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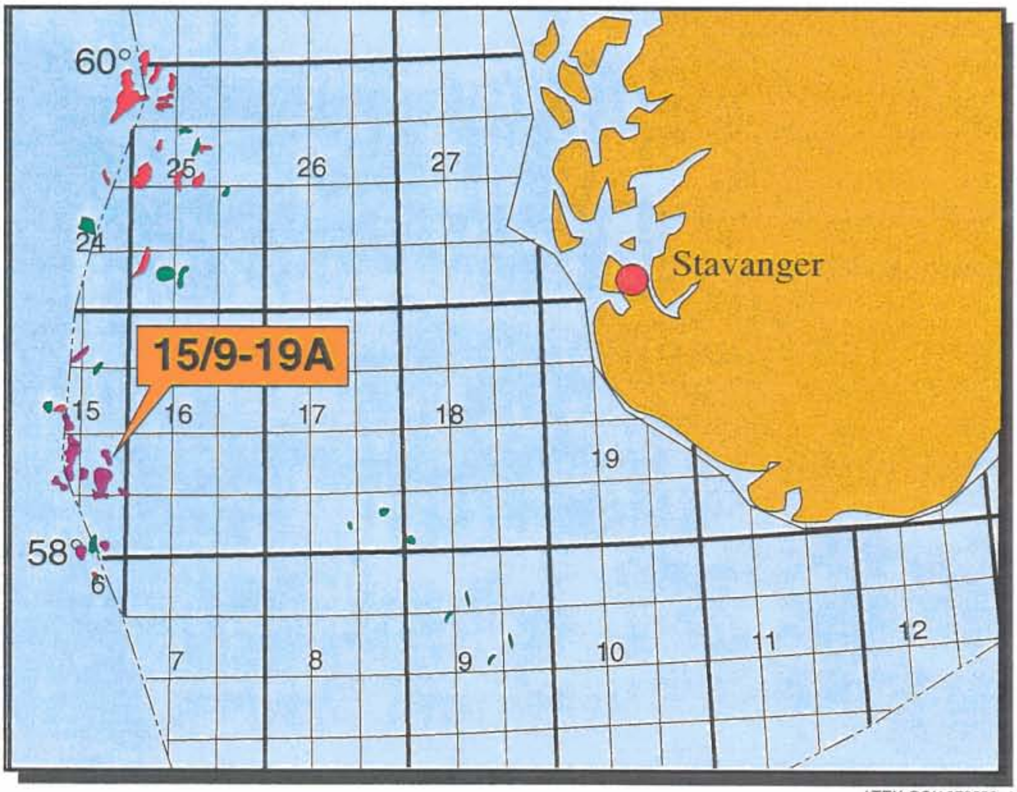

LTEK-GS/A970680_1

WELL TEST REPORT — PL046

WELL 15/9-19A

Test 1 and 2A&2B

98S94*18253

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Well Test Report
15/9-19A
PL 046
Test 1 and 2A&2B

98S94*18253

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Well Test Report **15/9-19A** **PL 046** **Test 1 and 2A&2B**			

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Table of contents

1 INTRODUCTION

Three tests were performed in the well 15/9-19A.

Test 1: Water test

Test 2A: Oil test, 3 m zone in the lower part of the Hugin formation

Test 2B: Oil test in the upper and middle part of the Hugin formation
Commingled test (zone 2A + 2B)

Figure 1.1 shows a map of the area with location of the well.
Figure 1.2 shows a time vs. depth presentation of the complete well history included the test period.
Figure 1.3 is a presentation of the formation with logdata / log interpretation, cored interval and test interval.

Total time used for the test phase is summarised in Appendix G, Figure G.1 where the test 2A&2B time consumptions are summarised.
In figure G.2 the complete test phase is summarised consisting of running casing, industrial action, logging in casing, water test and test 2A&2B

The test was performed with the rig Byford Dolphin in the last quarter of 1997, and ended 05.11.97. Operational time for tests 1 and 2 were approximately 7.2 and 12 days respectively. The operations went smoothly with only minor problems and no accidents.

PL046 Blocks 15/8 and 15/9
Location of Fields and Discoveries

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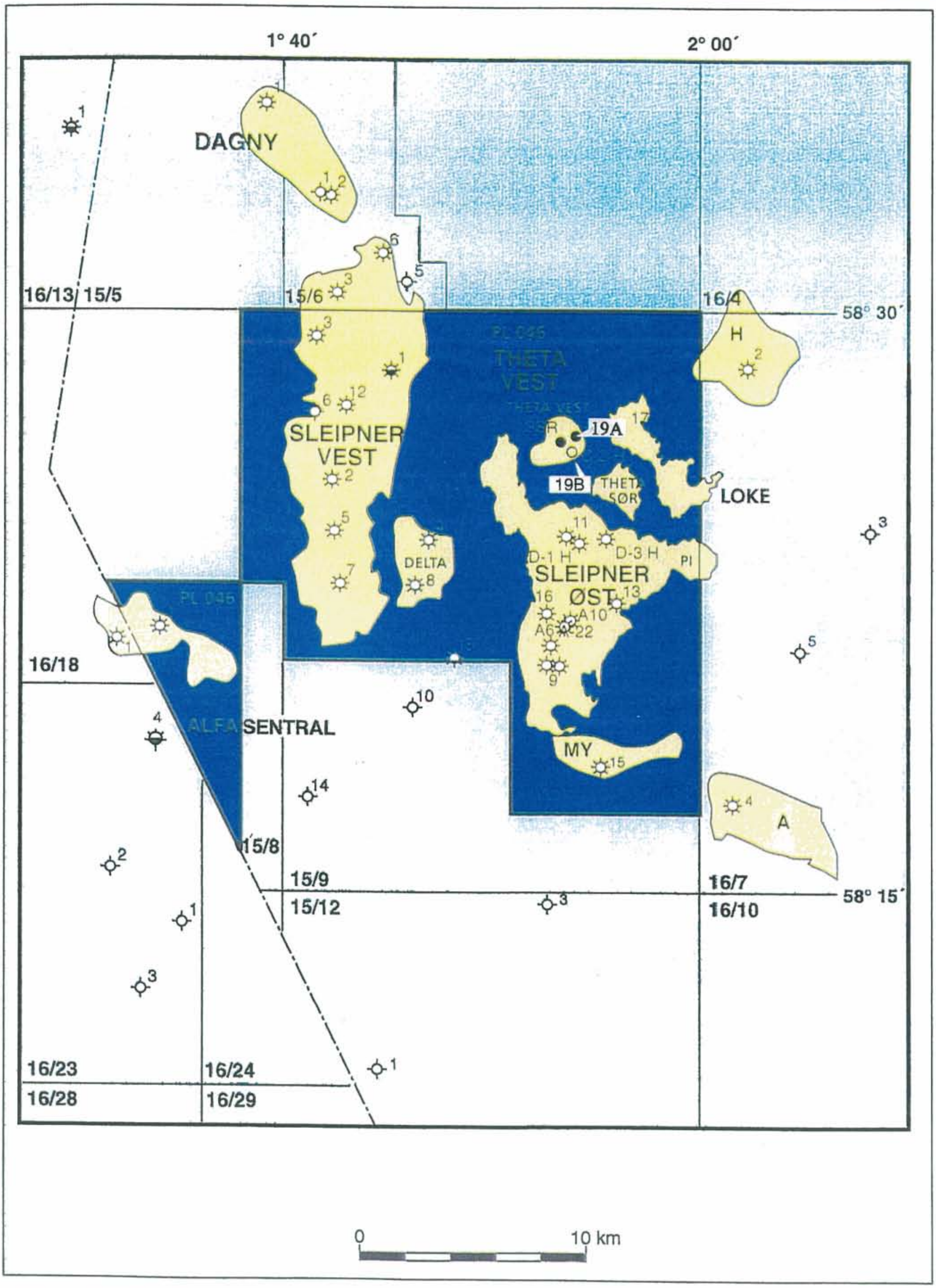

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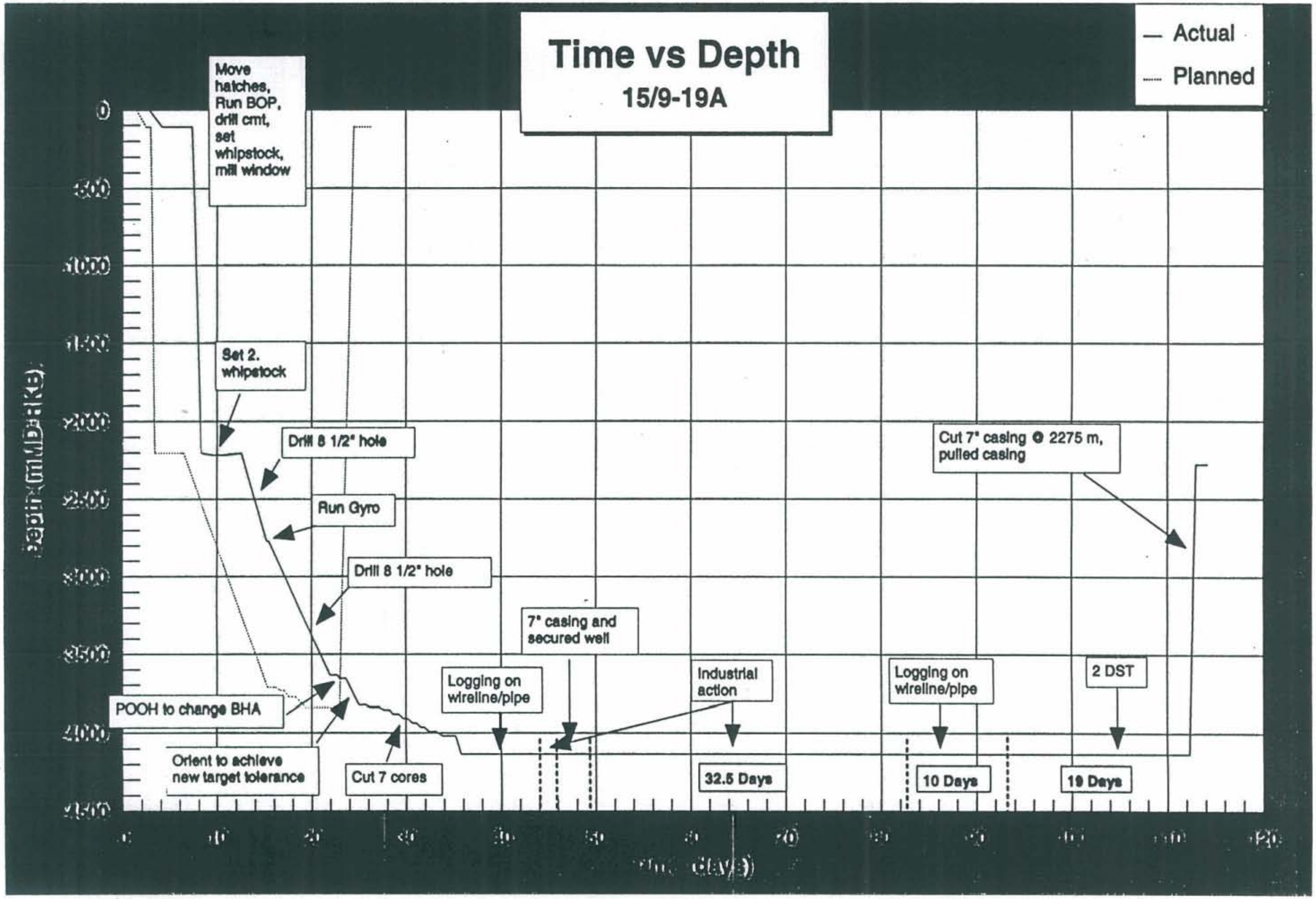
Fig.1.1


Time vs Depth
15/9-19A
Actual
Planned
Move hatches, Run BOP, drill cmt, set whipstock, mill window
Set 2. whipstock
Drill 8 1/2" hole
Run Gyro
Drill 8 1/2" hole
POOH to change BHA
Orient to achieve new target tolerance
Cut 7 cores
Logging on wireline/pipe
7" casing and secured well
Industrial action
32.5 Days
Logging on wireline/pipe
10 Days
2 DST
19 Days
Cut 7" casing @ 2275 m, pulled casing
0
500
1000
1500
2000
2500
3000
3500
4000
4500
10
20
30
40
50
60
70
80
90
100
110
120

15/9-19A Hugin reservoir
Perm, cores and test interval

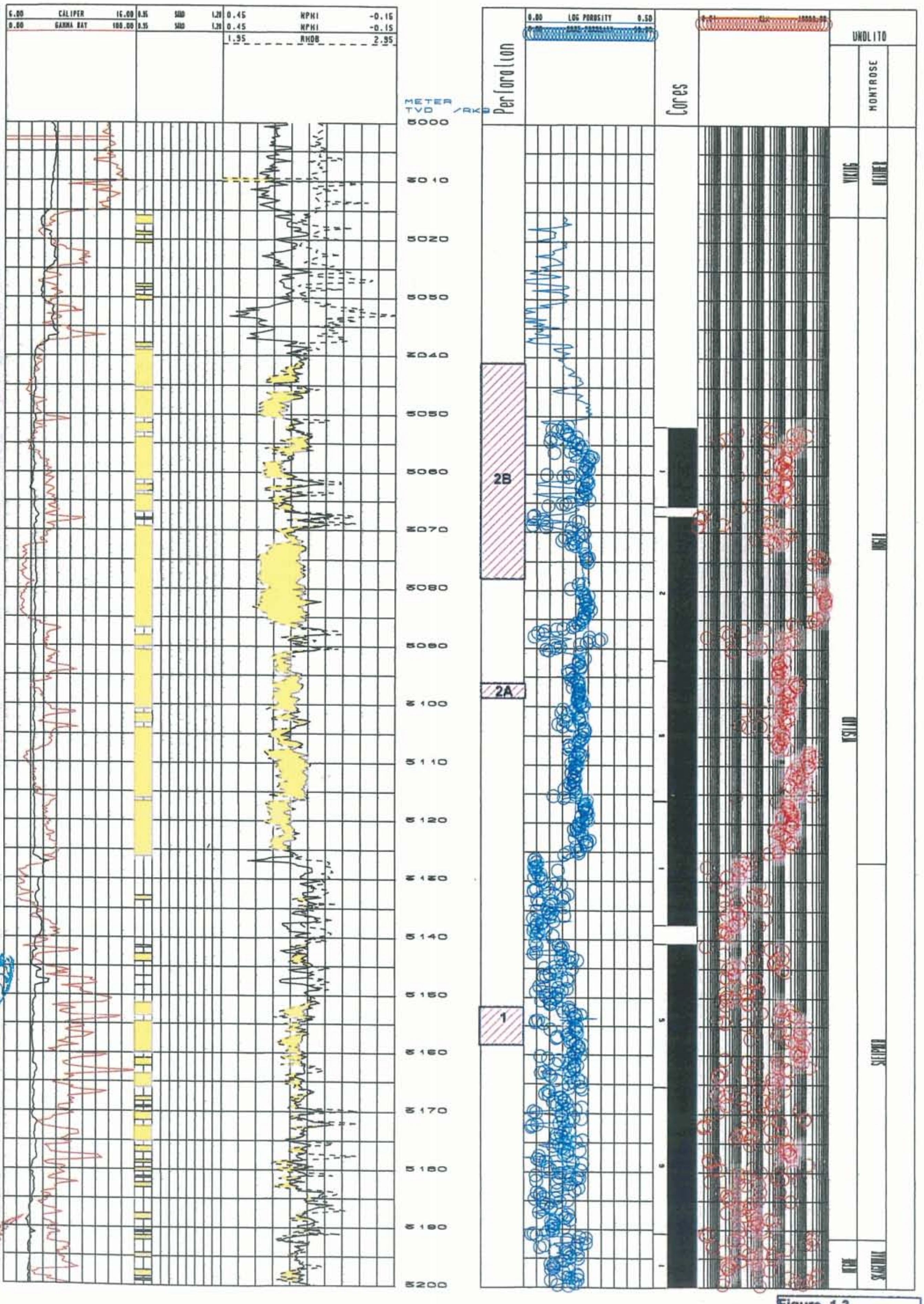


Figure 1.3

2 SUMMARY

One Drill Stem Test wasplanned in the Hugin sandstone in well 15/9-19A. The test was performed in the period 18/10-3/11-97, and the objectives were to:

- Obtain representative formation fluid samples
- Obtain reservoir pressure (pressures were not obtained during log operations)
- Obtain information about sand strength and minimum formation stress
- Obtain separation experience regarding water/oil emulsions (MTU)
- Obtain information about reservoir characteristics and initial well productivity
- Obtain data for determination of reservoir heterogeneity or boundaries

Top Hugin Fm. in this well was encountered at 3015.6 m TVDRT and bottom at 3126.3 m TVDRT
The test was planned and performed with 2 separately perforated zones, 2A and 2B.
2A perforated and produced first, then 2A + 2B commingled.
Perforated interval Zone 2A ; 3885.5 - 3888.5 m MDRT (3095.6-3098.3 m TVDRT)
Perforated interval Zone 2B ; 3826-3865 m MDRT (3041.9-3077.1 m TVDRT)

Figures in Chapter 4.

Due to industrial action and failure in log instruments, a water test was performed with the objectives of obtaining representative water samples from the Sleipner Formation.
The perforated zone was 3952 - 3958 m MDRT (3155.5 - 3160.9 m TVDRT)
Most of the information regarding the water test is in Chapter 3 and in Appendix D
Information regarding absolute pressures in the formations, see Chapter 7.

Figures in Chapter 3 show overview and analysis results from the water test.

2.1 Test design

To meet all the objectives with the Hugin formation test, the test was split into 2 parts.
To obtain the objective of sand strength and minimum formation stress, the first part (2A) was designed to create a draw-down across the perforation of approximately 70 - 80 bars at a production rate of 200-300 Sm^3/day.
At the same time a rate of 200-300 Sm^3/day was needed to get representative fluid samples. This rate also optimised the condition for a good cleanup of the perforated interval and prepared the well for bottom hole sampling.
The second part of the test (2B) incorporated most of the upper Hugin formation and partly the best sand zone in the formation plus the zone 2A. This to ensure that the response from the 2B part included a major part of the reservoir. Particularly if the 2A zone should indicate depletion, a need for a larger perforated area would be necessary to prove whether the reservoir tested were a relatively small compartment or not.
The test 2A flowed for approximately 43 hrs with a rate of 560 Sm^3/d. During 27 hrs of this time the flow was partly directed through the MTU unit for water/oil separation studies.

2.2 Hydrocarbon system

The hydrocarbon system in the wells 15/9-19A and 19SR seem to be of same origin.
Factors indicating this is geochemistry results, Thomson indices and all the similarities in the PVT data. There are differences in the PVT data like bubble point and asphaltene contents, but closer studies indicates that this is most probably caused by gravitation effects.
There are no significant differences in the fluids sampled in test 2A and test 2B in well 19A and are therefore interpreted to contain the same hydrocarbon system.
Evaluation of pressures in wells 19SR and 19A also indicates communication between the wells and that the pressure regimes are the same.
See pressure details in Chapter 7 and fluid details in Appendix C

3 TEST 1 , Water test

The main objective was to get representative water samples from the Sleipner Formation, then reservoir properties and formation strength.
Water samples were obtained using bottomhole samplers and reservoir properties calculated using pressure data during the shut-in period. The planned mini frac. was attempted but the test did not succeed, probably due to plugging of the perforated interval.

3.1 Summary

Short resume of events during the period from completing the drilling operations until the Test 1 commenced.

- Open hole logging commenced. Had to log "pipe conveyed" due to the well geometry and the wash outs in the Hordaland Group. Acquired all standard logs and VSP.
- The industrial action was commenced on Byford Dolphin.
- Went in with pipe and FMT tool to perform pressure survey and secure the well while waiting for a clarification of how to respond to the industrial action. Lost contact with the tool due to wet connection pulled out, cable clamp on the side entry sub did not hold the cable in place.
- Were not allowed to do any other attempts to perform the pressure and sampling run resulting in no pressure measurements or fluid samples.
- 7" casing was run and set. Industrial action continued.
- The operation started up after the industrial action approximately 30 days later. Due to the missing pressure measurements, the plan was to perforate 1 ft sections of holes in the casing at specified points. Then run in with the MDT dual packer tool and perform pressure measurements and fluid sampling.
- The MDT tool failed 3 times. Due to the fact that each trial took 24 hrs and Schlumberger was not able to pinpoint the error or come up with more equipment (all backup already used), it was decided to commence with a water test.

Operational summery of the test
The Sleipner Formation was perforated at 3952 - 3958 m MDRT
(3155.5 - 3160.9m TVDRT) using 3 3/8" wireline guns. The perforation was performed overbalanced.
The test string with retrievable packer was run in hole and set at approximate depth, and the well opened for flow at a 32/64" adjustable choke.
The wellhead pressure increased to approximately 12 bar before it slowly decreased to zero approximately 1 hrs 20 min later. At this time the down hole tester valve was closed and opened again in order to verify the valves were shut or partly shut.

At later stage it was discovered that the OMNI valve at this stage had been closed and continued being closed for the rest of the test period. This probably due to tool failure or operators lost track of the valve position.
Observing no flow from the well, it was decided to rig up wireline tools and run in hole with a bottom hole samplers to perform water sampling.
The first sampling run was performed as a combined sampling and correlation run to obtain the exact depth of the pressure gauges. The tool string contained a modified PLT string with bottom hole samplers with electric firing from surface. The tool string stopped at approximately 3907 m MDRT wich corresponds to the OMNI valve. It was then pulled out to approximately 3700 m (2950 m TVD) were the samplers were opened and the sampling performed. Function check at surface indicated malfunction of the samplers, hence a second run was performed.
(Analysis of content in one of these samplers proved that the samplers functioned but due to the fluid the actual sampling had been very slow. The analysis showed a fluid density of 1.69 sg. indicating segregated mud. The mud weight used during the reservoir drilling was 1.55 sg. and later during the logging and testing phase 1.47 sg.)
The second sampling run were performed at approximately 2500 m TVD , and 4 good samples were acquired.
The wireline equipment were then rigged down prior to reversing out the string contents. During the reversing continuously sampling of water took place.
After completing the reverce circulating, the OMNI valve was opened and an attempt to perform a mini frac was done. This did not succeed probably due to heavy segregated mud plugging the perforations.
The well was "killed" and the test string pulled out of the hole and prepared for test 2A&2B

3.2 Main results

The main objective to obtain water samples was achieved.
Due to the lack of good rate history, the data is of limited use for analysis and the result may be interpreted in different ways.
The average permeability from the core measurements in the perforated interval is approximately 330 mD with a maximum of approximately 900 mD.
The calculated permeability from the test is approximately 13 mD which does not correspond with the core measurements.
The core data is considered most reliable with respect tp permeability estimation in this case.
Rock mechanical properties were not obtained, due to the lack of minifrac data.
For more details see Appendix D.

	Test 1 , water test
Perforations m TVD RT, (m MD RT)	3155.5-3160.9 (3952 -3958)
Gauge depth m TVD RT (m MD RT)	3134.7 (3928.9)
Static pressure at top perf. bar	352.0 +/- 1.0
Fluid density at 20 °C kg/m³	1 104
Static pressure at gauge depth bar	recorded: 349.2 extrapolated: 352.0 +/- 1.0
Reservoir temperature deg C	Max. recorded: 112.7
Permeability thickness mDm	78
Test permeability h = 6 m mD	k= 13
Formation damage	0,4
Core permeability mD	330

Table 3.1 : Main results , Test 1 - water test.

3.2.1 Main fluid sampling results

Field	Volve
Well	15/9-19A
Formation	Sleipner
Sample type	BHS
Na^+ [mg/l]	44610
K^+ [mg/l]	1790
Mg^{2+} [mg/l]	2240
Ca^{2+} [mg/l]	7240
Sr^{2+} [mg/l]	290
Ba^{2+} [mg/l]	27
$Fe^{2+/3+}$ [mg/l]	0.1
Cl^- [mg/l]	94560
SO_4^{2-} [mg/l]	90
HCO_3^- [mg/l]	355
Total dissolved solids [mg/l]	151 202
Organic acids [mg/l]	176
pH @ 1.013 bara, 20°C	8.17
Resistivity @ 20°C [ohm·m]	0.067
Density @ 18 °C [g/cm³]	1.104

Table 1 Formation water compositions.

Well 15/9-19A, Test 1
Bottom hole Pressures and Temperatures

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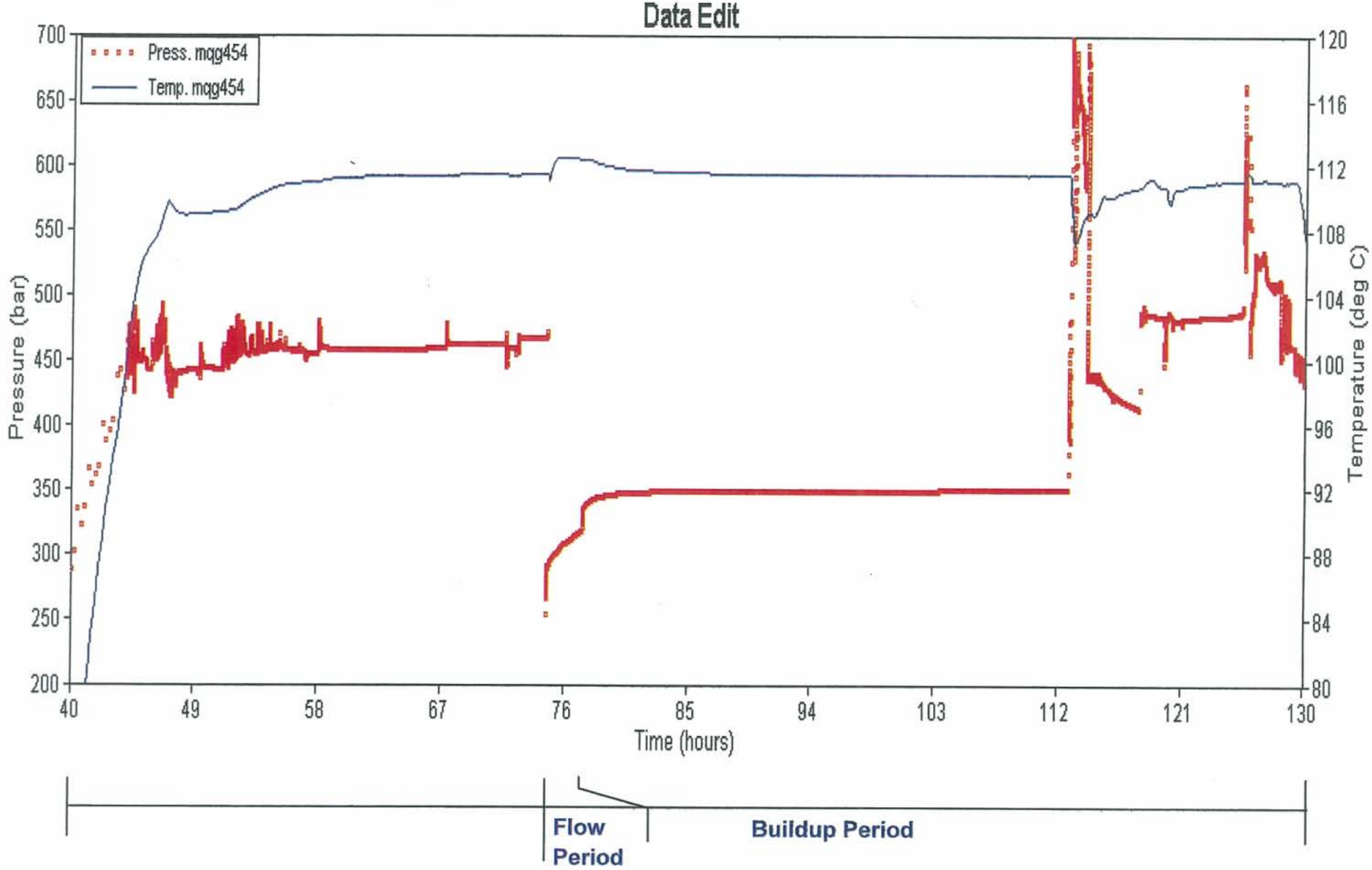


Figure 3.1A

Fig 3.1 Overview of test 1

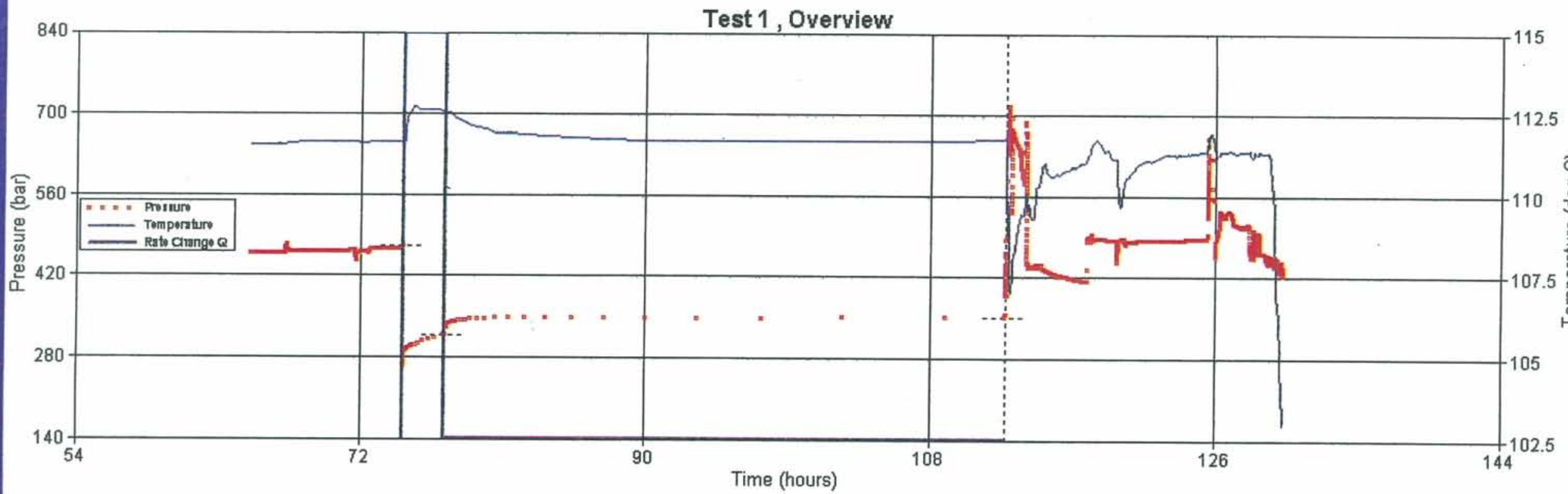
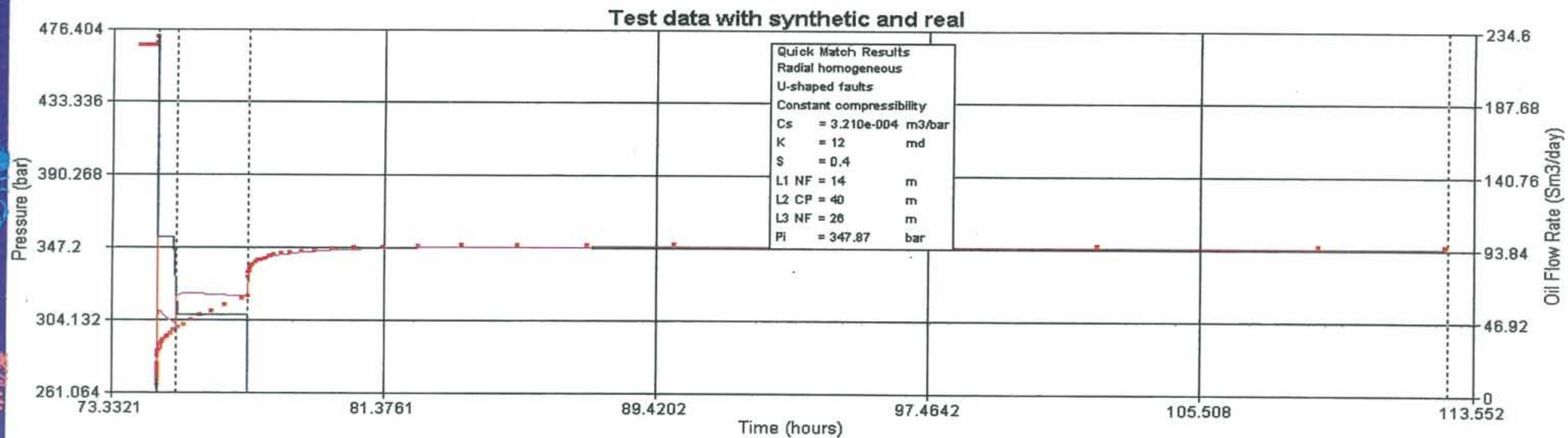


Fig 3.2 Test 1, real and synthetic data



4 TEST 2A&2B

4.1 Operational summary

The test 2A was perforated overbalanced with 3 3/8"- 6 shots/ft wireline guns before running the test string, due to the depth accuracy requirement for this test (designed based on core measurements for both draw-down and production rate). The test string was run in hole with TCP guns for zone 2B, retrievable packer, down hole tester valve and 6 pressure gauges (see also Appendix G for detailed bottom hole assembly).
The pressure gauges were programmed to record pressure during the complete Test 2A &2B.

The well was opened on 14/64" adjustable choke and increased in steps to 32/64". The produced cushion (diesel) directed to tank in the start up phase. Gas to surface after approximately 1 hour and mud after 2 hours.
The choke was then increased in steps to 58/64" before decreasing to 40/64" due to separator/separation problems, and then finally switched to a 38/64" fixed choke for the remaining time of the cleanup flow.
The well was shut in for pressure buildup at the tester valve after approximately 16 hours.
During the pressure buildup, the wireline equipment for the bottom hole sampling was rigged up.
A 2 hours conditioning flow (38/64" adjustable choke) was performed to heat up the well fluid before the well was shut in at surface and followed by a short pressure buildup period while the PLT string with the bottom hole samplers were installed.
The well was opened for production through the MTU at approximately 100 Sm^3/day and the wireline run in the hole. A correlation pass was performed to obtain accurate depth of the pressure gauges. The bottom hole samplers were stationed at depth, the well shut in at surface and the samplers fired electrically from surface. The samplers were then pulled out of hole and rigged down after verifying that all 4 samplers had fired.
The planned minifrac was then attempted without success and aborted after approximately 4 hours. Not possible to establish an injection rate.

Test 2B was initiated by perforating the upper interval against closed choke. Wireline equipment were pulled out of the hole and rigged down.
Well opened on 20/64" adjustable choke, decreased to 14/64" for a short period before increased in steps to 48/64". Had oil to surface approximately 5 min after opening, only traces of sediments. Decreased the choke size to 34/64" fixed choke for the remaining flow period, with an average flow rate of approximately 560 Sm^3/d. Part of the well stream was directed through the MTU for water/oil separation tests for approximately 27 hrs. (See separate MTU report)

Main flow period ended after approximately 42 hrs, when the well was shut in for Main buildup. Main buildup period lasted for approximately 43 hrs.
The test was finished by pumping 2 minifrac cycles as part of the well killing (approximately 3 hrs). Test string was pulled out of hole.

Fig 3.3 Test 1, real and synthetic data
Log-log plot, shut-in period

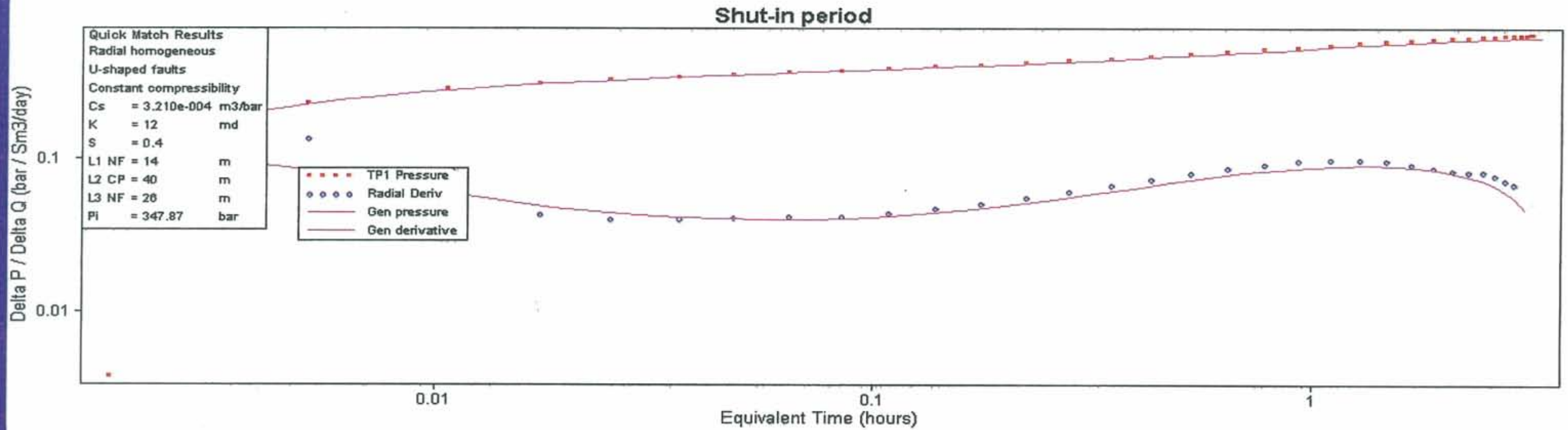
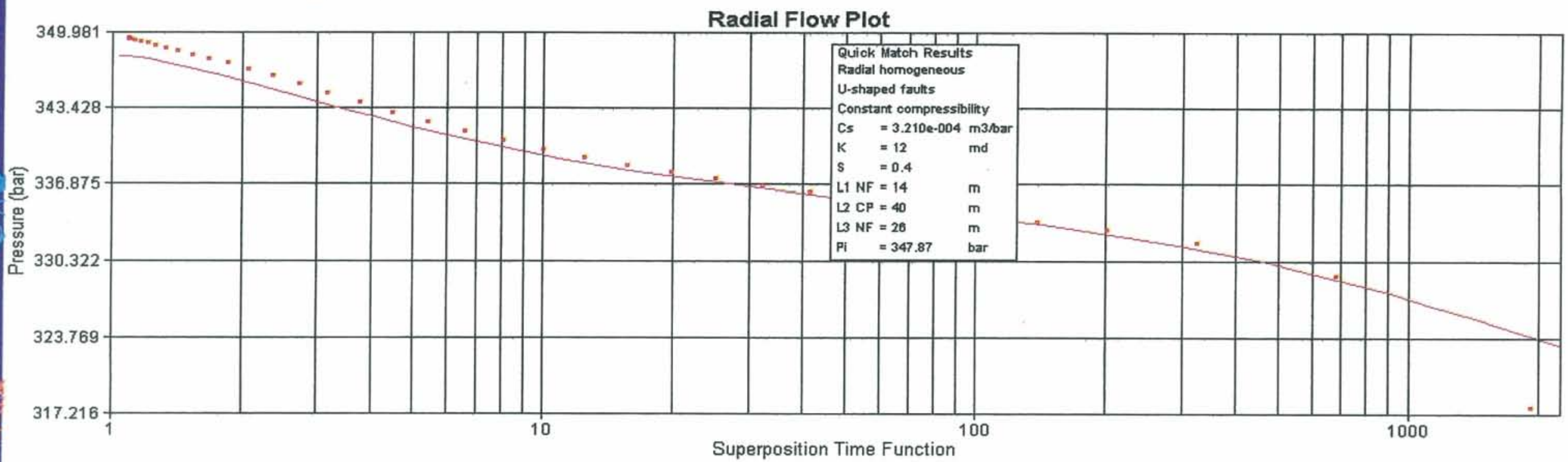


Fig 3.4 Test 1, real and synthetic data
Semi-log plot, shut-in period



Well 15/9-19A, Test 2A&2B
Bottom hole Pressures and Temperatures

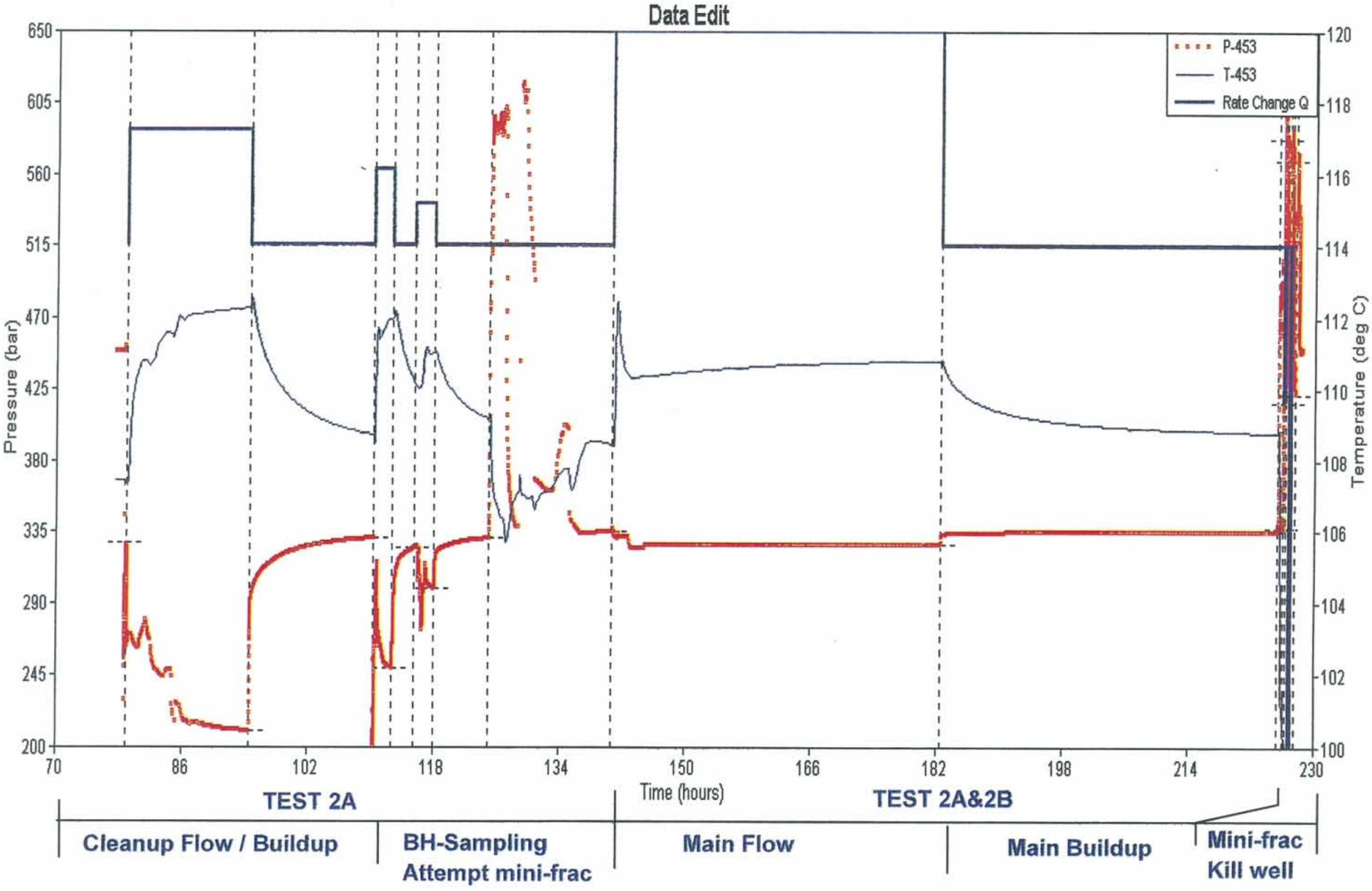


Figure 4.1.1

4.2 Production data

Table 3.1.1 shows the main production data obtained during both test 2A and 2B.
The rates have been corrected with respect to both meter factors and MTU rates.
Meter factor has been applied to all rates measured through the Halliburton test separator.
(Ref. MWS, Data Acqusition & Sampling Report)
The MTU rates have been converted to standard conditions and applied to the Halliburton separator rates where applicable. For Test 2B Main Flow , the rates are average rates based on cumulative production in the period.

