2.2 QUICKLOOK DRILLING OPERATIONS GUIDE

Summary	DOM Chapter	Forms
Preparing Site and Rig -Up		
Ensure all Regulatory and GSLM approvals have been given		
Ensure new location has been inspected and accepted by Drilling Contractor		
Toolpusher should notify local authorities of rig move timing		
Ensure wellsite and camp locations are prepared before the rig arrives.		
Ensure the turkeys nest is filled and water source recorded		
Check rig move distance. Report on morning report.		
Ensure the sump is prepared and lined if required.		
Ensure the rubbish and sewarge handling systems are in place.		
Ensure a plastic sheet is positioned between the rig tanks and sump to prevent washing out of the tank base.		
Check condition of roads. Notify DM of any problems. Check for power lines etc.		
Make up pre-spud equipment list including mud chemicals, bits, surface casing, cementing equipment and Bradenhead.		
Pre-spud Checks		
On first well of the program ensure 3rd party rig inspection is carried out and an action plan prepared for all critical items.		
Ensure rig is completely rigged up and work through Pre-spud Checklist.	3	
Ensure the conductor is set in the cellar correctly.		
Ensure all materials and equipment and back-ups are on site for drilling, casing and cementing the surface hole.	3, 5	
Check that the equipment delivered is what was ordered.		
Ensure adequate supplies of weighting material and LCM are available.	5	
Ensure a water sample is sent to the cementing company for analysis.	8	
Ensure downhole drilling tools (i.e. stabilisers, jars, bits, etc.) are in good condition and within wear limits and hours of usage.	3	
Check grade and specification of casing.	7	
Check Bradenhead matches casing and Drilling Program requirement.	11, 14	
Make up as much new mud as possible prior to spud. If water quality poor consider using fresh to pre-hydrate gel.		
Perform Pre-spud Safety Meeting		
Constructing Cellar		
Ensure the cellar has been dug and the cellar ring installed prior to rig move.		
Setting Conductor (This may be predrilled before rig arrives)		
Auger surface hole to 5-8 m below cellar floor. Set in firm clay.	7	
Ensure the conductor is vertical, the flange level and 'plumb bobbed' central.		
Ensure the conductor is cemented in place. Use 1% CaCl2 as accelerator	8	
Drilling Surface Hole (This may be predrilled before rig arrives)		
Ensure bit program, BHA design, survey requirements and mud properties are detailed in the Drilling Program.	3	
Drill-out of conductor with reduced flowrate until drill collars are below conductor to prevent washing out the cellar. Gradually increase flowrate so as to prevent mudrings.		
Drill to programmed casing depth and check the bottoms up sample for consolidated formation. Allow a maximum of 3 m of rathole below casing shoe.		
Wiper trip as required to maintain good hole condition.		
Survey at 30 m KB and every 150 m thereafter.		
Circulate hole clean (Minimum 1.5 times annular volume).	3	
Perform wiper trip at interval TD back to previous wiper trip depth	3	
Strap pipe whilst POOH.		
Grade bit.		
Order cement from cementing contractor. Provide cementing contractor with hole and casing details and ensure they confirm cement volumes.		
Running Surface Casing		
Number, measure and drift casing joints. Clean and inspect casing threads. DO NOT USE DIESEL TO CLEAN THREADS	7	
Space out casing so that Bradenhead flange depth suits rig.	7	
Prepare Casing Tally and adjust section TD to allow for 3m rathole below shoe	7	
Use 2 joint shoetrack. Threadlock shoetrack and centralise as per Drilling Program.	7	
Check circulating swedge to ensure it is the correct size and has the correct threads.		
Pick up casing using suitable thread protectors. Make up circulating swedge and wash last joint down. Do not tag bottom.	7	

