3

October 1985

Well resumé

6407/9-3

NSEP 277

Enclosures

1. Introduction

Well 6407/9-3 is located 4 km south of well 6407/9-1 in the crestal part of the structure.

The main objectives of the well were:

i) to evaluate the lateral continuity and quality of the reservoir
ii) to establish the velocity trend in a north-south direction
iii) to improve the volumetric estimate
iv) to evaluate the oil deliverability.

The final coordinates of the location are:

$64^{0}19'$ 48.94" N
$07^{0}46'$ 30.91" E

The well was spudded on 3 May 1985 and reached TD of 1868 mbdf in the Lower Jurassic Middle Drake equivalent. The well encountered light oil (40^{0} API) in sands of the Upper Jurassic Frøya Formation. A production test was carried out with a maximum production rate of 15700 BOPD. The well was suspended on 28 July 1985.

Well 6407/9-3

Summary of Well Data:

Well Classification	:	Appraisal well
Location coordinates	:	64^{0} 19' 48.94"N
(final)		07^{0} 46' 30.91"E
Water depth	:	279 m
Derrick Floor Elevation	:	25 m (26 m after 13 3/8")
Contractor/Rig	:	Dolphin Services A/S, "Borgny Dolphin"
BOP Stack	:	10 000 psi, 18 3/4"
Mudlogging Contractor	:	Gearhart
Start of Operations	:	01.05.85
Spudded	:	03.05.85
Completed	:	28.07.85
Objectives	:	Upper Jurassic Frøya Formation
Total depth	:	1868 m drillers depth
		1866 m (loggers depth)
Formation at TD	:	Middle Drake equivalent
Results	:	Oil produced from Upper Jurassic Frøya Formation
Tested interval	:	1606.5-1618.5 mbdf (production test)
Maximum rate	:	15700 stb/d
Oil gravity	:	40^{0} API
Present Status	:	Suspended
Casing Record	:	30" csg : 376 mbdf
		20" csg : 769 mbdf
		13 3/8" csg : 1601 mbdf
		9 5/8" csg : 1843 mbdf

2. Site Survey Report

2.1 Introduction

A/S Norske Shell commissioned A/S Geoteam to conduct a marine site survey for location 6407/9-3. Data acquisition was carried out during the period 4-8 March 1985 with the survey vessel M/V "Geo Scanner".

The purpose of the survey was to obtain bathymetric information and to detect any seabed obstructions or sub-seabed hazards to drilling operations.

Equipment used comprised: echo-sounder and side scan sonar, to map bathymetry and seabed features; deep towed sparker and analog sparker, to investigate shallow strata; a digitally recorded airgun to investigate the deeper strata.

2.2 Survey Programme

An area of 4 x 4 km over the location was covered by 24 NNE-SSW profiles and 9 WNW-ESE profiles with echosounder and side scan sonar. Deep towed boomer and analog sparker were alternated on every second line. The NNE profiles were spaced 175 m apart; line spacing between the WNW profiles was 400 m.

Twelve high resolution profiles were shot with digital equipment. Seven lines were running NNE-SSW (4.0 km, 200 m spacing) and five running WNW-ESE (1.5 km, 500 m spacing); the NNE-SSW centre line was extended to tie with well 6407/9-1.

In addition, three samples were obtained with a 3 metres gravity corer.

2.3 Summary

Survey centre position:	64^{o} 19' 48.80" N 07^{o} 46' 30.18" E	
Water depth:	276 m (mean sea level).	
Seabed slope:	location is in a NW-SE oriented plough mark.	
Seabed condition:	heavily scoured by icebergs. Gas seepages might occur north of the location.	
Seabed hazards:	None.	
Sub seabed conditions:	276-290 m	Glaciomarine clay and hard sediments in the lower half. Boulders might be present.
	290-320 m	Hard clay-dominated sediments.
	320-328 m	Sand layer with gas.
	328-370 m	Sand, silt and clay.
	370 m	Sand layer with gas.
	370-380 m	Layers of sand, silt and clay.
	380-390 m	Sand.
	390-2077 m	Soft tertiary clay stones with silt and sand layers.
Shallow gas hazards:	Possible gas charged sand layers at 320 m and 370 m, represented by amplitude anomalies at the digital sections at 420 and 470 milliseconds, respectively.	

In the event, no shallow gas problems were encountered.

NAVIGATION AND POSITIONING

OF

BORGNY DOLPHIN

WELL 6407/9-3

A/S NORSKE SHELL

REPORT NO. 30068

MAY 1985

Prepared by

A/S GEOTEAM

1320 Stabekk

Norway

C O N T E N T S

A P P E N D I C E S

1. FIELD LOG
2. MARINE REPORT
3. SYLEDIS ANTENNA OFFSET
4. SATELLITE NAVIGATION ANTENNA OFFSET
5. DECCA MAIN CHAIN ANTENNA OFFSET
6. POSITION PLOT

1. INTRODUCTION

1.1 GENERAL

The drilling rig BORGNY DOLPHIN was navigated to new location at Well 6407/9-3 using Syledis and Decca Main Chain. Final position was derived from satellite passes, utilizing single point positioning method.

Both operations were undertaken by A/S GEOTEAM in the period 29 April to 7 May 1985.

Final position, Well 6407/9-3, was:

WELL CENTRE

GEOGRAPHIC		UTM	
Latitude	64° 19' 48.94" N	Northing	7 134 564.0 m
Longitude	07° 46' 30.91" E	Easting	440 802.9 m

The co-ordinates refer to European Datum 1950, UTM projection, Zone 32 with central meridian 09 degrees east.

Observations	:	57 accepted 3-D satellite passes included in final position. With an applied RMS value of 30 cm, 7 passes were rejected in final solution. 12 passes were removed to achieve better geometry. 61 passes were rejected during postprocessing.
Time	:	Observations completed at 1200 hours, 7 May 1985.

Rig Heading	:	261.5 degrees.
Deviation	:	The rig is 10.8 metres in direction 67.7 degrees from intended location.
Personnel	:	U. Larsen and D. Høgvard
Syledis Derived Position	:	About 700 Syledis readings during 1 hour 37 minutes gave an average position of 20.3 m in direction 235.4 degrees from final satellite derived position.

1.2 FIELD LOG SUMMARY

All times refer to Local Norwegian Summer Time

Mobilization, Flesland, Bergen.	1700 hours 29 April 1985
All navigation equipment mounted	2100 hours 29 April 1985
First anchor dropped	1035 hours 1 May 1985
Last anchor reset	1627 hours 2 May 1985
Start of 3-D satellite computation	1715 hours 2 May 1985
Syledis equipment and One Operator left rig	1800 hours 3 May 1985
End of 3-D satellite positioning	1200 hours 7 May 1985
Demobilization, Kristiansund.	1530 hours 7 May 1985

2. NAVIGATION

2.1 GENERAL

While in transit to the new location in Block 6407/9 the rig was navigated by Decca Main Chain together with a Magnavox MX-1502 B Satellite Receiver operated in navigation mode. For the final approach to location, primary navigation system was Sercel Syledis utilizing the A/S GEOTEAM Halten-banken Syledis Chain.

2.2 INTENDED LOCATION

Intended location, referenced to the European Datum 1950, was:

INTENDED WELL CENTRE

GEOGRAPHIC		UTM	
Latitude	64° 19' 48.80" N	Northing	7 134 559.9 m
Longitude	07° 46' 30.18" E	Easting	440 792.9 m

The UTM co-ordinates refer to Zone 32 with central meridian 09 degrees east.

2.3 SYLEDIS CHAIN DETAILS

At present; the A/S GEOTEAM Haltenbanken Syledis Chain consists of five stations with the following co-ordinates in UTM Zone 32, Central Meridian 09 degrees east:

BEACON STATION	NORTHING	EASTING	HEIGHT
Slettringen	7 060 218 m	463 591 m	48 m
Ross Isle, Well 6506/12-3	7 213 111 m	400 649 m	80 m
Halten	7 116 546 m	519 805 m	39 m
Nortrym, Well 6507/7-2	7 247 224 m	421 291 m	70 m
Vega	7 284 761 m	630 114 m	735 m

The following details are relevant to location 6407/9-3:

BEACON STATION	DELAY	RANGE	L.O.S.*	BEARING
Slettringen	337.8 m	77.8 km	1.4	163°
Ross Isle, Well 6506/12-3	511.5 m	88.2 km	1.4	333°
Halten	345.0 m	81.1 km	1.5	103°
Nortrym, Well 6507/7-2	439.1 m	114.4 km	1.8	350°
Vega	328.8 m	241.8 km	1.9	52°

*Line of Sight ratio = Range/3.57 $(\sqrt{h}$ onboard + $\sqrt{h}$ remote)

The delay refers to total delay with Mobile S/N 453.

Delays onboard Borgny Dolphin:

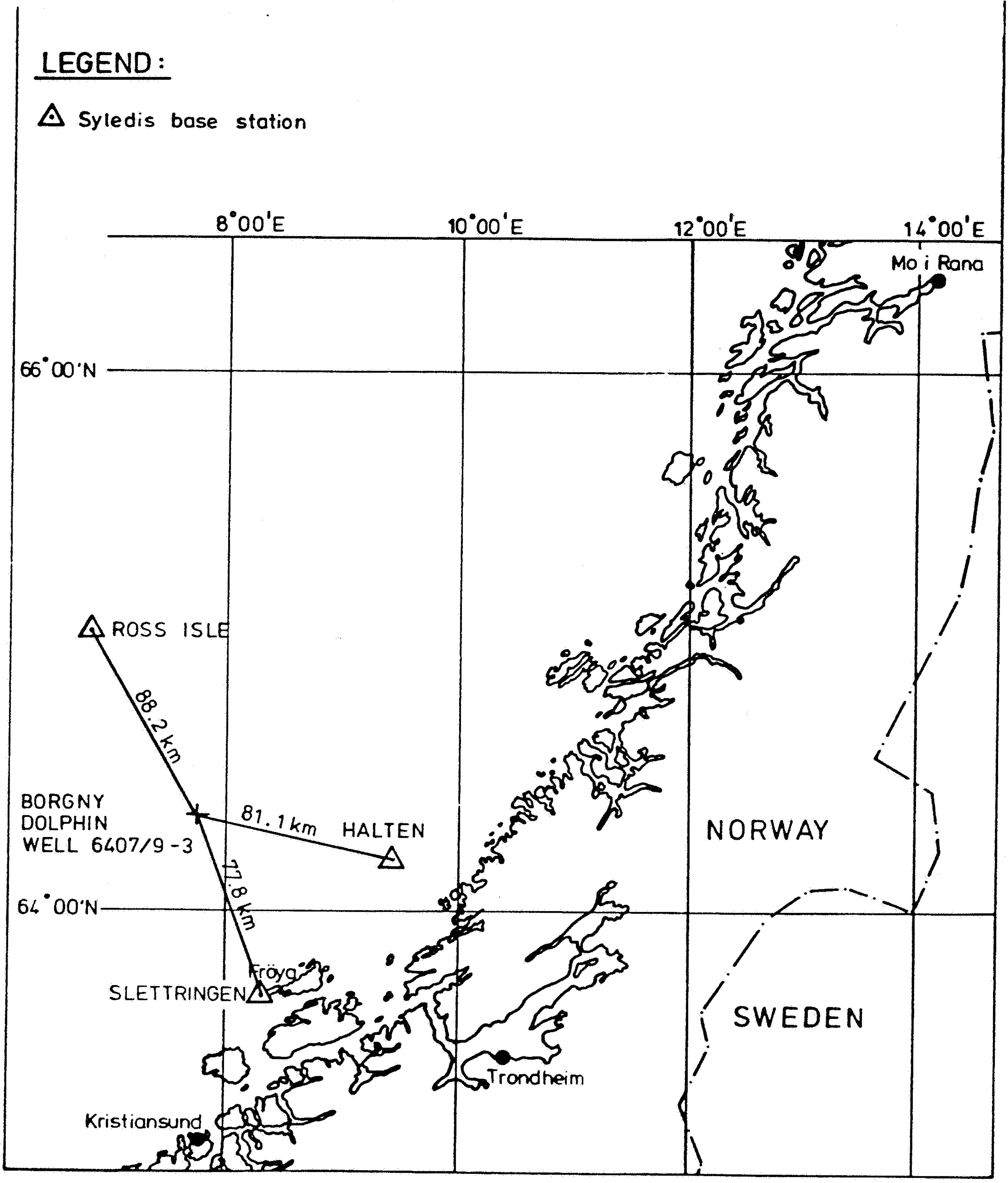
Antenna	1.1 m
Main cable	148.2 m
Extra cable inside wheelhouse	15.0 m
	164.3 m
Mobile S/N 453	153.0 m
Total delay	317.3 m

Stations in use were:

1	Slettringen
2	Ross Isle, Well 6506/12-3
3	Halten, Well 6507/7-2

Signal strength was good (See Appendix 1). The standard deviation of measured ranges, obtained from the fix calculation was 0-4 metres. All stations were stable, except Halten which in some shorter periods was slightly unstable, but without creating any problems.

The map below shows the Syledis beacon station locations:



2.4 NAVIGATION TO LOCATION

While in transit to the Haltenbanken Field, the rig was navigated by means of a Sjark Decca Main Chain Receiver. The receiver provided continuous position fixing through the display of latitude and longitude. In addition, it provided bearing and distance to intended location and average speed.

At first, the Decca system did not perform very well, but after placing the antenna higher, the performance improved.

The Magnavox MX-1502 B Satellite Receiver was operated in Navigate Mode. In this mode the receiver computes a continuous dead-reckoned position based on the updated position from the last satellite pass and the rig's speed and heading which are manually input by the user.

Provided the rig's speed and heading were updated regularly the MX 1502 gave a good agreement with the position from the Sjark Decca receiver.

For the final approach to location and maneuvering with anchors, a Sercel Syledis Navigation System was used. The Syledis MR3-B mobile was interfaced to a Hewlett Packard 9845 S computer for computation of real time position, graphic display and data recording on magnetic tape.

The Syledis antenna was mounted at the top of the derrick and connected to the receiver in the wheelhouse by a calibrated cable. Details of the antenna offset from derrick centre are given in Appendix 3.

At 0100 hours, 1 May, the rig was within the coverage area of the Syledis chain. At the same time Borgny Dolphin started transmission of synchronization signal for the chain.

The approach to location was made along the heading of anchor no. 8 which was the fist anchor to be dropped. This took place at 1035 hours, 1 May.

Logging of Syledis and final satellite positioning commenced when tension test was completed at 1705 hours, 2 May.

2.5 SYLEDIS STATISTICAL ANALYSIS

Below is a summary of all the logged Syledis ranges with their mean values and standard deviations.

Beacon Station	Number of Accepted	Mean Range	Standard Deviation	Number of Omitted
Slettringen	704	78 120.2 m	1.1 m	7
Ross Isle, Well 6506/12-3	692	88 762.9 m	1.6 m	19
Halten, Well 6507/7-2	677	81 421.1 m	3.0 m	30

Readings deviating more than 3 sigma from the mean values were omitted from the computation.

By applying a least squares adjustment to the mean ranges, minimizing the range residuals, and applying the antenna offset, the Well centre co-ordinates, referenced to the European Datum 1950 have been calculated:

WELL CENTRE, SYLEDIS

GEOGRAPHIC		UTM	
Latitude	64° 19' 48.56" N	Northing	7 134 552.5 m
Longitude	07° 46' 29.69" E	Easting	440 786.2 m

The UTM co-ordinates refer to Zone 32 with central meridian 09 degrees east.

This gives a position 20.3 metres in direction 235.4 degrees from the satellite derived position. (See Appendix 6).

After a least squares adjustment of the mean Syledis ranges, the standard error of observation of unit weight, one sigma, was found to be 1.9 metres with residuals as follows:

Beacon Station	Residual
Slettringen	1.3 m
Ross Isle, Well 6506/12-3	1.4 m
Halten, Well 6507/7-2	0.3 m

2.6 DECCA MAIN CHAIN

After the rig was in position the following data from Decca 4E Main chain was recorded.

Date	Time	Red	Green	Purple	Latitude	Longitude
2/5	1715	H14.08	C41.06	A67.40	64° 19.82' N	7° 46.51' E
2/5	1830	H14.10	C41.07	A67.44	64° 19.83' N	7° 46.50' E
2/5	2245	H14.14	C41.06	A67.39	64° 19.84' N	7° 46.52' E
3/5	0945	H14.10	C41.06	A67.41	64° 19.83' N	7° 46.51' E
3/5	1205	H14.10	C41.06	A67.41	64° 19.82' N	7° 46.52' E
				MEAN	64° 19.828 N	7° 46.512' E

No correction on any lane is used. Positions refer to the European Datum 1950.

Applying the antenna offset given in Appendix 5, the following Decca Main Chain position for the Well centre, was calculated:

WELL CENTRE, DECCA MAIN CHAIN

GEOGRAPHIC		UTM	
Latitude	64° 19' 49.6" N	Northing	7 134 584 m
Longitude	07° 46' 33.3" E	Easting	440 835 m

This is 38 metres in direction 58 degrees from final position.

3. FINAL POSITIONING WITH SATELLITE DATA

3.1 OBSERVATIONS

The final position of BORGNY DOLPHIN was derived from recorded satellite data, using the single point positioning method. This method is the process of collecting data from multiple satellite passes at one location, along with predicted ephemeris, to determine the independent station position. Accuracy of the final position is largely dependent on the quality of the orbital prediction process. Sources of error are ionospheric and tropospheric refraction, movements of the antenna during the observation period, imbalance in satellite passes, reflection of signals, elevation of the satellites, etc.

The MX-1502 Geoceiver tracks signals from the TRANSIT satellites and stores the raw data on magnetic tape cassettes for post-processing. From good quality passes, 3-D positions are calculated on-line. These are sequentially adjusted positions.

Final observations on BORGNY DOLPHIN started at 1715 hours, 2 May and were completed at 1200 hours 7 May 1985.

During the observation period, 144 satellite passes were recorded by the MX-1502 Geoceiver. 66 passes were approved for on-line 3-D computation.

3.2 DATUM SHIFT

Since the computations are carried out on the satellite's geodetic system (NWL-10D datum), a datum shift must be applied to the co-ordinates of the satellite antenna to obtain a position in the European Datum 1950 (ED 50).

The transformation parameters shown below are applicable in Norwegian waters north of 64°, provided the station co-ordinates have been established using the satellites "Broadcast Ephemerides".

Δx	=	+ 92.2 m	
Δy	=	+ 89.7 m	Translation
Δz	=	+ 129.7 m	
ϵ_x	=	+ 0.00"	
ϵ_y	=	+ 0.00"	Rotation
ϵ_z	=	+ 1.10"	
S	=	- 2.62 ppm	Scale correction

(X, Y and Z constitute a right-hand co-ordinate system fixed in the spheroid. X and Y lie in the equatorial plane and the Z-axis coincides with the rotation axis of the spheroid. X is positive towards the Prime Meridian and Y towards 90° E longitude. Z is positive towards the North).

3.3 PROCESSING

All the raw satellite data stored on magnetic tape cassettes were analysed and reprocessed on our VAX 11/780 computer, utilizing the Magnavox MAGNET programme. The main advantages of this programme compared to on-line processing are improved techniques for satellite orbit recovery and more sophisticated models for the tropospheric refraction correction. Further, the benefits of having all data available at the start of the processing, together with the general advantage of a larger computer should be appreciated.

The quality of a pass is normally characterized by the Root Mean Square (RMS) value for the scatter of all the Doppler counts in that particular pass, expressed in centimetres (cm). For onshore work a 25 cm acceptance limit is normally used, while rig observations are considered satisfactory if this value can be set to less than 40 cm.

Based on processing with different limits on the RMS value, the final position was determined with an RMS acceptance limit of 30 cm.

A total of 76 passes were accepted for the post processing 2-D computation by the Magnet program, resulting in a 47% rejection of passes during post-processing. This high rejection was mainly because of interference between the satellites. In order to obtain better balancing of the data. 12 passes were removed, and consequently 64 passes were used in the final solution. 57 met the main acceptance criteria and were included in the final 3-D processing. This results in a 11% rejection of passes during final point-processing.

The following table describes the balance of passes:

NW	NE	SW	SE	TOTAL
14	14	15	14	57

N and S indicate a Northerly or Southerly ascension of the satellites and E and W indicate whether they passed to the East or the West of the observer.

By utilizing these passes we have found the satellite antenna position onboard BORGNY DOLPHIN, referenced to the satellite datum to be:

Latitude: 64^{o} 19' 48.00" N
Longitude: 07^{o} 46' 21.49" E
Height: 60.3 m

Applying the datum transformation parameters gives the position referenced to European Datum 1950:

SAT. NAV. ANTENNA

GEOGRAPHIC		UTM	
Latitude	64° 19' 49.12" N	Northing	7 134 570.3 m
Longitude	07° 46' 28.28" E	Easting	440 767.6 m
Height	26.7 m		

The UTM co-ordinates refer to Zone 32 with central meridian 09 degrees east.

3.4 REDUCTION TO WELL CENTRE

The distances from satellite receiver antenna to the Well centre were scaled from an as-built plan of the rig. The rig heading, read from the gyrocompass, was 261.5 degrees. See Appendix 3, Antenna Offsets. With these data, the Well centre co-ordinates have been computed as:

WELL CENTRE

GEOGRAPHIC		UTM	
Latitude	64° 19' 48.94" N	Northing	7 134 564.0 m
Longitude	07° 46' 30.91" E	Easting	440 802.9 m

The co-ordinates refer to the European Datum 1950 and UTM Zone 32 with Central Meridian 09 degrees east.

Well centre is 10.8 metres off intended location in direction 67.7 degrees. See Appendix 6.

3.5 GEOID HEIGHT

The height from sea level to the electrical centre of the antenna was:

Roof wheelhouse above M.S.L.	22.3 m
Antenna height	2.65 m
Height above M.S.L.	25.0 m
Height above ED50 ellipsoide	26.7 m
Geoid height	1.7 m

In addition to the uncertainty in satellite data, the accuracy of the geoid height is directly proportional to the accuracy of measuring the antenna height above sea level. A third source of uncertainty is the distance between sea level and geoid due to meterological conditions.

4. ACCURACY CONSIDERATIONS

Based on the scatter of the satellite observations, a one sigma value of 3.9 metres has been computed for the latitude, 2.7 metres for longitude, giving a horizontal position accuracy of 4.7 metres.

This is within the equipment manufacturer's quoted accuracy obtained for single point positioning.

Uncertainty in the applied datum shift constants will influence the absolute position accuracy. The uncertainty between the satellite datum and the Norwegian Geodetic Network is believed to be better than 5 metres.

Offset from antenna position to derrick centre position may introduce an additional error of 1-2 metres due to uncertainty in rig heading and distance measurements.

Stabekk, 23 May 1985
for A/S G E O T E A M

Roar Normann Nilsen

Roar Normann Nilsen

Dag Høgvard

FIELD LOG

All Times refer to Local Norwegian Summer Time

Monday, 29 April 1985

1700 Leaving Flesland Heliport. Personnel from A/S GEOTEAM: U. Larsen and D. Høgvard.

1830 Arrived Borgny Dolphin.

2100 All equipment mounted. Decca Main Chain receiver in operation. Sat. nav. in operation in Navigate Mode.

Tuesday, 30 April 1985

Decca Main Chain receiver did not operate well. The antenna was mounted somewhat higher which solved the problem. After passing Stadt, Chain 4E, Trøndelag, was in use.

Wednesday, 1 May 1985

0100 Started transmitting Syledis synchronization signal.

0600 Started final approach to location.
Syledis stations in use:
1. Slettringen
2. Ross Isle, Well 6506/12-3
3. Halten, Well 6507/7-2

AGC:
1. 49%
2. 29%
3. 32%

which remained stable through most of the navigation period.

Standard deviation on a measured Syledis range, obtained from the least square navigation calculation was between 0-4 metres.
Comparison between Decca Main Chain and Syledis gave a difference of maximum 100 metres.

1035 Anchor no. 8, as the first, on bottom.
1320 Anchor no. 3, as the second, on bottom.

<u>Thursday, 2 May 1985</u>

1627 Anchor no. 10, as the last, reset.
1705 Tension test completed.
1715 Commenced logging of satellite data.
1720 Commenced logging of Syledis data.
1850 Rigs gyro read as 261.5^{o}.
1857 Stopped logging of Syledis.
1900 Slettringen switched off.
2100 Slettringen on air again.

<u>Friday, 3 May 1985</u>

1000 Switched off Syledis equipment. Dismounted Syledis equipment.
1205 Decca Main Chain receiver swithced off.
1800 Syledis equipment and one computer demobilized. Operator D. Høgvard left the rig.

<u>Saturday, 4 May 1985</u>

Logging of TRANSIT continued.

<u>Sunday, 5 May 1985</u>

Logging of TRANSIT continued.

Monday, 6 May 1985

Logging of TRANSIT continued.

Tuesday, 7 May 1985

1200 Last satellite pass recorded 66 3-D passes.
1445 Operator and equipment left the rig.
1530 Arrived Kristiansund.

MARINE REPORT

Date	Time	Temp. °C	Pressure (mbar)	Wind speed/dir (ms^{-1}/o)	Weather/ sea state
29/4	2000	12	1012	Var/3	a/2
	2400	8	1012	Var/2-3	a/2
30/4	0400	6	1011	Var/3	a/2
	0800	10	1011	ESE/3	a/2
	1200	6	1011	ESE/3	a/2
	1600	6	1012	NE/3	a/2
	2000	6	1012	NE/4	a/3
	2400	5	1011	NE/25	b/3
1/5	0400	4	1010	NE/25	b/3
	0800	6	1010	NE/25	b/3
2/5	0000	7	1010	ENE/32	b/3
3/5	0000	6	1010	NE/20	b/4
	0400	6	1012	NE/3	b/4
	0800	7	1013	ENE/15	c/3-4
	1200	8	1013	ENE/20	b/3-4
	1600	8	1013	ENE/16	b/3-4
	2000	6	1012	ENE/16	b/3-4
	2400	6	1012	ENE/14	b/3-4
4/5	0400	6	1012	ENE/14	c/3
	0800	7	1011	ENE/15	b/3
	1200	8	1011	ENE/24	b-c/3
	1600	8	1011	ENE/25	c/3
	2000	8	1009	E/32	c/3-4
	2400	6	1008	E/28	c/3-4
5/5	0400	6	1007	E/19	c/3-4
	0800	10	1006	E/5	c/3
	1200	7	1006	SE/6	b-c/2-3
	1600	7	1008	SW/10	c/2-3
	2000	8	1012	SSE/10	c/2-3
	2400	7	1013	E/14	b/2-3

Date	Time	Temp. °C	Pressure (mbar)	Wind speed/dir (ms^{-1}/o)	Weather/ sea state
6/5	0400	7	1016	SSE/6	b/2-3
	0800	8	1021	SE/5	a/2
	1200	8	1023	SE/6	a/2
	1600	8	1025	E/12	a-b/2
	2000	8	1025	E/18	a-b/2
	2400	8	1026	E/20	a-b/2
7/5	0400	8	1026	E/15	a-b/2
	0800	8	1025	E/12	a-b/2

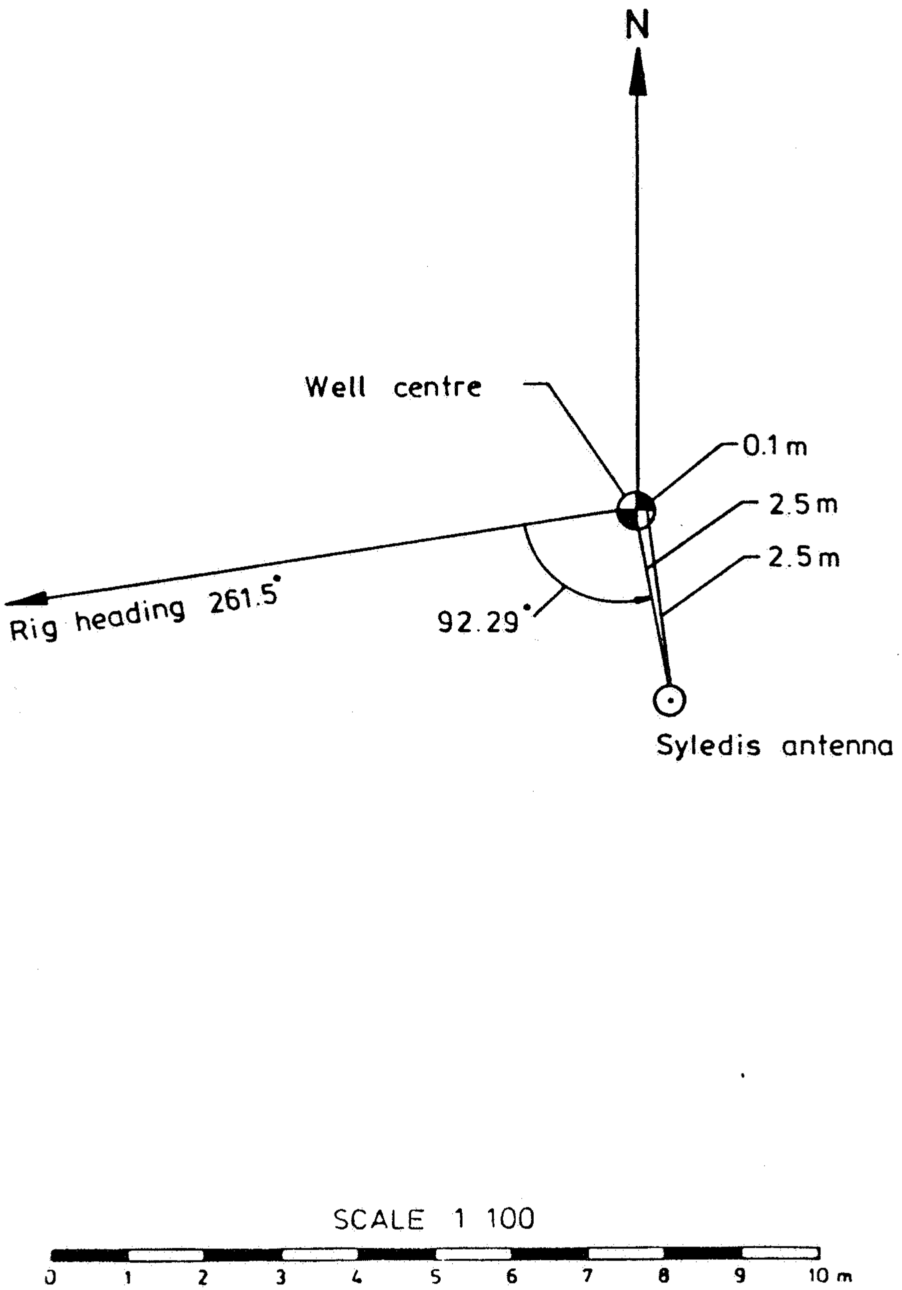
*** Weather**

symbol	description
a	clear/partly cloudy
b	variable cloudiness
c	partly cloudy/overcast