Period From - to	Approx. Time hrs.	Bottom hole Pressure bar	Wellhead pressure bar	BHT / WHT deg C	Q oil + MF* Sm3/d	Qgas Sm3/d	GOR Sm3/Sm3	Choke size /64"
Test 2A								
Cleanup flow 0651 - 2235	15.7	209,79	31,9	112,3 47,0	300 0.95	27000	90	38
Cleanup build-up 2235 - 1447	16.2	330,63	1,01	108,8 12,5	0	0	0	closed
Cond. flow 1447 - 1645	2.0	249,73	48,89	112,0 32,1	250 0.95	22500	90	38
Condit. build-up 1645 - 2010	3.4	309,38	81,89	110,2 14,8	0	0	0	closed
Sampl. flow 2010 - 2159	1.8	298,91	81,10	111,1 22,0	103 0.95	-	-	28
Sampl. build-up 2159 - 0504	7.1	330,31	102,10	109,3 10,9	0	0	0	closed
Test 2B								
Main flow 2051 - 1432	41.7	326,50	95,22	110,8 72,3	528 0.97 & 0.80	38107	72	34
Main Build-up 1432 - 0831	42.0	334,76	1,01	108,9 10,5	0	0	0	closed.

Table 3.1.1 : Production data.

* Meter factor used for calculation of oil rates. Due to a distinct change in separator conditions during the Main Flow 2 different meter factors has been used.

Table 3.1.2 shows values of oil / gas and trace elements during the cleanup flow and main flow periods. The values in this table are the last measured value during each flow period.

Measurements	**Cleanup Flow**	**Main Flow**
Density of Oil (g/cm³)	0.892	0.903 - 0.901
Density of Gas, air =1.0	0.738	0.736 - 0.723
Water in oil (%)	-	0.069
H_2S (ppm)	2.5	2.8
CO_2 (%)	3.0	3.5
Mercaptans (RSH)	0	0
Radon, Rn-222 (Bq/l)	0.916	0.758
Mercury, Hg	23.74	0
Carbonyl Sulphide	0	0

Table 3.1.2 Trace element sampling

4.3 Main results

Results from the two tests are based on the 2 most likely models.
The test results seem to fit 2 different models almost equally when using analytic analysis on the test pressure data.
The model that seems most likely both for both of wells 15/9-19SR and -19A has been a U-shaped homogeneous reservoir with 2 parallel no-flow boundaries and one perpendicular constant pressure boundary.

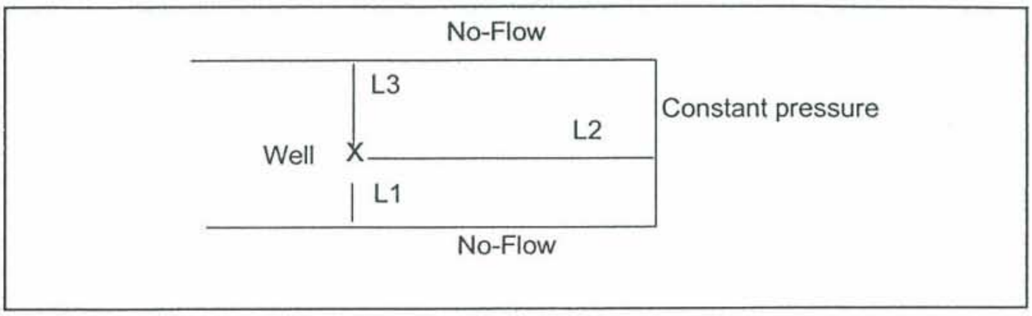


Figure 4.3.1, U-shaped boundary

This model gives a good match to the actual data on a log-log and semi-log plot, and on a Cartesian plot with all flow/build-up periods used. The difficult part here is to explain the constant pressure boundary. An increase in kh ratio may lead to a result like this, but a rather huge increase is needed with this channel model. Gas cap is not an issue here because of the very under saturated fluid (reservoir pressure at approx. 340 bar and bubble point at approx. 235.5 bar).
Water drive is not likely due to the distance from the well to the no-flow boundary.
Due to the relatively low formation dip, 200 - 300 m out from the well may not take the reservoir down to water oil contact.
The second model that seems to fit the data in the same manner as the above and which also seems to fit the actual impression of layered reservoir, is a so-called dual or dobbel porosity model (Pan-system). Here this model is pictured as a two layer system with kh contrast between the layers.

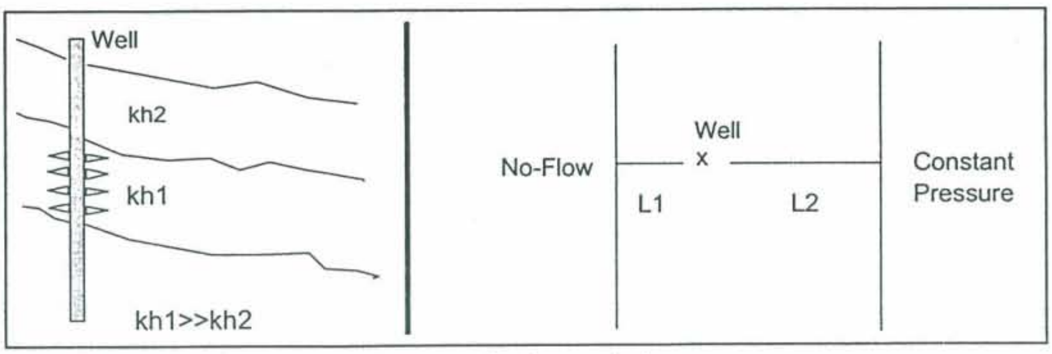


Figure 4.3.2, Layered reservoir (Pansys -> dual porosity)

Both logdata and coredata indicates a reservoir with huge differences in permeability and porosity, from a permeability of 20 D down to less than 1 mD. In Chapter 6.4 a special method (Lorenz plot) has been used to use core data to visualise differences in core data within the zone. These plots also indicate production only to take place from parts of the perforated zone.
The no flow boundary could be the fault mapped near the well. The constant pressure boundary may be easier to explain as an increase in kh ratio with this model. It seems easier to understand such an increase without the limits of a channel.

	Test 2A	**Test 2B**
Perforations m TVD RT, (m MD RT)	3095.6-3098.3 (3885.5-3888.5)	3 041.9-3077.1 (3826.0-3865.0)
Gauge depth m TVD RT (m MD RT)	3007.5 (3787.4)	3007.5 (3787.4)
Static pressure at top perf. bar	342.0 +/- 1.0	337.5 +/- 0.5
Fluid density at res conditions kg/m³	737	737
Static pressure at gauge depth bar	recorded: 330.5 extrapolated: 335.5 +/- 0.5	recorded: 334.7 extrapolated: 335.0 bar
Reservoir temperature deg C	Max. recorded: 112.3	Max recorded : 110.8
Results referring to U-shaped model		
Permeability thickness mDm	800	25000
Formation permeability mD Vertical permeability md hres = 10 m , hperf = 3 m	k = 70 h = 10 m k = 160 h = 5 m kv = 90	k = 640 h = 39 m k = 1500 h = 16.7m
Skin factor	4,5	9,6
Specific formation prod. Sm3/d/bar/m	0.8 (h = 3.0 m)	1.45 (h = 39 m)
Dist. to first no-flow boundary m	13 m	20
Dist. to second no-flow boundary m	45 m	120
Dist. to const. press. boundary m	90 m	140
Results referring to layered reservoir		
Permeability thickness mDm		19 500
Formation permeability mD		k = 500 h = 39 m k = 1100 h = 17.7 m
Formation damage		6.3 - 6.5
Specific formation prod. Sm3/d/bar/m		1.45 (h = 39 m)
Dist. to first no-flow boundary m		L1 = 50 h = 39 L1 = 100 h = 18
Dist. to const. press. boundary m		L2 = 300-350 h = 39 L2 = 400 - 500 h = 18

Table 4.3.1 Main data

4.4 Gauge performance and comparison

Two gauge carriers with a total of 6 pressure and temperature gauges were used for Test 2, 4 MQGX gauges from Maritime Well Services and 2 HMR gauges from Halliburton.
All MQGX and one HMR gauge run through the complete test, while the second HMR gauge stopped after Test 2A.
Due to sampling rate, specifications and performance the MQGX gauges have been preferred for the analysis. Based on comparison between the 4 MQGX gauges, gauge no. 453 has been selected for the final analysis. Most important for this choice has been the sampling rate at the end of the main flow (picked up more data than the others) and that the temperature compensation during the first part of the Main Buildup seems to be better on this gauge compared with the others.

Figures 4.4.1 - 4.4.3 shows comparison between the gauges.

Well 15/9-19A, Test 2A&2B
Gauge performance and comparison

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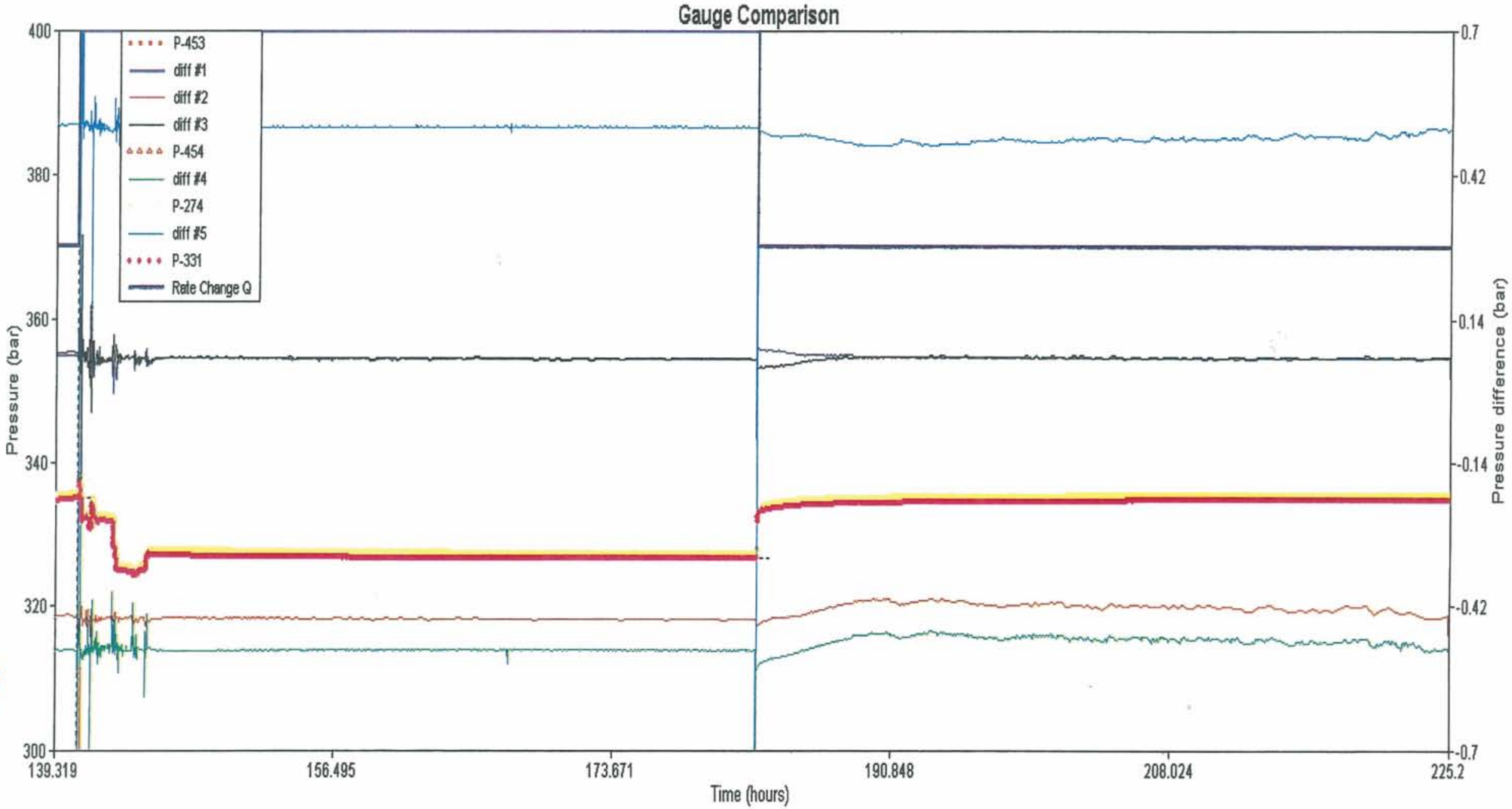


Figure 4.4.1, All MQGX gauges with differenses.

All gauges are measuring almost identical pressures
Due to the pressure scale all pressures are on top of each other

Well 15/9-19A, Test 2A&2B
Gauge performance and comparison

STATOIL

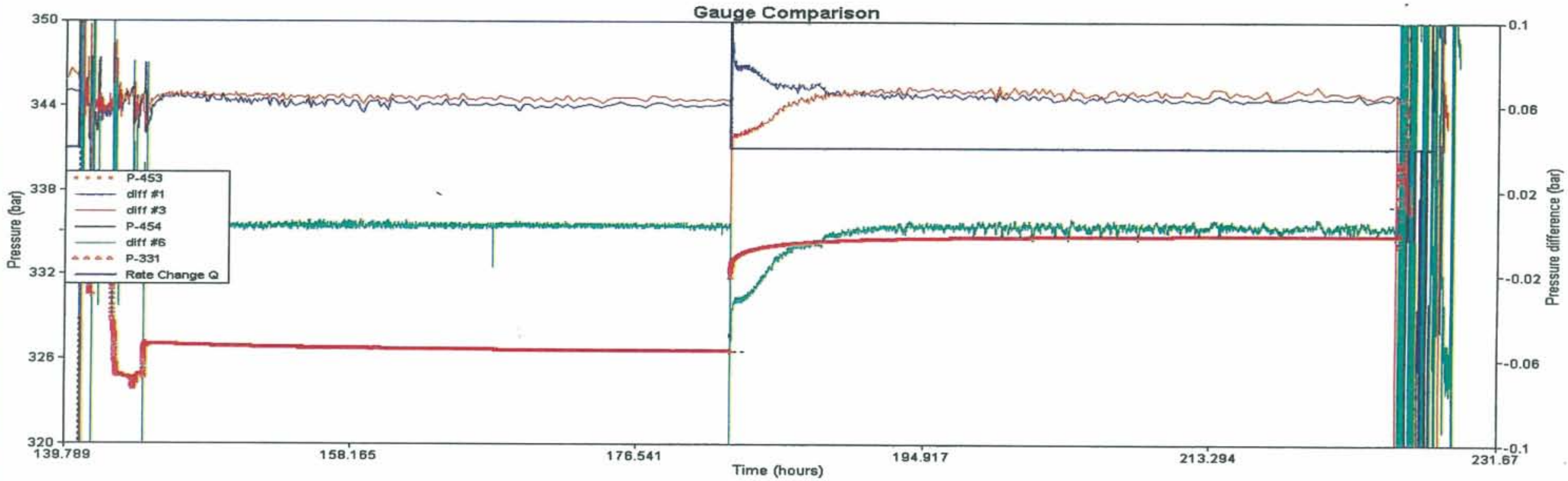


Figure 4.4.2, 3 MQGX gauges, blue: 453-454, red: 453-331, green: 454-331

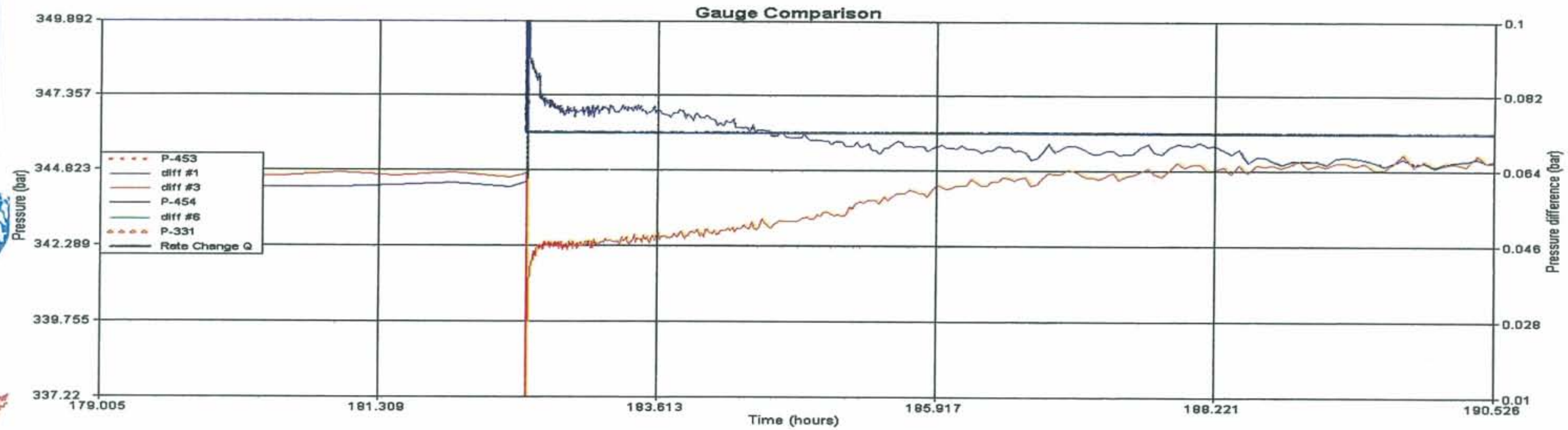


Figure 4.4.3, MQGX gauges, expanded view, blue: 453-454, red 453-331

4.5 Completion, formation and reservoir fluid data

The data listed here has been used for the analysis of both test 2A and test 2B.

	Test 2A&B, oil
Mud	Oil based mud 1.47 g/cc
Cushion	Diesel 0.84 g/cc
Overbalance perforation	approx. 130 bar
Underbalance opening well	approx. 115 bar
Well radius r_w	0.108 m
fluid density	737 kg/m^3
Bo	1.31 m^3/Sm^3
Oil viscosity	0,776762 mPa s
Oil compressibility	1,4504e-4 bar^{-1}
Gas compressibility	1,6311e-3 bar^{-1}
Formation compr.	4,8214e-5 bar^{-1}
Total compressibility	1,9815e-4 bar^{-1}
Porosity	25 %
Gas oil ratio	112 Sm^3/Sm^3

5 TEST 2A

5.1 Test data

The data from test 2A consist of 3 flow and shut-in periods. The number of periods makes the simulations relatively reliable with regards to permeability and extent of the reservoir. Since skin effects dominate the flow periods, with considerable changes during the test, the shut-in periods have been used in the analysis. With the cleanup flow/build-up period as the one with best response.
Fig. 5.1.1 to 5.1.3 show overviews of bottomhole and surface pressures, surface rates and separator pressures and temperatures. Choke sizes are also indicated.
The diagnostic plot in Fig. 5.1.4 shows consistence between the three build-up periods during the last part of the periods, while the beginning of the periods are hidden in well bore storage effects due to surface shut in for the two last shut-in periods.

5.2 Pressure analysis

The results from the analysis indicate that the distance of investigation into the reservoir is roughly 200 m.
Based on the objective of looking further into the reservoir, the emphasis for this part of the test has been to establish the layer pressure and the permeability, and not so much determination of boundaries. Only one boundary model and one well model has therefore been tested.
The homogeneous U-shaped reservoir in fig 5.2 1-4 and a partial penetration model in Fig. 5.2.5-10

Using the U-shaped boundary model a good match for all the periods has been obtained. To match the flow periods, different skin values and well bore storage have to be implemented, see Figure 5.2.1 and -9 were the match has been done with respect to the cleanup flow period.
To match the second and third flow, skin values of respectively 5 and 2.5 are needed.
The match and the analysis of the cleanup buildup period both give a permeability of approximately 165 mD using a reservoir height of 5 m. Using 10 m will give approximately 70 mD. A vertical permeability of approximately 90 mD can be calculated using the partial penetration model with 3 m perforation and reservoir height of 10 m.
The boundary condition used for the match (h=5 m), consist of a rectangle were the well is placed in one end with two parallel no-flow boundaries at 12 and 45 meter from the well and one perpendicular constant pressure boundary approximately 90 m from the well. The fourth side is open. See also drawing in Chapter 4.3 (Figure 4.3.1)

The partial penetration model matches the data quite well and confirms that more than the perforated interval is contributing to the production.
As this model seems to be the most likely model that can be related to real events and test performance, no further analysis has been done.

