TECHNICAL REPORT

MINERALS MANAGEMENT SERVICE (MMS)

MMS JIP – SAFETY OF WELL TESTING
FINAL PROJECT REPORT

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TECHNICAL REPORT

Date of first issue: 2004-10-13	Project No.: 440-3508
Approved by: Arne Edvin Løken, Head of Section	Organizational unit: Deepwater Production Systems
Client: Minerals Management Service	Client ref.: Matthew Quinney 0103PO72594

DET NORSKE VERITAS
Technology Services, N America

16340 Park Ten Place
Suite 100
Houston 77084
United States
Tel: +1 281 721 6600
Fax: +1 281 721 6833
http://www.dnv.com

Summary:

This final report summarizes the activities carried out as part of this MMS Joint Industry Project (JIP) which has looked at safety connected with well testing on the OCS. The report describes and documents the activities carried out within the project. The structure of the report is based on the main JIP project tasks.

These tasks were :

1. **Initial Fact Finding** by DNV on OCS and worldwide practice including involvement of major stakeholders
2. **Generic SWIFT/HAZID** of well testing operations addressing a number of operational/geographic variants, including identification of means to prevent, detect, control or mitigate against hazards.
3. **Development of Workshop Discussion Document** based on the SWIFT/HAZID.
4. **An Industry Workshop** to solicit input to Guidance Document.
5. **Create Guidance draft** based on workshop input.
6. **Submit draft to industry/MMS for hearing.**
7. **Finalize draft guidance and issue project report**

This report is part of Task #7.

Report No.: 4514774/DNV	Subject Group: Technical	
Report title: MMS JIP – Safety of Well Testing Final Project Report		
Work carried out by: Conn Fagan		
Work verified by: Charles McHardy		
Date of this revision: 15 Nov 2004	Rev. No.: 0	Number of pages:

Indexing terms

Safety

Well Testing

Offshore

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1 CONCLUSIVE SUMMARY

This final report summarizes the activities carried out as part of this MMS JIP which has looked at safety connected with well testing on the OCS. The report describes the activities carried out within the main project tasks.

These tasks were:

1. **Initial Fact Finding** by DNV on OCS and worldwide practice including involvement of major stakeholders
2. **Generic SWIFT/HAZID** of well testing operations addressing a number of operational/geographic variants, including identification of means to prevent, detect, control or mitigate against hazards.
3. **Development of a Workshop Discussion Document** based on the SWIFT/HAZID.
4. **Conduct Industry Workshop** to solicit input to Guideline.
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7. **Finalize draft guidance and issue project report**

This report is part of Task #7.

In addition to this report a number of other documents have been produced in this project:

- HAZID Report
- Workshop Discussion Document
- Workshop Record
- Guidance

These documents are included in this report as Appendices.

2 INTRODUCTION

The JIP investigated hazards associated with dynamic well testing operations on the Outer Continental Shelf (OCS). It is anticipated that flow testing activity is likely to increase to provide more certainty than obtained by static testing alone. The JIP has looked at the impact on well test safety of moving into deeper waters, the increased possibility of encountering high pressure or high temperature conditions in deep gas wells, and also the possibility of increased arctic activity.

The JIP comprised the following major project tasks:

1. Initial Fact Finding by DNV on OCS and worldwide practice including involvement of major stakeholders
2. Generic SWIFT/HAZID of well testing operations addressing a number of operational/geographic variants, including identification of means to prevent, detect, control or mitigate against hazards.
3. Development of Workshop Discussion Document based on the SWIFT/HAZID.
4. Conduct Industry Workshop to solicit input to Guidance.
5. Create Guidance draft based on workshop.
6. Submit draft to industry/MMS for hearing.
7. Finalize draft guidance and issue project report.

The JIP participants were DNV as coordinators and representatives from the major players involved in well testing:

- Oil Company BP
- Drilling Contractor GlobalSanteFe
- Well Test Company Schlumberger

3 INITIAL FACT FINDING

3.1 Objective

In order to provide the project team with an overview of the current state of technology, current industry practice, and US and other regulatory requirements, the project conducted an initial fact finding exercise.

3.2 Methodology

The project fact finding involved:

- document search of international codes and standards addressing well testing, primarily API codes, but also including UK and Norwegian guidance documents on selected topics
- document search of major offshore publications, conferences and offshore research projects (IADC, OTC, DeepStar)
- review of existing US and international legislation (Canada, U.K., Norway, Australia)
- interview of major players (BP, Schlumberger, GSF) and circulation of questionnaires to determine current practice and concerns

In addition an information meeting was held with MMS drilling engineers in New Orleans on 16th September 2003 in order to inform of the project approach and to obtain input on MMS concerns with respect to well testing.

3.3 Results

On the basis of the initial fact finding a framework for the next phase, the SWIFT/HAZID was developed with a number of initial topics identified. These topics included:

- Deepwater Drilling
    - Hydrostatic effects
    - Control system timing

- Testing from DP Vessels
    - Drive off/drift off
    - Requirements to DP system
    - Watch circles
    - Reaction time

- Testing in Arctic Conditions
  - Icing of equipment (burner boom)
  - Low temperature effects on materials
  - Low temperature effects on control systems
  - Low temperature effects on transported fluids

- Shallow Water / Deep Gas Drilling
  - High Pressure/ High Temperature
  - Jack ups

- Offloading of Produced Oil
  - Storage on drillships
  - Offloading to barges

- Quality of Equipment
  - Initial certification
  - Maintenance records
  - Test before use

- Impact on the drilling unit
  - Area classification
  - Drains
  - Firefighting
  - Esd
  - F&G detection

- Control of Operations
  - Simultaneous operations (offloading + testing)
  - Manning

- Responsibility
  - Operator vs Rig Owner vs Service Company
  - Verification requirements

These topics were fed forward into preparation for the SWIFT/HAZID.

4 SWIFT/HAZID

4.1 Objective

Although many of the hazards associated with well testing are reasonably well known, the project decided to conduct a SWIFT/HAZID in order to provide a formal technical basis of hazard identification and to ensure that all relevant hazards and combinations of hazards were identified in a structured manner for inclusion in the later work.

A SWIFT (Structured What IF Technique) is a systematic, multidisciplinary team-oriented analytic technique. To ensure comprehensive identification of hazards, SWIFT relies on a structured brainstorming effort by a team of experienced personnel with supplementary questions from a checklist

4.2 Attendance

In order to ensure an efficient process the number of participants was limited. However, to ensure that the group represented the different parties involved in well testing, it was decided to have representatives from a:

- Service provider
- Offshore Operator
- Drilling Contractor
- Regulatory Authority
- Classification Society

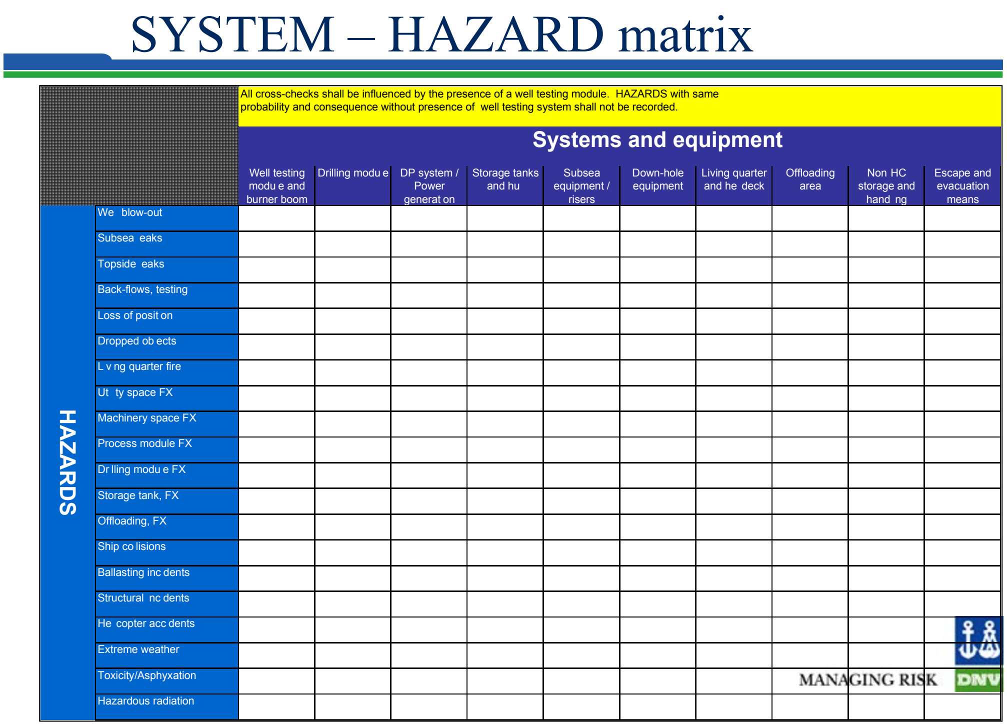
In addition a specialist in SWIFT/HAZID facilitation was used to create the necessary checklists and to run the session.

The following participants took part in the process :

- Christophe Rojas - Schlumberger
- Mark Barrileaux - BP
- Tom Weatherhill - GSF
- Andrew Konczvald - MMS
- Charles McHardy - DNV Technology
- Conn Fagan - DNV Technology
- Ernst Meyer - DNV Consulting (facilitator)

4.3 Methodology

The methodology used in this SWIFT/HAZID was specifically developed to address the objectives of the study. A SYSTEM-HAZARD matrix (Fig. 1) was developed to lead the discussion with respect to generic hazards and all systems/areas which might be affected by such hazards on a drilling unit.



SYSTEM – HAZARD matrix

All cross-checks shall be influenced by the presence of a well testing module. HAZARDS with same probability and consequence without presence of well testing system shall not be recorded.

Systems and equipment

HAZARDS	Well testing modu e and burner boom	Drilling modu e	DP system / Power generat on	Storage tanks and hu	Subsea equipment / risers	Down-hole equipment	Living quarter and he deck	Offloading area	Non HC storage and hand ng	Escape and evacuation means
We blow-out										
Subsea eaks										
Topside eaks										
Back-flows, testing										
Loss of posit on										
Dropped ob ects										
L v ng quarter fire										
Ut ty space FX										
Machinery space FX										
Process module FX										
Dr lling modu e FX										
Storage tank, FX										
Offloading, FX										
Ship co lisions										
Ballasting inc dents										
Structural nc dents										
He copter acc dents										
Extreme weather										
Toxicity/Asphyxation										
Hazardous radiation										

MANAGING RISK

Fig. 1 Hazard Matrix

The process involved investigating the hazards to the drilling unit arising from well testing and looked at both the probability side and consequence side as part of the assessment, i.e. how was the probability of a hazard occurring influenced by the fact that well testing was being carried out and then how was the consequence of a hazard influenced due to well testing. The results of the discussion were captured in the matrix worksheets (Fig 2).

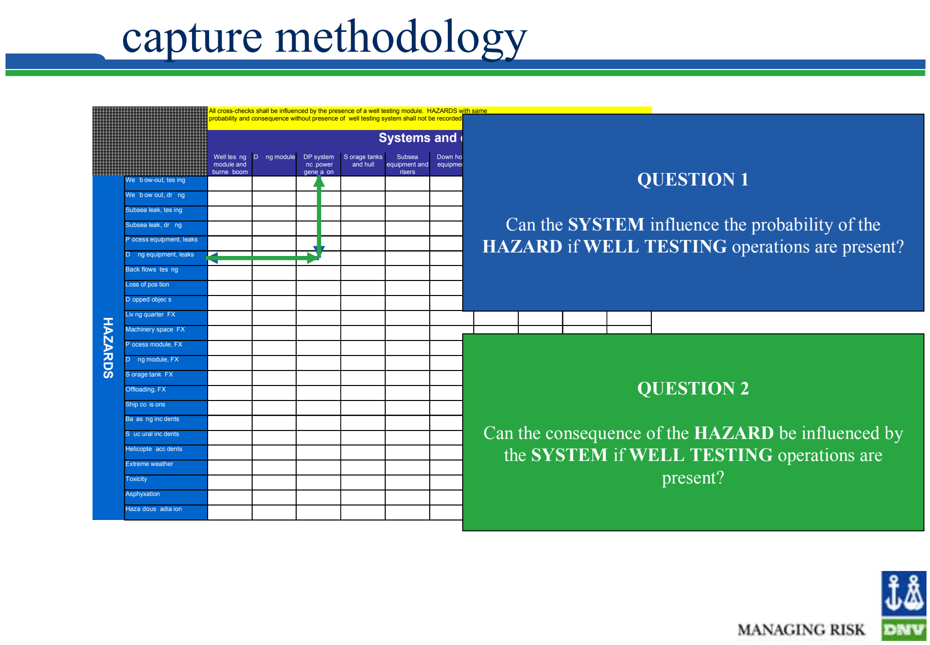


Fig. 2 Questions to determine probability and consequence influences

The approach considered the following major variants with respect to well test operations:

- Standard shallow water operations
- Deepwater operations (including from DP drilling units)
- Testing in arctic waters
- Testing of High Pressure High Temperature wells

Keywords as shown in Fig. 3 were used to encourage the discussion.

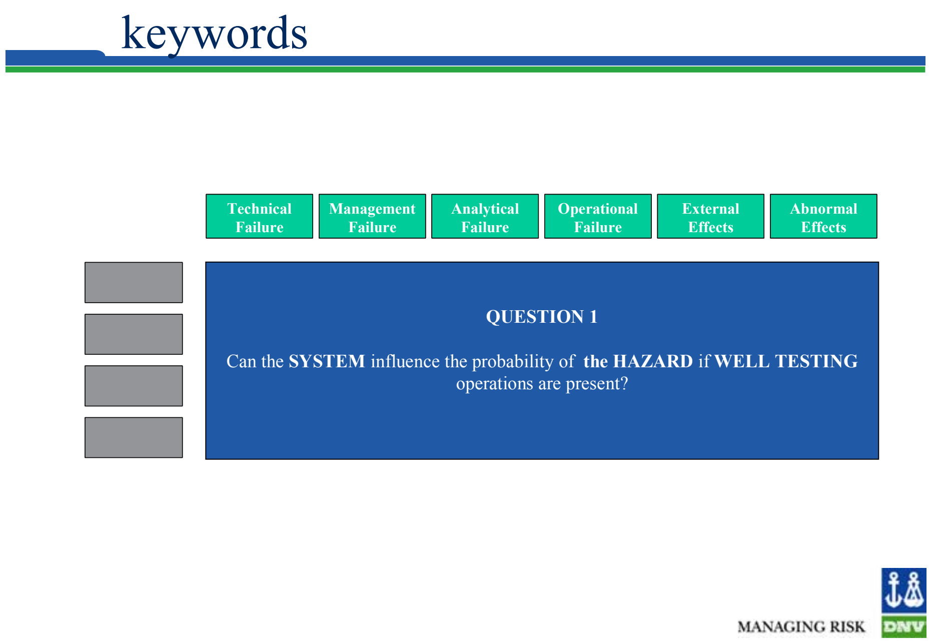


Fig. 3 Well Test Variants and Keywords

4.4 Results of the SWIFT/HAZID

The results of the analysis were documented in a report (ref DWTPROJ-J-297). This report is included in Appendix A of this report.

5 WORKSHOP DISCUSSION DOCUMENT

5.1 Objective

On the basis of the initial fact finding and the subsequent SWIFT/HAZID the key safety challenges were identified. These topics were selected as the areas on which to focus for the JIP Industry Workshop, and the subsequent Guidance Document to be created by the project.

In order to stimulate discussion for the Industry Workshop, a Workshop Discussion Document was produced and circulated to Workshop attendees prior to holding the workshop.

5.2 Format of the Discussion Document

The Workshop Discussion Document described the anticipated safety issues, and proposed a number of questions for each issue to be addressed by the workshop in order to focus discussion and to allow for preparation by the participants.

For example the following questions were developed for the topic of Testing in Deepwater :

Workshop Topics for Discussion:

1) *Guidance should address response time of the control system. Should limits be specified (e.g. 15secs or 30 secs)? What are influencing parameters?*
2) *Are there any specific recommendations on test string design for deepwater?*
3) *Should we recommend a specific documented procedure for handling a hydrate plug be created?*
4) *Intended guidance would include storage and safety of methanol. Should storage tanks meet IMDG (Code for transportation of dangerous goods) requirements? Should they be fastened to the deck? Do we need special drainage or collection arrangements? Do we need additional fire fighting?*
5) *Is there any need to specially follow up existing drilling equipment critical to the well test safety, e.g. special inspection of load carrying and tensioning equipment prior to a test?*
6) *Other considerations?*

The Workshop Discussion Document, ref DNV Report No. 3657149 is included in Appendix B to this report.

6 INDUSTRY WORKSHOP

6.1 Objective

An Industry Workshop was conducted in Houston on 16th and 17th June 2004, with the aim of soliciting input to the JIP Guidance, based on a discussion of the key safety issues raised in the Discussion Document. The intention was to broaden participation to other industry companies outside the core JIP participants.

6.2 Attendance

Representatives from the following companies/organizations attended the workshop:

Schlumberger

Halliburton

Layfayette

Shell

Anardarko

Amerada Hess

BP

ExxonMobil

ConocoPhilips

ChevronTexaco

Kerr McGee

Total

Noble Drilling

Diamond Offshore

GlobalSanteFe

Transocean

IADC

DNV

USCG

6.3 Methodology

The workshop participants were divided into 4 groups, each group having at least one representative from each of the main industry players, Operator, Drilling Contractor, Service Company.

