OPERATIONAL ASPECTS OF OIL AND GAS WELL TESTING

Handbook of Petroleum Exploration and Production, 1

STUART McALEESE

ELSEVIER

Handbook of Petroleum Exploration and Production
1

Series Editor

JOHN CUBITT

ELSEVIER

Amsterdam - Lausanne - New York - Oxford - Shannon - Singapore - Tokyo

Handbook of Petroleum Exploration and Production

OPERATIONAL ASPECTS OF OIL AND GAS WELL TESTING

STUART McALEESE

ELSEVIER
Amsterdam - Lausanne - New York - Oxford - Shannon - Singapore - Tokyo

ELSEVIER B.V.
Sara Burgerhartstraat 25
P.O. Box 211, 1000 AE Amsterdam
The Netherlands

ELSEVIER Inc.
525 B Street, Suite 1900
San Diego, CA 92101-4495
USA

ELSEVIER Ltd
The Boulevard, Langford Lane
Kidlington, Oxford OX5 1GB
UK

ELSEVIER Ltd
84 Theobalds Road
London WC1X 8RR
UK

First edition 2000
Second impression 2003

Library of Congress Cataloging in Publication Data
A catalog record is available from the Library of Congress.

British Library Cataloguing in Publication Data
A catalogue record is available from the British Library.

Cover illustration by Jenny Ryrie

ISBN: 0 444 50311 0

⊜ The paper used in this publication meets the requirements of ANSI/NISO Z39.48-1992 (Permanence of Paper).
Transferred to digital printing 2006

PREFACE

Well Testing is recognised by many operating oil and gas companies to be the most hazardous operation that they routinely undertake. The potential for loss of life, loss of assets or environmental catastrophe are proportionately higher than at any other time in the drilling or operating of oil and gas wells. Therefore, it is of great importance to the industry and to the wider public that such operations are extremely well planned and executed.

Planning a well testing operation is an extremely complex task and requires a great deal of experience. This book provides an insight into the techniques and procedures that are used by the skilled Well Test Engineer to effectively plan and execute a well test under a variety of circumstances.

The testing of oil and gas reservoirs is one of the few times in an operating oil company when petroleum engineers, drilling engineers, reservoir engineers, geologists and asset managers are brought together with such a focused objective. Therefore, well test engineering is very much a discipline that combines knowledge of all of these areas of expertise. The Test Engineer will be the focal point of this group of specialists and will obtain the views of the group before then formulating a plan to test the well to meet an agreed set of objectives. This can often be an extremely difficult task, particularly in the case of wild cat exploration wells in new frontier areas, where often the reservoir parameters are not well understood. In addition, there is often very little infrastructure, and poor logistics in these areas.

With well testing costs typically accounting for about one third of the cost of an exploration well and in many cases much more. The potential for a budget over run can be high, unless timely and effective well test planning takes place.

This book covers all the major operational aspects of oil and gas well testing. It uses a structured approach to guide the reader through the various steps that are required to effectively plan and implement a well test operation under just about any circumstances world-wide onshore or offshore. Clearly the level of detail required to plan a very complex well test cannot be covered in a single text. Therefore, the author has provided details of suitable reference material where appropriate to assist the reader.

This book covers the test engineers' liaison role within the various oil company departments to set realistic well test objectives. The text also covers the various types of tests that are routinely conducted.

Safety procedures and recommended practices are rigorously addressed, as are the responsibilities of those persons involved in well testing operations.

Perforating equipment, Drill Stem Testing equipment and bottom hole pressure gauges are discussed.

The use of sub sea equipment is covered in some detail; an area which is often not very well understood, even by experienced engineers who have been involved primarily in land operations or operations from jackup rigs.

There is a detailed coverage of all of the major equipment items of a surface well test package and this forms a major part of the text.

This book also covers operational and testing related problems such as hydrates, wax and sand, and offers the reader some possible solutions.

Sampling and onsite chemistry are covered mainly from an operational standpoint.

There is also an overview of Coiled Tubing and Nitrogen operations as they relate to well testing and also a section on basic well stimulation.

Finally there is an extensive section of appendices that provides the reader with useful technical information.

The recommended practices and guidelines, so defined in the book, are for direction in good working practices. As changes in technology, methodology and experience of the industry develops these practices and guidelines may in the fullness of time be superseded.

However, neither the author or Esprit Petroleum Technology Limited will be responsible for any consequences that may occur as a result of applying these practices and guidelines to an operation that has not been managed by the author or Esprit Petroleum Technology Ltd.

The opinions expressed in this book are the authors and they may not necessarily reflect those of any other organisation which has contributed material to aid in the preparation of this book.

The book provides information that will be useful to all those involved in well test planning; primarily Petroleum and Drilling Engineers. In addition, a significant part of this book has been directed at those involved in the supervision of testing operations; namely Drilling and Testing Supervisors.

ACKNOWLEDGEMENTS

The author wishes to acknowledge the following organisations for the provision of technical documentation for this book;

Expro Group,
Schlumberger Oilfield Services,
Halliburton Energy Services,
NACE International.

This Page Intentionally Left Blank

CONTENTS

This Page Intentionally Left Blank

LIST OF TABLES

This Page Intentionally Left Blank

LIST OF FIGURES

Appendix

NOMENCLATURE AND TECHNICAL ABBREVIATIONS

AFE/AFC	Authorisation for Expenditure / Authorisation for Cost
AMS	Auxiliary Measurement Sonde *
BA	Breathing Apparatus
bcpd	Barrels of condensate per day
BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BHT	Bottom Hole Temperature
BOP	Blow Out Preventer
bopd	Barrels of oil per day
BRT	Below Rotary Table
BSW	Basic Sediment and Water
BTU	British Thermal Units
bwpd	Barrels of water per day
C	Degrees Celsius
CBL	Cement Bond Log
CCL	Casing Collar Locator
CGR	Condensate Gas Ratio
cp	Centipoise
CT	Coil Tubing
CTU	Coil Tubing Unit
DID	Detonation Interruption Device
DST	Drill Stem Test
ESD	Emergency Shut Down
F	Degrees Fahrenheit
FRC	Fast Rescue Craft
FTHP	Flowing Tubing Head Pressure
FTHT	Flowing Tubing Head Temperature
GOR	Gas Oil Ratio
GR	Gamma Ray

HAZOP	Hazard and Operability (study)
HCL	Hydrochloric
HMX	Cyclotetramethylene Tetranitramine
HNS	Hexanitrostilbene
HP/HT	High Pressure / High Temperature
HSD	High Shot Density
ID	Inside Diameter
IPR	Inflow Performance Relation
IRIS	Intelligent Remote Implementation System *
IRDV	IRIS Remote Dual Valve
JAM	Joint Analysis Makeup
KB	Kelly Bushing
kpsi	Thousand psi
LGR	Liquid Gas Ratio
LMRP	Lower Marine Riser Package
LOT	Leak Off Test
MAWP	Maximum Allowable Working Pressure
MBR	Minimum Bend Radius
MD	Measured Depth
md	Millidarcy
MDBRT	Measured Depth Below Rotary Table
MDT	Modular Dynamics Tester *
MEG	Mono Ethylene Glycol
MMscfd	Millions of standard cubic feet per day
MPa	Mega Pascal
MSDS	Material Safety Data Sheet
MWP	Maximum Working Pressure
OD	Outside Diameter
OIM	Offshore Installation Manager
OMCF	Oil Meter Correction Factor
OTP	Outline Test Programme

PA	Public Address
PBU	Pressure Build Up
P&ID	Process and Instrumentation Diagram
PI	Productivity Index
PPD	Pour Point Depressant
PPE	Personal Protective Equipment
ppg	Pounds per gallon
ppm	Parts per million
PLT	Production Logging Tool
PON	Petroleum Operations Notice (UK)
POOH	Pull out of hole
psi	Pounds per square inch
psia	Pounds per square inch absolute
PVT	Pressure Volume Temperature
PYX	Dinitropyridine
RDX	Cyclotrimethylene trinitramine
RF	Radio Frequency
RFT	Repeat Formation Tester *
RIH	Run in hole
RTTS	Retrievable Test Treat Squeeze #
S	Skin
SAFE	Slapper Actuated Firing Equipment *
SG	Specific Gravity
SPAN	Schlumberger Perforation Analysis Program *
SPF	Shot per foot
SRO	Surface Read Out
STE	Surface Test Equipment
STT	Surface Test Tree
SSLV	Sub Sea Lubricator Valve
SSTT	Sub Sea Test Tree
SSV	Surface Safety Valve

SSSV	Sub Surface Safety Valve
SWHP	Shut in Well Head Pressure
TCP	Tubing Conveyed Perforating
TD	Total Depth
TEG	Tri Ethylene Glycol
THP	Tubing Head Pressure
THT	Tubing Head Temperature
TRBV	Tubing Retrievable Ball Valve
TVDSS	True Vertical Depth Sub Sea
UKCS	United Kingdom Continental Shelf
UV	Ultra Violet
USIT	Ultra Sonic Imaging Tool *
VBR	Variable Bore Ram
VDL	Variable Density Log
WEM	Well Evaluation Model
VHF	Very High Frequency
WHP	Well Head Pressure
WHSIP	Well Head Shut in Pressure
WHT	Well Head Temperature
W/L	Wire Line
WP	Working Pressure

See Table 10.1 and 10.2 for detailed DST tool nomenclature.

*	Mark of Schlumberger
#	Mark of Halliburton

ABBREVIATIONS FOR ORGANISATIONS

ABS	American Bureau of Shipping
AGA	American Gas Association
ANSI	American National Standards Institute
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BV	Bureau Veritas
CSM	Colorado School of Mines
DNV	Det Norske Veritas
DOT	Department of Transport (US)
HSE	Health and Safety Executive (UK)
IATA	International Air Transport Association.
IP	Institute of Petroleum
NACE	National Association of Corrosion Engineers
SPE	Society of Petroleum Engineers
UKOOA	United Kingdom Offshore Operators Association

This Page Intentionally Left Blank

CHAPTER 1

PURPOSE OF THE BOOK

This book seeks to establish the framework that Well Test Engineers and related professionals should use for the planning and conduct of well testing operations.

The book does not aim to be prescriptive in all areas of well operations and the practical implementation of the recommended practices and guidelines allows considerable flexibility. Additionally, the book cannot address all the specific hydrocarbon regulations that exist worldwide. However, the book does provide sound practical advice drawn from the authors experience of well operations in more than twenty five countries, covering all the principal oil and gas producing provinces worldwide. It is conceivable that on rare occasions and for specific operations that the guidelines as explained in this book may conflict with some local hydrocarbon regulations in the theatre of operations. On such occasions the local hydrocarbon regulations should take precedence.

Engineers embarking on test planning activities in countries in which they are personally unfamiliar with the relevant hydrocarbon regulations, should obtain a copy of these regulations and check that any programmes issued by them are in compliance with the relevant regulations.

There are currently a plethora of books on well test pressure transient analysis, for example; (5) Earlougher, R.C., "Advances in Well Test Analysis", (10) Mathews, C.S. and Russel, D.G., "Pressure Buildup and Flow Tests in Wells" and (8) Horne, R.N., "Modern Well Test Analysis". However, the author is unaware of any other book covering the operational aspects of oil and gas well testing. The techniques and procedures described in this book would not normally be taught as part of a university petroleum engineering course. Therefore, engineers must learn these techniques through a variety of means: postgraduate studies, seminars, training courses and via the mentoring process. This book brings together a wealth of information that the author has derived from his work with international oil industry service companies, major and independent oil and gas operating companies, government regulatory bodies and training organisations the world over.

This book provides engineers with the basic tools to allow them to start to plan well testing operations for themselves. However, complex well tests such as HP/HT, deep water and sour gas are best handled by an experienced consultant who has developed the necessary skills and has the experience to confidently manage such operations.

This book specifically aims at defining a structured approach to the following:

- Setting Well Test Objectives
- Safe Working Practices
- Test Design
- Enhancement of the Quality of Test Data

Setting Well Test Objectives

The setting of well test objectives is always a difficult process, within both the smallest independent to the largest multinational operating oil and gas company.

There are very many opinions to be sought and many agendas to be addressed while setting the well test objectives. The experienced test engineer has an important role in formulating these objectives. Through a knowledge of the technical capabilities of the equipment and the likely levels of expenditure the test engineer can focus the exploration group on what is important and realistic to achieve from an individual well test for a given level of expenditure. The information contained in this book provides the reader with the necessary technical information to assist in this process.

Safe Working Practices

Above all the main concern when planning a well test should be safety. In many parts of the world hydrocarbon regulations exist to control how tests are implemented both from a safety and environmental standpoint. However, in other parts of the world no such regulations exist. Working under these circumstances is in fact more difficult as the person orchestrating the test must substantially self regulate how the test will be conducted.

Large operating oil and gas companies usually have fairly well developed procedures written into their corporate well testing policy and procedures manuals to cope with most circumstances. However, these policy and procedures manuals may not cover all scenarios. Moreover in smaller and medium sized companies these policies and procedures may not even exist.

Therefore it will be the responsibility of engineers and managers to develop safe working practices and ensure that these practices are put into affect at the well site. This book will assist greatly in that task.

Test Design

Test design will include selection of appropriate equipment to carry out a well test within the context of the well test objectives. The test design should also comply with safe working and good oilfield practices that are appropriate for the theatre of operations.

Furthermore, the design of a test will also include a decision on the most appropriate type of test to conduct to achieve the objectives of the test, in a timely and cost effective manner. For example whether to carry out a flow after flow test or an isochronal test.

Again this book should assist the reader in this respect.

Enhancement of the Quality of Test Data

The quality of test data can be significantly enhanced through the selection of the most appropriate technology and procedures. For example downhole shut valves where appropriate to reduce well bore storage effects. Undebalanced perforating to improve perforating efficiency. The selection of the appropriate instrumentation with both the desired accuracy and reliability for a specific application. In addition preparation of quality well testing programmes with well explained step by step procedures will improve on the quality of the data acquired during a test.

Therefore, the purpose of this book is to assist the reader in the preparation, planning and execution of well tests: safely, efficiently and cost effectively, to the highest standards.

This Page Intentionally Left Blank

CHAPTER 2

WELL TESTING RECOMMENDED PRACTICES

This chapter provides a list of Well Testing Recommended Practices, which represents a good cross section of the industry norms for well testing standards. These recommended practices have been abstracted from subsequent chapters to provide the reader with a concise list to review each time they approach a new well test.

These recommended practices provide direction in good oilfield practices and the reader should adhere to these whenever possible.

2.1 Chapter 3 – Well Test Objectives

1. The well test objectives and the testing AFE/AFC should be set before or at the time of developing the well drilling programme and may be included as part of the drilling programme documentation.

2.2 Chapter 4 – Safety Procedures

1. The regulatory authorities “Environment, Health and Safety Policy” should be followed at all times.

2. Unless anticipated and prepared for, if H_2S levels exceed 10 ppm in the gas stream, the well should be shut-in and proper safety equipment should be sent to the location before continuation with the test.

3. The initial flow of hydrocarbons to surface should whenever possible be timed to coincide with daylight hours.

4. Well tests that are non routine should be considered for a formal HAZOP study. (See section 4.3)

2.3 Chapter 7 – Test Design

1. Tests should be kept as simple as possible whilst achieving the well test objectives.

2. Open hole testing should not be undertaken on floating rigs or on wildcat wells (see Section 7.9).

3. Barefoot testing may be carried out on all wells provided that the interval can confidently be killed at the end of the test. In all cases, the gas volume below the packer at the highest anticipated formation pressure must be able to be safely circulated out.

4. Premium tubing connections (e.g. VAM, NK 35 B etc.) should be run for well tests that could potentially flow gas to surface. Conventional drill pipe connections are not designed to be gas tight. Conventional drill pipe should only be used as a test string under certain circumstances (see Section 7.13).

5. There should be two valve isolation below or at the BOP in every test string, where possible these barriers should be tested in the direction of flow (see section 7.14).

2.4 Chapter 8 – Completion Fluids

1. The stability of the completion fluids should be checked for well tests which will take a long time, or which have high pressures / temperatures.

2. It should be ensured that the completion fluid is compatible with the perforating underbalance cushion fluid.

3. Compatibility tests with the completion fluid and any 'soft' goods such as packer elements and seals should be carried out whenever there is any doubt about the compatibility of the products.

4. If brine is used to avoid perforating skin damage, the brine should be filtered to an irreducible minimum of solids. In addition, pits and associated pipe work should be thoroughly cleaned.

2.5 Chapter 9 – Perforating

1. Wireline perforating with large underbalances should be avoided so as not to blow the guns up-hole and potentially birds nest the wireline. (Use < 200 psi)

2. Although it is possible to run 2 1/8" OD strip jet carrier guns through 2 ¼" ID test tools, <u>this is not recommended</u>. After firing the guns, the strips can bend and it

may become impossible to retrieve the guns through the mule shoe. Consideration should also be given to the maximum burr height when selecting hollow carrier guns to ensure that they can be safely retrieved.

3. Underbalances in excess of 1000 psi are unnecessary and should not be applied. Research by Schlumberger has determined that no further benefit is obtained above this figure (Reference (7) Halleck, P.M., Deo, M., SPE Paper No. 16895).

4. TCP guns should be run with a redundant firing head. (e.g. pressure activated and drop bar)

5. In the event that a pressure activated TCP gun fails to fire within the expected time frame, wait a further hour. Following this, re-apply tubing pressure up to the maximum allowable within pressure testing constraints. Should the guns fail to be fired hydraulically, then use the redundant firing mechanism, for example a drop bar.

   If a drop bar is used and becomes stuck in the tubing and cannot be fished, these live guns should not be pulled back through the rotary table. In such cases, the guns should be dropped, using tubing severance if required.

   In all other cases the recovery of live guns from a well shall be undertaken in accordance with the TCP contractors procedures. All TCP systems should be run with a 20' safety spacer between the firing head and the guns to provide protection for personnel in the event of recovering live guns.

2.6 Chapter 10 – Downhole Test Equipment

1. Two reversing valves should be used in a test string which operate by different means (e.g. annulus pressure, tubing pressure, string reciprocation). Annular pressure operated circulatory valves should not be used in open hole.

2. Prior to the first test all drill collars to be used shall be drifted, rattled and measured with a steel tape, then put aside.

3. For HP/HT tests, consideration should be given to using drill collars which have a ring groove for an o-ring to be fitted at the shoulder or alternatively use drill collars with premium connections. Premium connections are the preferred option.

4. All tubing or drill pipe to be used for the test, including pup joints and crossovers, shall be drifted and measured with a steel tape.

5. The dimensions of all downhole equipment to be used during a test shall be measured and recorded prior to the test. An equipment schematic complete with OD, ID and length of each component should be produced. All downhole equipment should be drifted.

6. A safety joint should always be run above a retrievable packer, in case the packer gets stuck and the string has to be backed off. At least one of the gauge carriers should be run above the safety joint to ensure recovery of the gauges. In heavy mud systems, the use of a safety joint may also be prudent when testing with a permanent packer.

7. A radioactive pip tag for TCP depth control should be run in the liner or casing and correctly located, above the uppermost test interval, taking the position of closed valves, etc. in the test string into account. A radioactive pip tag should also be placed in the test string.

8. If there is any likelihood of H_2S during the test, the correct tubing should be used (i.e. L80) and also H_2S compatible slickline or wireline should be used (refer to section 4.9 Hydrogen Sulphide, NACE MR0175-99 Sour Criteria)

2.7 Chapter 11 – Pressure Gauges

1. Mechanical gauges should only be used as back-up to electronic gauges, unless used for HP/HT tests.

2. Only electronic gauges with non-volatile memory sections should be used.

3. It should be ensured that the gauge battery life is sufficient for the test duration at the expected bottom hole temperature with contingency built in.

4. The "intelligent or smart" mode option for electronic pressure gauges should only be used in well understood pressure regimes, and not in new exploration areas.

5. Prior to permanent abandonment of a well or zone, following a well test, it should be ensured that the bottom hole pressure gauges have sufficient data recovery to meet the well objectives. If not a re-test may be required.

2.8 Chapter 13 – Surface Test Equipment

1. All tests should incorporate an Emergency Shut-Down (ESD) system. The manual shut-down buttons should be located in the following areas: close to the well testing spread, on the drill floor near to the drillers dog house and in safe locations away from the main testing area.

2. For high pressure, sour gas and sand frac clean ups, a dual isolation, double block and bleed valve arrangement is recommended for the choke manifold. In all other cases a single valve isolation arrangement is deemed acceptable if there are further tested latent barriers upstream of the choke that can be activated in the event of a leak.

3. The bubble hose and needle valve should be positioned downstream of the choke.

4. All flowlines should be tied down or pinned.

5. The number of flowline bends and elbows should be minimised.

6. There should be no valves in a vent line.

7. Where required, surge tanks should be used for all offshore tests, gauge tanks are not recommended.

8. Separators and surge tanks should be fitted with two relief lines.

2.9 Chapter 14 – Operations

1. Critical flow should be maintained across the choke if possible.

2. The well should be opened on a small (e.g. 16/64") choke and then beaned up no faster than 4/64" every 5 minutes, to a moderate choke size of about 28/64" depending on well conditions, then changed to a fixed choke. The cushion should then be unloaded and the well monitored for sand production, checks on equipment integrity should take place, prior to beaning up further.

3. The well should be shut-in at the tester valve first then at the choke manifold.

4. The separator flowmeters should be calibrated prior to the test.

5. For offshore tests the weather forecast (including wind direction) should be checked prior to igniting the flare to ensure that the flow is directed to the correct side of the rig. A good weather window is particularly important for operations from floating vessels, to ensure that the test can be carried out with the minimum of interruption.

6. Prior to flaring, the relevant authorities shall be informed of the impending flaring operations.

7. Portable air compressors must always be used for the oil burners where fitted. The rig air system must not be used under any circumstances.

2.10 Chapter 15 – Sampling Operations

1. Single phase downhole samples may be taken for oil wells with low water cut to compare with surface recombination samples. These samples are particularly useful for wax or asphaltene detection.

2. Ensure that sufficient separator gas is acquired when taking separator samples to allow recombination with the oil samples to replicate reservoir conditions.

3. Samples of separator water and any solids production should always be taken.

4. If samples taken during the main test are thought to be poor, further samples can be taken by reversing out the tubing contents. Maintaining back pressure at the choke manifold may allow single phase samples to be collected, however this will not always be possible.

5. Chemical injection (e.g. Methanol, Glycol) should not take place upstream of the sampling point, when samples are being collected, unless operationally unavoidable. If chemicals are injected upstream of the sampling point, this should be noted on the sampling tag and samples of the injected chemicals should be sent with the hydrocarbon samples to the laboratory.

6. Dead oil and condensate samples should be taken for assays. Small separator gas (300cc) and stock tank oil or condensate (100cc) and water (100cc) should be taken for geochemical analysis.

7. Duplicate samples should be taken as a minimum, triplicate are preferred.

8. Cylinders should never be shipped liquid full (it is illegal). If a piston cylinder is used, an inert gas should be used on the backside of the piston. Cylinders should be liquid filled to no more than 90% of capacity. All cylinder pressure ratings should be checked to make sure they are appropriate. The pressure rating needs to have been certified within the last five years and this will be shown by a stamp on the cylinder.

9. All samples must be packaged and labelled according to IATA or USA DOT regulations. A Shipper's Declaration for Dangerous Goods needs to be filled out with emergency procedures (or an MSDS) attached.

CHAPTER 3

WELL TEST OBJECTIVES

Setting the well test objectives requires consideration of the requirements of different departments. It is important to ensure that the viewpoints of all interested parties are collected and considered before setting the objectives. Once this is done it is equally important that the objectives are documented and distributed to the interested parties.

The requirements of the following parties should normally be considered:

- Senior Management
- Explorationists
- Petroleum and Reservoir Engineers
- Production, Process and Facilities Engineers
- Drilling Engineers
- Oil and Gas Trading
- Partners
- Regulatory Authorities

The statement of Well Test Objectives will be a significant part of the final audit trail.

A Well Test Planning - Input Data Sheet, such as the one at the end of this chapter, should be completed by the Asset group Explorationists, for each zone to be tested, in conjunction with the Petroleum and Drilling Engineering groups. This sheet should be completed as soon as a decision has been reached to drill a well. This will identify the most appropriate offset data to be used in the test planning. In addition, this will initiate dialogue between group on such items as the test objectives, type of test, perforation technique, environmental considerations, drilling rig details, logistics and much more.

Recommended Practice:

1. The well test objectives and testing AFE/AFC should be set before or at the time of developing the well drilling programme and may be included as part of the drilling programme documentation.

3.1 The Decision to Test

Within each operating company a clear statement should be produced specifying those parties who need to be involved in making the decision to test a well.

In general the decision to test will also require consideration of the views of other partner companies.

The decision to test will also involve considerations of the zones to be tested, the objectives of each individual test and the method of testing that best meets the objectives.

The decision to test must be made within the context of the well test objectives.

It is normally required that a formally signed off document is produced detailing the results of the decision to test, the test zones, the objectives of each individual test and an outline of the test method to be used.

This document will be signed off by those parties responsible for the decision to test. The document will be a significant part of the final audit trail.

Before the well is drilled a testing philosophy should be devised as part of a "Formation Evaluation Programme", this normally covers the requirements for mud logging, coring, open hole logging, well bore seismic and well testing. The formation evaluation programme would also be used as the basis for an "Outline Drilling Programme" and an "Outline Testing Programme" (OTP).

The OTP is written before the well is spuded, and develops the testing philosophy under the categories of testing objectives, detailed testing philosophy, outline test sequence, well data, test data, etc. When referring to equipment it may be generic or specific if contractors have been selected. Preparation of the OTP is very useful for flagging potential problems, showing compromises of well design and for identifying long lead items.

Finally the OTP itself is expanded into a "Detailed Testing Programme", before and during the drilling of the well. Naturally, before the well is drilled to TD, several testing options will need to be allowed for, to cover all the potential target horizons.

Once TD logging is complete, a formal recommendation can be written for Management (and subsequently for Partners, if appropriate) which gives a summary of the well evaluation (mud logging, coring and logging). This recommendation confirms the test objectives, described the testing methodology and outlines the testing sequence and asks for sanctioning of the testing Authorisation For Expenditure (AFE).

When the reservoir is of questionable quality, the decision to test is often difficult. It may be based on a consideration of political and commercial issues, as well as those purely technical. It is essential that all salient facts relating to the wells evaluation are clearly communicated to Management in a recommendation jointly written by Petroleum Engineering, Geoscience and Drilling Staff.

To a certain extent, some of the uncertainty relating to the performance of some poorer reservoirs can be reduced by the adoption of high resolution logging techniques and extensive formation pressure pre-tests (RFT/ MDT) targeted on the better intervals.

3.2 Mobilising Test Equipment

Within each operating company a clear statement should be produced specifying those parties who are responsible for the decision to mobilise well testing equipment.

For many wells the equipment will need to be mobilised before the well has reached total depth. In some extreme cases, where the well is very remote, the surface test equipment may have to be mobilised with the rig. However for most wells it should be possible to delay mobilising the equipment until a firm decision has been taken to test the well. The timing of the decision to mobilise test equipment must minimise the risk of lost rig time but balance this risk against the cost of mobilising the equipment too soon.

ESPRIT PETROLEUM TECHNOLOGY LTD.

Well Test Planning - Input Data Sheet

Country	______	Spud Date (dd/mm/yy)	______
Field	______	Time to Drill (days)	______
Well Name	______	Test Date (dd/mm/yy)	______
Location	______	TD (ft . m)	______
AFE No.	______	Deviation (degrees)	______
		Water Depth (ft . m)	______

Offset Data

Well Name	______	Well Name	______
Operator	______	Operator	______
Drilled (dd/mm/yy)	______	Drilled (dd/mm/yy)	______
Offset (miles . km)	______	Offset (miles . km)	______
Data Attached (Yes/No)	______	Data Attached (Yes/No)	______
Well Name	______	Well Name	______
Operator	______	Operator	______
Drilled (dd/mm/yy)	______	Drilled (dd/mm/yy)	______
Offset (miles . km)	______	Offset (miles . km)	______
Data Attached (Yes/No)	______	Data Attached (Yes/No)	______

Formation Properties (Best Offset:______)

Formation Name	______	Porosity (%)	______
Formation Type	______	Permeability (mD)	______
Formation Top TVD (ft . m)	______	Water Saturation (%)	______
Formation Thickness (ft . m)	______		
Pore Pressure (ppg . psi)	______	Consolidated (Yes/No)	______
Fracture Pressure (ppg . psi)	______	Comments:	______
Formation Temperature (F . C)	______		______

Fluid Properties (Best Offset:______)

Oil Gravity (deg API)	______	Gas Gravity	______
Viscosity (cp)	______	H_2S	______
Pour Point (F . C)	______	CO_2	______
Bubble Point (psi)	______	GOR	______
Formation Volume Factor (rb/stb)	______		

Rate Information (Best Offset:______)

Oil (bopd)	______	Comments:	______
Gas (MMscf/d)	______		______
Condensate (bcpd)	______		______
Water (bwpd)	______		______
Artifical Lift (Yes / No)	______	Method	______

ESPRIT PETROLEUM TECHNOLOGY LTD.

Well Test Planning - Input Data Sheet

Perforation (current well)

Liner / Casing Size (") ____________
Liner/Casing Weight (#) ____________

Preferred Perforation Technique:

W/L Casing Gun ____________
W/L Thru Tubing Gun ____________
TCP ____________

Gun Size (") ________
Shot Density ________
Shot Phasing ________

Estimated Perf Interval (ft) ____________
Underbalance (psi) ____________

Basic Test Objectives
(Identify which of the following are requirements of the test: Yes / No)

Initial Reservoir Pressure ________
Initial Reservoir Temperature ________
Bottom Hole Samples ________
Surface Samples ________
Oil Assay ________
Measure Contaminants (H_2S/CO_2) ________

SRO Required ____________

Quantity ____________
Quantity ____________
Details ____________

Reservoir Permeability ________
Skin ________
Well Bore Storage ________

Downhole Shutin Reqd. ____________

High Rate ________ Details ____________
Extended Well Test ________ Details ____________
Boundary Information ________ Details ____________

Well Site Chemistry ________ Details ____________

Detailed Test Objectives

____
____
____
____
____
____
____
____
____
____

ESPRIT PETROLEUM TECHNOLOGY LTD.

Well Test Planning - Input Data Sheet

Test Type (Complete the following)

	Yes / No		
Single Rate			
Short Initial Flow	______	Duration (min)	______
Initial PBU	______	Duration (hr)	______
Main Flow	______	Duration (hr)	______
PBU	______	Duration (hr)	______
Additional Sampling Flow Period	______	Duration (hr)	______
Flow after Flow			
Short Initial Flow	______	Duration (min)	______
Initial PBU	______	Duration (hr)	______
Main Flow	______	Number of Flow Periods	______
		Duration (hr) of Flow	______
PBU	______	Duration (hr)	______
Additional Sampling Flow Period	______	Duration (hr)	______
Isochronal			
Short Initial Flow	______	Duration (min)	______
Initial PBU	______	Duration (hr)	______
Main Flow	______	Number of Flow Periods	______
		Duration (hr) of Flow	______
PBU	______	Duration (hr)	______
Additional Sampling Flow Period	______	Duration (hr)	______
Modified Isochronal			
Short Initial Flow	______	Duration (min)	______
Initial PBU	______	Duration (hr)	______
Main Flow	______	Number of Flow Periods	______
		Duration (hr) of Flow	______
PBU	______	Duration (hr)	______
Additional Sampling Flow Period	______	Duration (hr)	______
Limit Test			
		First Boundary (ft)	______
		Second Boundary (ft)	______
		Third Boundary (ft)	______
		Fourth Boundary (ft)	______
Extended Well Test		Flow Duration (days)	______
		Shut in Duration (days)	______

Comments: Choke sizes etc. ______________________________

____

____

____

ESPRIT PETROLEUM TECHNOLOGY LTD.

Well Test Planning - Input Data Sheet

Stimulation

Comments: ____________________
____

Environmental Considerations / Licence Conditions

	(Yes / No)		
Flaring Permitted	______		
Green Burners Mandatory	______		
Crude Offloading Permitted	______		
Burning of Pits Permitted (onshore)	______		
Oil Spill Contingency Plan Required	______	Details:	______

Rig Details

	(Yes / No)		
Name	______	Type	______
Rig Inspection Undertaken	______	Date	______
By Whom	______		

Comments

eg. Burner booms, fixed pipework ____________________
____
____
____
____

H2S Procedures Required	______		
Cascade System Required	______	Contractor	______
HAZOP to be Carried Out	______	Date	______

Logistics / Infrastructure

Base Office Location	______	Supply Base Location	______
Distance to Well Site	______	Distance to Well Site	______
Driving Time (hrs)	______	Driving Time (hrs)	______
Sailing Time (hrs/days)	______	Sailing Time (hrs/days)	______
Flying Time(hr)	______	Flying Time(hr)	______

Service Company Base

Contractor	______	Contact	______
Contractor	______	Contact	______
Contractor	______	Contact	______

Signed	Asset	______	Drilling	______
	Res. Eng	______	Pet. Eng.	______

This Page Intentionally Left Blank

CHAPTER 4

SAFETY PROCEDURES

Safety during all aspects of well test preparation and execution is a primary consideration. All programmes should be written and carried out so that safe operations and safety awareness on the rig are maintained.

This chapter of the book identifies major areas where careful observance of good working practice will reduce the possibility of dangerous situations occurring. It should be noted however that generalised guidelines of this form cannot cover all aspects of well testing safety, or indeed all location specific legislation pertaining to the operation. During the formulation of individual well test programmes safety should be considered throughout all stages of the job and written into the detailed programme where appropriate.

Consideration should also be given to incorporating the outline test programme details into the pre spud presentations. This will ensure that all persons involved with the well are exposed to the testing plans, reservoir properties and any likely operational difficulties.

Recommended Practices:

1. The regulatory authorities "Environment, Health and Safety Policy" should be followed at all times.

2. Unless anticipated and prepared for, if H_2S levels exceed 10ppm in the gas stream, the well should be shut-in and proper safety equipment sent out to the location before continuation with the test.

3. The initial flow of hydrocarbons to surface should whenever possible be timed to coincide with daylight hours.

4. Well tests that are non routine should be considered for a formal HAZOP study. (See section 4.3)

4.1 Breathing Apparatus

Basic breathing apparatus will normally be available on the rig. However, this equipment may be limited in quantity.

Therefore, if a well test is to be carried out and H_2S is 'possible' in the well, sufficient breathing apparatus sets must be made available for all personnel on the rig. This breathing apparatus should be self contained and allow at least 20 minutes usage without refilling air bottles.

For tests where H_2S is 'expected' a full cascade air system should be installed in preference to the use of air bottles.

The use of breathing apparatus (particularly air bottles) to carry out normal well testing operations in an H_2S contaminated environment is more physically taxing to workers. Therefore, regular rotation of test crew working in contaminated areas will be required.

Spare sets of breathing apparatus should always be maintained in a safe area close to the work sites to enable rapid change over in the event of an equipment failure.

Emergency escape air packs found on the rig should only be used for this purpose and not for normal working.

Further information on H_2S is contained in section 4.9. However, the advice of a specialist H_2S contractor is recommended when planning a sour well test.

4.2 Certification, Service Testing and Safety Review

All equipment purchased, or rented to carry out a well test should be fit for purpose. This means the safe working limits in terms of pressure, temperature, flowrate, nature of services and tensile/compressive loading should not be exceeded during any part of the well test operation.

Well testing operations are often planned with very little information available about the reservoir and these tests carry the greatest risk. The worst case scenario cannot routinely be designed for and therefore a risk analysis, safety review or HAZOP should be undertaken in such circumstances. This will determine if worst case scenario is required in the well test design.

It is recommended that all equipment supplied for a well test should have current certification available prior to being sent to the rig. Full pressure testing and function testing of equipment should be carried out prior to and on arrival ot the rig. These tests should be witnessed by a competent person. Records of all certification and pre-service tests should be retained on the rig until completion of the test.

For North Sea tests it is a requirement that the equipment layout and P. & I.D. meets with the approval of the rig contractors certifying authority e.g., DNV, ABS, Lloyds (see also, section 13.23). Generally, this will be organised by the surface testing contractor. The equipment should be placed such that it complies with any zoning requirements. Although this may not be a regulatory requirement elsewhere, it is recommended that this be considered as part of a safety review.

It is strongly recommended that a HAZOP or safety review be conducted to ensure that the equipment and procedures are fit for purpose. The extent of the review will be dependent upon the complexity of the operation. At the very minimum, a safety review orchestrated by the surface testing contractor should be undertaken. HP/HT tests for example, would justify a formal HAZOP. These Safety Review/HAZOPS should follow a format as discussed in 4.3 below.

4.3 HAZOP Studies

Hazard and Operability studies (HAZOPS) were first conducted in the late 60's and early 70's in the U.K. chemicals industry. The technique was used to identify hazards in process plant and also to identify problems that although not hazardous could compromise the plants ability to achieve design productivity. Therefore, a HAZOP generally looks beyond routine hazard identification.

The results of a HAZOP study are qualitative in nature with the intent of providing as thorough a review of the system safety as possible. Therefore hazards with a low likelihood of occurrence are identified along with those with a high likelihood of occurrence.

The hazards of primary interest during a well test will usually involve the accidental release of hydocarbons due to leaks, venting of pressure and equipment failures.

The system or operation will normally be divided into a number of nodes (equipment or process nodes) and analysed individually.

The HAZOP meeting is usually overseen by an independent HAZOP chairman who must be familiar with the HAZOP technique, but need not be familiar with the process equipment or operation. The chairman along with the HAZOP team members will select the process nodes, the guide words and the deviations. The HAZOP team members should be drawn from operations and engineering staff and sometimes from outside the organisation. The team members should be thoroughly familiar with process, in this case, well test equipment, rig equipment, expected well performance and well test procedures.

It has been suggested that a successful HAZOP should have a minimum of 100 years experience among the HAZOP team members. HAZOP meetings have sometimes been described as structured brain storming sessions where the team systematically looks for possible upsets or deviations from the design intent.

HAZOPs need not be conducted for every well test. However, any tests which are non routine in nature should be considered for the HAZOP technique. These may include: HP/HT, sour gas, high flow rate oil or gas tests, extended tests, deep water, environmentally sensitive areas and rank wild cat wells with no infrastructure.

4.4 Dangerous Substances

During the course of a well test a wide variety of hazardous substances may be used. Prior to commencing a well test operation, consideration should be given to each of these substances to ensure that safe handling procedures are drawn up. Steps should be taken to ensure that exposure of personnel to these substances is minimised.

A log of all hazardous substances should be maintained at the rig site. This log should contain a copy of all relevant Material Safety Data Sheets (MSDS).

Any personnel handling these substances should be aware of the required precautions and associated hazards. These substances must only be handled in strict accordance with specified procedures and by authorised personnel.

Typical hazardous substances used during well testing are listed below:

Acid additives	Hydraulic oil
Benzene	Cement
Biocides	Diesel
Glycol	Oil based muds
Hydrochloric acid	Crude oil
Hydrofluoric acid	Hydrocarbon gas
Hydrogen Sulphide Scavengers	Scale Inhibitors
Methanol	Mineral Oils
Oxygen Scavengers	Brines
Pipe Dope	Mercury
Toluene	Xylene

Mercury

Mercury was extensively used in fluid sampling operations, but its use is gradually diminishing. However if used it should only be handled by trained service company personnel.

Mercury is a silver coloured metal which remains liquid at normal ambient temperatures. Long term contact with mercury or with mercury compounds can have a very serious effect on health.

Mercury vapour can be inhaled and absorbed by the lungs during normal respiration. Mercury can also enter the body by absorption through the skin and by ingestion.

If care is taken mercury can be used safely. The following should be regarded as the minimum precautions:

- Mercury should only be handled by trained personnel.
- Oversuits – should be worn (preferably plastic, but paper is acceptable).
- Overshoes – should be worn (preferably plastic, but paper is acceptable).
- Safety Glasses – should be worn.
- Masks – should be worn, either disposable 3M type or mercury specific replacement filter type.
- Gloves – should be worn (plastic/rubber at least wrist length).
- Work should be carried out in a well ventilated area which is as cool as possible.
- Brass fittings should not be used, mercury attacks brass.
- Smoking/eating/drinking should <u>not</u> be permitted in the vicinity of operations involving the use of mercury.
- Before using mercury a safety barrier should be erected and announcements made over the PA system.

4.5 Daylight/High Visibility Working

Some operations undertaken during the course of a well test will require good visibility in order to be carried out safely. Moreover, some operations which could be carried out without problems on offshore rigs, may not be possible on onshore rig sites where the overall site lighting may not be so good. Whenever possible, additional explosion proof lighting should be installed at onshore wellsites for testing operations.

Generally the following activities will become considerably more hazardous if carried out under low light conditions:

- Acidising and fracturing.
- Coiled tubing work.
- High pressure pumping.
- Igniting flares.

- Initial perforating and flowing the well.
- Slickline and electric wireline work.
- Well kill.

Where possible these activities should be avoided during the hours of darkness.

In certain circumstances some of the operations listed above will be required during the hours of darkness. In these cases it is imperative that adequate lighting is provided and that personnel involved in this phase of the test are alert and aware of any increased hazards. Restrictions on work requiring daylight or high visibility should be indicated within the detailed well testing programme.

4.6 Explosives

The importation, transportation, storage and use of explosives are increasingly a concern of both local and national authorities. It should be clear at the outset of any operations involving explosives whether the operating oil and gas company or the service company is accountable to the local and national authorities.

There are three main categories of explosives:

- Low or deflagrating explosives: These are propellant powders used mainly for power charges for plug setting tools or for side wall core guns. Heat, flames, sparks or impact may ignite these.
- Primary or detonating high explosives: These are used primarily in electrical blasting caps or percussion detonators. For safety reasons primary high explosives should be stored separately from other types of explosives.
- Secondary high explosives: These explosives are less sensitive than primary high explosives and require a high energy shock wave to initiate detonation, usually provided by a primary explosive such as a detonator. Secondary explosives are used in shaped charges, jet cutters, detonating cord and boosters.

Use of Explosives

Detonation of explosives is often achieved by the transmission of an electrical signal, from a logging unit via the logging cable, to the blasting cap / detonator. Safety measures must be taken to ensure that the mechanism for signal transmission is disabled until the pulse from the logging unit is required to be sent. Unfortunately, the logging cable itself is capable of acting as a receiving antenna, and in areas of strong electrical activity this could transmit sufficient current to detonate the explosives.

Two mechanisms exist to reduce the potential for premature detonation of the explosives.

- Radio Silence
- Downhole switches or signal identification devices.

Radio Silence

- Radio silence must be observed while the guns are at surface or are less than some pre-defined depth below the rotary table or mud line (Offshore usually 200' below the mud line). Offshore standby vessels and other vessels in the vicinity of a drilling rig need to be informed of the periods of radio silence. All vessels should be outside a 500m exclusion zone throughout the entire operation. The standby vessel will ensure that no other vessels enter the 500m exclusion zone during the operation.

- Particularly on land rigs signs should be posted to ensure that personnel arriving on the rig are aware that radio silence is in effect and that live guns may be at the surface.

- The Drilling Supervisor will ensure that the local office is informed when radio silence is about to begin and also when it is finished. Also ensuring that any appropriate local authorities (e.g. coastguards) are similarly informed.

- Some types of guns do not require radio silence while being loaded. This must be checked and clarified with the Logging/TCP Engineer.

- All active cathodic protection equipment should be turned off throughout the entire operation.

- Helicopters should not be allowed to land while armed guns are at or close to the surface.

- The guns must not be armed during electrical storms or when sand/dust storms are imminent (earthing/grounding can be a problem with very dry air).

- Electric welding shall be prohibited throughout all operations involving explosives.

- It is the responsibility of the Logging Engineer to ensure that the logging units generator or electrical supply is switched off and the safety key is removed while the armed explosives are close to the surface or are above ground level.

- The well casing must be monitored for stray voltages. These voltages should always be less than 250 mV (millivolts); if greater than this the source of the current must be identified and isolated before proceeding with the operation.

- All non-essential personnel should be kept away from the rig floor and the catwalk while the explosives are being armed. There should be an announcement to that effect before arming commences and there should be temporary warning signs placed at the access points to the danger areas. The same precautions should be followed when disarming the explosives.

- The catwalk etc. should be kept clear of part used explosives e.g. primacord.

- Onshore, safety grounding straps and spikes will be required to earth any stray voltages. This may prove difficult in permafrost areas or areas of dry sand in which case the earthing straps should be bolted to the rig.

- The Logging Engineer should be aware of the rig's proximity to high voltage power cables and radio transmitters.

- Care should also be taken when retrieving guns, cutters or punches from the well. Even when good indications of firing has been achieved, all tools pulled from the well should be treated as if they contain live explosive (and trapped pressure) until the detonating system has been disconnected and the tools thoroughly inspected. Live guns should not be brought back through the rotary table if a drop bar for a mechanical firing head becomes stuck in the tubing. In such a case the guns should be dropped, using tubing severance if required.

- Radio silence is much more difficult to comply with onshore due to the wide variety of users of radios, pagers, mobile phones, radar systems and air traffic. In certain circumstances secondary isolation systems such as those described below may be required.

<u>Secondary Isolation Systems (Downhole Switch)</u>

These systems of premature explosion prevention are relatively new. Each of the logging companies has its own system and designation (e.g. Schlumberger – SAFE). The systems may depend upon a signal being sent down a separate conductor to activate a switch in the tool, or alternatively it may use signal identifying circuitry to filter out alternating currents or direct current outside a pre defined range.

The use of these systems adds an additional cost to the operation. Therefore, they are primarily used in circumstances where the provision of adequate radio silence and or electrical isolation is outside of the control of the well site or in which such control carries additional problems.

Such circumstances might include:

- Areas of high electrical activity due to proximity to generating stations, industrial transformers, radio stations or radio beacons.

- Locations subject to severe electrical storms.
- Locations in which the radio system is an integral part of the safety system (e.g. offshore platforms), which may be compromised by radio silence, or in which some or all of the production operations may have to be shut down temporarily during the radio silence period.
- Onshore locations close to populated areas.

Each operating company must decide upon the desirability of using a secondary isolation system for a particular operation, bearing in mind that not all explosive systems which may be required are available in all operating region.

Responsibility for Explosives

- A log of all the explosives on site must be kept. It is the Drilling Supervisor's responsibility to ensure that this is kept up to date.
- The Drilling Supervisor and the logging or TCP Engineer is responsible for jettisoning the explosives in the event of an emergency.
- The Logging or Perforating Engineer is responsible for the use, arming and handling of all explosives.
- The security of explosives is a very important issue in most countries and the advice of specialists should be sought.

Storage of Explosives

The storage of explosives away from the well site should comply with local regulations. Where no such regulations exist the following should be used as a guide:

Explosive weight	Distance to buildings, roads, etc.
150 lb. (68kg)	85 ft. (26 metres)
300 lb. (136 kg)	131 ft. (40 metres)
1000 lb. (454 kg)	292 ft. (89 metres)
2000 lb. (907 kg)	459 ft. (140 metres)
4000 lb. (1814 kg)	705 ft. (215 metres)

The storage of explosives on the well site should be kept to a minimum and regardless of any local requirements all stores should at least meet the following standards:

- Storage should be well ventilated and dry.
- Storage should be away from the possibility of sparks or flames and away from radiated heat.
- The store should either have no electrical wiring or be provided with explosive proof wiring. The store should be earthed.
- The store should be locked and have external fencing. There should be signs in English and the local language reading, **"EXPLOSIVES, NO RADIOS"**.
- Fire extinguishers should be readily available.
- Primary explosives should be stored separately from secondary and deflagrating explosives. This separate store could be an annex to the main store.
- All explosives must be clearly marked. Part used detonating cord etc. must not be left on the store floor.
- On land sites the store must be at least 30 metres away from the rig and the accommodation.
- On offshore rigs the store must be away from the accommodation, easily accessible and away from conducted or radiated heat.
- Explosives age more rapidly with humidity. The service company should be able to provide a list of the explosives age and an account of their previous storage conditions.

4.7 Fire Fighting Equipment

Fire fighting equipment should always be available at the rig site. Prior to commencing a well test this equipment should be thoroughly checked to ensure it is in good working condition.

Fire extinguishers of the appropriate type should be moved to within easy reach of the test separator area.

All testing personnel should be trained in the use of hand held fire extinguishers.

The rig fire crew should be briefed on the layout of the test equipment and the location of any portable fire fighting equipment in the area.

For onshore testing the local fire department, where appropriate, should be made aware of the nature and timing of test operations.

4.8 Gas Detection

Gas detection equipment is used during well testing to monitor the area around the test equipment for hydrocarbon gas emissions and to ensure that H_2S concentrations in the atmosphere are safe for working.

Portable gas detection equipment is used for both monitoring contaminants in produced gases and to ensure a safe working environment exists before carrying out work in enclosed areas.

Permanent gas detection equipment should be located in areas where releases of gas are likely i.e. on rig floor, in the vicinity of the test separator and close to the choke manifold (if this is located away from the rig floor).

Permanent gas detectors should be located so that normal operations will not cause the detectors to be activated, however they must be located such that they will detect quickly any abnormal quantities of gas. For this reason the detectors should be located close to the equipment but away from "dead air" areas.

During the well test flow periods, regular sampling of the produced gases should be carried out.These tests are carried out using various hand held analysers, either disposable, or re-usable.

Gas measurements are usually in parts per million (ppm) by volume of H_2S and percentage of CO_2. These measurements are particularly important on wildcat wells to ensure that test equipment is not exposed to unsafe operating conditions. Regular measurments will ensure that personnel are continuously aware of any changes required in the safety procedures, should high concentrations of H_2S be present.

The measurements obtained from portable gas detection devices are generally regarded as a more qualitative than quantitative.To obtain quantitative analytical results more sophisticated equipment such as a gas chromatography may be used.

However, for the purposes of establishing a safe working environment prior to entry into any confined space e.g. test separator, gauge tank, mud pits etc. these portable devices are adequate. Work permits should be obtained where applicable and breathing apparatus must be available at the work site.

4.9 Hydrogen Sulphide

Hydrogen sulphide gas is extremely toxic and in relatively low concentrations can quickly cause unconsciousness and death.

At concentrations in the range of 1 – 30 ppm it can easily be identified by its characteristic smell of rotten eggs. However, a noticeable odour can be detected even at concentrations as low as (0.01 ppm)

At higher concentrations the smell becomes sweetish and at about 150 ppm olfactory paralysis occurs when the sense of smell can no longer be relied upon.

Table 4.1 provides a summary of the hazards and precautions to be taken if H_2S is expected.

Each operating centre should produce a detailed H_2S procedures document, specific to the rig, wellsite location and operating environment. The procedures described below are recommended for use in the testing section of these H_2S procedures document.

<u>Testing Limitations with H_2S</u>

When testing a wildcat or exploration well and in known H_2S areas, sour service equipment <u>must</u> be used. For equipment design and selection purposes Table 4.2 shows NACE MR0175-99 Sour Criteria and Table 4.3 shows the definitive material temperature cut off as per NACE MR0175-99.

An H_2S drill, plus a check on the H_2S systems <u>must</u> be performed prior to opening up a well in a known H_2S area. Table 4.4 presents a summary of the H_2S alert conditions during testing, and shows that the upper limit is 5000 ppm for ½ hour in the flow stream before testing must be terminated.

Unless anticipated and prepared for, if H_2S levels are over 10ppm in the gas stream, the well should be shut-in and proper safety equipment should be sent to the rig before continuation with the test.

Breathing apparatus must always be available on the rig floor and in the separator area when testing wildcat or exploration wells. Essential personnel are required to be trained in the use of the equipment prior to the start of testing.

Extra equipment such as a Cascade system will be required when testing in known H_2S regions. All personnel on the rig must be trained in the use of the cascade system and in the use of conventional BA sets under these circumstances. A specialist H_2S safety contractor will normally be appointed to install the Cascade system on the rig and provide training for the personnel.

Table 4.1

Hydrogen Sulphide: A Summary of Hazards and Precautions

HAZARDS TO LIFE	PRECAUTIONS / TREATMENT
1. Highly toxic above 20 ppm in air. 2. At low concentrations dulls the sense of smell. 3. Higher concentrations – Paralyses the olfactory nerves at about 150 ppm.	Monitoring H_2S concentration with detectors during flow. If H_2S levels in the gas stream reach 10 ppm the test will have to be terminated unless sour service equipment is being used.
4. Can be masked by other odours (such as Butane and Propane). 5. Heavier than air (S.G.1.185)– it can accumulate.	When testing sour wells (with sour service equipment) inform the drilling supervisor if H_2S concentration in the well stream exceeds 20 ppm.
6. Flammable gas (burns with a blue flame)	If H_2S is detected around the rig, locate and repair leaks. If H_2S persists, terminate test and bullhead fluids back into the formation.
Maximum allowable concentration 10ppm (Safe up to 8 hours) **100 ppm – May sting eyes and throat** **200 ppm – Kills sense of smell rapidly, stings eyes and throat.** **300 ppm – Severe headache, eyes and lungs affected – over 1 hour exposure may cause death** **500 ppm – Loose sense of reasoning and balance. Respiratory paralysis in 2 – 15 minutes. Casualty will need prompt artificial resuscitation.** **700 ppm – Breathing will stop and death will occur if not rescued promptly. Requires immediate artificial resuscitation.** **800 ppm –Fatal after few minutes Requires immediate artificial resuscitation** **1000 ppm – Unconscious at once. Permanent brain damage may result unless rescued promptly**	**First treatment for those affected by H_2S –** **Remove person to fresh air.** **Resuscitate if required.** **Oxygen may help.**

Table 4.2

NACE Sour Service Criteria – Sour Gas & Sour Multiphase System

MR0175-99

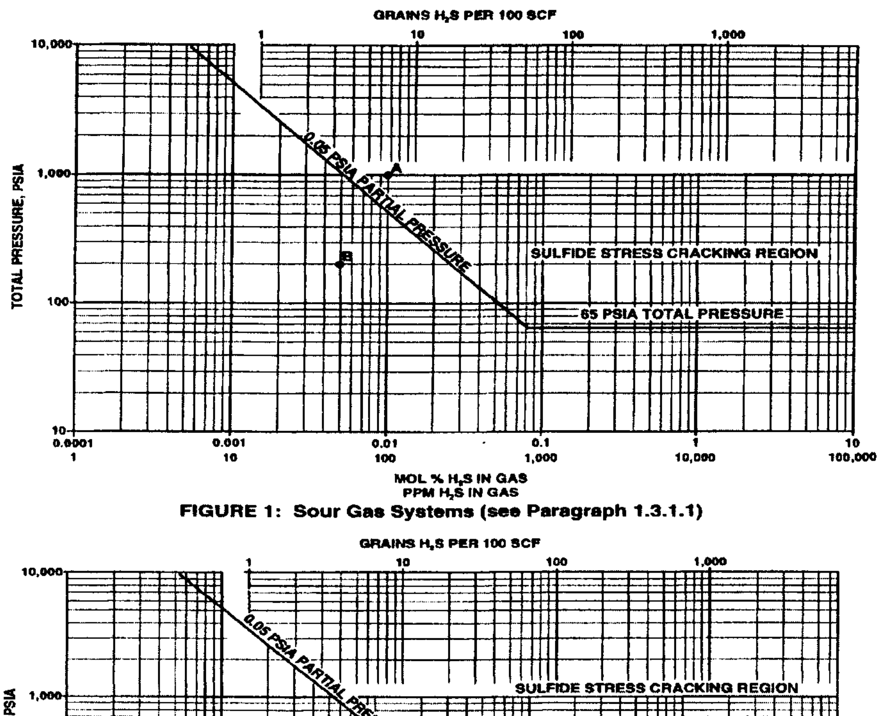


FIGURE 1: Sour Gas Systems (see Paragraph 1.3.1.1)

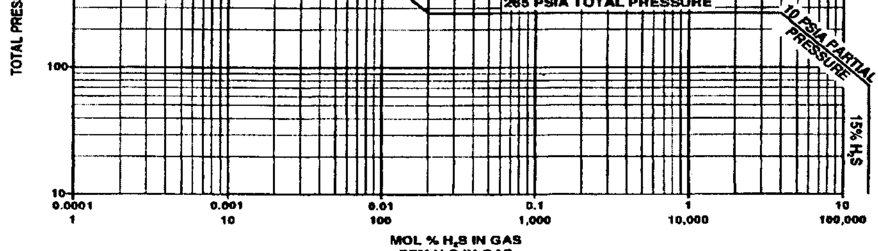


FIGURE 2: Sour Multiphase Systems (see Paragraph 1.3.1.1)
Metric Conversion Factor: 1 MPa = 145.089 psia

Table 4.3

NACE Material Temperature Operating Ranges (cut offs)

MR0175-99

TABLE 5
Acceptable API and ASTM Specifications for Tubular Goods
All materials complying with Section 3 or listed in Tables 3 and 4 are acceptable.
Materials listed in this table are acceptable under environmental conditions noted.

	Operating Temperatures[B]		
For All Temperatures[A]	**For 65°C (150°F) or Greater**	**For 80°C (175°F) or Greater**	**For ≥107°C (≥225°F)**
Tubing and Casing API Spec 5CT Grs H-40,[C] J-55, K-55, C-75 (types 1, 2, 3), and L-80 (type 1)	**Tubing and Casing** API Spec 5CT Gr N-80 (Q & T) & Gr C-95	**Tubing and Casing** API Spec 5CT Grs H-40, N-80, P-105, & P-110	API Spec 5CT Gr Q-125[G]
Proprietary Grades per Paragraph 10.2.3 UNS K12125 API 5CT Grades C-90 Type 1 and T-95 Type 1	Proprietary Q & T Grs with 110 ksi[H] or less maximum yield strength	Proprietary Q & T Grs to 140 ksi[H] maximum yield strength	
Pipe[D,E] API Spec 5L Grs A & B and Grs X-42 through X-65 ASTM A 53 A 106 Gr A, B, C A 333 Gr 1 & 6 A 524 Gr 1 & 2 A 381 Cl 1 Y35-Y65			
Drill Stem Materials[F] API Spec 5D Grs D, E, X-95, G-105, & S-135 (See 11.3.1.1)			

[A] Impact resistance may be required by other standards and codes for low operating temperatures.
[B] Continuous minimum temperature; for lower temperatures, select from Column 1.
[C] 80 ksi[H] maximum yield strength permissible.
[D] Welded grades shall meet the requirements of Sections 3 and 5 of this standard.
[E] Pipe shall have a maximum hardness of 22 HRC.
[F] For use under controlled environments as defined in Paragraph 11.2.
[G] Regardless of the requirements for the current edition of API Spec 5CT, the Q-125 grade shall always (1) have a maximum yield strength of 150 ksi;[H] (2) be quenched and tempered; and (3) be an alloy based on Cr-Mo chemistry. The C-Mn alloy chemistry is not acceptable.
[H] 1 MPa = 0.145 ksi.

Sampling for H_2S

The first hydrocarbons to reach the surface must always be tested for H_2S and CO_2 content. Frequent checks, every 15 minutes, should be made with H_2S detectors, (e.g. Draeger tubes) until satisfied that no H_2S is present or a stabilised level has been reached. Subsequent checks should be made every 1-2 hours during the flow period. On tests where sour service equipment is being used, the test may proceed as planned until levels in excess of 20 ppm are detected in the flow stream, then the Drilling Supervisor must be informed immediately. Refer to table 4.4 for additional measures that must be taken.

On exploration or wildcat wells initial sampling for H_2S requires BA sets to be worn by those carrying out the sampling. Masking up will not normally be required unless H_2S is detected (refer to table 4.4). This condition will continue until a stabilised level has been observed that is below the H_2S alert condition requiring BA.

The first samples will be taken downstream of the choke manifold and then later when flowing through the separator, at both the gas outlet line and the choke manifold. The higher of the two values will be taken as the H_2S level.

The sampling must occur in well ventilated areas and personnel must stand upwind of the sample point. In areas where winds are light, large fans may need to be installed to give ventilation. Remember H_2S is heavier than air and hence it will collect at the lowest points on the rig. This is particularly dangerous in the cellar deck area and especially on land rigs. Always wear a BA set when entering the cellar on an H_2S well. When working with high concentration H_2S wells i.e. greater than 250 ppm in the well stream, sampling must be carried out in pairs with one member standing back ready to rescue their colleague should difficulties arise.

Draeger tubes or similar detection systems are the recommended method of measuring the concentration of H_2S.

On land wells when flowing into stock or gauge tanks, personnel in the tank area must wear BA sets and be masked up if H_2S is present. There should always be two persons at the tank when H_2S is produced. Should the level exceed 50 ppm at the tank vent then the test must be terminated.

On offshore test only surge tanks with vents should be used regardless of whether or not H_2S is expected or produced during the test.

NOTE: Even though H_2S is a flammable gas, in extremely high concentrations, it is often difficult to burn. To ensure complete combustion of the gas, diesel may need to be pumped to the burner. In known H_2S areas onshore, if a full testing programme is being considered, then the gas should be flared from a stack, which is at least 10 metres above ground level and has a remote ignition system. The stack should be at least 50 metres from the wellhead.

When gas samples are to be collected from wells containing H_2S, consideration should be given to using special treated samplers and sample bottles as H_2S is absorbed by steel.

Emergency Contingency Measures

1. If H_2S is detected in the atmosphere around the rig at a concentration greater than 50 ppm even if full H_2S procedures are in place, the well must be closed in immediately and the Drilling Supervisor should be informed. These levels must be checked again and if the presence of H_2S is confirmed any leaks in the system must be traced and remedied. Air breathing apparatus must be worn while performing these operations.

2. If high levels of H_2S in the air persist, i.e. greater than 50 ppm, terminate the test and if necessary bullhead the well fluids back into the formation.

Table 4.4

Summary of H_2S Alert Conditions During Testing

H_2S Levels In Flow Stream	H_2S Levels In Air			
Ppm	$H_2S<10ppm$	$10ppm< H_2S<25ppm$	$25ppm< H_2S<50ppm$	$H_2S>50ppm$
20-150	BA to be worn by essential personnel. Masking up not necessary. Non-essential personnel to remain in accommodation. Flow periods may continue at night. Well may be re-opened at night.	BA to be worn by essential personnel and masked up. Shut down ventilation. Non-essential personnel in accommodation. Announce Safe Breathing Area. Investigate source of leak. Flow periods may continue in night. Well may be re-opened at night. No helicopters during flowing.	BA to be worn by all personnel. Mask up of all personnel outside. Shut down ventilation. Non-essential personnel to accommodation. Announce Safe Breathing Area. Investigate source of leak and if not possible to isolate, terminate test. No helicopters during flowing.	Terminate testing. Inform Drilling Superintendent
150 to 250	Masking up of all personnel in testing area and rig floor. Flow period may continue at night. No opening of well at night. No helicopters during flowing.	Masking up of all personnel in testing area and rig floor. Flow period may continue at night. No opening of the well at night. Shut down ventilation. Announce Safe Breathing Area. Investigate source of leak. No helicopters during flowing.	Mask up of all personnel outside. Shut down ventilation. Non-essential personnel to accommodation Announce Safe Breathing Area. Investigate source of leak and if not possible to isolate, terminate test. No helicopters during flowing.	Terminate testing. Inform Drilling Superintendent
250 to 5000	All personnel outside accommodation to mask up. Opening of the well and flow periods to be in daylight. No helicopters during flowing.	All personnel outside accommodation to mask up. Opening of the well and flow periods to be in daylight. Shut down ventilation. Announce Safe Breathing Area. Investigate source of leak. No helicopters during flowing.	Mask up of all personnel outside. Shut down ventilation. Non-essential personnel to accommodation, Announce Safe Breathing Area. Investigate source of leak and if not possible to isolate, terminate test. No helicopters during flowing.	Terminate testing. Inform Drilling Superintendent
Over 5000. For ½ hour.	Terminate testing. Inform Drilling Superintendent.	Terminate testing. Inform Drilling Superintendent	Terminate testing. Inform Drilling Superintendent	Terminate testing Inform Drilling Superintendent

4.10 Oil Spill Contingency

An oil spill contingency plan will normally be formulated prior to the drilling of any well. This plan should be written so as to include any possible spillage occurring during well testing.

Oil spills associated with testing would probably come from the following:

- Unburned oil falling from burner booms, " Fall Out ".
- Separator rupture disk blowing causing liquid dumping.
- Well blowout.
- Catastrophic failure of production piping or vessels.
- Unburned oil based mud falling from burner booms.
- Leakage of crude oil storage vessel or tanks.
- Rupture of tanks or compartment during crude oil transport.

Each of the above types of oil spill would vary in severity depending on the nature of the test or on the amount and type of oil storage at the well site.