Well 15/9-19A, Test 2A
Bottom hole and surface data

STATOIL

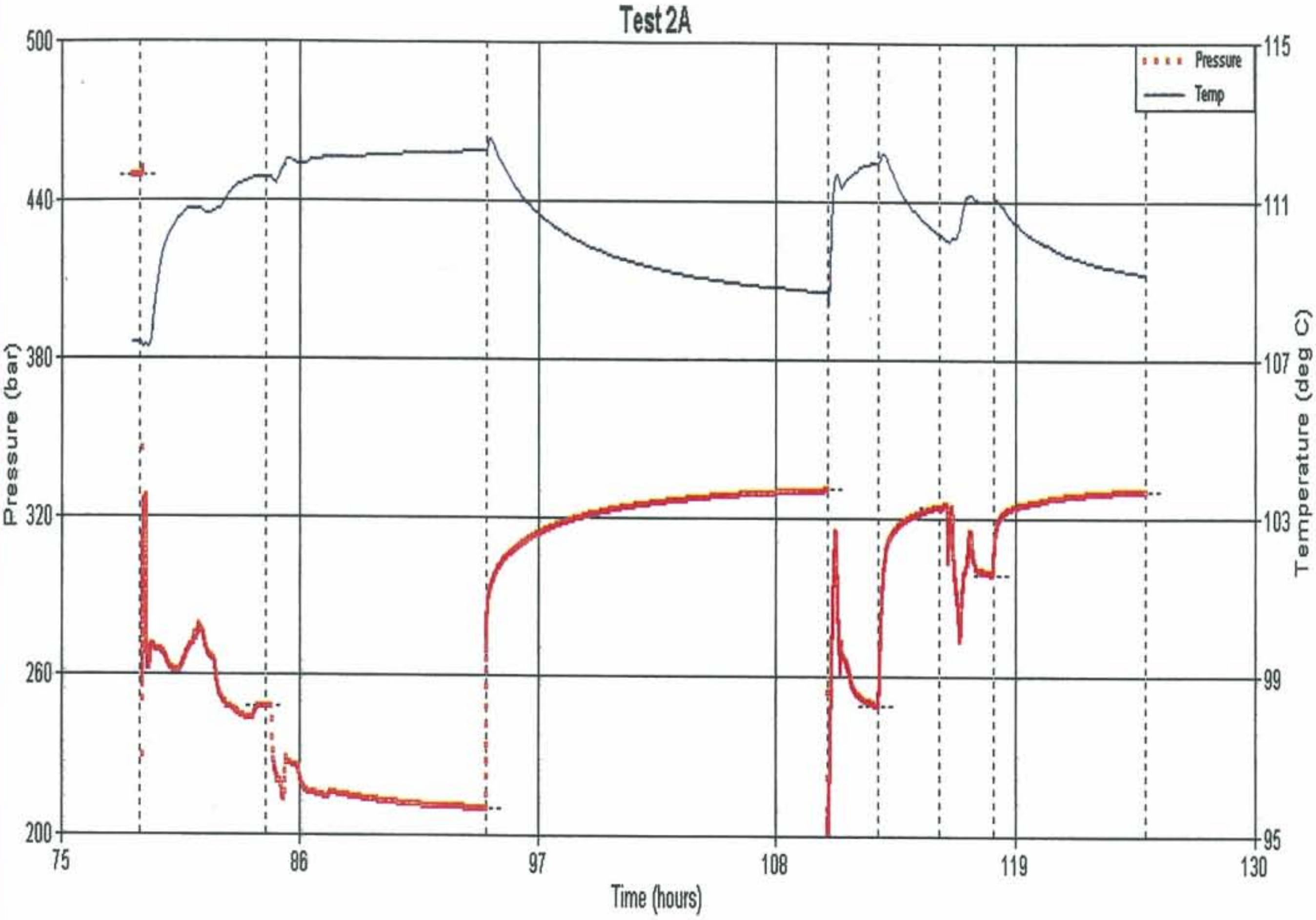


Figure 5.1.1

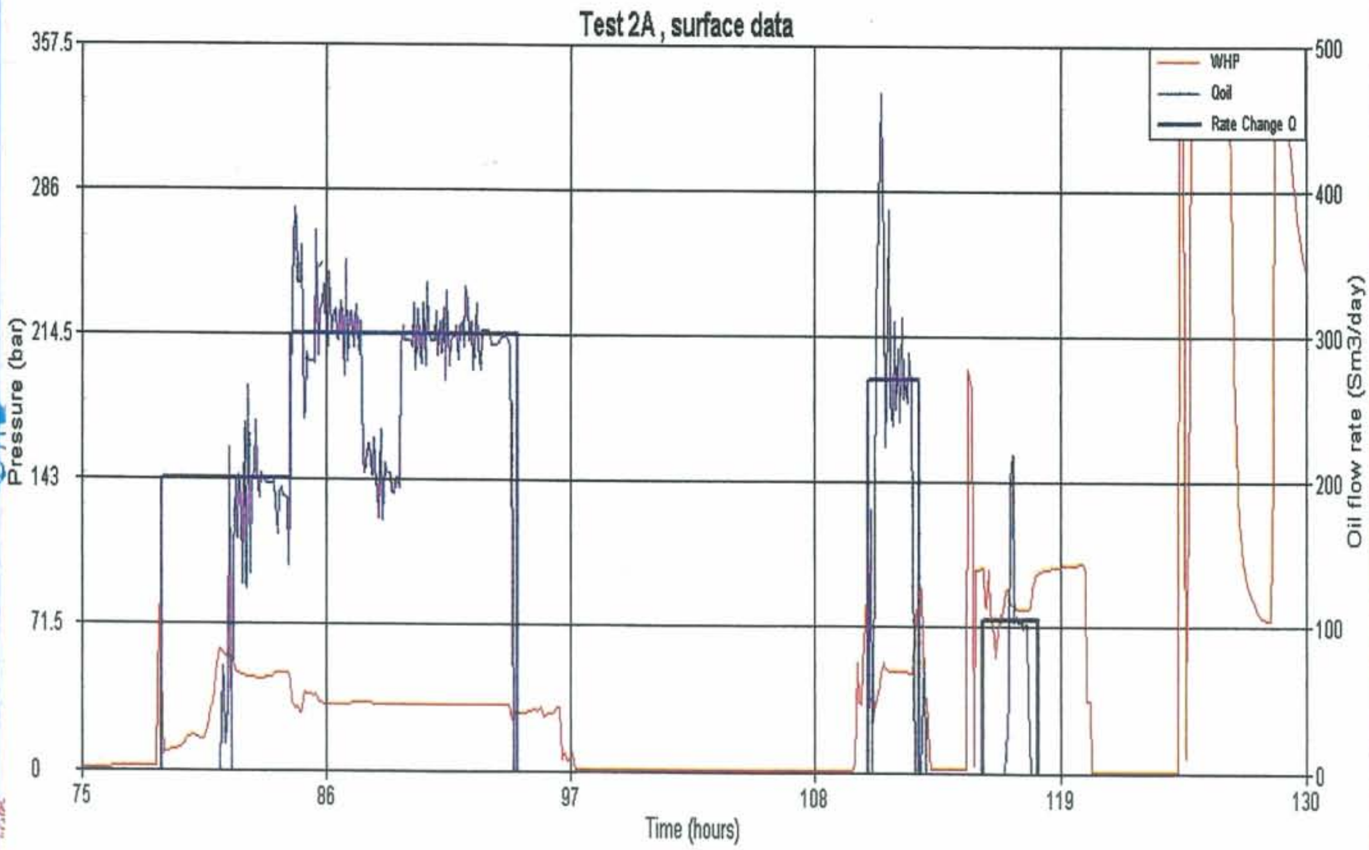


Figure 5.1.2

Well 15/9-19A, Test 2A
Bottom hole and surface data

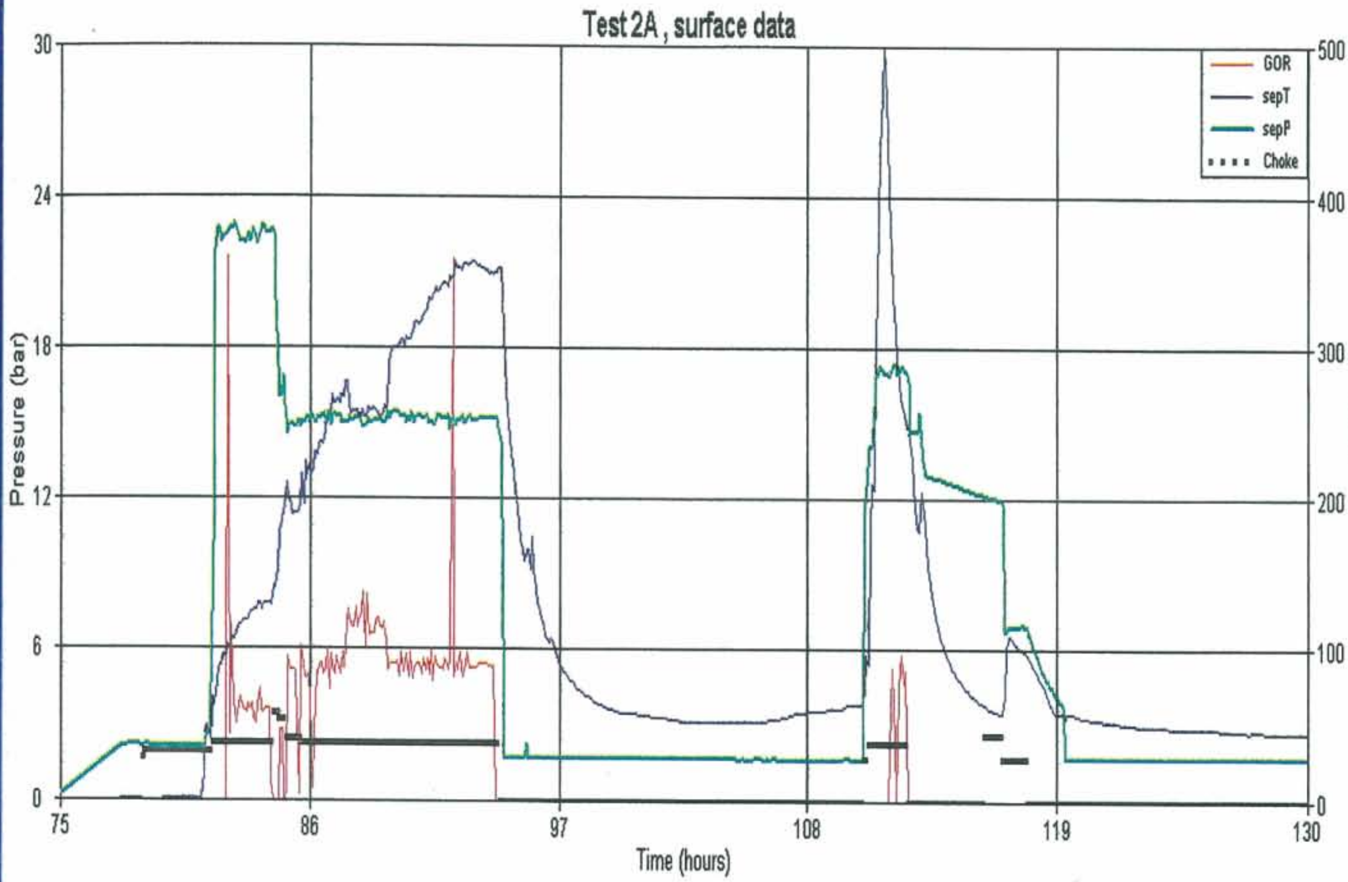


Figure 5.1.3

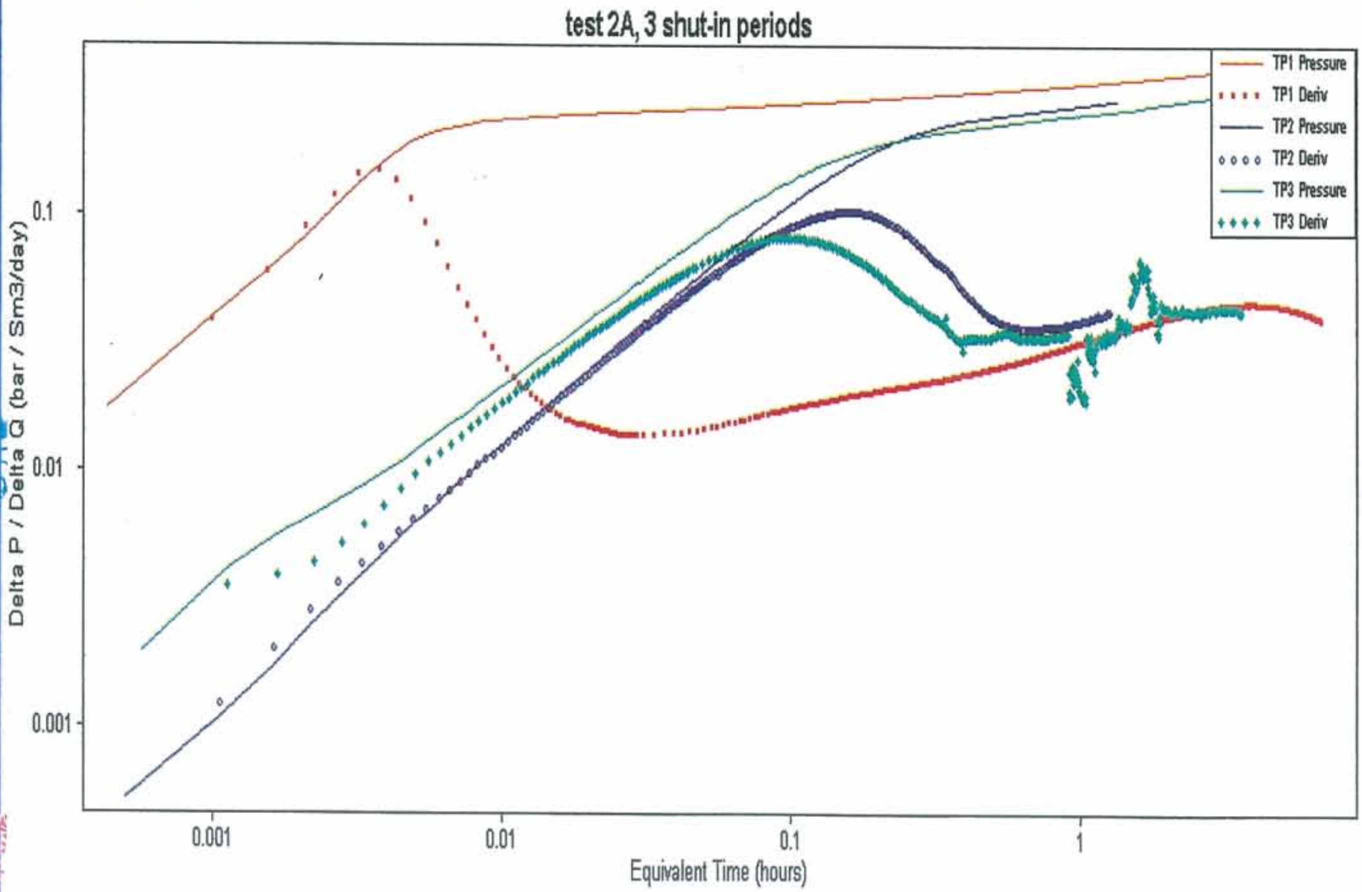


Figure 5.1.4, log-log plot, all three buildup periods

Well 15/9-19A, Test 2A
Analysis

STATOIL

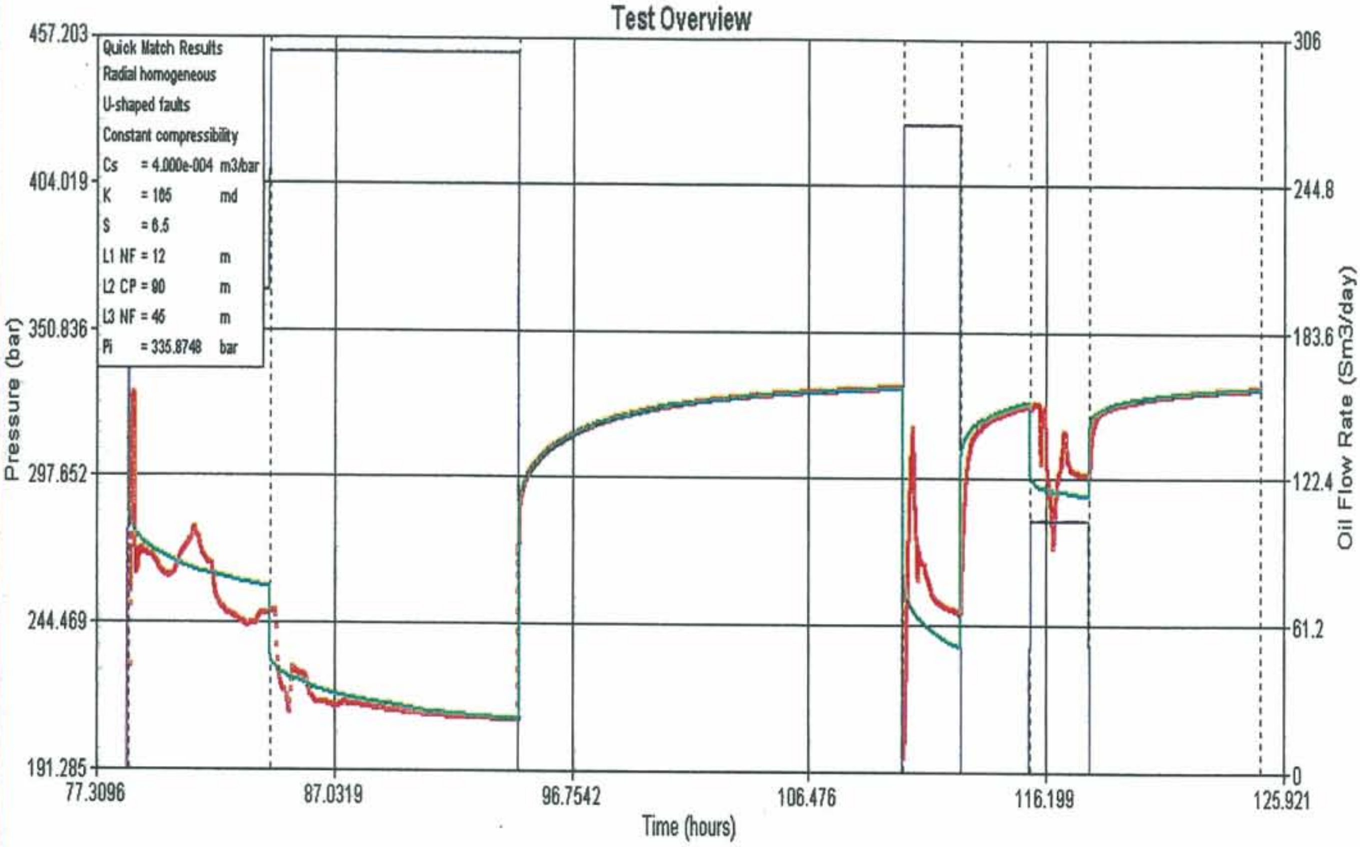


Figure 5.2.1, Match of all periods, homogeneus model h=5 m

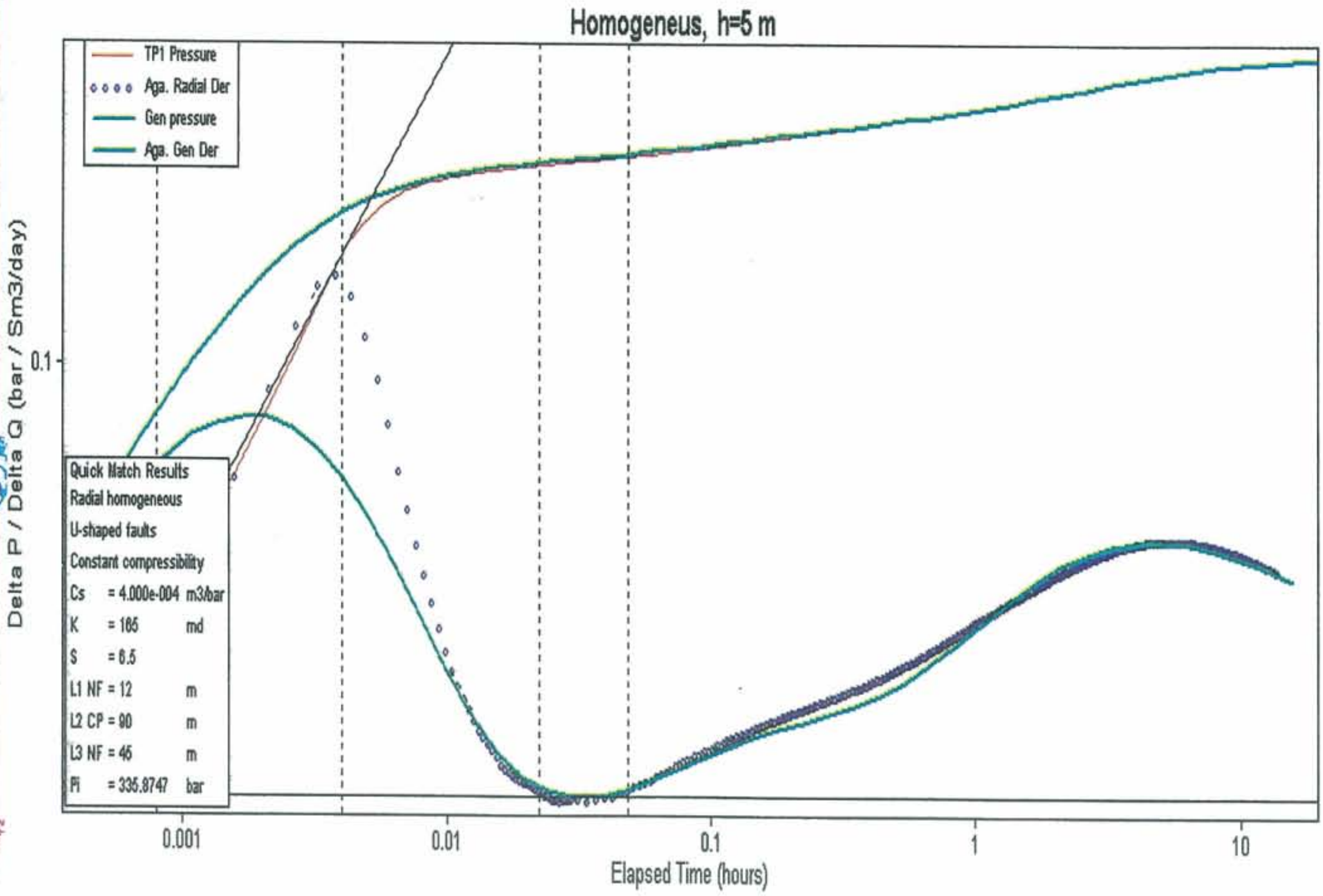


Figure 5.2.2, log-log plot, homogeneus model, h = 5 m

Well 15/9-19A, Test 2A
Analysis

STATOIL

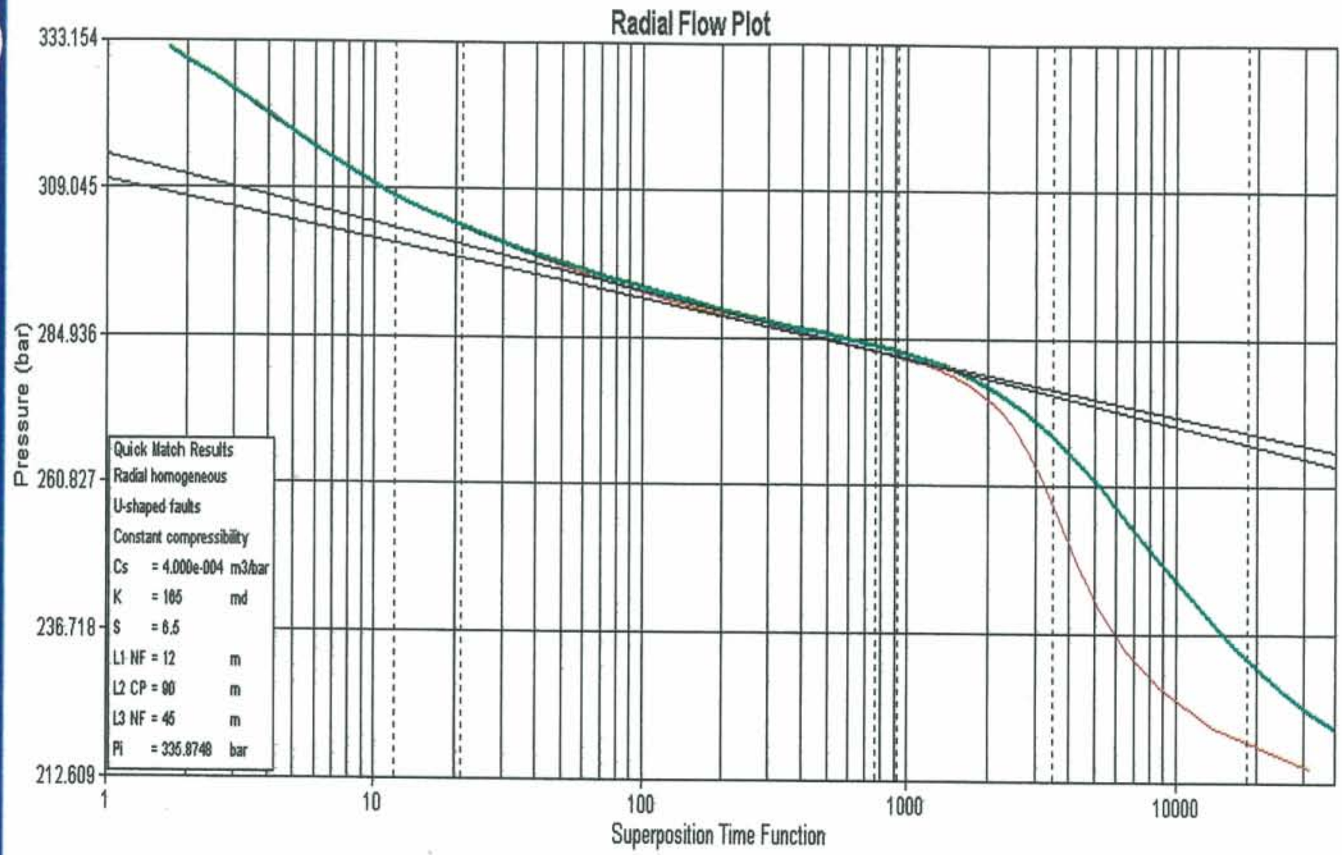


Figure 5.2.3, Semilog plot, Homogeneus model, h=5 m, quick match results

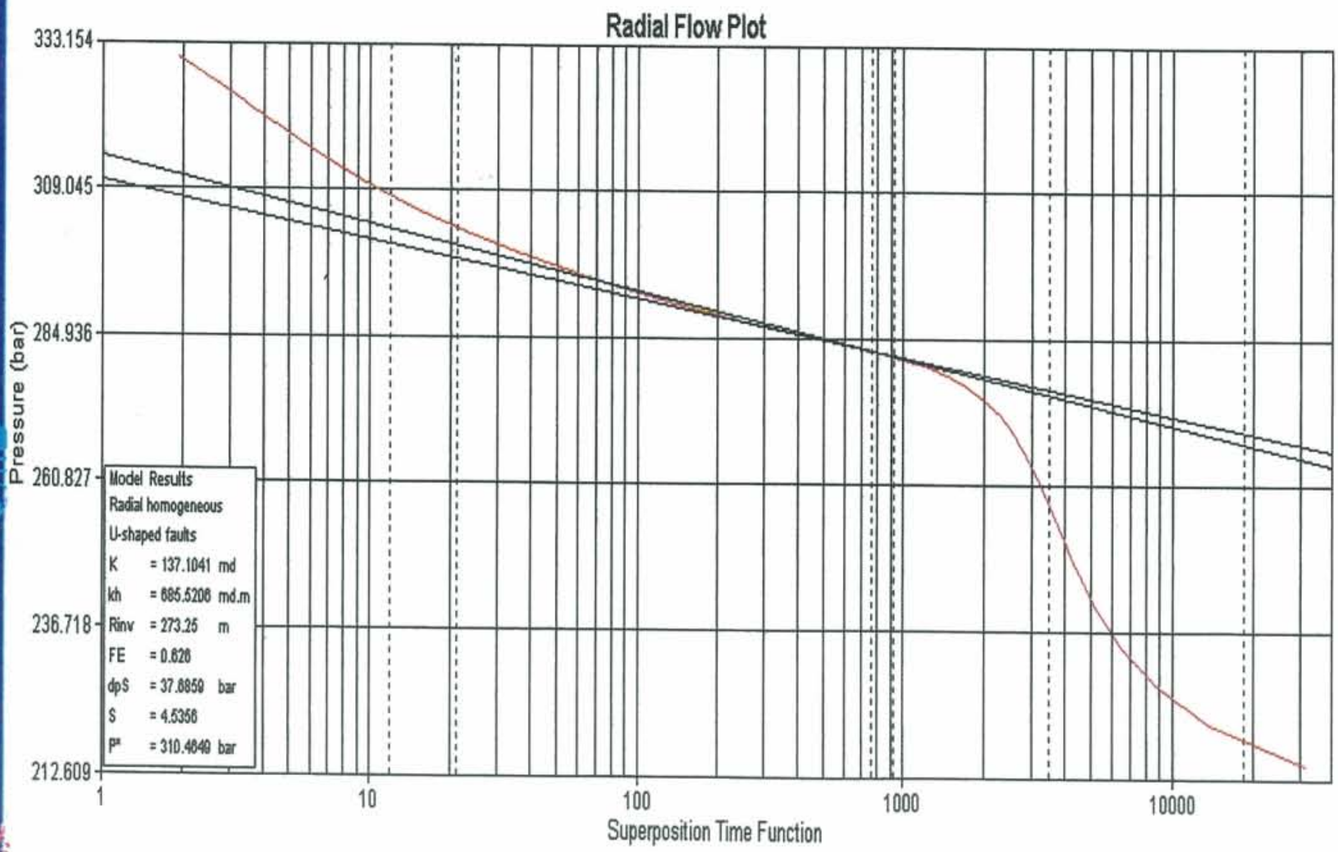


Figure 5.2.4, Semilog plot Homogeneous model h=5 m, result from semilog straight line

Well 15/9-19A, Test 2A
Analysis

STATOIL

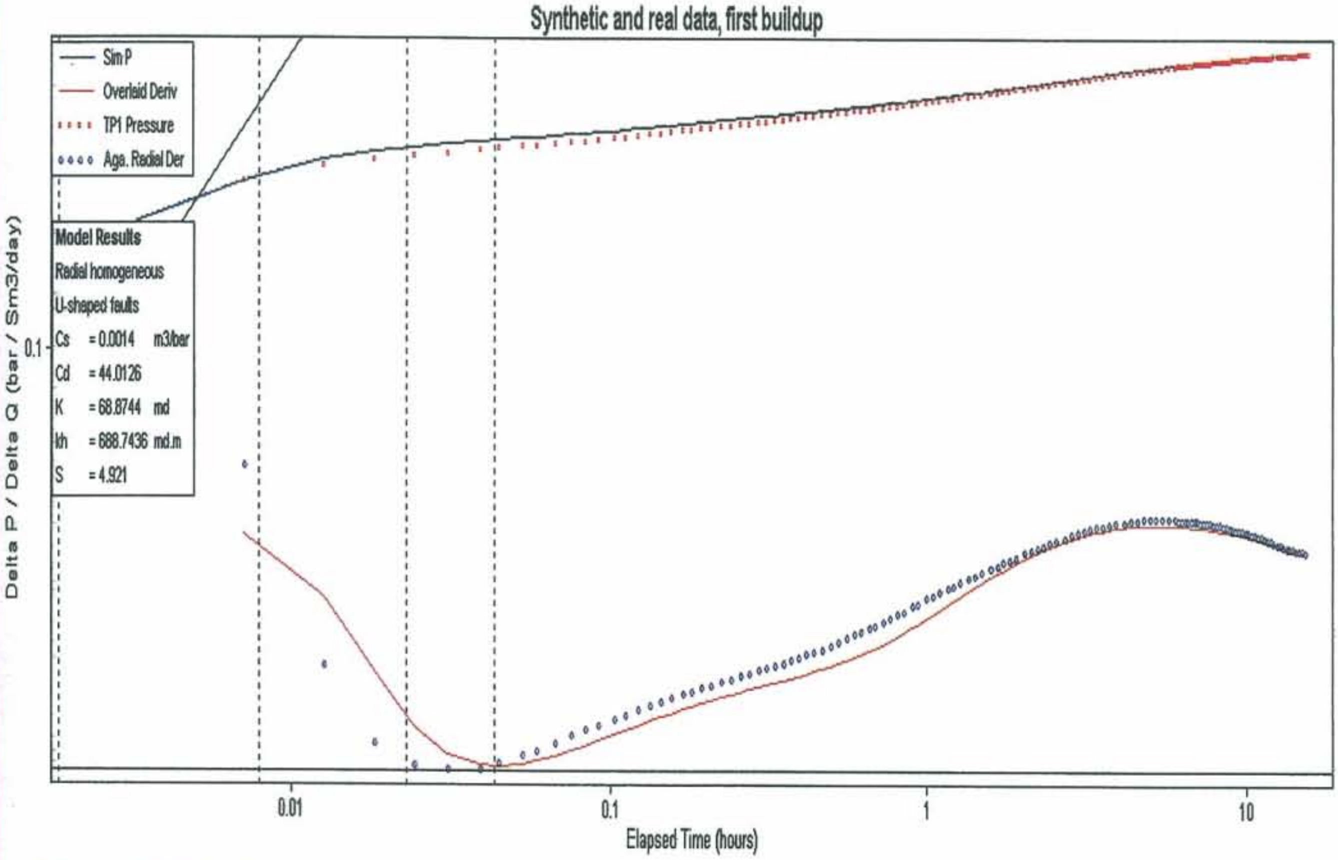


Figure 5.2.5, U-shaped model, Match with h=10 m, L1=10, L2=35, L3=65, k=70 mD

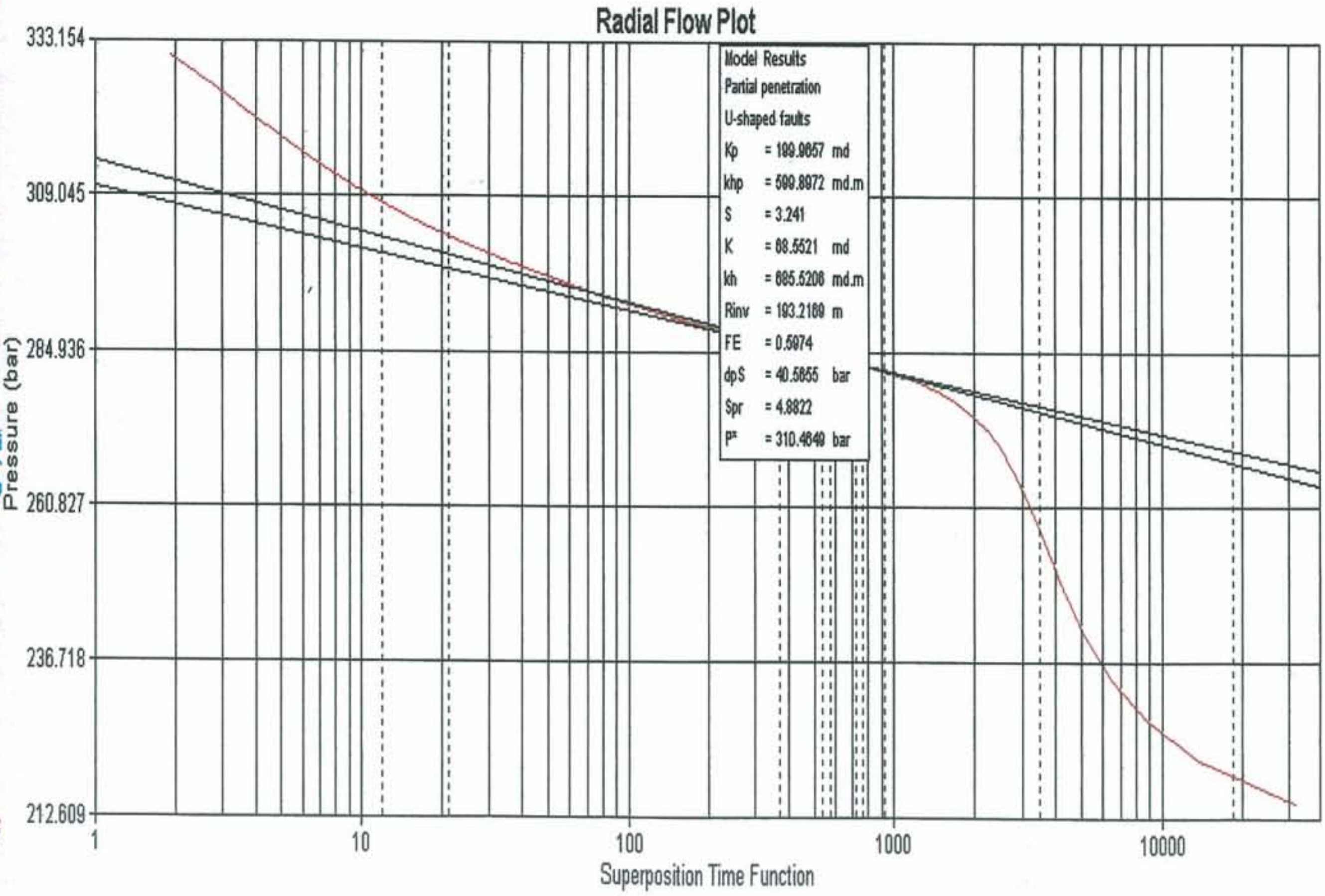


Figure 5.2.6, Partial perforation, hp=3 m, h=10 m

Well 15/9-19A, Test 2A
Analysis

STATOIL

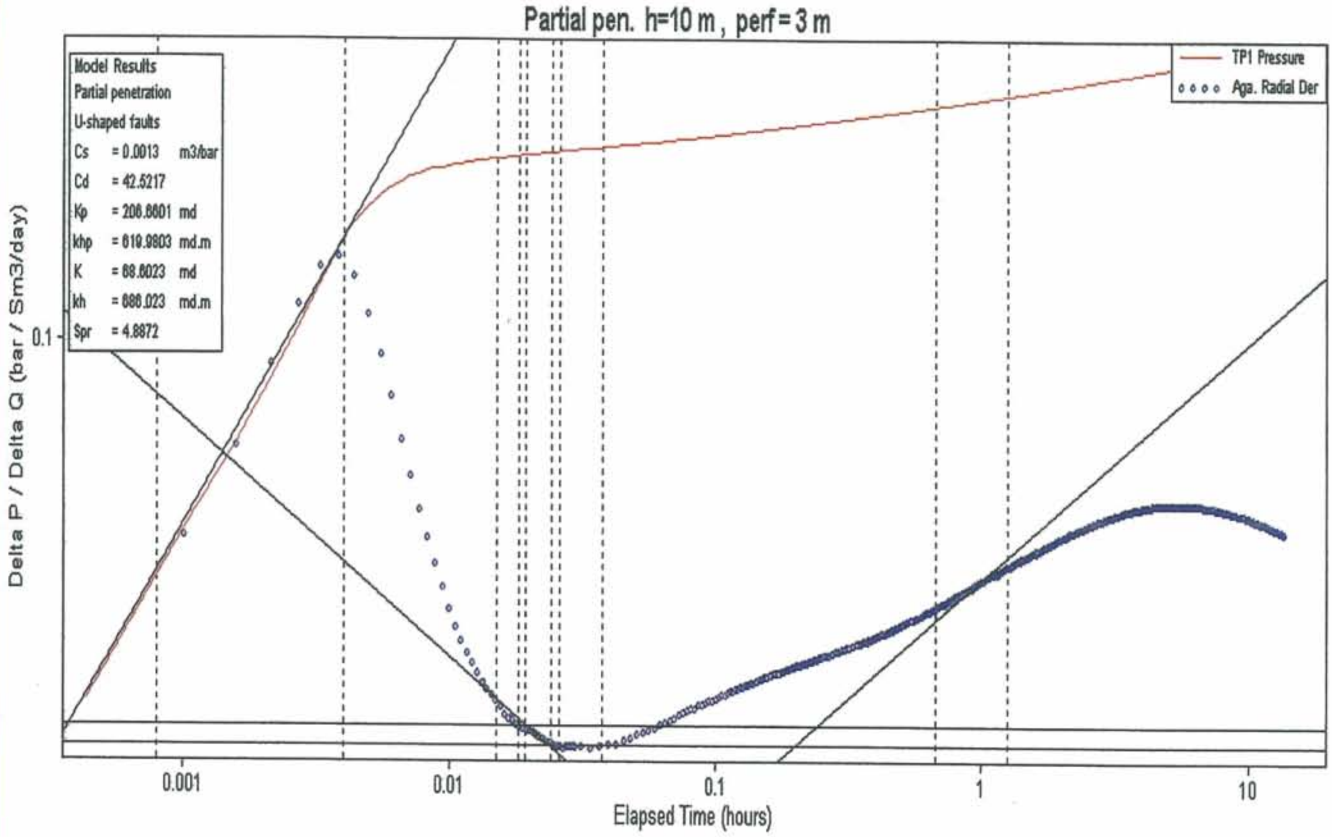


Figure 5.2.7, Partial perforation, hp=3 m, h=10 m

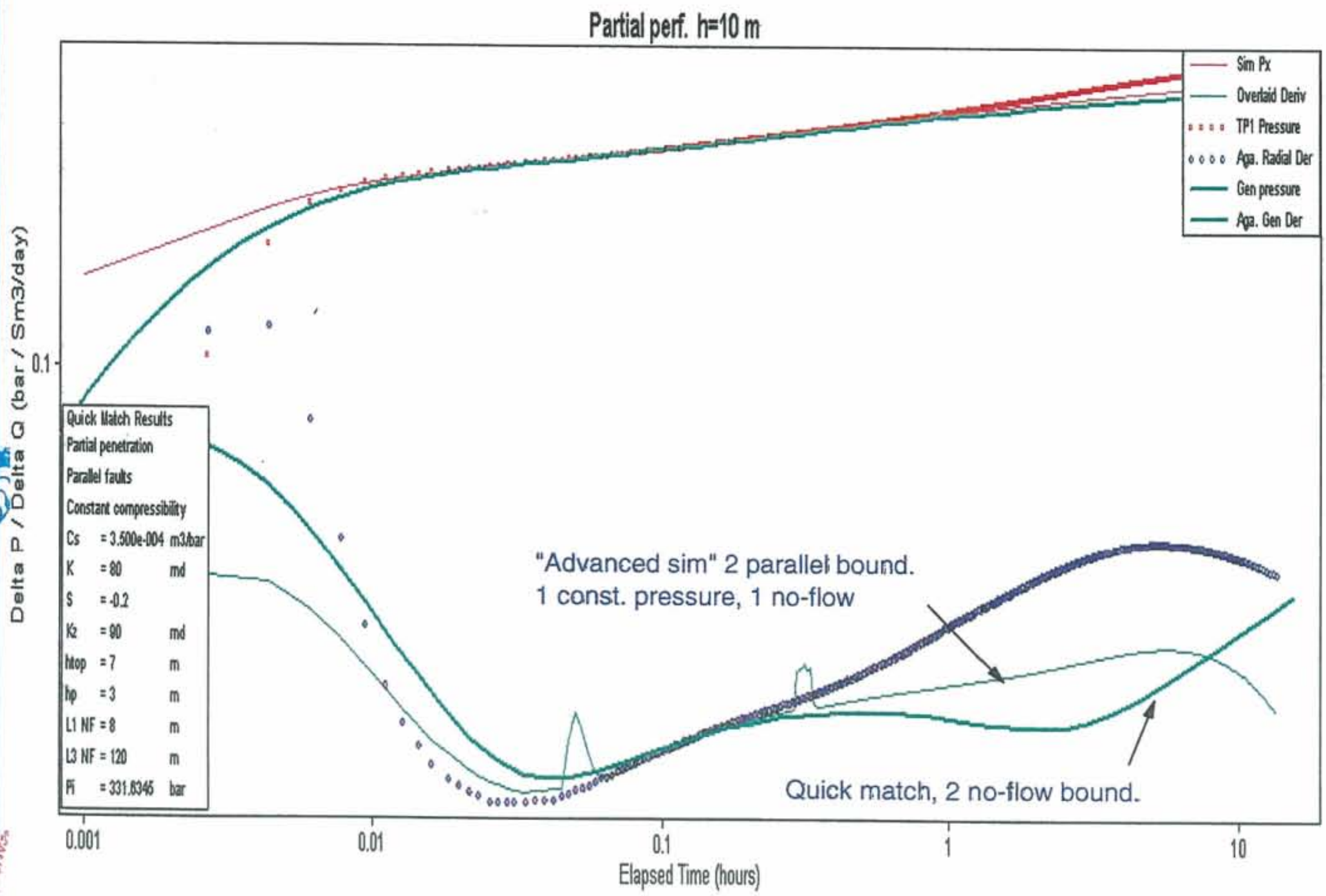


Figure 5.2.8, Partial perforation, hp=3 m, h=10 m

Well 15/9-19A, Test 2A
Analysis

STATOIL

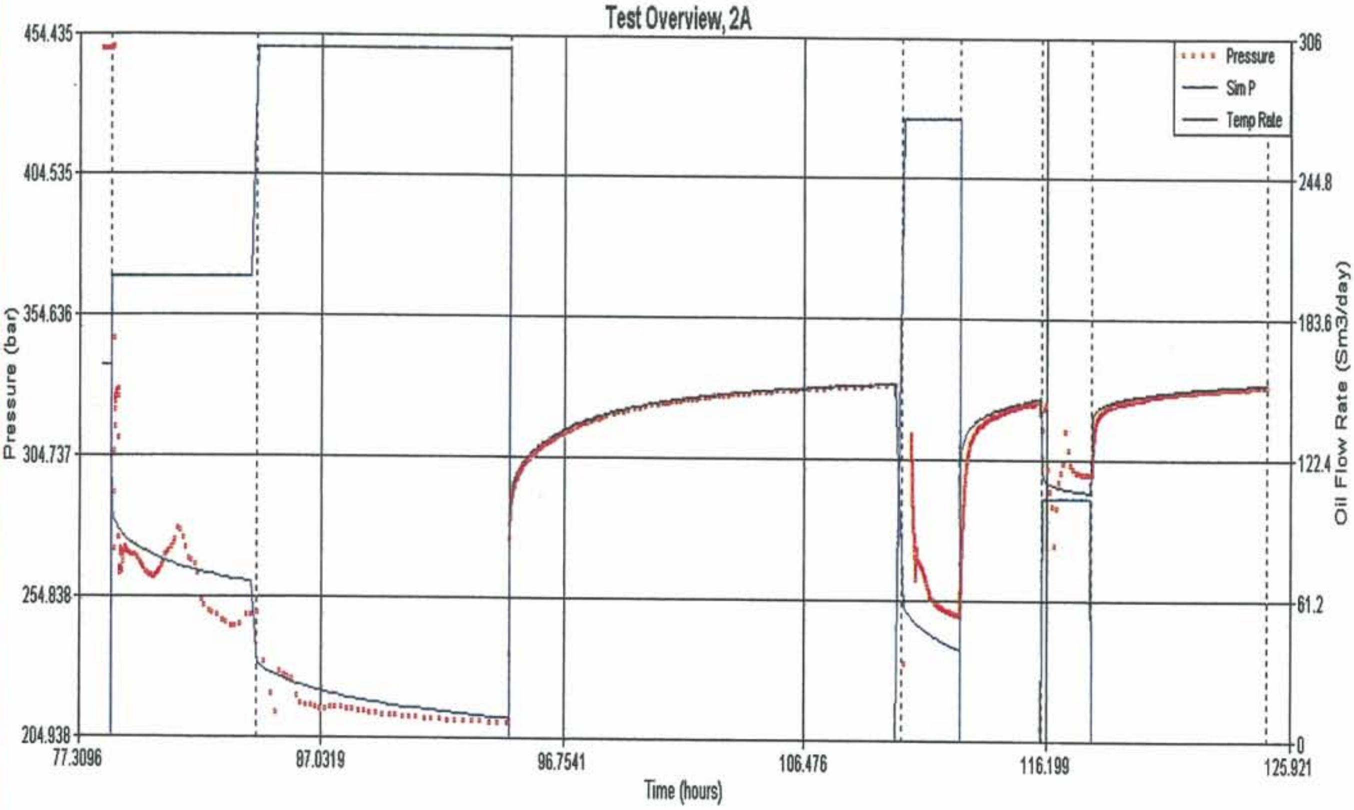


Figure 5.2.9, Partial perforation, Match with h=10 m, L1=10, L2=35, L3=65, k=70 mD

6 TEST 2B

6.1 Test data

Test 2B consists of one flow period and one buildup period, of approximately 42 hrs. duration each. The main objectives for this test were to investigate reservoir extension, reservoir parameters, possible water-oil emulsion problems and to obtain necessary hydrocarbon samples. The "Mobile Test Unit" (MTU) was used to investigate real time water-oil emulsions and the effect of different emulsion breakers.
Different adjustable choke sizes (14-48/64") were used during the first 4 hours of the flow period for cleanup, then set to a 34/64" fixed choke for the remaining flow period.

6.2 Pressure analysis

A number of models has been checked.

- Homogeneous reservoir with U-shaped boundaries (one constant pressure)
- Closed compartment.
- A layered model (in Pansys called dual porosity or dual permeability model) with 2 parallel boundaries (one constant-pressure boundary) and high contrast between horizontal layer permeabilities.
- A pinch out model has also been checked but requires too thick sand body compared to the actual situation and geological model

6.2.1 Homogeneous model, 3 boundaries, varying height (U-shaped boundaries)

The analysis and geological models have been updated since the time of the test. A considerable effort has been made trying to find other solutions that would fit both the data and a realistic geological model, but there seems to be only one or two analytical models that fit the data.
The Hugin reservoir seems to consist of several layers with and without communication.
There also seems to be rather large permeability contrasts both vertically and laterally within the same sand bodies and from sand to sand. This is based on core measurements in all three wells (15/9-19SR, -19A, -19B).
Test 2B covers several sand bodies in the upper part of the Hugin Formation (see Figure 1.3). The test data indicates that not all the perforated interval of 39 m contributes to the production. Using reservoir heights (h) =39 m and 13 m results in very different permeability values, 630 mD and

1900 mD respectively. The Figures 6.2.1.1 to 6.2.1.8 show the results from using different h, and Table 6.2.1 lists the results.
The 13 m zone corresponds approximately to the thickness of the best sand at the bottom of the perforated interval. None of those values match the average permeability of approximately 1500 mD that has been measured on the cores and derived from log interpretation.
To match the core average permeability a reservoir height or the contributing part of the sands have to be approximately 18 m. Using 18 m as height and the U-shape model, the distances are 28 m and 150 m to the two parallel no-flow boundaries and approximately 185 m to the constant pressure boundary.
A Lorenz plotting technique has also been looked into to see if a more conclusive height could be established, See Chapter 6.4

Due to the difficulties to give a good estimate of the height and the large uncertainties in matching well test response to core measurements, 39 m has been used as reservoir height for the rest of the analysis and results.

Height	k (mD)	s	Rinv. (m)	L1 (m) no-flow	L2 (m) const. p	L3 (m) no-flow
h = 39 m	650	9,7	890	20	150	130
h = 18 m	1 500	10,3	1 320	28	185	150
h = 13 m	2 300	11,7	1 550	25	260	200

Table 6.2.1: Results using different h.

6.2.2 Homogeneous model with 1, 2 and 4 boundaries

To visualise the response with different models figures 6.2.2.1 to - 9 show models with the response both on a linear plot with main flow and buildup period, and a log-log plot from the main buildup period to show the detailed match.
It is obvious that using those models the match is not going to be as good as with 3 boundaries. The Figures 6.2.2.8 - 9 showing the response from a closed segment do show a match on the log-log plot. This is due to the pressure derivative moving down towards zero or negative values as the pressure for the constant pressure model levels out to a constant pressure (derivative zero) and the closed segment pressure starts to fall off (derivative negative).
Using the linear plot where both periods are matched to the real data it is obvious that the closed segment model does not give the same response as the real data. See Figure 6.2.2.9.

6.2.3 Dual porosity model

The concept of dual porosity system is based on the existence of two porous regions of distinctly different properties. The first region is continuos and connects with the well whereas the second

region only feeds fluid locally to the first region. Two important physical systems have been identified with dual porosity behaviour. The naturally fractured reservoir, in which an interconnected fracture network forms the continuos system and separate matrix blocks are the supporting system, is the classic dual porosity example. However, a two layer system comprising a tight zone adjacent to a much more permeable zone also exhibits dual porosity behaviour where the contrast in permeability is such that radial flow in the tight layer may be neglected. In this case the tight zone, in primary depletion, only produces by vertical cross-flow into the communicating permeable layer.
The natural fractured reservoir will not fit into the model for the actual reservoir, but the layered reservoir is a more likely model to fit. This model is normally valid if the contrast in horizontal kh values is greater than about 100.

There are layers with very large contrast in horizontal kh in the tested zone.
Using this model with parallel boundaries creates a good match to the real data, indicating that this model may be as correct as the U-shaped model.
The simulated data shown in Figures 6.2.3.1 - 3 for both flow and shut in does not match properly, but the model used here has a limitation in that it does not accommodate the use of constant pressure boundaries with the dual porosity model.
A match of data using a different boundary configuration only results in poorer match.
Two intersecting faults intersecting at an angle of 45 deg. is shown on Figure 6.2.3.4
To be able to match the end of the build up where the pressure derivative dips, a constant pressure barrier has to be present. Figure 6.3.2.5 shows match both with 2 parallel boundaries, one no-flow and one constant pressure (magenta), and the green line where two no-flow boundaries has been used.

6.2.4 *Dual permeability, layered reservoir model*

This model will act as the above model, dual porosity model.