Each group was assigned a number of safety topics to discuss and to formulate guidance on, based on trigger questions from the Discussion Document. The groups then presented their work in plenum and other groups had the opportunity of commenting and providing additional input and discussion.

6.4 Workshop Record

The workshop discussions were recorded and related to the key questions assigned to the various topics. The related proposed guidance was also recorded.

The record of the workshop is included in Appendix C to this report.

7 GUIDANCE DOCUMENT

7.1 General

On the basis of both the Workshop Discussion Document and the input provided by the JIP Industry Workshop, a document titled "Guidance on Safety of Well Testing" was produced. This was circulated to the Workshop participants as a draft for comment. The comments received were assessed and incorporated as appropriate and a final Guidance document was issued.

The project report "Guidance on Safety of Well Testing" is included in Appendix D to this report.

7.2 Structure of the Guidance

The Guidance focuses on safety issues related to flow testing of wells. It provides a general discussion of well test options and outlines the regulatory background with respect to well testing. The Guidance provides a short description of important safety issues and then provides guidance on means to ensure safety.

7.3 Scope of the Guidance

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 judgment.

7.4 Guidance Checklists

For each of the major areas discussed, a checklist has been created summarizing the main points to be considered in assessing safety.

8 CONCLUSION

In accordance with the objectives of the JIP, an assessment of safety has been made with regard to well testing on the OCS in light of probable future activity.

Guidance has been created addressing key safety aspects of well testing on the OCS. The Guidance is based on current technology and industry practice. Development of the Guidance has been carried out based on a structured assessment of hazards associated with well testing.

The Guidance has been produced in consultation with representatives from the industry, primarily Offshore Operators, Drilling Contractors and Well Test Service Companies.

APPENDIX A

SWIFT/HAZID REPORT

TECHNICAL REPORT

MINERALS MANAGEMENT SERVICE
WELL TEST JIP – SWIFT/HAZID

REPORT NO. DWTPROJ-J-297

REVISION NO. 01

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TECHNICAL REPORT

Date of first issue: 2004-03-11	Project No.: 440-3708
Approved by: Arne Edvin Løken, Head of Section	Organisational unit: Deepwater Production Systems
Client: Minerals Management Service	Client ref.: Andrew Konczvald

DET NORSKE VERITAS
Technology Services, N America

16340 Park Ten Place
Suite 100
Houston 77084
United States
Tel: +1 281 721 6600
Fax: +1 281 721 6833
http://www.dnv.com

Summary:

This SWIFT/HAZID is carried out as part of a JIP which is looking at the safety of well testing operations.

The JIP is investigating the current practices and level of safety of well testing (within US OCS and World-wide), and aims to assess whether future applications introduce significant additional hazards not currently addressed. The study also aims to develop recommendations as to how to arrive at a consistent and verifiable level of safety with respect to current and future well test operations on the OCS.

The SWIFT/HAZID provides a structured approach to identifying the hazards and current safeguards associated with typical well test operations, and potential future operations. These aspects are identified in this document and will be assessed for future project phases.

Report No.: DWTPROJ-J-297	Subject Group: Technical	
Report title: MMS JIP - Well Testing		
Work carried out by: Conn Fagan		
Work verified by: Charles McHardy		
Date of this revision: 2004-03-10	Rev. No.: 01	Number of pages:

Indexing terms

Key words	Service Area
Well Testing Drilling Safety	Safety
	Market Sector: Oil and Gas

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The SWIFT/HAZID provides a structured approach to identifying the hazards and current safeguards associated with typical well test operations, and potential future operations. The results of the exercise are documented in the HAZID table in Appendix B of this report, and will be considered in the next phases of the project and in producing the planned guidance.

2 INTRODUCTION

DNV is leading a JIP to investigate the current practices and level of safety of well testing (within US OCS and World-wide), and aims to assess whether future applications introduce significant additional hazards not currently addressed. The study also aims to develop recommendations as to how to arrive at a consistent and verifiable level of safety with respect to current and future well test operations on the OCS. A presentation on the background and aims of the JIP is included in Appendix A.

Participants in the JIP are: DNV, MMS, Schlumberger, BP, and GSF.

The major JIP project tasks are as follows:

1. **Initial Fact Finding** by DNV on OCS and worldwide practice including involvement of major stakeholders
2. **Generic SWIFT*/HAZID** of well testing operations addressing a number of operational/geographic variants, including identification of means to prevent, detect, control or mitigate against hazards.
3. **Development of initial Position Document** based on the SWIFT/HAZID.
4. **Conduct Industry Workshop** to solicit input to Guideline.
5. **Create Guidance draft** based on workshop.
6. **Submit draft to industry/MMS for hearing.**
7. **Finalize draft guidance and issue project report.**

This report documents the results of Task #2 SWIFT/ HAZID which was carried out at DNV Offices in Houston on March 3rd and 4th 2004. The SWIFT approach (Structured What IF Technique) is a systematic, multidisciplinary team-oriented analytic hazard identification technique. To ensure comprehensive identification of hazards, SWIFT relies on a structured brainstorming effort by a team of experienced personnel with supplementary questions from a checklist.

3 PARTICIPANTS

In order to ensure an efficient process the number of participants was limited. However in order to ensure that the group represented the different parties involved in well testing it was decided to have representatives from a:

- Service provider
- Offshore Operator
- Drilling Contractor
- Regulatory Authority
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The following participants took part in the process:

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- Conn Fagan - DNV Technology
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4 METHODOLOGY

The methodology used in this SWIFT/HAZID was specifically developed to address the objectives of the study. A SYSTEM-HAZARD matrix (Fig. 1) was developed to lead the discussion with respect to generic hazards and all systems/areas which might be affected by such hazards on a drilling unit.

SYSTEM – HAZARD matrix

		All cross-checks shall be influenced by the presence of a well testing module. HAZARDS with same probability and consequence without presence of well testing system shall not be recorded.									
		Systems and equipment									
		Well es ing module and burner boom	Drilling module	DP system / Power generat on	Storage tanks and hu	Subsea equipment / risers	Down-ho e equipmen	Liv ng quarter and he deck	O oading area	Non HC storage and handling	Escape and evacua on means
HAZARDS	Well blow-out										
	Subsea eaks										
	Topside leaks										
	Back flows, testing										
	Loss of pos t on										
	Dropped ob ects										
	Liv ng quarter f re										
	Utili y space FX										
	Machinery space FX										
	Process module FX										
	Drilling module FX										
	Storage tank, FX										
	O oading, FX										
	Ship co lisions										
	Ballas ng inc den s										
	Structural inc dents										
	Helicopter acc dents										
	Extreme weather										
	Toxicity/Asphyxation										
	Hazardous rad at on										

MANAGING RISK

Fig. 1 Hazard Matrix

The process involved investigating the hazards to the drilling unit arising from well testing and looked at both the probability side and consequence side as part of the assessment, i.e. how was the probability of a hazard occurring influenced by the fact that well testing was being carried out and then how was the consequence of a hazard influenced due to well testing. The results of the discussion were captured in the matrix worksheets (Fig 2).

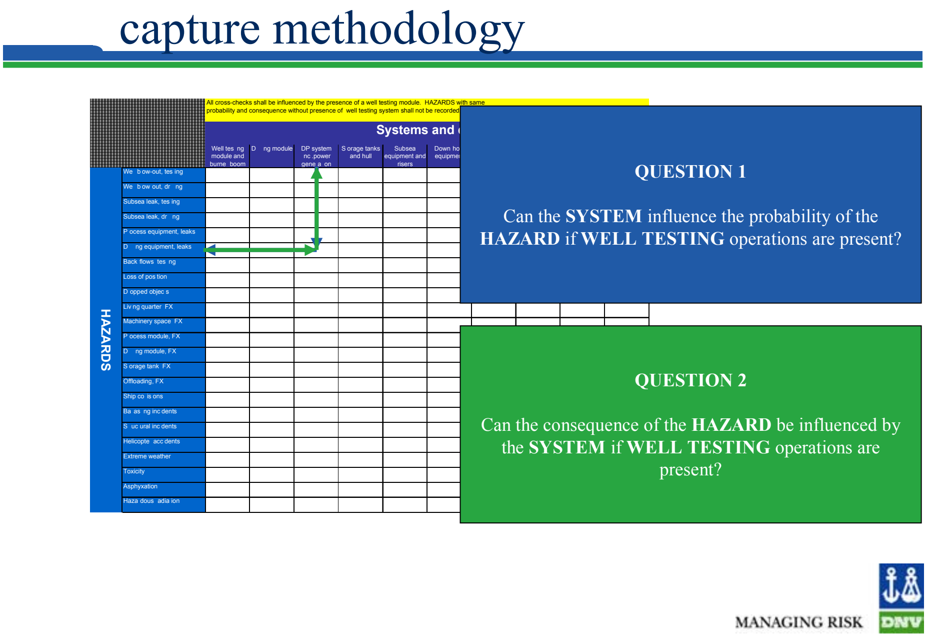

Fig. 2 Questions to determine probability and consequence influences

The approach considered the following major variants with respect to well test operations :

- Standard shallow water operations
- Deepwater operations (including from DP drilling units)
- Testing in arctic waters
- Testing of High Pressure High Temperature wells

The study considered a typical well test layout as shown in Appendix B.

Keywords as shown in Fig. 3 were used to encourage the discussion.

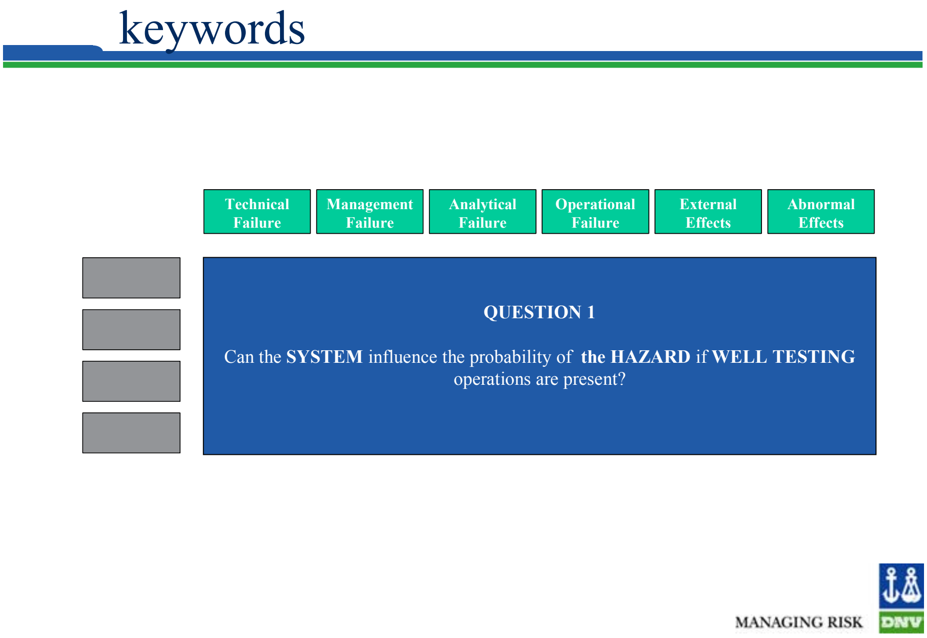

Fig. 3 Well Test Variants and Keywords

5 MAIN FINDINGS

The results of the HAZID are documented in the spreadsheets created during the meeting. These records are included in Appendix C.

The following areas general areas will be covered in future guidance:

- Management of well testing operations
- safety of the drilling unit
- selection and quality of equipment
- safety assessment
- special deepwater considerations
- special cold climate considerations
- special HPHT considerations

The safeguards and recommendations recorded here will be considered in development of the next discussion document and guidance.(task #3).

It is intended that the Workshop (task #4 in the project plan) to be held will provide further input to the potential guidance.

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APPENDIX A

Overview of Well Test JIP

Background

JIP to address MMS safety concerns connected to present and future well test activity on the US OCS.

JIP Objectives

- To investigate the means by which the worldwide industry prevents, detects, controls or mitigates against the hazards associated with well testing operations. Identification and management of potential risk will be a clear focus;
- To report on actual practices and Management Systems for different worldwide geographical areas; climatic conditions; drilling rig types; operators of the equipment and regulatory regimes including the statistics of the use of well testing spreads and accidents/incidents associated with them (including best practices and lessons learned);
- To lay the groundwork and make suggestions for a Guide for the use of well testing spreads in the US OCS so as to encourage a consistent and verifiable level of safety with respect to current and future well test operations.

Schedule

- Initial Fact Finding to commence Sept 2003.
- The SWIFT/HAZID process will run concurrently with the final stages of the Initial Fact Finding (March 2004).
- The Industry Workshop is expected to take place in mid April 2004.
- The Hearing Draft should be circulated June 2004.
- The Final Report and Draft Guideline could then be submitted to the sponsors by end of August 2004.