The oil spill contingency plan for a particular well should be reviewed prior to writing the detailed well test programme. If necessary, additional section should be added to the detailed programme to cover specific oil spill contingency planning.

4.11 Restricted Access

During certain parts of the well test operation it is important to restrict access of personnel to specific areas of the rig or well site. This may require using signs and barriers and making PA announcements.

Principally the times when restricted access will be required are as follows:

- Offloading areas while loading or backloading equipment.

- The rig floor or catwalk while making up perforating guns.
- The rig floor while running the test string.
- The rig floor and test separator area etc. while pressure testing.
- The rig floor, derrick and cellar, separator area, burner booms and flare area during perforating and flow periods.
- The rig floor, derrick and cellar while killing the well and pulling the DST string.

These restrictions are related to the type of work being carried out and details should be given in the detailed well test programme. Typically these restrictions would only allow access to personnel directly involved with the procedures.

The start and end of operations requiring restricted access should be announced where possible by using the rig PA system. The status of existing restrictions should be re-transmitted over the PA system at crew changes, so that on-coming personnel are made aware of the situation.

4.12 Safety Meetings

Safety meetings should be carried out prior to each critical phase of the well test operations. These meetings are required to inform all relevant personnel of the work being carried out, specific hazards and hazardous areas. Safety meetings are also a good opportunity to ensure that all personnel are aware of their individual responsibilities.

Typically safety meetings would be held at the following times.

- Prior to picking up the test string and perforating guns.
- Prior to perforating or initial flowing of the well.
- Prior to carrying out a stimulation treatment.
- Prior to killing the well and pulling the DST string.

Additional meetings may well be required depending on the nature of the test and in certain circumstances these may have to be held at the beginning and end of each tour with both day and night crews being represented. Some points, which may be discussed at a safety meeting are detailed below.

Pre-Test Considerations

A pre test meeting should take place with all supervisory personnel present and all the points below which are applicable to the operation should be addressed.

- All breathing apparatus should be checked for serviceability.
- All personnel should be trained in use of B.A. sets if H_2S is expected.
- Carry out an H_2S drill, if H_2S is expected.
- All fire fighting appliances to be inspected.
- Fire pumps to be functioned and the system pressurised.
- Fire drill to be carried out in test area.
- Fire appliances to be positioned next to the test spread.
- Gas detectors to be function tested.
- Explosion meter to be function tested.
- Lifeboat engines to be function tested.
- Lifeboat launching equipment to be function tested.
- Radio and telephones to be function tested.
- Life-jackets and survival suits checked.
- Drill floor sprinkler system to be function tested.
- List of safety muster points to be posted on the notice boards and reviewed at the pre-test safety meeting.
- Firedrill and abandon rig drill to be held prior to testing.
- Schematic showing hazardous areas to be posted.
- ESD system to be installed and tested. Personnel to know location and function.

- All rig cooling systems to be function tested.
- Kill fluid to be prepared in suitable quantities. Kill lines and pump to be tested and manifold correctly lined up to kill wing.
- All diesel units to be checked for spark emissions.
- All pressurised bottles to be stowed away from hazardous areas.
- All unnecessary electrical appliances to be disconnected.
- All annulus monitoring sensors to be checked and purged.
- Escape routes to be clearly marked and kept clear of obstructions.

Personnel Briefing:

Overleaf on a single page is a personnel briefing that may be copied and distributed to personnel at the well site prior to holding the pre-test safety meeting.

Personnel Briefing

Briefing to be handed to all personnel:

- No smoking outside of accommodations during testing.
- All personnel must have attended H_2S instruction if applicable and be trained in use of the escape sets and BA sets.
- All escape routes must be clearly marked and all personnel must be familiar with the routes.
- The test areas will be clearly marked so that no unauthorised entry to the areas will be permitted.
- A briefing will be held before testing takes place and immediately prior to perforating, demonstrating the actions to be carried out in the event of emergencies. The briefing will include the location of and use of the ESD system.
- No welding or hot-work to take place during testing.
- Cranes will not be used without the prior permission of the Drilling Supervisor. No heavy lifts should take place in the well test area.
- The drill floor and driller will be the control point throughout the testing operations. Any requirements, announcements or emergencies to be co-ordinated by driller.
- All spillage and leaks of any kind must be reported to the driller immediately, especially any overboard.
- All watertight doors to be closed during testing.
- Whenever tripping in or out of the hole, the following equipment must be available:
    - Stab in valves for tubing and drill pipe.
    - X-overs to the test string.
    - Appropriate circulating swage on the rig floor.
- All personnel must respond to any alarms immediately.

OIM and Drilling Supervisors Checklist

- All non-essential personnel to be kept out of the designated test area during testing.
- All rig pressure equipment to be tested prior to well testing.
- Safety drills to be held prior to testing and in between tests.
- Any spillage to be reported as per the 'Oil Spill Contingency Plan'.
- Pre-test meetings to be held with rig personnel and test personnel to cover any emergency procedures.

  To include:

  - Bad weather and unlatch procedures.
  - Action on a fire.
  - Action on leaks in all scenarios during tests.
  - Responsibilities.
  - Rig evacuation.
  - H_2S procedures.
  - Radio silence, perforating.
  - Kill procedures.
  - Monitoring of the annulus.

- Co-ordination of equipment and personnel transportation to and from the rig to be channelled through OIM or drilling supervisor.
- Weather and timing consideration.
  - Due consideration must be given prior to the start of testing operations as to future adverse weather conditions. A forecast must be obtained and conditions discussed by the OIM/Drilling Supervisor/Test Engineer.
  - Each test zone on the initial cleanup should whenever possible only be allowed to flow hydrocarbons to surface during periods of daylight.

4.13 Site Preparation

Site design should be considered at the earliest opportunity. For onshore operations this may be before land acquisition. Consideration should be given to a safe area for loading guns and a safe area for storing explosives.

Consideration should also be given to a suitable location for a flare pit at a land well taking prevailing wind direction into account.

The design should consider the layout required for well testing operations to be carried out in a safe manner (see also Section 14.2).

4.14 Start of Testing Operations

Running in the hole with test tools should commence at the discretion of the Drilling Supervisor after due consideration of rig and local conditions. Consideration should also be given to the area weather forecast for the duration of the test. In the event that weather conditions deteriorate during an offshore test, the Drilling Supervisor and Test Engineer in consultation with the OIM will decide whether testing operations are to be suspended or terminated.

The start of the flow test, i.e. initial flow, initial shut-in, and approximately one hour of the main flow period, should be timed to coincide with daylight hours. The initial flow and shut-in may occupy the hours of darkness provided adverse weather is not expected and <u>no</u> hydrocarbons are produced to surface. Flow into or throughout the night should only be permitted if the well has stabilised and the surface equipment has been commissioned in daylight.

Finally the flow of formation fluids to surface should normally only be performed with a complete set of surface equipment including choke manifold, separator and either a tank or burner arrangement. Very low budget land operations, on low GOR oil wells do occasionally omit the separator, however in general such operations should not be planned.

<u>Reverse Circulation</u>

Reverse circulating during the hours of darkness is only generally permitted if the test has previously produced hydrocarbons to surface. If no hydrocarbons have been produced to surface then this operation must be done during the hours of daylight.

This Page Intentionally Left Blank

CHAPTER 5

JOB RESPONSIBILITIES DURING WELL TESTING

Specific job responsibilities during well testing must be clearly defined before commencing with a well test. The responsibilities should be documented and agreed with all parties involved.

Discussed below are generalised responsibilities, which should be considered when, defining responsibilities for a particular test. These should be reviewed with regard to the particular rig being used and prior to writing the detailed testing programme. The test programme may also include an organigram showing responsibilities and reporting lines.

Note: For all testing operations, only personnel from the company providing specific items of equipment shall operate that equipment. This is particularly important for the choke manifold, separator and flare systems.

5.1 Barge Control Room (offshore)

Will keep the Drilling Supervisor informed of weather conditions. All relevant operations will be routed through the barge control room before implementation e.g. commencement of flaring operations. Work boat and standby boat movement will be controlled by barge control room prior to and during test.

5.2 Base Office

Will be manned 24 hours a day, or out of hours contact numbers e.g. mobile phone and pager numbers of on call personnel must be known to the relevant personnel at the well site. The base office must also maintain communication with the helicopter base or air strip if applicable.

5.3 Boat Captain (Standby Vessel)

Boat captain will position the standby vessel upwind of the rig with lifeboats and FRC (Fast Rescue Crafts) ready for instant launching.

The captain will post a 24 hour visual watch from the bridge to observe the rig and a 24 hour radio watch on International Maritime Distress Channel 16 and any other working channels used by the rig and local vessels.

The captain must be familiar with the contents of the well specific oil spill contingency plan. Having ensured that chemical dispersants for oil are onboard the standby vessel and that the spraying equipment has been function tested.

5.4 Cementers

Cementers will stand-by near the cement unit, with access to kill weight mud.

5.5 Derrick man

Derrick man will stand-by near the mud pumps, which should be lined up to supply kill mud to the cement unit.

5.6 Downhole Tool Operator

The downhole tool operator is responsible for ensuring the good working order of the downhole tools, including pressure testing, make up operations and packer setting.

A service company representative must be on the drill floor at all times during the test. In the event that the test crew comprises of only one downhole tools specialist, it is important that this specialist be on the drill floor while running in or pulling out of the hole with the test string. At other times the TCP specialist will normally relieve the DST operator.

5.7 Driller

The Driller will be located on rig floor at all times during the test and monitor annulus pressure and all equipment located on the rig floor.

The driller must ensure that the entire drill crew is familiar with the location and function of the ESD system.

For offshore operations from floating rigs the driller must be familiar with the SSTT (Sub Sea Test Tree) console and how it works.

The Driller should ensure that the hole remains full at all times.

The Driller should be given instructions at the programme meeting on the course of action to be followed if events do not go according to plan. The Driller will also be advised in which circumstances he needs to inform the Toolpusher and the oil and gas company onsite representatives about events.

5.8 Drilling Engineer

The Drilling Engineer will keep the Drilling Manager / Superintendent appraised of all engineering aspects of the test.

The Drilling Engineer will provide engineering and logistical support for the ongoing operations and liaise with the head office on engineering aspects of the test.

5.9 Drilling Manager / Superintendent

Responsible for transmitting all instructions pertaining to the conduct of the test from the base office, to the Drilling Supervisor on the rig.

The Drilling Manager / Superintendent is ultimately responsible for safety during testing operations and should therefore ensure that a system has been developed locally to keep him fully appraised of the progress of the ongoing testing operations.

The Drilling Manager / Superintendent may not be the only point of contact between the base office / head office and the rig, but he should be copied on all relevant correspondence.

5.10 Drilling Supervisor

Has overall responsibility for conducting the test in a safe and proficient manner. He is responsible for issuing all instructions to the drilling contractor and service company personnel. These instructions may have to be written formally. The well site Reservoir / Petroleum Engineer and or Test Engineer will advise the drilling supervisor on all aspects relating to the testing programme.

The Drilling Supervisor is responsible for:

- Ensuring that all operations are carried out in a safe and efficient manner.
- Communicating all instructions to the drilling contractor.
- Communicating instructions to the well test crew after consultation with the petroleum or test engineer.
- Transmitting normal daily reports to town.
- Co-ordination of transport for shipment of any additional equipment required for test.
- Liaising with local authorities and emergency services e.g. informing the Coast-Guard or local emergency services of impending hydrocarbon flaring.
- Making a final check on the test equipment by walking the route of the flow lines together with the Test Engineer and OIM to ensure that all the valves are correctly positioned and all function tests have been carried out, prior to opening the well.

5.11 Electric Wire Line Engineer

Will ensure that all necessary equipment is available to set packers, bridge plugs, cut or punch holes in the tubing, run PLT's, run correlation logs and make up perforating guns, as appropriate and required by the testing programme. In addition, must ensure that all wireline pressure control equipment has been tested and is ready for use.

5.12 Gauge Engineer

Responsible for checking and programming the pressure gauges prior to installing them in the gauge carrier. The gauge engineer should be on the rig floor for the running and recovery of the gauges and is responsible for data verification.

5.13 H_2S Service Company Representative

Will have familiarised all personnel on the hazards of H_2S and the use of breathing apparatus. Also will have established areas for stock-piling breathing apparatus and emergency escape packs. The H_2S representative will be ready during testing to provide assistance on the drill floor when requested by the Drilling Supervisor.

5.14 Mud Engineer

Will ensure that packer fluids are properly made up within the given tolerances and that adequate supplies of kill mud are readily available.

5.15 Mud Logger

Will monitor gas for H_2S. Will run samples of produced gas through the chromatograph as required.

5.16 Petroleum / Reservoir Engineer

Advises the Drilling Supervisor on the reservoir engineering aspects of the test and is responsible for:

- Ensuring all relevant data is collected and of the required quality.
- Advising the Drilling Supervisor on the evaluation aspects of the programme.
- Ensuring that all sampling is carried out as per programme.
- Transmitting all test information to base office at the stipulated times.
- Assisting the Test Engineer.

5.17 Production Testing Crew

Will ensure that the SSTT, retainer and lubricator valves are installed correctly and tested (offshore) and that all ESD systems are functioning properly. In addition they will ensure that the test package is complete and that compatibility exists with the rig equipment, e.g. stand pipe connections. Will ensure that the surface equipment is functional and that all equipment is installed and tested correctly. Test crew will monitor and operate the choke manifold, separator, burner heads and other test equipment during the operation. They will be responsible for ensuring that the data acquisition system is functioning correctly in addition to manually recording all pertinent parameters throughout the test.

5.18 Radio Operators

Will maintain open communications with the operations base and work boats (offshore) during the test to ensure that any message can be transmitted without delay.

Ensure radio silence is maintained while any explosive charges are being armed and until they are at a safe depth in hole. Then again when being pulled out of hole and near to the surface, until such time as they have been safely disarmed.

5.19 Slickline Operator

Run downhole gauges/samplers/TCP firing bars/TCP gun drop tools. Must also ensure that all the fishing tools relevant to all the operations are available on-site.

5.20 Sub-Sea Engineer (floating rigs)

Will monitor BOP, slip joints, riser tensioners and choke and kill manifold pressure gauges. Will provide assistance in sub sea space out of slick joint, fluted hanger and accessories.

5.21 TCP Engineer

The TCP Engineer is responsible for making the final firing head shear pin calculations and in addition must also ensure that these have been check and agreed upon by the Test Engineer and or Drilling Supervisor. The TCP Engineer will be on the drill floor for the make up, firing and recovery of the guns.

The TCP Engineer will also assist the Test Engineer and or Drilling Supervisor with any underbalance / cushion calculations related to the perforation operation.

5.22 Test Engineer

The test engineer will advise the Drilling Supervisor on all engineering aspects of the well testing programme. He is responsible for the following:

- Ensuring that all equipment is available at the rig and that it has the correct certification.

- Ensuring all equipment is prepared and tested as per programme.

- Running the test string and pressure testing it.
- Checking pipe tally.
- Ensuring TCP perforating guns are at the correct depth.
- Carrying out the test in a safe and efficient manner.
- Preparing the daily well test report.

The Test Engineer should also make a final check on the test equipment by walking the route of the flow lines together with the Drilling Supervisor and OIM to ensure that all the valves are correctly positioned and all function tests have been carried out, prior to opening the well.

5.23 Tool Pusher / OIM

The Tool Pusher will liaise with the Drilling Supervisor to ensure the safety of the rig or vessel and all personnel. He will ensure that all equipment is functioning and that safety rules are being observed. The Tool pusher and his delegated crew will:

- Ensure that all safety measures are being observed.
- All fire fighting equipment is checked and ready for use.
- Liaise with the test crew and confirm that the correct flare boom is to be used (offshore).
- Have flare boom / flare pit cooling water and rig cooling water shields operational.
- During the test will monitor the weather and inspect the engine room and verify that all power generation equipment is functional.
- Perform gas checks in all questionable areas.
- Will ensure that the standby boat is appraised of the situation (offshore).
- Will liaise with the Drilling Supervisor on any aircraft movements to the rig during test periods.

The Tool Pusher / OIM should also make a final check on the test equipment by walking the route of the flow lines together with the Drilling Supervisor and the Test Engineer to ensure that all the valves are correctly positioned and all function tests have been carried out, prior to opening the well.

CHAPTER 6

SPECIFIC WELL TEST OBJECTIVES

Specific well test objectives will vary from well to well and from zone to zone. The specific well test objectives for a particular test with be set by consideration of the requirements of the different departments in the same way as the overall well test objectives (refer to Section 3). It is important that the specific well test objectives are documented and distributed to interested parties. This document will be a significant part of the final audit trail and in the final analysis will help in determining whether the objectives of the test have been achieved.

The specific test objectives are normally set once the well has been drilled and logged. The decision making at this point often has to be rapid and in some circumstances may be taken at the well site. The specific objectives must be set within the context of the overall well test objectives and should be set by the responsible parties as defined within the decision to test (refer to Section 3.1).

Some common specific well test objectives are discussed below:

6.1 Boundaries

Boundaries may be sealing faults, permeability pinch outs, no flow boundaries or active pressure support boundaries in the form of mobile aquifers, or gas caps.

In order to evaluate these boundaries, flow and build-up periods must be sufficiently long so that late transient flow, or in the case of a small closed reservoir, pseudo steady state flow is developed. To help with the design of the test, the equation used to estimate the time taken to detect a boundary is shown in Appendix A. Increasingly now Reservoir Engineers will make use of the test design option that exists on most commercially available well test analysis programmes, to look at the likely pressure response that will occur during the test. These programmes can also model boundary effects and may be a useful guide to the length of flow and buildup required during a well test to obtain certain boundary information.

If verification of reservoir boundaries is a critical objective of the test, wireline retrievable, or surface readout gauges should be considered when designing the test string. Incorporating one of these systems will allow approximate calculation of reservoir parameters prior to pulling the test string. It will also allow decisions to be made on the rig as to when build-ups should be extended, or curtailed.

If the overall size of the reservoir is required to be determined then a longer term reservoir limits test would have be carried out.

6.2 Flowrate

Accurate measurement of flowrate and identification of flowing phases is one of the most important aspects of well testing. Flowrates are normally measured at surface using separation equipment. Flowrates are sometimes measured downhole using production logging equipment. Section 13.13 provides information and advice on flowrate metering.

6.3 Maximum Rate Testing

Measurement of the wells maximum flowrate is sometimes an objective. These high drawdown flow periods are used to evaluate the following well parameters; wells open flow potential, production behaviour with wellbore pressure below bubble point (oil wells), rate dependent skin effects (gas wells), water coning or gas coning effects (oil wells), and solids production tendencies. The high rate flow period is also useful as an indication of the wells flowrate potential as a future producer.

Maximum rate tests if required should be carried out after the main reservoir data has been collected.

When considering any high rate testing it is of utmost importance that the well is produced in a safe and controlled manner and that none of the downhole, or surface equipment working pressures, flow or temperature limits are exceeded. This includes the temperature of the rig and its equipment due to radiant energy from the flare. For this reason, flare simulations for the maximum anticipated flow rate should be carried out. On HP/HT wells, consideration would also have to be given to the maximum BOP elastomer temperature and the flexible hose temperature when flowing at high rates. In addition, if the well is to be suspended or completed as a potential development well it is important that no lasting damage is done to the reservoir.

6.4 Permeability

<u>Horizontal</u>

This is normally calculated from the bottomhole pressure response measured by downhole pressure gauges.

The most accurate and commonly used method for calculating permeability is from a a pressure build-up with downhole shut-in carried out after a period of stable flow.

Horizontal permeability is used for calculating well productivity, comparison with core data, and as an input for reservoir simulation.

Vertical

Vertical permeability is usually different from horizontal permeability (in most cases vertical permeability is much less), even in a homogeneous formation.

Vertical permeability can be calculated from analysis of a vertical interference or pulse test. These permeability measurements are used to estimate the coning potential within the reservoir – often with the use of simulation models.

It is further discussed in (5) Earlougher, R.C., "Advances in Well Test Analysis".

6.5 Reservoir Pressure

The initial reservoir pressure can measured by MDT or RFT and can also be measured from an initial build-up period after a short flow at the beginning of the test. Reservoir pressure is also calculated from build-ups following later flow periods.

Comparison of reservoir pressure measurements between build-ups can be used to identify reservoir depletion. However, caution should be exercised in the interpretation of tight formations where supercharging may be present and this may lead to an erroneous interpretation of depletion.

Note: Operationally - extended MDT flow periods in high pressure wells could be considered a well control issue, as the reservoir sample is discharged into the well bore, with the potential for gas migration to surface without a string in the hole.

6.6 Samples

Hydrocarbons

Collection of representative hydrocarbon fluid samples is an important objective of a well test. Results from the analysis of these samples are used in many areas including: pressure transient analysis, estimation of in place volumes and recoverable reserves, evaluation of development and artificial lift strategies, sizing permanent production facilities and confirming reservoir pressure support requirements.

Typically representative samples can be collected as follows:

- Downhole sampling using a tool incorporated in the DST string.
- Downhole sampling using electric line, or slickline conveyed samplers.
- Collection of monophasic samples upstream of the choke manifold.

- Collection of recombination samples from the test separator.
- Collection of dead oil crude samples in drums for crude assay.

The quality of samples collected is crucial to the accurate evaluation of the fluid property data. To this end specific sampling procedures are detailed in Chapter 15 of the book.

Special precautions are required when shipping and handling pressurised samples, for details see Chapter 15.

Solids

Collection of samples of produced solids during stabilised flow periods is often important when field development is being considered.

Evaluation of produced solid samples is used for the following; completion design, including the requirement for gravel packing, calculation of maximum production rates, artificial lift strategy, surface facility design, estimating frequency of wellbore cleanout work.

Samples should be collected upstream of the choke manifold if possible, and solids concentrations in produced fluids calculated. This procedure should be carried out at each flowrate over which the well is produced.

Any wax found in any part of the test equipment should be noted on the test report. If wax is found, bottom hole samples should be taken to allow quantitative analysis. This is a specialist subject and advice should be sought from a specialist company.

Water

Collection of representative formation water samples if produced during the course of the test is important for the following reasons:

- Verification of reservoir water resistivity for input into log analysis calculations.
- Ionic analysis of water for compatibility studies and facilities design.
- Identification of potential scaling problems.
- Analysis for environmental considerations prior to disposal.

Formation water samples may be collected by the following methods:

- Surface sampling from the test separator, or upstream of the choke manifold.

- Reversing out of samples from the test string on completion of DST.
- Collection of bottomhole samples using electric line/slick line samplers.
- Prior to well testing using a Formation Tester (RFT / MDT).

The quality of samples collected may be crucial to the calculation of reservoir fluids in place and field development plans. To this end specific sampling procedures are discussed in Chapter 15 of the book.

Onsite Chemistry

Where the hydrocarbons are known or suspected to be sour, onsite chemistry must be considered. Substances such as H_2S, for example, are absorbed into the surface of sample bottles, thus evading subsequent quantitative analysis. However, special treated bottom hole samplers are available which absorb little or no H_2S. These samplers may not be available in all locations at short notice and some advance planning may be required in order to have them available for a test.

6.7 Zonal Contribution

Often well tests are conducted as a single test over a long or multi-zone interval. Within this interval large variations in porosity and water saturations may have been noticed during logging runs. If it is decided to test the whole interval in one test, information on individual zonal contributions / injectivity may be required.

This information will typically be gained by running a suite of production logging tools (PLT's). In some cases where more qualitative results will suffice it may be quicker and more cost effective to run a memory recording spinner with temperature and pressure probes on slickline.

For deviated or horizontal wells the PLT tools that are used have to be carefully selected. Often this may mean replacing the gradiomanometer with a radioactive type fluid density tool, which is not sensitive to deviation. In horizontal wells it may mean selecting tools that can provide a more comprehensive coverage of the entire pipe cross section, to account for the effects of phase segregation and stratified flow. Failure to select the correct tools will result in data being recorded, which is erroneous and unrepresentative of the fluid flow. In such circumstances advice should be sought from the local service provider.

Information gained from evaluating zonal contributions can be used for the following; identifying reservoir recovery factors, identifying economic production intervals, sizing stimulation and diverter treatments, identifying prospective injection intervals, identification of zones requiring isolation during permanent completion, and verification of cement bond integrity.

This Page Intentionally Left Blank

CHAPTER 7

TEST DESIGN

The design of the test must start early, normally at the time when the overall well test objectives are being set and well before the final decision to test. Preparation is the key to safe and successful well testing; because the design process is an iterative one involving the consideration of many small details it will always take longer than anticipated. A complex or critical test for example, on an HP/HT well, may take one year to plan. This is to allow for the long lead times on equipment and to ensure that any necessary rig modifications can be scheduled. However, even for routine well tests the planning should begin three months before the issue of the test programme, which will usually be sent out to partners one month before drilling through the reservoir section.

The overall conceptual test design must be carried out within the context of the well test objectives.

However, the design process will also involve the selection of the most appropriate testing equipment and services and it will ensure that these services can be mobilised at the correct time for the well testing operations.

Once the well is drilled and logged the final test design can be fine tuned for the particular test requirements.

Recommended Practices:

1. Tests should be kept as simple as possible whilst achieving the well test objectives.

2. Open hole testing should not be undertaken on floating rigs or on wildcat wells (see Section 7.9).

3. Barefoot testing may be carried out on all wells provided that the interval can confidently be killed at the end of the test. In all cases, the gas volume below the packer at the highest anticipated formation pressure must be able to be safely circulated out.

4. Premium tubing (e.g. VAM, NK 35 B etc.) connections should be run for well tests that could potentially flow gas to surface. Conventional drill pipe connections are not designed to be gas tight. Conventional drillpipe should only be used as the test string under certain circumstances (see Section 7.13).

5. There should be two valve isolation below or at the BOP in every test string, where possible these barriers should be tested in the direction of flow (see section 7.14).

Test Types

The following is not intended to be an exhaustive coverage of all of the types of well tests than can be undertaken. However, it provides an overview of some of the more commonly conducted tests and the reason for carrying them out.

7.1 Single Rate Oil Well Testing

This would normally consist of a flow schedule similar to that shown below.

- Initial flow period 5 –10 minutes
- Initial shut in period 60 minutes
- Main flow period – Clean up well, then flow for 6 hours stabilised flow
- Main Shut in (Pressure Build Up – PBU)
- Sample flow period

The initial flow period is designed to provide the best estimate of initial reservoir pressure. With the greater use today of RFT / MDT pressure measurements and sampling, this initial flow period is often now not carried out. The initial flow period can also yield erroneous initial reservoir pressure measurements, in tight formations, due to supercharging. In addition on problematic wells: waxy crudes. high pour point etc. this initial flow period is seldom carried out. It can be substituted by a separate clean up flow period or this may be incorporated into the main flow period.

The duration of the main flow period will be determined by the well test objectives. That is, if a specific radius of investigation is required from the test then the main flow period may have to be extended. One of a number of equations used for estimating the radius of investigation during testing, is shown in appendix A. It is commonly misunderstood that the radius of investigation is dependent on the well production rate, this is not the case.

The rate at which the well is flowed will again depend on the objectives of the test e.g. flow above the bubble point pressure or flow to obtain commercial rates etc.

The main shut in period is important for the analysis of reservoir transient pressure response; it should be of sufficient duration to allow analysis of all the pressure responses that results from flowing the well. In the absence of a surface pressure read out capability it should be about 1.5 times the duration of the main flow period.

A simple test such as this will provide information on well bore storage, skin, permeability (kh) and flow rates. More complex tests with multiple rates or extended well tests (Reservoir Limit tests) would be carried out only if specified by the Asset or Reservoir Engineering group.

7.2 Gas Well Tests

Most gas well tests usually consist of <u>at least two</u> flow rate periods. This is because on low production rate gas wells there may be a flow rate dependent skin, which can be identified by carrying out a second flow and build up period. This is in fact the simplest form of a deliverability test. In practice most deliverability tests would have four flow periods as shown in figures 7.1, 7.2. and 7.3.

A deliverability test is run in gas wells to determine:

- Inflow Performance Relation (IPR)
- Absolute Open Flow Potential (AOFP)
- Rate dependent skin (non-Darcy skin)

Inflow performance relation (IPR) relates the flow rate to the amount of pressure draw down.

Absolute open flow potential is the theoretical flow rate at which the well would produce if the reservoir sand face were at atmospheric pressure. This calculated rate is only of practical importance because the governments of certain countries set the maximum rate at which the well can be produced as a fraction of this flow rate.

Rate dependent skin is an additional pressure drop in the near well bore which varies with the flow rate; this will be reflected on the wells inflow performance.

There are three types of deliverability tests:

- Flow after Flow tests (Rate on Rate or Back Pressure Tests)
- Isochronal tests
- Modified Isochronal tests

Each of these tests is proceeded by a clean up flow period and build up.

Flow after Flow Tests involve flowing the well on successively larger choke sizes one after another without shutting the well in. The well is flowed on each choke size until stabilised. Chokes sizes are normally selected such that stabilisation can be obtained relatively quickly and the duration of each flow period is normally the same. This test is terminated with a long final build up. (Figure 7.1)

Isochronal tests consist of a series of flow periods, on successively larger choke sizes, each of equal duration. Each flow period is separated by a build up of sufficient duration to reach stabilisation. The final flow period is extended to achieve a stabilised flowing pressure for defining the IPR. The test is then terminated with a long build up. The isochronal test is an excellent test for high permeability and thick reservoirs, but it is time consuming and costly for low flow capacity reservoirs. (Figure 7.2)

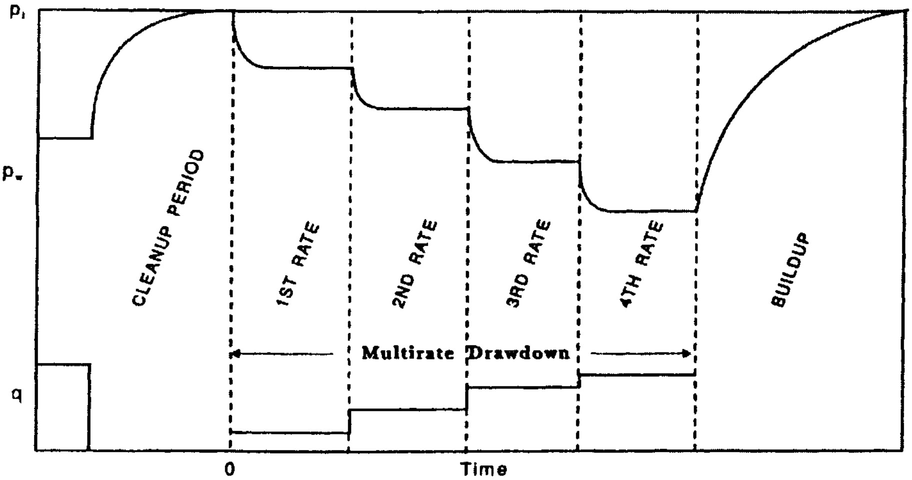


Figure 7.1 – Rate after Rate Test

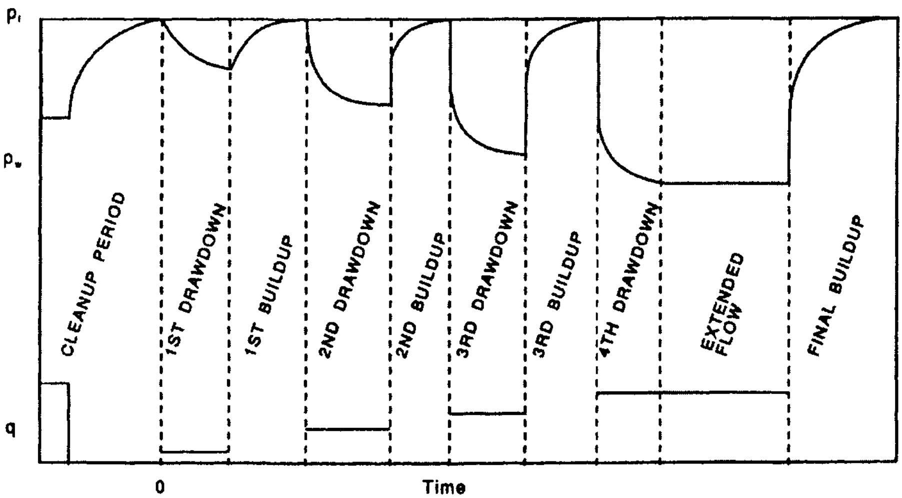


Figure 7.2 – Isochronal Test

Modified Isochronal tests are used on tight reservoirs where it would take too long for shut in pressures to stabilise. The modified isochronal test consists of flow periods (on successively larger chokes) and build-ups of equal duration, except the final flow period which is extended until the well is stabilised. The final build up is often continued until the initial pressure at the start of the extended flow period is reached. (Figure 7.3)

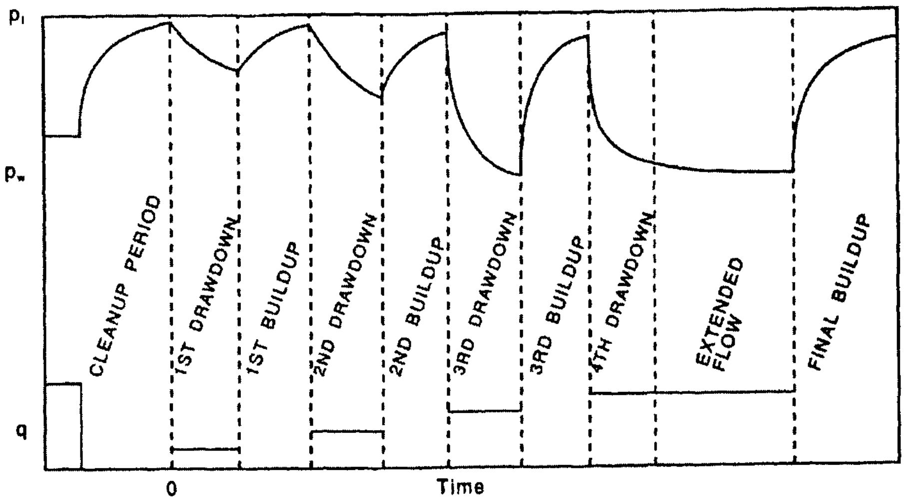


Figure 7.3 - Modified Isochronal Test

A basic gas well test may consist of only a single flow period and buildup which will yield the permeability thickness and total skin factor. It will however not allow the mechanical and non-Darcy skin factors to be separately determined, and thus does not allow deliverabililty calculations.

Often gas well tests are made unnecessarily long and complicated (e.g. isochronal testing). If the non-Darcy skin factor is required for input into deliverabililty calculations, then the flow/build-up/flow technique and analysis as described by Laurie Dake "Fundamentals of Reservoir Engineering"; section 8.11 may be used.

Use of a more complex testing procedure considerably lengthens the testing time and cost. Therefore, the additional information obtained must be valued against the additional costs of the operation.

Deliverability tests as described above are usually carried out over four distinct flowrates. However, if testing time is limited or there are surface equipment limitations, a three rate rather than a four rate test can be carried out. It should be noted however that reducing the number of flow periods will affect the accuracy of the deliverability relationship determined.

Careful consideration of the anticipated production rates should be made at the design stage of the test to allow a spread of data.

During gas deliverability testing as with other tests it is important that surface data is collected on a regular basis. Increases in LGR or CGR are particularly important as these may mean that the well is not staying clean of liquids during lower flowrates, or that the well is flowing below dew point.

For lower permeability tests, extended flow periods may be required to obtain representative samples at stable conditions.

Where it is known or suspected that the hydrocarbon will ultimately be gas condensate and that the bottom hole flowing pressure will fall below the dewpoint. A dedicated low rate sampling flow period should be considered before the main flow.

7.3 Transient Pressure Analysis

Transient pressure test analysis is not covered in this book, as there are many books available on this subject. However, it is worth noting that bottom hole shut in during a DST is often sought as it allows better determination of well bore storage effects. Moreover, downhole shut in helps prevents well bore storage effect from continuing into the middle and late time regions of the transient pressure response and possibly dominating that pressure response, with the effect that permeability and boundary information may be misinterpreted.

7.4 Artificial Lift Performance Testing

This section applies only to oil well tests. Frequently, discovery and appraisal wells are drilled into productive reservoirs than cannot flow to surface or cannot flow at a stable rate to surface. This is usually due to one of or a combination of the following reasons:

- Very low permeability
- Low initial reservoir pressure
- Heavy, viscous oil
- High initial water cut
- Very low solution gas/oil ratio
- Incorrectly sized tubing
- Formation damage

In these circumstances some form of artificial lift will be required to flow the well at a stable rate to surface.

The forms of artificial lifting that can be employed in DST's are nitrogen lift, electric submersible pumps, jet pumps and rotary pumps. The choice between these techniques will be based on the expected productivity of the well, production conditions such as GOR, equipment availability and whether the rig is fixed or floating. Environmental considerations may also dictate the choice of artificial lift method.

7.5 Aquifer Permeability and Mobility Testing

In certain oil and gas wells the behaviour of an underlying aquifer may be of interest.

In order that this can be examined a separate DST will be performed over an interval within the aquifer. This DST will normally be conducted in the same way as for a hydrocarbon producing interval. This means that a series of flow and build-up periods are conducted over the zone of interest. It should be noted that this type of test can only be reliably performed in an over-pressured reservoir.

Reliable samples are generally only obtained when a well can flow to surface long enough to fully clean the well of the completion fluid (mud or brine). It can be useful for the completion brine to be "spiked" with a tracer chemical so that the samples taken can be checked for contamination by the brine.

If the well is to be permanently abandoned or if a water zone can be plugged back later, it may be possible to add on a water zone to a hydrocarbon bearing zone (where normal pressures are found), in order to obtain water samples to surface.

7.6 Bare Foot Testing

Barefoot testing, where the packer is set inside the last string of casing is considered acceptable on all types of rigs, floaters and fixed structures. Special consideration must be given to the active sump volume below the packer to ensure that the well can be successfully killed at the end of the test. Consideration must also be given to the pressure regime, formation homogeneity and integrity, and hole condition. In all instances, the largest possible gas volume below the packer at the highest anticipated formation pressure must be able to be safely circulated out.

7.7 Slug or Closed Chamber Testing

Sometimes it is only necessary to evaluate the permeability and skin factor from a well test. This may be for development wells which have been cored and where RFT or MDT pressures have been measured.

The slug test or closed chamber tests allows results to be obtained without consuming much rig time.

Slug tests are used for wells that are unlikely to flow to surface (e.g. water injection wells or low pressure oil wells). The well is perforated usually with a nitrogen cushion, which is then bled off at surface. Bottom hole gauges measure the pressure build-up as the well dies and this data can be analysed for permeability and skin provided that the properties of the inflowing fluids are known.

A closed chamber test is similar to above, but as its name implies it is shut-in, usually at surface. This test is generally used for oil and water wells which will flow to surface. As long as the density and compressibility of the wellbore fluid are known only wellhead pressure gauges need be used. If the formation is of very high permeability, then analysis may not be possible because the build-up will be too quick.

The advantages of running these type of test are that they are both cheap and quick. The disadvantages are that only a small radius is investigated and no samples are usually obtained.

7.8 Injectivity Testing

When testing appraisal wells, additional information may be required which would not be required as part of a conventional well test on a discovery well. One such piece of information may be the determination of the ability of an underlying aquifer, or base layer of the oil reservoir to accept injected water.

An injectivity test will either be carried out following a conventional flow and build-up test on a producing zone, or as a separate zonal test. In either case it is important to try and encourage the well to flow prior to injecting water. This will allow the production of any dirty and solids laden fluids to surface prior to injection testing. It may also allow information on the zones pressure, permeability and skin factor to be gained. This information can then be used to estimate the maximum expected injection rates allowable in the well without exceeding fracture initiation pressure. It is critical during injectivity testing that fracture initiation pressure is not exceeded.

If the well does not flow to surface after perforating a new zone there are two courses of action. Firstly injection fluid can be bullheaded to the formation. This procedure will mean that any dirty fluids and suspended fluids will be pumped into the formation leading to a high skin factor. Secondly clean injection fluids can be circulated down the test string using a multi-reversing valve. This procedure will allow most of the dirty fluids within the test string to be displaced. The downhole tester valve is maintained closed during this operation. Careful calculation of fluid volumes can ensure that kill weight mud/brine is restored to the annulus as the injection fluid reaches the circulating valve.

The injectivity test itself should be carried out over a minimum of two stabilised flow rates, each below fracture pressure, followed by a pressure fall off with the well shut-in downhole.

During injectivity testing it is necessary to monitor the 'sand face' pressure continuously. In deep wells this should be done using downhole gauges, as correlations for friction pressure drops in the tubing will not be sufficiently accurate for quantitative analysis. For wells of less than 3,000 ft, corrected wellhead pressures can be used if downhole gauge rental is considered too expensive.

Samples of injection fluids should be collected during each injection period. These will be used to evaluate fluid specific gravity and sand face viscosity at downhole injection conditions.

7.9 Openhole Testing

Openhole testing is defined as any test where the packer is in direct contact with the open hole.

In general most prudent operating oil companies now have a policy that open hole testing may only be carried out on land and jack-up rigs, but not from floating rigs. Many operators also prohibit open hole testing on wildcat wells where reservoir parameters are not well known.

Openhole tests should generally not be considered for any of the following well types:

- High pressures (especially gas wells).
- Friable or weak formations.
- Long intervals (more than 20m).
- High productivity zones.
- High deviations.

7.10 Reservoir Limits Tests and Extended Well Tests

Long term testing of oil, gas or gas condensate wells is usually carried out separately from conventional DST's.

Conventional DST's can be used to gain parameters from which a long term test can be designed and implemented.

The main objectives of long term tests are usually as follows:

- Estimation of in place volumes from material balance calculations.

- Measurement of water or gas coning behaviour with respect to cumulative production and drawdown.
- Investigation of reservoir drive mechanisms.
- Investigation of possible reservoir boundaries.
- Early revenue from the field to fund development.

In most cases long term tests are carried out onshore in oil reservoirs where it is possible to obtain revenue from the sale of the produced oil. Offshore long term testing – extended well testing (EWT) is usually confined to situations where confirmations of certain reservoir parameters is vital to evaluate possible development options and these parameters cannot be ascertained from a conventional DST.

Long term tests are usually carried out with a completion in the well rather than using DST tools. For an onshore test the rig will often not be required on location. The tubing and downhole equipment can be run by a workover unit, which typically moves off location prior to commencing the test.

The time scale and data requirements of these tests will be set by the objectives of the test.

7.11 High Pressure High Temperature Testing (HP/HT)

High Pressure High Temperature (HP/HT) tests are typically defined as well tests where the bottom hole temperature exceeds 300°F and either the pore pressure exceeds 0.8 psi/ft or the required well control equipment exceeds 10000 psi working pressure.

Designing a test for these conditions requires rigorous procedures, uprated equipment and a great deal of time. It is a specialist subject normally undertaken by experienced consultants and space constraints prevent detailed coverage here. However, some useful information may obtained from (9) Institute of Petroleum, "Well Control during the Drilling and Testing of High Pressure Offshore Wells", Model Code of Safe Practices, Part 17.

7.12 Stimulation Techniques - Evaluation

Stimulation techniques may be used in either discovery, or appraisal well tests.

In discovery wells, stimulation treatments may be used when a prospective interval will not flow hydrocarbons after perforating. This will usually be as the result of low permeability and or severe near wellbore damage.

In appraisal wells, the effectiveness of the stimulation treatment will need to be evaluated. These well tests will normally be used to establish economic production rates from a well and evaluate the stimulation treatments.

Stimulation techniques can only be evaluated in the light of unstimulated performance. It is therefore of utmost importance that flow and build-up tests are conducted over the interval prior to carrying out a stimulation treatment.

Stimulation treatments should normally only be considered for cased hole tests, as stimulating open hole sections may result in possible well collapse and packer leaks.

Typical stimulations that are used to increase a well's productivity are:

- Matrix acidising – used to clean up near wellbore damage and to enhance near wellbore permeability.

- Acid fracturing – used to create a high conductivity channel in carbonate rocks giving an effectively enhanced wellbore surface area.

- Hydraulic propped fracturing – used to enhance effective wellbore surface area by providing a high permeability channel from the formation to the well.

- Chemical soaks for emulsion blocks.

Where possible stimulation treatments should be planned prior to the start of a well test as they may require special service DST tools and surface equipment.

All stimulation techniques involve additional risk. Therefore, a detailed stimulation programme should be formulated once any pertinent well information is obtained from the initial unstimulated well test.

7.13 The Use of Tubing or Drill Pipe for the Test String

The choice of tubulars for a test must be made early during the planning stage. For tests of normally pressured oil reservoirs drill pipe or tubing can be used.

For gas wells or HP/HT wells, only premium connection tubing is recommended.

However gas tight drill pipe does exist and currently there are two commercial sources of gas tight drill pipe specially designed for use during DST's. These special drill pipe products are available from Mannesmann and from Grant Prideco. Guidelines for use of these products for DST's would be similar to premium tubing, provided proper qualification and inspection is performed.

Factors that should be considered in choosing tubulars for a test, include:

- Safety
- Hydrocarbon type expected
- Reservoir conditions – pressure and temperature
- Hydrogen sulphide likelihood and expected concentration
- Regulations in the country of operations
- Availability
- Cost

In general it is recommended to use tubing for testing of both onshore and offshore wells and it must always be used when dealing with gas wells, H_2S, or HP/HT wells.

Circumstances when it is acceptable to use drill pipe are:

- Where no hydrocarbons are allowed to flow to the surface, i.e. a slug test or where the well is shut in downhole before the entire cushion has flowed to the surface. This applies to all offshore wells and onshore wells in unknown hydrocarbon areas.
- A known hydrocarbon area where there is no reasonable expectation of the well flowing to surface under natural drive. This applies to offshore and onshore wells.
- When testing oil wells with low pressure and low GOR. In this context low pressure is taken to be a WHSIP of less than 3000 psi and low GOR is less than 350 scf/stb. This is applicable only to onshore wells in known hydrocarbon areas.

NOTE: Conventional drill pipe does not have a gas tight seal (except for the 'special gas tight drill pipe' mentioned above) and the interference fit of a standard drill pipe connection relies on pipe dope to affect a seal, the dope is quickly removed during gas flow and consequently should not be used for gas tests or high GOR oils where there is likely to be a free gas fraction. Also high GOR oils often have solvent properties, which can attack and dissolve the pipe-dope that seals the drill pipe threads.

7.14 Two Valve Isolation

It is recommended to have two valve isolation below or at the BOP in test every string. One of these valves may be a downhole tester valve provided it is permanently in place. Thus tools that can be removed from the string during testing are not considered as isolation tools in this context. The other valve will normally be some form of safety valve.

On land wells both valves can be in the test tool section of the string. On jack-up rigs the second valve should be in the tubing string, the best position being approximately 15 metres below the sea bed. With floating rigs the (SSTT) sub-surface test tree will normally be the second isolation valve.

Tubing retrievable ball valves may be employed as one of the isolation valves on jack-ups and land rigs. However, when mechanically actuated test tools are being used, a TRBV hung in the BOP's is not recommended as it can become caught in the ram pockets while functioning the test tools.

Note - The two valve isolation requirement is sometimes relaxed, at local operating company discretion, on land operations in areas that are known to be unable to support hydrocarbon flow to surface and for slug or closed chamber testing.

Where wireline or coiled tubing operations are planned, the SSSV or SSTT should be capable of cutting the wire or tubing.

7.15 Well Preparation

- Prior to running the test tools, the final string of casing or a liner will normally be run, cemented and cleaned out according to the detailed casing or liner running programme. Consideration must be given to the required sump to accommodate TCP gun drop, wireline work and sand production.

- Before finally POOH, the pipe rams should be function tested and the mud thoroughly conditioned to ensure all cuttings are removed from the hole.

- The CBL/VDL/CCL/GR suite of logs perhaps with a CET, USIT or similar, should be run over the testing interval. Provided the bond logs are satisfactory and sufficient time has elapsed since cementation, the casing and or liner should be pressure tested to a predetermined test pressure. If annulus pressure operated testing tools are to be used, the test should establish that the maximum pressure required to actuate the tools (usually the SHORT or RD) can be contained in the casing – so called 'positive' (leak off) or casing pressure test. Pressure is applied to the casing or liner either directly from surface or in the case where a liner has been run by setting a retrievable packer on drill pipe above the overlap and applying pressure to the liner via the drill pipe.

- In addition, a so called 'negative' or inflow pressure test of the casing/liner overlap may also be required. A simple test string consisting of pressure gauges a retrievable packer with a tester valve, reversing valve and collars is run into the well on the drill pipe. The packer is set in the casing above but close to the liner overlap. The string is either run in with sufficient cushion so that when the tester valve is opened a predetermined pressure draw-down is applied to the overlap, or an underbalanced fluid is circulated into the string after the packer is set.

  Normally an inflow test is only required when it is envisaged that a drawdown will be applied to a liner overlap during the test programme.

  For example, if a well has been completed with 2 liner strings, 5" and 7" and the test programme has been designed such that a 7" packer will be run and set in the 7" liner above the 5" by 7" overlap. Quite obviously then the 5" by 7" overlap will "see" a pressure drawdown during testing, whereas the 7" by casing overlap will not. In this case it would normally be considered acceptable to only inflow test the 5" by 7" overlap during the preparatory phase.

- Should the bond logs and pressure tests indicate that remedial cementation is required, a separate programme will have to prepared and approved before the work is undertaken. Pressure testing of the casing will have to be repeated and satisfactory results obtained before continuing with the well testing programme.

7.16 Zonal Isolation

It is recommended that one DST interval should be isolated from another using a bridge plug or cement retainer and cement.

Both the bridge plug or retainer and the cement plug should be tagged and pressure tested to at least the leak off / casing test pressure.

It is not always possible to use the above method if the interval between zones is small. In this case it is recommended that two bridge plugs be used, rather than relying upon one only.

7.17 Well Test Planning Considerations - Check List

There is a great deal to be considered when planning a well test, particularly an offshore test.

To aid those involved in the planning phase of a test a "Well Test Planning Considerations / Check List" has been included in Appendix B.

CHAPTER 8

COMPLETION (PACKER) FLUIDS

The choice of completion or packer fluids for a completion or well test must normally be made early so that arrangements can be made to have the correct fluid available when required.

The choices for completion fluid are normally drilling mud or brine. There are a number of factors that must be considered in selecting a completion fluid and these are discussed below.

Recommended Practices:

1. The stability of the completion fluids should be checked for well tests which will take a long time, or which have high pressures / temperatures.

2. It should be ensured that the completion fluid is compatible with the perforating underbalance cushion fluid.

3. Compatibility tests with the completion fluid and any 'soft' goods such as packer elements and seals should be carried out whenever there is any doubt about the compatibility of the products.

4. If brine is used to avoid perforating skin damage, the brine should be filtered to an irreducible minimum of solids. In addition, pits and associated pipe work should be thoroughly cleaned.

8.1 Cost

It is generally cheaper to use drilling mud for a packer / completion fluid, but the increased likelihood of formation damage can make this choice unacceptable. Brines should be used for formations that are sensitive to formation damage by fine solids.

8.2 Formation Pressure

Up to a formation pressure of 10.5 – 11.5 ppg equivalent, brine can be used fairly cheaply (i.e. sodium chloride and calcium chloride). Above about 11.5 ppg the cost increases significantly with increasing density as more expensive chemicals are required to "weight-up" the brine such as in the case of sodium bromide and calcium bromide brines. All calcium based brines should however be checked for compatibility with the formation waters.

As the density requirements of the brine system increases even more exotic and considerably more expensive chemicals are required (i.e. Zinc Bromide). In the case of the UKCS, special HSE dispensation is required from the regulatory authorities for operations which wish to use Zinc Bromide. An alternative to Zinc Bromide which does not require HSE dispensation is Cesium Formate, however this is probably the most expensive of all the brine systems currently available. Figure 8.1 shows the typical stock solution density and maximum density for various brines.

It becomes markedly cheaper to use mud with barite beyond 11 ppg. However, consideration must be given to the pressure/temperature stability of the system i.e. unwanted crystallisation, mud gelation, barite drop out etc.

Table 8.1 Density of Brines

Brine	Stock Solution (ppg)	Maximum Density (ppg)
Fresh Water	8.33	-
KCl	-	9.7
NaCl	9.9	10
NaCOOH	10.9	11.1
$CaCl_2$	11.6	11.8
NaBr	12.5	12.8
KCOOH	13.2	13.3
$CaBr_2$	14.2	15.5
$CaCl_2/CaBr_2$	15.1	-
CsCOOH	19.7	20
$ZnBr/CaBr_2$	19.2	20.5

8.3 Formation Temperature

As temperature increases, brine quality is generally not impaired, although the density changes markedly.

However, many problems have been encountered with water based mud at high temperatures. As the temperature increases the ability of the polymer gels to hold the barite reduces and other gelling agents have to be used, such as bentonite. This phenomenon occurs between 250°F and 275°F for most natural polymers and between 300°F and 350°F for most synthetic polymers. Moreover too much bentonite leads to solidification and if this is not engineered properly it can result in the drop out of the solids and cause a stuck test string. It is recommended that oil based mud be considered at higher temperature conditions in place of water based mud. Recently, however, mud companies have undertaken significant research into high temperature water based systems (for environmental reasons) and these should be reviewed.

8.4 Fluid Deterioration with Time

For extended test durations even oil based mud will allow some solids settlement. If too much barite settles there is a high probability of the packer and lower test string becoming stuck. In these circumstances it is better to use a suitable brine formulation, and to consider the use of a permanent packer and stinger.

The static ageing properties of muds must be considered in detail during the planning of HP/HT well tests, if mud is to be used as a packer fluid. The poor performance of mud systems for HP/HT testing has encouraged a number of operators to perform HP/HT test with underbalanced packer fluids. In some cases sea water has been used, however, this results in very large differential pressures across the well bore packer and possibly the liner lap. Before planning an HP/HT test with a sea water packer fluid, significant research and procedural HAZOPs will be necessary in order to satisfy all concerned that the procedures are in place to deal with all eventualities.

8.5 Overbalance Perforating

If casing guns with a pressure overbalance are to be used it is often better to use a clean brine rather than mud in order to reduce formation damage.

8.6 Underbalance Perforating

When an underbalance perforating cushion is used, it should be ensured that it is compatible with the completion fluid. If diesel is used it may react with the mud causing barite drop out; in this case the base oil for the mud should be used. With brine in the hole, diesel or base oil can be used and there will be no mixing problems.

8.7 Skin Damage

Formations are frequently susceptible to skin damage, although this is by no means always the case. In these circumstances it is normally advisable to use clean filtered brine.

For brine it is important that the completion fluid is cleaned or filtered prior to use. There is no point in using expensive brine unless the fluid is filtered to remove debris, which could damage the formation. Additionally the pits and rig lines through which the brine will flow must be cleaned and or flushed.

Skin will also be reduced by perforating underbalanced by using TCP's or through tubing guns.

This Page Intentionally Left Blank

CHAPTER 9

PERFORATING

The selection of a perforating technique can be a critical factor in the successful testing of a well. It is therefore important to plan early so that the most suitable equipment will be available when required.

This chapter describes the major features of the various perforating techniques that may be considered. However when selecting a large perforating interval for a DST, it may be prudent to leave a space in the middle of the interval, for future workovers or PLT's to determine zonal contribution if the well is to be kept.

Recommended Practices:

1. Wireline perforating with large underbalances should be avoided so as not to blow the guns up-hole and potentially birds nest the wireline. (Use < 200 psi)

2. Although it is possible to run 2 1/8" OD strip jet carrier guns through 2 ¼" ID test tools, <u>this is not recommended</u>. After firing the guns, the strips can bend and it may become impossible to retrieve the guns through the mule shoe. Consideration should also be given to the maximum burr height when selecting hollow carrier guns to ensure that they can be safely retrieved.

3. Underbalances in excess of 1000 psi are unnecessary and should not be applied. Research by Schlumberger has determined that no further benefit is obtained above this figure (Reference (7) Halleck, P.M., Deo, M., SPE Paper No. 16895).

4. TCP guns should be run with a redundant firing head.(e.g. pressure activated and drop bar)

5. In the event that a pressure activated TCP gun fails to fire within the expected time frame, wait a further hour. Following this, re-apply tubing pressure up to the maximum allowable within pressure testing constraints. Should the guns fail to be fired hydraulically then use the redundant firing mechanism, for example a drop bar.

   If a drop bar is used and becomes stuck in the tubing and cannot be fished, these live guns should not be pulled back through the rotary table. In such cases, the guns should be dropped, using tubing severance if required.

   In all other cases the recovery of live guns from a well should be undertaken in accordance with the TCP contractors procedures. However, it is recommended that all TCP systems should be run with a 20' safety spacer between the firing head and the guns to provide protection for personnel in the event of recovering live guns.

9.1 Casing Gun Perforation

Features

- Wireline conveyed.
- Overbalanced technique - which can sometimes lead to skin damage as a result of well bore fluids entering the perforations.
- Simplest perforating technique to carry out in practice.
- Can fire a selection of different shaped charges ranging from deep penetrating with a narrow entrance hole to shallow penetrating with a large entrance hole.
- The guns can perforate in various phases for example 60 degrees, 90 degrees etc.
- High shot density may be useful for sand control.
- Short exposure time for the explosives to high temperatures in hot wells.

9.2 Through Tubing Perforation

Features

- Wireline conveyed.
- Underbalanced technique with full pressure control equipment.
- Run through the DST string or completion on wireline, therefore restricted in size to fit through the drift ID of the string.
- Charges are small; therefore the perforating performance is commensurately less than that of casing guns.
- Short exposure time for the explosives to high temperatures in hot wells.
- Two principle gun types: Metal Strip and Scalloped Tube.

  Metal Strip –

  Generally the strip charge guns have better performance than the similar sized scalloped guns that are capable of passing through the small test tool ID's. However, because of their open design the strip guns can result in perforating debris being produced into the tubing string, which can also occasionally plug up the surface choke.

Scalloped Tube –

Scalloped guns that may be used during a DST tend to have smaller charges than the comparable strip guns and therefore poorer performance. However, one advantage is that the bulk of the perforating debris is contained within the gun.

- Pivot guns although not applicable where DST tools are being used, are small enough to run through 2 3/8" tubing. These guns have a 0 degree and 180 degree phasing and performance comparable with most casing guns.

9.3 Tubing Conveyed Perforation (TCP)

Features

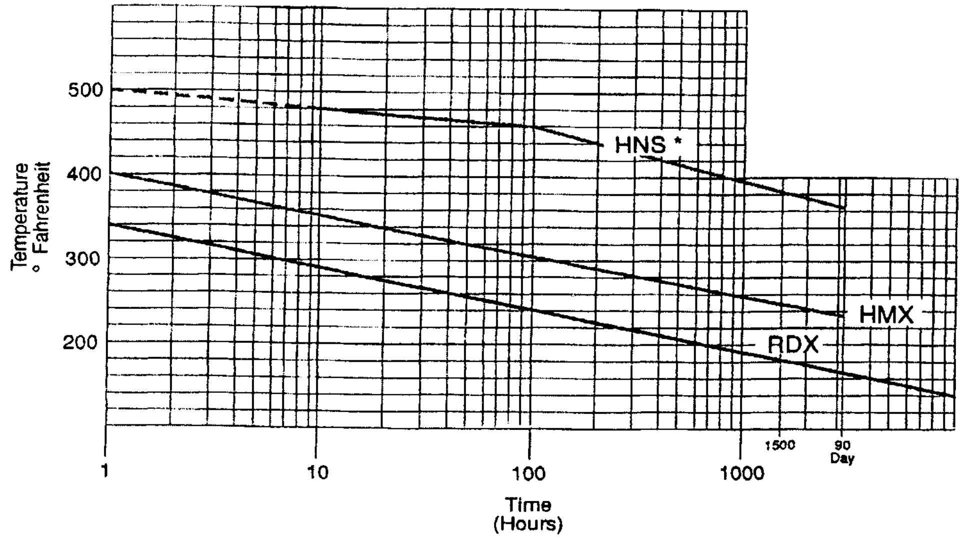
- Tubing or drill pipe conveyed.
- Underbalanced technique with test string in place.
- Can perforate large intervals underbalanced in one run.
- Large perforating charges and high shot densities can be used, increasing exposed sand face open to flow. Useful when sand production may cause a problem.
- Guns can be dropped off after perforating if sufficient rat hole exists and subsequent wireline runs across the perforations may be made (e.g. PLT or to add on perforated intervals).
- Depth control can be slightly more difficult than with wireline conveyed techniques and requires a separate wireline correlation run with a GR/CCL.
- TCP charges are often exposed to high bottomhole temperatures for a number of days. Some charges are more resistant to long term high temperature exposure than others. Figure 9.1 provides a guide to the length of time a given charge can be kept at a given bottomhole temperature before degradation occurs.

  There is a further high temperature explosive type known as PYX, which is not shown in figure 9.1, however this has similar performance to HNS.

  In all cases check with the supplier or manufacturer before selecting explosives, particularly in the case of high temperature wells.

  For extreme high temperature wells the gun system may have to be qualified by laboratory tests for the bottom hole temperature and duration of a planned well test.

TIME TEMPERATURE RATING FOR EXPLOSIVES



* Requires Special Hardware and clean gun practices

Figure 9.1

Courtesy of Schlumberger

9.4 Tubing Conveyed Perforating (TCP) Firing Heads

TCP guns can be detonated using a variety of firing heads. The basic types of firing head commonly available are listed below:

- Absolute pressure firing head – this requires an applied tubing pressure to initiate a detonation sequence. This system incorporates a variable time delay mechanism to allow bleeding down of tubing pressure prior to the guns firing. (Figure 9.2)

- Differential pressure firing head – this requires a set differential pressure between the annulus above the packer and the rathole to initiate a detonation sequence.

- Drop bar firing head – this requires a bar dropped or run on wireline from surface. Detonation results from mechanical impact of the bar on the firing head.

- Electric line firing head – this requires a signal from a wet connect electric line tool to detonate. A robust pressure gauge can be run in association with the wet connect to confirm detonation.

- Slickline activated firing head – this requires a fishing neck on the firing head to be latched with a slickline tool and jarred up or down to detonate.

- Slickline conveyed retrievable firing heads - where one of the above firing head types is run in the hole on slickline and latched into a receptor after the guns are on depth and the packer is set. In some operations this may provide enhanced safety. (Figure 9.3)

It is strongly recommended that a combination of two firing heads is run so that if one firing system fails another can be tried without pulling the string. It is common to run a hydraulic firing head (usually absolute pressure type) as the primary mechanism, with a mechanical firing head (typically a drop bar) as the backup.

So called 'dual firing or multiaction systems' allow combinations of firing mechanisms to be run together to provide redundancy, an example of such a system is shown in figure 9.4.

Detonation Interruption Devices:

A detonation interruption device (DID) provides an additional safety measure when using tubing conveyed perforating guns. These devices consists of a eutectic metal which is a solid at surface and near surface temperatures preventing pressure from being transmitted to pressure activated firing heads. As the TCP gun is lowered into the well bore and the temperature increases the eutectic metal changes from a solid to a liquid. When the guns are on depth pressure may then be transmitted to the firing head.

The detonation interruption devices are available in a range of temperature to suit various well bore environments.

SAFETY NOTE:

Live TCP guns should not be brought back through the rotary table if a drop bar becomes stuck in the tubing and cannot be fished. In such a case, the guns should be dropped, using tubing severance if required.

HALLIBURTON

Time-Delay Firer

Description

The Time-Delay Firer (TDF) allows under- or overbalanced perforating through the use of a pressure-actuated firing head with a time-delay fuse. The delay fuse allows 5 to 7 minutes for adjusting the actuating pressure in the tubing to achieve the desired pressure before firing the guns.

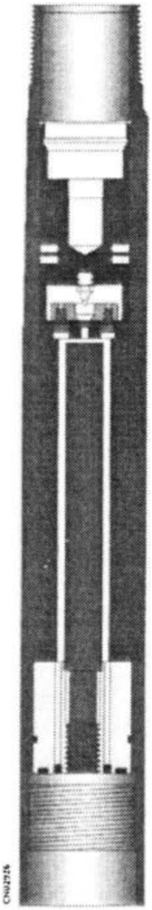
Features and Benefits

The TDF

- allows independent perforating of selected zones
- allows maximum use of under- or overbalanced pressure
- can be run in heavy mud systems
- can be used with full-opening or non-full-opening tools
- reduces cost by allowing the running of multiple guns without gun spacers
- is ideal for production completions, drillstem testing, and dual completions
- is recommended for running on the top and bottom of gun assemblies
- allows additional time-delay elements as needed for increasing delay time

Operation

The TDF is run with a predetermined number of shear pins for specific well conditions. The tubing is pressured to the maximum actuating pressure slowly. The maximum pressure shears the pins in the shear set and forces the firing piston into the primer. The primer ignites the pyrotechnic delay fuse. The delay fuse burns for a predetermined time (between 5 and 7 minutes) depending on the bottomhole temperature, and then detonates the perforating assembly.