Well 15/9-19A, Test 2B
Test 2B , Bottom hole and surface data

STATOIL

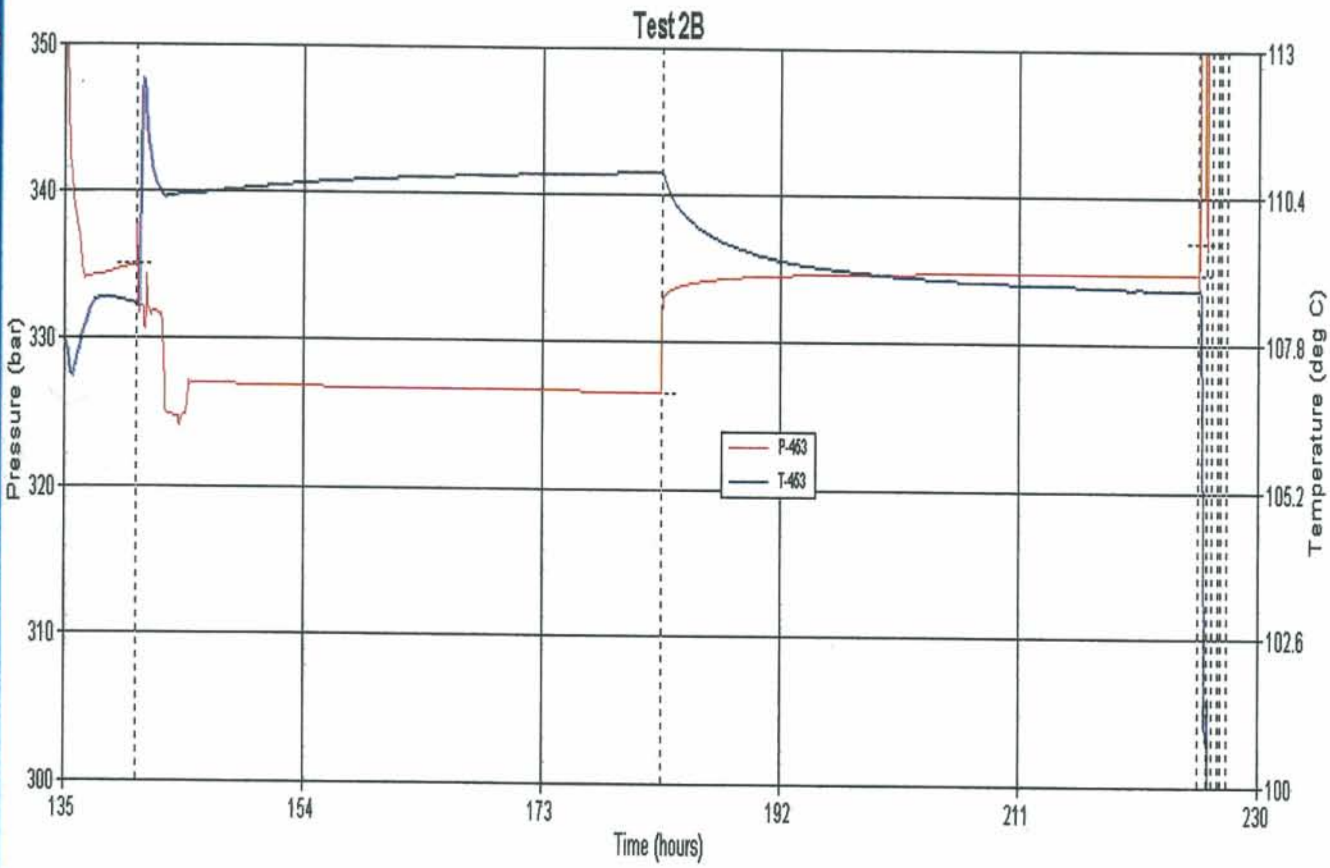


Figure 6.1.1, Test 2B, Overview, BHP & BHT

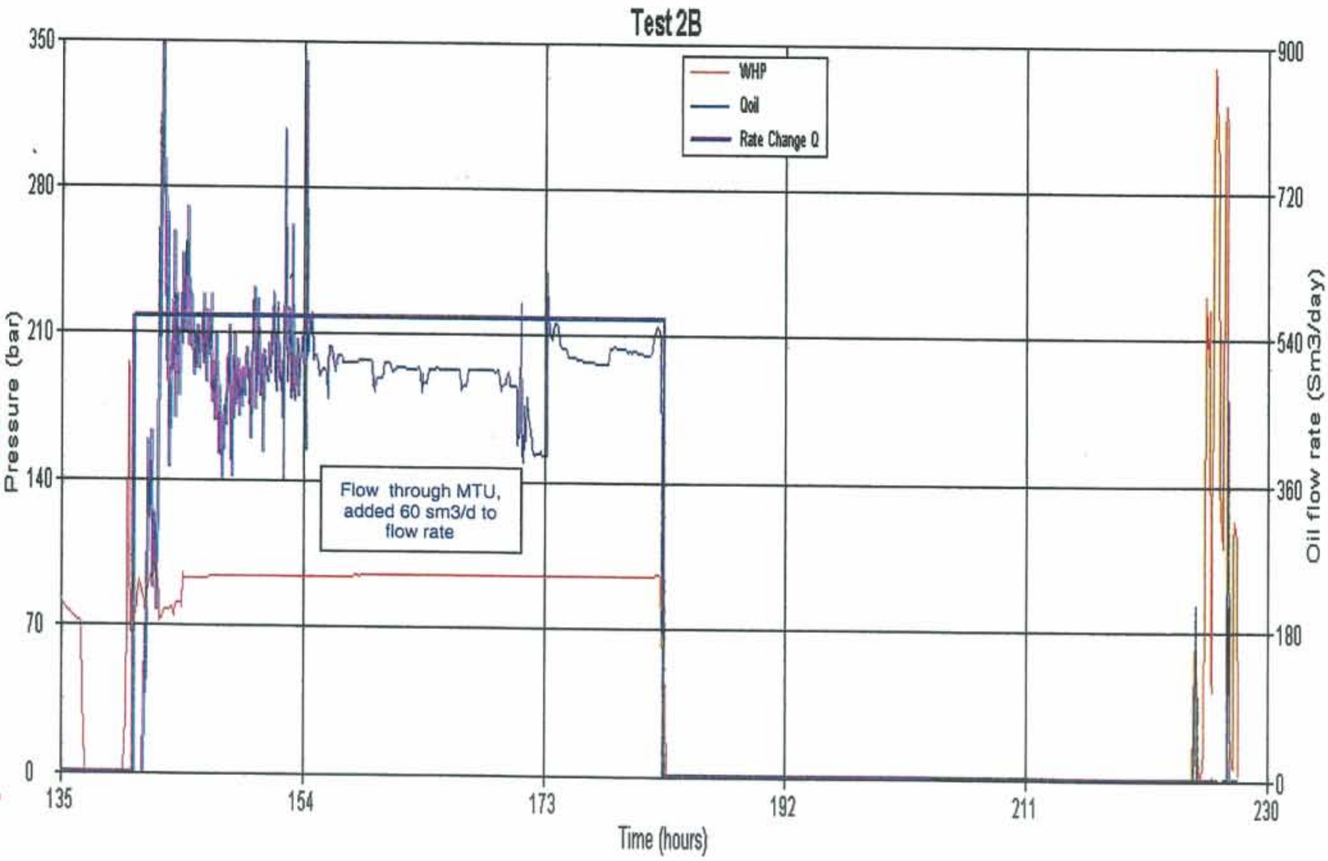


Figure 6.1.2, Surfac data: WHP, Qoil, Rate change used in the analysis

Well 15/9-19A, Test 2B

Test 2B , Bottom hole and surface data

STATOIL

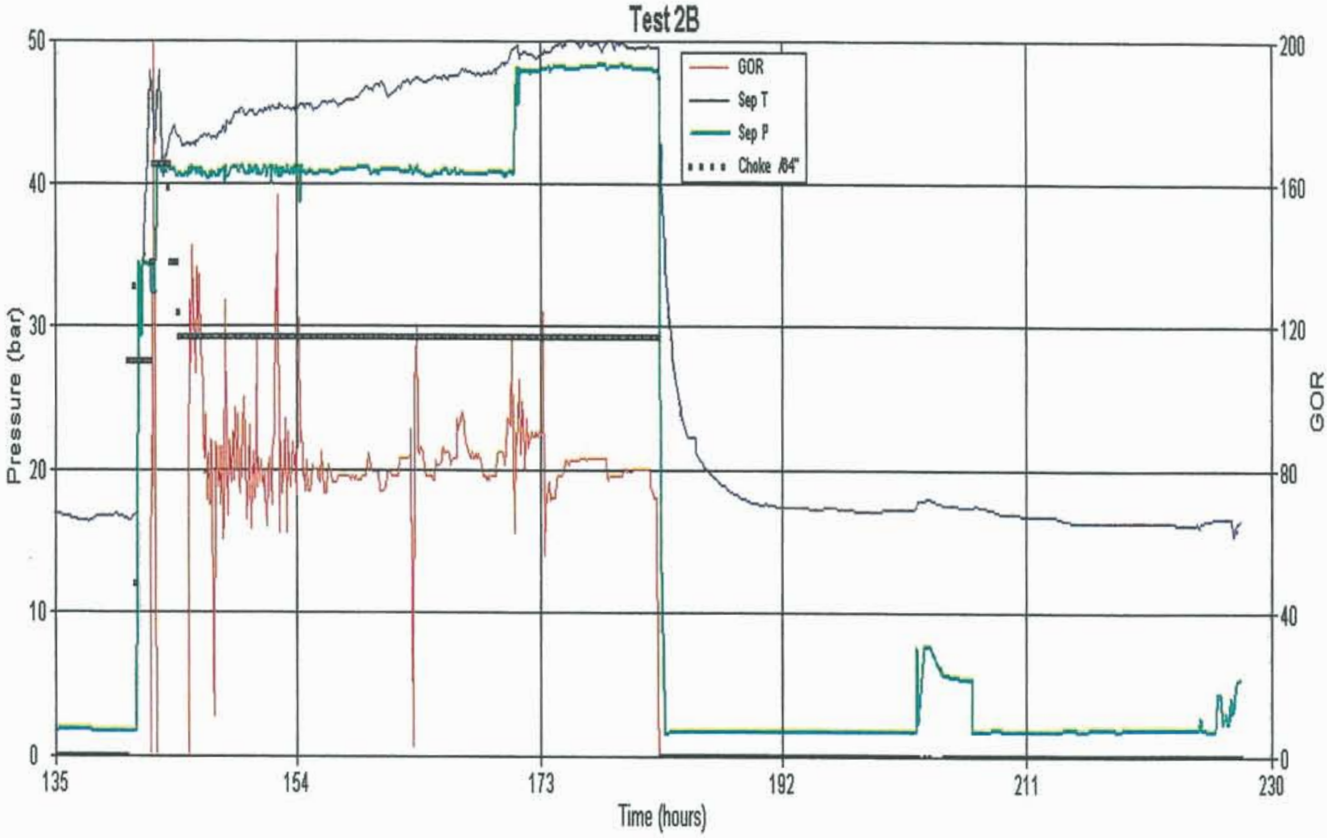


Figure 6.1.3, Surface data: GOR, Psep, Tsep, Choke size

Well 15/9-19A, Test 2B

Homogeneus reservoir, U-shaped boundary, 2 no-flow and 1 constant pressure boundary, Varying height

STATOIL

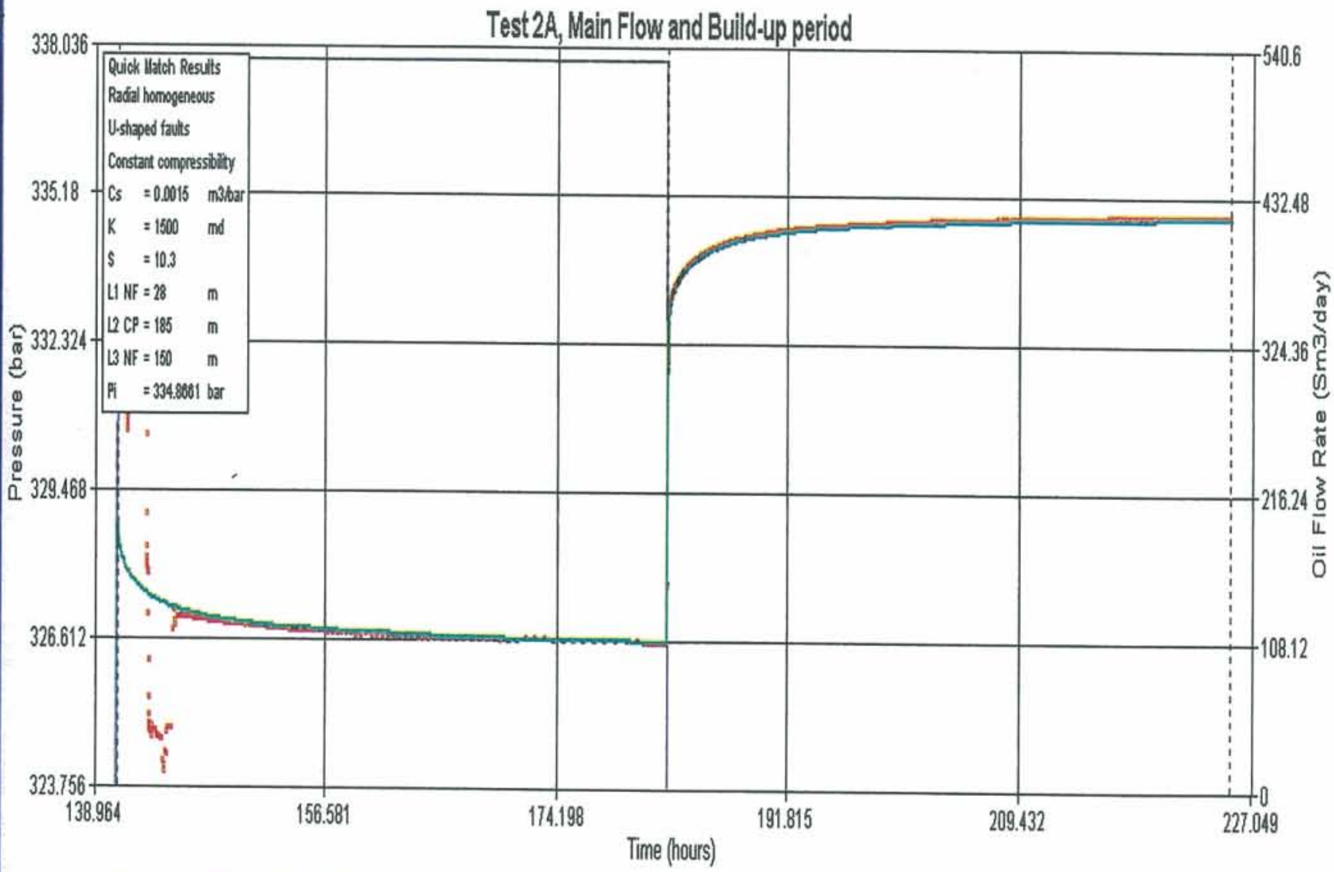


Figure 6.2.1.1, Test 2B, Simulated and real data, flow and build-up, h=18 m

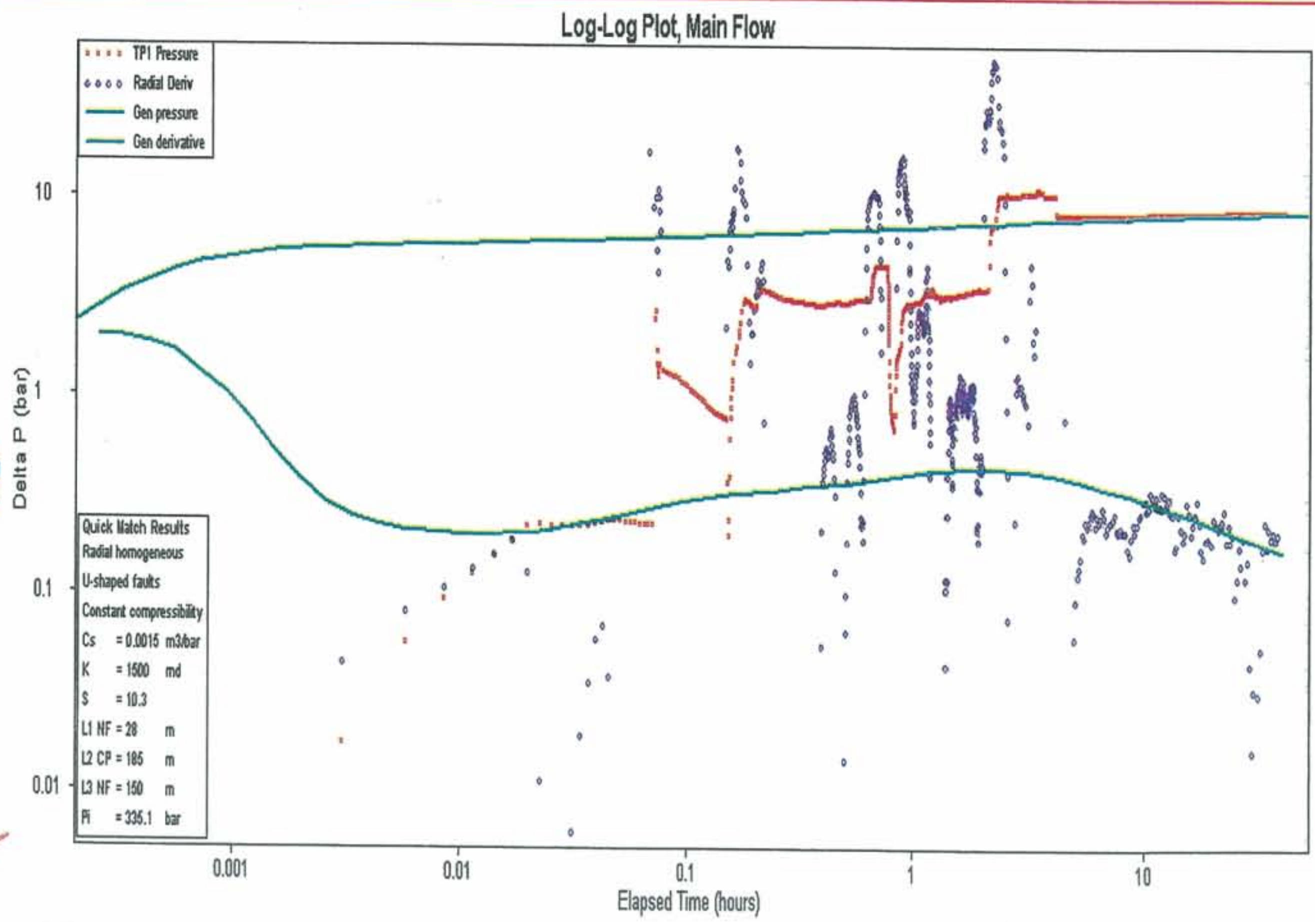


Figure 6.2.1.2, Log-Log plot, simulated and real data, main flow period, h=18 m

Well 15/9-19A, Test 2B

Homogeneus reservoir, U-shaped boundary, 2 no-flow and 1 constant pressure boundary, Varying height

STATOIL

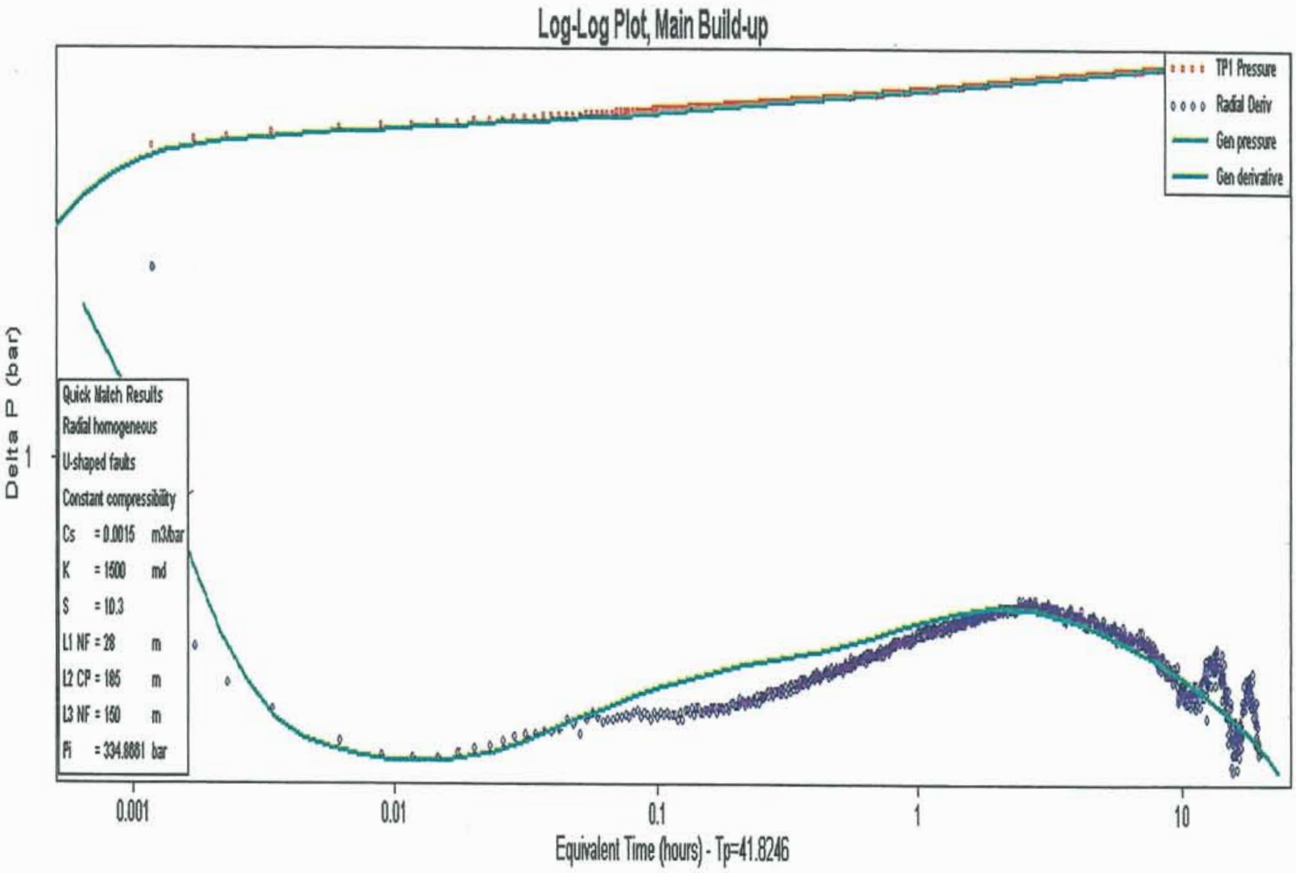


Figure 6.2.1.3, Log-Log plot, simulated and real data, main build-up, h=18 m

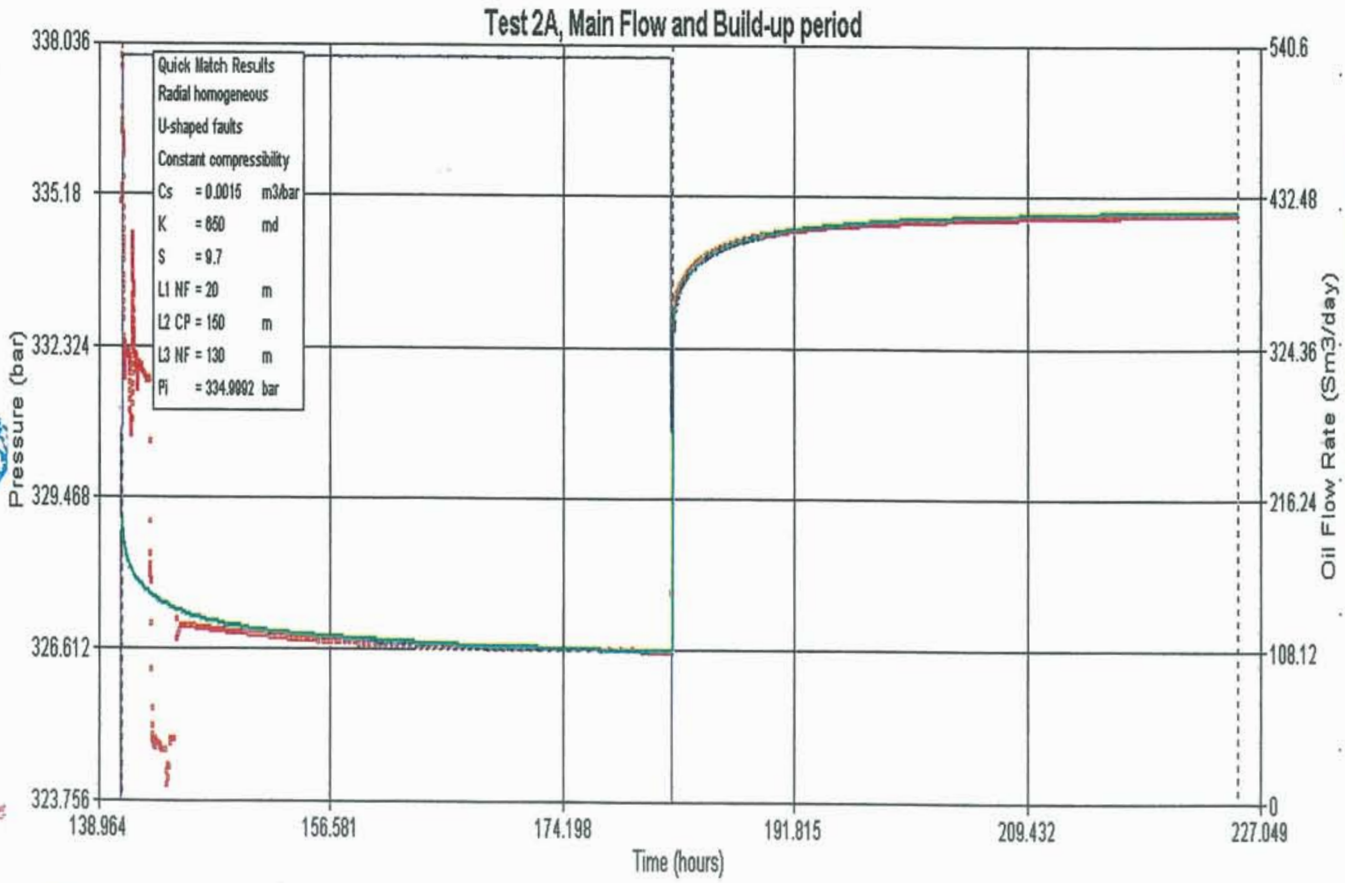


Figure 6.2.1.4, Simulated and real data, flow and main build-up, h= 39 m

Well 15/9-19A, Test 2B

Homogeneus reservoir, U-shaped boundary, 2 no-flow and 1 constant pressure boundary, Varying height

STATOIL

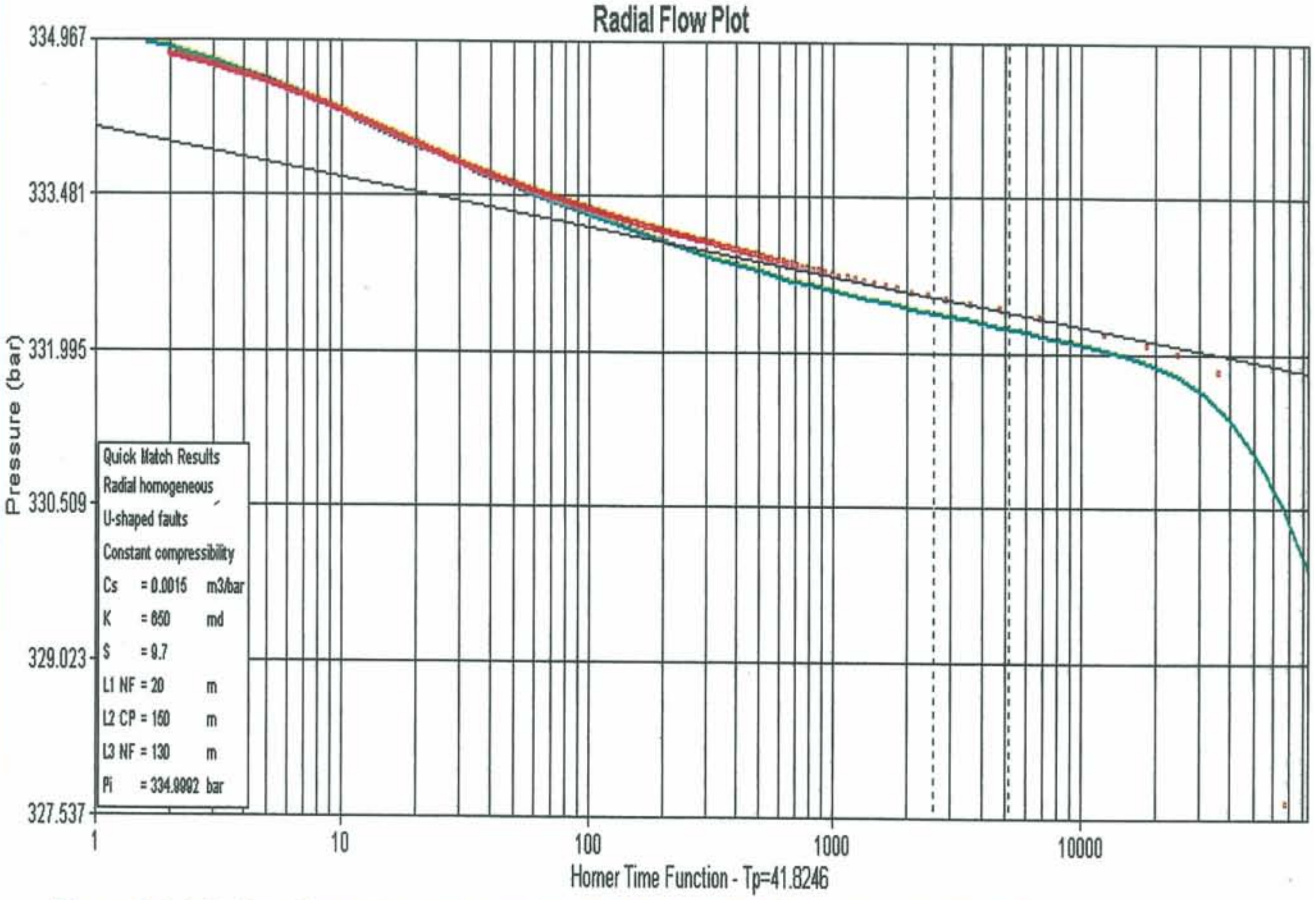


Figure 6.2.1.5, Semi-Log plot, simulated and real data, main build-up period, h= 39 m

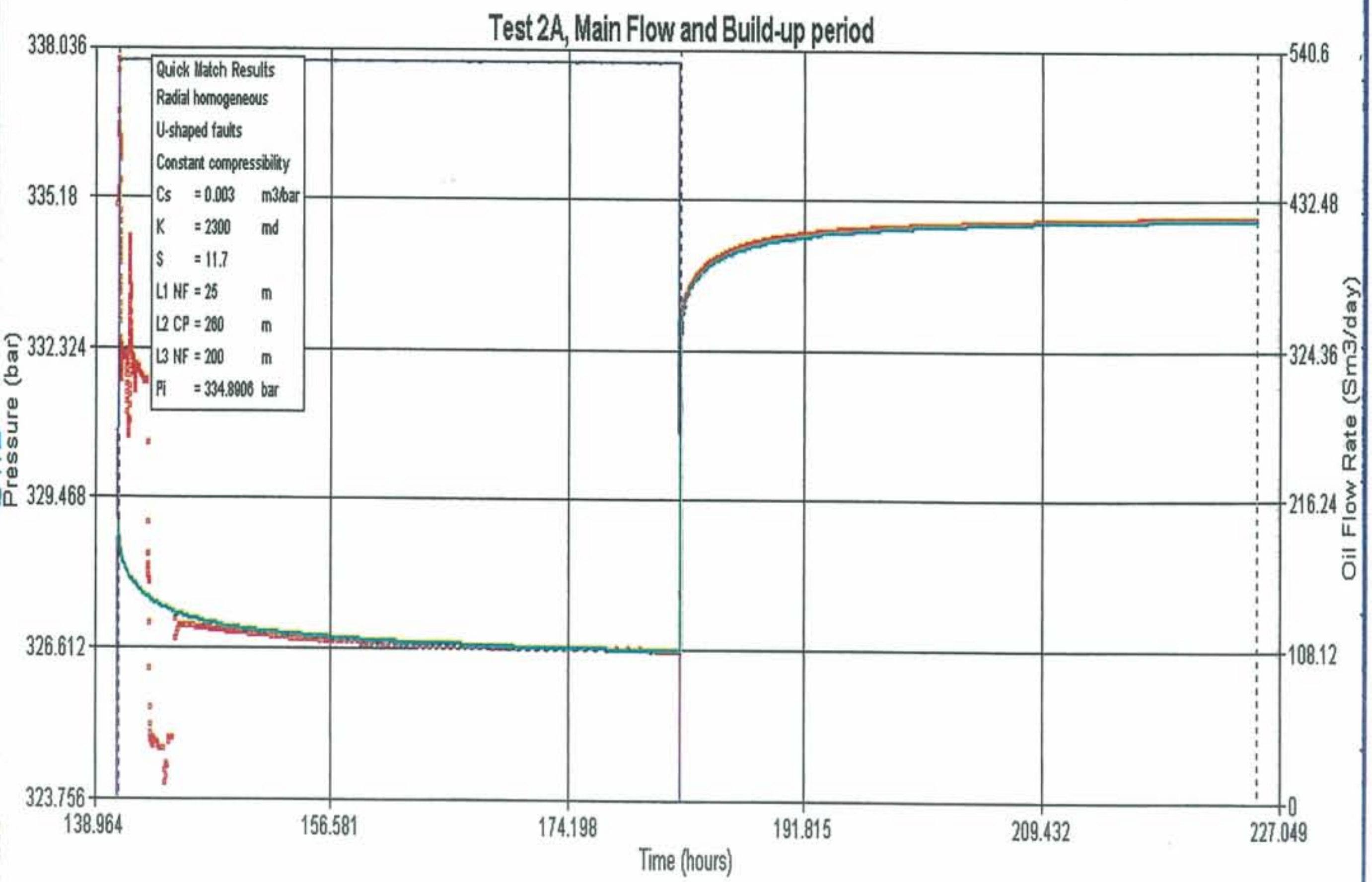


Figure 6.2.1..6, Simulated and real data, flow and main build-up, h=13 m

Well 15/9-19A, Test 2B

Homogeneus reservoir, U-shaped boundary, 2 no-flow and 1 constant pressure boundary, Varying height

STATOIL

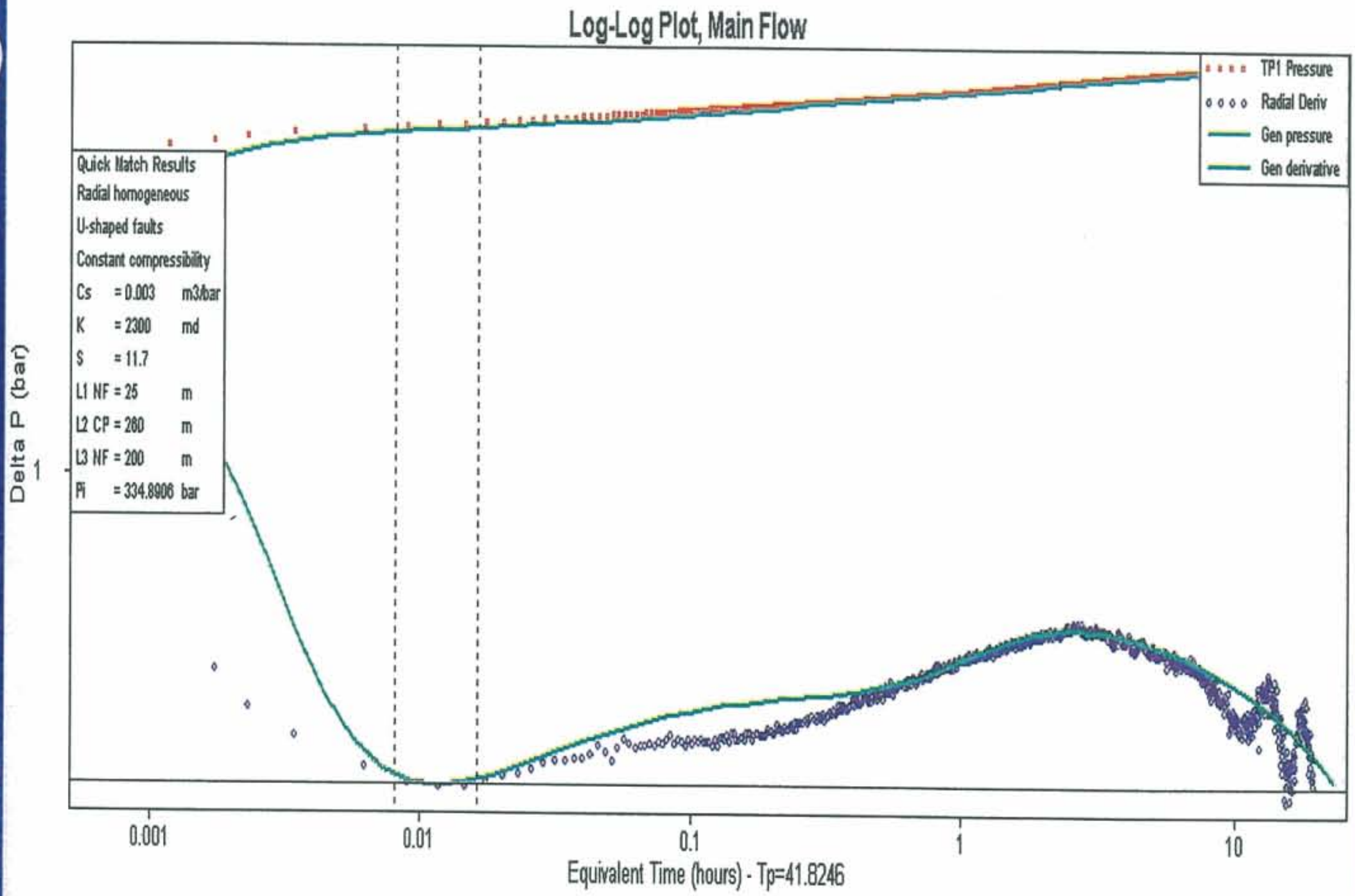


Figure 6.2.1.7, Simulated and real data, flow and main build-up, h= 13 m

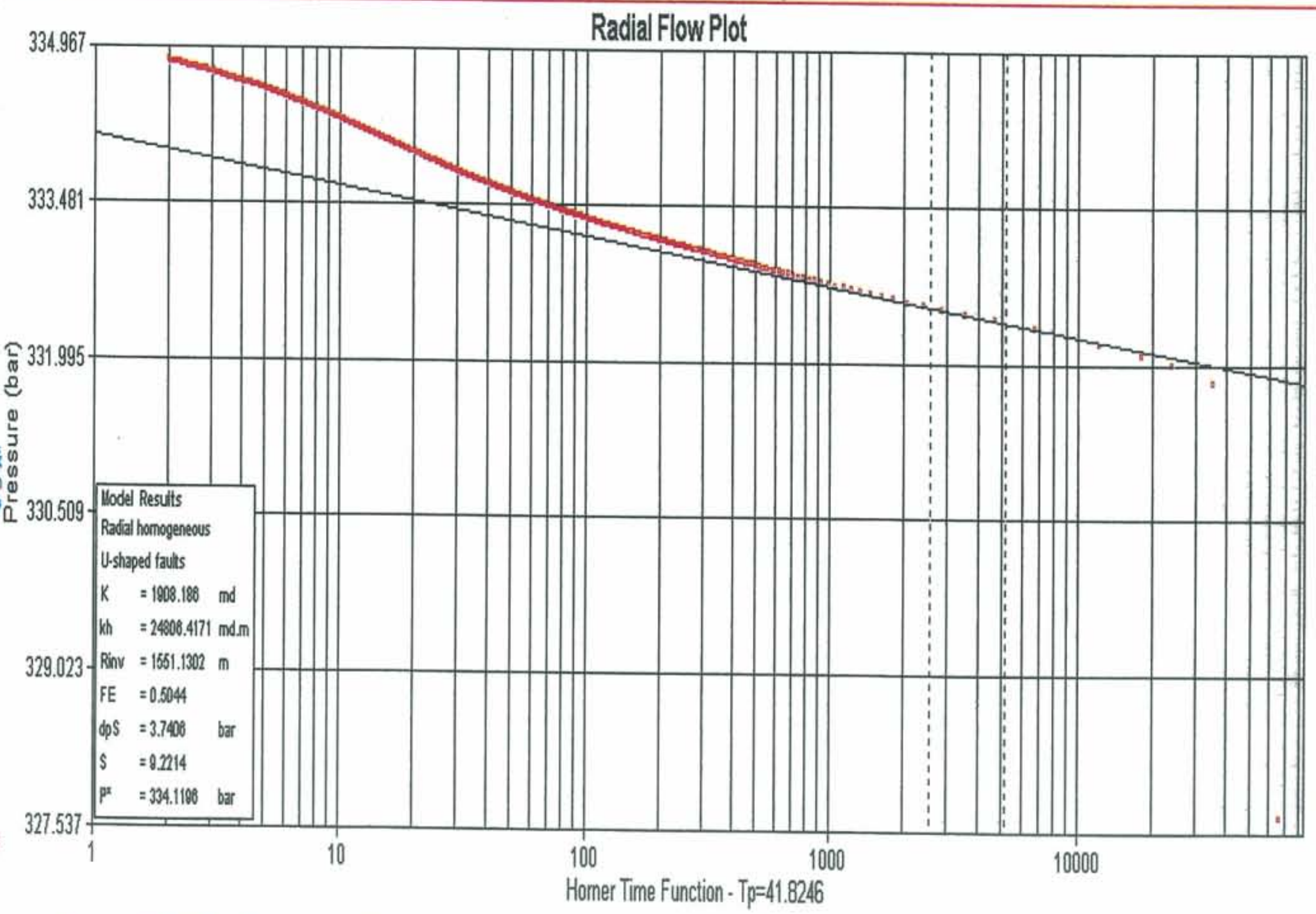


Figure 6.2.1.8, Semi-Log plot, simulated and real data, main build-up period, h= 13 m