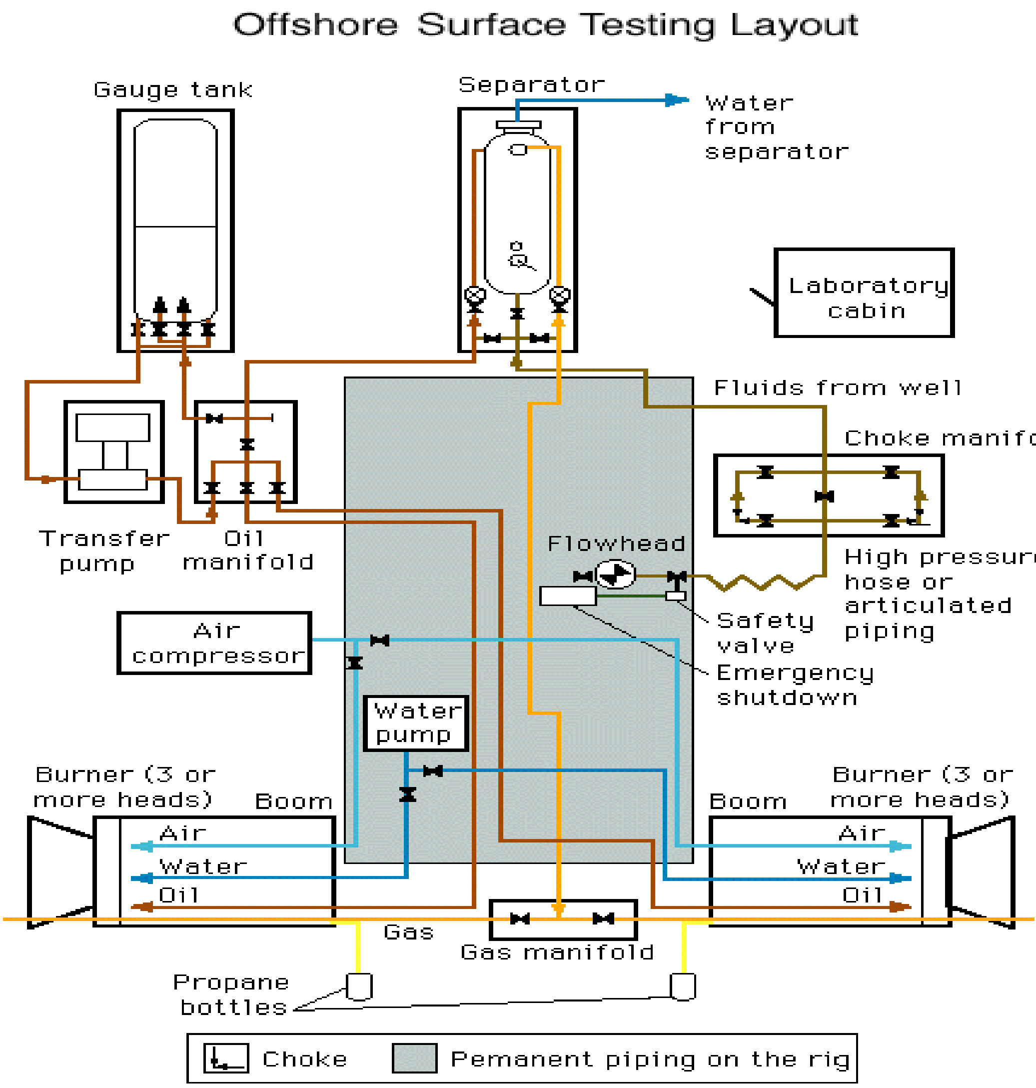
Flow Testing Study – Areas of Focus

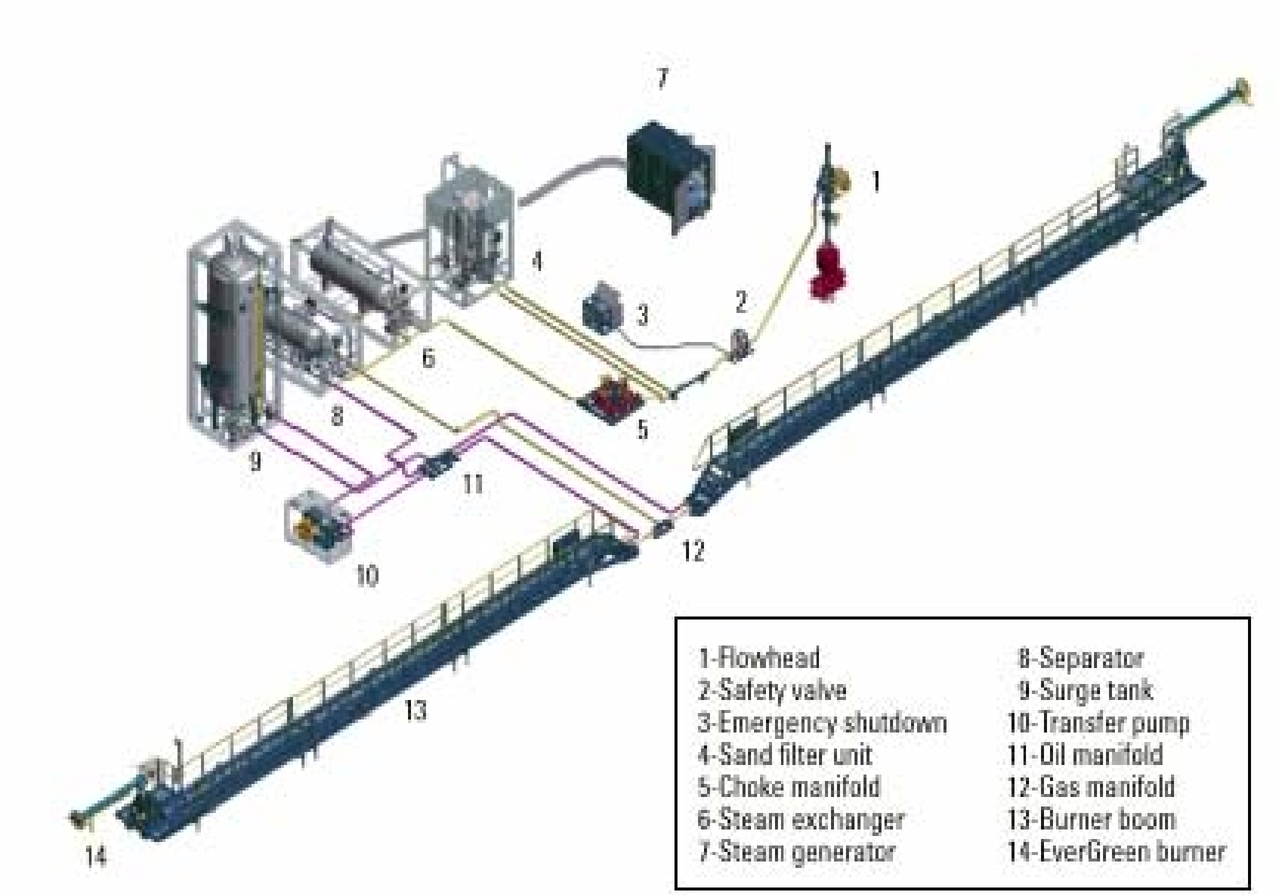
What are hazards associated with well testing operations and how are they dealt with for:

- Typical Current Applications in GoM
- Deepwater Wells
- Arctic conditions
- HPHT Wells

APPENDIX B

Typical Well Test Layout


Offshore Surface Testing Layout
Gauge tank
Separator
Water from separator
Laboratory cabin
Fluids from well
Choke manifold
Transfer pump
Oil manifold
Flowhead
High pressure hose or articulated piping
Safety valve
Air compressor
Emergency shutdown
Water pump
Burner (3 or more heads)
Boom
Air
Water
Oil
Gas
Gas manifold
Propane bottles
Choke
Pemanent piping on the rig



Typical Surface Well Test Plant

APPENDIX C

HAZID Record

HAZARDS			SYSTEMS & EQUIPMENT								
			A	B	C	D	E	F	G	H	I
			Well testing module and burner boom	Drilling module	DP system / DP Power generation/ Mooring System	Produced Fluids Storage tanks and hull	Subsea and Downhole equipment including control system	Living quarter and helideck	Offloading system including barge and floating hose	Non-HC flammable storage and handling (including Methanol)	Marine Safety systems (including escape and evacuation)
	1	Blow-out/Subsea Leaks									
	2	Burner boom incidents									
	3	Topside leaks									
	4	Back-flows									
	5	Loss of position			Same as for a drilling op.						
	6	Dropped objects									
	7	Living quarter fire									
	8	Utility/non-HC storage space FX				As for LQ					
	9	Machinery space FX	Similar to LQ			As for LQ					
	10	Drilling module, Leaks, FX									
	11	HC Storage tank, FX									
	12	Offloading, Leaks, FX									
	13	Ship collisions			As for drilling		As for loss of position				
	14	Stability incidents									
	15	Structural incidents									
	16	Helicopter accidents									
	17	Extreme weather									
	18	Toxicity/Asphyxation									
	19	Hazardous radiation									

TECHNICAL FAILURE

I.D.	Risk Issue	Probability and Consequence Influence	Safeguards	Comments & Recommendations
Not Condition Sensitive				
A1	Failure of control (well blowout)	Continuous presence of hydrocarbons	ESD, procedures	Well test operations and procedures need to be integrated into the overall rig
	Equipment containment failure (well blowout)	Presence of critical 3rd party equipment on board	Upstream closure devices, Design. Maintenance , Inspection.	Use of correct codes (e.g. NACE), Correct operating parameters (plus safety factor), Demonstration of ongoing integrity
A1	Increased ignition possibilities (including flare pilot)	Increased presence of Hydrocarbons. 3rd part equipment which might provide ignition source	ESD, gas detection, no hot work, certification of equipment	Shut down response time critical to reduce gas release Need to include hazardous area considerations for well testing. Need to ensure that 3rd party equipment suitable for hazardous areas
A1	Incorrect set points	safety valves and safety instrumentation dont function properly and result in damage, leakage etc.	Testing, backup valve, training, drills, manning and manual operation	Maintenance program, Calibration of valves and instruments
	Change in flow characteristics	Sand production Cement breakdown Change in GOR H2S, CO2 conc	Initial assessment, monitoring (manual sensors for gas analysis - procedure)	Consider and probe, sand trap Initial assessment is critical. If uncertain should plan for worst case (e.g. H2S rating of equipment)
A2	Excessive heat radiation	Flare/burner give off excess heat (affecting rig structure, escape ways etc)	Water curtain, design for flow	Need to predict worst case flow and associated radiation level.
A2	Change in wind direction	wind affects behaviour of flare, radiation	Monitor, procedure, switch over	Procedure needs to set parameter guidelines. ***See also Deepwater***
A2	Structural failure of boom	Release of hydrocarbons, and structural damage	Design, inspection	***See also Arctic***
A3	Leakage in surface equipment	Release of hydrocarbons	Detection and shutdown, testing (max expected shut in pressure with a margin), visual inspection	Consider time limitation (daylight or sufficient artificial lighting - deviation) on initial opening up of the well When testing a gas well consider a Nitrogen pressure test beforehand (additional safety precautions, e.g at a lower level than hydro test) Condition of equipment is important.
A4	Contamination and overpressure	Hydrocarbons enter utility systems and safe areas or high pressure enters lower pressure system	Design, (dedicated air supply or double NRV), maintenance and equipment certification	Consider an initial HAZOP (HPHT), certification

TECHNICAL FAILURE

I.D.	Risk Issue	Probability and Consequence Influence	Safeguards	Comments & Recommendations
A5	Loss of position	Flare upwind	ESD	Change of position will probably be relatively slow, giving sufficient time to react.
A6	Dropped methanol tank, chemicals	Increased movement of hazardous materials	Procedures, spill team, emergency response plan	Check of slings etc., certificates
A7	Ingest gas	Gas enter LQ, toxic and explosion	Location of intakes, gas detection, ESD	
A8	Methanol fire	Presence of methanol for flow assurance	Location, (cannot see - use salt, tape), training, deluge, MSDS	Cooling spray to keep vaporization down, no detectors for methanol, consider AFFF
	Propane fire	Presence of propane for burners	Propane detectors, protection from dropped objects(?), location, MSDS	Shutdown, consider cages, minimize routing and leak points, certification of hoses
	Solvents, inhibitors	Presence of chemicals for flow treatment	MSDS, location, secondary containment	
	Explosives	Presence on board	Location, locks	Explosives will be only used during completion/perforation, not during the actual testing. When stored they will need to be protected against any accident arising from the well test operation.
A10	Gas leak in drilling area	Hydrocarbon piping from drill deck to well test area	Hazardous area designated Gas detection Procedures	
A11	Fire and Explosion in cargo tanks	Temporary storage in either integral tanks (e.g. drillships) or in deck tanks	Inert system, tank cleaning (for integral tanks), deluge or fire extinguishers	No inert system in temp tanks (gauge tanks, 500 bbl tanks) and may only have additional fire extinguishers.
A12	Offloading pumps ignite gas	gas release from offloading lines or other gas leakage	Ventilation of pump rooms(integral tank vessels), gas detection,	Portable tanks have portable pumps, need to ensure drainage (manned operation), zone 2 rated diesel engines?
	Release of Oil	Pollution as a result of oil leakage	Location of isolation valve -(dry-break) (QCDC), maintenance	Large fine for spillage, OPA 90, OCIMF?
A13	Ship collision (testing)	Collision causes sufficient damage to affect testing (e.g. causes list)	Limit to ship visits during testing	Consider collision avoidance measures.
	Ship collision (offloading)	Increased traffic for offloading	availability of tugs, positioning of barge	Include requirements to offloading barge/tugs and parameters for positioning in offloading procedures.
A14	Ballasting - listing	Damage/injury from moving equipment	Protect against movement by fixing equipment	Consider designing sea fastenings for accidental list condition which may be caused by a ballasting failure or internal flooding.

TECHNICAL FAILURE

I.D.	Risk Issue	Probability and Consequence Influence	Safeguards	Comments & Recommendations
A15	Support for equipment	Failure of rig structure due to load from test equipment	Design of rig, selection of well test area	Need to check that deck can support the equipment to be placed on it (including when filled with fluid)
A16	Interference with helicopter	Turbulence, and obstruction	Procedures and operational limitations	Consider size of unit (large units may permit simultaneous operations), normally restrict flights while testing
	Helicopter crashes into well test area, or on helideck	Hydrocarbons on board	Restrict flights, shut down operations, isolate	Consider size of unit (large units may permit simultaneous operations), normally restrict flights while testing
A17	Weather	Severe weather causes listing	Forecast, develop emergency response procedure	Sea fastening, frequency of forecasting,
A18	Nitrogen	Confined space problem	Design, ventilation, procedures, training	Confined space entry procedure
	H2S/CO2	Release impacts personnel	Design, ventilation, procedures, training, detection, drills	Note corrosivity aspect Relatively predictable in current drilling regions, may be more unpredictable in deep gas drilling.
	Propane	Release impacts personnel	Small quantities, odorized, light	Not considered as significant hazard
B1	Block Failure/Compensator failure	Damage to flowhead etc. leads to blowout	Design, inspection, maintenance, barriers below mudline	Ensure integrity of equipment in the drilling plant which is critical for the well testing operation. This includes riser, riser tensioner, BOP, hoisting equipment, compensators, kill pump/cementing pump.
B3	Damage to hoses and chicksans by block failure	Leakage	Design, inspection, maintenance, barriers below midline	
B11	Drilling while hydrocarbon storage	Dropped pipes	Procedures, design for impact	Limit lifting over storage decks or deck storage tanks
C1	Hydrocarbon release due to loss of position	damage to test string by excess offset	ESD, failsafe valves, disconnect, shear rams , emergency procedures	Timing of actions is critical. Need to ensure that the control arrangement can provide sufficiently rapid response after warning of loss of position. For moored systems, consider limiting operations after loss of an anchorline
C2	Boom upwind due to loss of position	Excess radiation on rig	Procedures to address loss of position	Takes time to rotate, would have time to shut in. Plan heading so that any rotation due to loss of position keeping will be safe

TECHNICAL FAILURE

I.D.	Risk Issue	Probability and Consequence Influence	Safeguards	Comments & Recommendations
C3	Will dp be shut down on process ESD	Ignition sources present while gas leakage	Hazardous areas, location of air inlets, emergency procedures	Consider separate combustion air intakes for thrusters
	Sparks from chains	Chain movement gives ignition sources	Don't operate during well test, forecast so that line adjustment is not necessary	
C8	Damage to control, power lines for DP	loss of DP	Layout, design, redundancy	Consider fire protection in critical areas
C11	Fire in storage tanks causes damage to power and control	loss of DP	Fire fighting, detection, redundancy	Consider fire protection in critical areas
C12	Drive off while offloading	Damage to hose, collision with barge	Redundancy in DP system, multiple tugs , communication	
C17	Extreme weather	Loss of position	Define watch circles, operation limits	Wind, current, icing ***See Deepwater***
D2	Temp Storage tanks affected by heat from burners	Heat radiation from burners	Location, heat protection, water curtain if necessary	
D4	Backflow from tank to process	Inappropriate fluid or pressure	Design, NRV	Consider HAZOP
D6	Drop portable storage tank	Still fluid in tank	Certified slings etc	Consider clean before transport
	Drop object onto storage tank	Release of hydrocarbons	Certified slings etc	Consider limit lifting operations
D8	Located close to LQ/storage space etc	Fire affects LQ	Venting arrangement, location, gas detection in air intakes	Ensure that a possible fire from stored HC cannot affect LQ. Locate as far as possible away.
D10	Venting from storage	vented gas enters other areas	drilling area is a hazardous area	
D12	Pulling vacuum on tank	failure of storage tank	Procedures	Open vent, consider PV valve
D13	Penetrate tanks (integral tanks)	leakage of HC	Double hull	restrict larger traffic
D14	Cargo tank valves open	Unplanned movement of oil from one cargo tank to another	procedures, design	Consider FMEA (ref P 34 accident involving failure of cargo valves)
D15	Support of full tank	Insufficient deck strength	Design, location	ensure location suitable for support of full tank
D17	Tank collapse due to rig movement	movement and failure of portable tank	Seafastening, internal sloshing	Consider measures for seafastening
D20	Inert gas leakage	impact on personnel	Location of vent	No inerting of temp storage, inerting of permanent integral storage
E1	Failure of EZ tree to function	uncontrolled release of HC	Rating, consider safety factor to account for uncertainty	Rating for temperature, one umbilical two control lines in it.
	Failure of test string	uncontrolled release of HC	Use premium tubulars	Some companies may may select drillstring!
	Leakage from threads	uncontrolled release of HC	Use premium tubulars, procedures	
	Exposure to H2S	uncontrolled release of HC	Use premium tubulars	
	Flow from well while pulling test string	uncontrolled release of HC	Ensure well is overbalanced, ensure safety of DP system	While pulling BHA cannot close the BOP. Fluid may be less reliable than for equivalent drilling situation

TECHNICAL FAILURE

I.D.	Risk Issue	Probability and Consequence Influence	Safeguards	Comments & Recommendations
E3	Excess time for shut in on topsides leak	uncontrolled release of HC	Design	Ref deepwater and arctic effects. Design for 15sec (Sentree 7) shut in of test tree others may be longer. Can shut in at flowhead or choke manifold unless need to disconnect.
E4	Backflow via chem injection lines	HC at inappropriate location or pressure	NRV	
	Methanol in umbilical permeates into injection line outer jacket and backflows	Methanol at inappropriate location or pressure	Design	
	Backflow via kill line	HC at inappropriate location or pressure	NRV at cement pump or kill pump	This valve is tested against, in rig up phase
E5	Damage to umbilical	loss of control	Failsafe design	Minor pollution
E6	Damage to subsea equipment due to falling objects	possible release of HC	Operations, procedures	
E17	Riser failure due to extreme weather	Leakage into moonpool of HC or H2S	Disconnect, operations limits	Should not be testing in very extreme weather
F2	Heat effects on structure and escapeways	Excess radiation from burner boom	Location	Consider radiation study
F3	Fire and explosion	fire or explosion impacts LQ	Location, hazardous area	Location of well test plant needs to consider effects of fire and explosion on LQ
F8	fire etc from methanol and chemicals	Increased presence of chemicals for well testing	location, protection, extinguishing	
F11	Effects from temp storage or vent	fire and explosion affecting LQ	Location	
F12	Fire and explosion as a result of leakage	effects on LQ	Location of offloading with respect to LQ. Operations, Hazardous area	
F18	Toxic ingress to LQ	from venting from storage	Location, ventilation, H2S and CH4 gas detection in LQ air inlets	
G1	Blowout ignited by barge/tugs	presence of barge and tugs for offloading	Communications, emergency procedures,	
G2	Boom fall and affects offloading	presence of barge and tugs for offloading	Ensure location doesn't permit this	
G3	Fire and explosion in offloading area due to topsides leak	ignition of leakage	Hazardous area	
G5	Mooring lines into thruster	presence of barge and tugs for offloading	Procedures, redundancy	
G6	Dropped object in offloading area/on barge alongside	presence of barge and tugs for offloading	Operations, procedures	
G7	Effects of fire in one area impinging another	presence of flammable material	Ensure sufficient separation by location	