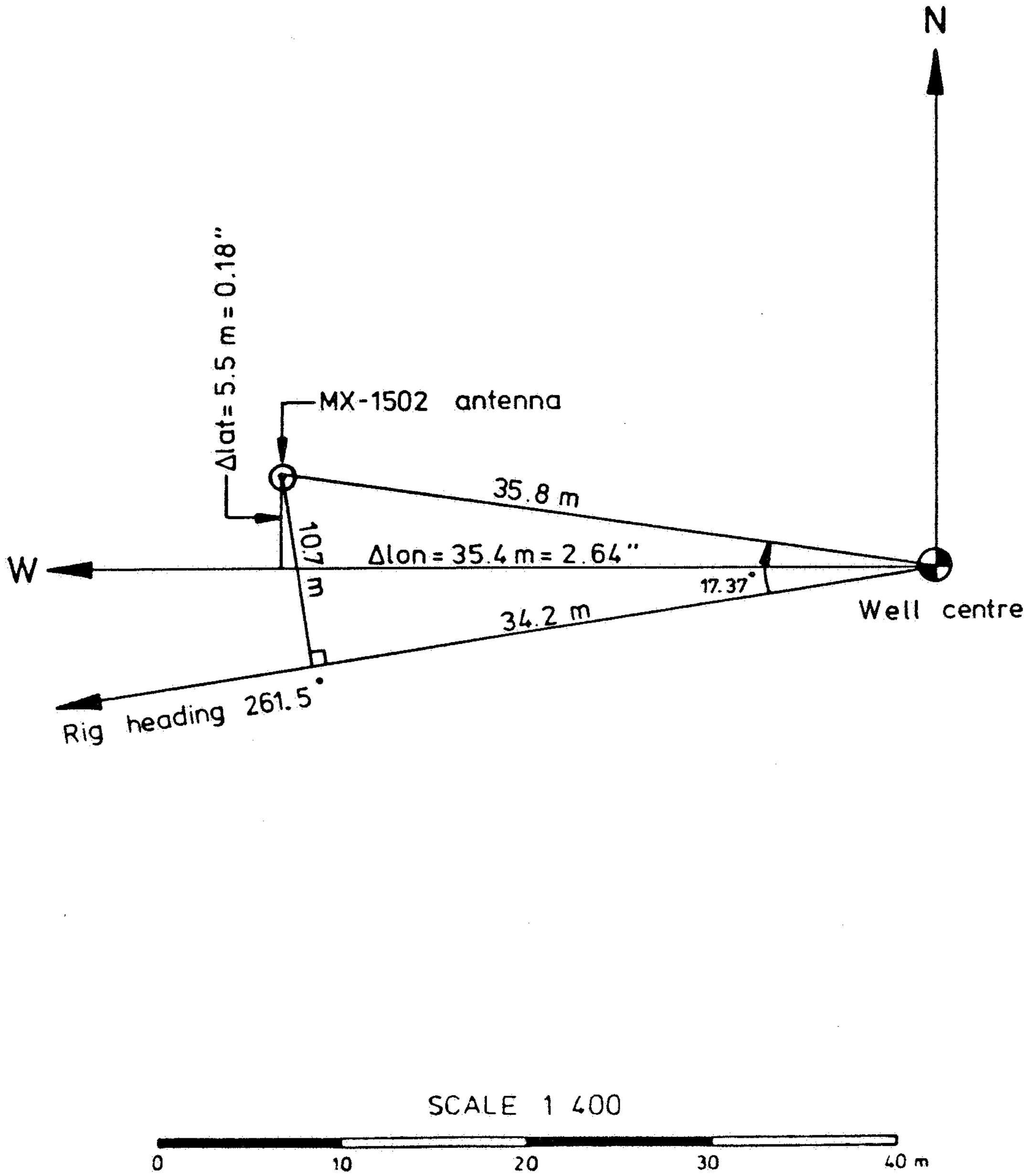
Appendix no.: 3

Project no.: 30068

SYLEDIS ANTENNA OFFSET



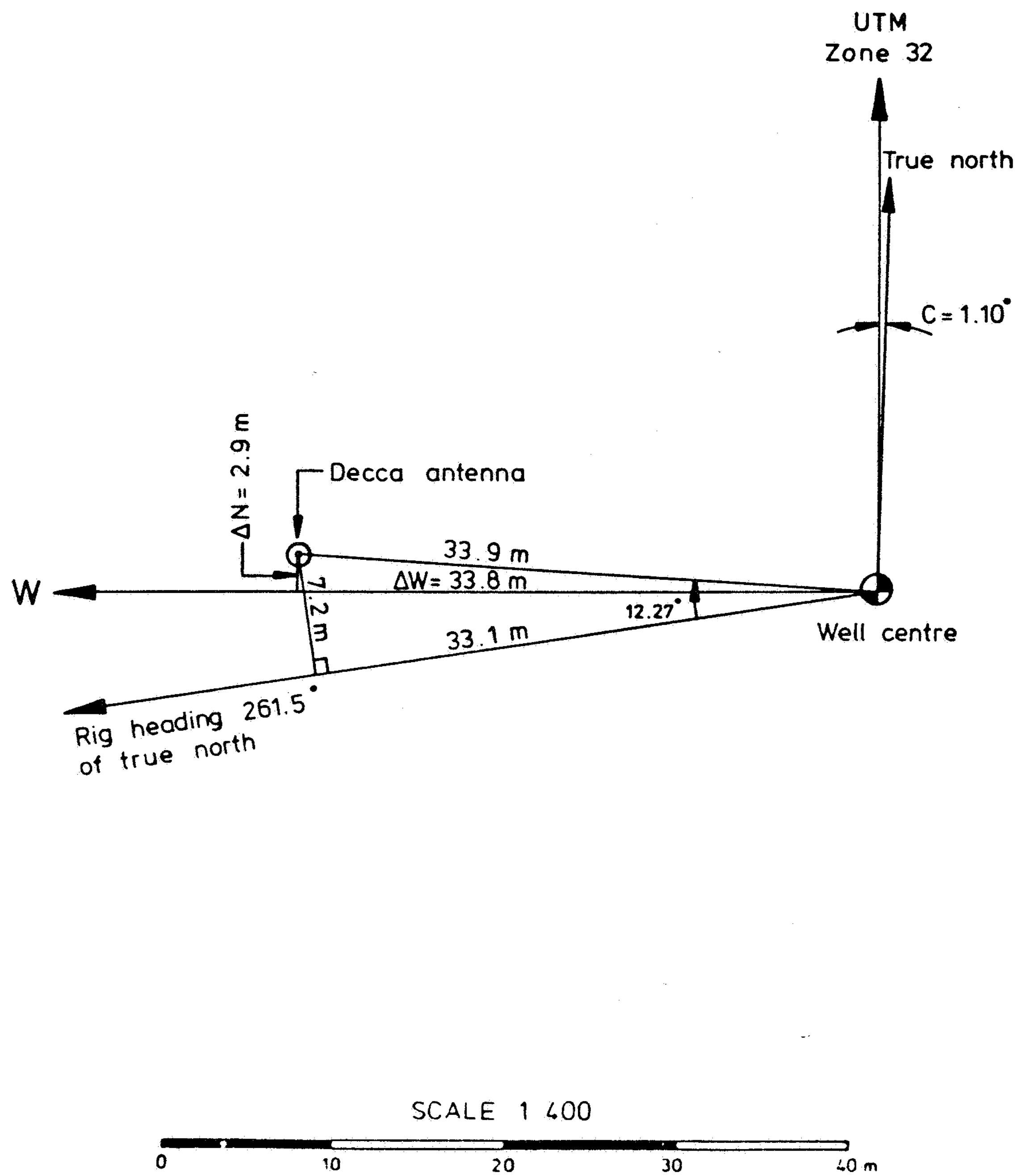
SAT. NAV. ANTENNA OFFSET



Appendix no.: 5

Project no.: 30068

DECCA MAIN CHAIN ANTENNA OFFSET



Appendix no.: 6

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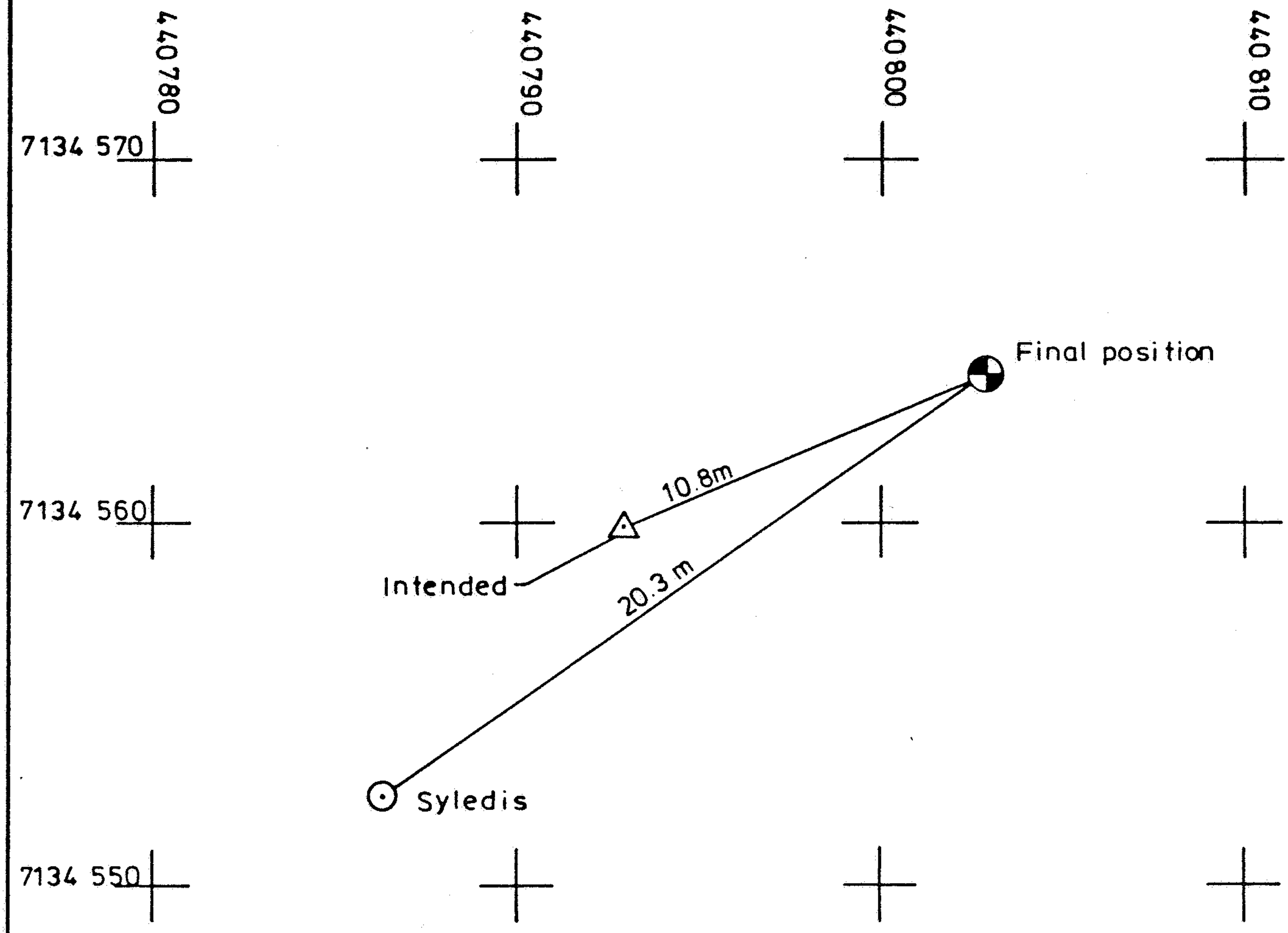
POSITION PLOT



UTM, zone 32

SCALE 1 200

0 5 10 15 20 m

DRILLING HISTORY, 6407/9-3 (BORGNY DOLPHIN)

The rig Borgny Dolphin began moving out from the Sandefjord yard following a minor refit at 19:00 hrs, 27.04.85, the contract with Norske Shell commencing at 07:00 hrs 28.04.85 whilst the rig was on tow.

Having arrived at the Haltenbanken (Draugen) appraisal well location 6407/9-C (3) at 10:00 hrs 01.05.85, the anchors were run and the rig ballasted to drilling draught. The rig was manoeuvered onto location with the aid of SYLEDIS and SIMRAD navigation equipment and the final position was:

N 64 deg 19' 48.94 sec
E 07 deg 46' 30.91 sec

A seafloor investigation gave 1 m penetration with 4000 lbs weight on a 26" bit. The temporary guide base was run and landed on seabed with zero degrees on the level indicator. The following distances were established:

Derrick floor to seabed	304 m
Water depth	279 m

At 22:30 hrs 03.05.85 the well 6407/9-3 was spudded with a 26" bit and 36" hole opener. After 11 m drilling, using viscous mud, boulders were encountered. The assembly was changed to a 17½" bit and 26" hole opener. The 26" pilot hole was drilled to 383 m and opened to 36" to a depth of 384 m using seawater and viscous pills. Viscous mud was spotted in the hole and 6 joints of 30" casing were run with a modular template/ primary base structure. This structure allows for possible future hook-up of flow-line pulling-in or cantilever guide base modules. The 30" casing was cemented with the shoe at 376.5 m and the housing at 301 m. The 30" shoe track and 1 m of new formation were drilled with a 26" hole opener and 14-3/4" bit.

The marine riser with hydraulic latch and dump valve was run and latched onto the 30" housing. A 14-3/4" pilot hole was drilled to 780 m using gelled seawater and viscous pills. The hole was circulated clean before the following logs were run:

DIFL/ACL/SP/GR	(Run no. 1)
CDL/CN/GR/CAL	(Run no. 1)

(There were no indications of shallow gas on the log).

The pilot hole was enlarged to 26" diameter with a hydraulic underreamer assembly. Upon checking the hole size, it was not possible to pass the top of the 26" hole section (384 m) with the 4 armed caliper tool. The section was re-underreamed and again the 4-arm caliper was run. At 550 m the tool stood up. The logged section of the hole was in places severely undergauge. The well was underreamed for the third time and checked for gauge and found satisfactory. The marine riser was circulated to seawater, with 1.11 SG mud left in the hole. The well was observed dead for 2 hrs, and after unlatching the connector the riser was pulled. Before running casing a caliper log was run again, confirming the hole to be acceptable for running casing. 40 joints of 20" 129 lbs/ft, X-52 casing were run and cemented with the shoe at 770 m. A thixotropic lead slurry was used to reduce the possibility of any gas migration during cement setting.

The BOP stack was run on the marine riser and successfully tested. The shoe track was drilled out with a 17½" bit, at the same time changing out the mud to 1.30 SG KCL mud. 5 m of new formation was drilled, and a leak off test gave an equivalent mud gradient of 1.46 SG. The 17½" hole was drilled to 1617 m gradually increasing the mud weight to 1.38 SG, whilst the KCL was maintained at 50 ppb. A check trip was made with a 12-1/4" bit and a further 3 m was drilled to ensure enough pocket for logging the top of the Kimmeridge clay before the following logs were run:

DIFL/ACL/SP/GR	(Run no. 2)
CDL/CN/GR/CAL	(Run no. 2)
COR gun (25 shots)	(Run no. 1)

During logging 20 m of fill was observed. A wiper trip was made to clean the hole and a viscous pill was spotted on the bottom before 112 joints of 13-3/8", N-80, 72 lbs/ft, BTC casing were run and cemented with the shoe at 1601 m.

Lost accumulator pressure on the BOP control lines made it necessary to pull the BOP. Leaking hose connections were repaired and the BOP stack tested before it was run back and landed. The accumulator was observed dumping fluid and the lower marine riser package was pulled. The accumulator was tested on surface and the LMRP re-run and latched to the BOP. Upon testing the BOP, the outer choke failsafe valve was not working. The BOP was again pulled, repaired and tested at surface, then re-run, latched and re-tested satisfactorily. Five days of rig-time were lost on repair of the BOP. Cement was drilled out to the 13-3/8" shoe with a 12-1/4" bit, before the hole was displaced to 1.20 SG chalk mud. The shoe and 3 m of new formation were drilled and a leak-off test performed to 1.66 SG equivalent mud weight. Coring commenced at 1620.5 m in the claystone overlaying the reservoir. The following intervals were cored using a 12-1/4" fibre glass sleeve coring assembly:

Core no. 1	1620.5 - 1621.8 m	recovery 54 %
Core no. 2	1621.8 - 1624.7 m	recovery 52 %
Core no. 3	1624.7 - 1626.7 m	recovery 0 %
Core no. 4	1626.7 - 1627.5 m	recovery 0 %
Core no. 5	1627.5 - 1628.8 m	recovery 38 %

Because of the slow coring rate (60 min per m), poor recovery and uncertainty of the thickness of the Kimmeridge clay overlaying the reservoir, drilling was resumed whilst circulating bottoms up every 3 m. The 12-1/4" hole was drilled to 1634 m where indications of top reservoir were encountered. Coring of the reservoir was continued as follows:

Core no. 6	1634 - 1652 m	recovery 94 %
Core no. 7	1652 - 1667 m	recovery 100 %
Core no. 8	1667 - 1673 m	recovery 83 %
Core no. 9	1673 - 1684 m	recovery 62 %

(Total cored 58.3 m with 80 % overall recovery).

12-1/4" hole was drilled to TD at 1868 m, and TD logging carried out as follows:

DIFL/ACL/SP/GR	(Run no. 3 c)
CDL/CN/CAL/Spectralog	(Run no. 3 c)
DLL/MLL/CAL/GR	(Run no. 3 a)
DIP log	(Run no. 3 a)
Velocity Survey	(by SSL)
FMT	(Run no. 3 a)

SWC (Run no. 3 b) (50 fired, 42 recovered)
CBL/VDL/GR (Run no. 3 a)

16.5 hours were lost during running of the DIP log, contaminated diesel causing the power unit engine to break down. The problem occured when the tool was just 3 m below the casing shoe. The tool was pulled into the casing using the block, and the diesel pump and injectors were replaced. The DIP tool was then recovered and logging resumed following a wiper trip. Following the completion of logging, a check trip was made and 103 joints BTC and 26 joints VAM, 9-5/8" N-80, 47 lbs/ft casing were run and cemented with the shoe at 1843 m, the casing being tested to 4500 psi when the cement plug was bumped. A bit and scraper run was made and TOC was found at 1806 m. A Sperry Sun gyro multishot survey was run from 300 - 1800 m, followed by a CBL/VDL/GR/CCL log (run no. 3b).

An RTTS packer with gauges set in a gauge carrier was run, and the packer set at 1665 m, both weight and pressure tested. The casing was perforated in a shale at 1680 m with 2-1/8" through tubing guns (2 ft, 2½ shots/ft, zero degree phasing). A formation breakdown test was carried out at 1680 m injecting chalk mud of 1.22 SG. Three tests were carried out, resulting in a repeatable fracture initial shut in pressure (ISIP) of 3964 psia.

The RTTS packer was subsequently released and reset at 1717 m, weight and pressure tested. A sand at 1738 m was then perforated as above, and a second formation breakdown test carried out as before resulting in an ISIP of 4456 psia. The RTTS and gauges were recovered and the gauges validated. The perforations were then squeeze-cemented with two cement plugs, the second plug being dressed off to 1672 m (the first cement plug had been set below the perforations after under displacing, necessitating a second attempt). A Baker N-1 bridge plug was then set at 1666 m. An RTTS packer was run in the hole on 5" DP, and set just above the bridge plug which was pressure tested to 4500 psi and thereafter inflow tested satisfactorily by displacing the drillpipe to diesel. The 5" DP was pulled and laid down, and a bit and scraper was run in the hole on 3½" DP in preparation for cleaning up the well

A rig crew strike was declared from 24.00 hrs 13.06.85, and the well had thus to be secured.

Operations were therefore continued by running in the 3½" DP, bit and scrapers to 1666 m. The hole was circulated clean, and the string hung off in the wellhead. The marine riser and lower marine riser package were pulled. A collet connector was run and landed on top of the BOP stack for protection. The well was standing secured at 23:30 hrs 15.06.85.

The strike was declared over at 12:00 hrs 28.06.85 by government intervention. Total time lost due to the strike was 16 days and 19.5 hours.

Problems with screwing into the collet connector with the retrieving tool, made it necessary to attempt to retrieve the connector by using the handling strops left on the connector, together with slings run on drillpipe. The collet connector was lifted off the BOP and the rig moved 50 ft forward before the connector was pulled. In the splash zone the handling strops parted and the connector was lost to the seabed.

The BOP and the seabed were inspected with the ROV and no damage could be seen on the BOP. No objects were observed inside a search radius of 200 ft around the BOP, however, a crater 30 ft from the well indicated the possible position of the connector, having sunken into the seafloor.

The marine riser was run and latched to the BOP stack which was subsequently function tested. Following function testing of the BOP, the hang-off tool and drill pipe were retrieved, and a bit and scraper run made to 1666 m. The well was then displaced to seawater discarding the chalk mud, and high viscous pills were used to sweep out solids. A 50 bbl, 15 percent HCL acid pill was circulated, followed by a 50 bbl caustic pill, with half a circulation volume of seawater as a spacer between the two pills. These pills were circulated slowly (4 BPM) around the system for optimum clean out effect.

Following a scraper trip to the well head, the BOP was sucessfully pressure tested and the bit and scraper were run back to bottom. The well was circulated for 11 hours at high rate (10 BPM) with seawater until the turbidity of the returns had reached a stable minimum of 6 NTU for the last 3 hours of circulation. The hole was then displaced to 1.15 SG clean filtered brine using a 20 bbl viscous pill as spacer. The brine was further circulated for 11 hours through 2 micron nominal filters and 10 micron absolute filters in series, until the cleanliness was again stabilized with a turbidity of less than 3 NTU, for the last 3½ hours of circulation.

Dresser - Atlas ran a gauge ring / junk basket, and set a Baker F-1 sump packer at 1646 m.

A space-out/dummy run was made with the subsea test tree (SSTT), lubricator valve and 5", 15 lbs/ft, L-80 VAM tubing riser, landing the fluted hanger in the wearbushing and closing the lower pipe rams to make an impression on the slick joint. The 5" riser was pulled and had to be laid down because the stands were too long to be racked back in the derrick.

The perforating guns (12 m of 6", 12 SPF, 120^0 phasing Schlumberger guns) and associated subassemblies were made up, and pressure tested to 5000 psi. The assembly was run in the hole on 5" tubing up to the position of the fluted hanger, wherafter one white painted joint was installed, and running in continued on 3½" DP to sting into the sump packer. The lower pipe rams were closed around the white painted single for impression and the string was pulled back to space out the perforating guns. The string was run back on the 5" tubing riser including SSTT and lubricator valve, pressure tested to 5000 psi, the flowhead and flowlines rigged up and the fluted hanger was landed into the wearbushing, positioning the guns in the interval 1630.5 - 1642.5 m BDF.

A 1- 11/16" GR correlation log was run inside the string and confirmed the guns to be on depth. The flowhead was pressure tested to 5000 psi, brine circulated and the packer set by pressuring up the tubing to 3000 psi against a wireline plug. The sump was tested to 1000 psi, the middle pipe rams closed around the slick joint and the annulus tested to 500 psi. In order to displace the tubing to diesel prior to perforating, the MORV was cycled with the cement pump unit until one cycle was left before the MORV was due to open.

In order to clearly see the MORV open on the next cycle, an attempt was made to apply 200 psi onto the annulus.

Rig pump no.2 was thus lined up to the annulus, and after having pumped 2.2 bbls of brine without noting any pressure on the pressure gauges in the dog house, pumping was stopped to check for leaks and valve line up.

Nothing was found wrong and it was concluded that the lines were still filling. (Prior to this pumping job the choke mainfold had been repaired for leaks). Pumping was resumed, and after 3.5 bbls pumped total, the mud pump pop-off valve went. The pressure gauges in the dog house did not indicate any pressure increase during this operation.

Operations resumed using mud pump no.1 to achieve 200 psi on the annulus. One further pressure cycle was applied to the tubing to open the MORV, and diesel was partially displaced into the tubing until high circulation pressures were suddenly observed. The diesel was reversed out and the DCK-2 kill valve was retrieved by wireline and found to have sheared. A replacement valve was run, the annulus tested to 500 psi, and the tubing to 2000 psi.

Again the MORV was cycled open and the tubing displaced to diesel. Pressure was applied to the annulus to open the PCT prior to running the detonating bar. At 700 psi however, the annulus pressure leaked into the tubing. The DCK-2 killvalve was pulled, and was found to be unsheared. The diesel was reversed out and a blank/dummy plug was run to blank off the side pocket mandrel.

A satisfactory pressure test of 5000 psi was made on the tubing, but when the annulus was pressure tested, it again leaked into the tubing at 700 psi.

The tubing string was pulled, no overpull being required to unset the packer, and upon retrieving the pressure gauges it was found that a pressure of 7900 psi had been recorded downhole at the time when the pop-off valve blew, when attempting to apply 200 psi annulus pressure, i.e. a surface pressure of 5300 psi must have inadvertantly been applied. It was then found that both pressure gauges in the drillers dog house were inoperative, thus the excessive pressure applied to the annulus when the pop off valve blew was not noted, and the following problems were encountered, causing a loss of 4 days rig time.

Analysis of the down hole gauges, and a remote annulus pressure recorder, revealed that the high pressure applied to the annulus sheared the DCK-2 kill valve resulting in a high pressure being trapped below the PCT when it closed. This high pressure, combined with a cooling effect by pumping diesel into the string caused the packer to unset, thereby causing all the subsequent leak problems.

An RTTS was run and set at 1250 m and the casing tested above the packer to 4500 psi. The RTTS was run to 1590 m and the casing above the packer pressure tested to 2500 psi.

Brine was cirulated for 5½ hours to clean up the well (final NTU = 4) and the RTTS pulled. The perforating guns and associated subassemblies were made up and rerun as before, pressure tested and landed with the guns positioned at 1630.5 - 1642.5 m. After having pressure tested, the MORV was opened and the tubing displaced to diesel giving a drawdown of +/- 400 psi on the formation. The MORV was closed and the detonating bar run on wireline to tag the PCT. The PCT failed to open with annulus pressures up to 2700 psi, but it finally opened at 3200 psi. Communication between the tubing and the annulus was observed, the diesel was thus again reversed out. A leaking valve on the mud manifold was isolated and the system tested satisfactorily. The tubing was displaced to diesel again.

The detonating bar was run on wireline with the well closed in at surface, and the interval 1630.5 - 1642.5 m was perforated at 08.22 hours on 11.07.85.

The well was backsurged on fully opened chokes into a seperator full of water for 20 bbls of flow, and then flowed through a 14/64" choke for clean up at low rate. When the produced fluids were clean (after +/- 5 hours) the flow was directed through the separator on a 16/64" choke, THP 525 psig, 600 BPD oil, and a GOR of 240 SCF/B. The well was then shut in at the PCT for a 2 hours pressure build up.

The well was killed by bullheading a 25 bbl viscous carbonate pill displaced with 70 bbl brine, the MORV was opened and the well circulated dead. The packer was unseated and the well observed dead before being circulated to a turbidity level of 6 NTU. The perforating string was pulled and a sand bailer run was made on wireline without any indication of fill.

A Baker gravel pack assembly with 5½" screens was run on 3½" DP and landed in the sump packer. The FAB-1 packer was set at 1583 m and after identifying the four work string positions, the gravel pack operation started with a 50 bbls 15% HCL pre-acid job to clean up the perforations. After soaking the acid for ½ hr, 19.5 bbls prepad, 18 bbls gravel pack slurry and 4 bbls post pad were pumped and displaced with brine. Screen out occured after 20.5 bbls pumped with a sharp increase in pressure to 750 psi. A final screen out pressure of 1500 psi was applied. The excess gravel was reversed out of the DP and the success of the gravel pack was reconfirmed with 750 psi surface pressure. The gravel pack work string was pulled out of the packer and a viscous brine pill was spotted above the reverse acting flapper valve. No losses were observed and the string was pulled out of the hole.

The tail pipe subassemblies and the SC-1L Baker packer of the tie back packer assembly were run on 3½" DP to 1621 m. The surface lines and circulating head were installed and the string lowered, shattering the flapper valve while circulating very slowly. The G-22 locator was set down with 20000 lbs on the FAB-1 packer and picked up 1.5 m. The Baker SC-1L hydraulic packer was set at 1571 m by pressuring up slowly the DP in 500 psi increments to 3000 psi, this pressure being held for 15 min to test the tie back packer assembly before pulling out with the SC-1 setting tool.

After having successfully pressure and function tested the BOP, the production test string sub assemblies were made up and run on 5" L-80, 15 lbs/ft VAM tubing up to the position of the fluted hanger, whereafter one white painted joint was installed and running in continued with 3½ DP as riser. The G-22 locator was landed into the SC-1L packer and the lower pipe rams were closed around the white painted single for space out impression purposes. The string was pulled back to the white painted joint, spaced out, and run in on the 5" VAM tubing riser including fluted hanger, slick joint, SSTT and lubricator valve as used for the perforating clean up. The flowhead and surface lines were connected, pressure tested to 5000 psi and the fluted hanger landed in the wearbushing. The PCT, which was run in locked open position, was actuated and closed, before opening the MORV and displacing the string to diesel. The MORV was closed, the PCT opened and the well was flowed for 17½ hrs to clean up with a maximum rate of 2900 BPD at 450 psig THP on a 36/64" choke.

The well was shut in at the lubricator valve and 3 bottom hole samplers with a crystal gauge were run, and the well opened. 2 samples were recovered but the crystal gauge failed.

A 100 bbls 15 % HCl acid stimulation was performed with a 25 bbls viscous brine pill ahead for divertion. The acid was displaced with diesel and soaked for ½ hr. The well was re-opened but died after 2 hrs flow. The tubing contents were reversed out and the tubing re-displaced to diesel whereafter the well flowed to surface, initially through a 20/64" adjustable choke beaning up gradually to maximum rate as follows:

CHOKE 1/64"	THP PSIG	THT F	OIL RATE BPD	GAS MSCF/D	GOR SCF/D	BSW %	DURATION HRS
32	525	70	3100	494	157	0	4½
40	502	76	5100	810	159	0,5	3
48	491	79	6090	740	120	0	3
2 x 40	450	82	8050	788	98	0	4
2 x 64	320	87	12500	1651	131	0	5
2 x 72	296	87	14060	1913	136	0	3½
2 x 88	260	87	15140	1916	127	0	3
2 x 128	242	89	15450	1714	111	0	1½

The well was shut in at surface and two HP crystal gauges with VALTOS memory module and one VALTOS strain gauge were run and landed in the F-nipple at 1630 m. The well was re-opened and flowed at various rates as follows:

CHOKE 1/64"	THP PSIG	THT F	OIL RATE BPD	GAS MSCF/D	GOR SCF/D	BSW %	DURATION HRS
32	558	62	3394	360	106	0	6
2 x 40	457	76	9954	995	100	0	6
2 x 72	306	89	12969	1840	142	0	17
2 x 40	461	79	8093	1005	124	0	7

During the flow period, PVT recombination samples were taken, and at the end of the flow period the well was shut in downhole at the PCT.

After a 24 hour build up period, the gauges were retrieved and 3 bottom hole samplers with one strain gauge were run. The well was flowed for 2½ hours, but when pulling the samplers, it was discovered that the wireline had broken and the samplers left downhole. The samplers fell into the GP sump below the tubing and after unsuccessful attempts to fish, it was decided to leave them in the hole.

An AFH wireline plug was set in the AF nipple at 1619 m in the tie back packer assembly, and the string was displaced to nitrogen to 1400 m via the SSD. The nitrogen pressure was bled of in steps of 500 psi, but at a tubing head pressure of approximately 350 psi, the DCK-2 valve sheared due to the differential pressure between tubing and annulus. The DCK-2 valve was pulled, redressed with stronger shear pins and rerun. The tubing was redisplaced to nitrogen and the pressure bled off in steps of 500 psi down to 300 psi and the AFH plug satisfactorily inflow tested for two hours.

A maximum temperature recorder was run on wireline and showed a temperature of 60,5 °C downhole. 25 kg MCP-47 (a low melting point alloy consisting of Gallium - Indium and Tin) was dumped on top of the plug and the well reverse circulated to brine. The production string was pulled thereafter and a SC-1 packer plug was run and set in the SC-1 packer at 1571 m. 340 kg MCP-47 alloy was dumped on top of the plug. A Baker C-1 bridge plug was run and set at 1543 m, whereafter 234 m of 2 7/8" stinger was run on 3½" DP to 1533 m and 840 lbs sand was dumped on top of the C-1 plug, 20 bbls of high viscous brine pill was spotted from

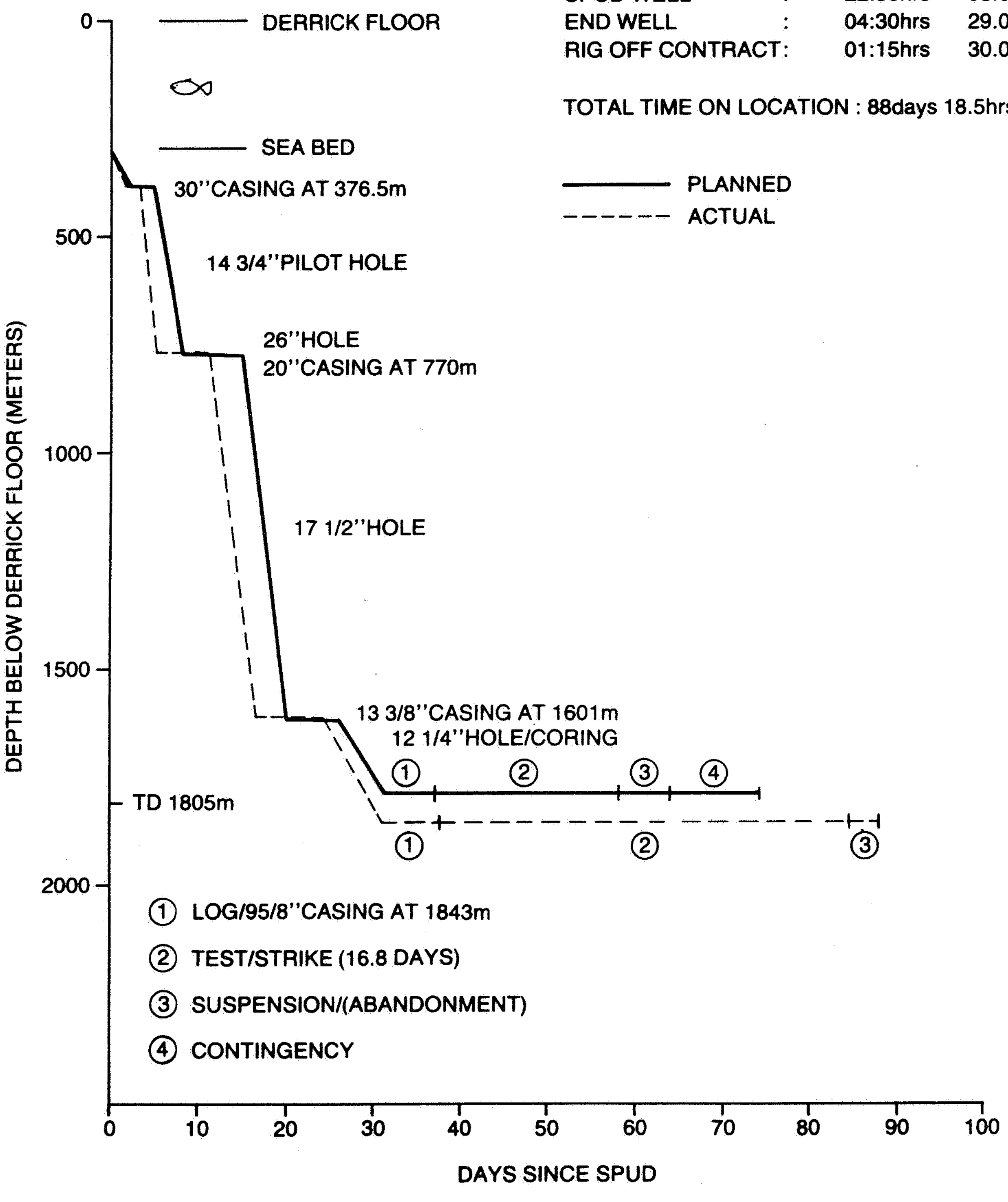
1537-1450 m and suspension cement plug no 1 was set in the 9 5/8" casing from 1450-1253 m.