Well 15/9-19A, Test 2B
Model with 1 ,2 and 4 boundaries

STATOIL

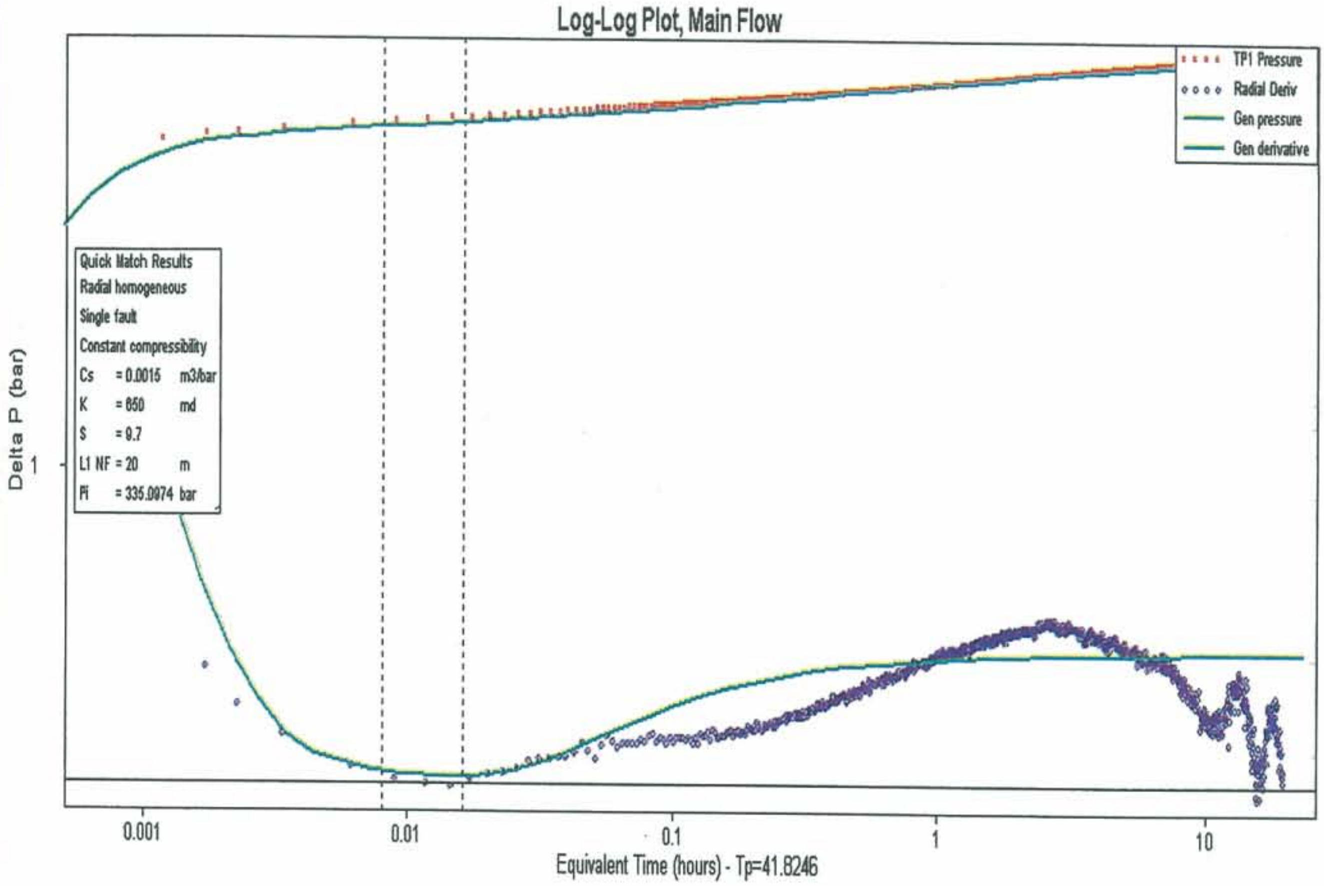


Figure 6.2.2.1, Single fault

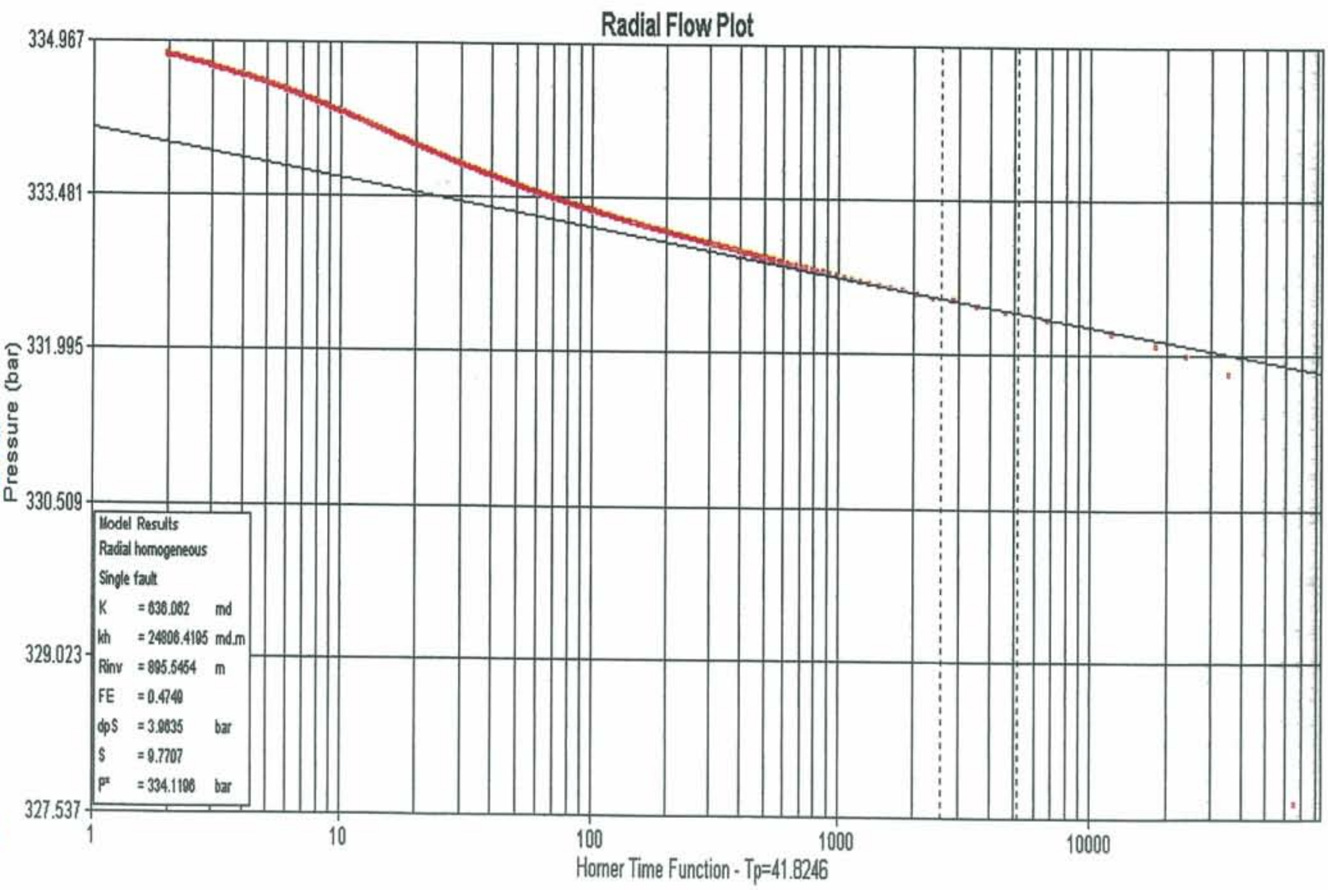


Figure 6.2.2.2 Single fault

Well 15/9-19A, Test 2B
Model with 1 ,2 and 4 boundaries

STATOIL

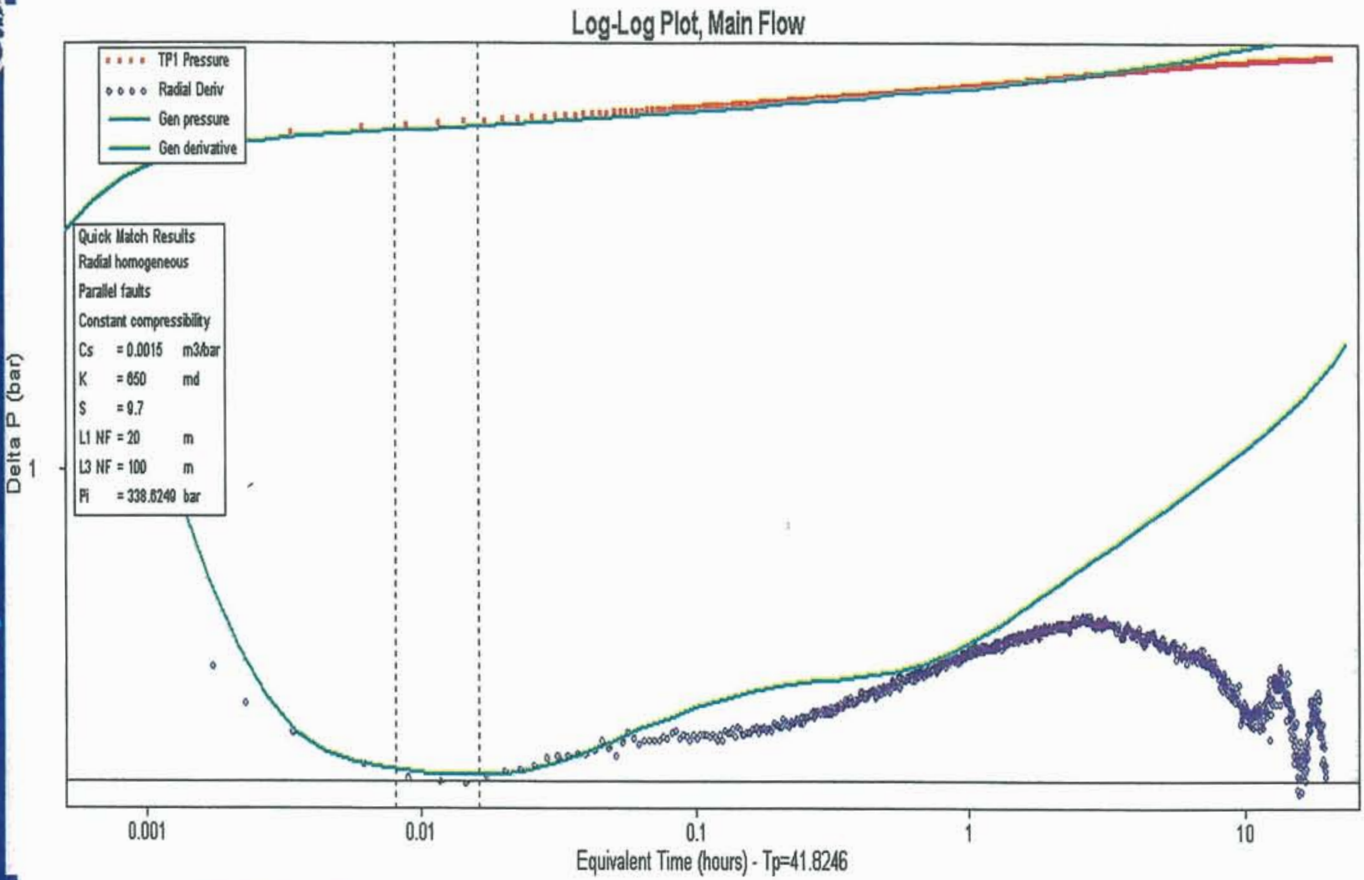


Figure 6.2.2.3, 2 parallel boundaries, no-flow boundaries

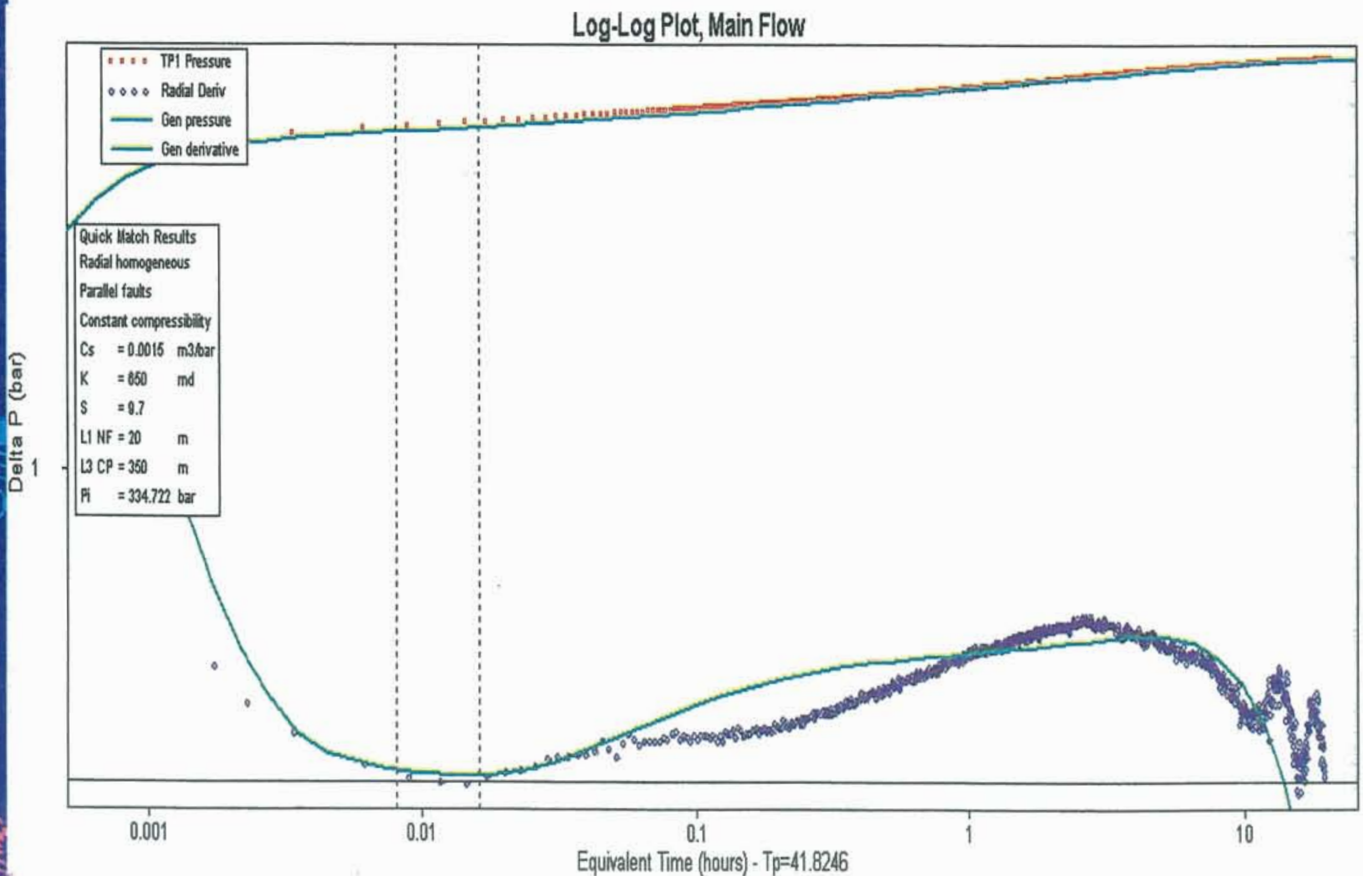


Figure 6.2.2.4, Parallel boundaries, no-flow + constant pressure.

Well 15/9-19A, Test 2B
Model with 1 ,2 and 4 boundaries

STATOIL

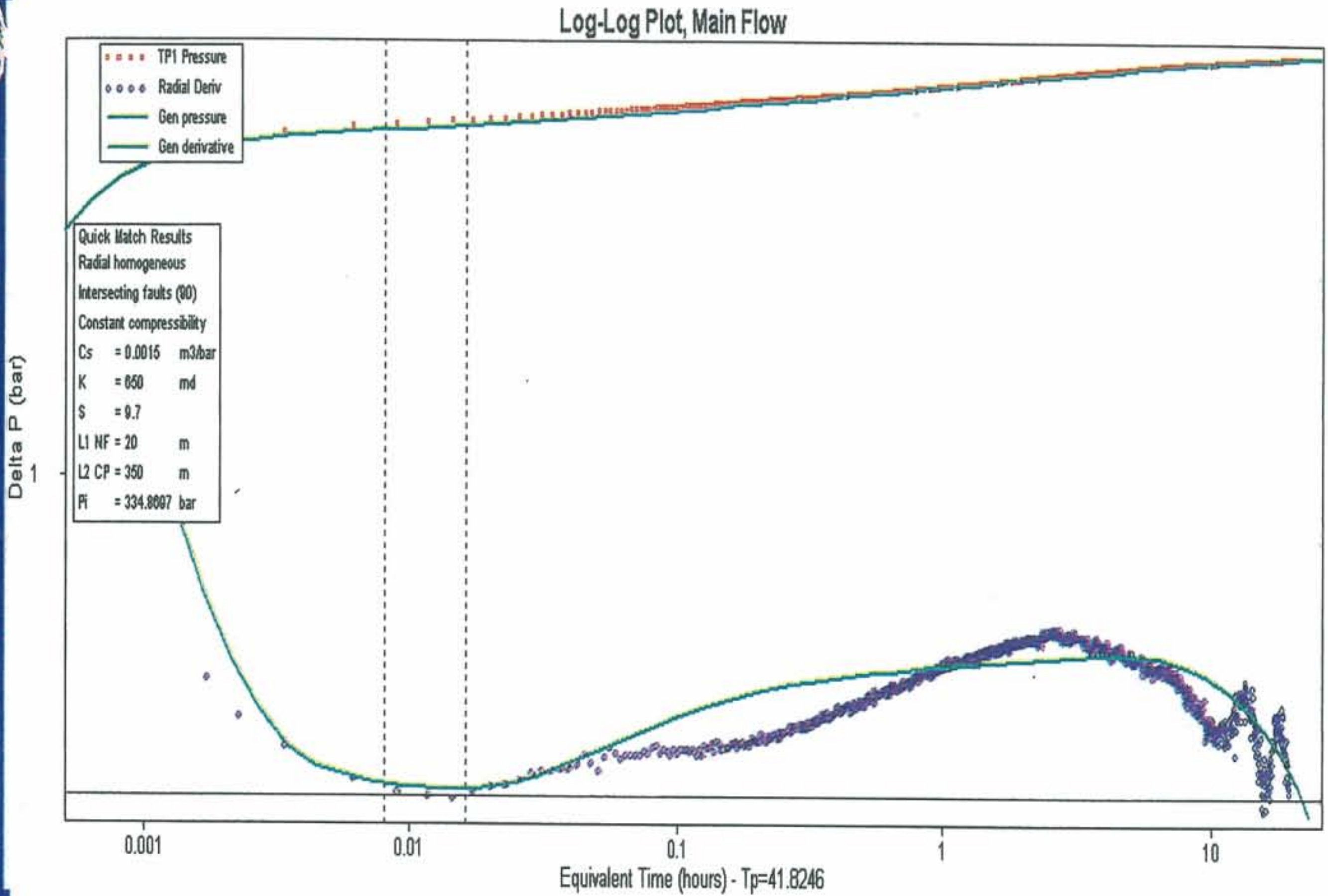


Figure 6.2.2.5, 2 boundaries 90 deg, 1 no-flow + one constant pressure

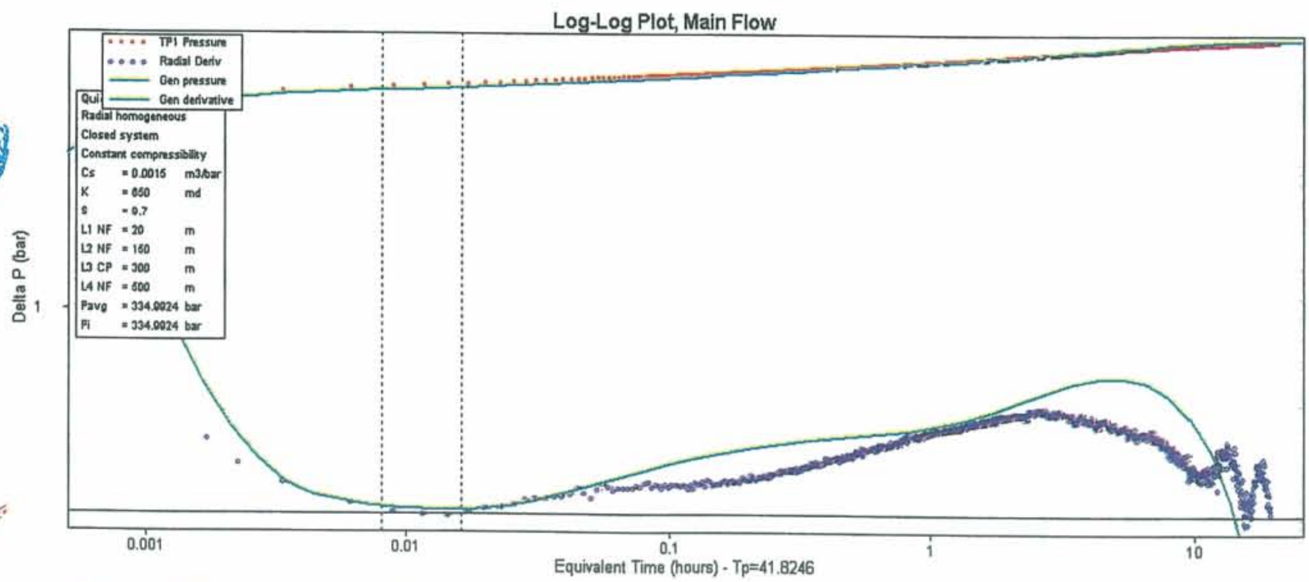


Figure Figure 6.2.2.6, Closed system, one constant pressure boundary

Well 15/9-19A, Test 2B
Model with 1 ,2 and 4 boundaries

STATOIL

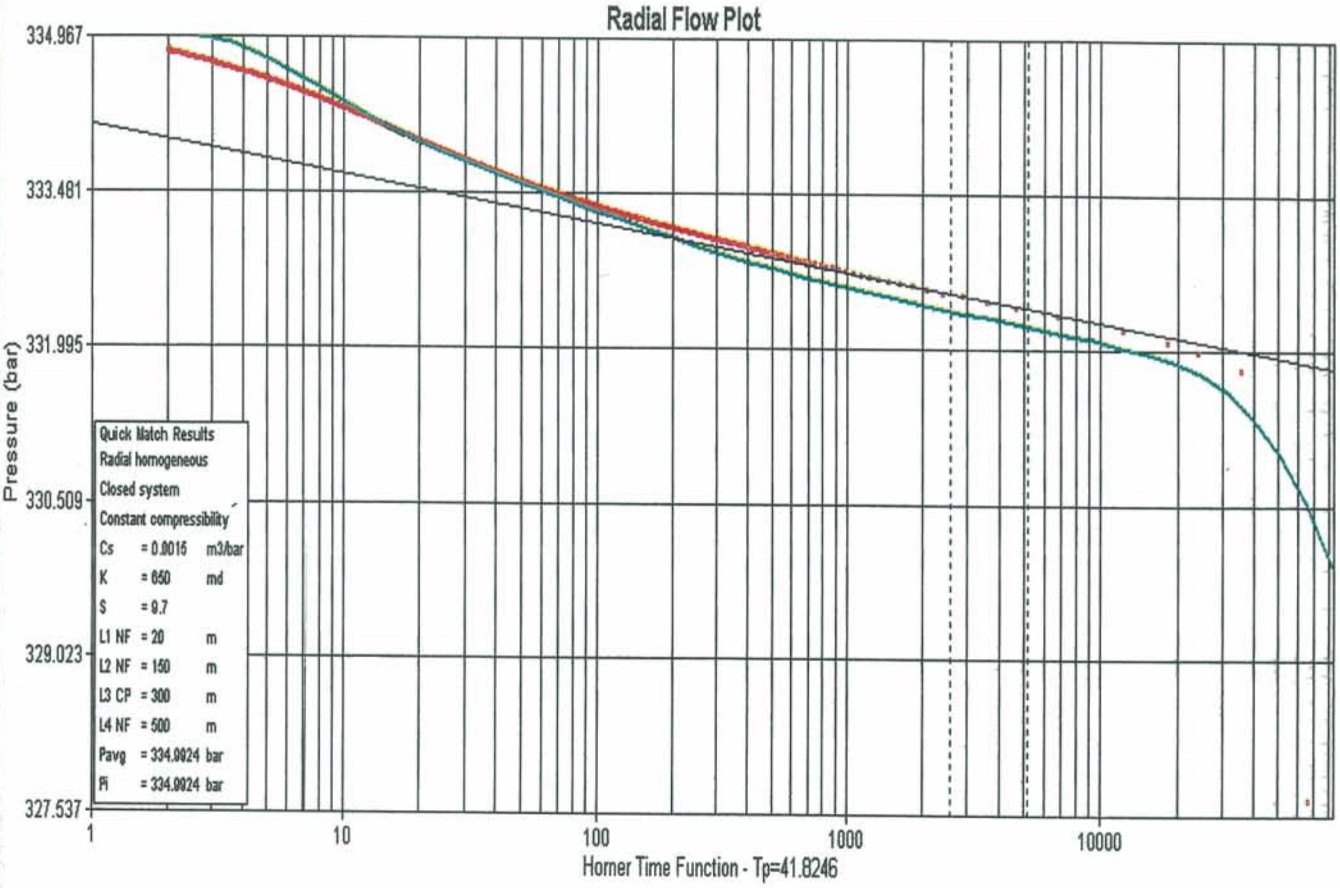


Figure 6.2.2.7, Closed system, 1 const press. boundary

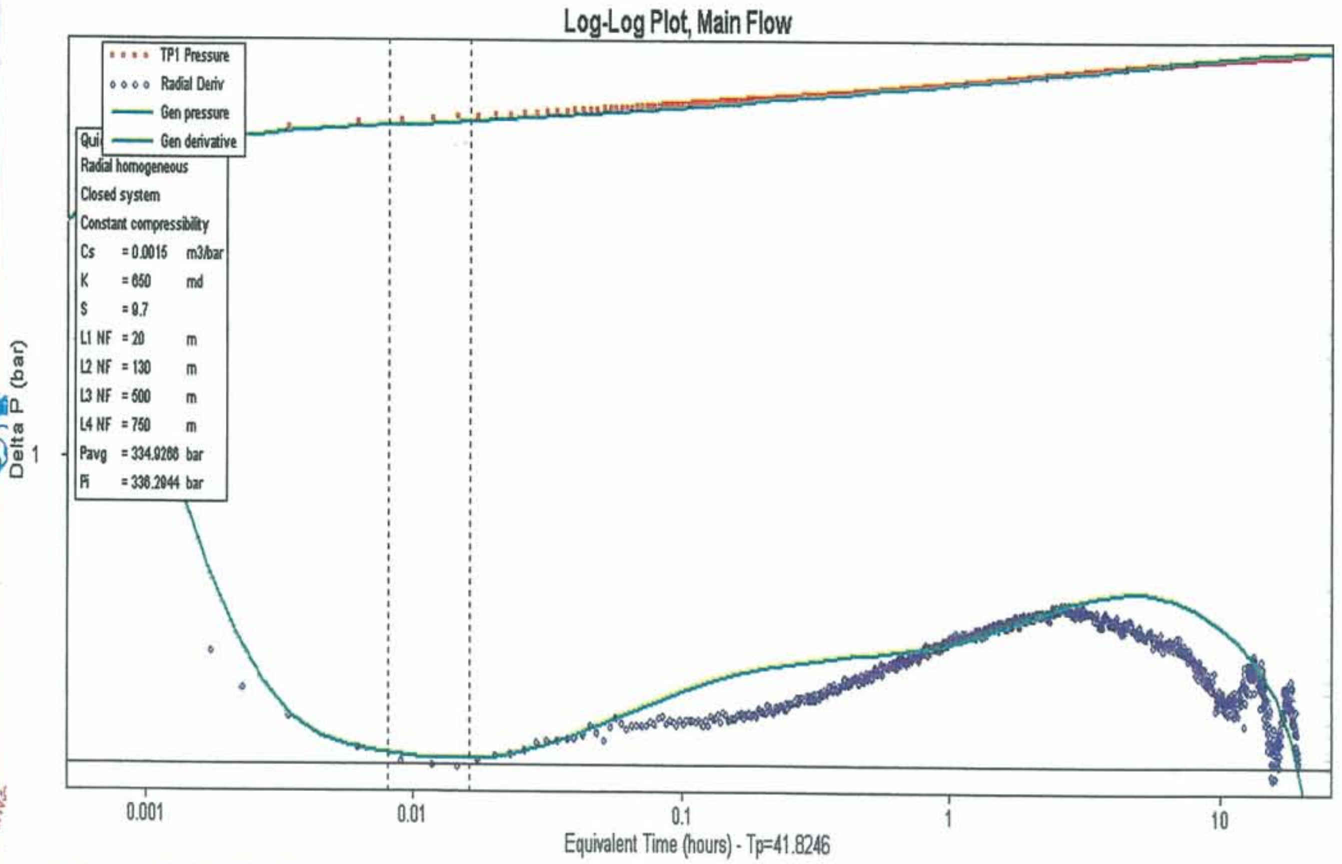


Figure 6.2.2.8 Closed system,

Well 15/9-19A, Test 2B
Model with 1 ,2 and 4 boundaries

STATOIL

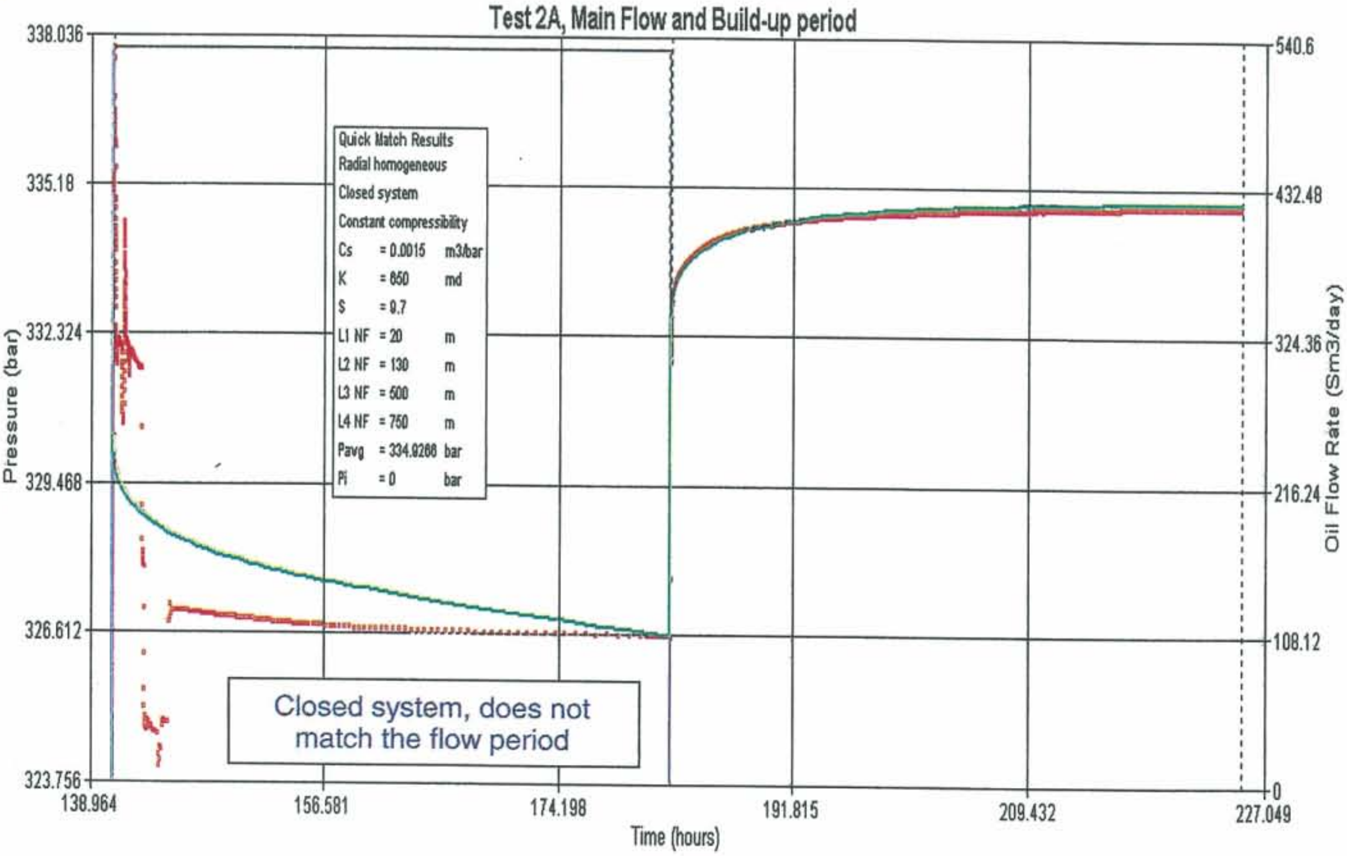


Figure Figure 6.2.2.9 Closed system,

Well 15/9-19A, Test 2B
Layered reservoir,dual porosity (Pansys)

STATOIL

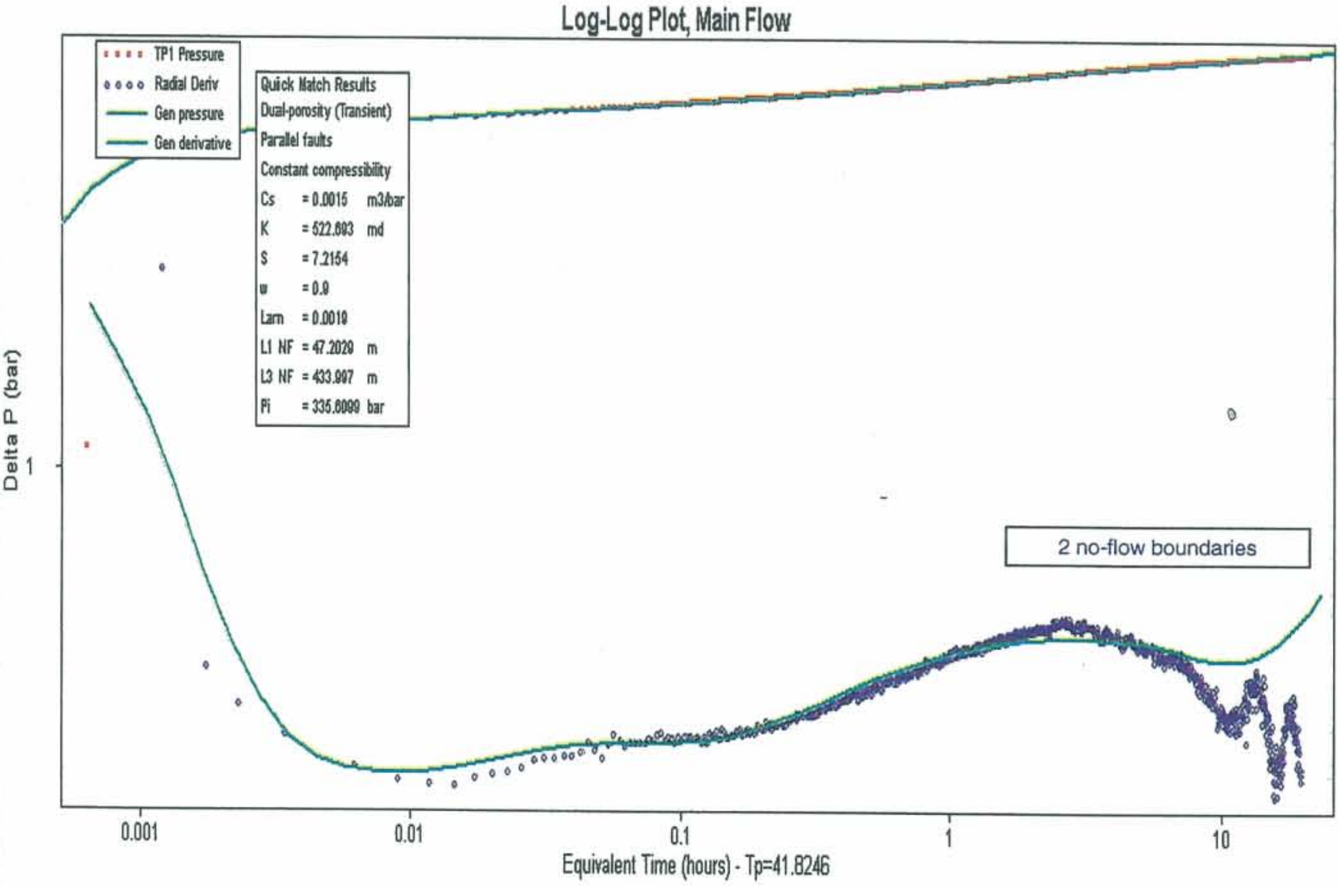


Figure 6.2.3.1, Dual porosity system, parallel boundaries

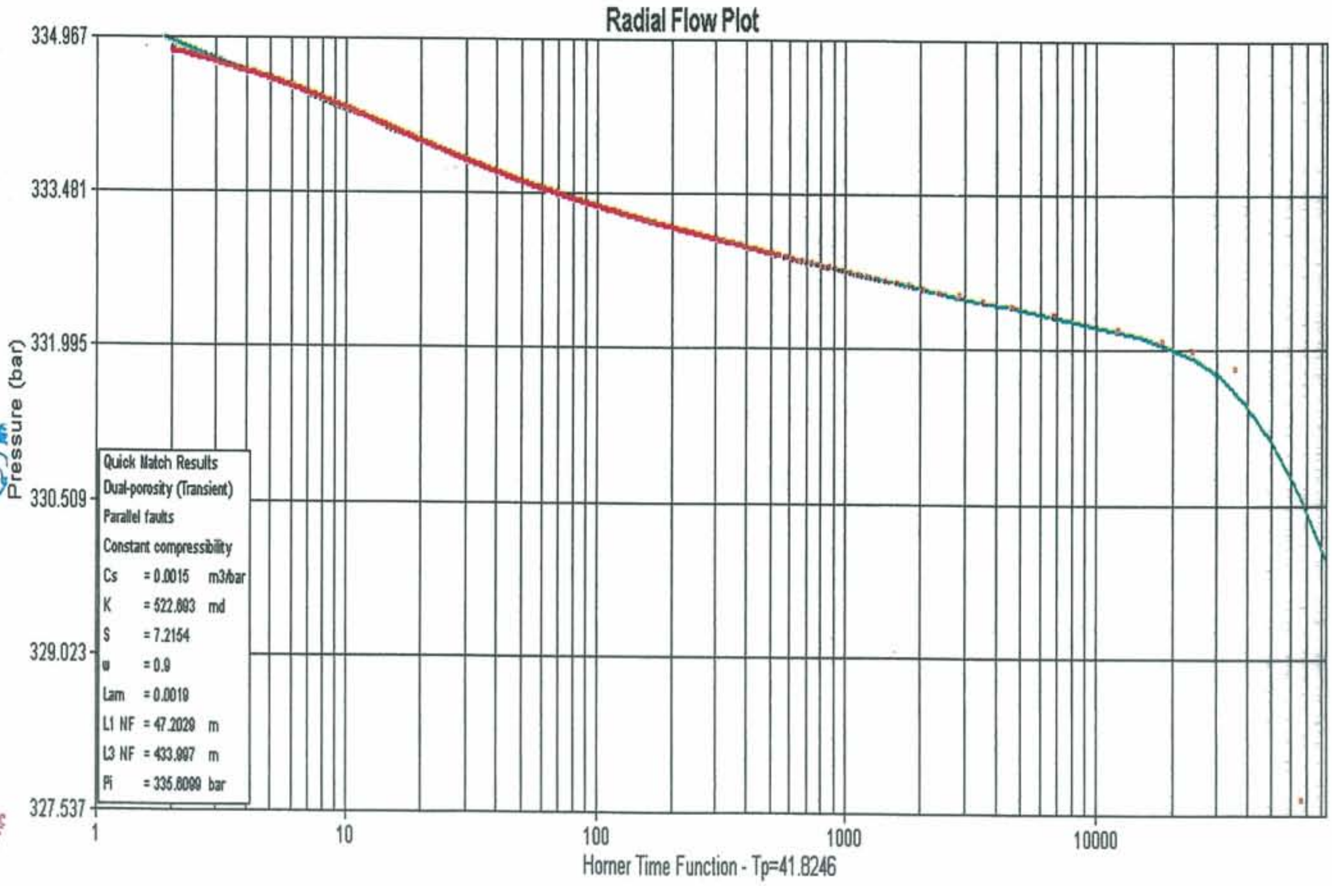


Figure 6.2.3.2 Dual porosity system, parallel boundaries ,

Well 15/9-19A, Test 2B
Layered reservoir,dual porosity (Pansys)

