5. FORMATION EVALUATION

5.3 Formation Pressure Measurements

An Atlas Wireline Services Formation Multi Tester (FMT) with a Hewlett Packard crystal gauge was used to obtain formation pressures (table 5.4, a-b).

An OWC at 2250 m RKB (2224 m MSL) is defined from formation pressure measurements, and is in agreement with logs. In the Brent Group an oil gradient of 0.070 bar/m and a water gradient of 0.098 bar/m were determined. The pressure points measured in the Cook Formation were not of reliable quality. The water gradient in the Statfjord Formation is 0.100 bar/m. The Stafjord Formation is 1.4 bar overpressured compared to the pressure regime in the Brent Group.

Results from 2 3/4 gallon chambers (segregated samples) opened on the rig floor are listed in table 5.4. The 1 gallon chambers were sent to laboratory for PVT studies, with the results presented in section 5.5.

5.4 Testing

The following production tests were performed in well 34/7-12:

Formation	Test No.	Fluid	Perforation Interval (m RKB)
Lower Brent	1	Water	2276.2 - 2282.2
Ness	2	Oil	2229.0 - 2235.0
Tarbert	3	Oil	2205.5 - 2209.5

The objectives of the tests were to:

Test No. 1:

- obtain formation water samples
- estimate the productivity
- estimate the formation characteristics

Test No. 2:

- measure the productivity
- investigate formation characteristics and sand continuity
- obtain formation fluid samples
- estimate sand free production rate
- investigate the continuity of the shale interval 2235 - 2241 m RKB

Test No. 3:

- measure the productivity
- estimate sandfree production rate
- obtain formation fluid samples
- estimate the formation characteristics

Operations:

Production test No. 1:

The interval 2276.2 - 2282.5 m RKB was perforated underbalanced with a 5 inch Schlumberger tubing conveyed perforation gun, 5 shots/foot. After perforation, the well was shut-in for 1 hour in order to get the initial reservoir pressure.

The well was opened through an adjustable choke. Due to sand production it was necessary to go straight into the main flow to avoid sand settling in the test string. During the 29.8 hours main flow, an 11 mm fixed choke was used. The last recorded water rate was 1284 Sm^3/D with a corresponding wellhead pressure of 106 bar and a productivity index of 186 $m^3/D/bar$. The sand production at the beginning of the main flow was 10% of the total flow. It decreased during the flow, and for the last 10 hours of the main flow it was approximately zero. The well was then shut-in for 30 hours.

During the sand detection flow, the well was flowed at different rates using choke sizes between 8 mm and 16 mm, with a maximum rate of 1810 m^3/D. When the flow rate was increased the sand production increased to a peak and thereafter decreased.

The pressures and rates are shown in fig. 5.2. A summary of the flow periods and flow data are listed in table 5.5.

Production test No. 2:

The interval 2229 - 2235 m RKB was perforated overbalanced with a 4 inch Atlas Wireline Services Jumbo Jet casing gun (120° phasing, 4 shots/foot).

Prior to opening the well for flow, 1 hour stabilization period was performed by opening the PCT valve underbalanced against a closed choke manifold to obtain the initial reservoir pressure.

The well was opened for a 6.3 hours clean-up flow through a 8 mm adjustable choke. The choke size was then stepwise increased to a 21 mm fixed choke. A final oil rate of 1670 Sm^3/D was recorded with a corresponding wellhead pressure of 104.8 bar. The total pressure drawdown was 46.3 bar. The well was then shut-in for 9 hours.

After installing the surface read-out system for pressure (MUST), the well was opened through a 13 mm fixed choke. The well was flowed for 73 hours through the same choke giving a final oilrate of 880 Sm^3/D with a corresponding wellhead pressure of 127 bar. The total pressure drawdown was 46.7 bar, giving a productivity index of 19 $Sm^3/D/bar$.

After the main build-up the well was opened for a 6 hours sampling flow, mainly through a 6 mm fixed choke. After the sampling flow, attempts were made to unlatch the MUST. This was not successful, and the weak point eventually broke.

The pressures and rates are shown in fig. 5.3. A summary of the flow periods and flow data are listed in table 5.6.

Production test No. 3:

The interval 2205.5 - 2209.5 m RKB was perforated underbalanced with a 5 inch Schlumberger tubing conveyed perforation gun, 5 shots/foot. After perforation, the well was shut-in for 1 hour to get the initial reservoir pressure.

The well was opened for a 10.1 hour clean-up flow through a 5 mm adjustable choke. The choke size was then stepwise increased to 26 mm. The last recorded oil rate was 2600 Sm^3/D with a corresponding wellhead pressure of 121.3 bar. The total pressure drawdown was 10.9 bar. The well was then shut in for 7.9 hours.

After installing the MUST, several attempts were made to open the well for the main flow. A large pressure drop was observed across the MUST, indicating a closed MUST valve, which only allowed fluid to flow through the equalizing ports. After cycling the MUST, the MUST opened and the well was flowed for 23.4 hours through a 11 mm fixed choke. After approximately 11.5 hours of sampling, the choke size was increased to 14 mm fixed.

The final oil rate was 1460 Sm^3/D with a corresponding wellhead pressure of 156.3 bar. The total pressure drawdown was 5.4 bar, giving a productivity index of 270 $Sm^3/D/bar$.

After the main build-up a minifracture test was performed to determine the formation strength.

The pressures and rates are shown in fig. 5.4. A summary of the flow periods and flow data are listed in table 5.7.

5.5 Fluid Analyses

FMT samples

5 one gallon chambers were brought to the laboratory. The FMT-chambre from 2249.5 m RKB was empty while the FMT-chambre from 2252.5 m RKB contained water. The others were filled with oil. PVT analyses were carried out on the three oil samples (table 5.8). The water sample was contaminated with mudfiltrate.

Test No. 1:

Water samples were taken regularly during the different flow periods and analysed offshore for pH, chloride, conductivity, density, alkalinity, barium/strontium, sulfate and turbidity to establish when formation water was produced to surface. Seven sample sets of true formation water were then collected at inlet test separator for onshore analyses.

A representative formation water composition is given in table 5.9.

