GLOBAL MARITIME
MARINE, OFFSHORE AND ENGINEERING CONSULTANTS
4th Floor, Irwin House, 118 Southwark Street, London, SE1 0SW
Telephone + 44 (0) 20 7922 8900 Fax + 44 (0) 20 7922 8901
Email: gm@globalmaritime.com Website: http://www.globalmaritime.com/

GLOBALSANTAFE

BOP FAILURE MODES EFFECTS ANALYSIS
DEVELOPMENT DRILLER I AND 2

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{ TC SUMMARY}SUMMARY

Global Santa Fe are installing Hydril Blowout Preventers, Lower Marine Riser Packages and Multiplex control systems on their new build semi submersibles DD I and DD II. As part of the verification process Global Maritime have been instructed to carry out an FMEA of these systems.

The FMEA reviewed Hydril documentation of the BOP, LMRP and control system hydraulic, electrical and electronic subsystems in order to identify any potential single point failures. Failures of importance are those that would result in loss of well control or prevent disconnection of the LMRP when required.

The study identified no single point failures in the multiplex control system however there are a number of potential single point failures in the LMRP and BOP. The most critical failures would be external leakage and connector failure to unlock on demand. External leaks at the BOP or LMRP connectors or the flex joint could result in loss of well control. However the probability of these occurring is very low. A recent SINTEF study in the Gulf of Mexico indicated that the majority of leaks reported were identified during regular BOP testing and not during operations.

Failure to disconnect on demand would only be a problem in an emergency disconnect situation, in normal operations this would result in operational delay only. Again the probability of this occurring is considered to be very low.

There are a number of situations where failures could result in adverse consequences in emergency conditions. However most of these would represent double or multiple failures and these are outlined below.

A fire could disable the blue or yellow network cabling, however if the cable routes were separate it is unlikely that both channels would be affected. (GM do not have details of the cable routes at this time) In the event of failure of the blue and yellow CCUs it would be necessary to deploy the ROV to close the stack rams as the system is not supplied with an Acoustic back-up control system. However the system is configured for the installation of an acoustic back up system if required by Clients. In the event of such a catastrophic event occurred it is likely that vessel safety would be more of a concern than that of the well. The probability of this occurrence is considered to be very low.

In a well control situation the failure of the shear rams to cut tubulars (drill pipe or casing) and seal the well bore would be critical. However the BOP is fitted with casing shear rams and blind shear rams and the probability of this occurrence is low. For large assemblies, such as the BHA, the time across the BOP would normally be kept to a minimum and heightened levels of alert are likely to be in place. These aspects would be addressed in the Global Santa Fe procedures.

The Autoshear system operates when there have been a number of failures (i.e. loss of hydraulic power to both control pods, <u>and</u> a loss of electrical power to both pods). Failure of one of the Autoshear components could result in the failure to seal the wellbore when required. However this requires multiple failures and the probability of this occurrence is likely to be very low.

When carrying out DP drilling operations any loss of position has the potential for catastrophic consequences and the Emergency Disconnect System (EDS) is provided to shut down the BOP and disconnect the LMRP. Any delay in the disconnect sequence could result in damage to the

riser or flex joint and DP operator procedures should provide clear guidance regarding position offset and riser angle limitations.

The EDS sequence times were recorded during FAT tests and these should be used to assist the development of emergency abandonment procedures. It is normal DP procedure to use green, yellow and red alert signals to inform drilling personnel the DP status and it is therefore essential that communications and procedures for DP and drilling personnel are clearly defined.

The FMEA has identified a number of recommendations including the following:

- A review of the PDP and CCU locations and power/communication cable routeing should be carried out to identify whether the MUX system could be disabled by a single occurrence of fire/explosion.
- EDS shutdown times should be recorded when the stack and MUX control system is installed and commissioned on the drilling rigs. The EDS times should then be reviewed in conjunction with vessel DP drive/drift off times so that appropriate abandonment procedures can be developed.

Following a review of the Hydril FAT procedures a series of FMEA tests has been outlined. It is proposed that these tests are carried out after the well control equipment has been installed and commissioned on the rig and could form part of the system integration tests. It is anticipated that more detailed procedures will be required when the scope of these tests have been reviewed and agreed by Global Santa Fe.

KEYWORDS

Global Santa Fe	Hydril	Multiplex Control	FMEA
BOP	LMRP	DP Drilling	

1. INTRODUCTION

1.1 Background

1.1.1 Global Santa Fe have ordered Hydril blowout preventers (BOP) and multiplex control systems for their newbuild semi submersible drilling DD I and DD II. As part of the system verification process Global Santa Fe have instructed Global Maritime (GM) to carry out a Failure Modes and Effects Analysis of these systems.

1.1.2 The items covered by the FMEA are to include:

- BOP and lower marine riser package (LMRP) functions.
- BOP and LMRP control system (electronics and electrical power systems).
- BOP and LMRP control system (hydraulic systems).
- BOP multiplex control system.
- Auto shear, EDS and back-up systems.

1.1.3 An initial meeting was held with Hydril in Houston on 14th May 2002. Following discussions with Bruce Pettey, Project Manager, and Randy Corliss, Project Engineer, a visit of Hydril manufacturing facilities was made to familiarise D Rankin (GM) with the project well control equipment.

1.1.4 At this stage the following Hydril documentation was issued to GM:

Documents:

- Technical Specification for Santa Fe Semi Rigs DD I and DD II BOP Control Systems – Document No. X-1001739 Rev NC.
- Santa Fe Rig 184 New Build Semi Submersible Hydril BOP Stack, Control System & Diverter Controls – Document No. AFP-184-040 Rev 0.
- Mux Control System Overview & Operations (Training Manual).

Drawings:

- Scope of Supply Rigs 184 & 185 Santa Fe – X-1001704 Rev A1.
- Stack Configuration for Santa Fe Rigs 184 & 185 – X-1002123 Rev E2.
- Block Diagram Power Distribution System – X-1002807 Rev A1.
- Block Diagram Hydraulic Interconnect Santa Fe Rig 184/185 – X-1001710 Rev C1.
- Hydraulic Mux Pod Santa Fe Rig 184/185 – X-1001538 Rev E1.
- Hydraulic LMRP Santa Fe Rig 184/185 – X-1001536 Rev C2.
- Hydraulic Stack Santa Fe Rig 184/185 – X-1001537 Rev E3.

Following the initial meeting in Houston Hydril forwarded a CD ROM containing the Operation and Maintenance Manuals for the Diamond Ocean Baroness.

1.2 Instructions

1.2.1 Global Maritime Inc. are carrying out a number of studies on the DP and ballast systems on the Global Santa Fe DD I and DD II and this scope has been extended to included the blowout preventer systems Instructions were received from Klaus Backstrom of Global Santa Fe and these were followed by the issue of a purchase order.

1.3 Scope of Work

1.3.1 The scope of work is to carry out an FMEA of the BOP stack and control system to verify that there are no single point failures in these systems. The main functions of these systems are to control the well and ensure safe disconnection of the LMRP when required. The FMEA will therefore concentrate on the functions required to satisfy these requirements.

1.3.2 The scope of work includes the following activities:

- Review vendor specifications, drawings and procedures.
- Identify safety critical items.
- Carry out FMEA of BOP, LMRP and multiplex control system.
- Revise FMEA in line with client/independent expert comments.
- Review vendor/project FAT and commissioning test procedures.
- Produce FMEA proving test procedures.
- Witness FAT and FMEA proving tests.
- Update FMEA following FMEA tests.

1.4 Approach

1.4.1 The FMEA is carried out by reviewing the main systems of the BOP and control equipment. Each of the main systems is divided into subsystems and the possible failures of each component are considered in turn. The failures are listed in tabular form included in Appendix I of this document.

1.4.2 The Diverter system is not included in the FMEA.

1.4.3 The failure is described in terms of failure mode, causes local effect, final effect and the criticality and probability of the failure. The analysis of failure effects considers the immediate and the possible final consequences of the failure with the most serious being a loss of well control or the inability to disconnect the LMRP on demand.

1.5 Report Layout

1.5.1 The report has been presented as follows:

- System Overview.
- Control System Hydraulics.
- Control System Electrical Power.
- Control System Electronics.
- LMRP Functions.
- BOP Functions.
- FMEA proving tests
- Conclusions and Recommendations
- Tabulated Failure Modes
- Tabulated FMEA tests

1.6 Abbreviations

BHA	Bottom hole assembly.
BOP	Blowout preventer.

CCU	Central control unit.
CP	Control processor.
DP	Dynamic positioning.
ECM	Electronic control module.
EDS	Emergency disconnect system.
EH	Electro-hydraulic.
ERA	Electronic riser angle.
FAT	Factory acceptance tests.
FRU	Fluid reservoir/mixing unit
HPHT	High pressure high temperature.
HPU	Hydraulic power unit.
I/F	Interface.
LHVC	Lower hydraulic valve control.
LMRP	Lower marine riser package.
MCC	Motor control centre
MRT	Marine riser tensioner
MUX	Multiplex.
NIC	Network inter-connection
NNP	Network node processor.
PDP	Power distribution panel.
RTU	Remote terminal unit.
SEM	Subsea electronics module.
UPS	Uninterruptible power supply.
VBR	Variable bore ram.

2. SYSTEM OVERVIEW

2.1 General Description

2.1.1 The multiplex control system is designed to operate the well control system on the LMRP and the stack. The system comprises hydraulic, electronic and electrical power subsystems. The system operation is summarised in the following paragraphs.

2.1.2 The surface hydraulic system comprises a fluid reservoir/mixing unit (FRU), a hydraulic pump unit (HPU) and accumulator banks to store hydraulic fluid under pressure. Potable water is UV filtered before it enters the FRU inlet and the mixed fluid from the FRU is then passed through suction strainer of 100 mesh. The pressurised mixed fluid is subsequently passed through high pressure 40 micron filters.

2.1.3 The HPU and accumulators supply hydraulic fluid at 5,000 psi from the surface to the subsea control system via blue and yellow rigid conduits running down the riser. Each conduit ends at a rigid conduit manifold which is used to direct fluid to the hydraulic stabs and either or both control pods. The hydraulic fluid is filtered and reduced to 3,000 psi before passing into the control pods through the riser receiver. A 3,000 psi Hot line supplies control fluid to the subsea control pods via a port on the lower valve unit frame. Each control pod has an electro-hydraulic section attached to a lower hydraulic valve control section. Fluid transfer between the two pod sections is achieved through sealed ports in the seal sub interface where the pod sections join together. Hydraulic communication between the pod, LMRP and stack components occur through the flow ports in extendable pod stab and receiver assemblies on the stack and LMRP. Two other extendable stabs supply 5,000-psi hydraulic fluid to the four-160 gallon subsea accumulator racks on the stack.

2.1.4 The HPU also provides fluid to a separate Diverter control system which comprises a skid mounted assembly of valves regulators and accumulators that are used to control the diverter functions. This system requires a compressed air supply from the drilling rig.

2.1.5 Three control consoles; the Driller's panel, the Central Control Unit (CCU) and the Remote Control panel are provided for operator control. Commands generated from these panels operate the Blue and Yellow control pods fitted to the LMRP. These pods can be operated from any one of the panels individually or in combination. Only the CCU is in direct communication with the pods. HPU and diverter control equipment can be operated locally or remotely from the operator panels. Remote control is achieved through communication between the CCU and HPU Interface panel and the Diverter Interface panel.

2.1.6 Commands from the CCU are transmitted down multiplex umbilical cables that run down the riser to the electro-hydraulic section of each pod. Two Subsea electronic modules (SEMs A and B) are located in each pod and are used for signal processing and distribution to the electrically operated solenoid valves. The solenoid valves apply or remove pilot pressure to subplate mounted (SPM) valves in the lower hydraulic sections of the pods. These SPMs then function accordingly to operate BOP control components on the stack and LMRP.

2.1.7 Inclinometers and gyros are provided in the pod instrumentation and electronic riser angle (ERA) sensors are located at the base and top of the riser. Signals from the inclinometers, gyros and ERA are processed in navigation computers located in each pod and the data is displayed on graphic screens in the panels and CCUs. Temperature and pressure sensors are also located in various parts of the stack.

2.1.8 Vessel electrical power is supplied to the blue and yellow power distribution panels which are also supplied by UPS systems. Vessel power is supplied through separate switchboards and generators.

2.1.9 The main elements of the control system are located on the upper hull intermediate deck and are distributed as follows:

BOP Control Room.
- The HPU pump unit.
- Reservoir/mixing unit.
- Diverter control unit.

Main Deck at Subsea Workshop
- The CCU cabinet (containing blue and yellow CCU).

Elevated deck adjacent to BOP Control Room.
- Blue UPS.
- Blue battery cabinet.
- Blue Power distribution panel (PDP).

Elevated deck adjacent to Engine Control Room.
- Yellow UPS.
- Yellow battery cabinet.
- Yellow Power distribution panel (PDP).

2.1.10 The MUX and hot line cable reels are located around the edges of the moonpool on the Upper Hull Main Deck as follows:

- Yellow reel at the forward end of the moonpool
- Blue reel at the aft end of the moonpool
- Hot line reel at the aft port side of the moonpool.

2.1.11 It is assumed that the Driller's panel is located in the control cabin adjacent to the drill floor and the Remote Control panel is located in the Command Centre on the bridge.

2.2 LMRP Assembly

2.2.1 The LMRP assembly includes a 10,000 psi annular blowout preventer, an LMRP connector, flex joint and booster, gas bleed valves, test valves, rigid conduit manifold, control system accumulators and electro-hydraulic components.

2.3 Stack Assembly

2.3.1 The stack assembly comprises a wellhead connector, a 10,000 psi annular blowout preventer, one single and two double 15,000 psi ram preventers, control system accumulators and electro-hydraulic components.