The well was displaced to 1.25 SG brine and suspension cement plug no 2 was set from 600 - 400 m. The plug was located at 418 m with 20000 lbs and the string pulled and laid down. The BOP was unlatched, the riser and BOP stack pulled, and a corrosion cap was run and landed on top of the wellhead. The divers were jumped to make a final seabed survey before deballasting the rig. The anchors were pulled and the last anchor was bolstered at 04.30 hrs on 29.07.85. The Borgny Dolphin was towed to the Sterk Odder shipyard in Kristiansund, and the rig went off contract at 01.15 hrs on 30.07.85.

6407/9-C (3) DRILLING PROGRESS CURVE

RIG ON CONTRACT	:	07:00hrs	28.04.85
RIG ON LOCATION	:	10:00hrs	01.05.85
SPUD WELL	:	22:30hrs	03.05.85
END WELL	:	04:30hrs	29.07.85
RIG OFF CONTRACT	:	01:15hrs	30.07.85

TOTAL TIME ON LOCATION : 88days 18.5hrs



A/S NORSKE SHELL

G2061/2

CASING DATA WELL NO 6407/9-3

DATE RUN	SIZE	GRADE	WT/FT (LBS)	COUPLING	SHOE DEPTH (MBDF)	REMARKS
6.5.85	30"	X-52	310	STII	376.5	Top of Housing at 301 meters Top joint 30", 1-1/2" wall thickness.
14.5.85	20"	X-52	129	Vetco LS-LH	770	Top of housing at 300 m ATD wellhead 18-3/4" hanger used
22.5.85	13-3/8"	N-80	72	BTC (RH with LH shoe track)	1601	Special drift for 12-1/4" bit. Top of hanger 301.14 msl bdf Hang of point 301.50 msl.bdf
8.6.85	9-5/8"	N-80	47	VAM and BTC	1842.8	Top of hanger 300.6 m msl bdf Hang off point 301.1 m msl bdf Radioactive tracer 1575.05 bdf. 101 JNTS BTC, 26 JNTS VAM,1 XO, 1 BTC PUP

CEMENTATION DATA WELL 6407/9-3

JOB DATE	JOB DESCRIPTION	HOLE SIZE/ DEPTH (M. BDF)	CASING SHOE (M.BDF)	CEMENT TYPE	SACKS USED	SLURRY WEIGHT (PPG)	MIXWATER	ADDITIVES	LOSSES (BBLS)	REMARKS
06.05. 1985	30" Casing	36"/384	376.5	Class G	738 625	13.2 15.8	Seawater Seawater	0.36 gps econolite 3 % BWOC $CaCl_2$	-	Good cement returns to seabed
14.05. 1985	20" Casing	26"/780	770	Class G Class G	2042 495	13.2 15.8	Seawater Seawater	1.5 gps econolite 0.31 lbs/sx caustic 1 % BWOC $CaCl_2$ bwoc	-	Returns to seabed
22.05. 1985	13-3/8" csg	17½"/1617	1601	Class G Class G	1718 398	13.2 15.8	Freshwater Freshwater	0.36 gps econolite 0.22 gps CFR-2L	-	Theoretical TOC 485 m bdf
08.09. 1985	9-5/8" csg	12-1/4"/ 1868 m	1843	Class G Class G	176 598	13.5 15.8	Freshwater Freshwater	0.27 gps CFR-2L 1.23 gps Halad 10L 0.18 gps Econolite 0.15 gps CFR-2L 0.70 gps Halad 10L 0.10 gps econolite	40 bbl -	Theoretical TOC 1410 m bdf
12.06. 1985	Abandonment plug no.1 (Following Frac. test)	9-5/8" csg	-	Class G	182	15.8	Freshwater	0.15 gps CFR-2L	-	Under displaced and reversed out 10 bbl cement squeezed 1.5 bbl 1000 psi. Cement plug: 1806-1762 m.
13.06. 1985	Abandonment plug no.2 (Following Frac test)	9-5/8" csg	-	Class G	131	15.8	Freshwater	0.15 gps CFR-2L	-	Attempted to squeeze at 1000 psi None squeezed away. Cement plug: 1762-1672 m
26.07. 1985	Suspension plug no.1	9-5/8" csg	-	Class G	235	15.8	Freshwater		-	Cement plug: 1450 - 1253 m.
27.06. 1985	Suspension plug no.2	9-5/8" csg	-	Class G	231	15.8	Seawater	2 % BWOC $CaCl_2$	-	Cement plug: 600 - 418 m.

code: cement data 6407/9-3
WELL/7

B I T   R E C O R D   S U M M A R Y   W E L L   N O   6 4 0 7 / 9 - 3

RUN NO.	BIT NO.	BIT SIZE INCH	EMFGR/TYPE	JET SIZE 1 2 3	DEPTH OUT	MTRS	HRS	WOB (1000 LBS)	RPM	PUMP PRESS (PSI)	GPM	MUD WT	MUD VIS	CODE T	CODE B	CODE G	REMARKS
1	1	26	HTC OSC 3A		Penetration test Submarine guide only												
2	1RR	26	HTC OSC 3A	3 X 24	315	11	2 ½	5/8	Slow	250	250/300	Seawater					Boulders
	2	36 H/O	H/O		314	10						+Hi vis slug					
3	3	17 1/2	HTC-OSC 1G	3 X 24	383	68	12½	5/10	60/80			Seawater		2	3	I	
	4	26	H/O									+Hi vis slug					
4	1RR	26	HTC OSC 3A	3 X 24	384	1	½	0/5	80/90	400/1000	800	Seawater					30" setting
	2RR	36	H/O									+Hi vis slug					depth
5	3RR	17 1/2	HTC OSC 1G	3 X 24	385	1	½	10/15	75	1500	900	Seawater					Drill cement +
	4RR	26	H/O									+Hi vis slug					Shoe + pocket
																	+ 1m new form
6	5	14 3/4	SDT	3 X 18	780	395	15	7/25	110	2750	950	1.08	47	3	2	1	
7	5RR	14 3/4	SDT	3 X 22	780	Pilot only								4	3	1	
	6	26	SVH	3 X 16	780	395	29	3/14	110	1400	930	1.10	59	7/8	4		Body intenal
			Underreamer														washed out
8	3RR	17 1/2	HTC OSC 1G	3 X 24	780	Pilot only								2	3		
	6RR	26	Underreamer	3 X 16	780	395	24	0/3	110	1800	1000	1.11	59	1	2	-	
9	7	17 1/2	HTC OSC 1G	3 X 18	1581	801	29.9*	25/50	110	3200	902	1.3	55	6	8	0	* Actual Drilling.
10	8	17 1/2	SEC M44N	3 X 22	1617	36	6	25/50	110	3200	902	1.34	56	1	1	0	
11	9	12 1/4	HTC X 1G	3 X 18	1620	3	0.5	10/20	100	2300	950	1.20	45	8	8	-	Drill shoe-track + 3m formation
12	10	12 1/4	HTC X 1G	3 X 18	1620.5	0.5	-	Fish for junk									
13	11	12 1/4	Reed Weasel	3 corehead	1621.8	1.3	3.5	10/20	90/140	600	450	1.22	47				Core Rec. 51%
14	11RR	12 1/4	Reed Weasel	3 corehead	1624.7	2.9	7	10/23	90/140	800	500	1.22	47				Core Rec. 52%
15	11RR	12 1/4	Reed Weasel	3 corehead	1626.7	2	6	10/23	90/140	800	500	1.22	47				Core Rec. 0 %
16	11RR	12 1/4	Reed Weasel	3 corehead	1627.5	0.8	3	10	120	800	500	1.22	47				Core Rec. 0 %
17	11RR	12 1/4	Reed Weasel	3 corehead	1628.8	1.3	4.5	10/23	90/140	800	500	1.22	47				Core Rec. 38%
18	10RR	12 1/4	HTC X 1G	3 X 18	1634	5.2	3	15	100	2000	1000	1.21	49	2	2	1	Broken teeth
19	12	12 1/4	Reed Weasel	3 corehead	1652	18	2	8	95	670	475	1.22	45	25 %			Core Rec. 94%
20	12RR	12 1/4	Reed Weasel	3 corehead	1667	15	1.5	5/8	100/120	800	475	1.23	48	25 %			Core Rec.100%
21	12RR	12 1/4	Reed Weasel	3 corehead	1673	6	4	10/20	120	780	450	1.23	49	35/40 %			Core Rec. 83%
22	13	12 1/4	Reed Shark Geo 3.		1684	11	7.5	25	130	1100	500	1.23	48	10 %			Core Rec. 62%
23	14	12 1/4	HTC X 1G	3 X 16	1868	184	13.5	15/25	110	2900	800	1.22	47	3	2	1	Broken teeth
24	14RR	12 1/4	HTC X 1G	3 X 16	1868	-	3.5	-	-	-	-	1.21	45				3 wiper trips.
25	15	8 1/2	OWVJ		1803	-	6	-	-	-	-	1.22	48	0	0	1	Scraper run
26	15RR	8 1/2	OWVJ		1672	26	5.5	-	-	-	-	1.23	49				Drill cmt and scraper run
27	15RR	8 1/2	OWVJ		1666	-	13	-	-	-	-	1.22	50				csg scraper

code: bit record 6407/9-3/WELL

FORMATION LEAK OFF TEST DATA WELL 6407/9-3

NO.	DATE	CASING		HOLE		MUD Wt. IN USE		MAX.EQUIVALENT MUD Wt.		STAB.EQUIVALENT MUD Wt		REMARKS
		SIZE (")	DEPTH (M)	SIZE (")	DEPTH (M)	SG	PSI/ 1000 FT	SG	PSI/ 1000 FT	SG	PSI/ 1000 FT	
1	16.5.85	20"	770	17-1/2	785	1.30	563	1.48	641	1.46	632.4	
2	28.5.85	13-3/8"	1601	17-1/2" 12-1/4"	1617 1620	1.25	540	1.66	720	1.66	720	

DEVIATION DATA WELL NO. 6407/9-3

(DISTANCE FROM DRILL FLOOR (DF) TO MEAN SEA LEVEL (M.SL) = 25 M)

DEPTH AH (M.BDF)	ANGLE (DEGREE FROM VERT.)	DIRECTION (DEGREE TRUE)	DEPTH T.V. (M.SL)	NORTHING (M.FROM LOCN)	EASTING (M.FROM LOCN)	DOG LEG (^{o}/ 100 M)
300	Tie co-ordinates		300.00	0.00	0.00	0.00
400	0.42	30.4	400.00	0.42	0.19	0.09
500	0.51	27.2	499.99	1.10	0.56	0.03
600	0.38	30.1	599.99	1.79	1.02	0.07
700	0.30	59.7	699.99	2.11	1.57	0.03
800	0.35	22.4	799.99	2.53	1.81	0.03
900	0.21	77.0	899.98	2.82	2.10	0.01
1000	0.27	135.6	999.98	2.62	2.39	0.02
1100	0.53	153.0	1099.98	1.95	2.81	0.03
1200	1.13	111.2	1199.97	1.17	3.96	0.07
1300	1.02	112.5	1299.95	- 0.48	5.82	0.04
1400	1.02	107.9	1399.93	- 0.07	7.47	0.03
1500	0.47	104.4	1499.92	- 0.47	8.89	0.11
1600	0.16	60.8	1599.92	- 0.61	9.17	0.13
1700	0.41	298.2	1699.92	- 0.38	8.85	0.05
1800	0.50	310.9	1799.91	0.11	8.23	0.03
1868 (TD)	0.50	310.9	1867.90	0.50	7.29	0.00 (Extrapolated)

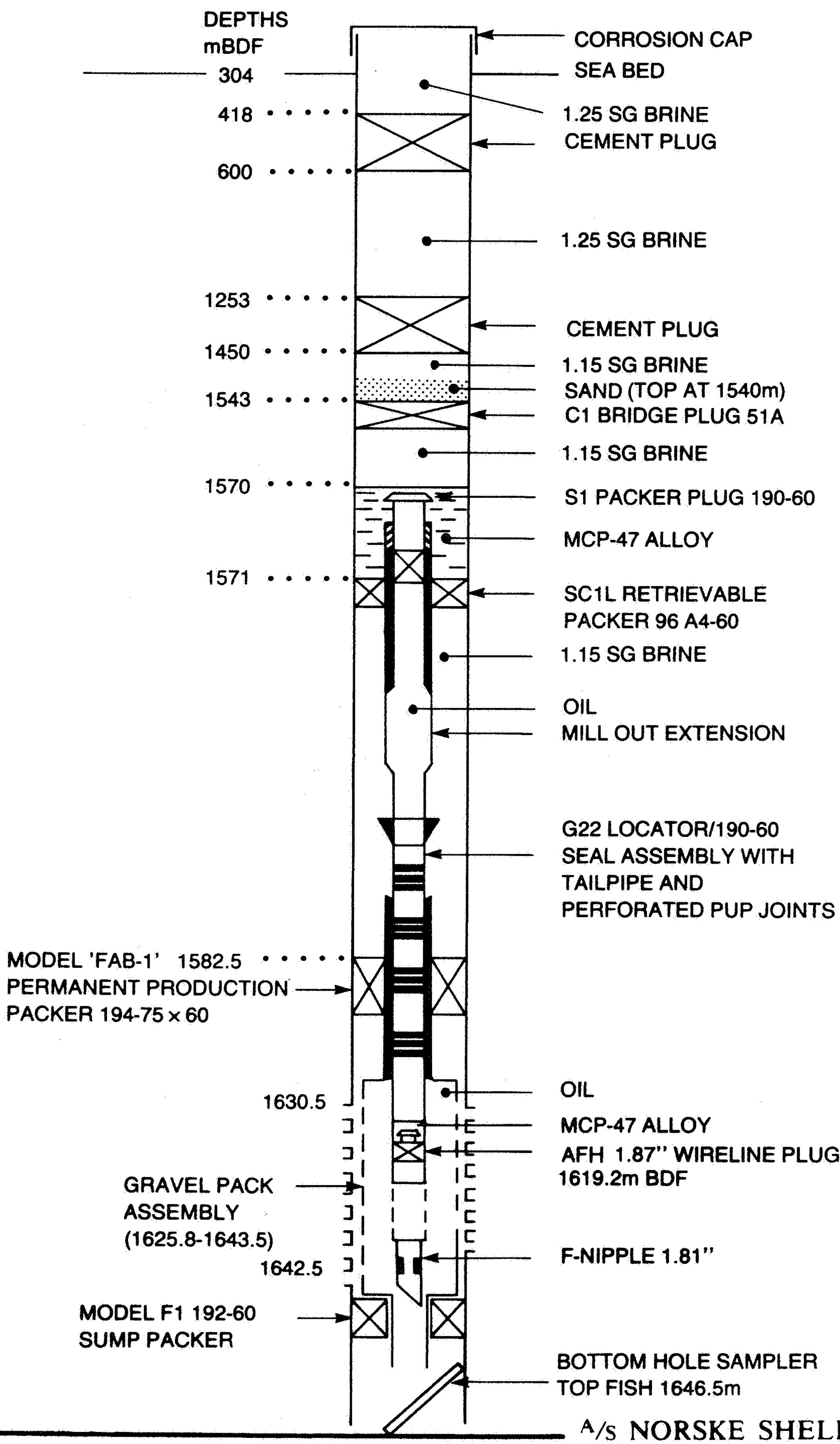
NOTE : Survey points from Sperry Sun Gyroscopic Multishot Directional Survey.

The survey is extapolated from 1800 m - 1868 m (TD)

Rig co-ordinates: N64 deg 19' 48.94"
(Used for tie in to wellhead) E07 deg 46' 30.91"

code: deviat data 6407/9-3/WELL

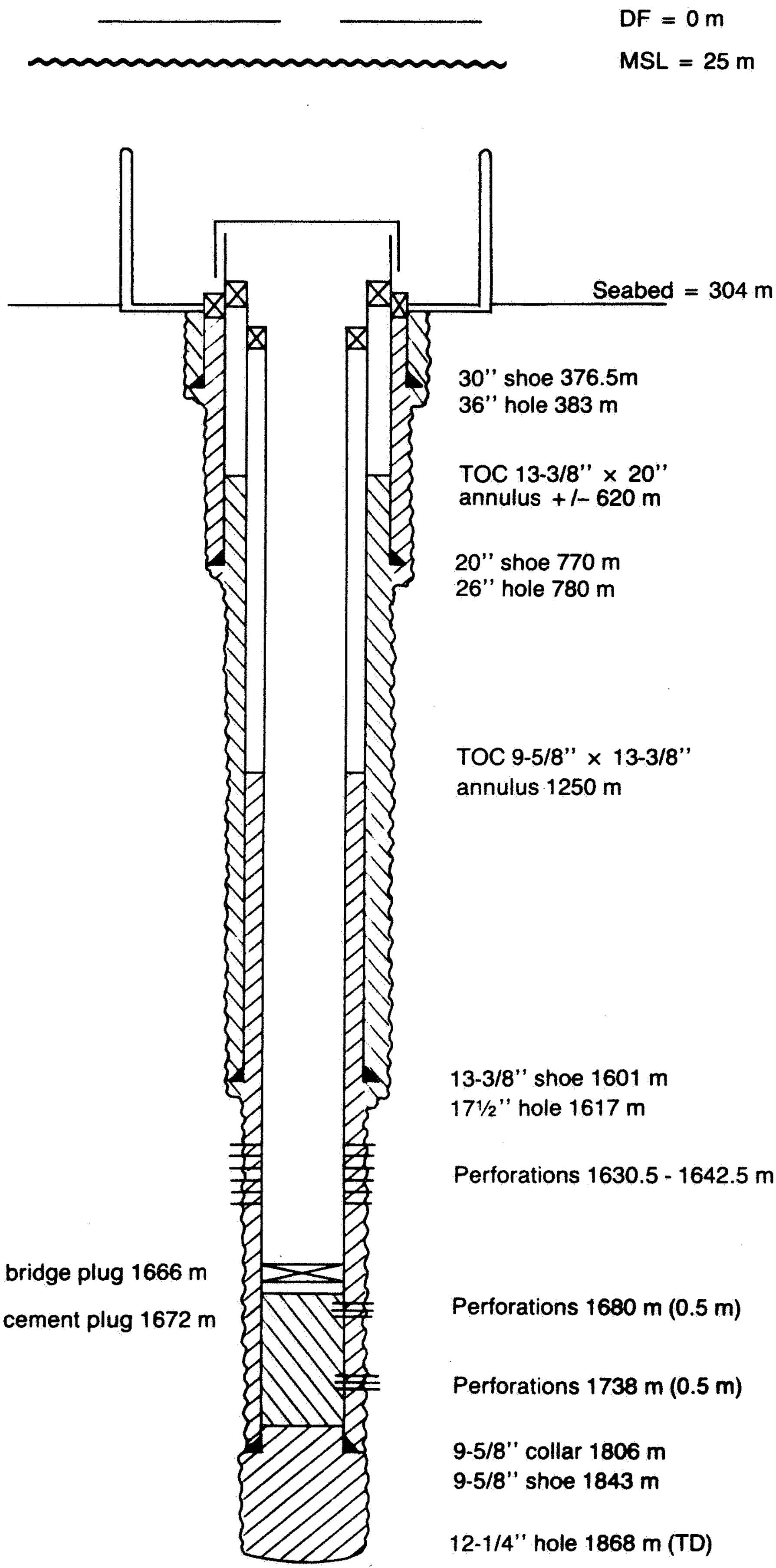
SUSPENSION PLUG STATUS 6407/9-3



A/S NORSKE SHELL

G2061/3

CASING STATUS 6407/9-3



A/S NORSKE SHELL

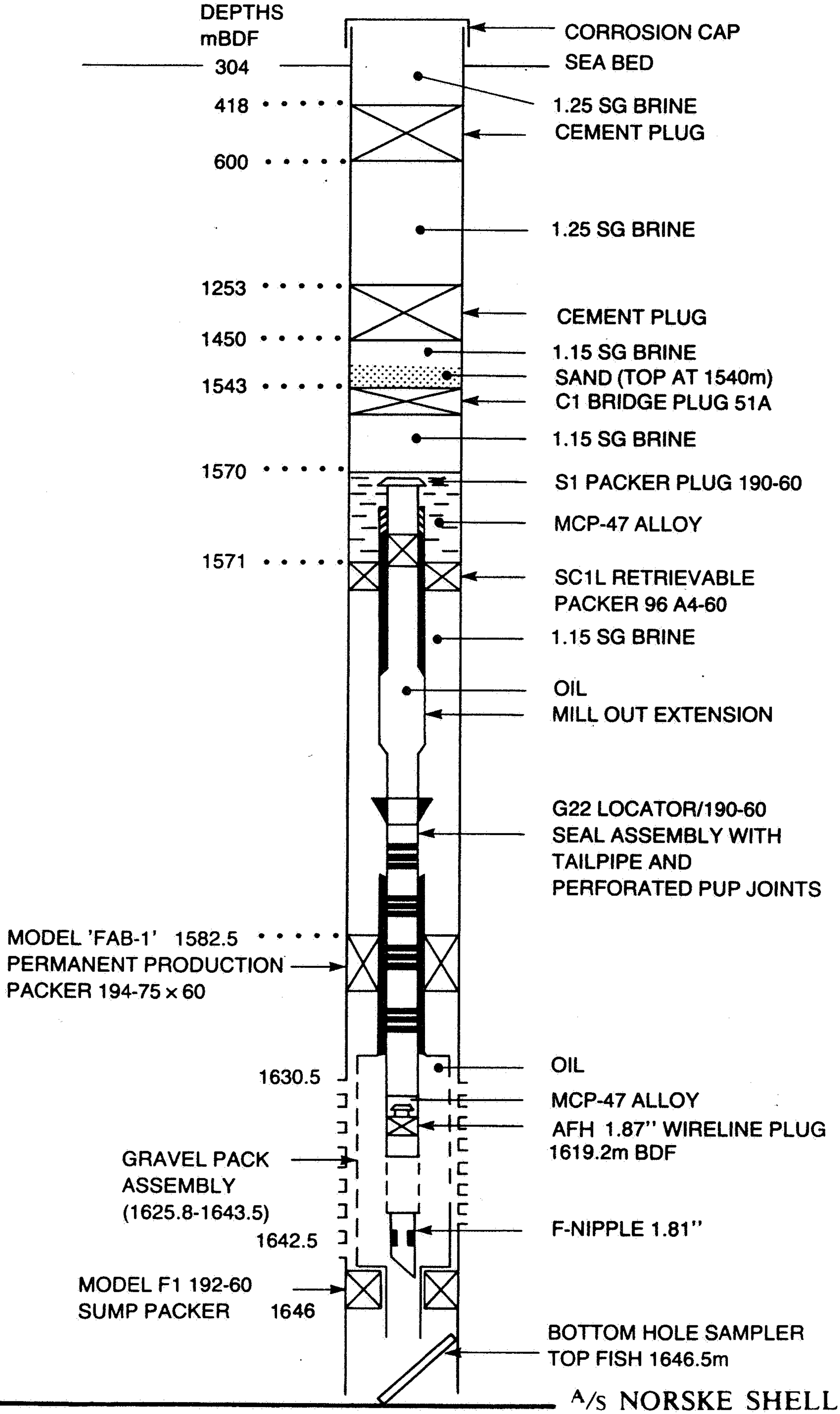
G2061/4

TIME ALLOCATION 6407/9-3

Started well at 07:00 hrs 28.04.85 spudded well at 22:30 hrs 03.05.85 and abandoned well at 04:30 hrs 29.07.85.

PHASE	ITEM	APRIL	MAY	JUNE	JULY	TOTAL HRS	%
PREPARATION	- Towing	65	10			75	3.40
	- Laying/ pulling anchors		32			32	1.45
	- General preparation		32			32	1.45
	Sub total					139	6.30
DRILLING	- Bit on bottom		90.5	13.5		104	4.72
	- Round tripping		89	70		159	7.21
	- Reaming/ enlarging		72.5	1		73.5	3.33
	- Circulation/condition mud		26	12.5		38.5	1.75
	- Condition hole for casing		13.5	4.5		18	0.82
	- Running casing/ drilling cmt.		46	10.5		56.5	2.56
	- Leak off tests etc.		3	31.5		34.5	1.56
	- Cementing & WOC		11	7		18	0.82
	- Running/ pulling riser and/or BOP's		101	23.5		124.5	5.65
	- Flanging up and testing		36	16		52	2.36
	- Repairs		53.5	10.5		64	2.90
	- Surveys		14.5	10.5		25	1.13
	- Side tracking		4			4	0.18
	- Fishing		2.5			2.5	0.11
	- Others/ strike		8.5	334.5		343	15.55
	Sub total					1117	50.65
EVALUATION	- Coring		24.5	15.5		40	1.81
	- Round trip with core barrel		17.5	11.5		29	1.32
	- Recovery of core		14	13.5		27.5	1.25
	- Condition hole for coring/ logging		14	8.5		22.5	1.02
	- Logging		28.5	51.5	4.5	84.5	3.83
	- RFT			11.5		11.5	0.52
	- Others			22		22	1.00
	Sub total					237	10.75
TESTING	- Condition hole for tubing/ testing				33	33	1.50
	- Running/pulling tubing/DP/GP			18.5	165.5	184	8.34
	- Rigging up surface eqp/BHA			0.5	44.5	45	2.04
	- Circulation/observing well				49.5	49.5	2.24
	- Bullhead/gravel packing				11.5	11.5	0.52
	- Dresser Atlas wireline/Baker P.				1.5	1.5	0.07
	- Expro wireline				82	82	3.72
	- Flowing well				91	91	4.13
	- Pressure build ups				32.5	32.5	1.47
	- Back surge operation				10	10	0.45
	- Pressure testing eqp.				87.5	87.5	3.97
	- Others			9.5		9.5	0.43
	- WOW/Repairs			12	16.5	28.5	1.29
	Sub total					665.5	30.17
SUSPENSION	- Plugging back a WOC				5.5	5.5	0.25
	- Pulling riser/ BOP stack				9	9	0.41
	- Laying down string/run corr. cap				16	16	0.72
	- Preparing for move				4	4	0.18
	- Anchor handling				12.5	12.5	0.57
	Sub total					47	2.13
	TOTAL HOURS					2205.5	100 %

SUSPENSION PLUG STATUS 6407/9-3



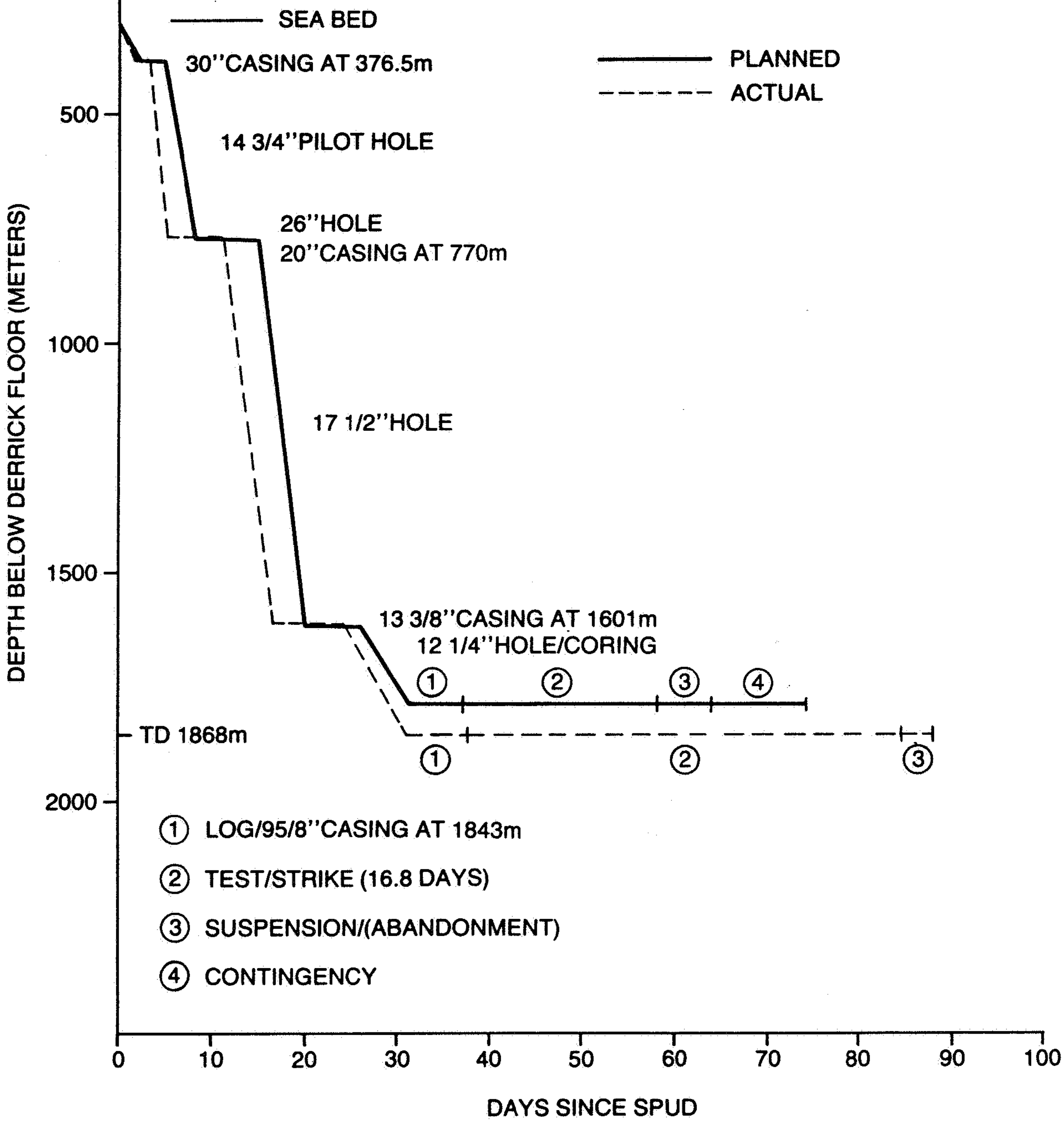
A/S NORSKE SHELL

G2061/3

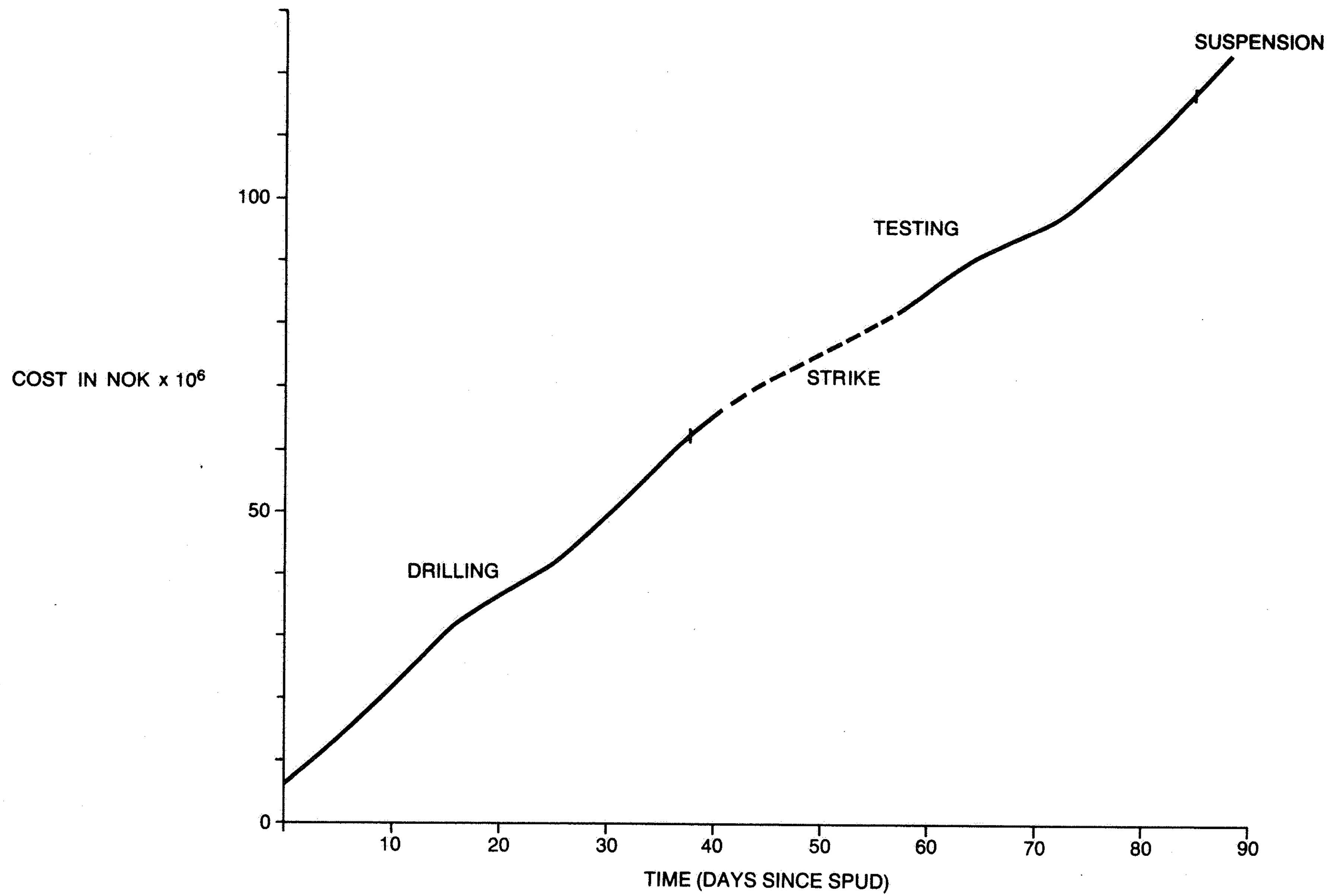
6407/9-C (3) DRILLING PROGRESS CURVE

RIG ON CONTRACT	:	07:00hrs	28.04.85
RIG ON LOCATION	:	10:00hrs	01.05.85
SPUD WELL	:	22:30hrs	03.05.85
END WELL	:	04:30hrs	29.07.85
RIG OFF CONTRACT	:	01:15hrs	30.07.85

TOTAL TIME ON LOCATION : 88days 18.5hrs



TIME COST CURVE 6407/9-3



A/S NORSKE SHELL

G2061/1

5. MUD REPORT

The Mud Report prepared by Gearhart was distributed to NPD and partners on September 17, 1985.

