Title:		
FINAL WELL REPORT **Drilling and Completion** **License no.: PL 050** **Well: 34/10-A-48/ A-48 A / A-48 B / A-48 B T2**		
Document no.: **GFRESU HF U-02 00039**	Contract no./project no.: **T.O050C.DH.A048** **T.O050C.DH.A048A** **T.O050C.DH.A048B** **T-O050C.DI.A048A**	Filing no.: **34/10-A-48/ A-48 / A-48 B / A-48 B T2**

Classification:	Distribution:
Open	**Open**

Distribution date:	Rev. date:	Rev. no.:	Copy no.:
30.09.2002		**0**	15

Author(s)/Source(s):	
Tor Tennfjord **Stefan Ødegård**	**Stig Gard Paulsen**
Subjects: **INJECTION WELL** **Drilling**	
Remarks:	
Valid from: **Distribution date**	Updated:
Responsible publisher: **TO GF RESU HØBA**	Authority to approve deviations: **TO GF RESU HØBA**

Techn. responsible:	Name:	Date/Signature:
Drilling Engineer **TO GF RESU HØBA**	**Tor Tennfjord** **Erik Dyrkolbotn**	5/9-02 Tor Tennfjord 5/9-02 [signature]
Responsible: **Lead Drilling Engineer** **TO GF RESU HØBA**	Name: **Arne Hjelle**	Date/Signature: 5/9-02 Arne Hjelle
Recommended: **Drilling Supervisor** **TO GF RESU HØBA**	Name: **Håkon Sletten**	Date/Signature: 20/9-02 [signature]
Approved: **Manager** **TO GF RESU**	Name: **Arild Hesjedal**	Date/Signature: 23/9-02 Arild Hesjedal

Distribution list

No.	Recipient	Number of copies
K-1, 2	NPD	2
K-3	Norsk Hydro, attn: B. Bue	1
K-4, 5	Technical document centre, DRT	2
K-6	Well file B&B, attn: T. Kjeldaas	1
K-7	Well file PGA, attn: Platform manager	1
K-8	Well file GFA, attn: Drilling supervisor	1
K-9	Prosafe Drilling Service, Sandsli	1
K-10	B&B Document centre, ST-FO, G42	1
K-11	NOM BEV DRB, attn:Ivar Morvik	1
K-12	Manager TO GF RESU HØBA, Erik Vikane	1
K-13	Manager TO GF RESU, attn: Arild Hesjedal	1
K-14	Sigve Hovda, GF RESU KOMP	1
K-15	Manager GF RESU HØBA Dril., attn: Håkon Sletten	1
K-16	LBI GF RESU HØBA Dril. , attn: Arne Hjelle	1
K-17	Manager GF RESU HØBA Comp., attn: Trond Hanssen	1
K-18	LBI GF RESU HØBA Comp., attn: Johan Fredrik Larsen	1
K-19	Manager GF RESU HSLC Dril., attn: Rune Gåsø	1
K-20	LBI GF RESU HSLC Dril., attn: Marit Kvinge	1
K-21	LBI B&B GFSAT , attn: Jens Louis Kvalsund	1
K-22	Manager B&B VFR, attn: Arvid Lokøy	1
K-23	Erik Dyrkolbotn, GF RESU HØBA	1
K-24	Svein Erik Ingdahl, NOM BEV DRB	1
K-25	Audun Netland, NOM BEV DRB	1
K-26	Stig Gard Paulsen, GF RESU HØBA	1
K-27	GF RESU HØBA	1

Table of contents

1 General well data

Drilling rig:	Gullfaks A
Licence number:	PL 050
Well name:	34/10-A-48 / A-48 A /A-48 B /A-48 B T2
Slot:	34 (south shaft)
Type of well:	Water Injector / Oil Producer
Water depth / air gap:	134.3 m MSL / 82.2 m RT
Distance RT - Wellhead:	38.8 m
Primary objective:	Water injection in Tarbert
Completion type:	7” monobore
Drilling of well 34/10-A-48 started:	12.12.01 @ 05:30 hrs.
Drilling of well 34/10-A-48 B T2 completed:	12.05.02 @ 07:00 hrs.
Initial completion of well 34/10-A-48 B T2 started:	12.05.02 @ 07:00 hrs.
Initial completion of well 34/10-A-48 B T2 completed:	27.05.02 @ 03:30 hrs.
Well status:	Perforated in Tarbert from 6922 m to 6931 m MD. Injecting water, with rate up to 9000 Sm3 / day.

Structure centre coordinates :

Geographic:	Lat.	61° 10' 33.982" N	Long.	02° 11' 20.935" E
UTM:		6782834.69 m N		456386.02 m E

Wellhead coordinates :

Rectangular:	4,19 m S	34,05 m E (from structure center)

2 Exemptions

Exemption from	Report no.	Date	Title
Main drilling programme	BGC96015F		Sementering av 20” casing
Main drilling programme	GFA99014F		Avledersystem.
Main drilling programme	GFA99015F		Trykktesting av avledersystem
Main drilling programme	GFA F01-00025	01.12.01	Sementering av 9 5/8” liner over Kritt.
Main drilling programme	GFA F-01 00027	12.12.01	Formasjonsstyrke under 32” lederør
Main drilling programme	GFA F-01 00024	01.01.02	Fravik 13 3/8” FR design 34/10-A-48 C
WR-0442	GF F-01-00026	03.12.01	Tidlig oppstart av boreoperasjoner på 34/10-A-48
Drilling Programme 34/10-A-48	GF-RESU-U-0100162	22.12.01	Boring av 17 ½” seksjonen med MWD directional og gamma
AR-003	GFA F-02 0001	06.01.02	Fravik BOP-test brønn 34/10-A-48
Drilling Programme 34/10-A-48		28.02.02	Forlengelse av brønn A-48 A for å undersøke et prospekt

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

3.1 Goals and results of the well

The main goals for this well were:

- Drill and complete the well without any injuries to personnel or equipment.
- Drill and complete the well and achieve the expected production.
- Drill the well within budget days and costs.

All goals were achieved. In addition, the well will serve as an injector for approx. one year before start of production.

3.2 RUH

Number of RUHs:	180
Number of lost time accident:	0

3.3 Quality

There were four major equipment / operational failures in this well:

- Negative pressure-test on the 9 5/8” liner-packer. A RTTS was run to localize the leak-point, and an extra packer was run. Prior to the negative test, the 9 5/8” liner was lost while running in hole. This is likely to have damaged the packer. Lost time was 73 hrs.
- The 7” liner could not be run to TD on first attempt. The liner had to be pulled out and a wipertrip was performed. Lost time: 226 hours.
- On the wipertrip above, a fish was left in hole. This caused the installation of a whipstock. Approx. 260 hours was used to install the whipstock and mill through the 7” liner.
- When cleaning the well prior to running completion, the clean-up string parted and a fish was left in hole. Fishing of the lost equipment gave 37 hrs lost time.

Distribution of down time can be seen in figure 3.5.5
Synergi reports are summarized in appendix 6.

The well was drilled without any down-hole tool failure. This should be recognized as a very good performance by the different service-companies.

3.4 *Experience listing*

System/Event	D time hrs	Experience	Immediate solution	Solution recommended for future	Ref.
24" section					
Did not get planned FIT		Formation leaked off at 1.23 s.g, expected > 1.28 s.g	Squeezed formation, no increase in LOT.	Reduce FIT to minimum required.	
12 ¼" section					
Lost 9 5/8" liner/negative pressure test on packer.	73	Lost liner when running in on HWDP.	Went in and screwed into lost connection. Set liner as planned. Sat extra packer.	Correct handling equipment & inserts for different sizes of string.	
8 ½" section					
Lost circulation when circulating after TLC		Pumps were brought too fast up, this can have initiated the loss.	Hole became unstable, and section had to be plugged back.	Increase flow in small steps and verify stable returns on each step.	
Sagging of barite during TLC-logging		Low flow-rates during TLC-logging, combined with high mud weight and high inclination will increase sagging-tendencies.	Tried to increase flowrate	Avoid TLC if possible.	
Did not get 7" liner to TD in first attempt.	226	Liner could not be worked to TD. Shoe on liner was severely damaged	Pulled out and performed wiper-trip with bullnose & hole-opener	Run reamer-shoes on similar jobs, standard liner shoe is not suited for this operation.	
Lost fish in hole on wipertrip		Bullnose, sub and XO was backed off and left in hole.	Ran 7" liner to 20 m above TD of hole. Installed whipstock in liner and milled through.	Ensure make-up of equipment.	

System/Event	D time hrs	Experience	Immediate solution	Solution recommended for future	Ref.
6" section					
Starter mill stopped up after milled 3 m		Progress stopped up after 3 m of milling. Starter mill was completely worn.	Went in with a similar mill-assy., milled only 0.7m before stopping. A third run with a PDC-bit had to be performed prior to running in with drilling assy.	Use PDC starter mills on first run.	
Completion					
Lost part of clean-up string in hole	37	Clean-up string was found parted in junk basket	RIH with fishing assy. and fished lost equipment		

3.5 Time distribution

3.5.1 Overview of time distribution

Distribution of down time	Hrs	Cause of waiting time	hrs
Rerun 7" liner	226	Waiting on cranes	5
Downhole equipment	20	WOW	25.5
Prosafe	109	ProCut shutdown due to gas-alarm	3
Lost 9 5/8" liner / negative pressuretest 9 5/8" packer	73	DDM hydraulic loop blown into derrick	3
Parted clean-up string	31	Modifying fishing assy. for washpipe	6
Other	43.5		
TOTAL D-TIME	502.5	TOTAL W-TIME	42.5

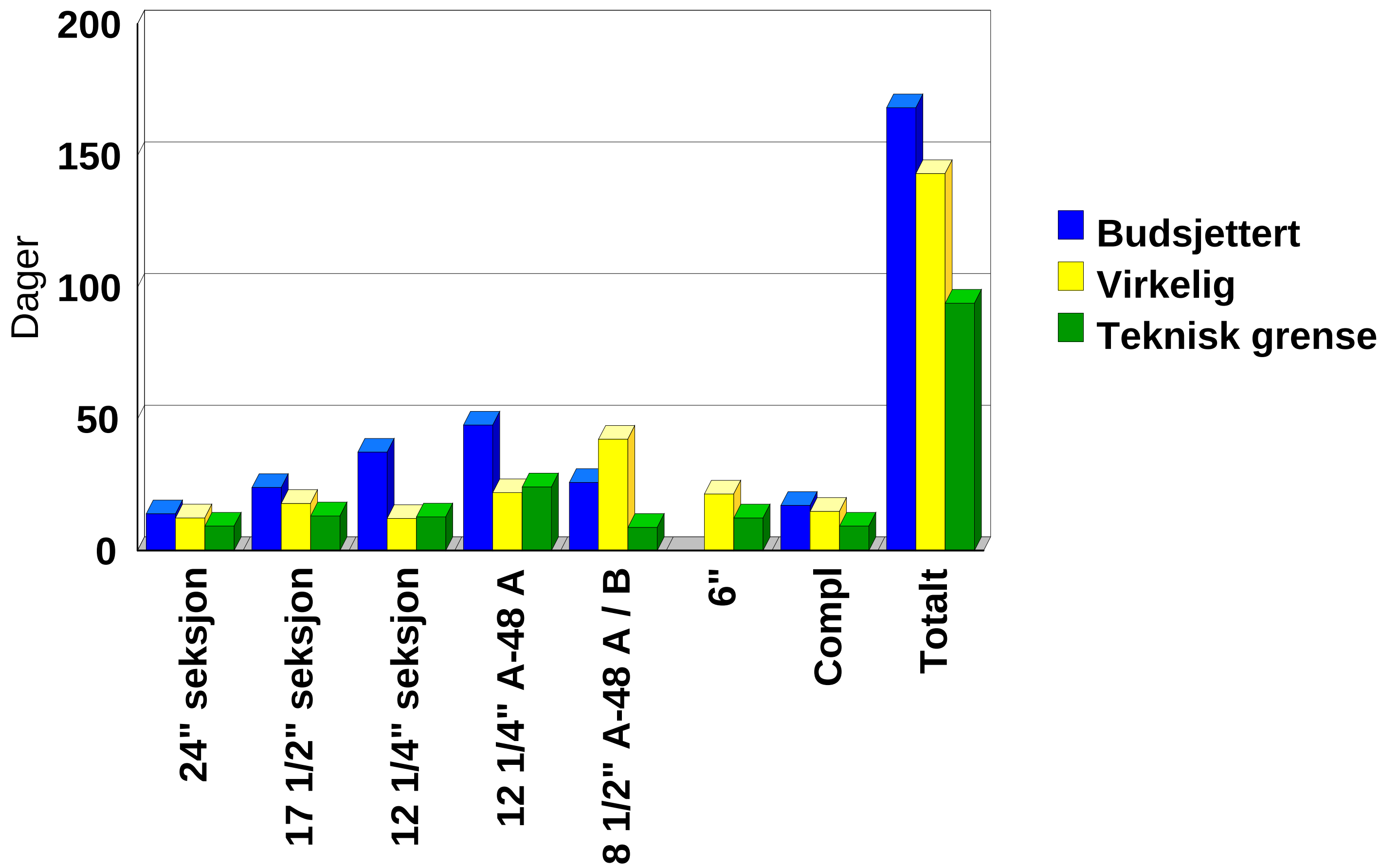
Activity	Days	Hrs	%
Budget time - drilling phase	149		
Optimum time - drilling phase[1]	85		
Actual time - drilling phase	128.3		
Budget time - initial completion phase	19.2		
Optimum time, completion phase[1]	9.3		
Actual time - initial completion phase	14.9		
Planned total operation time	168.2		
Actual total operation time	143.2		
Days ahead plan	25		
Total D+W-time		545	15.9
Total K-time		190	5.5
Efficiency, drilling phase			84.9
Efficiency, completion phase			90.0
Total Efficiency			85.4

1) Optimum time was estimated on workshops where the operations were planned in detail with the contractors.

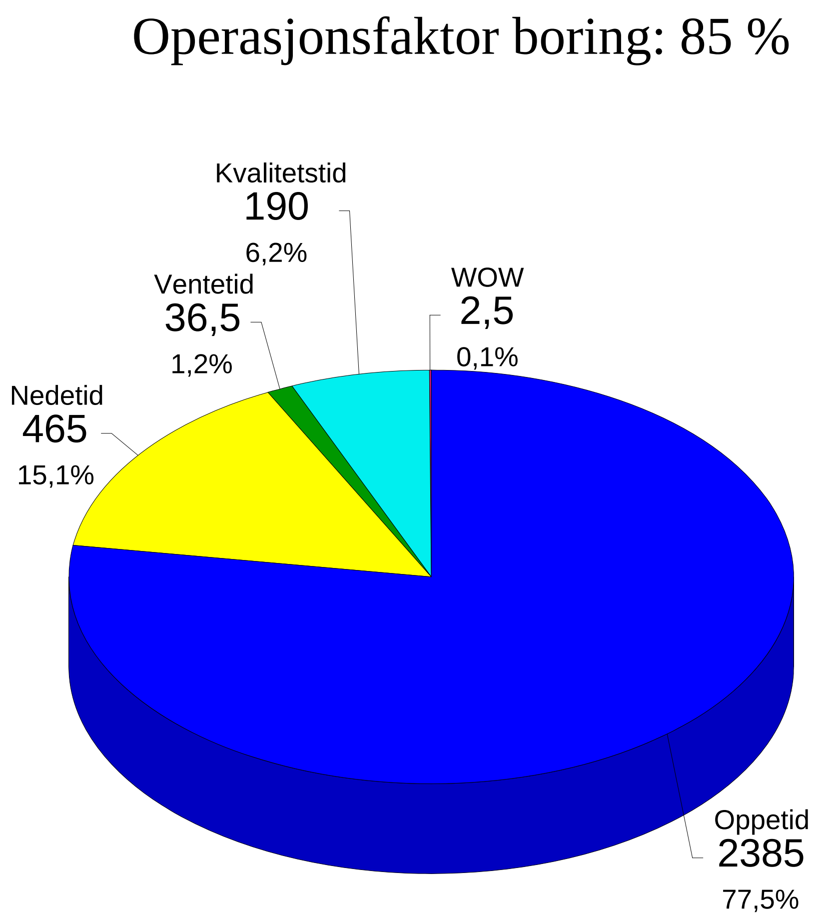
The budget time for the drilling phase was estimated by two different methods. First by gathering data and comparison from other similar Gullfaks wells. The time estimate was also found by Well Time Estimator. Both individual methods gave a time estimate at about 149 days for the drilling phase.