Time-Delay Firer

Firing Head

Figure 9.2

Time-Delay Firer			
Thread Size and Type in. (mm)	1 $^7/_{16}$ (36.51) 8 UN-2 B box x 1.315 (33.4) NU-10 Rd pin	1.90 (48.26) EUE 10 Rd pin x 2 (50.8) 6 P Acme box	2 $^7/_8$ (73.03) EUE 8 Rd pin x 2 $^7/_8$ (73.03) 6 P Acme box
Assembly Number	993.01200	993.1330	993.1270
Maximum OD in. (mm)	1.688 (42.88)	2.50 (63.5)	3.375 (85.73)
Minimum ID in. (mm)	N/A	N/A	N/A
Maximum Operating Pressure psi (bars)	17,000 (1170)	24,000 (1655)	13,000 (895)
Minimum Operating Pressure psi (bars)	2,200 (150)	4,000 (275)	4,000 (275)
Flow Area in.^{2} (cm^2)	0.64 (4.13)	N/A	N/A
Temperature Rating °F (°C)	425 (218) for 100 hours	415 (213) for 100 hours	350 (176) for 350 hours
Tensile Strength lb (kg)	56,000 (25 400)	160,000 (72 500)	220,000 (99 700)
Burst Pressure psi (bars)	N/A	N/A	N/A
Collapse Pressure psi (bars)	20,000 (1380)	30,000 (2070)	30,000 (2070)
Overall Length ft (m)	2.25 (0.69)	1.89 (0.58)	2.0 (0.61)

These ratings are guidelines only. For more information, consult your local Halliburton representative.

HALLIBURTON®

Figure 9.2 (cont.)

HALLIBURTON

Slickline-Retrievable TDF Firing Head

Description

The Slickline-Retrievable TDF (time-delay firer) Firing Head is a combination of two assemblies: the slickline- retrievable firing head and a 1 $^{11}/_{16}$-in. TDF firing head. It is a pressure-actuated firing head with a built-in pyrotechnic time-delay assembly.

Features and Benefits

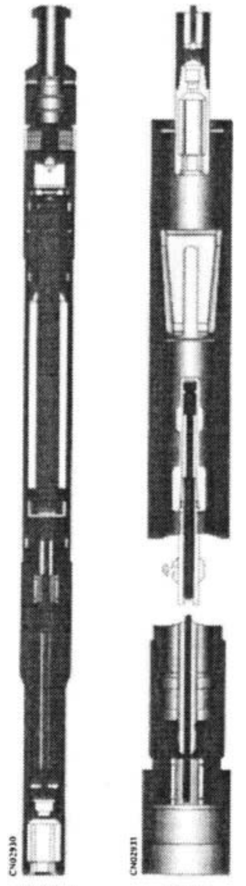
The Slickline-Retrievable TDF Firing Head

- allows the guns to be run in the hole without any type of firing mechanism installed
- allows the retrieval and reinstallation of a malfunctioning firing head without pulling the guns
- allows greatly reduced actuating pressures of the firing head because the firing head does not have to be in place when the guns are run

Operation

This firing head does not have to be run until after all pressure testing has been done and the heavy fluids have been displaced, which allows a reduced actuating pressure for the firing head.

This assembly allows the operator to run guns in the hole on the end of tubing without a firing head. This assembly can be run in on slickline and attached to the firing head after the tubing is in the hole. It can also be retrieved on slickline.



Slickline-Retrievable TDF Firing Head *Stinger Assembly*

Firing Head

Figure 9.3

Slickline-Retrievable TDF Firing Head	
Thread Size and Type	N/A
Assembly Numbers	993.01069 Firing Head - Slickline Retrievable 993.01200 TDF 993.1034 Stinger Assembly
Maximum OD in. (mm)	1.688 (42.88)
Minimum ID in. (mm)	N/A
Maximum Actuating Pressure psi (bars)	17,000 (1170)
Minimum Operating Pressure psi (bars)	2,200 (150)
Flow Area	N/A
Temperature Rating	Determined by explosives
Tensile Strength	N/A
Burst Pressure	N/A
Collapse Pressure psi (bars)	23,000 (1590)
Overall Length (1 delay fuse) ft (m)	3.83 (1.17)
Additional Fuses Length (each) ft (m)	0.87 (0.27)

These ratings are guidelines only. For more information, consult your local Halliburton representative.

HALLIBURTON®

Figure 9.3 (cont.)

HALLIBURTON

Multiaction-Delay Firing Head

Description

The Multiaction-Delay Firing Head is a pressure-actuated redundant firing system that can be run with any one of several other firing heads.

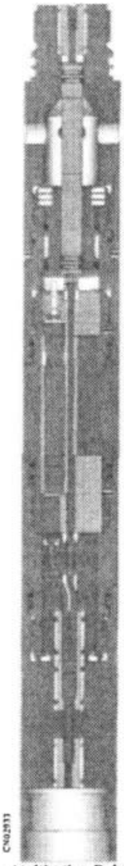
Features and Benefits

The Multiaction-Delay Firing Head

- allows the use of a redundant firing head without having a firing head on the bottom of the gun string
- allows multiple redundancy when a multiaction firing head is placed on both the top and bottom of the gun string
- allows operators to postpone the decision of whether to use the bar drop or pressure side of the firing head as the primary firing mechanism
- allows use of additional delay elements

Operation

One side of the multiaction firing head will always be pressure actuated. The other side of the firing head may be a bar drop-type head or another pressure-actuated firing head. Either side of the firing head may be used as the primary or backup firing system.



Multiaction-Delay Firing Head

Firing Head

Figure 9.4

Multiaction-Delay Firing Head		
Thread Size and Type in. (mm)	$2\frac{3}{8}$ (60.33) 6 P Acme box x pin	$2\frac{7}{8}$ (73.03) 6 P Acme box x pin
Assembly Number	993.01362	993.01351
Maximum OD in. (mm)	3.10 (78.74)	3.375 (85.85)
Minimum ID in. (mm)	N/A	N/A
Maximum Operating Pressure psi (bars)	18,000 (1240)	25,000 (1725)
Minimum Operating Pressure psi (bars)	4,000 (275)	4,000 (275)
Temperature Rating	Determined by explosives	Determined by explosives
Tensile Strength lb (kg)	170,000 (77 100)	201,000 (91 100)
Burst Pressure	N/A	N/A
Collapse Pressure psi (bars)	22,000 (1515)	29,000 (2000)
Overall Length ft (m)	3.68 (1.12)	3.68 (1.12)
Makeup Length	3.41 (1.04)	3.41 (1.04)

These ratings are guidelines only. For more information, consult your local Halliburton representative.

HALLIBURTON®

Figure 9.4 (cont.)

This Page Intentionally Left Blank

CHAPTER 10

DOWNHOLE TEST EQUIPMENT

This chapter provides an overview of downhole test equipment from the bottom of the hole to the wellhead for onshore tests and from the bottom of the hole to the mudline for offshore tests.

The text of this chapter has been prepared using the generic names of the various types of downhole test tool. This approach has been adopted because of the great diversity of DST tools currently on the market and because the nomenclature used to describe these tools varies from company to company. Furthermore, the specification and usage of such tools is continually changing, so a review of the principals of such tools is considered more appropriate that a detailed review of the specifics. The most recent product specifications should be obtained from the service companies at the start of the well test planning process to augment the principals described here.

However, the general principals of operation of the various Drill Stem Test (DST) tools are similar and they function in one of two ways, namely:

a) Movement of the string - rotation or reciprocation
b) Applied Pressure.

In each of the following sections an explanation of the usage of the different types of DST tools is given. In addition, possible applications for these tools are discussed and some example DST strings have been included.

Recommended Practices:

1. Two reversing valves should be used in a test string which operate by different means (e.g. annulus pressure, tubing pressure, string reciprocation). Annular pressure operated circulatory valves should not be used in open hole.

2. Prior to the first test all drill collars to be used should be drifted, rattled and measured with a steel tape, then put aside.

3. For HP/HT test, consideration should be given to using drill collars which have a ring groove for an o-ring to be fitted at the shoulder or alternatively use drill collars with premium connections. Premium connections are the preferred option.

4. All tubing or drill pipe to be used for the test, including pup joints and crossovers, should be drifted and measured with a steel tape.

5. The dimensions of all downhole equipment to be used during the test should be measured and recorded prior to the test. An equipment schematic complete with OD & ID and length of each component should be produced. All downhole equipment should be drifted.

6. A safety joint should always be run above a retrievable packer, in case the packer gets stuck and the string has to be backed off. At least one of the gauge carriers should be run above the safety joint to ensure recovery of the gauges. In heavy mud systems, the use of a safety joint may also be prudent when testing with a permanent packer.

7. A radioactive pip tag for TCP depth control should be run in the liner or casing and correctly located, above the uppermost test interval taking the position of closed valves, etc. in the test string into account. A radioactive pip tag should also be placed in the test string.

8. If there is any likelihood of H_2S during the test, the correct tubing should be used (i.e. L80) and also H_2S compatible slickline/wireline should be used. (refer to section 4.9 Hydrogen Sulphide, NACE MR0175-99 Sour Criteria)

10.1 DST (Drill Stem Test) Concepts

The drill stem test string is used to carry out flow tests on prospective hydrocarbon bearing zones. The string serves the purpose of providing isolation of three different pressures: (See Figure 10.1)

- Hydrostatic Pressure (P_h)
- Formation Pressure (P_f)
- Cushion Pressure (P_c)

During testing the hydrostatic pressure in the annulus must be isolated from formation and cushion pressure to allow a formation to flow to surface.

The packer provides isolation of the hydrostatic pressure (P_h) from the formation pressure (P_f) and the tester valve isolates the cushion pressure (P_c) from the formation pressure (P_f)

Clearly the cushion pressure (P_c) < formation pressure (P_f) in order for flow to occur. This is normally achieved in one of two ways: a lighter density fluid is introduced into the string at surface as it is run in the hole and the tester valve supports this column of fluid. Alternatively the lighter density cushion fluid is circulated into the string via a multi-operation circulating valve.

A classical DST string is shown in figure 10.2. and the sub sections which follow, describe using their generic names the purpose and general principals of operation of the various tools in the string.

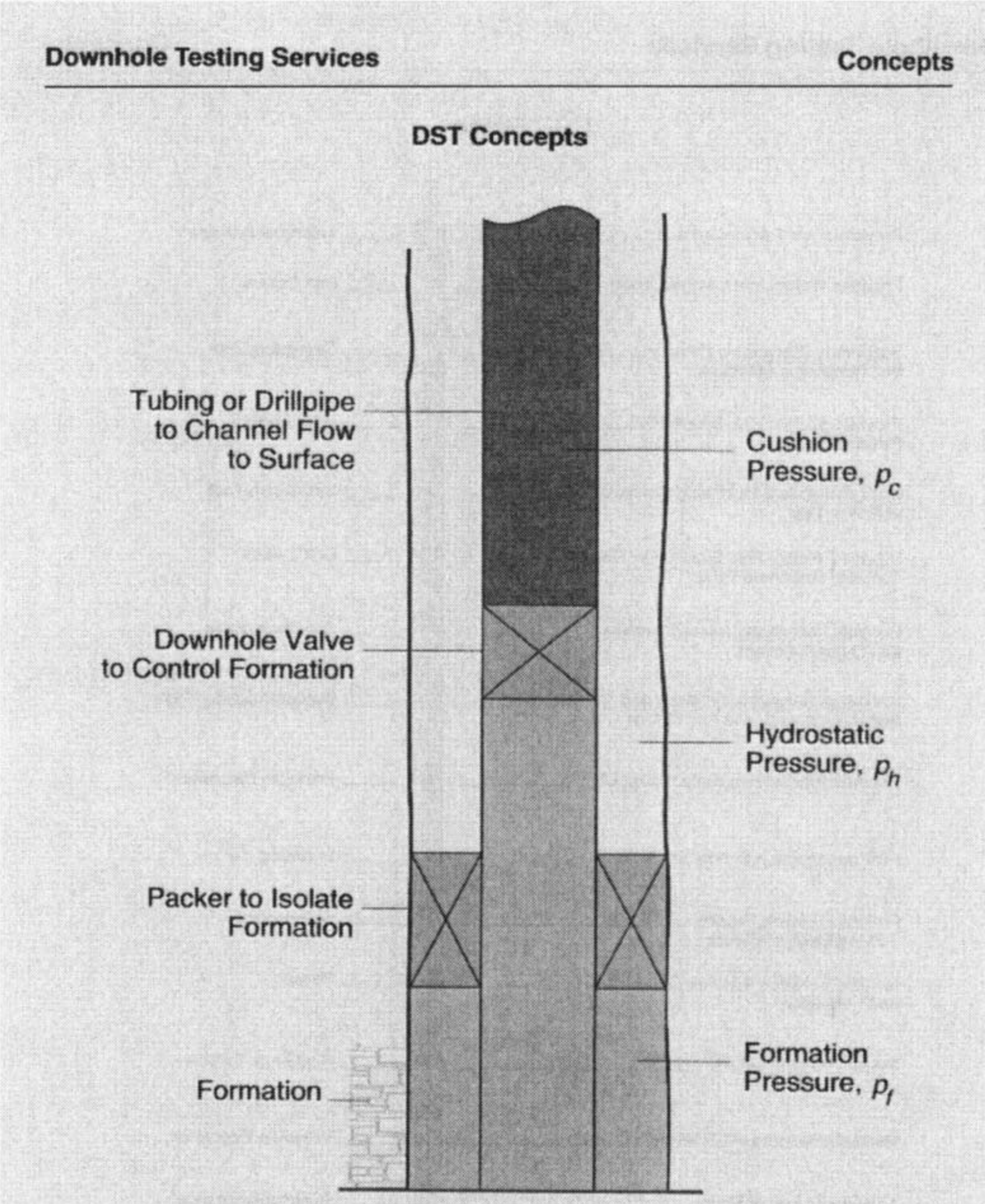


Figure 10.1

Courtesy of Schlumberger

DST String

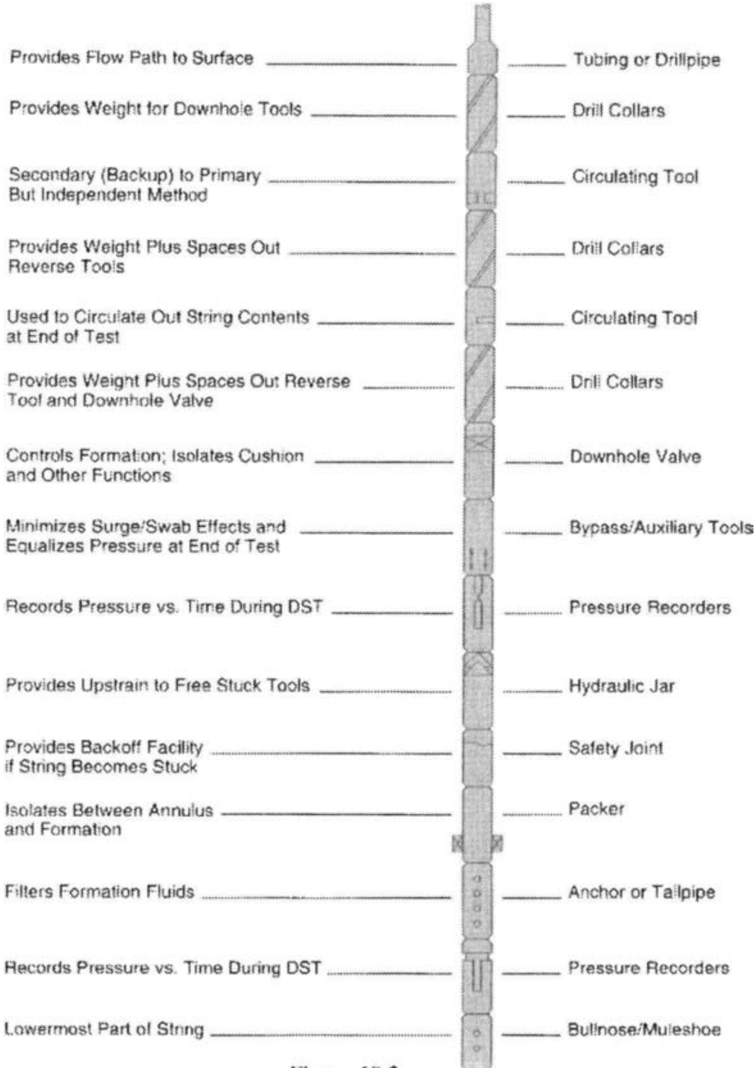


Figure 10.2

Courtesy of Schlumberger

Broadly speaking there are four types of DST: Open Hole, Cased Hole, Bare Foot and Zonal Isolation tests. (See Figure 10.3)

The DST string design for each of these types of tests will vary considerably.

However, the basic premise of DST string design is; "keep it simple".

Start the design with nothing more than a packer and add in those components necessary to meet the test objectives, provide flexibility of operations and meet the safety requirements of the test.

DST string design is however a specialist task, as there are many items to be considered such as well control, functionality and flexibility of operations.

The service companies can usually provide assistance with the design of DST strings. However, some in-house expertise or engineering consultancy services will be required to ensure that the string meets all the possible requirements of the test and complies with the operating oil and gas companies well control procedures.

Figure 10.4 to Figure 10.9 provides examples of various DST string configurations, which may assist the reader of this book with the design of DST strings.

At the end of this chapter, the DST tool nomenclature for many of the Schlumberger and Halliburton tools is given. Although other manufacturers and services providers exist, the author considers that providing this information gives a fairly wide coverage of the DST tool market.

NOTE: Most standard DST tools are 5" O.D. and 2.25" I.D. Slim hole versions of many of the tools exist, e.g. 4.68", 3.9", 3.75", 3.25" and 3 1/8" O.D., however availability and suitability of these tools must be checked with the service provider.

Downhole Test Strings **Types of Drillstem Tests**

DST Types

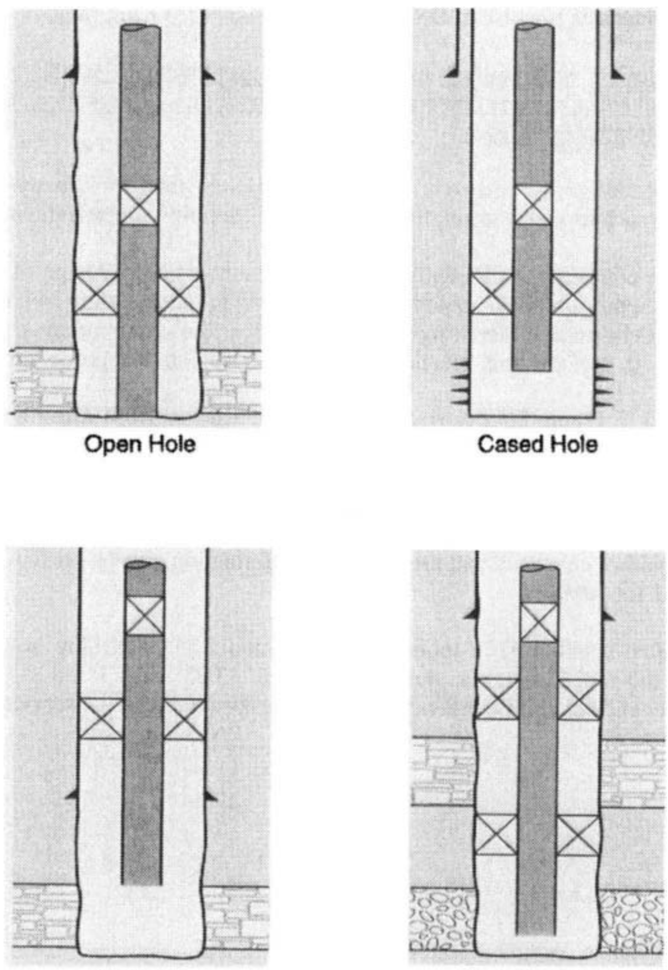
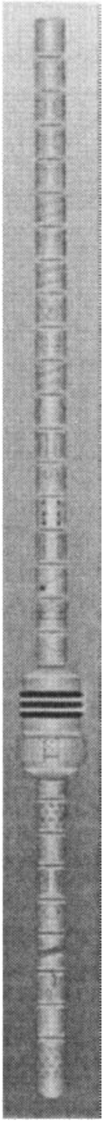


Figure 10.3

Courtesy of Schlumberger

Proposed 10,000 psi Retrievable DST String

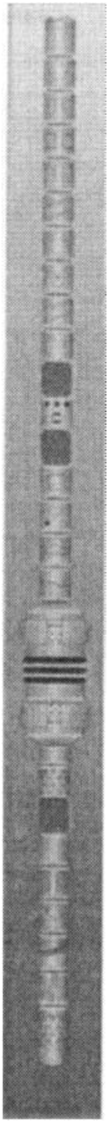


Description	O.D.	I.D.	Length
3-1/2 PH6 x 3-1/2" IF X-Over	5.00	2.25	2
Slip Joint	5.00	2.25	28
Slip Joint	5.00	2.25	25
Slip Joint	5.00	2.25	23
5 Stand. Drill Collar	4.75	2.25	450
S.H.O.R.T.	5.00	2.40	2.82
1 Stand. Drill Collar	4.75	2.25	90
RA Marker Sub	5.00	2.25	2
M.C.C.V.	5.00	2.25	7
1 Stand. Drill Collar	4.75	2.25	90
L.D.C.A.	5.00	2.25	11
M.S.R.T.	5.00	2.25	8
P.C.T.	5.00	2.25	23
H.R.T.	5.00	2.25	6
Gauge Carrier			
T.F.T.V.	5.00	2.25	6
JAR	5.00	2.25	6
Safety Joint	5.00	2.25	2
7" Packer	5.75	2.25	7
Perforated Tailpipe	3.67	2.44	10
2-7/8 EUE Tubing	3.67	2.44	30
Gun Release Sub	3.67	1.79 / 2.37	2
Ported Sub	3.67	2.44	2
2-7/8 EUE Spacer Tubing	3.67	2.44	As req'd
Hydraulic Firing Head (H.D.F.)	3.67	1.55	10
4-1/2" Safety Spacer	4.50	---	11
4-1/2" TCP Guns	4.50	---	As req'd
Bull Nose	4.50	---	1

Figure 10.4

Courtesy of Schlumberger

Proposed 10,000 psi Retrievable DST String

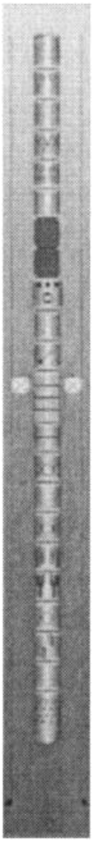


Description
3-1/2 PH6 x 3-1/2" IF X-Over
Slip Joint
Slip Joint
Slip Joint
5 Stand. Drill Collars
S.H.O.R.T.
RA Marker Sub
2 Stand. Drill Collars
Riser Tubes
D.G.A.
I.R.D.V.
D.G.A.
F.A.S.C.
T.F.T.V.
JAR
Safety Joint
9-5/8" Positrieve Packer
Perforated Tailpipe
D.G.A.
2-7/8 EUE Tubing
Gun Release Sub
Ported Sub
2-7/8 EUE Spacer Tubing
Hydraulic Firing Head (H.D.F.)
4-1/2" TCP Guns
Bull Nose

Figure 10.5

Courtesy of Schlumberger

10k Production DST String

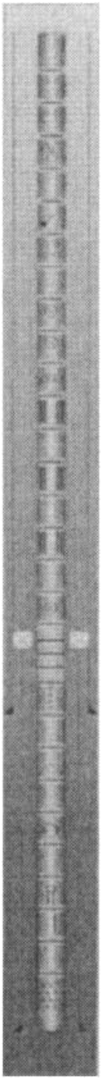


Description
Tubing
S.H.O.R.T.
1 Joint Tubing
RA Marker Sub
M.C.C.V.
1 Joint Tubing
L.D.C.A. (LINC)
D.G.A.
I.R.D.V.
1 Joint Tubing
T.F.T.V.
G Locator and Seal Assembly 7" Baker Permanent Packer
Seal Bore Extension
Circulating Sub
Tubing Joint
Circulating Sub
Gun Release Sub
Shock Absorber
Ported Sub
Firing Heads
Safety Spacer
HSD Guns
Bull Nose

Figure 10.6

Courtesy of Schlumberger

Proposed 15,000 psi Production DST String



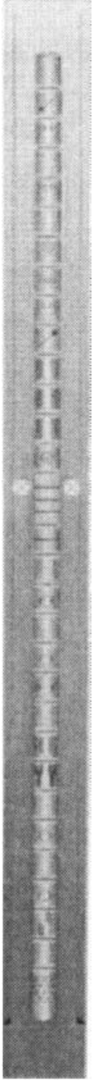
Description	O.D.	I.D.	Length
3-1/2" PH6 Tubing	3.50	2.55	
S.H.O.R.T.	5.00	2.25	3
S.H.O.R.T.	5.00	2.25	3
RA Marker Sub	5.00	2.50	2
1 Stand. 3-1/2" PH6 Tubing	3.50	2.55	90
T.F.T.V.	5.00	2.25	6
M.C.C.V.	5.00	2.25	8
1 Joint 3-1/2" PH6 Tubing	3.50	2.55	30
P.T.S.V.	5.00	2.25	5
P.C.T. with Hold-Open	5.00	2.25	24
P.O.R.T.	5.00	2.25	7
Gauge Carrier			
1 Joint 3-1/2" PH6 Tubing	3.50	2.55	30
Gauge Carrier			
1 Joint 3-1/2" PH6 Tubing	3.50	2.55	30
Gauge Carrier			
1 Joint 3-1/2" PH6 Tubing	3.50	2.55	30
P.T.V. (Pipe Tester Valve)	5.00	2.25	4
G Locator (3-1/2" PH6 Box) and Seal Assembly (2-7/8" EUE Pin)			
2-7/8" EUE Ported Pup	3.67	2.44	6
2-7/8" EUE Tubing	3.67	2.44	30
Drop Sub	3.75	1.791 / 2.44	2
2-7/8" Pup Joint	3.67	2.44	6
Debris / Ported Sub	3.67	2.44	1
2-7/8" EUE Tubing Joints	3.67	2.44	30
Redundant TCF Firing Head	3.67	1.6 NOGO	11
H.D.F. Firing Head	3.38	---	6
Safety Spacer	3.38	---	11
3-3/8" TCP HSD Guns	3.38	---	100
Bull Nose	3.38	---	1

Figure 10.7

ARR-DRT-0003 February 1994

Courtesy of Schlumberger

High Pressure High Temperature DST String Design with TCP Guns



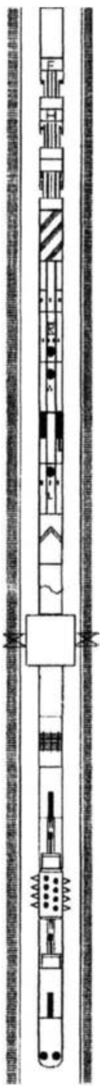
Description	Rupture Disc Settings (psi)
3-1/2" PH6 15.8 lbs/ft Tubing	
Tubing Fill Tester Valve (TFTV)	1500
Single Shot Reversing Tool (SHORT)	4000
3-1/2" PH6 15.8 lbs/ft Tubing Stand.	
Single Shot Reversing Tool (SHORT)	4000
3-1/2" PH6 15.8 lbs/ft Tubing Joint	
Pressure Controlled Tester Valve (PCT) with Hold Open	2000
Pressure Operated Reference Tool (PORT)	1500
Single Shot Reversing Tool (SHORT)	5000
Pump Through Flapper Safety Valve (PFSV)	3500
Gauge Carrier c/w Amerada Gauges	
DST Gauge Adapter (DGA) c/w 3 WTQR/WTSR	
DST Gauge Adapter (DGA) c/w 3 WTQR/WTSR	
(Pipe Tester Valve (PTV)	Opens running in hole
Seal Locator and Seal Assembly 7" Permanent Packer with 4" bore	
Seal Bore Extension	
Tubing Pup Joint	
Circulating Sub 2-7/8" EUE	
Tubing Joints (as required)	
Flow Sub 2-3/8" EUE	
1.87" F Nipple	
2-7/8" EUE Tubing Joint (Gauge suspension)	
Gun Release Sub 2-3/8" EUE	
Shock Absorber	
Tubing Pup Joint 2-3/8" EUE	
Flow Sub	
Blank Sub	
Flow Sub	
Dual Hydraulic Delay Firing Heads	
Safety Spacer	
TCP Guns	
Bull Nose	

Figure 10.8

Courtesy of Schlumberger

HALLIBURTON®

Company : Esprit Petroleum Technology Well :
Company Rep : Field :
Operator : Area : North Sea
Country : U.K.



Description	Minimum I.D. Inches	Maximum O.D. Inches	Length Feet
3 1/2" Tubing	2.54	4.500	30.00
Slip Joint (Open)	2.25	5.030	24.95
Slip Joint (Half Open)	2.25	5.030	22.45
Slip Joint (Closed)	2.25	5.030	19.95
Drill Collars			30.00
RD Circulating Valve	2.25	5.030	4.00
Express Circulating Valve	2.28	5.030	31.35
SELECT Tester Valve	2.25	5.030	23.87
Gauge Carrier	2.25	5.375	29.53
Multi-mode Pressure Test Valve (MPV)	3.50	7.000	13.66
Big John Jars	2.30	5.000	5.14
7" Safety Joint	2.25	4.870	3.66
7" CHAMP Packer	2.37	5.870	8.23
Tubing	2.44	3.660	30.00
2 7/8" Ported Flow Sub	2.25	3.670	1.00
3.375" TDF Time Domain Firing Head		3.375	1.85
Detonation Interruption Device		3.375	1.17
4 5/8" Vannguns		4.625	22.72
Detonation Interruption Device		3.375	1.17
3.375" TDF Time Domain Firing Head		3.375	1.85
Ported Bull Plug		3.500	0.50

Figure 10.9

DST STRING COMPONENTS:

10.2 Bull Nose / Mule Shoe

The bull nose is run on the DST string to aid its passage into the well, this is more of a consideration in open hole testing

A mule shoe is run on the end of the string to assist with the re-entry of wireline tools into the string, such as PLT tools and through tubing guns.

10.3 Gauge (Bundle) Carriers

Gauge carriers should generally be run above the packer for DST strings, which incorporate TCP guns. The packer helps to absorb the shock from the perforating guns, which can damage the gauges. Consideration should however be given to the placement of the carriers if run above the packer to ensure they are below any slip joints as movement of the carrier during flow and buildup may invalidate the data. However, when testing with a permanent packer with a floating seal assembly there is no option other than to have the gauges floating if they are to be positioned above the packer. Although consideration could be given to a ratch latch system if carrier movement is deemed to be critical to the acquisition of quality data.

Below packer gauges carriers are acceptable when there are no TCP guns and their position is fixed because of the packer, even if slip joints are used. However, it would be prudent to include a carrier above the packer in case the packer becomes stuck. Below packer carriers can normally only be run with retrievable packers.

The gauge carrier pressure rating should be checked prior to use because there are many types available on the market with different ratings. They should also be drifted prior to use as they often have the smallest internal diameter in the test string and sometimes the bore is eccentric.

Additionally the effective outside diameter of the carrier on rotation will have to be considered for offset carriers, if there is a requirement to rotate the string e.g. setting the packer.

Gauge carriers are sometimes prone to pressure leaks at the seal between the gauge and the gauge carrier. For this reason they should be pressure tested with the gauges installed on surface before running them in the hole.

The shorter length (newer) gauge carriers should be run in preference to the longer ones, as the shorter ones are easier to handle on the rig.

10.4 Debris Sub

A debris sub is run in DST strings where a mechanical or electric firing head is used to fire tubing conveyed perforating guns. The sub prevents solids gathering around the firing heads when running in the hole and carrying out pressure tests. The brittle barrier in the debris sub is broken by a drop bar or on contact with wireline tools.

10.5 Gun Release Sub

In wells where production rates are expected to be high or additional perforations are anticipated or where production logging below the test string may be required it is necessary to be able to release the TCP guns. This may increase the area available to flow and will allow access to the perforated interval with wireline tools.

There are a number of gun release types available, such as outo release or mechanical release. The requirements for gun release will be dictated by the anticipated forward programme for the well test.

However, a gun release sub should only be run if sufficient rat hole is available below the perforated interval to accommodate the full length of the dropped items.

10.6 Shock Absorbers

Shock absorbers should be run where possible on DST strings, which incorporate TCP guns. The lateral and vertical shock absorbers will reduce the transmission of mechanical shock energy to the downhole gauges at the time of perforating. The use of a shock absorber is particularly important if high accuracy quartz gauges are being used as these are more prone to shock failure that strain gauges or sapphire gauges.

When perforating long intervals damage to the packer may also occur if shock absorbers are not run. In addition, there have been a few isolated cases where the shock from TCP guns have caused single shot rupture disc tools to fail also.

10.7 Perforated Joint

The perforated joint is run below the packer on DST/TCP strings where there is no plan to drop off the guns. The perforated joint allows the entry of hydrocarbons into the tubing string but will also filter out any large debris.

Certain debris subs also have long slot ports which have an effective flow area greater than that of the tubing string and these can be used instead of a perforated joint.

Where there are open perforations and pressure activated TCP guns are being used the perforated joint may be substituted by a production valve.

10.8 Packers

Open Hole Conventional

The simplest type is where the bullnose of the DST string is sitting on the bottom of the hole and the packer is isolating the zone to be tested from zones higher up in the open hole section.

In this case the packer rubber is extruded to seal against the formation by slacking off the required amount of drillstring weight onto the packer.

Open Hole Inflatable

For zones where permeable formations are indicated above and below the zone of interest packers must be set to isolate both of these zones from the zone to be tested. This is typically achieved by using inflatable type packers in the test string. These packers are typically inflated by wellbore fluids using a pump located on top of the packer assemblies. This pump is run by rotating the drillstring at surface at a critical speed for a certain period of time.

Cased Hole Retrievable

These differ from open hole packers in that sets of slips are located above and below the sealing elements. The slips allow all the string weight to be slackened off on to the packer and the load is transmitted to the casing, drill collars are used for additional weight. Depending on the make of packer it may be possible to set, pull and reset the packer several times before retrieving the packer and redressing it at surface.

Cased hole retrievable packers are usually available with full bore thus allowing access for wireline and electric line tools.

Note: - Some older retrievable packers will unseat if used for injection tests.

Newer packers include a hydraulic hold down device designed to automatically activate whenever tubing pressure exceeds annulus pressure. When this occurs the hold down buttons are pushed out against the casing wall by the differential pressure created.

Permanent

During DST's permanent packers with seal bore extensions are normally used in higher pressure or sour well environments. These packers can be set either hydraulically on pipe or on wireline using an explosive charge setting tool.

Using a permanent packer the requirement for slip joints and drill collars (usually IF connections) is removed thus reducing the number of places where leaks may occur.

In addition, the test string is less likely to get stuck if using a permanent packer than a retrievable packer.

For an HP/HT test a 40 ft seal bore extension would be considered normal to ensure that a good seal is maintained and that string expansion is accounted for. However, detailed tubing movement calculations should be performed for TCP gun firing, flowing, buildup and well kill scenarios. See appendix G and H.

Packer Selection

Retrievable cased hole packers with differential pressure ratings of 10,000 psi are common and indeed 15,000 psi differential pressure rated retrievable packers are now available.

In general in a cased vertical hole where the reservoir pressure < 5000 psi and little losses have occurred in the course of drilling of the reservoir section, there should be little concern in running a retrievable packer.

At reservoir pressures between 5,000 – 10,000 psi greater consideration may be required before using a retrievable packer, e.g. losses during drilling, well kill, H_2S, (potential leak paths – slip joints, drill collars) etc.

The track record of 15,000 psi rated retrievable packers is still limited, therefore in most cases a permanent packer is recommended for > 10,000 psi reservoir pressure.

Permanent packers are usually preferred in deviated wells due to potential difficulties in obtaining the required rotation and set down weight on a retrievable packer.

10.9 Tubing Test Valve

This valve is run to pressure test the tubing and BHA as it is run in hole. The choice of placement in the string may be driven be a requirement to protect the gauges from the pressure cycles that occur during pressure testing. The placement could also be driven by a requirement to keep the rupture disk on the tubing test valve some distance above the packer, because of fears of barite drop out in the annulus. There may also be a requirement to pressure test the connections below the tubing test valve. This will necessitate making up the packer and the components below the tubing test valve as a sub assembly and pressure testing before sending to the rig.

In any event once the string has been tested, the tubing test valve is then be locked open for the rest of the test, by applying annulus pressure.

The two main categories of tubing test valve are manual fill or automatic fill. The manual fill tubing test valves require the string to be filled either from the top or after it is run into the hole using a circulating valve. The automatic fill tubing test valves, fill the string with the well bore fluids while they are run in the hole.

10.10 Safety Joint

A safety joint must be run immediately above a retrievable packer. This allows the majority of the test string (including pressure recording tools) to be retrieved in the event that the packer becomes stuck. The safety joint usually has a coarse left hand thread allowing it to be backed off relatively easily. When backed off the tool is usually designed to leave a standard fishing neck for easy washover with fishing tools run on drill pipe.

Ensure that the size of the fishing neck is known and that the correct fishing tools are available.

10.11 Hydraulic Jars

Hydraulic jars are run in the string above a retrievable packer. The jars allow the DST equipment to be hydraulically shocked. The additional force exerted on the packer is often sufficient to allow recovery of the lower part of the test string if it has become stuck.

10.12 Relief Valve and Bypass Tool

This tool allows fluid to bypass the packer when it is being run in the hole. On slacking off weight onto the packer the bypass is closed.

On pulling the string, tension in the tool first opens the bypass allowing pressure to be equalised across the packer elements. Further opening relieves the pressure inside the packer elements allowing them to deflate. These tools have on a few occasions been jolted open when TCP guns are fired, causing tubing – annulus communication. As discussed above, a shock absorber should be used when large intervals are to be perforated with TCP guns.

10.13 Tester (Downhole Shut In) Valves

<u>Annulus Pressure Operated</u>

This type is used in cased hole. The tool requires an applied annulus pressure to open. Without annulus pressure the valve stays in or returns to the closed position. Different features and refinements to this type of valve exist, such as hold open modules which allow the annulus pressure to bled off and the valve remains open.

The tool is primarily used for downhole shut in and in some cases, but not always, for pressure testing the string. When used as a downhole shut in valve it's function is to reduce the well bore storage effects to a minimum.

Many service companies prefer to supply an independent hydrotesting valve (tubing test valve) for pressure testing the tubing while running in the hole. Moreover, some operating oil and gas companies consider the tester valve as a safety device and therefore do not allow repetitive pressure testing to take place against the valve and for that reason always run tubing test valves in the string.

High Pressure – High Temperature

During high pressure – high temperature (HP/HT) testing there is an increased risk of solids fall out from the mud. This can lead to valve operating problems, it is therefore recommended that the tester valve should be locked open whilst running in hole and maintained open until required. This lessens the number of operations of the tools and increases the chances of the tool working.

Reciprocating Operated Tester Valves

These valves are opened and closed by string reciprocation. An indexing system within the tool allows it to be locked in either the open or closed position with the successive movements of the string. These tools are not recommended for operations from floating rigs.

This tool can be used for pressure testing the string as it is run into the well, for shutting in production downhole, shutting in the well to allow the opening of a reversing valve and in some cases it can be used to trap a downhole fluid sample.

10.14 Surface Read Out (SRO) Subs

These SRO subs are run in the DST string above the tester valve to provide real time surface read out of pressure and temperature data from below the tester valve. They are primarily used to examine the prerssure buildup data with a view to possibly terminating the buildup earlier. (Figure 10.10 shows an example)

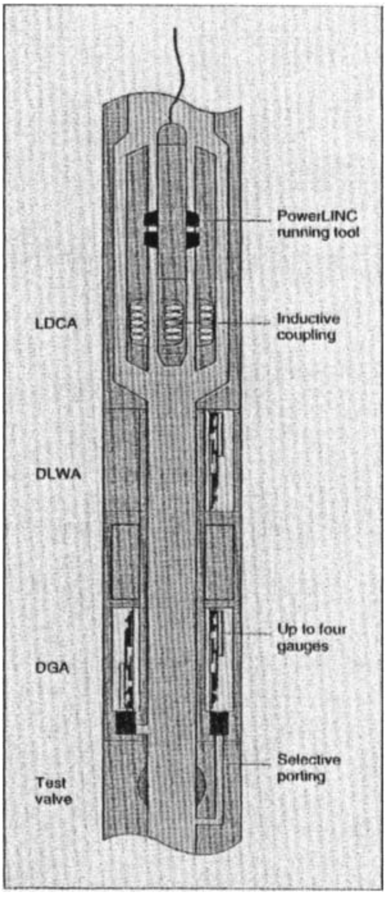
These systems usually consist of a number of sections:

- A gauge carrier / adapter section which allows pressure to be read below the tester valve, above the tester valve and in the annulus.

- A flow barrel with a latch mechanism into which an SRO tool is latched, this section provides an effective flow area equivalent to or greater than that of a standard 2.25" I.D test tool when the SRO running tool is in place. The method of data transfer from the gauges to the SRO tool can either be via an electrical wet connector or more commonly now by an inductive coupler.

- SRO running tool which latches into the flow barrel latch and makes an electrical or inductive coupling with the pressure gauges. Data is then transmitted to surface via a mono conductor cable to a surface data acquisition system.

DataLatch* DGA



Description

The DataLatch tool is the scaleable gauge carrier of the Universal Pressure Platform for downhole recording or surface readout during DST/TCP operations.

The DGA (DST Gauge Adapter) can hold up to four gauges of the Universal Pressure Platform, providing complete redundancy. The gauges can be ported to record the annulus pressure, pressure above the test valve, or pressure below the test valve. During surface readout operations the DGA is run in conjunction with the PowerLINC system.

The PowerLINC Latched Inductive Coupling is the center of the communication system. It transmits power and signals through a unique electromagnetic coupling that requires no electrical contact. In surface readout all the features and benefits of the DataLatch tool can be used.

- fullbore
- any combination of quartz/sapphire sensors
- complete redundancy
- reliable PowerLINC communication system
- cable in hole only during shut-in
- data for complete test
- reprogram of gauges
- power the gauges with PowerLINC, if needed.

Specifications (DGA + DLWA + LDCA)

Temperature rating	175°C
Pressure rating	
Differential	15,000 psi
Tubing, annulus	20,000 psi
Maximum OD	5.0 in.
ID	2.25 in.
Make-up length	
DGA + DLWA	10.8 ft
LDCA	10.9 ft
Tensile strength	350,000 lbf
Shock environment (TCP)	Class 6†
Service	H_2S, acid

PowerLINC running tool

Temperature rating	175°C
Pressure rating	15,000 psi
Maximum OD	2.0 in.
Make-up length	8.9 ft
Service	H_2S

*Mark of Schlumberger
†Summary of Class 6 specification tests along all three axes:
• Vibration: 10 to 185 Hz, 20 mm, 3 times per axis
• Shock: 500 g, 2 msec, 3 times per axis
Full details of these tests available on request

SMP-4561 (7/95)

Figure 10.10

Courtesy of Schlumberger **Datalatch* DGA Mark of Schlumberger**

Note:

Problems have occasionally been encountered with some SRO latching systems if used while flowing the well. That is, solids production from the well can build up in and around the latch and sometimes over the rope socket, making recovery of the running tool difficult.

If use of the tool is restricted to 'shut in periods only' then the tool can be run into the well after the tester valve has been closed, in soft latch mode (on floaters) or with the dogs removed completely from the running tool.

The advantage of using SRO during a test is usually linked to reducing the length of the time required for the final buildup. Therefore unless there is a specific requirement to obtain bottom hole flowing data throughout the test, running the tool during the buildup only is a much safer option.

10.15 Radioactive Marker Sub

A sub containing a radio active marker or pip tag is often included in cased hole DST strings above the downhole tester valve. This tag is clearly visible when running a gamma ray correlation log and will aid accurate depth correlation of the TCP guns.

The radioactive marker sub is usually run in combination with a radioactive tag in the casing to facilitate space out. It is especially useful if the formation gamma ray shows little character or if very many drill collars are being run causing the gamma ray response to be greatly attenuated.

10.16 Drill Collars

These are required during testing with a retrievable packer to add weight to the string to aid packer setting. Typically for a 9 5/8" retrievable packer about 20,000 lbs set down weight is used and for a 7" retrievable packer about 16,000 lbs is used. These set down weight requirements are however dictated by the equipment type and operating conditions occurring at the time of the test. Further, considerations will include the type of packer (manufacturers data), hydraulic hold down or not, casing weight, well pressure, packer fluid, requirements for stimulation and hydraulic actuation of TCP guns.

Drill collars normally have drilling threaded connections (I.F.) rather than premium threads and this can lead to leakage. 'O' rings can be added to drill collars to improve there sealing ability, however drill collars with premium threads should be sought.

Drill collars often have problems with internal drift due to their method of manufacture and from scale build up from their use during drilling. They should be thoroughly cleaned, drifted and then put aside prior to use during testing.

10.17 Slip Joints

Slip joints are usually run in DST's where the string is fixed in two points (e.g. the packer and the wellhead). Slip joints allow an amount of stroke while maintaining a pressure seal between the annulus and the tubing. The use of these joints in the string will compensate for thermal expansion or contraction of the string during production, stimulation and injection testing. The number of slip joints required should be calculated prior to running the string based on the amount of tubing movement expected. See Appendix G and H.

On spacing out the test string prior to setting the packer the required stroking of the slip joints should be checked.

Slip joints can often be the cause of leaks, so consideration should be given before using them particularly on high pressure tests.

The materials of the slip joint seals should be compatible with the brine used and the the expected operating temperatures in the well.

10.18 Reverse Circulation Valves

<u>Single Shot Pump Out</u> (e.g. SHORT / SORTIE, RD)

These valves works by shearing out of ports in the tool, by the application of internal or external pressure to the string.

Single shot reversing valves allow permanent communication between the tubing and the annulus. The pressure required to shear open these valves is set higher than the operating pressures of any other valves in the string e.g. the tester valve or the multi-reversing valve. This is done so that the one time reversing valve is not sheared out early in the test causing unscheduled abandonment of the test.

<u>Multi-Reversing Valve</u>

Depending on the service provider these valves can either be operated by cycling the pressure of the annulus or the tubing a number of times. An indexing system governs the number of pressure cycles required to open and close the valve.

The multi-reversing valve will stay open when annulus or tubing pressure is bled off and is normally closed by circulating through it above a specific rate.

Depending on the specific tool design the multi-reversing valve will normally allow a number of tubing pressure tests before the valve opens.

These valve can be cycled open and closed repeatedly throughout a test. This function allows it to be used for spotting fluids down the teststring as well for the final killing of the well.

Note, that if a tubing pressure activated multi-reversing valve is run in the string without a downhole tester valve, then the differential required to close the circulation valve could fracture the formation, however this is reasonably unlikely.

Drop Bar - Single Shot Reversing Valve

These valves are seldom used now, but this type of valve is opened by dropping a bar from surface. The bar impacts on shear plugs and these plugs then break off opening paths to the annulus and allowing reverse circulation.

10.19 Cross Overs

Sufficient crossovers for all pieces of test equipment including backups must be available on site. The crossovers must be checked to ensure that they have the correct internal diameter and are manufactured from the correct material. Over the years there have been many cases where cross overs have been manufactured with smaller internal diameters than the 2.25" bore of the test tools and this has led to difficulties when attempting to run wireline tools through the string. Similarly there have been cases where locally manufactured x-overs have been produced from sub standard materials and these have failed sometimes catastrophically during pressure testing of the string.

If there is free rig time, for example whilst waiting on cement, it is a good practice to make up the crossovers to the testing equipment. This reduces the time needed to make up and run in the hole with the complete test string.

10.20 Tubing / Drill Pipe Connections

Standard (5" O.D.) DST tools are manufactured either with standard drill pipe connection (3 ½" I.F) or a premium thread connection (3 ½" PH6 or 3 7/8" CAS).

As detailed in section 7.13, the use of tubing for testing of most wells is a requirement and drill pipe should only be used in a few specific cases. Caution should however be exercised prior to the use of any 'look a like' premium connection tubing as this may lead to a requirement to manufacture a considerable number of cross overs.

NOTE: All gas wells, high GOR oil wells and HP/HT wells should be tested with tubing and consequently the DST tools specified should have premium connections, x-overs from 3 ½" I.F. should not be used.

10.21 IRIS

IRIS is a trademark of Schlumberger and these tools represent such a significant departure from current technology that they warrant a specific section on their own.

IRIS (Intelligent Remote Implementation System) is a microprocessor based system incorporated into the downhole tools. These tools use only hydrostatic pressure as a mechanical energy source to operate the tools.

The tools respond to a sequence of low pressure pulses from surface. The pressure pulses serve only as a command signal and the energy from the pulses are not required to drive the tools. This technology opens up the future for further development in DST tools where the command pulses could be acoustic or electromagnetic.

For the moment IRIS tools use pressure pulses in excess of 250 psi for the command signal. Various command signals are required to operate the tools as the current arrangement of IRDV (IRIS Remote Dual Valve) has both a tester valve and a circulating valve.

It is worth noting that there is no requirement with IRIS tools to maintain pressure on the annulus as with conventional tools to hold the tester valve open after the command signal has been sent. In certain circumstances where annular integrity is questionable IRIS tools may be advantageous.

Figure 10.11 and figure 10.12 shows Schiumberger product information on the IRIS.

The inclusion of this section on IRIS tools is for the readers interest only. The decision to select downhole equipmet from a particular service provider will normally be arrived at via the tendering process in the particular area of operations and on the functional requirements of the test.

It is understood that other service providers also have some microprocessor based downhole equipment which operate by various means.

Underbalanced Drill Stem Testing
..... Beyond Conventional DST

Schlumberger have introduced a new generation of 'Intelligent' DST tools. Tools that will take well testing safely into a new cost effective era of underbalanced annular fluid testing, while ensuring data quality and flexibility of test string design remain uncompromised.

Description

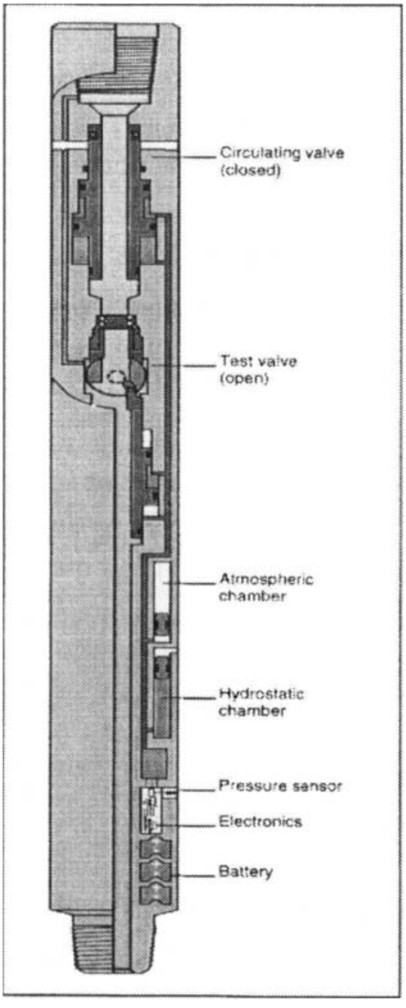
- Tubing
- S.H.O.R.T.
- Tubing
- L.D.C.A. (LINC) Latch Inductive Coupler
- D.G.A. DST Gauge Adapter
- I.R.D.V. Intelligent Remote Dual Valve
- P.T.S.F.V. Pump Through Safety Flapper Valve
- T.F.T.V. Tubing Fill Tester Valve
- Packer

FEATURES	BENEFITS
• Continuous referencing of hydrostatic pressure. Tester valve and circulating valve remain unaffected by change in annular fluid density	• Tools operate conventionally in an unconventional environment
• Low pulse annular pressure to operate tool	• Reduces liner lap pressure tests. Reduces operating pressure of other annulus controlled tools allowing flexibility of string design
• A downhole safety valve that operates irrespective of a leak in tubing and allows circulation at any time	• Allows uncomplicated well kill
• Mechanical tester valve over-ride	• Built in mechanical lock open or close for added safety
• Circulating valve and tester valve operate independently	• Reduced wear, increased tool reliability

Figure 10.11

Courtesy of Schlumberger

IRIS* Operated Dual Valve (IRDV-A)



Description

The IRDV-A, a compact, 5-in. OD, 2[1]/4-in. ID fullbore testing tool, combines a test valve and a circulating valve.

The tool is controlled by the IRIS Intelligent Remote Implementation System, which uses microprocessor based electronics and hydrostatic pressure as a mechanical energy source to operate downhole tools.

Using standard rig pumps, commands are sent as low-level pressure pulses in the annulus. These pulses are detected by a pressure sensor and decoded with a downhole microprocessor, which implements the commands via the tool electronics and hydraulics. Hydraulic control of each valve is achieved by alternating its operating pressure between hydrostatic and atmospheric.

Features

- Requires only low-pressure pulses in the annulus to operate
- Tool operation is independent of well temperature, pressure and deviation
- Simplified hydraulic design is immune to mud debris and well-effluent solids
- Automatic commands optimize operations
- No nitrogen is used for tool operation
- High flow area (1.56 in.^{2}) on circulating valve
- All tool operations recorded in memory to be read at surface after job

Specifications

OD	5 in.
ID	2[1]/4 in.
Length	22 ft
Service	H_2S/acid
Tensile strength (min. yield)	300 klbf
Temperature	300°F [150°C]
Min. operating pressure	1.5 kpsi
Pressure rating	
Differential (ID and OD)	10 kpsi
Max. hydrostatic (ID and OD)	13 kpsi
Test valve (static)	10 kpsi
Test valve (opening)	5 kpsi
Circulating valve (opening)	7.5 kpsi
Min. command pulse	250 psi
Number of valve openings or closings	20 (at least)
Connection	3[1]/2-in. IF or PH-6
Battery autonomy	> 600 hours

*Mark of Schlumberger

Figure 10.12

Table 10 .1 Schlumberger DST Tool Nomenclature

NAME	DESCRIPTION
ARV	Annular Reversing Valve, single shot annulus pressure operated reversing valve.
Break-off Sub	Single shot reversing valve operated by drop bar.
DBS	Dual Ball Safety Valve. Annulus pressure operated safety valve.
DGA	DST Gauge Adapter. Used for SRO operations.
DLWA	DST LINC Wireline adapter.
FASC	Fullbore Annular Sample Chamber. Annulus pressure operated sampling tool which retains full ID after tha sample has been collected.
FBSV	Full Bore Safety Valve – Mechanical Safety Valve that can be used on all MFE / PCT strings.
FPM	Formation Protector Module. Generally run with the PORT when there is open perforations. The tool prevents pressure applied to the PORT from communicating with the perforations
HOOP	Hold Open module - allows PCT to remain in open position after the annulus pressure has been bleed off. Until HOOP is cycled PCT behaves as normal.
HRT	Hydrostatic Reference Tool – provides reference pressure to operating section of PCT and has bypass feature. (HRT requires set down weight)
IRIS	Intelligent Remote Implementation System. (Microprocessor based system used to operate downhole tools using hydrostatic pressure as a mechanical energy source)
IRDV	IRIS Dual Valve Tool – IRIS operated tester valve and circulating valve, activated by low pressure pulses.

Table 10 .1 Schlumberger DST Tool Nomenclature (continued)

NAME	DESCRIPTION
LDCA	LINC Downhole Coupler Assembly.
LINC	Latched Inductive Coupling.
LRTC	LINC Running Tool Cartridge.
LSCI	LINC Surface Computer Interface.
MCCV	Multicycle Circulating Valve – Tubing pressure activated reversing or circulating valve.
MFE	Multi Flow Evaluator – tester valve works on string reciprocation – Open in compression.
MIRV	Multiple Opening, Internally Operated, Reversing Valve. Operated by pressure cycles on tubing ID.
MRV	Mechanical Reclosable Reverse Valve.
MSRT	Multisensor Recorder Transmitter Tool.
MSRV	Multistage Relief Valve – Equalises across packer then deflates packer.
MUST	Multiple Shut in Tool. Combination surface pressure readout tool and shut in device.
OSVS	Overpressure Safety Valve and Sampler – Slim hole tool, overpressure of the annulus shuts in tubing and traps a sample.
PCT	Pressure Controlled Tester valve – Opens on applied annulus pressure.
PFSV	Pump Through Flapper Safety Valve.
PORT	Operated Reference Tool – single shot device that traps a reference pressure for the PCT; unlike HRT no set down weight is required.

Table 10 .1 Schlumberger DST Tool Nomenclature (continued)

NAME	DESCRIPTION
PosiTest Packer	Cased hole retrievable packer with J slot mechanism.
Positrieve Packer	Cased hole retrievable packer with J slot mechanism. (Incorporates hydraulic hold down to stop packer being pumped out of the hole).
PTSV	Pump through safety valve with ball valve.
PTV	Pipe Tester Valve. Manual fill ball type.
RCAR	Recorder (Gauge) Carrier.
Rotary Pump	Used to pump up inflatable packers.
Safety Joint	A joint with a coarse thread that can be backed off by reciprocation and rotation.
Safety Seal	Run with MFE – Hydraulic locking tool helps keep the packer set.
SBSV	Single Ball Safety Valve.
SHORT	Single-Shot Hydrostatic Overpressure Reverse Tool. Annulus pressure operated.
Slip Joint	Slip Joint for space out and thermal effects.
SORTIE (Exit)	Single-Shot Overpressure Reverse Tool (internal / external) – can be set up to operate on internal or external over pressure.
SPRO	Surface Pressure Read-Out System
SSARV	Single Shot Annulus Operated Reverse Valve
TFTV	Tubing Fill Tester Valve. Automatic fill tester valve with flapper valve.
Time-regulated hydraulic jar	Hydraulic jar which can have its hitting time altered by an adjuster nut prior to running

Table 10.2 Halliburton DST Tool Nomenclature

NAME	DESCRIPTION
APR Circulating Valve	Annular Pressure Response Circulating valve. Single shot reversing valve.
APR M2 Safety Circulating Valve	Annular Pressure Response Safety, Circulating and Sampler tool.
APR S Internal Pressure Relief Valve	Vents pressure trapped below tester valve to the annulus, as the packer is set.
BIG JOHN Jar	Hydraulic Jar to aid in removal of stuck strings.
CHAMP III Packer	Hook wall type retrievable packer with concentric bypass.
Drill Pipe Tester Valve	Weight operated pipe tester valve.
Express Circulating Valve	Annulus operated recloseable circulating valve.
FUL-FLO Hydraulic Circulating Valve	Hydraulic Circulating valve – bypass around packer or circulating valve at end of test.
FUL-FLO Running Case	External gauge carrier.
FUL-FLO Safety Valve	Tension operated safety valve – open in tension.
HYDRO_SPRING Tester	Combination tester valve and bypass. Operated by string reciprocation, pull up to close.
Instream gauge Carrier	Instream gauge carrier. Internal type.
IPO Circulating Valve	Internal Pressure Operated Circulating Valve. Single shot device.
LPR N Tester Valve	Liquid Pressure Response Nitrogen, Tester Valve.
LPR NR Ratchet Tester Valve	As LPRN but has ratchet positions and will stay in a ratcheted position without pressure applied.
Model E SRO	Surface Read Out Sub.

Table 10.2 Halliburton DST Tool Nomenclature (continued)

NAME	DESCRIPTION
MPV	Multi-mode Pressure test Valve, auto fill tubing test valve valve and internal bypass.OMNI Circulating Valve Annulus pressure operated multiple cycle circulating valve.
RD Safety Circulating Valve	Rupture Disk Safety Circulating Valve. Single shot annulus pressure operated.
RD FUL-FLO Sampler	Rupture Disk FUL-FLO Sampler. Annulus pressure operated sampling tool which retains full ID after sample has been collected. Optional time delay metering cartridge to initiate sampling.
RS Valve	Reversing Spotting Valve. Requires cycles of differential pressure from string ID to annulus and vice versa.
RTTS Circulating Valve	Circulating valve and bypass run with RTTS packer. Operates with a J slot mechanism.
RTTS Packer	Retrievable Test Treat Squeeze Packer. Hook wall type packer used in testing, treating and cement squeezing operations. Operates on J slot mechanism.
RTTS Safety Joint	For removal of the tubing if packer is stuck. Requires pipe reciprocity and rotation.
Run in Open LPR N Tester	As LPRN above – but open while running in hole to allow the string to fill.
Select Tester Valve	Annuls pressure operated tester valve with a pressure activated lock open feature.
Slip Joint	Slip Joint for space out and thermal effects.
TST Valve	Tubing String Test Valve. Flapper valve tool which automatically fills the string while running in the hole.

CHAPTER 11

PRESSURE GAUGES

There are five main types of pressure gauge, which are commonly run during well tests. These are as follows, mechanical gauge, strain gauge, capacitance transducer gauge, vibrating crystal transducer gauge and the sapphire transducer gauge.

Recommended Practices:

1. Mechanical gauges should only be used as a back-up to electronic gauges, unless used for HP/HT tests.
2. Only electronic gauges with non-volatile memory sections should be used.
3. It should be ensured that the gauge battery life is sufficient for the test duration at the expected bottom hole temperature with contingency built in.
4. The "intelligent or smart" mode option for electronic pressure gauges should only be used in well understood pressure regimes and not in new exploration areas.
5. Prior to permanent abandonment of a well or zone, following a well test, it should be ensured that the bottomhole pressure gauges have sufficient data recovery to meet the well test objectives. If not a re-test may be required.

11.1 Mechanical Gauges

Mechanical gauges are now normally only used as a back-up to electronic gauges under most testing conditions. It is only for very high pressures and temperatures (i.e. above 350° F) wells where mechanical gauges are used as the main gauges. In this respect mechanical gauges have undergone somewhat of a resurgence in recent years as operators explore in ever hotter reservoirs around the world.

The mechanical gauge most commonly used over the years is Amerada gauge. This works using a helically wound "bourdon" tube which rotates as the pressure increases and inscribes a mark on a chart with a stylus. The reservoir pressures is calculated by measuring the deflection of the stylus on the chart and comparing the deflection against known pressures that were applied to the gauge during calibration.

Pressure Amerada gauges record only pressure, so a further temperature Amerada gauge needs to be run to acquire this data. These temperature Amerada gauges works on the same basic principle as the pressure gauges.

The duration of the recording life of the gauges is governed by a mechanical high temperature clock, which is installed inside the gauge body. These clocks are usually 60, 120 or 240 hour duration. However, single and double lead screw assemblies are available which allows the duration of the various clocks to be altered.

Mechanical gauges (Amerada, Kuster, Leutert etc.) can provide relatively accurate readings if they are regularly maintained and calibrated.

With the increasing use of mechanical gauges to meet the demands of the HP/HT market, which the electronic gauges still cannot satisfy. Certain service providers have focused on improving the results that may be obtained from mechanical gauges. Using improved calibration procedures and semi automated chart readers they have made these gauges far more useful than they were previously. The output from the chart readers can be in electronic format, which can then be used in any of the various pressure transient analysis software packages.

11.2 Strain Gauges

The strain gauge is bonded to a metal plate and electrically connected to a wheatstone bridge resistance circuit. As the plate deforms under pressure a change in resistance is measured as a voltage change of the order of a few milli-volts. Electronic circuitry is then required to amplify the voltage and produce a reading that can be stored. However, this electronic circuitry is often not very stable with temperature and generally causes gauge drift, particularly in the earlier models. In addition the strain gauge itself also suffers somewhat from hysterisis which effects the accuracy of the gauge.

Strain gauges were however probably the first competitor to the mechanical gauge. Although, early versions had very limited memory capacity and fixed sampling rates which were adjusted by moving electrical jumper connections on the circuit boards, these gauges represented a significant advance in gauge technology.

With the wide spread use of portable computers and more advanced interfacing techniques these strain gauges became even more functional. Additionally, with the introduction of microprocessor on board the gauges and "intelligent, smart or delta pressure" sampling, where the gauges alter their sampling rates based on changes in pressure, these gauges were state of the art in the early 80's.

11.3 Capacitance Transducer Gauges

There are two types of capacitance transducer. The first type is the gap capacitance transducer where two inconel plates are separated by a gap of 2/1000". One plate is exposed to well fluid and as the pressure increases the gap reduces (changes < 1/1000" occur) and this in turn changes the capacitance. The change is ultimately recorded as a variation in frequency.

The second type of capacitance transducer is the quartz capacitance transducer. This is very similar to that above except that the inconel plates are coated with quartz and the gap is reduced to 1/1000". As the gap changes (typically a few Angstroms) as a result of pressure changes, the capacitance changes and the pressure is measured as a change in frequency. Because the diaphragm is of twin substances there is a differential thermal expansion effect, which causes a "thermal transient". This is compensated for by a reference gap transducer.

