Assessing Geo-Hazards.

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Introduction

This document is intended for use by drilling personnel engaged in the evaluation of geo hazards through all phases of the well delivery processes in both exploration, appraisal and development wells.

- pre-data acquisition
- shallow seismic/site-survey review
- well planning
- well construction
- well execution phases

Its purpose is to ensure that hazards are recognised and analysed with risks determined so that well design, wellbore and equipment integrity, and drilling operational procedures can be executed at risks as low as reasonably practicable, meeting well objectives, in compliance to both company policy and regulatory requirements that exist.

Shallow Geo Hazards.

If geo-hazards exist in the subsurface sediments, they must be identified, ranked with all associated risks determined, at the earliest opportunity in the well planning process. Only such a process can then ensure that “best” operational guidelines and contingencies will exist to prevent and eliminate risks and operational loss to levels as low as safely practicable.

Shallow geo-hazards would include, but are not limited to:

- Sub Surface & seabed conditions.
- Incompetent sediments.
- Slump and scour features.
- Faulting and glide planes to shallow depths.
- Shallow water & gas flow pockets & reservoirs.
- Mud volcanoes.
- Gas hydrates and moulds.
- Over pressured zones.
- Soft seabed conditions
- Mud slides
- Low fracture pressures
- Shallow prospects
Addressing hazards

Geo-hazards such as shallow water flows, shallow gas, hydrates, mud volcanoes, seabed topography, and slump-fault features are key topics for drilling professionals and earth scientists.

The three main concerns offshore operators must deal with are;

1. site specific selection, for lowest risk.
2. surface and subsurface geo-hazard avoidance,
3. geo-hazard mitigation.

With respect to these concerns, a trend towards multidisciplinary team working, involving drilling engineers, geologists, petro-physicists, geophysicists, etc. has provided the offshore rig team members with much more open networks of information, allowing for better location selection and improved decision making.

Drillers should take note however that as while preparatory work for offshore site selection continues to take advantage of sophisticated sensing technologies and data packages. Operators have yet to fully develop and integrate effective processes to pay sufficient and more attended detail to the threat of near-surface geo-hazards (i.e. mud line through to surface and even intermediate casing points), perhaps even more so in the deep open water environments than often paid to the lower pay zones.

Why? because historic data clearly testifies that this is where significant operational "loss" exists. “Lost time” events in the shallow formations often resulting in well-control situations, lost wellheads, poor cement jobs, rig instability, damaged casing, re-entry problems, even abandonment, and expensive remedial action to ensue.

e.g. Shallow water flows (SWFs) on a recent well study of Gulf of Mexico deepwater wells, have cost an estimated $165 million in remedial actions (“shallow” in this context refers to the subsurface, not water depth). On such locations, operators spent 65% of their time performing remedial work, the remainder on prevention measures.

Just as important, dealing with hydrostatic and formation pressure relationships has also become a key subject area. “SWF for example is a key problem in narrow margin drilling, which arises from a combination of formation over-pressure and low formation strength.” “Drilling shallow, soft, and over pressured formations and controlling ECDs [equivalent circulating densities] within a tight margin, is no simple proposition, given margins as low as 0.2 to 0.5 ppg.”

If pore pressures are not therefore not determined, understood and mitigated against, the shallow formations will flow, leading to washouts, ineffective cementing, formation compaction, damaged casing, and hole re-entry problems.

Note: SWF indicators, risks and problem-solving strategies, because of their importance in successfully meeting well objectives in deep open water operations, require addressed in much more descript detail, in a separate document.
Data processing

Data used to identify geo-hazard occurrences include both conventional and reprocessed 3D seismic, 2D and 3D high-resolution seismic, seismic velocity data, analog site surveys, and core samples.

3D seismic data is used for improving understanding of the environment of deposition and sedimentological units and high-resolution 3D can be used to depict "vivid images" of the sea bottom.

In exploration plays with limited well data, seismic velocity data can be also be used to detect overpressure zones and hydrates. In additional, analog site survey data, which include high-frequency data acquired from echo sounding, side-scan sonar’s, and sub bottom profiling, can provide accurate bathymetry maps, seafloor mosaics, indications of seafloor gas, and shallow fault detection.

Finally, digital site-survey data can result in improved imaging of the subsurface near the seafloor, leading to improved fault and thin-bed mapping. Unfortunately, although these data consist of higher frequencies than 3D seismic, there is a disadvantage of being unable to resolve the 3D nature of the hazards. When used in conjunction with 3D data, they may aid in the interpretation, however. With such data, over pressurised (water flow/gas) pockets can be depicted by seismic data and attribute analysis that may produce anomalous high amplitudes and reflection time sags. Similarly, indications of hydrates can be found with seismic data, attribute, and velocity analysis. Mud volcanoes and pock marks, on the other hand, can be depicted through 3D seafloor visualisations and seismic sections.

Finally, moreover, seafloor debris can be seen with side-scan sonar, while slumps and faults can be shown as breaks in seismic reflections using 2D and 3D seismic sections and time slices.
Geo-technical assessment.

Geo-technical studies may also be required especially in deep open water well planning operations to assure that in execution, the placement of the conductor and surface string designs are well founded, as it is this seabed-supported structure which must sustain loading of some nature.

In fact, the loading regime acting on a well conductor is complex, varies throughout the conductor's life, and is often not afforded as much attention as is warranted.

One of the key considerations therefore when planning and installing conductors is the need to avoid geo-hazards - or to design around them. e.g. over-pressured shallow formations, boulders, excessively hard or soft soils or sensitive soils, faults and slopes.

Geo-technics assist to identify, avoid, determine and/or design around most of these hazards. e.g. when driving conductors in hard, boulder-strewn ground, often encountered in the North Sea. Geo-technical models can allow a minimum conductor shoe thickness to be specified in order to resist tip buckling. The conductor can then be drilled out for the first inner casing without the risk of the drill string getting stuck in a deformed conductor.

Geo-technics could result in the elimination of some design concepts and installation methods at an early stage of the project. This detection is thus necessary to avoid wasting money pursuing what turn out to be "no go" options.

Determining conductor size

As an example, during the planning stage of a proposed deepwater Norwegian Sea development, comprising a template-less array of conductors, it was possible to eliminate the initial proposed conductor size as inadequate because of the excessive soil movements predicted. However, as the geo-technical exercise was performed sufficiently early for there to be flexibility in the design. It became possible to remedy the design and bring it back within the bounds of feasibility. In that way the cost-saving, template-less array concept could be pursued.

It is thus vital to understand the soils at a new well site. Using geo-technical studies may avoid transferring blindly what may be "best practice" or "rule-of-thumb" from a mature area to a new area where the soil conditions render such practice inappropriate.

The message is, if you don't understand the soils, you may not end up with the same integrity that you were hoping for.
Jetting conductors

Jetting conductor installation provides a good example of this principle. While jetting is well established and considered the norm in the Gulf of Mexico, it is still a novel method throughout most of the world's other deepwater prospects, with problems reported off West Africa and Norway.

e.g. Initial attempts jetting offshore deepwater in the Norwegian Sea Norway run into difficulties, partly due to the lack of site-specific soils data, but also because of the operator's reluctance to believe the geo-technical prediction that the "off-the-shelf" conductor design would not have sufficient soil support, and that the wellhead would subside when the first inner casing was hung-off.

