Final Well Report (Exploration) 33/12-8 S / 33/12-8 A

TD , Version 1, Valid from 08.04.2003

Validity area:

UPN NOM OPR / BEV DRB / On- and offshore

Contents

1 Introduction

1.1 Well data record

Well name:	33/12-8 S and sidetrack -8 A
Well type:	Exploration wells
Prospect:	N3 / N2
Area:	Tampen Spur
Country:	Norway
License Number:	PL 152
Licences:	Statoil (Operator) 70% Petoro 30%
Drillling Rig:	Borgland Dolphin
Rig type:	Semi-submersible
Drilling contractor:	Dolphin
Water depth / air gap:	137 m MSL / 31 m RKB
Primary objective:	Exploration of Brent prospects
TD:	5098 m MD / 3399.0 m TVD RKB (33/12-8 A) 3750 m MD / 3380,7 m TVD RKB (33/12-8 S)
Formation at TD:	Rannoch Fm. (33/12-8 A) Statfjord Fm., Eiriksson Member. (33/12-8 S)
Start of operation:	22.03.2002
End of operation:	06.06.2002
Well status:	33/12-8 S: Permanently plugged 33/12-8 A: Plugged as possible producer

33/12 8-S co-ordinates at wellhead level:

UTM:	Geographic:
6 772 000.91m N	61° 04' 38.34" N
444 190.52m E	01° 57' 56.20" E

All depths in this programme are related to m MD RKB, unless otherwise specified.

1.2 Well objectives

Well 33/12-8 S (N3-Dole)
The main objective of the well 33/12-8 S was to evaluate the potential for hydrocarbons in the Dole Prospect (segment N3).

A secondary objective was to identify the hydrocarbon contact (s) in the Brent Group.
A sidetrack from 13 3/8" shoe into the N2 Structure (Ole) was considered in case of a positive hydrocarbon finding in the Middle Jurassic Brent Group. This sidetrack could (if optimal located) be left as a later producer.

The original Electrical Wireline Logging program was to run PEX/AITH (GR/DEN/NEU/RES) on the first run. MDT (pressure points and fluid samples) on the second run, DSI on the third run and also CMR on a third run if significant hydrocarbon discovery in the Statfjord Formation.

Well 33/12-8 A (N2-Ole)
Well 33/12–8 A was sidetracked from well 33/12-8 S, both wells are drilled within the license area PL 152. The main objective of well 33/12-8 A was to investigate the hydrocarbon potential of the Middle Jurassic Brent Group in segment N2 (Ole), as a result of the positive hydrocarbon discovery in the Dole structure (N3). The secondary objective was to identify the hydrocarbon contact in the Tarbert Formation in segment N3 (Dole).

The original electrical wireline logging programme for well 33/12-8 A was to run PEX/AITH (GR/DEN/NEU/RES) on the first run and MDT (pressure points and fluid samples) on the second run, both on TLC.

1.3 Results of the wells

33/12-8 S

Well 33/12-8 S drilled a Jurassic interval from the Heather Formation and 105 m into the Statfjord Formation. The well proved an approximately 81 m TVD thick hydrocarbon column in Tarbert and Upper Ness. The discovery was oil with a gas cap. A five meters column with oil (TVD) was in addition encountered in the Statfjord Formation. TD was set at 3750 m MD.

The stratigraphic column in the N3 (Dole) segment lies 30-50 m deeper than originally mapped. The oil-water contact in Ness came in as prognosed in depth, but to shallow compared to a relativ shift of the structure. The oil-water contact in Tarbert, identified while drillling the sidetrack –8 A, came in 45-50 m deeper than prognosed. Most of the resources (80%) belongs to Tarbert-3/2 whitch is of very good quality. The isochore thickness of the Tarbert 2/3 sand is approximately 55 m.

MDT- fluid samples have been carried out in the gas zone. Density in the gas zone was about 0,35 g/cm^3, GOR approx. 2000 Sm^3/Sm^3. Well 33/12-8 S has proven approximately 3 x 10^6 Sm^3 STOOIP and approx. 1 x 10^6 m^3 GOIP.

The drilling progress was slow in the uppermost 36" section because of cuttings falling into the hole giving high torque. In the following 26" section boulders were encountered around

478 m and 489 m and followed up with backreaming over the mentioned interval. Prognosed sand with potential shallow gas was encountered at 450 m MD RKB. Gamma ray and resistivity showed water filled sand. The drilling progress was good down to sandy part of Hordaland Group when the drilling nearly stopped. This resulted in a bit-trip, but the bit was OK. Went down with new equipment (bit/motor/MWD) and drilled on. Logs showed calcareous cemented sands in the Hordaland Group. Further drilling in the 17 ½" and 8 ½" section went well, with exception of the Shetland Group which was significantly slower to drill due to marl/calcareous claystone. The Brent Group and hydrocarbon filled Tarbert Formation was encountered. Lower part of Ness Fm. was waterfilled and when Etive Fm. also proved to be water filled it was decided not to core the Rannoch Formation. The CMR run was also cancelled due to interpreted water filled Statfjord Fm.

Well 33/12-8 A

Well 33/12-8 A (Ole) was drilled to TD at 5098 m MD/3368 m TVD MSL in the Rannoch Formation.

Both geology and oil-water contacts came in more or less as prognosed in segment N2-Ole. Gas is proven in the uppermost part of the reservoir, while the lower part is oil filled. The pressures are about initial, approximately 412 Bar in top of the gas zone, corresponding to EMW of 1,48 g/cm^3 Well 33/12-8 A has proven approx. 5 x 10^6 Sm^3 STOOIP and 0,5 x 10^9 Sm^3 GOIP.

MDT- fluid samples have been carried out. Results given from the oil zone showed a density of 0,63 g/cm^3 and GOR about 220 Sm^3/Sm^3.

It was difficult to sidetrack 33/12–8 A from the pilot well 33/12-8 S. It was necessary to pull out twice in the beginning of well 33/12-8 A because one could not attain the necessary azimuth turn to reach target T1. Powerdrive was exchanged with a motor on the second trip and the PDC bit was exchanged with a “rock bit”. This shift gave the desirable effect and it was possible to steer in the planned direction. Maximum dogleg was as high as 7,3 degrees/30 m. ROP varied between 8-12 m/hr, apart from when drilling the limestone stringers where it was necessary to rotate to get through. It was also necessary to rotate in other intervals to reduce the dogleg. The motor was shifted out with a Powerdrive from 2814 m MD. TD was set at 5098 m MD/3399,5 m TVD RKB.

Based on a STOOIP/KIIP of 16 x 10^9 Sm^3 and GIIP/AGIIP of 8,3 x 10^9 Sm^3 as a total potensial for all discoveries and probable prospects in the area there are now a development plan in progress, issued mid. 2003.

1.4 Drilling summary

1.4.1 Casing

- Well 33/12-8 A is drilled to TD at 5098 m MD.
- No HC bearing formation behind the 13 3/8" casing string.
- Max pore pressure in well 33/12-8 S, based on MDT measurements, is calculated to be equal to 1,38 g/cm^3 in estimated top of the reservoir (33/12-8 S). The pressures are about initial in well 33/12-8 A, approx. 412 Bar in top of the gas zone, corresponding to EMW of 1,48 g/cm^3 EMW.

- Status of casings:

Well 33/12-8 S

Casing size	Casing depth m MD RKB/ m TVD RKB	Hole depth m MD RKB /m TVD RKB	Test pressure/ mud weigth/ mud type	Result g/cm^3
30"	227/227	230/230		
20"	737/737	744/744	95 bar w/ 1,03 g/cm^3 SW	1,75 (LOT)
13 3/8"	2066,5/2033,0	2077/2042	290 bar w/ 1,45 g/cm^3 Glydril mud	1,74 (FIT)

Well 33/12-8 A

Casing size	Casing depth m MD RKB/ m TVD RKB	Hole depth m MD RKB /m TVD RKB	Test pressure/ mud weigth/ mud type	Result g/cm^3
9 5/8"	3677,7/ 2895	5098/3399	370 bar w/ 1,65 g/cm^3 Versavert mud	

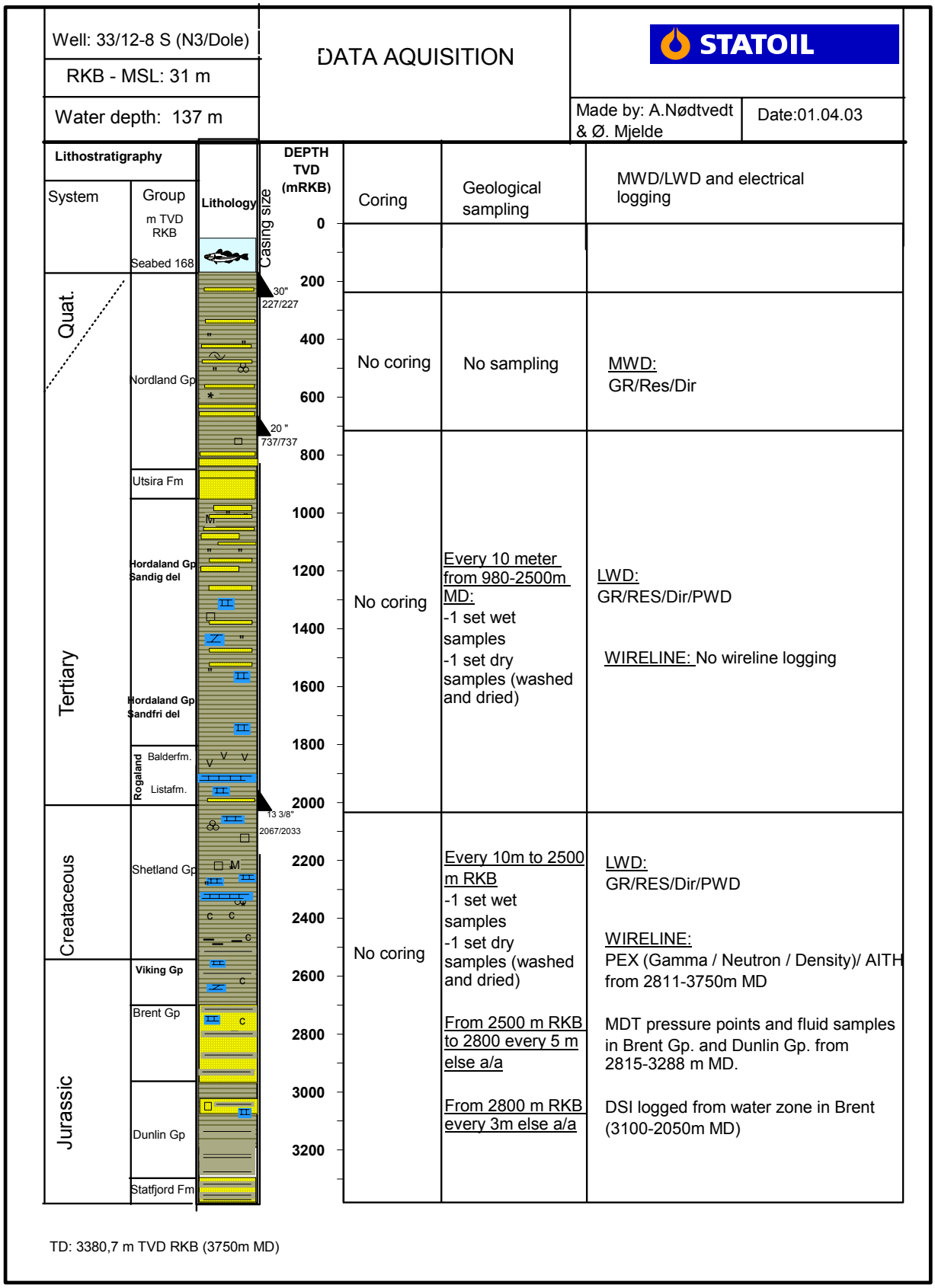
1.4.2 Drilling fluids

CMC/Seawater above 26" hole / 20" casing. The 17 ½" section was drilled with Glydril MC, a water based KLC mud. Versavert OBM was used below 17 ½" hole/13 3/8" casing in both well 33/12-8 S and the sidetrack 33/12–8 A to segment N2 (Ole).

