I.8 PRODUCTION TESTS/WIRELINE FORMATION TESTS

Summary

After the 7" casing was set at 5046 m bdf, the 5-7/8" hole was drilled to 5255 m bdf and a full set of logs were taken (ref. the petrophysical evaluation). When drilling at around 5070 m, the hydrocarbon shows diminished, but the log evaluation did not show a decrease in hydrocarbon saturation at this depth, which raised doubt about the evaluation, and about the Statfjord evaluation as a whole.

Due to operational constraints the 5-7/8" hole would only be tested if a production test of a similar sand development at a higher horizon behind the 7 inch casing would prove to be hydrocarbon bearing and productive. The open hole was plugged back to 5035 m bdf some 11 m above the 7 inch casing shoe and a production test (PT-1) was carried out on the interval 5015 - 5029 m bdf to obtain a formation fluid sample as deep as possible.

The well produced less than 2 b/d under drawdown of some 3500 psi. After a 60 bbls acid stimulation/frac the well produced some 16 bbls in 18 hours at a drawdown of 3500 psi, indicating a very tight formation.

As representative formation fluid samples could not be obtained due to the low production rates, the intervals 4823 - 4837 m and 4854 - 4875 m bdf with slightly higher hydrocarbon saturations and a slightly better porosity were tested after abandonment of the previously tested interval.

Prior to acidisation the well produced some 30 to 40 bbls formation water and some bubbles of gas over a period of 3 days under a drawdown increasing from 3440 psi to 9090 psi. After a 77 bbls acid stimulation 137 bbls spent acid/brine/formation fluid and some bubbles of gas were produced during 20 hours under an estimated drawdown of 3500 psi. Representative formation water samples and a gas sample were recovered. Gas analyses indicated a very dry gas with 14.7% CO_2 and 71.4% Methane (by weight). As the geological and petrophysical evaluation of the open hole section is not significantly different from the tested second interval the well was abandoned.

Production Test No. 1 (5015 - 5029 m bdf)
(ref. Fig. I.8.1 and Table I.8.3)

The interval 5015 - 5029 m bdf was perforated on 13.06.84 using 3-3/8" Baker tubing conveyed guns (4 shots per foot) through 7" casing. The brine (s.g. = 1.64) was displaced by drillwater down to 2670 m to obtain a BHP of 9250 psig resulting in an estimated drawdown of 1500 psi while perforating.

No inflow or pressure build-up were observed at surface. A leak off test confirmed contact with the formation but no significant injection rate could be obtained below expected fracture pressure (bottom hole pressure of 14600 psig). The formation was then fractured and 5 bbls injected at 1.2 bpm (estimated actual bottom hole fracture initiation pressure 16000 psig). Surface pressure build-up to 1360 psi was observed and the well was opened up for 5 minutes. It produced 1.3 bbls of brine and all pressure had bled off. The well was closed in and gauges run. A static bottom hole temperature of 167°C (333°F) and pressure of 11395 psig were recorded at 5000.6 m bdf after 8 hours shut-in. The pressure was still building up at about 100 psi/hr. It is believed that this pressure is not representative of the reservoir because of "supercharging" effects (see below). The well was again opened and flowed at 4 b/d rapidly declining to 1 b/d with no back pressure.

The well was displaced to freshwater to give a drawdown estimated at 3500 psi (based on reservoir pressure of 10750 psig extrapolated from RFT measurements). A flowrate of 2 b/d rapidly declining was observed.

The tubing was circulated to brine and 22 bbls of brine were pumped during an injectivity test (max. THP = 5350 psig).

The well was stimulated by circulating 5 bbls 15% HCl (containing HAI-75 corrosion inhibitor and Morflo surfactant) down to 4601 m bdf and squeezing 13 bbls brine. The well was opened up under an estimated drawdown of 1800 psi. Over 12 hours 10 bbls were produced with the rate declining from 50 b/d to 7 b/d at a tubing head pressure of 0 psig.

The well was stimulated again by injecting 60 bbls 15% HCl (containing HAI-75 corrosion inhibitor, HII-124 intensifier and surfactant) and 21 bbls brine. Total fluid volume injected into the formation at this stage was 116 bbls and total production 10 bbls. The well was reopened and flowed 20 bbls in 9 hours with zero backpressure.

The tubing was circulated to freshwater to increase drawdown to 3500 psi and the well produced 16 bbls in 18 hours. It was then closed in, killed and plugged back.

Conclusion PT-1

i) No representative formation fluid samples had been obtained.

ii) The formation is extremely tight and that injected fluids cannot leak off through the walls of a fracture but are produced back as the fracture closes.

Production Test No. 2 (4823 - 4837 m and 4854 - 4875 m bdf)
(ref. Fig. I.8.2 and Table I.8.4)

After the poor inflow of this first test, one further production test was made, this time selected for a maximum inflow chance; 35 m in total of the best quality sands were perforated.