Summary	DOM Chapter	Forms
Cementing Surface Casing		
Circulate hole and treat Drilling Fluid (if required) prior to cementing.	8	
Pump spacer.	8	
Load cement head with plugs (top and bottom).	8	
Ensure all lines are pressure tested.	8	
Discuss all cement calculations with DM, prior to cement job.	8	
Mix and pump slurries.	8	
Displace with mud using cementing pump.	8	
Do not over displace more than theoretical, plus half shoetrack volume.	8	
If plug bumps, pressure test casing to 80% of rated burst pressure, bleed-off pressure and measure backflow. Check floats holding	8	
If plug does not bump. Bleed-off pressure and measure backflow. Pressure test casing prior to drilling out. Check floats holding.		
Run cement stinger and perform top up cement job with cement unit.	8	
Installing Bradenhead.		
Wait on Cement until surface samples set.		
Slack-off casing		
Back-out landing joint.		
Prior to job check specifications and part numbers of Bradenhead.		
Install Bradenhead as per manufacturer's procedure.	14	
Install BOPs and pressure test BOPs and kill/choke lines (test pressures according to the Drilling Program). If possible test BOP's (on test stump) and choke manifold while drilling surface hole.	10	
Run wear bushing.		
Drilling Intermediate/ Main Hole		
Ensure all equipment is on site to drill entire hole section.	3	
Ensure bit program, BHA design, survey requirements and mud properties are detailed in the Drilling Program.	3	
Drill-out shoe track with mud. Drill maximum of 3 m of new hole		
Circulate hole until mud weight even. Perform LOT	9	
Drill ahead. Make wiper trips approximately every 24hrs if required by hole condition.		
Change bits as required.		
Run wireline surveys every 150 m. Circulate hole prior to each survey. If deviation increases above 3° consider running surveys every 45 m.		
Trip sheets to be filled out on each trip out of the hole. If potential reservoir has been penetrated then trip sheets should also be used on all trips in the hole as well.		
Flow check any significant drilling breaks or unexplained changes in pit volume.		
Control drill as requested by Wellsite Geologist to aid evaluation.		
Adjust mud properties as required to maintain good hole conditions.		
Monitor hours on jar and BHA condition.	3	
Grade bit and gauge stabilisers at each bit trip.		
At section TD, circulate and survey prior to POOH.	6	
Strap pipe whilst POOH		
Perform wiper trip at interval TD back to start of last bit run	3	
Logging Open Hole		
Mobilise logging crew prior to POOH. Confirm logging program with Electric Logging company prior to job.	9	
Make sure fishing equipment available for ALL logging tools.	9	
Measure and record size and lengths of all logging tools.	9	
Monitor well on trip tank while logging. Record losses and gains.	9	
Open Hole DST		
Mobilise testing and separator crews if required.	9	
Confirm test program (times, intervals, water cushion etc.) with DE, tester and wellsite geologist prior to test. Make up running list.	9	
Rig up testing manifold, surface lines and separator (if required) and pressure test. Secure/tie down all lines.	9	
RIH with test string. Correlate with CCL/GR if required	9	
DST tools can not be opened during the hours of darkness unless special dispensation is obtained from MRT and a risk assessment done.		
Set/Inflate packers.	9	

Summary	DOM Chapter	
Top-up annulus prior to opening tools.	9	
Open tools and perform test according to the relevant procedure (annulus to be continuously monitored whilst testing).	9	
Prior to POOH, close test tools, release packers, (pull above any thick coals) reverse circulate string contents. Circulate conventionally. DST tools MUST NOT be pulled out of the hole unless string contents have been reverse circulated.		

Running Intermediate and Production Casing		
Change out pipe rams to suit casing.	7	
Number, measure and drift casing	7	
Clean and inspect casing threads	7	
Space-out casing. Refer to Drilling Program for position of marker joints and centralisers	7	
Complete Casing Tally.	7	
Threadlock shoetrack and centralise according to Drilling Program.	7	
Check float equipment.	7	
A two joint shoe track will be run on intermediate casing and a single joint shoe track on production casing.		
Pick up casing using suitable thread protectors.		
Circulating swedge to be available for all grades of casing run.		
Circulate down landing joint.	7	
Cementing Casing		
Discuss cement formulations and calculations with DE prior to cement job. Determine displacement fluid type and weight and make up if required.		
Circulate hole and treat mud (reduce YP) prior to cementing.	8	
Load cement head with plugs. Top and bottom or bottom plug and top ball.	8	
Ensure all lines are tied down and pressure tested.	8	
Pump pre-flush.	8	
Mix and pump slurries as per the cementing contractors cement program	8	
Displace with either rig pumps or cementing unit at pumping rate to give annular velocities approximately the same as when drilling.	8	
On intermediate casing displace with mud. On production casing displace with kill weight brine.		
All mud to be left in annulus or between casings must be treated with Biocide.		
Do not over displace by more than half the shoe track volume on intermediate casing		
Pump to bump on all production casing cement jobs.		
When plug bumps, pressure test casing to 500 psi above bump pressure. Bleed-off pressure and measure backflow. Pressure test casing.	8	
Installing Casing Slips and Tubing/ Casing Spool		
If using tubing spool land spool in bowl. If using casing slips WOC until surface samples set. Pick up BOPs.		
Install slip assembly, slack-off casing, cut casing and install spool according to manufacturers procedure	14	
Install blank flange or adaptor flange on production casing.	14	
Plugging and Abandonment		
All plugs to be minimum 50 m long (25 m above and 25 m below the top of the formation to be isolated.		
Where possible a cement stinger and mule shoe should be used.		
Confirm Cement Program and plug depths with DM. Obtain formation tops from WGL.	11	
Circulate hole prior to cementing. Ensure all lines are pressure tested.	8	
Mix and pump slurry. Displace with mud. Pick up above plug and reverse circulate cement from string.		
Pressure test last casing shoe plug.	11	
Remove Bradenhead and return to logistics base for re-dress.	11	
Dump surface cement plug.		
Install Marker Plate.		
Back-fill cellar.	11	
Cleaning-up Lease		
Ensure lease is cleaned up, rubbish disposed of and pits back-filled.	11	
Complete End of Well Equipment List.		
Complete lease clean up form.		
Ensure Mud reconciliation is filled out and signed.		
Forward all equipment to next location or logistics base.		

