Evaluation of Automated Well Safety and Early Kick Detection Technologies

Prepared for: Bureau of Safety and Environmental Enforcement

Doc Ref: 100107.01-DR-REP-0004

Rev: 1

Date: November 2015

Final Report

This study was funded by the Bureau of Safety and Environmental Enforcement (BSEE), U.S. Department of the Interior, Washington, D.C. under Contract E14PC00042.

Client	
Bureau of Safety and Environmental Enforcement	
Document Title	
Evaluation of Automated Well Safety and Early Kick Detection Technologies	
WG Reference Number	Client Reference Number (if applicable)
100107.01-DR-REP-0004	Contract No. E14PC00042
Contact	

Jorge Alba, PhD., PE., CEng
BSEE Program Manager
Jorge.Alba@woodgroupkenny.com
Tel: +1 281 646 4160

Wood Group Kenny
15115 Park Row
3rd Floor
Houston, TX 77084

Tel +1 281 675 1000
http://www.woodgroupkenny.com

Revision	Date	Reason for Issue	Prepared	Checked	Approved
1	11/02/2015	Issue for Client Use	AC, WB, CS	BP, RC	JA
0	10/23/2015	Issued for Client Use	AC, WB, CS	BP, RC	JA
B	10/05/2015	Issued for Client Review	AC, WB, CS	BP, RC	JA
A	08/17/2015	Issued for Internal Review	AC, WB, CS	BP, RC	JA

Executive Summary

Automated systems are becoming more commonly used in well construction and operation. This study was commissioned by Bureau of Safety and Environmental Enforcement (BSEE) to evaluate and identify Automated Well Control System (AWCS) and Early Kick Detection System (EKDS) technologies and their potential to increase safety during U.S. Outer Continental Shelf (OCS) drilling, well completion, well workover, and production operations. A part of this assessment was to determine how these new technologies fit within the current framework of industry practices, standards, and regulations.

Work on this report began with a review of the well control barriers and equipment that are commonly associated with well construction operations today. Early Kick Detection (EKD) and AWCS were identified, and their roles within these barrier systems were assessed. Current impediments to well safety automation were also reviewed, and efforts or technologies that help overcome them were discussed. The role of applied backpressure Managed Pressure Drilling (MPD), the most established EKD technology in well safety, was assessed—including a review of its role in well control, its impact on the cause of kicks, and the frequency of loss of well control incidents. Case studies gathered from industry interviews illustrating the effectiveness of MPD in EKD and automated well safety were presented. Finally, regulation of EKD and MPD systems was reviewed. This report includes recommendations with respect to future regulation.

Early in this project, a review of loss of well control and blowout frequency showed that the highest risk of loss of well control occurs during drilling operations. According to a study conducted on wells drilled in the Gulf of Mexico (GOM) OCS from 1980 through 2011, frequency of loss of well control incidents during drilling operations is an order of magnitude larger than the next category, workover/intervention operations. Considering the drilling operations well safety risk that this data implies and the lack of EKD and automated well control technologies that have currently been developed for non-drilling applications, this report concentrates on technologies that are pertinent to drilling operations.

A major finding of this report is that EKDS and particularly applied backpressure MPD offer significant safety benefits, including:

- Data from a study by the Petroleum Safety Authority (PSA) of Norway implies that triggering causes[1] of 54% of kicks could be mitigated or prevented by EKDS and automated response.
- Regression analysis for the deployment of applied backpressure MPD on land in Texas demonstrates that MPD reduces the loss of well control incident frequency and enhances well safety.

[1] Triggering causes, as defined in the PSA study, are the immediate direct cause of the event in contrast to the underlying cause. For example, pore pressure that is higher than expected may be a triggering cause when the underlying cause is deficient planning or risk assessment.

- Applied backpressure MPD, the most established EKDS, offers opportunity to enhance safety not only through EKDS, but through active bottomhole pressure management during the response, thus reducing the influx size significantly.
- Some already available applied backpressure MPD systems are capable of automatically detecting an influx, increasing backpressure until influx cessation, and removing the influx, with less human intervention risk.

To gain a detailed understanding of the risk that automated systems may present, the project team performed a detailed System Reliability Assessment (SRA) of AWCS and EKDS technologies. The team achieved the SRA by performing Failure Modes, Effects, and Criticality Analyses (FMECA) workshops on each of the following generic systems:

- EKDS (MPD), led by Blade Energy Partners
- Measurement While Drilling (MWD) and Logging While Drilling (LWD), led by Wood Group Kenny (WGK)
- Wired Drill Pipe, led by WGK

The FMECA workshop performed on a generic EKDS (MPD) system proved to be a good means of identifying the high risk components for both system functionality and safety. Automated control of the MPD system presented a minor risk to both system functionality and safety, making this a creditable candidate MPD technology for automation. The MPD 'Pressure Relief system' and 'valves and piping' systems used to manage the high pressure upstream of the MPD choke represented the greatest risk to system function and safety. Critically, the design of these Pressure Management systems is application-specific and varies from rig to rig and even from operation to operation. When these variations are considered in conjunction with the risk findings; the design, planning, and risk assessment of any MPD operation must include these two items as a high priority (including appropriate consideration of high rate gas flow events). The system reliability analysis shows that MPD is a very good candidate technology for inclusion in an automated well control strategy to supplement (not substitute) standard well control practices[2]. On this basis, the project team recommends MPD for consideration in any such application.

The industry recognizes the requirement for automation in EKD and well control response. The Macondo incident demonstrated that signs of well control problems can sometimes be subtle, and operations can miss them. Automated systems can assist in detecting and responding to such events early and can prevent their escalation into disasters.

[2] AWCS, EKDS, and MPD are techniques that supplement, yet do not replace, standard well control operations. Respectively, each technique will assist all operations personnel in early identification of formation kicks versus other wellbore effects (and will handle them). Upon identifying a wellbore kick, operations personnel must immediately put standard well control procedures into effect.

A review of EKD and well control automation systems and their regulation around the world has led to the following recommendations:

1. Regulations in the U.S. currently treat EKDS and automation technologies as new technology. This forces closer evaluation of each deployment and is appropriate, given the only recent move of this technology into the deep water offshore environment and the rapid evolution that it is currently undergoing. This approach should be maintained until these technologies become well established in the OCS.
2. For MPD, in 2008, the Minerals Management Service (MMS) issued a Notice to Lessee (NTL), which gave sufficient guidance as to the operating boundaries of MPD and its role with respect to well control. This NTL has since expired. A revision and reissuance of this NTL in BSEE rulemaking may be needed, as the 2008 MMS NTL is still being used as industry's only regulatory guidance.
3. Regulations should be revised with respect to primary barrier requirements in view of MPD and EKD. Current BSEE regulations require in 30 CFR 250.414 (c) that a drilling prognosis must include, but is not limited to, the "Planned safe drilling margin between proposed drilling fluid weights and estimated pore pressures. This safe drilling margin may be shown on the plot required by §250.413(g)." This implies a statically overbalanced fluid that will increase wellbore pressures for MPD (with applied backpressure) higher than required for the stated safety margin. This will reduce the effectiveness of many MPD applications to provide the positive MPD well safety benefits. In many cases, particularly in deep water and high pressure, high temperature (HPHT) applications, it may completely prevent the use of applied backpressure MPD. A requirement for a safe drilling margin between the proposed wellbore pressure profile and the estimated pore pressures should be retained, but regulations should not preclude it from being achieved through a combination of drilling fluid hydrostatic and applied surface pressures. If the fluid density becomes underbalanced with respect to estimated pore pressures, the MPD equipment may enhance use of the primary barrier system, so appropriate steps must be taken to ensure that the MPD system is fit for this service. Shifting toward requirements to maintain a primary barrier will bring regulations into alignment with international regulations and certification standards such as those of NORSOK, DNV, and the American Bureau of Shipping (ABS).
4. A Rule published in Federal Register, Volume 80, No. 74, dated Friday, April 17, 2015 requires that "Static downhole mud weight must be a minimum of one-half pound per gallon below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient" be added in the eCFR §250.414 (c), where the regulation states what must be included as part of the drilling prognosis. This Proposed Rule could have a significant effect on the efficacy of advanced kick

detection and MPD applications that allows drilling operations to be performed safely at a lower pressure differential. For example, deep water wells drilling operations often require a lower margin than what is proposed in the new Rule.

5. In applications where a rotating control device (RCD) is used, consideration should be given to including a requirement to meet API Specification 16RCD to ensure that this critical element is fit for purpose as a primary barrier.

Revision History (Optional)		
Revision	**Date**	**Comments**
A	08/17/2015	Issued for Internal Review
B	10/05/2015	Issued for Client Review
0	10/23/2015	Issued for Client Approval
1	11/02/2015	Issued for Client Use

HOLDS		
No.	**Section**	**Comment**

Signatory Legend		
Revision	**Role**	**Comments**
1	Prepared	Arindam Chakraborty, Senior Engineer at WGK
	Prepared	William Bacon, Technology Development Engineer at Blade Energy Partners
	Prepared	Catherine Sugden, Senior Technology Development Engineer at Blade Energy Partners
	Checked	Bob Pilko, Strategic Relationship Director at Blade Energy Partners
	Checked	Rhonda Cavender, Senior Editor at Shea Writing & Training Solutions
	Approved	Jorge Alba, BSEE Program Manager at WGK

Table of Contents

List of Figures

List of Tables

1.0 Introduction

1.1 General

Wood Group Kenny (WGK) and Blade Energy Partners prepared this report to comply with the requirements of the Statement of Work in Contract No. E14PC00042 between the Bureau of Safety and Environmental Enforcement (BSEE) and WGK to evaluate and identify Automated Well Control System (AWCS) and Early Kick Detection System (EKDS) technologies with the potential to increase safety during U.S. Outer Continental Shelf (OCS) drilling, well completion and workover, and production operations.

The work executed under the BSEE contract is the result of a proposal submitted in response to Broad Agency Announcement (BAA) E14PS00016 to perform research on the Safety of Oil and Gas Operations in the U.S. OCS and Request for Proposal No. E14PS00016.

1.2 Project Objectives

The objectives of the work performed for this project were:

- Identification of automated well safety technologies with the potential to increase safety during OCS drilling, well completion and workover, and production operations.
- Each system's applicability to OCS operations has been identified and recommended to BSEE regarding how the system can be included in BSEE's regulatory program. WGK and Blade Energy Partners have conducted analysis to identify systems that can be used to override human behavior and take control of drilling operations when personnel are put into potentially unsafe situations.
- Assessment of early well kick detection approaches, equipment, techniques, and systems associated with drilling operations in the OCS. The following technologies/ systems have been addressed and evaluated:
  - Managed Pressure Drilling (MPD)
  - Measurement While Drilling (MWD)/Logging While Drilling (LWD)
  - Wired Drill Pipe (also known as Smart Pipe).

  The assessment addressed not only what is currently being used by the industry in the OCS, but it also included an assessment of how early kick detection (EKD) technologies, systems, and equipment are implemented globally under other regulatory jurisdictions for both onshore and offshore applications.

- Provision of a recommendation to BSEE advising whether and under what conditions such technologies may be included in the regulations.

1.3 Objective of This Report

The objective of this report is to document the work performed based on the Project Objectives as defined in Section 1.2, including providing recommendation to BSEE. The report is divided into three main focus areas:

1. The first focus area involves an overview of the state of the art of automation in well safety and EKDS, led by Blade Energy Partners. The report section includes the following sub-areas:
   a. Assessment of current well control equipment
   b. Identification and assessment of automated systems that contribute to well safety
   c. Assessment of MPD equipment, both generally and specifically, for offshore applications
   d. Discussion of case histories of EKDS
   e. Assessment of the frequency of kicks, their causes, and the impact of EKDS
   f. Assessment of recently developed early EKDS
   g. Assessment of how EKDS are being implemented globally under other regulatory jurisdictions
2. The second focus area includes a detailed literature review of local and global standards combined with surveys on AWCS and EKDS technologies, led by WGK. This was done to identify and evaluate Automated Well Safety Technology (AWST) that is deployed and used today, with reference to regulations related to well control and flow monitoring.
3. The final focus area involves a presentation of the findings of a qualitative System Reliability Assessment (SRA) of EKDS (MPD) and AWCS (MWD and LWD, and Wired Drill Pipe) technologies. The reliability assessment was performed for generic systems without considering vendor-specific equipment. The following sub-tasks are described in the report:
   a. Generic system functions and architecture were studied for the four system technologies considered.
   b. Failure Modes, Effect, and Criticality Analysis (FMECA) workshops were arranged, first to identify the failure modes based on functionality and safety of the system, and then to evaluate the likelihood of occurrence of failure (qualitative failure rates), severity, and detection ratings of each failure mode. Workshop participants included Subject Matter Experts (SMEs) such as vendor representatives and Operators, representatives from the current project team, and an independent FMECA facilitator.

c. Risk Priority Numbers (RPNs) were calculated as the product of the ratings of likelihood, severity, and detection and represented the relative risk to system functionality of the subject failure mode. Any safety concerns for a specific failure mode were also identified.

d. Results from the qualitative FMECA were used to draw general conclusions and recommendations about the system's reliability.

1.4 Abbreviations

Below is a list of abbreviations that are used throughout this report.

AAR	After Action Review
ABS	American Bureau of Shipping
AC	Alternating Current
ADC	Analog to Digital Converter
API	American Petroleum Institute
ASCII	American Standard Code for Information Interchange
ASM	Along-String Measurement
ASME	American Society of Mechanical Engineers
AWCS	Automated Well Control System
AWST	Automated Well Safety Technologies
BAA	Broad Agency Announcement
bbl	Barrel
BHA	Bottomhole Assembly
BHCP	Bottomhole Circulating Pressure.
BHP	Bottomhole Pressure
BOEM	Bureau of Ocean Energy Management
BOP	Blowout Preventer
Bpm	Barrels Per Minute (for flow rate)

BS	British Standard
BSEE	Bureau of Safety and Environmental Enforcement
BTR	below-tension-ring
BV	Bureau Veritas
CA	Certifying Authority
CBHP	Constant Bottomhole Pressure
CFR	Code of Federal Regulations
C-NLOPB	Canada-Newfoundland & Labrador Offshore Petroleum Board
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board
CT	Coiled Tubing
CTP	Community Technology Review
CV	Constant Velocity
DAQ	Data Acquisition System
DC	Direct Current
DCS	Drilling Control System
DDV	Downhole Deployment Valve
DFS	Downhole Filter Sub
DNV	Det Norske Veritas (currently DNV GL)
DSATS	Drilling System Automation Technical Section
DSP	Digital Sensor Processor
ECD	Equivalent Circulating Density
EKD	Early Kick Detection
EKDS	Early Kick Detection System
EM	Electromagnetic

EMT	Electromagnetic Transmission
ESD	Emergency Shut Down
FIT	Formation Integrity Test
FMEA	Failure Modes and Effects Analysis
FMECA	Failure Modes, Effects, and Criticality Analyses
ft.	Feet
GCT	Gas Clip Technology
GOM	Gulf of Mexico
H	High (alarm)
HCR	High Closing Ratio (Hydraulic Valve)
HH	High-High (alarm)
HIL	Hardware-In-the-Loop
HMC	Houston Monitoring Center
HMI	Human Machine Interface
HPHT	High Pressure, High Temperature
HPU	Hydraulic Pressure Unit
HSE (U.K.)	Health and Safety Executive
HSSE	Health, Safety, Security, and Environment
IADC	International Association of Drilling Contractors
ID	Identification Number
IDAPS	Influx Detection At Pumps Stop
IEC	International Electronic Commission
IMO	International Maritime Organization
IP	Internet Protocol

ISO	International Organization of Standardization
IT	Information Technology
JIP	Joint Industry Project
LMRP	Lower Marine Riser Package
LOT	Leak-off Test
LOWC	Loss of Well Control
LRP	Lower Riser Package
LWD	Logging While Drilling
MGS	Mud Gas Separator
MMS	Minerals Management Service
MPD	Managed Pressure Drilling
MPO	Managed Pressure Operations
MTBK	Mean Time Between Kicks
MTTF	Mean Time to Failure
MUX	Multiplex (System)
MWD	Measurement While Drilling
NCS	Norwegian Continental Shelf
NOPSEMA	National Offshore Petroleum and Environmental Management Authority
NORSOK	Norsk Sokkels Konkuranseposisjon
NOV	National Oilwell Varco
NPT	Non-Productive Time
NRCD	Non-rotating Control Device
NRR	Noise Reduction Rating
NRV	Non-Return Valve (Float valve)

NTL	Notice to Lessee
OCS	Outer Continental Shelf
OD	Outside Diameter
OEM	Original Equipment Manufacturer
OGP	International Association of Oil and Gas Producers
OPC	Open Platform Communications
P&ID	Piping and Instrumentation Diagram
PC	Personal Computer
PCB	Printed Circuit Board
PCE	Pressure Control Equipment
PDC	Polycrystalline Diamond Compact (bit)
PIG	Pre-emptive Information Gathering
PLC	Programmable Logic Controller
PMCD	Pressurized Mud Cap Drilling
PRV	Pressure Relief Valve
PSA	Petroleum Safety Authority
PVM	Personnel Video Monitoring
PVT	Pit Volume Totalizer
PWB	Printed Wire Board
PWD	Pressure While Drilling
QA/QC	Quality Assurance/Quality Control
QOP	Quality Operational Plan
RCD	Rotating Control Device
RCM	Reliability Centered Maintenance

RDD	Riser Drilling Device
RGH	Riser Gas Handling
RM	Reliability and Maintenance
ROP	Rate of Penetration
ROPO	Rate of Penetration Optimization
RP	Recommended Practice
RPN	Risk Priority Number
RRC	Railroad Commission
RTDV	Real Time Density and Viscosity
RTMC	Real Time Monitoring Center
RTOC	Real Time Operating Center
SBP	Surface Backpressure
SCSSV	Surface Controlled Subsurface Safety Valve
SICP	Shut-in Casing Pressure
SIDPP	Shut-in Drill Pipe Pressure
SIL	Safety Integrity Level
SINTEF	Selskapet for INdustriell og TEknisk Forskning ved norges tekniske hoegskole (The Foundation for Scientific and Industrial Research at the Norwegian Institute of Technology)
SME	Subject Matter Expert
SN	Standards Norway
SPE	Society of Petroleum Engineers
SPP	Stand Pipe Pressure
SRA	System Reliability Assessment
SSBOP	Subsea Blowout Preventer

SSV	Surface Safety Valves
TD	Total Depth
U.K.	United Kingdom
U.S.	United States
UA	Unified Architecture
UKCS	United Kingdom Continental Shelf
USV	Underwater Safety Valve
VPR	Voltage Protection Rating
WGK	Wood Group Kenny
WHP	Wellhead Pressure
WITS	Wellsite Information Transfer Standards
WITSML	Wellsite Information Transfer Standard Markup Language
WOB	Weight on Bit

1.5 Terms and Definitions

Below is a list of terms (and their definitions) that are used throughout this report.

Acceptable Gas Level	A gas reading (%) that does not require any modification to the ongoing operation or adjustment to the mud density.
Barrier	A means of preventing an uncontrolled flow of wellbore fluid to surface.
Bearing Assembly	Bearing assembly with seal elements for the Rotating Control Device (RCD).
Bell Nipple	The extended spool that provides fluid containment between the RCD and the rig flowline.
Circulation across the BOP	Circulation performed down the kill line across the BOP and back up the choke line.
Common	A barrier element that is common to two or more barrier envelopes.

Barrier	
Coriolis Meter	A mass type flowmeter than can measure mass flow rate, volumetric flow rate, fluid density, and temperature.
Drain-back	A volume of mud that is returned at surface due to the momentum change, bleeding off the stand pipe pressure, and temperature effects.
Dynamic Flow Check	A flow check, using the Managed Pressure Drilling (MPD) system with pipe rotation at 10 rpm. The MPD backpressure pump is used to apply backpressure (if required) against the well to maintain a constant Bottomhole Circulating Pressure (BHCP). The suction and returns are to/from the trip tank.
Dynamic Losses	Losses that occur while the well is being circulated or when movement of the drill string creates surge pressures.
ECD	Equivalent Circulating Density. The effective density of the drilling fluid due to combined effects of the fluid, hydrostatic head, and the dynamic pumping pressure.
Fast Shut-in Method	A method to shut in the well using the upper pipe rams. The actions can be summarized by spacing out, stopping pumps, closing the choke line High Closing Ratio (HCR) hydraulic valve, and closing the upper pipe rams and the valves upstream of the rig choke. This is the primary shut-in method.
Fingerprinting	Also known as Pre-emptive Information Gathering (PIG). A series of tests to establish reference curves on relevant parameters such as drain-back volumes.
Flowline Isolation Valve	A hydraulically operated 7-1/16”, 5,000 psi valve mounted on the RCD body that may be used to isolate the primary flowline.
Flowback	A volume of mud that is returned into the wellbore when the BHCP is reduced (wellbore ballooning effects). The flowback mud may lack some of its weighting material and may contain some formation fluids. Because BHCP is maintained constant in MPD operations, flowback volumes are minimized.
Intervention	For this report, intervention is used synonymously with the term ‘workover’ and refers to operations performed on a well during the production phase of the well lifecycle. This discipline covers various technologies that range in complexity from running basic slickline-conveyed rate or pressure control equipment to replacing completion equipment.
Kick Tolerance	The volume of influx that can be shut in and circulated out without breaking down the weakest formation in the open hole.

LOT	Leak-off Test. At some pressure, wellbore fluid will enter the formation. This pressure is called the leak-off pressure. The intent of an LOT to ascertain at which pressure the leak-off will occur to the exposed formations.
MPD	Managed Pressure Drilling. MPD is an adaptive drilling process used to control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. MPD is intended to avoid continuous influx of formation fluids to the surface. Any flow incidental to the operation will be safely contained using an appropriate process.
PDC Bit	Polycrystalline diamond compact (PDC) bits are fixed-head bits that rotate as one piece and contain no separately moving parts. When fixed-head bits use PDC cutters, they are commonly called PDC bits.
Primary Flowline	4” 5K flowline from the RCD outlet to MPD manifold
SBP	Surface Backpressure. SBP is performed by manipulating the MPD choke.
Secondary Flowline	A 2” 10K flowline from the rig choke manifold to the MPD primary flowline.
Static Losses	Losses that occur when the well is not being circulated and the drill string is not being moved up or down.
Stripping Operations	Operations that require manipulation of the drill string through the annular element under low or moderate pressure without the use of a snubbing unit.
Surge Pressure	An increase in BHP that results from a downward pipe movement.
Swab Pressure	A decrease in BHP that results from an upward pipe movement.
Workover	For this report, workover is used synonymously with the term ‘intervention,’ and it refers to operations performed on a well during the production phase of the well lifecycle. This discipline covers various technologies that range in complexity from running basic slickline-conveyed rate or pressure control equipment to replacing completion equipment.

2.0 State of the Art Automated Well Safety and Early Kick Detection Technology Assessments

2.1 Current Well Control Equipment

Current well control equipment is largely dependent on which operation is being undertaken. These operations fall into two main categories:

1. Drilling Well Control Equipment
2. Workovers, Completions, and Interventions Well Control Equipment[3]

Typical well operations require two barrier envelopes, a primary barrier and a secondary barrier against the flow of formation fluids to surface. NORSOK D-010 Well Integrity Standard [10] provides a good description of well control barrier envelopes and barrier elements. Figure 2-1 and Figure 2-2 show the primary and secondary barriers for drilling and coiled tubing operations.

In drilling operations, the fluid is normally overbalanced with respect to the reservoir fluids, and is therefore the primary barrier. The drilling Blowout Preventer (BOP) and well construction elements form the secondary barrier, which is depicted in Figure 2-1. However, some completions and workovers/interventions are performed through tubing with full well pressure when the well is underbalanced with respect to reservoir pressure. In those situations, the wellbore fluid column cannot be considered a barrier for well control, even though additional mechanical barriers are in place. The difference is illustrated in Figure 2-2, which shows the barrier envelopes for a coiled tubing (CT) operation on a vertical subsea tree. Here the production tubing with completion string has been installed, and it forms part of the primary barrier system.

[3] During the production phase, well control operations are limited to those times when the well is taken offline for remediation work. In such an event, well workover/intervention equipment is used.

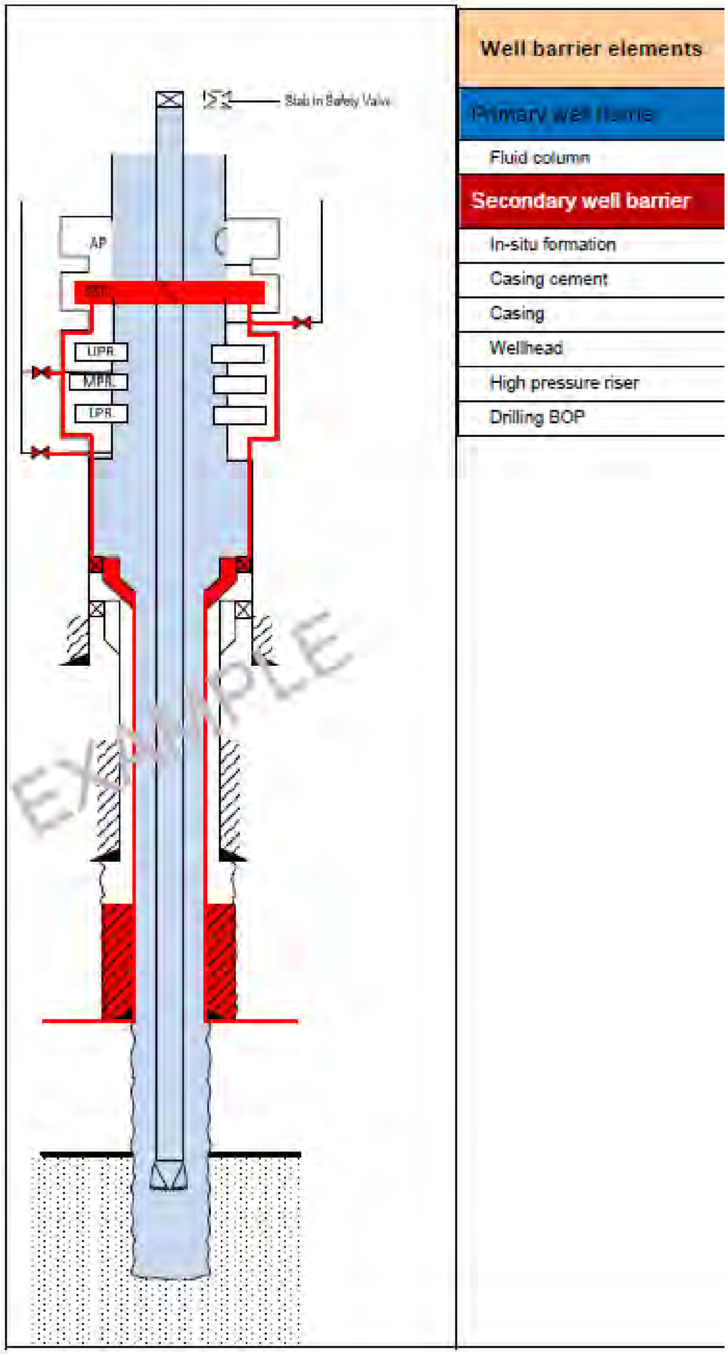

Figure 2-1: Barrier Envelopes for Drilling, Coring, and Tripping with Shareable String [10]

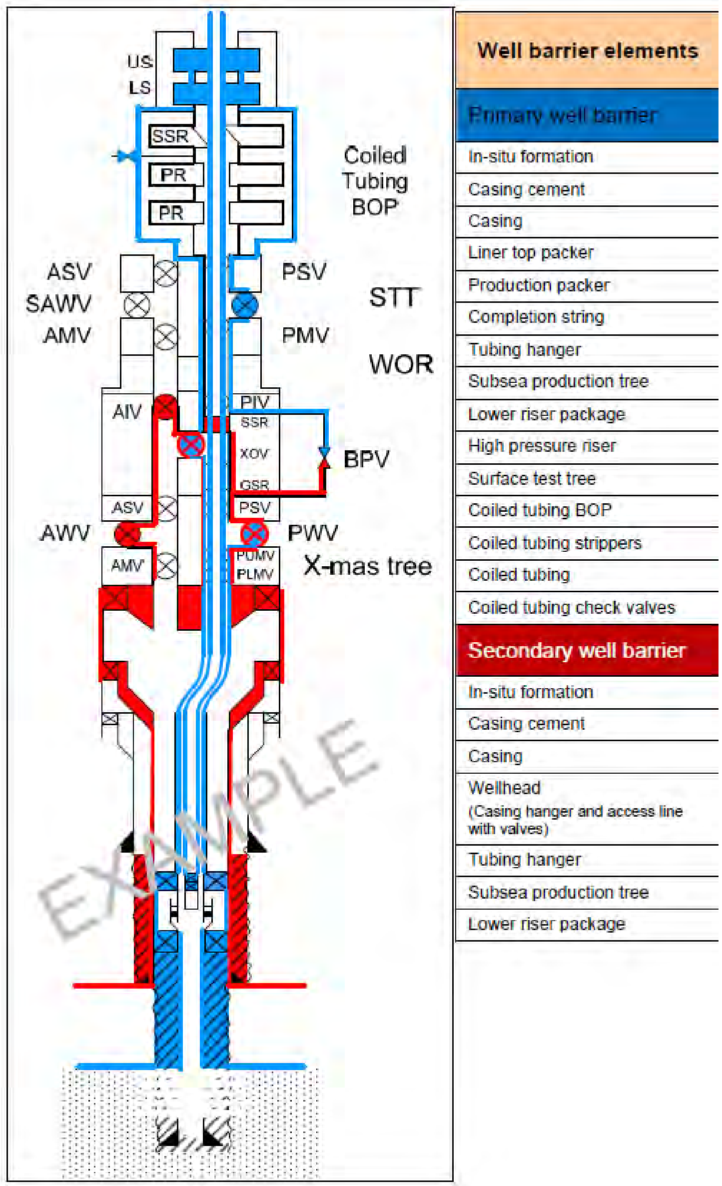

Figure 2-2: Barrier Envelope for CT Operations on Vertical Subsea Tree with LRP [10]

One of the objectives of this study is to determine how automation and early kick detection contribute to current well control procedures and how they may assist in overcoming the limitations in current equipment and practices. Early in this project it was determined that the vast majority of Loss of Well Control (LOWC) incidents occur during the drilling phase. Table 2-1 provides a list of five regions that have experienced LOWC. The information in the table comes from a BOEM study [2], which shows the frequency of LOWC incidents in the various regions during drilling, production, and intervention operations[4]. Frequency for LOWC during drilling is consistently an order of magnitude larger than that for either production or interventions. Note that most wells take less than a year to drill. Therefore, the use of "Per 1,000 Wells Drilled" for the drilling frequency would be diminished if a similar time-based denominator were used.

Table 2-1: Summary of LOWC Parameters from Key Regions [2]

Region	Exposure		Frequency of Loss of Well Control (LOWC)			LOWC Duration**	
	Drilling	Production	Drilling	Production	Interventions	50% Stopped	90% Stopped
	Wells Drilled	Well Years	Per 1,000 Wells Drilled	Per 1,000 Well Years	Per 1,000 Well Years	Minutes	Days
U.S. GOM	31,574	197,721	3.45	0.106	0.314	200	8
North Sea	13,727	59,141	2.99	0.051	0.355	3	20
Holland	1,143	2,948	0	0.339	0.339	n/d*	n/d
Australia	2,559	9,589	1.56	0.104	0	n/d	n/d
Canada East Coast	679	3,955	2.95	0	0	n/d	n/d

* n/d = no data.

** LOWC duration values give the percentage of the chance that an LOWC incident will cease within the given time.

The finding from Table 2-1 is even further supported by the more detailed GOM statistics shown in Table 2-2, where drilling frequency is an order of magnitude larger than interventions and two orders of magnitude larger than production.

[4] The source report does not specify the category for LOWC during completions, for this report we assume that completions statistics are either omitted or included within the initial drilling.

Table 2-2: U.S. GOM LOWC Frequency Summary [2]

U.S. GOM OCS Wells 1980-2011	Oil Production		Gas/Condensate Production		All Production		Well Interventions		Exploration Drilling		Development Drilling		All Drilling	
	101,262		96,459		197,721		197,721		12,299		19,275		31,574	
	#	Frequency per well-year	#	Frequency per well-year	#	Frequency per well-year	#	Frequency per well-year	#	Frequency per well	#	Frequency per well	#	Frequency per well
Blowout (surface flow)	9	8.89E-05	7	7.26E-05	16	8.09E-05	34	1.72E-04	40	3.25E-03	28	1.45E-03	68	2.15E-03
Blowout (underground flow)	1	9.88E-06			1	5.06E-06	1	5.06E-06	4	3.25E-04	5	2.59E-04	9	2.85E-04
Blowout Total	**10**	**9.88E-05**	**7**	**7.26E-05**	**17**	**8.60E-05**	**35**	**1.77E-04**	**44**	**3.58E-03**	**33**	**1.71E-03**	**77**	**2.44E-03**
Well Release	1	9.88E-06	3	3.11E-05	4	2.02E-05	26	1.31E-04	1	8.13E-05	3	1.56E-04	4	1.27E-04
Diverted Well Release							1	5.06E-06	9	7.32E-04	19	9.86E-04	28	8.87E-04
Well Release Total	**1**	**9.88E-06**	**3**	**3.11E-05**	**4**	**2.02E-05**	**27**	**1.37E-04**	**10**	**8.13E-04**	**22**	**1.14E-03**	**32**	**1.01E-03**
TOTAL	**11**	**1.09E-04**	**10**	**1.04E-04**	**21**	**1.06E-04**	**62**	**3.14E-04**	**54**	**4.39E-03**	**55**	**2.85E-03**	**109**	**3.45E-03**

Considering the drilling industry's history of exposing personnel to safety risks and its previous lack of early kick detection and automated well safety technologies being developed for non-drilling applications, this report focuses on drilling-based automation.

2.1.1 Drilling Well Control

During drilling operations, well control is primarily maintained by using a hydrostatically overbalanced fluid. The secondary barrier consists of mechanical/structural elements such as the well casing, wellhead, cement, and open hole formation. For a surface BOP, a high pressure riser also forms part of the secondary barrier envelope. On subsea applications, the BOP is placed at the seafloor, and the riser is not a barrier element.

Detection of a breach of the primary barrier (that is, a kick) occurs through monitoring of fluid volumes (the primary indicator) as well as other less direct indicators. These indicators are described in detail in the following sub-sections.

2.1.1.1 Primary Well Control Barrier – The Fluid Column

For drilling operations, retention of primary well control relies on the fluid column. This fluid column must have sufficient density to maintain pressure within the wellbore above the formation fluid pressure (pore pressure) throughout the open hole section. Maintaining this overbalance prevents an influx of formation fluid to the wellbore.

At the same time, the wellbore pressure must remain below fracture pressure (that is, it must not exceed the rock strength or fracture gradient of the open hole). Should the formation fracture gradient be exceeded, the formation can fracture, leading to gross loss of fluid from the wellbore. Should the losses be sufficiently large, this can lead to a drop in the fluid column height; loss of wellbore pressure; and, consequently, a loss in well control. The way in which open hole pressure gradients must be maintained between pore pressure and fracture gradient is illustrated in Figure 2-3. Note that the pressures increase with the pumps on as a result of frictional pressure losses in the open hole section.

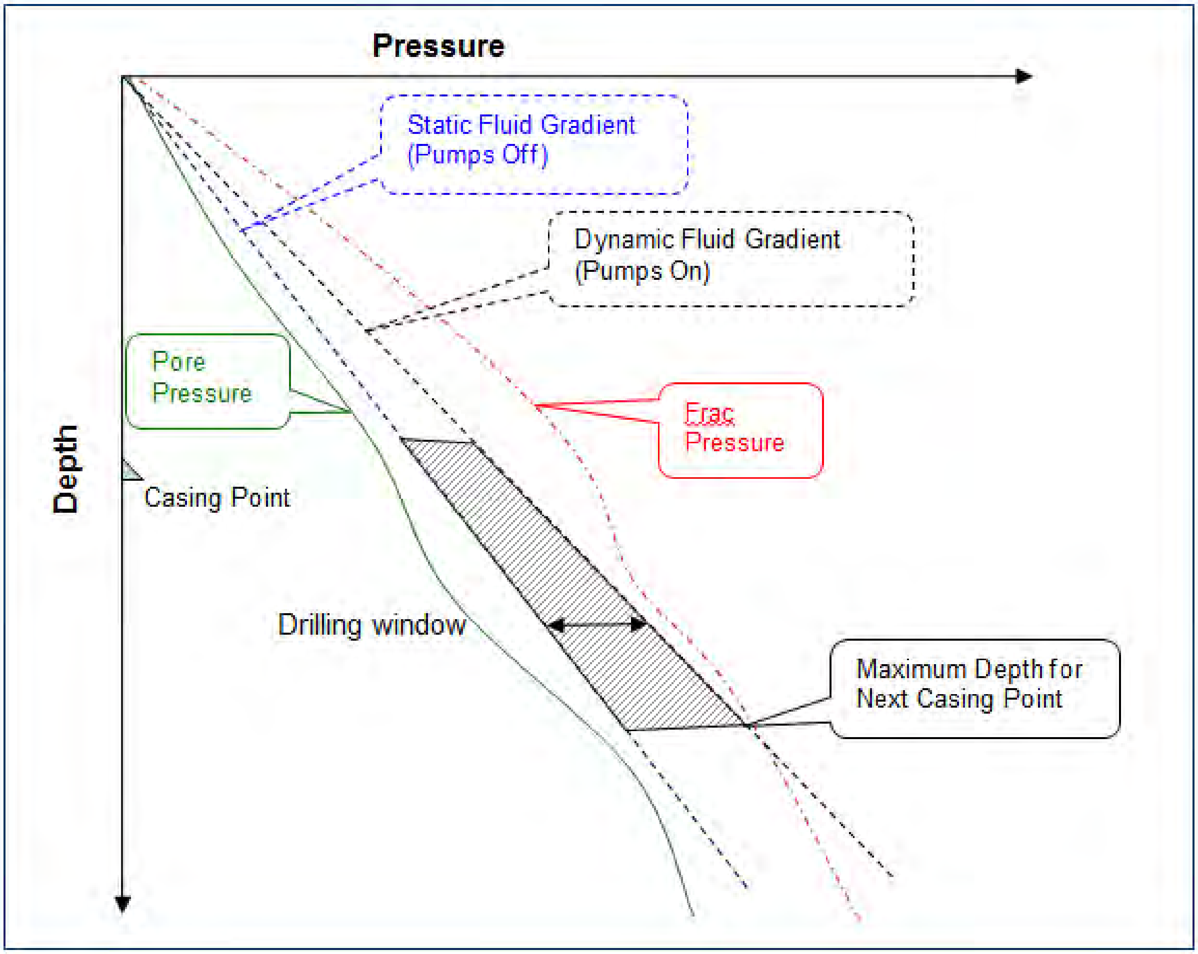

Figure 2-3: Conventional Drilling Fluid Gradients & Casing Setting Points [1]

The trouble with the fluid column as a primary barrier comes about as a result of changing fluid properties. Fluid properties, including mud density, vary with pressure and temperature. These properties vary with depth in the wellbore and potentially as a result of the flow history of the well. Depending on thermal properties, a fluid that has been in circulation at a high rate may be hotter on average than that same fluid when it has been static for a period of time. As such, the fluid column may have reduced density and resultant lower BHP when it has been being circulated for long periods. Secondly, fluid properties can be altered as a result of contaminants from drilled formation and wellbore construction materials (for example, cement). Finally, when they are left static in the hole for long periods, fluid systems are subject to degradation. Weighting agents can settle out quite quickly, a phenomenon known as barite sag. Barite sag can be particularly dangerous in high pressure, high temperature (HPHT) and deviated wellbores [62].

To maintain pressure profiles (circulating and static) within the drilling window, changes to fluid properties need to be constantly monitored, and adjustments need to be made to compensate for the changes. Fluid properties adjust slowly, requiring at least a full circulation of the wellbore to regulate properties throughout the column using additives and/or treatment at the surface. Fluid properties monitoring is typically done manually, relying on simple tests conducted by surface personnel. Such monitoring is intermittent and is subject to human error.

2.1.1.2 Drilling Kick Detection

Kick detection in conventional drilling where return fluid flow is open to the atmosphere relies on identifying key warning signs that a kick may be occurring. Some of these signs for drilling and tripping operations are listed below [63].

Kick indicators while drilling include:

- Drilling break – a sudden increase in drilling Rate of Penetration (ROP) resulting from underbalance
- Increased flow return rate – mud displaced from the annulus by the influx
- Gain in pit volume
- Well flows with the pumps shut off
- Decrease in circulating pressure[5]
- String weight change
- Reduced drilling fluid density in returns

Kick indicators while tripping include:

- Improper hole fill
- Well begins to flow
- Gain in trip tank volume

Should a kick be indicated, a typical reaction is to stop drilling, pick up the string from bottom, stop the pumps, and perform a flow check. When a kick is confirmed, the well is secured by activating the BOP.

Given how critical the measurement of pit volumes can be, it is quite common for rigs to use a Pit Volume Totalizer (PVT) system to assist in kick detection. An example of the sort of sensors that can be used by a PVT to monitor the fluid system is shown in Table 2-3.

[5] In some circumstances, an increase in circulating pressure can be seen.

Table 2-3: Sensors Used for Flow Monitoring [64]

Parameter	Sensor	Comments
Returns Flow Rate	Paddle Type Flow Sensor	Deflection of a paddle due to flow drives the potentiometer to produce a signal. Works in an open flowline
Pit/Tank Volume	Mud Level Probe	Uses a float to detect mud level
Pit/Tank Volume	Ultrasonic/Radar Tank Level Sensor	Can detect build-up of solids in the base of the tank that may distort float type readings [65]
Flow In	Mud Pump Stroke Counter	Mechanical or Proximity type

The signals from the sensors are fed to a centralized processor, which in this case is the PVT. This enables monitoring of flow and volume parameters (such as those listed in Table 2-3) and setting of alarms to automatically alert rig personnel should the monitored parameters deviate from expectation, potentially indicating either an influx or drilling fluid losses.

A problem that can be encountered with kick detection is the solubility of influx fluids and particularly methane gas in synthetic drilling fluids. According to O'Brien [66], natural gas solubility in oil-based fluids could be 10 to 100 times greater than solubility in water-based fluids, making it extremely difficult to detect a kick in oil-based systems [67]. This can be extremely hazardous, as the influx gas may stay in solution until it reaches lower pressure conditions higher in the wellbore, at which point there is very little time for rig crews to detect the kick and react appropriately. This can be especially significant in deep water wells, where the point at which gas breaks out of solution may be above the BOP and in the riser. In subsea wells, should the kick be detected and shut in, the presence of dissolved gas can create problems during subsequent well control circulations, where low temperatures at the wellhead promote hydrate formation and plugging of the choke and kill lines.

Indicators of a well control incident such as an influx can be subtle, and personnel can easily miss them. For instance, an indicator may be that the pressure or volume in the drilling fluid varies in a slightly different manner than expected.[6] Automated systems, which are designed to ensure that well control indicators are not missed, offer a valuable

[6] The Macondo incident was an example where the operators on board received several indications that something was wrong, but they did not take immediate action before the drilling fluid spilled over the drilling deck (Chief Council's Report, 2011) [68]. However, note that the Macondo blowout did not occur during a drilling phase in the well.

safety benefit. The development of new technologies such as MPD can enhance both kick detection capabilities and the well control response during drilling operations [69].

2.1.1.3 Secondary Well Control Barrier – Drilling BOP

Should the primary well barrier of the fluid column fail and an influx enter the wellbore, it falls to the secondary barrier to contain reservoir fluids within the well. This means closing the drilling blowout preventer (BOP). By shutting in the well at the BOP, the influx is contained in the wellbore, and free flow to the surface is prevented. After the well is shut in, the fluid will continue to flow into the wellbore, compressing the annular fluid and building annular pressure until the annular pressure (hydrostatic pressure and surface pressure) equals the formation pressure. The BOP is critical to the safety of the crew, the rig, and the wellbore itself [70]. The process for closing a subsea BOP (and thereby securing the well) is illustrated in Figure 2-4.

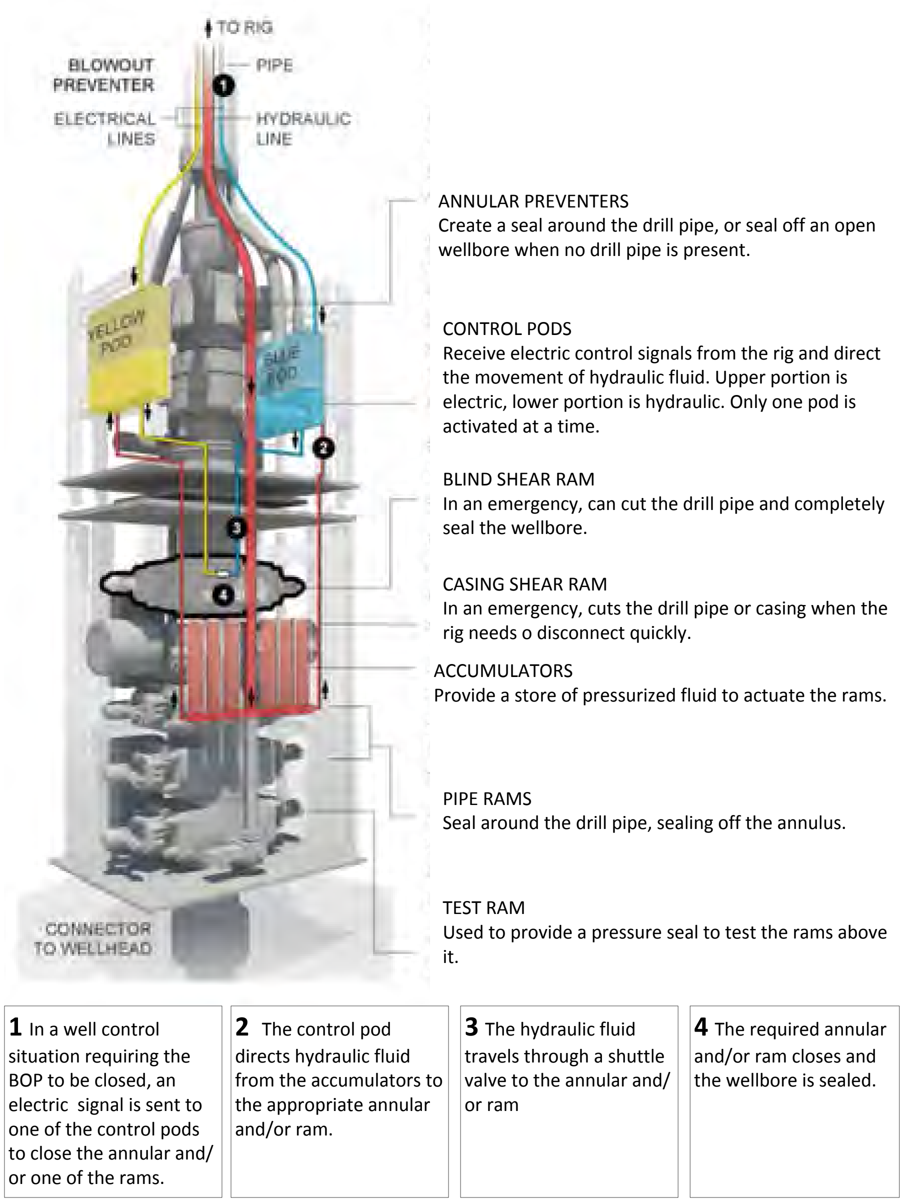

Figure 2-4: Closing of the BOP When a Kick Is Detected

Both subsea and surface BOP stacks consist of a number of ram type and annular type preventers that can seal off the well in different circumstances. The types of preventer are:

- *Annular preventer*: Extrudes an elastomeric element around the drill pipe, casing, or work string component and seals the wellbore. Odd-shaped tools can be sealed, and no space-out of tool joints is required. Annular preventers can be ‘stripped’ through under pressure while allowing pipe movement and maintaining a seal. Annular preventers are generally not as effective as ram type preventers at maintaining a seal, and they will typically have a lower pressure rating than the ram type preventers. Figure 2-5 pictures an annular preventer.

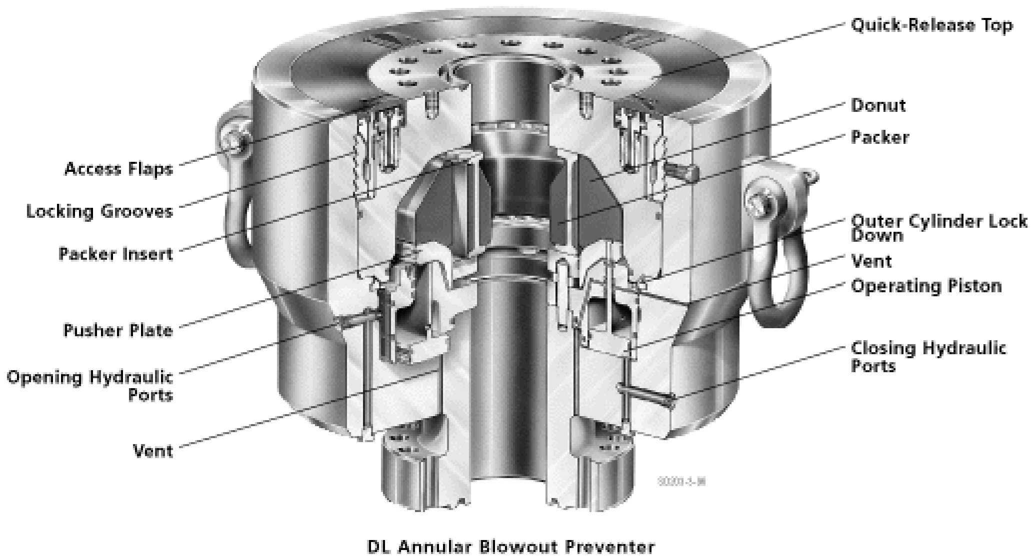

Figure 2-5: Cameron DL Annular Blowout Preventer

- *Pipe Rams*: Close around a drill pipe and restrict flow in the annulus. Variable type pipe rams can seal around a larger range of outside diameter (OD) strings. Space-out of tool joints is required.
- *Blind Rams*: Seal the wellbore when no work string is present. Rams have no opening for tubulars (drill/work string, casing/tubing).
- *Shear Rams*: Cut through the tubulars.
- *Blind Shear Rams*: Cut through the tubulars and seal the wellbore.

To illustrate ram type preventers, Figure 2-6 provides a depiction of a shear ram.

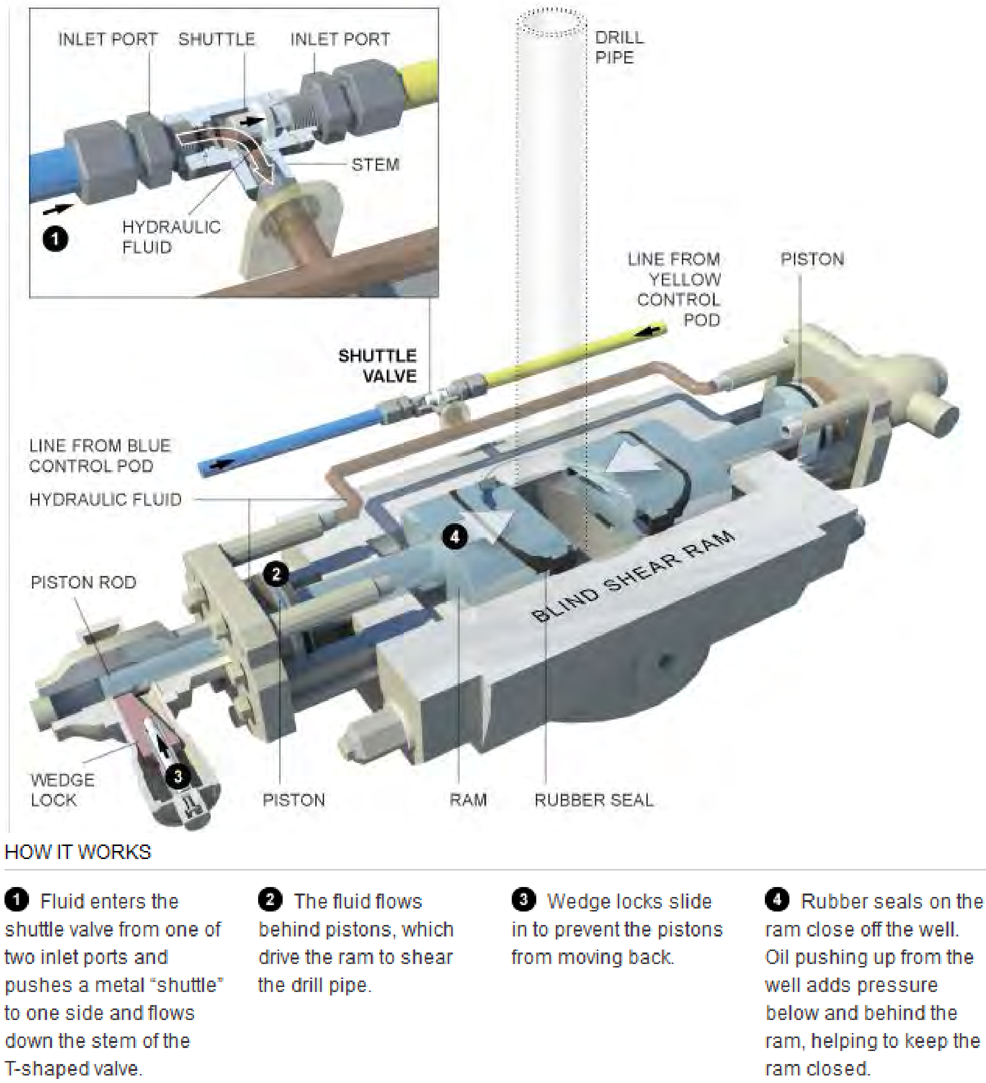

Figure 2-6: Illustration of a Shear Ram BOP [71]

BOPs are typically designed to hold pressure from below, but in some cases, a test preventer may be installed to hold pressure from above to facilitate pressure testing.

The BOP serves two safety-critical functions during a well control incident. The first is to provide the secondary barrier. The second is to allow a high pressure conduit to the wellbore for safe removal of formation fluids and circulation of higher weight drilling fluids to kill the well—that is, to re-establish the primary barrier. This function is achieved using the choke and kill lines, which are high pressure, hard lines that run from the BOP to the rig. Figure 2-7 provides a typical configuration that shows the intersection of the choke and kill lines with a subsea BOP. The valves must be operated through the BOP Control system and must allow for different circulating paths.

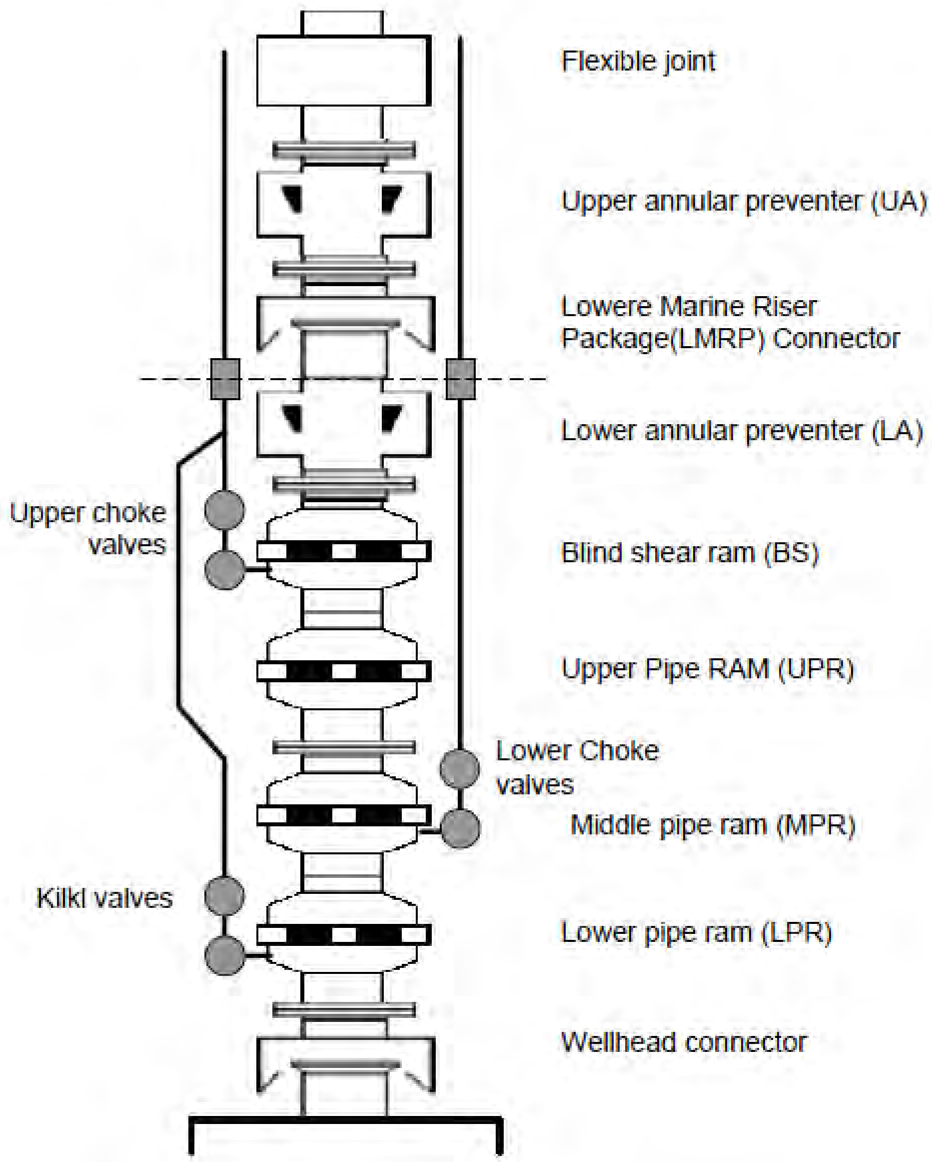

Figure 2-7: Typical Configuration for a Subsea BOP Showing Choke & Kill Lines & Associated Valves [72]

BOPs were first developed in 1920, and they have changed significantly since that time. Currently, BOPs are hydraulically activated; they operate at higher temperatures (higher temperature ratings for seals and packers); and they have variable bore rams, new shear ram geometries, and other technological advancements. However, the basic mechanisms have remained comparatively unchanged: the body is sandwiched between two operating systems, and the rams are opened and closed mechanically [73].