Capacitance transducer gauges are the most commonly used general purpose gauges for well testing. The advantage of the capacitance gauge over the mechanical or strain gauge is much better accuracy and resolution. These gauges are also far more robust than the quartz crystal gauges described below.

11.4 Vibrating Crystal Transducer

The vibrating crystal transducer is most commonly found in high accuracy pressure gauges, which operate, by the piezoelectric effect. A quartz crystal is wired to an electrical circuit which oscillates at a given frequency. The oscillation frequency varies as a function of pressure. A further crystal is used as a reference and this is only exposed to wellbore temperature, not pressure. The frequency difference between the two crystals allows the pressure to be calculated from calibrations performed on the gauge.

The Hewlett Packard gauge (the first gauge to make use of the above principle) was and is still one of the most accurate gauges on the market, but has some drawbacks. The gauge takes some considerable time to stabilise to changes in temperature and is not very robust to shock.

To get around the thermal problems, mono crystal quartz gauges are now being used. In these gauges there is no reference crystal, just a single measurement crystal which is cut at a different angle to the crystal lattice (e.g. Quartzdyne sensor). This allows pressure to be measured along one axis and temperature to be measured along the other. By measuring both pressure and temperature at the same location the transient effect seen in the Hewlett Packard gauge is removed.

11.5 Sapphire Crystal Transducer

These are designed for the most hostile of conditions (currently rated to 20,000 psi and 190 Celsius).

The sapphire crystal gauge is unable to match the accuracy and resolution of a Quartz crystal, but does exceeds the temperature and pressure specification of quartz sensors.

Sapphire gauges are also used in applications where a hostile environment gauge is not required, but a gauge with lesser accuracy than a quartz gauge is acceptable.

The sapphire sensor is constructed around a small evacuated sapphire crystal, which has a thin film strain gauge bridge and temperature compensation resistor deposited on its surface. This construction generally out performs the conventional strain gauge sensor.

11.6 Gauge Memory Sections

There are generally two types of memory in use. Volatile memory (RAM) and non-volatile memory (EPROM or EEPROM).

The volatile memory needs a battery in order to retain information. If the power supply is disconnected, the memory loses all stored data.

The non-volatile memory does not need power from a battery to retain data. Thus if the battery gets disconnected or discharged the data can still be retrieved. Non volatile memory is erased after the test using a U.V. source or it is done electrically.

Memory capacity was somewhat limited in the first electronic memory gauges that were available and engineers had to consider carefully the likely duration of a DST and factor in problem time into their DST time estimates. This lead to the introduction of delays or sleep modes, whereby the gauge would not acquire non essential data such as when running in the hole with the DST tools. Thankfully memory capacity is no longer really a concern, as there are now memory gauges available that can acquire 1,000,000 data sets. Therefore, only in the case of a DST with very extended flow and buildup period would there be any real concern about gauge memory capacity.

11.7 Memory Gauge Battery Packs

Typically the following battery packs are used in increasing order of temperature serviceability.

- Alkaline
- Silver Oxide
- Lithium

The correct battery must be selected, because if taken above their operating temperature range they may explode.

Shipping handling and disposal of Lithium battery packs can be problematic.

Currently high temperature alkaline battery packs are becoming available and advice should be sought from the service providers.

11.8 Surface Read Out (SRO) Gauges

Essentially all of the above types of gauge sensor are available in surface read out version. SRO can be very useful during a well test; for example it can be used to determine the required duration of a pressure buildup. Thereby, allowing a test to be curtailed sooner if all of the necessary data has been acquired, saving expensive rig time. SRO can also be useful on wells where there is a problem to maintain flow and fluid gradient surveys can be carried out quickly to help identify the problem.

However, SRO can add complication to a test, as it requires additional surface pressure control equipment and personnel. In addition, carrying out wireline operations on high pressure wells can be difficult and potentially dangerous.

11.9 Permanent and Semi-Permanent Gauges

Permanent gauges where a pressure recorder is installed in a gauge carrier or side pocket mandrel and hard wired to surface, usually with an encapsulated cable, was generally only undertaken during well completions. However, there are a number of circumstances where installation of a semi-permanent gauge for a well test is a cost effective and viable alternative to SRO. Such circumstances would be, extended well tests and deep water tests where chemical injection lines are being run deep in the well for hydrate prevention and a gauge cable could easily be installed at little extra cost. ESP (Electrical Submersible Pump) tests are obvious candidates for semi-permanent gauge installations, indeed most ESP systems already have parameter monitoring systems but a high accuracy quartz gauge may be required also.

11.10 Speciality Gauges

There are also some speciality gauges available on the market such as a Wireless Transmitted Data gauge. This gauge transmits pressure and temperature data acquired by either quartz or strain gauges sensors to surface by electromagnetic waves passing through the overlying rock formations.

The signal propagation from such gauges is dependent on the well bore configuration and the resistivity of the overlying rocks and therefore cannot be used in all circumstances. Under the correct circumstances these gauges offer the advantage of real time surface readout without the disadvantage of having wireline in the hole while testing. Where applicable these gauges are ideal in highly deviated or horizontal wells where the deployment of conventional wireline tools can be difficult.

Other gauge peripheral technology exists which allows communication between gauges below the tester valve with a sub above the tester valve using either acoustic or inductive couplers. These devices offer a system that has the benefits of memory gauges, that is no wireline permanently in the hole. However they can be interrogated and re-programmed before the DST tools are retrieved from the well.

11.11 Calibration of Gauges

Regardless of the gauge system that is used the quality of the data will depend on how accurately the gauges have been calibrated.

The ever increasing sophistication of gauges requires high accuracy calibration systems and particular attention to detail in terms of calibration procedures. Most service providers utilise high accuracy dead weight testers such as those manufactured by Desgrange et Hout and others which feature automatic mass loading systems and environmentally controlled chambers. These high accuracy devices are calibrated by independent third party calibration facilities, which are certified to undertake this work and have traceability to National Standards.

The service providers calibration facility will normally have a computer controlled calibration oven which has excellent temperature stability. These ovens feature multiple temperature sensors and in some cases liquid CO_2 is used as a coolant.

At major regional calibration facilities quality systems complying with ISO 9000 standards will be in place. These quality procedures may even include corrections for the accelaration due to local gravity.

The calibration procedure for a high accuracy gauge may have 10 or more temperature step and at each step perhaps 10 or more pressures steps from atmospheric pressure up to full scale and back down to atmospheric. The computerised nature of these sophisticated calibration facilities allows pressure and temperature to be applied incrementally over any timescale, therefore build-ups and long term stability tests can be undertaken.

The accuracy of gauges is particularly important for some tests such as interference tests. Therefore the test engineer specifying gauges for such a test will have to examine the performance of the various service providers gauges and look at their calibration facilities and procedures. The engineer should insist on before survey and after survey calibrations, if this is not already part of the service providers quality system. In addition specifying further pressure and temperature steps in the vicinity of the anticipated reservoir pressure and temperature will improve the accuracy of the gauges. This calibration procedure for gauges is sometimes referred to as a "closed calibration" and is generally only performed if the reservoir conditions are accurately known in advance of the test.

The author would recommend that the reader visit one of the service providers major region facilities in order to gain a greater insight into the procedures used to calibrate oilfield bottom hole pressure and temperature gauges.

CHAPTER 12

SUB SEA EQUIPMENT

On almost all well tests conducted from floating rigs – semi submersibles or drill ships it will be necessary to deploy sub sea equipment during the test.

The items of sub sea equipment, which should and can be run during a test, will depend on the type of test being conducted. However, common to almost all tests from floating rigs will be the requirement to run a sub sea test tree. An overview of the sub sea test tree and other commonly used sub sea equipment is presented below.

12.1 Sub Sea Test Tree (SSTT)

The purpose of the sub sea test tree (SSTT) is to provide a primary safety system to control tubing pressure and to provide a means to rapidly and safely disconnect from the well should adverse conditions occur.

All of the major testing contractors have sub sea test tree safety systems and various configurations exist to suit the requirements of the planned operation.

Figure 12.1 shows a typical configuration of a sub sea test tree safety system.

In common, all sub sea test trees consist of two valves for control of tubing pressure. These may be either independent dual ball valves or an independent ball and flapper combination. During flowing of the well the valves are held in an open position by hydraulic pressure applied through a control line. Release of the hydraulic pressure will close the valves i.e. these are fail safe closed systems. Therefore, if the control line bundle is damaged inadvertently or as a result of some catastrophic event, the tubing pressure and well fluids will be contained.

All sub sea tree systems also incorporate a hydraulic latch/unlatch mechanism, which provides a means of unlatching from the well should adverse conditions occur. In addition most trees also have a shear release mechanism in the event of failure of the primary hydraulic system.

In the selection of a sub sea tree system one should consider carefully the requirements of the planned operation. In addition, a very important requirement is the ability to space out the sub sea tree below the BOP shear rams whether the tree is latched or unlatched. Fig 12.2 shows the correct space out of a sub sea test tree, note that particular care is taken to ensure that the fluted hanger is compatible with the wear bushing. Also all the SSTT dimensions are checked against the BOP schematic and the BOP rams are configured for the testing operation.

Subsea Operating System

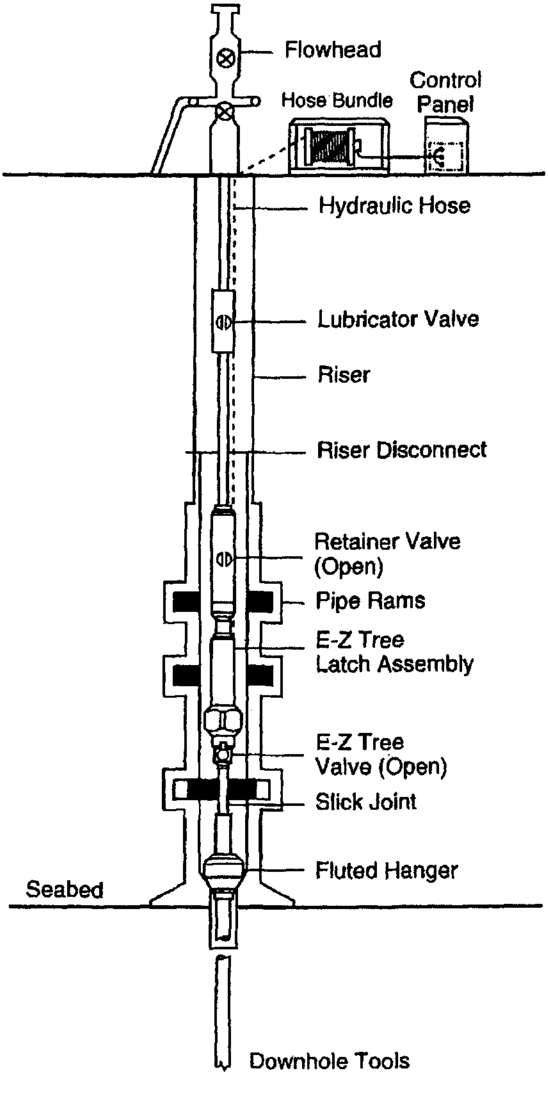
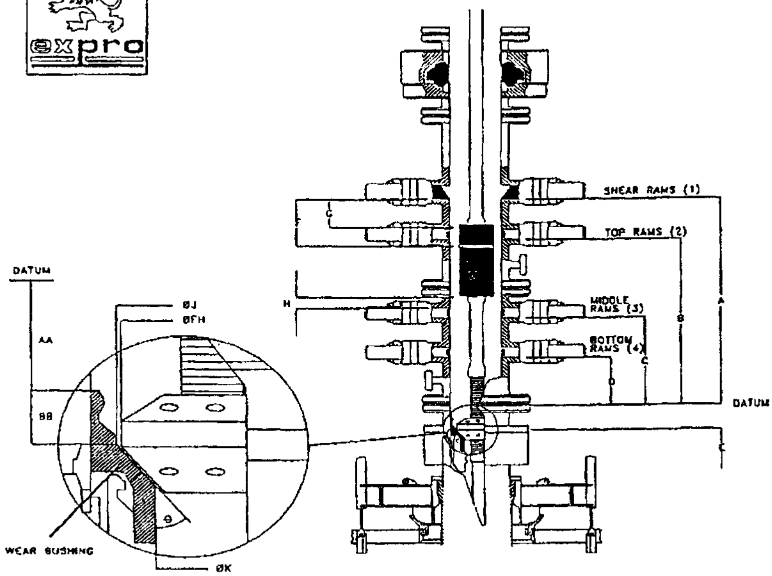


Figure 12.1

SUB SEA OPERATIONAL GUIDELINES

expro

SUB-SEA TEST TREE SPACEOUT DIAGRAM



CUSTOMER:	B.P.		
RIG:	OCEAN ALLIANCE		
WELL No:	22/20-F		
BOP. TYPE:			
BOP. SIZE:	18-3/4"		
WELL HEAD TYPE:	DRILQUIP		
HANG OFF POINT:	9-5/8" WEAR BUSHING		
DATE:	14/4/93		
OPERATOR:	B. CRUICKSHANK		
DIMENSIONS (inches)			
A	161.13	ØJ	13.25
B	141.33	ØK	8.82
C	81.33	ØFH	10.75
D	61.53	θ	60°
E	34.49	AA	13.625"
F		BB	20.86
G	10.15		
H	10.15		

RAM No.	WIDTH	SIZE
1	7.5"	SHEAR
2	7.5"	5" FIXED
3	7.5"	5" FIXED
4	7.5"	3.75" TO 5"

POSITION OF BOP RAM SEALS

X	Y	Z

CROSSOVER SIZES	
TOP:	5-1/2" RSU-6 (23 lbs/ft)
BOTTOM:	5-1/2" RSU-6 (23 lbs/ft)
ADJUSTABLE DIMENSION:	133.47

Figure 12.2

Another feature which may be important is the independent operation of the sub sea tree valves which would allow the upper valve to cut wireline or coil tubing and the bottom valve to close only after the cut is made therefore ensuring that the bottom valve will never be damaged.

Other requirements may include:

- Downhole chemical injection at or below the tree (glycol or methanol for hydrates or PPD or wax inhibitors for certain crudes)

- High torque mechanical unlatch to ensure that accidental unlatch does not occur during retrievable packer setting operations in deviated wells.

- Large bore trees – the 'standard' trees usually have a 3" internal diameter, however larger bore trees are available for high rate tests and extended well test (EWT) operations – 5", 6" and 7" I.D. versions.

- Rapid disconnect for deep water - Most trees were designed to provide rapid disconnect or unlatching in less than 20 seconds for water depths up to about 2000', this was achieved by developing hydraulic systems which required only a small displacement volume.

  However, as water depths in excess of 2000' are now fairly common, most services companies have now developed a deep water capability. These systems typically have an accumulator type hydraulic pod mounted on the landing string which can deliver the required hydraulic volume quickly and still maintain unlatch times in the 20-40 seconds range in water depths of 6000' – 8000'.

- There is continual development in this technology with SSTT designed to operate in 10,000' water depths with ever decreasing response times. At the cutting edge of this technology is the new generation of electro-hydraulic systems. Activation of these SSTT's is via an electrical signal from a computer system on surface, this electrical signal is then converted sub sea to a hydraulic signal to the SSTT. These systems provide unlatch times of 15 seconds or less regardless of the water depth.

- Electrical Submersible Pump (ESP) operations from a semi sub – these can be carried out using either a simple external break away connector near the latch or a more sophisticated internal sub sea wet connector included in the latch mechanism. The latter of the two systems is to be preferred as there will be no requirement to kill the well after any unlatch, i.e. to pull the landing string to repair the breakaway connector. At the time of writing there are currently very few of these trees available worldwide and they are used almost exclusively for ESP operation conducted as part of an Extended Well Test (EWT) operation.

12.2 Associated Sub Sea Equipment

Referring again to figure 12.1 there are a number of other considerations in the selection and rig up of a sub sea system.

The sub sea tree and associated sub sea equipment is run on a landing string which is often a robust 4 ½" PH4 tubing string. The landing string must meet the burst and collapse criteria of the main tubing string but have the tensile strength to pickup the weight of the entire tubing string, subsea package and meet any overpull requirements.

The main tubing string is landed off at the wear bushing using a fluted hanger supplied by the testing contractor. A dimensional check of the both the O.D and the hanger angle must be carried out to confirm it is suitable for the wear bushing.

The fluted hanger has either flutes on its diameter or more frequently holes through which pressure is transmitted to the annular operated DST tools from the BOP stack kill lines.

An adjuster sub is run above the fluted hanger and below the slick joint and sub sea test tree (SSTT) to allow the SSTT to be spaced out in the BOP stack such that the SSTT is below the BOP shear rams whether latched or unlatched.

The slick joint is run above the adjuster sub and directly below the SSTT and this allows both sets of the BOP pipe rams (if required) to be closed against this joint to affect a pressure seal.

The characteristics of the SSTT were described above – however when unlatched it is worth noting that both valves remain attached to the main tubing string to provide full control of the well if the unlatch has had to be carried out on a live well.

A dummy run with the fluted hanger and the slick joint with tubing or drill pipe is normally performed to ensure correct space out of the SSTT to allow dual BOP ram closure on the slick joint and maintain the SSTT below the blind shear rams.

A shear joint is always placed in the string opposite the BOP blind/shear rams. Similar joints have normally undergone shear tests with the major BOP manufacturers. If doubts exist about the BOPs shear capabilities this aspect of the test planning may require further investigation and testing of shear joints with the BOPs.

In order to prevent the landing string contents from escaping into the riser and ultimately into the sea particularly in the event of an unlatch of the LMRP (Lower Marine Riser Package) a retainer valve is used. This is essentially a flapper type valve, which is pressure retaining from above. The inclusion of a retainer valve is particularly important in deep water operations where the landing string volume is significant. Gas wells are occasionally tested without retainer valves, however it is advisable to bleed off the landing string pressure before unlatching.

Indeed in most cases the preferred unlatch method would involve bleeding off the landing string pressure whenever possible. Many subsea systems also include a bleed off valve to bleed off pressure trapped between the retainer valve and the SSTT latch. Assuming a retainer valve is installed then the landing string pressure may be bleed off at any time after unlatching. Figure 12.3 shows a typical disconnect sequence for a SSTT.

However, in the event of an emergency disconnect, such as in the case of loss of anchors or D.P. system there may be no time to blow down the landing string. See 12.3 DST Operating Criteria and 12.4 Sub Sea Test Tree Disconnect.

In deep water an accumulator type hydraulic pod is run above the retainer valve to act as a booster to increase the speed of actuation of the SSTT components or an electro-hydraulic system is used.

A centraliser can be placed in the landing string just above the BOP to centralise the slick joint and to assist in relatching operations. The centraliser O.D. should be checked in the planning phase to confirm compatibility with the BOP riser.

Close to the surface a lubricator valve is normally included in the landing string. This is usually placed about one stand of tubing below the rotary table. The lubricator valve is included for ease of operations when performing wireline and coil tubing work. The alternative would be to rig up a large wireline lubricator on top of the flow head. However, this can be hazardous when the sea states are anything less than perfect. As the rig is moving in relation to the landing string and surface test tree which is hung off at the wear bushing.

At the rotary table around 20' of tubing stickup (between the rotary table and the surface test tree) is usually required, to account for rig heave and tidal motion.

Depending on the landing string selected (lightweight tubing) it may be necessary to install a stiff joint at the surface to provide extra rigidity in the surface landing string. This is because the weight of the surface test tree and flow hoses can exert a bending moment on the tubing.

Sub sea equipment should always be considered early in the planning of a well test operation from a floating rig. A BOP stack drawing should be obtained when the drilling rig has been selected and a suitable length SSTT with the desired feature can then be selected.

Note: most modern sub sea tree systems are modular which can allow the SSTT valves to be placed below the slick joint should this be a required due to space limitations in the BOP stack.

Subsurface Safety Systems — E-Z Tree

E-Z Tree Disconnection Sequence

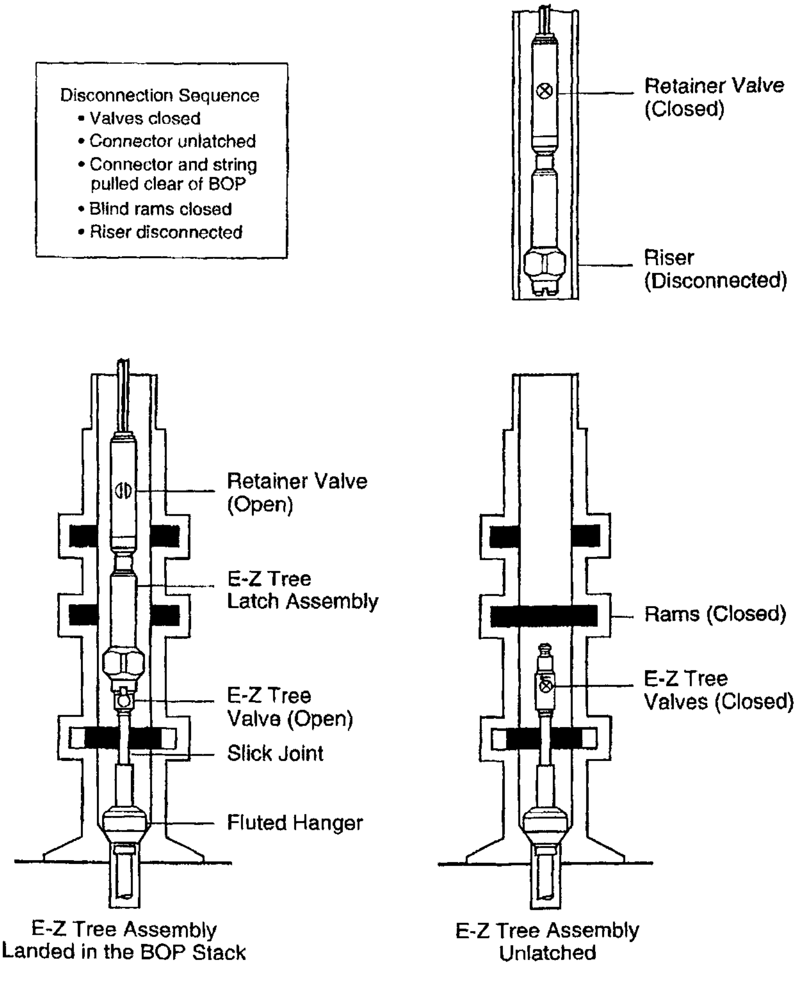


Figure 12.3

12.3 DST Operating Criteria

The vessel motion operating criteria for drill stem testing should be written somewhere in the drilling contractors documentation for the rig or in the rigs safety case. This will outline the acceptable vessel motion in terms of heave, pitch and roll where testing operations can safely be carried out. Note: the window of operations for testing may vary from those for drilling.

The operating criteria will vary from rig to rig and should be confirmed as part of the test planning procedures.

Typical DST vessel motion operating limits for a semi-submersible rig are:

Heave = 1.5m (5 ft) Pitch = 3^0 Roll = 3^0

12.4 Sub Sea Test Tree Disconnect

Bad Weather Disconnect:

Frequent weather reports should negate the requirement to disconnect as an emergency procedure. However, an emergency disconnect due to bad or deteriorating weather cannot be excluded.

Typical Bad Weather Disconnect Criteria for a semi-submersible rig are:

Operation	Wind Speed (Knots)	Sign Wave Ht. (metres)	Max. Wave Ht. (metres)
Testing Suspended (Ready to disconnect)	45 +/- 17.5	4.00	7.38
Disconnect SSTT & LMRP	50 +/- 17.5	4.61	8.62

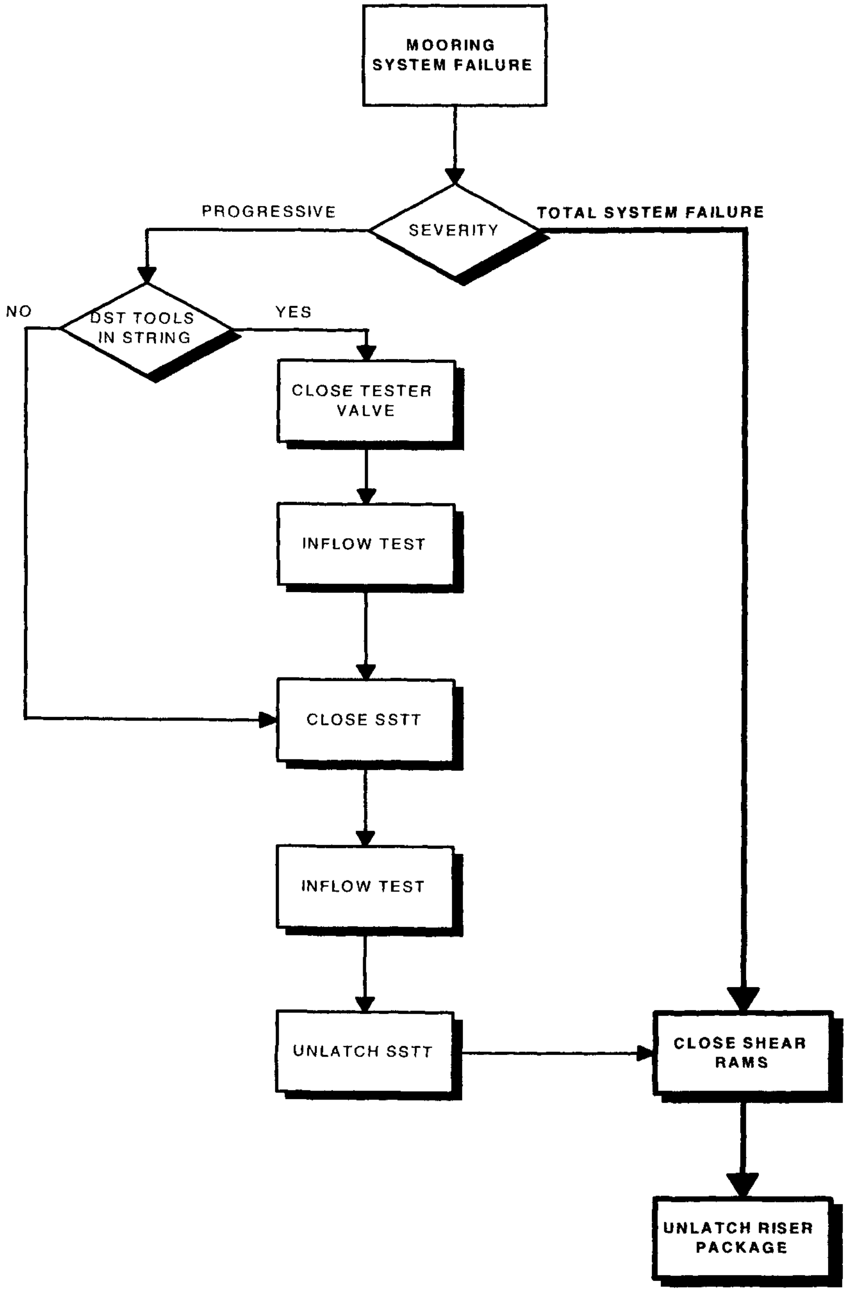
Note: **Most sub sea test trees will not unlatch if landing string is more than 4° to 6° off the vertical position, depending on which tree is used. These figures are in line with the disconnect angles for the LMRP.**

Mooring System Failure:

Mooring system failure can range in severity from total and immediate failure to a slowly deteriorating situation. If the mooring system failure is of such a nature that corrective measures may be taken, then follow normal well killing procedures prior to disconnecting.

Should the situation require more immediate action follow the steps indicated in the flow diagram, figure 12.4

Figure 12.4 Mooring System Failure Requiring Immediate Action



This Page Intentionally Left Blank

CHAPTER 13

SURFACE TEST EQUIPMENT

The surface test equipment required to conduct a well test will depend both on the planned operations and also on where the test is being conducted, onshore or offshore (jackup or a floating vessel). In this chapter we shall look at the major components of a surface test package which are commonly used on a variety of testing operations.

Recommended Practices:

1. All tests should incorporate an Emergency Shut-Down (ESD) system. The manual shut-down buttons should be located in the following areas: close to the well testing spread, on the drill floor near to the drillers dog house and in safe locations away from the main testing area.

2. For high pressure, sour gas and sand frac clean ups, a dual isolation, double block and bleed valve arrangement is recommended for the choke manifold. In all other cases a single valve isolation arrangement is deemed acceptable if there are further tested latent barriers upstream of the choke that can be activated in the event of a leak.

3. The bubble hose and needle valve should be positioned downstream of the choke.

4. All flowlines should be tied down or pinned.

5. The number of flowline bends and elbows should be minimised.

6. There should be no valves in a vent line.

7. Where required, surge tanks should be used for all offshore test, gauge tanks are not recommended.

8. Separators and surge tanks should be fitted with two relief lines.

13.1 Surface Test Tree (Flowhead)

The Surface Test Tree used during a DST is usually a fourway cross (often mono block construction) with four valves. The surface test tree should be able to support the full string weight and all four valves should be able to seal with differential pressure from either side.

However, there are some surface test trees available that cannot support the string weight. If this type of tree is to be used then programme must detail the fact and procedures must be arranged so that no load is applied to the tree.

It is quite common to find surface test trees with either the master valve, or the production wing valve, or both, hydraulically operated with these valves set to close on loss of hydraulic pressure from the control line.

It is good practice to include a non-return valve in the kill wing line

Most surface trees include a swivel to allow pipe rotation as this may be required to set packers or operate rotation type drill stem testing tools. The swivel is a pressure balanced sub that allows unrestricted rotation of the upper or lower half with respect to each other.

Particularly on high pressure wells the inclusion of a lower master valve below the swivel is recommended.

See Figure 13.1 – Surface Test Tree.

13.2 Coflexip Hoses

Coflexip hoses are the most common high pressure hose used for well testing. They are generally used in preference to chicksan type orientational pipe work, between the Surface Test Tree and the choke manifold on tests conducted from floating rigs. The Coflexip hose has many advantages over conventional pipe work; it comes in longer lengths, has greater flexibility, better resistance to corrosion and low restriction to fluids passing through it.

On the downside they can be difficult to handle during rig up in a restricted space.

Coflexip hoses are composed of a steel armour to withstand the rigours of work, resistance to pull and high burst pressures. The steel armour is not leak proof and it is the inner thermoplastic layers that is used to carry out this function.

Operational note: Water seeping from the outer wrap carcass of a Coflexip does not necessarily mean that the integrity of the Coflexip hose has been lost. This may be rain water trapped between the leak proof inner layers and the non leak proof outer layers. However, if fluid continues to be observed escaping then the operation should be terminated and the hose taken out of service and tested.

A standard service Coflexip for production operations will have a Rislan inner liner. Those used for HP/HT (High Pressure / High Temperature) will have a Coflon inner liner. It is not within the scope of this book to provide product information on Coflexip hoses or any other manufacturers high pressure hoses.

However, the current accepted limitations on HP/HT flexible hoses are 15,000 psi WP (- 4° F to + 266° F continuous temperature rating) with $CO_2+H_2S < 10\ \%$. In addition these hoses have a survival rating of 320° F for about one hour. Hoses exposed to temperatures greater than 266° F will be required to be taken out of service. The continuous temperature rating of Coflexips and other high pressure hoses can present a problem in the planning of HP/HT tests.

Coflexip hoses must be handled properly and a minimum bend radius exists for each class of hose while in storage and in service. For example a 5.83" O.D / 2.84" I.D 15,000 psi test flowline (Coflon) Coflexip has a minimum bend radius in storage of 3 feet and in service 5 feet. As a rule of thumb the minimum bend radius in service should not be less than 12 times the outside diameter of the hose.

When specifying Coflexip hoses a bend stiffener can be requested, this is an additional device mounted on the hose during its manufacture. The device is used to increase the local bend stiffness in the region of the end fitting, producing a smoother transition from the end-fitting to the flexible pipe structure. Figure 13.2 shows the correct handling of a Coflexip hose to avoid excessive strain on the hose.

The main use of Coflexips during testing is between the surface test tree and the choke manifold and also between the surface test tree and the kill line. Figure 13.3 shows the preferred hook up of a Coflexip hose on a semi-submersible or drill ship.

13.3 Rig Permanent Pipework

Many offshore rigs have substantial amounts of fixed pipe work. However, careful consideration will be required before using this pipe work.

Much of the information regarding fixed pipe work will be gathered during the rig visit by the service company Testing Supervisor and possibly the oil and gas company Test Engineer. Information relating to line size, wall thickness, sour service capability, inspection and certification reports and end connections must be checked. For example, it is not safe to assume that because a rig is rated for HP/HT drilling that all the pipe work will be suitable for HP/HT testing.

Generally the pipework can be considered under two categories – High Pressure and Low Pressure.

The high pressure pipework will usually be a derrick stand pipe as shown in Figure 13.3 and possibly a high pressure line to a dedicated well test area.

Low pressure piping will normally be gas, oil, air and water lines to burner booms and some times pressure relief lines.

The level of inspection, certification and testing of these lines will be dictated by the type of test, with more stringent requirements for HP/HT and sour gas wells.

THE EXPRO GROUP

Surface Test Trees (15Kpsi)

Expro's Surface Test Tree Flowheads offer full E.S.D. well head control

Description

The surface test tree is a major item of well test equipment. It is the first piece of surface equipment exposed to well effluent and therefore effectively controls the well upstream of the choke manifold. The flowhead is basically a four- valve arrangement with the master and flow valves being the main flow control valves. The kill valve permits injection of mud, or stimulation fluids to the string whilst the swab valve allows access for wireline operations.

Additional Information

The flow valve is normally hydraulically actuated to the fail safe close position and controlled from the E.S.D. panel, thus ensuring a fast shut-down response time.

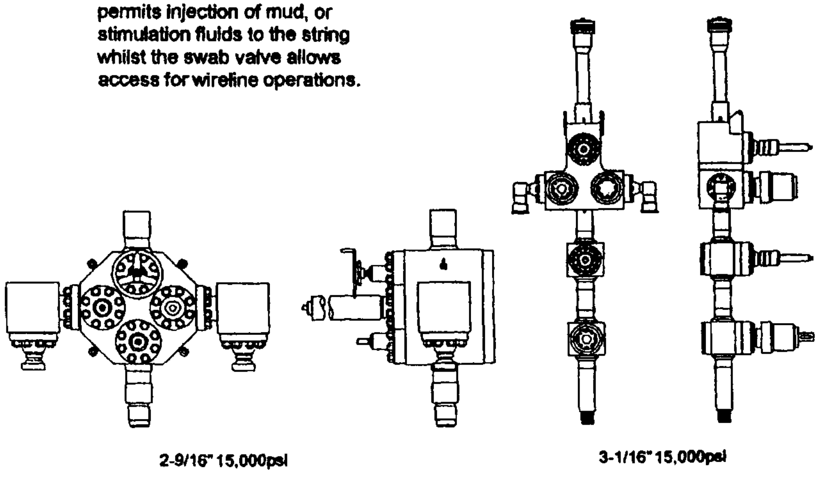


Figure 13.1

WELL TEST OPERATIONAL GUIDELINES

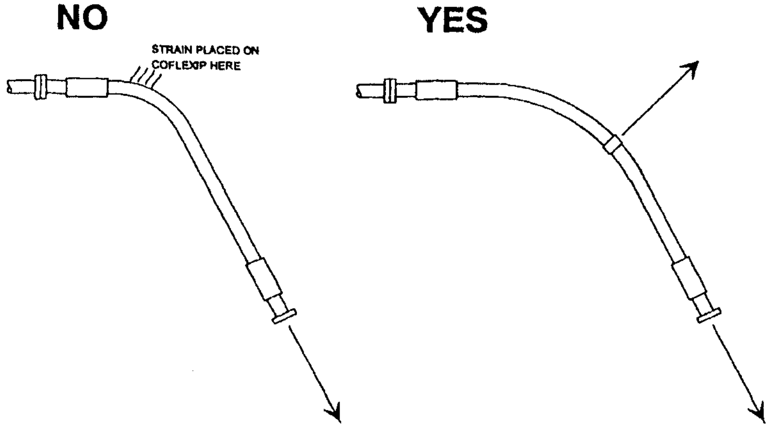
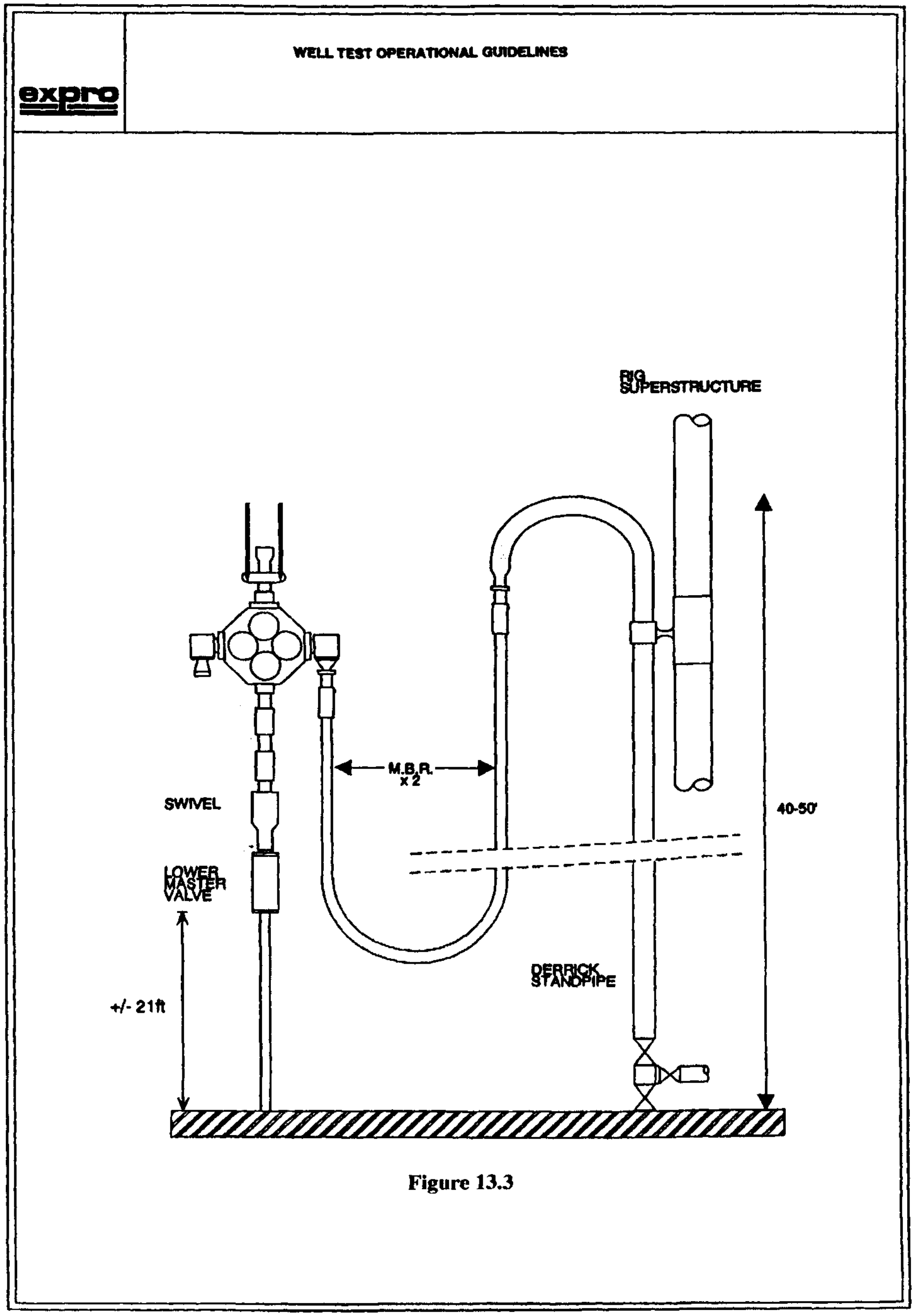


Figure 13.2



expro
WELL TEST OPERATIONAL GUIDELINES
RIG SUPERSTRUCTURE
M.B.R. x 2
SWIVEL
40-50'
LOWER MASTER VALVE
DERRICK STANDPIPE
+/- 21ft

Figure 13.3

13.4 Hydraulic Surface Safety Valve

The hydraulic safety valve is a free standing valve (Figure 13.4) that is incorporated in the surface testing equipment for additional safety. It is usually used where long high pressure flowlines are in place, as a further shut-off device in case of a leak and to reduce the leakage volume. Furthermore it forms part of the ESD System.

13.5 Surface Temporary Piping

Most temporary piping used by testing contractors are connected together using hammer unions, typically Weco unions. These unions have a ball and cone seat system and an Acme thread. The seal is made simply by hammering the two halves together.

On higher pressure pipe work an elastomeric seal is also included to facilitate a seal where the flow lines are slightly misaligned.

A range of Weco unions commonly in use is shown in the table 13.1 below.

Table 13.1

UNION	MAWP (COLD) Standard Service	MAWP (COLD) H2S Service
Fig 200	2000	N/A
Fig 206	2000	N/A
Fig 602	6000	6000
Fig 1002	10000	7500
Fig 1502	15000	10000
Fig 2202	N/A	15000

A union described by a '2' on the end refers to the fact that the union has an elastomeric seal ring fitted and is not only a metal to metal seal.

However, the Fig 206 union also has an 'o' ring fitted to improve the sealing qualities and protect the metal to metal seal against corrosion.

Care must be taken not to connect two differing unions together e.g. 1002 and 1502, although they may appear to be properly connected they may blow apart under pressure. To help safeguard against this problem most service companies use some form of colour coding for pipe and also install metal identification bands. The metal bands should be checked for information such as MAWP, sour service rating and date when last inspected and certified. In certain countries only pipe work which has been independently inspected (DNV, Lloyds etc.) may be used and the banding will confirm if the pipe work is approved for use.

On HP/HT tests clamp connectors (usually Graylock) are used for HP/HT pipework. These connectors are self-energising, metal to metal seals designed to withstand the severest conditions of corrosive and erosive elements and high and low temperatures.

Leaks: In the event of a leak in either a hammer union or a clamp connectors the pressure should be bled off first before attempting to repair the leak. <u>Under no circumstances must a leaking hammer union be hammered on while pressurised.</u>

13.6 Sand Trap

A sand trap functions as a sand separator and is used when excessive sand production is anticipated during a well test, for example following back a sand fracc or testing of unconsolidated formations. Sand traps typically consists of two vertical pressure cylinders, in which screens of varying mesh size can be inserted. A standard screen size would have a 200 micron mesh. For sand fraccs, the screens would be selected based on the size of proppant being used. However, when testing unconsolidated sands the screen sizes can be determined from sand grains obtained from percussion side wall cores obtained as part of the wireline logging programme.

Sand traps would normally be installed between the flowhead and choke manifold to avoid erosion of chokes. However, in certain regions the availability of high pressure sand traps can be limited and in these circumstances low pressure sand trap will be installed downstream of the choke manifold but upstream of the heater or separator.

Filters can to be removed from the sand traps so that the quantity of sand produced in a given period of time can be measured. During this time, flow is diverted to the other pot or else through a by-pass to avoid closing in the well. If the filter is by-passed for too long sand may erode the choke and piping and will settle in the separator.

If a test objective is to obtain quantitative measurements of sand rate continuously during flowing the well, sand detection equipment can be used. See section 13.7.

13.7 Sand Detection Equipment

There are a variety of sand detection systems available. However, one of the most commonly used systems has an intrusive probe set into the flow line. With the probe located in the flow stream it can reliably detect sand grains as they impact on the probe, across a broad range of monophasic or multiphasic flow conditions.

These probes are usually interfaced into the well test data acquisition system to allow continuous sand production rate versus flow rate or pressure drawdown to be determined and charted. To optimise the sensitivity of the probe and to provide quantitative measurements it is necessary to calibrate the probe by injecting known quantities of representative formation sand into the flow stream in a specially formulated slurry from a sand injector system while flowing at different rates.

THE EXPRO GROUP

Hydraulic Surface Safety Valve

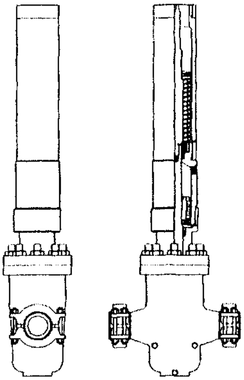
Expro surface safety valves are used in conjunction with the ESD system and ensure a fully fail-safe operation.

Description

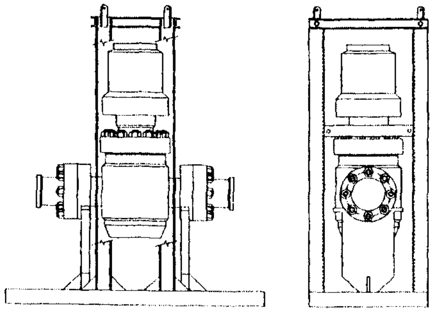
Expro's surface safety valves utilise standard gate valves with a reverse acting bonnet assembly for fail close operation. The valve is skid mounted so it can be used as a stand alone item. The end connections are normally API rated flanges, Expro will provide crossovers for hook-up to the flowline.

Additional Information

The unit ties in to the ESD system and provides a fail safe shut-in downstream of the well head.



3" 10,000 psi (skid not shown) surface safety valve



3-1/16" 15,000 psi skid mounted surface safety valve

Technical information overleaf

Figure 13.4

13.8 Data Header

The data header is usually installed just upstream of the choke manifold. It is used to monitor wellhead parameters such as pressure and temperature and to inject chemicals upstream of the choke. Data headers are also sometimes installed downstream of the choke to measure downstream choke pressure and for sampling. In the event that there is no bubble hose port downstream of choke it can be mounted on the data header upstream of the choke provided twin block valves are put on the bubble hose since they have a tendency to cut out-especially if barite is present in the mud. (See Figure 13.5)

13.9 Choke Manifold

Various configurations of choke manifold exist; some of which are shown in figure 13.6 and figure 13.7. In essence the all consist a variable choke used primarily for cleaning the well up and a fixed choke for more accurate flow control during main well flow periods (See Figure 13.8). The choke is the primary flow control device in a well test installation and if chosen correctly it will produce stable separation conditions and a stable bottom hole pressure. However, the stability of the well is also a function of the reservoir and tubing hydraulics and operation of surface equipment can only control the stability within limits.

During the test it may be necessary to change the flowrate, either to reach some previously decided optimum rate, or to allow for multiple rate testing. Such changes are best made as rapidly as possible and with the well still flowing. This is achieved by means of the choke manifold.

A minimum of two parallel flow sections, each with isolating valves are used. One section contains the fixed choke bean, the other, normally, an adjustable choke.

A choke manifold with a third parallel section, with valves but without a choke, is often convenient during initial well clean up or during circulating periods at the end of a test.

There are two primary types of chokes, adjustable and fixed each of which may be found in a variety of forms.

Adjustable choke

This is effectively a form of manually adjustable valve, the stem and seat of which are designed to wear only minimally under the conditions of high differential pressure, entrained liquids and solids, and the general operating conditions encountered during a test. The choke normally has some form of indication of the extent to which the system is open. This may be calibrated in terms of the equivalent orifice size in 64ths of an inch, millimeters or as a percentage of the maximum opening of the choke. The calibration is not generally very accurate, nor does it need to be, since it is the flowrate through the choke and the associated pressure differential which is important, not the absolute equivalent choke diameter.

Two types of adjustable choke are in common use:

Bean and Stem

The bean consists of a hard (tungsten carbide or ceramic) tapered orifice also known as the seat, into which a conical stem of similar taper and material is centred. The bean is fixed in the choke body but the stem may be inserted into or withdrawn from the bean by means of a threaded rod. The annulus between the bean and stem acts to control the flow through the total choke system. The bean and stem are both susceptible to erosion and each can be replaced.

Disc choke

This form of choke consists of two ceramic disc plates, fitted in the flow path through the choke body. Each of the discs has two (or more) circular holes, radially offset from the centre of the disc. One of the discs is fixed, the other can be rotated by means of an control shaft. Rotation of this disc allows of the holes to be positioned offset from each other resulting in a closed choke, or positioned in line resulting in the maximum choke size or in any intermediate position.

It should be remembered that an adjustable choke is not a pressure tight valve or sealing device and therefore some leakage can occur across a closed choke.

Fixed choke

The fixed choke is almost universally of the bean type. It has a cylindrical shape, which allows it to screwed into the choke body and a cylindrical hole of some fixed diameter passing through the centre. The diameter of the hole is made to a close tolerance and has a very smooth surface finish to minimise turbulence.

The inlet to the fixed choke suffers from a great deal of erosion during flow so they are typically manufactured about six inches long to give a reasonable service life.

The majority of chokes are manufactured in tungsten carbide. The best chokes however are manufactured with the body in tungsten carbide and have a ceramic insert, which greatly reduces the amount of erosion. Although the absolute size of a choke during well testing is not of great significance other than for media reports, the flow stability is important. Any erosion to the choke will result in an increase in the choke diameter. During the course of a long flow test this will be reflected in a steadily increasing flowrate and a decline in bottom hole and surface flowing pressure. These factors add a further degree of complexity to the well test analysis.

expro

WELL TEST OPERATIONAL GUIDELINES

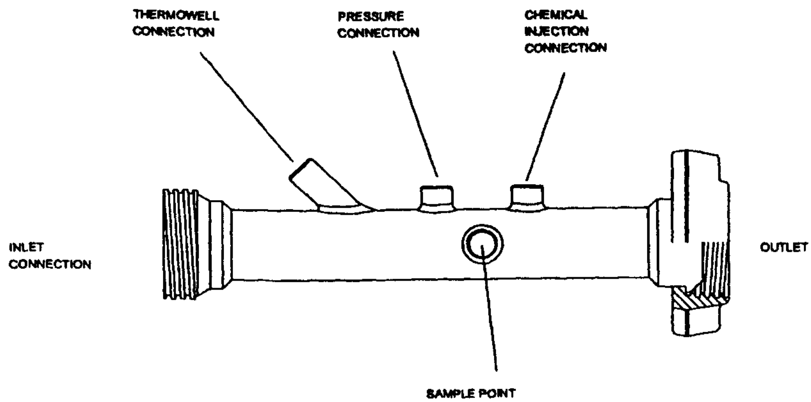


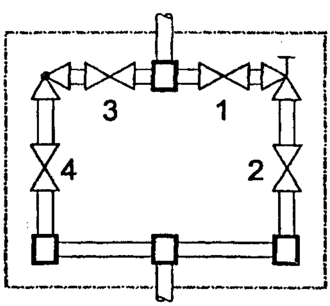
Figure 13.5

WELL TEST OPERATIONAL GUIDELINES

CHOKES AND CHOKE MANIFOLDS

SINGLE BLOCK CHOKE MANIFOLDS

STANDARD



MODIFIED

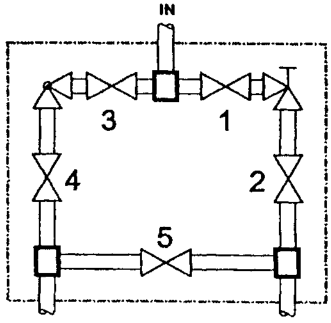


Figure 13.6

expro

WELL TEST OPERATIONAL GUIDELINES

CHOKES AND CHOKE MANIFOLDS

DOUBLE BLOCK CHOKE MANIFOLDS

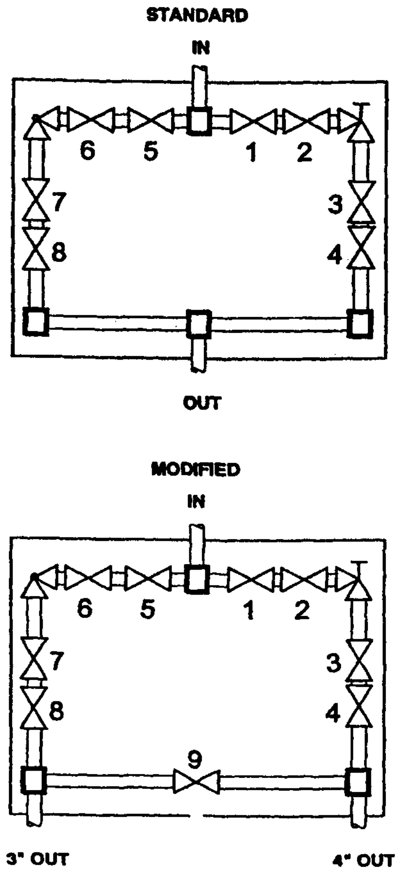


Figure 13.7

THE EXPRO GROUP

Choke Manifold (Four Valve)

Expro choke manifolds provide maximum versatility in well flow control and shut-in operations.

Description

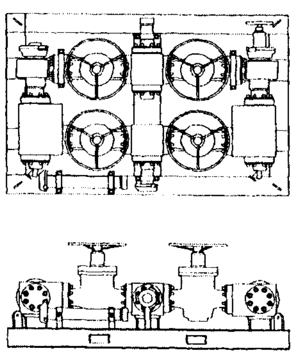
On one side of the flow path an adjustable choke is used allowing a more flexible control for the well bore clean-up. On the opposite side a positive fixed bean choke is installed which allows a more accurate flow control for pre determined flow rates.

Additional information

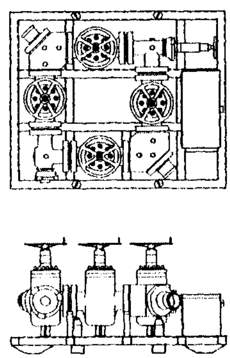
Available manifold configurations and sizes differ according to the clients demands and well conditions.

Both single and dual isolation valve arrangements are used, the later mostly for sand clean-up and high pressure applications where a double barrier between process fluids and the atmoshere when changing chokes.

There are also variations to the adjustable choke make and type. The larger bore units and some high pressure manifolds have a production choke installed rather than the traditional needle and seat.



Composite, 4 valve



Diamond Pattern, 4 valve

wt - 003

Tecnical information overleaf

Figure 13.8

13.10 Steam Heat Exchanger or Heater

The steam heat exchanger or heater is used to heat up the well effluent. Generally they are used when opening up wells where it is thought that hydrates may form, typically gas wells. However, they can also be used to aid separation of waxy or viscous crudes or to help break emulsions. These production related problems are further discussed in section 14.9

For offshore tests there is now a strong preference to use a separate steam generation unit and steam heat exchanger instead, of using a single heater unit. By using a separate steam generation unit, this removes a possible ignition source from the fluids passing through the heat exchanger.

The steam heat exchanger has two loops, a high pressure loop upstream of an internal choke and a low pressure loop downstream of the choke. Where a serious hydrate risk exists, it is possible to choke the well back using the internal choke at the heat exchanger. As this internal choke is at a much higher temperature than the regular choke manifold the possibility of forming a hydrate is consequently much reduced.

13.11 Horizontal Separator

The separator is the centre of the well test operation. It has many component parts, each of which must operate correctly if the test is to give meaningful results. Each well testing contractor has a slightly different design for their separators. However, there are many common features and figure 13.9 shows a typical design for a three phase horizontal test separator.

In the following sections some of the features of a typically test separator are discussed. Moreover, if these devices are installed within the shell of the separator they will greatly improve the operational efficiency. Among these devices are:

Impingement (Deflector) Plate

Fitted close to the separator inlet this plate produces an atomisation of the flow stream, particularly at higher rates. The resultant liquid droplets segregate more rapidly than they would during slug flow. However, at low rates the impingement plate loses its efficiency, but this is more than compensated for by the increase in retention time when flowing at a low rate.

Coalescence Plates (Dixon plates)

These plates are high surface area plates mid way in the separator and usually arranged in a chevroned design to allow coalescence (uniting or merging) of the liquid phase before it drops to the lower part of the vessel by gravity separation.

Horizontal Three-Phase Separator

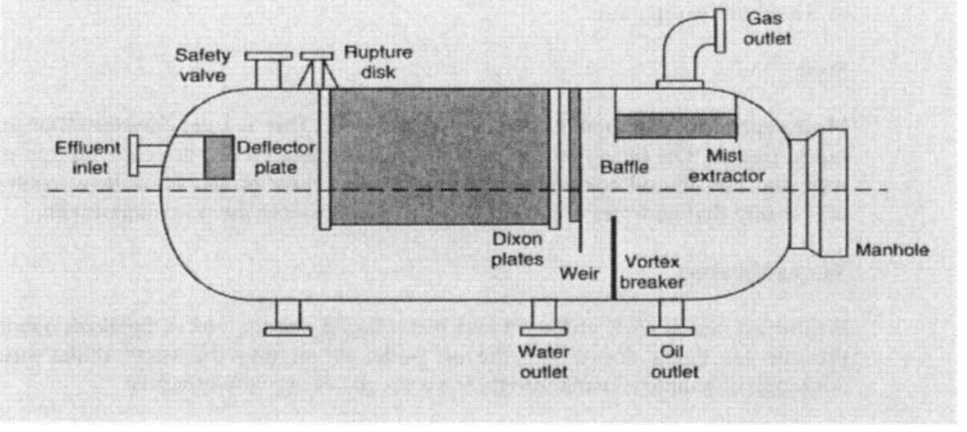


Figure 13.9

Courtesy of Schlumberger

Baffles

Baffles in the vessel body are usually either perforated metal plates or closely spaced sections of angle iron. Any gas flowing through these baffles is forced to follow a tortuous path. As the gas stream changes rapidly in direction any entrained liquid droplets are thrown, by centripetal force, against the baffles or vessel walls, from which they run down into the lower, liquid portion of the vessel.

Demister (Mist Extractor)

Positioned at the gas outlet line, a demister is a filter, fabricated from a metal or fibre glass mesh. They are limited in liquid capacity and are only capable of giving a final 'polish'. The lifetime of the mist extractor is limited and should be replaced during overhaul of the separator.

Weir

Most separators incorporate a weir of some kind. This is used for separation of the liquid phases. Oil sitting on top of water (if produced) will pass over the top of the weir and into the oil compartment. Correct adjustment of the water level controller; will ensure that no water is carried over the weir and into the oil compartment.

Vortex Breakers

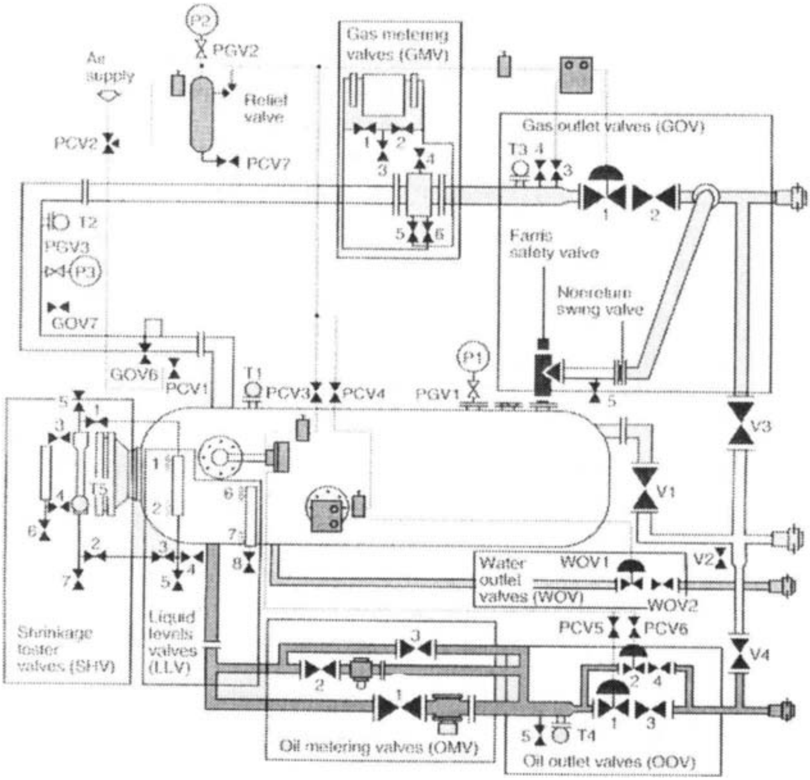
Positioned one at each of the oil and water liquid outlets, vortex breakers operate to prevent gas being drawn into the oil outlet or oil into the water outlet streams. Although of simple construction these vortex plates are very effective.

Control Systems

The operation of the separator is controlled by principally a back pressure valve on the gas line and liquid level controllers in both the water and oil compartments. The separator pressure is controlled by the gas back pressure valve (wizard) and the oil and water levels are controlled by two independent float type liquid level controllers. These control systems are pneumatic and can be run from either instrument air or indeed from well gas if required. Figure 13.10 shows the typical valve configuration, metering and control systems on a test separator.

It is not considered important to provide a detailed coverage of separator control systems in this chapter, as this is mainly dealt with by the service companies. However, some separator operational considerations are discussed in chapter 14.

Separator Flow Sheet



P1:	Separator pressure gauge	GMV:	Gas metering valves
P2:	Pressure gauge	GOV:	Gas outlet valves
P3:	Pressure gauge	LLV:	Liquid levels valves
T1:	Thermowell	OMV:	Oil metering valves
T2:	Thermowell	OOV:	Oil outlet valves
T3:	Thermowell	PCV:	Pilot circuit valves
T4:	Thermowell	PGV:	Pressure gauge valves
V1:	Separator inlet valve	SHV:	Shrinkage tester valves
V2:	Bleedoff valve	WOV:	Water outlet valves
V3:	Separator bypass valve		
V4:	Separator bypass valve		

Figure 13.10

Courtesy of Schlumberger

13.12 Vertical Separator

For testing of gas wells there are many advantages to the use of a vertical separator. As the total quantity of condensed hydrocarbon liquids and water is usually small the liquid chambers may be reduced in size, resulting in a smaller foot print for the separator, while still maintaining an adequate retention time.

One popular design of vertical separator is the vortex or centrifugal separator. In this type of separator the well stream inlet is tangential to the vessel producing a strong rotational effect. Any liquid droplets in the gas stream are thrown, by centripetal force, against the walls of the vessel and run down into the lower liquid section of the vessel, while the gas occupies the inner part of the vortex.

The gas stream is confined initially between two cylinders, consisting of the vessel wall and an internal cylindrical chamber. This confinement maintains the high gas velocity and centripetal force as the gas travels down the vessel. At the base of the internal cylindrical chamber the cross-sectional area available for gas flow is suddenly enlarged. The velocity is reduced and any remaining liquid droplets still in the gas stream fall to the base of the vessel as the gas escapes upwards inside the internal cylindrical chamber. A demister is used on the gas outlet for final droplet removal.

Owing to the considerable difference in density between condensate and water, the separation of the liquid phases is rapid and efficient. An 'anti-eduction' plate is positioned above the surface of the condensate to prevent the liquid being drawn up into the gas stream.

The vertical separator, where it is applicable, has two distinct advantages over the standard horizontal test separator. These are:

- The gas flowrate, at the maximum 1440 psi operating pressure can exceed 100 MMscfd. A typical horizontal test separator with low liquid level is rated for about 60 MMscfd.

- Being vertical, the separator and frame take up a smaller area (foot print), typically 6 ft. x 6 ft., as against the horizontal separator, which is normally 18 ft. x 8 ft. This factor may be particularly important for offshore testing operation where space tends to be limited.

13.13 Metering

Gas Metering

Gas measurement is universally performed by means of an inline orifice plate held in a gas meter which allows interchanging of the plates whilst flowing through the meter (Daniel orifice box or similar). The ability to change orifice plates as required allows measurements over an extended range of possible gas flow rates.

A calibrated instrument (usually a Barton) records the line pressure upstream of the orifice plate, the differential pressure drop across the orifice plate and the flowing gas temperature. (See Figure 13.11)

For accurate gas measurements the Test Engineer should ensure:

- That the recorder has been recently calibrated for each of the three scales.
- That the orifice plate fitted is flat, has sharp edges on the orifice and is installed correctly in the Daniels orifice box. (Chamfered edge downstream)
- That the orifice plate when installed, positions the differential pressure chart pen between about 50% and 80% of the chart range.
- That the method of calculation is traceable to an acceptable standard (normally the American Gas Association, AGA committee report No. 3). When manual calculations are being performed it is normally easy to confirm that the correct standard are being used. However, many well testers now use programmable hand held calculators or computers for gas rate calculations. The formulas used in these computations can come from many sources and may contain simplifying assumptions, thereby reducing the accuracy of the results. The AGA No. 3 method requires the calculation of eight different factors to give an accuracy of +/- 0.5% on gas rate measurements.

Operational Considerations of Gas Metering:

The control of separator gas pressure and therefore gas flow rate through the orifice meter is achieved by means of a pneumatic controller and diaphragm actuated valve. This control system can encounter problems with either a low gas flow rate or low separator pressure.

The valves commonly used on a horizontal test separator can pass up to 60 MMscfd at a maximum operating pressure of 1440 psig. However, with high separator pressures and low gas flow rates the valve is operating in a non linear portion of its range, which can result in unstable conditions. These conditions will manifest as rapid pressure changes across the orifice plate with detrimental effects on the quality of gas rate measurements. In such circumstances the separator pressure should be reduced to allow the valve to open further.