CHAPTER 3
GENERAL DRILLING PRACTICES

TABLE OF CONTENTS

3.1 OBJECTIVES

The objective is to produce a "fit for purpose" wellbore drilled in accordance with agreed specifications and the standard practices and procedures contained in this Manual.

The criteria for a "fit for purpose" wellbore includes the following, in order of importance:

1. Ensure GSLM's safety procedures are followed.
   These include accident – incident reporting, rig move policies etc.
2. Ensure the drilling rig and equipment is "Fit for Purpose" and remains in this condition for the duration of the well.
3. Drill the well with the risk to personnel, the environment and equipment reduced to as low as reasonably practicable. Ensure the wellbore design meets the requirements of the approved Environmental and Heritage objectives for the well.
4. Penetrate hydrocarbon bearing intervals without formation impairment.
5. Meet the planned trajectory without dogleg severity in excess of 1.5°/30 m (or as specified in the Drilling Program).
6. Provide hole conditions that allow good quality evaluation (logs, cuttings, cores, DST's etc.).
7. Attain the required bottom hole position.

It is the responsibility of the Drilling Contractor to drill the well to the correct specification. The quality of work must be monitored and controlled by the Rig Supervisor with support from the Drilling Manager to ensure that the well and Health, Safety, Wellfare and Environmental objectives are not compromised.

The following must be prevented:

1. Injuries to personnel or environmental damage.
2. Well control incidents that affect safety and integrity.
3. Impairment of the reservoir due to poor drilling fluid properties or excessive overbalance which affect logging and production.
4. Dog Legs due to poor trajectory control which may affect casing and completion running.
5. Washouts due to poor flow regimes which ultimately affect the logging operation and log quality.
6. Drilling practices that cause excessive formation damage.

3.2 RESPONSIBILITIES

Responsibilities for the implementation, supervision and verification of drilling operations are summarised in the table below.

Task	Performed by	Verified by
Report ALL incidents, near misses	Anybody	DSV / DM
Prepare the Drilling Program	DM	CEO
Select equipment	DM	DSV/CEO
Call-out Company supplied equipment	DSV	DM
Call-out Contractor supplied equipment	DSV	DM
Conduct drills	Drilling Contractor	DSV
Inspect tubulars	Drilling Contractor	DSV
Inspect and test BOP	Drilling Contractor	DSV
Monitor well trajectory	DSV	DM
Program and monitor drilling parameters	DSV / DM	DM
Monitor drilling costs versus plan	DM	CEO
Perform BHA design and bit selection	DSV / DM	DM
Measure and tally tubulars	Drilling Contractor / DSV	DSV
Operate rig equipment safely and properly	Drilling Contractor	DSV
Conduct primary well control when required	Drilling Contractor	DSV
Conduct secondary well control when required	Drilling Contractor	DSV
Decide when to conduct check trips	DSV	DM
Carry out flow checks	Drilling Contractor	DSV
Maintain Trip Sheets in and out of the hole	Drilling Contractor & Mud Loggers	DSV
Report drilling problems	Drilling Contractor	DSV
Maintain adequate drilling fluid, chemical, LCM and cement stocks	Drilling Fluids and Cementing Contractors	DSV

Table 2. Responsibilities for Implementation, Supervision and Verification of Drilling Operations.

3.3 GENERAL DRILLING STANDARDS

This section provides an overview of key drilling standards that should be adhered to by the DSV and Drilling Contractor.

3.3.1 Depth Referencing

All depths (either along hole or true vertical) must be referred to the Rotary Table (RT) of the rig which initially drilled the well (original derrick floor elevation). Depths must be reported in meters.

3.3.2 Chemical Stocks

The following are the minimum chemical stocks that shall be available for use at all GSLM wellsites (note barite etc may be stored off location):

- Mud chemical stocks adequate to re-build 1½ times the hole and surface volume of the drilling fluid system in use and the interval being drilled.
- Emergency barite stocks to be able to weight the total drilling fluid system by at least 1.0 ppg.
- Sufficient stocks of LCM material for both above and across the reservoir (as a guide should have enough LCM to add 2 lb/bbl to the entire system if required).
- Sufficient stock of surfactant, weightable pipe-freeing agent, Biocide and corrosion inhibitor materials.

These chemical stocks are based on worst lost circulation criteria and known reservoir pressure parameters.

Specific well requirements are individually documented in the Drilling Program.

Only Barite and KCl/NaCl shall be used as a weighting material unless otherwise specified in the Drilling Program.

3.3.3 Equipment Requirements

The DSV shall ensure that the availability (and serviceability) of equipment is in accordance with GSLM's requirements and the relevant contracts, prior to the commencement of drilling activities. These are summarised below (Sections 3.3.3.1 - 3.3.3.5).

3.3.3.1 Equipment Lists

Equipment Lists will be provided for each well. They provide an overview of the requirements for each hole interval. Note however that each hole section and each well must be considered separately.

