641001 See file Thylacine-2 letter 10/9/01

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AUSTRALIAN ENERGY

WOODSIDE ENERGY LTD

WELL TEST PROGRAMME

Thylacine 2

T/30P

Rev 0

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PROGRAMME ADDENDA

Thylacine 2 has been designed as an exploration/appraisal well and, as such, subject to uncertainties which become resolved as data is gathered during drilling/logging operations. In light of this the well test programme has been written with certain issues **" to be advised"**, and will be used as a base document.

Thus, a separate addendum to the programme will be issued prior to testing operations commencing, to address outstanding issues (eg number of zones to test, perforation intervals, perforation gun type, sequence of operations etc).

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1 Introduction

1.1 General

The enclosed well test programme is specific to Thylacine 2 exploration well. This programme has two primary objectives:

1. To facilitate the rapid preparation of any **required final test programme and addenda** , once logs become available, and the decision to test has been made.

2. **To serve as a reference document,** for operational sequences and safe working practices.

Thylacine 2 is prognosed to intersect the primary objective of the Flaxman and Upper Waare Formations at 2177m TVRT (top of Flaxman). If successful, there is a possibility of a single or dual zone test within the gas column. This is the basis by which the well test operation has been planned whilst maintaining the flexibility required to account for any additional test scenarios.

1.2 Reference. Documents and Procedures

The following Documents are to be utilised to enable the safe drilling/testing of Thylacine 2,

Thylacine 2 - Well Design Workbook Doc.
Thylacine 2 - Safety Case Bridging Document – Ocean Bounty A6000RF 130379
Thylacine 2 - Environmental Assessment ENV-538
Thylacine 2 – Well Specific Guidelines

WEL OHSE Manual – WO209
MODU Emergency Response Plan ERP-2800

Production Test Guidelines for Exploration and Appraisal Wells Woodside Energy Limited Document No. A1170SD002 (Rev.2)

Well Test Design Report, Thylacine 2, Schlumberger (Job No. 2001-015)

Statutory regulations that apply for this programme:

- Petroleum Submerged Lands Act - Schedule, Specific Requirements as to Offshore Petroleum Exploration and Production - 1995.
- Occupational Health and Safety Regulations.

1.3 Personnel and Responsibilities

The OCEAN BOUNTY OIM has the ultimate responsibility for the health and safety of all persons on board, and for the good practice and security of the installation. The OIM appoints a number of competent persons who are responsible for the control and safety of operations specific to their field of expertise. In all drilling matters, including well testing operations, the WEL Well Site Manager and the OCEAN BOUNTY Rig Superintendent are the appointed competent persons.

The WEL Well Site Manager is the senior authority offshore responsible for carrying out the Well Testing Programme in a safe and sound manner. For ensuring that the well testing operations are performed by DIAMOND OFFSHORE and the individual Service Companies in accordance with the agreed procedures, any regulations imposed by the authorities and any relevant industry codes and standards.

To assist the WEL Well Site Manager, the responsibility for specific aspects of the Well Testing Programme will be delegated to the on-site EGIS Well Test Engineer. However, overall responsibility for the Well Testing Programme will be retained by the WEL Well Site Manager.

The EGIS Well Test Engineer will report to the WEL Well Site Manager offshore whilst supervising the individual Service Companies involved in the well testing operations, and will provide technical support to the WEL Well Site Manager.

The EGIS Well Test Engineer has individual responsibility to monitor the quality of data being gathered, and to advise on the behaviour of the well being tested. The EGIS Well Test Engineer will independently advise the Woodside Well Test Focal Point (Well Site Manager) on the progress of the well testing operations.

The WEL Reservoir Engineer will analyse the test data to assess the performance and properties of the reservoir. Make recommendations on duration of flow and shut in periods and consult with the WEL office onshore.

The WEL Reservoir Engineer will liaise with the EGIS Well Test Engineer and make recommendations as to alternative approaches should the test data be insufficient to adequately evaluate the reservoir

Prior to the commencement of any new operations the WEL Well Site Manager and the Well Test Engineer will conduct a safety and operations briefing.

Refer also to Appendix A and Figure 1 for further details relating to responsibilities

1.4 Health, Safety and Environment

Woodside Energy Limited (WEL) expects the commitment of all service companies to uphold the highest standards of health, safety and environmental practice.

The testing operation shall be carried out safely and efficiently with special consideration for:

Safety Perform testing operations without injury or incident.

Environment Maximise burner efficiency to eliminate pollution due to incomplete combustion or spillage of produced fluids.

All work carried out under this programme will be carried out under the DIAMOND OFFSHORE Permit To Work System.

The well may be opened during darkness if an MDT sample and accurate reservoir pressures have been obtained and approval is given by the MODU Team Leader.

Fluid samples shall have been checked for the presence of H_2S and CO_2, critical reservoir parameters and fluid characteristics identified.

In the event that during testing instream Hydrogen Sulphide (H_2S) levels above 50 ppm are detected in the gas phase, or above 10 ppm detected in air, the well shall be shut in and the situation assessed with consideration for terminating testing operations. WEL does not condone conducting well testing operations in a "sour gas" environment without the installation of suitable breathing apparatus and training personnel in it's use prior to commencing well testing. **Refer to Section 19 of the DOGs and Section 14 of the PTGs.**

1.5 Operating Practices

Well Testing operations will be carried out in accordance with the Woodside **"Production Test Guidelines for Exploration and Appraisal Wells (Rev.2)"**. All well testing equipment will be operated as set out in the individual Service Company Field Operating procedures.

If a conflict arises between the WEL, DIAMOND OFFSHORE, or Service Company procedures, this should be resolved by relevant onshore management, and the proposed course of action approved by the WEL Well Site Manager and DIAMOND OFFSHORE OIM.

If a non-standard operation is required (i.e. one that is not covered in existing WEL, DIAMOND OFFSHORE, or Service Company procedures), an on-site risk assessment must be carried out and a set of written procedures agreed by all relevant parties. The proposed course of action should be fully discussed with the WEL Well Site Manager and DIAMOND OFFSHORE OIM and their approval given prior to the operation commencing.

Additionally, JHA's will be carried out prior to the commencement of any critical operations.

1.6 Changes to the Well Testing Programme

The Well Testing Programme will be agreed prior to commencing testing operations. If, during the test, a significant change to the Well Testing Programme is required, a revision will be approved by the MODU Team Leader. Minor procedural variations, such as may be required to enhance safety of operations, may be initiated offshore.

Once agreed, the amendments to the Well Testing Programme shall be put in writing and signed off by the MODU Team Leader. Amendments will be numbered sequentially, and passed to the rig for inclusion in the Well Testing Programme.

2 Safety When Testing

2.1 General

The OIM is in overall command of the OCEAN BOUNTY and has primary responsibility for rig and personnel safety. Prior to the test a general safety meeting will be held and will cover the following:

- Pressure testing
- Wireline operations
- Communications
- Perforating
- ESD Procedures
- Fire Prevention
- H_2S

JHA's will be carried out prior to the commencement of each critical operation.

Note: Prior to opening the well up to flow, the WEL Well Site Manager, Well Test Engineer, OCEAN BOUNTY Rig Superintendent and Well Testing Crew Chief will inspect all surface lines and well testing equipment. This should be done well in advance to allow any corrections to be made.

2.2 Fire Fighting Equipment

OCEAN BOUNTY fire fighting systems shall be active in the vicinity of the surface test equipment and burners. Portable foam extinguishers shall be available in the vicinity of the surface testing equipment.

The fire fighting team shall be equipped for hydrocarbon fire fighting and equipped with dedicated BA's. Fire fighting drills for the testing area shall be incorporated in the weekly emergency drills prior to, and during, the well test operation.

2.3 Personnel Safety

All shifts shall be briefed on general well testing procedures, equipment involved and its basic operation by the Well Test Engineer. The shifts should be walked around the testing equipment for familiarisation. All key personnel (OIM, Rig Superintendent, Well Site Manager etc.) shall be briefed on the equipment and their responsibilities during testing

Contractors involved in testing operations shall be briefed on Operator and Drilling contractor testing policies.

2.4 ESD's and Subsea Testing Valves

A drawing and location advice of all ESD devices shall be displayed in prominent locations (Drill Floor, Testing Area, Muster/Emergency Response Points etc.). A Status board on the rig floor will show the status of all valves from the testing choke manifold, Surface Tree, SSTT and downhole valves at all times during testing operations. It is the responsibility of the Driller, Well Test Engineer and the DST Operator to ensure the status board is updated after every valve operation.

A Schlumberger DST and SSTT Operator will be present on the rig floor at all times.

Prior to the well being brought on-stream the ESD system will be function tested (witnessed by the well test supervisor, OIM and Well Site Manager).

2.5 Emergency Muster, Fire, H_2S, and Abandonment Drills

These drills shall be exercised prior to the commencement of the production test.

2.6 Line Failures or Ruptures

Details of the main actions to be taken for the three major failure categories are contained in **Appendix B** of this programme, Production Testing Hazard Identification.

2.7 Emergency Procedures in the Event of Bad Weather

Well testing operations will be suspended if :

- The OIM, Well Site Manager or Rig Superintendent onboard consider that weather conditions are or will become unsatisfactory.
- Conditions on the rig floor are considered unsafe
- Heave is approaching equipment clearances on the drill floor (ca. 3-4 mtrs at high tide).
- Warning of severe storm.

In the event of weather preventing testing - there will be three distinct phases of suspension of operations:

- Suspend testing operations and make the well safe.
- Disconnect and recover the upper section of the test string.
- Pull and lay down the Marine Riser and LMRP.

The decision as to what particular suspension phase is applicable will be taken by the OIM and the Well Site Manager in consultation with the WEL Drilling Superintendent.

Refer also to Appendix F for sub sea test tree disconnect procedures

2.8 Vessel Collision Risk

Section 2.6 of the **Well Specific Guidelines** details the **Emergency Response Actions** if a risk of collision exists with an approaching vessel.

During Well Testing Operations the following details the procedure required and supersedes Sec. 2.6 of the WSG in this case:

If risk of collision exists and attempts to contact the approaching vessel by the stand-by vessel have been unsuccessful, further more frequent attempts to establish radio contact with the target shall be made by the stand-by vessel at a range to 12nm. To assist the target vessel in identifying itself, the rigs range and bearing from the target vessel is to be conveyed in radio transmissions.

If contact with the target vessel is not achieved by the time the range has decreased to 10nm, the stand-by vessel is to mobilise and proceed toward the target whilst continuing attempts to establish radio contact. The stand-by vessel must inform the rig when under way and must inform the rig of the size and type of vessel as soon as a clear description is possible.

If still no contact can be made with the on coming vessel the rig shall close the down hole tester valve **(PCT)** and the **Sub Sea Test Tree valve (SSTT)** and bleed off any hydrocarbons between the sub sea tree and surface.

The support vessel must inform the rig immediately if it is unable to divert the course of the oncoming vessel. Once it is clear that collision is imminent, the OIM shall consider unlatching at the sub sea test tree and disconnecting the LMRP from the BOP stack and using the anchor windlass emergency release system to move the rig out of the path of the vessel. Subsequently the OIM should consider evacuation.

In the event of a collision or evacuation, the stand by vessel will remain clear of the rig and prepare to assist with recovery of rig and vessel personnel.

2.9 Additional Safety Guidelines

The standby vessel will be stationed upwind of the rig and be prepared to provide immediate assistance as required. Standby vessel crews should be drilled in the correct standby and support procedures.

Confirm that gas detection equipment is operational and properly calibrated.

Ensure that the air compressors are fitted with spark arresters and emergency shut down systems are operational.

Schlumberger (for TCP operations and for electric line operations) procedures for handling explosives will be strictly adhered to.

Ground all production vessels **and sampling containers** to avoid static electricity ignition sources.

Pressure testing will be conducted in compliance with the Permit To Work system. Pressure testing areas will be cordoned off and non essential personnel warned to stay clear.

Assign personnel to tour the testing areas with gas detectors, and deploy breathing apparatus with procedures to follow if there is evidence of H_2S.

All doors, hatches and vents in the vicinity of the test equipment will be closed for the duration of the test.

Working on burner booms is covered under the Permit To Work system and it should be emphasised that work vests must be used when working on the booms.

Cranes will not be operated in the test area when the well is open to flow. Limited crane operations will be permitted during shut in periods at the discretion of the WEL Well Site Manager and the DIAMOND OFFSHORE OIM.

Perforating guns or wireline set packers will not be armed until radio silence has been imposed and the radio operator has notified the standby boat and shorebase.
NB. The above does not apply to mechanically or hydraulically fired guns.

Do not remove explosives from the magazine during electrical storms.

Preparation of perforating gun assemblies and wireline set production packers will be performed under the Permit To Work system. The work area will be cordoned off and all unnecessary personnel will vacate the area while perforating guns or packers are armed.

Prior to perforating an announcement **will be** made over the intercom that well testing is about to commence.

The radio room to be manned at all times during testing operations.

Non-essential personnel will keep clear of the rig floor and the test equipment areas during well testing operations.

The cement unit shall be connected to the kill line on the Surface Test Tree (STT) and be ready to start pumping immediately, if required.

Either the driller, the rig superintendent or the toolpusher must be on the rig floor at all times during flow and shut in periods.

Cordon off the area between the 'V' door and the wireline unit during slickline operations.

3 Objectives and General Well Data

3.1 Well and Test Objectives

The primary objective of testing Thylacine 2 is to is to demonstrate the presence of moveable hydrocarbons that can be produced at commercial rates.

Primary Objective Zone is the Flaxman and Upper Waare formations in the Thylacine structure.

As far as practical and at reasonable cost, data for determining reservoir and fluid properties will be acquired, therefore, the test program will attempt to meet the following objectives:

Primary Target

Technical Objectives:

- Determine well deliverability – permeability and skin (inflow performance)
- Obtain representative reservoir fluid samples for PVT analysis for CGR and Dew point determination
- Monitor produced fluid for H_2S, CO_2 and sand production.
- Measure reservoir pressure and reservoir temperature.

Practical Objectives:

- Conduct the test in a safe and efficient manner without placing personnel or equipment at unnecessary risk.
- To conduct the test without spillage of Hydrocarbon to the Environment and without any uncontrolled release of Hydrocarbons.
- Meet the technical objectives of the test.

3.2 Well Data Summary

Rig	OCEAN BOUNTY
Well Type	Appraisal
Drilling Datum	Drill Floor
Drill Floor Elevation	25 m above MSL
Water Depth	~ 101 m LAT
Total Depth	~ 2525m TVRT (+/- 30m)
Primary Objective	Flaxman and Upper Waare formations

3.3 Planned Casing Depths

30"x 20" Casing	184m TVRT
13-3/8" Casing	551m TVRT
9-5/8" Casing	2101m TVRT
7" Liner	~ 1950 - 2520m TVRT

3.4 9 5/8" Production Casing

9 5/8" 47 ppf L80 New Vam			
API Burst	6860 psi	(47.3 MPa)	
API Collapse	4757 psi	(32.8 MPa)	
API Yield	1,086,000 lbs	(493,600 kgs)	
Drift	8.525"	(216.5 mm)	
ID	8.681"	(220.5mm)	
Makeup Torque	Min	Opt	Max
Ft-lbs	13,050	14,450	15,850

3.5 7" Production Liner

7" 29ppf L80 13 Cr Vam Top			
API Burst	8160 psi	(56.3 MPa)	
API Collapse	7020 psi	(48.4 MPa)	
API Yield	676,000 lbs	(307,272 kgs)	
Drift	6.059"	(153.89 mm)	
ID	6.184"	(157.07mm)	
Makeup Torque	Min	Opt	Max
Ft-lbs	8,460	9,400	10,340

3.6 Production Tubing

Main Test String

3.5", 12.95 ppf, L80 PH6,			
API Burst	15,000 psi (103.3 Mpa)		
API Collapse	15,310 psi (105.5 Mpa)		
API Yield	294,530 lbs (133,887 kgs)		
Drift	2.625" (66.67 mm)		
ID	2.750" (88.90 mm)		
Makeup Torque	Min	Opt	Max
Ft-lbs	5,500	6,188	6,875

Landing String

4.5", 15.5 ppf, L80 PH6,			
API Burst	10,480 psi (72.31 Mpa)		
API Collapse	11,090psi (76.45 Mpa)		
API Yield	353,000 lbs (160,400 kgs)		
Drift	3.701" (94.01 mm)		
ID	3.826" (97.18 mm)		
Makeup Torque	Min	Opt	Max
Ft-lbs	6,000	6,750	7,500

4 Well Test Design and Operations Summary

4.1 Test Design

The test design assumes there will be a test in the 7" liner on the primary target, the Flaxman sands. In addition, the design also accounts for a contingency test on the secondary objective, the Upper Waare sands. This contingency will be performed in the event there is poor performance from the primary objective. in this case, production from the secondary objective will be commingled with the primary target.

