Well Planning, Design and Operating Standards Onshore UK

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1.0 GENERAL REQUIREMENTS

It is Horse Hill Developments Limited (HHDL) policy to reduce the risk to people, environment and communities to as low as reasonably practicable (ALARP). The purpose of these policies and standards is to document a common approach and methodology for well planning, design, operations and well testing / production within HHDL.

Where this document contains the word 'shall', this is a mandatory approach which can only be changed by utilising the Management of Change (MOC) process.

1.1 Barriers and Barrier Philosophy

Critical to the safe execution of all drilling, well testing, completion and well intervention operations are the concepts of well integrity and barrier philosophy. For the sake of clarity, the following definitions apply with respect to barriers:

1.1.1 A Barrier is any equipment, assembly or obstacle intentionally placed in a well that can be used to contain pressure and prevent flow. Examples of barriers are:

- Wellhead equipment
- Casings
- Annulus cement
- Cement plugs
- Blow-out preventers (BOPs) and pressure control equipment (PCE), such as lubricators, stuffing boxes, etc.
- Bridge plugs
- Production packers
- Tubing or nipple-set wireline plugs
- Tubing hanger plugs
- Production or well test tree valves (master, flow wing, kill and swab valves)
- A fluid column that exceeds the formation pressure by a safe margin

A production packer and tubing hanger may be considered as independent mechanical barrier for annulus isolation.

Once installed, a barrier must be verified either by pressure testing or by weight testing.

A barrier may serve as a permanent or temporary barrier:

1.1.2 A Permanent Barrier is one that will maintain isolation indefinitely. Cement is commonly used to construct a permanent barrier. A hydrostatic overbalance shall not be considered as an independent permanent barrier.

1.1.3 A Temporary Barrier is one that will maintain isolation over a finite period. Temporary barriers are usually tested mechanical devices which should contain pressure to allow for example the removal of the BOP or production tree, but which might eventually fail if left in place for a considerable length of time.

A fluid column may only be considered as a temporary barrier (in this case a Fluid Barrier) where it is kill weight (i.e. overbalanced for the entire well), where the fluid level can be both monitored and maintained at all times, and only where a Barrier Analysis has been authorized by the HHDL Drilling or Production Manager.

1.1.4 A temporary Barrier may be normally open or normally closed.

1.1.5 A Primary Barrier is the first barrier above a pressure source that is intended to isolate that pressure from surface.

1.1.6 A Secondary Barrier is an additional barrier above a primary barrier that serves to isolate pressure from surface in the event of a failure of the primary barrier.

1.1.7 A Separation Barrier is a barrier whose primary function is to isolate permeable zones within different pressure regimes from each other.

1.1.8 When a BOP stack or production tree is to be removed and hydrocarbons may be present which can flow to surface, at least two temporary tested mechanical barriers shall be placed in the flow stream and annulus in order to safely prevent the risk of fluid release from the well.

1.1.9 If a well containing hydrocarbons cannot flow to surface, one pressure tested mechanical barrier and a fluid barrier may be sufficient, subject to conducting a risk assessment and approval of the HHDL Drilling or Production Manager

1.1.10 A barrier risk assessment shall be conducted for all stages of every well and whenever a change is required, and conditions are present which trigger the requirement for a Barrier Analysis.

1.1.11 Operations conducted where degraded well conditions exist shall be subjected to a Barrier Analysis before proceeding.

1.1.12 A summary of the barriers required, depending on well operation, is given in **Table 1** below.

1.1.13 **The Oil & Gas UK Well Life Cycle Integrity Guidelines Section 4 "Well Integrity, Barriers, BOPs and Well Control"** provides further guidance and details on well barriers and the contents of that section should be considered in establishing and maintaining well barriers.

1.1.14 There is a clear definition of when this barrier philosophy applies and when the HHDL

Process Isolation Philosophy is applicable. The barrier philosophy applies when a barrier against well pressure is required and covers the well up to and including the wellhead, BOPs, production tree, well intervention pressure control equipment, such as wireline lubricator, and any valves connected to this equipment.

The Process Isolation Philosophy covers any equipment downstream of the well.

TABLE 1 - Summary of Barrier Policy depending on well operation

OPERATION	INTERNAL BARRIERS REQUIRED	ANNULUS BARRIERS REQUIRED
Spudding well and drilling non-hydrocarbon bearing zones	• A fluid column that exceeds the expected formation pressure by a safe margin[1] • Ported float valve in BHA	• A fluid column that exceeds the expected formation pressure by a safe margin[1]
Running and cementing conductor and surface casing through non-hydrocarbon bearing zones (no BOP installed)	• Casing float equipment • A fluid column that exceeds the expected formation pressure by a safe margin[1]	• A fluid column that exceeds the expected formation pressure by a safe margin[1]
Installing wellhead and BOPs on surface casing	• Casing float equipment • Cement in shoe track • A fluid column that exceeds the expected formation pressure by a safe margin[1]	• Cemented casing to surface. If cement in the primary cement job does not reach surface, a top fill cementation will be required
Drilling below the surface casing	• A fluid column that exceeds the expected formation pressure by a safe margin[1] • Ported float valve in BHA	• A fluid column that exceeds the expected formation pressure by a safe margin[1] • Cemented casing • Wellhead • BOPs
Electric logging of non-hydrocarbon bearing zones	• A fluid column that exceeds the expected formation pressure by a safe margin[1] • Ported float valve in BHA	• A fluid column that exceeds the expected formation pressure by a safe margin[1] • Cemented casing • Wellhead • BOPs
Running and cementing casing through non-hydrocarbon bearing zones (BOP installed)	• Casing float equipment • A fluid column that exceeds the expected formation pressure by a safe margin[1]	• A fluid column that exceeds the expected formation pressure by a safe margin[1] • Annular BOP
Removing BOPs to install drilling spool prior to drilling out	• Casing float equipment pressure tested prior to running or inflow tested • Cement in shoe track • A fluid column that exceeds the expected formation pressure by a safe margin[1]	• Cemented casing annulus • Wellhead seals if casing hanger or casing slip assembly installed prior to lifting BOPs
Drilling hydrocarbon bearing zones	• A fluid column that exceeds the expected formation pressure by a margin of 100 psi • Ported float valve in BHA	• A fluid column that exceeds the expected formation pressure by a safe margin[1] • Cemented casing • Wellhead

		• BOPs
Removing BOPs to repair wellhead or BOPs	• A fluid column that exceeds the expected formation pressure by a margin of 100 psi • As a minimum, one pressure tested retrievable packer and storm valve (or plugged packer) installed in casing below wellhead. If hydrocarbons present in the open hole section, then two temporary, tested, mechanical barriers are required.	• Cemented casing • Wellhead seals
Electric logging of hydrocarbon bearing zones	• A fluid column that exceeds the expected formation pressure by a margin of 100 psi • BOPs (blind rams)	
Running and cementing casing through hydrocarbon bearing zones	• Casing float equipment, pressure tested prior to running • A fluid column that exceeds the formation pressure by a margin of 100 psi	• A fluid column that exceeds the formation pressure by a margin of 100 psi • Annular BOP
Removing BOPs to install tubing spool prior to running completion	• Casing float equipment pressure tested prior to running or inflow tested • Cement in shoe track • A fluid column that exceeds the expected formation pressure by a safe margin[1]	• Cemented casing annulus • Wellhead seals if casing hanger or casing slip assembly installed prior to lifting BOPs
Running completion	• Tubing plug • A fluid column that exceeds the expected formation pressure by a margin of 100 psi	• Cemented casing • Wellhead seals • BOPs
Removing BOPs to install production tree (and vice versa) for wells which will not flow to surface without artificial lift	• A fluid column that exceeds the expected formation pressure by a margin of 100 psi • Tubing hanger plug	• Cemented casing • A fluid column that exceeds the expected formation pressure by a margin of 100 psi • Tubing hanger seals • Production packer (if installed)
Removing BOPs to install production tree (and vice versa) for wells which will flow to surface without artificial lift	• Tubing hanger plug • Deep set tubing or casing plug	• Cemented casing • A fluid column that exceeds the expected formation pressure by a margin of 100 psi • Tubing hanger seals • Production packer

Rigging up well intervention pressure control equipment (slickline, electric line, coiled tubing) onto production tree	• Production tree valves	
Well testing / production	• Production tree valves	
Temporary well suspension	• One or two mechanical plugs • A fluid column that exceeds the expected formation pressure by a margin of 100 psi	• Cemented casing • Wellhead seals
Permanent well abandonment	• One or two cement plugs or as specified by local regulations	• Cemented casing

[1] The safe margin of the fluid column hydrostatic overbalance required (in terms of psi, ppg equivalent mud weight or percentage increase over static hydrostatic column) will be reviewed on a case by case basis following a review of the offset well data and discussion and agreement with the HHDL Drilling or Production Manager. The safe margin should be sufficient to prevent any shallow aquifer flows while avoiding significant losses into the near surface formations.

1.2 General Standards

1.2.1 Well site and well specific risk assessments will be developed and must be referred to during the planning, design and execution of well operations.

1.2.2 All personnel working for HHDL or their contractors must be competent to carry out their duties.

1.2.3 Contractor HSE management shall be an integral part of the general management of contractors throughout the contract life cycle from contractor selection through contract execution and post-campaign review.

1.2.4 All lifting and handling operations must be carried out in accordance with LOLER.

1.2.5 Contractors supplying drilling or workover rigs, wireline or coiled tubing units, etc. and other safety critical equipment and services which can become part of the pressure containing envelope of the well must conform as a minimum with American Petroleum Institute (API) standards and onshore UK regulatory requirements. Safety or environmentally critical equipment and services are defined as any equipment or operation which penetrates or extends the pressure containing envelope of the well, which have a specific lifesaving or life support function or which has a specific role in protecting the environment. The BOP is an example of a safety and environmentally critical item of equipment.