A similarly effect will occur if the separator is operated at very low pressures, when a standard 1440 psi bourdon tube is fitted to the pneumatic controller. The action of the controller can be non linear and unstable and this will have the same detrimental effect on the quality of gas measurements. The solution to this problem is to increase the separator pressure, however this may not be possible because of low flowing well head pressure. In this case the problem can only be corrected by changing out the bourdon tube to one with a lower pressure rating.

expro

WELL TEST OPERATIONAL GUIDELINES

EQUIPMENT HOOK-UP

SEPARATOR BARTON HOOK-UP

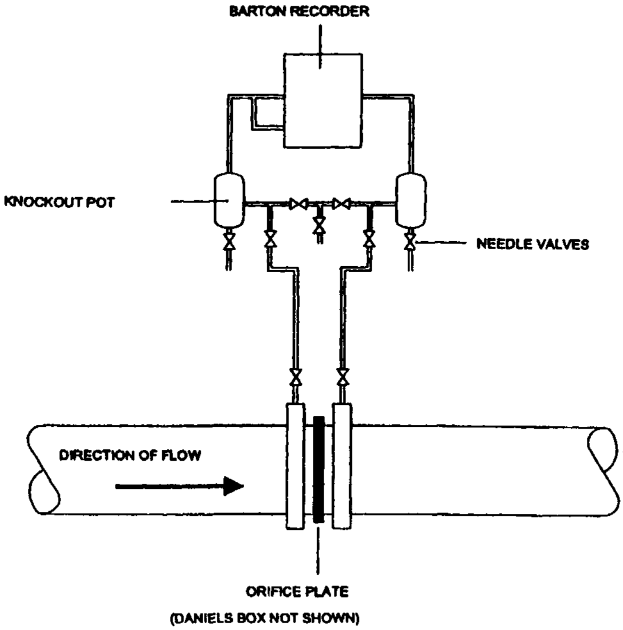


Figure 13.11

Oil Metering

The oil metering systems used on a well test separator will differ depending on the manufacturer and the well testing contractors. The simplest system consists of two meters in parallel linked to a common liquid level control valve. One of the meters is typically a low range positive displacement (paddle) type meter operating in the range 100 to 2,200 BPD; the other is often a cage type operating in the range 850 to 8,500 BPD or sometimes 2,200 to 22,000 BPD. Separators with a single liquid level controller arrangement operate satisfactorily over much of the separator range, but can experience problems under some conditions as discussed below.

Using only a single level controller when the flow rate is low and the pressure is high (as may occur with a gas and gas condensate well); the level control valve may be operating in the non-linear portion of its range and can become unstable. A similar effect may also occur at high rates and low pressures (as with a high flow rate and low GOR oil well) the valve may not be able to open sufficiently to allow control of flow, again resulting in fluctuating levels and separator pressures.

Both of these problems can be rectified by the introduction of a smaller level control valve in parallel with an enlarged main valve. At low rates the smaller valve alone may be used, changing over to the larger valve as the limit of the smaller is reached. The enlarged main valve and associated pipework will allow stable level control at higher rates and lower separator pressures. (See again figure 13.10)

A further refinement found on some modern test separators is the use of two mid range meters, such as 5,000 BPD turbine meters in parallel, as an alternative to a single 10,000 BPD meter. The lower range on each of these meters overlaps that of the dedicated low range meter. Each of these 5,000 bpd meters may be used for comparison against the other, assuming that the oil flowrate is within the capacity of one meter, and in that event they may also be changed out or maintained without shutting down the operation.

To ensure the accuracy of flow rate measurements the Test Engineer should request that all meters are independently calibrated and calibration certificates should obtained, prior to shipment of the separator to the well site. Field calibration can be performed using a gauge tank and water pumped via the rig pumps, cement unit or transfer pump. This will only be accurate if the calibration on the gauge tank is reliable. In any event the meters will always have a meter correction factor (MCF) and this is often combined with the oil shrinkage factor determined by flowing to the tank to give a combined OMCF (Oil Meter Correction Factor) and shrinkage factor.

The liquid volume flowing through an oil meter as it exits from the separator still contains a quantity of dissolved gas which is related to the temperature and pressure of the liquid and a small percentage of water, depending on the separator efficiency. Moreover, a quantity of the liquid passing through the meter will eventually be lost at the stock tank as a result of evaporation of 'light ends' which is known as shrinkage. In addition there will also be a volume reduction at the tank related to the temperature difference between the oil meter line and the tank. Thus there is a discrepancy between the metered volume and the stock tank volume. Indeed, there are a number of factors that have to be accounted for in order to report stock tank oil volumes at standard conditions, usually 14.73 psi and 60 degrees Fahrenheit.

Oil volumes at standard conditions are calculated as follows:

$$V_{sc} = V_s \cdot MCF \cdot (1-SHR) \cdot (1-BSW) \cdot K$$

Where:

Vsc	=	Oil volume at standard conditions
Vs	=	Oil volumes measured at separator conditions by the meter.
MCF	=	Meter Correction Factor = True Volume / Metered Volume
SHR	=	Shrinkage Factor (from shrinkage tester)
BSW	=	Water and sediment % measured at the separator outlet
K	=	Temperature volume correction factor to standard conditions

It is important to note that the temperature used to calculate the volume correction factor to standard conditions is either the tank temperature or the shrinkage tester temperature depending on which method was used to determine shrinkage.

The 'shrinkage factor' may be determined in one of two ways.

a) By flowing for a fixed period through the meter into a calibrated stock tank and comparing the two volumes. This operation is feasible at low to medium flowrates. At high rates the stock tank fills up rapidly and the inaccuracies measured in the times to open into and to bypass the tank can lead to significant inaccuracies if used to calculate rates. Using the tank to determine shrinkage will in fact provide a measurement of both the shrinkage factor and the meter factor at this rate. Under these circumstances the meter correction factor and shrinkage factor are combined in the above formula and is known as a combined meter correction factor and shrinkage factor. The tank volume is usually measured after 15 minutes, as there will be no further appreciable amounts of gas coming out of solution after this time. Along with the tank volume the temperature must be noted and this will be used for determination of the K factor.

b) By use of a 'shrinkage tester'. This consists of a calibrated chamber with a sight glass. Oil from the separator is slowly introduced into the chamber at separator pressure and temperature conditions. The filling operation is stopped when the level reaches some pre-calibrated mark. After isolating the shrinkage tester from the separator the gas cap and dissolved gas are very slowly vented off through a small orifice, venting too quickly allows heavier ends to flash off giving an erroneously large reduction in volume. The shrinkage tester sight glass is usually calibrated directly in percent shrinkage as shown in figure 13.12.

WELL TEST OPERATIONAL GUIDELINES

expro

3.16 GAS, OIL AND WATER SEPARATORS

FIG. 3.27 SHRINKAGE TESTER

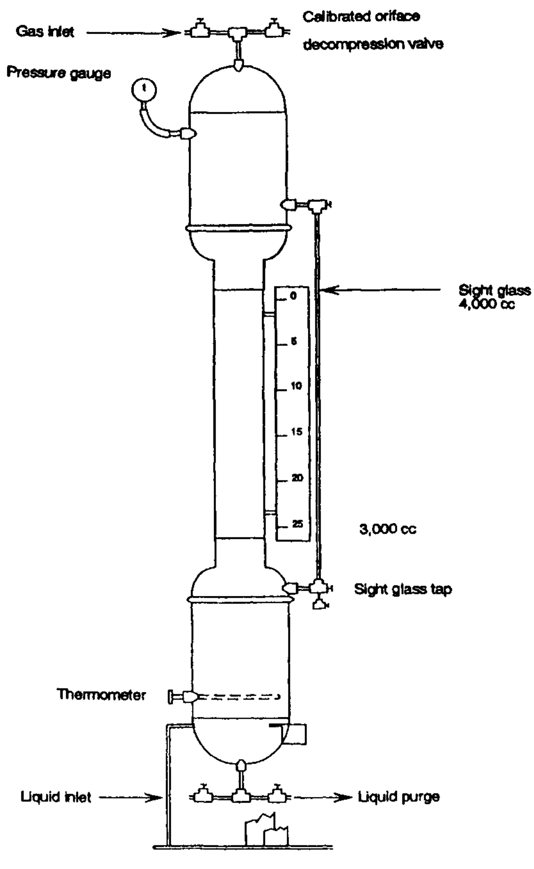


Figure 13.12

13.14 Electronic Surface Data Acquisition

All but the simplest of tests now usually have an electronic data acquisition system. These systems allow continuous monitoring of all pertinent parameters throughout the test. The parameters which are routinely measured are: annulus pressure, well head pressure and temperature, down stream choke pressure, separator pressure and temperature and orifice plate differential pressure. Sensors are also attached to the oil and occasionally the water meter to provide continuous liquid production rates.

The acquisition systems also allow connection of various sensors to detect hazardous substances such as H_2S or to connect sensors for monitoring of critical temperatures such as BOP temperature during an HP/HT test.

Pressure and temperature data from the surface read out (SRO) tools, if used during the test, can also be interfaced to the surface data acquisition system. This will then allow bottom hole pressures, temperatures, surface flow rates and GOR to be plotted on a single display if required. Where only memory gauges are being used during the test it customary to merge the memory gauge TTP (Time, Temperature, Pressure) file with the surface data after the job to provide plots similar to those acquired in real time with the SRO gauges.

The calibration all of the sensors must be checked before the start of test against a known standard such as a dead weight tester for pressure and for temperature, ice and the boiling point of water. In the past, some surface sensors were prone to drift and it is important to perform post job calibrations to confirm the accuracy of the data.

Finally, the electronically acquired data can be sent around the rig to the drill floor or company mans office or indeed transmitted by satellite to anywhere in the world allowing a variety of specialist the opportunity to view the data in real time.

13.15 Gauge Tank

The gauge tank is a calibrated liquid storage tank (usually twin compartment) which typically holds 50-100 barrels of liquid. The gauge tank is used for the following:

Pre-test calibration of the separator flowmeters.

Calibration of separator oil production rate to stock tank barrels.

Producing the perforating cushion back to surface for re-use or for measuring the clean-up rate.

Note: The gauge tank is never used where H_2S is present because gas released from the gauge tank is vented to atmosphere in the vicinity of the tank. Increasingly surge tanks are used in preference to gauge tanks offshore.

13.16 Surge Tank

The surge tank was originally designed as a second stage separation device. However, it is more commonly used to replace the gauge tank on offshore or H_2S tests.

From its original design as a second stage separation vessel the surge tank has the following features: single compartment pressurised vessel with a maximum working pressure of 50 psi and a pressure control valve on the gas outlet to maintain a back pressure. As with the gauge tank there are sight glasses to determine liquid levels and most tanks also have high and low level alarms.

A main feature of the surge tank is the gas outlet line, which is run independently from the atmospheric vent, to a safe location away from personnel and possible ignition sources.

13.17 Transfer Pumps

Transfer pumps are used to pump out dead oil from gauge tanks or surge tanks. With the gauge tank this can be done while the second compartment is being filled. With the surge tank this is undertaken when flowing to the burners or during a build up.

Most transfer pumps are electrically driven although diesel driven versions are available. There operate at fairly low pressures typically a few hundred psi and have pump rates of about 2000 bopd.

If the oil from the tank has to be pumped into a flow line such as on a platform then a high pressure / high capacity will be required with a pump discharge pressure exceeding the flow line pressure.

13.18 Gas Diverter Manifold

The gas diverter manifold (see Figure 13.13) is included in the well test rig up offshore to allow continuous testing with regard to the prevailing wing direction. The diverter manifold allows gas to directed to either the port or starboard burners without interruption to the flow.

13.19 Oil Diverter Manifold

The oil diverter manifold (see Figure 13.14) provides the same function as the gas manifold i.e., an ability to continuously flow the well by allowing oil to be directed to either the port or starboard burners to account for the prevailing wind direction.

However it also has the additional feature of allowing oil to be directed to a gauge or surge tank to obtain meter correction or shrinkage factors.

WELL TEST OPERATIONAL GUIDELINES

EQUIPMENT HOOK-UP

GAS DIVERTER HOOK-UP

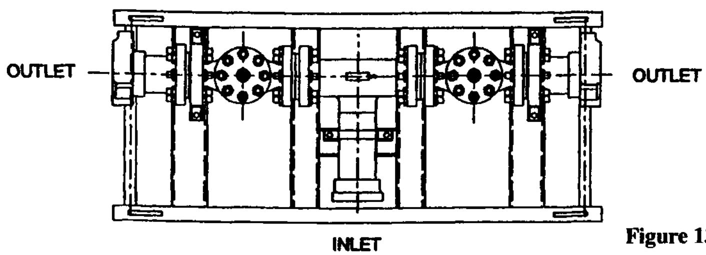


Figure 13.13

expro

WELL TEST OPERATIONAL GUIDELINES

OIL DIVERTER MANIFOLDS

OIL DIVERTER MANIFOLD

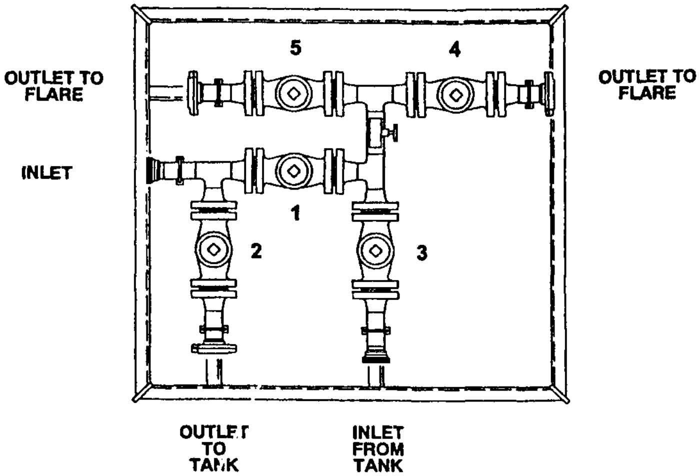


Figure 13.14

13.20 Burner Booms

The primary function of the burner boom in addition to supporting the burner is to limit the heat radiation and noise on the rig to an acceptable level.

Occasionally, offshore drilling rigs come equipped with their own burner booms. However, generally this is not the case and early consideration of the booms for the test should take place. Consideration must be given to the length of boom required as a variety of lengths exist between 60' and 90' long. The choice of boom will be driven by a number of factors: expected flow rates, king post loadings, requirements of the drilling contractor and availability.

The booms are of modular design and come equipped with the necessary piping: oil, gas, air, water and propane to feed the burner. They also have rotation plates allowing minor modifications to orientation to take place to account in part for changes in the prevailing wind.However, the principal way of accounting for major changes in wind direction is to divert to the opposite burner.

Installation and pressure testing of the boom flow lines should be carried out well in advance of the planned test. In some cases welding may be required and this has to be scheduled around other activities on the rig.

For high rate testing <u>additional</u> water spray cooling mid way along the burner may also be required to meets the heat radiation requirements of the rig.

13.21 Standard Oil Burners

Offshore well tests will normally have a proper hydrocarbon burning system, while for onshore tests a much simpler arrangement may be acceptable. For onshore test it depends principally on where the well is located, what local regulatory policy exists and on the environmental policy of the local operating oil and gas company .

<u>Onshore</u>

For onshore tests, oil and gas flare lines can be used which directs the flow to a dug out flare pit where well fluids are ignited. The flare line generally consists of old sections of drill pipe or tubing. These pipes should be pressure tested using a TIW valve or similar on the end of the pipe and then the valve must be removed.

Prior to digging the flare pit, the site layout should be considered and also the prevailing wind direction. Flow lines in particular gas lines, should be secured to the ground normally with stakes or concrete foundations.

Environmental considerations onshore now often require the use of atomising burner heads rather than the burning of fluids directly in the flare pit.

Offshore

Unless the oil is being exported via a pipeline or to a tanker oil burners will be required. Many types exist and all of the testing contractors have their own particular design, some examples are shown in figure 13.15.

Offshore tests use two burner systems, one on each side of the rig. This enables combustion of hydrocarbons from either one side of the rig or the other depending on the prevailing wind direction. The burner system includes a burner boom, air compressors, an ignition system, burner heads for the oil and an open pipe for the gas, with a water deluge system.

To ensure the full combustion of the hydrocarbon liquids, compressed air is used from independent air compressors. The rig air system is no longer used because of explosions that have occurred on rigs caused by hydrocarbons from the flare getting into the rig air system. On most designs of crude oil burner compressed air mixes with the oil in an atomising chamber and the oil is converted into tiny droplets by the turbulent action of the air on the liquid oil. The oil is then easily ignited and depending on the flow rate the flame may be 75' – 100' long. At about 6ft from the burner focused jets of water enter the flame, where the water is evaporated and a water gas reaction occurs. This reaction prevents the production of carbon black and the flame burns clean (yellow) and almost smokeless.

13.22 Green Burners

With increasing environmental awareness, all the major testing companies have developed some form of "Green Burner". These new generation burners produce essentially no fall out or smoke. An example of a green burner is shown in figure 13.16.

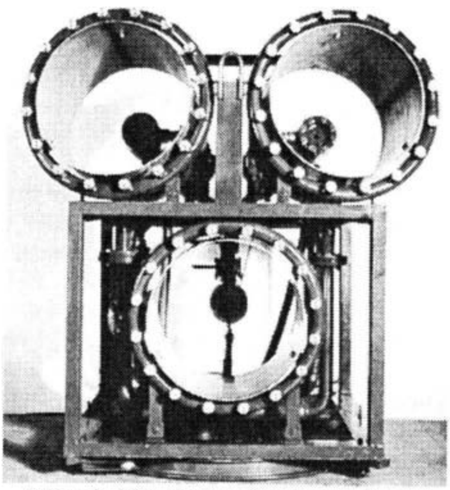
In common most green burners have a major drawn back, that is, the requirement for vast quantities of compressed air.

Typically a green burner will require 4 to 6 times the volume of compressed air that a standard burner requires. Therefore, before routinely specifying green burners one should consider the requirement for them, for example, local environmental regulations or green policy of the local operating oil and gas company.

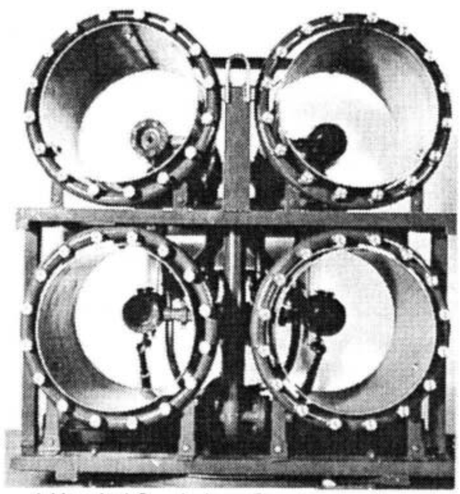
In summary, there are many reasons why green burners are not routinely used on all tests and they are: no regulatory requirement, not available in area of operations, may be impractical to locate the large number of compressors required on some offshore exploration drilling rigs and much higher operating costs (compressor rental).

Surface Testing **Standard Well Test Equipment**

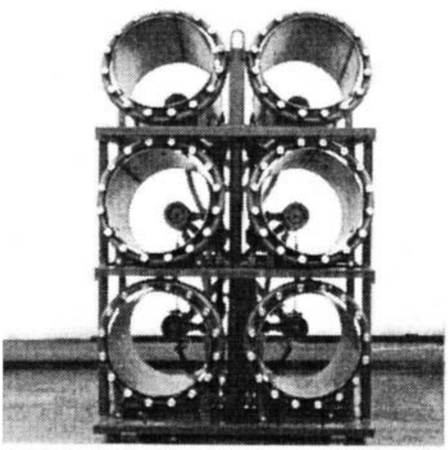
Burners



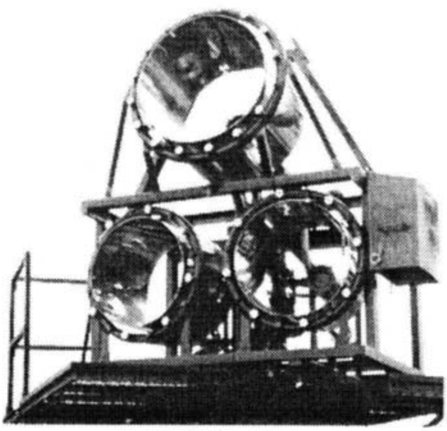
3-Headed Smokeless Seadragon Burner



4-Headed Smokeless Seadragon Burner



6-Headed Smokeless Seadragon Burner



Invert Oil Mud Burner

Figure 13.15

Courtesy of Schlumberger

EverGreen

A THERMIE PROJECT

The pioneer in offshore oil burning introduces a new environmentally friendly well test burner

In the late 1960s Schlumberger introduced the first offshore oil burner, the Giant*. It was followed by the Seadragon* series of burners, which remained the reference for many years.

In 1993, a new project was launched, with financial support from the European Commission THERMIE program and the scientific contribution of the Institut Français du Pétrole, to develop a radically new well test oil burner to eliminate liquid fallout and heavy smoke emissions. In March 1997, the new EverGreen* burner was used for the first time on a North Sea development and passed the test: no liquid fallout and no visible smoke.

Development

The EverGreen burner design is supported by extensive flame and combustion computer modeling performed by IFP's Energy Application Department. This research enabled the developers to make the best usage of free jet theory to introduce the required amount of air into the flame.

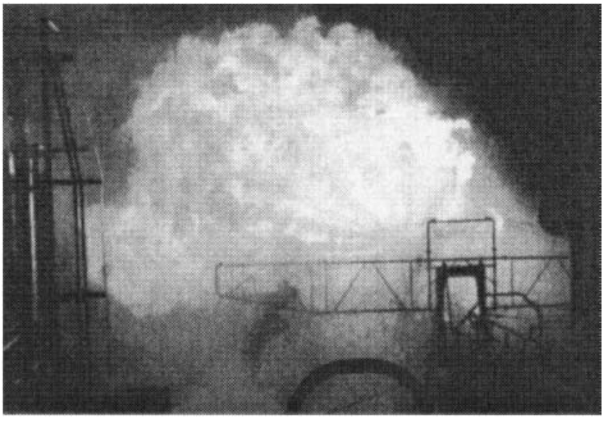
This theoretical work is backed by more than 100 live experiments performed on a dedicated burner test range specifically set up for the project. These included numerous burning trials with heavy fuels, as well as noise and heat radiation measurements.

Features

- Multiflame arrangement–The EverGreen unique multiflame arrangement promotes fresh air entry into the heart of the flame for a clean combustion.
- Ignition–The EverGreen burner's twin gas-fired pilots are lit by a flame-front ignition system. Oil ignition is instantaneous, eliminating any possibility of fallout during this critical phase of operation.
- Shutoff valve–An automatic shutoff valve in the burner head interrupts oil flow to the nozzles as soon as oil pressure drops below a few bars.
- Water screens–Highly efficient water screens absorb up to 60% of the heat radiated towards the back of the burner.

Benefits

- No smoke–Very high temperatures in the center of the flame prevent soot formation. This distinct characteristic eliminates any need for water injection into the flame, avoiding detrimental cooling of the flame.
- No fallout–High flame temperature and short flames ensure rapid vaporization of the oil, which burns over a short flame path. No liquid droplets escape the combustion field, thus eliminating liquid fallout.
- Low maintenance–The simple construction translates into little maintenance, which means your EverGreen burner is available and in top condition when duty calls. The burner head mounts on a rotating arm that brings it back over the boom catwalk for easy, safer inspection.
- No plugging–Water screens tolerate scales that typically plug conventional sprinkler nozzles.
- No dumping at end of burn–The shut-off valve in this environmentally friendly design avoids spilling the contents of the oil lines at the end of a burning run when oil flow is stopped upstream the burner head.
- Stable flame–Conical shape of flame gives it excellent stability even in adverse wind conditions.



First burn. In its first offshore operation on a development in the North Sea, the EverGreen oil burner passes the test: no liquid fallout and no visible smoke

Courtesy of Schlumberger

EverGreen* Mark of Schlumberger

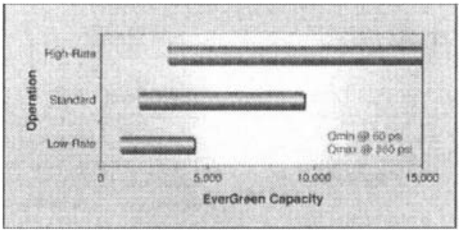
www.connect.slb.com

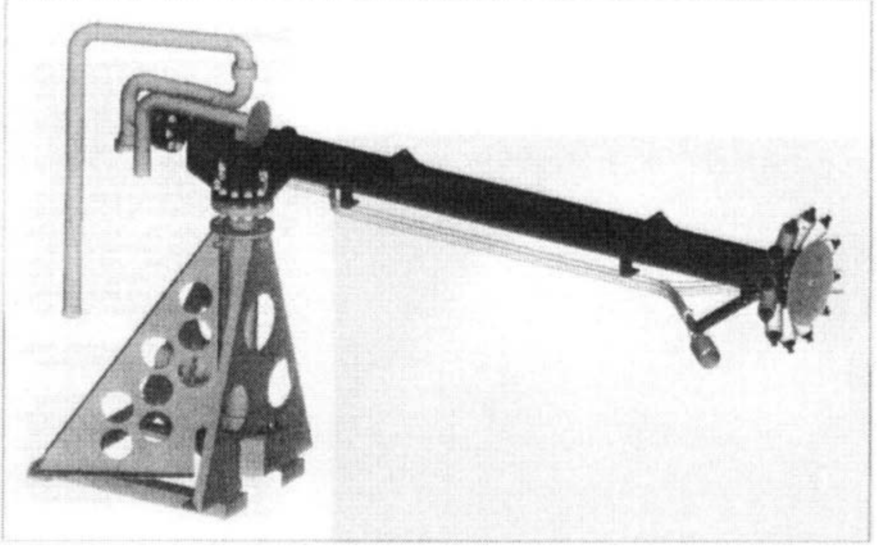
Figure 13.16

EverGreen

Specifications

Max. pressure	1000 psi [68 bar]
Max. oil viscosity	70 cp at ambient flowing temperature
Air requirement	5 x 1200 ft^3/min [33.98 m^3/min] at maximum oil flow rate
Flame diameter	42.65 ft [13 m] at maximum flow rate
Water screen	15,000 BWPD at 150 psi [10.2 bar]
Heat radiation	650 Btu/hr/ft^2 at 98.4 ft [2.048 kW/m^2 at 30 m] with water screen
Noise	90 dBA at 98.4 ft [30 m]
Weight	2000 lbm
Connections	3-in. [7.62-cm] oil line 4-in. [10.16-cm] air line 3-in. [7.62-cm] water screen line 1-in. [2.54-cm] flame front ignition line 0.5-in. [1.27-cm] gas pilot line





Computer-aided design of the EverGreen oil burner

Courtesy of Schlumberger

EverGreen* Mark of Schlumberger

Figure 13.16(cont.)

13.23 Equipment Hook Up and Location

Typically the surface equipment hook-up for a well test will vary depending on the nature of the fluids being tested, the anticipated flow rates and pressures and with the well location, on or offshore. For example during onshore tests of oil wells, if a market for the oil is readily available nearby, then the oil may be stored and sold rather than burned off.

Offshore the precise location of equipment may depend upon how much permanent pipework is available on any particular rig. Some rigs will have both high pressure and low pressure flowlines permanently installed and when possible these should be utilised, assuming they are in good condition. Some alterations to fixed pipework may be necessary, for example, flanges, flow 'T's and elbows and such work can only be carried out after consultation with the rig manager. No major modifications should be attempted unless (a) there is more than sufficient time to complete the work before the commencement of the test, (b) a long term drilling/testing campaign is envisaged with the same rig.

Another control on the equipment location is the amount of available deck space for the equipment that is planned to be utilised. Deck plans, deck loading and indeed the balance of the deck load and ballast of the rig are important for floating rigs and all these may have to considered to find the optimum equipment layout. Figure 13.17 shows a typical offshore surface testing setup.

In the North Sea, the well test equipment layout and P&I.D. (Process and Instrumentation Diagram), must also be approved by the rigs certifying authority.

Equipment layout problems generally do not occur during land operations; where adequate site clearance will allow the engineers to suit their own requirements. However this is not always the case, for example, wells being drilled in some locations in the South American rain forests are severely limited by the amount of land that can be cleared to locate the rig, because og environmental constraints.

<u>Offshore Rigs</u>:

On offshore rigs where no permanent pipework exists but the deck space is limited, the following guidelines should be adopted:

- Carefully plan how the equipment is to be laid out and discuss this with the drilling supervisor and rig superintendent.

- All pipework runs should be kept to a minimum length whenever possible, especially those that will be subjected to the highest pressures, for example between the flowhead and the choke manifold. Although this will probably mean placing the choke manifold on or close to the rig floor, the safety aspects generally outweigh any inconvenience caused.

When space limitations preclude locating the choke manifold on the rig floor it is advisable to select an area that is close to the main test equipment, so that good communication can be maintained.

- Limit the number of bends and elbows, especially if a frac job is planned, as cutting out of surface lines by sand production can be a problem. In some instances it might be worth considering a duplicate run of pipework (sacrificial line) so that production can be switched whilst remedial work is carried out.
- Secure all temporary flowlines, particularly those upstream of the separator. Normally pipe clamps will be provided by the testing contractor allowing for pipe runs to be wired together and attached to a rigid permanent fixture.
- A vent pipe from the surface storage tanks (surge tank) must be utilised to direct gases and vapours well away from deck areas and accommodation. It should be noted that these vapours can be heavier than air and therefore the pipe outlet should be below deck level.
- All tank outlets must have flame arrestors.
- Burners should be positioned with a regard to the prevailing wind direction.

13.24 Flare Lines

Normally oil lines to burners can be pressure tested to the burner heads and therefore can be considered in the same manner as any other pressurised process piping.

However, gas flare lines do not have valves fitted at the combustion end and are therefore a special case. The routing and sizing of gas flare lines also requires careful consideration with regard to the specific nature of the test.

General considerations are as follows:

- All flare lines should be run as straight as possible with no dead legs, they should have no instrument tappings and a minimum number of elbows.
- The number of pipe connections should be minimised.
- The only valve in the flare gas system should be a routing valve at the diverter manifold for directing gas to either flare. A block valve on the test separator will be required for pressure testing upstream of the flare lines. At the conclusion of pressure testing this valve should be locked in a fully open position to prevent accidental closure.

- A non-return valve and flame arrestor can be located towards the end of each burner boom, (or immediately prior to the flare stack or flare pit for onshore tests).

- All joints on the flare line should undergo a thorough visual inspection prior to the test. During the first production period an inspection for leaks should also be carried out on each connection.

- Flare lines should be sized to allow minimum pressure drop along the line and hence minimum back pressure on the separator control valve.

- For an onshore oil well test where the gas rates are expected to be low and the flow periods long, consideration should be given to installing a liquid knock out pot on the gas line to ensure liquids accumulating in the flare line do not slug through to the flare.

13.25 Vent Lines

Vent lines are typically run from surge or stock tanks to an atmospheric vent at a safe location away from personnel and any possible ignition sources. They should be directed overboard in the case of an offshore rig and extend 3m below deck level.

These lines allow any free gas or evaporated light ends to be released safely.

Tank vents should not be routed to the flare boom, as the quantity of flammable gas to be disposed of is small. Therefore it is likely that air would ingress into this system with the possibility of an explosive mixture being formed.

A continuous purge can also be run to the tanks using either a line from the test separator, or bottled Nitrogen. This will maintain a steady flow of gas to the vent and therefore reduce air ingress.

The end of the vent line should also be protected with a flame arrestor so that accidental ignition of the vent will not cause a flash back to the tank.

All vent lines should be run as straight as possible and should not contain valves between the tank and the vent tip. There should be no dead legs in the line and the whole line must have a sufficient gradient to drain freely under gravity. The ability to drain under gravity is very important as a few inches of condensate accumulating in a dead leg can create sufficient back pressure to cause an atmospheric tank to rupture.

13.26 Relief Lines

In addition to flow lines and vent lines in the system, there is also a requirement for a pressure relief line from the separator and surge tank. These line must be appropriately sized so as to provide the minimum back pressure vis-à-vis the expected operating pressure and allow fast blow down of the vessels.

The separator gas pressure relief line must not be tied common to the gas flare line and should be directed away from personnel and any possible ignition source.

On high H_2S wells it may be deemed appropriate following a HAZOP review to run the relief lines to the burner booms, as the risks associated with combustion of the separator contents on discharge may be less than those associated with release of H_2S close to the rig.

13.27 Emergency Shutdown System

The well and the surface test facilities should be protected by an integrated emergency shutdown (ESD) system. This system should be a "fail safe" system in order that any loss of instrument air or hydraulic power to the system will cause the well to be safely shutdown. The ESD system required for a test may be developed as part of a safety or hazardous operations review (HAZOP).

Input signals to the ESD system will vary from test to test.

Standard inputs are listed below:

- High pressure upstream and downstream of choke manifold.
- Low pressure upstream and downstream of choke manifold.
- High liquid levels in separator.
- High pressure in separator.
- High level in liquid stock/surge tanks.
- Local flammable gas detectors.
- Local H_2S detectors.
- Manually operated shutdown buttons located, on rig floor, near the separator, near burner booms or the flare and at a safe locations on the main evacuation routes from rig.

Additional shutdown inputs may be incorporated where considered appropriate depending on the nature of the test and the type of test equipment available.

Typically when the ESD system receives an input signal from any of the above sources the well will be shut-in. This will usually occur by the ESD system relieving hydraulic pressure to the hydraulic wing valve causing it to close.

A means of identify which pilot has tripped the ESD system is useful in the event of a shutdown as it allows the problem to be more easily identified and rectified.

On offshore HP/HT well tests, consideration may also be given to connecting the SSTT valves into the ESD system. However, if this is done there should be a facility to remove the SSTT valves from the ESD system when conducting wireline operations. Refer to The Institute of Petroleum, Model Code of Safe Practices, Part 17, "Well Control during the Drilling and Testing of High Pressure Offshore Wells".

It is advantageous if the remote shutdown buttons are linked to the hydraulic controls through a low pressure (instrument air) pilot operated system. This is not only safer in terms of the operating pressure, but it also allows the use of low pressure plastic hoses which will melt in the event of a fire, automatically shutting in the well.

There may be some cases, for example high pressure gas wells where a 'blow down' system incorporated in to the test separator is advisable. This is activated immediately after the well is shut-in, depressuring all the facilities downstream of the hydraulic wing valve, or surface safety valve. This is done through a 'blowdown' valve located on the test separator to a vent at a safe location or perhaps to the flare boom in an H_2S scenario. The back pressure in these lines must be carefully considered when venting at these rates to ensure that it does not exceed the design pressure of the line.

Typical Offshore Surface Testing Setup

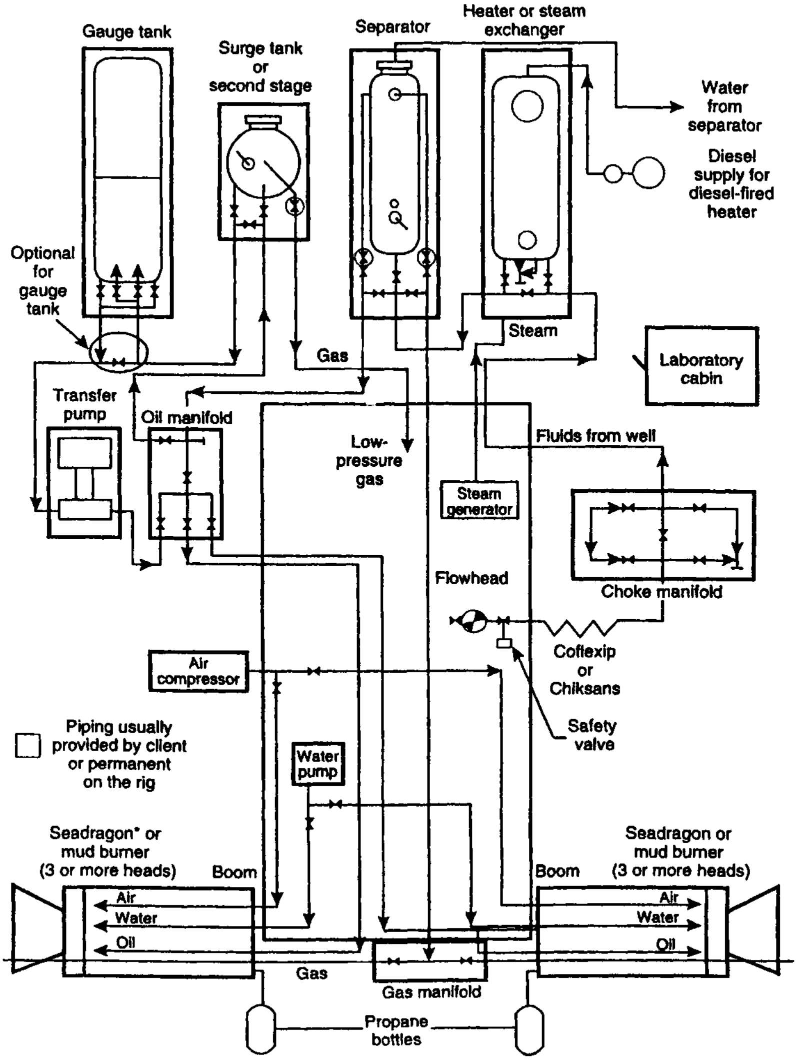


Figure 13.17

Courtesy of Schlumberger

CHAPTER 14

WELL TEST OPERATIONS

Recommended Practices:

1. Critical flow should be maintained across the choke if possible.

2. The well should be opened on a small (e.g. 16/64") choke and then beaned up no faster than 4/64" every 5 minutes to a moderate choke size of about 28/64" depending on well conditions then change to a fixed choke. The cushion should then be unloaded and the well monitored for sand production, checks on equipment integrity should take place, prior to beaning up further.

3. The well should be shut-in at the tester valve first then at the choke manifold.

4. The separator flowmeters should be calibrated prior to the test.

5. For offshore tests the weather forecast (including wind direction) should be checked prior to igniting the flare to ensure that the flow is directed to the correct side of the rig. A good weather window is particularly important for operations from floating vessels, to ensure that the test can be carried out with the minimum of interruption.

6. Prior to flaring, the relevant authorities should be informed of the impending flaring operations.

7. Portable air compressors must always be used for the oil burners, where fitted. The rig air system must not be used under any circumstances.

14.1 Equipment Checking

Tests must be planned well in advance. This may include identification of the equipment that will be used for a particular test at the service company yard and allocation of that equipment for the test. If possible pressure testing of this equipment should be witnessed at the yard as well as a check made on the equipment certification.

The following is a guideline to what should be checked:

- Traceability of components.
- Data books – inspected.
- Service records – inspected.

- Dimensional checks.
- Instrument calibration.
- Safety valves calibrated and certified.
- Piping threads - inspected.
- Elastomers rated for service.

Checks should also be made that adequate back-up equipment will be sent out to the rig. This is especially important in remote areas where spare parts may take a number of days to reach the well site in the event of equipment failure.

Once the test equipment arrives at the rig, serial numbers should be checked to ensure that the equipment sent is the same as was allocated at the yard. In order to facilitate equipment checking, a load out list with serial numbers, weights and dimensions should be requested from each service company. This will be also required for the supply boat cargo manifest when sending equipment to offshore locations.

14.2 Operational Considerations for Equipment Layout

The layout of well test equipment will to a large extent be dictated by the location of the well, offshore or onshore. The following guidelines should however help to ensure the safety of operations with regard to the layout of surface test equipment.

Whenever possible the equipment should be located in a 'quiet' area of the deck, or well site. This means away from areas that are frequently used for temporary equipment storage and over which equipment is frequently lifted. The location should be well ventilated and away from 'dead air' areas, and sub floor levels. In practice often the only area available on many offshore rigs is the pipe deck and this will require a great deal of back loading of drilling equipment before the test equipment can be picked up and spotted. However, some semi-submersible rigs have dedicated well test areas on the aft end with permanent piping to the drill floor and burner booms and these area should be utilised when available.

When positioning equipment, consideration should also be given to the distances separating individual pieces of equipment from possible ignition sources (see Zone System below).

In the North Sea, surface equipment layouts on contractors rigs must meet with their certifying authorities approval. This does not necessarily apply elsewhere, but the layout should at least be discussed with the rig contractor (See also Section 13.23).

When considering the placement of equipment all available space should be utilised to allow good access to both sides of the equipment. The equipment should also be located to make the best use of the available lighting, especially around instruments and controllers. The lighting available on offshore rigs in not always ideal for testing purposes but will usually suffice. On onshore locations the lighting is generally inadequate in all areas other than those immediately next to the rig and additional portable lighting will be required. The lights to illuminate the well test area will normally be on telescopic masts located at the perimeter of the site although explosion proof lighting will also be required near to the test separator area. Any temporary lighting installed at a well site should be approved for the particular zone or area of operations. In addition the installation of lighting or any other electrical equipment must be carried out with the assistance of the rig electrician.

The test equipment should also be located so that coverage by the rig or well site fire fighting equipment is adequate.

Lines of sight from the rig floor to the test separator, and from the separator, and rig floor to the flare is important especially when opening up or shutting in the well. If this is not possible then VHF radios will be required.

All flare lines should be tied down across elbows and along pipe lengths if possible. This is especially important when opening up wells, for wells which slug badly and for high pressure tests.

In laying out pipe runs, possible trip hazards should be considered especially in areas where access is likely to be frequent. Where a trip hazards cannot be avoided high visibility paint or tape should be applied to the pipework and safety signs should be posted. Alternatively steps over pipe runs can be constructed but this will normally only be undertaken when extended tests are planned.

Instrument control lines and electrical cables should be supported and protected to avoid mechanical damage. In many cases this will mean having the cables slung overhead although consideration for possible crane movements will have to be considered.

Finally the area around the surface test equipment should be classified as an area restricted to essential personnel only and roped off with signs posted. Permits to work must be obtained where applicable and regular announcements should be made over the public address systems during critical parts of the test.

Zone System

There is an Area Classification Code for Petroleum Installations, which forms Part 15 of the Model Code of Safe Practice series issued by the Institute of Petroleum, U.K.

Although relating to U.K. legislation, it is instructive in the placement of equipment. The code classifies hazardous zones by considering how long a flammable atmosphere is likely to occur in a particular area. It then gives guidance on the selection of electrical facilities according to hazard zones and on the location and control of non-electrical sources of ignition.

14.3 Flowmeter Calibration

Calibrations of the flowmeters on the test separator should have been carried out in the testing contractors yard. At the well site, the flowmeter calibration should be checked using the rig pumps, cement unit or transfer pump by flowing water through the meters to the gauge tank. If possible a number of different rates should be checked using 10-20 barrels volume per calibration rate. Should significant differences exist between the site check and the main calibration, a full re-calibration should be undertaken over the range of flowrates expected during the test. The meter tolerance should be better than 5% of the maximum reading. Moreover, the meters should be correctly sized for the test, which is can be a problem on low liquid production wells.

During the main flow period of an oil well test it is good practice to obtain a combined oil meter correction factor (OMCF) and shrinkage factor, by diverting the flow to the gauge tank. This combined factor is a product of the meter factor (true separator barrels divided by measured separator barrels) and the shrinkage factor (stock tank barrels divided by separator barrels). See also Section 13.13.

14.4 Pressure Testing

All pressure vessels and pipe work needs to be pressure tested prior to use.

A pressure chart recorder should be used when carrying out pressure tests and the witness should sign off on the chart after each test, with the chart being kept as a record. Tests should show "stabilised" pressure for at least 15 minutes duration.

When pressure testing the DST tools these should be tested against a closed valve below the tools and then again at regular intervals whilst running in the hole with the tubing string. If a diesel cushion is used in the test string the actual pressure test (usually with the cement unit) should <u>not</u> be carried out using diesel but with a glycol/water mix, since diesel and air can be explosive under high pressure.

The main problem which occurs during pressure testing is the time that it takes to stabilise a reading – especially where large volumes are involved. This problem is generally attributed to air in the lines and the pressure might need to be "bumped up" a number of times before an adequate test is achieved.

Each part of the system should be pressure tested to a pressure in excess of the maximum expected pressure that the equipment will experience during the test, but must not exceed the pressure rating of the particular piece of equipment.

Care should be taken when pressure testing lubricators with water in wells which will potentially flow gas or gas condensate wells. After pressure testing the water will enter the test string and could possibly form a hydrates. Using a glycol/water mix will help prevent this.

14.5 Running the Test Tubing or Drill Pipe

When running the test tubing or drill pipe some general precautions should be taken.

The tubing joints should be torqued up to the manufacturers recommended values. To ensure that the tubing is correctly made up it may be prudent to have JAM (Joint Analysis Make-up) specified with the power tongs. The JAM equipment will provide a strip chart showing the make up torque of every joint in the string and an audible alarm can be set to indicate when the tubing has been correctly torqued up.

The correct API pipe dope must be applied during make up of the string. If possible, pipe dope should be applied sparingly to the pin ends only on the tubing or drill pipe, to reduce the amount of excess getting into the pipe, which may cause problems with the TCP perforating systems. However, in some cases limited doping, that is none on the box, may lead to galling problems. In the event that galling occurs, dope should be applied to a least the sealing surface of the box and make up retried. If galling continues dope will have to be applied as required to both the pin and box ends.

Any pipe (including drill collars) should be cleaned before the test if possible. The recommended method is to rattle the pipe with a length of chain. This will remove any debris from the inside of the pipe, which again may cause problems for the operation of the downhole tools or TCP. If it is not possible to clean up the string beforehand, it is good practice to run in with the string to TD with a tubing test valve on the end and pressure cycle the string a number of times, a so called flex trip. The tubing test valve can be sheared open after flexing the tubing and rapid circulation through the pipe can be undertaken, This will help any scale or solids in the string to fall out. In addition the tubing can also be cleaned by circulating with a weak HCL solution; a so called pickling brine or pickling slurry.

All tubing should be drifted with an API drift of the recommended size for that pipe.

14.6 Running and Setting the Packer

Prior to running in the hole with the packer it is prudent to have carried out a scraper run in the well to ensure that all cement has been removed from the casing or liner. This scraper run should help to avoid hitting possible obstructions, when running in the hole with the packer, which could damage the packer elements or cause premature setting of the packer. The packer should be set in clean pipe where there is no connection and where no packer or plug has been previously set.

If two runs are made to test the same interval, it is worth adding or removing a section of pipe from the string to ensure a different packer setting depth. An adequate number of pup joints should be available on site for spaceout of the packer.

Where a wireline set packer is being used a gauge ring and junk basket should be run before running in the hole with the packer.

14.7 Choke Manipulation During Testing

The choke is the primary control device during flowing of the well. It generally consists of two sides, a fixed choke side and a variable choke side. For a well test the variable choke is usually a bean and stem type as described in section 13.9 and can vary between 0 and 2" maximum ID. The fixed choke side allows various sizes of fixed choke to be inserted as required. Sizes usually increase in steps of 4/64" up to 1" and often in 8/64" steps up to 2". It important to ensure that a full set of choke sizes is sent to the rig before the starting the test.

By use of a block and bleed system, fixed beans may be changed whilst flowing the well via the adjustable choke. Thereby allowing step rate testing without shutting in the well and causing the minimum of pressure surge.

When operating the choke, much better test results are obtained if it is adjusted sparingly and then left alone. Poor results will obtained if the choke is continually adjusted to obtain a specific flowrate. Once the initial flow period is completed, the choke size strategy can be decided upon. To assist with this, some choke performance equations are listed in Appendix C, which allow flowrate predictions to be made.

<u>Critical Flow</u>

Critical flow occurs through a choke when the velocity of fluid flow exceeds the velocity of sound in the fluid. Under conditions of critical flow, any disturbance to the fluid stream occurring downstream of the choke cannot be communicated upstream of the choke. In sub-critical flow disturbances can be transmitted upstream of the choke, for example a change in separator pressure may resulting in a pressure variations at the bottom hole gauges.

<u>Shutting In The Well</u>

If a downhole tester valve is used in the string, the well should be shut-in at the tester valve first and then once closure is confirmed by a drop in the flowing WHP, the well should be closed in at the choke manifold by closing the upstream valves.

14.8 Separator Operations

The primary function of the separator is to efficiently achieve division of the well effluent into its constituent phases; oil, gas (gas condensate) and water. This separation is achieved purely by means of density differences between the phases, resulting in gravity segregation. Where the density differences are large, as between the gas and liquid phases, a large part of the segregation occurs very rapidly. Where the density differences are small, as between water and a low API gravity crude oil, segregation of the constituents can be very slow.

The calculation of phase retention time in the separator is shown in Appendix D.

Optimum Separator Operating Pressure

The maximum pressure at which a separator should be operated under normal conditions is half the upstream pressure at the choke manifold. For a gas well this will result in critical flow conditions at the choke. Pressure fluctuations in the separator will not be transmitted back through the choke to the downhole pressure gauges and the flow will remain stable. At higher pressures up to within the maximum operating pressure of the separator the choke becomes redundant if critical flow is not maintained at the choke. Flow control is then being carried out by the separator back pressure control valve and as the separator controller operates within proportional bands, these changes are then seen on the bottom hole pressure gauges. This situation should be avoided if quality test data is to be obtained.

Although the critical flow regime criterion is only really applicable to gas flow, it is still a good 'rule of thumb' for oil producers.

If a test separator is operated at a high pressure the gas velocity through the vessel is low and any entrained liquid droplets have adequate time to segregate before the gas stream leaves the vessel. However, any gas bubbles entrained in the liquid stream are compressed to a small volume and gravity segregation may not have time to occur before the liquid is dispelled from the separator. This results in a meter error as discussed in section 13.13 with the meter measuring entrained gas bubbles as liquid. * Note: that the inclusion of a shrinkage meter in the separator package does not automatically correct for this error.

Under conditions of high pressure the quantity of gas remaining in solution in the oil phase will be high. Although this may be corrected for volumetrically by means of a shrinkage meter or a combined OMCF and shrinkage measurement at the tank. This gas is normally released at the stock tank and must be vented, if the quantity of gas being released are excessive this may present a safety hazard particularly offshore. However, offshore a surge tank will normally be used and this can act as a second stage separator to help reduce these effects.

At low separator pressures, the gas velocity is correspondingly high. Any entrained liquid droplets may not have time to coalesce and may form a 'mist', which will cause problems in the gas metering section of the separator. Some of the 'light ends' will evaporate into the gas phase, particularly if the separation is occurring at elevated temperatures, and will condense downstream in the gas flow lines. Under the worst conditions, if using a vertical gas flare, this condensed liquid may 'slug' causing a severe fire hazard.

Appendix D shows a theoretical approximation of the optimum separator operating pressure. This is derived by considering the well test system as a two stage separation process with the test separator as the first stage and the stock tank as the second stage.

14.9 Production Problems

Although the standard test separator can cope with the majority of well stream conditions to which it is exposed, there are certain problems which occur that requires additional treatment.

Emulsion Formation

Water / oil emulsion problems are caused by surface tension, viscosity and differential density effects between these two phases. Emulsion problems are often treated by heating the well effluent before passing the well stream into the separator. Pre-heating reduces the viscosity and surface tension of the oil and this facilitates better separation of the phases. Alternatively, the well effluent may be treated chemically by adding a surfactant (demulsifier) to the well stream before entry into the separator.

* Notes:

Surface Tension: In basic terms, is a force that holds the surface of a liquid to the rest of the liquid volume. Due to the mutual attraction between the molecules in a liquid, molecules in the interior are attracted in all directions, but those at the surface of the liquid are attracted inwards only. Thus the surface of the liquid will tend to contract to form the smallest possible area, that is a spherical shape or droplet, for example rain droplets. The addition of relatively small amounts of chemicals can alter the surface tension and cause these droplets to break up.

Surfactants: (Surface acting agents) are substances such as soap, that act on the surface of a liquid to change its surface tension. Surfactants are especially effective at changing the surface tension of water.

Foaming

Certain combinations of oil, water and gas can give rise to a condition known as foaming within the separator, resulting in carry over of liquids into the gas stream.

Foaming occurs when pressure is reduced in certain well effluents within the separator, causing the liberation of many tiny bubbles which are covered in a thin film of oil. A similar effects can also be caused by surface tension and viscosity effects between the fluids in the well effluent, but generally also requires a gas component.

Consequences of foaming can include:

- Poor separation and reduction in separator capacity.
- Poor quality oil and gas metering.
- Cavitation of pumps.
- Burning problems due to liquid carry over in the gas lines which is not atomised by burner heads.

Several solutions to this problem exist, they are as follows:

- Preheating of the well effluent will modify the surface tension of the oil (and to a lesser extent the water), reducing the probability of foaming.

- Surfactants (often silicon defoamers) may be injected, at low concentrations, into the well stream to destabilise the foam.

- Increase in retention time allows more time for the gas to break out of solution and generally creates less foam. Occasionally, a small change in the separator operating pressure is sufficient to cure the problem. However, if foaming conditions are anticipated in advance of the test then a multi-stage separation process using two separators in series may be considered.

- Agitation can help prevent foaming by causing the gas bubbles to coalesce and separate from the oil more quickly than if agitation were not used. The only practical way to agitate fluids in a separator is to include baffle plates in the separator.

High Viscosity/High Density Crude

If the well effluent contains high viscosity, high density crude oil together with water, this can result in two problems. The gravitational separation effect is greatly hindered by the relatively small difference in densities between the crude and the water and the viscosity of the oil prevents any droplets of entrained water from sinking. It is not unusual under these conditions for all of the produced water to be discharged through the oil outlet system, making ignition through an standard offshore burner almost impossible. However, special burners for such conditions are available.

These problems are not easily resolved. The best method is to preheat the well effluent through a heater or heat exchanger before entering the separator. This generally has a significant effect on the crude viscosity and enables better separation. An additional advantage is that reduction of the viscosity normally allows better level control through the liquid level control valve.

Hydrate Formation

Hydrates are formed when water and light end natural gases come into contact at certain temperature and pressure conditions. These gas hydrates are crystals formed by water with natural gases and associated liquids, in a ratio 85 % mole water to 15 % hydrocarbons. The hydrocarbons are surrounded in an ice-like solid which does not flow, but can grow rapidly to block flow lines and process equipment.

Under certain conditions hydrates can form spontaneously and do not always require a temperature drop to form. However, hydrates do usually occur in places where large pressure drops take place and consequently temperature reductions occur due to the

Joule-Kelvin / Joule-Thompson effect. This effect is in fact used commercially in the liquefaction of gases and in refrigerators.

In a well test scenario hydrates are most likely to occur sub sea in the landing string or riser during offshore tests and downstream of the choke manifold or downstream of the separator back pressure valve.

The hydrates risk is greatest during gas well testing or high GOR oil well testing. Moreover, the risk of hydrate formation also increases with increasing pressure and decreasing temperature as shown in the graph in figure 14.1. This graph shows the hydrate equilibrium pressures and temperatures for a fairly typical gas composition. There are a number of hydrate predictions models available that can be used to generate pressure and temperature equilibrium graphs for known gas compositions.

From the graph it can be seen that the likelihood of hydrate formation can be reduced by maintaining the well stream temperatures above the hydrate formation temperature for a given pressure. In practice this means flowing the well at higher rates. Alternatively inhibitors such as Mono Ethylene Glycol (MEG), Tri Ethylene Glycol (TEG) or Methanol are sometimes used to help prevent hydrates.

Hydrates - Operational Considerations

If the well operating conditions are such that they are taking place above the equilibrium line (see figure 14.1) then the formation of hydrates may occur. It should be noted that the equilibrium pressures are sensitive to gas composition and increased Propane content has a dramatic effect on reducing the equilibrium pressures. H_2S and CO_2 also reduce the equilibrium pressures and therefore increases the susceptibility for hydrates to form. However, liquid hydrocarbons tend to inhibit hydrate formation.

During the planning phase of a well test, if hydrate concerns exist then an equilibrium pressure temperature curve should be generated for the expected gas composition, based on offset data. This will help to identifying what hydrate prevention measures are need in the well test design.

Note: A well is most susceptible to hydrate formation when it is first opened up, while the well bore fluids are still cold. Once the temperature of the system increases the possibility for hydrate formation reduces.

Hydrates - Deep Water – Hydrate formation is of great concern during the testing of deep water offshore gas wells. Typically the sea floor temperature of these wells (1000' – 10,000' water depth) will be of the order of the 45 ^{0}F to 33 ^{0} F. Referring to the pressure / temperature equilibrium curve in figure 14.1 one can see that in this temperature range hydrates can form with a pressure of only a few hundred psi.

Testing a well located in deep water will require additional engineering studies to be performed, to look at the expected flowing temperature at various flow rates from the reservoir to the surface. A dynamic well bore temperature simulation model should be developed for the particular well and the anticipated flow rates, using a flowing temperature simulation programme such as WEST or WELLCAT.

Figure 14.1

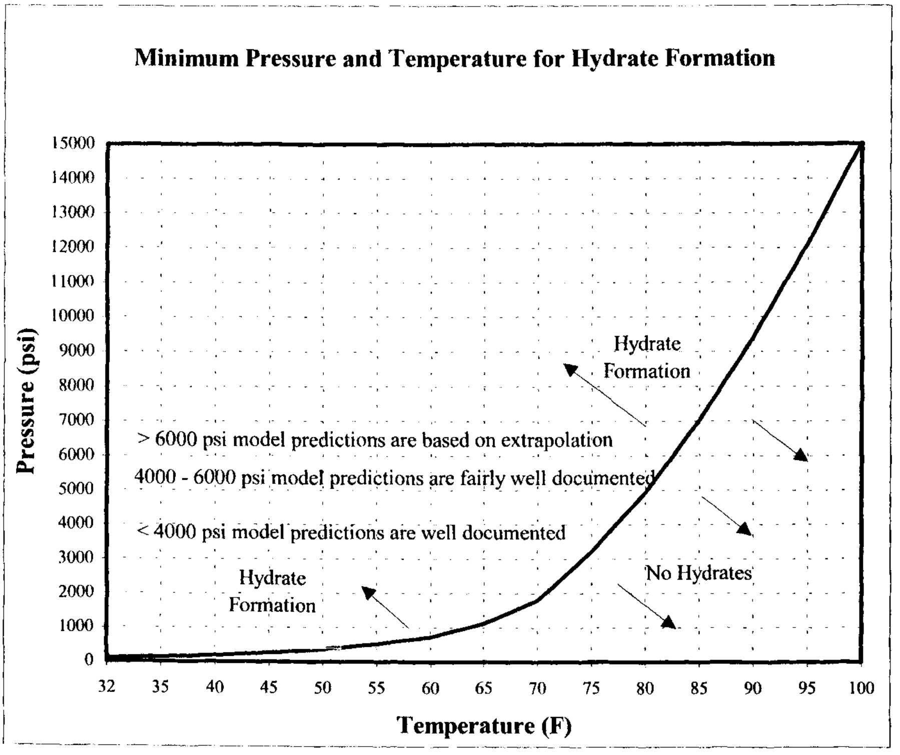


Figure 14.1.1 Gas Compositional Data for Figure 14.1

Gas	Mole %
Methane	85.0
Ethane	7.6
Propane	3.1
Iso-Butane	0.5
Normal Butane	0.8
Nitrogen	0.5
Carbon Dioxide	2.5
Total	100

Figure 14.1.2 Tabulated values for figure 14.1

Temperature (F)	Minimum Pressure for Hydrate Formation (Psi)
32	108
35	133
40	186
45	258
50	360
55	508
60	733
65	1111
70	1800
75	3200
80	4936
85	7028
90	9439
95	12126
100	15040

When generated the dynamic temperature model will show the flowing well temperature at various flow rates, depths in the well and times throughout the duration of each flow period. Referring then to the pressure temperature equilibrium curve for the anticipated fluid composition may lead to a requirement for injection of MEG, TEG or Methanol at or even below the sub sea test tree.

Chemical injection at the sub sea test tree is relatively straight forward and most SSTT have this capability. However, injecting below the SSTT will require the use of a down hole chemical injection valve in the tubing string, a chemical injection line clamped to the tubing and an axial ported fluted hanger / adjuster sub and an axial ported slick joint. Rigging up such equipment for a well test on a floating rig is complicated, time consuming and costly. Allowances for the additional cost associated with such an operation must be built into the well test AFE at an early stage. A useful source of reference when planning such a test is (4) Davalath J., Barker J.W. "Hydrate Inhibition Design for Deepwater Completions", SPE paper 26532.

Another technique, which has been used in deep water in an attempt to prevent hydrates, is the circulation of heated mud through the riser. This technique has been used by a number of operators with varying degrees of success to maintain the well stream temperature. Other operators have used insulated pipe to help reduce heat loss in the riser section.

When hydrates form during a test the surface flowing pressure may become erratic. If the problem is upstream of the choke, the surface flowing pressure measured at the choke manifold will drop and if downstream of the choke the opposite will occur. Hydrate formation can be very sudden and steps must be taken during the well test design to safeguard against these problems, by using appropriately placed high and low pressure pilots to protect the system.

There are a number of general measures that can be taken for hydrate prevention, these are as follows:

- Use of a process heater or steam heat exchanger; which can be a very effective measure in preventing hydrates at the separator back pressure valve.

- Opening up the well initially at the choke on the heater which is at a more elevated temperature than the choke manifold. As the well effluent passes through the choke manifold the temperature of the manifold will rise as a result of flowing the well. When the choke manifold reaches a temperature in excess of the equilibrium temperature for the particular flowing well head pressure, then the choke manifold can be used for the remainder of the test.

- Chemical injection of Glycol (MEG, TEG) or Methanol, each time the well is opened up until the temperature has increased above the hydrate formation temperature. Glycol is normally considered as a hydrate inhibitor while Methanol is regarded as a hydrate remover.

  Strategic positions to inject chemicals during a well test are.

  - Below the SSTT on wells in deep water (only if absolutely necessary).
  - At the SSTT.
  - Surface Test Tree.
  - Data header upstream of the choke manifold.
  - Upstream of the separator back pressure valve.

- Pressure test with a Glycol / fresh water or Glycol / sea water mixture. A 60/40 glycol (MEG) / sea water mix is commonly used offshore for pressure testing of components. See table 14.1 which shows a comparison of the freezing points of various glycol (MEG & TEG) fresh water mixtures.

- Avoid the use of fresh water tubing cushions. A glycol water mix such as those shown in table 14.1 should be considered for cushion fluids. Figure 14.2 shows the hydrate equilibrium pressures and temperatures for various glycol / water mixes across a range of operating pressures and temperatures. The addition of salts to the mix will further enhance the cushion fluids hydrate inhibition performance; NaCl is more effect than KCl in this respect. The hydrate equilibrium pressures for other glycol / methanol and salt mixtures can be generated with any of the hydrate prediction models that are available.

Table 14.1 Freezing points of Glycol fresh water mixes.