Well 33/12-8 A

Conduit	Fluid present	Fluid properties
13 3/8" x 20" annulus	WBM	1,45 g/cm^3
13 3/8" annulus	WBM	1,45 g/cm^3
9 5/8" annulus	OBM	1,65 g/cm^3

1.5 Data acquisition summary



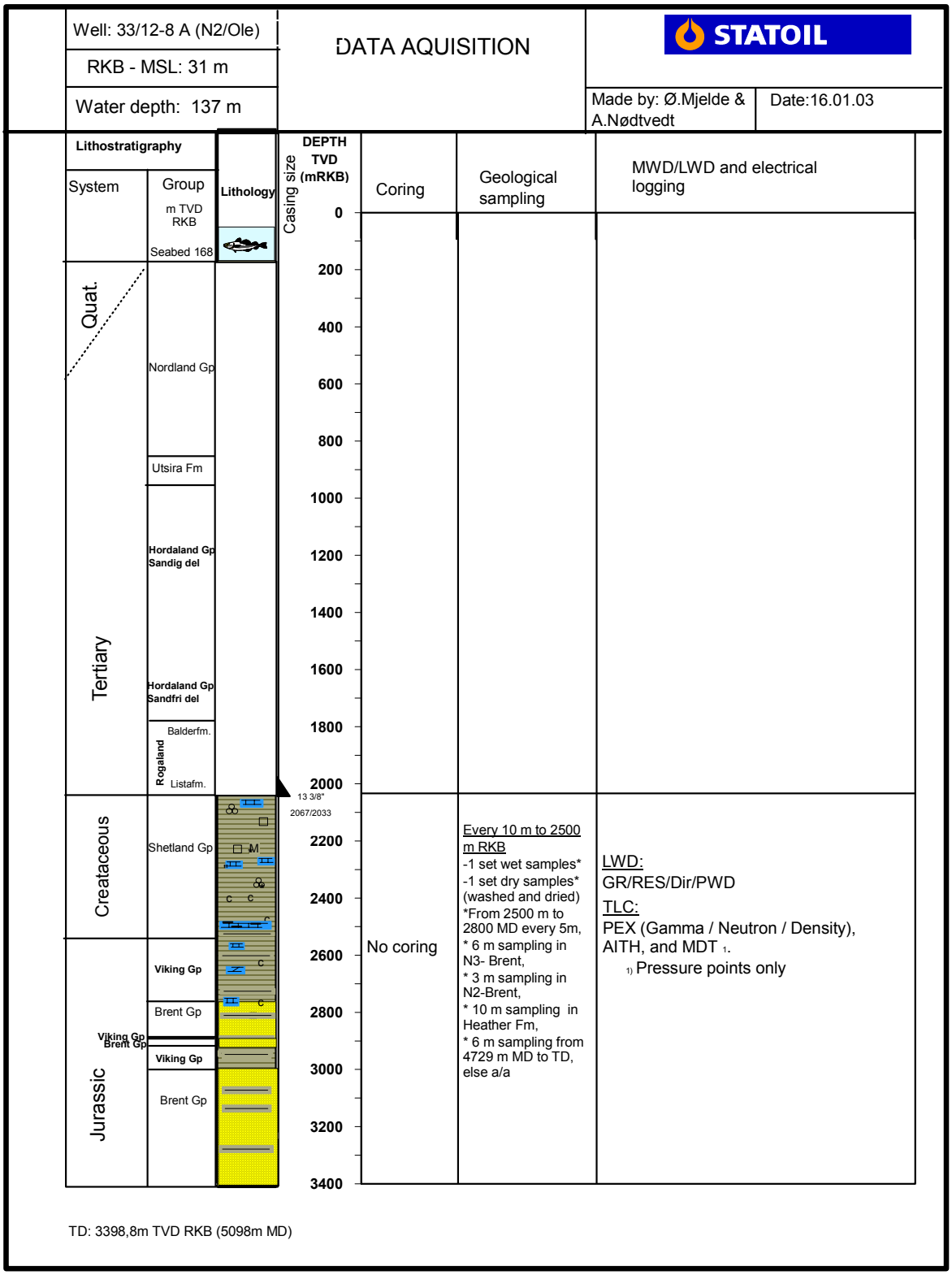
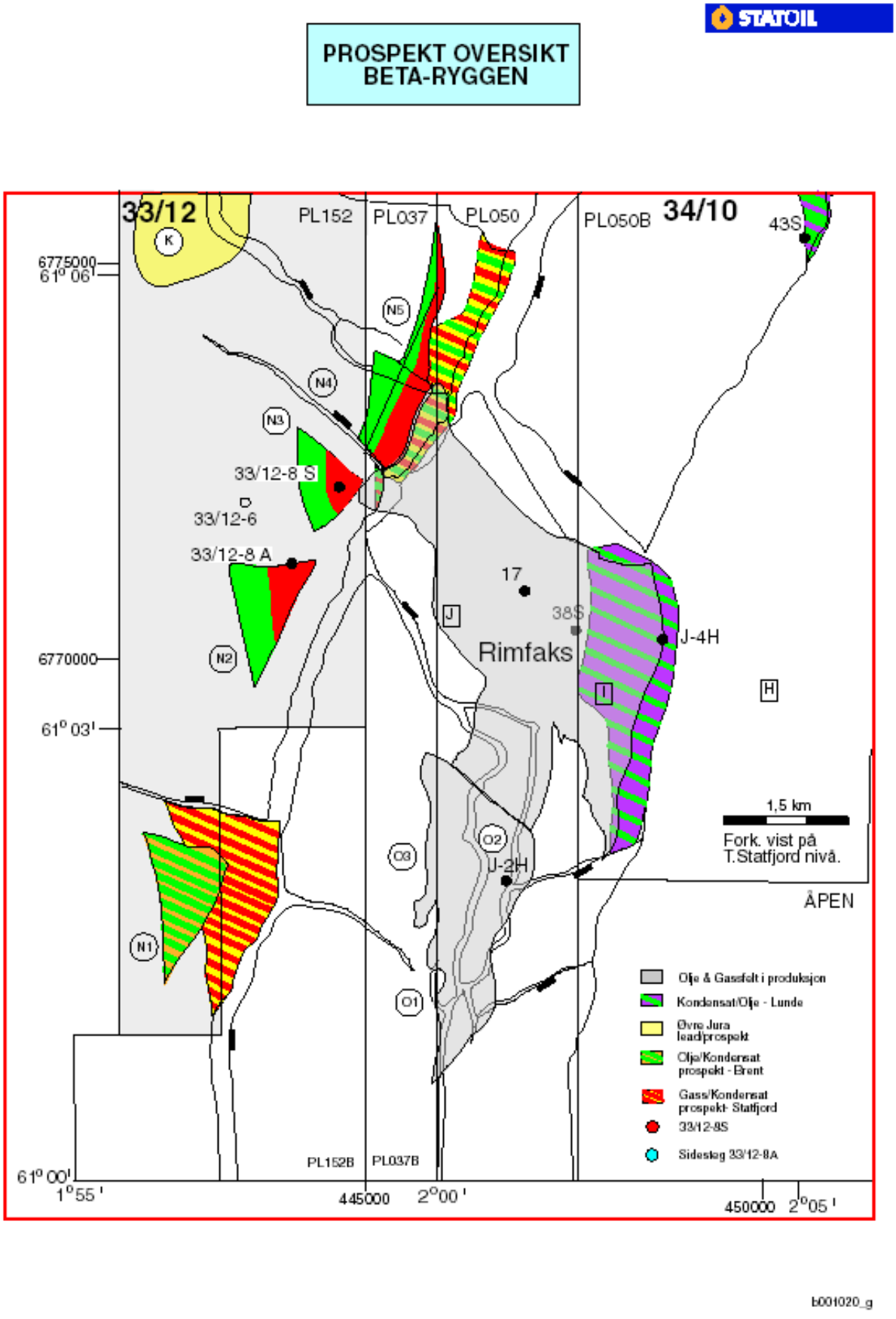

Well: 33/12-8 A (N2/Ole)
RKB - MSL: 31 m
Water depth: 137 m
DATA AQUISITION
STATOIL
Made by: Ø.Mjelde & A.Nødtvedt
Date:16.01.03
Lithostratigraphy
System
Group
m TVD RKB
Lithology
Casing size
DEPTH TVD (mRKB)
Coring
Geological sampling
MWD/LWD and electrical logging
Seabed 168
Quat.
Nordland Gp
Utsira Fm
Hordaland Gp Sandig del
Hordaland Gp Sandfri del
Balderfm.
Rogaland
Listafm.
Tertiary
Creataceous
Shetland Gp
Jurassic
Viking Gp
Brent Gp
Viking Gp
Brent Gp
Viking Gp
Brent Gp
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
2600
2800
3000
3200
3400
13 3/8"
2067/2033
No coring
Every 10 m to 2500 m RKB
-1 set wet samples*
-1 set dry samples* (washed and dried)
*From 2500 m to 2800 MD every 5m,
* 6 m sampling in N3- Brent,
* 3 m sampling in N2-Brent,
* 10 m sampling in Heather Fm,
* 6 m sampling from 4729 m MD to TD, else a/a
LWD:
GR/RES/Dir/PWD
TLC:
PEX (Gamma / Neutron / Density), AITH, and MDT 1.
1) Pressure points only
TD: 3398,8m TVD RKB (5098m MD)

Figure 1. Location Map



2 Exemptions and non-conformances

KP00-K200 Krav til fraviks- og avviksbehandling Dato: 29.01.2002

FRAVIKSBEHANDLING

Fravik fra:	__	_ __	Fraviket har sikkerhetsmessig konsekvens
Statoil, B&B- krav	___	___	Fraviket har økonomisk konsekvens
Myndighetskrav	__	___	Fraviket har konsekvens ved fremtidig bruk av brønnen.
Enhetsinterne krav	_x_	___	Fravviket kompenseres
Andre krav	___	___	Fraviket forblir ukompensert

REGELVERK, RETNINGSLINJER E.A (Referanse til krav): WR 0442 - Detailed planning requirements drilling and well operations.
KRAV: Fravik #1; Lag en prosjekt plan og ha en planlegger tilgjengelig for denne jobben. Fravik #2; Lag en " 15 min" plan, eller lignende detaljert plan.
BESKRIVELSE AV FRAVIK & KONSEKVENS: Fravik #1 & #2; Bortsett fra "gammel" type timeplan og aksjonslogg er det ikke planlagt å bruke annet verktøy i plannleggingsfasen. Denne prioriteringen er basert på begrenset tid og ressurser frem til borestart. Konsekvens; Det er ingen konsekvenser relatert til disse endringene.
TIDSRAMME FOR FRAVIKET: Til brønn 33/12- 8 S / 33/12-8 A er ferdig.
ESTIMERT FRAVIKSKOSTNAD Ingen tilleggsutgifter er relatert til disse forandringene.
KOMPENSERENDE TILTAK: Der er fokus på sammenstilling av prosedyrer fra Statfjord Satellitter og Gullfaks Satellitter. Samt at dedikerte arbeidsgrupper fra Statoil / Service og kontraktør er nedsatt for å tilvirke detaljplaner.
SAMLET VURDERING AV FRAVIK OG TILTAK: Fraviket er funnet faglig forsvarlig.
KOMMENTARER: (for områdeverneombudet/sikkerhetsstab/fagansvarlig):

3 Health, safety, environment and quality (HSE&Q)

3.1 Experience summary

See appendix.

3.2 Time distribution

Table 3.2.1 Time distribution for well 33/12-8 A and sidetrack 33/12-8 A

Drilling			
Duration (days)	Actual Duration (days)	Cost (NOK Mill)	Effec. Cost (NOK Mill)
58	72.6	162.0	191.5

See appendix, other reports, for a time distribution plot.

4 Geology and formation data report

4.1 Geological setting and results

Well 33/12-8 S and –8 A is situated is in the Tampen Spur area and the structure is a westerly rotated fault block on the southern part of the Beta Rigde. The structure is limited by an east-west fault towards the north. The structure is dipping towards west. The dominating rifting phase was in Late Jurassic-Early Cretaceous, which was controlled by an earlier Late Permian-Early Triassic phase. Small faults observed at the base Cretaceous might be a result of differential compaction over Late Jurassic faults. The general development of the Jurassic interval is very similar to the neighbouring exploration wells 33/12-6 and 34/10-17.

4.2 Shallow gas results

Prognosed sand with potential shallow gas was encountered at 450 m MD RKB. Gamma ray and resistivity showed water filled sand.

4.3 Stratigraphy

The stratigraphic zonation is based on logs from near-situated wells and Statoils own interpretation.