The well was extended from the planned TD in order to investigate a possible new Cretaceous-prospect. No extra budget was given for this work. Time used to drill to the new prospect was 21.5 days.
The down time distribution is shown in Section 3.5.5.

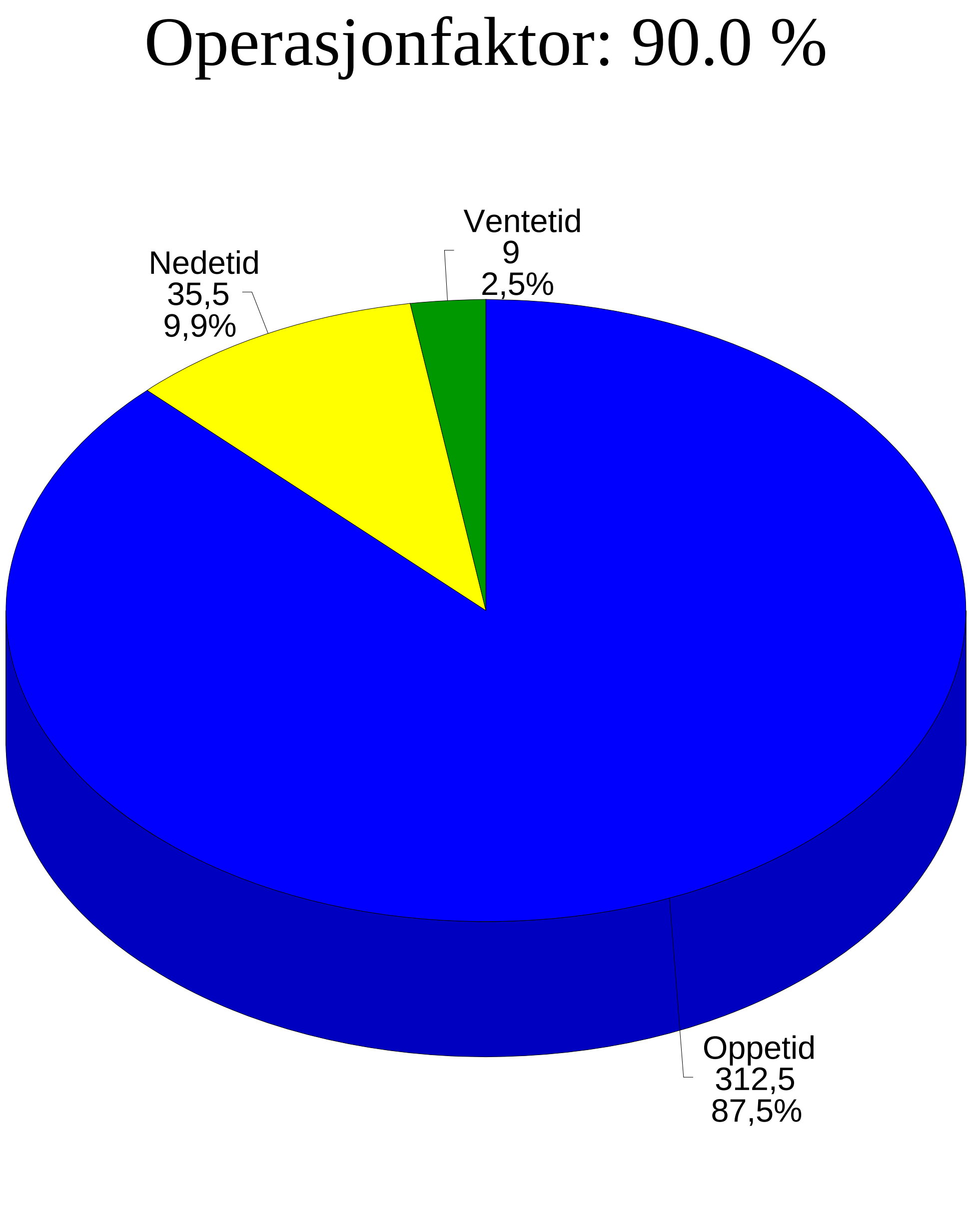
3.5.2 Comparison of budget, actual and optimum time



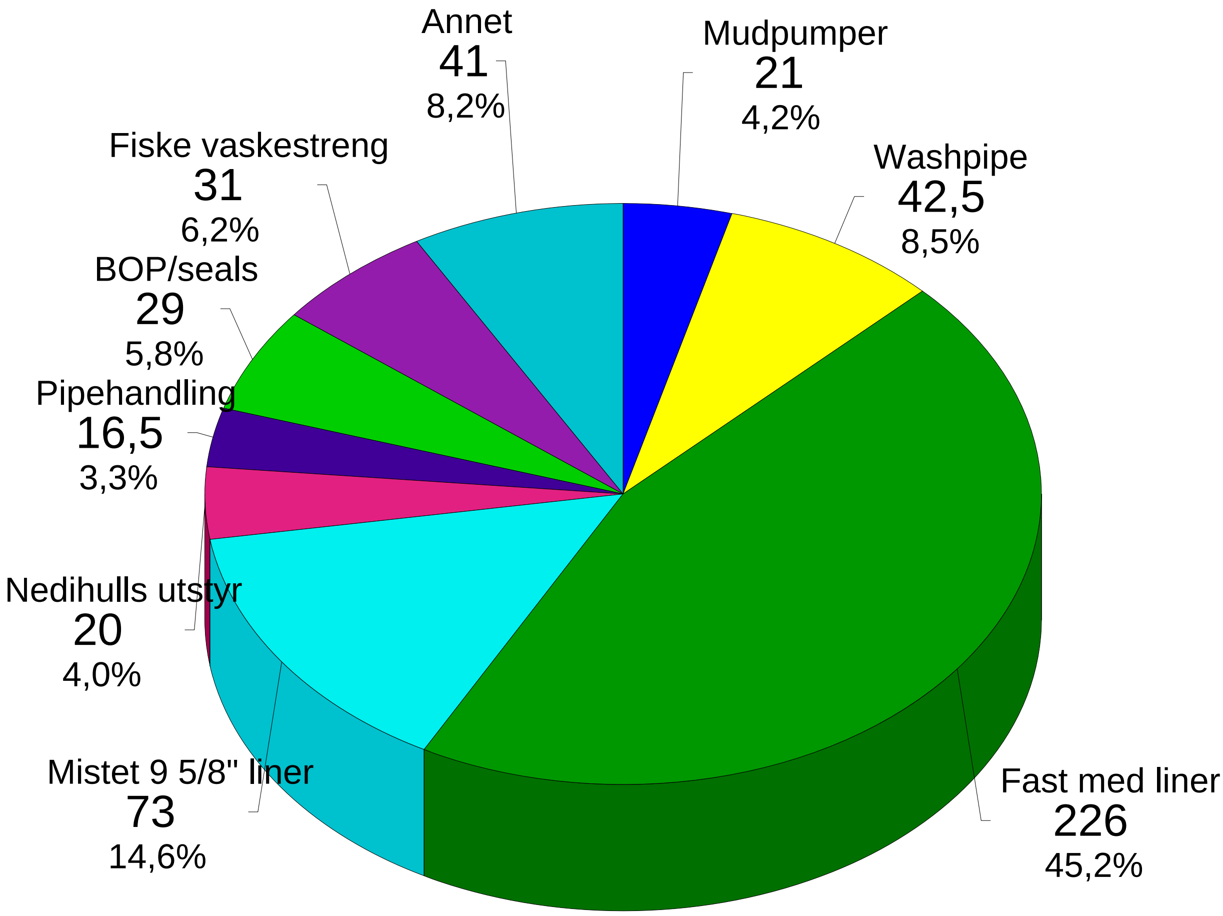
3.5.3 Operation Factor, Drilling



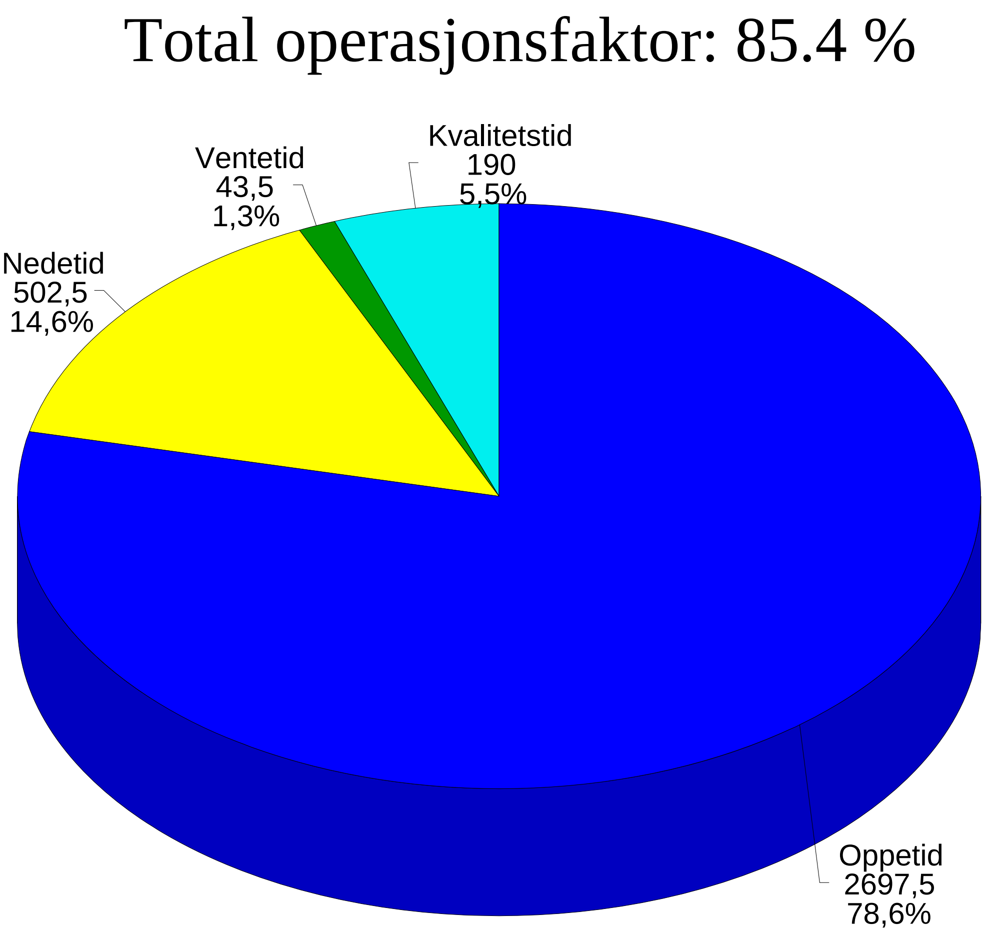
3.5.4 Operation factor, completion phase



3.5.5 Down time



3.5.6 Total operation factor



3.6 Real costs/ Cost estimate discussion

Budget, drilling: 164 M NOK
Actual cost, drilling: 148 M NOK (estimated pr.31.08)

Budget, completion: 60 M NOK (including perforation)
Actual cost, completion: 32 M NOK (estimated pr. 31.08, including perforation)

The cost estimate for drilling was found from the simple formula:

- Daycost = 1.1.MNOK x 149 days = 164 MNOK

With the real time used for the well, the costs calculated from the above would give a total drilling cost of 141 MNOK.

The increased actual cost compared to the calculated can be explained by the extra drilling length of the well. Planned drilling length was approx. 8000 m. Actual drilling length is approx. 9550 m, an increase of approx. 20 %.

The reduced completion-cost is caused by the fact that the well was planned with a gravel-pack installation but is completed with a standard cemented liner. The well is also completed with a carbon steel liner and tubing, compared to planned 13 % Cr steel.

3.7 Real time/ time estimate discussion

The budget time for the drilling phase was, as mentioned earlier, estimated by two different methods:

1) Gathering data/comparison with other similar Gullfaks wells
3) Well time estimator (WTE) simulations.

Both individual methods gave a time estimate at about 149 days for the drilling phase. WTE gave a P10 estimate of 88 days and a P90 estimate of 206 days. WTE is based on experience from former wells drilled on Gullfaks.

Drilling to the additional prospect in Cretaceous was not included in these budget-numbers. The work comparable to the budgeted work was carried out in 106.8 days; i.e. 42.2 days ahead of P-50 budget.

The most time saving activity was drilling of the two 12 ¼” sections. Both sections were drilled with rotary steerable systems, with high rate of penetration. Maximum penetration for one day (00:00 – 24:00) was 782 meters. There were neither down-hole tool-failures in the entire well, a quite unique result.

Detailed information for used time and meter/day for the different wellpaths is given in appendix 8.3.

3.8 Documents written in advance of the well

3.8.1 "Risikovurdering 34/10-A-48 / A-48 A / A-48 B" (GF RESU U-01 00137)

Based on a similar risk-evaluation done for well A-47, a document going through the different operations containing risks were made. Risk reducing actions were listed for critical events.

3.8.2 Individual drilling and completion programme 34/10-A-48 / A-48 A / A-48 B (GF RESU U-01 00162)

A standard drilling programme was written for this well.

3.8.3 Amendment to Drilling Programme Well 34/10-A-48 / A-48 A / A-48 B (GF RESU U-02 00009)

Prior to plugging A-48 and start drilling A-48 A, an amendment was written due to changed plans for drilling the reservoir in A-48 A. This included both changed targets for the well, changed wellpath and changed casing programme.

3.8.4 Amendment # 2 to Drilling Programme Well 34/10-A-48 / A-48 A / A-48 B (GF RESU U-02 00021)

During drilling of the 8 ½" section in A-48 A, a new prospect further west came up. It was decided to drill to the new prospect as an extension of the 8 ½" hole, and the amendment was then written.
During TLC-logging of A-48 A, the well became unstable. Finally well A-48 A had to plugged back. The planned 8 ½" extension was therefore changed, and the amendment was never distributed.

3.8.5 Amendment # 3 to Drilling Programme Well 34/10-A-48 / A-48 A / A-48 B (GF RESU U-02 00023)

After having plugged back A-48 A to the 9 5/8" liner-shoe, a new wellpath was made for A-48 B. Due to the experienced lost circulation and hole-problems in A-48 A, it was decided to drill to the Cretaceous prospect in 6" hole-size. A new amendment was therefore made.

3.8.6 Peer assist

A peer assist meeting was held prior to start drilling of the well.

3.9 *Workshop and project plan*

Two "Workshops" were held prior to drilling this well. The participants were Statoil onshore/ offshore personnel and personnel from Prosafe and all the service companies involved. The operation was planned in detail, and parallel activities and checkpoints were discussed. In addition, optimum time estimates for the operations were estimated. Times for main activities were systematically put together in a project plan implemented in Safran Planner, the plan also refers to different detail procedures and check lists. See Appendix 3.

The experiences from this project were:

Advantages:

- Both onshore and offshore personnel got more involved and showed more ownership in the operation.
- The detailed planning onshore helped to improve the planning offshore.

Disadvantages:

- If the operation takes unexpected turns, it can become quite time consuming to update the plan.

Recommendations:

Workshops are useful for engaging the personnel and going through the operation in detail. It helps both planning and building a team spirit.