STATOIL

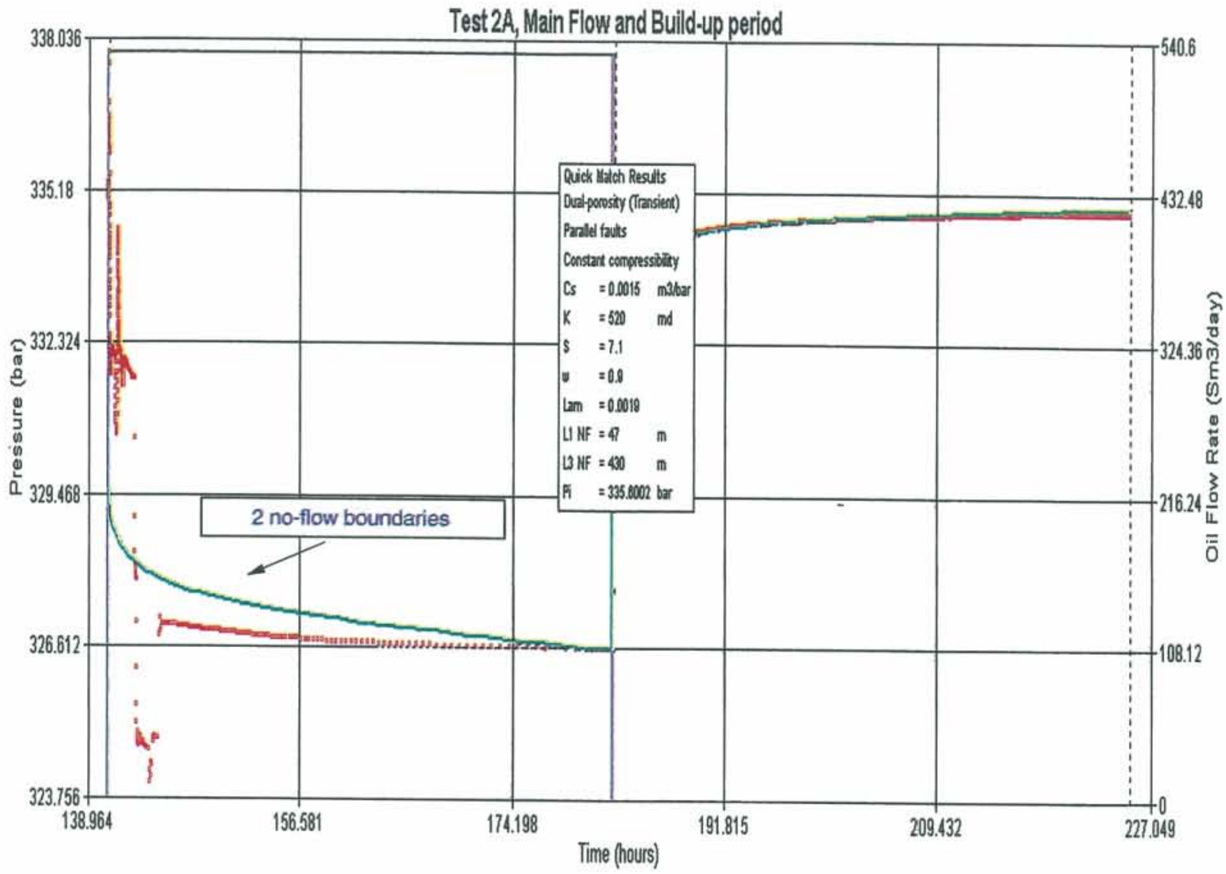


Figure Figure 6.2.3.3 Dual porosity system, parallel boundaries

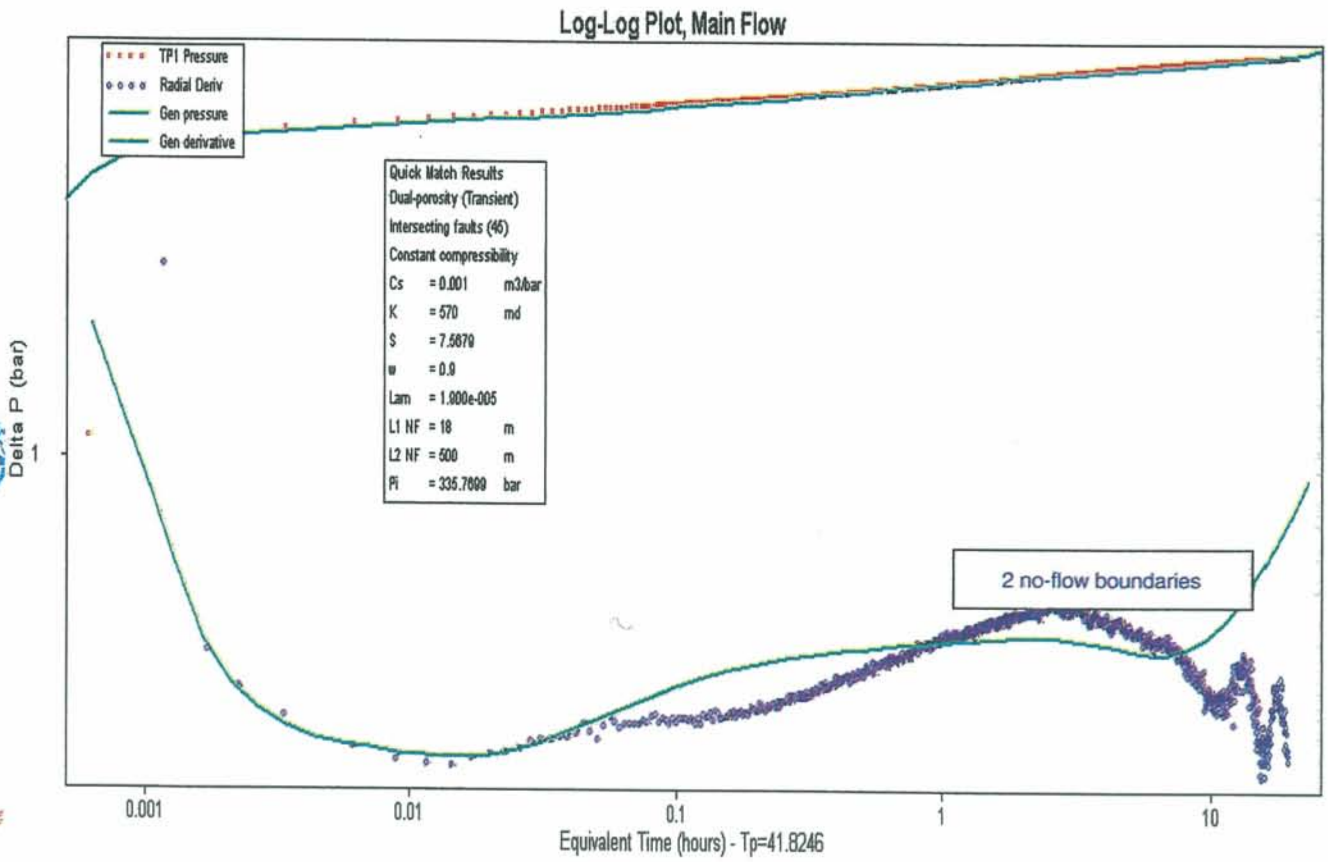


Figure 6.2.3.4, Dual porosity system, 45 deg boundaries

Well 15/9-19A, Test 2B
Layered reservoir,dual porosity (Pansys)

STATOIL

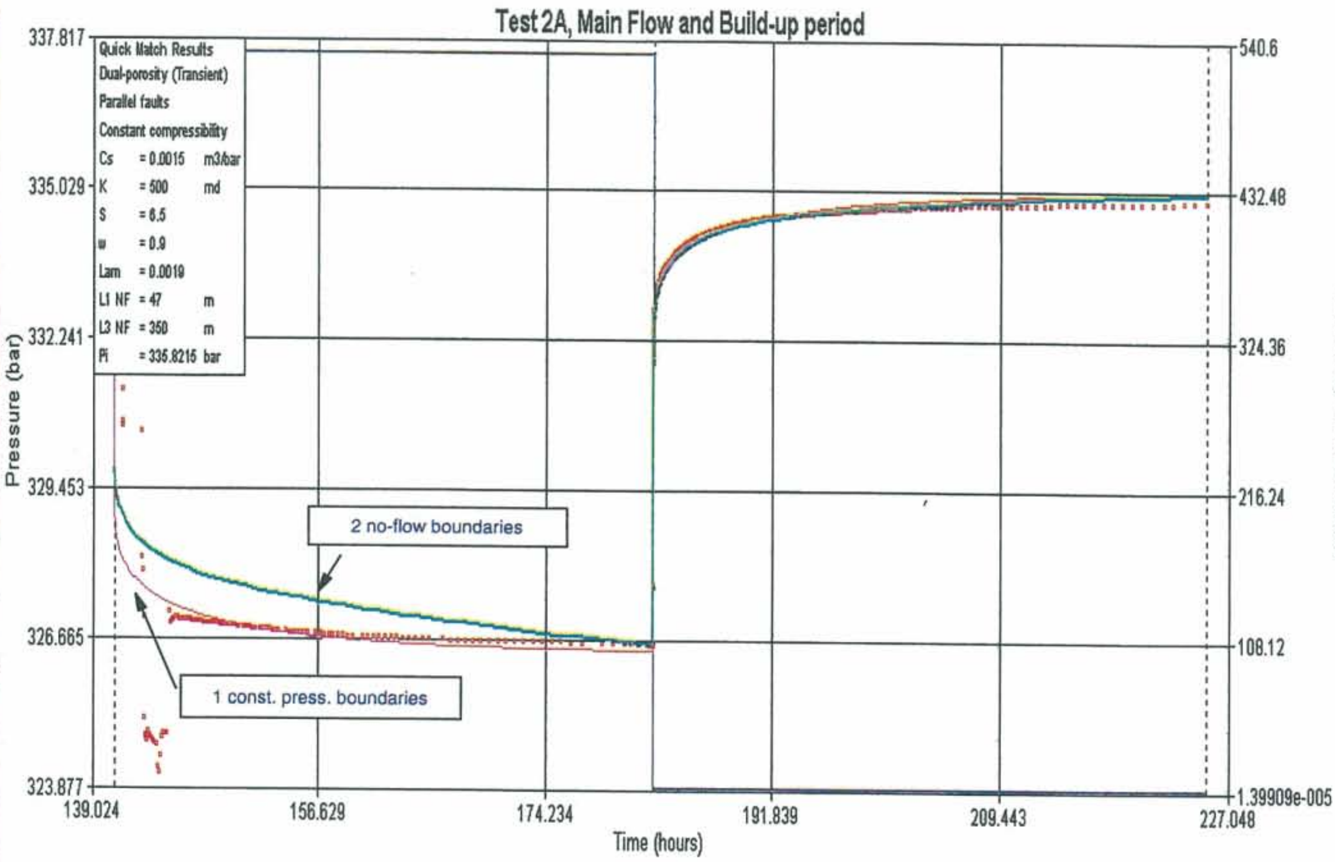


Figure 6.2.3.5 Dual porosity system, parallel boundaries,

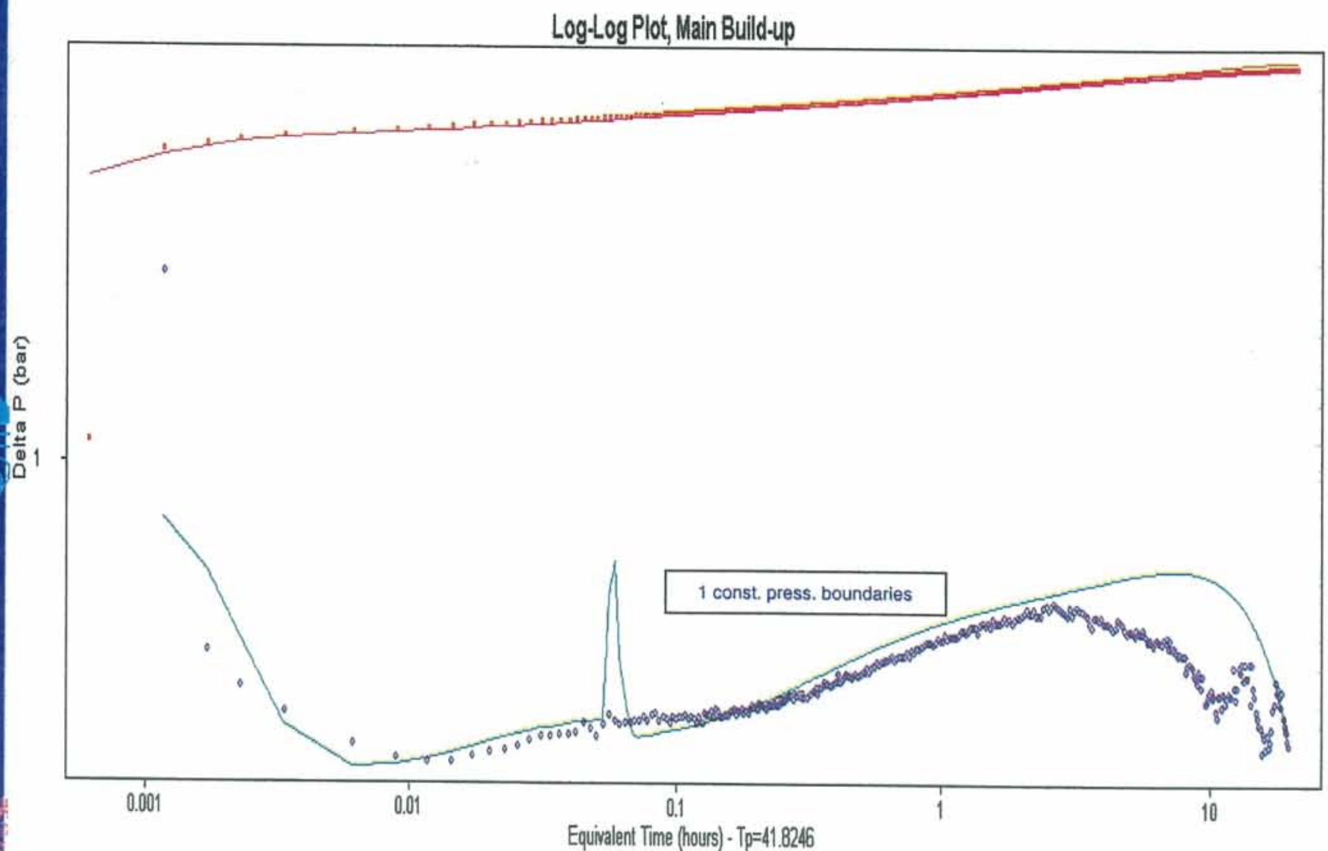


Figure 6.2.3.6 Dual porosity system, parallel boundaries, 1 const. press.

6.3 Minifrac results

A minifrac test was attempted without success in both Test 1 and Test 2A. This probably due to plugging of the perforation with mud in Test 1, and possibly due to sand production in test 2A. The latter attempt or failure to perform a successful minifrac will probably never find a good explanation due to very different signals.
There is no signs of sand production to surface during the flow periods. No problems after cleanup shut-in experienced. The tester valve opened and closed without problems. There were no sand in the bottom hole samplers and the sampling was performed without any problems.
Then the actual pumping pressure trends show signs of plugging.

Finally a minifrac was performed in connection with killing the well after Test 2B.
The results from this minifrac is shown in the Figures 6.3.1-5.
The fracture closure pressure seems to be approximately 540 - 545 bar using the bottom hole data. This is equivalent to approximately 1.81-1.82 g/cm^3 equivalent mud weight. This is very similar to the prognosed pressure of 1.78-1.79 g/cm^3

Well 15/9-19 A, Test 2B (minifrac.)
Bottom hole data, all cycles.

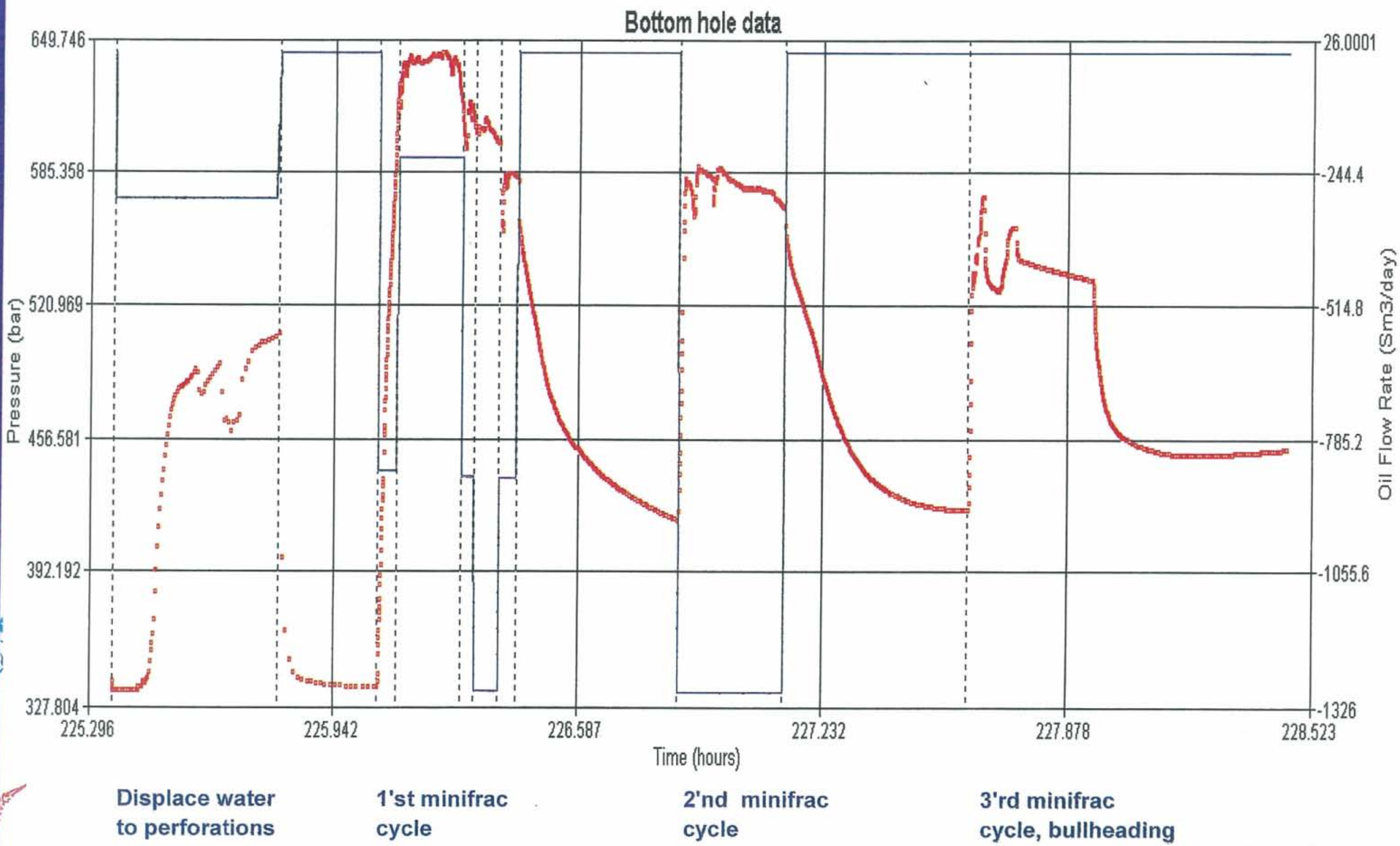


Figure 6.3.1

Well 15/9-19A, Test 2B (minifrac.)

Minifrac test, cycle 1 using sea water. Surface data

STATOIL

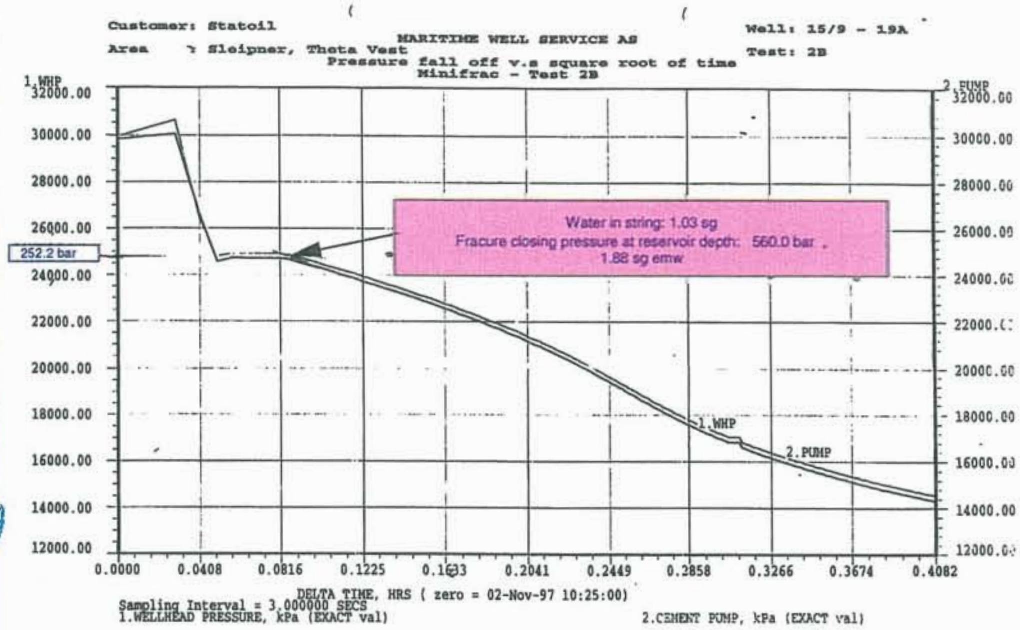


Figure 6.3.2

Well 15/9-19A, Test 2B (minifrac.)

Minifrac test, cycle 2 using mud.
Surface data

STATOIL

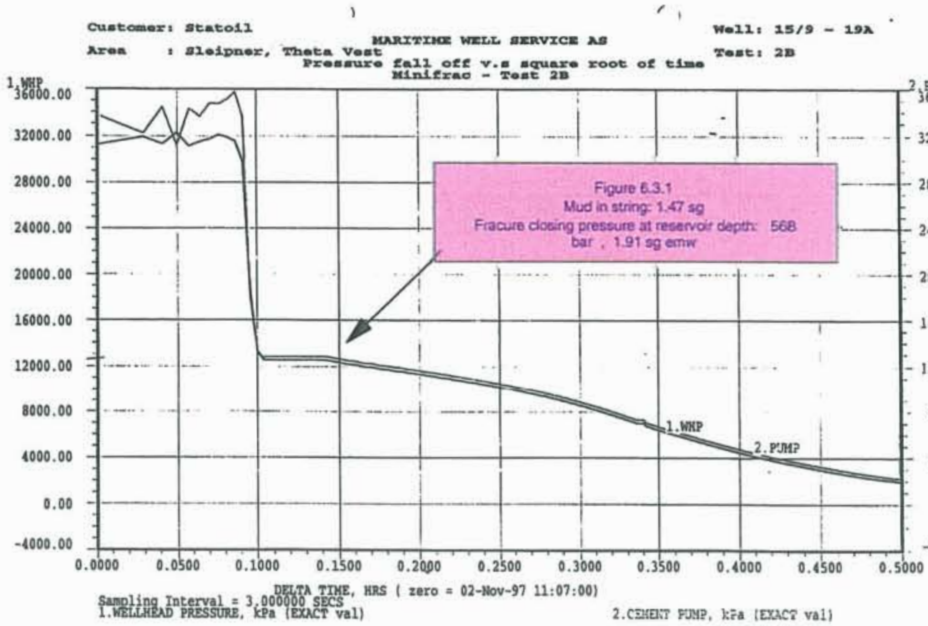


Figure 6.3.3

Well 15/9-19 A, Test 2B (minifrac.)
Bottom hole data, all cycles.

STATOIL

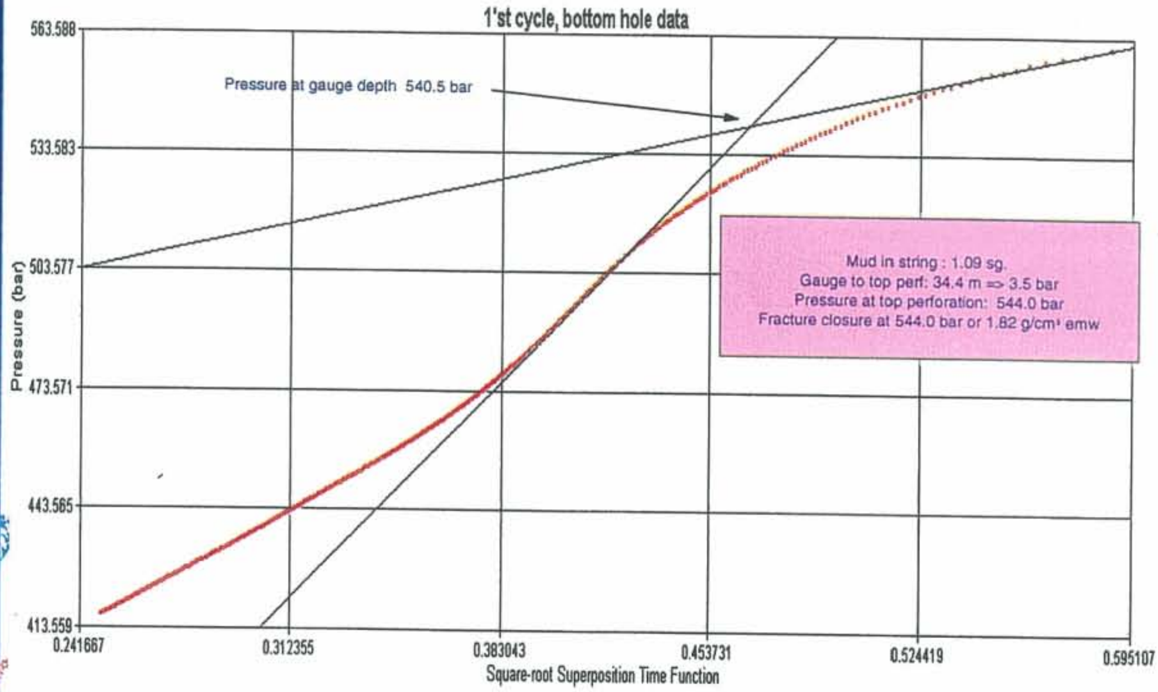


Figure 6.3.4

Well 15/9-19A, Test 2B (minifrac.)
Bottom hole data, all cycles.

STATOIL

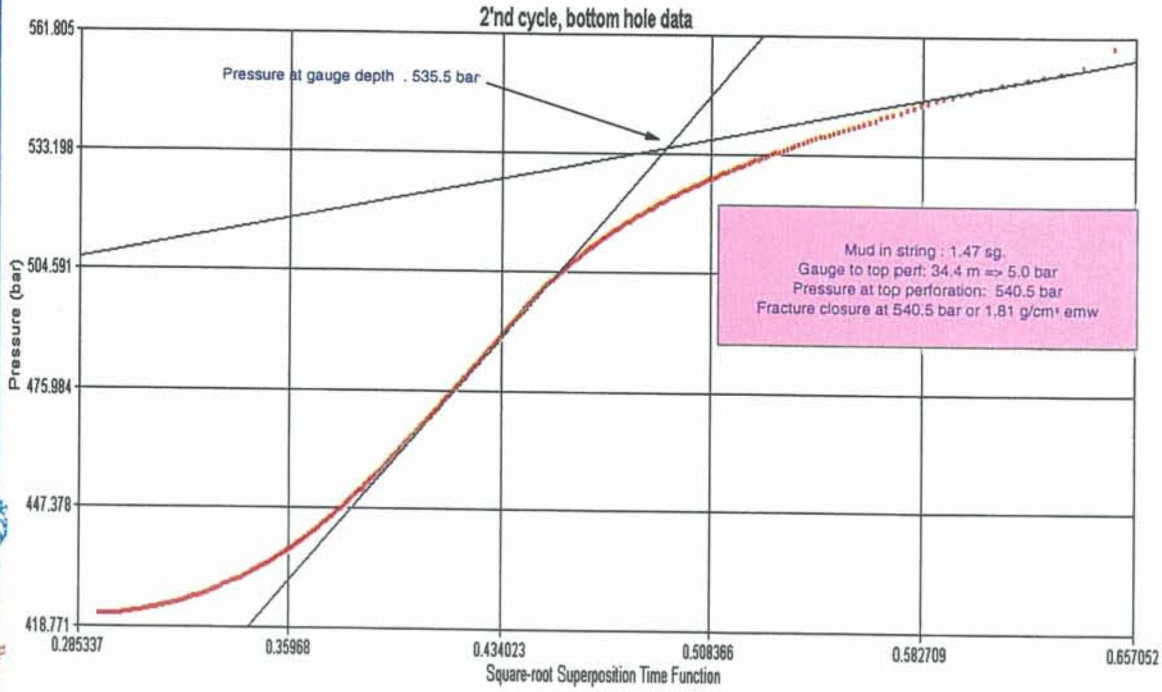


Figure 6.3.5

6.4 Lorenz plot

This is a statistic presentation of parameters measured on the cores in the well.
It is only used to show that there is huge contrasts in kh and øh ratios. The method is very dependent upon the data input, choose of start and end point.
The Lorenz plot, also a graphical display of heterogeneity, relates transmissivity (kh) to storativity (øh) for the reservoir layers.

Below is the equation for the to parameters given

$$Fj = \frac{\sum_{j=1}^{J} kjhj}{\sum_{i=1}^{I} kihi} \qquad Cj = \frac{\sum_{j=1}^{J} \phi jhj}{\sum_{i=1}^{I} \phi ihi}$$

k = core measured permeability
ø = core measured porosity
h = the interval represented by each plug or probe measurement.

Plotting Fj (fraction of total flow capacity) on the y-axis and Cj (fraction of total storage capacity) on the x-axis the Lorenz plot is created. This is a modified plot in that the core data is normalised from the top to the bottom of the core.
The actual Lorenz plotting technique will sort the data in decreasing order of transmissivity and storativity, and then normalise with respect to the total values to provide a dimension less parameter.
This difference makes it possible to see approximately where in the zone the contributing and not contributing zones are.

Ref. Well Testing for Fluivial Reservoir Description.
Final report March 1997, (Patrick Corbett, Moe Pinisetti, Shiyi Zheng, Georg Stuart, Heriott -Watt University)

Well 15/9-19A, Test 2A & 2B

evaluation of core data

STATOIL

Lorenz Plott

Blow-up data from test interval 2A, green line

Data below good sand and down to Sleiner Fm. , red line

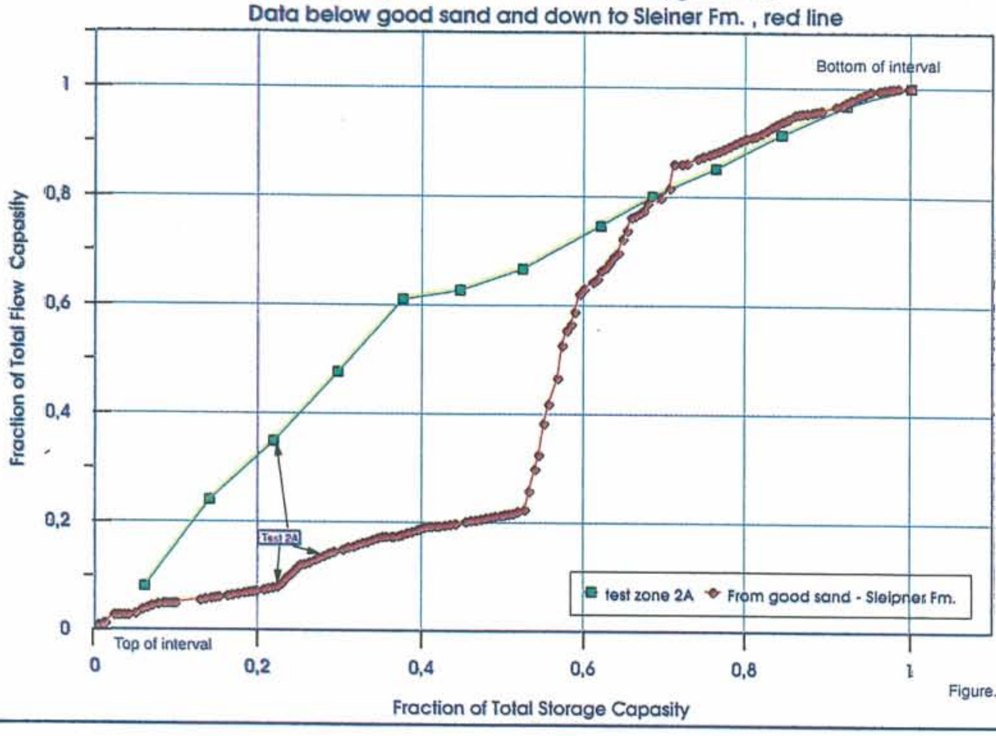


Figure. 6.4.1

Well 15/9-19A, Test 2A & 2B

evaluation of core data

STATOIL

Lorenz Plott

Data from core 1 and down to bottom test 2A. Best part includes the good sand partly perforated in test 2B

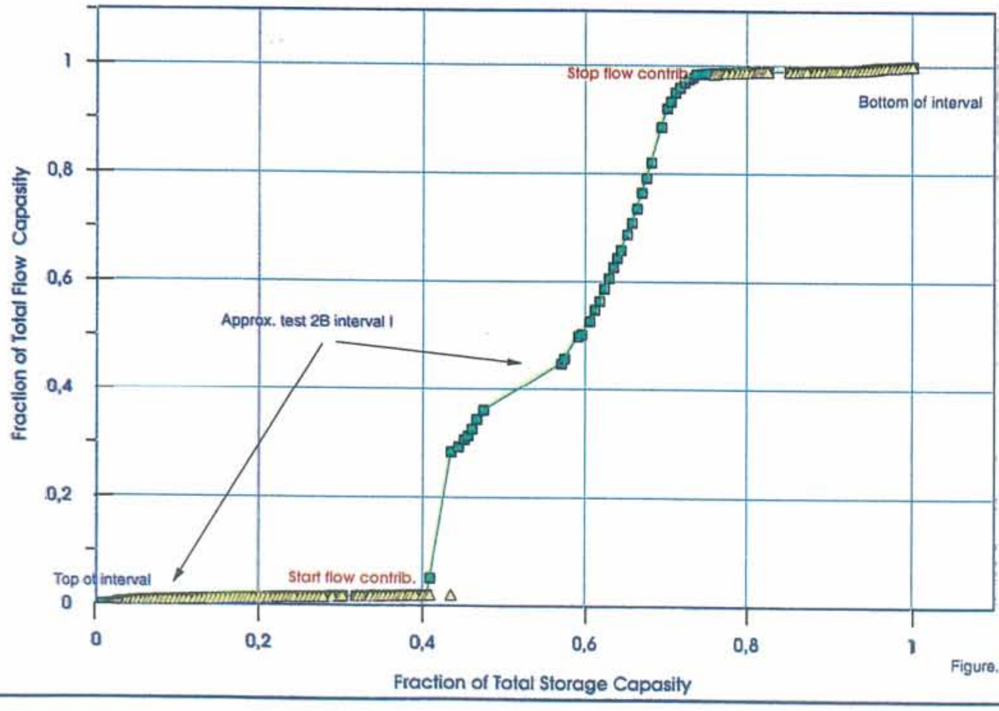


Figure. 6.4.2I

Well 15/9-19A, Test 2A & 2B
evaluation of core data

STATOIL

Lorenz Plott

Data from core 1&2 down to bottom test 2B.