4.3.1 Table of Listostratigraphy for Well 33/12-8 S

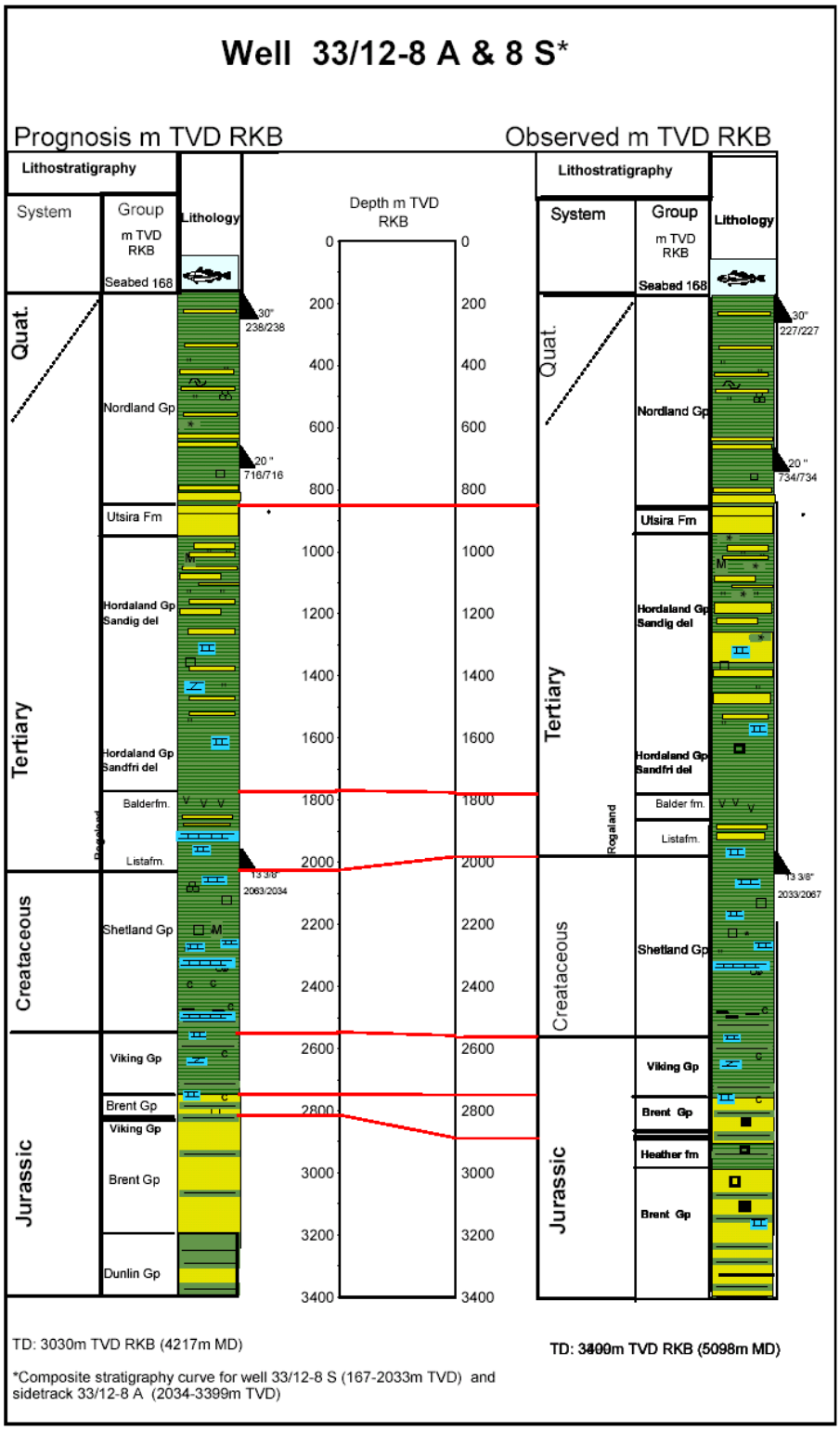
LITOSTRATIGRAPHIC TOPS	DEPTH MD (m RKB)	DEPTH (m RKB)	TVD (m MSL)	THICKNESS (m TVD)	Deviation from prognosis +/-
NORDLAND GROUP	168.0	168.0	137.0		
Usira Formation	840.0	840.0	809.0		-4
HORDALAND GROUP	931.0	931.0	900.0	863.0	-18
Sandy Hordaland	931.0	931.0	900.0	632.0	-18
Sandfree Hordaland	1563.0	1562.5	1531.5	231.0	-13,5
ROGALAND GROUP	1807.0	1794.0	1763.0	236.2	+17
Balder Formation	1807.0	1794.0	1763.0	71.0	+17
Lista Formation	1885.0	1865.0	1834.0	165.2	+1
SHETLAND GROUP	2030.0	1999,2	1968,2	561,7	-17,8
VIKING GROUP	2636.0	2560.86	2529.86	139.15	+50
Draupne Formation	2636.0	2560.86	2529.86	3.44	+50
Heather Formation	2640.0	2564,30	2533,30	135.71	+53
BRENT GROUP	2814.0	2700.01	2669.01	254.05	+45
Tarbert Formation	2814.0	2700.01	2669.01	66.30	+45
Ness Formation	2906.0	2766.31	2735.31	122.06	+48
Etive Formation	3075.0	2888.37	2857.37	16.52	+42
Rannoch Formation	3098.0	2904.89	2873.89	40.72	+34
Broom Formation	3155.0	2945.61	2914.61	8.45	+30
DUNLIN GROUP	3167.0	2954.06	2923.06	348.10	+28
Drake Formation	3167.0	2954.06	2923.06	83.8	+28
Cook Formation	3285.5	3037.83	3006.83	107.1	+27
Burton Formation	3429.0	3144.94	3113.94	34.50	+44
Amundsen Formation	3476.0	3179.44	3148.44	126.28	+38
Statfjord Formation	3646.5	3305.72	3274.72	74.96	+39
Nansen Member	3646.5	3305.72	3274.72	61.31	+39
Eiriksson Member	3730.5	3367.03	3336.03	13.65	+66
TD	3750.0	3380.68	3349.68		

Figure 4.3.1 Litostratigraphy for well 33/12-8 S, prognosed and observed.

4.3.2 Table of Litostratigraphy for well 33/12-8 A

LITOSTRATIGRAPHIC TOPS	DEPTH MD (m RKB)	DEPTH TVD		THICKNESS (m TVD)	Deviation from prognosis +/-
		(m RKB)	(m MSL)		
BRENT GROUP	2865.8	2751.39	2720.39	142.46	+10
Tarbert Formation	2865.8	2751.39	2720.39	135.06	+10
Ness Formation	3127.0	2886.45	2855.45	4.29	
Tarbert Formation	3630.0	2893.85	2862.85	7.40	
VIKING GROUP base	3630.0	2893.85	2862.85	3.86	
Heather Formation base	3630.0	2893.85	2862.85	3.86	
BRENT GROUP base	3901.5	2897.71	2866.71	14.29	
Tarbert Formation base	3901.5	2897.71	2866.71	14.29	
VIKING GROUP base	4166.8	2912.00	2881.00	91,69	
Heather Formation base	4166.8	2912.00	2881.00	91,69	
VIKING GROUP base	4553,45	3003,69	2972,69		
Heather Formation base	4553,45	3003,69	2972,69		
BRENT GROUP	4541.0	2997.52	2966.52	401.74	
Tarbert Formation	4541.0	2997.52	2966.52	139.34	
Ness Formation	4770.0	3136.86	3105.86	208.43	
Etive Formation	5041.0	3349,19	3318,19	29.60	
Rannoch Formation	5075.0	3378,79	3347,79	20.47	
TD	5098.0	3398.82	3367.82		

Figure 4.3.2 Composite litostratigraphy for well 33/12-8 A, prognosed and observed. The figure is composed of main well 33/12-8 S from seabed to 13 3/8" casing shoe (167-2033m MD) and sidetrack 33/12-8 A from 13 3/8" casing shoe to TD of the well (2033-3399m MD).



4.4 Lithostratigraphic description

General Information

Lithology: The lithological description is based on cuttings description.

The dephts are in meters with drillfloor as datum unless otherwise stated.

Geological summary

33/12-8 S

NORDLAND GROUP 168 – 840 m MD (137 – 809 m TVD MSL)

The upper part of the Nordland Group was drilled with returns to seafloor and logged with MWD (GR/RES/DIR). Log interpretation suggests mostly clay/claystone with some thin sand layers.

No shallow gas was recorded in the sands.

Utsira Formation 840 – 931 m MD (809 – 900 m TVD MSL)

The formation consists of sand/sandstone, predominantly loose quartz grains, clear to translucient, fine to medium, occasional very fine, moderately to poor sorted, subangular to subrounded, occasional rounded. Micropyritic in places.

HORDALAND GROUP 931 – 1807 m MD (900 – 1763 m TVD MSL)

The Hordaland Group consists of claystone with beds of sandstone. The upper part of the Hordaland Group have a high sand content and is much more sandprone than the lower part.

The sandstone/sand consists predominantly of translucient quartz grains, fine to medium, occasional very fine, occasional coarse, subangular to subrounded, moderately to poor sorted and dominantly loose. Glauconite is also recorded.

The claystones seen in samples varies in colour from light grey to medium grey, olive grey to dark greenish grey. Towards the base of the group the colour changes to reddish grey and brownish grey. The claystones are generally soft to firm, subblocky to blocky, micromicaceous, micropyritic and non to moderately calcareous.

Traces of pyrite occur throughout the group. Glaconite is frequently recorded in the upper part of the group, althougt predominantly recorded as trace it sometimes occurs with a faily high percentage in samples.

ROGALAND GROUP 1807 – 2030 m MD (1763 – 1999 m TVD MSL)

The Rogaland Group is marked on the logs by a decrease in the gamma ray and a gradual increase in resistivity. In this well the Rogaland Group consists of the Balder Formation and Lista Formation.

Balder Formation 1807 – 1885 m MD (1763 – 1834 m TVD MSL)

The Balder Formation is recognized on the MWD logs by the characteristic gamma ray and resistivity curves.

The Balder Formation consists of interbedded claystone and tuff.

The claystone varies in colour from medium grey, olive grey to greenish grey and dark greenish grey. It is firm to hard, subblocky to blocky, micropyritic in parts and non calcareous.

The claystone is tuffaceous in parts, and grades from dark greenish grey to medium blusish grey tuff. The tuffaceous claystone is firm and subblocky.

Lista Formation 1885 – 2030 m MD (1834 – 1968 m TVD MSL)

The Lista Formation consists of claystone with layers of limestone and minor sandstone.

The claystone is dominantly medium grey to medium dark grey and greenish grey, firm, blocky and occasional silty. The claystone is in places very calcareous, grading to marl. Traces of pyrite and micropyrite occurs throughout the Lista Formation.

The limestone is white to light grey, firm, subblocky, argillaceous and grading to marl, occasional silty.

From 13 3/8" casing shoe two sequences are drilled, -8 S and –8 A. Only –8 S is described here. Description of corresponding units have more or less the same descrioption in both –8 S and –8 A.

SHETLAND GROUP 2030 – 2636 m MD (1868,2– 2529,9 m TVD MSL)

The Shetland Group consists of claystone with marl/limestone beds.

The claystones is generally medium grey to medium dark grey, also greenish grey, firm, blocky, occasional silty. In places micropyritic and calcareous, grading to marl.

The marl/limestone is yellow white to light grey, occasional medium grey, soft to firm, subblocky, argillaceous and occasional slightly silty.

VIKING GROUP **2636 – 2814 m MD (2529,9 – 2669,0 m TVD MSL)**

The top of the Viking Group and the Draupne Formation was picked at the abrupt increase in the gamma ray. The Viking Group is presented by the Draupne Formation and the Heather Formation and consists of claystone with limestone beds.

Draupne Formation **2636 – 2640 m MD (2529,9 – 2533,3 m TVD MSL)**

The Draupne claystone is light olive grey to olive grey and dark greenish grey, soft to firm, blocky and non calcareous.

Heather Formation **2640 – 2814 m MD (2533,3-2669,0 m TVD MSL)**

The Heather Formation consists of claystones with limestone beds.

The claystones seen in samples varies in colour from medium grey to dark grey, brownish black to olive black and olive grey. The claystone is firm, blocky and occasional silty.

The limestone is described as pale to dark yellowish brown and light grey, firm, subblocky, argillaceous and occasional silty.

BRENT GROUP **2814 – 3167m MD (2669,0 – 2923,1 m TVD MSL)**

Well 33/12-8 S

The Brent Group in well 33/12-8 S comprises the whole Brent Group with the Tarbert, the Etive, the Ness, the Rannoch and the Broom Formations. The Tarbert Group and the upper part of the Ness Group proved to be hydrocarbon bearing. Bacground gas was very low 0,04-0,11%) through the whole 8 ½" section in the Shetland and Viking Groups with maximum gas values (~2,5-2,8%) reached from hydrocarbon filled sands in the Tarbert and Ness Formations.

Tarbert Formation **2814 – 2906 m MD (2669,0 – 2735,3 m TVD MSL)**

The Tarbert Formation is composed of sandstone interbedded with shale, siltstone and coal.

The sandstone is mainly composed of clear to translucient quarts grains, very fine to medium, occasional coarse, moderately sorted, subrounded. The sandstone has a light grey argillaceous matrix, is non calcareous, moderately cemented and predominantly loose.

The siltstone is medium grey and brownish grey to brownish black, blocky, soft to firm and non-calcareous.

The carbonaceous shale / coal is brownish black to olive black, soft to firm, blocky and subfissile, non-calcareous, carbonaceous, occasional grading to coal.

Ness Formation **2906 – 3075 m MD (2735,3 – 2857,4 m TVD MSL)**

The Ness Formation is composed of sandstone interbedded with siltstone, shale and coal.

The sandstone is light grey to yellowish brown, clear to translucient quartz grains, very fine to fine, good sorted, subangular to subrounded, argillaceous matrix, moderately silica cemented.

The shale is olive black, blocky, subfissile, carbonaceous and grading to coal.

The siltstone is brownish grey to brownish black, blocky, soft to firm and non-calcareous.

The coal is black, hard, blocky and shiny.

Etive Formation **3075 – 3098 m MD (2857,4 – 2873.9 m TVD MSL)**

The Etive Formation is composed of sandstone and shale.

The sandstone is light grey, translucient quartz grains, predominantly very fine to fine, good sorting, silica cemented, subangular to subrounded, silty, clay matrix, micropyrite in places.

The shale is medium dark grey to greyish black and olive grey, firm to hard, blocky to subfissile, silty, occasional carbonaceous, micropyritic.

Rannoch Formation **3098 – 3155 m MD (2873,9 – 2914,6 m TVD MSL)**

The Rannoch Formation is composed of sandstone/silty sandstone and shale.

The sandstone/siltstone is light grey, translucient quartz grains, predominantly very fine to fine, good sorting, silica cemented, subangular to subrounded, silty, clay matrix, micropyrite in places.

The shale is dominantly medium grey, occasional olive black, firm to moderately hard, bocky to subfissile, silty, micropyritic, occasional carbonaceous.

Broom Formation **3155 – 3167 m MD (2914,6 – 2923,1 m TVD MSL)**

The Broom Formation is composed of sandstone/siltstone and shale.

The sandstone is light grey, translucient quartz grains, predominantly very fine to fine, good sorting, silica cemented, subangular to subrounded, silty, clay matrix, micropyrite in places. The shale is dominantly medium dark grey, occasional olive black, firm to hard, blocky to subfissile, silty occasional carbonaceous.

