Peterhead CCS **Project**

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Executive Summary

As part of the Peterhead CCS project it is intended to inject 15 million tonnes of CO_2 into the Captain reservoir in the Goldeneye field. Results from geological and dynamic modelling (Key Knowledge Deliverable 11.122) with 20 million tonnes of injected CO_2 confirm structural and geological containment.

In order to ensure well integrity is maintained during and post injection it is essential to review the condition of all the engineered wellbores in the vicinity of the Goldeneye field. This includes an analysis of the original design parameters and the abandonment plugs set in the 13 abandoned Exploration and Appraisal (E&A) wells and a review of the suitability of the current Goldeneye platform wells for CO_2 injection. This report provides a comprehensive review of the condition of the abandoned E&A wells in the area, the proposed injection wells and plans for plugging and decommissioning of these wells post CO_2 injection.

The casing design for the abandoned exploration and appraisal wells and the existing Goldeneye wells has been reviewed. The conductor and casing condition has been analysed and deemed fit for purpose for the extended life under CO_2 injection.

A detailed review of the original drilling reports has been carried out to establish the casing cement placement and quality. Portland cement slurry has been used for casing cementation and hence the effect of CO_2 on Portland cement has been explored with the conclusion that it is suitable for CO_2 injection environments.

The condition of the abandoned Exploration and Appraisal (E&A) wells in the proximity of the Goldeneye field has been analysed and it has been concluded that only two wells present a potential risk of leakage outside the storage complex. A further analysis of these two wells demonstrates that the risk of flow along the tortuous pathways low enough that it can be considered as negligible.

In order to retain well integrity over the CO_2 injection phase an upper completion workover is necessary for the Goldeneye platform wells. At the end of injection life the wells must be plugged and decommissioned. To facilitate this, abandonment proposals for the Goldeneye injection wells have been prepared based on the well condition after the proposed CCS workover activities. The Goldeneye wells will be abandoned with secure primary and secondary seals, in such a way that they also will present a negligible risk of leakage outside the storage complex.

1. Introduction

Drilled wells may create potential fluid migration paths for reservoir fluids, as the caprock gets disturbed during the construction process of the well. The installed seal in and around the wellbore may not be as robust as the original caprock.

In order to establish that the area around the Goldeneye field is suitable as a storage site for CO_2, potential well related leak paths associated with all the wells in the area has been investigated.

The objective of this study is to review all the wells in the proximity of the Goldeneye field for their suitability to cope with CO_2, this includes the abandoned exploration and appraisal wells and the proposed CO_2 injection wells.

For the first part of the study, an area of 25 x 17.5 km has been selected with the Goldeneye field in the centre. This area has been selected as it encompasses the proposed storage complex. In this area, 13 abandoned Exploration and Appraisal (E&A) wells are present. These abandoned wells have been assessed for the quality of abandonment and their suitability to cope with CO_2 conditions.

For the second part of the study, the five proposed injection wells have been reviewed to establish their suitability for CO_2 injection. Plans for abandoning these wells have been included in a separate document (Abandonment Concept for Injection Wells (1), Key Knowledge Deliverable 11.100); however, some content is included under section 6 of this report for completeness.

The detailed assessment in this Report, taken together with formation modelling work, indicates that the eighteen wells in the vicinity of the reservoir fall into the following categories:

Wells with no credible risk of providing a leak path

1. Eight exploration and appraisal wells (20/3-1, 20/4b-3, 20/4b-4, 14/28a-1, 14/28a-3a, 14/28b-2, 14/28b-4, 14/29a-4) that have no contact with the reservoir and have been shown to be outside the maximum area to which CO_2 could migrate either from the reservoir or below the Lista formation;
2. One well (14/29-a2) which has no reservoir contact but is close to, but outside the maximum projected CO_2 migration distance. This well has good barriers at deep and shallow formations, and is considered very low risk as a source of leakage to surface;
3. Two exploration and appraisal wells (20/4b-6, 20/4b-7) in contact with the reservoir, and with an effective primary seal, but without a secondary seal at the Lista formation. These wells see relatively low quantities of mobile CO_2 from the reservoir. Also, modelling shows no credible potential for CO_2 leaking to formations above the Rødby Shale to reach these wells in detectable quantities. So any leakage would be following a failure in the reservoir barrier. Modelling shows that the majority (possibly all) of the CO_2 will remain in the formation within 3.5 km of the release point, and no significant quantity of leakage could occur from the Complex.

Wells with a credible, but low, risk of providing a leak path to surface

1. Five current Goldeneye wells (GYA-01, GYA-02s1, GYA-03, GYA-04, GYA-05) that will be made secure against reservoir leakage by abandonments providing secure primary (Rødby) and secondary (Lista) seals.
2. One exploration and appraisal well (14/29a-5) that has contact with the reservoir, but has effective seals at both the Rødby and Lista formations. For this well, it has been shown that, even in the improbable event of failure of the primary seal, CO_2 would take over 20 years to migrate as far as a well providing a secondary leak path (well 14/29a-3). This

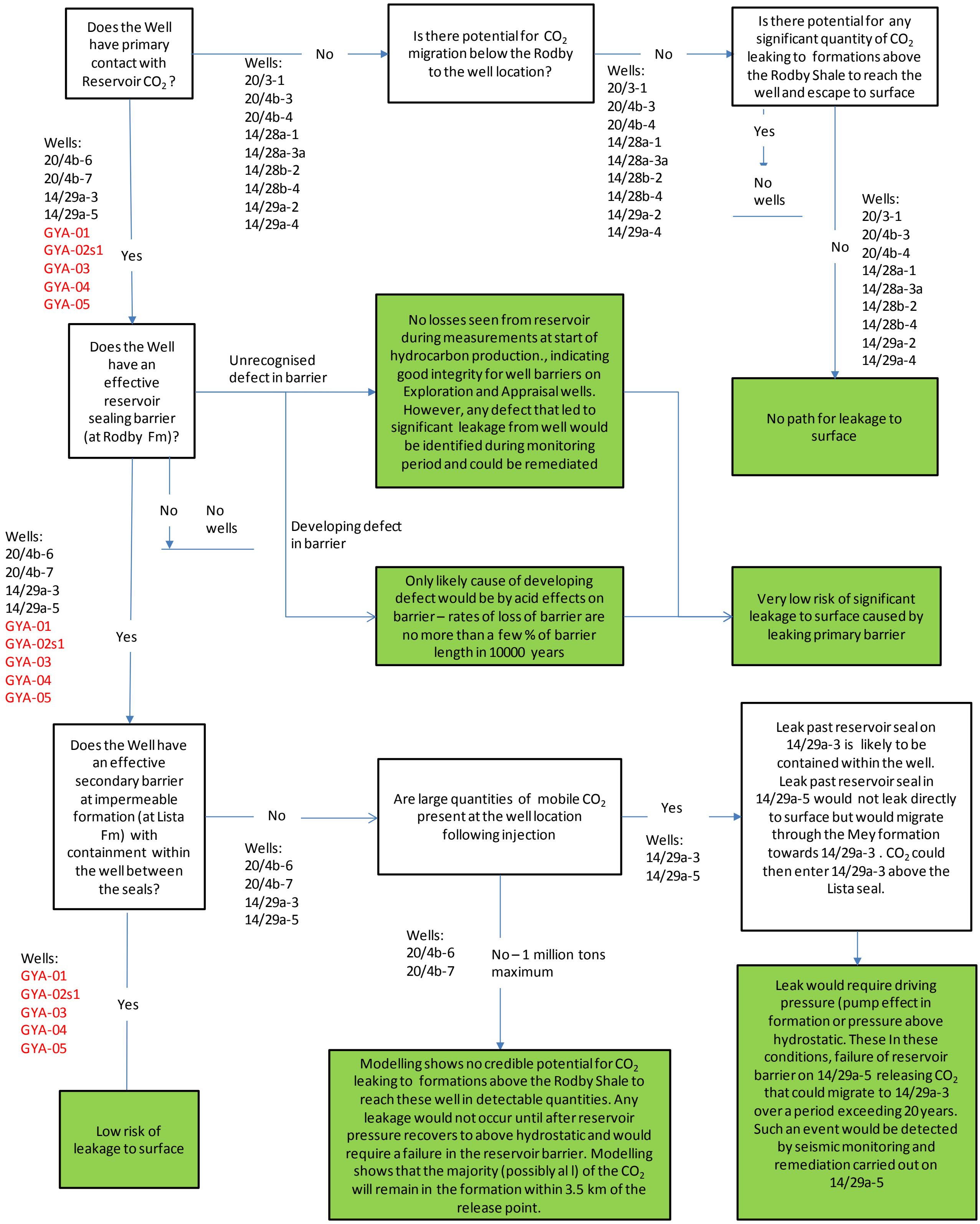
event would be detected through the monitoring programme and could be remediated before leakage to surface via well 14/29-a3 occurred.

3. One exploration and appraisal well (14/29a-3) that has contact with the reservoir, has an effective seal at the Rødby formation and further plugs higher in the wellbore. This well is considered low risk as a primary source of leakage from the reservoir, but could provide a path for secondary leakage from 14/29a-5. As stated above, this is a low probability, detectable and remediable event.

As a result it is concluded that exploration and appraisal wells present a low risk of leakage outside the Complex. Also, the Goldeneye wells will be abandoned with secure primary and secondary seals, in such a way that they also will present a low risk of leakage outside the Complex.

It should be noted that these leakage scenarios are based on an assumed driving force. Taking account of the current sub-hydrostatic Goldeneye reservoir pressure and the modelling that predicts that it will take thousands of years to reach hydrostatic pressures again, it is highly unlikely that such leakage scenarios could develop.

The flowchart included below illustrates the potential leak scenarios and risk of leakage for each well, as described above.



Note: Wells shown in Red are currently Suspended. Flowchart assumes these wells abandoned to Oil and Gas UK Standards as set out in Well Integrity Assessment Report

Figure 1.1: Summary of barriers in place to prevent releases to surface via a well

2. Casing Review

This casing review covers two areas. The first is a review of the casing design and it covers casing size, placement and loads. The second area of review is the suitability of the Goldeneye wells for CO_2 injection and it covers the material specification and compatibility.

2.1. Summary

From the results it can be seen that the E&A casing points vary widely. It seems the operators' targets, perception of the hazards from unstable shales and open hole hydraulics are the key drivers for casing points.

All the E&A wells have been abandoned with casing strings cut below the seabed, as such re-entering these wells is extremely challenging and not practically possible.

The Goldeneye Platform wells were all drilled with the same Shell casing design and casing setting horizons.

Present Goldeneye Platform casing design has been checked for suitability in CO_2 injection mode, assuming the expected values for CO_2 pressures, temperatures and volumes.

If the current Goldeneye Platform wells for CO_2 injection are retained, there are no concerns with:

- casing design
- carbon steel compatibility issues with CO_2 injection provided we keep to a maximum of 165 days of wet events in the next 15 years.

Studies show that the surface casing will be good for the expected load cases for the duration of the extended field life. There is no transfer of load to the conductor.

2.2. Exploration and Appraisal Wells Casing Review

All the offset exploration and appraisal wells were drilled with semisubmersible rigs. The water depth of ~400ft [1ft = 0.3048m] is ideal for a semisubmersible. This also means all wells were drilled with a seabed wellhead system and marine riser.

The area is a normally pressured / hydrostatic one. When these wells were drilled starting in 1978, there was limited data and different perceptions of the pressure regime. These perceptions will have changed the casing design to that of a more robust design.

None of the well designs was used to produce commercial hydrocarbons but some were used to perform DSTs. However, some designs were adapted to allow them to be used as keeper wells. For example 10 3/4" x 9 5/8" [1" = 25.4mm] casing was run in some instances to allow the use of a SSSV in the upper part of the well in the event that a tubing string was run.

Table 2-1: Goldeneye Offset Wells

Well Name	Date Drilled	Company
14/28a-1	Mar-90	Shell
14/28a-3A	Jul-00	Shell
14/28b-2	Nov-97	Shell

14/29a-2	Nov-80	Shell
14/29a-3	Jul-96	Shell
14/29a-4	Jan-98	Shell
14/29a-5	Apr-99	Shell
20/3-1	Nov-79	Conoco
20/4b-3	Apr-89	Amerada Hess
20/4b-4	Dec-90	Amerada Hess
20/4b-6	Dec-97	Amerada Hess
20/4b-7	Dec-99	Amerada Hess
14/28b-4	Jul-06	British Gas

2.2.1. Casing Design Approaches

Reviewing the casing programmes for all E&A wells, they allow for:

- Safely conducting drilling operations to the target TD (Total Depth) of the well.
- Logging the objectives with minimum risks.
- Testing operations to be conducted, with full containment.

Many variations of casing designs have been used in the E&A wells. These are summarised in the table below.

Table 2-2: E&A wells, casing design

Well Name	Casing Design				
14/29a-3	35" x 30"		20" x 13 3/8"	10 3/4" x 9 5/8"	7" Liner
14/29A-4	35" x 30"		20" x 13 3/8"	10 3/4" x 9 5/8"	
14/28b-2	35" x 30"	20"	13 3/8"	10 3/4" x 9 5/8"	
14/29a-5	30" x 20"		20" x 13 3/8"		
14/28a-3	30" x 20"		13 3/8"		
20/3-1	30"	18 5/8"	13 3/8"	9 5/8"	
14/28a-1	30"	20"	13 3/8"	9 5/8"	
20/4b-4	30"	20"	13 3/8"	9 5/8"	7" Liner
20/4b-7	30"		13 3/8"		
Goldeneye Wells	30" x 20"		20" x 13 3/8"	10 3/4" x 9 5/8"	7" Liner

2.2.2. Generalised Casing Setting Depths/Casing Setting Depth Criteria

All the E&A wells (13) reviewed were drilled with semisubmersible drilling rigs.

There is no consistent approach to drilling the E&A wells. Of thirteen wells reviewed:

Mud type beyond top hole:

- Seven wells were drilled with WBM (Water Based Mud).
- Six were drilled with OBM (Oil Based Mud).

Shoe setting depths:

- Seven wells had casing shoes set in the chalk formation at 5,000 - 6,000 ft. TVDSS (Tubing Retrievable Subsurface Safety Valve); and
- the rest in other formations

14/29a-3 was the only E&A well that was not drilled vertically (38.5 degrees hole angle).

Criteria for the casing design are not readily available but the reasons for different shoe depths are likely due to the differing reservoir targets. Not all E&A wells were targeting the Captain Reservoir. Eleven wells were drilled to beneath the Kimmeridge formation. Furthermore, it can be seen that not all the formations are present and many formations are pinched out in the local Goldeneye area. Captain reservoir was not present on the following wells - 14/28a-1; 14/28a-3; 14/29a-2; 20/3-1; and 20/4b-4.

Hence hydrocarbon containment and pressure regime, although hydrostatic pore pressure, were different for E&A wells.

All the E&A wells have been abandoned with casing strings cut below the seabed. The abandonment condition of each well is explored further in this report in section 4.

2.3. Goldeneye Platform Casing Review

A detailed review of the Goldeneye Platform Casing Design is included in the Conceptual Completion and Well Intervention Design Endorsement Report (2). This section provides a brief overview of the design and summary of the detailed review.

The Goldeneye platform jacket and topside was installed in 2003 by the Heerema Thialf heavy lift barge. Grade X52 30" x 1 1/2" wall thickness conductors, complete with Oil States internally upset Merlin connectors, and 2" wall thickness drive shoes, were installed and driven to refusal at ~190 ft. beneath the seabed. Following these operations, Maersk jack-up drilling unit Innovator batch drilled all the wells on Goldeneye Platform. That is all the 17 1/2" sections were drilled; followed by the 12 1/4" sections and finally the 8 1/2" sections.

All the wells consist of a 30” conductor, followed by a tapered surface casing string 20” x 13 3/8” and a production casing string 10 ¾” x 9-5/8”. The wells also incorporate a 7” pre-perforated 13Cr production liner.

2.3.1. Summary

Goldeneye Platform wells have been analysed with Halliburton WELLCAT software. The analysis models the conditions of CO_2 injection.

Pulsed Eddy Current (PEC) measurements conducted in 2007 and in 2010 show that the 20" Surface Casings and 30" Conductors of the Goldeneye platform are within the first-level severity criterion for Surface Casing wall loss of producing wells i.e. 25%.

An additional PEC survey was carried out in June 14, the detailed report and findings have not yet been received however preliminary analysis has shown favourable results.

Hence Goldeneye 20" casing will be good for the expected load cases for the duration of the extended field life. It follows that no load transfer to the conductor is expected.

Present Goldeneye platform casing design has been checked for suitability in CO_2 injection mode, assuming the expected values for CO_2 pressures, temperatures and volumes. No issues have been identified with the casing design. Carbon steel compatibility issues with CO_2 can be mitigated provided exposure is kept to a maximum of 165 days of wet events over 15 years.

2.3.2. Casing Design Safety Factors

Shell casing design safety factors are shown in Table 2-3 below:

Table 2-3: Casing Safety Factors

Scenario	Safety Factor
Burst	1.10
Collapse	1.00
Axial (tension)	1.30
Axial (compression)	1.15
Triaxial	1.10

2.3.3. Casing Design Assumptions

Assumptions

- Good casing cementation was assumed throughout.
- When cementation is across a permeable formation, pore pressure was assumed.
- Temperature de-ration was applied to all strings
- Buckling effects were taken into account

Pressure

The target Captain reservoir was taken as normally pressured at 3,852 psia [1psi = 0.0689bar] at ~8,300 ft. TVDSS.

There were no over pressured or hydrocarbon bearing zones prior to entering the Captain reservoir.

Temperature

The TD temperature for each well was taken as 82.7°C at ~8,300 ft. TVDSS.

2.3.4. Conductor

The chosen conductor design for Goldeneye was based on the following criteria.

- Conductor to provide marine protection only, no load-bearing requirement.

- Conductor to be driven - drilling or drill drive not acceptable due to shallow soil stability criteria.
- Fatigue resistance during installation and field life.
- Drive ability and resistance to directional deviation.
- Merlin mechanical connectors to reduce installation time

The final conductor design was generated as a result of collaboration between Heerema (Installation Contractor), UWG (Structural Analysis consultants), Aker (Conductor Fabrication) and Shell Expro. The final design is as follows.

Table 2-4: Conductor Design

Casing	TVD Depth Below Seabed	Minimum S.F. Burst	Minimum S.F. Collapse	Minimum S.F. Triaxial
30" 1.5" WT X52 Merlin HDEF connectors	190 ft.	N/A	N/A	N/A

The maximum wall loss determined by PEC was 10% or less, on the 20" Surface Casings and 30" Conductors of all wells, both in August 2007 and in May 2010, except for the 20" Casing of GYA-02 in May 2010 (maximum wall loss of 14%) and the 30" Conductor in August 2007 (maximum wall loss of 12%). The 10% criterion is a reporting criterion for PEC readings. Wall loss less than 10% is regarded as not significant, because 10% variation in PEC reading may be caused by metallurgic variations.

2.3.5. Intermediate Casing

A tapered string of 20" x 13 3/8" was set as the intermediate string; the tapered string of 20" x 13 3/8" included the 5,000 psia 18 3/4" Cameron SSMC wellhead system. As such, this string carries the load of the subsequent production casing and completion strings. Analysis of the loads induced (undertaken by UWG) indicated that a string of 13 3/8" casing would fail under the buckling load if run inside the 30" conductor. In consequence, a short section of 20" casing was run from the 18 3/4" wellhead to 700 ft. TVDBDF. A further finding of the analysis was that due to the bending loads induced by relative jacket and jack up movement, a joint of X80 20" x 1" WT is required for the initial 40 ft. below the wellhead.

The section was drilled using an un-weighted pre-hydrated bentonite mud with returns to surface. However, for the event that insufficient shoe strength to facilitate this was achieved at the 30" shoe, circulation ports were cut in the conductor above the seabed and the 17 1/2" section drilled with the bentonite mud system taking returns to the seabed.

The 13 3/8" shoe was set at 100 ft. below the top of the Lower Dornoch Mudstone. This was sufficiently deep to enable the 12 1/4" section to be drilled with a planned mud weight of 560 - 580 pptf (maximum mud weight of 620 pptf high inclination wells). An FIT (Formation Integrity Test) of 630 pptf was expected at the 13 3/8" shoe.

The string was cemented with returns to seabed, and top up grouting system included to ensure that the TOC was above the 13 3/8" x 20" crossover.

Table 2-5: Intermediate Casing

Casing	Setting Depth Ft MD	Minimum S.F. Burst	Minimum S.F. Collapse	Minimum S.F. Axial	Minimum S.F. Triaxial
20" x 1" WT, X80, SR20	40	1.13	100	2.33	2.64
20" x 1" WT, X65, SR20	700	1.12	12.74	2.70	2.59
13 3/8" 68 lb/ft. N80, Dino VAM	4,200	1.85	1.24	2.87	2.01

2.3.6. Production Casing

The production casing selected is a tapered string of 10 3/4" x 9 5/8". The 10 3/4" is required to allow the installation of a 7" TRSSSV within the completion string. The valve has a minimum setting depth of 2,600 ft. TVDSS. This is to ensure it is below the hydrocarbon hydrate formation depth for the initial hydrocarbon conditions. The 9 5/8" shoe was set at the Base Rødby. As such, there is no limitation on the kick tolerance with respect to formation strength.

The following table details the production casing design for the Goldeneye wells

Table 2-6 Production Casing

Casing	Setting Depth Ft MD	Minimum S.F. Burst	Minimum S.F. Collapse	Minimum S.F. Axial	Minimum S.F. Triaxial
10 3/4", 55.5, L80, VAM Top	2,890	1.41	2.27	1.81	1.44
9 5/8", 53.5, L80, VAM Top	8,500-13,000	1.51	1.29	1.77	1.49

9 5/8", 53.5 lb/ft., L80, VAM Top Alternative drift was used in all wells in order to ensure that the worst case collapse loading is met and to reduce logistical issues during the execution phase.

2.3.7. Pre-perforated Liner

Goldeneye Platform wells were lined with pre-perforated 7" liner and hung off with liner hanger and PBR.

Table 2-7: Goldeneye Wells Casing Setting Depths

DEPTHS TVDSS (FT)

Unit	Lithology	GYA01 Shoe	GYA01 Size	GYA02 Shoe	GYA02 Size	GYA03 Shoe	GYA03 Size	GYA04 Shoe	GYA04 Size	GYA05 Shoe	GYA05 Size	GYA02s1 Shoe	GYA02s1 Size
Water Column	N/A												
Nordland Gp	N/A	597	30"x20"	598	30"x20"	585	30"x20"	597	30"x20"	597	30"x20"		
Westray Gp (Lark Fm)	Sand												
Stronsay Gp (Horda Fm)	Mud + Sand												
Beauly Mbr	Sand												
Upper Dornoch Sandst	Mud + Sand												
Dornoch Mudst	Mud												
Upper Dornoch Sandst	Mud + Sand	3,923	20"x13 3/8"			3,942	20"x13 3/8"	3,921	20"x13 3/8"	3,947	20"x13 3/8"		
Lista Fm	Mud + Sand			3,931	20"x13 3/8"								
Mey Sst	Mud + Sand												
Upper Balmoral Sandst	Mud + Sand												
Lower Balmoral Sandst	Sand												
Maureen Fm	Mud + Sand												
Ekofisk Fm	Chalk												
Tor Fm	Chalk												
Hod Fm	Chalk												
Herring Fm	Chalk												
Marl)	Marl												
Hidra Fm	Marl												
Rodby Fm	Marl	8,255	10 3/4"x9 5/8"			8,357	10 3/4"x9 5/8"	8,295	10 3/4"x9 5/8"			8,130	
(Upper) Valhall Fm	Mud									8,235	10 3/4"x9 5/8"		
Captain Mbr	Sand	8,395	7" Liner	8,291 8,304	10 3/4"x9 5/8" 7" Liner	8,481	7" Liner	8,398	7" Liner	8,370	7" Liner		
(Lower) Valhall Fm	Mud												
Yawl Sst	Sand											8,398	7" Liner
(Lower) Valhall Fm (cont.)	Mud												
Scapa Sst	Sand												
Punt Sst	Sand												
Kimmeridge Clay	Mud												
Burns Sst	Sand												
Heather Fm	Mud + Sand												
Pentland Fm	Mud + Sand												
Smith Bank Fm	Mud												
Zechstein Gp	Carbonate												
Rotliegend Gp	Sand												
Total Depth		8,397		8,395		8,484		8,401		8,371		8,400	

2.4. Suitability of Casing Design for CO_2 Injection

This section of the casing review looks at the suitability of existing:

- casing corrosion (PEC measurements),
- casing material compatibility; and
- casing design for CO_2 injection.

2.4.1. Corrosion

The Goldeneye Platform 20" surface casing strings and 30" conductors have been periodically checked for corrosion.

The 30" conductor and the 20" surface casing are free standing and independent of one another. That is the 20" surface casing takes all the well loading and does not transfer the load to the 30" conductor.

Since the installation of the Goldeneye wells, the conductors and the surface casing strings have been measured for corrosion by means of a Pulsed Eddy Current (PEC) Tool. Wall thickness results from the latest survey are included in the following table.

Table 2-8: Maximum corrosion rate of Surface Casings and Conductors

Well	Spud Date	Date of PEC Inspection	Age of Well on Date of Inspection	Maximum Wall Loss (mm)	Maximum corrosion Rate [mm/yr.]
20" Surface Casing					
GYA-01	08/12/03	24/05/2010	6.5	2.0	0.31
GYA-02	13/12/03	25/05/2010	6.5	3.6	0.55
GYA-03	19/12/03	24/05/2010	6.4	2.0	0.32
GYA-04	05/10/03	26/05/2010	6.6	1.0	0.15
GYA-05	02/12/03	23/05/2010	6.5	1.8	0.27
30" Conductor					
GYA-01	08/12/03	23/05/2010	6.5	3.8	0.59
GYA-02	13/12/03	26/05/2010	6.5	3.8	0.59
GYA-03	19/12/03	24/05/2010	6.4	3.0	0.47
GYA-04	05/10/03	23/05/2010	6.6	3.4	0.52
GYA-05	02/12/03	25/05/2010	6.5	3.4	0.53

The 20" Surface Casings and 30" Conductors of wells GYA-01, GYA-02, GYA-03, GYA-04 and GYA-05 were inspected from the top of the Conductor to a few metres below LAT during three campaigns from August 2007 to May 2010. The following conclusions are drawn:

1. The PEC measurements both in 2007 and in 2010 shows that none of the 20" Surface Casings and 30" Conductors of the Goldeneye platform exceeded the 25% wall loss. 25% wall loss is a first-level severity criterion for Surface Casing wall loss of producing wells.
2. The maximum wall loss determined by PEC was 10% or less, on the 20" Surface Casings and 30" Conductors of all wells, both in August 2007 and in May 2010, except for the 20" Casing of GYA-02 in May 2010 (maximum wall loss of 14%) and the 30" Conductor in August 2007 (maximum wall loss of 12%). The 10% criterion is a reporting criterion for PEC readings. Wall loss less than 10% is regarded as not significant, because 10% variation in PEC reading may be caused by metallurgic variations.
3. The maximum corrosion rate on the 20" Surface Casing over the period from spud date in 2003 to the PEC measurements in May 2010 ranges from 0.15±0.39 mm/yr. (GYA-04) to 0.55±0.39 mm/yr. (GYA-02). Only the corrosion on 20" Surface Casing of GYA-02 is statistically significant.
4. This finding is consistent with conclusion 2.
5. The maximum corrosion rate on the 30" Conductor over the period from spud date in 2003 to the PEC measurements in May 2010 ranges from 0.47±0.59 mm/yr. (GYA-03) to 0.51 ±0.59 mm/yr. (GYA-01 and GYA-02), none of these are statistically significant. This finding is consistent with conclusion 2.
6. The maximum corrosion rates between spud date and August 2007 and between August 2007 and May 2010 are not statistically significant for any of the 20" Surface Casings and the 30" Conductors, except the 20" Casing of GYA-01 and the 30" Conductors of GYA-01, GYA-03 and GYA-05 between August 2007 and May 2010. The latter corrosion rates are only just statistically significant. Apart from these exceptions, PEC has therefore not detected statistically significant corrosion.
7. The corrosion rates of both 20" Casings and 30" Conductors in the period between August 2007 and May 2010 are not different from the corrosion rate in the period between spud date and August 2007 at the 95% confidence level.
8. The elevation of the maximum corrosion rates on the 20" Surface Casings is below the fluid level in the 'D' annulus, where no corrosion is expected, except for GYA-03. This is consistent with no significant corrosion on the 20" Casings.

2.4.2. Material Compatibility

All Goldeneye Platform production casing strings are made from carbon steel. The majority of this casing is protected by 13 Chrome material tubing. There are two zones that are exposed to CO_2. These are:

- below the lower sand screen packer; and
- a section between the two permanent packers (exposed by a perforated joint)

Goldeneye lower completion tubing steel is 13% Cr. This is also the case for the 4" Screens and 7" Pre-perforated liner. The 9 5/8" Production Casing is made of Carbon Steel. Free water in combination with CO_2 will lead to dissolution of CO_2, forming carbonic acid (H_2CO_3). This might lead to corrosion of carbon steel. For 13% Cr material this is not considered a corrosion threat.

The production casing above the existing packer has only been in contact with the completion fluid used in the A-annulus. That fluid was inhibited seawater installed during the completion operations. Hence the corrosion of this production casing above the production packer is expected to be negligible.

Condition of the casing below the production casing is less certain due to presence of Goldeneye hydrocarbon gas in contact with the casing.

The hydrocarbon gas in Goldeneye has a small content of CO_2 (0.4% mol). During the hydrocarbon production phase the 13% Cr components are estimated to have practically no corrosion. Goldeneye gas was in contact with elements below the 9 5/8" packer during the production phase. There is a perforated pup joint between the 9 5/8" production packer and the screens hanger creating a trapped volume of A-annulus fluid - most likely seawater. Due to the presence of CO_2 in the gas there is some corrosion potential in the production casing below the 9 5/8" production packer to the casing shoe, especially in the dead volume below the perforated pup joint and the screens hanger.

The Goldeneye reservoir is connected to a large aquifer and all five wells are suspended. As such, the lower completion may be in contact with formation water.

Over time, with CO_2 injection, the presence of water will decrease as the water is displaced by the CO_2, and eventually water presence will disappear.

The estimated wet events to avoid corrosion of the 9 5/8" production casing below the packer was previously estimated at 3% wet events in 15 years or 165 days of wet events. This represents the maximum time allowed to have wet events (CO_2 + water). CO_2 will be injected dry thereby limiting the wet events.

Because of the presence of water in the bottom of the well the displacing time of the formation water by the CO_2 should be considered. Based on CO_2 EOR projects it is estimated that the water in the bottom of the well will be displaced in the matter of weeks.

2.4.3. Casing Design for CO_2 Injection

Casing design has been verified using "WellCat"™ Halliburton Landmark software.

Casing design assumptions and results are included in Appendix 1.

The assumptions take into account the operating parameters - pressures, temperatures and rates that the Goldeneye Platform wells will see during the CO_2 injection phase.

A 3 1/2" tubing string was used in the casing design together with a base oil packer fluid. This tubing size is typical of the tubing size that will be employed during the injection phase. Base oil in the annulus is still subject to ongoing investigation, the alternative being brine.

The important result is that both the surface casing and the production casing are within limits for the loads modelled with the Shell minimum safety factors.

The following figure shows a typical Goldeneye well schematic with formations and casing setting depths.

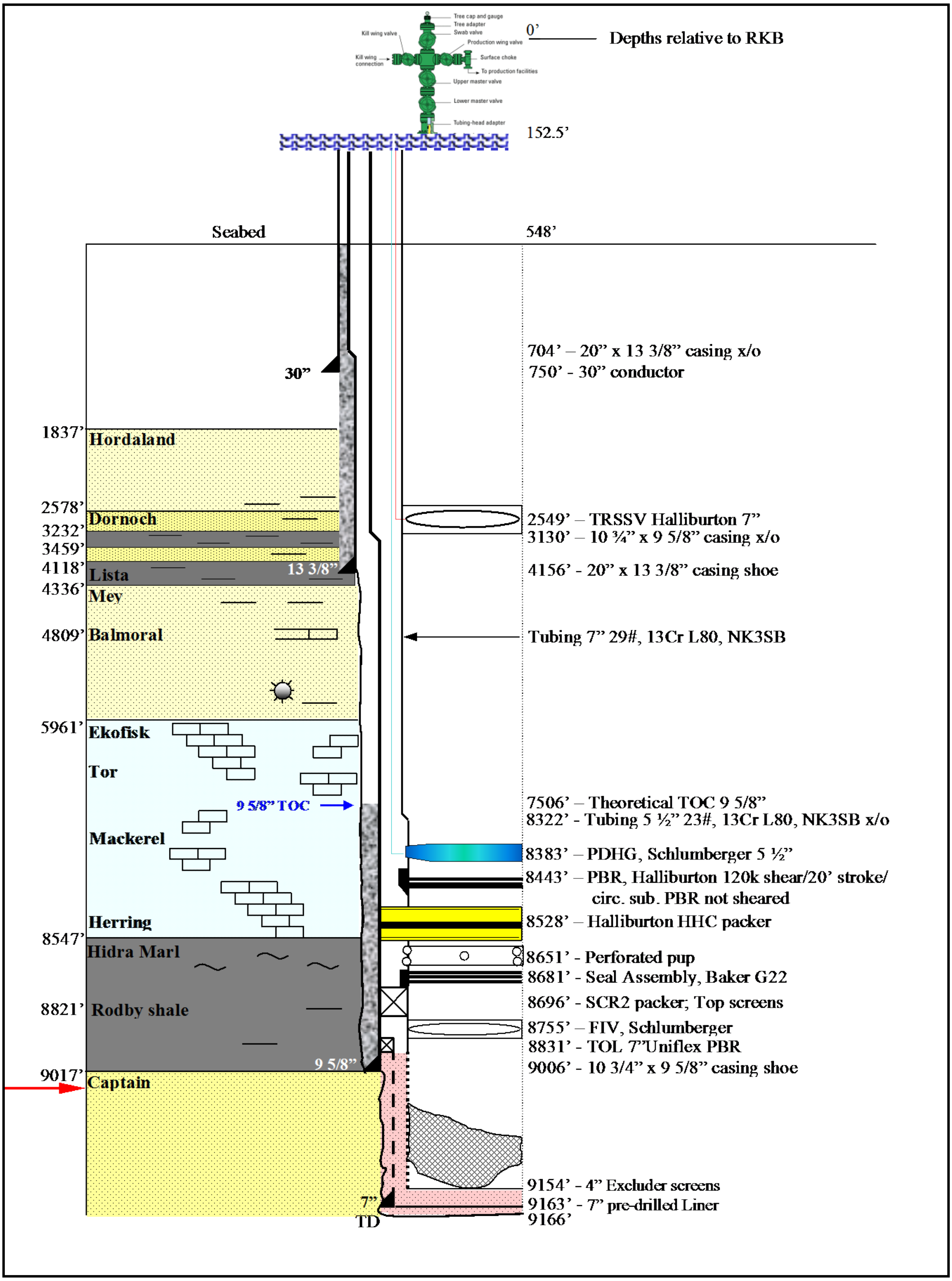


Figure 2.1 Goldeneye Platform, Typical Well Schematic

3. Cement Review

There are 13 E&A wells in the Goldeneye area but only five that will be affected by the 'CO_2 plume' created by injection of CO_2 into the Goldeneye reservoir. All of these E&A wells are abandoned.

Furthermore, there are five Goldeneye Platform wells. All of the wells have been drilled and then the casing strings cemented in place. These five wells have been producing hydrocarbons since October 2004. It is intended to inject CO_2 into these wells by 2019.

Post CO_2 injection the Goldeneye Platform wells will be abandoned. It is also possible that a sidetrack or 'new drill' well is performed on the Goldeneye Platform. A Concept Select workshop was held to discuss the possibilities around cement suitability with regard to CO_2 injection.

3.1. Summary

The effect of CO_2 injection on the cement in Goldeneye wells is discussed in this section.

Each well type has been reviewed for suitability to injection of CO_2, with the conclusion that all types of well will be fit for CO_2 injection.

Conclusions are:

- cement in existing wells will protect against CO_2 leaks
- special CO_2 resistant cements may be qualified to decide on suitability and improvements over Portland cement
- a Portland cement programme adapted for CO_2 resistant properties can be put together for the expected future operations and downhole conditions

Diana software, a specialist mechanical cement model has been run to ascertain the effects of CO_2 injection on Goldeneye Platform. The results indicate that there will be no mechanical problems due to CO_2 injection.

Chemically, due to the absence of water in the delivered CO_2 - injection phase, once water, and hydrocarbons have been displaced; there is no mechanism to create corrosive carbonic acid. Later in the life of the wells, after the injection phase, reservoir dynamics such as gravity, miscibility and reactions with downhole formations, will mean carbonic acid will reappear at the base of the cement in the Goldeneye wells. As above, this is not assessed to be a problem for Goldeneye wells.

After cessation of CO_2 injection, Goldeneye wells and the Goldeneye platform will be decommissioned. The choice of cements for abandonment and the style of abandonment will be decided by cementing technology and Governmental requirements in place at the time.

3.2. Summarised Cementing Offset Review

There are 13 E&A wells in the 17.5 x 25 km Goldeneye area but only five that will be affected by the 'CO_2 plume' created by injection of 20 million tonnes of CO_2 into the Goldeneye reservoir. All of these E&A wells have been abandoned.

Furthermore, there are five Goldeneye Platform wells. All of the wells feature cemented casing strings. These five wells have been producing hydrocarbons since October 2004. It is intended to commence injection of CO_2 into these wells by the end of 2019.

3.3. Effect of CO_2 on Cement and Casing

There is a wealth of published material on the effects of CO_2 injection on oilfield cement and tubulars. The degradation mechanisms are outlined in the sections below followed by a summary of some recent papers and their conclusions.

Possible fluid migration pathways through a well:

a) Between casing and cement.
b) Between cement plug and casing.
c) Through the cement pore space as a result of cement degradation.
d) Through casing as a result of corrosion.
e) Through fractures in cement; and
f) Between cement and rock.

Potential cementing defects include:

- Inadequate placement of cement resulting in channels or mud films,
- Channels caused by gas migration during cement hydration,
- Cracks caused by cement failure in compression/traction, and
- Micro annuli caused by lack of bonding at the interfaces with casing and/or rock, or due to poor P/T techniques

3.3.1. Cement Degradation General

Cement degradation occurs in three phases. That is to say, the interaction between Portland cement and CO_2 is a 3-step process:

- Carbonic acid diffusion,
- Cement (Portlandite) dissolution and carbonate precipitation, and decrease in porosity
- Leaching (calcium carbonate dissolution). Cement sheath defects would cause acceleration of the degradation process, generally leading to loss of density and strength and an increase in porosity.

This process relies on the presence of water. That is, water is required to form carbonic acid completing the first phase allowing the following two processes to occur. Goldeneye CO_2 delivery is expected to be more or less free of water. However, water may be present around the wellbore.

The other main factors in cement degradation are temperature, pressure, and time. Elevated temperatures and elevated pressures both speed up the degradation process. Goldeneye is fortunate in that the delivery temperature of CO_2 is expected to be around that of the sea at approximately 40 deg. F [5 °C], due to delivery via subsea pipeline. Initial injection pressure will be ~2,500 psia and rise higher as injection proceeds - towards 3,700 psia. Downhole temperature at the reservoir level will be in the order of 20°C during CO_2 injection. When injection has ceased, in the long term, the downhole temperature will return to the initial reservoir temperature of 83°C.

Due to the degradation mechanism, cement degradation from studies has been found to be time dependant. The equation can be simplified as a constant multiplied by the square root of time.

3.3.2. Steps To Avoid Cement Degradation

There are a number of basic steps that can be taken to minimise degradation of cement by CO_2:

- pump dry CO_2; no water in the injected CO_2 means no carbonic acid.
- cement placement; good spacer, lead and tail and good centralisation to avoid voids in the cement. In addition, for abandonment plugs, balanced cement plugs to avoid stringers and channelling.
- keep excess water to a minimum; have as little unreacted water as possible in cement slurry. Without water, CO_2 cannot form carbonic acid. Use a suitable filler, inert to CO_2, to close up the interstitial spaces.
- best cementing practices; all the standard requirements such as slurry testing, fresh cement, good additive control, mixing at constant density, no hold ups whilst pumping the job etc.
- avoid water based fluids in workovers; once CO_2 injection has commenced, if possible, avoid water based fluids in workovers. This is to minimise the combination with CO_2 in the well to produce carbonic acid

The reaction of Portland cement with carbonic acid forms a $CaCO_3$ film or layer on the cement surface. This slows and can stop the reaction process. Any free water in the cement can allow the formation of more carbonic acid and continue the reaction process.

Expansion and contraction can also cause micro-fractures in the cement or chip tiny bits off. If there is any free water, it will be exposed or the water released. The process of carbonic acid formation and cement attack then starts again.

3.3.3. Cementing / Casing Studies

Table 3-1: Injection Parameters

Attribute	Value
Surface CO_2 delivery temperature:	5 °C
Downhole reservoir temperature:	83 °C
CO_2 state:	Supercritical
Downhole pressure (2010):	2,100 psia
Eventual Pressure (post injection):	3,700 psia
Cement:	Class G
Temperature at reservoir during injection expected	~+20 to +30 °C

Since 2005, there have been a number of high profile studies into the effects of CO_2 on Portland cements. Short summaries of a few of the major studies that are frequently reported are included here.

The effect of CO_2 alterations on Portland cement containing calcium silicate hydrates and calcium hydroxide was studied in both laboratory experiments and field tests.

Regular Portland-based cements contain $Ca(OH)_2$, which reacts with CO_2 when water is present to form solid calcium carbonate through the following chemical reaction:

$$Ca(OH)_2 + CO_3^{2-} + 2H^+ = CaCO_3 + 2H_2O$$

This process is named cement carbonation. Even if this process alters the composition of the cement, it leads to lower porosity in the cement because calcium carbonate has a higher molar volume (36.9 cm3) than $Ca(OH)_2$ (33.6 cm3) (3). For cement sheath integrity, this reaction actually improves the cement's properties and the carbonation is therefore a self-healing mechanism in the carbonate.

In a CO_2 sequestration project, the supply of CO_2 around the wellbore will continue the carbonation process as long as $Ca(OH)_2$ is present in the cement. The calcium carbonate is also soluble with the CO_2, even though it is more stable than $Ca(OH)_2$. Experiments by Kutchko et al (4) showed that when all $Ca(OH)_2$ has reacted in the carbonation process, the pH will drop significantly.

When the pH drops, more of the CO_2 will react with water and form HCO_3-. The abundance of HCO_3- will lead to water soluble calcium carbonate which can move out of the cement matrix through diffusion (4).

The final reaction that occurs (close to the cement surface) is calcium silicate hydrate reacting with H_2CO_3 to form calcium carbonate ($CaCO_3$) according to the following chemical reaction:

$$3\ H_2CO_3 + Ca_3Si_2O_7 * 4H_2O = 3\ CaCO_3 + 2\ SiO_2 * H_2O + 3\ H_2O$$

The volume of calcium silicate hydrate is larger than the calcium carbonate and this reaction will increase the porosity of the cement in the region which is the closest to the reservoir formation containing the CO_2.