If possible, the workshop(s) should be held prior to distribution of the drilling programme, so that eventual changes of plans based on recommendations from the workshop(s) can be included in the programme.

The detail procedures should be revised and/or written in the workshops, they should not be more detailed than necessary. They will then be the basis for the procedures written offshore during the operation.

It should be unnecessary to have to update the Lotus 123 time planner as well as the Safran Planner plan. As of now, the Lotus 123 time planner is primarily used to make the time-depth curve. This curve should be obtained from either DBR or Safran Planner.

4 Activity Highlights

Well 34/10-A-48 / A-48 A / A-48 B / A-48 B T2 was a very challenging well. The well was drilled to TD 7725 m MD at a TVD of 2088 m. This gives a MD / TVD-ratio of 3.70; the highest ever drilled by Statoil. The 6” hole section (7023 m- 7725 m) is among the two deepest 6” sections drilled in Statoil.
A 7” whipstock was installed at 7023 m MD. This is the deepest installation in the North Sea.

Changing wellplans throughout the well called for short-time planning, but the well still came out well ahead of budget.

4.1 24" section

Section overview

Interval:	361 m MD (361 m TVD) to 1232 m MD (1199 m TVD)
Casing:	20” casing down to 1227 m MD / 1196 m TVD
Section length:	871 m
Inclination:	Build from 0º to 32º
Azimuth:	Kick off i 140° direction, turn to 225°
Mud:	1.03 – 1.20 SG WBM

When performing the planned FIT to 1.28 s.g. at 361 m, the formation leaked off at 1.23 s.g. A cement-squeeze of the shoe was performed, but resulted in a new LOT of 1.24 s.g. A possible reason for the low formation strength compared to previous wells on GFA could be that the test is taken some meters deeper in this well. Usually the tests are taken just below the 32” conductor at approx. 351 m TVD. Formation-compaction after driving the conductors can have contributed to a higher strength than normal below the conductor shoes.

Started reporting on 24” section after second LOT, the 12th of December 2001 @ 05.30 hrs.
The section was drilled to TD in three runs, one more than planned. .

The challenge of the section was to avoid the surrounding wells and nudge the well in the desired direction. This was done successfully, and a quite smooth wellpath was made.

The section was drilled in 12.4 days, 1.6 day ahead of budget.

Made up and RIH with 17 ½” BHA. At 1104 m MD it was discovered that the float was leaking and the BHA was pulled out.

Performed a LOT to 1.64 s.g. prior to drilling the 17 ½” section.

4.2 17 ½” section

Section overview

Interval:	1232 m MD (1199 m TVD) to 2751 m MD (1749 m TVD)
Casing:	13 3/8” casing down to 2747 m MD / 1748 m TVD.
Section length:	1519 m
Inclination:	Build from 32° to 78°
Azimuth:	Hold 221°
Mud:	1.30 – 1.59 WBM

The section was drilled in two runs as planned. A low KCL-content was tried in the upper part of the section to try to improve hole-cleaning. Due to surface handling problems, the KCL had to be raised to standard content at around 1700 m MD. Backreaming had to be performed on both trips out.
The section was drilled in 17.9 days, 6.1 days ahead of budget.

Performed a LOT to 1.79 s.g. prior to drilling the 12 ¼” section.

4.3 12 ¼” section A-48

Section overview

Interval:	2751 m MD (1749 m TVD) to 5568 m MD (2368 m TVD)
Casing:	Plugged back to 3930 m MD
Section length:	2817 m MD
Inclination:	Build from 78° to 83°, hold, drop to 54°
Azimuth:	221° - 230° - 222°
Mud:	1.65 SG OBM

The section was drilled in one run. Good penetration rate and good hole cleaning was experienced throughout the entire section. At TD, the well was circulated clean and the BHA was pulled out without necessary back-reaming.
Challenges with respect to diff.sticking or lost circulation were anticipated, however no problems were seen.
Only minor amounts of hydrocarbons were encountered, and the well was plugged back with three cement plugs. The kick-off plug from 4100 m to 3900 m was set using the recently developed “Perigon” cement support tool. This is expected to have contributed to the successful kick-off in well A-48 A.
The section was drilled and abandoned in 12.2 days, 25.2 days ahead of budget.

4.4 12 ¼" section A-48 A

Section overview

Interval:	3930 m MD (1749 m TVD) to 6400 m MD (2027 m TVD)
Casing:	9 5/8" liner from 2676.8 m MD to 6346.5 m MD (2003.5 m TVD)
Section length:	2470 m MD
Inclination:	Build from 82° to 90°, hold, drop to 64°
Azimuth:	Turn from 222° to 273 °
Mud:	1.65 SG OBM

The section was again drilled in one run. Good penetration rate and good hole cleaning was experienced throughout the entire section. At TD, the BHA was pulled out without necessary back-reaming.
Original plan was to drill the 12 ¼" section to TD of the well. However, lost circulation was experienced at 6400 m MD, most likely in a coal-stringer. Observed ECD when loss occurred was 1.75 s.g., well below the anticipated fracture-pressure. Losses could not be cured, and it was decided to install the 9 5/8" liner at top of the reservoir and drill a 8 ½" hole to TD.

The 9 5/8" liner was run in hole. During RIH on running string, the liner was lost in hole. A successful re-connection to the running string was done, and the liner was set at planned depth and cemented. Pressure-test of the liner-packer was not achieved. This is believed to be connected to the lost-liner incident.

22 days were used on the section, 25.7 days ahead of budget.

4.5 8 ½" section A-48 A

Section overview

Interval:	6400 m MD (2027 m TVD) to 6860 m MD (2105.5 m TVD)
Casing:	The section was plugged back
Section length:	460 m MD
Inclination:	Build from 64° to 90°, drop to 80°, build to 84°
Azimuth:	273 °
Mud:	1.50 SG OBM

The section was drilled in one run as planned. Good penetration rate and good hole cleaning was experienced throughout the entire section. No back-reaming was required. Loss during drilling was not experienced.

When logging on TLC, the logging string could not pass 6468 m MD. Sagging of barite due to circulation with low rate was observed. The logging cable was pulled out, and circulation with full rate was started. At this point the returns was lost. TLC-string was pulled out and the drillstring was run back in hole. Three Versapac pills were pumped, but loss was not cured. It was attempted to go in to TD, but at 6497 m MD it was observed that the wellpath had been sidetracked. The decision was then made to plug the well back to 9 5/8" shoe.

A 200 m cement plug was set from 6450 m MD to 6250 m MD. Drilling BHA was run in hole, and kick-off was done at 6380 m MD.

4.6 8 ½" section A-48 B

Section overview

Interval:	6380 m MD (2017 m TVD) to 7089 m MD (2181 m TVD)
Casing:	7" liner from 6265.5 m MD to 7069m MD (2181 m TVD)
Section length:	709 m MD
Inclination:	Build from 65° to 75°, hold, build to 90°
Azimuth:	Hold at approx. 273 °
Mud:	1.50 SG OBM

The section was again drilled in one run. Good penetration rate was experienced throughout the entire section. Hole cleaning varied, but was good at high RPM. At TD, the BHA was pulled out without necessary back-reaming.
The 7" liner was run in hole, but could not be worked pass 6437 m MD. Formation changes due to drilling into the Shetland-group is likely to be the reason for the improper hole-quality. The liner was pulled out and a clean-up run with bullnose and 8 ½" hole-opener was performed. When coming out of hole, the bullnose, a bit sub and a cross-over sub was missing and lost in hole.
The 7" liner was run to 7069 m MD, leaving a short distance down to the fish. The liner was cemented back to top of hanger with full returns.

Due to work-over operations on A-32, the well was temporary abandoned after the installation of the 7" liner. A 13 3/8" RTTS was set before the rig was skidded.

4.7 6" section A-48 B T2

Section overview

Interval:	7023 m MD (2180 m TVD) to 7725 m MD (2088 m TVD)
Casing:	No liner installed. A plug was installed in 7" liner @7012 m MD.
Section length:	702 m MD
Inclination:	Build from 86° to 100°, hold, build to 110°
Azimuth:	Hold at approx. 273 °
Mud:	1.61 SG OBM

Due to the fish in the hole below the 7" liner, it was decided to install a whipstock in the 7" liner and drill through the liner, thereby passing the fish in safe distance. The whipstock was set at 7023 m MD and is the deepest whipstock installed by Statoil. The whipstock was set as planned, but the window-milling required three runs, compared to one planned.

Drilling of the 6" hole was done in one run, with penetration rate well above what was expected. Orientation was not achieved in the sand, but could easily be done when drilling in the clay-formations.
Reservoir-sand was not found, and no cement was therefore required to plug the well. A 7" EZSV cement retainer was set at 7012 m MD, and the well was pressure tested to 225 bar.

4.8 Initial completion

The 10 ¾" dummy hanger and the TSR/ TSR extension was installed on the wellhead, before a test plug was set and the HP riser and the BOP re-installed and tested to 345 bar. A leak in the POD had to be repaired. The test plug was then retrieved and a wear-bushing installed in the wellhead.

A clean–up string was run, consisting of a 6"PDC bit on 730m 3 ½" DP to run into the 7" liner, followed by PBR mill assembly, junk basket and brush and scrape assembly on 5" and 6 5/8" DP, to polish and dress the PBR and the 9 5/8" tubing. Also a SABS circulation sub was included in the swash string.

Every stand was scraped down/up/down below 3495 m, and particularly the setting area of the production packer. Backflow was experienced RIH. Mud was circulated and the string rotated at every 5 stand. Finally, the 7" PBR was polished. The mud was then circulated and conditioned at 1600 lpm and 50 rpm. A total of 765 m3 was pumped. (11 hrs).

The OBM was circulated out with an oil based wash-train at 1200 – 2000 lpm, totally 400 m3, at constant DHP. This amounted to a final 220 bar WHP. The well was then pressure tested to 345 bar, followed by inflow testing.

The pits were cleaned in preparation for the water based soap wash sequence. Due to the large volumes involved, all available pits had to be cleaned. The pit cleaning needed 19 hrs.

A 412 m3 water based wash sequence was pumped at 2000 lpm and 50 rpm, while reciprocating the string, followed by sea water to attain satisfactory NTU readings. At the end of this pump sequence, a pressure drop from 284 bar to 180 bar was observed, hence surface equipment had to be checked. No leaks were found and the well was displaced to packer fluid.

POOH it was stated that the TB-Junk Catcher in the wash assembly had parted, leaving the lower 739m of the wash string left in hole. This was successfully fished out utilizing an overshot with grapple.

The 7” scab-liner was run in hole on 5” DP. A small problem was encountered when entering the 9 5/8” liner. Had to rotate ½ turn left and put on 12 ton weight. From 3602m the scab-liner was run on 6 5/8” DP. At correct depth, the hanger was set with 90 Bar and the packer with 20 ton.

The wear bushings were then pulled and the wellhead flushed with a dummy hanger. The exact hanger depth was recorded for later space out purposes.

The production tubing was run in hole in accordance to tally and detailed procedure. Up/down weights were checked and recorded every 10 joints. At 4478 m this amounted to 132 / 96 ton. Before landing the production tubing, the tubing was filled with 2% RX friction reducer. (85m3) in order to facilitate the planned wireline perforation operations. The electric and hydraulic lines were terminated and the hanger finally landed in the wellhead. The production packer was set and tested from below and above and the DHSV inflow tested. Finally a monolock plug was set at 65m and the BOP nippeled down.

5 Formation evaluation

5.1 Shallow gas

Shallow gas underneath GFA was expected in the intervals 392-399 and possibly 559-567 m TVD RKB. The possible shallow gas zones in the 24" hole section were not logged. There was no increase of gas values in the specified intervals.

5.2 Results from 34/10-A-48

The Brent Gp in segment E1 and the Statfjord Fm in segment D1 were reached by the 12 ¼'' section. Base Cretaceous was penetrated 65 m deeper than prognosis due to a too shallow seismic interpretation. The top of the Brent Gp was faulted out in the well and the Tarbert Formation was penetrated 29 m deeper than prognosis. The main fault between the E1 and D1 segments and the top Statfjord Formation were encountered at about estimated depths. A small gas discovery was made in the Brent Group in segment E1, whereas the Statfjord Fm in segment D1 was water-filled. It was decided to pull back and drill to the Brent Group prospect in segment D1.

Table 5.1: Geological formation tops, 34/10-A-48

Group/Formation	Actual m MD RKB	Actual m TVD RKB	Actual m TVD MSL
Balder Top	2230.0	1625.0	-1542.8
Balder Base	2230.0	1625.0	-1542.8
Lista Top	2530.0	1698.0	-1615.8
Lista Base	2530.0	1698.0	-1615.8
Cretaceous Top	3251.0	1818.0	-1735.8
SHETLAND GP. Top	3251.0	1818.0	-1735.8
Jurassic Top	5206.7	2165.1	-2082.9
SHETLAND GP. Base	5222.0	2173.3	-2091.1
Cretaceous Base	5222.0	2173.3	-2091.1
Jurassic Top	5222.0	2173.3	-2091.1
VIKING GP. Top	5222.0	2173.3	-2091.1
Heather Fm. Top	5222.0	2173.3	-2091.1
Heather Fm. Base	5245.0	2185.8	-2103.6
VIKING GP. Base	5245.0	2185.8	-2103.6
BRENT GP. Top	5245.0	2185.8	-2103.6
Tarbert Fm. Top	5245.0	2185.8	-2103.6
Tarbert-1 Top	5245.0	2185.8	-2103.6
Tarbert-1C Top	5245.0	2185.8	-2103.6
Tarbert-1B Top	5249.8	2188.4	-2106.2
Tarbert-1C Base	5249.8	2188.4	-2106.2

Tarbert-1B Top	**5251.3**	**2189.2**	**-2107.0**
Tarbert-1B Base	**5273.0**	**2201.3**	**-2119.1**
Tarbert-1 Base	**5273.0**	**2201.3**	**-2119.1**
Tarbert Fm. Base	**5273.0**	**2201.3**	**-2119.1**
BRENT GP. Base	**5273.0**	**2201.3**	**-2119.1**
DUNLIN GP. Top	**5273.0**	**2201.3**	**-2119.1**
Amundsen Fm. Top	**5273.0**	**2201.3**	**-2119.1**
Amundsen Fm. Base	**5428.0**	**2288.1**	**-2205.9**
DUNLIN GP. Base	**5428.0**	**2288.1**	**-2205.9**
Statfjord Fm. Top	**5428.0**	**2288.1**	**-2205.9**
Statfjord11 Top	**5428.0**	**2288.1**	**-2205.9**
Statfjord11 Base	**5468.6**	**2311.1**	**-2228.9**
Statfjord10 Top	**5468.6**	**2311.1**	**-2228.9**
Statfjord10 Base	**5528.5**	**2345.4**	**-2263.2**
Statfjord9 Top	**5528.5**	**2345.4**	**-2263.2**
Total Depth	**5568.0**	**2368.0**	**-2285.8**

A location map and the geological model along the well path of A-48 prior to drilling are shown on the figures below. The tables below sum up the prognosis and expectations prior to the drilling of A-48, and the subsequent well results.

Results A-48 A:
The well was drilled as a 12 ¼’’ section from the kick-off point at 3930 m MD RKB (1667 m TVD MSL). At 6344 m MD RKB (1920 m TVD MSL, 5 m deeper than prognosis) a gas-filled, pressure-depleted sandstone was encountered. Then, at 6401 m MD RKB, on drilling out of the sandstone, a loss situation arose. Casing was consequently set close to the top sandstone, at 6347. The well was then drilled to TD (6881 m MD RKB) as an 8 ½’’ section. From 6401 m to TD the well encountered Shetland shale three times and the Tarbert Fm twice. The well path is shown on the updated geological cross section on the next page.
The well missed the geological target (40 m to the west from target) and drilled too close to the western edge of the structure. This has resulted in a large uncertainty concerning the age of the uppermost sandstone between 6344 m and 6401 m MD RKB. Three different interpretations are possible:

The whole section is of Cretaceous age. This is substantiated by biodatings of the interval (if interpreting the rare mid-Jurassic palynomorphs between 6375 and 6401 m as reworked), the seismic data and the depth conversion velocities.
the whole section is Brent. This is substantiated by a possible coal at 6401 m, pressure depletion, and biodatings (no Jurassic palynomorphs above 6375 m because of no recovery, mid-Jurassic palynomorphs between 6375 and 6401 are not reworked) and no observed Cretaceous sandstone in near-by well 34/10-12
the upper half (down to 6375 m) is of Cretaceous age and the lower half of Brent age. This is substantiated by pressure depletion, and the biodatings (if the mid-Jurassic palynomorphs between 6375 and 6401 m are not reworked)

At the moment the first alternative is regarded most likely.