2.3.2 For the purposes of the FMEA it is assumed that the ram preventers are arranged from the top down as follows:

- Blind shear
- Casing shear
- Upper
- Middle
- Lower

2.4 Hydril Equipment Supply

2.4.1 The main items of the BOP system are listed below. Most components have been supplied by Hydril although a number of items have been supplied by Global Santa Fe.

LMRP assembly comprising:

- LMRP connector. (note 1)
- Annular preventer.
- Kill and choke valves. (note 1)
- Accumulators

Stack assembly comprising:

- Wellhead connector. (note 1)
- Annular preventer.
- One single ram preventer.
- Two double ram preventers.
- Kill and choke valves. (note 1)
- Accumulators

The supply also includes sets of preventer rams including fixed pipe, VBR, blind/shear and casing shear rams.

The Hydril scope of supply includes the ROV receivers and plugs.

Multiplex Control System comprising:

- Hydraulic system.
- Electrical power system.
- Electronic communication system.
- Subsea control pods and receptacles.

Note 1: Equipment supplied by Global Santa Fe.

3. CONTROL SYSTEM - HYDRAULIC SUBSYSTEM

3.1 Introduction

3.1.1 The surface control system comprises a fluid reservoir and mixing unit, a hydraulic pump unit and surface accumulator banks. The surface system supplies fluid to the diverter and subsea systems. The subsea system comprises the rigid conduits, the hot line, the rigid conduit manifold and the multiplex pods.

3.2 Fluid Reservoir and Mixing Unit

3.2.1 This unit contains three tanks; one holds water soluble oil concentrate, one holds ethylene glycol and the third tank is used for mixing. Measured amounts of potable water, glycol and soluble oil concentrate are mixed in the third tank.

3.2.2 The tank volumes are designed as follows:

- Mixing tank – large enough to hold total fluid volume stored in the control system accumulators with sufficient space to allow the largest bank of accumulators to drain back into the tank without overflowing. (In accordance with API 16D).
- Ethylene glycol – large enough to hold sufficient glycol to mix one and a half times the total hydraulic fluid volume stored in the system accumulators. (In accordance with API 16D).
- Water soluble oil concentrate – large enough to hold sufficient concentrate to mix ten times the total hydraulic fluid volume stored in the system accumulators. (In accordance with API 16D).

3.2.3 The mixing system uses variable drive motor controllers to control linear displacement pumps and refractometers to control the flow of water, glycol and concentrate. The mixing system supply pumps are designed to ensure that the mixing unit matches the HPU discharge rate. The mixing tank is fitted with float valves that automatically stop the system when the mixed fluid reservoir reaches the upper level and start the system when the fluid level drops to the low level.

3.2.4 There are a number of alarms for low glycol and concentrate level, low water supply, low mix level and flow rates out of specification. If fluid drains below a pre-set critical level the alarm system will shut down the HPU pumps.

3.2.5 The system requires electrical power and water to be provided by the drilling rig.

3.3 Hydraulic Pumping Unit

3.3.1 The HPU is a skid mounted pumping system fitted with pumps, piping regulators and valves. The HPU draws fluid from the fluid reservoir, pressurises it and distributes it to the surface and subsea control equipment. The pumps are connected to sensors in the reservoir unit which automatically control their operation. Low-low level sensors shut down the pumps while pressure transducers and switches control the operation of the pumps. The HPU outlet valves can be controlled locally or remotely from the Driller's or Remote Control panels or CCU screens. The high pressure (5,000 psi) hydraulic fluid is passed through dual filters to ensure that clean fluid (NAS 10) is supplied to diverter, the accumulators, the hot line reel and a header. The header has four outlets to the rigid conduits (blue and yellow), pod test area, moonpool and the rig floor. The HPU outlet valves are ball valves operated by electrical actuators which are fitted with manual overides. The Hot line outlet is fitted with a regulator to reduce the pressure to 3,000 psi.

3.3.2 The HPU system contains two 100 hp quintuplex pumps which are belt driven. With the accumulators isolated from the system each pump has the capacity to close one annular preventer on an open hole, open the hydraulic choke valves and provide minimum system operating pressure within 2 minutes. The combined output of both pumps is capable of charging the entire accumulator system from pre-charge pressure to the maximum working pressure within 15 minutes.

3.3.3 Provision has been made for the installation of additional pumps which could be used in the event of additional system requirements. Global Santa Fe will fit these back-up pumps as and if required.

3.3.4 The pumps are protected from over pressurisation by pressure transducers, pressure switches and relief valves. The system is protected from pressure fluctuations by pulsation dampers which are small accumulators with a pre-charge of 1,800 psi.

3.3.5 Electrical power for the reservoir/mixing unit and HPU pumps is distributed through the vessel MCC panels as follows. HPU pump No. 1 is supplied from the 480 Vac Emergency switchboard and HPU pump No. 2 is supplied from the Drilling MCC No. 2 switchboard. Loss of HPU pump power is alarmed on the CCU, Driller's Panel and Remote Control Panel.

3.4 Surface Accumulator Racks

3.4.1 Three racks of accumulators are provided for BOP functions and one rack is provided for diverter functions. Accumulator capacities are as follows:

- BOP - 2 racks with 20 accumulators and 1 with 8 accumulators (total capacity 720 gallons).
- Diverter -1 rack with 12 accumulators (total capacity 180 gallons).

Each accumulator capacity is 15 gallon with a working pressure of 5,000 psi.

3.4.2 Accumulator capacity must be sufficient to open and close all ram preventers and one annular preventer once at zero well bore pressure with at least 50% reserve. Furthermore the pressure of the remaining stored volume after the opening and closing cycle must exceed the greater of the following:

- The minimum calculated operating pressure required to close any ram type preventer at the maximum rated pressure of the stack.
- The minimum calculated operating pressure required to open and hold open any choke or kill valve in the stack at the maximum rated pressure of the stack.

Information on these volumes and pressures is not available at present but sizing calculations will be carried out in accordance with API 16D.

3.4.3 Accumulator pressure and low accumulator pressure is indicated and alarmed on the CCU, Driller's and Remote Control panels.

3.5 Rigid Conduit and Manifold

3.5.1 The hydraulic fluid is supplied to the control pods and the subsea accumulators via the blue and yellow rigid conduit lines which are attached to the sides of the marine riser. The rigid conduits terminate at the rigid conduit manifold located on the LMRP and comprise check valves, filter assemblies and SPM isolation and dump valves. The manifold is connected to the stack mounted accumulators via a 5,000 psi hydraulic extend/retract stab. The high pressure fluid is provided to the control pod supplies through pressure reducing and regulating valves, set at 3,000 psi. Seven SPM control valves are fitted in the conduit manifold circuit and are used for conduit isolation, accumulator charge and accumulator dump functions. A crossover valve connects the blue and yellow conduits.

3.5.2 A 1" hot line hose also provides hydraulic fluid for subsea start up functions, such as LMRP lock to the stack, and for all pod controlled functions. The hot line pressure is regulated to 3000 psi and cannot therefore be used to charge the subsea accumulators. The control fluid is piped subsea via a hose stored on an air powered reel and is connected to the MUX pods via a port on the lower valve unit frame. Four 15 gallon accumulators are used on the supply line for the few cases where volume demand exceeds the flow rate of the hot line hose.

3.6 Multiplex Control Pods

3.6.1 The blue and yellow multiplex control pods comprise the following three sections:

- Subsea electronics
- Pressure compensated electro-hydraulic (E/H) solenoid housing
- Hydraulic section (Lower hydraulic valve control – LHVC)

This section will consider the hydraulic components and the electrical and electronic components are considered in later sections.

3.6.2 The E/H and LHVC sections are bolted together to form a control pod which is bolted to a riser receiver assembly on the LMRP. A spring loaded stack receiver assembly is located on the BOP stack. Each receiver assembly has an open rectangular frame, two sides of which are angled and ported for hydraulic flow. In the LMRP receiver the two angled/port sides interface with the ported faces at each end of the LHVC section. The angled/ported sides of the stack receiver interface with the ported faces on a stab that extends from the LHVC section. The control pod stab conveys hydraulic flow between the LHVC section and the hydraulic components on the BOP stack and LMRP.

3.6.3 Once the LMRP is landed on the BOP section the pod stab can be extended bringing it into contact with the riser receiver and BOP receiver. Stab seals form a fluid tight seal between the ports on the riser receiver, the BOP receiver and the pod stab. The spring mounted BOP receiver is designed to allow for any vertical misalignment between the BOP and riser sections.

3.6.4 The EH unit comprises 5 sub- assemblies: the electronics control module enclosure, the transformer enclosure, the VCC-29 connector and 2 solenoid enclosures. As previously mentioned electrical and electronic systems are discussed later.

3.6.5 Each pressure compensated solenoid enclosure contains up to 48 solenoids and 10 pressure transducers. The Global Santa Fe system will be fitted with 47 solenoids in one enclosure and 46 in the other. The system will include 10 transducers in each enclosure with the remaining slots blanked off for future upgrades. The enclosures are filled with non-conductive silicon oil and are fitted with Hydril compensator bladders.

3.6.6 The shear seal valves are mounted on the outside of each solenoid enclosure and are operated by the solenoids. The solenoids are energised and de-energised to open and close the shear seal valves which in turn initiate and terminate pilot fluid flow to the SPM valves in the LHVC section. Pilot fluid flow between the EH section and the LHVC section is achieved through the use of seal subs fitted between the EH and LHVC junction plates. The hydraulic pilot signal actuates the SPM valves to provide fluid through the pod stab and to the appropriate BOP function on the stack. Two 2.5 litre accumulators are connected to the pilot circuit to actuate critical functions and allow for a faster response time. These accumulators are located in the hydraulic section of the pod.

3.6.7 The LHVC has 84 hydraulic ports through the receivers and can control up to 96 separate stack functions, although the Global Santa Fe system is designed for 93 functions. All hydraulic connections are hard piped or are made up through the stab block.

3.6.8 High pressure fluid is received via the rigid conduit system, the hot line and the stack mounted accumulators. Four hydraulic pressure regulators are provided to step down the 3,000 psi pod working pressure to those functions requiring lower pressures. These regulators are the Upper Annular, Lower Annular, the Wellhead Connector and the Subsea Manifold regulator. The first three regulators circuits have 2.5 litre and 1 quart accumulators connected to the circuit to enable operation at the surface and subsea. The 1 quart accumulator is provided for surface operations and the 2.5 litre accumulator is pre-charged at a higher pressure for subsea operation. The Subsea Manifold regulator circuit has two 2.5 litre piston accumulators connected to the circuit to allow operation at the surface and during the trip from surface to the seabed.

3.6.9 Three sizes of SPM valves are installed inside the LHVC: ½", 1" and 1½" and these route the hydraulic fluid to most of the BOP stack functions.

3.7 LMRP Disconnect Monitor

3.7.1 This mechanism is used to monitor the connection between the LMRP and BOP stack and comprises two assemblies which bolt to opposite sides of a sidebar on the LMRP. The lower assembly comprises an extendable rod and the upper assembly comprises a valve assembly (Disconnect Actuator). The lower end of the rod is forced upwards when the LMRP is landed on the BOP and the upper end of the rod moves upwards to effectively close the fluid flow path through the upper valve assembly. When the connection of the LMRP is completed the LMRP Disconnect Arm shear seal valve is activated from the surface and this applies 3,000 psi pilot fluid to the disconnect actuator valve. Should the LMRP separate from the stack, the springs in the valve and disconnect assembly will extend the rod and open the fluid flow path through the valve. The resulting fluid flow produces a pressure signal which is transmitted to a pressure transducer and pressure switch in the control pods. The pods then relay this signal to the surface control system. The pressure switch signals are used to activate the riser recoil system. There is also a dedicated pair of wires in each MUX cable connecting the switch contacts to the riser recoil system.

3.8 Autoshear Function

3.8.1 The autoshear function is designed to sever the drill string, shut in the well bore and unlatch the riser connector in an emergency. The emergencies are defined as:

- Loss of electrical power in both subsea pods and the loss of all hydraulic pressure in the rigid conduit and hotline which supplies the autoshear circuit.
- Unintended separation of the LMRP from the stack which results in a loss of hydraulic and electrical communication between the stack components and the pods.

When either or both of these conditions occur the autoshear system automatically activates to close the blind and casing shear rams and unlatch the riser connector.

3.8.2 The autoshear assembly comprises pod and stack mounted hydraulic circuits. These circuits operate a stack mounted dual valve assembly that controls the flow path between the shear rams and stack mounted accumulators. The system has three circuit configurations: disarmed, armed and activated. The disarmed and armed conditions are established by commands from the surface control panel. The activated condition results from loss of electrical and hydraulic communication with the surface.

3.8.3 The pod and stack valve status for each condition is indicated below. In the armed condition the stack mounted Hydraulic Autoshear valve is kept closed by the pilot fluid from the energised and open Wired On Supply solenoid valve. When the Wired On Supply valve is de-energised the hydraulic pilot line is depressurised and the stack mounted Hydraulic Autoshear valve opens and fluid from the stack mounted accumulators is directed to the close ports on the shear rams and the unlock ports on the riser connector. Fluid from the accumulators is reduced to 3,000 psi by a stack mounted regulator before passing to the stack ports. A 23 second delay, achieved through the use of an accumulator restrictor and filters, is incorporated to ensure clearance between the LMRP and BOP when disconnected.

Valve Status	**Disarmed**	**Armed**	**Activated**
Blue and Yellow Pods			
Wired on supply	Energised	Energised	De-energised
Autoshear arm	De-energised	Energised	De-energised
Autoshear disarm	Energised	De-energised	De-energised
Autoshear control reset	Energised	De-energised	De-energised
Hydraulic supply lines	Pressurised	Pressurised	De-pressurised
Autoshear control	Closed	Open	Open
On Stack			
Autoshear arm	Closed	Open	Open
Hydraulic autoshear	Open	Closed	Open
Riser connector	Locked	Locked	Unlocked
Pod stabs	Extended	Extended	Retracted
Shear rams	Open	Open	Closed

3.8.4 The Autoshear Control Reset solenoid is energised via software when any of the following solenoids is energised:

- Internal pod stab retract.
- Riser connector primary unlock.