Barlet-Gouedard et al (5) tested a Portland cement API Class G in both saturated water and supercritical CO_2 at 90 °C. The rate that carbonation occurred for wet supercritical CO_2 conditions was measured and the rate of the alteration front was calculated based on:

Depth of CO_2 alteration front (mm) = 0.26 (time in hours)$^{1/2}$

From graphical extrapolation in the Barlet-Gouedard example, the carbonation process will have penetrated 10 mm into the sample after 60 days or 100 mm after 17 years. Kutchko et al (6) performed similar experiments on a Class H Portland cement slurry at 50 °C with a CO_2 saturated brine (Figure 5 and 6). The results for CO_2 supercritical brine at 50 °C showed a slower alteration front within the cement. The curve fit estimating alteration depth based on Kutchko et al (6) results for supercritical CO_2, comes out as:

Depth of CO_2 alteration front (mm) = 0.016 (time in days)$^{1/2}$.

3.3.4. SACROC

SACROC is an interesting and relevant insight into the effects of CO_2 on oilfield cements and tubulars. A 52 year old SACROC well with conventional, Portland-based well cement, was exposed to CO_2 flooding operation for 30 years at the SACROC Unit, located in West Texas. At the end of its life, the well 49-6 was cored bringing to the surface samples of cement and casing. The well was being investigated as part of a programme to evaluate the integrity of Portland-cement based wellbore systems in CO_2 - sequestration environments.

The recovered cement had air permeabilities in the tenth of a milliDarcy range and thus retained its capacity to prevent significant flow of CO_2. There was evidence, however, for CO_2 migration along both the casing - cement and cement - shale interfaces. A 0.1 - 0.3 cm thick carbonate precipitate occurred adjacent to the casing. The CO_2 producing this deposit may have travelled up the casing wall or may have infiltrated through the casing threads or points of corrosion. The cement in contact with the shale (0.1 - 1 cm thick) was heavily carbonated to an assemblage of calcite, aragonite, vaterite, and amorphous alumino-silica residue and was transformed to a distinctive orange colour. The CO_2 causing this reaction originated by migration along the cement - shale interface where the presence of shale fragments (filter cake) may have provided a fluid pathway. The integrity of the casing - cement and cement - shale interfaces appears to be the most important issue in the performance of wellbore systems in a CO_2 sequestration reservoir.

The most basic observation of the SACROC core is that at well 49-6, Portland cement survived and retained its structural integrity after 30 years in a CO_2 - reservoir environment. While the cement permeability determined by air permeametry is greater than typical pristine Portland cement, it would still provide protection against significant movement of CO_2 through the cement matrix. The location of the sample at only 3 - 4 m above the reservoir contact suggests that the majority of the cement forming the wellbore seal has survived and would provide a barrier to fluid migration. The cement bond log supports this interpretation of the persistence of cement throughout the near CO_2 -reservoir environment.

The conclusions of the investigation are included in APPENDIX 2, SACROC Conclusions.

The SACROC well was first put on line over 50 years ago. Recovery of sections of SACROC well showed that ordinary Portland cement could be successfully used to produce hydrocarbons and then inject CO_2 for 30 years. With the improvements in cement formulations; placement techniques and volume of cement in North Sea wells, the resulting degradation resistance to CO_2 should be better than SACROC.

3.4. Existing Goldeneye Platform Wells

All the Goldeneye Platform wells have been cemented using Portland Class G cement.

3.4.1. Degradation Mechanisms

Water is needed to turn CO_2 into carbonic acid. Goldeneye is expected to inject dry CO_2 - that is without water. During the injection phase, if water and subsequently carbonic acid does get to the casing cement sheath, a product of carbonic acid reacting with cement is an insoluble precipitate - calcium carbonate ($CaCO_3$). It leads to lower porosity in the cement because calcium carbonate has a higher molar volume than $Ca(OH)_2$ and for cement sheath integrity, this reaction actually improves the cement's properties and the carbonation is therefore a self-healing mechanism in the carbonate.

Rate of cement degradation depends on three factors - heat, pressure, and the square root of time.

Goldeneye wells will be supplied with CO_2 at low temperature 0 to 5 °C at the wellhead in a supercritical state through a subsea pipeline. Injection wells in the United States are generally fed with CO_2 at ambient temperature. Hence, lower Goldeneye temperatures are working towards smaller rates of degradation than comparable American wells.

Once CO_2 injection is finished, in the reservoir, CO_2 will mix with the aquifer water producing carbonic acid. This may further react with any free $Ca(OH)_2$.

3.4.2. CO_2 Fluid Properties

As outlined above in the degradation section, injection into Goldeneye wells will be dry, supercritical liquid. During injection, the downhole temperature will be ~20 °C. Once injection is finished, over time, the reservoir will warm up to 83 °C, the original reservoir temperature.

3.4.3. SACROC Well

The SACROC well was first put on line over 50 years ago. Recovery of sections of SACROC well showed that ordinary Portland cement could be successfully used to produce hydrocarbons and then inject CO_2 for 30 years. With the improvements in cement formulations; placement techniques and volume of cement in North Sea wells, the resulting degradation resistance to CO_2 should be better than SACROC.

3.4.4. DIANA Software

TNO DIANA BV out of Delft in the Netherlands is a specialist software company that developed a mechanical cement model. This has been used to simulate the downhole conditions and effects on cement in Goldeneye Platform wells.

Diana Software is strictly a mechanical model. That is it takes no account of chemical effects on cement by carbonic acid. The injection model simulates the thermal effects on the mechanics of the system (casing / formation / cement).

Diana software is flexible. It can model a shut-in and 'turn the well around' to flow it or to switch to injecting something else such as water. It cannot simulate repeated cycles of start / stop simulations. Though there is no intention to repeatedly cycle the wells, the design does need to include periodic shut-ins, for instance to test the downhole safety valve.

Diana software was run at end 2009, to simulate the mechanical effects on production casing cement of Goldeneye Platform wells. It was used to look at the cement-formation, cement-steel bond in Goldeneye platform wells. The Diana software programme has many inputs and where possible, actual Goldeneye values were used. Values not available such as cap rock shale properties and vertical stress gradients have had typical values applied from local data around the Goldeneye area.

Diana results indicate that the remaining integrity of the cement is sufficient for CO_2 injection into the Goldeneye Platform wells. Reworking of input values to give better indication of expected well temperatures and actual centralisation stand-off was carried out in late 2010. These results similarly proved positive - the remaining capacity of the cement sheath for various simulated operational scenarios is sufficient for CO_2 injection into the Goldeneye Platform wells.

Inputs for the injection modelling include temperatures and pressures predicted from OLGA SPT software and WellCat software.

Inputs into the model include: cement formulation, placement, centralisation , cement tops, cement bond logs, temperatures, pressures, casing testing, thermal cycling, vertical stress gradient, max and min horizontal stress ratio, azimuth of max horizontal stress, Young's modulus, - Poisson's ratio, cohesion, friction angle, in-situ stresses, lithology types, volumetric specific heat, thermal conductivity, and thermal expansion, hardening type (linear hardening or softening, or parabolic softening) and corresponding hardening gradient and fracture energy.

There are other inputs but the list above demonstrates it is a comprehensive programme. The programme results indicate that the existing cement is not compromised and is good for CO_2 injection. The risk of damage over load phases have been calculated for various scenarios including curing , pressure testing, completion, shut-in and injection.

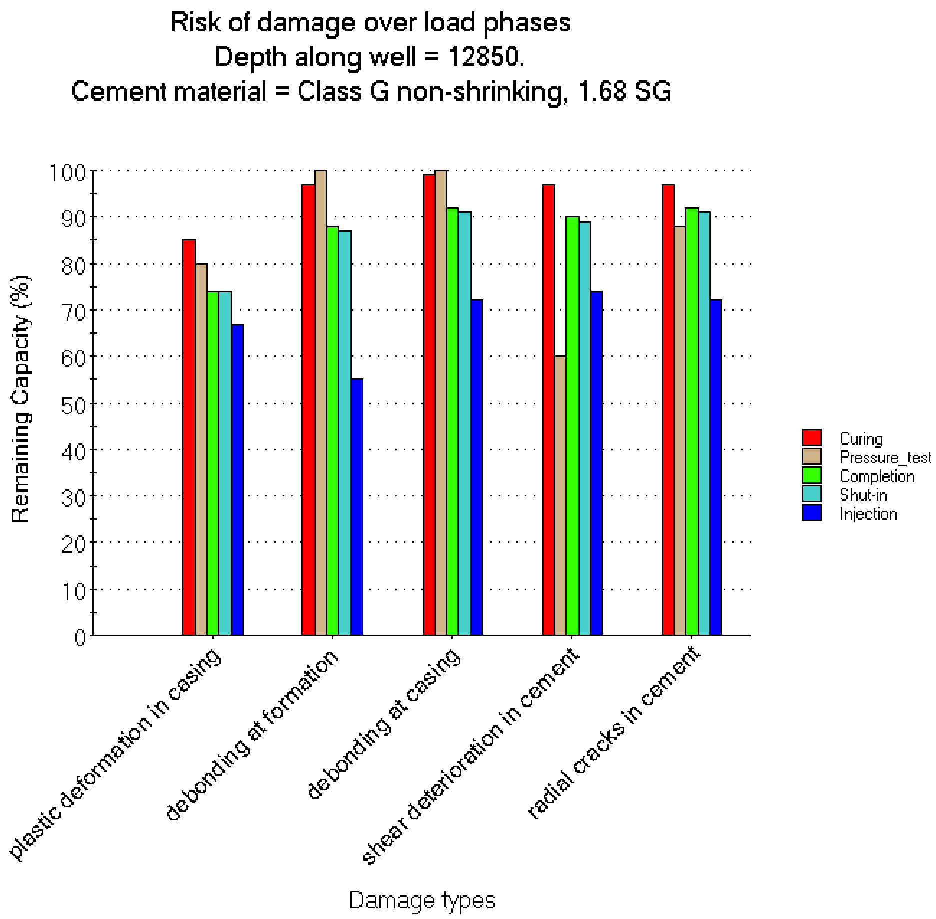


Figure 3.1: Diana Example - GYA04 Risk Analysis of Injection mode for 1000 days

Three cases have been modelled. These are:

- Risk of analysis of production mode for 5 years
- Risk analysis of injection mode for 1,000 days
- Risk analysis of injection mode for 1,000 days, maximum cool down but no reservoir or casing pressure increase.

These cases are evaluated against the following:

- de-bonding at formation
- de-bonding at casing
- shear deterioration in cement
- radial cracks in cement

In all cases and all instances, the results show the "remaining capacity" of the cement is good. The remaining capacity is a measure of the cycling or fatigue that is left in the cement system. The lowest remaining capacity case is down to 40 percent. Regarding remaining capacity, the internal Shell report regarding Goldeneye states that nothing is failing.

This lowest case is: 'Risk analysis of injection mode for 1,000 days, maximum cool down but no reservoir or casing pressure increase' and 'de-bonding at formation'.

The programme has been rerun 4Q2010 with updated input values and for CO_2 injection. The programme still gives acceptable values for remaining capacity. These are within five percent of the 2009 values and within the repeatability of results.

3.5. Future Cementing Operations

CO_2 resistant cements have been introduced by cementing companies in response to the upswing of CO_2 injection projects. These speciality cements first came to prominence around 2005. All three main suppliers to the oil industry have provided and used these specialist cements around the world in CO_2 environments. Products are:

- Schlumberger Well Services EverCRETE
- Halliburton ThermaLock Cement
- BJ Services PermaSet cement

Calcium Aluminate Cements, known as Fondu Cement are also available from companies such as Lafarge. Ciment Fondu is a cement with calcium aluminates comprising 40% to 50% of the composition, rather than calcium silicates, which are the basis of Portland cement. Unlike Portland cement, Fondu does not release free lime during hydration. This gives them low porosities that have an excellent resistance to chemical attack, from a wide range of aggressive substances such as CO_2. Fondu cements are however incompatible with Portland cements, as Fondu is an accelerator for Portland.

Fondu cement is six to seven times more expensive than Portland cement. The additives to control setting are even more expensive.

As CO_2 resistant cements, are inert, or close to inert, to CO_2, any research or qualification of these cements would need to concentrate on mechanical integrity. That is the bonding to formations, to metals, plus triaxial properties. Other factors that must be understood are:

- difficulty of predicting cement setup times
- incompatibility with Portland cements
- isolation of mixing system or cleanliness of mixing system
- mixing and issues around placement must be resolved
- age testing of these cements - how to satisfactorily simulate 1,000 years

3.6. Conclusion

Cement placement has been reviewed for all the wells including E&A wells. Cement composition and volumes placed are all consistent with good practices.

In the Goldeneye case, the injected super-critical CO_2 will be dry. Hence during dry CO_2 injection, carbonic acid is not formed and hence removes the potential for chemical reaction with Portland cement. This takes away the main cause of degrading the cement. However later in the wells' life there are cases where water shall be present around the wellbores so carbon acid degradation and cannot be discounted.

Field results such as the SACROC CO_2 injection well indicate that Portland cement can retain its integrity in a hostile CO_2 environment.

Software modelling indicates the remaining capacity of the existing cement is good.

Conclusion is that existing wells are suitable.

Portland cements can be modified to slow or prevent reaction with CO_2.

Specialist non Portland CO_2 resistant cements may have erratic setting times and are difficult to mix and to place downhole. If it is decided to use these cements, independent stress modelling and testing will be required. Shell Canada has used CO_2 resistant cements, knowledge and lessons may be shared from this existing experience.

There are other technologies that should be investigated such as swelling technologies, alternative plugging materials, and self-healing cements.

3.6.1. Other Evidence

In his SPE/IADC paper in 2009, Glen Benge (7) came to similar conclusions to the above, quoted as follows:

"While field results indicate the use of standard Portland cement in CO_2 injection wells would most likely not cause a long-term seal integrity concern, laboratory results are not consistent with the results from field observations.

Currently available technologies have been shown to be very effective in providing long-term seal integrity in wells. Used in concert, and supplemented with advanced simulation work, these technologies can assure long-term seal integrity for the full life cycle of the wellbore.

Seal integrity for CO_2 injection wells cannot depend solely on placing the cement in the well and allowing it to set. Proper design of the cement and future wellbore conditions is critical to maintaining long-term well integrity.

Developing technologies in the area of CO_2 resistant cements will allow the continued use of Portland based cement systems that do not react with CO_2. Combining these technologies with flexible and expansive materials can further reduce the risk of cement failure.

Incorporating swelling technologies, either through the use of swelling packers or self-healing cement systems, can add an additional layer of assurance of long-term seal integrity. These technologies are not necessarily intended to act as the initial seal in the wellbore, but function later in the life of the well ".

3.6.2. Shrinkage/Expansion tests

Shrinkage and expansion testing was carried out in a lab in 2011 following the procedure laid out in API RP 10B-5 (8).

This standard provides the methods for the testing of well cement formulations to determine the dimension changes during the curing process (cement hydration) at atmospheric pressure only. This is a base document, because under real well cementing conditions shrinkage and expansion take place under pressure and different boundary conditions.

It was not possible to use the exact cement (Rugby Class G) as used in the Goldeneye wells as Rugby has withdrawn from the oil well market. The samples were cured at BHST (bottomhole static temperature).

The results are relatively precise and repeatable.

It may be concluded that the results suggest a slight tendency for expansion but the significant conclusion is that the tests reveal both negligible shrinkage and expansion for this cement mix which is a close equivalent to the Goldeneye cement slurry.

Table 3-2: Cement Shrinkage/Expansion Test Results

	Test 1	Test 2
%Shrinkage	-0.087	0.029
%Expansion	0.043	0.043

4. Abandoned Exploration & Appraisal wells

4.1. Abandoned Exploration & Appraisal (E&A) Wells around the Goldeneye Field

Figure 4.1 shows a map of an area of 25 x 17.5 km around the Goldeneye field. Based on information from both the Shell database and CDA (Corporate Data Access – run by Schlumberger on behalf of the Government), 13 Exploration & Appraisal (E&A) wells have been drilled and abandoned in this area.

The 13 Abandoned E&A wells have been assessed for their capability to cope with CO_2 conditions when exposed to injected CO_2 at the Captain Reservoir level. All the E&A wells have been abandoned (subsurface cement barriers installed and the wellheads removed) and therefore do not feature access to the original well bores anymore. Any repairs to these wells, if needed, would be very complex and costly.

Figure 4.2 shows the main stratigraphy for the Goldeneye area with the characteristics of the individual formations, key features being the Injection reservoir in the Captain sands, the Rødby shale and Hidra marl forming the reservoir seal, and the secondary seal at the Lista shale.

4.2. Potential Leak Mechanisms from E&A Wells

The potential for an E&A well to provide a leak mechanism from the reservoir depends on:

- whether CO_2 would be present at, or could migrate to the well location;
- whether the current or future abandonment condition of the well provides adequate effective barriers to prevent leakage of CO_2 outside the Complex;
- whether any leakage into shallower formations that might occur could be detected and, if necessary remediated within the injection and subsequent monitoring period.

Section 4.3 provides a summary of the analysis of these factors for the E&A wells, with a detailed description of the well abandonment condition for each well included in sub-sections 0 to 4.18.

An important issue in considering the potential for leakage via the wells is whether there is a driving force for the leak. The Goldeneye reservoir pressure is currently below hydrostatic. Only if the reservoir pressure returns to its original (hydrostatic) pressure, or if the formation has the potential to create a hydraulic "pump", is there potential for a driving pressure to force CO_2 past the well abandonment plugs. The range of pressure-history matched aquifer models predict that even in the strongest aquifer scenario, and taking into account the pressure of injected CO_2, it will take thousands of years to reach hydrostatic pressures again.

No evidence exists for any hydraulic "pump" features in the formation. The wells exposed to mobile CO_2 have fluids in the well above the abandonment plug that will create local formation pressures above the reservoir abandonment plugs. As a result, it is very unlikely that a driving force for leakage will be present in a 1000 year timescale.

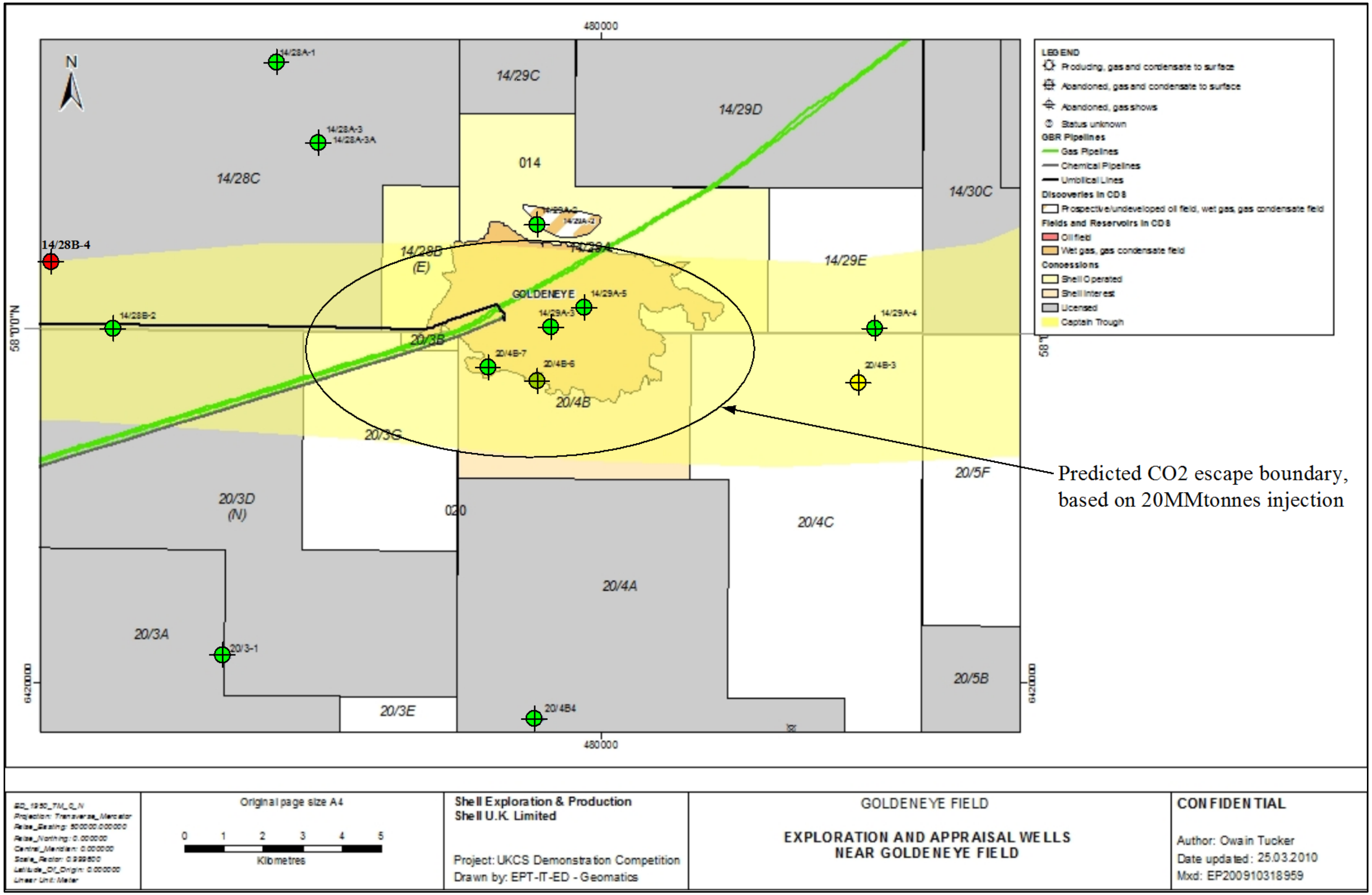


Figure 4.1: Exploration and Appraisal Wells near Goldeneye Field

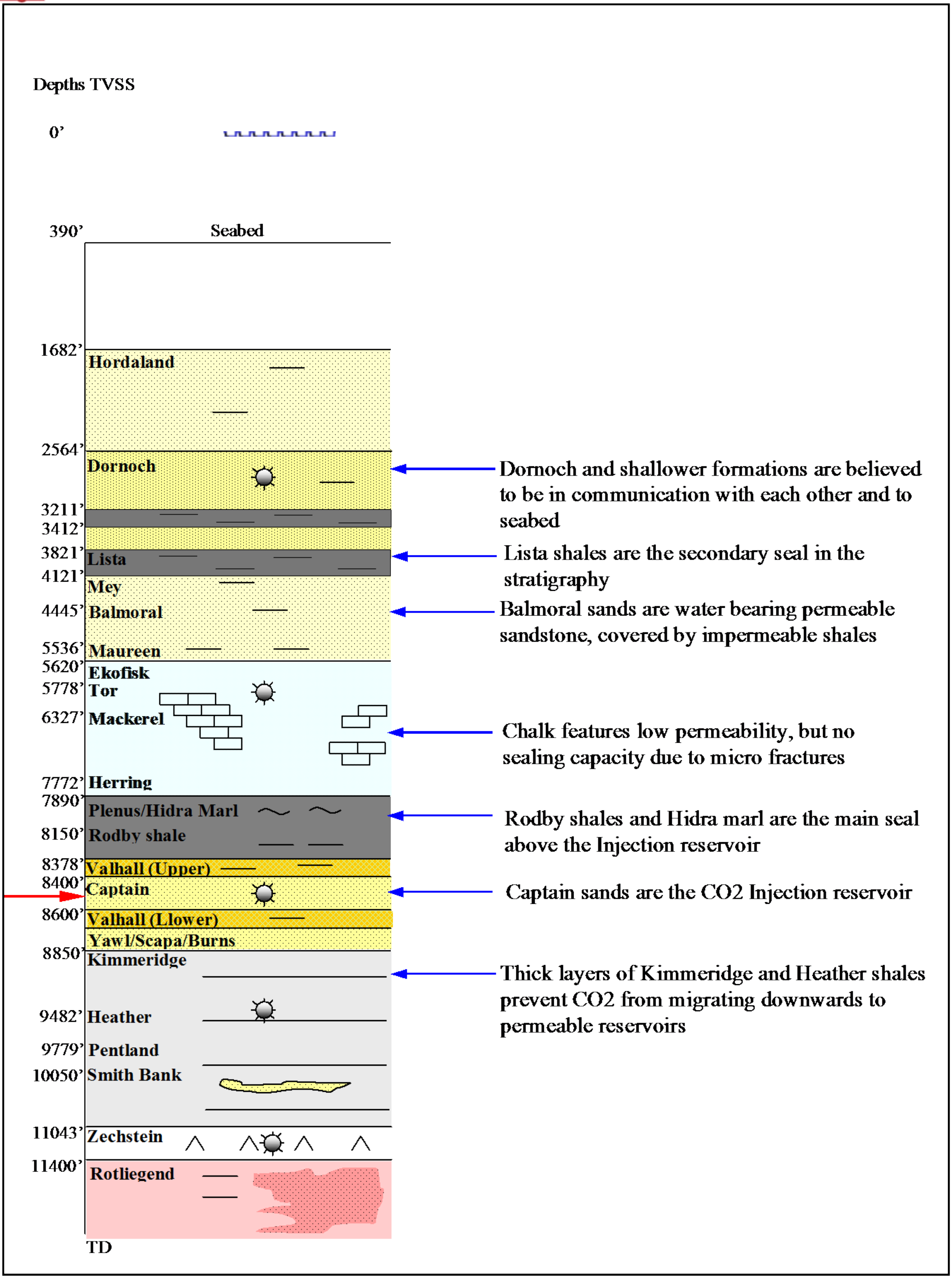


Figure 4.2: Main Stratigraphy for Goldeneye area, average depths of formation tops

4.3. Overall Assessment of Abandoned E&A wells

Table 4-1 below shows the current barrier tonnes of each exploration and appraisal well. Detailed information on each well is contained in Sections 0 to 4.18.

The assessment in the table of whether a well is "Outside area of potential CO_2 migration" is based on calculations described in the CO_2 storage estimate (9). This document establishes the maximum extent of a CO_2 plume at the end of the injection period (based on 20 million tons of CO_2 injected.) Wells outside the maximum potential CO_2 plume have no potential to provide a leakage path for CO_2 outside the complex.

The relevance of the required height of the Primary cement barrier above the Captain reservoir (CO_2 injection reservoir) originates from various studies (10). The highest estimated corrosion rates of Portland cement when exposed to CO_2 gas and wet supercritical CO_2 are in the range of 12.5 metres/10,000 years. Many of the measured cement corrosion rates for the temperatures experienced in the Goldeneye field are in the range of 0.5 – 2.5 metres/10,000 years. This issue is taken into account in the detailed assessments of well abandonment quality contained in Sections 0 to 4.18, although all barriers in place at the reservoir are considerably longer than this.

Carbon steel casing will corrode very quickly in a CO_2 wet environment. Corrosion rates on freestanding carbon steel tubing/casing in a wet CO_2 environment are in the order of millimetres per year. This means that a joint of casing can corrode through laterally in a matter of a few years. However, casing that is situated between primary cement and an internal cement plug, as is the case for the well abandonment plugs assessed here, can only corrode axially, and this is believed to be a very slow process. For typical production casing sizes of 9 5/8" casing, this reaction front has a width of ~1/2" enclosed by cement and with ongoing corrosion, the distance from the reaction front to the reservoir will increase. Due to this, the transport of reaction products from and to the reaction front will be slowed down due to the increasing vertical distance through the corrosion channel through which the diffusion needs to take place.

A review of the information in Table 4-1 is provided in Section 4.4.

Table 4-1: E&A Well barrier condition and Leakage Risk Level

Well	Reservoir Connected?	Outside area of potential CO_2 migration?	Condition of Well Barrier at Rødby (above Reservoir)	Condition of Well barrier at Lista	Overall Condition	Overall Risk Level for CO_2 leakage from the Complex
20/3-1	No	Yes	No barrier in place	No barrier in place	Abandonment plugs do not provide effective barriers against leakage up the well. However, the well has no contact with the Reservoir, and is outside the maximum potential CO_2 plume at the end of the injection period.	Low
20/4b-3	No	Yes	Plug in place, but has no bottom support and may have sagged. Cannot be guaranteed as effective	No barrier in place	Abandonment plugs do not provide effective barriers against leakage up the well. As such the well is categorised as Medium risk for barrier failure. However, the well has no contact with the Reservoir, and is outside the maximum potential CO_2 plume at the end of the injection period. As a result, it is low risk as a source of CO_2 leakage from the Complex	Low
20/4b-4	No	Yes	No barrier in place	No barrier in place	Barriers unlikely to be effective in preventing CO_2 from leaking to surface However, the well has no contact with the Reservoir, and is outside the maximum potential CO_2 plume at the end of the injection period.	Low
20/4b-6	Yes	N/A	Plug in wellbore and cement behind casing at Rødby – appears to be an effective barrier	No barrier in place	If Plug at Rødby fails, well fills with CO_2, with CO_2 likely to escape into Dornoch formation at the 13 3/8" casing shoe, or through casing corrosion. Could also be CO_2 leak to surface if shallow plug in the well fails.	Has potential as a source of leakage. But see analysis below for this well, which concludes that risk is Low
20/4b-7	Yes	N/A	Around 300 ft. of rock to rock cement at Rødby	No barrier in place	If Plug at Rødby fails, CO_2 likely to escape into Dornoch formation from open hole below the 13 3/8" casing shoe.	Has potential as a source of leakage. But see analysis below for this well, which concludes that risk is Low
14/29a-2	No	Well is relatively close to the maximum potential CO_2 plume. However, lack of communication	Good barrier in place	Good barrier in place	Many good abandonment barriers in the well. Low risk of leakage from the reservoir, or of this well providing a leak source to surface for CO_2 that may have leaked to shallow formations. Well 14/29a-2 found no hydrocarbons in the area close to	Low

		of this wellbore with the Captain sands indicates very low risk of CO_2 migration to the well.			the edge of the Captain sands. As a result, it appears that there is no communication between the Captain and the Scapa Sands	
14/29a-3	Yes	N/A	Good set of barriers in place	No barrier in place. However, there is a plug in the wellbore above the reservoir level plugs	Good set of barriers at the reservoir to prevent leakage from this well to surface. However, the well could provide a leakage path for CO_2 below the Lista to pass outside the casing into the Hordaland and to surface	Has potential as a source of leakage. But see analysis below for this well, which concludes that risk is Low
14/29a-4	No	Yes	Good barrier in place	Annular cement at Mey/Lista interface and down to Ekofisk. Rock to rock plug at shoe.	Well is not in contact with reservoir, and is outside maximum potential CO_2 plume at the end of the injection period.	Low
14/29a-5	Yes	N/A	Good barrier in place	Good barrier in place	Good barriers in place against the reservoir and against any CO_2 that may migrate into formations below the Lista. However, failure of the plug at the Rødby would result in CO_2 migrating into the Dornoch formation with the potential to leak to surface at another well.	Has potential as a source of leakage. But see analysis below for this well, which concludes that risk is Low
14/28a-1	No	Yes	Well not in contact with reservoir and does not pass through Rødby shale	Annular cement only across Lista	Well is not in contact with reservoir, and is outside maximum potential CO_2 plume at the end of the injection period.	Low
14/28a-3a	No	Yes	Good barrier in place	Viscous pill and plug at Lista / Dornoch interface – may not be effective	Well is not in contact with reservoir, and is outside maximum potential CO_2 plume at the end of the injection period.	Low
14/28b-2	No	Yes	Good barrier in place	Annular cement only at Mey/Lista interface	Well is not in contact with reservoir, and is outside maximum potential CO_2 plume at the end of the injection period.	Low
14/28b-4	No	Yes	No barrier in place	No barrier in place	Any CO_2 reaching this well at reservoir or shallower formation is likely to leak to surface, and so has been ranked a high risk for barrier failure. However, the well is not in contact with reservoir, and is outside maximum potential CO_2 plume at the end of the injection period. As a result the well is considered low risk as a source of CO_2 leakage from the Complex	Low

4.4. E&A Wells requiring more detailed consideration

From Table 4-1 it can be seen that the majority of wells either have (or will have) good barriers in place, or cannot be contacted by CO_2 at either the reservoir or shallower formations.

However, four wells require further consideration to determine whether they provide a potential leak path. These are 20/4b-6, 20/4b-7, 14/29a-3 and 14/29a-5.

The quantity of CO_2 available to be released following a barrier failure at these wells is shown below. For wells 20/4b-6 and 20/4b-7, it can be seen that no mobile CO_2 is available. Wells 14/29a-3 and 14/29a-5 are exposed to higher levels of mobile CO_2 – 13 and 8 million tonnes respectively.

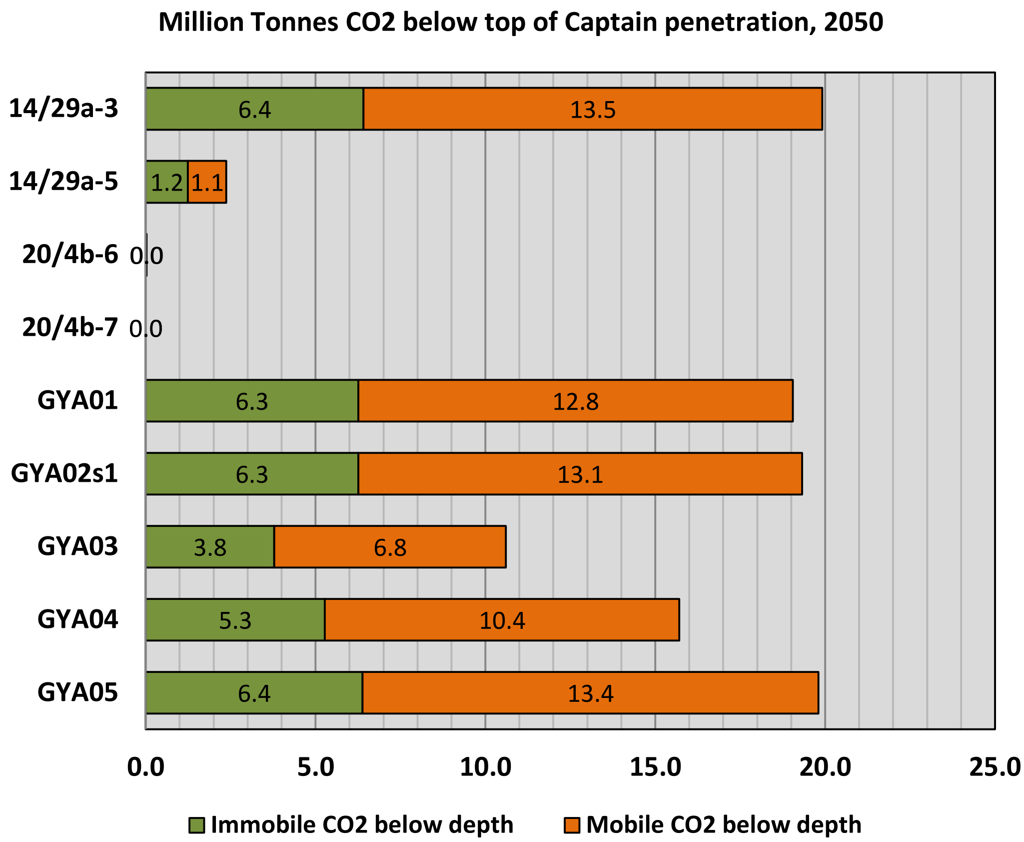


Figure 4.3: Mobile CO_2 at reservoir connected wells

The potential for these wells to be a cause of leakage to surface is discussed below.

4.4.1. Wells 20/4b-6, 20/4b-7

Both of these wells have good primary reservoir barriers. However, failure of this barrier would result in CO_2 filling the well and migrating into the Mey and Dornoch formations (11).

Modelling, using a 3D homogeneous sandstone model, has been carried out (12) to assess CO_2 migration in the Mey which indicates that, for a credible situation of a micro annulus in the plug cement, releasing 100 tonnes/day, the leak would continue for around 28 years before the full available 1 million tonnes had been released. The resulting plume from that release at the 1000 year point is shown below. It can be seen that the total plume length is around 3.3.km. As a result, most, if not all of the CO_2 released will remain in the formation. Taking account of the relatively low inventory available at the wells, and the extent that will remain in formation, the probability of CO_2 being released to surface from these wells is very low.

The modelling also shows that the plume length is no greater than shown below for higher leakage rates at the reservoir plug.

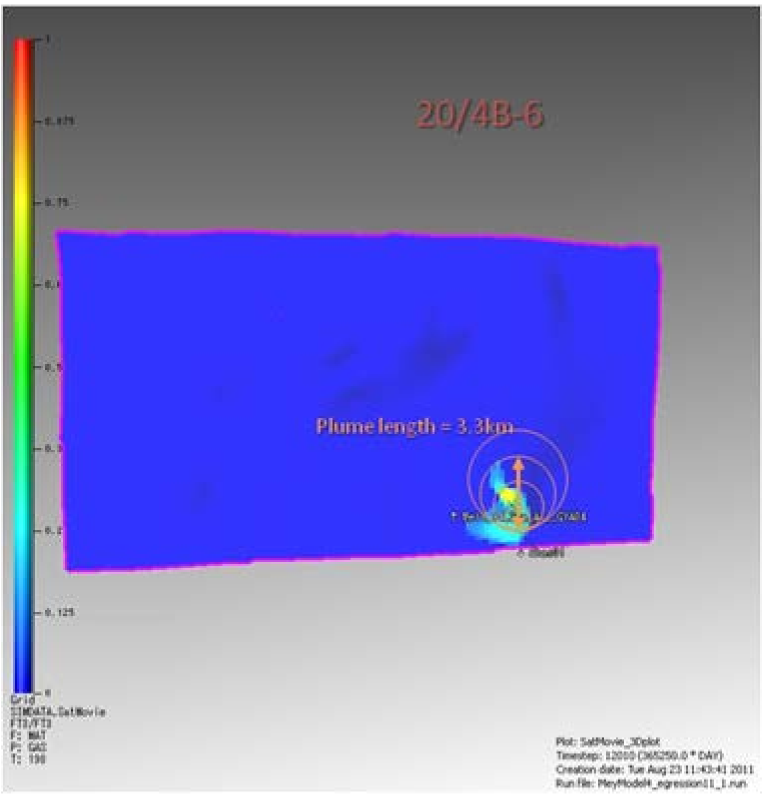


Figure 4.4: CO_2 plume length in Mey Formation from a leak from 20/4-b6

4.4.2. Wells 14/29a-3 and 14/29a-5

These wells have much larger quantities of mobile CO_2 available to be released by a reservoir barrier failure.

Well 14/29a-3 has three plugs at depth and a shallow plug such that a leak to surface or into a shallower formation from this well is very unlikely. However, the well does provide a route for CO_2 in the Mey to bypass the Lista seal and pass to surface through the Dornoch. Well 14/29a-5 has a good plug at the Rødby, again making leakage very unlikely, but there is a credible scenario that this plug leaks, releasing CO_2 into the Mey which then migrates up-dip to 14/29a-3 which would provide a path to surface.

Modelling (12) has been carried out to assess the plume size within the Mey from a major failure of the reservoir plug at 14/29a-5. This is a highly improbable event, but serves to illustrate a worst case situation.

In order to ensure accuracy of modelling for this larger potential leak event, modelling has been carried out on both homogeneous and heterogeneous 3D sandstone models.

The figure below shows the extent of the CO_2 plume at the end of 20 years of leakage, as calculated from the heterogeneous model. It can be seen that the plume has not reached the 14/29a-3 wellbore at this time. It is credible that the plume could reach the wellbore in a longer period. However, a plume of this size could only occur following total failure of the reservoir plug. Any CO_2 leak of this size occurring during, or in the years after, injection would be visible on seismic and so would be detected in the planned programme of seismic monitoring. Total failure later in life of a well plug that remains effective during injection and through the monitoring period is considered a very low probability event.

The homogeneous model shows similar conclusions, with a slightly slower time of migration of the plume between the two wells.

Overall, the integrity of the reservoir plugs at these wells is considered to be good, having been proven during the period of hydrocarbon production. As a result, the probability of a leak from one of these wells is considered low. In the unlikely event of such a leak occurring, the probability of the leak reaching surface before detection is considered extremely low.

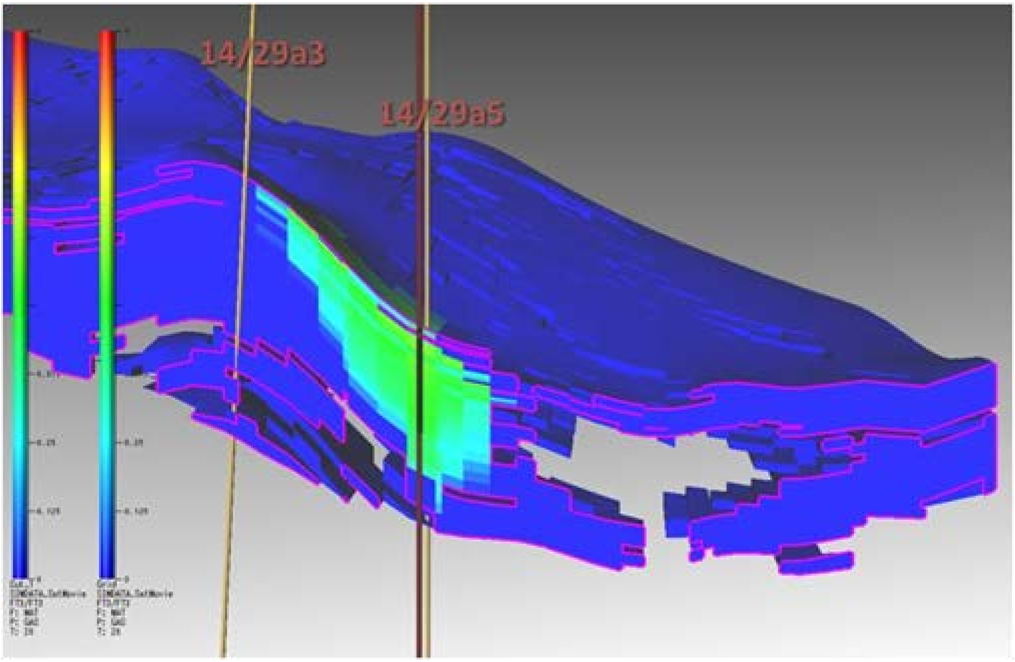


Figure 4.5: CO_2 plume leaking from 14/29a-5 – 20 years of leakage

4.5. Well related releases following non-well related loss of CO_2 from the reservoir

An alternative route to surface would be for CO_2 escaping through the reservoir caprock to then enter a well and bypass the Lista seal. This would require faulting in the Rødby shale allowing CO_2 to migrate through the Rødby to the shallower formations, with subsequent lateral migration to a well location.

Existing faults have been mapped and fractures have been analysed and none have been identified to be pervasive throughout the seal systems (13). Current caprock integrity has been proven by the presence of a gas field containing highly mobile gas under pressure compared to the surrounding formations. The injection of CO_2 could potentially initiate faulting by geochemical interaction between carbonic acid formed when CO_2 dissolves in water and the host rocks, or by pressure cycling and/or thermal effects. Both of these interactions have been studied (13) and have been demonstrated not to have effects that would create a leak path through the caprock.