1.2.6 Inspections and audits of rigs and safety / environmentally critical equipment and services shall be conducted and completed prior to contract award or, if not practical, as early in the campaign as possible, and shall address the following:

- Safety / environmental critical systems and controls
- HSE management systems
- Certification of safety critical equipment
- Maintenance of equipment
- Drilling fluids containment integrity
- Personnel competence

1.2.7 For 12 hour per day well site operations, HHDL shall have a day Site Supervisor as a minimum. For 24 hour per day operations, HHDL shall have either a day and night Site Supervisor if accommodation is located away from the well site, or one Site Supervisor providing 24-hour coverage if accommodation is located at the well site.

1.2.8 As a minimum, site HSEC (Health, Safety, Environmental and Community) responsibilities will be addressed as follows:

- The HHDL Site Supervisor has ultimate responsibility for HSEC on site
- The HHDL HSE Manager will address all HSEC issues at the pre-operations meeting, will audit / inspect the rig / site operations at the commencement of operations (and subsequently at a frequency commensurate with the HSEC risks) and will provide HSE support as required (e.g. accident investigations).
- A competent individual (typically the contractor managing site security) will provide the site HSE induction. The HHDL HSE Manager will provide this individual with the necessary training and support documentation.

1.2.9 A campaign plan and schedule shall be developed and maintained for all planned drilling, well testing, completion, well intervention or abandonment campaigns.

1.2.10 A bridging document shall be prepared which interfaces between HHDL and the primary contractor on location, which will typically be the rig contractor. The bridging document must include the requirements of the third-party contractors that will be on site during well operations and address both normal and emergency operations.

1.2.11 A site specific safety document, including medevac plan, must be formulated for all planned drilling, well testing, completion, well intervention or abandonment campaigns. Drills and exercises shall be held to confirm the effectiveness of these plans.

1.2.12 Site based induction training shall be conducted for all rig crews and service company personnel to explain operating plans and the safety systems that are in place, and to advise all the participants of the well operations of their operational and emergency roles and responsibilities. Rig crews and service personnel will be informed about the following policies:

- HHDL HSEC Policy

- HHDL Site Health & Safety Document
- Drug and Alcohol Policy
- Work Site Jewellery Policy
- Personnel Protective Equipment (PPE) Policy
- Well Control Plan

2.0 WELL DESIGN AND PLANNING

2.1 General

2.1.1 Authority for Expenditure (AFE) is prepared under the direction of the HHDL Drilling or Production Manager and approved by the Operations Director, Finance Director and Chief Executive Officer.

2.1.2 An agreed Basis of Well Design (BOWD) shall be developed for each well to be drilled, tested, completed, re-entered or abandoned. The recommended minimum contents to be included in the BOWD are listed in **Appendix 3**.

2.1.3 Relevant offset well data must be gathered and analysed during the planning of the well.

2.1.4 Drilling, completion, well testing, well intervention and abandonment work programmes shall be approved by the HHDL Drilling or Production Manager, Operations Director and Chief Executive Officer and shall contain the following as a minimum:

- Well description and general well data
- Programme objectives and procedures
- Pore and fracture pressure and temperature profiles
- Technical and operational risk assessments including any risk mitigation measures
- Detailed operational sequence
- Casing and tubing design safety factors
- Survey programme
- Pressure testing schedule
- Mud programme
- Cementing programme
- Bit programme
- BHA programmes
- Wellhead programme
- Abandonment philosophy (if applicable)

2.1.5 A document control system, including revision history, shall be used to manage the approval process for technical or operational documents that are subject to formal management approval.

2.1.6 Contingency plans shall be developed for any well specific drilling hazards that are identified during the planning phase.

2.1.7 All equipment and materials used in wells shall be designed, manufactured, inspected, installed, and tested in accordance with industry accepted standards, normally API.

2.1.8 All equipment purchased by HHDL that may become part of the pressure containing envelope of the well shall be supplied with relevant certification e.g. casing, tubing, wellheads, production trees and completion equipment.

2.1.9 All drilling, well testing, completion, well intervention or abandonment work programmes and designs shall be subject to HHDL's Independent Well Examination Scheme.

2.2 Casing Design

2.2.1 Minimum assumed kick volumes for well design shall be in accordance with the following:

Hole Size	Kick Volume (bbl)
12 ¼" or larger	50
Less than 12 ¼"	25

2.2.2 Kick tolerances shall be calculated for:

- a swabbed kick at the planned TD of the respective hole section, utilising the predicted formation pressure and the planned mud weights
- an increase in the predicted formation pressure of 1.0 ppg utilising the planned mud weight

2.2.3 A presentation of the casing design loads versus casing strengths with all design assumptions, actual design safety factors, and a well schematic shall be included in the well work programme.

2.2.4 Casing designs shall consider the effects of temperature, cementing, running, pressure testing, etc., with the following minimum design factors:

Loading	Minimum Design Factor
Burst (Refer to **Table 2**)	1.10
Collapse (Refer to **Table 3**)	1.10
Tension (Refer to **Table 4**)	1.60 for a vertical well 1.75 for a directional well

2.2.5 A tri-axial design analysis shall be conducted where the above safety factors cannot be met.

2.2.6 All surface, intermediate and production casings and liners shall be pressure tested prior to drilling out the shoe.

2.2.7 Casing strings shall be pressure tested to the maximum anticipated wellhead pressure plus a bull heading margin of 500 psi.

2.2.8 All wells shall use Buttress threads on casing and EUE 8 round threads on tubing as a minimum standard.

TABLE 2 - Loading criteria that must be considered when calculating the minimum **Burst** design factor

CASING STRING	INTERNAL LOAD		EXTERNAL LOAD	MINIMUM DESIGN FACTOR
	EXPLORATION WELL	DEVELOPMENT / APPRAISAL WELL		
Production (including liners)	Greater of: • Casing pressure test on plug bump with mud in the casing • Well shut in with gas to surface • Maximum SITHP with a near hanger tubing leak subjecting casing above packer to SITHP plus hydrostatic of packer fluid	Greater of: • Casing pressure test on plug bump with mud in the casing • Maximum SITHP with a near hanger tubing leak subjecting casing above packer to SITHP plus hydrostatic of packer fluid • Fracture / acid stimulation plus stimulation fluid hydrostatic, if relevant • Injection or jet pumped wells – maximum anticipated future injection pressure plus 500 psi plus hydrostatic of fluid	• Hydrostatic column of fresh water	1.10
Intermediate II	Greater of: • Anticipated formation fracture gradient at shoe with gas gradient to surface • Casing pressure test on plug bump with mud in the casing	Greater of: • Anticipated formation fracture gradient at shoe with hydrocarbon gradient to surface • Casing pressure test on plug bump with mud in the casing	• Hydrostatic column of fresh water	1.10
Intermediate I (Surface Intermediate)	• As per surface design criteria	• As per Surface design criteria	• Hydrostatic column of fresh water	1.10
Surface	Greater of: • Anticipated formation fracture gradient at shoe with gas gradient to surface	Greater of: • Anticipated formation fracture gradient at shoe with gas gradient	• Hydrostatic column of fresh water	1.10

	• Casing test pressure plus mud hydrostatic to shoe less normal external pressure (0.465 psi/ft) to shoe	to surface • Casing test pressure at surface • Casing test pressure plus mud hydrostatic to shoe less normal external pressure (0.465 psi/ft) to shoe		

TABLE 3 - Loading criteria that must be considered when calculating the minimum **Collapse** design factor

CASING STRING	**EXTERNAL LOAD**			**INTERNAL LOAD**	**MINIMUM DESIGN FACTOR**
	RUNNING / CEMENTING	**DRILLING**	**PRODUCTION**		
Production (including liners)	• Collapse pressure at shoe when cement displaced with planned fluid heights and densities outside	Greater of: • Salt collapse load if present assuming an external load of 1.0 psi/ft. • Hydrostatic pressure due to mud column outside casing in the event of total losses in next hole section	Greater of: • Salt collapse load if present assuming an external load of 1.0 psi/ft. • Hydrostatic pressure due to mud casing was run in • Depletion of reservoir pressure (for longer term consideration)	Lesser of: • Hydrostatic pressure due to cement displacement fluid • Maximum drawdown (abandonment below packer) • Gas at gas lift pressure (if relevant) • Evacuated below packer (worst case plugged perforation) or extreme drawdown on late field life	1.10
Intermediate	• Collapse pressure at shoe when cement displaced with planned fluid heights and densities outside	Greater of: • Salt collapse load if present assuming an external load of 1.0 psi/ft. • Hydrostatic pressure due to mud column		Lesser of: • Hydrostatic pressure due to cement displacement fluid • Partial or complete evacuation due to a loss zone at the next casing point or at the deepest known loss zone	1.10

		outside casing in the event of total losses in next hole section			
Surface / Conductor	• Collapse pressure at shoe when cement displaced with planned fluid heights and densities outside • Consider effects of annulus packing off during inner string cementation	• Collapse pressure at shoe when cement displaced with planned fluid heights and densities outside		• As per Intermediate casing criteria	1.10

TABLE 4 - Loading criteria that must be considered when calculating the minimum **Tension** design factor

CASING STRING	INTERNAL LOAD ALL WELLS
Production (including liners)	• Weight of casing in air plus overpull allowance of 100,000 lb (DF 1.60) • Axial load at the top due to buoyant weight after displacing cement plus extra tension if applied to energise the casing hanger slips (DF 1.60) • Buoyant weight casing or liner plus test pressure (DF 1.60) • Buoyant weight casing or liner plus test pressure plus bending stress if deviated assuming dog legs are 50% more than planned or additional 2 deg/30m, whichever is greater (DF 1.75) • If marginal, run tri-axial analysis incorporating temperature correction for yield strengths (DF 1.25)
Intermediate	• eight of casing in air plus overpull allowance of 100,000 lb (DF 1.60) • Axial load at the top due to buoyant weight after displacing cement plus extra tension if applied to energise the casing hanger slips (DF 1.60) • Buoyant weight casing or liner plus test pressure (DF 1.60) • Buoyant weight casing plus test pressure plus bending stress if deviated assuming dog legs are 50% more than planned or additional 2 deg/30m, whichever is greater (DF 1.75)

	• If marginal, run tri-axial analysis incorporating temperature correction for yield strengths (DF 1.25)
Surface / Conductor	• Weight of casing in air plus overpull allowance of 100,000 lb (DF 1.60) • Buoyant weight plus test pressure (DF 1.60) • Buoyant weight plus test pressure plus bending stress if deviated assuming dog legs are 50% more than planned or additional 2 deg/30m, whichever is greater (DF 1.75) • If marginal, run tri-axial analysis incorporating temperature correction for yield strengths (DF 1.25)

2.3 Tubing Design

2.3.1 Tubing designs shall consider the effects of expected life-cycle loads including; running weight, production loads, temperature changes, internal and external pressure, tensile and compressive loads, ballooning, buckling, bending, pressure testing, forces acting on bridge plugs, slack-off or overpull, packer release, etc. with the following minimum safety factors:

Loading	Minimum Design Factor
Axial (Tension and Compression)	1.30
Burst	1.10
Collapse	1.10
Tri-axial	1.25

2.3.2 All vendor-provided tubing and work string movement and load recommendations, e.g. pipe movement induced by packer setting, tool manipulation / function and shear pin / disc selection shall be verified by the HHDL Drilling or Production Manager.