A Schlumberger HP packer and seal bore extension carrying 4.5" TCP guns will be set in the 7" liner. The TCP guns will be positioned across the primary zone of interest. A gun drop sub will allow wire line conveyed guns to be run as a contingency in case of TCP failure or, if additional perforations are required.

The major test string will utilise 3-1/2" PH6 12.95ppf L80 tubing and the landing string will comprise of 4-1/2" PH6 15.5ppf L80 tubing. The string will be attached to the HP packer via a floating seal mandrel assembly.

Features of the test string design will therefore include :

- A production packer run with the test string will be used to isolate the annulus from the reservoir.
- Tubing Conveyed Perforating (TCP) with 4-1/2" OD guns using 34JL Ultrajet HMX charges at 12 spf.
- Reservoir pressure data acquisition will be from six quartz crystal memory gauges (WTQR) located in a LDCA/DGA upper gauge carrier above the tester valve and a DGA lower gauge carrier below the tester valve. The upper carrier will be ported so that three gauges measure pressure from below the tester valve. In addition, and if required the gauges in the upper carrier can be interrogated or re-programmed with the use of a wire line conveyed data latch tool.
- Surface read out (real time down hole data acquisition) is not planned but is an option to enable re-programming of the gauges in the event of bad weather, other causes of considerable delay, or if the reservoir response is such that well shut in time required is uncertain.
- Predominantly annulus pressure-operated Drill Stem Test (DST) tools.
- The tester valve (PCT) will incorporate a "hold open" feature to provide additional versatility.
- The circulating valve (MCCV) will be the primary method of circulating with system redundancy provided by a single-shot rupture disc circulating valve (SHRV). In addition, a below packer circulating valve (BPCV) is available for reverse circulating the string at the end of the test.
- A TFTV flapper type tubing fill tester valve will be used to pressure test the string against and then locked open for the remainder of the test.
- Testing will take place in the 7" liner.
- Diesel will be used as a cushion in the DST string to create the required underbalance prior to perforating.

4.2 Expected Reservoir Parameters

	Primary	Secondary
Describe Test Objectives:	Flaxman Formation	Upper Waarre Formation
Anticipated interval:	Ca. 50m	Ca. 10m
Anticipated depth:	2152m tvss	2257m tvss
Type of Test:	Multirate	Multirate
Stimulation required and type:	No	No
PLT required:	TBA	No
Other Logging (eg TDT, gradient survey):	No	No
Test Cushion:	Diesel	
Fluid Type:	Gas	Gas
Expected Reservoir pressure:	3315 psia	3345 psia
Expected Reservoir temperature:	97° C	102° C
Max. anticipated surface pressure:	2750 psia	2750 psia
Max. expected oil flow rate:	N/a	N/a
Max. expected gas flow rate:	20 MMscf/d	30 - 35 MMscf/d
Expected GOR/CGR:	5-10 bbl/MMscf CGR	5-10 bbl/MMscf CGR
GOC/GWC/OWC:	2304 mss GWC	2304 mss GWC
Expected Permeability:	50-500 mD	200-2000 mD
Expected bubble pt. / dew point pressure:	2250 psia	2250 psia
H_2S Expected:	No	No
CO_2 Expected:	Yes	Yes
Hydrates Expected:	Possible	Possible
Wax/Asphaltenes:	No	No

4.3 Tubing Stress Analysis

A triaxial tubing stress analysis was carried out for the following cases:

- Pressure test against downhole tester valve (PCT) 5000 psi (34.5 Mpa), 0 psi on annulus.
- Producing at 35 MMscf/day (991,200 m^3/d), 216 °F (102° C) BHT, 1500psi (10.34 mpa) on annulus).
- Down Hole shut in 0 psi on annulus at surface.
- Shear SHRV Reversing Valve 4000 psi (27.6 Mpa) on annulus, with zero psi THP.
- Cold Kill 5000 psi (34.5 Mpa) surface pressure.
- Overpull 50,000 lbs (22,727 kgs) zero psi on annulus

In all cases both the landing string and production string have safety factors exceeding 1.6, 1.33, 1.25 & 1.33 for axial, burst, collapse and tri-axial.

4.4 Perforations

The perforation interval **To Be Advised**

Maximum total perforation interval expected to be ca. 50 m in the Flaxman Formation

Reference Log: Thylacine 2, **To Be Advised.**

4.5 Test Procedure Summary

The test string will be displaced to diesel in the first instance to create an underbalance to the reservoir and the TCP guns will be activated using a HDF (time delayed) firing head hydraulically actuated.

Following this, the main well test period will commence which will probably consist of:

- An initial "pre flow" period to the gauge tank of 10 mins. Followed by a 1 hour shut in period to determine initial reservoir pressure.
- A clean up flow period up to max. rate at stable wellhead and separator conditions.
- Initial Down Hole shut in period
- Combined "Flow after flow" and Main flow period, comprising of 3 increasing flow periods of: 30%, 60% and 90% of maximum achieved. The first of these flow periods will also be the Sampling Flow period at the lower rate and lower draw down, during which PVT fluid samples are to be taken from the Schlumberger separator and IWSS manifold.
- Final Down Hole shut in period

4.6 Flow and Build Up Regime Table.

Flow / Build Up Period	Duration	Choke Size / Remarks
Preflow and Initial Shut In period	1 hr	
Clean Up Flow	6 hrs	To Be Determined Onsite
Shut In	6 hrs	n/a
1st Flow after Flow – incl. Sampling period.	4 – 6 hrs	To Be Determined Onsite
2nd Flow after Flow	4 hrs	To Be Determined Onsite
3rd Flow after Flow	4 hrs	To Be Determined Onsite
Shut In	12 hrs	n/a

**Variations to the choke sizes and the duration of flow and build up periods will be determined as testing operations progress and are dependent on well performance.

4.7 Sampling

The majority of reservoir fluid samples (PVT) will be collected during the 'Sampling' Flow period. Samples are to be collected after the flow has stabilized through the separator for 1 hour. Minimum sample requirement during this period is 3 sets of PVT recombination samples from the Iso Kinetic manifold facility (IWSS) and 3 sets of PVT recombination samples from the test separator.

Note: A Field Fluid Analysis (FFA) kit will be onsite for analysis of condensate samples to determine that there is no diesel contamination of the condensate prior to obtaining the PVT samples etc.

4.8 Summary of Equipment/Contractors

Equipment Type	Contractor	Equipment Description
Production Packer	Schlumberger	2 X Model HP packers with seal bore extensions.
Perforating guns TCP	Schlumberger	50m 4-1/2" 12 spf, HMX 34JL UJ TCP guns TCP Gun running string
Perforating guns W/L:	Schlumberger	60m 2-1/8" phased enerjet guns Pressure Control Package
Downhole Tools :	Schlumberger	10,000 psi (68.9 Mpa), 2.25" DST tools
Gauges :	Schlumberger	WTQR/WCQR Quartz memory gauges, 200,000 data sets.
Logging :	Schlumberger	CBL/VDL FOR 7" Liner Gauge ring and junk basket for 7" 29lb Liner
Surface Read Out	Schlumberger	LINC / LDCA
Surface Sampling :	Schlumberger	Separator PVT sampling Kit Iso Kinetic PVT sample kit FFA package
Tubulars :	PCS	3-1/2" 12.5 ppf L80 PH6 tubing 4-1/2" 15.5 ppf L80 PH6 tubing
Tubular handling:	Weatherford.	2-7/8",3.5" & 4.5" Slips, SJE, Elevators, Drifts, Stabbing Guides, Safety Clamps
Surface / Subsea :	Schlumberger	3" Subsea equipment. Standard surface well testing package
Surface Data Acquisition:	Schlumberger	STAN data acquisition system
Slickline:	Schlumberger	0.108 Slickline Unit Wireline Tools container and Workshop

5 Test Outline

The following is a step by step outline of the testing programme.

5.1 Well Preparation

- Run and cement 7" Casing . Pressure test prodn casing/liner to 4000 psi. Include short joints above and below reservoir and install a RA pip tag at a depth that can be logged.
- Displace well to brine (S.G. of brine to give 200 psi overbalance at reservoir)
- Pressure test BOP's. (Dimension check ram space out with BOP test)
- Perform a SSTT dummy run.
- Make up single to surface test tree.
- Run cement evaluation logging tools c/w GR/CCL/Gauge Ring Junk Basket in the casing across zone(s) of interest. Review perforation of well test zone based on cement logging tool results.

5.2 Run Test String

- Make up, 4 ½" TCP guns.
- Make up and run test tools BHA with HP Packer and integral seal assembly
- Pressure test BHA
- Run in hole with lower test string
- Run in hole landing string with sub sea tree assy and sub sea lubricator valve.
- Run slim hole GR/CCL to correlate TCP gun depth.
- Make up surface test tree, flow and kill lines
- Pressure test string against TFTV and inflow test sub sea test tree and lubricator valve
- Space out hanger to put guns on depth
- Pressure up annulus, set packer and lock open TFTV.
- Land hanger in wellhead.
- Shear PORT and cycle PCT out of hold open to closed position
- Function test ESD system.

5.3 Production Test

- Cycle MCCV valve to circulating position
- Circulate diesel cushion into string.
- Cycle MCCV valve to well test position
- Pressure up annulus and place tester valve in unlock/failsafe mode.
- Pressure up tubing to activate firing head.
- Bleed back tubing pressure to obtain the correct underbalance during HDF time delay period.
- Perforate.
- Flow the well for a 10 min. "preflow" period.
- Shut in down hole for initial build up period of 1 hr to obtain a reference reservoir pressure.
- Flow the well for clean up period – up to maximum rate.
- Shut in down hole for build up period.
- Flow the well for the first "flow after flow" period at 30% of maximum.
- Take 3 matched sets of PVT samples from the test separator and Iso Kinetic sampling manifold during the first period – flow rate to ensure draw down is not below Dew point – but sufficient to avoid liquid loading in the tubing.
- Continue "flow after flow" period for 2 further rates of 60 and 90% of maximum flow.

- Shut in the well for down hole period.

Depending on well productivity and performance – The following sections 5.5, 5.6, and 5.7 are provisional.

5.4 PLT Survey (to be confirmed)

- *Rig up slickline and drop TCP guns (if Auto drop sub has not been used)*
- Rig up Schlumberger ELS BOPs and lubricator and install PLT tools
- RIH and make static passes in the 7" liner
- Flow well and allow to stabilise
- Make flowing passes
- Shut in well at surface and POH with PLT string
- R/down PLT tools

5.5 Perforation of Additional Zone *(to be confirmed)*

- Make up Schlumberger 2-1/8" phased enerjet guns
- RIH and correlate to depth
- Perforate
- POH with spent guns
- Lay out spent gun
- Repeat as required to perforate total planned interval

5.6 Commingled Production Test *(to be confirmed)*

- Flow and build up sequence will be dependent on well performance

5.7 Kill Well and Pull String

- Lock open tester valve
- Bullhead kill well with ca.10 bbls of kill mud ahead of brine
- Flow check annulus and tubing
- Open BPCV and reverse circulate until even density brine all round.
- Flow check
- POOH with test string

6 Equipment Preparation and Pressure Testing Operations

In general all surface equipment shall be pressure tested as per Schlumberger procedures and witnessed by the Well Test Engineer. Subsea equipment will be drifted, function and pressure tested according to Schlumberger procedures, and witnessed by the Well Test Engineer. DST equipment will be drifted, function and pressure tested according to Schlumberger procedures, and witnessed by the Well Test Engineer.

Pressure test records will be maintained by the EGIS Well Test Engineer

Note: *Permit to work will be required for all pressure testing on deck with a written procedure attached to the permit.*

6.1 Drilling BOP Preparation

The BOP's shall have a full pressure test prior to the start of production testing operations.

6.2 Tubing Preparation

3-1/2" 12.5 ppf L80 PH6 and 4-1/2" 15.5 ppf L80 PH6 Main Test/Landing String

The tubing, shall be laid out, tallied, numbered and drifted with an API drift 2.625" (3 ½" PH6 Tubing) and 3.701" (4 ½" PH6 Tubing)). The connections will be cleaned and inspected. Each connection shall be re-doped with API modified thread compound and fitted with clean protectors (Note: Detailed inspection and internal water blasting as required will have been performed onshore prior to shipping the tubing).
Refer to Appendix C - tubing handling procedures

6.3 Sub Sea Test Tree Preparation

- All pressure tests to be recorded on a chart recorder.
- Function test the valve.
- Pressure test the valve on deck to 5,000 psig (34.5 mpa) from below.
- With the valve open pressure test the body to 5,000 psig (34.5 mpa)
- Function test unlatch mechanism.
- Drift the made up SSTT assembly

6.4 Sub Sea Lubricator Valve Preparation

- All pressure tests to be recorded on a chart recorder.
- With the valve open pressure test the body to 5,000 psig (34.5 mpa)
- Function test the valve.
- Pressure test the valve on deck from above and below to 5,000 psig (34.5 mpa)
- Drift the made up SSLV assembly

6.5 Surface Test Tree Preparation

- All pressure tests to be recorded on a chart recorder.
- Pressure is to be bled off between each test.
- Check all service breaks. Paint a white line through the swivel connections and attach end cap and lift sub.

- Function test the hydraulic wing valve.
- With all valves open, pressure test the tree body to 5,000 psig (34.5 mpa).
- Close the SWAB, KILL & WING valves. Pressure test valves 5,000 psig (34.5 mpa).Open KILL, WING and SWAB valves. Close MASTER valve and pressure test from below to 5,000 psig (34.5 mpa)
- Open KILL Valve. Connect test line to KILL wing and pressure test MASTER valve from above to 5,000 psig (34.5 mpa).
- Open MASTER valve and close KILL wing valve. Pressure test KILL wing from above to 5,000 psig (34.5 mpa)
- On completion of tree pressure testing all valves should be left OPEN and the tree should be drifted with a 2.875 inch drift.
- After a joint of tubing has been torqued up to surface tree assembly, connect test pump to the bottom of the tubing and pressure test against the MASTER valve to 5,000 psig (34.5 mpa).

6.6 Surface Test Package

Note: *Permit to work will be required for all pressure testing on deck with a written procedure attached to the permit.*

- Rig up surface test package as per **deck layout, Schlumberger Well Test Design Report and approved P&ID.**
- **Air supply to the well test package should be labelled and locked off from other users.**
- Check all vent lines are flushed, all blanking caps removed and valves left open prior to use. Ensure the area is barriered off, pressure test signs are displayed, and announcements are made to warn personnel that pressure testing is about to commence.
- All pressure tests to be recorded on a chart recorder.
- At the end of pressure testing ensure all barriers and signs are removed. Also inform personnel by the PA system and sign off permits.

The following should be completed as part of the pressure testing of the surface equipment:

- Rig a temporary line from the cement pump header on the rig floor to the rig floor test flowline.
- Flush all surface lines from rig floor through to the burner heads with water. Pressure test the entire system to both burner heads and the rig gas manifold to 500 psi. (3.5 mpa).

Note: *1. Verify oil & gas check valves (if installed) are working.*
2. Check pilot ignition system.

- Close the oil manifold and bleed off downstream. Increase pressure to 1200 psi and ensure pressure remains at 1200 psi (8.27 mpa).
- Close the separator gas outlet and bypass valve. Open the gas manifold and bleed off pressure downstream. Ensure that the upstream pressure remains at 1200 psi (8.27 mpa).
- Close the separator oil bypass, outlet and water outlet valves then bleed off downstream. Ensure pressure remains at 1200 psi (8.27 mpa).

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 that the pressure remains at 1200 psi (8.27 mpa)

- Close the choke manifold downstream valves and pressure test between the choke manifold and separator to 1200 psi (8.27 mpa).

Note: *This checks the choke manifold downstream valves from the direction of flow when inspecting chokes.*

- Open the separator bypass line to overboard and bleed off the pressure. Increase the upstream pressure to 5,000 psig (34.5 mpa) against the downstream choke valves.
- Close the choke manifold upstream valves and bleed off downstream and ensure that the pressure remains at 5,000 psig (34.5 mpa).

6.7 Calibration Checks

- Calibrate differential pressure gauges in inches of water, using a manometer.
- Calibrate all pressure transducers/gauges using a dead weight tester.
- Check flow meter calibrations by pumping a measured volume of water through each meter in turn. Two consistent results should be obtained for each meter. Several different flowrates should be used to cover the meter range.
- Check condition of each measuring instrument, eg. thermometers, hydrometers etc.
- Obtain a list of all fixed choke sizes and check condition of each.
- Ensure all Daniel's orifice plates are in good condition.
- Function test HP/LP pressure pilots using a hand pump and deadweight tester.

6.8 Burner Checks

- Ensure that all burner and spray nozzles are free from debris and are not plugged.
- Function test the rig spray system.
- Function test burner ignition system.
- Function test the non return valves on the air delivery lines.
- Function test the burner operation with a diesel 'test burn.