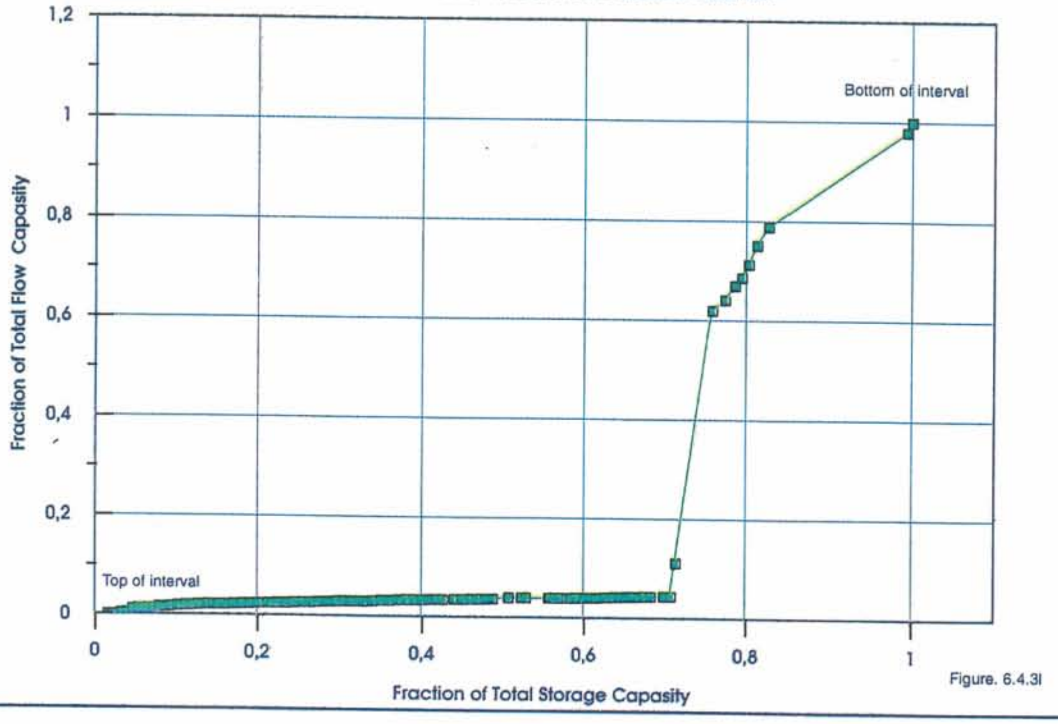


Figure. 6.4.3l

Well 15/9-19A, Test 2A & 2B
evaluation of core data

STATOIL

Lorenz Plott

Core data for interval top core1 down to good sand at approx. 3072 m TVD

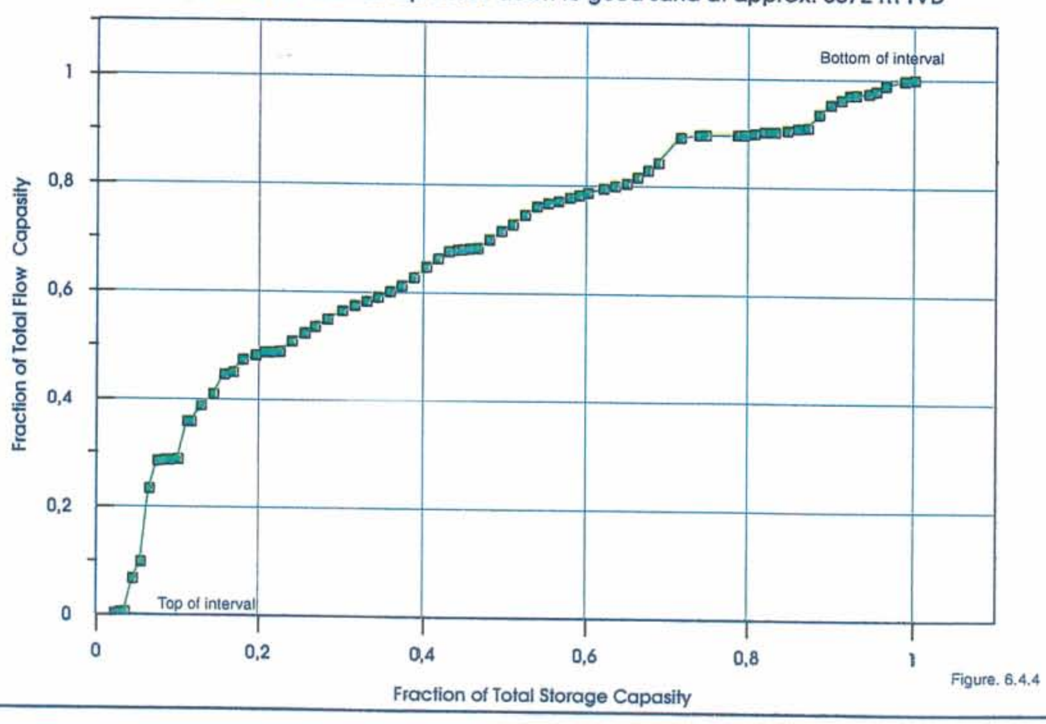


Figure. 6.4.4

7 Pressure gradient evaluation, based on test results

Pressure measurements from wireline logs like FMT or RFT has not been obtained in the wells 15/9-19SR and -19A, due to operational circumstances, equipment failure and industrial action. Below are listed pressures and depths used in the Figures 7.1 and 7.2
Gradients shown in Figure 7.2 indicate possible pressure communication between -19SR and -19A in the hydrocarbon zone. The water gradient also indicates that we have an oil down to situation in the well. The water gradient crosses the hydrocarbon gradient above where hydrocarbone are proven.

Figures 7.1 and 7.2 also includ pressures from DST -tests and FMT pressures from the well 15/9-19BT2
Figure 7.3 shows measured test temperatures.
Table 7.1 lists the different pressures with uncertainties from well 15/9-19A and -19SR pressure.
Table 7.2 lists FMt pressures obtained in 15/9-19BT2

Test	Gauge depth	Last BU press.	Extrap. press. Bar	Unsertain-ties Bar	Top res. depth m TVDRT	Fluid weight g / cm³	Extrap. press. at top Reservoir	Unsertain-ties
15/9-19SR test # 1					2 885,9		327,7	+/- 1.0
15/9-19A test # 1	3 134,7	349	349	+/- 0.5	3 155,5	1.09 - 1.47	352	+/- 1.0
15/9-19A test # 2A	3 007,5	330,5	335,5	+/- 1.0	3 095,6	0,7	341,5	+/- 1.5
15/9-19A test # 2B	3 007,5	335	335	+/- 0.5	3 041,9	0,7	337,5	+/- 0.5

Table 7.1

WELL NO.: 16/1-5 LOG RUN NO.: 2A

FMT-RESULTS											
Test No.	Depth m MD	Depth m TVD	Hydro-static pressure before kPa	QDYNE Formation pressure kPa	SG Formation pressure kPa	Hydro-static pressure after kPa	Flowing pressure kPa	Fill time sec.	Temp . °C	Good seal Y/N	Remarks
1	2024.5	2023.7	23145	20319		23152	19600	9.8		Y	Good
2	2031.2	2030.4	23226	20393		23234	15333	10.8		Y	Moderate
3	2042.0	2041.1	23346	20499		23360	16990	10.0		Y	Moderate
4	2055.0	2054.1	23490	20628		23493	20622	12.0		Y	Very good
5	2068.0	2067.0	23638	20759		23652	20758	11.8		Y	Very good
6	2090.0	2088.9	23880	20979		23922	14148	10.8		Y	Moderate
7	2123.0	2121.8	24249	21313		24289	16974	3.5		Y	Good
8	2184.5	2183.0	24941			24939				?	Pressure not stabilised
9	2183.5	2182.0	24927			24930				?	Pressure not stabilised
10	2202.5	2200.9	25146	22257		25146	22226	11.8		?	Pressure not stable, still increasing slightly
11	2024.5	2023.7	23180	20350		23169	19014	11.0		Y	Segregated sample

Water sample at 2024.5 m: Preflush chamber contained 20 liter of filtrate/formation water. Chlorides: 48000 mg/l. Opening pressure: 0 psi
4 liter PVT chamber: Opening pressure 1500 psi

Licence :PL 046	Well 15/9-19A&19B Formation pressures	STATOIL	
RT - MSL: 25 m			
Water Depth: 84 m		Made by: DFr	Date:10.11.98

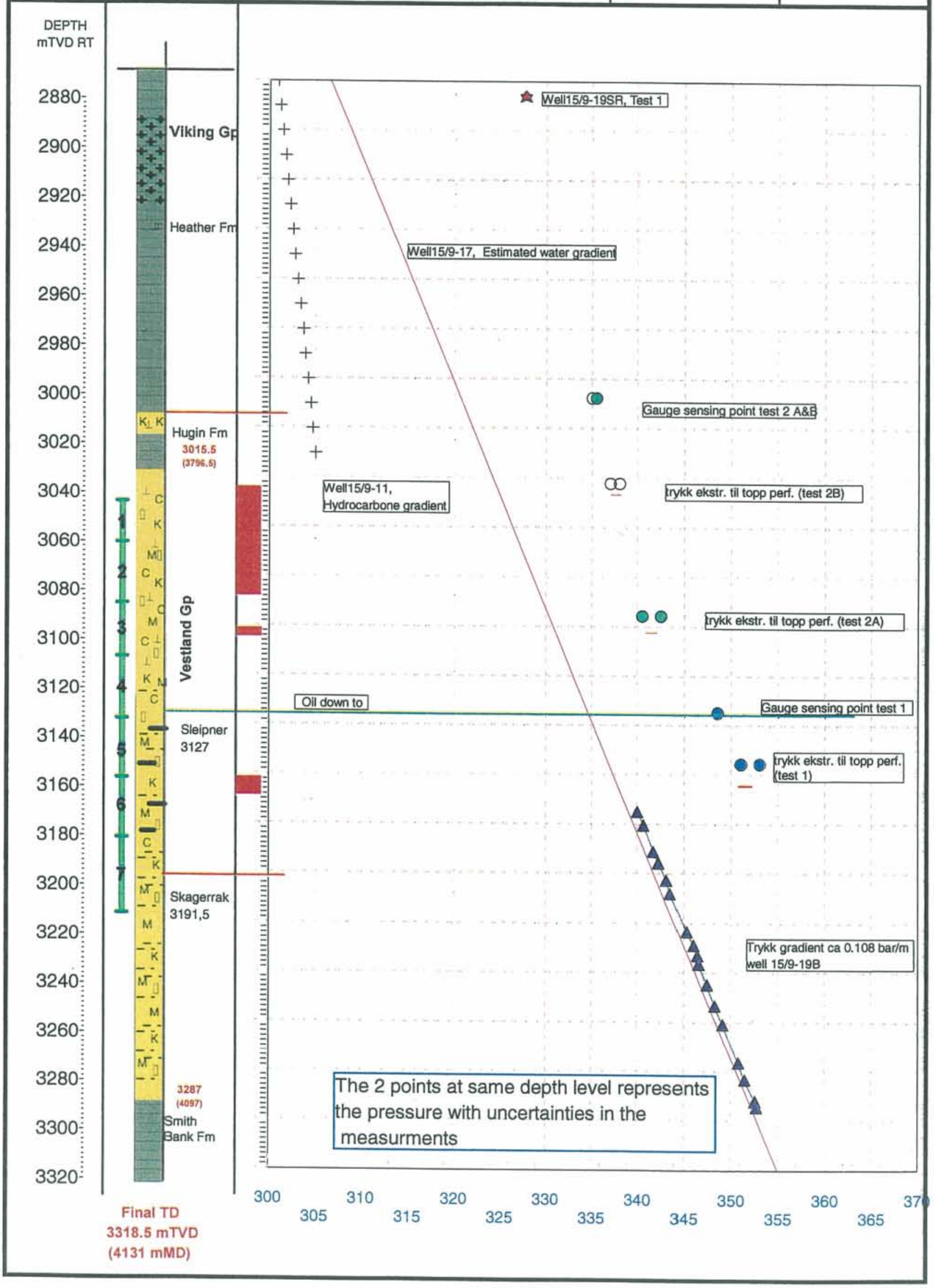


Figure 7.1

Licence :PL 046	Well 15/9-19A&19B	STATOIL
RT - MSL: 25 m	Formation pressures	Made by: DFr / Date:10.11.98
Water Depth: 84 m		

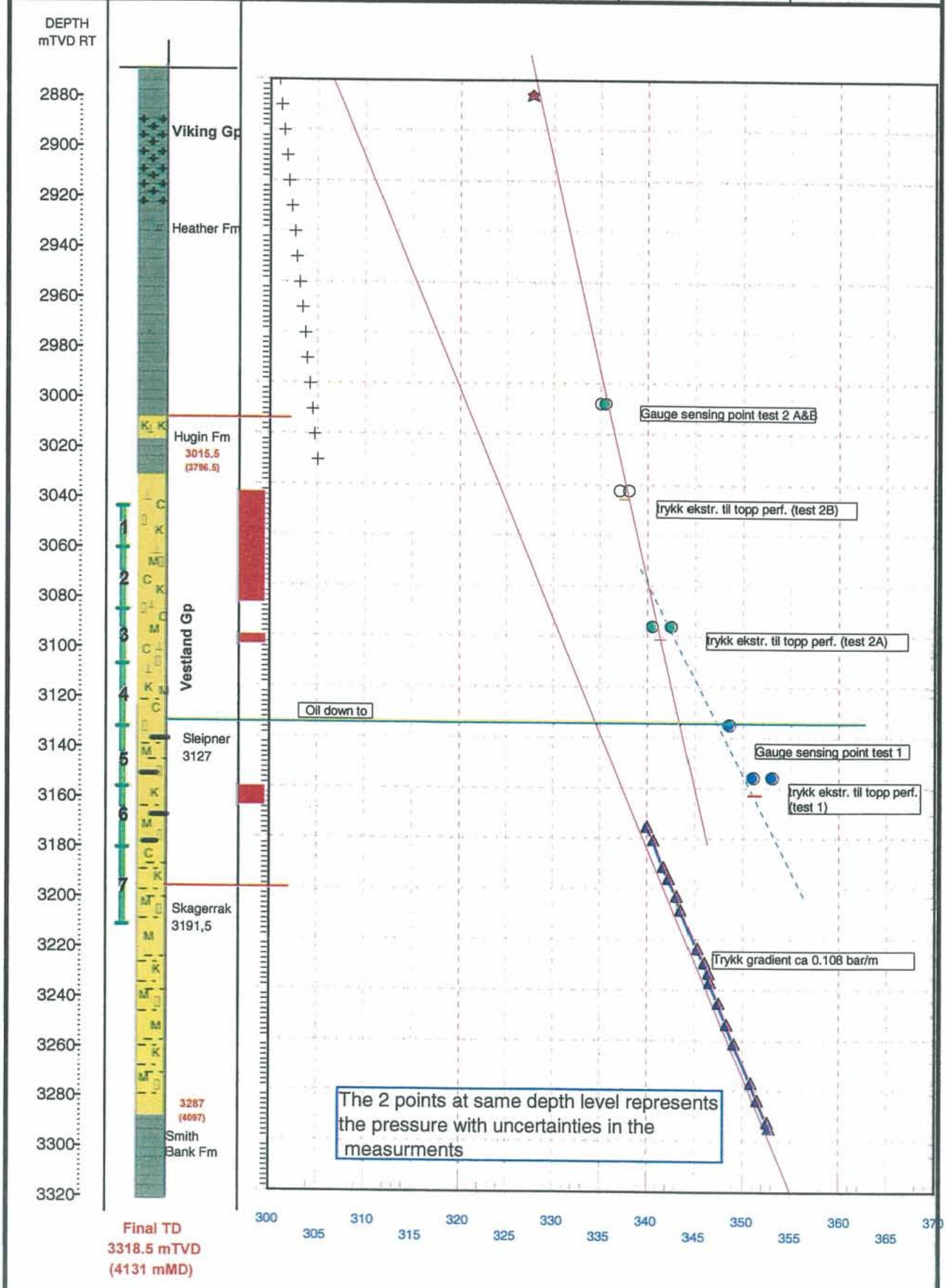


Figure 7.2

Licence :PL 046

RT - MSL: 25 m

Water Depth: 84 m

Well 15/9-19A
Formation temperatures

STATOIL

Made by: DFr

Date:10.11.98

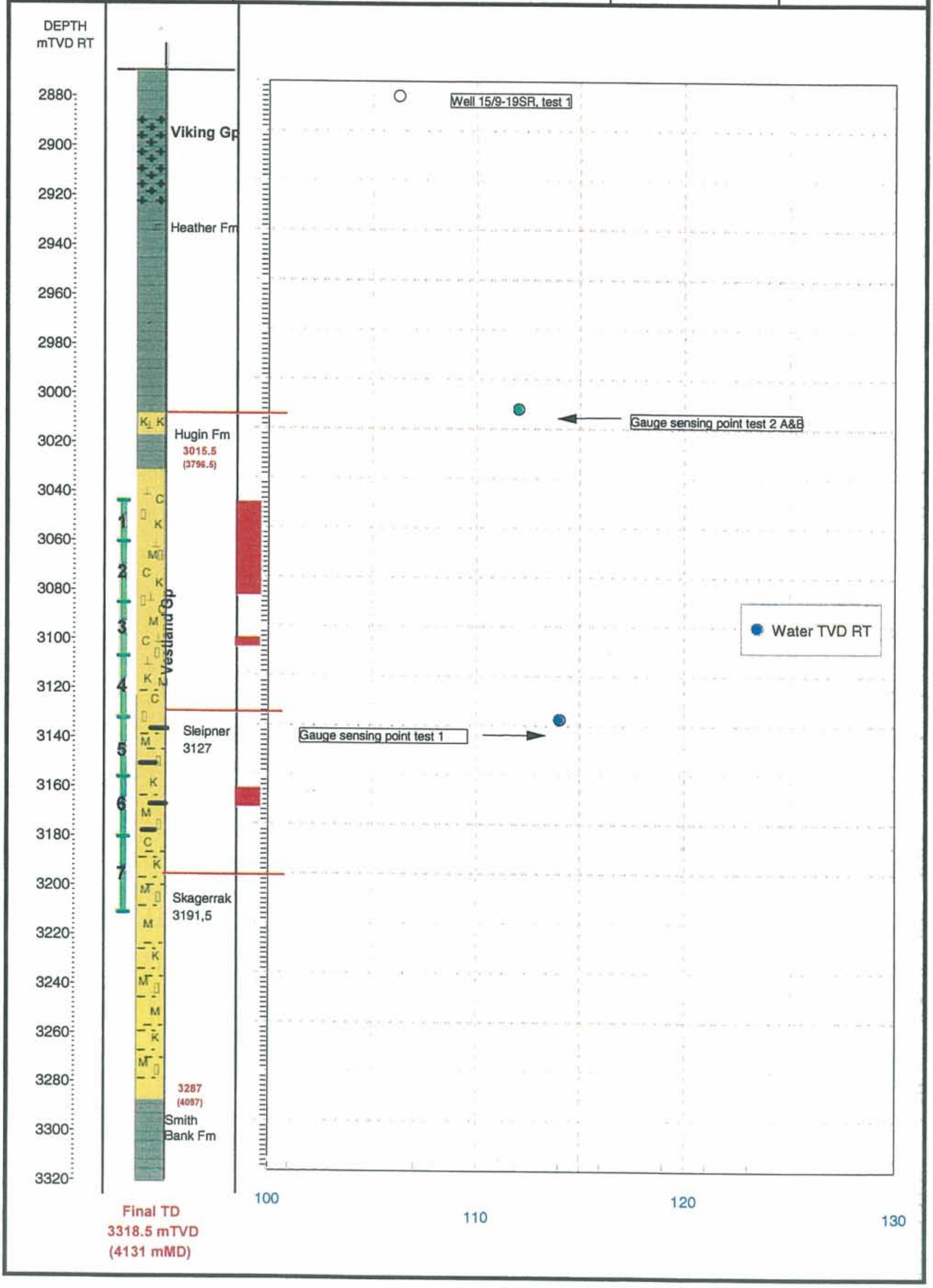


Figure 7.3

8 APPENDIX

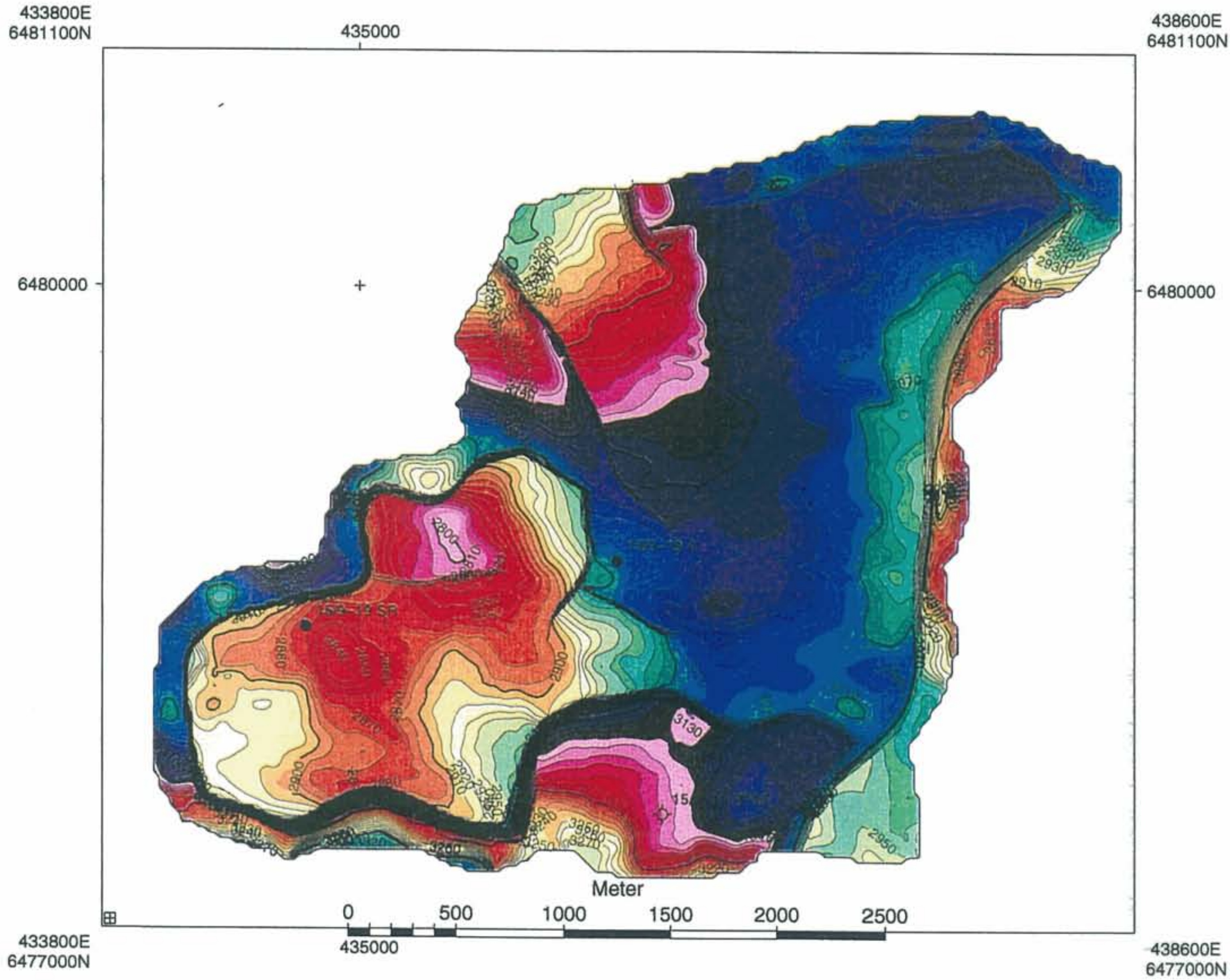
8.1 Appendix A Petrophysical evaluation, main results

Curve name	**Test 1** **3952 - 3958** **m MDRT**	**Test 2A** **38885.5 - 3888.5** **m MDRT**	**Test 2B** **3826 - 3865** **m MDRT**
Horisontal perm core (KLH) mD	348	259	925
Vertikal perm core (KLV) mD	169 (5 measurments)	327 (3 measurments)	284
Horisontal perm log (K) mD	342	195	748
Porosity core (POR) %	17,8	21	19,1
Porosity log (NPHI) %	17	18,1	19,1
Water saturation core (SW) %	88,5	20,2	24,6
Water saturation log (SW) %	-----	22	34,7
Sand %	85	100	89
Density log g/cm^3	2.34	2,27	2,3

Core values are not corrected for overburden.

8.2 Appendix B Geological model

STATOIL



30-Nov-98

8.3 Appendix C Fluid data, quick summary of PVT report

Table C12 Sample overview.

Well	Test	Formation	Perforations/Sample depth [m TVD MSL]	Reservoir fluid	Analysis				
					PVT	Comp.	Oil char.		Water
							Std. (*)	Ext. (**)	
15/9-19SR	DST 1	Hugin	2863.6 - 2880.5	Oil	x	x	x		
15/9-19A	DST 1	Sleipner	3159.8 - 3165.5	Form. water					x
	DST 2A	Hugin	3074.9 - 3077.5	Oil	x	x			
	DST 2B	Hugin	3074.9 - 3077.5 & 3021.2 - 3056.3	Oil	x	x	x	x	

(*) Including TBP-distillation and standard hydrocarbon analysis.
(**) Special fluid studies on wax, asphaltenes, rheology, emulsions, etc.

Table C23 : Reservoir fluid composition and summary of PVT data.

Field	**Volve**	**Volve**	**Volve**
Well	15/9-19A	15/9-19A	15/9-19 SR
Test	DST 2A	DST 2B	DST 1
Sample	BHS	Separator	BHS 2
Fluid type	oil	oil	oil
Formation	Hugin	Hugin	Hugin
Perforations [m TVD MSL]	3074.9 - 3077.5	3021.2 - 3056.3 + 3074.9 - 3077.5	2863.6 - 2880.5
Laboratory	Geco	Geco	Statoil
Reservoir conditions			
Reservoir pressure [bar]	340	340	328
Reservoir temperature [°C]	110	110	106
Composition [% by mole]			
Nitrogen	0.49	0.44	0.46
Carbon dioxide	1.65	1.69	4.95
Methane	40.54	38.18	43.50
Ethane	5.95	5.66	6.14
Propane	5.53	5.39	5.26
i-Butane	0.80	0.79	0.69
n-Butane	2.88	2.91	2.65
i-Pentane	1.07	1.13	0.92
n-Pentane	1.68	1.78	1.51
Hexanes	2.28	2.47	2.10
Heptanes / Heptanes+	3.49	3.78	3.29
Octanes	3.16	3.36	3.24
Nonanes	2.32	2.41	2.39
Decanes+	28.15	30.01	22.90
Properties of C7 - C10+ frac.			
Density, heptanes (+) [kg/m³]	739.0	739.0	742.0
Density, octanes [kg/m³]	759.0	759.0	759.0
Density, nonanes [kg/m³]	772.0	772.0	776.0
Density, decanes+ fraction [kg/m³]	927.0	92.0	916.0
Mole weight, heptanes (+) [g/mole]	90.9	91.3	91.5
Mole weight, octanes [g/mole]	105.7	105.7	105.5
Mole weight, nonanes [g/mole]	119.2	119.3	119.7
Mole weight, decanes+ fraction [g/mole]	346.0	325	320.0
Reservoir fluid properties			
Saturation press. at res. temp. [bar]	235.5	226.5	273.8
Density at bubble point [kg/m³]	733.4	734.0	701.0
Viscosity at bubble point [mPa·s]	0.790	0.790	0.547
S. flash Bo at bubble point [m³/Sm³]	1.388	1.383	1.505
S. flash gas oil ratio [Sm³/Sm³]	111.8	108.9	159.1
WAT (filter technique) [°C] (**)	28		
H_2S (in separator gas) [ppm by volume]	6	3	6

(*) Dew point.
(**) Wax Appearance Temperature

Table C34 True Boiling Point (TBP) data of stabilised oil.

		Volve 15/9-19A DST 2B			Volve 15/9-19SR DST 1		
Cut	Temp. °C	Comp. wt%	Density g/cm³	Mw g/mole	Comp. wt%	Density g/cm³	Mw g/mole
C4-		0.76	0.560	53.9	1.21	0.544	51.3
C5	36.5	1.14	0.628	72.2	1.41	0.629	72.2
C6	69.2	1.43	0.669	84.7	1.80	0.669	84.7
C7	98.9	3.08	0.743	91.4	3.30	0.741	91.6
C8	126.1	3.58	0.764	105.0	3.86	0.759	105.5
C9	151.3	3.26	0.775	118.8	3.21	0.776	119.7
C10+	>151.3	86.75	0.927	346	85.21	0.913	320
C10	174.6	2.72	0.783	131.4	2.46	0.792	132.0
C11	196.4	2.64	0.796	146.2	2.85	0.793	143.0
C12	216.8	2.55	0.811	159.7	3.15	0.810	156.0
C13	235.9	2.54	0.823	173.4	2.99	0.821	170.0
C14	253.9	2.62	0.832	185.6	2.84	0.831	183.0
C15	271.0	3.19	0.850	198.5	2.77	0.839	195.0
C16	287.3	2.79	0.851	218.5	2.55	0.849	209.0
C17	303.0	2.96	0.853	235.8	2.73	0.852	223.0
C18	317.0	2.56	0.863	249.4	2.71	0.855	239.0
C19	331.0	2.15	0.878	260.2	2.58	0.863	252.0
C20+	>331.0	60.03	0.973	570	57.58	0.957	506
C20	343.8						
C21	356.5						
C22	368.6						
C23	380.2						
C24	391.3						
C25+	>401.9						

Table 5 Stabilised oil properties.

Field		Volve	Volve	Volve
Well		15/9-19A	15/9-19A	15/9-19 SR
Test		DST 2A	DST 2B	DST 1
Formation		Hugin	Hugin	Hugin
Stabilised oil				
Molecular weight [g/mole]		263	256	239
Density [kg/m³]		899	891	879
°API		25.9	27.3	29.5
Water [% by weight]			0.1	0.12
C10+ [% by weight]		87.06	86.8	85.21
C20+ [% by weight]		58.12	60.0	57.58
C10+ aromatics [% by weight]			52.9	51.3
Total wax [% by weight]			17.4	13.0
Purified wax [% by weight]	(a)		4.9	4.0
C5-asphaltenes [% by weight] 1X	(b)	5.4/ 6.4	4.9	2.1
C5-asphaltenes [% by weight] 2X	(b)			
C7-asphaltenes [% by weight]		4.2	1.7	0.65
Resins [% by weight]			13.4	9.4
Sulphur [% by weight]			2.0	1.66
Total acid number [mg KOH/g]			0.07	-
WAT (microscopy) [°C]			32.7	34.0
Wax dissolution temp. [°C]			43	50
Pour point, minimum [°C]	(c)		-30	-34
Pour point, maximum [°C]	(d)		-10	-6
Pour point, "as received" [°C]			-4	-4
Viscosity [mPa·s]	(e)			
80 °C			5.9	3.6
70 °C			7.2	4.2
60 °C			9.1	5.0
50 °C			12.0	6.7
40 °C			16.5	8.5
35 °C @ 100 s^{-1}			21.8	12
30 °C @ 100 s^{-1}			27.2	18
25 °C @ 100 s^{-1}			34.8	36
20 °C @ 100 s^{-1}			45.7	34
10 °C @ 100 s^{-1}			103	81
5 °C @ 100 s^{-1}			188	137

a) Co-precipitated polar material removed by elution through a silica column.
b) 1X: Conventional precipitation with 40X pentane; 2X: 1X- material dissolved in toluene and reprecipitated with 40X pentane.
c) Sample thermally pretreated by heating to 80 °C in gas-tight cell.
d) Re-heated to 50 °C after reaching minimum pour point.
e) 35-5 °C : Same thermal pretreatment as for minimum pour point.

Table C5 :6 Thompson indices (stabilised oils).

Field Well Test Formation Laboratory	**Volve** 15/9-19A DST 2B Hugin Core Lab	 WestLab	**Volve** 15/9-19 Sr DST 1 Hugin Statoil
A	0.658	0.565	0.546
B	0.103	0.797	0.852
X	0.493	0.405	0.386
C	1.81	1.85	1.90
I'	0.683	0.721	0.732
F	1.460	1.480	1.470
H	30.0	30.0	30.1
U	0.612	0.626	0.654
R'	2.82	2.93	2.93
W	1.60	1.42	1.47

Definition of Thompson Indices:

A : benzene / n-hexane
B : toluene / n-heptane
X : m+p xylene / n-octane
C : (n-C6+n-C7) / (Cyc-C6+Me-Cyc-C6)
I' : 3Me-C6 / (1cis3- + 1tr3- + 1tr2-Di-Me-Cyc-C5)
F : n-heptane / Me-Cyc-C6
H : (100*n-C7)/(sumC7-(Me-Cyc-C5+2,4Di-Me-C5+benzene) + Me-CycC6
U : Cyc-C6 / Me-Cyc-C5
R' : n-C7 / 3Me-C6
W : benzene / Cyc-C6

8.4 Appendix D Offshore well reports (Sequence of operations)

FROM: STATOIL LTEK BO BYFORD DOLPHIN **DATE: 01.02.1999**
TIME: 10:31:27

SUBJECT: WELL 15/9-19A, TEST 1
PRELIMINARY WELL TEST REPORT.

Perforated interval: **3952 - 3958 m MD RKB, SLEIPNER FORMATION**

Sequence of events :

Date/time **Event**

Perforation on wireline

17/10
00:00 Started preparing 3-3/8" gun (100 charges, 2*10')
01:30 Started rigging up gun.
02:45 R.I.H.
04:45 Started logging down from 3475m, 0,7m shallow at first pup-joint
05:05 Stopped at shooting depth. Top perforation 3952 m.
05:20 Started pulling out of hole.
08:00 Finished rigging down guns. (continue with BOP test)

RIH with teststring

20:40 RIH RTTS packer, safety joint, jar, bypass, TST valve
21:45 RIH two gaugecarriers, lower: Halliburton-, upper: MWS-gauges

18/10
06:29 Pressure test of bottom hole assembly completed. Started RIH 3 1/2" drill pipe
21:30 RIH with dummy hanger

19/10
01:18 Pick up SSTT on rig floor
23:30 Pick up string 3.5 m. rotate to try to set packer.

20/10
00:27 Started to set packer.

Clean up flow

02:30 Opened choke on 32/64" adj. side
02:39 Started to pressure up annulus to open select tester valve
02:41 Opened select tester valve. WHP pressure increased to approximately 12 Bar.
02:43 Diverted flow through separator, flow through 3" oil meter

03:12 Diverted flow through 2" oil meter
04:09 Diverted flow to tank due to low production rate.
04:25 Tank volume 0.4 m^3
04:40 Tank volume 0.8 m^3
05:10 Tank volume 1.6 m^3

Buildup/bottomhole sampling
05:21 Bleed of annulus pressure to close select tester valve. (downhole valves were closed and open to make sure that none of them were just partly opened- the well had much lower production than expected and it was declining. At a later stage it was discovered that the well was actually shut in at this stage due to a failure in the OMNI valve)
05:25 Started pressuring up annulus to open select tester valve. (OMNI closed due to tool failure)
07:00 Started preparing BHS Samplers for running in hole
07:15 Started connection of tool on drill floor
08:13 Bleed off annulus pressure to close select tester valve. (For the same reason as earlier.)
08:30 Pressure up annulus to open select tester valve. (OMNI closed due to tool failure),
15:45 Tool in lubricator, ready for pressure test
16:45 RIH with BHS and GR/CCL & pressure gauge with surface readout.
18:40 W/L at 3500 m RKB, start correlation. (DST string 3 meter deeper that teoretically)
19:20 Toolstring stopped at 3907 m RKB (bottom of toolstring)
20:05 W/L at 3720 m RKB, ready to open sample tool
20:05 Opened sample valve. No indication of samples opening - troubleshooting.
21:49 Started POOH W/L
22:50 W/L tool in lubricator, waiting for the swells to reduce

21/10
03:30 Started disconnecting the W/L lubricator
06:30 New toolstring in lubricator ready for pressure test
07:00 Started RIH with BHS
08:20 W/L at 3580 m RKB, start correlation
08:40 W/L at 3200 m RKB, ready to open sample tool
08:45 Open sample valve, waiting for samplers to fill
09:30 Close sample valve
09:35 Start POOH W/L
11:17 Close USSLV, commence rig down W/L

Reversing out string content.
12:55 Bleed off annulus, started cycling OMNI to circulation position
13:38 Started to reversing out diesel/water
14:18 Stop pumping
14:19 Close choke manifold. Tank level 7.5 m3 water
14:43 Start to pump 11 m3 sea water down TBG
15:09 Finish pumping
15:12 Started circulating OMNI valve to well test position.
16:28 Pressure up annulus (omni should be in well test position)

Minifrac test
16:44 Pressure up TBG to 350 Bar, no injectivity.
16:47 Bleed down TBG to 210 Bar
16:49 TBG pressure suddenly dropped to 50 Bar??
16:54 Started minifrac
17:09 Stopped pumping. Not able to open a fracture in the formation. Just i small injection rate (total 277 litre).

17:12 Started pumping again, but still just a small injection rate.
17:38 Started bleeding off annulus to prepare to get Select tester valve into locked open position
17:54 Pressure up annulus (omni in pos 4, Select Tester valve in locked open position)
18:01 Started a new attempt for a minifrac test, but not injectivity.
18:05 Bleed down TBG to 100 bar. Started preparing to kill the well

POOH
22/10
09:15 Started to POOH
23:05 OOH with test string

Preliminary well test data :

DATE	TIME	WHP kPa	WHT DEGC
971020	02:43	962	8.8
	02:44	1048	8.7
	02:46	954	11.2
	02:48	992	10.9
	02:50	902	10.9
	02:52	815	11.0
	02:54	749	10.9
	02:58	599	11.5
	03:00	548	11.7
	03:02	507	11.8
	03:10	398	12.4
	03:20	294	12.7
	03:30	206	12.7
	03:40	150	12.8
	03:50	133	12.8
	04:00	101	12.7

WHP just readinig 101 kPa in the flow period after this stage.

Cumutative production during the test was approximately 7.4 m^3.

Sampling

Sample no	Sample type	Shipping Pressure	Bottle type	Bottle no	Samplins start		Sampling point	Comments
1	Water		1 ltr. Plastic	n/a	21.10.97	13:47	Choke manifold	
2	Water		1 ltr. Plastic	n/a	21.10.97	13:48	Choke manifold	Contains 1ml HNO3
3	Water		1 ltr. Plastic	n/a	21.10.97	13:50	Choke manifold	
4	Water		1 ltr. Plastic	n/a	21.10.97	13:50	Choke manifold	Contains 1ml HNO3
5	Water		1 ltr. Plastic	n/a	21.10.97	13:51	Choke manifold	
6	Water		1 ltr. Plastic	n/a	21.10.97	13:52	Choke manifold	
7	Water		1 ltr. Plastic	n/a	21.10.97	13:53	Choke manifold	Contains 1ml HNO3
8	Water		1 ltr. Plastic	n/a	21.10.97	13:54	Choke manifold	
9	Water		1 ltr. glass	n/a	21.10.97	13:55	Choke manifold	Contains 1ml HCl
10	Water		1 ltr. glass	n/a	21.10.97	13:56	Choke manifold	Contains 1ml HCl
11	Water		250ml glass	n/a	21.10.97	13,57	Choke manifold	Contains HgCl2
12	Water		1 ltr. Plastic	n/a	21.10.97	13:57	Choke manifold	
13	Water		1 ltr. Plastic	n/a	21.10.97	13:59	Choke manifold	Contains 1ml HNO3
14	Water		1 ltr. Plastic	n/a	21.10.97	14:00	Choke manifold	Contains 1ml HNO3
15	Water		1 ltr. Plastic	n/a	21.10.97	14:01	Choke manifold	
16	Water		1 ltr. Plastic	n/a	21.10.97	14:01	Choke manifold	
17	Water		1 ltr. Plastic	n/a	21.10.97	14:02	Choke manifold	
18	Water		1 ltr. Plastic	n/a	21.10.97	14:03	Choke manifold	
19	Water		1 ltr. Plastic	n/a	21.10.97	14:04	Choke manifold	
20	Water		1 ltr. Plastic	n/a	21.10.97	14:05	Choke manifold	
21	Water		1 ltr. Plastic	n/a	21.10.97	14:06	Choke manifold	
22	Water		1 ltr. Plastic	n/a	21.10.97	14:06	Choke manifold	
23	Water		1 ltr. Plastic	n/a	21.10.97	14:07	Choke manifold	
24	Water		1 ltr. Plastic	n/a	21.10.97	14:08	Choke manifold	
25	Water		1 ltr. Plastic	n/a	21.10.97	14:08	Choke manifold	
26	Water		1 ltr. Plastic	n/a	21.10.97	14:09	Choke manifold	
27	Water		1 ltr. Plastic	n/a	21.10.97	14:10	Choke manifold	
28	Water		1 ltr. Plastic	n/a	21.10.97	14:11	Choke manifold	Contains 1ml HCl
29	Water		1 ltr. Plastic	n/a	21.10.97	14:12	Choke manifold	Contains 1ml HCl
30	Water		1 ltr. Plastic	n/a	21.10.97	14:13	Choke manifold	
31	Water		1 ltr. Plastic	n/a	21.10.97	14:14	Choke manifold	
32	Water		1 ltr. Plastic	n/a	21.10.97	14:15	Choke manifold	
33	Water		1 ltr. Plastic	n/a	21.10.97	14:17	Choke manifold	
34	Water		1 ltr. Plastic	n/a	21.10.97	14:18	Choke manifold	Mud at surface
35	Water	400 Bar	BHS 072	n/a	21.10.97	08:45	3214.41 MD	
36	Water	400 Bar	BHS 072	n/a	21.10.97	08:45	3218.30 MD	

37	Water	400 Bar	BHS 072	n/a	21.10.97	08:45	3222.18 MD	
38	Water		1 ltr. Plastic	n/a	21.10.97	08:45	3210.52 MD	From BHS 071

Offshore analysis

Tritum analyse

Tritium was added to the formation prior to drilling into the reservoir. The consentration in the water phase of the mud was measured to 86 kBq/litre.