The intervals 4823 - 4837 m (14 m) and 4854 - 4875 m bdf (21 m) were perforated with 3-3/8" Baker tubing conveyed guns (4 SPF) through 7" casing at 1307 hrs on 27.06.84. The brine in the tubing was partly displaced by drillwater to obtain a BHP of 8850 psig resulting in an estimated drawdown of 1500 psig prior to perforating. The well was opened for 5 minutes but no flow was observed. It was then closed in and the pressure gradually built up. After 6 hours the THP had reached 1850 psig and the well was opened up.

Over a period of 24 hrs 74 bbls together with some gas were produced at rates too low to flow through the separator. Gas samples were analysed and were found to be mostly C1 with about 10% CO_2. A tandem bottom hole sample was taken at 4803 m bdf. The amerada and one sampler failed. The other sampler contained water (68160 mg/l Cl-) and little gas. The well appeared to die (estimated BHP = 6300 psig).

The tubing contents were reversed out and replaced with freshwater to give a drawdown of about 3500 psi. A sample taken after 1400 strokes (equivalent to tubing volume down to SSD = 117 bbls) contained 68338 ppm Cl-. The tubing appeared to be empty down to approximately 1866 m bdf which is equivalent to 45 bbls. Thus of the 74 bbls produced only 29 bbls can be attributed to water influx from the formation into the tubing.

Gauges were hung off at 4805 m bdf and the well reopened. A stable static bottom hole pressure was recorded as 10390 psig and a stable BHT of 162^o (323^{o}F) at 4809 m bdf prior to reopening the well (CITHP = 3440 psig). This is believed to be the reservoir pressure.

A further 155 bbls were produced over a 16/64" choke in 3 days with maximum tubing head pressure of 275 psig and substantial rate and pressure variations as gas bubbles came to surface. The well died and was shut in and the gauges recovered making gradient stops every 250 m.

The pressure survey indicated that the tubing was nearly full of gas and that during the flow period the flowing bottom hole pressure had declined from 6950 psig to 1300 psig (Fig. I.8.3 and Table I.8.4).

Of the 155 bbls produced only some 30 to 40 bbls can be attributed to water influx as the tubing contents is 118.2 bbls and the pocket volume is 7.5 bbls. The unloading of the well at the very low gas production rate can only be explained by a piston type displacement of the water column by bubbles of gas resulting in plug flow. The well was reopened and two unsuccessful attempts to recover bottomhole samples were made while flowing another 10 bbls.

The well was stimulated by injecting 77 bbls 15% HCl (containing surfactant, HAI-75 inhibitor and HI-124S intensifier) and 24 bbls brine (7 bbls to establish injectivity 13 bbls pocket volume and 4 bbls to over displace). The tubing was circulated to freshwater to give a drawdown of 3500 psi and a further 137 bbls were produced during 20 hours before the test was concluded. The rate fluctuated between 160 and 300 b/d water at a THP of around 15 psig. Whilst gas bubbles reached the surface the THP fluctuated to some 500 psig and the liquid (water)rate reduced to zero, indicating plug flow.

The bottom hole water sample, a sample reversed out of the tubing and a sample taken at surface from produced water were analysed. For the detailed results see Table I.8.1. It was concluded from the consistency between the three samples taken at different times and by different methods that a representative formation water sample had indeed been obtained.

Conclusions PT-2

The reservoir pressure is 10390 psig (323^{o}F) at 4805 m bdf. The well produced prior to acidization some 30 to 40 bbls formation water and some bubbles of gas over a period of 3 days at a FBHP declining from 6950 to 1300 psig. After a 77 bbls acid stimulation the well produced 137 bbls during 20 hours. The interval is concluded to be very tight.

Wireline Formation Tests

Objectives

Use of the repeat formation tester (RFT) was included in the logging program to achieve the following objectives:

1. To measure the formation pressure at a number of depths, permitting the estimation of fluid pressure gradients, fluid contacts, and initial reservoir pressure

2. To obtain reservoir fluid samples

3. To estimate reservoir permeability

Operational Summary

A total of four RFT runs were made (Table I.8.6)

Run	Bit Size inch	Interval m bdf	Number of Tests Attempts	Tight	No. Seal Failures
1	12-1/4"	2607	1	0	0
2	12-1/4"	3452-3984	17	3	3
3	8-1/2"	4644-5044	40	9	27
4	5-7/8"	5073-5203	26	4	22

After the first test in run 1 the tool failed and was rerun. During run 2 two samples were recovered at 3452 m bdf.

The number of seal failures in runs 3 and 4 are likely caused by the rugosity of the hole in combination with the tightness of the formation and the high mud pressure.

Evaluation

The RFT pressures of all the runs are plotted versus depth in Fig. I.8.4a. The reservoir pressure of 10,390 psig at 4805 m bdf as derived from production test PT-2 is also included in this plot.

An expanded plot of the interval 3000-4000 m bdf is given in Fig. I.8.4b.