A study conducted by SINTEF for the Minerals Management Service (MMS) [74] reviewed the reliability of subsea BOPs in water depths ranging from 1,312 ft. (400 m) to more than 6,562 ft. (2,000 m) of water in the U.S. GOM OCS during the period from July 1, 1997 to May 1, 1998. The study was dominated by anchored semi-submersible type rigs, which numbered 75 out of the total 83 rigs included. The others were dynamic positioned drillship type rigs for the deeper water wells. The study captured 117 failures, which are broken down by component in Table 2-4. The key component for failure was the Control system, with a Mean Time to Failure (MTTF) of only 67 days. The Control system was responsible for 60 failures, more than 4 times the failures of any other component[7].

Table 2-4: Overview of the Number of BOP Failures [74, pg. 12]

BOP subsystem	BOP-days in service	Days in service	Total lost time (hrs)	No. of failures	MTTF (days in service)	MTTF (BOP-days)	Avg. down-time per failure (hrs)	Avg. down-time per BOP-day (hrs)
Annular preventer	4009	7449	336,5	12	621	334	28,0	0,08
Connector*	4009	8018	117,75	10	802	401	11,8	0,03
Flexible joint **	4009	4009	248,5	1	4009	4009	248,5	0,06
Ram preventer	4009	16193	1505,25	11	1472	364	136,8	0,38
Choke/kill valve	4009	31410	255,5	13	2416	308	19,7	0,06
Choke/kill lines, all	4009	4009	36,5	8	501	501	4,6	0,01
Main control system	4009	4009	1021,5	60	67	67	17,0	0,25
Dummy item***	4009		116	2	-	2005	58,0	0,03
Total	**4009**		**3637,5**	**117**	-	**34**	**31,1**	**0,91**

* For one LMRP connector failure the lost time was not available because the daily drilling reports were missing. Two to three days were lost.

** For the flexible joint failure 250 hours more time was used to work on stuck pipe/fishing problems after the flex joint failure was repaired. This work was most likely a result of the flexible joint failure .

*** The Dummy item in Table 1.2 is used to include two BOP failures that were impossible to link to a specific BOP item. Both these failures occurred when preparing to run the BOP and were poorly described.

Although this study is more than 15 years old, SINTEF (Holland) [74] also found that as of their 1999 report, failure rates had been relatively steady since 1984.

The finding that the Control system is the component most likely to fail on the subsea BOP system was supported by a 2008 Joint Industry Project (JIP) that studied wells drilled in the GOM during the 2004 – 2006 period [75]. The study reviewed 238 wells using 37 different floating rigs and more than 415 wells from 78 surface rigs. This study captured 99.58% of subsea wells and 38.2% of wells drilled with surface BOPs in the GOM during the study period.

[7] The Control systems studied by the SINTEF report included MUX, pre-charged pilot hydraulic and pilot hydraulic Control systems. The Control system included all signal transmission components, the control pods, pilot valves, stack piping and shuttle valves.

Figure 2-8 shows the breakdown of failure distribution by key component. These results were compared to results from previous studies, including the SINTEF DW II study [74]. The JIP study report added a cautionary note in the interpretation of this finding, stating that for none of the Control system[8] failures, whether on subsea or surface BOP systems, was the ability of the well to be controlled compromised [76].

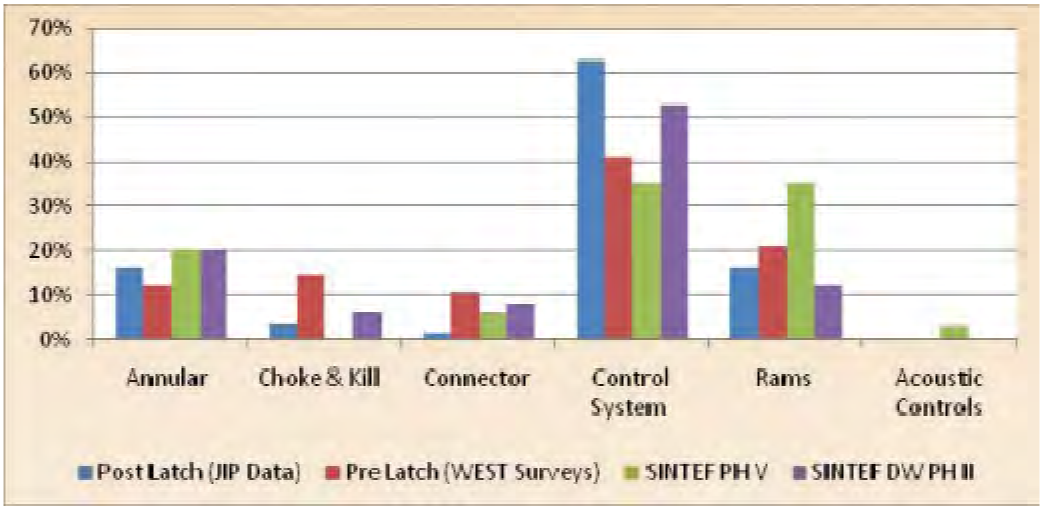

Figure 2-8: Failure Distribution of Subsea BOP Components [75]

The JIP also investigated surface BOP failures and compared the results, which showed that subsea systems have higher failure rates compared to Surface systems. It was suspected that this resulted from both increased complexity of subsea BOP systems and the hydrostatic pressure issues that come into play in deeper water [76]. The failure rates on the choke and kill line connectors were much higher on the surface stacks than the subsea BOPs. The authors expected that this higher surface stack choke and kill line connector failure rate was a result of the frequency of make/break cycles between the stacks and wellheads to which they are bolted, with a required cycle at least at the running of every casing string. Figure 2-9 provides a summary of the failure distributions for surface BOPs.

[8] The definition of the Control system was not defined within this report. However, the JIP study extensively used the SINTEF report for comparison purposes, implying a consistent definition.

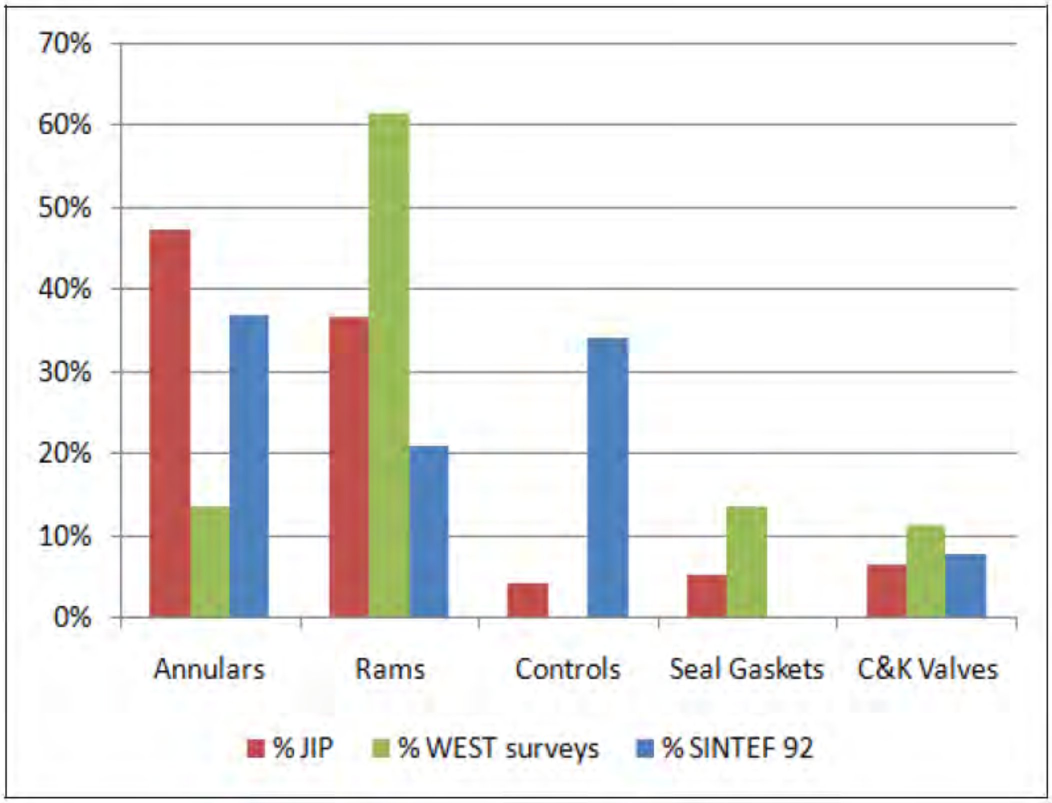

Figure 2-9: Failure Distribution of Surface BOP Components [76]

The study gave an excellent breakdown of MTTF by component based on those failures that occurred only after installation testing. Figure 2-10 provides these results.

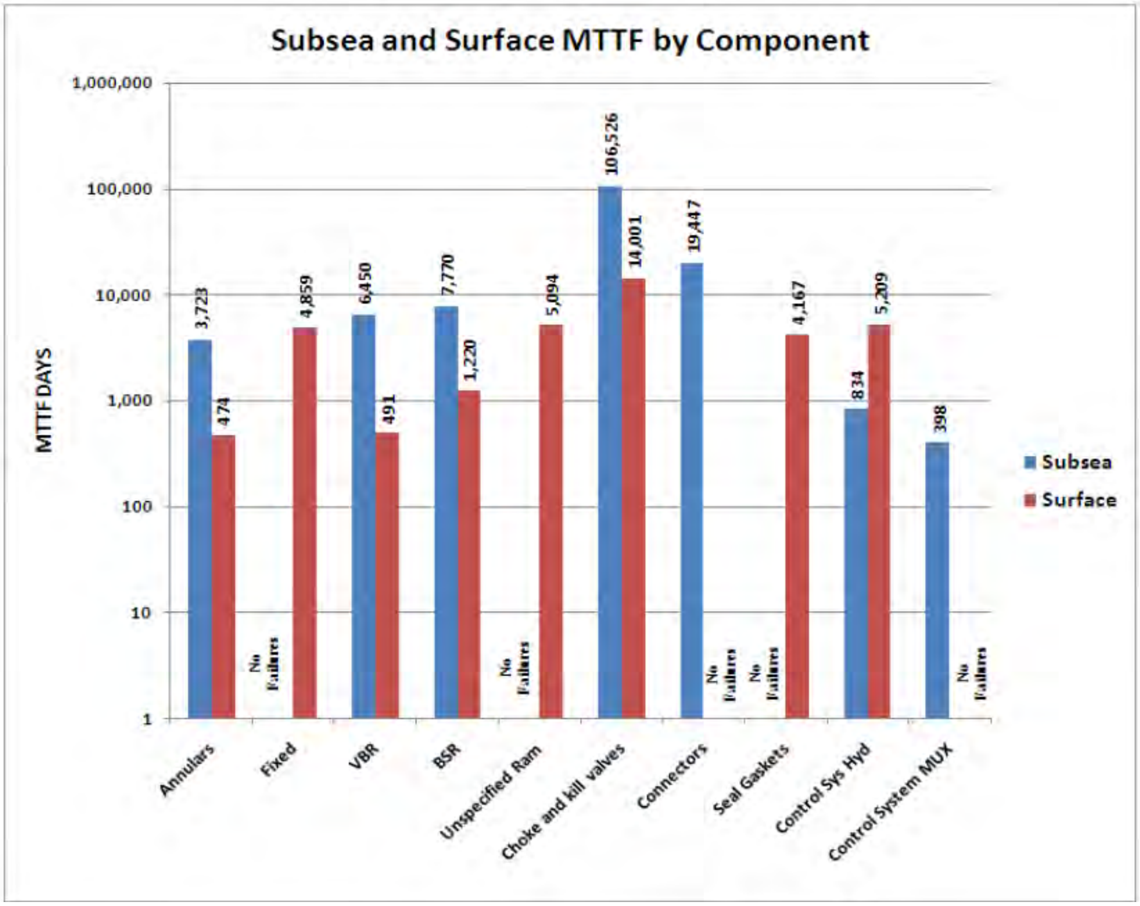

Figure 2-10: Breakdown of MTTF for BOP Components Based on Failures Observed After Installation Testing (BOP in Service). Both Surface & Subsea Systems

Other key findings from the 2004-2006 JIP study [76] are:

- MTTF was lower for higher class BOPs, which have a larger number of components, and therefore redundancy. This is not an unexpected result for increasingly complex systems. It should be noted that the additional redundancy in these systems reduces risk and positively affects safety, mitigating the reduced MTTF.
- Larger lease Operators[9] tended to have lower MTTF. The authors of the JIP study speculated that this was due to the use of more complex BOPs with increased redundancies.
- Smaller rig contactors appeared to have lower MTTF than larger ones for both surface and subsea BOPs. However, the authors of the JIP study were wary of drawing conclusions from this information, as only two small Contractors were included in the data set, and each Contractor had only one rig.

[9] The referenced study subjectively divided lease operators into three categories: small, medium, and large. The categorization method was not explained.

- Much more variation in performance was observed from rig to rig than from Contractor to Contractor. The authors' opinion was that this was due to the differences in rig staff[10].
- Although Control system failures are the most common, they can easily be identified during testing. Frequent function testing is therefore critical to safety.

The SINTEF/BOEM study [74] went on to determine what proportion of the failures was safety critical. The study defined safety-critical failures as those failures that occurred when the BOP was on the wellhead and during either routine operations or scheduled BOP testing. It can be considered that the BOP was acting as a barrier during these times. Table 2-5 details the breakdown of when the failures were observed. It is clear from the table that 57% of the failures in the study occurred with the BOP installed on the wellhead. Of those 67 failures, 15 occurred during installation testing, and the remaining 52 were deemed safety critical.

Table 2-6 shows the breakdown of the data to determine the probability of experiencing a failure during different tests of the subsea BOPs. Here the probability of a failure during installation is 15.6%. When testing is conducted after a liner or casing string is run, there is a 10.4% chance of experiencing a BOP failure. Although these probabilities seem high, a test failure does not mean total BOP failure. The figures highlight how critical it is to have frequent testing and a high level of redundancy within the BOP system.

[10] The authors of the JIP study offered no further evidence to support this opinion. It is not clear whether any differences in equipment, training, management, or experience could be identified as the cause of variation in performance from rig to rig.

Table 2-5: Observation of BOP Failures and When They Occurred [74, pg. 85]

BOP subsystem	BOP on the rig			Running BOP		BOP on the wellhead				Total
	Test prior to running BOP	*Not relevant*	*Unknown*	*Test prior to running BOP*	*Not relevant*	Installation test	Test after running casing or liner	Test scheduled by time	Not relevant	
	Safety non-critical failures						***Safety critical failures***			
Flexible joint									1	1
Annular preventer	1					1	4	3	3	12
Ram preventer	3				1	1	5	1		11
Connector	2	2				2			4	10
Choke and kill valve	9					1	1	2		13
BOP attached line	1			1						2
Riser attached line	1			2					1	4
Jumper hose line				1			1			2
Control system	16		3	5		10	6	7	13	60
Dummy Item	2									2
Total	**35**	**2**	**3**	**9**	**1**	**15**	**17**	**13**	**22**	**117**
	34%			**9%**		**57%**				

Table 2-6: Probability of Experiencing a Failure During Different Subsea Test Types Based on Collected Data [74, pg. 86]

Subsea test type	Total no. of tests	No. of failed tests	No of failures	Failure probability per test (%)
Installation test	83	13	15	15,6
Test after running casing or liner	163	17	17	10,4
Test scheduled by time (function & pressure tests)*	319	12	13	3,8
Other tests	10	0		
Not relevant (Normal operation)	-	-	22	
Total subsea	576	42	67	
1. 103 pressure tests, 217 function tets				

A FMECA of subsea BOPs supports the finding of the Control system being the main source of failures. A study in 2012 [70] found that the shuttle valves for ram and annular function are the most critical components, followed by blind shear ram, annular preventer (rubber housing), ram piston, hydraulic line from the Hydraulic Pressure Unit (HPU) to the BOP, flange, gasket, and fluid reservoir.

2.1.2 Completion, Workover, and Interventions Well Control

Completion, workover, and intervention operations vary significantly in the type of well control equipment that must be used. The selection of equipment depends largely on the type of operation, coiled tubing, wireline, slickline, and the running of completion tubulars, all of which require different configurations. Table 2-7 provides some examples of how the well control barriers can vary throughout the life of the well during drilling, completion, production, and workovers.

Table 2-7: Examples of Barrier Systems throughout the Life of the Well [77]

Example	Primary Barrier	Secondary Barrier
Drilling a well	Overbalanced mud capable of building a filter cake	Casing/wellhead, cement, and BOP
Running the upper completion	Isolated and tested reservoir completion (for example, inflow testing cemented liner or pressure tested isolation valve)	Casing/wellhead, cement, and BOP
Pulling the BOP	Packer and tubing. Isolated reservoir completion (for example, deep set plug)	Casing/wellhead, cement, and tubing hanger. Tubing hanger plug and possible additional barrier of downhole safety valve
Operating a naturally flowing well	Christmas tree, packer, and tubing	Downhole safety valve, casing, wellhead, cement, and tubing hanger
Operating a well with artificial lift (incapable of natural flow to surface)	Christmas tree or surface valve. Casing and wellhead	Pump shut down
Pulling a completion	Isolated and tested reservoir completion (for example, deep set plug and packer) or overbalanced mud	Casing/wellhead, cement, and BOP

2.1.2.1 Wireline Operations

Wireline operations fall into two main categories: slickline and electric line. With slickline, downhole tools are conveyed into the well on a single strand metal wire. There is no electrical conductor, so the tools are mechanical. Slickline can be used for simple operations, such as gauge ring runs, debris removal (bailing), shifting sleeves, setting and retrieving plugs, and setting and pulling gas lift valves. Electric line involves a braided line containing an electrical conductor. Electric line operations involve more complicated operations requiring electrical communication between the tool and the surface, such as setting packers, firing perforation guns, or running logging tools for downhole information gathering. Braided line is also often used when slickline strength is inadequate for the operation. The wireline is spooled from a drum for both slickline and electric line operations.

In wireline operations, the well can be underbalanced with respect to the formation. As such, the fluid column is not considered a barrier, and an additional well control barrier is required. Figure 2-11 shows a slickline rig up and its barriers.

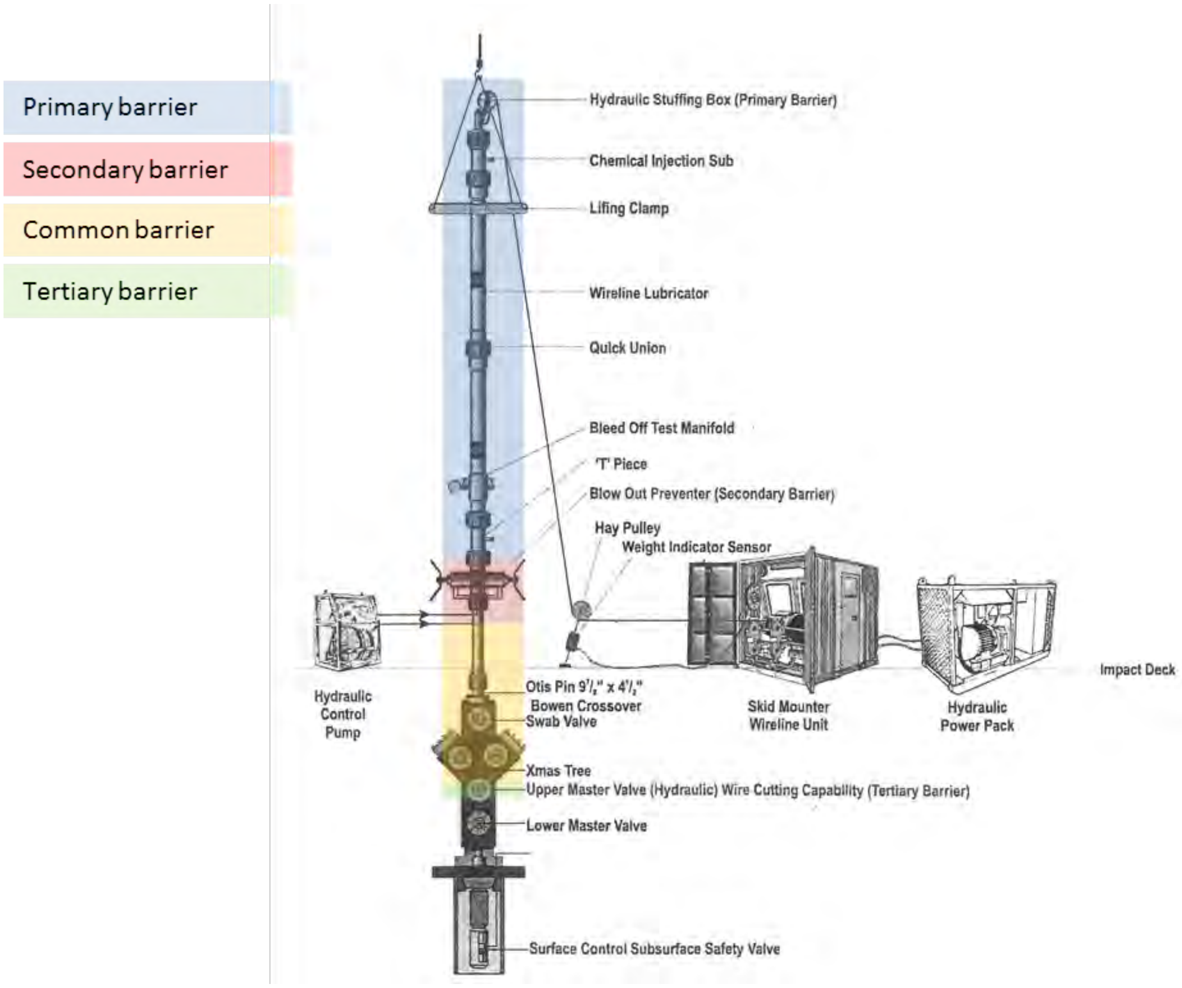

Figure 2-11: Slickline Rig Up on a Surface Tree Showing Pressure Control Equipment [78]

The set of Pressure Control Equipment (PCE) from the connection to the stuffing box provides the primary barrier. This is in place of the fluid column. The wireline BOP provides the secondary barrier. There is also a tertiary barrier in the form of the upper master valve, which will typically have a wire cutting capability, meaning it can close even if the slickline is deployed through it.

Tools are loaded into the PCE at the lubricator, above the closed swab valve. After the tool string is loaded, the quick union is made up and the pressure is tested. When the pressure integrity of the PCE is verified, the swab valve can be opened, and the tool string is run into the hole. The wireline enters the PCE equipment through the stuffing box. This simple piece of equipment maintains a seal around the moving wireline by means of rubber elements. The wireline passes through these elements, which are compressed by the use of a nut. The compression extrudes the rubber against the wireline, which maintains the seal. Stuffing boxes are available with hydraulic compression to allow remote tightening of the rubber element packings. In the event of a line breakage, a built-in ball and seat is used to seal the stuffing box.

Slickline operations are typically low-tech, with very little in the way of automation. After the tools are run in to the correct depth, many slickline manipulations are performed by hand, with the wire manipulated manually to perform the operation (such as setting or retrieving a plug). Operator experience and a good 'feel' for the wire can be critical to the success of the operation.

Automation is used in the wireline winch operation, with instrumentation providing feedback of the parameters (such as tool depth and weight). Winch operation uses simple controls rather than manual operation.

The wireline BOP can be either manual, requiring manual closure, or hydraulically actuated. Hydraulically actuated BOPs are usually preferred because of their fast response time.

Figure 2-12 shows the rig up for electric line operations. The braided line is typically much larger in diameter than the slickline. This results in two major deviations in the pressure control equipment form those used in slickline operations: a more robust BOP configuration, and the requirement for a grease injection system to maintain a good seal around the electric line cable.

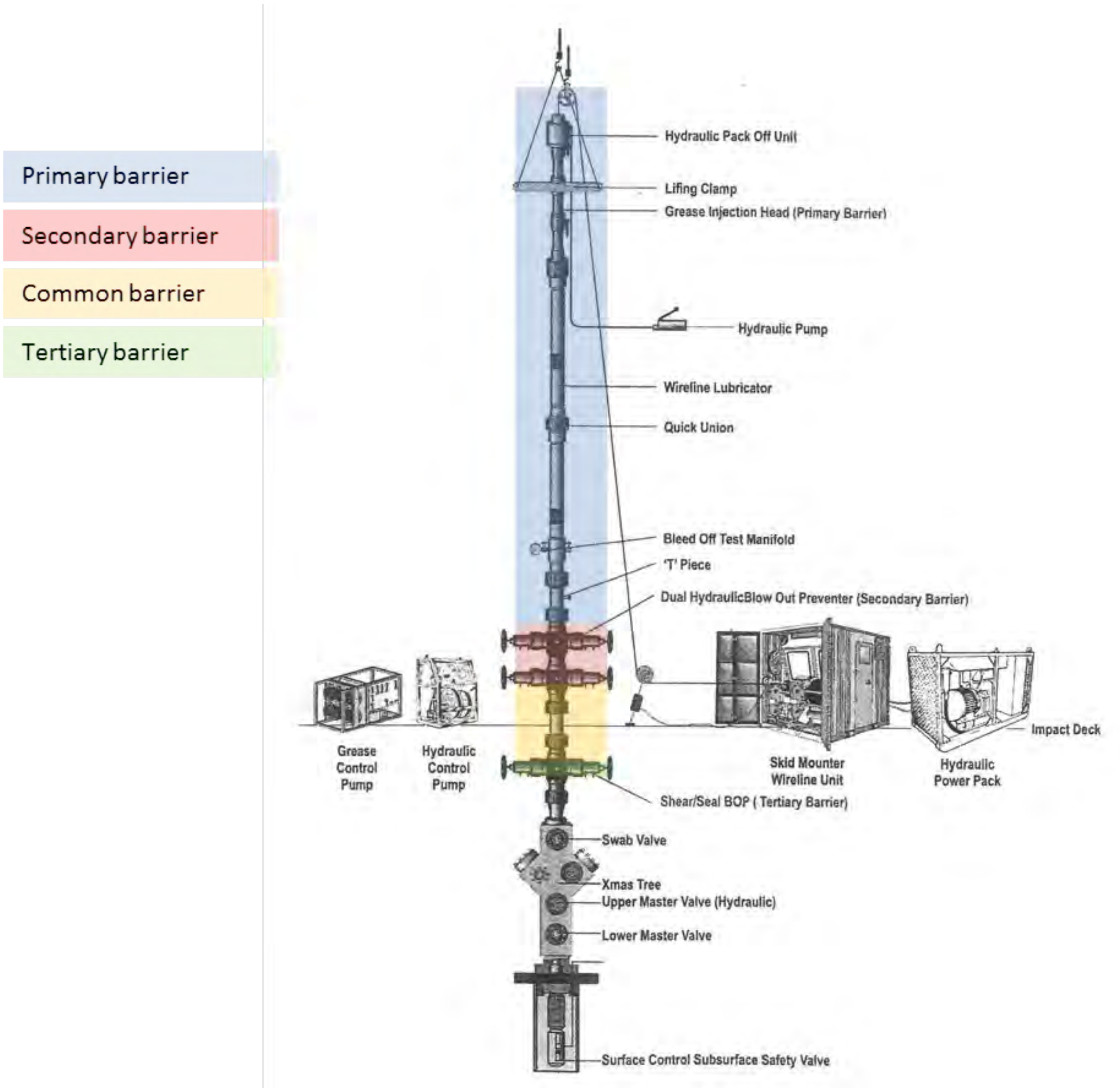

Figure 2-12: Braided Line (E-line) Rig Up Showing Barrier Elements [78]

Figure 2-13 shows a schematic of a grease injection head for braided line. With the grease injection system, flow tubes provide a close fit around the line, usually to within a 0.004-inch diameter [78]. Viscous grease is injected into the annulus between the flow tube wall and the braided line, thus providing a seal. The system relies on viscous forces and resulting pressure drops to maintain the seal, with the pressure rating of the injection head rising with the number of flow tubes used.

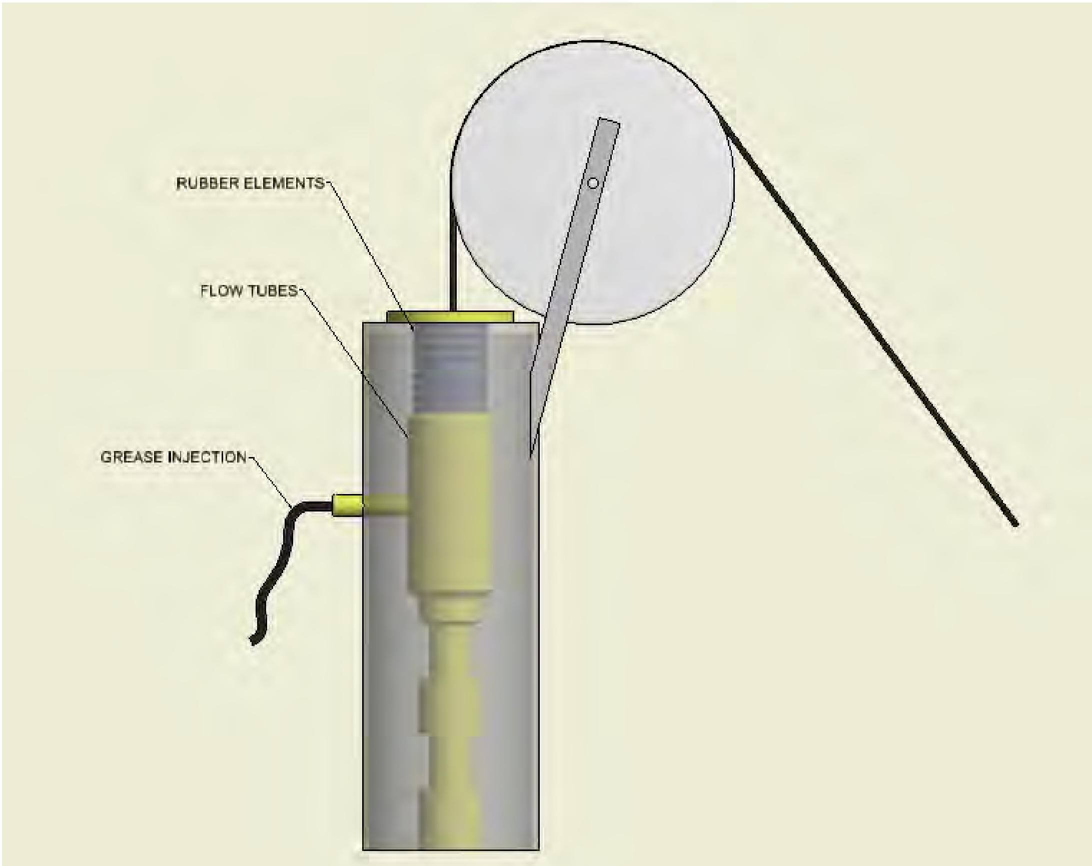

Figure 2-13: Schematic of Grease Injector [79]

Control system configurations for wireline BOPs vary, but they will have some degree of automation. The NORSOK standard [16] gives a good guideline of general requirements for the Control system, which include some low levels of automation. These requirements include:

- Control panels clearly indicate whether the functions are in the open or closed position.
- Control panels with motion selector valves and switch buttons are equipped with a securing device against unintentional operation of essential functions (such as shear ram).
- The BOP Control system is equipped with monitoring and alarms for low accumulator pressure, loss of power, and low level of control fluid.
- System regulators are unaffected by a loss of power.
- BOP ram operating pressure is regulated at a minimum from the BOP accumulator unit.
- Maximum response time when the BOP is located on a surface installation is 30

seconds. (Time from closing function activation at the control panel until the BOP reaches the closed position).

The addition of automation to a safety-critical device such as a wireline BOP can be extremely valuable. The simple act of automating the closing function of the BOP significantly reduces the risk of the function being performed incorrectly. Furthermore, automation of basic system status such as open or closed status, hydraulic pressure, fluid levels, and power supply can provide excellent assistance in ensuring that the equipment is ready to perform the required function when it is needed. Further enhancements may be applicable to grease injector heads, such as monitoring grease pressure, supply, and consumption and condition monitoring of packer elements in both stuffing boxes and grease injector heads.

The well control equipment used in wireline operations relies heavily on mechanical isolations. Correct valve line-up for each operation is therefore critical. For example, opening the lubricator without closing the swab valve may result in uncontrolled discharge of well fluids at surface. In all cases, the lubricator pressure must be bled off before opening; this allows for safe opening and confirmation that the swab valve is sealed closed.

Wireline operations rely heavily on correct sequence of operations and accurate recording of valve status. A lack of integration of the various systems can make it complicated to execute these operations correctly. The tree Control system and wireline BOP Control system are independent of each other. To further complicate things, the wireline pressure control equipment, which is located above the BOP, is usually operated manually. Operations must have very clear procedures that include frequent verifications to ensure correct line-ups at all times and to prevent accidental discharge. Correct operation relies heavily on personnel.

Clearly this type of operation could potentially benefit from a centralized automated valve status monitoring and lock out system. This system could automatically monitor valve status and could include logic that detects and prevents configurations that may cause a loss of well control. However, such a system would have to overcome the problems associated with integrating different Control systems. However, automation of the current manually operated pressure control equipment may prove to be both difficult and expensive, which could inhibit one of the main attractions of wireline intervention operations—their low cost and ease of use.

2.1.2.2 Coiled Tubing Operations

Coiled tubing (CT) is any continuously-milled tubular product manufactured in lengths that requires spooling onto a take-up reel during the primary milling or manufacturing process. The tube is nominally straightened before it is inserted into the wellbore and is recoiled for spooling back onto the reel. Tubing diameter normally ranges from 0.75 in. to 4 in., and single reel tubing lengths in excess of 30,000 ft. have been commercially manufactured. Common CT steels have yield strengths ranging from 55,000 psi to 120,000 psi. [80]

CT operations involve the use of continuous tubing, generally stored on a reel, to enter a well and convey tools designed to accomplish a specific well operation. The length of continuous tubing is generally sufficient to reach the bottom of the well (or the depth required for the specific operation to be conducted). CT units offer an efficient means to conduct well interventions, workovers, and even drilling and milling operations, often without killing the well. [81]

The use of CT in well operations eliminates the problems associated with making and breaking connections while going into or out of the hole. A key advantage of CT is the ability to continuously circulate through the CT while using CT pressure control equipment to treat a live well. This also avoids potential formation damage associated with well killing operations. The ability to circulate with CT also enables the use of flow-activated or hydraulic tools.

Other key features of CT for workover applications include the inherent stiffness of the CT string. This rigidity allows access to highly deviated/horizontal wellbores and the ability to apply significant tensile or compression forces downhole. In addition, CT permits much faster trip times as compared to jointed pipe operations. [80]

The main advantages of using continuous tubing in well operations are [81]:

1. There are no connections to make or break; therefore, safety is improved.
2. Well service time is reduced as compared with rigs that use jointed pipe.
3. Units are highly mobile, require fewer operations personnel, and allow for quick rig up.
4. CT can be deployed and retrieved while continuously circulating.
5. There is no need to kill the well; the well can continue to produce.
6. Formation damage is minimized if the well is not killed.
7. CT requires a small surface footprint.
8. The absence of tool joints and treaded connections eliminates potential leaks.
9. There is no need to remove existing completions tubing.
10. Continuous well control operations can be performed while tripping in or out.

There are some disadvantages to the use of CT in well operations. Some of the disadvantages are caused by the large number of times the tubing must be bent as it spools off/on the storage reel while going into or out of well. The disadvantages of continuous tubing are:

1. The tubing cannot be rotated. However, the applications of downhole motors allow some drilling and milling operations to be continued.
2. CT is subject to bend-cycle fatigue.
3. Bend-cycle fatigue reduces yield strength, which decreases the burst and collapse resistance of the tubing.
4. Tensile load capability is reduced because CT has smaller wall thickness than jointed pipe.
5. CT suffers diametrical growth and smaller wall thickness over time.
6. The length of the tubing that can be stored on a reel is limited, especially for larger diameter tubing. (Weight and height limits set by transportation regulations limit the physical size of storage reels.)
7. Circulating pressure losses are generally very high; therefore, slow pump rates must be used.
8. When ‘patches’ are attempted, tube-to-tube ‘butt welding’ is problematic.

Coiled Tubing Equipment

The CT unit comprises the complete set of equipment necessary to perform standard continuous-length tubing operations in the field. The unit consists of four basic elements:

1. **Reel** – for storage and transport of the coiled tubing
2. **Injector Head** – to provide the surface drive force to run and retrieve the coiled tubing
3. **Control Cabin** – from which the equipment Operator monitors and controls the coiled tubing
4. **Power Pack** – to generate hydraulic and pneumatic power required to operate the coiled tubing unit.

A schematic of CT rig up is shown in Figure 2-14.

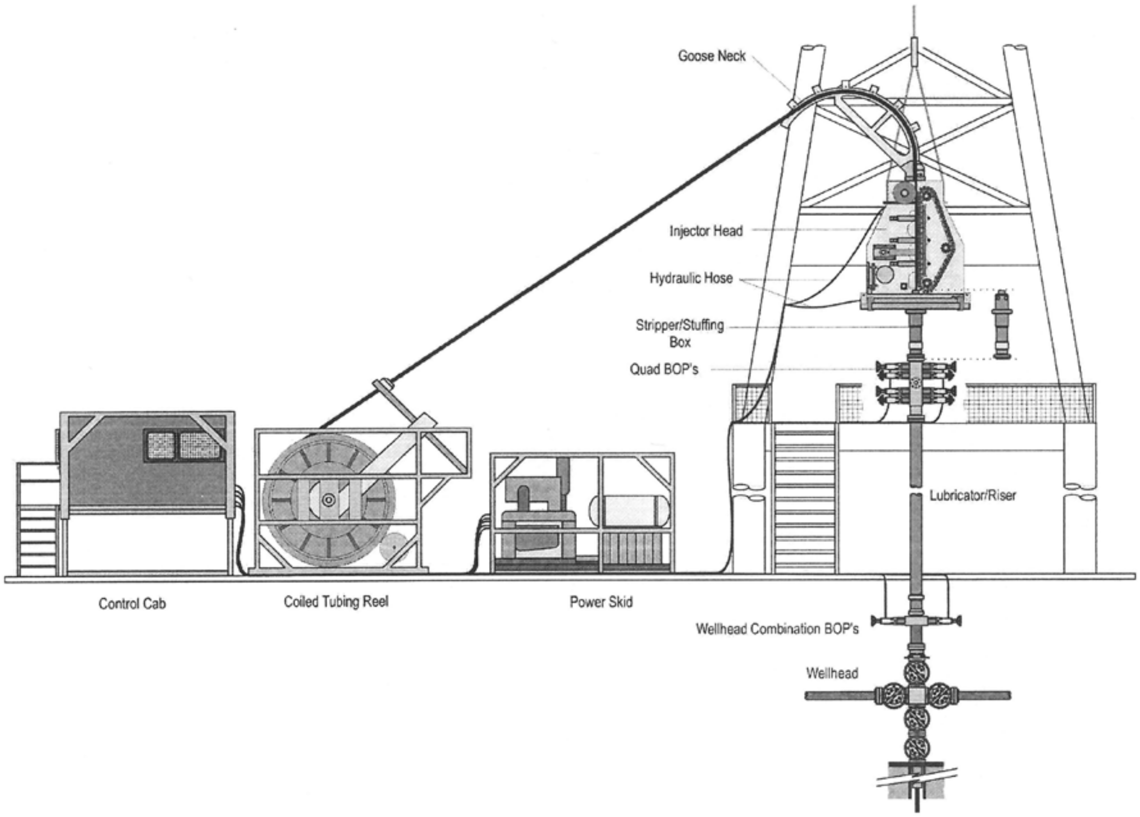

Figure 2-14: Coiled Tubing Rig Up on a Surface Tree Showing Pressure Control Equipment [78]

CT can also have internal electrical conductors or hydraulic conduits fitted with the tubing internal diameter, which enables downhole communication and power functions to be established between the Bottomhole Assembly (BHA) and the surface. In addition, modern CT strings provide sufficient rigidity and strength to be pushed or pulled through highly deviated or horizontal wellbores. This enables successful execution of downhole operations that would be impossible to perform with conventional wireline approaches or cost prohibitive if performed by jointed pipe [80].

Coiled Tubing Well Control and Pressure Control

Unlike conventional drilling, in CT operations, it is common for the well to be producing while the operations are underway. Because the well control procedures while producing are continuous in nature, they are often referred to as pressure control procedures. It is therefore important that the subject of well control in CT operations include pressure control equipment (PCE) and related practices [81].

Coiled Tubing Well Control Equipment and Benefits

Proper well control equipment is essential to CT operations, given that a majority of these operations are performed in the presence of surface wellhead pressure. Typical CT well control equipment consists of a BOP topped with a stripper (high pressure CT units have two strippers and additional BOP components). All components must be rated for the maximum wellhead pressure and temperature possible for the planned field operation.

The ability to perform work on a live well is the primary benefit associated with CT. To accomplish this task, three technical challenges must be overcome:

1. A continuous conduit capable of being inserted into the wellbore (CT string)
2. A means of running and retrieving the CT string into or out of the wellbore while under pressure (injector head)
3. A device that is capable of providing a dynamic seal around the tubing string (stripper or packoff device)

The stripper (sometimes referred to as a packoff or stuffing box) provides the primary operational seal between the pressurized wellbore fluids and the surface environment. It is physically located between the BOP and the injector head. The stripper provides a dynamic seal around the CT during tripping and a static seal around the CT when there is no movement. The latest style of stripper device is designed with a side door that permits easy access and replacement of the sealing elements, with the CT in place.

The BOP is positioned beneath the stripper and can also be used to contain wellbore pressure. A CT BOP has been designed specifically for CT operations. It consists of several pairs of rams, with each ram designed to perform a specific function. The number and type of ram pairs in a BOP are determined by the BOP configuration: single, double, or quad. A quad system is commonly used in most operations.

The four BOP rams (from top to bottom) and their associated functions are:

- *Blind Ram* – seals the wellbore when the CT is out of the BOP
- *Shear Ram* – used to cut the CT
- *Slip Ram* – supports the CT weight hanging below it (some are bi-directional and prevent the CT from moving upward)
- *Pipe Ram* – seals around the hanging CT

A standard CT BOP also contains two equalizing ports, one on each side of the sealing rams. It also has a side outlet between the slip and shear rams. This outlet can be used as a safety kill line. BOPs are available in a range of sizes, and they normally follow the API flange sizes [80].

Coiled Tubing String and Its Limitations

A CT string is the complete, uninterrupted length of the tubing that extends from the BHA up the wellbore to the surface and then wraps around the service reel. API 16ST further includes all tube-to-tube connections to be in the definition of the CT string. A CT string is a ‘consumable component.’ The safety of personnel, security of the well, and the efficiency of the well intervention operation are dependent on the integrity and predictable performance of the CT string. The safe working life of the CT must be predictable if personnel safety, security of the well, and economical operations are to be conducted. Modern CT operations are conducted with CT strings that are designed, manufactured, tested, operated, and monitored using a ‘life of the string’ approach.

CT string is an integral part of the well control equipment system. Therefore, well control considerations in the selection of CT materials and the tubing limitations must be known. The API’s recommended material considerations are fully described in API RP 5C7. API RP 16 ST describes the well control considerations for a string of CT.

The key considerations and limitations of CT include [81]:

- CT material strength: (a) yield strength, (b) tensile strength, (c) ductility, and (d) hardness
- Pressure ratings: (a) burst and (b) collapse
- Axial, torsional, and bending stress
- Buckling, downhole buckling, and surface buckling
- CT bend-cycle fatigue
- Surface damage
- Corrosion
- Sour gas corrosion and embrittlement
- Mechanical defects and slip marks
- Welds
- Erosion

Coiled Tubing Operations and Equipment Complications

CT Operations and equipment complications include:

- Collapsed coiled tubing
- Tubing runs away in to the well
- Tubing gets blown out of the well
- CT reel drive failure
- Power Pack failure
- Junk in the hole

- Stuck tool string and high angle of inclination
- Long BHA deployments
- Blockage and trapped pressure in tubing/wellbore
- Paraffin wax
- Hydrates
- Pressure on the casing
- Lost circulation

2.2 Emerging Technologies in Automated Drilling and Well Safety

Automation in drilling started with the mechanization of surface operations. Technologies such as iron roughnecks and pipe handlers, which are well established in the industry, have improved operational safety. Downhole, the automated tools such as rotary steerables have also become well established. These tools are forced to have a high level of automation, as communication between the surface and the bit is slow at best and is sometimes unreliable. These tools therefore typically work in a closed loop and correct themselves following preloaded instructions such as trajectory from surface. Corrections to the instructions can be signaled periodically.

This section, which discusses some of the more recent technologies, focuses on those technologies that contribute directly to well safety, help remove personnel from hazardous situations, or will become major enablers for future automation.

2.2.1 Standardization of Data Formats and Transfer Specifications

When it comes to drilling automation, a primary obstacle is the lack of a common communication protocol and language that allows multiple third-party companies to connect to and control drilling equipment on a rig [82]. Each of the companies involved in the operation will have its own proprietary hardware and software, with each speaking its own digital language. This situation is not only inhibitive to progress in automation, but potentially unsafe devices cannot communicate with each other across organizational boundaries, thereby obstructing the transmission of potentially safety-pertinent information [83].

Drilling automation requires seamless communication among the many parts of the operation. A standard protocol for electronic communication and data transfer is imperative for the advancement of drilling automation. A step in this direction is the Wellsite Information Transfer Specification (WITS). WITS is a data transfer protocol that has been widely used since the 1980s to move data from point to point through serial lines or Transmission Control Protocol (TCP)/Internet Protocol (IP) network connections [84][11]. The advantage of the WITS format is its flexibility, as it offers 5 levels of the format [85]. These levels are:

- Layer 0, which describes an ASCII-based transfer specification.
- Layer 1, which describes a binary-based format based on 25 predefined fixed-size records and the Log Information Standard (LIS) data transmission specification.
- Layer 2, which describes bi-directional communication using LIS Comment records.
- Layer 2b, which describes the buffering of data.
- Layer 4, which extends the previous layers to use a different data exchange format, API RP66.

Regardless of the level selected, a WITS data stream consists of discrete data records, each of which is generated independently of other data record types and has a unique trigger variable and sampling interval. A summary of pre-defined record types is shown in Table 2-8 [85].

Table 2-8: Record types for WITS protocol [85]

Rec	Name	Description
1	General Time-based	Drilling data gathered at regular time intervals
2	Drilling – Depth-based	Drilling data gathered at regular depth intervals
3	Drilling – Connections	Data gathered at drilling connections
4	Hydraulics	Hydraulics data gathered while circulating
5	Trip – Time	Tripping data gathered while running in/pulling out
6	Trip – Connections	Tripping data gathered at tripping connections
7	Survey/Directional	Survey/Directional data
8	MWD Formation Evaluation	MWD Formation Evaluation data
9	MWD Mechanical	MWD Mechanical data
10	Pressure Evaluation	Pressure Evaluation data
11	Mud Tank Volumes	Mud Tank (Pit) Volume data
12	Chromatograph Cycle-based	Chromatograph Cycle data

[11] The WITS protocol is still widely used today, but it is slowly being replaced by the updated WITSML for newer technologies.

Rec	Name	Description
13	Chromatograph Depth-based	Chromatograph data averaged over depth intervals
14	Lagged Mud Properties	Mud property data-based returns at depth increments
15	Cuttings/Lithology	Cuttings Lithology and related data
16	Hydrocarbon Show	Hydrocarbon Show-related data
17	Cementing	Well Cementing Operations data
18	Drill Stem Testing	Well Testing Operations data
19	Configuration	Drill String and Rig Configuration data
20	Mud Report	Mud Report data
21	Bit Report	Bit Report data
22	Comments	Freeform comments
23	Well Identification	Well Identification data
24	Vessel Motion/Mooring Status	Vessel Motion and Mooring Status data
25	Weather/Sea State	Weather and Sea State data

Although WITS has served the industry well, it also has a number of shortcomings [84]:

- Outdated MWD record format
- Data is not object oriented, which reduces flexibility
- Restrictions on the number of drill string and casing sections
- Inflexibility for handling data in different units of measurement
- Limited capacity for handling static well information
- Use of binary data formats is not platform-independent (for example, Windows versus Unix)
- Essentially a data 'push' from the rig with little capability to request specific information
- User-defined records that are all used and are not easily exchanged

In 2000, the Wellsite Information Transfer Standard Markup Language (WITSML) initiative began to provide an improved industry standard and enable service companies at the rig site to exchange dates with the Operator. In Phase 1, BP and Statoil jointly sponsored the project in cooperation with Baker Hughes, Halliburton/Landmark, Schlumberger/GeoQuest, and NPSi [84]. In 2002, a commercial WITSML was introduced, and it facilitated a functional implementation of Web Services for drilling data.

Although both of these protocols provide data transfer, it is largely limited to reporting of operational parameters. For automation, information flow needs to become more bi-directional, allowing both status reporting and communication of control parameters. For example, WITS/WITSML provides the protocol for recording information such as the torque at the bit (from MWD) or the top drive torque. However, should this be controlled by a computer algorithm, there is also a requirement for each of the desired control variables to be communicated. A new generation of WITSML, called WITSML2, will be capable of streaming real time data using updated technology. This new language, which was delivered in September 2014 as a Community Technology Preview (CTP), will be formally released in early 2015 [86].

In 2008, the Drilling Control System (DCS) subcommittee of the IADC and the SPE Drilling System Automation Technical Section (DSATS) began exploring Open Communications-Unified Architecture (OPC-UA) communication protocol to meet the previously mentioned communication gap [82]. OPC is the interoperability standard for the secure and reliable exchange of data in the industrial automation space and in other industries. It is platform-independent and ensures the seamless flow of information among devices from multiple vendors. The OPC Foundation is responsible for the development and maintenance of this standard [87].

Although OPC is a generic automation protocol used in many industries, combining its automation-based capabilities with the drilling-specific formats of WITS/WITSML can provide a basis for a standard for automation data transfer in the industry. In addition to the additional control components, the OPC platform has the advantage of providing much higher levels of security than other platforms. This is essential for the intermittent and flexible interconnectivity that automation in the industry demands. Service providers need to be able to connect for the time that their operation is being conducted but then disconnect when they are no longer required. Security is a major concern when accessing sensitive well data or allowing access to the control of hardware, but there are many ways in which security may be implemented through combinations of software and hardware techniques [88].

MacPherson et al., [83] described the importance of standards such as OPC-UA in information flow using the Purdue Automation Pyramid shown in Figure 2-15.

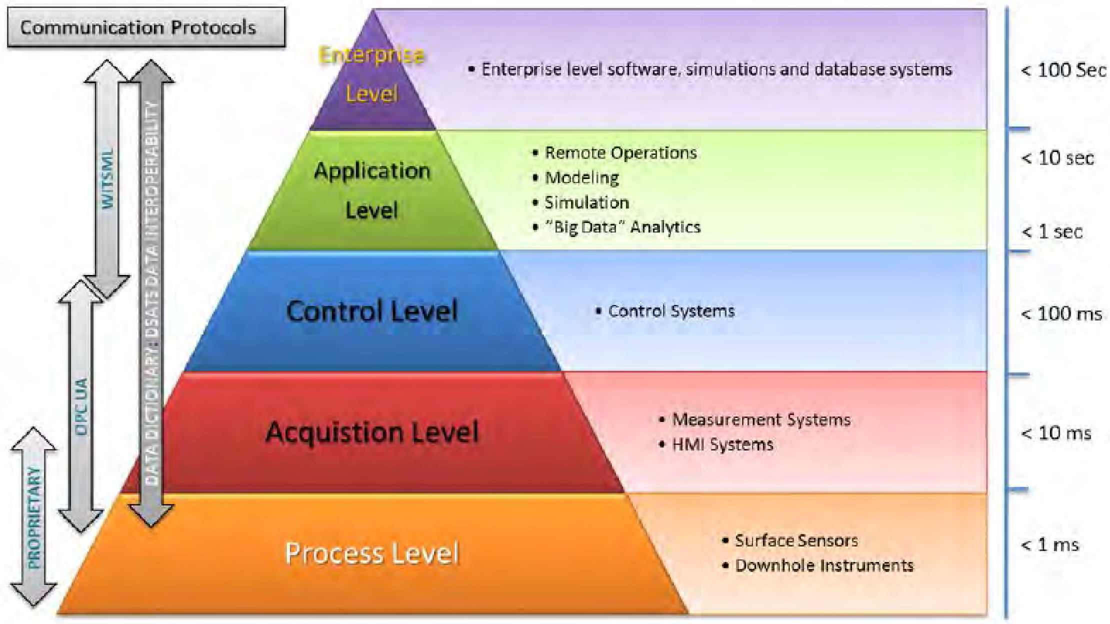

Figure 2-15: Modified Purdue Automation Pyramid [83] Showing Transition from Process Level (Measurement Instrumentation) to Enterprise (Remote) Software Systems

At the lowest process level, information is communicated using proprietary protocols. This level deals with instrumentation, actuators, tools, and hardware at surface and downhole. Above this level, integration begins at the acquisition and control levels. Here it starts to become necessary that devices communicate with each other, and OPC-UA plays an important role in facilitating this communication. Note that OPC-UA fills the gap between WITSML and the proprietary communication protocols. Finally across all levels, a data dictionary, in this case DSATS Data Interoperability plays the role of taking the general OPC-UA framework and customizing data formats to the drilling environment. The DSATS dictionary is still under development.

Another approach to solving this problem is the development of open rig control platforms. In this space, National Oilwell Varco (NOV) has taken the lead with the launch of their NOVA™ Control system. The Control system uses the NOVOS™ operating system to create a platform that handles applications through an online store [89]. According to the open system [90] or platform, the concept means that the surface Control system will have an application management system that will allow any company, for example, to write an 'app' to the Control system and perform intelligent well functions using the system as an interface to the rig.

NOV NOVOS allows development and loading of well plans into the rig Control system and creation of custom applications that can interact with the NOVA Control system. The NOVOS web page interface is presented in Figure 2-16.

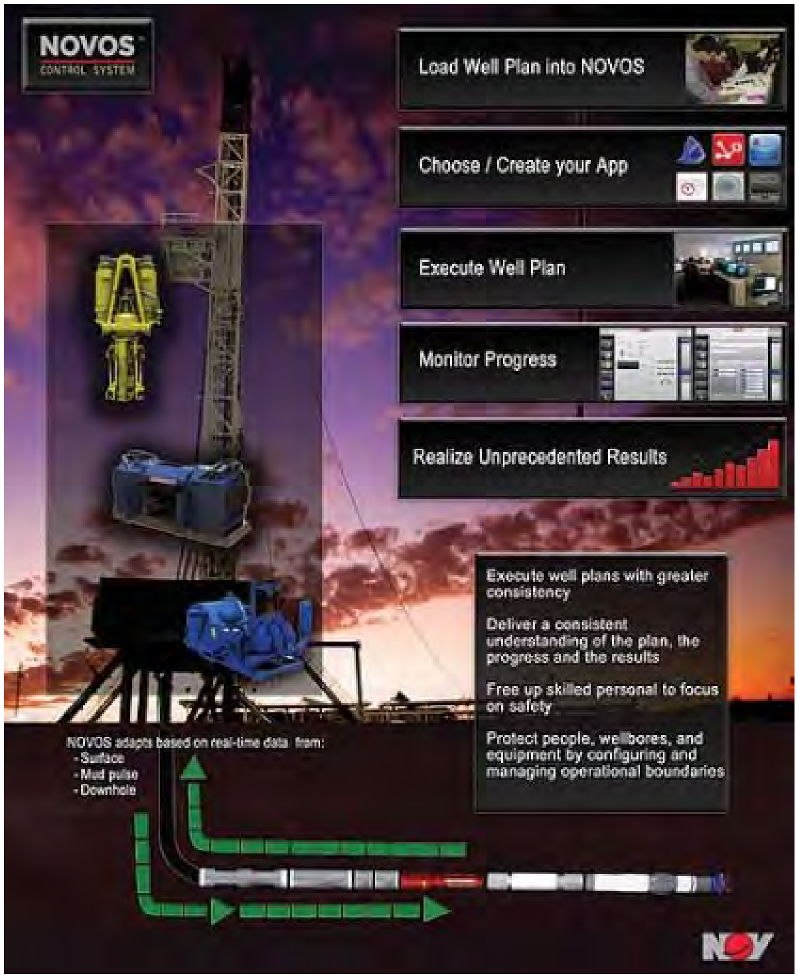

Figure 2-16: NOVOS Web Page Interface [89]

2.2.2 Automation of Surface Operations

One of the key ways for improving well safety during well construction is to remove people from dangerous areas. One of the best ways to achieve this is through the automation of surface operations on the rig floor.

Surface operations, such as pipe handling, are one of the areas where automation has seen significant acceptance in the drilling industry. In the 1990s, many rigs were built with mechanized pipe handling equipment, thereby automating an often dangerous manual task.

Drilling surface operations involve the coordination of several pieces of heavy machinery to handle downhole drilling equipment and pipe. This machinery includes the iron roughneck, top drive, draw works, pipe handling cranes, and manipulator arms.

