New Ventures

bp

Stromlo-1

Well Operations Management Plan (WOMP)

STRICTLY CONFIDENTIAL

Rev	Revision Description	Author	Date	Checker	Date	Approver/Issuing Authority	Date
B02	Updated changes to address NOPSEMA feedback	[redacted]	19-May-16	[redacted]	19-May-16	[redacted]	19-May-16
B01	Approved for use		30-Mar-16				
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A01	Issued for Review						

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Revision History

Revision Date	Revision Number	Approver	Revision
1-Dec-15	NA		Draft
03-Mar-16	A01		Issued for review
09-Mar-16	A02		Incorporated feedback
30-Mar-16	B01	[redacted]	Approved for use.
19-May-16	B02	[redacted]	Updated changes to address NOPSEMA feedback

Stakeholder Signatures

RAPID	Name	Role	Signature/Date
Recommend	[redacted]	[redacted]	[redacted] y-19-2016 | 13:20 AWST
Agree	[redacted]	[redacted]	[redacted] May-19-2016 | 00:21 CT
Decide	[redacted]	[redacted]	[redacted] ay-19-2016 | 13:36 AWST

BP decision rights; Recommend, Agree, Preform, Input, Decide (RAPID).

Input – Provides input to a recommendation

Recommend – Considers the input and provides a recommendation

Agree – Assesses a recommendation and concurs or disagrees

Decide – The single decision maker who decides on a course of action

Perform – Executes the resulting decision.

Abbreviations

AAR	After Action Review
ACT	Acceptance Criteria Table
AFE	Approval for Expenditure
ALARP	As low as reasonably practicable
APB	Annular Pressure Build-up
API	American Petroleum Institute
BAT	Barrier Assurance Table
bbl	Barrel (42 US Gallon/~159 litres)
BHA	Bottom Hole Assembly
BOD	Basis of Design
BOP	Blowout Preventer
CMP	Competency Management Process
CO_2	Carbon Dioxide
CVP	Capital Value Process
DDR	Daily Drilling Report
DGR	Daily Geology Report
DMR	Daily Mud (Fluids) Report
DOP	Drilling Operations Programme
DP	Dynamic Positioning
DPZ	Distinct Permeable Zone
DSP	Decision Support Package
DST	Drill Stem Test
DWOP	Drill Well on Paper (a key deliverable of the NWcp)
EIA	Equipment Integrity Assurance (a BP internal group focussing on equipment)
eMOC	Electronic Management of Change (online MOC management process)
EoWR	End of Well Report (a stage of the NWcp)
EPP	Exploration Permit for Petroleum
EWM	Equivalent Mud Weight
FG	Fracture Gradient
GAB	Great Australian Bight
GOO	Global Operations Organisation (the function within BP that is supporting logistics for this project)
GOP	Geological Operations Programme
GWO	Global Wells Organisation (the function within BP that delivers wells)
HoF	Head of Function
HPWHH	High Pressure Wellhead Housing
H_2S	Hydrogen Sulphide
IAT	Integrated Acceptance Test
IMT	Incident Management Team
JORP	Joint Operating and reporting Procedure
KT	Kick Tolerance
LCM	Loss Circulation Material
LEL	Lower Explosion Limit
LOT	Leak off Test
LPWHH	Low Pressure Wellhead Housing

MOC	Management of Change
MSL	Mean Sea Level
NOPSEMA	National Offshore Petroleum Safety and Environment Management Authority
NOPTA	National Offshore Petroleum Titles Administrator
NPT	Non Productive Time
NWcp	New Well Common Process
NWD	New Well Delivery (the function that offers subsurface support to GWO)
N_2	Nitrogen
OMS	Operating Management System (BPs Global overarching management system)
OPEP	Oil Pollution Emergency Plan
OPPGS(RMAR)	Offshore Petroleum Greenhouse Gas Storage (Resource Management and Administration) Regs 2011
OS	Oversight
PP	Pore Pressure
PPFG	Pore Pressure and Fracture Gradient
PSCM	Procurement and Supply Chain Management
PVT	Pressure, Volume, Temperature
RAPID	Recommend, Agree, Preform, Input, Decide
RAT	Risk Assessment Tool
RSPV	Retrievable Service Packer with Valve
RTE	Rotary Table Elevation
RtE	Readiness to Execute Review (a key deliverable of the NWcp)
RTPPFG	Real Time Pore Pressure and Fracture Gradient
RWP	Rated Working Pressure
SBM	Synthetic oil Based Mud
SCE	Safety Critical Equipment
SETA	Segment Engineering Technical Authority
SHA	Shallow Hazard Analysis
SOR	Statement of Requirements
S+OR	Safety and Operational Risk
SV	Self-Verification
SWSL	Senior Well Site Leader (BP senior rig site representative)
TD	Total Depth
TFN	Technical File Note
TOC	Top of Cement
TOL	Top of Liner
TVD	True Vertical Depth
TVDRT	True Vertical Depth relative to the Rotary Table
TVDss	True Vertical Depth relative to Subsea (MSL)
VOC	Volatile Organic Compounds
WBE	Well Barrier Element
WBM	Water Based Mud
WCBD	Well Control Bridging Document
WCD	Worst Credible Discharge
WID	Well Initiation Document
WOMP	Well Operations Management Plan
WSL	Well Site Leader (BP rig site representative)
WWI	Written Work Instruction

Table of Contents

Concordance Table

The following table has been provided to show which of the sections in this WOMP relate to the specific regulations from the Offshore Petroleum Greenhouse Gas Storage (RMA) Regulations 2011.

Regulation Identifier	WOMP Section
Reg 5.09(1) (a) a description of the well, and the well activities relating to the well, to which the plan applies	Section 2 – description of the well Section 2.1 – well activities Section 1 – title areas, well name, etc.
Reg 5.09(1) (b) a description of the risk management process used to identify and assess risks to the integrity of the well	Section 8
Reg 5.09(1) (c) a description and explanation of the design, construction, operation and management of the well, and conduct of well activities, showing how risks to the integrity of the well will be reduced to as low as reasonably practicable	Section 4 – management of the well Section 5 – design Section 6 – construction Section 3 – description of the geology Section 8 – risk management Section 4.1 – describing how BP assures its internal practices are ALARP
Reg 5.09(1) (d) a description of the performance outcomes against which the performance of the titleholder in maintaining the integrity of the well is to be measured	Section 9 – 'Outcomes'
Reg 5.09(1) (e) a description of the control measures that will be in place to ensure that risks to the integrity of the well will be reduced to as low as reasonably practicable throughout the life of the well, including periods when the well is not operational but has not been permanently abandoned	Section 9 – 'Control measures'

Regulation Identifier	WOMP Section
Reg 5.09(1) (f) a description of the performance standards for the control measures identified under paragraph (e)	Section 9 – 'Performance Standard'
Reg 5.09(1) (g) the measurement criteria that will be used to determine whether the performance outcomes identified under paragraph (d) and the performance standards identified under paragraph (f) are being met;	Section 6.3 – Well Barrier acceptance criteria tables
Reg 5.09(1) (h) a description of the monitoring, audit and well integrity assurance processes that will be implemented to ensure the performance outcomes and performance standards are being met throughout the life of the well, including periods when the well is not operational but has not been permanently abandoned;	Section 4.4.2 – SV&OS Section 6.3 – Well Barrier acceptance criteria
Reg 5.09(1) (i) a description of the arrangements that will be in place for suspension and abandonment of the well, showing: (i) how, during the process of suspending or abandoning the well, risks to the integrity of the well will be reduced to as low as reasonably practicable; and (ii) how the actions taken during that process will ensure that the integrity of the well is maintained while the well is suspended or abandoned;	Section 10
Reg 5.09(1) (j) a description of the measures that will be used to ensure that contractors and service providers undertaking well activities are aware of their responsibilities in relation to the maintenance of the integrity of the well, and have appropriate competencies and training;	Section 11
Reg 5.09(1) (k) a description of the measures and arrangements that will be used to regain control of the well if there is a loss of integrity	Section 12
Reg 5.09(1) (l) a timetable for carrying out and completing the well activities to which the plan applies.	Section 0

EPP39 Permit Conditions

Permit Condition	Discussion
EPP39 Permit Condition 6 Exploration well design: - All well casing and cement design is to be undertaken by an appropriately qualified & experienced engineer, who, along with other such personnel associated with the permit activities, will make themselves available for peer review at the discretion, and to the satisfaction of the National Offshore Petroleum Safety and Environment Management Authority.	Section 4.4 – Organisational Support Section 11 – Responsibilities and Competencies of Contactors and Service Partners In addition, BP acknowledges that NOPSEMA may request peer review and will make engineers available at request.
EPP39 Permit Condition 7 Prior to the commencement of drilling, the permittee is required to lodge with the National Offshore Petroleum Safety and Environmental Management Authority: **(a)** an approved well design and integrity monitoring plan designed to assure well integrity within each well drilled, which must be agreed to by the National Offshore Petroleum Safety and Environmental Management Authority and will include quarterly compliance reporting.	This document is considered evidence of compliance to this condition. Notification will be in line with regulations in the OPPGS(RMAR). Specifically; • Prior to commencement will be given as per Reg 5.22. • Reportable incidents during well operations as per Reg 5.26. • The End of Well Abandonment Report will be communicated to NOPSEMA as per Reg 5.25. In addition, as per the permit condition, BP commits to providing NOPSEMA with a status update in the event the well duration extends beyond 90 days at a frequency of every 90 days (i.e. quarterly). In this case, BP will provide a 'barrier status report' that outlines the current well barrier status and high level plans outlining what barrier work will be undertaken up to the point of abandonment.

Permit Condition	Discussion
EPP39 Permit Condition 7 **(b)** independent certification by the original provider, prior to installation, that each Blowout Preventer (BOP) to be used has been satisfactorily tested to design pressures.	The original manufacturer of the BOP will provide records (including pressure test data) as part of the Certificate of Conformance when the BOP is handed over to the rig contractor. BP will employ a third party company to verify this BOP certificate of conformance to assure the information is accurate. The owners ability to function and pressure test the BOP will also be assessed as part of the BP Integrated Acceptance Testing (before accepting the rig for work in the BP fleet). The Certificates of Conformance and third party verification letter will be provided to BP before running the stack and latching to the well head. A further BOP Integrated Acceptance Test will be carried out on the Stromlo-1 well after the BOP has been installed.
EPP39 Permit Condition 8 Prior to the commencement of drilling activities, the permittee must specify, and have approved by the National Offshore Petroleum Safety and Environmental Management Authority, the hydrocarbon spill mitigation technologies and risk mitigation process that it will deploy throughout the drill and maintain for the active life of the well.	Section 12 – Source Control and Blowout Contingency Measures. This is also provided and approved via the Environment Plan (EP) process, document number AU000-HS-PLN-600-00001 (currently under review). Drilling will not commence without an accepted EP which will include the Oil Pollution Emergency Plan (OPEP).
EPP39 Permit Condition 9 As soon as practicable after the completion of drilling, and prior to the commencement of any other exploration activity, the permittee will conduct and report to the National Offshore Petroleum Titles Administrator, for review by the National Offshore Petroleum Safety and Environmental Management Authority, on Cement Bond Logging to demonstrate effectiveness of cement jobs behind well casing.	BP will provide a summary of each annular cement verification log as soon as practicable after each log is completed to NOPTA and NOPSEMA. This will include the log used and a description of the verification of the annular barrier. Verification will be per the applicable ACT, as described in Section 6.3.1. This shall demonstrate effectiveness of cement jobs behind well casing and complies with Condition 9. There are no other exploration activities planned in EPP39, defined as drilling operations within the permit area.
EPP39 Permit Condition 10 The permittee will undertake an annual Environment, Health and Safety Management System self- assessment each year, as per requirements determined by the National Offshore Petroleum Safety and Environmental Management Authority, in relation to the effectiveness of system elements, including the Management of Change process & procedures.	BP refers to the letter dated 22 October 2014 from [redacted] NOPTA Titles Administrator, to [redacted]. This letter recommends that this condition is to be addressed in the Environment Plan and Safety Case. These documents are subject to NOPSEMA's audit capabilities, and are also subject to statutory reporting thresholds for incidents. In addition BP submits an Annual Title Assessment Report. This includes, amongst other things, an itemisation of reports made to the regulator during the year. With these reports together, BP agrees with the Title Administrator and submits that these established processes constitute compliance with Condition 10.

1 Introduction

The Ceduna sub-basin is located on the southern margin of Australia in the Great Australian Bight (GAB). Stromlo-1 is planned to be the first well in the BP drilling campaign, targeting this basin.

The shallow-water margins of the Great Australian Bight were lightly explored from the 1970s to late 1990s. Early 2D seismic surveys were acquired and eight wells were drilled targeting Late Jurassic to Tertiary targets, all of which were unsuccessful, most recently Gnarlyknots-1A in 2003.

In January 2011, BP was awarded four exploration permits in this area: EPP37, EPP38, EPP39 and EPP40.

The Stromlo prospect is considered to be the lowest risk play test of the Conniacian-Turionian (K65) lowstand shoreface play. The well purpose is to penetrate untested stratigraphy and will evaluate the presence of a working petroleum system.

This WOMP is specific to the operations related to the 'Stromlo-1' well and will cover the drilling and abandonment phases of the well. Stromlo-1 is a vertical, exploration only type well. No well test is planned.

Well Name	Stromlo-1	Title Area	EPP39
Latitude	-34.939298	Longitude	130.662388
UTM Easting	651815	UTM Northing	6132427
Water Depth	2239 ±3m		
Rotary Table Elevation	32.65m above mean sea level (Ocean GreatWhite)		

Table 1 – Stromlo-1 Location

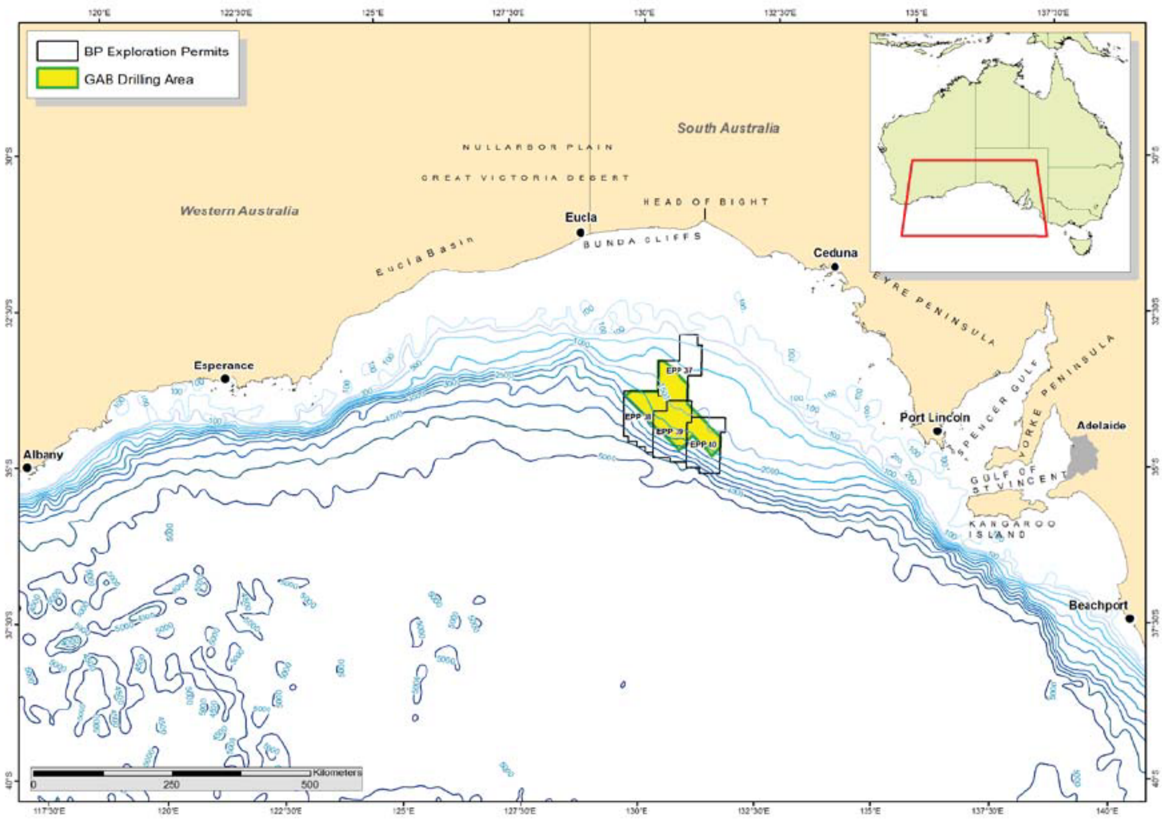


Figure 1 – BP GAB Permits

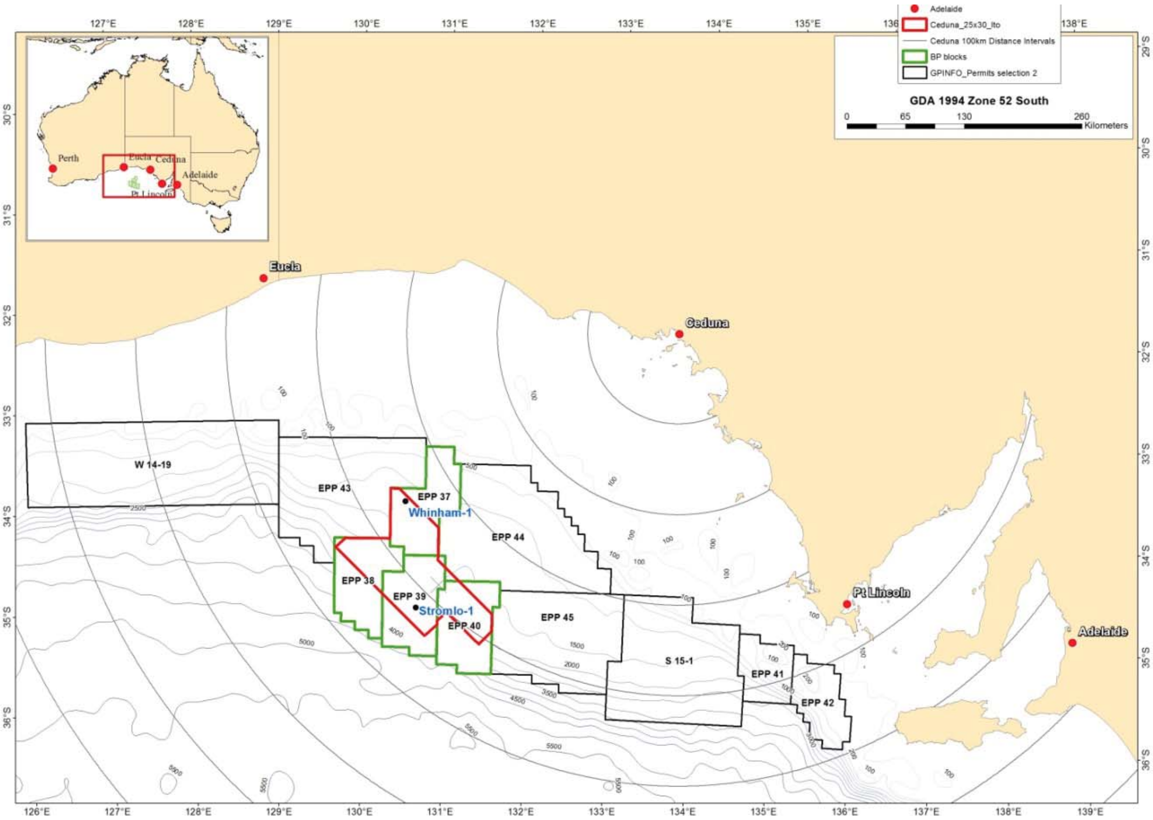


Figure 2 – Stromlo-1 Well Location

2 Description of the Well

Stromlo-1 has been designed as a four casing string, five hole section vertical well. Two additional casing strings will be carried for contingency use. The well will target the reservoir objectives in 8-1/2" hole to allow wireline logging. No well test or long term temporary abandonment is planned (short term temporary abandonment may be required for weather or maintenance reasons).

The well objectives of Stromlo-1 are described in the Stromlo-1 Well Statement of Requirements (SOR) as follows;

HSSE Objective:

- To deliver a safe, compliant and reliable well, underpinned by BPs Operating Management System (OMS) and our commitment to safety

Strategic Objectives:

- To confirm the presence of a working hydrocarbon system through the execution of a four well programme in BP's operated Ceduna sub-basin permits
- To acquire sufficient data to address the critical sub-surface play risks and determine the potential scale of oil and gas resources in the basin
- To calibrate the pore pressure regime to inform immediate operational and future well engineering decisions
- To fulfil the minimum work programme commitment and inform the decision to enter the secondary term or exit

- To deliver the well within the "not to exceed" budget while fulfilling the agreed work programme

Technical Objectives:

- To characterise the reservoir presence and quality of the target between the "K65" and the "K64" reflectors
- To characterise the fluid and phases in place and establish pressure gradients between the "K65" and "K64" reflectors
- To calibrate the well to the seismic dataset through an unambiguous well tie
- To acquire data to inform and optimise present and future drilling operations
- To appropriately evaluate formation overlying the target intervals

To achieve these objectives, BP has contracted the Ocean GreatWhite harsh environment semi-submersible rig from Diamond Offshore which will be used to drill Stromlo-1.

Feature	Particulars
Build design	Moss CS60E Design, 6th Generation, harsh environment.
Classification	DNV +1A1 column stabilized drilling unit.
Accommodation	180 people
DP system	Class 3 with eight azimuth thrusters (DYNPOS-AUTRO).
Derrick	Single, type SDBN-1250, 15x16 m, 64 m high. Static hook load of 1,134 tonnes. Derrick top 6x6 m.
Draw works	Type SSGD-1000-5750-55-82-10.5FMM-NE-CLAC, hoisting capacity of 908 tonnes.
Mud pumps	Four x 14-P-220, triplex type, rated at 1,600 kW each.
Shale shakers	Six balanced elliptical, VSM multi-sized.
Remotely operated vehicle (ROV)	One ROV platform, starboard aft
Primary BOP stack	NOV 18¾" guidelineless, 15,000 psi with multiplex control system six-ram preventer (3 shear, 3 pipe rams).
Ram type preventers	Three double NXT ram bodies.

Table 2 – Summary Details of the Ocean GreatWhite

Programmed section depths, casing specifications and top of cement targets are given in the well schematic below (Figure 3).

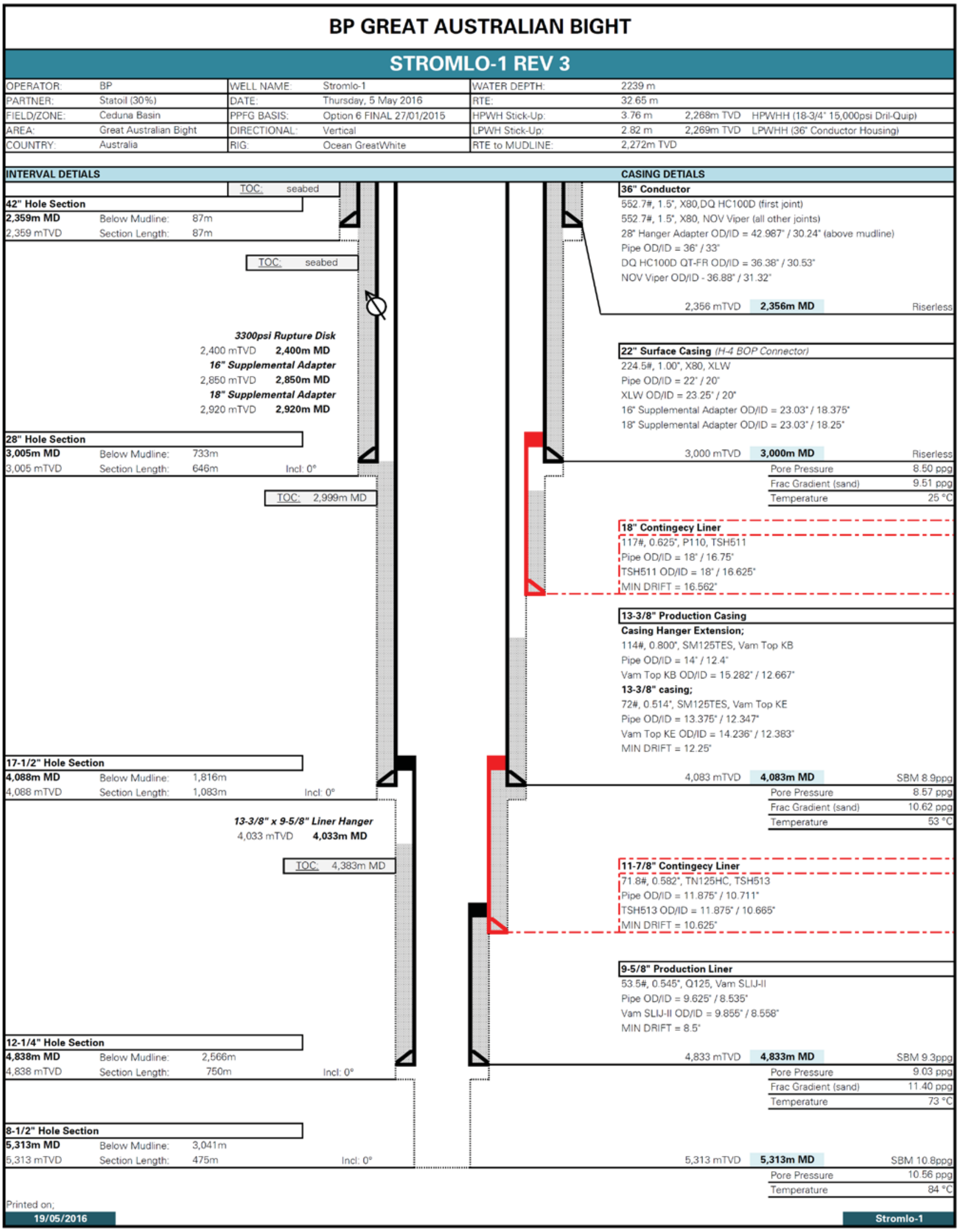
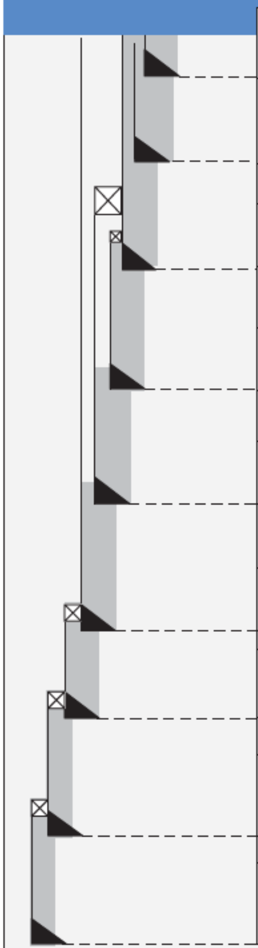


Figure 3 - Stromlo-1 Casing Schematic

The contingencies depicted in Figure 3 (18" and 11-7/8" liners) are considered relatively likely to differing levels and therefore have been designed (casing, cement, etc.). Not depicted in the casing schematic are other 'campaign contingencies' that may be needed in unlikely events. This would be subject to risk assessment, design and MOC as per BP Practices and Procedures. Figure 4 shows all potential casing strings that may be used in the drilling of Stromlo-1. Essentially these are a 28" supplemental conductor, 16" intermediate liner and 7-5/8" liner (beyond planned strings).

Campaign potential string options



42" Hole 36" Conductor	36", X80, HC100D, 1.5" WT (2 joints) x 36", X80, Viper, 1.5" WT
32-1/2" Hole 28" Supplemental Conductor	28", X56, XLW, 0.75" WT
26" x 28" Hole 22" Surface Casing	22", X80, XLW, 1.0" WT
18-1/8" x 21" Hole 18" Intermediate liner	18", P110, Wedge 511, 117ppf
16-1/2" x 20" Hole 16" Intermediate liner	16", Q125IC, Wedge 513, 109ppf
14-1/2" x 17-½" Hole 13-3/8" Casing	13-3/8", SM125TES, Vam Top KE, 72ppf
12-1/4" x 14-½" Hole 11-7/8" Liner	11-7/8", TN125HC, TSH513, 71.8ppf
10-5/8" x 12-¼" Hole 9-5/8" Liner	9-5/8", Q125, Vam SLIJ-II, 53.5ppf
8-½" Hole 7-5/8" Liner	7-5/8", Q125, Vam SLIJ-II, 39ppf

Figure 4 – GAB Campaign Casing Options

2.1 Description of the Activity

The Stromlo-1 well will involve the following activities;

- Drill 28" x 42" hole (open water)
- Run 36" conductor, complete with low pressure wellhead housing (LPWHH) and cement in place.
- Drill 28" hole (open water).

- Run 22″ surface casing, c/w high pressure wellhead housing (HPWHH) and cement in place.
- Run the BOP and test.
    - Note that this includes some integrated acceptance testing (IAT) for the rig as it will be the first time the BOP will be installed on a wellhead.
- Displace the well to SBM drilling fluid. Drill 17-1/2″ hole.
    - If problems occur during this hole section, a hole opening BHA may be run to allow installation of an 18″ contingency liner.
    - In this case an 18-1/8″ x 21″ BHA would be run to open the well to allow installation of the 18″ liner.
    - Following this, 16-1/2″ hole would be drilled to allow installation of the 13-3/8″ to planned depth.
- Run 13-3/8″ surface casing and cement in place. Install seal assembly and testing integrity. Install lock down sleeve.
- Drill 12-1/4″ hole.
    - The primary plan is to then log and run a 9-5/8″ liner (i.e. following steps). However;
        - If problems occur during this hole section, a hole opening BHA may be run to allow installation of an 11-7/8″ contingency liner.
        - In this case a 12-1/4″ x 14-1/2″ BHA would be run to open the well to allow installation of the 11-7/8″ liner.
        - Following this, 10-5/8″ x 12-1/4″ hole would be drilled to allow installation of the 9-5/8 liner to planned depth.
- Wireline logging (depending on LWD data and calibration to seismic)
- Run 9-5/8″ liner and cement in place.
- Drill 8-1/2″ hole to TD.
- Wireline logging.
- Abandon well.

No production, sidetrack coring or suspension is planned for Stromlo-1. However;

- Side-tracking may be required for operational reasons. This would be for remedial work rather than the planned base case (e.g. a stuck pipe event).
- Short term temporary abandonment of the wellbore may be needed for weather or unplanned events (BOP maintenance, weather issues, etc.), however no long term suspension is planned for ‘keeper well’ type situations.

This WOMP therefore covers the ‘**drilling**’ and ‘**abandonment**’ phases for the Stromlo-1 well activities only.

3 Description of the Geology

The Stromlo-1 description of the geology is described in the Well SOR and has been selectively included in this WOMP to provide context without providing excessive, non-relevant information. Some modifications have been made to clarify company specific jargon, references, etc.

3.1.1 List of Offset Wells

Well Name	Operator	Year Drilled	Distance to Stromlo-1	Comments
Gnarlyknots-1A	Woodside	Q2 2003	98 km	Near-vertical well with TD of 4736m MD (intra Coniacian, K70). Plugged and suspended, dry hole.
Potoroo-1	Shell	Q1-Q2 1975	172 km	Near-vertical well with TD of 2924m MD (Cenomanian, K60). Plugged and suspended, dry hole.
Jerboa -1	Esso	1980	324 km	Eyre sub basin. TD of 2538m MD (Early Late Jurassic/Early Cretaceous). Plugged and suspended, dry hole.
Greenly -1	BHP	1993	394 km	Duntroon sub basin. TD of 4860m MD (Cenomanian, K60). Plugged and suspended, dry hole.
Duntroon -1	BP	1986	433km	Duntroon sub basin. TD of 3510 m MD (Cenomanian, K60). Plugged and suspended, dry hole.
Apollo -1	Outback Oil	1975	267 km	TD of 876m MD. Plugged and suspended, dry hole.
Platypus -1	Shell	1972	384 km	Duntroon sub basin. TD of 3893m MD (Cenomanian, K60). Plugged and suspended, dry hole.

Table 3 – Stromlo-1 Offset Wells (Geological)

3.1.2 Geological Prognosis

Seismic Event	Chronostrat.	Lithostrat.	Depth+ (mTVDss)	Depth+ (mBML)	Error Bar (+/- m)	TWT (ms)
Seabed	Seabed		2239	0	+/ - 3	3011
K100	Cenozoic		2400	161	+/ - 20	3196
K88	Campanian - Santonian	Hammerhead	2540	301	+/ - 30	3352
K87			2665	426	+/ - 40	3483
K83			3980	1741	+/ - 170	4500
Detachment	Turonian	Tiger	4640	2401	+/ - 240	4980
K65			4895	2656	+/ - 270	5124
K64.8			4990	2751	+/ - 280	5178
K64.4			5080	2841	+/ - 280	5233
K64			5180	2941	+/ - 300	5294
TD			5280	3041	+/ - 300	5357

+Depth prognosis on PGS PreSDM volume,CEDU_B032_D_12KPrDM13P_KFINAL_FULLS_AGC.

Table 4 – Formation Tops with Depth Uncertainty

Depth+ (mTVDss)	Depth+ (mBML)	Error Bar (m)	Fault	Type	Offset (at well location)
3070	831	±80	Fault	Syn-depositional	50-60m
3210	971	±100	Fault Zone*	Syn-depositional	Large (unknown)
3430	1191	±110			
3580	1341	±130			
4350	2111	±210	Fault Zone associated with Detachment*	Post-depositional	Large (unknown)
4510	2271	±230			
4550	2311	±230			
4640	2401	±240			

+ Depth prognosis on PGS PreSDM volume,CEDU_B032_D_12KPrDM13P_KFINAL_FULLS_AGC.

* a fault zone has been defined as a zone in which the faults are closer together than the depth uncertainty or where the faults cannot be individually picked

Table 5 – Faulting with Depth Uncertainty

3.1.3 Primary Target Reservoir

K65 Reflector	4895mTVDss (2656m BML)
K64 Reflector	5180mTVDss (2941m BML)
Gross Interval thickness	285m
Hydrocarbon Type	Black Oil (GOR 180-310-1500)
Anticipated Lithology	Interval proposed here have not been penetrated in the deep basin, therefore rock properties are uncertain. The properties shown here are considered realistic based on worldwide analogues and modelling.

N:G (Net Sand)			Porosity (%)		
LC	ML	HC	LC	ML	HC
0.3	0.45	0.6	0.15	0.21	0.27

3.1.4 TD Criteria

The Stromlo-1 planned TD is 5,313mTVDRT / 5,280mTVDss / 3,041mBML, assuming a water depth of 2,239m and an RTE of 32.65m.

Stromlo-1 TD has been defined to allow the penetration of the expected K65 to K64 reservoir interval (Primary Objective). The planned TD depth has therefore been defined as the "top K65 at 4895m TVDss plus 385m" giving a TD depth of 5280mTVDss ±300m to account for depth uncertainty.

3.1.5 Interpretation of the Overburden

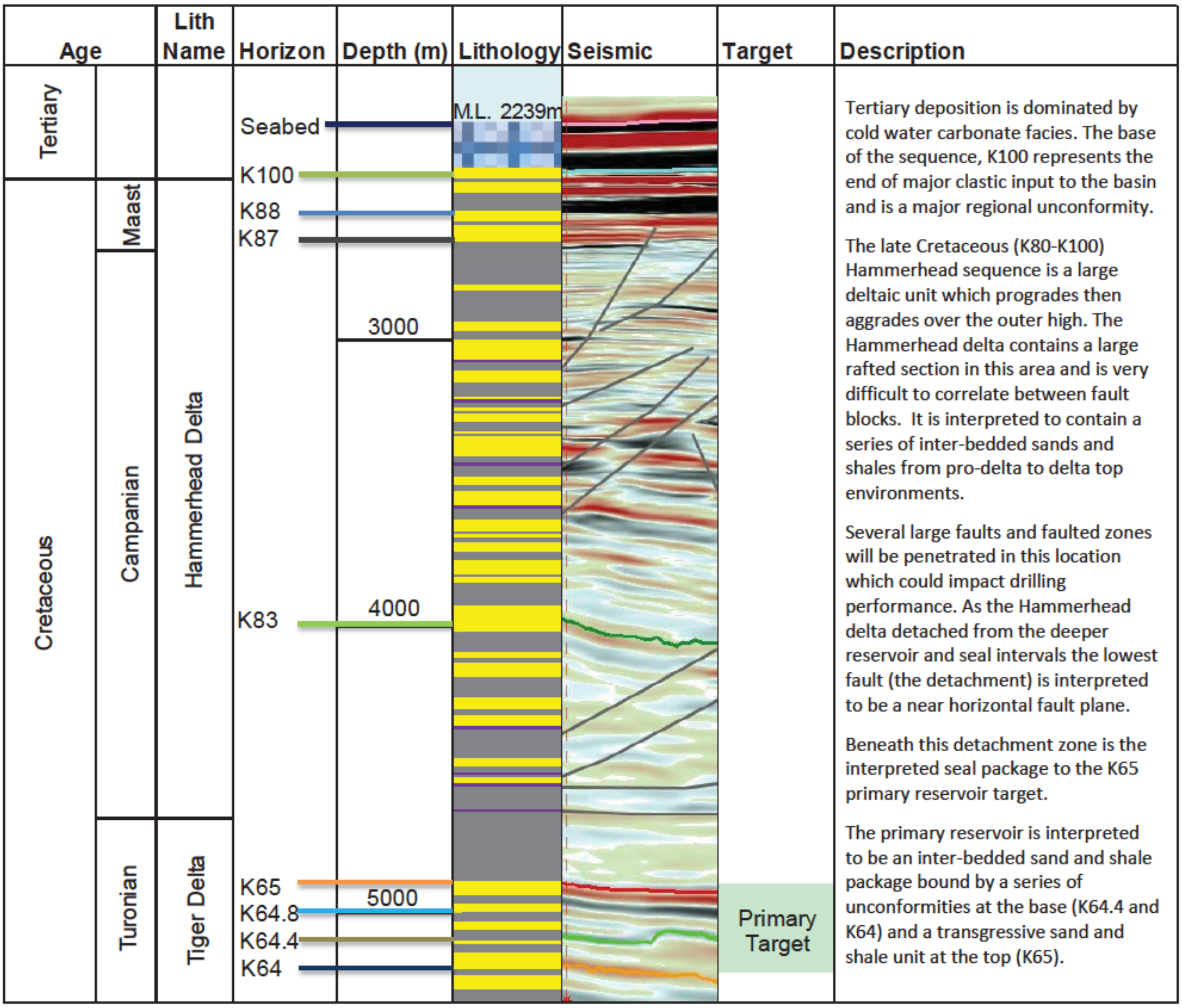


Figure 5 – Overburden Description

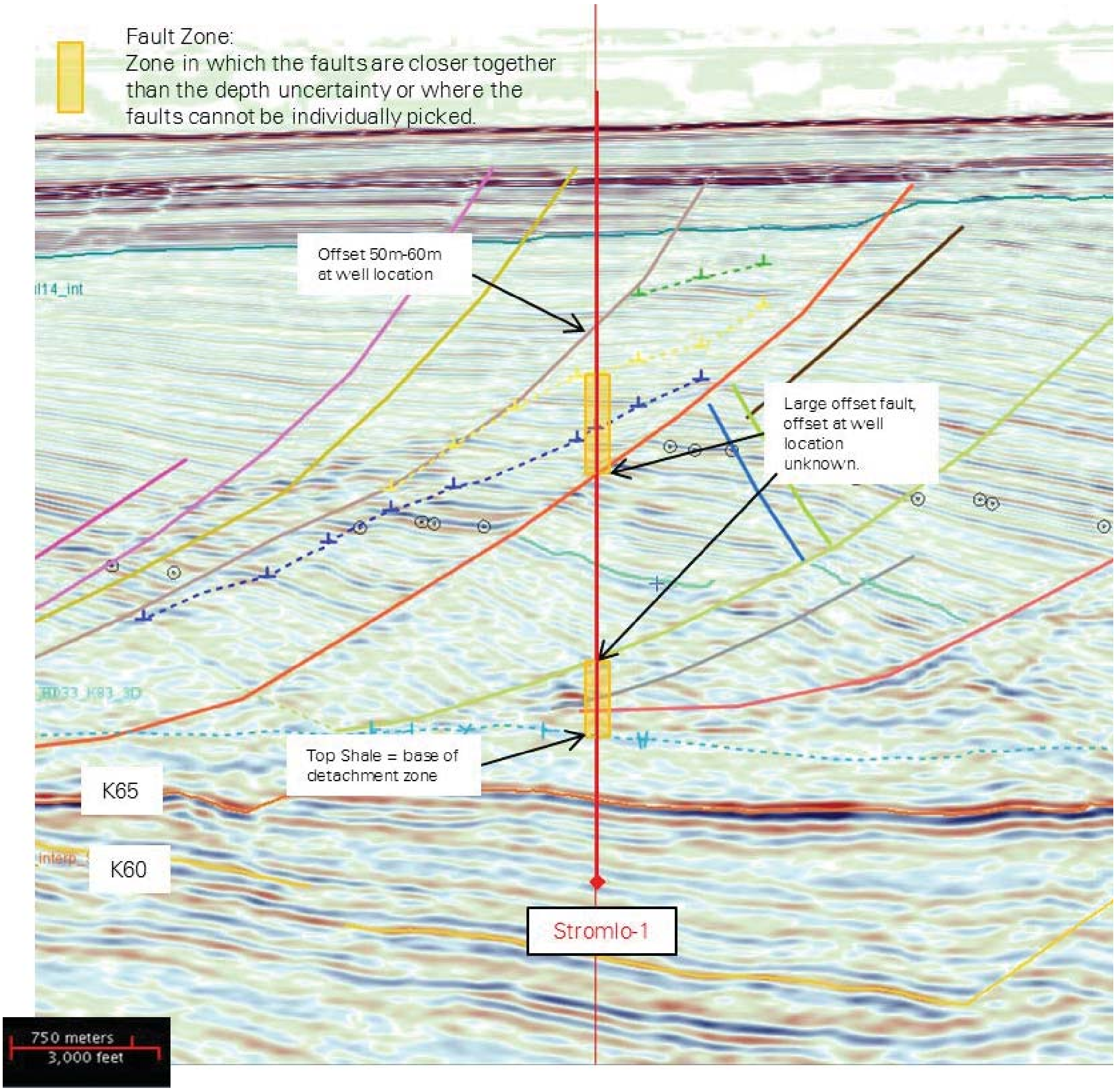
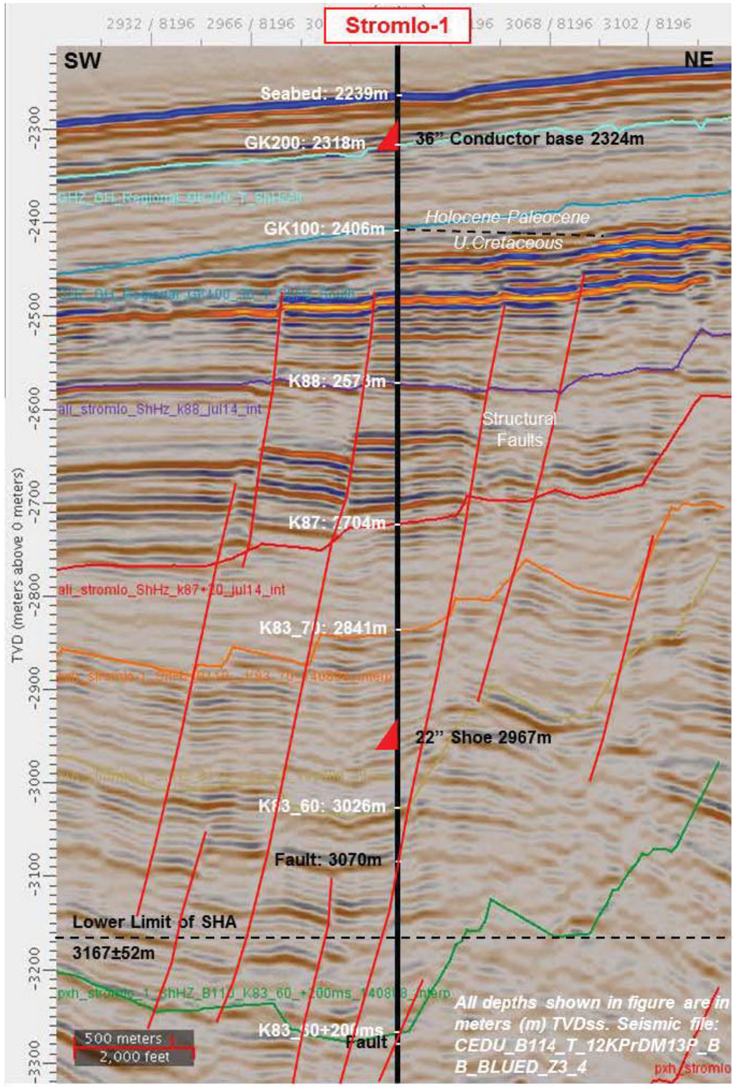


Figure 6 – Overburden Faulting

A shallow hazard study has been undertaken (Stromlo-1 SHA S-SST-0013-15). Below is a summary.