The well proved a gas column of 20 m in the possible Cretaceous sandstone (Krans Mb/Kyrre Fm) and an oil column of 2 m in the Brent Gp. Neither the gas-oil contact nor the oil-water contact was identified due to shale lithology at the respective depths. However, a hydro-carbon column of 70 m has been proven. Because of the uncertainty regarding the age (and distribution) of the top sandstone and the fluid contacts, reserve estimates are difficult and highly uncertain.

Table 5.2: Geological formation tops, 34/10-A-48A

Group/Formation	Actual m MD RKB	Actual m TVD RKB	Actual m TVD MSL
Kyrre Fm. Top	6343.8	2002.5	-1920.3
Krans Mb. Top	6343.8	2002.5	-1920.3
Krans Mb. Base	6400.8	2025.9	-1943.7
SHETLAND GP. Base	6474.5	2057.5	-1975.3
Cretaceous Base	6474.5	2057.5	-1975.3
Jurassic Top	6474.5	2057.5	-1975.3
BRENT GP. Top	6474.5	2057.5	-1975.3
Tarbert Fm. Top	6474.5	2057.5	-1975.3
Tarbert-2 Top	6474.5	2057.5	-1975.3
Tarbert-2B Top	6474.5	2057.5	-1975.3
Tarbert-2B2 Top	6474.5	2057.5	-1975.3
Tarbert-2B1 Top	6482.1	2060.2	-1978.0
Tarbert-2B2 Base	6482.1	2060.2	-1978.0
Tarbert-2B1 Base	6511.1	2068.3	-1986.1
Tarbert-2B Base	6511.1	2068.3	-1986.1
Tarbert-2 Base	6511.1	2068.3	-1986.1
Tarbert Fm. Base	6511.1	2068.3	-1986.1
BRENT GP. Base	6511.1	2068.3	-1986.1
Jurassic Base	6511.1	2068.3	-1986.1
BRENT GP. Base	6511.2	2068.3	-1986.1
Tarbert Fm. Base	6511.2	2068.3	-1986.1
Tarbert-2 Base	6511.2	2068.3	-1986.1
Tarbert-2B Base	6511.2	2068.3	-1986.1
Tarbert-2B1 Base	6512.2	2068.6	-1986.4
Tarbert-2B1 Top	6543.8	2074.2	-1992.0
Tarbert-2B2 Base	6543.8	2074.2	-1992.0
Tarbert-2B2 Top	6592.2	2076.4	-1994.2
Tarbert-2B Top	6592.2	2076.4	-1994.2
Tarbert-2 Top	6592.2	2076.4	-1994.2
Tarbert Fm. Top	6592.2	2076.4	-1994.2
BRENT GP. Top	6592.2	2076.4	-1994.2
Cretaceous Base	6592.2	2076.4	-1994.2
SHETLAND GP. Base	6592.2	2076.4	-1994.2
SHETLAND GP. Top	6645.0	2077.2	-1995.0

SHETLAND GP. Top	**6645.0**	**2077.2**	**-1995.0**
SHETLAND GP. Base	**6709.3**	**2083.7**	**-2001.5**
Cretaceous Base	**6709.3**	**2083.7**	**-2001.5**
BRENT GP. Base	**6709.3**	**2083.7**	**-2001.5**
Tarbert Fm. Base	**6709.3**	**2083.7**	**-2001.5**
Tarbert-2 Base	**6709.3**	**2083.7**	**-2001.5**
Tarbert-2B Base	**6709.3**	**2083.7**	**-2001.5**
Tarbert-2B2 Base	**6709.3**	**2083.7**	**-2001.5**
Tarbert-2B2 Top	**6756.0**	**2090.9**	**-2008.7**
Tarbert-2B3 Base	**6756.0**	**2090.9**	**-2008.7**
Tarbert-2B3 Top	**6758.0**	**2091.2**	**-2009.0**
Tarbert-2B Top	**6758.0**	**2091.2**	**-2009.0**
Tarbert-2 Top	**6758.0**	**2091.2**	**-2009.0**
Tarbert-3 Base	**6758.0**	**2091.2**	**-2009.0**
Tarbert-3A Base	**6758.0**	**2091.2**	**-2009.0**
Tarbert-3A Top	**6781.4**	**2094.7**	**-2012.5**
Tarbert-3 Top	**6781.4**	**2094.7**	**-2012.5**
Tarbert Fm. Top	**6781.4**	**2094.7**	**-2012.5**
BRENT GP. Top	**6781.4**	**2094.7**	**-2012.5**
Cretaceous Base	**6781.4**	**2094.7**	**-2012.5**
SHETLAND GP. Base	**6781.4**	**2094.7**	**-2012.5**
Total Depth	**6861.1**	**2104.0**	**-2021.8**

Results A-48 B:
As the running of the liner in A-48 A failed due to restrictions in the hole, A-48 B had to be drilled (see figure immediately above). It started at the casing shoe at 6346,5 m MD RKB and was drilled to a TD of 7076 m MD RKB (2099 m TVD MSL). The path of this well was partly governed by well inclination restrictions in the uppermost part, and by the location of a new Cretaceous sandstone target to the west. The well proved oil down to 1993 m MSL and an oil-leg of at least 5 m.

Table 5.2: Geological formation tops, 34/10-A-48B

Group/Formation	Actual m MD RKB	Actual m TVD RKB	Actual m TVD MSL
Krans Mb. Base	**6394.1**	**2022.4**	**-1940.2**
Jurassic Top	**6521.6**	**2066.8**	**-1984.6**
SHETLAND GP. Base	**6521.6**	**2066.8**	**-1984.6**
Cretaceous Base	**6521.6**	**2066.8**	**-1984.6**
BRENT GP. Top	**6521.6**	**2066.8**	**-1984.6**
Tarbert Fm. Top	**6521.6**	**2066.8**	**-1984.6**
Tarbert-2 Top	**6521.6**	**2066.8**	**-1984.6**
Tarbert-2B Top	**6521.6**	**2066.8**	**-1984.6**
Tarbert-2B2 Top	**6521.6**	**2066.8**	**-1984.6**
Tarbert-2B1 Top	**6579.2**	**2082.0**	**-1999.8**
Tarbert-2B2 Base	**6579.2**	**2082.0**	**-1999.8**
Tarbert-2B1 Base	**6635.0**	**2094.8**	**-2012.6**

Tarbert-2B Base	**6635.0**	**2094.8**	**-2012.6**
Tarbert-2 Base	**6635.0**	**2094.8**	**-2012.6**
Tarbert Fm. Base	**6635.0**	**2094.8**	**-2012.6**
BRENT GP. Base	**6635.0**	**2094.8**	**-2012.6**
BRENT GP. Base	**6635.0**	**2094.8**	**-2012.6**
Tarbert Fm. Base	**6635.0**	**2094.8**	**-2012.6**
Tarbert-2 Base	**6635.0**	**2094.8**	**-2012.6**
Tarbert-2B Base	**6635.0**	**2094.8**	**-2012.6**
Tarbert-2B1 Base	**6635.0**	**2094.8**	**-2012.6**
Tarbert-2B1 Top	**6682.0**	**2106.7**	**-2024.5**
Tarbert-2B2 Base	**6682.0**	**2106.7**	**-2024.5**
Tarbert-2B2 Top	**6976.0**	**2175.7**	**-2093.5**
Tarbert-2B3 Base	**6976.0**	**2175.7**	**-2093.5**
Tarbert-2B3 Top	**6980.0**	**2176.1**	**-2093.9**
Tarbert-2B Top	**6980.0**	**2176.1**	**-2093.9**
Tarbert-2 Top	**6980.0**	**2176.1**	**-2093.9**
Tarbert-3 Base	**6980.0**	**2176.1**	**-2093.9**
Tarbert-3A Base	**6980.0**	**2176.1**	**-2093.9**
Tarbert-3A Top	**7033.5**	**2180.0**	**-2097.8**
Tarbert-3B Base	**7033.5**	**2180.0**	**-2097.8**
Tarbert-3B Top	**7068.0**	**2181.3**	**-2099.1**
Tarbert-3 Top	**7068.0**	**2181.3**	**-2099.1**
Tarbert Fm. Top	**7068.0**	**2181.3**	**-2099.1**
BRENT GP. Top	**7068.0**	**2181.3**	**-2099.1**
VIKING GP. Base	**7068.0**	**2181.3**	**-2099.1**
Heather Fm. Base	**7068.0**	**2181.3**	**-2099.1**
Total Depth	**7076.0**	**2181.3**	**-2099.1**

Results A-48 BT2: This well was drilled to a Cretaceous prospect some 1500 m to the west of the crest of D1. It was milled out at 7023 m MD RKB from A-48 B, and drilled as a 6’’ section to a TD of 7701 m MD RKB (2014 m TVD MSL). No Cretaceous sandstone was found.

Table 5.2: Geological formation tops, 34/10-A-48BT2

Group/Formation	Actual m MD RKB	Actual m TVD RKB	Actual m TVD MSL
Tarbert-3A Top	**7035.1**	**2180.1**	**-2097.9**
Tarbert-3B Base	**7035.1**	**2180.1**	**-2097.9**
Tarbert-3B Top	**7074.1**	**2182.6**	**-2100.4**
Tarbert-3 Top	**7074.1**	**2182.6**	**-2100.4**
Tarbert Fm. Top	**7074.1**	**2182.6**	**-2100.4**
BRENT GP. Top	**7074.1**	**2182.6**	**-2100.4**
VIKING GP. Base	**7074.1**	**2182.6**	**-2100.4**
Heather Fm. Base	**7074.1**	**2182.6**	**-2100.4**
Heather Fm. Top	**7206.0**	**2177.9**	**-2095.7**
VIKING GP. Top	**7206.0**	**2177.9**	**-2095.7**

Jurassic Top	**7206.0**	**2177.9**	**-2095.7**
Cretaceous Base	**7206.0**	**2177.9**	**-2095.7**
SHETLAND GP. Base	**7206.0**	**2177.9**	**-2095.7**
Total Depth	**7701.4**	**2095.9**	**-2013.7**

5.3 Pore Pressure

The pore pressure was hydrostatic down to the sand free part of the Hordaland Group, and is here equal to 0,97 g/cm^3. The sand free part of the Hordaland Group was detected at 1385m TVD RT. The pore pressure increases rapidly through the rest of the Hordaland, Rogaland and Shetland Groups and reaches it's maximum value, 1,64 sg EMW near the base of the Shetland Group. No indications of high abnormal pressure (higher than normal over pressure) were seen in the top of the Shetland Group. Prognosed porepressure was reported during drilling. The reported reservoir pressures in wellbores A-48, A-48 B and A-48 BT2 are prognosed initial pressures, as no pressure measurements were performed in these welltracks. The MDT measurements in the Cretaceous sandstones penetrated in A-48 A show a pore pressure corresponding to ~1,36 sg EMW, as indicated in the presure prognosis given prior to drilling..

5.4 Formation Strength

The following integrity tests were performed:

34/10-A-48:		
*24" shoe	361 m MD / 361 m TVD RKB	LOT: 1,23 g/cm^3
**20 shoe	1232 m MD / 1202 m TVD RKB	LOT: 1.64 g/cm^3
***13 3/8" shoe	2747 m MD / 1748 m TVD RKB	LOT: 1.79 g/cm^3
34/10-A-48 B T2:		
6" Section	7033 m MD / 2180 m TVD RKB	FIT: 1.82 g/cm^3

*When performing the planned FIT to 1.28 s.g. at 361 m, the formation leaked off at 1.23 s.g. A cement-squeeze of the shoe was performed, but resulted in a new LOT of 1.24 s.g. A possible reason for the low formation strength compared to previous wells on GFA could be that the test is taken some meters deeper in this well. Usually the tests are taken just below the 32” conductor at approx. 351 m TVD. Formation-compaction after driving the conductors can have contributed to a higher strength than normal below the conductor shoes.

**Planned to take a FIT=1,67 SG. Got a LOT=1,64 SG which is within an acceptable limit (1,63 SG).

***Displaced to OBM during drilling of cement instead of after FIT due to operation would otherwise be “waiting on LCD screens on Hitec cyberbase”. Drilled out shoe and shoetrack (0,5 m intervals) and planned to take a FIT=1,82 SG. Got a LOT=1,79 SG which is within an acceptable limit (minimum needed:1,71 SG). However, the test was not easy to take and analyse due to the compressibility of the OBM. Prior the LOT the line tests had to be done several times before being acceptable.

5.4.1 Loss zones

At 4000 m, the total loss to the formation was reported to be 0.9 m3. With the 9 5/8" liner at 4024 m, the liner and running string were lost in hole. Loss rate was approximately 40 m3/hour with a total loss of 18m3. Gained back 8m3.

At 6400m MD/2026.7m TVD RKB the drilling was stopped due observed losses from trip tank. Initially the static loss reached 9.4 m^3/hr over a 15 min period. The loss occurred most likely in limestone, which is found at 6402 – 6404m MD. Max observed ECD prior to losses was 1.75 s.g; minimum estimated fracture gradient was 1.78 s.g.

5.4.2 Hole stability

34/10-A-48A:
Tight hole experience at 6676m MD while joining a pipe.

34/10-A-48A T2:
A short intervall (7560-7570m MD) in the Shetland Group generated unusual brittle cuttings, which normally were blocky elsewhere.

There were no further occurences of tight hole or severe hole cleaning cases during operation.

