TECHNICAL REPORT

MINERALS MANAGEMENT SERVICE (MMS)

GUIDANCE ON SAFETY OF WELL TESTING

REPORT NO. 4273776/DNV
REVISION NO. 01

DET NORSKE VERITAS

TECHNICAL REPORT

Date of first issue: 2004-07-01	Project No.: 72501050
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Summary:
Based on a Joint Industry Project managed by DNV this report has been produced providing guidance on a number of key areas with respect to flow testing of wells. The guidance focuses on aspects of well testing which represent a departure from fairly traditional testing carried out in shallow water, and for which there is a relatively good safety record.
The principal areas addressed include :

- Testing from floating installations in deepwater
- Testing of High Pressure High Temperature wells
- Testing from Dynamically Positioned vessels
- Temporary storage and offloading of crude oil
- Testing in arctic areas

The Guidance relates only to safety considerations and not operational efficiency. The Guidance is aimed at all the parties involved in a well test operation :

- The Licensee (Operator)
- Drilling Contractor
- Service Company
- Regulatory Inspector

Report No.: 4273776/DNV	Subject Group:	
Report title: Safety of Well Testing		
Work carried out by: Conn Fagan		
Work verified by: Charles Mc Hardy		
Date of this revision: 15 Nov 2004	Rev. No.: 01	Number of pages: 51

Indexing terms

Key words	Service Area
Safety Well Testing Exploration	Technical
	Market Sector

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1 STRUCTURE OF GUIDANCE

This Guidance focuses on safety issues related to flow testing of wells. Section 2 provides a general discussion of well test options and outlines the regulatory background. Section 3 provides a short description of important issues and then provides guidance on means to ensure safety.

The following major areas are addressed:

- Management of safety issues in well test operations
- Testing in deep water
- Testing in arctic conditions
- Testing in high pressure and high temperature areas
- Storage and offloading of oil from well testing

In many cases the Guidance does not propose specific solutions but may propose several alternatives, or may simply identify an area which the user needs to address using best engineering judgement.

For each of the major areas discussed, a checklist has been created summarizing the main points to be considered in assessing safety. These checklists are included in Section 4.

2 INTRODUCTION

2.1 General

This Guidance has been produced as a result of a Joint Industry Project sponsored by the Minerals Management Service (MMS) Engineering and Research Branch and has been completed in 2004. The JIP has involved representatives from the main parties concerned with well testing operations, Offshore Operators, Drilling Contractors, and Well Test Service Companies.

The main industry contributors have been:

- BP
- Schlumberger
- Global Sante Fe
- DNV

However workshops and hearings conducted within the project have had the participation of a much larger number of companies.

The guidance relates mainly to areas other than traditional shallow water well testing which has a relatively good safety record, and aims at safety of testing under more challenging conditions.

2.2 Terms and Acronyms

BOP	Blowout Preventer
DNV	Det Norske Veritas
DP	Dynamic Positioning
DST	Drillstem Testing
ESD	Emergency Shut Down
F&G	Fire and Gas
H2S	Hydrogen Sulfide
HAZOP	Hazard and Operability Study
HPHT	High Pressure High Temperature
HSE	Health Safety and Environment
LMRP	Lower Marine Riser Package
MMS	Minerals Management Service
MODU	Mobile Offshore Drilling Unit
MOU	Memorandum of Understanding

OCS	Outer Continental Shelf
SEMP	Safety and Environmental Management Program
SSTT	Subsea Test Tree
USCG	United States Coast Guard
WSOG	Well Specific Operating Guidelines

2.3 Static versus Dynamic Well Testing

2.3.1 General

In order to determine reservoir characteristics an Operator may decide to carry out well testing. This testing may be either static (Wireline Formation Testing) or dynamic (Drillstem Testing). Each of these methods provides certain types of information. Selection of the test method will depend on the objectives of the well test. Where the test for example, is intended only to confirm the existence of a hydrocarbon column, a wireline formation test may be sufficient. Where wells are drilled to prove a minimum volume of hydrocarbons in place, a flow test may be the only option.

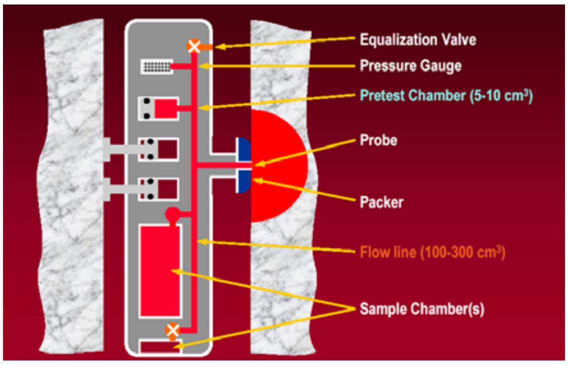
In mature areas the results of historic testing and availability of detailed seismic may be used and static testing may be sufficient for the Operator's purposes. In areas where there does not exist much if any historic data then a flow test may be the best option. Considerations such as cost of the testing and threat to the environment will also influence the choice of approach.

The guidance in this document addresses only dynamic flow testing (i.e. DST).

2.3.2 Wireline Formation Testing

Wireline Formation Testing is illustrated in the figures below and is employed to determine the following parameters:

- Formation pressure
- Pressure gradients
- Communication between zones
- Formation fluid collection
- Formation fluid mobility



Reservoir Characterization Instrument (RCI[SM]) – Baker Atlas

Some of the traditional challenges associated with Wireline Formation Testing have been:

- Contamination of reservoir samples (by drilling fluid filtrate and oil based mud)
- Drawdown and sandface control (sudden pressure change between formation and test bottle causing distortion of sample properties)
- Transportation of samples for assessment
- Limitation on type of data available

Considerable work is currently underway to address these areas and modern tools and procedures have largely overcome these issues.

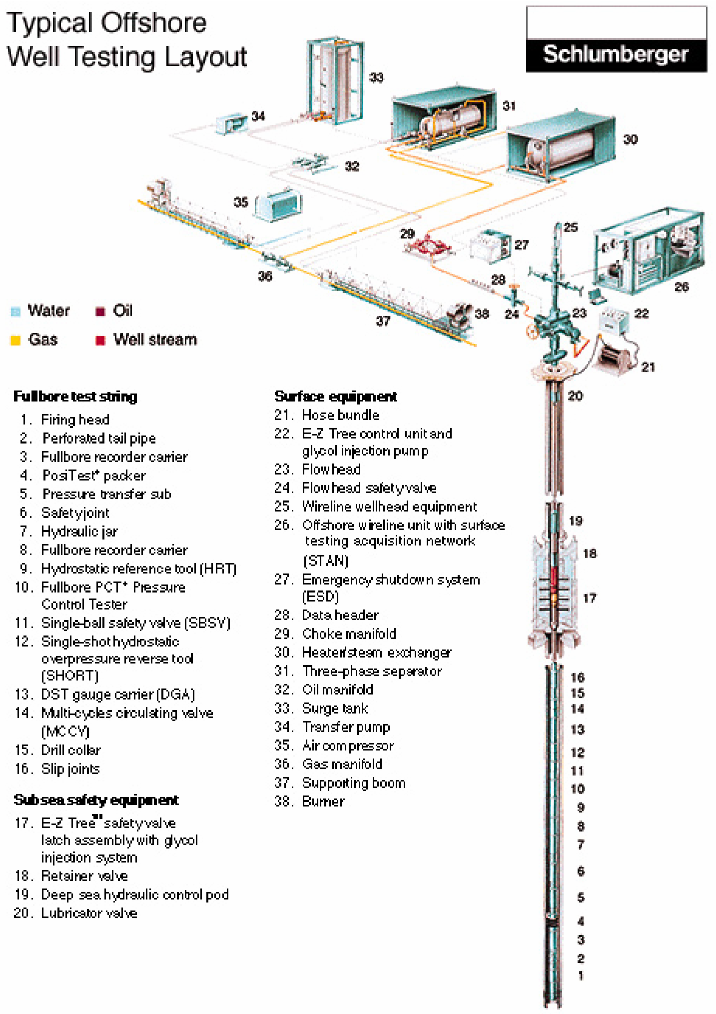
2.3.3 Drillstem Testing

Drillstem testing (DST) permits flow from the test zone to the surface, where the fluid is analysed. The following parameters are usually assessed.

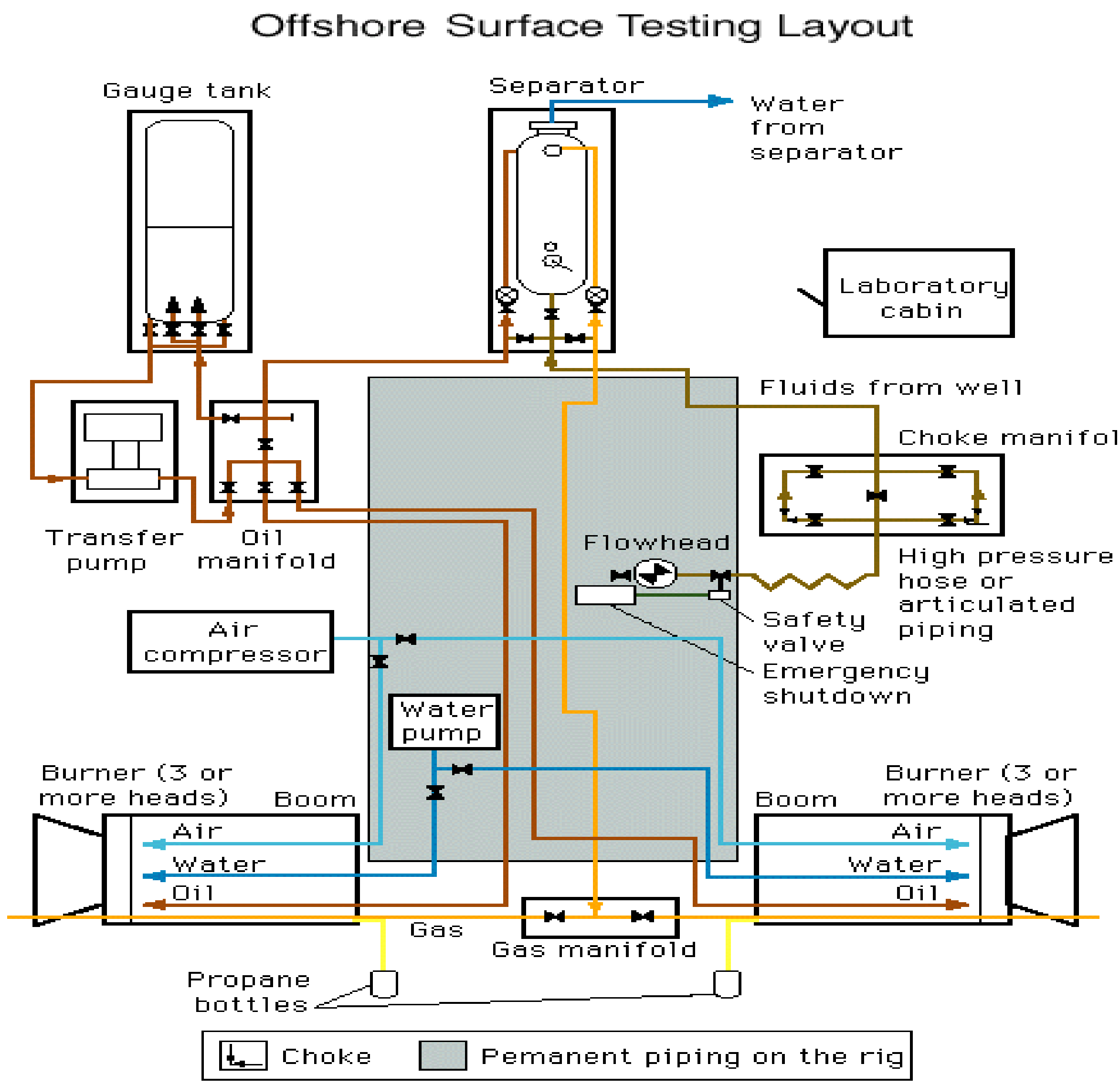
- Reservoir pressure and temperature
- Formation fluid collection
- Establish well productivity
- Permeability
- Drainage area delineation
- Possible production problems
- Drive mechanism