6.9 ESD System

- Remote shutdown points for the ESD system should be installed on the rig floor, at the separator in the well test area and outside the accommodation. The ESD system will be function tested once the string has been run and the surface tree connected. Report in the Well Test Report and the IADC report whenever the ESD System is function tested.
- The diesel steam generator (if used) is to be tied into the ESD system to allow automatic shut down of the generator when the ESD system is functioned. The ESD system should be rigged up to enable the isolation of the generator shutdown system from the main test ESD should the generator not be required.
- **The Separator air supply must also be tied into the ESD System via a low pressure pilot,** which will ensure the well is shut in automatically and prevent the separator vessel from flooding, should the air supply fail during testing.

6.10 Sand Monitoring

- A base line wall thickness survey will be performed over the Schlumberger surface equipment prior to test commencement.
- Further surveys will be performed as required during production if sand is detected.
- Erosion probes will be utilised in the surface test package down stream of the choke manifold as an initial indication of sand/erosional problems.
- Erosion probes to be monitored via STAN data acquisition system

6.11 Electric line

- Function test BOP rams.
- Inspect individual joint seals of the wireline lubricator sections to be used.
- Close upper & lower rams on test rod and pressure test in between rams 4,000 psig (27.6 mpa).
- Function Test Grease Injection System and check all hoses are in good working condition.
- Make up lubricator assembly on deck and pressure test to 5,000 psig (34.5 mpa).

6.12 Slick line

- Function test BOP rams.
- Inspect individual joint seals of the wireline lubricator sections to be used.
- Close blind rams and pressure test from below to 5,000 psig (34.5 mpa).
- Function test wireline counter head
- Make up lubricator assembly on deck and pressure test to 5,000 psig (34.5 mpa).
- Twist test wire with torsion gauge.

6.13 DST Tools Pressure Testing

- DST Tools will be made up in to sub assemblies on deck off the critical path (if possible) and pressure tested. *The seal assembly and the TFTV will be made up on deck into an assembly and pressure tested – since the TFTV to seal assembly connection is not accessible to pressure tests during running, as all tubing tests will be against the TFTV flapper.*
- Annular pressure response tools will be function tested on deck.
- All downhole tools will be pressure tested on deck to 5,000 psig (34.5 mpa).
- All pressure tests to be recorded on a chart recorder.
- Sub assemblies will be drifted to 2.20"
- The PCT will be run in hole LOCKED OPEN, the MCCV will be run in hole in the well test position.
- Lengths, ID, OD and thread type of all down hole tools to be checked by the Assistant Driller and the Well Test Engineer, and an accurate pipe tally maintained.
- Schlumberger DST representative to record the number of pressure cycles which the MCCV has passed through during pressure testing. An updated copy is to be maintained on the rig floor by the Schlumberger DST representative.
- Shear values for TFTV, SHRV and MCVL (If utilised) rupture discs to be confirmed by DST Engineer and Well Test Engineer depending on prevailing well conditions.

6.14 Bottomhole Pressure Gauges

- A total of 4 WTQR and 2 WCQR memory gauges will be deployed for the production test. 2 WTQR and 1 WCQR gauges will be installed in an upper DGA/LDCA carrier assembly, (2 gauges will be ported below the PCT tester valve, one gauge (WTQR) to the annulus). The lower carrier will contain 3 gauges (1 x WCQR, 2 x WTQR) installed below the PCT.
- Data sampling modes and duration's will be advised by the EGIS Well Test Engineer in conjunction with the WEL Reservoir Engineer to suit the proposed testing programme with contingencies for weather conditions and test programme variations.
- A list of all memory gauges and serial numbers should be compiled by gauge company representatives and held by the Well Test Engineer.
- DGA and LDCA with gauges installed shall be pressure tested on deck, LINC tool to be latched into LDCA and fully function tested. Ensure all wireline cross overs from the LINC assembly to the electric line cable head/Weight bar are available on the rig.
- Gauge carriers to be pressure tested on deck with gauges installed just prior to running.

Note: *The clocks in all the downhole gauges and the STAN system* ***must be synchronised****.*

6.15 TCP Guns

- 4-1/2" 12 spf 34J UJ HMX Tubing Conveyed Perforating guns will be run below the packer to the required depth. The guns contain only secondary explosives, the detonator (firing head) - primary explosive – will be connected at the time the gun string is run. A safety spacer will be installed between the guns and the firing head.
- A side by side HDF/TCF Firing Head will be ran in situ above the TCP guns. The activation pressure will be calculated to have a **2000psi**-safety margin over the maximum pressure the HDF will be exposed to over and above hydrostatic pressure at packer setting depth. Maximum hydraulic activation pressure will not exceed **4,000 psi** (27.6mPa).
- Guns will be loaded on the rig, when testing operations and the perforation interval have been confirmed.
- Function test mechanical drop sub with appropriate shifting tool.
- Function test the contingency TCF slick line conveyed firing head latching mechanism
- Function test TCF running/pulling tool.
- HDF time delay **To Be Advised** onsite by Well Test Engineer and Schlumberger TCP Engineer

  Note: *Well Test Engineer and Schlumberger TCP Engineer to specify 'No Fire' and 'All Fire' values;*

  No-Fire: Below this pressure the firing pin cannot fire the detonator

  All-fire: Above this pressure the firing pin will fire the detonator

  Firing Head Shear pin calculation sheet to be signed off by Schlumberger TCP engineer and Well Test Engineer.

  System incorporates dual firing heads HDF/TCF
- Ensure wireline tools are available to retrieve firing head in event of mis-fire.

6.16 Packers & Seal Assemblies

- Packers to be laid out on deck and inspected with particular attention paid to the elastomers. Protective packing to be re-installed on completion of the inspection.
- Packer/seal assembly to be drifted to 2.20".
- Packer/Seal assembly and TFTV to be made up into one assembly and pressure tested on deck to 5,000 psig (34.5 mpa).

6.17 Surface Sampling Equipment

- Prepare Oil sample bottles.
- Evacuate Gas bottles.
- Ensure all sampling equipment fitted with earthing straps.
- IWSS Sampling manifold to be pressure tested to 5,000 psig (34.5 mpa), while pressure testing surface test equipment.
- IWSS pre-job checks to be carried out as per Schlumberger procedure.
- Intrusive probe sampling line to be flushed out to ensure clear
- Intrusive probe hydraulic line to be pressure tested
- Inspect condition of mixing block.

Note: **All sampling containers are to be earthed prior to and during, the taking of oil and gas samples, pressurised or atmospheric.**

7 Well Preparation

7.1 Pre Completion Preparation

- 7" Liner will be run to TD.
- Pressure test the 7" Liner to a min. 4000 psi (27.6 mpa)

A casing pup joint (if available) or short joint should be run above and below the reservoir.

A RA pip tag should be installed in the casing string for correlation purposes – depth TBA.

- Well to be displaced to - (**S.G.** of brine to give 200 psi overbalance at reservoir)
  Note: expected max. CITHP (with gas to surface) is 2700 psi (18.6 Mpa). SHRV shear pressure (surface applied) will be set at ca. 3000 – 3500 psi (20.7 – 24.1 Mpa)

7.2 Perform BOP stack test.

Note: *While testing BOP stack check all rig gauges to ensure correct readings thereby avoiding confusion over annulus pressures during the well test.*

Minimum requirements for BOP tests, which will be performed after the 7" casing has been run.

Item	Test Pressures
BOP rams	500 psi / 5,000 psi. (3.45/34.5 Mpa)
Annular	500 psi / 3,500 psi. (3.45/24.2 Mpa)
Choke and kill manifold	500 psi / 5,000 psi. (3.45/34.5 Mpa)

During the BOP stack test confirm the depth of the Drillquip 10-3/4" casing hanger by marking the drill pipe at the rotary table and measuring out of the hole with the test plug. Correct depth for tide.

Schlumberger and Well Test Engineer to review and confirm SSTT space out dimensions.

7.3 Make up of Flowhead to Single Joint

➨ **<u>Review JHA before starting this operation</u>**

- Pick up Flowhead torque up connections and make up to a single. Paint a line across the swivel connections. Lay down flowhead.
- Run a pup joint directly below the Flowhead single to act as a saver sub.

7.4 Sub Sea Test Tree Dummy Run

It is strongly recommended that a SSTT dummy run is performed as this will be the first occurrence of the Schlumberger SSTT being ran into the Ocean Bounty Stack in it's present configuration. The decision to perform the SSTT dummy run will be made by the WEL Well Site Manager with advice from the Well Test Engineer, the Schlumberger SSTT operator and the DOGC Sub Sea Engineer.

➨ **Review JHA before starting this operation**

Make up a dummy Sub Sea Test Tree landing string assembly - fluted hanger and slick as follows (bottom up) :

- X Over — Tubing to fluted hanger
- Fluted hanger — Hangs off in wear bushing.
- Slick Joint — Freshly Painted White
- X Over
- Drill pipe to surface

Run in hole with the dummy landing string on 5" Drill Pipe. Strap in the landing string to confirm the fluted hanger has seated correctly in the wear bushing.

Seat the fluted hanger in the wear bushing. Confirm from the landing string measurements that the fluted hanger has landed in the correct place. Close the middle and bottom pipe rams on the painted joint.
Note the tide height at the time.

Open the pipe rams, pull out of the hole drill pipe and break out the dummy hanger.

Measure the distance from the marks on the slick joint made by closing the pipe rams to the landing point of the fluted hanger. Schlumberger and Well Test Engineer to review and confirm Sub Sea Test Tree space out dimensions with DOGC sub sea engineer and WEL well site manager.

7.5 Cement Evaluation Logging

➨ **Review a JHA before starting this operation**

Rig up Schlumberger ELS Wireline and RIH with :

CBL/VDL/GR/CCL/ 7" gauge ring and junk basket *(Single run)*

Log from TD across zone of interest to top of cement. Identify the casing pup joints and RA marker.

Note: *If no casing scraper clean out trip has been made then do not tag bottom in case of sticking. Maximum depth to run in to be advised by Well Test Engineer.*

Recover junk basket contents. Re-run as advised by Well Test Engineer / Well Site Manager

8 Test String Installation

8.1 Running TCP gun assembly

➠ **Review JHA before picking up TCP Guns**

Refer to Figure 2 for Packer - TCP Gun string Diagrams

8.1.1 Make up to the required length the Schlumberger **4-1/2" TCP guns and blank sections** under the supervision of the Schlumberger TCP Engineer.

8.1.2 Install

- Blank Gun (Safety Spacer.)

- Hydraulic Firing Head *(side by side HDF/TCF hydraulically ctivated)*

(Schlumberger HDF shear pin calculation sheet to be checked and signed off by Well Test Engineer).

Note: *All non - essential personnel to be kept clear of the drill floor.*

All Schlumberger handling subs will require 3 1/2" drill pipe elevators.

8.1.3 Make up and RIH with:

- 2-7/8" EUE 6.4 ppf tubing joints/pups as required.

- **Mechanical Gun Drop Sub**
Ensure that the gun drop sub is spaced out so there is a minimum distance of 15m between top shot and the drop sub. This to give ample room for a PLT string to be accommodated between the perforations and the tubing shoe ***To Be Advised by Well Test Engineer.***

- 2-7/8" EUE 6.4 ppf tubing pup joint
- **Ported Debris sub**
- 2-7/8" EUE 6.4 ppf tubing pup joint

Note: *Fill string below debris sub with clean fluid*

8.2 Run Lower Test String

General Comments

Record the hanging weight of the DST string.
The BOP rams must be kept open & trip tank monitored during all pressure tests.

Note: *All DST tools should be picked up as follows;*
- *Lift tools onto catwalk with crane.*
- *Lift tools in to V-door with crane.*
- *Hook up rig floor air tugger onto upper end of assembly and slack off and remove front crane sling.*
- *Assembly to be swung in to rig floor and latched with elevators.*
- *Remove rig floor air tugger.*
- *Assembly to be lifted into derrick with elevators while crane tails lower end of assembly in.*

Refer to Figure 2 for DST String Diagram

➨ **Review JHA before picking up DST Tools**

8.2.1 Make up to TCP gun assembly and RIH under the supervision of the Schlumberger DST Engineer:

Assembly no.1

- **7" HP Packer c/w 20 ft Seal Bore Extension and seal assembly.** Rupture disc shear value (– packer setting pressure -) set for ca. 500 - 1000psi (3.5 – 6.9 mPa) surface applied annulus pressure.
- **TFTV valve** (With by pass port open and pinned at ca. 500 psi, - 3.4 Mpa)
- **Lower DGA Gauge Carrier c/w 3 gauges installed.**

Assembly no. 2

- **PORT Pressure Operated Reference Tool**
- **PCT Tester Valve: Run in locked open position**
- **DGA/LDCA Gauge carrier c/w 4 gauges installed** (3 gauges ported to tubing below PCT one gauge ported to annulus)
- 1 Stand of tubing

Assembly no. 3

- **MCCV Circulating Valve**
- 1 Stand of tubing

Assembly no. 4

- **SHRV circulating valve** (Rupture disc shear value set for ca. 3000psi (20.7 Mpa) surface applied annulus pressure).
- *R.A. Pip Tag in box*

Note: *The TFTV valve will allow the string to fill as the DST tools are run in.*

8.2.2 Pick up 1 stand of tubing and make up to BHA.

8.2.3 Rig up to pressure test the BHA.

8.2.4 Install the 3-1/2" test sub and pressure test the BHA to 5,000 psi (34.5 Mpa) against the TFTV Valve. Record the volume pumped and pressure test for at least 15 minutes on the cement unit chart.

While pressure testing monitor for annulus returns which would indicate a leak.

➨ **Review JHA prior to running Tubing**

General Comments On Running string:

- Ensure all the tubulars for the test string have been drifted. All connections are to be cleaned and inspected. **Weatherford Senior Operator to visually inspect tubing connections on deck prior to running.**

- Recommended maximum running speed whilst running test string is **30 seconds per joint.** Schlumberger DST representative to be on floor at all times whilst running DST string to monitor and advise on exact running speed.

- Apply minimum dope to pin end only to ensure no build up of dope above TCP firing head.

- **All personnel to be aware of importance of guarding against and reporting Dropped Objects entering hole. Tie off all hand tools.**

- Have a stab-in kelly valve made up to the correct crossover available at all times when running tubing.

Refer to Appendix C - tubing running procedures

8.2.5 RIH with lower test string, as per Well Test Engineers pipe tally/running list, making up connections to correct torque using the Weatherford Torque Turn unit. (Refer section 3.6 for torque figures). Apply dope sparingly with a paintbrush. *Running list/tally should be prepared to place TCP gun string deeper than required to allow for packer setting procedure Section 8.4.9.*

8.3 Landing String Running Procedures and Pressure Testing

➨ **Review JHA prior to running Sub Sea Test Tree Assembly and Landing String**

8.3.1 Record DST string weight prior to picking up the Sub Sea Test Tree (SSTT).

8.3.2 Pick up the SSTT / slick joint / fluted hanger assembly as per the landing string tally.

8.3.3 Ensure at least one joint of 5" 18 ppf L80 New Vam tubing is installed below the SSTT.

Refer to Figure 2.

Note: *Ensure SSTT space out is correct such that the shear rams are aligned to close across the shear sub and the middle and lower pipe rams aligned to close across the slick joint. Space out to be calculated by Schlumberger Sub-Sea Supervisor and checked by Well Test Engineer. Space out to be agreed with WEL Well Site Manager.*

8.3.4 Install hydraulic control lines and chemical injection line, for methanol or glycol injection.

Perform Subsea equipment pre-operating and function checks as per the Schlumberger operating procedures. Pressure test SSTT control lines to their operating pressures for 5 minutes, inspecting for leaks.

8.3.5 On completion of the SSTT function checks, run the 4-1/2" landing string as per tally, using the Weatherford unit.

8.3.6 Make up the Sub sea Lubricator Valve (SSLV) to the landing string, spaced out ca. 3 singles below the Surface Test Tree assembly.

Note: *Ensure a tool joint is not located near the bottom of the riser slip joint inner barrel to prevent damage to collar and control lines*

Pressure test SSLV ball "close" and "open" lines to their operating pressures for 5 minutes, inspecting for leaks.

8.3.7 Run SSLV valve below the rotary. Close the SSLV from the Subsea panel, monitoring control line pressure and strokes required. Fill assembly above SSLV with drill water. Open the SSLV and observe drill water drain away.

8.3.8 Make up and run in hole with the remaining landing string joints, sufficient to land out the fluted hanger in the wear bushing. Land out fluted hanger.

8.3.9 Rig up Schlumberger wire line and run slim hole GR/CCL depth correlation log against RA marker sub in test string and RA pip tag in casing. Calculate distance to pull back to place top shot on depth when setting HP packer. POH and rig down Schlumberger.