However, certain operations, particularly in completions, frequently require the presence of human workers on the drill floor. Collision avoidance between pieces of machinery and between machinery and manual workers is a vital safety consideration. Because people cannot yet be eliminated from the drill floor, allowances for personnel safety in the machine control algorithms is one reason that automation has not yet resulted in faster well construction [91].

Among their suite of automation technologies, CoVar Applied Technologies is developing Personnel Video Monitoring (PVM) technologies, a novel solution to the human–machine collision problem. Working with Transocean, CoVar is developing a solution using video technology [92]. One of the advantages of this solution is that a key component—the video feed—is already installed on many existing rigs, which makes the system quite inexpensive. In addition, this solution requires no transponders, which removes the potential for system failure should personnel forget to wear a transponder, or if it fails.

The PVM system locates personnel in a 3-D model of the working environment using triangulation from multiple cameras. Currently, the system can reliably track up to three people, and it is sensitive to lighting, background, and scene changes. Figure 2-17 shows an example setup from a trial. Note that the system accurately tracks personnel despite significant challenges [92], including:

- Only cameras 1-7 were available (the rendering shows 9)
- The presence of distinct shadows and complex backgrounds
- A very large stand-off between the cameras and personnel
- Static camera zoom (most significant challenge)

Figure 2-17 presents an example of the PVM system tracking from a computer-generated video of rig personnel. The three persons visible in the bottom left image have been tracked by seven camera locations (shown in black or red symbols). The three persons are represented with red, blue, and green dots as shown in the bottom right image on a white background representing the flow rig. The personnel locations in rig coordinates are automatically determined using triangulation by using knowledge about the camera positions and orientations. Different camera views are displayed along the top image. The red camera symbol on the bottom right image represents the camera that is used to generate the rig floor view shown in the bottom left image.

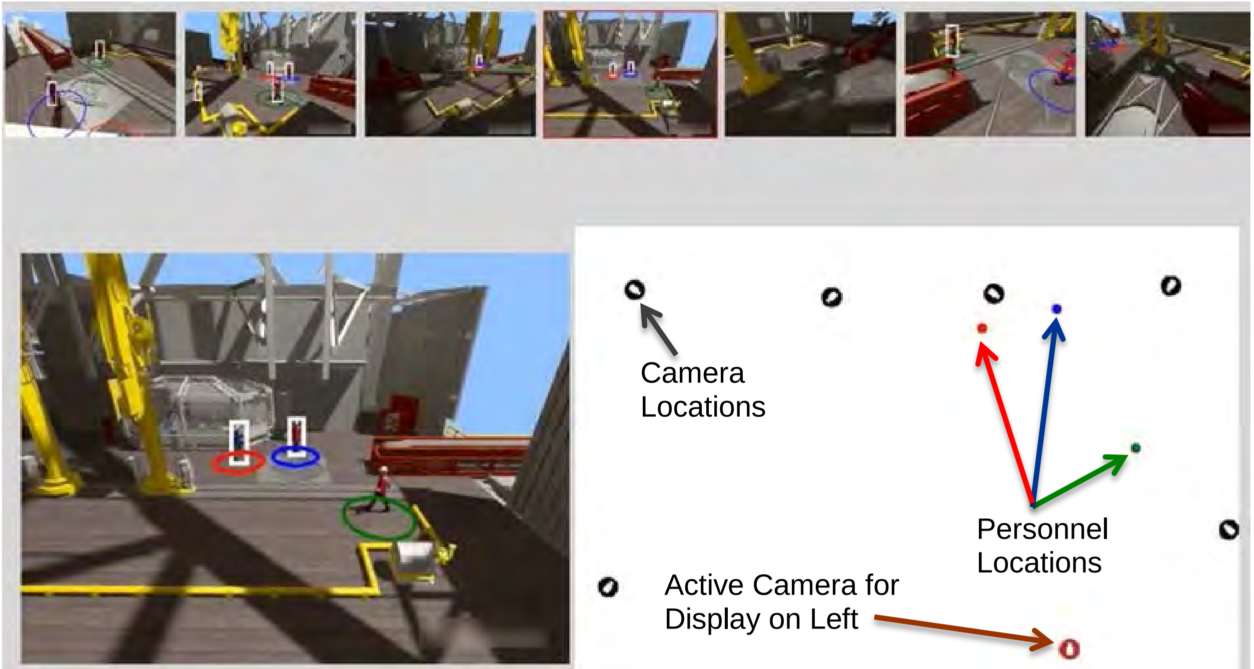

Figure 2-17: Example of Personnel Video Monitoring (PVM) System [92]

The system will allow appropriate variation of automated machine behavior to prevent potential collisions with personnel.

The PVM system, which is in a prototype stage, requires additional validation and testing and is not yet available commercially[12]. The prototype system is constrained to track a maximum of three persons, and too many people in close proximity can lead to errors. However, the PVM system can accurately localize many persons in a scene as long as the camera coverage is adequate (for example, persons are clearly visible from at least three cameras) [93]. Future goals of the PVM system are to integrate the spatial map of person locations with machinery location information to provide automatic warnings and safety-critical control logic.

The use of computer vision systems is in its infancy in the industry, and CoVar is developing numerous other applications in addition to anti-collision, such as muster point roster, personnel localization, pipe handling, and even shaker solids analysis.

The automation of rig floor equipment and surface operations is vital to removing personnel from this hazardous environment. However, automation will need to evolve from the current systems toward the ultimate goal of no personnel on the drill floor. Until full automation can be achieved, partial automation will be the reality, and people will

[12] A computer vision based personnel localization project was completed by CoVar for a service provider in 2013.

need to work alongside automated heavy machinery. To do so safely is therefore critical to the development of full automation.

2.2.3 Automatic Drilling

A key objective of this study is to identify those technologies that will allow automated responses to dangerous situations such as well control and allow the removal of personnel from these higher risk situations. During the course of this study, no system that automatically detects an influx, stops the pumps, picks up off bottom, and enables personnel to perform a flow check was identified. However, systems that have automated control of the top drive position and pump systems already exist or are in development. These systems started with advisory auto drillers from the 1990s, which assist in optimizing drilling parameters and are currently developing into highly sophisticated automated systems.

In traditional drilling, optimization of drilling parameters such as rotary speed and weight on bit (WOB) has been done by feel, relying heavily on the experience of the Driller. However, with so many experienced people retiring, there has been a large drive to automate this optimization process, enabling less experienced crew to achieve the same drilling performance as their more experienced counterparts. The result has been far more consistent, high performance drilling [94].

The path to automated drilling can be described in three tiers, as depicted in Figure 2-18. These tiers range from purely advisory systems where the automation serves to provide guidance to Drillers on the best decisions made, through a second tier where the decisions are made with Driller approval, to a fully automated system where the Driller (who may be located offsite) is informed of decisions that are made autonomously [95].

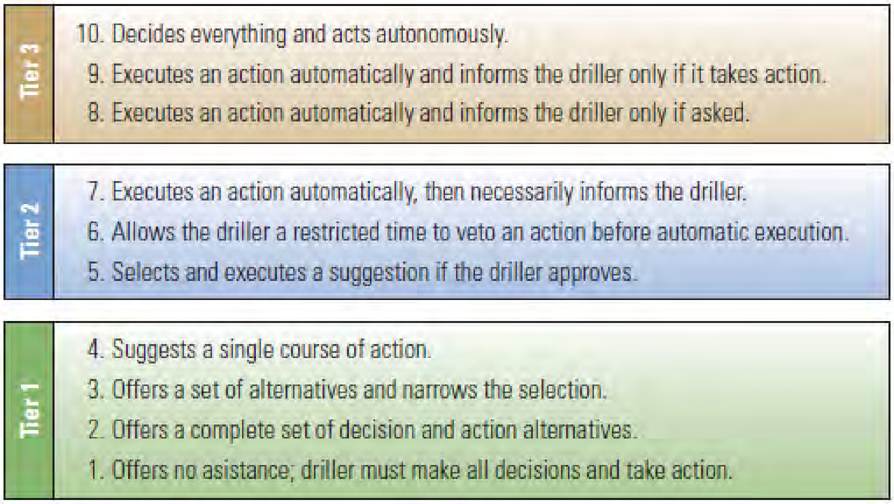

Figure 2-18: Levels of Automation Ranging from Advisory Systems (Tier 3) to Full Automation where the Driller is Informed of the Actions Taken [95]

The first area where automation has been implemented more directly into the drilling process is in controlling the brake, and thereby the (WOB). Autodrillers, using pneumatic controls to maintain constant WOB and ROP, have consistently outperformed human Drillers when drilling conditions (such as formation geology, pressures, and temperatures) are well known and vary only gradually. However, these autodrillers perform badly when these conditions change abruptly [95]. With the introduction of disk brakes, electronic autodrillers have been able to use computer algorithms and more sophisticated control software that is increasingly able to handle such changes. These autodrillers lie in the second tier of automation, relying on Driller approval of the actions taken [95].

Among many players in this area, Schlumberger has developed two automatic driller algorithms. The first optimizes ROP, and the second controls the trajectory of the drilling [94]. To optimize ROP, the Schlumberger Rate of Penetration Optimization (ROPO) system uses a model of a PDC bit, formation interaction, and a data processing technique that detects changes in bit response (as a result of wear or bit balling). The ROPO model breaks the bit formation interaction into three phases [95]:

- In Phase 1, the bit is only just beginning to contact the formation and increased WOB yields little in increasing the ROP.
- In Phase 2, increasing WOB increases the depth of the cut and therefore the ROP.
- In Phase 3, the upper limit of ROP is achieved; the bit cut depth begins to become too deep, limiting the ability of the fluid system to adequately clean the cutting surface and reducing cutting efficiency.

The Schlumberger model considers the state of the drilling system given WOB, torque, surface RPM, ROP, and motor limits, yielding optimal values of RPM and WOB to achieve maximum ROP.

Shell's SCADAdrill (SCADA stands for Supervisory Control and Data Acquisition) represents the next generation of this technology, which is designed to limit the number of workers at the wellsite. Should the operation deviate from the plan or problems occur, a person from a remote operating center following the operation is able to intervene [94]. Developed in 2009, the SCADAdrill system is an autonomous drilling and trajectory Control system that is linked to the well plan. It monitors drilling parameters, determines appropriate controls that need to be communicated back to the rig, and navigates the course of the wellbore. The system is being enhanced to perform consistent and reliable directional drilling. In this mode, it will automatically orient the tool face and slide-drill the required distance in the required tool face to correct the actual well path to the pre-programmed well path [90]. When it is started, the system starts the pumps and the pipe rotation and then takes the bit back to bottom and drills a stand. When the bit reaches the bottom of the stand, the system circulates the appropriate amount of fluid and places the tool joint at the correct height for the crew to set the slips and make a connection. By performing the more repetitive tasks, the system frees workers to perform more high-level tasks such as safety, crew competency, and preventive maintenance.

Another company that is developing more comprehensive automation packages is NOV, with NOVA, their open platform automated drilling system. NOVA updates the Control system to combine downhole data with surface data to automate the drilling process and eventually move toward autonomous drilling [90]. Their NOVOS™ system is a planning component that allows the well program to be built into the Control system.

2.2.4 Automation of Drilling Fluid Management

Drilling fluid is critical to successful and safe drilling operations. Not only does the drilling fluid provide the safety-critical primary well control barrier, but it must also have adequate properties to clean the hole, to build a filter cake on the wellbore wall to mitigate losses, and to maintain wellbore stability. Consistent management and knowledge of fluid properties is therefore critical to both drilling performance and well safety.

A second important role of fluid properties is in the hydraulics models used in many automation Control systems. A good understanding of fluid properties is required for accurate modeling of wellbore hydraulics, which is essential to many drilling control algorithms [96] and for the development of reliable EKDS. However, management of these properties is a highly manual task. A technician has to collect, treat, and manually analyze the mud sample. Measurements are only made periodically, the frequency of which depends on the complexity of determining the fluid property. The manual operation is prone to errors, both through human errors and the small sample size taken at a single point, which may not be representative of the system or provide sufficient information to identify problems early.

The drilling environment is challenging for the deployment of quality sensors and instrumentation. Fluids are solids laden, chemically active, and often corrosive; and they have complicated rheology. Budget constraints, reliability, accuracy, maintenance, and overall value to the operation are issues that hinder the development of these systems [83].

Currently, automation of drilling fluid property monitoring is only just entering the industry. Halliburton offers Real Time Density and Viscosity (RTDV), which measures fluid density and rheology properties according to the API standards. The system can measure fluid properties at the mud supply and return lines, updating density every 5 seconds. Rheology testing is performed at an average frequency of 1 test per 20 minutes [97]. The RTDV system measures viscosity and density. Viscosity is measured using a Couette (cylinder in cylinder) type viscometer, and density is measured using oscillating U-tube technology.

The Couette viscometer places the drilling fluid in a slim annulus between two concentric cylinders. The outer cylinder is then rotated around the common axis. The torque required to resist the motion of the fluid and keep the inner cylinder stationary is measured to indicate viscosity.

In 2009, Halliburton conducted a field trial on the RTDV system on a rig in South Texas [98]. The trial found that viscosity measurements were sensitive to the build-up of gel materials and solids within the instrumentation. The fluids had to pass through filter screens to prevent large solids from entering the viscometer, which was prone to plugging. Although there was good correlation for traditional manual measurements with oil-based fluids, the automated measurements for the water-based fluid system were significantly lower. This was particularly noticeable at the 300 rpm reading. The authors hypothesized that the deviation was a result of reduced solids content or potentially different base fluids. A large amount of noise, which was attributed to a build-up of solids material on the equipment, was also observed in the measurements,.

The oscillating U-tube density measurement exploits the principle that the natural frequency of an oscillating body will vary with the mass of that body. If the mass varies with density, then the frequency can give an indication of density. For the most part, the correlation between the automated and manual measurements was good. However, the automated equipment results were subject to occasional distortions from (1) solids build-up causing high readings and (2) gas becoming trapped in the density meter after it had been plugged, which resulted in erroneously low measurements.

The field trail resulted in design changes that address many of these issues; however, the example illustrates some of the unexpected problems that can occur. Clearly, robust design, field testing, and maintenance of these sensors to ensure correct function is critical to successful application.

Because the Couette viscometers are similar to the traditional instruments used to measure viscosity, they dominate the automated approaches that are available. Aspect Imaging has developed a novel new technique. Their system, FlowScan [99], is a rheology measurement system that uses Magnetic Resonance Imaging (MRI) technology to automatically measure fluid rheology (yield point, plastic viscosity, shear stress versus shear rate, viscosity as a function of shear rate, apparent wall slip, apparent yield stress), flow rates, and water cut directly through the pipe. The technology, which was launched at the 2014 IADC/SPE drilling conference in Fort Worth, is in its infancy for drilling applications.

Although there are other commercial offerings in this area, experimental research and trials dominate the literature. Magalhaes et al. [100] have reported the development of a large-scale drilling fluid flow loop that aims at the evaluation of commercially available fluid property sensors [101]. The system automates the assessment of rheology parameters, mud weight, water-oil content, emulsion, electric stability, fluid conductivity, and particle size distribution.

In the Magalhaes et al. study, the authors used a Brookfield process viscometer to measure viscosity, a commercial Coriolis meter to measure density and a Stratos Pro 4 to measure electrical conductivity [100]. The Couette viscometer obtained by the authors [100] uses a rotating cylinder in the same way as a more familiar FANN 35A viscometer. It is deployed in-line, as depicted in Figure 2-19. The problem with this sort of meter is its intolerance to solids and its vulnerability to plugging. The authors reported that the maximum acceptable solids diameter was 1 mm.

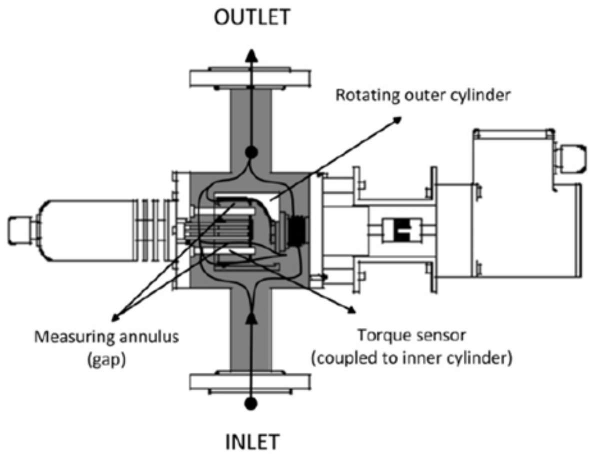

Figure 2-19: Process Viscometer Model TT-100 [100]

The authors used a prototype tool to measure electrical stability of fluid emulsion following the same technical designs as the standard measuring device (Fann 25D). They trained a neural network to interpret ultrasonic attenuation, the speed of sound viscosity, and density information to determine the solids content of the fluid stream. The addition of viscosity and density information allowed the differentiation between (1) changes to ultrasonic attenuation and speed of sound as a result of changes to the fluid system density from (2) those that occur as a result of changes to fluid viscosity. The novel technology performed well on the flow loop data collected. Field trials remain to validate the method.

Flow Measurement

As became clear in Section 2.1.1, flow measurement is a critical component for kick detection. To identify net gains (or losses) to the drilling system that are indicative of a kick, accurate measurements of both flow in and flow out are required. Early kick detection can be realized by increasing the resolution of flow monitoring such that discrepancies from normal behavior can be identified earlier.

Flow measurement technologies take one of two different approaches: volumetric flow measurement or mass flow measurement [101].

Volumetric flow measurement exploits the principle that the volume of fluid passing through a flowmeter (Q) is equal to the cross-sectional area of the pipe (A) times the average velocity of the fluid (V) (that is, Q=VA). Volumetric flow measurement is executed either through positive displacement flow measurements (such as pump stroke counters) or by estimating the flow velocity through the cross meter section. Examples of flowmeter technologies that measure velocity include electromagnetic, turbine, ultrasonic, and vortex flowmeters.

Mass flow measurement assumes that the mass flow of fluid passing through a flowmeter (W) is equal to the fluid density (R) times the volume of the fluid (Q). Examples of flowmeter technologies that measure mass flow include Coriolis mass.

Examples of simple volumetric flowmeters were outlined in the first interim *Evaluation of Automated Well Safety and Early Kick Detection Technologies* report. However, EKDS rely heavily on accurate flow metering. The most proven technology in this application is the Coriolis flowmeter, which is discussed in the following paragraphs.

Coriolis Mass Flowmeters: Coriolis flowmeters use the Coriolis effect to measure mass flow rate. Similar to a gyroscope, when a fluid is circulated through a circular path around the primary axis, rotation of the flow loop around a secondary axis will cause a rotation force around the tertiary axis. This force is directly proportional to the angular momentum of the fluid flow around the primary axis. Measurement of the induced rotation force provides a direct indication of the mass flow rate. With the Coriolis flowmeter, the degree to which the flow tube is deflected by the induced force is measured to give a reading of the mass flow rate.

Coriolis mass flowmeters can provide flow (mass or volume), density, and temperature measurements of liquids and gases, all within a single meter. Because the measurement principle is independent of the physical fluid properties, these meters typically have very high measurement accuracy at about 0.5 to 0.1% of the flow rate [102].

With the Coriolis meter, the flow is diverted through two flow loops and then back to the outlet as depicted in Figure 2-20.

Figure 2-20: Coriolis Flow Loop Paths [102]

The flow loops are vibrated in a transverse direction (secondary axis). This movement is detected through fluctuations in a magnetic field, creating a sine wave output signal. The frequency of the tube vibration provides a direct measure of the flow density. The flowmeter has signal pickoff coils at both the inlet and outlet of the flow loop. Under flow conditions, the Coriolis effect causes the flow tubes to twist, resulting in a shift in phase between the inlet and outlet side pickoff signals. The degree of this twist and the resulting phase shift is directly proportional to the mass flow rate through the flow loops, as shown in Figure 2-21. Figure 2-22 shows the phase shift between the inlet and outlet side coils during flow conditions.

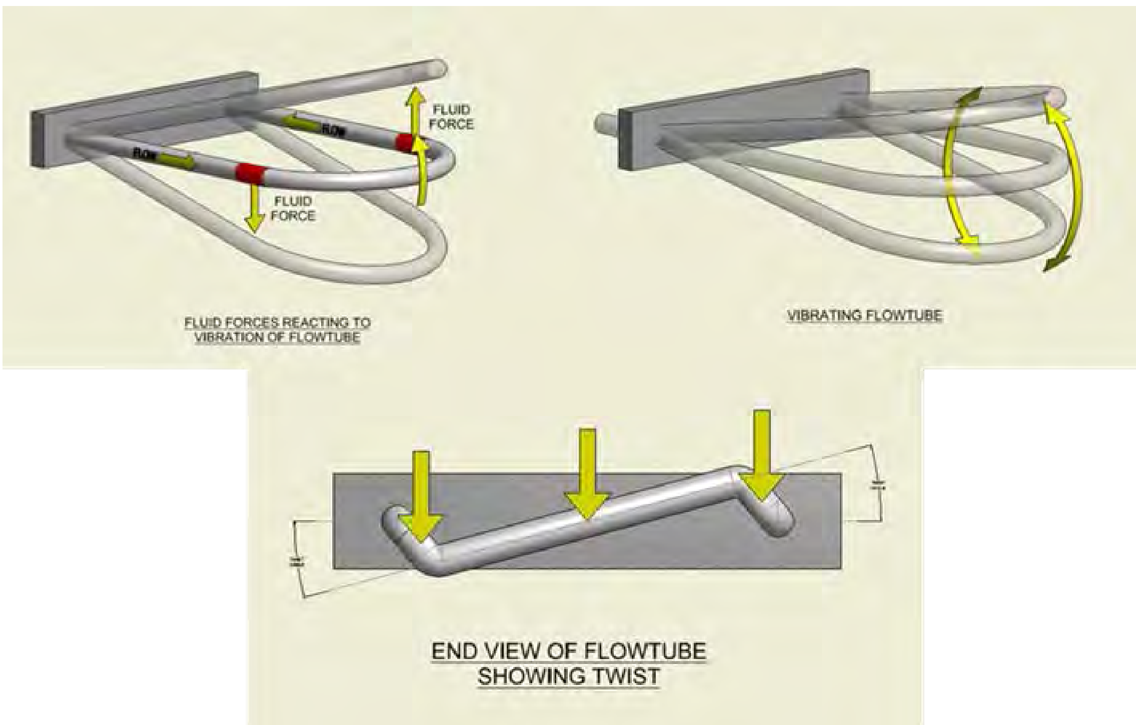

Figure 2-21: Function of Coriolis Flowmeter Illustrating Twist Induced under Flow Conditions Due to Coriolis Effect [103]

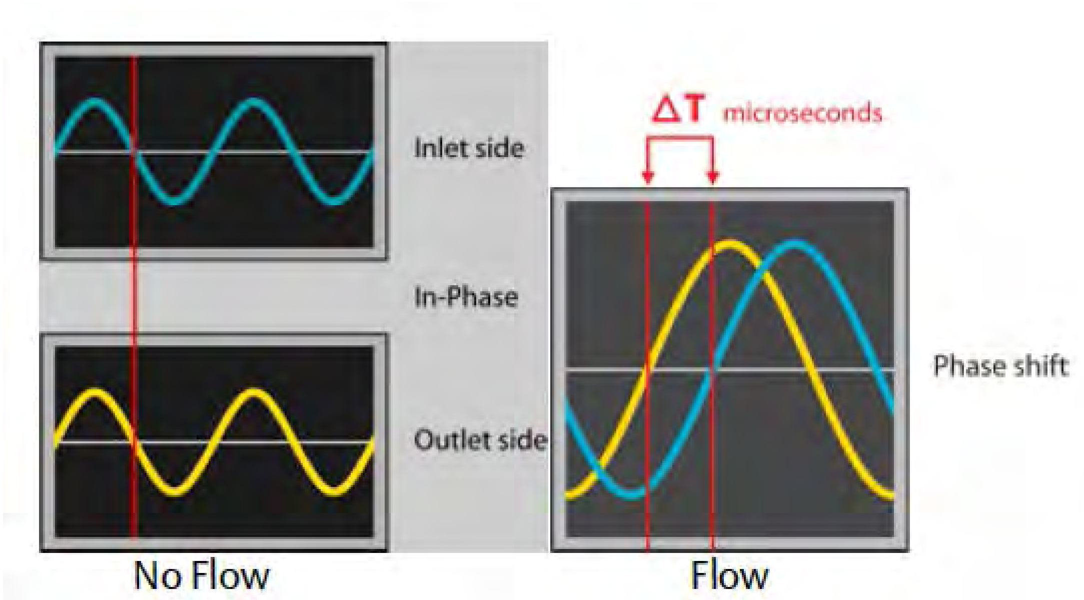

Figure 2-22: Phase Shift between Inlet and Outlet Side Pickoff Coils during Flow Conditions [102]

The Coriolis flowmeter measures the mass flow rate directly and is therefore independent of fluid composition. The meter can measure liquids, gas, or dense slurries. Changes in fluid properties caused by changing temperature, density, or viscosity do not directly alter sensor performance.

The advantages of Coriolis flow metering are clear. Not only is the fluid density measurement automated, but highly accurate measurements of flows are captured. This enables much faster detection of abnormalities in flow behavior than conventional pit level monitoring. When coupled with the correct interpretation software, this increase in the accuracy of flow measurement can result in far earlier detection of kicks, potentially reducing the influx flow time and the final kick severity.

Descriptions of the various challenges that can be encountered with Coriolis metering in drilling follow:

- **Entrained gas**: Coriolis meters can easily measure both the fluid density and the mass flow rate of a drilling fluid with entrained gas. However, the volumetric flow rate is calculated from these measurements by dividing the mass flow rate by the fluid density. When gas is entrained, the Coriolis will correctly measure the reduction in the fluid density. This results in an increase of the calculated volumetric flow rate. When gas volume fractions become greater than ~5%, both flow and density measurements can become degraded [102].

Installation of the Coriolis meter under some pressure can help overcome this problem by keeping gas volumes reduced and/or in solution in the drilling fluid.

- **Pressure rating**: The pressure rating of Coriolis meters depends on both the sensor size and the materials used, but they are typically limited to ~3000psi. For most applications, this precludes their use on the stand pipe. However, installation on the suction side of the pumps can enable increased accuracy of pumped fluid.
- **Flow rate range**: The Coriolis meter must be correctly sized for the application. The range of operating flow rates is dictated by two requirements [102]:
  1. Sufficient flow velocity (3 ft./sec) to flush any air or gas from the flow tubes. (This can be assisted by installation in the ‘flag position’ with the flow loops oriented in the vertical plane.)
  2. A flow rate that is below the erosion threshold (15 ft./sec).

  For a given Coriolis size, the operating range is fixed. Accuracy at the low and high ends of the operating range may also begin to deteriorate. In drilling applications, this can be problematic, as the required flow rates can vary significantly between different hole sections. Furthermore, on a given hole section, different operations will require broadly different flow rates, such as the differences between drilling, cementing, and well control circulation through the choke line. Correct sizing of the Coriolis meter and consideration for multiple meters is critical.

2.2.5 Early Kick Detection Systems

EKDS automate the kick detection process, as was outlined in Section 2.1.1.2. The most widely used indicator of an influx or loss scenario is to monitor the flow rates into and out of the well. By performing a mass balance, these two measurements can give a strong indication of whether an influx to the well has occurred. In this way, the use of high accuracy flowmeters (such as Coriolis meters) on the return line can offer significant improvements in kick detection.

However, the process is not as simple as a simple mass balance. Issues such as fluid compressibility, wellbore elasticity (breathing), gas solubility, and changing thermal conditions and fluid properties can all act to mask the mass balance indicator. Add to this the communications gap between surface and downhole conditions, and the problem of EKD becomes significantly complex. In this environment, developers have turned to complex hydraulics models to assist in both detection of the kick and an automated response.

In recent years, the industry has made efforts to develop EKDS that will address these issues. One such system is that offered by OnSite Integrated Services (established in 2013), which uses Coriolis meters on both the suction and return flowlines to measure the mass balance of the drilling fluid system [104]. However, by far the most developed and established technology for EKD is applied backpressure Managed Pressure Drilling (MPD). MPD uses advanced flow measurements to speed detection and a closed, pressurized system to provide an often automated rapid response to stop the influx.

However, other EKD technologies are also in development. Novel solutions are being developed for the detection of kicks during ‘pumps off’ events, when influx is most likely.

2.2.5.1 Managed Pressure Drilling as Early Kick Detection

A typical MPD system uses advanced, high accuracy flow metering, usually a Coriolis meter, on the return line to monitor for an influx. A comparison of the inflow (typically measured using a stroke counter) to the measured outflow gives a far more rapid indication of an influx than waiting for gains to be observed in the pits. In floating offshore applications, the rotating control device is installed below the slip joint with flow diverted through flexible lines to the return system. With this design, the circulating volume in the riser becomes constant, and it is unaffected by rig heave. By placing a Coriolis meter on the return line, resolution of kick detection is significantly increased.

Although the level of automation in MPD systems varies, with a fully automated choke that includes a kick detection algorithm, an automated response can be initiated. When the MPD system automatically detects an influx, it can respond by increasing the backpressure. This actively increases the BHP, accelerating influx cessation over a passive shut-in response. In this way, an automated MPD system can reduce kick severity in the following ways:

1. Increasing kick detection resolution, reducing inflow time and therefore volume
2. Maintaining ‘pumps on’ during initial response, maintaining annular friction, and avoiding a drop in BHP, thereby minimizing influx flow rate and therefore volume
3. Actively increasing BHP through choke manipulation, reducing the time to influx cessation and overall kick volume
4. For influx of sufficiently low severity, circulating the influx from the wellbore without ever shutting the pumps down, removing the requirement for difficult coordination between pumps and surface (rig) chokes. This reduces the risk of a secondary influx.
5. On applications with a subsea BOP and for sufficiently low severity influx, circulating the influx out through the riser annulus, significantly reducing peak surface pressures.

Automated MPD provides a powerful tool for EKD, kill, and removal of the influx from the wellbore. Section 2.3 provides a full discussion of MPD, and Section 2.3.4 provides information regarding its role in influx management and well control.

2.2.5.2 Early Kick Detection Through Automated Monitoring

A study on the causes of well control incidents during drilling [68] determined that there is a need to increase the visibility of well control indicators to the rig personnel, and most importantly, to the Driller. Currently, many parameters are monitored automatically, but they are presented as simple logs that can be difficult to interpret (refer to Figure 2-23).

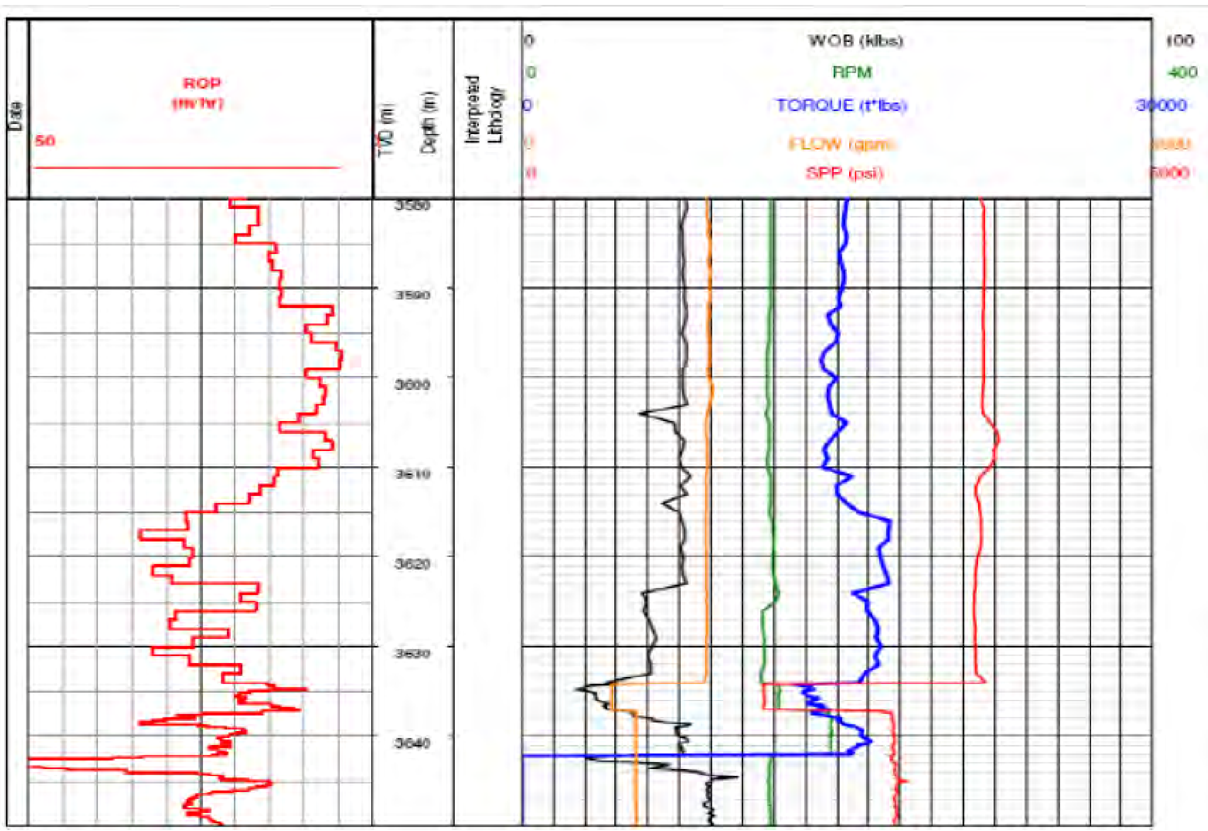

Figure 2-23: Typical Mudlog Presentation of Drilling Parameters that Can Be Difficult to Interpret [105]

Much effort is being expended to automate kick indicator observation, allowing trends to be more easily identified and facilitating earlier detection by rig personnel. Such automated observation solutions are software based and have the advantage of being relatively easily and economically fitted to existing rigs.

SafeKick, which operates out of the Houston area, offers their Safevision™ product for exactly this purpose. First launched in January 2012, the software takes raw data feeds that a Driller would commonly observe such as pump pressure, weight on bit, rpm, torque, and bit depth and interprets it to give a more comprehensive picture of downhole conditions. The interpretation is performed by feeding the data through a sophisticated wellbore model [106] using OPC, WITSML, or proprietary protocols [107]. The package includes integrated solids transportation and thermal models and a fully transient wellbore hydraulics model that accounts for changes in temperature, pressure, and fluid compressibility [108]. The result is a display that includes a schematic of the wellbore, including BOP valve status, alongside customizable plots that show values such as Equivalent Circulating Density (ECD), cuttings density, required trip margin, surge, and swab pressures along the entire wellbore. An example is shown in Figure 2-24. Such displays help the Driller to understand what is happening in the wellbore and to maintain control. The package includes a well control module that gives a real time display of BOP status and different fluid positions to assist control during well control operations.

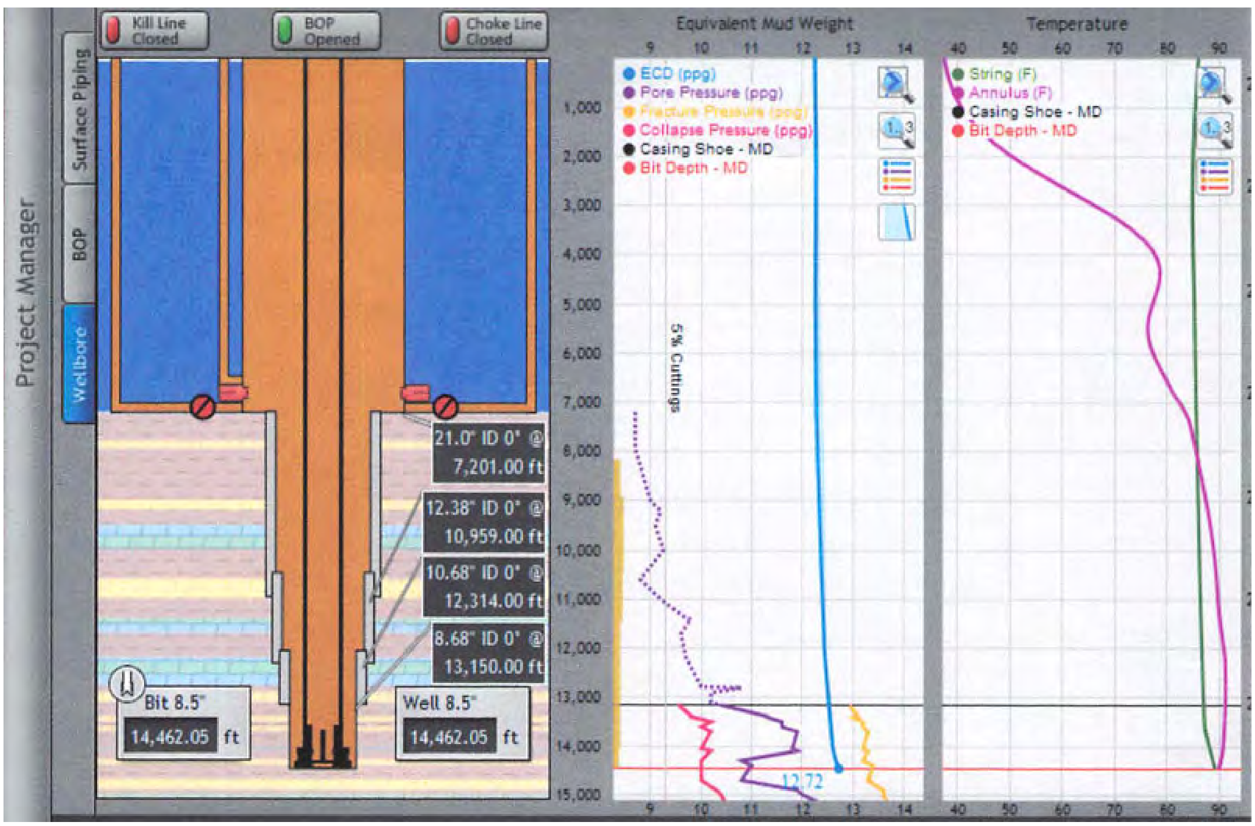

Figure 2-24: Screenshot of Safevision Display Showing Interpreted Log Data [106]

An alternative system is NOV's Rigsense Kick Monitoring Display system, which provides real time indications of potential kick or loss situations. The Kick Monitoring Display feature improves monitoring efficiency by reducing the amount of information required to detect a kick and grouping the data for faster notification of potentially hazardous situations. The software uses a combination of charting screens and customizable alarm systems to improve kick detection [109]. Working with an Operator in Houma La, the system caught an unexpected 22 barrel kick [110].

2.2.5.3 Kick Detection during Connections

A critical time for well control during conventional drilling operations is when pumps are turned off to facilitate making a drill pipe connection, conduct a flow check, or other such pumps off events. As discussed previously in Section 2.1.1, the cessation of drilling fluid circulation removes the friction between the drilling fluid and the annulus, and thereby reduces the BHP. This drop in pressure can cause fluid expansion and can potentially cause wellbore contraction (wellbore breathing). Under these conditions, it is normal to have a flow back to the pits during connections. However, with BHP minimized, it is also common for influx to occur at this critical time. This combination of influx and normal pit gain makes kick detection particularly difficult to implement. This has commonly been addressed by manually setting alarms to trigger when the normal connection 'fingerprint' is exceeded. This relies heavily on the judgment and experience of personnel.

To address this specific vulnerability, CoVar Applied Technologies has worked with a major Operator and their Real Time Operation Center (RTOC) staff in Houston, Texas, since January 2012 to develop a system called Influx Detection At Pumps Stop (IDAPS) [111].

The IDAPS solution is an intelligent step forward from current connection fingerprinting practices. The software uses a WITS feed of rig return flows, pit levels, hole depth, and bit depth to identify and monitor pumps off events. The software uses machine learning to track the data and develop a fingerprint of normal behavior and expected variance. After these acceptable limits have been established (after 1 to 4 connections or by using data from previous drilling intervals to initialize), statistically significant deviations from the profile can be detected, thereby allowing high probability of early detection of influx during pumps off events at extremely low false alarm rates. The IDAPS software reports the likelihood of influx at four levels of confidence (Low, Medium, High, and Confirmed). From evaluating a representative sample of historical data, a Confirmed level false alarm rate of less than10 per 1000 pumps off events was demonstrated.

Unlike many fingerprinting approaches, IDAPS makes use of multi-sensor data and data fusion to ensure that alarms are robust and the false alarm rate is minimized. By fusing deviations for flow in, flow out, pit volume, and rate-of-pit volume gain as separate patterns, the IDAPS pattern recognition algorithms overcome some limitations of single-sensor fingerprinting approaches (for example, high false alarm rates).

The IDAPS prototype was completed in 2012 with an operational prototype trialed within the Operator's RTOC environment during 2013. In 2014, the IDAPS development continued with more trials in the RTOC environment while in use for monitoring multiple offshore wells.

IDAPS is still a maturing technology, but it is already proving itself to be a useful addition to one Operator's current suite of RTOC applications that are used to monitor well operations in real time.

Another company attempting to address this issue is Baker Hughes, with their Smart Flowback solution. Ali et al. [112] have presented the Smart Flowback system, which is a means to take the guesswork out of the connection fingerprinting process. The system takes flowback data during drilling connections and generates normal trend curves and threshold alarms for kicks and losses based on statistical analysis.

Smart flowback is based on plots of pit gain versus time after pumps off. The normal fingerprint of the well is plotted for each pumps off event, and the mean flow back value versus time over the last N connections is calculated. Similarly, the standard deviation in flowback volumes is determined over the sample period. The alarm curve is then set as the average +/- a multiple of standard deviations for influx versus losses, respectively. Figure 2-25 illustrates the concept for a single standard deviation.

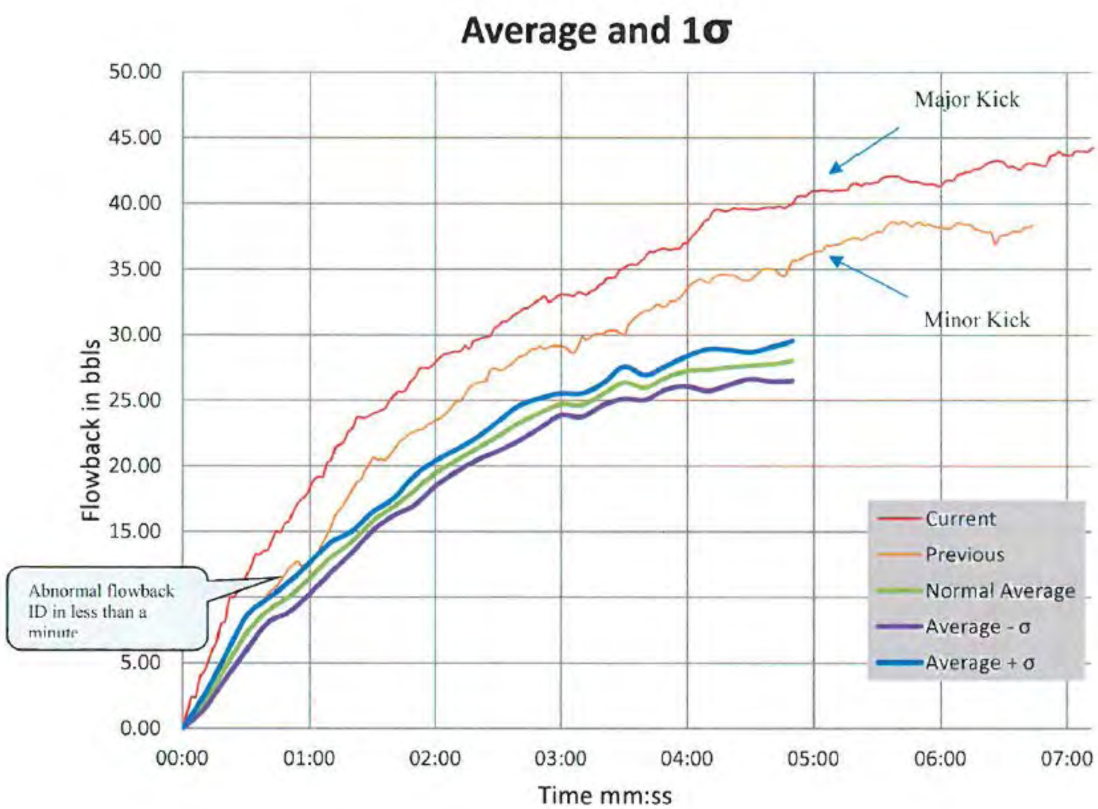

Figure 2-25: Baker Hughes Smart Flowback System Plots for +/-1 Standard Deviation [112]

During implementation of the system it became apparent that a function to exclude some pumps off events from the algorithm was required. This is because instances such as those where the pumps were turned off for a couple of minutes to take a survey would result in atypical flow back responses that could skew the automated alarm curves. The authors have flagged future work to include more complex algorithms to automate the exclusion process [112].

Field implementation of the Smart Flowback tool was dependent on the rig connection procedures to ensure quality measurement data for each connection. Procedures needed to include consistent pit usage as well as consistent time out of slips with pumps off. In its current form, the tool shows great promise in assisting in EKD; however, like many automated processes, system robustness and even automation of system surveillance and maintenance to ensure quality data without compromising operation flexibility is a challenge. The field trial After Action Review (AAR) identified improvements and future steps for this promising safety technology. It is not clear from the sources obtained how extensively Smart Flowback is currently being deployed.

2.2.6 Models and Simulators

Currently, automation in drilling requires some degree of modeling and simulation. The main driver for this is the delay in data transmission between surface and downhole. MWD transmission rates are limited to a maximum of 40 bits per second and are commonly as low as 3 bits per second [83], particularly in deep hole sections. Add to this the demands on bandwidth for petrophysical data, and the time between updates for downhole conditions can be prohibitively slow for automation purposes.

In the absence of useable update rates for downhole parameters, models that provide estimates of downhole conditions based on surface parameters are commonly used. The resulting estimates can be compared to downhole measurements when they become available, and in some cases, they can be automatically updated. A good example of where this is used is hydraulics models for the estimation of BHPs in MPD choke control. Models have also been used to optimize ROP and to take into account issues such as the inertia of the drill string and mud systems to optimize control in real time [83]. Connection of the model to the rig's Control system enables optimized implementation.

Even in the ideal case where wired pipe can provide distributed sensors giving measurements of wellbore conditions along the wellbore at usable update rates, there will be a gap between the base of the measured zone and the bit. Sensors must be placed behind the bit, which introduces a problem of spatial latency commonly encountered in geosteering applications. In this case, models calibrated and updated with the downhole measurements can play an important role in both bridging this gap [96] and providing intermediate estimates of downhole conditions in the event of equipment failure.

Models can also play a role in real time surveillance for measurement errors and sensor malfunction. The state of the drilling system can be estimated by using the model from multiple sensors. The data from each of these sensors, such as fluid return density, rates and temperatures, BHPs, stand pipe pressures, and trajectory measurements, should all be indicating parameters that are consistent with a single wellbore state. If the measurements from one sensor start to deviate, indicating a state that is incompatible with that indicated by all the other measurements, then this can be an indication of sensor failure. In this way, the model provides a means of verifying the different sensors against each other, improving the redundancy and robustness of the system. Advanced algorithms for state estimation such as Kalman filters can be particularly useful for these types of applications.

Recently, there has been significant advancement in modeling for drilling systems and particularly MPD:

- Cayeux and Daireaux [113] have achieved a piecewise approach using hydraulic, mechanical, and thermal models to develop a Control system algorithm.
- Torque and drag models have undergone significant development in recent years, including the string model of Tikhonov et al. [114] and work by Mitchell et al. [115].

According to MacPherson et al. [83], several models have been demonstrated to give good performance during trials—particularly when the inventing engineers remain at the rig site to maintain the sensors and the data quality. However, when these key players leave the rig, the effectiveness of the models is quickly lost. MacPherson et al. [83] suggest that there is a requirement to build systems that are self-calibrating and contain diagnostics that examine data, not just the status of the hardware.

2.3 Managed Pressure Drilling

MPD provides one of the best opportunities to implement EKD with current drilling technology. Although there are many variants of MPD, the most common application is surface backpressure MPD, often referred to as Constant Bottomhole Pressure (CBHP) MPD. In this variant, surface pressure is used in addition to the fluid hydrostatic pressure to control wellbore pressures and prevent formation fluid ingress to the wellbore. For the purposes of this study, the term MPD refers to surface backpressure MPD, the most widely deployed variant, with an established track record in EKD.

In general, MPD systems provide EKD by using comparison of flow out to flow in as a primary indicator of influx. The resolution of kick detection using an MPD system has been significantly enhanced over conventional systems by the use of Coriolis flow metering (see Section 2.2.4 for more detail on Coriolis mass flowmeters).

This section of the report gives an outline of MPD, a description of the impact MPD has on well control operations, and a detailed description and assessment of MPD equipment.

2.3.1 Managed Pressire Drilling Overview

According to the International Association of Drilling Contractors (IADC), MPD is "an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore." The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. MPD is intended to avoid continuous influx of formation fluids to the surface. Any influx that is incidental to the operation will be safely contained using an appropriate process.

MPD employs a collection of tools and techniques which are often used to mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits by proactively managing the annular hydraulic pressure profile. It may include control of annular surface pressure (backpressure), fluid density, fluid rheology, annular fluid level, circulating friction and hole geometry, or a combination thereof.

MPD allows faster corrective action to deal with observed well conditions by virtue of manipulating flow through the MPD choke. The ability to dynamically control annular pressures facilitates the drilling of what might otherwise be economically unattainable prospects.

Although there are many methods of MPD, of particular interest in some projects is drilling with a hydrostatically (referred to as statically) underbalanced fluid system and using surface backpressure to precisely control the annular pressure profile and maintain overbalance with respect to the formation.

Conventional drilling, which is described in Section 2.0, uses the hydrostatic pressure of the drilling fluid to maintain the primary well control barrier. The fluid system is open at surface, with circulated drilling fluid returning to atmospheric tanks. During circulation, friction resulting from fluid movement in the wellbore causes an increase in well pressure. Therefore, for conventional drilling, the bottomhole pressure (BHP) is described by the following equation:

$$BHP = P_{Gravity} + P_{Friction} \qquad \textbf{(1)}$$

Where:

$P_{Gravity}$ = hydrostatic pressure due to mud weight,
$P_{Friction}$ = friction pressure due to circulation.

With MPD techniques, additional measures are put in place to control BHP. This can most commonly be done through the application of surface backpressure, but other means are available, such as the addition of pumps or by acceleration of fluids.

The resulting equation for BHP during an MPD operation becomes:

$$BHP = P_{Gravity} + P_{Friction} + P_{Surface} + P_{Energy} + P_{Acceleration} \quad \textbf{(2)}$$

Where:

BHP = bottomhole pressure
$P_{Gravity}$ = hydrostatic pressure due to mud weight
$P_{Friction}$ = annular friction pressure due to circulation
$P_{Surface}$ = applied surface pressure
P_{Energy} = pressure changes as a result of the energy of another device (for example, a seafloor pump)

$P_{Acceleration}$ = pressure change due to acceleration of fluids (changes in velocity and momentum)[1].

(Note: [1]Pressure change due to acceleration, $P_{Acceleration}$ is also considered in high energy applications. The pressure effects due to acceleration are negligible in most MPD applications.)

2.3.2 Benefits of Managed Pressure Drilling

Some general benefits of MPD are discussed in the following sub-sections.

2.3.2.1 Managed Pressure Drilling Influx Management

MPD offers the capability to detect very small influxes when compared to using conventional rig equipment. When the influx is detected, MPD allows the BHP to be adjusted rapidly to control and minimize the size of the influx. Furthermore, the potential exists to control and circulate out the influx with the MPD equipment, without shutting in and performing conventional well control. When it is executed appropriately, this approach to managing an influx represents a higher degree of safety as well as cost savings [69].

2.3.2.2 Differential Sticking

During conventional drilling operations, the pressure exerted by the fluid in the annulus is always greater than the formation pressure. When the drill string makes contact with the wall filter cake opposite a permeable formation zone of lesser pore pressure, the drill string can get stuck to the filter cake against the wall of the hole. The hydraulic force now acts across the isolated portion of the drill string, holding it in place. The forces holding the pipe against the formation are proportional to the differential pressure and the area of contact of the pipe against the wall. MPD will reduce the probability of stuck pipe by lowering the differential pressure and by creating a thinner and tighter filter cake.

2.3.2.3 Recovery from Stuck Pipe

The propensity for stuck pipe will increase as the degree of overbalance increases. MPD will allow the degree of overbalance to be changed in minutes by opening the choke, thereby lowering the surface pressure and degree of overbalance. In the extreme case, and with a hydrostatically underbalanced fluid, the BHP can be brought underbalance to free the pipe. After the pipe is freed, any influx can be circulated out or bullheaded back into the formation. The system can then be returned to operational mode in hours, rather than days.

2.3.2.4 Lost Returns

Because there is less requirement to provide sufficient overbalance for variations in BHP, MPD can lower the probability of lost returns by reducing mud weight and therefore differential pressure across the formation. Depending on the degree of losses encountered with conventional techniques, MPD may eliminate losses or extend the length of the drilled section before losses occur. The ability to control losses by varying pressure will also mitigate problems associated with trying to fight lost returns using conventional methods.

Conventionally, losses are countered with lost circulation materials and by reducing the circulating rate. In the event of significant losses, gunk or cement squeezes are used. The use of lost circulation materials, gunk squeezes, and water-based fluids damages the properties of the drilling fluid system and can damage the permeability of the formation. This can increase the probability of having stuck pipe. MPD not only reduces the likelihood that these measures will be required, but by allowing controlled pressure variation at full circulation rates, it enhances the capacity to strategically place these treatments. Furthermore, the ability to monitor bottomhole conditions throughout the operation is maintained.

MPD will not eliminate losses if karsts are intersected, but the time required to switch from conventional drilling mode to Pressurized Mud Cap Drilling (PMCD) operations will be reduced. If MPD can delay the onset of losses, the problems associated with PMCD will also be delayed.

2.3.2.5 Improved Rate of Penetration

It is common knowledge in the drilling industry that a lower differential pressure from the annular fluid to the formation will result in a higher rate of penetration. Bourgoyne and Young demonstrated the relationship between ROP and differential pressure in 1974 [116]. They theorized that the hydrostatic pressure of the drilling fluid exerts a force against the rock that is being penetrated, thus requiring more energy to remove the rock. At the same time, a filter cake is deposited due to spurt loss of drilling fluid. The bit cutters must remove this deposit along the formation being penetrated.

MPD lowers the differential pressure across the formation and potentially reduces the solids content of the fluid system through lower mud weight. Saponja [117] used the theories of Bourgoyne and Young [116] to justify the implementation of managed pressure drilling in Canada. Field application showed an increase in ROP of up to 2.5 times conventionally drilled rates of penetration because of the reduced differential pressure and reduced mud solids.

2.3.2.6 Formation Instability

In conventional drilling operations, the starting and stopping of circulation creates transient pressure fluctuations. These fluctuations may exacerbate formation stability problems by creating stress cycles in the formation.

MPD avoids pressure fluctuations by manipulating the surface pressure to maintain more constant wellbore pressure. The minimization of pressure fluctuations will assist in mitigating formation instability events.

2.3.2.7 Ballooning

Ballooning (also called 'wellbore breathing') is the act of formations being charged by high annular pressures and flowing the charged fluids back when the annular pressure is reduced. In this scenario, significant time can be lost confirming that gains are from ballooning and not from formation influx. MPD aids in mitigating problems associated with ballooning by minimizing wellbore pressure fluctuations.

2.3.2.8 Improved Hole Cleaning

It is common practice to use conventional drilling techniques to reduce the circulating rate if losses occur. This reduces the frictional pressure losses and normally results in the reduction or elimination of losses. Because reducing the circulating rate can be detrimental to optimum hole cleaning, additional time may be spent circulating the hole clean. MPD can eliminate the correlation between circulation rate and induced pressure, allowing circulation at optimum rates for hole cleaning.

2.3.2.9 Ability to Drill Further and Reduce Costs

By eliminating the impact of ECD, MPD will allow longer hole sections to be drilled before the fracture gradient of the formation is reached. The lower annular pressure and improved hole cleaning may also allow higher angle wells to be drilled, thereby extending the reservoir section.

An example of the power of MPD to reduce costs is given in Sugden et al. [118], where MPD is used on a deep water well in Brazil to extend hole sections as far as the drilling window will allow while honoring kick tolerance criteria. Given a high uncertainty in pore pressure and fracture gradients, the result is a decision tree that identifies key depths where intermediate casing strings can be dropped from the plan without reducing the risk of failing to reach total depth (TD). The resulting plan is expected to eliminate two hole sections from the well, representing significant cost savings.

2.3.3 Drawbacks to Managed Pressure Drilling

MPD offers extensive safety and cost benefits. However, as a new technology there can be drawbacks to its implementation. Most difficulties arise in the integration of MPD with existing rig infrastructure and procedures. Positioning the MPD equipment, ensuring that mud gas separators have adequate capacities, and installing extensive pipework are some common issues. Deployment on floating rigs can therefore be costly.

Adjusting procedures and protocols to accommodate MPD can also be difficult. MPD offers vast enhancements to the ability to control the well, but personnel are often reluctant to change established procedures, particularly with respect to influx identification and management, until they become familiar and comfortable with the technology capacities.

As MPD is presently in a rapid expansion, another problem that can arise is difficulty in obtaining people with adequate expertise and competence to facilitate correct operation design, planning, and execution. Ensuring that adequate time is allowed to acquire adequate support and implement appropriate training is critical to successful operations.

2.3.4 MPD Influx Management and Well Control

This sub-section contains extracts from work by Bacon, Sugden, and Gabaldon [69].