- Riser connector secondary unlock.
- Autoshear disarm.

3.9 Emergency Disconnect Sequence

3.9.1 It is understood that the Emergency Disconnect Sequence is being developed and the sequence discussed here is based on the system proposed in January 2002.

3.9.2 The emergency disconnect is performed in a pre-programmed sequence contained within the MUX control system software and is activated by the EDS panel button on both BOP control panel touch screens. The EDS sequence has been defined by Global Santa Fe in accordance with the company's operating philosophy and rig specific equipment.

3.9.3 With regard to operating philosophies it is understood that there are ongoing discussions regarding the provision of a NO-SHEAR emergency disconnect function in addition to the SHEAR EDS. This would be required in situations where non-shearables are across the BOP during an emergency disconnect. This point has not yet been finalised, however a NO-SHEAR EDS sequence is included in the system description.

3.9.4 In order to understand the reason certain functions are included, and others excluded, and the order in which these appear in the EDS sequence the following points are made:

- The proposed sequence is based upon a maximum of 45 seconds to disconnect the LMRP upon activation of the EDS function. This is based on API 16E.3.1 which states: "Time to unlatch the LMRP should not exceed 45 seconds. Measurement of response time begins when the button is pushed and ends when the connector is fully unlatched and clear of the stack". Both sequences are quicker than this time and estimated function times are included in this section.
- The proposed sequence is based on using the casing shear rams to perform all cutting operations and the shear blind rams for securing the well bore.
- The proposed sequence is based on the current BOP configuration and does not allow for the 6-ram BOP option. This would require a software change to the EDS sequence should this option be adopted in the future.
- Sub sea accumulators are to be run in the isolated position dedicated to the Autoshear with LMRP/BOP and pod functions supplied directly from the surface through the rigid conduit lines.
- The proposed sequence takes into account that the shear/blind rams are closed by the Autoshear system (after a 20 to 30-second hydraulic time delay) in the event of LMRP separation. This will allow sufficient time for the 'fish' to leave the BOP prior to the shear/blind rams closing. This will be important when pipe, such as heavy weight or casing is across the BOP.

3.9.5 <u>Shear EDS Sequence</u>:

The EDS sequence is listed below with the times recorded during the FAT tests at Hydril:

Order	EDS (Shear Mode) Function	Operation	Time (secs)
1.	BOP Accumulator Isolation Valves	Block.	0-3
2.	LMRP Disconnect Indicator	Arm.	0-2
3.	Autoshear	Arm.	0-2
4.	Riser Recoil System	Arm.	0-2
5.	Casing Shear Rams High Pressure	Close.	0-20
6.	Upper Outer Kill	Close.	2-7
7.	Upper Inner Kill	Close.	2-7
8.	Lower Outer Kill	Close	2-7
9.	Lower Inner Kill	Close.	2-7
10.	Upper Outer Choke	Close.	2-7
11.	Upper Inner Choke	Close.	2-7
12.	Lower Outer Choke	Close.	2-7
13.	Lower Inner Choke	Close.	2-7
14.	Lower Annular	Block	4-6
15.	Upper Pipe Rams	Block	4-6
16.	Middle Pipe Rams	Block.	4-6
17.	Lower Pipe Rams	Block.	4-6
18.	Wellhead Connector	Block.	4-6
19.	Wellhead Connector Gasket	Block.	4-6
20.	Shear Blind Rams	Block.	4-6
21.	BOP Accumulator Dump Valve	Block.	4-6
22.	Upper Inner Kill	Block.	7-9
23.	Upper Outer Kill	Block.	7-9
24.	Lower Inner Kill	Block.	7-9
25.	Lower Outer Kill	Block.	7-9
26.	Upper Inner Choke	Block.	7-9
27.	Upper Outer Choke	Block.	7-9
28.	Lower Inner Choke	Block.	7-9
29.	Lower Outer Choke	Block.	7-9
30.	Choke and Kill Test Valves	Close.	20-25
31.	Mud Boost Valve	Close.	20-25
32.	Blue BOP Accumulator Charge/Dump Valve	Block.	20-25
33.	Yellow BOP Accumulator Charge/Dump Valve	Block.	20-25
34.	High Pressure Casing Shear Rams	Block.	20-25
35.	Riser Connector Gasket	Extend.	25-30
36.	5K Stabs	Retract.	25-30
37.	Blue Pod Stab	Retract.	25-30
38.	Yellow Pod Stab	Retract.	25-30
39.	Choke and Kill Stabs	Retract.	25-30
40.	Autoshear Arm/Disarm Valve	Block.	30-35
41.	Riser Connector Primary	Unlock.	30-35
42.	Riser Connector Secondary	Unlock	30-35
	Blind Shear Rams (By Autoshear Circuit)	Close	~45-55

3.9.6 Sequence Times

These times compare well with those estimated prior to the FATs, the main functions are summarised below:

Time (seconds)	Functions
T+0 to T+20	The first set of functions completed.
T+2 to T+7	The BOP mounted failsafe valves are closed.
T+4 to T+6	The ram and connector functions are blocked.
T+7 to T+9	The failsafes are blocked (after they were given 5 seconds to close).
T+20 to T+25	The mud boost valves are closed and pilot operated valves are blocked. The Autoshear and casing shear rams are blocked allowing the casing shears 20 seconds to complete cutting pipe and fully close the well-bore.
T+25 to T+30	All stabs are retracted into the LMRP and the Autoshear system is activated.
T+30 to T+35	The LMRP will lift off from the BOP. As it does the LMRP disconnect indicator arm will send both a hard wire and a multiplexed signal to the riser recoil system causing it to activate resulting in a controlled upward movement of the LMRP and riser string in the direction of the rig's offset from the wellhead. At this stage the EDS sequence has ended and the LMRP should be safely off the BOP in a stable condition.
T+30 to T+55	The Autoshear is activated: Firstly it will close the Casing Shear Rams, however as these were already closed during step 5 the 18-25 second delay will occur before closing the Shear/Blind Rams. Upon closure of the Shear/Blind rams well-bore pressure will be sealed and the wellbore will be in a safe condition.

3.9.7 No-Shear EDS

3.9.8 The No-Shear EDS sequence is very similar to the Shear EDS with the exception of the following:

- Step 3 — The Autoshear is disarmed rather than armed as the pipe across the BOP can not be sheared.
- Step 5 — Is omitted, as the Casing Shear Rams are not required to be closed.
- Step 20 — The Casing Shear Rams are blocked at this point rather than as in the Shear EDS as there is no requirement to wait 20-seconds for them to function.

3.9.9 As the Casing Shear rams are not functioned, thereby reducing the time taken to complete all functions, the estimated time to complete the No-Shear EDS is 23-seconds.

3.9.10 Due to the potential consequences following a No-Shear EDS (e.g. the string being dragged out of the BOP by the vessel offset, collars breaking at the BOP and subsequently dropping down-hole etc.), the Autoshear is not armed in the sequence. This means that the Shear/Blind Rams will not close. The reasoning here is that in such a rare, but still plausible, situation vessel safety is more important than that of the well. After weather conditions have abated, or vessel control regained, the ROV would be deployed to assess the situation and close the Shear/Blind Rams.

3.10 Subsea Accumulators

3.10.1 One accumulator is dedicated to each annular preventer for pipe stripping and one accumulator is dedicated to each control pod for pilot function hydraulic supply. The stripping accumulators for the annular preventers have a 15 gallon capacity. There is no specific requirement for subsea accumulator capacities but Hydril calculations indicate that the capacity provided in the main sub-sea accumulators is sufficient to close one pipe ram and the shear rams with adequate reserve volume to close kill and choke valves and unlock the riser connectors.

3.10.2 Four 160 gallon 5,000 psi accumulators are located on the BOP and used for emergency auto-shear situations. The accumulators can be charged from the surface via the rigid conduits and blue and yellow stabs which are extended/retracted from the LMRP. The charge circuit is fitted with isolation and dump valves which are also operated from the blue and yellow pods.

3.10.3 Two 15 gallon accumulators are used to store pilot pressure for the control pods one per pod. The working pressure of these accumulators is 5,000 psi although in stripping bottle applications the normal net pressure is 3,000 psi. These stripping accumulators have no annular close function and are only active when stripping.

3.10.4 As previously mentioned four 15 gallon accumulators are included in the hot line circuit.

3.11 Stack Mounted Shuttle Valves

3.11.1 Most LMRP and BOP hydraulic functions are connected to the blue and yellow circuits via a shuttle valve which is used to direct the control fluid from the selected MUX pod.

3.12 Failure Modes

3.12.1 Failure of the fluid reservoir and mixing unit would only be a problem if the subsea and surface accumulators were discharged. However the system is fitted with sufficient alarms to indicate the possibility of hydraulic fluid supply failure, this would enable the system to be repaired before fluid shortfall became critical.

3.12.2 Failure of the HPU system would only be a problem if the subsea and surface accumulators were discharged. Failure of one pump would not be critical with a second pump available. Electrical power to the HPU pumps is provided from the main switchboard with an automatic switchover to the emergency generator board. It is noted that the Hydril design includes a provision for additional back-up HPU pumps which would be installed if a 6th Ram was added to the BOP stack.

3.12.3 HPU valve failure would not be a problem as the ball valves are fitted with manual overrides. Pipe failures and leaks are a possibility but the safety systems (relief valves, pressure switches and pulsation dampers should minimise this possibility. In any event HPU leaks would only be a problem if the surface and subsea accumulators had been discharged.

3.12.4 Failure of the surface accumulators would result in loss of hydraulic fluid supply to the subsea control pods and accumulators. As previously mentioned, in the event of accumulator failure, the HPU pumps are sized to close one annular preventer on an open hole, open the hydraulic choke valves and provide minimum system operating pressure within 2 minutes. The probability of total loss of surface accumulator pressure is very low and it is considered that it would require a major incident (fire or explosion) for this to occur.

3.12.5 Failures of the rigid conduits and manifold could include leaks, filter blockage and valve failures. In the event of failure of one rigid conduit hydraulic fluid can still be supplied to the accumulators and control pods through the second conduit or hot line (control pods only) The provision of separate blue and yellow manifold crossover systems ensures system redundancy in the event of failure of valves, filters or piping.

3.12.6 Failures of the hot line system could include hose leakage/burst, fluid swivel leaks and fitting/piping leaks. These failures could result in loss or reduction of control fluid pressure, however the subsea control system hydraulic system would still be pressurised by the subsea accumulators or the blue and yellow rigid conduits. The hot line is only used during the running and recovery of the BOP or emergency back up if the rigid conduit fails.

3.12.7 External leakage of the rigid conduit crossover valve could result in the loss of hydraulic supply from the blue and yellow rigid conduits. However this would require the failure of a flange seal or the valve body and is considered unlikely. In any event the rigid conduits could be isolated and hydraulic control fluid would still be supplied by the hot line and the subsea accumulators.

3.12.8 Failure of the LMRP/BOP stabs, the stab seals, accumulator charge valve or piping would result in the inability to charge the BOP accumulators or supply accumulator fluid to the pods. However the manifold is arranged so that blue or yellow conduits supply the accumulator via two separate circuits. A crossover valve enables the blue rigid conduit to supply the yellow accumulators or pod and vice versa.

3.12.9 Failure of any of the control pod hydraulic components could prevent the operation of any of the BOP functions and the impact of the failure would obviously depend on the criticality of the function. In any event all functions can be operated through the blue or yellow pods and it would still be possible to maintain control of the stack functions.

3.12.10 Failure of the control pod stab seals or extend function would prevent the successful connection of a pod during LMRP/BOP mating operations. However it is unlikely to occur to both sets of control pod stabs and in the worst case it would be possible to recover the LMRP to the surface for repair.

3.12.11 Failure of a control pod solenoid or shear valve would disable the pilot fluid flow to the associated SPM valve and prevent the operation of the BOP function commanded from the surface. However this failure would be alarmed and it would be possible to actuate the function via the other control pod.

3.12.12 Failure of a pressure regulator could result in the failure of a group of functions depending on which regulator failed. However as with the solenoids and shear valves it would be possible to switch to the other control pod.

3.12.13 Failure of the riser disconnect monitor would result in the failure of the control system to identify the unplanned separation of the LMRP from the BOP and to transmit a signal to the riser recoil system. However the disconnect mechanism is very simple and there are two signal paths (hard wire and multiplex) and the probability of failure is very low. In addition the Marine Riser Tensioner system is fitted with a sensor and the separation of the LMRP from the BOP would be rapidly evident to drill floor personnel.

3.12.14 The Autoshear function is activated by the blue or yellow control pods and this provides an element of redundancy. However there is no redundancy for the stack mounted valves and as a result there are a number of failures that could prevent/delay the activation of the autoshear circuit. Failure of the Autoshear arm valve could prevent the arming of the autoshear circuit but this would be identified on the Autoshear Arm panel. Failures of the stack mounted Hydraulic Autoshear valve include internal leak and failure to open. In the armed condition a leak through the valve could result in the premature activation of the autoshear functions. However this valve is a Hydril designed SPM valve with seal that comprises a metal spool on a hard high strength plastic seat. The probability of this type of failure is very low and Hydril have never experienced this type of fault.

3.12.15 Failure of the return spring in the Hydraulic Autoshear valve could prevent the initiation of the autoshear function however Hydril have carried out the following steps to minimise the probability of this occurring:

- The return action is activated by two springs.
- The springs are high specification springs manufactured to a Hydril specification.