Bottom hole sample 0071

Measurement no	Consertration CPMA	Consentration kBq/litre	Pollution %	Average pollution %
1	910	15,25	18	13
2	663	9,1	11	
3	653	8,8	10	

Bottle no 34

Measurement no	Consertration CPMA	Consentration kBq/litre	Pollution %	Average pollution %
1	916	15,4	17	11.3
2	840	13,5	16	
3	751	11,3	13	
4	667	9	10,6	
5	620	8	9,3	

* Bottle no 34 represent last sampled water from reversing out the string content.

Water analysis from MWS

Date	Time	Samplin point	Measured Density		ph		Conductivity		Total Alkalin.	Ba& Sr	Sulph ate	Chlor.
			g/cm³	°C	ph	°C	mS/cm	°C	mg/l HCO_3	mg/l	mg/l	mg/l
21.10.97	13:50	3210.52 m MD RKB	1,104	18	8,65	17,7	165,3	18,2	121,93	5	69	96 000
21.10.97	13:50	Down Stream Choke	1,098	19,6	9,67	16,6	144,2	17,2	243,85	9	164	87 000
21.10.97	13:57	Down Stream Choke	1,101	17,2	9,34	16,4	163,7	16,3	182,89	5	112	93 000
21.10.97	14:07	Down Stream Choke	1,104	20,5	8,15	21,3	162,6	20,3	121,93	3	86	94 000
21.10.97	14:17	Down Stream Choke	1,105	19,9	8,16	19,4	163,7	19,9	91,44	2	82	96 000

Analysis of gas:

Gas analysis from bottoms up in connection with killing the well:

Total gas 8.4% C1: 72450 ppm, C2: 2440 ppm,C3: 52 ppm, C4: 4 ppm, iC4: 8 ppm, nC4: 8 ppm, C5: 0 ppm

Well 15/9-19, DST # 1 Downhole gauges

Gauge Type	Sensor depth (MD/TVD)	Delay hh	Mode	Started ddmmyy hhmm	Ended ddmmyy hhmm
MQGX #274 MWS	3928.9 31347	24	24 hrs delay. 2 sec. 224 hrs.	17.10.97 19:45	Lasted througout the test
MQGX #331 MWS	3928.9 3134.7	24	24 hrs delay. 2 sec. 142 hrs.	17.10.97 20:03	Lasted througout the test
MQGX #453 MWS	3928.9 3134.7	24	24 hrs delay. 2 sec. . delta pressure 1 psi/10 sec	17.10.97 19:53	Lasted througout the test
MQGX #454 MWS	3928.9 3134.7	24	24 hrs delay. 2 sec. . delta pressure 1 psi/10 sec	17.10.97 19:58	Lasted througout the test
HMR #10816 Hallib.	3931.4 3137.3	24	24 delay. 4 sec	17.10.97 18:55	Lasted througout the test
HMR #10817 Hallib.	3931.4 3137.3	24	24 delay. 24 hrs 4 sec. delta pressure 0.5 psi/2 min rest 2 sec	17.10.97 18:55	Lasted througout the test

Sensor point 0.74 m above bottom carrier (MWS)
Sensor point 0.49 m above bottom carrier (MWS)

REGARDS,

LTEK BO / BYFORD DOLPHIN

Terje Mogster

SUBJECT: WELL 15/9-19A, PRELIMINARY WELL TEST REPORT.

TEST # 2A & 2B

Perforated interval: **3885.5 - 3888.5 m MD RKB, HUGIN FORMATION**

3826 - 3865 m MD RKB, HUGIN FORMATION

Date/time **Event**

Perforation on wireline

24/10
10:45 Started rig up 3-3/8" guns
14:20 Fired guns, good indications. POOH.
16:00 Rigged down.

RIH with teststring

18:00 Start RIH teststring.
20:30 Pick up packer assembly
22:28 RIH select tester valve
25/10
02:07 Start pressure test BHA to 345 bar.
02:20 Test ok.
26/10
20:30 Run last joint of 5 1/2" tubing, change 40 bails.
21:00 Pick up STT
27/10
01:00 Land string in wear bushing
01:55 Test entire string against LPR-N
02:15 Good test close lower master valve
04:41 Set packer
06:35 Start pressure up annulus to open select tester valve
06:35 Initial tank level = 0.8 m3
06:35 Line up to tank. Heater and separator bypassed
06:41 Select tester valve open. Well open against choke

Clean up flow

06:51 Open choke on 14/64" adj (5.556 mm). Flow to tank
06:55 Tank level = 1.0 m3

06:55 Increase choke to 28/64" adj. (11.112 mm)
07:00 Increase choke to 32/64" adj. (12.700 mm)
07:00 Tank level = 1.5 m3
07:15 Tank level = 2.4 m3
07:30 Tank level = 3.6 m3
07:45 Tank level = 6.0 m3
08:00 Tank level = 7.8 m3
09:08 Gas to surface
09:15 Mud to surface
09:45 H_2S = 0 ppm, CO_2 = 2.0 %
10:00 Increase choke to 38/64" adj. (15.081 mm)
11:15 Oil density = 0.890 at 19.3 deg. C
12:38 Increase choke to 58/64" adj. (23.019 mm)
12:55 Decrease choke to 53/64" adj. (21.034 mm)
13:10 H_2S = 0.5 ppm, CO_2 = 4.0 %
13:12 Choke back to 40/64" adj. (15.875 mm)
13:54 Switch to 38/64" fixed choke (15.081 mm)
15:06 Meter factor: Manual=0.956325, Data=0.961441
20:00 BSW = Trace of solids
22:34 Bleed of annulus to close select tester valve

Buildup

22:35 Close well at Select tester valve
22:39 Close choke manifold, start Clean up Buidup
28/10
00:50 Close lower subsea lubricator
01:57 Start rig W/L
04:10 Finish rig W/L

Bottomhole sampling

13:15 Pre-test meeting for BHS flow
14:47 Open well on 28/64" adj. choke. (11.112 mm)
15:00 Increase choke to 38/64" adj. (15.081 mm)
15:30 Oil gravity = 0.897 at 17 deg. C
16:45 Shut in well at choke manifold
17:00 Start rig up BHS/PLT string
19:35 Start RIH with wireline
19:55 Line up to Petrotec Sep.
20:10 Open Well, start BHS flow through Petrotec sep. Flow to tank
20:12 Continue RIH W/L
20:38 W/L at 3765 m depth
21:59 Shut in well at choke manifold
22:30 Start POOH W/L
29/10
01:23 Toolstring out of hole. All 4 samplers ok.

Minifrac test

05:04 Start pumping. (injection rate 50 l/min.)
06:56 Stop pumping

08:48 Start pumping (injection rate 2 - 4 l/min)
09:29 Stop pumping. Cansel minifrac.

Perforate for test 2B

11:10 Install drop bar into W/L lubricator
13:15 RIH with drop bar for perforating
15:07 Activate TCP guns
15:13 Guns fired. Perforated interval: 3865 m - 3826 m, pooh.
20:00 Wireline equipment rigged down.

Cleanup / Main flow test 2B

20:51 Open well on 20/46" adj. (7.937)
20:54 Increase to 32/64" adj. choke (12.700 mm)
20:55 Oil to surface
21:21 Increase to 38/64" adj. choke (15.081 mm)
21:21 BSW = Trace of sediment
21:28 Decrease to 14/64" adj. (5.556)
21:32 Increase to 28/64" adj. choke (11.112 mm)
21:35 Increase to 32/64" adj. choke (12.700 mm)
22:50 Increase to 40/64" adj. choke (15.875 mm)
22:59 Increase to 48/64" adj. choke (19.050 mm)

31.10
00:07 Decrease to 44/64" fix. choke (18.256 mm)
00:11 Switch to 48/64" adj. choke (19.050 mm)
00:20 Decrease to 40/64" fix. choke (15.875 mm)
00:51 Decrease to 36/64" adj. choke (14.287 mm)
00:58 Decrease to 34/64" fix. choke (13.494 mm)
01:51 Lower 1.500" orifice plate
02:07 Meter factor: Manual=0.0.9777, Data=0.9756
02:30 Start flow throug Petrotec Sep. (MTU)
03:15 Increase pressure in separator to 46 bar, due to carryover in gas line
05:28 Finish testprogram for MTU
06:39 Start PVT set no.3
07:10 Finish PVT set no.3
07:35 Start PVT set no.4
08:06 Finish PVT set no.4
08:18 Start PVT set no.5
08:49 Finish PVT set no.5
09:02 Start PVT set no.6
09:31 Finish PVT set no.6
10:00 Start isokinetic sampling
11:37 Finish isokinetic sampling

Main build up test 2B

14:32 Close select tester valve
14:36 Close choke
14:50 Close flow wing valve
14:56 Bleed down to zero at choke

Mini frac test 2B

02.11
08:31 Open flow wing valve
Bleed off pressure in test string , fill up with water and pressure up to 100 bar.
09:20 Pressure up annulus to 200 bar and lock open the tester valve. Pressure on well head dropped to 76 bars. (Indications of tester valve ok)
09:26 Start displacing water down to perforations
Pumping 500 -600 l/min at approx. 230 bar.
09:48 Stop pumping, 15 m3 water pumped. Prepare for minifrac.
10:03 Start pumping 1'st minifrac cycle with water.
Pumprate : 600 l/min , Pressure 345 bar
10:07 Water at perforations.
Pumprate : 150 l/min , Pressure 345 bar.
10:15 Fracturing formation, Pumprate increasing
10:20 Pumprate : 920 l/min , pressure at 340 bar.
10:23 One pump fails, rate: 600 l/min , Pressure 300 bar.
10:26 Shut down pump for fall off.
Based on **surface data**, fracture closure pressure is approx. 560 bar / 1.88 g/cm^3 at 3045 m TVD at top perforations.
10:51 Start pumping 2'nd minifrac cycle, pumping 1.47 mud at surface, water into formation.
Pumprate : 1000 l/min , Pressure 340 bar
11:07 Shut down pumps for fall off, 14.5 m^3 mud pumped.
11:36 Finish minifrac. Start bullheading 1.5 m3 mud down to perforations.
12:13 Start flushing surface lines.
12:50 Pressure up annulus and shear APR-RD valve. Release RTTS packer and continue the killing program.
18:00 Start pooh with the test string.
03.11
20:00 Test string out of hole, (5 of 6 gauges ok, one stopped after test 2A)

END OF TEST

8.5 Appendix E Reservoir fluid sampling summary

Surface Sampling Test 2A & 2B

Flow Period	Sample type	Bottle no.		Sampling time	
		Gas	Oil	ddmmyy	hhmm
2A Clean-up	PVT set no. 1	50267/50358	20605	271097	1848-1910
2A Clean-up	PVT set no. 2	50281/50292	20672	271097	2003-2031
2A Clean-up	Oil, 20 l gas bottle		50458	271097	2054-2106
2A Clean-up	Oil, 20 l gas bottle		50335	271097	2115-2130
2A Clean-up	Oil, 20 l gas bottle		50353	271097	2136-2155
2A Clean-up	Oil, 20 l gas bottle		50347	271097	2158-2208
2A Clean-up	Geochemical	150--018		271097	2210-2211
2A Clean-up	Bottom hole sample		OC-074	281097	3757,5 m
2A Clean-up	Bottom hole sample		OC-070	281097	3764,4 m
2A Clean-up	Bottom hole sample		OC-076	281097	3765,0 m
2A Clean-up	Bottom hole sample		OC-073	281097	3769,2 m
2B CU/Main flow	PVT set no. 1(3),Hall	50269	20622	301097	1516-1543
2B CU/Main flow	PVT set no. 2(4),MTU	50302	20175	301097	1643-1712
2B CU/Main flow	PVT set no. 3(5),Hall	50208	20316	311097	0639-0707
2B CU/Main flow	PVT set no. 4(6),Hall	50247	20601	311097	0735-0756
2B CU/Main flow	PVT set no. 5(7),Hall	50261	20680	311097	0818-0849
2B CU/Main flow	PVT set no. 6(8),Hall	50249	20273	311097	0902-0924
2B CU/Main flow	Geochemical	150--020		311097	0345
2B CU/Main flow	Geochemical	150--019		311097	0348
2B CU/Main flow	Isokin, 20 l gas bottle	50250		311097	1000-1137
2B CU/Main flow	Oil, 20 l gas bottle		50154	311097	1205-1235
2B CU/Main flow	Oil, 20 l gas bottle		50262	311097	1241--1251
2B CU/Main flow	Oil, 20 l gas bottle		50273	311097	1255--1305
2B CU/Main flow	Oil, 20 l gas bottle		50350	311097	1308--1319
2B CU/Main flow	Oil, 20 l gas bottle		50042	311097	1321--1331
2B CU/Main flow	Oil, 20 l gas bottle		55015*	311097	1335--1340

* marked O&S

Stabilised samples:

6 x 1 l pb
6 x 10 l pc
6 x 18 l pc
1 x 18 l pc marked for Esso
3 x 20 l Jerry can marked for O&S / SFTK
6 x 200 l Drums

8.6 Appendix F Down hole pressure & temperature recorders

Well 15/9-19A, TEST 2A & 2B Downhole gauges

Gauge Type	Sensor depth (MD/TVD)	Delay hh	Mode	Started ddmmyy hhmm	Ended ddmmyy hhmm
MQGX #274 MWS	3787.4 3007.5	40	40 hrs , sample rate 15 min 11 d 10 hrs , sample rate 5 sec.	24.10.97 15:05	Througout the test
MQGX #331 MWS	3787.4 3007.5	40	40 hrs , sample rate 15 min 21 d 5 hrs , sample rate 10 sec.	24.10.97 15:12	Througout the test
MQGX #453 MWS	3787.4 3007.5	40	40 hrs , sample rate 15 min **dP mode** min. 4 d 22 hrs , sample rate 2 sec. Press change <1 psi => 10 sec rate	24.10.97 15:18	Througout the test
MQGX #454 MWS	3787.4 3007.5	40	40 hrs , sample rate 15 min **dP mode** min. 11d 10 hrs , sample rate 5 sec. Press change <1 psi => 10 sec rate	24.10.97 15:24	Througout the test
HMR #10816 Hallib.	3790.2 3010.0	40	40 hrs , sample rate 10 min 14 d , sample rate 10 sec	24.10.97 15:52	Througout the test
HMR #10817 Hallib.	3790.2 3010.0	40	40 hrs , sample rate 10 min 6 d , sample rate 4 sec	24.10.97 15:52	29.10.97 08:19:2

Sensor point 1.01 m above bottom carrier (MWS)
Sensor point 0.49 m above bottom carrier (Halliburton)

8.7 Appendix G Well completion , test string

TEST 1

DESCRIPTION	SUPPLIER	ID(min)	OD	LENGTH	DEPTH	Capacity	epth to nos
		inch	inch	meter	mRKB	m3	mRKB
					-7.09		
FLOWHEAD WITH SWIVEL	HALLIBURTON	3.00			-7.09		3943.97
CROSSOVER 6 1/2-4SA X 5" CS	HALLIBURTON	3.00	8.30	0.68	-6.41	0.003	3943.97
1 JOINT 5" TUBING CS AC95	INDEPENDENT	4.28	5.00	9.50	3.09	0.091	3943.29
1 JOINT 5" TUBING CS AC95 (NR. 1)	INDEPENDENT	4.28	5.00	*9.50*	12.59	0.179	3933.79
1 JOINT 5" TUBING CS AC95	INDEPENDENT	4.28	5.00	9.53	22.12	0.267	3924.29
CROSSOVER 5" CS x 4 1/2-4 SA	HALLIBURTON	3.00	6.40	0.61	22.73	0.270	3914.76
LUBRICATOR VALVE	HALLIBURTON	3.00	8.20	2.62	25.35	0.282	3914.15
CROSSOVER 4 1/2-4 SA x 5 CS	HALLIBURTON	3.00	6.40	0.54	25.89	0.285	3911.53
1 JOINT 5" TUBING CS AC95	INDEPENDENT	4.28	5.00	9.51	35.40	0.373	3910.99
CROSSOVER 5" CS x 4 1/2-4 SA	HALLIBURTON	3.00	6.40	0.55	35.95	0.375	3901.48
LUBRICATOR VALVE	HALLIBURTON	3.00	8.20	2.62	38.57	0.387	3900.93
CROSSOVER 4 1/2-4 SA x 5 CS	HALLIBURTON	3.00	6.40	0.61	39.18	0.390	3898.31
2 PUP JOINTS 5" CS (NR 2 og NR 4 ; 6,06 + 4,43)	INDEPENDENT	4.28	5.00	10.49	49.67	0.487	3897.70
5 JOINTS 5" CS (NR. 2-6)(9,49+9,52+9,5+9,47+9,52)	INDEPENDENT	4.28	5.00	*47.50*	97.17	0.927	3887.21
PUP JOINT 5" CS	INDEPENDENT	4.28	5.00	2.99	100.16	0.955	3839.71
CROSSOVER 5" CS x 4 1/2-4 SA	HALLIBURTON	3.00	6.40	0.61	100.77	0.958	3836.72
SHERABLE SUB	HALLIBURTON	3.00	5.00	1.53	102.30	0.965	3836.11
SUB SEA	HALLIBURTON	3.00	13.00	1.72	104.02	0.973	3834.58
SLICK JOINT	HALLIBURTON	3.00	5.00	1.82	105.84	0.981	3832.86
ADJUSTABLE FLUTED HANGER JOINT (ABOVE)	HALLIBURTON	3.00	5.50	0.85	106.69	0.985	3831.04
FLUTED HANGER	HALLIBURTON	3.00	15.25	0.37	107.06	0.986	3830.19
ADJUSTABLE FLUTED HANGER JOINT (BELOW)	HALLIBURTON	3.00	5.50	0.74	107.80	0.990	3829.82
CROSSOVER 4 1/2-4 SA x 3 1/2" IF	HALLIBURTON	2.25	6.80	1.02	108.82	0.992	3829.08
370 JOINTS 3 1/2" DP	DOLPHIN	2.50	3.50	3590.18	3699.00	12.362	3828.06
SLIP JOINT (OPEN)	HALLIBURTON	2.25	5.03	7.56	3706.56	12.382	237.88
SLIP JOINT (OPEN)	HALLIBURTON	2.25	5.03	7.55	3714.11	12.401	230.32
SLIP JOINT (CLOSED) (STROKE 1.52 m)	HALLIBURTON	2.25	5.03	6.01	3720.12	12.416	222.77
SLIP JOINT (CLOSED) (STROKE 1.52 m)	HALLIBURTON	2.25	5.03	6.03	3726.15	12.432	216.76
RADIOACTIVE MARKER SUB (0,20 m FROM BASE)	HALLIBURTON	2.50	4.65	0.41	3726.56	12.433	210.73
5 STANDS 4 3/4" DRILL COLLAR	HALLIBURTON	2.25	4.75	142.95	3869.51	12.800	210.32
CROSSOVER	HALLIBURTON	2.25	4.75	0.19	3869.70	12.800	67.37
RADIOACTIVE MARKER SUB (0,10 m FROM BASE)	HALLIBURTON	2.25	5.00	0.30	3870.00	12.801	67.48
APR-RD CIRCULATING VALVE w/crossover below	HALLIBURTON	2.28	5.03	1.29	3871.29	12.804	67.18
1 STAND 4 3/4" DRILL COLLAR	HALLIBURTON	2.25	4.75	28.26	3899.55	12.876	65.89
CROSSOVER	HALLIBURTON	2.25	4.75	0.20	3899.75	12.877	37.63
OMNI CIRCULATING VALVE (110 bar operating pressure)	HALLIBURTON	2.28	5.03	6.52	3906.27	12.894	37.43
DRAIN VALVE	HALLIBURTON	2.28	5.03	1.05	3907.32	12.897	30.91
CROSSOVER	HALLIBURTON	2.25	4.75	0.20	3907.52	12.897	29.86
1 JOINT 4 3/4" DRILL COLLAR	HALLIBURTON	2.25	4.75	9.30	3916.82	12.921	29.66
CROSSOVER	HALLIBURTON	2.25	4.75	0.19	3917.01	12.922	20.36
LPR-N TESTER VALVE (90 bar operating pressure)	HALLIBURTON	2.25	5.03	7.27	3924.28	12.940	20.17
GAUGE CARRIER	MWS	2.25	5.50	2.35	3926.63	12.946	12.90
GAUGE CARRIER	HALLIBURTON	2.25	5.50	2.35	3928.98	12.952	10.55
TST (PIPE TEST VALVE) w/crossover below	HALLIBURTON	2.25	5.03	1.43	3930.41	12.956	8.20
HYDRAULIC BYPASS/CIRCULATION VALVE	HALLIBURTON	2.25	4.68	2.12	3932.53	12.961	6.77
CROSSOVER	HALLIBURTON	2.25	4.75	0.18	3932.71	12.962	4.65
BIG JOHN JAR (STROKE 0.25 m)w/crossover below	HALLIBURTON	2.25	4.75	2.04	3934.75	12.967	4.47
RTTS SAFETY JOINT (STROKE 0.15m)	HALLIBURTON	2.44	5.00	0.96	3935.71	12.970	2.43
7" RTTS PACKER	HALLIBURTON	2.40	5.65	1.33	3937.04	12.974	1.47
2 7/8" EUE Collar	HALLIBURTON	2.75	3.67	0.14	3937.18	12.974	0.14

TEST 2A&2B

DESCRIPTION	SUPPLIER	ID(mm) inch	OD inch	LENGTH meter	DEPTH mRKB	Capacity m3	Depth to nose mRKB
FLOWHEAD WITH SWIVEL	HALLIBURTON	3.00			-7.10		3872.32
CROSSOVER 6 1/2-4SA X 5" CS	HALLIBURTON	3.00	8.30	0.68	-6.42	0.003	3872.32
1 JOINT 5" TUBING CS AC95	INDEPENDENT	4.28	5.00	9.50	3.08	0.091	3871.64
1 JOINT 5" TUBING CS AC95 (NR.1)	INDEPENDENT	4.28	5.00	*9.50*	12.58	0.179	3862.14
1 JOINT 5" TUBING CS AC95	INDEPENDENT	4.28	5.00	9.53	22.11	0.267	3852.64
CROSSOVER 5" CS x 4 1/2-4 SA	HALLIBURTON	3.00	6.40	0.61	22.72	0.270	3843.11
LUBRICATOR VALVE	HALLIBURTON	3.00	8.20	2.62	25.34	0.282	3842.50
CROSSOVER 4 1/2-4 SA x 5" CS	HALLIBURTON	3.00	6.40	0.54	25.88	0.285	3839.88
1 JOINT 5" TUBING CS AC95	INDEPENDENT	4.28	5.00	9.52	35.40	0.373	3839.34
CROSSOVER 5" CS x 4 1/2-4 SA	HALLIBURTON	3.00	6.40	0.55	35.95	0.375	3829.82
LUBRICATOR VALVE	HALLIBURTON	3.00	8.20	2.62	38.57	0.387	3829.27
CROSSOVER 4 1/2-4 SA x 5" CS	HALLIBURTON	3.00	6.40	0.61	39.18	0.390	3826.65
2 PUP JOINTS 5" CS (NR.2 and NR.4 ; 6.06 + 4,43)	INDEPENDENT	4.28	5.00	10.49	49.67	0.487	3826.04
5 JOINT 5" CS (NR.2-6) (9,49+9,52+9,5+9,47+9,52)	INDEPENDENT	4.28	5.00	*47.50*	97.17	0.927	3815.55
PUP JOINT 5" CS	INDEPENDENT	4.28	5.00	2.99	100.16	0.955	3768.05
CROSSOVER 5" CS x 4 1/2-4 SA	HALLIBURTON	3.00	6.40	0.61	100.77	0.958	3765.06
SHEARABLE SUB	HALLIBURTON	3.00	5.00	1.53	102.30	0.965	3764.45
SUB SEA	HALLIBURTON	3.00	13.00	1.72	104.02	0.973	3762.92
SLICK JOINT	HALLIBURTON	3.00	5.00	1.82	105.84	0.981	3761.20
ADJUSTABLE FLUTED HANGER JOINT (ABOVE)	HALLIBURTON	3.00	5.50	0.85	106.69	0.985	3759.38
FLUTED HANGER	HALLIBURTON	3.00	15.25	0.37	107.06	0.986	3758.53
ADJUSTABLE FLUTED HANGER JOINT (BELOW)	HALLIBURTON	3.00	5.50	0.74	107.80	0.990	3758.16
CROSSOVER 4 1/2-4 SA x 3 1/2" PH-6	INDEPENDENT	2.75	5.50	0.61	108.41	0.992	3757.42
CORRECTION FACTOR (THEORETICAL ERROR)				*0.61*		0.992	3756.81
2 PUP JOINTS 3 1/2" PH-6 TUBING (3.49+2.42)	INDEPENDENT	2.75	3.50	*5.91*	114.93	1.015	3756.21
358 JOINTS 3 1/2" PH-6 TUBING (410-53)	INDEPENDENT	2.75	3.50	*3445.39*	3560.32	14.217	3750.30
CROSSOVER 3 1/2" PH-6 x 3 1/2" IF	HALLIBURTON	2.25	4.75	0.41	3560.73	14.219	304.91
SLIP JOINT (OPEN)	HALLIBURTON	2.25	5.00	7.56	3568.29	14.238	304.50
SLIP JOINT (OPEN)	HALLIBURTON	2.25	5.00	7.55	3575.84	14.257	296.94
SLIP JOINT (CLOSED) (STROKE 1.52 m)	HALLIBURTON	2.25	5.00	6.02	3581.86	14.273	289.39
SLIP JOINT (CLOSED) (STROKE 1.52 m)	HALLIBURTON	2.25	5.00	6.04	3587.90	14.288	283.37
RADIOACTIVE MARKER SUB (0,20 m FROM BASE)	HALLIBURTON	2.50	4.65	0.41	3588.31	14.290	277.33
5 STAND 4 3/4" DRILL COLLAR	HALLIBURTON	2.25	4.75	142.95	3731.26	14.656	276.92
CROSSOVER	HALLIBURTON	2.25	4.75	0.19	3731.45	14.657	133.97
RADIOACTIVE MARKER SUB (0,10 m FROM BASE)	HALLIBURTON	2.50	4.65	0.30	3731.75	14.658	133.78
APR-RD CIRCULATING VALVE w/crossover below (260-270 bar)	HALLIBURTON	2.28	5.03	1.30	3733.05	14.661	133.48
1 STAND 4 3/4" DRILL COLLAR	HALLIBURTON	2.25	4.75	28.26	3761.31	14.734	132.18
CROSSOVER	HALLIBURTON	2.25	4.75	0.19	3761.50	14.734	103.92
OMNI CIRCULATING VALVE (100 bar operating pressure)	HALLIBURTON	2.28	5.03	6.53	3768.03	14.751	103.73
DRAIN VALVE	HALLIBURTON	2.28	5.03	1.03	3769.06	14.754	97.20
CROSSOVER	HALLIBURTON	2.25	4.75	0.20	3769.26	14.755	96.17
1 JOINT 4 3/4" DRILL COLLAR	HALLIBURTON	2.25	4.75	9.30	3778.56	14.778	95.97
CROSSOVER	HALLIBURTON	2.25	4.75	0.20	3778.76	14.779	86.67
SELECT TESTER VALVE (100 bar operation, 180 bar lock)	HALLIBURTON	2.25	5.03	7.27	3786.03	14.798	86.47
GAUGE CARRIER	MWS	2.25	5.50	2.35	3788.38	14.804	79.20
GAUGE CARRIER	HALLIBURTON	2.25	5.50	2.35	3790.73	14.810	76.85
TST (PIPE TEST VALVE) (lock open at surface)	HALLIBURTON	2.25	5.03	1.22	3791.95	14.813	74.50
					3791.95	14.813	73.28
HYDRAULIC BYPASS/CIRCULATION VALVE	HALLIBURTON	2.25	4.68	2.37	3794.32	14.819	73.28
BIG JOHN JAR (STROKE 0.25 m) w/crossover below	HALLIBURTON	2.25	4.75	2.13	3796.45	14.824	70.91
RTTS SAFETY JOINT (STROKE 0.15m)	HALLIBURTON	2.44	5.00	0.95	3797.40	14.827	68.78
7" RTTS PACKER	HALLIBURTON	2.40	5.65	1.33	3798.73	14.831	67.83
CROSSOVER	HALLIBURTON	2.25	5.00	0.40	3799.13	14.832	66.50
BELOW PACKER SAFETY JOINT	HALLIBURTON	2.25	5.00	3.05	3802.18	14.840	66.10
CROSSOVER	HALLIBURTON	2.25	5.00	0.24	3802.42		63.05
2 7/8" MTR (MECHANICAL TUBING RELEASE)	HALLIBURTON	1.88	3.40	0.51	3802.93		62.81
2 x 2 7/8" PERFORATED PUP JOINTS	HALLIBURTON	2.44	3.11	6.24	3809.17		62.30
2 7/8" BALANCED ISOLATION TOOL	HALLIBURTON	2.44	3.38	0.68	3809.85		56.06
2 7/8" EUE TUBING (4 PUPS)	HALLIBURTON	2.44	3.67	12.36	3822.21		55.38
CROSSOVER	HALLIBURTON	2.00	3.50	0.13	3822.33		43.02
MODEL II MECHANICAL FIRING HEAD WITH SAFETY SUB	HALLIBURTON	1.56	3.38	1.54	3823.87		42.89
EDA (EXTENDED DELAY ADAPTER)	HALLIBURTON	N/A	3.38	0.34	3824.20		41.36
DID (DETONATION INTERRUPT DEVICE)	HALLIBURTON	N/A	3.38	0.27	3824.47		41.02
					3824.47		40.75
SAFETY SPACER (BLANK 4 5/8" GUN)	HALLIBURTON	N/A	4.63	1.52	3825.99		40.75
4 5/8" TCP GUNS	HALLIBURTON	N/A	4.63	39.01	3865.00		39.23
BULLPLUG + Blank Gun	HALLIBURTON	N/A	4.63	0.22	3865.22		0.22

8.8 Appendix H Time distribution during test

Updated Final version

Current Time

PLANNED VERSUS ACTUAL TIME

Well 15/9-19A, Byford Dolphin

TEST 1and 2A&2B

Start date 18.10.97
Start time 06:00

Date	Time	Hrs	Lost Time	Status	Activity	Act. cum Lost time	Plan Hrs	Plan Days	Act. Days
						0,0	0	0,0	0,0
18.10.97	06:00	8,0	2,0	U	Reperforate water zone (6.0 m)	0,1	6	0,3	0,3
18.10.97	14:00	6,0	0,0	U	BOP test	0,1	6	0,5	0,6
18.10.97	20:00	90,0	18,0	U	RIH test string, Perform water test, POOH	0,8	72	3,5	4,3
22.10.97	14:00	44,8	8,8	U	Run EZSV on DP and squeeze cement, cond mud and poo	1,2	36	5,0	6,2
24.10.97	10:45	7,3	(0,8)	U	Perforate for test 2A, Atlas 3.0 m	1,2	8	5,3	6,5
24.10.97	18:00	61,0	13,0	U	Run in hole test string	1,7	48	7,3	9,0
27.10.97	07:00	31,5	9,5	U	Cleanup flow and buildup	2,1	22	8,3	10,4
28.10.97	14:30	14,5	(1,5)	U	Conditioning and BHS flow	2,1	16	8,9	11,0
29.10.97	05:00	0,0	(10,0)	U	Sandstrength	2,1	10	9,3	11,0
29.10.97	05:00	6,0	0,0	U	Minifrac	2,1	6	9,6	11,2
29.10.97	11:00	10,0	6,0	U	Perforation of zone 2B	2,4	4	9,8	11,6
29.10.97	21:00	41,5	9,5	U	Main flow	2,8	32	11,1	13,4
31.10.97	14:30	42,0	10,0	U	Main build up	3,2	32	12,4	15,1
02.11.97	08:30	3,5	3,5	U	Minifrac	3,3	0	12,4	15,3
02.11.97	12:00	32,0	14,0	U	POOH	3,9	18	13,2	16,6
03.11.97	20:00	0,0	0,0	U	End of Test	3,9	0	13,2	16,6
Total		398	82,0			4	316	13	17

BLACK : Originally planned operations
GREEN: Not planned operations
RED: Originally planned but not performed operations

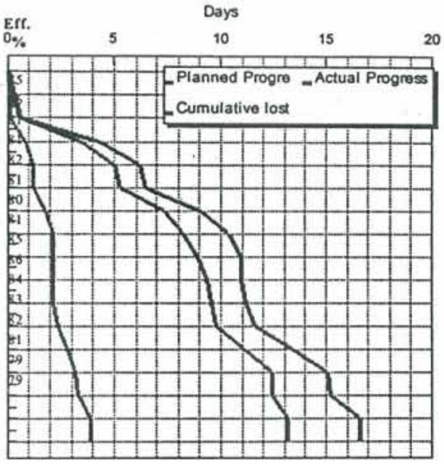


Fig 3.6 Planned vs. Actual Time

Updated Final version
Current Time

PLANNED VERSUS ACTUAL TIME

Well 15/9-19A, Byford Dolphin

Start date 30.08.97
Start time 02:00

TEST 1 and 2A&B

Date	Time	Hrs	Diff Time	Status	Activity	Act. cum More time	Plan Hrs	Plan Days	Act. Days
30.08.97	02:00	23,0	7,0	U	Wipertrip before running 7" liner	0,3	16	0,7	1,0
31.08.97	01:00	51,5	5,5	U	Run and set 7" liner, cement same	0,5	46	2,6	3,1
02.09.97	04:30	19,0	7,0	U	Set seal assy, BOP test	0,8	12	3,1	3,9
02.09.97	23:30	11,5	11,5	U	RIH with 3.5" DP to 2530 m.	1,3	0	3,1	4,4
03.09.97	11:00	2,0	2,0	U	RIH with HOT and secure well.	1,4	0	3,1	4,5
03.09.97	13:00	2,0	2,0	U	Displace riser to seawater	1,5	0	3,1	4,5
03.09.97	15:00	746,0	746,0	U	Operation suspended due to industrial action	32,5	0	3,1	35,6
04.10.97	17:00	37,5	37,5	U	Preparations to start operations	34,1	0	3,1	37,2
06.10.97	06:30	39,5	39,5	U	Circulate and condition mud.	35,8	0	3,1	38,8
07.10.97	22:00	4,5	(0,5)	U	Run shooting nipple on 7" casing to BOP	35,8	5	3,3	39,0
08.10.97	02:30	31,5	16,5	U	Wireline logging, SBT	36,4	15	3,9	40,3
09.10.97	10:00	27,0	27,0	U	Clean-up trip, cond. mud	37,6	0	3,9	41,5
10.10.97	13:00	8,0	0,0	U	Wireline logg. MAC	37,6	8	4,3	41,8
10.10.97	21:00	49,0	41,0	U	Perforation runs in waterzone, 3 separate runs	39,3	8	4,6	43,8
12.10.97	22:00	33,0	15,0	U	1'st MDT run failed	39,9	18	5,3	45,2
14.10.97	07:00	33,0	33,0	U	2'nd MDT run faile	41,3	0	5,3	46,6
15.10.97	16:00	33,0	33,0	U	3'rd MDT run failed	42,6	0	5,3	48,0
17.10.97	01:00	0,0	(8,0)	U	Perforate in HC zone	42,6	8	5,7	48,0
17.10.97	01:00	0,0	(18,0)	U	Run MDT in HC zone	42,6	18	6,4	48,0
17.10.97	01:00	0,0	(32,0)	U	Isolate waterzone from HC zone	42,6	32	7,8	48,0
17.10.97	01:00	12,5	12,5	U	Reperforate water zone (6.0 m)	43,2	0	7,8	48,5
17.10.97	13:30	6,0	6,0	U	BOP test	43,4	0	7,8	48,7
17.10.97	19:30	90,0	90,0	U	RIH test string, Perform water test, POOH	47,2	0	7,8	52,5
21.10.97	13:30	64,0	28,0	U	Run EZSV on DP and squeeze cement, cond mud and poo	48,3	36	9,3	55,1
24.10.97	05:30	12,0	4,0	U	Perforate for test 2A, Atlas 3.0 m	48,5	8	9,6	55,6
24.10.97	17:30	61,0	25,0	U	Run in hole test string	49,5	36	11,1	58,2
27.10.97	06:30	31,5	6,5	U	Cleanup flow and buildup	49,8	25	12,1	59,5
28.10.97	14:00	14,5	(1,5)	U	Conditioning and BHS flow	49,8	16	12,8	60,1
29.10.97	04:30	0,0	(20,0)	U	Sandstrength	49,8	20	13,6	60,1
29.10.97	04:30	6,0	0,0	U	Minifrac	49,8	6	13,9	60,4
29.10.97	10:30	10,0	9,0	U	Perforation of zone 2B	50,2	1	13,9	60,8
29.10.97	20:30	41,5	11,5	U	Main flow	50,7	30	15,2	62,5
31.10.97	14:00	42,0	2,0	U	Main build up	50,8	40	16,8	64,3
02.11.97	08:00	3,5	3,5	U	Minifac	50,9	0	16,8	64,4
02.11.97	11:30	32,0	2,0	U	Kill well POOH	51,0	30	18,1	65,7
03.11.97	19:30	34,0	0,0	U	Squeeze cement perforations	51,0	20	18,9	67,1
05.11.97	05:30	0,0	0,0		End of Test				
Total		1612	1 143,5			51	454	19	67

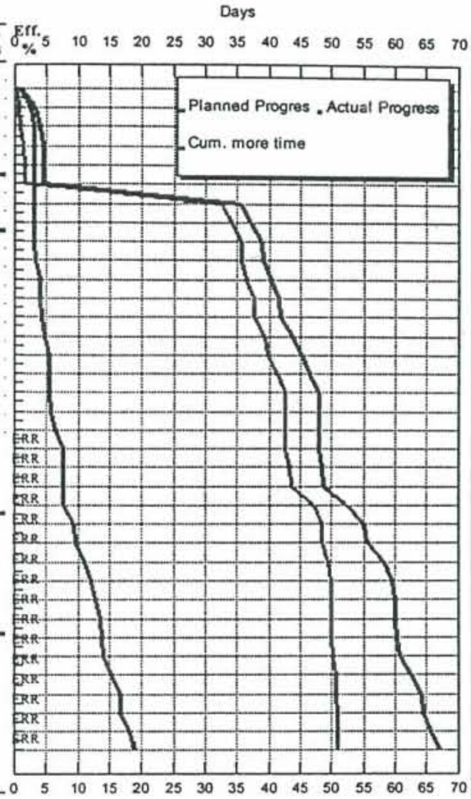


Fig 3.6 Planned vs. Actual Time

BLACK : Originally planned operations
GREEN : Not planned operations
RED : Originally planned but not performed operations