6. GEOLOGICAL REPORT

6.1 Sample Collection

Ditch Cuttings

Ditch samples were collected every 10 m from 375 mbdf to 1600 mbdf and every 3 m in the interval from 1600 mbdf to 1868 mbdf (TD).

The cuttings log was distributed to NPD and partners on 17th September 1985 (see also Encl.1).

Sidewall Cores

Sidewall cores were taken in the 17 1/2" and 12 1/4" hole. A total of 75 sidewall samples was attempted, 62 of which were recovered. A detailed description of the samples is given in Encl.2.

Fiberglass Sleeve Cores

To enable a detailed sedimentological and petrophysical analysis of the reservoir formation, cores were cut in the Frøya Formation and the overlying Kimmeridge Clay Formation:

Core no.1	1620.5 - 1621.8mbdf	(recovery 54%)	DD to LD shift: 0 m
Core no.2	1621.8 - 1624.7mbdf	(recovery 52%)	DD to LD shift: 0 m
Core no.3	1624.7 - 1626.7mbdf	(recovery 0%)	
Core no.4	1626.7 - 1627.5mbdf	(recovery 0%)	
Core no.5	1627.5 - 1628.8mbdf	(recovery 38%)	DD to LD shift:-2.5m
Core no.6	1634.0 - 1650.8mbdf	(recovery 94%)	DD to LD shift:-4.0m
Core no.7	1652.0 - 1667.0mbdf	(recovery 100%)	DD to LD shift:-4.0m
Core no.8	1667.0 - 1672.0mbdf	(recovery 83%)	DD to LD shift:-1.8m
Core no.9	1673.0 - 1679.8mbdf	(recovery 62%)	DD to LD shift:-1.6m

A detailed lithological description is presented in Encl. 3 and the summary of the reservoir geology and sedimentology in Encl. 4.

6.2 STRATIGRAPHY

The sedimentary sequence penetrated by well 6407/9-3 is subdivided into lithostratigraphic groups and formations which are defined in the regional framework of the area, based mainly on log correlation supported by biostratigraphic evidence.

The stratigraphic names have been given according to the existing Shell terminology, but the units are correlatable with those defined by Statoil and Saga in the Haltenbanken area. The names may be subject to changes when the stratigraphic nomenclature for the Haltenbanken area is formalised.

Formation tops and the biostratigraphic subdivision are presented in tables 6.1 and 6.2 respectively. The subdivision is also displayed on the completion log and the well summary sheet (Enclosures 1 and 9).

A lithological description of the different formations is summarised below.

Nordland Group/Hordaland Group (276 - 1285 mss)

From seafloor (276 m) to 350 mss no returns to surface.

From 350 mss to ca. 815 mss a light grey to grey, very soft, sandy to silty hydroturgid clay was encountered, slightly carbonaceous and occasionally glauconitic. The clay is dominantly non-calcareous to slightly calcareous and contains traces of quartz and lithic grains and occasional coal and shell fragments.

A highly glauconitic interval occurs between 725 and 815 mss. Between 815 and 1250 mss the clay becomes very silty and brownish grey with traces of glauconite and sand. Below 1250 mss the grey silty clay gradually becomes a reddish-brown claystone which contains some tuffaceous fragments at the base.

Rogaland Group (1285 - 1494 mss)

Balder Formation (1285 - 1326 mss)

The Balder Formation comprises medium-dark brown-grey claystone with multicoloured tuffaceous fragments.

Sele/Lista Formation (1326 - 1494 mss)

The Sele/Lista Formation is a sequence of light blue-grey, grey-brown, and medium grey claystones slightly glauconitic and micaceous. The boundary with the overlying Balder Formation is gradational reflected by a decreasing amount of tuffaceous fragments. Near the base of this formation the claystone becomes medium red-brown.

Shetland Group (1494 - 1529 mss)

The Shetland Group consists of a light to medium grey claystone which is silty and slightly glauconitic. A red-brown clay interval occurs at the top.

Cromer Knoll Group (1529 - 1567.5 mss)

The top of the Cromer Knoll Group consists of an orange/red-brown mottled, locally calcareous, claystone. The bottom part comprises a light grey to light green-grey marl locally grading into a limestone.

Humber Group

Kimmeridge Clay Equivalent (1567.5 - 1604 mss)

The Kimmeridge Clay Equivalent is a sequence of medium to dark grey, bituminous, pyrite-rich claystones.

Frøya Formation (1604 - 1659 mss)

The Frøya Formation comprises an overall coarsening upward sequence with grey silty and micaceous claystone at the base grading upwards into sandy claystone and micaceous sands which are laminated and strongly bioturbated. At the top a 30 m thick, grey-brown, well sorted, FU sand occurs, which is low and high angle x-bedded (see core description Encl.3 + 4). The base of the Frøya Formation consists of 14 m thick dark grey, bituminous, pyritic claystone.

Haltenbanken Formation (1659 - 1771 mss)

The Haltenbanken Formation consists of light grey to light brown-grey, locally silty and sandy kaolinitic claystone at the base. This passes upwards into blocky to funnel-shaped, light to medium grey, medium to coarse grained sand beds separated by thin micaceous and kaolinitic clays. The top consist of an overall coarsening upward sequence from silty shale at the base to fine grained well sorted sand at the top.

Dunlin Group (1771 - TD 1842 mss)

Upper Drake equivalent (1771 - 1796 mss)

The Upper Drake equivalent consists of medium grey, silty, occasionally kaolinitic claystone.

Middle Drake equivalent (1796 - TD 1842 mss)

The Middle Drake equivalent is a predominantly sandy sequence with occasionally thin intercalations of claystone. The sands are very fine to medium grained, glauconitic and micromicaceous. Occasionally coally layers occur.

6.3 HYDROCARBON INDICATIONS

The following is a brief description of hydrocarbon indications as encountered whilst drilling. The shows are indicated on the completion log (Encl.1).

<u>Tertiary/Quaternary</u> (304-1519 mbdf)
In this hole section traces of C_1 were registered (0.01 - 0.2%).

<u>Shetland Group</u> (1519 - 1554 mbdf)
C_1 gas readings of 0.07% to 0.1% were recorded in this interval.

<u>Cromer Knoll Group</u> (1554 - 1592.5 mbdf)
C_1 gas readings (0.02 - 0.05%) and traces of C_2 and at the top traces of C_3 were observed.

<u>Humber Group</u> (1592.5 -1797 mbdf)

Kimmeridge Clay Equivalent (1592.5 - 1630 mbdf)

Upon entering the Kimmeridge Clay Equivalent C_1 (0.02 - 0.1%) and traces of, C_2 and C_3 were encountered. The C_1, C_2 and C_3 gas readings gradually increased towards the base, up to 0.5, 0.1 and 0.01% respectively. Also traces of C_4 were encountered.

Frøya Formation (1630- 1685 mbdf)

Gas readings of C_1, C_2, C_3 and C_4 were recorded at the top of the Frøya Fm prior to coring. Direct pale yellowish/white fluorescence was observed in the cores of the interval between 1630 - 1665 m bdf. Below this depth no fluorescence was observed.

Haltenbanken Formation (1685 - 1797 mbdf)

In the Haltenbanken Formation C_1 (0.01-0.05%) and occasional traces of C_2 and C_3 were recorded.

<u>Dunlin Group</u> (1797 - 1868 mbdf TD)
Only traces of C_1, C_2 and C_3 were observed.

Table 6.1

FORMATION TOPS WELL 6407/9-3

	TOP(mss)
Nordland Group	276.0
Hordaland Group	779.0
Rogaland Group	
Top Balder Fm	1285.5
Top Sele/Lista Fm	1326.5
Shetland Group	1494.0
Cromer Knoll Group	1529.0
Humber Group	
Kimmeridge Clay Eq	1567.0
Frøya Fm	1604.0
Haltenbanken Fm	1659.0
Dunlin Group	
Upper Drake Eq	1771.0
Middle Drake Eq	1796.0

Table 6.2

Palynostratigraphy of well 6407/9-3

400 - 740		m	drd	Pliocene
at 800		m	drd	Miocene - Oligocene
900 - 1100		m	drd	Oligocene
1200 - 1300		m	drd	Eocene
1500 - 1519		m	drd	Paleocene
1519.6 - 1549		m	lgd	Upper Cretaceous - non diagnostic
at 1557		m	lgd	Late Albian
1567 - 1571		m	lgd	Aptian
1579.5 - 1591.3		m	lgd	Valanginian - Late Berriasian.
at 1592.3		m	lgd	Berriasian or younger.

6.4 Seismostratigraphy

Seismic Calibration

A velocity survey was carried out by SSL, with checkshot levels between 401 to 1863 mbdf. Those levels below 850 mbdf were at 25 m intervals and have been used for VSP processing.

Table 6.3 summarises the times and interval velocities, as defined by the calibrated velocity log, between the major seismic horizons.

Gamma Ray, Sonic and Density logs have been displayed at linear time scale together with the resulting zero phase synthetic seismogram (Encl. 5) for the stratigraphic identification of seismic reflectors. Encl. 6 illustrates the good correlation between the synthetic and seismic section.

Table 6.3

Seismic Interval Velocities 6407/9-3

	Depth mss	Time ms	Interval Velocity m/s	
Unconformity 1	376	486	1764	(Sea Level-UC_1)
Unconformity 2	545	646	2115	(UC_1 - UC_2)
Unconformity 3	688	764	2424	(UC_2 - UC_3)
Unconformity 4	779	849	2124	etc.
Top Balder	1286	1377	1918	
Base Tertiary	1494	1586	1995	
Top Lower Cretaceous	1529	1618	2215	
Top Kimmeridge Clay Fm	1567	1648	2568	
Top Frøya Fm	1604	1683	2131	
Top Haltenbanken	1660	1724	2707	
Top Dunlin	1772	1803	2835	

The times and interval velocities have been derived from the SSL calibrated velocity log.

6.5 Reservoir geology

Oil was encountered in the Upper Jurassic Frøya Formation with a total oil column of 34 m. The Frøya Formation consists of a 55 m thick coarsening upwards sequence from bituminous shales into fine grained unconsolidated sands.

Based on detailed core descriptions (Encl. 3 and 4) the reservoir formation can be subdivided in three distinct lithological units with varying reservoir characteristics.

Unit I: (1604 - 1635 mss) consists of fine grained, well to very well sorted glauconitic sand. Sedimentary structures gradually change from thoroughly bioturbated sands between 1631.5 - 1635 mss into bioturbated and cross-bedded sands between 1623.5 - 1631.5 mss. and sands with well defined cross-bedding at the top between 1604 - 1623.5 mss. The cross-bedded sets between 1612 - 1617 mss have mm-scale clay laminations on top of the foresets. Reservoir properties are very good; porosities range from 31 - 34 % and permeabilities between 1 and 14 Darcies.

Unit II: (1635 - 1645.5 mss) consists of an alternation of strongly bioturbated micaceous fine to very fine sands and silty claystone at the top (Unit IIa) and laminated claystone alternating with bioturbated siltstone (Unit IIb) which are calcite cemented. The increase in clay, mica content and decrease in grain size is reflected in the moderate to poor reservoir quality. In Unit IIa porosity ranges between 23 and 25% and permeability between 20 - 200 mD. In Unit IIb porosities are between 13 and 19% and permeabilities are less than 4 mD. The OWC falls within Unit IIa.

Unit III: (1645.5 - 1659 m) is a 14 m thick interval of predominantly laminated, bituminous shales with occasionally sandy and silty beds which are strongly pyrite cemented. This interval forms an impermeable layer between the Frøya and underlying Haltenbanken sands.

This overall coarsening upwards sequence has been interpreted as an offshore bar sequence from open marine shales (Unit III) into bioturbated shales and sands (Unit II) of the lower bar face and cross-bedded, well sorted sands (Unit I) of the upper bar face.

The sequence as encountered in well 6407/9-3 is interpreted as presenting the seaward facing side of the bar where the upper part has been strongly worked by waves and currents.

6.6 Dipmeter

The lithology as observed in the cores of the Frøya Formation was compared with the pad traces and processed dipmeter data to evaluate the reliability of the processed data and establish the direction of structural and sedimentological dips.

The four dominant lithofacies are recognised in the cores and their response on the dipmeter traces and processed results are summarised in Encl. 7 and discussed below.

a) Horizontally bedded shales (between 1672 and 1681 m) show a very serrate character on the traces with many continuous correlatable events. These events represent bedding planes and thus the structural dip has been established as 1 to 2^{0} towards the south.

b) Heterolithic intervals of alternating silt, shale and sand beds which are internally bioturbated occur between 1663 and 1671 m. The traces have a slightly serrate character with a considerable number of correlatable events representing bedding planes. The bedding planes, however, are irregular due to intensive bioturbation and a large scatter in the magnitude ($0 - 8^{0}$) and azimuth of the dips occurs.

c) Bioturbated sands occur between 1654 and 1663 m. The massively bioturbated character gives these sands a blocky response of the pad curves and subsequently there are very few correlatable events. The dip angle and directions are therefore irrealistic.

d) Well to moderately defined cross-bedding occurs in the sands between 1630 and 1654 m. The traces over these intervals are blocky to occasionally serrate and correlatable events are common but are only occasionally correlatable over all 4 curves. The more reliable dip data between 1630 and 1633 indicate sedimentary dips with a maximum angle of $3 - 7^{0}$ and large scatter in azimuth (towards the north, south and east).

Between 1637 and 1640 m less well correctable events indicate a southerly dip direction for dip angles larger than 5 .

In conclusion, structure dips are readily identifable from the dipmeter data and are consistent with the structural interpretation from seismic data. Sedimentary dips are however much less well defined due to the randomising effect of biotubation and a clear indication of sediment transport direction is not recognised from the dipmeter data.

7. Petrophysical Evaluation

A summary of the Dresser Atlas wireline logs run in the borehole is presented in Table 7.1, and the main logs run over the reservoir are plotted in Enclosure 8.

The top of the Frøya Formation is found at 1604 mss and the reservoir is oil bearing down to an oil-water contact at 1638 mss. The average hydrocarbon saturation is calculated as 82% over the 34 m oil column. Average porosity is 31% in this interval, of which 16.7 m has a porosity above 32.5%. In the water bearing Haltenbanken Formation 24.2 m has a porosity above 32.5%.

Routine porosity-permeability measurements on the core were performed by Geco-Stavanger, and cation exchange capacity (CEC) was measured on 19 core samples. The core permeabilities, porosities, grain densities and CEC measurements are tabulated in Table 7.2. The core porosities plotted in Enclosure 8 are corrected for compaction effect, and are smoothed by taking a 1:2:1 average with adjacent plugs. The core permeabilities are smoothed, but not corrected for compaction. The core values are plotted on log depth.

A compaction correction factor of 0.96 was obtained from special core measurements performed on stressed plugs for wells 6407/9-1 and 6407/9-2. A crossplot of porosities at in-situ stress (taken as 2500 psi net vertically) versus the porosities at standard conditions yielded a value of 0.96 for the slope of the best fit line forced through the origin.

The OWC in this well was not very clearly defined on the logs. It is located near the bottom of the Frøya reservoir sequence, where the quality of the formation diminishes. From the FMT pressure profile and log profiles the OWC is estimated at 1638 mss, which is in line with the OWC observed in the other Draugen wells.

Crossplots of core porosity (corrected for compaction) versus bulk density from the Density log (corrected for borehole effects) has established the following relationships for wells 6407/9-1,2 & 3 over the oil zone and water zone:

$$\text{Porosity} = \frac{2.68 - \text{Rhobulk}}{2.68 - \text{Rhofluid}}$$

with Rhofluid = 0.89 g/cm^3 in the upper five metres of the oil zone in well 6407/9-3 (Figure 7.1)

Rhofluid = 1.00 g/cm^3 in the oil zone (excluding the upper five metres in well 6407/9-3) (Figure 7.2)

Rhofluid = 1.10 g/cm^3 in the water zone (Figure 7.3)

The different fluid density assumed for the upper five metres of the oil bearing section in this well is attributed to gravity segregation of the mud filtrate. This results in an increased hydrocarbon effect on the Density log.

A constant matrix density of 2.68 g/cm^3 was assumed throughout the reservoir sequence.

Hydrocarbon saturation was calculated with the Waxman-Smits shaly sand equation. The virgin zone resistivity in the oil bearing interval was calculated from the borehole corrected Laterolog curves by a computerized version of the 'Tornado' chart. Over the waterbearing interval, the virgin zone resistivity was taken equal to the borehole corrected Induction log.

The cation exchange capacity was estimated from a relationship between Qv and the separation between the Density log and the Neutron log. A crossplot of Qv measured on core plugs versus the difference between the Neutron log porosity and the measured core porosity established the following relationship:

$$Qv = 0.03\ (CNL - \emptyset + 8)$$

where CNL is the Neutron log reading, and Ø is the porosity (Figure 7.4).

The parameters A* and m* of the Formation Factor-Porosity relationship $F^* = A^*\ \emptyset^{-m^*}$ for the Frøya Formation were established from core analysis. Figure 7.5 depicts a crossplot of F* versus Ø, obtained from stressed plugs. F* was calculated from measured values of F and Qv through the relationship $F^* = F\ (1 + Rw.B.Qv)$, where Rw denotes the brine resistivity, and B the Equivalent Conductance as defined by Waxman-Smits. An isostatic stress was applied of 1500 psi, which is assumed equivalent to an in-situ vertical isostatic stress of 2500 psi.

Over the Haltenbanken Formation, which was waterbearing in this well, different values for A* and m* were assumed. These values were obtained from a crossplot of calculated F* values from logs versus porosity from logs over the waterbearing interval.

A formation water resistivity of 0.10 Ohm.m was assumed for the evaluation. This value gives 100% water saturation in the waterbearing intervals in this well and in the previous wells. The value of 0.10 Ohm.m at in-situ temperature agrees with resistivity values measured recently on produced water from well 6407/9-4, the only well with reliable formation water samples.

The static formation temperature from the various production tests performed in Draugen is 160 deg F at 1630 m ss. However Horner analysis of the maximum temperatures recorded during logging runs in the Draugen wells indicates slight cooling of the borehole by the drilling mud. Taking into account this cooling effect of the borehole by deducting 10 deg F, 0.10 Ohm.m at in-situ temperature converts to a resistivity of 0.20 Ohm.m at surface conditions (70 deg F). Actual measured values on the samples were around 0.19 Ohm.m (preliminary reported only).

The saturation exponent n* was taken as 1.9, as in the previous wells. Recent core analysis results suggest a value of 1.95 for n*.

A summary of the evaluation parameters is listed in Table 7.3.

Table 7.1

Logging operations in well 6407/9-3

Contractor: Dresser-Atlas

DEPTH CASING mBDF	DEPTH DRILLING mBDF	BIT SIZE inches	LOG TYPE	RUN NO	INTERVAL LOGGED mBDF	DATE	REMARKS
370.5	780	14.75	DIFL/ACL/GR	1	266 - 779	09.05.85	
			CDL/CNL/GR	1	350 - 778	09.05.85	
768.6	1617	17.5	DIFL/ACL/GR	2	702 - 1605	20.05.85	
			CDL/CNL/GR	2	550 - 1596	20.05.85	
			Cor-gun	1		21.05.85	Rec. 20
1601	1868	12 1/4	DIFL/ACL/GR	3	1504 - 1867	04.06.85	
			CDL/CNL/SPL/GR	3	1450 - 1865	04.06.85	
			DLL/MLL/GR	1	1580 - 1863.8	04.06.85	
			Diplog	1	1595 - 1862	05.06.85	
			FMT	1	29 pressures with HP gauge		
					Segregated sample at 1637.5m		
			Velocity Survey	1		06.06.85	
			COR-gun	2		07.06.85	Rec 42
			CBL	1	in 13 3/8" casing	07.06.85	
			CBL	2	in 9 5/8" casing	10.06.85	

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GECO
GEOPHYSICAL COMPANY OF NORWAY A·S
Petroleum laboratory

COMPANY : SHELL
WELL : 6407/9-3
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 1

DATE: JULY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	k_{el}	vertical k_a	k_{el}	Porosity (%) He	Sum.	Pore saturation S_o	S_w	Grain dens. g/cc	Formation Description
	1620.50										
	1621.20										

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GECO
GEOPHYSICAL COMPANY OF NORWAY A·S
Petroleum laboratory

COMPANY : SHELL
WELL : 6407/9-3
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 2

PAGE: 1

DATE: JULY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	Permeability (mD), horizontal k_{el}	Permeability (mD), vertical k_a	Permeability (mD), vertical k_{el}	Porosity (%) He	Porosity (%) Sum.	Pore saturation S_o	Pore saturation S_w	Grain dens. g/cc	Formation Description
	1621.80										
	1623.30										

FINAL REPORT

GECO
GEOPHYSICAL COMPANY OF NORWAY A/S
Petroleum laboratory

PAGE: 1

COMPANY : SHELL
WELL : 6407/9-3
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 3

DATE: JULY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal		Permeability (mD), vertical		Porosity (%)		Pore saturation		Grain dens. g/cc	Formation Description
		k_a	k_{el}	k_a	k_{el}	He	Sum.	S_o	S_w		
	no recovery										

TABLE 7.2 Page 4

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GECO
GEOPHYSICAL COMPANY OF NORWAY A·S
Petroleum laboratory

COMPANY : SHELL
WELL : 6407/9-3
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 4

PAGE: 1

DATE: JULY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal		vertical		Porosity (%)		Pore saturation		Grain dens. g/cc	Formation Description
		k_a	k_{el}	k_a	k_{el}	He	Sum.	S_o	S_w		

no recovery

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FINAL REPORT

GECO
GEOPHYSICAL COMPANY OF NORWAY A/S
Petroleum laboratory

COMPANY : SHELL
WELL : 6407/9-3
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 5

DATE: JULY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	k_{el}	vertical k_a	k_{el}	Porosity (%) He	Sum.	Pore saturation S_o	S_w	Grain dens. g/cc	Formation Description
	1627.50										
	1628.00										

FINAL REPORT

GECO
GEOPHYSICAL COMPANY OF NORWAY A·S
Petroleum laboratory

COMPANY : SHELL
WELL : 6407/9-3
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 6

PAGE: 1

DATE: JULY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	horizontal k_{el}	vertical k_a	vertical k_{el}	Porosity (%) He	Porosity (%) Sum.	Pore saturation S_o	Pore saturation S_w	Grain dens. g/cc	Formation Description
	1634.00										
1	1634.35	7024	6854			34.2				2.65	
2	1634.65	5689	5540			34.7				2.65	
3	1635.00	6462	6301	7385	7210	33.5				2.65	
4	1635.35	6312	6154			33.4				2.65	
5	1635.65	7104	6933			32.6				2.65	
6	1636.00	6269	6111			34.9				2.65	
7	1636.35	1132	1078			31.0				2.64	
8	1636.65	3098	2996			32.2				2.65	
9	1637.00	3008	2908			33.2				2.65	
10	1637.35	4884	4748			33.0				2.66	
11	1637.65	6248	6091			33.4				2.66	
12	1638.00	1487	1423	5097	4958	25.7				2.73	
13	1638.35	4925	4789			33.2				2.66	
14	1639.00	5794	5644			31.8				2.65	
15	1639.35	8483	8293			32.3				2.65	
16	1639.65	7216	7044			33.3				2.65	
17	1640.00	4921	4785			33.6				2.65	
18	1640.35	4146	4023			34.1				2.65	
19	1640.65	9044	8846			34.7				2.65	
20	1641.00	6112	5957	3930	3812	32.8				2.66	
21	1641.35	11423	11195			34.0				2.65	
22	1642.00	nmp				nmp					
23	1642.35	6031	5877			33.7				2.66	
24	1642.65	4578	4448			32.7				2.66	
25	1643.00	7730	7551			33.1				2.65	
26	1643.35	6259	6101			33.6				2.65	
27	1643.65	5674	5525			32.9				2.65	

GECO
GEOPHYSICAL COMPANY OF NORWAY A·S
Petroleum laboratory

FINAL REPORT

COMPANY : SHELL
WELL : 6407/9-3
FIELD : 6407/9
STATE : NORWAY

PAGE: 2

CORE NO.: 6 (cont.)

DATE: JULY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	horizontal k_{el}	vertical k_a	vertical k_{el}	Porosity (%) He	Porosity (%) Sum.	Pore saturation S_o	Pore saturation S_w	Grain dens. g/cc	Formation Description
28	1644.00	9814	9606	5744	5595	32.4				2.66	
29	1644.35	5931	5779			31.3				2.63	
30	1644.65	2738	2644			33.3				2.65	
31	1645.00	7373	7198			33.6				2.65	
32	1645.35	17247	16952			36.1				2.66	
33	1645.65	13085	12836			32.3				2.66	
34	1646.00	9604	9398			34.5				2.66	
35	1646.35	12118	11881			33.8				2.67	
36	1646.65	6846	6679			30.6				2.65	
37	1647.00	5573	5426	3406	3298	33.5				2.66	
38	1647.35	5075	4937			31.9				2.67	
39	1648.35	4039	3919			33.2				2.65	
40	1648.65	6560	6397			31.9				2.64	
41	1649.65	9760	9552			34.5				2.66	
42	1650.00	5363	5219	nmp		33.6				2.65	
43	1650.35	5619	5472			34.1				2.65	
44	1650.70	20381	20055			36.6				2.65	
	1650.90										

FINAL REPORT

COMPANY : SHELL
WELL : 6407/9-3
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 7

PAGE: 1

DATE: JULY 1985

GECO
GEOPHYSICAL COMPANY OF NORWAY A·S
Petroleum laboratory

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	horizontal k_{el}	vertical k_a	vertical k_{el}	Porosity (%) He	Porosity (%) Sum.	Pore saturation S_o	Pore saturation S_w	Grain dens. g/cc	Formation Description
	1652.00										
45	1652.00	7917	7735	nmp		33.0				2.66	
46	1652.35	6152	5996			33.8				2.66	
47	1652.65	10034	9823			32.0				2.66	
48	1653.00	6431	6272			32.6				2.65	
49	1653.35	10178	9965			33.1				2.66	
50	1653.65	10667	10448			31.7				2.66	
51	1654.00	5756	5607			33.9				2.64	
52	1654.35	4477	4350			32.7				2.64	
53	1654.65	3281	3175			31.9				2.65	
54	1655.00	8768	8574	7877	7695	32.9				2.66	
55	1655.35	7989	7806			33.4				2.67	
56	1655.65	8859	8664			31.6				2.66	
57	1656.00	6635	6472			34.0				2.66	
58	1656.35	4899	4764			32.3				2.65	
59	1656.65	6228	6070			32.4				2.66	
60	1657.00	5880	5729			32.1				2.65	
61	1657.35	7941	7759			34.2				2.65	
62	1657.65	2388	2302			28.2				2.66	
63	1658.00	3402	3294	7472	7296	31.1				2.65	
64	1658.35	5416	5272			33.4				2.66	
65	1658.65	5185	5045			34.3				2.66	
66	1659.00	3685	3572			32.6				2.65	
67	1659.35	2316	2231			31.7				2.65	
68	1659.65	4360	4234			34.8				2.64	
69	1660.00	7265	7092			34.2				2.65	
70	1660.35	21303	20968			35.0				2.66	
71	1660.65	6021	5867			35.2				2.65	
72	1661.00	8363	8175	7352	7178	33.7				2.65	
73	1661.65	3192	3088			33.3				2.64	

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GECO
GEOPHYSICAL COMPANY OF NORWAY A/S
Petroleum laboratory

COMPANY : SHELL
WELL : 6407/9-3
FIELD : 6407/9
STATE : NORWAY

PAGE: 2

CORE NO.: 7 (cont.)