From the mud pressure gradient line it is concluded that the strain gauge worked properly. An anomaly in the reservoir pressures is observed at around 3580 m, which was also observed in well 30/11-3.

In view of a possible oil gradient between the two points at 3440 and 3452 m bdf a segregated sample was taken at 3452 m bdf.

The recovery is:

Sample chamber	2-3/4 gals	1 gal (segr.)
Surface pressure/temp psig/DF	1800/N.A.	1975/N.A.
Gas scft	10.5	8.8
Fluids volume liter	8.5	2.5
Fluid type recovered	7.5 l wtr.	2 l wtr.
	1.0 l oil emulsion	0.5 l oil emulsion
S.g. oil emulsion	0.83	0.82
Water resistivity Ohm m	0.083 at 15 DC	0.1 at 11 DC
Water salinity mg/l Cl	50,000	45,000

Through the remaining points a water gradient line with a gradient of 0.46 psi/ft could be drawn.

The permeabilities derived from the RFT give only an order of magnitude of the permeability values, as the measurement is restricted to only half an inch of formation at the wellbore. Influence of mud invasion, two phase flow relative permeabilities, etc, can not be eliminated.

The results however show a very low permeability over the majority of the sands in particular the sands below 3480 m bdf.

WELL: 30/11-4

RT = 29.0 MSL , Vertical well.

RFT DATA

Run 1: 6 - 4 -'84 mud wt = 1.25
Run 2: 6 - 4 -'84 gauge no = 59405

RUN Nr.	TEST Nr.	TEST DEPTH m AH BDF	MUD PRESS. PM psig (corr.)	FLOWING PRESSURE PF1 psig	PF2 psig	FLOWING TIME T1 sec.	T2 sec.	Remarks $k = 5660 \frac{qU}{Dp}$ (mD) $U = 0.5$ cp	CORR. FORMATION PRESSURE P psig
1	1	2607	4701	3783	3783			k > 100 mD	3783
2	1	3452	6225	5310	5135	14	7	k_1=18; k_2=14	5422
		sample	23/4 Gal	4509		458		k_1=68;	5426
		sample	1 Gal		4800		203	k_2=84,	5427
	2	3476	6264	1700		330		Tight	
	3	3520	6341	5548	5505	14	7	k_1=202, k_2=76	5558
	4	3528	6356	5308	4751	14	7	k_1=8, k_2=5	5570
	5	3539	6375	5500	5282	14	7	k_1=23, k_2=13	5587
	6	3563	6418	650		108		Tight	
		3562.5	6418	354		66		Tight	
	7	3580	6449	404	693	14	7	k_1=0.4, k_2=0.8	5820
	8	3590	6467	5536	5268	14	7	k_1=20, k_2=11	5639
	9	3623	6525	5413	5028	14	7	k_1=13, k_2=7	5572
	10	3642	6560	3024	1071	14	7	k_1=1, k_2=1	5408
	11	3652	6578	4661	3314	14	7	k_1=2.7, k_2=2	5418
	12	3665	6601	4672	3434	14	7	k_1=2.6, k_2=2	5438
	13	3713	6687	3719	1907	14	7	k_1=1, k_2=1	5527
	14	3804	6850					Seal Failure	
		3804.5						SF	
	15	3915	7046	6367	5468	14	7	k_1=3, k_2=2.6	7025
		3915.5	7046	6892	6549	14	7	k_1=15, k_2=8.5	7024
	16	3984	7166					SF	
		3984.5	7170	142				SF?	7141
	17	3440	6197	2510	436	14	7	k_1=0.7, k_1=0.8	5410

WELL: 30/11-4

RT = MSL , Vertical well.

RFT DATA

Run 3: 13 - 5 -'84, 40 tests (9 tight, 27 seal failures)
Run 4: 3 - 6 -'84, 26 tests (4 tight, 22 seal failures)

RUN Nr.	TEST Nr.	TEST DEPTH m AH BDF	MUD PRESS. PM psig (corr.)	FLOWING PRESSURE PF1 psig	PF2 psig	FLOWING TIME T1 sec.	T2 sec.	Remarks $k = 5660 \frac{qU}{Dp}$ (mD) U = 0.5 cp	CORR. FORMATION PRESSURE P psig
3	1	4644	10633	-	7435	14	7	$k_2 = 1.3$	10488
	4	4658	10664	10327	10339	14	7	$k_1 = 13$; $k_2 = 28$	10482
	5	4665	10682	-	9006	14	7	$k_2 = 3$	10492
	7	4683.5						Tight	
	8	4691.5						Tight	
	11	4782						Tight	
	16	4840						Tight	
	17	4868						Tight	
	22	4892						Tight	
	27	4977						Tight	
	33	5044						Tight	
	39	4658						Tight	
	40	4657	10664	-	10187	14	7	$k_2 = 13$	10485
4	3	5073.3						T	
	14	5150						T	
	15	5157						T	
	25	5203						T	