The costs of the geo-technical exercise that can predict such unwelcome events are probably in the region of 1% of the cost of the wellhead recovery operations.

Setting depth

Setting depth assessment is another important aspect of conductor planning. Application of geo-technical data may lead to a cost saving through reduced setting depth requirements. The benefits of a shorter conductor go way beyond the minimal saving incurred on conductor steel. A shorter conductor is easier and quicker to install, so the time savings can be of much greater value.

Another aspect that can benefit from geo-technical input is the avoidance of damage to other wells or foundations during the conductor installation and top-hole drilling operations.

Once a workable conductor design has been identified, the next step is to assess the cheapest way of getting it in the ground, while still fulfilling technical requirements. Installation methods can range from the conventional to the novel, but the feasibility of all concepts depends heavily upon the soil conditions.
Conductor installation

For instance, conventional driving techniques can often lead to excessive ground damage and unacceptable conductor deviation whenever refusal is reached and drilling-ahead has to be performed. However, an appreciation of the soil conditions enables a simple exercise to be performed to devise a driller-friendly installation program that avoids drilling ahead in strata susceptible to wash-out.

Conductors cemented in a pre-drilled hole - drilled and grouted conductors-are another well-established practice. But what about the problems peculiar to deep water and the very soft, often highly sensitive soils associated with these areas?

With jetting, the conductor is washed into place using fluid injected through a jet-head at the end of the drill string. The drill string also serves as the lowering tool for the whole conductor. The jet fluid erodes the soil inside and at the tip of the conductor, reducing the soil resistance, allowing the assembly to penetrate under its own weight.

Use of drill collars or heavy donut weights around the string assists the process. The big incentive here is the ability to disengage the drill string, then immediately start drilling the top hole section, without waiting on cement. The potential time and costs savings are immense, especially given today's rig rates. However, the big unknown is the degree of soil disturbance caused by the jetting process. An advancing zone of disturbed, wetted soil can be created, which the conductor then relies on for support. To make matters worse, it is often necessary to reciprocate the conductor to get it in, and also the jet-head is often badly positioned. In these cases, the disturbance is simply too great for the conductor to ever be of any use.

Conductor loading

What happens once the conductor is successfully installed? It then has to undergo and sustain a complex long-term loading history, which may last tens of years if the well becomes a producer. For axial loading, the immediate requirement is to support the first inner casing string and probably a BOP stack too. This may all have to be supported by the conductor before the first casing is cemented up. If the soil isn't strong enough, there can be subsidence problems. Upon hooking up of the drilling riser, the axial loading may then switch to tension, with significant cyclic variations from drilling vessel movements and current loads on the riser.

Returning to the requirement to support the first inner casing, this is a particular issue with jetted conductors because of the excessive soil disturbance mentioned earlier. It takes time for the soil strength to recover, and it might not become strong enough until quite a while after jetting is completed.

Good soil modelling is thus essential in predicting wellhead deflections and conductor stresses. Particularly in soft soils, the maximum conductor curvature under snag loading can occur quite far below the seabed, so the maximum stresses may even coincide with a connector. There is no escaping snag loading even in deep water - trawling activities can affect wells in 900-1,000 meters of water.

From that follows the problem of fatigue. Only a few cycles at extreme storm or snag loads can eat up a huge proportion of the fatigue life. If fatigue is critical, it becomes important to incorporate a good soil model in the riser analysis.
Sub surface & seabed operational hazards

Introduction

Unpredictable, high subsurface currents, high significant wave heights, low sea temperatures, unpredictable and multiple variant current conditions, and thermoclines, all presenting unique subsurface operating difficulties experienced during open water riserless drilling.

Seabed conditions

The site survey data and conditions found in pre site surveys and once rig is on location e.g. visual, penetration test, local knowledge etc. will determine the seabed conditions. If a soft seabed is presented at the drilling location, this may lead to and cause:

- Effects on wellhead and conductor requirements
- Anchoring / mooring difficulties
- Hole fill, slumping / instability
- Poor visibility
- Difficulty drilling section
- Difficulty re-entering wellbores (hole sloughing.)

E.g. Based on prevalent conditions, it may be preferable for conductor to be washed, jetted that wellbore section drilled, conductor individually run and cemented etc.

One therefore cannot simply apply a technique used in the Gulf of Mexico to another environment. All actions must be technically and engineered justifiable.
Effect on wellheads

Soft seabed conditions often result in shifting the point of support from surface to the depth where desired formation cohesion is obtained. Bending forces on the conductor and surface casing will increase due to longer momentum arm. The support for the wellhead may not be sufficient using standard conductor and reinforcement will be necessary. Before drilling at a specific well location part of the site survey will likely be to capture enough data to determine the wellhead support capabilities of the formations. This could, if critical enough, involve a core ship. Depending on the results, larger than standard 30” OD conductor may be required e.g. (36”), higher grade (X52 or X56) or thicker wall (1.5” or 1.75”). In addition, the first one/two connectors need to be of the preloaded type.

Effect on anchoring

For the soft soils the shear strength typically will be so low that a conventional anchored rig simply would pull the anchors back to the rig when tension is applied. Possible solutions to the problem would be to use specially designed “mud” anchors Stevpris anchors have been successfully used in sediments softer than at the Voring plateau in the Gulf of Mexico). Use of piggyback anchors or increased number of anchor lines from 8 to 12 or more can also be considered. e.g. A report “Shallow Stratigraphic Drilling, Voring Basin 1993”, reports that the sediments in the sampled spots generally where rather soft and unconsolidated. Porosity ranges from 51% - 81% and the shear strength (kpa) from 6.7 to 125.

The shear strength will increases with burial depth, yet the shear strength from this report indicating that it was generally less than half the shear strength found in soft clay on the Norwegian Shelf.

Mud slides

Mudslides represent mass movement of unconsolidated surface sediments that can be imagined as a subsea avalanche. Mudslides is an area of particular concern in the upper continental slope i.e. an active mud slide area within the GOM. Little is yet know about such phenomenon, nevertheless the risk of a slide hitting an active drilling area during open water drilling operations is low. Slides can however cover large areas up to several square miles in extreme cases. Lateral forces that result on a wellhead or drillstring in the path of a slide are however difficult to estimate, but could be considerable. Slides will follow the path of least resistance and on a smooth seabed would flow downhill until stopped by friction. Several hundred feet of sediment may be re-deposited. A seabed failure directly down-slope of location may thus weaken the support of the wellhead and upper casings.

In deepwater Norwegian Sea, one oil company reported that no mud slides have been identified at seabed. However, possible mudslides have been seen in the section just below seabed. Additionally, mud diapers extending to seabed affect a large area over and around the Vema dome. Some of these extend 70 – 80m “normal” sea beds. Mud injection features are also present in the shallow gas section in the same area.
Currents

Currents can vary considerably for differing environmental locations and water depths. Regional data and operating experience should be sourced prior to operating in any new such environment.

Subsurface currents e.g. in the U.K. deepwater western margins provide significant operating hazards, because multiple currents often exist that act and flow in different and variable conditions. This creates operating difficulties especially during open water operations.

Regional information or current monitoring data/equipment provided can indicated the surface and sub-surface current profiles i.e. strengths, direction, period and variance. Even in low sea states and favourable weather conditions, currents during open water operations may lead to and cause;

- ROV operating difficulties (maintaining station, umbilical vibration etc.)
- Hole marking, wellhead location difficulties
- Difficulty locating and allowing re-entry of drillstrings and conductor.
- Difficulty releasing subsea tools. (e.g. casing running tools.)
- Normal operating difficulties, (drillstring bowing, drag on lines, umbilicals etc.)

Often the best rules of thumb is simply to wait until slack water until executing critical operations. Even “Gung ho” driller’s have to sometime bite the bullet.

In many areas of the Gulf of Mexico, high currents from the loop current and eddies can exceed operating limits (exceeding 3knots at surface reducing with depth.) Such currents are still difficult to predict and may reach the drilling location without warning.

Finally, in new exploration regions, limited information regarding shallow hazards would exist. To foresee potential difficulties and give a realistic plan for handling the difficulties, experiences from other areas should also be considered and reviewed.
Faulting to shallow depths

A surface fault is an unsatisfactory location for a wellhead because of the poor structural support offered. The fracture rock sediments may cause bit control and well instability (slumping) problems. Shallow gas and over-pressured water may erode the sand/mud around the wellhead and reduce an already weak structural support.

Where sand lenses may be significantly over-pressured due to gas/water migration along fault planes from below. The formation pore pressure may approach and even exceed the formation fracture pressure. A shallow gas or shallow flow blowout may be caused by extreme pressure build as discussed. Craters in the floor of the Gulf of Mexico are thought to be the result of a naturally occurred shallow gas blowout. E.g. Shell Oil Company survey team found a crater in 2176m of water, about 115 km Southeast of the Mississippi River delta. The crater was elliptical in shape, 58m deep, 280m across and about 400m long.

Slow seepage of the abnormally pressurised gas was thought to be blocked by the formation of gas hydrates in the near surface sediments. When the pressure exceeded the formation fracture pressure, the blowout occurred.

Limited information from the area may be available. However, oil company reports may show that many shallow faults are identified. A large number of these may extend all the way to seabed. E.g.

Report “Shallow Stratigraphic Drilling Voring Basin 1993 – Environmental and Geological Background Data” described possible faults to shallow depths at borehole location 644. Significant gas content was found below 22m. Although the absolute values are somewhat uncertain due to unexplained differences between shipboard and land based results, it is clear that the content is 3-4 orders of magnitude greater than found in borehole 642. The gas content was highest between 80 and 150m, where large gas expansion cracks formed. The gas in the cracks had 45-89% methane according to shipboard results. Another methane peak occurred around 230-235m at the boundary between partly glacial muds above oozes. The gas content in 644 is in strong contrast to the other ODP sites, where maximum methane content of 23 ppm was measured. Based on the geochemistry and carbon isotope data the gas in borehole 644 is believed to be biogenic and formed from organic material within the gassy sediments. It may be noted, however, that this site is located in an area with young and possibly active faults dying out in Oligocene – Neogene strata less than 100m depth. This could indicate high pore pressure, perhaps related to biogenic methane formation in this interval.
Shallow gas reservoirs

Shallow gas accumulators have historically caused severe accidents to happen in certain areas where drilling for oil and gas has taken place, e.g. shallow gas has been reported in approximately 27% of all wildcat and appraisal wells drilled on the Norwegian continental shelf. Several smaller kicks have occurred, and seven blowouts as a result from shallow gas have been recorded.

In the Troms, Haltenbanken area and North Sea in general, observed shallow gas is found in many blocks where drilling has taken place. It shows that gas accumulations to a certain extent is related to the major tectonic elements and represents a special problem in the Viking Graben and in the East Shetland Basin to the north. This fact may be indicative of a petrogenic source for some of the shallow gas in this area.

Little information is currently available from the deepwater areas. Exception is evidence of gas from the shallow wells and gas chimneys and "bumps" that can be seen above a number of fault blocks. Shallow high amplitude reflections and pull down effects can be seen over the crest of the fault blocks. To illustrate a typical shallow gas problem, the hazards in the Norwegian Sea will be assessed on a general basis cap-rocks and possible overpressure.

Cap-rock

The Plio-Pleistocene sediments are soft and very fine grained in the Voring area (specific gravity of about 1.8g/cc, and typical clay content of about 50%-70%. Marine clays may have permeability’s in the $10^{-7}$ – $10^{-1}$ Darcy (Freeze and Cherry 1979), and due to the high clay content the Plio-Pleistocene cover sediments at the Voring plateau probably fall in the low range. The potential seal capacity of this cover is therefore significant. Still observations in shallower water indicate that in spite of a low permeability, silty clay leaks gas to the seabed resulting in pockmarks on the seabed surface. In the waterdepths found at the Voring Plateau, however, gas would be trapped as hydrates when entering into the stability field at around 320–250m burial depth (or deeper depending on geothermal gradient). The seal capacity of the Plio – Pleistocene cover will therefore not be utilised unless this cover is thicker than this. At such burial depths a cover of silty clay must be regarded as a seal fully capable of capping hazardous quantities of hydrocarbons.

Below the gas hydrate zone, the risk for potential gas occurrence should be judged from standard accumulation criteria (migration route, trap, seal). The evidence that hydrate may form a seal is poor (Joides Journal vol. 18, no. 7, 1992, p.7), and a base of gas hydrates does apparently not imply an impermeable layer, but rather it indicates the base of an upper zone where the free gas will not present in hazardous quantities. Still, if a BSR (bottom simulating reflector) is present it should be considered if this surface together with other geologic surfaces may form a trap.

Migration and accumulation of oil is likely to be associated with gas. It is therefore assumed that BSR indication of gas hydrates would be present if liquid hydrocarbons are trapped.
Overpressure

Shallow gas is always over pressured. The amount of over pressure at the top of the shallow gas accumulation is dependent on the vertical thickness of the gas column. By neglecting the density of the gas, the amount of over pressure may be approximated by:

\[
\text{Over pressure (bar)} = \text{SG}_{\text{saltwater}} \times G \times T/100
\]

\( G \) = Gravity constant
\( T \) = Vertical thickness of gas accumulation (m).

The gas accumulation thickness is dependent on factors like:
- the gas trap height
- the cap rock permeability
- the amount of gas supplied from the source
- the cap rock fracture gradient

In an area with near horizontal bedding and small structural closure, the gas height and corresponding over pressure will be low. However, where there is significant structural relief, small stringers, too thin to show up on shallow seismic, can contain large over-pressure.

Assuming the worst case, gas pressure equivalent to formation fracture pressure could occur. An example calculation is carried out for a water depth of 1000m. The result is shown in the table below. The fracture gradient is assumed to be identical to the overburden gradient and the soil gravity is set to 1.8 SG.

<table>
<thead>
<tr>
<th>Depth to top of gas (m MSL)</th>
<th>Fracture gradient</th>
<th>Maximum gas height (m)</th>
<th>Max over pressure at top of gas (bar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1100</td>
<td>1.07 SG</td>
<td>43</td>
<td>4.3</td>
</tr>
<tr>
<td>1200</td>
<td>1.10 SG</td>
<td>86</td>
<td>8.6</td>
</tr>
<tr>
<td>1300</td>
<td>1.13 SG</td>
<td>129</td>
<td>12.9</td>
</tr>
<tr>
<td>1400</td>
<td>1.16 SG</td>
<td>172</td>
<td>17.2</td>
</tr>
<tr>
<td>1500</td>
<td>1.18 SG</td>
<td>215</td>
<td>21.5</td>
</tr>
<tr>
<td>1600</td>
<td>1.19 SG</td>
<td>258</td>
<td>25.8</td>
</tr>
</tbody>
</table>

Recommendations
To reduce the possible overpressure problem, the well location should be moved away from the top and down flank from any structural closures.
If practically possible a weighted mud system should be used instead of seawater when possible shallow gas zones have to be penetrated.
A more detailed description of procedures and methods to reduce the shallow gas hazards are given in the “Shallow Gas” documentation.
Fracture pressure

Using the rotary table as reference point, fracture gradients generally will decrease as water depth increases. This is especially significant for the upper formation layers.

As a result of the lower fracture gradients, the difference between the mud weight that will cause formation fracture and the mud weight required to balance the formation pore pressure will be smaller.

Too high mud weight will cause lost circulation and reduced well control.

Too low mud weight will cause a kick if permeable formations are penetrated, and loss of well control will occur if no means of closing the well is available or dynamic killing is unsuccessful.

The lines shown on the figures below illustrate why fracture gradients are of more concern in deep water than in shallow water. The drawing to the left represents drilling at 200m water depth and the drawing to the right represents drilling at 1000m water depth. Both drawings show the sea water gradient, which is equivalent to the formation pore pressure in a normally pressured well. This is the gradient that must be exceeded by the gradient of the drilling mud to prevent fluid influx or a kick from a normally pressured reservoir. On the other hand, the fracture gradient must not be exceeded by the gradient of the drilling mud if lost returns should be avoided. The difference between minimum mud weight (seawater), and maximum mud weight at 1500m (assuming a casing is set at this depth) clearly indicate how the mudweight limits are reduced for the deep-water case. The small difference leaves smaller margins for error. Much more attention must be given to the circulation rates, the drilling rates and the mud control, especially at the shallow section of the hole.

The depth below seabed of the first casing string allowing circulation to surface increases with increasing water depth. As an example the minimum depth below seabed where estimated to 600m in a 2000m water depth well drilled by Shell (Reference 3). To reach a target at the same depth below seabed, a higher number of casing strings are likely to be required for the deep water case than for the shallow water case.
Shallow prospects

Shallow prospects may represent a blowout hazard since the margin between pore pressure and formation integrity is small. This is especially true for deep water.

- The formation fracture gradient generally is lower than for shallow water depth.
- The structure may be covered by only a thin section of caprock and the sediments above may be unconsolidated and loose. The integrity of the last casing shoe above the reservoir, and the bonding between cement and formation may be reduced due to the low integrity of the sediments. Reference is made to reports where loose top sediments are reported on some of the shallow well sites.
- The pore pressure may be abnormal, especially at the crest of the formation. The difference between minimum mud weight required to balance the pore pressure, and the maximum mud weight allowed to prevent lost circulation may be small.

If it is decided to drill a shallow prospect, a down flank well location is preferable from a risk reducing point of view. Attention must be given to the choice of casing point in order to obtain sufficient fracture at the shoe. The circulation rates, the drilling rates and the mud properties should be optimised to minimise swabbing effects and overloading of the annulus.

Solid-phase gas hydrates

Hydrates are ice like mixtures of natural gas and water. Hydrates are a binding between gas molecules and water molecules in the sense that water molecules form a cage entrapping the gas molecules. Methane, ethane, propane, n-butane, i-butane, carbon dioxide, hydrogen sulphide and nitrogen are the commonly known hydrate forming components. Hydrocarbons heavier than the butanes will not form hydrates as these molecules are larger than the water molecule formed cage.

One concerning property of hydrates are the amount of gas that can be bounded in a given volume. The solid/gas ratio can be as high as 1:70, e.g. one litre hydrate will produce as much as 170 litres gas (at 1 bar) where decomposing.

Gas hydrate deposits have been identified in the Russian, Canadian and Alaskan Arctic as well as several subsea locations (Makogen 1965, Katz 1971, Davidson et al. 1978, Matthews 1986). Hydrate cores have been obtained from the Gulf of Mexico, the western coast of Guatemala and Prudhoe Bay. Unusual drilling problems have been faced by the drilling companies in the past when they drilled through hydrate zones. Problems of well control due to severe mud gasification were reported by Imperial Oil Ltd. (Bily and Dick 1974) and Panartic Oil Ltd. (Franklin 1979). Other hydrate experiences include: fizzed cuttings, near blowout situations, wellbore freeze up and casing collapse.

Below the gas hydrate zone, the risk for potential occurrence should be judged from standard accumulation criteria (migration route, trap and seal). The evidence that gas hydrates may form a seal is poor, but the possibility should not be ruled out. If the bottom of the hydrate zone is possible to map, it should be considered if this surface may form a reservoir trap, and the well location should, if possible, be removed away from this position.
A study “Shallow Stratigraphic Drilling Voring Basin 1993 – environmental and geological background data” reports that gas hydrates were not visually observed in the cores taken.

Bottom simulating reflectors (BSR) which are seismic reflectors of the temperature-pressure dependent base of gas hydrates are not observed on geological data. Kvernvolden et al (1989) consider, however, that there is geochemical evidence that gas hydrates are present, and they suspect that the gas observed during drilling one of the shallow wells between 80 and 150m are possible results from gas hydrates decomposition. Lack of observation on seismic data may indicate that any gas hydrates in this area occur only scattered.

The base of hydrate stability zone (BSR) can also be determined from the phase equilibrium equation. Forming of hydrates is only possible within specific temperature and pressure ranges. A computer program for estimating depth to gas hydrates based on the bottom water temperature and geothermal gradients is given in Joides Journal Vol. 18, no. 7, 1992, p 22. In table 4.1, Appendix 1 this program is used to calculate depth to seabed to base of gas hydrates varies from 254m-321m for water depths in the range of 1300m-1550m. This suggests that any shallow gas accumulated at shallower burial depth than 254m-321m would be trapped as gas hydrates.
Survey methods and equipment

Introduction: Hazards and survey equipment
Drilling hazards can be split into two categories: seabed hazards and sub-seabed hazards.

The seabed hazards may consist of:
- Topography; slumps or faults extending up to the seabed
- Man made objects; wrecks, mines etc
- Poor anchoring conditions; very soft clay, cemented sand, anchoring is probably only relevant in “shallow areas”

Such hazards are mapped with combinations of data from echo sounder, side Scan sonar, very high resolution seismic and samples from the upper few Metres of the seabed.

Sub-seabed hazards may consist of:
- Shallow gas, shallow water flow reservoirs
- Gas hydrates
- Layers of boulders
- Shallow prospects

Such hazards are mapped with various seismic equipment.

Note:
The site survey term “shallow” normally refers to depths less than 1000m below seabed.
Factors influenced by depth

Energy
Seismic energy reduces with increasing water depth. For an omni-directional source, like a mini-seismic source, the energy is inversely proportional to the square of the distance the wave has travelled. It is possible, to a large degree, to compensate for this loss by adding more power to the source and by amplifying the returned signal.

Horizontal Resolution
When a geological event has a lateral extent less than the Fresnel zone the event will appear only as a diffraction in the unmigrated seismic sections

\[
R_f = \frac{rf}{t} = \frac{rf}{v} = \frac{rf}{f}
\]

rf = radius of Fresnel zone
t = two-way time in seconds
v = average velocity
f = dominant frequency in Hz

As can be seen from the t element of the Fresnel formula the Fresnel zone increases with depth.

Vertical Resolution
To detect both top and bottom of a layer the thickness must be at least half a wavelength. The wavelength (signal frequency) is therefore the limiting factor for vertical resolution. The water column removes relatively little of the higher frequencies. The water depth is therefore not critical for the vertical resolution.

Towcable Length
The longer the towcable, the more difficult it is to drag the towed equipment downwards.

Hydro acoustic Positioning
Becomes difficult with increased depths due to loss of energy and reflections caused by stratification of the water column (this does not apply to long baseline systems).
Survey methods

**ROV Survey**
It is possible to get excellent side scan sonar and echo sounder data using ROV, but the ROV cannot transport seismic systems to be used for detection of shallow gas/hydrates. The cost of ROV surveys is several times that of “analogue surveys”.

**Analogue Survey**
Surveys which use boomer/sparker/parametric source, mini-seismic source, towed sonar and hull-mounted single/multibeam echo sounder are often referred to as “analogue” surveys. Today all “analogue” data can be digitally recorded and enhanced by processing.

**2D High Resolution Seismic Survey**
This is multi channel seismic with high resolution sources. The target depth is approx. 300-1200m below seabed. These surveys use short group lengths, short streamers (600 to 1200m) and short shot distances.

**“Traditional Site Survey”**
This is a survey with both “analogue” systems and 2D high resolution seismic. Most commonly used equipment can be operated simultaneously with a minimum of interference between the systems.

**3D Deep Seismic**
The 3D data can also be used for interpretation of shallow gas/hydrates.

**3D High Resolution Seismic**
These are 3D surveys shot with a high frequency source and with fewer offsets than deep-seismic 3D. The sampling frequency is higher and the distance between shots is also less than for other 3D. The result should be very high vertical and horizontal resolution in the upper 1000m of sediment. Due to high cost compared to 2D high resolution seismic (about 2-3 times more expensive), it has yet to be tested.
Survey Equipment

Positioning
The survey vessel can employ the same surface positioning system as is used elsewhere. Positioning of deep towed equipment, like a side scan sonar or ROV, however, becomes more difficult. Deep water requires long tow cables and umbilicals and thus results in long ranges for the hydroacoustic positioning equipment (HPR). For these depths the commonly used hull-mounted HPR systems (ultra short baseline) are not technically feasible for towed systems.

In deep water long baseline acoustic positioning systems must be used for positioning of ROVs and deep towed systems.

Echo Sounders
Precise mapping with echo sounder is necessary to measure the depth, seabed slope and the presence of topographic features on the seabed like pockmarks, slumps etc.

The seabed topography is mapped by using either a single beam or a multibeam echo sounder. There are several systems available on the market. The multibeam echo sounder gives far more economic mapping than the single beam echo sounder,

At water depths around 1000m it is not expected that a bathymetric map processed from a single or multibeam echo sounder will reveal topographic details with lateral extent less than 50m.

Hull-mounted echo sounder with 2° beam:
Vertical resolution : +/- 2m at 100m depth
Horizontal resolution : 35 x 55m footprint at 1000m depth

Hull-mounted multibeam echo sounder:
Vertical resolution : +/-m at 1000m depths
Horizontal resolution : strongly dependent on other sensors, especially the roll, pitch and gyro sensors. Centre beams have similar resolution as single beam echo sounders, but the resolution of the outermost beams is far poorer than that of the centre beams.

The echo sounder can also be mounted on ROV. Both single and multibeam systems are available. Vertical and horizontal resolution can (depending on positioning) come down to decimetre magnitude.
Side Scan Sonars
The side scan sonar creates a photographic image of the seabed, but instead of light as in a camera, the sonar uses high frequency sound to illuminate the seabed. The sonar is used for detection of seabed objects/features, like boulders, wrecks and cables and particularly for details in the seabed topography which due to lack of resolution cannot be picked up with an echo sounder. The sonar can also reveal the presence of surface-extending faults and slumps in the area.

There are three different categories of survey sonars:

Hull-Mounted Sonar (ex EM1000/EM12)
This can be used for a coarse classification of the seabed materials, but not for detection of smaller objects like boulders.

Towed Sonar
There are several side scan sonars which can operate in deep water. The problem with towing sonars in deep water is to maintain the height above the seabed. The deeper the water, the higher above the seabed it must be towed. The result is decreased resolution. The side scan sonar should not be towed higher than 50m above the seabed. This may become difficult. If a 50-100 kHz side scan sonar is towed at 50m above seabed and with 300-500m range, it is possible to interpret details down 3 x 3 x 3m with some confidence.

ROV Mounted Side Scan Sonar
The ROV can survey just a few metres above the seabed, allowing the use of very high frequency sonars (500 kHz) which can detect details in the magnitude of two decimetres. When surveying at a higher altitude it may also operate with sonars of lower frequencies and longer range.

It is possible to process sonar data to make an image of the surveyed area. Combining such an image with processed bathymetry to produce one map, permits more confident detection of the critical features than was previously possible with pure manually methods.

Magnetometers
The magnetometer can be used to detect debris made by metals, particularly iron. To get any detection of such, the unit must be towed very close to the debris, not more than a few metres away, unless it is a very large object like a shipwreck. Since this is difficult to maintain the magnetometer is very little used for site surveys. A sonar gives far safer detection of debris.
Seismic Systems for the Upper 50m

There are several seismic systems for mapping the uppermost tens of metres of the seabed. The vertical resolution differs slightly between the systems, but is generally about 0.2-0.5m (at seabed, detection of top and bottom of a thin layer (1550 m/s 1500 Hz).

Pingers

The pinger, or sub-bottom profiler, is a high frequency (typically 3.5 kHz) seismic source (transducer) which only penetrates down to 1-5m. It is frequently used to map the uppermost layers for pipeline and other construction work. The pinger can be towed, ROV-mounted (though quite disturbed by noise from the ROV) or hull-mounted. The last of these is often the best solution. There is frequently quite a lot of ringing on the seismic data from the pinger.

Parametric Sources

Parametric sources may be either hull-mounted or towed. Since the source is parametric, it must be at several tens of metres above the seabed in order to produce any data, thus it is not good for usage on ROV. Parametric sources are used instead of the older, but more usual deep towed boomer/sparker systems.

Deep Towed Boomer/Sparkers

The boomer or sparker unit is towed at depths down to 300m. It produces good data at water depths down to 1000m.

Chirp Systems

These are seismic systems which employ the same method as used in vibroseis. Such systems have very little sensitivity to noise, and can be adapted for several target depths. Both towed and ROV versions are available. These systems are still evolving, and are not yet tested in the Norwegian sector but results elsewhere look very promising.

Mini Seismic Source

A mini air or watergun is very often used for detection of shallow gas and hydrates. The unit is towed at a depth of 0.5-1.0m. Resolution is very good in most of the depths at which shallow gas frequently occurs in the North Sea, i.e. 50-700m below seabed. Most such data is recorded as single channel data, but below the first seabed multiple quality is limited. When recorded as multichannel seismic, there is often good data down to 500m below seabed, depending on geology.

Vertical resolution: 1.4m (close to seabed, detection of top and bottom of a thin layer (1600m/s 600 Hz).

High Resolution 2d

An airgun array is normally used for mapping the geology of the upper 1500m. This system is used for detection of shallow gas below the range of the mini seismic source (1st multiple) and 1500m.

If good 3D data is available together with data from the mini-seismic source the high resolution 2D data may not be required.

Vertical resolution: 4m (close to seabed, detection of top and bottom of a thin layer (1600m/s 200Hz)).
3D Seismic
Resolution of 3D data shot and recorded with one vessel, is generally very good for
detection of shallow gas except for the uppermost hundred(s) metres of the seabed
where it must be combined with data from a mini-seismic system.

Today 3D seismic data is often recorded on multiple streamers and recording
vessels. When the distance between source and streamer (offset) is increased, the
upper part of the seismic section becomes very poor. It seems that 3D starts to
produce data of reasonable resolution at approximately twice the depth of the
maximum offset.

Vertical resolution: 10m (close to seabed, detection of top and bottom of a thin
layer (1600m/s 80Hz)).

If the existing 3D dataset is reprocessed for optimum resolution of the upper part, the
quality should be somewhat improved. However the quality depends on the number of
streamers (and thus the offset) and the water depth (the more shallow the more sensitive
for large offset).

High Resolution 3D
This is a 3D survey shot with a high frequency source, for example a mini airgun
array, and with a shorter distance between streamer and source than is used in
conventional 3D. The sampling frequency is higher and the distance between shots
are less than for other 3D surveys. The result is very high vertical and horizontal
resolution in the upper 1000m of sediment.

Vertical resolution: 2m (close to seabed, detection of top and bottom of a thin
layer (1600m/s 400Hz)).
Soil Sampling

Soil sampling is required to measure the geotechnical properties of the seabed. The common way to do this is with a gravity corer. This produces a continuous core of the upper 0-6m of the seabed. The unit is simple to operate and reliable. It is expected to operate well in water depths greater than 1000m.

The gravity corer does not function when the seabed consists of sand, gravel or other hard soils. Under such circumstances more comprehensive equipment must be used. Possible solutions for extraction of such sediments are push samplers or CPTs. Both are mounted on a weight platform (e.g. 7 tons, size 5 x 5m). Surface supplied hydraulics are used to force a test pipe into the seabed. Both solutions require dynamic positioning (DP) on the survey vessel. The gravity corer does not require DP. As far as Geoteam AS is aware such units have not been tested at depths exceeding 400m.
## SYSTEM OVERVIEW

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surface positioning</td>
<td></td>
</tr>
<tr>
<td>Diff. GPS/radio nav.</td>
<td>Very good</td>
</tr>
<tr>
<td>Hydroacoustic positioning</td>
<td></td>
</tr>
<tr>
<td>Ultrashort baseline Long baseline</td>
<td>poor, not acceptable very good</td>
</tr>
<tr>
<td>Hull-mounted echo sounders</td>
<td></td>
</tr>
<tr>
<td>Single beam</td>
<td>good (max. beam angle 2°) good</td>
</tr>
<tr>
<td>Multibeam</td>
<td>very good</td>
</tr>
<tr>
<td>ROV-mounted Echo Sounders</td>
<td></td>
</tr>
<tr>
<td>Single beam</td>
<td>very good (better than above)</td>
</tr>
<tr>
<td>Multibeam</td>
<td></td>
</tr>
<tr>
<td>Magnetometer Towed or ROV-mounted</td>
<td>good for big objects</td>
</tr>
<tr>
<td>Side Scan Sonar Towed</td>
<td>very good</td>
</tr>
<tr>
<td>Hull-mounted</td>
<td>good</td>
</tr>
<tr>
<td>Side Scan Sonar Hull-mounted</td>
<td>not acceptable</td>
</tr>
<tr>
<td>Seismic systems, target depth 0-50 metres:</td>
<td></td>
</tr>
<tr>
<td>Pinger</td>
<td>variable</td>
</tr>
<tr>
<td>Parametric source</td>
<td>good</td>
</tr>
<tr>
<td>Deep towed boomer/sparker</td>
<td>good</td>
</tr>
<tr>
<td>Chirp</td>
<td>good/very good</td>
</tr>
<tr>
<td>Seismic systems, target depth 50-500 metres:</td>
<td></td>
</tr>
<tr>
<td>Mini seismic source</td>
<td>very good</td>
</tr>
<tr>
<td>3D high resolution</td>
<td>very good</td>
</tr>
<tr>
<td>Seismic systems, target depth below 200 metres:</td>
<td></td>
</tr>
<tr>
<td>2D high resolution</td>
<td>good</td>
</tr>
<tr>
<td>3D seismic</td>
<td>can be good</td>
</tr>
<tr>
<td>3D seismic, reprocessed</td>
<td>can be good</td>
</tr>
</tbody>
</table>
Rules of thumb

1. Various methods exist for mapping of the shallow hazards. The optimum method for mapping of seabed hazards is to use ROV mounted sonar and multibeam echo sounder.

2. The upper tens of metres can best be mapped with a hull-mounted parametric source or a Chirp system. If ROV is used for mapping of the seabed hazards the seismic system should be mounted on the ROV.

3. Shallow water flow and gas reservoirs from 50 to 1000m below seabed, are best mapped with high resolution 3D seismic. The second best choice is a combination of seismic data from mini airgun or mini watergun and either high resolution 2D or possible conventional 3D seismic, if this shows good resolution in the interval not covered by the mini-seismic system.

4. Typical line spacing for the 3D seismic surveys is 25 meter. For 2D surveys it is 250m in one direction and 500m in the other. For 2D surveys it is common to make a denser pattern around the well location applying a 100m spacing in both directions. Typically a time frame of 4 weeks should be expected from when the field work is finished to presentation of final results.

5. It is recommended to avoid drilling at identified shallow hazards. The location of exploration wells should be moved away from:
   - Areas where faulting to shallow depths may be expected
   - Shallow depth structural closures, or a closure of the BSR (base of hydrates)
   - Shallow gas accumulation
   - Shallow reservoirs

6. If it is impossible to move away from shallow hazards, the well should be designed to minimize the risks.
   - If practically possible a weighted mud system should be used rather than sea water when a possible shallow gas zone has to be penetrated
   - The well should be placed as far down flank on a mapped structure as possible
   - Procedures and methods for risk reduction as described under the chapter “Shallow Gas” should be implemented

7. Soft seabed may cause anchoring problems. Possible solutions to the problem would be to use specially designed “mud” anchors (Stevpris anchors have been successfully used in sediments softer than at the Voring plateau in the Gulf of Mexico). Use of piggyback anchors or increased number of anchor lines from 8 to 12 or more can also be considered.

8. The soft formation’s support to the wellhead may not be sufficient for use of standard equipment. Depending on the results of the seabed strength analysis, larger than standard OD conductor may be required (36”), higher grade (X52 or X56) or thicker wall (1.5” or 1.75”).

9. Small margins between pore pressure and fracture pressure must be expected when drilling the upper hole sections.
Shallow gas risk Statements

Shallow gas definitions

For this and other documents on this web-site. The following definitions will be applied to the terms used to describe risk in the shallow gas assessment documents.

High
An anomaly showing ALL of the seismic characteristics of a shallow gas anomaly, that ties to gas in an offset well, or is located at a known regional shallow gas horizon.

Moderate
An anomaly showing MOST of the seismic characteristics of a shallow gas anomaly, but which could be interpreted not to be gas and, as such reasonable doubt exists for the presence of gas.

Low
An anomaly showing SOME of the seismic characteristics of a shallow gas anomaly, but that is interpreted not to be gas although some interpretative doubt exists.

Negligible.
Either there is NO ANOMALY PRESENT at the location or the anomaly is clearly due to other, non gaseous, causes.

Note: Any one indication can be spurious. Shallow gas interpretation on seismic data involves accumulation of evidence. The more guide points that can be answered by a yes, the greater the risk of gas being present.
# Shallow gas Interpretation guide points.

<table>
<thead>
<tr>
<th>Shallow gas interpretation guide points</th>
<th>Yes</th>
<th>No</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Is the reflection from the suspected gas pocket anomalous, or bright in amplitude?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Do seismic data allow the anomaly to be tied to an offset well where gas was present in the same interval?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3. Is the amplitude anomaly structurally consistent?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4. Is the amplitude of the anomaly equivalent to five times, or more than, the background (non bright value) for the same reflector?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5. If bright, is there one reflection from the top of the reservoir and once from the base?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6. Do the amplitudes of the top and base reflections vary in unison, dimming at the same point at the limit of the reservoir?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>7. Is a flat spot visible?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8. Is the flat spot dipping or consistent with gas velocity sag?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9. Is there a pull down effect of underlying reflectors indicative of gas velocity sag?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10. If present, is the flat spot uncomfortable with the structure but consistent with it?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11. Does the flat spot have the correct zero-phase character?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12. Is the flat spot located at the down dip limit of brightness (or dimness)?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>13. Is a phase change visible at the edge of the anomaly?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>14. Is the phase change structurally consistent and at the same level as the flat spot?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>15. Have the seismic data being used been converted to zero phase?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>16. Do the bright/dim spots or phase changes show the appropriate zero phase character?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>17. Is there an anomaly in velocity derived stacking velocity across the interval?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>18. Is there a low frequency shadow below the suspected reservoir?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>19. Did a study of amplitude versus offset on the un-stacked data support the presence of gas?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>20. Does a near offset range stack show a lower amplitude response than a far offset range stack for the same event?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>21. Are there any comparative P &amp; S wave sections available to aid in clarification of gas presence?</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Appendix 1

A typical Operator's Shallow gas policy.

Section: Shallow Gas

1 Definition
Shallow gas is defined as accumulations of gas, which occurs at a depth above the setting depth of the first pressure containment casing string.

2 General
1. The possibility of shallow gas shall be considered in the preparation of all drilling programmes.

2. A digital shallow seismic survey shall form part of the location site survey for offshore locations. If any anomaly is considered to have the possibility of indicating shallow gas then gas shall be assumed present.

3. If the risk of encountering shallow gas is considered high, the surface position of the well shall be relocated outside of the anomaly. If it is not possible to relocate, then appropriate mitigations shall be assessed and incorporated in the drilling programme.

4. A shallow gas kick shall not be shut in. The well initially shall be allowed to flow to deplete the shallow gas zone whilst pumping fluid into the well at the maximum sustainable rate.

5. Mutually agreed procedures between the Operator and Drilling Contractor shall be established prior to the start of a well. These shall cover foreseeable contingencies should shallow gas be encountered.

3. Floating Drilling Operations
1. Wells shall be drilled riserless unless:
   - It is a government regulation to drill with a riser and diverter installed.
   - A mud system is required to drill the hole for surface casing.

2. If the well is to be drilled with a riser and diverter installed, and a shallow gas kick is taken, immediate preparations shall be made to unlatch the riser assembly and subsequently move the rig off location. In the event of a riser/diverter equipment failure, the riser shall be unlatched and the rig shall be moved off location in an expedient manner.
Appendix 1.

Norwegian Petroleum Directorates (NPD) regulations

Section 40: Implementation of operations
Drilling and well activities shall at all times be carried out in a safe and proper manner in accordance with specified procedures.

Measures shall be taken to ensure high regularity to avoid unintentionally suspended operations.

Relevant equipment specifications for operation and maintenance with associated limitations shall to the extent necessary be reflected in applicable operations and maintenance procedures. Operational measures shall be taken to prevent blowout, fire, explosion, pollution or other damage.

Well casing shall be planned and carried out in such a way that well control is maintained at all times.

Safety equipment for drilling shall be installed on a continuous basis as required by the activities at any time, and otherwise as laid down in the present regulations.

Section 41: Measures against uncontrolled influx into the well/ blowout prevention.

The facility shall be fitted with accessible equipment ensuring well control, so that personnel during drilling and well activities are able to operate and shut down the installation in the event of uncontrolled influx into the well.

In the event of equipment failure, mobile facilities shall be capable of manoeuvring away from a well with an uncontrolled influx/blowout situation and to a safe area.

Before drilling and well activities are commenced, the operator shall have drawn up a blowout emergency plan describing suitable locations for the drilling of a relief well, for mobilization and organization of personnel, as well as equipment and services both for drilling and well killing by way of relief well and for a possible direct intervention in a blowing well.

The crew shall take part in regular and realistic drills which shall include measures to discover and prevent the loss of barriers and near cases of uncontrolled influx into the well in connection with drilling and well activities.

The personnel shall be trained in evacuation from an exposed area to a safe area. The well control drills shall be documented.
Section 42: Measures for handling of shallow gas
When probability of encountering shallow gas has been demonstrated, the operator shall take measures to ensure that all operations can be carried out with adequate safety.

A pilot well shall be drilled when there is a possibility of encountering shallow gas.

The minimum depth of a pilot well is the planned setting depth of the surface casing of the well.

During drilling of top hole sections with riser/conductor, a diverter system shall be installed and be operative prior to any drilling in a formation where shallow gas may be encountered.

Personnel controlling the drilling operations shall be capable of activating the system for handling of shallow gas. The diverter system shall furthermore be capable of being activated from a location which is independent of and which is located at a safe distance from the drillfloor/cellar deck.

Section 43: Formation strength
During drilling in well sections with formation pressure the operator shall have carried out an estimation of the weakest formation strength of the well section.

Procedures for implementation of drilling operations and methods for calculation of formation strength shall be documented in the drilling programme.

In case sufficient formation strength is not achieved, the further programme shall be subject to deviation procedure and corrective action shall be taken.
Re. Section 41: Measures against uncontrolled influx into the well/blowout prevention

The regulation requirement re. capability of being moved in a safe way from an uncontrolled influx into the well/blowout, will in the case of anchored installations be complied with through the following technical solution:

Chain/wire rope stoppers or if applicable, pal mechanism, shall individually be capable of being released from a well protected location near the winch and from a manned control room or bridge. The release must be possible to carry out without particular preparations and by means of stored energy, emergency power or similar within 15 seconds and up to a tension corresponding to the breaking strength of the anchor chain/wire rope.

During this operation the nominal stress of the structure shall not exceed the lowest specified yield point, however at a maximum 80% of the breaking strength of the material.

The safety level shall be maintained by initiating necessary compensatory measures. The operator furthermore has a duty to inform all involved personnel of these measures, cf section 24 of the safety regulations concerning adequate training. Furthermore it follows that procedures in connection with critical situations shall have been drawn up and shall have been made known to all involved personnel.

For each drilling crew, pit level drills should be carried out at least twice per week with a view to necessary measures to be taken in the event of pit level variations.

Drills involving use of blowout preventers to prevent the influx of fluid or gas into the well during drilling, should be carried out weekly for each crew.

When conditions permit, drills should be carried out as realistically as possible with fixed pressure build up and preparation and start up of circulation, as well as choke drills.

Corresponding realistic choke drills should be carried out with regard to well activities.

Drills should be repeated with sufficient frequency to achieve an acceptable reaction time and correct reactions from the personnel.

Drills carried out should be documented in the daily operations reports, including the IADC report where such report is used.

In order to comply with the requirements of the regulations with regard to a blowout emergency plan, the following items should as a minimum be covered:
a) relief drilling
   aa) organization plan (mobilization and organization);
   ab) mapping of suitable drilling locations (including shallow seismic interpretation of the top section);
   ac) evaluation of blowout scenarios and kill methods;
   ad) requirements to installation and equipment for relief drilling and well killing;
   ae) evaluation of relevant well profiles and casing programme;
   af) estimation of necessary pumping capacity;
   ag) list of available equipment and time critical activities;

b) direct well intervention
   ba) organization plan (mobilization and organization);
   bb) an evaluation of requirements to equipment with regard to capacities and dimensions;
   bc) mapping of and localizing relevant installations, well intervention equipment and services.

Through the emergency plan (ref. a and b above) installations with capacity for relief drilling or well intervention shall be identified. It shall be possible to mobilise these installations without the need for major structural or equipment upgrading/modifications, which entail loss of time.

Mobilisation time for the installation will depend on necessary security measures for the operation/well which is suspended and on ocean depth. There shall be documented agreements/options for this, so that initiation of relief drilling or well intervention at a relevant location should commence no later than 12 days after the option is declared.

Re. Section 42: Measures for handling of shallow gas

General
Measures against shallow gas blowout are applicable to all possible ways of communication from the well to the environment.

Location for wells must generally be selected where the probability of encountering shallow gas is lowest.

If there is a possibility of encountering shallow gas the regulation requirement entails that well data shall be evaluated before further opening of the well to the necessary diameter.

In top hole sections with pressure differentials that can cause influx into the well/blowout or where undesired communication between different pressure regimes may occur, drilling shall be carried out with two independent barriers, cf section 23:

a) at least one barrier against unintentional influx, e.g. drilling fluid
b) at least one barrier for diversion of shallow gas, e.g. a diverter system.

Penetration rate for pilot holes shall be limited according to the MWD/LWD equipment’s suitability and communication with the well, so that possible gas can be detected at a sufficiently early time.
Pilot holes shall be drilled in new areas, whereas in the case of areas with known geology they may be considered omitted if the operator can provide documentation that there is no shallow gas.

It is pre-assumed that the operator carries out a consequence analysis related to shallow gas and any possible omission of a pilot hole in the drilling of wells at sea depths less than 100 meters.

During drilling of top hole sections from mobile facilities there shall be a ROV operative at the wellhead and a sufficient amount of drilling fluid/kill fluid ready for use on board.

**Drilling with riser**

During drilling of top hole sections with riser/conductor installed, a pilot hole shall be drilled which does not have a greater diameter than to enable a gas influx to be stopped by means of the density of the drilling fluid and the anticipated dynamic pressure drop in the annulus, until drilling fluid/kill fluid has been circulated into the well.

The pilot hole shall be drilled with a diameter less than or equal to 12¼”.

Downhole equipment enabling effective handling of a possible influx into the well should be used.

During drilling of top hole sections with riser/conductor installed, a gas diverter system shall be installed. In the case of jack-up type facilities, conductor is in this connection regarded as marine riser.

The gas diverter system shall be fitted with elements that ensure closing also with drillstring in the well.

In order that the diverter system shall be operative irrespective of wind direction, it will normally have to consist of two pipes leading out to opposite sides of the installation.

In designing the diverter system it is important that the flow friction is reduced to a minimum.

For the purpose of releasing the riser from the wellhead activation should be possible from an additional control panel in a safe area.

**Drilling without riser**

When drilling top hole sections without riser in exploration and appraisal wells, a diameter of 9 7/8" should be used.
Re. Section 43 Formation strength

As a rule the regulation requirement means that in the case of drilling out of set casing, the formation below the casing shoe will be tested to a pressure corresponding to equivalent weight of drilling fluid for the highest expected pressure to which the formation is subjected in a well section where drilling has commenced.

If sufficient formation strength is not achieved, the deviation procedure may lead to pressure cementing of the casing shoe to check that it is the desired formation that has been tested, and not sources higher up in the well. If sufficient formation strength is still not achieved, the deviation procedure shall include a decision as to when further drilling is to stop, when a new casing programme is to be prepared as well as an assessment of relevant procedures before making further progress.

The operator shall prepare a procedure for testing of formation strength. If the strength test entails fracture of the formation, there shall be established requirements as to which point on the curve is measured formation strength. It is important that the correct value is selected before further drilling takes place in the well.

In order that full control of the well can be maintained at all times, it is important that the operator establishes a safety margin between maximum permissible weight of the drilling fluid in a well section and the formation strength of the open well.

This applies to the planning phase as well as the implementation phase. The safety margin may be expressed in density or maximum permissible influx volume for each well section. The value should be based on the influx volume resulting from the accuracy of the measuring equipment and the reaction time from influx is detected until the well is shut down.

The pressure effect of such influx will depend on well diameter and drill string diameter and the relevant friction loss during circulation. The safety margin must be adequate to be able to circulate the volume in question, without the formation breaking down from the pressure. The margin should not be less than 0.06 g/cm³ for any part of the well.