8.3.10 Lay out excess landing joints to allow for Surface Test Tree installation.

8.3.11 Rig up Schlumberger 40ft bails, Shackle to rig bails using Schlumberger supplied 85 tonne shackles.

Note: *Install special lifting eye sub to Top Drive with chain hoist attached – for future wireline lubricator rig up.*

8.3.12 Change out elevators for 5" DP elevators and make up to 40ft bails.

8.4 Make up Surface Test Tree

➨ <u>**Review JHA prior to picking up the Surface Test Tree**</u>

8.4.1 Pick up Flowhead and single and make up to string. Attach the Coflexips including NRV on kill line. Make up surface lines including Lo-Torque valve to cement unit.

Note: *Ensure the Driller has the facility to read tubing head pressure on the drill floor or is in contact with the* Schlumberger STAN *(data acquisition) unit on the main deck. Put a white painted line across the Weco unions attaching coflexips to the flowhead.*

8.4.2 Record the entire test string weight and running / pick-up weights. Engage compensator at mid stroke, **land off the fluted hanger on the wear bushing.**

8.4.3 Space out of the landing string to be such that the base of the flowhead swivel is approximately 6 m above the rotary table at high tide.

Note: *Hold ca. 20,000 lbs upward tension on the SSTT latch - exact requirements to be confirmed with Schlumberger Subsea representative.*

8.4.4 Pressure test entire string to 5,000 psig (34.5 mPa) for 10 mins against TFTV and choke manifold, annulus to be lined up to trip tank. Monitor volume pumped.

8.4.5 Close SSTT and bleed off pressure above to 500 psi (3.4 Mpa), Inflow SSTT for 5 minutes.

8.4.6 Pressure up to 5,000 psig (34.5 mPa) to equalise across SSTT and open SSTT. Bleed off pressure and note returned volume to ensure entire string has bled off and both SSTT and SSLV are confirmed open.

8.4.7 Pick up string to place TCP guns on depth, as determined in Section 8.3.9

8.4.8 Close BOP rams on 5" tubing below fluted hanger. Close in tubing at choke manifold.

8.4.9 Pressure up the annulus to 1000 psi (6.9 Mpa) to set HP packer, lock open the TFTV and shear the PORT (trapping hydrostatic reference pressure in the PORT).

Note: *Pressure in tubing will initially rise as annulus pressure is applied – until the HP packer sets, TFTV shears and locks open and isolates the by-pass port.*

Bleed off tubing head pressure via choke manifold, leave choke manifold open. *Annular pressure should remain steady indicating packer is set and TFTV is locked open*

Hold pressure on the annulus for a 10 min pressure test with the tubing open. At the end of the test, bleed off annulus pressure.

8.4.10 Open the BOP rams and land out the fluted hanger in the wear bushing. *When the packer is set, the seal mandrel is unlocked and able to "float" in the packer seal bore.*

Note: *Hold ca. 20,000 lbs upward tension on the SSTT latch - exact requirements to be confirmed with Schlumberger Subsea representative.*

8.4.11 Pressure up annulus to 1500 psi (10.4 Mpa) to function PCT out of Hold Open Position.

8.4.12 Bleed off annulus to close PCT. Line up annulus to trip tank.

8.4.13 Function test the ESD system to confirm the flow wing valve closes within the allowable operating time (15 seconds).

Note:

1. *At least one ESD function test should be with the flowhead under pressure (500 psi max).*
2. *Function testing to be witnessed by WEL Well Site Manager, OIM / Toolpusher and EGIS test engineer.*
3. *Record ESD function testing on IADC Daily Drilling Report.*
4. *The ESD should be function tested, witnessed and recorded at a convenient point during the well testing operations prior to opening up the well.*

9 Production Test Procedures

9.1 Circulate in Cushion

Notes: *The preparation and circulation of diesel will be carried out in compliance with any applicable Halliburton and DOGC procedures.*
The well is to be brought on with a diesel cushion to provide the maximum achievable underbalance.

The cushion will be circulated in via the tubing and the MCCV valve.
Before operating downhole tools, ensure that annulus pressure is being monitored by the STAN surface data acquisition system.

➨ **Review JHA prior to starting this Operation**

9.1.1 Using the cement pump via the tubing, cycle the MCCV to the circulating position under the direction of the Schlumberger DST tools operator.

9.1.2 Once the MCCV is in the circulating position, slowly establish circulation to the trip tank.

Note: *Schlumberger to monitor choke manifold pressure continuously during cycling of MCCV.*

9.1.3 Commence circulating Diesel to the test string via the cement unit. Monitor return volumes throughout pumping operations.

Note:

1. *The cushion will be placed to within 5 bbls (0.8 m3) of the circulating valve. (ca. 210m).*
2. *Confirm SG of Diesel prior to commencing and during circulation.*
3. *Do not exceed circulation rate of 3 BPM.*
4. *Once displacing has commenced* ***DO NOT*** *Stop Pumping until the total cushion has been pumped or the MCCV will close.*
5. *Schlumberger STAN unit should monitor annulus and tubing pressures. Any increase in annulus pressure should be immediately reported to the cement unit operator who should stop pumping until the cause has been established and rectified.*

9.1.4 Pump a 5 Bbl (0.8 m3) seawater tail spacer to ensure seawater in lines between the cement unit and the rig floor.

9.1.5 Cycle MCCV valve to the closed position by bleeding off tubing pressure to the Surge tank and monitor for returns - to confirm MCCV closed.

Note:

1. *MCCV will be set to 12 cycles.(6 if MCLV is used)*
2. *The MCCV will index by one cycle each time a differential of 500 psi between the tubing and annulus is applied. After 12 cycles it will open to the reversing position*

The well is now ready to be perforated.

9.2 TCP Detonation

➨ **Conduct a Safety Meeting on the rig floor with the on duty crew to discuss perforating and the subsequent flowing of the well.**

Agenda for Pre Flow Meeting:

1. Outline of immediate Test Programme – Description of expected flow characteristics, rates, pressures.
2. Duties of personnel involved.
3. Responsibilities and authority - communications - Driller as focal point.
4. H2S
5. Emergency Shut Down (ESD) – location of points – Appropriate use.
6. Shut down of other work – no welding, cutting or grinding. No crane lifts over test area.
7. Non essential personnel to stay clear. Call for vigilance.
8. Hand over to Woodside Drilling Supervisor / OIM to address meeting.

- A valve status board **must** be set up on the rig floor to denote the position of the surface test tree valves, sub sea tree and lubricator valves, MCCV and PCT. **It is the reponsibility of the Driller, assisted by Well Test Engineer and Schlumberger DST representative to ensure the valve status board is kept up to date after every operation.**
- Schlumberger DST representative to be on the rig floor **at all times when DST tools are in the hole.**
- The Tubing Head Pressure audible alarm set point on the Schlumberger STAN unit shall be active and set at 100 psi until the well has been perforated. **The tubing head pressure shall be monitored at all times.** The audible alarm value can be reset to a more practical value defined by the Well Test Engineer after the well has been perforated.
- During flow periods, 1200 psi (8.3 MPa) must be maintained on the annulus to keep the PCT open, or as advised by Schlumberger DST engineer.
- The PCT must be used in the fail-safe position.
- To effect PCT closure - rapid bleed off of annulus must be available.
- Prior to flowing the well, ensure all pre-flow checks have been carried out.
- Take a 5 litre sample of brine from the active pit.
- Take a 5 litre sample of the diesel cushion.
- The pressure on the annulus must be constantly monitored and recorded during the production testing operations. During the flow and shut in period the annulus pressure will change as a result of thermal expansion. The pressure must be maintained at the PCT operating pressure (bled-off or re-pressurise via the mud pump as required). Tie annulus into STAN data acquisition system to allow it to be continuously monitored.

9.2.1 Apply 1200 psi (8.3 Mpa) annulus pressure to open PCT (in failsafe mode).

9.2.2 Ensure that the SSTT and SSLV are open.

Ensure the STAN surface data acquisition system is set to fast sampling rate.

Refer to Appendix D - well test data requirements

Notify all rig personnel via rig Tannoy system

9.2.3 Pressure up tubing to activate firing head and fire the TCP guns. Hold pressure for circa 30 seconds and bleed off to the required perforating underbalance - as advised by Well Test Engineer during the time delay period.

Note:

1. *Activation pressure to be advised by Well Test Engineer and Schlumberger TCP Engineer. (max. 4000 psi,- 27.6 mPa)*
2. *Monitor wellhead pressure for confirmation that guns have fired. Allow wellhead pressure to stabilise & record final pressure.*
3. *If TCP guns fail to detonate -* ***Refer to Decision Tree - Figure 3.***

9.3 Pre Flow and Clean Up Flow

Flaring

- **Flaring can only take place when the wind is in a favourable direction.** An unfavourable wind is one where wind shear at the burner nozzle causes flame instability.
- Standby vessel to patrol during darkness using search lights to identify any pollution in the water.

Data Acquisition

- The Schlumberger STAN system will be online to monitor pressures, temperatures, flow rates (through separator).
- In addition, separator conditions will be monitored and recorded manually by Schlumberger test crew at regular intervals during flowing periods. Well test data requirements are detailed in **Appendix D.**

Sand Production

If any sand is detected, then wall thickness surveys must be carried out over the well test pipe work. If erosion becomes a concern, then the well must be beaned back until sand production levels are at an acceptable level.

Sampling Requirements

Obtaining representative gas and condensate samples for PVT analysis is one of the major objectives of this well test and to this end an extensive sampling programme will be carried out. The majority of PVT samples will be taken during the dedicated sampling flow period, but additional samples will also be obtained during the clean up and each of the flow periods.

Note: *Prior to commencement of sampling, gas and condensate rates measured at the test separator must allowed to stabilise. The Schlumberger FFA unit must be used to check for contaminents (diesel) in the condensate prior to sampling.*

PVT and Conventional Sampling requirements are detailed in Appendix E

9.3.1 Open well on the adjustable choke to the surge tank for 10 min. preflow period.

Close in well at PCT tester valve for a down hole shut in period of 1 hour to measure Initial reservoir pressure.

Shut well in at choke manifold. Monitor wellhead pressure at the choke manifold for indications of the PCT leaking.

9.3.2 Re-open PCT tester valve and open well on the adjustable choke for the clean up period. Monitor the downstream choke pressure. Commence beaning up well slowly and unload cushion and rathole fluids. Initial flow will be to the surge tanks to establish that the well is flowing and give an indication of flow rate.

Divert flow direct to burners.

The diesel cushion from the tanks may be burned off as appropriate.

Note:

1. *During burner operations - flare watch to be posted and in radio contact with Schlumberger Test Supervisor to communicate burner performance in case of incomplete combustion or spillage).*
2. *To minimise shocking the formation and inducing sand production, the choke should be increased slowly in stages and the well allowed to stabilise prior to each choke change.*
3. *Monitor continuously for indications of sand production.*
4. *The objective of the Clean Up period is to unload the tubing contents of diesel and mud and obtain clean gas/condensate at surface.*
5. *The clean up period is expected to be circa. 4-6 hrs.*

9.3.3 Once first hydrocarbons reach surface, monitor flow for H_2S and CO_2 at 10 minute intervals. Once levels have stabilised reduce test interval to 30 minutes.

Note: *Detection of H_2S or CO_2 shall be reported immediately to the EGIS Well Test Engineer, the WEL Site Manager and the DIAMOND OFFSHORE OIM.*

Monitor continuously for indications of sand production. Record quantity of any produced sand and keep a sample.

Bean up and continue clean up in a controlled manner to maximum – **as advised by Well Test Engineer.**

Note: If the well fails to flow or performance is poor – contact Duty Engineer.

9.3.4 Monitor the wellhead flowing pressure and the BS&W levels in the produced fluid. Guidelines for when the well will be considered cleaned up are as follows:

i) The BS&W level is less than 5%.

ii) The wellhead flowing pressure is constant or declining with time.

iii) Diesel is not present in fluid samples

Divert flow through **fixed choke** as soon as practical and if possible make further choke changes using fixed chokes

Divert flow through test separator as soon as practical.

Establish and stabilise separator conditions.

Monitor quality of condensate samples from IWSS manifold (upstream of choke) using Schlumberger FFA unit to ensure free from diesel contamination.

Monitor water production carefully in early stages, look for a decline to negligible rates

If water rate does not decline in a reasonable period, analyse samples and determine if completion fluid or formation water.

The initial clean up flow period is expected to be circa. 6 hrs

9.3.5 After 1 hour of stable flow through the test separator, **as advised by Well Test Engineer**. Close in the well. Bleed off annulus pressure and shut well in at the PCT, for a build up period of approximately 1 times the flow period.

**Prior to shut in take 1 set of PVT samples from the test separator and iso kinetic sampling manifold.*

9.3.6 Monitor wellhead pressure to confirm PCT closed. Shut well in at choke manifold. Continue to monitor wellhead pressure at the choke manifold for indications of the PCT leaking.

Note:
1. *Monitor annulus level throughout the build-up periods.*
2. *Monitor shut-in WHP throughout the build-up periods.*
3. *The duration of the flow and build-up periods may be adjusted depending on well performance in consultation with reservoir engineering and drilling department.*

9.4 Flow After Flow Period (Main Flow Period)

9.4.1 Re-open PCT tester valve. Flow the well for a main flow period of 3 increasing and consecutive flow rate periods of 30, 60 and 90% of maximum flow achieved in the clean up period. Each rate will be for 4 hours each.

Choke sizes required will be determined onsite from previous flow data and **advised by the Well Test Engineer.**

Produce well through test separator at earliest practicable opportunity

Ensure separator operating pressure is as per clean up flow period.

During the first flow period (~ 30% of max.), take the PVT samples required - iso kinetic split phase and separator surface sampling as detailed in the sampling schedule - **Appendix E.**

Monitor flow rates, CGR and THP carefully, checking for evidence of liquid loading (significant decline in rate, THP and / or CGR).

Ensure flow rate is sufficient to avoid liquid loading of wellbore/3-1/2" tubing and parameters have been stable for a min. of 2 hrs.

If required extend the Flow period at this rate until the sampling schedule has been completed

9.4.2 Continue with the remaining Flow periods at ca. 60 and 90% of maximum rate.

9.4.3 Towards the end of each of the final 2 flow periods, Schlumberger to take 1 set of PVT samples from the test Separator and iso kinetic sampling manifold.

9.4.4 At the end of the final flow rate period, bleed off annulus pressure & shut well in at the PCT for a build up period of approximately 12 hours. Monitor wellhead pressure and allow to drop by 200 psi to confirm PCT closed. Shut well in at choke manifold. Continue to monitor wellhead pressure at the choke manifold for indications of the PCT leaking

9.4.5 Monitor wellhead pressure to confirm PCT closed. Shut well in at choke manifold. Continue to monitor wellhead pressure at the choke manifold for indications of the PCT leaking.

Note: 1. *Monitor annulus level throughout the build-up periods.*
2. *Monitor shut-in WHP throughout the build-up periods.*
3. *The duration of the flow and build-up periods may be adjusted depending on well performance in consultation with reservoir engineering and drilling department.*

9.5 Run PLT Survey (to be confirmed)

A PLT survey **may** be conducted at the end of the main flow period **(to be confirmed by Well Test Engineer)** to determine the flow contribution from the intervals perforated. The procedure below is a guideline and is subject to amendment when well performance is known.

Prior to this operation the TCP gun string will need to be released if not already done so) to allow wire line access across the interval (Refer to section 9.8 for this procedure)

9.5.1 Close SSLV, bleed off above and inflow test for 5 mins

9.5.2 Rig up Schlumberger ELS wire line lubricator and BOPs

9.5.3 Make up PLT toolstring with sufficient sinker bars and install in wireline lubricator.

9.5.4 Pressure test wireline lubricator to Cithp + 500 psi (3.4 mpa) for 10 minutes with Glycol/Water mix (60:40, G/W).

9.5.5 Equalise across and open the SSLV.

9.5.6 Pressurise the annulus to 1200 psi (8.3 Mpa) and open the PCT tester valve.

9.5.7 Allow pressure to stabilise before RIH.
Check PLT pressure and temperature against surface instruments.
RIH and correlate depth correction.
Run to depth **as advised by Well Test Engineer**
Tag liquid level and report depth.

Make 3 spinner calibration passes in 7" casing (up and down) at 30/60/90 ft/min.

9.5.8 Position the PLT tools on depth **as advised by Well Test Engineer.** The base of the tool (spinner) should be at ca. 5m above the top perforations with the tool head below the tailpipe.
Open up the well to the required survey flow rate – **as advised by Well Test Engineer in agreement with Schlumberger Logging Engineer.**
Monitor for evidence of tool lift.

Good communication between Schlumberger ELS and well test personnel is essential for this operation.

9.5.9 Allow well to stabilise.

Produce well through test separator at earliest practicable opportunity

9.5.10 With well stable, make 3 flowing passes (up and down) at 30/60/90 ft/min across the interval **as advised by Well Test Engineer.**

Do not allow toolstring to enter the tailpipe during logging at any time due to the potential for tool lifting

9.5.11 After final pass, run back to bottom and take static readings with spinner at various depths across the interval **as advised by Well Test Engineer.**

9.5.12 Run back down to bottom and close well in at surface.
Observe build up for 1 hour
After 1 hour, make 1 x pass (up and down) over the interval and record liquid level.