In conventional drilling, the primary barrier to formation influx is a column of drilling fluid that is hydrostatically overbalanced with respect to pore pressure. Pressure control is slow and cumbersome, with mud weight adjustments being the primary means by which BHP can be adjusted. This makes the response to any influx—to activate the secondary barrier system to control the well—a simple one. As stated in Section 2.1.1.3, when the secondary barrier is activated, the continued influx from the well compresses the annular fluid and builds surface pressure. This continues until the annular pressure and the formation pressure and influx cease.

Recalling the discussion of well control barriers of Section 2.1.1, surface backpressure MPD can potentially change the primary barrier system. Should the chosen fluid be underbalanced with respect to the formation pressure, the MPD equipment used to apply the surface pressure becomes essential to containing formation fluids and is therefore part of the primary barrier system.

With the addition of the MPD pressure equipment, there will be alternative responses to influxes of low severity. BHP can be quickly increased to an overbalanced condition through choke adjustments, potentially achieving influx cessation much more quickly than for a conventional well control response.

This raises some questions:

- If MPD equipment can not only increase BHP sufficiently to terminate an influx, but can also facilitate safe removal of influx fluid from the wellbore—is that considered well control?
- What if the BOP was not required to control an influx event?
- How can personnel know when the BOP is required?

Clearly, the definition of well control that has been developed for conventional drilling must be clarified for an extension to MPD.

A commonly perceived definition of well control is “operations required to terminate influx flow and circulate the influx from the wellbore.” However, this definition may erroneously classify normal operations as well control, even in the case of conventional drilling. For example, consider the case of connection gas. Here an influx has been incurred, but the amount of gas is so small as to be considered within the capacity of the normal drilling equipment and operations to both terminate the influx (by turning the pumps back on) and remove the influx fluids from the wellbore.

A more broadly applicable definition of well control is “operations beyond the capacity of the primary barrier and requiring the activation of the secondary barrier system.” Under this definition, which is consistent with a recent publication [119], MPD pressure control equipment is considered part of the primary barrier, and by extension, MPD operations are not considered well control. From this definition the role of MPD equipment and secondary barriers such as BOPs can become clear. The challenge becomes one of defining the limitations of the primary barrier system and the protocols for handover to the secondary barrier system – the conventional well control equipment.

To clarify these concepts further; from conventional drilling we are familiar with two categories for pressure control operations:

1. Primary barrier operations – normal drilling operations
2. Secondary barrier operations – well control operations

With the advent of MPD, we now introduce the new sub-category of MPD influx management for primary barrier pressure control operations:

1. Primary barrier operations
    a. Normal drilling operations
    b. MPD influx management
2. Secondary barrier operations – well control operations

Handover from primary to secondary barrier operations requires not only definition of the limitations of the primary barrier system, but protocols for handover. For conventional operations, these definitions are quite clear: if an influx is detected, the primary barriers that depend on the maintenance of hydrostatic overbalance have been breached. The resulting actions are straightforward: drilling ceases and the secondary barrier system is activated to contain the well.

In the case of MPD, influx detection does not necessarily imply breach of primary barriers. Furthermore, handover from primary to secondary barriers can be achieved in a variety of ways. Some of the operations encompassed in the term MPD influx management include [120]:

- **Full MPD influx management**: Here the surface pressures and influx volumes are sufficiently low that influx flow can be quickly terminated by increasing BHP using the MPD system. Similar in concept to the first circulation of the Driller's method, the influx can be removed from the well using the MPD system, adjusting the MPD choke to maintain constant BHP. There is no need to shut in the well or stop circulation at any point. Additionally it may be unnecessary to increase the drilling fluid weight. This method provides significant benefits over conventional well control. These benefits include the influx being removed from the well much more quickly and maintenance of annular friction pressure, which prevents increased influx flow that results from a decrease in BHP when the pumps are shut down.
- **MPD influx termination with conventional influx removal**: This operation involves terminating influx flow by proactively using the MPD system to increase BHP. On influx flow cessation, as is evident from mass balance and potential pressure signatures [121], circulation can be staged down while adjusting the choke to compensate for lost annular friction. On pumps off, the well can be shut in conventionally and handed over to the secondary barrier system for influx removal.

- **MPD assisted conventional shut-in**: In this method, it is assumed that the influx will be controlled using the secondary barrier system. The role of MPD is therefore limited to optimizing handover to the secondary barrier system. The MPD system is used for mitigation—increasing BHP as much as possible while the pumps are turned off for the conventional shut-in. By proactively using the MPD equipment to increase wellbore pressures before shut-in, the resulting influx will be reduced in volume. Subsequent peak surface pressures and flow rates will be similarly reduced.

In an attempt to define the limitations of the primary barrier system and give guidance for resulting operational protocols, the former U.S. Minerals Management Service (MMS), now the Bureau of Safety and Environment Enforcement (BSEE) has published an MPD Operations Matrix in its Notice to Lessees [122]. The matrix provided an excellent framework for understanding when corrective measures are required to bring an influx into control while performing applied backpressure MPD.

The matrix is based on honoring a surface pressure indicator and influx indicators, as shown in Figure 2-26. In the NTL example, the top axis of the matrix represents the pressure limitation of the primary barrier in terms of applied back-pressure. The vertical axis is simply labeled ‘kick indicator,’ which is defined as influx state, influx rate, influx duration, and volume gain. The Notice to Lessee (NTL) includes some example values for the limits as applied to the matrix, but it remains up to the Operator to determine the basis for the limits and calculate them appropriately.

The objective of the MPD Operations Matrix is to define appropriate actions to retain the integrity of the primary barrier system and facilitate handover to the secondary barrier system, as appropriate. The limits of the primary barriers can be related to two key MPD equipment limitations:

1. Pressure limitations of the primary barriers
2. Surface flow rate limitations for gas and liquids

MPD Drilling Matrix		Surface Pressure Indicator (See Chart 2 Below)			
		At Planned Drilling Back Pressure	At Planned Connection Back Pressure	> Planned Back Pressure & < Back Pressure Limit	≥ Back pressure Limit
Influx Indicator (See Chart 1 Below)	No Influx	Continue Drilling	Continue Drilling	Increase pump rate, mud weight, or both AND reduce surface pressure to planned or contingency levels	Pick up, shut in, evaluate next action
	Operating Limit	Increase back pressure, pump rate, mud weight, or a combination of all	Increase back pressure, pump rate, mud weight, or a combination of all	Increase pump rate, mud weight, or both AND reduce surface pressure to planned or contingency levels	Pick up, shut in, evaluate next action
	< Planned Limit	Cease Drilling. Increase back pressure, pump rate, mud weight or a combination of all	Cease Drilling. Increase back pressure, pump rate, mud weight or a combination of all	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action
	≥ Planned Limit	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action

Figure 2-26: MPD Operations Matrix from MMS (BSEE) NTL 2008-G07 [122]

The pressure indicator of the MPD operations matrix is easy to understand and implement. Limitations on this axis should relate to the surface pressure capacity of the primary barrier system. However, things become confusing on the ‘kick indicator’ axis.

It is clear from well safety theory that the severity of an influx will drive the peak pressures during shut-in and their subsequent removal from the wellbore. For example, a larger volume of gas influx will result in greater loss of hydrostatic pressure; therefore, surface pressures will increase during shut-in. Similarly, a larger volume influx at BHP conditions will be subject to more expansion as it is circulated up the annulus, resulting in greater peak surface pressures. Between them, the kick indicators of influx rate and duration attempt to capture an indication of the kick severity other than volume. However, it is the premise of work by Bacon, Sugden, and Gabaldon [69] that by reviewing how the influx characteristics drive the well condition toward primary barrier limits, the definition and application of ‘kick indicators’ can be simplified. To do this, a thorough understanding of wellbore response to influx of varying severities has been developed.

The use of MPD for influx management has created much confusion in the industry as to what is and what is not well control. In the work by Bacon et al. [69], MPD influx management is clearly defined as part of the primary barrier system for well containment. The demarcation between MPD influx management and well control centers on the requirement to activate the secondary containment barrier. This definition not only adequately fits our understanding of the boundary between conventional drilling and well control, but it assists in developing a workable operations protocol for MPD.

2.3.5 Managed Pressure Drilling Equipment

In general, all applied backpressure MPD systems work from the same design premise, with all systems using some form of Rotating Control Device (RCD) to provide a seal between the pipe and the annulus. The system also uses a backpressure choke that allows the annular fluid to be pressurized. A major differentiator of these systems is how the choke is managed: manually, semi-automatically, or automatically (refer to Section 2.3.5.3). The other major component is a high resolution flowmeter, which is essential to the EKD capability of MPD. Figure 2-27 provides a version of schematic showing applied backpressure MPD equipment for a fixed platform or rig.

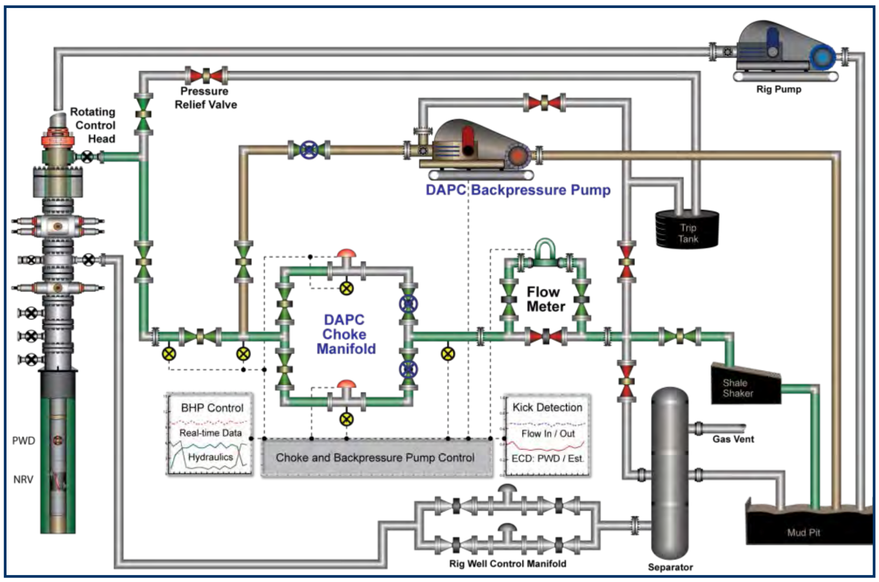

Figure 2-27: Schematic Showing Applied Backpressure MPD Equipment (Courtesy of Schlumberger) [1]

The following sub-sections contain an assessment of the key MPD equipment.

2.3.5.1 Rotating Control Device

The Rotating Control Device (RCD) is considered the main enabling piece of equipment for MPD operations. The function of the RCD is to provide a seal between the wellbore and the atmosphere, while allowing the pipe to move (up/down and rotate) and diverting the returns flow from the well to a contained system.

For many MPD operations, such as those planned to be statically underbalanced, the RCD and the flow control choke are considered part of the primary barrier for well control. Prior to 2005, there were no standards controlling the design and testing of RCDs, so Operators relied on the manufacturer to set system ratings. In 2005, the American Petroleum Institute (API) released the first addition of API Specification 16RCD for the design, testing, and certification of RCDs. Although many of the RCDs used in the industry have not been certified under this specification, this certification is a critical step in standardizing the ratings of this equipment. Those systems that have undergone testing have been required to downgrade their design limits, which shows the shortfalls of the manufacturers' ratings.

For operations that are not performed from a floating rig, the RCD is typically mounted on top of the rig's existing annular preventer. However, when MPD is executed from a floater, placement of the RCD becomes more difficult (refer to Section 2.3.5.9). Placement of the RCD below the slip joint fixes the position of the RCD with respect to the BOP and prevents rig heave from affecting the circulating system volume. This greatly enhances kick detection capacity on floating rigs.

Several vendors offer RCDs, which includes major service companies as well as smaller companies. However, almost all RCDs work from the same basic design. They all have a packing element that forms the seal around the drill pipe. These packing elements are expendable elements that must be replaced as they wear. For the majority of heads that are in use today, particularly in land and surface stack applications, the packing element rides on a bearing system that allows the packer to rotate with the pipe. In addition, specific designs of RCDs for marine applications, in which the RCD is installed in the riser, are available.

RCD providers include Weatherford, Schlumberger, Halliburton, MPO, NOV, Drilco Grant, Strata, Elite, and Stacey. However, at the time of this report, only the Weatherford and MPO systems are certified for below-tension-ring (BTR) riser systems.

2.3.5.2 MPD Choke Manifold

The primary purpose of the flow Control system is to provide a controllable flow path through an adjustable choke to maintain the BHP required for drilling or well control operations. The MPD choke manifold is vital for pressure control and is considered part of the primary barrier for well control in many MPD operations.

2.3.5.3 MPD Control Systems

The Control system is at the core of any MPD equipment setup—whether it is as simple as an RCD and a choke manifold, or it includes a backpressure pump, flowmeter, and software control algorithm. The type of equipment layout depends on many factors, with the simpler systems used in a more benign and forgiving drilling environment and the more complex ones in higher risk wells. The systems may be categorized as follows:

- *Manual* – a system in which an Operator manually controls the annular pressure by opening or closing the drilling choke valve.
- *Semi-Automatic* – the required surface pressure is determined by an engineer using hydraulics software, and the choke is automatically adjusted to obtain the specified surface pressure.
- *Automatic* – A Programmable Logic Controller (PLC), which is programmed with hydraulics software, is connected to the choke and the backpressure pump controls the desired annular pressure automatically.

For ultra-deepwater applications, it is most likely that semi-automatic or automatic systems would be most appropriate due to the risk level of the well.

One of the problems that can occur with automated MPD choke Control systems is instability that results from inappropriate tuning. A typical sign of a non-robust Control system is an oscillating choke position [123]. Depending on the controller type, correct setup of the controllers requires experienced and qualified personnel.

2.3.5.4 Mud Gas Separator

Typically, the rig's existing mud gas separator is used for a MPD operation. Because the MGS is not intended to take continuous influx during MPD, liquid and gas flow rates should be similar during drilling, whether the rig is using conventional or MPD.

Particular attention needs to be given when considering MPD influx management. As specified in Section 2.3.4, one of the potential limiting factors during MPD influx management is surface flow rates, usually the liquid or gas limits of the MGS.

2.3.5.5 Drillstring Valves

Non-return valves (also known as float valves) placed in the drill string are an essential addition for MPD operations. These valves allow fluid flow in one direction only, from the drill pipe into the wellbore. In most statically underbalanced operations, they provide the only primary barrier between the formation fluids and surface from inside the drill string during connections.

2.3.5.6 Operational Annular Preventer

During MPD deep water operations, an additional operational annular preventer should be installed a small distance below the RCD to allow isolation of the RCD in the event of element failure. Because changing of the RCD element is required on a periodic basis, the additional annular preventer should only be used while replacing the RCD element.

Industry experience indicates that RCD element life has been highly variable. Issues of pipe condition, fluid type and density, alignment, lateral vibration of the pipe, wellbore pressure, fluid temperature, and compatibility of the element material play an important part in the life of the elements. Experience has shown failures in as little as a few hours to lasting in excess of 10 days. In most cases, elements should last for a bit run and are regularly replaced on bit trips to manage the time and complexity of changing out the elements.

For surface stacks, the well control annular preventer is used in the event of a failure of the RCD element until the element is changed out.

2.3.5.7 Backpressure Pump/Rig Pump Diverter Systems

To actively control applied backpressure during connections, flow across the choke is required. The two primary methods include the addition of a backpressure pump and the use of a Rig Pump Diverter system. The backpressure pump is a stand-alone pump that is plumbed into the MPD system and pumps fluid across the backpressure choke when the circulating pumps are off. The Rig Pump Diverter system diverts flow from the primary circulation system across the backpressure choke during non-circulation events.

On some rigs, the need for a backpressure pump or Rig Pump Diverter system has been eliminated by using a pump from the primary circulation system. This is particularly the case on floating vessels, where the booster pump can provide the necessary flow.

2.3.5.8 Rig Modifications for MPD

An extremely important factor to consider well in advance of executing MPD is the set of modifications that may be required to the rig or other equipment to allow MPD equipment to properly function. The required modifications to have ‘MPD ready’ rigs are being engineered and manufactured, but they are still in early stages.

It is important to realize that ‘MPD-ready’ may refer to anything from the rig having its own MPD equipment installed, to simply that the rig has suitable space and dimensions to allow for MPD equipment to be installed without further significant modifications. Factors that need to be considered to accommodate MPD equipment are rotary table IDs, riser and slip joint (telescopic joint) IDs, slip joint movement, deck space and loads, and additional temporary piping to integrate MPD equipment and the associated certification requirements[13].

[13] Requirements by certification bodies such as ABS and DNV.

To date, for the applications where MPD has been applied from floaters, it is typical for these rig modifications to take at least 12 months, including planning, engineering, fabrication, and installation. Therefore, it is of paramount importance that modifications to the rig be considered and initiated early in the MPD project planning phase.

2.3.5.9 RCD and Flow Spool Placement on a Floating Rig

For MPD operations performed from a floating rig, it is critical the RCD be kept stationary, relative to the earth. If the RCD is allowed to move with the heave-induced motion of the rig, the resulting uncontrolled movement of sealing elements over the compensated tool joints could cause premature and catastrophic failure of the elements. In addition, the benefit of having a constant volume fluid system, which is a critical factor in EKD, would be lost if the RCD were allowed to move with the rig.

There are a number of options for placement of the RCD and flow spool on a floating vessel: above the slip joint, above the tension ring, below the tension ring, or some combination (such as flow spool below and RCD above the tension ring). There are advantages and disadvantages for each option. However, when pushing ultra-deepwater limits, dynamically positioned rigs are more prevalent, which makes below the tension ring the ideal location for the flow spool.

Installation of the flow spool below the tension ring brings the most benefit for dynamically positioned rigs because this positioning overcomes the problems associated with hoses and other MPD components getting caught up with tension lines as the vessel rotates. If the RCD is also below the tension ring, the slip joint does not require modification, and the slip joint pressure rating will not affect the MPD system pressure rating. However, one disadvantage of installing the RCD below the tension ring is the requirement to disconnect the Lower Marine Riser Package (LMRP) for any required maintenance to the surface annular or RCD bowl.

If the RCD is above the tension ring but below the slip joint, the slip joint will require modification. Such modification has included removing the inner barrel to the existing slip joint and manufacturing a termination joint and new multi-part slip joint to allow adequate vertical movement.

2.3.6 Riser Gas Handling Systems

Numerous incidents, including the Macondo incident, have shown the disastrous results that can occur if an influx is not controlled before it migrates or is circulated above the Subsea Blowout Preventer (SSBOP). On most floating vessels, if this event occurs, diversion of the influx is the only available option. In many cases, particularly when using oil-based fluids, the gas may not break out until it is near surface, which leaves little time to react.

The installation of Riser Gas Handling (RGH) systems is integral to the riser system. They contain a near surface quick closing annular preventer, flowlines, pressure control chokes, and a high capacity Mud Gas Separator (MGS). During a riser gas event, the quick close annular and the SSBOP are closed, thereby allowing the influx in the riser to be circulated out in a controlled manner.

2.3.7 MPD Equipment for Offshore Deployment

The following sub-sections, which describe MPD equipment by vendor, also indicate whether the equipment is available or in development for offshore application.

2.3.7.1 Weatherford

Weatherford provides a complete range of MPD equipment that is available for offshore application. To date, they are the leading provider for Rotating Control Devices (RCDs) for deep water MPD applications. In 2010, they received API 16RCD certification for their Model 7875 below-tension-ring (BTR) RCD. Since then, they have successfully deployed the technology in many deep water projects worldwide.

Weatherford also provides the Microflux® Control system, which uses an RCD to keep the fluid system closed and diverts the return flow through an automated MPD choke manifold. Return flow is measured accurately with a mass flowmeter, enabling real time detection and control of minute downhole influxes and losses in gallons rather than barrels [124].

The Microflux system contains a fully automatic kick and loss detection system. With its fully automated capabilities, the system detects an influx by measuring the difference between the volumes being pumped into the well against the flow out of the well over a discrete period of time. When a threshold is exceeded, the system automatically increases surface backpressure until the volumetric flow rate being pumped in equals that of the flow rate that is returning. It then adds an additional pre-set backpressure for a safety margin. At this point, the system automatically switches to Stand Pipe Pressure Control, maintaining the stand pipe pressure constant until the influx has been circulated out of the hole. To date, this is the closest the industry has come to a fully automated kick detection and response system.

In combination with the riser annular and RCD, the Weatherford system can also be used as an RGH system.

2.3.7.2 Schlumberger

Through its MI-Swaco division, Schlumberger provides various levels of MPD systems, including manual, semi-automatic, and automatic Control systems. A feature of the @balance system is the surface circulating pump, which allows fine BHP control, even with the mud pumps off (during connections and trips). The @balance system also uses an automated choke Control system that is managed by a hydraulic model. It has a feedback system that will help correct the model based on real time BHP data. The system has influx detection capabilities, but the control and removal of the influx is semi-automatic and requires human intervention.

The current RCDs supplied by Schlumberger MI-Swaco are not API 16RCD certified and are designed for surface stack applications.

2.3.7.3 Managed Pressure Operations

Managed Pressure Operations (MPO) supplies MPD equipment in the areas of RGH, continuous circulation, and kick detection. The RGH system has been developed to enable safe handling of gas entry into the riser [125]. The Riser Drilling Device (RDD) is an API 16RCD certified non-rotating RCD that can be used below the tension ring. Currently, the system has a semi-automated Control system that manages a set surface pressure. Hydraulic modeling is performed off line. The Coriolis meter is placed upstream of the pressure control choke, making it less susceptible to gas cut of the return fluid. MPO has also incorporated Coriolis meters that are designed to give a more accurate differential rate at the pump inlet.

2.3.7.4 Halliburton

The Geobalance system is offered by Sperry, a subsidiary of Halliburton. Halliburton offers several levels of the Geobalance system from manual to fully automatic systems. Halliburton supplies numerous RCDs for surface stack applications. Some of these systems are API 16RCD certified. Halliburton also provides an automated Rig Pump Diverter that diverts flow from the stand pipe across the pressure control choke during connections, which eliminates the need for the backpressure pump.

2.3.7.5 SafeKick

The SafeKick MPD package is a new system providing integration of information and automation based on data that is read directly from rig sensors or Control systems. The MPD choke manifold uses an advanced, fully transient hydraulics module that has been optimized to quickly simulate complex wellbore relationships.

Unlike other providers, SafeKick has also put significant effort into applying choke automation technology, which is typically used in MPD, to well control. Current well control equipment includes manually operated chokes. The use of this manually operated equipment forces inexperienced people to perform non-routine tasks during safety-critical operations. These often difficult operations, which involve coordinating choke adjustments with rig pumps and reacting to changes in friction pressures as gas reaches the choke, often lead to errors and secondary well control problems. The automation of rig chokes to maintain the desired annular pressure profile during well control operations is a significant enhancement to well safety.

At the time of this report, SafeKick is working with an Operator to place an automated choke (IntelliChoke™) downstream from the rig choke to automate well control influx circulation. The choke Operator will be able to select from three different pressures—choke, stand pipe, or kill line—and define the pressure set point. The system will then automatically deliver the selected pressure. There is no need for any manipulation from the Operator, which allows him or her to concentrate on the well and whether there is any change needed, rather than on manually keeping the desired pressure where it should be [107].

2.4 Managed Pressure Drilling and Early Kick Detection Systems in light of Well Control

2.4.1 Frequency and Cause of Kicks

During SINTEF's 2001 study of deep water wells in the U.S. GOM OCS for the MMS [72], kick data was collected for 83 wells in water depths ranging from 1,335 ft. to 6,725 ft. during 1997 and 1998. The data was collected for drilling operations only, when the blowout preventer (BOP) was located on the wellhead; shallow gas or water flows were not considered. Kicks in this study were defined as influxes requiring the BOP to control the event.

In the SINTEF study, mean time between kicks (MTBK) was calculated as ~ one kick every 1.7 days that the BOP was present on the wellhead. Detailed MTBK results from the study are shown in Table 2-9.

Table 2-9: Mean Time between Kicks from 2001 MMS – SINTEF Study [72]

Phase	No. of kicks	No. of wells	BOP- days in operation	MTBK (wells between kicks)	MTBK (BOP- days between each kick
Development drilling	9	25	1,000	2.8	111.1
Exploration drilling	39	58	3,009	1.5	77.2
Total	48	83	4,009	1.7	83.5

In 2010, the International Association of Oil and Gas Producers (OGP) published more recent blowout and well release frequencies [126]. This report gives data for well operations in the North Sea and other offshore areas where the equipment aligns with the North Sea Standard, following the Scandpower analysis of the SINTEF blowout database [127]. The OGP report defines the North Sea Standard as "operations performed with BOP installed including shear ram and two barrier principle followed" [126]. Refer to Table 2-10 for a compilation of blowout and well release frequency data. The data is based on blowout data from the U.S. Gulf of Mexico OCS, the United Kingdom Continental Shelf (UKCS), and Norwegian waters for the period between January 1, 1980, and January 1, 2005. It should be noted that the workover category was defined as workover activities that did not include coiled tubing, wireline, and snubbing operations, often called 'heavy workover.'

Table 2-10: Blowout and Well Release Frequency Data Table [126], based on Scandpower Analysis of SINTEF Database [127][14]

Blowout and Well Release Frequencies for Offshore Operations of North Sea Standard

Operation	Category	Frequency				Fraction Subsea
		Average	Gas	Oil	Unit	
Exploration Drilling, shallow gas	Topside Blowout		6.0×10^{-4}	-	per drilled well	
	Diverted Well Release		8.3×10^{-4}	-	per drilled well	
	Well Release		9.3×10^{-5}	-	per drilled well	
	Subsea Blowout		9.8×10^{-4}	-	per drilled well	
Development Drilling, shallow gas	Topside Blowout		4.7×10^{-4}	-	per drilled well	
	Diverted Well Release		6.5×10^{-4}	-	per drilled well	
	Well Release		7.3×10^{-5}	-	per drilled well	
	Subsea Blowout		7.4×10^{-4}	-	per drilled well	
Exploration Drilling, deep (normal wells)	Blowout	3.1×10^{-4}	3.6×10^{-4}	2.5×10^{-4}	per drilled well	0.39
	Well Release	2.5×10^{-3}	2.9×10^{-3}	2.0×10^{-3}	per drilled well	0.39
Exploration Drilling, deep (HPHT wells)	Blowout	1.9×10^{-3}	2.2×10^{-3}	1.5×10^{-3}	per drilled well	0.39
	Well Release	1.6×10^{-2}	1.8×10^{-2}	1.2×10^{-2}	per drilled well	0.39
Development Drilling, deep (normal wells)	Blowout	6.0×10^{-5}	7.0×10^{-5}	4.8×10^{-5}	per drilled well	0.33
	Well Release	4.9×10^{-4}	5.7×10^{-4}	3.9×10^{-4}	per drilled well	0.33
Development Drilling, deep (HPHT wells)	Blowout	3.7×10^{-4}	4.3×10^{-4}	3.0×10^{-4}	per drilled well	0.33
	Well Release	3.0×10^{-3}	3.5×10^{-3}	2.4×10^{-3}	per drilled well	0.33
Completion	Blowout	9.7×10^{-5}	1.4×10^{-4}	5.4×10^{-5}	per operation	0
	Well Release	3.9×10^{-4}	5.8×10^{-4}	2.2×10^{-4}	per operation	0
Wirelining	Blowout	6.5×10^{-6}	9.4×10^{-6}	3.6×10^{-6}	per operation	0
	Well Release	1.1×10^{-5}	1.6×10^{-5}	6.1×10^{-6}	per operation	0
Coiled Tubing	Blowout	1.4×10^{-4}	2.0×10^{-4}	7.8×10^{-5}	per operation	0
	Well Release	2.3×10^{-4}	3.4×10^{-4}	1.3×10^{-4}	per operation	0
Snubbing	Blowout	3.4×10^{-4}	4.9×10^{-4}	1.9×10^{-4}	per operation	0
	Well Release	1.8×10^{-4}	2.6×10^{-4}	1.0×10^{-4}	per operation	0
Workover	Blowout	1.8×10^{-4}	2.6×10^{-4}	1.0×10^{-4}	per operation	0
	Well Release	5.8×10^{-4}	8.3×10^{-4}	3.2×10^{-4}	per operation	0
Producing Wells (excluding external causes)	Blowout	9.7×10^{-6}	1.8×10^{-5}	2.6×10^{-6}	per well year	0.125
	Well Release	1.1×10^{-5}	2.0×10^{-5}	2.9×10^{-6}	per well year	0.125
Producing Wells, external causes	Blowout	3.9×10^{-5}	3.9×10^{-5}	3.9×10^{-5}	per well year	0.125
	Well Release	-	-	-	per well year	-
Gas Injection Wells	Blowout	-	1.8×10^{-5}	-	per well year	0.125
	Well Release	-	2.0×10^{-5}	-	per well year	0.125
Water Injection Wells	Blowout	2.4×10^{-6}	-	-	per well year	0.125
	Well Release	-	-	-	per well year	-

[14] HPHT is defined as a well with expected shut-in pressure equal to or above 10,000 psi and bottomhole temperatures equal to or greater than 300°F.

The data provides an excellent breakdown of which operations are the most likely to result in well release or blowout. The highest risk category is exploration drilling of deep HPHT wells with a blowout frequency of 1.5 x 10^{-3}, or 1 blowout per 667 wells. This is fairly frequent, even when compared with the worst completion/intervention operation of snubbing with a frequency of 1 blowout for every 5,263 operations. As would be expected, production operations have the lowest frequency at 2.6 x 10^{-6}, or one blowout every 385,000 well years.

Blowout frequency data is also available in a report on blowout evaluation in the Labrador Sea, which was put together by the Danish Centre for Environment and Energy, based on data from the SINTEF Blowout Database for the U.S. GOM, Norway, and the U.K. from 1980 until January 1, 2008 [128]. Here the data was not specific to deep wells, giving lower frequencies. Table 2-11 shows the number of wells drilled per blowout taken in the Labrador Sea [129].

Table 2-11: Number of Wells Drilled per Blowout Taken[15] [129]

Drilling operation	Well category	Number of wells drilled per blowout of average well	Number of wells drilled per blowout of gas well	Number of wells drilled per blowout oil well
Exploration	Normal	8 929	9 804	8 130
	HPHT	1 445	1 582	1 307
Wildcat	Normal	9 434	10 309	8 547
	HPHT	1 520	1 664	1 374
Appraisal	Normal	8 547	9 346	7 692
	HPHT	1 374	1 504	1 242
Development	Normal	42 194	46 296	38 168
	HPHT	6 803	7 463	6 173

It is clear from the data that the greatest loss of well control occurs most frequently during drilling operations. However, although one can surmise that this is because of the unknown formation pressures and difficulties in controlling the primary barrier during drilling, the cause of these incidents is not clear from this broad blowout data.

In 2011, the PSA of Norway conducted a review of well control incidents on the Norwegian shelf with the objective of identifying the most common causes of well control incidents and appropriate preventive measures that can reduce the frequency of these incidents [68]. The study included a detailed review of available investigation and

[15] Although not specifically defined, this report used the Scandpower data, implying an definition of HPHT as follows: a well with expected shut-in pressure equal to or above 10,000psi and bottomhole temperatures equal to or above 300°F

incident reports over the period of 2003 to 2010. During this time, 146 well control incidents were registered, 117 of which were classified Category 1 (Regular), 7 were Category 2 (Serious), 3 were Category 3 (High Risk), 17 were Category 4 (Shallow Gas), and 1 was Category 5 (High Risk Shallow Gas). Investigation reports were available for ten of these incidents (in Categories 2–5). The investigation was related to exploration and production drilling, and it excluded incidents related to well intervention.

The PSA study developed a classification system for both the triggering and the underlying causes of each incident, breaking them into three categories: Human, Organizational, and Technology. (Refer to Table 2-12.)

Table 2-12: Classification Form for Triggering and Underlying Causes and Types of Measures for Well Control Incidents [68]

General	Specified type of cause or measure
Human	Error type slip/ carelessness / mistakes
	Cognitive error (due to deficient expertise and/or risk understanding)
	Error directly connected to poor/deficient design
	Error connected to breach of applicable practice/procedures
Organisation	Company management, facility management
	Work management
	Risk assessments/analyses (SJA, etc.)
	Planning/preparation
	Procedures/documentation
	Work practice/operational follow-up of the barriers
	Work load
	Inspection/check/verification
	Communication/cooperation/interfaces
	Competence/training
	Goal conflicts – safety/efficiency
	Change management
Technology	Technical well design (cement, plugs, casings, etc.)
	Technical fault in, or inadequate detection of well kick
	Technical fault/weaknesses in primary barriers/mud column
	Technical fault/weaknesses in secondary barrier/BOP
	Other technical equipment fault or weaknesses in safety-critical equipment
	Ergonomics/human-machine interface/design of workplace
	External causes – geology and reservoir

Note: Generally, "deficient" can be put in front of the organisational causes

Note that each incident was given both triggering and underlying cause(s). For example, 'insufficient mud weight' or 'unforeseen conditions in the reservoir' may be identified as the triggering causes and then be classified under technology as 'technical fault/weakness in primary barrier/mud column' and 'external causes—geology and reservoir,' respectively. The reason for these triggering causes may not be connected to technical equipment failure, but they could be due to deficient planning or risk assessment, which are classified as organizational failures. This would become apparent in the underlying cause.

The findings for the triggering causes of the well control incidents in the PSA study are illustrated in Figure 2-28 and Figure 2-29.

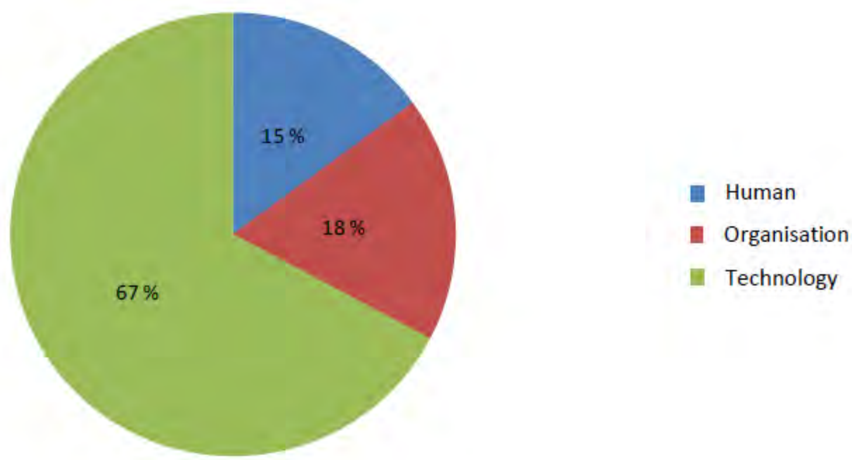

Figure 2-28: Triggering Cause of Well Control Incidents Distributed by Human, Organization, and Technology [68]

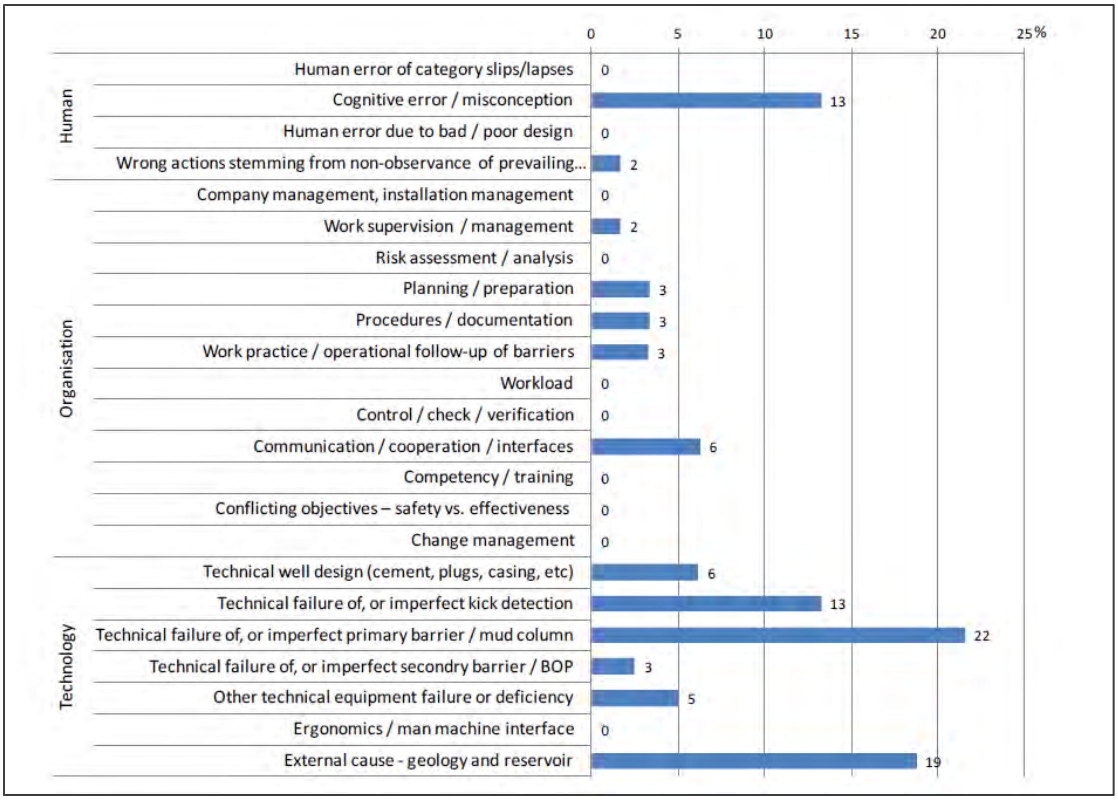

Figure 2-29: Percentage Distribution of Triggering Causes for Well Control Incidents based on Internal Company Investigations [68]

These results show that the three most common triggering causes of well control incidents in this study were:

- Technical failure or imperfect primary barrier/mud column (22%)
- External causes – geology and reservoir (19%)
- Technical failure or imperfect kick detection (13%).

Based on a review of the internal company reports, classification was then performed for the underlying causes for these same incidents. The results are shown in Figure 2-30 and Figure 2-31.

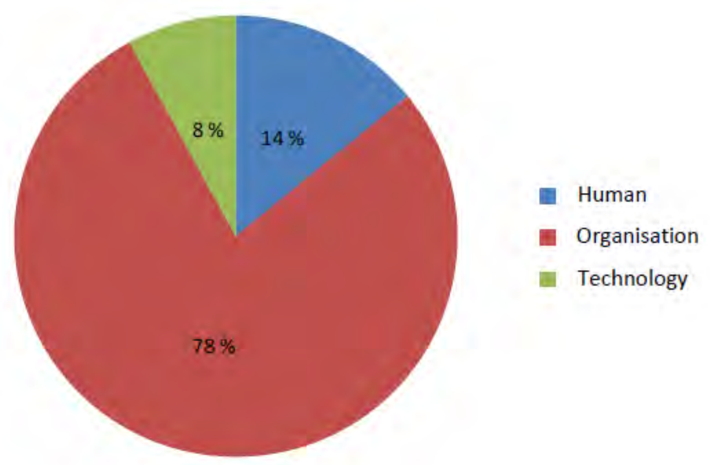

Figure 2-30: Underlying Causes for Well Control Incidents Distributed by Human, Organization, and Technology [68]

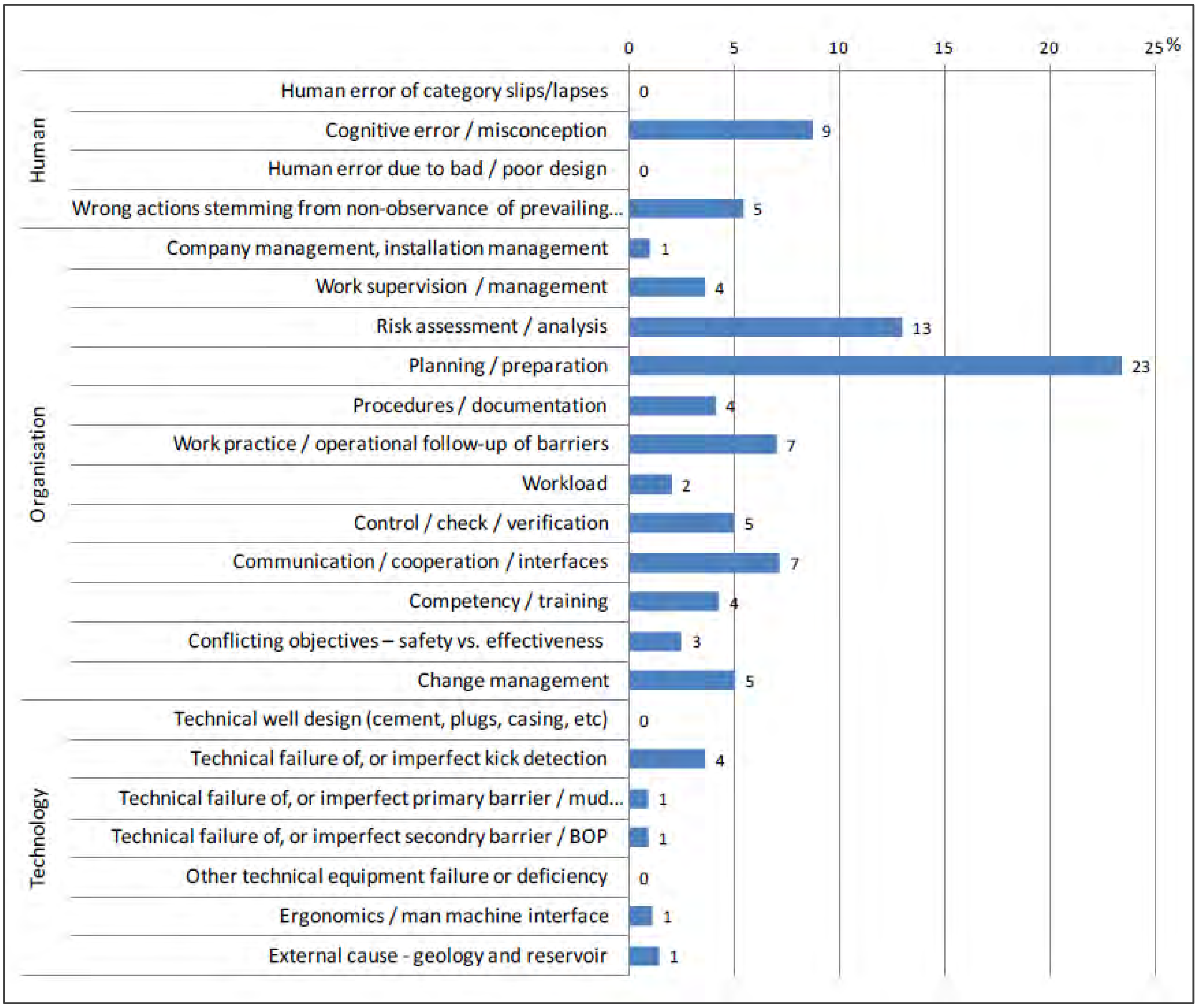

Figure 2-31: Percentage Distribution of Underlying Causes of Well Control Incidents based on Internal Company Investigations [68]

The contrast between the triggering and underlying causes is quite stark. The percentage of events attributed to the organizational category has exploded from 18% of triggering to 78% of underlying causes. Those events attributed to technology have declined from 67% to a mere 8%, and the human category has remained relatively unchanged. The key contributors to the underlying cause emerged as:

- Deficient planning/preparation (23%)
- Deficient risk assessment/analysis (13%)
- Deficient communication/cooperation/interfaces (7%)
- Deficient work practices/operational follow-up on barriers (7%)

The PSA of Norway study [68] went on to conduct a series of interviews with industry professionals. A total of 18 two-hour interviews were conducted, with three operating companies and three Drilling Contractors participating. The interviews were conducted as both one-on-one interviews and group interviews involving a total of 33 people representing the following technical professions:

- Drilling Supervisors
- Toolpushers and Drillers
- Drilling and Subsea Contactors
- Operations Managers/Rig Managers
- Managers who are technically responsible for well operations
- Maintenance personnel
- Operational Advisors – drilling and wells

The PSA report authors state that interviewers indicated a need for various measures to assist in the detection of well kicks, including better presentation of safety-critical information. Following is an excerpt from the report [68]:

> *Following the Deepwater Horizon accident, many have questioned how the drilling personnel could have missed all the signals that a blow-out was developing. It may be tempting to ask: Given that all the signals were available and unambiguous, why do we not have a system to automatically shut in the well?*

The top three triggering causes stated in the report, which contribute to 54% of incidents, could be addressed through improved EKDS and automated response. All of these triggers—failure of the primary well barrier (inadequate fluid density), inadequate knowledge of the drilling window, and inadequate kick detection—could have been prevented or mitigated by high resolution EKDS such as those provided by MPD technology. If MPD technology were coupled with automatic shut-in procedures, the data would have indicated a large improvement in safety.

Clearly, improvement in the underlying organizational causes must also be addressed. Automation cannot assist with inadequate planning and risk assessment. In the event that planning and risk assessment are inadequate, automation can help prevent the acceleration of incidents into higher consequence events.

MPD and Kick Frequency

Conventional wisdom suggests that drilling with increased control over downhole pressure profiles and increased kick detection resolution through a closed system with accurate flow metering should strongly reduce the likelihood of LOWC and blowout [130]. Although MPD has been in the industry for more than two decades, hard data on the impact of MPD on EKD, influx size, and well safety is not readily available. As would be expected with a new technology, the worldwide blowout and well release databases do not include entries for the presence of EKDS technology and as such cannot be expected to provide this information. Examples of database fields and incident records from the SINTEF blowout database are shown in Table 2-13 and Table 2-14.

Table 2-13: SINTEF Database Fields [2]

BlowoutID	BlowoutDate	MainCategory	SubCategory	CountryName	Field
WaterDepth	Operator	InstallationName	InstallationType	WellDepth	WellStatusType
CasingSize	CasingDepth	MudWeight	BH_Pressure	MaxMeasuredShutIn Pressure	MaxTheoreticShutInWH _Pressure
API_grade	GasVolume	OilVolume	WaterVolume	GasOilRatio	RockType
FormationAge	FormationName	LossOfBarrier1	LossOfBarrier1Desc	LossOfBarrier2	LossOfBarrier2Desc
NorthSeaStandards	ExternalCause	HumanError	PhaseType	Activity	OperationType
FlowPath	FlowPathDesc	ReleasePoint	ReleasePointDesc	FlowMediumType	Flowrate
PollutionType	LostProduction	Duration	Fatalitie	IgnitionTime	IgnitionType
ConsequenceClass	MaterialLoss	ControlMethod	ControlMethodDesc	RevisionDate	
DataQuality	ActivityDesc	OperationDesc	InstallationTypeDesc	ExternalReference	Remarks

Table 2-14: SINTEF Blowout Database Incident Details Example [2]

Category and location			Field	: Mississippi Canyon Block 252, Macondo, lease G32306	X
Blowout ID	: 611	X	Water depth	: 1521	[m] X
Date	: 20.04.2010	X	Operator	: BP Exploration & Production Inc.	X
Category	: Blowout (surface flow)		Installation name	: Deepwater Horizon	X
Sub category	: Totally uncontrolled flow, from a deep zone		Installation type	: SEMISUBMERSIBLE	
Country name	: U.S./GOM OCS		Remark		
Well description			API grade	: 0	X
Well depth	: 5579	[m] X	Gas volume	: 0	[1.000 m^3/day] X
Well status	: KILLED		Oil volume	: 0	[m^3/day] X
Casing size	: 9,625	[inch] X	Water volume	: 0	[m^3/day] X
Casing depth	: 5579	[m] X	Gas/oil ratio	: 0	[Sm^3/Sm^3] X
Mud weight	: 0	[kg/m^3] X	Rock type	: A.SANDSTONE	
B.H. Pressure	: 817	[bar] X	Formation age	: B.MIOCENE	
MMSIP	: 0	[bar] X	Formation name		X
MTSIP	: 0	[bar] X			
Blowout causes			Loss of barrier 2	: B1.FAILED TO CLOSE BOP	
Loss of barrier 1	: C14.CASING PLUG FAILURE		Remark		
Remark	: Cement in casing failed		External causes	: NO	
	: No, acoustic backup BOP control system		Human error	: Failed to observe kick before well was flowing	X
Present operation			Activity	: B1.CIRCULATING	
Phase	: EXPL.DRLG WILDCAT		Remark		
Operation	: W9.ABANDON WELL				
Op Remark		X			
Blowout characteristics			Release point	: DRILLFLOOR - THROUGH ROTARY	
Flowpath	: A.THROUGH DRILL STRING/TUBING			SUBSEA BOP	
	B.THROUGH ANNULU.S.		Remark		
Remark			Flowrate	: 8000	[m^3/day] X
Flow medium	: Oil, Gas (deep)		Ignition time	: 0	[hrs] X
Pollution	: LARGE		Ignition type	: EXPLOSION	
Lost production		X	Consequence Class	: TOTAL LOSS	
Fatalities	: 11	X	Material loss	: 0	[mil U.S.$] X
Duration	: 85	[days] X			
Other					
Control method	: CAPPED				
Remark					
Revision date	: 06.10.2010	X			
Data quality	: VERY GOOD				
Reference	: www.bp.com	X			

One study conducted by the University of Texas at Austin performed a regression analysis to test for a link between the presence of an RCD and reduced blowout frequency [131]. The study examined the Railroad Commission (RRC) public database of blowout incidents in Texas during the period between 1995 and 2007. To test whether RCD usage decreases the likelihood of blowouts, a measure of RCD usage during the time period in question needed to be obtained. To this end, the authors obtained job data by a major RCD provider with substantial market share for a subset of the data period (2001 – 2007). This data was used as a proxy for total usage, assuming that different providers would exhibit similar performance and usage trends. The authors argued that this assumption made the resulting statistical interpretation conservative, such that the results would be considerably stronger if all the RCD usage data were made available. Figure 2-32 and Figure 2-33 show the blowout frequency data and RCD usage data for the study period.

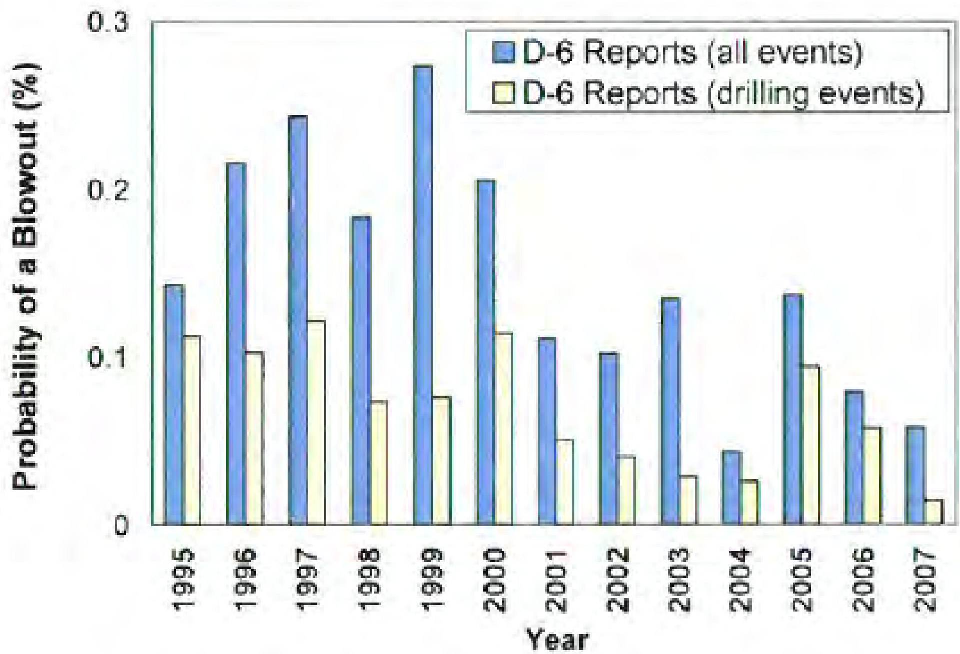

Figure 2-32: Onshore Texas Blowout Frequency by Year (1995 – 2007) [131]

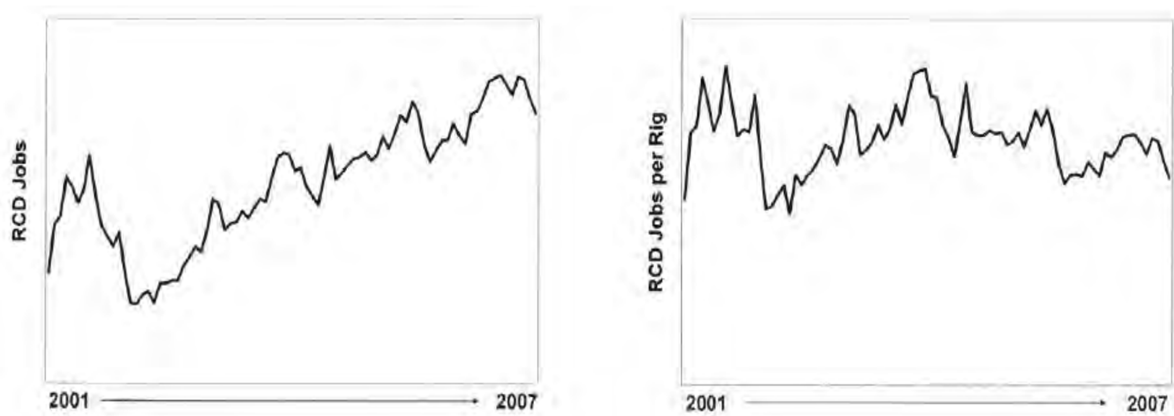

Figure 2-33: Onshore Texas RCD Jobs and RCD Jobs Per Rig (2001 – 2007) [131]

The authors reviewed three different regression models and concluded that there was consistent statistical evidence that the use of RCDs decreased the number of blowout incidents. This was despite the natural selection of RCDs on those wells where drilling conditions were considered more difficult and therefore the risk of blowouts increased.

The study also found that rig count, or increasing activity, dominates the well count in explaining the number of blowouts. This suggested that blowouts do not increase when existing rig crews drill more wells, but that they do increase when new rigs with new crews are brought into service.

2.4.2 Managed Pressure Drilling Case Histories

In this sub-section, case histories are provided to illustrate the effectiveness of EKDS and MPD in well control events. The case studies that follow were compiled from the survey data responses, discussions with industry personnel, and Blade Energy Partners' direct involvement working on MPD operations. Because of the confidential nature of the information and the data disclosed through these case histories, a very small amount of information was collected.

Table 2-15: Influx 1, 2013 – Statistically Underbalanced – Influx Detected while Drilling

Parameter	Parameter Value	Comments
Hole Depth (ft./m)	10,817/3,298	N/A
Water Depth (ft./m)	105/32	N/A
Hole	14 ¾" x 17 ½"	N/A
Flow Rates (Drilling)	1000 gpm	N/A
Operation	Drilling	Observed formation change, influx at time of drilling.
Formation	Sand/Shale	Sand stringers interbedded shale
Measured Influx	1.8 bbl	Measured flow out increase with Coriolis meter
Mode of Influx	Underbalanced	N/A
ECD (ppg)	13.7 –14.3	N/A
Mud Weight (ppg)	14.2	Correct to 122°F
SBP with MPD (psi)	90	While drilling.
SICP (psi)	209	Shut well in with BOPs (VBR)
SIDPP (psi)	NA	N/A
Circulation of Influx	280 gpm	Circulate out through MPD lined up to MGS

Parameter	Parameter Value	Comments
Equipment Used	—	Rig Equipment: BOP, MGS (circulated influx out of well through MGS) MPD Equipment: MPD Auto Choke System, Coriolis Meter

Influx 1 @ 10,817 ft. (3,298 m) MD – Statically Underbalanced – Influx Detected while Drilling (Table 2-15)

1. Influx 1 detected at 10,817 ft. (3,298 m). Instantaneous gain of 20 gpm over drilling rate of 980 gpm. Total influx volume of 77 gal (1.8 bbl) detected.
2. Spaced out drill pipe. Attempted to line up MPD choke manifold for dynamic flow check on active system through both MPD chokes. Incorrect valve lineup on MPD choke manifold – MPD choke valves were closed, resulting in spike in surface pressure. Pressured up with mud pump to approximately 500 psi. Attempted to close both MPD chokes and then open MPD gate valves to slowly bleed off pressure. MPD manifold gate valves opened before MPD chokes closed and Surface Backpressure (SBP) was rapidly bled off.
3. Closed annular, opened lower choke line, monitored pressures – 209 psi SICP.
4. Lined up MPD manifold to circulate through to the Rig Mud Gas Separator (MGS). Aligned MPD manifold through two chokes. Started pumping with Rig Pump (designated MPD pump). Increased surface backpressure to 209 psi to equalize above the annular. Opened the annular.
5. Staged up rig pumps 2 and 3 to drilling rates of 1,000 gpm. Maintained 8,080 psi BHP while monitoring for further gains.

Figure 2-34 shows the immediate response for Influx 1, and Figure 2-35 is an enlarged version of the same response.