DUNLIN GROUP **3167 – 3647 m MD (2923,1 – 3349,7 m TVD MSL)**

The Dunlin Group consists predominantly of claystone/shale and siltstone, with some laminations of limestone and sandstone. Well 33/12-8S compromises the whole Dunlin Group with the Drake, the Cook, the Burton and the Amundsen Formations present. Well 33/12-8 A was not drilled into the Dunlin Group since TD was set in the Brent Group.

Drake Formation 3167 – 3286 m MD (2923,1 – 3007.1 m TVD MSL)

The Drake Formation consists of shale and siltstone with limestone and dolomite stringers and traces of pyrite.

The shale is medium dark grey, dark grey, greyish black and olive black, firm to hard, blocky to subfissile, silty, micromicaceous, non calcareous and micropyritic.

The siltstone is light grey with clear and translucient quarts grains and frosted grains, very fine to medium, silica cemented, friable, also loose, subangular to subrounded, pyrite in places.

The limestone is light grey to white, blocky, firm to hard, argillaceous and microcrystalline in places.

The dolomite is dark yellowish brown, blocky, hard and argillaceous.

Cook Formation 3286 – 3429 m MD (3007,1 – 3114,0 m TVD MSL)

The Cook Formation consists predominantly of sandstone interbedded with siltstone and shale.

The sandstone consists of clear and translucient quartz grains, also white to light grey, very fien to fine, occasional coarse, especially in the upper part of the Formation. The sandstone is well sorted, subangual to subrounded, argillaceous matrix, calcareous cemented, friable and kaolin.

The shale seen in the Cook Formation is dark grey to greyish black and also olive black, firm to hard and blocky.

Burton/Amundsen Formations 3429 – 3647 m MD (3114,0 – 3274,7 m TVD MSL)

The Burton/Amundsen Formation consists predominantly of shale/claystone interbedded with siltsotne and sandstone, occasional traces of Limestone.

The shale/claystone is dark grey to brownish black, subfissile, firm, micromicaeous, micropyritic, silty and grading to siltstone.

The sandstone/siltstone consists of clear to translucient quartz grains, also light grey to white and light yellowish brown, very fine to fine, well sorted, subangular to subrounded, calcareous cemented, friable and with an argillaceous matrix.

STATFJORD FORMATION 3646,5 – 3750 m MD (TD), (3274,7 – 3349,7 m TVD MSL)

The top of the Statfjord Formation is clearly recognised by a lithological transition from the silty shale of the Amundsen Formation toward a clean sandstone of the Statfjord Formation. The logs exhibit a sharp drop in the gamma ray readings and an increase in the resistivity.

The Statfjord Formation in well 33/12-8 S consists of the Nansen and Eiriksson member where the uppermost part in the Nansen Member proved to be hydrocarbon bearing and TD was set at 3750 m MD in the Eiriksson Member.

The Nansen Member 3646,5 – 3731 m MD (3274,7 – 3336,1 m TVD MSL)

The Nansen member in the Statfjord Formation consists of sandstone with minor amounts of claystone and coal.

The sandstone consists of clear to translucient qartz grains, fine to coarse, occasional with very coarse grains, predominantly fine to medium, moderately to poor sorted, subrounded and with traces of pyrite.

The claystone is brownish grey to olive grey, soft to firm and silty.

The coal is grading to claystone and is olive black to black, firm to hard, fissile to blocky and with pyrite.

The Eiriksson Member 3731 – 3750 m MD (TD), (3336,1 – 3349,7 m TVD MSL)

The Eiriksson Member in the Statfjord Formation consists of sandstone with minor amounts of claystone.

The sandstone consists of clear and trannslucient quarts grains, very fine to coarse and grading to siltstone, moderately sorted and subrounded.

The claystone is brownish grey and olive grey, soft to firm and silty.

4.5 Hydrocarbon indications

Background gas was very low during drilling of the Shetland Group and the Viking Group, variating between 0.04-0.11% and increasing to 0.2-0.4 when drilling into hydrocarbon filled Brent Group in well 33/12-8 S.

Maximum gas values around 6.8-11.0% in segment N3-Dole were measured from hydrocarbon filled sands in the Tarbert Formation. In segment N2-Ole, maximum gas values appeared when drilling through hydrocarbon filled sands in the Tarbert Formation. Gas values were low and stable between 0.2-0.4% when drilling through Heather Formation and waterfilled Brent sandstones.

Table 4.5.1 Gas peaks for well 33/12-8 S

Depth m MD	Depth m TVD	Gas peak %	BG	C1	C2	C3	iC4	nC4	Gas type
2823	2707	2,87	0,8	17852	1190	320	36	54	FG
2835	2715	2,84	1,0	17418	1162	329	36	54	FG
2858	2731	2,80	1,8	17030	1174	345	40	62	FG
3643	3304	0,39	0,04	1780	84	20			STG
3650	3308	0,43	0,15	2391	275	88	7	22	FG

Table 4.5.2 Gas peaks for well 33/12-8 A

Depth m MD	Depth m TVD	Gas peak %	BG	C1	C2	C3	iC4	nC4	Gas type
2870	2755	3,40	0,40	33187	2099	587	63	103	FG
2920	2767	3,91	0,40	34370	3028	1082	137	226	FG
3940	2900	10,35	0,50	112117	6189	1617	179	261	FG/CG
3968	2901	9,54	0,50	107744	6120	1676	193	277	FG/CG
4050	2906	9,37	1,00	100617	6807	1991	238	350	FG
4092	2909	9,17	1,00	106304	7345	2314	292	441	FG
4114	2911	11,01	6,00	73214	4932	1528	197	308	FG/CG
4572	3014	6,80	0,40	31368	2721	961	122	211	FG

4.6 Geophysical results

The sediment layers in segment N3-Dole came in 30-50 m deeper than originally mapped and 30 meters deeper than prognosed in N2-Ole.

Drilling of well 33/12-8S and 33/12–8A proved the geophysical interpretation of the area to be correct. However, the velocity model had to be adjusted to obtain the correct depths. See figures in appendix.

4.7 Data acquisition

4.7.1 Cuttings and mud samples

One set of bulk sample and one set of washed and dried sample (100 g) was collected every 10 m from 980 m MD in the 17 ½" section and down to 2500 m MD. It was decided to gather wet samples in 5 L tin cans but Baker Hughes Inteq had not sent out the proper amount to cover the whole section and due to this problem samples were taken in bags in the uppermost part of the 17 ½" section. Samples was also thinned out in the upper part of the 17 ½" section due to powerful washing of the shakers (capasity problems at the shakers), resulting in bad quality samples and problem to fulfill the Norwegian Petroleum Directorate`s (NPD) requirement of 3 kg material in every sample.

Baker Hughes INTEQ had the mudlogging for well 33/12-8 S and –8 A. The mudlogger had a very hectic time when drilling through Shetland Formation and Viking Group because of 3 m sample intervals, extensive sampling and high drilling rate. A combination of too quick washing of the dry samples and too low capasity of the dry owen triggered the fire alarm in the unit. The mudlogger unit was shut down in approximately one hour. After this incident drilling rate was redused to 30 m/hr to ensure proper sample catching and one extra mudlogger were also sendt to the rig to help out.

Sampling interval was changed to 5 m from 2500 m MD to 2800 m MD and further increased to 3 m below 2800 m MD to TD. 6 meters samples were taken in the upper part of the Tarbert Formation while drilling the horisontal section and the sample interval was further increased to every 10 meter when drilling in the Heather Formation between segment N3 and N2. A new interval with 3 meters samples came to pass while drilling into the Tarbert Formation in the Ole structure (N2) and down to 4729 m MD. At 4729 m MD the sampling interval again was changed, this time to 6 meters samples, an interval which was maintained to TD.

Mud samples (1 litre in geochemical tin cans) were collected from the active pits every 100 m from 2600 m RKB and down to TD. Extra mud samples were intended to be taken when drilling through hydrocarbon bearing formations. Mud samples from drilling of the Ole prospect (N2) are however missing and no one has managed to track them up in the system, or confirme that they have been taken at all.

4.7.2 Conventional coring

No coring.

4.7.3 MWD/LWD

Table 4.7.1 MWD/LWD Data acquisition for well 33/12-8 S and sidetrack 33/12-8 A

Section Run #	Contractor	Equipment	Failure & problems	Interval	Date	Lost time
	33/12-8 S					
1	Anadrill	MWD/Dir	None	168-232		
2	Anadrill	CDR	None	232-744	30-31.03.02	-
3	Anadrill	CDR	Decoding	744-1479	04-05.04.02	
4	Anadrill	CDR		1479-2077	07-08.04.02	
5	Anadrill	V675R	Decoding	2077-3643,5	12-18.04.02	2
6	Anadrill	V675R		3643,5-3750	17-19.04.02	-
	33/12-8 A					
1	Anadrill	CDR, Powerdrive	No steering respons. Changed Powerdrive	2100-2283	27-28.04.02	
2	Anadrill	CDR, Powerdrive	Not the right steering respons from Powerdrive. POOH and change to motor	2283-2411	29.04.02	
3	Anadrill	CDR, BHI motor	Drilled with motor. Trip out to change BHA to Powerdrive	2411-2814	30.04-01.05.02	
4	Anadrill	CDR, Powerdrive	Transmission to geol. Office/Res-failure. Relogged 4460-4490 m MD due to loss of GR signal during initial pass. Attenuation RES failed at 4500, Phase RES failed at 4636 m MD.	2814-5098	02-09.05.02	

Remarks:

17 ½" section in well 33/12-8 S
GR memory data from run 3 was OK. The resistivity data are questionable. The data seems to be good from the steered section, but spikes a lot where the string was rotating. During the first run Anadrill had a persistant problem decoding the MWD signal due to high downhole noise associated with the X-treme mud motor and complicated by the lower than expected flow rates due to losses over the shakers limiting the flow. The quality of the log is therefore not satisfactory. During the second run a different motor type and much higher flow rate resulted in higher signal to noise ratio and a good real-time log.

Baker Hughes INTEQ`s Riglink was working through the whole section. Transference of MWD/LWD data to BHI was however not working properly. Neiher GR/RES or ECD did appear on the screen in run # 3. ECD was OK in run #4 but GR/RES came througt unsatisfactory on the screen. BHI belive Anadrill is sending the wrong format, but anyway no proper log did appper on the screen in the geologists office or to land.

8 ½" section in well 33/12-8 S
Persistent problems with decoding of signals occurred from approximately 3200 mMD mainly owing to noise from the mud pumps. True time logs were of especially low quality in

the Cook Formation probably because of downhole noise acting in combination with mud pump noise. Two stands were re-logged in the upper part of the Cook Formation (3255-3225 m MD and 3315-3283 mMD) to confirme waterfilled formation.

MWD logs were transfered from Anadrill through BHI`s Riglink to the geologists office. It worked mainly OK but it was necessary to restart the display a number of times each day because GR and Resistivity data were not automatically updated.

Table 4.7.2 Intervals with missing logs/incoherent logs due to tool failure in well 33/12-8 S

Section Run #	Contractor	Equipment	Failure & problems	Interval with missing logs*/ or bad quality logs**	Lost time
3	Anadrill	CDR	Decoding Resistivity	747-1479** 747-1479**	
4	Anadrill	CDR	Decoding Resistivity		

12 ¼" section in Well 33/12-8 A

Schlumberger had problems with their database resulting in missing real-time logs over the interval 3210-3232 m MD.

Real-time resistivity log became very incoherent when drilling into segment N2-Ole. After drilling to approximately 3970 m MD, it was decided to pull out to 3880 m MD to ream over the interval to check if there were problems related to the resistivity tool. Reaming of the above mantioned interval gave the same results as when drilling and it was conluded to continue drilling.

Attenuation-resistivity failed at approximately 4500 m MD and it was drilled further on with only phase resistivity and gamma ray logs. Phase resistivity failed at 4636 m MD and it was drilled on to TD with only real-time gamma ray log. Gamma ray functioned maily OK but some noise appered on the log from approximately 4750 m MD at kelly down on every stand (probably related to mud pump noise).