Geohazard	Description	Potential Presence	Potential Impact
Conductor slumping into soft soils	Conductor may sink into very soft seabed and near-seabed soils if jetted.	MODERATE	Negligible impact potential for conductor emplacement as the well is expected to be drilled.
Slope Stability	Location on 3.8° slope and is positioned at the top of a 10m high scarp (with max. 5.5° slope gradient).	LOW	Negligible impact as any failure would be small and localised and would not impact drilling.
Hydrogen Sulphide	Other drilling operations in the region experienced very high levels of H_2S whilst drilling.	LOW of encountering high levels of H2S following peer review	High impact if it were to be present potential for corrosion and highly toxic.
Structural fault	3070±80m TVDss.	HIGH	Low potential for well bore instability or other drilling issues.
Minor tight spots	Minor tight spots encountered in offset wells in the shallow section.	LOW	Low potential impact as expected that can be worked through using appropriate drilling practices.
Shallow water flow	From seabed to the limit of the SHA at 3167±52m TVDss.	NEGLIGIBLE	Negligible
Shallow gas	From seabed to lower limit of assessment at 3167±52m TVDss.	NEGLIGIBLE	Negligible; anomalies 72m north at 2731m TVDSS; be aware for any trajectory changes.
Gas Hydrates	Encountering natural gas hydrate and technogenic hydrate formation	LOW	Low potential to impact drilling. Unlikely to observe gas hydrate or gas at wellhead while drilling.
Underground blow out	In the very unlikely event of an underground blowout, assessment of potential for gas to reach the seabed in the vicinity of the wellhead.	In the very unlikely event of occurrence, MODERATE potential for damage to seabed infrastructure.	

SOR Pre-drill Geohazards Summary for Stromlo-1 (2nd December 2014)

Figure pre-dates the Full SHA, to be completed by 1Q15 by Gayle Hough

Figure 7 – SHA Summary (Extract from the Stromlo-1 SOR)

3.1.6 Pore Pressure and Fracture Gradient

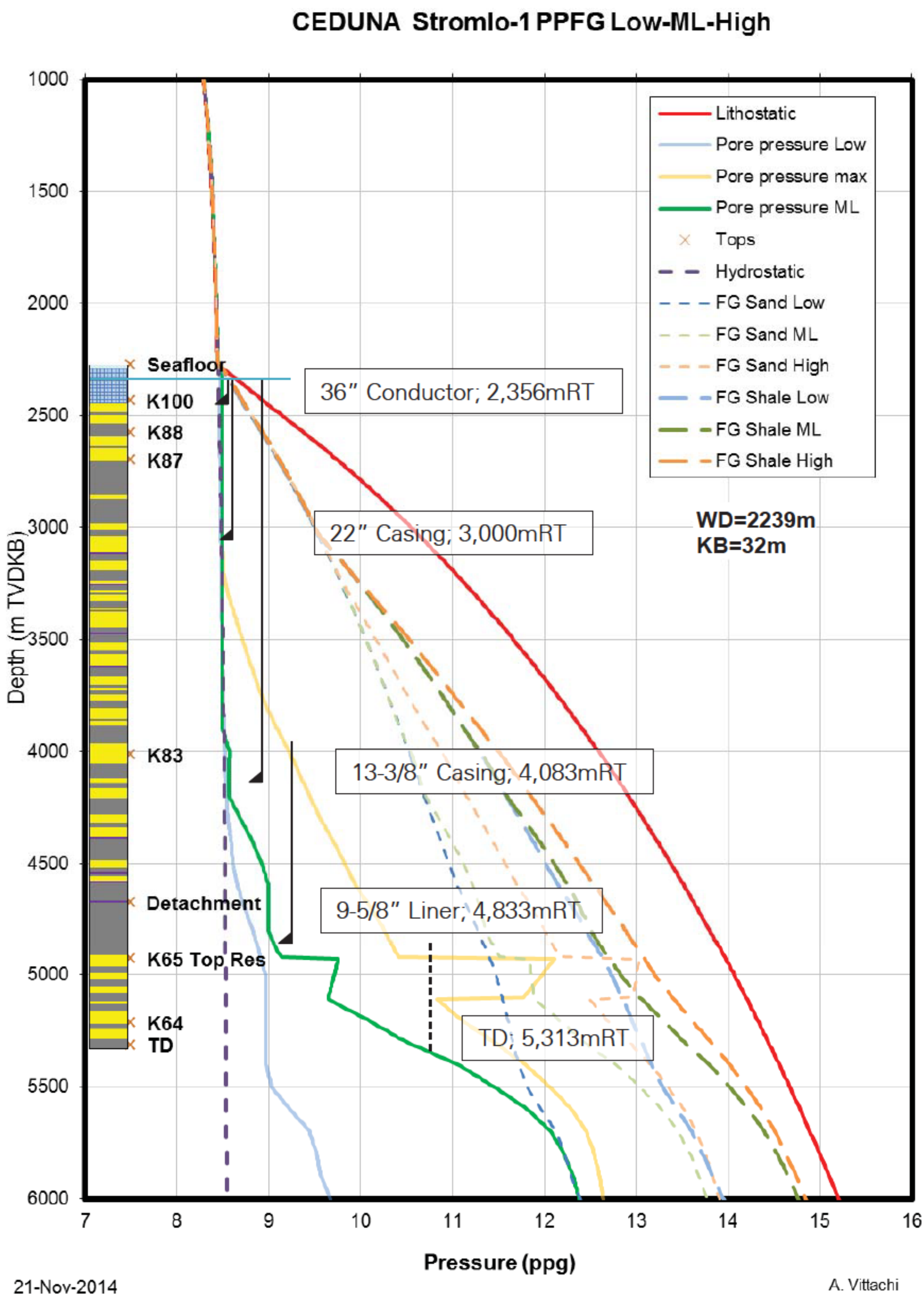


Figure 8 – PPFG Prediction

The PPFG forecasts for Stromlo-1 integrates 2D basin modelling, 2D/3D seismic velocity-pressure transforms and offset well data. The forecast has been performed in accordance with BP Practice 100208 – Pore Pressure Prediction (10-15) requirements and consists of 'most likely', 'likely low' and 'likely high' predictions. The actual pore pressure is expected to be within this range.

<u>Most likely pore pressure:</u> based on shale pressure derived from seismic velocities; sand lithologies were superimposed to calculate sand pressure within shale boundaries.

<u>Low pore pressure:</u> based on sand and shale pressure derived from basin modelling, allowing for up-dip pressure communication; both sand and shale pore pressure is reflected in the prediction.

<u>High pore pressure:</u> based on integrating seismic and basin modelling results assuming facies are predominantly muddy.

<u>Sand fracture gradient:</u> based on the Eaton equation with a Poisson's ratio of 0.33 in accordance with BP's worldwide recommendation. The Low/ML/High forecasts are based on the respective pore pressure profile.

<u>Shale fracture gradient:</u> is based on the Brumfield shale FG equation. The shale FG prediction was constrained to be equal to or higher than sand in the riser-less section. The Low/ML/High forecasts are based on the respective pore pressure profiles.

The pressure discontinuity in 'most likely' and 'high' case pore pressure at the K65 is due to the buoyancy/centroid effect of the target reservoir section.

- For most likely case this is based on a predicted oil column (0.337 psi/ft) of 177m in the K65 sand.
- For high case this was calculated for a dry gas (0.1 psi/ft) column of 342m in the K65 sand.

3.1.7 Predicted Temperature

The Ceduna basin is a frontier area with limited offset data for calibration, and no penetrations into the stratigraphy targeted in the BP prospects; there is significant uncertainty in the prognosed temperature gradient.

Temperature predictions are based on basin modelling. A regional basin model has been built and calibrated to all available offset data. The key offset for temperature calibration is Gnarlyknots-1A (~100 km from Stromlo), where corrected logging temperatures indicate a geothermal gradient of 26 °C/km, however the regional model extends to cover wells in shallow water (Potoroo-1, Jerboa-1 and wells in the Duntroon sub basin) where thermal gradients are higher.

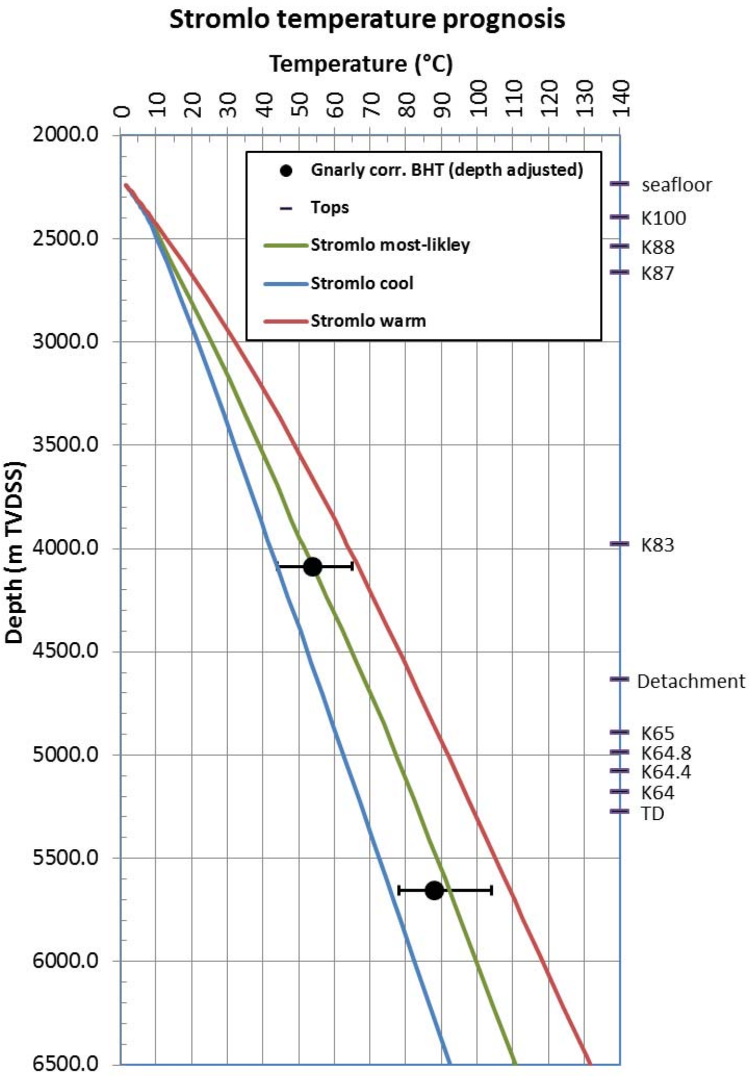


Figure 9 – Temperature Prediction

3.1.8 Distinct Permeable Zones (DPZ)

BP defines a 'permeable zone' as; a zone with sufficient permeability such that a credible pressure differential is expected to result in the movement of fluids (oil, water, or gas) and/or development of sustained casing pressure. A 'DPZ' is identified as; a group of permeable zones in which intrazonal isolation is not required for operation or abandonment of the well. Identification of DPZs is a key step in designing well barriers.

Two pre-drill DPZs have been identified in the Stromlo-1 well. Faults are assumed to be sealing in the overburden due to their large offset of faults and the proportion of shale in the section.

The well casing and cementing will be designed to ensure zonal isolation of these DPZs in accordance with BP Practice 100221 – Zonal Isolation (10-60).

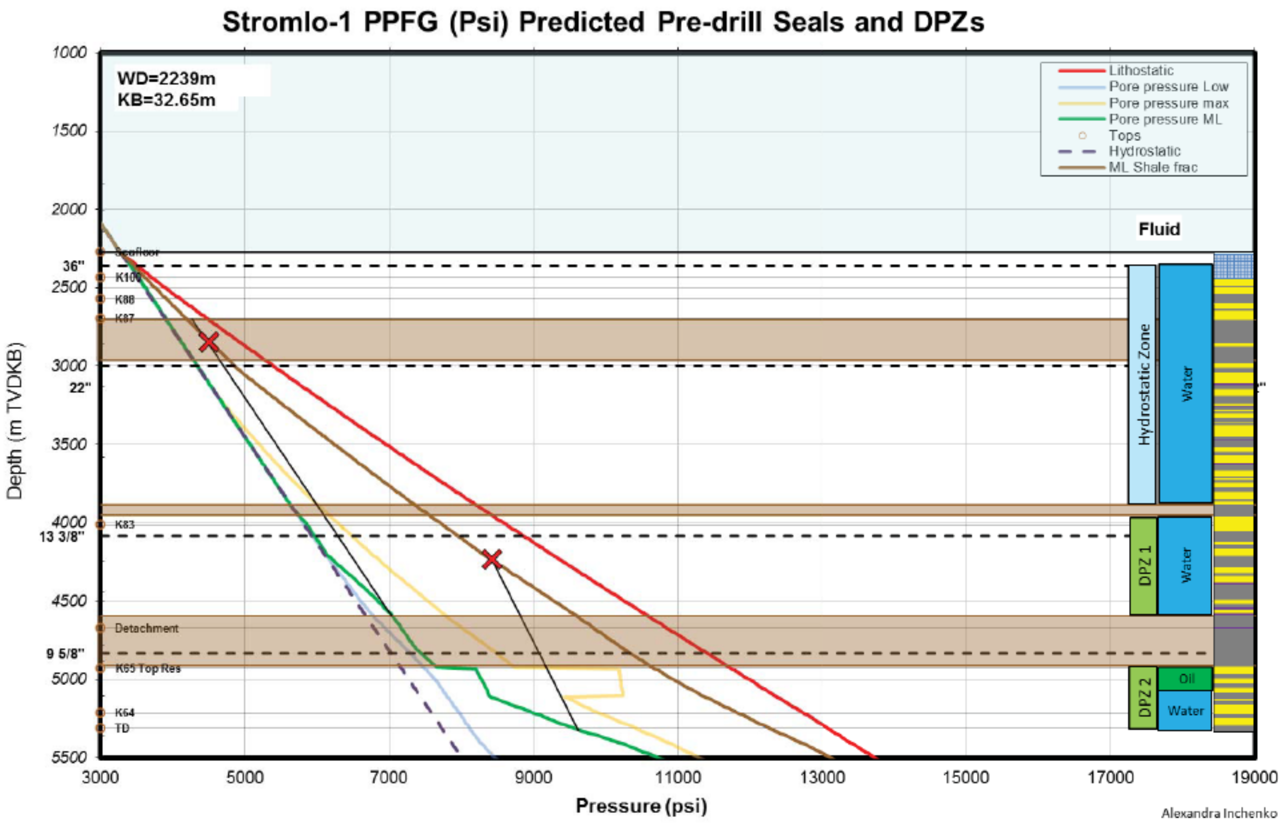


Figure 10 – DPZ Prediction

3.1.9 Predicted Reservoir

				Low-case			Most-likely			High-case		
Target	Horizon	Depth	Depth	Pressure	EMW	Temp	Pressure	EMW	Temp	Pressure	EMW	Temp
		m TVDss	m TVDRT	psi	ppg	°C	psi	ppg	°C	psi	ppg	°C
Primary	K65	4895	4927.65	7492	8.92	60	8200	9.76	75	10180	12.12	89
	K64	5180	5212.65	7965	8.97	66	8980	10.11	81	9886	11.13	97

Table 6 – Assumed Reservoir Properties

Likely source rock properties and charge models in the Ceduna basin are uncalibrated. Furthermore, since Stromlo is in a frontier, play-test well there is no relevant top-down fluid data on which to base predictions. Therefore there is significant uncertainty in all fluid predictions.

A series of deterministic charge models have been built, taking into account uncertainty in the type and richness of source rock, maturity uncertainty and charge migration pathway. Different deterministic scenarios have been simulated which illustrate both oily and gassy cases. The results illustrate that reasonable geological models give rise to a very broad range of fluid predictions, ranging from a low GOR oil, through wet gas, to a dry gas. All these outcomes are considered possible. However, the most-likely model is based on charge from the K60 source, mixed with additional charge from deeper disseminated organic matter.

The predicted fluids associated with the various charge models that have been simulated are tabulated below.

			SCENARIOS					MOST-LIKELY HC SCENARIO
			K60 Base Case	K60 Oily Case	K60 Gassy Case	K55 DOM Case	K45 Late Trap case	K60 Base Case + DOM
Inputs / Assumptions		Depth	most-likely	shallow	deep	most-likely	most-likely	K60 Oil charge plus top up gas charge from deeper DOM. Gas fraction and Geochemical Parameters calculated by assuming 75% charge from K60 Base Case Scenario and 25% charge from K55 DOM Case. Bulk properties calulated in BP-PPT Phase Calculator (Based on GF). This is a reasonable most-likley hydrocarbon outcome
		thermal model	most-likely	cool	hot	most-likely	most-likely	
		source rock interval	K60	K60	K60	K55 (DOM)	K45	
		source rock organofacies	100% B	100% B	100% B	20% DE, 80% F	50% A, 50% B	
		TOC (%)	5	5	5	1.5	5	
		HI	500	600	300	DE 330, F 150	500	
		Source Clay Fraction (%)	45	45	45	45	45	
		Source saturation threshold for expulsion (%)	5	5	5	5	5	
		Fetch area	K65 fill-spill fetch	K65 fill-spill fetch	K65 fill-spill fetch	K55 4-way fetch	K45 4-way fetch	
		BP-PPT thermal history location	80% cumulative STS within fetch	80% cumulative STS within fetch	80% cumulative STS within fetch	80% cumulative STS within fetch	80% cumulative STS within fetch	
		trapping	cumulative	cumulative	cumulative	cumulative	late trapping (post K83, 77Ma)	
		Pore Presure	most-likley Stromlo (AMSI)	most-likley Stromlo (AMSI)	most-likley Stromlo (AMSI)	most-likley Stromlo (AMSI)	most-likley Stromlo (AMSI)	
		biodegredation	no	possible	no	no	no	no
		modelled source kithchen temperature	128	109	170	158	219	n/a
		modelled Reservoir temperature	72	67	86	72	72	72
		modelled Reservoir pressure	8200	8200	8200	8200	8200	8200
Modelling results		cum. Expelled gas mass fraction (from porosity)	0.051	0.027	0.284	0.528	0.926	0.170
	Bulk properties	Phase	Liquid	Liquid	Liquid	Liquid+Gas Cap	Gas	Liquid
		Formation Volume Factor (rbbls/bbls)	1.14	1.09	1.95	3.77	n/a	1.46
		Gas Expansion Bg (scf/cf)	n/a	n/a	n/a	337	369	n/a
		surface GOR (scf/bbl)	227	117	1663	4345	n/a	861
		surface CGR (bbls/MMscf)	n/a	n/a	n/a		14	n/a
		surface gas density (kg/m3)	1.19	1.2	1.08	0.99	0.75	1.13
		surface gas gravity (air)	0.97	0.98	0.88	0.8	0.61	0.92
		surface oil density (kg/m3)	891	904	819	795	772	845
		surface oil gravity (°API)	27	25	41	46	52	36
		Glasso bubble point pressure (psi)	1213	667	4726	8882	19232	3092
	Geochemistry	Saturates (%)	34.8	32.8	47.7	72	65.5	38.0
		Aromatics (%)	40	41.1	33.8	16.2	22.5	38.5
		Polars (%)	16.2	16.4	14.8	10.1	11.9	15.9
		Asphaltines (%)	9	10.2	3.6	1.6	0	7.7
		Wax (%)	7.7	6.7	9.7	9.5	2	8.2
		Nickel (ppm)	25	28	15	7	6	22.5
		Vanadium (ppm)	95	112	39	4	9	81
		Sulphur (%)	0.87	1	0.42	0.06	0.15	0.76

Deterministic scenarios are modedelled to give an indication of the likely range on each paramters. Values are reported as output from the model, which leads to a high apparent precision. However, the uncertainty range is large on all paramters and in reality it is not possible to make highly accurate or precise predicitions in frontier exploration areas.

Temperature, depth and efective stress histories were extracted from the Ceduna Trinity model, which is calibrated to a series of 1D Genesis models (August 2014).

Fluid Predictions were made in the BP Petroleum Predicition Toolkit (BP-PPT 5.1.8.1963)

Geochemical paramters calulated in the BP-PPT Source & Fluids Advanced module, Bulk properties caluclated in the BP-PPT Phase Calulator (using Gas Fraction from source & fluids and PVT assumptions detailed above).

Gas exapansion factors calulated in the BP Reservoir Engineering Toolkit (BP-RET 1.1.4.904) using reservoir gas gravity as an input (Caluclated in BP-PPT Phase Calulator).

Oil formation Volume Factors were calulated in the Amoco Black Oil Calulator (excell sheet)

Table 7 – Assumed Fluid Properties

3.1.10 Non-Hydrocarbon Gasses

There are no relevant top-down fluid data available for assessment of H_2S risk at reservoir depths as the Stromlo is in an untested play. Non-hydrocarbon gas predictions carry significant uncertainty due to the frontier nature of the Stromlo prospect. It is not possible to make predictions of absolute concentrations due to the lack of calibration data and uncertainty in the petroleum system, therefore a series of risk statements have been developed and are tabulated below. These were peer-reviewed and endorsed.

	Primary Target (K65)
H_2S	MOST-LIKELY H_2S concentrations at Stromlo K65 are <10ppm. 100s ppm H_2S is possible in the primary target (K65) resulting from in-reservoir BSR, this is considered LOW RISK
CO_2	There is a MODERATE RISK of CO_2 < 10 mol% There is a LOW RISK of high-% CO_2 associated with volcanics
N_2	Stromlo K65 is considered LOW RISK for N_2

Table 8 – Assumed Non-Hydrocarbon Gasses Summary (BSR = Bacterial Sulphate Reduction)

4 Management of the Well Activity

The function responsible for well delivery within BP is called the 'Global Well Organisation' (GWO). BP GWO manages well design and operation under 'BP Practice 100100 - New Well Common Process (NWcp)'. The NWcp is a form of Capital Value Process (CVP) stage gate model. An overview is shown in Figure 11. It incorporates decision rights for well stage gates along with the well design and operation documents. It provides a decision-making framework to facilitate systematic management with clear accountabilities. The practice supports the delivery of safe, reliable, and compliant wells through;

- Standardisation of the CVP framework for drilling, completion, and handover of new wells.
- Standardisation of process and language to more efficiently on-board new personnel.
- Teamwork and collaboration among Reservoir Development, Exploration, GWO, Global Operations Organisation (GOO), and other functions.
    - Specifically with the assistance of New Well Delivery (NWD).
- Staff awareness of appropriate roles associated with primary steps in the NWcp.
- Management of Change (MoC) requirements for principal documents.
- Systematic planning, operations, and learning to support delivery of high quality wells.

There are five phases to the NWcp; Appraise, Select, Define, Execute and Review. At the end of each phase a Decision Support Package (DSP) is generated and, at a minimum, includes the items listed below for each phase.

Although GWO is responsible for the delivery of wells, they work closely with NWD to achieve this. The Appraise and Select phases of the NWcp are led by NWD (all other phases are led by GWO). NWD it part of the Reservoir Development Organisation and provides the geological support required to plan and execute new wells within BP.

Stage Gate 1 – Appraise to Select

- Well Initiation Document (WID)
- Project Plan and Organisation Chart
- Long Lead Equipment List and Long Lead AFE

Stage Gate 2 – Select to Define

- Well-specific Risks in Risk Register
- Preliminary Cost and Time Estimates
- Well Statement of Requirements (SOR)
- Updated Project Plan

Stage Gate 3 – Define to Execute

- Update Level 3 and 4 Risk Register with Risk Management Measures
- Geological Operations Programme (GOP)
- Well Basis of Design (BOD)
- Approval for Expenditure (AFE)
- Regulatory Permits

- Drilling Programme
- Relief Well and Capping Plans
- Updated Project Plan
- SimOps Plan

Stage Gate 4 – Execute to Review

- Not applicable to this WOMP – production well based activities.

Stage Gate 5 – Review/Close out

- End of Well Report (EoWR)
- Well Closeout Checklist
- Integrated Well Review

Approval to move into the next stage is determined by the 'gatekeeper' who holds the 'decide' rights as per the Recommend, Agree, Perform, Input, Decide (RAPID) decision rights, shown in Figure 12.

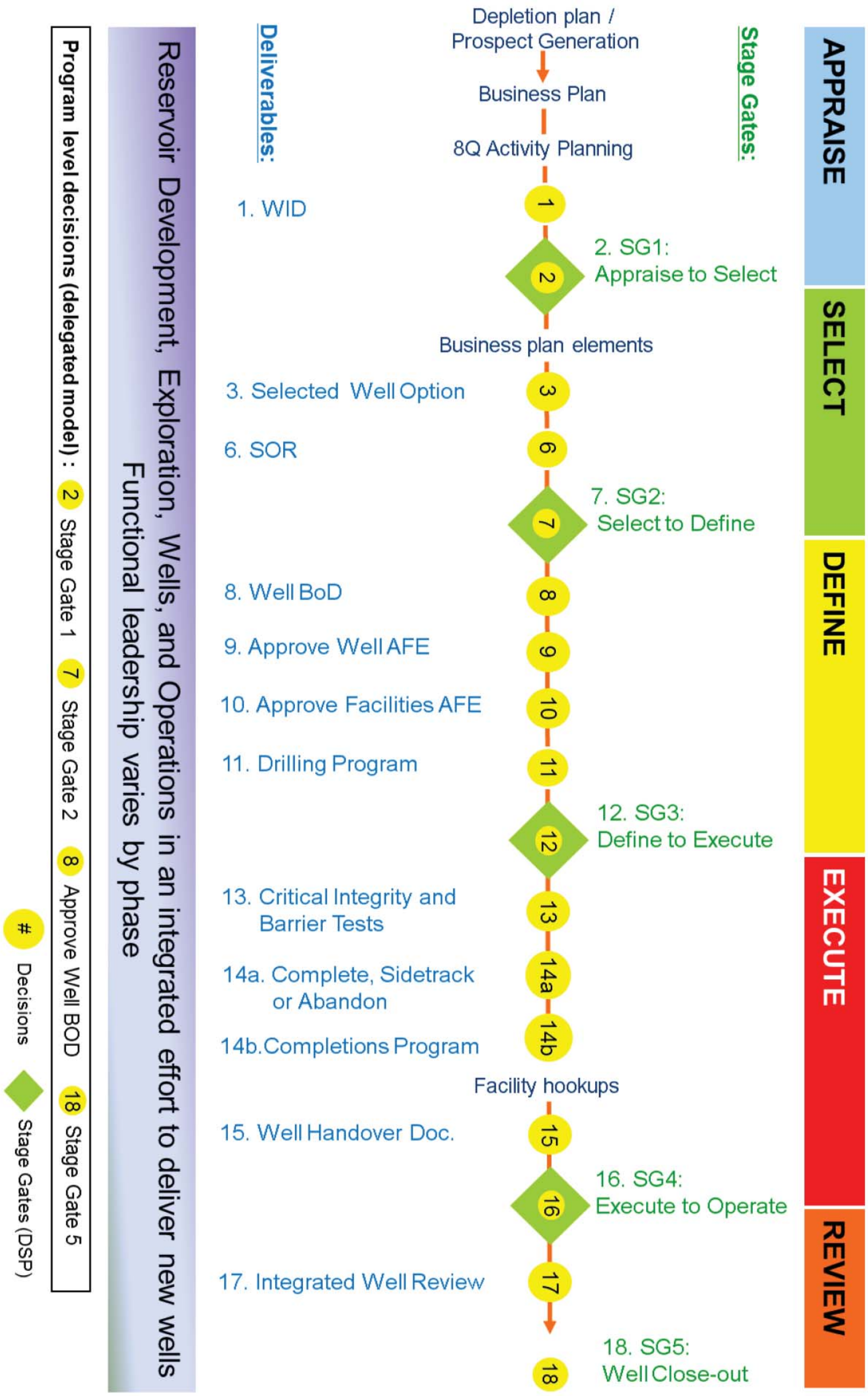


Figure 11 – The Fundamental NWcp Workflow

New Well Common Process and Decision Rights (RAPID) Version 1.4	Role Title: Subsurface											Wells											Operations			Finance
No. ■ Key decision	VP Res Dev, VP X or PGM	Res Mgmt Mgr, Exp. Mgr or Res Dev Manager	Reservoir Mgmt TL or Expl. Lead	NWD Mgr or Res Dev Mgr (2)	NWD TL (9)	Petrophysicist	Base Mgmt Mgr	Base Mgmt TL	NWD Function Lead (5)	Global Exploration NWD Mgr (8)	VP Res Dev GPO	VP Wells	Drilling Eng. Manager	Drilling Eng. TL	Drilling Engineer	Completions Eng. Manager	Completions Eng. TL	Completions Engineer	Wells Operations Manager	Wells Superintendent	Wellsite Leader	Well Integrity TL	Subsea Wells TL	VP Operations	Area Eng Support TL	AOM	Regional Finance
1.- Appraise																											
1 ■ Approve Well Initiation Document (WID)		D	R		A																						
2 ■ SG1- Appraise to Select	D	R								A (8)		A															
2.- Select																											
3 ■ Approve selected Well option			A	D	R			A	A (5)	A (8)				A			A										
6 ■ Approve Well Statement of Requirements (SoR)		A (4)		D	R		A (14)			A (8)			A			A											
7 ■ SG2- Select to Define	A (6)			R							A (7)	D															
3.- Define																											
8 ■ Approve Well Basis of Design (BOD)	Refer to the Well or Field BoD RAPID in Annex D (13)																										
9 ■ Approve Well Authority for Expenditure (AFE) input	A												D (11)	R (11)		D (11)	R (11)										A (10)
10 ■ Approve Facilities and/or Subsea AFE input	A																						R	D (12)	R		A (10)
11 ■ Approve Drilling Programme														D	R					A							
12 ■ SG3- Define to Execute												D							R							A (12)	
4.- Execute																											
13 ■ Approve critical integrity and barrier tests for wells (as per Drilling Programme)						A (1)														D (3)	R						
14a ■ Approve recommendation to complete, side-track or abandon	D (12)			R							A (7)									A							
14b ■ Approve Completions Programme			A														D	R		A							
15 ■ Approve Well Handover Document								R												R		A				D (12)	
16 ■ SG4- Execute to Operate							R																	D (12)		R (12)	
5.- Review																											
17 ■ Approve Integrated Well Review - Static			A	D	R			A	A (5)	A (8)				A			A			A							
18 ■ SG5- Project closeout	D (6)			R								A														A (12)	

1. Cement Bond Log (CBL) Technical Interpretation Specialist designated by the Region agrees on Cement Evaluation Logs interpretation [as defined BP Practice Zonal Isolation (10-60)].

2. The NWD Manager's Decision Rights are taken by the (Area) ResDev Mgr if that position exists in the organization.

3. May require higher level approval as stated in the Well Programme.

4. Delegates to RM TL if Area RD Mgr in place.

5. NWD Functional lead role only applies when NWD Manager not in place.

6. When Region RD resources are used to support Exploration and Appraisal and GPO activity both the VP Exploration / PGM and VP Res Dev have agree rights.

7. For Major Projects wells only.

8. For Exploration and Appraisal wells only.

9. When there is no NWD TL reporting to the NWD Manager these decision rights can be delegated to a competent senior NWD Geoscientist. In the absense of a NWD Manager a bespoke Function approved plan is required.

10. As delegated by Regional CFO.

11. Where there is an R for both Drilling and Completions decisions, only one may be required as appropriate.

12. Or delegate.

13. Decision 8 is a compilation of subcomponents including well deisgn documents and the BoD summary.

14. Base Mgmt assures Ops is included as appropriate.

R Recommend
A Agree
D Decide

Figure 12 – NWcp RAPID Decision Rights as per BP Practice 100100 – New Well Common Process (Version 1.4)

Note; Regional organisations that do not have all roles assigned in the New Well RAPID shall delegate Decide rights to a higher level in the organisation and Recommend, Agree, and Input rights to the same or a lower level. For Stromlo-1 this is specifically applicable as the region does not have a 'Wells Superintendent'. This role has been delegated up to a 'Wells Manager' (see Figure 16) which is a role that encompasses both the 'Drilling Engineering Manager' and 'Wells Operation Manager' (i.e. the three roles have been amalgamated for this, limited campaign, project).

4.1 Governance Documentation and ALARP Principles

With this NWcp as an overarching format, BP GWO uses 43 Practices, 12 Procedures, 67 Guides and 7 Specifications to define the well activities. BP GWO manages its own practices to assure it has full control over content.

BP Practices and Procedures contain 'Shall' statements to designate a BP Requirement.

The Stromlo-1 well design conforms to BP Practices and Procedures. Where BP Practices and Procedures cannot be met, deviations with associated risk assessments will be undertaken as per section 4.5.

Whilst the Practices are owned by GWO, BP has an allocated S+OR Segment Engineering Technical Authority (SETA) who is responsible for the content of each of the Practices. These SETAs regularly review the content against globally recognised guidelines to understand where variances may exist. Where there is a requirement to follow specific requirements within an industry standard, these are identified through normative documents and reference to the specific industry clauses. BP actively participates on several industry bodies to assure it is both aware and is able to influence the development and content of industry standards positively. Specifically BP participates in;

- American Petroleum Industry (API). BP is heavily involved with the generation and review of content.
- The Oil and Gas UK (OGUK) Guidelines. BP has representation on the various OGUK workgroups and a BP representative co-led the workgroup that prepared the Well Life Cycle Integrity Guidelines.
- NORSOK including development and review of the D-010 Standard.
- ISO. BP participated on the committee that is currently preparing ISO 16530 (yet to be released).

The SETAs are responsible for the generation of the Practices that define the minimum standards that BP well planning and operations must meet. However to identify and assure the risks are managed to an ALARP level, BP uses the New Well Common Process (NWcp) and specifically the steps within this process, to identify and apply risk prevention and mitigation measures. Through this process BP brings exposure down to a level that is considered acceptable. This process helps identify the risks which are then formally documented in the BP Risk Management Process. The NWcp and Risk Management Process are documented at length in this WOMP (section 4 and 8 respectively).

For the BP GAB operations on Stromlo-1, BP intends to use BP internal governance documentation (i.e. BP's Practices and Procedures). These Practices and Procedures are constantly reviewed against globally recognised 'good oilfield practices'. Through using these as a minimum, and following the NWcp to identify and implement barriers where required, the GAB team demonstrates the design and operations are to an ALARP level.

4.2 Well Design (BOD Generation)

Part of the NWcp process is the generation of a 'Well Basis of Design (BOD)'. A 'Well BOD' is made up of the key design documents with a 'BOD Summary' to highlight areas that require elevated awareness. It is the documentation that defines the wells technical makeup. For clarity, the 'Stromlo-1 Well BOD' is the combination of;

- The Stromlo-1 BOD Summary (AU000-DR-BOD-600-00005), which references;
  - o Stromlo-1 Casing BOD (AU000-DR-BOD-600-00002),
  - o GAB Drilling Riser Analysis Summary 2015 (UE-2015-0028),
  - o Stromlo-1 Fluids BOD (AU000-DR-BOD-600-00004), and,
  - o Stromlo-1 Cementing TFN (AU000-DR-BOD-600-00003).

The Stromlo-1 well design is described in the Well BOD Summary and has been selectively included in the sections 5 and 6 of this WOMP to provide context without providing excessive, non-relevant information. Some modifications have been made to clarify company specific jargon, references, etc. As shown in Figure 12, well BODs do not follow the same RAPID rights. Instead, the following is used. This is to assure that the correct technical specialists are involved in key design aspects. The elevated sign-off of the 'Well BOD Summary' allows the engineering team to elevate key risks and issues to the appropriate level.

Well or Field Basis of Design (BoD) Decision Rights (RAPID) Version 1.4	Engineering						Specialists				I&I
	Drilling Eng. Manager	Drilling Eng. TL	Drilling Engineer	Completion Eng. Manager	Completion Eng. TL	Completion Engineer	Completion Technical Specialist or Advisor	Cementing Technical Specialist	Fluids Technical Specialist or Advisor	Technical Specialist	Interventions and Integrity Team Leader
▪ Well or Field BoD Subcomponent											
Design Documents											
▪ Well or Field Casing Design Document		D	R (1)								
▪ Well or Field Tubing Design Document					D	R (1)					
▪ Well or Field Cementing Design Document		D	R					A (2)			
▪ Well or Field Fluids Design Document		D	R						A (3)		
▪ Well or Field Completion Design Document					D	R	A (4)				
▪ Other Well or Field Design Documents		D (8)	R		D (8)	R (6)				A (5)	
BoD Summaries											
▪ Well or Field BoD Summary	D	R		A (6)	R (5)						A (6,7)

1. With inputs as required per BP Practice 100202 Casing and Tubing Design.
2. As required per BP Practice 100221 Zonal Isolation.
3. Regional or as designated by Fluids Manager.
4. As designated by Completion and Interventions & Integrity Director.
5. As designated by the Drilling or Completion Director.
6. If well to be completed.
7. If position exists in Region.
8. Drilling or Completion as appropriate.

R Recommend
A Agree
D Decide

Figure 13 – Well BOD RAPID Decision Rights EXTRACT from the BP Practice 100100 – New Well Common Process (Version 1.4)

Note; Regional organisations that do not have all roles assigned in the New Well RAPID shall delegate Decide rights to a higher level in the organisation and Recommend, Agree, and Input rights to the same or a lower level. For this table during Stromlo-1, this is specifically applicable as the region does not have a 'Drilling Engineering Manager'. This role has been delegated up to a 'Wells Manager' (see Figure 16).