For Flow testing (DST), the cost and environmental regulation challenges have been considered as negative factors. Current practice on the OCS prohibits burning of oil so that it is necessary to collect produced oil, temporarily store it and then transport it to shore, usually via a barge. Gas produced during well testing may be flared.

Some variants on traditional well testing are being considered in order to reduce cost and



possible environmental impact. One area being looked at is injection of produced oil into another formation rather than taking it to the surface.



Drillstem testing usually comprises a number of flow periods

- Initial Flow period : to ensure a pressure differential from the formation into the well and also to remove debris and mud from the hole
- Initial Build-up period : to measure the initial reservoir pressure
- Major Flow period : to measure flow rates, reservoir temperature, and to sample produced fluids
- Major Build-up period : to measure and record the pressure build-up response, to determine formation permeability, wellbore damage, and indications of reservoir heterogeneities and boundaries

2.4 Well Testing and MODU Type

2.4.1 Well Testing from a Floating Offshore Unit

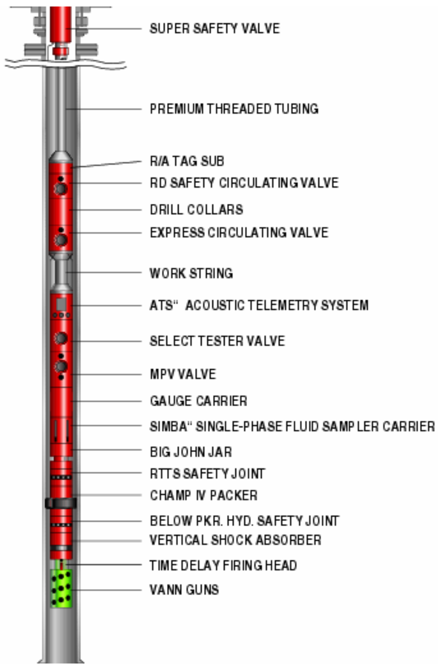
Typically well testing on a floating offshore unit, i.e. a semisub, or a drillship is conducted through the subsea BOP and marine riser.
Conventional well test systems consist of a temporary well completion with tubing supported by a fluted hanger set below the BOP stack. A test valve located near the packer controls flow from the reservoir into the tubing string. Gauge bundles hold temperature and pressure recording devices. Above the hanger is a slick joint or a test tree which spans the BOP ram cavities. One or more of the BOP pipe rams will be closed around the slick joint/ test tree, sealing off the wellbore/tubing annulus. Choke and kill lines, with failsafe valves provide access to the annulus. Above the slick joint is an emergency disconnect device that can close off the tubing bore and disconnect the tieback tubing string above from the wellbore tubing string below alternatively the subsea test tree can achieve the same function. . Valves in the quick disconnect assembly close off both ends of the tubing string to prevent wellbore fluids leaking out of the tubing string. The tieback tubing string runs through the marine riser to a point above the rig's drillfiloor. The surface production tree or flowhead is made up to the top of the tubing string and is supported by the rig's travelling block and motion compensator.
The downhole test valve and emergency disconnect are direct hydraulic controlled via an umbilical strapped to the test string. Alternatively the test valve may be mechanically or hydraulically actuated.
Generally, annulus pressures are monitored via the rig's choke and kill lines to check for downhole tubing or packer leaks.
The diverter will be closed around the top of the tieback string and the drilling riser monitored either for pressure or flow, indicating a tubing leak in the tie-back tubing. On the rig's deck a well test unit separates the gas and liquids and meters each constituent. The gas is normally flared through the burners and the oil is offloaded to a storage vessel (barge) tied up to the rig.

2.4.2 Well Testing from a Jack-Up

The surface equipment for well testing is essentially similar for test from a floating platform or from a jack-up rig. There may be some changes in the test string from one application to the other.
A typical jack-up test string is shown in fig. 2.3.2 (Halliburton)

Some key differences between resting from a jack-up compared to a floater are:

- A safety valve is usually installed inside the BOP on the drilling rig
- No unlatching mechanism is required as with a subsea tree



2.5 Regulatory Framework (OCS)

2.5.1 General

Drilling Units (MODUs) operating on the OCS are covered by federal regulations administered by the Department of Homeland Security (U.S. Coast Guard) and the Department of the Interior (Minerals Management Service). In general the USCG scope covers the drilling unit in maritime and general safety terms and the MMS are concerned with safety of the drilling and production operations.

The principal Code of Federal Regulations (CFR) references are:

33CFR Subchapter N - Outer Continental Shelf Activities
46CFR Subchapter I-A - Mobile Offshore Drilling Units
And
30CFR Subchapter B – Offshore

2.5.2 USCG and MMS

Responsibility for follow up of safety on Mobile Offshore Drilling Units (MODUs) on the OCS is divided between the MMS and USCG. The division of responsibility is defined in a Memorandum of Understanding between these two bodies. (ref MOU of December 16 1998)

For MODUs the USCG is the lead agency for the following areas :

- MODU design and construction
- Bilge and ballast systems
- Afloat stability
- Hazardous Area Classification
- Lifesaving equipment
- Firefighting and fire detection equipment
- Workplace safety and health
- Vessel manning requirements
- Lightering operations
- Safety Analysis

For MODUs the MMS is the lead agency for the following areas :

- Drilling, Completion, Well Servicing and Workover Systems
- Production systems (including those installed for a finite time and designed for removal)
- Emergency Shut Down systems
- Gas detection (including H2S)
- Risers
- Pollution (associated with drilling and testing)

In general the lessee must use the best available and safest technology in order to enhance the evaluation of abnormal pressure conditions and to minimize the potential for uncontrolled well flow.

Specifically for well testing the requirements of 30CFR.460 are valid, and will be followed up by the MMS. These are as follows:

(a) If you intend to conduct a well test, you must include your projected plans for the test with your Application for Permit to Drill (APD) (formMMS–123) or in an Application for Permit to Modify (APM) (form MMS–124).

Your plans must include at least the following information:

(1) Estimated flowing and shut-in tubing pressures;
(2) Estimated flow rates and cumulative volumes;
(3) Time duration of flow, buildup, and drawdown periods;
(4) Description and rating of surface and subsurface test equipment;
(5) Schematic drawing, showing the layout of test equipment;
(6) Description of safety equipment, including gas detectors and fire-fighting equipment;
(7) Proposed methods to handle or transport produced fluids; and
(8) Description of the test procedures.

(b) You must give the District Supervisor at least 24-hours notice before starting a well test.

However other requirements in 30CFR250 related to drilling which cover systems used in well testing will also be applicable (e.g. with respect to well control, mud systems, lifting equipment, etc) and requirements to the drilling unit itself (e.g. contingency plan, Certificate of Inspection/Letter of Compliance from USCG) will also be relevant.

In addition practices related to production may also influence the well test operation, for example the practice of not flaring produced liquid. (see Section 3.7.1 on MMS philosophy on disposal of produced fluids)

Drills and safety precautions for drilling and production (e.g. H2S precautions) will also be applicable with respect to well testing

3 GUIDANCE ON MAJOR SAFETY ISSUES

3.1 Management of Well Testing Operations

3.1.1 General

Offshore operations, including well testing, should be covered by some form of safety management system. Reference is made to the MMS recommended Safety and Environmental Management Program (SEMP) and to API RP 75, *"Recommended Practice for Development of a Safety and Environmental Management Program for Outer Continental Shelf (OCS) Operations and Facilities"*. An equivalent company safety management program may also be used.

The SEMP is a voluntary complement to compliance with the MMS operating regulations. A SEMP is intended to specify how to:

- Operate and maintain facility equipment;
- Identify and mitigate safety and environmental hazards;
- Change operating equipment, processes, and personnel;
- Respond to and investigate accidents, upsets, and "near misses;"
- Purchase equipment and supplies;
- Work with contractors;
- Train personnel; and
- Review the SEMP to ensure it works and make it better.

3.1.2 API RP 75 – Development of a SEMP

In cooperation with the MMS, the International Association of Drilling Contractors (IADC) and the National Ocean Industries Association (NOIA), API developed API RP 75 to assist in development of a management program to address safety from hazards and environmental impact. The recommended practice is intended to cover all phases of offshore installation operation and addresses mobile offshore drilling units (MODUs) in addition to production installations.

The following Management Program Elements are described in API RP 75:
a. Safety and environmental information
b. Hazards analysis
c. Management of change
d. Operating procedures
e. Safe work practices
f. Training
g. Assurance of quality and mechanical integrity of critical equipment
h. Pre-start-up review
i. Emergency response and control
j. Investigation of incidents
k. Audit of safety and environmental management program elements
l. Documentation and record keeping

Special consideration is given to MODU's in recognition of the international safety regime to which they are usually subjected. MODU owners are required to have a safety management program in accordance with the International Maritime Organization's (IMO) International Safety Management (ISM) Code. The ISM Code is however normally only applicable to self-propelled MODU's. Many of the hazards associated with the MODU are already identified and addressed by prescriptive requirements in rules developed by the Flag State (i.e. the maritime authority of the country in which the unit is registered) and the Classification Society for the unit, so that hazard analysis can be limited. It should be noted however that drilling and well testing operations are not normally covered by maritime requirements which focus on marine systems and operations. Therefore safety hazards and environmental threat from these operations will need to be specially considered.

3.1.3 Contractor's Safety Management System

Reference is also made to API RP 76, *Contractor Safety Management for Oil and Gas Drilling and Production Operations*.

API RP 75 recommends use of the API RP 76 as a means of ensuring that contractors employed by the operator also maintain an acceptable level of safety management, in keeping with the operator's own safety policy. It therefore recommends that contractors consider requesting documentation of this by submittal of the following:

a) A copy of the contractor's written safety and environmental policies and practices endorsed by the contractor's top management.
b) A statement of commitment by the contractor to comply with all applicable safety and environmental regulations and provisions of this publication.
c) Recordable injury and illness experience for the previous years.
d) An outline of the contractor's initial employee safety orientation.
e) Descriptions of the contractor's various safety programs, including: accident investigation procedures; how safety HSE inspections are performed; safety meetings; substance abuse testing, inspection and preventive maintenance programs.
f) Description of the safety and environmental training that each contractor employee has or will receive and the contractor's programs for refresher training.
g) Description of the contractor's short-service employee training program.
h) Description of contractor's involvement in industry affairs.

3.1.4 Specific management considerations with regard to well testing.

3.1.5 Organization

In any well test operation there will be a division of responsibility between the major players. It is assumed that the Operator will have the overall responsibility and will typically contract the Well Service company to carry out the testing. Both these parties will need to also interface with the Rig Owner. Managing of well testing and associated operations and the interfaces between the various players will be important for safety.

Clear lines of responsibility and communication will need to be established for the well testing operation.

3.1.6 Responsibility

The Operator will typically have responsibility for determining the reservoir characteristics, specifying the objectives of the well testing, planning the well test program and following up the service company.

The Drilling Contractors will typically have responsibility for ensuring that rig safety and utility systems are in good working order, and have responsibility for overall safety considerations such as fire fighting, evacuation etc.

The Service Company will have responsibility to ensure that the equipment supplied is in good condition and is suitable for the intended application and adequate procedures should be available to address all key operations.

Some key interface areas will be:

- conducting an overall safety assessment of the test
- timing and content of a Job Safety Analysis
- timing and implementation of safety drills
- ensuring personnel are qualified
- ensuring all personnel on board receive safety training
- ensuring that the drilling rig meets regulatory requirements
- ensuring that 3^{rd} party equipment meets an acceptable standard
- integration of permit to work system

The roles and responsibilities of the various personnel involved in the well test must be defined.

3.1.7 Manning and Qualification

All personnel involved must be competent and adequately trained for the job. The management system should consider the sort of qualifications personnel need and how their level of training is maintained. This will apply to all the parties involved. A training and qualification program should address initial educational requirements, initial training provided, and program for continued maintenance/development of competence.

The level of manning depends on the complexity of the well test operation. There should be sufficient manning for each shift so that personnel are adequately rested.

Special training, (in addition to items such as record keeping, warning signs, equipment, sensors and alarms), is required when operating in areas where H2S is anticipated. Reference is made to 30CFR250.490 with respect to precautions to be taken when operating in an H2S area. Training for H2S must be documented in an H2S Contingency Plan.

Training for well control and production is addressed in 30 CFR Subpart O.

Reference is made to the following with regard to guidance on training:

- API RP T-6 Recommended Practice for Training and Qualification of Personnel in Well Control Equipment and Techniques for Completion and Workover Operations on Offshore Locations
- API RP 59 Recommended Practice for Well Control Operations
- API RP 49 Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide
- API RP 2D Recommended Practice for Operation and maintenance of Offshore Cranes

3.1.8 Parameters for Well Test Spread

In designing the test and specifying the equipment to be used the following parameters will usually be considered:

- Tubing design (incl. design factors as Burst, Collapse and Tri-axial stress)
- Casing design (incl. design factors as Burst, Collapse and Tri-axial stress)
- Bottom hole temperature and pressure
- Surface flowing temperature and pressure
- Shut in well head pressure
- Flow rates
- Seabed depth
- H2S or CO2 concentration
- Sand production (e.g. erosion of chokes)
- Water cut
- Heavy viscous crude (plugged lines)
- Separation problems or foaming
- Flow Assurance
- Hydrate formation
- Wax or asphaltenes
- Need for methanol and arrangement for storage
- Need for liquid Nitrogen (coil tubing) and arrangement for storage

3.1.9 Suitability of the Drilling Rig

In accordance with 46 CFR 143, all drilling units operating on the OCS must have their general level of safety assessed by the US Coast Guard either via a Certificate of Inspection (COI) for US documented rigs and via a Letter of Compliance (LOC) for a foreign documented drilling unit. The assessment confirms compliance with 46 CFR 107 and 108 or a standard considered equivalent by the USCG. Typically, as part of this assessment, the USCG will rely on the records of the Classification Society with which the mobile unit is classed.

In general however the assessment carried out will not necessarily address the suitability of the unit to conduct a specific well test operation, with a specific well test spread installed on board. This will need to be separately addressed in order to comply with 30 CFR 250.

The Operator (in cooperation with the Drilling Contractor) will need to confirm that the following safety considerations on the drilling unit have been addressed prior to start of the operation:

- Area classification
- Availability of escape ways
- Flare radiation levels
- Deck drainage
- Fire fighting arrangement
- ESD coordination
- Fire and Gas detection
- Provision of utilities
- Steam
- Combustion air to burner
- Instrument air
- Electric power

3.2 Deepwater Drilling and Well Testing

Drilling in increased water depths imposes additional hazards compared to shallow water conventional drilling. These hazards are also reflected in the well testing operation.

3.2.1 Control of Subsea Equipment

As water depth increases, the response time of the tie-back tubing emergency disconnect controls increases. This may affect the ability of the drilling unit to quickly disconnect should an emergency arise, for example the drilling vessel losing its position-keeping ability, either DP or anchor lines.

Further, the hazards associated with a gas leak into the marine riser in very deep water may be more significant than in shallower water depths. A tie-back tubing leak in 10,000 ft water depth could quickly evacuate a riser and result in collapse of the drilling riser. It could resemble a kick in a 10,000 ft well with little or no BOP equipment to control it.

Close monitoring of the riser and rapid closure of the test valves and emergency disconnect are therefore essential to safety.

The challenge has been to decrease the time between signalling from the drilling unit and initiating the function at the subsea test tree (SSTT). Disconnecting a subsea test tree is a complex task involving shutting in the well, closing the landing string, bleeding pressure between two valves, and then unlatching. All these functions must be completed as rapidly as possible. The typical closing time of a subsea BOP is between 45 secs to 60 secs at which time disconnection of the Lower Marine Riser package can be carried out. The well test string must therefore be capable of being shut in and disconnected well within this limit to permit safe disconnection of the riser.

Systems are now available that utilize telemetry in the wellbore annulus for positive control. Direct hydraulic control systems are being replaced by electro-hydraulic multiplexed systems. These new control systems can effect a shut off and disconnect of the test string inside the BOP within 15 seconds (an equivalent direct hydraulic system could take several minutes to transmit signals in large water depths). In an emergency situation, the well test system can therefore be safely isolated, disconnected and blown down before the drill rig disconnect system completes its sequence.

In the event that disconnection of the test string is not possible the BOP must be capable of shearing the shear joint in the landing string. In order to ensure that this is possible the spacing out of the landing string is very important to ensure that the shear joint and the shear rams are correctly aligned.

The BOP and LMRP operation are normally the responsibility of the Driller. The control of the Subsea Test Tree is normally the responsibility of the Service Company representative. It is critical that procedures and operation of these two systems are clearly defined and coordinated. Current practice is not to integrate these systems into one control system, but to ensure constant manning and communication.

A normal operating envelope for the operation should be clearly defined and limits set to the various parameters which may affect safety, such as : environmental conditions, offset. In addition procedures for tackling accidental situations should also be documented, e.g. fire, leakage.

3.2.2 Hydrate and Wax Plugs

Deepwater applications are also more susceptible to hydrate and wax plug formation which may represent a safety hazard where plugs prevent the correct actuation and function of the subsea equipment. Hydrates may occur where gas and water come into contact under pressure at a temperature below the hydrate formation temperature. In deepwater, the low seabed temperature and the riser length will contribute to possible solid formation. Critical areas of the well test system will be areas which experience a significant reduction in temperature, for example at the seabed and downstream of the choke manifold.

In order to inhibit hydrate formation in situations where the temperature may drop below the critical level, methanol or glycol injection may be employed. This will be effective in preventing the necessary contact between water and gas to permit hydrate formation. Use of these hydrate-inhibiting fluids should be considered during pressure testing and at start up until the flow conditions are above the critical hydrate temperature.

It should be noted that methanol use raises additional potential hazards on the drilling unit with respect to handling and storage of the methanol (see below).

It is important to design the string and to develop operational procedures to minimize the potential of solid formation. It is also important to develop procedures to tackle solid formation should it occur.

Some factors to be considered will include:

- Procedures for start-up, flow, and shut-in (including during mechanical breakdowns, scheduled platform maintenance, or hurricane related extended shut-ins)
- test string configuration (minimize any restrictions)
- sizing of components (ensure sufficient velocity to lift water out)
- chemical injection points, capacity , and properties
- Use of inhibitor pills and procedure for displacement of shut in fluid
- Need for seabed sensors (e.g. at SSTT) to monitor pressure and temperature

3.2.3 Use and storage of Methanol

Methanol is a colorless alcohol, hygroscopic and completely miscible with water, but much lighter (specific gravity 0.8). It is a good solvent, but very toxic and extremely flammable. It burns producing a faint bluish non-luminous flame.

Storage and transportation of methanol should be in tanks specifically designed and certified for the purpose. Reference is made to 49 CFR 178 for requirements to tank design and construction.

The tank should be properly secured to prevent any movement in the event of listing of a floating rig.

Storage of methanol will give rise to a hazardous area which in turn will place requirements on limitation of potential ignition sources in the vicinity of the tank (ref API RP 500 or RP 505).

In order to protect against fire the tanks should be protected by firewater. Alcohol resistant foam should also be available.

Since a methanol flame is very difficult to see it is recommended to provide salt on the tank to make any flame luminous.

3.2.4 Increased Demand on Drilling Equipment

Deepwater drilling will place greater demand on support equipment on which the well test system also depends (e.g. well control equipment, tensioning system, hoisting system). These systems will be specified to the ratings necessary to operate for the specific drilling operation.

Drilling in deepwater areas has also resulted in increased possibility of encountering high pressure and high temperature wells which will also require special attention in well testing (this is addressed in a later section).

3.3 Testing from Dynamically Positioned (DP) Vessels

3.3.1 General

Testing from DP vessels is typically conducted in deep water. Therefore the considerations listed above for deep water will normally also apply to such operations.

3.3.2 Requirements to DP system

A dynamic positioning system on a drilling installation is a mandatory part of the classification of the unit, it is also subject to follow up by the flag state and the USCG as part of their scope.

There are several levels of reliability in a DP system, which are defined by their worst case failure modes as follows:

DP1 (Equipment Class 1) : Loss of position may occur in the event of a single fault

DP2 (Equipment Class 2) : Loss of position is not to occur in the event of a single fault in any active component or system. Normally static components will not be considered to fail where adequate protection from damage is demonstrated,. Single failure criteria include:

1. any active component or system (generators, thrusters, switchboards, remote controlled valves, etc.)
2. any normally static component (cables, pipes, manual valves, etc.) which is not properly documented with respect to protection and reliability

DP3 (Equipment Class 3) : Loss of position is not to occur in the event of a single failure. A single failure includes:

1. Items as listed for DP2, and any normally static component is assumed to fail
2. all components in any one watertight compartment, from fire or flooding
3. all components in any one fire sub-division, from fire or flooding

The probability of failure of a DP1 system is therefore greater than for a DP3 system. However the consequences of failure may not be different provided correct procedures are in place to react to a failure. In addition the behaviour of a rig on loss of DP will be dependent on the rig design and not on the type of DP system. Therefore it will be up to an Operator to assess selection of rig type based need for DP reliability.

3.3.3 Drive off/drift off

A failure of the DP system is potentially more serious than the equivalent failure of an anchor line (assuming that well testing will not be conducted during the worst storm situation). Failure may be either as a result of shut down of thruster power with subsequent movement off location (drift off) or as a result of uncontrolled thrust from some or all thrusters with subsequent movement off position (drive off). In cases of drive-off this may typically involve an initial period of drive-off subsequently followed by a period of drift off if power to the thrusters is shut off. In theory drive off represents a potentially greater hazard, however due to continuous manning and positioning instrumentation and the time taken for thrusters to power up, drive offs can be relatively rapidly tackled. Drift off on the other hand typically represents a situation where the operator has no means of taking control.

A DP vessel must be capable of carrying out a safe emergency cut, seal and disconnect before the critical flex joint angle is reached and within the disconnect time of the lower riser package, in the worst case drive off or drift off scenario. Other limiting parameters may also be : structural casing stress, tensioner stroke, and telescopic joint stroke.

3.3.4 Watch circles

Loss of position is critical during well testing (and other drilling operations) since it may lead to an inability to disconnect the riser and shutting in of the well and it may also lead to damage to equipment suspended from the drilling unit, both during the period of testing and in periods outside the actual flow test. Before the riser reaches an angle where disconnection is not possible, the rig needs to establish safety zones (watch circles) with clearly defined plans of action, should the rig offset move into these zones. These watch circles need to be established taking account of the likely speed at which the rig displacement may take place, and linked to the response time necessary to shut in and disconnect. Shut in involves shutting in the well and disconnecting the landing string at the blowout preventer (BOP). The riser may then be disconnected at the Lower Marine Riser Package (LMRP).

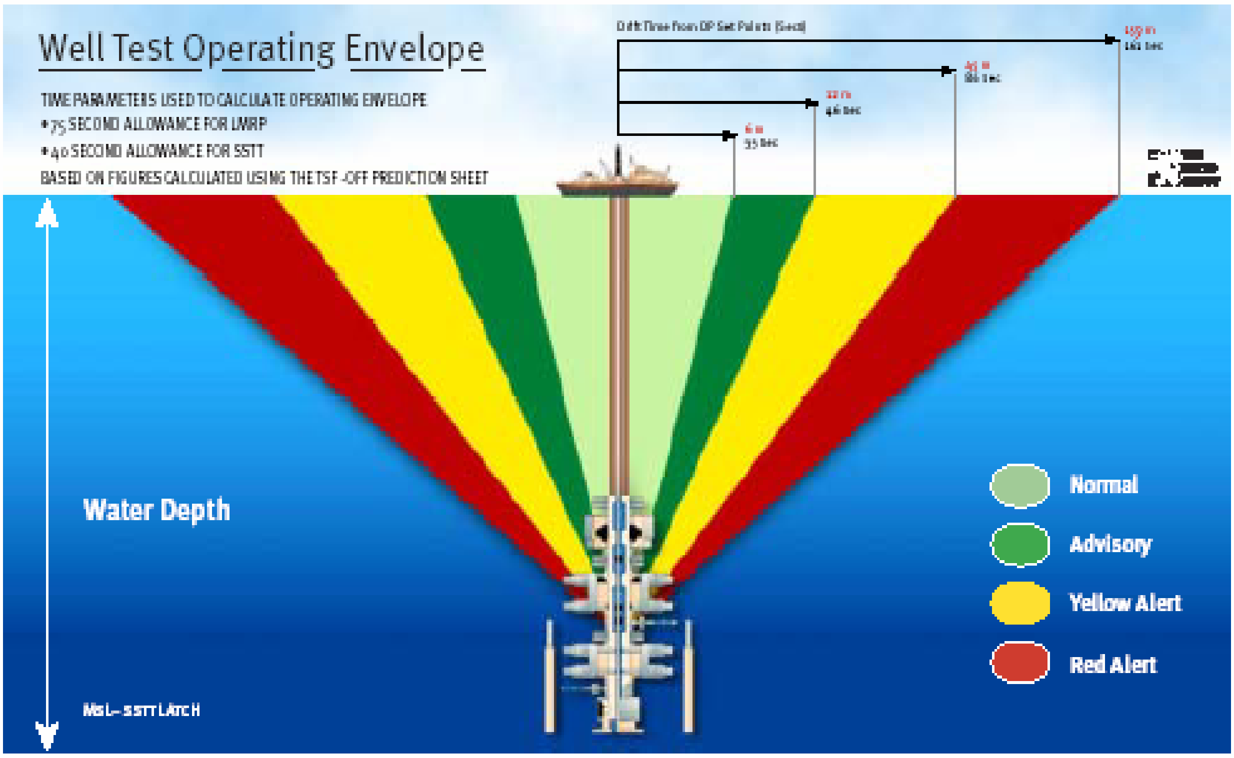


Fig. Example of Watch Circles (Expro)

The vessel excursion behavior at a specific well location will need to be established by a Drift Analysis. The results of this analysis together with information on BOP and sub-surface test tree (SSTT) disconnect times will be used to determine the watch circles.

Procedures need to be established to define which operations can be carried out when the vessel is in the various zones and which safety actions must be performed either when in a particular zone or when moving from one zone to another. These must be established prior to operation. The size of the various circles will be dependent on vessel characteristics and environmental conditions. The circles may fluctuate with changing weather conditions.

In general the zones are defined as follows:

Green Zone : Safe working zone, operating parameters within acceptable limits. An advisory area may be specified at outer boundary of the Green Zone to prepare operator for action if the unit should enter the Yellow Zone

Yellow Zone : positioning unsatisfactory and corrective action required. Prepare for disconnection.

Red Zone : danger for exceeding safety limits, disconnect from the well

Operational instructions will need to be developed to define the actions to be taken when in or moving into the different zones.

Certain hazardous conditions (e.g. brown out) may initiate alarms without waiting for offset to occur. In addition reduced power or thrusters capacity may also lead to alarms and precautionary actions.

These considerations are generally collected into a document describing the conditions and the actions to be taken. Such a document is typically termed Well Specific Operating Guidelines (WSOG). A sample WSOG is included in Appendix A.

3.3.5 Response time

As mentioned above the response time needs to be related to the overall time for the rig to disconnect before rig excursion exceeds acceptable limits.

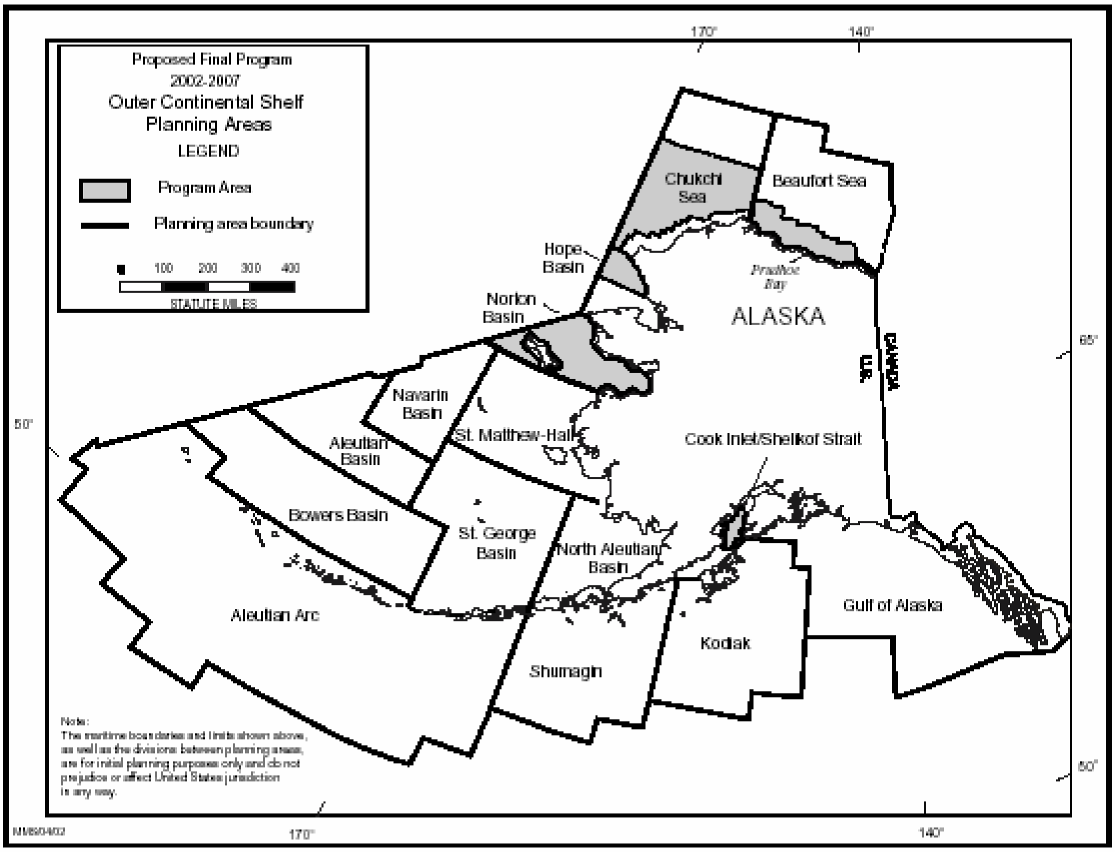
Response time will depend on water depth and on selected control technology (e.g. direct hydraulics vs electro hydraulic system).

Depending on how the situation is developing and the time available, the disconnect may be either controlled (i.e. disconnect at SSTT) or emergency (cutting the shear joint).

3.4 Testing in Arctic Conditions

3.4.1 General

Well testing in arctic OCS locations has been relatively limited to date however it is anticipated that this activity may increase in future years. With respect to the term “arctic areas” it is important to differentiate between different locations which are typically designated under the same term but which have in fact somewhat different characteristics as a result of variation in environmental conditions. Arctic areas include the Beaufort Sea, Chukchi Sea, Bering Sea, Gulf of Alaska and the Cook Inlet. Developments, for example, in the Cook Inlet may be subject to significantly different conditions than operations in the Beaufort Sea.



In contrast to Eastern Canada, where there may be many thousands of icebergs (typically calved from the Greenland ice cap), some hundreds of which may approach offshore installations, there are no icebergs in the Beaufort Sea. Large bodies of ice (ice islands) may however detach from the ice shelf and subsequently drift, however these events are very rare and detection and monitoring should ensure possibility of avoidance. Pack Ice may form pressure ridges which may range in thickness from 5m (for multiyear ice) to 2m (for 1st year ice). The movement of floes and ridges against offshore installations will cause high lateral loads and may also be difficult for icebreakers to tackle.

Most arctic drilling to date has been in the Beaufort Sea, Cook Inlet and the Gulf of Alaska. Drilling has been from artificial islands (in fast ice areas) and from mobile drilling units (in open water areas). While concrete-armoured gravel islands may be used all year round, mobile drilling unit use has been seasonal. The mobile unit drilling season may be limited to the summer months and will be also dependent on increasing distance offshore.

Drilling vessel and icebreaker in Beaufort Sea

In addition to ice floes and ridges, ice accretion from sea spray and from the atmosphere can represent a significant hazard to offshore installations. Ice from sea spray will mostly affect the drilling rig substructure and possibly the deck area and can be of such magnitude to require adjustments to stability and ballasting on semisubmersible units. Atmospheric ice accretion will occur on exposed structural areas and may also affect stability as it will affect areas at the highest elevations on the unit.

Operating in arctic areas may lead to a need for winterizing of the drilling unit unless operations are limited to periods of mild conditions. In general winterizing of mobile drilling units should consider:

- Design of major structural items such as the hull itself, crane pedestals, helideck, derrick foundation and mooring system
- Design of key support systems such as ballast system, air systems, ventilation system, fire water system
- Consequences of atmospheric and spray ice loading on equipment and structures
- Stability under ice conditions
- Means to ensure continued availability of features such as escape ways, lifesaving equipment, work areas

- Protection of work areas by provision of wind screens, walls, heating
- Safety measures to account for closing in of normally open spaces (e.g. gas detection, ventilation)
- Maintenance of sufficient lighting conditions
- Material selection for cold climate
- Operational and contingency procedures

In addition where air temperatures may drop below freezing for significant lengths of time special attention will need to be paid to design and selection of the drilling equipment for suitability of operation in cold climate.

In addition to the challenges from weather conditions and ice, some arctic areas may be subject to seismic activity (e.g. the Gulf of Alaska is classified by API as a Zone 4/Zone 5 area) and since many areas are characterized by seafloor profiles with steep gradients there is also the possibility of slope failure resulting in tsunami.

3.4.2 Well Testing Hazards

The above considerations will primarily be made when determining the drilling program and in selecting the drilling unit to be used. Well test considerations will need to be part of that consideration, so that the hazards associated with testing are part of the overall assessment of the unit operating in an arctic environment.

The forecasting of weather changes, the warning available for any ice hazards and reaction time to events which may affect rig safety will be especially critical if well test operations are being conducted.

With respect to well testing the following specific aspects will be reviewed:

- Effects of low temperature on materials used for well testing
- Icing on surface equipment due to atmospheric or spray ice
- Low temperature effects on control systems
- Low temperature effects on produced fluid

3.4.3 Low temperature effects on materials

Low temperature effects on both metallic and non-metallic materials should be considered. Exposed metallic material may be subject to brittle fracture at low temperature and non metallic material may be subject to perishing. Design temperature should consider both ambient and operational conditions (note choking and venting may lead to a significant drop in temperature).

Metallic material and elastomeric seals and hoses should have documented low temperature properties or be protected in such a way as to ensure that they are not exposed to temperatures below their temperatures rating (e.g. by insulation or heat tracing).

Such considerations will primarily apply to safety-critical equipment exposed on the deck of the drilling unit, i.e. piping, vessels, burner boom.

Operational limitations should be set so that where environmental conditions exceed the defined operational envelope, measures can be taken to ensure safety.

3.4.4 Icing of equipment

Icing may occur either from the atmosphere or as a result of sea spray. Low air temperature increases the danger of atmospheric icing and sea spray icing.

Ice loads on the burner boom need to be considered in defining the capacity of the boom. Means to ensure that ice accretion will not exceed acceptable levels need to be put in place (e.g. application of coating, de-icing procedures, covering). In addition the possibility of ice being present in nozzles etc prior to start up should be considered and measures should be taken to prevent or remedy. The effects of ice formation as a result of water curtain cooling during testing should also be taken into account.

Ice formation on the external surfaces of valves may inhibit both manual operation of the valves and inhibit performance of position indication.

Work areas associated with well testing should be protected in the same way as the drilling package and drilling areas.

3.4.5 Low temperature effects on control systems

Systems using hydraulic fluids may be affected by low temperature due to the possibility of increased viscosity at lower temperatures. The control fluid must be documented to possess satisfactory properties at low temperature.

Where pneumatic systems are used the need to ensure dryness of the air should be considered to prevent freezing.

Relays may become slow at low temperatures.

3.4.6 Low temperature effects on transported fluids

Where gas and water are mixed at low temperature, hydrates may form in the pipework. Therefore in low temperature applications special attention needs to be paid to avoiding moisture in gas and in preventing temperatures reaching the hydrate formation temperature. In some cases it may be considered to inject methanol or glycol. Safety aspects in connection with storage and use of methanol need to be considered, and measures planned in the event of a plug forming.

Similarly wax may be secreted at low temperature causing a plug hazard.

Procedures should consider identification of critical systems, protection of these systems against low temperature, and measures to be taken on possible loss of protection. Measures to be considered are provision of insulation, heating, circulation, draining (on shut in) and displacement with glycol or methanol. For example this may be relevant when switching from one burner boom to another.

3.5 High Pressure/ High Temperature Well Testing

3.5.1 General

The probability of encountering high pressure and high temperature wells increases as deepwater exploration becomes more common. Drilling of deep wells in shallow waters will also open the possibility of increased HPHT encounters. In cases where problems may result in a subsea blowout, the operation may be more critical in shallow water than in deep water, since the gas plume released will not have the same possibility to disperse before reaching the surface and the drilling unit. In addition the possibility of moving off position may be easier in deepwater, although control times to disconnect may be longer.

Typically high pressure is defined as surface pressure in excess of 10000psi. High Temperature is defined as bottomhole temperature in excess of 300 degr F. In addition high flow wells may also be considered as critical. High flow rate can typically be specified as greater than 8000 bbl fluid per day or 30 MMSCF/day. These figures however represent current experience and measures have been taken to deal with the hazards. It should be borne in mind however that as these values become more extreme, i.e. ultra HPHT (e.g. surface pressures in excess of 15k or 20k) then available measures may need to be reconsidered (ref. Deepstar Project).

Whereas many of the technical considerations for a HPHT well will be similar to a conventional well, the consequences of error in a HPHT operation may be more severe.

Working in these conditions represents a higher level of risk than with standard wells. Some of the safety considerations include:

- Test String
- Equipment suitability for high temperature and pressure
- High pressure testing
- Need to conduct a HAZOP
- Procedures and Training

3.5.2 Test String Design

Design of the test string should consider factors such as :

- Casing size
- Predicted bottom-hole pressure
- Predicted bottom-hole temperature
- Duration and objective of the testing
- Composition of produced fluids

A number of safety considerations may be made to reduce risk in HPHT wells :

- Use of premium threaded metal-to-metal sealing should be considered
- Use of permanent packers should also be considered (to remove need for slip joints)
- Use of an annulus pressure-operated downhole tester valve should be considered
- Use of a lubricator valve (even when no wirelining involved) should be considered

Further guidance is given in the Institute of Petroleum Publication IP 17 "Well Control During the Drilling and Testing of High Pressure Offshore Wells".

3.5.3 Equipment Selection

Both rig owned equipment and service company equipment must be suitable for the anticipated service. This is of course applicable to any operation. For high pressure service, a number of service companies add a safety factor when selecting equipment .

The selection of elastomers and sealing material is critical. In addition to being rated for the temperature to which they may be exposed they must also be suitable for the fluids to which they may be subjected (e.g. H_2S, CO_2, amines, bromides).

The effects on certain alloys of exposure to high pressure and high temperature environments should also be considered, especially in the presence of H_2S or CO_2.

3.5.4 Pressure Testing

High pressure wells will require high pressure hydro testing onboard before equipment is taken into use. An area around the pressure test should be suitably cordoned off and notices erected warning that testing is underway.
Testing with gas at high pressure offshore is not recommended.

3.5.5 HAZOP

A HAZOP should be carried out before conducting the test. Aspects such as time to gain control over a well should be considered, and well control and affected operating procedures should reflect this.

3.5.6 Procedures and Training

Since the consequence of error in a HPHT operation may be more severe than in a conventional operation, it is essential that the right people follow the right procedures. Personnel need to be qualified and procedures need to be developed. Vigilance needs to be maintained. Some guidance recommends not permitting first hydrocarbons to the surface during the hours of darkness. This should be considered with respect to available lighting, availability of contingency resources and availability of rested personnel.

3.6 Hydrogen Sulfide (H_2S)

3.6.1 General

The primary concerns with H_2S are its toxicity for personnel and stress corrosion cracking effects on steel and negative effects on sealing material and other elastomerics.

Precautions to be taken depend on whether H_2S is anticipated or not, i.e. whether testing is being conducted in zones where the presence of H_2S is known and in areas where its presence is unknown, compared to areas where its absence has been confirmed.

Should H_2S be discovered in areas not previously classified as H_2S areas, the requirements to operation in H_2S areas should immediately be followed.

In H_2S areas and potential H_2S areas the precautions listed in 30 CFR 250.490 are to be followed.

3.6.2 H2S Contingency Plan

When carrying out drilling operations in a known H_2S area the operator must create a contingency plan. The contingency plan should include information on the following :

- Safety procedures
- Training
- Record Keeping
- Drills
- Job positions and function
- Actions on detection of H_2S
- Location of briefing areas (2)
- Criteria for evacuation
- Procedures for positioning attendant vessels
- Protective breathing equipment
- Agencies and facilities to be notified in the event of release
- Medical personnel and facilities
- H_2S detector location
- Flaring
- SO_2 detection and procedures and protective measures

These items will also be valid for the well test operation.

3.6.3 Well Testing Precautions

Specifically In accordance with 30 CFR 250 490, the following actions must be taken when testing in a zone known to contain H_2S. (references refer to the CFR)

(1) Safety Meeting

Before starting a well test, conduct safety meetings for all personnel who will be on the facility during the test. At the meetings, emphasize the use of protective-breathing equipment, first-aid procedures, and the Contingency Plan. Only competent personnel who are
trained and are knowledgeable of the hazardous effects of H_2S must be engaged in these tests.

(2) Manning Level

Perform well testing with the minimum number of personnel in the immediate vicinity of the rig floor and with the appropriate test equipment to safely and adequately perform the test. During the test, you must continuously monitor H_2S levels.

(3) Flaring

Not burn produced gases except through a flare which meets the requirements of paragraph (q)(6) of this section. Before flaring gas containing H_2S, you must activate SO_2 monitoring equipment in accordance with paragraph (j)(11) of this section. If you detect SO_2 in excess of 2 ppm, you must implement the personnel protective measures in your H_2S Contingency Plan, required by paragraph (f)(13)(iv) of this section. You must also follow the requirements of Sec. 250.1105. You must pipe gases from stored test fluids into the flare outlet and burn them.

(3) Suitability of Downhole Test Tools

Use downhole test tools and wellhead equipment suitable for H_2S service.

(4) Suitability of Tubulars

Use tubulars suitable for H_2S service. You must not use drill pipe for well testing without the prior approval of the MMS District Supervisor. Water cushions must be thoroughly inhibited in order to prevent H_2S attack on metals. You must flush the test string fluid treated for this purpose after completion of the test.

(5) Suitability of Surface Equipment

Use surface test units and related equipment that is designed for H_2S service.

3.6.4 H_2S Drills

H_2S drills should be conducted periodically. It is required to conduct a drill for each person at the facility during normal duty hours at least once every 7-day period. The drills must consist of a dry-run performance of personnel activities related to assigned jobs.
Further a safety meeting or other meeting of all personnel should be held at least monthly to, discuss drill performance, new H_2S considerations at the facility, and other updated H_2S information.

3.6.5 H_2S Detection

H_2S sensors (typically with a set point of 10 ppm for low level alarm and 30ppm for high level) should as a minimum be located at :

- Bell nipple
- Mud return line receiver tank
- Pipe trip tank
- Shale shaker
- Well control fluid pit area

- Drillers station
- Living quarters
- All other areas where H_2S may accumulate

An adequate number of sensors (fixed or portable) should be provided for personnel. The distribution of such sensors should be discussed prior to commencing operations. Gas metering equipment should be checked regularly when in use, in accordance with the user guide for such equipment.

Fixed H_2S detectors should be connected to an alarm system which gives a visual and audible alarm throughout the work area.

Alarms should be monitored by a central alarm monitoring system.

3.6.6 H_2S Standards

Further to the regulatory requirements the following standards are a useful reference for H_2S hazards:

Selection of Metallic Material

Guidance is given in *NACE MROI75 Sulphide Stress Cracking Resistant Metallic Materials for Oilfield Equipment*

This standard covers requirements to metallic materials which may be subject to sulphide stress cracking. The mechanism for the cracking is diffusion of atomic hydrogen into the metal and remaining in solid solution in the crystal lattice. This has the effect of reducing material ductility and the ability to deform, a condition termed hydrogen embrittlement. When subjected to tensile loading (either an applied tensile load or as a result of cold-forming or welding) the embrittled material readily cracks. Such cracks may propagate very rapidly to result in catastrophic failure of the material. The NACE standard provides guidelines for material selection.

Selection of Non- Metallic Material

Currently there are no normative standards addressing use of non-metallic material in H_2S service. For non-metallic equipment the suitability may need to be documented by full scale testing. Parameters such as concentration of H_2S, operating temperature and the presence or absence of water should be considered.

General Safety

Guidance is also given in the API Publication API RP 49 “Recommended Practice for Drilling and Well Service Operations Involving Hydrogen Sulfide”. The guidance addresses :

- Personnel training
- Detection equipment
- Personal protection equipment
- Contingency planning

Training should include such topics as:

- The hazards, characteristics, and properties of hydrogen sulfide and sulfur dioxide.
- Sources of hydrogen sulfide and sulfur dioxide.
- Proper use of hydrogen sulfide and sulfur dioxide detection methods used at the workplace.
- Recognition of, and proper response to, the warning signals initiated by hydrogen sulfide and sulfur dioxide detection systems in use at the workplace.
- Symptoms of hydrogen sulfide exposure; symptoms of sulfur dioxide exposure
- Rescue techniques and first aid to victims of hydrogen sulfide and sulfur dioxide exposure.
- Proper use and maintenance of breathing equipment for working in hydrogen sulfide and sulfur dioxide atmospheres, as appropriate theory and hands-on practice, with demonstrated proficiency
- Workplace practices and relevant maintenance procedures that have been established to protect personnel from the hazards of hydrogen sulfide and sulfur dioxide.
- Wind direction awareness and routes of egress.
- Confined space and enclosed facility entry procedures (if applicable).
- Emergency response procedures that have been developed for the facility or operations.
- Locations and use of safety equipment.
- Locations of safe briefing areas.

3.7 Storage and Offloading of Produced Oil

3.7.1 General

Disposal of produced liquid hydrocarbons during well testing is addressed in 30 CFR 250.1105. This states:

`Lessees may burn produced liquid hydrocarbons only if the Regional Supervisor approves. To burn produced liquid hydrocarbons, the lessee must demonstrate that the amounts to burn would be minimal, or that the alternatives are infeasible or pose a significant risk that may harm offshore personnel or the environment. Alternatives to burning liquid hydrocarbons include transporting the liquids or storing and re-injecting them into a producible zone.`

The practice on the OCS has been to flare only produced gas and to store liquids for later transport to shore.

The development of "green" burners continues to improve efficiency of oil burners and reduce levels of pollutants. The safety and environmental advantages of storage and transportation should therefore be continually reviewed with respect to the flaring alternative.

It should be noted that in some coastal locations, ozone restrictions may be in place. It may be therefore necessary to obtain authorization to flare from state authorities (i.e. nearest County Air Pollution Control District) in addition to the MMS.

When dealing with H2S wells special precautions will need to be made. This will include collection and safe disposal of tank vents, normally to the flare.

3.7.2 Oil Storage on Mobile Drilling Units

Permanent Storage Tanks

Some modern drillships have been designed to store oil in designated storage tanks in the ship's hull.

The presence of integral oil storage tanks however increases the level of potential hazard for a standard drilling installation. Incremental hazards need to be identified and measures taken to ensure that the overall level of safety continues to remain at an acceptable level. This includes hazards originating in the storage tanks and those affecting the storage tanks as a result of escalation from other areas.

By being integral in the hull the tanks themselves are covered by the Classification of the ship itself (i.e. according to the rules of a Classification Society such as DNV or ABS) and are subject to third party follow up in design, construction and during the in-service phase of the drillship. Review of the classification status will give an indication of safety level associated with the storage tanks. However the relationship between the storage tanks and other systems should still be assessed. For example location of tank vents with respect to area classification and deck equipment, access for tank fire fighting, protection against falling objects.

Temporary Storage Tanks

Other drilling units, typically semisubmersibles and jack-ups, store the oil produced during testing in temporary storage tanks located on the deck of the drilling unit. These tanks will form part of the well test package and may be lifted on and off the unit as desired.

Some key safety issues include:

- Location of tanks with respect to area classification
- Location of tanks with respect to burner boom radiation
- Location of tanks with respect to escapeways
- Fastening of tanks on floating units
- Venting arrangements for tanks
- Protection against falling objects
- Firefighting arrangements
- Pipework connection to tanks
- Pumping procedures
- Handling of tanks

3.7.3 Offloading to barges

Offloading of stored oil is typically via a floating hose to a barge. The barge may be manoeuvred by tugs or may be dynamically positioned. Where tugs are used the number involved should be based on consideration of safety and required reliability of the operation.

Tank barges are required to be certificated by USCG by issue of a Certificate of Inspection. This certification covers the design and construction of the barge, safety features and regular inspection. Requirements are set also to the design and testing of the loading hose.

Where offloading to a barge takes place there will also be an interface between the barge company and the rig owner. Procedures need to be established covering operational limits with respect to weather, positioning etc. Communication needs to be established to coordinate actions in the event of emergency situations arising either on the rig or on the barge.

Line tension between the barge and the rig should be monitored and a quick release provided for emergency disconnect.

The connection (e.g. hose) from the well test storage tank to the barge needs to be suitable for the application and the operation itself needs to be assessed for possible hazards.

3.8 Quality of Well Test Equipment

3.8.1 General

Equipment supplied by the well test service company should maintain a certain quality to ensure continued safety of operation. The quality will be related to the initial standard of the equipment at the time of its fabrication and the continued maintenance and inspection it undergoes during its service life. A final verification will be the testing of the equipment prior to putting into use.

3.8.2 Initial Quality

Equipment supplied needs to conform to the relevant offshore standards. Typically these may include:

API Spec. 5CT	Specification for casing and tubing
API RP 7G	Recommended practice for drill stem design and operating limits
API Spec. 6A	Specification for valves and wellhead equipment
API Spec. 14A	Specification for sub surface safety valve equipment
API RP 14C	Recommended practice for analysis, design, installation and testing of basic surface safety systems on offshore production platforms
API RP 14E	Recommended practice for design and installation of offshore production platform piping systems
API 17B	Recommended practice for flexible pipes
API RP 44	Recommended practice for sampling petroleum reservoir fluids
API RP 520	Recommended practice for sizing, selection and installation of pressure-relieving devices in refineries
API RP 521	Recommended practice for pressure-relieving and depressuring systems
ASME VIII	Rules for construction of pressure vessels
ANSI/ASME B31.3	Chemical plant and petroleum refinery piping
NACE MR-01-75	Sulphide stress cracking resistant metallic materials for oil field equipment

These codes (or equivalent) should be applied to the design and fabrication of the well test equipment.
Operating limits (rating) for each item of equipment need to be specified and should include such parameters (as appropriate) as :

- Pressure
- Temperature (high and low)
- Service (specifically H2S)
- Water Depth
- Area Classification Zone
- Response Time
- Safe Working Load (SWL) (e.g. for burner boom)
- Tensile rating (subsea equipment)

Ability of the BOP to shear the test string shear joint needs to be addressed. This could be by actual testing or by documentation of previously carried out similar testing.

In order to permit an evaluation of this initial quality, compliance with the above standards should be documented.

The level of documentation would typically include the following:

- Statement of Compliance from the Manufacturer
- Reference to design specification and drawings
- Material certification
- Welding procedure specifications
- Heat treatment records
- Non Destructive Examination (NDE) records
- Load, pressure and functional test reports

3.8.3 Maintenance records

Condition at purchase represents a benchmark level of quality and is documented by initial certification. Continued suitability for the initial operating limits is determined by the service loading and by regular inspection and maintenance.

An inspection and maintenance program should be developed which should follow:

- Code recommendations
- Manufacturer recommendations
- Regulatory requirements
- Operating experience

Typical codes may include:

- API
    - API 8A — Specification for Drilling and Production Hoisting Equipment
    - API RP8B — Recommended Practice for Procedures for Inspection, Maintenance, Repair & Remanufacture of Hoisting Equipment
    - API RP 9B — Application, Care, and Use of Wire Rope for Oilfield Service
    - API RP53 — Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells

For well test equipment the basis for inspection and maintenance will typically be recommendations from the equipment manufacturer.

3.8.4 Test before use

Both initial quality and ongoing condition monitoring will typically be verified by reference to documentation. Final confirmation of fitness for intended purpose will normally be carried out by witnessed testing of the intended equipment and control arrangement.

The following should be considered:

- Test of individual components or test of entire system
- Test at service company premises or test after assembly offshore
- Definition of test parameters (pressure and temperature)
- Simulation of control system signals

In general, testing should be carried out to the based on the worst case anticipated condition during well testing, e.g. pressure testing to maximum anticipated close-in pressure.

3.9 General Safety on the drilling unit

3.9.1 General

The presence of the well test package on the drilling unit will influence existing safety measures on the unit. It must be ensured that these are adequate to address the additional hazards introduced by well testing. These aspects, in the drilling mode, are normally covered by the requirements of the flag state of the unit and the Classification Society, and followed up by USCG. However it is important that well testing mode is also included in such safety considerations.

Safety documentation should be updated to include the well test operation.

3.9.2 Arrangement

Hazardous plant should be located as far as possible from safe areas. Escape ways should be maintained after well test spread is installed, or new escape ways marked up and notified. Equipment on the deck should be fixed to the extent that movement will not cause damage or injury.

Equipment should be arranged with consideration of adequate deck support.

Heat loads from the burner boom should be considered in design of the water curtain, location of escapeways, location of storage tanks, location of methanol storage etc.

3.9.3 Area classification

The well test package will give rise to a hazardous area, from the drill floor to the deck area in which the package is located, and also in connection with storage and venting. This needs to be compatible with the overall area classification of the drilling rig. Equipment in the well test package should be suitable for the zone in which it is located. Special attention will also need to be paid to any control or testing container associated with the well testing unit.

3.9.4 Rig Supply Interfaces

A number of rig systems will typically interface with the well test system. This allows the possibility of well test hydrocarbons backflowing into these systems. This should be addressed in a system HAZOP, and measures put into place to prevent such an occurrence. This would apply to systems such as steam supply to heaters, air supply to burner booms, chemical injection, and kill fluid supply. Provision of separate dedicated systems or inclusion of non return valves should be considered.

3.9.5 Drains

Possible leakage from the well test plant needs to be accounted for. Whereas minor leaks will be accommodated in drip trays or in the skid bunds, a major leakage (e.g. from a separator) will spill over onto the rig deck. This leakage should not cause a hazard or an environmental problem. Special consideration should be given to drainage of methanol.

3.9.6 Firefighting

The well test package introduces an additional fire hazard on to the drilling rig. Typically portable equipment will be provided by the well test company. The rig owner will need to ensure that there is adequate fixed fire fighting capability in the area. Typically this will involve ensuring water monitor coverage of the well test area. Special equipment (e.g. alcohol resisting foam) may be necessary for combating a methanol fire. Use of salt to make a potential methanol fire visible should also be considered.

3.9.7 Venting arrangement

Vent pipes and relief lines need to be properly sized for the particular well test application. In addition piping should be supported and secured in such a way that it will withstand any loading to which it may be subjected in operation.

3.9.8 Emergency Shut Down (ESD)

The shutdown arrangement of the well test plant will typically be designed depending on the complexity of the project, in terms of level of automatic action taken by the system. There will need to be communication with the rig shutdown system, so that a shutdown in the well test plant is informed to the rig system, and a shutdown initiated by the rig safety systems is informed to the well test plant. Communication between the driller and the well test service engineer to coordinate emergency action will be critical.

In DP applications, communication between the DP operator and the driller will be critical.

Communication and coordination between the offloading barge and the drilling unit will also be necessary in order to tackle any problems during the offloading operation.

3.9.9 Fire and Gas detection

Gas detection may be automatic or there may be reliance on the operator to detect leakage. This needs to be fed into the rig safety system. Similar considerations apply for fire detection.

Special precautions need to be taken in the event that H_2S is anticipated (ref 30 CFR 250.490).

H_2S sensors (typically with a set point of 10 ppm for low level alarm and 30ppm for high level) should as a minimum be located at:

- Bell nipple
- Mud return line receiver tank
- Pipe trip tank
- Shale shaker
- Well control fluid pit area
- Drillers station
- Living quarters
- All other areas where H_2S may accumulate

An adequate number of sensors (fixed or portable) should be provided for personnel. The distribution of such sensors should be discussed prior to commencing operations. Gas metering equipment should be checked regularly when in use, in accordance with the user guide for such equipment.

Fixed H_2S detectors should be connected to an alarm system which gives a visual and audible alarm throughout the work area.

Instructions on actions to be taken on fire or gas detection should be informed to all personnel and drills carried out.

3.9.10 Other Safety Systems

Other safety systems such as emergency lighting, Public Address/General Alarm (PA/GA) system, emergency communication should also cover the well test areas.

3.9.11 Cross Contamination of Rig Utility systems

Where rig systems are in contact with hydrocarbon containing parts of the well test system, it must be ensured that there is no possibility of backflow onto these systems in the event of a leakage. Typically this will include such systems such as combustion air to the burner booms, steam for the steam heater, and the drains system in the well test area. Any other interfaces should be identified in a HAZOP of the well test plant (generic or specific).

4 CHECKLISTS

The following checklists summarize the key points in the text and are intended to provide a framework for assessment of key safety issues. For any well test aspects such as Management, Quality of Equipment and Safety of the Drilling Rig will be relevant. These can then be combined with the specific checklist or checklists to cover the other special cases.

The following issues are covered :

Checklist #1 : Management of Operations
Checklist #2 : Deepwater Well Testing
Checklist #3 : Well Testing from DP Vessels
Checklist #4 : Well Testing in Arctic Areas
Checklist #5 : Well Testing of HPHT wells
Checklist #6 : Well Testing and H2S
Checklist #7 : Storage and Offloading of Oil
Checklist #8 : Quality of Equipment
Checklist #9 : Safety of Drilling Rig

4.1 Checklist #1 : Management of Operations

Checklist for Well Test Safety #1 : Safety Management System			
Ref	*Item*	*Satisfactory (Y/N)*	*Comment/Recommendation*
1	*Does the Operator have a functioning SEMP in place?*		*This may be in accordance with API RP 75 or in accordance with the Operators own system.*
2	*Has a Hazard Analysis or HAZOP been carried out ?*		*This may be specific for this operation or may be generic if the operation is considered as standard. Special consideration should be given when the well is high profile (e.g. H2S, HPHT). Limitation on simultaneous operations (e.g. helicopter landing) should be considered during certain well test operations such as heavy flaring.*
3	*Is there a procedure for evaluating Contractors?*		*Consideration can be given to a Contractors service record with similar jobs.*
4	*For the well test operation, is there an organization plan and a clear definition of responsibilities?*		*This should cover key personnel in each of the three organizations.*
5	*Do the Operators and Contractors have plans for qualification and training of personnel? Is training documented?*		*Training should ideally involve an initial training and subsequent follow-up training*
6	*Have all personnel received rig familiarization training?*		*All major safety aspects on the rig should be covered.*
7	*Is there a bridging document between existing procedures and the actual planned well test?*		*This should include aspects such as Permit to Work, Simultaneous Operations.*

8	*Is a Job Safety Analysis planned prior to the testing?*		*This should involve participation from the three parties, and include precautions against accidents and actions to be taken in the event of an emergency.*
9	*Are contingency plans available and are appropriate drills planned?*		*Periodic drills should be planned and conducted to cover emergency situations and the results should be documented. Note that some contingency plans (e.g. for H2S should be pre-approved by MMS)*
10	*Have the test spread design considerations been documented in a Test Program?*		*This should include aspects such as downhole tool design, tubing specification, type of safety barriers, specification of completion fluid and well kill fluid, surface equipment specification.*
11	*Are the rig Classification and USCG papers in order and any outstanding conditions being followed up?*		*MODU should have either a Certificate of Inspection (COI) or a Letter of Compliance*
12	*Are safety drawings updated to include the well test spread?*		*This should include Area Classification and Escapeway drawings.*
13	*Has an assessment been made of the drilling rig for available utility systems and suitability of fixed equipment?*		*Utility systems include air, power, steam, firewater. Fixed equipment includes piping and burner boom.*

4.2 Checklist #2 : Deepwater Well Testing

Checklist for Well Test Safety #2 : Deepwater Well Testing			
Ref	*Item*	*Satisfactory (Y/N)*	*Comment/Recommendation*
1	*Is reaction time of SSTT operation within acceptable limits?*		*Consider disconnect time of LMRP, water depth, vessel motion characteristics.*
2	*Is rating of equipment appropriate for application?*		*In addition to pressure and temperature ratings, tensile rating may also be important.*
3	*Is control of the subsea tree coordinated with the driller?*		*Ideally there should be direct communication between driller and operator at test tree panel.*
4	*Have potential flow assurance problems been assessed?*		*This will include hydrates, wax, asphaltenes.*
5	*Does there exist a contingency plan in the event that a blockage occurs?*		*Such a procedure should also be discussed at the pre test meeting.*
6	*Is Methanol stored on board? And if so are the tanks certified for such use?*		*Tanks should be DOT certified or equivalent.*
7	*Is location of the methanol tank such that a fire originating there will not impact the LQ, or alternatively that the tank is unlikely to be impacted by a fire anywhere else on the rig.*		*Location should consider proximity to burner boom and to LQ, and also to escapeways.*
8	*Is the tank safely secured to prevent movement in the event of the rig listing?*		

9	*Has adequate fire protection been provided in the event of a methanol fire?*		*Fire extinguishing equipment suitable for use on methanol should be available. Salt should be placed around the tank to make visible any methanol fire.*
10	*If in an area of high or unusual currents (e.g. loop currents), are these taken into account when defining operational limitations?*		

4.3 Checklist #3 : Well Testing from DP Vessels

Checklist for Well Test Safety #3 : Well Testing from DP Vessels			
Ref	*Item*	*Satisfactory (Y/N)*	*Comment/Recommendation*
1	*What criteria have been used in selecting the DP vessel?*		*Level of reliability required should be considered. Classification documentation should be reviewed.*
2	*Has a drift analysis been carried out ?*		*Drive off should also be considered.*
3	*Have watch circles been established for the well test?*		*This should consider environmental limitations, available thruster power, available electrical power, in addition to current position, reaction time for disconnect, limitations on riser and ball joint.*
4	*Are procedures and limitations specified for operations within the watch circles?*		
5	*Are procedures specified for transition from one circle to another?*		*Alarms and actions should be specified before start of the operation.*
6	*Is responsibility for emergency action clearly specified?*		*The actions and responsibilities of both the driller and the marine crew should be clearly specified.*

4.4 Checklist #4 : Well Testing in Arctic Drilling

Checklist for Well Test Safety #4 : Well Testing in Arctic Drilling			
Ref	*Item*	*Satisfactory (Y/N)*	*Comment/Recommendation*
1	*Has a HAZID/HAZOP been carried out?*		*An analysis should be carried out to identify systems and components which may be impacted by low temperature or by ice formation*
2	*Are structural items designed for ice loading?*		*Design of the burner booms should consider a defined ice loading.*
3	*Is there a procedure in place to ensure that ice rating is not exceeded?*		*If the defined ice load may be exceeded there should be measures in place to safely remove ice.*
4	*Are valves and other active components protected against icing?*		*Operation and position indication should be possible in all conditions.*
5	*Is metallic material suitable for low temperature use?*		*Equipment should either be rated for low temperature or be heated.*
6	*Is non-metallic material suitable for low temperature?*		*Equipment should either be rated for low temperature or be heated or insulated.*
7	*Are control systems designed for use at low temperature?*		*Hydraulic oil should be rated for low temperature use. Instrument air should be sufficiently dried to prevent freezing.*
8	*Are operating stations suitable protected against the environment?*		
9	*Are weather conditions and reliability of forecasting taken into account in specifying operational limitations?*		*Changes in weather conditions may shorten the operating windows compared to areas with more predictable weather.*
10	*Are flow assurance precautions put into place?*		*Measures to prevent blockage and contingency to tackle such should they occur should be in place.*

4.5 Checklist #5 : Well Testing of HPHT Wells

Checklist for Well Test Safety #5 : Well Testing of HPHT Wells			
Ref	*Item*	*Satisfactory (Y/N)*	*Comment/Recommendation*
1	*Has a HAZID/HAZOP been carried out?*		*An analysis should be carried out to identify systems and components which may be impacted HPHT and what precautions are put in place.*
2	*Are sufficient safety barriers in place in the string design?*		*Consider permanent rather than retrievable packer, metal to metal sealing and inclusion of a lubricator valve (on floaters).*
3	*Is downhole equipment suitable for HPHT service?*		*Consider both metallic and non-metallic material.*
4	*Is surface equipment suitable for HPHT service?*		*Certification and test and inspection records should be available.*
5	*What precautions are put in place for pressure testing of equipment on board?*		*Limitation on use of gas for testing should be considered.*
6	*What pressure and temperature monitoring is in place?*		
7	*Has a safety meeting been held?*		*Should include all parties, and address procedures and contingencies.*
8	*Have contingency plans and procedures been developed for the operation?*		
9	*What training and qualification is necessary for personnel?*		
10	*Is there a limitation on receiving first hydrocarbons in daylight hours?*		*If not, the associated hazards and additional precautions should be specified.*

4.6 Checklist #6 : Well Testing and H2S

Checklist for Well Test Safety #6 : Well Testing and H2S			
Ref	*Item*	*Satisfactory (Y/N)*	*Comment/Recommendation*
1	*Is H2S anticipated for the well test?*		*If H2S anticipated then specific precautions should be taken. If H2S is not anticipated then a contingency plan should still address actions to be taken in the event of unexpected H2S being found.*
2	*Has a HAZID/HAZOP been carried out?*		*An analysis should be carried out to identify systems and components which may be exposed to H2S and what precautions are put in place.*
3	*Is downhole equipment suitable for H2S service?*		*Consider both metallic and non-metallic material.*
4	*Is surface equipment suitable for H2S service?*		*Certification and test and inspection records should be available.*
5	*Is sufficient gas detection in place?*		*Gas detectors should be calibrated and certified.*
6	*Are sufficient breathing apparatus available?*		*Instructions for how and when to use should be available and drilled.*
7	*Has a safety meeting been held?*		*Should include all parties, and address procedures and contingencies.*
8	*Have contingency plans and procedures been developed for the operation?*		
9	*What training and qualification is specified for personnel?*		
10	*Are drills planned and carried out?*		*Drills should be documented.*
11	*Are gas detectors in place and tested? Is functioning of alarms confirmed?*		*Detectors should be calibrated and alarms should be tested.*

4.7 Checklist #7 : Storage and Offloading of Oil

Checklist for Well Test Safety #7 : Storage and Offloading of Oil			
Ref	*Item*	*Satisfactory (Y/N)*	*Comment/Recommendation*
1	*Is unit fitted with temporary or permanent tanks?*		*Permanent tanks on drillships are covered by Classification of the ship.*
2	*Are storage tanks vented to a safe area?*		
3	*Are storage tanks located sufficiently distant from the LQ and effects of the burner boom?*		
4	*Is there any interference with escapeways?*		*If temporary tanks are located on existing escape ways, alternate escapeways should be arranged for the duration of the well test.*
5	*Is quality of permanent piping from oil manifold satisfactory?*		*Inspection, NDE, and pressure test records should be available.*
6	*Is the tank barge correctly certified?*		*USCG Certificate of Inspection, Classification for powered barges*
7	*Is the barge mooring system fitted with means to monitor line tension?*		
8	*Are procedures established with the barge company for the offloading operation?*		*Procedures should specify the environmental limitations, contingency plans, communication, alarms and responsibilities.*

4.8 Checklist #8 : Quality of Equipment

Checklist for Well Test Safety #8 : Quality of Equipment			
Ref	*Item*	*Satisfactory (Y/N)*	*Comment/Recommendation*
1	*Have operating parameters been specified for the well test equipment?*		
2	*Are equipment ratings compatible with the test specified parameters?*		*Parameters should include (as appropriate) ratings for temperature, pressure, fluid service, tensile loads, SWL, Hazardous Zone, etc.*
3	*Are settings of relief valves in accordance with safety system evaluation?*		*Should be based on a HAZOP and actual intended operating conditions. Calibration records for safety valves should also be available.*
4	*What documentation is available to confirm that equipment has been designed and fabricated in accordance with recognized codes and standards?*		*This may include manufacturer statements, code certificates, 3rd party reports, material certificates, welding and NDE reports.*
5	*Is there a program in place to confirm regular maintenance and inspection of the well test equipment?*		*Such a program should be based on recognized codes, manufacturer recommendations, and owner experience.*
6	*Are there records available to confirm regular inspection and maintenance?*		
7	*Has a pre-test assembly of the equipment been carried out?*		
8	*Has pressure testing and inspection of the well test plant been carried out?*		
9	*Is capability of rig BOP to shear well test shear joint documented?*		*This might include manufacturer statements, documentation of actual shear testing*
10	*Are adequate measures taken to ensure space out of test string within BOP to ensure that shearing can be carried out?*		
11	*Is reliability of burner ignition confirmed?*		

4.9 Checklist #9 : Safety of Drilling Rig

Checklist for Well Test Safety #9 : Safety of Drilling Rig			
Ref	*Item*	*Satisfactory(Y/N)*	*Comment/Recommendation*
1	*Is the area designated for location of the surface equipment considered suitable?*		*Should consider location with respect to LQ, deck support.*
2	*Is the Area Classification of the area acceptable and are drawings updated?*		*Should consider the area classification of the well test spread and the impact on area classification of adjoining areas (e.g location of doors and ventilation openings).*
3	*Have suitable arrangements been made to deal with a possible leakage from the well test plant?*		
4	*Are there adequate measures for fire fighting provided in the event of fire?*		*This should also include temporary storage area and chemical storage area.*
5	*Has a burner boom radiation study been carried out to ensure that the rig, rig equipment and escapeways are not subjected to excessive heat load?*		
6	*Have a philosophy and a communication routine for shut down been established and integrated with other operations?*		*Upsets and hazards in the well test plant should affect the overall rig shutdown system, and similarly events outside well testing may also lead to a shutdown of the well test plant.*
7	*Are measures taken to ensure that any fire or gas leakage associated with well testing will be quickly detected?*		*This may include provision of additional detectors (CH4 or H2S), establishment of a fire watch team.*
8	*Is suitable normal and emergency lighting available in the well test area?*		*Special attention may be necessary if it is intended to conduct critical operations at night (e.g. first hydrocarbons on board)*

9	*Are alarms and emergency communication arranged so that they are also covering the well test area?*		
10	*Are adequate measures taken to ensure that rig systems will not be contaminated in the event of a hydrocarbon leakage?*		*This should include air systems, drains, steam systems*

APPENDIX A

Generic "Well Specific Operating Guidelines" (WSOG)

Typical Well Specific Operating Guidelines

Condition	Green	Advisory	Yellow	Red
DRIVE OFF **DRIFT OFF** **FORCE OFF** Unit offset deviation Waterdepth: xxx metres	0 – xx m	xx –ss m	> xx m or Immediately when recognised	Immediately when confirmed that situation cannot be controlled. No later that at Xx metres offset
Power consumption each network (2-split HV net)	<50%	50%	Consequence alarm	Situation specific
Power consumption each network (4-split HV net)	>70%	70%	Consequence alarm	Situation specific
Thrust consumption each online unit (2-split HV net)	<50%	50%	Consequence alarm	Situation specific
Thrust consumption each online unit (4-split HV net)	< 70%	70%	Consequence alarm	Situation specific
DP position footprint (5 min. maximum from set point)	<3 m	3m	Situation specific	Situation specific
DP heading footprint (5 min. maximum from set point)	<3 deg.	3 – 5 deg.	5 deg.	If threat to position
Position reference available	3 independent	Any failure or loss of performance in any system	2	If threat to position
DP control system	3 + 1 backup	Any failure or loss of performance in any system	1 or failure/loss of backup controller (F)	0
Wind sensors	3	2		If threat to position
Motion sensors (VRS)	3	2		If threat to position
Heading sensors (Gyro)	3	2		If threat to position
Network	2	N/A.	1	0
Comm.'s systems	Dual systems(DP/Driller	1	Situation specific	Situation specific

Riser limitation UFJ	0 – 1,5 deg	2 deg.	> 2 deg.	Situation specific
Riser limitation LFJ	0 – 1,5 deg.	2 deg.	> 2 deg.	Situation specific
Wind speed (10m/10s)	0 – 15 m/s	15 – 20 m/s	Situation specific	Situation specific
Wind direction	Situation specific.	15 deg. When wind speed > 15 m/s	Situation specific	Situation specific
Sign waveheight	0 – 4,5 m	4,5 – 6,5 m	Situation specific	Situation specific
Riser twist	+/- 180 deg. From BOP landout	> 160 deg. When vessel heading cannot be rewound	Situation specific	Situation specific
ACTION REQUIRED	Normal status	Advise OIM, Driller, Toolpusher, Company Rep.	Issue alarm and follow procedures	Issue alarm and follow procedures
Notify OIM immediately (Y/N)	Normal Conditions	Y	Y	Y
Notify Operator Rep. immediately (Y/N)	Normal Conditions	Y	Y	Y