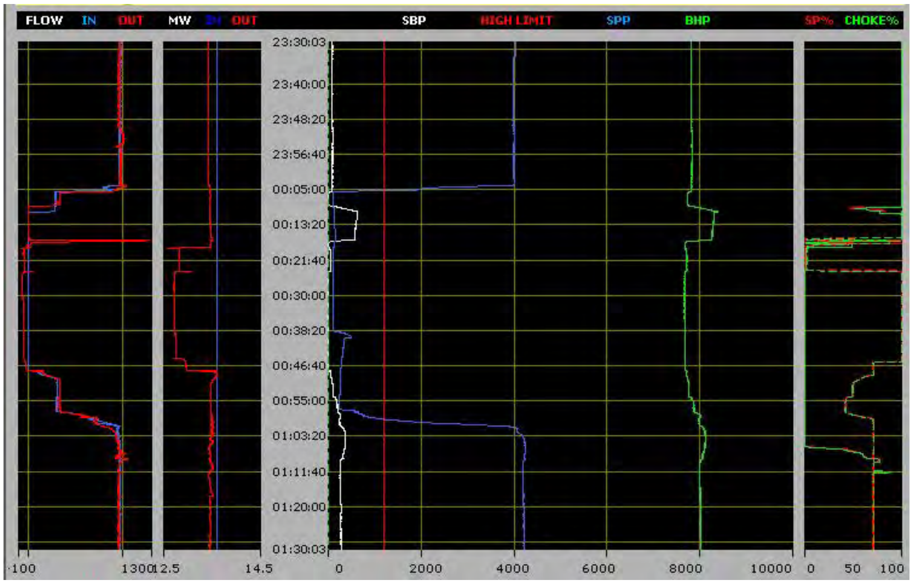

Figure 2-34: Influx 1 and Immediate Response

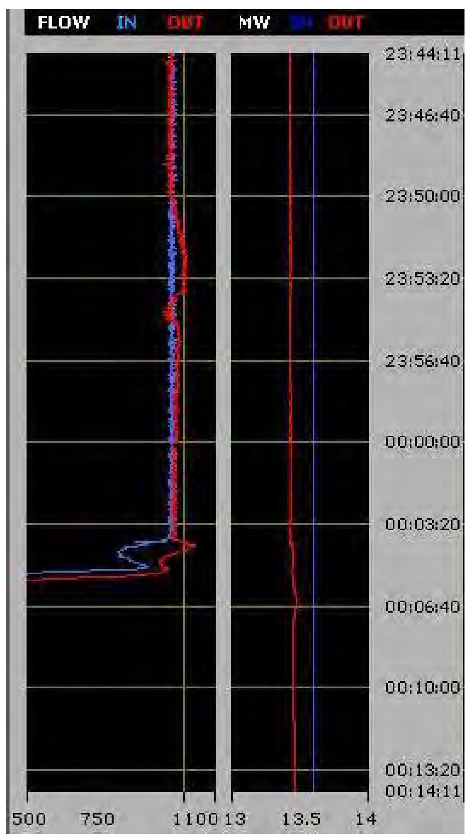

Figure 2-35: Influx 1 and Immediate Response – Zoomed Area

6. Circulate out influx with 1000 gpm; maintain 8,080 psi BHP. Chokes in Automatic mode to maintain constant stand pipe pressure automatically.

7. Gas readings from GCT increase (not shown), Coriolis readings noisy, reduce flow rate, maintain BHP at 8080 psi
8. Automatic choke adjustment made by the system as circulate rates changed to reduce flow rates from 1,000 gpm to 200 gpm as flow was diverted to the rig's MGS.
9. Increase flow rate as GCT gas readings decrease.
10. Stage up flow rate to drilling rates based on GCT gas readings, maintaining BHP at 8080 psi with choke adjustments being made automatically.
11. Complete circulating bottoms up.

Figure 2-36 shows the circulation out of Influx 1, with Figure 2-37 showing a bottoms-up view of the same circulation.

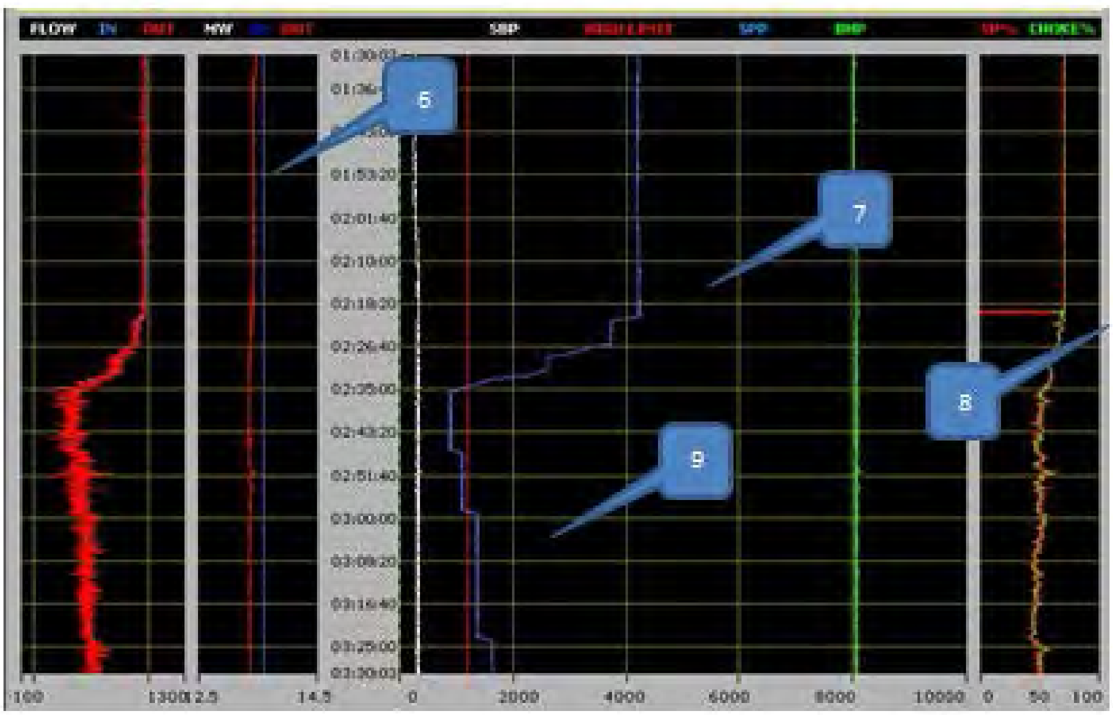

Figure 2-36: Circulating out Influx 1

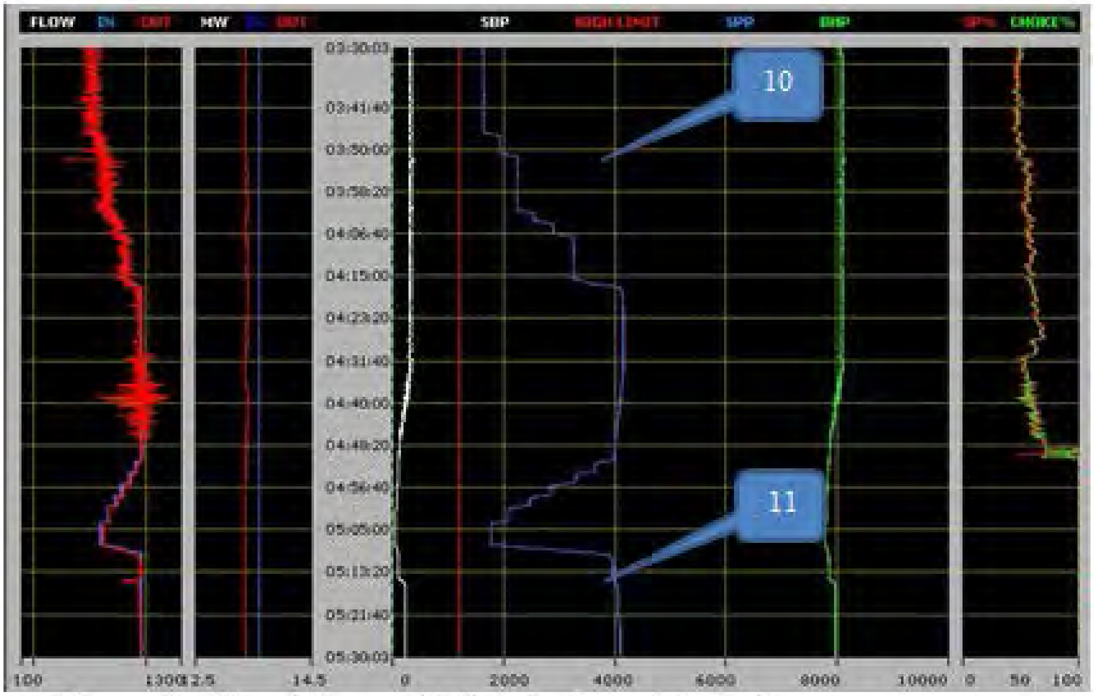

Figure 2-37: Circulating out Influx 1. Complete Bottoms Up.

Table 2-16: Influx 2, 2013 – Statistically Underbalanced – Influx Detected While Drilling

Parameter	Parameter Value	Comments
Hole Depth (ft./m)	18,742/5,714	N/A
Water Depth (ft./m)	105/32	N/A
Hole	12 ¼” x 14 ¾”	N/A
Flow Rates (Drilling)	600 gpm	N/A
Operation	Drilling	Drilling Ahead. Influx during Dynamic Flow Check.
Formation	Sand/Shale	Sand stringers interbedded shale
Measured Influx	2 bbl	Measured flow out increase with Coriolis meter.
Mode of Influx	Underbalanced	N/A

Parameter	Parameter Value	Comments
ECD (ppg)	16.1	N/A
Mud Weight (ppg)	15.5	Correct to 122°F
SBP with MPD (psi)	40 – 175	While drilling
SICP (psi)	175	Shut well in with BOPs (VPR). Initial 175 psi built to 220 psi.
SIDPP (psi)	280	250 psi initial, pumped open NRV
Circulation of Influx	280 – 500 gpm	Circulate out through MPD lined up to MGS
Equipment Used	—	Rig Equipment: BOP, MGS (circulated influx out of well through MGS) MPD Equipment: MPD Auto Choke System, Coriolis Meter

Influx 2 @ 18,742 ft. (4714 m) – Statically Underbalanced – Influx Detected Prior to Flow Check (Table 2-16)

1. Drilled through new formation (interbedded sand/shale), attempted to conduct a Dynamic Flow Check – picked up off bottom while circulating across the top of the well with 40 psi surface backpressure.
2. From fingerprinting baseline the flowback was higher than normal flow back after 5 minutes.
3. The backpressure was increased manually using the MPD system, increasing the choke setting from 40 psi to 145 psi.
4. Flow in/out stabilized, and an additional 35 psi SBP was applied as a safety factor
5. The pumps were stopped, well was shut in with the Variable Bore Rams to accommodate a discussion about the well control situation. Two bbl influx measured. Held a safety meeting to discuss a plan to circulate out the influx.

The first five steps are shown in Figure 2-38.

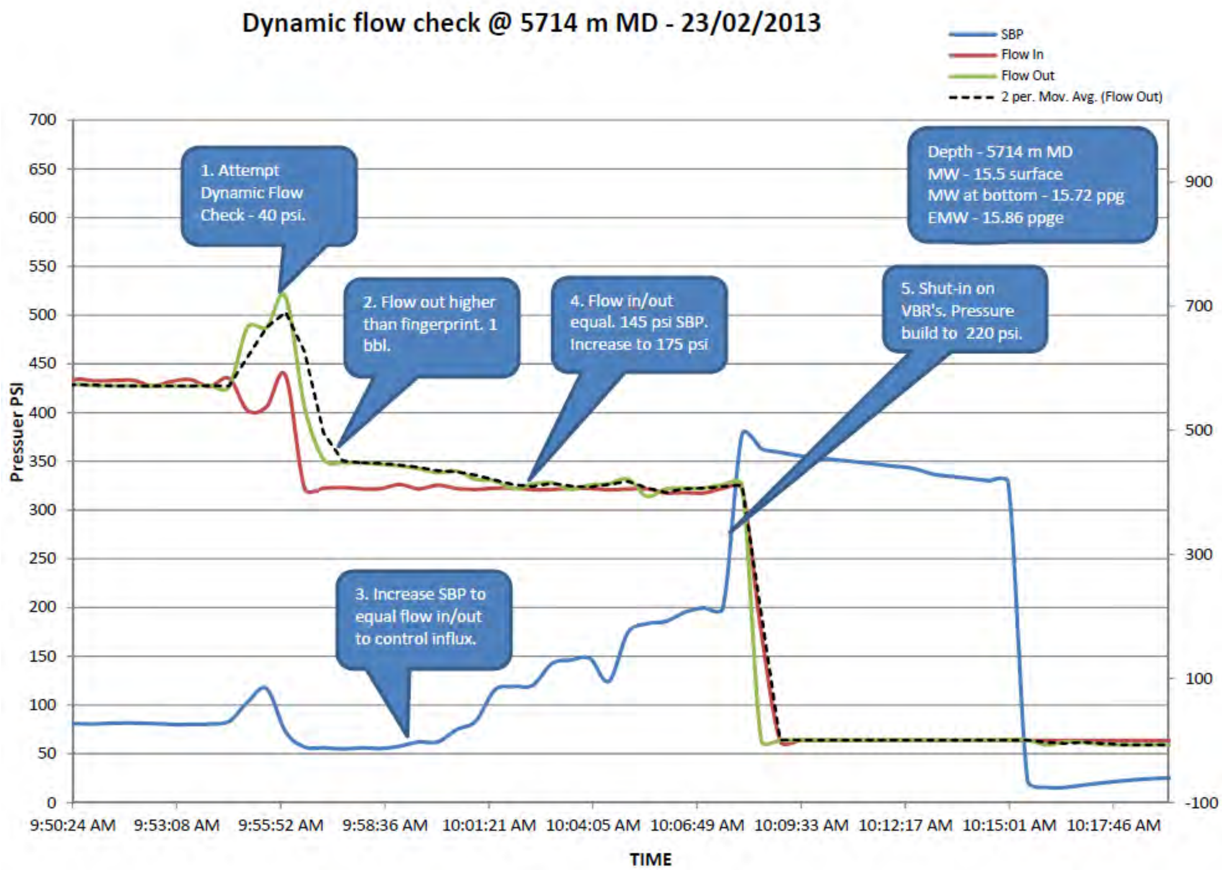

Figure 2-38: Dynamic Flow Check @ 18,742 ft. (5714 m) MD

6. Equalize pressure below the Variable Bore Rams to the MPD Chokes.
7. Increase pump rate to 500 gpm and begin to circulate influx out of the well, allowing the MPD system to automatically adjust choke position to maintain stand pipe pressure; route all return flow through the MGS.
8. Reduce pump rate to 175 gpm once the influx is 1,000 ft. from surface, while allowing MPD system to automatically adjust choke position to maintain constant BHP. Surface backpressure increased from 300 psi to 350 psi during pump rate decrease.
9. Complete circulation of influx from well, shut down pumps, and shut in well. Monitor Shut-in Casing Pressure (SICP) at 350 psi.

Steps 6 through 9 are shown in Figure 2-39.

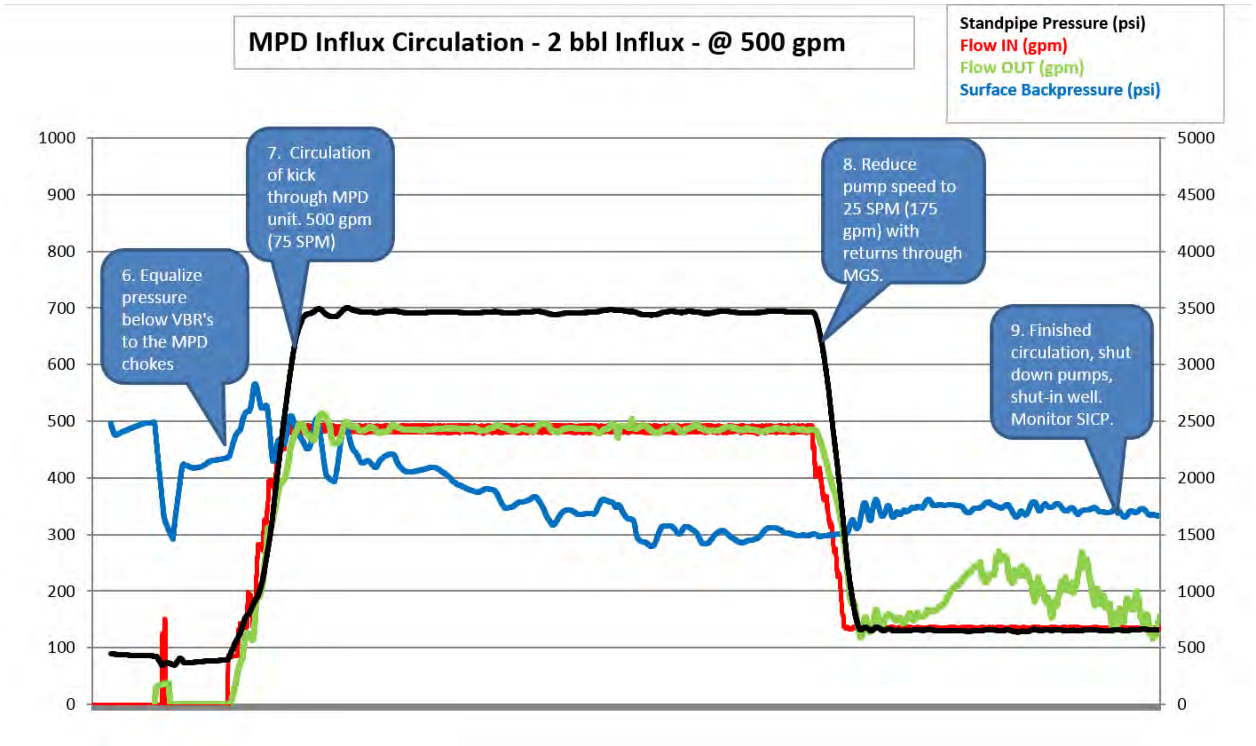

Figure 2-39: Circulation of Influx through MPD System

Various MPD components are shown in Figure 2-40, Figure 2-41, Figure 2-42, Figure 2-43, and Figure 2-44.

Figure 2-40: Rotating Control Device

Figure 2-41: MPD Auto Choke Manifold

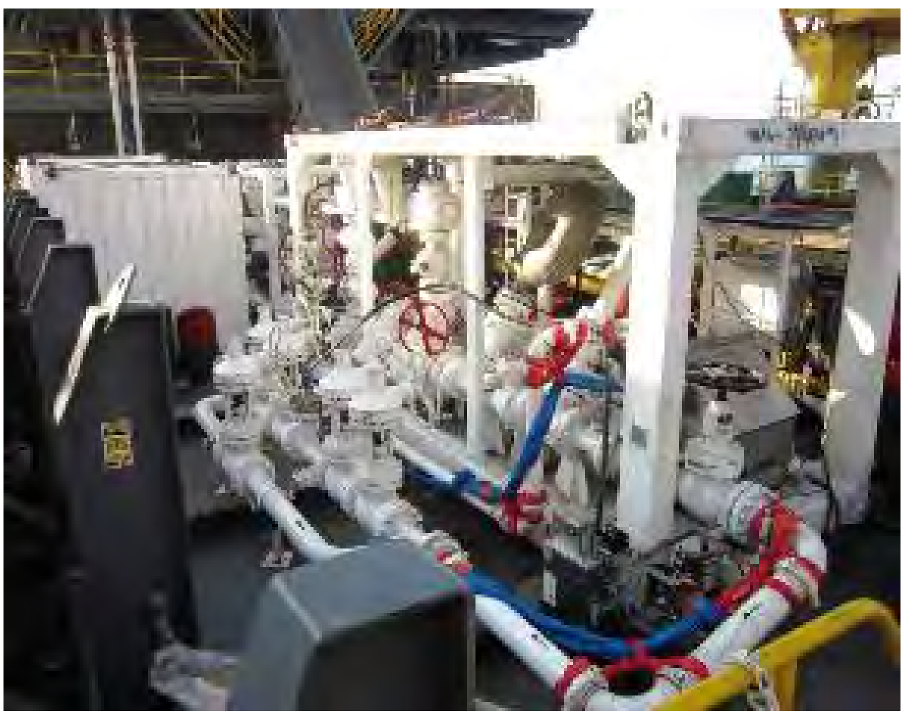

Figure 2-42: Pressurized Gas Meter

Figure 2-43: MPD Equipment – Cantilever Deck

Figure 2-44: MPD Junk Catcher and Piping

Table 2-17: Influx 3, 2010 – Statistically Underbalanced – Pore Pressure Test

Parameter	Parameter Value	Comments
Hole Depth (ft./m)	16,508/5,033	N/A
Water Depth (ft./m)	98.4/30	N/A
Hole	8 ½”	N/A
Flow Rates (Drilling)	500 gpm	N/A
Operation	Drilling	Suspected PP/FG window change. Test PP/FG. Allowed 2 bbl influx
Formation	Sand/Shale	Sand stringers interbedded shale
Measured Influx	2 bbl	Measured flow out increase with Coriolis meter
Mode of Influx	Underbalanced	Statically Underbalanced – Pore Pressure Test
ECD (ppg)	18.12 – 18.14	During Test
Mud Weight (ppg)	17.4	Correct to 122°F
SBP with MPD (psi)	40 – 200	While drilling. 390 psi during circulation.
SICP (psi)	NA	Did not stop to shut in. Allowed MPD Choke to automatically manage influx.
SIDPP (psi)	NA	4450 SPP circulating @ 500 gpm
Circulation of Influx	500 gpm	Circulate out through MPD lined up to MG
Equipment Used	—	Rig Equipment: (Well was not shut-in on BOP) MGS (circulated influx out of well through MGS) MPD Equipment: MPD Auto Choke System, Coriolis Meter

Influx 3 @ 16,508 ft. (5,033 m) Statically Underbalanced – Pore Pressure Test (Table 2-17)

1. Drilled through new formation (interbedded sand/shale), estimated change in pore pressure and/or fracture pressure based off LWD and real time pore pressure prediction. Mapping of the pore pressure and fracture pressure was used throughout the well to identify pressure ramps, conducting pore pressure tests (reducing ECD and allowing 2 bbl influx) as well as Formation Integrity Tests.
2. Depth 16,508 ft. (5,033 m) MD, on bottom drilling with ECD of 18.21 ppg (Emergency Shut Down [ESD] 17.68 ppg), MW in/out 17.4/17.4+, stand pipe pressure (SPP) 4489 psi, SBP 120 psi, ROP 15.6 ft./hr (4.8 m/hr), RPM 95, Torque – 5,000 ft./lbs.
3. Stopped drilling, picked up off bottom, reduced RPM to conduct a Pore Pressure/Fracture Integrity Test. After flow was stabilized off bottom, the surface backpressure of 170 psi was reduced in steps until influx was measured. With the SBP at 100 psi (ECD 18.12 – 18.14 ppg), the Coriolis meter measured a 2 bbl influx. When the MPD system acknowledged an influx, the surface backpressure was increased manually to 200 psi; the MPD system was then set to auto-mode to circulate the influx out of the well.
4. The pumps were kept running at 500 gpm while the MPD system continued to maintain constant SPP, automatically adjusting the choke position while circulating the influx out of the well.
5. When the theoretical top of the influx reached 3,281 ft. (1,000 m) from surface, the flow was directed (on the fly) from the shakers to the rig's MGS.
6. The influx was circulated out of the well, the flow out was diverted back to the shakers, and operations continued, conducting a formation integrity test.

Table 2-18: Influx 4, 2010 – Statistically Underbalanced – Pump Failure

Parameter	Parameter Value	Comments
Hole Depth (ft./m)	17,013/5,187	N/A
Water Depth (ft./m)	98.4/30	N/A
Hole	8 ½"	N/A
Flow Rates (Drilling)	425 gpm	N/A
Operation	Drilling	Lost SBP due to pump failure

Parameter	Parameter Value	Comments
Formation	Sand/Shale	Sand stringers interbedded shale
Measured Influx	4 bbl	Measured flow out increase with Coriolis meter
Mode of Influx	Underbalanced	Statically Underbalanced – Pump Failure
ECD (ppg)	18.24	During Drilling
Mud Weight (ppg)	17.5	Correct to 122^{o}F
SBP with MPD (psi)	350	During Circulation of influx
SICP (psi)	NA	Did not stop to shut in. Allowed MPD Choke to Automatically manage influx
SIDPP (psi)	NA	4,290 SPP circulating @ 425 gpm
Circulation of Influx	425 gpm	Circulate out through MPD lined up to MGS
Equipment Used	NA	Rig Equipment: (Well was not shut in on BOP) MGS (circulated influx out of well through MGS) MPD Equipment: MPD Auto Choke System, Coriolis Meter

Influx 4 @ 5187 m (17013 ft.) – Statically Underbalanced – Pump Failure (Table 2-18)

1. Drilled ahead through interbedded sand/shale statically underbalanced. A pump failure occurred, causing the pump to shut down immediately. The MPD chokes automatically closed to maintain CBHP before the backup pump was brought online. The BHP decreased enough to allow a 4 bbl influx into the annulus. When the backup pump was brought online, the MPD chokes automatically opened and targeted the set BHP until the pump rate was brought up to near full drilling rate, 428 gpm.
2. Depth 17,013 ft. (5,187 m) MD, on bottom drilling with ECD of 18.24 ppg (ESD 17.81 ppg), MW in/out 17.5/17.5+, SPP 4230 psi, SBP 120 psi, ROP 15.7 ft./hr (4.8 m/hr), RPM 95, Torque – 5,000 ft./lbs.
3. Pump failure occurred; the MPD chokes automatically responded by closing and attempting to maintain CBHP. In the meantime a backup pump was brought online to aid in surface pressure; the pump output was increased to 428 gpm, targeting the surface backpressure used prior to the pump failure, 120 psi.

When the surface backpressure and pump speed were set, the MPD system was set to automatic mode to maintain constant stand pipe pressure.

4. The pumps were kept running at 428 gpm while the MPD system continued to maintain constant SPP (4,230 psi) with an ECD of 18.24 ppg, with the MPD chokes automatically adjusting the choke position while circulating the influx out of the well.
5. When the theoretical top of the influx reached 3,280.8 ft. (1000 m) from surface, the flow was diverted (on the fly) from the shakers to the rig's MGS.
6. The influx was circulated out of the well, the flow out was diverted back to the shakers, and operations continued with drilling ahead.

2.4.3 EKDS Redundancy, Backup Availability, and Competence of Personnel

To date, it has been difficult to compile a detailed list of redundancies and backups on a case by case basis for each MPD and EKDS service provider, as they each maintain confidentiality of the interworking components of their systems and equipment. Most of the systems in use continue to use statically overbalanced fluid systems, with influx management being handled by the Rig Contractor. However, in recent years there seems to be a movement toward statically underbalanced fluid regimes resulting from the advantage of hydraulics management and the use of the MPD system for influx management. This movement has occurred because the MPD system provides more accurate pressure control and minimizes the time required to deal with small influxes and nuisance gas. Older well control requirements did not incorporate the MPD equipment as part of the primary barrier, but the newer applications are pushing the limits and changing recommended practices such as API 92M to consider MPD as a primary barrier.

As MPD and EKDS are used more as primary barriers, the reliability and redundancy of the systems should be consistent with the requirements for their designation as primary barriers and safety-critical systems. Standards such as International Electronic Commission (IEC) 61508 [137] and IEC 61511 [138] for reliability and redundancy have been developed for safety-critical systems in other regions using the MPD and EKDS equipment and as such provide a guideline for the petroleum industry. IEC 61508 [137] describes a risk-based approach for determining the Safety Integrity Level (SIL). IEC 61511 [138] describes the practices in the engineering of systems that ensure the safety of an industrial process through the use of instrumentation.

A current view is that EKDS and MPD systems in today's marketplace may lack automation of safety-critical redundancy in the form of computer logic programing, which allows or disallows specific sequences and functions to occur. The current redundancy levels vary from project to project, as the design application is tailored to fit each operation. Safety-critical redundancy currently relies heavily on the implementation of training, procedures, and physical barriers in the form of pressure relief valves, manual valves, double isolation, and set points in the system's user interface. The set points are typically not used from the perspective of containment of a primary barrier or safety, but rather to protect overpressuring of formations or equipment or both.

Personnel competency has yet to be standardized for MPD/EKD operations, aside from the basic well control certificates issued every two years to crew Supervisors/Engineers. Instead, competency is managed on a project by project basis by developing and involving the Drilling Contractor, Operator, and service provider in project-specific training such as simulator training, on-site presentations and drills, permit to work, and Health, Safety, Security, and Environment (HSSE).

A list of the four sub-systems present in each of the MPD and EKDS pressure Control systems and a brief discussion of the redundancies that should be considered for implementation in future equipment based on IEC 61508 [137] and IEC 61511 [138] are addressed in the following sub-sections.

2.4.3.1 MPD and EKDS Controller Unit

The control logic unit performs all arithmetic and logical operations. If the MPD and EKDS Control system is designated as a primary barrier, as in API 92M, some of the system's functions should be defined as safety critical. Because these systems will be used as safety critical, they should adhere to the standards included in IEC 61508 [137] and IEC 61511 [138], which define safety instrumented systems. For example, if the logic unit fails to control the BHP, the safety logic unit should take over and effectively bring the well into a safer mode. One of the important principles of the IEC standards is placing safety and non-safety functions in independent systems or building the systems so that all functions are safety critical when the system's control logic unit recognizes it has failed and places the well into a safe mode.

The arithmetic and logical operations performed by the control unit include:

- Interface to dynamic and static MPD pressure control equipment.
- Interface to hydraulic and mechanical models.
- Connection to internal well monitor systems (flowmeters).
- Connection to external well monitoring systems (pit volumes).
- Connection to drilling Control systems.
- Hydraulics models used to simulate physical parameters of fluid in the well in addition to flow, pressures, and temperatures.

- Mechanistic models used to simulate other relevant operational parameters.
- Safety logic units used to perform dedicated safety functions.

2.4.3.2 Well Monitoring System

To maintain control over the well, a configuration of measuring devices is used to monitor the well condition. These devices include:

- Pressure Transmitters located close to dynamic or passive MPD pressure control equipment.
- Flowmeters that measure mud return flow through mud return lines and MPD choke manifolds.
- Gas rate sensors and level and temperature transmitters.

These measurements are input into the MPD and EKDS Control system, where algorithms determine appropriate actions. Signals from the measuring devices are therefore required to provide a primary barrier and to maintain safe well conditions. As a redundancy, a safety logic unit should be present and be able to measure or read measuring devices at the same points as those used by the logic control unit, either by cable or signal. The use of the same cable/signal to supply both the logic and safety control should not be allowed in the event of failure. A redundancy should be present in the measuring device, control, and safety logic to ensure that the system is truly redundant in its capacity to function in a safe manner should the logic control unit fail.

2.4.3.3 Dynamic MPD and EKDS Pressure Control Equipment

Dynamic MPD and EKDS Pressure Control Equipment are used to dynamically adapt the annular hydraulic pressure profile. Automated MPD chokes are used to regulate annular hydraulic backpressure and fluid return.

This equipment includes:

- Chokes
  - Adjustable (manual) chokes are used to regulate annular hydraulic backpressure and return flow.
  - Automated chokes are controlled by hydraulic and/or electric systems.
- Pumps
  - Conventional pumps are used to circulate or pump fluid or cement.
  - Kinds of pumps include rig pumps, booster pumps, and cementing pumps.
  - Backpressure pumps are used to maintain flow through the Automated MPD Choke Manifold.
  - Subsea pumps are used to adjust mud return flow.

- Piping and Equipment
  - Separate injection lines are used to mix gas or fluid with the drilling fluid in the well.
  - A separate mud return line is used to conduct mud return flow back to the surface.
  - The bypass line is used to conduct and regulate mud flow.
- Additional Equipment
  - Dedicated tools to restrict flow in the drill string or in the well
  - The inside drill string valve to prevent U-tubing
  - Valve(s) to prevent U-tubing between the mud return line and the well
  - Annular preventers that are not part of the BOP stack

The control logic interfaces with the dynamic MPD and EKDS pressure control equipment. If it is considered to be a part of the primary barrier, the safety control unit should be able to monitor and activate this equipment. The safety control unit should have the ability to override the control logic unit to ensure that the well remains in a safe mode.

2.4.3.4 Static MPD Pressure Control Equipment

Static MPD Pressure Control Equipment is used to isolate and maintain backpressure. This equipment includes:

- Rotating BOP or Rotating Control Device (RCD) to close the well system and maintain backpressure.
- Non-rotating control device (NRCD) to close the well system and maintain backpressure.
- Tubing to isolate pressure.
- Drill string to prevent unintentional flow between the drill string and the well.

Breakdown of the rotating BOP or RCD will result in a loss of a primary barrier, but it should be noted that the loss of EKDS or MPD equipment such as a Coriolis meter will not necessarily result in the loss of a primary barrier. Safety control logic should therefore be programmed with the view to maintain a primary barrier and should only be tied to that equipment which is defined as well barrier elements.

2.4.4 Systems Used in the Outer Continental Shelf

The project team sent survey questions to many MPD service providers, Operators, and other equipment providers supplying or using MPD/EKDS within the OCS. Two service providers returned limited information regarding their current systems, while one

Operator declined to participate, and another Operator responded with limited information.

The service provided the following information regarding systems in use:

- RCD – passive
- Advanced Control systems with automated chokes
- Rig pump diverters, which divert flow from downhole through the stand pipe manifold to across the MPD chokes to maintain surface backpressure, eliminating the requirement of a backpressure pump
- Coriolis Meter – measuring flow out, correlated against flow in pump stroke counter
- Real time hydraulic models and data systems that are capable of sending and receiving WITS.
- Software monitoring system – Human Machine Interface (HMI) with adjustable alarms and response capabilities
- Downhole Deployment Valve (DDV)

The information provided by the Operator included:

- MPD was currently being used on Tension Leg Platforms.
- Main use is to apply surface backpressure for hydraulic management
- MPD system includes:
  - Automatic operated chokes
  - Coriolis meter
  - Manifolds
  - RCDs

Respondents also confirmed that second and third generation MPD/EKDS equipment is currently in the development stages and is being tested online and offline within various scopes of drilling, in both conventional and MPD operations. To date, the use of fully automated systems has not been implemented in the U.S. OCS.

2.4.5 Regulatory Environment for EKDS and MPD outside the U.S.

The current regulation of EKD and MPD systems varies around the world. Figure 2-45 shows the various regulations and rules that may be applicable to a drilling unit, and to which the MPD system must subscribe as part of the drilling system.

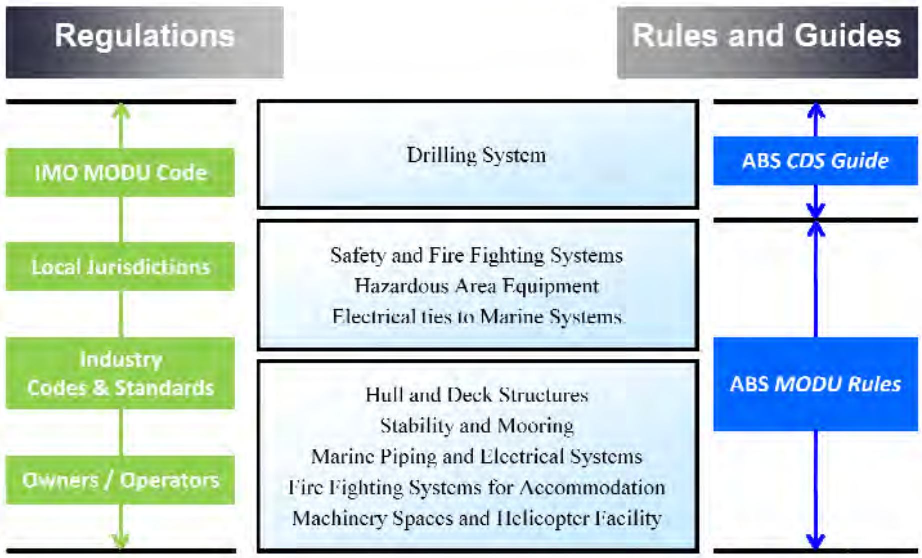

Figure 2-45: Regulations and Rules for Drilling Units as Depicted by ABS [132]

The regulations begin at the international level with the International Maritime Organization (IMO), which establishes regulations that focus on safety at sea and the protection of the marine environment.

The next level is related to the classification of the offshore structure. The class society rules/flag rules are a recognized and independent set of technical standards and/or rules that certify adherence to a certain level of safety. For MPD equipment, the classification of the intended vessel for deployment will affect the level of standard to which the equipment must be manufactured and tested.

DNV GL, which is a certification body and an international ship and offshore classification society, notes in a 2011 technical newsletter [133]:

- "They consider MPD to be well Control systems controlling the primary barrier while drilling. Well Control systems are categorized as Essential Systems when drilling according to DNV-OS-E101 'Drilling Plant' and thus subject to approval and certification by DNV for drilling units with a class notation of DRILL or DRILL(N)."
- "Approval and certification of MPD systems will be done on a case by case basis. To evaluate each system the following documentation shall be submitted to DNV as a minimum:
  - A system description, including explanation of the Control system and any need for intervention in/modification to the existing well Control system
  - The shutdown philosophy, including procedures for converting to conventional well control
  - A FMECA report on the MPD system

– P&IDs of the MPD system, including revised rig P&IDs to show interface with the MPD system
– Arrangement drawings showing onboard location of the MPD system with respect to Hazardous Areas
– Revised documentation for any existing DNV-certified equipment that is modified due to the MPD system
– A DNV product certificate for MPD safety-important components."

In the U.S., the American Bureau of Shipping (ABS) is currently finalizing requirements and drafting a detailed guideline for the certification of MPD systems. ABS has been in discussion with more than 50 companies, including a mix of Operators and Drilling Contractors, to include an update to their Guide for Classification of Drilling Systems, adding an Appendix outlining MPD rules. Because the MPD system and all of its sub-systems will be considered a part of the primary well barrier system, all associated components used in MPD operations will require ABS design approval and an ABS survey for installation, which will be classed by ABS [134].

At the local level, each nation will impose its own level of regulation, which will be enforced by its respective agencies:

- Norway: Petroleum Safety Authority (PSA).
- United Kingdom: Health and Safety Executive (HSE)
- Australia: National Offshore Petroleum and Environmental Management Authority (NOPSEMA).

Similarly, Canada, Brazil, and other countries have authorities who are responsible for overseeing drilling activities. Unlike the U.S. regulations, which have prescriptive requirements, the U.K. HSE, the PSA, and NOPSEMA regulations are mainly performance based with supplementary prescriptive requirements. However, these agencies include mandatory requirements for performing risk identification and providing risk mitigation measures that are not required in the U.S. [132].

Although specific requirements are not defined for the HSE, NOPESMA, and PSA, a Norsok DS-010 [10] standard is often referred to for best practices, particularly in Norway and the UK. With a heavy emphasis on well control barriers, the standard varies its requirements for MPD operations, depending on whether the primary barrier fluid is underbalanced. In each case, the barriers must be determined and the barrier envelopes drawn.

Should the MPD equipment form part of the primary barrier system, the well barrier acceptance criteria are specified [10] in Section 13.3.3 of Norsok DS-010:

> *13.3.3 Well barrier acceptance criteria for managed pressure drilling. The primary well barrier in MPD operations is maintained by a statically underbalanced fluid column with applied surface pressure. The BHP is controlled by means of a closed loop surface system and equipment providing back-pressure.*
>
> *a) The RCD shall be installed above the drilling BOP.*
>
> *b) A dedicated MPD choke manifold shall be used to control the wellbore pressure and reduce the pressure at surface to acceptable levels before entering the separation equipment or the shakers. A manual MPD choke system is not accepted as a part of the primary well barrier.*
>
> *c) Plugging, erosion, or wash-outs of surface equipment shall not impact the ability to maintain well control.*
>
> *d) The surface system shall be selected and dimensioned to handle the anticipated fluid/solids, including formation fluids if potential exists for influx removal with MPD.*
>
> *e) Snubbing facilities shall be used in all pipe light scenarios. Alternatively, the well can be brought into hydrostatic overbalance or a qualified isolation WBE can be placed downhole prior to any probable pipe light scenarios.*
>
> *f) During any tripping operation, the ability shall be in place to measure either positive backpressure if the RCD is installed, or verify level of liquid in the annulus when the RCD is not installed.*
>
> *g) The BHP shall be kept at a level that prevents continuous influx of formation fluid into the well. The BHP shall be above maximum confirmed pore/reservoir pressure (including safety margin to account for expected variations in BHP). The pressure can be confirmed by pressure measurement or interpreted from well signals.*

Of most relevance to the manufacture and deployment of MPD systems are the industry codes, standards, and industry recommended practices. These items focus on the structural and mechanical integrity of the components, which include their design, manufacture, and testing. These standards are produced by industry bodies such as the

American Petroleum Institute (API), which has a body of more than 500 such documents for the oil and gas industry. However, no specific standard covering EKD and MPD has yet been provided. Furthermore, in the absence of standards that specifically address the requirements for equipment in MPD applications, manufacturers are left to navigate a variety of different standards that are pertinent to each of the components in their systems. The resulting confusion often leads to the practice of defaulting to the most rigorous standard.

3.0 Regulations and Industry Survey on Automated Well Safety and Early Kick Detection Technologies

3.1 Regulations and Standards

Standard organizations such as American Petroleum Institute (API), International Organization for Standardization (ISO), and British Standards (BS) have developed specifications, standards, and recommended practices for the development, design, and maintenance of well control equipment. This section provides a detailed review of the existing regulations, standards, and guidelines related to well control equipment by various organizations and associations around the world (refer to Figure 3-1).

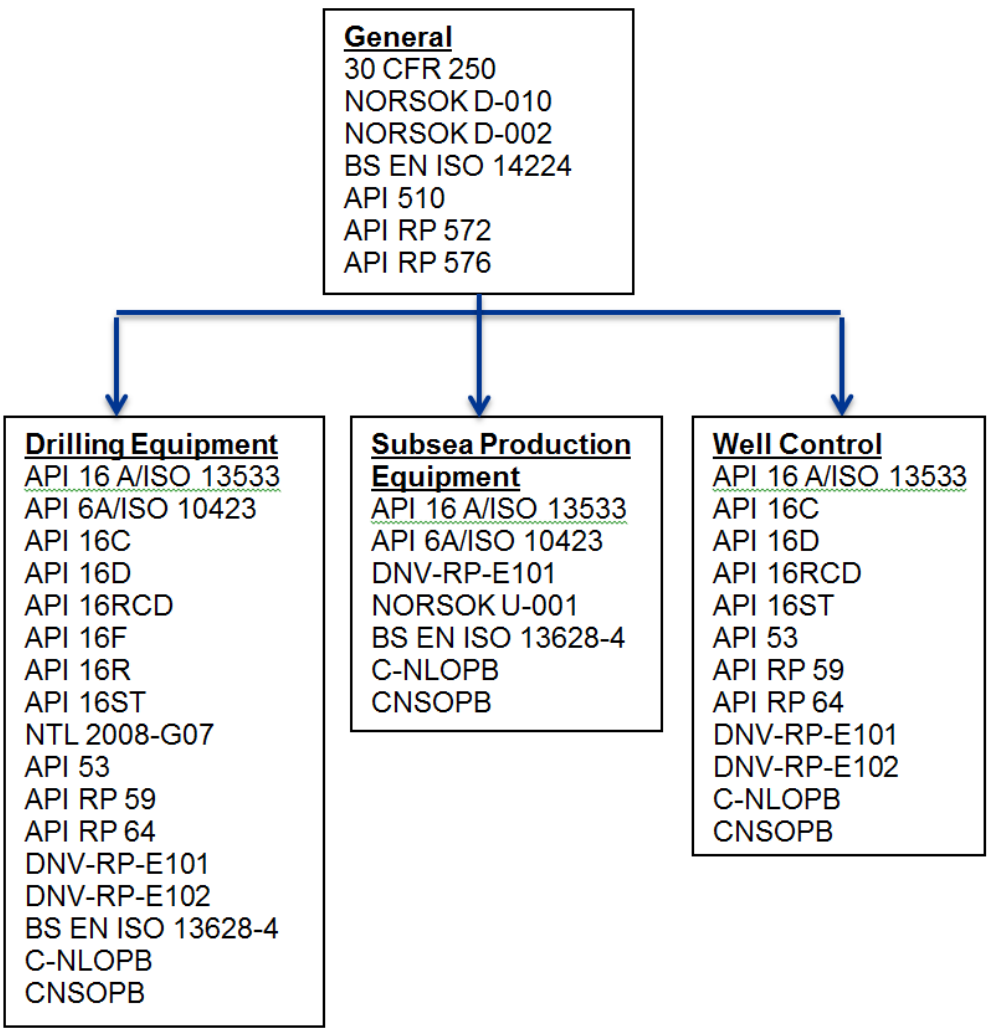

Figure 3-1: Regulations and Standards

3.1.1 General Global Standards

Different countries have their own regulations that are enforced by their respective government agencies. Norway has the Petroleum Safety Authority (PSA), the United Kingdom (U.K.) has Health and Safety Executive (HSE), and Australia has the National Offshore Petroleum and Environmental Management Authority (NOPSEMA). Similarly, Canada, Brazil, and other countries have authorities who are responsible for overseeing drilling activities.

Unlike U.S. regulations, which have prescriptive requirements, the U.K. HSE, the PSA, and the NOPSEMA regulations are mainly performance based with supplementary prescriptive requirements. However, these agencies include mandatory requirements for performing risk identification and risk mitigation measures that are not required in the U.S.

3.1.1.1 DNV-RP-E101: 2012 – Recertification of Well Control Equipment for the Norwegian Continental Shelf [8]

This Recommended Practice (RP) document describes DNV's recommendations for a recertification process of well control equipment for the Norwegian Continental Shelf. Recertification of well control equipment that is used for drilling, completion, workover, and well intervention operations should be performed at least every five years. The purpose of a recertification process is to verify and document that the equipment condition and properties are within the specified acceptance criteria and the specified recognized codes and standards, thus ensuring that documentation of the condition of the equipment is available at all times.

Some of the well monitoring systems to monitor the well and MPD pressure control equipment can include:

- Pressure and flow sensors in the marine riser or mud flowlines.
- Measurement of downhole conditions using MWD or Pressure While Drilling (PWD) data.
- Other measuring devices for safety or control of the well barriers.

3.1.1.2 DNV-RP-E102: 2010 – Recertification of Blowout Preventers and Well Control Equipment for the United States Outer Continental Shelf [9]

This document is similar to DNV-RP-E101, but it is specifically related to Blowout Preventers (BOPs) and well control equipment used in drilling operations on the U.S. OCS. Recertification of BOPs and well control equipment used for drilling, completion, workover, and well intervention operations should be performed at least every five years. Recertification intervals other than five years may apply when justified through, for instance, an approved Reliability Centered Maintenance (RCM) analysis. The purpose of a recertification process is to verify and document that the equipment condition and properties are within the specified acceptance criteria and the specified codes and standards, thus ensuring that documentation regarding the condition of the equipment is available at all times.

3.1.1.3 NORSOK Standard D-010: Rev 4, 2013 – Well Integrity in Drilling and Well Operations [10]

The Norsk Sokkels Konkuranseposisjon (NORSOK) Standards are recommended for fulfilling Norwegian PSA requirements. The Norwegian petroleum industry developed the NORSOK standards to "ensure safety, value adding, and cost effectiveness for petroleum industry developments and operations" [11]. NORSOK standards are intended to replace oil company specifications and serve as references to the authority's regulations.

According to the *Standard Online* website:

> *The preparation and publication of the NORSOK standards is supported by Norwegian Oil and Gas Association (Norsk Olje og Gass) and Federation of Norwegian Industries. NORSOK standards are managed and issued by Standards Norway [11].*

Standard Online states that:

> *Standards Norway (SN) is a private and independent member organisation, and is one out of three standardisation bodies in Norway. Standards Norway is responsible for standardisation activities in all areas except the electro technical field and the telecommunications field [12].*

Because NORSOK is a private organization similar to DNV and others, it seems that Norwegian regulators do not formally require compliance with NORSOK guidelines. According to the *Standard Online* website:

> *The operators on the Norwegian shelf are allowed to make their own addition[s] or deviation[s] to the NORSOK standards available on the web. If a company has such additions or deviations, their name will appear on the page presenting the subject standard. By clicking the company name you will be connected to the company's own document [13].*
>
> *According to the* Petroleum Safety Authority Norway *website, The PSA is responsible for developing and enforcing regulations which*

govern safety and the working environment for petroleum operations on the NCS [Norwegian Continental Shelf] and associated facilities on land.

Norway's current regulatory regime for the oil and gas industry is the result of a continue[d] series of changes and improvements from the early 1970s to the present day [14].

Norwegian offshore regulations rely heavily on various standards such as NORSOK. NORSOK is often perceived as Norwegian regulatory requirements, but it is a standard and is simply one of several ways of fulfilling PSA regulations. PSA regulations are general, with guidance such as “the work environment must be satisfactory.” Based on this statement, the ship owner must document that everything is ‘satisfactory’ and complies with underlying intentions. The PSA does not stipulate the solutions. Rather, it is up to the ship owner to comply (based on a set of underlying norms) and to verify that the chosen solution results in the best working environment onboard the vessel [15].

The focus of NORSOK Standard D-010 is well integrity throughout the entire lifecycle of the well (drilling, well testing, completion, sidetracks, suspension and abandonment, wireline operations, coil tubing operations, snubbing operations, underbalanced drilling and completion operations, pumping operations, workovers, and production). The well barriers; well design; well barrier elements acceptance criteria; well control action procedures; and drills, casing, and completion design criteria are covered in detail in Standard D-010.

3.1.1.4 NORSOK Standard D-002: Revision 2, 2013 – Well Intervention Equipment [16]

The main objective of this NORSOK standard is to provide common requirements for well service and intervention facilities, their systems, and their equipment with respect to use, operational efficiency, lifecycle cost, and the stipulation of acceptable safety levels. NORSOK Standard D-002 is an overall improvement and expansion of the former standards for coiled tubing, snubbing, and wire line equipment. It replaces the following NORSOK standards:

- D-SR-005 Coiled Tubing Equipment, Revision 1 – January 1996
- D-SR-006 Snubbing Equipment, Revision 1 – January 1996
- D-SR-008 Wireline Equipment, Revision 1 – October 1996

Some areas of improvement from the earlier revision are:

- The well barrier terminology of the standard is harmonized with NORSOK D-010.
- The requirements of safety valves have been expanded to reflect current expectations and understanding.

- Test requirements for pressure control equipment are further specified.

3.1.1.5 NORSOK U-001: Revision 3, 2002 – Subsea Production Systems [17]

This standard is based on ISO 13628 Petroleum and Natural Gas Industries – Design and Operation of Subsea Production Systems. Many of the specified requirements are detailed in other NORSOK standards, including dropped object and fishing gear loads, manifold valve and piping system design, sealing material design, subsea system design, and well intervention. The drilling load cases for water depths up to 2,461 ft. (750 m) and deeper are also specified.

3.1.1.6 The C-NLOPB and the CNSOPB, 2011 Drilling and Production Guidelines [18]

The Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) and the Canada-Newfoundland & Labrador Offshore Petroleum Board (C-NLOPB) have co-published the Drilling and Production Guidelines. These guidelines address each of the 91 sections of the Nova Scotia Offshore Petroleum Drilling and Production Regulations and cover a full range of topics associated with drilling and production projects.

Section 28.12 of this regulation explains the following:

> *The mudlogging unit should be manned continuously by dedicated personnel who measure, monitor and record the amount and composition of hydrocarbon gases in the return drilling fluid, the density of the drilling fluid, flow rate, pit volumes, drilling fluid returns, trip tank volumes and other parameters critical to the safety of the drilling operations or critical to the detection of a loss of drilling fluid to the sea [18].*

Section 30.2 of this regulation explains that:

> *Consistent with good oilfield practice, all pressure detection parameters including the rate of penetration, drilling exponent, shale density, cuttings size and shape, mud gas levels, torque, drag, fill, temperature and any other pertinent parameter should be monitored while drilling in an effort to detect any transition zone from normal to abnormal pressure and to detect any kicks. The use of logging while drilling (LWD) may also greatly assist in abnormal pressure detection. If necessary, wire line logs should be acquired if such are needed to confirm formation pressures [18].*

3.1.1.7 C-NLOPB: 2011 Guidelines for Drilling Equipment [19]

This standard applies to drilling in the Newfoundland offshore area and meeting the requirements of Section 15 – Requirements for Drilling Installations and Section 21 – Standards for Drilling Equipment of the Newfoundland Offshore Petroleum Drilling (Newfoundland) Regulations. The intent of the C-NLOPB is to verify that drilling equipment proposed for use in works or activities authorized by the Board pursuant to Section 138 of the Canada-Newfoundland Atlantic Accord Implementation Act and Section 133 of the Canada-Newfoundland Atlantic Accord Implementation (Newfoundland) Act meets these requirements.

All drilling installations operating in the Newfoundland offshore area are now required to have a Certificate of Fitness issued by a recognized Certifying Authority (CA) such as the American Bureau of Shipping (ABS), Bureau Veritas (BV), DNV Germanischer Lloyd, or Lloyd's Register of Ships. The Board expects that the CA will use this document to assess the drilling equipment. The Certificate issued will confirm that the installation to which it refers complies with these standards and requirements.

3.1.1.8 Code of Federal Regulations (CFR) – Title 30: Mineral Resources. Part 250 [20]

- Subpart D of this regulation applies to lessees, operating rights owners, operators, and their contractors and subcontractors in § 250.401 and provides the following guidance:

  "What must I do to keep wells under control?"

  You must take necessary precautions to keep wells under control at all times. You must:

  (a) Use the best available and safest drilling technology to monitor and evaluate well conditions and to minimize the potential for the well to flow or kick;

  (b) Have a person onsite during drilling operations who represents your interests and can fulfil your responsibilities;

  (c) Ensure that the tool pusher, operator's representative, or a member of the drilling crew maintains continuous surveillance on the rig floor from the beginning of drilling operations until the well is completed or abandoned, unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers [20].

- § 250.457 explains the following about the different fluid monitoring systems:

What equipment is required to monitor drilling fluids?

Once you establish drilling fluid returns, you must install and maintain the following drilling fluid-system monitoring equipment throughout subsequent drilling operations. This equipment must have the following indicators on the rig floor:

(a) Pit level indicator to determine drilling fluid-pit volume gains and losses. This indicator must include both a visual and an audible warning device;

(b) Volume measuring device to accurately determine drilling fluid volumes required to fill the hole on trips;

(c) Return indicator devices that indicate the relationship between drilling fluid-return flow rate and pump discharge rate. This indicator must include both a visual and an audible warning device; and

(d) Gas-detecting equipment to monitor the drilling fluid returns. The indicator may be located in the drilling fluid-logging compartment or on the rig floor. If the indicators are only in the logging compartment, you must continually man the equipment and have a means of immediate communication with the rig floor. If the indicators are on the rig floor only, you must install an audible alarm [20].

- Subpart E relates to Oil and Gas Well Completion Operations, Well Control Equipment and Fluids Requirements, and Casing Pressure Management.
- Subpart F relates to Oil and Gas Well Workover Operations.
- Subparts E and F state that detailed written procedures (on the Application for Permit to Modify) must be submitted for BSEE's approval to displace kill-weight fluids to an underbalanced state. The step-by-step displacement procedures must address the following:

(1) Number and type of independent barriers, as described in § 250.420(b)(3), that are in place for each flow path that requires such barriers

(2) Tests you will conduct to ensure integrity of independent barriers

(3) BOP procedures you will use while displacing kill weight fluids

(4) Procedures you will use to monitor the volumes and rates of fluids entering and leaving the wellbore [20].

3.1.1.9 BS EN ISO 14224: 2006 – Petroleum, Petrochemical, and Natural Gas Industries – Collection and Exchange of Reliability and Maintenance Data for Equipment. [21]

This standard provides a comprehensive basis for the collection of Reliability and Maintenance (RM) data in a standard format for equipment in all facilities and operations within the petroleum, natural gas, and petrochemical industries during the operational lifecycle of the equipment. This international standard also describes data quality control and assurance practices to provide guidance for the user.

3.1.1.10 BS EN ISO 13628-4: 2010 – Petroleum and Natural Gas Industries – Design and Operation of Subsea Production Systems – Part 4: Subsea Wellhead and Tree Equipment [22]

This standard provides specifications for subsea production equipment such as subsea wellheads, mud line wellheads, drill-through mud line wellheads, and vertical and horizontal subsea trees. It also specifies the associated tooling necessary to handle, test, and install the equipment. Additionally, it specifies the areas of design, material, welding, quality control (including factory acceptance testing), marking, storing, and shipping for both individual sub-assemblies (used to build complete subsea tree assemblies) and complete subsea tree assemblies.

3.1.2 API Specifications

3.1.2.1 API Specification 16A: Third Edition, 2004/ISO 13533 – Specification for Drill-through Equipment [23]

This standard provides requirements for performance, design, materials, testing and inspection, welding, marking, handling, storing, and shipping of drill-through equipment used for oil and gas drilling. It also defines service conditions in terms of the pressure, temperature, and wellbore fluids for which the equipment will be designed. This standard establishes requirements for the following specific equipment: ram BOPs, ram blocks, packers and top seals, annular BOPs, annular packing units, hydraulic connectors, drilling spools, adapters, loose connections, and clamps. This standard does not apply to field use or field testing of drill-through equipment.

3.1.2.2 API Specification 6A: Twentieth Edition, 2011/ISO 10423 – Specification for Wellhead and Christmas Tree Equipment [24]

This standard is a comparison of the original 2010 edition and the 2014 edition; it is not inclusive of the current edition. This document specifies requirements and gives recommendations for the performance, dimensional and functional interchangeability, design, materials, testing, inspection, welding, marking, handling, storing, shipment, purchasing, repair, and remanufacture of wellhead and Christmas tree equipment for use in the petroleum and natural gas industries. This document does not apply to field use, field testing, or field repair of wellhead and Christmas tree equipment. The Surface Safety Valve (SSV) and Underwater Safety Valve (USV) design, manufacture, and testing criteria are specified.

3.1.2.3 API Specification 16C: First Edition, 2010 – Choke and Kill Systems [25]

This standard provides for safe and functionally interchangeable surface and subsea choke and kill systems equipment that is used for drilling and gas wells. Other parts of the choke and kill system, which are not specifically addressed in this document, must be used in accordance with the applicable sections of this specification. The technical content of this document provides the minimum requirements for performance, design, materials, welding, testing, inspection, storing, and shipping.