A detailed well analysis including information from the original drilling reports and an assessment of the abandonment is provided in sections 4.6 to 4.18

In these sections a detailed well abandonment schematic has also been included.

4.6. 20/3-1

Table 4-2: 20/3-1 Well Summary

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N E	57 deg. 55 min. 30.2 sec. N 00 deg. 29 min. 57.3 sec. W	
Operator	Conoco		
Drilling Unit	Venture Two		
Spudded	28/08/1978		
Abandoned	26/10/1978		
Duration	64 days 17 ½ hours		
Formation pressure	8.65 ppg at 11006/7' (RFT)		
Total depth (8 ½" OH)	12880' AHD (RKB)		
Water depth	374'		
Derrick Floor elevation	77'		
Maximum Inclination	7.0 degrees		
Casing Details		Weight – Grade - Threads	FSG (ppg)
30" conductor	716' AHD (RKB)	310#– Vetco ATD	
18 5/8" casing	1494' AHD (RKB)	87.5# - X-52 – Vetco L	
13 3/8" casing	5718' AHD (RKB)	68# - K55 - Buttress	15.3 @ 5719'
9 5/8" casing	9713' AHD (RKB)	47# - N80 - Buttress	16.2 @ 9713'
Cement Details			
30" cement job:	Class G	Returns to seabed	2100 sx
18 5/8" cement job:			
Lead	Class G, 13.2 ppg		1875 sx
Tail	Class G, 15.8 ppg		500 sx
Final diff. pressure	500 psi	180 bbl cement back at seabed	
Pressure test	900 psia		
13 3/8" cement job:			
Lead	Class G, 13.3 ppg	Centralisers: 1 each joint for bottom 6 joints, 1/3 for next	2100 sx

		100 jts	
Tail	Class G, 16.0 ppg	Ruff Cote on bottom 6 joints	500 sx
Final diff. pressure	2400 psi		
Pressure test	3000 psia	Full cement returns	
9 5/8" cement job:			
Lead	Class G, 13.2 ppg	Centralisers: 1 each joint for bottom 6 joints, 1/3 up to 5600'	1400 sx
Tail	Class G, 15.8 ppg	Ruff Cote on bottom 8 joints	500 sx
Final diff. pressure	2800 psi	TOC unknown; 150bbl cement returns, which indicates Channeling - Poor cement job	
Pressure test	3200 psia	Cement squeeze was performed at the shoe to improve LOT	
Abandonment			
Plug 1	300' cement plug, Class G	Plug set off bottom 12880', without support. Plug may have sagged.	100 sx
	12400' - 12100'	No confirmation (tag, test)	
Plug 2	1000' cement plug, Class G	Plug not set on support or viscous pill ; may have sagged	350 sx
	11400' – 10400'		
	Plug not tagged		
Plug 3	400' cement plug, Class G	No information about bottom support of plug	150 sx
	9900' – 9500'		
•	EZSV-1 set at 9450'	No information about testing of EZSV	
•	Perforated 5735' – 5737' with 4 spf		
•	EZSV-2 set at 5500'		
Plug 4	Class G neat	Running string stung into upper EZSV. Squeezed cement through perforations at 3 bpm. Dumped 50 sx of cement on top of EZSV.	250 sx 50 sx
Plug 5	400' cement plug, Class G	No information about bottom	150 sx

	neat	support of plug
	1050'- 650'	
Wellhead/Casing recovery	9 5/8" casing	Cut at 466' and recovered
	13 3/8" casing	Cut at 466' and recovered
	18 5/8" casing	Cut at 466' and recovered
	30" casing/wellhead/PGB/TGB	Cut at 466' and recovered

4.6.1.20/3-1 abandonment assessment

This exploration well was abandoned with 5 cement plugs, 2 cement retainers, a cement squeeze at the 9 5/8" casing shoe and a cement squeeze through perforated 9 5/8" casing as a result of a poor 9 5/8" casing cementation. Furthermore, all casing strings were cut 15' below seabed. There is no primary entry point of CO_2 into this well, because the CO_2 injection reservoir (Captain) is not present. There have been gas shows in the Kimmeridge and Rotliegend formations. Some minor oil shows were witnessed in the Valhall (9950'), Kimmeridge and Zechstein. All casing strings are made of carbon steel and the cement used was standard "Class G".

Plug #1, a 300' cement plug, was set 480' off bottom in open hole bridging the Zechstein/Rotliegend formations. This plug was set without any kind of bottom support and was not tagged.

Plug#2, a 1000' cement barier (11400'-10400'), was set in open hole over the Kimmeridge formation. This plug was not supported at bottom nor was it tagged. Its position has to be questioned.

Plugs#1&2 isolate the HC's observed in the Kimmeridge, Zechstein and Rotliegend formations, but play no part in containing CO_2 from primary entry points into the well.

Plug#3 is an unsupported 400' cement plug, not tested, nor tagged set 9900' - 9500'. It is not supported by any kind of means in this vertical well, so the position of this plug, depth wise, has to be questioned. The position of the plug is across the 9 5/8" casing shoe, covering part of the Valhall formation in open/cased hole. It is unclear if the cement inside the 9 5/8" casing is supported on the outside by annular cement from the primary casing cementation.

EZSV-1 was set at 9540', its purpose unknown, perhaps to have a contained pressure-vessel for the latter cement squeeze and prevent cement dropping out of the 9 5/8" casing due to the uncertainties about the position of plug#3.

EZSV-2 was set at 5500' and was used to squeeze cement through the perforations between 5735' – 5737'. 250 Sacks of cement were squeezed below EZSV-2 . Due to the large area between the two EZSV's (4000') it is unclear how much cement has gone through the perforations into the annulus and how much cement ended up between the two EZSV's. As a worst case, it can be assumed that cement sagged out between the two EZSV's and that *mud* was squeezed through the perforations. At best, about 1000' of cement could have been squeezed though the perforations (up to ~4735').

Plug#4, is 100' of cement (5500' – 5400') dumped on top of EZSV-2 , not tagged nor tested. This plug can *potentially* have full lateral cement coverage if annular cement has indeed been squeezed above the perforations. However there is no evidence of this.

Plug#5, is a 400' cement plug (1050' – 650') set inside the 9 5/8" casing. There is no information available that would suggest that this plug was set on any kind of support (bridge plug, viscous pill). Therefore it has to be assumed that with this kind of length of cement plug, that there will be severe contamination/sagging. Furthermore, this plug was not tagged, nor tested.

There is no evidence, nor can it be expected, that there is cement behind the 9 5/8" casing at this depth, so no full lateral cement coverage.

4.6.2. Conclusion

There are doubts about the general quality of abandonment of this well. However, in the absence of the primary entry point of CO_2 into this well (Captain reservoir), primary leakage of CO_2 to shallower zones/seabed is considered low.

To start with, the primary cementation of the 9 5/8" production casing was not successful:

- 150bbl cement returns at suface
- First cement squeeze performed at shoe when cement was drilled out
- Second cement squeeze performed through perforations in the 9 5/8" casing at the time of abandonment

Plugs #1&2 are unsupported, untagged plugs set in open hole and play no part in the evaluation of CO_2 containment.

Plug#3 is set across the 13 3/8" shoe without any kind of bottom support. There is only some coverage from *annular* cement from a poor 9 5/8" cement job (eventhough cement squeezes have been performed in order to repair this). At best, there is 200' overlap (inside /outside casing) if plug#3 has not sagged.

Plug#4 can at best feature 100' of full lateral cement coverage and that is only in case the cement squeeze through the perforations has been successful. There is however no evidence of that, other than 250 sx (about 50bbls) having been squeezed through EZSV-2.

Plug#5, which is a shallow set (1050' – 650') plug has no annular coverage and is likely to be bypassed in the 9 5/8" x 13 3/8" annulus.

Despite the doubts about the quality of the general abandonment of this well, the absence of a primary CO_2 source (Captain reservoir) makes the longterm Risk of CO_2 leaking to shallower zones/seabed from this well is considered to be ***Low.***

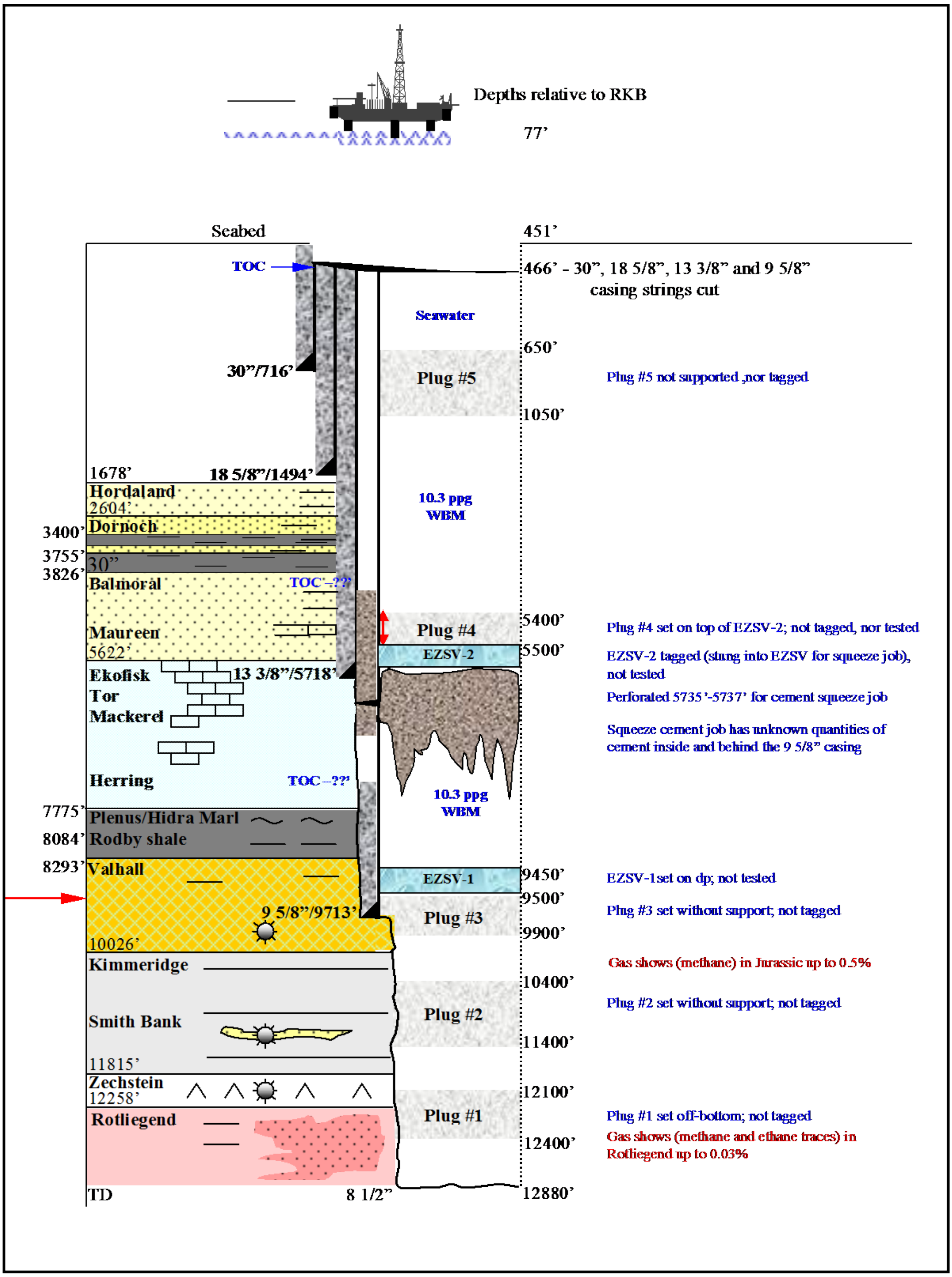


Figure 4.6 20/3-1 – Conoco

4.7. 20/4b-3

Table 4-3: 20/4b-3 Well Summary

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6 432 266m E 308 892m	57 deg. 59 min. 22.369 sec. N 00 deg. 13 min. 38.040 sec. W	
Operator	Amerada Hess		
Drilling Unit	Sedco 703		
Spudded	30/04/1989		
Abandoned	20/06/1989		
Duration	51 days		
Formation pressure			
Total depth (8 ½" OH)	13090' AHD (RKB)	Bottomhole T = deg. F	
Water depth	394'		
Derrick Floor elevation	90'		
Maximum Inclination	7.8 degrees		
Casing Details		Weight – Grade - Threads	FSG (ppg)
30" conductor	725' AHD (RKB)	1 ½" WT, ST-2 1 jt 1" WT, ST-2 5 jts	
20" casing	2008' AHD (RKB)	0.438" WT, RL4S	12.3 @ 2008'
13 3/8" casing	6496' AHD (RKB)	68# - N80 - Buttress	16.7 @ 6496'
9 5/8" casing	10095' AHD (RKB)	53.5# - P110 – New Vam	17.0 @ 10095'
Cement Details:			
30" cement job:			
Main	16.0 ppg Class G	Excess 100%	1169 ft³
Top-up job	16.0 ppg Class G		292 ft³
20" cement job:			
Lead	13.2 ppg Class G	Excess 100%	3612 ft³
Tail	16.0 ppg Class G (250')	Excess 100%	791 ft³
Final diff. pressure			

Pressure test		No info on CBL	
13 3/8" cement job:			
Lead	13.2 ppg Class G	Excess 30%	2437 ft^3
Tail	16.0 ppg Class G (500')	Excess 30%	339 ft^3
Final diff. pressure			
Pressure test		No info on CBL	
9 5/8" cement job:			
Lead	13.2 ppg Class G	Excess 16%	807 ft^3
Tail	16.0 ppg Class G (500')	Excess 15%	224 ft^3
Final diff. pressure		Calculated TOC 7496'	
Pressure test		CBL/VDL 7472' – 9212'	TOC 8600' CBL
Abandonment			
Plug 1	600' cement plug	Plug set 40' off bottom	
	12450' - 13050'	No confirmation (tag, test)	
Plug 2	1400' cement plug	No information about the plugs being supported by a viscous pill or any other mechanism	
	10200' – 8800' in 2 stages	No confirmation (tag, test)	
Plug 3	Bridge plug set at 5900'	Tagged with 15,000 lbs	
	Tested to 3500 psia		
Plug 4	500' cement plug	Cement tagged at 649' with 15,000 lbs	
	1100' – 600'		
Wellhead recovery	9 5/8" casing	Cut at 899' and recovered	
	13 3/8" casing	Cut at 517' and recovered	
	20" casing	Cut at 498' and recovered with 18 ¾" housing	
	30" casing/housing/PGB	After 2 unsuccessfull cuts, the 30" housing joint was blown at 490' and the housing/PGB recovered	

4.7.1.20/4b-3 abandonment assessment

This exploration well was abandoned with 3 cement plugs, 1 bridge plug and all casing strings cut. It is assumed that the highest point where the CO_2 plume contacts this well, is at 9109' (top Captain). Furthermore, there have been gas shows in the shallower Durnoch sands and Chalk formations as well. The 9 5/8" casing cement job was evaluated with a CBL/VDL in preparation for perforation at the Captain sands for a cased hole RFT. All casing strings are made of carbon steel and the cement used was standard "Class G".

Plug #1, a 600' cement plug, serves no purpose other than isolating the Rotliegendes from the other reservoir formation in the 8 ½" hole section.

Plug#2, a 1400' cement barier, was set in 2 stages (10200'-9500'-8800'). This plug has no firm base (bridge plug, viscous pill, etc) and is likely to have sagged down this vertical well to some extent. Furthermore, this plug was not tagged, nor pressure tested. Unfortunatley this is the only barrier this well can rely on. In the best case, the top of plug#2 is at 8800' (TOC of the 9 5/8" casing is ~8600' (CBL)) and will therefore only provide 300' of full lateral cement coverage above the point of influx of the CO_2 stream (top Captain). The likely case is to be less than 300'. Unfortunately, without actually physically tagging this plug#2, it is impossible to assess the actual TOC inside the casing and determine how much this plug has sagged down the hole.

Plug#3 is a bridge plug, tagged with 15k lbs and tested to 3500 psia. However, this bridge plug is not supported by cement on the outside (9 5/8" x 13 3/8" annulus) nor is there cement set above the plug. This may have been a barrier if the 9 5/8" casing was cut deeper and the bridge plug was used as "bottom support" for the cement plug. Right now it does not serve a purpose longterm.

Plug#4 was set over the cut 9 5/8" casing and eventhough it was tagged with 15k lbs, there is no full lateral coverage of cement at the depth where the plug is set. Again, if the 9 5/8" casing would have been cut above the bridge plug and the plug set at that depth it would have had full lateral coverage of cement.

4.7.2.Conclusion

This well will *at* best only have 300' of cement above the highest point of influx in order to prevent CO_2 from leaking to shallower zones/seabed. This is because the main barrier for this well (Plug#2) has no bottom support and may have sagged down the well. Furthermore, this barrier plug#2 has not been tagged in order to confirm its position.

Because of this uncertainty this well is classified as ***Medium*** risk. The shallower sands that exhibited gas shows, have not been properly abandoned at the time with a dedicated barrier. The chance exists that if CO_2 would percolate upwards in the well via this zone, that further hydrocarbon gas may start to leak into the environment, after the casing and annular cement have been corroded by CO_2, or CO_2 starts to migrate via these shallower permeable sands.

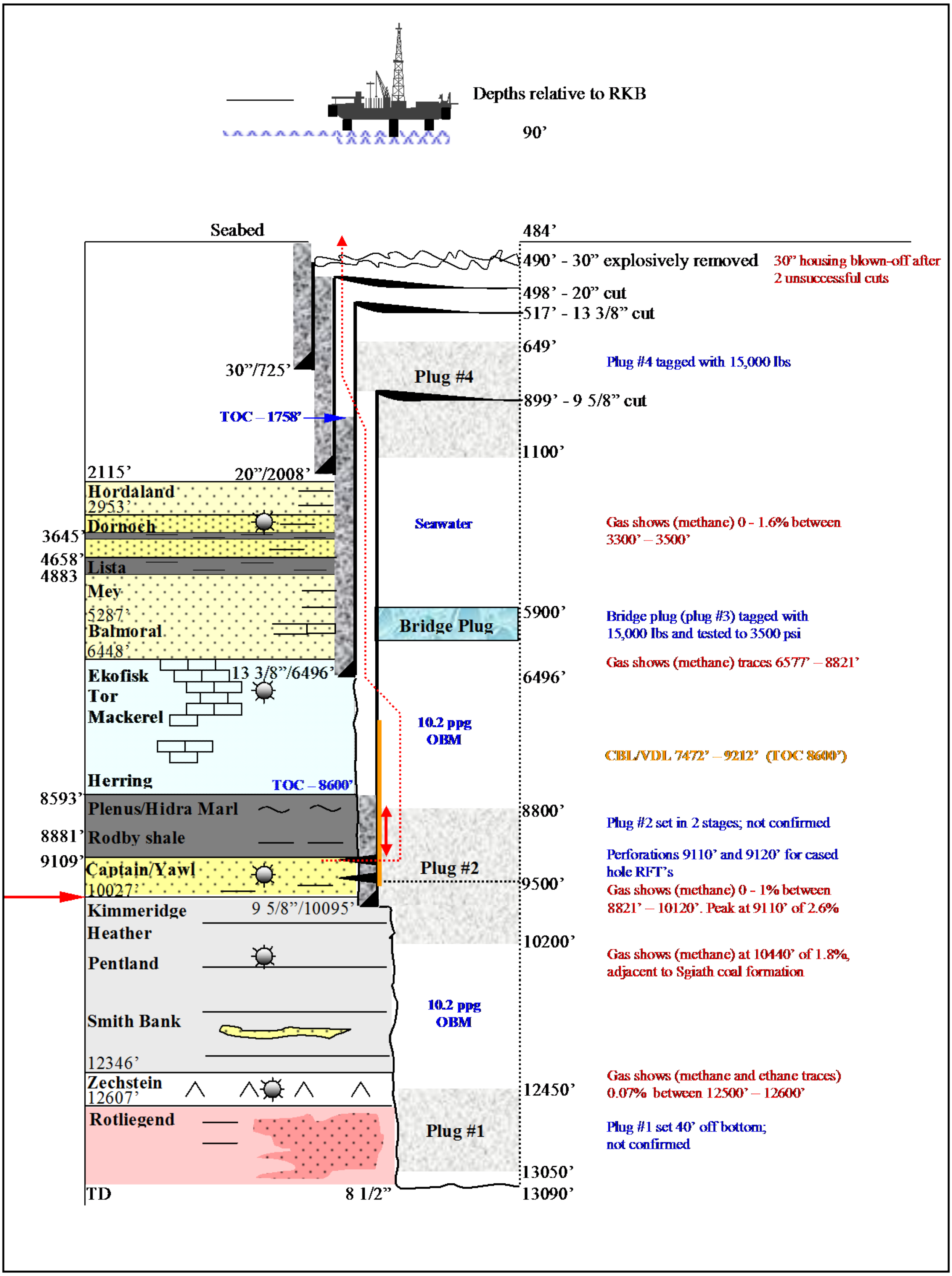


Figure 4.7 20/4b-3 – Hess

4.8. 20/4b-4

Table 4-4: 20/4b-4 Well Summary

Well attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6 422 059.2m E 656 284.7m	57 deg. 54 min. 42.53 sec. N 00 deg. 21 min. 49.43 sec. W	
Operator	Amerada Hess		
Drilling Unit	Sedco 707		
Spudded	10/12/1990		
Abandoned	18/02/1991		
Duration	69 days		
Formation pressure	Influx in Kimmeridge: 11.6 ppg at 10824'		
Total depth (6" OH)	12150' AHD (RKB)		
Water depth	375'		
Derrick Floor elevation	80'		
Maximum Inclination	7.0 degrees		
Casing Details		Weight – Grade - Threads	FSG (ppg)
30" conductor	694' AHD (RKB)	310# - L80	
20" casing	2013' AHD (RKB)	94# - L80	12.0 @ 2013'
13 3/8" casing	5431' AHD (RKB)	68# - N80	11.8 @ 5431'
9 5/8" casing	9805' AHD (RKB)	47# - L80	13.3 @ 9805'
7" liner	9379'–11462' AHD (RKB)	29# - L80	17.2 @ 11462'
Cement Details			
30" cement job:			
Main	16.0 ppg Class G	7.0 bpm TOC tagged with stinger at 515', therefore top-up job done	209 bbls
Top-up job	Executed but no data		
20" cement job:			
Lead	13.2 ppg Class G	8.0 bpm	695 bbls

Tail	16.0 ppg Class G (250')	8.0 bpm	145 bbls
Final diff. pressure			
Pressure test		Cement back to seabed as Observed with ROV	
13 3/8" cement job:			
Lead	13.2 ppg Class G	8.0 bpm	345 bbls
Tail	16.0 ppg Class G (500')	8.0 bpm	62 bbls
Final diff. pressure	1300 psi (prior to bump)		
Pressure test	2500 psia	TOC 1763' from calculations, No losses	
9 5/8" cement job:			
Lead	13.2 ppg Class G	10 bpm	273 bbls
Tail	16.0 ppg Class G (500')	10 bpm	43 bbls
Final diff. pressure	1800 psi (prior to bump)	TOC 5181', on volumes	
Pressure test	5500 psia		
7" cement job:			
Tail	16.0 ppg Class G w. 35% silica	5 bpm	85 bbls
Final diff. pressure	1100 psi (prior to bump 2 bpm)	TOC 9129', on volumes	
Pressure test			
Abandonment			
Plug 1	457' cement plug	Plug set 7' off bottom	
	12143' - 11600'		
	No confirmation (tag, test)		
Plug 2	500' cement plug	Plug tagged	
	11600' – 11100'		
Plug 3	500' cement plug	No information about bottom support of plug	
	9600' – 9100'		
Plug 4	Bridge plug at 8900'	Tagged Pressure tested 3000 psia Inflow tested	

Plug 5	184' cement plug	No information about bottom support of plug
	850'- 666'	
Plug 6	121' cement plug	Supported by plug#5 Tagged
	666' – 545'	
Wellhead/Casing recovery	9 5/8" casing	Cut at 647' and recovered
	13 3/8" casing	Cut at ??' and recovered
	20" casing	Cut at 466' and recovered with housing
	30" casing/housing/PGB	Cut at 466' and recovered

4.8.1.20/4b-4abandonment assessment

This exploration well was abandoned with 5 cement plugs, 1 bridge plug and all casing strings have been cut.

There is no primary entry point of CO_2 into this well, because the injection reservoir (Captain) is not present. There have been gas shows in the Valhall, Kimmeridge (overpressured sandlense where the well took a kick) and Sgiath coal formation. All casing strings are made of carbon steel and the cement used was standard "Class G".

Plug #1, a 457' cement plug, was set (near enough) at bottom and serves as a support for plug#2.

Plug#2, a 500' cement barier (11600'-11100'), was set on plug#1 and extends about 360' into the 7" liner. This plug was tagged. The combination of plugs#1&#2 act as abandonment barriers for the Pentland/Smith Bank formations

Plug#3 is a unsupported 500' cement plug, not tested, nor tagged. It is not supported by any kind of means in this vertical well, so the position of this plug, depth wise, has to be questioned. The position of the plug is opposite the Valhall formation, however it does not provide full coverage over this formation and at the top there is still 430' of Valhall formation exposed, eventhough behind cemented 9 5/8" casing.

Plug#4, is a bridge plug, set at 8900'. It has been tagged, pressure to 3000psia and inflow tested. However, its position has to be questioned, since it is positioned ~230' below the top of the Valhall formation. When a leak occurs through the annular cement/casing above the bridge plug, it will travel right up the production casing. It would have been better if a cement plug would have been set above the bridge plug extending up to the sealing formations above the Valhall. As it is, this bridge plug serves little purpose.

Plug#5, is a 184' cement plug (850' – 666') set just below the cut 9 5/8" casing. There is no information available that would suggest that this plug is set on any kind of support (bridge plug, viscous pill), therefore it has to be assumed that with this kind of length of cement plug that there will be severe contamination. Furthermore, this plug was not tagged, nor tested.

Plug#6, is a 121' cement plug (666' – 545') set on top of plug#5 over the cut 9 5/8" and 13 3/8" casing strings. This plug was tagged. Above the cut 13 3/8" casing, the cement plug is supported by annular cement behind the 20" and 30" casing strings, however only for a distance of less than 100'.

4.8.2. Conclusion

There are doubts about the quality of some of the barriers that have been placed in the well, like the lack of bottom support and tag/test for plug#3, the position and purpose of the bridge plug#4 and the lack of support for plug#5.

However, since the CO_2 containing reservoir is not present in this well, the chance of a primary CO_2 source leaking via these sub-optimal barriers to shallower zoes/seabed is irrelevant.

The Risk of CO_2 leaking into the sea from this well longterm, is therefore classified as ***Low***.

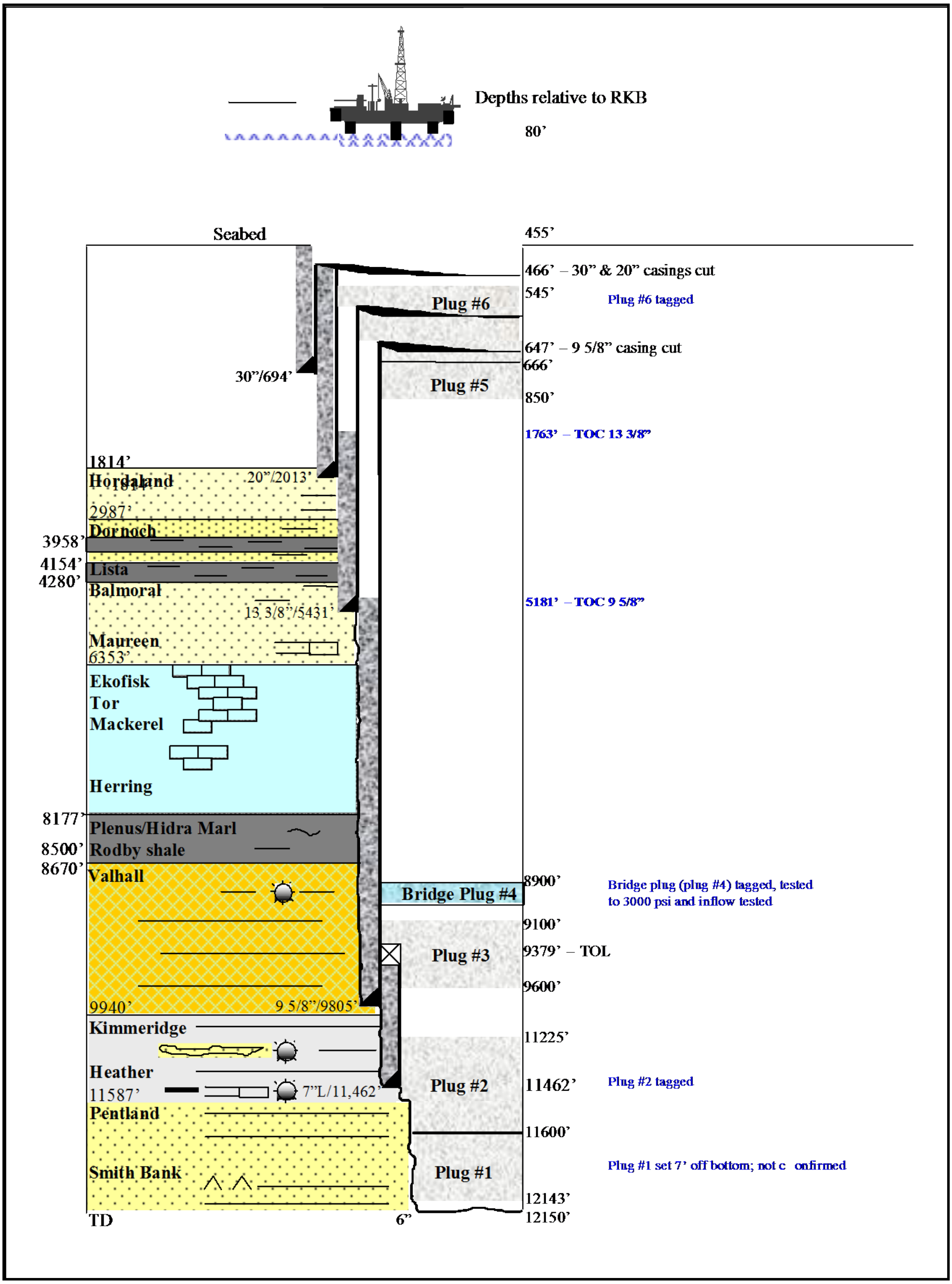


Figure 4.8 20/4b-4 - Hess

4.9. 20/4b-6

Table 4-5: 20/4b-6 Well Summary

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6,430,751.72 m E 655,751.68 m	57 deg. 59 min. 23.083 sec. N 00 deg. 15 min. 20.632 sec. W	
Operator	Amerada Hess		
Drilling Unit	Stena Spey		
Spudded	29/12/1997		
Abandoned	15/02/1998		
Duration	52 days		
Formation pressure	All formations found to be normally pressured		
Total depth (12 ¼" OH)	9965' AHD (RKB)		
Water depth	390'		
Derrick Floor elevation	83'		
Maximum Inclination	18.7 deg. at 8765'		
Casing Details		Weight – Grade - Threads	FSG (ppg)
30" - 20" conductor	752' AHD (RKB)	30": 310# - X52 20": 133# - X56 30" x 20" x/o at 710'	
20 - 13 3/8" casing	3084'AHD (RKB)	20": 133# - X56 13 3/8": 68# - N80 20" x 13 3/8" x/o at 487'	11.2 at 3084'
10 ¾" – 9 5/8" casing	9900' AHD (RKB)	10 ¾": 53# - L80 9 5/8": 47# - L80 10 ¾" x 9 5/8" x/o at 1128'	
Cement Details			
30" - 20" cement job:			
Main	16.0 ppg Class G	8 bpm, dye observed after pumping calculated volume w/o excess	556 bbl

Top-up job	Not performed		
20" - 13 3/8" cement job:			
Lead	12.5 ppg G+35% Silica	100% Excess	592.5 bbl
Tail	16.0 ppg Class G	100% Excess	152 bbl
Final diff. pressure	600 psi		
Pressure test	2000 psia	TOC at seabed (calculations)	
10 3/4" - 9 5/8" cement job:			
Lead	16.0 ppg Class G	10% Excess	184.7 bbl
Tail			
Final diff. pressure	2000 psi		
Pressure test	4000 psia	TOC 7600' (calculations)	
		CBL (7470' – 9800') indicated good cement in the 12 ¼" x 9 5/8" casing annulus from 8300' – 8570'	
Abandonment			
Plug 1	*Cement retainer*		
	K-1 cement retainer set at 8500'		
	Tested to 0.1 psi/ft over fracture pressure at 8638'	3000 psia pressure test	
	Cement plug:		
	16.0 ppg, Class G, 500'		36 bbl
	8500' - 8000'		
	No confirmation (tag, test)	TOC based on calculation	
Plug 2	*Cement retainer:*		
	K-1 cement retainer set at 1000'		
	Tested to 500 psia over LOT at 3084'	Formation strength is 11.2 ppg at 13 3/8" shoe at 3084' = 1796 psia	
	Cement plug:		
	16.0 ppg, Class G, 300'	8.5 bpm	45 bbl
	1000' – 700'	TOC based on calculation and firm base.	

	Since cement was set on a cement retainer , no confirmation required	Cement displaced with 10.7 ppg mud
Wellhead recovery	30" conductor and 20" casing cut 12' below seabed at 485'	
	10 ¾" casing cut at ~ 1069'	

4.9.1. 20/4b-6 abandonment assessment

This exploration well was abandoned with 2 cement plugs, 2 bridge plugs and all casing strings (30", 20" and 10 ¾") cut. It is assumed that the highest point where the CO_2 plume contacts this well, is at 8615' (top Captain). The geological seal is provided by the Plenus/Hidra/Rødby/Sola formations. All casing strings are constructed of carbon steel and the cement used was standard "Class G".

Plug#1; a K-1 cement retainer set at 8500' inside the 9 5/8" casing provides the basis for plug #1. This cement retainer was tested to 3000 psia, which is about 0.1 psi/ft over the fracture pressure at 8638'.

A 500' cement plug was set on top of the K-1 cement retainer (8500' – 8000'). Since the cement plug was set on top of a tested cement retainer, tagging and/or testing was not required.

Plug#2; a K-1 cement retainer set at 1000' inside the 13 3/8" casing provides the basis for plug #2. This cement retainer was tested to 700 psia, which is about 500 psia over the LOT at the 13 3/8" shoe at 3084'.

A 300' cement plug was set on top of the K-1 cement retainer (1000' – 700'). Since the cement plug was set on top of a tested cement retainer, tagging and/or testing was not required.

4.9.2. Conclusion

Based on the *CBL*, there is good annular cement behind the 9 5/8" casing between *8300' – 8570'*, eventhough TOC has been calculated to be at 7600'. For plug #1, with the K-1 cement retainer set at 8500' and 500' cement set above it, gives at least ***200'*** (8500' – 8300') of full lateral cement above the highest point of CO_2 influx into the well (8615').

The next barrier up will be Plug#2 inside the 13 3/8" casing set between 700' – 1000'. The 300' cement plug set on a tested cement retainer seems to give full lateral coverage in combination with annular cement from the 13 3/8" casing cementation and the 30" x 20" casing cementation.

However, if Plug #1 fails, the 13 3/8" casing shoe and other shallower formations are potentially exposed to CO_2. The 13 3/8" shoe LOT of (only) 1796' is potentially worrying if CO_2 is injected at the highest planned injection pressure (Pres = 3400 psia will give a presure of ~2000 psia at 3100'). Some of the uncemented formations may fracture when exposed to this pressurised CO_2.

This well is classified for now as ***Low-Medium*** risk.

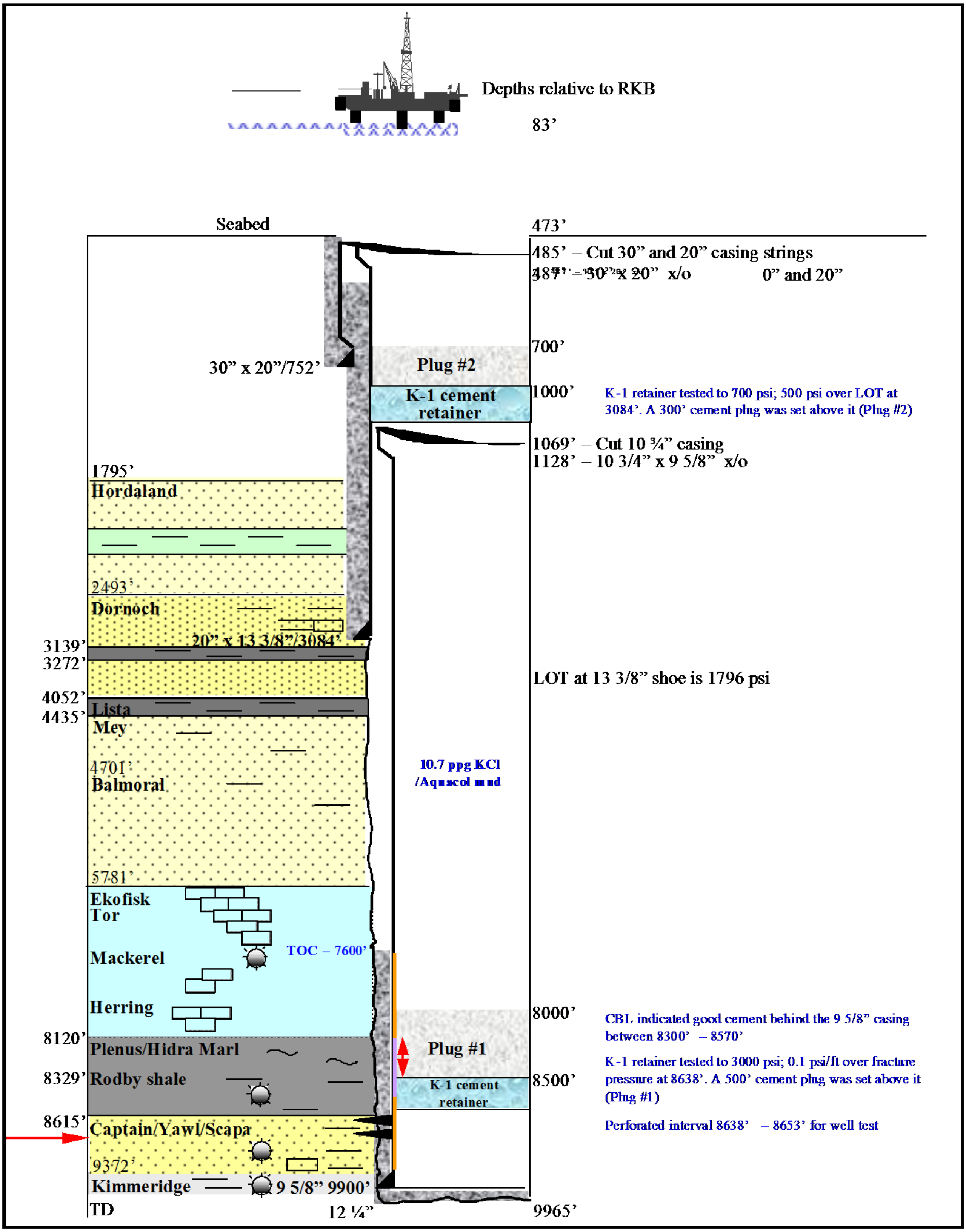


Figure 4.9 20/4b-6 - Hess

4.10. 20/4b-7

Table 4-6: 20/4b-7 Well Summary

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6,430,963.71 m E 654,525.19 m	57 deg. 59 min. 31.471 sec. N 00 deg. 23 min. 09.880 sec. W	
Operator	Amerada Hess		
Drilling Unit	Stena Spey		
Spudded	14/12/1999		
Abandoned	09/01/2000		
Duration	28.14 days		
Formation pressure	3827 – 4113 psia	MDT pressures (8634' – 9308')	
Total depth (12 ¼" OH)	9500' AHD (RKB)	Bottomhole T = 198 deg. F	
Water depth	393'		
Derrick Floor elevation	83'		
Casing Details		Weight – Grade - Threads	FSG (psi/ft)
30" conductor	753' AHD (RKB) (20" float shoe)	456.6# - X56 - HD90 2 jts 309.7# - X52 - SF60 4 jts 133.0# - X52 - SF60 1 jt	
13 3/8" casing	3652' AHD (RKB) (Gastight connections)	72.0# - L80 – NSCC 22 jts 72.0# –P110 – NSCC 55 jts 72.0# - L80 – NSCC 1 jt	0.63 (EMW)
30" cement job:			
Main	16.0 ppg Class G	Excess 300%, 7.0 bpm	475 bbl
Top-up job	16.5 ppg Class G		50 bbl
13 3/8" cement job:			
Lead	13.1 ppg G+35% Silica	Excess 50%, 7.4 bpm	557 bbl
Tail	16.0 ppg Class G	Excess 100%	175 bbl
Final diff. pressure	730 psi	No shear noticed on top plug, Therefore cement was under-displaced by 15 bbls (~120'). As a result, planned "cement	Cement tagged at 3483' (84' above FC)

		back to seabed" was not achieved. This was confirmed during abandonment.	
30" cement job:			
Main	16.0 ppg Class G	Excess 300%, 7.0 bpm	475 bbl
Top-up job	16.5 ppg Class G		50 bbl
13 3/8" cement job:			
Lead	13.1 ppg G+35% Silica	Excess 50%, 7.4 bpm	557 bbl
Tail	16.0 ppg Class G	Excess 100%	175 bbl
Final diff. pressure	730 psi	No shear noticed on top plug, Therefore cement was under-displaced by 15 bbls (~120'). As a result, planned "cement back to seabed" was not achieved. This was confirmed during abandonment.	Cement tagged at 3483' (84' above FC)
Pressure test	2500 psia	No CBL	
Abandonment			
Plug 1	16.0 ppg, Class G, 650'	7.5 bpm,	95 bbl
	8850' - 9500' (bottom)	7 bbl losses during cement job	
	No confirmation (tag, test)		
Plug 2	16.0 ppg, Class G, 650'	7 bbl losses during cement job	95 bbl
	8200' – 8850'	No confirmation (tag, test)	
Plug 3	Bridge plug 3588'	Hydromech II - BOT	
	Tested to 900 psia with 10.25 ppg mud	Formation strength is 12.0 ppg at 13 3/8" shoe at 3652' = 2279psia	533 psia over shoe strength
	16.0 ppg, Class G, 500'	6.0 bpm	74 bbl
	Cement not tagged	POBM displaced with 10.0 ppg Scavenger slurry	
Plug 4	16.5 ppg, Class G, 300'	5.0 bpm	44.0 bbl
	Plug set on Hivis pill, 300' 1100' – 1400'	Displaced well to seawater above cement plug	
	Cement not tagged		
Wellhead recovery	30" conductor and 13 3/8"	No cement found between 30"	MOST cutting

	casing cut 11' below seabed in one go	and 13 3/8" from recovered cut casing strings	tool

4.10.1. 20/4b-7 abandonment assessment

This exploration well was abandoned with 4 cement plugs, 1 bridge plug and all casing strings (30" and 13 3/8") cut. It is assumed that the highest point where the CO_2 plume contacts this well, is at 8633' (top Captain). The geological seal is provided by the Plenus/Hidra/Rødby/Sola formations.