3.12.16 The Emergency Disconnect System is based on a pre-programmed sequence contained within the control system software. Provided the sequence is thoroughly tested during the FAT programme failure is unlikely since the relevant control signals are transmitted through the blue or yellow circuits. Apart from the Autoshear components all other EDS functions can be controlled through the blue or yellow circuits.

3.12.17 Failures of the subsea accumulator 5,000/3,000 psi regulator include external leakage and plugged outlet. External leaks would be identified by the reduction in accumulator pressure which is alarmed. It is unlikely that a plugged outlet would completely block supply to the shear rams but reduced flow rate could extend the ram response time.

3.12.18 With the current arrangement failure of the Autoshear circuit components could result in the loss of well control with the LMRP separated from the BOP. In this situation the only back-up option is the use of the ROV to close the shear and upper pipe rams. The use of the ROV could be limited by environmental conditions preventing the launch of the vehicle.

3.12.19 Failure of the main subsea accumulators could result in the loss of hydraulic supply for BOP functions, however it would still be possible to supply fluid from the surface via the hot line or rigid conduits.

3.12.20 Failure of a stack mounted shuttle valve could interrupt or impede control fluid flow and prevent operation of a particular function. This would only be relevant if it was necessary to change control from one pod to another and the shuttle failed to operate, however this would require two failures. There have been problems in the past with internal contamination (e.g. O-rings would separate from the spool and enter the shuttle chamber) but this did not affect valve reliability or functionality. However the shuttle valves provided on the DD I and DD II BOPs are of a different design and have not suffered from these problems. The probability of this type of failure is therefore considered to be extremely low.

4. CONTROL SYSTEM - ELECTRICAL SUBSYSTEM

4.1 Introduction

4.1.1 The control system operates from electrical power supplied by the vessel. The power is routed through the uninterruptible power supply (UPS) system and then to the yellow and blue power distribution panels (PDP). Power is routed from the PDP to the blue and yellow CCU, the Driller's panel, the Remote Control panel, the HPU interface panel, the diverter interface panel and the yellow and blue pods.

4.2 Vessel Supply

4.2.1 The control system is powered by 480 Vac from the vessel switchboards and is arranged so that power to the blue and yellow supplies are distributed from different vessel switchboards. The Blue power supply and HPU pump No. 1 are supplied from the 480 Vac Emergency switchboard and the yellow power supply and HPU pump No. 2 are supplied from the Drilling MCC No. 2 switchboard.

4.3 UPS System

4.3.1 The UPS is designed to provide continuous power to the multiplex control system for a minimum of 2 hours in the event of failure of the vessel power supply. As indicated above the UPS systems are powered from different switchboards. Incoming power from the vessel power sources is routed to the respective side (blue or yellow) of the PDP and through a circuit breaker. The 480 Vac is stepped down to 240 Vac and directed to the UPS system via a maintenance bypass switch. The 240 Vac supply is fed to the rectifier in the UPS cabinet. The rectifier converts the 240 Vac into a 240Vdc output which is used to charge the battery bank and drive the UPS inverter. The inverter takes the 240 Vdc output and converts it back into a regulated 120 Vac output.

4.3.2 In the event of vessel power supply failure the UPS batteries provide power to the inverter without any system interruption. Each UPS unit is designed to provide 12 Kva and since 8 Kva is the normal system load for both yellow and blue loads there is extra capacity for future expansion. The UPS batteries have sufficient capacity to operate the BOP control system for a minimum of 2 hours. The battery status is monitored by the battery charging system and any abnormal conditions are alarmed to designated locations.

4.4 Power Distribution Panel

4.4.1 The UPS 120 Vac out put is routed to the PDP where it is routed into two power source select switches. These switches can be used to operate the system in one of two modes:

- Isolated, parallel operation of the blue and yellow circuits.
- System wide operation from either the blue or yellow UPS.

4.4.2 The input power from the UPS is fed to the PDP via two source switches that allow the blue and yellow systems to be supplied from the blue or yellow UPS systems.

4.4.3 Both blue and yellow circuits have their own set of circuit breakers and each of the load circuits (including subsea power) has its own isolation transformer to protect the load side of the power distribution system from faults on other circuits. The secondary side of these isolation transformers is connected to a ground fault detection system.

4.4.4 The PDP provides 120 vac to the following assemblies:

- Blue and yellow CCU.
- Driller's panel (via isolation J-box).
- Remote Control panel.
- HPU interface panel.
- Diverter interface panel.
- Pod test junction box

4.4.5 The Driller's panel is air purged to maintain a positive internal pressure in hazardous zones. In the event that internal pressure drops relays in the power isolation junction box cut power to the panels and sound an alarm. There is an option to only sound the alarm.

4.5 Surface Power CCU

4.5.1 The blue and yellow 120 Vac power is routed to the blue and yellow CCU respectively and filtered as it enters the panels or is routed to the dual redundant power supply for the blue control processor (CP) and the yellow CCU. Within the yellow CCU blue power is routed to the dual redundant power supply for the yellow CP and the dual 24 Vdc power supply which converts the ac voltage to 24 Vdc.

4.5.2 Yellow power is routed to the yellow CCU and part is routed to the dual redundant power supply for the yellow CP, the dual 24 Vdc power supply and the blue CCU. The dual redundant power supplies are contained in drawers in the CCU assembly and they supply 5 Vdc and 12 Vdc to the CPs.

4.6 Surface Power (Driller's and Remote Control Panels)

4.6.1 The blue and yellow 120 Vac power enters the Driller's and Remote Control panels and each supply is routed to a Modular Power Supply. The modular power supplies convert the ac voltage to 5Vdc, 12Vdc, 24Vdc and other DC voltages used by the panel.

4.7 Surface Power (Interface Panels)

4.7.1 The blue and yellow 120 Vac power enters the HPU and Diverter Interface panels and is routed to a modular supply and a dual 24Vdc power supply. This power supply converts the ac voltage to 24 Vdc.

4.8 Subsea Power

4.8.1 The 120 Vac from the PDP is routed to step up transformers to provide 720 Vac to the subsea pods via the multiplex cables. The multiplex cable is a multi-conductor with # 10 AWG power conductors and # 20 AWG TPSJ signal conductors.

4.8.2 The multiplex cables are stored on reels fitted with slip rings rated to 1000 volts at 5 amps. The slip ring assembly has 30 rings with two brushes per ring.

4.8.3 The multiplex cables from the surface are connected to the control pods through a VCC-29 connector which is rated to 12,000 feet water depth.

4.8.4 The incoming 720 Vac power is routed into the transformer stack contained in a separate one-atmosphere container. The transformer stack comprises five step down transformers which output 42 Vac and 90 Vac. The top two transformers provide 42 Vac to Subsea Electronics control Module (SEM) A and the third and fourth transformers provide 42 Vac to SEM B. The 42 Vac output provides power to the solenoid driver boards to fire the solenoids. The fifth transformer provides 90 Vac to both SEM A and B and is used to power the redundant power supply boards.

4.9 Failure Modes

4.9.1 Failure of the vessel power supply to one of the power distribution panels would not be a problem as power would still be provided by the second switchboard. In the event of a blackout the UPS system would provide power for a minimum of two hours which should be sufficient time to reinstate mains power. If the vessel was on DP at the time of the failure it is likely that power would be reinstated in much shorter time.

4.9.2 The provision of two UPS ensures power supply redundancy in the event of failure of the inverters, rectifiers or batteries and chargers. The blue and yellow UPS and PDP are located in separate compartments and it is therefore extremely unlikley that a common mode incident, such as a fire, could shut down the control system.

4.9.3 There is a similar level of redundancy in the PDP systems which can be supplied by either UPS power supply. In the event of an electrical fault occurring in one of the PDPs it will still be possible to supply the various consumers using the second panel.

4.9.4 The blue and yellow CCUs provide system redundancy and no single component failure could result in the loss of control of the subsea system. Since the CCUs are contained in the same cabinet a compartment fire could result in total loss of the system. The fire detection and fire fighting arrangements for the main deck area where the CCUs are located (next to the subsea engineers workshop) are not known but they should be verified to ensure that the probability of fire, and subsequent loss of the control system, is minimised. In the event of loss of the control system the only back up system requires the deployment of the ROV to close the shear and upper pipe rams.

4.9.5 The Driller's and Remote Control panels are arranged to provide identical operation of the control system and thus provide system redundancy. Although failure of the Driller's panel is likely to cause operational difficulties (i.e. operation from the Remote Control panel rather than the drill floor) it should be possible to carry out repairs providing relevant spares are available.

4.9.6 Power to the HPU Interface panel can be provided by the blue and yellow power distribution panels and in the unlikely event of total power failure to the panel HPU control can still be carried out by manual operation of the motor controllers.

4.9.7 Failure of the subsea step-up transformer, the MUX cable reel slip ring or the MUX cable will result in the failure of power supply to one pod. However a slip ring by-pass cable is available and power could still be provided by the other pod. The only common mode failure would be a major incident such as a fire in close proximity to the MUX winch reels however the reels are located on different sides of the moonpool and the probability of all reels being disabled is very low.

4.9.8 Similarly failure of a VCC-29 connector, subsea transformers, or power to the ECM boards and solenoids would result in the loss of one subsea pod. However the second pod would still be available to maintain control of the BOP systems.

4.9.9 Power failure to the solenoids could disable control functions but again the provision of a second pod provides system redundancy. The solenoid enclosures are pressure compensated and it is conceivable that failure of the compensating bladder could result in water ingress which would eventually displace the electrolyte and disable all the solenoids in one of the two enclosures. However the pods are fitted with water detection sensors and the solenoids are fitted with visual sensors to reduce possible failures due to bladder failure or fluid loss. Pressure test ports are provided for testing before running the stack.

5. CONTROL SYSTEM - ELECTRONIC SUBSYSTEM

5.1 Introduction

5.1.1 The electronic control system is contained in the various surface panels and subsea control pods. The control system communicates and performs functions based on operator inputs and actions. The electronic control system is based on the communication between the following components:

- Central control units (CCU)
- Driller's panel
- Remote Control panel
- HPU interface panel
- Diverter interface panel
- Subsea control pods

5.2 Electronic Communication

5.2.1 Three surface panels: Driller's, Remote Control and CCU, are used to operate the system. However only the CCU is connected to the pods and support equipment and all communication between the subsea pods, control panels and surface equipment is routed through the CCU.

5.2.2 The electronics package in the subsea pods processes the commands from the surface and energises and de-energises the solenoids that operate the shear seal valves. Temperature, pressure and navigational data from the subsea instrumentation is also processed in the pods and transmitted to the surface.

5.2.3 The surface panels also serve as remote control stations for the HPU and Diverter systems. As indicated above all control signals are passed through the CCU. The HPU and Diverter systems communicate with the CCU via an electronics package contained in the interface panels (I/F).

5.2.4 The CCU and electronics packages in the subsea pods use RS232/Modbus protocol for internal data processing while data and command communication between the CCU, and subsea pods is in RS485/Modbus protocol. Communication between the CCU, I/F panels and the Driller's and Remote Control panels is in ethernet protocol. Circuits within the CCU carry out protocol conversions for internal processing.

5.2.5 The communication system consists of three controller processors (CP), seven network node processors (NNP), two communications controller processors, four touchscreen control computers and two ethernet switches. The system operation is summarised in the following paragraphs.

5.2.6 During operation one of the three CPs (primary, secondary and tertiary) is defined as the primary processor, one is defined as the secondary processor and another is defined as the tertiary processor. These processors act as the hub of the multiplex control system. Each CP contains a file with the status of all components in the system stored in its memory. This file is called the configuration (config) file.

5.2.7 Commands to the CPs can be sent from one of the four touchscreen monitors in the Driller's or Remote Control panels, or the keyboard/mouse in the blue or yellow CCUs.

5.2.8 The NNPs are contained in the HPU I/F panel, the Diverter I/F panel, the Subsea Electronics Modules (SEM) A and B in the blue and yellow pods and the utility NNP located in the CCU. Each NNP contains a portion of the config file that contains the components that it controls and monitors.

5.2.9 The NNPs work as "dumb" terminals and each performs the task(s) assigned to it by the primary CP and updates its portion of the config table. The primary CP polls each NNP that it has access to on a regular and rotating basis. As the NNP is polled each CP receives an update on the config table within that NNP. The primary CP then updates its config table. The secondary and tertiary CPs each operate in the same way to update its config table. All CPs then compare their config tables and update them.

5.3 Central Control Unit

5.3.1 The CCU comprise two (blue and yellow) separate electronic circuits which are contained in separate sides of the CCU cabinet. The blue CCU contains the following components:

- 18" flat panel, colour monitor.
- Keyboard/video/mouse switch.
- Logic drawer.
- Ground fault detection system.
- Keyboard.
- System controller 1.
- Communications processor 1.
- Utility communications processor.
- 10/100 12 connection ethernet switch.

The yellow CCU contains the following components:

- 18" flat panel, colour monitor.
- Keyboard/video/mouse switch.
- Control/alarm drawer.
- 10/100 12 connection Ethernet switch.
- Keyboard.
- System controller 2.
- Communications processor 2.
- System controller 3.

5.3.2 The CCU diagnostic system monitors critical functions and reports alarms and events. Visual alarms are provided at the CCU, Driller's and Remote Control panels. The system covers a comprehensive range of alarms and function indicators.

5.3.3 The following graphic displays are accessible via the MMI main menu screen. Some are stand alone and others consist of a series of related screens.

- Stack display: control/indication of stack functions.
- Subsea display: control/indication of subsea control functions.
- Diverter display: control/indication of diverter functions.

- ERA and HPHT displays (3 related screens): indication of ERA, inclinometer, gyro and HPHT data.
- Meters and regulators display (2 related screens): control/indication of accumulator and regulator pressures.
- Utility display (5 related screens): control/indications of "emergency functions", indication of UPS, RTU, power flags and HPU status.
- Configuration display (4 related screens): control/indication of network node/SEM modules, alarm setpoints, function lockouts and user administration control.
- Diagnostics (5 related screens): indication of the status of the following components: pods, solenoids, solenoid cards, analog/utility cards and temperatures and water monitors.
- Alarms and events (6 related screens): indication of active alarms, alarm log and event display for the blue and yellow pods.