Test No. 2:

During production test No. 2, six sets of separator samples containing separator gas and oil were collected. For five of the sets, the separator gas was sampled isokinetically to establish the correct recombination GOR and to examine the separator efficiency. Nine monophasic oil samples were taken at the wellhead, since the wellhead flowing pressure exceeded the bubble point pressure at wellhead temperature.

A complete PVT analyses was carried out on one of the monophasic wellhead samples. The main results are given in tables 5.10 and 5.11.

Samples of gas and oil were taken regularly throughout the test for trace component analyses (table 5.12). A small amount of water was produced at the separator and analysed offshore. This water is likely to be seawater from cleaning the separator.

Test No. 3:

Six sets of separator samples containing gas and oil were taken throughout test No. 3. The separator gas was sampled isokinetically to establish the correct recombination GOR and to examine the separator efficiency. At low rates the flow was monophasic at wellhead, as the wellhead flowing pressure was above the bubble point pressure for the actual wellhead temperature. Nine monophasic oil samples were taken on the wellhead.

One monophasic wellhead sample was brought to the laboratory for PVT-analysis. The main results from the PVT-analysis are listed in tables 5.13 and 5.14.

Samples of gas and oil were taken regularly throughout the test for trace component analyses (table 5.15).

A small amount of water was produced at the separator and analysed. This water is likely to be seawater from cleaning the separator.