All casing strings are constructed of carbon steel and the cement used was standard "Class G".

Plug #1, a 650' cement plug, was set on bottom of the well (9500' – 8850') and experienced 7 bbl losses during the cement job. Since it was set on the bottom of the well in open hole, it was not tagged nor pressure tested.

Plug#2, another 650' cement plug, was set on top of plug#1 (8850' – 8200') in open hole. During this cement job, another 7 bbls was lost.

This plug was, again, not tagged nor pressure tested. Taking into account the 2 x 7 bbl losses that were experienced during the placement of the plugs#1+2, it has to be assumed that the TOC of plug#2 is likely to ~100' deeper (ie 8300' instead of 8200').

This is important, since this plug is positioned opposite the highest point of CO_2 influx (8633'). This will result in a barrier with a height of 333' above the highest point of influx of CO_2.

Plug#3 is a Hydromech-II bridge plug, set just inside the 13 3/8" shoe at 3588', pressure tested to 533 psia. over the shoe strength at that depth. On top of the bridge plug, a column of 500' of cement was placed. This cement plug has not been tagged nor tested. The combination of the bridge plug and cement plug forms a good abandonment barrier, since it is supported on the outside of the 13 3/8" casing by annular cement, eventhough that has not been confirmed other than by pumped fluid volumes during the 13 3/8" cement job.

Plug#4 is a cement column of 300' set 800' – 1100' on top of a 300' viscous pill. This plug was not tagged, nor tested. This plug qualifies as an abandonment barrier since it is supported by cement on the outside of the 13 3/8" casing, despite the 15 bbl (~120') underdisplacement during the cement job.

4.10.2. Conclusion

This well has 300' of "rock-to-rock"cement in open hole from plug#2 above the highest point of CO_2 influx (8633'). The next barrier is Plug#3 at the 13 3/8" casing shoe. Eventhough plugs #3 and #4 are thought to be good barriers, the open hole is exposed at the 13 3/8" casing shoe with a 2300 psia formation strength.

In the unlikely event that plug#2 (300' of cement) would fail, with CO_2 injection pressures up to 3400 psia in the reservoir, CO_2 could potentially rise up the open hole and expose the Dornoch formation at the 13 3/8" shoe. This is a permeable zone and may cause escape of CO_2 to other shallow formations and wells. Some mitigating factors are that the open hole may have (partially) collapsed by then and a CO_2 pressure of 3400 psia at reservoir depth, translates to ~2000 psia at the 13 3/8" casing shoe with a full column of CO_2 (which is lower than the 13 3/8" shoe LOT). This well is classified as ***Low*** risk.

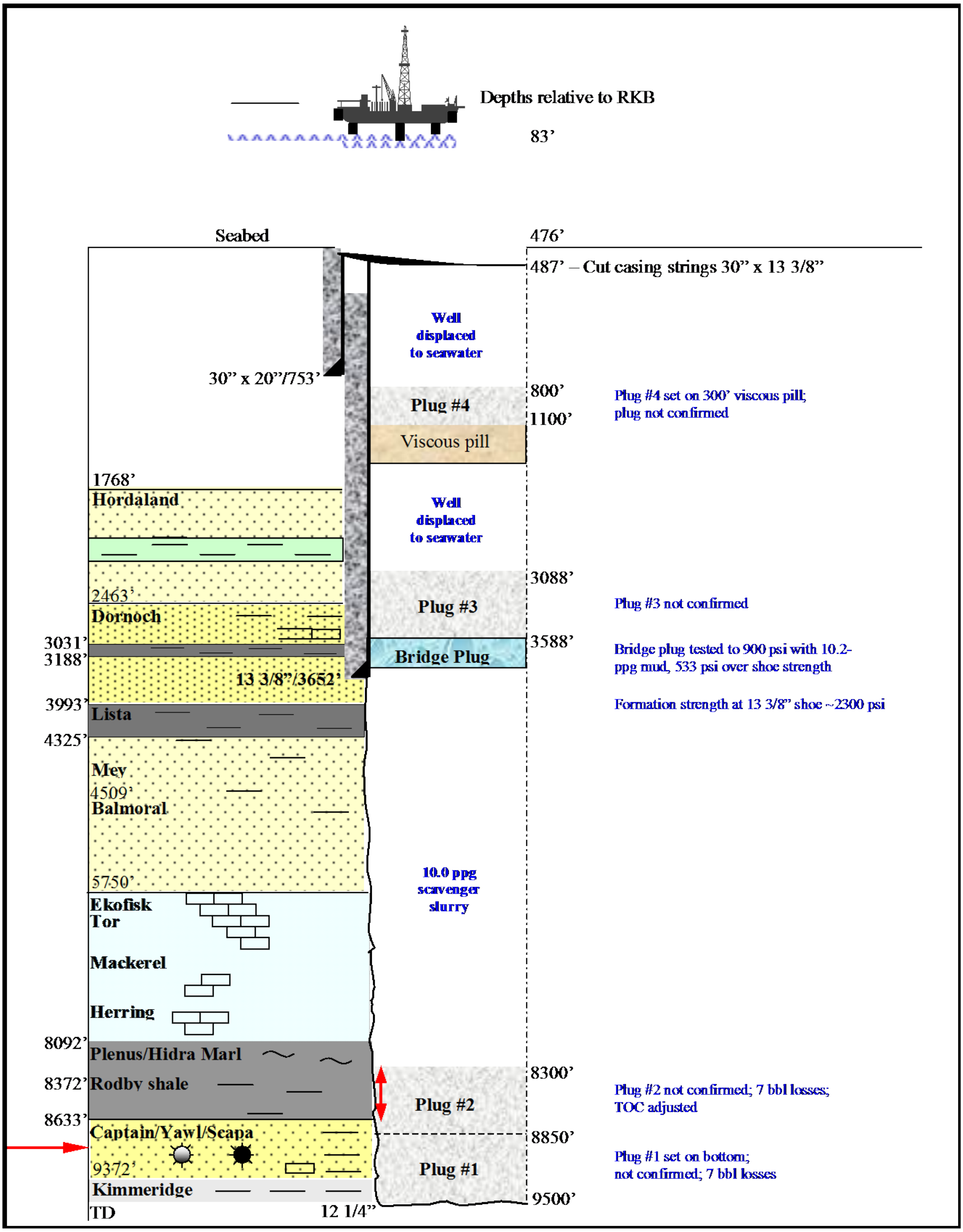


Figure 4.10: 20/4b-7 – Hess

4.11. 14/29a-2

Table 4-7: 14/29a-2 Well Summary

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N E	58 deg. 01 min. 30.12 sec. N 00 deg. 21 min. 58.50 sec. W	
Operator	Shell		
Drilling Unit	Sedco 709		
Spudded	23/11/1980		
Abandoned	30/01/1981		
Duration	68 days		
Formation pressure	Hydrostatic (RFT)	0.45 psi/ft	
Total depth (8 ½" OH)	10625' AHD (RKB)		
Water depth	406'		
Derrick Floor elevation	80'		
Maximum Inclination	6.8 degrees		
Casing Details		Weight – Grade - Threads	FSG (psi/ft)
30" conductor	617' AHD (RKB)	250# - ¾" WT/L	
20" casing	1391' AHD (RKB)	94# - K55 – Vetco LS-LM	0.585
13 3/8" casing	4453' AHD (RKB)	68# - N80 - BTC	0.728
9 5/8" casing	7881' AHD (RKB)	47# - N80 - BTC	0.733
Cement Details			
30" cement job:	Pozmix	No data	
20" cement job:	Pozmix	No data	
13 3/8" cement job:	Pozmix	No data	
9 5/8" cement job:			
Lead	Pozmix, 13.2 ppg		722 sx
Tail	Pozmix, 13.7 ppg		145 sx
Final diff. pressure		Casing contents circulated prior to cementation 500gpm	
Pressure test	3000 psia	No losses experienced	Bumped plugs

		No verification or indication on TOC other than planned (500' inside the 13 3/8" casing)	
Abandonment			
Plug 1	565' cement, Class G, 15.4 ppg	Plug set 10'off bottom 10615', without support.	37 bbl of mixwater
	10615' - 10050'	613' stinger of 2 7/8" dp	
	No confirmation (tag, test)	Reverse circulated out 5 bbl of cement after pulling back 6 stands	
Plug 2	555' cement, Class G, 15.4 ppg	Plug#2 set on plug#1directly after it was placed.	47 bbl of mixwater
	10050' – 9495'	Plug tagged with 20klbs	
Plug 3	448' cement, Class G, 15.7 ppg	After placement of cement, pulled back to 8693' and spotted hi-vis pill (8693'- 8599')	39 bbl of mixwater
	9448' – 9000'	Plug not tagged	
Plug 4	599' cement, Pozmix, 13.3 ppg	Reverse circulated out 8 bbl of cement after pulling back to 8001'	39 bbl of mixwater
	8599' – 8000'	Plug set on 100' viscous pill : 8693' – 8599'	
		Plug not tagged	
Plug 5	490' cement, Pozmix, 13.4 ppg	Plug set on top of plug#4. Circulated b/u at 6964'	30 bbl of mixwater
	8000' – 7510'	Plug tagged with 20 klbs and P/T 1500 psia	
Plug 6	586' cement, Pozmix, 13.3 ppg	Plug set on 2100' viscous pill. Reverse circulated b/u at 4811' after cement placement; 7 bbl cement returned	31 bbl of mixwater
	5397' – 4811'	Plug not tagged/tested	FIT 5311'
Plug 7	481' cement, Pozmix, 13.1 ppg	This plug was set on top of plug#6 right after it was placed. After placement of plug#7 pulled back to 3793' and circulated b/u	26 bbl of mixwater

	4811' – 4330'	Tagged 15klbs, P/T 1500 psia	FIT 4640'
Plug 8	455' cement, Pozmix, 13.2 ppg		42 bbl of mixwater
	1696' – 1241'	Plug tagged 15klbs, P/T 1000 psia	
Bridge plug	Baker model "N"	Bridge plug set at 1175'	
Wellhead/Casing recovery	9 5/8" casing	Cut at 1509' and recovered	
	13 3/8" casing	Cut at 498' and recovered	
	20" casing	Cut at 498' and recovered	
	30" casing/wellhead/MGB	Cut at 498' and recovered	TGB left below the mudline

4.11.1. 14/29a-2 abandonment assessment

This exploration well was abandoned with 8 cement plugs and 1 bridge plug. The 9 5/8" casing was cut at 1509' and the remaining 13 3/8", 20" and 30" casing strings were cut at 498' (12' below seabed). All casing strings are made of carbon steel and the cement used was a combination of "Class G" and POSIX cement.

It is assumed that the highest point of primary CO_2 contact for this well is at 8204' (Scapa sandstone).

Plug #1, a 565' cement plug, was set 10' off bottom in open hole covering part of the Rotliegend formation. This plug was not tagged.

Plug#2, a 555' cement barrier (10050'- 9495'), was set in open hole over the Rotliegend/Zechstein formations. This plug was set on top of plug#1 directly after it was placed. The plug was tagged with 20 klbs.

Plug#3 is an unsupported 448' cement plug, set 9000' – 9448' in open hole. It is set ~50' above (tagged) plug#2. This plug covers the remainder of the exposed Zechstein formation and ~200' of Smith Bank formation. Plug#3 was not tagged, nor tested.

Plug #4, a 599' cement plug, was set in open hole on top of a 100' viscous pill. This plug covers ~200' of Kimmeridge, all of the Scapa reservoir and ~200' of Rødby seal. This plug was not tagged/tested. This is the first barrier to upward CO_2 flow from the Scapa reservoir.

Plug#5 is a 490' barrier of cement (7510' - 8000') and has been set on top of plug#4. It has been tagged with 20 klbs. and pressure tested to 1500 psia. This plug is set partially in open hole as well as in cased hole (resp. 120'/370'). In the cased hole section, this plug has full lateral cement coverage if the 9 5/8" primary casing cementation has been successful. Information from the 9 5/8" casing cementation is scarce (no operational data wrt. TOC confirmation, etc.), but it has to be assumed that at least the bottom 370' of that cement job was good based on the fact that the plugs bumped and there were no losses during the cementation.

Plug#6 is a 568' cement plug (5397' – 4811') set inside the 9 5/8" casing on top of a 2100' viscous pill. This plug was not tagged, nor tested.

The *planned* TOC for the 9 5/8" casing was 500' back into the 13 3/8" casing (3953'). There is no verification of this, even though the plugs bumped and there were no reported losses. It could therefore be assumed that the annular cement covers the height of plug#6, so full lateral cement coverage.

This plug covers the area where an FIT was performed through the casing (5311').

Plug#7 is a 481' cement plug (4811' – 4330') set inside the 9 5/8" casing on top of plug#6, right after placement of plug#6. This plug was tagged with 15 klbs and tested to 1500 psia.

The *planned* TOC of the 9 5/8" casing was 500' back into the 13 3/8" casing (3953'). There is no verification of this, even though the plugs bumped and there were no reported losses during the cementation. It could therefore be assumed that the annular cement covers the full length of plug#7, so full lateral cement coverage.

This plug covers the area where an FIT was performed through the casing (4640').

Plug#8 is a 455' cement plug (1696' – 1241') set over the 9 5/8" casing stump (1509'). This plug was tagged with 15 klbs and tested to 1000 psia.

For the part inside the 9 5/8" casing, there is no overlap with annular cement from the 9 5/8" cement job. For the part inside the 13 3/8" casing, there is overlap with annular cement from the 13 3/8" cementation, assuming that the 13 3/8" casing cementation went as planned with a TOC 500' back inside the 20" casing shoe. This means that if the area inside the 13 3/8" casing (1509' – 1214') is covered behind the 13 3/8" casing (planned TOC 891'), than there is full lateral coverage.

Bridge plug; Baker model "N" was set at 1175', without any further information.

4.11.2. Conclusion

The first 3 cement plugs are good "rock-to-rock" open hole cement barriers, but only isolate the "Rotliegend" from the "Scapa" reservoir and provide no barrier to upward CO_2 flow.

Plug#4, which is set on a viscous pill, provides full "rock-to-rock" cement coverage over the Scapa reservoir section. It extends 200' into the Rødby cap rock.

Plug#5 has a good base from plug#4 and is set partially in open hole and partially back into the 9 5/8" casing where it is supported by cement in the annulus.

Plug#6 is set on a viscous pill inside the 9 5/8" casing and covers the FIT area (5311'). It can be assumed with the information available, that there is annular coverage.

Plug#7, which is set on top of plug#6 and was tagged/tested, can be assumed to have annular coverage of cement as well. This plug also covers the FIT area (4640').

Plug#8, which was set over the 9 5/8" casing stump, most likely has full lateral coverage from the 13 3/8" casing cementation. This plug was tagged/tested.

The *bridge plug* by itself does not serve any long-term barrier purpose. It is unclear why it was installed but it does not harm the abandonment.

This well is full of good abandonment barriers all the way from reservoir up to shallow depths. These abandonment barriers are "supported" plugs (viscous pills) of which most have been tagged/tested. All of the barriers set inside casing are laterally covered by annular cement.

The long term Risk of CO_2 leaking into the sea from this well is therefore classified as ***Low.***

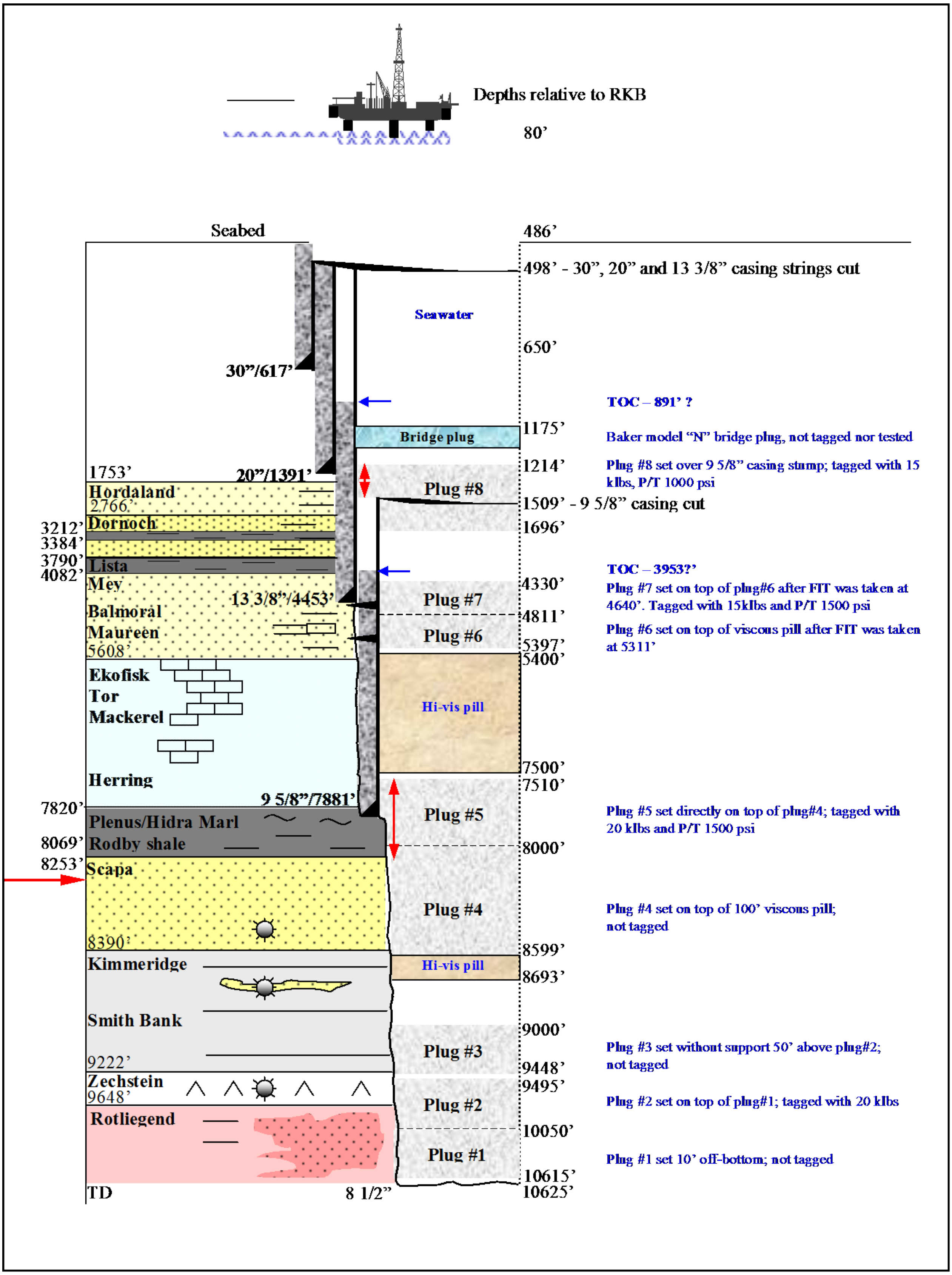


Figure 4.11 14/29a-2 - Shell

4.12. 14/29a-3

Table 4-8: 14/29a-3 Well Summary

Well Attibrute	Data		
Surface location	UTM	Lat/Lon	
	N 6 429 049m E 478 650m	58 deg. 00 min. 04.30 sec. N 00 deg. 21 min. 40.30 sec. W	
Operator	Shell		
Spudded	02/08/1996	Duration	68.3 days
Abandoned	06/10/1996	Drilling Unit	Sedco 704
Formation pressure	Hydrostatically pressured throughout	Top Captain 9656' AHD (8265' TVSS)	
Total depth (8 ½" OH)	11637' AHD (RKB)		
Water depth	396'	Maximum Inclination	36.6 degrees
Derrick Floor elevation	83'		
Casing Details		Weight – Grade - Threads	FSG (pptf)
35" - 30" conductor	783' AHD (RKB)	35": 710# - X52 – 2" WT 1 jt 30": 310# - X52 – SL-60	
20" - 13 3/8" casing	2583' AHD (RKB)	20": 129# - X56 – HD-90 1 jt 13 3/8": 68# - N80 – BTC x/o @ 518'	570 @ 2583'
10 ¾" - 9 5/8" casing	9275' AHD (RKB)	10 ¾": 55.5# - L80 - NVAM 9 5/8": 47# - L80 – NVAM x/o @ 525'	572 @ 9275'
7" liner	8760'–11629' AHD (RKB)	29# - L80 – VAM-HT	
Cement Details			
35" - 30" cement job:			
Main	697 pptf, RHC	6 bpm	380 bbl
	TOC at seabed, tagged with stinger	Top-up was not required	
20"- 13 3/8" cement job:			
Lead	640 pptf, Class G	7 bpm	471.4 bbl
Tail	712 pptf, Class G	7 bpm	115.3 bbl

	Cement at seabed (ROV)	Plug bumped, casing test 2400 psia	
10 3/4" – 9 5/8" cement job:			
Lead	832 pptf, Class G	8 bpm displacement	189 bbl
		Plug bumped with 1000 psi differential	
	TOC 7040' (planned)	Casing test 3200 psia	
7"L cement job:			
Main	832 pptf, Class G		106 bbl
	TOC 300' above TOL 8460'	Plug bumped, 2200 psia, *no losses*. Reverse circulated out, no cement	P/T linerlap 3000 psia
		VSP/SBT run prior to DST: SBT indicates good cement over liner and below 8300'	
Abandonment			
Plug 1	Failed cement plug	Plug fell through XC-polymer support	22 bbls
	No resisitance encountered when trying to weight-test plug		
Plug 2	600' cement, Class G, 16ppg	Plug set on 243' (9 bbl) of Mudpush spacer	22.3 bbls
	9800' – 9200'	Plug 2 not tagged/tested	
Plug 3	309' cement, Class G, 16ppg	Plug 3 set on top of plug2.	22.3 bbls
	9200' – 8891'	Weight tested 15Klbs, P/T to 1000 psia for 10 minutes and inflow tested	
Plug 4	664' cement	Plug 4 set on 6 bbl mudspacer	38.5 bbls
	8886' – 8222'	Weight tested 15-20Klbs	
Plug 5	571' cement , Class G, 16ppg	Plug set on 18bbl 250' XC-polymer spacer	76 bbls
	2686'- 2115'	Weight tested 15Klbs, P/T to	

		1000 psia for 10 minutes and inflow tested
Wellhead/Casing recovery	9 5/8" – 10 ¾" casing	Cut at 2536' and recovered
	20" and 30" casing strings	Attempted cut at 495' But not recovered
		Due to the problems encountered to recover the wellhead/guidebase, (unable to pull free and unwilling to use explosives) the recovery of the wellhead and guidebase was left to a Diving Support Vessel for a later date. No information is available that confirms that this has indeed been done.

14/29a-3 abandonment assessment

This exploration well was abandoned with 5 cement plugs and the 9 5/8" casing string cut and recovered. A shallow cut at 495', in order to recover the wellhead/guidebase by cutting the 30" and 20" casing strings, was unsuccessful.

It is assumed that the highest point where the CO_2 plume contacts this well, is at 9656'AHD (top Captain). All casing strings are made of carbon steel and the cement used was standard "Class G".

Plug #1, was supposed to be a 600' cement plug, but this plug failed since it fell through its XC-polymer base and did not set.

Plug#2, a 600' cement barrier (9800'-9200'), was set on a viscous pill inside the 7"L and straddles the perforations from the well test. This barrier stretches about 450' AHD above the highest CO_2 influx point. This plug was not tagged nor tested. It is unclear if the cement behind the 7"L is good, based on operational data, other than the liner cement job being "event free". In addition, an SBT was run prior to perforating for the well test, this indicated good cement behind the 7"L.

Plug#3, ~300' of cement, is set on top of plug#2 to the TOL. This plug was tagged and pressure/inflow tested. Despite some cement having been circulated out due to tagging green cement and washing down, this still qualifies as good cement plug. For full lateral cement coverage, the same applies as with plug#2; there is lack of operational data from the 7"L cement job, eventhough it was described as "event free". However, the SBT indicated good cement behind the 7"L.

Plug#4 is a 664' cement plug, set at 8886' – 8222'. It has been tagged, but not pressure/inflow tested since this was already done on plug#3. For full lateral coverage it is mainly the 9 5/8" production casing cement job that needs to be evaluated at this depth. The cement job was described as a "good cement-job" with bumped plugs (1000 psi differential) and a successful casing pressure test. The SBT indicated good cement behind the 9 5/8" casing below 8300' to the TOL.

Plug#5 is a 571' cement plug (2686' – 2115') set over the 9 5/8" casing cut (2536'). This plug is supported by a XC-polymer base inside the 9 5/8", however there is concern that some cement may have sagged into the 13 3/8" x 9 5/8" casing annulus. The 13 3/8" casing cementation featured a bumped plug, cement at seabed (ROV) and a successful casing pressure test. It can be assumed that the 13 3/8" casing shoetrack, which is positioned opposite plug#5, provides full lateral cement coverage. This plug was tagged and pressure/inflow tested.

4.12.1. Conclusion

The quality of the abandonment plugs looks good. If the primary casing cementations of the production casing and liner is assumed to be good, than there is about 1400' of solid cement from plugs#2/3/4 above the highest point of CO_2 influx into the well.

At shallow level there is potentially also another 400' of full lateral cement coverage if there has not been sagging of cement into the annulus at the level of the 9 5/8" casing cut and a good 13 3/8" cement job was performed.

The long-term Risk of CO_2 leaking into the sea from this well, is therefore classified as ***Low***.

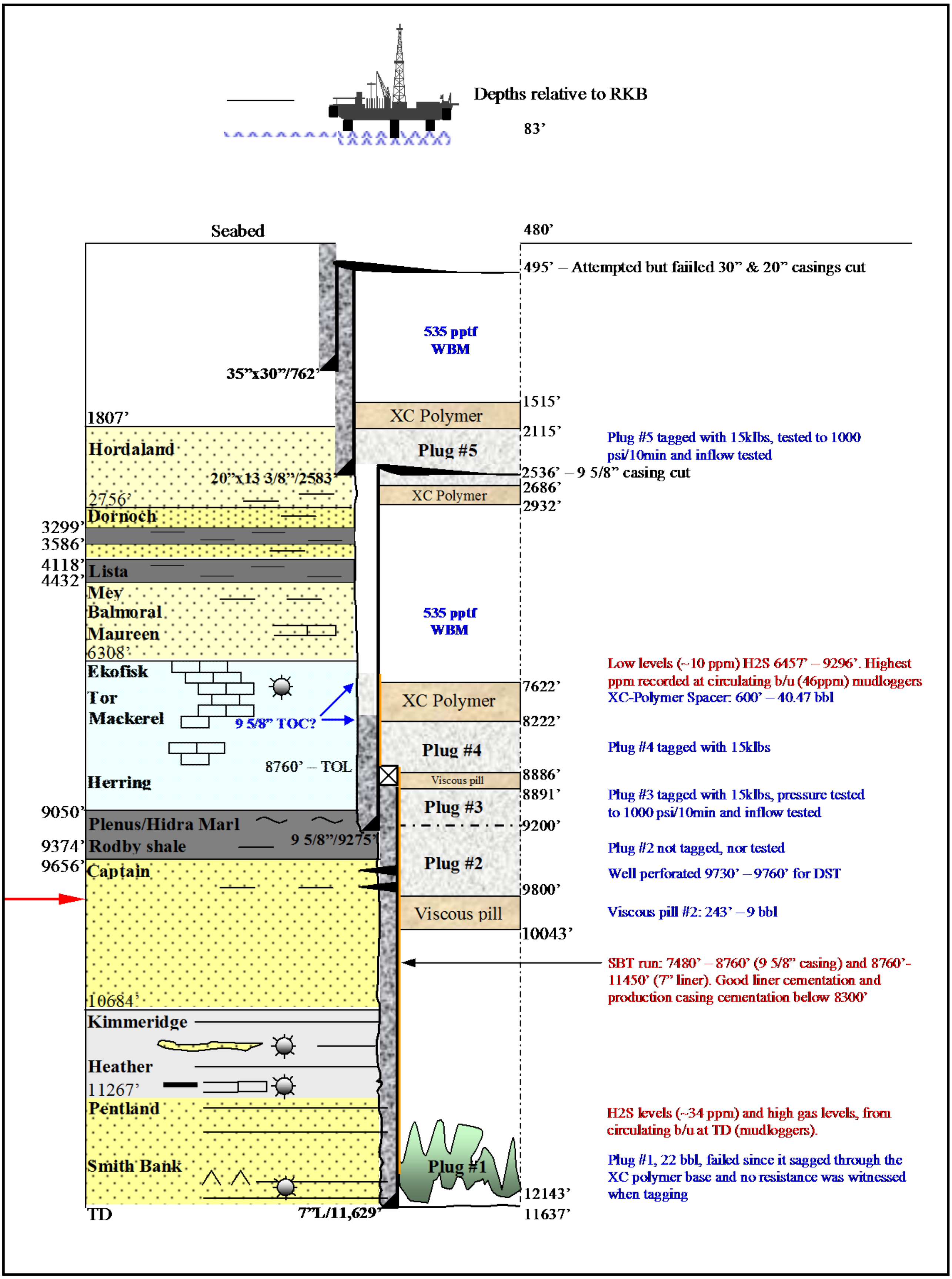


Figure 4.12: 14/29a-3 - Shell

4.13. 14/29a-4

Table 4-9: 14/29a-4 Well Summary

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N E	58 deg. 00 min. 04.64 sec. N 00 deg. 13 min. 11.79 sec. W	
Operator	Shell		
Drilling Unit	Borgny Dolphin		
Spudded	06/01/1998		
Abandoned	31/01/1998		
Duration	26.71 days		
Formation pressure	Hydrostatic pressure regime: 8847' – 9313' (3922 - 4107 psia)	Measured by MDT	
Total depth (8 ½" OH)	9484' AHD (RKB)		
Water depth	397'		
Derrick Floor elevation	82'		
Maximum Inclination	7.4 degrees	STM-15 wellhead	
Casing Details		Weight – Grade - Threads	FSG (ppg)
35" x 30" conductor	738' AHD (RKB)	705# - X52 – ALT-2HT 310# – X52 – ST2RB x/o at 535'	
20" x 13 3/8" casing	2500' AHD (RKB)	129# - X56 – ALT-2 68# - N80 – Buttress x/o at 496'	13.41 @ 2500'
10 ¾" x 9 5/8" casing	6502' AHD (RKB)	55.5# - L80 – VAM TOP 47# - L80 – New VAM x/o at 1462'	14.79 @ 6502'

Cement Details			
35" x 30" cement job:	Class G, 16.0 ppg	Returns to seabed	473 bbls
	Top up job performed		70 bbls
20" x 13 3/8" cement job:			
Lead	Class G, 12.3 ppg		544 bbls
Tail	Class G, 16.0 ppg		112 bbls
Final diff. pressure	350 psi		
Pressure test	2000 psia		
10 ¾" x 9 5/8" cement job:			
	Class G, 15.4 ppg	TOC 4502'	138 bbls
	Plugs did not bump; so ½ shoetrack volume was displaced additionally	Pressure test could only be done when the shoetrack was drilled out due to the plugs not bumping.	
Abandonment			
Plug 1	568' cement, Class G, 16ppg	Plug set on bottom	39.86 bbls
	9484' - 8916'	No confirmation (tag, test)	
Plug 2	550' cement, Class G	Plug not set on support or viscous pill; only 60' above plug#1	38.60 bbls
	8850' – 8300'	Plug not tagged	
Plug 3	596' cement, lass G	Plug set on 300' Hi-vis pill 6900' – 6600'	25.49 bbls
	6600' – 6004'	Plug tagged with 10 klbs (6004') and pressure tested 3000 psi/15 min	
Plug 4	599' cement, Class G, 16ppg	Plug set on 300' Hi-vis pill 1500' – 1200'	86 bbls
	1200' – 601'	Plug tagged 10 klbs and pressure tested 1000 psi/10 min	

Wellhead/Casing recovery	10 ¾" casing	Cut at 994' and recovered
	20" and 35" casing/ wellhead/RRGB	Cut at 491' and recovered

4.13.1. 14/29a-4 abandonment assessment

This exploration well was abandoned with 4 cement plugs. All three casing strings were cut. It is assumed that the highest point where the CO_2 plume contacts this well, is at 8842' (top Captain). There have been no reports of gas/oil shows during drilling. All casing strings are fabricated from carbon steel and the cement used was standard "Class G".

Plug #1, a 568' cement plug, was set at bottom in open hole. This plug was not tagged nor tested. This plug was set 9484' – 8916' and does not cover the Captain sands (highest point of inflow for CO_2)

Plug#2, a 550' cement barrier (8850'-8300'), was set in open 66' above plug#1. This plug was not supported at bottom when it was set, nor was it tagged/tested afterwards. This is the first plug that provides a barrier to CO_2 flow from the Captain sands. This plug potentially provides 543' of "rock-to-rock" cement above the Captain sands. Even if this plug has sagged by 66' (to contact plug#1) there should be sufficient cement above the Captain sands.

Plug#3 has been set on top of a 300' Hi-vis pill and covers 100' open hole and 500' inside the 9 5/8" casing; 596' total 6600' – 6004'. This plug is positioned oposite the bottom part of the 9 5/8" casing cementation and despite the plugs not bumping (but did get pressure test when drilling out shoetrack) and lack of operational data form the cementation, it has been assumed to provide full lateral cement coverage.

Plug#4 has been set over the 10 ¾" casing stump on top of a 300' Hi-vis plug. This plug was tagged (at 601') and pressure tested. There may be concern that some cement may have sagged down the 13 3/8" x 10 ¾" annulus, but this gap is only ~0.8" wide and if there would not have been cement, the pressure test would have been against the 13 3/8" casing shoe (open hole) and would have failed.

4.13.2. Conclusion

Plug#1 plays no part in isolating the Captain sands, even though it is probably a good cement plug. Plugs#2/3/4 all seem to be of good quality as well.

For *plug#2*, even in the worst case that the plug would have sagged 66', it would still provide sufficient cement coverage above the top Captain sands and exhibits "rock-to-rock" cement coverage for 477'.

The only unknown for *plug#3* is the quality of the 9 5/8" casing primary cementation. The TOC of 4502' is a theoretical number (2000' of cement column); there is no verification of this from reports. The cement darts from the primary cement job were not seen to bump during the cement job, so an additional ½ shoe track volume was displaced. This does not make it a poor cement job though. However, plug#3 also covers 100' of open hole below the 9 5/8" casing shoe, so even if the 9 5/8" casing cementation was doubtful, there would still be 100' of cement barrier underneath it.

Plug#4 is a good shallow cement plug (tagged/tested). If CO_2 percolates upwards through the well (in case that barriers fail) one can wonder if the CO_2 would ever get to plug#4, or would the CO_2 plume migrate via the permeable Dornoch formation. Another consideration is that the 13 3/8" shoe can break down (breakdown pressure ~1743 psia). This depends on the CO_2 pressure in the reservoir. Generally speaking, this well has been abandoned properly and poses very little risk to CO_2 percolation. The long-term Risk of CO_2 leaking into the sea from this well, is therefore classified as ***Low.***

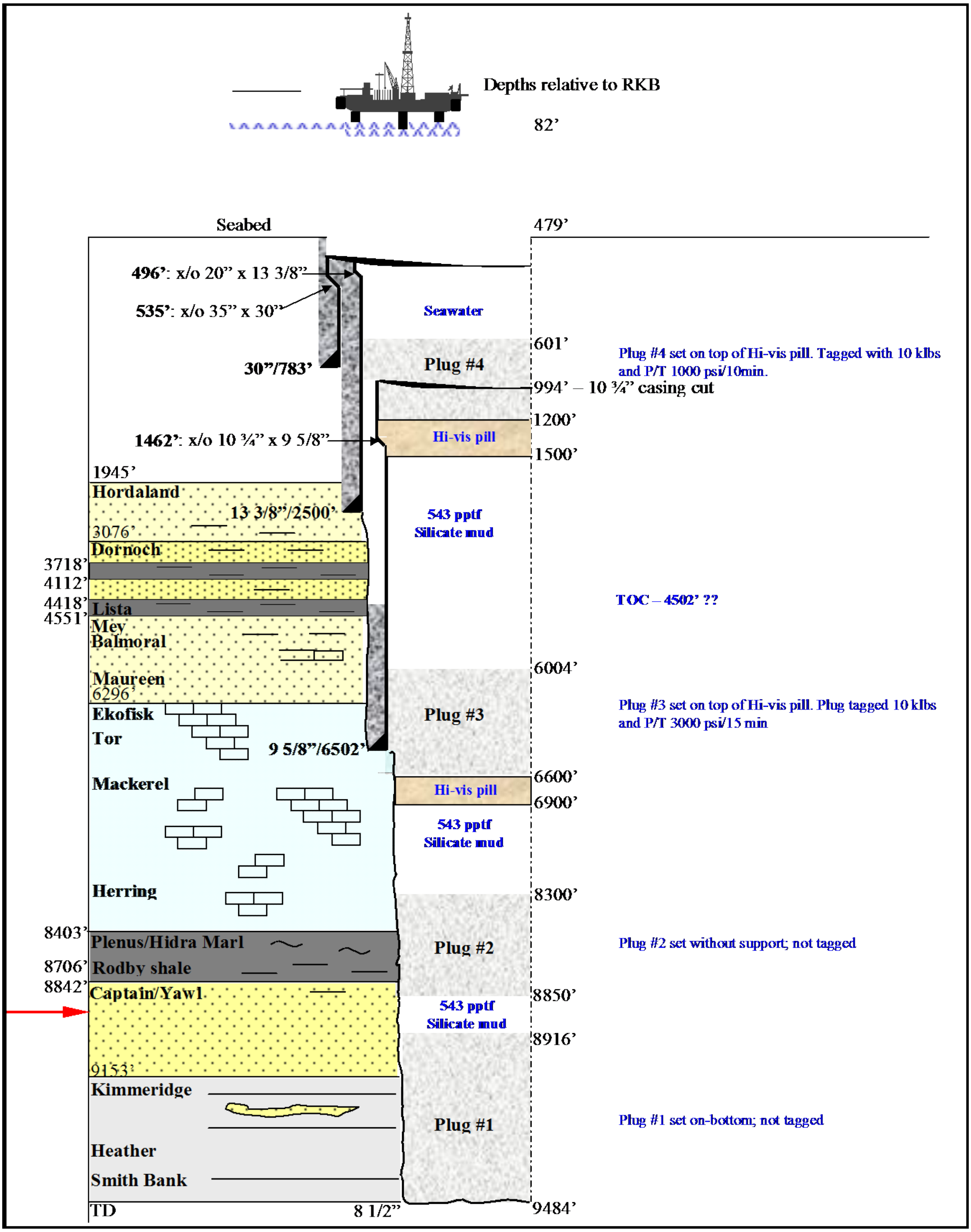


Figure 4.13: **14/29a-4 – Shell**

4.14. 14/29a-5

Table 4-10: 14/29a-5 Well Summary

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6,429,582.12 m E 479,621.48 m	58 deg. 00 min. 21.788 sec. N 00 deg. 20 min. 41.289 sec. W	
Operator	Shell		
Drilling Unit	John Shaw		
Spudded	18/04/1999		
Abandoned	08/05/1999	18 ¾" Vetco MS700 wellhead	
Duration	21.63 days		
Formation pressure	3813 – 4003 psia	MDT pressures (8478' – 9038')	
Total depth (8 ½"" OH)	9190' AHD (RKB)	Bottomhole T 8478' = 177.7 deg. F 9038' = 189.9 deg. F	
Water depth	400'		
Derrick Floor elevation	80'		
Maximum Inclination	2.95 degrees @ 8442'		
Casing Details		Weight - Grade - Threads	FSG
30"x 20" conductor	714' AHD (RKB)	30": 310.0# - X52 - ST2RB 20": 129.0# - X56 – ALT-2 x/o at 677'	
20" x 13 3/8" casing	3960' AHD (RKB)	20": 129.0# - X56 - ALT-2 13 3/8": 68.0# - N80 – BTC x/o at 503'	626 pptf
Cement Details			
30" cement job:			
Main	676 pptf, Class G + 15% Litefill	Excess 200%, 7.5 bpm	261 bbl
	Cement seen at seabed		
13 3/8" cement job:			

Lead	686 pptf, Class G	Excess 100%, 5 bpm	803 bbl
Tail	832 pptf, Class G	Excess 100%, 3.5 bpm	149 bbl
Final diff. pressure		1 spring bow centraliser/joint: 3831'-3624' and 3916'	
Pressure test	2500 psia	Top plug bumped at 97% pump efficiency	
		TOC was planned to seabed. Only confirmation of this is withVSP (2400').	
Abandonment			
Plug 1	832 pptf, Class G, ~1000'	3.5 bpm,	70 bbl
	8100' - 9190' (bottom)	No losses during cement job	
	No confirmation (tag, test)	Theoretical top of plug#1 is 8100'	
Plug 2	832 pptf, Class G, ~560'	Cement set on base of 35 bbls hi-vis (top 4160')	92 bbl
	3590' – 4152'	No losses during cement job	
	Tagged at 3590' with 10 klbs and P/T to 1000 psi (500 psi over LOT)	Theoretical bottom of plug#2 is 4152'	
Wellhead/Casing recovery	30" conductor 20" casing	Cut 12' below seabed at 492' in one go.	MOST cutting tool
		Wellhead and PGB recovered	

4.14.1. 14/29a-5 abandonment assessment

This exploration well was abandoned with 2 cement plugs. The 30" and 20" casing strings were cut 12' below seabed. It is assumed that the highest point where the CO_2 plume contacts this well, is at 8475' (top Captain). The geological seal is provided by the Plenus/Hidra/Rødby formations.

All casing strings are constructed of carbon steel and the cement used was Rugby "Class G".

Plug #1, a 1090' cement barrier, was set on bottom of the well (9190' – 8100') in open hole. No losses were experienced during the cement job. This cement barrier was not tagged nor pressure tested. This plug covers the Captain sands and the seal above it (Rødby/Hidra). The plug extends about 375' above the Captain sands, assuming that the volumes pumped are correct, no losses were experienced and an 8 ½" hole diameter is correct. For instance the impact of a larger hole diameter is as follows: 9" open hole diamter instead of 8 ½" makes the plug height ~100' shorter.

From the wireline logging data, an average hole diameter of 8.34" was established for this open hole section.This diameter reduction increases the height of the cement plug by ~30'.

Plug#2, a 562' cement plug, was set on top of a 35 bbl base of hi-vis pill. During this cement job, no losses were reported. This plug is positioned 200' in open hole just below the 13 3/8" casing shoe and about 370' inside the 13 3/8" casing.

This plug was tagged with 10 klbs and pressure tested to 1000 psia, which is 500 psia over the LOT value at the 13 3/8" shoe.

4.14.2. Conclusion

The main barrier to primary CO_2 flow in this well is plug#1, which is set on bottom in open hole and provides "rock-to-rock" coverage over the Captain reservoir, as well as the Hidra/Rødby seal above it.

An estimated total of 375' of cement from plug#1 extends above the highest point of influx (8475').