TECHNICAL FAILURE

I.D.	Risk Issue	Probability and Consequence Influence	Safeguards	Comments & Recommendations
G8	Effects of fire in one area impinging another	presence of flammable material	Ensure sufficient separation by location	
G9	Effects of fire in one area impinging another	presence of flammable material	Ensure sufficient separation by location	
G11	Explosion in tank during offloading	Oxygen ingress	Control ignition sources	
G13	Collision with barge	Pollution risk	tugs, weather limitations, procedures	
G14	Free surface effects	Rig movement	Baffles, loading plan for permanent storage tanks	
G17	Weather damage to barge	Pollution	Limit operations for weather, forecast	Check seaworthiness of barge for defined conditions
G18	Leakage on barge	H2S exposure	H2S precautions	
H2	Overheating from burner	ignition of flammables	Design, protection, location	
H4	Backflow	Inappropriate fluid or pressure	Design, NRV	Consider HAZOP
H6	Dropped object impacting storage	release of flammables or toxiic material	Operations, procedures	Consider protective frames. Nunding around chemicals, not around methanol as wish to allow to drain away
H7	Effects of fire in one area impinging another	presence of flammable material	Ensure sufficient separation by location	
H8	Effects of fire in one area impinging another	presence of flammable material	Ensure sufficient separation by location	
H9	Effects of fire in one area impinging another	presence of flammable material	Ensure sufficient separation by location	
H12	Ignition by static electricity	fire and explosion	Grounding, procedures	Grounding of equipment during transfer of chemicals
H15	Structural failure	Methanol tank heavy	Design, placement	
H16	Helicopter crash causes release of chemicals	Presence of chemicals	Location	
H17	Extreme weather causes listing and release of chemicals	Presence of chemicals	Forecast	Consider seafastening of chemicals
H18	Toxicity	Presence of chemicals	Procedures, training, MSDS, PPE	Don't want to contain spilled methanol, rather allow spill to sea. Other chemicals contained.
I1	Evacuation routes blocked by extra equipment	presence of extra equipment	Training, information, marking	May need to change routes to alternate sites. Need to inform.
	Emergency lighting, PA	additional areas in use		May need to provide additional lighting, PA to well test area.
	Signs	different usage than normal		New areas off limits
	Emergency response plan	Well test scenarios		Needs to be updated to include well test and offloading operations
	Fire protection	Additional heat sources		Heat protection
	Impairment of escape routes and means of evacuation	effect of heat		Heat protection

TECHNICAL FAILURE

I.D.	Risk Issue	Probability and Consequence Influence	Safeguards	Comments & Recommendations
I2	Heat from flare impairs safety systems	escape and evacuation		Radiation study to determine location
	Noise from flare may impair communication	communication		Consider in design of PA system, hearing protection, headset communication, radio, limit to no. of personnel on deck, procedures
I3	Oil leakage	possible fire inventory		Drainage plan needed
I8-I12	Fire in topsides or process	loss of safety systems		Need to protect safety systems or provide redundancy
	Explosion of methanol drums or process modules, storage tanks	effect on safe refuge, muster area		Consider design load on LQ
	Loss of emergency power, PA	Methanol or process explosion		Need to protect safety systems or provide redundancy
I18	Toxicity	effect on safe refuge, muster area		Ventilation inlets location, upgrade signs
Deep Water				
A2	Change in wind direction	wind affects behaviour of flare, radiation	Monitor, procedure, switch over	A DP Drillship can be oriented into the most favourable weather direction.
E1	MEG Injection control system failure	Hydrate plug	test, procedures	Consider HAZOP of methanol injection system
	Blocked MEG injection check valve	Hydrate plug		Consider HAZOP of methanol injection system
	Failure in MEG supply system	Hydrate plug		Consider HAZOP of methanol injection system
E1	Hydrate prevents closure of valves		Methanol, glycol	
C17	Extreme weather	Total shut in time is longer in Deepwater	Define watch circles, operation limits	Wind, current, icing. Control system reaction time will be critical.
E1	Failure of EZ tree to function	Hydrate plug	Prevent by methanol injection, pressure/temp sensors, test for function	More critical when well is cold
	Failure of safety valve to close	Perm DHSV is hydraulically op., may be sensitive to temp	Failsafe close	Depends on annulus pressure (DST) or hydraulic pressure bleed-off (for permanent DHSV)

TECHNICAL FAILURE

I.D.	Risk Issue	Probability and Consequence Influence	Safeguards	Comments & Recommendations
	Retainer valve does not close during disconnect	pollution	testing, quality of equipment	
E3	Excess time for shut in on topsides leak	uncontrolled release of HC	Design	Design for 15sec (Sentree 7) shut in of test tree others may be longer. Can shut in at flowhead or choke manifold unless need to disconnect.
E4	Backflow results in seal failure			If pump N2 into kill line for underbalancing can get a problem if lose pressure and get influx past seals.
Arctic Water				
A2	Structural failure of boom	Ice accretion causes failure resulting in Release of hydrocarbons, and structural damage	Design, inspection	Design needs to consider the potential ice loads. Ability to withstand needs to be documented. Material should be suitable for the lowest operating temperature
A17	Weather forecasting more difficult		Adjust operation to weather window	
E17	Extreme weather	Total shut in time is longer	Define watch circles, operation limits	Wind, current, icing on wind sensors, pack ice limitation
	Wind sensors			Common mode failure of both sensors
E1 E3	Control fluid deterioration Excess time for shut in on topsides leak	Failure to disconnect uncontrolled release of HC	Control viscosity Design, selection of control fluid	Specific fluid for arctic Control fluid is sensitive to temperature
D17	Storage tank vent blocked	Ice	design to prevent accumulation	inspection

MANAGEMENT & OPERATIONAL ISSUES

I.D.	Risk Issue	Probability & Consequence Influence	Safeguards	Comments & Recommendations
Not Condition Sensitive				
A1	Equipment failure	hydrocarbon release	Quality of material	Responsibility for integrity management of equipment
	Design failure	hydrocarbon release	Check on design	Responsibility for safety design of the system
	Operator error	hydrocarbon release	Training and qualification, management control Develop procedures	Safety Training Requirement (CFR ref), Test layout HAZID, JSA, Permit to Work, Coordinate with rig Roles and responsibilities to be defined
A2	Change in wind direction	Close wrong valve	Procedure, training,ESD and safety system	
D2	Closed connection between pressurized closed storage tank and burner boom	Overpressurize tank	Procedure, pressure sensors, PSV	
A12	Oil spill	pollution, hydrocarbon release	Responsibility, training	
G13	Collision due to increased activity during offloading	pollution, hydrocarbon release	Procedure, management controls, chain of command	Establish integrated procedure
Deep Water				
Arctic Water				

EXTERNAL EFFECTS

I.D.	Risk Issue	Probability & Consequence Influence	Safeguards	Comments & Recommendations
Not Condition Sensitive				
A1	Terrorism			USCG Securith requirements Emergency response planning
	Cell phones (EMI)	ignition source	Radio silence	
	Sabotage		Exclude non-essential personnel	Increased check of personnel who handle exposives
A3	Hurricane		Prediction adequate	
	Leakage in surface equipment		Green water design	Shutdown and test before reuse
Deep Water				
A1	Disconnection fails due to high tensile and bending loads		Set limits, procedures	
	Loss of well control due to hydrate formation		methanol injection	
	Nitrogen pressure below production tubing pressure when injecting nitrogen		procedures	
E1	VIV failure of riser	Umbilical also fails	Failsafe closure of BOP and subsea test tree	
	Gas onto rig	Umbilical next to test string prevents full closure of the diverter annular BOP	Consider design to permit closure for diverting	Diverter design
Arctic Water				

ABNORMAL MODES

I.D.	Risk Issue	Probability & Consequence Influence	Safeguards	Comments & Recommendations
Not condition sensitive				
A1	Trapped volume between retainer valve and SSTT can not be vented			Consider addressing in a HAZOP
E6	Need to disconnect and procedure fails		Backup	Even if test tree doesnt function you can still shear with the BOP
E7	Cant disconnect because connector angle exceeded		Clear criteria and responsibility	Limit on connectors may be up to 10degr
Deep Water				
A1	Response time for disconnect during drive off/drift off is too long.		Design	Need to set adequate limits and select correct equipment
	Repairs during testing		Prohibit such activity (procedure), Permit to Work	
Arctic Water				
A1	Disconnection in arctic conditions		Heating on critial equipment exposed to icing.	

APPENDIX B

WORKSHOP DISCUSSION DOCUMENT

TECHNICAL REPORT

MINERALS MANAGEMENT SERVICE

MMS JIP - WELL TESTING
WORKSHOP DISCUSSION DOCUMENT

REPORT NO. 3657149

REVISION NO. 01

DET NORSKE VERITAS

DET NORSKE VERITAS

TECHNICAL REPORT

Date of first issue: 2003-10-30	Project No.: 440 -3708-0
Approved by: Arne Edvin Løken, Head of Section	Organizational unit: Deepwater Production Systems
Client: Minerals Management Service	Client ref.: Andrew Konczvald 0103PO72594

DET NORSKE VERITAS
Technology Services, N America

16340 Park Ten Place
Suite 100
Houston 77084
United States
Tel: +1 281 721 6600
Fax: +1 281 721 6833
http://www.dnv.com

Summary:

This Position Document is created as part of an ongoing MMS JIP which is looking at safety connected with well testing on the OCS. It is intended that this document will form the basis of discussion at the planned Industry Workshop carried out within the JIP.

This Position Document discusses some of the key safety issues associated with offshore well testing. The areas discussed have been identified on the basis of discussions within the JIP members and on a formal HAZID carried out for a standard well test layout.

These areas include :

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

The JIP eventually aims to produce some guidelines on these issues. In that respect this document includes some outlines of possible guidance.

Report No.: **3657149**		Subject Group: Technical
Report title: MMS JIP - Well Testing Workshop Discussion Document		
Work carried out by: Conn Eagan		
Work verified by: Charles McHardy		
Date of this revision:	Rev. No.: 01	Number of pages: 28

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Safety
Well Testing
Offshore

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1 CONCLUSIVE SUMMARY

This Position Document discusses some of the key safety issues associated with offshore well testing. The areas discussed have been identified on the basis of discussions within the JIP members and on a formal HAZID carried out for a standard well test layout.

These areas include:

- 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

The discussion in this document includes both technical and management considerations.

The JIP eventually aims to produce some guidelines on these issues. In that respect this document includes some outlines of possible guidance. It is intended that these issues will form the basis of discussion at the planned Industry Workshop, where further input will be collected before progressing the guidance.

2 INTRODUCTION

The JIP is investigating hazards associated with dynamic well testing operations on the OCS. It is anticipated that flow testing activity is likely to increase to provide more certainty than obtained by static testing alone. The JIP will look at the impact of moving into deeper waters, the increased possibility of encountering high pressure or high temperature conditions in deep gas wells, and also the possibility of increased arctic activity.

The JIP comprises the following major project tasks:

1. Initial Fact Finding by DNV on OCS and worldwide practice including involvement of major stakeholders
2. Generic SWIFT*/HAZID of well testing operations addressing a number of operational/geographic variants, including identification of means to prevent, detect, control or mitigate against hazards.
3. Development of initial Position Document based on the SWIFT/HAZID.
4. Conduct Industry Workshop to solicit input to Guideline.
5. Create Guidance draft based on workshop.
6. Submit draft to industry/MMS for hearing.
7. Finalize draft guidance and issue project report.

(* SWIFT – Structured What IF Technique - is a systematic, multidisciplinary team-oriented analytic technique. To ensure comprehensive identification of hazards, SWIFT relies on a structured brainstorming effort by a team of experienced personnel with supplementary questions from a checklist.)

This Position Document (ref Task 3 above) discusses some of the key areas influencing safety and will raise a number of questions which it is intended will be answered as this JIP progresses, based on industry input. This document is distributed to Workshop participants and will form the background for discussions on key safety issues.

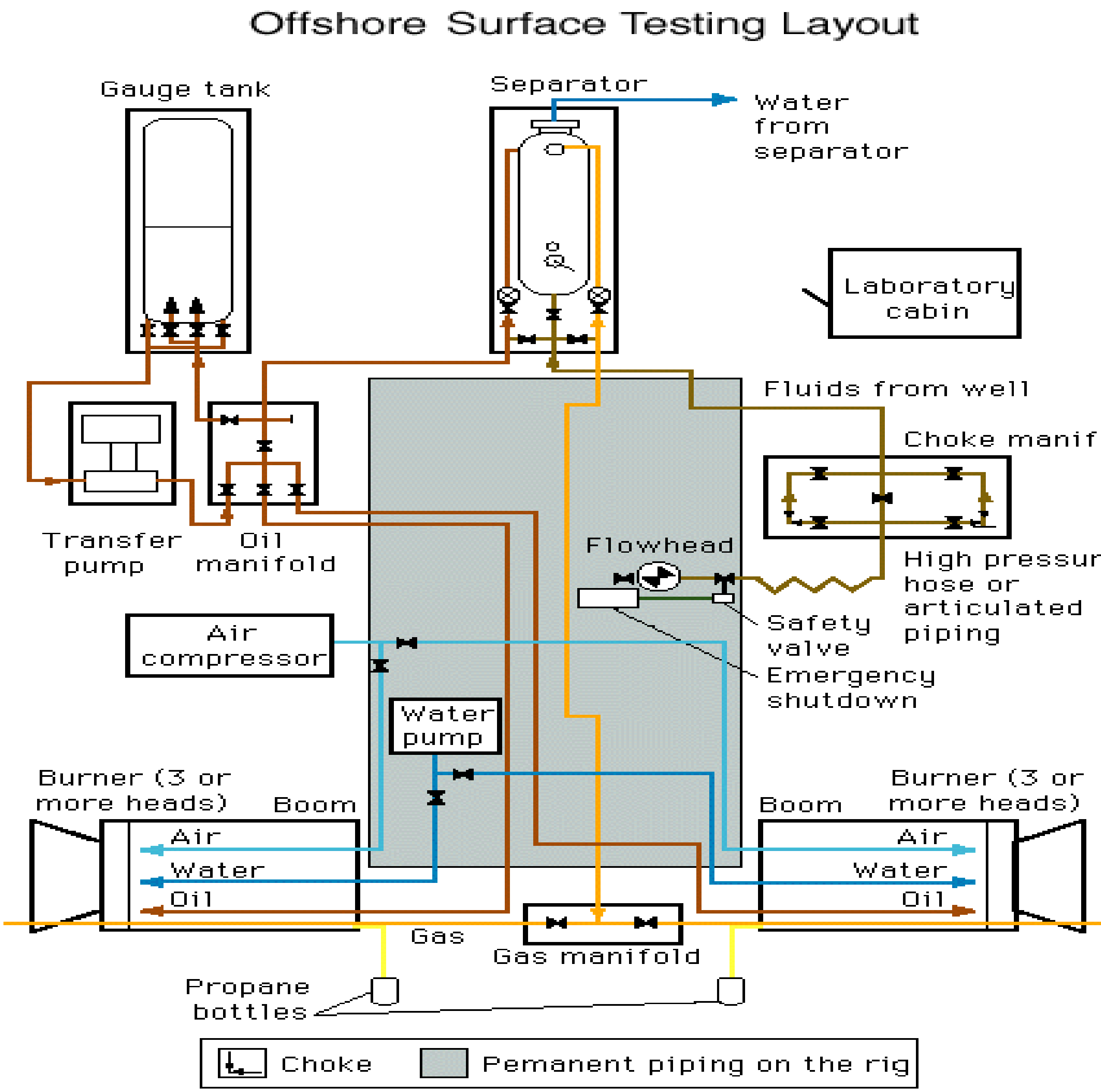
2.1 Standard Well Test Arrangement

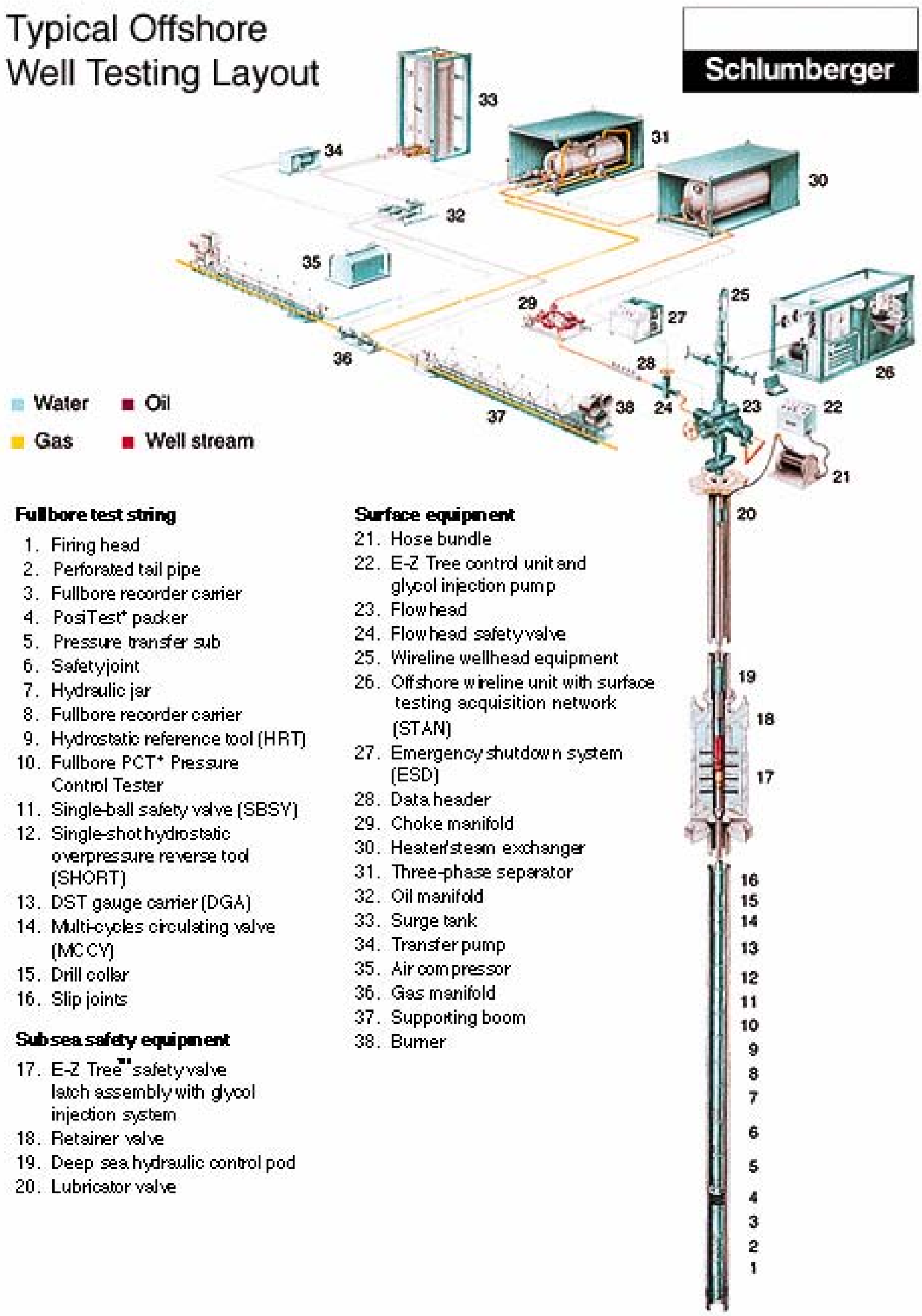
Typically well testing on a floating offshore unit, i.e. a semisub, or a drillship is conducted through the subsea BOP and marine riser.