Test Performance, Production Test no. 1

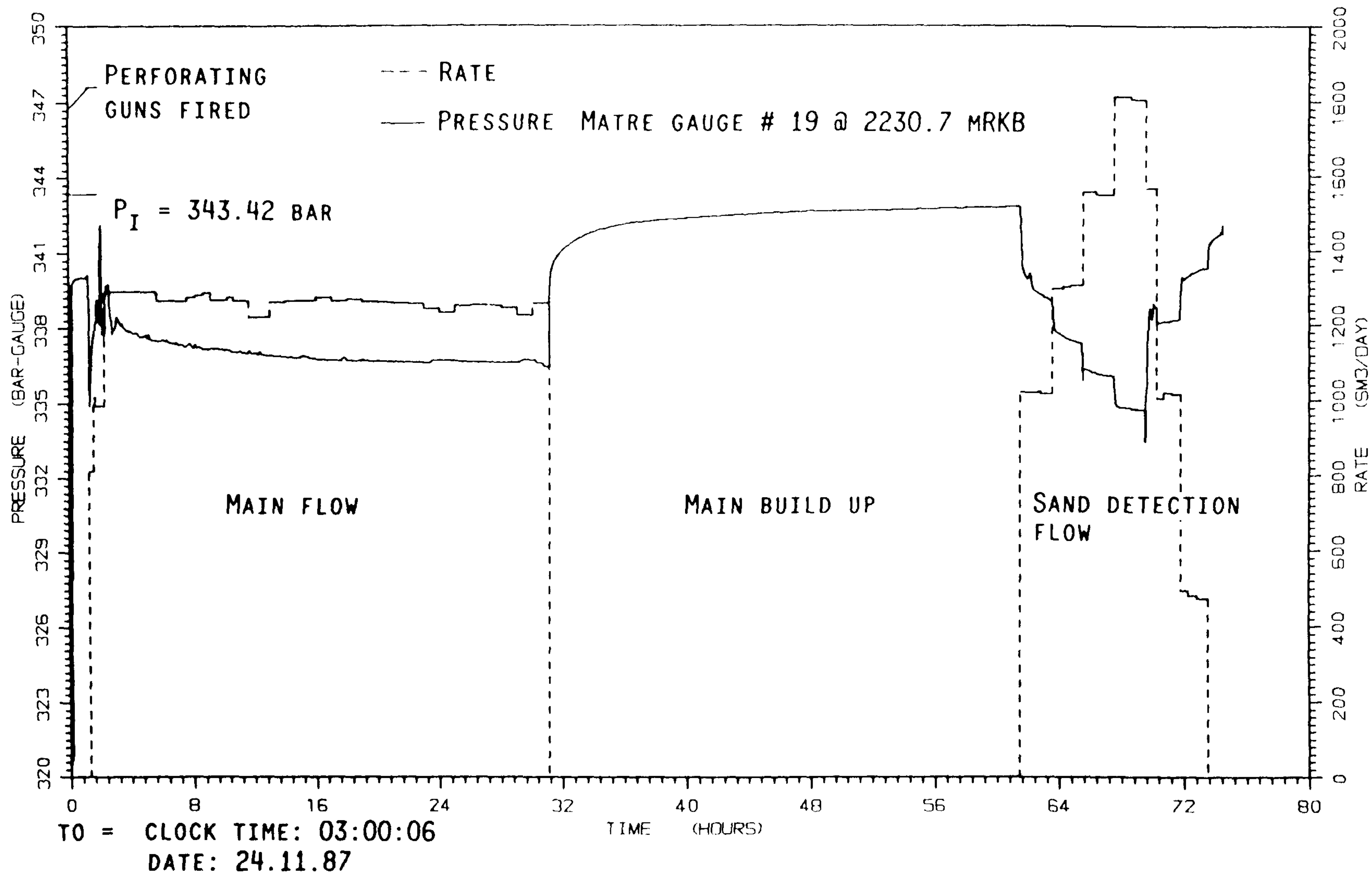


Fig. 5.2 Test performance, test no. 1, well 34/-12

07.03.88 HØd/GAJ/EPF GAF

Test Performance, Production Test no. 2

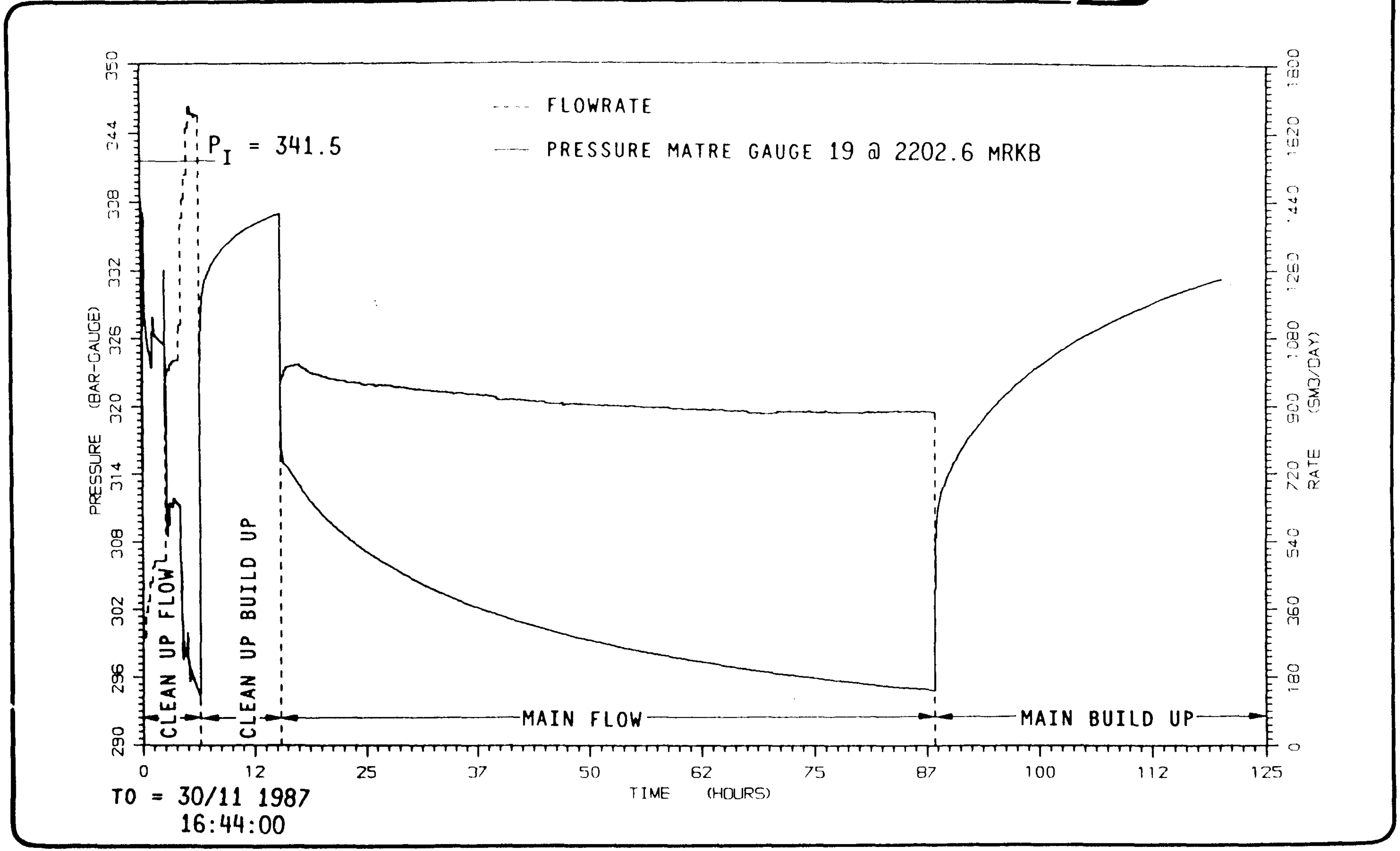
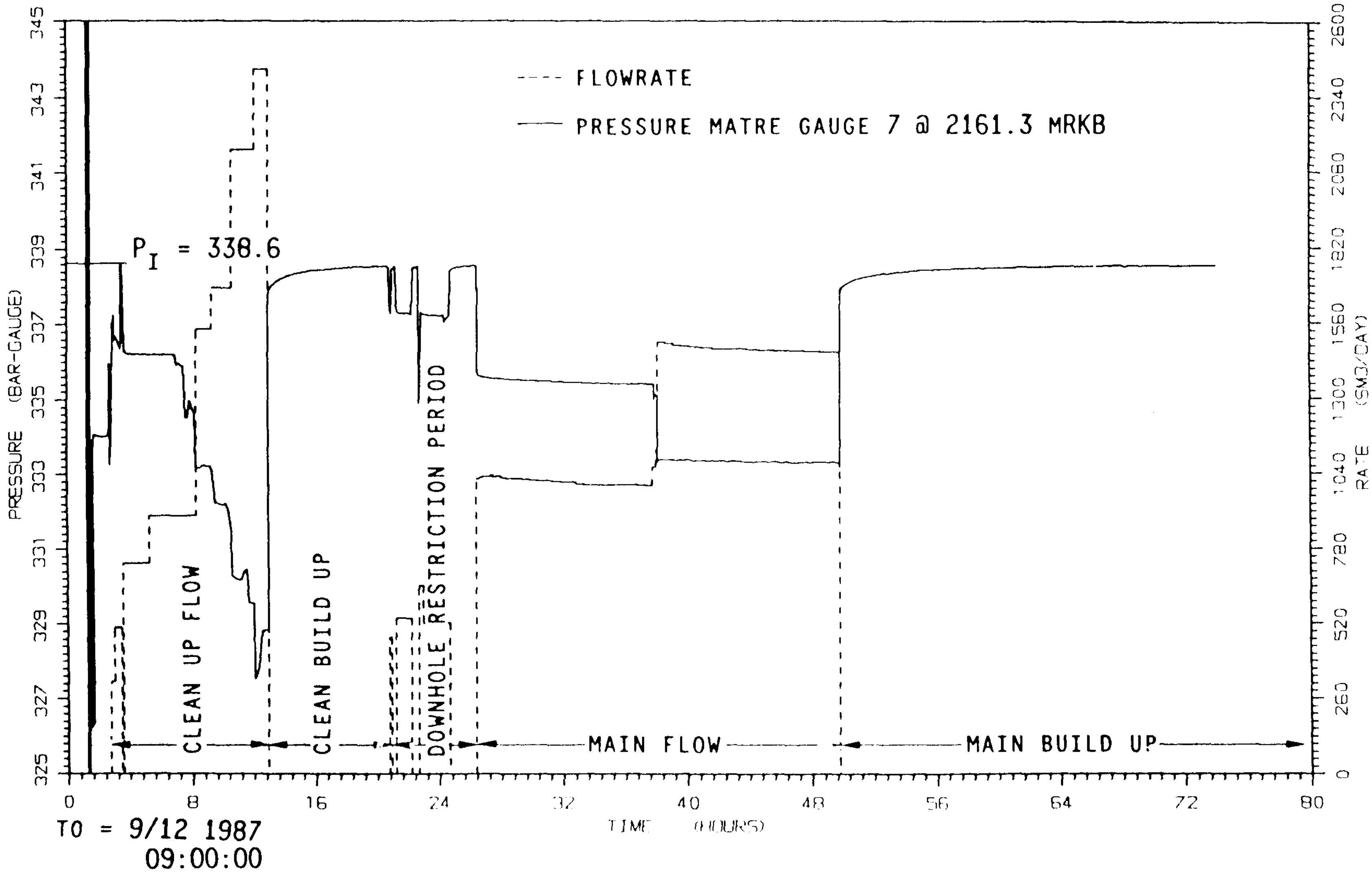