4.3 Well Operations (Documentation and Workflow)

During the 'Execute' phase of the well lifecycle, several key documents and meetings define the operational steps for well construction. These are;

- Drilling Operations Programme (DOP) (also called 'drilling programme' or 'well programme')

  - The drilling programme delivers well information and task-based procedures for the planned operation and is consistent with the SoR and Well BoD. The DOP provides operational instructions to convert a specific engineering design and permit requirements to a tangible well product in the ground that meets evaluation objectives. It includes detailed information on components of the drilling operation including casing, cement, fluid, directional drilling, logging equipment, and others.
  - The drilling engineer completes the well programme with input from the multidisciplinary team and suppliers. The Wells Manager uses the programme to execute the well with the field operations team.
- Geological Operations Programme (GOP)
  - This document is developed by New Well Delivery (NWD) and supports the drilling programme by detailing the geological scope of work during drilling operations. This GOP is a subsurface document that operationalises the SoR. It is intended to be the subsurface reference document for the team during Execution (this includes the office based team, wells superintendent, wellsite geologist(s) and suppliers).
  - The document contains the final version of the well objectives, subsurface prognosis and uncertainties, PPFG forecast, well specific hole section montages, detailed TD criteria for each hole section, detailed data acquisition plan (formation evaluation), detailed data collection and distribution requirements, and an up-to-date contact list. Additional attachments may include well specific hole section montages, decision trees, and offset data package or information.
- Drill Well on Paper (DWOP)
  - A DWOP session, will be led by the drilling engineer, in a line-by-line review of the drilling programme with a group of reviewers, selected to critique and improve the document. Attendees will include supplier company representatives, Rig Contractor Representative, NWD personnel, GWO engineers, technical specialists, and field personnel. These sessions will be used to review the entire drilling programme.
- Readiness to Execute Review (RtE)
  - The RtE Review is a peer review.
  - It is performed on wells classified by the GWO Well Classification Process as Well Category A or B or on any priority well (Note, Stromlo-1 is classified ‘B’). This review evaluates the robustness of the final well design, the well programme and/or work instructions, the GOP, and contingencies. Equipment and service provider availability and preparedness are confirmed, and the team assures that the skills and competence can deliver the plan. Examples of topics discussed in an RtE review may include:
    - Quality and robustness of execution plans.
    - Understanding and communication of risks and subsequent risk management plans.
    - Understanding and communication of key decision and verification points.
    - Resourcing the team to successfully deliver the plan.
- Rig Site Crew Engagement

  - Crew engagement in the Execute stage engages the field personnel to foster their understanding of the well programme and rig site details. Crew engagement activities will include pre-spud meetings, pre-tour meetings and pre-job meetings. These meetings are led by the Well Site Leaders and rig contractor leadership and include rig personnel and supplier crews.
  - Pre-section meetings may also be held onshore with specific vendors to review detailed procedures around specific technical equipment. Participation in these meetings may extend to the offshore teams as appropriate.
- Daily morning calls
  - Each morning a call will be held between the rig and the shore based support team to discuss operations. These will focus on the activities of the previous day and forward planning.
- Written Work Instruction (WWI)
  - WWIs are generated for specific work scopes to provide detailed, specific and sequential information needed to carry out the well activity. They are based on the DOP/GOP however involve more detail as to how the rig crew are planning to execute the operations. These instructions are prepared by the Well Site Leader and are strictly oriented toward rig operations.
  - For Stromlo-1, the following flowchart (Figure 14) provides an example as to how the DOP/GOP, pre-section meetings, WWIs and AARs interact.
- After Action Review (AAR)
  - An AAR captures lessons by obtaining immediate feedback with the office and field participants of the activity while memories are fresh and field personnel are available. The objective is to obtain a shared understanding of occurrences following an activity, why it happened, and determine if changes are needed to enhance performance for future activities. Examples of activities where AARs are often used include the end of a hole section, completion of a production casing run, or the end of a logging phase.
  - The outputs of AARs are lessons that are identified and captured in TeamLink (discussed in Section 4.4.4).

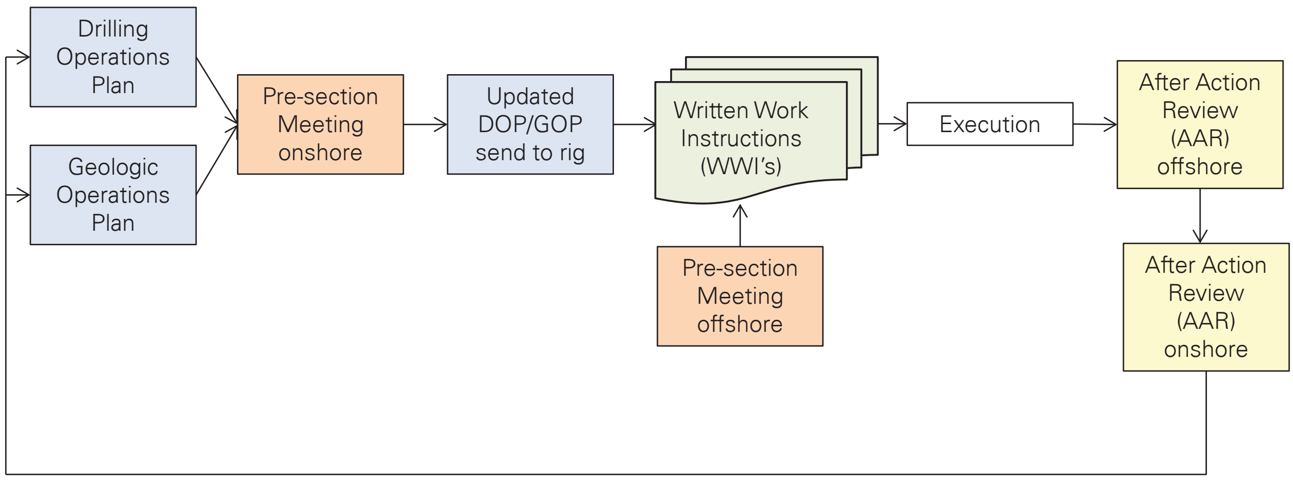


Figure 14 – Execution Workflow (from Plan to Rig Floor)

In addition, the following regular reporting will take place during operations.

- Daily Drilling Reports (DDR)
  - Daily for every day of wells operations.
  - BP uses OpenWells to manage DDRs.
- Daily Mud Report (DMR)
  - Generated by the drilling fluids vendor on a daily basis.
- Daily Geology Report (DGR)
  - Generated by the wellsite Geologist each day (drilling activities take place)
- Cementing Job Report
  - Generated by the cementing vendor after every cement job. Prepared by the offshore Cementing Engineer.
- End of Well Report (EoWR)
  - At the end of the well prepared by the Drilling Engineer.
- Pressure Test Results
  - Report showing the pass/fail of all Well Barrier Element (WBE) pressure tests (including charts).
- Leak Off Test (LOT) Report
  - Generated for every LOT/FIT by the wellsite DE
  - Used for the official kick tolerance calculation
- Top of Cement (TOC) calculation report and acceptance verification checklist.
  - Generated by the Engineering team to provide an official TOC for each annular cement job.

4.3.1 Fluid and Cementing Programmes

Drilling fluid and cementing programmes are managed under a defined process in the NWcp. They are considered to be key documents for the safe delivery of Stromlo-1. Specifically, the following process was used to manage Fluids and Cementing Programmes;

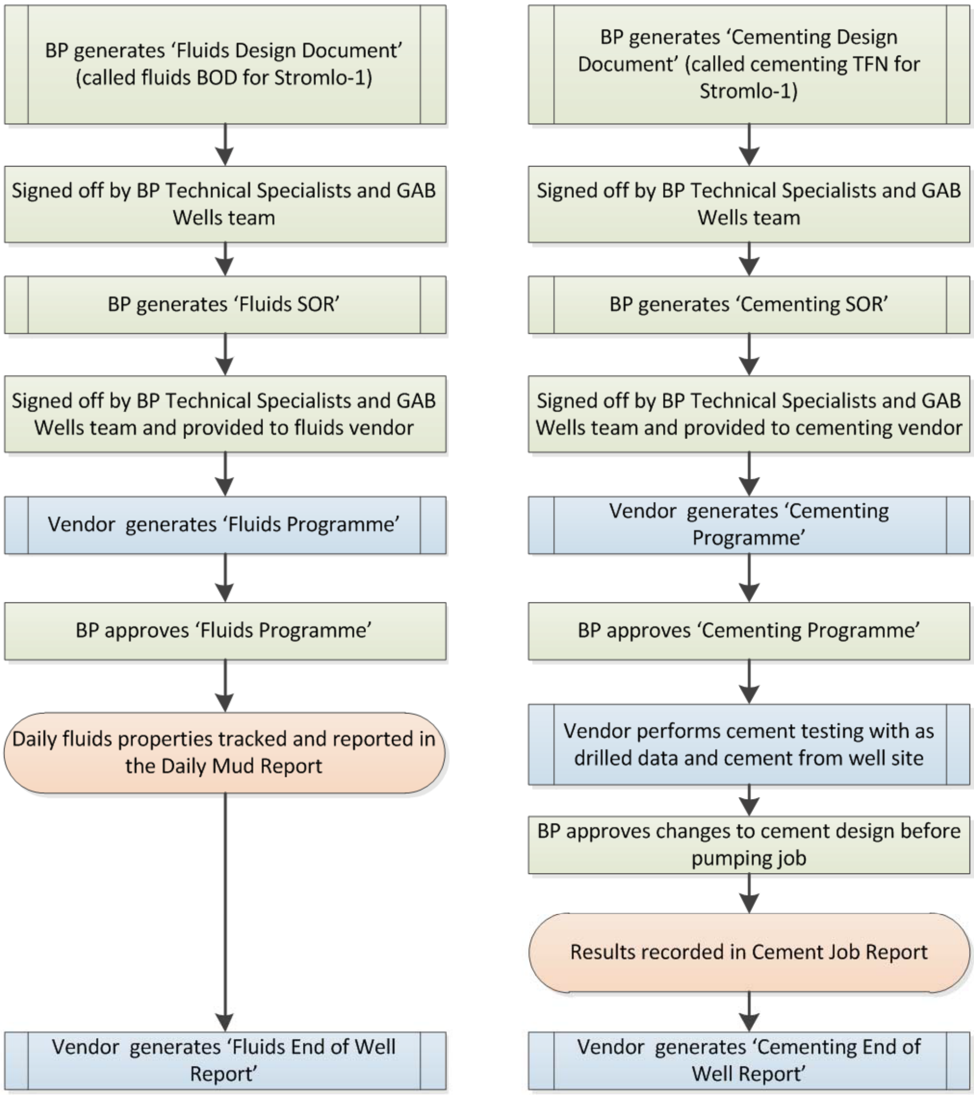


Figure 15 – Fluids and Cementing Design Workflow

4.4 Organisation Supporting Well Activities

BP operates under a functional model. However the following provides clarity as to the general structure the GAB team work under within BP;

Company	BP
Segment	Upstream
Operating Function	GWO
Region	New Ventures
Team working Stromlo-1	GAB team

Stromlo-1 drilling operations in the Great Australian Bight will be managed by the 'New Ventures' region. New Ventures is a region of the Global Wells Organisation (GWO). GWO New Ventures deliver BP's Deepwater Exploration and Appraisal wells globally, in locations where GWO does not have a pre-existing 'Regional' team with the required expertise. This project is one of several ongoing in the overall New Ventures portfolio.

GWO New Ventures follows a controlled organisational structure. This develops as operations expand into multiple concurrent locations across the globe. The present organisational structure is aligned to existing operational commitments. As programmes progress, the structure will incorporate the additional capabilities as required.

GWO New Ventures organisational structure will retain a 'core' wells team, and be supported by upstream functions, geographical regions and by using third party contractor resources. The roles, accountabilities, responsibilities and expectations are clearly defined, with clear lines of reporting relationships.

- GWO New Ventures are accountable for the delivery of safe, reliable and compliant wells, including identification, self-verification, contractor oversight, and management of safety and operational risk.
- S&OR Function provide independent verification and assurance, and GWO technical functions will be used to provide technical support to deliver major activities.

Specifically, the current Australian New Ventures team, along with the defined upstream support functions, is outlined in Figure 16.

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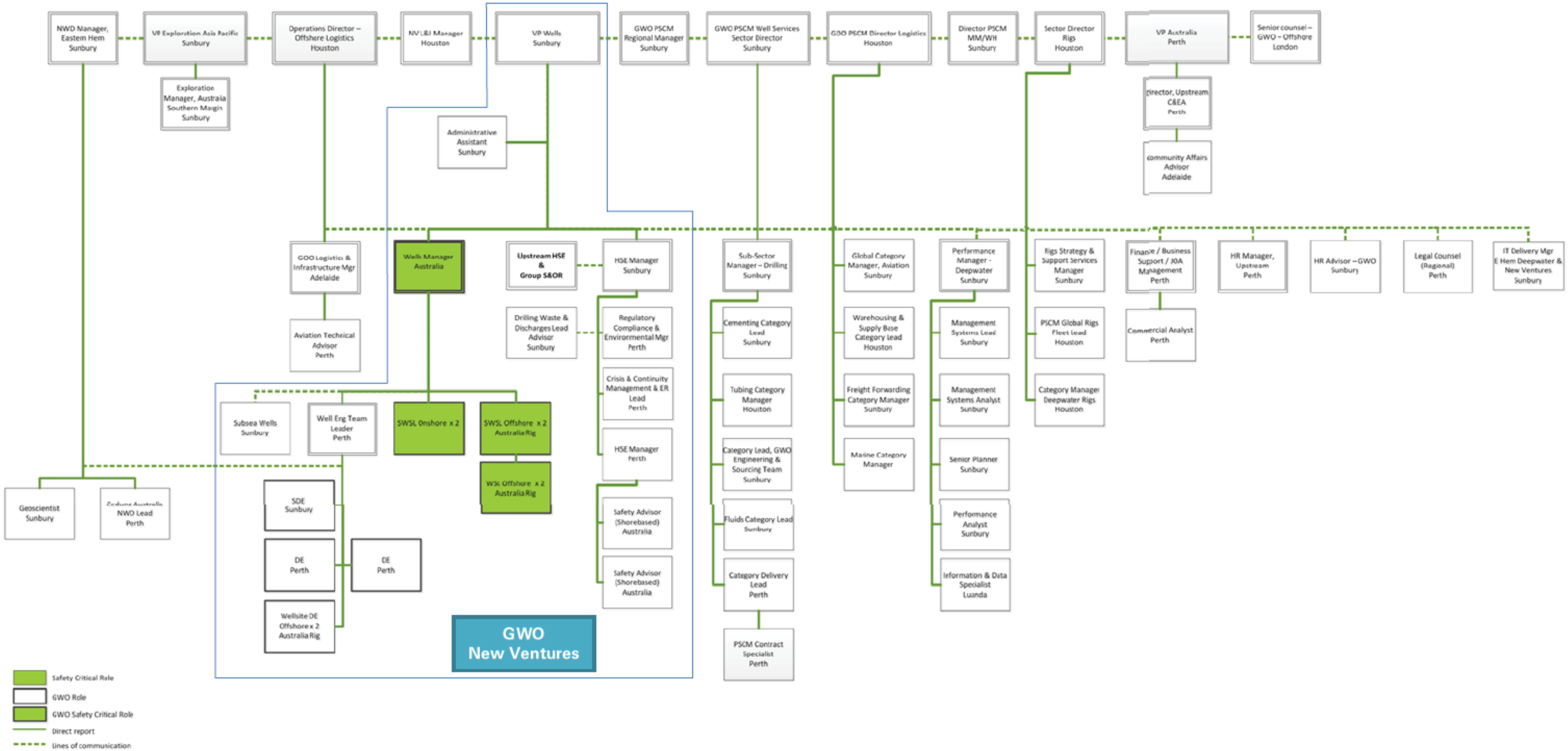

Figure 16 – New Ventures Australia Organisational Structure (DRAFT as of 25-Feb-2016)

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Change out of any personnel, or change to the structure, that could lead to a loss of knowledge, continuity or experience is managed under the MOC process as described in section 4.5. It is expected that this structure may change as operations evolve.

New employees are on-boarded through a formal process called 'Discover BP' / 'Discover GWO'. It provides checklists to assure personnel are introduced to BP's values & behaviours, risk management, code of conduct and other important requirements in a systematic way.

4.4.1 Organisational Competency

GWO New Ventures uses the 'MyLearning' management system to capture and manage individual personnel records. It provides a single window for registration and tracking of training history.

In addition to this, the green highlighted roles in Figure 16 are those considered 'safety critical' under *BP Procedure 100188 – GWO Competence Management Process for Safety Operational Risk (SOR) Critical Roles*. Safety critical roles are managed through a Competence Management Programme (CMP) which assesses and verifies the employees behaviours, skills, knowledge and understanding to assure competence.

4.4.2 Self-Verification (SV) and Oversight (OS)

GWO uses a Self-verification and Oversight model to verify that operations on a BP site and BP-contracted assets are conducted safely in accordance with BP Practice and the applicable SMS (Safety Management System) standards. This is described in *BP Guide 100412 – GWO Self-verification and Oversight during Wells Operations*.

Self-Verification

This model consists of three levels of SV;

- Task-level self-verification and oversight (typically by Well Site Leaders)
  - Evaluation of whether a barrier is in place and fully functional.
  - This is managed by the GWO team and provides the first line of defence.
- System level self-verification (typically by Senior Leaders such as Wells Manager)
  - Evaluation of conformance to, and effectiveness of, a practice, procedure, or combination of technical requirements.
- Management-level review (typically Wells Manager and above)
  - Evaluation of the conformance to, and effectiveness of, both BPs and the Contractors SV programmes.

Oversight

Oversight will be the review of contractor management systems during certain activities on the rig. BP focuses on areas where incidents have occurred in the past and look at global trends. These are updated regularly; however currently these focus areas are;

- Shift and tour handover
- Pressure handling
- Pipe handling
- Red zone management
- DROPS
- Created openings (e.g. removed grating)

- Fluid management
- Control of Work
- Operating procedure

New Ventures will use the eWells tablets (https://ewells.bpglobal.com) and dashboard for conducting Self Verification and Oversight of BP and contractor operations and performance. The eWells tablet is a handled portable device (tablet) that is used at the wellsite. It is zone rated and used for SV+OS checks as well as regular well control drills. It contains templates for the checklists, has the ability to maintain records, take photos, log users and participants, etc. It also pushes relevant learning alerts to BPs Wellsite Leaders as they become available, ensuring personnel see these when they log on to the device. The eWells dashboard data is reviewed centrally by GWO HSSE quarterly for global trends in the operations and potential areas of intervention by management.

Practical barrier checks and frequency of SV and OS will be based on the GWO Safety Plan and reviewed for GAB prior to spud.

4.4.3 Safety and Operational Risk (S+OR) Function

The safety and Operational Risk (S+OR) function operates independent of GWO, to drive safe, compliant and reliable operations across the company. It focuses on doing four things:

- Setting clear S+OR requirements.
  - This is done by issuing and managing the BP Practices at a group-level.
- Maintaining an independent view of implementation of requirements and of safety and operational risks.
  - This is done through an assurance process in line with S+OR requirements. It is independent assurance of the GWO New Ventures team beyond the SV and OS process.
- Providing deep technical expertise to the GAB team (and other teams).
  - This is through specialist engineering support with deep technical knowledge that can be drawn upon if required.
- Intervening and escalating as appropriate to cause corrective action.
  - As with all BP employees, S+OR has the authority to intervene on safety matters. Due to their technical knowledge, they offer an independent outside technical view on engineering issues.

S+OR operate across BP and report to the BP Group executive team (not the Wells organisation) to provide independent review.

4.4.4 Organisational Learning

BP Procedure 100373 – GWO Organisational Learning defines the 5-step Learning Process that the GAB team will go through to assess learnings, decide actions and report to the correct level.

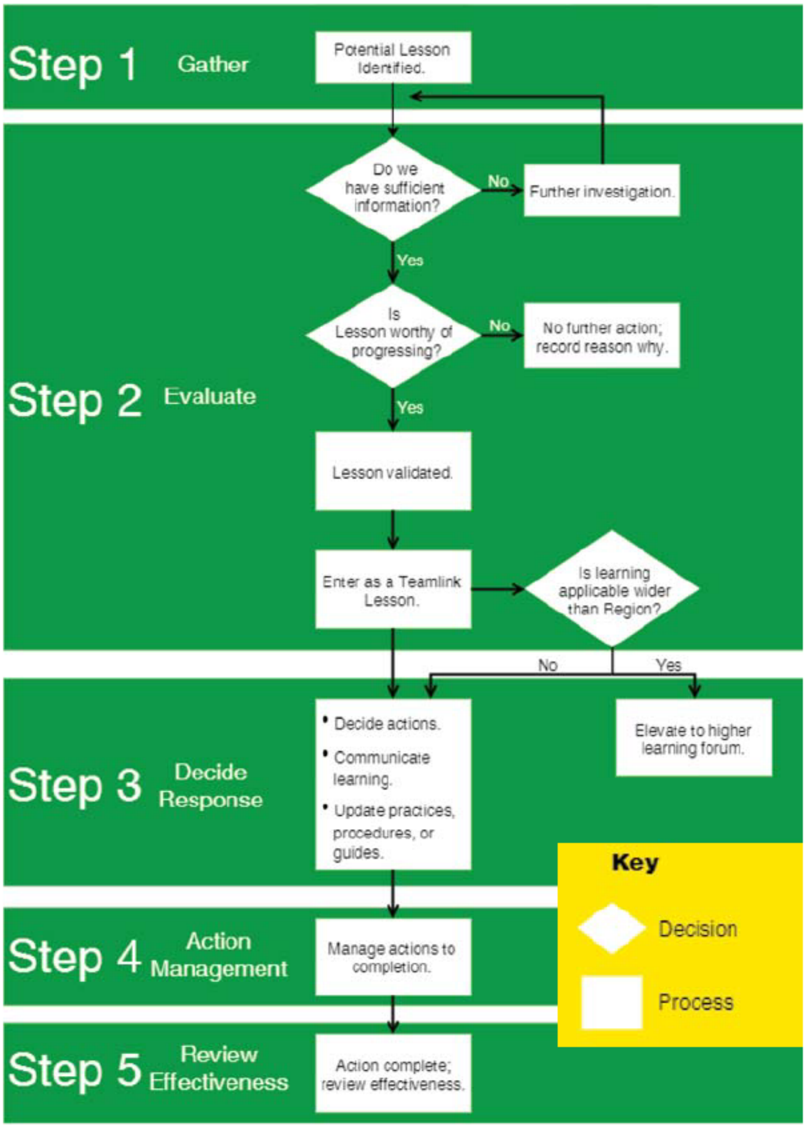

Figure 17 – Application of the 5-Step Learning Process

BP GWO uses 'Teamlink' to share learnings across the company (https://teamlink.bpglobal.com/ContentPages/Home.aspx). Teamlink is an intranet based system that allows the sharing of lessons across all BP regions. It is has searchable categories for historical learnings and also generates automatic emails to all engineers that have subscribed to certain topics when new learnings are shared.

The programme also links to the BP Well Engineering & performance Forum (WEPF). This forum is an online system where engineers can query the wider BP community with technical questions when specific challenges require support. The queries are sent out to BP specialists in the particular area the information is relating to.

The Teamlink system is managed by the BP GWO Organisational Learning function.

In addition, specific for HSE learnings, BP utilises the following;

- GWO New Ventures Safety & Operational Risk Committee (SORC) – hold quarterly sessions, where outcomes are communicated to the GAB team.
- Operational, engineering and S&OR Learning Communications/Bulletins – these are received and communicated by VP Wells and HSSE Managers.

- High Value Learning (HVL) database (accessible through Teamlink)
- HiPo notifications.
- Safety moments at bi-weekly team meetings.

4.5 Management of Change (MOC)

MOC is defined in BP Practice 100152 – GWO Management of Change and Deviations. BP defines four types of MOC;

1. 'People' changes shall include changes to personnel, organisation structure, or roles and responsibilities that could lead to a loss of knowledge, experience, or continuity.
2. 'Process' changes shall include changes to approved, controlled documents.
3. 'Plant' changes shall include changes to an existing GWO operated facility, well, rig, equipment, or deviation from either the documented design or operating limits.
4. 'Deviation' changes are a specific type of change, where a change is needed to a BP, GWO issued, Practice or Specification.

All four types of MOC require a risk assessment to be completed as part of the MOC process.

Specifically for 'deviations', The Practice also provides guidance to RAPID rights to assure the correct level of rigour regarding subject matter experts, Safety & Operational Risk (S+OR) and management oversight.

In addition, the NWcp defines the MOC decision rights for a change to a controlled document (i.e. a 'process' change). These are relevant to the well design and drilling operations and will be applied for the Stromlo-1 operations.

MANAGEMENT OF CHANGE (MoC) New Well Common Process and Decision Rights (RAPID) Version 1.4		Role Title											
		Subsurface						Wells					
		Reservoir Mgmt Mgr, Exp. Manager or Res Dev Manager	Reservoir Mgmt TL, Exp. TL or SS TL	NWD Mgr or Res Dev Mgr (1)	NWD TL (3)	Base Mgmt Mgr	Global Exploration NWD Mgr (2)	VP Wells	Drilling Eng. Manager	Drilling Eng. TL	Completions Eng. Manager	Completions Eng. TL	Wells Superintendent
No.	► MoC decision												
3.- Define													
MoC D1	► Approve changes from Well or Field BOD	Refer to the Well or Field BoD RAPID in Annex D (5)											
MoC D2	► Approve changes from Well SOR	A		D	R	A (4)	A (2)		A		A		
4.- Execute													
MoC E1a	► Approve changes from Drilling Programme									D		A	R
MoC E1b	► Approve changes from Completions Programme		A									D	R
MoC E2	► Approve changes from Well or Field BOD including operational inability to meet the design (Design Documents and BoD Summaries)								D		A		R
MoC E3	► Approve changes from Well SOR	A		D		A (4)	A (2)	A					R

1. The NWD Manager's Decision Rights are taken by the (Area) ResDev Mgr if that position exists in the organization.
2. For Exploration and Appraisal wells only.
3. When there is no NWD TL reporting to the NWD Manager these decision rights can be delegated to a competent senior NWD Geoscientist. In the absense of a NWD Manager a bespoke Function approved plan is required.
4. Base Mgmt assures Ops is included as appropriate.
5. Changes are approved by the original roles and associated decision rights.

Figure 18 – MOC RAPID Decision Rights EXTRACT from the BP Practice 100100 – New Well Common Process (Version 1.4)

MOCs for GWO operations are controlled through the 'eMOC' system. This assures changes are consistent, tracked and implemented in a controlled and verifiable manner. As can be seen, Well

BOD changes in the Define phase are defined under a different RAPID (as per the original sign off rights shown in Figure 13).

For day-to-day operations, management will be via an ‘operational decision making’ matrix (Figure 19). This describes the process the operational personnel will undertake under certain changes. Note that if the changes are to the SOR, BOD or drilling programme, they may still require an additional eMOC to be generated (i.e. if they are a ‘people’, ‘process’, ‘plant’ or ‘deviation’ type changes).

GAB Operations Decision Matrix

(SOP: Rig Operations Decision Rights Using RAPID Chart)

Level	NWD/Base Mgmt TL	VP Wells	Wells Manager	Engineering Team Leader (ETL)	Drilling Engineer (DE)	Well Site Leader (WSL)	GAB HSE Manager	Level Description	Documentation Protocol	Communication Protocol	Mandatory Decisions (those which MUST be treated in this level)
Minor					D	A		**Minor changes only, outside the Well Programme.** (Changes which clearly do not change the risk of the programmed operation.) Conflict: ETL - D	**E-mail only** Level 1 e-mails stored electronically in the office G:drive Well File, printed e-mails may be saved in the Rig Site Well File	Initial verbal communication confirmed by e-mail (initiated by DE or WSL) and acknowledged verbally or by e-mail (DE or WSL) **BEFORE action is taken** DE to cc ETL and Wells Manager	**Examples of Programme Changes:** - Changes to BHA - Changes to mud rheology
Major	Inform Only		D	A	R	R		**Major changes outside the Well Programme** **Includes changes to Pressure Testing and Well Barriers or Well Barrier Elements.** Conflict: WM - D	**Operations Change Notice (OCN)** Level 2 OCN's stored electronically in the office G:drive Well File, printed OCN's may saved in the Rig Site Well File Proof of D is required documentation, required before proceeding	Initial verbal communication confirmed by e-mail (DE) - after I, A and D are acquired - and receipt acknowledged verbally or by e-mail (WSL) **BEFORE action is taken.** **OCN is not required prior to proceeding.** DE completes OCN e-mail ASAP (& within 12hrs) and sends. Rig to acknowledge OCN (verbal or e-mail). DE to cc ETL, Wells Manager & NWD TL on OCN. Additional Correspondence as required (Ops Notes, etc.).	**Unplanned Well Barrier or Well Barrier Element changes:** - Number, type, pressure rating, position, weight (fluid) or Wellbore WBE's - Cement tops **Unplanned Pressure Test changes:** - Pressure, duration, verification method **Unplanned Well Control Operations:** - Level 1 Well Control Event
Process Safety Impact		I	D	A	R	R	I	**Decision having potential for Process Safety Impact OR which deviates from Standard Operating Procedures.** Conflict VP Wells - D	**Operations Change Notice (OCN)** Level 3 OCN's stored electronically in the office G:drive Well File, printed OCN's may saved in the Rig Site Well File Proof of D is required documentation, required before proceeding	ETL escalates and acquire D and A consent. DE completes OCN email ASAP and send. Rig to acknowledge OCN (verbal or e-mail) **BEFORE action is taken.** **OCN is required prior to proceeding.** DE to cc ETL, Wells Manager and VP on OCN. Additional Correspondence as required (Ops Notes, etc.).	**Unplanned Process Safety related activities:** - BOP ram configuration changes - BOP modifications - Operating with rig SCE protective systems defeated - Operating outside the Well Control or SMS Bridging Documents **Unplanned Well Control Operations:** - Level 2 & 3 Well Control Event

Boundary Conditions For This RAPID

Decisions / Actions within the Well Programme do not fall under the remit of this RAPID and require no formal communication
Changes during execution which affect the delivery of an SoR objective should be managed per the NWD RAPID (eMoC)
Changes during execution which create non-conformance with an GWO Practice are managed per BP 100152 GWO MoC & Deviations
Changes during execution which take the well beyond the BoD should be managed per the NWD RAPID (eMoC)
Agree rights holders DO have veto rights requiring escalation to the Level Conflict resolver (s)

R	Recommend & submit plan forward
A	Agrees with decision prior to moving forward
P	Performs decision
I	Input on plan prior to final decision
D	Decides to move forward with plan

Revision 17/02/2016

Figure 19 – Stromlo-1 Operational Decision Making Matrix

4.5.1 Changes That Would Require an Update to the WOMP

Due to the short nature of the work anticipated for Stromlo-1, an update of the WOMP is not considered likely during the drilling/abandonment phases. The majority of changes will be carried under the Management of Change process is described in Section 4.5. Following approval of the WOMP, this table provides examples of what will or will not trigger a WOMP revision.

Change	MOC Process	WOMP revision?
Shoe placement change in line with defined limits (i.e. Section 5.5)	Variance in shoe depth is expected and planned for. This change would be controlled by a 'process' MOC to the drilling programme.	No
Shoe placement change outside of defined limits (i.e. Section 5.5)	Variance in shoe depth is expected and planned for. This change would be controlled by a 'process' MOC to the drilling programme. Significant change to depth may also trigger process MOC to casing design if beyond reasonable limit.	No
Additional casing string as per planned contingencies (18" and 11-7/8")	Possibility is planned for. This change would be controlled by a 'process' MOC to the drilling programme. Casing design applies.	No
Additional casing string beyond planned contingencies (28", 16" and 7-5/8")	'Process' MOC to Well BOD, drilling programme, data acquisition.	No
Change to casing design due to PPFG being beyond limits expected (i.e. outside of min/max prediction)	Variance in PPFG is expected and planned for. This change would be controlled by a 'process' MOC to the drilling programme. Significant change may also trigger process MOC to casing design if beyond reasonable limit.	No
Change to water based drilling fluids due to excessive losses	'Process' MOC to documentation (drilling and fluids programme). This possibility is considered in the fluids programme.	No
Change of hole size without change of casing (i.e. 17-1/2" increased to 18-1/8")	'Process' MOC to drilling programme, casing BOD.	No
Deviation to <25bbl kick tolerance (as per Section 6.1.2)	'Deviation' MOC requiring BP global well control expert input.	No
Suspension of operations due to equipment failure, move to other well operations	'Process' MOC to suspension and subsequent restoration of operations.	No (however notifications as per regs)
Change of abandonment strategy that does not impact barriers (i.e. decision change to remove Wellhead)	'Process' MOC to abandonment programme.	No
Rig equipment failure, operations continue with change to 'people' H&S exposure (i.e. Iron Roughneck fails, manual make up of pipe required)	'Plant' MOC to review and ensure risks are managed.	No
Change of rig to be used to drill Stromlo-1	Major 'Plant' MOC and deviation.	**Yes**
Change to the Strategy used for drilling – i.e. change to batch type operations	Major 'Process' MOC and deviation.	**Yes**

Change	MOC Process	WOMP revision?
Change of well abandonment strategy (i.e. conversion to 'keeper well'.)	Significant change to concept. May require review of abandonment strategy, etc. MOC to various documents of the NWcp required.	**Yes**
Sidetrack of the well to target a different area of the reservoir (i.e. up-dip/ down-dip, etc).	Significant change to concept. May require review of abandonment strategy, etc. MOC to various documents of the NWcp required.	**Yes**

Table 9 – Examples of Changes Requiring Revision of the WOMP

5 Lifecycle – Well Design

The New Ventures team aligns itself with the GWO goal to “deliver safe, compliant and reliable wells as a One Wells organisation, with the support of other functions working as One BP”.

The Stromlo-1 well design philosophy is;

- Design flexibility into the casing design due to the inherent PPFG uncertainty,
- Conform to the BP standardisation agenda as best possible, without compromising well design,
- Plan 8-1/2” hole through the reservoir target.

The design objectives are focused on minimising risk and maintaining well integrity throughout the life of the well. Specifically, these objectives are;

- Conformance with BP Design Practices and good oilfield practice.
- Sufficient casing strings with contingencies to achieve all well objectives;
    - Well integrity throughout the well construction phase,
    - Evaluate the reservoir target.
- No casing/well component failures as a result of;
    - Any foreseeable well control incidents (including ‘Worst Credible Discharge’),
    - Metallurgical incompatibilities with the drilling environment,
    - Inadequate casing connections.

The following assumptions have been made for the Stromlo-1 well design:

- Design to Most Likely PPFG case and temperature, with enough latitude to satisfy the High and PPFG case.
- DST is not required.
- The well will be abandoned immediately following the final TD data acquisition phase with wellhead left in place.
- The risk of encountering H_2S in high percentage is low, however the most likely concentration of H_2S is <10ppm.
    - The 13-3/8” casing shall be classified for partial sour service resistance based on the most likely H_2S concentrations and most likely reservoir pressures.

The following boundary conditions have been made for the Stromlo-1 well design;

- BP Practice Requirements to be met (including management of change where required),
- Rig equipment capabilities, including landing string limits,
- 18 ¾” BOP nominal ID,
- All casing and liners able to withstand the stresses caused by relevant load cases as approved in the casing Basis of Design.

Specific challenges and risks facing the Stromlo-1 well casing design are;

- Frontier basin; limited offset data

- Deepwater environment
- Uncertainty in PPFG
- Potential loss zones resulting in casing shoes being set shallower than desired.

5.1 Casing Design Philosophy

BP defines its Casing and Tubing requirements under *BP Practice 100202 – Casing and Tubing (10-01)*. It provides the minimum requirements that the Stromlo-1 casing design must meet.

This practice draws on BP and industry experience and information available in globally recognised documentation. Although this references many international standards, the BP Practice outlines if these are appropriate, depending on the tubular use. It defines design requirements including; standard load cases, well control screening, issues around lock-down loads and loads during well operations.

The Practice also defines material and connection specifications. These have been applied to Stromlo-1, and are summarised as following;

- API Spec 5CT, API Spec 5L, API Spec 5B, API RP 5C6 and API RP 5A3. Procurement of tubulars conform to the requirements (shall statements) contained within these API Specs and give consideration to the recommendation's (should statements). Where proprietary tubulars/connections are used, a gap assessment against the practice is performed and an approved specification is agreed between the vendor and BP. Note that BP does this on a global level (i.e. not Stromlo-1 specific).
- NACE MR0175. Note that the BP Practice only requires use of this document if well testing is planned. Although Stromlo-1 will not be performing well testing, consideration to sour service conditions was carried out. This was a decision made by the GAB team due to the nature of this exploration campaign.

Stromlo-1 is an exploration-only well with no well test planned. The well has been designed for abandonment following exploration drilling. Due to the wildcat nature of the well, the design has been generated to cover maximum anticipated load cases (i.e. maximum anticipated pore pressure and conservative estimates of formation fluids, temperatures, etc.). The well has been designed to shut-in and contain of a full dry gas gradient column from the high case pore pressure in all hole sections below the BOP (i.e. no limited kick loads are used).

The load modelling used the well architecture described in Figure 20 for primary and contingency strings. As the 18″ and 11-7/8″ liners are contingency, these depths are assumptions used for design purposes.

5.1.1 Casing Design for Stromlo-1

Without Contingencies Installed With Contingencies Installed

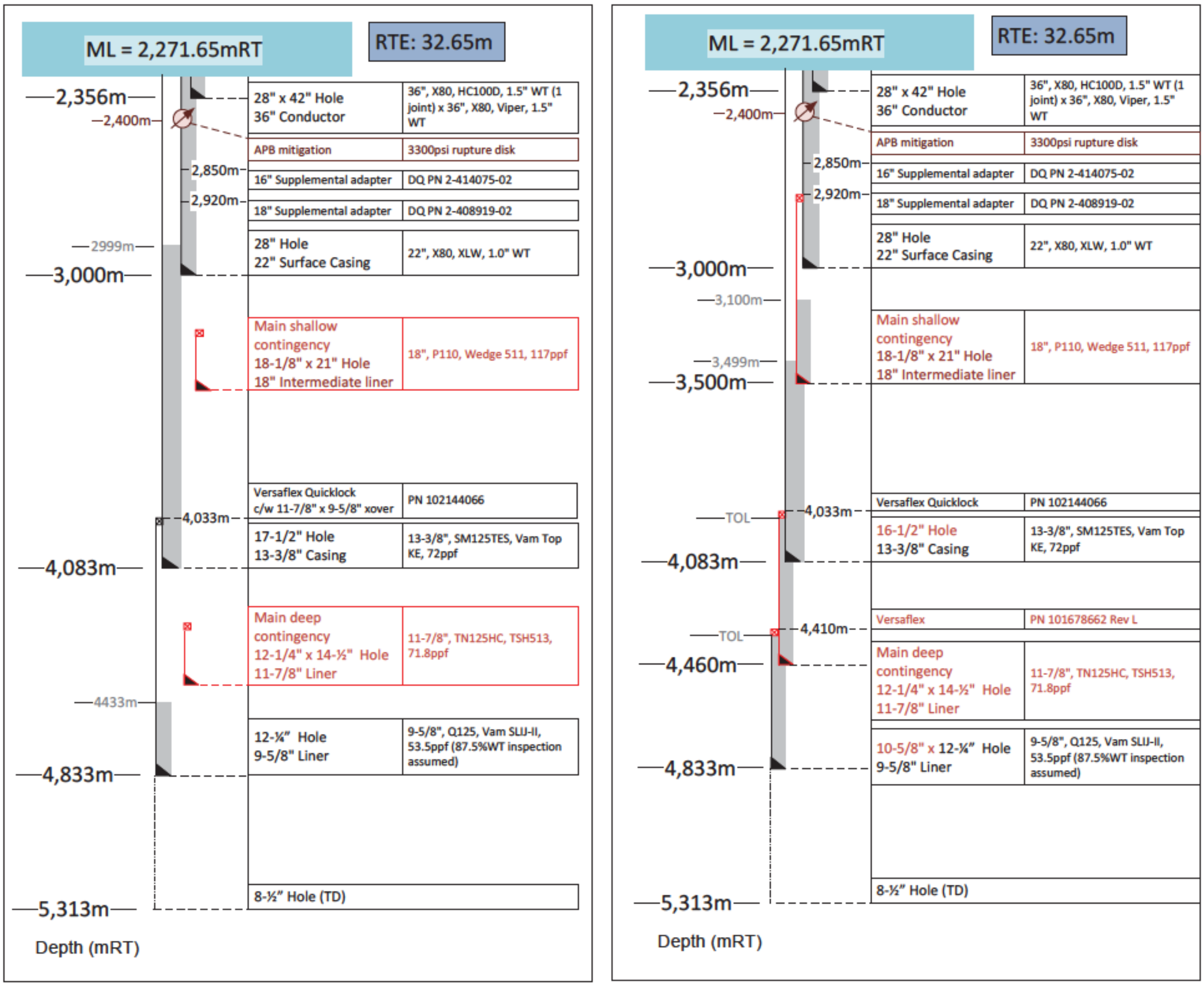

Figure 20 - Stromlo-1 Primary and Contingency Schematics

Tubular properties are summarised in Table 10.

Description	Pipe Body				Connection								
											MUT (ft-lbs)		
	ID (in)	Drift (in)	MIYP (psi)	Collapse (psi)	OD (in)	ID (in)	Internal (psi)	External (psi)	Tension (klbs)	Compr. (klbs)	Min	Target	Max
36", 1.5"WT, X80, HC100D	33.000	NA	5 830	3 190	36.380	30.180	8 600	2 150	10 250	16 240	36 000	50 000	50 000
36", 1.5"WT, X80, Viper 1ST	33.000	NA	5 830	3 190	36.880	31.320	6 430	3 340	13 864	15 445	62 000	68 000	68 000
22", 1"WT, X80, XLW	20.000	NA	6 360	3 870	23.250	20.000	6 360	3 870	5 278	5 278	28 800	32 000	70 000

Description	Pipe Body				Connection								
											MUT (ft-lbs)		
	ID (in)	Drift (in)	MIYP (psi)	Collapse (psi)	OD (in)	ID (in)	Internal (psi)	External (psi)	Tension (klbs)	Compr. (klbs)	Min	Target	Max
18", 117ppf, P110, TSH511	16.750	16.562	6 680	2 110	18.000	16.625	6 680	2 110	2 331	2 762	52 000	62 000	91 000
13-3/8", 72ppf, SM125TES, Vam Top KE	12.347	12.250	8 650	4 090	14.236	13.383	8 650	4 090	2 596	2 077	30 600	34 000	37 400
11-7/8",71.8ppf, TN125HC, TSH513	10.711	10.625	11 030	7 800	11.875	10.665	11 030	7 800	1 595	1 923	30 000	36 000	53 000
9-5/8", 53.5ppf, Q125, Vam SLIJ-II	8.535	8.500	12 390	8 440	9.855	8.558	12 390	8 440	1 449	1 014	22 800	25 300	27 800

Table 10 – Casing Ratings

The Stromlo-1 casing design has the following key conclusions:

- The 36" and 22" strings are all in line with BP Practice 100202 – Casing and Tubing (10-01) B01.
- The 18" contingency liner and 13-3/8" production casing meet BP Practice 100202 B01 with the exception of;
  - Drill-ahead load cases. Both show buckling during drill-ahead. This is not in line with BP recommendations. This has been documented and approved in line with BP required practice.
    - (a) This issue is described at length in the Casing BOD. But in summary, buckling occurs due to the differential pressure between internal (drilling fluid + ECD) and external (lighter fluid casing was run in). The WellCat software shows minor helical buckling that would not be seen in other programmes such as StressCheck. This issue was reviewed and accepted by casing design specialists within BP. It is not anticipated to cause issues for Stromlo-1 but has been documented for completeness.
- The 11-7/8" and 9-5/8" liners meet BP Practice 100202 B01 with the exception of;
  - Worst Credible Discharge (WCD) dynamic load case. Both the primary and contingency architecture loads cause the liner hanger safety factor to be below the design factor for tubulars (1.4). This has been investigated and accepted for the reasons described in Section 4.4 and 5.2 of the Casing BOD and outlined below in section 5.1.1.1. This will be managed via the BP Management of Change process.