Conventional well test systems consist of a temporary well completion with tubing supported by a 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 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 drillfloor. The surface production tree or flowhead is made up to the top of the tubing string and is supported by the rig's traveling 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.

This arrangement has been successfully used in shallow water applications on the OCS for many years. This study looks at potential hazards associated with well testing in applications where there is currently relatively little experience on the OCS, i.e. deepwater applications, HPHT applications, arctic applications, and larger scale storage arrangements on board.


Offshore Surface Testing Layout
Gauge tank
Separator
Water from separator
Laboratory cabin
Fluids from well
Choke manifold
Transfer pump
Oil manifold
Flowhead
High pressure hose or articulated piping
Safety valve
Emergency shutdown
Air compressor
Water pump
Burner (3 or more heads)
Boom
Boom
Burner (3 or more heads)
Air
Water
Oil
Air
Water
Oil
Gas
Gas manifold
Propane bottles
Choke
Pemanent piping on the rig


Typical Offshore
Well Testing Layout
Schlumberger
Water
Oil
Gas
Well stream
Fullbore test string
1. Firing head
2. Perforated tail pipe
3. Fullbore recorder carrier
4. PosiTest* packer
5. Pressure transfer sub
6. Safety joint
7. Hydraulic jar
8. Fullbore recorder carrier
9. Hydrostatic reference tool (HRT)
10. Fullbore PCT* Pressure Control Tester
11. Single-ball safety valve (SBSV)
12. Single-shot hydrostatic overpressure reverse tool (SHORT)
13. DST gauge carrier (DGA)
14. Multi-cycles circulating valve (MCCV)
15. Drill collar
16. Slip joints
Subsea safety equipment
17. E-Z Tree** safety valve latch assembly with glycol injection system
18. Retainer valve
19. Deep sea hydraulic control pod
20. Lubricator valve
Surface equipment
21. Hose bundle
22. E-Z Tree control unit and glycol injection pump
23. Flowhead
24. Flowhead safety valve
25. Wireline wellhead equipment
26. Offshore wireline unit with surface testing acquisition network (STAN)
27. Emergency shutdown system (ESD)
28. Data header
29. Choke manifold
30. Heater/steam exchanger
31. Three-phase separator
32. Oil manifold
33. Surge tank
34. Transfer pump
35. Air compressor
36. Gas manifold
37. Supporting boom
38. Burner

2.2 Identified Areas to be Addressed

Following initial research and also discussions with MMS personnel a number of areas were identified as being in need of more detailed study as part of this project. In addition a HAZID/SWIFT was held by the project in March 2004 with selected personnel from the following areas:

- Regulators
- Drilling Contractor
- Well service company
- Offshore Operator
- Classification Society
- Safety Consultant

The results of that study have also contributed to the listing of key areas to be further addressed in the Workshop and Guidance to be produced.

The following areas have been identified and are addressed further in this discussion document, together with possible guidance which might be appropriate.

- Management of the Well Test Operation
  - Responsibility
  - Verification requirements
  - Simultaneous operations (offloading + testing)
  - Manning

- Deepwater Drilling
  - Hydrostatic effects
  - Control system timing

- Testing from DP Vessels
  - Drive off/drift off
  - Requirements to DP system
  - Watch circles
  - Reaction time

- Testing in Arctic Conditions
  - Icing of equipment
  - Low temperature effects on materials
  - Low temperature effects on control systems
  - Low temperature effects on transported fluids

- Shallow Water / Deep Gas Drilling
    - High Pressure/ High Temperature
    - H_2S

- Offloading of Produced Oil
    - Permanent and Temporary Storage Tanks
    - Offloading to barges

- Quality of Equipment
    - Initial certification
    - Maintenance records
    - Test before use

- Impact on the drilling unit
    - Area classification
    - Drains
    - Firefighting
    - Esd
    - F&G detection

- Miscellaneous issues from HAZID

Note that many of the considerations discussed will be relevant for conventional well test operations as well as for more challenging applications in deepwater, arctic areas etc..

3 DISCUSSION OF KEY AREAS

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 specifies 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.

Reference should be made to the MMS website for more information.

Below are some specific considerations with regard to well testing.

3.1.2 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.

3.1.3 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 plant supplied is in good condition and is suitable for the intended application and adequate procedures should be available to address all key operations.

3.1.4 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 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.

There is no formal regulatory scheme for qualification of personnel therefore any system will normally be a company specified system. The system should ideally be documented and auditable.

3.1.5 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
- H_2S or CO_2 concentration

- Sand production
- Water cut
- Heavy viscous crude's
- Separation problems or foaming
- Hydrate formation
- Wax or asphaltenes

3.1.6 Suitability of the Drilling Rig

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

Workshop Topics for Discussion:

1) *Should it be recommended that the Operator has a safety management system in place in accordance with the principles in SEMP?*
2) *Should it be recommended that a safety assessment of each well test operation be carried out and documented? Should this be a HAZID, a HAZOP or a Safe Job Analysis?*
3) *Should it be recommended that an audit of subcontractors (i.e. Drilling Contractor and Well Service Company) be carried out and documented?*
4) *Should it be recommended that documentation (e.g. Joint Operations Manual) be created to address aspects such as :*
    a. *Responsibility*
    b. *Lines of communication*
    c. *Safety drills*

  d. *Familiarization with safety features of rig*
  e. *Contingency plans*
  f. *Limitations on simultaneous operations*
  g. *Testing and maintenance of safety barriers*

5) *Any other areas to be addressed*

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.

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 the drilling vessel lose its position-keeping ability (e.g failure in the dynamic positioning system).

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.

The challenge has been to decrease the time between signaling from the drilling unit and initiating the function at the subsea tree. Disconnecting a subsea tree is a complex task: 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. Old direct hydraulic control systems are being replaced by modern 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 it's sequence.

Deepwater applications are also more susceptible to hydrate 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. 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.

In addition 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, diverter). These systems need to be adequately designed with sufficient safeguards to ensure safety of the well test 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).

Workshop Topics for Discussion:

1) *Guidance should address response time of the control system. Should limits be specified (e.g. 15secs or 30secs)? What are influencing parameters?*
2) *Are there any specific recommendations on test string design for deepwater?*
3) *Should we recommend a specific documented procedure for handling a hydrate plug be created?*
4) *Intended guidance would include storage and safety of methanol. Should storage tanks meet IMDG (Code for transportation of dangerous goods) requirements? Should they be fastened to the deck? Do we need special drainage or collection arrangements? Do we need additional fire fighting?*
5) *Is there any need to specially follow up existing drilling equipment critical to the well test safety, e.g. special inspection of load carrying and tensioning equipment prior to a test?*
6) *Other considerations?*

3.3 Testing from DP Vessels

3.3.1 General

Testing from DP vessels is almost by definition always 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:

DP1: dynamic positioning system without redundancy

DP2: dynamic positioning system with an independent joystick back-up and a position reference back-up

DP3: dynamic positioning system with redundancy in technical design and with an independent joystick back-up. Plus a back-up dynamic positioning control system in an emergency dynamic positioning control centre, designed with physical separation for components that provide redundancy

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. Obviously drive off represents a potentially greater hazard.

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 BOP. The riser may then be disconnected at the LMRP.

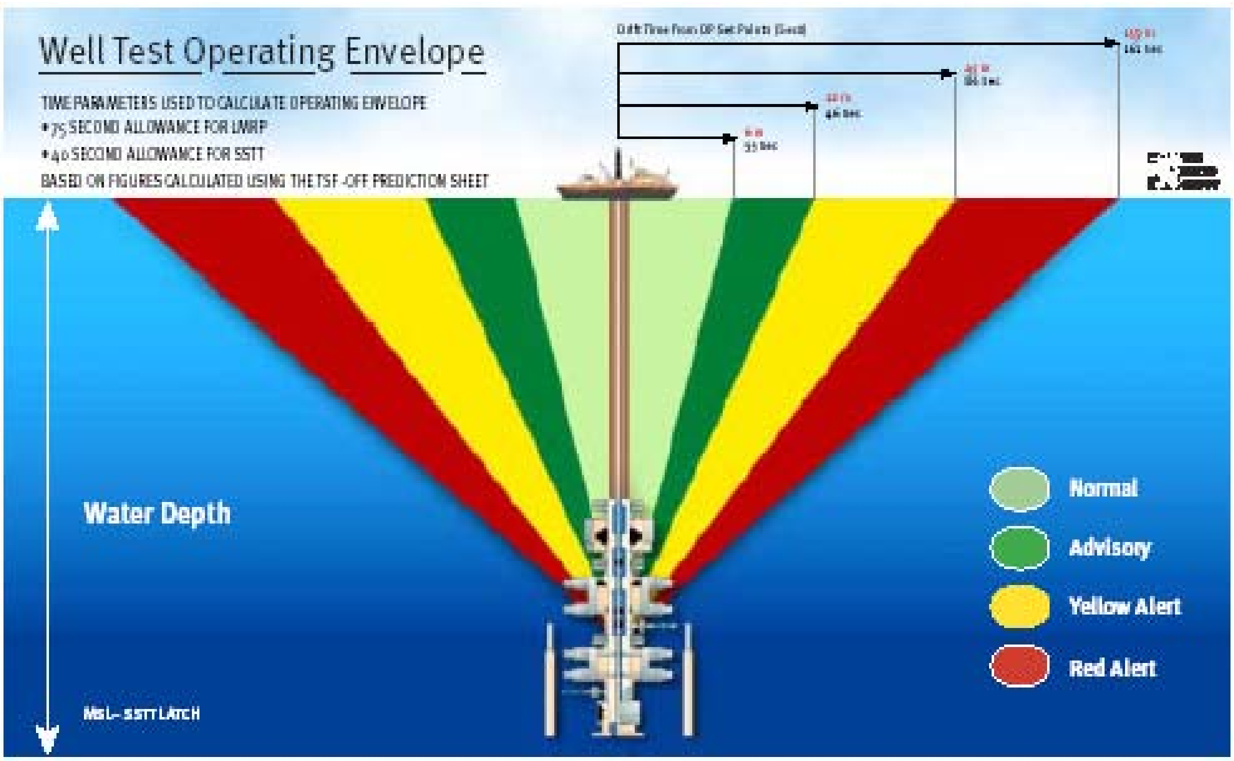


Fig. Example of Watch Circles (Expro)

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 movement exceed acceptable.

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

Workshop Topics for Discussion:

1) *Is there a criterion for selection of the level of DP on a drilling unit which will carry out a well test? Should it be minimum DP2?*
2) *Is there a standard assumption of drive off? E.g. Thruster power ramping up to 80% output over 30secs followed by manual power shut-off and subsequent drift off.*
3) *Is there a standard approach to defining watch circles and the associated actions to be taken? E.g.*
    a. *Green Zone : Safe envelope, where only 50% of maximum thruster capacity is required to withstand environmental forces.*
    b. *Yellow Zone : Disconnect SSTT, 65% of maximum thruster capacity is required to withstand environmental forces.*
    c. *Red Zone : Disconnect LMRP, 80% of maximum thruster capacity is required to withstand environmental forces.*
4) *Should an individual rig drift analysis be performed for each location?*
5) *What sort of alarm, ESD and communication system should be arranged?*
6) *Is it necessary to have separate combustion air inlet to thrusters in order to ensure continued operation in the event of a gas leak?*
7) *Other considerations?*

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-armored 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.

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)
- 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.
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.

The above considerations will primarily be made when determining the drilling program and in selecting the drilling unit to be used and will not be further addressed here, however the warning available and reaction time to events which may affect the 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

3.4.2 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 low temperatures (e.g by heat tracing).

3.4.3 Icing of equipment

Icing may occur either from the atmosphere or as a result of sea spray.

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.

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

3.4.4 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.

3.4.5 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.

Workshop Topics for Discussion:

1) *Will arctic drilling from mobile units be confined to open water areas?*
2) *Will it be confined to mild seasons?*
3) *Is icing relevant and how would it be accounted for? E.g. Confirm "structural ice rating" of burner booms? Any experience with measures to combat icing?*
4) *Should certification of equipment be required to confirm low temperature service suitability?*
5) *Should a HAZOP be required for arctic applications to identify all systems (hydrocarbon and auxiliary) which might be impacted by low temperature?*
6) *Are there specific specifications for low temperature control?*
7) *Should it be required to have a written procedure to tackle prevention of plug formation and actions in the event of such occurring?*
8) *Other considerations?*

3.5 High Pressure/ High Temperature Well Testing

As mentioned previously 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 by releasing anchor lines 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).

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

- Equipment suitability
- Material suitability for high temperature (particular elastomers)
- High pressure testing
- Need to conduct a HAZOP
- Drilling operations and monitoring

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

Workshop Topics for Discussion:

1) *Should permanent packers be used as opposed to retrievable packers?*
2) *Should an annulus pressure operated downhole tester valve be used?*
3) *Should a lubricator valve be used in the test string, even where no wirelining is planned?*
4) *What sort of BOP arrangement should be selected?*
5) *What sort of pressure testing should be carried out prior to test start up?*
6) *Is it necessary to limit first hydrocarbon flow period to daylight hours?*
7) *Is it necessary to have safety meeting for all involved personnel (Operator representative, Rig personnel, Service Company personnel) prior to testing?*
8) *What sort of temperature monitoring should be arranged? How can temperature be adjusted?*
9) *What sort of contingency plans should be available?*
10) *Is 3rd party certification desirable for equipment? If not how can quality be assured?*
11) *Other considerations?*

3.6 H_2S

Although little H_2S has been encountered to date on the OCS, deep drilling represents an area where there remains some uncertainty. Special safety considerations apply when drilling in areas where H_2S may be encountered :

- Training of personnel
- Personal Protective Equipment
- Monitoring for gas
- Rating of equipment (including elastomers)
- Venting from storage tanks
- Drills and Contingency Plans

Guidance is given in the API Publication API RP 49 "Recommended Practice for Drilling and Well Service Operations Involving Hydrogen Sulfide".

Workshop Topics for Discussion:

1) *Are the recommendations in API RP 49 used for well testing operations on OCS?*
2) *Is number of rig personnel on board reduced to a minimum during testing?*
3) *What sort of safety equipment is kept on board (escape sets, BA sets)?*
4) *Are indications of wind direction (flags, socks) visible from all locations?*
5) *How is gas detection arranged? Are gas detectors tested prior to well test?*
6) *Is a safety meeting held?*
7) *Are BAs and masks worn when first flow is received? What is policy on wearing BA sets?*
8) *Are written contingency plans produced?*
9) *Other considerations?*

3.7 Offloading of Produced Oil

3.7.1 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. 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.

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.

Temporary Storage Tanks

Other drilling units intending to store the oil produced during testing will be fitted with 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.

3.7.2 Offloading to barges

Offloading of stored oil is typically via a floating hose to a barge. The barge may be maneuvered by tugs or may be dynamically positioned.

Where offloading to a barge takes place there will also be an interface between the service company and the rig owner. 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.

Workshop Topics for Discussion:

1) *What measures should be taken to ensure that permanent rig piping is satisfactory?*
2) *How are temporary storage tanks located and are they secured to prevent movement? (location with respect to LQ, escapeways etc)*
3) *Do storage tanks require vacuum protection?*
4) *Where there are several permanent storage tanks on a drillship should an FMEA be carried out of the cargo control system to ensure that un controlled flow between tanks can not occur (P-34 scenario)?*
5) *What measures should be taken to ensure safety during offloading to barge? (responsibility, no. of tugs, communication, weather orientation, simultaneous operations).*
6) *What requirements should be placed on barges and tugs, to ensure safety on the rig and of the operation? Are DP barges used and what requirements are put on them?*
7) *Other considerations?*

3.8 Quality of Equipment

3.8.1 General

Equipment supplied by the well test 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 H_2S)
- Water Depth
- Area Classification Zone
- Response Time
- SWL (e.g for burner boom)
- Tensile rating (subsea equipment)

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
- 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

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.