DATE: JULY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal		vertical		Porosity (%)		Pore saturation		Grain dens. g/cc	Formation Description
		k_a	k_{el}	k_a	k_{el}	He	Sum.	S_o	S_w		
74	1662.00	5316	5177			34.4				2.65	
75	1662.35	1174	1118			32.1				2.65	1
76	1662.65	1121	1067			31.8				2.64	
77	1663.00	1526	1460			32.9				2.65	
78	1663.35	1787	1715			33.1				2.65	
79	1663.65	1446	1383			33.2				2.64	
	1667.00										

FINAL REPORT

GECO
GEOPHYSICAL COMPANY OF NORWAY A·S
Petroleum laboratory

COMPANY : SHELL
WELL : 6407/9-3
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 8

PAGE: 1

DATE: JULY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	k_{el}	vertical k_a	k_{el}	Porosity (%) He	Sum.	Pore saturation S_o	S_w	Grain dens. g/cc	Formation Description
	1667.00										
80	1667.00	148	140	44.2	40.8	23.7				2.66	
81	1667.35	210	200			27. 0				2.66	
82	1667.65	55.5	51.5			25.0				2.68	2
83	1668.00	19.7	17.7			22.2				2.67	
84	1668.35	0.27	0.20			11.8				2.72	
85	1668.65	0.093	0.069			9.5				2.74	
86	1669.00	4.2	3.6			17.3				2.72	
87	1669.35	0.19	0.15			14.6				2.73	
88	1669.65	0.045	0.033			8.2				2.69	
89	1670.00	5.8	5.0	0.69	0.54	21.4				2.64	
90	1670.35	3.9	3.4			21.1				2.64	
91	1670.65	0.11	0.082			10.6				2.72	
92	1671.00	0.72	0.56			16.5				2.69	
93	1671.35	2.2	1.8			18.7				2.65	
94	1671.65	2.0	1.7			20.1				2.66	
	1672.00										

FINAL REPORT

GEOPHYSICAL COMPANY OF NORWAY A·S
Petroleum laboratory

COMPANY : SHELL
WELL : 6407/9-3
FIELD : 6407/9
STATE : NORWAY

CORE NO.: 9

PAGE: 1

DATE: JULY 1985

Plug No.	Depth (meter)	Permeability (mD), horizontal k_a	Permeability (mD), horizontal k_{el}	vertical k_a	vertical k_{el}	Porosity (%) He	Porosity (%) Sum.	Pore saturation S_o	Pore saturation S_w	Grain dens. g/cc	Formation Description
	1673.00										
95	1673.40	nmp				14.7				2.46	
96	1674.20	nmp				17.1				2.57	
97	1677.45	nmp				16.7				3.06	
98	1677.80	2.4	2.0			14.7				2.71	
99	1678.00	4.7	4.0			14.5				2.63	
100	1678.40	0.87	0.68			13.8				2.76	
101	1678.70	1.1	0.86			15.0				2.75	
102	1679.00	0.92	0.72	0.069	0.051	14.4				2.67	
103	1679.35	1.5	1.2			15.3				2.63	
104	1679.80	1.9	1.5			12.2				2.83	
	1679.80										

Table 7.3

Summary of the Evaluation Parameters

Porosity -Density Calibration:

Rhomatrix = 2.68 g/cm^3

Rhofluid = 0.89 g/cm^3 (in upper 5 m of oil zone in well 6407/9-3)

Rhofluid = 1.00 g/cm^3 (in oil zone)

Rhofluid = 1.10 g/cm^3 (in water zone)

Porosity Compaction : In-situ porosity = 0.96 x (surface porosity)

Formation temperature : 150 deg F at 1630 mss

Formation water resitivity: Rw = 0.10 Ohm.m

Formation Factor : F* = 0.162 $Ø^{-3.3}$ in Frøya Formation

Formation Factor : F* = 0.447 $Ø^{-2.61}$ in Haltenbanken Formation

Saturation exponent : n* = 1.9

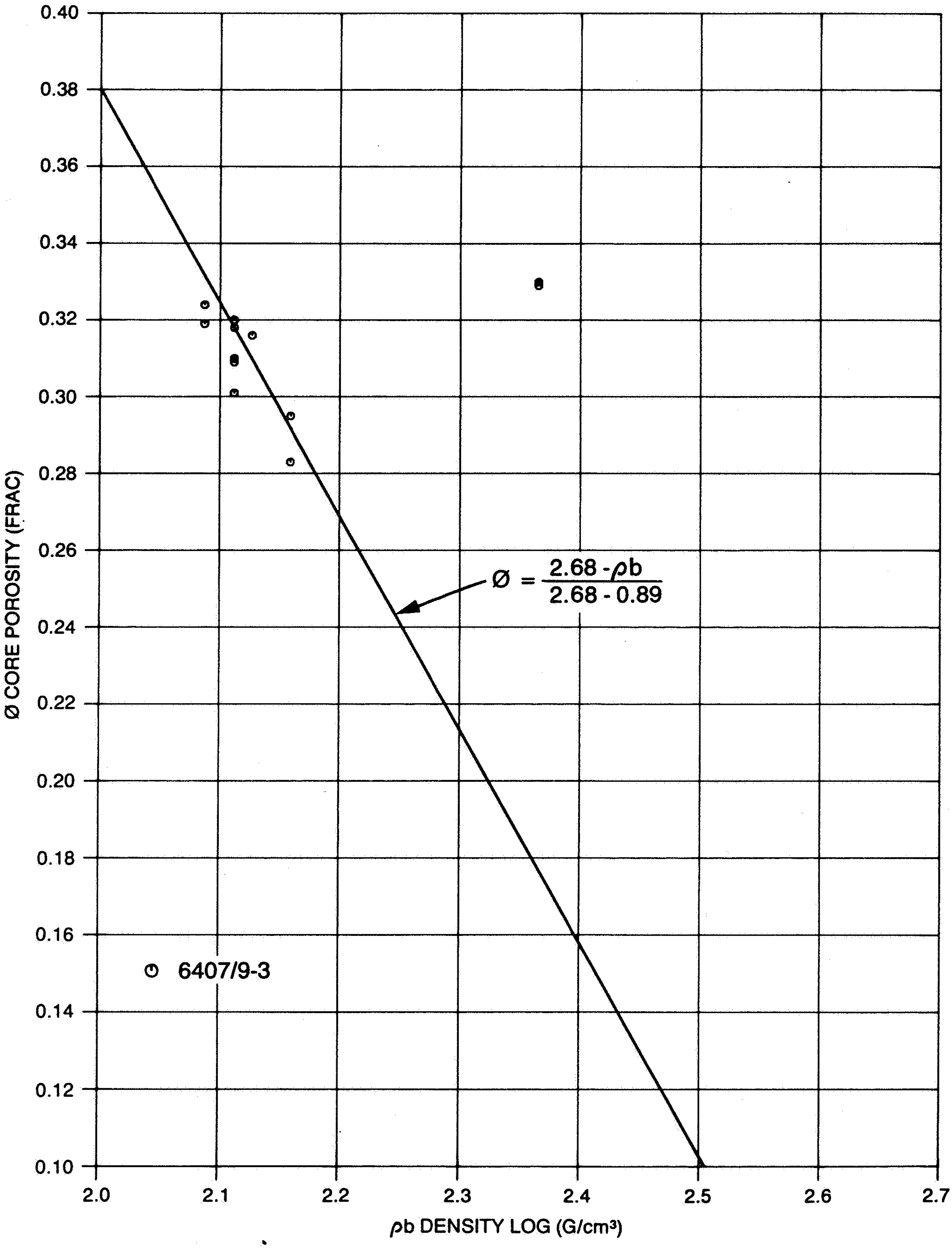
CEC : Qv = 0.03 (CNL - Porosity + 8)

Average hydrocarbon saturation: 82%

Net pay thickness : 34 m

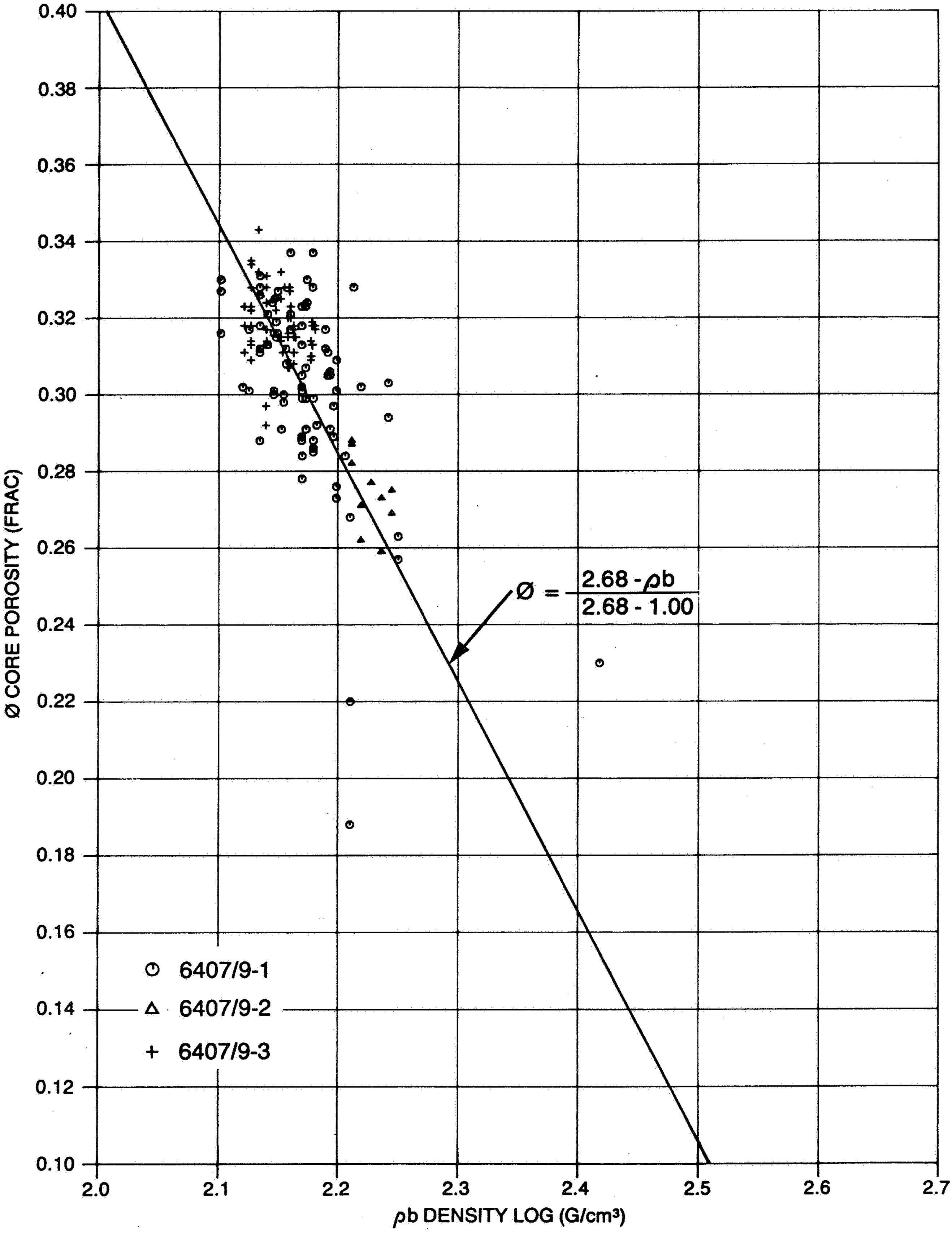
Oil-Water Contact :1638 m

Ø - ρb CROSSPLOT OVER TOP 5m OIL ZONE



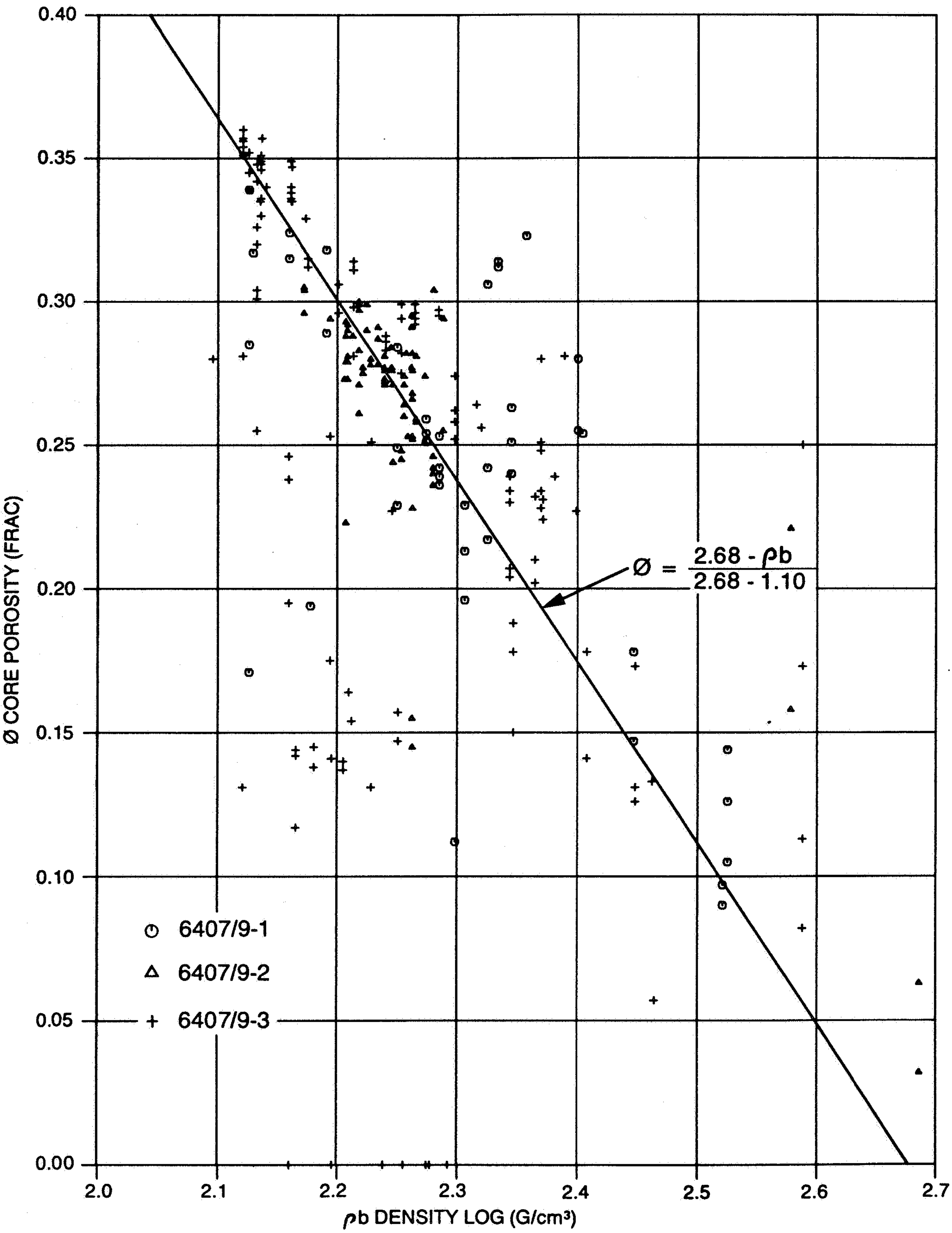
CORE POROSITY VERSUS BULK DENSITY
OVER TOP FIVE METRES OF THE OIL ZONE

Ø - ρb CROSSPLOT OVER MAIN OIL ZONE



CORE POROSITY VERSUS BULK DENSITY
OVER OIL ZONE EXCLUDING TOP 5 METERS

Ø- ρb CROSSPLOT OVER WATER ZONE



CORE POROSITY VERSUS BULK DENSITY
OVER WATERBEARING INTERVALS

CROSSPLOT Q_V VERSUS (CNL-Ø)

RELATIONSHIP BETWEEN Q_V AND THE DIFFERENCE BETWEEN CNL RESPONSE AND COMPACTED CORE POROSITY IN THE FRØYA FORMATION

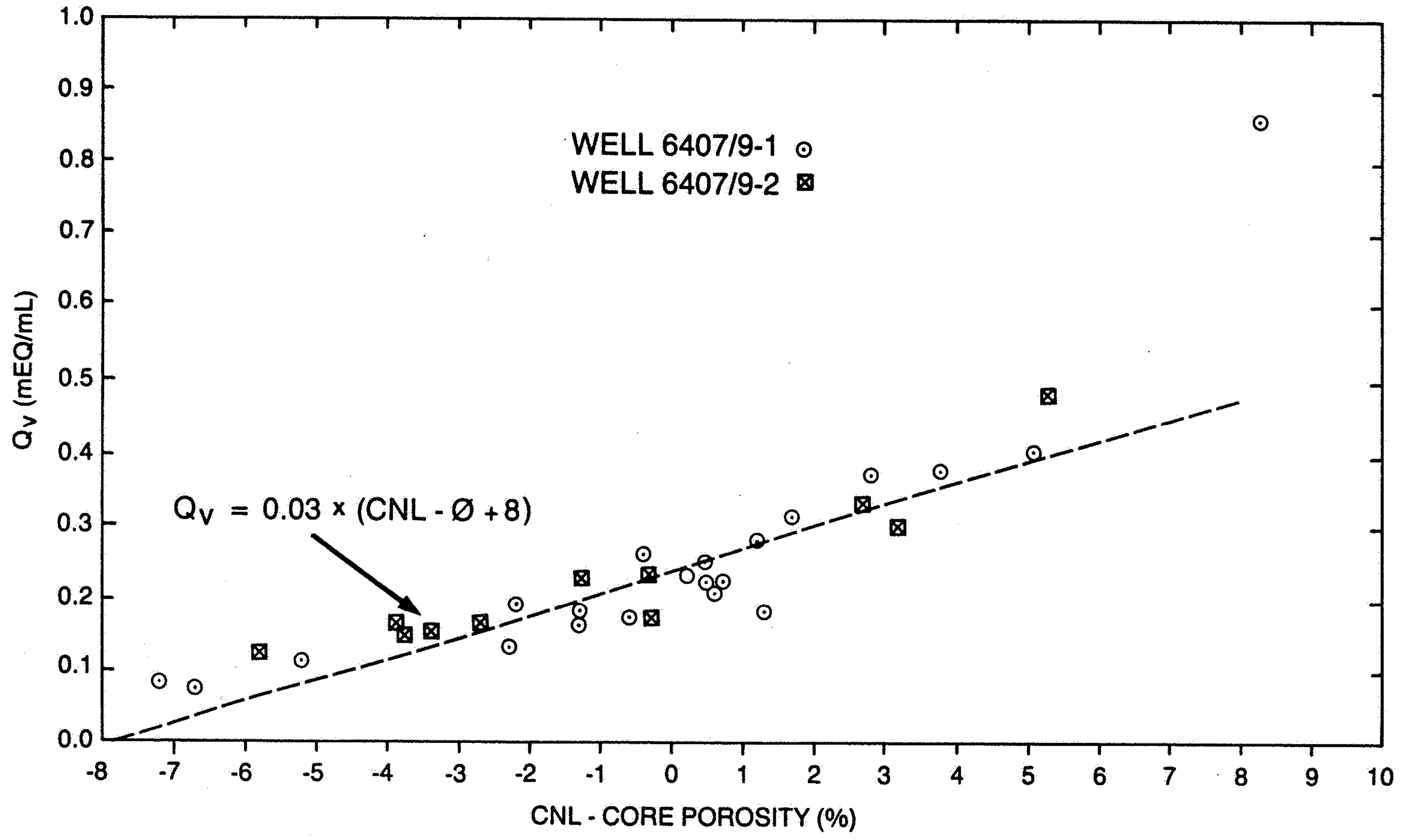
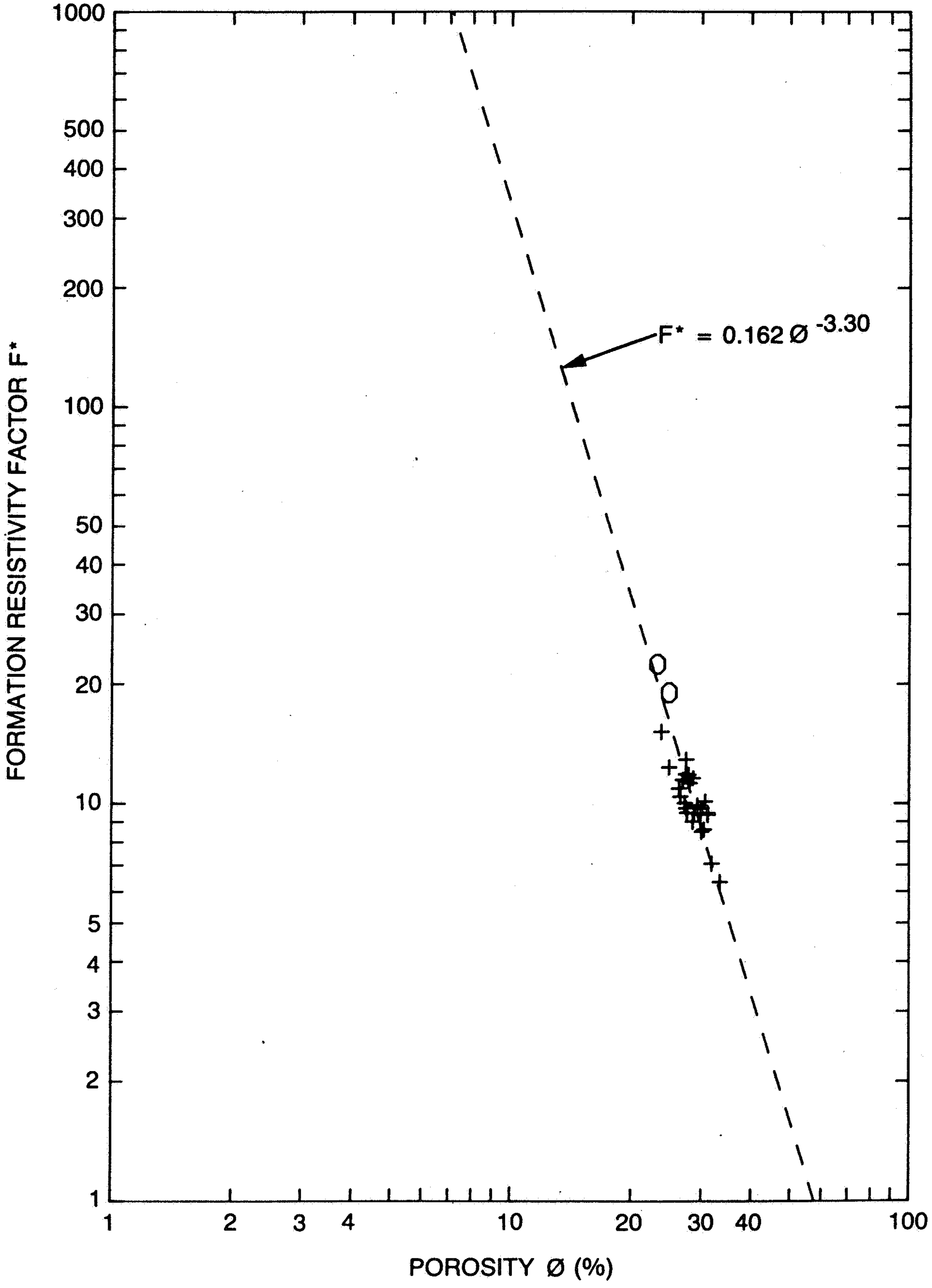


FIG.7.4

F* VERSUS Ø RELATIONSHIP
OVER FRØYA FORMATION



Chapter 8

PRODUCTION TEST EVALUATION

OF WELL 6407/9-3

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8.1 SUMMARY

Well 6407/9-3, the second Draugen appraisal well, which was drilled some four kilometers south of the discovery well, encountered a 34m hydrocarbon column in the Frøya Formation. The OWC, established at 1638.5m ss in well 6407/9-2, was interpreted at approximately 1638.5 m ss between the very good sands and the basal shale and was for that reason not very clear.

Prior to testing an FMT survey was carried out: the reservoir pressure measured was hydrostatic, 2395 psia at datum (1630m ss).

In-situ stress tests were carried out at 1680 and 1738 m bdf. A maximum allowable bottom hole injection pressure based on fracturing of 3660 psia was evaluated from these tests and the Breckels and Van Eekelen correlation (Fig. 4.3).

The oil column was perforated from 1606.5 to 1618.5 m ss. The interval was gravelpacked and flowrates up to 15700 stb/d were achieved during the clean up. A multirate test incorporating 4 flow periods with a total flow duration of 36 hrs and a 24 hrs pressure build-up survey was carried out. The evaluation showed an average permeability of 5.7 Darcy over 36m. Skins calculated ranged from 24 to 29. Observed productivity indices after gravelpacking varied from 147 to 166 stb/d/psi. The calculated ideal PI is 660 stb/d/psi.

The evaluated datum pressure was 2391 psia. Both this pressure and the FMT pressure of 2395 psia are well within measurement accuracy of the previously established reservoir pressure of 2392 psia.

8.2. INTRODUCTION

8.2.1 Background

Well 6407/9-3 is the second appraisal well on the Draugen structure in block 6407/9 (see Fig. 2.1). Both the discovery well and the first appraisal well encountered a highly undersaturated 40^{o} API oil. The main results obtained from production tests in these wells were:

Well	6407/9-1	6407/9-2
Max. stable oilrate, stb/d	8500	7400
GOR sep, scf/stb	210	210
BSW, %	0	0
kh product, D.ft	950	221
Permeability, Darcy	7.1	2.6
Total skin	110	118
PI actual, stb/d/psi	63	15
PI ideal, stb/d/psi	833	210
Static pressure, psia	2394	2392

This second appraisal well was drilled during May/June 1985. An oil-bearing interval was encountered from 1604 to 1638.5 m ss (see Fig. 2.2). The OWC, interpreted at 1638.5 m ss, was not as clear as in well 6407/9-2, where it was also established at 1638.5 m ss.

8.2.2 Test Objectives

The objectives for testing the well were:

1. to acquire in-situ stress data
2. to determine reservoir quality parameters
3. to carry out a high rate flow test
4. to collect oil samples, both at surface and downhole.

8.3. OPERATIONS

8.3.1 FMT Survey

The objectives of the FMT (Formation Multi Tester) survey were to define oil and water gradients, to define the oil water contact in the Frøya Formation, to measure the initial formation fluid pressures in the Frøya, Haltenbanken and Drake Formations, and to collect a formation fluid sample from the hydrocarbon bearing column.

The FMT tool of Dresser Atlas was equiped with a 10 cc pretest chamber and a fixed choke. Pressures were measured both with a strain gauge and with a quartz crystal gauge. In case of sand plugging problems whilst sampling, a problem that prevented sampling in well 6407/9-2, a back-up tool incorporating a variable choke, but with just a strain gauge, was available on site.

In total 48 pretests were carried out: 28 measured stabilised formation pressues, 15 had seal failure, and the remaining 5 were not fully stabilised.

A successful segregated fluid sample was taken at 1637.5 m bdf. The big 2 3/4 U.S. gallon chamber was filled first to collect the invasion fluid, the small (one U.S. gallon chamber) was filled thereafter to collect the actual sample. No plugging occurred.

8.3.2 In-situ Stress Tests

Data on in-situ stress is required to determine borehole stability as a function of deviation and to establish fracture pressures for water injection wells. Ideally, these data should be collected in and above the reservoir. However, well 6407/9-3 was to be suspended, so this was considered risky. Therefore, two intervals below the reservoir, one shale (1680 mbdf) and one sand (1738 mbdf), were selected for a mini-frac test.

An RTTS packer was used to enable frac tests over the two intervals in one trip. In each case, a 2 ft interval was perforated and a fracture was created with 1.20 SG chalk mud. Formation breakdown and fracture propagation were observed before stopping the pumps to determine the instantaneous shut-in pressure (ISIP) which corresponds to the minimum horizontal in-situ stress. Pressures were recorded downhole using strain gauges in a bundle carrier below the packer. The tests were repeated several times as shown in Fig. 3.1. Details of test 2A are shown in Fig. 3.2.

8.3.3 Oil Zone Test

8.3.3.1 Sequence of Events

Achievable well flowrates is an important parameter in the economic evaluation of the Draugen development. One of the main objectives of this well was therefore to prove the feasibility of drilling and completing a high rate oil producer.

The completion procedures were upgraded to minimise the Darcy skin and the test facilities were modified to cope with a flow of more than 15000 stb/d.

Major steps taken to obtain the optimum completion/high rate were the use of

- fully acid degradable mud
- sand blasted production casing
- completion fluid mixed with 99 % pure calcium chloride
- plastic coated 3.5" gravel packing workstring
- knockout reverse flapper valve to eliminate fluid loss whilst running the tubing
- 5" tubing string
- larger perforated interval
- upgraded surface facilities.

The well was perforated under drawdown using a 6", 12 spf tubing conveyed gun from 1630.5 to 1642.5 m bdf (Fig. 3.3). After the initial unchoked backsurge (PT-1A) of some 10 bbls the well was flowed at rates up to 1500 stb/d at 500 psig FTHP (see App. A and B for details of this and ensuing flow periods).

The well was killed by bullheading the oil with a viscous pill followed by brine. The perforating string was pulled and the perforated interval was gravel packed using 12/20 mesh gravel. The total volume of brine and acid lost up to the end of the gravel pack job was approximately 160 bbls.

The production test string run subsequently is shown in Fig. 3.4.

The gravel pack was stabilised (PT-1B) by flowing the well for six hours on a 24/64" bean ($\pm$ 1100 stb/d) and for six hours on a 36/64" bean ($\pm$ 2800 stb/d). Fig. 3.5 shows the test performance for this and ensuing flow periods. BSW was zero, H_2S zero ppm and CO_2 0.75 %.

A BHS run was made (PT-1C). Two out of three samples showed corresponding bubble points of 510 psig at 60^oF. The third showed an opening pressure of only 100 psig and had probably leaked.

The well was stimulated with 100 bbls 15% HCl. After 30 mins. soaking the well was opened up and produced clean (PT-1D). The maximum flowrate measured was 15752 stb/d whilst flowing "non-critical" through 2 x 128/64" beans. The constraining factor on the flowrate was the burner back pressure.

Following the clean up a multirate drawdown and build up test was carried out (PT-1E). Two Hewlett-Packard crystal gauges and one Flopetrol SDP strain gauge were run. Four flow periods investigated rate-PI relationships:

Period	Rate (stb/d)	Duration (Hrs)	
1	3400.	6	
2	8800.	6	
3	13000.	17	
4	8100.	7	
5	0.	24	(pressure build-up survey)

Some separator problems were experienced whilst flowing through two separators during period 2. This rate value is based on only three measurements at the start of that period. The other three rates are considered reliable.

The bottomhole samples collected during PT-1C showed bubble points of 510 psig at 60^{o}F. This corresponds to 750-775 psi at 160^{o}F. Previous PVT analyses (wells 6407/9-1 and -2) indicated values around 850 psig. The separator GOR was also lower than measured previously: $\pm$ 130 scf/stb for this well compared to 210 scf/stb for wells 6407/9-1 and -2. Although a large part of this difference could be explained by higher separator operating pressures it was decided to make a further run to collect additional bottom hole oil samples (PT-1F). However, the toolstring was lost downhole and all fishing was unsuccessful.

On completion of testing the well was suspended as a potential oil producer

8.3.3.2 Pressure Gauges.

Pressure gauges were run during the initial flow period (PT-1A), with the two BHS toolstrings and during the multirate test (PT-1E).

To combat turbulent flow along the pressure gauges during the multirate test a blanked off bombhanger in combination with a perforated flowtube was used.

Three types of gauges were initially planned for use:

- EPG capacitance gauge
- Valtos strain gauge
- HP quartz crystal gauge

Due to failures of the EPG (PT-1A and in-situ stress test) and the HP gauge (PT-1C) a Flopetrol SDP strain gauge was used in addition to two HP gauges during the multirate test (see Table 3.1).

The use of the EPG capacitance gauge is not recommended until the failures are explained. Both the HP gauge and the Valtos strain gauge worked satisfactorily. However due to the poor resolution of the Valtos strain gauge (0.6 psi) this gauge is of very limited use when testing high permeability zones. Subsequent investigations have shown that this gauge can be changed from a " T" sampling mode to a " P" sampling mode thus improving the resolution in pressure to 0.06 psi. The associated loss of resolution in temperature is not considered relevant in pressure build up testing.

The memory modules used with the Valtos strain gauge have a capacity of some 15000 pressure points. This same module was also used with the HP gauge, the capacity then becomes 8000 pressure + temperature points. The disadvantage is that these modules are RAM resulting in gauge unloading times of 5-7 hrs.

However, the operational flexibility that is gained by doubling the memory size when using RAM compared with ROM modules far outweighs this. The contractor (Stavanger Oilfield Services) is presently developing means of speeding up the unloading of these gauges.

8.3.3.3 Fluid Sampling

Details of the samples collected during the oil zone test are given in Table 3.2.

A total of 2 oil BHS and 4 sets of recombination oil and gas samples were recovered. A full PVT analysis of one of the BHS will be carried out. In addition the bubble points of the FMT sample and one of the recombination samples will be determined.

As no water was produced no surface water samples were recovered.

Measured separator oil gravities during testing varied from 0.808 - 0.829 g/cm^3 (39 - 43 ^{o}API). Separator gas gravities ranged from .785 to .810 (air =1). The gas gravities are significantly lower than measured previously probably due to the high separator pressures ($\pm$ 170 psig versus 60 - 100 psig for wells 6407/9-1 and -2). No H_2S was produced while up to 0.75 % CO_2 was measured in the gas.

8.4. EVALUATIONS

8.4.1 FMT Survey

Both the oil and water gradients, respectively 0.325 and 0.443 psi/ft, were identical to those established in well 6407/9-1. The calculated datum pressure (at 1630 m ss) was 2395 psia using the HP gauge data (see Fig 4.1 and 4.2 and Table 4.1). The strain gauge data confirmed the gradients but the measured pressures were 10 - 12 psi higher. These strain gauge values do not agree well with the formation pressure observed during the multirate test nor with the previously established datum pressure of 2392 psia. The difference is within the strain gauge specifications since a 15000 psi pressure element was used ($\pm$ 19 psi). The absolute accuracy of the FMT and RFT strain gauges can be improved upon by using 5000 psi pressure elements.

From FMT pretests permeabilities may be calculated using an empirical Dresser Atlas equation. Some values are shown in Table 4.1. In general they are low when compared with the PBU results (section 4.3).

8.4.2 In-situ Stress Tests

The following results (corrected for gauge depth) were obtained:

Depth (mbdf)	Formation breakdown pressure (psi)	ISIP(psia)
1680	4709	3964
1738	5404	4456

The instantaneous shut-in pressure (ISIP) corresponds to the minimum in-situ horizontal stress. These results are indicated in Fig. 4.3 which also shows the Breckels and Van Eekelen correlation for predicting in-situ stress.

It is noted that the stress measured for the shale interval is some 200 psi more than the stress predicted. The data on which the correlation is based is predominantly from sands. Shales generally show higher stresses than sands, so although the deep water and shallow reservoir might suggest lower stresses than normal, this result is reasonable. The stress measured in the sand interval exceeds the predicted stress by some 400 psi. Assuming normal faulting and no overpressure, this observation is the reverse of what might be expected. There are no indications in the Draugen area of reverse faulting or overpressures.