Table 4.7.3 Intervals with missing logs/incoherent logs due to tool failure in well 33/12-8 A

Section Run #	Contractor	Equipment	Failure & problems	Interval with missing logs*/ or bad quality logs**	Lost time
4	Anadrill	CDR, Powerdrive	Attenuation Res Phase Res Gamma ray	4500-5098* 4636-5098* 4750-5098**	

4.7.4 Wireline logging

Table 4.7.4 Wireline logging in well 33/12-8 S

Hole section (Run/Pass)	Contractor	Equipment	Tool Combination	Log interval (m MD)	Comments
Wireline above Reservoir					
8 ½" run 1A	Schlum.	PEX/AITH		2811-2068	
8 ½" run 1A	Schlum.	DSI		2811-2068	
Wireline in Reservoir Section (s)					
8 ½" run 1A	Schlum.	PEX/AITH		3750-2050	
8 ½" run 1A	Schlum.	MDT			Tool hung at shoe
8 ½" run 1A	Schlum.	MDT		3570-2815	Did not get down to Statfjord
8 ½" run 1A	Schlum.	DSI		3100-2050	Logged from water zone in Brent

Table 4.7.5 Time distribution wireline logging well 33/12-8 S

Run/Pass	Equipment	Operations time (Hours)	Lost time (hours)	Comments
8 ½" run 1A	PEX/AITH	10		
8 ½" run 1A	MDT	26		
8 ½" run 1A	DSI	6		
Total		42		

Table 4.7.6 Wireline logging in Well 33/12-8 A

Hole section (Run/Pass)	Contractor	Equipment	Tool combination	Log interval (m MD)	Comments
Wireline in Reservoir Section (s)					
12 ¼" /1A	Schlumberger	PEX/AITH/GR/MDT		2066,5-3170	PEX/AIT-H/GR miss-run, 18 pressure points taken
12 ¼" /1A	Schlumberger	PEX/AITH/GR		3801-2778	First pass
12 ¼" /1A	Schlumberger	PEX/AITH/GR		5078-3700	Second pass
12 ¼" /1B	Schlumberger	MDT on TLC	MDT-GR-HTCS	RIH to 2456	Took weigth at 2456 m MD. Unable to pass below this depth. POOH and wait for MDT backup probe
12 ¼" /1B	Schlumberger	MDT on TLC		3125-5078	POOH due to probe/valve failure.
12 ¼" /1C	Schlumberger	MDT on TLC		2850-4606	

Table 4.7.7 Time distribution Wirelinelogging Well 33/12-8 A

Run/Pass	Equipment	Operations time (Hours)	Lost time (hours)	Comments
12 ¼" /1A	PEX/AITH/GR/MDT	30 hrs,15 min		MDT pressure points only
12 ¼" /1A	PEX/AITH/GR	70 hrs,30 min	0,5 hrs	Lost time because of wire jumped out of wheel
12 ¼" /1B	MDT on TLC	52 hrs, 50min	6,50 hrs	Re-terminating locomotive, tested communication.
12 ¼" /1B	MDT on TLC	86 hrs,30 min	19 hrs,15 min	Failure probe/valve. POOH
12 ¼" /1C	MDT on TLC			

4.7.5 Data quality

Extra mud samples
Extra mud samples were intended to be taken when drilling through hydrocarbon bearing formations. Mud samples from drilling of the Ole prospect (-8 A) are however missing and no one has managed to track them up in the system, or confirme that they have been taken at all.

MWD/LWD
For comments on MWD/LWD see remarks under section 4.7.3. MWD/LWD

Wireline Logging
For comments on Wireline Logging see tables in section 4.7.4.

MDT fluid samples
Some of the fluid samples had a very high degree of contamination, see table 4.7.8 and 4.7.9 under.

Table 4.7.8 Contamination of WFT samples in Well 33/12-8 S

Sample no.	Chamber no.	Depth m MD	Sample type	Contamin-ation %	Comments
1,01	MPRS 190	2914	Oil	3,3	Good sample
1,02	MPRS 753	2914	Oil	2,8	Good sample
1,04	MPRS 770	2864	Gas/Cond.	9	
1,03	MPRS 754	2864	Gas/Cond.	11	
1,06	MPRS1011	2845	Gas/Cond.	10,5	
1,05	MPRS 854	2845	Gas/Cond.	11	
1,07	MPRS 33	2815,5	Gas/Cond.	25,5	
1,08	MPRS 86	2815,5	Gas/Cond.	25,5	
1,10	MPRS 152	2830	Gas/Cond.	36	
1,09	MPRS 112	2830	Gas/Cond.	40	

Table 4.7.9 Contamination of WFT samples in Well 33/12-8 A

Sample no.	Chamber no.	Depth m MD	Sample type	Contamination %	Comments
1,01	MPRS 803	2922	Oil		Problems with piston in the bottle
1,02	MPRS 852	2922	Oil	12	
1,03	MPRS 855	4565	Oil	15,5	
1,04	MPRS 927	4565	Oil	15	
1,05	MPRS 972	4606	Water		
1,06	MPRS 973	4136,4	Gas/Cond.	19	
1,07	MPRS 173	4136,4	Gas/Cond.	17	
1,08	MPRS 650	4033	Gas/Cond.	3	Good sample
1,09	MPRS 768	2954	Oil		Leak in valve TS-4509
1,10	MPRS 769	2906	Gas/Cond.	28	
1,11	MPRS 773	2868	Gas/Cond.	40	
1,12	MPRS 776	2868	Gas/Cond.	38	

4.8 Formation pressure

The pressure prognosis was mainly based on information from exploration well 34/10-38 S and –17, 34/12-7 and the wells drilled from the Rimfaks- and Gullveig templates. Experiences from the wells 34/10-37, -37 A and –43 S were also taken into consideration. The final pore pressure is mainly based on estimations of the pore pressure by resistivity measurements and D'exponent calculations while drilling the top hole sections. In the Brent reservoirs, pore pressure is based on MDT-pressure testing results.

The final pore pressure, fracture pressure and overburden gradients as well as FIT/LOT for well 33/12-8 S and –8 A are graphically presented in fig. 4.8.1 and 4.8.2.

The pore pressure was experienced to be hydrostatic down to early Eocene at approximately 1576 m TVD RKB, where it is equal to 1,01 g/cm^3 EMW.

Pressure buildup started where the sand content of the Hordaland Group decreased, at the same time as presence of limestone and calcite cemented zones was increasing. The pore pressure increased rapidly through the rest of the Hordaland Group and the Rogaland Group. At the top of Balder Formation the pore pressure was experienced to be approximately 1,13 g/cm^3 EMW and 1,17 g/cm^3 EMW at top of the Lista Formation.

Steering in large parts of the Hordaland Group made estimation of the pore pressure increase in the lower part of the Group from the drilling data render difficult. It was observed that the pressure were increasing from from approximately 1650-1675 m MD and down to top Balder were pore pressure is estimated to be 1,13 g/cm^3 EMW. A new pressure shift are observed in the transition from the Balder to the Lista Formation were the pressure is increasing to 1,15 g/cm^3 EMW. However, the pore pressure seems to be constant in the lower part of the Lista Formation. The pressure/depth ratio increased strongly from approximatley 2200m TVD, about 100m earlier than prognosed, down to close base Heather Formation where pore pressure is equal to initial reservoir pressure, 1,48 g/cm^3 EMW. Our interpretation of the pore pressure corresponds seemingly well with the prognosis.

The segment N3 (Dole) has the same pressure regime in the water zone as in the neighbouring fields (Gullfaks Vest, Gullveig, Tordis and Rimfaks). It was assumed depletion in the Brent reservoir via the water zone as a result of production in adjacent reservoirs. Pressure testing showed that the hydrocarbon filled part of the upper Brent reservoir (N3) is depleted with 20-30 Bars (as expected). The pressure at top of the prognosed reservoir (2625 m TVD MSL) is estimated to be 359 Bar based on MDT-pressure tests in the drilled part of the reservoir, corresponding to 1,39 g/cm^3 EMW. In segment N2 the pore pressure in the Brent Group was tested to be much the same as the prognosed initial pressure. The pore pressure at top of the Brent prospect in segment N2 is calculated to be 411 Bars (2825 m TVD MSL), corresponding to 1,48 g/cm^3 EMW.

No pressure tests were taken in the Statfjord Formation in segment N3. The pressure at top of the prospect (3215 m TVD MSL) is prognosed to be 446 Bars, corresponding to 1,41 g/cm^3 in EMW.