Need to document the extent of this testing in terms of:

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

Workshop Topics for Discussion:

1) *Should Well test equipment considered critical for safety be subject to some form of formal certification ?*
2) *Should such certification involve any 3rd Party to provide an independent confirmation of quality?*
3) *Should the well service company have a documented inspection and maintenance program?*
4) *Should the certification and in service record be audited prior to each test?*
5) *Should the quality of the equipment be followed up by a third party who documents continued acceptable standard?*
6) *Should it be recommended that before being taken into service, the equipment is to be tested to the maximum anticipated load for the particular application? Are there any additional recommended tests (e.g. NDE, thickness measurements etc.)?*
7) *Other considerations?*

3.9 Impact 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 their safety considerations.

3.9.2 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.

3.9.3 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.

3.9.4 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. Special equipment (e.g. alcohol resisting foam) may be necessary for combating a methanol fire.

3.9.5 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. Whether such communication is automatic or manual should be decided.

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.

3.9.6 F&G 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 H2S is anticipated.

3.9.7 Other Safety Systems

Other safety systems such as emergency lighting, PA/GA system, emergency communication should also cover the well test areas.

Workshop Topics for Discussion:

1) *Should the arrangement of the well test spread be formally approved by the Classification Society?*

2) *Should there be an updated area classification drawing, fire plan, escapeway drawing, ESD Cause and Effect drawing? Other documents to be updated?*
3) *Is it necessary to carry out a HAZOP or HAZID for a specific application where safety aspects such as drainage, cross-contamination, fire fighting etc. are addressed?*
4) *Should the SSTT shutdown be integrated with the rig ESD or should this be manual? Is there a SSTT panel and what is the manning level?*
5) *Should documentation be specifically created to address the procedures and operations associated with well testing and offloading? Updating of rig procedures or creation of new documents covering for example Permit to Work?*
6) *Other considerations?*

3.10 Miscellaneous Issues Raised in the HAZID

In the course of the HAZID held in March 2004 a number of additional issues, to those covered above, were raised. In order to gain a broader discussion of these points they will also be discussed at the Workshop.

Workshop Topics for Discussion:

1) *What sort of safety factor should be applied to predicted operating limits when specifying equipment rating to take account of uncertainty in prediction? Is this uncertainty more relevant for different types of test area (e.g. arctic, deepwater, deep gas).*
2) *Should a radiation study be carried out prior to each test to determine burner boom radiation loads are within acceptable limits?*
3) *Should special collision avoidance measures be put in place during a well test?*
4) *Should all lifting operations over well test plant and storage tanks be restricted during well test?*
5) *For moored units, what should be the consequence to operations in the event of loss of an anchor line?*
6) *Should premium tubulars be used in all well test operations?*
7) *Should drills be held immediately prior to well testing? (Fire, abandon platform etc.)*

4 CONCLUSIONS

The Workshop is intended to solicit discussion and input on the areas listed above. The final Guidance will then be based on the direction indicated by the Workshop participants and the previous work carried out in the project HAZID and research into worldwide practice.

The Guidance documented will be circulated for hearing to the industry.

APPENDIX C

WORKSHOP RECORD

Management

Ref	Workshop Question	Discussion	Guidance
1	***Should it be recommended that the Operator has a safety management system in place in accordance with the principles in SEMP?***	Most already using, smaller operators should aslo follow SEMP for complex operations **Bridging** document Operator, contractor, driller SEMP recommended to be used. SEMP or safety management system equivalent to SEMP	A Safety Management system (SEMP or equivalent) should be in place by the Operator. Such a system should also address quality requirements to subcontractors (including both drilling contractors and service companies).
2	***Should it be recommended that a safety assessment of each well test operation be carried out and documented? Should this be a HAZID, a HAZOP or a Safe Job Analysis?***	Use a bit of both HAZID & HAZOP as the compliment each other. In addition a JSA, the detailed assessement should be done on the rig with the crew Already relatively standard process, especially hpht-complex jobs Group 2 JSA should always be done. This workshop represents the big players. How to the smalller independents operate. Same jobs should require same procedures. Statistics show the the smaller/independents are resonsible for most of the incidents Guidance would be very helpful for especially the independents Can the service company push the JSA down to the operator? All three parties need to be presented-participate in the JSA. The only rigs that have requested certifcation of such equipment is DNV classed rigs in GOF	As a minimum a Job Safety Analysis should be carried out prior to each well test. This should include participation from all the involved parties.HAZID and/or HAZOP should be considered especially for high profile operations (HPHT etc).
3	***Should it be recommended that an audit of subcontractors (i.e. Drilling Contractor and Well Service Company) be carried out and documented?***	Subcontractors should have some kind of safety management system. Or other there any other ways of ensuring safety Are there any statistics available. MMS probably have the data available. Injuries to humans are recorded, but what about near misses. They are probably not recorded. So databases miss a lot of the data. Should the operator confirm the drilling contractor subcontractor are capable of doing the job safely?	The Operator should have some criteria for assessing the quality of his subcontractors as part of his Safety Management system. It may not be necessary to carry out a formal audit, however it is advisable to document some form of assessment, to confirm that the contractor is serious and experienced.

Management

Ref	Workshop Question	Discussion	Guidance
4	***Should it be recommended that documentation (e.g. Joint Operations Manual) be created to address aspects such as :*** ***Responsibility*** ***Lines of communication*** ***Safety drills*** ***Familiarization with safety features of rig*** ***Contingency plans*** ***Limitations on simultaneous operations*** ***Testing and maintenance of safety barriers***	Minimum should reference procedures. Generic document and individual well test procedures. This may also be spelled out in the test program for complex operations.	It may not be necessary to create a specific document as it may be possible to refer to existing documentation. A Bridging document may be necessary. For complex operations this information may be included in the Test Program.
5	***Any other areas to be addressed***	(HP)Relief lines: Routing and how sholuld they be dealt with: Uncertainty about requirements. Each job needs to be assessed. Maximize safety, minimise environmental impact. Mitigation of liquid carried out trhough the relief lines to the flare. Proper assessement for each job. Route overboard or to separate vessel where issues can be dealt with. High profile & smaller wells. Oil carry over: instability in separator. Knock out pot/drain should possibly be included Organizatiosn deal with it differently. What about the smaller organizations? They may not have the equipment available. Operators responsibility to ensure safaty systems is in place. Again it is recommended, it is not a requirement. DNV standards say it needs to be considered. It is up to the operator/contractor to decide how to consider it, and document it. Management of change. Communication is important. Defining chain of commmant. Must ensure crosstraining of personell Coniderations to maximum hours worked. '	LP relief lines may be routed to the burner. There are different practices regarding HP lines. Some Operators believe it desirable to route to burner and others to a vent overoard. There is concern about liquid carryover and regulatory permission to burn liquids.

HPHT

Ref		Workshop Question	Discussion	Guidance
1		***Should permanent packers be used as opposed to retrievable packers?***	Case by case basis. Well parameters shoudl decide.	Use of permanent packers should be considered. This will be determined by consideration of well parameters on a case by case basis.
2		***Should an annulus pressure operated downhole tester valve be used?***	Yes it is recommended to run a tester valve, or some form of tester valve of DST. Permanent completions already have subsee safety valves.	A tester valve should preferably be installed.
3		***Should a lubricator valve be used in the test string, even where no wirelining is planned?***	Yes it shoudl be used on DST operations on floaters. Makes it possibly to run coiled tubing-wireline. It will increase safety aspects, and adds a second barrier. Some valves don't hold form the bottom. Flappers hold from the bottom. Should there be one or two lubricator valves? Operations specific	On floaters, it is recommended to install a lubricator valve, even where no wirelining is planned, in order to provide an additional level of pressure protection.
4		***What sort of BOP arrangement should be selected?***	How many rams, where shears to be. The subsea test tree design and spaceout shoudl allow for the BOPs full functionality. HPHT should require two pipe rams if BOP stack allows it. Circulations points? You want full functionality of chokes and kills BOP layout shold account for well testing form the start off. Coiled tubing & cutting aspects need to be considered.	The arrangement of the BOP stack should be such as to ensure continued well control functionality with the test tree in place. Space out of the subsea tree should ensure that the shear rams can fully shear. When coiled tubing is in use it should be ensured that the arrangement is also capable of shearing the coiled tubing. This may involve fitting of additional shearing capacity. Preferably two pipe rams should be arranged for HPHT wells. The arrangement needs also to ensure that full choke and kill functionality is maintained.
5		***What sort of pressure testing should be carried out prior to test start up?***	Casing needs to be tested within the limits Tubing string also needs to be tested (Against valve, internal-external) Flow head and into the testing facilities need to be tested to WP No N2 testing if can be avoided. Safety and seal issues. N2 testing offshor : NO, In controlled environment: Maybe (waterbath) Offshore N2 testing. Open ended HC lines should be tested. Variations between organizations with regards to test pressure. 80% for example. SLB never test any equipment above 80% of WP in the field HP critical components: Should be tested to the Maximum working pressure of the well, or maxiumem 80% of the equipment WP. Lines should be tested to maximum test of vessesl	Pressure testing of the test string should be carried out to a minimum of the maximum expected shut in pressure. Testing with N2 at high pressure offshore is not recomended.

HPHT

Ref		Workshop Question	Discussion	Guidance
6		***Is it necessary to limit first hydrocarbon flow period to daylight hours?***	No, case by case basis. Operator and rig crew deciced if safe. JSA should b held. Rigs better, lights better did not feel it was a safety issue H2S may be different. Very important that JSA, HAZID, HAZOP are done. No single point failure. Weahter may be a consideration. People offshre assure adequate lighting. Evacuation coverage (helicopters) adequate. Lighting at water level need be adequate. GOF Office: Critical to have HAZIDS; JSA etc before first oil. 12 hours delay cost, but accident cost more. Have the crew rested when before opening well. Some organizations require 8 hours of sleep before opening well. Also agrees that if all aspects are considered, then opening well aat night OK Some wells are slow to come on. If it the HCs come up after daylight, shoudl we shut in well. Safety issues: Evacuation, fatigue, ligting.	The Operator needs to make a case by case consideration which includes the following factors : - lighting (also at sea level) - fatigue of crew - availability of evacuation means
7		***Is it necessary to have safety meeting for all involved personnel (Operator representative, Rig personnel, Service Company personnel) prior to testing?***	YES YES	A safety meeting including all parties should be held prior to testing.
8		***What sort of temperature monitoring should be arranged? How can temperature be adjusted?***	MonitorØ Flow stream temperature, downstream-upstream of choke, also subsea trea if possibly. Flow stream issue. Chemicals, heat exchanger. Assure that you donæt exceed your API ratings. If you do, reduce the other parameter like pressure and tension. This needs to be addressed up front as it involves some number crunching. Bottom hole temperature must be looked at as well as the temps may be higher Radiating heat temperature to be monitored. Are the hot spots where they are calculated to be? Add water curtain in radiant issue.	Temperature of the flowstream should be monitored to ensure that temperature ratings of equipment is not exceeded. Burner temperature needs to be monitored and addition water curtain provided if necessary.
9		***What sort of contingency plans should be available?***	Plan in place developed from HAZID, HAZOP. ESD plan should be required. Plans for re-entering the well should aslo be required. What ifæs need to be considered. Higher pressures or temperatures then rating, H2S. What do you do the? Decision tree models may be helpful	Consider developing Decision Tree models to determine actions on abnormal situations, e.g. encountering H2S, exceed temperature or pressure. The abnormal scenarios should be addressed in the initial safety evaluation.

HPHT

Ref		Workshop Question	Discussion	Guidance
10		*Is 3rd party certification desirable for equipment? If not how can quality be assured?*	Yes it is desirable. What do you certify agianst. API, organizations guidelines. The vision of certification may be different. Especially the smaller organizations may have a different vision. If certification can prevent injury to humans, then it should be in place. Certify against what operator has asked for. Demonstrate integriy of equipment. Inspectors sometimes do not know the equipment. But do they need to? Coastguard: If its on your rig, its yours. Supplies to the subcontractors also need to covered.	Responsibility for quality of equipment is with Operator (for MMS) and Rig Owner (for USCG).
11		*Any other areas to be addressed*		
			MMS 30 CFR 250.4.460-.. Include…. Listing of what is required. This is what MMS can audit against. IF they have the documentation, is it actually fit for purpose. Physical parameters are given, what about how to carry out the operations safetly. Rules are rules. Not following guidelines may put you at risk. But it leaves you the option to select methods better suitable for your specific operations. CFR references API. The work completed by this workshop may in the future be incorporated as a reference in future MMS rules. This group is already doing it, but by creating regulations the other players are also forced to do it.	It is unclear at present exactly how any guidance will be used. Current practice has been to encourage API to develop documents which can then be incorporated by reference in 30CFR250.

H2S

Ref	Workshop Question	Discussion	Guidance
1	***Are the recommendations in API RP 49 used for well testing operations on OCS?***	Yes, anyone dealing with H2S should be using RP 49. Increased occurance for deepwater? Possibly very low levels. These low levels may dissapear by the time it gets to the surface. Therefore coupons are used to effectively determine H2S presence. Even special sample chambers may eliminate H2S. Deep gas drilling? Should be checked for everytime.	It is important to differentiate between situations where H2S is anticipated and planned for and where it occurs unexpectedly. Presence of H2S should be detected during the drilling operation, so that this information will be available during well testing. Where anticipated the measures recommended in API 49 should be followed. Where it is discovered unexpectedly this should be covered by contingency planning. There is little experience with H2S in current OCS operations, possibility of more in deep gas wells. Reference is also made to IP 17Section 7.3.6.
2	***Is number of rig personnel on board reduced to a minimum during testing?***	Yes, essential personell outside only. Using masks all the time may increase the number of poeple because poeple can not operate as logn with BA. Some organizations never mask up. Causes fatigue and increased personell BA should at least be used during critical operations like opening sample chambers	The number of personnel on deck should be kept to the minimum (essential personnel only). Use of BA equipment should be related to the operations being undertaken and be based on Operator safety philosophy.
3	***What sort of safety equipment is kept on board (escape sets, BA sets)?***	RP 49 should guide what equipment is on board. If known, then certainly the rig will be set up for H2S H2S unexpected. Shut down then.:Decision tree, evaluations… training, equipment, H2S card) Rigs may carry only 5 min evacuation packs. Sometimes also discovered during drilling. Acid flowbacks sometimes contain H2S. H2S card need before personell on location . When prepared, succesfully testing H2S wells should possibly to do safely.	When H2S is anticipated, equipment as recommended in API RP 49 should be available on board.
4	***Are indications of wind direction (flags, socks) visible from all locations?***	Absolutely should be.	Wind direction indication should be sisible from all relevant locations.
5	***What sort of pressure testing should be carried out prior to test start up?***	N2 testing? Some organization required equipment to be N2 testing. LP N2 test and regular hydro test is possibly recommedable. Hydro may not show leaks: HP N2 testing is dangerous, especially on the rig.	Hydrotesting of hydrocarbon lines should be carried out. Use of N2 for testing is generally not recommended however may be considered for gas wells, and for low pressure systems.
6	***How is gas detection arranged? Are gas detectors tested prior to well test?***	Placement shoudl be recommended. MMS has some guidelines. Also on tanks separators. Audible alarm at 10 ppm. At 20, should the well be shut in, or continues work wiht masks. H2S detectors should be tested prioer to well test. Are they? Maybe.	Gas detectors are in place for the drilling operation. If H2S is anticipated during well testing a specialist company will usually be contracted and will have their own detection equipment. Gas detectors should be certified.
7	***Is a safety meeting held?***	MUST BE DONE.	A Safety Meeting involving all parties should be held prior to the well test operation.

H2S

Ref	Workshop Question	Discussion	Guidance
8	***Are BAs and masks worn when first flow is received? What is policy on wearing BA sets?***	See above RP 49 should be investigated. Different from rig to rig	This will be determined by company policy. Therwe is a possibility of H2S being present even if not detected during drilling.
9	***What sort of contingency plans should be available?***	RP 49 should address this	Contingency plans in accordance with API RP 49 should be developed with specific reference to the actual well test operation.
#REF!	***Any other areas to be addressed***	Position of burners considered. Wildlife andh S02 Stand by vessels tie up down wind! They donæt carry H2S gir. NACE does not cover weight loss corrosion, but covers many aspects of H2S equipment and operations. Slick line. Trapped gas released and caused injury	Where H2S is anticipated, operation and location of the standby boat should be taken into account.