3.3.3.2 Surface Equipment

Rig surface equipment requirements shall be detailed in the Drilling Contractor's contract. Critical items to be inspected by the DSV include:

- A trip tank complete with a mechanically operated level indicator, visible from the driller's position.
- A fully functional Crown-o-Matic or equivalent safety brake installed on the draw-works.
- Martin Decker or equivalent weight indicator.
- BOP's with two ram type and one annular preventer.

3.3.3.3 Monitoring Equipment

The minimum level of rig monitoring equipment required:

- Active and trip tanks volume.
- Return flow.
- Total gas at header box. (Mudlogger)
- H2S at shakers, BOP's and drillfloor (Mudlogger)
- Weight on bit.
- Hookload.
- Rotary torque (Relative torque on mechanical rigs).
- Rotary speed.
- Standpipe pressure.
- Casing pressure.
- ROP.
- SPM for each pump.
- Rig air pressure.
- Accumulator unit pressures.
- 6 channel pen recorder (geolograph) or better.

It is the responsibility of the DSV to ensure that the above list of monitoring equipment is available and in working order.

3.3.3.4 Downhole Equipment

The provision of downhole drilling equipment shall be detailed by the DM in the relevant contracts between the Company, the Drilling Contractor and the relevant Service Companies. The following information should be included:

- The dimension of any contractor item run into the hole shall be recorded on the BHA sheet. The Drilling Contractor shall be responsible for providing fishing tools for all contractor supplied equipment.
- Only drill pipe with smooth hardbanding or no hardbanding shall be used when rotating inside casing.
- Only "fit for purpose" drill pipe shall be used (i.e. as defined in the latest edition of API RP7G).
- Drill pipe and BHA shall be NDT inspected every six months. Copies of the inspection records shall be kept on the rig.
- Drilling jars must be used when drilling. The normal procedure shall be to position the jars two or three drill collars from the top of the DC section while drilling vertical wells.
- All roller reamers shall be of the sealed bearing type.
- Either Integral Blade or sleeve type stabilisers will be run. Stabilisers will be 1/64" undergauge when new. Stabilisers will be gauged on each trip and those more than 3/16" undergauge should be laid out.

📖 API RP7G (specifications for Drill Pipe)

3.3.3.5 Typical Bottomhole Assemblies

Each generalised configuration of bottomhole assembly (BHA) shown below demonstrates a typical directional tendency while drilling.

The effect of each configuration depends on a number of variables, including formation hardness and bed dip, bit type, stabiliser type and diameter, hole size and drilling parameters such as weight on bit and rotary speed.

Stabiliser wear in abrasive formations has a significant effect on directional control, where sleeve stabilisers may be preferable to integral blade types. The general directional tendencies due to stabiliser placement for drilling main hole are described in the following diagram and table.