A summary of design factors and minimum safety factors for governing loads are provided in Table 11, Table 12 and Table 13.

	Casing		Tubing (pressure testing)		Tubing (service loads)	
	Pipe	Connection	Pipe	Connection	Pipe	Connection
Tension	1,4	1,4	1,1	1,1	1,33	1,33
Burst (1)	1,1	1,1	1,1	1,1	1,25	1,25
Collapse (2)	1,0	1,0	1,1	1,1	1,1	1,1
Triaxial	1,25	N/A	1,1	N/A	1,25	N/A
Compression	1,4	1,0	1,1	1,0	1,33	1,0

Notes:

1. Burst design factor is modified to 1,0 for surface and intermediate casing well control designs using gas gradient from shoe fracture pressure.
2. Collapse design factor is modified to 1,1 for casing with 10 < D/t < 12.
3. Design factors are applicable to seamless pipe with nominal material yield of 125 ksi (862 MPa) or lower.
4. Tension design factor is applied to yield of both pipe body and connection critical cross section.

Table 11 – BP Policy Minimum Design Factors (Practice 100202 Rev B01)

Casing String	Load Case	Internal Pressure Profile	External Pressure Profile
36" Conductor	B1.1 Pressure Test	Displacement Fluid: 8.6ppg seawater 1000psi applied pressure	TOC: mudline MW above TOC: 8.6ppg (Seawater) MW below TOC: Pore pressure in open hole
	C1.4 Cementing (static load)	Displacement Fluid: 8.6ppg seawater	TOC: mudline MW above TOC: 8.6ppg (Seawater) MW below TOC: 15.8ppg (to ML)
	B1.2 Drill ahead	Seawater to mudline Drilling model with 12.5ppg spud mud below mud line, no riser present. (Drill link)	TOC: mudlineTOC: mudline MW above TOC: 8.6ppg (Seawater) MW below TOC: Pore pressure in open hole
22" Surface Casing	B2.6 Burst disk ruptures	8.9ppg above 13-3/8" TOC. APB of 3371psi (limit from burst disk design)	TOC: seabed MW above TOC: 8.6ppg MW below TOC: 8.33ppg
	C2.7 Partial evacuation	Evacuated to 1000m seawater below	TOC: seabed MW above TOC: 8.6ppg MW below TOC: 8.6ppg Pore pressure in cemented hole section
13-3/8" Production Casing	B3.2 Pressure test	Pressure Test: 5600psi Test Mud Weight: 8.9ppg	TOC: 2999m MW above TOC: 0.778sg (Amodril 1200) MW below TOC: 8.6ppg pore pressure in open hole
	C3.9 WCD dynamic	WCD case. Temperature updated to match PPFG. Pressure at wellhead as per seawater hyrostatic.	TOC: 2999m APB to burst disk limit (3371psi over existing) MW above TOC: 8.9ppg Pressure profile below TOC: manually entered MWPP.
9-5/8" Production Liner	B4.2 Green cement PT (also covers LH setting pressure)	Pressure Test: 5000psi Displacement Fluid: 9.3ppg	TOC: 4433mRT MW above TOC: 9.3ppg (non-degraded) MW below TOC: 15.8ppg
	C4.7 partial evacuation	1000m evac then seawater	TOC: 4433mRT MW above TOC: 9.3ppg MW below TOC: 8.6ppg pore pressure in open hole
	C4.10 - WCD dynamic	WCD case. Temperature updated to match PPFG. Pressure at wellhead as per seawater hydrostatic	TOC: 4433mRT MW above TOC: 9.3ppg MW below TOC: 8.6ppg

Casing String	Load Case	Internal Pressure Profile	External Pressure Profile
18" Contingency liner	B5.6 Burst disk ruptures (in 22")	8.9ppg fluid. APB of 3371psi (limit from burst disk design)	TOC: 3,100m MW above TOC: 8.9ppg MW below TOC: 8.6ppg
	C5.7 Partial evacuation	1000m evacuated then seawater	TOC: 3,100m MW above TOC: 8.9ppg MW below TOC: 8.6ppg Pore pressure in cemented hole section
11-7/8" Contingency Liner	B6.2 Green cement PT (also covers LH setting pressure)	Pressure Test: 5000psi Displacement Fluid: 9.3ppg	TOC: TOL MW above TOC: 9.3ppg (non-degraded) MW below TOC: 15.8ppg
	C6.6 Partial evacuation	1000m evacuated then seawater	TOC: TOL MW above TOC: 9.3ppg MW below TOC: 8.6ppg pore pressure in open hole
	C6.9 WCD dynamic. Below DF (1.4). Discussed below.	WCD case. Temperature updated to match PPFG. Pressure at wellhead as per seawater hydrostatic.	TOC: TOL MW above TOC: 9.3ppg MW below TOC: 8.6ppg

Table 12 – Governing Loads Summary

String / Component	Minimum Safety Factors				Governing Load(s)
	Triaxial	Burst	Collapse	Axial	
36" Conductor	6.01	5.54	7.14	4.82	Triaxial & Burst - B1.1 Pressure test Collapse - C1.4 Cementing (static load) Axial - B1.2 Drill ahead
22" Surface Casing	2.10	1.53*	1.17	4.82	T & B - B2.6 Burst disk ruptures C& A - C2.7 Partial evacuation
13-3/8" Production Casing	1.73	1.45	1.01	2.47	T & B - B3.2 Pressure test C & A - C3.9 WCD dynamic
9-5/8" Production Liner	2.33	2.11	2.35	2.43	T & B - B4.2 Green cement PT (also covers LH setting pressure) C - C4.7 partial evacuation A - C4.10 - WCD dynamic
9-5/8" Production Liner Hanger	NA	1.47	2.72	**1.21**** [5.59][A]	B - B4.2 Green cement PT (also covers LH setting pressure) C - C4.7 partial evacuation A - C4.10 - WCD dynamic. Below DF (1.4), disused below.
18" Contingency liner	2.07	1.48	1.15	1.88	T, B & A - B5.6 Burst disk ruptures (in 22") C - C5.7 Partial evacuation
11-7/8" Contingency Liner	2.63	2.17	3.24	3.11	T, B & A - B6.2 Green cement PT (also covers LH setting pressure) C - C6.6 Partial evacuation
11-7/8" Contingency Liner Hanger	NA	1.47	2.76	**0.86**** [3.93][A]	B - B6.2 Green cement PT (also covers LH setting pressure) C - C6.6 Partial evacuation A - C6.9 WCD dynamic. Below DF (1.4). Discussed below.

Table 13 - Well Minimum Safety Factor Summary Table

*minimum pipe rating shown only. Rupture disk has lower SF as it is designed to rupture.

**As described in section 5.1.1.1, the liner hangers fail to meet the OCTG design factor of 1.4 in axial load.

[A] Values in brackets are safety factors using the Halliburton ratings (discussed in the following section).

5.1.1.1 Liner Hanger Safety Factor Consideration

The liner hanger discussed in this section is a Halliburton Versaflex (Quicklock) design that has BP Equipment Integrity Assurance (EIA) approval. This liner will be used for the 11-7/8" liner and the 9-5/8" liner (with a x-over).

During the WCD load cases, the modelled axial load exceeds the EIA specified rating, although it is within the Halliburton specification.

Note that the EIA team have rated this component to tested values, not to the point of failure (i.e. they are significantly lower than the Halliburton specified limit). The axial test on the liner hanger system was limited to 400klbs and as such, that is the maximum the EIA team have specified the component. The test was limited by test equipment fixtures, not the liner hanger system.

13-3/8" x 11-7/8" Versaflex (Quicklock) 102144066 Rev E						
	Description		**Internal (psi)**	**External (psi)**	**Tension (klbs)**	**Compr. (klbs)**
Halliburton Rating	Liner hanger elements		8,920	8,145	1,854	1,854
	Liner hanger (below elements)				1,612	1,837
	Bottom connection (assumes P110, no HC dimensional checks)		9,430	5,290	1,612	1,837
BP EIA	Liner hanger assembly **(USED VALUES IN MODEL)**		**7,500**	**5,290**	**400**	**400**

Table 14 – Versaflex Ratings for BP and Halliburton

Safety factors using the Halliburton ratings are shown in Table 13 above in brackets. However, as per BP practice, the EIA values, not Halliburton ratings, have been used for casing design. For the 9-5/8" liner;

- During load C4.10 (WCD) an axial compression load of 330klbs occurs which results in a SF of 1.21 (which is a fail against the OCTG casing minimum axial design factor of 1.4).

BP has accepted this because;

- Actual well loading on this liner will be less than the 400klbs EIA value and well below the Halliburton rating.
- The new revision of the BP Practice 100202 Casing and Tubing (10-01) Rev B02 states that "For casing, a tension design factor of 1.2 is acceptable after landing the casing or liner". This revision came out after Stromlo-1 Casing BOD sign off and as such, this clause had not been incorporated to Stromlo-1 design.

For the 11-7/8" liner, a similar situation exists, however it is more severe;

- During load C6.9 (again, WCD, this time with the 11-7/8" liner installed) an axial compression load of 452klbs occurs which results in a SF of 0.86.
    - In this case, the load exceeds the EIA value.

BP has accepted this because;

- The load is still well below the Halliburton rating.
- The 11-7/8" liner is planned to be cemented to TOL. In the unlikely event of WCD, if the liner hanger was to fail in axial compression, there would be no breach of containment.
  - A TOC of TOL was assumed as it is likely this would be a short liner (it is contingency planned to give the option of splitting an 800m hole section).

However note, as the liner is a contingency, the exact conditions it is run in are unknown and may result in it not being cemented to TOL. In addition, if losses occur, a low TOC may be unavoidable. In this unlikely outcome, if the liner hanger were to fail, once the well was shut in an underground crossflow may result.

The risk of exceeding the EIA axial value during WCD is accepted by the BP GAB team. It requires a documented and approved MOC, as per BP practice. This will be completed prior to spud.

5.1.1.2 Special Material Considerations

The 13-3/8" Production casing utilises SM125TES. This is a medium sour service grade.

During regular operations, the drilling fluid will be used to mitigate against H_2S. Scavengers will be included and pH will be maintained to prevent H_2S, if present, causing any issues to the materials used downhole. Even if gas were to enter the wellbore, the fluid is the primary method of dealing with sour gas. However in the event of large volumes of gas entering the wellbore, there is a low risk of free gas being held under the BOP for a period of time (for instance, a large kick with mechanical issues preventing circulation or a cap and contain scenario). With the cold temperatures at the mudline and the high tension in the casing, the environment could result in sulphide stress cracking if high yield strength tubulars are present. For this reason, sour service resistant components are included in the design. Although the exact concentration of H_2S is unknown, SM125TES provides a good range of resistance. As per Section 3.1.10;

- MOST-LIKELY H_2S concentrations at Stromlo K65 are <10ppm
- 100s ppm is possible in the primary target (K65) however this is considered LOW RISK.

For Stromlo-1, assuming high pore pressure, the SM125TES grade allows for H_2S ppm concentrations of;

- 139ppm assuming a pH of 3.5
- 1,391ppm assuming a pH of 4.

pH is unknown however 3.5 and 4 are considered conservatively low assumptions. This means that Stromlo-1 is designed to meet the most likely anticipated condition and various deviations from that prediction.

Note, the casing hanger and extension (as well as x-over joint) will also meet this specification.

It is understood that the 11-7/8" and 9-5/8" liners are not designed to meet the same H_2S rating as described above. This has been accepted because;

- In the event reservoir fluid enters the wellbore, it is likely to be in solution at deeper depths. The drilling fluid will contain H_2S scavengers and the pH of the fluid will be managed.
- Temperatures at the liner hanger are higher (which causes faster diffusion rates and results in critical concentrations causing SSC being less likely),

- Failure of the liners results in a significantly different risk profile (i.e. underground crossflow rather than release of reservoir fluids at seabed).

5.1.1.3 Annular Pressure Build-up (APB) Mitigation

A rupture disk is required and has been designed for Stromlo-1.

VSP data of the overburden is important to the subsurface team. This data can only be collected in open hole or across casing that is cemented in place (i.e. not free pipe). To maximise the data the team can gather and prevent requiring an additional wireline run before the casing is installed, the planned TOC for the 13-3/8" is across all openhole, back to the 22" shoe. This will result in a trapped annulus between the 13-3/8" production casing and 22" surface casing.

WellCAT was used to model the APB load case of WCD flowing up the production casing and the temperature increase in the A annulus causing fluid expansion. It shows that the load on the 13-3/8" casing will exceed the collapse design factor. For this reason, mitigation is needed.

For this reason, a rupture disk has been designed for the 22" casing. This is designed to burst and vent to formation in the event of WCD only. All other load cases do not cause build-up of pressure in the annulus that would cause rupture of the disk or risk collapse of the 13-3/8" casing. The design covers Stromlo-1 for the base case and for the 18" liner option. This design has been verified by the global GWO team and it is consistent with BP deepwater operations in other regions.

Rupture disk design

- Depth of installation; 2,400mRT
- Pressure rupture will occur at; 3,300psi differential

The disk is a designed, one-time pressure relief, failure point. It is manufactured to a tight tolerance rupture pressure in only one direction (i.e. burst or collapse only). All other properties are designed to meet the pipe specification it is set in. Figure 21 below shows the safety factors for all loads. 'Burt of rupture disk' is a custom load showing pressure differential required to rupture. This would only occur during WCD load case.

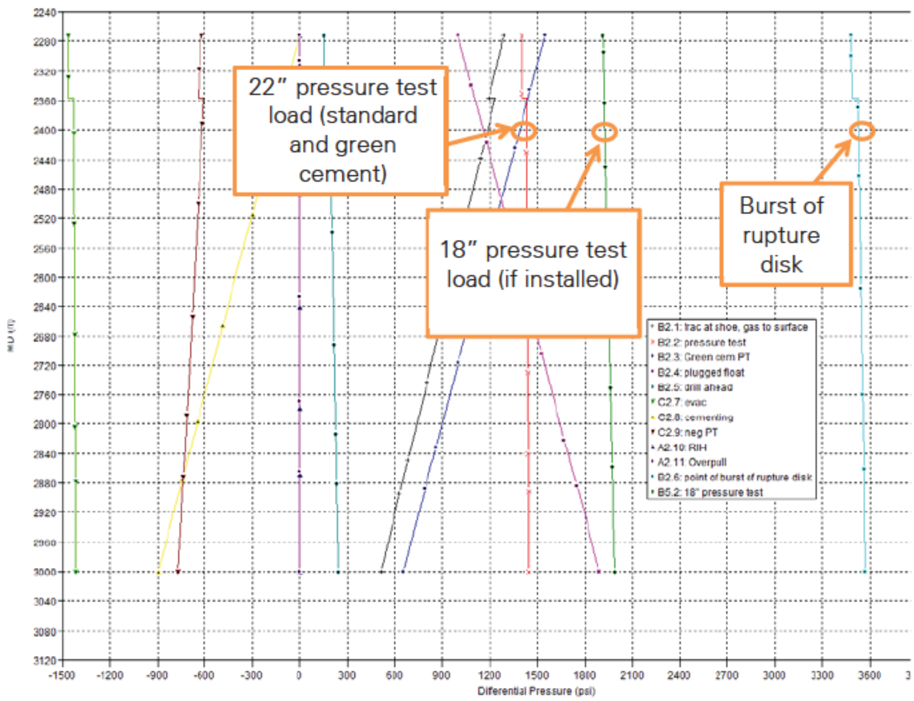

Figure 21 – Differential Pressures for all 22" Loads

Further detail is available in the Stromlo-1 Casing BOD describing the load cases and design of the disk.

5.2 Conductor/Wellhead Design Philosophy

Conductor design load cases are specified in the Casing and Tubing Practice. However additional wellhead design requirements are defined in *Global Practice 65-76 – Marine Drilling Riser and Wellhead Global Analysis* and *Global Practice 78-23 – Subsea Christmas Trees and Wellheads*. These documents are detailed as they cover riser and xmas tree systems, but specific to Stromlo-1, they have been used to define design, manufacturing requirements and the fatigue requirements for the wellhead.

- GP 65-76 defines the analysis process requirements and considerations for low pressure riser and wellhead systems. This was used as a basis to generate a fatigue, drive off and drift off analysis. It was also used to define the analysis of open water deployment of conductor and surface casing strings. This GP is a supplement to API RP 16Q.
- GP 78-23 defines the requirements and recommendations for wellhead selection and design. This GP uses API Spec 17D as a basis and supplements certain requirements where BP deems appropriate.

The general design philosophy for the Stromlo-1welhead is based on API Spec 17D with reference to other listed specifications. The wellhead shall bear the API 17D/ISO 13628-4 monogram.

5.2.1 Conductor/Wellhead Design for Stromlo-1

A detailed geotechnical site investigation was carried out at 17 locations across the BP blocks to assess the shallow soil strength in the GAB. This was used to define the required conductor length. The results showed that the 36" conductor shoe was required to be 73mBML to maintain a SF of 2.0 under conservative (i.e. hash weather) load conditions. For this reason, the GAB intends to use a 6 joint conductor (1 x 24m low pressure housing with extension and 5 x range 3 joints). Accounting for stickup, this will put the shoe approximately 84m BML.

In addition, the BP Upstream Engineering Centre used this information to carry out a wellhead and riser fatigue analysis.

The wellhead selected is considered suitable for the planned Stromlo-1 operations. For this WOMP, the following should be noted;

Wellhead and Riser Fatigue;

This analysis considered various cement shortfalls for wave and Vortex Induced Vibration (VIV) fatigue. It showed the wellhead and riser to have a minimum fatigue life of 457 days (wellhead limit under surface casing cement shortfall). This is considered a suitable fatigue life for Stromlo-1.

Drift Off Analysis;

Analysis of the riser, wellhead and conductor shows that, in the event of drift off, failure would occur above the BOP; provided the TOC is brought to mudline. For the modelled load of a 10m shortfall on TOC, failure occurs below the BOP in some environmental situations.

Operating limits analysis concluded that under normal operating conditions disconnect is possible before reaching the 'Point of Disconnect' (point where equipment limits are reached). However, for extremely conservative weather loading this is not the case.

The drift off analysis has been accepted as suitable due to;

- A top up cement system will be run to cement around the top of the conductor (if needed),
- Using a drillpipe stinger to top up cement is a further option if a low TOC occurs,
- ROV can confirm cement returns visually or with a pH meter,
- The likelihood of all the conservative assumptions occurring simultaneously to cause this failure is extremely low. i.e. This would be;
    - Cement job results in low TOC and;
    - Top up system fails to rectify TOC and;
    - Drillpipe stinger fails to rectify TOC and;
    - Vessel black out occurs during operations and;
    - This black out occurs during high wind and current conditions and;
    - The BOP cannot be disconnected in the required time limit.

Drive Off Analysis;

Analysis was also conducted on the possibility of drive off under max thruster power. For Stromlo-1, all cases (even cement shortfall) resulted in the weak point being above the BOP.

5.3 Cement Design Philosophy

The purpose of the cement used in Stromlo-1 is structural support (for conductor and surface casing) and for zonal isolation for all other sections. Structural requirements have been included in the casing and wellhead design, described above. Zonal isolation uses of cement are described at length in section 6.3.1 of this WOMP.

BP uses internal expertise as well as industry guidelines to provide guidance on cementing. Specifically for Stromlo-1, BP uses guidance from API in the following forms;

- Cement and materials are in line with API 10A
- Testing is as per API RP 10B-2 and 10B-3
- Other recommendations from API RP 10B-5, and 10-B6, API 10D and 10D-2 and API RP 10F.

BP follows a cement design workflow to ensure the design is fit-for-purpose. This ties into the well BOD generation and is defined in BP Guide 100388 – Cementing Design and as per the New Well Common Process.

5.3.1 Cement Design for Stromlo-1

The cement design is documented in the 'Stromlo-1 Cementing TFN' and has been selectively included in the following sections of this WOMP to provide context without providing excessive, non-relevant information. Some modifications have been made to clarify company specific jargon, references, etc.

5.3.1.1 36" Conductor Cement Design

	Lead Slurry	Comments
Cement Type or blend	Class G	
Density	15.8ppg	
Mix Water Type	Drill water	
Volume	415bbls	
Annular Excess	Dependant on returns, estimate 200%	Plan 400% for bulk management. Note, drill string volume is > conductor annular volume (i.e. once returns confirmed, >100% to be pumped). Titus top up system available
Planned TOC depth	Seabed (2,272mRT)	Confirm visually or with pH meter.
Spacer Type / Density	Seawater	
Planned Shoe Depth	2,357mRT	
BHST / BHCT	7°C / 10°C	Seabed temperature 2°C. Circulating temperature based on simulation.
ECD at Shoe	8.67ppge	At 8bpm. Exceeds predicted FG. Accepted as shallow FG predictions unreliable and offsets showed good returns.
	Description	
Objectives	Cement conductor to seabed.	
Key risks	Low TOC due to losses.	
Key assumptions	Returns can be confirmed with ROV visually or with pH meter.	
Centralisation	Not required.	
Equipment requirements	Inner string. Titus top up system available if cement returns not achieved. A drillpipe stinger is also an option.	

Table 15 –36" Conductor Cement Summary

Operational procedures will be developed to manage Titus activation. Notionally, decision to use Titus will be made if no returns are seen after annular volume + 200% has entered the annulus. If returns are confirmed during conventional cementation operations, Titus will not be activated.

5.3.1.2 22" Surface Casing Cement Design

	Lead Slurry	Tail Slurry	Comments
Cement Type or blend	Class G		
Density	12.5ppg	15.8ppg	
Mix Water Type	Drill water	Drill water	
Volume	2,125bbl	622bbl	
Annular Excess	200%	200%	On annular volume
Planned TOC depth	Seabed (2,272mRT)	2,900mRT	
Spacer Type / Density	100bbl viscosified spacer		No seawater to be circulated before cement job.
Planned Shoe Depth	3,000mRT		Exceeds predicted FG. Accepted as shallow FG predictions unreliable.
BHST / BHCT	26°C / 10°C		Seabed temperature 2°C. Circulating temperature based on simulation.
ECD at Shoe	9.65ppge		At 8bpm
	Description		
Objectives	Cement to seabed.		
Key risks	Losses were seen on offsets, even at very low cement weights.		
Key assumptions	Returns can be confirmed with ROV visually or with pH meter.		
Centralisation	Bow spring type. 1 per 4 joints.		
Displacement	Avoid Newtonian fluids (seawater) in the pre-circulation. Us PAD mud as per drilling TD displacement.		
Equipment requirements	Inner string.		

Table 16 –22" Surface Casing Cement Summary

ECDs are predicted below the fracture gradient until the end of the job. This is at odds with offset experience where returns were not achieved on the 20" tophole string of any well. Gnarlyknots-1A reduced the density of the lead slurry even further down to 10.5ppg and still reported no returns. This indicates that excessive ECDs are not likely to be the cause of any failure to achieve returns. Instead, it is thought that seawater circulation pre-cementing caused hole stability issues and packoff. It is recommended that any pre-cementation circulation is done with PAD fluid similar to that used for TD displacement.

An inner string cement job has been chosen over a plug system. This is because the jewellery in the 22" casing (18" and 16" supplemental adapters and rupture disk), have complex internal profiles that could cause concern if cement is caught within them.

5.3.1.3 13-3/8" Production Casing Cement Design

	Lead Slurry	Tail Slurry	Comments
Cement Type or blend	Class G		
Density	13.5ppg	15.8ppg	
Mix Water Type	Drill water	Drill water	
Volume	535bbl	98bbl	
Annular Excess	20%	20% on annular vol	Reduced to limit risk of debris/cement reaching seal assembly or BOP.
Planned TOC depth	2,999mRT	3,933mRT	
Spacer Type / Density	200bbl 11.5ppg viscosified spacer		Follow rheological hierarchy.
Planned Shoe Depth	4,083mRT		
BHST / BHCT	53°C / 26°C		Circulating temperature based on simulation.
ECD at Shoe / at Previous Shoe	10.55ppge / 9.32ppge		At 8bpm

	Description
Objectives	1. Cement >450mAH above shallowest DPZ. 2. Cement to previous casing shoe to allow VSP data to be collected.
Key risks	Overly generous excess combined with under gauge hole could result in debris or cement extending to seal assembly or BOP.
Key assumptions	Single DPZ penetrated in hole section. TOC extends >450mAH above DPZ.
Centralisation	1 per 2 joints for cemented interval. Slip on bow spring.
Displacement	Optimised based on actual drilling experience.
Equipment requirements	Full bore, top and bottom SSR wiper plugs.

Table 17 –13-3/8" Production Casing Cement Summary

Assuming 20% excess pumped and gauge hole, TOC will be at ~2,850mRT. This is ~580m (400bbl) away from casing hanger. Top spacer will be at ~2,550m (~280m below hanger).

5.3.1.4 9-5/8" Production Liner Cement Design

	Tail Slurry	Comments
Cement Type or blend	Class G	Single slurry
Density	14ppg	
Mix Water Type	Drill water	
Volume	115bbl	
Annular Excess	25%	On annular volume
Planned TOC depth	4,433mRT	
Spacer Type / Density	100bbl 11.5ppg viscosified spacer	Follow rheological hierarchy.
Planned Shoe Depth / TOL Depth	4,833mRT / 4,033mRT	
BHST / BHCT	73°C / 41°C	Circulating temperature based on simulation.
ECD at Shoe / at Previous Shoe	10.1ppge / 9.5ppge	At 8bpm
	Description	
Objectives	Isolate DPZ#1 from DPZ #2. Provide suitable annular barrier for DPZ #2.	
Key risks	Compatibility of liner hanger/plugs/darts/cement head has caused failures in the past.	
Key assumptions	Pre drill DPZ isolation only. TOC extends 450m above shoe. To be used as combination barrier provided cement job meets requirements of BP Practice 100221 (10-60).	
Centralisation	1 per 2 joints across cemented interval. Slip on bow spring.	
Equipment requirements	Full bore, top and bottom SSR wiper plugs, compatible with liner hanger system.	

Table 18 –9-5/8" Production Liner Cement Summary

5.3.1.5 18" Contingency Liner Cement Design

The below table is based on pre-drill assumptions. Pre-drill planning carriers this liner as a contingency only. In the event it is required, it is probable that 'most likely' well assumptions have not occurred. The below is provided screening only.

	Tail Slurry	Comments
Cement Type or blend	Class G	
Density	14ppg	
Mix Water Type	Drill water	
Volume	290bbl	
Annular Excess	30%	On annular volume
Planned TOC depth	2,920mRT (TOL)	No zonal isolation requirements on pre-drill assumptions. Assumed TOC=TOL for cementing model to verify job feasibility.
Spacer Type / Density	200bbl 11.5ppg viscosified spacer	Follow rheological hierarchy.
Planned Shoe Depth / TOL Depth	3,500mRT / 2,920mRT	Assumption for model only.
BHST / BHCT	39°C / 18°C	Circulating temperature based on simulation.
ECD at Shoe / at Previous Shoe	9.3ppge / 10.0ppge	At 8bpm
	Description	
Objectives	Suitable shoe for drilling liner only. However model covers more demanding objective of cement to TOL.	
Key risks	Tight tolerance liner. Risk of losses during cementing.	
Key assumptions	Model assumes TOC to TOL with suitable standoff required.	
Centralisation	Centraliser subs needed. 1 per 3 joints across cemented interval. To be reduced if no DPZ isolation requirement and as drilled survey.	
Equipment requirements	Full bore, top and bottom SSR wiper plugs.	

Table 19 –18" Contingency Liner Cement Summary

Running the 18" liner will also directly affect the following 13-3/8" cement job. High level modelling has been run and shows feasibility. Centraliser strategy for the 13-3/8" will not require modification as the slip on bow spring centralisers will be capable of passing through the 18" liner.

A top/bottom plug system has been selected over an inner string option. This is because the required TOC for this liner is unknown. If TOC to TOL is needed, running an inner string may mean tripping the inner string through the excess cement above the liner (if cement is above the liner). The plug system has been chosen as it offers more flexibility (i.e. release the hanger and circulate immediately). This method should also result in less risk of contamination.

5.3.1.6 11-7/8" Contingency Liner Cement Design

The below table is based on pre-drill assumptions. Pre-drill planning carries this liner as a contingency only. In the event it is required, it is probable that 'most likely' well assumptions have not occurred. The below is provided for high level planning only.

	Tail Slurry	**Comments**
Cement Type or blend	Class G	
Density	14ppg	
Mix Water Type	Drill water	
Volume	113bbl	
Annular Excess	25%	On annular volume
Planned TOC depth	4,033mRT (TOL)	Assumed TOC=TOL for cementing model to verify job feasibility.
Spacer Type / Density	100bbl 11.5ppg viscosified spacer	Follow rheological hierarchy.
Planned Shoe Depth / TOL Depth	4,433mRT / 4,033mRT	Assumption for model only.
BHST / BHCT	63°C / 32°C	Circulating temperature based on simulation.
ECD at Shoe / at Previous Shoe	9.9ppge / 10.2ppge	At 8bpm
	Description	
Objectives	Suitable shoe for drilling liner only (depending on drilling outcome). However model covers more demanding objective of cement to TOL.	
Key risks	Tight tolerance liner. Risk of losses during cementing.	
Key assumptions	Model assumes TOC to TOL with suitable standoff required.	
Centralisation	Centraliser subs needed. 1 per 3 joints across cemented interval. To be reduced if no DPZ isolation requirement.	
Equipment requirements	Full bore, top and bottom SSR wiper plugs, compatible with liner hanger system.	

Table 20 –11-7/8" Contingency Liner Cement Summary

Running the 11-7/8" liner will also directly affect the following 9-5/8" cement job. High level modelling has been run and shows feasibility. Centraliser strategy for the 9-5/8" will not require modification as the slip on bow spring centralisers will be capable of passing through the 11-7/8" liner.

5.4 Fluids Design Philosophy

Drilling fluid is a critical part of the Stromlo-1 well design. The objectives of the fluid are;

- Provide appropriate well control,
- Provide hole stability,
- Provide good quality hole for wireline logging,
- Provide stable mud properties under prevailing conditions,
    - Maintain flat rheology over the entire range of temperatures encountered,
    - Maintain the specified fluid loss characteristics at the maximum anticipated BHT,
- Work with the engineering, sub surface team and cementers to verify that ECD control can manage down hole losses during drilling and cementing operations,
- Deliver wellbore in a condition that allows cementing design to be implemented and achieve the zonal isolation objectives,
- Produce minimal environmental impact as per the GAB environmental plan,
- Verify compatibility with data acquisition requirements.

As with cement design, there is no single practice that defines the fluids philosophy. Instead, several practices contain specific clauses relating to fluids. However, the most relevant practice regarding well integrity is BP Practice 100222 – Well Barriers (10-65). This describes the design requirements for using drilling fluid as a well barrier.

For Stromlo-1, this is planned at various phases. The Acceptance Criteria Table (ACT) regarding fluid column describes that the fluids must be designed to meet the well conditions (described in Section 6.3.3). This includes;

- Testing and reporting in line with relevant API 13 series documents. Properties must be designed to remain within specified tolerances under downhole conditions when no circulation is performed.
- The hydrostatic pressure exerted by the fluid column shall be equal to or greater than the estimated or measured pore or reservoir pressure plus the design margin.
    - For Stromlo-1, a trip margin of 200psi has been selected.
    - No riser margin is maintained for Stromlo-1. As the water depth is significant, maintaining riser margin would result in an extremely over balanced condition.
    - As an example, for TD, 12.1ppg mud would be required to maintain riser margin (for most likely pore pressure).
        - This would exceed the 11.5ppg most likely sand fracture at the previous shoe.
        - It would also result in 1,000-1,400psi overbalance. This is not considered a suitable overbalance.
        - In this example, maintaining riser margin would result significant losses and risk of stuck pipe due to differential sticking. It is not considered a suitable solution.
    - BP does not have any specific practice regarding the requirement of riser margin.
- Fluid properties that define the fluids ability to be a well barrier must be identified and documented in the drilling programme.

BP follows a fluids design workflow to ensure the design is fit-for-purpose. This ties into the well BOD generation as per the New Well Common Process.

5.4.1 Fluid Design for Stromlo-1

The fluids design is documented in the 'Stromlo-1 Fluids BOD' and has been summarised in this section of this WOMP to provide context without providing excessive, non-relevant information.

Hole Size (in)	Casing Size (in)	Depth (mRT)	Mud Weight Range (ppg)	DPZ	Selected Fluid Systems by Hole Interval
42	36	2,357	10.7 (PAD)	No	Seawater and Viscous Sweeps
28	22	3,000	9.0 (PAD)	No	Seawater and Viscous Sweeps
17-1/2	13-3/8	4,083	8.5-9.2 (target 8.9)	Yes, DPZ#1 (Top 3,953m)	SBM (with driers and cuttings discharge)
12-1/4	9-5/8 (liner)	4,833	9.0-9.5 (target 9.3)	Yes, DPZ#1 (Top 4,083m)	SBM (with driers and cuttings discharge)
8-1/2	TD	5,313	9.5-10.8	Yes, DPZ#2 (Top = 4,913m)	SBM (with driers and cuttings discharge)

Table 21 – Fluids Selection Summary

The candidate materials for building the sweeps are prehydrated bentonite (PHB), guar or xanthan gum. Guar/xanthan reduces reliance on drill water and reduces the time required to build the viscous fluid. PHB may provide some stability to loose sands.

Displacement fluid (PAD mud) is required to provide some degree of mechanical borehole stability for casing running and should be built from PHB and weighted with barite. The addition of 5% potassium chloride will provide a degree of chemical borehole stability should clays be present in the interval. The inclusion of small concentrations of LCM will minimise loss of the PAD mud to the formation maintaining fluid hydrostatic in the wellbore.

A flat rheology, synthetic oil based mud (SBM) drilling system has been selected for all following hole sections on Stromlo-1. The synthetic base oil selected is a Linear Alpha Olefin (LAO), Amodrill 1200. Selection of the drilling fluid and base oil is detailed extensively in the Stromlo-1 Fluids BOD. This fluid has been selected as it offers the best solution considering;

- Performance in deepwater temperature environment,
- Fluid stability,
- Formation stability (chemical),
- Ability to use lighter (than water based mud) weights for shallow hole section where needed,
- Greater kick tolerance due to gas solubility,
- Hydrate inhibition.

Testing of fluid stability under predicted downhole conditions is currently being carried out. Once this testing is complete, the exact chemical make-up of the drilling fluid will be finalised. The fluids programme and drilling programme will then detail the allowable variations from these properties. Testing shall be carried out, and reported, in line with API RP 13B-2 at a minimum of three times per 24 hour period (when drilling).

5.5 Shoe Depths

As Stromlo-1 will be drilled in an uncalibrated geological area, real time data will be used to optimise shoe depths. Planned shoe depths represent a 'most likely' outcome based on pre-drill data. As the well design has used conservative limits, it allows for flexibility in shoe placement. The following sections describe the shoe placement philosophy.

5.5.1 22" Shoe – 3,000mRT

A 'cleaner' area of the seismic has been identified below the K87 marker down to ~3100mRT. This is likely to be inter-bedded sandstone. It would be beneficial if a suitable shale package can be identified to set the surface casing shoe. LWD gamma ray and resistivity will be run to assist with the pick of the 22" shoe and for geological data reasons.

Shoe to be set ~3,000mRT. TD to be based on;

- Wellsite DE to provide approximate available shoe depths based on casing measurements and LPWHH landout.
- Offshore Ops Geologist in consultation with WSL to monitor and assess if formation identification is likely based on drilling experience.
- Consider potential fault identified at 3,103mRT (+/-80m) on seismic.

- Maximum drill to depth is 3,013mRT. This is ~10m shallower than the fault with uncertainty.

Note; if no shale can be found, no design change is needed. Kick tolerance for the following hole section has been based on sand fracture. Setting the shoe in a shale package is preferred, but not mandatory.

5.5.2 13-3/8" Shoe – 4,083mRT

Below the K83 marker, a shale package has been identified on the lithlog. The currently planned shoe depth is midway through this shale package. Ideally, this shoe will be pushed as deep as possible based on real time kick tolerance monitoring. It should be noted that very little data is available to calibrate the lithology prediction. As such, the current assumption is that real time monitoring will be required to identify a suitable location to set the 13-3/8" shoe. Kick tolerance for the following 12-1/4" section has been based on sand fracture in the event a suitable package is not identified.

Based on pre-drill PPFG, with 'most likely' LOT, drilling can continue to 3,700m with suitable kick tolerance, even with high case pore pressure. Drilling this section will allow real time PPFG to be established and drill to depths calculated.

The following flow chart is shown to provide guidance for forward planning only. All operational decisions will be discussed with Wells Manager.

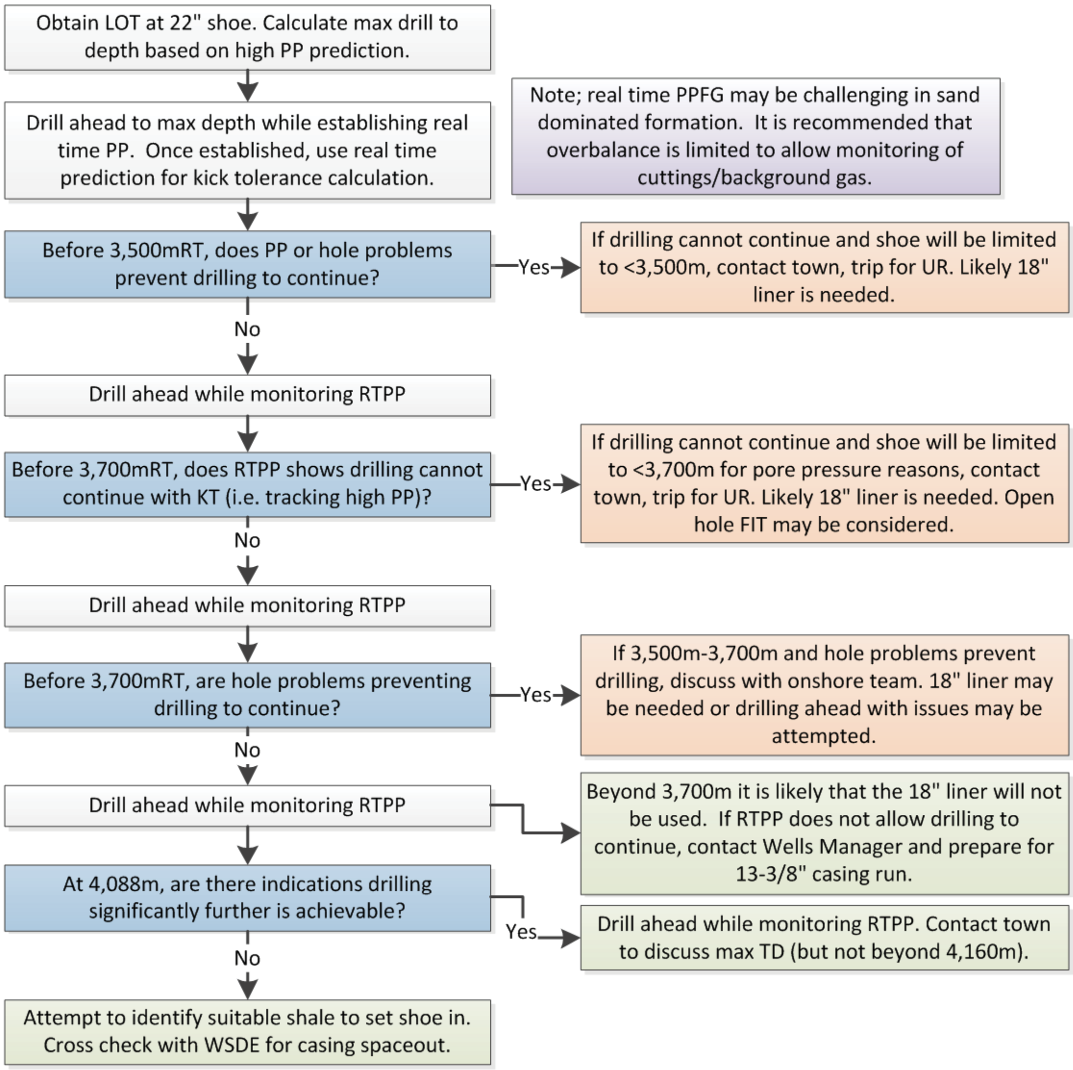

Figure 22 – 13-3/8" Shoe Placement Strategy with 18" Contingency Liner Consideration

A maximum drill to depth of 4,160mRT exists based on being ~15m shallower than the shallowest a fault identified at 4,383m (±210m) could be at (i.e. preventing the risk of losses during casing run).