3.1.2.4 API Specification 16D: Second Edition, 2005 – Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment [26]

This standard establishes design standards for systems that are used to control BOPs and the associated valves that control well pressure during drilling operations. The design standards, which are applicable to sub-systems and components, do not include material selection and manufacturing process details. The manufacturer specifies which material to use, depending on the particular application. Although diverters are not considered well control devices, their controls are often incorporated as part of the BOP Control system.

3.1.2.5 API Specification 16RCD: First Edition, 2005 – Drill Through Equipment – Rotating Control Devices [27]

This standard provides design standards for the availability of safe and functionally interchangeable Rotating Control Devices (RCDs) that are used in air drilling, drilling operations for oil and gas, and geothermal drilling operations. This standard provides requirements for design, performance, materials, tests and inspection, welding, marking, handling, storing, and shipping. This specification does not apply to field use or field testing of RCDs. Critical components are those parts that have specified requirements in this document.

3.1.2.6 API Specification 16F: First Edition, 2004 – Specifications for Marine Drilling Riser Equipment [28]

This standard provides standards of performance and quality for the design, manufacture, and fabrication of marine drilling riser equipment used in conjunction with a subsea BOP stack. This specification covers the following major sub-systems in the marine drilling riser system: riser tensioner equipment; flex/ball joints; choke, kill, and auxiliary lines; drape hoses and jumper lines for flex/ball joints; telescopic joints (slip joint) and tensioner rings; riser joints; riser running equipment; special riser system components; and lower riser adapters.

3.1.2.7 API Specification 16R: First Edition, 2010 – Specification for Marine Drilling Riser Couplings/ISO 13625 Marine Drilling Riser Couplings [29]

This specification covers the design, rating, manufacturing, and testing of marine driller riser couplings. Coupling capacity ratings have been established to enable the grouping of coupling models according to their maximum stresses developed under specific levels of loading, regardless of manufacturer or fabrication method. This specification relates directly to API 16Q, which covers the design, selection, and operation of the marine drilling riser system as a whole.

3.1.2.8 Notice to Lessee No. 2008-G07 [30]

The purpose of this document, which expired on June 15, 2013, was to promote planning and provide an approval process before the MPD equipment and specific procedures for wells with surface BOPs were implemented. While subsea BOPs are referenced within this document, the main focus of the document is surface BOPs.

30 CFR 250.401(e), 30 CFR 250.408, and 30 CFR 414(h), which are all referenced in this Notice to Lessee (NTL), need to be reviewed to include approved current industry procedures and any recommendations. MPD procedures and equipment can be approved under 30 CFR 250.408 only if safety and environmental protection requirements are satisfied.

3.1.2.9 API Specification 53: Fourth Edition, 2012 – Blowout Prevention Equipment Systems for Drilling Wells [31]

The purpose of this standard is to provide requirements for the installation and testing of blowout prevention equipment systems on land and marine drilling rigs (barge, platform, bottom-supported, and floating). This standard provides some guidelines on flow detection by stating the need for a trip tank, a Pit Volume Totalizer (PVT) system, and a return line flow sensor. The trip tank may be of any shape as long as there is capability to read small fluid changes. The PVT measuring system is used to monitor while circulating by measuring the total volume of drilling fluid in the tanks. The standard also specifies that a flow rate sensor must be affixed to the return flowline for early indication of fluid gains or losses. Guidance on which specific sensor should be used is lacking.

3.1.3 API Recommended Practices

The RPs in the following sub-sections cover the topics of design, operations, maintenance, inspection, rerating of well control, and pressure vessel equipment. These RPs provide a basis for the existing well control equipment and help in determining the requirements for future additions to well control equipment to improve kick detection and automated well safety.

3.1.3.1 API RP 59: Second Edition, 2012 – Well Control Operations [32]

The purpose of this RP is to provide information that can serve as a voluntary industry guide for safe well control operations. This publication is designed to serve as a direct field aid in well control and as a technical source for teaching well control principles. Additionally, this publication establishes recommended operations to retain pressure control of the well under pre-kick conditions and recommended practices to be used during a kick. It serves as a companion to API RP 53 – RP for Blowout Prevention Equipment Systems for Drilling Wells and API RP 64 – RP for Diverter Systems Equipment and Operations.

3.1.3.2 API RP 64: Second Edition, 2012 – Diverter Systems Equipment and Operations [33]

This RP covers surface and subsea diverter systems and components, including design; controls; operating procedures; and maintenance for land, bottom-supported offshore, and floating offshore installations.

3.1.3.3 API RP 16 ST: First Edition, 2009 – Coiled Tubing Well Control Equipment Systems [34]

This RP addresses coiled tubing well control equipment assembly and operation as they relate to well control practices. Industry practices for performing well control operations using fluids for hydrostatic pressure balance are not addressed in this RP. This document covers well control equipment assembly and operation used in coiled tubing intervention and coiled tubing drilling applications performed through:

- Christmas trees constructed in accordance with API 6A or API 11IW or both.
- A surface flow head or surface test tree constructed in accordance with API 6A.
- Drill pipe or work strings with connections manufactured in accordance with API 7 or API 5CT or both.

API RP 16 ST is fully dedicated to coil tubing and includes more specific details than NORSOK D-002, which contains only one section about coil tubing.

3.1.3.4 API Specification 510: Tenth Edition, 2014 – Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration [35]

This inspection code covers the in-service inspection, repair, alteration, and rerating activities for pressure vessels and the pressure-relieving devices that protect these vessels. This inspection code applies to all hydrocarbon and chemical process vessels that are placed in service unless specifically excluded according to Section 1.2.2 in the standard. However, the inspection code can also be applied to process vessels in other industries at the discretion of the owner/user. These vessels include:

- Vessels constructed in accordance with an applicable construction code (for example, American Society of Mechanical Engineers [ASME] Boiler and Pressure Vessel Code [ASME Code]).
- Vessels constructed without a construction code (non-code vessels) – vessels that are not fabricated to a recognized construction code and meet no known recognized standard.
- Vessels constructed and approved according to special acceptance of particular design, fabrication, inspection, testing, and installation standards.
- Nonstandard vessels – vessels that are fabricated to a recognized construction code but have lost their nameplates or stamping.

Vessels that have been officially retired from service and abandoned in place (that is, no longer an asset of record from a financial or accounting standpoint) are no longer covered by this 'in-service inspection' code.

The ASME Code and other recognized construction codes are written for new construction; however, most of the technical requirements for design, welding, non-destructive examination, and materials can be applied to the inspection, rerating, repair, and alteration of in-service pressure vessels.

3.1.3.5 API RP 572: Third Edition, 2009 – Inspection of Pressure Vessels [36]

This RP covers the inspection of pressure vessels. It includes a description of the various types of pressure vessels (including pressure vessels with a design pressure less than 15 psig) and the standards for their construction and maintenance. API RP 572 also includes reasons for inspection, causes of deterioration, frequency and methods of inspection, methods of repair, and preparation of records and reports. The inspection of the pressure vessel determines its physical condition, which determines the types and causes of failure mechanisms. Documenting detailed failure information contributes to the planning of future inspections, repairs, and replacements and creates a case history that can form the basis of a risk-based inspection assessment.

3.1.3.6 API RP 576: Third Edition, 2009 – Inspection of Pressure Relieving Devices [37]

This RP describes the inspection and repair practices for automatic pressure-relieving devices commonly used in the oil and petrochemical industries. This publication covers such automatic devices as pressure relief valves, pilot-operated pressure relief valves, rupture disks, and weight-loaded pressure vacuum vents. This publication does not cover weak seams or sections in tanks, explosion doors, fusible plugs, control valves, and other devices that either depend on an external source of power for operation or are manually operated. This publication does not cover training requirements for mechanics involved in the inspection and repair of pressure relieving devices. Anyone seeking these requirements should see API 510, which gives the requirements for a quality Control system and specifies that the repair organization must maintain and document a training program which ensures that personnel are qualified.

3.2 Industry Survey

Multiple surveys were sent to hardware manufacturers, MWD and LWD manufacturers, and Operators. Appendix A includes two responses from hardware manufacturers for automation and EKD equipment that were obtained during the course of the project.

Some notable points that came from the survey responses are:

- Deployed automation- and EKDS-related equipment almost always contributes to safety.
- Automation may compromise safety through lack of Operator training and competence, using equipment outside its design rage, and using systems that have been developed without proper design and validation testing, and lapses in data communication.
- There is a need for supervised automation with manual override capabilities.
- Many research projects are underway by Original Equipment Manufacturers (OEMs) for automation and EKDS.
- Equipment manufacturers regularly perform reliability analysis and related testing.
- The industry is combining automation and EKD with MPD technology.

Note that because only two responses were obtained among all the surveys that were sent, the survey responses are not statistically significant. Therefore, any conclusion drawn from the survey responses should be viewed in light of this limitation.

3.3 Fluid System Monitoring

In drilling operations, the fluid system is the first barrier preventing the ingress of formation fluid into the well, which can lead to potential loss of well control. The two most important aspects of well control are the pressure and fluid system monitoring. Pressure monitoring is important because if pressure is maintained above formation pressure, LOWC will not occur. The fluid system is important because the mud weight or completion fluid weight is used to maintain the hydrostatic column above the formation pressure. Drillers often believe that maintaining the topped off mud level is enough, but in reality, an appropriate mud weight is not maintained by simply topping off the mud column.

As discussed previously, some of the most reliable signs of an influx can be observed because of the changes to the fluid system. Automation of fluid system monitoring is instrumental to improving the reliability of kick detection in conventional drilling operations. Moving from manual fluid monitoring to automated fluid monitoring reduces the human error, which improves the reliability of detecting kicks. Some fluid system monitoring can be conducted by using Flow Out and Pit Volume sensors as described in Sections 3.3.1 and 3.3.2. Most of the flow detection systems are used in conjunction with each other. A summary of the advantages and disadvantages of the Flow Detection Systems is shown in Table 3-1.

Table 3-1: Summary of Flow Detection Systems

Equipment	Description	Type of Rig	Advantages	Disadvantages
Flow Out Sensors	Paddle-type measures from a return flowline (annulus) caused by the rotation of the paddle. Various paddle sizes are available to suit the different flowlines.	Jack-up, Floater	This very simple design has been used in the market for decades.	Measurements are very unreliable. The errors in the measurements can be as high as 40% on an uncalibrated paddle flowmeter. A calibrated paddle meter is accurate only up to 10 to 15%.
Pit Volume Sensors	Some of the sensors are ultrasonic, radar, floatation, optical, and pressure sensors.	Jack-up, Floater	Robust, reliable, field-proven design	Rig heave effects (up and down motion of the rig) can lead to false readings.

Equipment	Description	Type of Rig	Advantages	Disadvantages
Mud Logger	Pump stroke counters, gas detected from mud. Monitor returning drilling fluids for indications of hydrocarbons.	Jack-up, Floater	Simple and reliable	Manual operation can be prone to human error.
Drill/Stand Pipe Pressure	Provides a direct hydraulic connection to the bottomhole conditions.	Jack-up, Floater	Provides valuable information for kick detection and well control. A change in drill pipe pressure can indicate washouts in the drill pipe, plugged bit nozzles, condition of the downhole motor (if used), etc.	It is difficult to interpret kicks by looking at the drill pipe pressure alone because of the multiple factors that can affect the pressure.
Smart Flow Back Fingerprinting	The return flow tends to have a certain repeatable flow profile; flow profiles are collected and compared against each other, and base case flow is determined.	Jack-up, Floater	Can detect flowbacks from the annulus exceeding normal volumes in real time without human intervention by minimizing false alarms.	Need good return flow data to make accurate detection.
MWD	LWD, PWD	Jack-up, Floater	Bottomhole temperature, pressure, and flow rate can be monitored and transmitted to the surface in real time.	When there is a low flow rate during well control, the data is not transferred to the surface, which leads to MWD running blind.
Wired Drill Pipe	Transmission system	Jack-up, Floater	High data transmission rate up to 57,600 bits/sec, downhole data is transmitted to the surface even when the pumps are off. This allows for detection of kicks in the wellbore even during making connection when the pumps are off.	Emerging technology, doubles the costs of regular drill pipe. Operator has to work with the MWD provider, Rig Contractor, and other third parties whose equipment is affected to be fully involved and aligned to implement this system.

3.3.1 Flow Out Sensors

The flow out sensor provides an early indication of a sudden increase in flow rate (kick scenario) or a decrease in flow rate (loss of circulation). The paddle-type flow out sensor, which measures the flow rate from a return flowline (annulus) caused by the rotation of the paddle, is normally used. Various paddle sizes are available to suit the different flowlines.

Flow out sensor measurements are generally unreliable. Paddle-type flowmeters interfere with the mud flow, and its measurements vary, depending on the fluid density, viscosity, and level in the flow return line. Measurement errors can be as high as 40% on an uncalibrated paddle flowmeter. A calibrated paddle meter measurement is only up to 10 to 15% accurate [38].

3.3.2 Pit Volume Sensors

The pit (mud/fluid tank) monitoring system uses a sensor to monitor individual pits (refer to Figure 3-2). The most current sensor technologies (for example, ultrasonic, radar, floatation, optical, pressure sensors) can be used for specific applications. Any combination of mud pits can be assigned as being ‘active’ by operating the pits’ selector switches. The sensor technologies calculate the total volume of mud in the active pits and display it on an easy-to-read analog gauge. A second gauge continuously displays the gain or loss of mud from the active total, making the drill crew aware of the prevailing well conditions.

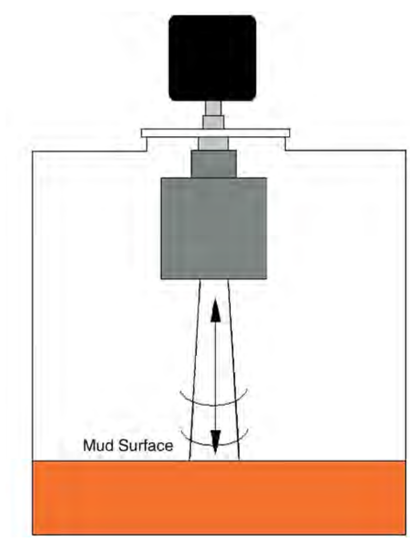

Figure 3-2: Pit Monitor Sensor [39]

Computerized systems allow flexibility in defining the active and reserve pit systems. The configuration can be changed quickly through the keyboard. Alarms are computer controlled and can be set up for low and high levels on the active system, the reserve system, or individual pits. The system can monitor up to 16 pits. On trips, the gain tanks and trip tanks are also assigned through the trip monitoring program for complete coverage of the pit system. The expected flow back gain encountered at various pump rates is entered during drill pipe connections. The system can correct for an alarm if unexpected changes occur during the connection. The pit monitoring system is very robust and has been field proven for years as the simplest and one of the most commonly used of pit measurement systems under normal situations. However, the rig heave effects (up and down motion of the rig) can lead to false readings with this method.

3.3.3 Mud Logger

Mud logging personnel continuously monitor returning drilling fluids for indications of hydrocarbons using both a hot wire and a gas chromatograph. An abrupt increase in the gas or oil carried in the returning fluid can be an indication of an impending kick. The mud logger also monitors the drill cuttings that are returned to the surface in the drilling fluid for changes in lithology, which can be an indicator that the well has penetrated or is about to penetrate a hydrocarbon-bearing interval. This process currently relies heavily on mud logger personnel to manually collect and evaluate samples; however, the results can be uploaded to a live mud log that can be continuously monitored by rig personnel. Although very limited in scope, this automated communication facilitates faster recognition of potentially hazardous drilling situations and increases well safety.

The mud log may also have an automated feed to the surface sensors. The variety of available sensors depends on the application and the rig. It is possible to automate monitoring for hook position, hook load, drill string torque, rotary speed, pump rate, return flow rates, pit volumes, and stand pipe pressures. From these surface parameters, software can calculate drilling parameters, such as rate of penetration, to provide an early indication of drilling breaks, which can indicate that the bit may be penetrating a hydrocarbon.

Additional available mud monitoring systems are:

- Pump stroke counters – These are mechanical sensors used on each mud pump to monitor the number of strokes and the stroke rate. They help calculate the volume and rate of fluid being pumped into the wellbore. Pump stroke counters may be used to monitor pressure based on the pump type, flow rate, and location within the wellbore, as well as whether the pump is applied with an open or closed system.

- Gas detection sensors – Gas is detected from the sensor located on the shale shaker header box by detecting the increase in gas levels in the mud. The mud returning from the well is directed to the shale shaker, where it is processed.

3.3.4 Drill/Stand Pipe Pressure

The drill pipe or stand pipe pressure is the measurement of the fluids inside the drill pipe. Drill pipe/stand pipe pressure provides a direct hydraulic connection to the bottomhole conditions. Unlike the annulus, where an influx may compromise hydrostatic calculations, the drill pipe is always filled with a known fluid. Drill pipe/stand pipe is critical in well control operations, where maintenance of BHP is essential. Additionally, should bottomhole conditions change as a result of an influx, corresponding changes to stand pipe pressure may be observed.

Although stand pipe pressure can provide valuable information for kick detection and well control, variations in drill pipe pressure may not be caused by influxes alone. A change in drill pipe pressure can indicate washouts in the drill pipe, plugged bit nozzles, the condition of the downhole motor (if used), etc. It is difficult to interpret kicks by looking at the drill pipe pressure alone because of the multiple factors that can affect the pressure, so any sudden changes in drill pipe pressure should be investigated further. Automated monitoring and logging of stand pipe pressure can assist in this process, thereby removing the human error in deciphering the detection of kick.

3.3.5 Smart Flowback Fingerprinting

When the pumps are turned off during drill pipe connections, the pressure conditions of the drilling fluid reduce significantly, which can result in decompression of the fluid and a flow back to the mud pits. The resulting increase in pit volume can be confused with and/or potentially obscure the early signs of an influx. This is particularly critical because of the loss of annular friction when the pumps are off. This masking fluid behavior coincides with the period when a kick is most likely to occur [40].

Currently, the manual alarm system relies heavily on the experience of the rig personnel to detect kicks and lost circulation in this scenario. The rig personnel undergo well control training and should also have equipment-specific training and experience.

Automated fingerprinting of connections has been developed to detect well kicks and a lost circulation scenario faster than the manual alerting methods [34]. This process uses sensors to monitor trends in a variety of surface parameters, such as pump rate and pit volumes, to determine the 'fingerprint' of a typical connection. The basic form of fingerprinting is widely used in the drilling industry.

In drilling, the annulus return flow tends to have a certain repeatable flow profile. These repeatable flow patterns are collected and compared against each other, and base case flow is determined (flowback fingerprinting). Smart flowback fingerprinting is designed to detect flowbacks from the annulus that exceed normal volumes in real time without human intervention.

Wellbore breathing can be identified by flowback monitoring. Based on previous flowback profiles, the system automatically generates threshold and alarm curves based on statistical analysis. Currently available systems have taken into account some factors such as flowback exclusion, which are instances where pumps were turned off briefly or were operating at a low rate. New algorithms have been developed to account for rig heave on the surface pits being measured to avoid false alarms at the beginning of the flowback cycle.

Video cameras are placed on multiple areas, including the rig and flowlines, for monitoring purposes. The flowline camera can be used to visually monitor flow rate to the pits. All of the collected data is displayed on customized screens, which consist of real time numerical data; historical trend lines; and features such as tables, charts, and graphs (Figure 3-3).

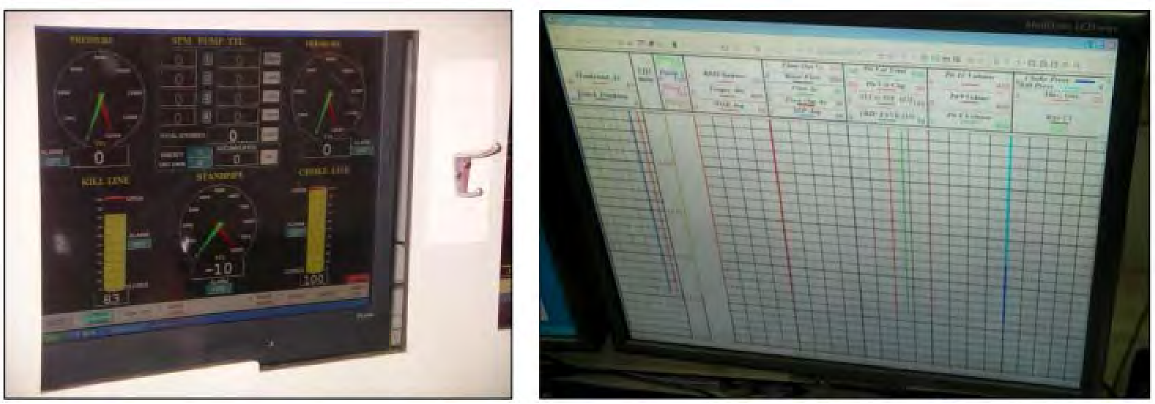

Figure 3-3: Live Data Presented on Screen [41]

All of the monitoring systems have options to set and adjust visual and audible alarms for multiple data parameters such as pit gain, flow out, and drill pipe pressure. The alarms can be set manually to activate whenever the incoming data crosses preselected high and low thresholds. These alarms can also be turned off completely.

3.3.6 Automation in Bottomhole Assembly Tools

Various automation tools are used as part of the standard Bottomhole Assembly (BHA) to capture real time drilling data. Some of these tools are described in the following sub-sections.

3.3.6.1 Measurement While Drilling and Logging While Drilling Tools

MWD tools are downhole electro-mechanical measurement tools that are part of the standard drilling BHA, and they are very effective in guiding the drill bit to the target pay zone. MWD is specifically used for [42]:

- Acquisition and collection of wellbore deviation directional surveys.
- Acquisition and collection of drilling mechanics data such as downhole torque, pressure, and vibration.
- Real time transmission of data to the surface for operational decision making.

Other applications of MWD that help in well control are accurate downhole measurement of BHP using the Pressure While Drilling (PWD) tool. This is covered in detail in Section 3.3.6.3.

LWD tools provide petrophysical data such as porosity, resistivity, density, and gamma ray.

A major drawback with using MWD/LWD is that the signal transmission requires a minimum fluid flow rate. This means that at low flow rates (some of the tools need a minimum flow rate of 130 gallons per minute or more), the data may not be received at the surface in real time. Furthermore, there is no data transmission during connections and when the pumps are turned off [40].

LWD tools have downhole memory sections, so all LWD measured data can be downloaded after the LWD tools are pulled out of the hole back to surface and removed from the drill string [43, 44].

The electronic sensors and batteries in the MWD/LWD tools are packaged in the housing in such a way that they do not impede the high flow rates that occur during drilling. Real time MWD/LWD information can immediately define well placement with respect to the known formation characteristics and can assist in predicting drilling hazards.

A detailed description of the MWD/LWD tools is provided in Section 4.1.2.

3.3.6.2 Wired Drill Pipe

Existing MWD/LWD sensors are capable of measuring a large amount of formation data. However, these sensor measurements cannot be used to their full advantage because the technology of mud pulse telemetry can only provide low data transmission rates to surface, and there is a time lag between when the mud pulse is generated downhole and the time the mud pulse reaches the surface.

Wired drill pipe, which provides an alternative to mud pulse telemetry [46], has very high bandwidth and thus allows a large amount of data to be transmitted quickly to surface while drilling. The Wired Drill Pipe system incorporates an embedded high strength coaxial cable and low-loss inductive coils, which are inserted during manufacture in each drill pipe joint. A cross-section of wired drill pipe featuring the armored coaxial cable design is shown in Figure 3-4.

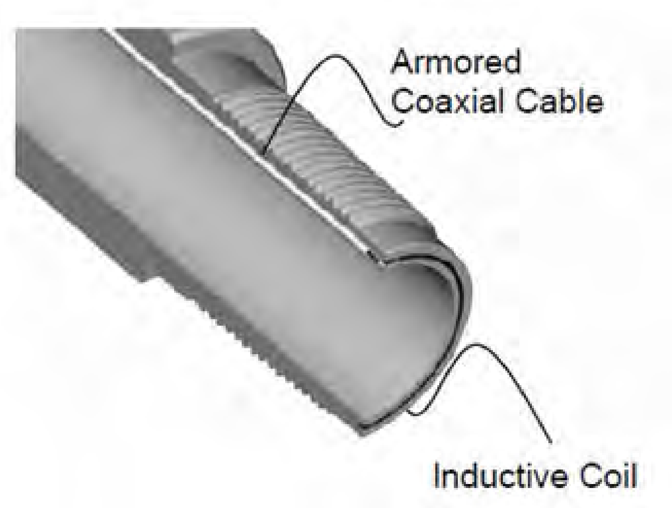

Figure 3-4: Wired Drill Pipe with Armored Coaxial Cable Design [46]

A cross section of a wired drill pipe is shown in Figure 3-5.

Figure 3-5: Wired Pipe [47]

To implement this system, the Operator must work with the MWD provider, the Rig Contractor, and other third parties whose equipment is affected so that they are fully involved and aligned [48]. Two of the Operators who have used this technology are BP and Statoil.

Some rig equipment, such as the top drive, will require modification to adapt to the wired drill pipe. One Operator noted that the wired drill pipe was generally reliable, and network uptimes were approximately 90 to 100% [48]. Durability issues were caused by the drill pipe connection and material problems, such as corrosion of the steel flares (the component that is embedded within the tool joint and connects the coil to the coaxial cable), downhole overtorquing of connections, and damage to coils caused by pipe handling [48]. A total of 150 wells have been drilled using wired drill pipe. Development wells where many wells are drilled from a single rig are normally good candidates for this technology.

BP has successfully deployed the wired drill pipe in 16 wells in diverse locations such as Wyoming, Deep Water GOM, North Sea, Trinidad, and Colombia [49]. Some of the drilling conditions and challenges faced during deployment were wellbore stability, hole cleaning, BHA vibrations, formation pressure measurements in depleted zones, complex geology, and challenging directional scenarios.

A detailed description of the wired drill pipe system is provided in Section 4.1.3.

3.3.6.3 Pressure While Drilling

PWD (also Annular Pressure Drilling) tools are other MWD tools that use high-accuracy quartz pressure gauges to measure annular and wellbore pressure. PWD systems can be used to:

- Enable highly accurate measurement of small pressure changes.
- Monitor and avoid pressure swabs and surges while tripping and reaming.
- Detect kicks and shallow water flows.
- Monitor Equivalent Circulation Density (ECD) and make sure it remains within safe operating limits [44].
- Monitor hole cleaning.
- Make sure annular pressure is less than the reservoir flow pressure in underbalanced drilling. (BSEE's regulations do not currently allow underbalanced drilling without special approval.)
- Monitor pressure drops across the downhole motor and drill bit.
- Minimize formation fracturing and the resulting mud loss.
- Reduce wellbore instability.
- Avoid annular pressure build-up, especially in deep water environments.
- Provide early detection of pipe washouts.
- Provide kick detection, including shallow water flows.
- Enable accurate downhole measurement of hydrostatic pressure and effective mud weight (only applicable when the pumps are off and no surface pressure is applied).
- Provide accurate Leak-off Test (LOT) and Formation Integrity Test (FIT) data without circulating to condition the mud [45].

Real time BHP can be compared to the prediction of pore pressure and fracture gradient to ensure that the BHP remains inside the drilling window. PWD tools can monitor the wellbore continuously, even when there is no flow in the well during operations (such as LOT when the pumps are shut down). However, the data is not transmitted to the surface unless the pumps are on.

When the BHP increases, it often shows that the cuttings have not been removed effectively and the hole has not been cleaned properly. Either of these scenarios can lead to lost circulation. If the annular pressure increase is detected in real time, drilling fluid parameters and operating procedures can be modified to improve hole cleaning. Figure 3-6 shows a multi-function tool that has numerous capabilities, including the capabilities of the LWD and PWD tools.

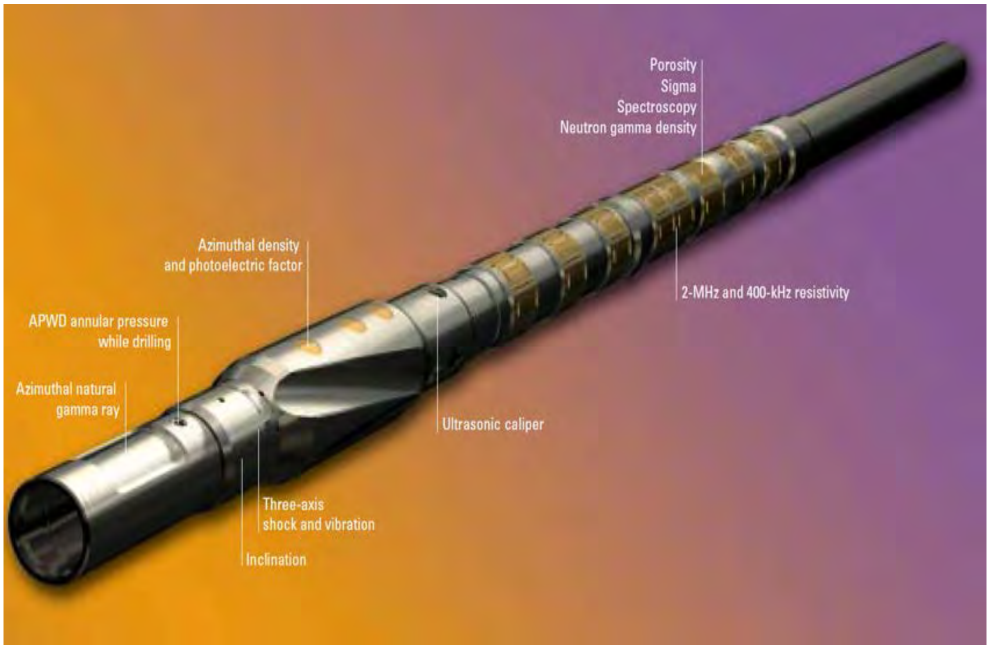

Figure 3-6: Example of Multi-function BHA Tool [44]

3.4 Automation in Drilling

The highest frequency of LOWC incidents occurs during drilling operation, with approximately three incidents per 1,000 wells drilled from 1980 to 2011 [2]. Apart from drilling, intervention (workover) is the leading area for LOWC. Table 3-2 shows the frequency of LOWC incidences in drilling, production, and interventions across five regions, including the OCS. However, interventions at approximately 0.3 LOWC incidents per 1,000 wells have roughly three times the frequency of events during production at approximately 0.1 LOWC incident per 1,000 wells (GOM figures) [2]. Note that most wells take less than a year to drill. Therefore, the use of 'per 1000 wells drilled' for the drilling frequency is diminished from what it would be if a similar time-based denominator were used. It should be noted that in Table 3-2, LOWC duration values give the percentage of the chance that an LOWC incident will cease within the time given in each case.

For the Pacific OCS, there is limited availability of drilling LOWC incident data. Pacific OCS drilling operations have a very low frequency of LOWC incidents, with approximately 0.00134 incidents per well for a total of 875 wells drilled between 1980 and 2011 [2]. There is no publicly available LOWC incidents data for the Alaska OCS.

Automation of drilling system monitoring is instrumental in increasing the reliability of kick detection in drilling operations. However, automation is still an emerging technology in the drilling industry. Until the technology is proven and reliable, the drilling industry will not be comfortable using it.

Table 3-2: Summary of Principal LOWC Parameters for Key Region [2]

REGION	EXPOSURE		LOWC FREQUENCY			LOWC DURATION	
	Drilling	Production	Drilling	Production	Interventions	50 % stopped	90 % stopped
	wells drilled	well-years	per 1000 wells drilled	per 1000 well-years	per 1000 well-years	minutes	days
U.S. GOM	31,574	197,721	3.45	0.106	0.314	200	8
North Sea	13,727	59,141	2.99	0.051	0.355	3	20
Holland	1,143	2,948	0	0.339	0.339	n/d*	n/d
Australia	2,559	9,589	1.56	0.104	0	n/d	n/d
Canada East Coast	679	3,955	2.95	0	0	n/d	n/d

* n/d = no data

3.4.1 Managed Pressure Drilling

MPD is an adaptive drilling process to control the annular pressure profile precisely throughout the well. The MPD concept is to maintain pressure within close tolerances and near the boundary of the operation envelope. One of the main MPD objectives is to reduce lost circulation and, therefore, to decrease the cost of mud and reduce a rig's Non-productive Time (NPT). MPD allows for EKD and enables reduced kick response time, which significantly reduces the risk of LOWC.

MPD has multiple types of automation influence. Automation in MPD is conducted by controlling the BHP by applying backpressure and choke control, both of which can be partly or fully automated [50]. Most suppliers use a feedback loop in which installed sensors monitor multiple controlled variables. The values from the signals received are transmitted to a feedback Control system, where a controller makes automatic determinations of deviations between the desired values and the actual values. Based on the values from the signals, the controller calculates any required choke adjustments, which are automatically transmitted to the choke.

The Human Machine Interface (HMI) is used to assist user friendly interaction and monitoring by accepting and processing user instructions and commands (Figure 3-7) [50]. The HMI allows the Driller to switch between different modes of automation during the drilling process, but it also provides the Driller the absolute authority of the operation, even when the Driller is using the automation mode. This gives the Driller the means to override the automation when necessary.

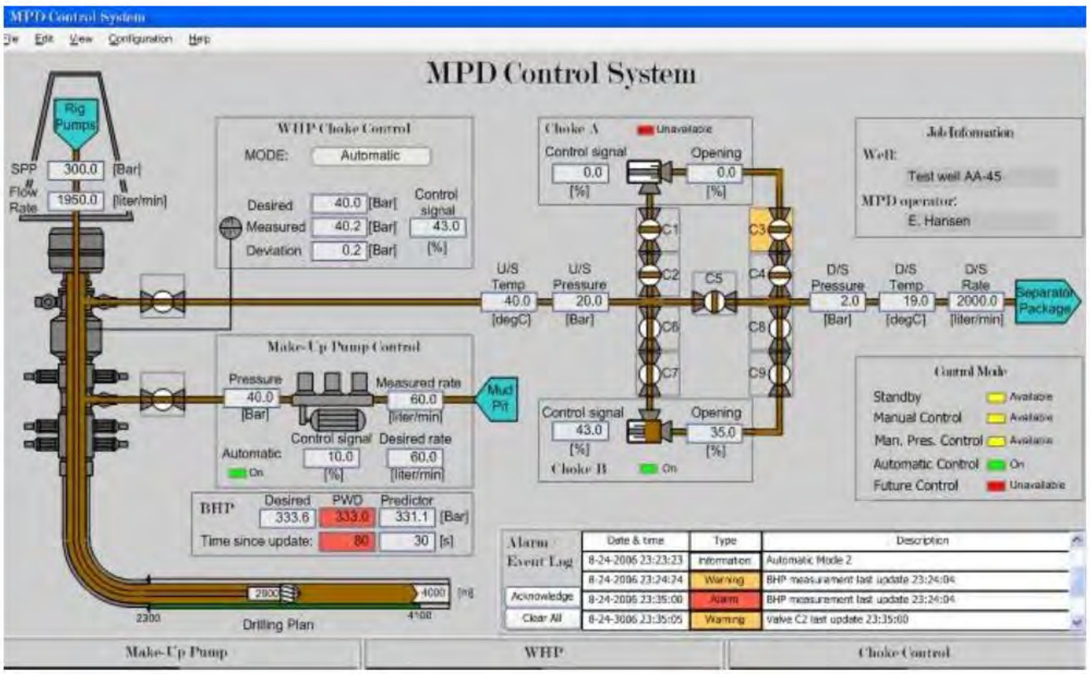

Figure 3-7: The Human Machine Interface [50]

3.4.2 Real Time Monitoring of Blowout Preventers

When a signal is transmitted from the drilling rig to the subsea BOP to execute a command, the BOP sends a message back that the signal has been received. However, there are typically no devices on the BOP to send a signal indicating that any command has been executed (such as pressure or displacement sensors confirming that hydraulics have been actuated or that rams have moved or pipe has been cut). There are no flow sensors to measure whether the well has been sealed.

The BOP monitoring system on a hydraulic BOP Control system comprises three sub-systems: data acquisition, data transfer, and data analysis and presentation (Figure 3-8 and Figure 3-9) [51]. Data acquisition is part of the Multiplex (MUX) BOP Control system [51]. The MUX system provides the control signal, electrical and hydraulic power, and communications to control various BOP functions.

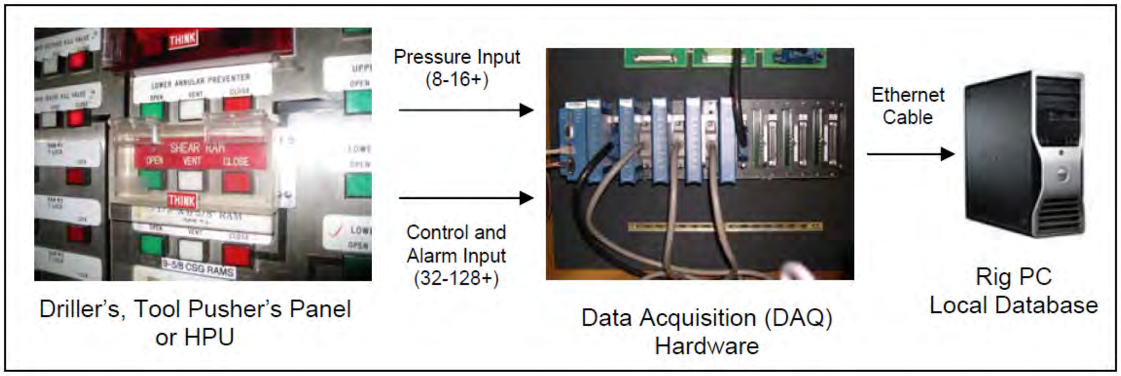

Figure 3-8: BOP Monitoring Data Acquisition System [51]

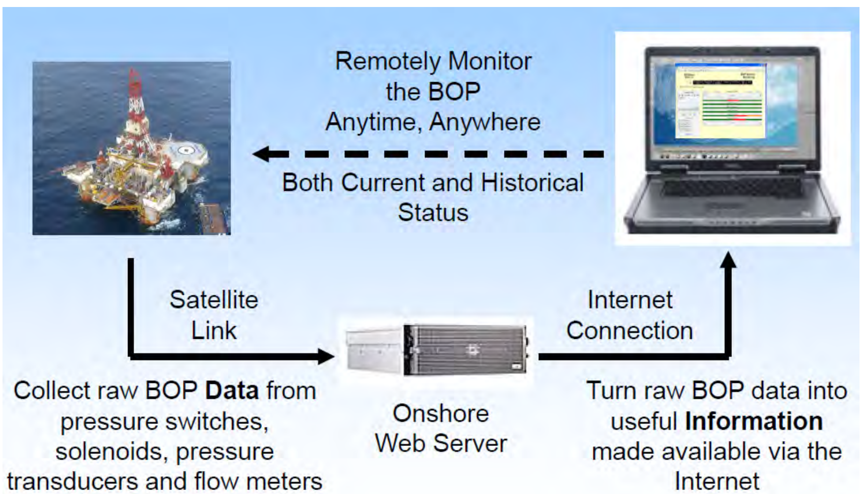

Figure 3-9: BOP Monitoring [51]

Significant technological advances have been made in the process of collection, transfer, analysis, and presentation of BOP Control systems. New systems have been developed that allow for a fully automatic collections mode with user friendly presentation, time logs, and graphs to allow for quick decision making.

These systems can automatically acquire the data and transfer it to an onshore facility. At the onshore facility, the data can be analyzed and converted into useful information and can be available for access anytime and anywhere through the internet. Many of the newer rigs are incorporating this technology.

The older generation BOPs do not have this technology, but they can be retrofitted to bring them up to the same level as the newer rigs. Multiple technologies are being developed for BOP monitoring. These technologies are discussed in the following sub-sections.

3.4.2.1 Rig Watcher

Ashford Technology has developed Rig Watcher™ for real time BOP monitoring. The software aids in proactive preventive maintenance and early identification of problems. The primary aim of this technology is to allow for remote monitoring of the BOP 24 hours a day, 7 days a week.

The main function of Rig Watcher is to allow for cycle maintenance, which helps in determining the useful life of the BOP components. As more data (such as pressure and flow versus time profile signature) is collected on the equipment, good metrics, which will aid in identifying potential equipment problems, can be developed [52].

The raw BOP data from the rig is collected from pressure switches, solenoids, pressure transducers, and flowmeters and is transferred to the rig computer. The data is then transferred (using the internet) to the onshore web server. The onshore server can receive multiple data simultaneously from different rigs through the internet. This helps in maintaining a BOP monitoring database for the entire rig fleet.

Having access to live monitoring data offers advantages such as [51]:

- Access to rig and BOP information anytime and anywhere.
- Monitored data presented in a user friendly web browser format.
- Monitoring of multiple rigs at one time by a Subject Matter Expert (SME) who is located onshore.

With the use of the Rig Watcher, the cycle report for all the valves associated with the BOP function can be tracked. The cycle report gives a clear picture of valve functional cycles and can monitor all valve pressures on the BOP (Figure 3-10 and Figure 3-11). Detailed daily summary reports for all the major BOP functions can be tracked.

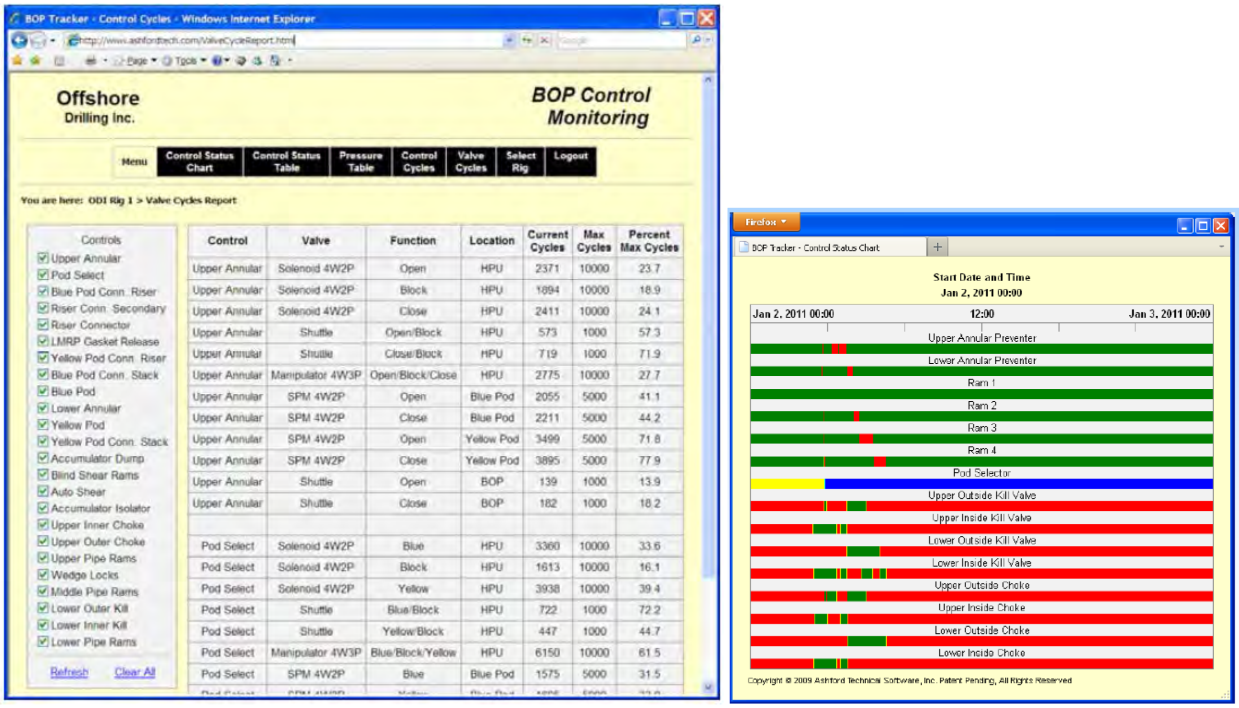

Figure 3-10: Daily Summary of All BOP Functions [51, 52]

Figure 3-11: Rig Pressure Report [51, 52]

Onshore personnel can simultaneously monitor multiple rigs in a fleet on a regular basis (Figure 3-12). Drilling Contractors can better predict preventive maintenance on their BOP equipment and can monitor and improve their offshore operations as better access to greater amounts of data becomes available. In addition, onshore personnel can provide expert guidance to the offshore personnel.

Because the Operators can access and monitor the BOP from onshore, they can oversee both the drilling and the safety of their operations.

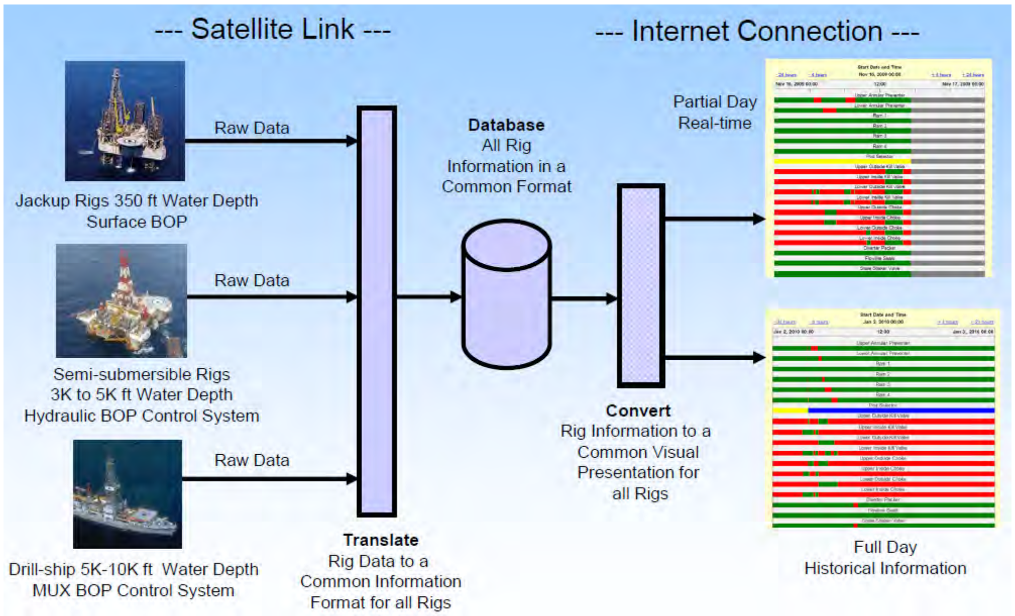

Figure 3-12: Multiple Rigs with Common Monitoring Display [52]

3.4.2.2 National Oilwell Varco BOP Dashboard System [53]

The main function of the BOP Dashboard System, which is an emerging technology, is to simplify complex BOP diagnostics in a graphical user interface format to enable the operation to easily assess any issues that may arise (Figure 3-13). Since early 2011, multiple companies have collaborated to develop the system, which takes existing alarms, analog data, and events from the BOP event logger and translates them into a high-level 'traffic light' status. The event logger records and monitors all BOP functions that are operated from the control panel. The traffic light, which shows the different levels of system redundancy, allows the user to understand and make decisions based on the failure of critical functions on the BOP. This system helps in determining how the critical components are functioning. It also allows the Drilling Contractor to predict a problem or the length of service life remaining on the component, which in turn allows the BOP to stay on the well without needing to be pulled out of the water for repairs or inspection [53].

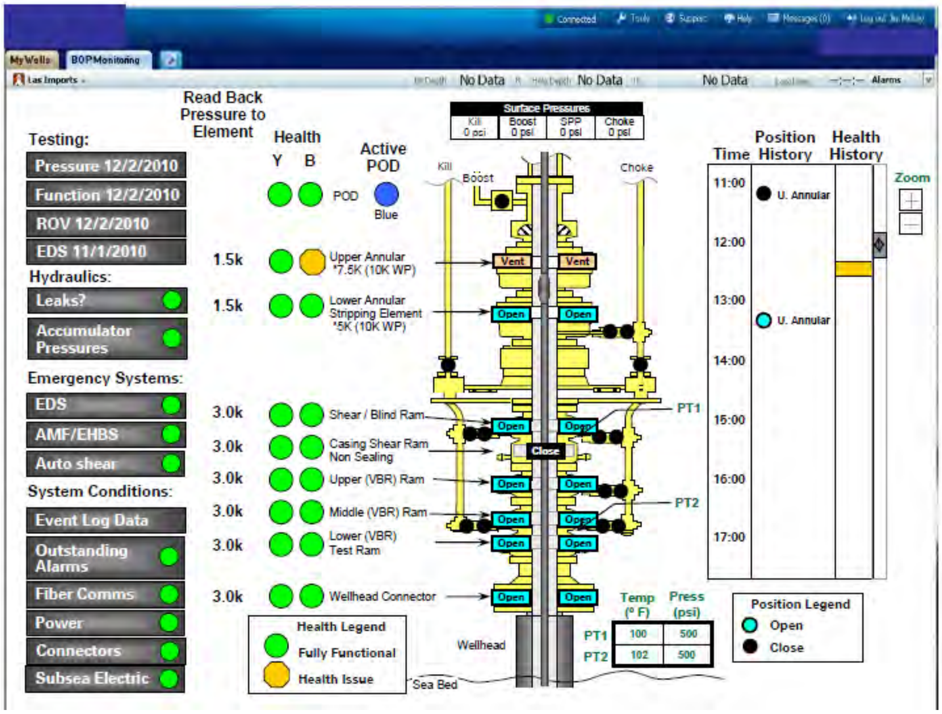

Figure 3-13: BOP Dashboard [53]

The primary diagnostic system on the rig is the event logger. The workflow process requires that the event logger be used to confirm with the BOP dashboard before making any decisions. Because not all alarms are equally important, the distinction between them must be made clear when using the dashboard system. System designs, scenario training, and operations must be coordinated and integrated as much as possible. By doing so, those personnel who are operating and monitoring drilling operations will understand and properly react to changing data and events. Perceiving, identifying, and interpreting data trends aid in setting alarm points for subsequent similar operations.

A decision tree protocol is being developed so that the operations teams can make standard operations decisions (Figure 3-14). This will remove any potential for subjective BOP health solutions. BP has been piloting the BOP dashboard system on the Ensco DS-4 drillship in Brazil with NOV and Ensco. BP's first installation in the GOM is planned on the Ensco DS-3 drillship [54].

BOP dashboard monitoring is a standard option on NOV’s fifth and sixth generation BOP stacks, and it is used on multiple rigs in the GOM.

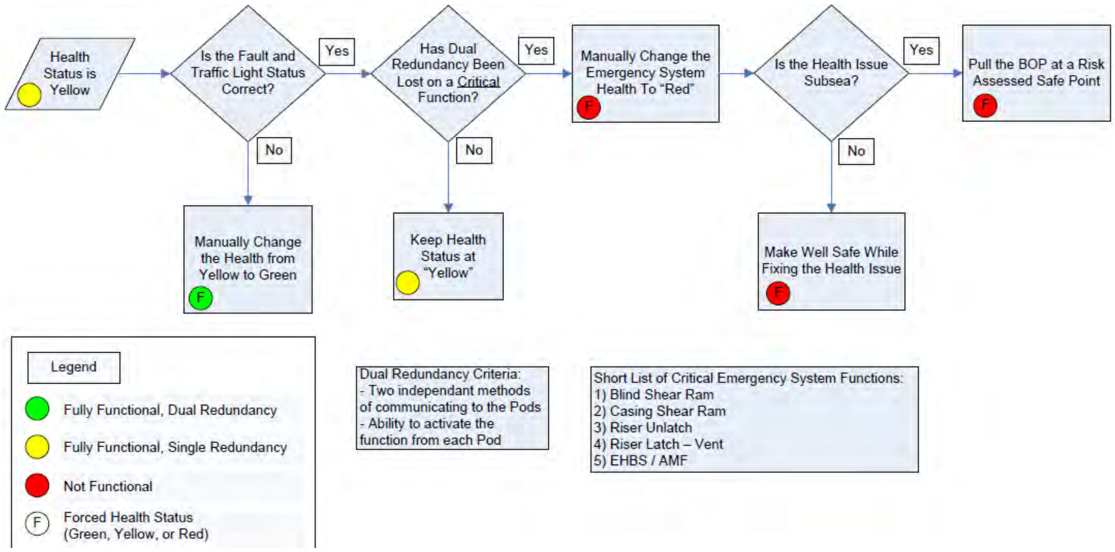

Figure 3-14: Operations Decision Tree [53]

3.4.3 Real Time Monitoring Center [55]

Operators must now address the 'big crew change,' which has resulted from the retirement of experienced rig personnel, who in turn are being replaced by younger, less experienced personnel. With new personnel being involved in the drilling operation and in detecting and handling kicks, EKD technology can improve operational safety. To resolve this issue, several companies, including Shell, BP, Talisman Energy, Halliburton, Baker Hughes, and many more have started Real Time Monitoring Centers (RTMCs), which provide monitoring of well parameters from an onshore location 24 hours a day, seven days a week (Figure 3-15). This capability has been designed to enhance the safety of deep water operations in a global environment. Having experienced personnel at the RTMCs to watch all the different rigs can significantly improve operational safety.

Figure 3-15: Houston Monitoring Center (HMC) [56]

The data that has been made available to the personnel at the RTMC allows for an extra pair of eyes to monitor well parameters. The monitoring center provides full-time monitoring of well parameters by specialists who have extensive experience in deep water operation combined with relevant key skills in wellbore monitoring. The center provides constant communication with offshore rig teams and real time data monitoring. The real time data includes flow in, flow out, standby pressure, mud weight, and mud logging data, which are major functions of the BOP (Figure 3-16).

The center also uses standardized processes and procedures that have been derived from best practices across all of the deep water fleet. The accountabilities are very clear within the RTMC, as the primary control of monitoring the well remains at all times with the offshore Driller. Processes and procedures for escalation if any observed parameters fall outside defined and agreed ranges are also in place.

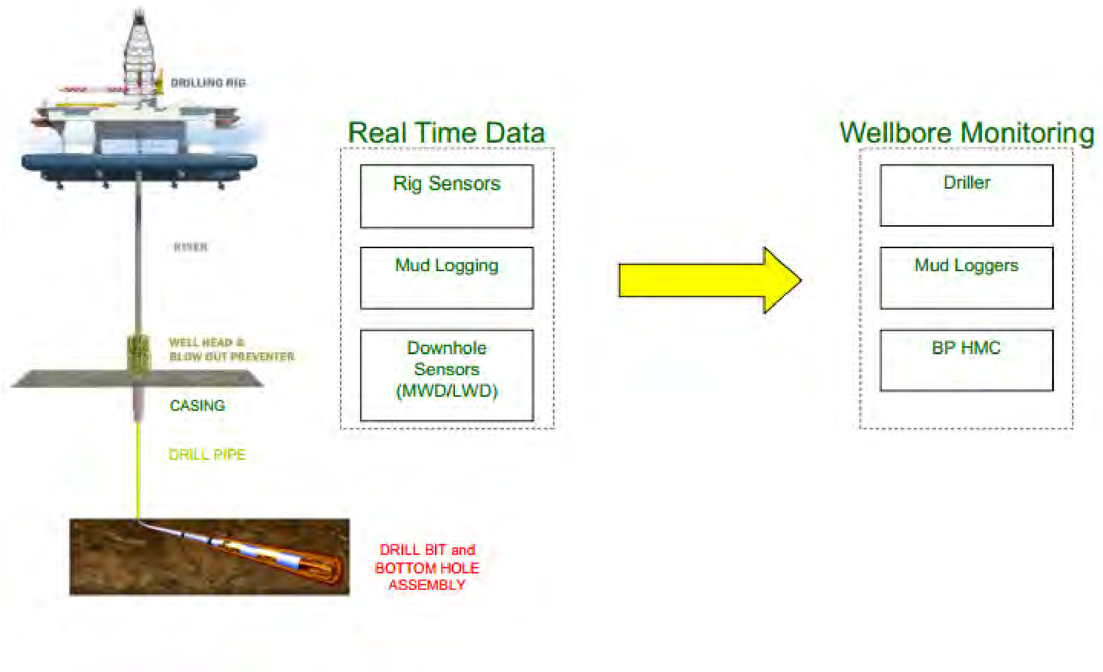

Figure 3-16: Real Time Data and Wellbore Monitoring Process [55]

Additional costs are required to set up the RTMC system and hire highly experienced personnel. All of the data from the offshore rig must be transmitted to the onshore facility, which also results in additional costs. One of the drawbacks of these systems is that they stretch Information Technology (IT) capacities. Such centers are vulnerable to network outages, and they require good management of infrastructure elements to ensure network reliability. Furthermore, procedures and personnel must be in place in the event of network outages so that when the monitoring system is down, operational decisions can still be made. Such problems can severely limit the reliance and therefore usefulness of these systems.

Sometimes the Driller on the rig has to work with an inexperienced crew in a very busy environment. Automation and real time monitoring systems will aid safe drilling operations while improving the quality and efficiency of the well construction process.

3.5 Automation in Completion and Workover

A production well requires monitoring and maintenance because of the changing well conditions. Workover or intervention operations are conducted by inserting tools in wellbores to conduct maintenance or remedial actions. (The terms ‘workover’ and ‘intervention’ are used interchangeably in the industry.)

As discussed in Section 3.4 of this document, intervention/workover operations have the second highest frequency of LOWC incidents after drilling, with 0.3 LOWC incidents per 1,000 wells. Automation is still an emerging technology in offshore completions and workovers, and reducing the number of interventions can have a significant impact on LOWC incidents.

In traditional wells, the only method for production management is through surface observations and operations (such as choke adjustments, gas lift adjustments). Any required changes to the downhole production profile, such as zonal shut-off/isolation, require an intervention. The objective of intelligent completions is downhole monitoring and finessing of production for optimal reservoir management. This can be accomplished through real time adjustments to inflow control devices from different completion zones. The impact on safety is the drive toward the 'intervention less' completion. When such intelligent well management capabilities can eliminate the need for costly interventions, the associated safety risks will be eliminated.