It has been concluded that the Breckels and van Eekelen correlation is applicable to the Draugen field but that it may result in the inclusion of generous safety margins. Therefore, it has been recommended that additional in-situ stress data at shallower depths should be acquired in a well which is to be abandoned. The maximum allowable bottom hole injection pressure based on the correlation assuming no fracturing is permitted is 3660 psia at 1630 m ss and 160^{o}F.

8.4.3 Oil Zone Test.

Transient state drawdown analysis proved to be impossible in this highly permeable reservoir. Pressure fluctuations caused by slightly varying rates, well head temperatures and tides masked the transient pressure response. The bottom hole pressure during the maximum rate stage fluctuated between 2287 and 2289 psia whereas the actual rate varied by several 100 b/d at the same time.

Pressure build up (PBU) surveys were recorded after the initial backsurge (PT-1A) for 2 hrs and after the multirate test (PT-1E) for 24 hrs. No analysis of the PT-1A PBU could be carried out due to the low resolution of the two Valtos strain gauges used (Fig 4.4). A third gauge (EPG capacitance) failed on that run.

Two gauges successfully recorded the PBU after PT-1E : 1 HP quartz crystal gauge and 1 Flopetrol SDP strain gauge. Analysis of the PBU did not follow the Gringarten type curve matching technique. A downhole shut-off tool had succesfully been used to eliminate wellbore storage effects.

Fig. 4.5 shows the superposed log time plot of the PBU recorded by the Flopetrol strain gauge. Tidal effects are clearly present towards the end of the survey. After filtering out these by use of a cosine function with an amplitude of 0.15 psi and a wavelength of 12 hrs (high tide at 1400 hrs) a slightly upwardly bending curve remained (Fig.4.6).

A detailed analysis of this filtered PBU is given in Appendix C. For the transient analysis it is assumed that the total Frøya Formation is drained: 36m. From Fig. 4.6 it is clear that two straight lines can be drawn through respectively the early and late data. The first straight line section (point 18 to 28) yielded a kh of 674 D.ft, the second (point 85 to 136) of 495 D.ft.

The change in slope (+30%) occurs 22 mins after closing in the well. If the change of slope is due to a reservoir feature the distance of this event from the well bore can be estimated from

$$L = 0.01217 \left(\frac{k.\ t}{ø.u.Ct} \right)^{0.5}$$

where

L - distance of event (ft)
k - permeability (mD) : 5700
t - shut in time of event (hr) : 0.37
ø - porosity (fraction) : 0.32
u - fluid viscosity (cP) : 0.67
C_t - total compressibility (psi^{-1}) : $20 * 10^{-6}$

(Gray, K.E.: " Approximating Well-to-Fault Distance From Pressure Build-Up Tests," J. Pet. Tech. (July 1965) 761-767)

This equation may be used when the shut in time is short compared to the producing time. In this case the assumption was valid as the ratio was smaller than 0.01. The distance thus calculated was 268 ft. The event that caused the slope change could be a reduction in sand thickness, permeability or a partially sealing fault.

Earlier work in connection with the well test of 6407/9-2 has shown that changes in permeability may not show up clearly on PBU plots (see NSEP 258 and the 6407/9-2 well test report).

The skins calculated for the four flow periods of PT-1E varied from 24 to 29. The partial penetration skin calculated using the Brons and Martin correlation is about 5.

The bottom hole flowing pressures for each of the four flow periods were approximately constant i.e. no additional clean up occurred. The actual PI's can then be calculated from (Pi - Pwf) and the oil rate. For the crystal gauge this results in PI's of 162, 164, 147 and 150 stb/d/psi for each of the four flow periods. The first value was calculated using a drawdown of 21 psi. A drawdown of 22 psi would have resulted in 154.5 stb/d/psi. As was indicated in chapter 3 measurement of flowrates during period 2 was inaccurate. No evidence for rate dependency is therefore considered to be present.

Turbulence inside the tailpipe was eliminated by blanking off the pressure gauges below the perforated flow tube.

The ideal PI calculated was some 660 stb/d/psi.

A summary of the evaluation of the 3 gauges used during PT-1E is given in Tables 4.2 and 4.3.

The reservoir pressure established during the FMT survey was 2395 psia (at datum 1630 m ss). The initial reservoir pressures before and after PT-1E ranged from 2393 to 2391 psia (at datum) (see Table 4.4). The normalisation of the test pressures to datum was carried out using the oil gradient established from the FMT survey.

These initial pressure values are all within measurement accuracy of the previously established initial pressure of 2392 psia (at datum). The latter value can therefore still be used.

8.5. RESULTS AND CONCLUSIONS

8.5.1 FMT Survey

i The oil and water gradient established were identical to well 6407/9-1, 0.325 and 0.443 psi/ft respectively.

ii The Frøya and Haltenbanken Formations belong to the same hydrostatic pressure regime.

iii The average reservoir pressure was 2395 psia at datum (1630 m ss) and is within measurement accuracy of the previously established initial reservoir pressure of 2392 psia (at datum).

iv A downhole oil sample was recovered.

8.5.2 In-situ Stress Tests

i The minimum in-situ horizontal stresses measured for the two tests were 3964 psia at 1680 m bdf and 4456 psia at 1738 m bdf.

ii These results are somewhat higher than predicted from the Breckels and Van Eekelen correlation (Fig. 4.3). The use of this correlation may therefore lead to inclusion of generous safety margins.

iii The maximum allowable bottom hole injection pressure at datum and 160^{o} F, assuming no fracturing is allowed, can be estimated at 3660 psia using the Breckels and Van Eekelen correlation.

iv Additional measurements at shallower depths are required to establish the Draugen correlation.

8.5.3 Oil Zone Test

i The well produced up to a maximum of some 15700 stb/d of 40^{o} API oil from the interval 1604.5 to 1616.5 m ss. The separator GOR was 130 scf/stb. Cummulative oil production amounted to 28,550 stb.

ii The evaluated kh product was 674 D.ft, equivalent to an effective oil permeability of 5.7 Darcy for the drained interval of 36m.

iii The average post gravel pack PI was some 150 stb/d/psi and the total skin was 29. The partial penetration skin was 5. The calculated ideal PI is 660 stb/d/psi (skin zero).

iv The PBU survey indicates the presence of a reservoir feature some 268 ft from the wellbore causing a slope increase on the log time pressure build-up plot.

v The initial reservoir pressure calculated was 2391-2393 psia at datum (1630 m ss). The previously established value of 2392 (at datum) is still valid.

WELL 6407/9-3
PT-1 : TECHNICAL DATA GAUGES

TEST PT-1A

GAUGE NUMBER	64446/66410	8410-018	8410-037
COMPANY	SOS	SOS	SOS
TYPE (see note)	EPG CP.G.	VALTOS S.G.	VALTOS S.G.
DELAY TIME, hrs	-	-	-
SAMPLING RATE, secs	144	15	15
MEMORY POINTS	FAILED	14985	14985
DEPTH, m bdf	1610.2	1610.2	1610.2

TEST PT-1C

GAUGE NUMBER	HP 0784
COMPANY	SOS
TYPE	H.P. C.G.
DELAY TIME, hrs	
SAMPLING RATE, secs	
MEMORIZED POINTS	FAILED
PRESSURE THRESHOLD,psi	
TEMP. THRESHOLD, ^{o}C	
DEPTH, m bdf	

TEST PT-1E

GAUGE NUMBER	HP 1076	HP 0784	83117
COMPANY	SOS	SOS	FLOPETROL
TYPE	H.P. C.G.	H.P. C.G.	S.D.P. S.G.
DELAY TIME, hrs	-	-	40
SAMPLING RATE, secs	VARIOUS	VARIOUS	10
MEMORIZED POINTS	FAILED TIMER	4224	5400
PRESSURE THRESHOLD,psi	50	50	N/A
TEMP. THRESHOLD, ^{o}C	10	10	N/A
DEPTH, m bdf	1635.7	1640.2	1643.2

NOTE:
- CP.G. = capacitance gauge, S.G. = strain gauge, C.G.= crystal gauge
- The H.P. crystal gauge run with the BHS (PT-1F) was lost together with the toolstring.

WELL: 6407/9-3
PT-1 SAMPLES COLLECTED

No.	TEST	TIME	DATE	NATURE	S.G	SAMPLING POINT	CONTAINER DESCRIPTION /VOLUME	No.	REMARKS
BHS 1	PT-1B	10.23	17.7.85	OIL	N/A	BOTTOM HOLE DEPTH 1625.2m	680 cc SHIPPING BOTTLE	811515	BUBBLE POINT 510 PSIG à 60.5^{o}F
BHS 2	PT-1B	10.23	17.7.85	OIL	N/A	BOTTOM HOLE DEPTH 1627.4m	675 cc SHIPPING BOTTLE	811077	BUBBLE POINT 510 PSIG à 60^{o}C
BHS 3	PT-1B	10.23	17.7.85	OIL	0.821 à60^{o}F	BOTTOM HOLE DEPTH 1629.6m	1 LITRE PLASTIC BOTTLE		BAD SAMPLE
WTR 1	PT-1B	22:50	16.7.85	WATER		WATER LINE AT SEPARATOR	5 LITRE PLASTIC CAN		PH = 1
WTR 2	PT-1B	02:00	17.7.85	WATER		WATER LINE AT SEPARATOR	5 LITRE PLASTIC CAN		PH = 1
WTR 3	PT-1B	04:20	17.7.85	WATER		WATER LINE AT SEPARATOR	5 LITRE PLASTIC CAN		PH = 1
OIL 1	PT-1B	15.00	16.7.85	OIL/WATER		UPSTREAM SANDCATCHER	1 LITRE PLASTIC CAN		
OIL 2	PT-1B	04.20	17.7.85	OIL	.819	SEPARATOR OIL LINE	5 LITRE PLASTIC BOTTLE		
OIL 3	PT-1D	13.50	18.7.85	OIL	.818	UPSTREAM SANDCATCHER	1-LITRE PLASTIC BOTTLE		

WELL: 6407/9-3
PT-1 SAMPLES COLLECTED

No.	TEST	TIME	DATE	NATURE	S.G	SAMPLING POINT	CONTAINER DESCRIPTION /VOLUME	No.	REMARKS
OIL 4	PT-1D	16.00	18.7.85	OIL	.820	UPSTREAM SANDCATCHER	1-LITRE PLASTIC BOTTLE		
OIL 5	PT-1D	16.10	18.7.85	OIL	.820	UPSTREAM SANDCATCHER	1-LITRE PLASTIC BOTTLE		
OIL 6	PT-1D	23.00	18.7.85	OIL	.818	UPSTREAM SANDCATCHER	1-LITRE PLASTIC BOTTLE		
OIL 7	PT-1D	04.05	19.7.85	OIL	.820	UPSTREAM SANDCATCHER	1-LITRE PLASTIC BOTTLE		
OIL 8	PT-1D	08.35	19.7.85	OIL	.818	UPSTREAM SANDCATCHER	1-LITRE PLASTIC BOTTLE		
OIL 9	PT-1E	01.15	20.7.85	OIL	.820	UPSTREAM SANDCATCHER	1-LITRE JERRY CAN		
OIL 10	PT-1E	02.30	20.7.85	OIL	.821	UPSTREAM SANDCATCHER	1-LITRE JERRY CAN		
OIL 11	PT-1E	08.00	20.7.85	OIL	.817	UPSTREAM SANDCATCHER	1-LITRE JERRY CAN		
OIL 12	PT-1E	08.30	20.7.85	OIL	.817	UPSTREAM SANDCATCHER	1-LITRE JERRY CAN		

WELL: 6407/9-3
PT-1 SAMPLES COLLECTED

No.	TEST	TIME	DATE	NATURE	S.G	SAMPLING POINT	CONTAINER DESCRIPTION /VOLUME	No.	REMARKS
OIL 13	PT-1E	21.25	20.7.85	OIL	.818	UPSTREAM SANDCATCHER	1-LITRE JERRY CAN		
OIL 14	PT-1E	23.35	20.7.85	OIL	.816	UPSTREAM SANDCATCHER	1-LITRE JERRY CAN		
OIL 15	PT-1E	04.00	21.7.85	OIL	.808	UPSTREAM SANDCATCHER	1-LITRE JERRY CAN		
OIL 16	PT-1E	06.00	21.7.85	OIL	.808	UPSTREAM SANDCATCHER	1-LITRE JERRY CAN		
P.V.T 1A	PT-1E	02.30	20.7.85	OIL		SEPARATOR-2	700 cc PVT CYLINDER	811448	
P.V.T 1B	PT-1E	02.30	20.7.85	GAS		SEPARATOR-2	20 LITRE PVT GAS BOTTLE	1019	
P.V.T 2A	PT-1E	08.30	20.7.85	OIL		SEPARATOR-2	700 cc PVT CYLINDER	811505	
P.V.T 2B	PT-1E	08.30	20.7.85	GAS		SEPARATOR-2	20 LITRE PVT GAS BOTTLE	1038	
PVT 3A	PT-1E	20.40	20.7.85	OIL		SEPARATOR-2	700 cc PVT CYLINDER	810873	

WELL: 6407/9-3
PT-1 SAMPLES COLLECTED

No.	TEST	TIME	DATE	NATURE	S.G	SAMPLING POINT	CONTAINER DESCRIPTION /VOLUME	No.	REMARKS
PVT 3B	PT-1E	20.40	20.7.85	GAS		SEPARATOR-2	20 LTR GAS PVT CYLINDER	1021	
BULK 1	PT-1E	01.30	20.7.85	OIL	.820	SEPARATOR-2	45 GALLON BARREL		
BULK 2	PT-1E	08.00	20.7.85	OIL	.817	SEPARATOR-2	45 GALLON BARREL		
BULK 3	PT-1E	21.10	20.7.85	OIL	.818	SEPARATOR-2	45 GALLON BARREL		
BULK 4	PT-1E	04.10	21.7.85	OIL	.808	SEPARATOR-2	45 GALLON BARREL		

FMT SURVEY

WELL 640793 SURVEY DATE 070685

HP GAUGE DATA

RESERVOIR DATA:-

FLUID CONTACTS (M-TVSS)		FLUID GRADIENTS (PSI/M)	
DATUM DEPTH =	1630.0	GAS =	.000
GOC =	.0	OIL =	1.066
OWC =	1638.0	WATER =	1.452

GEOLOGICAL DATA:-

FORMATION TOP	DEPTH (M-TVSS)
FROYA FORM	1604.0
HALTENBANK	1659.0
DRAKE	1771.0

PRESSURE DATA:-

GEOLOGICAL ZONE	DEPTH(M) AHBDF	TVSS	PRESSURE (PSIA) MEASURED	DATUM	MUD(PRE-SETTING)	COMMENT
FR	1630.7	1604.7	2368.7	2395.7	2855.0	70 MD
FR	1634.0	1608.0	2372.3	2395.8	2861.0	180 MD
FR	1638.0	1612.0	2375.8	2395.0	2867.0	800 MD
FR	1643.0	1617.0	2380.4	2394.3	2875.0	480 MD
FR	1648.0	1622.0	2386.7	2395.2	2884.0	540 MD
FR	1651.0	1625.0	2389.5	2394.8	2890.0	410 MD
FR	1655.0	1629.0	2393.6	2394.7	2896.0	850 MD
FR	1657.5	1631.5	2396.0	2394.4	2901.0	85 MD
FR	1659.5	1633.5	2398.3	2394.6	2904.0	230 MD
FR	1664.0	1638.0	2404.4	2395.9	2913.0	210 MD
FR	1662.2	1636.2	2402.2	2395.6	2910.0	45 MD
FR	1661.8	1635.8	2402.0	2395.8	2910.0	120 MD
FR	1666.0	1640.0	2407.8	2396.4	2917.0	70 MD
HA	1694.0	1668.0	2446.1	2394.0	2964.0	2790 MD
HA	1707.0	1681.0	2465.3	2394.3	2987.0	120 MD
HA	1718.5	1692.5	2482.3	2394.6	3008.0	1335 MD
HA	1736.0	1710.0	2507.8	2394.7	3038.0	830 MD
HA	1754.5	1728.5	2534.3	2394.4	3070.0	1335 MD
HA	1760.5	1734.5	2543.3	2394.7	3081.0	490 MD
HA	1763.5	1737.5	2547.2	2394.2	3087.0	
DR	1831.0	1803.0	2647.2	2399.1	3205.0	280 MD
DR	1834.1	1808.1	2651.3	2395.8	3209.0	480 MD
DR	1843.4	1817.4	2664.8	2395.8	3225.0	135 MD
DR	1847.0	1821.0	2671.7	2397.5	3231.0	25 MD
FR	1664.0	1638.0	2405.5	2397.0	2913.0	REPEAT, 45 MD
FR	1662.2	1636.2	2403.2	2396.6	2911.0	REPEAT,100 MD
FR	1643.0	1617.0	2381.7	2395.6	2875.0	REPEAT,315 MD
FR	1638.0	1612.0	2376.0	2395.2	2867.0	REPEAT,145 MD
FR	1634.0	1608.0	2372.7	2396.2	2860.0	REPEAT,225 MD
FR	1637.5	1611.5	2376.9	2396.6	2865.0	OIL SAMPLE,450 MD

WELL 6407/9-3
SUMMARY OF EVALUATION PT-1E

	HP 0784	SG 83117
Kh Product, D.ft	602	674
Permeability, Darcy	5.1	5.7
Skin Period 1	24.8	-
" " 2	24.2	-
" " 3	27.7	-
" " 4	25.9	29
Distance to Kh Reduction Event, ft	214	268

Note: - An unclear slope change occurs after 4 hrs shut in time (Fig. 4.6). This slope change is clearer when using HP 0784 data. The inferred distances are 760 ft for SG 83117 and 850 ft for HP 0784. Both these changes of slope occur however in the area where tidal corrections were significant ($\pm$ 0.2 psi).

- SG 83117 was used as back-up gauge for the SOS HP gauges and was programmed to record the end of period 4 and the build-up.

WELL 6407/9-3
SUMMARY OF PI'S FOR PT-1E

	HP 1076 (stb/d/psi)	HP 0784 (stb/d/psi)	SG 83117 (stb/d/psi)	Oil rate stb/d
Period 1	166	162	-	3400
Period 2	165	164	-	8800
Period 3	147	147	-	13000
Period 4	151	150	152	8100

Note: The Period 2 rate is based on limited data and cannot be considered reliable.

TABLE 8.4.4

WELL 6407/9-3
EVALUATED RESERVOIR PRESSURES
PT-1A AND PT-1E

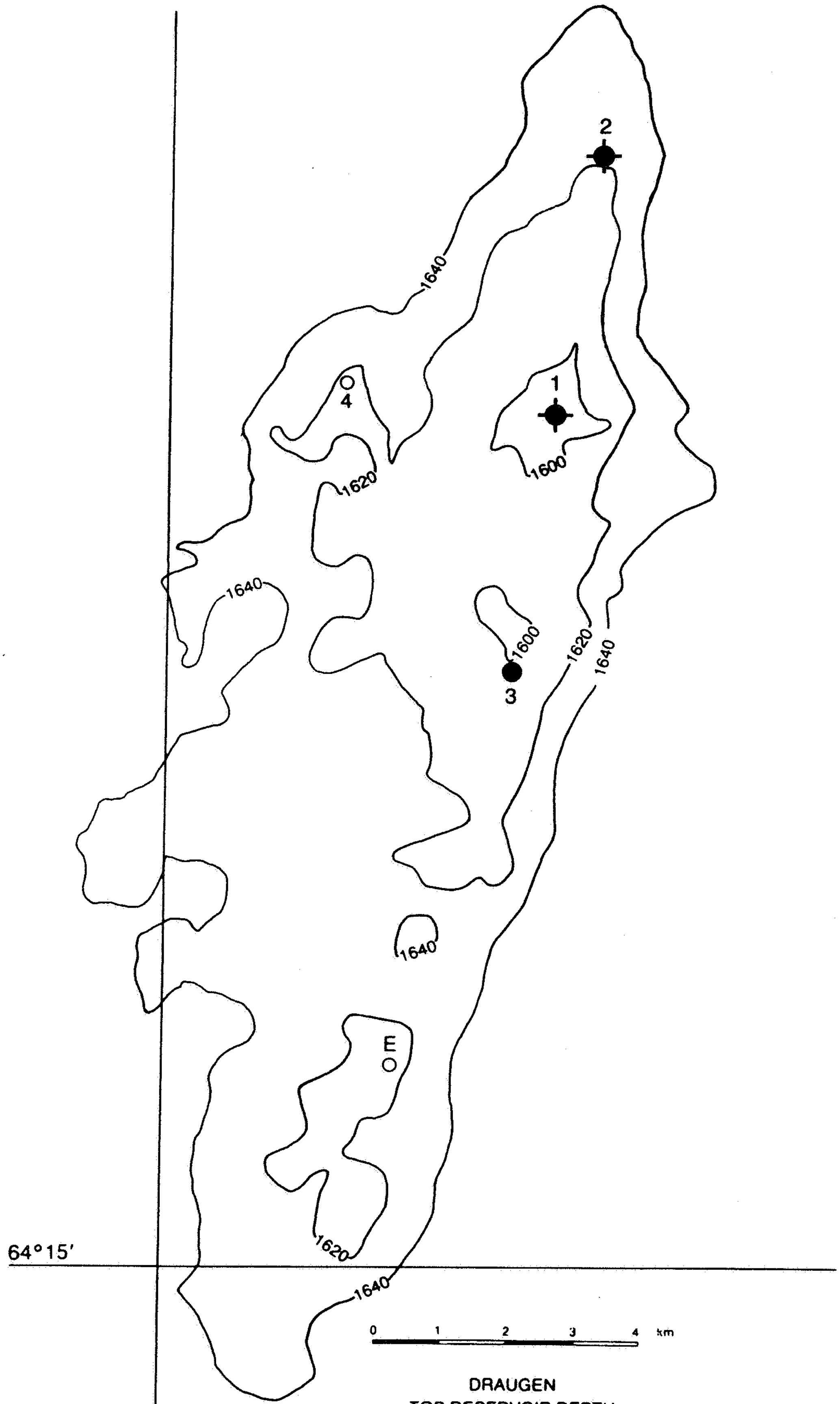
TEST	GAUGE	PRESSURE BEFORE (PSIA)	PRESSURE AFTER (PSIA)
PT-1A	8410-018	-	2405.0
PT-1A	8410-037	-	2398.0
PT-1E	HP 0784	2392.8	2393.3
PT-1E	SG 83117	-	2391.0

Note: The "pressure before" is the pre test measured pressure corrected to datum (1630 m ss). The "pressure after" is the evaluated initial reservoir pressure at datum.

WELL 6407/9-3
OIL GRADIENTS FROM GRADIENT SURVEYS

Date Time	Depth m bdf	THP psig	Press psia	Temp ^{o}C	Remarks
19.07.85					HP 0784 data
18.00	1278.0	573	2005.64	60.5	PT - 1E running in
18.10	1278.0	573	2004.01	60.4	
18.30	1378.0	572	2093.84	62.1	
18.45	1378.0	572	2094.09	62.0	
19.10	1478.2	573	2220.09	64.6	
19.20	1478.2	573	2220.89	64.5	
20.30	1640.2	577	2375.82	70.3	
20.46	1640.2	577	2375.96	70.4	

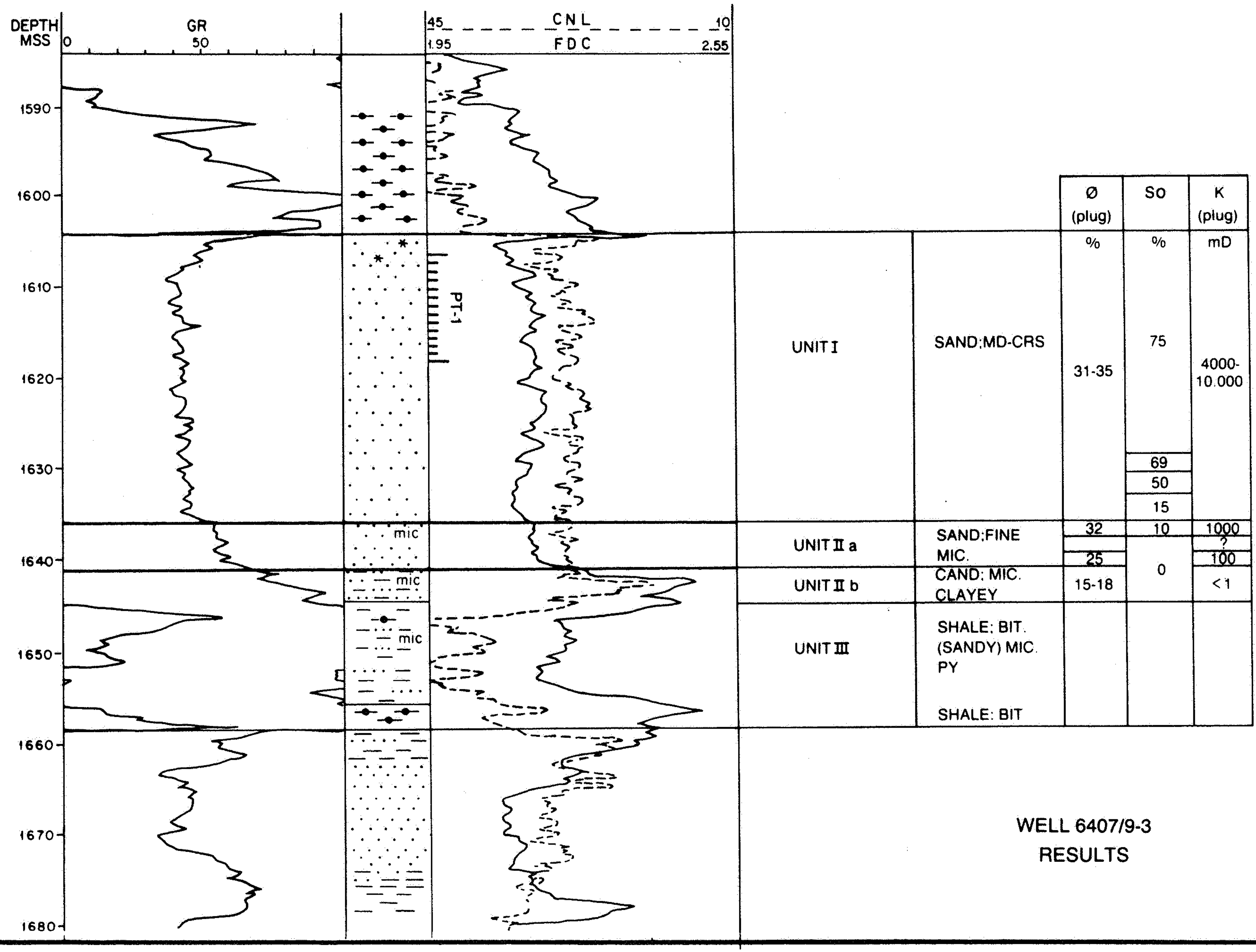
The average gradient between 1278.0 and 1640.2 m bdf is 0.31 psi/ft



DRAUGEN
TOP RESERVOIR DEPTH
CONTOUR MAP
(SIMPLIFIED)

G.2053/13

A/S NORSKE SHELL



WELL 6407/9-3
RESULTS

FIG.8.2.2

NORSKE SHELL 6407/9-3 FRACTURE TESTS 1 + 2.   GAUGE NO. 8430-037

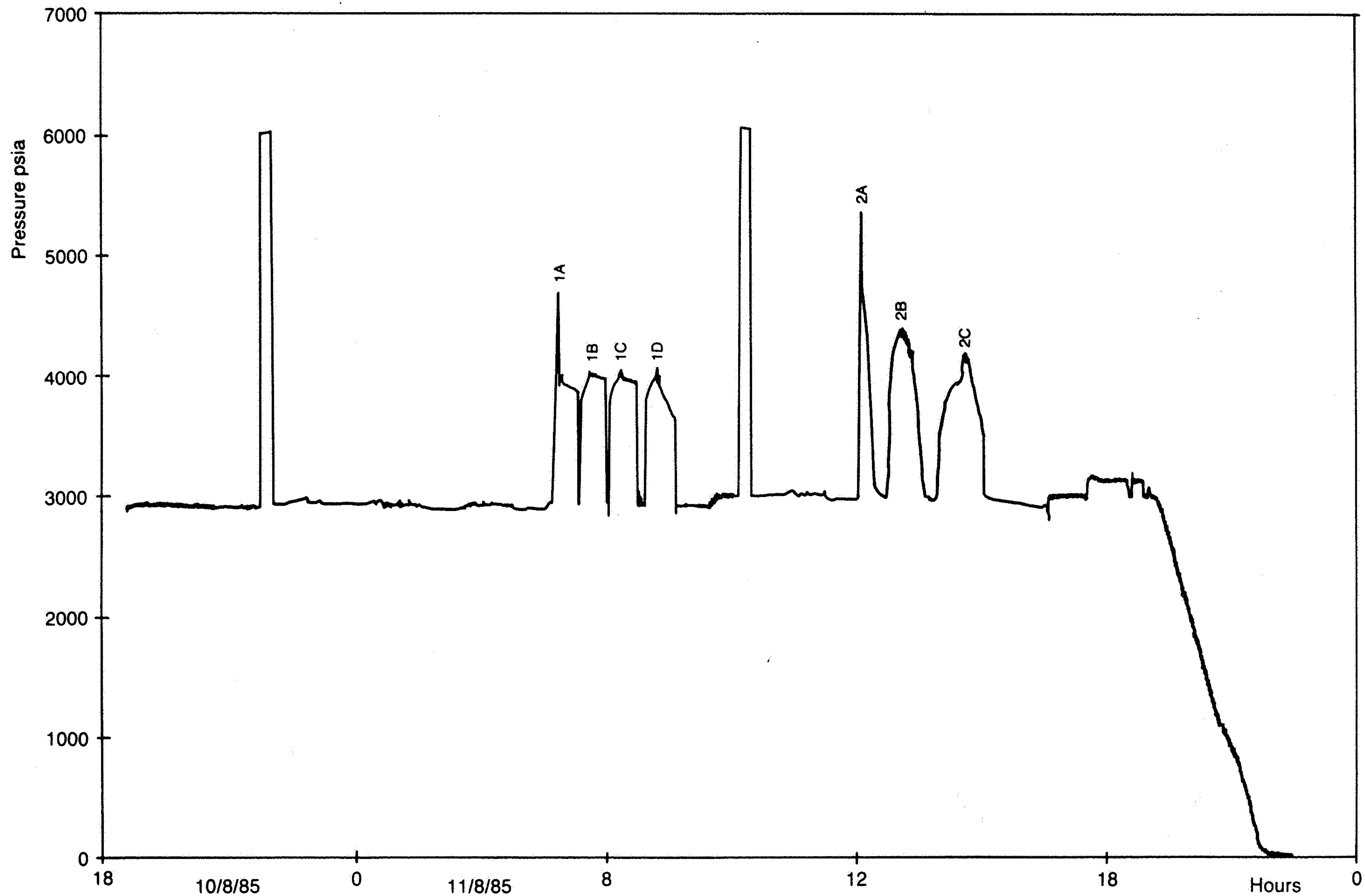
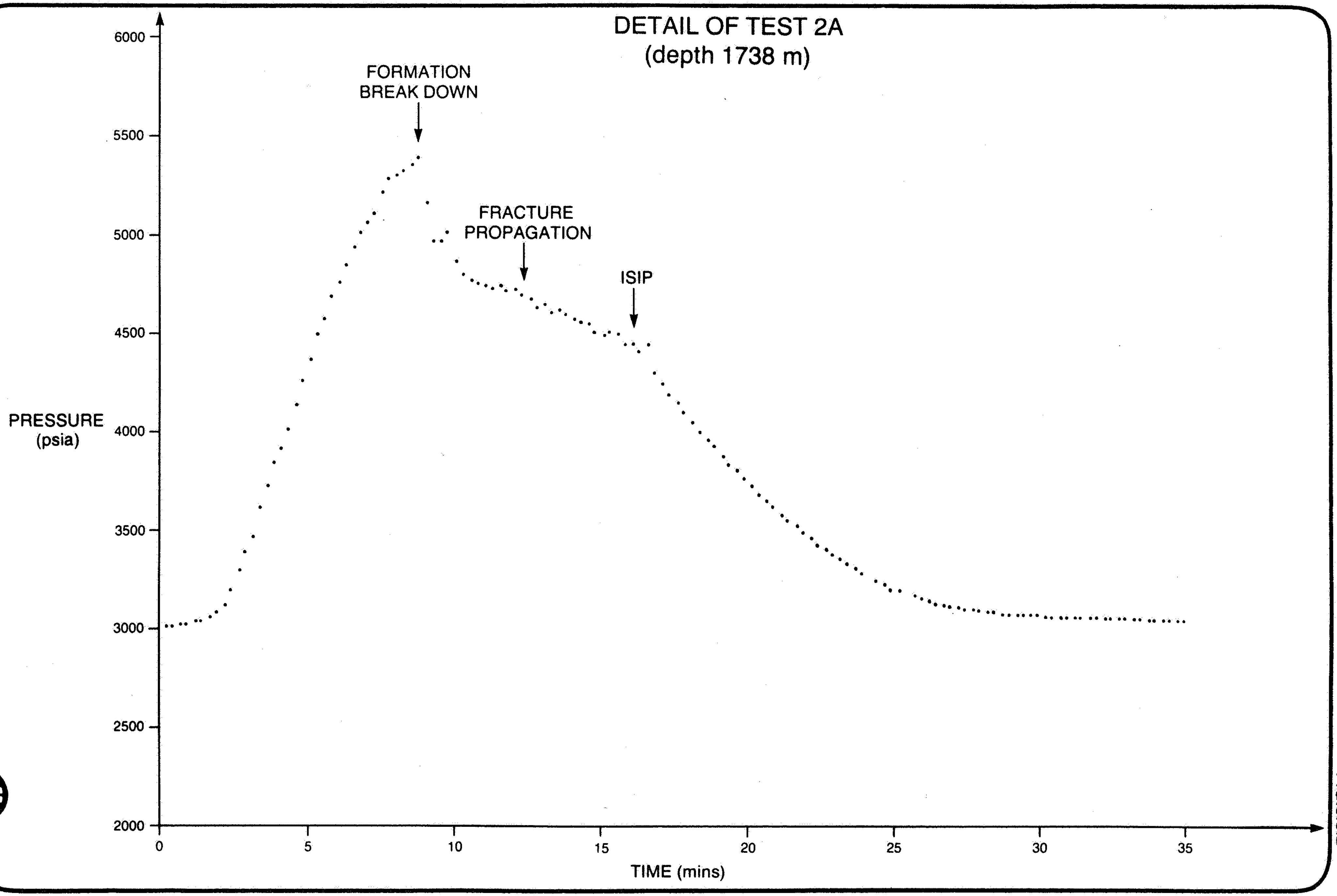