5.5.3 9-5/8" Shoe – 4,833mRT

This shoe is planned to be positioned below the detachment zone but above the potential reservoir considering the error uncertainties. However, the detachment zone plus the uncertainty is a depth greater than the reservoir less the uncertainty. Hence this is not possible. Instead, real time LWD monitoring will be required to predict the relative depth. Due to the limited depth control, this may not be possible. In this event, TD will be called and the intermediate VSP will be analysed to select a shoe depth. In this event, choosing the best estimate depth for shoe placement will reduce the chance of having to deepen the hole following the VSP.

Note, the reservoir uncertainty may be reduced based on the data collected in previous hole sections. It is possible a drill to depth will be identified after setting the 13-3/8" casing.

In summary;

- Target will be to set shoe below detachment, and above reservoir.

- Previously collected data will be reviewed to attempt to identify a suitable depth (considering uncertainty).
- Real time data will be used to improve understanding and optimise shoe placement. Information will be collected in the form of;
    - Drilling data (cuttings, Dx, etc).
    - Real time LWD data to improve depth correlation and uncertainty.
    - Real time PPFG. Increasing MW to cover expected reservoir pressure may be possible. In this event, even with uncertainty on reservoir tops, drilling could continue with a mud weight that covered expected reservoir pressure.

The following flow chart is shown to provide guidance for forward planning only. All operational decisions will be discussed with Wells Manager.

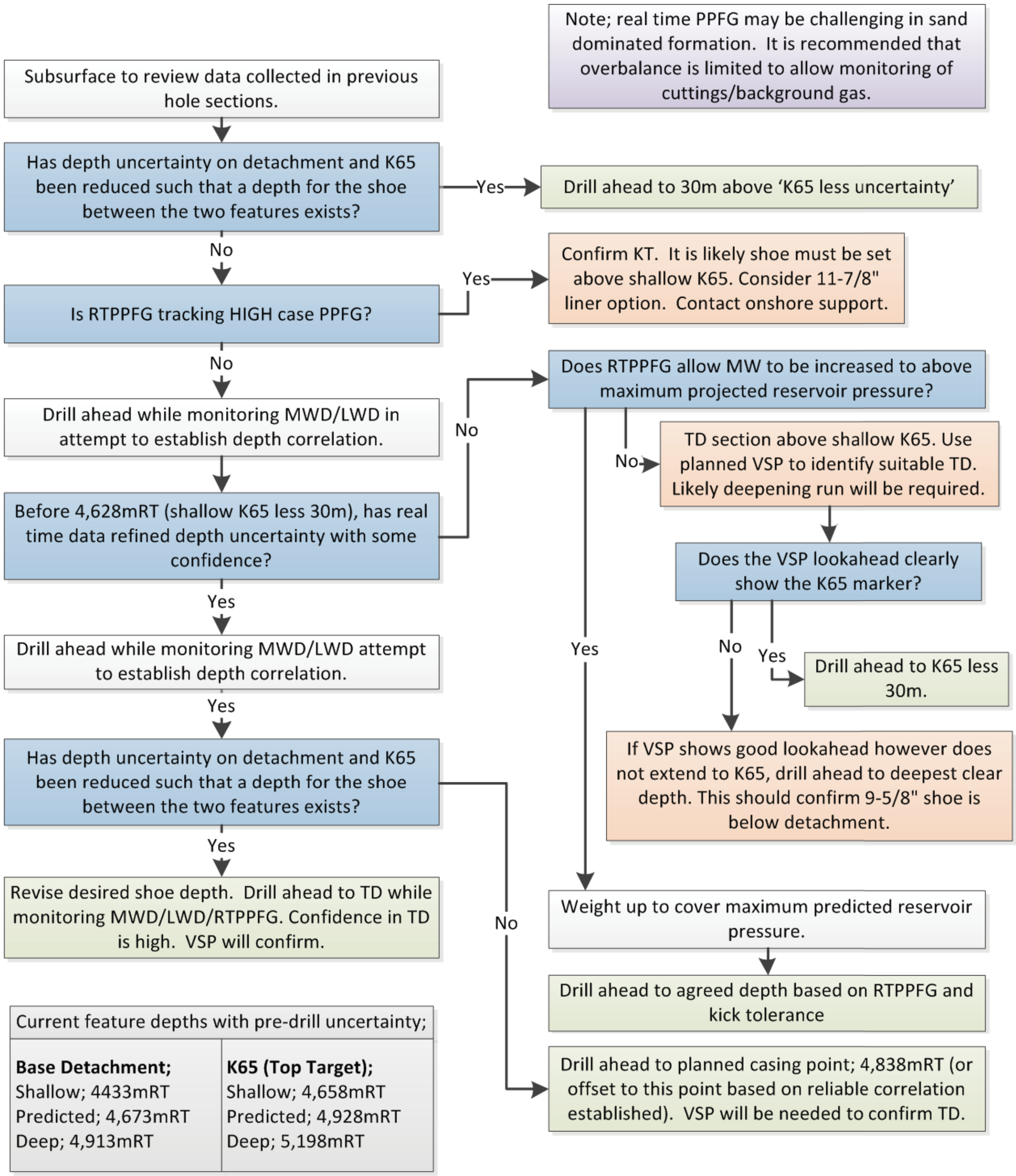

Figure 23 – 9-5/8" Shoe Placement Strategy

6 Lifecycle – Well Construction

BP's philosophy for well construction is 'to deliver safe, compliant and reliable wells'.

6.1 Well Control Standards

BP Practice 100204 – Well Control (10-10) outlines the requirements for well control. The general requirement of this practice is that BP operations shall conform to API Standard 53 (4th edition), sections 4, 5, 6 and 7. For the rig selected to be used on Stromlo-1 well operations, this is part of the contractual requirement and as such, conformance shall be verified through the rig audit process.

6.1.1 Documentation

For Stromlo-1, the following well control documents are required;

- A Well Control Bridging Document (WCBD)
    - This document outlines a gap assessment between well control procedures between BP and the drilling contractor (Diamond Offshore General Company).
    - Where gaps or differences exist, it provides clarity on which requirement is to be adopted for operations in the Great Australian Bight (including for Stromlo-1).
- A Well Control Response Guide (WCRG)
    - This plan addresses the first 48 hours of operations during a various severity well control events.
    - This document also defines the activation of the regional incident management team (IMT) who will define the following activities as per operational needs.
- Cap and containment plan
    - Discussed at length in section 12.2
- Relief well plan
    - Discussed at length in section 12.3
- Well monitoring and responsibility document
    - This document outlines the various parameters that require monitoring. It provides guidance on the recommended levels alarms should be set, however the alarms themselves will be defined in the hole section specific work instructions (at the rig site).

Day to day tracking of well control drills, kick tolerance and other issues will be reported in the Daily Drilling Report (DDR).

6.1.2 Kick Tolerance Philosophy

BP considers two kinds of kicks when discussing kick tolerance;

1. Intensity Kick – an influx that occurs when formation pressure exceeds the hydrostatic pressure of the mud.

2. Swab Kick – an influx that occurs when formation pressure is less than the hydrostatic pressure of the mid.

BP Practice 100204 – Well Control (10-10) outlines the requirements for kick tolerance. Specifically, the requirements relevant to Stromlo-1 are;

- Kick tolerance shall be based on high side anticipated pore pressure (for exploration wells),
- For intensity and swab kicks, the kick tolerance shall be greater to or equal to 25bbl in all hole sizes,
    - 25bbl is the BP globally used standard for minimum kick tolerance as per BP Practice 100204 – Well Control (10-10). This is applied as a baseline starting point for all BP operations (including UK and Norway North Sea).
    - BP's view is that kick tolerance volume is driven by alarm limits and should not be expected to vary with hole size/system volume. This is why BP uses a consistent 25bbl across all operations.
- Kick tolerance calculations shall be performed while drilling all hole sections after the first pressure containing string has been set,
- The kick tolerance of the weakest known point of the hole section being drilled shall be;
    - Verified or updated daily,
    - Updated if mud weight changes by 0.5ppg or more,
    - Updated if changes to the pore pressure or fracture gradient are encountered while drilling.

BP uses the Well Monitoring and Responsibilities and Requirements Practice (NV001-DR-PRO-600-00001) to define monitoring requirements. Specific to kick tolerance, this includes guidance on;

- Pit alarm levels. BP's requirement is that the maximum pit alarm limit is set at 50% of calculated kick tolerance for the hole section, not to exceed 25bbls. Alarms will be set below this, at the lowest resolution of the system, considering operational practicalities.
- Flow in/out monitoring. To be set at 25% from midpoint on the normal operating envelope.
- Responsibilities, including a matrix to define roles.

Furthermore, kick drills will test the responsiveness of the set alarms and personnel. These tests will be implemented as per the BP/Rig operator well control bridging document (AU000-HS-PLN-600-00004). These are described below with the minimum test frequency;

- D1 – Tripping
    - Performed inside casing and at a minimum of every 7 days.
- D2 – Drilling
    - Performed inside casing and at a minimum of every 7 days.
- D3 – Diverter
    - After running the BOP and installing the diverter.
- D4 – Well Kill
    - Prior to drilling a hydrocarbon-bearing interval.
- D5 – Stripping.

- Conducted at a frequency determined by the OIM and Senior WSL.

For calculating kick tolerance, BP uses the 'Global Well Engineering Toolkit' (GWET) as the primary method. This is an online, BP owned program that calculates kick tolerance based on a simplistic single bubble model.

In the event that the kick tolerance calculated in this program is not suitable, a BP approved, third party proprietary software may be used. Currently the Schlumberger simulation software Drillbench is the only approved software. This is a transient multiphase model that uses advanced PVT models to provide more accurate simulation of kick incidents. As it is more sophisticated, it offers a less conservative estimate for kick tolerance calculations. If this software is required, a BP well control technical specialist or designated 'superuser' shall verify the results are correct and the model is being used in line with BP global expectations. A 'superuser' must be trained (above standard user level) and designated by the BP well control central team to assure they are competent.

6.1.2.1 Kick Tolerance on Stromlo-1

Due to the lack of offset data near Stromlo-1, large variance exists between low, most likely (ML), and high case pore pressure predictions. As stated above, the high case pore pressure must be used for calculating kick tolerance. In addition, there is large variation between low, ML and high case sand and shale fracture pressures. Due to these reasons, no kick tolerance exists when performing screening level calculations. Real time pore pressure prediction and a kick tolerance monitoring strategy are needed to be in place for Stromlo-1. This is discussed in section 6.1.2.2.

For screening, high case pore pressure, and ML sand fracture pressure was used to assess kick tolerance. This was done using the GWET tool and this calculation method did not provide suitable kick tolerance.

As this project will be using synthetic oil based mud (SBM) and is a deepwater project, using the more sophisticated Drillbench software is considered a suitable approach. When using this software, the following has been calculated;

	Kick Tolerance		
Hole Size	**High PP / ML Sand FG**	**ML PP / ML Sand FG**	**High PP / ML Shale FG**
17-1/2" hole* (3,000-4,083m)	0 bbl	>150 bbl	0 bbl
12-1/4" hole (4,083-4,833m)	15 bbl	>200 bbl	192 bbl
8-1/2" hole (4,833-5,313m)	0 bbl	25 bbl	381 bbl

Table 22 – Drillbench Screening Kick Tolerance (various sensitivities) [*originally modelled as 18-1/8" hole, indicative numbers shown, to be updated]

Essentially what the kick tolerance modelling showed was that real-time pore pressure and fracture gradient prediction is required for Stromlo-1. This means that an MOC (in the form of a deviation) against the BP Practice requirements for kick tolerance will be generated prior to spud.

The following parameters were used for kick tolerance modelling in DrillBench;

Parameter / Hole Size	17-1/2" hole*	12-1/4" hole	8-1/2" hole
Influx Density	Dry gas (0.68 gas gravity)		
Choke Operator Error (psi)	100psi		
Assumed Mud Weight	8.9ppg	9.3ppg	10.8ppg
Kick Intensity (for High PP cases)	0.42ppg	1.01ppg	0.71ppg
Annular Pressure Loss (at 3bpm)	32psi	94psi	104psi
Choke Line Friction Loss (at 3bpm)	143psi	162psi	154psi
Assumed Reservoir Section	4,050-4,100mMD	4,800-4,840mMD	4,930-5,313mMD
Assumed Porosity (%)	32	25	21
Assumed Permeability (md)	1200	700	400

Table 23 – Drillbench Screening Kick Tolerance Assumptions [*originally modelled as 18-1/8" hole, indicative numbers shown, to be updated]

Kick intensity is shown for high pore pressure cases only. As the *high* predicted pore pressure has been used and compared against most likely predicted fracture gradients, no additional intensity has been added. For most likely pore pressure cases mud weight exceeds pore pressure and therefore swabbed kicks have been modelled (i.e. constant influx in Drillbench software).

6.1.2.2 Real Time Kick Tolerance Monitoring

As pre-drill screening shows that kick tolerance may be a concern, real time pore pressure monitoring and review of kick tolerance will be done during operations. The BP team in the Gulf of Mexico have an approved procedure for calculating and reporting kick tolerance during operations (GMGWO-WD-PRO-000-00221). The GAB team will adopt this procedure for Stromlo-1. The high level summary is as follows;

- Real time pore pressure prediction will be used to estimate projected pore pressure. This will be done in real time and reported daily.
    - BP Practice 100209 – Pore Pressure Detection during Drilling Operations (10-16) provides a framework for accountabilities, competencies, qualifications and responsibilities during this process.
- Rig site engineer will generate GWET kick tolerance model,
- Projected depth at midnight will be used,
- Kick tolerance for that depth assuming most likely projected PP and maximum projected PP will be calculated,
- Kick tolerance will be based on shoe pressure integrity, unless other 'known weak point' is in the hole section,
- Kick tolerance will be reported daily,
- In the event **projected** kick tolerance is <25bbls, several options exist;
    - Model kick tolerance in Drillbench via approved BP methods. If projected kick tolerance is >25bbl in this, more accurate model, drilling can continue.
    - Project to maximum depth with 25bbl kick tolerance. Limit drilling to that depth (additional drilled length will allow further calibration of real time pore pressure and potentially increase in kick tolerance). Or;

  - Stop drilling and set casing.

If drilling ahead with less than 25bbls kick tolerance is required, it would only be possible under strict MOC with an associated risk assessment.

6.2 Surveying Philosophy

BP Practice 100203 defines the trajectory and surveying requirements which Stromlo-1 will comply with. As the well is vertical with no close offsets, requirements focus mainly around documentation and assurance of the survey data. Specifically applicable areas are;

- Regarding well location (from planned location, tolerance and actual as drilled survey) the electronic Well Location Memorandum (eWLM) process shall be used.
  - This is an online database that defines location details, map co-ordinate systems, etc. BP uses this process to control the risk of spudding the well in the incorrect location.
- Objectives of the survey programme are;
  - To penetrate the geological targets for the well,
  - Quantify and minimise the risk of intersection with any nearby wellbore or structural foundation,
  - Allow a relief well to be successfully drilled to intersect the target wellbore (if required),
    - It is a BP recommendation that absolute uncertainty of any shoe above an abnormally pressured hydrocarbon bearing zone shall be <30m at 2 standard deviations (2σ). For Stromlo-1 this recommendation will be met.
  - Avoid shallow hazards.
- Well position calculation method shall be from survey data using the Minimum Curvature method as described in SPE paper 84246.

In addition, a Joint Operating and Reporting Procedure (JORP) exists between BP and the chosen surveying company. This defines other requirements around tool codes, calibration, etc. Importantly for this WOMP, the JORP also defines the BP survey frequency requirements of;

- For tangent sections and directional sections with a dog leg severity less than 5°/30m, the required interval is one survey every stand.
- For directional sections with a dog leg severity greater than 5°/30m, the required interval is one survey every single (i.e. 3 per stand).

6.2.1 Surveying on Stromlo-1

Stromlo-1 will be spud with an absolute positional tolerance of +/-25m (to a 95% confidence level). This is suitable to ensure Stromlo-1 is capable of meeting the reservoir target requirement. Following installation of the low pressure wellhead housing, but prior to running the BOP, this uncertainty will be reduced to within +/-10m (to a 95% confidence level).

Note that;

- The survey plan can be achieved with standard MWD surveying measurements. No further accuracy is required. This considers the wellhead uncertainty described above.

- Dog legs will be minimised. Allowance of 1.0deg/30m will be defined in the survey programme. Exceeding this may be acceptable, however this will be subject to approval from the Wells Manager.
  - A survey frequency of one per stand will be applied.
- Inclination will be minimised, however provided drilling target can be achieved, minor inclination is not a concern (i.e. <10^{o} inclination).
- No infrastructure or wellbores exist in the nearby area. There are no anti-collision concerns for Stromlo-1.
- For relief well planning, an error ellipse report has been generated to show that;
  - At the planned 13-3/8" shoe, absolute lateral uncertainty is 10.42m at 2σ;
  - At the planned 9-5/8" shoe, absolute lateral uncertainty is 10.56m at 2σ.

6.3 Well Barrier Standards

For clarity, BP defines the following elements when assessing zonal isolation and well barriers;

- Permeable Zone (PZ)
  - One with sufficient permeability that a credible pressure differential is expected to result in the movement of fluids (oil, water, or gas) and/or development of sustained casing pressure.
- Distinct Permeable Zone (DPZ)
  - Group of permeable zones in which intra-zonal isolation is not required for operation or abandonment of the well.
    - An example would be a laminated reservoir where isolation between sand packages is not required.
    - For Stromlo-1, pre-drill DPZ identification was done and peer reviewed (see Section 3.1.8). This will be updated post-drill to identify actual DPZs encountered and plan the abandonment requirements to suit.
- Well Barrier Element (WBE)
  - A pressure and flow containing component that relies on other component(s) to create a well barrier envelope and is verified to conform to specific acceptance criteria.
- Well Barrier
  - Envelope of one or more dependent WBEs that prevents fluids from flowing unintentionally from either the formation or well into or from another formation or to the surface.
- Acceptance Criteria
  - Technical and operational requirements that are to be fulfilled to qualify the well barrier or a WBE for its intended use.

Stromlo-1 uses two key documents to define barrier requirements;

- BP Practice 100221 – Zonal Isolation (10-60). This document provides requirements and permissions for cement WBEs installed during well construction and permanent abandonment. e.g. cement barrier length requirements, compressive strength, etc.
- BP Practice 100222 – Well Barriers (10-65). This practice specifies the minimum mandatory requirements for well barrier management throughout the life cycle of the well. e.g. casing, BOP, fluid column, shoetrack, etc. It does define annulus and plug cement ACTs, however, it points to BP Practice 100221 for the specific requirements (as cement barriers are defined in the zonal isolation practice).

Essentially, Practice 100221 – Zonal Isolation talks to cement barriers and barriers specific to hydrocarbon bearing zones. Practice 100222 – Well Barriers covers all barriers to be used in the lifecycle including plugs, valves, etc.

To summarise the general philosophy, a primary and secondary well barrier is required during all operations after the BOP is installed. Other, relevant, specific requirements include;

- The primary annular cement WBE above any DPZ shall be across a natural seal for that DPZ.
- Annulus cement height requirement is;
  - 30mMD when using the circumferential logging method.
  - 300m when using a TOC estimate method.
- During temporary abandonment (suspension), mechanical barriers are acceptable. To be qualified as a suitable WBE, the well component must meet the acceptance criteria detailed in its specific Acceptance Criteria Tables (ACT), which specify test requirements, depending on the specific WBE being used.
  - BP define three levels of temporary abandonment; short, medium and long term. Depending on the term of temporary abandonment, different barriers are considered allowable. For Stromlo-1, no temporary abandonment is planned (however short term temporary abandonment may be required for Non Productive Time (NPT) events such as weather suspension).
    - Short term is defined as a duration in which the response time could be sensitive, a weather or safety threat could be imminent, or BOP repair is required, all with the intention of returning to the well as soon as practical (typically days or weeks). This is not planned for Stromlo-1, however may be needed for NPT events.
    - Medium term is defined as a duration in which the response time is not sensitive, and plans do exist to return to the well for additional construction activity (typically months or years). This is not planned for Stromlo-1.
    - Long term is defined as a duration in which plans do not exist to return to the well, yet access to the wellbore could be required for future activity (typically many years). This is not planned for Stromlo-1.

When permanently abandoning the well, other specific requirements are;

- At least two lateral cement barriers shall be in place for;
  - Each potential flow path between any DPZs,
  - Any DPZ and surface,
  - A DPZ and a hydrostatic permeable zone.

- WBEs isolating the wellbore shall be constructed of cement.
- To construct a lateral barrier, the wellbore cement WBE shall be placed across the equivalent height of the annulus WBE.
- BP does not consider mechanical barriers suitable for permanent abandonment.
    - Stromlo-1 will be permanently abandoned following completion of the data acquisition phase. See section 10 for details.

6.3.1 Cement Barrier Verification (ACT tables from BP Practice 100221 – Zonal isolation)

BP Practice 100221 Zonal Isolation (10-60) describes the requirements for well barriers installed to achieve zonal isolation (i.e. cement barriers). This includes annular cement and cement plugs for the use of abandonment. Further well barrier requirements are defined in *BP Practice 100222 – Well Barriers (10-65)* and that document focuses on the selection, installation verification and maintenance of various barriers.

BP Practice 100221 – Zonal Isolation (10-60) uses BP experience and good oilfield practice as a basis. It is not dependent on any international standards. Relevant requirements to the Stromlo-1 cement design are outlined below.

6.3.1.1 Annular Cement Barrier Verification (ACT 1 and 2 from BP Practice 100221 – Zonal Isolation)

The well shall contain at least two WBEs isolating each annulus flow path between each DPZ and the seabed. Annular cement can be considered a WBE, provided it conforms with the relevant methods and requirements outlined in the BP Practice (i.e. the ACT for annular cement). BP has two different ACT for annular cement. Both require chemical stability of the cement at the expected temperature ranges. Both require the construction criteria as per the BP Practice. The variance is with the verification of the annular cement.

Due to EPP39 permit condition 9, only logging will be used to verify TOC for Stromlo-1 annular cement that will be used as a barrier for a DPZ. Due to tool limitations, this means the BP acceptance criteria can be broken into two distinct methods;

Method 1; ACT 5.5.1 (from BP Practice 100221) – TOC estimate verification for annular cement WBE.

Various options can be used to estimate the TOC however as described above, for Stromlo-1 only one method is relevant;

- Non-circumferential sonic or ultrasonic log

This method requires 300mMD column of cement above the uppermost DPZ to be considered a barrier. It may be required where full circumferential data cannot be achieved. This is most likely in the event logging of the 18” contingency liner cement is required where, due to hole size, tool limitations may prevent full circumferential data. In this situation, only TOC can be confirmed and therefore a larger cement column is enforced.

Method 2; ACT 5.5.2 (from BP Practice 100221) – Circumferential logging verification for annular cement WBE.

The annular cement can be verified to the required length in intervals of circumferential cement built up from 2mMD intervals to a total of 30mMD of verified cement (for a single barrier).

In line with globally available guidelines, BP Practices require a single, verified barrier to be 30mMD length. However unlike these guidelines, BP specifies how the quality of the barrier is assessed. This is because there are practical limits when interpreting these types of logs (i.e. there are regularly minor points of concern that could be interpreted as a log issue or formation change). It should be noted that 'continuous bonded cement' is not the same as 'circumferentially verified cement'. BP believes that the requirement for circumferentially verified cement is a more stringent requirement.

For that reason, BP has defined the specific requirement to verify the 30mMD as circumferentially verified cement to be considered as indicating an effective barrier. This requirement must show that 100% of the casing annulus circumference is cemented for that given interval to be considered as part of the barrier. As this is a very strict requirement, BP allows this to be made up of intervals, no less than 2mMD in length. A minimum of 2m has been selected as it provides an adequate number of data points to determine if a log response is valid or anomalous. This is based on the transmitter to receiver spacing and firing frequency. BP also has offsets where short (2-3m), circumferentially verified cement lengths have been proven to be effective barriers.

Note that in addition to this, the barrier must be verified by a BP cement bond log interpretation specialist.

As this is a more stringent definition of what constitutes an effective barrier, BP considers this approach to be ALARP and will use this method to verify annular cement when using a circumferential logging technique. In practice, this method is used for BP globally (including Norway and UK North Sea) where globally available guidelines require a 30mMD continuous bonded cement barrier.

Combination Barriers

BP Practices allow an annular cement barrier to be used as a 'combination barrier' (i.e. primary and secondary barrier in a single annular cement column) if the annular cement height is, at minimum, 1.5 times the height of a single annular barrier.

For combination barriers verified using non-circumferential log methods (ACT 5.5.1) this will result in a 450mMD cement column.

- Although this is not 2x the height of a single column, it has been compared with other globally available guidelines.
    - OGUK Well Life Cycle Integrity Guidelines Issue 3 (paragraph 465) states that annular cement shall be 300mMD if the TOC is calculated indirectly and is considered adequate for two permanent barriers or a combination permanent barrier for the eventual abandonment of the wellbore. Paragraph 466 states that this may be reduced if verified by a direct measurement (i.e. log).
    - NORSOK D-010, 15.22, Table 22 requires a 50mMD verified by displacement calculations (i.e. not circumferential logging) for a single barrier. In line with other sections of this practice, 2 x that length (i.e. 100mMD total) would be required for a combination barrier. Non-circumferential logging of TOC is not discussed as it is only required for production casing or liners (i.e. large sizes where non-

circumferential tools don't exist are not likely and the displacement calculation method would be more commonly applied).

- For this reason, if the non-circumferential log method described in ACT 5.5.1 is used, the BP requirement of 450mMD length for a combination barrier is considered ALARP and will apply.

For combination barriers verified using circumferential logging (ACT 5.5.2) this would result in a 45mMD interval.

- However, globally available guidelines require more stringent height requirements in the situation of bond log verified cement. Both OGUK and NORSOK specify or imply 2 x annular lengths being required for a combination barrier that is verified in this method.
- For this reason, if the circumferentially verified cement method described in ACT 5.5.2 is used, the BP requirement of 45mMD length for a combination barrier is not considered ALARP.
- 2 x annular length of 60m will be required. This will be verified in line with ACT 5.5.2.

For full clarity, see table below for Stromlo-1 the current annular cement verification options. Actual methods (if required) will depend on DPZ identified during drilling operations and will be detailed in the abandonment report. This table demonstrates tool limitation and need for ACT 5.5.1.

Casing Size / Hole Size	Annular Cement Verification Method	Height Required for Single Barrier (m)	Height Required for Combination Barrier (m)
36" Conductor / 42" Hole	Not required		
22" Surface Casing / 28" Hole	Not required		
18" Contingency Liner / 21" Hole (base case)	Not required. No DPZs are anticipated.		
13-3/8" Production Casing / 17-1/2" Hole	Circumferential Logging	30m	60m
9-5/8" Liner / 12-1/4" Hole	Circumferential Logging	30m	60m
18" Contingency Liner / 21" Hole (contingency case with DPZs identified)	Non-circumferential log*	300m	450m
11-7/8" Contingency Liner / 14-1/2" Hole	Circumferential Logging	30m	60m

Table 24 – Planned TOC Logging Options

*Circumferential logging tools in this casing size may only provide limited, omnidirectional data (i.e. not full circumferential coverage due to limited probes on the logging tool body). For this reason, only a non-circumferential log is possible and ACT 5.5.1 will need to be applied if this annular cement is used as a WBE.

6.3.1.2 Wellbore Cement Barrier Verification (ACT 4 from BP Practice 100221 – Zonal Isolation)

Lateral barriers within the wellbore are designed to match the accepted barrier in the annulus (i.e. if a TOC system is used in the annulus, the cement plug will meet that height requirement). The Practice also defines an ACT for verification of wellbore cement (i.e. cement plugs). This ACT requires;

- Cement plug height shall be a minimum of 30mMD above the DPZ and place across a natural seal.
- To construct a lateral barrier in casing, the wellbore cement WBE shall be placed across the equivalent height of the annulus WBE.
- Primary barriers in the open hole to be weight tested only.
- The deepest barrier inside the casing shall be both positively and negatively pressure tested and mechanically weight tested.
- Weight and pressure testing on all subsequent plugs can be omitted if;
  - The cement plug is placed on a reliable base*
  - The plug is effectively placed as per design
  - Greater than 90% of cement volume is mixed at a density of no less than 0.25ppg below the planned density
  - The cement plug is at least 100mMD long.
- The primary barrier to the shallowest hydrocarbon bearing zone shall be mechanically weight-tested.
- Where an annular 'combination barrier' (i.e. primary and secondary barrier in a single cement column) has been used, a combination wellbore cement WBE shall be installed across the vertical extent of the annular barriers and set of a reliable base (i.e. viscous reactive pill).

*Note that BP considers viscous reactive pills or cement support tools to be considered 'a reliable base'. However, globally available guidelines have differing requirements regarding this. For this reason, the use of viscous reactive pills on Stromlo-1 is not considered ALARP.

Instead, for Stromlo-1, a 'reliable base' will only be considered to be a mechanical or cement plug that has been tagged and pressure tested. Negative pressure testing will be omitted provided the lower plug has been successfully negatively tested in the same direction of flow.

Various other details are contained in BP Practice 100221 – Zonal Isolation. However the above sections describe the general philosophy the GAB project used to design the cement barriers for Stromlo-1. This practice aims to assure the geological seals, that were broken in order to drill the well, are replaced by suitable cement barriers.

6.3.2 Casing and Liner Hanger Barrier Verification (ACT 5, 23 and 65 from BP Practice 100222 – Well Barriers (10-65))

For casing or liners to be used as a barrier during the Stromlo-1 well lifecycle, they must comply with the relevant ACT regarding casing, liner packer or hanger adapter system defined in BP Practice 100222 – Well Barriers (10-65). These ACT points to the casing design practice (discussed at length in Section 5.1) for design requirements. The verification and testing is described in a different practice; BP Practice 100218 – Pressure Testing (10-45).

For Stromlo-1, all pressure tests will be performed in line with this Practice. The values shown below are notional only. Actual test will depend on the mud weight that is required to TD the section or, for negative tests, the DPZ identification and pressure evaluation.

Pressure Level		**Minimum Pressure**	**Maximum Pressure**
Low		250 psi	350 psi
High	Liner lap	The highest of the following: a) 500 psi above the formation leakoff pressure at the covered casing shoe. **(3)** b) A value greater than the calculated service load. **(1)**	Not to exceed the lowest of the following: a) Test pressure limitations in the applicable casing and tubing design document. **(2)** b) Lowest RWP of any WBE in the well barrier envelope under test. **(2)** *Applies to all high pressure tests.*
	Other High Pressure Tests	A value greater than the calculated service load. **(1)**	
	Annular BOP	The lowest of the following: a) 70% of RWP. b) A value greater than the calculated service load. **(1)**	70% of RWP.
Negative		For normally pressured (or greater) DPZs, the target test pressure is less than the pressure in the DPZ for which the WBE is providing isolation. For sub-normally pressured DPZs, the target test pressure need only equal the normal hydrostatic pressure at the component being tested. **(4)**	The lowest design collapse rating of the WBEs in the well barrier envelope under test.

Notes:

1. Calculated service load is the pressure as calculated from the table in BP Practice 100202 - Casing and Tubing (10-01) titled "Load cases for tubular design" and documented in the applicable casing and tubing design document.
2. RWP includes any derating due to considerations such as casing wear, corrosion, erosion, or tubing movement calculations.
3. The shoe is associated with the parent casing.
4. The intent is not to require displacing with nitrogen or a base oil to achieve a target test pressure below hydrostatic pressure. Negative testing prior to removal of a subsea BOP stack does not require use of base oil to remove the hydrostatic equivalent of the air gap.

Table 25 – Extract from BP Practice 100218 – Pressure Testing (10-45)

Test Type Number	Test Description	Test Evaluation Period (1)	Acceptance Criteria	Pressure Behaviour During Test	Additional Criteria
1a	Low pressure test BOP equipment.	5 min.	5 psi/min Loss Rate.	Decreasing pressure falloff or stable pressure.	1. Test pressure shall remain within the low pressure range during the test evaluation period. 2. No visible leaks.
1b	Low pressure test non-BOP equipment.	5 min.	10 psi/min Loss Rate.	Decreasing pressure falloff or stable pressure.	1. Test pressure shall remain within the low pressure range during the test evaluation period. 2. No visible leaks.
2a	High pressure test. (non-WBE)	5 min.	50 psi/min Loss Rate.	Decreasing pressure falloff or stable pressure.	1. Test pressure shall remain above or equal to the target pressure during the test evaluation period and until the pressure is released. 2. No visible leaks.
2b	High pressure test. (WBE) **(2)**	5 min.	10 psi/min Loss Rate.	Decreasing pressure falloff or stable pressure.	1. Test pressure shall remain above or equal to the target pressure during the test evaluation period and until the pressure is released. 2. No visible leaks.
3a	High pressure well integrity testing. (small volume WBE) **(3)**	15 min.	5 psi/min Loss Rate.	Decreasing pressure falloff or stable pressure. **(4)**	1. Test pressure shall remain above or equal to the target pressure during the test evaluation period and until the pressure is released. 2. No visible leaks.
3b	High pressure well integrity testing. (WBE) **(4)**	30 min.	Stable or decreasing pressure fall off less than 5 psi/min for the final 15 min. .	Decreasing pressure falloff or stable pressure. **(5)** (see Figure 1)	1. Test pressure shall remain above or equal to the target pressure during the test evaluation period and until the pressure is released. 2. Fluid volumes pumped and bled back within allowable range. 3. No visible leaks.

4a	Negative pressure testing. (atmospheric)	30 min.	No flow. **(6)**	No flow. **(6)**	Negative load requirement is satisfied during entire test.
4b	Negative pressure testing. (shut in pressure)	30 min.	No pressure buildup outside of the allowable range.	No pressure buildup outside of the allowable range. **(5)**	Negative load requirement is satisfied during entire test.

Notes:

1. Approved predictive pressure test analysis software results are equivalent to acceptance criteria listed in Table 2.
2. Type 2b WBE tests are for WBEs that serve as temporary elements in the well barrier envelope (i.e., blowout prevention equipment).
3. These Type 3a WBE tests are for WBEs that require long term integrity but contain volumes less than 5 bbls (e.g., subsea control lines).
4. These Type 3b WBE tests are for WBEs that serve as long term elements in the well barrier envelope (e.g., casing and tubing strings, hangers, packers).
5. Pressure buildup is allowable according to 5.3.1d.
6. Volumes as determined in 5.3.1c.

Table 26 – Extract from BP Practice 100218 – Pressure Testing Acceptance Criteria (notes in table are referencing the BP practice, not this document)

For test evaluation periods pressure tests, predictive pressure testing analysis software can be used. The predictive software planned for Stromlo-1 is the BP Well Advisor software.

6.3.2.1 Positive Pressure Tests

All positive pressure tests are designed to be greater than the maximum service load as per BP Practice 100218 – Pressure Testing (10-45). For Stromlo-1 the selected design pressure test value varies between ~100-200psi over the maximum service load (to round number at surface).

Note, for all strings, the gas to surface load is the maximum service load.

Pressure testing with the displacement fluid for the cement job has been assumed for all pressure test load cases in the following table. In the event a different mud weight is used, the required surface pressure will be re-assessed.

Casing String	Pressure Test Type	Surface Pressure Test Value	Fluid in hole	Comments
22” Surface Casing	Positive pressure test	1,400psi	8.6ppg (seawater)	
	Green cement pressure test	1,550psi	8.6ppg (seawater)	Higher value than standard PT is required due to differential at shoe
13-3/8” Production Casing	Positive pressure test	5,600psi	8.9ppg displacement fluid	
	Green cement pressure test	5,600psi	8.9ppg displacement fluid	
9-5/8” Production Liner	Positive pressure test	3,500psi	9.3ppg displacement fluid	Test creates differential at 13-3/8” shoe >500psi over high shale fracture pressure as per BP practice 100218 – pressure testing (10-45) table 1.
	Green cement pressure test	3,500psi	9.3ppg displacement fluid	

Casing String	Pressure Test Type	Surface Pressure Test Value	Fluid in hole	Comments
18" Contingency Liner	Positive pressure test	1,800psi	8.9ppg displacement fluid	Test creates differential at 22" shoe >500psi over high shale fracture pressure as per BP practice 100218.
	Green cement pressure test	1,800psi	8.9ppg displacement fluid	
11-7/8" Contingency liner	Positive pressure test	3,500psi	9.3ppg displacement fluid	Test creates differential at 13-3/8" shoe >500psi over high shale fracture pressure as per BP practice 100218.
	Green cement pressure test	4,100psi	9.3ppg displacement fluid	

Table 27 – Pressure Test Values

Note that green cement pressure test values for the 11-7/8" and 9-5/8" liners in the casing design have been increased to 5,000psi to cover deployment of the versaflex flapper (installation of the liner hanger). The table above covers minimum test values, the modelled load is to cover operational installation.

6.3.2.2 Negative Pressure Tests

A negative pressure test will be conducted before abandonment. As this is a wildcat exploration well, the GAB team is not planning to refine the negative pressure test values at this stage. To account for this uncertainty, the casing design has confirmed the well is capable of full displacement to base oil. This models a negative test beyond the actual test that will be carried out. The GAB team will perform negative pressure tests in line with BP Practice 100218 – Pressure Testing. Specifically, the logic by which the negative test will be performed is;

- DPZ depth and pressure will be estimated by subsurface team following logging campaign.
- A 200psi negative test will be performed. To do this;
    - Fluid column (either drillpipe, annulus or choke and kill line) will be designed such that it would establish 300psi underbalance statically.
    - When pressure is bled off, 100psi gauge pressure will be maintained to ensure visual changes can be identified.
    - This results in a 200psi underbalance at the top of the DPZ for negative test duration.

6.3.3 Fluid Column Barrier Verification (ACT 20 from BP Practice 100222 – Well Barriers (10-65))

Design of fluid as a barrier is described at length in Section 5.4 which outlines the testing and design requirements used on Stromlo-1. In addition to the design requirements, ACT 20 of the BP Practice 100222 – Well Barriers outlines the verification requirements. Specifically;

- Fluid levels shall be documented and maintained to a height that allows for visual confirmation if the wellbore is capable of maintaining a fluid column to the surface.
- Fluid properties that define the fluids ability to be a well barrier shall be within specifications as defined in the drilling programme.

  - For Stromlo-1 these will be defined in the well specific fluids programme. Testing is being conducted on the planned fluid chemistry currently. This testing will provide guidance on allowable limits and desired properties.

6.3.4 BOP Barrier Verification (ACT 4 from BP Practice 100222 – Well Barriers (10-65))

As defined in BP Practice 100204 – Well Control (10-10), BOP equipment must conform to API standard 53 Sections 4, 5, 6 and 7. Verification shall be in the form of pressure testing, conducted in line with BP Practice 100218 – Pressure Testing (10-45). This defines that;

- Testing frequency will be in line with API Standard 53, Section 7.
- Test Acceptance Criteria and durations are in line with the table shown above in Section 6.3.2 (Table 26).

In addition, operating and monitoring the BOP shall be conformant with BP Practice 100206 – Subsea Blowout Preventer (BOP) Systems (10-11).

6.3.5 Mechanical Plug Barrier Verification (ACT 25 from BP Practice 100222 – Well Barriers (10-65))

To be used as a barrier, the mechanical plug shall be;

- Confirmed to be set prior to pressure testing (i.e. weight tested to confirm set),
- Tested according to BP Practice 100218 – Pressure Testing (10-45) (as described in section 6.3.2),
- Inflow tested unless;
  - Its seal design confirms that a test from above also constitutes a successful seal test from below, or
  - A differential pressure cannot be established to perform an inflow test.

Note, although tagging of this plug is not required, if it is to be used as a cement plug base and tagging of the cement plug is not planned, this plug will require tagging (in line with 6.3.1.2).

6.3.6 Cemented Shoetrack Barrier Verification (ACT 6 from BP Practice 100222 – Well Barriers (10-65))

For a cemented shoetrack to be considered a barrier, the following conditions shall be met;

- The cemented shoetrack shall have a minimum of 2 redundant float valves;
- The height of the cement column extends at least 30mMD above the shoe and one of the following conditions are met;
  - The plug and landing collar are drilled, and the cement is verified by drill string weight and pressure tested in accordance with the requirements of a wellbore cement plug (Section 6.3.1.2).
  - At least 10mMD of cement placed above the top plug is verified by a drill string weight and pressure tested in accordance with the requirements of a wellbore cement plug (Section 6.3.1.2).

6.3.7 Additional Barrier Verifications (ACTs 18, 35, 52 and 60 from BP Practice 100222 – Well Barriers (10-65))

Other Acceptance Criteria Tables exist for equipment that may be used as a barrier during the construction of Stromlo-1. These haven't been detailed in this WOMP. Generally the ACT tables use the pressure test Practice as a basis, with some variances as required to suit specific equipment operations. Examples include but are not limited to;

- Drill string
- Stab in safety valves
- Wellhead,
- Retrievable service packers (eg DLT packers)

Overall BP has 65 acceptance tables defining the requirements of various barriers.

6.3.8 Temporary Abandonment

As mentioned above, no temporary abandonment is planned. Short term temporary abandonment may be required for Non Productive Time (NPT) events such as weather suspension.

Temporary abandonment is covered under BP Practice 100222 – Well Barriers, applicable to Stromlo-1, short term temporary abandonment is defined as; Duration in which the response time could be sensitive, a weather or safety threat could be imminent, or BOP repair is required, all with the intention of returning to the well as soon as practical (typically days to weeks). Key points in the practice are;

- If the temporary abandonment is short term, one of the WBEs isolating the wellbore may include a work string underneath a retrievable service packer with valve (RSPV, also referred to as a storm valve or storm packer in industry).
- If conditions prevent the setting of an RSPV, an MOC shall be authorised according to the risk level, before using an emergency hang off tool as an alternative.
  - Excessive rig heave can prevent successfully setting an RSPV or potentially damage casing or the RSPV running tool.
  - The risk assessment can be performed in advance and the resulting decision incorporated into an emergency response plan.
- Two verified mechanical WBEs may be used for short-term or medium-term temporary abandonment.