Fig 5.3 Test performance, test no. 2, well 34/7-12

07.03.88 HaS/GaJ/EPF GAF

Test Performance , Production Test no. 3



07.03.88 HaS/GaJ/EPF GAF

Fig. 5.4 Test performance, test no. 3, well 34/-12

Formation Pressures

Well 34/7-12

Depth (m RKB)	Hydrostatic mud pressures Before (psia)	After (psia)	Formation pressures (psia)	(bar)	Comments
<u>Run 2A</u>					
2171.0	5372.7	5372.3	4924.9	339.56	
2182.0	5399.4	5399.4	4936.3	340.35	
2189.5	5418.2	5417.9	4943.8	340.86	
2194.5	5430.4	5430.0	4948.9	341.21	
2203.5	5452.5	5452.5	4958.1	341.84	
2210.0	5468.7	5468.5	4964.9	342.32	
2218.5	5489.5	5489.4	4976.6	343.12	
2230.0	5517.3	5517.4	4986.7	343.82	
2242.0	5546.5	5546.6	5005.1	345.09	
2244.0	5551.3	5551.3	5006.9	345.21	
2249.5	5564.6	5564.7	5007.3	345.24	
2253.0	5573.0	5573.0	5010.2	345.44	
2261.0	5592.4	5592.5	5021.5	346.22	
2271.0	5516.8	5617.0	5037.7	347.33	
2280.0	5639.0	5639.2	5048.5	348.08	
2289.5	5662.5	5662.5	5062.0	349.01	
2302.5	5694.2	5694.5	5080.5	350.29	
2312.0	5717.5	5717.5	5094.2	351.23	
2171.0	5372.8	5371.5	4925.3	339.59	Segregated sample 1 gallon chamber empty
<u>Run 2B</u>					
2171.5	5371.7	5371.6	4925.8	339.62	Segregated sample 1 gallon chamber empty

REMARKS:

The pressures are temperature corrected

KB = 26 m

Table 5.3 a Formation Pressures, well 34/7-12

Date 03-88	Auth CS	Appr BR
Draw by RM	Ref EPF	

Formation Pressures

Well 34/7-12

Depth (m RKB)	Hydrostatic mud pressures Before (psia)	After (psia)	Formation pressures (psia)	(bar)	Comments
Run 2C					
2189.5	5419.5	5418.6	4943.4	340.84	Segregated sample
Run 2D					
2189.5	5420.0	-	4943.9	340.87	Segregated sample
Run 2E					
2249.5	5565.0	5564.4	5006.9	345.21	Segregated sample 1 gallon chamber empty
Run 3G					
2210.0	5477.2	5477.4	4964.9	342.32	
2312.0	5729.8	5729.9	5094.8	351.27	
2471.0	6122.3	6122.2	5363.2	369.78	Pressure draw down 3000 psi
2474.0	6121.8	6122.1	5362.3	369.72	Pressure draw down 3500 psi. Tool differential stuck at 2465 m RKB
Run 3H					
2210.0	5294.9	5294.9	4970.8	342.72	
2210.0	5261.4	5281.6	4964.9	342.32	
2312.0	5531.6	5533.2	5093.6	351.19	
2609.0	6259.5	6258.9	5556.9	383.13	
2626.0	6278.2	6297.6	5581.4	383.44	
2647.0	6348.1	6347.6	5611.7	386.91	
2677.0	6420.2	6420.2	5654.9	389.89	Pressure draw down 1500 psi
2692.0	6459.1	-	5676.4	391.37	
2252.5	5384.9	-	5009.9	345.42	Segregated sample

REMARKS: The pressures are temperature corrected

KB = 26 m

Table 5.3 b Formation Pressures, well 34/7-12

Date 03-88	Auth CS	Appr BR
Draw by RM	Ref EPF	

Segregated Samples

Well 34/7-12

Run	Depth	2 3/4 gallon[1]	1 gallon[2]
2A	2171.0	Opening pressure: 1700 psi Gas: 18.4 cuft Oil: 8000 cc	
2B	2171.5	Opening pressure: 100 psi Gas: 15.5 cuft Oil: 8000 cc	Empty[3]
2C	2189.5	Opening pressure: 1700 psi Gas: 14.6 cuft Oil: 7500 cc	
2D	2189.5	Opening pressure: 1600 psi Gas: 19.0 cuft Oil: 7750 cc	
2E	2249.5	Opening pressure: 450 psi Gas: 4.9 cuft Oil/mud: 8800 cc	Empty[3]
3H	2252.5	Opening pressure: 150 psi Water: 9600 cc	

Remarks

1. 2 3/4 gallon chambers opened at rig floor.
2. 1 gallon chambers sent ashore for PVT studies.
3. Empty, probably, due to plugging.