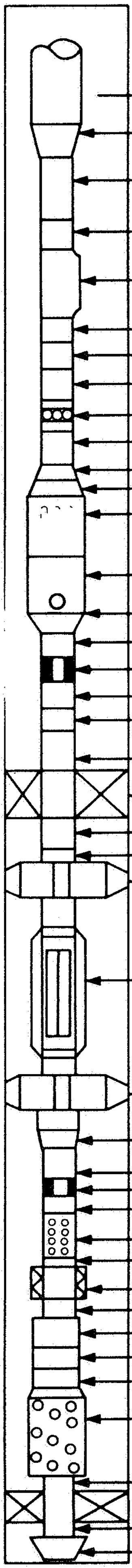
FIG.8.3.1

FIG.8.3.2

DETAIL OF TEST 2A
(depth 1738 m)



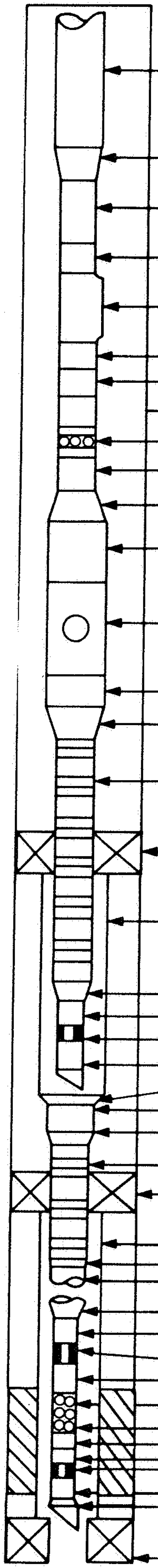
6407/9-3
TUBING CONVEYED PERFORATING STRING



	MIN ID.	MAX O.D.
5" L80 VAM 15ppf TUBING		
X - OVER 5" VAM (B) x 3½ VAM (P)		
20FT PUP JOINT 3½ VAM (BxP)		
PUP JOINT 3½ VAM (B x P)		
KBUG S.P.M. 3½ VAM(B x P)		
PUP JOINT 3½ VAM (B x P)		
X-OVER: 3½ VAM(B) x 3½ CS(P)		
PUP JOINT 3½ CS (B x P)		
3½ x A S.S.D. 3½ CS(B x P)	2.75	
PUP JOINT 3½ CS(B x P)	2.797	
X-OVER 3½ CS(B) x 3½ IF(P)	2.25	5.000
RADIOACTIVE TRACER SUB 3½ IF(B x P)	2.25	5.000
M.O.R.V. 3½ IF(B x P)	2.25	5.000
P.C.T. 3½ IF(B x P)	2.25	5.000
X-OVER 3½ IF(B) x 2⅞ VAM(P)	2.25	5.000
PUP JOINT + 2⅞ VAM(B x P)	2.260	3.330
HF TOP NO GO NIPPLE 2⅞ VAM (B x P)	2.125	3.690
PUP JOINT 2⅞ VAM(B x P)	2.260	3.335
X-OVER 2⅞ VAM(B) x 3½ EU(P)	2.250	3.730
PUP JOINT 3½ EU(B) x 3½ EU(P)	2.992	4.495
BAKER FH PACKER 51 A4	3.000	8.437
PUP JOINT 3½ EU(B) x 3½ EU(P)	2.992	4.520
X - OVER 3½ EU(B) x 3½ IF(P)	2.235	5.155
DRAG BLOCK 3½ IF(B) x 3½ IF(P)		
BUNDLE CARRIER 3½ IF(B) x 3½ IF(P)		
DRAG BLOCK 3½ IF(B) x 3½ IF(P)		
X-OVER 3½ IF(B) x 2⅞ VAM(P)	5.005	2.441
PUP JOINT 2⅞ VAM(B x P)	2.220	3.330
HF TOP NO GO NIPPLE 2⅞ VAM(B x P)	1.87	3.645
PUP JOINT 2⅞ VAM (BxP)	2.220	3.345
PERFORATED PUP JOINTS 2⅞ VAM(B) x 2⅞ EU(P)	2.441	3.680
CIRCULATING SUB 2⅞ SU(B x P)		
SHOCK ABSORBER 2⅞ EU(B x P)		
PUP JOINT 2⅞ EU(B) x (P)		
FILL SUB		
FIRING HEAD		
BLANK SUB		
6" 12 SPF GUN		
X - OVER 2⅞ EU PIN DOWN		
PUP JOINTS 2⅞ EU BxP		
BAKER, 190-60 INDICATING COLLET		

FIG.8.3.4

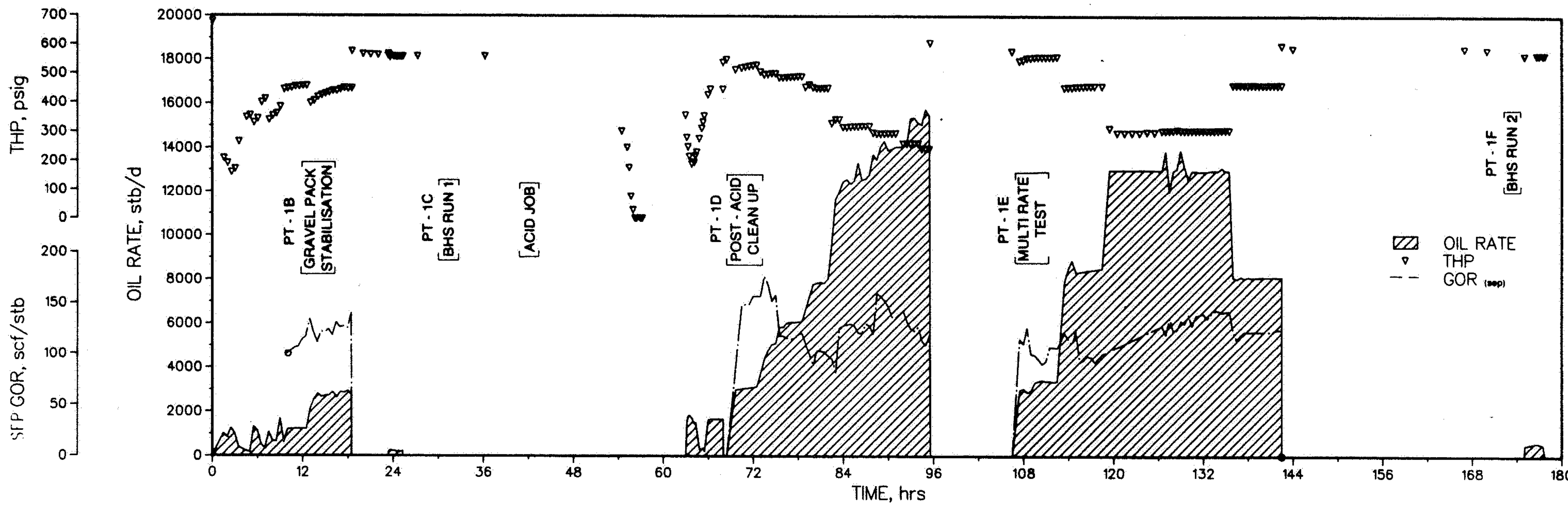
6407/9-3
PRODUCTION TEST STRING



	MIN ID	MAX O.B.
5" L80 VAM 15ppf TUBING	4.283	5 563
X - OVER 5" VAM (B) x 3½" VAM (P)	2.797	5.563
20FT PUP JOINT 3½ VAM B x P	2.797	
PUP JOINT 3½ VAM (B) x 3½ VAM (P)	2.992	3.885
KBUG S.P.M. 3½ VAM (B) x 3½ VAM (P)	2.797	5.220
PUP JOINT 3½ VAM (B)x(P)	2.992	3.530
X - OVER 3½ VAM (B) x 3½ CS (P)	2.900	3.920
PUP JOINT 3½ C.S (B) x 3½ CS (P)		
3½ XA. SSD 3½ CS (B) x 3½ CS (P)	2.75	
PUP JOINT 3½ CS (B) x 3½ CS (P)		
X - OVER 3½ CS (B) x 3½ IF (P)	2.25	5.000
FLOPETROL MORV 3½ IF (B) x 3½ IF(P)	2.25	5.000
FLOPETROL PCT 3½ IF(B) x 3½ IF(P)	2.25	5.000
X - OVER 3½ IF (B) x 3½ CS (P)	2.25	5.000
G-22 LOCATOR 3½ CS BOX UP	4.875	6.250
SEAL ASSEMBLY 190-60 20FT STANDARD SEALS	4.875	6.000
BAKER SC1L PACKER 96 A4-60	6.00	8 450
20FT MILL OUT EXTENSION 7⅝ S.T.C.(P) x LTC(P)		7 705
BOTTOM SUB x 2⅞PM VAM (P) DOWN	2.220	5.960
PUP JOINT 2⅞ VAM (B) x 2⅞ VAM (P)	2.220	3.3350
BAKER H.F. TOP NO GO NIPPLE 2⅞ VAM (B x P)	2.125	3.690
WIRELINE ENTRY GUIDE 2⅞ VAM (B) UP	2.220	3.905
X-OVER 7⅝ LTC (B) x 5" VAM (P)		8.240
2 x 5" VAM PUP JOINT (B x P)	4.283	5.598
G22 LOCATOR 5" VAM(B) UP	4.875	6.250
SEAL ASSEMBLY 190-60 10FT PREMIUM SEALS	4.875	6.000
BAKER FAB1 PACKER 194-75 x 60	6.00	
BAKER I.G.P.		
BOTTOM SUB 3½ VAM (P) DOWN		5.970
TUBING 3½ VAM (B x P)		4.870
x-OVER 3½ VAM (B) x 2⅞ VAM (P)	2.125	3.880
PUP JOINT 2⅞ VAM (B) x 2⅞ VAM (P)	2.220	3.340
BAKER H.F. TOP NO GO NIPPLE 2⅞ VAM (B x P)	1.87	
PUP JOINT 2⅞ VAM (B)x(P)		
PERFORATED PUP JOINTS 2⅞ VAM (PxB)	2.350	3.685
x-OVER 2⅞ VAM (B) x 2⅞ EU(P)	2.210	3.330
PUP JOINT 2⅞ EU (B x P)	2.350	3.670
BAKER F TOP NO GO NIPPLE 2⅞ EU (B x P)	1.81	3.090
PUP JOINT 2⅞ GU (B x P)	2.35	3.670
FLAPPER KNOCKOUT SUB/WIRELINE ENTRY GUIDE	2.425	4.450
BAKER F1 SUMP PACKER 192-60	6.00	8.220

HALTENBANKEN 6407/9-3

OILZONE TEST – TIME ZERO IS 1032 HRS. 16/7/85



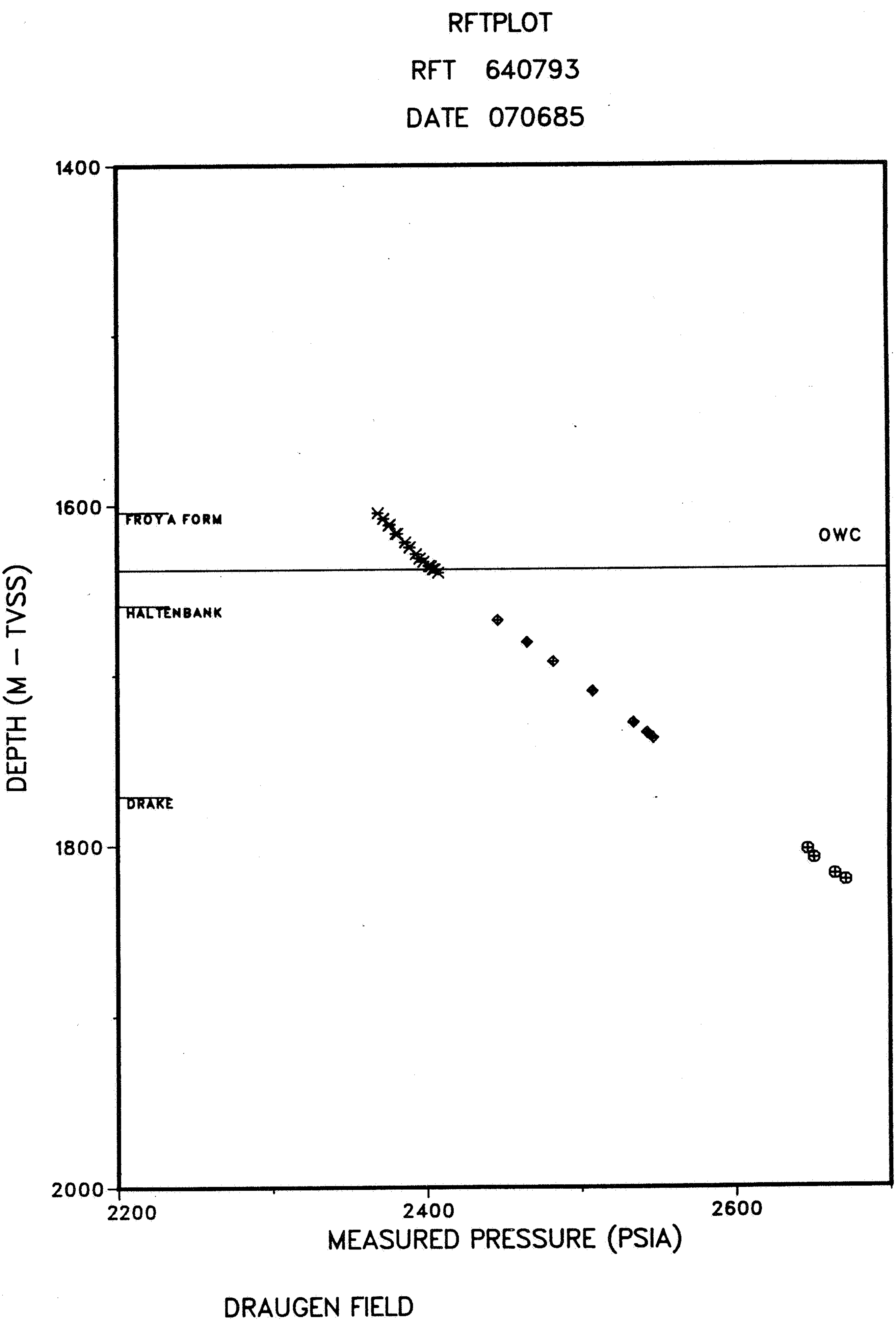
PMR JULY'85 ENCL F5

FIG.8.3.5

G.2053/19

A/S NORSKE SHELL

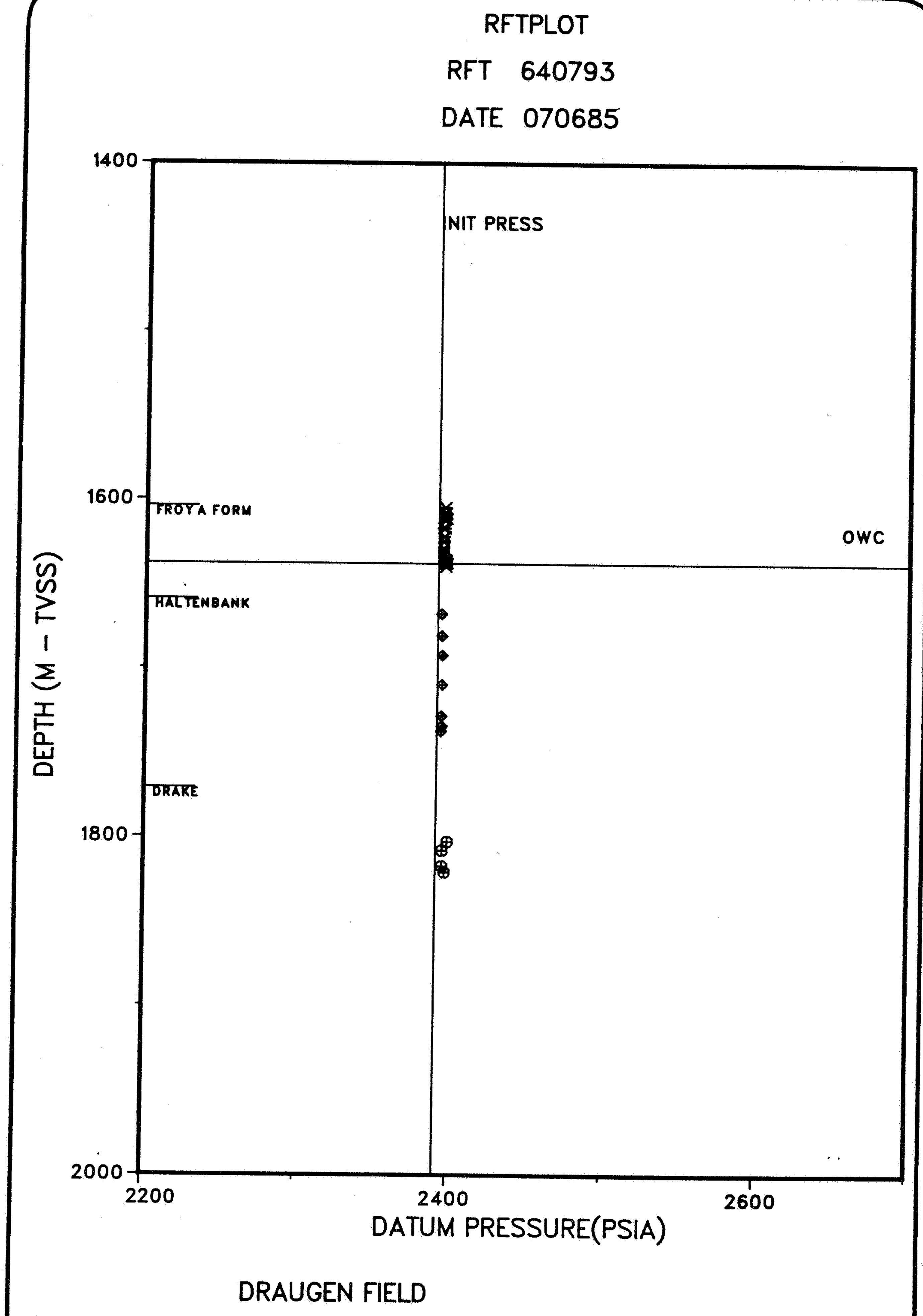
FIG.8.4.1



A/S NORSKE SHELL

G.2053/20

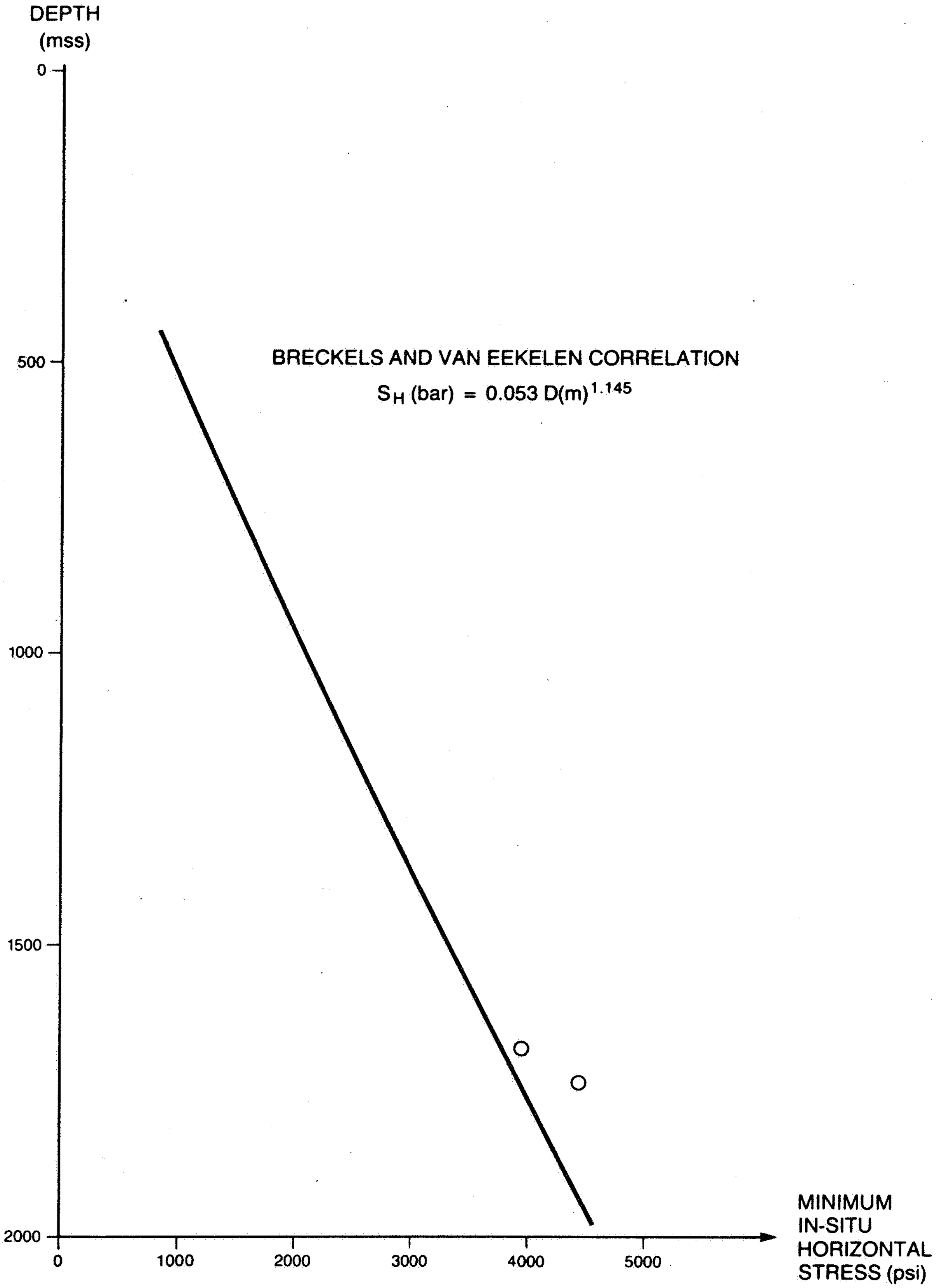
FIG.8.4.2

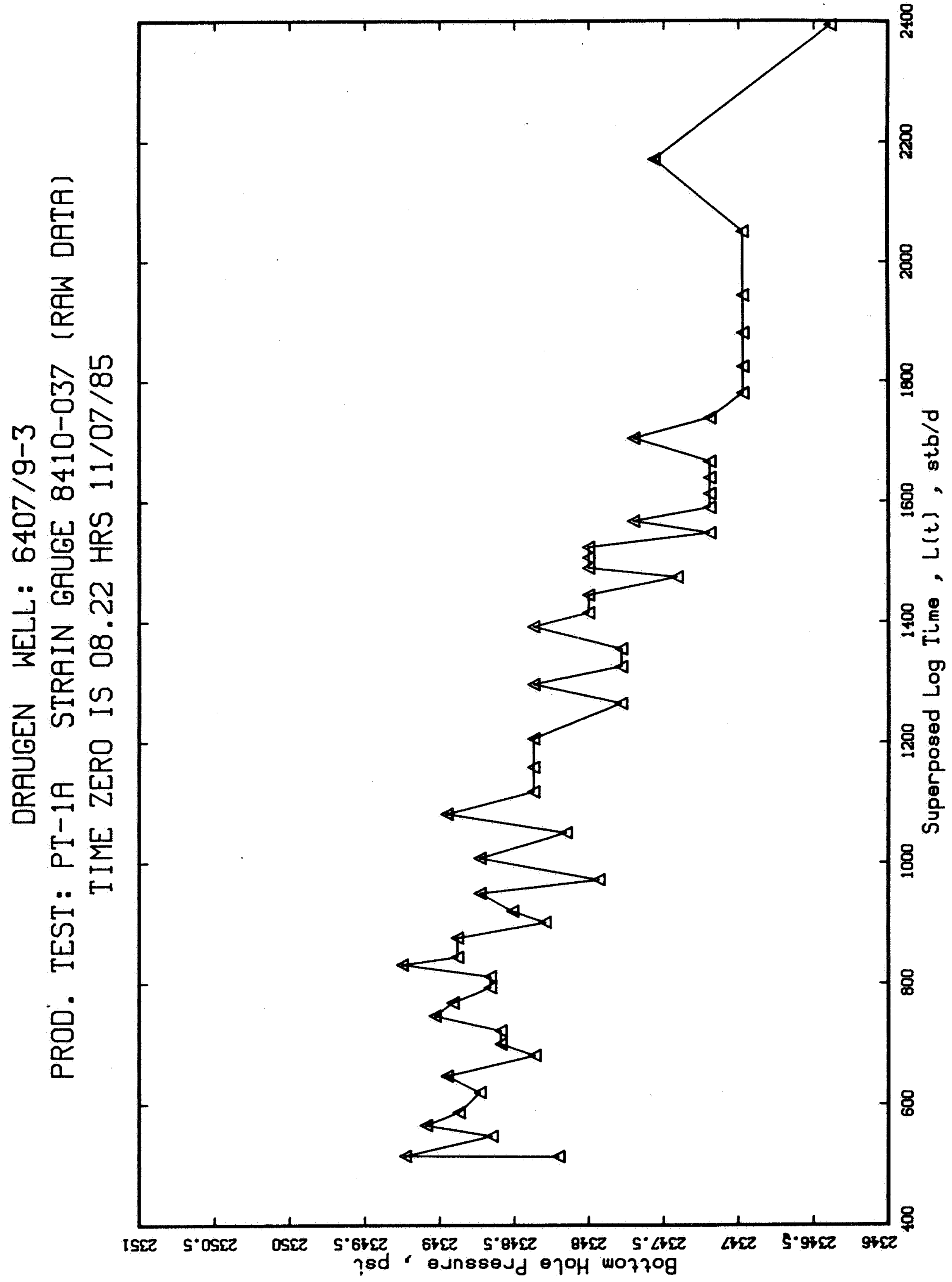


G.2053/21

A/S NORSKE SHELL

CORRELATION FOR PREDICTION OF IN-SITU STRESS





DRAUGEN WELL: 6407/9-3
PROD. TEST: PT-1A STRAIN GAUGE 8410-037 (RAW DATA)
TIME ZERO IS 08.22 HRS 11/07/85
Bottom Hole Pressure , psi
2346
2346.5
2347
2347.5
2348
2348.5
2349
2349.5
2350
2350.5
2351
Superposed Log Time , L(t) , stb/d
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400

FIG.8.4.5

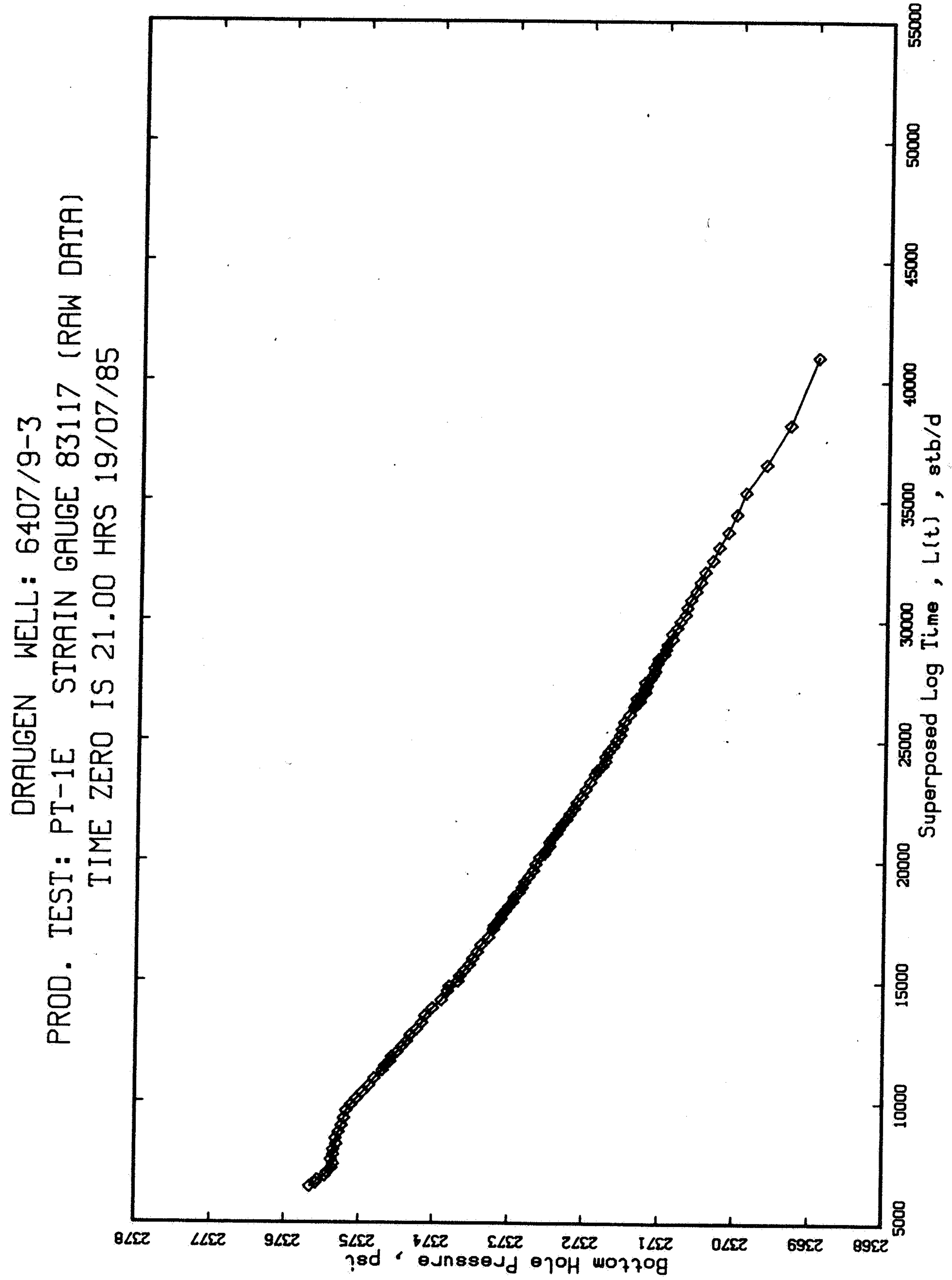
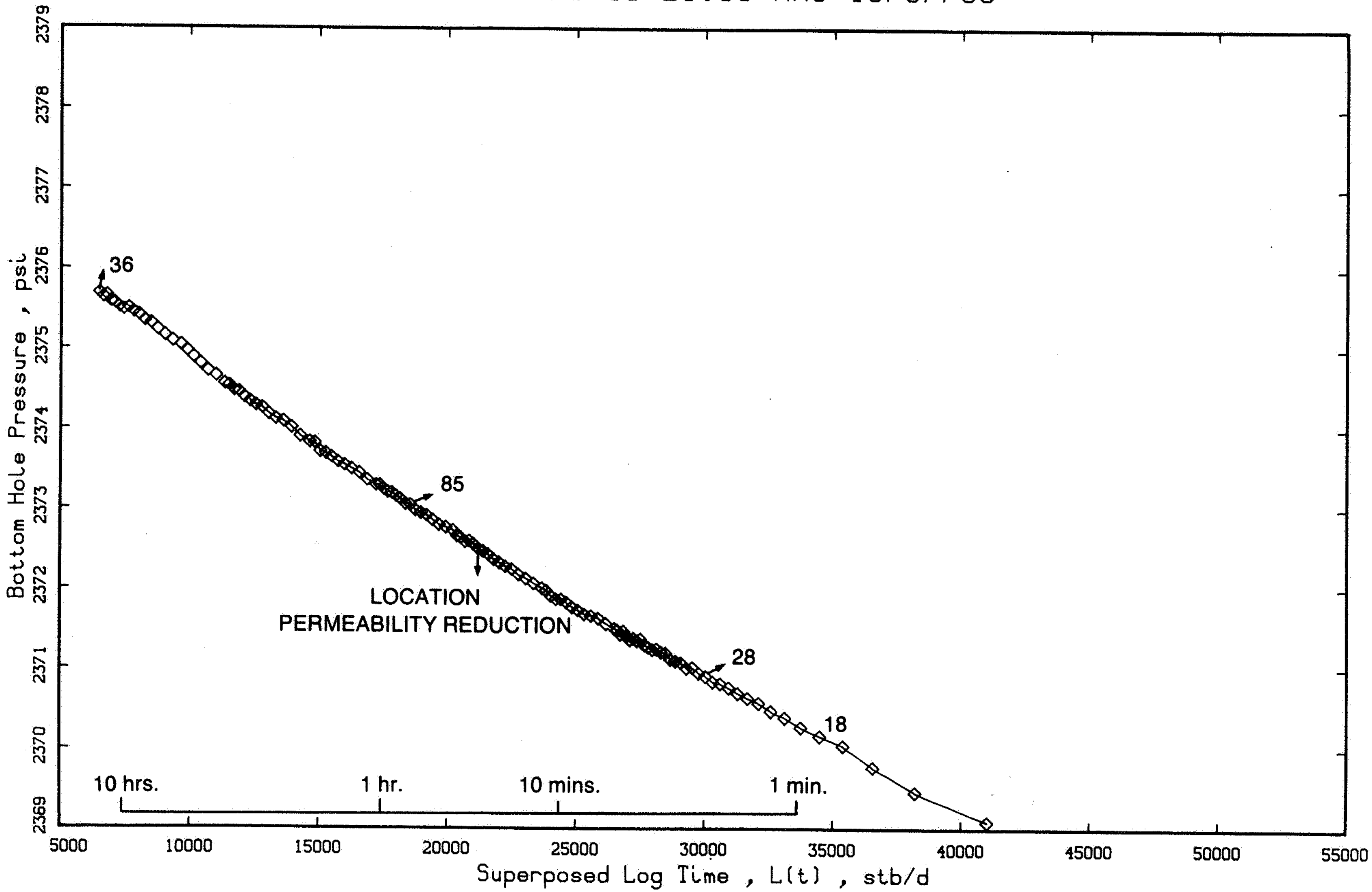