2.4 Casing and Tubing Selection

2.4.1 All casing, liner, and tubing pipe bodies shall be manufactured to **API Spec 5CT** or better.

2.4.2 Large diameter tubulars (16" and larger) shall be manufactured to **API Spec 5L or 5CT**.

2.4.3 Non-premium connections shall be manufactured to **API Spec 5CT**.

2.4.4 All pipe connections shall be of a recognized and qualified design.

2.4.5 Premium casing and tubing connections with a metal to metal seal effective for gas shall be used for the following:

- In potentially corrosive environments
- For production casing and liners in the following:
  - High angle deviated or horizontal wells
  - Deep or high-pressure oil wells
  - Gas wells and high GOR oil wells
  - Where H_2S is expected
  - Gas lift wells
  - Fracture stimulated wells

2.4.6 Torque-turn equipment shall be used when running all premium-threaded casing and tubing.

2.4.7 Where H_2S is expected, tubulars shall comply with **NACE MR-01-75**.

2.5 Wellheads and Production Tree Specifications

2.5.1 Wellhead equipment shall be specified in accordance with API spec 6A.

2.5.2 Wellhead and production tree equipment shall have a rated working pressure in excess of the maximum anticipated wellhead pressure which must include any kill, stimulation or production system (e.g. jet pump) loads unless a production tree saver device is provided for.

2.5.3 Casing hanger systems will have integral (normally weight set) annulus seals.

2.5.4 Where fluid composition is unknown (e.g. exploration wells), then sour service wellhead equipment shall be specified.

2.5.5 On conventional production trees, all valves shall be rated to a minimum of the same API pressure rating as the production tree body unless the body is de-rated to match the valve rating.

2.5.6 Surface wellhead side-outlets shall be configured as follows:

- Side 1 = instrument flange with needle valve and VR Plug.
- Side 2 = single gate valve on starter head, dual gate valves, API flanged and studded on all other spools.

2.5.7 Side outlet valves shall be rated to the same pressure as the wellhead unit to which they are attached.

2.5.8 All wellhead tubing hangers shall be provided with a means of isolating the production tree (e.g. nipple or Cameron H back pressure valve profile) to allow for well intervention and repair of the production tree valves or other downstream pressure controlling equipment.

2.5.9 It is recommended to use tubing hangers which do not have tie down bolt energised seals. Utilising a tubing hanger without tie down bolt energised seals allows the tie down bolt gland seals to be tightened and pressure tested against the tubing hanger body seals and the BOP after they have been retracted.

2.5.10 All production trees installed on gas wells capable of flowing naturally to surface (i.e. with any positive potential shut-in wellhead pressure) must have at least one valve in the flow stream on the production tree fitted with a fail-safe closed actuator in accordance with **ISO Standards 10423 / API 6AV2**. During well interventions this valve alone must be fitted with a fusible lockout cap or other mechanical isolation device.

2.5.11 Unless operational or design considerations require a contrary approach, all production trees should be fitted with a separate kill inlet not forming part of the well flow stream pipework.

2.6 Wellhead and Production Tree Quality Assurance and Quality Control

2.6.1 Formal records shall be kept of any witnessing of factory acceptance testing, or pressure testing of pre-installed equipment whether by HHDL personnel or third parties acting on their behalf.

2.6.2 Interference checks shall be carried out on all wellhead equipment prior to despatch to the well site.

2.7 Cementation

2.7.1 The pre-drill temperature model shall be based on the accurate static temperature measurements from nearest offset wells.

2.7.2 The accuracy at which cement will set is critical to cement slurry design and shall be accurately estimated based on measured bottom hole static temperature (BHST) and bottom hole circulating temperature (BHCT).

2.7.3 All oilfield cements shall undergo quality control analysis in accordance with **API Spec 10A**.

2.7.4 Programmed waiting on cement (WOC) time shall be greater than the time that it takes for a cement system to achieve 500 psi compressive strength based on slurry testing results.

2.7.5 All cement slurry properties shall be tested in accordance with the methods described in **API RP 10B-2** and the following tests shall be conducted on all slurries:

- Surface and down-hole rheology
- Down-hole gel strengths
- Free fluid
- Thickening time
- Compressive strength

2.7.6 Casing centralisation modelling shall be carried out to model the centralisation of the casing of at least 80% stand-off and adequate centralisers shall be run to achieve at least 80% stand-off.

2.8 Directional Drilling Planning and Collision Avoidance

2.8.1 For directional wells the drilling programme shall include as a minimum:

- A spider plot (if other wells are expected to interfere with the planned well).
- A vertical section and plan view
- A well path interference summary
- The survey programme

2.8.2 Surface and target coordinates shall be specified in the BOWD.

2.8.3 The HHDL Drilling Manager shall approve the directional plan, usually by signing the drilling programme.

2.8.4 At the planning stage, a check shall be made for any collision issues of nearby wells within a two (2) kilometre radius on the intended well path.

2.8.5 If a risk of collision is identified then a mathematical model shall be used to ensure that sufficient separation is maintained between the new well and existing well(s).

2.9 Directional Surveying

2.9.1 The directional drilling contractor shall have the capability to provide all the necessary calculations and plots.

2.9.2 All surveys measuring inclination and direction, including directional surveys at multi-slot locations, shall be referenced to Grid North.

2.9.3 At multi-well locations, all surveys shall reference a single fixed point in space (variously called the survey reference point or drilling centre) as the origin of the local coordinate grid.

2.9.4 All surveys shall reference the rig's Rotary Table (RT) as the vertical reference.

2.9.5 Each rigs RT elevation shall be referenced to the adopted vertical datum, referenced to True Vertical Depth Sub Sea (TVDSS).

2.9.6 Each well will have an accurate surveyed in hole centre prior to spud.

2.9.7 The minimum radius of curvature method shall be used to calculate bottom hole location from survey data.

2.9.8 For directional wells, a check survey shall be taken with the MWD on every trip in the hole. The check survey depth shall be a minimum of 75 metres below the previous casing shoe depth in a magnetically stable environment.

2.9.9 Only corrected survey data shall be used on the daily drilling report or in any reports delivered by directional drilling or surveying contractors.

2.9.10 All surveys taken shall be recorded for future reference.

2.9.11 Survey programmes shall be designed to limit the positional uncertainty at the deepest planned objective or possible abnormal pressure zone, whichever is the deeper, to a maximum of 50 metres.

2.9.12 All survey tools shall be inspected and calibrated by the directional drilling company prior to use in any well.

2.9.13 A survey report shall be provided by the surveying contractor. The Drilling Engineer shall review the survey report and ensure that all appropriate input data is correct.

2.9.14 At the end of each well, the definitive survey shall be agreed between the drilling surveying contractor and HHDL and maintained in the well file.

3.0 DRILLING OPERATIONS

3.1 General

3.1.1 In the event that a significant programme change is required, the Management of Change (MOC) (**refer to Appendix 1**) shall be utilised.

3.1.2 A significant programme change is one which effects a barrier in the well, increases AFE cost by more than 1% or compromises the technical objectives of the well.

3.1.3 A pre-spud meeting must be held prior to the spudding or re-entry of all wells to explain the upcoming operation, key hazards, and to address all HSEC issues and any non-routine or HSE critical operations.

3.1.4 An HSE site induction must be held for all rig crews and service company personnel when they first arrive at the well site (**refer also to section 1.2**). This induction will, as a minimum, address:

- What to do on arrival /departure
- PPE requirements
- Equipment not allowed or only allowed with a permit or only allowed in selected areas (e.g. cameras, matches, mobile phones)
- Welfare facilities
- HSE Hazards and arrangements to mitigate risk
- What to do in an emergency (including identification of muster areas)

3.1.5 A general safety meeting with on-site service providers shall be held weekly. The drilling contractor shall hold a weekly safety meeting with the drilling crews.

3.1.6 Pre-tour safety meetings on-site, with participation by drilling contractor crew and service providers, shall be held daily.

3.1.7 Prior to commencing HSE critical or non-routine operations, a toolbox talk (TBT) shall be carried out to identify procedures required to prevent failure or loss of well control, or to mitigate the consequences of such a failure or loss of well control. The TBT shall be documented by the HHDL Site Supervisor.

3.1.8 All rig based HHDL personnel shall be inducted into reporting requirements, campaign specific well control policies, bridging arrangements, HSE policies, standards, plans, programmes, and other relevant documents.

3.1.9 Crew change and shift change handover procedures shall be in place for all HHDL rig based personnel and drilling contractor and service contractor supervisory personnel.

3.1.10 Detailed daily progress reports using the HHDL reporting system shall be prepared by the HHDL Site Supervisor for all well operations and distributed as appropriate.

3.1.11 All BHA components and tools being run in the well shall be measured, drifted and accurately recorded.

3.1.12 The HHDL Site Supervisor shall visually inspect and confirm all aspects of the equipment being run in the hole, such as but not limited to, bit nozzle size, BHA configuration and component dimensions and specifications, drill pipe dart and activation ball size and compatibility, etc.