Table 5.4 Results from 2 3/4 gallon chambers (segregated samples), well 34/7-12

Date 03-88	Auth CS	Appr BR
Draw by RM	Ref EPF	

Summary of Flowperiods, Production Test no 1

Table 5.5 Flowperiods and flow data, 34/7-12

EVENT		TIME	FLOW-RATE (Sm3/D)	BOTTOM HOLE PRESSURE/TEMP. (bar) (DegC)	WELLHEAD PRESSURE/TEMP. (bar) (Degc)	GWR (Sm3/Sm3)	SEPARATOR PRESSURE/TEMP. (bar) (DegC)	CHOKE (mm)
Main	Open	24/11/87 04:16						
flow		05:00		341.1/81.2	103.9/34.3			11.1
		09:00		337.6/83.5	105.9/59.7			12.7
		17:00	1269	336.9/83.9	105.2/61.7		7.7/30.3	12.7
		25/11/87 02:00	1271	336.7/84.1	104.8/64.0	1.3	9.2/30.9	12.7
	Shut-in	10:04	1297	336.5/84.2	104.6/65.5	1.4	9.1/32.7	12.7
Sand-	Open	26/11/87 16:26						
prod.		17:00	1025	340.0/83.1	112.5/37.1			11.1
flow		21:00	1555	336.2/84.2	98.8/68.1			14.3
		27/11/87 01:00	1570	338.5/84.2	112.7/65.0			11.1
	Shut-in	04:30	475	340.9/84.2	118.0/56.4			7.9

Bottomhole pressures measured at 2230.7 mRKB

Date 04-88 | Auth HaS | Appr GaJ
Drawn by | Ref EPF

Summary of Flowperiodes, Production Test no. 2

Table 5.6 Flowperiods and flow data, 34/7-12

EVENT		TIME	FLOW-RATE (Sm3/D)	BOTTOM HOLE PRESSURE/TEMP. (bar) (DegC)	WELLHEAD PRESSURE/TEMP. (bar) (Degc)	GOR (Sm3/Sm3)	SEPARATOR PRESSURE/TEMP. (bar) (DegC)	CHOKE (mm)
Clean-up	Open	30/11/87 16:45						
flow		17:00		336.7/74.1	115.9/9.3			7.1
		20:00		311.1/81.2	139.0/50.3			12.7
	Shut-in	30/11/87 23:05	1666	294.3/82.8	104.8/63.6	67	44.6/57.7	20.64
Main	Open	1/12/87 08:07						
flow		09:00		314.5/82.1	139.8/50.5			
		13:00	895	310.2/82.9	138.3/61.1	68	40.4/53.8	12.7
		2/12/87 11:00	922	300.8/83.2	131.6/62.7	68	39.9/55.0	12.7
		3/11/87 10:00	894	297.0/83.3	128.6/63.4	68	40.2/55.9	12.7
	Shut-in	4/11/87 09:06	888	294.8/83.4	127.0/63.2	68	40.0/55.3	12.7

Bottomhole pressures measured at 2202.6 mRKB

Date 04-88 Auth HaS Appr GaJ
Draw by Ref EPF

Summary of Flowperiods, Production Test no. 3

EVENT		TIME	FLOW-RATE (Sm3/D)	BOTTOM HOLE PRESSURE/TEMP. (bar) (DegC)	WELLHEAD PRESSURE/TEMP. (bar) (Degc)	GOR (Sm3/Sm3)	SEPARATOR PRESSURE/TEMP. (bar) (DegC)	CHOKE (mm)
Clean-up	Open	9/12/87 11:45						
flow		12:00		336.6/74.5	112.9/10.6			9.5
		16:00	791	336.2/80.0	174.2/33.9	35.3/44.3	67	12.7
	Shut-in	21:53	2470	328.8/81.6	129.8/56.6	69.7/55.2	54	25.4
Main	Open	10/12/87 11:21						
flow		12:00	1032	335.6/81.3	169.2/29.0	42.7/23.8	70	11.1
		16:00	1014	335.3/81.6	170.1/37.2	42.8/35.2	66	11.1
		22:00	999	335.4/81.8	170.5/38.5	35.3/34.4	70	11.1
		11/12/87 04:00	1477	333.3/82.0	155.8/48.5	48.1/44.7	65	14.3
	Shut-in	10:45	1460	333.2/82.1	156.3/50.3	48.0/46.4	68	14.3

Bottomhole pressures measured at 2161.3 mMRKB

Table 5.7 Flowperiods and flow data, 34/7-12

Date 04-88 Draw by | Auth HaS | Ref EPF | Appr GaJ

Fluid Analysis

FMT Sample	ST 014	ST015	ST019
Sampling depth [mRKB]	2171.0	2189.5	2189.5
Bubblepoint pressure at 82.0°C [bar]	171.0	171.0	170.0
From single stage flash:			
Gas oil ratio [Sm^3/Sm^3]	100.8	113.9	108.9
Density of oil at 15°C [kg/m^3]	845.7	844.7	845.3
Gas gravity (air = 1)	0.863	0.854	0.879
Composition of reservoir fluid [mol%]			
CO_2	0.29	0.25	0.22
N_2	0.64	0.67	0.65
C_1	33.51	35.72	34.31
C_2	6.69	6.98	6.81
C_3	6.26	6.76	6.60
i-C_4	1.10	1.15	1.16
n-C_4	3.34	3.41	3.54
i-C_5	1.27	1.24	1.29
n-C_5	1.85	1.79	1.85
C_6	2.63	2.47	2.48
C_{7+}	42.42	39.56	41.09
Molecular weight of C_{7+}	227	228	226
Density of C_{7+} [kg/m^3]	862	861	861

Table 5.8 Analyses of oil from FMT-sampling.
Well 34/7-12.

Dato 04.88	Forf ToK	Godkj JMH
Tegn av	Ref EPR	

Fluid Analysis

SAMPLING TIME: 03.00 SAMPLING DATE: 27.11.87

CATIONS

			1	2	
1.	Lithium	(Li)	3.3		mg/l
2.	Aluminium	(Al)	<0,5		mg/l
3.	Boron	(B)	67		mg/l
4.	Barium	(Ba)	35	39	mg/l
5.	Calcium	(Ca)	560	690	mg/l
6.	Cobalt	(Co)	<0,1		mg/l
7.	Cromium	(Cr)	<0,1		mg/l
8.	Cupper	(Cu)	<0,1		mg/l
9.	Iron	(Fe)	5.0	0.3	mg/l
10.	Potassium	(K)	200	172	mg/l
11.	Magnesium	(Mg)	110	106	mg/l
12.	Manganese	(Mn)	0.27		mg/l
13.	Molybdenum	(Mo)	<0,1		mg/l
14.	Sodium	(Na)	11000	11093	mg/l
15.	Nickel	(Ni)	<0,1		mg/l
16.	Silicon	(Si)	17		mg/l
17.	Strontium	(Sr)	100	105	mg/l
18.	Zinc	(Zn)	<0.1		mg/l
19.	Phosphorus	(P)	<1		mg/l

ANIONS

1.	Chloride	(Cl)	18500	mg/l
2.	Sulfate	(SO4)	4	mg/l
3.	Carbonate	(CO3)	<1	mg/l
4.	Bicarbonate	(HCO3)	677	mg/l

OTHER PROPERTIES

pH	7.44	6.39 *
Specific gravity 60/60 F	1.0221	g/cm3
Resistivity (25oC)	0.208	ohm-m
Iron (total)	13	mg/l

***The pH-value is measured offshore**

1. Cations are analysed by ICP-technique
2. Cations are analysed by atom absorbtion technique

Table 5.9 Formation Water Composition.
Well 34/7-12.