Glycol / Water	Mono –Ethylene Glycol		Tri – Ethylene Glycol	
% Mixture	Freezing Point (deg C)	Specific Gravity	Freezing Point (deg C)	Specific Gravity
100 / 0	- 7	1.116	- 5	1.126
90 / 10	- 28	1.109	- 22	1.122
80 / 20	- 43	1.101	- 37	1.116
70 / 30	- 60	1.091	- 38	1.107
60 / 40	- 60	1.079	- 35	1.095
50 / 50	- 44	1.068	- 23	1.078
40 / 60	- 27	1.054	- 12	1.068
30 / 70	- 17	1.040	- 7.5	1.049
20 / 80	- 9.5	1.028	- 4.5	1.033
10 / 90	- 5.5	1.008	- 2	1.018

Figure 14.2 Minimum Pressure and Temperature for Hydrate formation with a MEG free water mixture. (Gas composition as in figure 14.1.1)

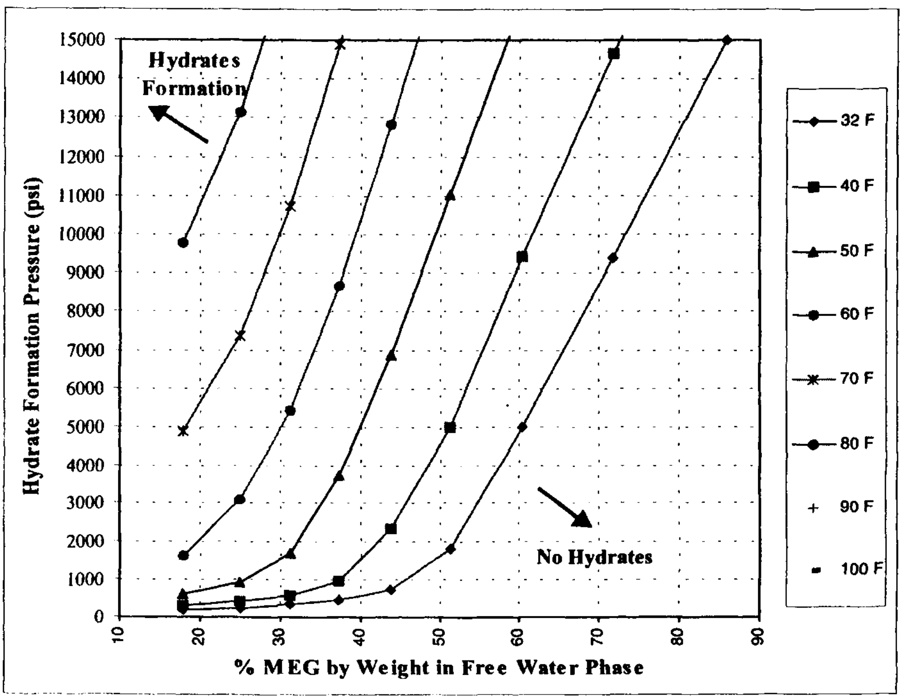


Figure 14.2.1 Tabulated Values of Figure 14.2

(Gas Composition as in Figure 14.1.1)

% Methanol by weight in free water phase	% MEG by weight in free water phase	32 F	40 F	50 F	60 F	70 F	80 F	90 F	100 F
10	17.8	176	310	616	1602	4876	9785	16005	23190
15	24.9	235	408	902	3077	7374	13123	*	*
20	31.2	325	586	1668	5418	10714	17260	*	*
25	37.3	470	937	3744	8660	14896	*	*	*
30	43.8	740	2342	6870	12806	19843	*	*	*
35	51.3	1778	5019	11012	17820	*	*	*	*
40	60.4	4995	9429	16070	*	*	*	*	*
45	71.7	9399	14646	*	*	*	*	*	*
50	85.8	15019	20697	*	*	*	*	*	*

* => Not normally applicable > 15,000 psi

As can be seen from the table above, methanol is more effective than glycol at preventing hydrates from forming. However flammability concerns often precludes the use of methanol if large volumes are required, particularly offshore.

General Procedures to Follow After Formation of a Hydrate Plug

In the event that a hydrate plug occurs, the well should be closed in upstream of the plug if feasible and as close as possible to the plug. The pressure downstream can then be bled off, which may allow the plug to evaporate.

In addition, a methanol soak can be performed by injecting methanol onto the hydrate until it clears. Care should be taken during this operation as trapped pressure upstream of the plug may cause the plug to clear with some considerable velocity and force.

If hydrates are just in the process of forming at say the choke manifold a steam line can be run from the steam generator (if used) and the steam can be applied directly on to the choke manifold.

Waxy Crude

Waxing in crudes is caused by the formation of solid like, long chain organic compounds of high viscosity in the oil. They usually occurs as a result of low temperatures in the case of waxes or low pressure in the case of asphaltenes. If waxing is suspected, it is imperative that a single phase pressurised downhole sample is taken in order to carry out representative laboratory experiments.

Severe waxing can cause pipework to block up and separator level controllers to jam. Waxy crude is difficult to burn and there may be problems separating entrained water.

Whether a crude is waxy or not depends on the precipitation rate for wax, which is driven to a great extent by the temperature. Below are a few terms that are used to describe the onset of waxing, however the prediction of the deposition rate of wax is much more complex as it is also influenced by flow effects.

Cloud Point: Also known as the wax appearance temperature, this is the temperature at which 0.1% precipitated wax occurs in the crude.

Pour Point: As the name suggest, this is the temperature below which the crude will no longer pour due to a significant rise in viscosity and usually corresponds to about 4 % insoluble wax.

There are two main ways to prevent wax causing problems during a well test. The first is to use the heater or heat exchanger, which keeps the wax in solution. The second is to use chemical treatments. There are however a variety of chemical treatments that can be applied to wax problems depending on the nature and severity of the problem. Chemical treatments will either be in batch or continuous application, but for most well test scenarios continuous application will be used. The four main types of chemical treatments are dispersant, detergents, solvents and crystal modifiers.

A brief explanation of these chemical treatments is given below.

Dispersants: These coat small particles in the wax changing their ability to adhere to each other and to pipe surfaces. Dispersants are usually injected continuously and are used to treat wax, which has already formed in the crude.

Detergents: These surfactants alter the nature of the wax allowing it to become water wet. They are used where there is high water cut (> 20 %) and effectively break down the surface tension, causing a repulsion force preventing deposition of wax.

Solvents: Usually used neat and at as high a temperature as possible because wax solubility increases with temperature, these solvents break down the wax deposits after an extended soak period.

Crystal Modifiers: These chemicals must be injected at temperatures above the cloud point because they work by altering the way in which the wax forms and have an effect on deposition, viscosity and pour point.

When using methanol injection to avoid the formation of hydrates, it should be noted that it can cause wax to become harder and more difficult to remove. If waxing is expected, the methanol injection (for hydrate prevention) should only be used for a limited period, until the wellhead temperature has warmed up sufficiently.

Solids Production

Solids production can come from a number of sources. It may be from a friable or unconsolidated sandstone coming apart as a result of the drawdown, from fragments of chalk coming into the well for the same reasons, or proppant from a hydraulic sand fracture.

If solids production is expected, special equipment and procedures can be used to remove it from the flow. Sand traps as described in section 13.6 is the normal means of removing solids from the well effluent during a test. With appropriately sized screens and the ability to divert flow to the other pot whilst emptying the first this method can be very effective.

It can be very dangerous to allow sand production to continue unchecked during a well test where there are high flow rates, solids production can cause the flowline to erode away and leak. The most vulnerable areas are flowline bends downstream of the choke where the flow velocities are much increased due to the pressure drop. On tests where sand production is expected sacrificial lines as described in 13.23 should be considered. Ultrasonic wall thickness testers can be useful for checking for erosion in critical areas during the test.

The sand production rate can be measured by using sand traps or sand detection equipment as described in section 13.6 and 13.7. The latter can be of questionable accuracy unless the instrument is calibrated with a representative sand slurry; otherwise small droplets of liquid in a gas stream can register as solids.

14.10 Well Control

Well control procedures from the point of starting to run the DST string until the end of the test should be contained within the detailed well testing programme.

These well control procedures will be written into the detailed steps of the programme and will be dependent on the nature of the test, for example, open hole, cased hole and underbalanced packer fluids. Particular attention to well control will be required whenever running or pulling pipe in a well with a live interval.

Well control specifics are not considered in this book, as they will be highly specific to individual wells. However, good well control practices during a DST will include the following. Maintain the annulus full, carefully monitor annulus pressure, maintain twice the hole volume of kill weight mud onboard ready to be pumped and having stab in valves and all necessary x-overs available on the rig floor while running and pulling pipe

It is important that the DST programme is reviewed prior to issue by a person with considerable well control experience, preferably the Drilling Manager or Drilling Superintendent.

This Page Intentionally Left Blank

CHAPTER 15

RESERVOIR FLUID BEHAVIOUR & SAMPLING OPERATIONS

The collection of representative reservoir fluid samples is an important part of well testing. The samples may be used for a variety of measurements, for example, PVT, H_2S, wax, asphaltenes, water analysis and much more.

After consultation with the reservoir engineers and production technologists the sampling programme should be clearly specified in the detailed well testing programme. It is worth noting that sampling is a potentially dangerous process, as the samples contain pressurised, explosive and flammable fluids which are also sometimes highly poisonous. Therefore, appropriate safety measures are required during both sampling and transportation of samples.

Recommended Practices:

1. Single phase downhole samples may be taken for oil wells with low water cut to compare with surface recombination samples. These samples are particularly useful for wax or asphaltene detection.

2. Ensure that sufficient separator gas is acquired when taking surface separator samples to allow recombination with the oil samples to replicate reservoir conditions.

3. Samples of separator water and any solids production should always be taken.

4. If samples taken during the main test are thought to be poor, further samples can be taken by reversing out the tubing contents. Maintaining back pressure at the choke manifold may allow single phase samples to be collected, however this will not always be possible.

5. Chemical injection (e.g. Methanol, Glycol) should not take place upstream of the sampling point, when samples are being collected, unless operationally unavoidable. If chemicals are injected upstream of the sampling point, this should be noted on the sampling tag and samples of the injected chemicals should be sent with the hydrocarbon samples to the laboratory.

6. Dead oil and condensate samples should be taken for assays. Small separator gas (300cc), stock tank oil or condensate (100cc) and water (100cc) should be taken for geochemical analysis.

7. Duplicate samples should always be taken as a minimum, however triplicate are preferred.

8. Cylinders should never be shipped liquid full (it is illegal). If a piston cylinder is used, an inert gas should be used on the backside of the piston. Cylinders should be liquid filled to no more than 90% of capacity. All cylinder pressure ratings should be checked to make sure they are appropriate. The pressure rating needs to have been certified within the last five years and this will be shown by a stamp on the cylinder.

9. All samples must be packaged and labelled according to IATA or US DOT regulations. A Shipper's Declaration for Dangerous Goods needs to be filled out with emergency procedures (or an MSDS) attached.

15.1 Reservoir Fluid Behaviour

The aim of PVT sampling is to obtain a small volume of reservoir fluid, under pressure, which is identical to the reservoir fluid at initial conditions. The results of any analyses made in the laboratory can then reasonably be applied to the reservoir as a whole and form the basis for further engineering studies to predict reservoir behaviour. These engineering studies can then be used to decide the economic viability of the reservoir and possible offtake strategies.

It is therefore important to obtain samples from reservoirs before any appreciable amount of depletion has occurred and this condition is satisfied by taking them while testing exploration wells.

<u>Oil Reservoir Behaviour</u>

The saturation pressure, or bubble point pressure in an oil reservoir under initial conditions may be either equal to or less than the reservoir pressure. Where the bubble point of the oil is equal the reservoir pressure the oil is described as saturated (gas saturated oil). Moreover, where the bubble point is less than the reservoir pressure the oil is described as undersaturated.

The presence of a gas cap within an oil reservoir always indicates saturated oil. In other words the oil is so completely saturated in gas that the excess gas has separated by gravity to form a gas cap in the reservoir.

Undersaturated oil is never associated with a gas cap; there is insufficient gas to saturate the oil so consequently there is no excess gas to form a gas cap. In an undersaturated reservoir as the reservoir pressure is drawn down a single phase hydrocarbon liquid is produced. This production mechanism is called solution gas drive or expansion drive (expansion of the in place fluids) and this will carry on until the bubble point is reached and then free gas will start to appear in the reservoir. From this point onwards the production mechanism is the same as that of an originally saturated reservoir, namely gas cap drive.

While undersaturated conditions exist, the produced gas oil ratio remains constant, and it is relatively easy to obtain representative samples of the reservoir fluid.

Provided the flow rate is kept to a minimum, single phase liquid enters the well bore, which presents no problem for bottomhole sampling. Gas is only released from the oil when the pressure reaches bubble point during flowing to surface.

On the other hand, in a saturated reservoir, the bottom hole flowing pressure is always lower than the bubble point pressure, hence free gas will be released in the formation itself, and the producing GOR will tend to be higher than the solution GOR. This will be more marked as the reservoir pressure declines and the reservoir gas saturation rises correspondingly. The producing GOR will only start to increase above the solution GOR after critical gas saturation is reached. Until this condition is satisfied the producing GOR will be lower than the solution GOR.

This fluid behaviour can raises problems in obtaining representative oil samples, that is samples with the correct gas oil ratio. The problem occurs in initially saturated reservoirs and in undersaturated reservoirs if the flowing bottom hole pressure has been drawn down below the bubble. However, a period of conditioning of the well prior to sampling can usually overcome the problem.

This conditioning period can in fact be the final pressure build up, conducted as part of the well test sequence to allow pressure transient analysis to be performed. Alternatively, it may be a flow period of a few hours on a small choke to allow free gas in the proximity of the well bore to go back into solution followed by a pressure build up. For reservoirs known to be at the bubble point pressure the bottom hole samples should be taken with the well shut in. However for undersaturated reservoirs the sample should be taken with the well flowing on a small choke with the bottom hole pressure above the bubble point.

In order to confirm that representative samples have been collected a number of samples should be obtained. Then, onsite bubble point determination should be carried out on each sample using the transfer bench. If the bubble point of the samples is substantially different, then either the well has not been conditioned properly or one or more of the samplers has failed.

Note:

When taking oil samples from wells for PVT analysis, the reservoir conditions should be at or as close as possible to initial reservoir conditions. Flow at the sampling point should preferably be single phase liquid with no excess gas.

Gas Reservoir Behaviour

Gas reservoirs can be classified into two main categories:

- Dry gas reservoirs,
- Retrograde gas condensate reservoirs.

Dry Gas Reservoirs

In a dry gas reservoir, the composition of the gas is such that it remains entirely in the gas phase in the reservoir during the whole depletion process from initial flow to abandonment pressure. Assuming that the temperature remains above the critical value on the PVT relationship the well effluent remains in a single phase, that is the gas phase. Its composition therefore remains constant both in the reservoir and in the well stream.

Two subdivisions of this type of reservoir can be made:

- Where gas is dry even at separator condition, that is, there is negligible liquid recovery. This is a true dry gas in every sense.

- Where the dry gas at reservoir conditions becomes a wet gas at surface conditions and hence liquids are recovered at the separator. This is usually referred to as a wet gas to distinguish it from the truly dry gas reservoirs. This type of reservoir may not be easily be distinguishable from a retrograde gas condensate reservoir and generally only PVT analysis will yield the answer.

Retrograde Gas-Condensate Reservoir

In this type of reservoir, the composition of the hydrocarbon mixture is such that as pressure drops below the dew point, there is liquid hydrocarbon condensation of the heavier ends within the reservoir.

The amount of liquid condensation is however generally small and is often below the critical saturation which must be exceeded before the liquid can be produced. Therefore, this condensed liquid hydrocarbon remains within the pore space of the reservoir and hence the name retrograde condensate. Retrograde, the grade of condensate that is left behind in the reservoir, as all the heavier ends condense first this represents a loss of the more valuable components from the produced fluids.

In this type of reservoir the produced effluent composition will therefore vary with pressure. At separator conditions there will always be two phases as some of the lighter ends condense.

As mentioned above, wet gas and retrograde gas condensate reservoirs show similar surface behaviour and well-testing alone will probably be insufficient to categorise them.

In gas condensate reservoirs, the dew point pressure may be equal to the reservoir pressure, so that condensation occurs immediately depletion begins, or else it may be below the initial reservoir pressure and may be termed undersaturated. Depletion in this case initially causes no liquid condensation in the reservoir, which only starts to occur when the reservoir pressure reaches dew point.

In the undersaturated reservoir, the fluids entering the well bore can consequently have the same composition as the reservoir fluids, providing that the flowing bottom-hole pressure remains above the dew point.

On the other hand, in dew point type retrograde condensate reservoirs, where the well-stream composition changes with depletion and is different from reservoir fluid composition, it is clearly important to obtain PVT samples under initial conditions, before there is a significant change in the composition.

Note:

Sampling of dry gas reservoirs is not critical with regard to time, but for retrograde condensates the reservoir conditions should be at or close to initial reservoir conditions. The sampled gas composition will only be representative if it contains the total amount of heavier components occurring in the initial reservoir fluid.

15.2 Sampling Programmes

Following on from the above discussion on reservoir fluid behaviour. The particular sampling programme for a test must be designed taking account of the expected fluid type, reservoir conditions and overall aims of the test.

Many test procedures include a low rate sampling flow period after completion of the main test. If sampling is preceded by a high rate test with flowing bottomhole pressures below the saturation pressure of the fluid, then the well needs to be conditioned prior to sampling. This conditioning period is designed produce out all the fluid that has been below the saturation pressure. If the saturation pressure is not known or the reservoir fluid is saturated, all fluid that has seen more than about 100 psi drawdown needs to be produced before sampling, in order to ensure that the sample is representative.

In all cases it is important that the samples are collected under stable flowing conditions. For fluids near their saturation pressure, it is sometimes recommended that the low rate sampling flow period should be early on in the test, to assure that the reservoir has not been dropped below the dew point or bubblepoint pressure during previous flows. Unfortunately, information on saturation pressures are in many cases unknown before conducting the test.

The typical sampling requirements for oil, gas and gas condensate reservoirs are as shown in Table 15.1. These are however only a guideline and depending on the detailed objectives of the test additional samples may be required.

TABLE 15.1

TYPICAL SAMPLING REQUIREMENTS

Sample Type	Source	Container Type	Typical Size	Number Required	Remarks
Separator Gas	Separator Gas Line	Pressure Bottle	20 Litre 300cc for Geochem. Analysis	3 per flow period	Used for PVT recombination of reservoir fluid. Geochemical Analysis.
Separator Oil or Condensate	Separator Oil Line	Pressure Bottle	600 cc	3 per flow period	Used for PVT recombination of reservoir fluid. Condensate also for Geochemical Analysis
Single Phase Oil	Wellhead	Pressure Bottle	600 cc	As Required	Only if saturation pressure is less than the flowing wellhead pressure
Dead Oil or Condensate	Separator or Gauge Tank	Metal Drum	45 gallon	2 per test	For crude assay
Produced Water	Separator water outlet Gauge Tank or Reverse Circulation	Plastic Bottle	1-5 litre 100 cc for Geochem Analysis	Water salinity every hour and retain 2 to 3 samples per flow period.	For water salinity analysis, Rw and Geochemical analysis
Produced Solids	Wellhead or Separator	Plastic Bottle	1 cubic centimetre packages. 5 litre well head fluid samples for filtration.	Check every hour or more frequently if high solids production retain 2 to 3 samples per test	For gravel pack sizing.
Bottom hole Fluid Sample	Bottom of test string	Pressure Bottle	Tool Size Dependant	Minimum of 3, but as required to obtain representative reservoir samples.	Reservoir PVT fluid analysis.

It is important that all necessary flowing conditions are noted whilst sampling. This information is used for the recombination of samples and for fluid analyses. Indeed this data is as critical to good sampling as the samples themselves.

The conditions to be noted are as follows:

Upstream of Choke	Downstream of Choke	Reservoir
Flowing Pressure	Separator liquid rate	Reservoir Pressure
Flowing Temperature	Separator gas rate	Reservoir Temperature
	Separator temperature	Flowing Bottomhole Pressure
	Separator pressure	
	Stock tank liquid rate	
	Stock tank temperature	
	Stock tank pressure	

Other:

Choke size
Gas lift rate and composition (if used)
Gas gravity used to calibrate orifice meter readings (Fg)

15.3 Stable Flow

When sampling to obtain representative samples for PVT analysis the following producing conditions are needed:

- Stable flowing bottom hole pressure with minimum drawdown.
- Stable flowing wellhead temperature and pressure.
- Well producing clean, fresh fluid from reservoir.
- Separator flowrates stable and measurable.
- No major fluctuations in separator levels.
- Stable separator pressure.
- Flowrates not too high – avoid liquid carry over.

Although separator samples are the most convenient samples to take, the accuracy of the PVT analysis on these samples relies on a large number of conditions being stable. Even fairly small disturbances to separator the equilibrium or stability will effect the sample quality.

The absolute accuracy of any PVT data derived from these surface samples is a direct function of the accuracy of the measurement of oil and gas production rates. Since oil rates can generally be measured to no better than 5% accuracy and gas rates to no better than 3 % accuracy, recombination GOR's are always uncertain. This means that bottomhole sampling will usually always give more representative fluid samples.

15.4 Downhole Sampling Conditions

As previously discussed in order to obtain representative downhole samples it is important that the well should be produced at a minimum drawdown (to maintain bottomhole pressure above dew point or bubble point) but still allow continuous flow of produced liquids (oil or water) to surface. Surface readout pressure gauges should most definitely be considered to monitor flowing bottomhole pressure to ensure the draw down is low.

Samples should always be collected at a known downhole depth, temperature and pressure. Samplers run into the well on either electric line or slickline should always be run in association with a pressure and temperature gauge (SRO or memory gauge).

Samplers should normally be positioned within 300 ft of the perforations, never attempt to take samples below the perforations as the samplers may become stuck in debris and samples recovered may be of mud or water from the rat hole. A gradient survey may be required prior to sampling to locate any oil water contact in the well. The sampler should be placed at the very least 30 ft above the oil water contact to avoid sampling emulsion.

15.5 Electric Line Sampling

This type of sampler is usually run with surface readout temperature and pressure gauges. These samplers have the greatest flexibility in that sampling can be delayed until stable downhole conditions are observed from the surface readout gauge. When optimum conditions have been achieved then the samplers can then be activated electrically from the surface to obtain a sample.

The samplers should be run into the well during a shut-in period or when the well is flowing at a very low rate to avoid any risk of blowing the tools up hole.

Due to the fact that mono conductor electric line cable has a much larger cross sectional area than slickline, it is more difficult to run tools in the hole on mono conductor cable. This may in part influence the choice of samplers on higher pressure wells. In addition the rig up of pressure control equipment for mono conductor line is more complicated and time consuming than for slickline.

15.6 Slick Line Sampling

This method of sampling is essentially the same as the electric line method except the sampler takes a sample either after an allotted time set on a clock within the samplers or by a jarring action on the tool. The well conditioning procedure for collecting samples using this method is the same as for electric line sampling except no downhole information is available for making a decision as to when to collect the samples.

The jarring action samplers should be jarred repeatedly to ensure a sample is caught but softly enough to ensure that the pressure and temperature memory gauges are not damaged. Some of these type of sampler require a locating nipple to be run in the string. This should be considered at the string design stage.

Time delay action samplers should be left downhole for a sufficient time after the theoretical sampling time to ensure that a sample is caught. Usually these samplers are run in tandem with clocks set to sample at slightly different times. This allows more chance of stabilising the well prior to the samples being taken.

15.7 Transfer of Bottom Hole Samples

After the samples have been recovered to surface they will normally be transferred to a suitable container for transportation to the laboratory. Triplicate samples should be obtained for comparison purposes and to ensure that a good sample reaches the laboratory in case a sample container leaks in transit.

A quality check on the reservoir sample should be carried out during the transfer process. This consists of determining the saturation pressure (at ambient temperature) and comparing it with expected during the test flow periods. If the sample exhibits a saturation pressure substantially higher or lower than expected the validity of the sample must be questioned. All of the bottomhole samples should have ambient temperature bubblepoints that agree within 50 psi and these should be less than the flowing bottomhole pressure if the well has been conditioned properly.

15.8 Test Tool Sampling

These samplers are run as part the DST string and normally each tool acquires only a single sample. Therefore, to provide redundancy it is necessary to run multiple samplers. Depending on the supplier these, tools can operate by a variety of means.

Some of the systems trap a sample between two ball valves in the string; therefore the sample will only be retained from the time immediately before the last closure of the ball valves, often prior to pulling out of hole.

Other systems available, operate by the application of annulus pressure to a rupture disc which in turns activates a porting system which allows fluid to enter into a chamber between the outside diameter and the inside diameter of the tool.

However, as previously discussed it may be difficult to obtain a representative sample using any of these tools if the reservoir has been drawn down below saturation pressure. Therefore, some planning of the flow period in which the samples are to be acquired will be necessary and conditioning of the well may be required to ensure a representative sample is caught.

The other major drawback all of these tools have is that the samplers are not recovered until after the well has been killed and the DST tools have been retrieved to surface. Therefore, if either no sample or indeed a bad sample has been acquired it is too late to acquire any further samples.

These tools can however be useful in certain circumstances where running of wireline samplers can be difficult such as highly deviated wells or wells with severe waxing problems.

Recently a new system of test tool samplers has become available which consists basically of a carrier that allows multiple wireline type monophasic samplers to be run together. These samplers can be activated by either rupture discs or pressure pulse technology. This variety of activation methods and the multiplicity of samplers in the carrier may increases the possibility of obtaining representative samples.

15.9 Reverse Circulation Sampling

Where a well will not flow to surface it may still be desirable to obtain samples of reservoir fluids. This can sometimes be achieved by reversing out samples from the DST string. Although it should be noted that slickline or electric line samplers are the only sure method for collecting PVT quality samples in this situation.

The main consideration with reversing out samples is to try to maintain the fluids in the string at the same pressure up the length of the tubing string as they are reversed out to surface. The pressure of the fluids must be maintained to prevent gassing off of the sample. It is very unlikely that the samples collected by this means will be of sufficient quality for PVT analysis. However, the only case where representative samples may be obtained is where a heavy crude with a very low GOR and bubble point had been produced into the string.

In order to reverse out samples from the string it is necessary to first establish the depth in the string that reservoir fluid has reached. This can be established by evaluating how much fluid flowed from the well prior to flow stopping. Knowledge of this volume, and the volume of the test string will allow calculation of the depth at which cushion fluid interfaces with produced fluids. This of course is not possible for a slug test with an air cushion.

Reverse circulation should be carried out from the mud pumps down the annulus up the tubing and through the choke manifold to the flare, or stock tank. Once the required volume of mud has been pumped down the annulus to push the produced fluids to the choke manifold, samples can start to be taken upstream of the choke manifold. Initial dead samples should be taken into glass bottles in order that a visual check on quality can be made. Monitor any produced gases for H_2S, sample gas into a sample balloon for chromatographic analysis. Once fluid of consistent quality is being produced take a pressurised samples using liquid displacement bottles. Also collect as much dead crude as required for analysis before completing the reverse circulation.

It should be noted that the reverse circulation process can be stopped by shutting in the choke, and mud pumps at any time during the procedure. This may allow more time to collect the required samples.

15.10 Surface Sampling Points

The choice of sampling location will depend on the fluid properties and the flowing conditions of the well. In general the following will apply:

Well head pressure greater than bubble point pressure – surface samples upstream of choke. (see section 15.11)

Well head pressure less than bubble point pressure – downhole sampling or separator recombination sampling (see section 15.12)

The following guidelines should be followed in selecting sample points:

<u>Separator Gas Line</u>

- Upstream of the Orifice Plate / Daniels Box.
- As close to the separator vessel as possible.
- Not immediately downstream of thermowell or other tappings in the flowline.
- Not immediately after a bend in the flowline.
- Ideally the sampling point should protrude into the centre of the gas flowline and face upstream. However, a pipe into the stream is acceptable.

Note: The sampling point should <u>not</u> be on the lower half of the flowline cross section, due to any possible free liquid or liquid carryover being present. If the sampling point has to be fitted flush to the inside surface of the flowline, then it is preferable that it is on the <u>top</u> of the line and not on the side.

<u>Separator Oil Line</u>

- As close as possible to the exit of the oil flowline from the separator vessel.
- Not immediately downstream of the thermo wells or bends in the flowline.
- Ideally the sampling point should protrude into the centre of the flowline, with the mouth facing upstream. However a pipe into the stream is acceptable.
- It should be upstream of any increase in flowline diameter.

Note: The sampling point should <u>not</u> be on the upper half of the flowline cross section, due to any possible free gas. If the sampling point is on the wall of the flowline, then it is preferable that it is on the <u>side</u>, rather than the top or the bottom – due to possible free gas or water in the flowline.

Wellhead

- Upstream of the choke manifold as close to the flowhead as possible. However, in practice samples are normally taken at the data header, upstream of the choke.
- Ideally the sampling point should protrude into the centre of the flowline with the mouth facing upstream. However a pipe into the centre of the flowline is acceptable.
- Not immediately after a bend in the flowline.
- Ensure that the sampling point is chosen where the main flow is passing through. Not in any dead legs or alternative flow paths.

15.11 Monophasic Surface Sampling

In order to take single phase samples on the surface that are representative of the reservoir, for PVT analysis, the fluid must be above bubble point (oil) or dew point (gas) at the wellhead.

This will be known, if the well is an appraisal of an existing field where PVT samples have been taken before, or where correlations have been used based on data collected at the separator, GOR, oil and gas densities.

To try and fulfil the above requirements the well should be flowed with a minimum drawdown and be fully cleaned up prior to taking the samples.

Monophasic liquid samples should be drawn off into sample bottles usually by displacing a heavier fluid, in the past mercury, now usually water /glycol. All sample lines should be flushed with the fluid being sampled prior to taking samples.

As long as a well is capable of producing monophasic samples upstream of the choke this will be a very accurate method of collecting samples for determination of fluid PVT properties. If a well is produced at different rates during the course of a DST and the fluid upstream of the choke remains monophasic, samples should be taken at each flowrate.

Monophasic surface sampling is not suitable if asphaltene or wax content is of concern and so bottomhole samples are to be preferred.

Note:

Care must be taken when assembling and connecting the sampling manifold. In most cases, when monophasic wellhead samples are required, the flowing wellhead temperature and pressure will be far in excess of the normal separator conditions encountered.

15.12 Recombination Sampling

The most common form of sampling is recombination sampling from the test separator.

It is advantageous to take some samples as soon as possible after flowing clean fluid into the separator. In the event of problems occurring during the test these samples may be the only ones obtained. Although the samples collected early on may not be under ideal conditions of stability these samples should be retained, until such time as better samples have been collected, at which time they may be discarded. Some service companies refer to these first samples as 'safety samples'.

Separator samples should always be taken simultaneously (at least within 30 minutes of the other) as matched sets of oil and gas samples, thus being sampled under identical conditions. They should also be taken as slowly as possible to minimise the impact of any fluctuations in separator conditions. As noted in 15.2 all pertinent parameters must be recorded while sampling at the wellhead, separator and the tank.

Normally three sets of separator samples should be taken, so that there is comparability between sets of samples at the laboratory for selection of the best.

As with bottomhole sampling, the well needs to be conditioned properly to assure that representative fluid samples are obtained. Ensure that all sampling lines are flushed thoroughly before sampling. The sample of gas will be taken into evacuated cylinders and liquids into piston cylinders or water/glycol displacement cylinders. Once the samples have been taken the isolation valves on the bottles should be firmly closed, and plugged to ensure no leaks occur.

The ratio of the number of gas samples to oil samples taken is dependent upon the GOR and the separator conditions.

Assuming 600 cc oil bottles and 20 litre gas bottles are used, the following equation can be used to estimate the gas volume necessary for recombination. Where GOR is the separator gas oil ratio (scf /bbl). Psep is the separator pressure and Gv is the gas volume in litres at separator sampling conditions.

$$Gv > 2.5 * \frac{GOR}{Psep}$$

In general an additional gas bottle is routinely filled to ensure that there is adequate gas to recombine the full oil sample at reservoir conditions.

15.13 Labelling of Samples

Once samples have been taken they **must** be clearly identified with robust labelling using indelible ink and attached to the sample containers as well as the transportation boxes.

Samples should be catalogued on site so that a permanent record of the samples is made. It is important that the bottle serial numbers are also cross referenced in case the labelling becomes detached.

Table 15.2 shows a typical sample label and the information that should be recorded at the time of taking the sample.

Table 15.2

ESPRIT PETROLEUM TECHNOLOGY LTD.	**Fluid Sample Label**
Country	
Block	
Well Number	
Interval Tested	
Test Number	
Sample Number	
Container Serial Number	
Fluid Type	
Sampling Location	
Date : Time	
Reason for Sample	
Sample Temperature	
Sample Pressure	
Wellhead Pressure	
Wellhead Temperature	
Separator Pressure	
Separator Temperature	
Stock Tank Pressure	
Stock Tank Temperature	
Sampled By	
Witnessed By	
Remarks	

The samples should then be packaged and labelled according to IATA or US DOT regulations. A Shipper's Declaration for Dangerous Goods needs to be filled out with emergency procedures (or an MSDS sheet) attached.

15.14 Storage and Disposal of Samples

Short Term Storage

All apparently representative samples collected during a production test will normally be stored for 6 to 12 months. This will ensure that sufficient back-up samples are available until all analyses are completed.

Once PVT analyses are completed and validated, some samples will be selected for long term storage and the rest will be discarded

This should be done no later than 12 months after the test but sooner if possible. The Test Engineer should monitor the status of sample storage and disposal to ensure that disposal instructions are issued on time.

Samples will be selected for long term storage on the basis of PVT analysis results and validity checks on the surplus bottles.

Sample should not be committed to long term storage without a validity check, which will consist of either a contact pressure measurement for gas samples or a bubble point determination at ambient temperature for oil samples.

The long term storage period for a sample may be as long as the operating company has an interest in the reservoir, which allows for any unforeseen requirements. However, it is stressed that every conceivable analysis that is required should be done, if possible, on fresh samples.

Note:

As the sample bottles in which the samples were sent to the laboratory are usually supplied on a daily rental basis from the testing contractors. Arrangements may have to be made to purchase these bottles if long term storage is envisaged or alternatively the samples may be transferred to the operating companies own bottles.

This Page Intentionally Left Blank

CHAPTER 16

GAS, OIL & WATER – MEASUREMENTS AND ANALYSIS

This chapter is intended to provide the wellsite petroleum engineer with sufficient information on oil, gas and water property measurements to allow quality control of the measurements made during the test. Only onsite measurement techniques are dealt with as laboratory analysis techniques will be specific to the laboratory work request raised by the reservoir engineers and production technologists of the operating oil and gas company.

16.1 Gas Measurements and Analysis

Specific Gravity

The usual measuring instrument for gas specific gravity is the torsion balance gravitometer (Ranarex). A gas sample is normally first collected in a rubber bladder or stainless steel sample bottle. Then continuous supplies of the gas sample and dry reference air are drawn into two separate chambers and impinge against the vanes of impulse wheels, creating torques which are proportional to gas and air densities. By setting the torque created by the reference air to 1.000, the torque on the gas wheel can be read directly as a specific gravity relative to air.

Hydrogen Sulphide

The most reliable measurement of H_2S is often that made at the wellsite, this is because the sample containers absorb H_2S, unless specially treated containers are used. The most practical method of measurement at the well site is using the Draeger method. A controlled amount of gas (100 cm^3 per stroke, using a hand pump) is drawn through a tube containing a reagent. The number of pump strokes required is dependent on the tube used and the scale used on the tube (multi scale tubes are available). Any hydrogen sulphide present in the gas reacts with the reagent (a mercury substance), to form a pale brown sulphide compound. The length of discolouration is proportional to the amount of hydrogen sulphide which has reacted, with the reagent at ambient conditions, and is read directly from the scale on the tube. H_2S tubes are normally calibrated in ppm (parts per million).

Care must be taken to sample the gas at atmospheric pressure: a higher pressure will result in more gas passing through the tube than assumed in the calibration.

Before use, the pump bellows should be checked for leaks by attempting to suck against an unopened tube. If the bellows are sound the pump will not open.

The pump should also be checked for plugging, with no tube inserted, the bellows should open suddenly after being released.

Tubes suitable for a variety of ranges of H_2S concentration should be available at the well site in order to obtain the most accurate results.

There are also tubes available for Mercaptans Sulphur, which after pumping the required volume through the tube an ampoule is then broken to release another reagent, to indicate the presence of Mercaptans.

Note, if full well site chemistry services have been specified for the test then measurements of H_2S and Mercaptans Sulphur can be made at the well site to the appropriate ASTM or IP standard. However, these determinations can take up to 6 hours to complete. Therefore, for practical purposes the Draeger tube measurements will be used to determine the appropriate H_2S safety measures required for the test.

NOTE: Only take H_2S readings in the open air or in well ventilated areas.

Carbon Dioxide

This can be measured in the same manner as H_2S described above, using a Draeger hand pump and appropriate CO_2 tubes. CO_2 readings are normally expressed in %.

Radon

Wellsite chemistry services may also include analysis of Radon (Rn^{222}) in the separator gas. These measurements, if required, are best conducted as soon as possible on the gas sample, as Radon has a short half life, only 3.8 days. Therefore, a measurement with a Radon meter (scintillation cell) at the well site is preferable.

Mercury

It is also possible to obtain a measurement of mercury in gas at the wellsite. One method involves flowing known volumes of gas through a gold sand trap where the mercury is absorbed. The mercury can later be desorbed from the gold and measured by an atomic flourescence technique.

16.2 Oil Measurements and Analysis

Specific Gravity of Crude Oil

This is normally measured using a Hydrometer.

The oil should be taken on the separator oil line and must free of any water, therefore, the sample must be allowed to stand to allow any separation of water before taking off an oil sample for measuring. The sample should attain a uniform temperature before taking a reading, with the temperature preferably as near 15°C as possible. However, the temperature will be measured at the time of making the reading and will be corrected using tables to give a value at 15°C. It is also important to remove any air bubbles from the surface of the sample with a piece of clean filter paper or by gently blowing across the surface. When the thermometer indicates a constant temperature, record temperature to the nearest 0.2°C. Find true hydrometer level by depressing it with a rotating motion about two scale divisions and then releasing it. Avoid wetting the hydrometer any higher than necessary. Note the hydrometer reading to which the hydrometer rises to the nearest 0.0005. Add 0.0007 to allow for miniscus.

Use ASTM or IP tables to correct SG (specific gravity) to value at 15°C.

<u>Pour Point</u>

The determination of pour point in advance of a well test may be important when testing oil wells located in deep water or when exporting oil via a pipe line, particularly sub sea lines.

The pour point determination would be carried out on the oil samples obtained from RFT / MDT runs made during logging. This would then indicate if there was likely to be a pour point problem, for example in relation to the low sea bed temperatures encountered in deep water offshore locations.

The method for determination of oil pour points is covered in the American Society for Testing and Materials (ASTM) – D 97-96A, " Standard Test Method for Pour Point of Petroleum Products".

In the situation where the decision to test hinges on the pour point, it may only be necessary to determine whether the pour point is above or below a certain critical value. In this case, a temporary ice bath may be rigged up to check whether the oil is pourable at a specific temperature and the complete ASTM procedure may not need to be followed. In the event that the pour point as determined by this quick look method is close to some critical temperature such as sea floor temperature, then the fully ASTM procedure should be followed. However, large variations in the pour point can be experienced depending on what temperature the sample is pre-heated to. Therefore, In general the sample should be heated to reservoir temperature before carrying out the pour point test.

16.3 Water Measurements and Analysis

<u>Specific Gravity of Water</u>

Hydrometer method as for crude oil.

Produced water is seldom fresh and has a SG (specific gravity) greater than 1.0.

Base Sediment and Water (BS & W)

On the rig site this is normally measured by centrifuging.

Shake the sample can or bottle and rapidly fill a stoppered glass container. Maintaining a representative sample is vital. With high water cuts and non-emulsion forming crude, it may be necessary to measure and separate off the total free water in the sample using a thistle funnel with a tap as the first step in the procedure. Fill both centrifuge tubes to the 50ml mark with solvent (toluene). Shake sample in glass bottle and immediately pour into the centrifuge tubes, filling up to the 100ml mark. Add 1 ml of emulsion breaking chemical (demulsifier). Stopper each tube and shake vigorously. If required to obtain separation, stand the tubes in a water bath at ~ 140°F for 15 minutes. Place tubes in centrifuge and spin at 1500-1800 rpm for 5-10 minutes. Read the final volume of water, emulsion and sediment in each tube and calculate their sum as the percentage of water and sediment present. If only one sample was used the results must be multiplied by two since half of the sample was solvent.

Chloride Concentration of Water

Two methods can be used to determine the chloride concentration of a water sample.

Resistivity – Resistivity meters are a common device and are frequently used by the wireline logging company and to determine the resistivity of muds and mud filtrates. These devices utilise an electrical Wheatstone Bridge arrangement to measure resistivity and the NaCl equivalent concentration can then be determined from charts.

Mohr Method (Titration) – this is based on the reaction of an indicator solution, potassium chromate, with the first excess of standard silver nitrate titrant forming an insoluble red (salmon pink) silver chromate precipitate at the end point. When the end point is reached the chlorides concentration is calculated by multiplying the number of ml of standard silver nitrate used to obtain the end point. Various conversion factors are then used to yield a chlorides concentration in ppm.

This method is suitable for analysing water with a pH between 6.0 and 8.5. The Mohr method is subject to interference from bromides, iodides, thiocyonates, phosphates, carbonates and sulphides which also precipitate silver ions. The concentrations of bromide and iodide are normally insignificant, in most water samples and sulphides can be removed by acidifying the solution with nitric acid and boiling.

Other Water Determinations

Depending on the requirements further analysis can be undertaken, particularly when it is required to differentiate between mud filtrate and formation water, such as:

- Free carbon dioxide content of produced water
- Bicarbonate and carbonate concentrations
- Ca and Mg concentrations

CHAPTER 17

REPORTING

Reporting information over the period of the well test is a very important task. This information is necessary to inform the local management, corporate management and partners of the conduct of the test. These reports also provide an account of the operation for use in the future.

Information that may seem trivial at the time of the test may hold the key to explaining some anomaly during later analysis of the test data. This is particularly important when memory gauges are being used to record downhole pressure and temperature, as events recorded by the gauges will not be available until after the test is completed and the gauges have been recovered.

Suggestions are given in this chapter on the information that should be recorded for daily well test reports and the information that will be required for end of well reporting. It is worth noting, that often there is a period of many years between testing of the first exploration well in a new area to the field going into development. In the intervening years many of the original personnel involved in testing the discovery well will have moved on, therefore all that will remain to guide others in the future will be that information contained in the end of well report. Consequently it is important that the information is as comprehensive and accurate as possible.

17.1 Daily Reporting From The Well Site

It is normally the responsibility of the well site Petroleum Engineer or Test Engineer to send a daily well test report to the base office each day by fax or E-mail. The daily report will summarise the well test operations of the preceding 24 hours, give details of the current operations and also provide a look ahead for the planned operations.

The daily well test report is in addition to the daily drilling report, which the Drilling Supervisor will continue to send during the testing operations. However, often the drilling report will only state under the operations section "Well Testing", but will provide some useful information to the shore base such as, weather, sea state, inventory of mud and brines.

Therefore it is important for the Test Engineer to communicate as much information as possible to the shore base to adequately reflects the progress of the well testing operations.

An example format for a daily well test report is shown in Table 17.1.

Table 17.1

DAILY WELL TEST REPORT

DATE:

COUNTRY:
BLOCK:
WELL NUMBER:
INTERVAL TESTED:
DST NUMBER:

1. **Summary of Operations** from ...... hrs to ...... on (date)

2. **Time Breakdown** (Sequence of events)

a. **Date / Time**

Operation e.g. Make up BHA, set packer, flow and shut in periods.

b. **Production Details** (to include the following)

Time	Choke	THP	THT	Psep	Tsep	Oil	Gas	GOR	H_2O
hh:mm	64ths	psig	°F	psig	°F	bopd	MMscfd	scf/bbl	bwpd

c. **Additional Information**

Perforated intervals, thickness, depths MDBRT and TVDSS

Gauge sensor depths (MDBRT and TVDSS)

Depths of key items in the test string (MDRT and TVDSS)

Sample information (source, sampling time and condition, results – gravity, density, salinity, pH, resistivity at stated temperature).

Bottom hole pressures and temperatures, quick look interpretation results.

BSW, H_2S, CO_2, gas gravity, oil density, cumulative volumes produced.

d. **Current Operations**

e. **Forward Programme**

Plans for next 24 hours.

The Test Engineer must ensure that all relevant data is reported correctly and is available to the shore base in a timely manner. Normally the following reporting times are used:

AM Summary sheet (due before 08:00)	Faxed report covering time period midnight to midnight previous day with update to 06:00 on the report date
AM Phone call	Call duty Engineer 08:30 daily
PM Summary sheet	Faxed report covering time period 06:00 hrs that morning to 15:00 hrs on the report date. (due before 17:00)
PM Phone call	Call duty engineer 17:00 daily.
Fax Reports	Fax in contractor data sheets, sample data sheets, provisional results, production logs, computer data sheets and any interpretation data etc. as and when they become available.
Downhole Gauge Data	Pressure gauge data should be down loaded onto floppy discs at the end of each test. Send data electronically as an E-mail attachment, if possible or else send a disc to town as soon as possible after each test. The Test Engineer should also keep a spare copy of each data disc and hand carry them to the shore base on completion of the test.

17.2 Final Well Test Report

A final well test report should be completed soon after the well testing has finished. This document should contains as much information about the well as possible, to give a full picture of the operations, formation evaluation, coring, pressure analysis and production results.

The final well test report should include input from all those involved in the well, including Petrophysicists, Geologists, Test Engineers / well site Petroleum Engineers as well as the Reservoir Engineer carrying out the pressure transient analysis.

A guideline for the main section headings for a final well test report is shown. It is designed such that it can be incorporated directly into the end of well file or it may be a stand alone document. The report should contain an operational summary, which details equipment performance, problem analysis and future recommendations.

FINAL WELL TEST REPORT

SUMMARY

Should contain comments on the following :-

- where the well is,
- dates when the tests were conducted,
- which zones flowed and which did not,
- what the test objectives were and whether they were achieved.

CONTENTS

1. Formation Evaluation Results
    - Core Results
    - Log Interpretation Results
    - RFT Pressure Results

2. Summary of Welltest Results
    - Results of DST 1
    - Results of DST 2 etc.

3. Conclusions and Recommendations
    - Conclusions
    - Recommendations for Future Tests

4. Analysis of Welltests

    Analysis of DST 1, 2 & 3 etc.
    - Flowing Performance Summary
    - Sampling Summary
    - Test String & Operational Summary
    - Perforation Summary
    - Pressure Gauge Performance Comparison
    - Pressure Transient Analysis

LIST OF TABLES

LIST OF FIGURES

APPENDICES

REFERENCES

SERVICE COMPANY REPORTS

CHAPTER 18

COIL TUBING AND NITROGEN

Coil tubing and nitrogen are commonly used during well testing, either individually or together. Coil tubing on its own has many varied uses during well testing such as running PLT tools and bottom hole samplers in horizontal wells, spotting acid or other chemicals across perforations, acid jetting of perforations, spotting wax solvents to remove wax plugs inside tubing and much more. The list of uses for coil tubing only seems to be limited by the imagination of engineers planning the operations.

Similarly the uses for nitrogen are quite varied, such as, drill stem test cushion, mud weight reduction, dry perforating and gas lift displacement.

However, the coil tubing nitrogen combination is one that seems to be particularly useful during well testing and other well operations. Coil tubing and nitrogen are used for gas lifting after completion or to restart a well after a shut in or after an acid job to encourage clean up. Coil tubing and nitrogen along with a high viscosity fluid is effective for cleaning sand outs of wells.

Therefore, in this chapter we shall review the basics of coil tubing equipment, some uses of coil tubing and some aspects of coil tubing operations. We shall also review the properties and uses of nitrogen and then finally look at some of the uses of the coil tubing nitrogen combination.

18.1 Coil Tubing Equipment

The basic elements of equipment required to run and utilise coiled tubing with or without nitrogen are as follows:

Tubing

The original technology available confined operations to the use of 1" tubing only. Now much larger OD tubing is becoming more common, although 1¼" and 1½" is the norm. The benefit of the larger size is that it is mechanically stronger, and therefore has the ability to be used at greater depths under more rigorous conditions. The tubing itself is manufactured from stainless steel, being seam-welded using the argon arc process to make singled coiled lengths which are then heat treated. Alternatively, lengths can be joined using crimp type internal couplings although the continuous tubing is to be preferred.

Tubing Reel

The tubing is stored on a reel in the same manner as the flexible cable of a wireline logging unit. Up to 15,000 feet of tubing can normally be stored on a single reel. The reel is supported on an axle and rotated by hydraulic motors through a chain drive. This drive system has a dual function: when injecting the tubing into the well, the motor acts as a brake providing control over the rotational momentum of the reel. When coiling, the drive system revolves the reel so as to coil the tubing under a constant tension. The drive system is not used to lower or hoist tubing in the well.

To control the coiling process, a spooling mechanism is synchronised with the rotation of the reel using a drive taken from the axle.

The inner end of the coiled tubing string is connected to the hub of the reel, which incorporates a rotating joint. Any normal oilfield fluid, for example acid, or gas, can be pumped through this joint and down the coiled tubing whilst the reel is in motion at any pressure up to the operation limit of the tubing itself.

Injector Head

The injector head is installed onto the wellhead, tubing or drillstring and is the means by which the tubing is manoeuvred into and out of the well. It is connected to the wellhead through a blow-out preventer and stripper (stuffing box). The stripper is designed to strip the tubing in and out of the hole under pressure, while the BOP acts only as a safety device. The stripper is activated primarily by wellhead pressures, but is also adjustable by means of a hydraulic hand pump.

Mounted above the stripper is the actual injection system. The tubing is gripped between contoured blocks carried by two sets of chains. Over the area of contact between the blocks and the tubing, the chains are guided by a system of rollers. Each set of chains is powered by a hydraulic motor, which drives through a safety clutch and gearbox. The clutch is arranged to prevent the tubing falling into the hole in the event of a prime-mover failure and also serves as a brake.

On top of the injector's subframe is usually mounted a continuous straightening device and a depth measuring odometer. The straightener comprises three contoured wheels arranged so that the curvature of the tubing which was imposed by coiling is substantially removed by bending it in the opposite direction. Above the subframe is also a hydraulic press, which is designed to crimp the tubing to produce a positive closure on the tubing string without having to operate the BOP.

To complete the injector equipment there is a roller guide (goose neck) on the top of the main frame that supports the tubing during its transition from motion along the vertical axis of the wellhead to the horizontal coiling axis of the storage reel.

Control Cabin and Power Pack

The coil tubing operator is located within an elevated control cabin overlooking the coil tubing reel. From the control cabin the various power systems and controls are operated. These system usually contain two hydraulic pumps driven by a diesel engine; one pump provides hydraulic pressure for the drive motors of the injector, whilst the other is used to drive the tubing reel. In response to the operators commands, control valves impose a given hydraulic pressure on the hydraulic motors.

The hydraulic tensioner for the injector chains and the stuffing box control are each controlled with its own hand pump. The blow-out preventer is hydraulically opened and closed by oil stored in an accumulator.

Figure 18.1 shows the principal equipment components of a coil tubing unit (CTU).

18.2 Uses of Coil Tubing

The following are some of the more common applications for coiled tubing.

- Spotting acid, cement, or chemicals on bottom or across perforated zones.
- Spotting diverting agents across one set of perforations and squeezing acid into another set.
- Acid jetting perforations and slotted liners plugged with calcium carbonate or other soluble materials.
- Scale jetting and milling in production tubulars.
- Running memory PLT tools and samplers in horizontal or highly deviated wells.
- Running real time PLT tool and samplers in horizontal or highly deviated wells with so called stiff wireline. (Coil tubing with mono conductor cable inside)
- Drilling out cement from drill pipe, tubing or casing using a dyna drill.
- Spotting oil or chemicals at the bottom of a stuck drill string.
- Spotting wax solvents to remove a wax plug inside tubing.
- Spotting methanol or heated glycol/water to melt a hydrate plug inside tubing.
- Deployment of TCP gun systems.
- Squeeze-killing producing horizons prior to workover.

COIL TUBING EQUIPMENT – PRINCIPAL EQUIPMENT COMPONENTS

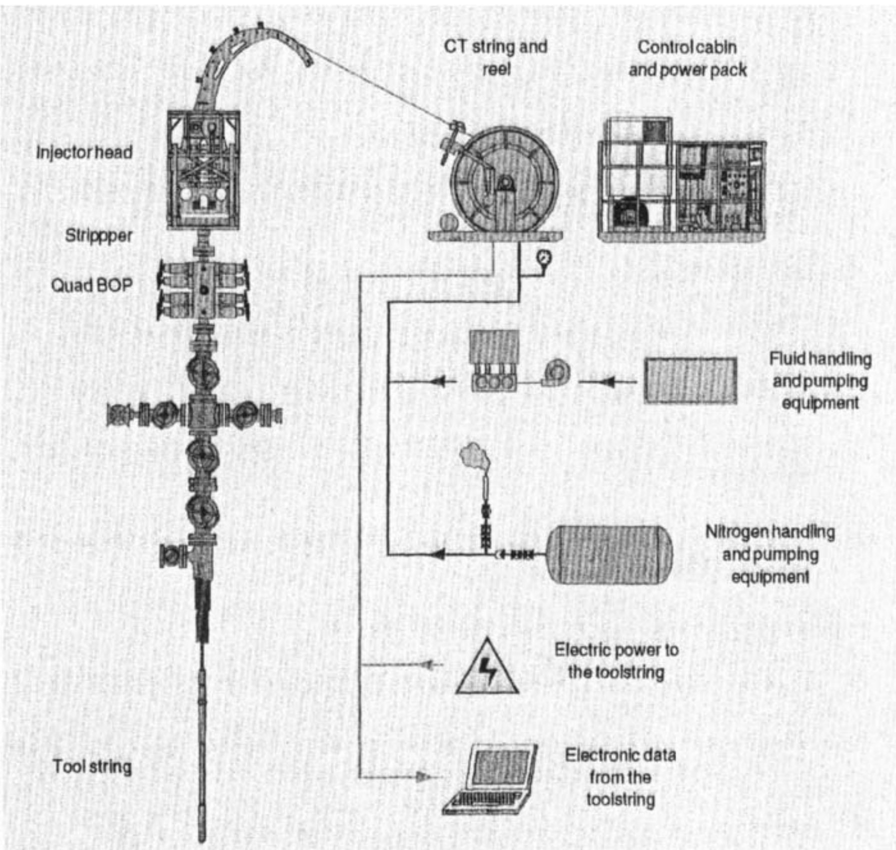


Figure 18.1

18.3 Typical Coil Tubing Operating Procedures

- All hydraulic lines are coupled to the injector and tubing reel systems.
- The operation of the BOP is checked.
- The tubing end is spooled out from the reel and fed into the injector head so that the contoured blocks of the traction chains take hold of it.
- The lubricator and wellhead connections are made.
- The BOP is installed on the lubricator.
- The injector head is picked up to allow the check valve and other tools to be installed on the downhole end of the tubing and then the injector head is mounted onto the BOPs.
- The pumping system to be used with the tubing is rigged up and the treating lines are connected to the rotating joint on the hub of the reel.

  The treating lines should include:

  - an isolation valve,
  - a bleed off valve,
  - a check valve,
  - a pressure recorder.
- The treating lines, tubing and wellhead lubricator are filled with water and pressure tested.
- Open master valves and swab valve or lubricator valve.
- Commence RIH slowly until the downhole tool assembly has passed through the wellhead. Provided the holdup depth is known the running in speed may be increased to a maximum of 140 ft./min.
- The job now proceeds according to the nature of the programme.
- Pulling out, care must again be taken when passing through the wellhead so that when the tool assembly contacts against the stripper, the weight indicator registers only a gradual increase.
- All the wellhead valves should be closed carefully; checking that they are all closed fully and not on the coil tubing. End of job.

18.4 Uses of Nitrogen

Nitrogen in its liquid state is available in most oilfield regional locations and is obtained from the air liquefaction process, by which liquid oxygen is also produced. In its gaseous form nitrogen is inert and odourless. It is safe to handle being non-flammable, non-toxic, non-polluting and will not support combustion. It is also insoluble in water and therefore remains in bubble form when injected into a well. These properties make nitrogen a very attractive fluid.

Equipment

The basic equipment required to utilise nitrogen can be divided as follows:

Storage Tanks

Transportable nitrogen storage tanks normally have a capacity of around 200,000 scf although larger trailer drawn tanks are available for land based operations; stimulation vessels usually have their own permanently sited storage facilities. In each case the overall design is similar. The nitrogen is stored in tanks at about -320°F (-196°C). The tanks are insulated and consist of an evacuated double skin with perlite or foil layers between the skins. Even with this insulation losses do occur, though these can be limited to 0.5% remaining volume per day. The normal transport pressure of the tanks is atmospheric pressure, but as evaporation takes place, pressure inside the storage tank builds up and this must be vented off regularly.

Nitrogen Membrane Units

There are only a few onsite nitrogen membrane units available world-wide which can produce a continuous nitrogen supply at the well site by liquefaction of air. However, these units are both very expensive to hire and to operate, requiring large quantities of diesel fuel. Nitrogen conversion units are really only be considered for testing of wells which require a large and continuous supply of nitrogen for lifting throughout the test and where no other feasible lift mechanism is available.

Pump Unit

Usually comprises:

Cryogenic pump – capable of pumping 4,000 scf/min at pressures of up to 10,000 psi (when using coiled tubing, maximum surface treating pressure would normally be kept at 4,500 psi). This unit often has a diesel engine to drive the pump.

Heater – indirect diesel fired type with a capacity of up to 5 MMBTU/HR capable of raising the nitrogen to an operating temperature of 70-200°F.

Fig. 18.2 shows a typical nitrogen pump schematic.

NITROGEN PUMP SCHEMATIC

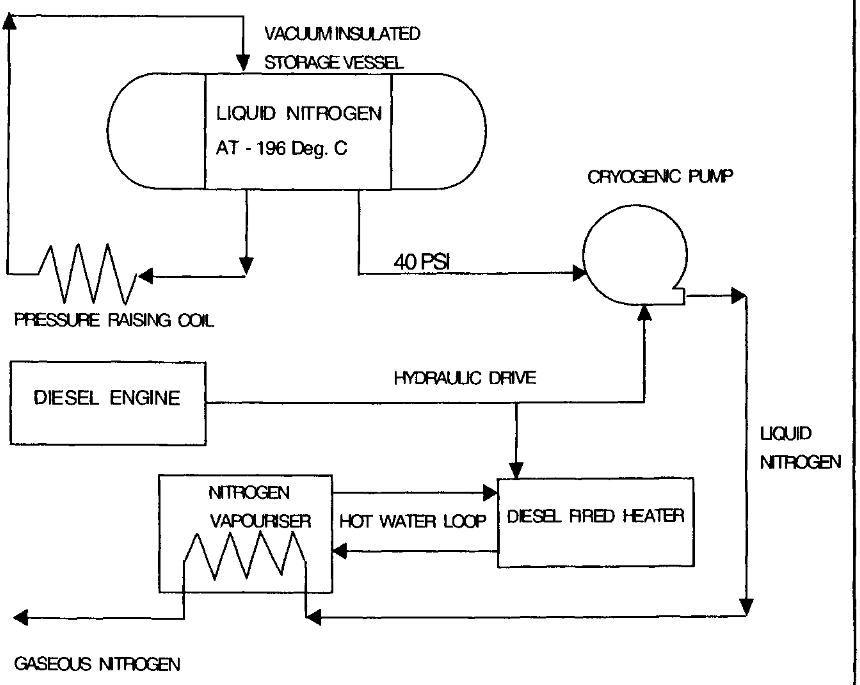


FIGURE 18.2

Within the pump unit liquid nitrogen is rapidly vaporised in a pressure-raising coil to build up and maintain pressure in the vacuum insulated storage vessel. It is this pressure which drives the liquid nitrogen to the cryogenic pump. The pump then directs the flow through a vaporiser where it is gasified to the required delivery temperature and then finally passed to the wellhead or coiled tubing by 2" or 1" chicksans at a controlled rate and pressure.

Some service companies offer pumping units than can only output 2500 scf/minute. In deep wells, with large volume test string this limited pump rate causes long time delays when filling up with the nitrogen cushion. In such cases it is wise to seek a nitrogen pump unit with a larger delivery rate.

The applications for nitrogen can be divided into two categories:

As a gas commingled with various well treating fluids (acid, viscous fluid, etc.) and on its own as a gas to be used as a displacement or pressurising medium.

Nitrogen Commingled with Treating Fluids:

A problem that occurs in both acidising and fracturing is the recovery of the treating fluids after the treatment has taken place.

Due to the low solubility of nitrogen gas in both oil and water, this makes it an excellent medium to incorporate with these fluids to reduce the hydrostatic pressure to less than that of the formation flowing pressure. Generally, nitrogen is injected ahead of the treatment and then mixed with the treating fluid and after-flush at ratios of from 300-1000 scf/bbl. After sufficient time is allowed for the fracture to close or the acid to spend, the treating fluid and the nitrogen is then flowed from the well.

<u>Foam Generation</u>

Nitrogen is used to generate foam for clean out of well fracturing treatments. It has excellent fluid-loss properties and transports proppant detritus material efficiently.

Water-sensitive gas-bearing formations with low matrix permeability and low reservoir pressure are candidates for nitrogen-foam fraccing treatments.

<u>Mudweight Reduction</u>

Nitrogen can be commingled with drilling fluids in order to reduce mudweight and thereby combat lost circulation. Nitrogen is quickly dissipated from drilling mud on return to the surface, allowing a quick return to heavier mud weights.

Nitrogen Gas as a Displacement or Pressurising medium:

<u>Gas Lifting Displacement</u>

Typically, fluid displacement using nitrogen would be performed on a newly completed production well, by pumping nitrogen down the annulus in order to "kick" the well off. This technique require a port in the tubing such a sliding side door (SSD). A slightly more refined version of gas lifting is achieved by injecting gas into the tubing via gas lift valves, but these gas lift valves would only be included in the completion if there were plans to continually gas lift the well in the future.

Deep lifting can be performed by running coiled tubing into the well to below a static fluid column and then slowly pumping nitrogen until the column begins to move of its own accord.

These applications are particularly important where:

- A well with a high GOR has been shut in for a long period allowing phase separation.
- The natural gas lift system is shut down or insufficient quantities are available.
- Commissioning the gas lift valve system to check for correct valve settings.

Dry Perforating (Through Tubing)

Serious formation damage can occur during the perforating phase of testing and completing wells. Using nitrogen and a wireline lubricator, a pressure differential can be created in the wellbore. This technique virtually eliminates the possibility of excess hydrostatic pressure in the hole pushing perforation debris and other solids into the formation.

When the well is ready to be perforated, nitrogen is used to displace the well fluid out of the tubing. With the packer set, the wireline gun in position, and the well pressured with nitrogen, the gun can be fired. After the gun is removed into the lubricator the nitrogen pressure is slowly bled off to help bring the well in.

The procedure outlined above could be used to perforate with a overbalance of say 500 psi, but it is also feasible to perforate with a slight underbalanced. Reservoir characteristics tend to determine which method of perforating should be used to give the best results.

Drill Stem Test Cushion

Nitrogen can be particularly useful during drill stem testing.

When well depths and mud weights are such that the drill stem near the bottom of the hole is not in danger of collapse, it can be practical to pressure the entire tubing string (from surface) with nitrogen. This can be undertaken before the retrievable packer is set and the bottom hole tester valve is opened. This procedure replaces water or diesel as the cushion.

Once the well has been perforated the downhole and surface valves may be opened and the nitrogen pressure slowly bled off to induce formation fluid flow into the test string. This gradually increases the differential pressure across the packer rather than subjecting it to a sudden shock and avoids possible packer failure.

When the well depth and mud density are such that protection from collapse is required, the lower section of the string may have to be run with a water cushion and the remaining cushion made up with nitrogen, again yielding the end result of a "flexible" cushion.

A complete nitrogen cushion is however of particular value if the fluid recovered from the well is expected to be water. When a water cushion is used, for example on a low permeability formation test, it is often impossible to detect a small recovery of formation water unless a tracer is used in the mud during the drilling phase. When nitrogen is used, there is however no question as to whether or not water obtained during the test came from the formation and also there is no question as to the quantity of the water produced. There is also no dilution of the produced water by the cushion water which would alter the salinity. Finally, when only small quantities of oil are produced, the oil can be recovered in one body rather than being strung out through a long cushion of water.

Tubing Conveyed Perforating Guns

A nitrogen cushion can also be used to detonate a TCP system in conjunction with a differential pressure firing head. Constant pressure is held in the annulus whilst the nitrogen tubing pressure is bled off. Shear pins are selected for the differential pressure firing head, which controls the differential pressure between the annulus and tubing pressure at which the guns fire. This allows underbalanced perforating with TCP's.

Leak Detection

Nitrogen gas has been used to pressure test water sensitive systems, and systems not designed to handle the weight of water used in hydrostatic testing. With the addition of helium into the nitrogen and the use of a helium mass spectrometer, this type of gas testing has evolved into a highly sensitive and reliable means of leak detection. The testing procedure can be long and time-consuming and therefore is only suited to completion technology.

Its accuracy (quantifying leaks to as little as 0.1 scf/year) also makes the detection system ideal for completions and long term installations. Extreme caution should be exercised when using Nitrogen to pressure test due to the large quantity of stored energy.

18.5 Uses of the Coil Tubing and Nitrogen Combination

Treatments involving the use of both coiled tubing and nitrogen can be broadly divided under three sub-headings; gas lifting, acidising and sand clean outs.

Gas Lifting

May be required:

- After re-completion of a producing well or completion of a new well when in both instances reservoir pressure is insufficient to overcome the applied hydrostatic of the workover or completion fluid.

- Break out of gas from oil in wells with a high GOR during a period of shut-in. On re-opening, the gas cap would be dissipated leaving a column of dead oil of sufficient gravity to kill the well.

- After an acid job to encourage clean up.

In each case the coiled tubing would be run into the hole to below the static fluid level and then nitrogen pumped until flow to surface is established. There is no hard and fast rule as to how deep the column should be gas lifted and how fast the nitrogen should be pumped. However, a rate of 500-1000 scf/min is reasonable, but lift curves can be generated if required before the job.