3.1.13 Gauge rings used to gauge drill bits and stabilizers shall be measured to confirm size prior to use.

3.1.14 Casing tallies shall be prepared by the HHDL Site Supervisor and independently checked by the Tool Pusher and Drilling Engineer.

3.1.15 Prior to any cement job, a method of volume monitoring for the mud tanks and cement displacement shall be in place in order to determine whether downhole fluid losses occur whilst cementing. This method must include allowance for independent checking by the HHDL Site Supervisor. This fluid monitoring system shall comply with **API S53**.

3.1.16 When running casing with conventional float equipment, the casing shall be filled at least every ten (10) joints.

3.1.17 The HHDL Site Supervisor shall witness the loading of all cement or drill pipe plugs into the cementing head and verify the correct type of plug(s) are being used.

3.1.18 The HHDL Site Supervisor shall confirm critical depths and compliance with the drilling programme (casing float shoes and collars, landing collars, casing centralisers, etc.)

3.1.19 Driller's instructions shall be prepared daily by the HHDL Site Supervisor and records maintained in the well files.

3.1.20 Where possible, engineering calculations shall be independently checked by the HHDL Site Supervisor and relevant service company engineer.

3.1.21 An End of Well Report (EOWR) shall be prepared for all wells. The EOWR shall include all service provider end of well reports as appendices.

3.1.22 If H_2S has not been anticipated, and in excess of 10 ppm is detected, then drilling operations shall be suspended, and a risk assessment conducted prior to continuing.

3.1.23 When designing the well site layouts, hazardous areas shall be defined.

3.1.24 A risk assessment, involving HHDL and service provider personnel shall be conducted prior to spud to provide assurance that all drilling and HSEC hazards have been identified and that appropriate arrangements are in place to mitigate these risks.

3.2 Drill String

3.2.1 The drill pipe inspection records and service history shall be inspected prior to commencement of the drilling contract. In the case of highly deviated wells, or where there is concern over the condition of the drill pipe, a 10% sample of the drill pipe shall be inspected by an independent third-party inspection company to determine if it is necessary to inspect the complete drill string.

3.2.2 The inspection records and service history of all down hole tools shall be reviewed and if there are any concerns about the condition of the tools, they shall be inspected by an independent third-party inspection company.

3.2.3 Drill string pin connections shall have stress relief grooves, and box connections shall have a 'DRILCO' or equivalent bore-back feature.

3.2.4 Any tools that do not have bore-back features require exemption by the HHDL Site Supervisor. Exemption may be given to rental and other short-term usage tools which do not require bore-backs or stress relief groove features, including some fishing tools, wellhead running tools, jars, roller reamers, stabilisers, shock subs, accelerators and mud motors.

3.2.5 The requirements for hard facing on drill pipe tool joints shall be reviewed on a well by well basis.

3.2.6 BHA components (HWDP, drill collars, drilling tools, subs, Non-Magnetic drill collars, etc.) shall be inspected and graded in accordance with **API RP 7G** and the **DS 1 Level 5** specifications prior to contract commencement, and thereafter to the lesser of:

- At the end of each well, or
- 250 rotating hours

3.2.7 All crossovers shall be inspected prior to each well and replaced with new crossovers as necessary.

3.3 Well Control - General

3.3.1 Prior to commencing a campaign, the drilling contractor's Well Control Policy shall be reviewed to ensure compatibility with HHDL's Well Control Standards as specified in this document. Any differences which are identified shall be documented in the bridging document with a clear statement of the agreed procedures to be used.

3.3.2 HHDL's drilling operations supervisory and senior drilling contractor personnel shall be trained in well control procedures by an accredited IWCF or WellCAP institution and shall have a valid well control certificate to supervisory level which shall be renewed no less frequently than at two-year intervals.

3.3.3 The following specific positions must hold valid level 4 well control certificates:

- HHDL Site Supervisors
- Drilling contractor Tool Pushers and Drillers

3.3.4 A well control audit addressing plans, training, standard operating procedures (SOPs), equipment, and contingencies shall be conducted for all drilling operations.

3.3.5 Standard Operating Procedures (SOPs) for well control are required for every rig and shall be included in the Bridging Document between HHDL and the drilling contractor covering wireline operations through drill pipe, tripping and well shut-in operations, pit and trip drills, and preferred kill methods.

3.3.6 The pre-spud inspection audit, which is carried out on all rigs contracted to HHDL shall specifically assess the condition of the drilling contractor's BOPs and other well control equipment and ensure compliance to **API S53**.

3.3.7 On all wells, an appropriate shallow hazards assessment shall be performed to identify any anomaly that may be indicative of shallow gas.

3.3.8 Where a shallow hazards assessment indicates the presence of shallow gas at the intended drilling location and it is not possible to move the surface location, procedures, such as drilling with a diverter, drilling a pilot hole and having a sufficient quantity of kill mud available, shall be developed and put in place prior to spudding the well.

3.4 Well Control Equipment Requirements

3.4.1 The BOP and associated equipment must be rated to exceed the maximum anticipated surface pressure plus a 500 psi safety factor for bull-heading operations.

3.4.2 The BOP stack configuration shall comply with **API S53**. Ram and outlet configuration shall be subjected to a risk assessment prior to each drilling operation.

3.4.3 Rams shall be installed to fit all sizes of drill pipe used. BOP shear rams, if fitted, must be able to shear and seal all standard drill pipe tube in use.

3.4.4 Blind or blind/shear rams will be installed in the lowermost ram cavity.

3.4.5 An annular preventer shall be installed which can seal on all drill string sizes.

3.4.6 The inlet below the lowest ram on the BOP shall not be used as a choke line during well control operations.

3.4.7 The shear rams, if fitted, shall not be closed routinely when out of the hole on trips or tagged with the drill string at any time. Pipe rams shall only be closed on the correct size of drill pipe.

3.4.8 BOP closing times shall, at a minimum, meet **API Spec 16D or API S53**.

3.4.9 The BOP accumulator volume shall comply with **API Spec 16D** as a minimum.

3.4.10 An uninterrupted power supply (UPS) and air supply are required for remote BOP control panels

3.4.11 New steel ring gaskets shall be installed between the wellhead and the BOP or production tree each time that the BOP or production tree is installed on the wellhead.

3.4.12 All active mud tanks shall have independent level indicators and a mud volume totalizer readout located on the Driller's console on the rig floor. This equipment must always be regularly tested and calibrated and be operational , to comply with **API S53**.

3.4.13 A circulating trip tank with a read out easily visible to the Driller shall always be used while tripping, when out of the hole, when the BOP is installed, and during logging to confirm the hole is static.

3.4.14 A float sub shall be installed in all BHAs. A ported float shall be used for all BHA run in hole.

3.4.15 A Full Opening Safety Valve (FOSV) shall always be available on the rig floor with crossovers to the drill pipe, tubing, or casing through the rotary.

3.4.16 A FOSV shall be installed any time a trip is interrupted.

3.4.17 A rapid installation system for the FOSV shall be available and rigged up, if required.

3.4.18 A Gray Valve (drill string check valve) shall be available on the rig floor.

3.4.19 A kick joint assembly incorporating a full opening safety valve and Gray Valve, shall be made up and available for casing running operations.

3.4.20 Choke and kill lines shall be circulated prior to the drilling out of each section and, additionally, as required. Choke and kill lines will be displaced to water, or water glycol mix during freezing conditions.

3.4.21 The mud gas separator and degasser must have sufficient gas handling capacity for the well(s) to be drilled, shall comply with **API S53** as a minimum and compliance must be confirmed during the pre-spud rig audit.

3.5 Well Control Equipment Pressure Testing

3.5.1 BOP equipment shall be pressure tested at an interval of 14 days and not exceeding 21 days and function tested every 7 days. Shear rams may be tested after setting casing.

3.5.2 BOP pressure test acceptance criteria shall be 5 minutes minimum straight line at low pressure (200-300 psi) and 10 minutes minimum straight line at high pressure. All pressure tests will be recorded on a correctly scaled chart, annotated with

- Chart recorder serial number
- Chart recorder calibration date
- Details of the test – components and against which other components
- Pressure test ad duration
- Signature of two witnesses
- Date

3.5.3 The BOP, choke manifold, kill and choke lines, inside BOPs and surface equipment shall be pressure tested to the pressure specified in the drilling programme after installation and at the frequency specified above.

3.5.4 All well construction and integrity pressure tests shall be recorded on a chart recorder or electronic data logger and the pressure recorder charts and electronic data files for all tests, whether successful or otherwise, shall be retained in the well files.

3.5.5 Shear rams if fitted shall be pressure tested to the casing test pressure specified in the drilling programme.

3.5.6 The BOP test on initial installation on a well shall include an accumulator drawdown test and the accumulator shall be tested every BOP test thereafter.

3.5.7 The BOPs and associated well control equipment shall be tested with water.

3.5.8 Casing shall be tested on plug bump as per the detailed drilling programme or prior to drilling out the lower half of the shoe track.

3.5.9 Surface and intermediate casing pressure testing acceptance criteria shall be a minimum of 15 minutes straight line and recorded on a chart.

3.5.10 Production casing pressure testing acceptance criteria shall be a minimum of 30 minutes straight line at the required test pressure and recorded on a chart.

3.5.11 Formation leak-off (LOT) or formation integrity (FIT) tests shall be conducted in accordance with the requirements of the drilling programme.

3.6 Pressure Testing Criteria

This section applies to all well operations.

3.6.1 Pressure tests are carried out on newly installed equipment / barriers to provide confidence that:

- Equipment has been correctly installed
- Equipment is suitable for the intended service
- The integrity of the barrier is verified

3.6.2 A generic pressure test procedure consists of the following basis steps:

1. Apply a low pressure test to the system of 200 to 300 psi
2. Monitor the volume pumped
3. Allow pressure to stabilise and hold for 5 minutes
4. Increase the pressure to the test pressure and hold for 10 minutes monitoring the volume pumped
5. Visually inspect the surface lines and equipment for leaks
6. If a leak is visible or a leak is observed on the chart, depressurise the system and remedy the leak. Monitor volume bled back if possible
7. Repeat from step 1
8. Under no circumstance should a fitting be tightened whilst under pressure / during test
9. Allow pressure to stabilise and hold for the test duration
10. Bleed off the pressure and monitor the volume returned

3.6.3 Under field conditions it can be difficult to achieve a straight-line pressure test. Several factors including the atmospheric conditions, trapped air, dynamics / fluids settling, and the test volume can all impact the test results.