Dato	04.88	Forf	ToK	Godkj	JMH
Tegn av		Ref	EPR		

Fluid Analysis

RESERVOIR FLUID COMPOSITION, PT 2

Component	Weight %	Mol %
CO_2	0.10	0.26
N_2	0.12	0.49
C_1	4.97	34.36
C_2	1.80	6.64
C_3	2.76	6.95
$i-C_4$	0.65	1.25
$n-C_4$	2.00	3.82
$i-C_5$	0.92	1.41
$n-C_5$	1.34	2.06
C_6	2.12	2.78
C_7	3.25	3.91
C_8	4.34	4.56
C_9	2.94	2.75
$C_{10}+$	72.69	28.76

Average molecular weight	:	111.0
Molecular weight C_7+ (calculated)	:	231
Density of C_7+ (calculated)	:	859 kg/m^3
Molecular weight of $C_{10}+$ (measured)	:	280
Density of $C_{10}+$ (calculated)	:	876 kg/m^3

Table 5.10 Reservoir Oil Composition, PT 2.
Well 34/7-12.

Fluid Analysis

SUMMARY OF GENERAL PVT DATA
WELL 34/7-12 , PT 2

Initial pressure used in analysis	[bar]	:	343.8
Temperature used in analysis	[° C]	:	83.5
Saturation pressure	[bar]	:	160.0
Reservoir oil density	[kg/m3]	:	715
Viscosity at initial pressure	[cP]	:	0.540
Viscosity at reservior pressure	[cP]	:	0.441

Differential liberation

Bo at reservoir conditions	[m3/Sm3] :	1.363
GOR	[Sm3/Sm3] :	112.4
Residal oil density	[kg/m3] :	843

Flash data		SINGLE	MULTI
Bo at reservoir conditions	[m3/Sm3] :	1.339	1.290
GOR	[Sm3/Sm3] :	108.9	93.6
Stock tank oil density	[kg/m3] :	841.7	835.4

Separator conditions for single stage flash :

1) 1.01 bar and 15 ° C

Separator conditions for multi stage flash :

1) 63 bar and 66 ° C
2) 31 bar and 60 ° C
3) 11 bar and 54 ° C
4) 1 bar and 15 ° C

Table 5.11 Summary of general PVT-data, PT 2.
Well 34/7-12.

Date 04.88	Auth ToK	Appr JMH
Draw by	Ref EPR	

Fluid Analysis

TRACE ELEMENT ANALYSES, PT 2

		Range	Arithmetic average	# of measure-ments
GASPHASE				
Hydrogen Sulphide	[ppm-mol]	< 0.45	0.29	25
Mercaptans	[ppm-mol]	< 0.1		19
Carbon Dioxide	[mol%]	0.5-0.6	0.5	22
Radon 222	[Bq/l]	0.008-0.092	0.038	14
Water	[mg/l]	0.3-0.7	0.5	13
Total Mercury	[$\mu g/m^3$]	0.26-6.9	2.7	6
Helium	[mol%]	0.008-0.012	0.009	6
OILPHASE				
Density @25°C	[g/cm^3]	0.840-0.841	0.840	14
Water in Oil	[mg/l]	39.5-146.5	57.5	14
Total Sulphur	[weight %]	0.25-0.29	0.26	6
Polonium - 210	[Bq/l]	0.2-2.5	1.7	3
Nickel	[ppm-weight]	0.2-0.5	0.3	6
Vanadium	[ppm-weight]	1.6-1.7	1.7	6
Mercury	[ppm-weight]	0.4-4.1	1.4	6

Table 5.12 Trace Element Analyses, PT 2. Well 34/7-12.

Date 04.88	Auth ToK	Appr JMH
Draw by	Ref EPR	

Fluid Analysis

RESERVOIR FLUID COMPOSITION, PT 3

Component	Weight %	Mol %
CO_2	0.11	0.27
N_2	0.16	0.60
C_1	5.42	36.39
C_2	1.96	7.03
C_3	2.80	6.85
$i\text{-}C_4$	0.64	1.18
$n\text{-}C_4$	1.87	3.47
$i\text{-}C_5$	0.85	1.27
$n\text{-}C_5$	1.19	1.78
C_6	1.91	2.44
C_7	3.09	3.63
C_8	4.11	4.24
C_9	2.99	2.71
$C_{10}+$	72.90	28.14

Average molecular weight	:	107.8
Molecular weight C_7+ (calculated)	:	231
Density of C_7+ (calculated)	:	862 kg/m^3
Molecular weight of $C_{10}+$ (measured)	:	279
Density of $C_{10}+$ (calculated)	:	878 kg/m^3

Table 5.13 Reservoir Oil Composition, PT 3.
Well 34/7-12.

Fluid Analysis

SUMMARY OF GENERAL PVT DATA
WELL 34/7-12 , PT 3

Initial pressure used in analysis	[bar]	:	342.1
Temperature used in analysis	[° C]	:	82.0
Saturation pressure	[bar]	:	171.5
Reservoir oil density	[kg/m3]	:	709
Viscosity at initial pressure	[cP]	:	0.554
Viscosity at reservior pressure	[cP]	:	0.461

Differential liberation

Bo at reservoir conditions	[m3/Sm3] :	1.380
GOR	[Sm3/Sm3] :	118.9
Residal oil density	[kg/m3] :	847

Flash data		SINGLE	MULTI
Bo at reservoir conditions	[m3/Sm3] :	1.355	1.303
GOR	[Sm3/Sm3] :	115.8	101.8
Stock tank oil density	[kg/m3] :	845.0	837.4

Separator conditions for single stage flash :

1) 1.01 bar and 15 ° C

Separator conditions for multi stage flash :

1) 63 bar and 66 ° C
2) 31 bar and 60 ° C
3) 11 bar and 54 ° C
4) 1 bar and 15 ° C

Table 5.14 Summary of general PVT-data, PT 3. Well 34/7-12.