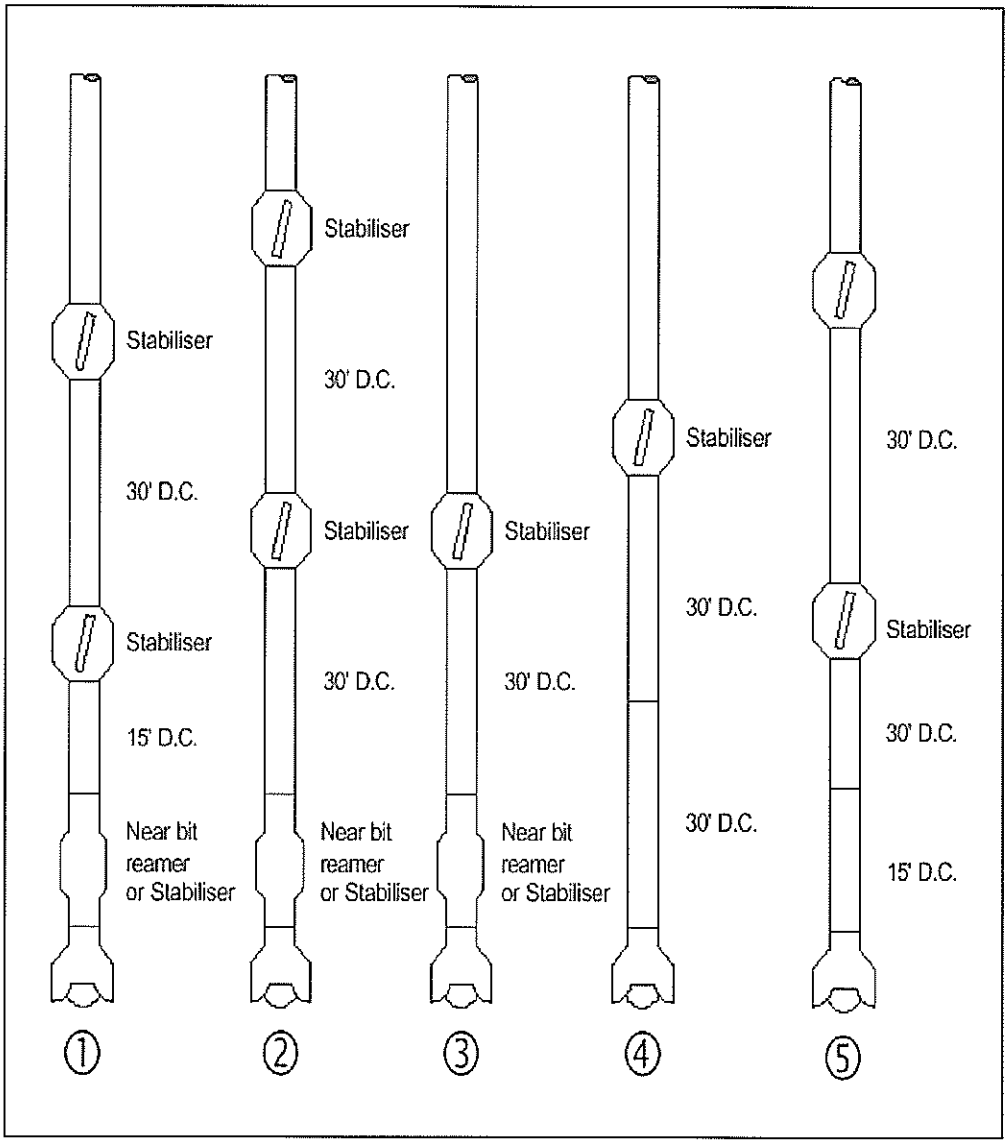

Figure 1. Vertical Well Generalised BHA Configurations

Bottom Hole Assembly Type	Configuration and Directional Tendency
Assembly 1	The near-bit stabiliser or reamer is the primary angle building and hold tool.The stiffer the BHA near the bit, the less likelihood of bit deviation (more contact area gives a higher degree of control). This **"locked", "stiff" or "packed"** assembly is commonly used to hold angle in vertical and low angle wells; it will drop angle at moderate to high inclinations. The second stabiliser may be moved upward 15 - 20' to ease the degree of stiffness if required.
Assembly 2	This assembly may be more effective in certain areas than Assembly 1 due to the combination of variables listed, but represents a **reduced stiffness** and therefore a medium or more neutral angle-holding configuration for moderate inclinations. If the distance between the near-bit and next stabiliser is increased towards 45', the assembly may start to demonstrate gentle building tendencies. Also, the diameter of the stabiliser will influence the tendency to either build or drop.
Assembly 3	This configuration will hold angle at higher inclinations, and may also exhibit stronger building tendencies due to the removal of the second stabiliser and resultant reduction in stiffness.
Assembly 4	This configuration is a classic **"pendulum"**, or dropping assembly, with the stabiliser placed as far as possible above the bit without causing wall contact with the pipe. This spacing is typically 60'. However if a low bit weight is used in a low-angle hole, greater drop-off may be achieved with the stabiliser placed further than 60' from the bit. The behaviour is less predictable unless low bit weights are used.
Assembly 5	This configuration is a **modified "pendulum"** assembly with stabilisers positioned 45' and 75' above the bit. Although the dropping tendency is reduced in comparison to the 60/90' pendulum assembly (described above), the modified assembly allows higher bit weights to be used without compromising directional control. The modified pendulum assembly may be of particular use while drilling vertical wells.

Table 3. Vertical Wells Bottom Hole Assembly Configurations.

3.3.4 Pressure Control Equipment

Pressure control equipment shall be supplied and maintained in accordance with Chapter 10 of this Manual. It is the responsibility of the DSV to ensure that all equipment is in full compliance with the specifications detailed in the relevant contracts between the Company and the Drilling Contractor. A summary of the main requirements are listed below:

- Only original equipment spare parts shall be used in the BOP/Koomey (accumulator) system
- Pressure control equipment shall be function tested every day except the blind rams which shall be tested on every trip and pressure tested every 14 days, or on the closest trip to this date.
- As a minimum the 'Poorboy' mud gas separator should have a minimum 8" vent line and a mud seal of at least 1.5 m (5').
- A full bore kelly cock shall be installed at the base of the kelly at all times. A ball type stabbing valve, with connections or a cross-over to suit the workstring, shall be available on the rig floor at all times, together with an operating handle for the valve.
- During drilling, the outer side outlets of the wellhead exposed to the live annulus shall have manual or hydraulically operated side outlet valves.
- A wellhead wear bushing must be installed in the wellhead during all drilling and logging operations.
- A float must be used while drilling production hole sections.

The following safety equipment shall be on the drilling unit at all times and shall be fully functional:

- Full opening inside BOP.

- Crossovers to allow installation of above into any type of connection used in the drill string or tubing string.

3.3.5 Kick Detection and Well Monitoring Equipment

Kick detection and well monitoring equipment shall be supplied and maintained in accordance with the requirements detailed in Chapter 10.