3.6.4 In general, a pressure test is deemed acceptable if:

- No leaks are visible at surface or along any of the system lines

- A straight line is observed on the pressure test chart
- In cases where a straight line is not achieved, the test may still be deemed acceptable if:
    - No leaks are visible
    - The pressure drop is trending to zero
    - The pressure drop is no more than 3% of the test pressure over the test duration; and
    - The pressure drop can be attributed to an outside factor – i.e. drop in temperature during the test

3.6.5 A numerical definition for a successful hydrostatic test is defined in **API 6A**, however it is noted that the use of this definition as a pass / fail criteria may detract from the engineering judgement and experience of the operators at the well site and therefore it is considered more acceptable to follow the parameters defined above. It is recommended that the parameters above are considered the primary means of confirming test acceptance where the API guidance is considered as a secondary limit subject to the conditions at the time of the test.

3.6.6 During pressure testing, the downstream side of the component being pressure tested shall be monitored for pressure and fluid movement e.g. monitoring the B annulus when the A annulus is being pressure tested.

3.7 Well Control Procedures

3.7.1 Shut in procedures shall be posted on the drill floor and shall address:

- Normal drilling operations
- Tripping operations
- Casing or liner across the BOP
- BHA across the BOP
- Specific shut-in situations (e.g. slotted liners, screens, spent guns, etc.)

3.7.2 Procedures for BOP jetting after drilling and cement jobs shall be prepared in advance.

3.7.3 Diverter drilling shall not be performed through a hydrocarbon zone or a zone of known overpressure, unless associated with shallow gas.

3.7.4 Where Hydrogen Sulphide (H_2S) gas is expected to be encountered in a well, an H_2S contingency procedure shall be prepared. The contingency procedure shall include a risk assessment, evacuation plans, and details of emergency breathing equipment which shall be made available to the rig crew prior to entering the suspected zone of H_2S.

3.7.5 The Barytes stock level on location, or kill mud in reserve, shall always be sufficient to raise the active mud weight (hole and active pits volume) by 1 ppg.

3.7.6 Standing orders shall be posted requiring the driller and mud loggers to advise the HHDL Drilling Supervisor when pre-agreed hole fill discrepancies and gas levels or abnormal cuttings or any other abnormal hole condition is observed.

3.7.7 A hole fill record / trip sheet shall be completed for each trip out and in the hole.

3.7.8 Swab and surge calculations shall be done for all tripping after the BOPs have been installed on the well.

3.7.9 Whenever the BOP is installed, the HHDL Site Supervisor and drilling contractor Tool Pusher shall be on the rig floor for the first 10 stands when pulling out or until hole fill-up is confirmed correct.

3.7.10 The drill string shall not be tripped out if the well is not static, unless losses are low enough to be controlled with the available mud on location. Tripping out of the hole with losses requires the approval of the HHDL Drilling Manager.

3.7.11 Drilling shall stop whenever problems are experienced with any of the BOP components or the BOP control system and drilling shall not resume until the problem has been rectified, unless an MOC has been raised and approved.

3.7.12 Kick tolerance shall be calculated once the BOP stack has been installed. Drilling operations with a kick tolerance of less than the design approved in the drilling programme shall require an approved MOC.

3.7.13 The hard shut-in procedure (closing of the annular BOP before opening the choke) shall be used on all well kicks after the surface casing is set.

3.7.14 The recommended method of circulating an influx out of the well is the Drillers Method.

3.7.15 The well shall be shut in on a ram preventer if the surface pressure exceeds 1,500 psi.

3.7.16 Slow circulating rates (SCRs) shall be taken every tour whilst drilling or after BHA or mud weight changes. SCRs shall be taken at 20, 30 and 40 spm. Well kills shall be performed at a rate for which the SCR has been recorded unless an MOC is raised.

3.7.17 Kick drills and trip drills shall be conducted every tour or trip until the HHDL Site Supervisor is satisfied with the response, and weekly thereafter.

3.7.18 Flow checks shall be conducted after a material drilling break (greater than 20%

increase / decrease), after penetrating the reservoir objective, prior to tripping, prior to pulling the BHA through the BOP stack, after pumping out and any other time when anomalous pit volume readings are observed. The flow check duration shall be a minimum of 10 minutes with the well lined up on the trip tank.

3.7.19 A BOP space-out and tool joint space-out diagram shall always be posted on the rig floor and verified by the HHDL Site Supervisor. The length of the tool joint internal upset shall be considered in the space-out calculation.

3.7.20 The drill string shall not be reciprocated through the BOP stack during well kill operations unless approved by the HHDL Drilling Manager.

3.7.21 Pre-recorded data for well kick calculations, including MASP, shall be updated every tour and kept on the rig floor and in the contractor and company offices.

3.7.22 Choke manifold valve line up shall be checked every tour and confirmed by the HHDL Site Supervisor.

3.7.23 Wireline retrievable survey tools shall not be dropped into the drill string unless the well is static.

3.8 Completion and Well Intervention Operations

Pressure testing criteria in section 3.6 applies to completion and well intervention operations.

3.8.1 All completed wells shall have a minimum of two independent tested mechanical barriers installed

3.8.2 Acceptable production tree valve leakage criteria shall be as provided for in API Standards. Where tree valves fail to close or do not meet the leakage acceptance criteria, they shall be repaired or replaced.

3.8.3 Where production tree valves require repair or removal, a minimum of two tested mechanical barriers shall be placed upstream of the valve being repaired. The valve being repaired shall also be isolated from downstream pressure by a double block and bleed system.

3.8.4 The production tree lower master valve (LMV) shall not be used as a working valve.

3.8.5 The production tree valves shall not be used to throttle flow or to control well fluid flowrate.

3.8.6 When pressure testing tree valves or requiring to open any valves with a pressure differential across the valves, the pressure shall be balanced across the valve, where possible, before opening the valve.

3.8.7 All wells which can flow naturally to surface shall be completed with a down hole packer, capable of withstanding full reservoir pressure, irrespective of the annulus fluid used in the well.

3.8.8 On live well interventions, a risk assessment must be conducted for all penetrations of the well pressure envelope.

3.8.9 The Well Handover Form **(Appendix 2)** shall be completed on transfer of the control of the well.

3.8.10 Prior to rigging up pressure control equipment required to conduct a well intervention (wireline BOPs, lubricator, coiled tubing injector head, etc.), all production tree valves shall be pressure tested, to ensure that they are leak tight.

3.8.11 Operations shall stop, and the well shall be made safe, whenever problems are experienced which may affect the integrity of the pressure control equipment. Operations shall not resume until the problem has been rectified.

3.8.12 Production annuli, completion tubing, and production tree pressure test acceptance criteria shall be 15 minutes straight line and recorded on a chart or electronic data logger.

3.8.13 The HHDL Site Supervisor shall confirm critical depths and compliance with the completion programme (production packer, SCSSSV, wireline nipple setting depths, etc.).

3.8.14 Work instructions for the main contractor's supervisory personnel shall be prepared daily by the HHDL Site Supervisor.

3.8.15 A well handover form **(Appendix 2)** shall be produced when a well is initially completed and should contain the following information:

- Fluid properties (density, type, etc.) for each annulus and for the tubing
- A table of pressure tests performed, and acceptance criteria used
- The position of all surface and down hole valves, sleeves, and circulating devices
- An as-built well diagram complete with position and dimensions of any debris/junk remaining in the well
- Tubing and annulus pressures and maximum operating limits
- Details of all temporary barriers and plugs installed in the well

3.9 Wireline (slickline and electric line) and Coiled Tubing Pressure Control Equipment

3.9.1 Temporary pressure control equipment used in well testing, completion and well intervention operations, such as slickline, electric line or coiled tubing BOPs, shall have a unique identification number and be provided with details of its service rating and intended operating envelope. All such equipment shall be accompanied by current certificates evidencing its maintenance record, pressure testing verification and inspection record.

3.9.2 All wireline work carried out on a live well (i.e. with hydrocarbons to surface) shall be conducted with pressure control equipment installed to maintain a double barrier and allow pack-off on the wire, shut in and removal of the wireline tools, circulation of the drill or tubing string and cutting of the wire.

3.9.3 Wireline BOPs shall have a minimum of two sets of rams which shall not be considered as an 'additional valve' and used for testing against, whether for the purposes of pressure testing the well or lubricator, or for routinely shutting in a well during operations.

3.9.4 BOPs shall have flanged bottom connections. BOPs with threaded top and bottom connections made up into drilled and tapped flanges, and similar back-welded connections, shall not be used.

3.9.5 Lubricator assemblies (including the lubricator, stuffing box and other connections above the BOPs) shall be constructed using full penetration welded components.

3.9.6 Lubricator assemblies must be pressure tested to the maximum anticipated surface pressure plus a 10% safety factor.

3.9.7 The lubricator shall be isolated by two barriers (closed valves) whenever the lubricator connections are broken.

3.9.8 The BOP operating system shall always be remote from the well and operable when well intervention operations are being conducted. The system shall be hydraulically operated and ideally situated close to the wireline or coiled tubing unit. A manual back-up system is also required.

3.9.9 An accumulator draw down test will be performed on the BOP operating system when the BOPs are first installed on the well.

3.9.10 Wireline and coiled tubing BOPs shall be manufactured from forgings, have a flanged bottom connection and a minimum of two sets of rams, and shall not be considered as additional valves for the purpose of well isolation.

3.9.11 A device with the capability to cut wire or coiled tubing and subsequently seal off the wellbore shall be installed directly onto the production tree, with flanged connectors below the wireline lubricator or coiled tubing injector.

3.9.12 Connections that rely on O-rings to provide pressure integrity must not be used between the swab valve (or tubing hanger) and the intervention BOPs during coiled tubing operations.

3.9.13 Wireline and coiled tubing BOPs shall be fully rated to the maximum anticipated wellhead pressure plus a safety factor of 10% and shall be hydraulically operated (with manual backup) with the operating controls remote from the well.