The ACT relating to a RSPV is ACT 60 from BP Practice 100222 – Well Barriers. This states that for an RSPV to be considered a barrier it must;

- Be designed such that pressure above and below can be equalised before un-setting;
- Only be installed in a section of casing that either has sufficient wall thickness or is supported by cement to withstand the setting and operational loads;
- When using in casing before drilling out, shall be positively pressure tested according to BP Practice 100218 – Pressure Testing from below to verify that the RSPV is sealing and the casing has pressure integrity;

- When used in casing above an open hole, shall be pressure tested from above to a value that exceeds the strength of the formation.

An example of this, short term abandonment, barrier status is shown below;

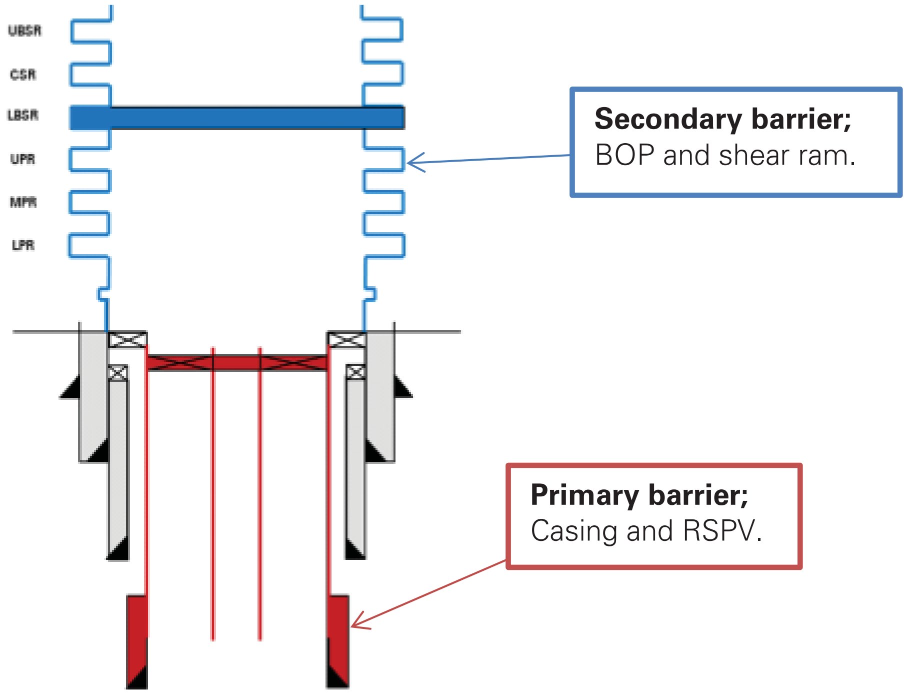

Figure 24 – Example Short Term Abandonment Arrangement

As the weather conditions in the Great Australian Bight may not provide enough time to run this type of barrier configuration. This is similar to BPs experience in the North Sea, where weather events are more frequent, usually less severe (storms rather than cyclones or hurricanes) but the severity is more difficult to predict. In these operations it is common to run a hang-off tool with a workstring below with a closed pipe ram as the primary barrier and a BOP shear-seal ram is used as the second barrier.

In recent years with the introduction of BOPs with two shear-seal rams these have been used in some operations to provide the primary and secondary barriers. Both these configurations may be used in the event weather predictions do not allow suitable time to suspend the well as per Figure 24. As per BP Practice 100222 – Well Barriers, this would require a risk assessment and MOC to be performed. This will be in place before drilling operations begin. In these situations, the following barrier configurations would be used.

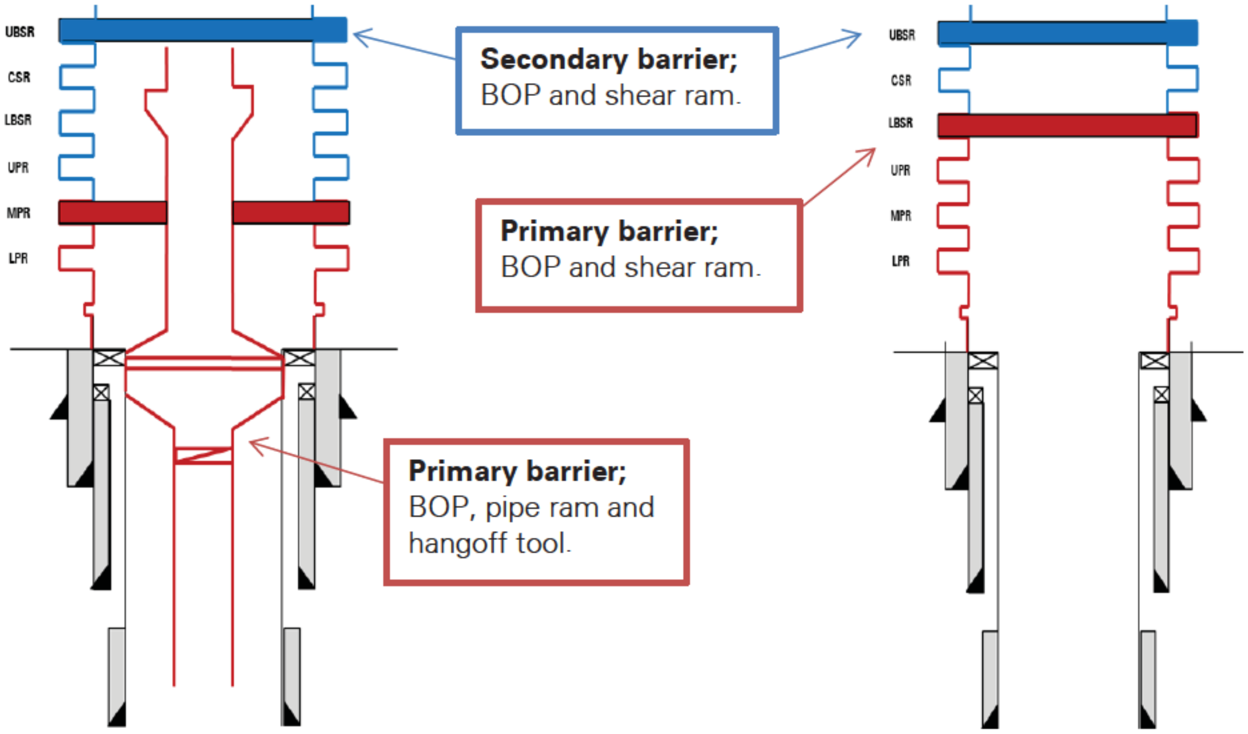

Figure 25 – Example Short Term Abandonment Arrangements (if time does not allow RSPV installation). Suspension in this method will require MOC.

In the situation where a hang-off is used, the following requirements are applied:

- The tool enables the drill pipe to be disconnected above the hang-off tool at a point below the blind/shear rams.
- It is equipped with a back pressure valve (Gray valve) or other pressure isolation device to restrict upward flow through the drill string, but permit fluids to be circulated down the drill pipe.
- It enables the drill pipe to be efficiently reconnected to the suspended drilling assembly and allow circulation of fluids down the drill pipe.

As BOP rams cannot be tested against the direction of flow, it is not possible to test these barriers once installed if open hole is present below deepest shoe (i.e. cannot test between rams). Equipment would be tested as part of the regular BOP test sequence (as per API Specification 53).

7 Timeline

As Stromlo-1 will be drilled with the new build rig the Ocean GreatWhite, timing depends greatly on rig delivery. For well planning, a spud of 1 October 2016 is being assumed. This may vary depending on rig construction schedule and acceptance testing. For the purpose of this WOMP, it should be assumed that spud will be 4Q 2016 and notification will be provided in line with regulatory requirements (i.e. 21 days prior to spud).

Well operations are anticipated at;

P10	*P50 (Mean)*	*P90*
38 days	71 days	118 days

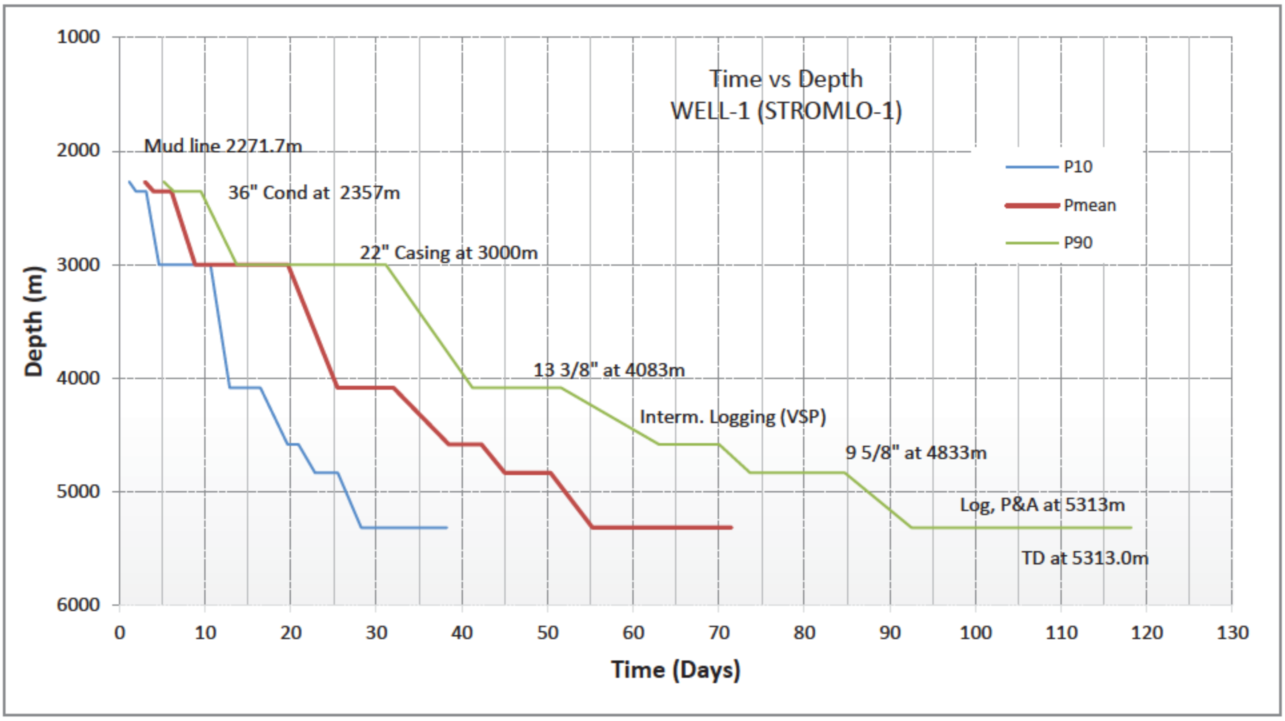

Figure 26 – Stromlo-1 Time vs. Depth Curve

8 Risk Management

BP defines risk (OMS Glossary) as *"A measure of loss/harm to people, the environment, compliance status, Group reputation, assets or business performance in terms of the product of the probability of an event occurring and the magnitude of its impact."*

GWO New Ventures Risk Management follows the Global Wells Organisation Risk Management Procedure 100096. This Practice is in conformance to:

- BP Policy 000030 Risk Management
- BP Procedure 100363 Upstream Risk Procedure

Additionally, the Risk Management Procedure 100096 provides:

- A structured risk management process
- Incorporates change to notification and endorsement requirements per Upstream Risk Management and Reporting – 2015 Simplification Plan
- A GWO risk register hierarchy that facilitates risk aggregation and simplifies documentation of risk information, (see Figure 28)
- Defines the GWO Level 1 and 2 Risk Registers that are used for BP Risk Process and redefines the GWO Level 3 and 4 Registers that are used for New Well Common Process
- A reference to common risk management tools, (e.g. GWO Standard Level 3/4 Risk Register Template, level 2 risk register in BP Risk Assurance Tool, (RAT), GWO Standard Bowties, Group Risk Classification Tool).

Risks within BP are assessed on an 8x8 matrix. These consider likelihood against severity.

		Likelihood							
		1	2	3	4	5	6	7	8
Impact	A	8	9	10	11	12	13	14	15
	B	7	8	9	10	11	12	13	14
	C	6	7	8	9	10	11	12	13
	D	5	6	7	8	9	10	11	12
	E	4	5	6	7	8	9	10	11
	F	3	4	5	6	7	8	9	10
	G	2	3	4	5	6	7	8	9
	H	1	2	3	4	5	6	7	8

Figure 27 – BP Risk Matrix

Likelihood varies from 1 (the lowest) to 8 (the highest). Guidance on scoring likelihood is provided in BP Policy 000030 – Risk Management. Essentially, a quantitative criteria is used where data sets can be used. Otherwise, qualitative values are assigned based on BP and industry experience.

Consequence is considered across 4 key segments. Qualitative guidance is also provided in BP Policy 000030 – Risk Management.

- Health and Safety
- Environment
- Financial
- Non-Financial (Accounting and control, Media/Public reaction, License to Operate, Government/key stakeholder reaction and Management time)

Depending on the level of risk identified, notification levels and endorsement are elevated to assure suitable visibility at the appropriate management level (Table 28).

	Recommend	S+OR Agree (for S&O risks only)	Endorse
Purple / Blue C+	HoF Head of GWO	Head of Upstream S+OR	COO
Blue D/E	HoF – 2* VP Wells Region or Manager – Wells	N/A	HoF – 1* VP Wells
Turquoise	Team Lead - Wells	N/A	Manager - Wells
White	No formal endorsement required		

Table 28 – Risk Notification Levels

*For Stormlo-1 the roles for Blue D/E risks are;

- **Head of Function (HoF) – 2**; VP Wells - New Ventures
- **HoF – 1**; VP Performance, New Ventures and Asia Pacific

BP uses a tiered risk register approach for identifying and managing risks for well operations;

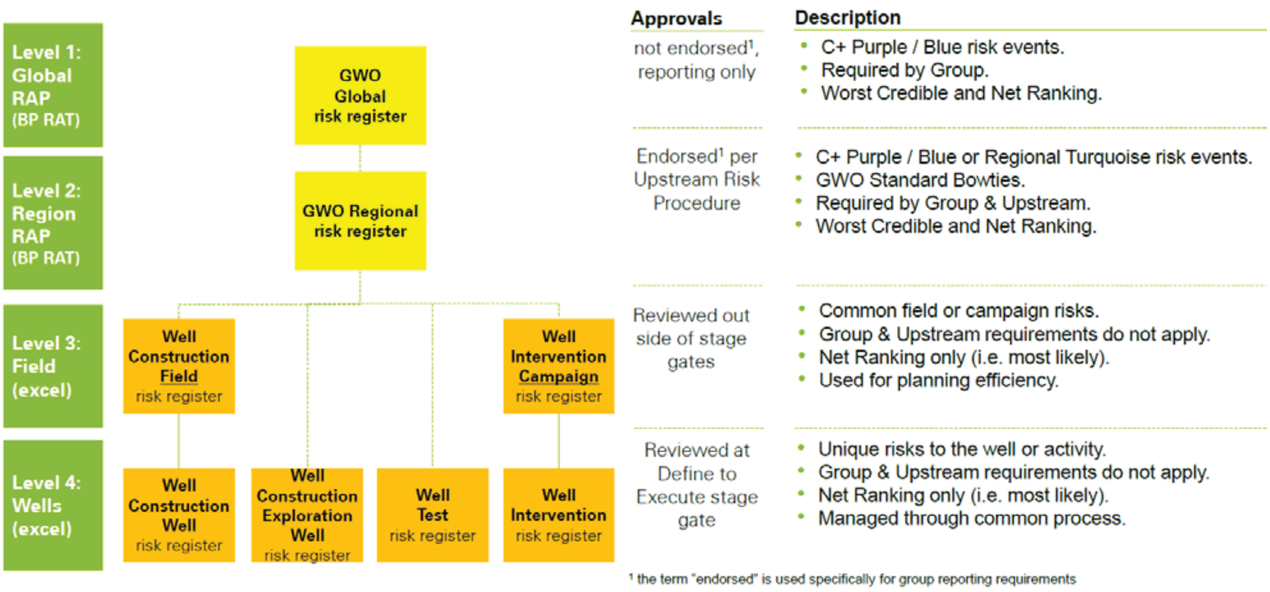

Figure 28 – BP GWO Risk Register Hierarchy

As this is a general BP risk process, some areas are not applicable to this WOMP. For Stromlo-1, the flowing description of the risk level provides guidance;

- Level 4 risk Register
  - Well specific risk register
  - Provides details of risks associated with a specific well in a GWO region
  - Uses a GWO standard excel table format
  - Populated and maintained by team working on Stromlo-1 well activity
- Level 3 Risk Register
  - Used for multi-well field development. Not applicable to Stromlo-1.
- Level 2 Risk Register
  - Regional risk register
  - Provides an aggregated view of GWO risks within the region
  - Mapped to the Group Risk Classification Tool. In terms of well integrity, includes;
    - Loss of well control; well construction,
  - Uses the BP Risk Assurance Tool (RAT) to document.
  - Uses 'bowtie' format to visually demonstrate barriers.
  - Populated and maintained by GWO in Region Risk Management Coordinator.
- Level 1 Risk Register
  - An aggregate of all Purple and Blue C+ risk events from each GWO region. This is generated for communication at a GWO Risk Management Report (RMR) level for reporting key risks.
  - Notification and endorsement is completed based on level 2 risk events. No additional response is required for level 1.

This tiered approach allows BP to elevate appropriate risks. If a level 4 risk is rated at Purple/Blue C+, it is evaluated to the Level 2 risk register.

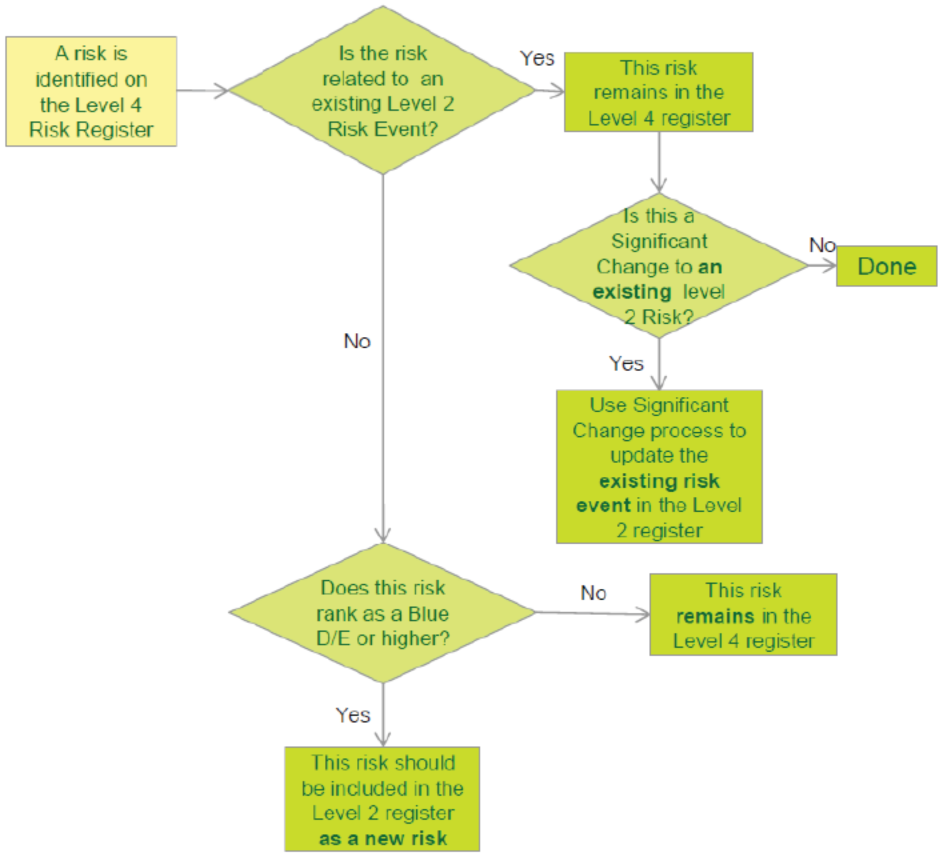

Figure 29 – Level 4 and Level 2 Risk Register Interaction

During the NWcp process (described in Section 4), regular risk reviews of the level 4 risk register take place. A summary of the type of activities that occur in each phase is outlined below;

Stage	Purpose	Documentation of Risks	Risk Register Owner
Appraise	No risk register is used in this stage.	High-level key risks and uncertainties are captured in the WID for NWcp.	N/A
Select	Use Level 4 risk register to identify well-specific geologic risks, selected well option risks, and project risks such as long lead items or scheduling for well options. After Select Well Option (D3) decision, focus on the well path and the well concept risks.	The Level 4 risk register is created in Select. The Level 4 risk register spreadsheet is placed in the well file and referenced for the Decision Support Package deliverable.	GWO Engineering Team Lead (Level 4 risk register)
Define	Further develop the Level 4 risks and risk management measures, incorporate these in detail in the Well Programme, GOP, and other execution documents prior to Execute. To have review and acceptance of the risks prior to Execute.	The Level 4 risk register spreadsheet is placed in the well file and referenced for the DSP deliverable.	GWO Engineering Team Lead (Level 4 risk register)

Stage	Purpose	Documentation of Risks	Risk Register Owner
Execute	The risk register is frozen and is not a live document in Execute.	The risk register is placed in the well file.	N/A
Review	If the risk occurred or if risk management measures have changed, then consider updating the following well Level 4 Risk Register.	The final risk register used for the well is placed in the well file.	GWO Wells Manager

Table 29 – Level 4 Risk Register Activities During the NWcp

The level 2 risk register is managed by the region (i.e. is not part of a single NWcp). It follows reviews as per the GWO group risk management process.

8.1 Stromlo-1 Identified Risks

8.1.1 Stromlo-1 Level 2 Risks

For this WOMP, only one risk in the Level 2 Risk Register is applicable. This is the Loss of Well Control – Well Construction'. The other risks (Marine Collision and Marine Loss of Stability and the Aviation Transport risks) are captured in the Safety Case and Safety Case Revision.

The bowtie for the Loss of Well Control – Well Construction risk is shown in Figure 30. A Barrier Attribute Table (BAT) for all barriers identified in this bowtie has been generated by the BP multi-disciple engineering and operations team as well as review by Safety & Operational Risk function. The BAT is used to assess and record the barrier description, associated documentation, identify the accountable party and then define and record the monitoring/self-verification, audit and assurance requirements and any associated gaps. The BAT is used for assessing the effectiveness of the barrier.

8.1.2 Stromlo-1 Level 4 Risks

The Stromlo-1 Level 4, well specific risk register contains 52 risks, 23 of which are relevant to well integrity. The Register is revised and updated as part of the planning phase on a continuous basis with formal reviews as part of the NWcp Stage-Gate Reviews. The current Level 4 Risk Register around these 23 risks is shown in Table 30.

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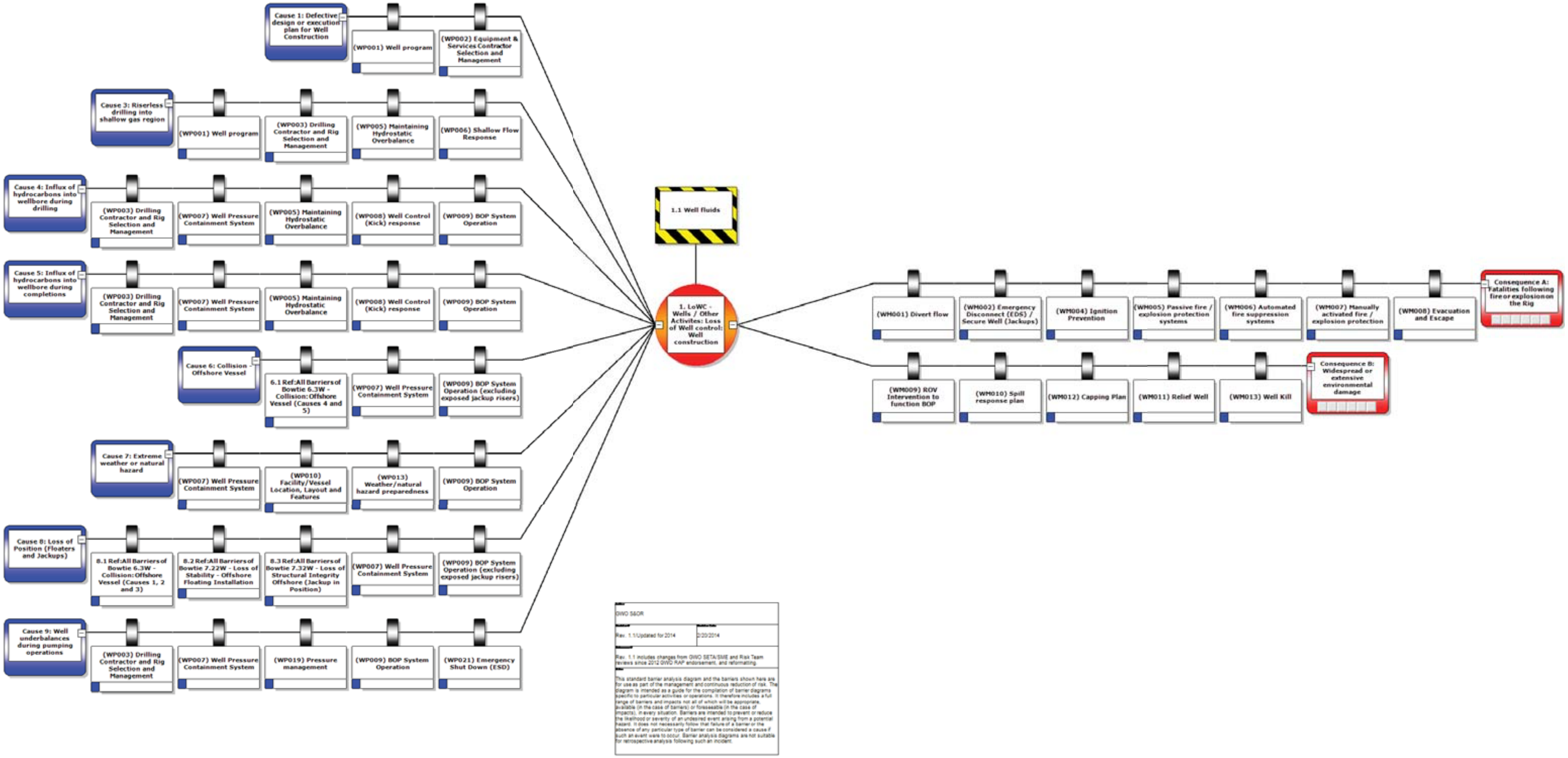


Figure 30 – Loss of Well Control; Well Construction Bowtie

Level 4 Risk Register

ster for Project: Stromlo 1 | View: Assess Net Ranking | Last Updated: 24 Mar 16

Step 1 Identify and categorize the Risk Event							Step 2 List Risk Management Measures		Step 3 Assess Net Ranking				
General									Net Assessment (Current Representative Risk)				
Risk no	Risk Name	Potential Cause(s)	Potential Consequence(s)	Category	Sub Category	Owner	Preventions (Pre event Risk Management Measures)	Mitigations Post event Risk Management Measures)	Likelihood of Occurrence	Health and Safety	Environmental	Non Financial	Financial
15	Zonal isolation not achieved	- Uncertainty of DPZ depths - Fractures/faulting - Losses - Cement out of spec - Cement unit failure - Poor execution of cement job	- Extended abandonment operations - Remedial cement jobs - Cross flows between DPZs	All Sections	Cementing	Arthur Jongejan	- Real-time update of DPZ during well construction. - Understand what issues need to be rectified immediately vs end of well. - Use of BP Cementing Guides - Acceptance criteria determined before drilling - Detailed cementing programs - Cement unit PMS - BP Practice 100221 Zonal Isolation	- Contingency shoe squeeze plan - Contingency plans for the abandonment phase: cut& pull, perf & squeeze etc. - Additional cement plugs	6				E
21	Losses	- PPFG Uncertainty - No of sets - Surge due to excessive tripping rates - LGS build up - Excessive pump rates - Too coarse shaker screens - Mud in riser cooling on trips, increasing density - Faulting - Permeable formations - High overbalance	- Induced fractures - Losses - Wellbore ballooning - NPT - Run out of SBM - Pumping LCM pills - Remedial cementing operations - Low TOC - Well Control, well kicks due to going underbalance	All Sections	Well Control	Arthur Jongejan	- Determine maximum anticipated ECD. Model this against prognosed sand FG - Consider circulating to warm mud up after trips - Observe good drilling and tripping practices (follow trip schedule) - Monitor PWD / volumes - Maintain trip sheet in and out of hole - Run finest possible shale shaker screens consistent with bridging requirements - Circulate riser on trips and measure mud weight. - LCM decision trees - Finger print flow back - Model ECD for fluids and cement job. Use as drilled fluids data. - Maintain programmed mud properties - Ensure sufficient LCM and mud chemicals on board - Autofill shoe tracks if required	- LCM plan - Contingency strings - Stethoscope tools available - Remediate TOC isolation issues on abandonment. - Cement plugs - BP Lost Circulation Manual	7				E
22	MW/ECD below PP limits (underbalance)	- PPFG Uncertainty - No of sets - Poor pore pressure prediction - Swab due to excessive tripping rates - Poor maintenance of mud properties. - Temperature effects on SBM in Deepwater wells.	- Wellbore breakout in shales - Influx enters the well - Well control remedial operations - Underground blowout - Surface blowout	All Sections	Well Control	Arthur Jongejan	- Determine minimum anticipated ECD. - Observe good drilling and tripping practices (follow trip schedule) - Monitor PWD / volumes - Maintain trip sheet in and out of hole - Use software to model ECD and ESD for a given surface MW and temperature - Use PWD to verify modelling and adjust surface MW to provide required down hole hydrostatic pressure. - Plot MW against temperature to understand MW variations in the active pit - Well Monitoring Roles & Responsibilities for the OGW - BP Practice 10020 Well Control - BP Practice 100208 Pore Pressure Prediction - BP Practice 100209 Pore Pressure Detection During Drilling Operations	- Well control training of relevant personnel - WCRG (Well Control Response Guide) - Well control procedures - Minimum weighting material available on the rig - BP Well Control Manual	5				E
25	Drilling fluid out of specifications	- Ineffective products at well site - Mud engineers do not perform mud tests correctly or do not notice adverse mud property trends. - Mud engineers react adverse properties trends - High BHT, beyond planned limits.	- Influx - Losses - NPT - Blockages in drill string, bit or surface system - Poor quality logging data - Low ROP	All Sections	Mud	Arthur Jongejan	- Mud testing procedures - BP to audit service provider to ensure that adequate QA / QC procedures are in place - Mud company to conduct competency assessment of mud engineers and project engineer to ensure knowledge and experience of all proposed mud systems. - Ensure that all critical properties are plotted on a daily basis by both offshore mud engineer and project engineer - Keep mud engineering team together - Secure engineers with previous Reliant/Deepwater experience. - Thoroughly lab test all formulations for long term stability at high temperature. - Mud BoD	- Maintain adequate stocks of chemicals - LMP available to make new mud	5				F
2	Well Barrier Failure	- Casing/Liner leak - No cement around the shoe - Seal assembly fails to set	- Time to perform a leak hunt - Remedial cement job - Casing patch - Cased hole sidetrack	All Sections	Casing	Arthur Jongejan	- Well Design as per BP Practices - Equipment testing prior to installation - Detailed running procedures - Competent personnel - QAQC of casing and cement - QAQC of liner hanger - QAQC inspector - BP Practice 100202 Casing and Tubing - BP Practice 100218 Pressure Testing - BP Practice 100221 Zonal Isolation	- Sidetracking - Casing patch - Remedial cementing	5				E
27	BOP pressure test failure	- Annular not sealing - Ram not sealing - Valve not sealing - Test tool not sealing	- Additional testing - Pulling the LMRP - Pulling the BOP - Suspension operations	All Sections	BOP	Mike Stefanov / Charlie Gilbertson	- IAT 2 - BOP surface testing prior to running - Well advisor - BOP pressure testing procedure	- BOP spares on the rig - Re-testing	7				E
29	Cement Failure	- Cement unit failure - Wrong recipe - Pumped vs planned didnt match - Contamination during placement - Failure of cement to set - Darts not landing in plugs	- Zonal isolation not achieved - Remedial cement jobs - Additional abandonment plugs - DPZ cross flows	All Sections	Cementing	Arthur Jongejan	- Cement testing procedures - BP to audit service provider to ensure that adequate QA / QC procedures are in place - Cement company to conduct competency assessment of cement engineers and project engineer to ensure knowledge and experience of all proposed cement systems. - Keep cement engineering team together - Secure engineers with previous Deepwater experience. - Thoroughly lab test all formulations for long term stability at high temperature. - Cement BoD - Cementing SME involved in procedures development - Cement program - Stack up diagrams - BP Practice 100221 Zonal Isolation - BP Cementing Guides	- Remedial cement jobs - Additional abandonment plugs	7				F
30	Conductor Slumping	- Poorly executed cement job - Losses during the cement job - Insufficient time spent waiting on cement to harden - Incorrect cement slurry - Cement slurry contamination - High vugs in clastic carbonate lithologys - Weak formations lead to lost circulation while cementing.	- TOC not achieved - Top up cement job required - Unable to land the BOP on the wellhead - Re-spud - Loss of 36 Conductor string	2 Hole	Casing	Arthur Jongejan	- Soil testing performed - Minimise the length of time that the hole is left open by ensuring that there is a weather window to drill, run conductor and cement without interruption. - Displace to hi-vis weighted mud before POOH. - Hold the conductor weight while WOC. - Use of fibres in the cement - Titus top-up job - Large cement excess - ROV and pH metre - Land 36 Casing on 28 under-reaming ledge	- Re-spud location - Sufficient equipment for a re-spud - Run 28 conductor or additional support - Cement stinger	5				E
33	Shallow Hazards	- Soft soils - Slope Stability - H2S - Shallow water flows - Shallow gas - Gas Hydrates	- Well flows - Loss of well - Re-spud - Poor cement job - Unsuccessful zonal isolation - Damage to reputation	28 Hole	NDS	NWD Team	- Shallow Hazards Assessment - Well location chosen to meet negligible risk - ROV on bubble watch - Section drilled riserless - BP Practice 100211 Marine Geohazards Evaluation and Assessment	- Shallow gas procedures - Re-spud location identified - Contingency gas tight cement slurry	5				E
35	Failure to achieve planned top of cement for the 22 Surface Casing	- Losses - Washout in the 28 section - Faults - Cement unit failure - Pack off during cementing	- Increased wellhead fatigue once the BOP is landed - Zonal isolation not achieved	28 Hole	Cementing	Arthur Jongejan	- Wellhead fatigue modelling showed TOC can be low - Use of fibres in the cement plan pre-cement displacement with weighted fluid - not seawater. - No DPZ expected - Use of inner string - Use of CEMnet - BP Practice 100221 Zonal Isolation	- Maintain adequate mud stocks modelling shows low TOC is acceptable for WH fatigue. - Address during abandonment	7				F
36	Faulting in 17-1/2" Hole	- Large number of faults highlighted in well interpretation of seismic	- Losses - Ledges - Pressure ramps - Wellbore breakout	17-1/2 Hole	NDS	Arthur Jongejan	- Drilling practices - LCM - Shoe placement decision tree	- Stuck pipe first response - BP Stuck Pipe Manual - LCM - 18 liner, under-reaming	6				F
37	Failure to achieve planned top of cement for the 13 3/8 casing	- Losses - Washout in the 17-1/2 section - Faults - Cement unit failure	- Cement doesnt reach planned TOC - Failure to cover DPZs - Loss of VSP data in 12 1/ section	17-1/2 Hole	Cementing	Arthur Jongejan	- Minimise the length of time that the hole is left open by ensuring that there is a weather window to drill, run conductor and cement without interruption. - Use of fibres in the cement - Appropriate cement excess (to little results in a poor VSP, to much could end up with cement in BOP) - BP Practice 100221 Zonal Isolation	- Remedial cementing operations - Isolate DPZs during abandonment operations	5				F
39	Faulting and detachment in 12-1/ " Hole	- Detachment fault expected at the base of the 12-1/ section - Large number of faults seen on seismic across the section	- Losses - Ledges - Pressure ramps - Wellbore breakout	12-1/ Hole	NDS	Arthur Jongejan	- Drilling practices - LCM	- Stuck pipe first response - BP Stuck Pipe Manual - LCM - 11-7/8 liner	7				E
1	9-5/8 liner hanger failure	- Procedure not followed - Debris around hanger/packer - Hanger/seal failure	- Halliburton Versaflex are being sold, uncertainty over the future of the people and equipment - Personnel competency - Hanger wont set - Packer wont seal, therefore well	12-1/ Hole	Casing	Arthur Jongejan	- QAQC of hanger make up prior to mobilisation - Correct procedures and liner hanger engineer on the rig - Ensure WOC time allows secondary setting method (ball drop and gravitate) - Monitor Halliburton sale - Liner hanger engineers being identified before the sale - BP Practice 100220 Engineered Equipment	- Remedial cementing - Tie back system	5				E
2	Failure to achieve planned top of cement for the 9 5/8 liner	- Losses - Washout in the 12 1/ section - Faults - Cement unit failure	- Cement doesnt reach planned TOC - Failure to cover DPZs - Failed LOT	12-1/ Hole	Cementing	Arthur Jongejan	- Ensure that there is no debris in the well that could cause damage to the packer. - Carry out wiper trip if any debris in the well - Detailed procedures and competent personnel - BP Practice 100221 Zonal Isolation	- Abandonment perf and squeeze	5				F
3	Pressure across faults	- PPFG Uncertainty - No of sets - First well in the basin	- Kick - Well control remedial operations - Insufficient drilling PPFG window to reach section TD	12-1/ Hole	NDS	NWD Team	- PPFG modelling - VSP - Real time pore pressure predication - BP Practice 10020 Well Control - BP Practice 100208 Pore Pressure Prediction - BP Practice 100209 Pore Pressure Detection During Drilling Operations	- Well control procedures - Contingency liner strings	5				E
5	Kick in the reservoir	- PPFG Uncertainty - No of sets - First well in the basin	- Kick - NPT - Well control remedial operations - Underground blowout - Surface blowout	8-1/2 Hole	Well Control	Arthur Jongejan	- Real time pore pressure predication - Well monitoring procedures - Well design based on high case PPFG modelling - Well monitoring roles & responsibilities - BP Practice 100208 Pore Pressure Prediction - BP Practice 100209 Pore Pressure Detection During Drilling Operations - UP 1-0005 Responsibilities and Requirements for Well Monitoring - BP Practice 10020 Well Control	- Well control training of relevant personnel - Deepwater well control training - Closing the BOP - Evacuation procedures - Oil spill response plan - BP Well Control Manual	5				E
6	Gas in the riser	- Gas entering the well will go into solution in the SBM and will only breakout when it is in the riser, above the BOP. - Not following well monitoring procedures	- Uncontrolled well flow - Well goes underbalance resulting in further influxes - Gas release at surface - Fire/explosion - SBM being diverted over the side - SBM flowing through the rotary table at a high rate	8-1/2 Hole	Well Control	Mike Stefanov / Charlie Gilbertson	- Well monitoring procedure with Drilling Contractor & Mud logging - Use of advanced well control practices for the management of drilling breaks and suspected lows - Hazop of surface gas handling equipment - Modelling - Fingerprinting - Set up to automatically divert overboard if gas in the riser - BP Practice 10020 Well Control - UP 1-0005 Responsibilities and Requirements for Well Monitoring	- Diverter - EDS - Well control training of relevant personnel - Deepwater well control training - Evacuation procedures - Oil spill response plan - BP Well Control Manual	4	D	E		E
8	TD pick	- Depth & Stratigraphical Uncertainty - No of sets - Geological surprises	- Drill longer than planned - Call TD too early and miss reservoir - Failure to achieve well objectives	8-1/2 Hole	NDS	NWD Team	- VSP in 12-1/ section - Wireline logging - LWD while drilling 8-1/2 Hole - TD criteria	- Availability of contingency strings - Additional logging - Section can be deepened if required	6				E
9	Failure to successfully obtain wireline logs	- TD not reached - Logging tools cannot reach TD - Reservoir damage due to drilling - Tools becoming stuck and cannot be recovered	- Well objectives not achieved - Reputational damage - Unable to fully evaluate the prospect	8-1/2 Hole	Wireline	Mike Stefanov / Charlie Gilbertson	- Wellbore clean up procedures - LWD data - Run wireline logs in order of importance	- Wiper trips and additional wellbore clean up - TLC	6				E
50	Unable to isolate DPZs during abandonment	- DPZs identified during drilling that weren't identified upfront - Poor cement jobs during well construction - BHA stuck across multiple DPZs - Unable to recover the 13 3/8 casing (if it has to be)	- Reputational damage - Additional abandonment operations - Cross flow between DPZs - Long term reservoir damage	Plug & Abandonment	Abandonment	Arthur Jongejan	- Wireline logging to categorise each DPZ - Cement job planning - Cement job execution - BP Practice 100221 Zonal Isolation	- Additional cement plugs - Fishing and milling operations - Perf and squeeze	6				E
51	Contingency hole section for 18 liner	- Unable to reach 17-1/2 section on planned TD	- Under-reaming operations - Running additional liner string - Mobilisation of additional equipment	Contingency	Drilling	Arthur Jongejan	- Well planning common process (stage gates, peer reviews, detailed design work, etc.) - Detailed drilling program - Execution as per the plan	- Detailed contingency plans available ahead of time - Contingency equipment available in Adelaide or can be mobilised in time	6				E
52	Contingency hole section for 11-7/8 liner	- Unable to reach 12 1/ section on planned TD - Results of VSP uncertainty - Geological uncertainty	- Under-reaming operations - Running additional liner string - Mobilisation of additional equipment	Contingency	Drilling	Arthur Jongejan	- Well planning common process (stage gates, peer reviews, detailed design work, etc.) - Detailed drilling program - Execution as per the plan	- Detailed contingency plans available ahead of time - Contingency equipment available in Adelaide or can be mobilised in time	6				E

Table 30 – Level 4 Risk Register

9 Well Outcomes, Control Measures and Performance Standards

ID	Description	Outcome	Control Measures			Associated Risks		Performance Standards
			Acceptance Criteria	Controlling Document	WOMP Section	Level 2 Risk Register	level 4 Risk Register	
A	Cement 36" conductor in place	Achieve TOC to seabed to provide: - Structural support for following casing strings - Suitable fatigue resistance for well operations	Cement slurry pumped to seabed. Written contingencies to deploy cement top up system if unsuccessful conventionally (no formal ACT).	Stromlo-1 WH and riser analysis (UE-2015-0028)	NA	NA	#29 - Cement failure #30 - Conductor Slumping	Cement job report (cement returns to seabed verified either through pH meter or visually with ROV)
B	Cement 22" surface casing in place and confirm casing integrity	Assure casing can withstand following potential well control loads.	ACT 5 - Casing	Stromlo-1 Drilling Operations Programme BP Practice 100222 - Well Barriers	6.3.2	Loss of Well Control; Well Construction	#24 - Well barrier failure	Pressure test results charts or data recordings (documented as per BP Practice 100218 - Pressure Testing (10-45))
C		Achieve formation integrity test (FIT) to assess 22" shoe strength to allow suitable kick tolerance in the following hole section.	ACT 1or 2 - verification for annular cement	Stromlo-1 Cementing Programme BP Practice 100221 - Zonal Isolation	6.3.1.1	Loss of Well Control; Well Construction	#29 - Cement failure #35 - Failure to achieve planned TOC for the 22" Surface Casing #36 - Faulting in 17-1/2" Hole	Cement job report. LOT chart kick tolerance calculation in DDR
D	BOP test	Suitably confirm the BOP is appropriate for use as a barrier.	ACT 4 - Blowout Preventer	Well Control Bridging Document BP Practice 100222 - Well Barriers	6.3.4	Loss of Well Control; Well Construction	#27 - BOP pressure test failure	Pressure test results charts or data recordings (documented as per BP Practice 100218 - Pressure Testing (10-45)
E	Cement 13-3/8" production casing in place and confirm casing integrity	Assure casing can withstand following well control loads.	ACT 5 - Casing	Stromlo-1 Drilling Operations Programme BP Practice 100222 - Well Barriers	6.3.2	Loss of Well Control; Well Construction	#24 - Well barrier failure	Pressure test results charts or data recordings (documented as per BP Practice 100218 - Pressure Testing (10-45)
F		Provide shoe strength to allow following hole section kick tolerance.	ACT 1or 2 - verification for annular cement	Stromlo-1 Cementing Programme BP Practice 100221 - Zonal Isolation	6.3.1.1	Loss of Well Control; Well Construction	#29 - Cement failure #37 - Failure to achieve planned TOC for the 13-3/8" Production Casing #39 - Faulting at detachment in 12-1/4" hole #43 - Pressure across faults	Cement job report. LOT chart kick tolerance calculation in DDR
G	Cement 9-5/8" liner in place and confirm liner integrity.	Assure liner can withstand following well control loads.	ACT 5 - Casing and ACT 23 - Liner Top Packer	Stromlo-1 Drilling Operations Programme BP Practice 100222 - Well Barriers	6.3.2	Loss of Well Control; Well Construction	#24 - Well barrier failure	Pressure test results charts or data recordings (documented as per BP Practice 100218 - Pressure Testing (10-45)
H		Provide shoe strength to allow following hole section kick tolerance.	ACT 1or 2 - verification for annular cement	Stromlo-1 Cementing Programme BP Practice 100221 - Zonal Isolation	6.3.1.1	Loss of Well Control; Well Construction	#29 - Cement failure #41 - 9-5/8" liner hanger failure #42 - Failure to achieve planned TOC for the 9-5/8" Production Liner #45 - Kick in the reservoir #46 - gas in the riser	Cement job report. LOT chart kick tolerance calculation in DDR
I	Drilling Fluid property	Maintain suitable properties to assure the drilling fluid is capable of being relied upon as a barrier.	ACT 20 - Fluid Column	Stromlo-1 Drilling Operations Programme Stromlo-1 Fluids Programme BP Practice 100222 - Well Barriers	6.3.3	Loss of Well Control; Well Construction	#21 - Losses #22 - MW/ECD below PP limits (underbalance) #23 - Drilling fluid out of specification #43 - Pressure across faults #45 - Kick in the reservoir #46 - Gas in the riser	Daily Mud Report Daily drilling report tracking key fluid properties. Kick tolerance calculation in DDR.
J	Achieve geological well objectives	Acquire data across target interval	Data acquisition plan (no associated ACT)	Geological Operations Programme	NA	NA	#48 - TD pick #49 - Failure to successfully obtain wireline logs.	Data acquired as per Subsurface requirements. Daily Geological Report Well Completion Report

ID	Description	Outcome	Control Measures			Associated Risks		Performance Standards
K	Cement 18" liner in place and confirm liner integrity.	Assure liner can withstand following well control loads.	ACT 5 - Casing and ACT 65 - Supplemental Hanger Adaptor System	Stromlo-1 Drilling Operations Programme BP Practice 100222 - Well Barriers	6.3.2	Loss of Well Control; Well Construction	As per previous hole sections plus; #51 - Have to run 18" Contingency liner	Pressure test results charts or data recordings (documented as per BP Practice 100218 - Pressure Testing (10-45)
L		Provide shoe strength to allow following hole section kick tolerance.	ACT 1or 2 - verification for annular cement	Stromlo-1 Cementing Programme BP Practice 100221 - Zonal Isolation	6.3.1.1			Cement job report. LOT chart kick tolerance calculation
M	Cement 11-7/8" liner in place and confirm liner integrity.	Assure liner can withstand following well control loads.	ACT 5 - Casing and ACT 23 - Liner Top Packer	Stromlo-1 Drilling Operations Programme BP Practice 100222 - Well Barriers	6.3.2	Loss of Well Control; Well Construction	As per previous hole sections plus; #52 - Have to run 11-7/8" Contingency liner	Pressure test results charts or data recordings (documented as per BP Practice 100218 - Pressure Testing (10-45)
N		Provide shoe strength to allow following hole section kick tolerance.	ACT 1or 2 - verification for annular cement	Stromlo-1 Cementing Programme BP Practice 100221 - Zonal Isolation	6.3.1.1			Cement job report. LOT chart kick tolerance calculation
O	Annular cement suitably above experienced DPZ (any hole section that have DPZ identified during drilling)	Cement suitably above DPZ to provide suitable isolation to seabed	ACT 1or 2 - verification for annular cement	Stromlo-1 Abandonment Programme (part of DOP) Stromlo-1 Cementing Programme BP Practice 100221 - Zonal Isolation	6.3.1.1	Loss of Well Control; Well Construction	#15 - Zonal isolation not achieved #29 - Cement failure #43 - Pressure across faults #45 - Kick in the reservoir #46 - gas in the riser #50 - Unable to isolate DPZ's during abandonment	TOC calculation report and acceptance verification checklist. Pressure test results charts or data recordings (documented as per BP Practice 100218 - Pressure Testing (10-45)
P	Set cased hole abandonment plugs (DPZ identified during drilling)	Isolate DPZ from surface and any other DPZs	ACT 4 - Verification of wellbore cement	Stromlo-1 Abandonment Programme (part of DOP) Stromlo-1 Cementing Programme BP Practice 100221 - Zonal Isolation	6.3.1.2	Loss of Well Control; Well Construction	#15 - Zonal isolation not achieved #24 - well barrier failure #29 - Cement failure #50 - Unable to isolate DPZ's during abandonment	TOC calculation report and acceptance verification checklist. Pressure test results charts or data recordings (documented as per BP Practice 100218 - Pressure Testing (10-45)

Table 31 – Stromlo-1 Performance Outcomes, Control Measures and Standards

Measurement criteria for each ACT is defined in section 6.3 – Well Barriers.

9.1 Defined Contingency Plans

In the event the outcome cannot be met, the following contingencies will be implemented;

- Respud well at defined respud location.
    - This is applicable to Outcome ID# A
- Shoe squeeze to repair a 'wet shoe'.
    - This is applicable to Outcome ID# C, F, H, L and N
- Change to different drilling fluid (i.e. Saraline 185V base or WBM)
    - Applicable to Outcome ID# I
- Sidetrack (openhole or cased hole) for mechanical reasons (stuck pipe, etc.) or for geological reasons (data acquisition over a particular area). Sidetrack would be to minor inclination only (still ~vertical well design).
    - Applicable to Outcome ID# J
- Cut and pull casing, section mill or perf and squeeze to isolate DPZs if required.
    - Applicable to Outcome ID# O and P.
- Casing patch to repair a hole in the casing.
    - Applicable to Outcome ID# B, E, G, K, M.
- Emergency casing hanger seal assembly or liner top tieback (short tieback to isolate liner top only). Or liner top squeeze.
    - Applicable to Outcome ID# E, G, K, M.
- Temporary suspend and recover BOP for unplanned maintenance.
    - Applicable to Outcome ID# D

This contingencies will be managed through the MOC process and will be communicated to the rig though modifications to the programme (described in section 4.3).

10 Well Abandonment

Stromlo-1 will be permanently abandoned in line with BP Practice 100221 – Zonal Isolation (10-60). Section 6.3.1 describes the philosophy standards and verification methods for cement barriers (note that only cement barriers can be used for permanent abandonment). That section also describes the required quantity and verification methods.

Figure 31 shows the pre-drill abandonment assumption. Currently the assumption is;

Well Barrier#2 is a combination barrier (primary and secondary) and isolates DPZ #2 from surface. Well Barrier #2 = WBE #2a + WBE #2b;

- WBE #2a; annular cement, combination barrier;
    - Annular cement can be verified and used as a 'combination barrier' provided it meets the requirements in Practice 100221.
    - Circumferential logging will be required to verify this as a combination barrier. In this case, minimum 60mMD would need to be verified.
    - This process is described in section 6.3.1.1.
- WBE #2b; cement plug, combination barrier;
    - This plug requires tagging as well as positive and negative pressure testing as it is the deepest inside casing (as per Practice 100221)
    - This will be set at the top of DPZ #2
    - Minimum 30mMD, however;
        - Length, at a minimum, will match WBE #2a (i.e. if used as a combination barrier, this length will be matched at minimum).
    - This process is described in section 6.3.1.2.

Well Barrier #1 is a combination barrier (primary and secondary) and isolates DPZ#1 from surface and from DPZ #2. Well Barrier #1 = WBE #1a + WBE #1b;

- WBE #1a; annular cement, combination barrier;
    - Annular cement can be verified and used as a 'combination barrier' provided it meets the requirements in Practice 100221.
    - Circumferential logging will be required to verify this as a combination barrier. In this case, 60mMD would need to be verified.
    - This process is described in section 6.3.1.1.
- WBE #1b; cement plug, combination barrier;
    - This will be set at the top of DPZ#1.
    - This plug will be tagged as well as positive and negatively pressure tested
    - Tag and test can be omitted provided lower plug meets conditions in Practice 100221 and it is set on a tagged and positively pressure tested mechanical plug or previously set cement plug (as described in 6.3.1.2).
    - Minimum 100mMD (a condition of omitting a weight test), however;
        - Length, at a minimum, will match WBE #1a (depending on verification method of WBE #1a).
    - This process is described in section 6.3.1.2.

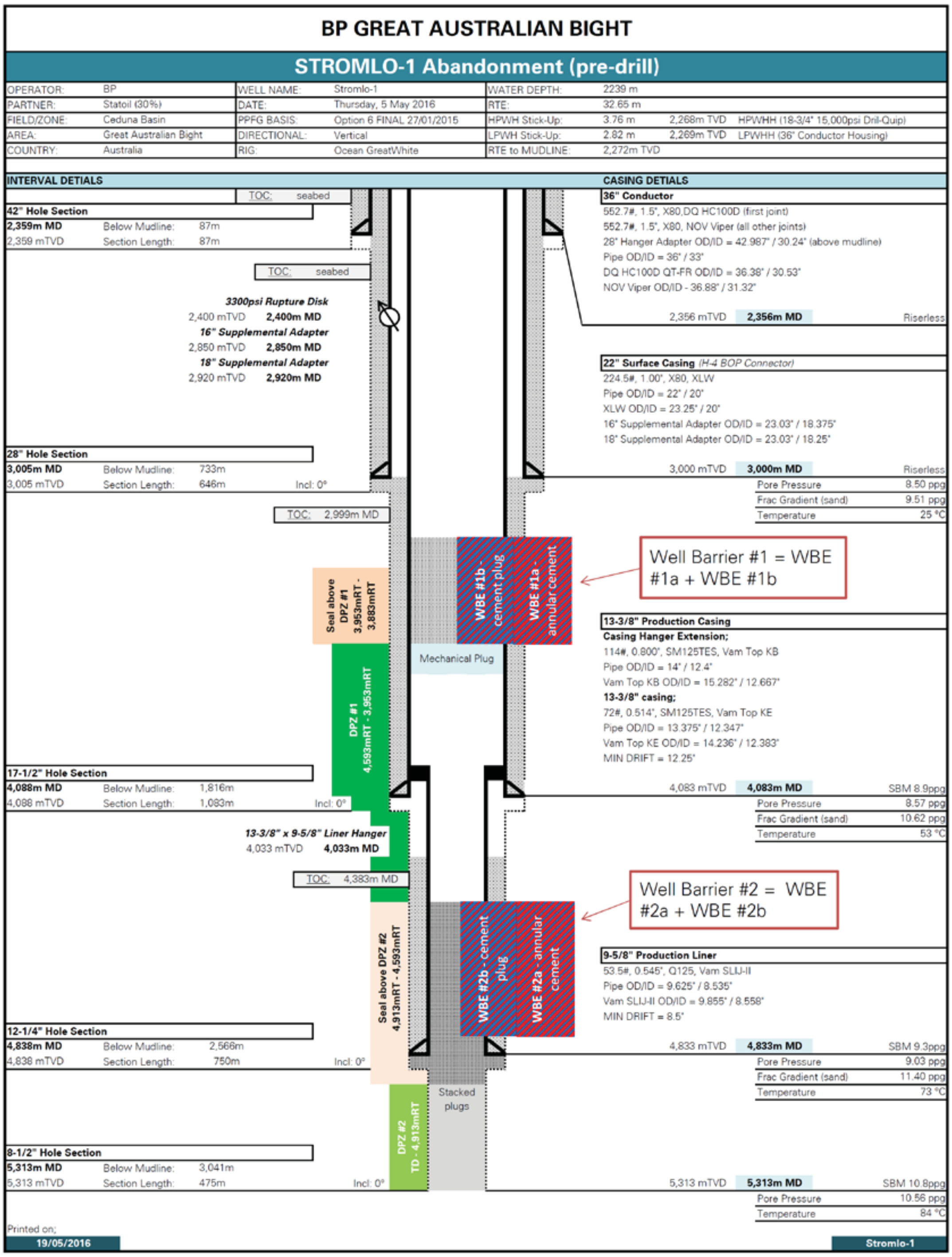


Figure 31 – Pre-Drill Abandonment Schematic

As an indication of what could potentially change, Figure 32 shows the abandonment strategy that would be implemented in the event only 100m annular cement around each shoe is achieved. In this scenario;

- Circumferential logging would be required to confirm 60mMD annular cement around the 9-5/8" shoe (as described in 6.3.1.1).
- The lack of cement in the 13-3/8" annulus would change the DPZ#1 abandonment strategy. Perforation would be needed to allow cement to be installed in the annulus

above DPZ#1. A single plug across the entire annular and wellbore would be installed and tested as per Section 6.3.1.2.

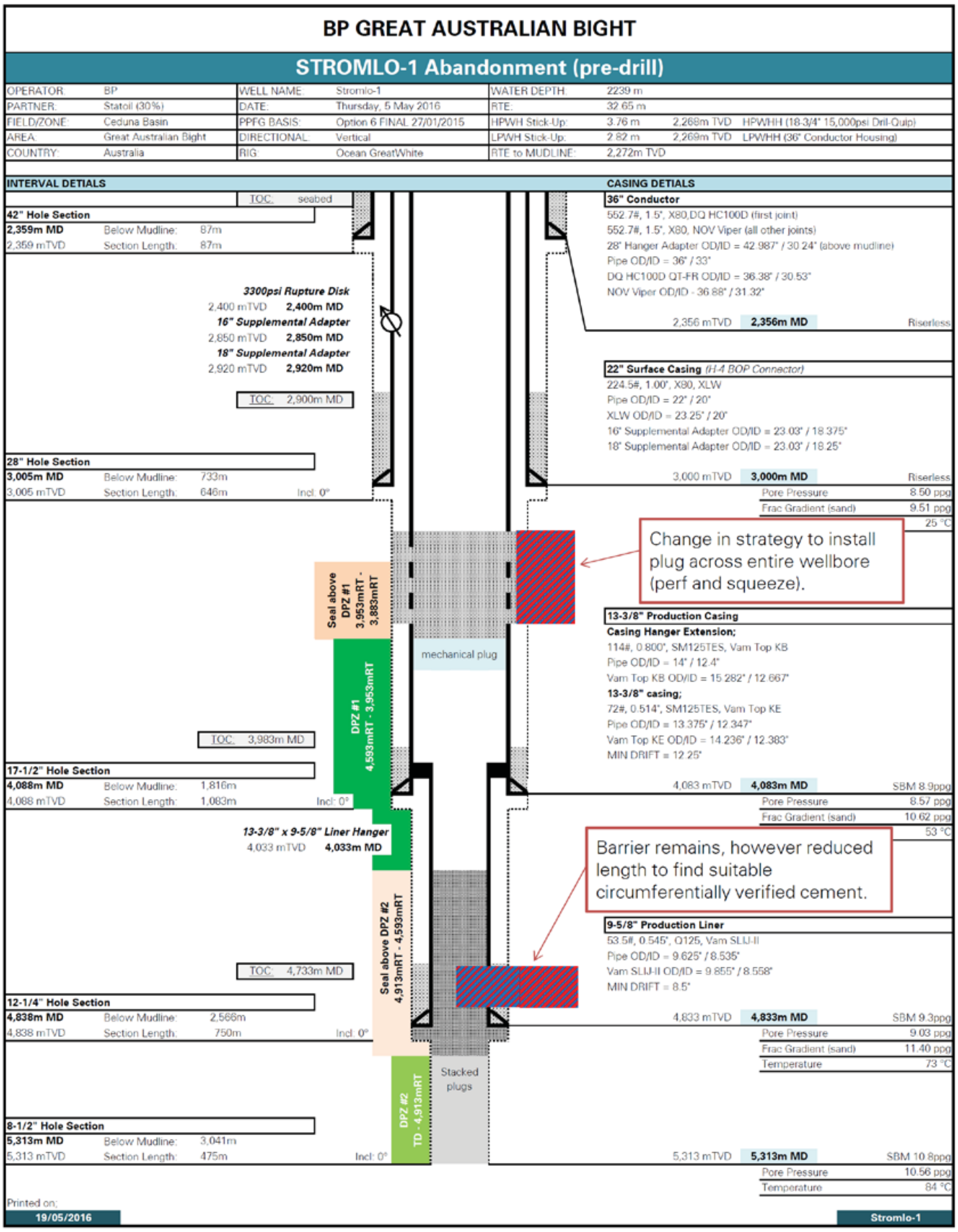


Figure 32 – Abandonment Schematic for Low Annular TOC (example only)

NOTE; abandonment of Stromlo-1 cannot be finalised until post TD of the well. Exact conditions will be communicated to NOPSEMA in the End of Well Abandonment Report.

BP intends to leave the wellhead in place following the abandonment of the Stromlo-1 well. Cutting and removing the wellhead is common in some areas to prevent the wellhead interfering with other industries (e.g., commercial trawl fishing). In the GAB, fisheries fish to depths of a maximum of about 750m. Beyond this water depth, leaving the wellhead in place will not impact other marine users. The benefits of leaving the wellhead in place are:

- Reduced safety exposure by eliminating operations required to remove the wellhead (e.g. manual handling).
- Ability to re-latch onto the wellhead with a BOP system. Although this is highly unlikely, it may be required for;
    - Further well evaluation (or reservoir or barriers).
    - Emergency response.
    - Future BOP acceptance testing in the region with other rigs.
- Leaving the annulus seal in place provides a mechanical, third annular barrier to any DPZ's identified during drilling. Although note that BP does not consider mechanical barriers suitable for permanent abandonment (i.e. it will not be used as a primary or secondary barrier).

The method for installation and verification of the barriers for abandonment will not differ due to the wellhead remaining in place. The ROV will be equipped with video and a 2D (or 3D) sonar, which will be used to provide a permanent record of the seabed at each drill site before and after operations. At no stage does BP intend to remove this wellhead. Removal adds no technical benefit and, while the wellhead is intact, offers the benefits described above. Environmental impacts have been addressed in the GAB EP.

Using the BP Practices for zonal isolation, which are benchmarked against globally recognised practices, assures that the abandonment of Stromlo-1 will be managed to an ALARP level.

10.1 Well Suspension

Well suspension is not planned however it may be required short term for various reasons (weather issues, BOP maintenance, etc.). For these events, BP will suspend the well with two suitable barriers as per the well status at the time. Barriers will be installed and verified in line with *BP Practice 100222 – Well Barriers (10-65)* (some of the more likely barriers are described in section 6.3).

11 Responsibilities and Competencies of Contractors and Service Providers

11.1 Contractual Requirements

GWO New Ventures employs contractors to support delivery of its operational commitments. Contractor selection and management is led by the Procurement and Supply Chain Management (PSCM) Function using the PSCM Category Management common process (see Figure 33). The GWO New Ventures PSCM Regional Manager and PSCM Sub-Sector Managers work with the VP Wells, Wells and Engineering Team Leads, and HSSE to define the services to be contracted, and identify suitable contractors. All contractors working for GWO New Ventures are from the PSCM Approved Vendor List (AVL).

Contractor selection and screening assessments are corresponding to the technical, commercial and HSSE risk associated with the work contracted. The contractor selection and screening process includes assessment of contractor capability, competency, financial viability and HSSE performance. GWO New Ventures expectations and HSSE requirements for contractors and sub-contractors will be clearly defined in the request for proposal and the terms and conditions of the contract. Bridging documents are developed to communicate the requirements of BPs Practices and Procedures to contractors where required.

The standard approach for PSCM and HSSE will be Section 6 of the contract (HSSE appendix) which is written centrally and put into all contracts. Annex 8 of section 6 includes any regional variations and these will be updated on a contract by contract basis. The GWO Function is in progress of developing guidance for 'Working with contractors', which GWO New Ventures will implement when developed.

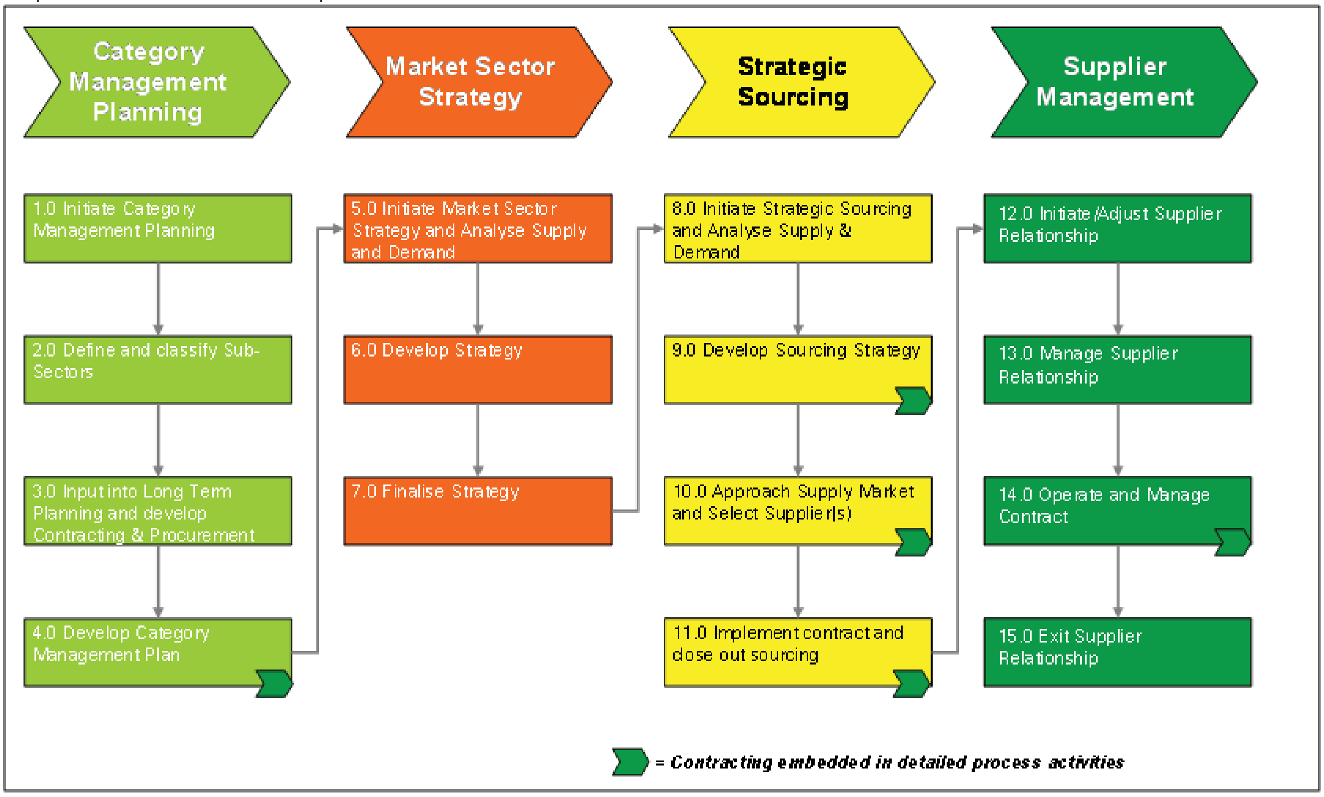


Figure 33: Category Management Common Process

11.2 Personnel Competency

Certain key positions within a contract are defined as 'Key Personnel'. This varies depending on the vendor service being provided. Key personnel require contractor competency assessments. These assessments, along with work experience, education and training levels, are submitted to BP for review.

This process involves;

- BP allocates a 'Contract Account Manager' for all contracts that the project considers containing 'Potential High Consequence Activity' (PHCA).
- This person, with assistance from global category specialists, defines what roles in the contract should be considered 'Key Personnel'.
- Contractual requirements are in place that requires vendors to complete competency assessments of personnel that are considered 'key'.
- Contractual requirements are in pace that require various levels of review of these competency reviews (review of CV or involvement in the assessment, etc. depending on exact role.)
- Personnel competencies are tracked and managed through the rig contractor or third party vendor internal management system.

This process is defined in BP Procedure 100130 – Upstream Category Management.

BP then reviews these competency assessments to assure completeness. Confirming competency is done by BP through continuous interaction on the rig with these key personnel. This includes regular interface meetings and audits (covered in the 'Oversight' programme detailed in Section 4.4.2.11.3)

It is the responsibility of the contractor to assess, assure and track competency of the contractor personnel. BP reviews these assessments as described above, however assurance is through the vendor internal process.

BP also has regular interface meetings which include;

- Daily pre-tour meetings on the rig
- DWOP sessions in town
- Morning calls
- Pre-section meetings.

These meetings allow BP supervisors to interact with vendor personnel directly. This interaction is key to confirming vendor personnel understand their role over the well duration.

No changes to key personnel can take place without prior BP agreement and a comprehensive management of change review.

For vendors providing service for Stromlo-1, the following contractual requirements are in place regarding key personnel.

Rig Operator;

Rig operator shall provide BP with evidence documenting proficiency of personnel on request. The following roles are considered 'Key Personnel';

- OIM

- Helicopter Landing Officer (HLO)
- Crane Operator
- Rig Manager
- Toolpusher
- Paramedics
- Barge Engineer
- Driller
- Safety Officer
- Senior Toolpusher
- Assistant Driller
- Subsea Engineer
- Maintenance Superintendent
- Chief Engineer
- Dynamic Positioning Officer

Varying requirements exist depending on the exact role providing third party services. Key roles for Stromlo-1 are;

Cementing;

BP requires that the contractor develops and implements an internal process for assessing competency assessment prior to assigning key personnel to the project. These shall be submitted to BP along with a Curriculum Vitae and job history for the following positions;

- Account Coordinator
- Project Coordinator
- Cementers

Fluids;

BP requires competency assessments of Key Personnel be completed by the contractor in the presence of a BP representative. All skills assessments shall be completed by the contractor and shall be reviewed by BP prior to commencement for the following positions;

- Project Engineer
- Lead Drilling Fluids Engineer

Mud Logging;

BP requires that the contractor develops and implements an internal process for assessing competency. No changes can take place without prior BP agreement and a comprehensive management of change review for the following positions;

- Service Coordinator
- Data Engineer
- Pore Pressure Engineer

Well Placement;

BP requires that the contractor develops and implements an internal process for assessing competency. No changes can take place without prior BP agreement and a comprehensive management of change review for the following positions;

- Service Coordinator
- Drilling Engineer/Well Planner (accountable for survey management and well planning)

In addition, BP requires specific offshore roles (lead directional driller and lead MWD/LWD engineer) to have specific competencies as outlined in the contract. This includes review of these competencies with BP before operations.

11.3 Audit and Verification

BP audits and oversees vendors under the Self-Verification (SV) and Oversight (OS) programme described in Section 4.4.2.

Offshore vendor performance is supervised closely by BP Wellsite Leaders (WSL) on a day-to-day basis. Verification of process is under taken during regular meetings (as described in section 4.3). Vendor continual and open feedback is encouraged.

12 Source Control and Blowout Contingency Measures

The primary methods of well control are discussed in the other sections of this WOMP. If these fail, the next line of defence is the subsea BOP automatic sequencing. This functionality is described in the rig safety case, but in general involves;

- Emergency Disconnect Sequence (EDS). This is a programmed sequence of events that operates the functions to leave the stack and controls in a desired state and disconnect the LMRP from the lower stack. This would be used in the event the rig was able to function before moving away from the rig location.
- NOV Emergency Hydraulic Backup System (EHBS). This system shall fulfil the requirements of the 'deadman' and 'autoshear' systems as defined in API Standard 53.
- ROV and acoustic intervention of the BOP.

If this functionality were also to fail, BP would then look to intervene via two key areas – cap & containment (which includes detail of the immediate ROV intervention response) and relief well planning. These two areas are described in section 12.2 and 12.3.

All source control options would begin simultaneously. BP New Venture's policy is to *over react* and then scale down a response in order not to delay mobilisation of any possible critical path equipment.

12.1 Stromlo-1 Worst Credible Discharge

As a technical basis to plan these types of interventions, BP designs to a 'Worst Credible Discharge' (WCD) event. BP define a WCD event in *Engineering Practice Segment Guidance 4.6-0001 – Steady State Uncontrolled Well Discharge – Rate Calculation*. This document defines the assumptions and calculation methods that are to be implemented when calculating a WCD event. For Stromlo-1 the following assumptions were assumed;

- Open hole conditions to TD of the section,
- No drillpipe, or other pipe, in the wellbore,
- Discharge at seabed with no BOP closure or other partial restriction,
- Zero mechanical skin,
- Most likely porosity and permeability prediction,
- Most likely predicted pore pressure with hydrocarbon column buoyancy added,
- Most likely fluid prediction (for hydrocarbon outcome) to TD of section.

Essentially, BP model WCD as a worst case wellbore outcome (i.e. full wellbore open to seabed, no pipe in hole) with a most likely hydrocarbon reservoir outcome (i.e. success case based on analogues and data analysis).

For Stromlo-1, this results in the following WCD load case (taken from AUS-NWD-TFN-049);

Parameter	WCD
Scenario description	Planned TD, All flow units in hydrocarbon and aquifer legs open to flow
Rationale / comment	Official defined WCD scenario
Reservoir	K65 reservoir target
Fluid	Black Oil, GOR- 861 scf/stb
Initial rate oil	54 mbd
Initial rate gas	46 mmscf/d
Initial rate water	105.5 mbd
Cummulative oil (35 days)	1.9 mmstb
Cummulative gas (35 days)	1.6 bcf
Cummulative water (35 days)	3.7 mmstb
Cummulative oil (149 days)	7.9 mmstb
Cummulative gas (149 days)	6.8 bcf
Cummulative water (149 days)	15.5 mmstb

Table 32 – WCD Summary Table for Stromlo-1

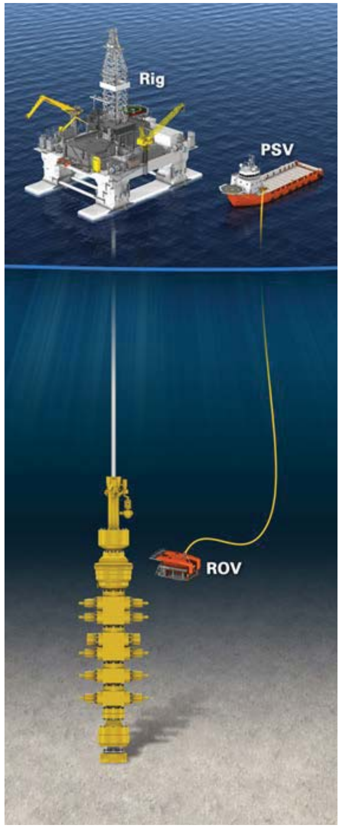
12.2 Cap and Containment Plan

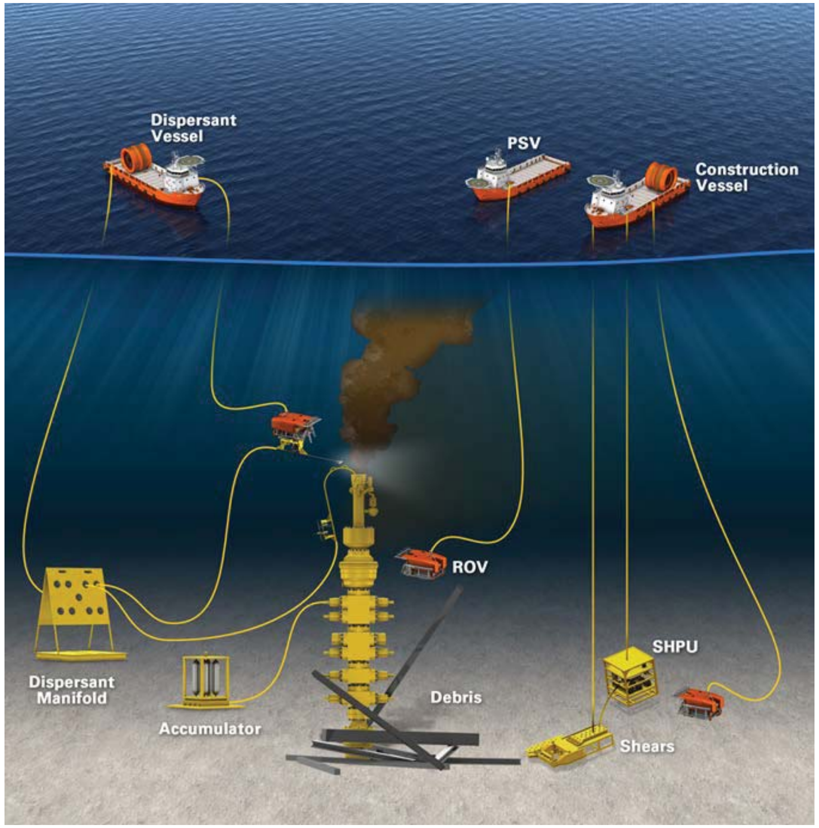
Details as to how BP would implement a capping plan are described in the *New Ventures Containment Response Plan for the Great Australian Bight (AU000-HS-PLN-600-00003).* This plan describes how BP will meet three key containment requirements;

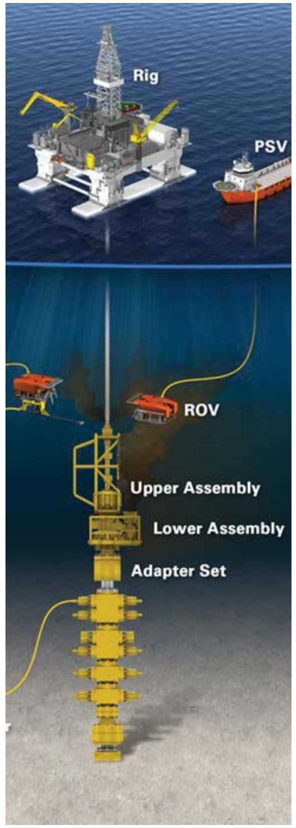
1. *BP Practice 100249, Remotely Operated Vehicle (ROV) Intervention System for Emergency BOP Intervention* defines that ROV surveillance and BOP intervention capability must occur within 48 hours of a WCD incident.
    - For Stromlo-1 this is achieved through the use of a First Response Vessel, which will be part of the fleet supporting operations. This vessel will have an ROV installed that is capable of BOP intervention.
2. *GP 10-90, Oil Spill Preparedness and Response for Deepwater Operations* requires that subsea dispersant delivery shall be within 10 days. This is to reduce hydrocarbon concentrations at surface, thus reducing the VOCs in the source area. The benefit reducing the VOC exposure to personnel working and lowering LELs to accommodate vessel operations in the area.
    - For Stromlo-1 this will be achieved via the use of vessels of opportunity in the region, the AMOSC Subsea First Response Toolkit (SFRT) and an integrated delivery system. This is detailed in the GAB Containment Plan (AU000-HS-PLN-600-00003).
    - Note, it is possible that the 10 day requirement may not be met. This is due to metocean conditions in the GAB causing excessive fatigue on coil tubing strings if hung off work vessels. This issue is currently under review and will be subject to MOC (including risk assessment) as per BP Practices if this cannot be met.
3. *BP Practice 100005, Containment Response System for Emergency Well Capping Operation* requires that the target for well capping shall be within 35 days.
    - For Stromlo-1 this will be achieved via the use of one of four the OSRL capping stacks that are available to BP. Both designs of OSRL capping stacks (15kpsi and 10kpsi) are suitable for Stromlo-1, with the 10kpsi system in Singapore being the primary option. Again, details are provided in the Containment Response Plan however an outline is shown for reference in section 12.2.3.

Note; The stated deadlines have been used for implementation planning. Issues such as met-ocean conditions, applicable regulations, customs clearance, logistics, debris removal etc. may all impact actual implementation timing and have been taken into consideration for planning purposes to the extent possible.

Generic story boards that detail the minimum capping and containment conditions for a well blowout are outlined below.







Well Incident	ROV Surveillance/ BOP Intervention	Subsea Dispersant Injection (SSDI), Debris Clearance and LMRP Removal	Well Capping Operation
Response Timeline	(<48 hours)	(<10 days for SSDI)	(<35 days)

12.2.1 Capping Connection Options

BP has assessed the possibility of capping Stromlo-1 by landing the capping stack at three* possible points. To achieve these options, various BOP/LMRP components may require removal. These, along with a mobilisation schedule, are provided in the Containment Response Plan.

*Note, the option of installing the cap on the flex joint is currently under review and may not be feasible due to specific valving on the BOP. This is a wider impacting issue, however has only been identified during detailed review for this project. It affects all BOPs with a boost line that is below the riser flex joint flange. The issue is currently ongoing and will be subject to MOC (including risk assessment) as per BP Practices if this cannot be met. Note this does not impact the primary and secondary options of installing on the BOP or wellhead.

On the BOP

The primary capping stack landing point is on the top of the BOP following LMRP removal.

The OSRL 10kpsi or 15kpsi capping stacks, with the OSRL 27" 15kpsi H4 connector below it, can land on the BOP mandrel without a spool piece or any additional connector. The Ocean GreatWhite BOP mandrel is an 18 ¾" 15k H4 connector.

A fixture to check clearance for the 27" 15kpsi H4 connector, which fits bottom of the 10kpsi or 15kpsi OSRL capping stack, was placed over the LMRP connector mandrel and the fixture was rotated 180 degrees to find any potential clash issues. The fixture was rotated around the LMRP connector mandrel and there was at least ¼" clearance between the fixture and the any obstructions (Figure 34 and Figure 35). CAD modelling was also completed to confirm the interfaces between the capping stacks and BOP.

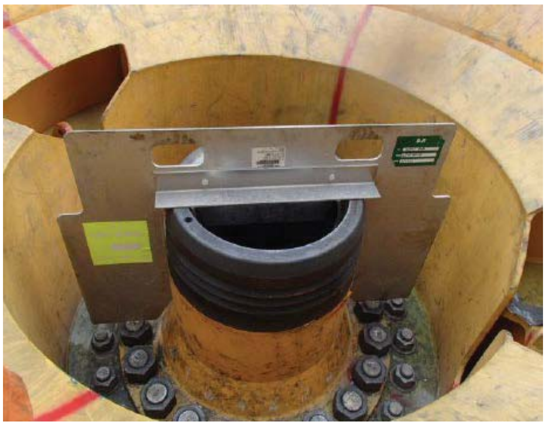


Figure 34 – Shows interface fixture on the LMRP connector mandrel

Figure 35 – Shows measurement clear of obstruction

On the Wellhead

The secondary capping stack landing point is on the wellhead following BOP and LMRP removal.

The wellhead for both Stromlo-1 is the 15kpsi Dril-Quip Big Bore II system. The wellhead connector is a 30" SHD H-4 High Capacity Connector.