5.4 Driller's and Remote Control Panels

5.4.1 The Driller's and Remote Control panels allow identical operation of the control system. The panels contain the same internal equipment with the exception of the air purge test unit in the drillers panel. The panel components send and receive data to/from the network control processors via the processors within the panels.

5.5 Subsea Electronic Control Modules

5.5.1 The subsea electronic control equipment comprises two (blue and yellow) identical electronic control modules (ECM) which in turn contain two identical subsea electronic modules (SEM) A and B. The SEMs (A and B) and the various sensors (temperature, pressure, water detection, external sensors and disconnect trip switch) are located in one atmosphere pods. Each SEM has its own communication paths, solenoid drivers, I/O interface and power supplies for electronics and solenoids. One SEM acts as master and the other acts as a back-up, the choice of master being made on the surface.

5.6 Sensors and Probes

5.6.1 Subsea sensors include, inclinometers, gyros, electronic riser angle (ERA) and High Pressure High Temperature (HPHT) probes. The inclinometers and gyros are located in the subsea pods and one ERA sensor is attached near the stack and each transmits signals to the NNP boards in the associated SEM in the control pods. A single ERA sensor is located at the top of the riser and this transmits signals to the Communication Processor in the CCU. Inclinometer, gyro and ERA signals are transmitted to the CCU.

5.6.2 The HPHT probes in the stack also transmit signals to the NNP boards in the associated SEM in the control pods.

5.7 Remote Terminal Unit (RTU)

5.7.1 The RTU is a subsea instrument package that contains two data acquisition modules that monitor sensors external to the control pods. In this application the upper and lower stack RTUs transmit stack temperature and pressure to the pods.

5.8 HPU and Diverter Interface Panels

5.8.1 The interface panels receive the input commands from the Driller's panel, the Remote Control panel and the CCU to actuate the valves on the HPU and Diverter skid respectively. When one of the valve buttons are pressed on any of the control panels the CP updates the Interface Panel NNP data table. The NNP sends a signal to the output board that operates a solenoid which allows air to operate the selected valve.

5.9 Failure Modes

5.9.1 Failure of the control system networks would have no immediate effect as the second and third systems would continue operation. The routeing of the BOP network cables is not known but in the event of a fire there is a possibility that the whole network would fail if blue and yellow cables were passed along the same routes.

5.9.2 Failure of CCU processors, communications, and network switches and other system components would result in the failure of one CCU leaving the other CCU available. As previously discussed, since the blue and yellow CCUs are located in the same cabinet, a major fire in the main deck location would disable the whole control system.

5.9.3 Failure of the panel processors, network connections or other components could result in the loss of the Driller's or Remote Control control panel functions. However each panel comprises two touch screens and two ethernet network links and no single failure is likely to disable the panels. In the worst case it would always be possible to monitor and control the BOP system by one of the other panels or CCU.

5.9.4 Failure of a Multiplex control cable or MUX reel slip ring would result in loss of power and communications to the subsea pod. However the second cable and reels would continue to provide power and communication to the second subsea pod. A slip ring bypass cable is also available in the event of slip ring failure. As previously mentioned the probability of both reels being disabled by a major incident (e.g. fire) is very low as they are located on different sides of the moonpool.

5.9.5 Similarly the failure of the VCC 29 connector or the electronic components in an ECM would result in the loss of communications to one pod but the control systems would be continued by the second pod. Additional redundancy is provided by the provision of two SEMS in each pod.

5.9.6 The subsea ERA sensors are arranged as separate circuits so that signals are routed to separate pods and thence to the surface navigation processor. Thus the failure of one sensor will not result in the loss of riser inclination information.

5.9.7 A recent SINTEF study (Reliability of Subsea BOP Systems for Deepwater Application – ISBN 82-14-01661-4 November 1999) of 83 wells drilled in the Gulf of Mexico referred to one incident where loss of all subsea functions occurred on a multiplex control system. However this was due to a hydraulic failure and it appears that the electronic systems are very reliable.

6. LOWER MARINE RISER PACKAGE

6.1 Introduction

6.1.1 The main components of the LMRP are:

- Flexjoint *
- Annular preventer
- LMRP connector *
- Kill and choke connectors (stabs)
- Kill and choke test valves*
- ROV valves

* Global Santa Fe supply.

6.2 Flex Joint

6.2.1 The flex joint is a flexible coupling which connects the bottom joint of the riser to the top of the LMRP. The flex joint deflects in any direction about its pivot point reducing bending stresses in the riser and wellhead. The main component of the flex joint is the flex assembly which consists of an elastomeric flex element, a nipple and a back flange. The flex element has spherical layers of steel reinforcement and elastomeric pads moulded together with a layer of elastomeric material. The flex element is integrally moulded to the nipple and back flange so that the assembly acts as a bearing and a seal between the body and upper end connection. The maximum deflection of the flex joint is +/- 10°.

6.3 Annular Preventer

6.3.1 The annular preventer is designed to seal around drill pipe, tool joints, tubing, wireline or completely seal off the open hole to contain well bore fluids held under pressure in the well. The annular preventer is normally used to effect a "soft" shut down to minimise hydraulic shock or to contain pressure during stripping operations. The preventer is fitted with a 15 gallon surge accumulator.

6.3.2 The preventer is actuated by hydraulic pressure which forces an annular piston upwards against a steel reinforced rubber packing unit forcing the packer to close inwards. The packer is designed to close around tubular, square or hexagonal cross sections.

6.3.3 The rig DD I and DD II Annular preventers are designed for a working pressure of 10,000 psi and a well bore of 18 ¾".

6.4 LMRP/BOP Connector

6.4.1 The LMRP connector secures the LMRP to the BOP forming a tight seal while withstanding the bending stresses and separation forces caused by well pressure, riser tension and rig motion.

6.4.2 The LMRP connector is a Vetco H-4 HAR Ex F model. The connector is actuated by an annular hydraulic cylinder which acts against a locking taper which then engages and locks the dog segments onto the BOP mandril profile. The Vetco notation 'HAR' indicates that the connector is designed for High Angle Release. The connector is fitted with a secondary unlock piston to ensure the connector can be unlocked. The primary unlock pressure is 1,500 psi and the secondary unlock pressure is 3,000 psi, using the primary and secondary release systems together results in a releasing force which is 25% greater than the locking force. The seal between the LMRP and BOP bores is generally made up using VX-VT ring gaskets.

6.5 Kill and Choke Stabs

6.5.1 The kill and choke line connections between the LMRP and BOP are made up using non-locking hydraulic extend/retract stabs.

6.6 Kill and Choke Valves

6.6.1 The kill and choke lines are fitted with gate valves to allow pressure testing of the kill and choke lines during the installation of the riser sections. These valves are fail safe open. A gas bleed line line from the kill line is connected to the well bore below the upper annular preventer and this line is fitted with inner and outer gate valves. This line is used to assist the venting of gas trapped between the annular preventers.

6.7 ROV Valves

6.7.1 ROV overrides are fitted for the following functions:

- Riser connector unlock (primary and secondary).
- Riser connector chemical flush.
- Connector gasket retract.
- Connector lock cut.
- Pod stabs retract.
- Funnel drop – when fitted.

6.8 Failure Modes

6.8.1 Flex joint failure could result in leakage of riser fluid to the sea. However a number of SINTEF reliability studies have concluded that the probability of flex joint failure is very low. In the SINTEF Gulf of Mexico study one flex joint failure was reported where a manufacturing fault resulted in an external leak. In this particular case the leak resulted in loss of well control and the well kicked. This failure occurred on a ball joint type of flex joint while the flex joint on the Global Santa Fe system is based on a flexible element.

6.8.2 Annular preventers failures include failure to close, failure to open, internal and external leaks. The GoM study identified internal leaks and failure to fully open as the most frequent failures. Control system or piston seal leaks may also prevent the annular preventers achieving a seal when actuated. While internal leaks could cause problems during stripping operations they would not compromise well safety as the lower annular preventer provides redundancy and in the worst case ram preventers could be used to close the well bore.

6.8.3 The most critical LMRP connector failures would be external leakage and failure to unlock. As with the flex joint external leakage of the connector could result in loss of well control, depending on the well status it may be possible to shut-in the BOP and investigate the leak. It is noted that the only LMRP connector external leaks in the GoM study was observed during surface pressure tests. Failure to unlock would be critical in an emergency disconnect situation such as a DP drift/drive off. In previous incidents disconnection failures have been attributed to location pins jamming as the riser angle increased. The connector disconnect system comprises a primary (1,500 psi) and secondary (3,000 psi) unlock capability to provide an unlocking force which is greater than the locking force. Incident data indicates that the secondary unlocking system is generally successful in unlatching operations.

6.8.4 Failure of the kill and choke lines and stabs seals would result in leakage of well control fluids and cause additional problems in case a kick has to be circulated out of a well. However the kill and choke lines are regularly pressure tested when the BOP is connected to the well and any failures should be detected before the kill and choke lines are required for well control. Some instances of plugged lines have been reported but these were cleared through the application of high pump pressure.

6.8.5 Kill and choke test valve failures include internal leaks, external leaks, fail to open and fail to close. The most critical would be an external leak which could result in the loss of well control fluid, however this would require a major leak for this to occur. These valves are tested as riser sections are connected during the installation of the BOP and/or LMRP and the probability of external leaks is very low.

6.8.6 Failure modes of the kill bleed valves include internal leaks, external leaks, fail to open and fail to close. As with the kill and choke valves the most critical failure would be an external leak which could result in the loss of well control fluid.

6.8.7 It is noted that the majority of failures reported in the SINTEF study occurred during regular surface (pre-installation) or subsea tests.

7. BLOW OUT PREVENTER

7.1 Introduction

7.1.1 The BOP stack comprises the following components:

- Annular preventer
- Single ram preventer
- Double ram preventers (upper and lower)
- Kill and choke valves *
- ROV valves
- Wellhead connector*

* Global Santa Fe supply.

7.1.2 The annular preventer is identical to the LMRP annular preventer.

7.2 Ram Preventers

7.2.1 The single and double ram preventers are rated for 15,000 psi with an 18 ¾" bore and multiple position locks. The ram preventers are arranged to provide five pairs of rams. Depending on operational requirements the preventers can be fitted with pipe rams, variable bore rams, blind/shear rams and casing shear rams. The DD I and DD II BOP stacks are arranged as follows:

Top upper double ram	Blind shears.
Bottom upper double ram	Casing shears.
Top lower double ram	4 ½" – 7" VR.
Bottom lower double ram	4 ½" – 7" VR.
Bottom single ram	5 7/8".

7.2.2 The Hydril scope of supply includes the provision of the following ram block sets:

Pipe rams	5 7/8" and 6 5/8".
Variable bore rams	4 ½" to 7".
Blind/shear rams.	
Casing shear rams.	

Hydril data on shear ram (18 ¾", 15,000 psi) capability indicates that the shear rams can shear all ranges of drill pipe up to 6.625" (grade S-135, weight 27.7) and casing up to 7.625" (grade N-80, weight 47.20). The values are based on calculations and actual tests have been carried out on 5.5" drill pipe (grade S-135, weight 21.90) and 4.5" casing (grade C-95, weight 26.10).

7.2.3 Shear tests were successfully carried out on the DD I and DD II shear rams in December 2002 and the results indicated in the following table:

Shear Ram	Drill Pipe Sheared (Grade S-135 Drill Pipe)	Closing Pressure Required for Shear
Blind Shears	6 5/8", 34.02#. 0.522 wall	1950
	5 7/8", 24.17#, 0.415 wall	1650
Casing Shears	6 5/8", 34.02#. 0.522 wall	1750
	5 7/8", 24.17#, 0.415 wall	1600

7.3 Kill and Choke Valves

7.3.1 The BOP is fitted with four sets of double kill and choke gate valves which are arranged as upper and lower kill and choke valves. These valves are fail closed type.

7.4 Wellhead Connector

7.4.1 The wellhead connector is a Vetco Super HD model connector.

7.5 ROV Valves

7.5.1 ROV overrides are fitted for the following functions:

- Blind shear ram close.
- Casing shear rams close and autoshear arm.
- Upper pipe rams close.
- Wellhead connector unlock (primary and secondary).
- Riser connector chemical flush.
- Connector gasket retract.
- Connector lock cut.

7.6 DP Drilling Operations

7.6.1 Although DP reliability has improved considerably, loss of position keeping capability is always a possibility. In the event of position loss it is necessary to secure the well and disconnect the LMRP before damage occurs to the wellhead or riser. During drilling or tripping pipe this requires the following actions:

- Decision to initiate emergency disconnect.
- Hang off the drill pipe.
- Shear the drill pipe.
- Seal off the wellbore.
- Release and clear the LMRP from the BOP.

7.6.2 It is critical that the abandonment is completed before the disconnect angular limit is exceeded or the slip-joint strokes out. It is normal industry practice to provide disconnect guidance to drilling and DP personnel and this is generally related to riser angle or excursion distances. Other considerations are related to the various operations which have an impact on emergency disconnect procedures. IADC guidance for deepwater well control (Deepwater Well Control Guidelines – October 1998) estimates levels of vulnerability in increasing order of severity as follows:

- Bit above BOP stack – this is the point of least vulnerability.
- Drill pipe across stack – the provision of two shear rams provide redundancy in the event of an emergency disconnect.
- Bottom hole assembly (BHA) across stack – since it is unlikely that the BOP could shear the BHA, the time across the BOP should be kept to a minimum and heightened levels of alert implemented at this time.
- Well kick – the IADC guidance advises hanging off during well control situations so that activity is minimised in the event that emergency disconnect is required.
- Casing across BOP – this could be the most critical situation if the casing size is in excess of the casing shear ram capability.

