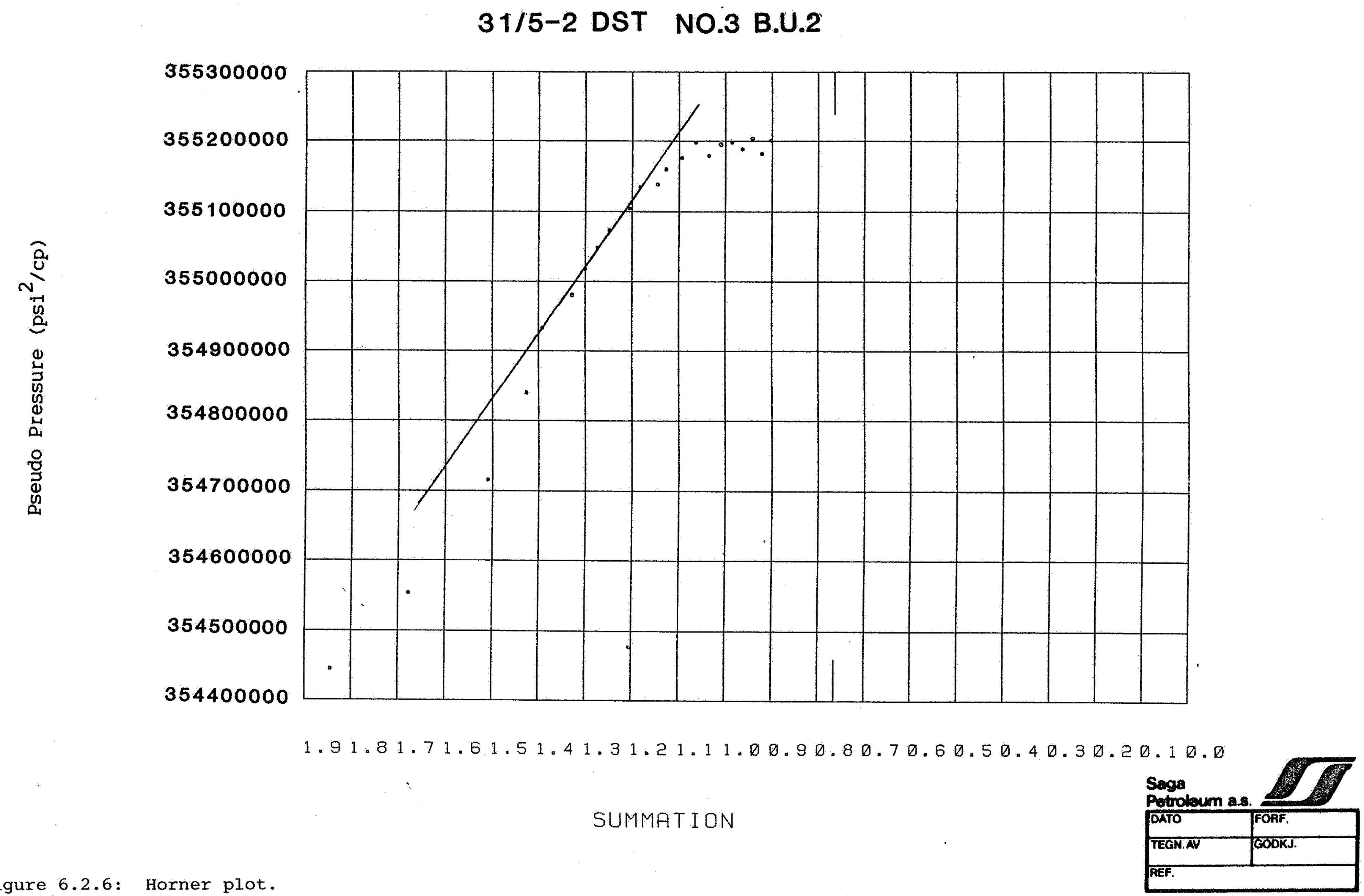


Figure 6.2.6: Horner plot.