3.5.1 Permanent Downhole Gauges

Monitoring of downhole conditions such as temperature and pressure has been traditionally performed by using temporary memory gauges. The temporary memory gauges are not wired and therefore must be retrieved using intervention techniques such as wireline. Permanent downhole gauges provide access to live downhole data and have the potential to eliminate the requirement for costly and hazardous data gathering interventions. Alarms can be programmed to actuate when a predetermined limit is reached. This allows for automation of the production output.

The gauges are often installed as part of the casing or tubing pipe string with an electric cable strapped to the outside of the pipe string to surface. The cable provides power to both the permanent downhole gauge and the telemetry for the gauge sensor data transmission to the surface. In some instances, such as monitoring wells that are not hooked up for production (well test), or when gauges are required to be located in a lower completion assembly (precluding the use of cables), the gauges may be battery powered, which gives them a limited life. By permanently installing these gauges into the well completion, they can provide valuable data that can help interpret and optimize reservoir and well performance.

3.5.2 Inflow Control Devices

If a well crosses multiple production zones and/or has a long horizontal profile, a common requirement for intervention during the life of the well is to optimize production. It may be that certain zones have begun to produce water and require shut-off to optimize hydrocarbon production from other zones. The management of different pressures in different zones may also require adjustments to the balance of flows between adjacent zones. When these problems become severe, an intervention is often required to address required changes downhole. Depending on the equipment in the well, these interventions can range from a simple wireline adjustment to a sliding sleeve to a full re-completion [57].

The use of smart inflow control devices offers the possibility of avoiding the need for intervention. If these devices are permanently wired to the surface, they can allow 'on demand' adjustments to flow from each production zone. By increasing control, this technology can compensate for geological uncertainty [58]. In conjunction with automated downhole monitoring, this technology can allow many zones to be targeted by a single well and can reduce both the number of wells required to exploit a given reservoir and the number of needed interventions. By reducing well intervention activity, the risk of exposure to personnel can be dramatically reduced [59].

The drawback of this technology is a reliance on fewer wells. When the production control is automated, fewer wells are needed. Therefore, if one well is offline, production is significantly reduced.

3.6 Automation in Production

Automated production systems have been around for decades. The primary objectives of the automated production systems are safety and environmental protection, cost reduction, surveillance, production optimization, reservoir recovery, well integrity, staff efficiency, and remote operations. These systems, as with non-automated systems, must incorporate an Emergency Shut Down (ESD) system, where the main impact of automation on safety occurs. Some of the major types of automation in production systems are described in the following sub-sections.

3.6.1 Surface Controlled Subsurface Safety Valves

Surface Controlled Subsurface Safety Valves (SCSSVs), which are installed in the production tubing, are among the simplest types of automated valves (Figure 3-17). The valve, which is operated remotely by a control line that connects the valve with the ESD system on the surface [60], is designed to allow the flow of fluids during normal operation. The SCSSV's hydraulic pressure is used to control the operation of the valve and keep it open during production. The valve is designed to have a fail-safe mechanism. During a catastrophic event, if the hydraulic pressure is lost, the valve closes automatically and stops the reservoir fluid flow.

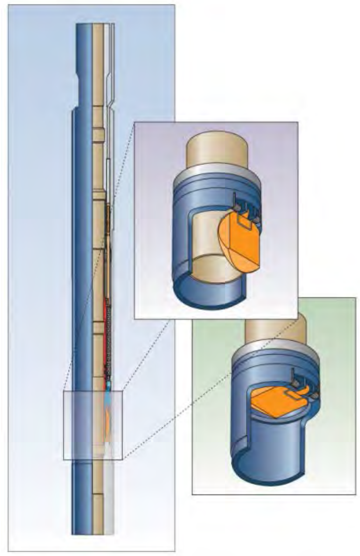

Figure 3-17: Surface Controlled Subsurface Safety Valve (SCSSV) [60]

3.6.2 Emergency Shut Down

In an emergency scenario, the ESD system immediately terminates all production. Some safety actions, such as the start of fire pumps and emergency generators, are automatically activated.

ESD systems are based on a ‘fail-safe’ principle. The principal aims and objectives of an ESD system are to reduce the consequences of an accident or a hazard to ensure:

- Personnel safety.
- Protection of plant and equipment.
- Maintenance of safe operation compatible with production requirements.
- Minimization of environment pollutions.
- Maximization of plant production (reducing unnecessary shut downs) [61].

4.0 System Reliability Assessment of Automated Well Control System and Early Kick Detection System Technologies

4.1 System Description

Various well control equipment types, which are currently used around the world, can be broadly categorized in two main groups:

- Drilling Well Control Equipment
- Workover, Completion, and Intervention Well Control Equipment.

Loss of well control occurs more frequently during drilling operations than during production or intervention operations (Bercha, 2014 [2]). The frequency of drilling loss is consistently an order of magnitude higher than production or intervention losses; therefore, the current FMECA-based System Reliability Assessment (SRA) considers drilling operations only.

A major cause of loss of well control is a 'kick' that results in formation fluids entering the wellbore. Kick detection in conventional drilling relies on identifying key warning signs (increases in flow rates and pit volume) during the drilling operation. Early Kick Detection (EKD) gives Drilling Operators time to take preventive and remedial actions for well control and drilling intervention, as necessary.

One of the most developed and established technologies for EKD is Managed Pressure Drilling (MPD). MPD uses advanced flow measurements to detect early signs of a kick; using a closed, pressurized system may provide an automated rapid response to stop or mitigate the influx of fluid into the wellbore. Proper MPD system operation provides accurate pressure control and minimizes the time required to deal with small influxes and nuisance gas.

To optimize drilling operations (especially during directional drilling) and to enhance safety during drilling, it is often helpful to acquire downhole petrophysical and directional drilling information. Continuously monitored directional drilling information, such as inclination, direction, and tool face angle, helps to guide a wellbore along a non-vertical trajectory. Estimates of formation parameters (such as formation type, porosity, water content) and downhole conditions (such as BHP) are necessary to keep the BHP within the drilling 'window' between formation pore pressure and fracture pressure gradients. The drilling window for current drilling operations is often narrow, especially in deep wells. Downhole measurements can increase the accuracy of estimating formation pressure and can enhance the ability to maintain wellbore pressure within the drilling window. Downhole measurements can also enable early recognition of unsafe conditions, such as formation fluid influx into the wellbore.

The data from MWD/LWD tools helps the Drilling Operators to make:

- Informed decisions about the drilling operation.
- Necessary adjustments during operations.
- Adjustments to future operational plans.

Using data transmission processes that are currently prevalent (by sending pulses through the mud column), the MWD/LWD systems transmit downhole data to the surface equipment.

However, the processes have their limitations. Communication between the downhole and surface monitoring and the control station has a time lag and is limited by the data transmission rate. Also, MWD/LWD tools are limited to measuring data only at the bottomhole assembly (BHA), which is some distance from the drill bit. Most drilling systems use software models to estimate downhole pressure profiles. The estimated measurements from the software models are then compared to the data that is directly measured at the BHA. If there is a significant mismatch between the direct measurement and the estimated measurement, a review by experienced personnel may determine that recalibration is necessary.

Therefore, new advancements are under way to increase the data transfer rate to better capture and transmit measurements throughout the wellbore, advance the software modeling capabilities, and improve automation implementation. To achieve fast data transfer from wellbore sensors to the Surface systems, one technology that is currently being implemented for commercial use is Wired Drill Pipe.

4.1.1 Early Kick Detection Systems/Managed Pressure Drilling

An EKDS provides the means to detect the influx of formation fluids into or the loss of formation fluids out of the wellbore significantly faster than for conventional operations. The most widely used indicator of an influx or loss scenario is to monitor the flow rates into and out of the well. The comparison of flow rates in to flow rates out provides a strong indication of whether an influx or losses have occurred. Adding high accuracy flow metering to this mass balance significantly improves kick detection.

Although many EKDS exist or are being studied, the most developed and established system by far is the use of applied backpressure MPD. A typical MPD system uses advanced flow metering on the return line (usually a Coriolis meter) to monitor for the influx of formation fluids. Comparing the inflow (which is typically measured using a stroke counter) to the measured outflow gives a far more rapid indication of influx than waiting for gains to be observed in the pits.

In floating offshore applications, a Rotating Control Device (RCD) is installed below the slip joint, with flow diverted through flexible lines to the return system. With this design, the circulating volume in the well becomes constant, and it is unaffected by rig movement that causes contraction and expansion of the slip joint located in the marine drilling riser system. The RCD removes the effects of rig heave on the measurements of return flow rate. In conjunction with a Coriolis meter on the return line, resolution of kick detection significantly increases when comparing MPD to conventional kick detection for floating offshore applications.

Although the level of automation in MPD systems varies, some systems include a fully automated choke and kick detection algorithms, which allow an automated backpressure response to influx or losses. This system actively increases BHP, thereby accelerating influx cessation better than a passive, conventional shut-in response.

An automated MPD system may significantly reduce influx severity in the following ways:

- Increasing kick detection resolution reduces inflow time and, therefore, volume.
- Maintaining pumps on during initial applied backpressure response minimizes influx flow rate and volume by:
  - Maintaining annular friction (Equivalent Circulating Density [ECD]).
  - Precluding reduced BHP associated with a conventional shut-in approach.
- Actively increasing BHP through choke manipulation reduces the time to minimize or cease influx and overall kick volume. For an influx of sufficiently low severity, there may be capacity to circulate the influx from the wellbore without ever shutting down the pumps, thereby reducing the risk of a secondary influx caused by minimizing pressure fluctuations. This approach also significantly reduces the time to manage the influx, which in turn reduces the likelihood of further well control problems.
- Significantly reducing peak surface pressures with the capacity to circulate the influx out through the riser annulus on applications with a Subsea Blowout Preventer (SSBOP) and for sufficiently low severity influxes.

These are some of the means by which automated MPD provides a powerful tool for EKD and subsequent influx management.

Because of the reasonably established nature of MPD systems as compared with other EKD methods, the FMECA for EKD Systems described in this report is applied to a generic MPD system for a floating offshore application.

4.1.2 Measurement While Drilling and Logging While Drilling

MWD/LWD systems are part of the BHA in a drilling system. Figure 4-1 shows a typical MWD/LWD system in the perspective of drilling that extends from the downhole to the Surface systems.

MWD tools, as the name suggests, perform measurements and store that data in real time, and they transmit the data to the surface during operations. The measurements are related to direction and drilling mechanics.

These measurements include:

- Wellbore trajectory measurements in terms of direction and inclination (using magnetometer).
- Rate of wellbore penetration (using accelerometer).
- Tool face angle.
- Drilling mechanics parameters, such as torque on bit and weight on bit.
- Natural gamma radiation measurements (to determine formation markers).

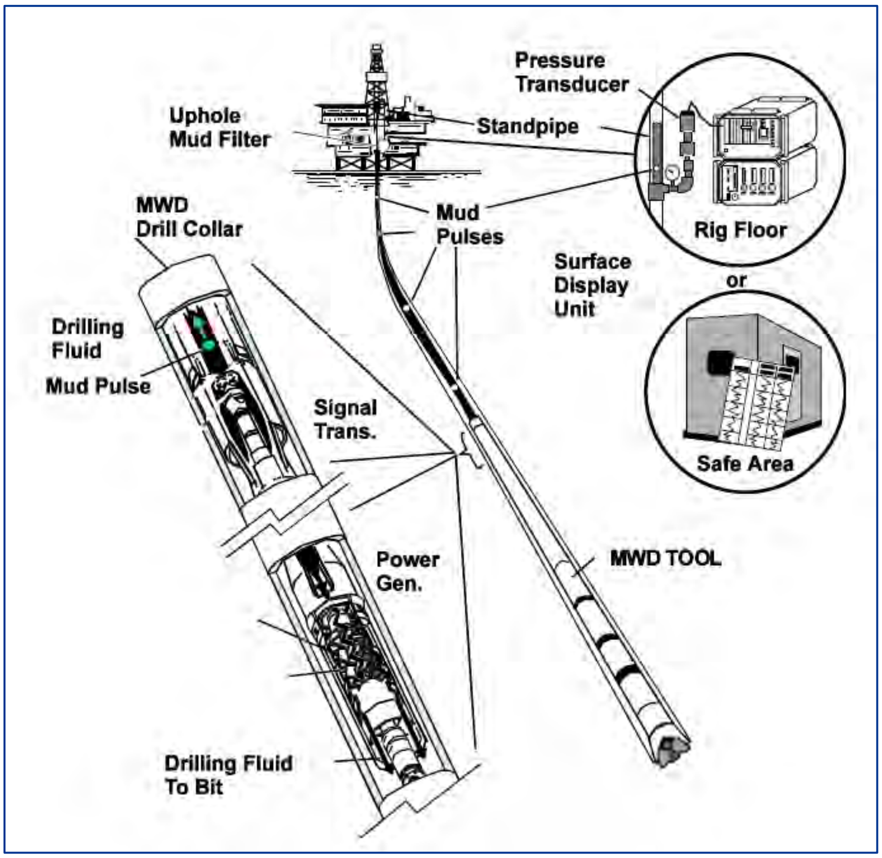

Figure 4-1: Example Illustration of a Typical MWD/LWD System (Baker Hughes, 2008 [3])

LWD tools measure petrophysical data such as resistivity, porosity, and sonic velocity. As the LWD tools measure large volumes of data, the measurements are logged (stored) downhole. Downhole memory storage may be limiting because the memory stored data can be retrieved and analyzed only when the downhole tool returns to the surface. Conventional mud pulse telemetry transmits MWD and LWD data to the surface but with time lags and data gaps. With technological advances in data transmission methods, larger volumes of data can be transmitted faster to the surface in real time, so the limitations of LWD are diminishing.

In the context of the current industry, the terms MWD and LWD are sometimes used interchangeably because the tools are assembled together to measure directional drilling, drilling mechanics, and petrophysical data.

For the current scope of work, MWD and LWD tools are considered similar systems, with the difference being the type of data measured. MWD primarily measures directional drilling and drilling mechanics data, while LWD primarily measures petrophysical data.

MWD/LWD systems, as part of the BHA, consist of sensors, control electronics, power generation devices (such as turbines and batteries), telemetry devices, and general mechanical components (directional steering pads and pressure housings, seals and couplings). Another BHA component, Downhole Filter Sub (DFS), prevents debris from entering the MWD/LWD systems. MWD/LWD systems also have surface equipment that interacts with and receives data from the downhole modules.

The MWD/LWD systems are categorized into four main functional sub-systems:

- Power Supply System
- Sensors
- Telemetry and Data Transmission System
- Surface Module

4.1.2.1 Power Supply System

The power supply system provides electrical power to various components in MWD/LWD systems. It may consist of a turbine-powered electrical generator, which is powered by the dynamic pressure of the drilling fluid as it flows past a multi-stage combination of stators and rotors. The rotational energy from the turbine is converted to alternating current (AC) electrical power through the generator. Electronic circuitry further rectifies the power to a direct current (DC) supply for use by electrical devices.

Batteries are available as an alternate source (and sometimes as supplemental source or the primary source) to power the system devices. The batteries used for downhole applications are designed for harsh environments and, during their service life, they provide a stable voltage supply. The combination of turbine and battery power forms an uninterrupted source of electrical power to the MWD/LWD systems. Note that various system modules may have the same power source, or they may have independent power sources.

4.1.2.2 Sensors

Sensors are electronic components and electro-mechanical devices that measure data related to directional drilling, drilling mechanics, or petrophysical properties. They have on-board circuitry that converts analog signals to digital data for storage and transmission.

A sensor's directional tool measures the direction and angle of the drill bits. These data feed back to the surface where, combined with depth measurements, Operators can calculate the trajectory of the tool and the drilled well and make informed decisions for corrective actions to control the drilling operation.

The main directional sensors are the magnetometers and accelerometers. Magnetometers measure the earth's magnetic field, upon which the Operator performs a relative correction to measure the direction and angle of the tool assembly relative to the magnetic North-South. Accelerometers are gravity-based sensors that measure the motion and inclination of the tool assembly. When used in tandem, magnetometers and accelerometers provide high-resolution measurements that Operators use to accurately pinpoint the direction, orientation, and inclination of the drilling tool.

In some situations, where external factors can cause significant interference in the magnetic field, the functionality and accuracy of the magnetometers becomes limited. In such cases, using gyroscopes powered by electrical motors with gravity-based accelerometers can accurately measure the direction, angle, and orientation of the drill bits.

In addition, various electronic sensors and transducers measure drilling mechanics data such as torque on bit, weight on bit, borehole pressure, and stick-slip.

Petrophysical data such as formation properties help engineers and analysts make decisions to steer and drill the wells into locations that are abundant and rich with hydrocarbons. The main tools that industry uses to determine formation properties are resistivity and gamma ray logs. Resistivity logs are created by an array of transmitters and receivers that send and receive high-frequency, electromagnetic (EM) pulses to measure phase shift and attenuation of pulses. The phase shift and attenuation data are used to create a resistivity log of the formations. Depending on the content of the formation (water, hydrocarbons, and minerals), the resistivity of the formation will vary, and petrophysical engineers can use this data to identify rich hydrocarbon formation zones and to geosteer[16].

Gamma ray sensors measure the natural gamma radiation emitted by various minerals in a well's formations, which engineers use to characterize and evaluate the type of sedimentation and rock that is present. Because gamma rays can travel through steel casings, this measurement technique is common for both open and cased holes. Gamma ray sensors have a high-voltage power supply and a detector assembly made up of photomultipliers and crystals (such as sodium iodide). The crystals and photomultipliers detect the naturally occurring gamma radiation from the formation, which is then amplified and recorded as a voltage pulse using high-voltage electronic circuitry. A spectral log of the formation is created, and reservoir engineers and geophysicists use the data for well planning and decision making.

The sensors also include temperature sensors and pressure transducers.

Other electronic components associated with MWD/LWD sensor and associated data storage systems include circuitry for power electronics, analog-to-digital converters (ADCs), solid-state storage devices (memory), oscillators, shock sensors, and vibration sensors. Mechanical housing and centralizers, along with metallic, ceramic, and polymeric components such as seals and packers, are used to protect the electronics and sub-systems.

4.1.2.3 Telemetry and Data Transmission System

Telemetry and data transmission system components create a uni-directional or bi-directional communication channel between the BHA and the surface terminal.

Downhole measurements from the MWD/LWD tools are stored in solid-state memory and are subsequently transmitted to the surface. Encoded data is transmitted to the surface through pressure pulses using mud pulse telemetry, low-frequency electromagnetic wave transmission through the formation layers, acoustic signals, or wired drill pipe. Wired Drill Pipe systems are discussed in Section 4.1.3.

Mud pulse telemetry is today's conventional telemetry system, but it has a number of limitations, including:

- It relies on a continuous column of incompressible fluid for data transmission, which makes it unsuitable in cases where compressible fluids are used (such as situations where light or aerated mud is used in low reservoir pressure formations).

[16] Geosteering is the process of adjusting the drilling trajectory on the fly to reach a targeted geological area.

- It has the slowest data transfer rate, generally in the range of 1.5 to 40 bits per second (Stalford, 2014 [4]). However, it can operate in harsh environments of up to 20,000 psi and more than 350°F.

Electromagnetic transmission (EMT) systems' data transfer rates vary between 10 and 100 bits per second (Stalford, 2014 [4])—faster than that of mud pulse telemetry. But EMT systems have their own limitations.

These systems can:

- Experience interference problems when two rigs are operating in close proximity.
- Have an operating depth limit.

EMT systems require high natural resistivity of the earth's formations from bottomhole to surface, and many wells have downhole formations with low resistivity. However, adding signal boosters can increase the operating depth limit.

Sometimes Operators employ acoustic telemetry to transmit acoustic data through the drill string at a rate of 10 to 30 bits per second (Stalford, 2014 [4]). However, this method may produce a high level of data noise (meaningless, sometimes corrupt data).

4.1.2.4 Surface Module

The surface module serves as an interface for human and data interaction at the surface. The module receives, decodes, processes, displays, and stores data from the downhole MWD/LWD sensors. It also monitors Surface systems that connect or form a functional part of the MWD/LWD systems.

4.1.3 Wired Drill Pipe

The Wired Drill Pipe system is a wired communication channel through drill pipe that transmits alternating electrical signals between the BHA and the Surface systems. Data transfer rates are about 57,000 bits per second, which is several orders of magnitude faster than mud pulse telemetry or electromagnetic telemetry (Jellison et al, 2003 [5]; Veeningen, 2011 [6]). The benefits of this enhanced data transfer rate include improved geosteering capabilities, better downhole tool control, and acquisition of geophysical data at faster rates of tool penetration.

In addition to measuring data near the drill bit, wired drill pipe allows for data measurement along the entire length of the drill pipe string.

The Wired Drill Pipe system has various sub-systems or components, as shown in Figure 4-2.

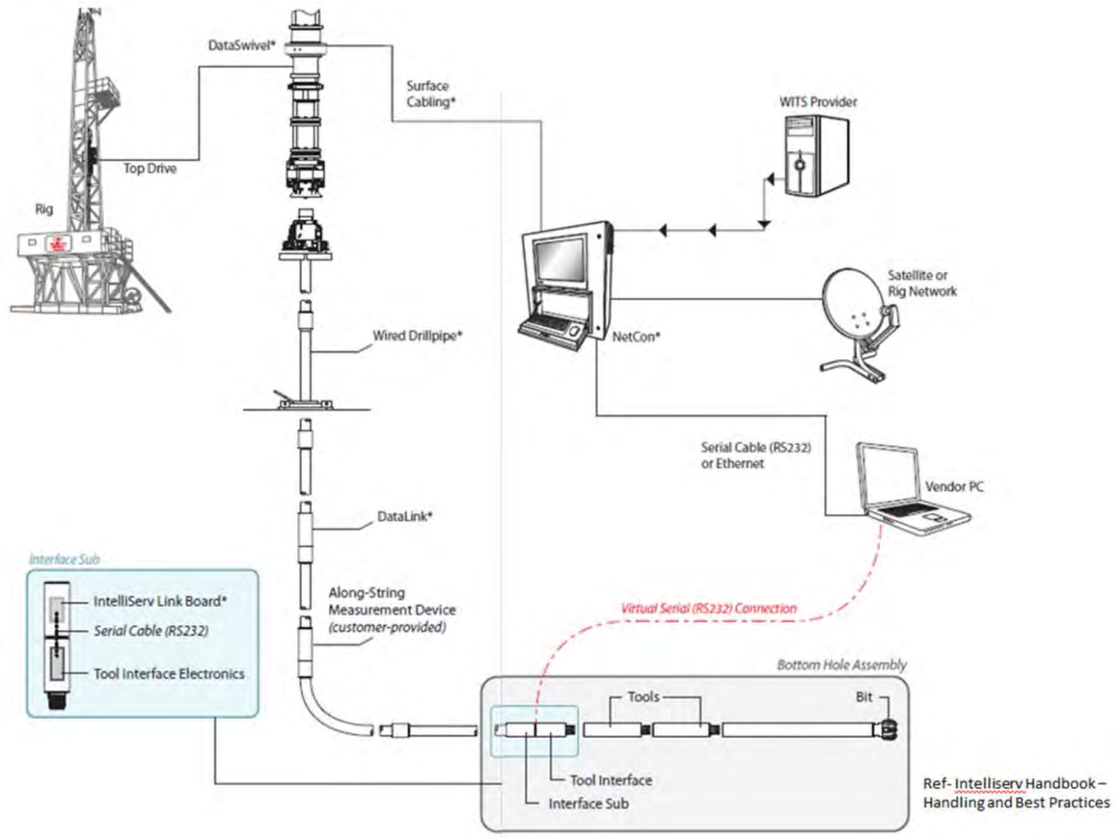

Figure 4-2: Sample Schematic of a Wired Drill Pipe System (NOV, 2013 [7])

At the top system level, wired drill pipe is categorized into three main functional sections:

- Data Link Sub
- Wired Drill String Assembly
- Surface Devices.

4.1.3.1 Data Link Sub

The data link sub contains batteries and electronics and is a signal amplification and boosting device. Data link subs connect to a shortened drill pipe section and are periodically present throughout the depth between the surface and the BHA.

4.1.3.2 Wired Drill String Assembly

The wired drill string assembly forms the backbone of the communication in the Wired Drill Pipe system. The wired drill string is a combination of an armored data cable within a modified shouldered drill pipe that uses an inductive coil at the junction between the drill strings.

The data cables are not fixed in the drill pipes but are kept taut by tension applied at the connection joints. The radial inductive coil mechanism at the end of the drill string makes the communication between the drill pipes seamless without worrying about the position of the data cable. Figure 4-3 shows a sample schematic of a wired drill string assembly.

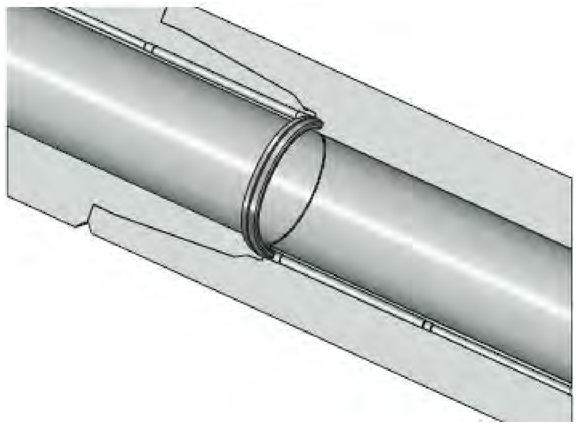

Figure 4-3: Sample Schematic of a Wired Drill String (NOV, 2013 [7])

4.1.3.3 Surface Devices

On the surface, the Wired Drill Pipe system has a data swivel that connects to the wired drill string. Surface cabling connects the data swivel to the network controllers, rig monitors, and display systems.

4.2 Failure Modes, Effects, and Criticality Analysis

Failure Modes, Effects, and Criticality Analysis (FMECA) is a method of systematic analysis that can be used to increase system reliability. It involves reviewing a given system in as much detail as reasonably practical to identify all conceivable failure modes and causes and the effects of such failures. FMECA is an effective way to manage, mitigate, and minimize the risks resulting from the failure of systems, equipment, and processes, thus increasing safety, availability, and the reliability of the systems.

To distinguish it from a Failure Modes and Effects Analysis (FMEA), the FMECA method quantifies the criticality of each failure mode to rank a list of failure modes in an order of relative priority (Rausand and Høyland, 2004 [135]). A FMEA does not use this ranking process.

Note that FMECA is also fundamentally different from root cause analysis, where FMECA is used to identify and mitigate a perceived risk before it actually occurs, and root cause analysis is performed after an incident has already occurred.

FMECA can be performed for a system at multiple levels of detail, depending on the available information and application involved. Guidance for equipment hierarchy can be found in International Organization for Standardization (ISO) 14224 (ISO, 2006 [136]).

4.2.1 FMECA Objectives

In this project, the primary objectives for FMECA analysis were common across all of the analyzed systems (MPD, MWD/LWD, and Wired Drill Pipe).

The objectives were to:

- Ensure that all conceivable failure modes and their effects on the operational success of the system were considered.
- List potential failures and identify the criticality of their effects.
- Provide a basis for establishing recommendations or corrective actions and their priorities.
- Assist in the evaluation of design requirements related to redundancy, failure detection systems, fail-safe characteristics, and automatic and manual overrides.
- Determine whether the currently available equipment types are suitable to be used for automated well control technology and then make subsequent recommendations.

4.2.2 FMECA Approaches

Based on the end objective and the system analyzed, various approaches to FMECA can be taken, including:

- A top-down approach, or functional-level FMECA, that considers component functions rather than specific hardware. This is particularly appropriate during the design phase, where functional requirements of equipment are the main focus.
- A bottom-up, or component-level FMECA, that analyzes each sub-system and its individual components separately in detail.

Because the FMECAs in this report were performed for existing systems, a bottom-up (component-level) approach was adopted.

Criticality can be measured by either a qualitative or quantitative approach, depending on the availability of reliability data for the system being considered. Despite efforts to obtain quantitative data, the commercial sensitivity of such data hampered collection efforts in this project. Because of the absence of specific and reliable failure rate data for this application, a qualitative approach was adopted. In this report, qualitative measures of occurrence, severity, and detection criteria were established, with the product of these approaches being the Risk Priority Number (RPN).

Because various commercially available systems have differences in design and application, the best FMECA effort was to consider sub-systems and components that are substantially similar in design and common to the available systems for deep water applications. For example, the latching assembly for the RCD, which is common to all of the available systems, was considered for the FMECA, with the typical failure modes of most commercially available latching assemblies being identified.

An example of the generic approach that was applied to the MWD/LWD systems FMECA was to combine mechanical components (such as seals and bearings) into a generalized sub-system grouping that was termed 'general mechanical components.'

Similar groupings of components were created for 'piping and valves' and the 'Pressure Relief system' for the EKDS FMECA.

The workshop participants discussed and agreed to execute each FMECA with a generic, qualitative, component-level approach.

The following guidelines were established for the FMECA approach:

- The subject systems (EKDS, MWD/LWD, Wired Drill Pipe) were considered in isolation (interdependencies between the FMECA subject system and other rig systems were not considered).

  In general, multiple layers of system redundancies that may provide backup in case of complete failure of any individual system are available. For example, conventional well control practices always remain fully operable and are used whenever needed (because MPD is not a well control method). MPD will supplement well surveillance and operations, whether there is an MPD system failure or not. Thus, an individual failure of a system may not imply a major catastrophic event at the global level, such as loss of well control.

- The project team considered only currently available commercial systems.

  As described above, the systems were evaluated in a generic sense without looking at vendor-specific equipment details.

- The project team did not consider specific vendor Quality Assurance/Quality Control (QA/QC) processes, which can affect the reliability of a specific system.

4.2.3 FMECA Procedure

Each FMECA was executed with the following systematic procedure:

1. Define and delineate the system (which components are within the boundaries of the system and which are outside). Each system was categorized into sub-systems and components that could be handled effectively.
2. Define the main system objectives being considered.
3. Describe the operational modes of the system.
4. Review system functional diagrams and drawings to determine interrelationships between the various sub-systems.
5. Populate worksheets for each component, identifying failure modes, causes, effects, and safeguards; and performing a qualitative criticality assessment of each failure mode. Note that safeguards (inspection, protection, and maintenance) of the systems were considered in the criticality scores.
6. During the workshop discussion of failure modes, note workshop participants' recommendations, comments, and corrective actions. Generally, the implementation of preventive actions instead of mitigation actions should always take precedence unless they are dictated by other factors (such as cost of implementation versus the benefit gained).
7. Prepare the FMECA report. The report provides a framework that can be used to perform FMECA of the various commercially available systems when adequate information is available. The report also highlights significant components of the analyzed systems.

4.2.4 FMECA Workshop

A FMECA workshop requires participants who are specialists or SMEs. A mix of independent consultants, participants from industry (manufacturers, vendors, service providers, and Operators), classification societies, and government bodies forms an ideal team for discussion that provides various perspectives on the analysis.

For this project, a FMECA workshop was conducted at Blade Energy Partners' offices in Houston, Texas, according to the schedule in Table 4-1.

Table 4-1: FMECA Workshop Schedule

System	Date	Location	Session		Facilitator
			Morning	Afternoon	
EKDS (MPD)	April 27-28, 2015	Houston	Y	Y	WGK – Independent from the Project Team
MWD/LWD	April 29, 2015	Houston	Y	—	
Wired Drill Pipe	April 29, 2015	Houston	—	Y	

4.2.5 FMECA Worksheet

During the workshop, participants populated a unique worksheet for each component. Appendix E.1 illustrates an example worksheet. Section 4.2.6 describes the FMECA worksheet fields.

4.2.6 FMECA Terminology

The following terms were used during the FMECA analysis:

Component/System Function: Description of the necessary task(s) to be performed by a component or system. For example, the function of a braking system in a vehicle is to slow down and stop a vehicle.

Corrective Actions: Actions that focus on decreasing risk by reducing failure occurrences, reducing the consequences of failures, increasing the ability to predict or detect failures, or any combination of these events.

Detection: Ability to detect or predict failure within sufficient time to perform mitigation or intervention and avoid the failure event from occurring. For example, a visual inspection of a brake pad at regular intervals can show whether the pad is wearing out so that remedial measures can be taken (replace the brake pad) before it loses functionality from excessive wear.

The ranking categories used for detection during the FMECA analysis are in Appendix B, Table B.3.

Effect on the Component Function (Local Effect): All the main effects of the identified failure mode on the component. For example, uneven wear of the brake pads and rotor discs can generate excessive heat from friction, thereby accelerating further damage to the components.

Effect on the System Function (Global Effect): All the main effects of the identified failure mode on the function of the system. For example, a vehicle that is unable to slow or stop because of loss of brake pad functionality may result in an accident.

Failure: The inability of a system or component to perform its intended function under stated conditions. For example, failure for a braking system is not being able to slow or stop a vehicle under normal driving conditions.

Failure Cause: The physical or operational situation or flaw that caused the failure. Examples may include overpressure, faulty design, and worn bearings.

Failure Mechanism: A process that leads to the failure mode. Examples may include corrosion and yielding of material.

Failure Mode: Observable possibilities for the component failing to perform its function. Examples may include leaking, excessive deformation, and cracking.

Indication: Signs or changes by which occurrence of the failure mode is detected.

Maintenance: Actions or measures performed to prevent or correct failures.

Occurrence: Estimation of the likelihood (or probability when a quantitative estimate can be made) that a failure mode will occur.

The ranking categories used for occurrence during the FMECA analysis are shown in Appendix B, Table B.1. **Operational Mode**: System function mode under operating conditions.

Protection: Equipment redundancy provided by the design to automatically respond to the failure mode so that the function performed by the equipment is not lost due to the mode of failure. For example, a secondary pressure barrier in a pressure containing structure protects against the failure of the primary barrier.

Reference ID: Unique identification number (ID) assigned to refer to a particular failure mode.

Risk: The product of the likelihood of a failure and the severity of failure.

$$Risk = Likelihood \times Severity$$

Risk Priority Number (RPN): The product of occurrence, severity, and detection, which assigns relative priority to each failure mode. Note that the RPN does not provide an absolute quantity of risk, but rather a relative risk of a failure mode when compared with other failure modes considered in the same analysis.

For this project's FMECA, the team applied RPN to system functionality, rather than to safety, environment, downtime, etc.

Safeguards: The preventive, indicative, or maintenance related procedures or mechanisms that will decrease the likelihood of failure. For example, dashboard indicators will indicate loss of hydraulic pressure (or hydraulic fluid), and this early indication can safeguard against loss of pneumatic pressure.

Severity: Estimate of the consequence of the failure mode. For example, the severity score of a failed brake system may range from minor damage to property to loss of life.

The ranking categories used for severity during the FMECA analysis are shown in Appendix B, Table B.2. System Reliability Assessment

As was discussed in Section 4.2.2, a detailed quantitative SRA was not performed because the project lacked vendor-specific system information such as detailed system architecture and component details and corresponding quantitative failure data. In the absence of these details, a qualitative FMECA was conducted using generic system categories.

4.3 EKDS (MPD) FMECA Results

4.3.1 Summary of findings

The two system components identified as representing the highest risk to the MPD system function were the:

- ‘Pressure Relief system’ with 32% of the summed total RPN scores
- ‘Valves and piping upstream of the MPD choke’ with 14% of the summed total RPN scores.

Further review of these components’ failure modes showed that not only were the individual failure mode RPNs high, but also that these components dominated the list of failure modes with a significant safety concern. Therefore, it can be concluded that careful design of these two components is critical to safe and efficient deployment of an MPD system.

Indeed, this finding is intuitively correct, given that these two systems perform the function of managing the high pressure upstream of the MPD choke. Note that the design of these two components is application-specific, and it varies from rig to rig and even from operation to operation. When these variations are considered in conjunction with the risk findings; the design, planning, and risk assessment of any MPD operation must include these two items as high priorities.

This finding raised an important discussion with respect to system design which, although it was not specifically captured during the component-based FMECA, it is reflected in the high representation of the mud gas separator (MGS) component in the failure modes of concern for safety. That is, when designing the Pressure Management system, appropriate consideration of high rate gas flow events such as may occur with riser gas unloading should be included as a high priority.

The component contributing the third highest percentage of total RPN score was the 'Stroke Counter system' at 13%. In this case, although the percentage of the total RPN score was comparable with the 'piping and valves upstream of the MPD choke,' close inspection of the analysis revealed that high RPNs were driven by low component reliability, and they did not reflect the same level of risk in terms of both functionality and safety. The effect of the stroke counter's single failure mode of 'failure to measure correct volume' was identified as impaired operational awareness and impaired EKD with a severity score of 3. This was not flagged as a failure mode of significant concern for safety. Therefore, the stroke counter component, although it is a good focus for efforts to improve system reliability, is not deemed as high a priority as the 'Pressure Relief Valve (PRV)' or 'Upstream Piping and Valve system.'

The remaining components had relatively few failure modes, with no individual component exceeding 8% of the total RPN. In addition, aside from the MGS, none of the components were identified as significant sources of failure modes of concern for safety. This leads to the conclusion that careful consideration of pressure management as determined by the Pressure Relief system, piping and valves upstream of the choke, and the MGS is the highest priority for reducing total system risk. In addition, efforts to improve the reliability of the stroke counter component will offer significant improvement to the system functionality risk.

The most critical component for assessing EKDS (MPD) suitability as an automated well control technology is the Control system. Not only does the Control system represent only a minor risk to system functionality at 3% of total RPN, but no failure mode was flagged as a significant safety concern. When combined with the benefits to well control safety as detailed in the second interim *Evaluation of Automated Well Safety and Early Kick Detection Technologies* report for this project, one may conclude that MPD is an excellent candidate technology to be part of an automated well control strategy. On this basis, the authors of this report recommend MPD for consideration in any such application.

The FMECA that was performed on the generic EKDS (MPD) system proved to be an excellent means of identifying the high risk components for both system functionality and safety. The RPN ranking quickly flags those components that present high risk to system functionality, and, combined with the safety flags of this analysis, it provides quick recognition of the highest priority systems and components for MPD planning and execution.

4.3.2 FMECA Workshop on EKDS (MPD)

The FMECA on EKDS (MPD) was performed in a two-day workshop at the Blade Energy Partners' offices in Houston, Texas. Industry participation included independent consultants, representatives from vendors and service providers, Operators, certification bodies, the Bureau of Safety and Environmental Enforcement (BSEE), and the project team (refer to Appendix C.1).

Pre-populated FMECA worksheets (as described in Section 4.2.5) were used as starting points for the FMECA workshops. Based on input from the workshop attendees, the FMECA worksheets were updated, and criticality rankings for each component were obtained. RPNs were calculated based on agreed likelihood, severity, and detectability of failure modes.

4.3.3 EKDS (MPD) FMECA Method

4.3.3.1 Identify System and Components

Because of the established nature of MPD systems and their inherent ability to provide EKD with particular applications, this FMECA was applied to a generic, high-end MPD system for a floating offshore application.

The FMECA was limited to the consideration of a generic form of existing MPD systems. The generic system was necessarily simple and consisted of hardware components that can be uniquely identified (for example, RCD, Coriolis meter, MPD choke). Therefore, a simple, component-level approach was adopted as most appropriate for this analysis.

4.3.3.2 Quantify Failure Mode Criticality

The criticality of each failure mode was quantified to facilitate the relative priority ranking of the failure modes. As discussed in Section 4.2.2, the absence of specific failure rate data for this application forced the adoption of a qualitative approach, relying heavily on the engineering judgment of the workshop participants. Group consensus established qualitative measures of occurrence, severity, and detection criteria, with the product of these being the RPNs.

To assess the failure mode criticality, the occurrence, severity, and detection criteria (as shown in Table B.1, Table B.2, and Table B.3 in Appendix B) were applied to each failure mode by assessing how each failure mode affects the following EKDS functional objectives:

1. To effectively and safely control surface pressure on the well as intended by virtue of wellbore pressure containment and MPD choke manipulation
2. To provide early kick and loss detection (significantly earlier than conventional methods of kick and loss detection)

4.3.3.3 Establish Methods to Identify Failure Modes Affecting Safety

According to the FMECA objectives, the RPN scale was not representative of safety but rather of system functionality. That is, a high RPN indicates that a failure mode represents a high risk to system functionality but not necessarily to safety.

Because safety is of high importance, the project team employed additional means beyond RPN to flag those failure modes where a safety concern was identified:

- For failure modes that affect safety, the severity ranking was driven to the maximum level of 5 and highlighted where appropriate.
- Failure modes causing potential safety concerns were shown in separate results tables without reference to RPNs so that failure modes affecting safety could be considered separately.

4.3.3.4 Assumptions

In this project, it was appropriately assumed that with an MPD application, conventional well control methods can and will be used because MPD is not well control. Similarly, the project considered operational processes and exceptions[17] that were not reviewed. These processes and exceptions are outside the scope of this analysis, yet they are and must be considered during the planning stages of a project.

Within this project scope, when assessing failure modes, the workshop participants considered and noted factors such as safety, environment, cost, and downtime. However, the participants applied criticality ratings and subsequent RPNs solely to the functionality of the system, without regard to those factors.

[17] For example, consider the scenario where influx gas has entered the riser and the diverter may not be used because of the location of the RCD. In this case, appropriate processes must be in place with regard to handling the gas at surface.

4.3.4 Detailed System Breakdown

Workshop participants agreed upon a detailed breakdown of EKDS into sub-systems and components (Table 4-2). The system reflected is a generic form of MPD system for an offshore floating application. In the FMECA worksheet, each component's function is described, and a reference ID that is specific for each component is defined. Some components are grouped into a common sub-system to aid general understanding. However, each component was assessed separately in the FMECA workshop.

Table 4-2: EKDS Breakdown and Function Statements

Sub-system	Component	Component Function	Reference ID
MPD Manifold	Control System	Controls MPD choke operation and kick/loss detection safely and effectively	1.1
	Coriolis Meter	Provides density, flow rate, and temperature measurements	1.2
	MPD Chokes	Restrict flow downstream from the RCD, thereby accurately controlling annular surface pressure on the well	1.3
Rotating Control Device (RCD)	Latching Assembly	Maintains bearing assembly position and contains annular pressure from the well	2.1
	Bearing Assembly	Allows seals to rotate with drill pipe and contains annular pressure from the well	2.2
	Element	Contains annular pressure from the well by sealing against the drill pipe (while static, rotating or stripping, or both)	2.3
Pressure Relief System	Pressure Relief System	Protects RCD, riser, and wellbore against overpressure by relieving pressure if calculated maximum is exceeded	3.1
Mud Gas Separator	Mud Gas Separator	Captures and separates large volumes of free gas within the drilling fluid	4.1
Instrumentation	Stroke Counter	Measures the stroke rate and number of strokes on the mud pumps, providing total volume of mud flow into the well	5.1

Sub-system	Component	Component Function	Reference ID
Drill String Valve	Drill String Valve	Prevents backflow under any circumstances into the drill pipe	6.1
Piping and Valves	Hard Piping	Provides pressure and flow containment upstream from the MPD choke	7.1
	Hoses		
	Valves		

Because of the requirement that the FMECA must be applied to a generic MPD system, components were defined in general terms so that failure modes common to most MPD equipment would be included. For example, the component ‘Pressure Relief system’ was not defined as a set of specific pressure relief valves (PRVs) installed in specific locations and orientations. Rather, it was defined generally, as a Pressure Relief system designed appropriately for the application for which it is intended. Consequently, in determining failure modes for this example, workshop participants considered conditions in which typical pressure relief components may be exposed (for example, overpressure of a PRV).

However, to some degree, certain specific component assumptions were necessary. For the Pressure Relief system example, the workshop participants assumed that PRVs are hydraulically controlled with active pressure release. Such assumptions made it possible to define specific failure modes and consequential effects that would not have been possible without that level of component definition.

Before the workshop, system detail was loosely defined. However, during the workshop, participants agreed upon more rigorous definitions for these systems and components as detailed in the discussion section of this report (Section 4.3.5).

Figure 4-4 shows a generic schematic similar to, although less detailed than, a Piping and Instrumentation Diagram (P&ID) for an offshore, floating MPD application. This diagram is by no means comprehensive in terms of presenting all components required for any specific MPD application. In addition, specific flow paths defined there may not be appropriate for a particular application. However, when considering a specific component’s potential failure modes and effects, workshop participants occasionally referred to the diagram to gain some insight into typical conditions to which particular components may be subjected.

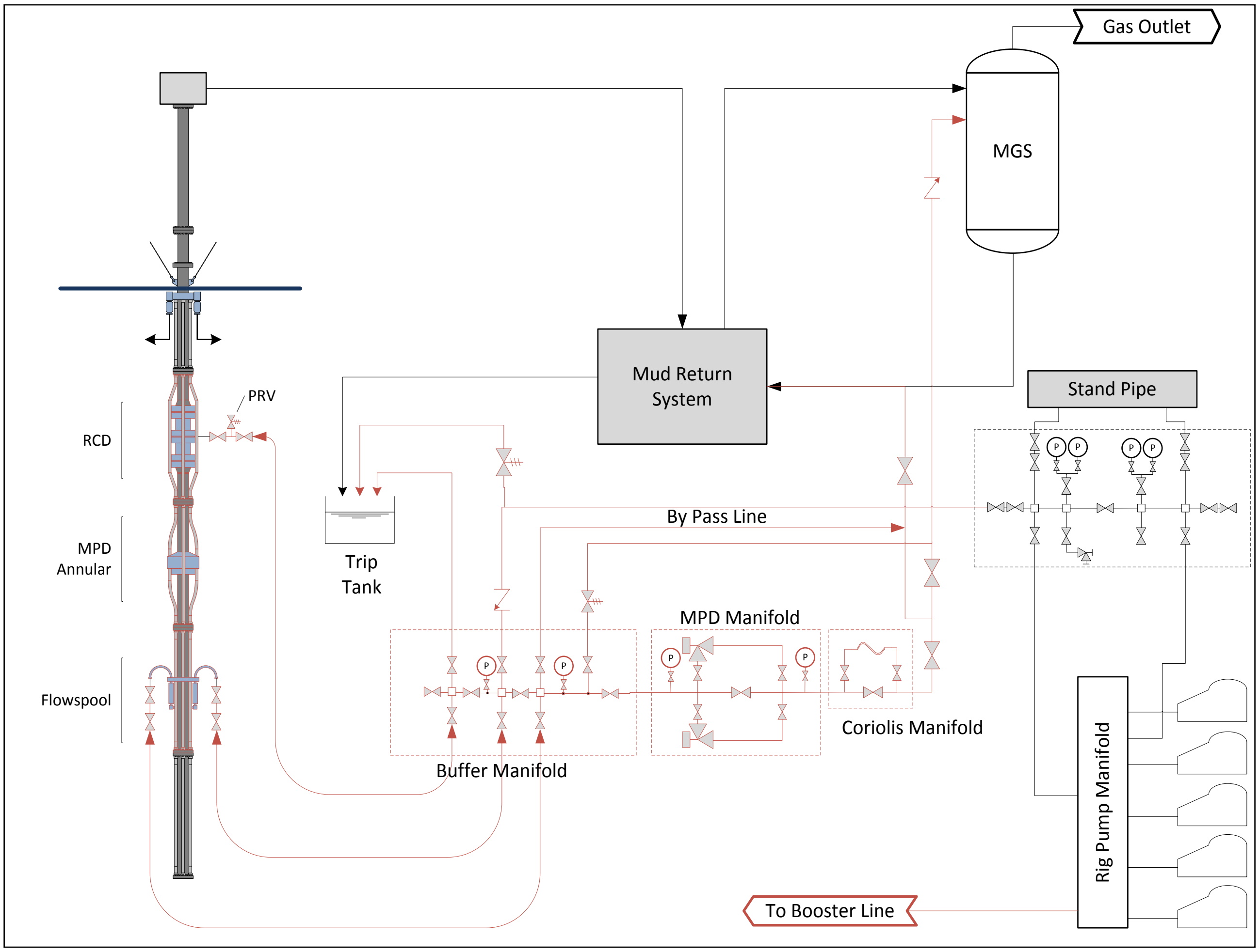

Figure 4-4: General Schematic for Floater Rig MPD System[18]

4.3.5 EKDS (MPD) FMECA Results

All of the EKDS FMECA worksheets are in Appendix E.2. The worksheets include detail that goes beyond the scope of this section. For each failure mode, this section and Section 4.3.6 cover:

- Existing Mitigations (Indication/Protection/Maintenance)
- Effects on Components
- Recommendations, Comments, and Corrective Actions

Appendix F.1 contains all failure modes identified for all components and is sorted by decreasing RPNs. The RPN values determined for all failure modes ranged from 1 to 100, and some components (such as piping and valves upstream from the MPD choke,

[18] This generic schematic does not include an option to divert fluid in event of high gas flow events. This option was specifically identified in the workshop as something to be considered during the design of any specific MPD system.

Pressure Relief system, and stroke counter) repeatedly contributed relatively high values for RPN. A detailed discussion of the drivers and implications of this trend is included in the subsequent section. Also, the percentage of the contribution of individual failure mode toward the total RPN of a component is reported. These data represent how severe a failure mode is for a given component.

Determining the total for all RPN numbers provides a number representing 100% of the total population of failure modes identified for the EKDS. Table 4-3 shows the EKDS FMECA results with the percentage of contribution to total RPN by component. On examination of Table 4-3, one can see, for example, that 32% of the total RPN is the highest contribution by a single component and is attributed to the Pressure Relief system. This finding flags the Pressure Relief system as a component that represents a high risk to system functionality, and it requires scrutiny. Similarly, for the other components analyzed, Table 4-3 provides a gauge for each component's relative contribution to the system functionality risk.

Failure modes identified to have a potential effect on safety are shown in Appendix F.2. The RPN value for each failure mode is not shown because criticality ratings applied to RPN generally reflected system functionality rather than safety. Because of the importance of safety and to highlight their significance, these failure modes were included in Appendix F.2.

Table 4-3: EKDS FMECA Results – Contribution to Total RPN by Component

Component	Component Function	Total RPN for Component	% Total RPN for System
Pressure Relief System	Protects RCD, riser, and wellbore against overpressure by relieving pressure if calculated maximum is exceeded	439	32
Piping and Valves (Hard Piping, Hoses, and Valves)	Provide pressure and flow containment upstream from the MPD choke	196	14
Stroke Counter	Measures the stroke rate and number of strokes on the mud pumps, providing total volume of mud flow into the well	180	13
Mud Gas Separator (MGS)	Captures and separates large volumes of free gas within drilling fluid	115	8
RCD Element	Contains annular pressure from the well by sealing against drill pipe (while static, rotating or stripping, or both)	86	6
Coriolis Meter	Provides density, flow rate, and temperature measurements	85	6
Drill String Valve	Prevents backflow into the drill pipe under any circumstances	82	6
MPD Chokes	Restrict flow downstream from the RCD, thereby accurately controlling annular surface pressure on the well	48	4
Control System	Controls MPD choke operation and kick/loss detection safely and effectively	45	3
RCD Bearing Assembly	Allows seals to rotate with the drill pipe and contains annular pressure from the well	44	3
RCD Latching Assembly	Maintains bearing assembly position and contains annular pressure from the well	42	3

4.3.6 Discussion of EKDS (MPD) FMECA Results

The following is a discussion (by component) of findings, recommendations, comments, and corrective actions that were noted during the EKDS FMECA workshop.

4.3.6.1 Pressure Relief System

The Pressure Relief system (component reference 3.1) provided the largest contribution to the overall RPN scores of all components analyzed. Indeed, at 32% of the total RPN score, the Pressure Relief system contributed more than double the next highest score (piping and valves with 14% of the total RPN).

Although this information highlights the Pressure Relief system as a component contributing significant risk to the system's functionality, a comprehensive review of a specific system is required to determine the proper cause. A high percentage of the total RPN score may be driven by:

- A component with failure modes that have high RPNs.
- A component that has a large number of failure modes and causes, each of which has a low RPN.

In the first instance, the component represents a significant risk to system functionality. In the second instance, the component may simply be capable of failing in a large number of ways that may be of little consequence.

Further insight into the risks posed by a component can be gained by considering the individual RPN values, the number of failure modes, and the scores that drive the RPNs.

In the case of the Pressure Relief system, deployment is application-specific. Therefore, for the generic FMECA method employed here, the Pressure Relief system must be considered as a single component consisting of an unspecified number of sub-components. This component's score was an aggregate; therefore, its summed RPN score (from which the 32% was calculated) was inflated by the number of sub-components and their associated failure modes.

Closer inspection of the individual failure mode RPNs gives a more realistic picture of risk associated with the Pressure Relief system. Most of those failure modes lead to the perceived effect of overpressurizing the system with the potential to fracture the formation, rupture the riser or system components upstream from the MPD choke, or both. Naturally, this effect leads not only to significant individual RPN scores relative to other components in terms of system functionality, but it also presents a safety concern. Although the percentage of total RPN may be inflated by its being an aggregate of sub-component RPNs, the system function risk associated with the Pressure Relief system is correctly indicated as high.

Identified failure modes and causes that may lead to overpressure of the system include:

- Failure of the PRV to open because of mechanical failure.
- Insufficient pressure relief capacity caused by blockage of the PRV.
- Insufficient pressure relief capacity caused by blockage downstream from the PRV.
- Failure to open because of sensor failure.
- Late release because of incorrect set point.

Identified recommendations and corrective actions to mitigate failure modes leading to overpressure of the system include:

- Hydraulically control all PRVs with active pressure release.
- Provide independent backup power supplies for all PRVs. Correct discharge piping sizes should be assessed.
- Lock open all valves downstream of any PRV.
- Install all PRVs at the highest point in vertical position to avoid debris accumulation.
- Investigate installation procedures for temporary versus permanent piping and equipment.
- Install redundant sensors for all PRVs.
- Provide High and High-High alarms all PRVs.

Other failure modes identified for the Pressure Relief system included premature release caused by incorrect set point and external leakage because of erosion, corrosion, or installation damage. These failure modes may lead to loss of pressure integrity with the potential for a kick scenario.

Although a kick scenario is typically associated with being a safety issue, in this case, it is assumed that conventional well control procedures can be called upon to manage an influx scenario in the event of MPD system failure. Therefore, these items were not flagged as immediate safety concerns. However, mitigations to these failure modes include having PRV release alarms and signals integrated into the Control system.

4.3.6.2 Piping and Valves

Piping (hard pipe and hoses) and valves upstream from the MPD choke (component reference 7.1) contributed the second highest score (14%) toward the total RPN value and the highest single RPN (100) of all the failure modes identified.

As with the Pressure Relief system, the piping and valves upstream from the MPD choke component were necessarily an aggregate of sub-components. Each of the multiple sub-components may have numerous failure modes. For example, the upstream piping and valves component (component reference 7.1) is vulnerable to an inflated summed RPN, which can lead to a higher percentage of total RPN. Consideration of the individual failure modes for this component gives an insight into the system risk of the upstream piping and valves component.

In this case, although the total RPN is for an aggregate of components, the total number of failure modes was not high. The high RPN for each of the individual failure modes drove the high percentage of total RPN. Furthermore, the piping and valves upstream of the MPD choke component (reference 7.1) was strongly represented among the failure modes of safety concern outlined in Appendix F.2. Therefore, in this case, the high percentage of total RPN correctly identifies the piping and valves upstream of the MPD choke as a high contributor to system risk for both function and safety.

The failure mode with the highest relatively ranked score was overpressure of valves, which was caused by valves being in the wrong position (a valve mistakenly closed). This led to the pressure control being compromised and the potential for hydrocarbon release with a significant safety impact. Because of its association with human error, this failure mode was assigned an occurrence rating of 4. The assumptions for this failure mode were that:

- Valves were being operated manually.
- Normal mitigating strategies, such as valve position indication and procedures, were used. Recommended further mitigating strategies would be to automate valve control with a tested and secure Control system, and provide associated interlocking mechanisms, indications, and alarms.

Another failure mode identified with both high functionality RPN and a high safety impact was loss of pressure containment with hard piping caused by overpressure, since overpressure can result in the potential to lead to significant, partial loss of MPD. For this failure mode, workshop participants recommended installing a PRV to account for different pressure ratings where the buffer manifold connects to the stand pipe.

4.3.6.3 Stroke Counter

The third largest contributor to the total RPN score was the stroke counter (component reference 5.1), with 13% of the total score. The stroke counter component function was generalized to include measurement of both the stroke rate and the total number of strokes on the mud pumps that provide total volume of mud flow into the well. For the assignment of ratings, note that existing mitigating strategies, such as monitoring stand pipe pressure trends, calibration, and measurement of efficiency, were assumed. Workshop participants recommended giving particular attention to these mitigating strategies to reduce the likelihood and severity of failures and to increase the chance of detection.

Similar to the Pressure Relief system (component reference 3.1), the stroke counter (component reference 5.1) component was an aggregate of sub-components such as mud pump valves, pistons, and liners across multiple pumps. This aggregation can lead to an inflated summed RPN and higher percentage of total RPN than those of single element components, such as the RCD. As with the Pressure Relief system and the upstream piping and valves (component reference 7.1), the stroke counter requires closer inspection of the individual failure mode RPNs to accurately determine the risk to system functionality and safety represented by the stroke counter component.

For the stroke counter component, a single failure mode was identified—incorrect volume measurement. This failure mode had a number of different associated causes that could arise from multiple sub-components, such as degraded pump efficiency, stroke counter error, liner or piston wear, and leaking suction valves on the pumps. The single effect on the system for all causes was identified as impaired operational awareness and impaired EKD with a severity score of 3.

The failure mode of incorrect volume measurement was not flagged as being a direct safety concern. The high individual RPN for each cause was driven by occurrence, at a ranking of 5. This rank reflects the low reliability of stroke counter systems for flow measurement. The combination of a large number of causes and a high occurrence drove the high summed total RPN for the stroke counter system. The resulting percentage of total RPN (13%) rivals that of the upstream piping and valves component (component reference 7.1) at 14%.