Fig. 4.8.1 Final pore pressure 33/12-8 S

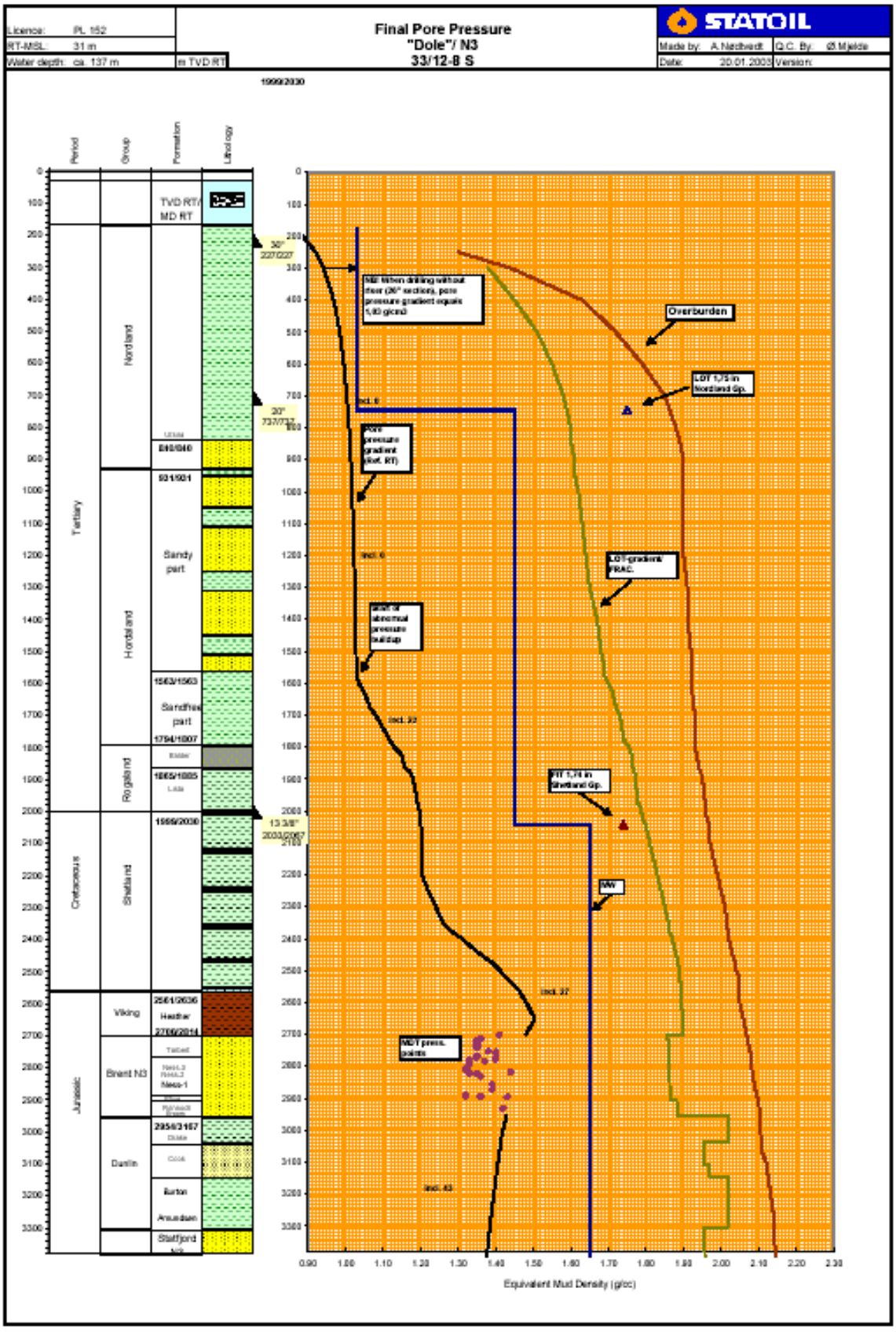


Fig. 4.8.2 Final Pore Pressure 33/12-8 A

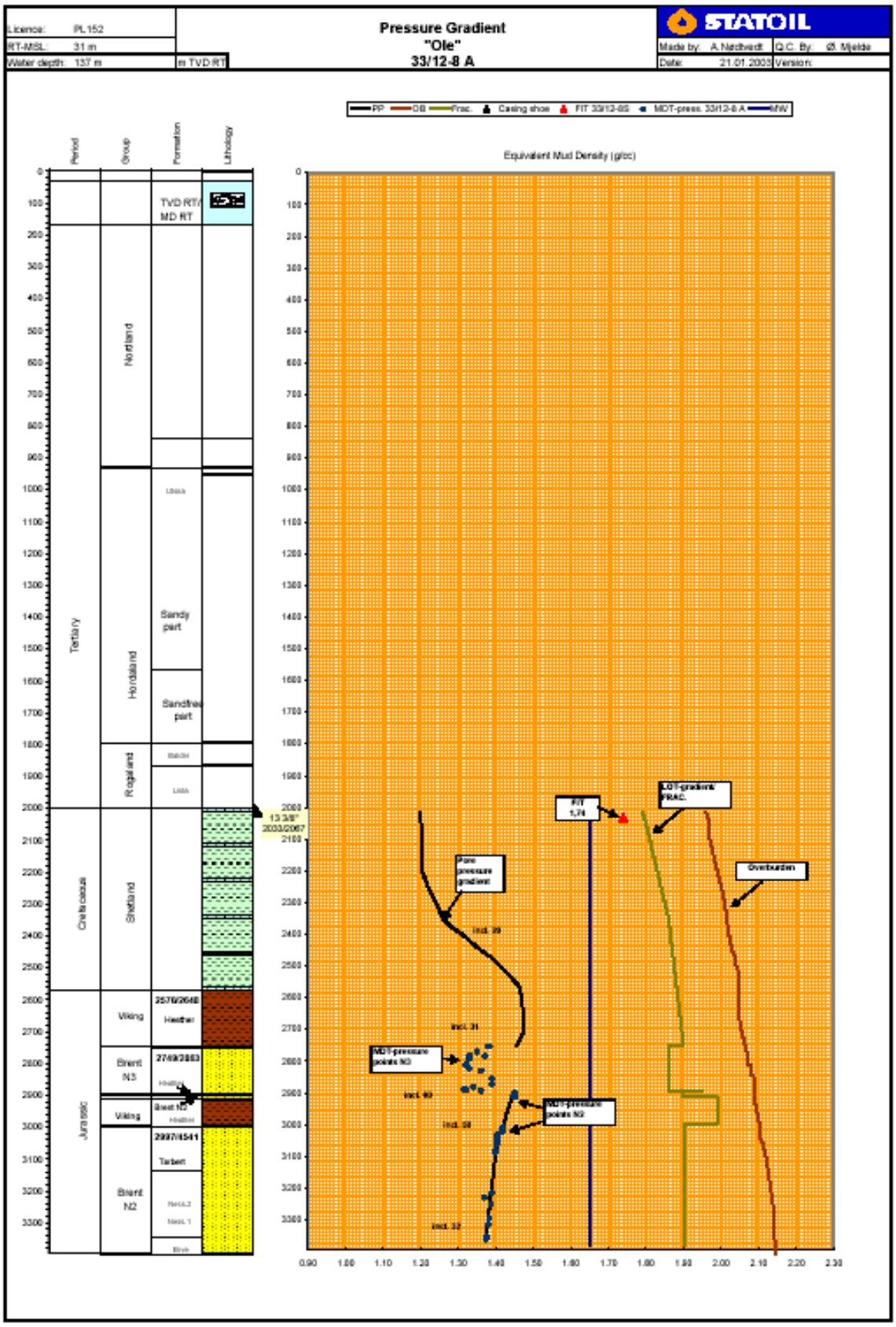


Fig. 4.8.3 Well 33/12-8 S MDT – Formation pressures

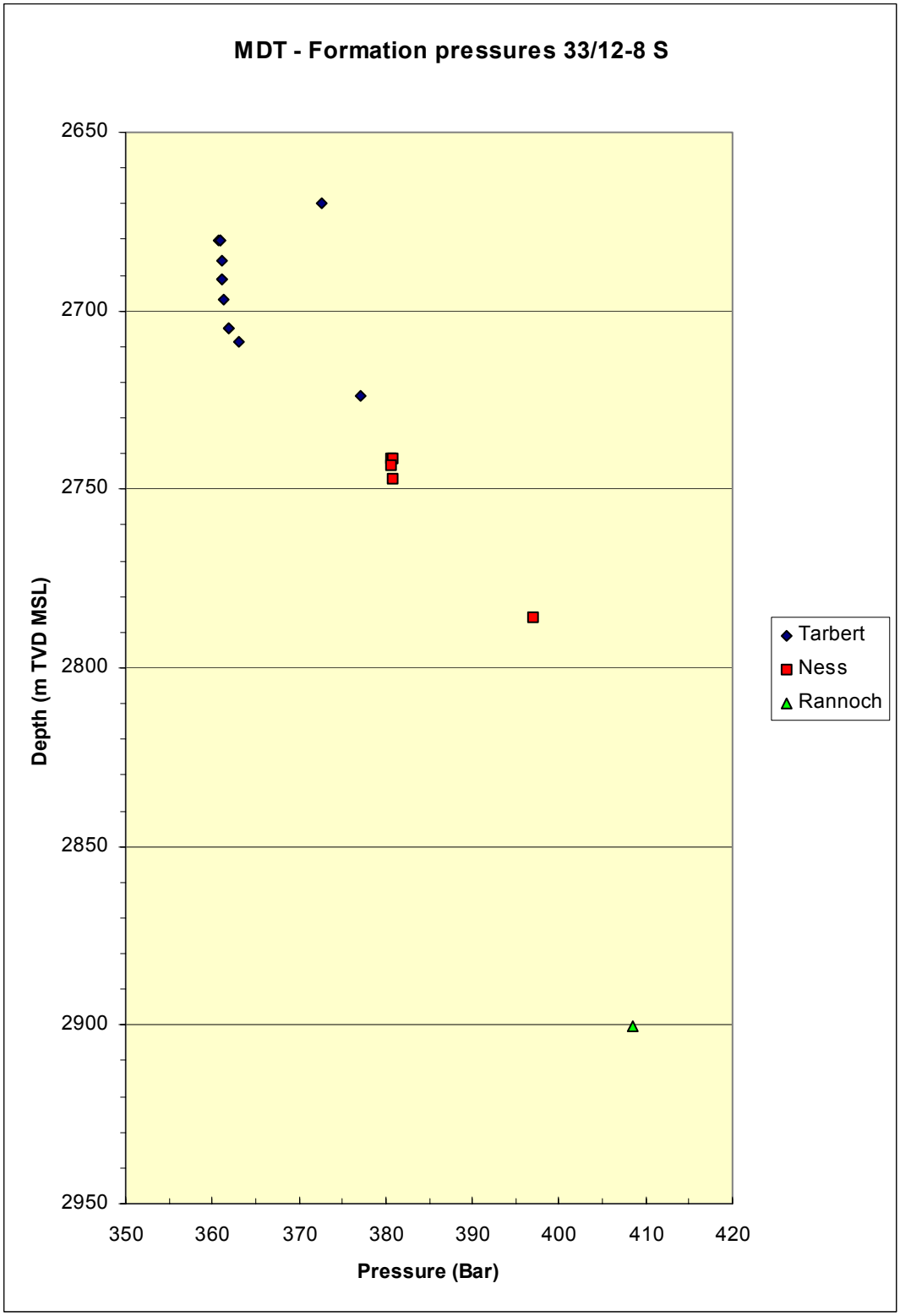
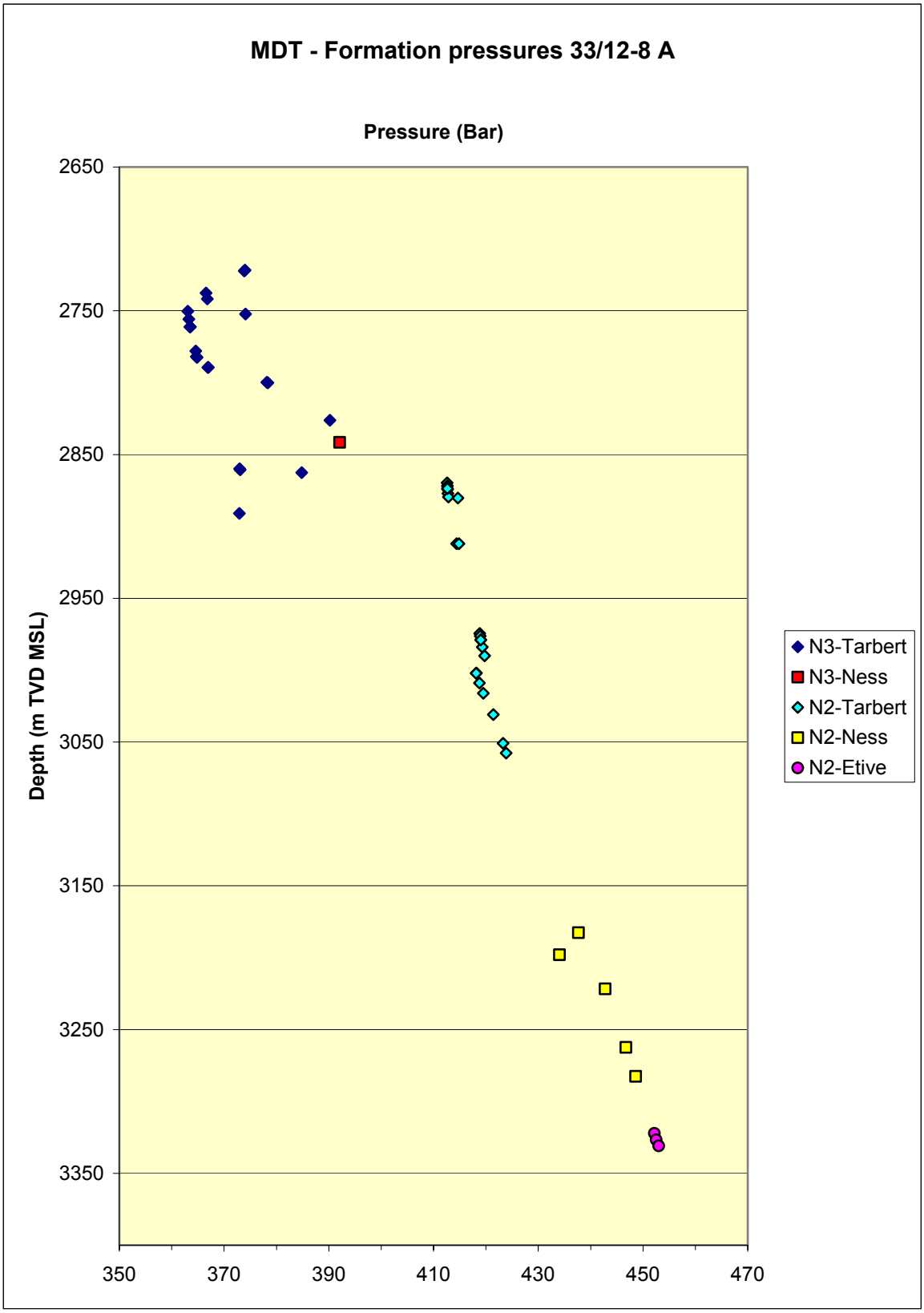


Figure 4.8.4 Pressure plot for well 33/12-8 A



4.8.1 Reservoir pressure summary

One MDT run were performed in well 33/12-8 S. MDT- fluid samples and pressure tests have been carried out in the gas zone. Density in the gas zone was about 0,35 g/cm^3, GOR approx. 2000 Sm^3/Sm^3.

Two MDT runs were performed in Well 33/12-8 A. MDT- fluid samples and pressure tests have been carried out and results given from the oil zone showed a density of 0,63 g/cm^3 and GOR about 220 Sm^3/Sm^3. Density in the gas zone was about 0,32 g/ccm, GOR of approximately 2600 220 Sm^3/Sm^3.

Pressure results from MDT-tests in wells 33/12-8 S and 33/12-8 A are illustrated in figure 4.8.3 and 4.8.4.

All the MDT fluid samples were transferred to 400 ml MDT pressure data and MDT fluid sample bottles on the rig by Petrotech.

MDT pressure data and MDT fluid samples are results are given in the appendix.

4.9 Reservoir fluid sampling

Table 4.9.1 WFT sample list for 33/12-8 S

Sample List (WFS)

K-no:	
Operator:	Statoil
Rig:	Borgland Dolphin
Well:	33/12-8 S

Sample no.	Date	Time	Run no.	Chamb. no.	Bottle no.	Sample type	Depth	Res. temp	Vol. ml	P.Res bar	Comments
1,01	21.04.02		1	190	TS-45705	Gas / mud?	2914,0	98,0	370	380,533	Mud/greasy oil in lines after transfer
1,02	"		1	753	TS-46405	Gas / mud?	2914,0	98,0	360	380,533	Mud/greasy oil in lines after transfer
1,03	"		1	754	PT-1161	Gas / cond.	2864,0	97,1	320	361,811	
1,04	"		1	770	TS-37504	Gas / cond.	2864,0	97,1	340	361,811	
1,05	"		1	854	PT-1148	Gas / cond.	2845,0	96,4	370	361,176	
1,06	"		1	1011	TS-46606	Gas / cond.	2845,0	96,4	300	361,176	
1,07	"		1	33	TS-45402	Gas / cond.	2815,5	95,7	350	372,615	Signs of mud in lines after transfer
1,08	"		1	86	PT-1151	Gas / cond.	2815,5	95,7	360	372,615	Gas on glycol side after transfer*
1,09	"		1	112	PT-1163	Gas / mud?	2830,0	97,0	350	360,826	Mud/greasy oil in lines after transfer
1,10	"		1	152	TS-45806	Gas / mud?	2830,0	96,9	390	360,826	Mud/greasy oil in lines after transfer

Table 4.9.2 WFT sample list for 33/12-8 A

Sample List (WFS)

K-no:	55110
Operator:	Statoil
Rig:	Borgland Dolphin
Well:	33/12-8 A

Sample no.	Date	Run no.	Chamber no.	Bottle no.	Sample type	Depth	Res. temp	Vol. ml	P.Res bar	Comments
1,01	25.05.02	1B	803	PT 1166	Gas / cond.	2922	87,9	400	363	Transfer ok
1,02	"	1B	852	PT 3153	oil	2922	88,4	390	363	Transfer ok
1,03	"	1B	855	PT 1007	oil	4565	110,8	380	419	Transfer ok
1,04	"	1B	927	PT 3182	oil	4565	110,9	390	419	Transfer ok
1,05	"	1B	972	PT 3105	water	4606	111,8	400	418	Transfer ok
1,06	"	1B	973	PT 2056	Gas / cond.	4136	107,2	210	415	Leak during transfer might have damaged sample
1,07	"	1B	173	PT 3108	Gas / cond.	4136	107,3	370	415	Transfer ok
1,08	"	1B	650	TS 46407	Gas / cond.	4033	106,7	350	413	Transfer ok
1,09	"	1B	768	TS 4509	oil	2954	95,6	270	365	Leak during transfer might have damaged sample
1,10	"	1B	769	TS 1164	Gas / cond.	2906	93,7	380	363	Transfer ok
1,11	"	1B	773	TS 5008	Gas / cond.	2867	92,3	390	374	Transfer ok
1,12	"	1B	776	TS 3505	Gas / cond.	2867	92,3	320	374	Transfer ok

4.10 Formation temperature

Figure 4.10.1 shows measured temperatures from wireline logs in wells 33/12-8 S and 33/12-8 A.