Date 04.88	Auth ToK	Appr JMH
Draw by	Ref EPR	

Fluid Analysis

TRACE ELEMENT ANALYSES, PT 3

		Range	Arithmetic average	# of measure-ments
GASPHASE				
Hydrogen Sulphide	[ppm-mol]	< 0.20	0.11	14
Mercaptans	[ppm-mol]	< 0.1		9
Carbon Dioxide	[mol%]	0.5	0.5	12
Radon 222	[Bq/l]	0.031-0.075	0.055	5
Water	[mg/l]	0.03-0.56	0.29	7
Total Mercury	[$\mu g/m^3$]	2.8-3.8	3.2	3
Helium	[mol%]	0.010-0.012	0.011	2
OILPHASE				
Density @25°C	[g/cm^3]	0.840-0.845	0.844	8
Water in Oil	[mg/l]	45-500	294	6
Total Sulphur	[weight %]	0.22-0.26	0.24	3
Polonium - 210	[Bq/l]	4.1	4.1	1
Nickel	[ppm-weight]	< 0.1		3
Vanadium	[ppm-weight]	1.3	1.3	3
Mercury	[ppm-weight]	0.8-9.3	4.2	3

Table 5.15 Trace Element Analyses, PT 2.
Well 34/7-12.

Date 04.88	Auth ToK	Appr JMH
Draw by	Ref EPR	

SAGA PETROLEUM A.S.

6.2.1 MUD PROPERTIES, DAILY REPORT

Well no: 34/7-11

Date	Hole size	Hole depth	Mud weight	PV	YP	Gel strength	pH	Alkalinity Pf / Mf	Ca++ mg/l	Cl- mg/l	KCL ppb	Sand %	Solids %	Mudtype
870929		.0	1.03											SPUD MUD
870930		.0	1.03											SPUD MUD
871002	36	248.0	1.03											SPUD MUD
871003	36	332.0	1.05											SPUD MUD
871004	26	332.0	1.12											SPUD MUD
871005	17-1/2	664.0	1.13	5	26	23/28	9.0	0.1/0.0		11000		0.1	7.0	SPUD MUD
871006	26	861.0	1.14	6	28	23/29	8.7	0.1/0.0		12500				SPUD MUD
871007	26	861.0	1.16	5	25	21/26	8.0			13000		0.5	9.0	SPUD MUD
871008	26	861.0	1.20	5	21	17/25	9.4			13000		0.5	9.0	SPUD MUD
871009	26	861.0	1.03											SPUD MUD
871010	26	861.0	1.07	19	20	3/14	8.2	0.5/0.1		40000	28	0.1	3.5	KCL MUD
871011	PB	216.0	1.07	22	22	2/3	8.1	0.2/0.3	200	75000	33	0.5	11.5	KCL MUD

Well no: 34/7-12

Date	Hole size	Hole depth	Mud weight	PV	YP	Gel strength	pH	Alkalinity Pf / Mf	Ca++ mg/l	Cl- mg/l	KCL ppb	Sand %	Solids %	Mudtype
871011	36	225.0	1.05											SPUD MUD
871012	36	332.0	1.05											SPUD MUD
871013	17-1/2	379.0	1.13	5	25	21/23	8.6	0.2/0.3		9500		0.3	7.0	SPUD MUD
871014	17-1/2	852.0	1.15	6	28	22/26	9.0	0.2/0.3		12500		0.3	9.5	SPUD MUD
871015	26	852.0	1.17	5	28	23/27	9.0	0.2/0.3		13000		0.3	10.5	SPUD MUD
871016	26	852.0	1.20	6	26	23/26	9.0	0.2/0.3		13000			11.5	SPUD MUD
871017	26	852.0	1.20	6	26	23/26	9.0	0.2/0.3		13000			11.5	SPUD MUD
871018	26	852.0	1.05	22	18	2/2	8.5						2.0	KCL MUD
871019	17-1/2	852.0	1.05	20	21	4/4	8.5		120	50000	35		8.0	KCL MUD
871020	17-1/2	852.0	1.05	20	21	4/4	8.5		120	50000	35		5.0	KCL MUD
871021	17-1/2	870.0	1.09	18	18	2/2	8.0		120	49000	29		6.0	KCL MUD
871022	17-1/2	1334.0	1.17	22	22	2/3	8.1	0.2/0.3	200	75000	33	0.5	11.5	KCL MUD
871023	17-1/2	1544.0	1.25	25	25	3/5	8.2	0.0/0.1	240	68000	33	1.0	13.0	KCL MUD
871024	17-1/2	1865.0	1.58	34	25	4/5	8.4	0.0/0.1	360	60000	33	1.5	24.0	KCL MUD
871025	17-1/2	1865.0	1.58	35	26	8/10	8.4	0.1/0.4	400	60000	31	1.5	24.0	KCL MUD
871026	17-1/2	1865.0	1.58	35	24	6/10	8.3	0.1/0.3	400	60000	31	1.5	24.0	KCL MUD
871027	12-1/4	1870.0	1.58	32	22	5/8	8.9	0.2/0.3	240	60000	31	1.0	24.0	KCL MUD
871028	12-1/4	2106.0	1.72	32	18	6/8	9.0	0.2/0.4	40	57000	31	1.0	26.0	KCL MUD
871029	12-1/4	2183.0	1.72	27	13	8/25	9.6	0.2/0.8	240	60000	32	1.0	27.0	KCL MUD
871030	12-1/4	2214.0	1.72	31	15	5/14	10.8	0.2/0.6	120	61000	34	1.0	27.0	KCL MUD
871031	12-1/4	2234.0	1.72	29	11	2/5	10.9	0.3/1.0	160	56000	36	1.0	27.0	KCL MUD
871101	12-1/4	2276.0	1.72	30	10	2/8	10.9	0.3/1.1	200	56000	34	1.0	27.0	KCL MUD
871102	12-1/4	2314.0	1.72	30	13	2/10	10.9	0.3/1.1	200	58000	32	0.5	26.0	KCL MUD
871103	12-1/4	2357.0	1.72	30	11	2/10	10.8	0.3/1.1	200	59000	31	0.5	26.0	KCL MUD
871104	12-1/4	2364.0	1.72	28	11	2/9	10.4	0.3/1.0	280	58000	31	0.5	27.0	KCL MUD
871105	12-1/4	2480.0	1.72	27	13	3/20	9.8	0.3/0.9	240	58000	28	0.5	27.0	KCL MUD
871106	12-1/4	2480.0	1.72	28	10	2/9	9.6	0.3/0.9	280	60000	28	0.5	27.5	KCL MUD
871107	12-1/4	2480.0	1.70	28	11	2/10	9.6	0.3/0.9	280	60000	28	0.5	27.5	KCL MUD
871108	12-1/4	2510.0	1.72	25	12	3/18	9.6	0.2/0.8	280	60000	28	0.1	28.0	KCL MUD
871109	12-1/4	2595.0	1.72	26	13	3/22	9.3	0.2/0.7	320	61500	30	0.1	29.0	KCL MUD
871110	12-1/4	2609.0	1.72	22	11	2/13	9.3	0.2/0.7	360	57500	23		26.5	KCL MUD