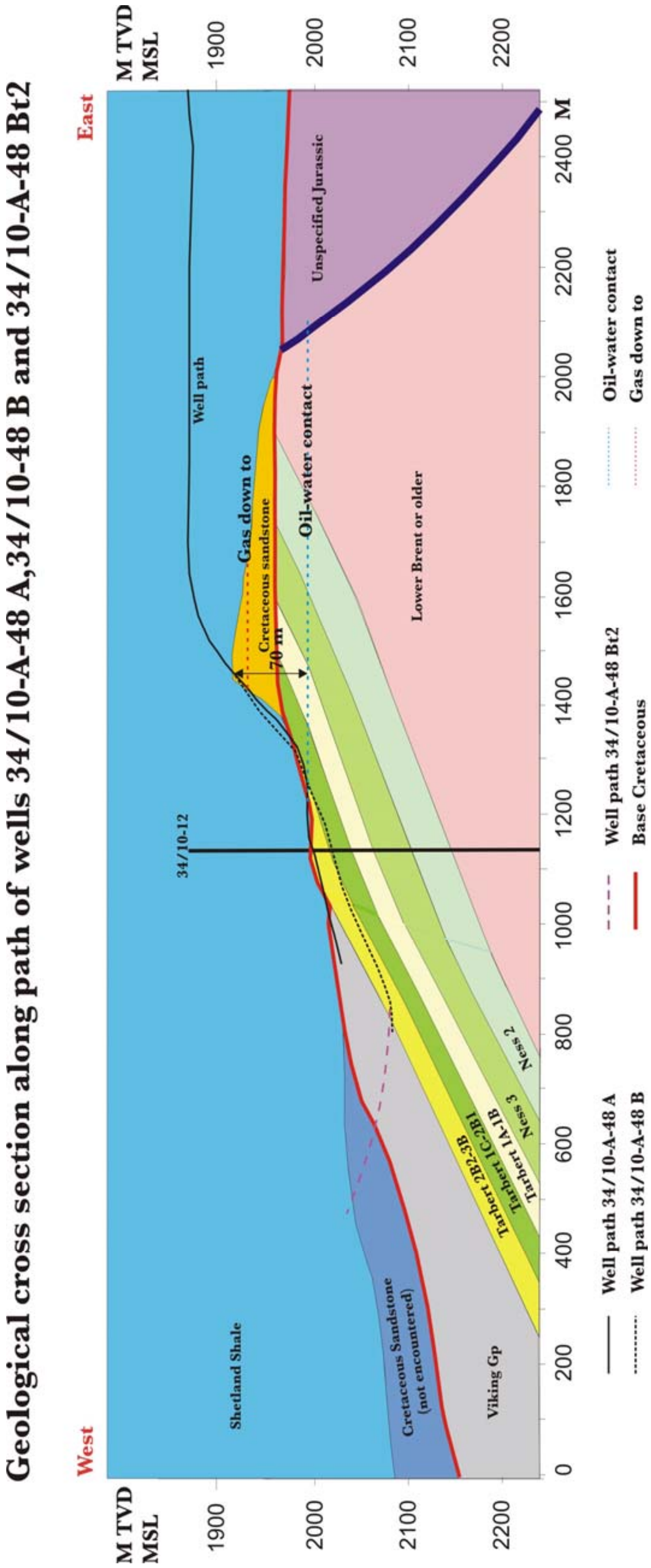
5.5 Logging (formation evaluation purposes)

MWD/LWD

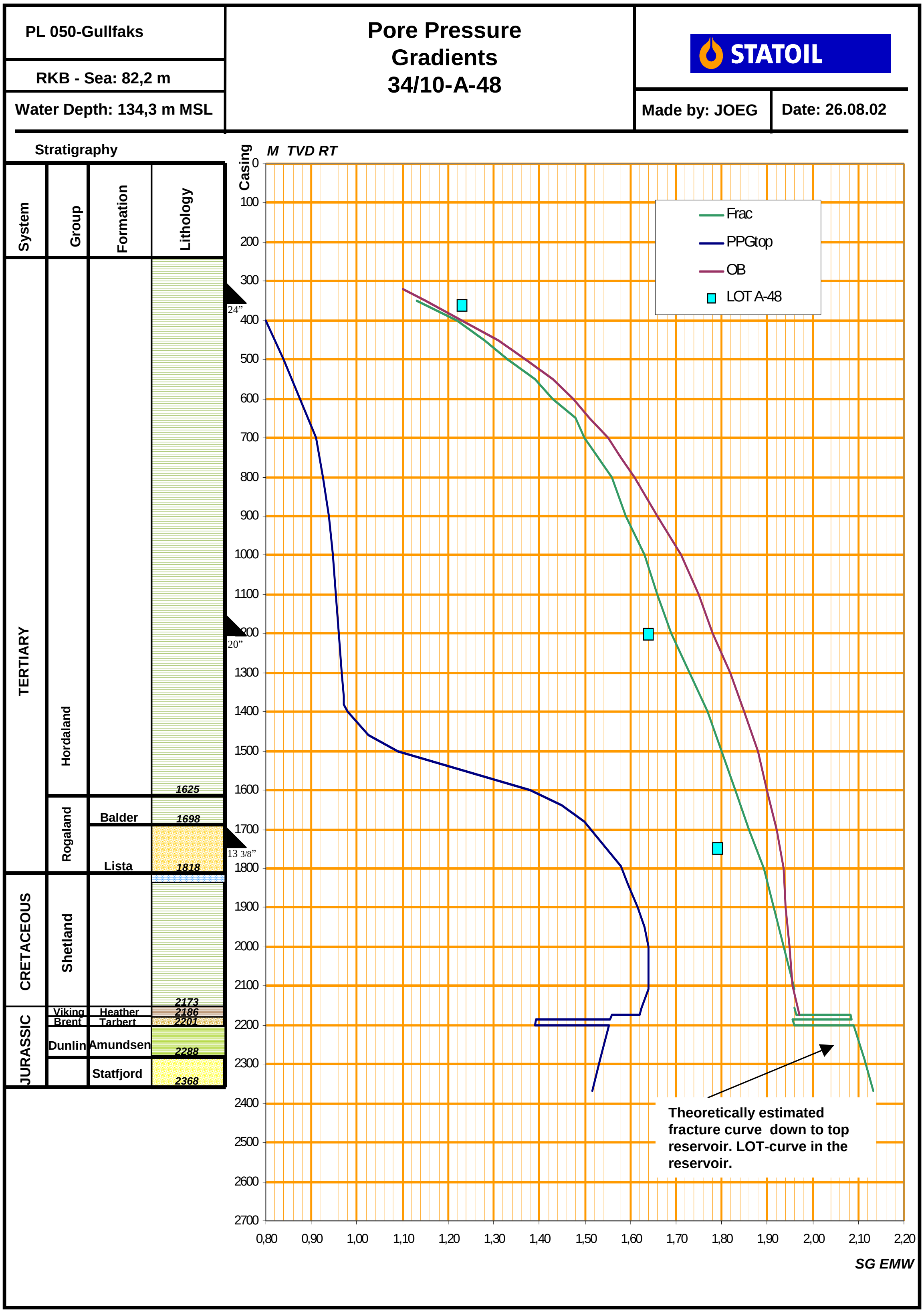
Well	Section	Tool
34/10-A-48	17 ½"	GR
34/10-A-48	12 ¼"	GR
34/10-A-48A	12 ¼"	GR
	8 ½"	GR/RES/DEN/NEU
34/10-A-48BT2	8 ½"	GR/RES/DEN/NEU
	6"	MWD/ARC/AND

Wire line logging
In 34/10-A-48A, in 8 ½" section, PEX and MDT was implemented.

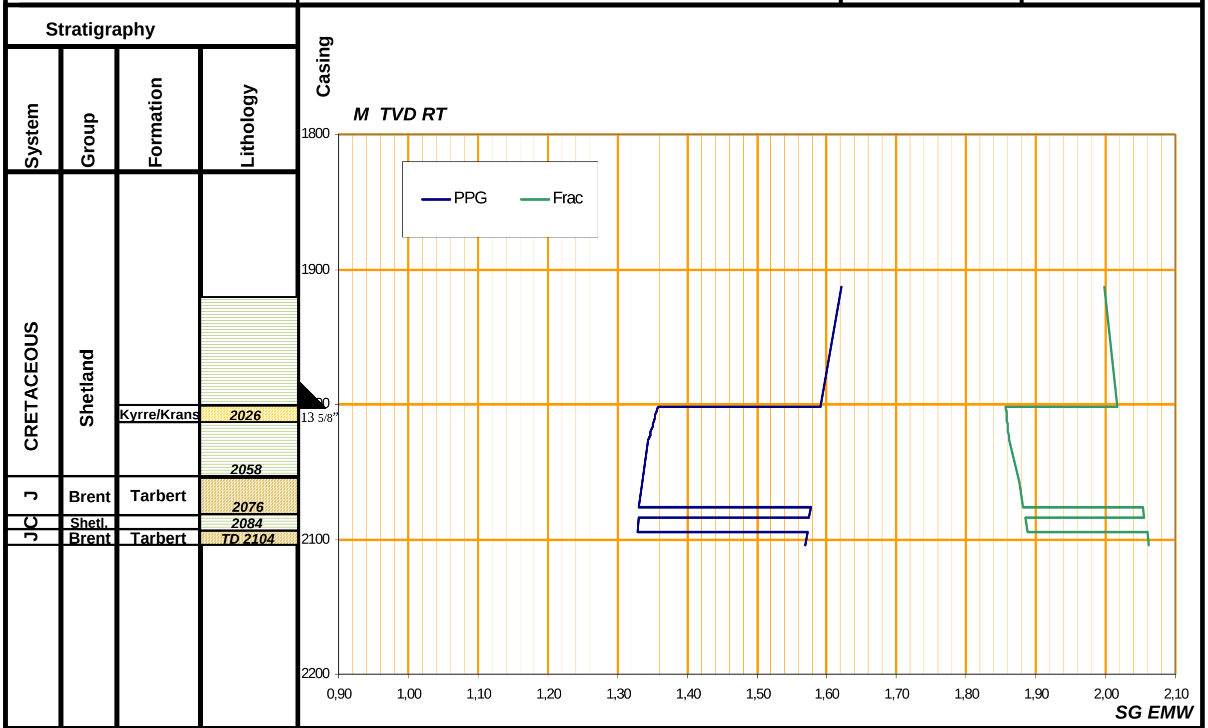
Geological cross sections wells 34/10-A-48 A, A-48 B and A-48 BT2 :



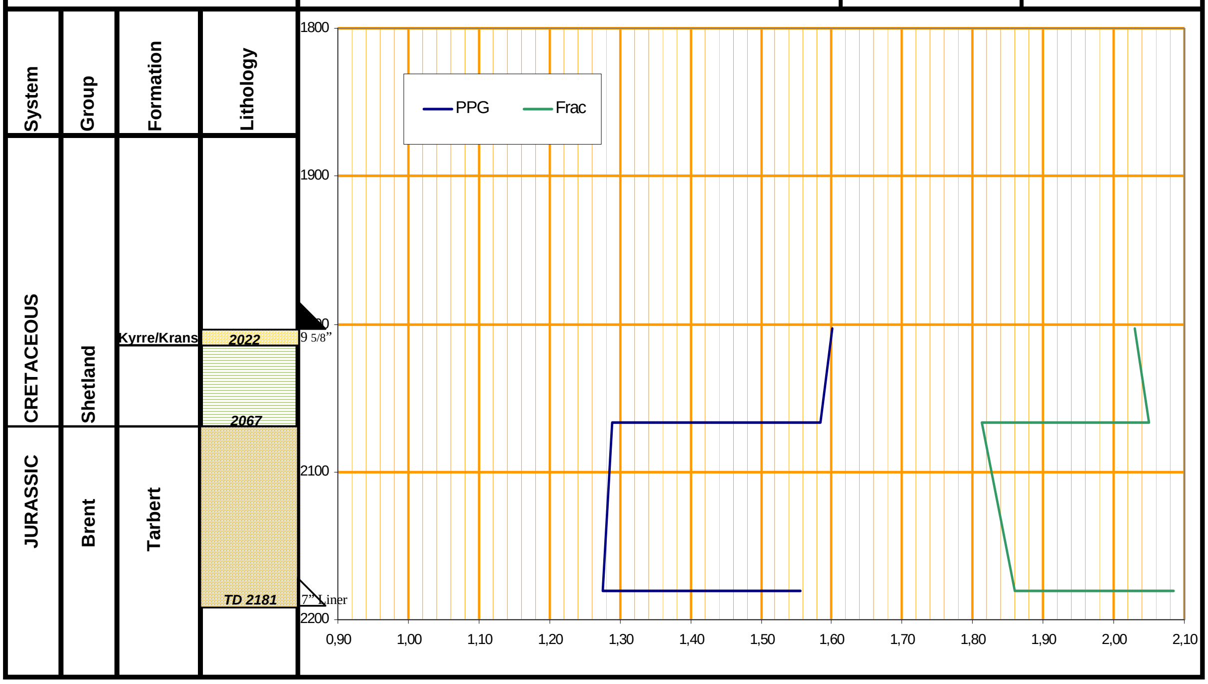
Summarized pore pressure and fracture gradients, wells 34/10-A-48, A-48 A and A-48 B :

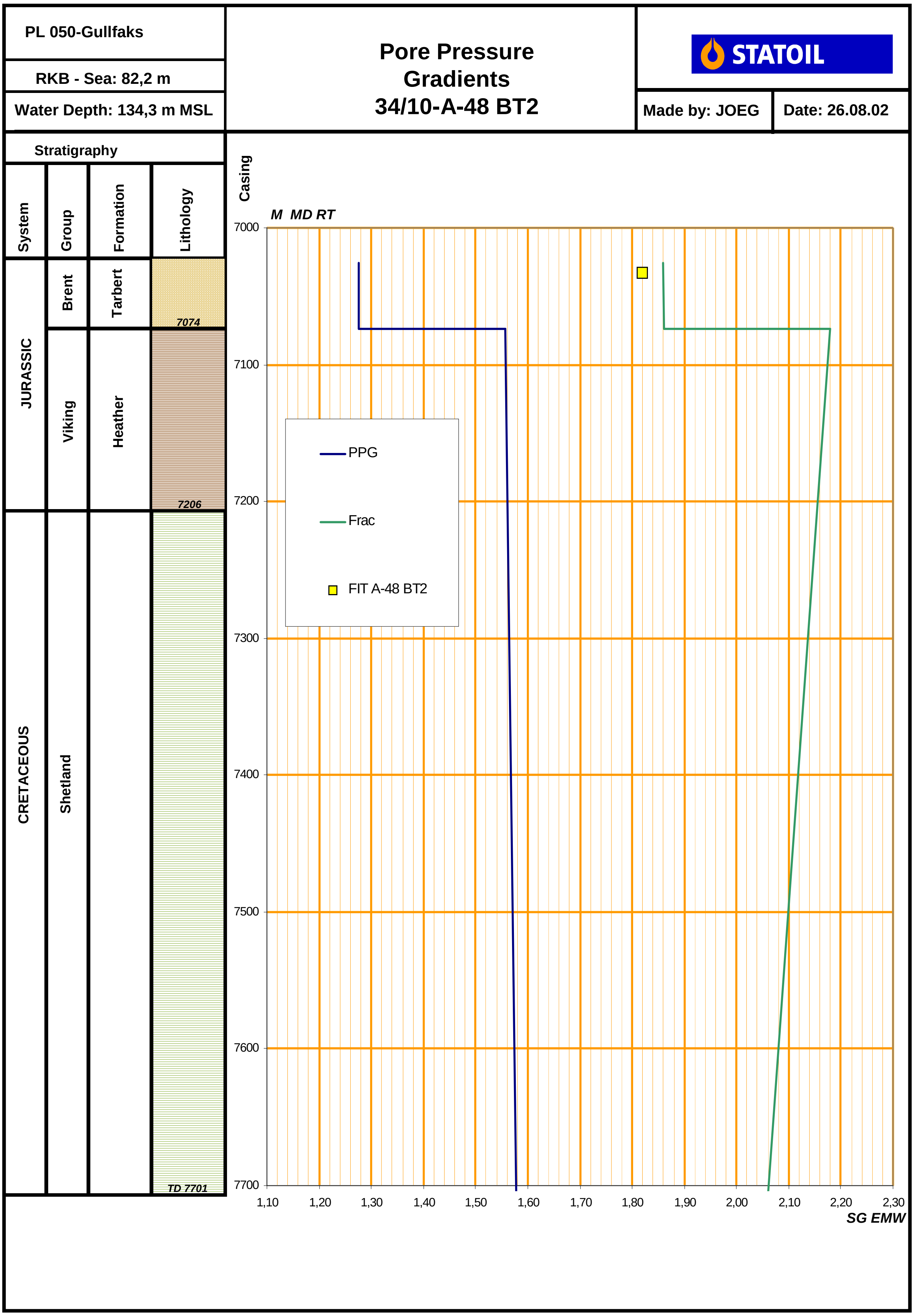


PL 050-Gullfaks	Pore Pressure Gradients 34/10-A-48 A	STATOIL
RKB - Sea: 82,2 m		Made by: JOEG
Water Depth: 134,3 m MSL		Date: 26.08.02



PL 050-Gullfaks	Pore Pressure Gradients 34/10-A-48 B	STATOIL
RKB - Sea: 82,2 m		Made by: JOEG
Water Depth: 134,3 m MSL		Date:26.08.02





PL 050-Gullfaks
RKB - Sea: 82,2 m
Water Depth: 134,3 m MSL
Pore Pressure Gradients
34/10-A-48 BT2
STATOIL
Made by: JOEG
Date: 26.08.02
Stratigraphy
System
Group
Formation
Lithology
JURASSIC
CRETACEOUS
Brent
Tarbert
7074
Viking
Heather
7206
Shetland
TD 7701
Casing
M MD RT
7000
7100
7200
7300
7400
7500
7600
7700
PPG
Frac
FIT A-48 BT2
1,10
1,20
1,30
1,40
1,50
1,60
1,70
1,80
1,90
2,00
2,10
2,20
2,30
SG EMW

6 Appendix 1: Directional Data

7 Appendix 2: Operational Experience

34/10-A-48 (361 m – 5568 m MD)

7.1 24" Hole Section (361 m – 1232 m MD)

Due to early start up, the planned philosophy of only using 5 ½" lifting subs for the BHA was unsuccessfully implemented. Lifting subs with 5", 5 ½" and 6 5/8" body were used and resulted in more time spent than planned.