3.9.14 During wireline and coiled tubing activities, there shall be at least two BOP rams positioned above the kill inlet.

3.9.15 The kill inlet shall be fitted with a minimum of two fully rated flanged or integral full-bore isolation valves.

3.10 Sub-Surface Safety Valves

3.10.1 Surface controlled sub-surface safety valves (SCSSSVs) must be fitted on all gas wells that can naturally flow to surface.

3.10.2 All SCSSSVs shall have pump-through capability.

3.10.3 The depth at which a SCSSSV shall be installed at, is deeper than, the shallowest competent formation and no shallower than 30 m below ground level.

3.11 Wireline Operations

3.11.1 For operations where no drilling or work over rig is used, hazardous areas shall be designated.

3.11.2 All internal combustion engines, their exhausts, air-intakes, fuel lines, electrical equipment and controls shall be positioned a minimum of 10 (ten) metres distant from the well centre, i.e. in a non-hazardous designated area.

3.12 Perforating Operations

3.12.1 Operations involving perforating guns at the surface shall not be conducted during electrical storms.

3.12.2 All perforating shall be conducted using radio safe perforating systems.

3.13 Well Suspension

3.13.1 Well suspension requires two temporary pressure tested barriers to be installed.

3.14 Well Abandonment

3.14.1 The latest revision of the Oil & Gas UK, Well Decommissioning Guidelines shall be used for all abandonment operations.

3.14.2 The wellhead and casing strings shall be cut off a minimum of 2m below the restored site level. A non-pressure retaining cap will be installed on the remaining casing strings with the well name and OGA assigned well number welded on the cap.

3.15 Well Incident Reporting

3.15.1 The Site Supervisor will complete a well incident report immediately following a well incident. This will be transmitted to the HHDL Drilling or Production Manager, HSE Manager, Operations Director and Chief Executive Officer.

3.15.2 The HSE Manager will ensure that RIDDOR reportable incidents are reported to the HSE.

3.15.3 A well incident is defined as follows:

- An uncontrolled flow of fluids from the well
- The failure of the well control equipment (Divertor / Blow Out Preventor) to control a flow from the well
- The detection of Hydrogen Sulphide in the course of operations, or in a sample of well fluid where the presence was not anticipated before detection
- The mechanical failure of a safety critical element in a well

4.0 WELL TESTING AND WELL INTERVENTION OPERATIONS

4.1 Well Testing Operations

4.1.1 Well test objectives shall be clearly defined in a written BOWD.

4.1.2 The Management of Change form **(Appendix 1)** shall be used to document any material change to the approved procedure or test objectives. A material change is a change which effects a barrier in the well or increase operational costs by 1% or more.

4.1.3 Shut-in procedures addressing all intended operations shall be posted on the rig floor or at the well site if no rig is on location.

4.1.4 Piping and instrumentation diagrams (P&IDs), process flow diagrams (PFDs), equipment diagrams, specifications, and certification shall be prepared for all equipment to be used in the well test.

4.1.5 A HAZOP involving relevant service contractor, rig contractor and HHDL personnel shall be conducted whenever well tests are to be performed.

4.1.6 The HAZOP for well test equipment shall include all safety / environmentally critical equipment and all ancillary equipment containing hydrocarbon or well fluids interfaced into the well test package and representatives from each service contractor supplying equipment shall participate in the HAZOP.

4.1.7 Hydrate suppression capability shall be available for all intervention operations where hydrate formation is a possibility.

4.1.8 All surface pressure equipment, surface lines, well test spread etc. between the wellhead and the separator shall be pressure tested to the maximum anticipated wellhead pressure plus a 10% safety factor prior to use. The calculation of the maximum anticipated wellhead pressure shall consider anticipated kill and stimulation pressures. Downstream of the test separator, the equipment shall be pressure tested to the maximum separator operating pressure.

4.1.9 All pressure containing test equipment shall have valid third-party certification.

4.1.10 The flare stack shall be supplied from an independent air compressor.

4.1.11 Vents, drains, and other process outlets shall not be routed back to the rig mud system (if a rig is on location).

4.1.12 For gas or H_2S bearing wells, pressurised pipe connections of larger than ¾” diameter to high pressure systems shall be of welded or flanged construction. The only exception to this is the BOP control system piping.

4.1.13 For wells without gas or H_2S, a risk assessment shall be conducted to determine the type of pipe work connections that can be used.

4.1.14 Back welded threaded connections are not acceptable.

4.1.15 Natural gas shall not be connected to any compressed air system for any instrumentation.

4.1.16 The entire well test package, including ancillary equipment handling hydrocarbon or well fluids, shall be subjected to a design and certification validation by an independent competent third-party inspector.

4.1.17 A site emergency evacuation drill for all personnel shall be held as close as possible to the commencement of testing operations.

4.1.18 The well-stream shall be monitored for H_2S and other potentially hazardous components.

4.1.19 If H_2S has not been anticipated, and in excess of 10 ppm is detected, then the well test shall be suspended, and a risk assessment conducted prior to continuing operations.

4.1.20 For rig-based well testing, either the Driller or Tool Pusher shall be on the drill floor for the start of the test until steady state flow conditions are achieved.

4.1.21 A fire watch shall be posted throughout the test during flowing periods.

4.1.22 A fit for purpose well test emergency shut down (ESD) system based on the well testing requirements shall be provided and tested before any well testing operations commence. The ESD system must be capable of being operated from a remote location.

4.1.23 Lifting shall not be permitted over the well test area during flowing periods or while there is pressure in the lines unless subject to a Job Safety Analysis (JSA) and specifically approved by the HHDL Drilling or Production Manager.

4.1.24 Annulus operated test tools shall be continuously monitored by the down hole tool operator whenever they are in use.

4.1.25 Initial flow of hydrocarbons to surface shall be during daylight hours only.

4.1.26 Well kill procedures shall ensure the removal of all hydrocarbons from the well and that the well is flow-checked and static prior to pulling out of the hole.

4.1.27 If rig-based testing, the BOP and choke manifold shall be pressure tested immediately prior to the start of a well test.

4.1.28 Any lines that are likely to see formation fluids or gas shall be certified, at minimum, in accordance with **ANSI B31.3** and in accordance with **NACE MR0175** for sour service conditions.

4.1.29 All flowlines (gas, oil, and water), vent lines, and relief lines, shall be properly secured with appropriately fixed clamps, brackets, or tie-down cables.

4.1.30 Flow lines shall not run through rig work areas.

4.1.31 All high-pressure lines, including instrumentation lines, shall have double isolation. Specification changes between items of differing pressure rating shall have double valve isolation.

4.1.32 Double valve isolation shall be installed on the kill line to prevent flow-back to the kill/cement pump. One of these valves shall be a one-way check valve protecting the pump.

4.1.33 Pipework shall be thickness checked in areas at high risk of erosion prior to and during testing operations to confirm no metal erosion during such activities. If material erosion is evident, the test shall be stopped, and the pipework replaced.

4.1.34 All pressure relief valves shall be certified, tested and set at an agreed pressure to protect the component parts of the well test spread.

4.2 Well Kill Systems

4.2.1 In gas wells or where the maximum anticipated surface pressure is in excess of 1,000 psi, all kill line isolation valves shall be API or ANSI flanged (i.e. with metal ring-type joints or gaskets) or solid welded.

4.2.2 In oil wells or where the maximum anticipated surface pressure is less than 1,000 psi, Chicksan plug valves may be used as kill line isolation valves so long as they are suitably rated.

4.2.3 Flexible steel hoses (e.g. Chicksan lines, Coflexip hoses, etc.), which rely on a resilient seal for pressure integrity, may only be used between the kill pump side of the kill line isolation valves in gas wells or where the maximum anticipated surface pressure is less than 1,000 psi. In oil wells or where the maximum anticipated surface pressure is less than 1,000 psi, flexible steel hoses with a resilient seal may be used on the production side.

4.2.4 Where it is not possible to use the kill wing outlet on the production tree for a kill injection point, the kill inlet shall be positioned below the lower-most BOP ram.

4.2.5 Back-welded threaded connections shall not be used on any pipe work.

5.0 WELL PRODUCTION OPERATIONS

5.1 Well Production

5.1.1 The standards in this section apply to the following activities:

- Maintaining production well integrity including:
  - Well maintenance and pressure testing
  - Well monitoring
- Well Examination of production well operations

5.1.2 The Production Manager is responsible for planning and managing routine production well operations, including production well monitoring, maintenance and testing.

5.1.3 The Production Manager shall ensure sufficient competent personnel are allocated to carry out the tasks and a competent person is appointed to supervise the site when operations are taking place.

5.1.4 The HSE Manager is responsible for maintaining an up to date "Environmental Compliance Register" for the well sites.

5.1.5 The Production Manager is responsible for accepting a production well following workover completion. An accurate well status schematic shall be maintained for both the well and wellhead equipment with well barriers identified and barrier issues highlighted.

5.2 Routine Production Operations

5.2.1 Routine production well operations consist of:

- Monitoring well production and maintaining production records
- Monitoring well annuli pressures
- Routine wellhead and tree valve maintenance and testing
- SCSSSV testing
- Testing well safety systems including tubing and casing integrity
- Documenting activities pertaining to the wells
- Following company procedures on water well injection pressure limits

The tables in **Section 5.8** is a summary of the performance standards for well testing and maintenance operations for well equipment.

Production Operations - Summary of Responsibilities

- The Production Manager is responsible for assurance of compliance against these standards
- The Operations Director is responsible for technical assurance of operating procedures and policies associated with well maintenance and intervention activities

5.3 Well Annulus Monitoring and Well Integrity Standards

This standard applies to all wells.

5.3.1 On all production, injection, rod-pumped wells, the annular pressures on all annuli shall be monitored and recorded in accordance with the tables in **Section 5.8**.

5.3.2 Records of annulus pressures shall be maintained and kept for the life of the well**.**

5.3.3 The Production Manager will always issue written instructions to operations personnel that define the maximum allowable surface pressure (**MASP**) for each annulus.