9.5.13 POH to lubricator and check PLT pressure and temperature readings against surface instruments.

9.5.14 Close SSLV. Bleed off above, Inflow test and break out wire line lubricator. Lay down PLT string.

9.6 Perforation of Additional Zone (if required – to be confirmed)

➨ **<u>Conduct a Safety Meeting on the rig floor with the on duty crew to discuss perforating and the subsequent flowing of the well.</u>**

Unless Schlumberger 'SAFE' system is used - Radio silence will be required for perforating.

- 1200 psi (8.3 Mpa) must be maintained on the annulus to keep the PCT open. *The pressure on the annulus must be **constantly monitored** and recorded.*
- The PCT must be used in the fail-safe position.
- Release TCP guns if not already done so (refer Section 9.8)

9.6.1 Close SSLV and inflow test for 5 mins.

9.6.2 Make up and arm 2-1/8", 6 spf, 45° phased perforating gun and toolstring (sinker bars, CCL) and install in wireline lubricator.

Gun length will be as advised by Well Test Engineer in agreement with Logging Engineer, based on required interval to perforate and manageable gun length.

9.6.3 Pressure test wireline lubricator to CITHP + 500 psi (3.4 mpa) for 10 minutes with Glycol / water mix.

9.6.4 Equalise pressure and open the SSLV.

9.6.5 RIH and correlate depth with **Ref. log - to be advised.**

9.6.6 Fire guns. Perforate interval **- to be advised**

9.6.7 Monitor wellhead pressure for confirmation that guns have fired.

9.6.8 POOH. Close SSLV and inflow test. Break out wireline lubricator. Check guns for misfire.

9.6.9 Once guns are clear of the flowhead, shut swab valve and re-install Schlumberger lubricator.

Repeat above steps if subsequent runs required.

9.6.10 Equalise pressure with water/glycol mix and open the SSLV.

9.7 Conduct Flow and Build Up Periods for Lower Zone.

Flow and build up sequences will be dependent on performance of the primary objective and **be advised once these results are known.**

9.8 Procedure to Release TCP gun string if required (contingency).

➨ Review JHA prior to starting this operation

9.8.1 Close Master valve, bleed off above and inflow test for 5 mins.

9.8.2 Rig up Schlumberger slick line. Install 1-1/2" toolstring with Otis B shifting tool in wire line lubricator.

9.8.3 Pressure test wireline lubricator against master valve with water to Cithp + 500 psi (3.4 MPa)

9.8.4 RIH with shifting tool and latch into mechanical drop sub.

Note: *Exercise caution when running through DST Tools*

9.8.5 Jar up to shift sleeve in TCR drop sub and release TCP gun string. When released RIH and drift down to 10 – 20 m below lowest depth PLT tools or wire line perforating guns are expected to be run to. POH.

9.8.6 Close master valve and inflow test prior to breaking out lubricator.

9.8.7 Rig down Schlumberger wire line.

10 Well Kill

➡ **Review JHA prior to starting this operation**

Note : Kill fluid volumes and pump pressures are to be determined by the Well Site Manager in conjunction with the Mud Engineer and Well Test Engineer.

10.1 Bullhead Kill

10.1.1 Once the test is complete (to be advised by the Well Test Engineer) bullhead the tubing contents back into the formation with kill brine.

10.1.2 Cycle the PCT by pressuring up the annulus to 1200 psi (8.3 Mpa) around to the lock open position. Bleed off annulus pressure (Tool should be in HOOP).

10.1.3 Line up the cement unit to the kill side of the surface test tree and bullhead away kill brine to the formation (Quantity to be advised onsite) Bleed off the tubing pressure and flow check the well is static for 15 mins.

10.2 Pull String Out Of Hole

10.2.1 Lock open the surface test tree kill wing check valve and line up to take returns to the pits via the test tree kill wing and drilling choke manifold.

10.2.2 Using the rig pumps, pressure up the annulus to ca. 2500 psi (17.3 mPa) and shear the rupture disc to open the Below Packer Circulating Valve (BPCV).

10.2.3 Reverse circulate the string contents to flush gas pocket below packer via the rig choke manifold & de-gasser to kill weight brine until the brine is of a consistent density and gas content has reduced to a stable & acceptable level (approx. 2%).

10.2.4 Open the pipe rams. *Flush beneath rams prior to opening in case of gas pocket.* Ensure there is no annulus pressure and the riser is full.

10.2.5 Unseat HP packer (straight upward pull – as advised by Schlumberger DST Engineer). Flow Check.

10.2.6 Rig up Weatherford tubing handling equipment.

➡ **Review JHA prior to starting this operation**

10.2.7 Rig down and layout flowhead. Flow check. POOH laying out landing string in singles.

Note: *Prior to laying out flowhead - pump seawater across Schlumberger surface test tree and flush out surface well test package - pipework and all valves. Follow up by flushing through with inhibited drill water. Ensure no pressure is trapped anywhere in the system.*

The test string will drain automatically through the locked open PCT while POOH. Hole fill volumes are to be monitored at all times while POOH.

10.2.8 Lay out Lubricator Valve and Subsea Test Tree

10.2.9 Pull out of hole with tubing.

Note: ***To avoid subsequent corrosion, each joint should be thoroughly washed, internally and externally with copious quantities of fresh water. Pin and box ends should***

dried prior to applying fresh pipe dope. Ensure thread protectors are screwed onto pin ends of tubing prior to laying out. Prior to bundling ensure both box and pin end protectors are fitted and tight.

10.2.10 Break out and lay out DST tools.

Recover the memory gauges from the gauge carriers and retrieve the data stored.

10.3 Contingency Well Kill

Should bull heading not prove possible - or if the well did not flow to surface during the test - then it will be necessary to reverse circulate the string.

➠ **Review JHA prior to starting this operation**

10.3.1 Limit any differential pressure across the BPVC. Pressure up on the annulus with the rig pumps to shear the BPCV rupture disc at ca. 2500 psi (17.3 mPa) and place into the reverse circulating position.

10.3.2 Reverse circulate the entire string with kill brine to Burners

10.3.3 If the well did not flow reverse circulate to the Schlumberger surge tank.

10.3.4 Open the pipe rams. Flush beneath rams prior to opening in case of gas pocket. Ensure there is no annulus pressure and the riser is full.

10.3.5 Proceed as per 10.2.5 above.

11 Well Suspension/Abandonment

A separate procedure will be issued by the WEL Well Site Manager.

APPENDIX A

Personnel Responsibilities

WOODSIDE ENERGY LIMITED

1. WEL Well Site Manager

- Review weather forecasts to ensure the environmental conditions will allow an adequate window for the test to be conducted safely.
- Review with key personnel contingency plans for potential testing emergencies
- Co-ordinate the overall conduct of the production test and assign personnel responsibilities.
- Liase with the DIAMOND OFFSHORE OIM to ensure that all safety preparations are made.
- Hold a safety meeting with all personnel involved in testing at an opportune time prior to running the test string and assign personnel responsibilities.
- Ensure the Permit To Work system is utilised for all test preparations.
- Ensure test procedures are implemented in a safe and efficient manner.
- Arrange reporting and communications procedures with shore base.
- Co-ordinate logistics, including standby helicopters and standby/supply vessels, with shore base.
- Ensure operations are managed in a manner that protects the environment, complies with all government regulations and follows Company policy.
- Formally notify the relevant authorities prior to perforating and commencing flaring.

2. WEL Reservoir Engineer/Production Technologist

(If not onboard - duties will be assumed by Well Test Engineer with advice from on shore WEL Reservoir Engineer).

- Quality control on the well test data.
- Review metering arrangements.
- Technical supervision of wireline logging to ensure packers are set and the well is perforated at the correct depth.
- Advise data acquisition parameters for memory gauges.
- Advise on the duration of the flow and build up periods.
- Advise surface sampling requirements.
- Specify requirements for alternate procedures, such as bottom hole sampling or PLT surveys.
- Analyse well test data to ensure test objectives have been achieved.

3. WEL/EGIS Well Test Engineer

- Supervise the Contractors' test preparations. Check equipment condition for completeness and condition.
- Review and confirm with the respective contractor supervisor the operating parameters of the entire well testing package and associated equipment:
- The Drill Stem Test tools

- Sub Sea Test Tree
- Perforating equipment.
- Surface Equipment.
- Act as liaison between WEL, testing contractor(s) and DIAMOND OFFSHORE to ensure sufficient co-ordination.
- Act as a technical adviser to the Well Site Manager in the planning and conduct of the well testing operation.
- Assist Well Site Manager in conducting safety and procedural meetings.
- Ensure that downhole and surface equipment has been functioned and pressure tested prior to the commencement of the test.
- Provide a daily report on the progress and results of the test for the Well Site Manager.

DIAMOND OFFSHORE

1. OIM

The OIM has overall authority regarding the safety of personnel and the drilling rig and is responsible for the following duties:

- Ensure that all lifeboats, fire-fighting equipment, breathing apparatus and alarm systems are operational.
- Ensure the Permit To Work system is implemented, as appropriate, for all test preparations .
- Provide formal instruction to the support vessels specifying responsibilities and duties during the production testing programme.
- Organise and conduct fire and rig evacuation drills prior to commencing well testing & ensure that key personnel are trained in use of breathing apparatus.
- In conjunction with the Well Site Manager and the Rig Superintendent ensure all safety checklists items are addressed and implemented prior to testing.
- Co-ordinate the implementation of the Oil Spill Contingency Plan.
- Inform personnel of the basic production test procedure and ensure all work is conducted in a safe manner.
- Liase with the Well Site Manager in implementing the detailed step by step production test procedures.

2. Rig Superintendent / Toolpusher

- Assist the OIM to perform responsibilities specified above with particular consideration for those aspects which ensure the continuity of testing operations.
- Check the availability and condition of the necessary tongs, slips and other handling and makeup equipment for the permanent packer, DST tools, SSTT Package and the Surface Test Tree (STT).
- Function test the deluge system to ensure adequate protection will be provided during flaring of hydrocarbons.
- Ensure the Permit To Work system is implemented, as appropriate, for all test preparations .
- Provide relief for the driller to take scheduled breaks during testing activities.

3. **Driller**

- Stay on the drill floor with two floormen at all times during the test.
- During flow and build-up periods, the driller may be relieved only by the Toolpusher / Rig Superintendent.
- Immediately report to the Well Test Engineer, Well Site Manager or Rig Superintendent / Toolpusher any abnormalities.
- The Driller is to be familiar with the Surface Test Tree (STT) Emergency Shut Down (ESD) system and the mode of operation.
- Ensure that one person (Assistant Driller or Derrickman) is in the pump room at all times to line up kill fluids to the cement unit.
- Monitor annulus pressure and trip tank volume through the flow and build up periods. Record pressures and volumes every 15 minutes.

4. **Radio Operator**

- Make a register of all portable radios and telephones onboard the rig. Ensure all transmitters are collected and secured prior to radio silences.
- Implement 'Radio Silence' procedures and notify shorebase when Radio Silence will be in effect and when communications are re-established.
- Liaise with Radar Watchman and standby vessels and warn other vessels to remain outside the safety zone around the rig during testing operations.
- Keep the helicopter base advised of expected flaring times.

5. **Standby Vessel Captain**

- Review standby and support vessel responsibilities and duties as designated by the DIAMOND OFFSHOREOIM.
- Maintain station upwind of the rig as instructed by the drilling vessel.
- Watch for oil spills and report immediately to the Barge Engineer.

TEST CONTRACTORS

1. **Test Supervisor/Co-ordinator (Schlumberger)**

- Supervise and co-ordinate the Schlumberger test personnel and the activities being performed.
- Act as a liaison between the WEL/EGIS and Schlumberger to ensure all activities are carried out safely and efficiently.
- Brief test personnel on the testing procedures and responsibilities.
- Review inventory quantities and condition of all test equipment onboard.
- Organise and co-ordinate pressure and function testing in compliance with the Permit To Work system.
- Ensure all rig supervisory personnel are aware of the location and operation of emergency shut down equipment.
- Ensure all data acquisition equipment is functioning correctly.
- Calibrate gas, oil and water meters.

2. **Downhole Tools Supervisor (Schlumberger)**

- Make up, function and pressure test the down hole tools.
- Prepare a report detailing the running list, with all critical dimensions and operating pressures.
- Check the availability and condition of the necessary tongs, slips and other handling and makeup equipment for the DST tools.
- Ensure that adequate backup equipment and spares are available at the rig.
- Man the rig floor at all times to instruct the driller in the correct operation of annulus pressure operated tools.
- Prepare and function test the BHP gauges.
- Check downloading data capabilities, reporting and plotting software
- Ensure adequate batteries and spares are available.
- Programme the BHP gauges with the sampling frequencies prescribed by the EGIS Test Engineer.

3. **Schlumberger TCP Engineer**

- Ensure that adequate backup equipment and spares are available at the rig.
- Prepare and function test the TCP ancilliary equipment.
- Prepare and load TCP guns as required for the confirmed interval specified.
- Prepare TCF Firing Head as required for the planned hydraulic actuation pressure and time delay.
- Prepare a report detailing the running list, with all critical dimensions.
- Check the availability and condition of the necessary tongs, slips and other handling and makeup equipment for the TCP gun strings.

4. **Logging Engineer (Schlumberger)**

- Liase with the EGIS Well Test Engineer on perforating requirements.
- Liase with the EGIS Test Engineer to ensure that the permanent packer is set at the correct depth and perforating is also at the correct depth.
- Maintain inventories of all explosives devices and ensure that adequate spares are available.
- Review explosives safety procedures with Well Site Manager and ensure that all safety procedures are followed when handling explosives.
- Liase with the Well Site Manager and Radio Operator for the implementation of 'Radio Silence".

5. **Cementer (Halliburton)**

- Function and pressure test the cement lines.
- Operate the cement unit pumps to perform pressure testing and calibration as directed. Keep all pressure test charts and records.
- Review well kill procedures with the Well Site Manager.

- Line suction up to pump kill fluid and be ready to implement well kill procedures at short notice.

6. Mud Loggers

- Take periodic gas samples from the separator for chromatograph analysis
- Monitor gas detectors in the shaker area, moon pool and on the rig floor.
- Monitor annulus pressure, trip tank volumes and flow detector.

8. Mud Engineer

- Maintain completion fluid properties as specified in the test programme.
- Ensure adequate volumes are on hand to kill the well.
- Analyse produced fluids for salinity and pH as requested by the Test Engineer.

APPENDIX B

Production Testing Hazard Identification

1. WELL TEST HAZARD REVIEW PROCESS

Well Testing Hazards have been identified, assessed and managed using the following process:

Hazard Identification meeting:-

- Compilation of HAZID work sheets
- Risk ranking of Hazards
- Ability to Manage ranking of Hazards

Preparation of the Well Test Hazard Register for each hazard event where the risk ranking is High.

For the High risked items the following additional assessments have also been conducted.

- Causes and safeguards
- Consequence and probability assessment (using the W/E Risk Assessment Matrix).

2. SUMMARY OF WELL TEST HAZARDS

No.	Event
0.5 (New item)	Equipment failure – high pressure testing
1	Detonation of TCP gun at surface
2	Diesel spill when displacing tubing
5	Leak in landing string above BOP
6	Leak/rupture in surface equipment
7	Hydrogen Sulphide release
9	Unplanned hydrocarbon release – relief valve lifts
10a	Burner Inefficiency
10	Burner Failure
11	Unplanned hydrocarbon release.- erosion
12	Unplanned hydrocarbon release – wire line lubricator
13	High gas flow from surge tank
16	Hydrocarbons in annulus – when unseating packer *(Cat 1. Test string only)*
16.5	Hydrocarbons in Riser – when opening BOPs
17	Failure of annulus pressure transmissibility to DST tools *(applicable if testing in mud)*
19	Electric Shock
20	Restricted escape routes

No.	Event
22	Non well test personnel non routine operation
23	Personnel fatigue
24	Rupture of landing string, flow head or coflexip due to contact with rig.
25	Vessel collision with rig during well testing
26	Production/Kill standpipe falls from derrick

3. DANGEROUS GOODS

On board during testing operations.

Material	Quantity	Class	UN#	Comments
Nitrogen	Up to 10 racks	2.2	1076	DST Tools
Propane (LPG)	8 Bottles	2.1	1075	Burner pilots
Lithium Batteries	14 packs	9	3090	Down hole pressure gauges
Methanol	400 Lt	3/6.1(b)	1230	Hydrate suppression. Contained in IBC containers.

4. HAZARD IDENTIFICATION WORKSHEETS

The following tables have been included in this document as they are directly relevant to the procedures and operations which will be undertaken as part of the Well Testing process.