<u>Acidising</u>

Two types of acid treatment may require the use of nitrogen to aid clean-up. The nitrogen can be used as gas lift after the job. Alternatively pumped in combination with the acid flush (Nitrified acid) in order to lighten the effective hydrostatic pressure on the formation thus providing in situ gas lifting.

- Acid washing is used to remove carbonate scale, detritus, and clay build up from wireline nipples, gas lift valves, etc. Occasionally an acid wash on perforations is undertaken to reduce skin. The acid is circulated to the bottom and the area to be treated allowed to soak. To aid clean up, the acid may need to be nitrified, or nitrogen gas lift may be required.

- Acid squeezing as the name suggests requires the pushing of acid into the formation via the perforations. The coiled tubing is run into the production tubing and the acid is pumped from surface through the coiled tubing and once it is in contact with the formation, the well is shut in and the acid is squeezed into the formation. The acid may be nitrified, usually 300-350 scf/bbl, to aid clean up. Deep gas lifting with nitrogen through the coiled tubing may be necessary on the more reluctant wells.

<u>Sand Clean-outs</u>

These may be small jobs, for example to remove fine insoluble detritus material or much larger operations to remove large quantities of sand from tubing, clear sanded up perforations or clean up a well after a frac job has screened out.

The normal procedure is to pump alternating pills of a viscous fluid (for example HEC) and nitrogen. The viscous fluid provides the solids carrying capacity and the nitrogen when pumped at high pressure provides the fluid column velocity. The coiled tubing is steadily lowered through the sand body until it has been cleared.

This Page Intentionally Left Blank

CHAPTER 19

STIMULATION OPERATIONS – SAFETY

This chapter is primarily concerned with the organisation of stimulation operations and the necessary safety considerations. The particular details of a stimulation operation will be very much dictated by the requirements to carry out the stimulation. Broadly speaking there are two main types of stimulation, that is, stimulation by acid and stimulation by fraccing. There is a discussion on each of these techniques below, together with details of appropriate safety considerations.

The requirement to carry out reservoir stimulation will normally be dictated by the Reservoir Engineering department. However, it will often be the Test Engineer or well site Petroleum Engineer who will develop the operational procedures for the stimulation in conjunction with the drilling department.

19.1 Responsibilities

Generally the Drilling Supervisor on the rig site will have administrative authority throughout the stimulation operation. However, the Test Engineer or wellsite Petroleum Engineer will be responsible for the conduct of the operations and will personally supervise the work. The Drilling Supervisor will have overall responsibility for the safety of the stimulation operation

19.2 Safety

The following general safety procedures and practices should be observed during any stimulation operation.

1. The Petroleum Engineer will convene a safety meeting attended by the Drilling Supervisor, the drilling contractors personnel, stimulation service company representative and all personnel directly involved in the stimulation operation. The Petroleum Engineer will outline the expected course of events and ensure that personnel responsibilities and contingency measures are fully understood. Lines of communication will be clearly established so that in the event of an emergency rapid action can be taken.

2. Verbal communication equipment (radio or rig telephone) should be available at all times between the rig floor and stimulation unit.

3. Chain or rope off the work area. Warning signs should also be placed at the access points to hazardous areas.

4. An announcement should be made prior to the of stimulation treatment taking place. All non-essential personnel should be instructed to keep clear of the hazardous areas.

5. Treatment pumps should be equipped with automatic shutdown systems in case of over pressuring occurring.

6. All treatment lines must be tied or chained to secure points. Onshore stakes will be required to secure treating lines.

7. Adequate lighting must be available on the rig, treating equipment, frac-boat, etc., if the stimulation is to be performed during the hours of darkness. Should insufficient lighting is available, then it will be necessary to wait for daylight.

8. Appropriate personal protective equipment (PPE) must be worn by those persons directly involved in the stimulation operation. This may include: eye and ear protection, rubber gloves, rubber boots, slicker suits or aprons, in addition to the normal protective clothing worn at the well site.

19.3 Stimulation by Acid

Formations with low poroperm characteristics, or those which have suffered damage during the drilling process due to high overbalance or poor fluids control, can often improve or recover their original productivity by acid stimulation.

A number of different types of acid and additives are currently available to help obtain the maximum production enhancement to the reservoir. The service providers will normally provide recommendations to the Reservoir Engineering department on the type of treatment they consider most appropriate.

The hazards involved with acid stimulation are however largely dependent on the acid type and concentration, but as a general guide the following precautions need to be taken:

- Have a fresh water supply on the rig floor and pumping area. This is to remain turned on during the treatment to allow rapid wash down of personnel or equipment affected by a leak or spillage.

- Eye baths should be positioned at strategic points on rig floor and pumping areas.

- For offshore operations where possible have a constant running water supply over those decks in use during the treatment. Or have the ability to quickly wash down the effected area.

- Full protective clothing, that is slicker suits with hoods, gloves and eye protection, to be worn when mixing, handling, pumping or monitoring returns. Protective equipment must be thoroughly cleaned after use.

- Chemical hazard sheets (MSDS – Material Safety Data Sheets) for the acid and additives in the treatment must be readily available. Personnel involved with the stimulation must be fully conversant with the contents of the chemical hazard sheets and the emergency treatment necessary in the event of an accident. The chemical hazard sheets should be incorporated as appendices into the written stimulation programme.

- Check the compatibility of the chemicals with surface piping, tubing and downhole tools, that is principally there effect on tubing coatings, 'O' rings and elastomer seals.

19.4 Stimulation by Fraccing

Frac stimulations can vary from a cheap mini-frac treatment to an expensive full scale propped fracture treatment. The proppant is used to keep the fracture open once the pump pressure has been bled off.

The main dangers during frac operations occur in the pumping stages, particularly when pumping at high rates and pressure and when a proppant is involved. Under these circumstances there is always the possibility of a 'screenout', resulting in rapid pressure build-ups and the necessity to quickly shut-down the pumps.

During the flow back and clean up period large quantities of proppant (often sand) will be produced which can cut-out equipment and lines, releasing hydrocarbons to the atmosphere (refer to section 13.6, 13.7, 13.23 and 14.9). This is obviously both extremely dangerous, damaging to the environment and expensive. The major danger occurs with gas wells, in particular downstream of the choke manifold, where the pressure reduction allows the expansion of the gas and an increase in velocity.

During frac stimulation treatments the following precautions should to be adhered to:

- The safety features for burst, collapse and tension should be carefully considered for the frac string design. The situation may warrant a dedicated frac string.

- If the frac string is to be used for flow hydrocarbons back to surface then it should also conform to the test string safety requirements, that is two valve isolation.

  If a dedicated frac string is used that will be pulled after the treatment, then less stringent criteria can be used:

- If at all times during the frac job the hydrostatic pressure of the fluid in the frac string is greater than reservoir pressure then no down hole valves are required in the string.

- If at any time during the treatment the reservoir pressure is greater than the hydrostatic of the fluid in the frac string then, one safety valve must be used in the string.

Note: Under-balanced conditions are likely to occur if diesel frac fluids or nitrified fluids are used.

- With offshore operations there should be a manual shutdown system on both the rig and stimulation vessel. This would only be operated in serious emergencies, such as a high pressure treatment line rupturing and the stimulation pumps not automatically stopping.

- For offshore work there should be a quick disconnect on the lines between the stimulation vessel and the rig in case of an emergency, that is rapid deterioration in weather conditions, loss of the vessels engine power.

  There should be a properly fabricated 'frac point' welded on both sides of the rig. This would allow the stimulation vessel to safely connect the stimulation Coflexip from the boat to the rig irrespective of wind direction.

- If a propped frac has been performed on a gas well, some form of sand trap should be placed in the flow line between the flowhead and choke manifold and used whenever possible, to remove the proppant produced during the clean-up. Apart from removing the sand at the earliest stage and helping to prevent cut-out of chokes, valves, lines, etc., the sand trap also allows better monitoring of the sand produced back from the well.

- A sacrificial line should be considered for use during the clean-up period of propped fracs on gas wells. This should may be a high pressure line to the flare. To further reduce cut-out, the choke manifold in the sacrificial line should be as close to the flare as possible, thus limiting high velocity gas flow to only a short section of line.

- Coflexip lines, if practical and available, should be used from the flowhead to the choke manifold.

- Straight lines should be used wherever possible and the number of bends and elbows reduced to a minimum.

- All flowlines should be visible, that is, do not use hidden rig lines that cannot be observed for cut-out and are difficult to replace.

- Some method of monitoring flow line erosion should be considered, such as erosion probes, sand monitors or ultra-sonic devices for measuring pipe-wall thickness. This will allow the flow to be switched to the normal flow lines before any release of hydrocarbons occurs.

- Service company personnel must constantly observe all flowlines during the clean-up period.

- Initial flow back and clean-up of the well, following a sand frac, should occur during the hours of daylight. There should be sufficient time to allow several hours of flow before darkness as the first few hours of clean-up will normally produce the largest quantity of sand and therefore present the greatest safety hazard.

- With gelled oil and emulsion based frac fluids it is important to consider the disposal of the flowed back fluids. In environmentally sensitive areas where any liquid drop out at the flare is a serious problem, the burners should be arranged such that at least one and preferably two burner heads are burning neat diesel and the effluent is burnt at burner heads placed above those burning the diesel. Using this arrangement the diesel flare should burns any uncombusted emulsion or gelled oil fluids (see figure 13.15 Invert oil mud burner). Discussions with the services companies on the most appropriate burners for such frac fluids will be useful.

- The pumping of diesel under pressure, as is often the situation with an unpropped mini-frac, is normally considered acceptable as long as the diesel is not pumped from open tanks, that is, no air is allowed to mix and be pumped with the diesel.

This Page Intentionally Left Blank

REFERENCES:

1. Bourgoyne, A.T., Millheim, K.K., Chenevert, M.E., Young, F.S., 1992, "Applied Drilling Engineering": Volume 2, SPE Text Book Series.
2. Bradley, H.B., 1992, "Petroleum Engineering Handbook": SPE.
3. Dake, L.P., 1978, "Fundamentals of Reservoir Engineering": Developments in Petroleum Science 8, Elsevier.
4. Davalath, J., Barker, J.W., 1993, "Hydrate Inhibition Design for Deepwater Completions": Paper 26532, SPE.
5. Earlougher, Robert, C., JR, 1977, "Advances in Well Test Analysis": SPE Monograph Series.
6. Frick,Thomas, Corwin, 1962, "Petroleum Production Handbook": Mathematics and Production Equipment, Volume 1, McGraw-Hill.
7. Halleck, P.M., Deo, M., 1988, "Effects of Underbalance on Perforation Flow": Paper 16895, SPE
8. Horne, R.N., 1997, "Modern Well Test Analysis": Second Edition, Petroway, Inc.
9. Institute of Petroleum, 1992, "Well Control during the Drilling and Testing of High Pressure Offshore Wells": Model Code of Safe Practices, Part 17, Institute of Petroleum.
10. Mathews, C.S. and Russel D.G., 1967, "Pressure Buildup and Flow Tests in Wells": SPE Monograph Series.
11. NACE, 1999, "Sulphide Stress Cracking Resistant Metallic Materials for Oilfield Equipment": MR0175-99, NACE.
12. Rawlins, E.L. and Schellhardt, M.A., 1936, "Back-Pressure Data on Natural Gas Wells and Their Application to Production Practices: Monograph Series, U.S. Bureau of Mines.

This Page Intentionally Left Blank

CHAPTER 20

APPENDICES

APPENDIX A

RADIUS OF INVESTIGATION CALCULATION

As the pressure response of a reservoir is assumed to follow a radial diffusivity type response, this implies that a pressure change at the well bore would be experienced everywhere in the reservoir. However, the pressure change at the extremities of the reservoir would be infinitesimally small. For practical purposes there will be a point at some distance from the well bore at which no detectable change in pressure is observed, this point is considered the radius of investigation of the test or the drainage area.

There have been a number of formulae defining the radius of investigation, however as the definition of radius of investigation is at best an estimate of where no further pressure change is detected they all have some validity.

The following equation is frequently used to estimate the radius of investigation of a pressure transient:

$$R_{inv} = 0.029 [k\, t / Ø\, \mu\, Ct]^{1/2}$$

Where:-

R_{inv}	=	radius of investigation	(feet)
k	=	permeability	(md)
t	=	time	(hours)
Ø	=	porosity	(fraction)
μ	=	viscosity	(cp)
C_t	=	total compressibility	(l/psi)

It is interesting to note from this radius of investigation formula that the radius of investigation is independent of flow rate. This fact is not well understood, as many within the industry appear to believe that in order to have a good radius of investigation during a test it is necessary to flow the well at a high rate. Flowing at high rates and consequently large draw downs will only ensure that the pressure transient is seen by the gauge, however with accurate quartz gauges this is hardly a consideration and should not be a reason in itself for high rate testing.

Where a reservoir boundary is known; the time taken for the pressure response to reach a boundary at a known distance from the well is estimated as follows.

$$t = 1200 \frac{\varnothing \mu C_t r_b^2}{k}$$

Where:-

t	=	time	(hours)
$\varnothing$	=	porosity	(fraction)
μ	=	viscosity	(cp)
C_t	=	total compressibility	(l/psi)
r_b	=	radius to boundary	(feet)
k	=	permeability	(md)

These calculations are discussed further in, (5) Earlougher, R.C., "Advances in Well Test Analysis", (10) Matthews & Russell "Pressure Build-Up and Flow Tests in Wells" and (8) Horne, R.N., "Modern Well Test Analysis"

APPENDIX B

ESPRIT PETROLEUM TECHNOLOGY LTD.

WELL TEST PLANNING CONSIDERATIONS - CHECK LIST

Consideration should be given to the following bullet points when first planning a well test. This section can also be used as a check list or 'aid memoir' that can be reviewed at any stage up to execution of the test to see if there are any points that have been over looked.

Offset Data:

Formation Properties
Fluid Properties
Production Rate Information

Well Construction:

Casing & Liner -	Grade, weight, drift I.D., shoe depths, liner lap top.
Short Joints & RA Markers -	Above the packer setting depth of the uppermost zone.
Well Deviation -	Packer selection, TCP drop bar firing & Gun drop
Kick off points -	As Above
Well Head Details -	Fluted Hanger Dimensions, hang off point.

Drilling Information:

Mud Type and Weight -	Barite sag, gellation, pressure transmissibility to DST tools, compatibility with elastomeric seals.
Leak off Tests -	Pressure to operate DST tools and fire TCP
Inflow Tests -	Maximum drawdown with test packer above the lap.

Perforation Technique:

Wireline Casing Guns -	Overbalance, formation damage (mud) or use clear brine.
Through Tubing Perforation -	Underbalance – brines or nitrogen Twisting of strip carriers Ballooning of hollow carriers Wireline entry guide for tail pipe

Tubing Conveyed Perforating – Safety spacer
Debris sub
Redundant firing heads (e.g. pressure activated/drop bar)
Wireline conveyed firing heads
Perforated joint / (production valve - open perforations)
Gun release sub – automatic / mechanical release
Maximum allowable pressure against sump to fire guns
RA marker sub
Maximum deviation for drop bar ~ 70 °
Detonation Interruption Devices (DID – Halliburton)

Gun Shot Density – Sand control
(gravel packing => large diameter entrance holes)
Sand prevention (small diameter / deep penetrating)
Laminated sands (high shot density)
Stimulation – fracturing (low shot density)

Consolidation of Formation – Maximum underbalance and drawdown

Test Objectives: (Typical)

Reservoir pressure
Reservoir temperature
Bottom hole samples (PVT)
Pressurised surface samples (PVT)
Pressurised and non-pressurised surface samples (Geochemical Analysis)
Atmospheric samples (Assay)
Water samples
Reservoir permeability
Skin
Well bore storage
Rate information
Boundary Information – Radius of investigation –drainage area calculations
Well site chemistry on produced fluids

Test Types:

Single rate
Multi rate
Isochronal
Modified isochronal
Interference
Extended well tests
Also - Duration and number of flow periods
- Duration of build up

Stimulation:

Extensive pre-planning is recommended
Acid types
Fraccing – proppants
Development of programme

Environmental and Licence Considerations:

Environmental Impact Study (EIS)	
Flaring	
Green burners	
Crude offloading	
Burning of pits (onshore)	
Oil Spill Contingency Plan -	Dispersants, Spill booms
Disposal of produced water	
HAZOPS	
HSE Requirements	
Regulatory requirements -	HSE Notification (e.g. UKCS) PON (Petroleum Operations Notices e.g. UKCS) UKOOA – Industry Guidelines (UKCS) Department of Energy Department of Trade and Industry Impending flaring operations – PON, Coast Guard (local fire department for onshore wells)
Environmental Action Groups -	PR (Public Relations) – Consultants / Agencies
Legal Jurisdictions -	International Maritime Law, Territorial Waters, Local Police- Oil Industry Liaison Unit (UKCS)

Safety:

HAZOPS
Operating oil and gas company HSE policy for upstream operations.

Detailed Test Programme –	Organisation and Responsibilities Safety Specific Measures

Rig Details:

Rig Inspection	
Fixed Pipework-	Pressure rating, wall thickness, diameter, end connections
Stand Pipe -	Pressure rating, wall thickness,diameter, elevation above RT, end connections
Burner Booms -	fitted to rig or not, length, rotation plates, slings, king post loading

Burners-	Capacity, green (environmentally friendly), air/water supply
Maximum flaring rate -	Oil and gas
Thermal flare simulations -	e.g. "Flare Sim"
Rig Water Screens -	Quantity, condition, when last tested.
Additional Water Screens -	Mid burner boom screens. Helme crop duster type
BOP Schematic -	Rating, ram configurations, dimensions, size of SSTT to space our correctly in the stack.
HAZOP requirements -	Operator, rig contractor
DST Operating Criteria -	Pitch, roll and heave
Deck Space-	Test equipment
Rig Certifying Authority -	Test equipment layout
Variable Deck Loading	

Logistics:

Supply Base => Rig -	Driving time, sailing time, flying time.
Emergency Evacuation Plan	
Local emergency services	
Customs clearance of equipment	
Out of hours contact details	

Perforating Equipment:

Explosives-	Temperature Rating / Duration – RDX, HMX, HNS, PYX
Explosives-	Shipping, handling and storage.
Charge performance modelling-	WEM (Halliburton & Baker), SPAN (Schlumberger)
API-RP43 Performance data	
PEGS Verified	
Low debris charges	
Low side perforating	
Gun de-centralisation	

Packers:

Differential Pressure Rating	
OD/ID tolerances -	Packer to liner and casing
Packer element / seal assembly-	Compatibility with well bore fluids. Hardness e.g. 80/90 Duro
Retrievable-	With / without hydraulic hold down, redressing
Permanent -	Drill Pipe Setting Tools Wireline setting tools and adapter kits,
Tubing movements calculations-	Seal bore length Conditions: flowing, shut in, firing guns, well kill

Tubulars:

Tail Pipe Test string Landing string Pup Joints	Burst, collapse, tensile strength, O.D, I.D, Make up torque Tubing hydraulics/dynamics Sour Service
Tubing Running Services -	JAM (Joint Analysis Makeup) Tubing drifts Stabbing Guides Non marking Equipment Slips
Cross Overs-	Procurement or manufacture; dimensional checks.

Sub Sea Equipment:

Size considerations for rig BOP
Pump through facility
Coil Tubing & E-line cutting capability
Chemical injection capability
Requirements for a retainer valve, oil spills, deep water.
Requirements for a lubricator valve e.g. (E-line SRO, slickline BHS etc.)
Shear Sub (BOP Shear ram cutting capabilities)
Slick Joints (ported slick joints), ram lock devices

DST Equipment: (Typical)

Safety Joint -	Normally with retrievable packer
Jars -	Used with retrievable packer
Slip Joints-	Used with retrievable packer
Drill Collars-	Used with retrievable packer
Bypass valve-	Used with retrievable packer
Tester valve-	Optional lock open
Pipe tester valve-	Optional tubing fill type tester valve
Single shot Reversing Valves	Annulus or tubing pressure activated
Multi Cycle circulating valve	
Radio active pip tag	
Shock Absorber-	Radial /Axial when running TCP guns
SRO Latch sub / bypass	
X-overs	

Annular pressure operated safety valve
Nitrogen pressure charging (accurate BHT required)

* Back up Tools

Gauge / Bundle Carriers:

External type
Internal type
O.D. and effective O.D. on rotation of offset carriers
I.D. and effective drift I.D.
End connections (PH6, IF, other)
Pressure testing end caps and blanks for gauge ports.
Pressure and temperature rating
Backup carriers

Down Hole Pressure / Temperature Gauges:

Pressure range	
Temperature range	
Accuracy	
Repeatability	
Hysteriesis	
Sensor type-	Mechanical, Strain, Gap Capacitance, Quartz, Sapphire
Memory capacity-	Standard, Intelligent, sleep (delay) mode
Battery type-	Temperature considerations Shipping, handling, storage Battery life at well temperature
Mechanical gauges-	Generally only in HP/HT wells.

Surface Test Equipment:	(Typical Test Cell)
Surface Test Tree-	Pressure balanced swivel, Master valve below swivel, Hydraulic actuator on flow wing, Optional hydraulic actuators on master or any other valves.
Coflexip hoses	
Check valve (kill line to STT)	
Stand alone isolation valve	
Data Header	
Pipe Set-	Low pressure & high pressure (hammer unions or Graylock connectors) X-overs to rig permanent pipework
Choke manifold -	Standard – Single block and bleed Hostile well – HP/HT, sour gas etc. Double block and bleed Comprehensive set of fixed chokes: normally in 64ths
Tests Separator- (Standard 1440 psi)	Typical Max: 14,400 bopd + 25 MMscfd Gas Pop off (Farris/Anderson Greenwood) valve and rupture disk Rotron, Floc or Turbine type meters for oil and water Daniel Senior Orifice plate meter, Differential pressure recorder. Optional Shrinkage Tester

Steam Heat Exchanger-	c/w Adjustable choke
Steam Generator-	c/w hoses
Gauge Tank-	Twin compartment, sight glasses, may have flame arrestor (used only onshore)
Surge Tank-	Typically 50 psi max.WP controlled by back pressure valve, High and Low level alarms, sight glasses, pop off valve and rupture disk (Recommended tank for offshore or may be used onshore)
Transfer Pumps-	Diesel or Electric driven
Oil Manifold(s)	
Gas Manifold(s)	
Burner Booms and Slings	
Burners-	Selected for anticipated rate (3 head, 4 head etc.) Green options available Green burners : 4-6 * air requirement of standard burners Ignition system plus backup
Propane Bottles-	Transportation / storage racks required Sufficient bottles for test duration.
Air Compressors-	Independent from rig air supply Air hoses to connect to burners
Chemical injection pumps-	Methanol, glycol, demulsifier etc.
ESD system -	Hi/Lo pilots, ESD panel, ESD remote buttons
Electronic data acquisition -	Calibrated surface sensors and acquisition computer
Lab cabin -	May be pressurised e.g. sour wells, many offshore locations

Well test container / workshop
Long bails (40'- 60')
Surface sampling kit
Sample transfer bench
H_2S/CO_2 (Drager tubes + hand pumps)
Gas Graviometer (Ranarex)
Centrifuge
Oil Hydrometers
Water Salinity meter or titration kit
Thermometers
Dial pressure gauges
Dead weight tester
Pressure / Temperature chart recorder – e.g. Foxboro

SRO:

Single / Double drum unit + hydraulic power pack

Pressure control equipment -	W/L BOP, lubricator, grease head, pack off tool trap / catcher Grease injection pump Supply of injection grease for duration of test.

H_2S inhibitor for injection grease
Sour service cable
Cable clamp + T-bar fishing clamp
Sufficient weight bars to run in against SWHP
(Charts exist for various cable O.D.)

SRO operation to be thoroughly pre-planned with contractor (cable size, type, length, cable head weak points, fishing tools, O.D. of tools, power requirements of unit, location etc.)

PLT:

Tool selection -	Pressure, Temperature, Flow, Fluid Density, GR, CCL
	Deviated wells-Centralisation, accuracy of results
	Liner / Casing size – accuracy of results
	Real time surface read out or memory PLT

Slickline:

0.092", 0.108", 0.125"	Depending on application.
Basic Tools for DST:	Gauge ring
	Stem
	Knuckle joints
	Lead impression block
	Bailers – pump / hydrostatic
	X-over for gauges or BHS
	Fishing tools for SRO cable

Braided cable for Fishing, only when things get really bad.

Sampling Equipment:

Bottom hole samplers
Treated bottom hole samplers- To avoid H_2S absorption
Surface Sampling Kit
Vacuum Pump
Oil pressurised transport/storage bottles e.g. 600cc
Gas pressurised transport/storage Bottles e.g. 20 litre
Geochemical pressurised sample bottles e.g. 300cc
1 litre plastic samples bottles c/w lids
10 litre IATA/US DOT cans
Oil Drums

Iso-kinetic sampling – Separator efficiency – measurement and sampling of liquid carryover

Equipment Checking:

Lloyds, DNV, Bureau Veritas, ABS certification of pressure vessels etc.
Traceability of components
Data books inspected
Service records inspected
Dimensional checks
Instrument calibration
Safety valves checked, calibrated and certified
All threads inspected
All elastomers rated for service

Production Problems:

Hydrates-	Glycol, Methanol (quantities and injection rates)
Wax-	Inhibitors, Solvents
Pour Point-	Pour Point Depressants (PPD)
Sand-	Sand Traps, Sacrificial flow lines, Sand Probes.

Contingency Items:

Tubing Punches -	Explosive or Mechanical
Tubing Severance -	Explosive (Flash Cutter)
	Chemical Cutter
Coil Tubing -	Artificial lift
	Well bore / tubing clean outs
	Acidising
	CT lifting frame for floating rigs
Free Point / Back Off	

APPENDIX C

CHOKE PERFORMANCE EQUATIONS

Gas Flow Choke Equation – Critical Flow

For single phase gas flow through a choke under critical flow conditions (where flow has reached the velocity of sound – acoustic velocity, with the downstream pressure less than or equal to half of the upstream pressure, the following may be used to estimate the gas flow rate.

$$Q = \frac{C \times P}{(G \times T)^{1/2}}$$

Where:-

Q = Gas Flowrate (Mscf/d)
C = Choke Coefficient (see table below)
P = Upstream Pressure (psia) [psig + 15]
G = Gas Gravity
T = Inlet Temperature °R = (°F + 460)

Choke Coefficients Table *

Choke Size (inches)	Coefficient (C)
1/8	6.25
3/16	14.44
¼	26.51
5/16	43.64
3/8	61.21
7/16	85.13
½	112.72
5/8	179.74
¾	260.99

Notes:

°R is the Rankine Temperature – This is now essentially an obsolete thermodynamic temperature scale linked to the Fahrenheit degree, where °R = °F + 459.67
* Choke Coefficients are from (12) Rawlins, E.L. and Schellhardt, M.A.

Oil Flow Choke Equation

The estimation of oil flow through a choke (which consists of two phases – oil and gas) is often undertaken using the empirical equation developed by W.E. Gilbert. The equation is based on data obtained from flowing wells and relates tubing pressure, GOR, oil flow and choke size. The Gilbert equation is also only valid for conditions of critical flow. There are also several other equations such as Ros, Achong and Crane. The Ros equation was also converted to oilfield units by Poettman and Beck and is presented in a number of nomographs.

However, the most widely used equation to estimate oil flow through a choke is Gilbert, and this is shown below.

$$P_{tf} = \frac{435 \times R^{0.546} \times q}{S^{1.89}}$$

Where:-

P_{tf}	=	Flowing Tubing Head Pressure (psig)
R	=	Gas Liquid Ratio (Mscf/bbl = 10^3 scf/bbl)
q	=	Gross Liquid Rate (oil and water bbl/day)
S	=	Choke Size (1/64")

In order to estimate gross liquid rate the Gilbert equation may be expressed as follows:

$$q = \frac{P_{tf} \times S^{1.89}}{435 \times R^{0.546}}$$

As can be seen from the above definitions the gas liquid ratio R is expressed as Mscf/bbl which sometimes leads to confusion. Therefore, the rate estimation equation is sometimes expressed as follows

$$q = \frac{P_{tf} \times S^{1.89}}{435 \times (GLR/1000)^{0.546}}$$

Where:-

GLR = Gas Liquid Ratio in scf/bbl

APPENDIX D

SEPARATOR CALCULATIONS

Phase Retention Time

The basic unit of measurement of separator efficiency is the Phase Retention Time, defined as being the time that an average molecule in a particular phase remains within the vessel.

$$\text{Oil Retention Time (in minutes)} = \frac{\text{Separator Oil Capacity (bbl)} \times 1440}{\text{Oil Production Rate (bopd)}}$$

The following alternative representation is often given in literature, because separator dimensions are usually in feet and inches and separator volumes are given in ft^3.

$$\underset{\text{(mid level)}}{\text{Oil Retention Time (in minutes)}} = \frac{128 \times \text{Separator Volume (ft}^3\text{)}}{\text{Oil Production Rate (bopd)}}$$

$$\text{Water Retention Time (in minutes)} = \frac{\text{Separator Water Capacity (bbl)} \times 1440}{\text{Water Production Rate (bwpd)}}$$

$$\underset{\text{(@ separator conditions)}}{\text{Gas Retention Time (in minutes)}} = \frac{\text{Separator Gas Capacity (Cubic Feet)} \times 1440}{\text{Gas Prod. Rate (scf/d @ separator conditions)}}$$

* 1440 is merely a conversion factor, that is the number of minutes in a day (24 x 60).

The majority of well testing companies have similarly sized separators for general test purposes, rated as being 1440 psi maximum pressure with an oil retention time of one minute for a flow rate of 10,000 BOPD (no water production), and a gas retention time of one minute for a flow rate of 40 MMscfd at a separator pressure of 1440 psi.

Within certain limits it is possible to adjust the retention time of a particular phase within the separator. If there is no (or very low) water production, the water liquid level controller should be set to operate at the minimum stable level, increasing the effective oil capacity and retention time. If the production GOR is low the oil liquid level controller may be set high to increase the oil retention time at the expense of the gas retention time. Conversely, if the GOR is high (gas or gas/condensate producer) the oil liquid level control may be set low.

Theoretical Optimum Separator Operating Pressure

The standard test setup with a separator and a non pressurised stock tank or gauge tank is in fact a two stage separation process. Moreover, when testing with a pressurised stock tank (surge tank) this is considered a three stage process. The surge tank acting as a second stage separator as discussed in 13.16.

The theoretical optimum separator operating pressure for each stage of the process assumes that differential separation of fluids is aimed for, with maximum liquid recovery from the separation process. The alternative process being flash separation which yields the most gas and the least amount of liquid. In reality all almost all separation process are a combination of flash separation and differential separation.

However, in an attempt to obtain ideal or differential separation, multistage separation can be used, with each successive separator operating at a lower pressure.

The ratios of operating pressures between stages in a multi stage separation process were approximated by Garman O. Kimmel in a paper presented in 1949. (Kimmel,G.O., 1949, "Stage Separation", paper 48-PET-15, ASME)

Considering the stage process that occurs between the separator (first stage) and the stock tank (second stage) we can calculate the theoretical optimum separator operating pressure. The first stage input pressure is the separator inlet pressure and the second stage pressure is the operating pressure of the tank .

Using the following equation (Kimmell) the theoretical optimum separator operating pressure, if achievable, may be estimated as follows:

$$\text{Optimum Psep (psia)} = \text{Tank pressure (psia)} \times \left[\frac{\text{Downstream choke pressure (psia)}}{\text{Tank Pressure (psia)}}\right]^{1/2}$$

Example:

If downstream choke pressure is 1,000 psig and stock tank (gauge tank) is operating at atmospheric pressure (15 psia) optimum pressure is

$15 \times (1015/15)^{1/2} = 123$ psia = 108 psig.

However this is not always achievable. Sometimes a higher pressure is required to force the produced oil through the oil level control valve at adequate rates to the stock tank.

APPENDIX E

SELECTION OF DST TUBULARS

This section contains some guidelines for selection of DST tubulars.

Tubular Selection

DST's can be carried out using either tubing or drill pipe as discussed previously. In either case it is necessary to evaluate the required sizes, grades and weights of tubulars prior to carrying out the test.

In many cases tubing is used for testing prospective gas wells and high pressure oil wells and drill pipe is used for testing low pressure oil wells. The advantages of using drill pipe are its ease of handling and high tensile strength. However, the disadvantage is that the threads are not gas tight under moderate pressure and therefore should not be used for gas well testing. When carrying out an open hole DST's drill pipe should be used due to the higher tensile loading requirements.

New strings of tubulars are often purchased for testing specific wells, but a range of strings are available for rental or from existing stock. Therefore, it is necessary to carry out some basic design calculations to ensure the most appropriate string is used.

The three design parameters that must be considered are size (internal cross-sectional area), grade (type of metallurgy), and strength (wall thickness). The required cross-sectional area must be evaluated to ensure that the well can unload the cushion fluid, drilling mud, water and hydrocarbons without the friction pressure loss being excessive. The required cross-sectional area and hence internal diameter of tubing is normally now estimated using tubing hydraulics software, which generates vertical lift performance curves. However, useful estimates of pressure loss from tubing flow can also be calculated as shown in appendix F.

Tubing grade should be considered with regard to reservoir conditions that could cause early failure of some steels. These conditions will be mainly limited to pressure, temperature, and the presence of H_2S. Refer to (11) NACE MR0175-99 for guidance in the selection of tubing grades.

Tubular weight requirements can be confirmed once the grade of steel has been established. The tubing weight must be able to withstand the maximum expected loadings with regard to burst, collapse and tension. The required loadings would normally be multiplied by following safety factors before comparing with performance properties of the tubulars available.

Tension Safety Factor -	1.4
Burst Safety Factor -	1.1
Collapse Safety Factor-	1.0

APPENDIX F

ESTIMATION OF PRESSURE LOSS FROM TUBING FLOW

In order to select the most appropriate tubing for a test it may be necessary to calculate the frictional pressure loss. This will be particularly important in high rate testing to avoid having a tubing limited flow rate.

The following equations allow an estimate of frictional pressure loss for tubing flow.

Flow rate q = volume / time = (area x length) / time = area / velocity

Therefore q = A / v => velocity (v) = q / A (A is the x-sectional area of tubing)

In oil field units $v = 17.16 \times q\ (\text{bbl/min}) / d^2$

$v = 3.056 \times q\ (\text{cu ft/min}) / d^2$

$v = q\ (\text{gal/min}) / 2.448\ d^2$

Where v = average velocity in ft/s and d = internal diameter of the pipe in inches.

A simplified form of the Fanning turbulent flow equation is adequate for estimation of tubing frictional pressure losses during most well test scenarios, where turbulent flow is occurring. This equation assumes smooth pipe and a moderate Reynolds number.

$$d\,P = \frac{\rho^{0.75} \times v^{1.75} \times \mu^{0.25} \times L}{1800 d^{1.25}}$$

Where:	dP	=	Frictional pressure loss (psi)
	ρ	=	Fluid density (ppg)
	v	=	Fluid velocity (gal/min)
	μ	=	Plastic viscosity
	L	=	Length of test string (ft.)
	d	=	Internal diameter of tubing (inches)

On substitution of the velocity component $v = q\ (\text{gal/min}) / 2.448\ d^2$

$$d\,P = \frac{\rho^{0.75} \times q^{1.75} \times \mu^{0.25} \times L}{8624\ d^{4.75}}$$

Where:	q	=	Flow rate (gal/min)

Example Calculation:-

The cushion to be recovered at the start of a DST operation is 9.5 ppg mud having a viscosity of 20 cp. The DST string consists of 3 ½ " tubing with an internal diameter of 2.75" and is 9800ft long. Assuming the cushion is recovered at a rate of 4 bbls/min, what is the friction pressure drop in the tubing.

The friction pressure drop is given by:

$$d\,P = \frac{\rho^{0.75} \times q^{1.75} \times \mu^{0.25} \times L}{8624\ d^{4.75}}$$

In the above equation, flow rate is required in gpm, therefore: 4 bbls/min = 4 x 42 = 168 gpm

$$d\,P = \frac{(9.5)^{0.75} \times (168)^{1.75} \times 20^{0.25} \times 9800}{8624\ (2.75)^{4.75}}$$

$$= \frac{5.41 \times 7839.55 \times 2.11 \times 9800}{8624 \times 122.13}$$

$$= \ 832.7 \text{ psi}$$

Clearly the friction pressure drop is very dependent on the diameter of the tubing, that is $d^{4.75}$.

By way of example recovering the same cushion through a similar length string of 4 ½" tubing with an internal diameter of 3.958" yields a considerably smaller friction pressure loss as shown below.

$$d\,P = \frac{\rho^{0.75} \times q^{1.75} \times \mu^{0.25} \times L}{8624\ d^{4.75}}$$

$$= \frac{(9.5)^{0.75} \times (168)^{1.75} \times 20^{0.25} \times 9800}{8624\ (3.958)^{4.75}}$$

$$= 147.7 \text{ psi}$$

APPENDIX G

TEMPERATURE EFFECTS ON TUBULARS

When planning a drill stem test an important factor to consider is the likely maximum temperature change to be encountered in the test string and then to calculate the likely expansion or contraction of the string. This information may be required to determine the number of slip joints if testing with a retrievable packer or to determine the length of seal bore / tubing seal assembly if testing with a permanent packer.

Once the temperature variation has been determined (WEST, WELLCAT or estimation), the following formula can be used to estimate the change in length of the test string :-

$$dL = L \times C \times dT \times 12$$

Where:

dL	=	Length change (inches)
L	=	Length of test string (ft)
C	=	Coefficient of expansion of steel per °F (6.9×10^{-6})
dT	=	Average temperature change (°F)

Note: The average string temperature during each operating mode is one half of the sum of the temperature at the top and bottom of the string.

Example Calculation :-

Maximum bottomhole temperature = 315 °F
Surface temperature before flow = 80 °F
Maximum flowing surface temperature = 190 °F

Average temperature before flow = (315 +80)/2 = 197.5 °F
Average temperature during flow = (315 +190)/2 = 252.5 °F

The maximum average temperature change is therefore 55 °F. If we assume that the test string is 9000 ft. long then the resultant expansion of the tubing can be calculated as follows :-

$$dL = 9{,}000 \times 6.9 \times 10^{-6} \times 55 \times 12$$

$$dL = 41 \text{ inches}$$

APPENDIX H

PRESSURE EFFECTS ON TUBULARS

During the course of a DST the tubulars will be exposed to a number of differential pressure effects, for example pressuring up on the tubing to fire TCP guns or bullhead killing the well or pressuring up on the annulus to operate DST tools or reversing out the string.

These various pressure changes cause effects on the tubulars which can be categorised under the following:

(a) Piston Effect (Hooke's Law)
(b) Ballooning & Reverse Ballooning
(c) Buckling

The effects in (a) and (b) above will cause an expansion or contraction in the string depending on the whether the pressure is applied to the tubing or to the annulus. The buckling effect will only cause shortening of the string.

The necessary equations to calculate the various length changes due to pressure effects are shown below without derivation, as the derivation of these formulae have been shown in many other texts. In addition, these tubing movements are also now generally calculated using various software packages.

As well as the three pressure effects and the temperature effect discussed previously, there is one further effect that will result in a change in length. This effect occurs when weight is slackened off on the string for example by slacking off weight on to a packer. Slack of weights are typically of the order 10,000 lbs to 40,000 lbs.

Therefore, the total amount of movement in a tubing string as a result of well operations is <u>sum</u> of all of the above effects. Where expansions are +ve and contractions are –ve. It is important to ensure that all tubing movements are summed in the same units, that is inches or feet.

$$dL_{Total} = dL_{temp} + dL_{piston} + dL_{ballooning} + dL_{buckling} + dL_{slack\ off}$$

(a) Piston Effect (Hookes Law)

$$dL = \frac{F \times L}{E \times A}$$

Where -

F = Force in pounds
L = Length of tubing in feet
E = Young's Modulus for steel, 30 x 10^6 lbs/in^2
A = Cross sectional area of the tubing

Noting that F=Pressure x Area

In the specific case of the piston effect on tubing, the force occurs as a result of pressure changes in the tubing and annulus at the packer acting on different areas.

The change in length (in inches) is given by the following:

$$dL_{piston} = \frac{12\,L}{E\,A_{xs}}[dP_t(A_{pi} - A_{ti}) - dP_a(A_{pi} - A_{to})]$$

Where:

dL	=	Change in length (inches)
L	=	Length of tubing (feet)
dP_t	=	Change in tubing pressure at packer (psi)
dP_a	=	Change in annulus pressure at packer (psi)
A_{pi}	=	Area of packer ID, (inches^2)
A_{ti}	=	Area of tubing ID, (inches^2)
A_{to}	=	Area of tubing OD, (inches^2)
A_{xs}	=	X-sectional area of the tubing, (inches^2)
E	=	Young's Modulus for steel, 30 x 10^6 lbs/in^2

(b) Ballooning and Reverse Ballooning

When the tubing pressure exceeds the annulus pressure there will be a small increase in internal diameter, this effect is known as ballooning. When ballooning of the tubing occurs there will be a reduction in tubing length. Likewise if the annulus pressure exceeds the tubing pressure there will be a squeezing effect on the tubing causing it to elongate, this is known as reverse ballooning.

The change in length (in inches) is given by the following:

$$dL_{ballooning} = L \times 2.4 \times 10^{-7} \times \frac{d\overline{P}_t - R^2 d\overline{P}_a}{R^2 - 1}$$

Where:

dL	=	Change in length (inches)
L	=	Length of tubing (feet)
$d\bar{P}_t$	=	Change in average tubing pressure between modes (psi)
$d\bar{P}_a$	=	Change in average annulus pressure between modes (psi)
R	=	Ratio of the tubing OD to ID

Example Calculation:

Assuming 9500' of 3 ½", 13.6# New Vam tubing is being used as a DST string. In order to fire the TCP guns a pressure of 3500 psi must be applied to the tubing. Calculate the reduction in length in the string due to the ballooning effect as a result of the applied tubing pressure assuming at all times the pressure in the annulus remains constant.

$$dL_{ballooning} = L \times 2.4 \times 10^{-7} \times \frac{d\bar{P}_t - R^2 d\bar{P}_a}{R^2 - 1}$$

$$= \frac{9500 \times 2.4 \times 10^{-7} \times 3500}{(3.5 / 2.673)^2 - 1}$$

$$= 11.17 \text{ inches}$$

The tubing therefore <u>contracts</u> 11.17 inches due to the ballooning effect.

(c) Buckling

Tubing strings will buckle if the pressure in the tubing is greater than the pressure in the annulus. It should be noted that the magnitude of the buckling effect is related to the radial clearance between the tubing OD and the casing ID.

The change in length (in inches) is given by the following:

$$dL_{buckling} = \frac{-r^2 A_{pi}^2 (dP_t - dP_a)^2}{8EI(W_t + W_{ft} - W_{fa})}$$

Where:

r	=	(casing ID-tubingOD) / 2 (inches)
A_{pi}	=	Area of packer ID, (inches^2)

dP_t	=	Change in tubing pressure at packer (psi)
dP_a	=	Change in annulus pressure at packer (psi)
E	=	Young's Modulus for steel, 30 x 10^6 lbs/in^2
I	=	Moment of inertia of tubing about its axis. $\pi/64(d_{to}^4 - d_{ti}^4)$ (inches^4), where d_{to}= tubing OD and d_{ti} = tubing ID.
W_t	=	Weight of tubing (lbs/in)
W_{ft}	=	Weight of fluid in tubing (lbs/in) (tubing fluid density x area of tubing ID)
W_{fa}	=	Weight of annular fluid displaced by one inch of tubing (lbs/in – annular fluid density x area of tubing O)

Slack off weight

The final effect which will cause a change in tubing length is slack off of tubing weight. This was discussed previously, although not a result of pressure or temperature changes it will need to be summed with all the other tubing movements when it occurs.

The change in length (in inches) is given by the following:

$$dL_{slack\ off} = \frac{W_{SO}}{E}\left[\frac{L}{A_{pi}} + \frac{r^2 W_{SO}}{8IW_i}\right]$$

Where:

W_{SO}	=	Slackened off weight (lbs)
L	=	Length of tubing (feet)
r	=	(casing ID – tubing OD) / 2 (inches)
E	=	Young's Modulus for steel, 30 x 10^6 lbs/in^2
A_{pi}	=	Area of packer ID, (inches^2)
I	=	Moment of inertia of tubing about its axis. $\pi/64(d_{to}^4 - d_{ti}^4)$ (inches^4), where d_{to}= tubing OD and d_{ti}= tubing ID.
W_i	=	Initial buoyed weight of tubing (lbs/in)

As discussed previously the overall length change is the sum of the various length changes that occur as a result of changing mode. Clearly it is possible to offset one or more of the length changes by the use of other pressures. For example by increasing annulus pressure during a frac stimulation to compensate for the reduction in the length of the string that will occur because of ballooning. This may provide an additional safety margin to ensure that the tubing seal assembly stays within the packer bore.

APPENDIX I

EXAMPLE - DETAILED WELL TEST PROGRAMME

INTERNATIONAL OIL & GAS COMPANY

WELL TESTING PROGRAMME

WELL : EXPLORATION #1

EXAMPLE

Prepared by: ______________

Stuart McAleese
Esprit Petroleum Technology Ltd

Reviewed by: ______________ ______________

Staff Drilling Engineer **Staff Petroleum Engineer**

Approved by: ______________ ______________

Drilling Manager **Operations Manager**

INTERNATIONAL OIL & GAS COMPANY
WELL TESTING PROGRAMME
WELL : EXPLORATION # 1

1.0 INTRODUCTION

2.0 ORGANISATION AND RESPONSIBILITIES

3.0 SAFETY

4.0 TEST OBJECTIVES, TEST OUTLINE & WELL INFORMATION

5.0 EQUIPMENT PREPARATION

6.0 PRE - TEST PREPARATION

7.0 TESTING PROCEDURES

8.0 PRODUCTION TEST PROGRAMME

9.0 WELL KILL PROCEDURE

10.0 APPENDICES

LIST OF APPENDICES

1.0 INTRODUCTION

Well exploration #1 is located offshore approximately 140 km North West of the shore base.

The well will be drilled and tested from a drillship in a water depth of 1,758 feet (536 m).

The well will be drilled to encounter reservoir sands of the Tertiary and Cretaceous. Where the primary objective is in the Miocene at an estimated depth of 4454 ft (1358 m) TVDSS and the secondary objective is in Cenomanian at an estimated depth of 6032 ft (1839 m) TVDSS. This vertical exploration well will have a total measured depth of 7580 ft (2311 m) TVDSS and will be drilled using a sodium chloride water based mud system.

The following is a detailed programme for two DST's to evaluate the reservoir and production characteristics of the target intervals.

Contingencies have been included for the following scenarios:

TCP hydraulic firing head failure.
Mooring system failure and sub sea emergency disconnect.

2.0 RESPONSIBILITIES

2.1 O.I.M.

The O.I.M. has the final authority on all decisions related to the safety of personnel and the vessel.

The O.I.M. will liaise with the Drilling Supervisor to ensure the safety of the vessel and all personnel. He will administer the Permit to Work System for the test programme. He will ensure that all equipment is functioning and that safety rules are observed.

2.2 Drilling Supervisor

The Drilling Supervisor has administrative responsibility for conducting the test and will liaise with the O.I.M, Well Test Engineers and the Supervisors from the testing contractors. He will provide the O.I.M. with the daily written instructions for the ongoing well operations. Additionally he is responsible for the co-ordination of Oil & Gas Company controlled Third Party Services. The Oil & Gas Company Well Test Engineers will advise the Drilling Supervisor on all aspects relating to the test.

The Drilling Supervisor is responsible for:

a. Ensuring that all operations are carried out in a safe and efficient manner.

b. Communicating all instructions (after liaison with the Well Test Engineers) to the Drilling Contractor.

c. Transmitting normal daily reports to town.

d. Co-ordinating and liaising with the shore base for transport and shipment of any additional equipment required for the test.

e. Ensuring that local authorities are informed of "testing operations offshore in progress".

2.3 Oil & Gas Company Well Test Engineers

The Test Engineers are directly responsible for the conduct of the test and specifically for the following:

a. Carrying out the test in a safe and efficient manner.

b. Ensuring that all equipment is available offshore and that it has the correct certification.

c. All equipment is prepared and tested as per the programme.

d. Running and pressure testing of the test string.

e. Initiating all stages of the test programme after consultation with the Drilling Supervisor and the O.I.M.

f. Supervising the well test service companies.

g. Checking the pipe tally and ensuring perforating guns are on depth.

h. Verification of GR/CCL log correlation and perforation interval space out.

i. Ensuring that all relevant data is collected during the test and for checking the quality of the data, including on site pressure transient analysis.

j. Advising the Drilling Supervisor on the evaluation aspects of the programme.

k. Ensuring that the Drilling Supervisor is immediately informed of any equipment problems or adverse condition on the well.

l. Ensuring that all sampling is carried out as per programme.

m. Transmittal of test information to shore at the stipulated times in the format detailed in Appendix A1 of the test programme.

n. Recommending changes to the test programme if applicable, to ensure the objectives of the test are met in the most efficient manner.

2.4 Shore Base

The shore base is responsible for sanctioning any changes to the programme. These will be transmitted by the Drilling Superintendent in the shore base to the rig. Any amendments and additions to the conduct of the test will be issued by the Petroleum Engineering department at head office, following consultation with the Drilling Superintendent and the Test Engineers. Significant programme amendments will be transmitted to the rig with a signature page including signatures by the following personnel, Petroleum Engineering Manager, Drilling Superintendent and Head of Drilling. However structural amendments (e.g. change of agreed perforation interval etc.) must be discussed between the shore base and the head office and approved by the Head of Geoscience and Petroleum Engineering.

2.5 Service Company Supervisors

The Service Company Supervisors reports directly to the Oil & Gas Company Well Test Engineers and assists them with the following:

a. Carrying out the test in a safe and efficient manner.

b. Executing all stages of the test programme after instructions from the Oil & Gas Company Well Test Engineers.

c. Ensuring that the Driller is informed PRIOR to any actions taking place with the well test equipment (Opening well, switching burners, operating downhole tools,etc.).

d. Ensuring that all the equipment is available offshore and that it has the correct certification, including cross-overs to the rig and third party equipment.

e. Ensuring that all equipment is prepared and tested as per the programme.

f. Running and pressure testing of the test string.

f. Ensuring that all instructions issued to well test personnel are carried out.

2.6 Toolpusher

Liaises with the Drilling Supervisor and the O.I.M. to ensure that operations required during the test are carried out safely as per the test programme.

2.7 Driller

Responsible for all actions taking place on the drill floor, in particular, the following:

a. All operations concerning the Annulus and any operation of valving on the rig manifold.

b. Ensuring that all Annulus monitoring instrumentation is checked on a regular basis and that a record is kept of the annulus pressure at all times throughout the testing operation.

Note: Record times when the Annulus pressure is pumped up / bled off, also volumes pumped and bled off , throughout the testing operation.

c. All activities carried out during the test must be cleared through the driller. The driller must inform all key personnel immediately of any problems or deviations from the programme.

d. Monitoring of the string tension and compensator throughout the testing programme.

e. Ensuring that the pump room and mud pit area is manned at all times.

f. The driller will be in direct communications with the Schlumberger well testing personnel throughout the test and he is responsible for maintaining a watch on the test equipment and flowlines on the rig floor.

2.8 Programme Meeting

Prior to the test programme being implemented, a meeting should be held on board the rig between the following staff:

- O.I.M, Toolpushers, Drillers / Assistant Drillers (day and night shifts to be represented)
- Drilling Supervisor
- Well Test Engineers
- Boat Captain (Standby Vessel)
- Schlumberger Well Test Supervisor
- Schlumberger DST and TCP Supervisors
- Power Tongs Hand
- Schlumberger Logging Engineer
- Cementer
- Mud Engineer
- Mudloggers
- Any other relevant personnel

The purpose of the meeting is:

a. To introduce people and establish communication channels.

b. To discuss safety issues.

c. To discuss the programme.

d. To discuss special circumstances, e.g. weather conditions, well conditions, equipment, Schlumberger and rig equipment interfaces etc. (Operation of Sentree 3 to be reviewed)

e. To ensure all personnel are aware of their duties and responsibilities.

Minutes of the meeting should be taken by one of the Oil & Gas Company Well Test Engineers.

A meeting will be held twice daily to discuss the short term programmed well test activities at the start of every tour.

3.0 SAFETY

The test will be conducted in accordance with the Oil and Gas Company's safety procedures which primarily state that safeguarding personnel, the environment, and the rig are paramount and will not be compromised for any operational reason.

A meeting will be held to review the test procedure and safety requirements. The Oil & Gas Company Well Test Engineers will review in detail with key personnel the test procedure, equipment and personnel assignments prior to testing. Duties will be assigned to provide maximum surveillance of the operation and for the efficient collection of quality test data.

Prior to and on completion of any testing that involves flaring the OIM or Drilling Supervisor will inform the relevant authorities, in addition he will ensure the standby boat is ready with dispersants. The Drilling Supervisor shall also notify the Oil & Gas Company shore base.

The service personnel on board the rig for the testing operation must be thoroughly briefed regarding emergency stations and emergency drills.

3.1 Safety - Specific Measures

1. All non-essential personnel to be released from the rig.

2. Hold an "Abandon Rig Drill" and conduct a fire drill specific to a fire in the well test area.

3. Offload all surplus explosives.

4. Flare boom, water cooling spray systems, burner and pilot light must be thoroughly checked and pre-tested and a secondary means of lighting the flare must be available.

5. The rigs main power plant must be online prior to opening the well, to provide maximum power at all times should it be required. However should a leak be detected, ensure that no exhaust system could ignite the gas.

6. During the production test, the operation of cranes over test lines and surface equipment shall be restricted and conducted under the permit to work system.

7. Wind direction will be monitored during the test and a weather forecast for the next 72 hours obtained. Ensure that a windsock (or flag) is visible from Drill floor and Test area.

8. All breathing apparatus, fire extinguishers, fire hoses, foam makers, fire suits, H_2S gas detectors and portable explosimeters must be operational.

9. Ensure that the station bill is reviewed to reflect the planned operations.

10. One mud pump shall be lined up on kill mud to the annulus and the other shall be lined up to pump sea water to the burner at the maximum rate. The cement unit shall be lined up to pump kill mud to the kill line on the flowhead during testing operations.

11. Power should be available to the cementing unit throughout the operation.

12. The operation of electrical equipment in the designated testing areas and not directly associated with the execution of the test, shall be strictly governed by the permit to work procedures.

13. Working areas around the testing equipment must be kept clean and there must be unobstructed access to these areas at all times.

14. Test the communication system.

15. Smoking is to be strictly confined to the quarters and hot work restricted.

16. Prepare two fire hoses close to each burner boom. Before perforating, the fire fighting system should be pressurised and tested.

17. Perforation of the well or initial flowing of formation hydrocarbons to surface during darkness, will be at the discretion of the Oil & Gas Company onsite representatives and the OIM, in consultation with the Oil & Gas Company Drilling Superintendent in the shore base.

18. During any tubing punch/tubing cutting operations, the radio beacon, VHF transmitter, SSB and portable radios must be shut down until the Schlumberger tools are 300ft below the seabed. Standby / supply boat(s) should be informed of radio silence. This precaution is not required for TCP operations or if Schlumberger SAFE system is used.

19. In the event that wireline perforating guns are used, the Cathodic Protection System will be turned off during gun loading and perforating, if applicable. Radio silence will also be required. These precaution are not required for TCP operations.

20. Hot work will be restricted and controlled by the permit to work system.

21. No helicopter landings can be made during perforating operations.

22. Termination of 18,19,20 and 21 above can only be authorised by the Oil & Gas Company Drilling Supervisor in conjunction with the O.I.M.

23. A safety spacer of 3 metres (10 ft) minimum length will be used between the top shot and the TCP firing head.

24. The standby boat will be on full alert and upwind with lifeboats ready for instant launching. The spraying system on the vessel should be ready and chemical dispersants should be available in case any accidental oil spills occur during the test but should not automatically be used. The oil spill contingency plan will be followed.

25. Fluids from the well shall be checked for H_2S as soon as reasonably possible.

26. Frequent checks shall be made during the test to detect any gas leaks or unexpected gas accumulations and oil drop out from the burners.

27. In case of any oil reaching the surface of the sea the oil spill contingency plan will be followed.

28. Standby boat shall be on close standby when personnel are working on burner booms. Personnel undertaking such work shall wear lifejackets.

29. Helicopter fuel tanks and all pressurised bottles are to be located in a safe place and cooled with water if required.

30. Separator relief lines should be directed overboard away from the flare booms. All lines must be properly secured.

31. The surface master valve shall be hydraulically operated via remote control from a safe location. In addition high/low pilots will be incorporated into the well test rig up, upstream and downstream of the choke manifold and upstream of the separator.

3.2 Location of Sub-Sea Test Tree and Lubricator Valve Control Panel

It is essential that the control panel be located in an accessible and safe area on the rig floor. Specifically, access to the panel should not be hampered by high pressure lines or production test equipment. A control panel operator must be on the rig floor at all times to operate the downhole valves.

All members of the drill floor crew shall also be briefed on the emergency closing procedure of the sub-sea test tree.

3.3 Helicopter Operations During Testing

Helicopter flights will be restricted during the well testing operation. Generally landings shall not take place during perforating or flowing the well. The Oil & Gas Company Drilling Supervisor and OIM will determine the flight requirements and timing.

3.4 Communication and Organisation

i. General

Good communications are an essential part of an efficient and safe well test operation. Prior to the actual test, a meeting will be held to highlight the test sequence and ensure that each person's area of responsibility is known to the rest of the personnel. The Drilling Supervisor will co-ordinate the test operation. The O.I.M. however, will be the central point of authority for safety and communication.

ii. Communications on the Rig

Most locations around the rig should have access to the rig telephone system. However, the following work stations will require constant monitoring and open communication lines during the test.

a. Separator area.
b. Rig floor.
c. Wireline unit.
d. Schlumberger cabin.

The Testing company VHF Frequency is to be dedicated for their sole use. The control room operators and Driller / Toolpusher will monitor the frequency at all times to co-ordinate activities and requirements.

Note: Other communication requirements may be identified prior to the test. It is essential that sufficient portable VHF units are available to satisfy the requirements.

3.5 Hydrogen Sulphide (H_2S)

Offset wells indicate that less than 10ppm H_2S will be encountered in the well stream. Should H_2S be detected at a level higher than 10 ppm, mask up with a BA set for any operations that vent gas, the shore base should be informed immediately.

> 50 ppm in wellstream then BA sets must be worn continuously, should insufficient sets be available on board then the test may have to be terminated.

4.0 TEST OBJECTIVES, TEST OUTLINE & WELL INFORMATION

4.1 Test Objectives

- To conduct the test in a safe, environmentally responsible and efficient manner.
- To measure initial reservoir pressure and temperature.
- To collect representative samples for PVT analysis and refinery assay.
- To identify and measure any contaminants (H_2S, CO_2, etc.)
- To determine interval / well productivity and flow capacity.
- To determine permeability and skin.
- To determine the presence and nature of any heterogeneity within the test radius (e.g. faults, fluid contacts, reservoir boundaries etc.).
- To identify any problems associated with hydrocarbon production from a low temperature deep water environment.

4.2 Test Outline - DST # 1 - Lower Zone (Cenomanian)

- Run and cement 9-5/8" or 7" contingency liner (must be 200' rat hole to drop TCP)
- Ensure that a short liner joint and R/A pip are above the uppermost DST interval.
- Run casing scraper and scrape thoroughly at the proposed packer setting depth.
- Run AMS (Temp)/CBL/VDL/USIT/GR/CCL log.
- Test BOP and set wear bushing. Conduct leak of test on liner lap and casing.
- Do not conduct inflow test if LOT and bond logs are both acceptable.
- Function test all surface, subsea and downhole equipment.
- Carry out dummy run with painted slick joint and fluted hanger.
- Carry out tubing test and flex trip. Rack back tubing in stands in the derrick.
- RIH TCP guns and Positrieve packer.
- Run DST Tools and 3 ½" tubing string, pressure testing half way.
- RIH 4 ½" landing string, rig up GR/CCL, RIH perform correlation, POOH E-line.
- Position guns on depth and function upper pipe ram to mark pipe.
- POOH landing string and perform space out with 3 ½" tubing pup joints if required.
- RIH landing string with subsea equipment, 15 feet before landing off set slips.
- Rig up coil tubing lifting frame, surface test tree and Coflexips
- RIH and land off fluted hanger in wear bushing.
- Rig up GR/CCL, re-correlate TCP guns, POOH E-line.
- Pickup and set retrievable packer then land off fluted hanger in wear bushing.
- Pressure test the string and surface connections.
- Close BOP pipe rams. Pressure test annulus. Lock open tubing fill tester valve.
- Hold safety meeting, Circulate in diesel cushion via IRDV circulating port.
- Pressure up on tubing to fire TCP guns and bleed back to give 200 psi underbalance.
- Perform initial flow period to clean up well.
- Perform initial PBU by shutting in the well at the tester valve (if pour point < 5°C).
- Flow well for 24 hours stabilised main flow period and collect samples.
- Shut well in downhole at tester valve for 1.5 times the main flow period.
- Displace tubing string to mud above tester valve if oil pour point is above 5 °C.
- Run SRO tools immediately after shutting in (and displacing) the well, record PBU.
- Bullhead kill well. Open rams and unseat packer, POOH and plug back zone.

4.2.1 <u>**Test Outline**</u> **- DST # 2 - Upper Zone (Miocene)**

- RIH TCP guns and Positrieve packer.
- Run DST Tools and 3 ½" tubing string, pressure testing half way.
- RIH 4 ½" landing string, rig up GR/CCL, RIH perform correlation, POOH E-line.
- Position guns on depth and function upper pipe ram to mark pipe.
- POOH landing string and perform space out with 3 ½" pup joints if required.
- RIH landing string with subsea equipment, 15ft before landing off set slips.
- Rig up coil tubing lifting frame, surface test tree and Coflexips.
- RIH land off fluted hanger in wear bushing.
- Rig up GR/CCL, re-correlate TCP guns, POOH E-line.
- Pick up and set retrievable packer, land off fluted hanger in wear bushing.
- Pressure test the string and surface connections.
- Close BOP pipe rams. Pressure test annulus. Lock open tubing fill tester valve.
- Hold safety meeting, circulate in diesel cushion via IRDV circulating port.
- Pressure up on tubing to fire TCP guns and bleed back to give 50 psi underbalance.
- Perform initial flow period to clean up well.
- Perform initial PBU by shutting in the well at the tester valve (if pour point < 5°C).
- Flow well for 24 hours stabilised main flow period and collect samples.
- Shut well in downhole at tester valve for 1.5 times the main flow period.
- Displace tubing string to mud above tester valve if oil pour point is above 5 °C.
- Run SRO tools immediately after shutting in (and displacing) the well, record PBU.
- Bullhead kill well. Open rams and unseat packer.
- Pull out of hole with test string. RIH and lay cement abandonment plug above packer.

4.3 Reservoir Properties (Cenomanian - Lower Zone)

Perforated Intervals:	To be advised.
Formation Pressure:	2579psi @ 6032 ft (1839 m) MDBRT (Top Reservoir)
Formation Temperature:	129°F (54°C)
Estimated SITHP:	359 psia (35 API dead oil) 444 psi (Diesel Column)
Expected Production	1000 bopd GOR: 800 scf/bbl
Estimated Porosity:	25 %
Estimated Water Sat:	15 %
Expected H_2S	< 10 ppm
Expected CO_2	< 10 %
Oil Gravity	35 degrees API

4.4 Reservoir Properties (Miocen - Upper Zone)

Perforated Intervals:	To be advised.
Formation Pressure:	1894 psia @ 4454 ft (1358 m) MDBRT (Top Reservoir)
Formation Temperature:	83°F (28° C)
Estimated SITHP:	206 psia (30 API dead Oil) 317 psi (Diesel Column)
Expected Production	2500 bopd GOR: 800 scf/bbl
Estimated Porosity:	28 %
Estimated Water Sat:	20 %
Expected H_2S	< 10 ppm
Expected CO_2	< 10 %
Oil Gravity	30 degrees API

4.5 Additional Information

TCP Guns:	4 ½ " HSD (5 spf) 51B HJ II, RDX 37 g DP. 7 " HSD (12 spf) 51B HJ II, RDX 37 g DP.
Electronic Gauges:	8 x Schlumberger Sapphire gauges
Annulus fluid:	Sodium Chloride Water based Mud, +/- 10.0 ppg.
Test string:	3 1/2" L-80, R2 TS-HD 12.95 ppf. (Interchangeable with 3 ½" Hydril PH-6 connection)
Landing string:	4 1/2" C-95, R2 AB STC 12.75 ppf. (Interchangeable with 4 ½" Hydril CS connection)
Water Depth:	1758 feet (536 m)
RKB above MSL	33 feet (10 m)
Mud Line temperature	Estimated @ 43 ^{0}F (6 ^{0}C)
Production Casing	9 5/8" 53.5 #, L80 New Vam Nominal Pipe I.D. = 8.535"
Production Liner	7" 29 #, L80 New Vam Nominal Pipe I.D.= 6.184"

5.0 EQUIPMENT PREPARATION

5.1 Pressure Control Equipment

Prior to mobilisation, all pressure control equipment shall have been approved and certified by the rig certifying authority. Specific sub-assemblies will be made up and tested in the shore base (packer sub assemblies). All equipment shall be inspected, and pressure tested to its working pressure rating and function tested and signed off by the Oil & Gas Company Well Test Engineers.