It is the responsibility of the Drilling Contractor to ensure that the following minimum kick detection equipment is available, tested and fully operational:

- Flowline monitor.
- Active pit volume monitors.
- Gas detection at header box (supplied by the mudlogging contractor).
- ROP recorder.
- Trip tank with a system for accurately monitoring returns during tripping.

The Mudlogging Contractor shall ensure that all gas detection equipment (including H2S detectors) and alarms are functioning properly. The Drilling Contractor shall ensure continuous monitoring and recording (if applicable) of the following parameters is available on the drilling site for all wells:

- Active pit volume.
- Weight on bit and hook load.
- Rotary torque and speed (not installed on every rig).
- Standpipe pressure and choke pressure.
- Rate of penetration.
- Mud pump SPM.
- Rig air pressure
- Koomey (accumulator) unit pressures

Although kick detection and well monitoring equipment is supplied and maintained by the Drilling Contractor, it is the responsibility of the DSV to ensure that regular equipment checks are maintained. All equipment shall be audited on a regular basis during safety visits by the DE / DS.

Drilling of the main hole section shall not commence without written approval of the DM if any of the above equipment is inoperable.

3.4 GENERAL OPERATIONAL PRACTICES

3.4.1 General Practices

The following general practices shall be adhered to during drilling operations. It is the responsibility of the DSV to ensure conformance.

3.4.1.1 Pre-spud Preparations

The DSV shall ensure that the drilling crew are familiar with Company Well Control Procedures detailed in Chapter 10 and the following are available:

- Adequate mud weighting materials are on site or readily available in sufficient quantities to support the drilling operation.
- All fishing tools relevant to the hole interval are available at the wellsite. Drilling Contractor fishing tools shall be available for all Contractor supplied downhole tools as per the relevant contract.
- The ID of all downhole equipment shall be checked for free passage of a free point indicator tool and survey instrument fishing tools.
- All BOP equipment and drillstring well control equipment.
- The DSV shall also inspect the rig and fill out the Pre Spud Checklist prior to the well being spudded.

3.4.1.2 Drilling Operations

The DSV is responsible for ensuring that all relevant Drilling Contractor and service personnel are aware of the GSLM General Drilling Practices during all hole sections. The General Drilling Practices are detailed below:

- Flow checks shall be performed in accordance with the requirements tabulated in Section 3.4.2. A minimum of one bottoms up shall be circulated prior to any trip out of the hole or after completion of any well kills.
- The trip tank shall be used on all trips out of the hole.
- Trip sheets shall be used in all trips in and out of the hole.
- Slow Circulating Rates (SCR) shall be performed in accordance with the requirements tabulated in Section 3.4.2.
- Drill-off tests may be conducted on each new bit run for optimum WOB
- Kill sheets shall be completed as per the Well Control section.

3.4.2 Primary Well Control

Detailed procedures for the conduct of well control operations are contained in Chapter 10. The table and text below provides the standard guidelines and practices which must be observed during drilling operations to maintain primary well control.

Operation	Guidelines
Slow Circulation Rates (SCR)	Must be performed as a minimum • Once per tour. • After every bit change • .After every BHA change. • After significant drilling fluid density or rheology changes. • After any work on mud pumps or surface lines
Flow checks	Should be considered in any of the following circumstances. • Pit gain or loss. • Significant drilling break. • At start of trip out, after 10 stands, with bit at shoe and at top of BHA.Drilling break. • Variation in pump pressure or speed. • Gas, oil or salt water contamination (chloride increase). • Erratic rotary torque. • Lost circulation. • Variation in observed string weight.

Table 4. Well Control Guidelines

The following guidelines are also applicable to well control:

- Additional checks must be performed whenever there is any concern about well control.
- Kick drills shall be carried out according to procedures defined in Chapter 10.
- Time spent with the pipe out of the hole shall be minimised.
- A minimum of one complete circulation shall be performed after completing all well kills.
- Casing shall be pressure tested to a maximum of 80% of the rated burst pressure of the weakest casing when bumping the plug. If the plug dose not bump the casing must be pressure tested prior to drilling out the shoe.
- Leak-off tests shall be performed after drilling 3 m of new formation at all casing shoes, unless otherwise specified (See Section 9.7).

3.4.3 Diverter

Incidences of shallow gas have been reported in Tasmania so the use of a diverter while drilling surface hole is required.

3.4.4 BHA Handling

BHA handling shall be performed according to the guidelines in the table below.

BHA and Connections	Guidelines
Stabilisers	Serial numbers and rotating hours for each stabiliser must be recorded on the morning report. Make up or break down stabilisers in the drill collar string using a winch line or maintain vertical using a mechanical support (e.g. pin in rotary table, clamp support hooked around drill collar in rotary). Manual support of the stabiliser without mechanical back up while engaging or disengaging the threads is not permitted. All stabilisers shall be gauged on each trip and consideration should be given to laying out all stabilisers more than 1/8" undergauge.
Chicksan Connection	Such connections shall not be made up to a downhole string component before the component is incorporated in the string and lowered through the rotary table to refusal or safe working height. In the event that circumstances dictate otherwise, the chicksan connection shall be safeguarded by attaching a safety line to prevent free fall.
Threaded Connection	Any threaded connection carried on top of a string suspended above safe working height and not made up to the recommended torque, shall be marked with chalk and continuously monitored when rotating (part of) that string.
New Threads	New threads which have been cut shall be broken-in carefully when making up for the first time (i.e. Make/break/make each joint).