5.3.4 Annulus pressures will be maintained below MASP.

5.3.5 Where an annulus pressure is approaching the MASP, pressure may be bled off following a risk assessment of the consequences.

5.3.6 If, following an annulus bleed off operation, the pressure rises again the Operations Director shall be informed and a programme for further investigation formulated.

5.3.7 Pressure bleed down operations shall be carried out in accordance with a written procedure to ensure that there can be no risk of an uncontrolled release of fluids.

5.3.8 A tubing to production casing annulus leak shall be investigated, via a programme of diagnostic tests. If there is no other effective downhole barrier to flow (e.g. the leak point is below the SCSSSV), then the Production Manager shall take the appropriate action, based on a risk assessment.

5.3.9 For jet pumped and gas lift wells, the tubing by production casing annulus pressure will mask a tubing leak. In addition, the tubing to production casing annulus pressure presents an additional risk to pressure build up in the production casing to surface / intermediate casing annulus and potentially to a flow of well fluids into the formation behind the production casing. These wells will not normally flow naturally and the risk of an uncontrolled flow due to a surface barrier being lost is low. However, the Production Manager shall ensure that the production casing to surface / intermediate casing annulus is regularly monitored and does not exceed the MASP for that annulus.

5.4 Maintenance and Testing Standards for Tree and Sub-Surface Safety Valves

5.4.1 The majority of HHDL wells are produced via artificial lift and cannot flow hydrocarbons to surface. However, where a well can flow to surface, the wellhead design shall be suitable to allow the well to be left in service with no less than two tested and operational production tree valves in the flow path. On a dedicated gas producing well, one of these must be an actuated valve. Water injection wells are to be risk assessed to determine whether they can flow to surface when injection is stopped.

5.4.2 Any well unable to maintain this level of barriers shall be subjected to a risk assessment and formal dispensation by HHDL to justify continued operation of the well.

5.4.3 The frequency for maintaining and testing production tree valves, including SCSSSVs, will be as per the summary tables in **Section 5.8.** The maximum allowable leak rates are 900 SCF per hour for gas and 400 cc per minute liquid as per **API S6AV2.**

5.4.4 Rod pumped well valves will be inspected and maintained in accordance with the applicable section of this document and records maintained by the Production Manager.

5.4.5 Jet pumped well valves will be inspected and maintained in accordance with the applicable section of this document and records maintained by the Production Manager.

5.4.6 Water injection well valves will be inspected and maintained in accordance with the applicable section of this document and records maintained by the Production Manager.

5.4.7 Downhole safety valves will be tested as per the summary tables in this document**.** The maximum acceptable leak rate for downhole safety valves is 900 SCF per hour for gas and 400 cc per minute for liquid. The valve will conform to **API Spec 14A and RP 14B.**

5.5 Routine Wellhead Equipment Inspection and Maintenance

5.5.1 Wellhead pressure-containing equipment is classified as safety critical and should be maintained in accordance with the planned maintenance system.

5.5.2 The Production Manager shall ensure that all wellhead equipment is inspected and maintained in accordance with the planned maintenance system.

5.5.3 The Production Manager is responsible for maintaining up to date operating instructions for wellhead maintenance and testing.

5.5.4 The Production Manager is responsible for maintaining up to date records of maintenance and pressure testing of safety critical wellhead equipment.

5.6 Casing Integrity Policy

5.6.1 Production casing is classified as safety critical. The production casings shall be inspected and / or tested in accordance with this policy.

5.6.2 The Production Manager is responsible for maintaining up to date operating instructions for casing inspection and testing. All tests are to be recorded and records kept for the life of the well.

5.6.3 Well integrity requires two barriers between formation and atmosphere on wells which can flow to surface. The production casing is the second barrier where the tubing is the primary barrier when a production packer is installed. On a pumped well, the production casing is often the only barrier.

5.6.4 Each well shall be assessed to determine if a casing inspection is required utilising wireline tools, or whether a pressure test is acceptable. Historical records should be used as input to the assessment process.

5.6.5 Casing integrity shall be assessed at least once every five years, or more often if indicated by well history and records. Whenever the risk assessment indicates a high risk of an issue with the casing integrity, further investigation shall be evaluated.

5.6.6 Casing condition may be evaluated with wireline logs but shall always be verified with a pressure test. That test shall normally be to the maximum expected surface pressure plus a 500 psi bull-heading safety factor. Future maximum surface pressures (e.g. for water injector wells) shall be estimated and the test pressure based on this. The test pressure value may ultimately be dictated by the lowest component rating, such as the wellhead flange. Consideration shall always be given to the age and estimated wear on the casing, and the pressure test shall consider this.

5.6.7 Where casing leaks or unacceptable casing wear on any well is detected, the wells are to be repaired, suspended or abandoned.

5.6.8 As a casing repair is a material change to the well, the work shall be subject to HSE notification and IWE review.

5.7 Water Injection Pressure Management

5.7.1 Maximum water injection operating pressures are set by the Production Manager for each well, with levels set to prevent any formation breakdown or well integrity issues. The pressure operating envelope of the well is monitored to ensure that injection pressures do not exceed this limit.

5.7.2 The Production Manager is responsible for review of the injection pressures and the barrier integrity of the well.

5.8 Summary of Well Maintenance and Testing Requirements

For all tests and maintenance, records shall be kept detailing the examinations and tests which were carried out and the findings of this verification work. These records are to be kept for the life of the well.

Table 5 Shut in / Suspended Wells

Equipment	Test or Inspection	Frequency	Responsible Person
Manual Master, Kill, Wing and Swab Valves	Visual inspection Grease Perform inflow/leakage tests	Annually	Site Operator
	Pressure test*	Every two years	
Actuated Tree and Production Wing Valves	Operate and perform opening and closing timing checks and inflow/leakage test Inspect operating system	Annually	Site Operator
	Function test ESD system and test automatic closure	6 monthly	Site Operator
	Pressure test*	Every two years	
Wellhead Annulus Valves	Visual inspection Grease Perform inflow/leakage tests	Annually	Site Operator
	Pressure test*	Every two years	
A and B Annulus	Check and record A and B annulus pressures. Ensure pressures do not exceed MASPs Inspect for leakage	6 monthly	Site Operator
Tubing	Check and record tubing pressure	6 monthly	Site Operator
Sub Surface Safety Valves	Operate, perform opening and closing timing checks Inflow/leakage test Inspect operating system	6 monthly	Site Operator
	Function test ESD system and test automatic closure		
Production Casing	Risk assessed for integrity	Every 5 years	Production Manager
	Wireline inspection or pressure test*	As required by risk assessment	

***Pressure test value is maximum anticipated surface pressure plus 500 psi bull-heading safety margin**

Table 6 Production Wells

Equipment	Test or Inspection	Frequency	Responsible Person
Manual Master, Kill, Wing and Swab Valves	Visual inspection Grease Perform inflow/leakage tests	6 monthly	Site Operator
	Pressure test*	Annually	
Actuated Tree and Production Wing Valves	Operate and perform opening and closing timing checks and inflow/leakage test Inspect operating system	6 monthly	Site Operator
	Function test ESD system and test automatic closure	6 monthly	Site Operator
	Pressure test*	Annually	Site Operator
Wellhead Annulus Valves	Visual inspection Grease Perform inflow/leakage tests	6 monthly	Site Operator
	Pressure test*	Annually	
A and B Annulus	Check and record A and B annulus pressures. Ensure pressures do not exceed MASPs Inspect for leakage	Monthly	Site Operator
Stuffing Box	Visual inspection Functional inspection	Weekly	Site Operator
Sub Surface Safety Valves	Operate, perform opening and closing timing checks Inflow/leakage test Inspect operating system	6 monthly	Site Operator
	Function test ESD system and test automatic closure		
Production Casing	Risk assessed for integrity	Every 5 years	Production Manager
	Wireline inspection or pressure test*	As required by risk assessment	
Tubing Hanger Body and Neck Seals and Tubing Head Adaptor Ring Joint Void	Sting void and check for pressure Pressure test*	Annually	Site Operator
Production Casing Hanger, Casing Seal Assemblies and Ring Joint Void	Sting void and check for pressure Pressure test*	Annually	Site Operator

***Pressure test value is maximum anticipated surface pressure plus 500 psi bull-heading safety margin**

Table 7 Water Injection Wells

Equipment	Test or Inspection	Frequency	Responsible Person
Manual Master, Kill, Wing and Swab Valves	Visual inspection Grease Perform inflow/leakage tests	6 monthly	Site Operator
	Pressure test*	Annually	Site Operator
Actuated Tree and Production Wing Valves	Operate and perform opening and closing timing checks and inflow/leakage test Inspect operating system	6 monthly	Site Operator
	Function test ESD system and test automatic closure	6 monthly	Site Operator
	Pressure test*	Annually	Site Operator
Wellhead Annulus Valves	Visual inspection Grease Perform inflow/leakage tests	6 monthly	Site Operator
	Pressure test*	Annually	
A and B Annulus	Check and record A and B annulus pressures. Ensure pressures do not exceed MASPs Inspect for leakage	Daily	Site Operator
Sub Surface Safety Valves	Operate, perform opening and closing timing checks Inflow/leakage test Inspect operating system	6 monthly	Site Operator
	Function test ESD system and test automatic closure		
Production Casing	Risk assessed for integrity	Every 5 years	Production Manager
	Wireline inspection or pressure test*	As required by risk assessment	
Tubing Hanger Body and Neck Seals and Tubing Head Adaptor Ring Joint Void	Sting void and check for pressure Pressure test*	6 monthly	Site Operator
Production Casing Hanger, Casing Seal Assemblies and Ring Joint Void	Sting void and check for pressure Pressure test*	6 monthly	Site Operator

***Pressure test value is maximum anticipated surface pressure plus 500 psi bull-heading safety margin**

5.9 Wellhead and Production Tree Intervention Procedures

5.9.1 This standard applies to all operations involving the physical intervention into pressure-containing elements of surface wellhead and production tree equipment. Typical operations within the scope of this standard are:

- Testing voids and seal assemblies
- Installation/removal of side outlet valves and VR plugs
- Installation/removal of backpressure valves in tubing hangers
- Valve maintenance
- Installation/removal of instrumentation
- Removal of tie-down bolts

5.9.2 In all cases, work will be undertaken and supervised by a competent person nominated by the Production Manager in accordance with a written procedure. Where appropriate, this procedure shall refer to the wellhead/production tree manufacturer's procedures.

5.9.3 If the operations are carried out in connection with a well re-entry to carry out workover or drilling operations under the management of the HHDL Drilling Manager**,** they are responsible for ensuring that the correct procedure is issued and adhered to.

5.9.4 Prior to commencement of wellhead work, a pre-job safety meeting shall be held at the work site. Specific reference will be made to:

- Which ports will be used for access to voids or cavities
- Which internal fittings are present within the ports
- Which other parts of the system are in communication
- All the potential sources of pressure
- Suitability and condition of pressure-relieving devices such as stinger tools
- Known integrity issues on the wellhead

5.9.5 If the work involves equipment that is hidden from view, a cross-sectional drawing of the relevant components shall be made available at the work site.

5.9.6 Prior to stabbing or opening any void, potential pressure sources shall be isolated and/or disconnected. Such sources of pressure may include:

- Well bore and annular pressure
- Downhole safety valve control lines pressure
- Test pumps
- Residual pressure in production flow line
- Thermal expansion of trapped fluids
- Gas lift, chemical injection systems or jet pump well pressure

5.9.7 Where equipment provides for dual access to internal voids, the internal pressure within the void shall be monitored from a port other than one through which pressure is applied. When checking for trapped pressure in wellhead voids, the void shall be flushed through from one port to the other to establish communication across the void space.

5.9.8 Where only a single access is available there is the potential for spurious pressure indications if the port is blocked. This should be highlighted at the pre-job safety meeting. Procedures should be in place to minimise the risks, such as:

- Monitoring of bleed fluid volumes to confirm correct relationship to the size of the void
- Extra precautions when releasing fittings in communication with the void

5.9.9 If venting operations release small volumes of oil, water or other fluids, these should be contained. If gas is anticipated, then suitable precautions should be made for monitoring wind direction and control of ignition sources.

5.9.10 When backing out tie-down bolts or other items in communication with voids, personnel should take up a safe position away from the direct line of the fitting. A specific procedure for each type of wellhead shall be followed.

5.9.11 Circumstances may arise in which it is not possible to confirm the absence of trapped pressure behind a fitting prior to its removal. The Production Manager shall ensure that they are informed of such a situation and that work does not proceed until a safe operations plan has been agreed and documented.

5.10 Pressure Testing Standards for Surface Equipment

5.10.1 A pressure test programme shall be documented and include the test pressure value and duration. Pressure testing shall be performed by increasing the pressure in a series of appropriate pressure increments. The volume of test fluid pumped shall be monitored and recorded.

5.10.2 All pressure tests shall include a low-pressure test of 200 to 300 psi for 5 minutes before proceeding to the full test pressure for 10 or 15 minutes. All tests shall be recorded on a chart or electronic data logger.

5.10.3 Only essential operations personnel shall be in the vicinity of equipment that is under test.

5.10.4 In the event of a leak on the system during pressure testing, the pressure shall be bled off prior to accessing the system under test. It is not acceptable to tighten a fitting under test.

5.10.5 See **Section 3.6** for pressure test acceptance criteria.

5.11 Retrieval and Running Jet Pumps

5.11.1 Jet pumps are retrieved and run routinely by staff managed by the Production Manager. The high pressures involved with these wells require staff to follow a standard procedure to catch the pump and bleed down pressure before pump removal.

5.11.2 The length of the pump shall not exceed the length of the catcher and the master valve shall not be used to hold the pump in position.

5.11.3 Jet pump catching lubricators shall be subject to the same inspection testing and certification standards as wireline lubricators.

6.0 APPENDICES

APPENDIX 1 Management of Change (MOC) Form

<table>
<tr><th colspan="4">HORSE HILL DEVELOPMENTS MANAGEMENT OF CHANGE FORM

TO BE USED FOR:
EXEMPTIONS TO WELL PLANNING, DESIGN AND OPERATIONS STANDARDS
CHANGES TO DRILLING / WELL TESTING / COMPLETIONS PROGRAMMES</th></tr>
<tr><td colspan="4"></td></tr>
<tr><td>STANDARD OR WELL</td><td colspan="3"></td></tr>
<tr><td>ORIGINATOR</td><td></td><td>DATE</td><td></td></tr>
<tr><td colspan="4"></td></tr>
<tr><th colspan="4">EXEMPTION OR CHANGE REQUIRED</th></tr>
<tr><td colspan="4"></td></tr>
<tr><th colspan="4">EXPLANATION FOR EXEMPTION OR CHANGE</th></tr>
<tr><td colspan="4"></td></tr>
<tr><th colspan="4">SUMMARY OF RISKS / MITIGATIONS</th></tr>
<tr><td colspan="4"></td></tr>
<tr><th colspan="4">JUSTIFICATION FOR EXEMPTION / CHANGE</th></tr>
<tr><td colspan="4"></td></tr>
<tr><th colspan="4">THIS REQUEST IS SUPPORTED BY THE FOLLOWING ATTACHMENTS (Risk assessments, etc)</th></tr>
<tr><td colspan="4"></td></tr>
<tr><th>DATE</th><th>REVISION</th><th>REQUEST MADE BY</th><th>REQUEST APPROVED BY</th></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
</table>

APPENDIX 2 Well Handover Form

HORSE HILL DEVELOPMENTS WELL HANDOVER FORM					
WELL					
WELL TO BE HANDED OVER FROM:			**WELL TO BE HANDED OVER TO:**		
ITEM	**STATUS**	**PRESSURE**	**UNITS**	**NUMBER OF TURNS TO FUNCTION**	**COMMENTS**
Tree Cap			psi		
Swab Valve			psi		
Upper Master Valve			psi		
Lower Master Valve			psi		
Tubing Hanger Back Pressure Valve	Installed?	Tested to?	psi		
Production Wing Valve			psi		
Kill Wing Valve			psi		
SCSSSV		Pressure required to open	psi	Volume operating fluid required to open	
Tubing / Casing Plugs	Installed?	Tested to?	psi		
Well Fluid			ppg		
Last Closed in Tubing Head Pressure					
'A' Annulus Pressure				MAASP	
'B' Annulus Pressure				MAASP	
'C' Annulus Pressure				MAASP	
Last Flow Rate					
Well Schematic Attached with Barriers Defined					
Known Barrier Issues					
Known Well Issues					
Well Examination Documentation Attached					

DATE		**PREPARED BY**	**WELL ACCEPTED BY**

APPENDIX 3 BOWD Contents

Basis of Well Design

Well:

CONTENTS

APPENDIX 4 Reference Documents

	DOCUMENT
Oil & Gas UK	Well Decommissioning guidelines – Issue 6 June 2018
Oil & Gas UK	Well Life Cycle Integrity Guideline – Issue 4 March 2019
HSE	A guide to the Well aspects of the Offshore Installations and Wells (Design and Construction) Regulations 1996 (DCR)Regulation 18.
API 5L	Line Pipe
API Spec 5CT	Casing and Tubing
API Spec 6A / ISO Standards 10423	Specification for Wellhead and Tree Equipment
API S6 AV2	Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore
API RP 7G	Recommended Practice for Drill Stem Design and Operating Limits
API Spec 10A	Specification for Cements and Materials for Well Cementing
API RP 10B-2	Recommended Practice for Testing Well Cements
API Spec 14A	Specification for Subsurface Safety Valve Equipment
API RP 14B	Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems
API Spec 16D	Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment
API S53	API Standards Blowout Prevention Equipment Systems for Drilling Wells
API RP 500	Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2

APPENDIX 5 Terms and Definitions

TERM	DEFINITION
ALARP	As Low as Reasonably Practicable. This is a well-established methodology in the oil and gas industry to demonstrate that all risks associated with an operation are reduced to an acceptable level. The methodology includes taking safety, community, practical and financial implications into account before work can proceed
ANSI	American National Standards Institute
API	American Petroleum Institute
API RP	American Petroleum Institute Recommended Practice
Barrier	Any equipment, assembly or obstacle intentionally placed in a well that can be used to contain pressure and prevent flow
BBL	Barrel
BHA	Bottom Hole Assembly
BHCT	Bottom Hole Circulating Temperature
BHST	Bottom Hole Static Temperature
BOP	Blow-out Preventer
BOWD	Basis of Well Design
DF	Design Factor
DRILCO	Drill collar manufacturer's trade name
ESD	Emergency Shutdown Device. Equipment installed to automatically shut in and make safe a live well in the event of problems being encountered during well testing or production operations
FIT	Formation Integrity Test
FOSV	Full Opening Safety Valve
FSR	Fundamental Safety Rule
GOR	Gas Oil Ratio
H_2S	Hydrogen Sulphide
HAZOP	Hazard and Operability Study
HWDP	Heavy Weight Drill Pipe
HSEC	Health, Safety, Environment and Community
IADC	International Association of Drilling Contractors
IWCF	International Well Control Forum
JSA	Job Safety Analysis
LMV	Lower Master Valve
LOT	Leak Off Test
MASP	Maximum Allowable Surface Pressure
MWD	Measurement While Drilling
NACE	National Association of Corrosion Engineers
P&ID	Piping and Instrumentation Diagram
PBR	Polished Bore Receptacle

PFD	Process Flow Diagram
PPE	Personal protective Equipment
PPG	Pounds Per Gallon
PPM	Parts Per Million
PSI	Pounds Per Square Inch
PSI/FT	Pounds Per Square Inch / Foot
RT	Rotary Table
RTTS	Retrievable Test Treat Stimulation packer
SCR	Slow Circulating Rate
SCSSSV	Surface Controlled Sub-Surface Safety Valve
SITHP	Shut in Tubing Head Pressure
SOP	Standard Operating Procedure
TD	Total Depth
UBD	Underbalanced Drilling
UMV	Upper Master Valve
UPS	Uninterrupted Power Supply
VR	Valve Removal
WellCAP	IADC Well control programme
WOC	Wait on Cement