Item	Hazard	Causes	Consequence	Safeguards / Recommendations	C	P	R	Ability to Manage
0.5	High Pressure. Testing On Pipe Deck	Equipment Failure	Personnel injury/Fatality	Permit to work . JHA PA announcements. Designated areas barriered off P/tests kept below MAWP design 5,000 psi max. test pressure All equipment Certified. Schlumberger Pressure Operations Manual procedures in place.	B	3	High	High
1	Detonation of TCP perforating gun at surface	Firing head prematurely activated	Personnel injury/fatality	TCP operations Permit to Work JHA 3m blank gun safety spacer installed between loaded guns (secondary explosive and firing head (primary explosive), therefore live guns are below RT when firing head is installed. Firing head requires hydraulic pressure to shear pins and release firing pin to start firing sequence. Firing pin requires a min. of 150 psi hydrostatic pressure to fire the percussion detonator (equivalent to a depth of 96m in 1.1 SG brine) The firing mechanism is not exposed and cannot be accidentally struck by falling debris in the string.	A	1	High	High

Item	Hazard	Causes	Consequence	Safeguards / Recommendations	C	P	R	Ability to Manage
2	Diesel spill when displacing tubing to diesel prior to perforating	Leak. Wrong alignment of valves	Pollution Ignition Explosion Personnel injury/fatality	Permit to Work JHA Equipment design Equipment pressure rating Pressure tests on installation Rig operator/cementer specific procedures Pressure limit of 1500 psi when pumping diesel Lines displaced to water after completion of diesel.	A	1	High	High
3	Leak in test string below BOP	Tool leak/failure, tubing leak/failure	Annulus pressure rises H/Cs below BOP	Test string design – premium tubing Tubing inspection prior to m/up JAM system make up DST tools Equipment rating (10KWP) Pressure tested on installation If annulus pressure reaches 3000 psi – single shot circ valve will shear. Tubing Stress analysis Cross overs certified PH6 tubing connections(met/met seal) Record of volumes vs pressure Well kill system rigged up.	C	2	Med	High

Item	Hazard	Causes	Consequence	Safeguards / Recommendations	C	P	R	Ability to Manage
4	Leak in test string below BOP	Tool failure, tubing failure	Annulus pressure decrease	Test string design – premium tubing Tubing inspection JAM make up DST tools Equipment rating (10KWP) Pressure tested on installation PCT valve closes on low annulus pressure. Well can then be circulated dead. Well kill system rigged up.	C	2	Med	High
5	Leak/rupture in test string above BOP	EZV leak, tubing leak	Trip tank level increase. H/Cs in riser	String design – premium tubing. Tubing inspection. JAM make up. SSTT Equipment rating (10KWP). Pressure tested on installation. Driller/DST eng. monitoring trip tank. Well kill system rigged up. Shear Rams	B	2	High	High
6	Leak/rupture in surface equipment	Equipment failure Over pressure	H/Cs in atmosphere Pollution Ignition Personnel exposure/fatality	Equipment design (to API 14C RP) Pressure rating Certification Pressure testing on installation Operators in attendance Well test parameters visual alarm in Schlum. control room (STAN electronic monitoring system) ESD system (auto and/or manual) Pressure relief valves system	A	2	High	High

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Item	Hazard	Causes	Consequence	Safeguards / Recommendations	C	P	R	Ability to Manage
7	H2S in flowstream	H2S in reservoir New reservoir - uncertainty	Equipment failure Personnel exposure to H2S Fatality Cost of mobilising H2S safety equipment / training	H2S detection at first H/Cs to surface and continually through out test. PTG - H2S conc. >50 ppm in well stream or >10 ppm in air – well shut in and either: Test abandoned or full H2S cascade equipment mobilised and crews trained in H2S procedures before re commencement of test. Down hole MDT sample checked for H2S during logging. All down hole and surface equipment rated to NACE MR.01.75. All tubulars L80 steel grade. No H2S on previous well (Thylacine 1)	A	2	High	High
8	Planned gas release to take initial sample for H2S ppm check.	Planned	Personnel exposure to H2S	SCBA donned by sample personnel	E	1	Low	High
9	Unplanned H/C release – relief vale lifts	Overpressure Leakage	H/C release Pollution Ignition Personnel exposure/fatality	Operators in attendance Well test parameters visual alarm in Schlum. control room (STAN electronic monitoring system ESD system (auto/manual) R/Vs routed to safe area (as agreed between Schlum. and DOGC OIM at time of pre well test survey visit) Relief lines tied down.	A	1	High	High

Item	Hazard	Causes	Consequence	Safeguards / Recommendations	C	P	R	Ability to Manage
10	Unplanned H/C release – Flare extinguished	Process upset Type or contamination of well fluids	Pollution	Dual independent pilot light system Boom selection cogniscent of wind direction. Flare watcher in attendance in radio contact with Schlum. test crew/supervisor. Rig orientation optimised for prevailing wind direction. ESD system – for rapid well shut in.	C	3	High	High
10a	Unplanned H/C release – Flare inefficiency.	Type or contamination of well fluids. Sub optimal burner performance. Not able to detect during night time. Compressor failure	Pollution	Gas well with low CGR expected (ca. 10-20 bbls/MMscf) Compressor QA onshore Compressor mechanic offshore	C	3	High	High
11	Unplanned H/C release – erosion of surface equipment.	Solids (sand) production	H/C release Pollution Ignition Personnel exposure/fatality	Base line wall thickness survey established Erosion probes / Sand Ranger installed in system Sampling for sand production Operator in attendance Wall thickness checking during flow periods ESD system. Low probability of sand production	A	1	High	High

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Item	Hazard	Causes	Consequence	Safeguards / Recommendations	C	P	R	Ability to Manage
12	Unplanned H/C release – wire line lubricator	Stuffing box or Grease Injection Head seal failure Lubricator O ring failure	H/C release Pollution Ignition Personnel exposure/fatality	Equipment design/certified Equipment Pressure rating Pressure testing on installation Wire line BOP hydraulically operated to isolate leak when wire in hole. SSLV Valve to isolate leak when wire on surface. PCT, SSTT, SSLV can cut wire if required. Well Kill equipment rigged up.	A	1	High	High
13	Uncontrolled H/C release – flow from surge tank	High flow rate to tank High GOR	H/C release. Personnel exposure	Operator in attendance Vent line adequate sizing Hi press alarm ESD system (auto and manual) R/V Flow restrictor at tank inlet Observer at tank	C	2	High	High
14	H/Cs release during breaking down of well test hook up	Incomplete flushing	Pollution Personnel exposure	Entire well test package to be displaced and flushed through with inhibited water after test and prior to rigging down. Written procedure to be followed.	C	2	Med	High
15	Reverse circulation – gas release		Pollution Ignition Personnel exposure	Normal procedure is to bullhead kill well. If bullheading not possible then, Well can be reversed out over well test equipment until H/C free. Diverted to mud system when annular fluid at surface – controlled with BOP, choke manifold and degasser.	F	5	Low	high

Item	Hazard	Causes	Consequence	Safeguards / Recommendations	C	P	R	Ability to Manage
16	H/Cs under packer when unseating. ***(Cat. 1 test string only)***	Void space under packer seal element that cannot be flushed during circulating.	Percolation up hole. Flow indication Mud ejection Gas / mud released on rig floor	Normal procedure. Well full of kill fluid BOP and choke in use Gas detection from mud loggers Circulating procedures before POH Flow check procedure before POH.	A	2	High	High
16.5	H/Cs under rams when opening BOPs		Percolation up riser. Flow indication Mud ejection Gas / mud released on rig floor	Flush below BOP rams prior to opening. W.T. Programme	A	2	High	High
17	Annulus pressure transmission to DST tools interrupted. ***(Testing in mud only – not planned)***	Mud out of condition	Inability to circulate NPT	Space out PCT, MCCV and SHRV to avoid sand plug problems	B	3	High	Med
18	Radiant Heat from burners exceeds recommended API exposure levels for personnel	Flaring	Damage to rig facilitiy Burns to skin Damage to burner boom rigging	Water curtain. Water curtain efficiency testing. Portable water curtain equipment available if required Additional water curtain	C	2	Med	High
19	Electric Shock	Deluge Water at burner ignitor buttons Rain/inclement weather	Injury / fatality Fire	Contractor electrical compliance prior to installation QA in town / checked on rig Install ignitors in dry area.	B	3	High	High

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Item	Hazard	Causes	Consequence	Safeguards / Recommendations	C	P	R	Ability to Manage
20	Restricted Escape Routes in event of emergency	Blocked walk ways	Trip hazard Trapped personnel	Access and Egress routes marked on well test lay out poster and posted on rig notice boards Safety meetings Equipment lay out plan to provide sufficient access/egress. Site inspection / walk round Emergency drill – included in test programme	B	2	High	High
21	Standby Boat too close to flare	Engine failure / loss of power Communication failure	Hydrocarbons on decks / ignition Radiation burns to personnel Toxic fumes / smoke inhalation	Standby boats stationed at safe distance during well test ops. Communication maintained with control room – Captain briefed on duties as per test programme Permit to Work system informs boat of operations	C	2	Med	High
22	Non testing personnel exposed to hydrocarbon release / ignition. Non testing personnel disrupt operation	Communication failure New personnel / shift change Unfamiliar operation / changed procedures	Injury Process disrupted / well shut in	Rig emergency procedures Pre well test muster and awareness drill Pre-test meetings PA announcements Communication via pre tour meetings JHA Permit to Work	B	2	High	High
23	Personnel Fatigue	Overwork – crew arrive onboard without sufficient field break between jobs. Excessive hrs worked onsite	Injury Incorrect decisions – disruption to test programme. Damage to assets	Screen crews to ensure personnel have had 7 days onshore prior to job. 2 x crews on site to ensure 24 hour coverage (12 hrs per shift)	B	2	High	High

Item	Hazard	Causes	Consequence	Safeguards / Recommendations	C	P	R	Ability to Manage
24	Rupture of landing string, flowhead or coflexip flow/kill hoses due to contact with rig	Excessive rig heave Weather conditions, swell Inability to compensate Anchor slippage	H/C release Ignition Pollution Personnel injury Fatality	Review Schlumberger and DOGC unlatch criteria. Determine which to use and include in WT programme. Essential personnel only on rig floor Inspect clamps.	B	3	High	High
25	Vessel collision with rig during well testing	Lack of vessel awareness of rig in shipping lane. Inadequate communication	H/C release Ignition Pollution Personnel injury Fatalities Loss of Asset	Well specific guidelines for vessel watch and interception. Anti collision procedures. Review anti collision procedures to check adequate for well test ops. and determine responses and adequate timings required - would be to close PCT,SSTT and bleed of pressure above SSTT. Standby and unlatch if required.	A	2	High	High
26	Production/Kill standpipe falls from derrick	Brackets fail Excessive rig heave	H/C release Ignition Pollution Personnel injury Fatalities Dammaged Assets	Driller on rig floor at all times ESD system closes in prodn valve Essential personnel only on rig floor Inspect clamps Check load capacity of clamps	B	2	High	High

APPENDIX C

Production Tubing Handling

Weatherford, the casing and tubular running contractor will supervise the handling, preparation and running of the production tubing and the landing string tubing.

1. Handling Procedures

- Tubing should not be stacked higher than five tiers on the rig pipe deck.
- Provide wooden dunnage as separators between successive layers of pipe so that no weight rests on the connection.
- Thread protectors should always remain in place when moving or handling the tubing.
- Avoid rough handling and do not drop pipe when unloading.
- Number and measure each joint with a steel tape as it is laid out on the pipe deck. Measurement units are metres to two decimal places.

2. Equipment Preparation Procedures

- Ensure all necessary running equipment and accessories are available and in good operating condition.
- The correct sized slips and slip type elevators for 2-7/8", 3-1/2" and 4-1/2" tubing.
- Ensure API modified thread compound is used.
- A stabbing board or yoke may be required to offer stability for ease of make up.
- Power tongs with a lead line at 90deg and level with the tongs.
- Ensure that an accurate torque monitoring device is available.

3. Cleaning

- All tubular connections will be thoroughly cleaned, inspected on the rig.
- All compounds applied to connections and thread protectors are to be wiped or washed off using detergent and a non-metallic brush. Wipe off and then air blast the connections. Apply a light coating of pipe dope.
- Check and clean the internals of the tubing for scale, debris, or other foreign matter.
- Air blast from the box to the pin end.
- Carefully inspect the thread connections. Discard any damaged joints.
- Apply dope and install thread protectors on all unused tubing.

4. Running Procedures

- Tubing is to be inspected for damage and drifted on the pipe deck prior to running.
- Lifting subs or thread protectors must be installed when ever tubing is moved.
- Slings should be used to move tubing joints from the pipe rack to the catwalk.
- Single joint elevators should be used to raise the joints of tubing from the 'V' door up into the derrick.
- Remove the pin end thread protector and inspect the threads.
- Apply an API modified thread compound to the box end threads and seals.
- Use a stabbing guide on the joint of tubing in the rotary table.
- Ensure correct alignment of the tubing joints before attempting the make up.
- If the connection is not made successfully re-inspect the threads.

5. Make Up Procedures

- Power tongs only are permitted for tubing make up, however a pipe wrench or the rig tongs may be used for unusually shaped tools.
- A back up tong should be installed immediately **below** the upset.
- Ensure the elevators are slacked off.
- Start make up by hand or with the power tong at low speed. Do not make up tubing at greater than 25 RPM. Change to low gear and reduce to 1 0 RPM for final make up.
- An accurate torque monitoring device shall be used.

6. Pulling Tubing Procedure

- Breaking Out
- Use slip type elevators, power and back up tongs.
- Set the torque adjustment so that the tubing is not damaged.
- Rotate the pipe joint out with the power tongs carefully.
- Inspect thread connections on joints that require excessive torque to break out.

APPENDIX D

Well Test Data Requirements

General

- Raw data shall be recorded in the units actually measured.
- Original "raw data" report forms shall be completed and maintained for all well testing activities. These are in addition to that recorded by the computerised data acquisition system.
- The data acquired shall be recorded with the relevant date and time.
- The frequency of data acquisition should match the stability of the flow or pressure data.
- Guidelines are detailed below on data type and recommended frequency.

Note:

The WEL "J" Forms well test data sheet sets shall be completed for each test

Wellhead Measurements

- Pressure (by DWT) and temperature, upstream and downstream of the choke.
- Choke size (64th) and type (fixed or adjustable).
- BS&W %.
- H_2S and CO_2 concentrations (by Draeger analysis).
- Annulus pressure. Monitor and record throughout the test to ensure the correct operation of the annulus pressure operated test tools.

Flow Rate Calculations

- Well test data shall be reported in Oilfield Units (Imperial) except for depth which will be reported in meters.
- Correction factors to calculate oil and gas flow rates at standard conditions of 14.73 psi @ 60 ^oF.
- Production rates and ratios (GOR, CGR,GLR) of produced well fluids.
- Cumulative production (including clean up flow) of produced well fluids.
- Meter calibration records to be included in the test reports.

Separator

- Vessel - Pressure and temperature.
- Oil - Shrinkage(Wf).
  - Meter calibration for non-linearity correction.
  - Oil flowline temperature.
  - Physical properties (density).
- Water - Physical properties (density, salinity, resistivity and pH).
- Gas - Gas meter run and orifice plate sizes.
  - Static (Pf) and differential pressure (Hw).
  - Gas flowline temperature.
  - Physical properties (gas gravity, H_2S/CO_2 content and chromatograph analysis).

Data Type and Acquisition Frequency

Data acquisition frequency will be dependent on well performance, the stability of flow rates or build up data. Minimum guidelines can be found in the Data Acquisition Table

Data Acquisition Table

Data Type	Acquisition Frequency	
Wellhead		
Pressure and temperature	15 minutes initially	30 minutes stabilised
BS&W	15 minutes initially	30 minutes stabilised
H_2S / CO_2 content	10 minutes initially	30 minutes stabilised
Choke changes / opening and shutting the well	Every 15 secs for 1 minute Every 1 minutes for 15 minutes Every 15 minutes thereafter 30 minutes stabilised	
Separator		
Pressure and temperature	15 minutes initially	30 minutes stabilised
Oil / Gas flow rate variables	15 minutes initially	30 minutes stabilised
Physical properties	30 minutes	
Shrinkage	60 minutes	
H2S & CO2	30 minutes	
Meter Calibration	2 times per flow rate.	

APPENDIX E

Well Test Sampling Requirements

The following table details sampling requirements:

Sample Type	Analysis	Frequency	Sample Point	Volume	Remarks
Clean-up					
Gas	H_2S	10-30 mins	Choke Manifold	-	Draeger
Gas	CO_2	10-30 mins	Choke Manifold	-	Draeger
Water	Cl,pH,alkilinity Barium/strontium, conductivity	Hourly if possible	Choke Manifold/Test Separator	1 Ltr	Inc. 1 at res.fluid to surface and 1 at end of flow period. Will depend if any water is produced.
Wellstream	CGR determination	30 mins	IWSS manifold		Iso Kinetic CGR determination
LP Cond..	Diesel contamination	As Req'd	Test Separator	-	Use of Field Fluid Analyser to ensure condensate is diesel free.
Gas/Cond.	PVT	1 set	Test Separator	20Lgas 640ccoil	Ensure FFA shows no contaminants
Gas/Cond.	PVT	1 set	IWSS manifold	20Lgas 640ccoil	Ensure FFA shows no contaminants
LP Cond..		1	Test Separator	5Ltr/1Ltr	
PVT Sampling Flow (30% rate)					
Gas	H_2S and CO_2	hourly	Test Separator	-	Draeger
Gas	H_2S	1 per flow period	Test Separator	-	UOP 212/77
Gas	Mercaptans	1 per flow period	Test Separator	-	UOP 212/77
Gas	Radon	1 per flow period	Test Separator	-	Scintrex Analysis
Gas	Mercury	1 per flow period	Test Separator	-	Sir Galahad method
Gas	Total Sulphur	1 per flow period	Test Separator	10 Ltr	Non reactive bottles Onshore analysis
Water	Cl,pH,alkilinity Barium/strontium, conductivity	2 per flow period	Test Separator	1 Ltr	If produced
Wellstream	CGR determination	30 mins	IWSS manifold		Iso Kinetic CGR determination
Gas/Cond.	PVT	3 sets	IWSS manifold	20Lgas 640ccoil	
Gas/Cond.	PVT	3 sets	Test Separator	20Lgas 640ccoil	
LP Cond.		1	Test Separator	5Ltr/1Ltr	
Main Flow (60% rate)					
Gas	H_2S and CO_2	hourly	Test Separator	-	Draeger
Gas	H_2S	1 per flow period	Test Separator	-	UOP 212/77
Gas	Mercaptans	1 per flow period	Test Separator	-	UOP 212/77

Sample Type	Analysis	Frequency	Sample Point	Volume	Remarks
Gas	Radon	1 per flow period	Test Separator	-	Scintrex Analysis
Gas	Mercury	1 per flow period	Test Separator	-	Sir Galahad method
Gas	Total Sulphur	1 per flow period	Test Separator	10 Ltr	Non reactive bottles Onshore analysis
Water	Cl,pH,alkilinity Barium/strontium, conductivity	2 per flow period	Test Separator	1 Ltr	If produced
Wellstream	CGR determination	30 mins	IWSS manifold		Iso Kinetic CGR determination
Gas/Cond.	PVT	1 set	IWSS manifold	20Lgas 640ccoil	
Gas/Cond.	PVT	1 set	Test Separator	20Lgas 640ccoil	
LP Cond.		1	Test Separator	5Ltr/1Ltr	
Main Flow (90% rate)					
Gas	H_2S and CO_2	hourly	Test Separator	-	Draeger
Gas	H_2S	1 per flow period	Test Separator	-	UOP 212/77
Gas	Mercaptans	1 per flow period	Test Separator	-	UOP 212/77
Gas	Radon	1 per flow period	Test Separator	-	Scintrex Analysis
Gas	Mercury	1 per flow period	Test Separator	-	Sir Galahad method
Gas	Total Sulphur	1 per flow period	Test Separator	10 Ltr	Non reactive bottles Onshore analysis
Water	Cl,pH,alkilinity Barium/strontium, conductivity	2 per flow period	Test Separator	1 Ltr	If produced
Wellstream	CGR determination	30 mins	IWSS manifold		Iso Kinetic CGR determination
Gas/Cond.	PVT	1 set	IWSS manifold	20Lgas 640ccoil	
Gas/Cond.	PVT	1 set	Test Separator	20Lgas 640ccoil	
LP Cond	Bulk/Assay	1	Test Separator	200 Ltr	at end of flow.
LP Cond.		1	Test Separator	5Ltr/1Ltr	

Sample Identification

1. Plastic containers must be suitable for hydrocarbons
2. All samples are to be marked, in a waterproofed manner, with the following information:
3. Date; Time; Well Name; DST Number; Sampling Point; Sample Number
4. PVT samples should additionally have the following information:
5. GasRate; OilRate; Stabilised CGR; Other bottle in pair; Separator or Wellhead Conditions (as appropriate);Perforation Interval

APPENDIX F

Sub Sea Test Tree Disconnect Procedures

General

The purpose of the Sub Sea Test Tree (SSTT) is to provide a fail safe, seabed master valve to shut in the test string and allow disconnection and subsequent reconnection with the well in a controlled state.

Components and Features

The system consists of the following components:

Hydraulic Control Console
Umbilical Hose Reel Pack
Sub Sea Test Tree

The SSTT consists of a hydraulically operated "fail close" ball valve / flapper and unlatch mechanism. Functions include:

Ball valve pressure to open / bleed off to close.

Ball valve – pressure to assist closure.

Latch – pressure to release.

Chemical injection above ball / flapper

A mechanical latch release provides system redundancy. The seabed to rig floor riser can be disconnected from the SSTT lower assembly by applying right hand torque to shear latch head shear pins (pre-set to below tubing torque)

SSTT Disconnection Procedures

1. The decision to disconnect will be made by the OIM following discussions with the Drilling supervisor.
2. The Subsea Test Tree being utilised for this program can be disconnected under tension, but it is advisable to have the tool in neutral tension when unlatching to prevent any sudden string movement after disconnecting.
3. As a guide the following disconnection criteria can be used to assist in making the decision. If the heave has reached 2.5-3m (8-10ft) and the weather forecast predicts worsening weather or there is a chance of the heave increasing, the SSTT should be disconnected. It is not recommended to reconnect until the heave has dropped below 1m (3ft).
4. The Standard Disconnect procedure described below is the preferred method for unlatching the SSTT, it verifies the two mechanical barriers (PCT and SSTT) and allows the kill weight fluid to be placed above the PCT. At least 2 hours should be allowed to disconnect using this method.
5. The Quick Disconnect procedure should be used when it is not clear if there is sufficient time to complete the standard disconnect procedures. This method of unlatching will take at least 15 minutes. This method verifies the two mechanical barriers but does not allow for kill weight mud to be placed above the PCT.
6. The tubing pressure at the tree must exceed the hydrostatic due to annular fluid or seawater above the tree, otherwise the over pressure may open the valve allowing hydrocarbons to release into the sea. This problem will be more likely to occur in deepwater work but may also

occur on any well where the fluids being produced is a relatively dry gas and the tubing pressure is bled off sufficiently.

7. The Emergency Disconnect procedures should be used in "emergency situations" only. The time required to disconnect would be 2 to 5 minutes and only the closure of the SSTT valve is verified.
8. The Mechanical Disconnect procedure should be used when the hydraulic unlatch has failed to operate.

Standard Disconnect Procedure

1. For all downhole tool operations, actual pressures used to cycle tools will be as directed by DST specialist.
2. Bleed off the annulus pressure to close the PCT downhole valve.
3. Bleed off the tubing pressure above the PCT, then monitor to ensure it is closed.
4. Lubricate in kill weight fluids above the PCT.
5. Apply sufficient pressure to the annulus to create an imbalance of annulus over tubing of 4.1 Mpa (600psi) at the MCCV.
6. Apply and release tubing pressure to cycle the MCCV to the reverse position (the annulus pressure will drop when the tool opens).
7. Reverse circulate two string volumes over the rig degasser.
8. Maintain the annulus pressure below 2.7 Mpa (400psi).
9. Close the MCCV.
10. Apply 2.1 Mpa (300psi) to the string, close the SSTT and perform a leak off test for 5-10 minutes, then vent the landing string pressure to zero.
11. With the pressure trapped below the SSTT, slack off the weight of the string and landing string (SSTT should be at least neutral).
12. Pressure the control line to disconnect the tree, wait until the line is fully pressured then pick up the string until the latch mechanism is clear of the riser connector.
13. Close the blind rams above the SSTT valve assembly.
14. Lay down the Flowhead and POOH with the landing string.

Quick Disconnection Procedure

1. Bleed off the annulus pressure to close the PCT downhole valve.
2. Bleed off the tubing pressure above the PCT to ensure the PCT has closed and is sealing, but do not bleed below the hydrostatic of the annular fluid at the seabed.
3. Close the SSTT.
4. Bleed off the landing string pressure to zero and monitor to ensure the valve is holding pressure.
5. Slack off the weight of the string and landing string (SSTT should be at least neutral).
6. Pressure the control line to disconnect the tree, wait until the line is fully pressured then pick up the string until the latch mechanism is clear of the riser connector.
7. Close the blind rams above the SSTT valve assembly.
8. Lay down the Flowhead and POOH with the landing string.

Emergency Disconnect Procedure

1. Close the SSTT.
2. Bleed off the landing string pressure.
3. Bleed off the annulus pressure to close the PCT
4. Slack off the weight of the string and landing string (SSTT should be at least neutral).
5. Pressure the control line to disconnect the tree, wait until the line is fully pressured then pick up the string until the latch mechanism is clear of the riser connector.
6. Close the blind rams above the SSTT valve assembly.
7. Lay down the Flowhead and POOH with the landing string.

Mechanical Unlatch of SSTT Procedure

1. Slack off the weight of the string and landing string (SSTT should be at least neutral).
2. Apply right hand torque using the rig tongs to shear the shear pins.
3. Rotate the string 6 turns.
4. Pick up straight with the elevators and the SSTT will unlatch.
5. The SSTT must be pulled to surface and redressed after a mechanical unlatch.

SSTT Relatch Procedures

- The following procedure assumes the SSTT was retrieved to surface following the disconnect / unlatching. Prior to running in, the latch assembly should be function tested and inspected, the control line hoses and methanol injection hose should be flushed with clean fluids and pressure tested.
- This procedure also assumes a standard unlatch where the tubing has been reversed to kill weight fluids. If this was not the case and hydrocarbons were left in the tubing, immediately after reconnecting and opening the SSTT, fluids will have to be lubricated into the string to allow a pressure test on the relatched SSTT body.

1. Run in hole with the latch assembly and landing string clamping the hoses to the tubing as it is run.
2. Pick up and run in hole the Lubricator valve, flush and pressure test the control hoses and verify the valve is open before running in hole.
3. Pressure test above the Lubricator valve for 10 minutes.
4. Run in hole to the joint below the Flowhead, then pick up the extended bails.
5. Pick up the Flowhead with the single and saver sub attached, make up to the string.
6. Connect surface lines.
7. Run in hole and land onto the tree (note: the latch may land on the top of the valve assembly, if this happens ensure only a small amount of weight is released and using a chain tong rotate the landing string). Rotate the string clockwise using the chain tong, to verify the latch profile has engaged correctly.
8. Bleed off the unlatch pressure and apply 2300kg (5000lb) overpull to verify the latch has engaged.
9. Verify the correct stick-up (check tides).
10. Make up the surface lines and pressure test across the Flowhead.
11. Apply pressure to the landing string to equalise across and open the SSTT.

12. Continue to apply pressure to the tubing after equalisation and perform a 10 minute pressure test on the Test string and the SSTT.
13. Proceed with the Test program

APPENDIX G

Glossary of Terms

API	American Petroleum Institute
bbl(s)	Barrel(s)
BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BOP	Blow Out Preventer
BOPD	Barrels Of Oil Per Day
BS&W	Basic Sediment and Water
CBL/VDL	Cement Bond Log / Variable Density Log
cc	Cubic centimetres
CET	Cement Evaluation Tool
CITHP	Closed In Tubing Head Pressure
DP	Deep Penetrating
DST	Drill Stem Test
DWT	Dead Weight Tester
ESD	Emergency Shut Down
FTHP	Flowing Tubing Head Pressure
FCH	Flow Control Head (same as surface test tree)
gms	Grams
GOR	Gas Oil Ratio
GLR	Gas Liquid Ratio
GR/CCL	Gamma Ray / Casing Collar Locator
HCl	Hydrochloric Acid
Hg	Mercury
HP	High Pressure
Hw	Differential Pressure (inches of water)
ID	Internal Diameter
JHA	Job Hazard Analysis
JSA	Job Safety Analysis
KCl	Potassium Chloride
kPa	Kilo Pascals
LGR	Liquid Gas Ratio
lbs	pounds
LMRP	Lower Marine Riser Package
LPR	Lower Pipe Rams
LP	Low Pressure
MD	Measured Depth
MIC	Man in charge
mm	Millimetres
MMSCFD	Millions Of Standard Cubic Feet Per Day
Mpa	Mega Pascals
MPR	Middle Pipe Rams

MSL	Mean Sea Level
NaCl	Sodium Chloride
OD	Outside Diameter
PBTD	Plug Back Total Depth
PCT	Pressure Controlled Tester valve
Pf	Separator Pressure
POB	Personnel Onboard
POOH	Pull Out Of Hole
ppf	Pounds per Foot
PPG	Pound Per Gallon
PSIA	Pounds Per Square Inch (absolute pressure)
PSIG	Pounds Per Square Inch (gauge pressure)
PVT	Pressure Volume Temperature
RA	Radio Active
RD	Rupture Disc
RIH	Run In Hole
RT	Rotary Table
SITHP	Shut In Tubing Head Pressure
SIBHP	Shut In Bottom Hole Pressure
SHRV	Single Shot Reversing Valve
SPF	Shots Per Foot
SSLV	Sub Sea Lubricator Valve
SSTT	Sub Sea Test Tree
SSV	Surface Safety Valve
STT	Surface Test Tree
sx	Sacks
tba	To Be Advised
TCP	Tubing Conveyed Perforating
TVDRT	Total Vertical Depth Rotary Table
UPR	Upper Pipe Rams
VPR	Variable Pipe Rams
Wf	Weathering Factor
XO	Crossover

Thylacine 2 Well Test Organogram

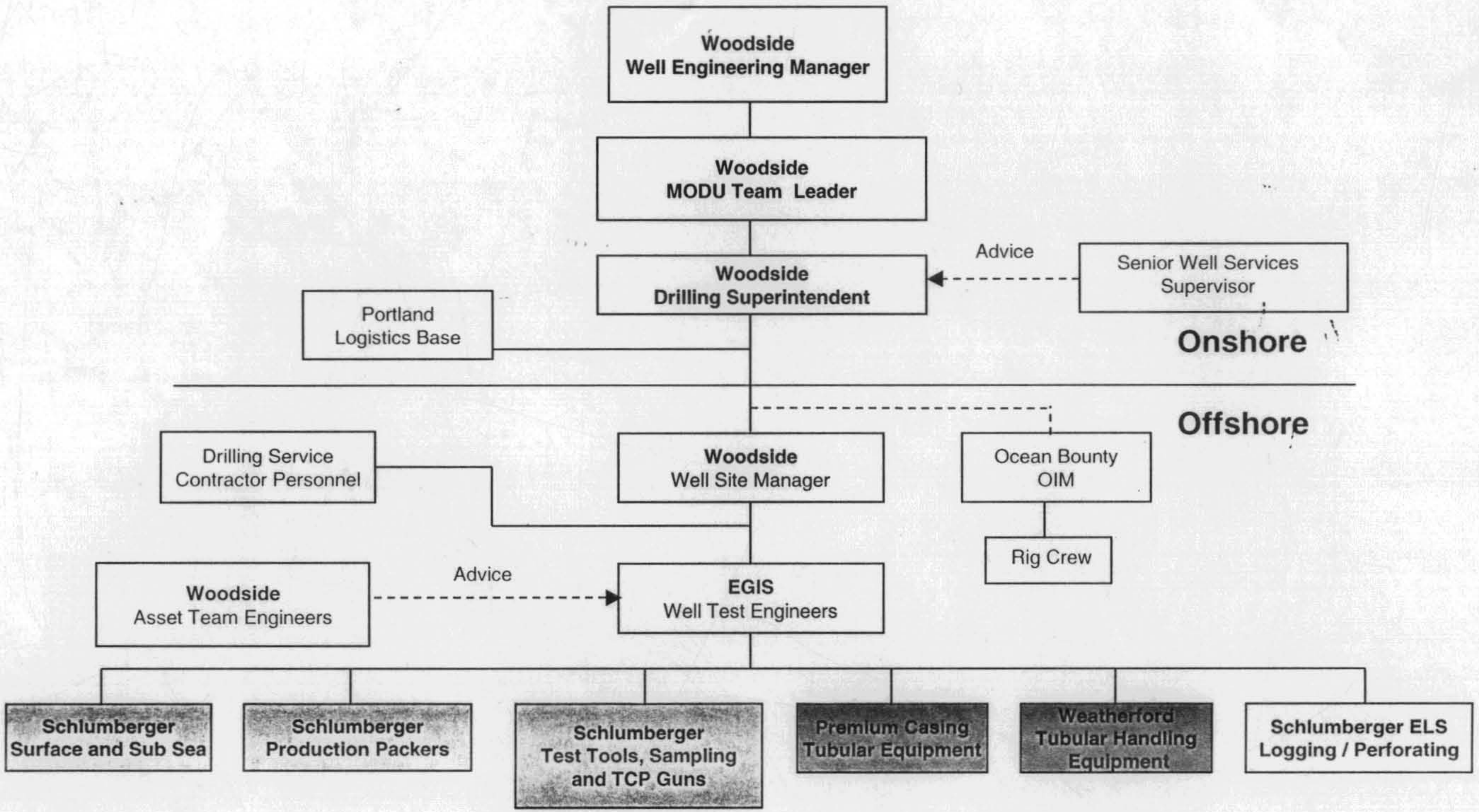

Figure 1

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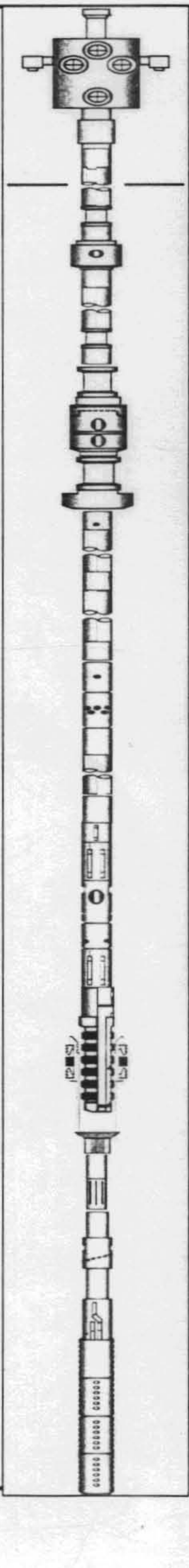
Well No.: Thylacine 2
Rig: Ocean Bounty
Permit No. T/30P

DST STRING DIAGRAM



Description	Connections	Supplier	ID (ins)	OD (ins)	Length (m)	Depth (m)
Flow Head	5"SA pin-down	Schlum.	3.00			
Swivel	5" SA box/pin	Schlum.	3.00			
Crossover		Schlum.	3.00			
4-1/2" 15.5 ppf L80 Tubing	Hydril PH 6	PCS	3.83	5.13		
Pup Joint/Handling Sub	Hydril PH 6	PCS	3.83	5.13		
Crossover		Schlum.	3.00	6.50		
Lubricator Valve	5" SA box/box	Schlum.	3.00	8.25		
Crossover		Schlum.	3.00	6.50		
4-1/2" 15.5 ppf L80 Tubing	Hydril PH 6	PCS	3.83	5.13		
Pup Joint/Handling Sub	Hydril PH 6	PCS	3.83	5.13		
Crossover		Schlum.	3.00	6.50		
Shear Sub	5" SA box/pin	Schlum.	3.00	5.00		
Sub Sea Test Tree	5" SA box/box	Schlum.	3.00	13.00		
Slick Joint	5" SA pin/pin	Schlum.	3.00	5.00		
Adjustable Fluted Hanger	5" SA box/pin	Schlum.	3.00	10.75		
Crossover (5"4-SA box by 5" NV pin)		Schlum.	3.00	6.50		
5" 18 ppf L80 Tubing	5" New Vam	WEL	4.27	5.59		
Crossover (5"NV box by 3-1/2" PH6 pin)		WEL	2.75			
3-1/2" 12.95 ppf L80 Tubing	Hydril PH 6	PCS	2.75	4.31		
Crossover adapter		Schlum.				
Single Shot Reversing Valve		Schlum.	2.25	5.00		
Multi Cycle Circulating Valve		Schlum.	2.25	5.00		
Crossover adapter		Schlum.	2.25	5.00		
3-1/2" 12.95 ppf L80 Tubing	Hydril PH 6	PCS	2.75	4.31		
Crossover adapter		Schlum.	2.25	5.00		
LDCA		Schlum.	2.25	5.00		
DGA Upper Gauge Carrier		Schlum.	2.25	5.50		
Pressure Control Tester Valve		Schlum.	2.25	5.00		
Pressure Operated Reference Tool		Schlum.	2.25	5.00		
DGA Lower Gauge Carrier		Schlum.	2.25	5.00		
TFTV Tubing Test Valve		Schlum.	2.25	5.00		
7" HP Packer and seal mandrel		Schlum.	2.25	6.00		
HP Packer Seal Bore Extension		Schlum.	2.25	6.00		
Crossover		Schlum.	2.44			
2-7/8" Pup Joint		WEL	2.44	3.67		
Ported Flow/Debris Sub		Schlum.	2.44	3.67		
2-7/8" Pup Joint		WEL	2.44	3.67		
Mechanical Gun Drop Sub		Schlum.	2.44	3.67		
2-7/8" Pup Joint		WEL	2.44	3.67		
Hydraulic Firing Head		Schlum.				
Safety Spacer (Blank Gun)		Schlum.		4.50		
4-1/2" TCP Guns		Schlum.		4.50		

5 cm

Figure 2

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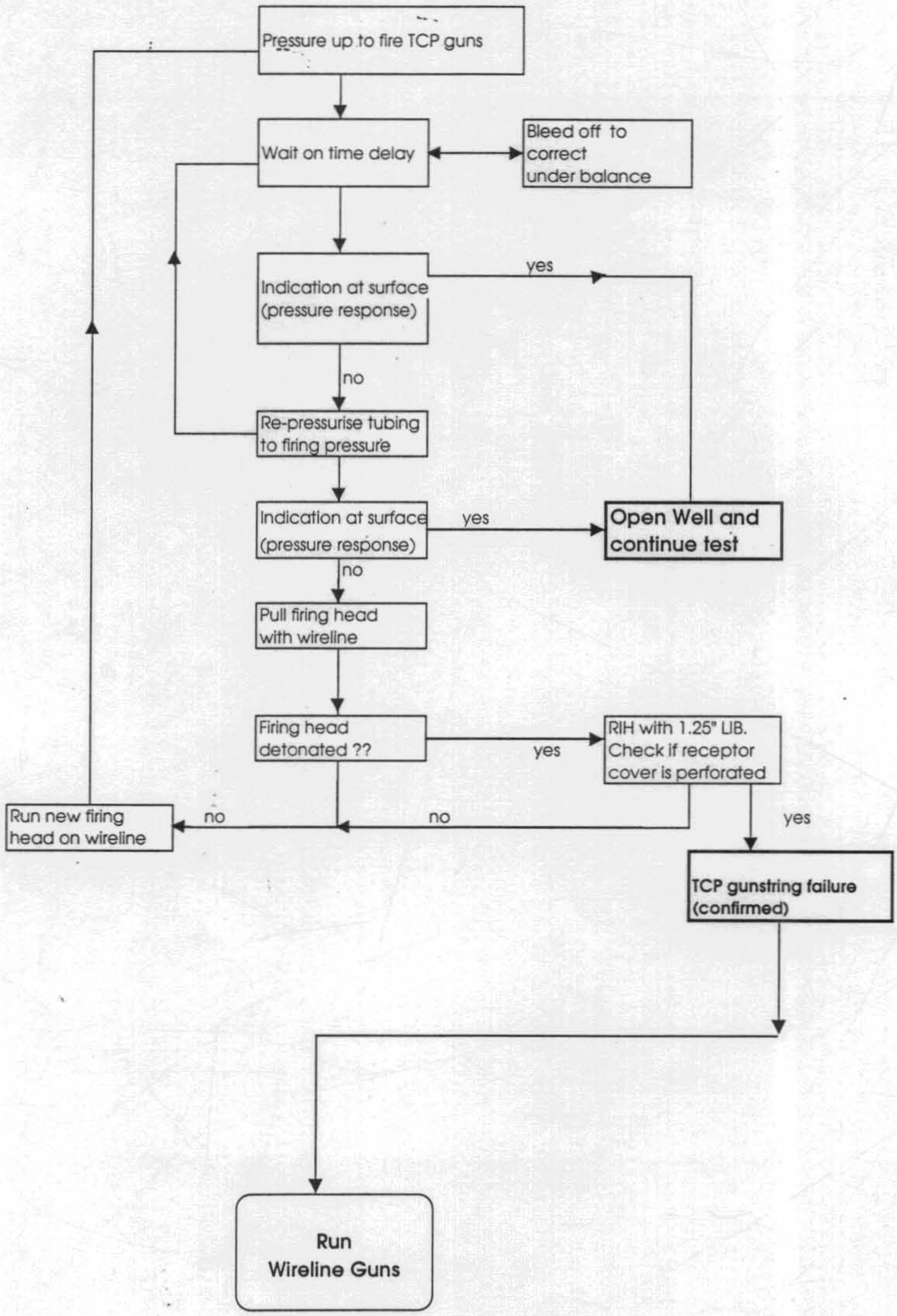
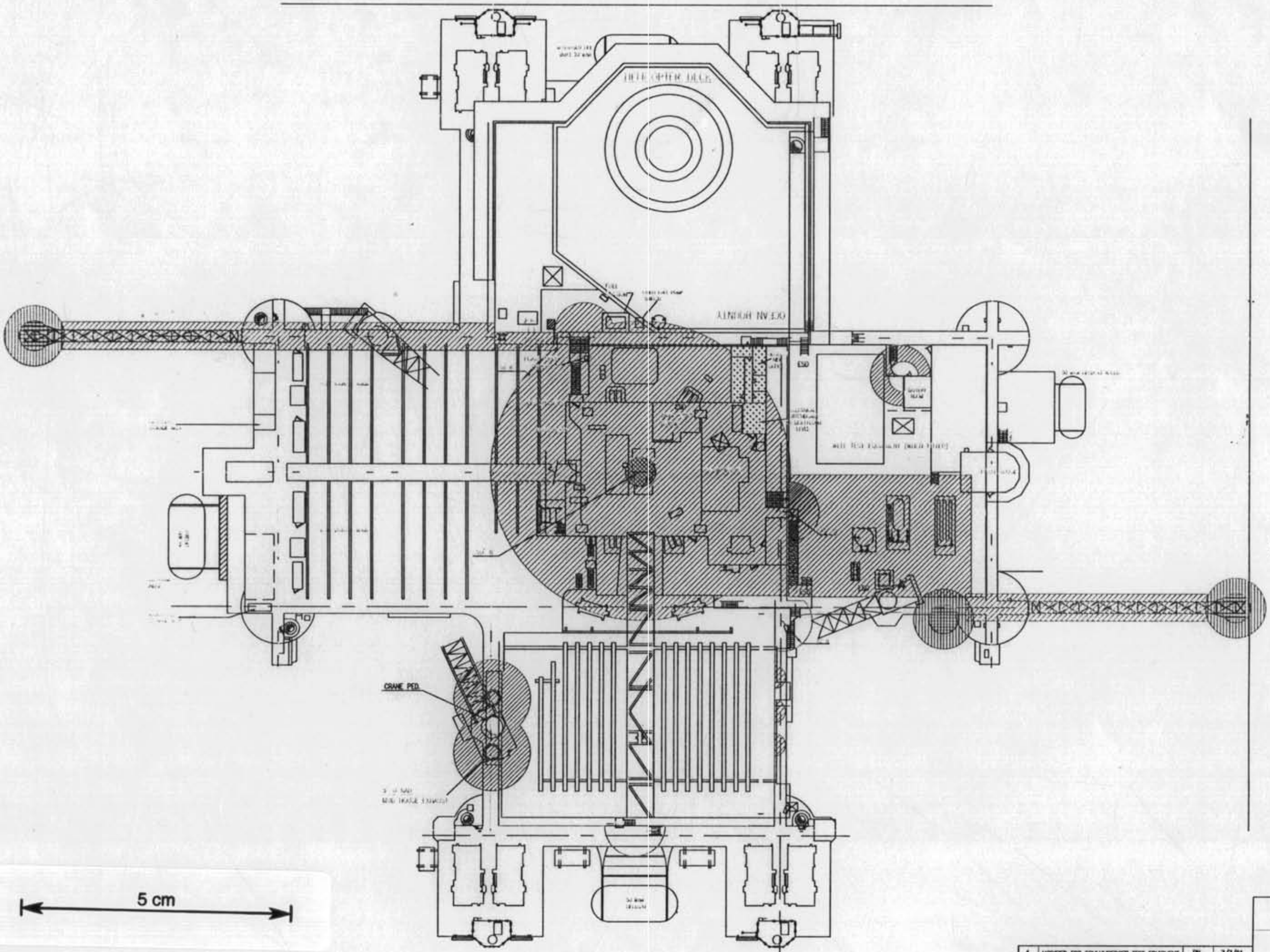
FIGURE 3

WIRELINE PERFORATING - FALL BACK OPTION DECISION TREE





5 cm

MAIN DECK

Figure 4

REV	DESCRIPTION	DWN	DATE
4	MODIFIED FOR SCHLUMBERGER TEST EQUIPMENT	PN	7/7/01
3	THIS REV SUBJECT TO RIG CHECK	APB	2/2/92
2	MODIFIED AS ADVISED BY RIG	P.C.	30/8/91
1	REDRAWN ON CAD	M.A.R	13/5/91
REVISIONS			

Schlumberger

OCEAN BOUNTY

HAZARDOUS AREAS
MAIN DECK

DRAWN M.D	CH'KD	DATE AUG 01	SCALE 1:200
APP'D	DWG NO. 14.80	SHEET	REV 3

080149

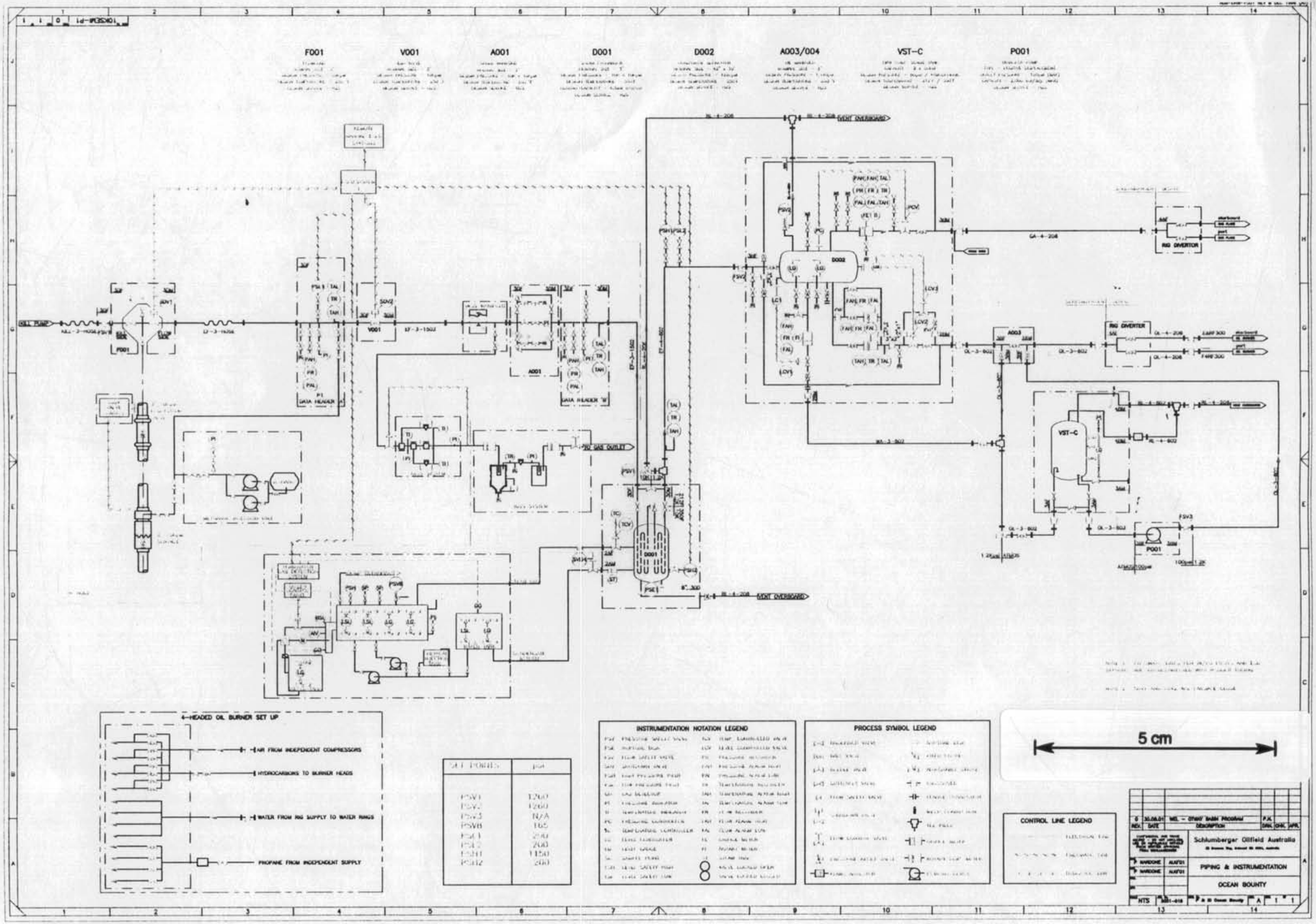


Figure 5.

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