31/5-2 DST NO.3 B.U.3

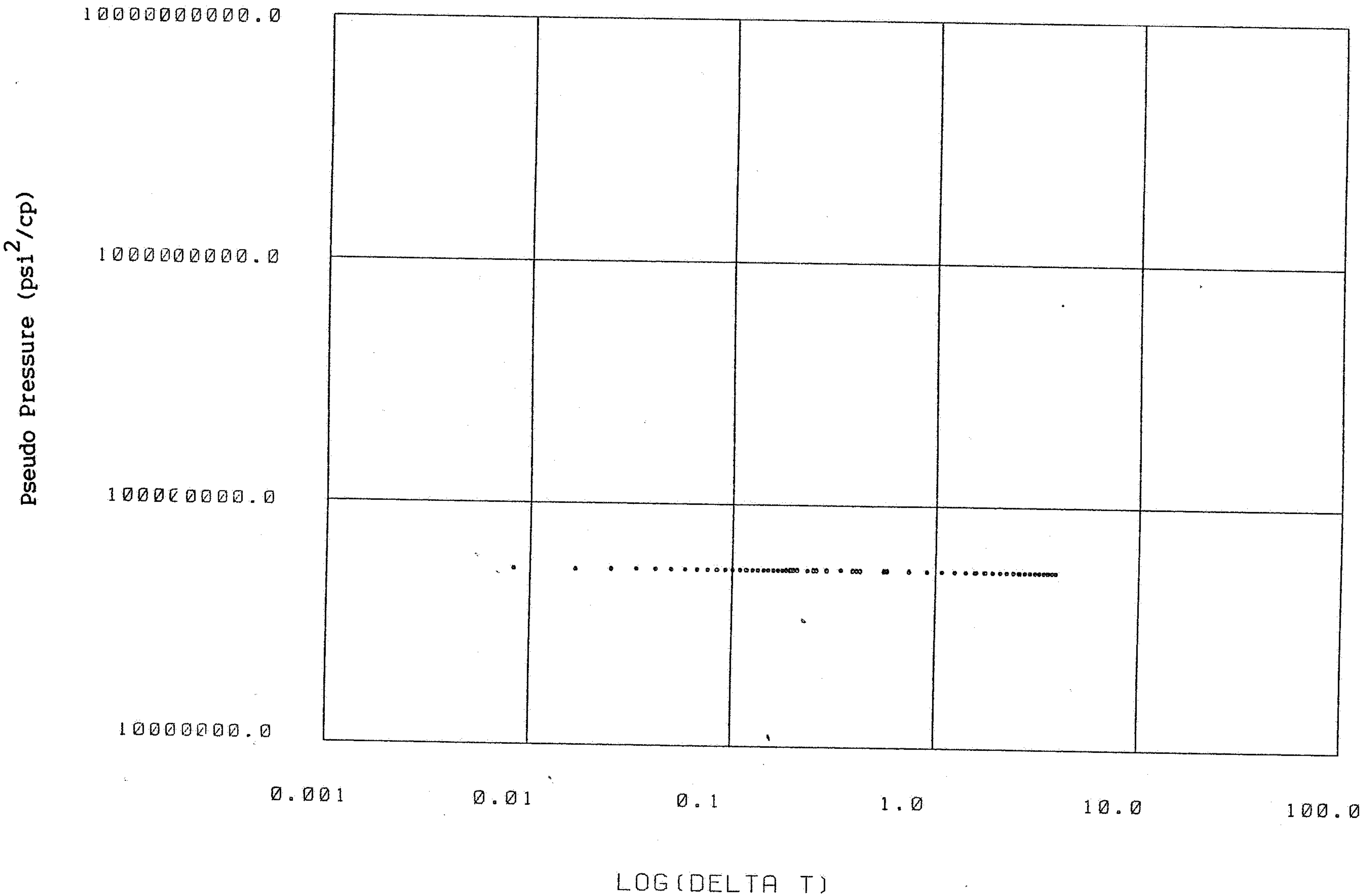


Figure 6.2.7: Log/log-plot.

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DATO	FORF.
TEGN. AV	GODKJ.
REF.	

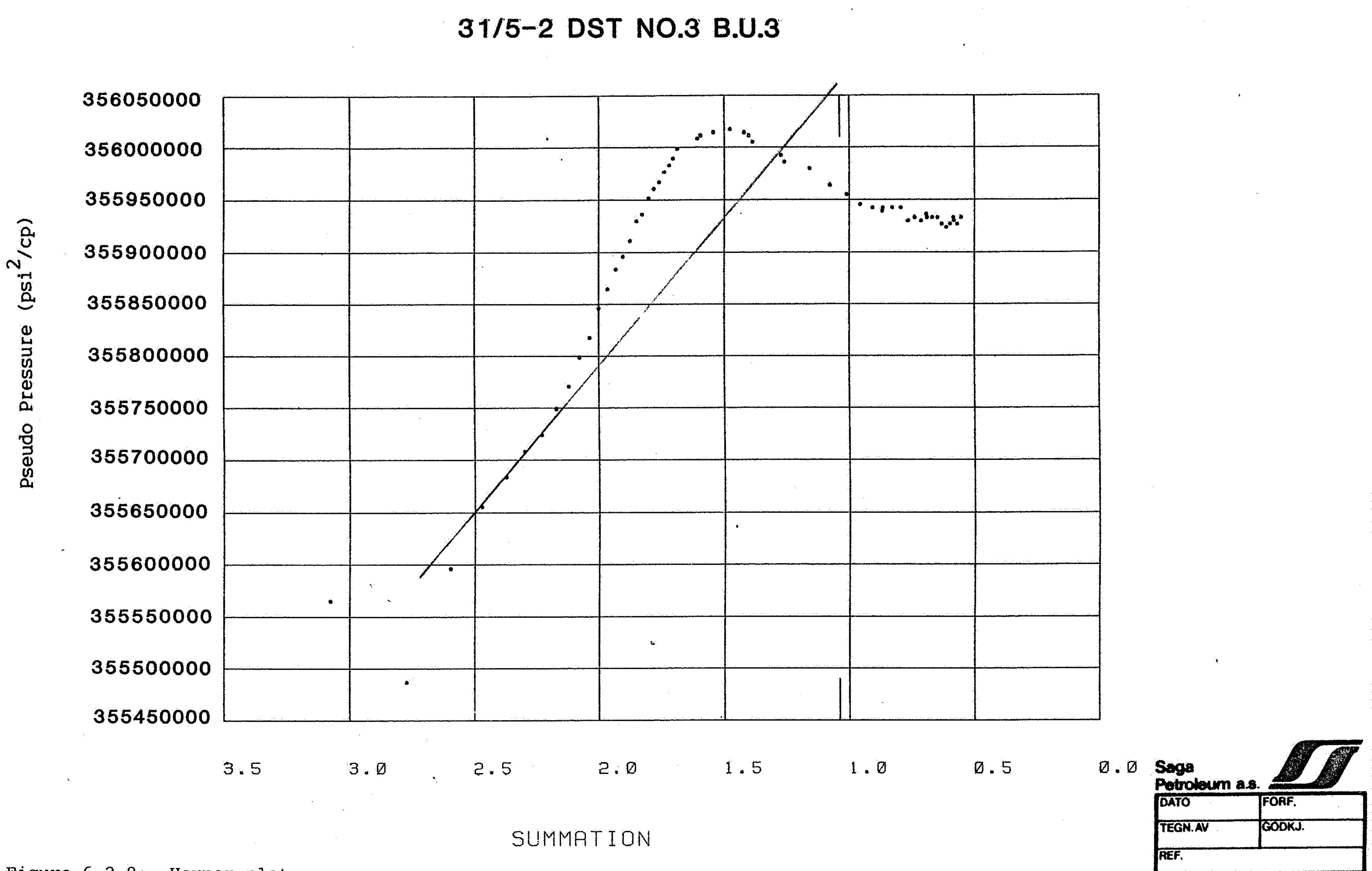

Figure 6.2.8: Horner plot.

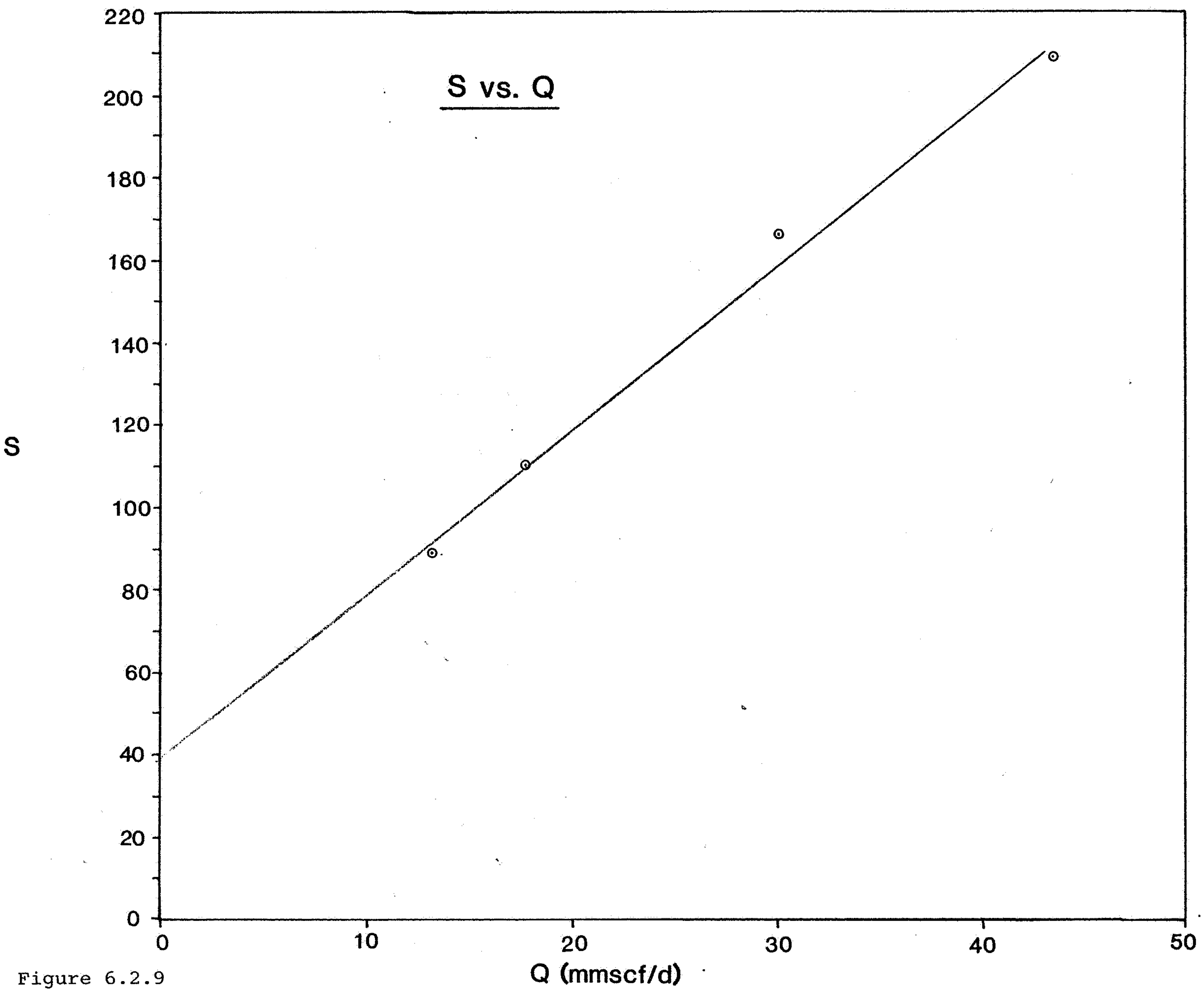

Figure 6.2.9

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DATO 17/12-84	FORF. ThS
TEGN. AV IJS	GODKJ.
REF.	

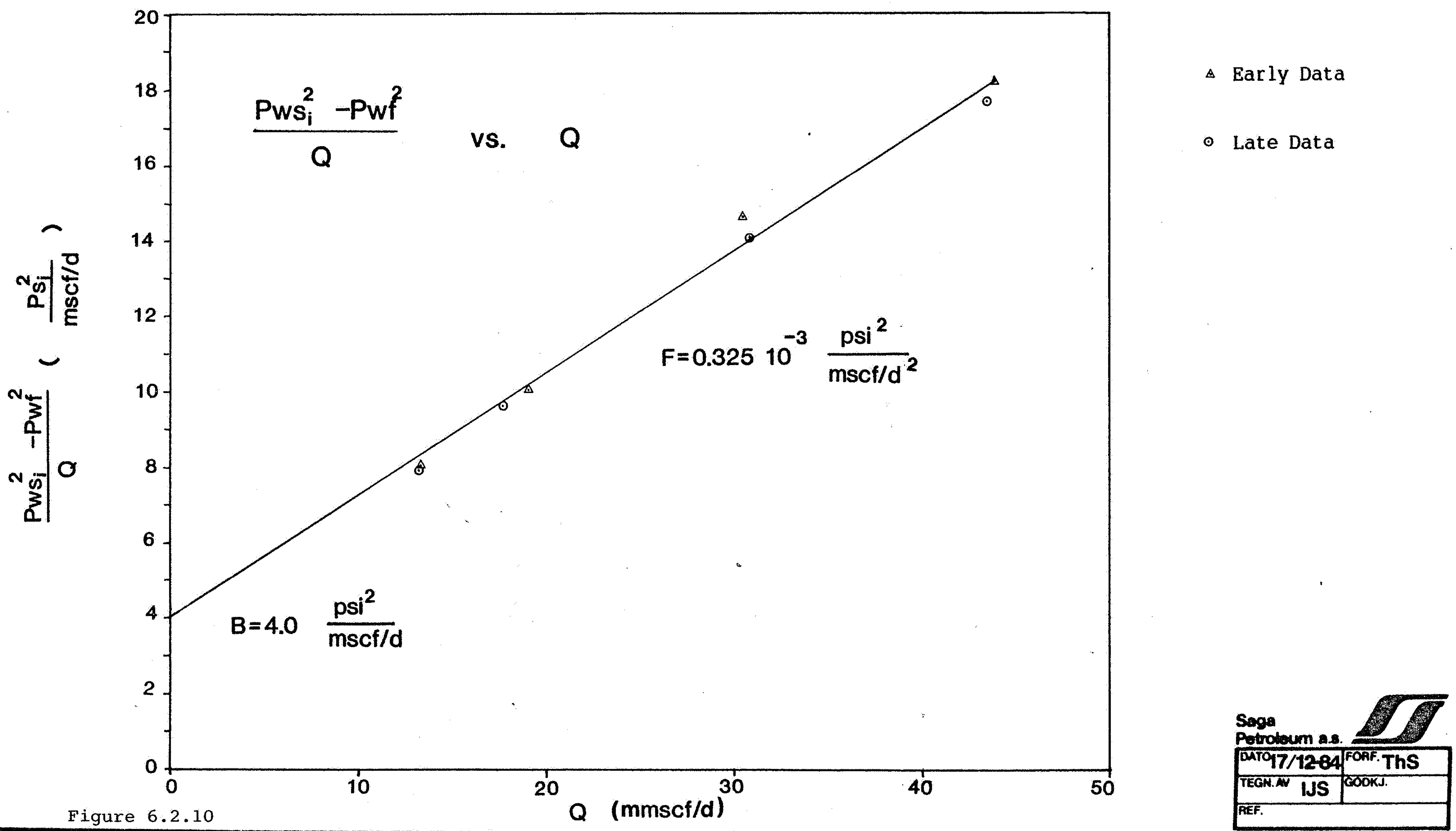
Pws_i^2 - Pwf^2 / Q vs. Q
Pws_i^2 - Pwf^2 / Q (Ps_i^2 / mscf/d)
Q (mmscf/d)
F=0.325 10^-3 psi^2 / mscf/d^2
B=4.0 psi^2 / mscf/d
Early Data
Late Data
0
2
4
6
8
10
12
14
16
18
20
0
10
20
30
40
50
Saga Petroleum a.s.
DATO 17/12-84
FORF. ThS
TEGN. AV IJS
GODKJ.
REF.

Figure 6.2.10

Appendix A-2

Sampling sheets DST No. 1

PB= Plastic Bottle
JC= Jerry Can

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar t-°C	Container vol & type	Remarks
1	23/6	11-15	OIL+BRINE	WELL HEAD		2 1/21, PB	
2	"	11.45	"	"		"	
3	"	11.50	"	SEP BYPASS		"	
4	"	12.15	"	"		"	
5	"	12.25	OIL	WELLHEAD		"	
6	"		OIL EMULSION	SEP BYPASS		11,PB	REVERSE OUT ±25bbl
7	"		"	"		"	REVERSE OUT ±20bbl
8	29/6	11.30	OIL+BRINE	WELLHEAD		2 1/21, PB	REVERSE OUT ±5bb
9	"	11.45	"	"		"	" ±25bbl
10	"	12.00	"	"		"	" ±40bbl
11	"	12.15	"	"		"	" ±50bbl
12	29/6	20.45	DIESEL	"		2 1/21, PB	
13	"	20.55	OIL+ACID+BRINE	"		"	
14	"	21.15	"	"		"	
15	"	21.45	"	"		"	

Sampling sheets DST No. 1

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar t-°C	Container vol & type	Remarks
16	29/6	22.300	OIL+BRINE+ACID	WELL HEAD		1/21, PB	
17	"	23.00	"	"		"	
18	"	23.30	EMULSION demul-	"		"	
19	"	24.00	" tifier	"		"	
20	30/6	01.00	"	"		"	
21	"	01.30	"	"		"	
22	"	02.00	"	"		"	
23	"	02.30	"	"		2 1/21 "	
24	"	03.00	"	"		2 1/21 "	
25	"	03.30	"	"		2 1/21 "	
26	"	15.20	"	"		1/21, "	
27	"	16.45	"	"		"	+ DEMULSIFIER
28	"	17.45	"	"		"	
29	1/7	20.15	"	"		2 1/21,PB	

A2

Sampling sheets DST No. 1

JC= Jerry Can
PB= Plastic Bottle

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar t-°C	Container vol & type	Remarks
30	1/7	16-17.00	EMULSION	WELLHEAD		JC, 201	NOR EMULSIFIER
31	"	15.30-1600	"	"		"	"
32	"	00.30	WATER	OUTLET SEP WATER°		11,PB	
33	"	01.30	"	"		"	
34	"	01.50	"	"		"	
35	"	02.15	"	"		"	
36	"	02.30	"	"		"	
37	"	03.00	"	"		"	
38	"	03.30	"	"		"	
39	"	04.00	"	"		"	
40	"	04.30	"	"		"	
41	"	05.00	"	"		"	
42	"	06.00	"	"		"	
43	"	07.00	"	"		"	
44	"	08.000	"	"		"	
45	"	09.00	"	"		"	
46	"	10.00	"	"		"	
47	"	11.00	"	"		"	
48	"	12.00	"	"		"	
49	"	13.00	"	"		"	
50	"	14.00	"	"		"	

A2

Sampling sheets DST No. 1

PB= Plastic Bottle

JC= Jerry Can

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar t-°C	Container vol & type	Remarks
51	1/7	18.00	WATER	WATER OUTLET SEP		101,PB	
52	1/7	19.00	"	"		"	
53	"	21.00	"	"		"	
54	"	22.00	"	"		"	
55	1/7	15.00	OIL	SEPARATOR		2 1/21,PB	
56	"	17.00		SEP OUTLET			
57	"	18.00		"		"	
58	"	19.00		"		"	
59	"	20.00		"		"	
60	"	21.00		"		"	
61	"	22.00		"		"	
62	"	19.00		SEP INLET		"	
63	"	20.00		"		"	
64	"	21.00		"		"	
65	"	22.00		"		"	

A2

Sampling sheets DST No. 1

PB= Plastic Bottle
JC= Jerry Can

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar t-°C	Container vol & type	Remarks
66	1/7	17.00	OIL	STORE TANK		201, JC	
67	"	18.00	"	"		"	
68	"	19.00	"	"		"	
69	"	20.00	"	"		"	
70	"	21.00	"	"		"	
71	"	22.00	"	"		"	
72	"	22.30	"	"		"	
73	8/7	4.10	WATER	SEPARATOR		101,PB	
74	"	"	"	"		"	
75	"	"	"	"		"	
76	"	"	"	"		251,PB	
77	"	"	"	"		"	
78	"	"	"	"		"	
79	"	"	"	"		"	
80	"	"	"	"		"	
81	"	"	"	"		"	
82	"	"	"	"		"	
83	"	"	"	"		"	
84	"	"	"	"		"	
85	"	"	"	"		"	

Sampling sheets DST No. 1

A2

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar t-°C	Container vol & type	Remarks
86	8/7	4.10	WATER	SEPARATOR		251, PB	
87	"	"	"	"		"	
88	"	"	"	"		"	
89	"	"	"	"		"	
90	"	"	"	"		"	
91	"	"	"	"		"	
92	"	"	"	"		"	
93	"	"	"	"		"	
94	8/7	5.00	WATER	SEPARATOR		251, PB	
95	"	"	"	"		"	
96	"	"	"	"		"	
97	"	"	"	"		"	
98	"	"	"			"	
99	"	"	"	"		"	
100	"	"	"	"		"	
101	"	"	"	"		"	
102	"	"	"	"		"	
103	"	"	"	"		"	

Sampling sheets DST NO. 1

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar	t-°C	Container vol & type	Remarks
104	02.07.84	13.08	OIL	BH @ 106.4	156.6 PSIA		84032905	
105	"	13.10	OIL	BH @ 106.7	156.6 PSIA		84032811	
106	03.07.84	01.20	OIL	BH @ 106.4	156.6 PSIA		84032807	
107	01.07.84	17.15	OIL	WELLHEAD	26.7	11.7	84032701	
108		18.00						EVACUATED
109	"	19.15	OIL	"	26.5	11.7	84032718	"
110		20.00						
111	"	21.40	OIL	"	26.1	12.2	84032210	"
112		22.25						
113	"	17.02	OIL	SEPARATOR	12.0	60.5	8212703	
114		17.32						
115	"	17.02	GAS	"	"	"	A - 14581	
116		17.32						
117	"	19.15	OIL	"	12.0	56.7	8207111	
118		19.45						
119	"	19.15	GAS	"	"	"	A - 14410	
120		19.45						
121	"	20.25	OIL	"	12.0	56.7	84032911	
122		21.07						
123	"	20.25	GAS	"	"	"	A - 14583	
124		21.07						
125	"	21.26	OIL	"	12.0	56.7	84032808	
126		21.55						
127	"	21.26	GAS	"	"	"	A - 14603	
128		21.55						
129	"	22.10	OIL	"	12.0	53.9	84032108	
130		22.40						
131	"	22.10	GAS	"	"	"	A - 14640	
132		22.40						

APPENDIX A-3

Pressure/temperature gauge sheets, DST no. 1.

RTE__________ MAMSL

Owner	Gauge Type	Position in String	Gauge Depth m BRT	Date Clock m SS	Time Clock Set	Sampling rate	Sensing rate	Gauge No.	Range BAR	Remarks
Flopetrol	SDP/CRG	F-nipple	1556.44	23/6	07.50	0.05		83866	689.7	Perforation run
Flopetrol	SDP/Strain	F-nipple	1560.55	23/6	07.53	0.02		83064	689.7	"
Sperry Sun	Strain	F-nipple	1539.81	22/6	01.25	1.0		0096	689.7	"
" "	"	Bundle-carrier	"	"	01.26	0.30		0143	689.7	"
" "	"	"	"	"	0127	1.0		0114	344.8	"

Pressure/temperature gauge sheets DST No. 1.

RTE________ MAMSL

Owner	Gauge Type	Position in String	Gauge Depth m BRT	Date Clock Set	Time Clock Set	Sampling rate min	Sensing rate min	Gauge No.	Range BAR	Remarks
Flopetrol	SDP/CRG	DST-hanger	1564.25	26/6	21.25	5.00		83832	689.2	Gauge stopped after 10 days (batteries went out)
Sperry Sun	Strain	Bundle carrier	1541.22	26/6	21.46	8.00		0089	344.8	Used for analyses
" "	"	"	"	"	21.50	8.00		0143	689.2	.14 bar too low
" "	"	"	"	"	21.52	16.00		0096	689.2	-1.1°C too low

Pressure/temperature gauge sheets DST no. 1.

RTE________ MAMSL

Owner	Gauge Type	Position in String	Gauge Depth m BRT	Date Clock Set	Time Clock Set	Sampling rate min	Sensing rate min	Gauge No.	Range (Bar)	Remarks
Flopetrol	SDP/STRAIN	F-nipple	1557.56	29/6	0811		0.10	83035	690	
"	SSDR/CRG	"	1553.45	"	0807	0.30		82816	690	Used for interpret
"	" "	"	1553.45	30/6	1129	0.30		83866	690	Pressure not correct
"	SDP/STRAIN	"	1557.56	"	1132		0.10	84178	690	Gauge run out of spacen
"	" "	in line	1546	2/7	0450		0.05	83035	690	BHS-run # 1
"	" "	" "	"	"	1700		0.05	83064	690	
"	SSDR/CRC	F-nipple	1553.45	3/7	0311	5.00		83871	690	
"	SDP/STRAIN	" "	1557.56	"	0308		0.10	83065	690	Reach end of memory.

B2

APPENDIX B2

Sampling sheets DST No. 2

Test No. 2 Formation: Sognefjord

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar t-°C	Container vol & type	Remarks
1	19/7-84	16.10-17.00	DIESEL/OIL	WELLHEAD		5x2,51 PB 1x0,51 PB	
2	22/7-84 23/7-84	23.25 08.45	DIESEL/ACID GEL/OIL	SEPARATOR BYPASS		4x11 PB 5x0,51 PB	REGULARY INTERVALLS THROUGH THE FLOW
3	"		"	WELLHEAD		"	"
4	4/8-84	22.00-24.00	OIL	SEPARATOR INLET		3x11 PB	
5	5/8-84	12.00	OIL/EMULTION	SEPARATOR INLET		20x11	SAMPLES WERE TAKEN AT REGULARY INTERVALLS THROUGH ALL THE FLOW
	6/8-84		"	"		"	"
	7/8-84		"	"		"	"
	8/8-84		"	"		"	"
	9/8-84	06.00	"	"		"	"

B2

<u>Sampling data sheet Well No. 31/5-2</u>

Test No. 2 Formation: Sognefjorden

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar t-°C	Container vol & type	Remarks
6	24/7-84		OIL/POLLUTION	DOWNMIND THE RIG		1l PB	SAMPLE WAS PICKED UP FROM THE SEA
7	9/8-84	12.00	WATER	SEPARATOR		4x2,5l PB	
8	9/8-84	12.00	OIL	"		6x20l JC	

B2

Sampling data sheet Well No. 31/5-2

Test No. 2 Formation: Sognefjord

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar	t-°C	Container vol & type	Remarks
9	24/7-84	05.30	OIL	SEP OIL LINE	12.1	35.6	84032112	
10		05.34	GAS	SEP GAS LINE	"	"	A - 14614	
11	"	06.45	OIL	SEP OIL LINE	11.9	30.6	8310205	
12	"	"	GAS	SEP GAS LINE	"	"	A - 144077	
13	"	07.35	OIL	SEP OIL LINE	11.8	26.1	8212818	
14	"	07.40	GAS	SEP GAS LINE	"	"	A - 14827	
15	"	08.30	OIL	SEP OIL LINE"	11.8	23.3	83101711	
16	"	"	GAS	SEP GAS LINE	"	"	A - 14579	
17	"	09.05	OIL	SEP OIL LINE	11.8	22.8	84062611	
18	"	09.07	GAS	SEP GAS LINE	"	"	A - 14409	
19	"	09.45	OIL	SEP OIL LINE	11.8	21.7	84062415	
20	"	09.47	GAS	SEP GAS LINE	"	"	A - 14421	
21	"	10.35	OIL	SEP OIL LINE	11.8	21.1	84062115	
22	"	"	GAS	SEP GAS LINE	"	"	A - 14740	
23	31/7-84 "	02.50	OIL	SEP OIL LINE	11.4	21.1	84062617	
24		"	GAS	SEP GAS LINE	"	"	A - 13977	
25	"	03.35	OIL	SEP OIL LINE	11.4	21.1	84062311	
26	"	"	GAS	SEP GAS LINE	"	"	A - 14412	
27	"	02.10	OIL	SEP OIL LINE	11.4	21.1	84662203	
28	"	"	GAS	SEP GAS LINE	"	"	A - 13982	

APENDIX B 3

Pressure/temerature gauges sheets, DST No. 2 RTE________ MAMSL

Owner	Gauge Type	Position in String	Gauge Depth m BRT	Date Clock Set	Time Clock Set	Sampling rate	Sensing rate	Gauge No.	Range BAR	Remarks
Sperry Sun	Strain	Bundle -	1539.81	18/7	16.09	2.00		207	690	Perforation run
"	"	carrier	"	"	16.10	2.00		089	345	"
"	"	"	"	"	16.11	1.00		257	690	"
Flopetrol	SDR/CRG	F-nipple	1553.3	19/7	12.30		0.02	82816	690	"
"	SDP/ strain	"	1557.3	"	12.34	0.05		84178	690	"

Pressure/temperature gauges sheets, DST No. 2

Owner	Gauge Type	Position in String	Gauge Depth m BRT	Date Clock Set	Time Clock Set	Sampling rate	Sensing rate	Gauge No.	Range BAR	Remarks
Sperry Sun	Strain	Bundle-carrier	1540.06	21/7-84	17.48	8.00		0213	345	2.1°C too high temp recorded.
"	"	"	"	"	17.51	8.00		089	345	"
"	"	"	"	"	17.53	4.00		114	690	
Flopetrol	SSDR/CRG	DST-hanger	1563.5	21/7-84	16.42	5.00		83871	690	
"	"	F nipple	1552.0	22/7-84	20.53	0.05			690	Gauge run out,no build up.
"	SDP/ strain	"	1556.0	22/-84	20.55		0.02	83043	690	Gauge run out far too early.
"	SSDR/CRG	"	1552.0	23/7-84	15.59	0.10		82816	690	Gauge run out W.L snapped off.
"	SDP/ strain	"	1556.0	23/7-84	16.00		0.02	84178	690	Gauge lasted more than 4 days.

Pressure/temperature gauges sheets, DST No. 2

After rerun of test string

Owner	Gauge Type	Position in String	Gauge Depth m BRT	Date Clock Set	Time Clock Set	Sampling rate	Sensing rate	Gauge No.	Range BAR	Remarks
Sperry Sun	Strain	Bundle - carrier	1540.0	28/7-84	11.45	16.00		213	690	
"	"	"	"	"	11.49	"		89	345	Pressure 3psi higher than other
"	"	"	"	"	11.53	8.00		207	690	
"	"	"	"	"	11.57	16.00		114	345	
Flopetrol	SSDR/CRG	DST-hanger	1563.0	28/7-84	11.37	5.00		83832	690	Gauge went out.
"	SDP/ strain	F nipple	1551.0	"	11.29		0.30	83064	345	Memory full.
"	SSDR/CRG	"	1555.7	"	11.34	5.00		83866	690	Gauge went out.

Sampling sheets, DST No. 3

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar	Sampl.point t-°C	Container vol & type	Remarks
65	24/8-84	19.30	OIL, 670cc	SEPARATOR	26.7	15.6	8207321	
	"	20.04	GAS, 201	"	"	"	A - 14658	
	"	"	"	"	"	"	A - 14571	
	"	"	"	"	"	"	A - 14572	
66	26/8-84	01.25-02.22	OIL, 604cc	THORNTON MANIFOLD	32.0	13.7°C	84062301	
	"	"	GAS	"	"	"	A - 14566	
	"	"	"	"	"	"	A - 14582	
	"	"	"	"	"	"	A - 14584	
67	26/8-84	07.30-08.30	OIL, 670cc	SEPARATOR			84062417	
	"	"	GAS	"			A - 14617	
	"	"	"	"			A - 14831	
	"	"	"	"			A - 13986	
68	26/8-84	08.30-09.45	OIL	SEPARATOR			84062504	
	"	"	GAS	"			A - 14666	
	"	"	"	"			A - 14641	
	"	"	"	"			A - 14585	
69	26/8-84	10.00-11.00	OIL	SEPARATOR			84062315	
	"	"	GAS	"			A - 14577	
	"	"	"	"			A - 14576	
	"	"	"	"			A - 14848	
70	26/8-84	11.00-11.30	GAS	SEPARATOR			A - 14619	
	"	"	"	"			A - 14807	
	"	"	"	"			A - 14750	

2039P/ASa

Sampling sheets DST No.3

Test No. 3 Formation: Sognefjord

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar°C	Container vol & type	Remarks
61	24/8-84	13.15	GAS, 20l	SEPARATOR	26.5 15.6	A - 14758	
	"	13.45	"	"	" "	A - 14392	
62	"	16.08	OIL, 670cc	"	26.7 15.6	84062303	
	"	16.32	"	"	" "		
	"	15.00	GAS, 20l	"	" "	A - 14402	
	"	16.32					
	"	"	"	"	" "	A - 14798	
	"	"	"	"	" "	A - 13978	
63	"	17.15	OIL, 670cc	"	26.7 15.6	84061805	
	"	17.45					
	"	"	GAS, 20l	"	" "	A - 14600	
	"	"	"	"	" "	A - 14634	
	"	"	"	"	" "	A - 14594	
64	"	18.10	OIL, 670cc	"	26.7 15.6	8308820	
	"	18.48				A - 14602	
	"	"	GAS, 20l	"	" "	A - 14631	
	"	"	"	"	" "	A - 14588	

2039P/ASa

Sampling sheets DST No. 3

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar t-°C	Container vol & type	Remarks
41	26/8-84	01.00-02.00	WATER w/COMP	SEP INLET			
42	"	02.00-03.00	"	"			
43	"	03.00-04.00	"	"			
44	"	04.00-05.00	"	"			
45	"	05.00-06.00	"	"			
46	"	06.00-07.00	"	"			
47	25/7-84	08.00-08.30	"	"			
48	"	09.35-10.00	"	"			
49	"	08.30-09.00	"	"			
50	"	10.40-11.50	"	"			
51	"	10.00-11.00	"	"			
52	"	13.30-14.05	"	"			
53	"	14.05-14.30	"	"			
54	"	14.30-15.05	"	"			
55	"	15.10-15.30	"	"			
56	"	15.30-16.00	"	"			
57	"	16.00-16.30	"	"			
58	"	22.30-23.30	"	"			
59							
60							

Sampling sheets, DST No. 3

TEST NO. 3 FORMATION: JURA

SAMPLE NO.	DATE	TIME	SAMPLE TYPE	SAMPLE POINT	SAMPL. POINT P-BAR	T-°C	CONTAINER VOL & TYPE	REMARKS
1 2 3 4 5 6	26.8.84 " " "	-	Condensate	Separator Outlet	-	-	Jerry	Merket: Condensate 31/5-2 26.8.84 Dst 3B Separator outlet
7 8 9 10	25.8.84 " " "	-	Condensate	Saparator Outlet	-	-	Jerry	Merket: Condensate fra Multirate test 31/5-2 DST III 25.8.84, Outlet
11 12 13 14	25.8.84 " " "	-	Condensate	Separator Outlet	-	-	Jerry	Merket: Well 31/5-2 Pst 3B Separator outlet
16 17 18 19 20 23	24.8.84 " " " " "	-	Condensate	Separator Outlet	-	-	Jerry	Merket: W 31/5-2 Post Gravel 24.8.84, Separator
21 23	24.8.84 "	-	Condensate	Separator	-	-	Jerry	Merket: Outlet sep. 11.00 11.30 24.8.84 Well 31/5-2 DST III

2039P/ASa

Sampling sheets DST No. 3

Sample No.	Date	Time	Sample type	Sample point	Sampl.point p-bar t-°C	Container vol & type	Remarks
24	25/6-84	06.30	BRINE	DOWEL TANK		1/2l	
25	24/8-84	11.20	WATER			"	
26	25/8-84	11.00	"	SEP WATER OUTLET		1/2l	
27	"	13.00	"	"		1l	
28	"	15.00	"	"		"	
29	"	1630	" w/COM	"			
30	"	22.00	" "	"		"	
31	26/8-84	00.00	WATER	"		"	
32	"	02.00	"	"		"	
33	"	04.00	"	"		"	
34	"	06.00	"	"		"	
35	25/8-84	06.00-07.00	" w/COM	SEP INLET		1/2l	
36	"	09.00-09.35	" "	"		"	
37	"	10.00-10.30	" "	"		"	
38	"	11.00-12.00	" "	"		"	
39	"	21.30-22.30	" "	"		"	
40	26/8-84	01.00-	?	"		"	

Appendix C.3

Pressure/temperature gauges sheets, DST No. 3

Perforation run

Owner	Gauge Type	Position in String	Gauge Depth m BRT	Date Clock Set	Time Clock Set	Sampling rate	Sensing rate	Gauge No.	Range BAR	Remarks
Sperry Sun	Strain	Bundle - carrier	1511.2	12/8-84	03.47	0.30		207	690.0	
"	"	"	"	"	03.46	1.00		089	345.0	
"	"	"	"	"	0342	1.00		213	690.0	Gauge failure.
Flopetrol	SSDR/CRG	F-nipple	1525.2	13/8-84	02.00	0.05		83871	690.0	Gauge used.
"	SSDR/ strain	"	1529.4	"	02.05	0.02		84178	690.0	

2039P/ASa

Pressure/temperature gauges sheets, DST No. 3

Owner	Gauge Type	Position in String	Gauge Depth m BRT	Date Clock Set	Time Clock Set	Sampling rate min	Sensing rate min	Gauge No.	Range BAR	Remarks
Sperry Sun	Strain	DST-hanger	1521.2	21/8-84	1451	8.00		096	690.0	Lost battery contact
"	"	Bundle - carrier	1498.8	"	15.12	4.00		089	345.0	
"	"	"	"	"	15.10	4.00		214	690.0	
"	"	"	1354.0	"	16.58	8.00		207	690.0	Recorded 10°F too high temperature.
"	"	"	1354.0	"	17.02	8.00		120	690.0	
"	"	"	328.9	"	22.04	8.00		106	690.0	
"	"	"	"	"	22.32	8.00		257	690.0	Recorded 15 psi press too low
Flopetrol	SSDR/CRG	F-nipple	1510.9	23/8-84	01.58	0.02		83871	690.0	
"	SSDR/ strain	"	1506.3	"	02.00	0.02		83073	690.0	Used for interpret
"	"	"	?	24/8-84	23.04	0.05		84178	690.0	

Pressure/temperature gauges sheets, DST No. 3

Owner	Gauge Type	Position in String	Gauge Depth m BRT	Date Clock Set	Time Clock Set	Sampling rate	Sensing rate	Gauge No.	Range BAR	Remarks
Flopetrol	SSDR/CRG	F-nipple	1510.9	24/8-84	23.04	0.30		83866	690.0	Gauge used for interpret.