The second barrier is plug#2, which is set partially in open hole (~200') and partially in cased hole on top of a viscous pill. This plug was tagged with 10klbs and pressure tested to 1000 psia, which is ~500psia over the 13 3/8" casing shoe LOT. It covers the Lista and Dornoch formations. Not much information is available from the 13 3/8" casing cementation, but the top plug bumped at displacement. No information about losses. A VSP gave an indication of TOC of 2400' (about 1500' of annular cement). For the 370' cement plug inside the 13 3/8" casing it can be assumed that there is full lateral coverage with the tail slurry behind the casing.

This well is classified as ***Low*** risk for CO_2 leakage.

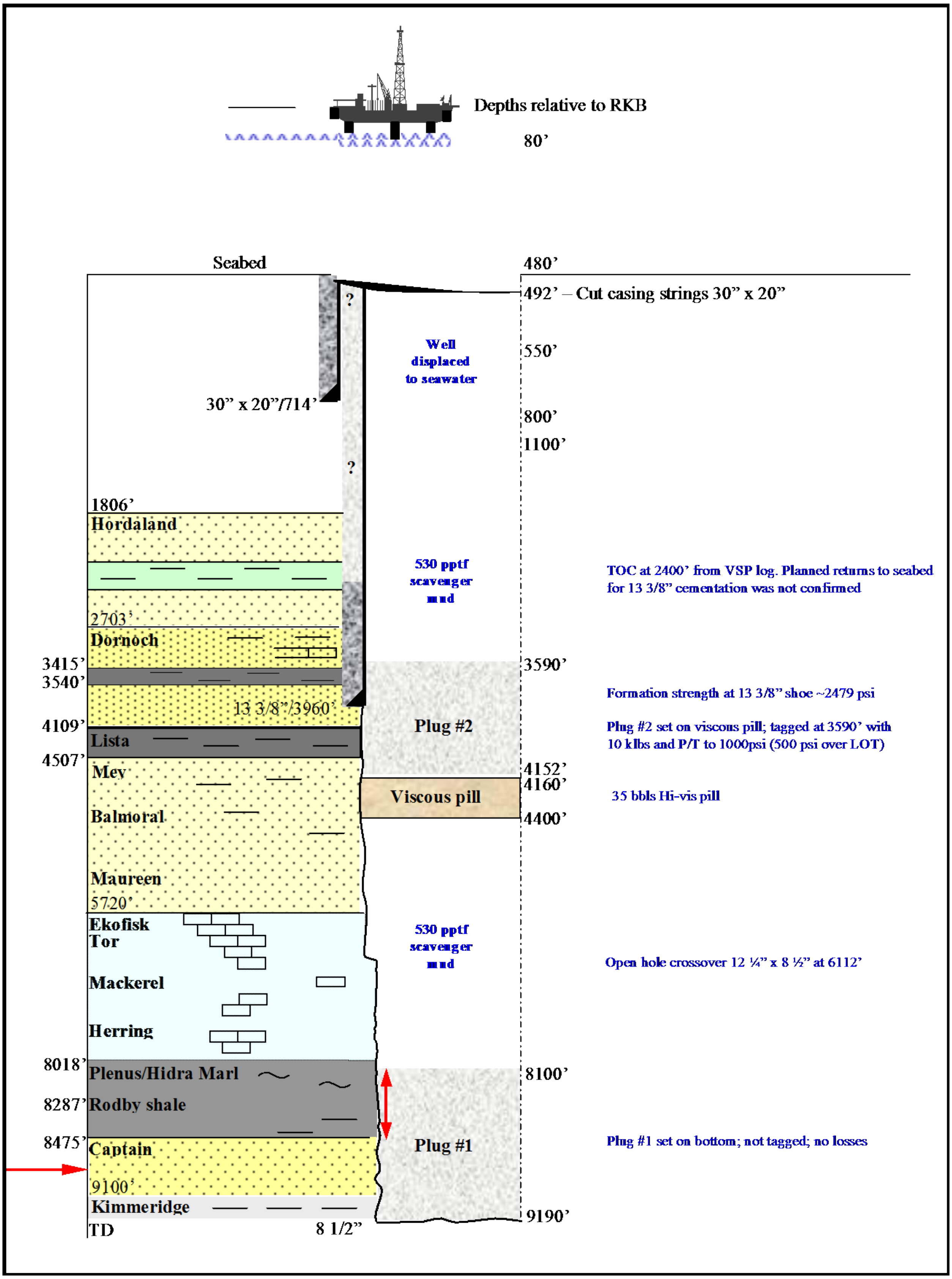


Figure 4.14 14/29a-5 – Shell Well Summary

4.15. 14/28a-1

Table 4-11: 14/28a-1 Well Summary

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6 435 766m E 471 802m	58 deg. 03 min. 40.2 sec. N 00 deg. 28 min. 40.2 sec. W	
Operator	Shell		
Drilling Unit	Sedco 714		
Spudded	22/04/1989		
Abandoned	17/05/1989		
Duration	25 days		
Formation pressure	Reservoirs found hydrostatically pressured and water bearing	No RFT's taken	
Total depth (8 ½" OH)	7055' AHD (RKB)		
Water depth	384'		
Derrick Floor elevation	85'		
Maximum Inclination	3.3 degrees at TD		
Casing Details		Weight – Grade - Threads	FSG (psi/ft)
30" conductor	720' AHD (RKB)	234# - B – ST-2RB	
20" casing	1957' AHD (RKB)	129# - X56 – Vetco LSLH	0.607
13 3/8" casing	3008' AHD (RKB)	68# - N80 - BTC	0.839
9 5/8" casing	5189' AHD (RKB)	47# - L80 - VAM	1.007
Cement Details			
30" cement job:	12.3 ppg, Pozzo 12.3 ppg, Class G lightfill	TOC seabed	112 bbl cement 230 bbl cement
20" cement job:	13.7 ppg, Pozzo	TOC seabed, cement observed	837 bbl cement
	Casing tested to 1000 spi	No losses	
13 3/8" cement job:	13.0 ppg, problems with mixing cement due to	Severe losses experienced due to expected plugged ports in the	271 bbl cement

	mixwater quality issues.	hanger. At some point the blockage was cleared by increasing the pump rate, as losses stopped.	
	Differential pressure prior to bump 300 psi		
	Casing tested to 2500 psia	TOC 1284' (diff pressure)	
9 5/8" cement job:	13.7 ppg, Pozzo	Lost 58 bbls during cementjob	210.5 bbl cement
		Plug bumped	
	Casing tested to 3000 psia	TOC 2508' (theoretical, based on all losses being mud. When all losses are assumed to be cement, the TOC = 3398')	
Abandonment			
Plug 1	500' cement, Class G, 15.4 ppg	Plug set 5'off-bottom 7050', without support.	35 bbl of cement
	7055' - 6555'	718' stinger of 3 ½" dp	
	No confirmation (tag, test)	Pulled back to 6555' and circulated b/u. No cement returns.	
Plug 2	500' cement, Class G, 15.4 ppg	Plug#2 set on plug#1 directly after it was placed.	35 bbl of cement
	6555' – 6055'	Plug not tagged.	
		Pulled back to 6055' and circulated b/u. No cement returns.	
Plug 3	500' cement, Class G, 15.4 ppg	Plug#3 set on plug#2, directly after it was placed.	35 bbl of cement
	6055' – 5555'	Plug not tagged	
		Pulled back to 5555' and circulated b/u. No cement returns.	
Plug 4	600' cementClass G, 15.4 ppg	Plug#4 set on plug#3, directly after it was placed.	46 bbl of cement
	5555' – 4955'	Pulled back to 4700' and circulated b/u. No cement returns.	

		Plug tagged with 10 klbs, P/T to 3000 psia	
Plug 5	458' cement, Class G, 13.4 ppg	Plug set on top of hi-vis pill. (50 bbls from 1650' – 1150')	64 bbl of cement
	1150' – 692'	Pulled back to 600' and circulated b/u. No cement returns.	
		Plug tagged with 10 klbs, P/T to 1800 psia	
Wellhead/Casing recovery	9 5/8" casing	Cut at 1018' and recovered	
	13 3/8" casing	Cut at 559' and recovered	
	20" casing	Cut at 485 and recovered	
	30" casing	Cut at 485' and recovered	
	20"/30" retrieved with PGB		

4.15.1. 14/28a-1 abandonment assessment

This exploration well was abandoned with 5 cement plugs. The 9 5/8" casing was cut at 1018', the 13 3/8" casing was cut at 559' and the remaining 20" and 30" casing strings were cut at 485' (16' below seabed). All casing strings are made of carbon steel and the cement used was "Class G".

This well does not feature the formations where CO_2 will be injected into (Captain/Yawl/Scapa) and therefore the assessment of containment of CO_2 is not really applicable to this well.

Plug #1, a 500' cement plug, was set 5' off bottom (7050' – 6555') in open hole covering most of the Rotliegend formation. This plug was not tagged. No cement returns were witnessed when circulating out at 6555'. 35 bbl. of cement equals 499' of height in gauge 8 ½" open hole.

Plug#2, a 500' cement barrier (6555'- 6005'), was set in open hole over the remainder of the Rotliegend/Zechstein/Kimmeridge formations. This plug was set on top of plug#1 directly after it was placed. This plug was not tagged.

Plug#3 is a 500' cement barrier (6005' – 5555') in open hole. It was set on top of plug#2 directly after placement of plug#2. This plug covers part of the Chalk formation. Plug#3 was not tagged, nor tested.

Plug #4, a 600' cement plug, was set on top of plug#3 directly after it was placed. This plug covers the remainder of the Chalk in open hole and also covers 235' of cased hole. Despite losses during the 9 5/8" cement job, the bottom section of the 9 5/8" casing is thought to have good cement and thereby provides full lateral coverage with that part of the cement plug inside the casing. This plug was tagged with 10 klbs. and pressure tested to 3000 psia.

Plug#5 is a 458' barrier of cement (1150' - 692') and has been set on 500' of hi-vis. pill. It has been tagged with 10 klbs. and pressure tested to 1800 psia. This plug is set over the 9 5/8" casing stump (1018'). For the part of the plug that is positioned inside the 13 3/8" casing (1018' – 692'), it is unlikely to have full lateral coverage from annular cement of the 13 3/8" cementation (TOC 1284').

4.15.2. Conclusion

The open hole section has been completely filled with cement ("rock-to-rock") from the first four cement plugs. Even though the plugs were not tagged and no cement returns were witnessed during circulating-out after pulling back, it has to be assumed that there is quality cement in the open hole, since there were no reported losses during the placement of the cement plugs.

Plug#5 could be bypassed by CO_2 (if encountered at this shallow depth from failed barriers) since it does not feature full lateral cement from the 13 3/8" cementation.

The absence of the injection reservoir (Captain, Scapa) makes it impossible to assess primary CO_2 containment for this well. If CO_2 is for some unlikely reason present in the Balmoral sands, it will only have to overcome annular cement in order to breakthrough into the well and percolate upward to plug#5, which is not a long term barrier. The latter is an unlikely scenario though, since CO_2 can only be present in these shallow reservoirs via other leaking wells and that scenario is not part of this study.

The long term Risk of CO_2 leaking into the sea from this well is therefore classified as ***Low.***

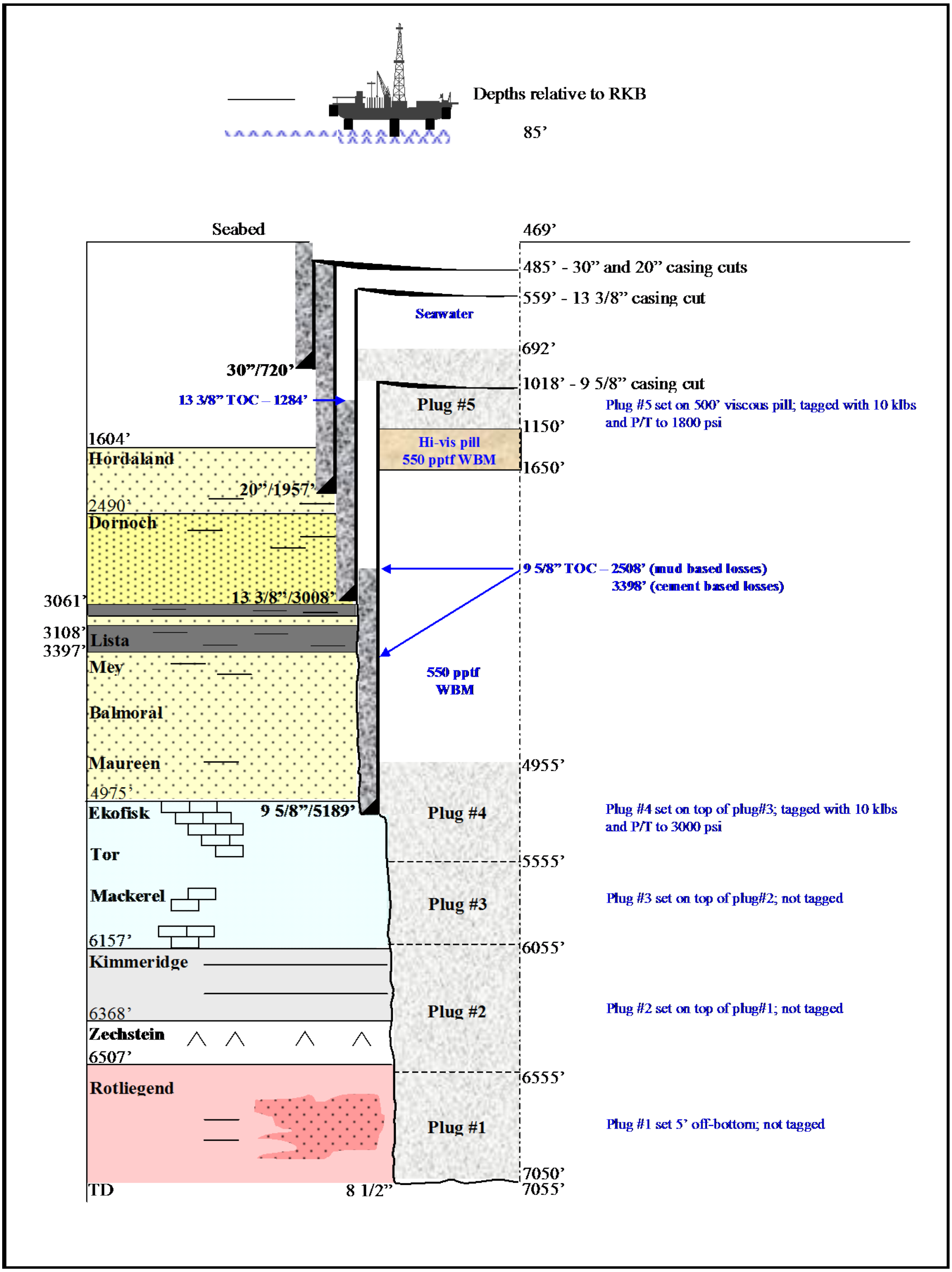


Figure 4.15 14/28a-1 – Shell

4.16. 14/28a-3a

Table 4-12: 14/28a-3a Well Summary

Surface location	UTM	Lat/Lon	
	N m E m	58 deg. 02 min. 31.800 sec. N 00 deg. 27 min. 27.409 sec. W	
Operator	Shell		
Drilling Unit	John Shaw		
Spudded	03/08/2000		
Abandoned	22/08/2000		
Duration	20 days		
Formation pressure			
Total depth (8 ½”” OH)	9090’ AHD (RKB)	Bottomhole T	
Water depth	387’		
Derrick Floor elevation	80’		
Maximum Inclination	1.01 degrees @ 6185.8’		
Casing Details		Weight - Grade - Threads	FSG
30”x 20” conductor	761’ AHD (RKB)	30”: 310.0# - X52 - ST2RB 20”: 133.0# - X56 – ALT-2 x/o at 724’	
20” x 13 3/8” casing	3369’ AHD (RKB)	20”: 131.0# - X56 - ALT-2 13 3/8”: 68.0# - N80 – Dino VAM x/o at 507’	740 pptf
Cement Details			
30” cement job:		No data	
Main			
13 3/8” cement job:		No data	
Lead			
Tail		There is only an indictaion for the 13 3/8” TOC from the VSP. The	

		TOC could be at 1750'.	
Final diff. pressure			
Pressure test			
Abandonment			
Plug 1	16 ppg		42.2 bbl
	9090' - 8490' (bottom)		
	No confirmation (tag, test)		
Plug 2	16 ppg		42.2 bbl
	8490' – 7890'		
	Not tagged		
Plug 3	16 ppg		46.3 bbl
	7890' – 7230'		
	Not tagged		
Plug 4	16 ppg		88 bbl
	7890' – 7230'		
	Tagged at 3100' with 15 klbs, P/T to 1200 psia		
Wellhead/Casing recovery	30" conductor 20" casing	Cut 12' below seabed at 479' in one go.	
		Wellhead retrieved	

4.16.1. 14/28a-3a abandonment assessment

This exploration well was abandoned with 4 cement plugs. The 30" and 20" casing strings were cut 12' below seabed. The reservoir that CO_2 will be injected to (Captain), is not present in this well. The geological seal, provided by the Plenus/Hidra/Rødby formations, is positioned above the Valhall formation, which will not be containing CO_2.

All casing strings are constructed of carbon steel and it is assumed that the cement used was Rugby "Class G".

Plug #1, a 600' cement barrier, was set on bottom of the well (9090' – 8490') in open hole.. This cement barrier was not tagged nor pressure tested. This plug covers the Smith Bank, Pentland and Heather formations.

Plug#2, a 600' cement plug, was set on top plug#1 (8490'- 7890') in open hole. This plug is positioned across the Heather, Kimmeridge and Valhall formations.

This plug was not tagged nor tested.

Plug#3, a 660' cement plug, was set on top plug#2 (7890'- 7230') in open hole. This plug is positioned across the Valhall, Plenus/Hidra/Rødby and Lower Chalk formations.

This plug was not tagged nor tested.

Plug#4, a 500’ cement plug, was set on top of a 300’ viscous pill (3600’- 3100’). This plug is set across the Lista and Dornoch formations.

This plug was tagged at 3100’ with 15 klbs and pressure tested to 1200 psia.

4.16.2. Conclusion

The first three cement barriers are set on top of each other in open hole, starting from bottom and provide “rock-to-rock” coverage. However, non of these barriers seal-off any formations that may potentially contain CO_2.

Non of these three barriers were tagged.

The next (and last) barrier in the well is set across the 13 3/8” casing shoe on top of a viscous pill.

This plug was tagged with 15klbs and pressure tested to 1200 psia (~500psia over the 13 3/8” casing shoe LOT).

It covers part of the Lista and Dornoch formations. Not much information is available from the 13 3/8” casing cementation. The best possible indication for TOC is from the VSP log, which gave an indication of TOC of around 1750’ (about 1600’ of annular cement). For the 250’ cement plug inside the 13 3/8” casing, it can be assumed that there is full lateral coverage (up to 3100’) with the tail slurry behind the casing.

To summarise, there is no risk for CO_2 leakage from primary source, since the Captain reservoir is absent in this well.

This well is classified as ***Low*** risk for CO_2 leakage.

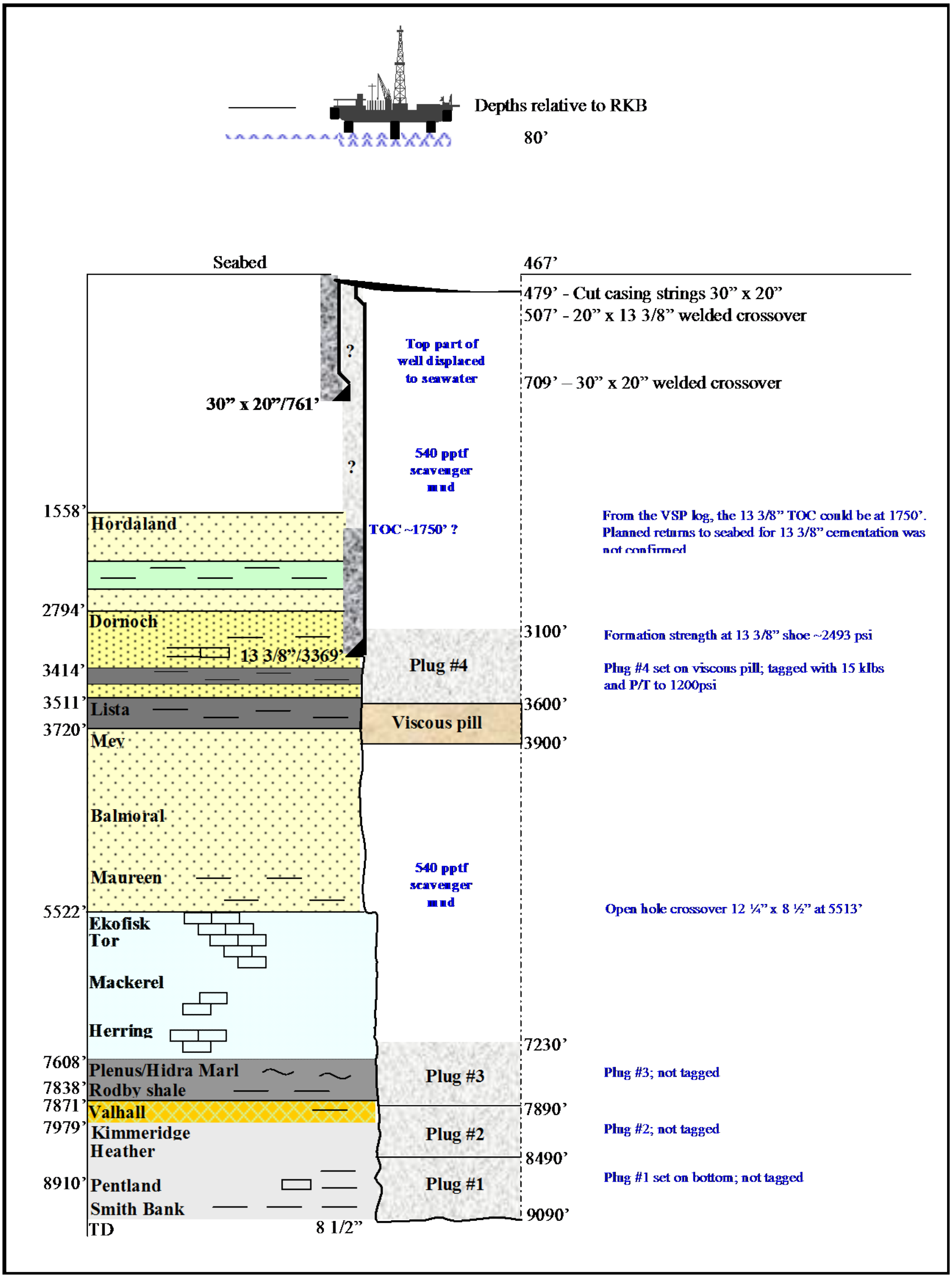


Figure 4.16: 14/28a-3a – Shell

4.17. 14/28b-2

Table 4-13: 14/28b-2 Well Summary

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6 429 025m E 457 600m	58 deg. 00 min. 01.213 sec. N 00 deg. 32 min. 53.30 sec. W	
Operator	Shell		
Drilling Unit	Borgny Dolphin		
Spudded	16/11/1997	Duration	44 days
Abandoned	30/12/1997		
Formation pressure	Hydrostatically pressured throughout (gradient ~0.44 psi/ft)	MDT 8270' – 9128' AHD (3655 – 4075 psia)	
Total depth (8 ½" OH)	10780' AHD (RKB)		
Water depth	356'	Maximum Inclination	3.93 degrees
Derrick Floor elevation	82'		
Casing Details		Weight – Grade - Threads	FSG (pptf)
35" x 30" conductor	672' AHD (RKB)	35": 705# - X52 – ST2RB 1 jt 30": 310# - X52 – ST2RB 4 jts x/o @ 473'	
20" casing	2011' AHD (RKB)	129# - X56 – RL-4SLH	640 @ 2011'
13 3/8" casing	5524' AHD (RKB)	68# - N80 - BTC	787 @ 5524'
10 ¾" x 9 5/8" casing	8839' AHD (RKB)	10 ¾": 73.2# - AC110SS- NKHW 9 5/8": 53.5# - ST95 – VAM Top x/o @ 1612'	832 @ 8839'
Cement Details			
35" x 30" cement job:			
Main	16.0 ppg Class G	5-7 bpm, 300% excess	349 bbl
Top-up			60 bbl
20" cement job:			
Lead	13.2 ppg Class G	7 bpm	575 bbl
Tail	16.0 ppg Class G (500')	5 bpm	150 bbl

	Differential press: 380 psi ROV witnessed "dye" returns at seabed from spacer, but no cement	Problems during cementation after lead slurry was started accounted for large discharge of cement 120 bbl	TOC ?
13 3/8" cement job:			
Lead	13.2 ppg Class G – 7040'	30% excess on OH, 7bpm	148.5 bbl
Tail	15.4 ppg Class G (660')	30% excess on OH, 4bpm	71 bbl
	TOC 2450', no losses	Plug bumped, casing tested to 3000 psia	
10 ¾" x 9 5/8" cement job:			
Main	13.2 ppg	6 bpm	61.5 bbl
	15.4 ppg	6 bpm	88 bbl
	TOC 7300' (volumes)	Plug bumped, P/T 3700 psia	No losses
Abandonment			
Plug 1	600', 16.0 ppg	Plug set at bottom, 10 bpm	48.5 bbls
	10780' – 10180'	Pulled back to 10130', did not circulate b/u	
		Plug#1 not tagged	
Plug 2	600' cement, 16.0 ppg	Plug#1 set on top of plug#1, 10 bpm	48.5 bbls
	10180' – 9580'	Pulled back 9480', did not circulate b/u	
		Plug#2 not tagged	
Plug 3	600' cement, 16.0 ppg	Plug#3 set on top of plug#2, 10 bpm, 15% excess on O/H volume used	48.5 bbls
	9580' – 8980'	Pulled back to 8810' and circulated b/u; contaminated cement returned	
		Plug not tagged	
Plug 4	600' cement, 16.0 ppg	Plug#4 set above plug#3	48 bbls
	8810' – 8210'	Tagged at 8000' with 10 klbs, P/T 3000 psi/15 min	
Plug 5	713' cement, 16.0 ppg	Plug set on 300' of hi-vis mud 1650'- 1350' with 6.5 bpm. Circulated b/u at 520', no cement returns	212 bbls

	1350'- 637'	Tagged at 637' with 10 klbs, P/T 1000 psi/10 min
Wellhead/Casing recovery	9 5/8" – 10 ¾" casing	Cut at 1190' and recovered
	13 3/8" casing	Cut at 1127' and recovered
	20" and 35" casing strings	Cut at 449'with MOST tool. Recovered casing stubs with wellhead and guidebase

4.17.1. 14/28b-2 abandonment assessment

This exploration well was abandoned with 5 cement plugs and the 9 5/8"and 13 3/8" casing strings cut and recovered. A shallow cut was made at 449' through the 35" and 20" casing strings and the casing stubs were recovered with the wellhead/guidebase It is assumed that the highest point where the CO_2 plume contacts this well, is at 8261'AHD (top Captain). All casing strings are made of carbon steel and the cement used was standard "Class G".

Plug #1 is a 600' cement barrier (10780' – 10180') set at bottom in open hole, featuring "rock-to-rock" coverage over the Smith Bank, Heather and partially over the Kimmeridge formations. This plug was not tagged

Plug#2 is a 600' cement barrier (10180'-9580') set on top of plug#1 in open hole, covering the middle-part of the Kimmeridge formation. This plug was not tagged.

Plug#3 is a 600' cement barrier (9580' – 8980') set on top of plug#2 in open hole, covering the top-part of the Kimmeridge formation. This plug was not tagged.

Plug#4 is a 600' cement barrier (8810' – 8210') set on top of plug#3. It was tagged at 8000' with 10 klbs. and P/T to 3000 psia. It is set mainly in cased hole opposite the "Captain"/"Punt" reservoir formations. There was some discrepancy between reported TOC; from placement 8210' was stated in the DDR, but the plug was actually tagged at 8000' and the latter one has been used as the correct TOC. With the TOC from the 9 5/8" casing primary cementation being reported as 7300', full lateral cement coverage is provided between 8810' – 8000'.

Plug#5 is a 713' cement plug (1350' – 637') set over the 10 ¾" and 13 3/8" casing stumps (resp. 1190' and 1127'). This plug is supported by 300' hi-vis pill (1650' – 1350').

However, there is no support for cement in the 10 ¾" x 13 3/8" and 13 3/8" x 20" *annuli* and there is concern that some cement may have sagged in these annuli. With little information available about the 20" casing cementation other than "dye" being witnessed at seabed from the spacer (60 bbl) pumped before the lead slurry, it is difficult to establish the TOC behind the 20" casing and make statements wrt. to full lateral coverge of cement above the 13 3/8" casing stump. As a worst case, it can be assumed that if only the beginning of the 60 bbl spacer was seen at seabed, that the top of the lead slurry is 160' below it (~600'). This plug was tagged with 10 klbs and pressure tested 1000psi/10 min.

4.17.2. Conclusion

The 13 3/8" and 9 5/8" casing cementations did not suffer any reported fluid losses; therefore the TOC's based on the volumes seems a fair assumption. The quality of the abandonment plugs looks good. The main barrier to primary CO_2 flow into this well is plug#4, which was tagged at 8000' and P/T to 3000 psia and therefore gives a column of 260' of full lateral cement above the highest point of influx (top Captain).

At shallow level, it can be assumed that the top part of plug#5 above the 13 3/8" casing stump, is supported by cement on the outside of the 20" casing as described above and therefore gives full lateral coverage for a cement column of ~500'. It is most likely to be less, because of the non-supported nature of cement over the 20" x 13 3/8" annulus (no base).

Furthermore, it has to be assumed that if CO_2 would have leaked past the main barrier (plug#4), that it is likely to leak away via the Dornoch sandstones and by-pass the shallow barrier plug#5. It would have to create a leakpath via 2 more uncemented carbon steel casing strings, in order to do this.

The long-term Risk of CO_2 leaking into the sea from this well, is classified as ***Low***.

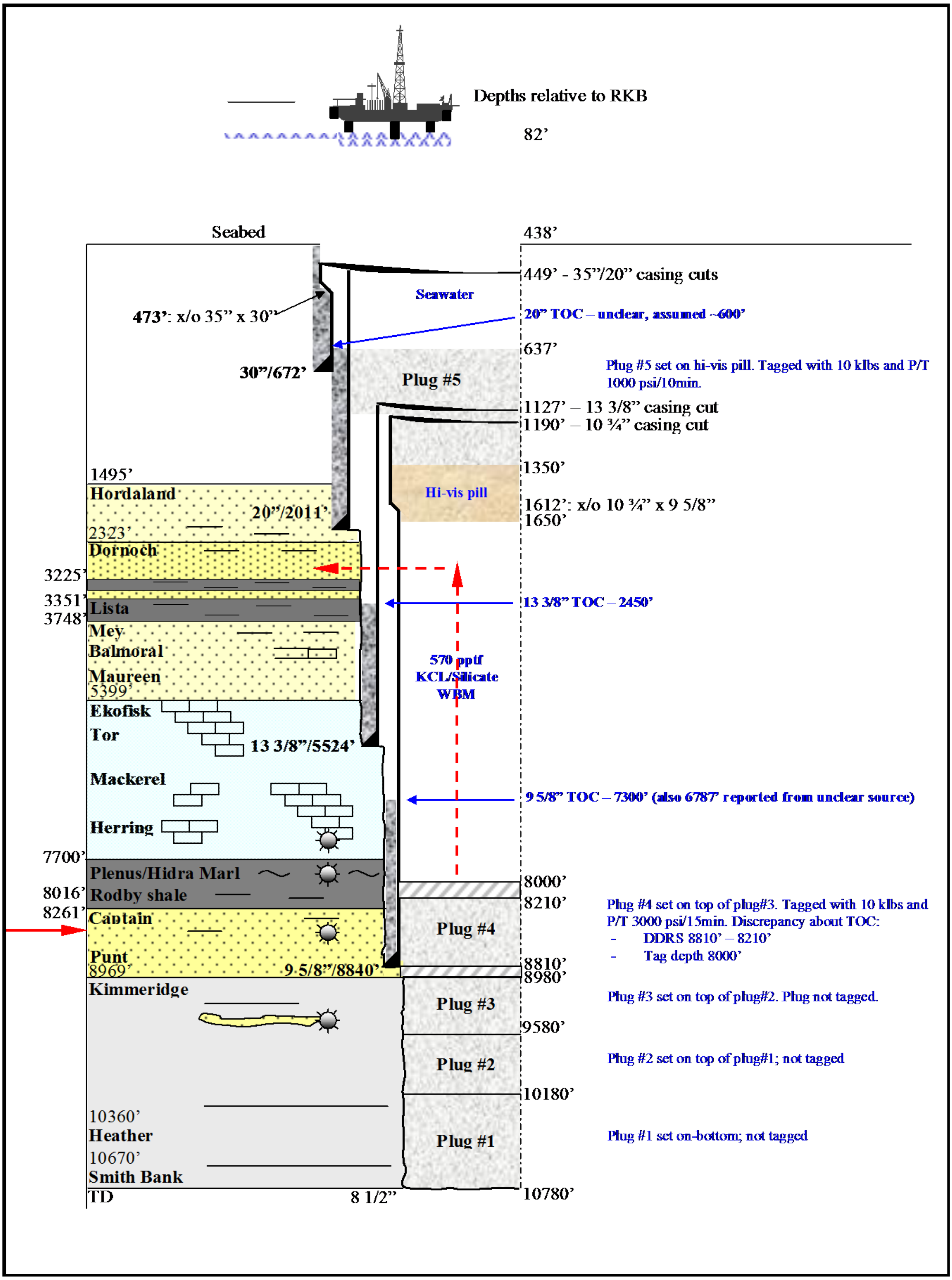


Figure 4.17: 14/28b-2 – Shell

4.18. 14/28b-4

Table 4-14: 14/28b-4 Well Summary

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6,433,106.35 m E 643,265.24 m	58 deg. 00 min. 54.256 sec. N 00 deg. 34 min. 30.165 sec. W	
Operator	British Gas		
Drilling Unit	GSF 140		
Spudded	26/07/2006		
Abandoned	26/08/2006		
Duration	31 days		
Formation pressure	No data, but expected hydrostatic	No MDT'RFT taken	
Total depth (12 ¼" OH)	9950' AHD (RKB)	Bottomhole T = 192 deg. F (TD)	
Water depth	354'		
Derrick Floor elevation	85'		
Maximum Inclination	0.97 degrees at TD		
Casing Details		Weight – Grade - Threads	LOT (ppg)
30" x 20" conductor	869' AHD (RKB)	456.6# - X52 – ALT2HT/RL4 309.7# - X52 – RL4 20": 129.0# - X52 – RL4 x/o at 841'	
13 3/8" casing	5609' AHD (RKB)	72.0# - L80 – Dino VAM	15.0
Cement Details			
30" cement job:			
Main	12.5 ppg X-lite	No cement returns at seabed	970 bbl
Top-up job	16.0 ppg Class G	Top –up performed after tagging TOC 9' below seabed	30 bbl
13 3/8" cement job:			
Lead	12.5 ppg, Class G	5.4 bpm. Bumped plug 600 psi differential. Tested casing to 2000 psia	160 bbl

Tail	16.0 ppg		95 bbl
	TOC estimated 4100'	After completion of the cement job movement in the wellhead was noticed, therefore another top-up job was performed with a stinger run down the side of the conductor with 160 bbl "G" neat cement. Cement was tagged around the wellhead	
Final diff. pressure	600 psi		
Pressure test	2000 psia		
Abandonment			
Plug 1	16.0 ppg, Class G, 650'	Plug#1 set on 75 bbls viscous reactive pill (9480' – 8945')	109 bbl
	8945' - 8333'	Plug tagged at 8333' with 5 klbs	
Plug 2	16.0 ppg, Class G, 650'	Plug#2 set on 75 bbls viscous reactive pill 10.0 ppg	99 bbl
	5800' – 5141'	Plug tagged at 5141' with 5 klbs and P/T to 2200 psia	
Plug 3	16.0 ppg, 400'	Plug#3 set on viscous reactive pill (866' – 805') 75 bbl	412 bbl
	805' – 439'	Plug not tagged/tested	
Plug 4	16.0 ppg,	Set on top of plug#3	120bbl
		ROV confirmed cement at seabed	
Wellhead recovery	30" conductor	Cut at 454' and retrieved with the wellhead	MOST tool cutting assembly
	13 3/8" casing	Cut at 796' and retrieved	

4.18.1. 14/28b-4 abandonment assessment

This exploration well was abandoned with 4 cement plugs and the 30" and 13 3/8" casing strings were cut and retrieved. It is assumed that the highest point where the CO_2 plume contacts this well, is at 8045' (top Captain). The geological seal is provided by the Plenus/Hidra/Rødby/Sola formations.

All casing strings are fabricated of carbon steel and the cement used was standard "Class G".

Plug #1, a 600' cement plug, was set close to bottom of the well (8945' – 8333') on a 500' viscous reactive pill, in order to isolate the Ettrick-B sands from the Captain sands. This barrier was tagged at 8333' with 5 klbs.

Plug#2, a 650' cement plug, was set on top of a 500' viscous reactive pill (5800' – 5141'). This plug was set partially in open hole (200') across the Chalk formation and partially set inside the

13 3/8" casing. This barrier was tagged with 5 klbs and tested to 2200 psia (500 psi over leak-off pressure).

Plug#3 is a ~ 400' cement barrier, set over the 13 3/8" stump (805' – 439'). This plug was set on a 60' viscous reactive pill. From 796' to seabed, this plug is likely to be supported by cement on the outside of the conductor. Unclear if tagged at seabed.

Plug#4 was 120 bbl of cement dumped on top of plug#3 at seabed. The top of cement was confirmed at seabed by ROV. The previous cement (plug#3) was supposed to be set to seabed, it is unclear why this plug was set in addition.

4.18.2. Conclusion

Plug#1 was set in 12 ¼" open hole to isolate the Ettrick-B sands from the Captain sands, but this plug leaves about 300' of the Captain sands uncovered and therefore serves no purpose in containing CO_2 in the Captain sands.

The next barrier in the well is plug#2, which is set at around the 13 3/8" shoe (5609'), partly in open hole, partly inside the casing (5141' - 5800'). This is the primary barrier of the well for CO_2 containment. The quality of plug#2 is believed to be good (set on viscous reactive pill, tagged and pressure tested 500 psi over LOT strength). The concern around this plug is its position, it should have been set deeper, around the Rødby shale and not in the Chalk.

The open hole area, if not collapsed, between the Captain sands and plug#2 will fill up with CO_2 and expose the Chalk. There are serious concerns that with the known fractures in the Chalk that CO_2 can freely percolate to the Balmoral sands and further up the well. There is no concern that the CO_2 pressure itself would fracture the Chalk formation.

Plugs#3/4 do little to contain CO_2 once it would have broken through to these shallow depths. It is likely that CO_2 will escape from the well, once in the Balmoral sands to seabed:

- either via the uncemented 13 3/8" casing section
- or, in case the Lista shales are sealing off against the casing, by corroding through the carbon steel casing.

This well is classified as ***High*** risk since there are no barriers to primary CO_2 flow and therefore direct communication between the Captain sands and shallower formations/seabed via Chalk fractures (600') and Balmoral sands.

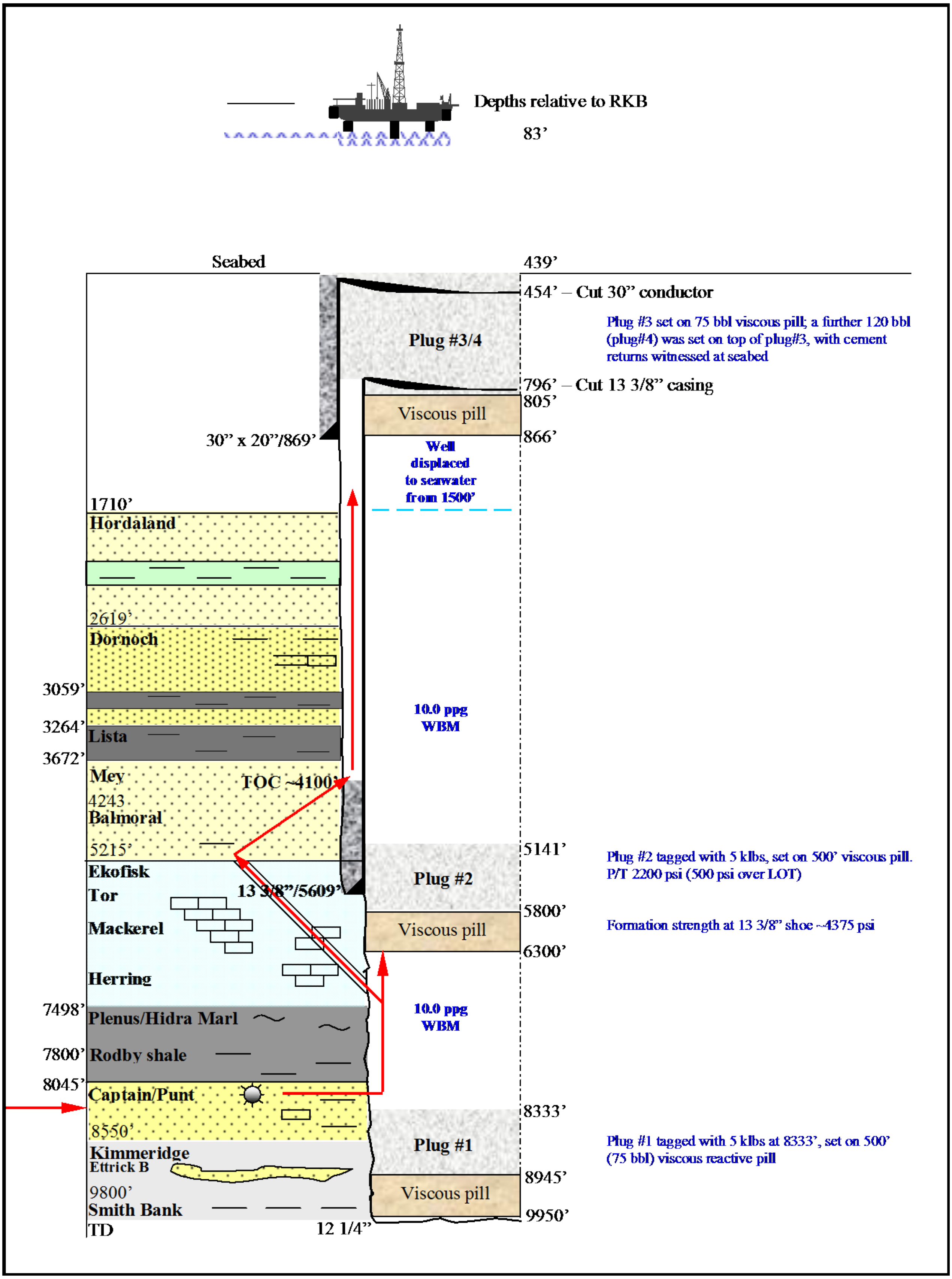


Figure 4.18: 14/28b-4 - BG

4.19. Conclusions

Of the thirteen abandoned E&A wells, situated in close proximity to the Goldeneye field, eight wells have no contact with the reservoir and have been shown to be outside the maximum area to which CO_2 could migrate either from the reservoir or below the Lista formation. Four wells in contact with the reservoir have effective primary, but no secondary seals. The primary abandonment seals on these wells are considered to be good.