7.6.3 Equipment failure modes in emergency disconnect operations have been included in this section.

7.7 Failure Modes

7.7.1 Annular preventers failures have been discusses in the LMRP section.

7.7.2 Critical ram preventer failures include fail to close, fail to open, fail to shear pipe, internal leaks and external leaks. Failure to close the rams during emergency abandonment would be particularly critical although some redundancy is provided as the stack is fitted with a blind/shear, casing shear and three other ram preventers. The causes of this type of failure include hydraulic piping/fitting leaks or malfunction of BOP mounted shuttle valves (see comments in Section 3).

7.7.3 Failure to open is not such a critical failure and is more likely to cause operational delays. In the worst case it could require the recovery of the BOP for repair on the surface.

7.7.4 Internal leakage through a closed ram would be critical in a well control operation although there may be additional preventers available depending on the drilling operation. As indicated above internal leakage may occur after a shear ram has severed a tubular.

7.7.5 External leaks through flanges or bonnets would also be more of a concern during well control operations. However it is likely that this type of failure would be detected during tests before and after the BOP was run.

7.7.6 The most critical failure of kill and choke valves would be external leakage. If an external leak occurs in the lower inner valve below the lower rams, the BOP would leak if attempting to close in a well kick. Internal leakage is not as critical as external leaks and, since the kill and choke valves are installed in series of two, the probability of internal leakage is very low.

7.7.7 Kill and choke line failures have been discussed in the LMRP section.

7.7.8 As discussed in the previous section the most critical wellhead connector failures would be external leakage and failure to unlock. External leakage would be a problem if this occurred during well control operations, however it is noted that connector leaks are generally identified during regular BOP testing. In general, wellhead connectors are only used when the BOP is latched at the beginning of a drilling operation and unlatched when the well is abandoned at the end of the well. Failure to unlock the wellhead connector is therefore not as critical as the failure to unlock the LMRP connector.

7.7.9 Failure to shear pipe could be critical in emergency abandonment or well control operations and the driller should always be aware that it may become necessary to hang off the drill pipe, shear and disconnect. The Autoshear system on the BOP is designed to automatically close the casing and blind shear rams and unlock the LMRP connector in the event of failure of total loss of hydraulic pressure and electrical power to the subsea pods. This includes a delay circuit so that the casing shear ram starts closing before the blind shear ram. If the casing shear ram is ineffective or if any casing is still lodged in the well bore the blind shear ram would not be effective.

7.7.10 Failure of the Autoshear system could result in the LMRP becoming separated from the BOP while the shear and upper rams were still open. In this event the only way of closing the BOP rams would be to deploy the ROV and use the ROV overrides. It should be noted however that this represents a double failure (LMRP/BOP disconnect and Autoshear system failure) and the probability of such an event is most likely very low. The control system and stack have been designed to allow the installation of an acoustic back-up if required by clients.

7.7.11 Operator delay in initiating an emergency disconnect could result in vessel/riser offsets exceeding safe limits with the potential for catastrophic consequences. To assist operators the system response times for the various disconnect sequences should be measured and made available to the Drilling and DP personnel. It is not known if operating procedures have been developed but these should include contingencies for DP failures taking into account the various drilling scenarios. These procedures could be developed along the lines of the green, yellow, red alerts used for DP diving operations.

8. FMEA PROVING TESTS

8.1 Introduction

8.1.1 In order to understand the level of testing before equipment is installed on the drilling rigs a review of the Hydril FAT Procedure (X-1004668) has been carried out. This has also been used to ensure that tests are not duplicated during FMEA proving trials.

8.2 FAT Procedure Review

8.2.1 The purpose of the FAT procedures is to define the functional tests to be carried out on the LMRP and stack. This includes both MUX pods, LMRP and stack mounted assemblies and ROV operated functions. The procedure describes equipment testing in 10 categories which are listed below:

<u>LMRP hydraulic supply and leak tests</u>
The hydraulic supply tests verify that the supply valves and regulators are functioning correctly. The tests are carried out on the blue and yellow pod functions, which are pressurised via the hotline hose, and the rigid conduits. Leak tests are carried out on the 5,000 psi hydraulic circuits and valves.

<u>LMRP function tests</u>
These tests verify that the hydraulic circuits are correctly connected and include riser connector functions and the operation of all LMRP valves. All tests are carried out through the blue and yellow pod circuits.

<u>Stack hydraulic supply tests</u>
The hydraulic supply tests verify that the supply valves are functioning correctly and include riser and wellhead connector functions. The tests are carried out via the blue and yellow circuits (pods and rigid conduits).

<u>Stack function tests and response times</u>
This series of tests verifies the function of all stack valves and rams using the blue and yellow pods. The response times for these operations are also recorded in this section.

<u>Stack accumulator tests</u>
These tests check the functions related to the stack accumulators and autoshear regulator. The pressure output (3,000 psi) of the autoshear regulator is verified during these tests.

<u>EDS Function tests</u>
The EDS function tests verify the shear mode and non-shear mode emergency disconnect actions and record the times for the various sequences. The shear mode is tested using the yellow pod and the non-shear mode is tested using the blue pod.

<u>ROV operated function tests</u>
These tests verify the ROV operated functions including riser connector and ram close functions.

Shear tests
The shear tests have been carried out on the drill pipe that the rigs will be using and the results are summarised in paragraph 7.2.3. The function tests confirmed the ability of the pipe shear and blind shear to shear the drill pipe samples using the blue and yellow control circuits. Tests also confirmed that the blind shear rams sealed the wellbore following the shear tests.

Wellbore and function tests
These are wellbore, ram and stack valve pressure tests. The tests are arranged so that valves are tested from both directions and the rams are tested from the downhole direction.

API Drift test
In this test an API drift (18.72" diameter and 13.5" length) is run through from the top of the riser adapter to the bottom of the stack.

8.3 FMEA Proving Tests

8.3.1 It is proposed that these tests are carried out after the well control equipment has been installed on the rig and could form part of the system integration tests. The purpose of these tests would be to demonstrate that system alarms, shut-offs and standby systems function as designed. The tests are outlined in Section 11 and an overview of these tests is listed in the following paragraphs.

8.3.2 The tests are based on the system outlined in the Hydril drawings which are listed in Section 1.1. However it is understood that there may have been a number of changes to the system and the proposed FMEA tests have only been outlined to indicate the philosophy of failure mode tests. It is anticipated that more detailed procedures will be required when the scope of these tests have been reviewed and agreed by Global Santa Fe.

8.3.3 Hydraulic System

Fluid reservoir and mixing unit:
- system low level, water supply and pump alarms.

Hydraulic pumping unit:
- electrical power supply redundancy.
- reservoir low level alarms/switches.
- pump operation pressure switches.
- pump capacity to shut-in stack functions (annular rams and choke valves).
- pump capacity to charge surface accumulators.

Surface accumulators:
- accumulator capacity with HPU isolated (ability to operate ram and annular preventers).

Subsea accumulators:
- accumulator capacity with HPU isolated (ability to operate ram and annular preventers).

LMRP disconnect monitor:

- function test of disconnect mechanism (signals to CCU and riser recoil system).

Autoshear function:
- function test loss of hydraulic and electrical power.

EDS:
- covered in FAT tests although it is recommended that these are repeated when the system is installed on the drilling rigs.

8.3.4 Electrical System

- vessel power supply redundancy.
- blue and yellow UPS switchover and durability.
- power distribution panel redundancy.
- driller's power isolation J-box.
- surface power redundancy.
- subsea power redundancy – tested in Hydril function tests.

8.3.5 Electronic System

- Network redundancy – surface.
- Network redundancy – subsea.
- Modem redundancy.
- CCU (CPU cards) redundancy.
- SECM s.
- Subsea sensors – tested in Hydril function tests.
- Interface panels - tested in Hydril function tests.

8.3.6 LMRP

Tested in FAT tests.

8.3.7 BOP

Tested in FAT tests.

9. CONCLUSIONS AND RECOMMENDATIONS

9.1 General

9.1.1 Hydril documentation and drawings of the BOP multiplex control system have been reviewed in order to understand the operation of the system and identify possible failure modes. An FMEA test has been proposed and this is based on the results of the FMEA and a review of the Hydril FAT and integration test programmes.

9.1.2 As mentioned earlier failures of importance are those that would result in loss of well control or the inability to disconnect the LMRP on demand or in an emergency. These failures are discussed below and considered under Normal and Emergency conditions.

9.2 Normal Conditions

9.2.1 No single point failures in the MUX control system have been identified that could prevent operation in normal conditions. The surface and subsea components of MUX control system are duplicated and provide at least one level of redundancy.

9.2.2 The vessel electrical power supply to the HPU pumps is provided from two separate sources and this ensures system redundancy. There is provision for an auxiliary pump skid to be connected into the HPU skid but this would only be installed if the system size increased or if a client specified it as an additional requirement.

9.2.3 However there are some potential failures on the BOP and LMRP. The most critical failures would be external leakage and connector failure to unlock on demand. External leaks at the BOP or LMRP connectors or the flex joint could result in loss of well control. However the probability of these occurring is very low. A recent SINTEF study in the Gulf of Mexico indicated that the majority of leaks reported were identified during regular BOP testing and not during operations.

9.2.4 In normal conditions a connector failure to release on demand would cause operational delays, but since the connectors are fitted with primary and secondary unlocks the probability of this is low.

9.2.5 There is a remote possibility that failure of a BOP mounted shuttle valve could prevent operation of a stack valve or ram. However this would only become apparent if control was changed from blue to yellow or vice-versa. This implies that there has already been a failure of the blue or yellow control circuits and this represents a double failure.

9.3 Emergency Conditions

9.3.1 A fire could disable the blue or yellow network cabling, however if the cable routes were separate it is unlikely that both channels would be affected. (GM do not have details of the cable routes at this time). In the event of failure of the blue and yellow CCUs it would be necessary to deploy the ROV to close the stack rams, however the use of the ROV could be limited by environmental conditions preventing the launch of the vehicle. However the control system is configured for the installation of an Acoustic backup if required by a Client and this would provide additional contingency. In any event if such a catastrophic event occurred it is likely that vessel safety would be more of a concern than that of the well. The probability of this occurrence is considered to be very low. It is understood that a number of HAZIDS have been carried out and it is likely that this vulnerability has been addressed.

9.3.2 Failure of the riser disconnect monitor would result in the failure of the control system to identify the unplanned separation of the LMRP from the BOP. However the disconnect mechanism is very simple and is activated by the ambient water pressure and the probability of failure is very low. In addition the Marine Riser Tensioner system is fitted with a sensor and the separation of the LMRP from the BOP would be rapidly evident to drill floor personnel.

9.3.3 EDS and Autoshear functions

9.3.4 The EDS is based on a pre-programmed sequence contained within the control system software. Provided the sequence is thoroughly tested during the FAT programme, failure is unlikely since the relevant control signals are transmitted through the blue or yellow circuits. Apart from the Autoshear components all other EDS functions can be controlled through the blue or yellow circuits.

9.3.5 Since the Autoshear system comprises a single circuit with components arranged in series failure of any of these components could disable the Autoshear function. This would result in the loss of well control with the LMRP separated from the BOP. However the failures associated with an Autoshear disconnect are alarmed and it should be possible to activate the EDS system to close in the well and disconnect the LMRP.

9.3.6 Well Control

9.3.7 In a well control situation the failure of the shear rams to cut tubulars (drill pipe or casing) and seal the well bore would be critical. However the BOP is fitted with casing shear rams and blind shear rams and the probability of this occurrence is low. For large assemblies, such as drill collars or the BHA, the time across the BOP would normally be kept to a minimum and heightened levels of alert are likely to be in place. These aspects would be addressed in the Global Santa Fe procedures. In the worst case a No-Shear EDS sequence would be initiated and the well bore would not be sealed. The philosophy of this function is that vessel safety is more important than well integrity.

9.3.8 As indicated above external leaks would be problematic and this type of failure would be even more relevant in a well control situation.

9.3.9 The most critical LMRP or BOP failures would be external leakage through the flex joint, riser or wellhead connector or ram bonnets. External leakage could result in loss of well control, depending on the well status it may be possible to shut-in the BOP and investigate the leak. It is noted that the only LMRP connector external leaks in the GoM study was observed during surface pressure tests and the probability of external leaks is considered to be very low.

9.3.10 Emergency Abandonment (DP)

9.3.11 Operator delay in initiating an emergency disconnect could result in vessel/riser offsets exceeding safe limits with the potential for catastrophic consequences. To assist operators the system response times for the various disconnect sequences should be measured and made available to the Drilling and DP personnel. It is not known if operating procedures have been developed but these should include contingencies for DP failures taking into account the various drilling scenarios. These procedures could be developed along the lines of the green, yellow, red alerts used for DP diving operations

9.3.12 Failure to shear pipe could be critical in emergency abandonment or well control operations and the driller should always be aware that it may become necessary to hang off the drill pipe, shear and disconnect. The Autoshear system on the BOP is designed to automatically close the casing and blind shear rams and unlock the LMRP connector in the event of failure of total loss of hydraulic pressure and electrical power to the subsea pods. This includes a delay circuit so that the casing shear ram starts closing before the blind shear ram and casing could still be lodged above casing shear ram and the blind shear ram would not be effective. The system is being reviewed to tie-in the draworks to pick up the drill string after EDS has been activated, this will be based on the time delay before the blind shears close.

9.3.13 Failure of the Autoshear system could result in the LMRP becoming separated from the BOP while the shear and upper rams were still open. In this event the only way of closing the BOP rams would be to deploy the ROV and use the ROV overrides. It should be noted however that this represents a double failure (LMRP/BOP disconnect <u>and</u> Autoshear system failure) and the probability of such an event is most likely very low. However the consequences could be catastrophic. It may be possible to close the BOP rams using an acoustic back up system, however this would only be fitted if specified by the client.