Storage and Offloading

Ref	Workshop Question	Discussion	Guidance
1	***What measures should be taken to ensure that permanent rig piping is satisfactory?***	Initial planning . Operations: Wall thckness test periodically. (pressure test, traceability, initial design conditions)	Initial planning in selection of the drilling rig should ensure that equipment on board is suitable for the application. This will involve checking equipment records for initial design, material traceability, rating, wall thickness. It will also involve records of pressure testing.
2	***How are temporary storage tanks located and are they secured to prevent movement? (location with respect to LQ, escapeways etc)***	Welding tanks to decks in not always preferred. But they should be secured. This needs to be planned for. Overall safety plan needs to consider position and securing. Also the pressure lines to from tanks. (Consider structure, escapeways, walkways, air intakes...) Not only HC storage tanks, but also other tanks. N2 for example.	Temporary tanks should be secured against movement on floating platforms. Location of storage tanks and associated vent lines and consequences for hazardous areas and escapeways should be considered in an initial safety review. Location of existing air intakes with respect to temporary well test equipment should be considered.
3	***Do storage tanks require vacuum protection?***	Prevent collapsing of tank. Suck in air results in combustible mixture. Most tanks have flame arrestors. Vacuum and overpressure protection should be installed. Third parties supply these tanks. Are they in accordance with codes. Do the smaller independents suppply same quiality systems	Vacuum protection of storage tanks needs to be considered to prevent collapse and/or possible ignition.
4	***Where there are several permanent storage tanks on a drillship should an FMEA be carried out of the cargo control system to ensure that un controlled flow between tanks can not occur (P-34 scenario)?***	Required FMEA's to have been done. Sould be considered prior to well testing, offloading stages. Classification covers these aspects. Some ballast systems have failsafe as is valves. Not many vessels with large cargo capacities in GOM	Permanent tanks are covered by Classification of the ship.
5	***What measures should be taken to ensure safety during offloading to barge? (responsibility, no. of tugs, communication, weather orientation, simultaneous operations).***	Need to be in the well test plan and safety assessement. Communication lines, station keeping, means of disconnect, shut down of flow. Mooring and DP considerations. QCDC operations need to be considered. Who regulates: MMS well testing. Other issues life saving, transfer issues have not been addressed sufficiently. Coast guard has not had many incidents related to well testing. MMS may have had many more incidents recorded. Responsibility of MMS and Coastguard.	Offloading operations should be part of the overall well test plan. This should include, operating envelope, communication, station keeping, disconnection criteria, shut down of flow. It is noted that this may be a gray area of responsibility between MMS and USCG.

Storage and Offloading

Ref	Workshop Question	Discussion	Guidance
6	***What requirements should be placed on barges and tugs, to ensure safety on the rig and of the operation? Are DP barges used and what requirements are put on them?***	Barge companies need to be involved and integrated with the rest of the decision makers. Cenac, Roger Bodine. Good company, lots of informaton. QCDC need to be integral to system. DP barges are used. 46 subchapter D covers barges. 33 & 90 rules also become applicable. Also DA policy letter deals with DP. Also talks about QCDC systems Number fo tugs. DP level may be guided by hose system (coast guard)	Barge companies should be integrally involved in the well test. Barges should comply with 46CFR Subchapter D and also with OPA 90.
7	***Any other areas to be addressed***	Continous lines, less leak points. Flaring contingencies. Clean burners, new technology allows for environmentally clean burning. Can it be considered by MMS to allow burning, which would not require the barge to be there. (Maybe especially when considerng, short flow times) Many risks are reduced by burning instead of complex barge operations. MMS need to consider this.	Note : Barge operations introduce complexity and some hazard. With modern burner design the amount of pollution from liquids may be minimal. This should be something which can be documented and presented to MMS for consideration.

Deepwater

Ref	Workshop Question	Discussion	Guidance
1	***Guidance should address response time of the control system. Should limits be specified (e.g. 15secs or 30secs)? What are influencing parameters?***	Not one prescribed time is right. Water depth , vessel characteristics, ocean conditions. Needs not to interfere with the overall riser disconnect. Electric hydraulic has less downsides, than pure hydraulic.	Response time should be related to the parameters relevant for the specific well test. These will include water depth, vessel motion characteristics, time to disconnect the
2	***Are there any specific recommendations on test string design for deepwater?***	MMS does not need to be involved in the detail design Some general conditions (packer type?) Minimize not shearable equipment, mostly related to DP operations Material selection needs attention (hydrates, temperatueres etc) Components, downhole test valve and circulation device, subsea test tree, retainer valve, flowhead, lubricator valve, should be given attention. B But too much detail should not be prescribed. The operator is best positioned to choose the best design of test string Coiled tubing operations should ma Certain level of redundancy should be built into the system, (on component basis?)	Detailed design of the test string is up to the Operator . Some general safety principles should be applied : - material selection - minimize non shearable equipment - selection of safety valves and packers
3	***Should we recommend a specific documented procedure for handling a hydrate plug be created?***	Study or assessement need be performed. (coil tubing lift frame). If potential for hydrates, then systems shoudl be put in place to PREVENT it becoming a problem.	Assessment of flow assurance problems should be carried out. Measures should be taken to prevent such from occurring and contingency if such should occur.
4	***Intended guidance would include storage and safety of methanol. Should storage tanks meet IMDG (Code for transportation of dangerous goods) requirements? Should they be fastened to the deck? Do we need special drainage or collection arrangements? Do we need additional fire fighting?***	Needs to be shipped in qualified tanks (DOT, IMDG) to recongnized standards. Do they need certification (49 cfr DOT, class,...) Likely to be DOT tanks because have to be shipped on the road. Coast guard does not certify, make rules …. STORAGE Dedicated space. Fire protection, ESD system. Portoble fire protection maybe rented, drainage. These factors need to be considered. Water curtain needs to protect the tank from heat from the flare. Needs to be through through. Special training	Methanol should be shipped in dedicated tanks (DOT or IMDG approved). Special safety features should be considered : - dedicated storage space - drainage - water curtain - portable fire fighting equipment - salt ring to show any flame
5	***Is there any need to specially follow up existing drilling equipment critical to the well test safety, e.g. special inspection of load carrying and tensioning equipment prior to a test?***	Loads are light compared to drilling load. Compensations systems used to dealing with heavy loads, may have issues or problems dealing with lighter loads. What happends if they systems fail	Compensation system should be suitable for loads involved in well testing (light loads). Contingency plan in the event of failure of lifting/compensating system should be developed.

Deepwater

Ref	Workshop Question	Discussion	Guidance
6	***Any other areas to be addressed***	Active heave compensatied (drawworks): What happens if brown out, black out. Need some lift compensated frame. Self compensating coiled tubing lift frame.	see #7

DP Vessel

Ref	Workshop Question	Discussion	Guidance
1	***Is there a criterion for selection of the level of DP on a drilling unit which will carry out a well test? Should it be minimum DP2?***	Clearly define in the white paper the definition of the different levels of DP. Many rigs out there that operate and do well tests that are old and the DP systems are not classified as DP1,2,3. DP level affects economic risk, not HSE risk is the general opinion. Have contingency plans for the case of disconnect. DP level does not take into account weather conditions. DP1s may handle a storm better than a DP3 rig.	It is noted that some existing DP systems are not clearly defined as DP1,2,3. The DP level should be seen in connection with environmental limitations on the spexcific vessel.
2	***Is there a standard assumption of drive off? E.g. Thruster power ramping up to 80% output over 30secs followed by manual power shut-off and subsequent drift off.***	Drive off events are preventable. Does it really happen? Yes they do occur, but they can be stopped very early. Watch circles should be layed out. If you have exceed watch cirles, you need to take action regardless of power. Drive off analysis are done less frequently due to newer generations DPs reduce likelyhood of drive offs	In general the focus is on drift off events in determining operational envelopes. Drive off analysis should however be considered.
3	***Is there a standard approach to defining watch circles and the associated actions to be taken? E.g. Green Zone : Safe envelope, where only 50% of maximum thruster capacity is required to withstand environmental forces. Yellow Zone : Disconnect SSTT, 65% of maximum thruster capacity is required to withstand environmental forces. Red Zone : Disconnect LMRP, 80% of maximum thruster capacity is required to withstand environmental forces.***	Use zones, standard practice. Develop specificn guidelines for operations to take within each zone. Take into accoutn specif rig All parties need be involved, service company, operator,…. What actions to what parties take at what zone. Close well, make safe. Then assess situation in yellow. Red> Shear rams or other disconnect? Most entries to red require shear. Specific well conditions need be considered. When hit red, hit disconnect. Bent BOP stack is not idead situation... Need to be clear up front	Operating zones should be established and guidelines for operation within those zones should be specified. These need to involve all concerned parties so that responsibilities and actions are defined for each party. Transition from one zone to another needs to be addressed in the procedures.
4	***Should an individual rig drift analysis be performed for each location?***	Drift analysis is recommended	To determine operating limits a drift analysis should be carried out.

DP Vessel

Ref	Workshop Question	Discussion	Guidance
5	***What sort of alarm, ESD and communication system should be arranged?***	Depends on rig. Well testers need to be well trained, have access to alarms and understand the systems. SSTT disconnect is the test crew responsibiliyt to unlatch Tree operator and driller pushes the disconnect buttons. Again all crews should know exaclty what to do in specific zones(step by step actions) Are the systems tested, should they be? DP drills, or JSA, should be done prior to well testing. Compensator failure (regardless of failure mode) need to be considered. Should alarms be in place for compensator failure	Actions and alarms in the event of an emergency should be clearly defined beforehand. Responsibility for disconnect should be specified. The system should be designed so that all relevant information is available to the driller who will initiate the disconnect.
6	***Is it necessary to have separate combustion air inlet to thrusters in order to ensure continued operation in the event of a gas leak?***	Flag up where inlets are. Vents in test area. Should be shut. Should be caught in HAZOPæs. Limitations to explosion proof equipment in well test area. Rule of thumb. Hard to prescribe Should likely hood of gases be considered. Normally put in open areas. Impact to rig, does it change classified areas.	The impact on the rig in terms of hazardous area needs to be assessed beforehand. This will include consideration of location of air intakes with respect to the new hazardous areas associated with location of the well test plant.
7	***Any other areas to be addressed***		

Arctic

Ref	Workshop Question	Discussion	Guidance
1	*Will arctic drilling from mobile units be confined to open water areas?*	Not specific to well test issues. How does it affect things specically	Decision to operate in arctic regions will relate primarily to drilling considerations. The Guidance will look only at specific well test issues.
2	*Will it be confined to mild seasons?*		Decision to operate in arctic regions will relate primarily to drilling considerations. The Guidance will look only at specific well test issues.
3	*Is icing relevant and how would it be accounted for? E.g. Confirm "structural ice rating" of burner booms? Any experience with measures to combat icing?*	Make sure all the equipment can stand up the the extreme cold.	Ice loads should be considered in design of load bearing structures. In addition operation of surface equipment (e.g. valves) should not be inhibited by ice.
4	*Should certification of equipment be required to confirm low temperature service suitability?*	Yes materails need to be assued-certified cold temperature.	Equipment subjected to low temperature should be documented as being suitable for that temperature. Alternatively the equipment should be protected in such a way that low temperature is not experienced.
5	*Should a HAZOP be required for arctic applications to identify all systems (hydrocarbon and auxiliary) which might be impacted by low temperature?*	Definetely	It is recommended that a HAZOP be carried out to identify sytems and components which might be impacted by low temperature or ice formation.
6	*Are there specific specifications for low temperature control?*	Control fluids need be assessed. Nothing specifically prescribed.	Control fluids should be suitable for low temperature application.
7	*Should it be required to have a written procedure to tackle prevention of plug formation and actions in the event of such occurring?*		Assessment of flow assurance problems should be carried out. Measures should be taken to prevent such from occurring and contingency if such should occur.
8	*Any other areas to be addressed*	What about the issue of testing offshore, but on ice.? Learn from environment impact testing in Alaska. 200% of tank volume needs to be held by bund.	

Rig Safety

Ref	Workshop Question	Discussion	Guidance
1	*Should the arrangement of the well test spread be formally approved by the Classification Society?*	That is one means, but there are other means, and should be other means of assuring safe operatoins	Primarily the Operator should make an assessment of the arrangement. Approval by a Classification Society would be one means for the Operator to ensure a safe design.
2	*Should there be an updated area classification drawing, fire plan, escapeway drawing, ESD Cause and Effect drawing? Other documents to be updated?*	Absolutely. Audits, maybe. That is one way to assure these are in place. Is it actually done. Should drawing be updated when wt spread comes on board. Yes, they need to reflect the current situation. The process certainly is needed. Should it even be done on small operations, small vessels, etc. Maybe not formally approved, by certainly that documentation needs to be available on rig. (Life boats next to separtors, green lines etc). But they do need to be updated. Crew needs to be clearly informed about changes due to well testing. Risk is almost the same for a 4 hour operations as for a much longer operation. Best way to do it may be to initially approve area classification drawings for both situations. With well test equipment on board, and without it on board.	Safety drawings should be updated to reflect the situation with the well test spread installed. This includes such aspects as area classification, escapeways.
3	*Is it necessary to carry out a HAZOP or HAZID for a specific application where safety aspects such as drainage, cross-contamination, fire fighting etc. are addressed?*	Initial risk assessement should cover this. So yes. Guidelines should be more specific on what should be included in the assessement.	Safety implications for the drilling unit (firefighting, drainage etc) should be covered by an initial safety assessment.

Rig Safety

Ref	Workshop Question	Discussion	Guidance
4	***Should the SSTT shutdown be integrated with the rig ESD or should this be manual? Is there a SSTT panel and what is the manning level?***	No, should not be integrated. Advantage speed and simplification. Why should not do it. Systems are complex and integration of systems from other organizations introduce many uncertainties (software integreation, hardware integration, system integration...) This should refer to the emergency disconnect system, not ESD........ ? Some organizatons actually want it integrated. But they are not drilling contractors.	The rig shutdown system (primarily the Emergency Disconnect System) does not have to be an automatic system. It is important that there is adequate communication between the rig and the test company so that actions taken are informed to the other party so that safety actions can be carried out (e.g. emergency disconnect should not be carried out before the SSTT closure and disconnection has been executed.
5	***Should documentation be specifically created to address the procedures and operations associated with well testing and offloading? Updating of rig procedures or creation of new documents covering for example Permit to Work?***	Safey management plan needs to consider all these things. Integration and assuring that all the procedures are meshed well together is very important. Service company needs to be involved in Permit to work.	Safety management of the various companies needs to ensure that necessary procedures are in place. In addition a briging document should mesh overlapping procedures and create new ones to address new hazards. It is impoertant that the service company is involved in the Permit to Work process.
6	***Any other areas to be addressed***		

Misc HAZID			
Ref	**Workshop Question**	**Discussion**	**Guidance**
1	***What sort of safety factor should be applied to predicted operating limits when specifying equipment rating to take account of uncertainty in prediction? Is this uncertainty more relevant for different types of test area (e.g. arctic, deepwater, deep gas).***	Where do you draw the line of when runnign a 10k vs 15 system? 9.9 or 8k? Organizations best practices address this. SLB POM addresses this. Operating pressure for 10k system is 20%, less. 8 ksi. But this is not regulated or covered by any recommendation. Should it be covered by standards. deeper water, hpht introduce more uncertainteees. More SF needed. There should be some guidance on how much uncertainty or safety factor to use. Use gas gradient and or worst case scenario, to plan the operations and equipment selection. Also consider possibly stimulation and kill of well.	In specifying the rating of equipment, the uncertainty of the information available should be taken into account and the worst case pressure situation should determine the rating.
2	***Should a radiation study be carried out prior to each test to determine burner boom radiation loads are within acceptable limits?***	Yes API spec may be used as a guideline, standard Seems like recongnizes standards, or rps should be used to get results in line with each other. Large deviations between different simulations have been found. How supply water? What to curtain? Where to hang it and how to power it. There may be limitations put on flow so major changes to protection do not occur.	Burner boom radiation levels should be determined by a radiation study. Acceptable radiation levels per API should be achieve by provision of a water curtain. Uncertainties in determining the radiation level may require some flexibility in the water curtain design and location
3	***Should special collision avoidance measures be put in place during a well test?***	Yes. Especially when uncertainties are induced by deeper water, barges, and other equipmen tinstalled. Should there be a stand by vessel to run off other vessels	All hazards, including collision should be considered in planning of the well test. It may be necessary to place traffic limitations during the operation.
4	***Should all lifting operations over well test plant and storage tanks be restricted during well test?***	Absolutely	All hazards, including dropped objects should be considered in planning of the well test. It may be necessary to place tliftinglimitations during the operation.
5	***For moored units, what should be the consequence to operations in the event of loss of an anchor line?***	Preplanned. Actions should be defined in plans Analysis prior to event. What if two lines are lossed. Make the well safe needs to be priorit one. Risk has to be analyses objectively. Mooring analysis. Maybe reduce operating limitations, but only if based on scientific analysis. Change the word premium.	Loss of position keeping is a scenario that should be addressed in the pre-planning for the well test operation. Potential offset and safety level represented by remaining lines, together with stage of the operations should be considered.
6	***Should premium tubulars be used in all well test operations?***	Certainly of gas, and liquired production above 5k. Halliburton: Premium tubing. Surface through BOP stack Drill pipe not used. The connctions need to be investigated and confirmed fit for purpose (sealing) Smaller operators will possibly not use premium tubing.	It is recommended that premium tubulars are used in the test string, especially for gas wells.

Misc HAZID			
Ref	**Workshop Question**	**Discussion**	**Guidance**
7	***Should drills be held immediately prior to well testing? (Fire, abandon platform etc.)***	Yes. Is also common practice. Everyone is briefed.	Safety drills should be held prior to the well test operation commencing.