Table 5. BHA Handling Guidelines

Rotating the drill string below the rotary to make up pipe once the BHA is run shall be avoided.

Backing the rotary into a string to make up a connection is poor practice and can result in a dropped string or an accident due to damaged threads. This practice is not permitted.

All BHA components shall be measured for OD, ID, length and fishing neck sizes. A diagram of each BHA shall be submitted by the Drilling Contractor to the DSV. The serial numbers and rotating hours of all roller reamers, stabilisers, NMDC, jars etc. shall be recorded on the morning report.

3.4.5 Specific Drilling Procedures

Specific drilling procedures are provided in detail in each Drilling Program to ensure that wells are drilled:

- Safely.
- In line with good oilfield practice.
- In accordance with GSLM's policies, standards and guidelines.

The essential items to observe while drilling a well are contained in this chapter of the Drilling Operations Manual, the Generic Drilling Program and, where relevant, are referenced elsewhere. All critical items shall be included in each Drilling Program to ensure that wells are drilled safely and in line with good oilfield practice, as well as in accordance with the GSLM's policies, standards and guidelines given in this Manual.

3.4.6 Local Hole Problems

Hole problems may be encountered during drilling operations in Tasmania. The problems and solutions are tabulated below.

Cause	Problem	Solution
Dioritic sills (possibly fractured)	Mechanical sticking. Very low ROP. Lost circulation	• Drill with slick BHA • Work pipe frequently • Good hole cleaning • Dill bits (eg impreg on motor) • Air drill • Hammer drill • Low mud weights. • LCM
Low pressure and permeable water-bearing sands at shallow depths	Hole instability	• Low mud weights and effective hole cleaning are essential to minimise losses and washouts
Poor wall filtercake	Tight hole	• Low mud weight combined with optimal rheology, fluid loss and hole cleaning should minimise the problem
Sloughing at deeper depths	Hole instability	• Increasing the mud weight, typically up to 9.6 ppg. A relatively in-gauge hole is required to provide a packer seat just above the pay zone.
Fragile coal seams	Packing-off hole	• Avoid packing off hole when pulling the BHA and swabbing the hole by pulling slowly through known coal seams. • Cuttings returned to surface should be closely monitored and compared to the ROP. Inconsistencies may indicate a sloughing coal seam higher in the hole • Drilling coal generally requires frequent, short wiper trips to ensure that the hole is kept clear of cuttings and to avoid the risk of stuck pipe. • For thick coal seams drill no more than 5' before picking up and working a full single 2-3 times while maintaining full pump rate.

Table 6. Solutions to Hole Problems.

It is the responsibility of the DSV to ensure that the Drilling Contractor is fully aware of the potential problems.

3.4.7 Tripping Practices

a) A minimum of bottoms up shall be circulated up prior to any trip out of the hole. In high angle wells this should be increased to at least 2x times bottoms up (at drilling circulating rate) or until the shakers are free of cuttings.

b) A trip sheet shall be filled out by the Driller and Mud Logging Contractor for each trip in/out of the hole. All variances from expected fill/return shall be investigated. The trip tank shall be used on all trips.

c) The time spent with the pipe out of the hole shall be minimised wherever possible. Operations such as routine BOP testing, repairs and slipping and cutting of the drill-line shall be performed with pipe at the casing shoe whenever possible.

d) Check trips may be required in the following cases:
   - During logging when hole conditions deteriorate and become sticky.

- Before RFT/MDT tools are run if previous runs indicate poor or deteriorating hole conditions. If required this wiper trip can be made one logging run before the MDT.
- Before running casing if hole conditions during logging indicate that this is necessary.

Notes

i. In all of the above cases, the BHA must be as short as possible.
ii. In upper hole sections, the BHA should include full gauge stabilisers and be at least equal in stiffness to the casing string if required.
iii. Monel DCs shall not normally be run in check trips.

e) When the condition of the hole is unknown due to a major change in parameters, a short trip shall be made. The procedure is as follows:

1. After circulating bottoms up flow check for 15 minutes. Slowly pull 10-15 stands while using the trip tank to ensure that the hole is taking the correct quantity of mud. Check for flow. Run back to bottom, check for fill and check for flow again.
2. Circulate bottoms up and condition the mud. Check the mud returns for gas and salinity. Increase the mud weight if there are signs of an influx.

f) Slow trip speeds while running drill collars (and BHA's) past coal seams is essential to the stability of the seams.

Tripping procedures to be posted in the doghouse are shown in Appendix 1.

Wiper Trips

As a general guide wiper trips may be run as follows:

- Once every 24 hrs or 450 m (1,500'). These trips will generally be made back to the depth of the previous wiper trip, the start of the bit run or the previous casing shoe whichever is deepest.
- Wiper trip back to surface prior to POOH to run surface casing.
- Wiper trip back to old hole when POOH to run intermediate casing, logs, DST's cut cores etc.

Standard Tripping Procedures.

1. Fill the trip tank to the highest recording level using mud from the suction tank. Do not fill the tank by diverting returns - this will allow cuttings to settle. Record the initial volume in the tank.

2. If required, in top hole only:
   - While circulating prior to tripping, prepare a heavy slug (normally 1 ppg heavier than mud weight in use) in the pill tank..
     The volume of heavy slug required is calculated as follows:
     Slug Volume = (Drop length x pipe capacity x Mud wt) / (Slug wt - Mud wt)

3. Prepare the trip sheet. Shut down the pump and flow check. If the hole is stable; (in top hole only, pump the slug) break out and set back the kelly.

4. When the levels have equalised and annulus flow has stopped, switch the returns to the trip tank.

5. Pull the first 5 - 10 stands without continuously filling the hole to allow the level to be visually monitored for piston type swabbing. Wiper rubbers are not to be installed until at least these 5 - 10 stands have been pulled without indication of swabbing.

   Remember that bottom hole pressure is reduced by the swab pressure plus the loss of hydrostatic head due to the lower fluid level in the annulus.

6. Start the trip tank pump and run continuously while pulling the remaining pipe.

7. If the hole does not take the full calculated fill, flow check. If the well is flowing the BOP must be closed immediately and the pipe stripped back to bottom if possible.

   Under no circumstances must an attempt be made to 'outrun the kick' by running quickly back to bottom without closing the BOP. The situation will deteriorate rapidly and a blow out is almost inevitable.

   If the well is not flowing then the reason for the discrepancy must be determined before pulling any further pipe. If there is any doubt, the pipe should be run back.to bottom and the hole circulated. Monitor returns while running in.

8. When the trip tank has to be refilled, stop the trip and wait for the tank to fill. Do not trip and fill simultaneously. Take the opportunity to flow check the hole.

9. The crew should develop the habit of watching the hole level while tripping.

10. Perform a flow check with the bit at the casing shoe, and prior to pulling the collars across the BOP rams.

11. If tight hole is experienced, the annulus level must be closely monitored for piston type swabbing. When working the tight hole, work up cautiously ensuring that the pipe can always be run back down. Be aware that if an influx occurs in a tight hole situation, any flow will tend to be directed inside the drill pipe. If the flow occurs with the pipe high in the mast, it may very quickly become very difficult to install the stab valve.

    If the tight hole cannot be safely worked through, do not hesitate to pick up the kelly and circulate/ream the hole.

12. While running in the hole the procedure should be reversed so that the volume of mud returns are monitored.

13. The drilling line must not be slipped with pipe out of the hole or with collars across the BOP. The pipe should be run back to the shoe and the stabin valve installed.

14. Trip sheets must be retained and filed.

3.5 PREVENTION OF STUCK PIPE

The following guidelines outline key requirements (during well planning and at the wellsite) to minimise the incidence of stuck pipe.

3.5.1 General Preventative Measures

The DM is responsible for identifying all stuck pipe preventative measures during planning and documenting them in the Drilling Program. The DSV is responsible for ensuring that the stuck pipe preventative measures tabulated below are performed by the Drilling Contractor at the wellsite.

Activity	Prevention
Planning	• The Drilling Programme should include identification of potentially troublesome formations and procedures for their prevention i.e. frequency of wiper trips, etc. • Careful consideration must be given to proper design and selection of BHA's and their components. • The amount of open hole time for each section of the hole must be kept to a minimum. • The drilling fluid system must be properly designed. • Troublesome formations must be cased-off.
Wellsite	• Allow sufficient time to properly condition the drilling fluid. • In open hole, keep the drill string moving whenever possible. • Time spent in open hole shall be minimised. • Ensure that the drillers have been told what action to take in the event of tight hole or other problems. • At the first sign of tight hole, the Toolpusher and DSV shall be called to the rig floor. • Exercise extreme caution when tripping in open hole. • Never try to force the string through a tight spot. • Never pull more overpull than the weight of the drill collars as this will almost always result in the string becoming stuck. • The last three joints (at least) should always be washed to bottom. • Always clean the hole before tripping. • Regular wiper trips must be made, either at pre-determined intervals or as hole conditions dictate. • The shale shakers must be monitored regularly by the DSV as well as by the Drilling Fluids Engineer • Utilise all solids control equipment to minimise the amount of drilled solids in the mud.

Table 7. General Preventative Measures against Stuck Pipe.

3.5.2 Prevention of Differential Sticking

The DM is responsible for identifying in the Drilling Program the potential for all likely incidents of differential sticking whilst the DSV is responsible for ensuring that the preventative measures tabulated below are performed by the Drilling Contractor at the wellsite.