For two of these wells, the quantity of mobile CO_2 available to the well is small and that the majority (possibly all) of the CO_2 will remain in the formation within 3.5 km of the release point. No significant quantity of leakage could occur from the Complex.

One exploration and appraisal well (14/29a-5) has contact with the reservoir, and has 8 million tonnes of mobile CO_2 available to the well. This well has effective seals at both the Rødby and Lista formations, but, if the primary seal failed, there is the possibility of CO_2 migrating as far as a well providing a secondary leak path (well 14/29a-3). For this well, it has been shown that, even in the improbable event of failure of the primary seal, CO_2 would take over 20 years to migrate as far as well 14/29a-3. This event would be detected through the monitoring programme allowing mitigating action to be taken to remediate before leakage to the surface occurred.

As a result it is concluded that exploration and appraisal wells present a low risk of leakage outside the Complex.

5. Goldeneye Well Upper Completions

This section evaluates the suitability of the current well completion during the injection phase and long term exposure to CO_2. The following paragraphs highlight some of the concerns with the current design and materials used in the existing completions, the most critical being the Joule Thomson cooling and associated effects.

A review of these concerns leads to the conclusion that the existing upper completion is not suitable for the project and shall hence require to be replaced.

5.1. Current Well Integrity Concerns

Well integrity tests (WITS) are carried out on an annual basis. All well integrity information is captured and stored in eWIMS (global electronic database that captures well integrity data for Shell operated wells) under the responsibility of a Well Integrity Focal Point. Additionally, the control room monitors annulus pressure gauges on all wells continuously, with alarms at predetermined levels, and the data stored in RTMS. None of the wells is subject to any known major integrity issues.

An intervention campaign was carried out in 2012 and suspension plugs were set in all the wells. At the time some safety valve control line integrity issues were noted on wells GYA01 and 03. Corrective measures were also required to some FWV and UMV stem seals. This was carried out during subsequent intervention trips in Nov 2012 and February 2013. From Table 5-1 it can be seen that this work ties in with the wells suspension activities.

In a number of wells (GYA 02, 04 and 05) the lowermost suspension plug was set above the downhole gauge thereby allowing the reservoir pressure & temperature to be monitored.

Table 5-1: Well Integrity Overview – eWIMS data

General		Tubing	A Annulus						B Annulus				
Well Name	Condition	Tubing OK	MAASP [bar]	Trigger [bar]	Min [bar]	Actual reading [bar]	Recording date	MAASP [bar]	Trigger [bar]	Min [bar]	Actual reading [bar]	Recording date
GYA01	Suspended	Y	206	103	10	30	12/19/2013	22	19	2	5	12/19/2013
GYA02S1	Suspended	Y	206	103	10	16	12/19/2013	8	7	2	3	12/19/2013
GYA04	Suspended	Y	206	103	10	22	12/19/2013	17	15	2	6	12/19/2013
GYA05	Suspended	Y	206	103	10	22	12/19/2013	22	19	2	8	12/19/2013
GYA03	Suspended	Y	206	103	10	21	12/19/2013	8	7	2	4	12/17/2013

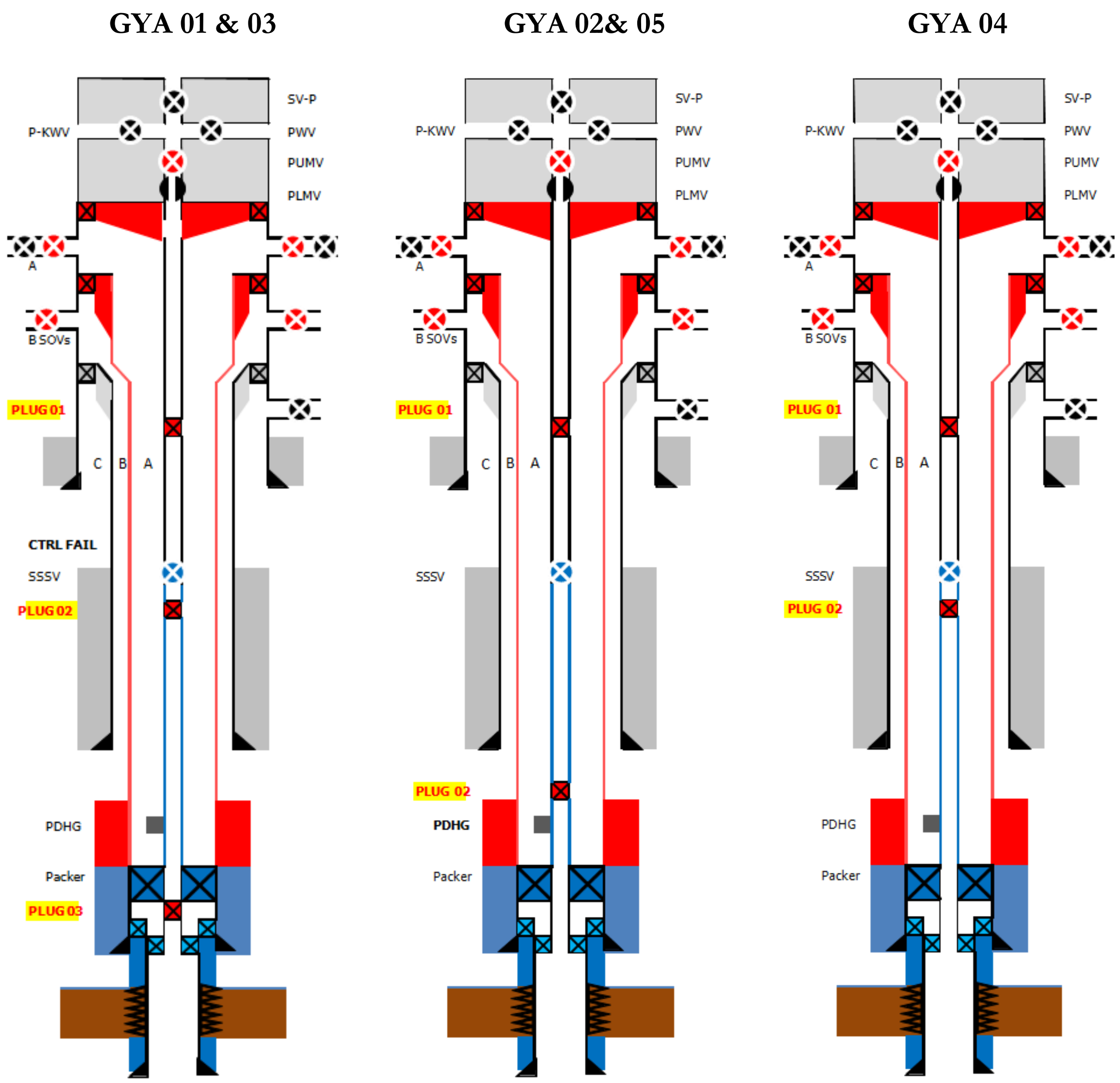


Figure 5.1: Wells Suspension Condition

Table 5-2: Suspension Plugs – Setting Depths (ft)

	GYA01	GYA02	GYA03	GYA04	GYA05
Suspended	Nov 2012	May 2012	April 2012	May 2012	Feb 2013
Plug 01	139ft	124ft	134ft	118ft	148ft
Plug 02	2669ft	10362ft	2618ft	2976ft	7731ft
Plug 03	8595ft		9017ft		
	Gas migration through SSSV control line		Gas migration through SSSV control line		

5.2. CO_2 Phase Behaviour

The combination of initial low reservoir pressures, circa 285psia [172bar], large bore tubing 7" and low arrival temperature of CO_2 to the platform 4-7°C make it impossible to maintain CO_2 above the saturation point when injecting CO_2 through the existing 7.00" x 5 ½" Goldeneye completion tubing. Injecting CO_2 through the existing completion tubing will allow the CO_2 to expand and cross the gas liquid phase boundary causing a Joule Thomson effect and extremely low temperatures. These extremely low temperatures caused by injecting CO_2 in the existing completions will create serious complications in terms of well design and operability as the temperature in the CO_2 will be below the lower threshold limit of some existing well equipment. The low temperature threshold of the existing completion is detailed further in this section.

In order to prevent this, there will be a requirement to change the shallow well equipment (Christmas tree, hangers, a portion of the tubing) for extremely low temperature service. There will also be integrity issues associated with freezing of annuli fluids in the wells.

5.3. Well Integrity Concerns Due to Extreme Cooling

The very low temperature raises concerns with the current completion design relating to well bore freezing, material specification and tubing contraction. Of particular concern is that the forces exerted on the Polished Bore Receptacle (PBR) will exceed the shear ring rating of 120klb. Regular movement of the PBR mandrel due to variation in downhole pressure and temperature will cause the PBR seals to fail allowing the CO_2 to enter the A annulus. In the A annulus the CO_2 will mix with the water based completion brine resulting in the formation of carbonic acid. The resultant carbonic acid would corrode the 9 5/8" L80 casing in a relatively short period of time; potentially resulting in failure of the well envelope. The following figure indicates that in three out of four load cases studied, the rating of the PBR will be exceeded.

Table 5-3: Tubing to Packer Forces (GYA-02)

Load case	WH CO2 inj temp (°C) (input)	Tubing-to-Packer Force (lb)	calculated WH CO2 inj Pressure (psi)	Length change / PBR movement: Hooke's Law (ft)	Buckling (ft)	Balloon (ft)	Thermal (ft)	Total (ft)
CO2 inj 45 MMscf 1800 bhp	-5	-79,031	445	2.51	0.00	1.37	-5.91	-2.02
CO2 inj 75 MMscf 1800 bhp	-5	-144,500	445	3.26	0.00	1.48	-9.24	-4.5
CO2 inj 45 MMscf 5000 bhp	-5	-132,521	1630	3.14	0.00	-1.13	-4.60	-2.59
CO2 inj 75 MMscf 5000 bhp	-5	-138,785	1720	3.19	0.00	-1.17	-4.87	-2.85

Other items of concern with regard to low temperature are detailed in the table below together with suggested mitigations.

Table 5-4: Low Temperature Threshold of current Completion Equipment

Item of Equipment	Lower Temp. Limit	Remarks/Mitigation
Cameron Christmas tree block	-18 °C	Predicted temperature (-25°C) is colder than low temperature threshold. Current Xmas Tree material can be up graded from 4140 low alloy steel to F6NM stainless steel which has a low temperature threshold of -60 °C.
Cameron 3 Stage Compact Spool	-18 °C	Predicted temperature (-25°C) is colder than low temperature threshold. Compact spool is made from 4130 Low alloy steel and cannot be replaced without adding complexity to the workover operation.
Cameron Tubing Hanger	- 18 °C	Predicted temperature (-25°C) is colder than low temperature threshold. Tubing hanger material can be upgraded in line with the increased Xmas Tree specification.
Production casing 10 ¾" x 9 5/8"	- 40 °C	Temperature OK for steady state injection. Potential complicated operation to replace L80 casing in the upper section of the well.
Production Tubing 13Cr L80	-20 to - 30 °C	More investigation required to confirm the use of this for steady state production. Can be replaced with super 13Cr which has a low temperature threshold of -50°C
A- Annulus Fluid Sea Water	- 1.8 °C	Predicted temperature (-25°C) is colder than low temperature threshold. Replace with Base Oil
TRSSSV	-7 °C	Temperature OK for steady state injection at SSSV depth. Further qualification to be carried out in advance

		(one year) of workover operations commencing
TRSSSV Control Line Fluid	- 40 °C	Temperature OK for steady state injection. Alternative control line fluid is available

5.4. Tree & Wellhead Concerns

The Goldeneye tree/wellhead is a robust system adopting primary metal to metal seals. The tree and wellhead were primarily designed for gas production, which makes it a good candidate for CO_2 injection. The three main areas of concern are ED (explosive decompression) resistance, corrosion resistance and low temperature performance.

- ED resistance - The tree has provided good ED resistance so far in gas production service. The elastomers, which could be susceptible, are in the annulus regions, which would require breakdown of the primary seals to be exposed. If the elastomers were exposed to an ED environment, they would show signs of ED damage on the side exposed to the gas, however as they are constrained in the groove severe damage does not occur until the seal is removed allowing it to expand and tear as gas escapes from inside the elastomers.
- Corrosion resistance - This tree/wellhead system is material class FF rated, which will be resistant to dry CO_2. However if the CO_2 becomes wet, it will form carbonic acid, which will corrode carbon steel and depending upon the ph level may corrode stainless steel.
- Low temperature performance - The tree is designed for temperature class U (-18 to 121°C), limited by the bonnet and the tree block, both being 410 stainless steel and temperature class U.

It is anticipated that the tree/wellhead is suited to CO_2 injection for the specified steady state operating parameters, only for temperatures down to -18°C. Thermal analysis would be required to verify that that the tree is suitable during the transient condition during valve closure. The integrity of the completion is also paramount to prevent CO_2 in the annulus areas.
The main issue is that 410 stainless steel has a low Charpy impact value that could generate cracking. The F6NM alternative in ES-002019-01 conforms to API-6A impact requirements.

5.5. Upper completion Workover

To mitigate against the aforementioned effects it is necessary to design a completion string that will introduce sufficient back pressure to the injection system so that CO_2 can be maintained above the critical point in a single dense liquid phase, thus preventing the extreme cooling from the Joule Thomson Effect occurring.

A re-completion operation would provide an opportunity to:

- Remove the perforated pup joint between the production packer and the screen hanger.
- Carry out cement bond logs and casing calliper runs
- Set the new production packer deeper, to be in front of the Hidra seal. Ideally the production packer should be placed in front of the sealing formation. The current packer in the wells GYA01 and GYA05 are across of the bottom of the Chalk
- Optimise in-well surveillance.

5.6. Upper Completion Concept - Workover

Modifications are required to ensure well integrity and create frictional pressure losses into the injection system, creating a backpressure at surface sufficient to maintain the supplied CO_2 above the gas liquid phase boundary in the dense liquid phase, thus minimising the effects of low temperature in the well due to the Joule Thomson effect. Modelling has shown that the optimum method for creating backpressure into the system is to re-complete the Goldeneye wells with small-bore tubing.

A comparison of the available concepts was carried out and a single tapered string options was deemed the best fit solution. The concept select comparison is included in the Conceptual Completion and Well Intervention Design Endorsement Report (2).

Under this scenario a single tapered tubing string is used in all the wells to create the required delta pressure to keep the CO_2 in single phase at the wellhead. The string will comprise of 4 ½ and 3 ½ inch tubing. In order to maintain the CO_2 in a single dense liquid phase a minimum rate is imposed per well. By changing the setting depth of the tubing crossover each well can have its own individual operating envelope. By injecting into a combination of wells the overall operating envelope will allow for flexibility to handle the varying range of CO_2 delivered from the capture plant. This design will allow for standardisation of the well components, the variable would be the placement of the tubing crossover. In addition the monitoring well may have some enhanced instrumentation. This has to be defined in the FEED phase.

Changing out the tubing string allows for wireline logging runs for cement bond evaluation to be carried out along with casing calliper runs. This will allow for optimisation of the production packer setting depth.

The ideal placement of the production packer would be across the impermeable Rødby shale; however this is not possible as existing screen hanger is set in the Hidra formation immediately above the Rødby shale. The production packers can be set across the Hidra Marl which has been deemed suitable for this requirement. The Hidra Marl along with the Rødby Shale forms the main seal above the Captain Reservoir.

In the case of GYA 01 and 05 this would mean setting the new production packer deeper than the existing production packers, i.e. setting the packers in a section of casing that has previously been exposed to the production fluids due to the inclusion of a perforated pup joint in the existing completion design. It is therefore essential to evaluate the condition of this section of casing and to carry out any required remedial work.

When the wells were originally drilled and completed cement bond logging was not carried out, records of the cementing operation have been kept and theoretical top of cements are documented, however the workover would provide an opportunity to carry out cement evaluation and determine the top of cement.

The cement bond logs along with the casing evaluation and final position of all the production packers will help align the Goldeneye wells with the abandonment philosophy outlined in Abandonment Concept for Injector Wells Report (1).

The packer fluid will be selected during the FEED phase, the considerations and options that are being evaluated are discussed further in this section. It may be necessary to include a circulation sub above the production packer to allow the selected packer fluid to be circulated.

The current proposed upper completion design will seal inside the lower completion PBR and will not include a perforated pup, thereby containing all the wellbore fluids within the tubing and protecting the entire casing above the screen packer from CO_2 and the resultant carbonic acid. This will be explored further during the FEED phase.

The selected option allows for the deployment of permanent downhole pressure and temperature gauges. These are attached to mandrels which form part of the tubing string and are powered and communicate via a dedicated electric control line to surface. Multiple gauges can be deployed on a single line. Deployment of such systems is standard practice within the North Sea and knowledge of this exists within SHELL. Also to be evaluated during the FEED phase is wireless monitoring systems which offer advantages such as ease of deployment and reduce the number of hanger penetrations required, but these systems have a finite battery life,

Pressure and temperature modelling suggests that the BHT (Bottom Hole Temperature) is likely to be in the region of 17°C-35°C [63- 95°F]. The selected gauge shall have to be calibrated for this temperature range. It is proposed to include at least two pressure and temperature gauges in each well which shall allow for an inferred density measurement. In one of the injection wells are third gauge shall be installed close to the 4 ½ x 3 ½ crossover to help understand the CO_2 phase behaviour and help calibrate the injection rates.

The concept also allows us to include fibre optic monitoring systems that can provide distributed temperature measurements (DTS) across the entire length of the completion, allowing for well integrity monitoring, and injection optimising and early detection of potential issues. Acoustic/vibration sensing may also be incorporated within this monitoring package. The monitoring well may incorporate additional instrumentation in comparison to the injection wells.

Installing a new completion means critical items such as the downhole safety valve which forms part of the ESD system can be placed at the most optimal depth. The formation of hydrates has been identified as a potential concern; this along with other requirements will determine the new setting depths for the safety valves. The SSSV shall be positioned deep enough in the well so as to be unaffected by the same failure mechanisms that can compromise surface ESD systems, and shallow enough that closure times are not compromised by having to overcome high hydrostatic pressures in the control line and to facilitate the testing of the valve by reducing the volume to bleed off.

Control line fluid qualified for cold temperature operations with a low pour point shall be utilised.

Changing the original upper completion will allow for a new safety valve control line to be run as part of the new completion, this will allow for the control line material and fluid to be optimised for the new well conditions.

Testing of the SSSV is predicted to be a lengthy operation (24-40 hours) especially when the tubing between the valve and the wellhead is filled with dense $CO_{2.}$ In order to minimize this time the top of the tubing is proposed to be 4 ½in tubing rather than 5 ½ in.

Modelling has revealed that the most severe effects due to the JT cooling occur in the tubing above the safety valve; therefore the option of using Super 13Cr tubing above the safety shall be evaluated during the FEED phase.

The generally accepted low temperature limit for 13Cr steel is from -10 to -30°C (depending on manufacturer) and for Super 13Cr it is estimated at -50°C. In any case, impact testing of 13Cr or Super 13Cr tubing will be required for equipment to be run in the wells (especially in the top part of the wells, where extreme low temperatures are expected during the transient cases).

The Christmas tree and tubing hanger shall be changed to low temperature compatible materials and service class.

Any elastomers used in components such as packers and tree valves etc. which come in contact with CO_2 or the JT associated low temperatures can be selected with these specific concerns in mind thereby mitigating against effects such as explosive decompression. Elastomers lose flexibility at low temperatures with reduced or failing sealing as a result. The elastomers selected must be adequate for the corresponding piping class and their suitability for CO_2 service has to be analysed.

The single string completion is considered to be the best solution for CO_2 injection operations for the following reasons:

- Solution for the lifecycle of the well, no late life workover are foreseen
- Minimum modifications required to christmas tree and well head
- All monitoring requirements PDGM / DTS can be accommodated.
- Best solution for well intervention operations, Coiled Tubing, Wireline Etc.
- Least complex of all the options considered
- Packer setting depth can be optimised for final abandonment.
- PBR removed, no elastomeric sealing elements above the production packer.

5.7. Conclusion

A complete evaluation of the Goldeneye wells is covered in The Conceptual Completion and Well Intervention Design Endorsement Report (2). This covers all the components of the well construction, existing and proposed.

This evaluation highlighted the upper completion as an area of concern for well integrity.

The proposed upper completion addresses all those concerns:

- The upper completion design will bring the JT cooling effect within manageable levels
- The upper completion and selected packer fluid will protect the carbon steel casing.
- The production packers will be set deep in the Hidra Marl.
- Cement bond logs and casing calliper runs will be carried out. Safety valve setting depths will be optimised
- Well monitoring for early detection will be installed
- The monitoring capability will further allow calibration of the injection rates
- The tubing above the safety valve, the tubing wellhead and Christmas tree will be replaced with suitable low temperature class of service equipment.
- Elastomers will be replaced with suitable compounds to mitigate against explosive decompression

Well integrity for the wells in a CO_2 injection application can only be assured after an upper completion workover. The proposed workover is the best solution for longevity and long term well integrity.

6. Goldeneye Wells Abandonment Concept

The purpose of this section is to propose an abandonment concept for the Goldeneye injection wells, taking into account the current design concept which requires that the wells be worked-over prior to commencing CO_2 injection. The number of wells will allow for redundancy and provide for flexibility with injection rates. In addition one of the wells shall be used as a monitoring well.

6.1. Summary

There are currently five producer wells on the Goldeneye platform, drilled and completed by the Maersk Innovator in 2003. An intervention campaign was carried out in 2012 and suspension plugs were set in all the wells.

The current conceptual design involves working over these wells for CO_2 injection. It is proposed to set the new production packers as deep as possible in the Plenus/Hidra Marl. Abandonment proposals for the Goldeneye wells have been prepared, based on the well condition after the proposed CCS workover activities.

It is also planned to carry out cement bond logs and casing calliper runs prior to running the new upper completions. Results from this will help further develop the abandonment concept however the abandonment philosophy and horizons shall remain unchanged.

6.2. Goldeneye Wells

The Goldeneye field consists of a normally unmanned platform with five gas production wells. The wells are all very similar in design and were drilled with a jack-up rig (Maersk Innovator) during 2003/2004. An intervention campaign was carried out in 2012 and suspension plugs were set in all the wells.

The current well construction is as follows:

- 30” Conductor driven to ~750’ (by barge). Trepanned at seabed level.
- 20” x 13 3/8” to ~4000’ (x/o @ ~700’)
- 10 ¾” x 9 5/8” production casing (x/o ~3100’) of L80 steel
- 7” slotted liner with screens and gravel pack
- 7”, 13Cr upper completion
- 9 5/8” production packer with perforated joint below
- PBR above the production packer
- Permanent Downhole gauge
- TRSSSV at around 2500’
- Christmas tree 6 3/8” mono-bore, 5000 psia, Cameron
- Wellhead, Cameron SSMC compact design

The proposed completion concept is to workover the five wells with a tapered slim (4-1/2”, 3-1/2”) completion that shall comprise of a safety valve, monitoring package (Permanent downhole gauge, DTS, DAS) and a packer with a stinger. The new upper completion shall sting into and seal in the existing lower completion screen packer.

The existing casing and lower completion shall not be changed. The existing casing strings, conductors, cement and lower completion have been reviewed and the effects of CO_2 injection and long term storage have been evaluated. Further detailed study in order to validate this shall be carried out during the FEED phase.

All Goldeneye wells are deviated wells with the following details:

Table 6-1: Goldeneye wells directional data

	GYA-01	GYA-02s1	GYA-03	GYA-04	GYA-05
Max. Inclination	30.4° @ 7574'	60.5° @ 10622'	40.1° @ 5983'	68.1° @ 6020'	7.2° @ 1785'
Total Depth	9166'	11464'	9507'	13262'	8535'

An intervention campaign was carried out in 2012 and suspension plugs were set in all the wells. At the time some safety valve control line integrity issues were noted and corrective measures were required to some tree valves. In a number of wells the deep suspension plug was set above the downhole gauge thereby allowing the downhole pressure and temperature to be monitored. A & B annuli were left with positive pressures for monitoring purposes.

The well details and schematics of the five Goldeneye production wells are included in the subsequent sections.

6.3. Goldeneye Stratigraphy

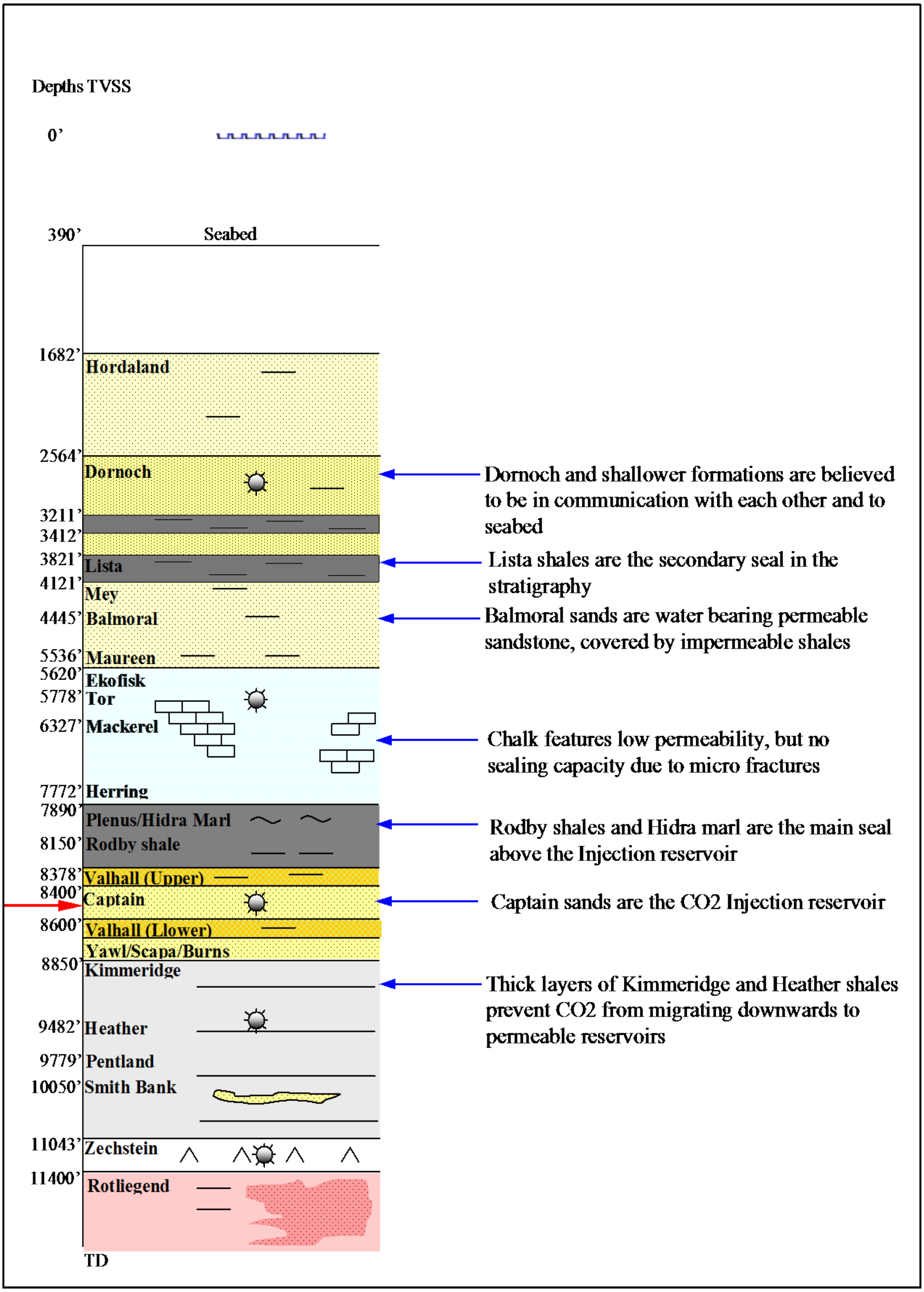


Figure 6.1: Main Stratigraphy for Goldeneye area, average depths of formation tops

6.4. Goldeneye Well GYA01 (14/29a-A3)

Table 6-2: GYA01 (14/29a-A3)

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6,429,207.70 m E 477,554.30 m	58 deg. 00 min. 9.323 sec. N 00 deg. 22 min. 47.073 sec. W	
Formation pressures	Initial: 3800 psia (8265' TVSS) Current : 2650 psia Abandonment : 3800 psia	No MDT/RFT's taken on the production wells	
Total depth (8 1/2" OH)	9166' AHD (RKB)	Reservoir T = ~180 deg. F (TD)	
Water depth	395'	Cameron SSMC wellhead	A: 460 inhib
Derrick Floor elevation	152.5'	Tree:Cameron 6 3/8" monobore 5k	B: 560 OBM
Maximum Inclination	30.4 degrees at 7574'	A-annulus 460 pptf inhib. seawater	C: Seawater
30" conductor	749.8' AHD (RKB)	1.5" WT - X52 – Merlin (Int Upset) 2" WT used for drive shoe	
20" x 13 3/8" casing	4155' AHD (RKB)	20": 202.7# - X80 – Merlin (top jt) 20": 202.7# - X65 – Merlin top/ SR20 bottom (2nd joint) 20": 202.7# - X65 – SR20, all 1"WT 13 3/8": 68# - L80 – Dino VAM x/o at 704'	675 (EMW 630)
10 ¾" x 9 5/8" casing	9006' AHD (RKB)	10 ¾": 55.5# - L80 - VAM Top 9 5/8": 53.5# - L80 - VAM Top x/o at 3130'	N.A
7" Liner (pre-drilled)	9163' AHD (RKB)	29.0# -13CrL80 – NK3SB	
30" cement job:	N/A	Driven (Heerema barge)	
20" x 13 3/8" cement job:			
Single	582 pptf, X-Lite	6 - 7 bpm. Stinger cementation	707 bbl
Final diff. pressure	200 psi		
Pressure test	2400 psia	Returns observed at seabed by ROV (after 680 bbl)	
10 ¾" x 9 5/8" cement job:			
Single	728 pptf, Class G	8.5 bpm, plugs bumped	
	TTOC 7506'	Centralisers: (Weatherford TR3)	113 bbl
Final diff. pressure	1460 psi	No losses	
Pressure test	4500 psia		

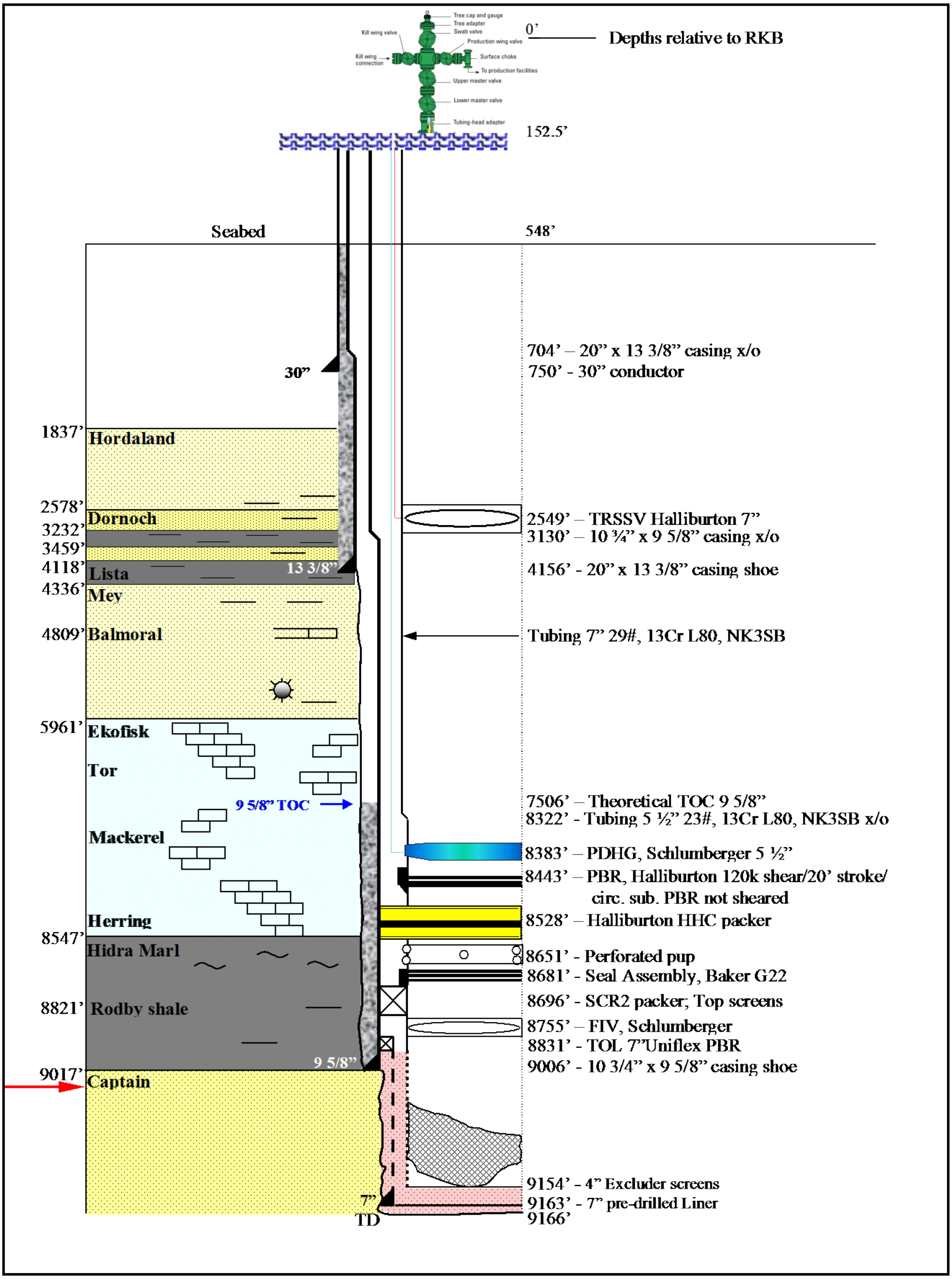


Figure 6.2: **GYA01 (14/29a-A3)**

6.5. Goldeneye Well GYA02s1 (14/29a-A4)

Table 6-3: GYA02s1 (14/29a-A4z)

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6,429,207.60 m E 477,558.00 m	58 deg. 00 min. 9.321 sec. N 00 deg. 22 min. 46.848 sec. W	
Formation pressures	Initial: 3811 psia (8289' TVSS) Current: 2650 psia Abandonment: 3800 psia	No MDT'RFT taken	
Total depth (8 1/2" OH)	11464' AHD (RKB)	Reservoir T = ~182 deg. F (TD)	
Water depth	395'	Cameron SSMC wellhead	A: 550 inhib
Derrick Floor elevation	152.5'	Tree:Cameron 6 3/8" monobore 5k	B: 610 OBM
Maximum Inclination	60.5 degrees at 10622'	A-annulus 460 pptf inhib. seawater	C: Seawater
30" conductor	749.8' AHD (RKB); 2 x 6" holes cut 10' above seabed	1.5" WT - X52 – Merlin (Int Upset) 2" WT used for drive shoe	
20" x 13 3/8" casing	4154.6' AHD (RKB)	20": 202.7# - X80 – Merlin (top jt) 20": 202.7# - X65 – Merlin top/ SR20 bottom (2nd joint) 20": 202.7# - X65 – SR20, all 1"WT 13 3/8": 68# - L80 – Dino VAM x/o at 703'	679 (EMW 631)
10 ¾" x 9 5/8" casing	11268' AHD (RKB) window at 10990' for S/T	10 ¾": 55.5# - L80 - VAM Top 9 5/8": 53.5# - L80 - VAM Top x/o at 3155'	N.A
7" Liner (pre-drilled)	11462' AHD (RKB)	29.0# - 13 CrL80 – NK3SB	
30" cement job:	N/A	Driven (Heerema barge)	
20" x 13 3/8" cement job:			
Single	582 pptf, X-Lite	7 bpm. Stinger cementation	775 bbl
		No losses	
Final diff. pressure	230 psi	Returns observed at seabed by ROV (after 638 bbl)	
10 ¾" x 9 5/8" cement job:			
Single	728 pptf, Class G	13 bpm, plugs bumped	
	TTOC 9768'	10 Centralisers: Weatherford TR3	115 bbl
Final diff. pressure	1600 psi	No losses	
Pressure test	4500 psia		

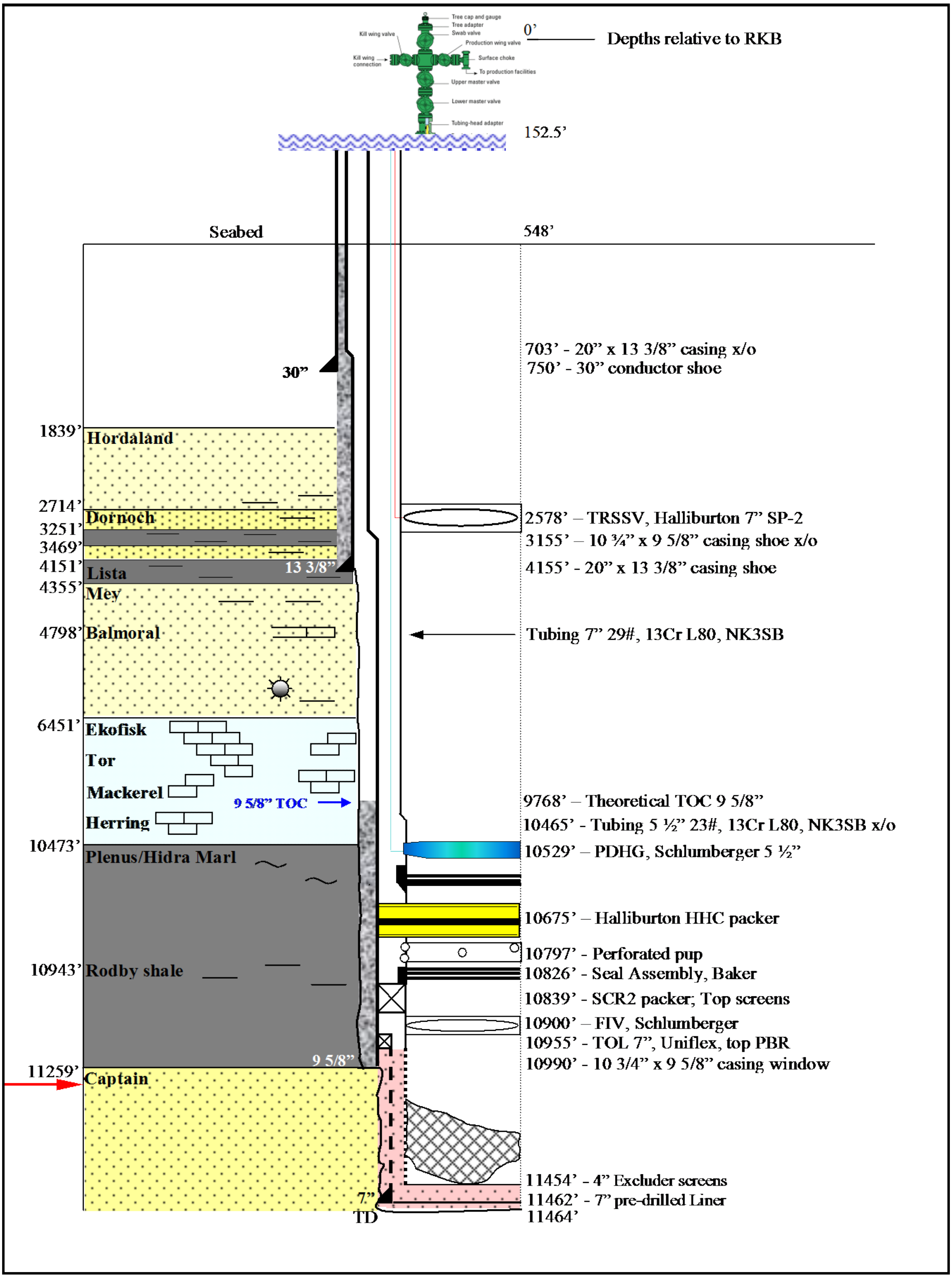


Figure 6.3: GYA02s1

6.6. Goldeneye Well GYA03 (14/29a-A5)

Table 6-4: GYA03 (14/29a-A5)

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6,429,204.91 m E 477,554.30 m	58 deg. 00 min. 9.233 sec. N 00 deg. 22 min. 47.072 sec. W	
Formation pressures	Initial:~3820 psia (8387'TVSS) Current: ~2650 psia Abandonment: ~3800 psia	No MDT'RFT taken	
Total depth (8 1/2" OH)	9507' AHD (RKB)	Reservoir T = ~182 deg. F (TD)	
Water depth	395'	Cameron SSMC wellhead	A: 550 inhib
Derrick Floor elevation	152.5'	Tree:Cameron 6 3/8" monobore 5k	B: 610 OBM
Maximum Inclination	40.1 degrees at 5983'	A-annulus 460 pptf inhib. seawater	C: Seawater
30" conductor	738' AHD (RKB); 2 x 6" holes cut 10' above seabed	1.5" WT - X52 – Merlin (Int Upset) 2" WT used for drive shoe	
20" x 13 3/8" casing	4143' AHD (RKB)	20": 202.7# - X80 – Merlin (top jt) 20": 202.7# - X65 – Merlin top/ SR20 bottom (2nd joint) 20": 202.7# - X65 – SR20, all 1"WT 13 3/8": 68# - L80 – Dino VAM x/o at 703'	685 (EMW 630)
10 ¾" x 9 5/8" casing	9365' AHD (RKB)	10 ¾": 55.5# - L80 - VAM Top 9 5/8": 53.5# - L80 - VAM Top x/o at 3013'	N.A
7" Liner (pre-drilled)	9503' AHD (RKB)	29.0# - 13 CrL80 – NK3SB	
30" cement job:	N/A	Driven (Heerema barge)	
20" x 13 3/8" cement job:			
Single	572 pptf, X-Lite	8 bpm. Stinger cementation	653 bbl
		6 bbl/hr losses before job	
Final diff. pressure	300 psi	Returns observed at seabed by ROV (after 627 bbl)	
10 ¾" x 9 5/8" cement job:			
Single	728 pptf, Class G	8 bpm, plugs bumped	
	TTOC 7865'	10 Centralisers: Weatherford TR3	115 bbl
Final diff. pressure	1320 psi	No losses	
Pressure test	4500 psia		