DRAUGEN WELL: 6407/9-3
PROD. TEST: PT-1E STRAIN GAUGE 83117 (RAW DATA)
TIME ZERO IS 21.00 HRS 19/07/85
Bottom Hole Pressure , psi
2368
2369
2370
2371
2372
2373
2374
2375
2376
2377
2378
Superposed Log Time , L(t) , stb/d
5000
10000
15000
20000
25000
30000
35000
40000
45000
50000
55000

FIG.8.4.6

DRAUGEN WELL: 6407/9-3
PROD. TEST: PT-1E STRAIN GAUGE 83117 (tide corrected)
TIME ZERO IS 21.00 HRS 19/07/85



WELL: 6407/9-3
PT-1: SEQUENCE OF EVENTS

FLOW PER.	START TIME	END TIME	DURATION HOURS	CUM. PROD.	FINAL OIL RATE STB/D	COMMENTS
PT-1A	11.07.85					
	08.22	Perforated under drawdown from 1630.5-1642.5 mbd				
1Dd	08.22	12.49	4.450			-oil+gas to surface
2Bu	12.49	18.17	5.467	172	672	-through separator
3Dd	18.17	20.36	2.317			-build-up

KILLED WELL - PULLED STRING - GRAVEL PACKED - RAN COMPLETION STRING

FLOW PER.	START TIME	END TIME	DURATION HOURS	CUM. PROD.	FINAL OIL RATE STB/D	COMMENTS
PT-1B	16.07.85		GRAVEL PACK STABILISATION			
1Dd	10.32	14.00	3.467			-oil + gas to surface
2Dd	14.00	16.37	2.617		1300	-through separator
3Dd	16.37	23.14	6.617		1125	-24/64 " choke
4Dd	23.14	05.01	5.783	1124	2724	-36/64 " choke, closed in well
PT-1C	16.07.85	COLLECT BOTTOM HOLE SAMPLES				
1Dd	09.55	11.52	1.950	216	195	-took 3 BHS, closed in well.

ACID JOB WITH 100 BBLS 15 % HCl

FLOW PER.	START TIME	END TIME	DURATION HOURS	CUM. PROD.	FINAL OIL RATE STB/D	COMMENTS
PT-1D	17.07.85	POST ACID CLEAN UP				
1Dd	17.40	19.53	2.217			-Flowed well:died
2Dd	19.53	01.30	5.617			-Displaced to diesel
3Dd	01.30	12.00	10.500	1261	4441	-Cleaned up well
4Dd	12.00	17.30	5.500	2500	6088	-Flowed through sep.

FLOW PER.	START TIME	END TIME	DURATION HOURS	CUM. PROD.	FINAL OIL RATE STB/D	COMMENTS
5Dd	17.30	20.52	3.367	3600	8046	-2 * 40/64 " bean
6Dd	20.52	01.55	5.050	6400	12600	-2 * 64/64 " bean
7Dd	01.55	05.41	3.767	8450	14059	-2 * 72/64 " bean
8Dd	05.41	08.38	2.950	10300	15141	-2 * 88/64 " bean
9Dd	08.38	10.06	1.467	11250	15449	-2 *128/64 " bean
10Dd	10.06	21.00	10.900			-well shut in: wind unfavourable.
PT-1E	19.07.85	MULTIRATE TEST WITH GAUGES				
1Dd	21.00	03.00	6.000	803	3394	-32/64" bean, one sep.
2Dd	03.00	09.00	6.000	3155 ?	9954 ?	-2 * 40/64", 2 seps.
3Dd	09.00	02.00	17.000	12230	12969	-2 * 72/64", 2 seps.
4Dd	02.00	09.01	7.017	14588	8093	-2 * 40/64", 2 seps.
5Bu	09.01	09.00	23.983		0	-build up
PULLED GAUGES						
PT-IF	22.07.85	REPEAT BOTTOM HOLE SAMPLING RUN				
1Bu	17.35					-ran sampler
2Dd	17.35	20.16	2.683	$\pm$1200	454	-took 3 BHS, 12/64" bean
3Bu	20.16					-sampler lost downhole, not recovered.

WELL: 6407/9-3
SUMMARY OF SEPARATOR DATA

DATE TIME	THP/THT psig/^{o}F	OILRATE stb/d	GOR scf/stb	Psep/Tsep psig/^{o}F	BHP psia	COMMENTS
11.07.85						PT-1A 2Dd
14.00	425/60	24			2346.3	20/64" bean
14.30	428/60	-			2346.1	16/64" bean
15.00	467/56	1512			2336.6	BHP data from
15.30	481/57	579			2345.7	8430-037 Valtos
16.00	495/58	792	100	30/54	2343.3	18/64" bean
16.30	498/58	984	140	30/54	2342.0	
17.00	510/57	1032	152	40/56	2342.0	One gauge failed
17.30	520/56	984	156	45/52	2343.2	
18.00	525/56	672	239	50/52	2343.5	16/64" bean
16.07.85						PT-1B 3Dd
17.30	412/61	336				
18.00	340/63	1068				32/64" bean
18.30	354/58	660				
19.00	362/58	636				
19.30	385/58	1680				
20.00	445/58	588		90/53		24/64" bean
20.30	446/58	1122		90/53		
21.00	450/58	1131	109	90/52		
21.30	455/57	1144	112	100/52		
22.00	455/57	1146	120	100/52		BSW=0.5 %
22.30	457/56	1138	120	90/51		o ppm H2S
23.00	457/56	1125	123	90/51		.75 % CO2
16.07.85						PT-1B 4Dd
23.30	398/56	1932	146	110/51		36/64" bean
24.00	406/56	2343	132	100/51		
00.30	419/57	2795	111	95/52		

WELL: 6407/9-3
SUMMARY OF SEPARATOR DATA

DATE TIME	THP/THT psig/°F	OILRATE stb/d	GOR scf/stb	Psep/Tsep psig/°F	BHP psia	COMMENTS
01.00	425/57	2657	122	105/52		
01.30	430/58	2709	121	105/52		
02.00	435/58	2723	124	110/53		
02.30	440/59	2865	118	110/54		
03.00	440/60	2615	131	110/53		
03.30	445/60	2869	126	105/54		
04.00	450/60	2848	127	105/54		BSW = trace
04.30	447/60	2926	125	105/55		
05.00	449/60	2724	140	110/56		
16.07.85						PT-1C 2Dd
10.05	556/63	252				8/64" bean
10.35	559/63	216				took 3 BHS: 2 OK
11.05	559/62	179				
11.35	559/64	195				Gauge failed
18.07.85						PT-1D 3Dd
02.00	217/60					28/64" bean
03.00						
04.00						32/64" bean
05.00	455/61					
06.00	516/64					
07.00	505/64					
08.00	514/65					
09.00	521/67	1894	237	87/60		
10.00	527/69	3079	149	87/60		
11.00	531/70	3145	157	90/62		
18.07.85						PT-1D 4Dd
12.00	497/75	4441	176	120/68		40/64" bean

WELL: 6407/9-3
SUMMARY OF SEPARATOR DATA

DATE TIME	THP/THT psig/^{o}F	OILRATE stb/d	GOR scf/stb	Psep/Tsep psig/^{o}F	BHP psia	COMMENTS
13.00	502/76	5069	152	110/71		no H_2S
14.00	504/76	5080	159	105/72		0.5 % CO2
15.00	488/-	6035	116	165/-		48/64" bean
16.00	490/78	6062	116	170/74		
17.00	491/79	6088	121	155/73		

WELL 6407/9-3
SUMMARY OF SEPARATOR DATA

DATE TIME	THP/THT psig/°F	OILRATE stb/d	GOR scf/stb	Psep/Tsep psig/°F	BHP psia	COMMENTS
18.07.85						PT-1D 5Dd
18.00	463/81	4089	67	195/71		Flowed through
19.00	450/82	4022 3824	98 108	210/71 210/73		2seps.each on
20.00	450/82	3662 4186	108 98	210/72 210/73		40/64" bean
18.07.85						PT-1D 6 Dd
21.00	331/86	5141 4521	72 121	250/73 250/78		2 seps. on
22.00	316/88	5745 6281	119 121	150/76 135/79		2* 64/64"bean
23.00	317/88	5903 6678	129 129	150/78 155/79		
24.00	320/88	5814 6700	127 129	160/77 155/79		
01.00	321/85	5890 6656	126 128	160/78 160/80		
19.07.85						PT-1D 7Dd
02.00	301/?	6245 6554	123 133	155/79 160/81		2 seps. on
03.00	295/88	6976 6500	161 159	135/79 140/82		2* 72/64" bean
04.00	295/87	7719 6598	138 169	135/78 140/81		
05.00	296/86	7397 6564	131 145	135/78 140/79		
19.07.85						PT-1D 8Dd
07.00	261/?	7212 7576	145 134	145/76 155/78		2 seps. on
08.00	261/?	7773 7611	113 134	145/78 160/77		2* 88/64" bean
19.07.85						PT-1D 9Dd
09.00	243/?	7760 7308	113 114	145/79 160/76		2 seps. on
09.30	242/?	7488 8264	117 101	145/79 155/76		
10.00	243/?	7444 8005	120 103	150/79 150/78		2*128/64" bean

WELL 6407/9-3
SUMMARY OF SEPARATOR DATA

DATE TIME	THP/THT psig/°F	OILRATE stb/d	GOR scf/stb	Psep/Tsep psig/°F	BHP psia	COMMENTS
19.07.85						PT-1E 1Dd
21.00	577/63					
22.00	577/59	2976	115	160/56	2354.7	one sep. on
23.00	554/60	2880	126	165/56	2355.1	32/64" bean
24.00	556/60	3328	99	170/56	2355.6	
01.00	557/61	3434	90	175/57	2355.6	BHP from HP 0784
02.00	557/61	3394	107	160/57	2355.5	1640.2 m bdf
03.00	558/62	3394	106	160/57	2355.5	

DATE TIME	THP/THT psig/°F	OILRATE stb/d	GOR scf/stb	Psep/Tsep psig/°F	BHP psia	COMMENTS
20.07.85						PT-1E 2Dd
04.00	452/70	4490 3431	102 146	150/63 170/65	2323.3	2 seps. on
05.00	453/73	4513 4349	104 115	155/63 170/66	2323.0	2* 40/64" bean
06.00	456/74	? 4552	81 108	150/65 170/68	2322.9	
07.00	457/74	? 4414	87 111	150/66 170/69	2322.7	0 % BSW
08.00	457/74	? 4432	79 110	150/65 170/69	2322.6	0 ppm H2S
09.00	457/76	? 4256	88 116	155/66 175/69	2322.7	0.4 % CO2

DATE TIME	THP/THT psig/°F	OILRATE stb/d	GOR scf/stb	Psep/Tsep psig/°F	BHP psia	COMMENTS
20.07.85						PT-1E 3Dd
10.00	313/84				2291.3	2 seps.on
11.00	297/85				2287.3	2* 72/64"bean
12.00	297/86				2287.2	
13.00	297/86	? 6730	159 166	150/75 160/79	2287.2	
14.00	297/87	? 6788	116 143	145/75 160/81	2287.3	
15.00	300/88	6480 7228	130 137	140/76 155/81	2287.2	
16.00	299/90	6538 6832	138 172	150/79 150/83	2287.1	
17.00	304/91	6163 6814	131 127	175/80 175/83	2288.0	0 % CO2
18.00	305/92	6110 5898	127 146	170/80 175/83	2288.3	0 ppm H2S
19.00	308/92	6184 6886	125 123	175/80 180/83	2288.2	
20.00	305/92	6241 6935	134 126	155/80 180/84	2287.7	sediment traces
21.00	305/92	6270 6696	135 140	160/79 180/84	2287.8	

WELL 6407/9-3
SUMMARY OF SEPARATOR DATA

DATE TIME	THP/THT psig/^{O}F	OILRATE stb/d		GOR scf/stb		Psep/Tsep psig/^{O}F		BHP psia	COMMENTS
22.00	305/92	6270	6664	135	143	160/79	180/83	2287.8	
23.00	305/92	6270	6694	134	136	160/79	160/83	2288.0	
24.00	--	6313	6672	135	151	160/79	180/82	2288.2	
01.00	306/90	6299	6815	136	146	165/78	180/82	2288.3	
02.00	306/88	6262	6707	135	148	165/80	180/82	2288.5	
21.07.85									PT-1E 4Dd
03.00	461/81	3746	4270	128	101	150/69	195/72	2322.4	2 seps. on
04.00	461/80	3796	4251	124	119	150/68	165/71	2322.4	2* 40/64" bean
05.00	461/79	3832	4240	123	121	145/68	165/70	2322.4	
06.00	460/78	3842	4251	123	121	145/67	165/69	2322.4	
07.00	460/79	3836	4272	123	121	145/68	165/69	2322.4	sediment trads
08.00	461/78	3840	4268	123	122	145/69	165/69	2322.3	0.4 % COs
09.00	461/79	3834	4259	123	125	145/69	165/69	2320.7	0 ppm H2S
22.07.85									PT-1F 2Dd
18.00	564/56								8/64 " bean
18.30	566/56								12/64" bean
19.00	566/56								
19.30	566/56	576							
20.00	566/56	518							

DRAUGEN WELL: 6407/9-3
PROD. TEST: PT-1E STRAIN GAUGE 83117 (tide corrected)
TIME ZERO IS 21.00 HRS 19/07/85

WELL AND RESERVOIR DATA

Formation net thickness	:	118.10 ft
Reservoir fluid	:	oil
Pre-test reservoir pressure	:	2376.0 psi
Perforated interval	:	5264.1- 5303.5 ft
Wellbore radius	:	.510 ft
Absolute porosity	:	.320

OIL PVT PROPERTIES

FORMATION VOL FACTOR BO bbl/bbl	OIL VISC AT RESV CONDITIONS cP	TOTAL COMPRES SIBILITY ct psi-1
1.1850	.670	.2000-004

DRAUGEN WELL: 6407/9-3
PROD. TEST: PT-1E STRAIN GAUGE 83117 (tide corrected)
TIME ZERO IS 21.00 HRS 19/07/85

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
1	0	.0	.00000	.00000	2376.0
2	1Dd	3400.0	6.00000	6.00000	.0
3	2Dd	8800.0	12.00000	6.00000	.0
4	3Dd	13000.0	29.00000	17.00000	.0
5	4Dd	8100.0	34.75000	5.75000	2323.8
6	4Dd	8100.0	34.91667	5.91667	2323.9
7	4Dd	8100.0	35.00000	6.00000	2323.9
8	4Dd	8100.0	35.25000	6.25000	2323.9
9	4Dd	8100.0	35.50000	6.50000	2323.1
10	4Dd	8100.0	35.75000	6.75000	2323.1
11	4Dd	8100.0	36.00000	7.00000	2323.8
12	4Dd	8100.0	36.01667	7.01667	2323.8
13	4Dd	8100.0	36.03333	7.03333	2323.8
14	5Bu	.0	36.03611	.00278	2369.1
15	5Bu	.0	36.03889	.00556	2369.5
16	5Bu	.0	36.04167	.00833	2369.8
17	5Bu	.0	36.04444	.01111	2370.0
18	5Bu	.0	36.04722	.01389	2370.2
19	5Bu	.0	36.05000	.01667	2370.3
20	5Bu	.0	36.05278	.01944	2370.4
21	5Bu	.0	36.05556	.02222	2370.5
22	5Bu	.0	36.05833	.02500	2370.6
23	5Bu	.0	36.06111	.02778	2370.6
24	5Bu	.0	36.06389	.03056	2370.7
25	5Bu	.0	36.06667	.03333	2370.8
26	5Bu	.0	36.06944	.03611	2370.8
27	5Bu	.0	36.07222	.03889	2370.8
28	5Bu	.0	36.07500	.04167	2370.9
29	5Bu	.0	36.07778	.04444	2370.9
30	5Bu	.0	36.08056	.04722	2371.0
31	5Bu	.0	36.08333	.05000	2371.0
32	5Bu	.0	36.08611	.05278	2371.1
33	5Bu	.0	36.08889	.05556	2371.1
34	5Bu	.0	36.09167	.05833	2371.1
35	5Bu	.0	36.09444	.06111	2371.2
36	5Bu	.0	36.09722	.06389	2371.2
37	5Bu	.0	36.10000	.06667	2371.2
38	5Bu	.0	36.10278	.06944	2371.2
39	5Bu	.0	36.10556	.07222	2371.3
40	5Bu	.0	36.10833	.07500	2371.3

DRAUGEN WELL: 6407/9-3
PROD. TEST: PT-1E STRAIN GAUGE 83117 (tide corrected)
TIME ZERO IS 21.00 HRS 19/07/85

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
41	5Bu	.0	36.11111	.07778	2371.4
42	5Bu	.0	36.11389	.08056	2371.3
43	5Bu	.0	36.11667	.08333	2371.4
44	5Bu	.0	36.11944	.08611	2371.4
45	5Bu	.0	36.12222	.08889	2371.4
46	5Bu	.0	36.12500	.09167	2371.5
47	5Bu	.0	36.12778	.09444	2371.4
48	5Bu	.0	36.13056	.09722	2371.5
49	5Bu	.0	36.13333	.10000	2371.5
50	5Bu	.0	36.14167	.10833	2371.5
51	5Bu	.0	36.15000	.11667	2371.6
52	5Bu	.0	36.15833	.12500	2371.6
53	5Bu	.0	36.16667	.13333	2371.7
54	5Bu	.0	36.17500	.14167	2371.7
55	5Bu	.0	36.18333	.15000	2371.8
56	5Bu	.0	36.19167	.15833	2371.8
57	5Bu	.0	36.20000	.16667	2371.9
58	5Bu	.0	36.20833	.17500	2371.9
59	5Bu	.0	36.21667	.18333	2371.9
60	5Bu	.0	36.22500	.19167	2372.0
61	5Bu	.0	36.23333	.20000	2372.0
62	5Bu	.0	36.25000	.21667	2372.1
63	5Bu	.0	36.26667	.23333	2372.1
64	5Bu	.0	36.28333	.25000	2372.2
65	5Bu	.0	36.30000	.26667	2372.2
66	5Bu	.0	36.31667	.28333	2372.3
67	5Bu	.0	36.33333	.30000	2372.3
68	5Bu	.0	36.35000	.31667	2372.4
69	5Bu	.0	36.36667	.33333	2372.4
70	5Bu	.0	36.38333	.35000	2372.5
71	5Bu	.0	36.40000	.36667	2372.5
72	5Bu	.0	36.41667	.38333	2372.5
73	5Bu	.0	36.43333	.40000	2372.6
74	5Bu	.0	36.45000	.41667	2372.6
75	5Bu	.0	36.46667	.43333	2372.6
76	5Bu	.0	36.48333	.45000	2372.6
77	5Bu	.0	36.50000	.46667	2372.7
78	5Bu	.0	36.53333	.50000	2372.8
79	5Bu	.0	36.56667	.53333	2372.8
80	5Bu	.0	36.60000	.56667	2372.9

DRAUGEN WELL: 6407/9-3
PROD. TEST: PT-1E STRAIN GAUGE 83117 (tide corrected)
TIME ZERO IS 21.00 HRS 19/07/85

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
81	5Bu	.0	36.63333	.60000	2372.9
82	5Bu	.0	36.66667	.63333	2372.9
83	5Bu	.0	36.70000	.66667	2373.0
84	5Bu	.0	36.73333	.70000	2373.0
85	5Bu	.0	36.76667	.73333	2373.0
86	5Bu	.0	36.80000	.76667	2373.1
87	5Bu	.0	36.83333	.80000	2373.1
88	5Bu	.0	36.86667	.83333	2373.2
89	5Bu	.0	36.90000	.86667	2373.2
90	5Bu	.0	36.93333	.90000	2373.2
91	5Bu	.0	36.96667	.93333	2373.3
92	5Bu	.0	37.00000	.96667	2373.3
93	5Bu	.0	37.08333	1.05000	2373.4
94	5Bu	.0	37.16667	1.13333	2373.4
95	5Bu	.0	37.25000	1.21667	2373.5
96	5Bu	.0	37.33333	1.30000	2373.5
97	5Bu	.0	37.41667	1.38333	2373.6
98	5Bu	.0	37.50000	1.46667	2373.6
99	5Bu	.0	37.58333	1.55000	2373.7
100	5Bu	.0	37.66667	1.63333	2373.7
101	5Bu	.0	37.75000	1.71667	2373.8
102	5Bu	.0	37.83333	1.80000	2373.8
103	5Bu	.0	38.00000	1.96667	2373.9
104	5Bu	.0	38.16667	2.13333	2374.0
105	5Bu	.0	38.33333	2.30000	2374.1
106	5Bu	.0	38.50000	2.46667	2374.1
107	5Bu	.0	38.66667	2.63333	2374.2
108	5Bu	.0	38.83333	2.80000	2374.3
109	5Bu	.0	39.00000	2.96667	2374.3
110	5Bu	.0	39.16667	3.13333	2374.3
111	5Bu	.0	39.33333	3.30000	2374.4
112	5Bu	.0	39.50000	3.46667	2374.5
113	5Bu	.0	39.66667	3.63333	2374.5
114	5Bu	.0	39.83333	3.80000	2374.5
115	5Bu	.0	40.00000	3.96667	2374.6
116	5Bu	.0	40.33333	4.30000	2374.7
117	5Bu	.0	40.66667	4.63333	2374.7
118	5Bu	.0	41.00000	4.96667	2374.8
119	5Bu	.0	41.33333	5.30000	2374.9
120	5Bu	.0	41.66667	5.63333	2375.0

DRAUGEN WELL: 6407/9-3
PROD. TEST: PT-1E STRAIN GAUGE 83117 (tide corrected)
TIME ZERO IS 21.00 HRS 19/07/85

SEQUENCE OF EVENTS

PNT	PER	PRODUCTION RATE stb/d	CUMULATIVE TIME SINCE INITIAL CONDITIONS hours	TIME SINCE START OF PERIOD hours	PRESSURE OBSERVED psi
121	5Bu	.0	42.00000	5.96667	2375.0
122	5Bu	.0	42.50000	6.46667	2375.1
123	5Bu	.0	43.00000	6.96667	2375.2
124	5Bu	.0	43.50000	7.46667	2375.2
125	5Bu	.0	44.00000	7.96667	2375.3
126	5Bu	.0	44.50000	8.46667	2375.3
127	5Bu	.0	45.00000	8.96667	2375.4
128	5Bu	.0	45.50000	9.46667	2375.5
129	5Bu	.0	46.00000	9.96667	2375.5
130	5Bu	.0	46.50000	10.46667	2375.5
131	5Bu	.0	47.00000	10.96667	2375.5
132	5Bu	.0	47.50000	11.46667	2375.6
133	5Bu	.0	48.00000	11.96667	2375.6
134	5Bu	.0	48.50000	12.46667	2375.7
135	5Bu	.0	49.00000	12.96667	2375.6
136	5Bu	.0	49.50000	13.46667	2375.7

```
HORNER ANALYSIS
   PERMEABILITY ANALYSIS

      Period (0 if no more) (          1) ? >  >5

        Period range =            14           136
         Horner begin point   (          14) ? >>18

         Horner end    point   (        136) ? >>28


     CALCULATED FORMATION AND WELLBORE PARAMETERS
        Period                                                       5
        Selected semi log straight line segment               18 to  28
        Fitted semi-log slope (psi)/(stb/d)                 -.16628-003
        Flow Capacity , mD.ft                                  674228.
        Permeability , mD                                     5708.957
        Extrapolated (pseudo) pressure psi                   .2376+004

        No. of points fitted                                        11
        Correlation coefficient                                   -.999

      Period (0 if no more) (          6) ? >  >5

        Period range =            14           136
         Horner begin point   (          14) ? >>85

         Horner end    point   (        136) ? >>136


     CALCULATED FORMATION AND WELLBORE PARAMETERS
        Period                                                       5
        Selected semi log straight line segment               85 to 136
        Fitted semi-log slope (psi)/(stb/d)                 -.22645-003
        Flow Capacity , mD.ft                                  495074.
        Permeability , mD                                     4191.988
        Extrapolated (pseudo) pressure psi                   .2377+004

        No. of points fitted                                        52
        Correlation coefficient                                   -.999

      Period (0 if no more) (          6) ? >  >0

    SKIN ANALYSIS FOR DRAWDOWN PERIODS
      Permeability, mD ( 4192.     ) ? >   >5709


      Period (0 if no more) (          1) ? >  >4

        Period range =             5            13
         Horner begin point   (           5) ? >>

         Horner end    point   (          13) ? >>

        Drawdown period                                              4
        Selected semi log straight line segment                5 to  13
        Initial (pseudo) pressure psi                        .2376+004
        Extrapolated (pseudo) pressure psi                   .2327+004
        Total skin                                              29.243
        No. of points fitted                                         9
```

RADIUS OF INVESTIGATION TABLE, Rinv (feet)

n\j	1	2	3	4	5
1	2589.				
2	3662.	2589.			
3	5693.	5070.	4359.		
4	6346.	5793.	5182.	2803.	
5	7437.	6972.	6473.	4786.	3879.

Rinv (n,j) is the radius of investigation, at the end of period n, of the pressure transient induced by the rate change which took place at the start of period j.

Base Permeability , mD	5709.000
Hydraulic Diffusivity , mD.psi/cP	.133+010

MULTI-RATE PRESSURE TRANSIENT DURATION TABLE, DT (hours)

n\j	1	2	3	4	5
1	6.0				
2	12.0	6.0			
3	29.0	23.0	17.0		
4	36.0	30.0	24.0	7.0	
5	49.5	43.5	37.5	20.5	13.5

DT (n,j) is the duration, at the end of period n, of the of the pressure transient induced by the rate change which took place at the start of period j. Note that the duration of the last period may have been extended so as to reach beyond the start of semi-steady state (if finite reservoir).

RATE CHANGE HISTORY (INDUCING PRESSURE TRANSIENTS)

Rate change at start of period 1, stb/d	3400.000
Rate change at start of period 2, stb/d	5400.000
Rate change at start of period 3, stb/d	4200.000
Rate change at start of period 4, stb/d	-4900.000
Rate change at start of period 5, stb/d	-8100.000

WELL 6407/9-3

SIDEWALL SAMPLE

DESCRIPTION

Encl. 2

Sidewall samples.

Gun 1	20 samples recovered
	2 bullets lost down hole
	1 misfire
	2 empty core-bullets.
Gun 2	2 x 25 swc guns
	42 samples recovered
	5 bullets lost down hole
	2 misfires
	1 empty

GUN 2a

top no	gun depth (m)	recovery (mm)	Lithology	show s/f c/c c/f
1	1712.0	15	slst: dk gy, sft (mb, micro mic, carb	nil nil nil
2	1707.5	5	s: lt gy, fsl-fsu, (srt), lse, (rnd)	nil nil nil
3	1704.1	20	s: med -dkgy, fsu-fsl, lse, srt, (rnd) prly cmtd, (mic), carb	nil nil nil
4	1696.5	10	s: ltgy, fsu-fsl, lse, srt, (ang)-(rnd), prly cmtd, (mic), (carb)	nil nil nil
5	1691.5	6	s: lt-med gy, fsl-msu, lse, mod srt, (ang) -(rnd), calc cmt, prly cmtd, (mic), (pyr)	nil nil nil
6	1687.5	25	s: ltgy-gy, fsl-fsu, lse, srt, (ang)-(rnd), prsly cmtd, (mic), (carb), (calc)	nil nil nil
7	1684.7	23	sst: gy, fsu-msu, sft-frm, occ pb (rnd), (ang)-(rnd), calc cmt	nil nil nil
8		lost		
9	1682.5	15	slst: dk gy, (hd), cmb, calc, grdg sd, fsl-fsu, pyr, mic	nil nil nil
10	1681.5	22	slst: gy, frm, calc, clmtx, carb, pyr, (mic)	nil nil nil
11	1679.5	20	clst: dkgy, frm, (calc), (fiss), (mic), (carb)	nil nil nil
12	1677.0	45	clst: dkgy-blk, frm-(hd), (calc), (fiss)-fiss, mic, (carb)	nil nil nil
13		lost		
14	1631.5	17	sst: lt gy, (hd)-frm, (calc), fsu, occ crssl, srtd, (ang)-(rnd)	good ylgn mod pale blue
15		lost		
16	1629.5	20	clst: dk gy-blk, (hd), (fiss), (mic)	nil nil nil
17		lost		
18	1628.0		clst: dkgy-blk, frm-(hd), (fiss), (calc) (pyr)	nil nil nil
19	1625.5		clst: dk gy, (hd), (fiss)-fiss, mic	nil nil nil
20	1623.0		clst: dk gy, (hd), fiss, (mic)	nil nil nil
21	1620.5		clst: dk gy, (hd), (fiss), mic	nil nil nil
22		lost		
23	1611.5	5	clst: dk gy, (md), fiss, mic	nil nil nil
24	1605.2	38	clst: dkgy-blk, frm-(hd), (calc),	nil nil nil
25		lost		

19	1746.5	30	s: med gy, fsu-fsl, srtd, lse, (ang)-(rnd)mica, prly cmtd, calc cmt	nil	nil	nil
20	1743.5	25	s: med gy, fsu-fsl, srtd, lse, (ang)-(rnd)mica, prly cntd. calc cmt	nil	nil	nil
21	1735.5	5	s: lt gy-wh, fsl-fsu, lse prsly srtd, calc cmt	nil	nil	nil
22	1730.5	30	s: med gy, fsu-fsl. srtd, lse, (ang)-(rnd) mica, prly cmtd, calc cmt	nil	nil	nil
23	1723.2	30	s/slst:-med-dkgy, fsu-fsl, (srtd) lse	nil	nil	nil
24	1716.5	30	s: ltgy, fsl-fsu, srtd, lse, (rnd)	nil	nil	nil
25	1712.9	30	s: lt gy-gy, fsu-msl, srtd, lse, (ang) prly cmtd. calc cmt	nil	nil	nil