The OSRL 10kpsi or 15kpsi capping stack, with the BP owned 30" 15kpsi GE SHD H4 connector installed below it, can land on the wellhead without a spool piece or any additional connector between them. Figure 36 below shows the BP owned 30" 15kpsi GE SHD H4 connector over the test stump.

Note that to achieve this, the BP owned 30" 15kpsi GE SHD H4 connector is (stored in Houston) would have to be mobilised by air to Singapore or Australia to be installed on the capping stack prior to loading the capping stack onto the vessel. Details for this are covered in the Containment Response Plan.

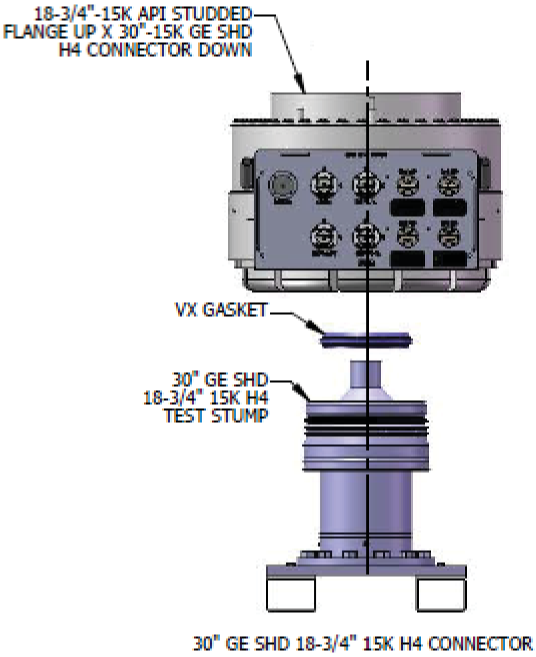


Figure 36 - The BP owned 30" 15kpsi GE SHD H4 connector and Test Stump

On the Flex Joint

The tertiary capping stack landing point is on the riser Flex Joint (FJ) if the BOP and LMRP cannot be removed. The Ocean GreatWhite riser is NOV FT-H.

There are 3 stages to landing the capping stack on the riser flex joint.

1. Install the FJ tool to straighten the riser adapter, then restrain it in place by using the segmented wedges.
    a. The planned system for the OGW is the Oil States Industries CRS Flexible Joint Alignment and Locking System – Dual API Tool. Figure 37 and Figure 38 show a high level overview of the system and how it straightens the flex joint.

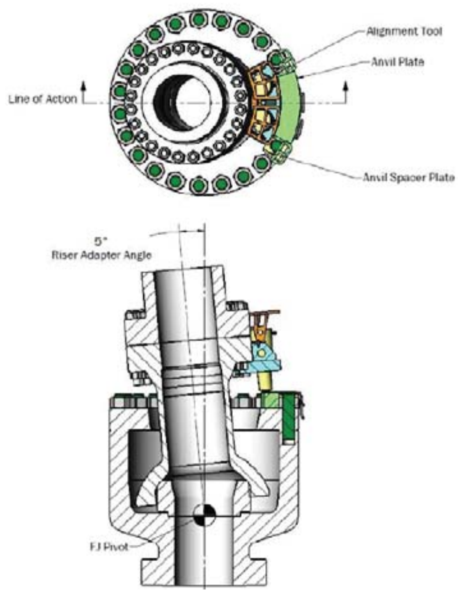


Figure 37 – Alignment tool giving a positive angle of deflection

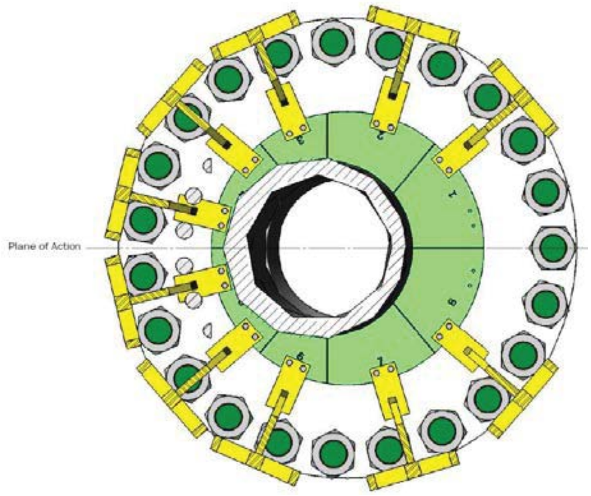


Figure 38 – All wedges installed to straighten the FJ with a 5° configuration shown

2. Land the H4 adaptor, with the FT-H Adaptor below it, on to the connection above the flex joint. See Figure 39.

    a. This needs to be run prior to the capping stack as the bottom connection of the FT-H adaptor is bolted. Trying to bolt this connection with the weight of the capping stack above it would make the operation extremely difficult.

    b. Both the H4 adaptor and FT-H adaptor are BP owned, stored in Houston and would have to be mobilised by air to Singapore or Australia to be installed on the capping stack prior to loading the capping stack onto the vessel.

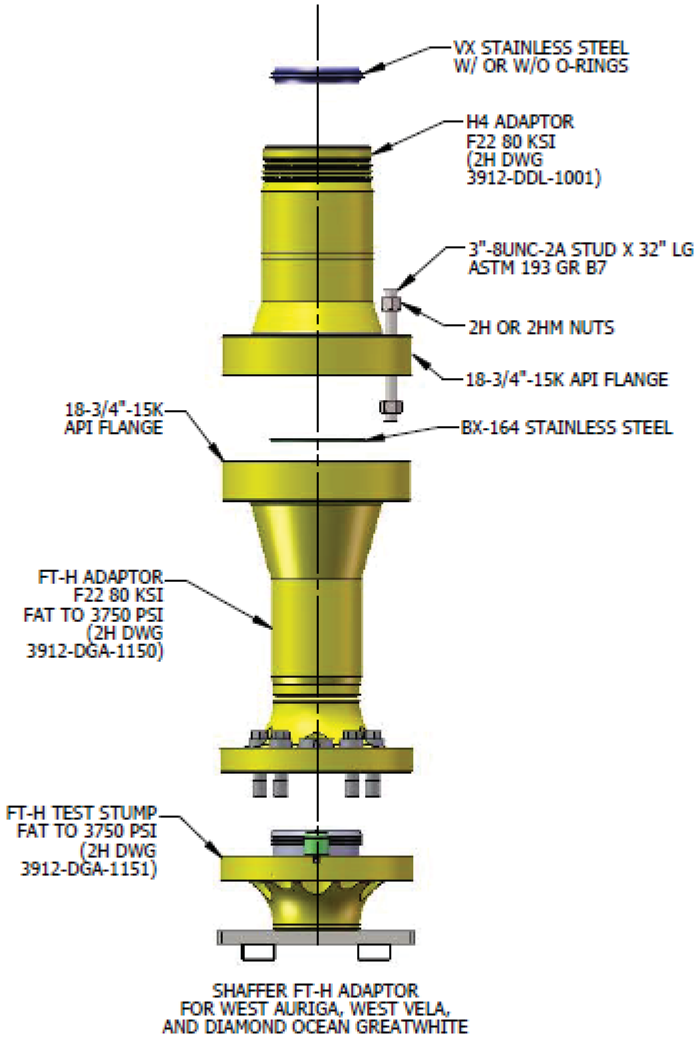


Figure 39 – The BP owned H4 adaptor, FT-H Adaptor and test stump

3. Land the OSRL capping stack, with the OSRL 27" 10kpsi H4 connector below it, on to H4 adaptor.

   a. There is a specification break (a reduction in pressure rating between BOP body and 18 ¾" hub due to the annular preventer) in the BOP from 15kpsi to 10kpsi. This is not a concern for Stromlo-1 as only a 10kpsi cap is required. If the LMRP cannot be removed, then under no circumstances would the system be rated to 15kpsi, even if the 15k OSRL stack is used.

12.2.2 Capping Stack Deployment (Overview)

Once the top of the BOP has been cleared of any protrusions (using debris removal cutting tools where necessary) it is ready to accept the capping stack. The cap will be deployed on wire or on drill pipe by an active heave compensated crane or draw-works, lowered to within 0.5-1.5m of the BOP hub before being moved into the hydrocarbon stream and landed.

Below is a high level plan of events during a capping stack installation. Detailed scenario specific procedures will be developed covering all phases of the installation including risk assessments, vessel details, flow regime, hydrates mitigations, vessel waypoints, story boards, etc. in the event of having to land the cap,

- Once the LMRP has been removed and any debris protruding above the upper mandrel of the BOP has been removed, the capping stack can now be installed.
- The capping stack running tool or rigging is installed on the capping stack assembly.
    - Note the capping stack bore will be open to allow flow from the well to pass through it while landing.
- The capping stack will be run to a predetermined depth at a predetermined safe location away from the BOP while being followed by an ROV.
- The ROV will provide instructions to enable the vessel to follow waypoints until the capping stack is within a short distance of the BOP and ready to be landed.
- The capping stack will be oriented and brought into the well stream and landed. The well stream is shown to have a centralising effect on the capping stack.
- The ROV will disconnect the running tool / rigging while another ROV handles the locking of the connector.
- The well is closed in by closing the rams or the gate valves and then choking back the outlets for final shut-in assuming the well can be shut in.
- Perform a survey of the BOP and capping stack to ensure that there are no additional leaks formed during shutting in the well.
- Survey the seabed, BOP and containment cap over the next 24-hours to confirm no additional leaks have formed during shutting in the well.

12.2.3 Deployment Timing (Overview)

The well capping plans for the GAB project have identified OSRL's 10kpsi capping stack in Singapore as the primary option, and details for the proposed mobilisation and deployment of this equipment is summarised in Figure 40. Logistical studies have demonstrated that the capping equipment will be delivered to the site while preparatory work is completed.

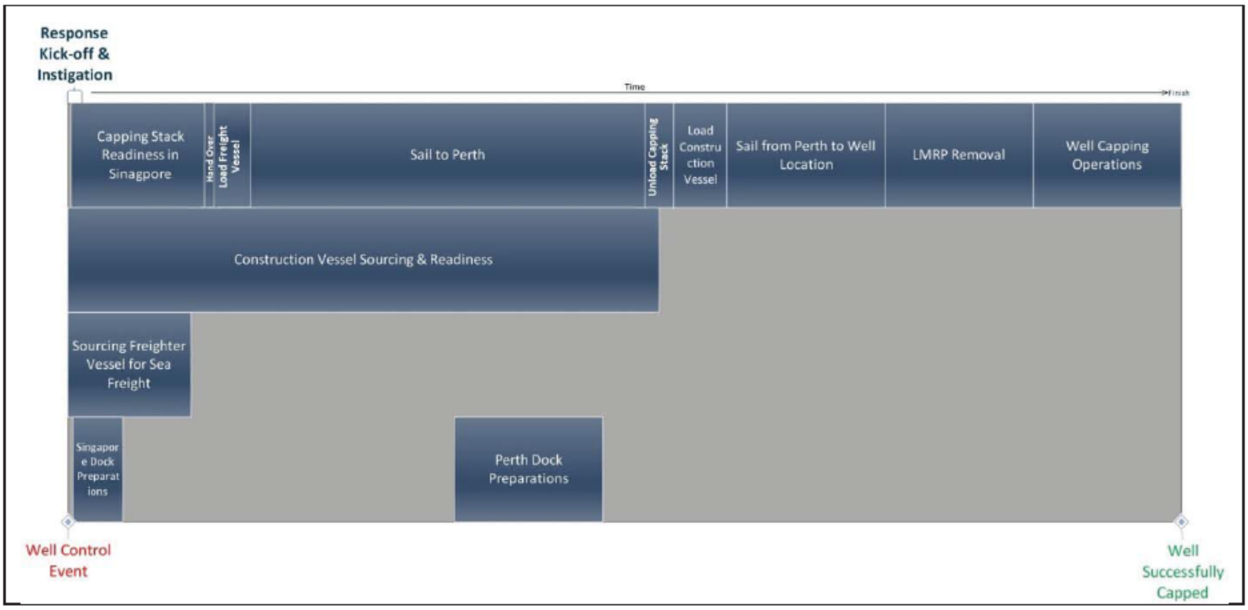


Figure 40 – Sequence of proposed mobilisation and deployment of well capping equipment from Singapore

BP plans to instigate ROV intervention work as soon as possible and deploy the AMOSC-managed SFRT. Preparatory work using the SFRT would include activities such as debris removal and ROV surveillance in anticipation of the arrival of the capping equipment from OSRL and BP.

Task	Duration	Comments & key assumptions
1. Response kick-off	**0.29 days***	
Notification of incident	0 days	Communication protocols and channels defined in the regional Capping and Containment Response Plan.
Activation of OSRL (SWIS) equipment	0.29 days	
Instigate personnel deployment	0.08 days	
2. Capping stack readiness in Singapore	**2.8 days***	
OSRL team starts work to prepare for Trendsetter technicians	0 days	Advance prepatory work.
Trendsetter technicians and BP personnel arrive at OSRL base	1.5 days	Personnel arrive by charter flight and check into hotel. Most likely two Trendsetter crews will be mobilized; one directly to Singapore to prepare capping stack and a second crew to Australia to begin preparations for receival. BP personnel will include HSSE, Lifting and Technical personnel.
Mobilise cranage at OSRL base	0 days	
Capping equipment preparation and transfer to quayside	1.1 days	Equipment preparations
Provide packing list, customs documentation (carried out in parallel to other readiness operations)	0.2 days	Including destination requirements
3. Sourcing freighter vessel for sea freight	**2.5 days**	
Source suitable freighter vessel	0.5 days	This will be managed via BP's logistics contractor
Security clearance for port of arrival		Can apply when vessel is identified
Arrive at OSRL location	2 days	Vessel arrives at OSRL location

Task	Duration	Comments & key assumptions
4. Construction vessel readiness	**12 days**	
Source suitable construction vessel	5 days	Estimated time dependant on availability of vessels at the time.
Construction vessel transit to Perth	7 days	Estimated time dependant on location of vessels at the time. Current location would be a crucial factor in vessel choice.
5. Handover at the docks	**0.1 days***	
BP representative for handover	0 days	BP officially takes responibility of capping stack
Receipt of handover documentation	0.1 days	
6. Singapore dock preparations	**1 day**	
Mobilise cranage	0 days	Freighter (multipurpose heavy lifter) has on-board crane and second shipping stand is available
Mobilise other equipment	1 day	
7. Load vessel in Singapore	**0.75 days***	
Install spare shipping stand on vessel deck	0.1 days	Assumes vessel deck has sufficient strength and that no additional grillage required. A project is currently in process to look at grillage options to ensure readiness to ship on a wide range of vessels.
Unlock capping stack from shipping stand, loadout on spare shipping stand and lock back	0.2 days	
Seafasten	0.5 days	Seafastening to vessel deck
Marine warranty survey	0.5 days	Marine warranty survey
8. Sail to Perth	**8 days***	Sailing times based on an average speed of 13.5 knots with a 10% weather delay allowance factored in
9. Perth dock preparations	**3 days**	
Cranage mobilised at destination	3 days	Cranes mobilised
Trendsetter personnel mobilised to destination	2 days	Trendsetter technicians arrive at destination to prepare for capping stack receival
10. Unload capping stack in Perth	**0.7 days***	
Customs clearance	0.1 days	Where feasible as much advance work as possible will be done to expedite this process
Unloading at destination docks	0.4 days	Unloading at destination quayside
Confirm all items unloaded via documentation	0.2 days	
11. Load subsea construction vessel and readiness to sail	**1.2 days***	Loading vessel
Construction vessel staged at quayside	0.4 days	
Install spare shipping stand on vessel deck	0.1 days	Assumes vessel deck has sufficient strength and no additional grillage needed
Unlock capping stack from shipping stand, loadout on spare shipping stand and lock back	0.2 days	Second shipping stand available as of March 2016
Seafasten	0.5 days	Seafastening

Task	Duration	Comments & key assumptions
Marine Warranty survey (carried out in parallel to loading activities)	0.5 days	Marine Warranty Survey
12. Sail from Perth to well location	**3.3 days***	Transit to well site
Sea voyage to well site	3.22 days	Sailing times based on an average speed of 13.5 knots with an 10% weather delay allowance factored in
13. LMRP removal	**3 days***	May not be required and may be possible to carry out in advance of cap arriving and off critical path, if suitable vessel can be sourced. LMRP will be wet parked in a suitable location.
14. Well capping operations	**3 days***	Deploy capping stack
Run and land the capping stack	2 days	Over boarding the capping stack is limited by a maximum sea state of approximately 3.5 to 4 m, so some WOW delays could be experienced.
Choke back and shut in the well	1 day	Could vary depending on flowing conditions
Well successfully capped	**23.5 days**	

Table 33 – Tasks Required to Mobilise a Well Cap from Singapore to the Drilling Area (*Denotes critical path activity)

The key assumptions made for the capping stack mobilisation and deployment are:

- The primary and most likely option is to mobilise the OSRL stack from Singapore and sail directly to Australia on board a commercial freighter (multipurpose heavy lift vessel), which would be sourced by BP's logistics contractor. This vessel would then be unloaded in Perth and the stack loaded onto a suitably sized construction vessel (which would have been sourced in parallel).
- It is the preferred solution that the capping stack be installed directly on to the BOP and this would necessitate the removal of the LMRP. To do this a subsea construction vessel with a suitably sized crane would be required. The plan above is based on limited availability of such vessels and therefore that the same vessel that is designated for capping stack deployment will also lift the LMRP from the BOP. However, efforts would be made to secure and mobilise additional vessels to the well site including for LMRP removal, potentially removing this task from the critical path.
- Plan assumes that the ROV debris clearance operations have been completed prior to the capping stack arriving at the well location and that no other major debris is blocking access to the well. ROV debris clearance would be started as soon as possible.
- All shipping times include a 10% weather delay allowance and assume an average sailing speed of 13.5 knots.
- Capping stack preparation assumes no connector change out is required. If connector was required to be changed out, this would add an additional two days to the preparation tasks.
- Initial analysis shows that the maximum angle the capping stack could be safely installed on the BOP is around 8.3 degrees. Any angle beyond this may require the deployment of conductor-straightening equipment.

- Overboarding of the capping stack would be limited by a maximum sea state of around 3.5-4m. Any sea state at the wellsite beyond this may necessitate 'waiting on weather' (WOW) delays.
- Times relating to the sourcing and readiness of a suitable subsea construction vessel are estimates based on potential regional availability.

12.2.4 Capping Stack Load Cases

To confirm capping Stromlo-1 is a viable option, various design work has been carried out.

- Casing design for Stromlo-1 includes consideration for full displacement to gas. This is described at length in Section 5.1.
- Computational Fluid Dynamics analysis to confirm the uplift force generated by WCD can be overcome by the weight of the capping stack. This has been confirmed for all OSRL capping stacks. Details are in the Containment Response Plan.
- Wellhead analysis to confirm the stack could be installed on the WH or BOP, and the loads would not exceed the design. This showed that the cap can be installed on the BOP up to inclinations of 8.3°. This is well beyond operational limits that are enforced for general operations. Details can be found in the Upstream Engineering Centre Report EU-2015-0028. The overall results graph is included in Figure 41 for reference only (load cases on LMRP should be ignored).

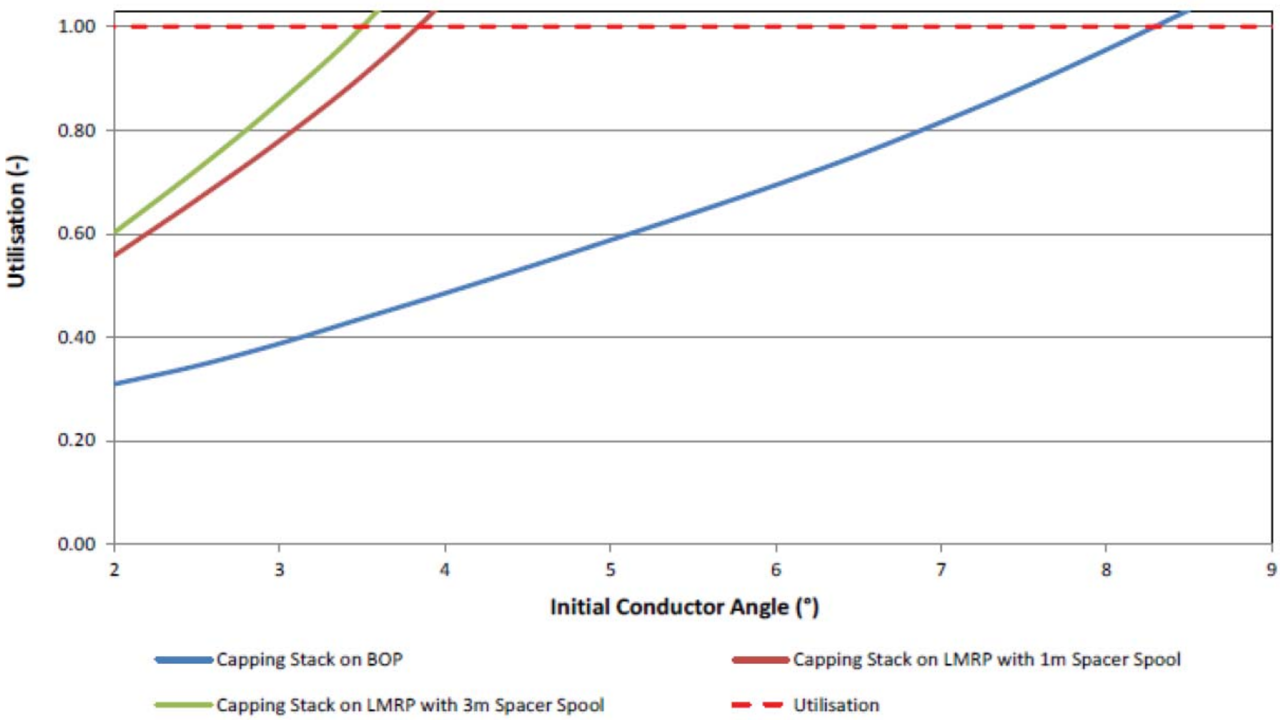


Figure 41 – Initial Conductor Angle vs Max Utilisation at Final Conductor Angle

12.3 Relief Well BOD and Plan

A Stromlo Specific Relief Well BOD and Plan (AU000-DR-BOD-600-00001) has been generated. This section of the WOMP is a summary of that document.

The Relief Well BOD design results show that a single relief well is capable of killing Stromlo-1 based on pre-drill data. The casing and wellhead equipment identified is suitable to meet the anticipated load cases of a Stromlo-1 relief well. The hydraulic horsepower, volume and pressure requirements are within the rig specifications also identified. Design has been completed for two relief well options.

The Relief Well Plan concludes that a suitable rig would need to be mobilised from the South East Asia/Indian Ocean/Far East or Australia/New Zealand region. This would depend on rig availability at the time of requirement. It is likely this will not be a ‘Harsh Environment’ (HE) rated rig. Expected duration of a relief well is 149 days (including suspending previous operations, mobilisation, operations and well kill). Operations are based on a P90 duration estimate to account for the additional weather related NPT expected using a non-HE rig in the Great Australian Bight (GAB).

Key aspects of the ‘Relief Well BOD and Plan’ sections are outlined below.

12.3.1 Surface Location

Relief well surface locations have been identified as part of the Stromlo-1 Shallow Hazards Assessment·

- Two potential relief well locations have been selected.
    - These have been screened against the shallow hazard review.
- For the two RW locations, a Dynamically Positioned (DP) rig has been assumed.
- A minimum 500m offset from the target well/rig has been applied. This is as per *OPGGSA Volume 2, Division 1, section 616 – Petroleum safety zones* and as per Upstream Practice EP SDP 5.6-0002 – Close Approach and Dynamic Positioning.
    - >500m separation between the two RW locations also exists to allow both wells to be drilled simultaneously if required.

These two locations were selected to account for prevailing wave direction (typically from the south-west, year round) and variation in wind through the year (no prevailing direction).

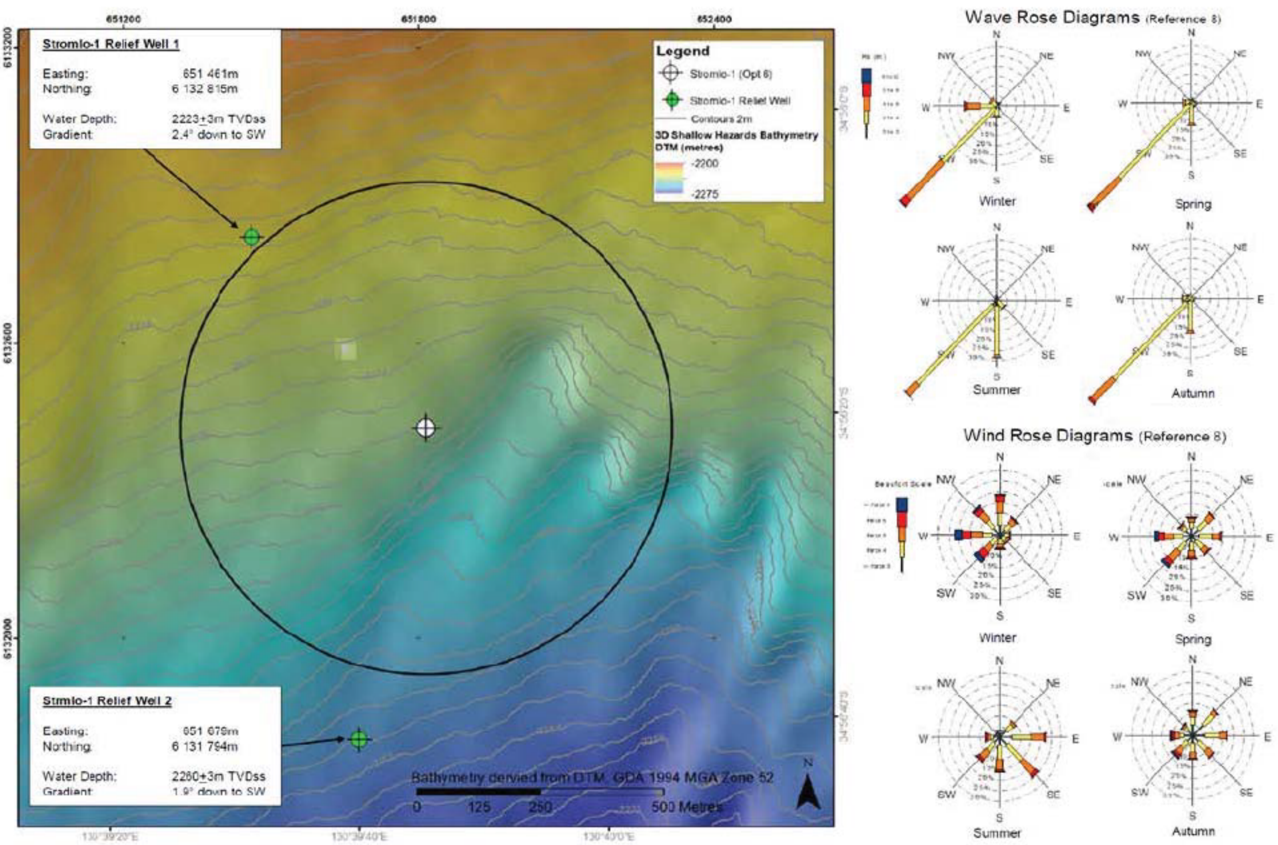


Figure 42 – Stromlo-1 and Relief Well Locations

12.3.2 Trajectories

Relief well trajectories have been generated. Both RW1 and RW2 are oriented intercept RW designs. The following summarises BP recommended RW design attributes from the GOM RW planning guide;

Recommended Attributes	RW1	RW2
Phase 1 – Drill		
Plan the trajectory to minimise complexity, ideally 2D.	2D, S-shaped well	2D, S-shaped well
Keep trajectory inclination low for WL ops (<50° inc)	Max 30° inclination	Max 35° inclination
Avoid high DLS, particularly at shallow KOP	Max 1.09°m/30m DLS in the shallow section below the 22" shoe and 1.54°m/30m below the 14" shoe	Max 1.15°m/30m DLS in the shallow section below the 22" shoe and 1.59°m/30m below the 14" shoe
Phase 2 – Locate		
Begins when wellbore separation is just outside of ranging tool limitations (typically 13-50m, depending on formations, casing magnetics, etc.)	Assumed first ranging run will be done at 50m separation (typical value used).	Assumed first ranging run will be done at 50m separation (typical value used).

Recommended Attributes	RW1	RW2
Lateral distance between wellbores to be > combined lateral error (to avoid accidental collision)	At first locate point, error of uncertainty has Allowable Deviation from Plan (ADP) to meet this requirement	At first locate point, error of uncertainty has Allowable Deviation from Plan (ADP) to meet this requirement
Advisable to begin locate >300m to allow course corrections.	650mMD before intercept	500mMD before intercept
Phase 3 – Track		
Include a 'pass by' to minimise well-to-well uncertainty	'Pass by' included 450m above intercept point	'Pass by' included 300m above intercept point
Maximise 'track' phase	300m track phase used.	300m track phase used.
Phase 4 – Intercept		
Last casing shoe to be <30m or one stand above intercept point	9-7/8" shoe set at 30mMD from intercept	9-7/8" shoe set at 30mMD from intercept
Intercept of the wellbore at 3-5deg closure angle	5° closure angle	5° closure angle

Table 34 – Trajectory Key Features

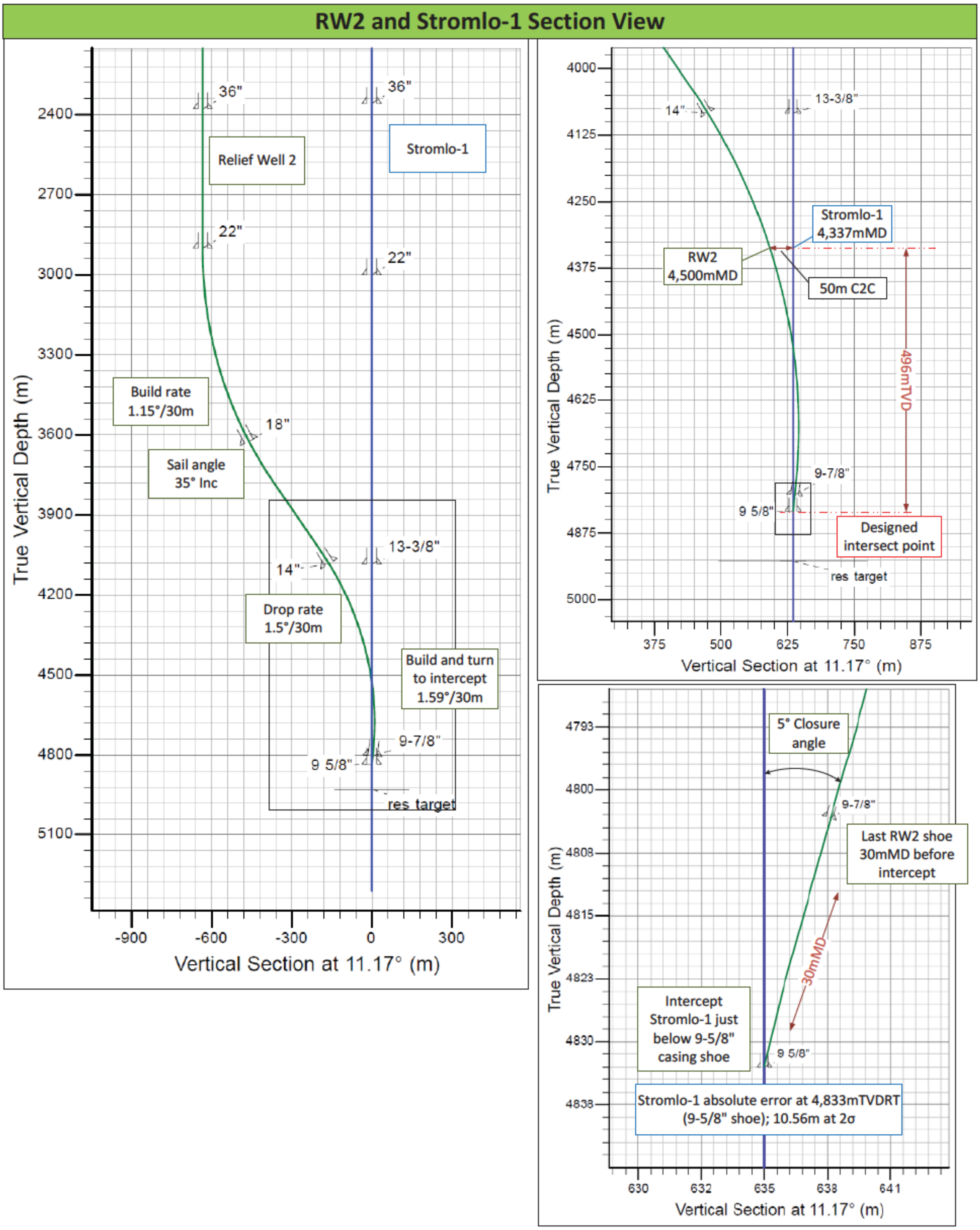


Figure 43 – RW2 Section View (various scale changes to highlight features). RW1 shows similar trajectory features

12.3.3 Hydraulic Modelling

Hydraulic kill modelling has been undertaken using OLGA software by the BP central well control team. This model has used the formation and reservoir data from the Stromlo-1 Statement of Requirements (SOR) to calculate the hydraulic requirements a relief well would need. Intercept and casing shoe depths from RW2 were used as it represents the longest relief well and therefore the more challenging hydraulic load.

Dynamic Kill Summary at Casing Intercept Point			
Case		2*	3
Choke and Kill line ID	in	4.5	4
Kill Mud Wt.	ppg	12.5	12.5
Kill Rate	bbl/min	40	40
Maximum Pump Pressure	psi	1,640	2,740
Hydraulic Horsepower Required	HHP	1,590	2,670
Minimum Kill Mud Volume Required	bbls	2,000	2,000
Additional Volume to Circulate out Influx	bbls	2,800	2,800
Pump Time to Stop Influx	Mins	50	50

*Case 1 used a lighter mud weight and did not result in a suitable well kill (so is not shown here).

Table 35 – Well Control Dynamic Results Summary

The results show that the volume requirement is around 4,800bbls. For redundancy, it should be assumed that ~10,000bbls (2 x required volume) would be needed at the well site. All rigs identified have this capacity.

The results also show that a maximum of 2,670HHP and 2,740psi would be needed to kill Stromlo-1 in this method. Again, a 2 x redundancy is recommended. All rigs identified meet this requirement.

12.3.4 RW Casing Design

Only 'relief well specific' loads have been verified. For standard installation loads, no relief well specific modelling has been performed. The GAB team is comfortable with this approach for the following reasons;

- Well design is very similar to Stromlo-1. Loads would be expected to be very similar to Stromlo-1.
- Actual relief well casing design would need to be validated against the data collected in Stromlo-1 as there are no other offsets.
- This project has chosen to use BP Relief Well Tubular Standardisation (RWTS) equipment for relief well plans. The sizes, grades and weights have been selected by the global relief well team to provide the most flexibility.
    - These grades and weights are equal to, or greater than, those used in Stromlo-1.
    - Grades and weights are at the limit of what is commercially available (i.e. Q125 and high collapse casing is used for majority of the relief well).

The selected casing is suitable to meet the load cases generated during a relief well pumping situation.

12.3.5 Rig Availability

To assess rig availability globally, BP subscribe to an online, third party provided service (PetroData). This system can be filtered to provide only specifically suitable rigs. For Stromlo-1 relief wells, the following filter has been used;

This results in 3 suitable rigs.

Rig Name / Owner	Contracted Location (Q4 2016)	Rig Type	Rated Water Depth	Mud Pumps	Mud Tank Capacity	Choke and Kill Lines
Saipem 10000 *Saipem*	Mozambique	Drillship	3,048m	4 x 2,200HP, 7,500psi	12,300bbl	Not public (assume 4" ID min)
Discoverer India *Transocean*	India	Drillship	3,048m	4 x 2,200HP, 7,500psi	20,000bbl	6-1/2" OD x 4-1/2" ID
Noble Bully II *Noble*	Malaysia	Drillship	2,514m	4 x 2,200HP	13,385bbl	6" OD x 4" ID

Table 36 – Identified Relief Well Rig Options (contracted rigs)

Note that if uncontracted rigs were included, a further 26 suitable rigs would available. It is likely a portion of these would be suitable. For this study, of the uncontracted rigs, only the 'Hot Stacked' rigs are assumed suitable. These are listed below;

Rig Name / Owner	Hot Stacked Location	Rig Type	Rated Water Depth	Mud Pumps	Mud Tank Capacity	Choke and Kill Lines
Deepwater Frontier *Transocean*	Malaysia	Drillship	3,048m (2,285m outfitted)	4 x 2,200HP, 7,500psi	13,890bbl	6-1/2" OD x 4-1/2" ID
ENSCO 8504 *Ensco*	Malaysia	Semi-sub	2,590m (8,500ft)	4 x 2,200HP, 7,500psi	15,900bbl	4-1/2" ID
ENSCO DS-9 *Ensco*	Singapore	Drillship	3,658m (12,000ft)	4 x 2,200HP (upgradable to 6)	16,970bbl	Not public (assume 4" ID min)
Maersk Venturer *Maersk*	Singapore	Drillship	3,658m (12,000ft)	5 x 2,200HP, 7,500psi	12,010bbl	Not public (assume 4" ID min)
Belford Dolphin *Dolphin*	Malaysia	Drillship	3,048m (10,000ft)	4 x 2,200HP, 7,500psi	15,050bbl	Not public (assume 4" ID min)

Table 37 – Identified Relief Well Rig Options (hot stacked rigs)

It is recognised that these rigs are not harsh environment rated. Stromlo-1 will be drilled with a harsh environment rig to maximise drilling windows to a level that is considered commercially suitable. A non-harsh environment rig could be used, however down time due to waiting on weather would be increased (particularly in winter). As harsh environment rigs are rare, it is extremely unlikely one will be available in a short timeframe for a relief well. For this reason, the use of a non-HE rig, with a high level of NPT, has been incorporated into the time estimate.

The above rig options have been assessed for mobilisation suitability. The average timing has been used as the assumption for the relief well timing shown in 12.3.7.

12.3.6 Well Equipment Availability

In the event a relief well was required, vendors and operators in the region would be contacted in an effort to find suitable equipment already available in country. However, this cannot be relied on to be always available. For this reason, BP uses globally available inventory to assure full coverage is always possible. This is via the Relief Well Tubular Standardisation (RWTS) Project. The RWTS Equipment Guide summarises the globally held equipment. It also identifies the equipment the region is required to provide. This guide has been reviewed for the Stromlo-1 relief wells and suitable arrangements are made for locally required equipment where needed.

Mobilisation plans have been generated to show that the globally held equipment can be mobilised to the region in a suitable time period. Wellheads, wellhead running tools and large bore tubulars that are required to immediately spud the well would be sent via air freight. The smaller bore tubulars would be sent via sea. This mobilisation plan was commissioned (and is managed by) the BP Containment Response System (CRS) team with the assistance of a globally recognised subcontractor. Currently this timing shows that;

- Running tools and equipment needed for 36" and 22" casing will be at Adelaide airport after 28 days via air freight.
  - Including 3 days mobilisation to well site (1 day to unload and transit to port plus 2 days sail), this is 31 days
  - Within the 41 day estimate for rig to spud.
- Additional equipment for 18" and smaller casing will be available at Adelaide airport after 38 days via sea freight.
  - Including 3 days mobilisation to well site, this is 41 days.
  - Within the 61 day estimate for the 18" liner.

12.3.7 Relief Well Timing

For the Stromlo-1 relief well the following timing is assumed;

Phase	Assumption	Timing Days	Operations	Cumul. days after incident	Equipment Required
Mobilise Rig	Stromlo-1 specific timing. Includes P90 suspension time or hot stack prep time.	41 days	Suspend previous operations, mobilise to site	41.0	
Well Construction (spud through setting casing above discharge zone)	Relief well specific timing. Assumes P90 duration.	73 days	Drill 28" x 42" Hole	42.1	LP Wellhead housing and conductor required on rig.
			Run and Cement 36" Conductor	45.2	
			Drill 28" Hole	48.4	18-3/4" HP wellhead and 22" casing required on rig.
			Run and Cement 22" Casing	53.4	
			Run BOP and Riser	60.7	
			Drill 18-1/8" x 21" Hole	68.7	18" hanger and 18" casing required on rig
			Run and Cement 18" liner	77.0	
			Drill 16-1/2" Hole	84.4	Casing hanger and 14" casing required on rig.
			Run and Cement 14" Casing	94.3	Ranging tooling required on rig.
			Drill 12-1/4" Hole	104.7	Liner hanger and 9-7/8 casing required on rig.
			Run and Cement 9-7/8" Liner	113.5	
Ranging	Standard assumption, not GAB unique.	35 days	Ranging, intercept and kill well	149	
	Total Time	**149 days**			

Table 38 – Relief Well Timing Summary

13 Supporting Studies (References)

This WOMP references many documents throughout, complete with descriptions of content. Below is a summary of referenced documents only;

- The Stromlo-1 BOD Summary (AU000-DR-BOD-600-00005),
- Stromlo-1 Casing BOD (AU000-DR-BOD-600-00002),
- GAB Drilling Riser Analysis Summary 2015 (UE-2015-0028),
- Stromlo-1 Fluids BOD (AU000-DR-BOD-600-00004), and,
- Stromlo-1 Cementing TFN (AU000-DR-BOD-600-00003).
- New Ventures Containment Response Plan for the Great Australian Bight (AU000-HS-PLN-600-00003).
- Stromlo-1 Relief Well BOD and Plan (AU000-DR-BOD-600-00001)
- Stromlo-1 Statement of Requirements (SOR)
- Stromlo-1 SHA (S-SST-0013-15)
- Stromlo-1 Steady State Uncontrolled Well Discharge Modelling – WCD (AUS-NWD-TFN-049).