Had a LOT to 1,235 SG, which was unexpected. (Almost all FIT's taken under conductors on Gullfaks have given min. 1,28 SG) The shoe was squeezed, but it still leaked off at 1,24 SG. An exemption was written, and the drilling started. Performed a roundtrip after drilling to 413 m MD due to low ROP. Changed motor and bit and drilled to 545 m MD. As for A-47, the first part of the section was drilled without MWD in order to get the gyro survey closer to the bit.

7.1.1 Prespud preparations

Some 3m was drilled out inside the 30" conductor and a 26" casing run and cemented inside. This was performed to repair a small leak in the conductor.

7.1.2 Drilling out shoetracks (26" and 36")

The 6 5/8" DP had to be spinned in and out several times with the iron roughneck to be made up, and took therefore longer time.

Drilled hard cement from 327 m to 343 m (3 m below 26" shoe) and tested 26" casing and 32" conductor to 25 bar to test cement job done as prespud preparation. Continued drilling cement and 6 m new formation to 360 m. Attempted three times to perform FIT to 1,28 SG, however the pressure bled off at 5,4 bar (1,18 SG), 3,4 bar (1,13 SG) and 3,95 bar (1,14 SG). Due to uncertainties of if the leak was at the shoe or between the 26" casing and 32" conductor after the vibration from drilling out the cement it was decided to perform a squeeze job. Performed a fourth attempt to perform FIT to 1,28 SG but the pressure bled off at 4,25 bar (1,15 SG).

7.1.3 Squeeze job

Pumped 25 m^3 cement through 6 5/8" open ended DP. Squeezed 10,4 m^3 in hesitation squeeze in intervals of 5 m^3, 2,7 m^3 and 2,7 m^3. Waited 10 min between every squeeze sequence. Held annular closed and waited for cement to set. POOH. RIH with 24" BHA and drilled out 26" casing shoe and tested 26" casing and 32" conductor to 25 bar again to check if any leaks between these casings. Drilled out of 32" conductor and 1 m new formation. Attempted to perform FIT to 1,28 SG and ended up with a LOT of 1,24 SG.

7.1.4 Drilling of 24” Hole

Due to the very small clearances to other wells, gyro surveys were run every 10m until at 545m MD and thereafter every stand down to 765 m MD. A total of 33 runs were performed.
A very close pass was made with respect to the closest well. A closing factor of 0,8 was observed and cement was seen in the returns.
ROP detoriated drastically after only 4 hrs bit time (at 412m). The BHA was pulled and the motor bearing seals were found to allow bypass of some 30-40% of the mud. Probable cause of poor ROP is thought to be insufficient motor power due to this leak.
The same BHA was run (with new bit). No steering problems were encountered and the planned wellpath was followed. The assembly could easily achieve the desired buildrate.
Changed BHA again at 545m to include the MWD. Drilled to TD 1232 m MD / 1199 m TVD.

7.1.5 Running 20” casing

Used 20” air operated slips for the first time. Slips would initially not fit but was repaired and refitted. Had major problems with the hydraulic elevator and ended up running with manual. Experienced MU problems on many joints (Antares coupling).

Lesson learned:
20” casing joints should not be more than 13m. The shoe and float was longer than this and it was a very tight fit to get these into the rigfloor.

7.1.6 Cementing 20” casing

Found leak in o-ring on cement head when RU same. Decided that leak was so small that the job could be performed anyways.
Lost circulation while displacing cement. Flow-out sensor showed total losses, volumes suggest partial losses. Reduced rate to 1100 lpm to regain returns. Managed to bring rate up to 2500 lpm with increasing returns, last 10-15 100% returns. Lost returns again after 202m3 displacement (almost at end). Reduced to 1500 lpm and bumped plug with calculated efficiency of 98,9%. Could not achieve good test due to leak on cement head. Installed swedge and tested again.

Had to take in extra csg jnt to back out RT as upper casing tong jaw would not fit on low stickup. Used snubline on frame to enable breakout.

By a mistake the pumps were brought up after the plug had bumped and the casing was exposed to a total of 212 bar surface pressure. No leaks were seen during the minute it took before pressure was bled off. Plug pressure rating was given as 145 bar.

7.2 17 ½" Hole Section (1232 m –2751 m MD)

7.2.1 Drilling of 17 ½" Hole

Planned to take a FIT=1,67 SG. Got a LOT=1,64 SG which is within an acceptable limit (1,63 SG). The mud weight will then be reduced from planned 1,61 to 1,59 SG by the end of 17 ½" hole section.
Experienced good hole cleaning when drilling with KCl mud, 3-7 RPM readings, 4500 LPM and 135 RPM on the drilling string.
From just before 1700m the cuttings became very sticky. Flowline and shakerbox got plugged and had to be cleaned out several times. Increased KCL content to solve problem. Ideally the KCL content should have been increased a little earlier. As we were almost out of barite at the time it was not possible to increase KCL content right away without also cutting mudweight (KCL on board as 1,10sg brine). The surface handling problems stopped as the KCl content was increased.

Had a planned trip after drilling to 1999 m due to building tendencies of BHA (not surprising due to the BHA being a building BHA). It was decided to pull due to orienting time took a long time and bit hours would be reached before reaching TD of the section. Went in with a holding BHA (changed out the 16" stabilizer with a 16 5/8" stabilizer). Drilled to TD 2751 m MD / 1749 m TVD.

Due to leakages in seats/valves in mudpumps we had to backream out of hole with mostly 2 pumps running at a time, giving a pumprate of 3000 lpm/ 110 rpm (instead of planned 4500 lpm).

Lessons learnt:
Backreaming with 3000 lpm/110 rpm went well with only some packoff tendencies/ tight hole in the area between 1570 m to 1434 m (where the angle of the wellpath decreases from 59^{o} to 47^{o}).

The waterbased KCl mud had a tendency of becoming airy/ foamy. This was observed during a flowcheck with the trip tank pump running, and during drilling when the active volume did not decrease as expected with respect to hole cleaning. This was solved by adding some defoamer.

7.2.2 Run 13 3/8" Casing

RIH with 13 3/8" casing was more time consuming than expected. This was mainly due to problems making up the joints. (Reaching shoulder torque). Had to wash the connections and redope due to this problem.

Lessons learnt:
- Dope practice in Statoil?. → Weather conditions influence.
- Increase make up torque as shoulder torque was higher than expected.

7.2.3 Run RIGS

Running of RIGS went according to procedure.

Lesson learnt:
- A-46, A-47 and A-48 all good RIGS jobs.

7.2.4 Cementing 13 3/8" casing

Mixing and displacing of 40 m3 cement went according to plan.

Lesson learnt:
- "Easy Flow" cement was easy to mix. The cement slurry density was held very stable, and no problem during the mixing was observed.

Experienced problem when setting Seal Assembly. Used 3 attempts. These problems may be due to inappropriate washing tool and inadequate washing.

7.2.5 Performing FIT/LOT

Displaced to OBM during drilling of cement instead of after FIT due to operation would otherwise be "waiting on LCD screens on Hitec cyberbase". Drilled out shoe and shoetrack (0,5 m intervals) and planned to take a FIT=1,82 SG. Got a LOT=1,79 SG which is within an acceptable limit (minimum needed:1,71 SG). However, the test was not easy to take and analyse due to the compressibility of the OBM. Prior the LOT the line tests had to be done several times before being acceptable.

Lesson learnt:
Perform FIT/LOT using WBM if possible.

7.3 12 ¼" Hole Section (2751 m MD - 5568 m MD)

7.3.1 Drilling of 12 ¼" Hole

After the LOT general maintenance was performed until the LCD screens for Hitec cyberbase and Procut unit was functioning (except for the high pressure injection pump). During the operation pumped at shoe with 2435-3500 lpm so as not using batteries on MWD tool (need to pump more than 2200 lpm). Even though screens were put above the chutes and in the MPA and pieces from the wiperplug were found coming over the Procut shaker and suction pump to crusher.

Lesson learnt:
Drill out casing shoe using WBM if possible.

Waited 24 hrs after LOT was taken and prior to drilling. During most of this time we circulated in the shoe. When starting drilling, the ECD from pressure sub increased to 1,76 SG. This occurred just as the BHA was going out of the shoe and the mud below the shoe was circulated past the pressuresub. This can be a combination of barite sag in the in the mud and low clearance between the BHA and 13 3/8" casing.

Drilled 12 ¼” hole with three pumps (flowrates 3660-3450 lpm) with PowerDrive tool in setting or in neutral. However, when only two pumps were available (flowrates 2660 lpm) the PowerDrive tool could only drill when in neutral position.
Lessons learnt:
PowerDrive tool with setting needs a pressure difference of 30-50 bar to be able to drill.

Drilled 12 ¼” with high rotation, 160-185 rpm, and one single was reamed after each stand drilled (with few exceptions).

Had several shut downs of the Procut unit due to early gas detection alarms (all false). This is due to Procut unit being connected to the Platforms “tennkilde utkobling”. As long as the unit is connected this way this can not be avoided.

The Procut unit was manned with 4 persons on each shift. The unit handled cuttings with ease with instant ROP of 40-50 m/hr. However, with long intervals of ROP of 80-90 m/hr, the unit got overloaded. For more details and suggested improvement see a separate report written by toolpusher/drilling supervisor.

The 12 ¼” section after LOT from 2751 m to 5568 m was drilled in one run, and the string BHA was easily pulled out of hole without backreaming. However, rig tongs had to be used on 9 out of 10 connections due to high torque (100 000-140 000 ft*lbs) when breaking 6 5/8” DP.

Lesson learnt:
Drilling with PowerDrive assy. and high pumprate and rotation and reaming one single after each stand drilled gave a hole which could be pulled out of without backreaming.

Washpipe was changed twice during the section. Once before entering reservoir while moving pipe every 30 mins (washpipe hrs approx. 100+ hrs). Secondly at TD while moving the pipe every 40 mins (washpipe 25 hrs). Had no overpull during/after the operations.

7.3.2 Plug back of A-48

Mixing and setting of the 3 cement plugs went according to plan. When circulating after cement plug no.2, cement was observed in returns, even though it was theoretically impossible. On cement plug no.3, smaller amount of cement in returns than expected was seen. Prior to setting plug no.3, a “Perigone” plug was pumped through the open ended drillpipe and served as a base for the cement. When RIH with 12 ¼” BHA, a couple of cementspots were observed.
When sidetracking A-48 A, medium hard cement was drilled from 3910 m MD, and hard cement was drilled from 3922 m MD.

Lesson learnt:
- The recommended procedure from Halliburton did not contain any information regarding pulling wet or dry.

- Mixing of cement went very well.
- Setting cement plugs in high deviated holes with oil based mud with 5 ½" DP is OK.
- Pull one stand above cement plug prior to circulate BU due to contamination of top of cement plug.
- Circulated at least 1,5 BU after the plug is set.
- The "Perigone"-plug is expected to have contributed to a successful kick-off plug.

34/10-A-48 A (3930 m MD – 6860 m MD)

7.4 Kick off A-48A

Kicking off with 12 ¼" bit and PowerDrive at 72 deg R in a 82° hole went very well. DLS of 3,5° / 30 m was seen, but this is very satisfying.
It is of most importance to evaluate hardness of cement and weight used to kick off plug. Experience with high WOB have shown very high dogleg when kicking off and resulted in greater problems to get casing down.
Keep WOB between 5-10 ton (mostly 5-6 ton WOB). If cement plug is hard it's possible to go out highside. If problems to kick off go low side. Be aware of cement falling in behind bit. Ream first stand and second stand after kick off several times to prevent stuck pipe.

7.5 12 ¼" Hole Section (3930 m MD – 6400 m MD)

7.5.1 Drilling 12 ¼" Hole

Drilled 12 ¼" hole with three pumps (flowrates 3400-3300 lpm) with PowerDrive tool in setting or in neutral. However, when only two pumps were available (flowrates 2600 lpm) the PowerDrive tool could only drill when in neutral position.

Drilled 12 ¼" with high rotation,175 rpm, and one stand (in between 2 times) was reamed after each stand drilled (with few exceptions) with 185 rpm.

High penetration rate, good hole cleaning and very good wellpath control when drilling with Powerdrive. However, towards TD it was difficult to achieve the desired drop-rate due to stringers. This resulted in missing the drillers target with some meters.

Had several shut downs of the Procut unit due to early gas detection alarms (all false). This is due to Procut unit being connected to the Platforms "tennkilde utkobling". As long as the unit is connected this way this can not be avoided.

The Procut unit was manned with 4 persons on each shift. The unit handled cuttings when drilling with instant ROP of 100-120 m/hr and reaming stand once.

12 ¼" hole was planned drilled to TD at 6480 m MD. Top reservoir was hit at 6346 m MD. At 6400 m MD returns was partially lost. Static mudloss of 9.4 m3/hr was observed over a 15 min period with a mudweight of 1.65 s.g. Reported ECD from the pressure sub was 1.75 s.g. when losses was initiated. Minimum fracture gradient was prognosed to 1.78 s.g.
LCM-material was pumped, but could not cure the loss. TD for 12 ¼" section was therefore set.

Lesson learnt:
- Drilling with PowerDrive assy. and high pump rate and rotation and reaming one single after each stand drilled gave a hole cleaning which also resulted in good torque /drag and up/down weights.
- PowerDrive has given us the highest penetration rate ever done on the GF-field.
- Drilling with 175 rpm, reaming with 185 rpm gave good hole cleaning and there were no problems POOH from 6400 m.

7.5.2 Running of 9 5/8” liner

The 9 5/8” liner shoe track was tube locked with an extra 3 joints; reamer shoe with float, 2x9 5/8” joints, float collar, landing collar and 3 x 9 5/8” joints. The 3 extra joints were tube locked to avoid a possible back out when milling through the shoe (ref. incident on GFB just recently). The 9 5/8” liner was run with a running speed of 9-10 joints per hour inside 13 3/8” casing. All of the 9 5/8” casing joints (New Vam threads, P-110 grading and 53.5 lbs/ft) were made up with approximately 19.000 ft-lbs. No joints were laid down.

At 4000 m, the total loss to the formation was reported to be 0.9 m3. With the 9 5/8” liner at 4024 m, the liner and running string were lost in hole. Loss rate was approximately 40 m3/hour with a total loss of 18m3. Gained back 8m3.

<u>Short summary of lost in hole incident:</u>
One 6 5/8" HWDP with 5 1/2" IFM tool joint was picked up from pipe deck. The hydraulic slips (PS 21) had been made up with inserts for running 6 5/8" DP and **not** 6 5/8” HWDP. The joint was picked up and made up to the landing string. The landing string was lifted up with the elevator and set down in the PS 21 slips. After a short time, approximately 10 minutes, the landing string slipped through the slips and was lost in hole. According to Prosafe, the direct cause was wrong inserts in PS-21 slips.
<u>NB:</u> The 6 5/8” HWDP came with two different slips setting area diameters. Some were equal to normal 6 5/8” DP, but others (like the one that was in the rotary when the string was lost) were modified to be used with 5 ½” DP slips.

After this incident it was also discovered that the inserts (bushing) in the BX elevator was wrong. Later when planning the “fishing” job it became clear that the running string had been run with wrong configuration with the 8” DC at bottom and 6 5/8” HWDP on top. According to the A48A amendment 8” DC should have run on top of the running string.

The “fish” was tagged at 1050m. Set down 18 ton but weight returned to normal. At 1280 m the string took 1-3 ton weight when running in hole. Started rotating onto top of the running string with 26 kNm and worked torque down. Pushed string down from 5304m to 5318m with maximum 139 ton. Pulled string free with 249 ton and pulled up 2m to confirm free string.

Continued to RIH with 9 5/8” liner and had to work through several tight spots with all available weight (50 ton). Managed to reach setting depth of 9 5/8” liner at 6346.5 m. Spaced out and set liner hanger according to procedure.

Lessons learnt:
- It is possible that the reamer shoe helped passing through several tight spots. Running in hole, weight was set down, picked up string and slid down in most cases with normal down weight indicating that the reamer shoe had worked the area.
- Check that correct inserts in PS-21 slips and BX elevator have been made up.
- The offshore detail plan must be verified against the drilling program and amendments.

7.5.3 Cementing of 9 5/8” liner

Circulated in 1.50 sg mud with maximum 900 lpm / 53 bar. Increased in steps to 1500 lpm / 98 bar after return of 1.50 s.g mud. No loss was observed. Max. gas 6.2%.

Pumped 5m3 of base oil, 15 m3 of 1.70 sg spacer with 1000 lpm/ 70 bar. Mixed and pumped 88.1 m3 (planned 91 m3) of 1.90 sg cement slurry with 850-950 lpm / 45-115 bar. Released dart from cement head and displaced cement with 1.50 sg mud with 1500 lpm / 63-115 bar. Unable to see when dart landed in hanger. Decreased pump rate to 1000-950 lpm / 85- 107 bar when wiper plug bumped at 95.3% pump efficiency. Maximum gas was 4.3%. Total loss of cement slurry was only 0.5 m3.

<u>During the cement job a short stop of 20 minutes was encountered due to;</u>
- Densiometer was plugged. Lumps of cement had blocked the discharge line.
- Lost suction to mixing pump but came back after restart.
- Mixer was plugged below the knife. Lumps of cement were found in the mixing bowl. This also caused some dry cement to be blown through the packing element between knife and mixer.

Because of these incidents the last 21.7 m3 was mixed and pumped, taking cement slurry weights manually. Cement slurry weight varied between 1.75-1.97 sg during this period.

<u>9 5/8” TSP liner packer failure:</u>
Tested well in steps to 260 bar with 200 lpm for testing 9 5/8” liner, Nodeco/ Weatherford 9 5/8” TSP liner packer and 13 3/8” casing. Pressure dropped off to 63 bar in 5 minutes and levelled off at 51 bar after 30 min. After several attempts to achieve good pressure test, it was decided to pull out of hole to run 9 5/8” RTTS packer to locate the leakage.

A 9 5/8” Halliburton RTTS packer was run and set inside top of the 9 5/8” liner. The 13 3/8” casing and 9 5/8” TSP liner packer was pressured up to 102 bar before pressure dropped off. The 9 5/8” liner below was tested to 290 bar / 10 min. It was decided to run the back-up Nodeco/Weatherford BSP tieback packer without any clean up run. After installing 9 5/8” BSP tieback packer, performed a good test of 290 bar/ 10 min.

Lesson learnt:

- According to Halliburton the cement unit on GFA is very old and short stops during a cement job is not unusually. Increase maintenance on cement mixer system.
- The failure of the TSP 9 5/8” liner packer is not known. The lost in hole incident (ref. Chapter 5.5) may have damaged the packing element.

7.6 8 ½” Hole Section (6400 m MD- 6860 m MD)

7.6.1 Drilling 8 ½” Hole

Drilled landing collar with various drilling parameters. Pump rate 0-1350 lpm/160 bar, 1-12 ton WOB, 20-155 rpm/ 28 kNm, mw in/out: 1,50 sg. Used 3 hours to drill landing collar.

Washed down and drilled float and shoe collar with 1450 lpm/ 180 bar, max 10 ton WOB, 70 rpm/ 18 kNm, mw in/out: 1,50 sg. Observed no firm cement. Used 4 hours to drill float and shoe collar.

Washed down 5 m into 12 ¼” rat hole, in 0,5 m intervals/ pulling into 9 5/8” shoe with 1450 lpm/ 180 bar, 70 rpm/ 18 kNm. Observed no firm cement in 12 ¼” rat hole from 6346 m to 6400 m.

Drilled 8 ½” hole (6400-with 2 pumps (flow rate 1900-2000 lpm) with PowerDrive tool in orienting mode or in neutral, with 150 rpm, reamed between 10m and one stand depending of torque and drag readings. Had to ream tight hole 6687-6659 m, due to not able to slide down string. Drilled to TD 6860 m MD.

Penetration rate was limited to 45 m/hr due to logging purposes.
Observed good hole cleaning.

Had some problems to set orienting mode on Powerdrive. The well path went to high on inclination before we were able to reset Powerdrive. Then the inclination dropped.
Unable to set Powerdrive and due to low inclination at 6703 m we had to trip out to casing shoe and set Powerdrive.

Had several shut downs of the Procut unit due to early gas detection alarms (all false). This is due to Procut unit being connected to the Platforms “tennkilde utkobling”. As long as the unit is connected this way this can not be avoided. The Procut unit was manned with 2 persons on each shift. Observed no mechanical problems during the section.

When POOH 8 ½” BHA, stopped with LWD tool at approx 50 m from RKB due to racking, making space for more stands in derrick. Because of radioactive sources in LWD tool, the 2 UV-sensors at wellhead area trigged off and performed NAS2 shutdown. Had production shut down in both shafts.

Lesson learnt:

- Drilling with 150-160 rpm and reaming with 150-175 rpm gave good hole cleaning.
- At 6703 m, not able to set PowerDrive. Continued drilling to 6716 m, performed several attempts to set PowerDrive, no success. POOH to 9 5/8" shoe at 6346 m and set PowerDrive.

7.6.2 TLC logging

When pumping down locomotive to 3127 m with 1700 lpm/170 bar, had gas peak of 16.8 % in return. Shut in well with annular preventor and circulated out gas through choke and poor boy degasser. Latched locomotive to docking head and RIH with TLC assembly to 6379 m. Logged MDT, first interval from 6379 m to 6447 m.

Worked tight spots at 6438 m with max. 3.5 ton compression on logging tool. RIH to 6448 m and took weight, had 20 ton overpull. Worked several tight spots from 6448 to 6468 m, not able to pass 6468 m. From logs. limestone stringers can be seen every 5 m from 6440 m to 6470 m. In addition to limestone stringers the dog-leg at 6460 m is 4.4 deg/ 30 m.

Decided to log PEX from 6468 m to 6330 m. While logging, gas increased to 9.7 %, shut in well with annular preventor. Circulated out gas through choke and poor boy degasser with 600-700 lpm, limited to 60 bar because of limitation on Schlumberger Side Entry Sub. With higher pump pressure then 60 bar, wash out of logging cable inside side entry sub is possible. MW in/out: 1.50/1.47 sg. The low mud weight in return could be explained by low pump rate over time.

Took fluid samples according to program down to 6370 m. RIH to 6427 m, took weight. Worked string with max. 4 ton compression on logging tool, no go. POOH to 6291 m and pulled locomotive free from docking head. Circulated out gas through choke and poor boy degasser, max gas 13 % with 800-1000 lpm, while moving logging cable during circulation.

Flow checked well, static. Disconnected side entry sub and POOH with logging cable/ locomotive. Had losses when increasing pump rate 3 times to 2000 lpm/219 bar.

1.) Increased pump rate from 0-360 lpm/ within 5 min, from 360 to 2000 lpm/ within 7 min. Kept 2000 lpm for 5 min., before losses was discovered. Reduced pump rate to 1000 lpm. Circulated with 1000 lpm for 39 min. without losses.

2.) Increased pump rate from 1000 to 2000 lpm/ within 6 min. Kept 2000 lpm for 2,5 min. Stopped pumping and checked (pressure tested) surface equipment for leakage.

3.) Increased pump rate from 0-1100 lpm/ within 2 min, from 1100 to 2000 lpm/ within 5 min. Kept 2000 lpm for 4 min. Stopped pumping due to severe losses.

4.) Total loss was 21 m3, loss rate 14 m3/hr.

Lesson learnt:

- When restriction was met in the well we were not able to work pass the restriction because of compression limitation on the Schlumberger TLC assembly. It is recommended that compression limitation is increased on the tool to enable to work pass well bore restrictions.

- With the locomotive latched to docking head, pump pressure is limited to 60 bar due to rubber/ packer in side entry sub. When circulating gas out of the well with low pump rate, gave barite sagging. MI engineer estimated that a total of 16-24 ton of barite was left in the well, due to low circulating rate (less then 1200 lpm). It is recommended to increase the area of holes close to docking head, so pump rate can be increased above 1200 lpm, and still be below 60 bar pump pressure.
- Max pump rate in TLC-logging procedure was 60 bar pump pressure or 1500 lpm. Before or during logging operation it was never mentioned not to use higher pump rate then 1700 lpm. No good communication or misunderstanding resulted in using of 2000 lpm. When circulating, the pump rate was increased from 0 lpm to 2000 lpm in too short steps. These short steps gave not enough time to see if full returns, before 2000 lpm was reached. Always check if full return for each step, before increasing pump rate.

7.6.3 Cure loss with Versapac pill

Attempt #1:

According to the geologist, the most likely loss interval was from 6402-6404 m (coals or lime stone stringer). This was based on previous experience when 12 ¼" was drilled. Drilling into the stringer caused loss to the formation. With the string at 6309 m (37.5 m inside 9 5/8" liner) a 12 m3 Versapac pill (MI product) was squeezed into the formation with 500-600 lpm . Observed 25 bar WHP after squeeze. Stripped out one stand and circulated with 800-1000 lpm/89-112 bar to flush mud through the MWD tool and PowerDrive. Lost 4.8 m3. Stopped pump. Observed 23 bar WHP. Waited for Versapac pill to set up. Opened choke and bled off pressure to zero. Gained 6 m3 on trip tank. Increased pump rate in steps to 1600 lpm, observed loss. The Versapac pill #1 had no effect. Later it was found out that the Versapac pill was mixed with too low concentration, only 60% of the chemicals was used.

Attempt #2:

With the string at 6335 m a 5 m3 LCM pill, 2 m3 1.50 sg OBM and 18 m3 Versapac pill was squeezed into the formation with 600 lpm/ 91-122 bar. Stripped out one stand while pumping 85-100 lpm/ 41-49 bar. Observed 25 bar WHP, static. Circulated 20 m3 of 1.50 sg mud with 600 lpm with 20 bar WHP. Waited for Versapac pill to set up.

Washed down to 6451 m (wrong depth in DBR) with 1750 lpm / 80 rpm when observed loss with ECD=1.67 sg EMW. Reduced pump rate to 500 lpm, still loosing mud. Lost total 12 m3 in 2 hours. Max. MW out was 1.63 sg.

Attempt #3:
RIH to 6405 m and prepared another pill to cover several possible loss zones, including sand stone intervals below the 9 5/8" shoe and limestone stringer from 6402-6404 m. Pumped 13.4

m3 Versapac pill and displaced 8 m3 out bit with 500 lpm while rotating the string with 100 rpm. POOH to 6101 m while pumping CED and rotating string with 15 rpm. Circulated 20 m3 1.50 sg mud with 900 lpm. Then squeezed 6.9 m3 Vesapac pill into the formation with 120-250 lpm. Waited for pill to set up.

Washed down to 6440 m with 1400 lpm / 40 rpm. Had variable MW out; 1.47-1.56 sg EMW. At 6440 m, took 6 ton weight, torque and pump pressure increased and lost return. Pulled up when string stalled out and had to pull 44 ton OP before freeing the string. POOH to 6336 m and established circulation. It was concluded from this that the loss was below 6440 m (have sand intervals further down). Reamed down from 6250 m to 6497 m and found wellpath sidetracked. Pulled back to 6422 m and tried to slide down without success. Tried to work string down without success. Hole probably collapsed. POOH and prepared to set a cement plug in the open hole and into the liner.

Lesson learnt:

- The first Versapac pill was incorrectly mixed due to using 15 kilo sacks instead of 25 kilo.

7.6.4 Setting cement plug in 8 ½" OH

RIH with 3 ½" DP to 6497 m. When circulating BU losses were observed. Max lossfree rate was 1300 LPM. Set 1,80 sg hives pill from 6497 m to 6450 m.
Pumped 17 m3, 1,95 sg cement slurry, displacement rate was 1300 LPM (equal to 100 % excess in OH) from 6450 to 6250 m (103,5 m inside 9 5/8" liner), using pump and pull method.
When RIH we did not tag firm cement before 6350 m and had severe problems to sidetrack well due to mixed layers with soft and hard cement.
According to best practice it is recommended to pump 100 % excess cement slurry when setting plug in OH and displace cement with high flow rate.
Due to losses we were limited to 1300 lpm.

Lesson learnt:
For cement plugs in OH with high inclination and long reach excess must be evaluated to be higher than 100 %. There should be no problem to increase the excess to 200 %.
It's also important to keep as high flow rate as possible and max RPM for a good displacement.
(It was planned to set a Perigone tool as a base for the cement but this had to be cancelled do to Prosafe had installed stinger in bottom of the 3 ½" DP when RIH without telling anybody. Keyword: Communication)
It may be that a higher rate during the cement job would have been preferable to full returns. As the loss zone was close to the shoe a bit of losses would probably not have mattered too much. In total though it would probably be better to stay on loss free rate and rather increase the slurry volume.

34/10-A-48 B (6380 m - 7089 m)

7.7 8 ½" Hole Section

7.7.1 Sidetracking and drilling 8 ½" Hole

Was unable to sidetrack before 6380m due to poor cement. Was able to set some weight down at isolated spots but washed through easily.
After having kicked off, drilling went smoothly. Observed poor hole cleaning after having reduced rotation to 100-120 rpm. Hole cleaning OK at 140-160 rpm. Reduced rate in intervals to 1400 lpm due to plugging of bit nozzle. This to avoid too much pressure on the Powerdrive pads (excessive wear + too high directional force).
Some difficulty achieving the desired build rate. Seems like a closer eye should have been kept on the nearbit data and action could have been taken earlier. Increasing rpms to 160 gave a higher than anticipated bitwalk.
Drilled to TD 7089 m MD, into the Viking group to ensure required formation strength to drill 6" hole to Cretaceous.

7.7.2 Running of 7" liner, first attempt.

Met problems running 7" liner already at 6420 m MD, just outside 9 5/8" shoe. Worked liner in small steps down to 6436 m, no further progress. It was then decided to POOH and perform a clean up run. The 7" liner had by a mistake an ordinary shoe, not reamer shoe. When out of hole, the shoe was found severely damaged. Cement-nose was missing and remaing metal-joint was worn and damaged.

Lesson learnt:

-7" and 9 5/8" liners in inclined wells should be run with reamer shoe.
- Experienced ballooning. (Loss then gain).

7.7.3 Clean up run

The drill line had to be changed before entering OH section. When changing drill line, the swivel connection between old and new drill line snapped and the drill line felt down on the rig floor.A report is written about this incident. (on ESOP).
Had to work the string through the stringers, and lost return occasionally. When flow checking the well, decreasing gain (Ballooning) was seen as when POOH with 7" liner.
When out of hole with the BHA, the bullnose, bitsub and XO were gone. The threads looked OK, so it looks like the fish has been "backed off".

Lesson learnt:

- Experienced ballooning.