9.3.14 Failure to unlock the riser connector would be critical in an emergency disconnect situation such as a DP drift/drive off. In previous incidents disconnection failures have been attributed to location pins jamming as the riser angle increased. The connector disconnect system comprises a primary (1,500 psi) and secondary (3,000 psi) unlock capability to provide an unlocking force which is greater than the locking force. Incident data indicates that the secondary unlocking system is generally successful in unlatching operations.

9.3.15 A power blackout would represent the worst case failure, however power to the blue control circuit is supplied from the emergency switchboard and provided the changeover to emergency power is successful the control system would still be operational. If the vessel was on DP the excursion could exceed safe limits within the 45 second shut down time. It is therefore critical that DPOs and drillers are aware of the limitations related to each well location so that EDS can be initiated early enough.

9.4 Recommendations

9.4.1 Although the MUX control system provides at least one level of redundancy the system could be disabled by fire/explosion on the drilling rig. It is recommended that fire vulnerability studies include a review of the PDP and CCU locations and power/communication cable routeing to identify whether the system could be disabled by a single occurrence of fire/explosion.

9.4.2 The EDS shutdown times have been recorded during the FAT tests (see section 3.9) and it is recommended that these are repeated when the equipment is installed and commissioned on the drilling rigs. The EDS times should then be reviewed in conjunction with vessel DP drive/drift off times so that appropriate abandonment procedures can be developed.

10. TABULATED FAILURE MODES

BOP Control System – Hydraulic Subsystem

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
	Fluid Reservoir & Mixing Unit						
1.	Power failure	Vessel supply failure	Medium	Pumps, valves, PLC shut down	System shut down	Low	Failure of the Reservoir & Mixing unit would only be problematic if surface and subsea accumulators were completely discharged
2.	Air supply failure	Vessel supply failure	Medium	Failure	On Auto system shuts down	Low	
3.	Water supply failure	Vessel supply failure	Medium	Failure of water supply	On Auto system shuts down	Low	
4.	Pump failure	Electrical, mechanical fault	Low	Concentrate mix incorrect	On Auto system shuts down	Low	
5.	Flow control valve failure	Actuator, mech fault	Low	Concentrate mix incorrect	On Auto system shuts down	Low	
6.	PLC failure	Component failure	V Low	Local control system fails	System shut down	Low	
	Hydraulic Pumping Unit						
7.	Power failure	Vessel supply failure	Medium	System shuts down	No supply of fluid to accumulators	Low	Failure of the HPU would only be problematic if surface and subsea accumulators were completely discharged
8.	Pump failure	Electrical, mech failure	Low	Loss of 1 pump	Reduced output flow rate	Low	
9.	HPU outlet valve failure	Elec, mechanical failure	Low	Supply to outlets interrupted	None – manual override	Low	

BOP Control System – Hydraulic Subsystem

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
	Surface Accumulators						
10.	Fluid leak	Connector, manifold, valve fault	Low	Pressure drop in accumulator	Reduction in total volume available	Low	Accumulators arranged in 3 racks. Spare capacity for maintenance. Subsea accumulators would still available
11.	Bladder leak	Material failure	Low	Pressure drop in accumulator	Reduction in total volume available	Low	
	Rigid Conduits & Hot Line						
12.	Conduit or Hot Line Leaks	Valve leaks, riser connection faults	Low	Loss of HP supply to BOP and subsea accumulators	Dual supply - no loss of supply to BOP & accumulators	Medium	Rigid conduits tested during installation.
13.	Conduit, hot line blockage	Line plugged with contaminants	V Low	Reduced or blocked supply	Dual supply	Medium	Fluid filtered to NAS 10. UV filters fitted to potable water supply
	Rigid Conduit Manifold						
14.	Filter blockage	Filter plugged with contaminants	Low	Reduced or blocked supply	No loss – redundant circuit	Low	System fitted with 2 filters
15.	Lower isolation valve fails in closed pos'n	Spring, mechanical failure	Low	Inability to supply fluid to regulator/pod	No loss - redundant circuit	Low	Valve is normally in open position
16.	Regulator failure	Mechanical failure	Low	Inability to supply fluid to pod	No loss – redundant circuit	Low	
17.	Accumulator charge stab extend/retract failure	Mechanical, control system failure	Low	Inability to supply control fluid to accumulators	No loss – redundant circuit	Low	

BOP Control System – Hydraulic Subsystem

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
18.	Charge stab seal failure	Seal face damage, debris	Low	Control fluid leak	No loss – redundant circuit	Low	
19.	Conduit crossover valve external leak	Gasket failure	Low	Control fluid leak to environment	Potential loss of control fluid supply from Blue and Yellow conduits	Medium	Hot line redundancy
20.	Control pod stab seal failure	Control system failure, seal or seal face damage	Low	Potential leak at stab interface	Function via second pod	Low	
21.	Solenoid valve failure	Water ingress, mech, electrical failure	Low	Solenoid malfunction	Function via second pod	Low	
	Subsea Pods						
22.	Shear valve failure	Solenoid failure, mech failure	Low	Shear valve malfunction	Function via second pod	Low	
23.	Regulator failure	Mechanical failure,	Low	Regulator failure	Function via second pod	Low	
24.	SPM valve failure	Control system failure, mechanical failure	Low	SPM valve failure	Function via second pod	Low	
	LMRP Disconnect Monitor failure	Mechanical failure	V Low	Disconnect flow path remains closed	Failure to transmit LMRP separation signal	Medium	
	Auto Shear Function						
25.	Autoshear valve failure (control pod)	Solenoid, mechanical failure	Low	Valve fails to function	Autoshear function disabled	Medium	Control pod redundancy
26.	Autoshear Arm valve failure (stack)	Control system failure, mechanical failure	Low	Valve fails to function	Autoshear Arm function disabled	Medium	Failure would be indicated on Autoshear panel

BOP Control System – Hydraulic Subsystem

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
27.	Hydraulic Autoshear valve failure (stack)	Control system failure, mechanical failure	V Low	Valve fails to open when Autoshear is initiated	Autoshear function disabled	High	This failure would be critical if it occurred during an emergency disconnection
28.	Hydraulic Autoshear valve failure (stack)	Mechanical failure	V Low	Internal leak through valve	Unplanned closure of shear rams	Medium/ High	
29.	Accumulator Autoshear Regulator failure	Mechanical failure, external leak, plugged regulator	Low	Regulator fails	Loss of subsea accumulator supply to autoshear functions	High	This failure would be critical if it occurred during an emergency disconnection
30.	**Subsea Accumulator leaks**	Connector, manifold, valve fault	Low	Pressure drop in accumulators	Reduction in control fluid pressure	Low	Surface supply still available
31.	**Stack Mounted Shuttle Valve failure**	Mech failure, stuck /jammed spool	V Low	Change over from blue to yellow pod disabled	Possible loss of BOP function	Low	This would only be a problem if the current system (blue or yellow) failed i.e. double failure

TABULATED FAILURE MODES

BOP Control System – Electrical Subsystem

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
1.	Vessel Power supply failure – loss of 480V	Generator failure	Medium			Low	
2.		Short circuit	Low	Loss of power to one PDP	No power loss – supply via second PDP (blue or yellow)	Low	
3.		Earth fault	Low			Low	
4.		Breaker fault	Low			Low	
5.	Power Blackout	Generator overload	Low	Total loss of mains power to control system	UPS system provides power to control system	Low	
6.	UPS	Mains supply failure	Medium	UPS provides power	None – dual supply	Low	
7.		Inverter failure	Low	AC output fails	None – dual supply	Low	
8.		Charger &/or battery failure	Low	UPS supply failure	None – dual supply	Low	
9.		Rectifier failure	Low	Battery charge failure	None – dual supply	Low	

BOP Control System – Electrical Subsystem

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
10.	Power Distribution Panel	Power supply failure	Medium	UPS provides power	None – dual supply	Low	
11.		Short circuit	Low	Failure to PDP consumers switch to second PDP	None – dual supply	Low	
12.		Earth Fault	Low	As above	None – dual supply	Low	
13.		Breaker fault	Low	As above	None – dual supply	Low	
14.		Transformer fault	Low	As above	None– dual supply	Low	
15.	Central Control Units	Power supply failure	Medium	UPS provides power	None – dual supply	Low	
16.		Short circuit	Low	Failure to CCU consumers switch to second CCU	None – dual supply	Low	
17.		Earth Fault	Low	As above	None – dual supply	Low	
18.		Breaker fault	Low	As above	None – dual supply	Low	
19.		Transformer fault	Low	As above	None – dual supply	Low	
20.		Fire/flood in CCU compartment	V Low	Potential loss of blue and yellow CCU	Loss of subsea control system	High	

BOP Control System – Electrical Subsystem

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
21.	**Driller's and Remote Control Panels**	Power supply failure	Medium	UPS provides power	None	Low	
22.		Short circuit	Low	Panel power failure	None – control via CCU or other panel	Low	
23.		Earth Fault	Low	Panel power failure	None – as above	Low	
24.	**HPU Interface Panel**	Power supply failure	Medium	UPS provides power	None	Low	
25.		Short circuit	Low	Failure of HPU control functions	Control HPU from local panel	Low	
26.		Earth Fault	Low			Low	
27.	**Power Supply Subsea**	Step up transformer failure	Low	Loss of supply to pod	None – redundant supply	Low	
28.		MUX cable failure	Low	Loss of supply to pod	None – redundant supply	Low	
29.		MUX cable slip ring failure	Low	Loss of supply to pod	None – redundant supply	Low	
30.	**Subsea VCC29 Connector**	Water ingress, component fault	Low	Failure of supply to solenoids and ECM	None – redundant supply	Low	

BOP Control System – Electrical Subsystem

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
31.	**Subsea Electronic Control Module**						
32.	Subsea Transformer failure	Water ingress, component fault	Low	Failure of supply to solenoids and ECM	None – redundant supply	Low	
33.	Solenoid failure	Water ingress, component fault	Low	Solenoid failure	None - redundant supply	Low	
34.	ECM power supplies	Supply failure, water ingress	Low	Solenoid, board failure	None - redundant supply	Low	

TABULATED FAILURE MODES

BOP Control System – Electronic Subsystem

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
1.	Network Failure	Electrical fault, noise, software failure, corrupted data	Low	Loss of one network	None – redundant system	Low	
2.	CCU	Power supply failure	Low	Change to UPS power	None – redundant system	Low	
3.		Communication Processor failure	Low	Loss of comms to one pod	None – redundant system	Low	
4.		Ethernet switch failure	Low	Loss of comms to I/F panels	None – redundant system	Low	
5.		System controller failure	Low	Failure of one controller out of three	None – redundant system	Low	
6.		Utility processor failure	Low	Loss of utility functions	None – redundant system	Low	
7.	Driller's and Remote Control panels	Power supply failure	Low	Change to UPS power	None – redundant system	Low	In the event of total failure of Driller's or Remote Control panels CCU can be used to control system
8.		Panel processor failure	Low	None – second processor failure	None – redundant system	Low	
9.		Ethernet NIC failure	Low	None – second NIC available	None – redundant system	Low	

BOP Control System – Electronic Subsystem

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
10.	**MUX Cable and Slip Ring Failure**	Connector failure	Low	Communication failure on one cable	None – switch to second MUX cable system	Low	
11.		Conductor failure	Low	Communication failure on one cable	None – switch to second MUX cable system	Low	
12.		Slip ring failure	Low	Communication failure on one cable	None – switch to second MUX cable system	Low	
13.	**ECM Failure**	VCC 29 Connector failure	Low	Communication failure to one ECM	None – change to second ECM	Low	
14.		Water ingress to one atmosphere pod	Low	Component failures in ECM	None – change to second ECM	Low	
15.		SEM Network Node Processor failure	Low	SEM failure	None – 2nd SEM available	Low	
16.		SEM board solenoid failure	Low	SEM failure	None - 2nd SEM available	Low	
17.		External sensor connector failure	Low	Signal failure from ERA	None – change to 2nd ECM	Low	
18.		Sensor failures	Low	Loss of signals from temp, pressure and water detector sensors	None – change to second ECM	Low	
19.	**ERA Sensor Failure**	Sensor, cable, connector failure	Low	Loss of one ERA sensor	None – 2nd sensor available	Low	

TABULATED FAILURE MODES

BOP System – Lower Marine Riser Package

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
	Flex Joint Failure						
1.	External leak	Overstressed Joint, Material fatigue	V Low	External leak	Potential loss of well control	Medium	
2.	**Annular Preventer**						
3.	Fail to close	Control System failure, seal failure	V Low	Inability to close annular	Loss of one annular preventer	Medium	
4.	Fail to open	Failure of packer to relax	Low	Difficulty in passing tool through annular	Operational delay	Low	Not critical with respect to well control operation
5.	Internal leak	Damaged rubber	Low	Leak through annular preventer	Loss of one annular to seal wellbore	Low/ Medium	
6.	External leak	Flange gasket failure?	V Low	External leak	Potential loss of well control		
	LMRP/BOP Connector						
7.	External leak	Damaged seal area, gasket ring,	Low	External leak	Potential loss of well control	Medium	
8.	Fail to unlock	Control system failure, excessive riser angle	Low	Inability to recover LMRP	Potential damage to riser, loss of well control if emergency disconnect	Medium/ Critical	

