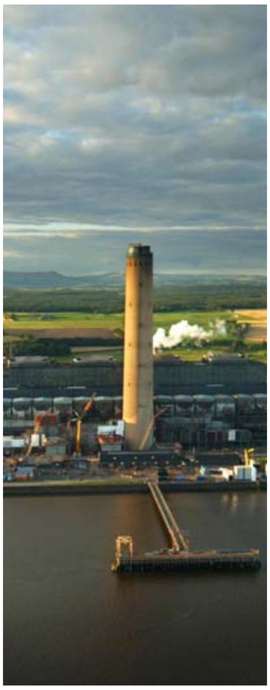

UK Carbon Capture and Storage Demonstration Competition

UKCCS - KT - S7.16 - Shell - 004

Well Proposal

April 2011

ScottishPower CCS Consortium

SCOTTISHPOWER nationalgrid

Carbon Capture & Storage Consortium

UK Carbon Capture and Storage Demonstration Competition

UKCCS - KT - S7.16 - Shell - 004

Well Proposal

April 2011

ScottishPower CCS Consortium

ScottishPower Generation Limited
Longannet Power Station
Kincardine on Forth
Clackmannanshire
Scotland

ScottishPower Consortium UKCCS Demonstration Competition: Knowledge Transfer

KEYWORDS

Goldeneye, CO_2, .

Produced by Shell U.K. Limited

ECCN: EAR 99 Deminimus

IMPORTANT NOTICE

Information provided further to UK Government's Carbon Capture and Storage ("CCS") competition to develop a full-scale CCS facility (the "Competition")

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1. Executive Summary

Editor's note:

This document was previously issued at Revision K01. It has been revised to Revision K02 following the outcome of an internal Shell technical review and approval exercise held in early March 2011. Changed sections are marked in yellow. The main revisions relate to better definition and expression of clarity regarding the extent of the proposed well arrangements, together with further detail resulting from developments in the design. Two figures have been replaced in order to provide greater clarity

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The purpose of this well proposal is to provide enough information to allow planning of the well work required. At this stage of the project the document is not definitive. Once the project has reached a suitable level of maturity, it is expected that the document will be re-worked.

The Goldeneye CCS project plans to store 20 million tonnes of CO_2 in the depleted Captain Sandstone reservoir of the Goldeneye field.

In order to convert the wells from hydrocarbon production to CO_2 injection, all five existing production wells are to be worked over and re-completed. The workovers will replace the upper completion tubing with a smaller size in order to allow injection of dense liquid phase CO_2 into the storage reservoir, re-completed wells can also be used for monitoring functions if not in use for CO_2 injection. Should workover of any well prove to be unsuccessful, the motherbore will be sidetracked. The technical requirements for such a sidetrack are also described in this document.

Well work is expected to start in early-mid 2014 and will also replace completion elements which could lead to integrity problems under CO_2 service. CO_2 injection is planned to begin in late 2014.

The Goldeneye area wells have been reviewed. Neither the Goldeneye area E&A wells nor the Goldeneye platform wells have any known integrity issues.

The document includes the latest (Q1 2011) details on the following:

- completion / re-completion technical detail
- risks
- hazards and uncertainties
- programme outline
- geological prognosis
- notional target locations
- reservoir pressure
- pore pressure
- well engineering design

2. Background

The Goldeneye field consists of a normally unmanned platform with five development wells. The wells were drilled by batch drilling with a jack-up rig in late 2003 - early 2004. The platform / production wells are all very similar and were drilled with the same casing design and casing-shoe formations. A number of options for converting this existing infrastructure to operate with CO_2 are being considered[1]. Two of these options are relevant for the technical content of this report.

- Workover all of the existing Goldeneye wells to make them suitable for CO_2 injection and long term monitoring, which is currently the base case.
- Sidetrack an existing well from the Goldeneye platform in case it should become necessary to change the location of a CO_2 injection well because of mechanical or near well bore damage to the original well bore or to optimise the location for a monitoring well.

Workover of the existing Goldeneye wells to make them suitable for CO_2 injection and long term storage monitoring is the current base case scenario for Goldeneye CCS.

[1] Shell, 2010. Well programme-Draft

3. Objectives

The objectives of the well workovers and possible sidetrack are as follows:

- Workover and recomplete wells with no harm to people or the environment through compliance with Shell Goal Zero standards
- Workover / Recomplete wells in order that they may collectively inject ~34 Million scf/d CO_2 minimum - ~115 Million scf/d maximum into the reservoir in dense liquid phase
- Re-complete the wells in order that they may monitor downhole pressures and temperatures to detect the arrival of the CO_2 plume
- In the event that a well becomes unusable for any reason, it will be sidetracked to allow completion of the CO_2 injection programme
- If a well is sidetracked, the opportunity will be taken to obtain a core from the caprock. This is to collect material for geomechanical analysis, to constrain models of caprock fracturing.

4. Introduction

4.1. Overview

The well proposal document describes the well objectives, critical success factors, data gathering and recovery plan for the well interventions and includes a potential drilling outline for the base case Goldeneye storage operations. The document also includes an outline of a sidetrack that would be required in the event of mechanical failure of a workover. The example given here pertains to well GYA05 but similar processes would be followed to sidetrack any of the injection wells that had been compromised. **The specific needs and expectations of the well will be captured in Well Technical Specification and Well Functional Specification documents to be generated during the Detailed Design and Execute phases of the project**

The Well Proposal document captures the following information:

- Well type & locations (definition of well coordinates (surface / subsurface), review well trajectory and deviation, and subsequent monitoring of the well), identify unstable formation areas and current stress regime, overpressures and shallow hazards (geohazards), including shallow gas.
- Description of overburden geology, determine fault locations & depth prognoses in overburden and reservoir.
- Prognosis of detailed stratigraphy on the basis of offset wells (including geohazards) and to include (picking core points / reservoir tops / casing settings / TD).
- Potential for H_2S and CO_2 presence, define overburden pressure & fracture gradient prediction for wells.
- Specific production requirements (*e.g.*, artificial lift modelling).
- List of well data requirements (*i.e.*, logs, cores, cuttings, pressure data *etc.*), incorporate into data acquisition plan.
- Ensure appropriate use of seismic data is made in the definition of the above information.
- Duty cover for relevant activities and ensure full set of offset data is available to duty personnel.

This will be the official set of data for the well. The document must ensure that the proposed well meets business planning objectives and that all contributions from the petroleum engineering and geology disciplines are included. It also acts as the official set of data for the well - collected together in one controlled and approved place. It is designed to encourage close cooperation between all subsurface disciplines and to ensure that all HSE aspects are addressed. It provides input to Regulatory / Government Well Site Permitting & Environmental Permitting.

At the present stage of project maturation (prior to the compilation of the SDP), it is only possible to give an outline proposal with indicative costs and technical data. It is only when final drilling targets, pressure and temperature modelling, well modelling, casing reviews, *etc.*, have been fully evaluated that more detailed planning will be undertaken and proposals produced for all of the well completion / drilling work identified.

4.1.1. Basic Well Data

The Base Case is to perform workovers to allow CO_2 injection. There is a sidetrack option which is provisionally planned to sidetrack at around the depth of the Hod formation (~7,000 ft [2134 m] TVDSS) of the Chalk Group (see Figure 5-1, Stratigraphic Column), though the precise depth will depend upon the depth of the mechanical failure that is to be mitigated.

Goldeneye reservoir is made up by a 3-way dip closure and stratigraphic pinch-out to the North.

Reservoir top seal is provided by the Upper Valhall Member & Rødby Formation – both part of the Cromer Knoll Group – and the Hidra Formation and Plenus Marl Bed – both part of the Chalk Group.

The properties of the storage facility, Goldeneye reservoir, are well understood, comprised of the Captain Sandstone with average porosity and permeability values of 25% and 790 mD respectively. The strong aquifer in the area extends east-west along the Captain trough, the area where Captain Sandstones have been deposited.

4.1.1.1. Operator

Shell U.K. Limited
Shell Centre,
London
SE1 7NA

4.1.1.2. Location

Central Meridian	0^0
Projection:	Transverse Mercator
Spheroid:	International 1924
Datum:	D European 1950
Transformation EPSG Code	1311
Surface Co-ordinates	Lat 058 deg 00' 09.213" N
	Long 000 deg 22' 47.334" W
TD Formation:	Captain Sandstone, Lower Cretaceous
Planned Total Depth Of Well:	8,636 ft [2632 m] MDBRT (8,471 ft [2582m] TVDSS)
Target 1: Depth (Top Captain C Sst):	8,256 ft TVDSS
Projected Co-ordinates :	6 429 181.7 mN
	477 539.9 mE
Geological Target Size & Shape:	25 m radius circle
Target 2: Depth (Top Captain C Sst):	8,471 ft [2582 m] TVDSS
Target Co-ordinates :	6 429 181.7 mN
	477 539.9 mE
Geological Target Size & Shape:	25 m radius circle

Miscellaneous Data

Principal Offset Wells:	Goldeneye Platform wells were drilled in 2003 / 2004. Data available.
Other Offset wells:	14/29a-3 (1996 discovery well), 14/29a-5, 20/4b-6 and 20/4b-7 (appraisal wells all drilled 1997 - 1999).

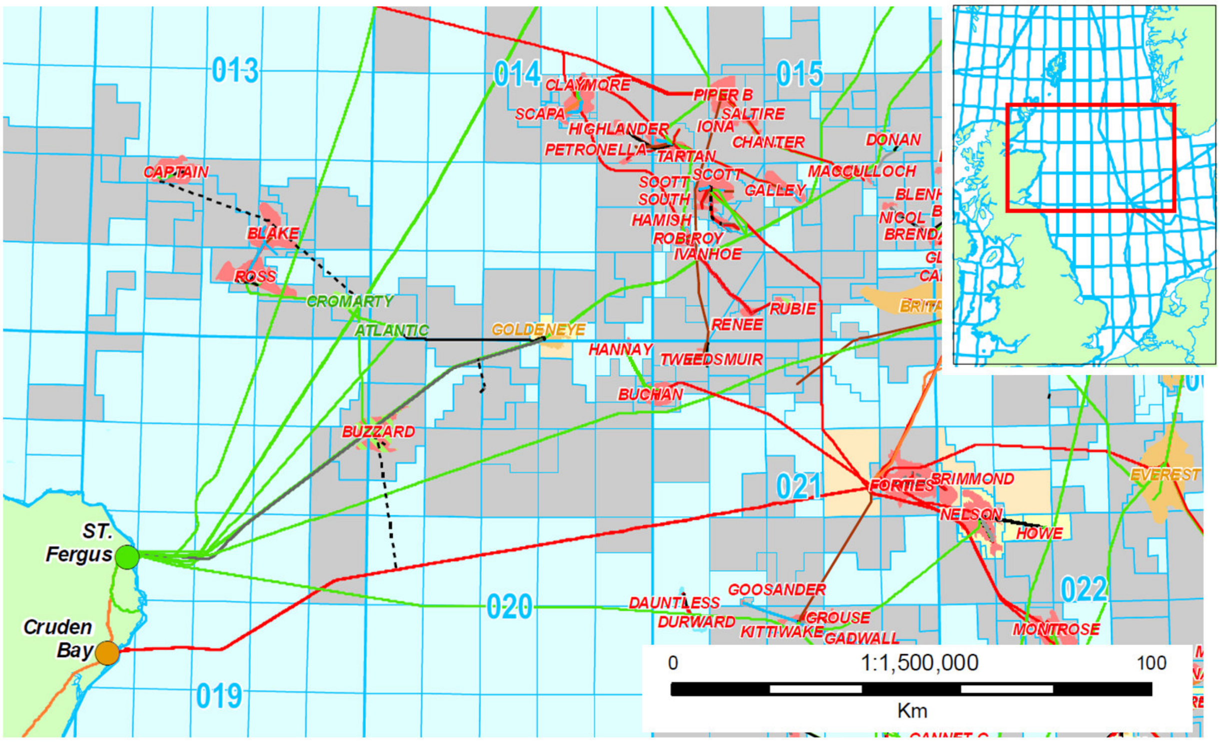


Figure 4-1 Location Map for Goldeneye Field, Central North Sea

4.1.1.3. Sidetrack Prospect from Goldeneye - Data

Quadrant/Blocks:	14/29a, 14/28b, 20/4b and 20/3b
Licence Number:	N/A (would be new CO_2 Storage licence), currently HC production licence P257, P732, P592 and P739
Prospect Name:	Goldeneye CCS (e.g. GYA05-S1)
Licence Operator:	Shell U.K. Limited Shell Centre, London SE1 7NA
Well Operator:	Shell U.K. Limited Shell Centre, London SE1 7NA
Partners %:	Shell (X %) CO_2 Deepstore (Y %) Others (Z %)
Well Classification:	Development (Deviated) converted to CO_2 injection / monitoring
Proposed Spud Date:	Early-Mid 2014

Rig Data

Rig Name:	TBA - Heavy Duty Jackup
Drilling Contractor:	To be advised
Depth Measurement (ft/m):	ft
Datum:	Mean Sea Level (MSL)
Rig Datum Elevation:	To be advised
Water Depth:	395 ft (120 m)

5. Geological Information

5.1. Introduction

A stratigraphic column for the Goldeneye area is shown in Figure 5-1.

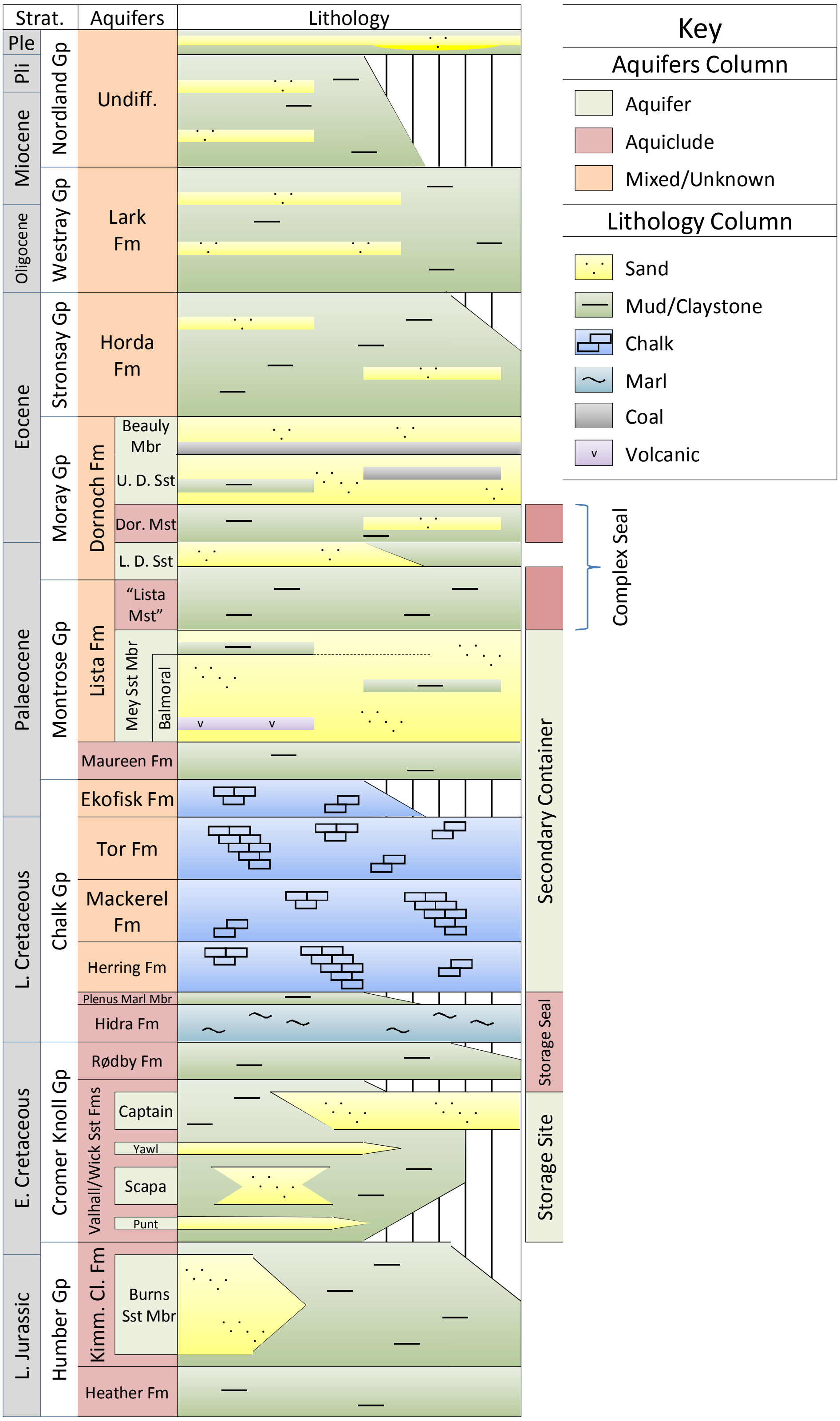


Figure 5-1 Stratigraphic Column for Goldeneye Area

5.1.1. Sidetrack

The purpose of a sidetrack would be to allow injection or monitoring of dense liquid phase CO_2 within the storage reservoir, as required.

A notional sidetrack example from well GYA05 has been designed which penetrates the storage reservoir at a crestal injection location (8,256 ft [2516m] TVDSS - 2,516 m). The location, kick-off point and structural setting of the sidetrack well trajectory are shown in figures 5-2 and 5-3. As can been seen, the sidetrack would kick-off in the Hod Formation of the Chalk Group at ~7,040 ft TVD SS. The notional sidetrack is designed to penetrate the entire Captain 'E' and 'D' reservoir sandstone stratigraphy down to Top Captain 'C' level (8,471 ft [2582m] TVDSS).

5.1.2. Workover

For the well workovers, no new stratigraphy will be drilled, hence a discussion of geology and geophysical data is not required. A general overview of the geological setting however, is described below.

5.2. Structural Setting

5.2.1. Regional

The Goldeneye field is a combined structural and stratigraphic trap within the Lower Cretaceous Captain Sandstone Member of the South Halibut Trough, Outer Moray Firth. It is proximal to the site of other hydrocarbon fields such as Cromarty, Atlantic, Blake, Captain and Hannay, which were all discovered between 1977 and 1997. All of these fields produce from the Lower Cretaceous Captain reservoir which was deposited predominantly west-east along the Captain Fairway in a submarine base of slope turbidite environment.

5.2.2. Reservoir

Three-way structural dip closure of the reservoir exists to the east, south and west. Stratigraphic pinch-out of the reservoir sands occurs to the north. Top seal is provided by the Upper Valhall Member & Rødby Formation – both part of the Cromer Knoll Group – and the Hidra Formation and Plenus Marl Bed – both part of the Chalk Group.

5.3. Reservoir Characteristics

5.3.1. Primary Target - The Captain Formation Sandstones

The sand-rich reservoir section can be subdivided into 4 lithostratigraphic units, from top to base Units E, D, C and A. Units C-E can be correlated across Goldeneye, with Unit 'C' representing a field-wide shale-rich horizon. In contrast, Unit A occurs only in wells 14/29a-3 and 14/29a-5 and appears to be controlled by the fault geometry at base Captain Sandstone level. These units can be further subdivided into discrete genetic flow units that are not correlatable between wells.

The five producing wells within the structure are all completed within the same reservoir unit, the Captain D sand. The production history from these wells shows no evidence of compartmentalisation within this unit. This conclusion is supported by the Operator's geochemical investigation into recovered gas condensate samples, which shows a constant geochemical fingerprint across field.

The average porosity of the Captain D reservoir is 25% and the average permeability is 790 mD. Average net-to-gross is 0.94.

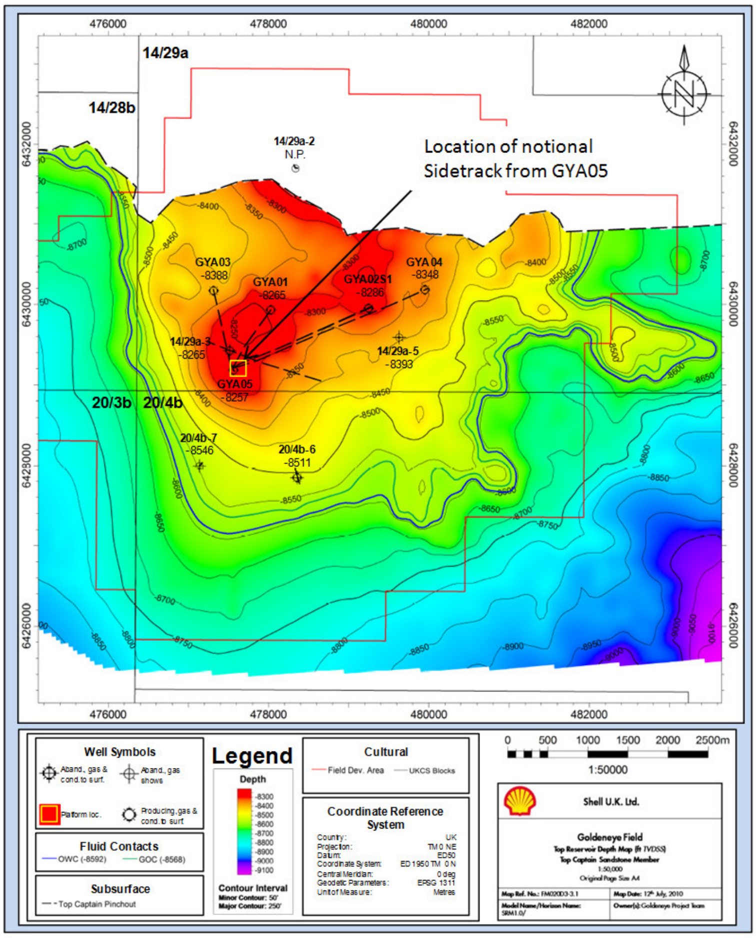


Figure 5-2 **Map to show the location and trajectories of existing appraisal and development wells in the Goldeneye field.**

5.3.2. Reservoir Fluid Characteristics

The field is a gas condensate field with a thin oil rim and was originally fill-to-spill. It has been in production since 2004. The new CO_2 storage project is not planned to fill the Captain reservoir at Goldeneye location to the spill point (dynamic reservoir studies have confirmed this).

Table 5-1 Reservoir Fluid Properties

Type	Sandstone
Reservoir Fluid Type	Gas Condensate + Oil + Brine/Formation Water
Formation temperature	~83°C
	Reduction of temperature around the injectors due to cold CO_2 injection (~17 to 35°C bottomhole injection temperature)
	Reference Case: 20°C
Formation Water	Present
	Water will initially be at the sandface.
	Formation water around the wellbore will reduce significantly after 1 to 3 months of CO_2 injection.
	Water Gradient 0.4408 psi/ft
Average Reservoir (Captain D) Porosity and Permeability	~25% porosity / 790 mD permeability
Pressure Regime	An active edge drive aquifer supports the field.
	Variable reservoir pressures with time and injection (Current 2010 pressure is ~2,000 psi - 138 bar). Datum 8400 ft [2560 m] TVDSS
	Pressure Gradient Range (For reservoir pressure of 2,750 psi - 0.34 psi/ft)
	Minimum expected reservoir pressure before CO_2 injection - 2,750-3,000 psia - 190-207 bar. Reference Case: 2,850 psi (197 bar). Datum 8400 ft [2560 m] TVDSS (~Year 2014)

5.4. Formation Tops

The Base Case is to perform a workover to allow CO_2 injection. There is a sidetrack option but this is expected to sidetrack at around the depth of the Hod formation of the Chalk Group. Hence, the formation information given here details only this stratigraphy downwards.

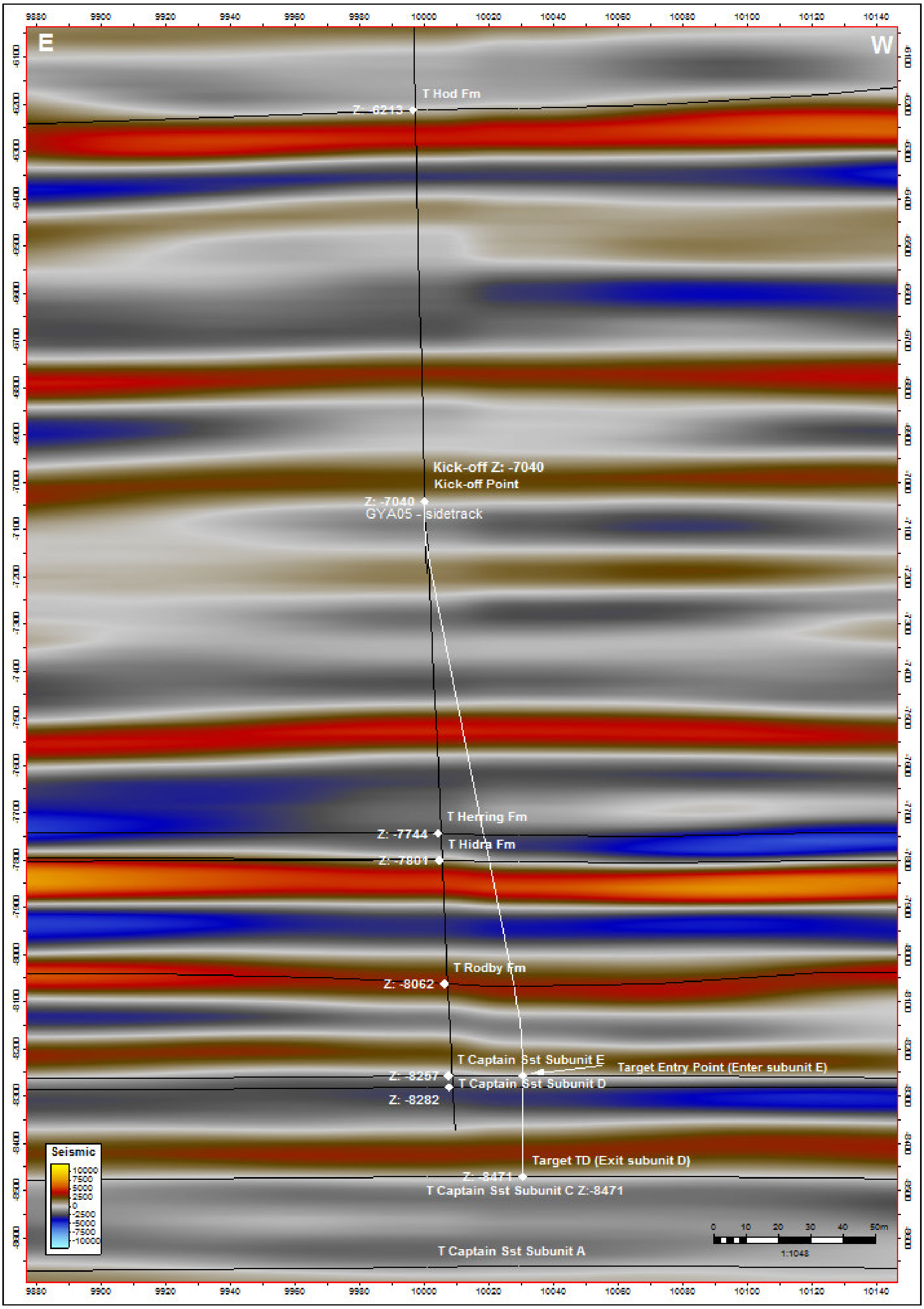


Figure 5-3 **Seismic well section (reservoir) for GYA05 sidetrack trajectory**

Table 5-2 Prognosed well tops for GYA05 sidetrack

Horizon/Surface	X	Y	Z/TVDSS (ft)	MD	Dip Angle	Dip Azimuth
Top Herring Formation	477551.8	6429178.9	-7746.86	7909.57	7.93	340.04
Top Plenus Marl Formation	477550.2	6429179.3	-7804.07	7967.04	7.96	336.03
Top Hidra Formation	477550.2	6429179.3	-7804.23	7967.2	8.15	336.74
Top Rodby Formation	477542.7	6429181.1	-8066.71	8230.87	2.77	81.81
Top Captain Sandstone/Subunit E	477539.9	6429181.7	-8255.97	8420.45	0.88	1.8
Top Captain Subunit D	477539.9	6429181.7	-8280.59	8445.07	0.66	40.13
Top Captain Subunit C	477539.9	6429181.7	-8470.71	8635.18	2.01	5.33

5.4.1.1. Hod Fm. - Herring Fm. interval (Chalk Group) (7,040 - 7,804 ft TVDSS, 2,146 - 2,379 m)

This interval will consist of limestone and chalks with localised claystones. There is a limited possibility of Chert, trace samples were seen in one of the offset wells.

The Hod Formation is predominantly composed of an off white to light grey limestone with pink and medium grey colouration appearing towards the base. Throughout the formation, there are intermittent beds of medium to dark grey claystone.

> Limestone: white - off white, occasional light grey - pale pink, firm-medium hard, brittle, splintery in places, sub blocky-blocky, micaceous crystalline, no visible porosity

The Herring Formation is chalk.

> Limestone: light grey - medium grey, occasional white - off white, occasional pale pink, firm-medium hard, sub blocky-blocky, splintery in places, micaceous crystalline

5.4.1.2. Plenus Marl Bed - Rødby Fm. interval (7,804 - 8,256 ft TVDSS, 2,379 - 2,516 m)

This interval will consist mainly of mudstone, limestone and claystone. In this section ROP can increase.

The Plenus Marl is sometimes called the 'Black Band Bed'. It is a marl.

> Claystone: Dark grey to medium grey, pale red brown in parts, firm to moderately hard, non calcareous (dark grey, medium grey), soft to firm, calcareous (pale red brown), sub-blocky to blocky, amorphous, occasionally plastic, grading to limestone / chalk.
>
> Limestone: Light grey to off white, pale pink to whitish in parts, firm to moderately hard, occasionally soft, sub-blocky to blocky, argillaceous in parts, brittle, occasionally amorphous, grading into marl.

The Hidra Formation is predominantly composed of limestone, interbedded with occasional layers of claystone.

> Limestone: Light grey, pink, creamy, orange to red, firm to moderately hard, blocky, occasionally very argillaceous, locally grading to claystone.
>
> Claystone: Black, occasionally light green, soft to firm, sub-blocky to blocky, silty in parts.

Rødby formation is composed of a calcareous grey and brown mudstone. Within the formation, there are intermittent beds of argillaceous limestone.

Limestone: pale reddish brown to brick red, light grey to medium grey, off white in parts, firm to moderately hard, occasionally soft, amorphous, occasionally brittle, argillaceous, sub-blocky to blocky, microcrystalline, grading to marl and mudstone.

Claystone: medium grey to dark grey, reddish brown to brick red, light grey in parts, occasionally black, olive grey, occasionally dark grey, red brown, firm to moderately hard, occasionally soft, plastic in part, sub-blocky to blocky, occasionally amorphous, splintery in parts, brittle, very calcareous.

5.4.1.3. Captain Sandstone Mbr. interval (reservoir section, 8,256 - 8,471 ft TVDSS, 2,516 - 2,582 m)

The target Captain reservoir interval is divided into three units - Captain 'E', 'D' and 'C' - with 'E' being the shallowest. This interval consists of mass flow sandstone with interbedded mudstone and siltstone. The reservoir rock has reasonably high fracture strength but is highly permeable in certain zones. Incorrect total depth (TD) pick, losses, and differential sticking are the main areas of risk while drilling this section. However, the offset wells were drilled without losses or sticking.

This formation consists predominantly of medium to coarse sandstone in the upper and middle part of the unit and very fine to fine sandstone in the lower part of the unit and minor occurrences of claystone.

Sandstone: Clear, transparent to translucent, medium to fine, occasionally coarse, very fine to fine and silty towards the end of the reservoir, sub-angular to sub-rounded, sub-spherical, moderately to well sorted, predominantly loose quartz grains, occasionally cemented grains, siliceous cement in parts, cemented grains are moderately hard, traces of glauconite, good intergranular porosity, spotty direct yellow fluorescence.

Claystone: Grey brown to reddish brown, light to medium grey, dark grey in parts, firm to moderately hard, occasionally soft, plastic in part, sub-blocky to blocky, silty, calcareous.

TOTAL DEPTH

8,636 ft [2632m] MD RKB / 8,471 [2582m] TVD SS

5.5. Stratigraphy and Pressure Gradients

The Base Case is to perform a workover to allow CO_2 injection. There is a sidetrack option but this is expected to sidetrack at around the depth of the Hod formation of the Chalk Group. Hence the Formation information given here covers only that stratigraphy downwards.

Pressure regime in the Goldeneye area is hydrostatic. For the present-day depleted Goldeneye reservoir, the pressure regime is shown below.

A thorough review of 17 wells in the area of the Goldeneye Field indicated that the lowest mud weights used to drill the stratigraphic sequence from the seabed to TD (Total Depth) in the Permo-Triassic sequence ranged from 0.447-0.520 psi/ft, indicating a relatively low pore pressure regime compared to other parts of the North Sea.

The drilling data showed indications of pore pressure above hydrostatic pressure in the Tertiary mudstones (0.480 psi/ft), which is similar to the range of RFT (Repeat Formation Test) data from the AOI (Area of Interest) which ranged from 0.475-0.500 psi/ft. Both the Chalk Group and

Cromer Knoll Group sequence appear hydrostatically pressured, supported for the latter by the consistency in Goldeneye well RFT data. The deeper Jurassic to Permian sediments encountered in the Goldeneye Field appear normally pressured based on drilling and RFT data, however, the Kimmeridge Clay Formation is under compacted relative to the general mudstone compaction trend, which indicates possible overpressure. This is supported by the kick that occurred in well 20/4b-4 from a sand unit within the Kimmeridge Clay Formation.

A depth trend of minimum principal stress (also termed the formation strength) for the Goldeneye Field and surrounding area has been calculated based on the available LOT (Leak-Off Test) and FIT (Formation Integrity Test) data from the well review.

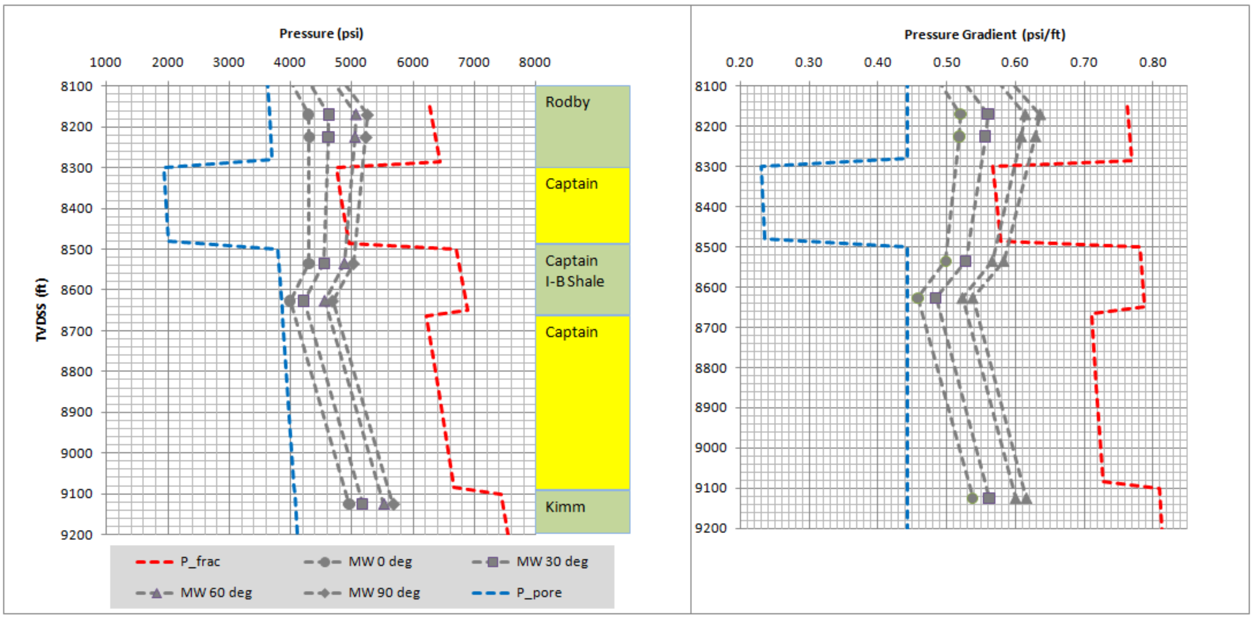


Figure 5-4 Goldeneye Reservoir pressure regime

The Goldeneye Captain reservoir has abundant pressure data, from both pre-production logging and testing through to the production wells which all had downhole gauges installed. The virgin pressure at the water contact was 3,825 psi at 8,592 ft TVDSS (True Vertical Depth Subsea), whilst the gas pressure at 8,400 ft TVDSS was 3,814 - 3,818 psi. An extensive dynamic aquifer model for the Captain sand fairway has been constructed which covers adjacent fields including Hannay, Atlantic, Cromarty, Blake, as well as Goldeneye. The model predicts that by 2015 the reservoir pressure in the Captain sand will be in the range 2,830 - 2,960 psi. Although the production and well test data indicate that the Goldeneye reservoir is well connected, isolated pockets of high and low pressures cannot be ruled out

Downhole reservoir temperature reference is 83 deg C at 8,565 ft [2611m] TVDSS.

5.6. Formation Evaluation

The final formation evaluation programme is yet to be confirmed, however, some options remaining in consideration include:

- Possible coring of the Rødby Formation to improve geomechanical modelling

- Sidewall coring not proposed
- Injection testing not proposed - six years of hydrocarbon production considered best injectivity test (see injectivity analysis report[25] for further comment)
- Gamma ray and resistivity logs in reservoir to detect latest fluid contacts and enable calibration of dynamic models
- Fluid Samples and RFT in overburden formations if not too tight, *e.g.*, Chalk.

5.6.1. Mud logging

A full mud logging unit, staffed by two data engineers and two mud loggers, will be present. This is to ensure that approach to the base of the caprock is recognised so that operations stop and preparations made prior to entering the depleted reservoir. As well as sample collection and description, full pressure evaluation will be provided.

5.6.2. Bottom Hole Coring

The Upper Valhall, Rodby, Hidra and Plenus Marl Formation seal may be cored to improve project geomechanical models.

5.6.3. MWD/LWD Logging Programme

The sidetrack logging programme is outlined in table below.

Hole Size	Measured Depth, ft	LWD
26"	N/A	-
17 1/2"	N/A	-
12 1/4"	N/A	-
8 1/2"	7,200 - 8,420	GR-Res
6"	8,421 - 8,635	GR-Res-Den-Neu

5.6.4. Electric Wireline Logs

It is intended to perform electric wireline logging of formation during sidetrack operations, including MDT, sonic and FMI. Cement bond logging will be conducted to verify the integrity of cementing operations.

Cement bond logging and casing integrity logging will be conducted during workover operations.

5.7. Target Tolerances

The tolerance of the geological target is a circle of 25 m radius centred on the target location.

5.8. Total Depth Criteria

On the basis of the well results, a flexible TD may be adopted (either shallower or deeper than the proposed 8,471 ft [2582 m] TVDSS). Object is to expose enough Captain D Sandstone reservoir at the sidetrack location to allow the running of approx 150 ft [46 m] of excluder screens over the formation in preparation for CO_2 injection.

Note: 190 ft [58 m] TVT of Captain D sandstone is prognosed.

6. Well Design and Programme Summary

6.1. Operational Summary

6.1.1. Workover

Each ex-production well will be worked over to remove the existing 7" x 5 1/2" completion tubing and re-completed with smaller ID tubing. This will have the effect of , introducing sufficient pressure losses (friction) into the injection system and maintaining CO_2 above the saturation line in dense liquid phase.

Time estimates suggest each well workover operation will take around 23 days. The outline programme for the workover is as follows:

- Mobilise rig to location
- Kill well / set downhole barriers
- Remove Xmas tree
- Rig up & test BOPs (Blow Out Preventers)
- Recover downhole barriers
- Recover existing completion tubing
- Recover packer
- Clean scrape 9 5/8" casing
- Carry out cement logging
- Run new completion tubing
- Set packer
- Test tubing, annulus and TRSSSV
- Install and test Xmas tree

For further task detail please refer to the draft well programme[2], well functional specification[3] and well technical specification[4] documents.

6.1.2. Sidetrack

The option to sidetrack any of the Goldeneye wells has been reviewed in case it should become necessary to change the location of a CO_2 injection well because of mechanical or near well bore damage to the original well bore or to optimise the location for a MMV well.

It is presumed that the well will be:

- Directionally drilled

---

[2] Shell, 2010. Well programme-draft

[3] Shell, 2010. Well functional spec.

[4] Shell, 2010. Well technical spec.

- Completed with sand control

In the event that a sidetrack is performed, the likelihood is that it will be carried out at the same time as the tubing change-outs / workovers on grounds of cost and rig availability. Time estimates suggest a sidetrack operation would take around 55 days. An outline programme for the Sidetrack operation (Gravel Pack option) is as follows:

- Mobilise rig to location
- Kill Well / set downhole barriers
- Remove Xmas tree
- Rig up & test BOPs (Blow Out Preventers)
- Recover downhole barriers
- Recover existing completion tubing
- Recover packer
- Carry out cement logging
- Abandon donor wellbore
- Orientate and set packstock
- Mill window in 9 5/8" casing
- Sidetrack through 9 5/8" casing
- Drill 8 1/2" hole to top of Captain Reservoir
- Set 7.00" casing
- Drill 6.00" hole to TD
- Make up Pre drilled liner
- Install false rotary table and make up excluder screens
- Make up FIV (Formation Isolation Valve)
- Make up internal wash string
- Run in hole with one trip gravel pack system.
- Circulate open hole to solids free brine
- Set gravel pack packer
- Pump detergent pill
- Carry out gravel pack operations
- Close and test FIV
- Circulate well to completion fluid
- Scrape casing at packer setting depth
- RIH and perform CBL/VDL
- Make up Completion tailpipe, packer, PDGM & DTS.
- Run completion tubing to TRSSSV
- Install and test TRSSSV and control lines.
- Continue to RIH with completion
- Space out completion, install tubing hanger, terminate and test PDGM, DTS cable & TRSSSV C/L
- Land and test tubing hanger
- Set packer, pressure test tubing and annulus
- Inflow test TRSSSV
- Set and test shallow plug

- Nipple down diverter, riser and BOP
- Install & test Xmas tree
- Recover shallow plug
- Install tree cap and pressure test
- Pressure test tree valves
- End of Well Operations

6.2. Casing Design

Base case for Goldeneye is a tubing changeout - workover. Such an operation does not require a change of casing.

In the event that a sidetrack is performed through the existing 9 5/8" the final well will be drilled to the top Captain in 8 1/2" hole size and a 7" liner set. The reservoir section will be drilled in 6" hole size and excluder sand screens run into open hole. The lowest casing joints may be designed using CO_2-resistant alloy.

This casing design has not been subjected to a design check with Third party stress check Software. The change of loading due to a long cemented liner would need to be modelled for this sidetrack case. However, from the conductor concept select document[5], it is known that the surface casing is suitable for the expected loads involved and the production casing is good for CO_2 injection before sidetracking.

Casing Size	SETTING DEPTH (ft)		Wt (lb/ft)	Grade	Coupling	Collapse (psi)	Burst (psi)
	TVD SS	MDRKB					
30"	Existing	Casing					
20"	Existing	Casing					
13 3/8"	Existing	Casing					
10 3/4"	3,130	TBA	55.5	L80	VAM Top	4,020	7,930
9 5/8"	7,040 Kick-	7,200 Off	53.5	L80	VAM Top	6,620	6,870
7" Liner	8,256	8,420	26	L80	Premium Thread	8,600	9,060
4" Screens	8,471	8,635	N/A			Sand	Screens

[5] Shell, 2010. Conductor concept select report

Table 6-1 Casing Properties, GYA-05 Sidetrack - Depths Based on Notional Sidetrack

As the base case is for tubing change out / workover this casing design has not been modelled.

1 Both the surface casing and the production casing are within limits for the loads modelled with the minimum safety factors listed in the table below

2 Due to injection of cool CO_2, the load cases are driven towards tensile loading due to thermal contraction. These load cases exist in Q1 & Q4 of the design limits plots (top right and bottom right quadrants).

Note: All safety factors are Absolute Safety Factors

Hole Size	Casing O.D.	Setting Depth (ft) TVD RKB	CASING SEAT JUSTIFICATION
36"	30"	N/A	N/A
26"	20"	N/A	N/A
17 1/2"	13 3/8"	N/A	N/A
12 1/4"	9 5/8"	N/A	N/A
8 1/2"	7" Liner	8,420	Replacement Production Casing Shoe - Base Rodby
6"	Sand screens	8,635	New Total Depth for sidetrack well

Table 6-2 Casing philosophy for GYA05 notional sidetrack

6.2.1. Casing Design Results

Table 6-3: Goldeneye Platform Casing Minimum Absolute Safety Factors

Min SF's 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 CO2 inj (-25F 50Mscf)	1.83 @ 4256.9 ft	---	2.32 @ 9767.9 ft	1.96 @ 754.6 ft (T)
PC.2 Late CO2 inj (37F 60Mscf)	2.3 @ 4256.9 ft	---	2.43 @ 9767.9 ft	2.51 @ 754.6 ft (T)
PC.3 Early CO2 inj (37F 40Mscf)	2.34 @ 4256.9 ft	---	2.43 @ 9767.9 ft	2.56 @ 754.6 ft (T)
PC.4 Early CO2 inj (37F 54Mscf)	2.3 @ 4256.9 ft	---	2.43 @ 9767.9 ft	2.51 @ 754.6 ft (T)
PC.5 Mid CO2 inj (37F 32Mscf)	2.36 @ 4256.9 ft	---	2.43 @ 9767.9 ft	2.58 @ 754.6 ft (T)
PC.6 Mid CO2 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)
	Triaxial	Burst	Collapse	Axial
MINIMUM SAFETY FACTORS	1.42	2.77	1.12	1.73

Safety Factors for the production casing above have been computed for Goldeneye Platform wells subject to CO_2 injection and are given above. . These are absolute Safety Factors. Safety Factors for the surface casing are given and discussed in the Conductor Concept Select report[6]. All the safety factors for all the casing strings in the Goldeneye Platform wells fall within Shell design criteria, hence are acceptable for CO_2 injection use. See casing concept select report[7] for further discussion.

[6] Shell, 2011. Conductor concept select

[7] Shell, 2010. Casing concept select report

6.2.2. Casing Pressure Testing

Table 6-4 Casing pressure data

CASING	SURFACE PRESSURE (PSI)	CRITERIA
30"	N/A	N/A
20"	N/A	N/A
13 3/8"	N/A	N/A
9 5/8"	4,000 psi	Maximum anticipated downhole pressure at end of injection phase 3,850 psi
7"	4,000 psi	Maximum anticipated downhole pressure at end of injection phase 3,850 psi
4"	N/A	Sand screens

6.2.3. Proposed Casing Schematic

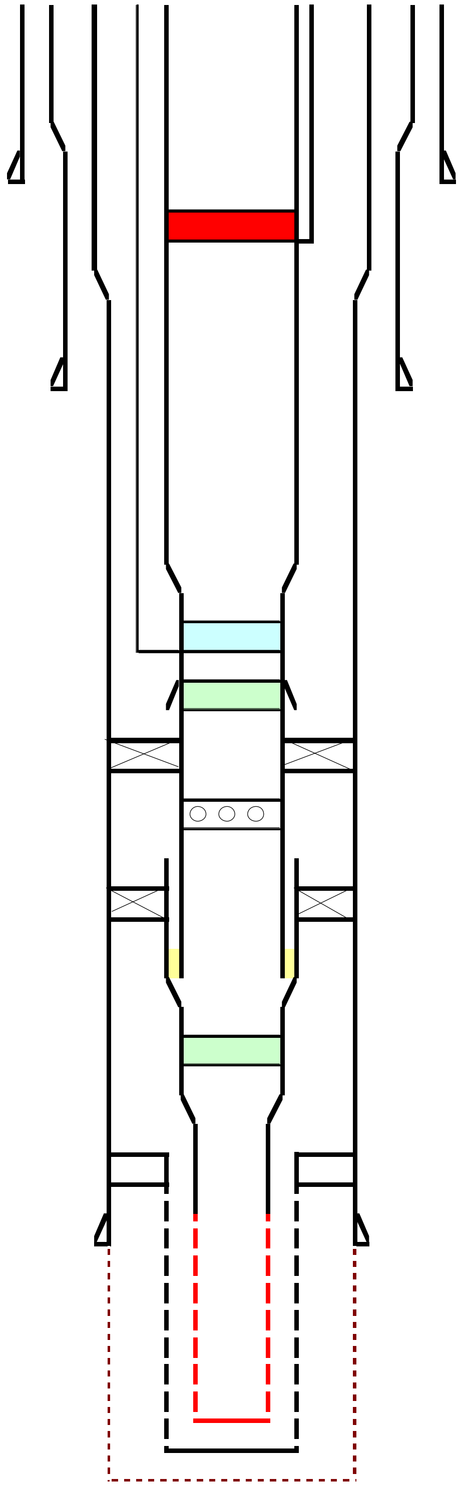
A workover will have the same casing design but will have smaller tubing in the well. Therefore, the existing casing and completion status for GYA01 is shown in Figure 6-1 and Figure 6-2 for information purposes. All of the Goldeneye production wells produced from the Captain E and D sandstone reservoirs through a 7" pre-drilled liner, 4" sand screens and a gravel pack.

6.2.4. Proposed Recompleted Status of Well

Each re-completed well is planned to be capable of performing both CO_2 injection and monitoring functions as required and will contain PDGM(s) (permanent downhole gauge mandrel) and DTS (distributed temperature sensing) in reduced ID (2 7/8" - 4 1/2") tubing. The exact number of PDGMs in each well and exact tubing sizes are to be confirmed. Figure 6-3 & 6-4 show a proposed new completion string, which uses tapered tubing to achieve the frictional pressure losses needed to maintain the supplied CO_2 above the saturation line over the range of operating pressures and temperatures. However, this is only one of several options under consideration that could achieve the same result. These other options include use of: dual completion; concentric completion; insert string; small bore completion; downhole choke, or cemented completion [8, 9].

[8] Shell, 2010. Upper completion review

[9] Shell, 2010. Completion concept select



	GYA01 AHD	TVD
20 x 13 3/8" X-Over	704	704
30" Conductor	750	749.75
TRSSSV	2549	2525
10 3/4" x 9 5/8" Casing X-Over	3130	3090
13 3/8" Shoe	4156	4076
7 x 5 1/2" Tubing X-Over	8322	7805
Gauge Mandrel	8383	7859
PBR (Not sheared)	8443	7911
9 5/8" Halliburton Packer	8528	7986
Perforated Pup Joint	8651	8094
9 5/8" Baker Seal Assembly	8681	8121
9 5/8" Baker Packer	8696	8134
5" Baker Ratcheting Mule	8705	8142
7" x 5 " X-Over	8744	8176
FIV	8755	8186
5" x 4" X-Over	8785	8212
Liner Hanger	8831	8253
4" Baker screens	8952	
9 5/8" casing shore	9006	8408
7" Predrilled liner		
Baker Screens Bull Nose	9154	8539
Pre-drilled liner Shoe	9163	8547
TD	9166	8550

Figure 6-1 GYA01 current well status - existing well completion schematic

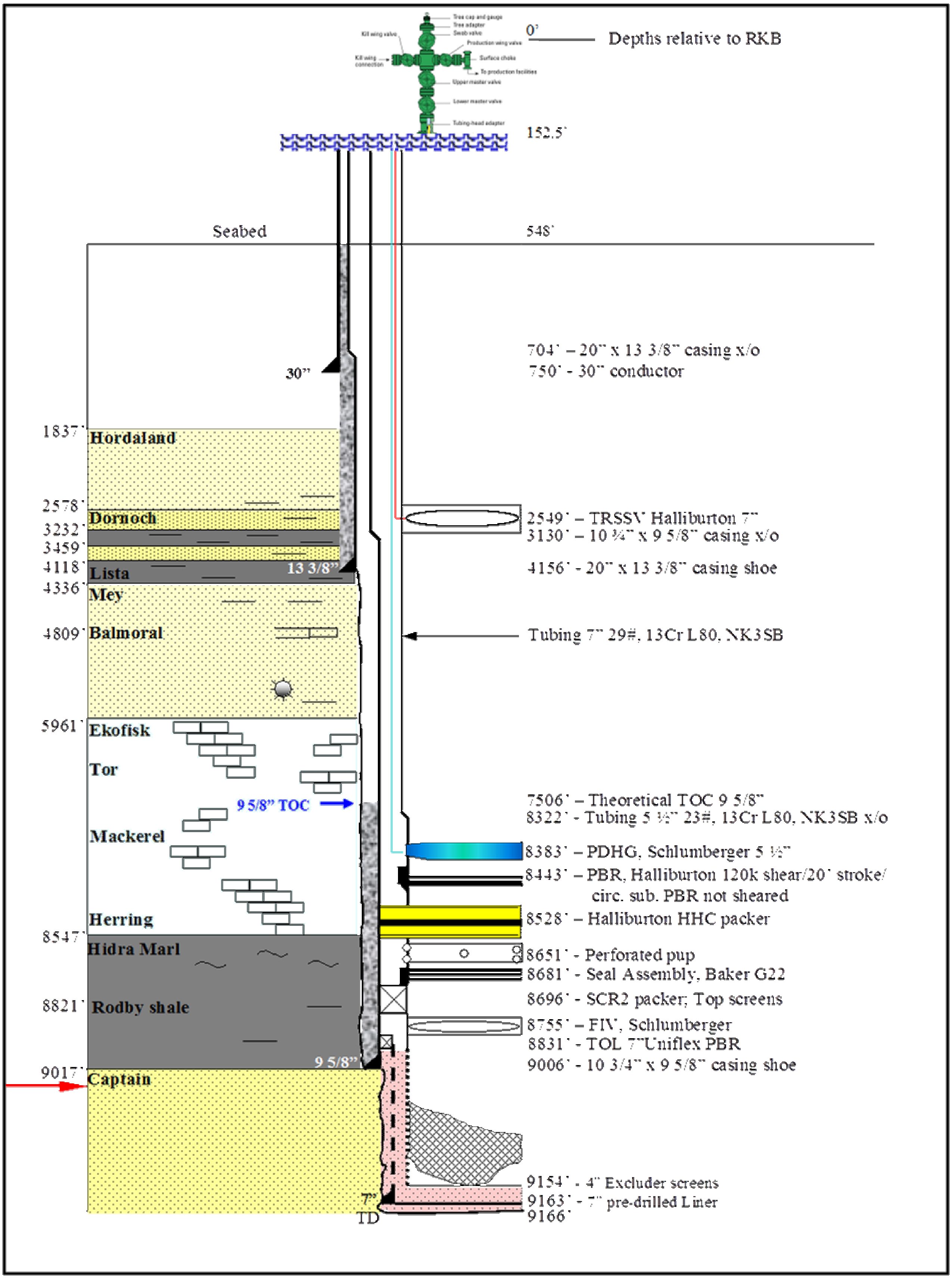
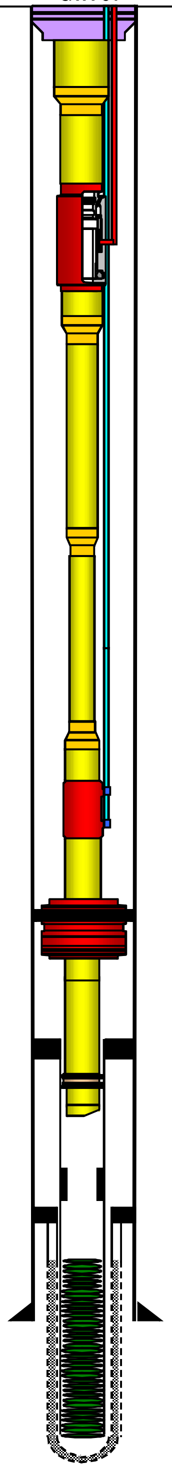


Figure 6-2 GYA01 current well status including formation data

6.2.5. Revised Completion Diagram (With Installed Downhole Equipment)

Revised completion status (including perforations and injection interval) is shown in figures 6-3 and 6-4.

GYA-01



Item Nos	Depth MD	Depth TVD	Nos Joints	Description of Item Including Part Nos & Serial Nos Where Applicable	ID (Inches)	Drift (Inches)
	79			Tubing Hanger	6.169	
				7.00 29 # Vam Top Tubing	6.184	6.059
	139			X/O 7.00" 29# x 4 1/2" 12.6#	3.958	3.833
				4 1/2" 12.6 # Vam Top Tubing	3.958	3.833
	2500			SCTRSSSV 4 1/2" 13cr	3.813	
	2540			X/O 4 1/2" 12.6 x 4.00" 9.5#	3.548	
				4.00" 9.5# Vam Top tubing	3.548	
	6500			XO 4.00" 9.5 # x 3 1/2" 10.2#	2.992	2.797
				3 1/2" 10.2# Vam Top tubing	2.992	2.797
	8430			X/O/ Wire Finder Trip Sub 3 1/2" 10.2 # x 4 1/2" 12.6#	2.992	2.787
	8536			4 1/2" PDGM	3.958	3.833
				4 1/2" 12.6 # Vam Top tubing	3.958	3.833
	8596			AHC Packer	3.818	
				4 1/2" Tubing	3.958	3.833
	8696			Baker SC-2R packer screen hanger		
				G22 Seal Assy	3.958	3.833
	8705			Mule Shoe	3.958	3.833
	8755			Schlumberger FIV	2.94"	
	8831					
	8952			Top of 4.00" Screens	3.548	
	9152			TD		

Figure 6-3 Proposed completion string for GYA01 post-workover, including a tapered tubing string to increase friction

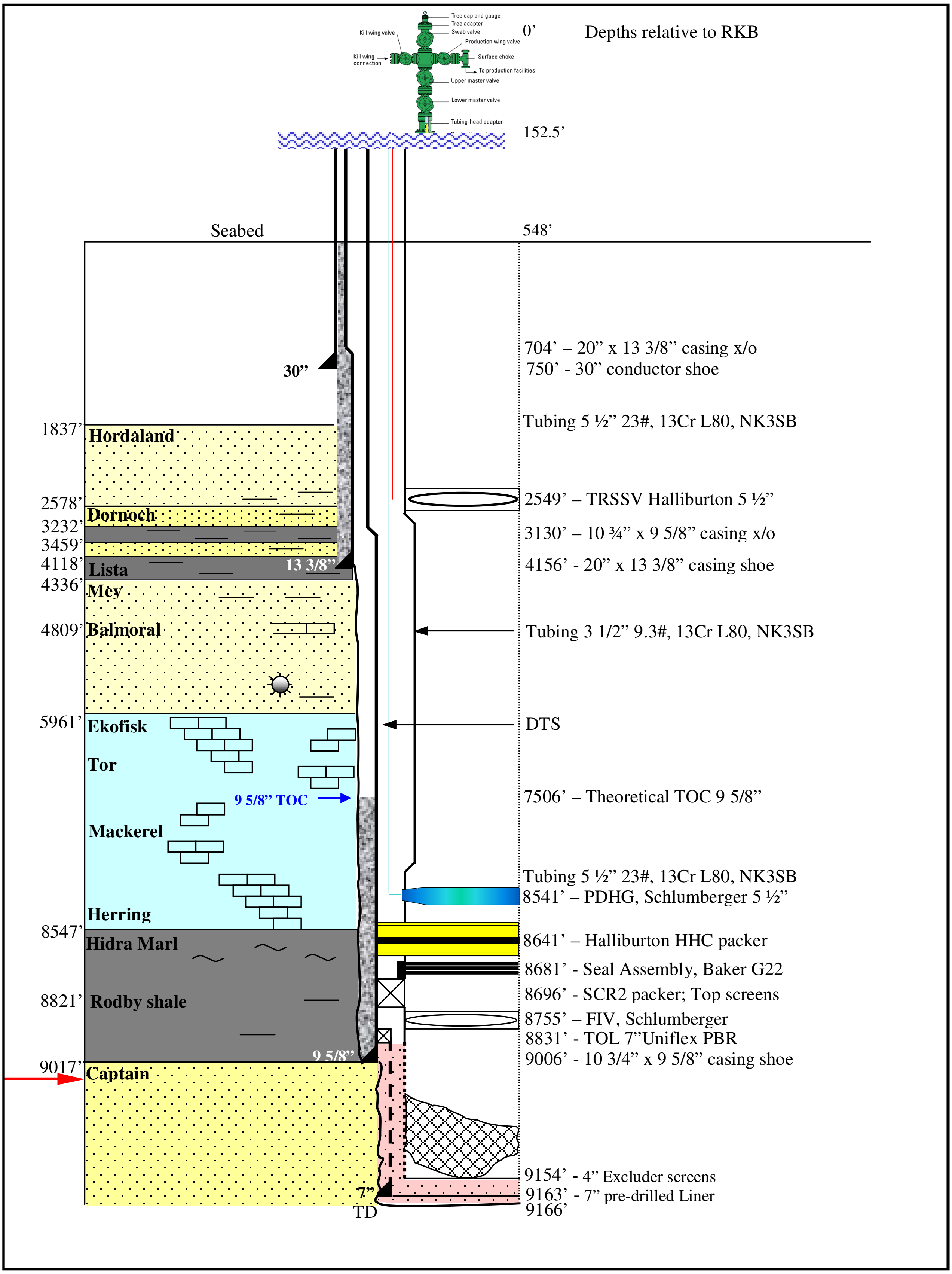


Figure 6-4 GYA01 post-workover status

6.3. Directional & Survey Design

6.3.1. Sidetrack

6.3.1.1. Well Profile

A notional sidetrack crestal injector target has been modelled from the GYA05 well using Third Party directional design software. It has a short step out of about 100 ft [30 m], with build and turn angles around 3°/100 ft. It is a straightforward design and can be performed without difficulty. See figures 6-5, 6-6 and tables 6-4 and 6-5.

- Well will be sidetracked through an existing Goldeneye well slot.
- Shallow hazard assessments are not applicable.
- BOP will be in place before any formations are drilled into.

6.3.1.2. Anti-collision

The most proximal well for the sidetrack is obviously GYA05, however, since the trajectory is only preliminary, further anti-collision study (separation factors) is yet to be carried out. The next closest offset well would be 14/29a-3, which is ~250m away at kick-off and ~480m at sidetrack TD, see Table 4-4. Well 14/29a-3 was drilled by Shell in 1996. These separations are presently not considered hazards for this notional near vertical sidetrack well.

Normal Shell well anti-collision practices will be followed in all cases. The GYA02 and GYA04 wells are both going in the same general direction - towards the North-East. Any sidetrack in this direction may need further planning to ensure no collision.

Table 6-5 Offset well data

Well		Separation from Sidetrack* (m)	Faults ft TVDSS	Reservoir Markers (ft TVDSS)			Captain D Isochore (ft)
Name	Spud year			Top Captain Sandstone/subunit E	Top Captain subunit D	Top Captain Subunit C	
GYA05	2003	22		8257	8282		25
14/29a- 3	1996	480	9315	8265	8280	8495	15
GYA01	2003	910		8265	8289		24
GYA03	2003	1030		8388	8411		23
20/04b- 7	1999	1255		8546	8582	8673	36
20/04b- 6	1997	1460		8511	8532	8665	21
GYA02S1	2004	1920		8286	8296	8382	10
14/29a- 5	1999	2120		8393	8415	8487	22
GYA04	2003	2650		8348	8360		12
*at TD							

6.3.1.3. Survey Programme

All surveying will be carried out in accordance with the Shell *Directional Control and Survey Procedures*.

Table 6-6 Directional control requirements

Hole Section	Survey Type	Survey Interval (m)
Rig Position	N/A	-
26" x 36" Hole Opener	N/A	-
26"	N/A	-
17 1/2" Hole	N/A	-
12 1/4" Hole	N/A	-
8 1/2" Hole	Gyro at kick-off until clear of 9 5/8" then MWD	30 m
6" Hole	MWD	30 m

6.3.1.4. Directional Control and Monitoring

MWD / GR surveys will be taken whilst drilling to above the reservoir and MWD / GR / RES through the reservoir to TD. Survey frequency is every 30 m. Should there be any discrepancies between surveys of different MWD tools, a gyro survey will be run.

No gyro survey is planned for this well.

Well path will be tracked by both the directional drilling company as well as Shell.

6.3.1.5. Directional Plot

Goldeneye Well GYA05 Sidetrack

MD (ft)	CL (ft)	Inc (°)	Azi (°)	TVD RKB (ft)	NS (ft)	EW (ft)	V.Sec (ft)	Dogleg (°/100ft)	T.Face (°)	Build (°/100ft)	Turn (°/100ft)	Section Type	Target Target
7,200		1.5	310.6	7,193	-98	63	44	0.0	0.0	0.0	0.0	Tie Line	
7,338	138	5.4	283.3	7,331	-96	59	47	3.0	-36.9	2.8	-19.7	OPT AL DLS	
8,241	902	5.4	283.3	8,229	-76	-25	79	0.0	0.0	0.0	0.0	(ditto)	
8,422	181	0.0	0.0	8,410	-74	-33	82	3.0	180.0	-3.0	42.3	(ditto)	GYA-05s1 Entry
8,635	213	0.0	0.0	8,623	-74	-33	82	0.0	0.0	0.0	0.0	DT6 Curv	GYA-05s1 Exit

Table 6-7: Goldeneye Well GYA05 Sidetrack Trajectory

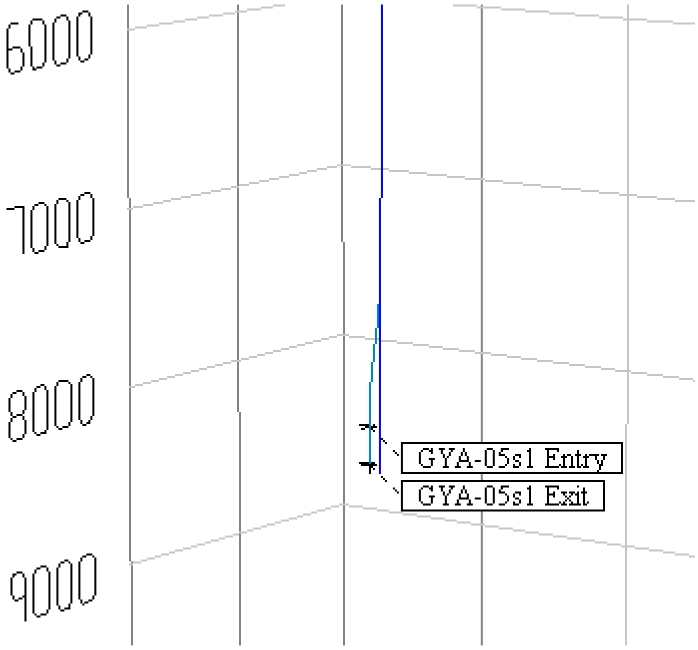


Figure 6-5: Goldeneye Well GYA05 Sidetrack Extract of 3D View

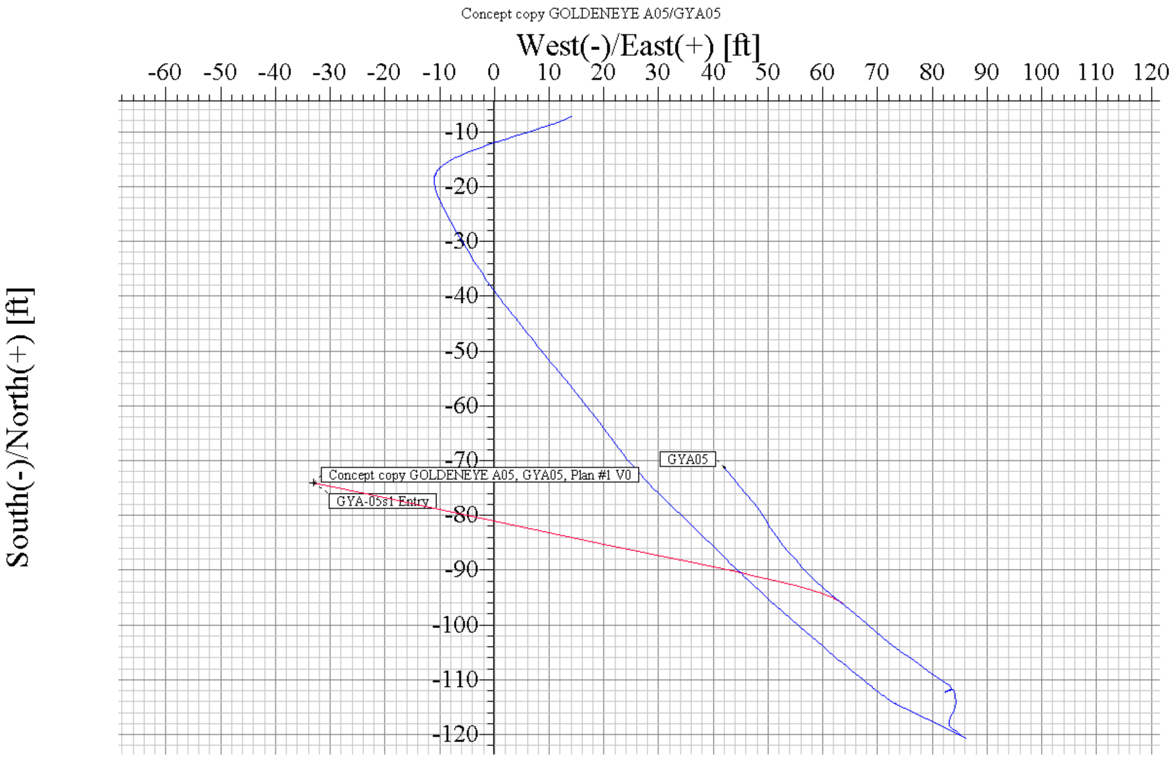


Figure 6-6: Goldeneye Well GYA05 Sidetrack Plan View

6.4. Drilling Fluids Design

6.4.1. Sidetrack

The hydrostatic pore pressure and fracture gradient down to the top reservoir has not altered over field production life. Based on the Fluids Concept Workshop a sidetrack can be drilled to base Rødby using the original Goldeneye Platform mud programme.

For a sidetrack, oil based mud (OBM) is proposed down to the base Rødby at ~8,256 ft TVD SS to inhibit shales.

Through the reservoir, a WBM reservoir drill-in fluid (RDIF) would be used. The weight of this fluid would be matched to the hole angle and to the pore pressure and fracture gradient calculated for the reservoir. A sidetrack well would likely be gravel packed, the same as the original wells. The gravel carrier fluid would contain enzyme and chelants to remove WBM filter cake. Please see fluids concept select report[10] for further discussion.

The risk that needs to be investigated is the mud weight needed for drilling above the reservoir and for drilling through the reservoir.

During the drilling phase of the Goldeneye Platform, the section above the reservoir was around hydrostatic and drilled with OBM above that value. Following on, the reservoir was drilled with a drill-in fluid, again at above that hydrostatic value.

For a sidetrack either before or during CO_2 injection, there will be a large difference between the desired mud weights above the reservoir and through the reservoir and consideration will be given to casing off the Rødby shales prior to drilling reservoir. Factors pointing to casing off include:-

- unstable Rødby shales at high angles
- depleted reservoir drilling - losses
- sands in the 'catastrophic region' for sand control
- possible sidetrack in the CO_2 plume - unexpected pressures
- effect of cold CO_2

6.4.2. Workover

Due to the depleted, and now less than hydrostatic nature of the Goldeneye reservoir, when the tubing is pulled, there will be losses into the reservoir. To overcome the losses there are a number of main options:

- use lost circulation material (LCM) to plug the reservoir
- use base oil as the workover fluid
- employ a cross linked polymer to prevent losses

Lost circulation material (LCM) is not acceptable due to the possibility of plugging the downhole sand screens, thereby preventing the injection of CO_2 into the reservoir. Using a fluid such as base oil during workover operations gives problems of overbalance with pressure above that of the reservoir. Base oil also introduces another phase into the reservoir and is to be avoided if possible. Cross linked polymers have been used successfully in similar situations of depleted reservoirs. The outline is at commencement of operations, to pump the crosslink polymer to prevent losses with a

10 Shell, 2010. Fluids concept select report

'breaker', and enzyme that will break down the polymer over a long time period. The breaker time can be varied according to the time that the workover is expected to take. After operations are completed, the polymer is converted to a clear fluid. This is further explained in the Fluids Concept Select document[11].

Hence a cross linked polymer, that will form a plug that will initially support a full column of water, is the preferred option for workover work. The design of the fluid will need to be selected according to downhole conditions and duration of the work to be performed. Refer to the well technical specification document for the completion and packer fluids recommended for these wells[12].

6.5. Cementing Design

6.5.1. Sidetrack

Use of CO_2 resistant cement has been discussed in the cement concept select report[13]. Although special cement is not required, qualification of CO_2 resistant cement may give an alternative to Portland cement to consider, for a new well or for a sidetrack.

All the summary indications are that existing Portland cement is acceptable for use in Goldeneye CO_2 injection wells.

Cement placement has been reviewed for all the production wells. Cement composition and volumes placed are all consistent with good practice.

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 this therefore removes the potential for chemical reaction with Portland cement. This mitigates the main cause of cement degradation. However, later in the well's life there are cases where water will be present around the wellbores so carbon acid degradation cannot be discounted in the unlikely event of a a leak occuring

Field results such as those from the SACROC CO_2 injection project (CO_2-EOR project in the Permian Basin, Texas), indicate that Portland cement can retain its integrity in a hostile CO_2 environment.

Software modelling indicates the remaining capacity of the existing cements is good. Conclusion is that existing wells are suitable for the planned works.

With regard to a sidetrack, the above calls into question the need for special cements. 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 have used these CO_2 resistant cements. Their first experiences were poor and they have reverted back to Portland cements with tighter properties for CO_2 work at present.

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

11 Shell, 2011. Fluids Concept Select

12 Shell, 2011. Well Technical Specification

13 Shell, 2010. Cement concept select report

6.5.2. Workover

It is not intended to perform any cementing operations during tubing change-out. However, if cement bond logs indicate poor cement bond, there may be a need for a remedial squeeze to repair the cement.

6.6. Drilling-related Hazards

6.6.1. Sidetrack

A sidetrack from an existing Goldeneye Well would require a heavy duty jackup.
During sidetrack operations there will be the normal hazards of:

- premature setting of a packstock whilst running in
- correctly orienting and setting a packstock
- passing through the window that has been made when drilling and tripping afterwards

Once the sidetrack has been performed, the hazards are the same as for a new well and include:

- borehole instability
- fluid losses
- low ROP
- unable to maintain directional control
- influx of wellbore fluids
- incorrect pick for 9 5/8" casing point
- differential sticking
- poor hole cleaning
- inability to handle cuttings
- inability to run casing to bottom
- impairment of reservoir sands
- H_2S
- incorrect section td
- stuck pipe and logging tools

6.6.2. Workover

The hazards identified for a workover on the Goldeneye Platform are:-

- General hazards
- Heavy duty jackup rig

Before start-up of CO_2 injection, a workover is like any workover in the presence only of hydrocarbons.

Table 6-8 Drilling hazards

HAZARD		REMARKS
Overpressure	☐ Yes ☒ No	Goldeneye stratigraphy for this well is hydrostatic.
Depletion	☒ Yes ☐ No	Depleted Reservoir. Q12011 predicted Captain pressure for Q42012 is 2,850 psi.
Wellbore stability	☒ Yes ☐ No	Yes - at high angle, 68° in GYA04
Lost Circulation Zones	☐ Yes ☒ No	Some offset wells had losses in reservoir in the order of 1 to 2 bbls/hr.
Formation related stuck pipe	☐ Yes ☒ No	No
Chemically reactive Formations	☐ Yes ☒ No	No
Problems relating to formation drillability	☐ Yes ☒ No	No - Goldeneye Platform wells drilled in 10 days
Kick tendency	☐Yes ☒ No	No
Faults	☐Yes ☒ No	Not prognosed.
Salts	☐Yes ☒ No	No
Shallow gas	☐Yes ☒No	N/A
H2S	☐ Yes ☒ No	No
Formation dip	☐ Yes ☒ No	Low - less than 10°
CO_2	☒ Yes ☐ No	0.5% - reservoir will experience CO_2 injection

6.7. Well Control Design

The original hydrocarbon column was approximately 300' (90m), indicating an effective overpressure of *c.*115psi (7.9 Bara) above hydrostatic at the crest (8225' [2507m] TVDSS) held by the caprock . During production of hydrocarbons the pressure has reduced. At the end of carbon dioxide injection, the reservoir will have re-pressurised to ~3,850 psi. The region has a strong edge-drive aquifer that over time would recharge the Captain Sandstone to this value without the aid of CO_2 injection.

Hence, for workover and drilling work on the Goldeneye Field, a 5,000 psi rated rig is all that is required. However, for the water depth at the platform location a heavy-duty jackup is required. Such a rig will most likely be rated to 10,000 psi or 15,000 psi. Hence, there will not be any problems with well control, the rig being over-specified for Goldeneye needs.

Typical Specification will include:

Diverter

Low pressure rated 500 psi with lines going to opposite sides of the drilling platform

BOP Programme

A minimum 5,000 psi BOP is required. As stated above a 10,000 psi or better specification will be provided.

A typical 10,000 psi stack will be:

18 3/4" 10,000 psi WP Modular BOP Stack comprising:

- 18 3/4" x 5,000 psi. Annular preventer
- 18 3/4" x 5,000 psi. Annular preventer
- 18 3/4" x 10,000 psi. Double Ram BOP
  - Top Rams — Blind/Shear Rams
  - Mid Upper Rams — VBR 4 1/2" x 7"
- 18 3/4" x 10,000 psi. Double Ram BOP
  - Mid Lower Rams — VBR 3 1/2" x 5"
  - Lower Rams — 5" Pipe

Choke and Kill Lines

A minimum 5,000 psi Choke arrangement is required.

A typical 10,000 psi Choke will comprise:

Two valves on each Choke line and two on each Kill line:

3 1/16" Control Flow Type valves - 10,000 psi rated

Cement Unit

A minimum 5,000 psi Cement Unit arrangement is required.

6.8. Rig Positioning

6.8.1.1. Metrological and oceanographic conditions

Weather conditions in the Central North Sea are variable, however conditions would not be expected to exceed a rig's maximum environmental survival conditions. The 100-year joint probability extreme ocean conditions for the Goldeneye platform location are listed below from the original GYA05 well proposal:

Wave height (Maximum):	24.6 m (80.7 ft)
Wave period (Significant):	15.1 secs
Wind speed (Sustained 10 min):	39.0 m/s (76 knots)
Surface current velocity:	0.40 m/s (0.78 knots)
Water depth:	119.0 m (390.5 ft)

6.8.1.2. Site surveys

There is already good data on the area of interest from previous seabed geophysical surveys, site selection for the platform and previous drilling with a jack-up rig. The spud-can footprints from the 2003-2004 drilling will also need to be surveyed and accounted for.

6.8.1.3. Seabed obstructions

From the original GYA05 well proposal the following was noted:

"Five small objects up to 0.3 m in height were identified in the site survey of the 1.0 km x 1.0 km area centred on the proposed location. The closest object to the proposed location lies 78 m to the SE and is 0.2 m high.

Two pipelines occur within the survey area. The Beryl A to St. Fergus 36" gas pipeline (exposed) trends WSW to ENE through the survey area, passing 415m NNW of the proposed location. The Miller to St. Fergus 30" gas pipeline (buried) is parallel to the Beryl A to St. Fergus pipeline, passing 340 m NNW of the proposed location."

6.8.1.4. Bathymetry

From the original GYA05 well proposal the following was noted:

"The seabed is essentially flat over the surveyed area. The water depth at the platform location is 119.0 m LAT (395 ft MSL). However, water depths in the survey area range from a minimum of 118.8 m LAT (394 ft MSL) in the SSE to a maximum of 122.0 m LAT (405 ft MSL) in a pockmark 290 m NNW of the proposed location, a range of 3.2 m.

Two pockmarks, between 100 and 200 m in diameter, occur in the NW of the survey area. The closest pockmark to the proposed location lies 245 m NNW and has an estimated depth of 2.6 m.

The difference between LAT and MSL in this area is approximately 1.3 m."

6.9. Wellhead Design

6.9.1. Completions Design

6.9.1.1. Tubing

In general 13 Cr material is considered to be suitable material for the completion tubing. Dry CO_2 is not considered to be corrosive to 13 Cr materials. Dry CO_2 is not corrosive even if oxygen is present in the feed gas. Even at wet conditions, 13 Cr tubing is considered to be resistant to CO_2 corrosion if oxygen is not present, although it could be susceptible to corrosion at higher temperatures and salinity. However because certain transient operations can generate temperatures as low as -17°C, the upper completion down to a depth of circa 2,500 ft [762m] MD will be completed with Super 13 Cr tubing. Super 13 Cr tubing has a Charpy brittle transition temperature at -50°C.

6.9.1.2. Wellhead

In general the Goldeneye tree / wellhead design is a robust system adopting primary metal to metal seals, which are field proven. The Xmas tree and wellhead were primarily designed for gas production, making it a good design for CO_2 injection. The current Goldeneye Xmas tree is designed for temperature class U which is (-18 to +121°C); the limitation being the bonnet and the tree block, both being made from 410 stainless steel which has a very low Charpy impact value. Therefore the

Xmas tree selected for CO_2 injection operations will be up graded to F6NM, Material class FF which conforms to API-6A impact requirements.

6.9.1.3. Lower Completion

Goldeneye lower completion consists of open hole gravel pack including a premium screen. From the analysis to date, there is no reason to sidetrack the wells and to install a new lower completion. There are some operational restrictions related to the characteristics of CO_2 and some limitations related to the particles in the CO_2 but these are considered to be manageable. The maximum particles size in the CO_2 stream should not exceed 17 microns to avoid erosion and plugging of the screens and gravel pack.

6.9.1.4. MMV

The WRM philosophy for the Golden Eye project is to ensure optimal CO2 injection to meet the contractual agreement while maintaining well integrity. This will be done through very active monitoring of the wells from start up through acquisition of baseline data during the workover operations and continuous acquisition of pressure, temperature and other required data in the wells and reservoirs. The acquired data will be used to calibrate the well and reservoir models for active well and reservoir monitoring.

Permanent downhole gauges will be installed in both the injection (two gauges) and monitoring wells (four gauges) for continuous measurement of the downhole injection pressure and reservoir pressure

The Distributed Temperature Sensor (DTS) and Distributed Acoustic Sensor (DAS) will be run in the injector wells for tubing integrity monitoring. It is expected that a tubing leak will be picked up by the difference in temperature profile across the leak point and/or well 'noise'

6.9.1.5. Well Operation

The Goldeneye wells will be designed such that the well will be able to cope with the design case transient scenarios (low temperatures). The design case has been calculated for winter conditions and considers a pre-established steady state at different pressures and temperatures. The lowest temperature for the design case is -20°C for CO2, 15°C average for the tubing, -11°C in the A-annulus fluid and -10°C for the production casing.

6.9.1.6. Well Intervention

Routine intervention operations to carry out Bottom Hole Pressure (BHP) surveys etc will occur during the lifecycle of the well. In addition to considering routine intervention operations a worst case scenario was considered and modelled to confirm that the operation could be carried out. Baker Hughes (formally BJ Services) carried out a detailed analysis into Coiled Tubing (CT) intervention operations on Goldeneye. The most challenging CT operation foreseen on Goldeneye was to clean up any debris or fill across the screens, which could severely impair injection rates. Each of the proposed Goldeneye wells was modelled and in each case modelling shows that it is possible to access the Goldeneye wells and circulate out debris in a sub hydrostatic well.

6.9.1.7. Completion and Injection Risks and Uncertainties

Risks to injectivity include:

- impairment or damage of downhole sand control due to pipeline debris
- blocking of formation or lower completion due to pipeline debris

- hydrate formation near wellbore
- Joule-Thompson cooling
- halite precipitation
- organic deposits (wax, asphaltenes)

These risks are further analysed and discussed in the injectivity analysis report[14].

For completion risks, please see completion concept select report[15].

Risks include:

- Installation of PDGMs and DTS
- Corrosion
- Unable to recover plugs through new smaller ID completion (if option selected)
- Sand production (at start-up / shut down)

[14] Shell, 2010. Injectivity Analysis Report

[15] Shell, 2010. SP-CW040D3 Completion concept select report

7. INTERFACE ARRANGEMENT

The purpose of a Combined Operations Safety Case (COSC) - often termed 'Bridging document' in other sectors other than the UK, is to provide a summary of both installations, an outline of program of works, the Safety Management Systems (SMS) individual and interface arrangements, an analysis of additional hazards during combined operations and conclusions as to the safety of the combined operation where hazards have been reduced to a level that is As Low As Reasonably Practical (ALARP).

If combined operations (any operation involving either installation where a hazard arising from the operation significantly effects the other) are not planned, then the preparation of a combined operations safety case (COSC) may not be required by the Health & safety executive (HSE). However it is recommended that one be prepared to as a management control measure, assist with the generation of Safety Critical Elements (SCE's) and population of performance standards.

The COSC must be submitted to the Health and Safety Executive (HSE) for review and acceptance in advance of the commencement of any combined operation. It is recommended that the Hazid process be utilised as the basis for a COSC preparation.

8. Abbreviations

ADL	Asset Development Lead
BOP	Blow-Out Preventer
CCS	Carbon Capture & Storage
CO_2	Carbon Dioxide
CO_2-EOR	Enhanced Oil Recovery using CO_2 flood
DTS	Distributed Temperature Sensing
E&A	Exploration and Appraisal [Wells]
FEED	Front End Engineering Design
FIV	Formation Isolation Valve
H2S	Hydrogen Sulphide
HHC	Hydrostatic-set Production Packer
ID	Inner Diameter
LCM	Lost Circulation Material
MD	Measured Depth
MEG	Mono-ethylene Glycol
MMV	Measurement, Monitoring and Verification
OBM	Oil Based Mud
PBR	Polished Bore Receptacle
PDGM	Permanent Downhole Gauge Mandrel
PDHG	Permanent Downhole Gauge
RDIF	Reservoir Drill-In Fluid
ROP	Rate of Penetration
SDP	Storage Development Plan
TD	Total Depth
TOC	Top of Cement
TRSSSV	Tubing Retrievable Subsurface Safety Valve
WBM	Water Based Mud

In the text well names have been abbreviated to their operational form. The full well names are given in **Table 8-1**.

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