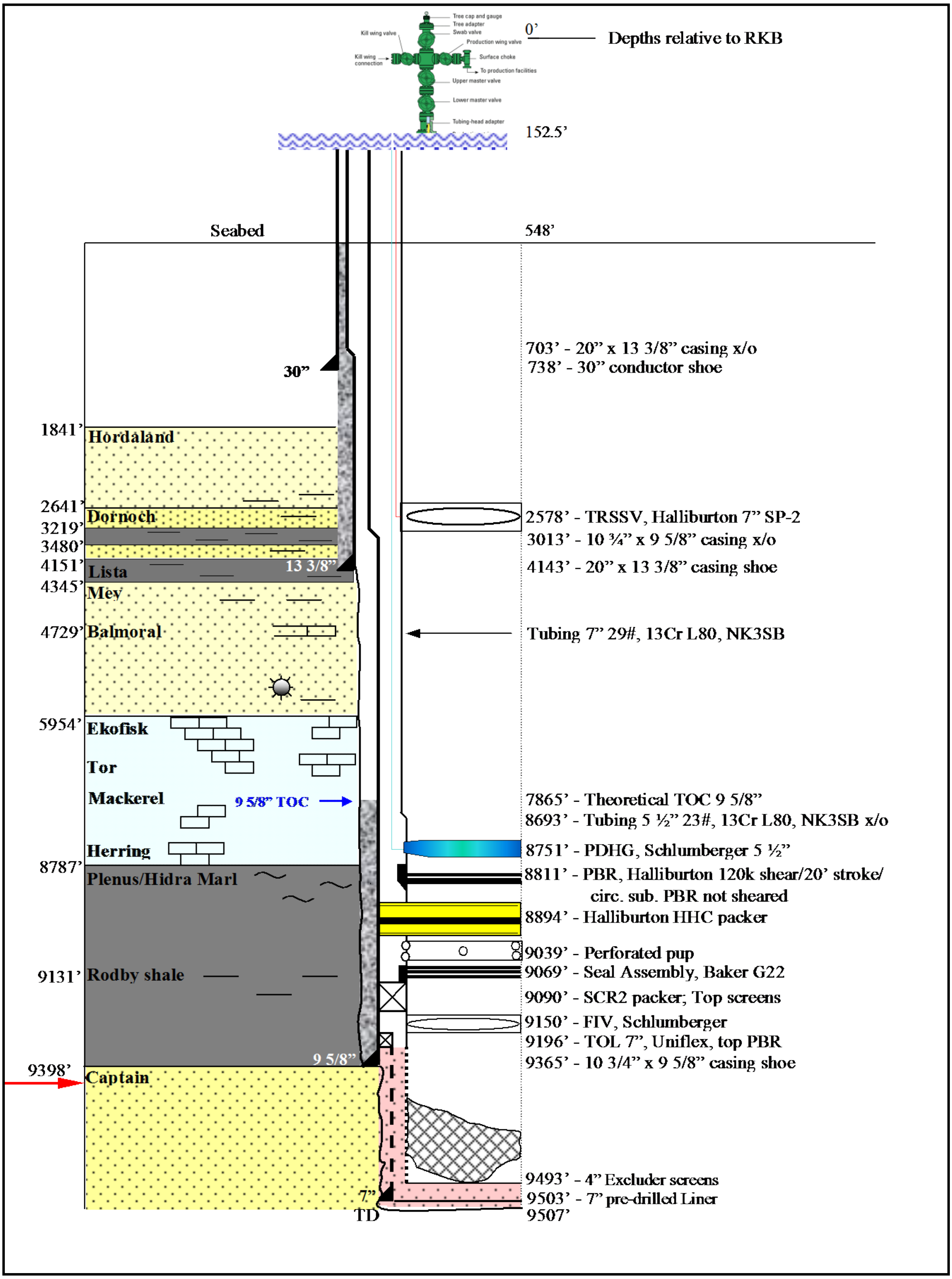


Figure 6.4: GYA03 (14/29a-A5)

6.7. Goldeneye Well GYA04 (14/29a-A1)

Table 6-5: GYA04 (14/29a-A1)

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6,429,205.1 m E 477,558.4 m	58 deg. 00 min. 9.230 sec. N 00 deg. 22 min. 46.847 sec. W	
Formation pressures	Initial:~3820 psia (8348'TVSS) Current: ~2650 psia Abandonment: ~3800 psia	No MDT'RFT taken	
Total depth (8 1/2" OH)	13262' AHD (RKB)	Reservoir T = ~182 deg. F (TD)	
Water depth	395'	Cameron SSMC wellhead	A: 550 inhib
Derrick Floor elevation	152.5'	Tree:Cameron 6 3/8" monobore 5k	B: 580 OBM
Maximum Inclination	68.1 degrees at 6020'	A-annulus 460 pptf inhib. seawater	C: Seawater
30" conductor	750' AHD (RKB); 2 x 6" holes cut 10' above seabed	1.5" WT - X52 – Merlin (Int Upset) 2" WT used for drive shoe	
20" x 13 3/8" casing	4224' AHD (RKB)	20": 202.7# - X80 – Merlin (top jt) 20": 202.7# - X65 – Merlin top/ SR20 bottom (2nd joint) 20": 202.7# - X65 – SR20, all 1"WT 13 3/8": 68# - L80 – Dino VAM x/o at 705'	688 (EMW 633)
10 ¾" x 9 5/8" casing	13010' AHD (RKB)	10 ¾": 55.5# - L80 - VAM Top 9 5/8": 53.5# - L80 - VAM Top x/o at 2768'	N.A
7" Liner (pre-drilled)	13255' AHD (RKB)	29.0# - 13 CrL80 – NK3SB	
30" cement job:	N/A	Driven (Heerema barge)	
20" x 13 3/8" cement job:			
Single	572 pptf, X-Lite	8 bpm. Stinger cementation	1450 bbl
Pressure test	2400 psia	44 Centralisers: (Econolisers)	
	Returns observed at seabed by ROV (after 1400 bbl)	4225' – 4136': 1 per jt 4136' – 725': 1 per 2 jts	
10 ¾" x 9 5/8" cement job:			
Single	728 pptf, Class G	6 bpm, plugs bumped	
Final diff. pressure	1500 psi	24 bbl losses during cementation	
Pressure test	4500 psia		

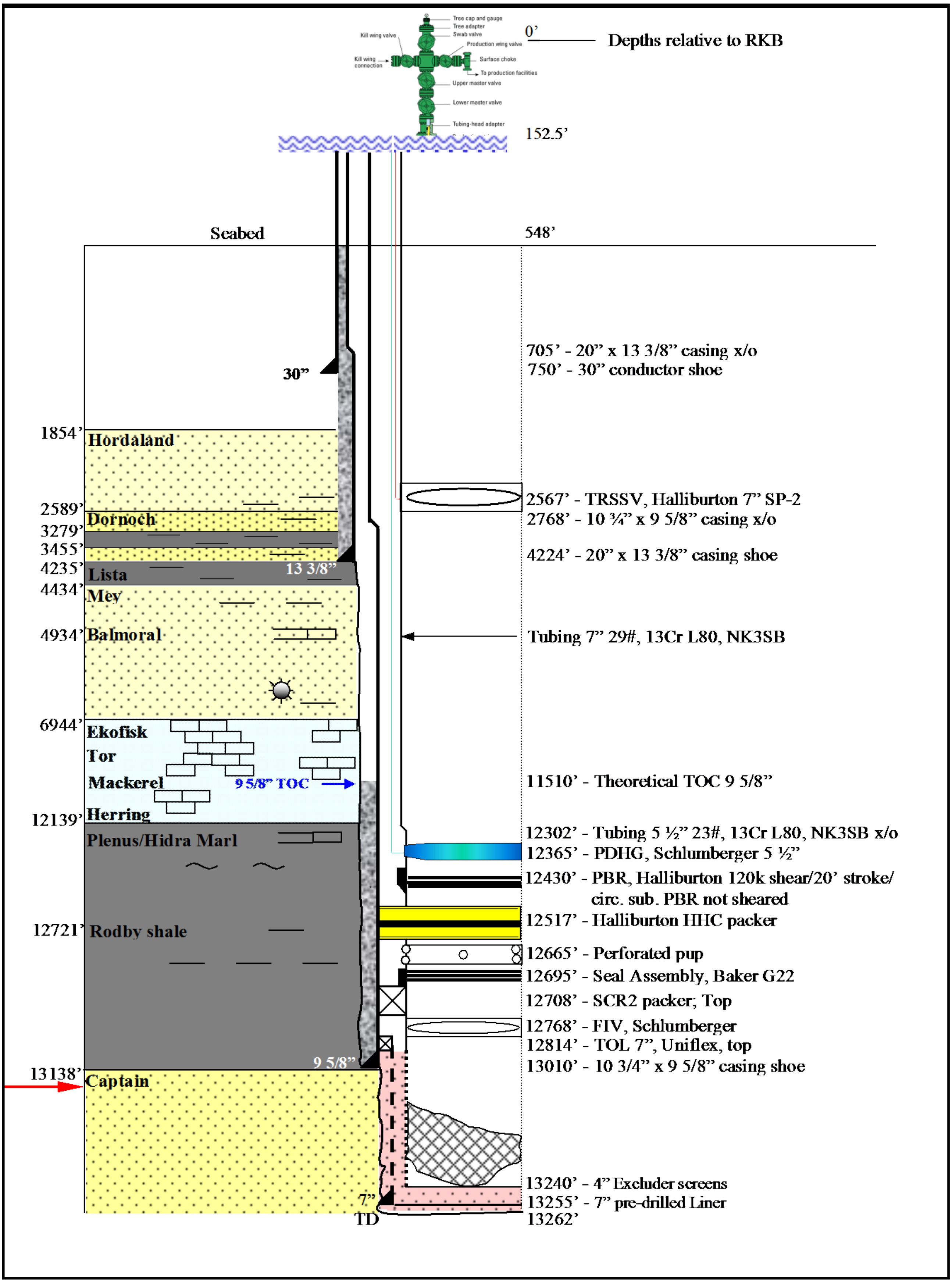


Figure 6.5: **GYA04 (14/29a-A1)**

6.8. Goldeneye Well GYA05 (14/29a-A2)

Table 6-6: GYA05 (14/29a-A2)

Well Attribute	Data		
Surface location	UTM	Lat/Lon	
	N 6,429,202.11 m E 477,554.30 m	58 deg. 00 min. 9.143 sec. N 00 deg. 22 min. 47.071 sec. W	
Formation pressures	Initial:~3820 psia (8257'TVSS) Current: ~2650 psia Abandonment: ~3800 psia	No MDT'RFT taken	
Total depth (8 1/2" OH)	8535' AHD (RKB)	Reservoir T = ~179 deg. F (TD)	
Water depth	395'	Cameron SSMC wellhead	A: 550 inhib
Derrick Floor elevation	152.5'	Tree:Cameron 6 3/8" monobore 5k	B: 560 OBM
Maximum Inclination	7.21 degrees at 1785'	A-annulus 460 pptf inhib. seawater	C: Seawater
30" conductor	750' AHD (RKB); 2 x 6" holes cut 10' above seabed	1.5" WT - X52 – Merlin (Int Upset) 2" WT used for drive shoe	
20" x 13 3/8" casing	4107' AHD (RKB)	20": 202.7# - X80 – Merlin (top jt) 20": 202.7# - X65 – Merlin top/ SR20 bottom (2nd joint) 20": 202.7# - X65 – SR20, all 1"WT 13 3/8": 68# - L80 – Dino VAM x/o at 704'	676 (EMW 630)
10 ¾" x 9 5/8" casing	8395' AHD (RKB)	10 ¾": 55.5# - L80 - VAM Top 9 5/8": 53.5# - L80 - VAM Top x/o at 3130'	N.A
7" Liner (pre-drilled)	8530' AHD (RKB)	29.0# - 13 CrL80 – NK3SB	
30" cement job:	N/A	Driven (Heerema barge)	
20" x 13 3/8" cement job:			
Single	577 pptf, X-Lite	6-7 bpm. Stinger cementation	719 bbl
Pressure test	2400 psia	41 Centralisers: (Econolisers)	
	Returns observed at seabed by ROV (after 520 bbl)	4107' – 3893': 1 per jt 3893' – 766': 1 per 2 jts	
10 ¾" x 9 5/8" cement job:			
Single	728 pptf, Class G	9 bpm, plugs bumped	
Final diff. pressure	1200 psi	No losses during cementation	
Pressure test	4500 psia	80 bbl 676 pptf spacer	

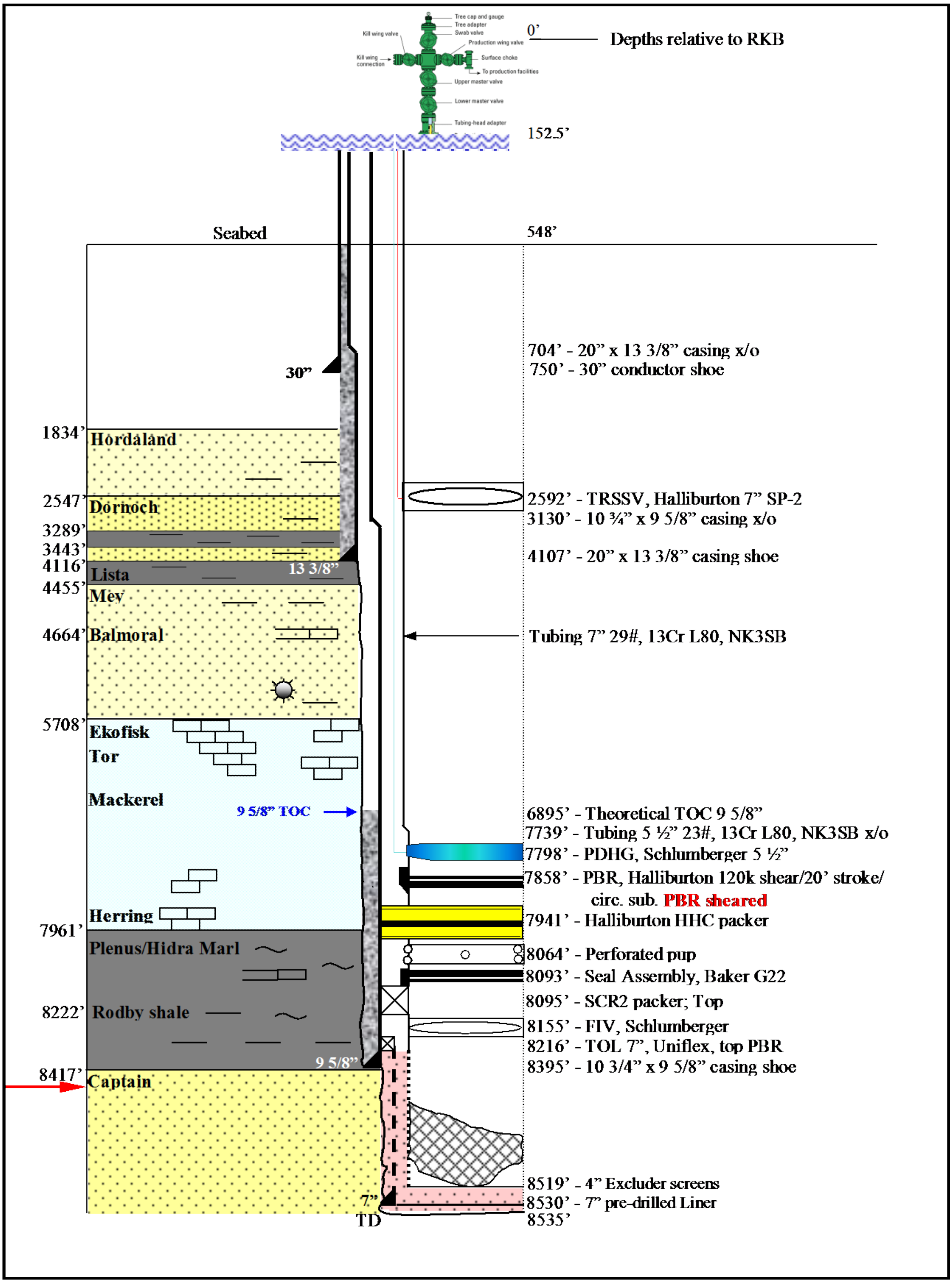


Figure 6.6: **GYA05 (14/29a-A2)**

6.9. Proposed completion, Packer Placement – Setting depths

An evaluation of the current wells highlights a requirement to workover the upper completions for the CCS project. It is proposed to re-complete the wells prior to CO_2 injection. The proposed completion is as illustrated in the following figure. Further details on the proposed completion design are included in the Conceptual Completion & Well Intervention Design Report (2).

The table below shows the suggested setting depths for the 9 5/8" packer when re-completing the wells for CO_2 injection. It is proposed to set the packers as deep as possible in the Plenus/Hidra Marl to ensure the integrity of the containment area. The table also shows the approximate available height to the top of the Plenus/Hidra in relation to the various well components for setting a cement plug during final abandonment. (This is to be examined and confirmed during the FEED phase).

Table 6-7: Proposed packer setting depths in (ft.) / Cement interval (ft.)

Key depths vs Top of Cement	GYA-01	GYA-02s1	GYA-03	GYA-04	GYA-05
Theoretical Top of Cement	7506	9490	7865	11510	6895
Top Plenus/Hidra Marl	8547	10485	8799	12154	7961
Proposed Packer Setting Depth (40'-100' above SC-2R packer)	8656 - 8596	10800 - 10740	9050 - 8990	12668 - 12608	8055 - 7995
Cement to Top Plenus/Hidra	109 - 49	315 - 255	251 - 191	514 - 454	94 - 34
SC-2R Packer (screen packer)	8696	10840	9090	12708	8095
Cement to Top Plenus/Hidra	149	355	291	554	134
FIV (cut point)	8755	10900	9150	12768	8155
Cement to Top Plenus/Hidra	208	415	351	614	194
Uniflex 7.00" Liner Hanger	8831	10955	9196	12832	8237
Cement to Top Plenus/Hidra	284	470	397	678	276
9-5/8" Casing Shoe	9006	10990	9365	13010	8395
Cement to Top Plenus/Hidra	459	505	566	856	434
Proposed packer above 9-5/8" Shoe	350 - 410	190 - 250	315 - 375	342 - 402	340 - 400

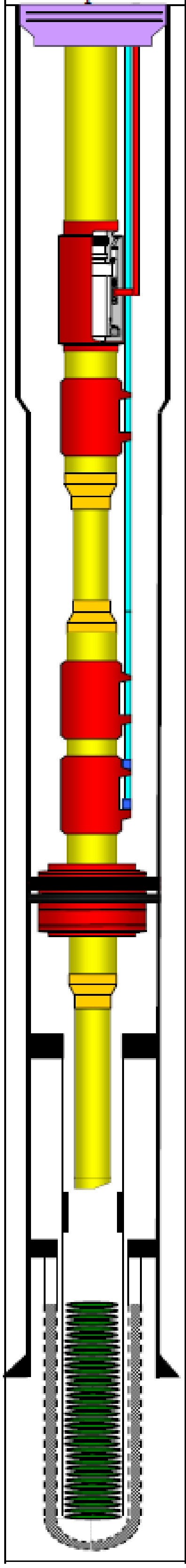
GYA 01 Proposed	Depth MD (ft)	Description of Item	ID (Inches)	Drift (Inches)
	79	Tubing Hanger		
		4 1/2" 12.6# Tubing S13Cr	3.958	3.833
	2500	SCTRSSSV 4 1/2"	3.813	
	3130	Casing XO 10 3/4" x 9 5/8"		
		4 1/2" PDGM for PDG (tubing gauge)	3.958	3.833
	6800	XO 4 1/2" 12.6# x 3 1/2"	2.922	
		3 1/2" Tubing	2.922	
	8430	X/O/Wire Finder Trip Sub 3 1/2" x 4 1/2" 12.6#	2.992	2.787
	8336	4 1/2" PDGM for PDG (tubing gauge)		
	8536	4 1/2" PDGM for PDG (2x tubing + 1 x annulus)	3.958	3.833
		4 1/2" 12.6 # Tubing	3.958	3.833
	8596	9 5/8" x 4 1/2" Packer		
		Tubing		
	8696	Baker SC-2R packer/screen hanger 13Cr (existing)		
	8755	Schlumberger FIV (existing)	2.94"	
	8952	Top of 4.00" Screens (existing)	3.548	

Figure 6.7: Proposed completion schematic for CCS

6.10. Abandonment options for Goldeneye wells

For the CCS project, upper completion workovers are required in order to make the Goldeneye wells suitable for CO_2 injection. All five wells are proposed to be worked over; one of the wells shall be used as a monitoring well. The final abandonment of the five Goldeneye production wells will therefore be based on the well condition after the workover.

6.10.1. Zones requiring abandonment

Permeable zones requiring abandonment according to *"Guidelines for the suspension and abandonment of wells"* (14)*:*

- Captain sandstone: Initially hydrostatically pressured, currently depleted to 2500 psia, but expected to re-pressurise to hydrostatic (~3800 psia) long-term. This zone was originally hydrocarbon bearing (gas condensate) and will contain remaining gas/condensate and injected CO_2 at the time of abandonment.
- Tertiary sandstones (Balmoral, Dornoch): Hydrostatically pressured, water bearing permeable zone. The Balmoral sandstone formation is contained by the Lista shales. The Dornoch sandstone is believed to be in communication with shallower zones to seabed. The tertiary sandstones featured gas shows during drilling, however it is believed to be small amounts of background gas and not mobile gas that can flow and build up pressure.

Over-pressured permeable zones (both water and hydrocarbon bearing) and normally pressured permeable zones containing hydrocarbons require a minimum of two Permanent (abandonment) barriers between the permeable zone and seabed/surface.

Normally pressured permeable zones containing water require one Permanent (abandonment) barrier between the permeable zone and seabed/surface.

Permanent barriers are normally cemented. The type of cement to be used will be reviewed later and may include CO_2 resistant additives. Some alternatives to cement (like resins, etc.) may be considered as well. This will be influenced by the best practices and standards of the day at the time of abandoning.

The cap-rock for the Captain reservoir is the Rødby shales/Hidra marl. These formations are impermeable, strong and about 500' in vertical thickness. In Goldeneye, these formations are positioned right above the Captain reservoir.

For the abandonment plans of the Goldeneye wells it is important to establish what the predicted pressure and content is for each of the permeable zones in the wells' stratigraphy.

The following assumptions have been made:

- Captain reservoir: CO_2 and hydrocarbon containing, hydrostatically pressured (~3600-3800 psia)
- Balmoral formation: water bearing, hydrostatically pressured

However, in case of CO_2 leakage to the Balmoral formation:

- Balmoral formation: water and CO_2 bearing, hydrostatically pressured

In instances where it is not possible to install two barriers across the Rødby or Hidra Marl due to restrictions as indicated in the section on packer placement it is required to rely on the second barrier being placed across the Lista formation. The formation strength around the second barrier is based on the 13 3/8" casing shoe formation strength test.

Table 6-8: Goldeneye wells, 13 3/8" casing shoe formation strength

13 3/8" shoe	GYA-01	GYA-02s1	GYA-03	GYA-04	GYA-05
AHD (ft.)	4155	4155	4143	4224	4107
TV depth (ft.)	4076	4085	4097.7	4073.2	4099.9
EMW (psi/ft.)	0.630	0.631	0.630	0.633	0.630
Pressure (psia)	2568	2577	2580	2578	2583

The pressure from a CO_2 column to the 13 3/8" casing shoe is as per the following figure (Figure 6.8). As can be seen from Figure 6.8, the formation strength pressure at the 13 3/8" shoe is around 2570 psi. The highest predicted pressure at the casing shoe based on the highest CO_2 injection pressure is ~2200 psi. The placement of the second barrier would therefore not risk a situation whereby CO_2 would fracture below the casing shoe past the second barrier.

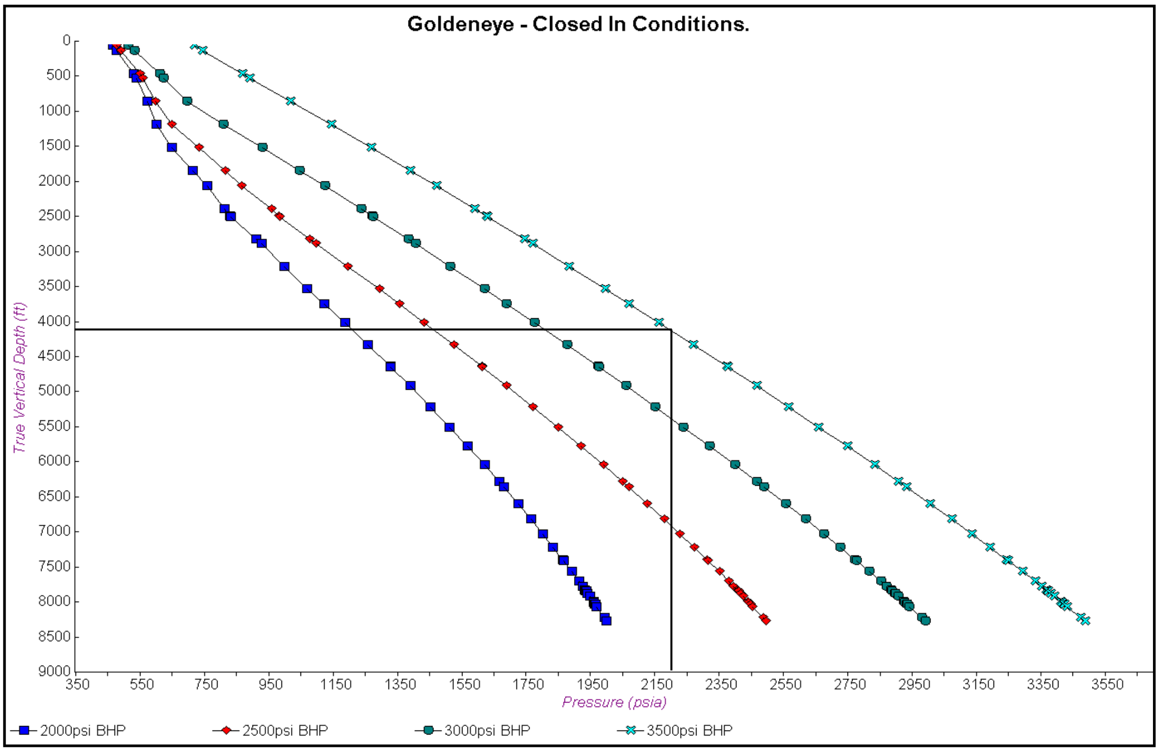


Figure 6.8: CO_2 pressure as function of depth, based on various reservoir pressures

6.10.2. *Well Abandonment Proposal 1*

For this proposal, it has been assumed that (some of the) CO_2 has migrated to the Balmoral formation and is therefore present in both the Captain reservoir and the Balmoral formation. Each formation will therefore require a minimum of two permanent barriers between the formation and seabed.

The "pancake" plug concept is used for placement of a permanent barrier over the Rødby shales. The Rødby shales are believed to be the best sealing formation above the reservoir. In order to achieve this, most of the completion components need to be removed. See Figure 9.

The deep-set barrier above the Captain reservoir, based on the "pancake " plug concept, is achieved by section milling production casing and cement opposite the Rødby shales. This gives "rock-to-rock" cement coverage, the best possible solution.

For this proposal, the idea is to place two cement barriers at this level; the first one is the cement plug (plug#1) set over the section-milled window.

The second barrier (plug#2) will be placed directly on top of plug#1 in order to make best use of the removal of completion components and getting deep into the cap-rock. The second barrier is supported on the outside of the production casing by annular cement from the primary cementation and partly the cap-rock (Hidra marl).

The third barrier (plug#3) around the 13 3/8" casing shoe is set in the open hole in order to get a barrier opposite the Lista shales (seal).

The fourth barrier (plug#4) is required since the Balmoral sands in this case are CO_2 bearing and this plug will act as the second permanent barrier for the Balmoral sands. Its position will be opposite the Dornoch shales.

This abandonment proposal is based on the following:

- The upper completion is removed
- The production packer is retrieved
- The SCR-2 packer is retrieved (screens cut). A variation to this is to set the pancake plug on top of the SCR-2 packer
- Bridge plug placed below the milled window to support the pancake plug
- 200' section milled/under-reamed over the Rødby shales
- Plug#1 is set over the section milled window (~250' on top of cement retainer)
- Plug#2 is set on top of the first barrier (~500')
- The 9 5/8" casing is cut and milled to about 250' below the 13 3/8" casing shoe in order to place cement opposite the Lista shales (250' open hole section)
- An open hole inflatable plug or viscous reactive pill is placed for support of cement plug #3
- Plug#3 (500' cement plug) is placed on top of the support
- Plug#4 is set on top of plug#3 in order to benefit from placement opposite the Dornoch shales.
- The 30" and 20" casing strings are cut 10' below seabed

In this proposal plug #1 is placed after section milling the 9-5/8" casing, other alternative methods could be employed and shall have to be evaluated after quantifying and qualifying the cement behind the casing.

Similarly plug#3 could be placed without retrieving the 9-5/8" casing, this would involve techniques such as circulating a viscous reactive pill & cement into the B annulus and placing a cement plug inside the 9-5/8" casing.

Furthermore, for the cement plugs yet to be installed, CO_2 resistant cement types can be selected. This will be explored in detail as part of the FEED process.

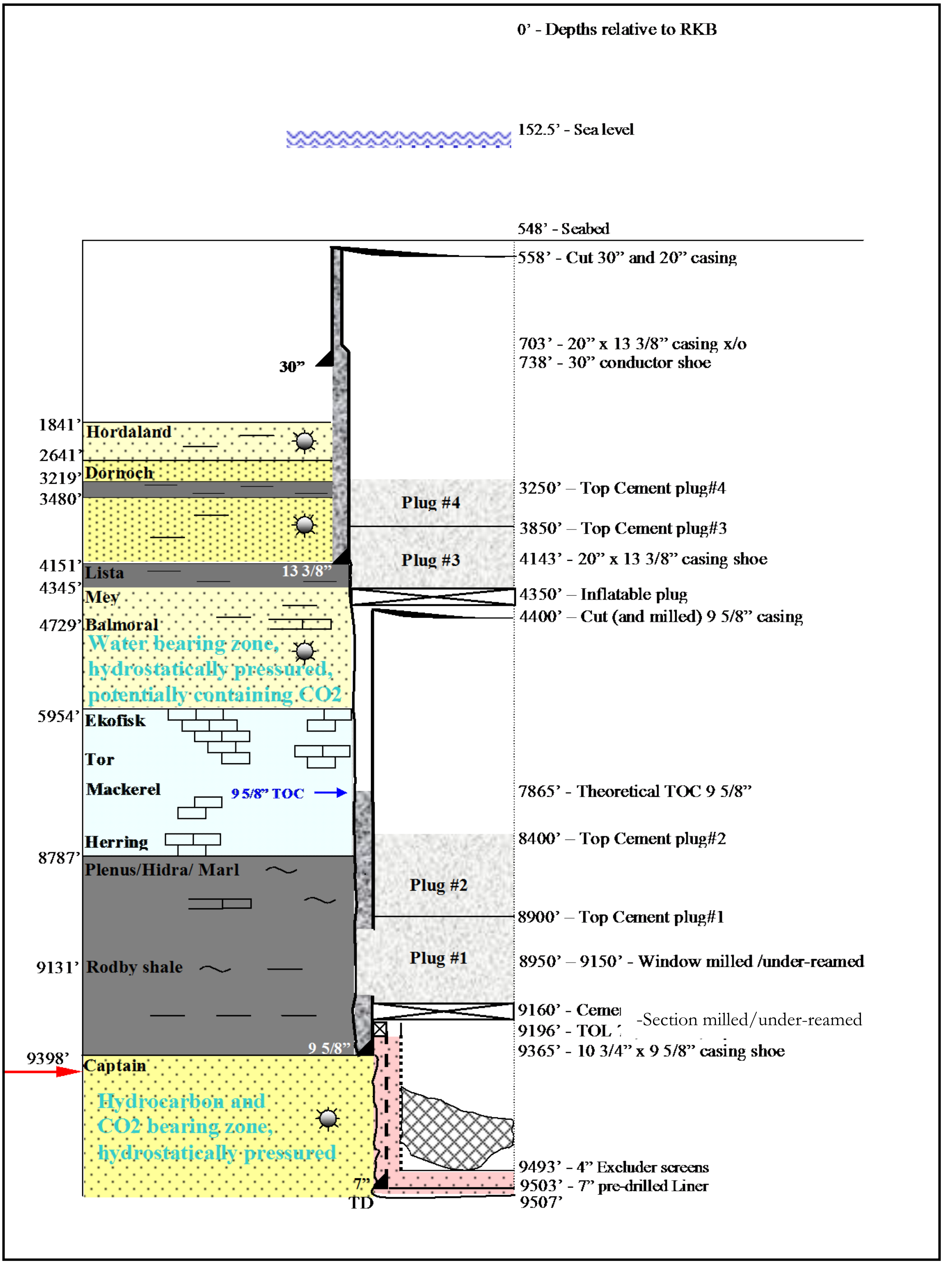


Figure 6.9: GYA03: Abandonment Proposal 1

6.10.3. Well Abandonment Proposal 2

For this proposal, it has been assumed that (some of the) CO_2 has migrated to the Balmoral formation and is therefore present in both the Captain reservoir and the Balmoral formation. Each formation will therefore require a minimum of two permanent barriers between the formation and seabed.

For the wells with the production packer positioned at the Chalk level, the production packer will have to be removed in order to get deeper into the well to the reservoir sealing formations (Rødby shales/Hidra marl). For this particular well it will be difficult to get two individual permanent barriers installed at the Rødby/Hidra level, even with removal of the SC-2R packer and 200' of window milling. This is due to the relative position of the completion components to the sealing formations. The second permanent barrier (plug#2) for the Captain reservoir will therefore be the same as the first permanent barrier for the Balmoral. See figure Figure 6.11 for illustration.

The Balmoral formation is assumed for this proposal to have been charged with CO_2 and therefore requires two permanent barriers opposite the Lista shales for containment. The Lista shales are the seal for the Balmoral formation. Since two permanent barriers are required at the Balmoral level, the second barrier at this level (plug#3) will be set on top of plug#2 opposite the Dornoch shales.

High-level operational steps:

- Removal of upper completion (3 ½" x 5 ½") tubulars with cables (TRSSSV and PDHG)
- Removal of production packer
- Removal of SCR-2 packer (cut screens). Alternatively, the SCR-2 can be used as base for the first cement plug
- Installation of cement retainer (or alternative)
- 200' Section milling/under-reaming
- Plug#1; pancake plug (500' height) set on top of cement retainer or SCR2 packer
- 9 5/8" Casing cut and milled to sufficient depth in open hole, in order to place cement opposite the Lista shales (250' open hole section)
- Open hole inflatable plug/Viscous reactive pill for support of Plug#2
- Plug#2; 500' cement plug set on top of support
- Plug#3; 600' cement plug set on top of plug#2 opposite the Dornoch shales.
- 30" and 20" casing strings cut 10' below seabed

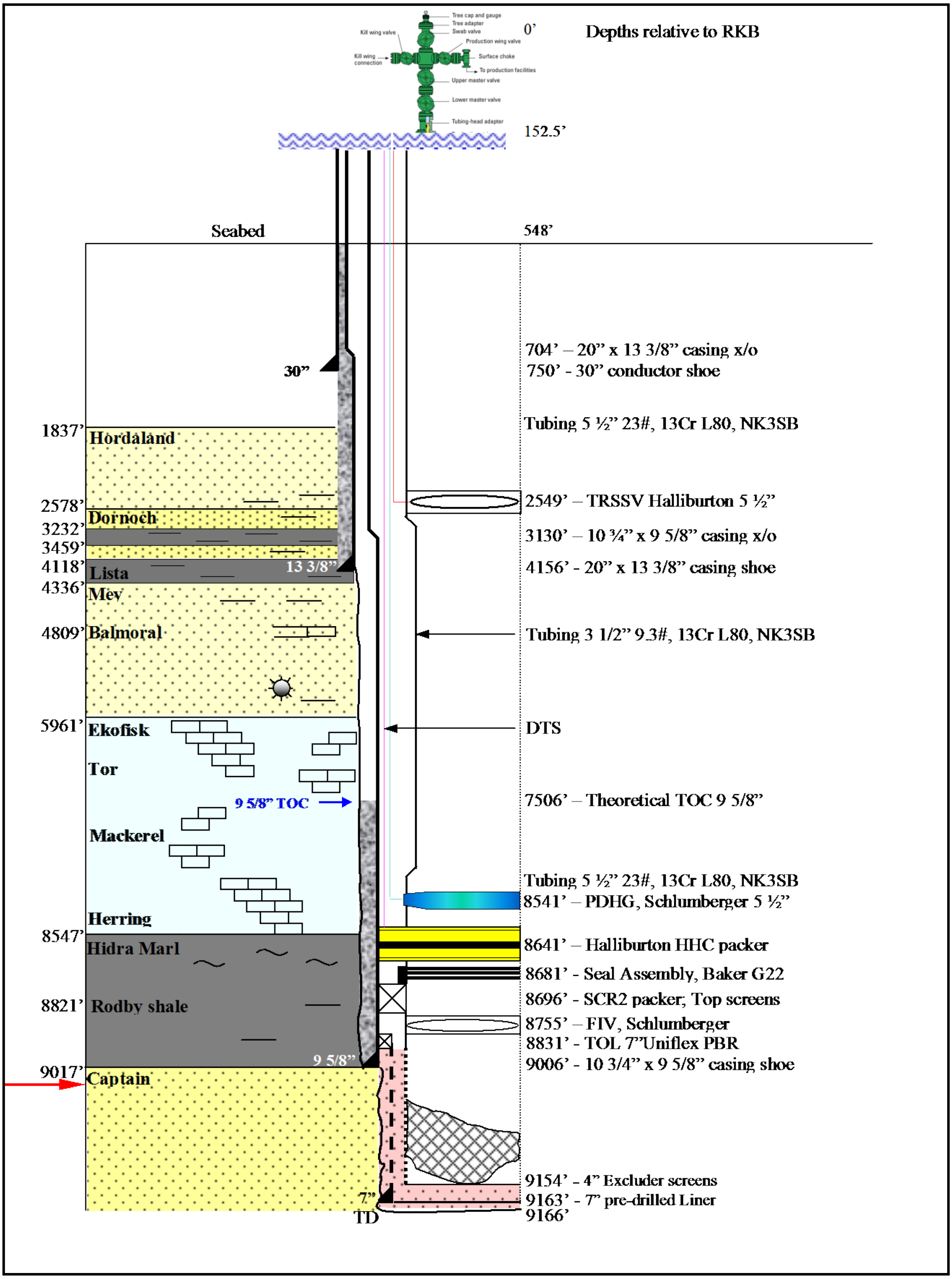


Figure 6.10: **GYA01: CCS Workover**

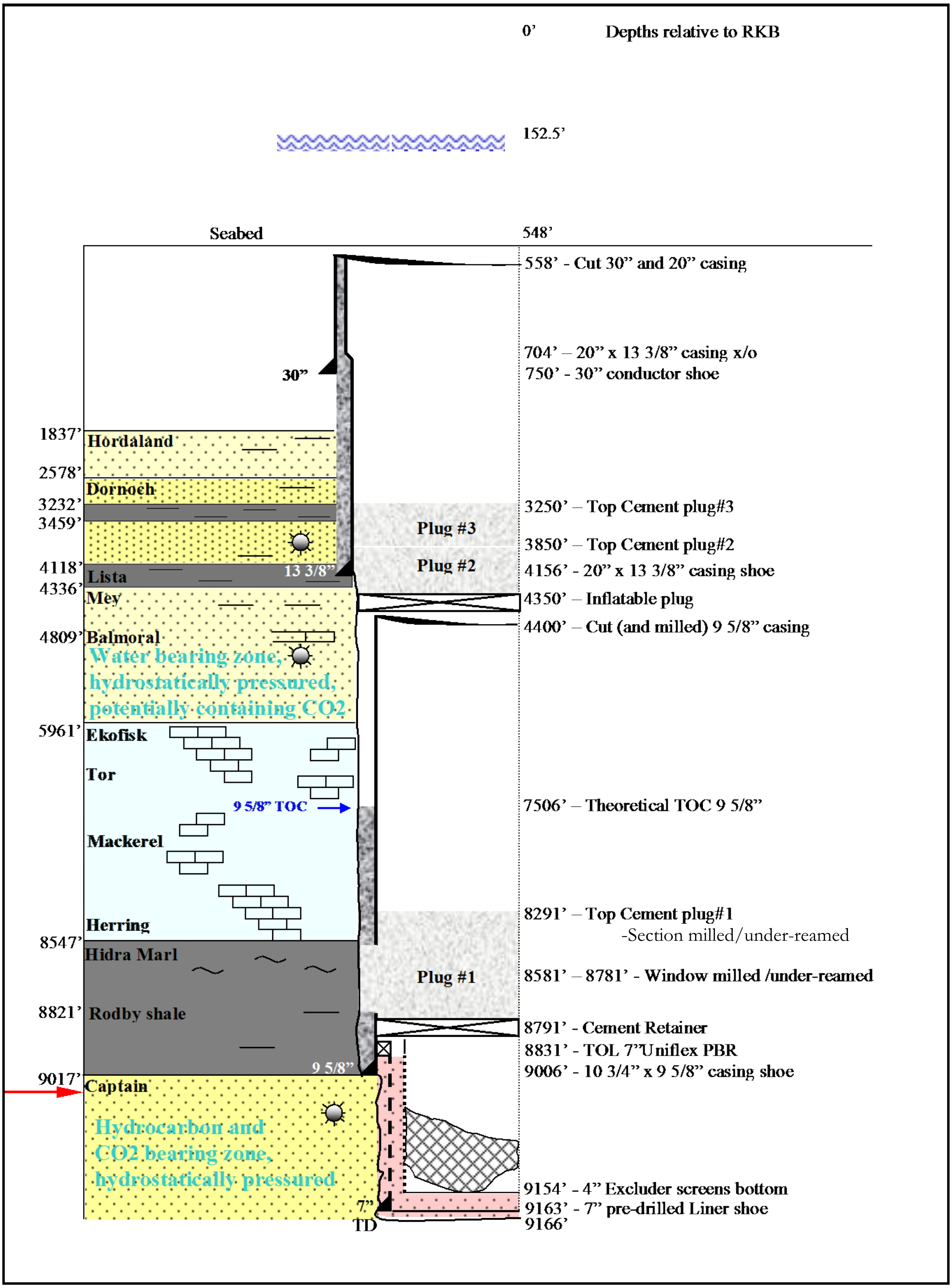


Figure 6.11: GYA01: Abandonment Proposal 2

6.10.4. Well Abandonment Proposal 3

For this proposal, it has been assumed that the CO_2 is contained at the Captain Reservoir level only. The Balmoral formation is therefore water bearing and hence only requires a single barrier from surface.

Due to the position of the production packer in relation to the caprock, it is believed that only a single barrier (plug#1) can be placed above the packer taking the TOC and the formations behind the casing into account. The Chalk formations are assumed not to be a seal due to the presence of micro-fractures. This proposal is only an option for wells with the production packer positioned across the Rødby/Hidra formations with sufficient height for a cement column to the top Hidra.

The second barrier (plug#2) is placed across the Lista formation and also serves as the single barrier for the Balmoral formation. See Figure 7.12.

This proposal is based on the following:

- Plug#1 is set on top of the production packer with overlapping annular cement from the 9 5/8" casing cementation and reservoir cap-rock (Hidra marl)
- Complete removal of the completion and control line cables
- 9 5/8" casing removed to below the 13 3/8" casing shoe in open hole in order to allow plug#2 to be placed opposite the Lista shales
- Inflatable plug (or viscous reactive pill) set opposite the Lista shales as support for the second barrier
- Plug#2 is placed on top of the support plug
- Plug#2 will have rock-to-rock coverage in open hole and cement supported on the outside of the casing for that part of the barrier extending inside the 13 3/8" casing
- Plug#2 will act as the required single permanent barrier for the Balmoral formation, as well as the second barrier for the Captain reservoir.
- 30" and 20" casing strings cut 10' below seabed

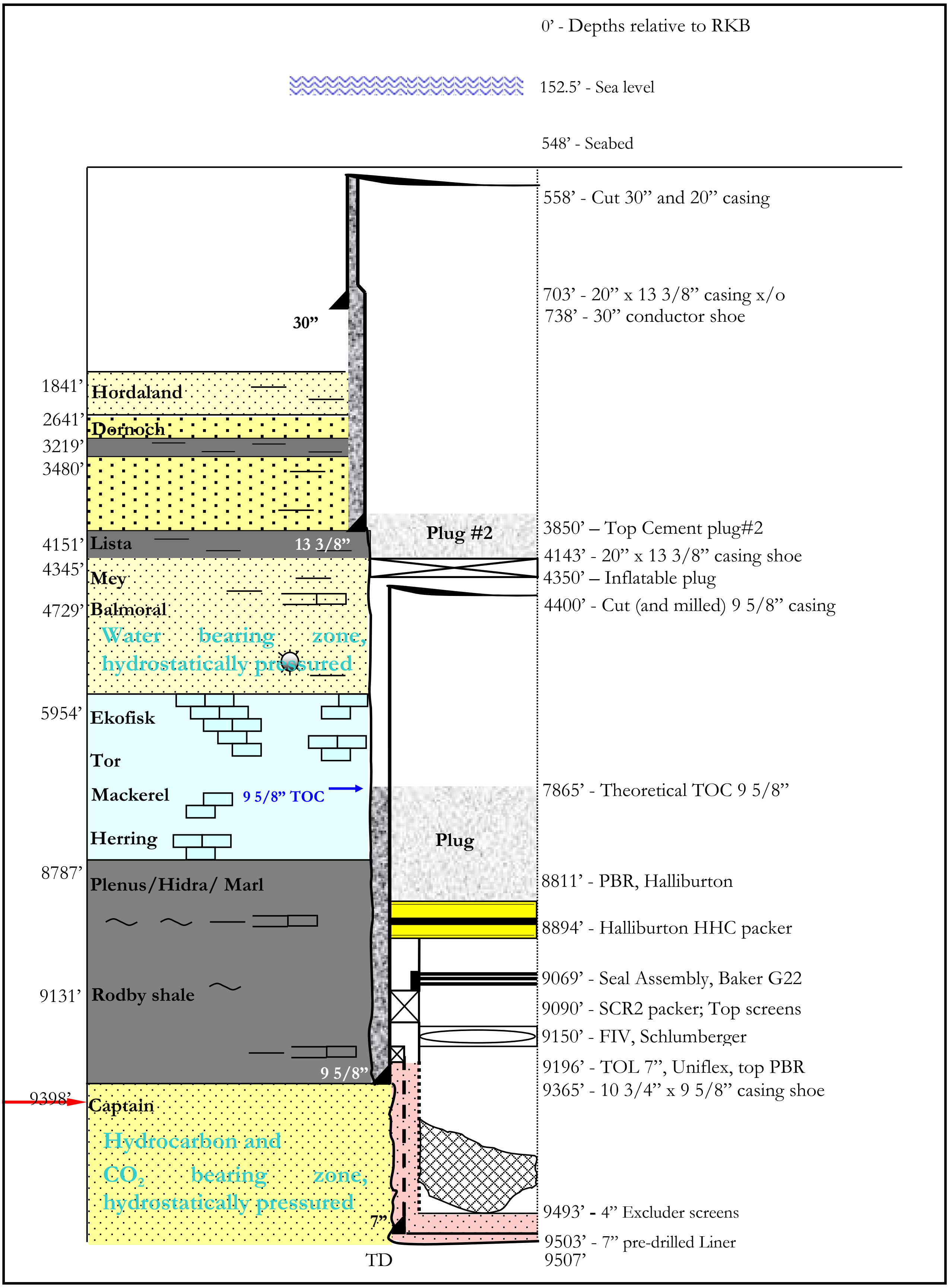


Figure 6.12 GYA03: Abandonment Proposal 3

6.11. Conclusions

Abandonment proposals have been prepared for the Goldeneye wells. These proposals take into account the upper completion workovers that are necessary for CO_2 injection and long term storage.

It is believed that a CO_2 leak tight solution for these wells can be provided, in doing so the oil based mud (OBM) can also be removed from the 'B' annulus.

There are various options that shall need to be explored to ascertain the exact techniques that shall be employed to abandon the wells. These will potentially vary from well to well depending on the most optimal setting depths for the packers and relative position of the top of cement in the annulus. This further emphasises the requirement to carry out cement bond logs and casing calliper runs prior to recompleting the wells.

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8. Glossary of terms

Term	Definition
13Cr	13 percent chrome content metallurgy
'A' annulus	Annulus between the production tubing and production casing string
AHD	Along Hole Depth
ALARP	As Low As Reasonably Practicable, and is a term often used in the environment of safety-critical and high-integrity systems. The ALARP principle is that the residual risk shall be as low as reasonably practicable
Annuli	The space between adjacent strings of tubing or casing
'B' annulus	Annulus between the production casing and intermediate casing string
Barrier	Barriers prevent of mitigate the probability of each threat or prevent, limit the extent of, or provide immediate recovery from the Consequences
Base oil	Oil with Carcinogenic elements removed
BHP&T	Bottom Hole Pressure and Temperature
BHST	Bottom Hole Static temperature
Cap rock	The shale layers above a reservoir that provide geological isolation to upward migration and provide the primary seal
CBL	Cement Bond Logging
CCS	Carbon Capture & Storage
CCS	Carbon Capture Sequestration
CDA	Corporate Data Access
Cement squeeze	Injection of cement to isolate a leak in the cement behind casing
CO_2	Carbon Dioxide
Completion	The conduit for production or injection between the surface facilities and the reservoir. The upper completion comprises the tubing and packer, etc. The reservoir completion is the screens, etc., across the reservoir interval.
CoP	Cessation of Production
DECC	Department of Energy and Climate Change
DIANA	Software package from TNO that solves, with the aid of FEM, problems relating to design and assessment activities in concrete, steel, soil, rock and soil-structure.
DTS	Distributed Temperature Sensing
ECP	External Casing Packer
ED	Explosive Decompression
EMW	Equivalent Mud Weight
ESD	Emergency Shut Down
FEED	Front End Engineering Design

FIT	Formation Integrity Test
FIV	Formation Isolation Valve
HSSE	Health, Safety, Security, and Environment
ID	Inside Diameter
Injection phase	The injection phase includes the period of site preparation for injection, the injection period itself and the period of well abandonment
JT	Joule Thompson
Leakage	Migrated CO_2 out of the containment that leaks into the biosphere (shallow subsurface and atmosphere). In contrast to seepage, leakage involves medium fluxes and medium concentrations
Leakage scenario	Group of threats that form cause-consequence relations leading to a certain route of migration and eventually leakage into the biosphere
LOT	Leak-off Test
MD	Measured Depth
Migration	Escaped CO_2 out of the containment into the subsurface where it moves or trapped in other layers
MMV	Measurement, Monitoring and Verification
MSL	Mean Sea Level
OBM	Oil Based Mud
OD	Outside Diameter
Open shoe	An annulus that is open to a formation
Packer	A device that both anchors and seals the tubing to the production casing. The term production packer is still used even when the well is in injection mode
PBR	Polished Bore Receptacle
PDG	Permanent downhole gauge
PEC	Pulsed Eddy Current
POOH	Pull Out of Hole
pptf	Mud Weight measured in psi per thousand feet
Production casing	The casing providing the secondary wellbore barrier during production or injection (valid term even in injection mode)
PSI	Pounds per Square Inch
Relief well	A well constructed specifically to intersect the wellbore or reservoir of a blowing out well
RKB	Rotary Kelly Bushing
ROV	Remotely Operated Valve/Vehicle
SBT	Segmented Bond Tool
Seepage	Migrated CO_2 out of the containment that seeps into the biosphere (shallow

	subsurface and atmosphere). In contrast to leakage, seepage involves low fluxes and low concentrations
Straddle	A device comprising two packers and tubing designed to isolate leaking tubing or casing
TD	Total Depth
TNO	Netherlands organization for applied scientific research
TOC	Top of Cement
TRSSSV	Tubing Retrievable Subsurface Safety Valve
TTOC	Theoretical top of cement
TVD	Total Vertical Depth
UKCS	United Kingdom Continental Shelf
Under ream	To mill out a section of casing / cement by the use of an expandable milling bit
USIT	Ultrasonic Imaging Tool
UWG	Structural Analysis Consultants
VDL	Variable Density Log
VSP	Vertical Seismic Profile
WBM	Water Based Mud
WH	Wellhead
WIT	Well Integrity Tests
XLOT	Extended Leak Off Test
XO	Cross Over

8.1. Abbreviations

Table 8-1: Well name abbreviations

Full well name	Abbreviated well name
DTI 14/29a-A3	GYA01
DTI 14/29a-A4Z	GYA02S1
DTI 14/29a-A4	GYA02
DTI 14/29a-A5	GYA03
DTI 14/29a-A1	GYA04
DTI 14/29a-A2	GYA05
DTI 14/28a-1	Abandoned E&A Well
DTI 14/28a-3A	Abandoned E&A Well
DTI 14/28b-2	Abandoned E&A Well

DTI 14/29a-2	Abandoned E&A Well
DTI 14/29a-3	Abandoned E&A Well
DTI 14/29a-4	Abandoned E&A Well
DTI 14/29a-5	Abandoned E&A Well
DTI 20/3-1	Abandoned E&A Well
DTI 20/4b-3	Abandoned E&A Well
DTI 20/4b-4	Abandoned E&A Well
DTI 20/4b-6	Abandoned E&A Well
DTI 20/4b-7	Abandoned E&A Well
DTI 14/28b-4	Abandoned E&A Well

Table 8-2: Unit Conversion Table

Unit	Imperial to Metric conversion Factor
Length	1 Foot (ft) = 0.3048 metres (m) 1 Inch (") = 25.4 millimetres (mm)
Pressure	1 Bara = 14.5 psia
Temperature	°F=(1.8)(°C)+32 °R=(1.8)(K) (absolute scale)
Weight	1 Pound (lb) = 0.454 Kilogram (kg)

APPENDIX 1. Casing Design for CO_2 Injection

A1.1. Casing Design Assumptions

1. 10 % drill through wear has been simulated on both the 20" x 13 3/8" surface casing and the 10 3/4" x 9 5/8" production casing. (10% is the standard default value to allow for casing affected by mechanical abrasion - drilling through casing).
2. A number of sensitivities have been carried out with respect to CO_2 injection rates with the design rate being 50 MMscf/day at 115 bar wellhead pressure with a wellhead inlet temperature of 0.1 °C.
3. Full drilling thermal based on the original well build has been simulated to accurately assess the casing initial conditions
4. A fixed wellhead approach has been taken for the initial casing analysis and will be revised once a wellhead movement analysis has been performed
5. When performed the surface load analysis will include the substantial corrosion seen in the surface casing
6. A single section 3 1/2" tubing string has been used in the design with base oil packer fluid
7. The predrilled liner for the gravel-pack has not been analysed

A1.2. Results

The load cases are listed in A1.5 and A1.6 with the corresponding safety factors. The loads are also shown graphically and listed in the graph 'legend box'.

Surface casing loads give low safety factors in the early days of CO_2 injection into the well. Safety factor values are 2.4 SF for axial loads and 3.2 SF for triaxial loads.

For the production casing, the tubing leak near surface and the casing evacuation cases result in the smallest safety factors.

1. Both the surface casing and the production casing are within limits for the loads modelled with the minimum safety factors listed in the following tables
2. The driving load cases exist in Q1 & Q4 of the design limits plots indicating the tensile loading due to thermal contraction.

A1.3.Surface Casing Loads

Table 8-3: 20" Section – Surface Casing

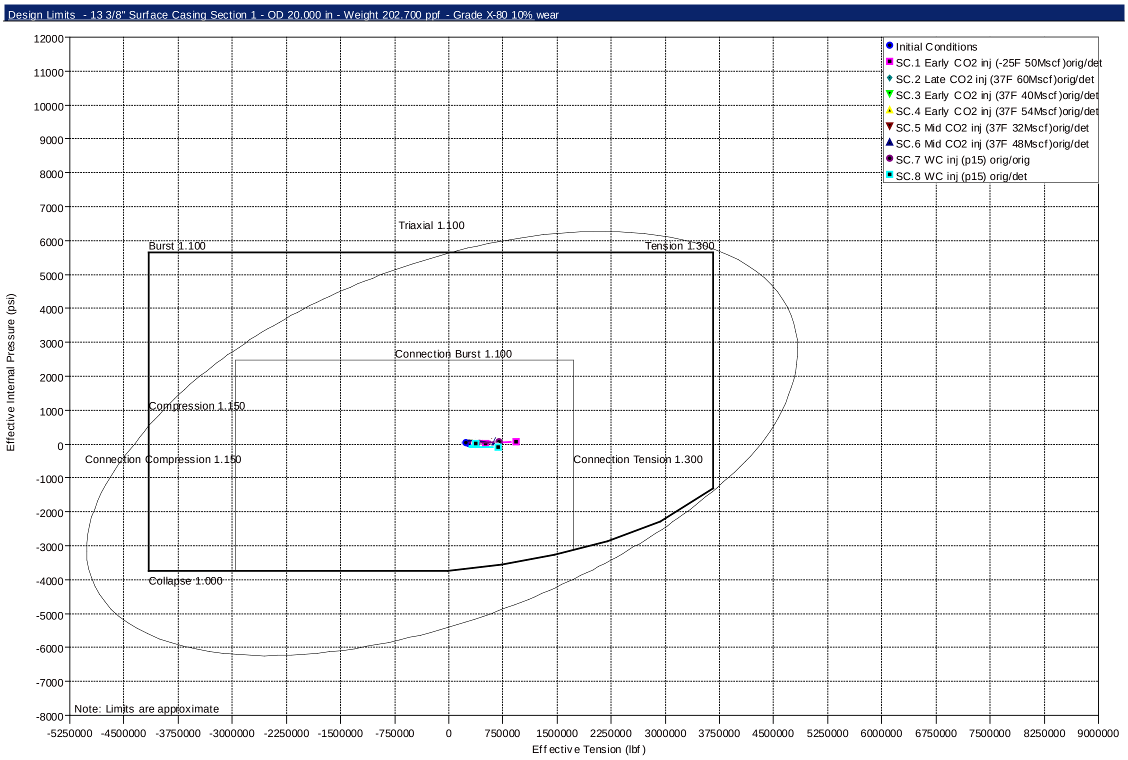
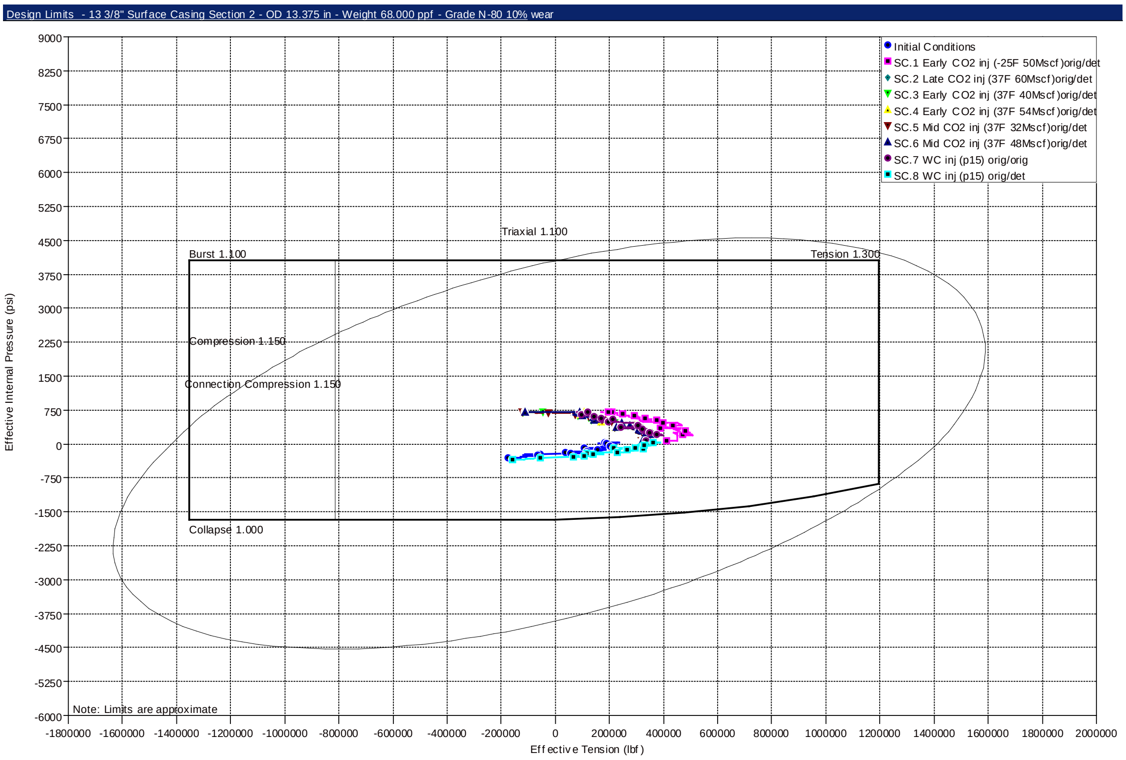


Table 8-4: 13 3/8" Section – Surface Casing



A1.4.Production Casing Loads

Table 8-5: 10 3/4” Section – Production Casing

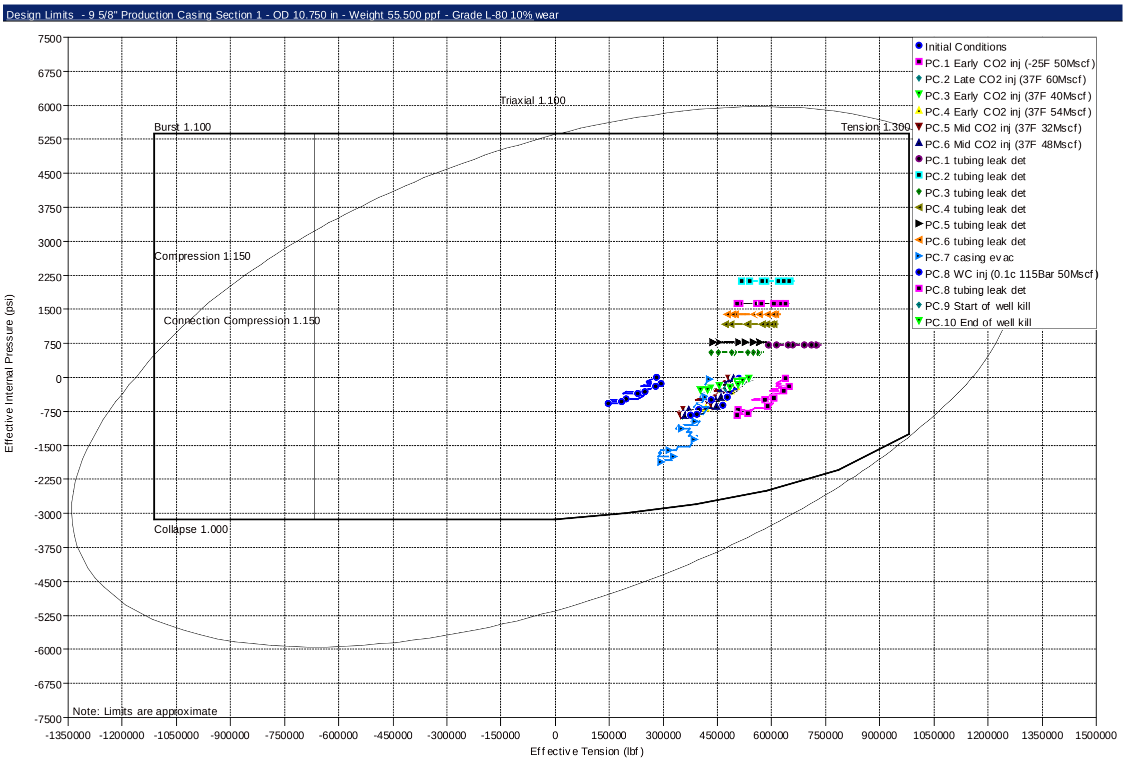


Table 8-6: 9 5/8” Section – Surface Casing (above packer)

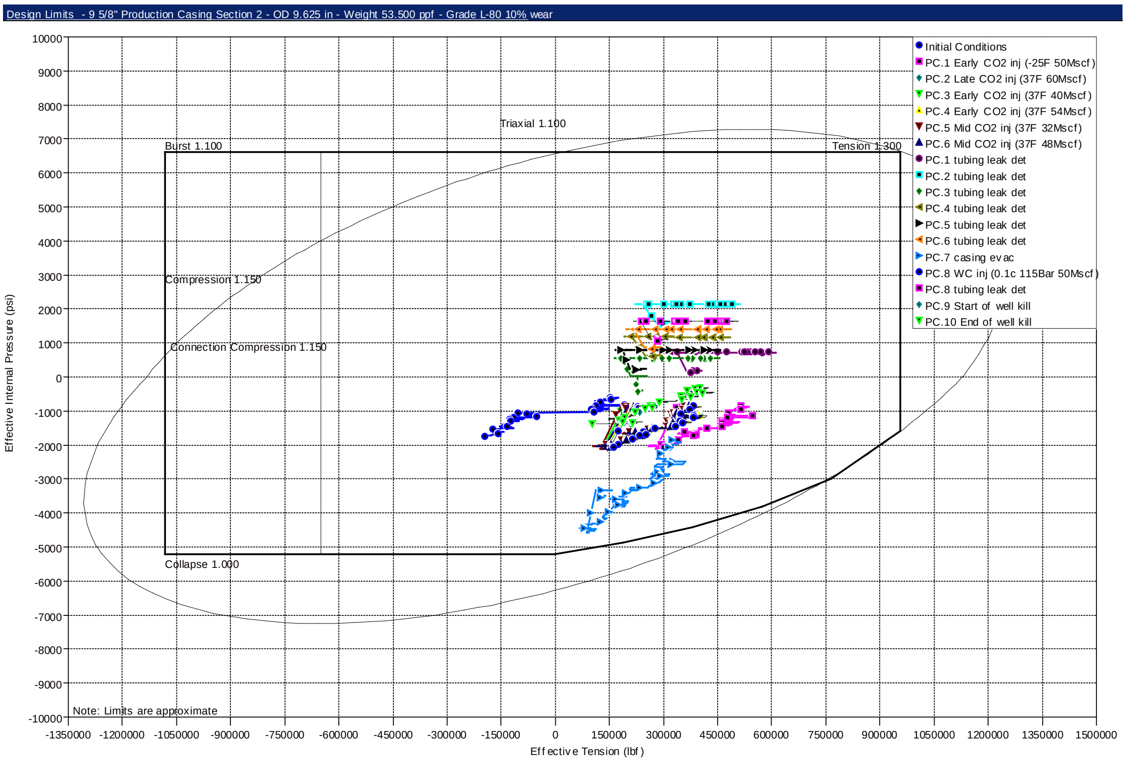
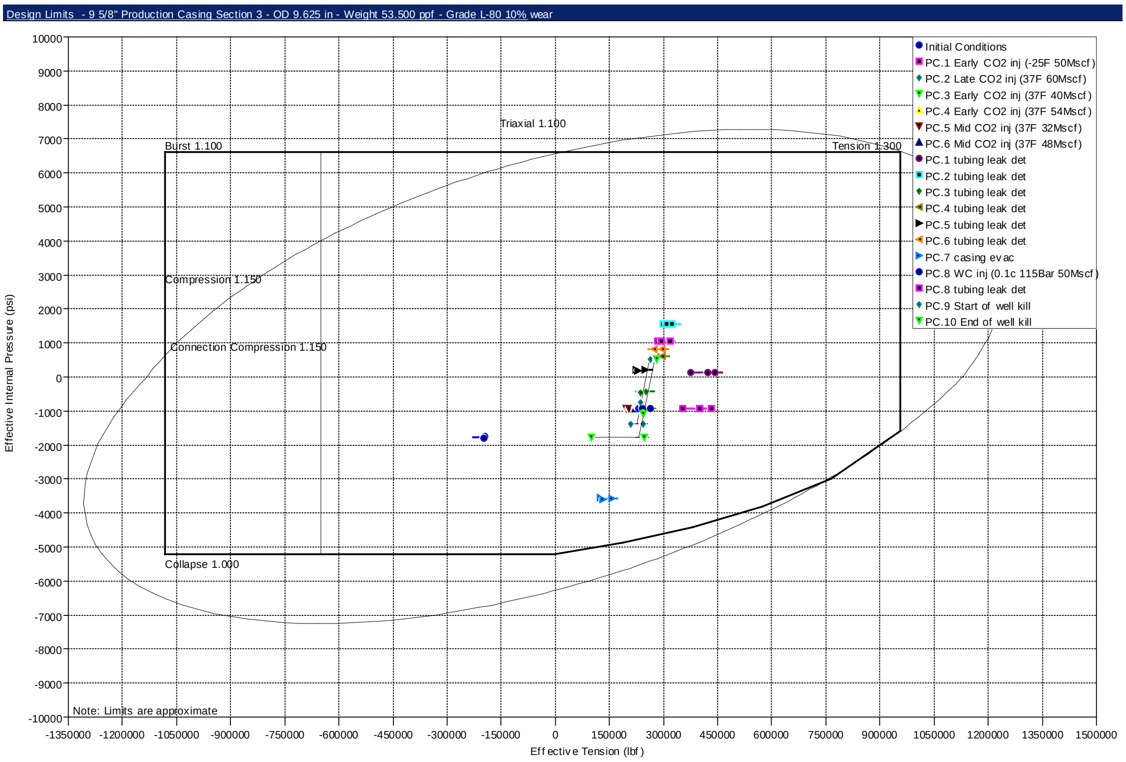


Table 8-7: 9 5/8" Section – Surface Casing (below packer)



A1.5.Minimum Safety Factors - Surface Casing

	TRIAXIAL SAFETY FACTOR	BURST SAFETY FACTOR	COLLAPSE SAFETY FACTOR	AXIAL SAFETY FACTOR
Initial Conditions	6.45 @ 754.6 ft	80.07 @ 539 ft	5.7 @ 4153.9 ft	5.47 @ 4153.9 ft (C)
SC.1 Early CO_2 inj (-25F 50Mscf)orig/det	3.19 @ 754.6 ft	6.35 @ 4153.9 ft	---	2.42 @ 702.9 ft (T)
SC.2 Late CO_2 inj (37F 60Mscf)orig/det	4.29 @ 754.6 ft	6.35 @ 4153.9 ft	---	3.42 @ 702.9 ft (T)
SC.3 Early CO_2 inj (37F 40Mscf)orig/det	4.31 @ 754.6 ft	6.35 @ 4153.9 ft	---	3.44 @ 702.9 ft (T)
SC.4 Early CO_2 inj (37F 54Mscf)orig/det	4.29 @ 754.6 ft	6.35 @ 4153.9 ft	---	3.42 @ 702.9 ft (T)
SC.5 Mid CO_2 inj (37F 32Mscf)orig/det	4.32 @ 754.6 ft	6.34 @ 4153.9 ft	---	3.45 @ 702.9 ft (T)
SC.6 Mid CO_2 inj	4.3 @ 754.6 ft	6.35 @ 4153.9 ft	---	3.42 @ 702.9 ft (T)

(37F 48Mscf)orig/det				
SC.7 WC inj (p15) orig/orig	4.09 @ 754.6 ft	6.35 @ 4153.9 ft	---	3.19 @ 702.9 ft (T)
SC.8 WC inj (p15) orig/det	3.97 @ 754.6 ft	---	4.93 @ 4153.9 ft	3.29 @ 702.9 ft (T)
MINIMUM SAFETY FACTORS	3.19	6.34	4.93	2.42

Notes: These are all CO_2 load cases - early, midterm, and late injection cases.

WC above is "Worst Case" - actually CO_2 injection rates with the design rate being 50 MMscf/day at 115 bar wellhead pressure with a wellhead inlet temperature of 0.1 °C. p15 refers to the thermal load case modelled in PROD.

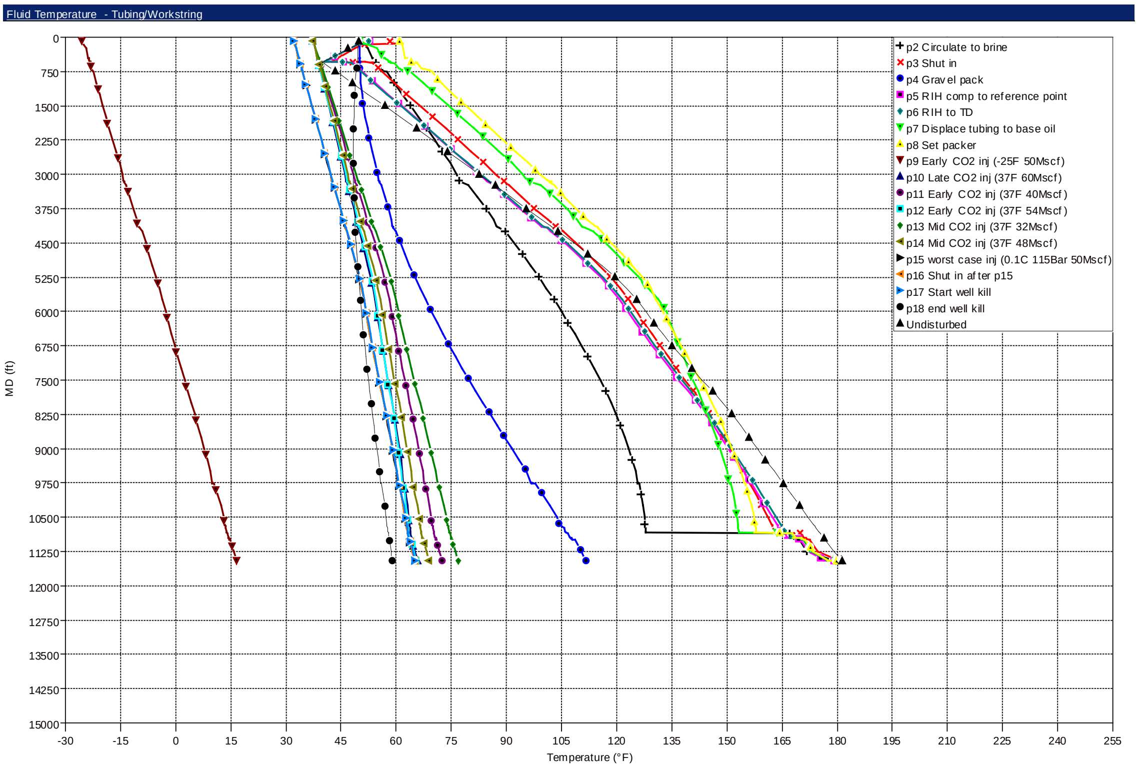
A1.6.Minimum Safety Factors - Production Casing

	TRIAXIAL SAFETY FACTOR	BURST SAFETY FACTOR	COLLAPSE SAFETY FACTOR	AXIAL SAFETY FACTOR
Initial Conditions	4.08 @ 754.6 ft	---	2.95 @ 10989.9 ft	3.29 @ 10891 ft (C)
PC.1 Early CO_2 inj (-25F 50Mscf)	1.83 @ 4256.9 ft	---	2.32 @ 9767.9 ft	1.96 @ 754.6 ft (T)
PC.2 Late CO_2 inj (37F 60Mscf)	2.3 @ 4256.9 ft	---	2.43 @ 9767.9 ft	2.51 @ 754.6 ft (T)
PC.3 Early CO_2 inj (37F 40Mscf)	2.34 @ 4256.9 ft	---	2.43 @ 9767.9 ft	2.56 @ 754.6 ft (T)
PC.4 Early CO_2 inj (37F 54Mscf)	2.3 @ 4256.9 ft	---	2.43 @ 9767.9 ft	2.51 @ 754.6 ft (T)
PC.5 Mid CO_2 inj (37F 32Mscf)	2.36 @ 4256.9 ft	---	2.43 @ 9767.9 ft	2.58 @ 754.6 ft (T)
PC.6 Mid CO_2 inj (37F 48Mscf)	2.32 @ 4256.9 ft	---	2.43 @ 9767.9 ft	2.53 @ 754.6 ft (T)
PC.1 tubing leak det	1.86 @ 754.6 ft	8.35 @ 80.1 ft	17.33 @ 10989.9 ft	1.73 @ 754.6 ft (T)
PC.2 tubing leak det	2.06 @ 754.6 ft	2.77 @ 80.1 ft	---	1.93 @ 754.6 ft (T)
PC.3 tubing leak det	2.36 @ 754.6 ft	10.9 @ 80.1 ft	11.98 @ 10989.9 ft	2.21 @ 754.6 ft (T)
PC.4 tubing leak det	2.3 @ 754.6 ft	5.06 @ 80.1 ft	---	2.07 @ 754.6 ft (T)

PC.5 tubing leak det	2.39 @ 754.6 ft	7.65 @ 80.1 ft	24.13 @ 10989.9 ft	2.19 @ 754.6 ft (T)
PC.6 tubing leak det	2.27 @ 754.6 ft	4.26 @ 80.1 ft	---	2.05 @ 754.6 ft (T)
PC.7 casing evac	1.42 @ 9767.9 ft	---	1.12 @ 9767.9 ft	2.91 @ 754.6 ft (T)
PC.8 WC inj (0.1c 115Bar 50Mscf)	2.26 @ 4256.9 ft	---	2.42 @ 9767.9 ft	2.46 @ 754.6 ft (T)
PC.8 tubing leak det	2.17 @ 754.6 ft	3.63 @ 80.1 ft	---	1.97 @ 754.6 ft (T)
PC.9 Start of well kill	2.27 @ 754.6 ft	13.89 @ 10989.9 ft	3.69 @ 10934 ft	2.32 @ 754.6 ft (T)
PC.10 End of well kill	2.28 @ 754.6 ft	13.92 @ 10989.9 ft	2.84 @ 10934 ft	2.34 @ 754.6 ft (T)
MINIMUM SAFETY FACTORS	1.42	2.77	1.12	1.73

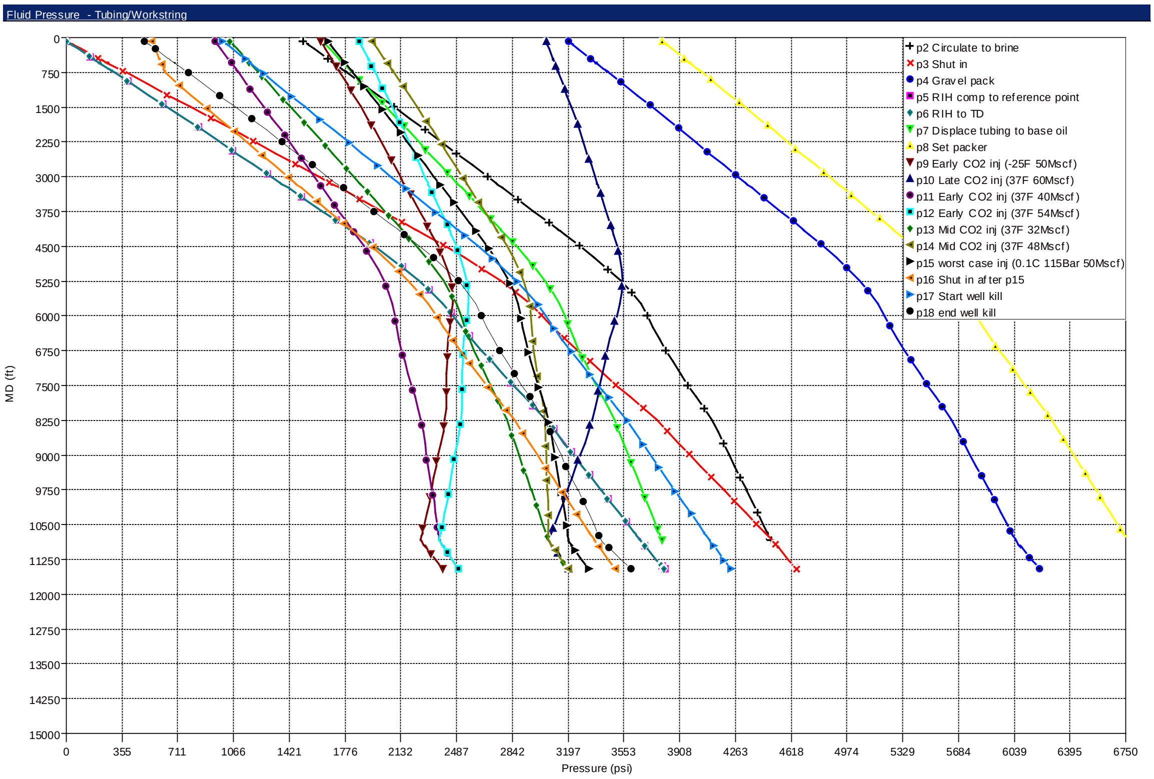
A1.7.Production Temperature Predictions

Table 8-8: Production Temperature Predictions



A1.8.CO_2 Injection Pressures

Table 8-9: CO_2 Injection Pressures



APPENDIX 2. SACROC Conclusions

The Portland cement recovered from a 55-year old well with 30 years of CO_2 exposure showed evidence of exposure to CO_2 in the form of carbonate precipitate adjacent to the casing and heavily carbonated, orange-coloured cement adjacent to the shale cap rock. However, the structural integrity of the recovered cement core, petrographic observations, air permeameter data, and cement bond log indicate that the cement retained its capacity to prevent significant transport of fluid through the cement matrix. Observations and numerical calculations suggest that the CO_2 producing the orange CO_2 alteration originated by movement from the reservoir along the shale-cement interface. The CO_2 producing a carbonate precipitate at the casing-cement interface may have originated by migration along the casing interface from the reservoir or from the interior of the well at casing joints or regions of casing corrosion.

Numerical modelling shows that carbonation induced by diffusion of CO_2 - saturated brine reproduces key features of the SACROC cement core. We used observations of the core to constrain the porosity, tortuosity, and reaction rates used in the modelling to values appropriate to well 49-6 at SACROC.

Additional samples would be necessary to construct a more generally applicable model of CO_2 - induced cement degradation. The observations demonstrate that Portland cement can retain its integrity at least over decades in a CO_2 reservoir with conditions similar to SACROC. Numerical calculations are consistent with a slow rate of degradation by diffusive attack of CO_2 that would allow a thick column of cement to survive for long periods of time. However, the observations also show that CO_2 migrated along the casing-cement and shale-cement interfaces for some period of time. We were unable to quantify the amount of CO_2 migration that may have occurred along these interfaces. The integrity of these interfaces appears to be the most critical issue in wellbore performance for CO_2 sequestration.

The cement core recovered at SACROC provides some help in understanding the experimental variability in studies of cement carbonation at reservoir conditions. The laboratory experiments of Duguid et al. 2005 (15) investigated cement deterioration under conditions of flowing CO_2 - saturated brine and they observed rapid degradation and loss of structural integrity within weeks of exposure. The SACROC sample clearly did not experience a similar flux of acidic brine. This indicates that for properly completed wells, the cement– cap rock interface does not experience flowing CO_2 - saturated brine and the rapid cement decomposition observed by Duguid et al. 2005 (15) is unlikely to occur. In contrast, the experiments of Barlet-Gouedard et al. 2006 (5) and Kutchko et al. (2006b) (16) were conducted with a static volume of brine subject to high CO_2 pressure. Barlet-Gouedard et al.'s experiments were conducted at 90 °C and 28 MPa, and they observed rapid penetration of CO_2 and complete carbonation within 6 weeks. Their porosity and mechanical strength studies showed that the cement appears to retain significant hydrologic integrity but had clearly been substantially altered. Kutchko et al.'s experiments were conducted at 50 °C and 30 MPa and showed very limited (slow) penetration of CO_2 after 9 days (and after 3 months as presented in Kutchko et al., 2006a) (17). The SACROC cement samples (exposed to CO_2 at 54 °C and 18 MPa) showed rates of carbonation more compatible with the experiments of Kutchko et al., which may reflect the more similar temperatures of CO_2 exposure. However, it also possible that the amount of CO_2 exposure for the SACROC samples at 3 m above the reservoir contact was more limited. The time and conditions for cement curing times prior to CO_2 exposure is another important variable: SACROC at 35 years (54°C) compared to Kutchko et al. at 28 days (22 and 50°C) and Barlet-Gouedard et al. at 2 days (90°C). In any case, both the Barlet-Gouedard et al. and Kutchko et al. Studies are consistent with cement retaining hydrologic integrity in a CO_2 -rich environment, although the results of Barlet-Gouedard et al. indicate that CO_2 - induced cement degradation in higher temperature reservoirs may be of greater concern. The SACROC core in combination with the available experimental data allows some preliminary conclusions regarding wellbore integrity and CO_2 storage. These studies indicate that Portland cement based wellbore systems, if properly completed, can prevent significant migration of CO_2 from reservoirs for long periods of time (at least decades). A properly completed well need not be completely free of defects, but should not have continuous openings along either the cement-casing or cement–caprock interfaces that might permit a CO_2 – brine mixture to flow that could dissolve cement and further widen the interface. The key variables appear to be the initial width and connectivity of the interfaces in addition to the pressure gradient driving flow from the reservoir. Future work to develop and strengthen these conclusions should include collecting additional core to understand whether the observations at well 49-6 are unique or typical at SACROC and to explore the significance of differing caprock and reservoir chemistries as well as differing operational histories. These studies could improve on our work by obtaining fluid samples to better constrain the geochemistry and collecting samples at multiple intervals to determine the maximum extent of carbonation. In addition, more experimental studies are needed to help interpret the field observations. These should focus on the evolution of cement-casing and cement–caprock interfaces as a function of initial interface width/quality and the CO_2 - brine flux. Observations at SACROC suggest that under limited flux the interfaces may be self-sealing. Determining the conditions under which these interfaces become more transmissive with time remains a key unknown in evaluating the longevity of the Portland cement seal in wellbore systems.

APPENDIX 3. Goldeneye CO_2 Delivery

CO_2 for injection will be captured at Peterhead Power Station. Capture technology is expected to deliver CO_2 at 99.982% purity.

The significance of this CO_2 purity is the absence of carbonic acid in the injection wells during the CO_2 injection phase.

Later in the life of the wells, after the injection phase, reservoir dynamics such as gravity, miscibility and reactions with downhole formations, will mean carbonic acid will reappear at the base of the cement in the Goldeneye wells.

CO_2 will be supplied in a supercritical state, that is, it will be supplied compressed to such a pressure that it behaves comparable to a liquid, and will be injected into the reservoir down one or more of the existing Goldeneye wells. The supplied CO_2 will have been dried - water removed, to prevent possible corrosion in pipeline and corrosion in the injection well.