Figure 4.10.1 Formation temperature for Well 33/12-8 S &-8 A

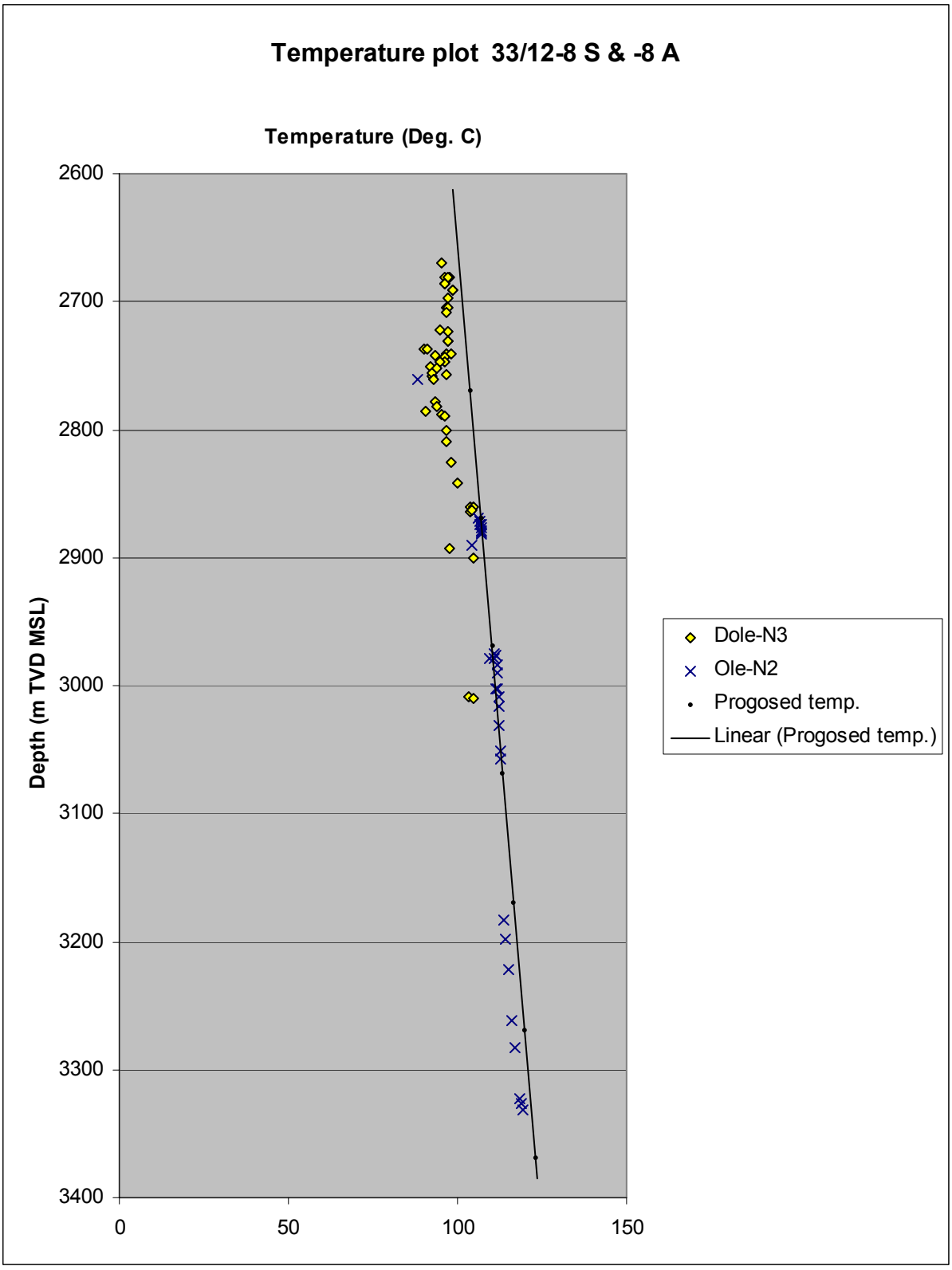


Table 4.10.1 Measured Wireline temperatures in 33/12-8 S

Depth m MD RKB	Depth m TVD MSL	Log. run	Temp. (deg. C)
2974,9	2785,6	1A	90,6
2937,0	2758,0	1A	92,4
2936,5	2757,6	1A	96,9
2922,9	2747,6	1A	94,6
2922,0	2747,0	1A	96,0
2917,0	2743,4	1A	96,3
2914,0	2741,2	1A	96,5
2914,0	2741,2	1A	98,1
2900,0	2731,0	1A	97,4
2899,4	2730,5	1A	97,1
2890,0	2723,7	1A	97,0
2869,0	2708,5	1A	96,6
2864,0	2704,9	1A	96,5
2864,0	2704,9	1A	97,1
2853,0	2697,0	1A	97,2
2845,0	2691,2	1A	98,7
2845,0	2691,2	1A	98,4
2838,0	2686,2	1A	96,4
2837,5	2685,9	1A	96,1
2830,0	2680,5	1A	96,0
2815,5	2670,1	1A	95,5
2815,5	2670,1	1A	95,7
3288,0	3009,0	1A	103,4
3288,5	3009,4	1A	104,5
3135,0	2900,5	1A	104,6
3085,0	2864,6	1A	103,9
2830,0	2680,5	1A	97,8
2830,0	2680,5	1A	97,3

Table 4.10.2 Wireline temperatures in 33/12-8 A

Depth m MD RKB	Depth m TVD MSL	Log. run	Temp. (deg. C)
3475	2890,85	1B	103,6
3545	2891,70	1B	104,8
3622	2893,60	1B	104,3
3962	2900,78	1B	106,3
4000	2902,90	1B	106,6
4035	2905,20	1B	106,8
4075	2908,10	1B	107,1
4115	2910,60	1B	107,3
4556	3005,50	1B	110,8
4559	3007,19	1B	111,3
4564	3009,95	1B	110,8
4573	3014,92	1B	111,6
4584	3021,00	1B	111,6
4605	3033,10	1B	111,8
4617	3039,90	1B	112,1
4629	3047,00	1B	112,2
4654	3061,90	1B	112,4
4686	3081,80	1B	112,5
4697	3088,70	1B	112,7
4876	3213,60	1B	113,8
4896	3228,90	1B	114,3
4926	3252,70	1B	115,0
4975	3293,30	1B	116,0
4999	3313,50	1B	117,0
5045	3353,20	1B	118,4
5050	3357,60	1B	119,0
5055	3362,00	1B	119,4

4.11 Experiences / recommendations

Well 33/12-8 S proved a 5 m TVD oil column in the Statfjord Formation. This discovery makes presence of hydrocarbons in prospect north of well 33/12-8 S; N4 and N5 probable. Prospects N4 and N4 had from before a very high probability of containing hydrocarbons, 71%. Regarding the last official estimate, N4 and N5 represents 1,6 x 10^9 Sm^3 (recoverable) gas and 0,6 x 10^6 Sm^3 (recoverable) oil, given a positive hydrocarbon finding.

5 Drilling operations report

5.1 Comparison final / original well design

Well 33/12-8 S was drilled mainly as planned after the well programme. The Statfjord Formation was interpreted to have a five meters hydrocarbon column at top (see fig. 5.1.1 and 5.1.2).

Well 33/12-8 A was geosteered. After drilling out of the Tarbert Formation and confirming drilling into the Heather Formation, in segment N2, it was planned to drop the angle of the well and get straight back to the Tarbert Formation. However, the Powerdrive did not manage to drop the angle fast enough and the well drilled a long sequence in the Heather Formation before the Powerdrive managed to steer back into the Tarbert Formation. The steering problem mentioned above led to problems of reaching helping point one (H1), with the planned inclination of 65 degrees. H1 was reached with approximately 55 degrees and made it render difficult to accomplish one of the goals with this well, namely to drill the well in a good Tarbert sand long enough to confirm an eventual hydrocarbon contact in this sand (see fig 5.1.3 and 5.1.4).

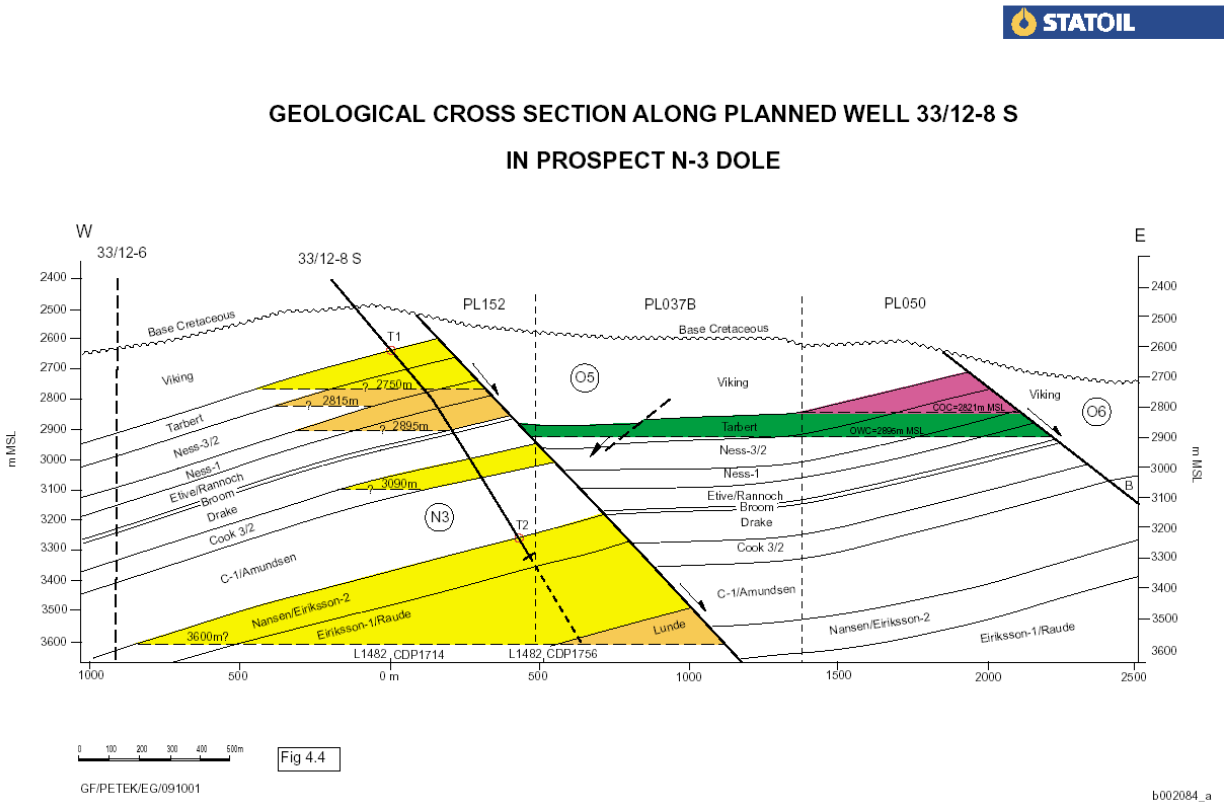


Figure 5.1.1 Geological cross section along planned well 33/12-8 S in prospect N3-Dole.

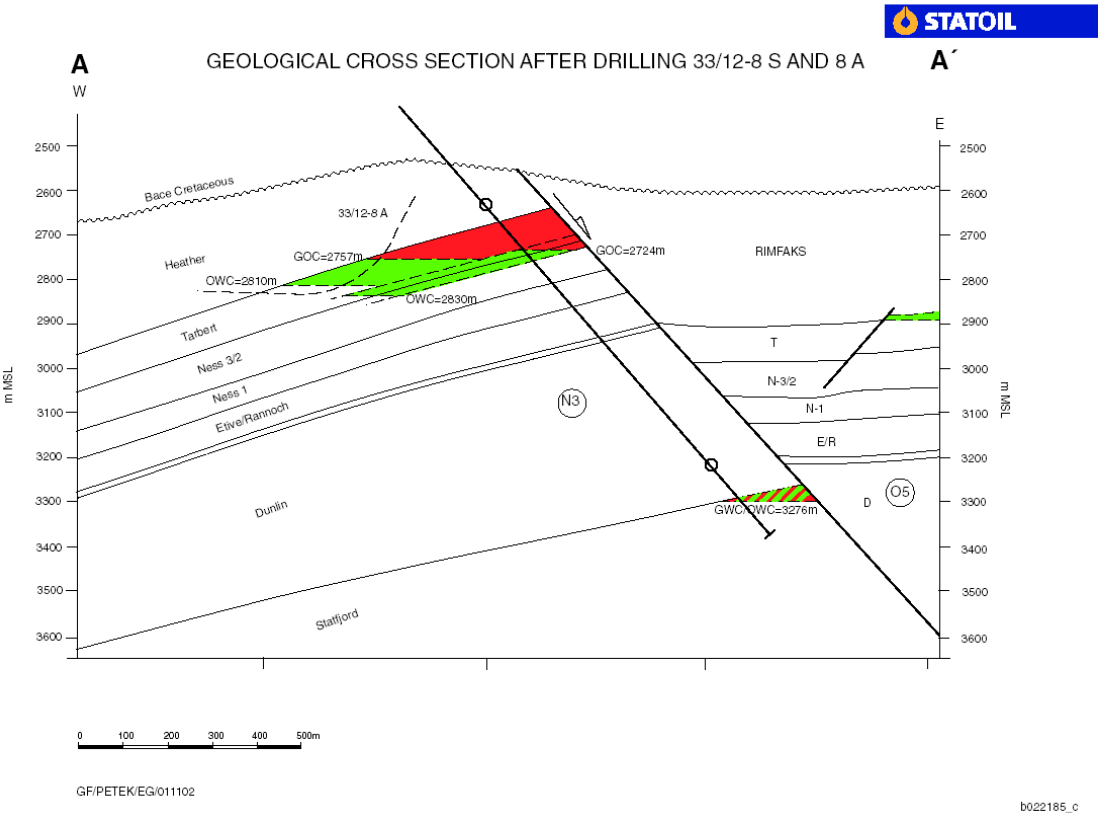


Figure 5.1.2 Geological cross section of well 33/12-8 S, after drilling.