5.2 Surface Testing Equipment (see appendix A10 for pressure test procedures)

After installation offshore, all surface pressure control equipment, including flow lines, shall be pressure tested and witnessed by the rig certifying authority or their nominated onboard designate, usually the OIM. Pressure test charts will be produced and documented for the above tests. The separator oil and water meter calibration charts should be available on the rig.

5.3 Downhole Test Tools, Sub-Sea Test Tools and Surface Test Tree

Prior to the test, the above tools shall be tested to the appropriate test pressure. This shall include a full body test and against all valves. All pressure tests shall be charted and approved and signed off by the Oil & Gas Company Well Test Engineers or delegate. Appropriately sized drifts shall be passed through each sub-assembly and these details shall be recorded. Final rupture disc calculations for all annulus operated tools shall be performed by the DST Engineer and approved by the Test Engineer. Figures quoted in this programme are nominal only.

5.4 Bottom Hole Pressure Gauges

8 electronic gauges shall be used. Sampling modes will be supplied by the rig site Oil & Gas Company Well Test Engineers. Pre-job calibrations will be carried out prior to load out and these will be available offshore.

5.5 Pressure Testing prior to Opening Well

The down-hole tools and bottom hole assembly shall be tested during running to 3,000 psi. The main tubing string, surface lines from the cement unit through the kill Coflexip, STT, the flow Coflexip hose to the test choke manifold downstream valves, shall be tested to 3,000 psi against the upper SSLV.

5.6 Tubing 3 ½" and 4 ½"

Lay out all tubing, strap and number same. Drift all tubing with an API drift. Clean and inspect pin and box ends of all connections, offshore prior to running in hole. All tubulars will be inspected prior to shipment offshore.

6.0 PRE - TEST PREPARATION

6.1 BOP Preparation

For the testing programme the BOP stack will be dressed as follows:

5k Hydril "GL" annular
Shear/Blind rams
10 k 3 ½" - 5" variable rams
10 k 5" Fixed rams
10 k 3 ½" - 7 5/8" variable rams

The BOP's will be tested prior to conducting the well test.
The test pressure for the rams, fail safes, choke and kill manifold will be 200psi and 5,000 psi. The test duration will be 5 minutes low; 15 minutes high.

6.2 Landing String Space Out

A dummy run to space out the SSTT will be performed and the following checks will be carried out:

Check BOP dimensions against SSTT and slick joint measurements. Ensure that the shear rams can be closed above the SSTT whether the SSTT is latched or unlatched. A shearable sub shall be positioned opposite the shear rams to ensure the shear rams are able to shear and close with the SSTT latched.

6.3 Contingency

The logging company should have available for load out as required either chemical or flash cutting devices for both the 3-1/2" and 2-7/8" tubing for contingency purposes. In addition tubing punches should be available on board for both tubing sizes. A full wireline fishing package must be available on board.

String Pressure Test Failure

If the string fails to pressure test at the first test point the string should be pulled back to find and replace the leaking component. If the string fails to pressure test after all the tubing has been run, reverse circulate through the TFTV Valve and attempt to retest. If a tubing leak is suspected pull 1/4 of the string in stands and re-test. Repeat this method of pulling the remaining string until the leak is found. This method will identify the leak source within the shortest time frame.

TCP Gun Failure

If the guns fail to fire within the expected time frame wait a further 1 hr. Following this, re-apply tubing pressure up to the maximum allowable within pressure testing constraints. Should the guns fail to be fired hydraulically then drop the bar. If the failure is with the TCP guns, then the string will be have to be pulled. Follow Schlumberger procedures for recovering guns in the event of a misrun. There will be 100% back up TCP guns available offshore.

Tester Valve Failure

If the downhole tester valve fails to close for a buildup then the well will be shut in at the choke manifold.

However, the tester valve should be cycled a number of times in the event of a failure to attempt to obtain downhole shut in as this is the preferred method of conducting a pressure buildup.

7.0 TESTING PROCEDURES

The annular fluid during testing will be NaCl water based mud, +/- 10.0 ppg.

7.1 Pre Test Preparation

Refer to Oil & Gas Company Drilling Programme : The following operations will be carried out before commencing the well test:

7.1.1 Run and test 7" contingent liner if required as per the Oil & Gas Company Drilling procedures.

Note:-

The 9-5/8" casing shall have a radioactive marker located above the proposed packer setting depth for the upper zone. A pup joint should also be included.

7.1.2 Should the BOP configuration be unsuitable for the testing operations, pull BOP stack as per Oil & Gas Company Drilling procedures, and reconfigure rams for testing operations as per section 6.1. Carry out function and pressure tests on BOP stack and re-run as per Oil & Gas Company Drilling Procedures.

7.1.3 Re-run the wear bushing on drill pipe and land off on well head. POOH with running tool.

7.1.4 RIH with clean-out / scraper assembly spaced out to scrape over the proposed packer setting depths in the 7 " and or 9-5/8 " casing (packers will normally be set about 100 ft above the top of the zone of interest). Clean-out 7" and 9-5/8" casing.

Note:-

The 7" and or 9-5/8" casing is to be scraped thoroughly over the proposed packer setting depths.

7.1.5 Circulate and condition the mud to ensure kill weight mud above packer. POOH with scraper assembly.

Note:-

The mud must be well conditioned for the testing operations, with mud properties as per mud programme for testing.

7.1.6 Rig up electric line and run AMS(temp)/CBL/VDL/USIT/GR/CCL log on 7" x 9 5/8" casing from PBTD to top of cement.

7.1.7 Conduct leak off test (casing pressure integrity test) on liner lap and casing as per drilling programme.

7.1.8 Do not conduct inflow test if LOT and bond log are both acceptable.

7.1.9 Function test all surface, subsea and downhole equipment.

7.1.10 Carry out SSTT space out dummy run with the fluted hanger assembly and the 4 ½" tubing, to verify that the subsea tree assembly will be below the blind/shear rams whether unlatched or latched. A joint of freshly white painted tubing, should be run immediately above the fluted hanger. When the fluted hanger has been landed off, function the upper pipe ram (3 ½ " x 5" VBR) to mark the pipe. POOH and check for a mark on the pipe to verify the distance from the upper pipe ram to the fluted hanger shoulder.

7.1.11 Make up Surface Test Tree complete with hydraulic quick release stinger on top (CTU operations) and TIW valve below to a joint of tubing and lay down.

7.1.12 Carry out tubing test and flex trip. Pick up TFTV with suitable shear disk rating. RIH TFTV plus 3½" by 4 ½" tubing string to PBTD testing every 5 stands to 5000 psi for 5 minutes.

7.1.13 When the entire string has been run, close upper VBR. Apply pressure on tubing equivalent to shear disk rating plus 1500 psi to hold flapper closed. Apply sufficient pressure on the annulus to rupture shear disk and lock open TFTV, this will avoid pulling the string wet. Bleed of tubing and annulus pressure. Circulate bottoms up to remove any debris from tubing.

7.1.14 Open VBR and POOH tubing, rack back tubing in stands in the derrick

7.2 Running TCP / Positrieve Packer

7.2.1 RIH Gauge ring and junk basket on wireline (Schlumberger to advise on gauge ring dimensions) to +/- 30ft above 9 5/8" shoe or TOL (contingent 7") if packer is to be set in the 9 5/8", POOH. Repeat run if required on contingent 7 " liner, (Schlumberger to advise on gauge ring dimensions), POOH.

A safety meeting / tool box talk must be held prior to any operations involving the use of explosives.

- All necessary crossovers (including well control crossovers) must be available on the rig floor.
- Ensure that the correct slips are available.
- All equipment to be lifted on to the rig floor should be correctly stropped and equipped with tag lines.

Important:

Only essential personnel shall be present on the rig floor whilst making up the guns. The TCP specialist will conduct a short safety briefing immediately prior to picking up the guns. A short safety briefing should also be held prior to picking up DST tools.

7.2.2 Pick up the 4 ½" TCP gun assembly loaded at 5spf with 37g RDX deep penetrating charges in the case of the 7" liner. If the 9 5/8" casing is to perforated 7" TCP guns loaded at 12 spf with 37g RDX deep penetrating charges will be used. Run in hole TCP guns under the supervision of the Schlumberger TCP specialist.

7.2.3 Make up safety spacer, hydraulic delay firing head and mechanical drop bar firing head with SXAR drop sub, 2-7/8" EUE tubing pup, long slot ported debris/circulating sub, vertical shock absorber and 2 7/8" EUE perforated joint.

7.2.4 Make up to the string the Schlumberger Positrieve packer for 9-5/8"or contingent 7 ". Running the packer in the 9-5/8" will require a 2 7/8" EUE pin x 3 ½ EUE box x-over below the packer and a 3 ½" EUE pin x 3 ½" IF box x-over above. Running the packer in the 7" will require only a 2 7/8" EUE pin x 3 ½" IF box x-over above the packer as this packer has a 2 7/8" EUE pin down connection.

Maximum OD of the packer for the 9-5/8" casing is 7.00" and for the 7" liner 5.50".

7.2.5 While RIH the packer take care to run slowly to avoid hydraulicing. Every 5 stands pickup a full single to ensure that the bypass is open. Caution should be exercised while travelling through the BOP or entering a liner to avoid hanging up.

A Schlumberger representative must be on the drill floor at all times while running in or pulling out of the hole with the packer.

7.3 **Running the Test String.**

- All necessary crossovers (including well control crossovers for stab in valves) must be available on the rig floor.
- Ensure that the correct slips are available.
- All equipment to be lifted on to the rig floor must be correctly stropped and equipped with tag lines.

7.3.1 Make-up and run the Tubing Fill Tester Valve (TFTV) this will automatically fill the string while RIH.

7.3.2 Make up and run (FGCA-C) gauge carrier c/w four Schlumberger Sapphire electronic memory pressure and temperature gauges. Sampling rates for gauges will be provided by the Oil & Gas Company well site representative.

7.3.3 Make up and run the IRIS Tester/Circulating valve.

7.3.4 Make up the DST gauge adapter (DGA-B) and SRO latch (DWLA). Two Sapphire gauges should be ported below the tester valve, one above the tester valve and one to the annulus. RIH with assembly.

7.3.5 Make up one stand of 4 ¾" drill collar 48 # (3 ½ " IF connections) , RA marker sub and the MCCV. Make up a further 4 - 6 stands of 4 ¾" drill collars followed by 3 slip joints and a 3 ½" IF pin x 3 ½" PH6 Box x over and RIH.

7.3.6 RIH with the LINC tool to ensure that communication can be established with the DWLA/DGA then POOH with SRO.

7.3.7 RIH half the tubing and then make up circulating head to tubing and test against TFTV to 3,000 psi for 15 minutes. (BOP rams will be open during pressure tests)

7.3.8 Remove the circulating head and run the remainder of the 3 ½" PH6 tubing.

7.3.9 Refer to the tally and RIH sufficient stands and singles of 3 ½" PH6 to position one of the last two joints of 3 ½" PH6 opposite the BOP rams for space out, when the TCP guns are at depth. The last two joints of 3 ½" should be freshly painted white.

7.3.10 Make up 3 ½" PH6 pin x 4 ½" CS Hydril box x over and RIH 3 ½" tubing on 4 ½" landing string. Position guns on depth according to the pipe tally.

7.3.11 Rig up 1 11/16" GR/CCL and perform a TCP gun correlation run.

7.3.12 Correlate the guns to the cased hole log run in step 7.1.6, POOH GR/CCL.

7.3.13 Position TCP guns on depth and close the upper VBR on the freshly painted joint.

7.3.14 POOH landing string and examine the painted joints. Perform space out calculation, taking into consideration the distance between the upper pipe ram and the shoulder of the fluted hanger, obtained in step 7.1.10 and the stroke of the slip joint, one full closed, one half open and the other fully open.

7.3.15 Replace 3 ½" tubing joints with appropriately sized pup joints for space out.

7.3.16 Make up 3 ½" PH6 pin x 4 ½" Stub Acme Pin x over to the string, make up adjustable fluted hanger set-up as in 7.1.10 and 5" slick joint and RIH.

7.3.17 Carefully pickup Sentree 3 and make up to the string, ensure the string is held in the slips before connecting the umbilicals then RIH.

Care must be taken during RIH with landing string to avoid damage to the hydraulic and chemical injection lines, particularly when landing off in the slips.

7.3.18 Make up shear sub and retainer valve with deep water hydraulic pod system and riser centraliser to x over 5" Stub Acme pin x 4 ½" CS Hydril box and RIH.

7.3.19 Make up and RIH sufficient 4 ½" CS Hydril to position the lubricator valve at +/- 100' below the rotary table.

7.3.20 Make up 4 ½" CS Hydril pin x 4 ½" SA pin x over to the string, make up SSLV and 4 ½" SA pin x 4 ½" CS Hydril box and RIH on 4 ½" CS Hydril tubing. 15' before landing off the fluted hanger in the wear bushing set slips.

A tubing joint has previously been made up to the TIW valve and flow head

7.3.21 Coil the umbilical and control line 3 to 4 times around the landing string in a right hand direction.

7.3.22 Pickup the coil tubing lifting frame with the crane, make up to the elevators and raise to the vertical position.

7.3.23 Make up the flow head (C/W TIW valve and tubing joint) to the coil tubing lifting frame then pickup the surface test tree.

7.3.24 Stab the tubing joint below the flowhead into the landing string held in the slips.

7.3.25 RIH and land off fluted hanger in the wear bushing and confirm there is adequate stickup. Should be +/- 20' of stickup above the rotary table when landed off. (review tide tables and heave

7.3.26 Make up a Coflexip to the kill side of the flowhead and pressure test the entire string to 3000 psi for 15 minutes.

7.3.27 Rig up 1 11/16" GR/CCL, perform log and confirm guns are on depth, accounting for stroke of slip joints. Guns will be lower than planned at this stage as the slip joints will be extended.

7.3.28 Pickup the string as required to position the guns on depth. This should be equivalent to the stroke of one and a half slip joints + packer squat.

7.3.29 Rotate the string 3 to 4 turns to the right at surface (¼ turn required at the packer) and set down. An indication that the packer has set will be loss of the string weight below the slip joints.

7.3.30 Continue to RIH and carefully land off the fluted hanger in the 9 5/8" wear bushing.

7.3.31 Make up a Coflexip from the flow side of the flow head to the choke manifold and carry out pressure tests as per section 7.4.

The coil tubing BOP's and injector head will only be rigged up if it becomes necessary to carry out a clean out of the string as described in Appendix A12.

7.4 Pressure Testing the String & Surface Connections

Note:-

1. **Prior to pressure testing operations taking place, conduct a toolbox talk with all personnel on the drill floor, only essential personnel should remain on the drill floor during pressure tests.**

2. **It is important during pressure testing of valves in the production test string that accurate measurements of fluid volumes are taken.**

3. **All BOP rams must be open during pressure testing of the string.**

4. **All test equipment downstream of the choke manifold will have been tested as per section 5.2 and appendix A 10.**

7.4.1 Pressure test the Coflexip down to the choke manifold to 3000 psi for 15 minutes against the TIW valve. Bleed down pressure to zero. Open TIW valve and pressure test the entire string against the TFTV to 3,000 psi for 15 minutes and record the volume pumped. Monitor the SSTT and lubricator valve chemical injection lines to ensure that the check valves are holding pressure and not leaking back to the tank.

7.4.2 Prior to bleeding off test pressure, pump through the chemical injection lines with MEG and PPD as appropriate to ensure lines are holding .The injection pressure should be the same as the tubing pressure plus friction losses in the injection lines. Check the backup pump at this stage then bleed off chemical lines to zero.

Note: It is important to check the chemical injection system thoroughly as there is a potential for wax, asphaltenes or hydrates to occur in the landing string, because of the low temperatures consistent with deep water testing.

Ensure that an adequate volume of chemicals is lined up to the surface pumps to allow delivery at the required rates through out the duration of the test.

7.4.3 Close the SSTT valves sequentially and bleed off the pressure above to 500 psi. Measure volume returned. Inflow test the SSTT for 15 minutes.

7.4.4 Equalise the pressure across the SSTT and open same. Close the lubricator valve and bleed off the pressure above to 500 psi. Inflow test for 15 minutes. Equalise the pressure across the lubricator valve and open same. Monitor volumes pumped and returned.

7.4.5 Bleed down the production tubing string to zero and check volume returned. Close the lubricator valve and pressure test from above to 3,000 psi for 15 mins. Bleed down pressure to zero psi. Open lubricator valve. Note volume pumped and returned.

7.4.6 Close the BOP middle (5") pipe ram on the slick joint and pressure test the annulus to a nominal 500 psi.

7.4.7 Pressure up on the annulus to +/- 1500 psi to lock open TFTV. Note volume pumped.

7.4.8 Bleed off annulus pressure to zero and monitor returns.

7.4.9 Pressure up on the tubing to 1000 psi for 15 minutes. Monitor the annulus for returns. Note: This pressure test will confirm string integrity after shearing out TFTV.

7.5 Circulate in Diesel Cushion

Hold Pre Test safety meeting with all the on duty rig crew and relevant service company personnel – Schlumberger Supervisor will provide a briefing.

OIM, Drilling Supervisor, Test Engineer and Well Test Crew Chief will walk and inspect surface lines and well testing equipment.

7.5.1 Pulse annulus as per instructions of Schlumberger DST specialist and open circulating valve on IRDV.

7.5.2 Establish circulation by pumping 5 bbl mud at 1-2 bpm down the tubing to confirm IRDV valve is open. Do not exceed TCP gun initiation pressure during circulation, however IRIS tester valve should be closed.

7.5.3 Circulate in diesel cushion via IRDV circulating ports. Volume to be advised onsite, do not over circulate. Note that the surface pressure will be bled down after applying gun detonation pressure to give an underbalance of 50-100 psi.

7.5.4 Once the cushion has been placed, close the wing valve on the STT, pulse the annulus as per the instructions of Schlumberger DST specialist to close the circulating valve. Bleed off any U-tube pressure from the tubing via the choke manifold as required.

Note: In the event of a failure in the IRDV then use MCCV to spot cushion.

7.5.5 Apply approximately 100 psi on the annulus for monitoring purposes during the testing phase.

7.6 Detonation of TCP Guns

For 7" liner the TCP guns are 4 ½" 5 spf 37g RDX deep penetrating charges.

For 9 5/8" the TCP guns are 7" 12 spf 37g RDX deep penetrating charges.

The method of detonation will be hydraulic via an applied surface pressure. A redundant mechanical drop bar system is also included in the gun system. The guns will auto release via an SXAR drop sub.

7.6.1 Test Engineer / Drilling Supervisor and Schlumberger TCP Engineer to calculate and agree applied surface pressures for gun detonation. This should be around 3000 psi above mud hydrostatic, account for diesel hydrostatic in string. These are provisional values.

7.6.2 Hold a pre-test safety meeting on the rig floor with the on-duty rig crew and all relevant service companies. Walk and inspect surface lines and well testing equipment - OIM, Drilling Supervisor, Test Engineer and Well Testing Crew Chief prior to commencing perforating operations.
Ensure that the pre-flow checks, given in Appendix A 9, have been carried out.

7.6.3 Line up the cement unit to the Flowhead via the Flowhead kill wing valve. Ensure the tubing string is open to the choke manifold and the choke manifold is closed. Monitor and hold annulus pressure. The Schlumberger data acquisition system will continuously monitor annulus pressure.

7.6.4 Ensure Schlumberger surface data acquisition system is set to fast sampling rate.

7.6.5 Open kill wing valve and pressure up tubing using mud or glycol / sea water mix 60/40 to the required gun detonation pressure as instructed by the Schlumberger TCP representative.

7.6.6 Close kill wing valve. Bleed off excess tubing pressure at the Schlumberger choke manifold to achieve the required underbalance of 50-100 psi. A time delay of approximately 15 minutes is incorporated into the TCP firing head.

7.6.7 Monitor surface pressures for indications of gun detonation.

7.6.8 If there is no indication of gun detonation, repeat steps 7.6.4 to 7.6.7, increasing WHP to the maximum allowable pressure set by tubing and liner pressure tests.

7.6.9 If there is still no indication of gun detonation following step 7.6.8, then follow Schlumberger procedures to drop the bar and fire the TCP guns.

7.6.10 Once there is confirmation of successful guns firing, proceed as per section 8 of the well test programme.

8 PRODUCTION TEST PROGRAMME

8.1 Clean-up Flow Period

8.1.1 During flow periods, 100psi (+/- 50 psi) should be maintained on the annulus. The Schlumberger DST engineer must monitor the annulus pressure at all times. The pressure will rise as the well heats up and may require bleeding down intermittently.

Notes:

1. **Schlumberger DST operator to record time, volumes and pressures for each annulus bleed off.**
2. **The Schlumberger data acquisition system will continuously monitor annulus pressure.**

8.1.2 Open well on a 16/64th adjustable choke to clean up the well. While recovering the diesel cushion direct flow to the surge tanks and monitor the rate and volumes returned. Monitor the downstream choke pressure. When the cushion has been recovered direct flow to the burners and bean up the choke as necessary to clean up the well.

Notes:-

1. **Commence injecting Glycol or wax inhibitor / PPD (Pour Point Depressant) at the subsea test tree. Quantities required will have been determined from onsite PVT / Chemical analysis of MDT samples.**

2. **Refer to the dynamic temperature model to determine the potential for flow related problems, due to the low sea bed temperature. Refer to any operational guidelines issued following determination of the pour points from MDT samples.**

3. **In the event that the production tubing becomes completely blocked by wax or hydrates a contingency procedure has been included in Appendix A12. This will necessitate rigging up the remainder of the coil tubing package.**

* The packer is set as close as reasonably possible to the zone of interest to minimise the volume of mud to be flowed back during clean up. In the event that the well dies during clean up consider the following.

1. Is the tester valve still open ?
2. Has the string become blocked - wax, hydrates, sand, debris etc. ?
3. Has diesel cushion been replaced by a mud column. ? Consider pressure gradient survey to determine fluid interfaces or circulate diesel cushion back into the string to replace mud volume, do not over circulate.

8.1.3 When first hydrocarbons come to surface, test for H_2S and CO_2 until levels have stabilised, then test at regular intervals (1 hour). Use sampling point downstream of choke manifold. Appropriate H_2S safety measures will be taken depending on actual H_2S levels detected.

Notes:-

1. **On initial opening of well BA equipment and masks will be worn by two of the Schlumberger well test crew when sampling for H_2S until the level of H_2S in air has been established. All other personnel must remain upwind of the choke manifold when sampling is taking place.**

2. **If the H_2S level in the wellstream is detected at >10 ppm, BA sets must be worn for any operation that vents gas. Inform the shore base immediately.**

3. **If the H_2S level in the well stream is >50ppm then BA sets must be worn continuously. Should there be insufficient sets onboard then the well test must be curtailed until a cascade system is rigged up and operable.**

8.1.4 Monitor the surface flowing pressure, temperature and the BS&W levels in the produced fluid, as per appendix A8. Guidelines for when the well will be considered cleaned up are as follows:

1. The BS&W has been constant over the last two hours.
2. The solids content is less than 2%.
3. The surface flowing pressure is constant or is declining as a log function of time.

8.1.5 Divert flow from the adjustable choke setting established in 8.1.4 when the well was clean, to a suitable fixed choke, which maintains critical flow (Downstream choke pressure < 0.5 times upstream choke pressure). Once stable, flow well through separator for 2-3 hours stable flow at this fixed choke size as directed by the Oil & Gas Company Well Test Engineer.

Diesel recovered to the surge tanks may be sent to the burners when operationally convenient.

Re-test for H_2S and CO_2 from the separator gas line once flowing to the separator, BA sets and masks to be worn. When H_2S levels are below 10 ppm masks will not be required.

8.1.6 During this stable separator flow period take 1 set of matched separator oil and gas PVT samples. Each set of samples to consist of 1* 600cc oil and 2 * 20 litre gas samples. Take samples over a minimum period of 30 minutes per matched pair. Attempt to take samples without injecting chemicals during sampling if this is considered operationally acceptable.

8.1.6 (Continued)

Atmospheric samples of dead oil and water (if produced) should be taken in combination with the matched separator PVT samples.

Volume of samples required with each set :

Dead Oil - 4 x 11 litres + 5 Gallon (Oil Assay)
Water - 4 x 5 litres.

8.2 Initial Pressure Build-up (Downhole Shut-in)

* **Note: If the pour point of the oil is greater than 5 ^{0}C then an initial build up will <u>not</u> be performed following the cleanup flow. In this event proceed with the main flow period as per section 8.3.**

8.2.1 At the end of the initial flow period and assuming the pour point of the oil is less than 5^0 C close the well in at the IRIS tester valve for a pressure build up by pulsing the annulus as per the instructions of the Schlumberger DST specialist.

Note:-
Due to "mud shrinkage" on cooling the annulus may require topping up during the build up period.

8.2.2 The pressure build up period should be equal to 1.5 times the duration of the initial flow period. Monitor annulus pressure throughout.

8.3 Main Flow Period

8.3.1 During flow periods, 100psi (+/- 50 psi) should be maintained on the annulus. The Schlumberger DST specialist must monitor the annulus pressure at all times. The pressure will rise as the well heats up and may require bleeding down intermittently.

Notes:

1. **Schlumberger DST operator to record time, volumes and pressures for each annulus bleed off.**
2. **The Schlumberger data acquisition system will continuously monitor annulus pressure.**

8.3.2 Ensure that the subsea test tree and lubricator valves are fully open. Line up well against closed choke.

8.3.3 Prior to opening up the well, ensure that the pre-flow checks, given in Appendix A10, have been carried out. Pulse annulus to open IRIS tester valve as per the instructions of the Schlumberger DST specialist.

8.3.4 Open well on a 16/64th adjustable choke. Monitor the downstream choke pressure. Commence beaning up well to the choke size established in step 8.1.4. and divert to fixed choke of the same size.

8.3.5 Once stable, flow the well through separator for 24 hours at this fixed choke size or as directed by the Oil & Gas Company Test Engineers. (Monitoring as per appendix A8)

When flowing to the separator re-test for H_2S and CO_2 from the separator gas line BA sets and masks to be worn. When H_2S levels are < 10 ppm masks will not be required.

8.3.6 During this stable separator flow period take 2 sets of matched separator oil and gas PVT samples. Each set of samples will consist of 1* 600 cc oil and 2 * 20 litre gas samples. In addition take 2 * 300cc samples of separator gas for geochemical analysis. Take samples over a minimum period of 30 minutes per matched pair. Atmospheric samples of dead oil and water (if produced) should be taken in combination with the matched separator PVT samples.

Attempt to take samples without injecting chemicals during sampling if deemed operationally acceptable.

Volume of samples required with each set :

Dead Oil - 4 x 11 litres + 5 Gallon (Oil Assay)
Water - 4 x 5 litres.

Note: In the event that the production tubing becomes completely blocked by wax a contingency procedure has been included in Appendix A12.

8.4 Main Pressure Build-up (Downhole Shut In)

8.4.1 At the end of the main flow period, close the well in at the IRIS valve for the main pressure build-up. After the tester valve has been closed, bleed down the WHP to approximately 100 psi, shut in the well at choke manifold and monitor the pressure for 5 minutes to confirm the IRIS valve is closed.

Notes:

1. **The entire tubing string contents are to be reverse out to 10.0 ppg mud if the pour point of the oil is 'greater' than 5°C. This operation should be performed immediately after step 8.4.1. Firstly ensure that the pilot lights at the burners have been ignited then pulse the annulus as per the instruction of the Schlumberger DST specialist to open the circulating ports on the IRDV. Then reverse out the tubing contents via the Schlumberger choke manifold to the burners, in addition pump out any oil remaining in the surge tank to the burners. When mud returns are observed at the burners stop circulating, then shut in at the flow head master valve. Open the kill wing valve on the flow head and flush through the testing lines with water to the burners. Close the flow and kill wing valves and the choke manifold, then re-open the flowhead master valve and monitor WHP.**

   At no point during the displacement will the dumping of hydrocarbon in the sea be permitted.

2. **Due to "mud shrinkage" on cooling the annulus may require topping up during the build up period, maintain a pressure on the annulus of 100 psi.**

8.4.2 Rig up SRO equipment and pressure test using a 60/40 glycol /sea water mix, the short lubricator, grease injection head and BOP to 3000 psi against the SSLV.

8.4.3 RIH slowly (< 200ft / min) with the SRO.

8.4.4 Land off SRO in no go shoulder and initiate BHP/BHT data read out and recording.

8.4.5 Pressure build up period should normally be equal to about 1.5 times the duration of the main flow period. Monitor annulus pressure throughout.

Using SRO may allow the buildup period to be reduced. Oil & Gas Company representatives should continuously monitor the build up pressure to determine the duration of the buildup. Pressure derivative plots may assist in identifying the end of the IARF (Infinite Acting Radial Flow) period and as boundary information is not deemed an objective of the test this may signal an appropriate end to the buildup period.

Do not compromise the main objective of the test, namely obtaining quality test data, by terminating the build up prematurely.

8.4.6 At the end of the build up, pull out of the hole with the SRO tool, close SSLV and bleed off surface pressure.

8.4.7 Rig down SRO data acquisition tools.

8.4.8 Open SSLV, kill wing valve and equalise pressure across the IRIS tester valve, then pulse the annulus to open the tester valve and commence bull head killing the well. (recommended practices and contingencies are detailed in section 9.0)

8.4.9 Once the well has been killed, bleed off any remaining annulus pressure.

8.4.10 To unseat the packer pickup string tension until the original string weight is regained and then exceed this slightly, do not exceed 80% of the safe lifting capacity of the coil tubing lifting frame. Closely observe the annulus for gas trapped below the packer, this may have to be circulated out.

Note: Should difficulty be experienced in unseating the packer, consideration should be given to first rigging down the flow head and coil tubing lifting frame, then installing a circulating head on the string and picking up the string using the elevators.

8.4.11 When satisfied that the well is dead, rig down Coflexip hoses, flow head and coil tubing lifting frame.

8.4.12 POOH carefully with DST string, stop and flow check periodically.
Recover memory gauges and download data.

8.4.13 Rack back tubing in stands in the derrick if another DST is to be conducted, otherwise lay down tubing.

End of Test

RIH and lay cement abandonment plugs above the zone as per the Oil & Gas Company drilling procedures.

Second Zone : If both zones are to be tested, repeat as per section 7.2 through 8.4.13 above.

Carry out permanent abandonment of well as per the drilling programme.

9.0 WELL KILL PROCEDURE

9.1 Well Kill Procedure

After confirmation from the shore base proceed with killing the well.

Note:

- The preferred method of killing the well is to bullhead the tubing contents. If bull heading is not possible then the reverse kill method can be used.
- The procedure below is for ending a test with no tubing or equipment leaks.
- Ensure during pulling of the string that the correct sized crossovers and stab in valves are available on the rig floor at all times. A constant monitor of correct hole fill must be noted at all times.

9.1.1 Ensure that all unnecessary well test instrumentation has been rigged down from the flowhead.

9.1.2 By-pass all the surface test process equipment straight to the burner heads.

9.1.3 Ensure the testing choke manifold is closed. Equalise the pressure across the tester valve and open.

9.1.4 Commence bull heading with kill weight mud to the formation. Work with a kill graph and follow the barrels pumped against well head pressure, pump at maximum rate to avoid gas passing mud in the tubing. At the theoretical tubing and sump volume watch for an increase in pump pressure denoting the mud screening out to the formation. Attempt to squeeze mud to the formation but do not exceed the fracture gradient at any time.

9.1.5 Flow check well for 60 minutes or until confirmed static.

9.1.6 Pulse annulus and open IRIS circulating valve. Then circulate the well to mud conventionally until even weight mud is around the system.

9.1.7 Flow check for 60 minutes or until confirmed static.

9.1.8 If flow check is good, open pipe rams and unseat the packer.

9.1.9 Flow check for 15 minutes or until confirmed static. This will allow the packer elements to relax

9.1.10 Break down surface equipment and prepare to pull the test string.

9.1.11 Ensure all well control valves and crossovers are on the rig floor before POOH

9.1.12 POOH test string, stop and flow check periodically.

9.2 Contingency Well Kill - Reverse Circulation Method

In the event that the well cannot be bull headed then the following option should be adopted

9.2.1 Pulse the annulus and open IRIS circulating valve.

9.2.2 Reverse the contents of the tubing and annulus straight to the burners.

9.2.3 When mud returns reach the flowhead stop the mud pumps. Line up to allow circulation through the mud/gas separator.

9.2.4 Reverse a further tubing volume. Flow check the well for 60 minutes.

9.2.5 Attempt to bull head the remaining volume of mud / oil below the circulating valve to the perforations. Do not exceed the fracture gradient.

9.2.6 Flow check the well for 60 minutes or until confirmed static.

9.2.7 If flow check is good, open pipe rams and unseat the packer.

9.2.8 Flow check for 15 minutes or until confirmed static, this will also give time for the packer elements to relax before POOH.

9.2.9 Break down surface equipment and prepare to pull the test string.

9.2.10 Ensure all well control valves and crossovers are on the rig floor before starting to pull the test string.

9.2.11 POOH test string, stop and flow check periodically.

9.3 Contingency Well Kill - Tubing Punch

In the event of mechanical failure of the downhole tools then a tubing punch will have to be run. The following procedures should be adopted.

9.3.1 Close the sub sea lubricator valve and bleed off pressure above through the choke manifold to burners. Inflow test lubricator valve.

9.3.2 Check subsea control panel to ensure valve has functioned.

9.3.3 Hold a pre-job safety meeting on the rig floor with the rig crew and all relevant service company personnel prior to rigging up the tubing punch.

Note:- Radio silence will be a requirement during this operation.

9.3.4 Make up the required tubing punch assembly including CCL and sufficient weights to enable string to be RIH.

9.3.5 Place tubing punch in landing string and pressure test wireline BOP equipment to 3000 psi against the SSLV using a 60/40 glycol / sea water mix for 15 minutes.

9.3.6 RIH with string taking care when passing through restrictions. Correlate tubing punch depth with CCL.

9.3.7 Reduce annulus to tubing differential pressure by applying annulus pressure. Fire tubing punch in tubing joint above DST tools. Observe wellhead pressure at choke manifold for indication of gun firing.

9.3.9 POOH with tubing punch. Once tool string is at surface, close lubricator valve and bleed off above through choke manifold to burners. Inflow test lower lubricator valve.

Radio silence will be required prior to the tool string entering landing string.

9.3.10 Rig down tool string and Schlumberger pressure control equipment.

9.3.11 Re-instate swab cap. Pressure test swab cap from below to 3000 psi.

9.3.12 Reverse circulate the well to mud conventionally until even weight mud is around the system.

9.3.13 Flow check for 60 minutes or until confirmed static.

9.3.14 Attempt to bull head the remaining volume of mud / oil below the circulating point to the perforations. Do not exceed the fracture gradient.

9.3.15 Flow check for 60 minutes or until confirmed static.

9.3.16 If flow check is good, open 5" pipe rams and unseat the packer.

9.3.17 Flow check for 15 minutes or until confirmed static, this will also give time for the packer elements to relax before POOH.

9.3.18 Break down surface equipment and prepare to pull the test string.

9.3.19 Ensure all well control valves and crossovers are on the rig floor before starting to pull the test string.

9.3.20 POOH test string, stop and flow check periodically.

9.4 Well Abandonment

A separate programme will be issued for abandonment of the well.

LIST OF APPENDICES

DAILY TEST REPORTS **Appendix A1**

DATE:

COUNTRY:
BLOCK:
WELL NUMBER:
INTERVAL TESTED:
DST NUMBER:

1. **Summary of Operations** from ...... hrs to ...... on (date)

2. **Time Breakdown** (Sequence of events)

a. **Date / Time**

Operation e.g. Make up BHA, set packer, flow and shut in periods.

b. **Production Details** (to include the following)

Time	Choke	THP	THT	Psep	Tsep	Oil	Gas	GOR	H_2O
hh:mm	64ths	psig	°F	psig	°F	bopd	MMscfd	scf/bbl	bwpd

c. **Additional Information**

Perforated intervals, thickness, depths MDBRT and TVDSS

Gauge sensor depths (MDBRT and TVDSS)

Depths of key items in the test string (MDRT and TVDSS)

Sample information (source, sampling time and condition, results – gravity, density, salinity, pH, resistivity at stated temperature).

Bottom hole pressures and temperatures, quick look interpretation results.

BSW, H_2S, CO_2 , gas gravity, oil density, cumulative volumes produced.

d. **Current Operations**

e. **Forward Programme**

Plans for next 24 hours.

The Test Engineer must ensure that all relevant data reported is correct and is available to the shore base in a timely manner. Normally the following reporting times are used:

AM Summary sheet (due before 08:00)	Faxed report covering time period midnight to midnight previous day with update to 06:00 on the report date
AM Phone call	Call duty Engineer 08:30 daily
PM Summary sheet	Faxed report covering time period 06:00 hrs that morning to 15:00 hrs on the report date.(due before 17:00)
PM Phone call	Call duty engineer 17:00 daily.
Fax Reports	Fax in contractor data sheets, sample data sheets, provisional results, production logs, computer data sheets and any interpretation data etc. as and when they become available.
Downhole Gauge Data	Pressure gauge data should be down loaded onto floppy discs at the end of each test. Send data electronically as an E-mail attachment, if possible or else send a disc to town as soon as possible after each test. The test engineer should also keep a spare copy of each data disc and hand carry them to the shore base on completion of the test.

Contact Numbers:

Shore Base

Staff House

Hotel

TEST STRING SCHEMATIC — Appendix A2

Insert provided by DST Contractor

LANDING STRING SCHEMATIC — Appendix A3

Insert provided by Testing Contractor

BOP STACK LAYOUT — Appendix A4

Insert Provided by Drilling Contractor

SURFACE EQUIPMENT LAYOUT — Appendix A5

Insert provided by Testing Contractor

SURFACE EQUIPMENT P & ID — Appendix A6

Insert provided by Testing Contractor

EMERGENCY DISCONNECTS **Appendix A7**

1 Mooring System Failure

Failure in this system can range in severity from total and immediate failure to a slowly deteriorating situation.

Figure A7-1 To be posted in the drillers dog house during testing operations.

If the mooring system failure is of such a nature that corrective measures may be taken, then follow normal killing procedures as per section 9.0 Well Kill Procedure otherwise proceed as per Figure A7-1

2 Bad Weather Disconnect

Assess the weather window available for operations and ensure that there is adequate time. Frequent weather reports should negate the requirement to disconnect as an emergency procedure. However, an emergency disconnect due to bad or deteriorating weather cannot be excluded.

Typical Vessel Motion Operating Limits: (Testing)

Heave = 1.52m (5 ft) Pitch = 3^0 Roll = 3^0

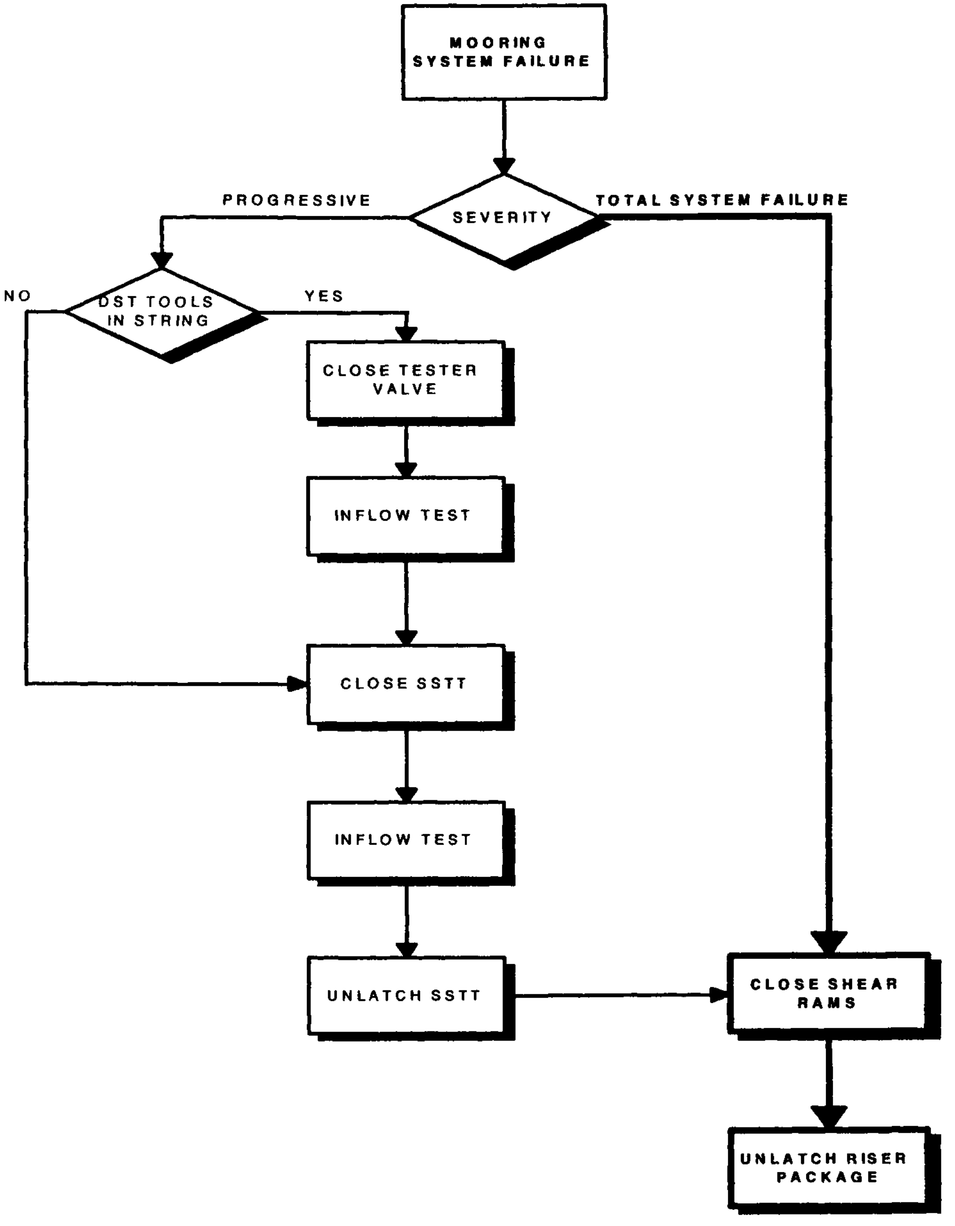
When disconnecting due to bad weather follow the steps as outlined in Figure A7-1 for a mooring system failure. Also refer to Schlumberger procedures for controlled disconnect and emergency disconnect at the Subsea Test Tree.

Typical Bad Weather Disconnect Criteria: (Data supplied by Drilling Contractor)

Operation	Wind Speed (Knots)	Sine Wave Ht. (metres)	Max. Wave Ht. (metres)
Testing Suspended (Ready to disconnect SSTT)	45 +/- 17.5	4.00	7.38
Disconnect SSTT & LMRP	50 +/- 17.5	4.61	8.62

Note : The Schlumberger SENTREE 3 will not unlatch if landing string is more than 6^o off the vertical position.

FIGURE A7-1 Mooring System Failure Which Requires Immediate Action



MONITORING and SAMPLING REQUIREMENTS **Appendix A8**

1.0 Monitoring Requirements

1.1 The following parameters should be recorded every 30 minutes: FTHP, FTHT, separator pressure, separator temperature, BS&W.

The following should be recorded continuously by chart recorders: THP, THT, separator pressure, orifice plate differential pressure and separator temperature.

Uncorrected oil flow rate, gas flow rate and flowing GOR to be recorded every 30 minutes.

Note: Each time the well is opened or shut in at surface or a choke is changed the THP (surface pressure) should be recorded as follows:

- First ten minutes every minute.
- Next 20 minutes every 2 minutes
- Next 30 minutes every 5 minutes
- Next 60 minutes every 10 minutes
- Next 4 hours every 15 minutes
- From 6 hours onwards every 30 minutes

1.2 Oil flow rate to be measured every 30 minutes. Combined oil meter correction factor and shrinkage to be obtained as often as reasonably possible during stabilised flow. Ensure that the tank temperature is recorded when making these measurements. In any event a meter factor must be obtained at least once on each choke size.

1.3 H_2S and CO_2 by Drager tube (or equivalent) every hour and also when directed by the Oil & Gas Company Engineer.

1.4 Oil and gas gravity measurements should be obtained every hour and as directed by the Oil & Gas Company Engineer.

2 Sampling Procedures

2.1 Separator Samples

Separator samples always consist of a matching pair; a sample from the gas and a sample from the liquid phase. Because the composition of both phases is strongly dependent on the flow conditions, care is necessary to ensure that the gas and liquid samples are taken under stable conditions, preferably simultaneously. Sampling lines should be kept as short as possible.

Gas Samples (20 litre bottles)

a. The sample bottles should be properly evacuated with a vacuum pump.
b. The bottles will be connected to the separator gas outlet and slowly filled up to separator pressure.
c. Care will be taken to ensure that the bottle valves have been closed prior to disconnection from the sample point.

Oil / Condensate Samples (600 cc bottles)

a. The oil / condensate sample containers will be mercury free with water / glycol solution displacement.
b. Keep the bottle in a vertical position during the entire sampling operation. Displace slowly 85 % of the container fluid with oil / condensate.
c. Ensure that the bottle is at separator pressure prior to being closed.
d. Draw off another 10% of the original fluid (water / glycol) to create a gas cap.
e. Check container and valves for leaks.
* A gas cap is to be created to accommodate expansion of the liquid in the event of temperature increase of the sample bottles during transportation.

2.2 Surface Samples

Dead Oil

Crude samples are to be taken regularly into IATA or DOT cans throughout the test and the gravity determined and reported at standard conditions. Clean samples can be obtained from a sampling point on the oil manifold.

Water

Water samples are to be taken regularly throughout the stabilised flow period. Samples should be checked regularly for salinity, specific gravity and pH.

A total of about one gallon of water samples should be collected.

2.3 Reporting

Sample Numbering

All samples should be numbered sequentially in the order they are taken (including failures). An alphanumeric system should also be used to identify the type of sample.

Dead oil samples could be identified, eg. 1DO, 2DO, ...

Pressurised samples could be identified, eg. 1PO, 2PO,.. for oil or 1PG, 2PG,..for gas.

Water samples samples could be identified, eg. 1W, 2W, ...

Labelling

All samples are to be labelled as follows:

Oil & Gas Company	Fluid Sample Label
Country	
Block	
Well Number	
Interval Tested	
Test Number	
Sample Number	
Container Serial Number	
Fluid Type	
Sampling Location	
Date : Time	
Reason for Sample	
Sample Temperature	
Sample Pressure	
Wellhead Pressure	
Wellhead Temperature	
Separator Pressure	
Separator Temperature	
Stock Tank Pressure	
Stock Tank Temperature	
Sampled By	
Witnessed By	
Remarks	

Reporting

Each time samples are taken, this must be reported on the daily production test report, indicating the sample number, type and time of sampling.

For pressurised samples (bottom hole, wellhead, separator samples) all of the sampling details are to be sent with the laboratory work request, the sampling or testing contractor will provide logistic support for the shipping of samples.

Directly after completion of the test the testing contractors "Production Test Sample Identification Form" has to be duly completed and returned to shore. This form should summarise all the samples, including the failure and status.
e.g. The dead crude sample numbers was taken and destroyed. The dead crude sample numbers was taken and sent to shore.

2.4 **Separator sampling details** - (To be included with recombination PVT samples)

Country:	
Well:	
Test:	Producing interval:
Date sampled:	
Time sampled:	
Sample number:	
Bottle number:	
Bottle contents:	Oil / Condensate / Gas
Oil / Condensate flowrate:	b/d at operating conditions
Gas flowrate:	MMscf/d at operating conditions
Water cut:	
FTHP (psig)	
FTHT (°F)	
Separator pressure (psig)	
Separator temperature (° F)	
Oil gravity (degrees API)	
Gas gravity (relative to air)	
Water salinity (NaCl equivalent) (g/ml)	
Shrinkage factor	
GOR (scf/bbl)	
Final bottle pressure:	
Final bottle temperature:	
Sampled by:	
Witnessed by:	

PRE-FLOW CHECKLIST **Appendix A9**

- Well Test Supervisor/Well Test Crew Chief to obtain necessary 'Permits To Work' from the OIM and ensure they are valid at all times.
- Tool box talks are to be held for all rig personnel prior to flowing the well and before all hazardous operations.
- Avoid first flow of hydrocarbons to surface during hours of darkness.
- All relief lines must lead directly overboard or into the rig vent header and not 'T' into any other flowline.
- Well is lined up to the burners, by-passing the heater, separator and surge tank.
- The burner pilots are lit and water screens on.
- Ensure that the steam generator is fully fired up.
- Inform the Radio Operator that the well is to be opened up shortly. Radio operator will ensure any boats and helicopters in the area are aware that flaring is about to commence.
- Inform the Drilling Supervisor, OIM, Toolpusher and Driller that the well is about to be opened up. Drilling Supervisor will ensure that the coast guard or other regulatory authorities are informed.
- Make a final check on the wind direction, ensure that the helideck is clear and that there are no boats adjacent to the rig.
- Confirm that all testing personnel are in position and that all non essential personnel keep clear of the drill floor and the well testing area.
- Confirm that the standby boat is upwind of the rig.
- Make a PA announcement to inform all personnel, that the well is about to be opened.

SURFACE EQUIPMENT PRESSURE TESTING **Appendix A10**

Pressure Test Procedures

General Comments

- Ensure a work permit is raised prior to any work commencing.
- Refer to Schlumberger Operational Guidelines before commencing pressure tests.
- Ensure the area is cordoned off, pressure test signs are displayed and announcements are made to warn personnel pressure testing is about to commence.
- At end of pressure testing, ensure all barriers and signs are removed. Also inform personnel via the PA system and sign off work permits.
- Record all pressure tests on a calibrated chart recorder and identify each test.
- All pressure tests should last for 15 minutes and be witnessed by an Oil & Gas Company representative and or the OIM.

Section A Surface Equipment

Section B Test String & Landing String

Section C Flow Head (Pre-Installation)

Section A

Surface Equipment

The following tests on the surface equipment, should be completed in advance of running the test string.

1.

- Confirm there are no boats underneath the burner booms, then flush the oil and gas lines to each burner with sea water. Pressure test entire system to both burners and the Schlumberger oil and gas diverter manifolds to 1000 psi.

- Close the Schlumberger gas diverter manifold valves and bleed off downstream (burner heads). Ensure the pressure remains at 1000 psi.

- Close the Schlumberger oil diverter manifold valves and bleed off downstream (burner heads). Ensure the pressure remains at 1000 psi.

- Close the Schlumberger oil manifold inlet valve and bleed of downstream. Ensure the pressure remains at 1000 psi.

- Close the separator gas outlet and bypass valve, bleed off downstream. Ensure the pressure remains at 1000 psi.

- Close the separator oil bypass and outlet valves, the water outlet valves and bleed off downstream. Ensure the pressure remains at 1000 psi.

- Note: On this test check that the separator Daniel sliding valve holds pressure.

- Close the separator inlet and bypass valves, bleed off downstream and ensure the pressure remains at 1000 psi.

2.

- Close the heat exchanger bypass and outlet valves, bleed off downstream and increase the pressure to 3000 psi.

- Close the heat exchanger inlet valve and open the downstream valve. Ensure the pressure remains at 3000 psi.

- Close the heater inlet and bypass valves. Close the choke manifold downstream valves and pressure test between the choke manifold and heater to 3000 psi.

  Note: This checks the choke manifold downstream valves from direction of flow when inspecting chokes.

3.

- Close the choke manifold downstream valves, bleed off downstream.
- Close the choke manifold upstream valves and bleed off downstream, ensure the pressure remains at 3,000 psi.
- Close ESD valve upstream of the choke manifold and bleed off downstream, ensure the pressure remains at 3,000 psi.

4.

- Fill the surge tank, hydrotesting the vessel, drain and outlet valves.
- Open the surge tank and hydrostatic test the line to the Schlumberger oil manifold.
- Pump out the surge tank after removing the burner head pressure test caps.

Section B

Test String & Landing String

1.

- Pressure test string against sump to 3,000 psi.
- Note: If hydrocarbons are in the string then only use mud or glycol/water to pressure test.
- Close Sub Sea Test Tree and bleed off pressure above to 500 psi:-
- Volume returned = ____________________ Bbls.
- Equalise pressure and open Sub Sea Test Tree, bleed off pressure to zero psi.
- Volume returned = ____________________ Bbls.

  Note: Volume returned should equal volume pumped.

- Re-apply 3,000 psi to test string and close Sub Sea Lubricator Valve, bleed off pressure above to 500 psi:-
- Volume returned = ____________________ Bbls.

- Equalise pressure and open Sub Sea Lubricator Valve, bleed off pressure above to zero psi.

  Volume returned = ____________________ Bbls.

  Note: Volume returned should equal volume pumped.

2.

- Sub Sea Lubricator Valve. Pressure test above to 3,000 psi:

  After pressure testing bleed off pressure, open Sub Sea Lubricator Valve and rig up surface test tree.

Section C

Flow Head (Surface Test Tree)

1.

- Connect test pump to the test cap below the swivel at the bottom of the tree and pressure test surface test tree body to 3,000 psi. Pressure test caps will have been installed on the other outlets.

- Bleed off pressure and open the needle valves on all three upper tests caps. Close kill, swab and flow wing valves. Pressure test these valves from below to 3,000 psi.

- Close the hydraulic master valve and open the swab valve. Pressure test from below hydraulic master valve to 3,000 psi.

- Close the manual master valve and open the hydraulic master valve. Pressure test below the manual master valve to 3,000 psi.

- Connect test pump to kill line test cap and close swab valve. Pressure test the manual master valve from above to 3,000 psi.

- Close the kill valve and open the flow wing and master valves. Pressure test the kill valve from outside to 3,000 psi.

- After the joint of tubing has been torqued onto the swivel, connect the test pump to the bottom of the tubing and pressure test against the manual master valve and TIW valve to 3,000 psi.

Note: This test ensures the integrity of the connection between swivel and tubing.

Tubing Specifications 3 ½" and 4 ½" **Appendix A11**

<u>3 ½" (Production Tubing)</u>

Body OD	3 ½"
Body Nominal ID	2.75'
Body API drift ID	2.625"
Coupling (Upset) OD	4.313"
Wall Thickness	0.375"
Nominal Pipe Body Area	3.68sq"
Make up loss	3.236"
Grade	L-80
Weight	12.95 ppf
Connection	R2 TS-HD
(Interchangeable with 3 ½" Hydril PH- 6 connection)	
Collapse Pressure (minimum)	15,310 psi
Burst Pressure (minimum)	15,000 psi
Minimum Yield Strength	80,000 psi
Minimum Yield Load	294,500 lbs
Torque (min - max)	5400 - 6000 ft/lbs

<u>4 ½" (Landing String)</u>

Body OD	4 ½"
Body Nominal ID	3.958"
Body API Drift ID	3.833"
Coupling (Upset) OD	4.920"
Nominal Pipe Body Area	3.6 sq"
Make up loss	2.88"
Grade	C-95
Weight	12.75 ppf
Connection	R2 AB STC
(Interchangeable with 4 ½" Hydril CS connection)	
Collapse Pressure (Approx.)	8,100 psi
Burst Pressure (Approx.)	10,000 psi
Minimum Yield Strength	95,000 psi
Minimum Yield Load	342,000 lbs
Torque (min-max)	4,500 - 5625 ft/lbs

Dewaxing of the Tubing String with Coil Tubing (Contingency) **Appendix A12**

The following is an procedure for a contingent dewaxing of the tubing string using a Dowell Schlumberger 1 ½" coil tubing unit with a coil tubing lifting frame for floating rigs.

The coil tubing lifting frame will have been rigged up as a contingency before commencing the test. The CTU (coil tubing unit) and ancillary equipment will either be on standby in the shore base or held offshore on a supply boat along side the rig, depending on the potential for wax related problems, which will have been determined from the MDT samples.

Preparation

- Hold safety meeting – Oil & Gas Company personnel, Dowell, Schlumberger Wireline & Testing and Drilling Contractor.
- Spot equipment (CT reel as close as possible to the rig floor).
- Hook up and test all hydraulic hoses from the power pack.
- Function test BOP's, Injector and reel. Rig up recording system CTSI.
- Rig up coil tubing BOP's and treating lines.
- Pressure test all equipment initially to 250 psi.
- Pressure test treating lines to 50 % above the maximum expected working pressure during the job.
- Pressure test blind rams to 3000 psi . Pressure test BOP body to 3000 psi.
- Pressure test the swab valve on the flow head to 3000 psi.
- Pressure test kill line and valves to 5000 psi.
- Function test the hydraulic actuators for blind, shear and annular BOP's

Pressure Testing the CT reel, Pipe Rams and Stripper

- Install CT pipe into the injector chains, apply a minimum 300 psi skate pressure.
- Install check valve and pump water through it.
- Install CT, BHA consisting of a set screw connector, dual flapper check valve, hydraulic disconnect and a nozzle head.
- Connect the injector head to the BOP's, set weight indicator and depth counter at zero.
- Open pipe rams, pressure equalising valve, close the kill port isolation valve and circulate slowly to make sure the equalising valve is not blocked.
- Retract all strippers. Pump slowly until fluid leaks past the strippers and stop pumping
- Close the pressure equalising valve.
- Pump slowly through the CT and pressure test the pipe rams to 3000 psi.
- Energise the upper stripper to a minimum pressure of 500 psi, open the pipe rams the equalising valve and test the upper stripper to 3000 psi.
- Close the pipe rams and equalising valve.
- Release pressure to 1500 psi through the flow head and the choke.
- Bleed off pressure to zero inside CT to make sure that the check valve holds 1500 psi.
- Bleed of all remaining test pressure from the flow head. Before opening the well close all chokes and kill port valves and pressure up stripper to 150 psi.

Dewaxing of the Tubing String with Coil Tubing (Contingency) **Appendix A12**

Dewaxing Operation

- Check well head pressure, equalise across the master valve as necessary and open the valve.
- RIH coil tubing at 10 ft/min, while pumping solvent at 1.0 bpm
- RIH CT and pull test every 50 ft, check returns constantly, if wax is severe (indications would be a decrease in weight on weight indicator and poor returns to surface) stop running in the hole with CT and continue circulating solvent at 1.0 bpm.
- Continue RIH as before pumping solvent at 1.0 bpm to +/- 500' below the mud line or until there is no evidence of waxy deposits returning to surface
- POOH CT, flush lines with water.
- When CT is above the master valve, close the valve and bleed off surface pressure
- Rig down equipment.

Note: Returns from the well should be taken to a Dowell tank and if the constituency is such that the returns could easily be burned then pump out the tank to the burners. Otherwise the tanks and their contents will be back loaded and contents disposed of in accordance with local procedures.

The composition of the solvent used will depend on the severity of any wax problem. The formulation will be determined on site by testing the ability of various compositions of solvents to break down the wax. However the formulation is likely to consist of Dowell Mutual Solvent U66, Paran P121 Solvent mixed with base oil and demulsifier.

The solvents are both flammable and pose a risk to health.

Refer to the Dowell Material Safety Data Sheets for handling and storage.

APPENDIX J

TESTING & RELATED SERVICES CONTRACTORS WEB SITES

There is a large amount of information on testing equipment and related products and services available via the contractors web site pages. For those working in remote areas with web access this can be an excellent source of up to date information.

The web site addresses are as follows:

Halliburton:
www.halliburton.com

Expro
www.expro.co.uk

Schlumberger:
www.connect.slb.com

Baker Hughes
www.bakerhughes.com

NOWSCO
www.nowsco.com

BJ Services Company
www.bjservices.com

ENGINEERING CONSULTANTS

Esprit Petroleum Technology Ltd.
Tel: +44 1475 639030
Fax: +44 1475 659261
E-mail ept@globalnet.co.uk
Contact: Stuart A. McAleese

APPENDIX K

SIMULATOR PRODUCTS

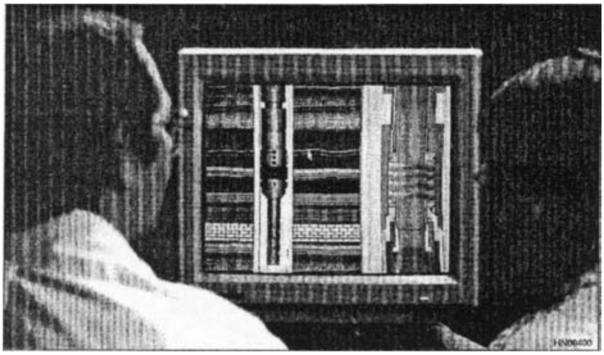
A range of visualisation and simulation products are now available for downhole tools and sub sea or ocean floor equipment.

These products available on CD ROM from the service providers, allows detailed examination of the operation of the tools. However, some of the products go further than merely visualisation and they allow the user the opportunity to see how the various combinations of tools interact with each other under differing pressure and temperature conditions.

Refer to the product information on Halliburtons Global Simulator and Simulator Lite.

HALLIBURTON

Simulator Products



Global Simulator

The Halliburton Simulator products let you run simulations of individual Halliburton tools and simulate how multiple tools interact in a well environment. Some of the products are meant primarily as visualization tools; others are scientifically accurate, true-to-life simulations—analysis tools. Together, they represent the industry's premier simulation and learning tools.

Simulator Products include:

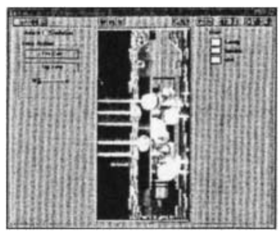
- Simulator Lite, a training tool that helps operators visualize and better understand the operation of individual tools. This is a CD-ROM-based product that will work on any multimedia equipped PC.
- Tool Simulator, an internal planning tool that Halliburton uses to plan and setup well testing strategies for customers.
- Global Simulator, an advanced simulation tool that enables Halliburton employees to see how multiple testing tools interact in a well environment.

Features and Benefits

- Intuitive interfaces are easy to use.
- Drag-and-drop functionality makes arranging test strings easy.
- Realistic simulations duplicate pressure, loads, temperature and sound.

Simulator Lite

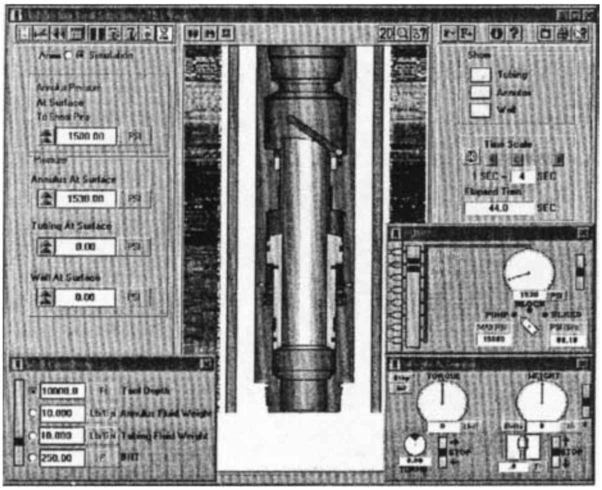
- Just double-click the SimLite object to see the SimLite screen.
- Push the buttons under "Show Actions" to see how the tool works.
- Click on the double back-arrows to reset the animation.
- Click under "Show" to turn color zones on and off.
- Click on the binoculars to make the tool larger or smaller on the screen.
- To move the tool around, hold down the mouse button while on the tool and move it.



Simulator Lite Animation

Simulations Show How Well Testing Tools Interact In Your Well Environment

Appendix K
Figure 1.0



Tool Simulator Screen

Tools/Global Simulator

The simulator analysis engine used in the Halliburton Simulator and Global Simulator keeps track of down hole pressures, externally applied loads from the surface, and hydrostatic forces between all tools. Drag-and-drop functionality allows operators to apply pressure and forces at will.

Applications

- Pre-job, the Halliburton Simulator and Global Simulator enable better planning so there are fewer surprises on the job.
- On the job, they provide real-time feedback, giving technical advice on every factor.
- Post-job, they make review and analysis more accurate and faster.

HALLIBURTON®

Appendix K
Figure 1.0 (cont)

INDEX

Z

Printed in the United Kingdom
by Lightning Source UK Ltd.
117107UKS00001B/23

9 780444 503114