BOP System – Lower Marine Riser Package

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
9.	Fail to lock	Control system failure, mechanical fault	Low	Inability to lock onto BOP	Operational delay	Low	
	Kill and Choke Lines and Stabs						
10.	Kill/choke line external leaks	K/C line joint seal failure	Low	External leak	Potential loss of circulation in well control operation	Low	Leak would be identified during K/C line installation
11.	Stab seal failure	Seal face damage, debris	Low	K/C line failure to seal	K/C line failure to seal	Low	Leak would be identified during LMRP/BOP test
12.	Plugged line	Mud/cement blockage	Low	Line blocked	Potential loss of circulation in well control operation	Medium/ critical	
	Kill and Choke Valves (bleed)						
13.	External leak	Flange, ring gasket leak	Low	External leak	Leakage of well fluid/gas if wellbore under pressure	Medium/ critical	
14.	Internal leak	Damaged gates, seats	Low	Internal leak past one valve	None if 2nd valve does not leak	Low /medium	2 Valves in common block
15.	Fail to open	Control system failure, mechanical fault	Low	Fail to open	Inability to vent trapped gas	Low/med	
16.	Fail to close	Control system failure, mechanical fault	Low	Fail to close	None if 2nd valve closes	Low	2 Valves in common block

BOP System – Lower Marine Riser Package

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
	Kill and Choke Valves (test)						
17.	External leak	Flange, ring gasket leak	Low	External leak	Leakage of circulation fluid	Medium	
18.	Internal leak	Damaged gates, seats	Low	Internal leak past valve	Inability to test line	Low	
19.	Fail to open	Control system failure, mechanical fault	Low	Fail to open	Inability to circulate through line	Medium	
20.	Fail to close	Control system failure, mechanical fault	Low	Fail to close	Inability to isolate/test line	Low	

TABULATED FAILURE MODES

BOP System – Blowout Preventer

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
	Annular Preventer						
1.	Fail to close	Control system failure, seal failure	V Low	Inability to close annular	Loss of one annular preventer	Medium	
2.	Fail to open	Failure of packer to relax	Low	Difficulty in passing tool through annular	Operational delay	Low	Not critical with respect to well control operation
3.	Internal leak	Damaged rubber	Low	Leak through annular preventer	Loss of one annular to seal wellbore	Low/ Medium	
4.	External leak	Flange gasket failure?	V Low	External leak	Potential loss of well control		
	Ram Preventers						
5.	Failure to close	Control system failure, hydraulic leak, inadequate pressure	Low	Ram fails to close	Potential loss of well control	Medium/ critical	Additional rams may be available
6.	Failure to open	Locking system failure, control system failure	Low	Ram fails to open	Operation delay	Low	
7.	Failure to shear pipe or casing	Control system failure, hydraulic leak	Low	Ram fails to shear pipe or casing	Potential loss of well control	Medium/ critical	Potential leak through rams after shear ram closure
8.	Internal leak (through closed ram)	Packer, seal failure	Low	Leak through ram	Potential loss of well control	Medium/ critical	As above
9.	External leak	Flange, bonnet gasket failure, loose studs	Low	External leak	Potential loss of well control	Medium/ critical	

BOP System – Blowout Preventer

Item	Failure Mode	Causes(s)	Probability	Local Effect	Final Effect	Criticality	Remarks
10.	Spurious closure	Control system failure	Low	Ram closed	Potential to shear pipe, jam on tool	Low/ medium	
	Kill and Choke Valves						
11.	External leak	Flange, ring gasket leak	Low	External leak	Leakage of well fluid/gas if wellbore under pressure	Medium/ critical	
12.	Internal leak	Damaged gates, seats	Low	Internal leak past one valve	None if 2nd valve does not leak	Low /medium	2 Valves in common block
13.	Fail to open	Control system failure, mechanical fault	Low	Fail to open	Potential loss of circulation	Low	
14.	Fail to close	Control system failure, mechanical fault	Low	Fail to close	None if 2nd valve closes	Low	2 Valves in common block
	Wellhead Connector						
15.	External leak	Damaged seal area, gasket ring,	Low	External leak	Potential loss of well control	Medium	
16.	Fail to unlock	Control system failure, mechanical fault	Low	Inability to recover BOP	Operational delay	Low	
17.	Fail to lock	Control system failure, mechanical fault	Low	Inability to lock onto wellhead	Operational delay	Low	

11. TABULATED FMEA TESTS

11.1 Equipment Sub-System 1 Hydraulic

11.1.1 Fluid Reservoir and Mixing Unit

Method:
Set AUTO mode at OIU:
1. Drain concentrate tank contents below low level switch
2. Drain glycol tank contents below low level switch
3. Reduce water supply pressure
4. Close off rig water supply
5. Fail concentrate pump (IF POSSIBLE IN AUTO MODE)
6. Fail glycol pump (IF POSSIBLE IN AUTO MODE)
7. Reduce concentrate flow by more than 10% for 25 seconds
8. Reduce glycol flow by more than 10% for 25 seconds

Results expected:
1. Low level alarm and then no concentrate flow alarm – system shut down
2. Low level alarm and then no glycol flow alarm – system shut down
3. Low water pressure alarm – system shut down
4. No water flow alarm – system shut down
5. Concentrate pump failure alarm
6. Glycol pump failure alarm
7. Concentrate flow out of range
8. Glycol flow out of range

NOTE: The feasibility of tests 5 and 6 to be verified with Hydril

Results found:

Comments:

Witnessed by: Date:

11.1 Equipment Sub-System 1 Hydraulic

11.1.2 Fluid Reservoir and Mixing Unit – Continued

Method:
Set AUTO mode on OIU
1. Fill mix tank to upper level
2. Drain mix tank so that level is 10% below fluid fill shut-off
3.

Results expected:
1. System pumps should stop when high level switch is actuated
2. System pumps restart

Results found:

Comments:

Witnessed by: Date:

11.1 Equipment Sub-System 1 Hydraulic

11.1.3 Hydraulic Pumping Unit

Method:

Both pumps operating

1. Fail electrical supply (480 Vac emergency switchboard) to pump No. 1
2. Reinstate power to pump No. 1
3. Fail electrical supply (Drilling MCC No. 2) to pump No. 2
4. Reinstate power to pump No. 2
5. Drain/transfer fluid from reservoir to actuate low level switch

Results expected:

1. Pump No. 1 shut down – Pump No. 2 continues operating
2. Both pumps operating
3. Pump No. 2 shut down – Pump No. 1 continues operating
4. Both pumps operating
5. Pump(s) stop

Results found:

Comments:

Witnessed by: Date:

11.1 Equipment Sub-System 1 Hydraulic
11.1.4 Hydraulic Pumping Unit
Method: Both pumps operating in AUTO mode 1. Pressurise system to 5,000 psi – monitor pump operation 2. Reduce pressure to 4,500 psi (or 90% of system pressure) – monitor pump operation **Results expected:** 1. Pumps stop 2. Pumps start
Results found: **Comments:**
Witnessed by: Date:

11.1 Equipment Sub-System 1 Hydraulic

11.1.5 Hydraulic Pumping Unit

Method:
Open all annulars and rams and close hydraulic choke valves. Set 5" mandrel in wellbore.
1. Isolate accumulators from system
2. Select one pump
3. Close one annular ram **(must be closed on 5" mandrel)**
4. Close choke valves
5. Record time to close ram and choke valve
6. Reinstate well bore and isolate rigid conduits and hot line
7. Reduce accumulator system pressure to pre-charge pressure
8. Charge accumulator system to working system pressure using both pumps

Results expected:
1. Time to close ram and choke valves should be less than 2 minutes
2. Time to charge accumulator system should be less than 15 minutes

Results found:

Comments:

Witnessed by:		Date:

11.1 Equipment Sub-System 1 Hydraulic

11.1.6 Surface Accumulator Racks

Method:

Start status – wellbore pressure at zero and all annular and ram preventers closed – **annular ram closed on 5" mandrel**

1. Charge accumulator system to full working pressure
2. Isolate HPU pumps
3. Open all ram preventers and one annular preventer
4. Close all ram preventers and the annular ram **(closed on 5" mandrel)**
5. Record accumulator pressure

Results expected:

1. After the opening and closing cycle there should be at least 50% reserve and the remaining stored pressure shall exceed the greater of the following: 1. the minimum calculated pressure required to close any ram preventer at maximum rated pressure of the stack or 2. the minimum calculated pressure required to open and hold open any choke or kill valve at maximum rated pressure of the stack

Results found:

Comments:

Witnessed by: Date:

11.1 Equipment Sub-System 1 Hydraulic
11.1.7 Subsea Accumulators
Method: 1. With LMRP locked onto stack open stack rams and kill & choke valves 2. Fully charge subsea accumulators 3. Isolate rigid conduits and hot line 4. Close one pipe ram 5. Close casing and blind shear rams 6. Close kill and choke valves 7. Unlock riser connector 8. Record accumulator pressure **(Note: Rams to be closed on 5" mandrel)** **Results expected:** 9. There should be adequate subsea accumulator capacity to carry out above operations
Results found: **Comments:**
Witnessed by: Date:

11.1 Equipment Sub-System 1 Hydraulic

11.1.8 Autoshear Function

Method:

1. With LMRP latched onto stack power up blue and yellow pods and pressurise blue and yellow rigid conduits
2. Arm auto shear function
3. Power down blue and yellow pods
4. Vent blue and yellow rigid conduits
5. Record function timings

Results expected:

1. Autoshear function activated

Results found:

Comments:

Witnessed by: Date:

11.2 Equipment Sub-System 2 Electrical	
11.2.1 Vessel Power Supply	
Method: 1. Power up blue and yellow supplies 2. At PDP set blue and yellow breakers to ON 3. Power up blue and yellow UPS 4. Fail blue supply at 480 Vac emergency switchboard 5. Verify control system operation 6. Reinstate blue power 7. Repeat steps 2 and 3 with yellow supply **Results expected:** 1. Power supply to control system not interrupted – AC power alarms	
Results found: **Comments:**	
Witnessed by:	Date:

11.2 Equipment Sub-System 2 Electrical	
11.2.2 Blue and Yellow UPS	
Method: 1. Blue and yellow power online – at PDP set up parallel operation with UPS connected 2. Fail blue rectifier supply 3. Verify operation and UPS endurance (2 hours) 4. Reinstate blue rectifier supply 5. Fail yellow rectifier supply 6. Verify operation and UPS endurance (2 hours) 7. Reinstate yellow rectifier supply **Results expected:** 1. Changeover to UPS supply no supply interruption – UPS alarms 2. UPS duration at least 2 hours	
Results found: **Comments:**	
Witnessed by:	Date:

11.2 Equipment Sub-System 2 Electrical	
11.2.3 Power Distribution Panel	
Method: 1. Power source switches set for system wide operation 2. At PDP set blue mains breaker to OFF 3. Verify system status 4. At PDP set blue mains breaker to ON 5. Repeat steps 2 to 4 with yellow supply **Results expected:** 1. No interruption to system operation – PDP Alarms	
Results found: **Comments:**	
Witnessed by:	Date:

11.2 Equipment Sub-System 2 Electrical
11.2.4 Driller's Power Isolation J-Box
Method: 1. System configured in normal mode with electrical power and air supplies connected 2. Shut off air supply and purge internal pressure 3. Verify Power Isolation Junction box status **Results expected:** 1. Power to driller's panels isolated and alarm illuminated
Results found: **Comments:**
Witnessed by: Date:

11.2 Equipment Sub-System 2 Electrical

11.2.5 Surface Power CCU

Method:
System configured in normal operational mode
1. Operate system with power to Blue and Yellow CCU
2. Fail power Yellow power supply (CCU breaker OFF)
3. Verify operation of Yellow CCU
4. Reinstate Yellow power supply
5. Repeat steps 2 to 4 on the Blue power supply

Results expected:
1. No power interruption to CCUs

Results found:

Comments:

Witnessed by: Date:

11.2 Equipment Sub-System 2 Electrical	
11.2.6 Subsea Power	
Method: 1. Set pod power selection to 'Local' on Logic Drawer panel 2. Attempt pod power control from CCU, Driller's, or Remote Control Panels 3. Monitor results **Results expected:** 1. In 'Local' mode it should not be possible to control pod power from CCU, Driller's, or Remote Control Panels	
Results found: **Comments:**	
Witnessed by:	Date:

11.3 Equipment Sub-System 3 Electronic	
11.3.1 CCU Network Links (subsea)	
Method: MUX System in normal operation 1. Select Blue pod 2. In CCU fail Blue NCP processor (RS 485 interface) 3. Observe results 4. Restore Blue NCP 5. Repeat steps 2 to 4 on Yellow CP **Results expected:** 1. Loss of communications to subsea pods – change over to standby pod. Commnications alarm	
Results found: **Comments:**	
Witnessed by:	Date:

11.3 Equipment Sub-System 3 Electronic
11.3.2 CCU Network Links (Surface)
Method: Normal operation: For each link (Remote Control, Driller's and interface panels (HPU & Diverter): 1. Select Blue pod 2. In CCU fail Blue Ethernet link 3. Observe results 4. Restore Blue Ethernet link 5. Repeat steps 1 to 4 with Yellow pod **Results expected:** 1. Communication maintained through spare Ethernet network. Communications alarm
Results found: **Comments:**
Witnessed by: Date:

11.3 Equipment Sub-System 3 Electronic	
11.3.3 Subsea Electronic Control Modules	
Method: On Blue and Yellow pods in turn: 1. Select SEM A 2. Fail SEM A RS 485 Interface 3. Observe results 4. Restore SEM A RS 485 Interface 5. Repeat steps 1 to 4 with SEM B **Results expected:** 1. Loss of communications with SEM A should result in change over to SEM B and Communications alarm.	
Results found: **Comments:**	
Witnessed by:	Date:

11.3 Equipment Sub-System 3 Electronic
11.3.4 Subsea Sensors
Method: TESTED IN FAT TESTS **Results expected:**
Results found: **Comments:**
Witnessed by: Date:

11.3 Equipment Sub-System 3 Electronic
11.3.5 Interface Panels
Method: TESTED IN FAT TESTS   **Results expected:**
Results found: **Comments:**
Witnessed by: Date: