Open water, Riserless Drilling fundamentals
By Peter Aird

Synopsis

This document illustrates “open water” drilling operations, to emphasise operational and engineering considerations that need to be combined with best practices to reduce operational loss.

Basic drilling fundamentals, lessons learned, practical experience, provide discussion, “rules of thumb” & operating guidelines.
**Introduction**

In deeper water environments, drilling characteristics and conditions change. In spite of that, the fundamentals of drilling operations are principally the same. In that a technical, systematic and practical approach must be applied to assess the hazards, identify the risks, to result in a preferred outcome as low as reasonably practicable.

If operations were so managed, then the industry would begin to develop a learning culture rather than re-invent methods to drill what should be unproblematic riserless wellbores. As figures 1 & 2 illustrate however based on a West of Shetland drilling study, straight vertical deepwater exploration wells are not as loss free as they should be.

**i.e. where approximately 60% of all operational loss** is accounted to *Open water*

**Figure 1 : Productive & lost time in deepwater**
When considering the productive time in the open water phases should account for perhaps only 30% of the total wells operations. The magnitude of loss that occurs in these operations phases should be fully appreciated.

This document is intended therefore to focus team members to review the basic fundamentals and essentials to drill trouble free in the open water sections and additionally to generate a fuller understanding and awareness of how loss can occur and how to identify then hazards, assess risk and manage these to deliver optimum performance at minimal loss.

**Figure 2 : Drilling operational loss in deepwater**
Open water fundamentals.

**Deepwater Sedimentary environments**
Open water rotary drilling in marine environments results in cuttings returned to the seabed using sea water and viscous mud sweeps pumped through the drill string and out through the wellbore.

Open water environments are broadly described as “Shallow to Deep marine.”

“Shallow” extend from the shore to the edges of the continental shelves. “Deep” characterise the deep oceans beyond the continental slopes and include deep sea fans and abyssal plains.

![Figure 3: A Profile of a typical Atlantic passive continental margin](image)

The agent for transportation of the sediments is through a sequence of repeating ocean (turbidity) currents and settling. The open water sediments drilled are also generally deposited in nearly horizontal layers.

The influencing characteristics of sediments in open water are porosity, permeability and in situ stress of the formation(s). After deposition, sediments are buried and compacted. Porosity and permeability of sedimentary formations decrease with depth due to this. Sediments drilled in open water have generally high porosity & permeability, are not well compacted, resulting in poor formation integrity.
While drilling in deepwater, drillers must first appreciate how sediments form and why every practicable measure must be taken to ensure the well bore is maintained to prevent hole collapse or enlargement. In that, preventative measures should ensure that formations are not agitated to result in formations that will become unstable or collapse.

To enforce this, the rock stresses originate from the overburden and the formation fluid pressure. Stress produced by the combined weight of the rock and formation fluids overlying a depth of interest then exerts vertical stresses to the formation. The resulting horizontal stress developed depends on the rock stiffness. As rock stiffness is poor in open water, horizontal stresses will be high and rock can be prone to shear failure.

The formation fracture strength is defined by overburden stress, compaction, formation pressure and strength of the rock type. As no leak off tests are conducted in the open water sections. **Exact fracture and pore pressure gradients are in general unknown** but to some extent may be extrapolated from the shallow seismic data.
**Formation & Filtrate Invasion.**

The pressure exerted by the column of drilling fluids results in fluid being forced to invade into the formation. The porous and permeable rocks act as a filter, separating the drilling fluids from their liquid and solid constituents. Heavier drilling fluids flow into the formation, while the solids drilled form a deposit around the borehole. These then accumulate to develop a mud cake on the wellbore wall and a skin is formed over the interval drilled. **Again fundamental for all driller’s to appreciate.** *(back-reamer’s take note!!)*

Initially as the bit enters new formation complete disequilibrium and dynamic filtration takes place. Below and around the bit there is a continuous flow of filtrate into the formation. Gradually mud cake builds, an impermeable barrier forms and filtration’s ceases. **A non penetrating wellbore results.**

The replacement of original formation fluids by drilling fluid filtrate is called invasion. Invasion is important to understand since it effects both porous and permeable formations in the immediate vicinity of the borehole and is a vital ingredient to wellbore stability and quality.

**Rules of thumb**

1.) **A non penetrating wellbore is much stronger than a penetrating wellbore.**
2.) **A formed mud cake is the primary combatant to stability.**
3.) **Invasion is shallow in very porous and permeable formations.** Mud cake builds up rapidly to block dynamic filtration.
4.) **A formed mud cake should not be agitated, removed or eroded.**
**General BHA considerations**

In open water formations a BHA does not always respond to its theoretical behaviour, due to a greater or lesser degree on type of bit and stabilisers used.

The net effect of hole inclination can thus be primarily diminished due to the reduction of wall support of the bit and stabilisers. More importantly curvature or dogleg can be further compounded by the forces acting to enlarge the hole.

*“Rock bit selection, parameters and BHA component design have a significant effect on bottom hole assembly, hole quality, formation response, and well performance”*. E.g. Cone offset, tooth design length, motor or rotary assembly, all influence on how much a bit will cut sideways for a given force. The speed at which the bit or hole opener cutters are turned also effect this and should be duly considered in bottom hole assembly planning.

Formations bit walk can be however be anything from a slight ; left, right meandering to a stronger left or right hand walk tendency *i.e. due to rotary drilling assemblies, Motors etc*. Therefore directional control in its entirety needs to be carefully appraised to evaluate the amount and direction of lead that will result due to these effects. In top and surface hole sections lead needs to be counteracted to ensure wellbore paths remain vertical, without compromising ROP & overall drilling performance. *How much effect does a motor or rotary assembly play in this respect.?*

To drill a straight hole therefore the resultant force at the bit must coincide with the formation, drillstring effects and bore hole axis, so that the total deviation force lends towards vertical. Any deviation force must be counteracted by an equal an opposite side force produced by the BHA, stabiliser size, placement or adjustment of weight on bit & RPM. **BHA design must therefore reflect this.**

**Rules of thumb**

1.) Instantaneous doglegs can occur in top & surface hole & should be avoided.
2.) Bottom hole assembly design must consider the conditions anticipated.
3.) Components must be duly selected taking all hazards, risks and implications *(cost, hole quality, time, performance)* into account.
4.) Stratigraphy will determine the number, type and placement of stabilisers required to produce best effect.
5.) To maintain verticality and ROP, parameters need to be optimised.
**Formation characteristics.**
Formation characteristics effect ROP and drilling performance. Each formation has a threshold force that requires bit weight to initiate drilling. Normally pressurised formations allow the drilling fluid filtrate to more readily penetrate into the rock ahead of the bit allowing equalising of pressure. This makes the rock easier to drill. High drillability is possible under normal conditions in open water. Some formation characteristics can inhibit performance. E.g.

**Soft sticky clays** can cause the bit and stabilisers to **“ball up”** reducing drilling efficiency and performance. The importance of maintaining clean cutters is therefore fundamental.

**Unconsolidated, loose, friable, formations** are also often encountered in top hole sections. They present hazards such as shallow gas, unconsolidation, shallow water flows. And once unstable, can mechanically “flow” into the wellbore where they may crumble and collapse again resulting in a stuck drillstring and at worst a requirement to re-spud the well.

**Rules of thumb.**

1.) Evaluated data from offsets, similar regional data or through drilling a pilot hole to highlight **all formation hazards**

2.) A mud log of the open water sections provides the only record for future well planning.

3.) Control instantaneous penetration rates through unconsolidated formations.

4.) **Avoid mechanical or hydraulic agitation of the wellbore.** E.g. *BHA rotation off bottom (backreaming) can often than not lead to stuck pipe and re-spud resulting.
Stuck pipe & re-spud data testifies to this.*
Bit type & selection

Bit type.
Bits selection criteria should be on a balance of teeth, bearing and gauge wear, to meet section objectives at optimum performance. During open water drilling, roller cone bits/hole openers are generally used. They generally warrant small pin angles allowing for larger cones, thinner bit legs and longer gauge length. Cone angle facilitates larger cone angles for larger cones, and multiple cone angles for each cone for a non-true rolling. This results in one row of teeth driving with the other rows sliding, providing a preferred scraping action of teeth to benefit to drilling performance. Finally cone offset is higher to enforce a scraping gouging action of bit teeth as they rotate about their offset axis.

Bit selection
In open water use the longest tooth bits and consider formation characteristics, section length to be drilled, directional work required, bit availability, desired bit features and offset well data. In the open water section(s) teeth wear is rarely a problem. “Roller” bearings however are often subject to wear and a sealed bearing may be preferred especially on hole openers if a long section length is to be drilled.

Rules of thumb.
1.) 1-1-5 bit is best suited to open water environments.
2.) If motors run, ensure hole openers are fitted with sealed bearings.
3.) BHA, WOB, rotary and cutter speeds should be engineered for minimum cost per foot.
4.) Centre jet, jet type, and optimisation will provide optimum drilling performance.
5.) Bits and hole openers perform under designed, engineered and specific operating parameters.
Bit / hole cleaning hydraulics

In methodology, there is little choice between optimising hydraulic horsepower (HHP) or jet impact force (JIF) in open water. *i.e. Maximum HHP = 90% max of impact force and visa versa.* In holes > 17 ½", HHP and JIF criteria have not been truly defined. Experience has shown that optimised cutter cleaning and flow balance between hole opener and bit should be applied relative to the volume of cuttings generated. Field data demonstrates that significant increased performance can be achieved through such hydraulics optimisation.

**Optimising bit/hole opener flow.**

Considers each cutter cuts a specific volume of rock and a balanced flow is applied. When calculating to provide a Jet velocity of for example 250ft/sec at each nozzle. Then for a rig max. pump rate of 1200gpm, the following results when the continuity equation is applied.

<table>
<thead>
<tr>
<th>Cutter area</th>
<th>Volume removed / ft</th>
<th>Flow balance</th>
<th>TFA required*</th>
<th>Nozzles required.</th>
</tr>
</thead>
<tbody>
<tr>
<td>26”</td>
<td>3.7 ft^2</td>
<td>625gpm</td>
<td>0.8 sq ins</td>
<td>3 x18, 1x12 CJ</td>
</tr>
<tr>
<td>36” – 26”</td>
<td>3. 4 ft^2</td>
<td>575gpm</td>
<td>0.735 sp ins</td>
<td>6 x 14</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>7.1 ft^2</strong></td>
<td><strong>1200gpm</strong></td>
<td><strong>1.54 sq ins</strong></td>
<td></td>
</tr>
</tbody>
</table>

**Rules of thumb :**

1.) Use all pump power available.
2.) Engineer to provide a balanced flow and adequate jet velocity (250-350ft/sec)
3.) Review offset wells to establish best performance
4.) Vertical wells are easiest to clean, don’t get too hung up on flow rate.
5.) Keep the pipe moving to prevent enlarging hole.
6.) Reduce pump rate while wiping and if reaming required.
**Bit & hole opener operating conditions.**

**Weight on bit. (WOB)**  
WOB is required to initiate penetration, a linear increase in ROP occurs as WOB is applied to a point where there-after WOB will not significantly increase ROP. Maximum WOB depends upon hole, formation characteristics, bit type, BHA run, stabiliser placement, formations being drilled, ROP and hole cleaning requirements.

To establish optimal WOB, engineering calculations can be performed to establish when tangency of drill collars is reached and the point where hole build will theoretically occur.

**Rules of thumb :**
1.) WOB must be controlled until sufficient length of BHA has penetrated the seabed.
2.) Drill collars size selected have a significant effect on axial, lateral loading that can be safely used for optimised WOB and drilling performance.
3.) If no build tendency is observed, WOB can be increased to pre-determined values.
4.) Weight on bit must be maintained below the point of tangency to ensure verticality.
5.) *When a negative drilling break is observed*, reduce WOB to prevent an instantaneous dogleg resulting.

**RPM**  
ROP increases linearly with increased rotary speed *to a certain value.* Thereafter at higher speeds, the response of penetration rate to rotary speed diminishes. In 26" and 36" hole sizes, optimum speeds vary depending on formation types. See table 1.

**Table 1 : Recommended manufacturers rotary speeds (Bits and hole openers.)**

<table>
<thead>
<tr>
<th>Bit &amp; Hole opener</th>
<th>Hard</th>
<th>Medium</th>
<th>Soft</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Rpm (Rpm)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>36”</strong></td>
<td>30 - 60</td>
<td>40 -70</td>
<td>50 – 80</td>
</tr>
<tr>
<td><strong>26”</strong></td>
<td>45 - 75</td>
<td>55 - 95</td>
<td>65 – 105</td>
</tr>
<tr>
<td><strong>17.5”</strong></td>
<td>60 - 90</td>
<td>75 - 125</td>
<td>80 – 140</td>
</tr>
</tbody>
</table>
**Cutter speeds.**

Roller cone and hole opener peripheral cutters speeds are faster due to the size of cutter and circumferential distance required to be travelled. Drilling optimisation and hole quality is effected if cutter speed, hole circumference, bearing and cutter type(s), are not accounted for.

Table 2 illustrates cutter speeds for a drillstring rotating at 100rpm, if a 36” hole opener has 10” cones, a 26” bit, 14” cones and a 12 1/4” bit, 8” cones

<table>
<thead>
<tr>
<th>Bit / Hole size</th>
<th>12 ¼” bit</th>
<th>26” bit</th>
<th>36” hole opener</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cutter / Bit ratio</td>
<td>Ratio : 1.5 - 1</td>
<td>Ratio: 1.9 - 1</td>
<td>Ratio : 3.5 - 1</td>
</tr>
<tr>
<td>Cutter RPM</td>
<td>150 rpm</td>
<td>190 rpm</td>
<td>350 rpm</td>
</tr>
</tbody>
</table>

With the above in mind, mud motors are often used in open water to aid in drilling a straighter hole. Historically however wells have been successfully spudded without motor utilisation simply through sensible drilling practices to ensure a straight and cylindrical hole results.

When all aspects of a motor are considered especially higher peripheral cutter speeds and limited control available. The overall technical merits of mud motors in vertical deep open water drilling has to be fully assessed.

**Rules of thumb**

1.) Peripheral cutter velocities on bits & hole openers must be accounted for.
2.) Apply rotary speeds as prescribed in table 2.
3.) If rough drilling is noted change rotary speeds, if no effect is noted, formation may be the root cause.

**Drillstring vibration.**

Severe vibration is often found encountered in open water drilling and generally considered to be predominantly due to formation characteristics (e.g. boulders). However drillstring dynamics logs available no show that severe lateral and longitudinal vibrations are most likely in vertical wellbores. In that the effects of verticality & limit pipe stretch provide non-dampening conditions where any energy input can be used to build up amplitude that can increase without limit.

Vibration are often then attributable to drillstring conditions and will vary for weight on bit, rotary speed, drillstring, wellbore size, length and geometry. Longitudinal, lateral or torsional related vibrations can occur and could be coupled with natural frequencies resulting.
Vibrations can severely inhibit wellbore, BHA performance and hole quality.

**Rule of thumb**

1.) In vertical wells dampening is minimal. Vibration excitation can readily occur.

2.) Design BHA to avoid vibration speeds for section length and formations drilled

3.) Rough drilling is often noted at surface in open water drilling. Change rotary speed. If no difference, stop rotating, pick up of bottom and re-establish parameters. If vibration persists then conclude formation may be the culprit.

4.) Plan the BHA length for section to be drilled.

5.) Select BHA components to minimise unforced excitation and those that can afford greatest exercise and control. I.e. Ability to change WOB/ROP etc.
**BHA component and design.**

BHA performance analysis.

**Resulting forces on the BHA**

The resulting forces acting on the active portion of the BHA, affects the trajectory of the wellbore. All BHA's cause a side force at the bit that in turn cause the bit and wellbore path to build, drop and/or turn. Stabilisers contacting the wellbore exert forces at the point of contact. The forces and displacements for a WOB and rotary speeds for any BHA can be determined to a certain degree of accuracy if the physical properties of all component and shape and size of the trajectory of the well are known.

Bit tilt, is another influencing factor in BHA mechanics to direction and inclination. The curvature of the BHA centreline causes the bit to tilt and deviate from the bore hole centreline to its own centreline. The softer the formation the more the bit tilt will control the trajectory of the bit.

It is important to note that the principles governing simple BHA design and performance analysis will provide the basis and understanding required for more complex ones. These principles should be engineered into vertical hole drilling
**Component stiffness.**

Drill collars provide axial support (stiffness & rigidity) to prevent bucking of the drillstring. They should be selected so maximum anticipated weight can be applied to the bit with the neutral point located safely within the drill collars, preventing the drillstring from bucking. Stiffness determines where the stabilisers are to be placed and the resistance of the drill collar to be deflected by the combined forces created by the bit, formation, drillstring and BHA effects.

As drill collar diameter increases so does its stiffness. Stiffness is measured by inertia. Axial stiffness of a BHA refers to its resistance to axial bending and is proportional to the cross sectional second moment of inertia. The stiffness of the BHA could also be though of as its resistance to twisting or torsional stiffness. Definition being the product of the modulus of shear and the polar moment.

**Stabiliser placement**

As a stabiliser is moved towards the bit, a point occurs where the drill collar is lifted off the side of the hole. This point is twice the distance from the bit, and the original tangency point that occurred *i.e. ignoring bit and stabiliser weight and degree of restraint at the bit and stabiliser*. At this point the pendulum force at the bit is doubled and provides a greater drop tendency. As weight is increased the tangency point may be re-established below the stabiliser and the behaviour of the assembly will change for further increases in weight on bit. If the stabiliser is now moved closer towards the bit, a point occurs where no further weight on the bit can be applied to move the tangency point down. As the stabiliser moved towards the bit acts as a fulcrum point, increasing the upwards side force acting on the bit. Once again the tangency point is the determining factor. This time behind the stabiliser as it moves towards the bit with increase in weight, the build assembly is again increased.

Placing a second stabiliser in the string, again at a distance twice the tangency length will have an effect on the behaviour of the BHA. With the first stabiliser back sufficient distance from the bit, the second stabiliser will have little effect other than holding the drill collar away from the side of the wall. However as the position of the lead stabiliser approaches the bit. The relative position of the second stabiliser decreases the build tendency of the BHA as it approaches the lead stabiliser (for a given weight on bit.)

Such simple analysis is however effected by other factors *e.g. when rotation is introduced and a dynamic situation then exists*. Detailed computed analysis is then required for bottom hole prediction and is beyond the scope of this paper.
Rules of thumb:
1.) Component selection and placement, can effect rate of penetration, performance and resulting forces on the BHA.
2.) If hazards exist, larger collars will prove to be cost effective to reducing problems.
3.) The position of the first two stabilisers is critical to determining BHA response.

Properties of the drilling fluid.
At the end of each section drilled, the wellbore is displaced to a weighted mud. This supports and stabilises the well-bore, providing more than hydrostatic support to allow the running and cementing of the steel casing strings.

Drilling fluid properties effecting penetration rates include, density, rheology, solids removal, cooling, lubricating and transportation qualities.

The pore pressure in open water sections is normal hydrostatic. Mud density is therefore not required for pressure control, and in that seawater can be used for drilling. This aids drilling efficiency by having virtually no chip hold down. However as transport efficiency is poor, cuttings soon build up and can overload the annulus.

Viscosity of the drilling fluid is therefore required to lift and carry the cuttings from the wellbore. High viscous mud sweeps provide the lift to transport and carrying the cuttings from the wellbore and in combination with solids provide the filter cake on the wellbore wall. The rheology of the mud is primarily designed however to provide adequate carrying and transport capacity.

Rules of thumb.
1.) High viscosity sweeps, 100secs+.
2.) Pre-hydrate bentonite results in better quality viscous mud to lift and transport cuttings from the well.
3.) Calculate sweep volumes required and ensure sufficient drill water is on board.
4.) Use soda ash at 1lb / 100bbls of water for every one (1ppm) of total hardness of water, then add caustic soda to obtain required PH.
5.) 10sec / 10minute gels should be a minimum of 3/6 lb/100ft²
Solids removal and cuttings transport capability.

Vertical wells
Inadequate solids removal and poor cuttings transport will prove hazardous and can result in hole collapse or a stuck drillstring. Sufficient flow rate is the first priority required to clean larger wellbores more efficiently e.g. > than 17 ½". The sweep “mud annular velocity” should be greater than the cuttings slip velocity to carry cuttings effectively from the hole.

Transport efficiencies
Transport efficiency is the ability to effectively transport and carry cuttings from the wellbore to the seabed. Transport ratio : (TR) = 1 – (Vs/Vt), Where ; Vs = annular velocity, Vt = Particle slip velocity
Transport efficiencies during open water drilling, state that the hole can only be drilled as fast as it can be cleaned. With such low ratio’s, i.e. 25% in 36” hole, 50% in 26” hole, Sweeps must be pumped more often, otherwise annulus can become overload, with wellbore instability, stuck pipe, fill or other hole problems resulting.

Sweep volume and size
Sweeps should therefore be based on the amount of solids drilled to prevent overloading the wellbore and causing hole difficulties. Sweeps also serve to ensure that the bit cutters are kept clean lending towards more efficient drilling. Finally, sweep size must not allow drilled cuttings to become dispersed in the wellbore and should allow sufficient contact time with the formation for a mud cake to be formed on the wellbore wall.

Rules of thumb.
1.) “Don’t drill a hole faster than you can clean it.”
2.) If fill encountered, pump sweeps more frequently, increasing circulation time prior to connections.
3.) If fill persists, spot viscous mud on the bottom of the hole prior to making a connection.
4.) At section TD displace open hole contents plus 50% excess.
5.) When a pump failure occurs ands recommended flow cannot be obtained, do not drill ahead and circulate until sufficient pumps and flow rates are back on line.