Equipment

Ref	Workshop Question	Discussion	Guidance
1	***Should Well test equipment considered critical for safety be subject to some form of formal certification ?***	Yes for the primary system ustream of the choke and other equipment at operators discretion. H	The Operator must ensure that the well test equipment being used meets acceptable safety standards. In most cases this will be documented by the equipment supplier.
2	***Should such certification involve any 3rd Party to provide an independent confirmation of quality?***	Case by case at operators discretion.	The Operator must ensure that the well test equipment being used meets acceptable safety standards. In most cases this will be documented by the equipment supplier. Either party may choose to use 3rd party confirmation as a means of increasing confidence in the level of safety.
3	***Should the well service company have a documented inspection and maintenance program?***	Yes. Is also required. Integrity management system	The well service company should have a documented inspection and maintenance program to confirm that the standard of his equipment meets and will continue to meet acceptable safety levels.
4	***Should the certification and in service record be audited prior to each test?***	No, case by case. Each test needs to be clarified. Each company has their own quality management plan.	The need for audit should be decided by the Operator on a case-to-case basis. Consideration should be taken of experience with the service company, degree of novelty of the particular test.
5	***Should the quality of the equipment be followed up by a third party who documents continued acceptable standard?***	Open for discussion	The Operator must ensure that the well test equipment being used meets acceptable safety standards. In most cases this will be documented by the equipment supplier. Either party may choose to use 3rd party confirmation as a means of increasing confidence in the level of safety.
6	***Should it be recommended that before being taken into service, the equipment is to be tested to the maximum anticipated load for the particular application? Are there any additional recommended tests (e.g. NDE, thickness measurements etc.)?***	Quality system in place when periodic checks are done shoudl be in place. For critical equipment extre requirements. What are the current failure rates. New environments-equipment little stats avaialble If legislation is imposed on well testing in will affect also other services (mud etc). Service company shoudl have integraty management docucmenation covering desing, testing, inspections. Third party not required, method of documenting integrity up to operators, service compenetns.	The maintenance and inspection records of the test spread should be reviewed before taken into use, additional NDE and thickness measurements carried out as necessary. Pressure testing should be carried out before being taken into use.
7	***Any other areas to be addressed***	MMS does not govern the service companies. But the do govern them through the operators. Focus should not be on the hardware. It should be on the systems assuring integrity. But considerations also needs to be given to hardware, but not main focus.	Hardware is considered as important however focus must also be placed on the management system governing the selection and evaluation of the hardware.

APPENDIX D

GUIDANCE

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
Approved by: Arne Edvin Løken Head of Section	Organisational unit: Marine & Process Systems
Client: Minerals Management Service (MMS)	Client ref.: Mathew Quinney

DET NORSKE VERITAS
Technology Services, N America

16340 Park Ten Place
Suite 100
Houston 77084
United States
Tel: +1 281 721 6600
Fax: +1 281 721 6833
http://www.dnv.com

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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- ☐ Strictly confidential
- ☒ Unrestricted distribution

Table of Contents

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.

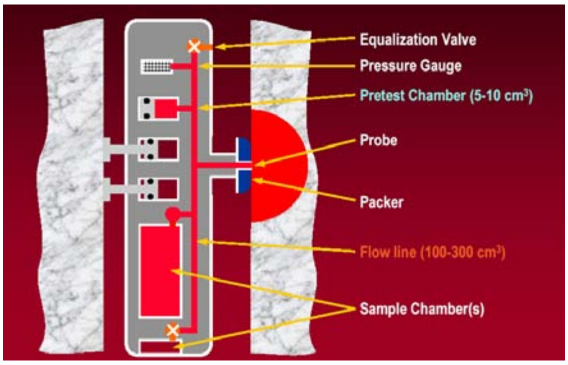
In mature areas the results of historic testing and availability of detailed seismic may be used and static testing may be sufficient for the Operator's purposes. In areas where there does not exist much if any historic data then a flow test may be the best option. Considerations such as cost of the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

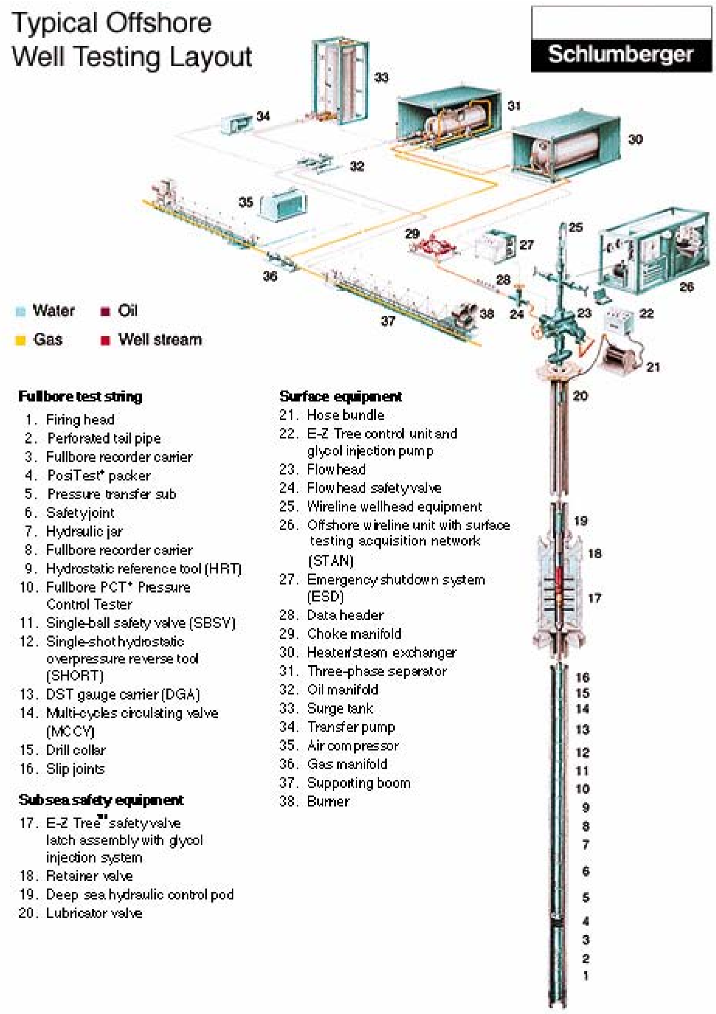
2.3.3 Drillstem Testing

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

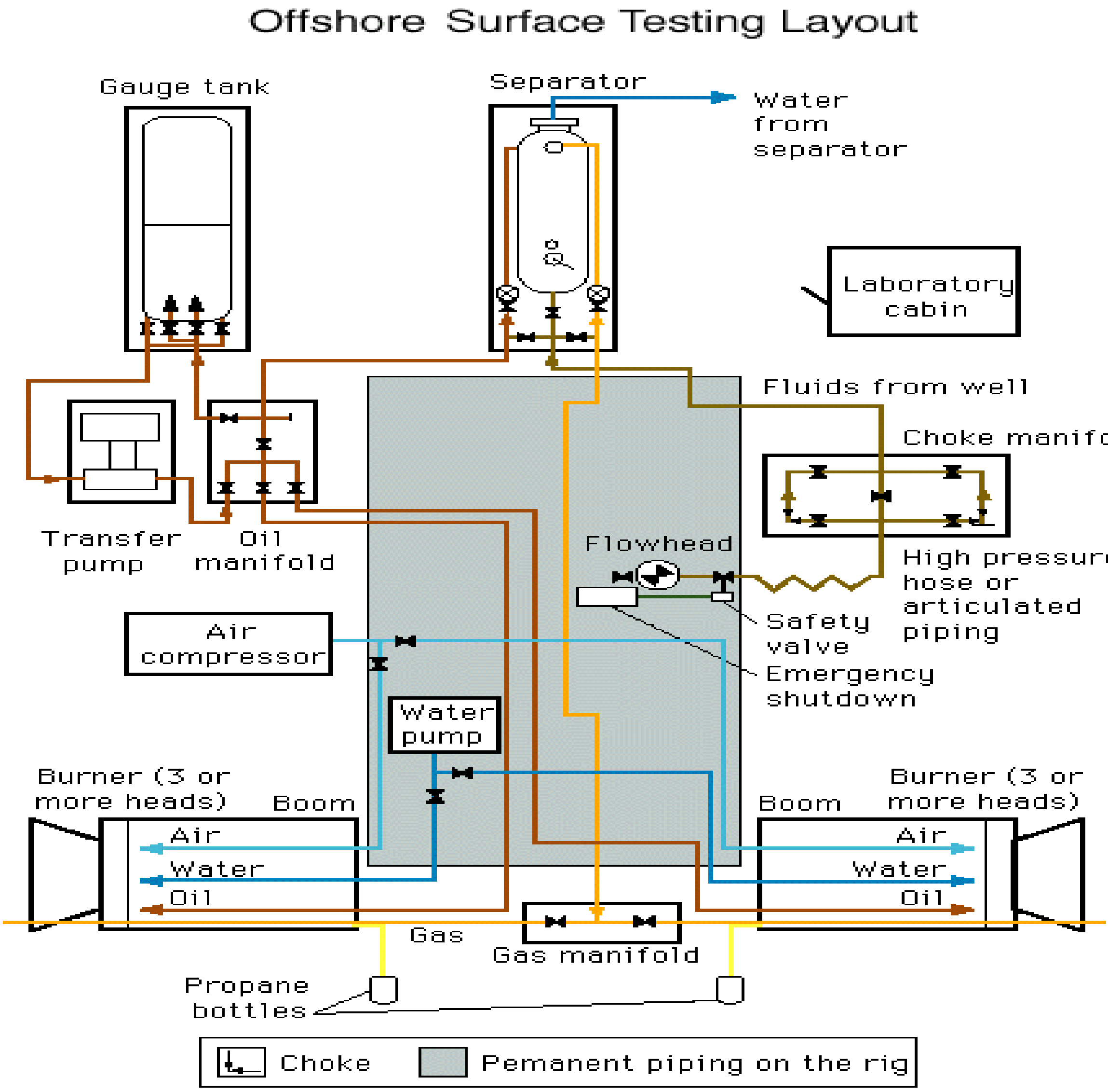
- Reservoir pressure and temperature
- Formation fluid collection
- Establish well productivity
- Permeability
- Drainage area delineation
- Possible production problems
- Drive mechanism

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

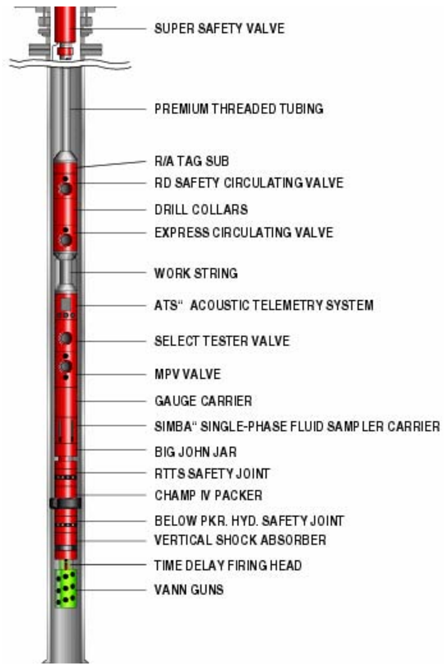
Typically well testing on a floating offshore unit, i.e. a semisub, or a drillship is conducted through the subsea BOP and marine riser.
Conventional well test systems consist of a temporary well completion with tubing supported by a fluted hanger set below the BOP stack. A test valve located near the 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 3rd 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).

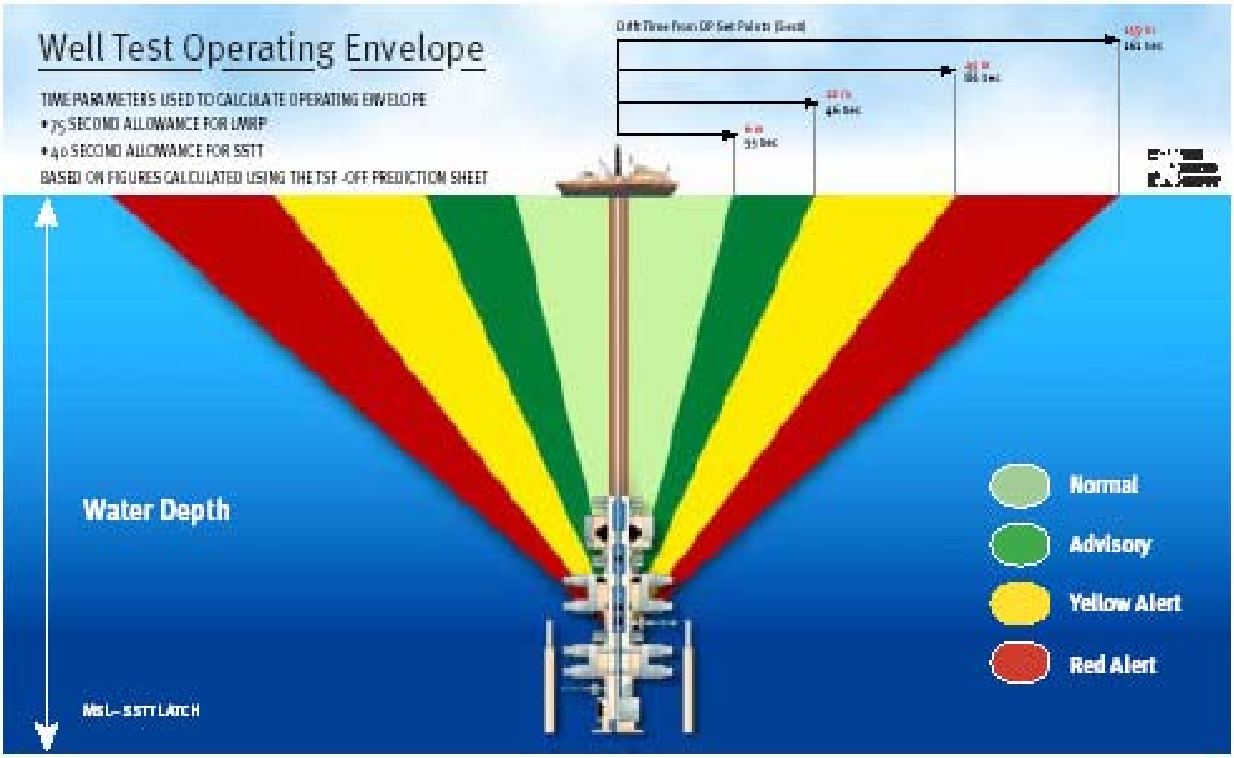


Fig. Example of Watch Circles (Expro)

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.

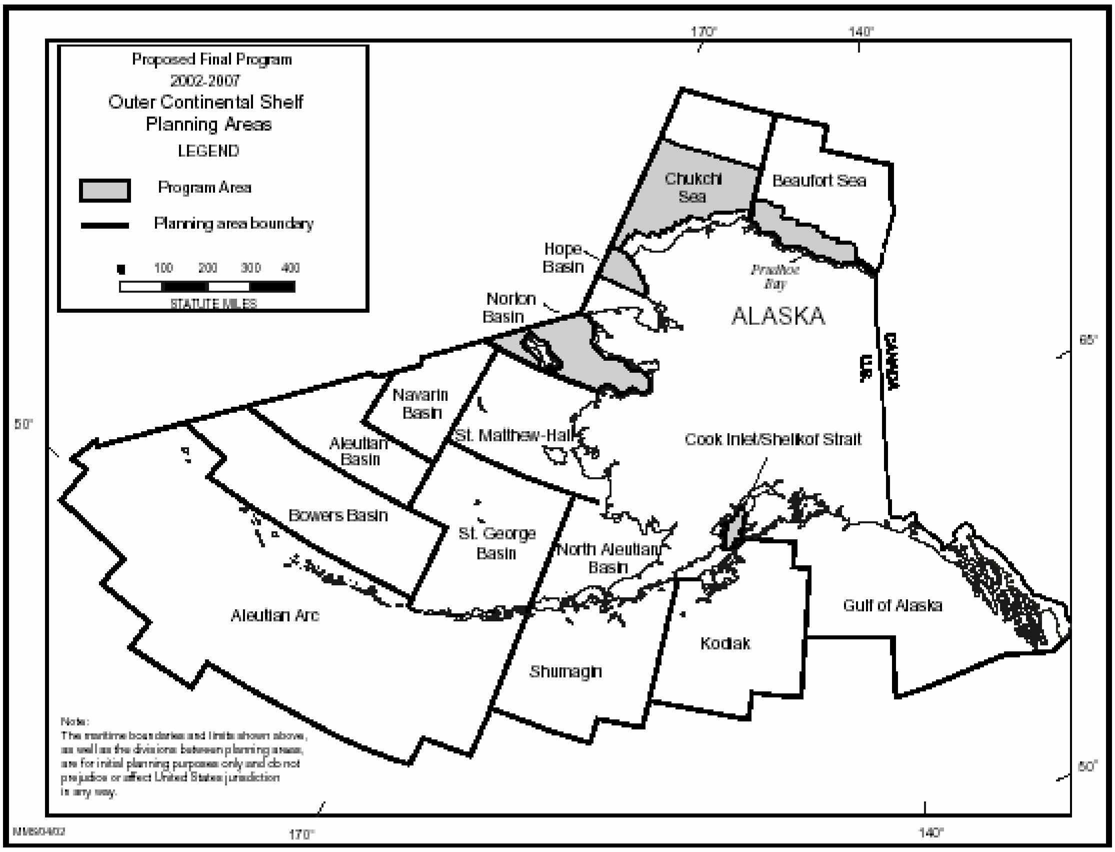
Response time will depend on water depth and on selected control technology (e.g. direct hydraulics vs electro hydraulic system).

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