Well no: 34/7-12

Date	Hole size	Hole depth	Mud weight	PV	YP	Gel strength	pH	Alkalinity Pf / Mf	Ca++ mg/l	Cl- mg/l	KCL ppb	Sand %	Solids %	Mudtype
871111	12-1/4	2622.0	1.72	23	11	2/8	9.6	0.2/0.7	360	57000	25		26.0	KCL MUD
871112	12-1/4	2655.0	1.72	25	11	3/9	9.4	0.2/0.9	280	57000	25	0.1	26.5	KCL MUD
871113	12-1/4	2705.0	1.72	25	13	3/17	9.3	0.2/0.9	240	56500	23		26.5	KCL MUD
871114	12-1/4	2778.0	1.72	28	13	3/21	9.7	0.2/1.1	220	52000	21	0.3	27.0	KCL MUD
871115	12-1/4	2784.0	1.72	28	14	3/24	9.5	0.2/1.0	200	51000	20	0.3	27.0	KCL MUD
871116	12-1/4	2784.0	1.72	28	14	3/24	9.4	0.2/0.9	200	51000	20	0.1	27.0	KCL MUD
871117	12-1/4	2784.0	1.72	26	13	3/21	9.2	0.2/0.9	200	50500	20	0.1	27.0	KCL MUD
871118	12-1/4	2784.0	1.72	26	13	3/21	9.2	0.2/0.9	200	50500	20		27.0	KCL MUD
871119	PB	2381.0	1.72	31	22	5/31	11.5	0.5/1.8	320	40000		0.1	27.0	GEL MUD
871120	PB	2330.0	1.72	29	11	3/30	11.5	0.5/1.5	320	42000			27.0	GEL MUD
871121	PB	2330.0	1.72	30	15	4/25	11.8	0.5/1.5	240	42000			27.0	GEL MUD
871122	PB	2330.0	1.72	30	15	4/25	11.5	0.2/1.5	240	42000			27.0	GEL MUD
871124	PB	2330.0	1.72	30	15	4/25	11.8	0.5/1.5	240	42000		0.1	27.0	GEL MUD
871129	PB	2267.0	1.72	28	13	3/18	11.8	0.5/1.5	240	42000			27.0	GEL MUD
871206	PB	2267.0	1.72	25	14	3/22	12.5	0.7/1.7	320	39000			27.0	GEL MUD
871207	PB	2224.0	1.72	24	14	3/24	12.5	0.7/1.7	340	39000		0.1	27.0	GEL MUD
871213	PB	2120.0	1.72	24	14	3/24	12.2	0.6/1.5	320	37000		0.1	27.0	GEL MUD
871214	PB	2120.0	1.72	24	14	3/24	12.2	0.6/1.5	320	37000		0.1	27.0	GEL MUD

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6.2.2 MUD MATERIALS USED

Well no: 34/7-11

Materials	Unit	36 in hole	26 in hole	17-1/2 hole	12-1/4 hole	8-1/2 hole	Total
BARITE	M/T	0	123	0	0	0	123
CAUSTIC SODA	25 KG	4	7	0	0	0	11
Antisol FL 30	25 kg	0	22	0	0	0	22
LIME	40 KG	4	10	0	0	0	14
SODA ASH	50 KG	4	7	0	0	0	11
BENTONITE	M/T	15	53	0	0	0	68
ANTISOL FL 30	25 KG	0	68	0	0	0	68
KCL - BRINE	BBL	0	600	0	0	0	600

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6.2.2 MUD MATERIALS USED

Well no: 34/7-12

Materials	Unit	36 in hole	26 in hole	17-1/2 hole	12-1/4 hole	8-1/2 hole	Total
SAPP	50 KG	0	0	18	3	0	21
BARITE	M/T	0	67	356	758	0	1181
BICARBONATE	50 KG	0	0	8	16	0	24
CAUSTIC SODA	25 KG	6	8	1	52	0	67
Antisol FL 30	25 kg	0	0	103	161	0	264
Magconol	25 l	0	0	4	2	0	6
Resinex	50 lb	0	0	0	120	0	120
Oilex	GALLO	0	0	0	20	0	20
Sodium Sulpha	50 kg	0	0	0	2	0	2
LIME	40 KG	2	7	0	42	0	51
KOH -POTASS.	50KG	0	0	36	32	0	68
SODA ASH	50 KG	4	0	7	0	0	11
BENTONITE	M/T	28	21	0	3	0	52
BENTONITE	50 KG	0	0	33	0	0	33
ANTISOL FL 10	25 KG	0	0	0	3	0	3
ANTISOL FL 30	25 KG	0	0	195	70	0	265
BORREWELL C	25KG	0	0	0	244	0	244
MAGCO 101 INH	55 GA	0	0	0	15	0	15
XC-POLYMER	25 KG	0	0	2	10	0	12
KCL - SXS	50 KG	0	0	921	1072	0	1993
KCL - BRINE	BBL	0	0	1830	0	0	1830
XP-20	50 LB	0	0	0	265	0	265