- No problem sliding down after using bull nose and hole opener. → Good job??
- Use tube-lock on bull nose and XO to connect to hole opener.

7.7.4 Running of 7” liner, 2’nd attempt

RIH with 7” liner with “Pen-O-Trator” shoe. (Peak’s reamershoe). Had to work the liner down, rotated for 6 m through stringers. The string took weight on almost every stand, this can indicate that the centralisers hung up in the stringers.

The liner was run to 7069 m MD, 20 m above TD to have some distance to the fish in the hole.

Had to pump 192 m3 before the ball landed prior to setting the hanger. This is 2,5 x theoretically string volume. (77 m3). Sat hanger according to Weatherford procedure.

Lessons learnt:
- Use reamer type of shoe
- Had to pump 2,5 x theoretically volume before hanger ball landed.

7.7.5 Cementing of 7” liner

Due to unstable returns, the cement volume was increased to 22 m3. During the displacement of cement, the returns increased, and when the cement entered the annulus, full returns were observed. Increased the pump rate to 1250 lpm, and started loosing.

Due to the big amount of excess, great focus was on stuck pipe. The time spent on setting the packer was minimized.

As seen in the first liner run and the clean up run, the well gained after losses. From bumping the plug until the packer was set, the well gained approx. 5 m3.

Lessons learnt:
- Focus on stuck pipe whenever cement above the liner top.

34 /10-A-48 B T2 (7031 m - 7725 m MD)

7.8 6" Hole Section (7031 m – 7725 m).

7.8.1 RIH and pull RTTS.

Entered top of RTTS several times with 11 ¼" Bowen Overshot with 6 1/8" Basket Grapple before latched onto RTTS with 20 ton set down weight. Pulled up but where unable to pull RTTS free with max. 33 ton OP. Slacked off to neutral, closed bag and pressure up well to 60 bar. Pulled RTTS free with 26 ton OP.

7.8.2 Clean up run.

RIH with 6,0" PDC bit, XO, 6,059" String and melon mill, 4 5/8" DC, 3 ½" DP, 5" DP circ.sub and 6 5/8" DP to clean out old OBM and displace to 1.55 sg OBM. Inside 7" liner at 6861 m (7" liner connection at same depth) the string took 20 ton weight. PU string and started to wash down with 1500 lpm/295 bar.

At 6912 m another obstruction was tagged (7" liner connection at same depth). Tagged same depth 10-12 times with max. 10 ton weight without passing. A pressure increase was not seen. PU and stopped pumps. RIH and tagged 6910 m with max. 10 ton. PU string and observed 8-10 ton OP. Tried to rotate string with 17-22 kNm when string stalled out. Managed to established rotation with 23 kNm/ 17 rpm after working the pipe. Washed down and was able to pass obstruction. RIH to TD at 7031 m and cleaned the well. Displaced to 1.55 sg OBM. POOH without any problems.

Conclusion/recommendations:
The BHA run was planned without running a jar. In clean up run with tight tolerances like in this well, we offshore strongly recommend to implement jar in the string to be able to jar a stuck string loose.
There will be a very strong spring effect in the string on this depth.
For setting of whipstock in deep wells like this, Red Baron also recommended to use a MWD in the clean up run to observe how to obtain high side. However, this showed not to be a problem on the whipstock-run.

7.8.3 Whipstock run.

MU MWD, 5" Multi-Cycle By-Pass valve and closed kelly cock. Had some problems to program the MWD at surface. RIH to 100 m. Performed a shallow test at 100 m pumping 800 lpm. Also the 5" Multi-Cycle By-Pass valve was tested twice at 100 m then pumping 700 lpm. In first cycling sequence 10 cyles required to close valve, while in second sequence cycle valve closed after (as per spec) 6 cycles (sixth pumping sequence). POOH, MU 7" whipstock assembly and

RIH. At top of 9 5/8" liner top (2676.8 m) the string took 6 ton weight. Turned string 300 deg. and worked string pass liner top. Continued to RIH. When RIH with 6 5/8" DP had to run slowly, at times, to allow pipe to fill up. Filled pipe and broke circulation at 100 lpm at 4690 m due to more fluid than theoretically coming back. Did not see anything on weight when entering 7" liner top at 6265 m.
Oriented whipstock on last stand above LC. Torque was easily worked all the way down. Working the std 4-5 times was sufficient to work almost all the torque down.
Pump pressure declined 60 bars for no appearant reason while circulating to orient whipstock. Cycled multi-cycle tool 5 times and observed pressure buildup when increasing circulation the 6th time. Suspect that cycle valve did not close completely or that hydraulic- hose/connections between mill and whipstock was leaking. A decreasing pressure trend was observed. Rate was increased to maintain required pressure to set packer.
Sheared off whipstock. Pressure decreased in steps as plugs in mill was sheared off.

Lessons learnt:

- When cycling "Multi Cycle By-Pass valve" it is important to bleed off <u>all</u> standpipe pressure each time for the tool to cycle.

7.8.4 Milling Operation.

1st Run (6,00." Starter- /Follow mill and 6,059" Watermelon mill):
Started milling at 7023 m (DP tubing tally). Typical milling parameters; 700 lpm, 160 bar, 120 rpm, torque 26-30 (max 36 knm). Back reamed after each 0.5 m of progress. Achieved to mill totally 3 m before the progress stopped. It was tried to pull off bottom several times and increase WOB without making any further progress. Had to pull out of hole and found starter mill severely worn. 2/3 of starter mill worn down to 3-6"-4.6" OD while upper 1/3 of starter mill is 5,8". Follow mill is bigger than 5.925" and melon mill is not worn. Based on 3 meter milling length from top of whipstock this indicates that the starter mill has been 0.5-1 m below bottom of the whipstock (gusset on whipstock is 2.18 m long with a ramp on the middle).

2nd Run (6,00" Starter- /Follow mill and 6,00" Watermelon mill):
Discussed alternatives for BHAs were; **1**) 6"undergauge PDC bit with 6,059" watermelon mill, **2)** 6" Trackmaster mill (same as 1st run) and **3)** 5 5/8" PDC mill and 6.059" watermelon mill. At the time when OOH the 5 5/8" PDC mill mobilized from Red Baron was not onboard GFA because of bad weather.

Because of the severely worn starter mill, most probably leaving an edge at the depth of milling and possible steel pieces at the depth of the window the Trackmaster mill was selected ahead of the PDC mill for this run.

RIH with 6" milling assembly, took weight at 7026 m with string rotating which confirms actual 3 m of milling on previous run. Milled 0,7 m during 4,5 hours with constant very slow progress. Milling parameters 500-700 lpm, 80-120 rpm, 30-38 knm, 8-16 ton WOB. 8 ton WOB acted as a zero point down hole (pumping off bottom). Very small fluctuations in torque and WOB, the mill did never drill off. POOH due to no progress at the end. Some formation between blades on starter mill. Found milling assembly to be between 5.925" and 6.00" for all three mills. Indications are that this mill assembly would not drill this formation.

3rd Run (6,00" Lyng Bit and 6.059" Watermelon mill):
Discussed alternatives for BHAs were; **1**) 6"undergauge PDC bit with 6,059" watermelon mill, **2)** 5 5/8" PDC mill and 6.059" watermelon mill. **3)** 6" Junk mill that was mobilized when POOH with Trackmaster mill #2.

The 6" PDC bit was selected as all indications are that the window has been opened up to 6" and that the Trackmaster mill spins without progress (worns out) when starting to drill formation. The 6,059" watermelon mill is added behind the bit to support it. 6,059" OD is the only size available single sub watermelon mill onboard.
Drilled from 7026 m to 7033 m in less than 1 hour. Performed FIT at 1.82 SG EMW.

Conclusion/recommendations:
Experience from this well have shown that conventional mills are not suited to drill formation. Based on this experience and Red Baron's experience it is strongly recommended to use PDC-mill in combination with whipstock when it's planned to drill new formation.

The 3 ½" HWDP joint (flex joint) just above the mill assembly, that enters into the window, was changed out for each milling run. The joints pulled had some ring marks.

7.8.5 Drilling 6" Hole.

(6,00" Hughes Christensen BX447 bit):
Drilled to approximately 7080 m before being able to steer. Drilled to TD at 7725 m with a final angle of 110 deg, no problems to orientate. No signs of sand. Maximum pumping rate at 850-900 lpm with 300-310 bar which is slightly lower rate than simulated values.

7.8.6 Setting of mechanical plug

Ran mechanical plug according to plan. Installed at 7013 m MD. Tested same to 225 bar/ 15 min.

7.9 Completion

ND BOP and installed TSR/ TSR ext. Due to tight clearance, the wing valves on the TSR had to be removed before lowering the TSR through BOP deck. This caused some extra time nippeling up and testing.

7.9.1 Clean up run

RIH with clean up assy. Experienced back flow, and could not RIH on elevator. This caused extra time spent on RIH. When reverse circulating out OBM while running the first wash train, maximum pressure was set as limitation. Since the well was tested to 225 bar, and maximum pump pressure was 320 bar, the well experience more pressure than tested.

18,5 hrs was used to clean the pits, (19 hrs A-47), after the well was displaced from OBM to sea water.

When circulating the well clean with sea water, it was not allowed to dump any returns before the oil content was below 40 ppm. When the first measurement was taken, the oil content was 20 ppm.

A pressure drop was seen when the well was circulated clean with sea water. The pressure dropped 100 bar/ 10 min.

When POOH with the clean up string, traces of dope was attached outside of the pipe despite that the pipe was wiped off prior to RIH. The dope was most probably from the inside of the DP.

739 m of wash string was left in hole due to twist off in the junk basket. (Explains the pressure drop seen earlier). BHI data operator went through the data previously to the pressure drop, but there are no indications of high torque or excessive forces applied on the string.

Recommendations:

- The well will see most of the pump pressure when revers circulating, this should be taken into account when making the clean up (circulation) program.
- Measure oil content in returns even if the NTU measurements still are high. (Avoid to inject water that is clean)
- Focus on minimizing the use of dope when RIH with completing clean up string.
- Rate after a pressure drop is seen?
- The incident should be taken towards the supplier of the junk basket.

7.9.2 Fishing of 739 m of washing string

RIH with 5” grapple and overshot (Prosafe property). Had good indication of catching the fish. (Upweigth increased from 138 to 146 ton, and pump pressure increased from 5 bar to 7 bar @ 250 lpm).
Successfully performed fishing job. Lost a total of 37 hrs due to the parted junk basket incident.

7.9.3 Running 1750 m scab liner

The drilling contractor had changed casing crew, so this was their first casing job on GFA. The job went very well, and no problems experienced.

The definition of setting depth of the PBR / hanger was discussed. It was agreed that the setting depth should be recorded with the landing string going down, tagging with 0 WOB, i.e. the landing string in frictional compression.

7.9.4 Running 7” production (injection) tubing

This part of the job went fully in accordance to the programme and detailed procedure.

8 Appendix 3 : Figures and tables

8.1 Figure 8.1 Wellbore schematic

8.2 Figure 8.2 Completion Schematic

8.3 Time/depth curve & key figures

8.4 Figure 8.4 Lotus 123 Time planner

8.5 Safran Planner Timeplanners

8.6 Figure 8.6 Final pore pressures/ fracture gradient

See chapter 5, pages 35 - 37

8.7 Table 8.1 Drilling fluids recap table

8.8 Table 8.2 Cement Recap table

8.9 Figure 8.7 Well head / TSR / X-tree schematic

9 Appendix 4 : DBR Summary/BHA/Bit

10 Appendix 5 : Friction factors

10.1 General

The friction factors are found from matching real torque and drag seen when drilling the different wellbores with simulations in Ideas Slider. The drag friction factors are calculated from recorded up and down weights during drilling and running of casing/liner. The torque friction factors are calculated based on real torque observed in rotary drilling.

10.2 17 ½" section

Drillstring:
Off bottom torque in the 17 ½" section is found to be best matched with a friction factor of 0.28 in casing and 0.30 in open hole.

13 3/8" casing:
The reported numbers for up- and down-weight do not correspond to the calculated numbers. Neither is it possible to re-calculate friction factors to fit the curves. As an example: Down-weight at bottom of 20" casing correspond to a friction factor of 0.85. Upweight at the same depth correspond to a friction-less case (ff = 0.0). The quality of the recorded numbers must therefore be questioned.

10.3 12 ¼" sections

For the 12 ¼" sections in both A-48 and A-48 A, a good match between calculated and observed torque is found with friction factor of 0.18 in both casing and open hole.

The 9 5/8" liner was lost in hole during running, and data for a long interval is therefore missing. It seems however that the used friction factors of 0.18 in casing and 0.26 in open hole give a good match for the down-weights.
For the up-weights, friction factors of 0.15 in casing and 0.20 in open hole seem to give a good match at TD. However, as can be seen from the curves, the discrepancy between calculated and observed up-weight starts to increase from around 1000 m MD. This discrepancy can not be explained, and no friction factor can be found to match the observed up-weight. The quality of the recorded up-weights must therefore be questioned.

10.4 8 ½" sections

For the 8 ½" sections in both A-48 A and A-48 B, a friction factor of 0.18 in both casing and open hole again give a good match between calculated and observed torque.

The 7" liner had to be washed and worked down on every stand after reaching a problematic zone just below the 9 5/8" shoe. Open hole friction factor for this job is therefore not achieved. For running in inside casing, a friction factor of 0.15 gives a good match for both up– and down-weight.

10.5 6" section

A friction factor of 0.18 was used prior to drilling the section. This gave a good match when drilling out of the 7" liner, but as can be seen from the plot, there is in fact no increase in torque through the remaining section. The likely reason is that the recorded torque at start of the section not is "normalized" before drilling some stands below the shoe. This can be caused both by getting the assembly out in new formation, initial wear of new casing, increasing mud-temperature and addition of G-seal in the mud. The off bottom torque seems to have stabilized at approx. 7300 m MD. By extrapolating these values back to the shoe, friction-factors of 0.16 in casing and 0.15 in open hole give the best match with the observed torque.

10.6 Conclusion:

For the 17 ½" section, friction factors of 0.28 in casing and 0.30 in open hole give a good match between calculated and observed torque for drilling. Reasonable numbers for running 13 3/8" casing is not found.

Predicted friction factors when drilling 12 ¼" and 8 ½" sections was 0.18 for both casing and open hole. This gives a good match with the observed torque for these sections.

For the 9 5/8" liner, data for a long openhole interval is missing due to the liner was lost in hole. It seems however that the predicted friction factors of 0.18 in casing and 0.26 in open hole give a good estimate for down-weight.
For calculation the up-weights, the friction factors are lower, and shows at TD the best match with 0.15 in casing and 0.20 in open hole. The up-weight shows however discrepancies between calculated and observed numbers which can not be explained by altering friction factors.

For the 7" liner, the cased hole friction factor is estimated to 0.15. Open hole friction factor can not be evaluated as the liner had to be washed / worked down due to sections with tight hole.

Drilling of the 6" liner gave lower friction than estimated. Best match is found with a cased hole factor of 0.16 and a open hole factor of 0.15.

11 Appendix 6 :Synergi short reports

12 Appendix 7 : Contractors list

Service	Contactor
Drilling Contractor	Prosafe Drilling Services (PDS)
Directional Drilling	Baker Hughes Inteq (BHI) / Anadrill Schlumberger
Directional Surveying	Baker Hughes Inteq (BHI) / Anadrill Schlumberger
Whipstock	Smith Red Baron (SRB)
Drilling Fluids	MI
Cement	Halliburton
Liner hanger	Weatherford
Casing / tubing make up	Franks A/S and Prosafe Drilling Services (PDS)
Well head etc.	Prosafe/ABB Offshore Technology A/S / Maritime Hydraulics (Koomey Inc.)
Completion Fluids	BJ
Tubing hanger, X-mas tree, etc.	Cameron Norge AS
DHSV	Camco
Production packer, PBR, etc.	Camco