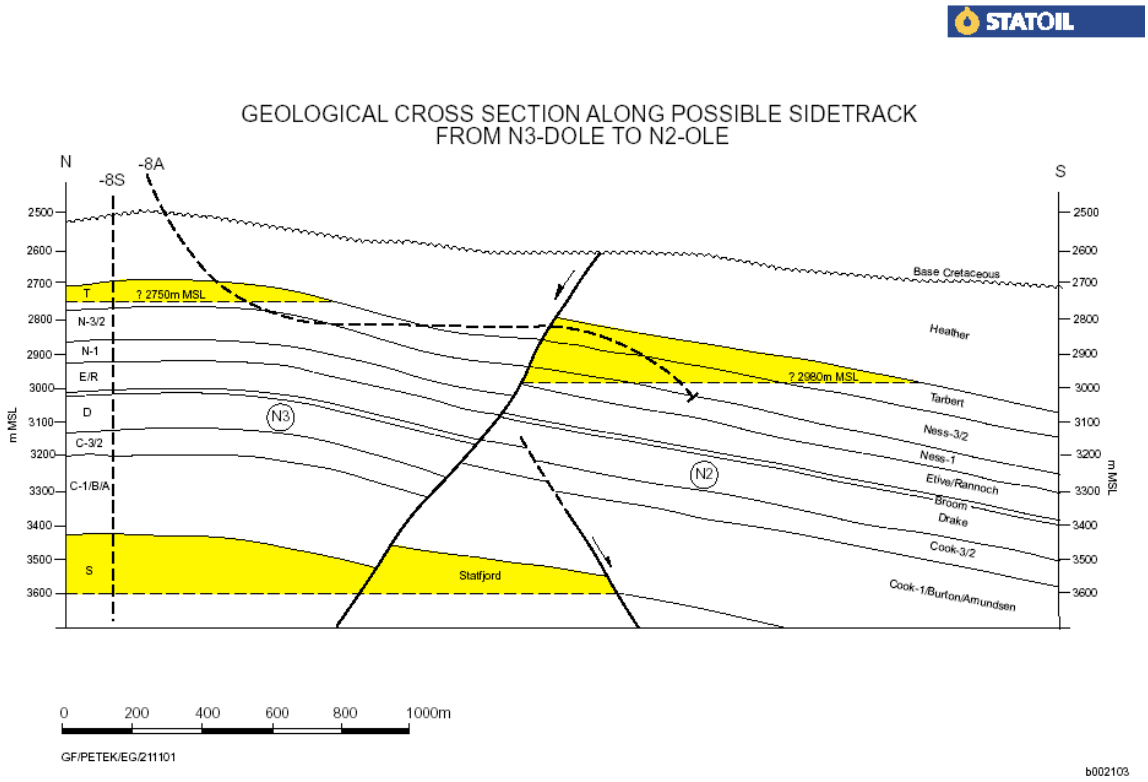


Figure 5.1.3 Geological cross section along the possible sidetrack from N3-Dole to N2-Ole.

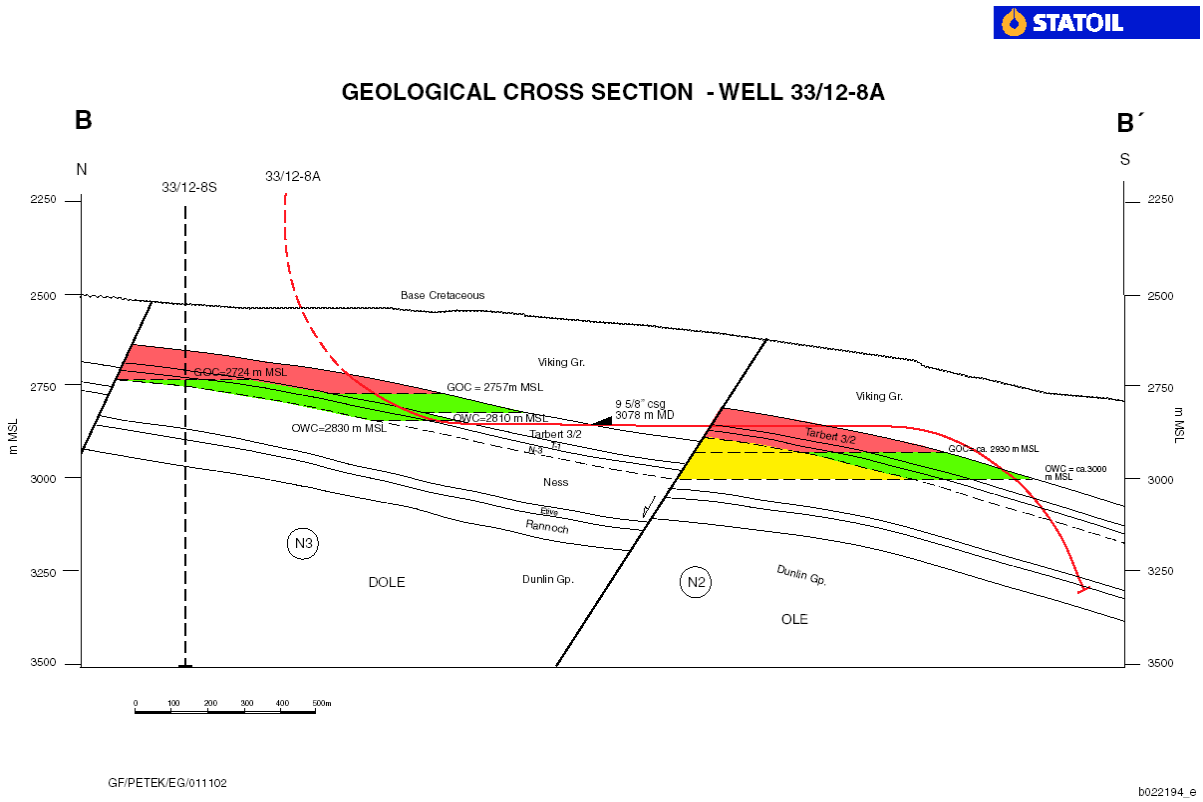


Figure 5.1.4 Geological cross section along sidetrack from N3-Dole to N2-Ole, after drilling.

5.2 Rig move and anchor handling

Borgland Dolphin was moved from Statfjord East to 33/12-8 S well location in 7 hours. The anchor handling was performed in 19 hours. Experienced problems setting anchor 1 and 4 (6 hrs downtime). See operational listing for further details.

5.3 36" Hole section (167 m to 230 mMD)

Drilling

- Drilled 36" hole from seabed, 167 m MD to 230 m MD, in one run.

Bit run

- From 167 m MD to 230 m MD.
- Run #1: 17 ½" x 26" x 36" hole opener assembly. Bit; Smith MGSSH+ODC.
- Comments: The purpose of this hole was to drill 36" hole as vertical as possible to TD of section.

MWD/BHA

- Anadrill, MWD.
- Hole opener assembly.

MUD

- The section was drilled with seawater from 167 m to 230 m MD. 20 m^3 Hi Vis was swept at TD. The well was displaced to 1,40 g/cm^3 EMW mud before pulling out of hole.

30" Condutor

- Housing: 0,50 deg.
- Shoe is set at 227 m MD (227 m TVD).

Cement job

- Lead slurry: 15,8 m^3, 1,56 g/cm^3 EMW lead slurry.
- Tail slurry: 15,8 m^3, 1,95 g/cm^3 EMW tail slurry.

5.4 26" Hole section (230 m to 744 m MD)

Drilling

- Drilled 26" hole from 227 m to 744 m MD, in one run.
- **Well profile;**

Inclination:	Start:	0,36º	End:	0,26º
Azimuth:	Start:	331º	End:	351º

Bit run

- From 227 m to 744 m MD.
- Run # 2: 26" Security XT02CP.

MWD/BHA

- Anadrill's MWD and CDR (no conventional motor used in this assembly).

MUD

- The section was drilled with seawater from 227 m to 744 m MD. 20 m^3 Hi-Vis was swept at TD. The well was displaced to 1,20 g/cm^3 EMW mud before pulling out of hole.

20" Casing

- Shoe is set at 737 m MD (737 m TVD).

Cement job

- Lead slurry: 77,2 m^3, 1,56 g/cm^3 EMW lead slurry.
- Tail slurry: 46,2 m^3, 1,92 g/cm^3 EMW tail slurry.

LOT

- Performed LOT equivalent to 1,75 g/cm^3 EMW.

5.5 17 1/2" Hole section (744 m - 2077 mMD)

Drilling

- Drilled 17 1/2" hole from 737 m MD to 1479 m MD. POOH to change bit.
- Drilled 17 1/2" hole from 1479 m MD to 2077 m MD.

- **Well profile;**

Inclination:	Start: 0,26º	End:	23,09º
Azimuth:	Start: 351º	End:	73,4º

Bit run

- Run # 3: From 737 m MD to 1479 m MD. 17 ½" Hughes MXT03DX.
- Run # 4: From 1479 m MD to 2077 m MD. 17 ½" Smith 10GMODPD.

MWD/BHA

- Anadrill's MWD/PWD and CDR sensors were incorporated in the BHA for the 17 ½" section. BHI's M1XL X-Treme motor was used during the first run in the 17 ½" section. During the second run the Navidrill M1/ XL conventional motor with 1,2 deg bend was used to TD for the section.

MUD

- 1,15 SG – 1,45 g/cm^3 EMW Glydrill mud was used.

13 3/8" Casing

- Set shoe at 2067 mMD (2033 m TVD).

Cement job

- Slurry: 21,4 m^3, 1,90 g/cm^3 EMW.
- Estimated top of cement: 1867 m MD.

FIT

- Performed FIT equivalent to 1,74 g/cm^3 EMW.

5.6 8 1/2" Hole section (2077 m - 3750 mMD)

Drilling

- Run # 5: Drilled 8 ½" hole from 2067 m MD to 3643 m MD.
- Run # 6: Drilled 8 ½" hole from 3643 m MD to 3750 m MD.

- **Well profile;**

Inclination:	Start:	23,09º	End:	45,8º
Azimuth:	Start:	73,40º	End:	91,7º

Bit run

- Run # 5: 8 1/2" Hughes BX 606. From 2067 m MD to 3643 m MD.
- Run # 6: Lyng LD 470 HG. From 3643 m MD to 3750 m MD.

MWD/BHA

- Anadrill's MWD/PWD and CDR sensors were incorporated in the BHA for the 8 ½" section. BHI's Navidrill M1/ XL conventional motor with 1,0 degree bend was used in the 8 ½" section.

MUD

- 1,52 – 1,62 g/cm^3 EMW Versavert OBM was used.

5.7 12 1/4" Hole section (2077 m - 5098 m MD) Well; 33/12-8 A

Drilling

- Drilled 12 1/4" hole from 2067 m MD to 5098 m MD, in 4 runs.

- **Well profile;**

Inclination:	Start: 23,09º	End:	29,5º
Azimuth:	Start: 73,40º	End:	249º

Bit run

- Run # 1: 12 1/4" Hycalog RSX 130 DF. From 2067 m MD to 2282 m MD.
- Run # 2: 12 1/4" Hycalog RSX 130 DF. From 2067 m MD to 2411 m MD.
- Run # 3: 12 1/4" Hughes Christensen MXC09DDT. From 2411 m MD to 2814 m MD.
- Run # 4: 12 1/4" Hycalog RSX 130 DF. From 2814 m MD to 5098 m MD.

MWD/BHA

- Schlumbergers MWD/ CDR and PWD sensors were incorporated in all the BHA runs in the 12 ¼" section. For run 1,2 and 4 in the 12 ¼" section the Powerdrive 3 D system was used. A conventional motor was used during run 3 from 2411 m MD to 2814 m MD .

MUD

- 1,65 g/cm^3 EMW Versavert OBM was used.

9 5/8" x 10 ¾" casing

- Shoe is set at 3678 m MD (2895 m TVD).

Logging

- Performed PEX/AITH (GR/DEN/NEU/RES) logging from 2850 – 3815 and 3694 – 5085 m MD on the first TLC run.
- Performed MDT logging (pressure points and fluids) from 3125 – 5080 and 2850 – 3125 m MD on the second TLC run.

Cement job

- Cement slurry: 44,89 m^3, 1,90 g/cm^3 EMW.
- Top of cement; 2400 m MD (2345 m TVD).

5.8 P&A

RIH with clean out assembly and displaced well from oilbased mud to treated seawater. Inflow tested 9 5/8" x 10 ¾" casing and pressure testet casing to 370 Bar with seawater.
An EZSV bridge plug was run and set at 2645 m MD. A HE-3 plug was set at 645 m MD and tested to 305 Bar / 10 min. Thereby, a junk basket was set on top of HE-3 plug. Before preparing for rig move the BOP and the retrievable guidebase (RGB) was pulled and a wellhead protection structure was installed.

See well schematic in appendix, for further details.

6 Appendix

APP A Operational listing

APP B Directional data, survey listing

APP C Contacts

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APP D Wellsite sample description

APP E MDT-Pressures

APP F Geophysical results

APP G Other reports

APP H Enclosures