Although the stroke counter system is not reliable, the consequence of failure is far less significant than that of the upstream piping and valves. Upstream piping and valves failure modes have a high severity for functionality and were flagged as a safety concern. For the stroke counter, the high percentage of total RPN identifies an unreliable component, but total risk for system function and safety is not significant. Therefore, the stroke counter is of far less importance for system design consideration than other components with a high percentage of total RPN.

4.3.6.4 Other Components

Some of the other identified failure modes, causes, effects with comments, and recommendations for various components include:

- Gas out of the liquid line was identified as a failure mode for the MGS. This failure mode can arise from an MGS that does not have the size or the controls capable of handling a high gas flow rate, and it could lead to gas flowing to the shakers. The workshop participants recommended that the MGS have adequate pressure and level indicators as well as adequate sizing to increase detection of this failure mode.[19]

- Liquid out of the gas line was identified as an MGS failure mode that can be caused by blockage of the liquid line leading to liquid-to-vent line, with the potential for an environmental spill. Workshop participants recommended ensuring that there is a procedure to regularly flush the MGS and the liquid line downstream from the MGS.
- Leaking/degraded seal was identified as a failure mode for the RCD element, where the failure can be caused by wear from normal operations and can lead to the potential for a return leak. Workshop participants recommended testing the seals before each use and functional tests during the standard BOP test.
- Elastomer failure was identified as a failure mode for the RCD element, where the failure can be caused by mechanical damage from the drill pipe and can lead to the potential for loss of pressure containment, functionality, and operational downtime. Workshop participants recommended that drill pipe tool joint profiles be considered during the qualification of RCD sealing elements.
- Evident backflow was identified as a failure mode for the drill string valve, where the failure mode can be caused by washout or the valve fails open, thereby compromising the MPD connection process, potentially resulting in a trip. Workshop participants recommended conducting a drill string valve shake-out after each run, which may involve a valve check, pressure test, and redress before the drill string is run in the hole with the BHA.
- Trapped pressure was identified as a failure mode for the MPD chokes, where the failure mode can be caused by a blockage, and it potentially leads to a safety concern. It was noted that this occurs when the system is isolated after a blockage. While it did not directly imply loss of MPD system functionality, this failure mode was flagged solely as a safety issue.
- Degradation was identified as a failure mode for the MPD chokes, where the failure mode can be caused by general wear and cuttings, and it potentially leads to inadequate control of surface pressure. Workshop participants recommended that it is essential that the MPD chokes not be used as gate valves. Therefore, flow should be maintained across the choke (typically using the booster line) to apply surface pressure as necessary during periods of pumps off, negating the requirement to trap pressure on connections. In addition, the MPD chokes system should be designed as a dual choke manifold with bypass.

[19] The requirement for the emergency option to divert gas overboard was discussed during the workshop. Although not specifically captured in the workshop results, discussion highlighted that allowance for emergency diverting of gas overboard in conjunction with the consideration of whether the operation is planned to be statically underbalanced or overbalanced should be carefully considered during the planning stages of any deep water MPD application.

- Failure to operate the MPD choke(s) as intended, which was caused by inaccurate programming (and thereby leading to loss of the ability to control surface pressure) was identified as a failure mode for the Control system. Workshop participants recommended that Hardware-in-the-Loop (HIL) testing be mandatory for MPD Control systems.

4.4 MWD/LWD Systems FMECA Results

4.4.1 Summary of findings

Based on the high-level and generic scope of the FMECA, the MWD/LWD systems were divided into seven generic sub-systems or components. The sub-system categorized as 'general mechanical components' was identified to have the highest risk in terms of failure, with a 30% percent contribution to the summed RPN score. This general mechanical components sub-system comprises components such as seals, bearings, and valves; and this sub-system is critical to maintain the operational requirements of the MWD/LWD systems.

The most critical failure modes identified were the failure of the pistons, control valves, rotor, and stator, caused by poor mud quality, erosion, and assembly error, with an RPN score of 60. Even though the occurrence of these failure modes is sporadic, these failures happen in a manner in which detection during operation may not be obvious. Some preventive measures that can minimize these failure modes include regular inspection and maintenance and the use of good quality mud. On the other hand, the failure of bearings and nuclear source leaks were identified with low RPN scores (20 and less), primarily because of the extremely low likelihood of failure for these components.

Two other sub-systems with about 20% each of summed RPN scores are system control electronics and transmitters. Failure modes associated with transmitters have a high RPN score of 60, mainly because of low detectability and a medium likelihood of failure.

Each of the other sub-systems (surface modules, data sensors, power supply, and downhole filter subs) were identified as providing a small contribution to failure risk, with only 10% or less of the summed RPN values.

For MWD/LWD systems that were considered in isolation, well safety was a concern, even in the event of complete loss of system functionality. However, a loss of system functionality can lead to inefficient drilling or the loss of productive time or both.

It was noted that software security, calibration of sensor tools, and vendor quality checks all play important roles in reducing failure rates for MWD/LWD systems.

4.4.2 FMECA Workshop on MWD/LWD Systems

The FMECA on MWD/LWD systems was performed in a half-day workshop at the Blade Energy Partners' offices in Houston, Texas. Industry participation included independent consultants, representatives from vendors and service providers, Operators, BSEE, and the project team, as detailed in Appendix C.2.

Pre-populated FMECA worksheets (as described in Section 4.2.5) were used as a starting point for the FMECA workshop. Based on input from the workshop participants, the FMECA worksheets were updated and criticality rankings for each component were obtained. RPNs were calculated based on agreed likelihood, severity, and detectability of failure modes.

4.4.3 MWD/LWD Systems FMECA Method

A number of different MWD/LWD tools are available in the market because of the diversity in applications and the many number of vendors that manufacture them. Therefore, the current FMECA was limited to consideration of a generic form of existing MWD/LWD systems. The generic system was considered in such a way that it captured two broad functionalities: capturing directional drilling and drilling mechanics parameters and obtaining petrophysical data. The hardware components considered consisted of the basic functional modules, namely sensor module, power module, transmission module, surface module. Because modules and components within the system were considered for the FMECA, a component-level (bottom-up) approach was adopted for this analysis.

The criticality of each failure mode was quantified to facilitate relative priority ranking of the failure modes. As discussed in Section 4.2.2, the absence of specific failure rate data for this application forced adoption of a qualitative approach, relying heavily on the engineering judgment of the workshop participants. Group consensus established qualitative measures of occurrence, severity, and detection criteria, with the product of these being the RPN.

To assess failure mode criticality, the occurrence, severity and detection criteria ((as shown in Table B.1, Table B.2, and Table B.3 in Appendix B) were applied to each failure mode.

These criteria were applied by assessing how each failure mode affects the MWD/LWD systems' functional objectives:

1. To capture petrophysical and directional drilling and drilling mechanics data in real time at BHA to provide accurate and timely drilling data.

2. To increase efficiency of drilling and increase safety by transferring measured data to the Surface system during operation, storing data for future retrieval, and analyzing data to make informed plan for future drilling operations.

Early in the workshop, participants identified that, for MWD/LWD systems considered in isolation, well safety was not a concern even in the event of complete loss of system functionality. These systems are deployed to obtain directional drilling and petrophysical data that helps Drilling Operators make informed decisions about the drilling operation and plan for future operations. Also, in operation, other backup systems are available to perform similar tasks.

4.4.4 Detailed System Breakdown

Appendix D.1 provides the detailed MWD/LWD systems breakdown into sub-systems and components that was prepared prior to the FMECA workshop. However, during the workshop, the participants agreed that such a detailed breakdown would be intractable for the current FMECA scope, which was limited to a high-level, generic review of the systems. Therefore, a simplified, high-level system breakdown was used for the workshop (refer to Table 4-4). The system reflected a generic form of an MWD/LWD system for an offshore or onshore application. Table 4-4 describes each general component sub-system's function and defines a reference ID specific to each component or sub-system. Each component or sub-system was assessed separately in the FMECA workshop.

Table 4-4: Final MWD/LWD Systems Simplified Breakdown and Function Statements

Sub-system/Component	Sub-system/Component Function	Reference ID
System Control Electronics	Provide control functions to various MWD/LWD components	1
Downhole Filter Sub	Captures debris	2
Transmitter	Transmits data from tool to surface sensors	3
Power Supply	Provides power to all electronics in the system	4
Data Sensors	Provide accurate data to drill well as planed or changes to wellbore path as needed	5
Surface Module	Receives, decodes, processes, displays, stores and distributes real time downhole data and monitor Surface system	6

Sub-system/Component	Sub-system/Component Function	Reference ID
General Mechanical Components	Maintain design operational requirements	7

Because the FMECA was applied to generic MWD/LWD systems, the sub-systems or components were defined in such a way that generic system functionality and associated failure modes could be considered. For example, the sub-system 'Data Sensors' was not defined as a collection of specific sensors or gauges located along the tool to collect some specific data. Rather, it was defined as a generic sensor designed to collect wellbore data. Thereby, in determining failure modes for this example, workshop participants considered the conditions to which a typical data sensor and its components might be exposed (for example, temperature, degradation, and shock).

Figure 4-5 shows a generic schematic for an MWD/LWD system primarily based on the component/sub-system details shown in Table 4-4. The schematic represents a simplification of the components from a more detailed system architecture than is shown in Appendix D.1 (which was referred to at the beginning of the workshop and includes elements that may be applicable for specific systems).

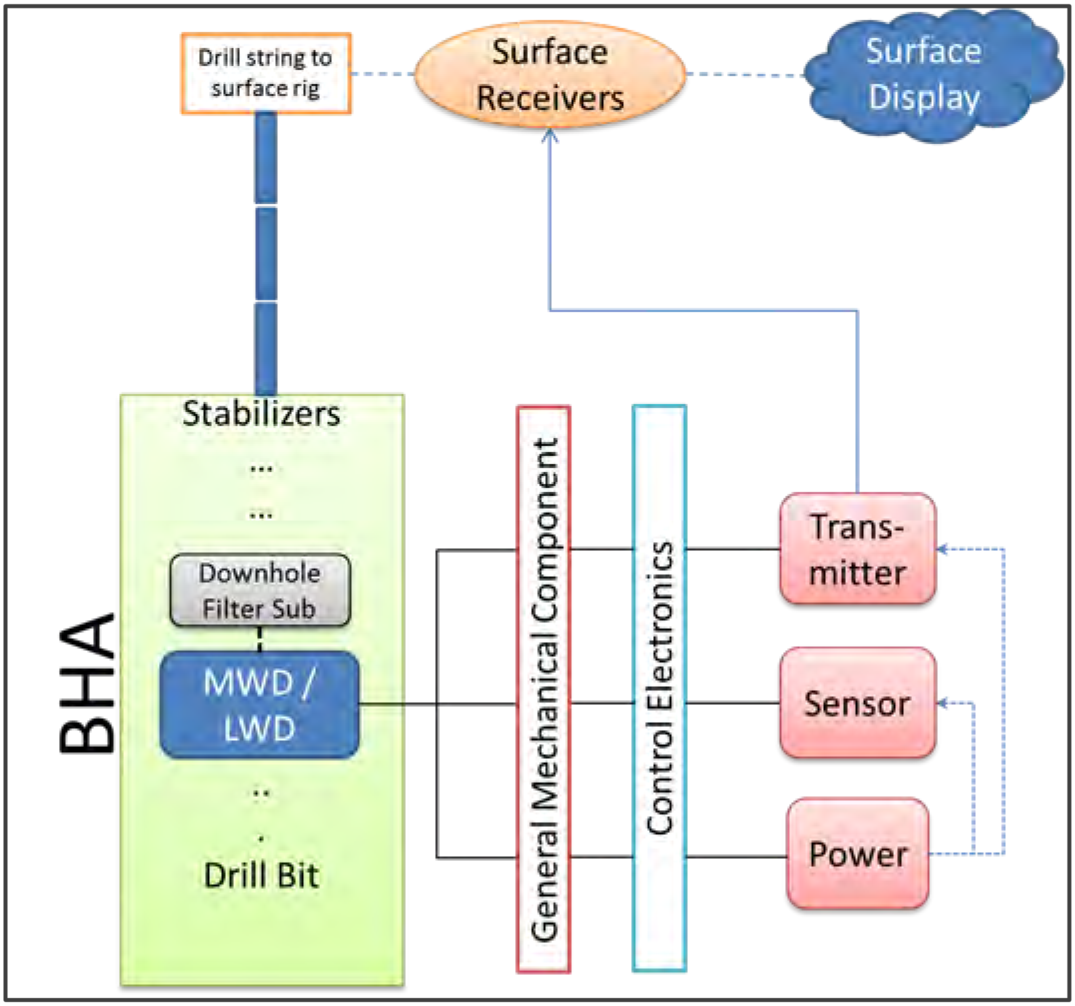

Figure 4-5: General Schematic for MWD/LWD Systems

4.4.5 MWD/LWD Systems FMECA Results

All of the MWD/LWD systems FMECA worksheets are in Appendix E.3. The worksheets include detail that goes beyond the scope of this section. For each failure mode, this section and Section 4.4.6 covers:

- Existing mitigations (Indication/Protection/Maintenance).
- Effects on components.
- Recommendations, comments, and corrective actions, if captured during the workshop.

Appendix F.3 contains all failure modes identified for all sub-systems or components and is sorted by decreasing RPNs. The RPN values determined for all failure modes ranged from 8 to 60, and some components (such as transmitter components subjected to electrical and mechanical failures and general mechanical components) repeatedly contributed relatively high values for RPN. Also, percentage of the contribution of individual failure mode toward the total RPN of a sub-system or component is reported. These data represent how severe a failure mode is for a given sub-system or component. It can be observed that human factor-related failure modes have a high contribution to surface module failure. Also, failure modes associated with nuclear sources have a very low contribution toward failure of general mechanical component failures.

Table 4-5 shows the MWD/LWD systems FMECA results with the percent contribution to total RPN by sub-system or component. On examination of Table 4-5, one can see, for example, that 30% of the total RPN is the highest contribution by a sub-system or component, and it is attributed to the general mechanical components. This flags the general mechanical components for representing a high risk to system functionality, requiring scrutiny. Similarly, for the other components analyzed, Table 4-5 shows each sub-system's or component's relative contribution to the system functionality risk.

Table 4-5: MWD/LWD Systems FMECA Results – Contribution to Total RPN by Sub-system or Component

Sub-system/Component	Function	Total RPN of Sub-system/Component	% of Total RPN for System
General Mechanical Components	Maintain design operational requirements	275	30
System Control Electronics	Provide control functions to various MWD/LWD components	188	21
Transmitter	Transmits data from tool to surface sensors	180	20
Surface Module	Receives, decodes, processes, displays, stores and distributes real time downhole data and monitor Surface system	112	12
Data sensors	Provide accurate data to drill well as planed or changes to wellbore path as needed	81	9
Downhole Filter Sub	Captures debris	36	4

Sub-system/Component	Function	Total RPN of Sub-system/Component	% of Total RPN for System
Power supply	Provides power to all electronics in the system	34	4

4.4.6 Discussion of MWD/LWD Systems FMECA Results

The following is a discussion of findings, recommendations, comments, and corrective actions (categorized by sub-systems or components) that were noted during the MWD/LWD systems FMECA workshop.

4.4.6.1 General Mechanical Components

MWD/LWD systems include a variety of general mechanical components such as seals, bearings, pistons, control valves, rotor and stator, drive assembly, inter tool connections, and radioactive source containments. During the FMECA workshop, all such mechanical components were grouped under the term 'General Mechanical.' This category of components provided the largest contribution to overall RPN score of all the components analyzed (refer to Table 4-5). Indeed, at 30% of the total RPN score, general mechanical components contributed about one and one-half times the second highest score, which was for system control electronics.

A collection of all general mechanical components was considered under a single component category. This aggregate component included all various mechanical components that were not identified separately. For this aggregate component, the summed RPN score was augmented by the many sub-components and their associated failure modes and mechanisms. Therefore, the 30% contribution to total system RPN may be exaggerated.

An inspection of the individual failure mode RPNs gives a more representative picture of risks that are caused by individual failure modes associated with general mechanical components. Most of the critical failure modes associated with general mechanical components are caused by erosion, especially for poor mud quality, excessive torque and vibration, and debris. These causes lead to the failure of components such as piston and control valves, rotor and stator, seals, drive assemblies, and inter tool connections. These failure modes were identified to occur sporadically or in isolation, but they had the ability to temporarily create complete loss of system functionality. Their detectability is remote because these components can fail without giving any noticeable indication, and they cannot be inspected during operation. However, some of the failure modes can be prevented by ensuring good mud quality, periodic inspection and replacement, proper job planning and maintenance, Quality Operational Plan (QOP), and avoiding out-of-spec operation.

Note that these identified unlikely failures have low RPN scores:

- Failure of bearings: unlikely because they are regularly replaced during maintenance cycles.
- Failure of nuclear sources: unlikely because of redundancy in the component design and detectability of such failure is moderate because a radioactive source failure can be monitored during operation.

4.4.6.2 System Control Electronics

System control electronics, which consists of various electronic components used in the MWD/LWD systems, has the second highest contribution (21%) to the overall RPN score. A closer look into the various failure modes reveals:

- The most significant mechanisms leading to loss of functionality are inaccurate programming, overheating, semiconductor, and soldering failure, and mechanical damage to the components.
- System control electronics failure may lead to inaccurate data driving poor decisions or no data. Such failure can cause drilling delays because the drilling operation is suspended to fix the failed component to avoid any potential safety impact.
- The failure modes mostly occur sporadically, but they can temporarily create complete loss of system functionality.
- Detectability is low because electronic component failure appears with little warning.
- Human error may contribute to the failure. Such occurrence is unlikely but has low detectability. However, proper training and competency, procedures, and guidelines can help to avoid this cause of failure.
- Failure caused by inaccurate programming can be reduced with measures such as proper quality assurance and quality control (QA/QC), software and firmware testing, and diagnostics.
- Out-of-spec operation of the MWD/LWD tools is a common phenomenon that can lead to immediate failure or can initiate a failure mode that can fail the component after a few cycles of operating outside of design specifications. Proper pre-job planning, alarms, clear procedures, and personnel training can help to reduce this cause of failure.

4.4.6.3 Transmitters

The contribution of transmitters to the total RPN (20%) is similar to that of system control electronics. A closer look into the various failure modes reveals that:

- Failure modes caused by electrical, mechanical, and fluid related factors mostly contribute to the failure of transmitters.
- Some of the identified failure causes are vibration and shock, high temperature, failure of stabilizer, and poor control of fluid properties (solid contaminants on the fluid).
- The occurrence of such failures is sporadic but it leads to temporary complete loss of system functionality, and the possibility of detection is remote.
- Real time alarms, better indicators, and clear procedures can protect against these failures.

4.4.6.4 Other Sub-systems and Components

Surface modules and data sensors contribute about 10% to the overall RPN score. Downhole Filter Sub (DFS) and power supply modules contribute little to RPN (only 4%). A closer look into the various failure modes of these sub-systems or components revealed:

- Sensor failure, software error, equipment failures such as cables and displays, and human error contribute to the failure of surface modules. However, these failure modes appear to occur only in isolated cases that lead to moderate contribution (each of about 28.5% or lower) toward the summed RPN scores for the sub-systems.
- Electronic and electrical failures, mechanical failure, and programming error contribute to the failure of data sensors. Although these failure modes have significant impact on the system functionality, they occur sporadically and have a moderate detection rate because many of these failures occur without any warning signs. Together, these criteria for occurrence and detection lead to medium RPN scores.
- Blockage caused by large debris and washout caused by erosion (sand content in the drilling fluid) contributes to the failure of filter sub. However, these failure modes are unlikely to occur because drilling fluid qualities are usually well maintained and large debris are rare or, if present, are easily detected. These factors lead to moderately low RPN scores.
- Various mechanical and electrical failures and loss of mud flow lead to power supply failure. However, such failures are rare occurrences because of the system

redundancy, and because some failure modes are easily detectable. These criteria for occurrence and detection together lead to low RPN scores.

It must be mentioned separately that, during the FMECA workshop, participants identified that software security, calibration of sensor tools, and vendor quality check all play an important role in reducing failure rates for MWD/LWD systems. Especially with the advent of real time data-sharing between rigs and onshore RTMCs, it is ever more important to protect electronic systems that are primarily automated from intentional cyber-attack, which can have severe consequences, and from unintentional software errors. However, none of the aforementioned aspects were examined in detail because of the high-level scope of the FMECA and because cyber-attacks and unintentional software bugs were outside the scope of this project.

4.5 Wired Drill Pipe FMECA Results

4.5.1 Summary of findings

Based on the high-level and generic scope of the FMECA, the Wired Drill Pipe system was categorized into two generic sub-systems or components: Surface systems and Downhole systems.

The Surface system was identified to have a high risk contribution, with 60% of the summed RPN score. The critical failure modes were identified as failure of network and failure of equipment. Equipment failures included plugs and cables, top drive couplings, a data swivel, and the saver bus. These failures could be caused by human error, software and equipment failures, and normal wear and tear. Failure of network was identified as a low occurrence event but with a high impact because it causes temporary complete loss of system functionality. Failure of the equipment and data swivel was identified to have a higher occurrence rating with a lower chance of failure detection. Preventive measures (such as quality control, training and competency, and regular maintenance) can reduce the occurrence of such failures.

The Downhole system was identified to have the rest of the failure risk contribution, with 40% of the summed RPN score. Two major types of failures were identified as electrical and electronic failure and mechanical failure. Electrical and electronic failure can occur because of overheating, manufacturing defects, out-of-spec operation, and failure of battery cell. Mechanical failure can occur because of improper operation and handling, out-of-spec operation, material degradation, and faulty manufacturing. The mechanical failures were identified to have a relatively higher occurrence compared to electrical and electronic failure, but both failures can result in complete loss of system functionality. Some preventive measures to reduce the likelihood of failure can be monitoring, training, maintenance, and quality assurance and quality control (QA/QC).

For the Wired Drill Pipe system, well safety was not of a concern even in the event of complete loss of system functionality. Generally, other data transmission modes, such as mud pulse telemetry, are available.

4.5.2 FMECA Workshop on the Wired Drill Pipe System

The FMECA on the Wired Drill Pipe system was performed in a half-day workshop at the Blade Energy Partners' office in Houston, Texas. Industry participation included independent consultants, representatives from vendors and service providers, Operators, BSEE, and the project team, as detailed in Appendix C.3.

Pre-populated FMECA worksheets (as described in Section 4.2.5) were used as a starting point for the FMECA workshops. Based on input from the workshop participants, the FMECA worksheets were updated and criticality rankings for each component were obtained. RPNs were calculated based on agreed likelihood, severity, and detectability of failure modes.

4.5.3 Wired Drill Pipe System FMECA Method

This FMECA considered the generic, primary components of the Wired Drill Pipe system without considering details from application-based customizations and variations in Operator specifications. The generic system consisted of a hardware components data link, wired pipe components, data swivel, etc. that are common to any application for the system. Because component information is available, a simple component-level (bottom-up) approach was adopted for this analysis.

The criticality of each failure mode was quantified to facilitate priority ranking of the failure modes. As discussed in Section 4.2.2, the absence of specific failure rate data for this application forced adoption of a qualitative approach, relying heavily on the engineering judgment of the workshop participants. Group consensus established qualitative measures of occurrence, severity, and detection criteria, with the product of these being the RPNs.

To assess failure mode criticality, the occurrence, severity, and detection criteria (as shown in Table B.1, Table B.2, and Table B.3 in Appendix B) were applied to each failure mode.

These criteria were applied by assessing how each failure mode affects the following Wired Drill Pipe system functional objectives:

1. To transmit downhole data to the Surface system with a very high transmission rate to send a large volume of real time measurement data for analysis and

monitoring of drilling activity and thereby increase both the efficiency and the safety of drilling operations.

2. To increase drilling efficiency by allowing measurements along the drill string.

Early in the workshop, participants identified that, for the Wired Drill Pipe system, well safety was not a concern, even in the event of complete loss of system functionality. This system is deployed to transmit BHA and along-string measurement (ASM) data with a high data transmission rate. The additional capability to acquire ASM data and the high data transmission rate aids in advanced software-modeling capabilities and improved automation implementation. Generally, other data transmission modes, such as mud pulse telemetry, are available.

4.5.4 Detailed System Breakdown

The detailed Wired Drill Pipe system breakdown into sub-systems and components is shown in Appendix D.2, which was prepared prior to the FMECA workshop. For reasons similar to those used with the MWD/LWD systems breakdown (refer to Section 4.4.4), a simplified, high-level system breakdown was used for the workshop (refer to Table 4-6). The system reflected is a generalized form of the Wired Drill Pipe system for an offshore or onshore application. In Table 4-6, the function of each general sub-system or component is described, and a reference ID that is specific to each sub-system or component is defined. Each sub-system or component was assessed separately in the FMECA workshop.

Table 4-6: Final Wired Drill Pipe System Simplified Breakdown and Function Statements

Sub-system/Component	Sub-system/Component Function	Reference ID
Surface System	Provides network connection between downhole components and surface tool provider	1
Downhole System	Provides bi-directional data transfer	2

Because the FMECA applied to generic Wired Drill Pipe systems, the sub-systems or components were defined in such a way that generic system functionality and associated failure modes could be considered. For example, the ‘Downhole System’ sub-system was not defined as a set of specific components such as tool interface electronics and power source for specific functionalities. Rather, it was defined generally, as a collection of all downhole components that are designed appropriately for transferring measured data to the Surface system. Consequently, when they determined failure modes for this example, the workshop participants considered conditions to which typical downhole components might be exposed (for example, temperature and battery cell failure).

Figure 4-6 shows a generic schematic for a Wired Drill Pipe system that is primarily based on the component/sub-system details shown in Table 4-6. The schematic represents a simplification of the components from the more detailed system architecture presented in Appendix D.2, which was referred to at the beginning of the workshop and includes elements that may be applicable for specific systems.

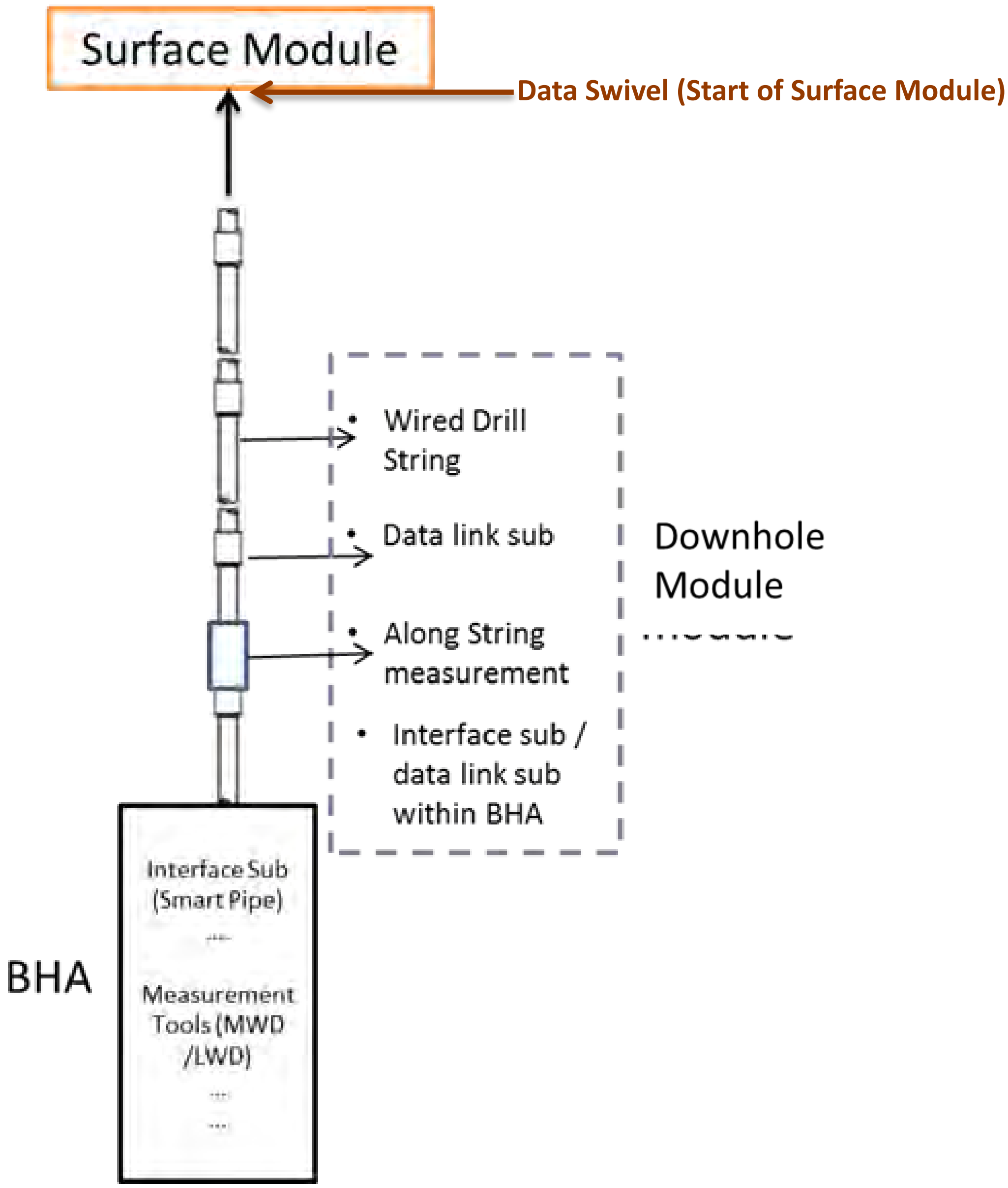

Figure 4-6: General Schematic for Wired Drill Pipe System

4.5.5 Wired Drill Pipe System FMECA Results

All of the FMECA worksheets for Wired Drill Pipe systems are included in Appendix E.4. These worksheets include detail that goes beyond the scope of this section. For each failure mode, this section and Section 4.5.6 cover:

- Existing mitigations (Indication/Protection/Maintenance).
- Recommendations, comments, and corrective actions captured during the workshop.

Appendix F.4 contains all identified failure modes for all sub-systems or components, and it is sorted by decreasing RPNs. The RPN values determined for all failure modes range from 32 to 60, and some components (such as cables and the data swivel) contributed relatively high values for the RPN. Also, the percentage of the contribution of individual failure modes toward the total RPN of a sub-system or component is shown. These data represent how severe a failure mode is for a given sub-system or component. It can be observed that mechanical equipment or mechanical connection-related failure modes have a higher contribution toward Surface system failure when compared to network-related failure modes. For Downhole systems, a similar trend is observed when mechanical component-related failure modes have a higher contribution compared to electrical and electronic component-related failure modes.

Table 4-7 shows the Wired Drill Pipe system FMECA results with the percentage of contribution to the total RPN by sub-system or component. As can be seen in the table, 60% of the total RPN, which is attributed to the Surface system, is the highest contribution by a sub-system or component. This observation flags the components associated with the Surface system for representing a high risk to system functionality.

Table 4-7: Wired Drill Pipe System FMECA Results – Contribution to Total RPN by Sub-system or Component

Sub-system/Component	Function	Total RPN of Sub-system/Component	% of Total RPN for System
Surface system	Provides network connection between downhole components and surface tool provider	152	60
Downhole system	Provides bi-directional data transfer	100	40

4.5.6 Discussion of Wired Drill Pipe System FMECA Results

The following is a discussion of findings, recommendations, comments, and corrective actions by sub-system or component that were noted during the Wired Drill Pipe system FMECA workshop.

4.5.6.1 Surface System

The Surface system consists of all sub-systems and components that provide the network connection between the downhole components (from the data swivel onward) and the surface tool provider. As shown in Table 4-7, the Surface system provided the largest contribution to overall RPN score out of all sub-systems or components analyzed. Indeed, at 60% of the total RPN score, the Surface system contributed one and a half times the second highest score, which was for the Downhole system that performs the bi-directional data transfer between the downhole data sensors (at BHA and along the string) and the Surface system.

A close look at the various failure modes reveals that three factors contribute to the failure of a Surface system:

- Failure of the network
- Failure of surface equipment such as cables and plugs
- Failure of top drive coupling, the data swivel, and the saver bus

The causes of network failure are similar to the causes of software and equipment failures for MWD/LWD systems, as noted in Section 4.4.6. Normal wear and tear and human factors are the main causes of failure of surface equipment and of the drive couple and the data swivel.

Although network failure is generally an isolated event, it can create temporary, complete loss of functionality, and failure detectability is low. Therefore, network failure mode has a moderate contribution of 21% toward the summed RPN score for the Surface system. Preventive measures are similar to those discussed in Section 4.4.6 for the software and equipment failures for MWD/LWD systems.

The failure of surface equipment, the drive couple, and the data swivel is relatively higher than that for the network system, and detectability is remote. Therefore, these failures have a high contribution of 80% (total) toward the summed RPN score for the surface module. Some preventive measures are training, competency, procedures to minimize human error, and maintenance to reduce damage from wear and tear.

4.5.6.2 Downhole System

The Downhole system consists of all sub-systems and components that perform the bi-directional data transfer between the downhole data sensors (at BHA and along the string) and the Surface system. The Downhole system comprises the wired drill string, interface subs, and data link subs for the Wired Drill Pipe system. Compared with the surface module, the Downhole system provides a lower contribution of 40% to the overall RPN score (refer to Table 4-7).

A close look at the various failure modes reveals that two main factors contribute to the failure of the Downhole system: (1) electronic and electrical failures and (2) mechanical failure.

Some of the causes of electrical and electronic failures are vibration and shock, elevated temperature, failure of battery cell, operating out of the specified range, and manufacturing defects. Mechanical failure can occur from material degradation, faulty manufacturing, out of spec operation, improper running and handling, etc.

Electronic and electrical failures are less likely to occur, compared with mechanical failures. However, both types of failure can create temporary, complete loss of functionality, and failure detectability is moderate. Therefore, electrical and electronic failures are associated with a lower contribution (40%) toward the summed RPN score for Downhole systems compared with the 60% contribution toward the summed RPN score for Downhole systems associated with mechanical failures.

Some preventive measures include proper monitoring, pre-job training, preventive maintenance, and QA/QC.

5.0 Conclusion

The objective of this report is to identify automated well safety technologies with the potential to increase safety during OCS drilling, well completion, well workover, and production operations.

Work on this report began with a review of the well control barriers and equipment commonly in use today. The project team has identified early kick detection and automated well safety systems and has assessed their roles within these barrier systems. The team has also reviewed current impediments to well safety automation and discussed efforts or technologies that help overcome these impediments. The role of applied backpressure Managed Pressure Drilling, which is the most established EKD technology in well safety, was assessed, including a review of its role in well control, its impact on the cause of kicks, and the frequency of LOWC incidents. Case studies gathered from industry interviews have been presented. The regulation of EKD and managed pressure drilling systems has been reviewed, and the project team has made recommendations with respect to future regulation.

Key findings of the study are:

1. A review of LOWC and blowout frequency shows that the overwhelmingly highest risk of LOWC occurs during drilling operations. According to a study conducted on wells drilled in the GOM OCS during 1980 – 2011, during drilling, a LOWC occurs for ~3.45 out of every 1,000 wells drilled, 2.44 of which result in blowout. This is an order of magnitude higher than those for the next most risky category interventions/workovers, with LOWC ~3.14 times every 10,000 well years. Production operations are far safer with a frequency of LOWC two orders of magnitude less than that of drilling operations. For this reason, this report concentrated on technologies that are pertinent to drilling operations.
2. A study of causes of LOWC during drilling operations shows that 54% of triggering causes could be mitigated or prevented by EKDS and an automated response such as that provided by the automated choke control in MPD systems.
3. The industry recognizes the requirement for automation in EKD. Given that the signs of LOWC were present in incidents such as Macondo, the need for an automatic detection and shut-in is clear.
4. Current automation efforts reflect the industry's organizational boundaries, with Rig Contractors, Service Companies, and Operators often having their own technologies operating with their own proprietary communication protocols. Automation requires integration and communication across organizational boundaries, and it is being impeded by this issue. Industry efforts are being

made to address these issues, with the SPE DSATS preparing standards to facilitate integration and a higher level of automation in drilling.

5. There is a communication gap between the surface and downhole environments as a result of low bandwidth in MWD telemetry, forcing current automation efforts to rely heavily on advanced wellbore models. The advent of wired pipe will likely contribute significantly to increased automation in well safety.
6. Current well control equipment has manually operated rig chokes, which force personnel to perform tasks that are outside their normal daily duties while under pressure and while participating in safety-critical operations. These operations, which are often difficult, involve coordinating choke adjustments with rig pumps and reacting to changes in friction pressures as gas reaches the choke, often leading to errors and secondary well control problems. Automation of rig chokes to maintain the desired annular pressure profile during well control operations provides an opportunity for significant well safety enhancements.
7. Applied backpressure MPD, which is the most established EKDS, offers the opportunity to enhance safety through not only EKD, but through active BHP management during the response, thereby significantly reducing the size of the influx.
8. Some already available applied backpressure MPD systems are capable of automatically detecting an influx, increasing backpressure until the influx ceases, and removing the influx, all without requiring human intervention.
9. In offshore applications with subsea BOPs and for influxes of sufficiently low severity, MPD enables the circulation of influx in the riser, which hugely reduces circulating friction pressures and the peak pressures at surface. The former can make influx removal without bull heading viable in deep water, while the later can improve surface safety.
10. Regression analysis for the deployment of applied backpressure MPD on land in Texas demonstrates that MPD reduces LOWC incident frequency and enhances well safety.

5.1 Risk Assessment of Early Kick Detection Systems (MPD)

The two system components that represent the highest risk to MPD system function are:

- Pressure Relief system, with 32% of the summed total RPN scores
- Valves and piping upstream of the MPD choke, with 14% of the summed total RPN scores

Further review of these components' failure modes showed that not only were the individual failure mode RPNs high, but they also dominated the list of failure modes with safety concerns.

Therefore, this project team has concluded that careful design of these two components is critical to the safe and efficient deployment of an MPD system.

This finding raised an important discussion with respect to system design that could not be specifically captured during the component-based FMECA. The Pressure Management system design should include appropriate consideration of high rate gas flow events, such as riser gas. Although this conclusion is not captured by the RPN rankings, it is reflected in the high level of representation of the MGS component in Appendix F.2, which lists failure modes that have significant impacts on safety.

The third highest percentage of MPD total RPN score (13%) is attributed to the Stroke Counter system. Although this percentage of total RPN score was comparable with that of the 'piping and valves upstream of the MPD choke,' close inspection of the analysis reveals that high RPNs were driven by low component reliability and did not reflect the same level of risk. The effects of the stroke counter's single failure mode (failure to measure correct volume) were identified as impaired operational awareness and impaired EKD, with a severity score of 3. This failure mode was not flagged as a concern for safety. Although the stroke counter component is a good focus for efforts to improve system reliability, it is not deemed as high a priority as the 'PRV' or 'upstream piping and valve' systems.

The remaining MPD components had relatively few failure modes at less than 10% of the total RPN. Aside from the MGS, none of those failure modes were identified as a significant source of concern for safety.

Therefore, this project team concluded that:

- The highest priority for reducing system risks is careful consideration of pressure management (as determined by the Pressure Relief system, piping and valves upstream of the choke, and the MGS).
- Efforts to improve reliability of the stroke counter component will offer significant improvements to the system functionality risk.

The most critical component for assessing the suitability of EKDS (MPD) as an automated well control technology is the Control system. Not only does the Control system represent a minor risk to system functionality at 3% of the total RPN, but no failure mode was flagged as a significant safety concern.

Thus, this project team has concluded that when combined with the benefits to well control safety (as detailed in the second interim *Evaluation of Automated Well Safety and Early Kick Detection Technologies* report for this project), MPD is an excellent candidate technology to be part of an automated well control strategy. On this basis, the project team recommends MPD for consideration in any such application.

5.2 Risk Assessment of Automated Well Control System – (MWD/LWD)

Based on the high-level and generic scope of the FMECA, the MWD/LWD systems were categorized into seven generic sub-systems or components:

- General mechanical components
- System control electronics
- Transmitters
- Surface modules
- Data sensors
- Power supply
- Downhole filter sub

A discussion of the generic sub-systems or components follows.

General Mechanical Components: The highest risk in terms of failure was the general mechanical components sub-system, with an RPN score of 60—a 30% contribution to the summed RPN score. This sub-system comprises components such as seals, bearings, and valves, and it is critical to the operational requirements of the MWD/LWD systems. The sub-system's most critical failure modes were identified as the failure of the pistons, control valves, rotor, and stator, which were caused by poor mud quality, erosion, and assembly error. Even though the occurrence of these failure modes is sporadic, the failures can happen suddenly and with a remote chance of detection during operation. Some preventive measures that can minimize these failure modes include regular inspection and maintenance and the use of good quality mud. On the other hand, failures of bearings and nuclear sources were identified with an RPN score of 20 and lower—a mere 7.3% or lower contribution to the summed RPN score for general mechanical components (because of the extremely low likelihood of failure).

System Control Electronics and Transmitters: About 20% of summed RPN scores were contributed by both the system control electronics sub-system and the transmitter sub-system. For system control electronics, failure modes involve mechanical or thermal damage as well as programming errors, each with around 12.8% contribution to the summed RPN score for the sub-system. The occurrence of these failure modes is low, but they can lead to temporary loss of system functionality. Also, detectability of these failure modes is low. However, preventive measures such as QA/QC in manufacturing and operating procedures, job planning, and training may reduce the likelihood of such events. For transmitters, failure modes have a high RPN score of 60, mainly because of low detectability and a medium likelihood of failure.

Other Sub-systems: Surface modules, data sensors, power supply, and DFS were identified to have a small contribution to failure, with only 10% or less of the summed RPN values.

For MWD/LWD systems considered in isolation, well safety was not a concern, even in the event of complete loss of system functionality.

In addition, important preventive measures to reduce failure rates for MWD/LWD systems include software security, calibration of sensor tools, and vendor quality checks.

5.3 Risk Assessment of Automated Well Control System – Wired Drill Pipe

Based on the high-level and generic scope of the FMECA, the Wired Drill Pipe system was divided into two generic sub-systems or components:

- Surface system
- Downhole system

5.3.1 Surface System

The Surface system was identified to have a higher risk contribution than the Downhole system—60% of the summed RPN score. The Surface system comprises all sub-systems and components that provide network connections between downhole components (from the data swivel onward) and the surface tool provider. The Surface system critical failure modes were identified as failure of network and failure of equipment, such as plugs and cables, top drive couplings, the data swivel, and the saver bus. These failures could be caused by human error, software and equipment failures, or normal wear and tear. Failure of network was identified as a low occurrence event, but it had a high impact because it causes temporary, complete loss of system functionality. Failure of equipment and the data swivel was identified to have a higher occurrence rating, with a low chance of failure detection. Preventive measures that can reduce the occurrence of such failures include quality control, training and competency, and regular maintenance.

5.3.2 Downhole System

The Downhole system was identified to have the rest of the failure risk contribution, with 40% of the summed RPN score. The Downhole system comprises the wired drill string, interface subs, and data link subs for the Wired Drill Pipe system. Two major types of failures were identified: (1) electrical and electronic failure and (2) mechanical failure. The electrical and electronic failure can occur because of overheating, manufacturing defects, out-of-spec operation, and battery cell failure. Improper operation and handling, out-of-spec operation, material degradation, and faulty manufacturing may cause mechanical failure. The mechanical failures were identified to have a relatively higher occurrence compared with electrical and electronic failure, but both types of failure can result in complete loss of system functionality.

Some preventive measures that can reduce the likelihood of these failures include monitoring, training, maintenance, and QA/QC.

6.0 Recommendations

Based on the key findings outlined in Section 5.0, the project team recommends the following regulatory changes for consideration:

1. Regulations in the U.S. are currently treating EKDS and automation technologies as new technology. This forces closer evaluation of each deployment and is appropriate, given the only recent move of this technology into the offshore environment and the rapid evolution that it is currently undergoing. This approach should be maintained until these technologies become well established in the OCS.
2. Early in this investigation it became clear that the development of applications for EKD and automated well safety are concentrated on drilling operations. Although drilling dominates the LOWC statistics, there are still a significant number of incidents that occur during non-drilling well construction, intervention, and production operations. The project team therefore recommends that a separate study be conducted on applications of EKDS technology and automated well safety techniques applied to non-drilling well construction and maintenance operations. Such a study should facilitate industry engagement to explore:
   a. The key issues with applying EKD and automated well safety to non-drilling well construction and maintenance operations (and possible solutions).
   b. How some drilling-focused technologies (such as automated connection fingerprinting) could be adapted for EKD in non-drilling well construction operations.
3. A major impediment to automation is the lack of a generic data protocol to facilitate easy communication among the rig, service provider, and Operator systems. The project team recommends the establishment of liaisons between BSEE and the industry bodies (such as SPE DSATS) that are working on solutions to this problem.
4. During the course of this report, the project team encountered different positions as to whether a traditional flow check is the best method for confirming an influx into the well. This suitability of the flow check approach starts to be questioned when technologies such as MPD can facilitate detection without requiring pumps to be turned off. This prevents the resulting loss of annular friction and associated reduction in BHP, which can worsen any influx. The project team recommends a concentrated study on the alternatives to the traditional flow check and the impact of new drilling technologies on well control procedures.

5. For MPD, the MMS issued an NTL in 2008, which gave good guidance as to the operating boundaries of MPD and its role with respect to well control. This NTL has since expired. The project team recommends revision and reissuance of this NTL, as it is still being used to provide guidance to the industry.
6. Regulations should be revised with respect to primary barrier requirements in view of MPD and EKD. Current BSEE regulations require in 30 CFR 250.414 (c) that a drilling prognosis must include, but is not limited to, the "Planned safe drilling margin between proposed drilling fluid weights and estimated pore pressures. This safe drilling margin may be shown on the plot required by §250.413(g)." This implies a statically overbalanced fluid that will increase wellbore pressures for MPD (with applied backpressure) higher than required for the stated safety margin. This will reduce the effectiveness of many MPD applications to provide the positive MPD well safety benefits. In many cases, particularly in deep water and high pressure, high temperature (HPHT) applications, it may completely prevent the use of applied backpressure MPD. A requirement for a safe drilling margin between the proposed wellbore pressure profile and the estimated pore pressures should be retained, but regulations should not preclude it from being achieved through a combination of drilling fluid hydrostatic and applied surface pressures. If the fluid density becomes underbalanced with respect to estimated pore pressures, the MPD equipment may enhance use of the primary barrier system, so appropriate steps must be taken to ensure that the MPD system is fit for this service. Shifting toward requirements to maintain a primary barrier will bring regulations into alignment with international regulations and certification standards such as those of NORSOK, DNV, and the American Bureau of Shipping (ABS).
7. A Rule published in the Federal Register, Volume 80, No. 74, dated Friday, April 17, 2015 [139] requires that "Static downhole mud weight must be a minimum of one-half pound per gallon below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient" be added to eCFR §250.414 (c), where the regulation states what must be included as part of drilling prognosis. This Proposed Rule could have a significant effect on the efficacy of advanced kick detection and MPD applications, which allows drilling operations to be performed safely at a lower pressure differential. For example, deep water wells drilling operations often require a lower margin than what is proposed in the new Rule. Therefore, the new Proposed Rule, if implemented, may significantly reduce drilling operations. However, the Proposed Rule may be revisited in light of the findings of this report and the comments received by BSEE prior to the final adoption of the Rule.

8. In applications where a rotating control device (RCD) is used, consideration should be given to include a requirement to meet API Specification 16RCD to help ensure that this critical element is fit for purpose as a primary barrier.

Limitations of the Report

The scope of this report is limited to the matters explicitly covered and is prepared for the sole benefit of Bureau of Safety and Environmental Enforcement (BSEE). In preparing the report, Blade Energy Partners (BEP) and Wood Group Kenny (WGK) relied on information provided by BSEE and third parties. BEP and WGK made no independent investigation as to the accuracy or completeness of such information and assumed that such information was accurate and complete.

All recommendations, findings, and conclusions stated in this report are based on facts and circumstances as they existed at the time this report was prepared (October 2015). A change in any fact or circumstance on which this report is based may adversely affect the recommendations, findings, and conclusions expressed in this report.

7.0 References

1. Blade Energy Partners. “Managed Pressure Drilling Design and Operations – Training Manual,” 2014.
2. Bercha, F. G. “OCS Study BOEM 2014-772 - Loss of Well Control Occurrence and Size Estimators for Alaska OCS,” BOEM and Bercha Group, Calgary, 2014.
3. Baker Hughes Technical Report on Microhole Wireless Steering while Drilling System, March 2008.
4. Stalford, Harold. “Intelligent Casing-Intelligent Formation Telemetry (ICIFT) System,” RPSEA Ultra-Deepwater Drilling, Completions, and Interventions TAC Meeting, June 4, 2014.
5. Jellison, M. J., Prideco, G., Hall, D. R., Howard, D. C., Hall, H. T., Long, R. C., Chandler, R. B., ,and Pixton, D. S. (2003).Telemetry Drill Pipe: Enabling Technology for the Downhole Internet. SPE paper #79885.SPE/IADC Drilling Conference, Amsterdam, Netherlands, February 19–21, 2003.
6. Veeningen, Daan. “Along-String Pressure Evaluation Enabled by Broadband Networked Drillstring Provide Safety, Efficiency Gains,” OTC Brazil, October 4-6, 2011.
7. National Oil Well Varco, “IntelliServ Handling and Best Practices Handbook, May 2013, D392005027-MKT-001 Rev. 02,” [Online]. Available: https://www.nov.com/WorkArea/DownloadAsset.aspx?id=10492. [Accessed 12 May 2015].
8. Det Norske Veritas. DNV-RP-E101, “Recertification of Well Control Equipment for the Norwegian Continental Shelf,” January 2012.
9. Det Norske Veritas. DNV-RP-E102, “Recertification of Blowout Preventers and Well Control Equipment for the U.S. Outer Continental Shelf,” June 2010.
10. NORSOK Standard D-010, "Well Integrity in Drilling and Well Operations," Rev.4, June 2013.
11. “Petroleum/NORSOK – Standard.” www.standard.no [Accessed March 10, 2015].
12. "Standards Norway." https://www.standard.no/en/toppvalg/about-us/standards-norway/#.VUer9Y5VhBc [Accessed March 18, 2015].
13. "Communication Guideline." https://www.standard.no/en/sectors/energi-og-klima/petroleum/communication-guideline/#.VUesJ45VhBc [Accessed March 12, 2015].

14. "From Prescription to Performance in Petroleum Supervision." http://www.psa.no/news/from-prescription-to-performance-in-petroleum-supervision-article6696-878.html [Accessed March 10, 2015].
15. "Regulatory Compliance on the Norwegian Shelf." http://www.inocean.no/regulatory-compliance-on-the-norwegian-shelf/ [Accessed March 29, 2015].
16. NORSOK Standard D-002. "System Requirements Well Intervention Equipment," Rev.2, October 2013.
17. NORSOK Standard U-001. “Subsea Production Systems,” Rev.3 October 2002, https://www.standard.no/en/PDF/FileDownload/?redir=true&filetype=Pdf&item=132403&category=4 [Accessed February 2, 2015].
18. Canada C-NLOPB & CNSOPB. “Drilling and Production Guidelines.” Section 36, Well Control Equipment. March 2011, http://www.cnsopb.ns.ca/sites/default/files/pdfs/DrillingandProduction_Guidelines_Mar312011.pdf [Accessed January 7, 2015].
19. Canada-Newfoundland & Labrador Offshore Petroleum Board Regulations (C-NLOPB). “Guidelines for Drilling Equipment.” http://www.cnlopb.ca/pdfs/guidelines/guidelines_for_drilling_equipment.pdf [Accessed January 7, 2015].
20. Code of Federal Regulations. Title 30: Mineral Resources. Part 250 – Oil and Gas and Sulphur Operations in the Outer Continental Shelf. http://www.ecfr.gov/cgi-bin/text-idx?SID=d589bff60dab011abe9574be79f83274&node=pt30.2.250&rgn=div5. [Accessed December 10, 2014].
21. British Standard BS EN ISO 14224:2006 “Petroleum, Petrochemical and Natural Gas Industries.” Collection and Exchange of Reliability and Maintenance Data for Equipment, February 2007.
22. British Standard BS EN ISO 13628-4:2010, “Petroleum and Natural Gas Industries. Design and Operation of Subsea Production Systems.” Subsea Wellhead and Tree Equipment, January 2012.
23. API Spec 16A/ISO 13533:2001, "Specification for Drill-though Equipment," Third Edition, June 2004.
24. API Spec 6A/ISO 10423:2009, "Specification for Wellhead and Christmas Tree Equipment," Twentieth Edition, October 2010.
25. API Spec 16C (R2010), "Choke and Kill Systems," First Edition, July 2001.
26. API Spec 16D, "Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment," Second Edition, July 2004.

27. API Spec 16RCD, "Drill Through Equipment – Rotating Control Devices," First Edition, February 2005.
28. API Spec 16F, "Specifications for Marine Drilling Riser Equipment," First Edition, August 2004.
29. API Spec 16R, "Specification for Marine Drilling Riser Couplings," Reaffirmed, 2010, ISO 13625 “Marine Drilling Riser Couplings,” First Edition, January 2001.
30. NTL No. 2008-G07, “Managed Pressure Drilling Projects,” May 2008.
31. API RP 53, "Blowout Prevention Equipment Systems for Drilling Wells," Fourth Edition, November 2012.
32. API RP 59, "Recommended Practice for Well Control Operations," Second Edition, January 2012.
33. API RP 64, “Diverter Systems Equipment and Operations," Second Edition, November 2011.
34. API RP 16 ST, “Coiled Tubing Well Control Equipment Systems," First Edition, March 2009.
35. API 510, “Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair and Alteration," Tenth Edition, May 2014.
36. API RP 572, “Inspection of Pressure Vessels," Third Edition, November 2009.
37. API RP 576, “Inspection of Pressure-relieving Devices," Third Edition, November 2009.
38. Burgess, T. et al. "Improvements for Kick Detection."
39. Surface Data Sensors During Drilling. http://petrowiki.org/Surface_data_sensors_during_drilling [Accessed February 10, 2015].
40. Fraser, D. et al. "Early Kick Detection Methods and Technologies," SPE 170756-MS, 2014 SPE ATCE.
41. “National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling Chief Counsel’s Report.” http://www.oilspillcommission.gov/chief-counsels-report [Accessed January 13, 2015].
42. “Pressure-While-Drilling.” http://scientificdrilling.com/content/uploads/2014/01/Product-Spec-Sheet_Pressure-While-Drilling.pdf [Accessed January 7, 2015].
43. “Using Downhole Annular Pressure Measurements.” https://www.slb.com/~/media/Files/resources/oilfield_review/ors98/win98/using.pdf [Accessed January 11, 2015].
44. “LWD Ecoscope.” http://iodp.ldeo.columbia.edu/TOOLS_LABS/LWD/IMG_LWD/lwd_ecoscope.jpg [Accessed January 12, 2015].

45. Wilson, J. “Real-time Formation Pressure Testing Extends ‘While-Drilling’ Capabilities.” Offshore, April 2009.
46. Lawrence, L. et al. "Intelligent Wired Drill Pipe System Provides Significant Improvements in Drilling Performance on Offshore Australia Development." OTC-20067 presented at OTC 2009.
47. Pavel, D. and Grayson, B. “Advanced Pressure Control Improves Kick, Loss Detection.” Oil and Gas Journal, December 20, 2010.
48. "Wired-Drillpipe Field Trials Reveal Potential Benefits Over Traditional Pipe." JPT, June 2013.
49. Edwards, T. et al. "A Summary of Wired Drill Pipe Field Trials and Deployments in BP" SPE 163560, SPE/IADC 2013.
50. Grebstad, L. "The Influence of Automation on Human Error in Managed Pressure Drilling Well Control." NTNU, June 2014.
51. Chapman, F. et al. “Deepwater BOP Control Monitoring – Improved BOP Preventive Maintenance with Control Function Monitoring.” OTC 20059 Houston May 4–7, 2009.
52. Chapman, F. “Drilling Safety: Off-Rig BOP Monitoring,” BOP Forum, May 2012.
53. McKay, J. et al. “Blowout Preventer (BOP) Health Monitoring,” 2012 IADC/SPE Drilling Conference.
54. Panel No. 4: “What Real-Time Technologies Are Available to Measure the ‘Health’ of BOPs in Service and Aid in the Detection and Response to ‘Kicks?’” BSEE BOP Forum, May 2012.
55. Zanghi, M. "Advancing Global Deepwater Capabilities." http://www.bp.com/content/dam/bp/pdf/investors/SRI_field_trip_monitoring_center.pdf. [Accessed February 12, 2015].
56. Levine, Joe. "BSEE and BOEM Workshop with Government of Israel." BSEE.
57. Robertson, M. “Intelligent Well Completions.” JPT Technology Today Series, August 2003.
58. Yeten, B., Brouwer, D.R., Durlofsky, L.J., Aziz, K. “Decision Analysis under Uncertainty for Smart Well Deployment.” Journal of Petroleum Science Engineering (2004).
59. “Schlumberger Intelligent Completions: Middle East and Asia Reservoir Review.” November 2007.
60. Garner, J. et al. “At the Ready: Subsurface Safety Valves.” Oilfield Review (Winter 2002-2003), 53.
61. Huse, J. "Review Of and Experience with Emergency Shutdown Systems," Offshore Europe, September10–13, 1985, Aberdeen, United Kingdom.

62. Bern, P. A., van Oort, E., Neusstadt, B., Ebeltoft, H., Zurdo, C., Zamora, M., and Slater, K. IADC/SPE 47784 Barite Sag: Measurement, Modelling and Management, Jakarta, 1998.
63. Randy Smith Training Solutions, Well Control Drilling Operations Training Manual, 2002.
64. Innovative Electronics, “Pit Volume Totalizer,” Innovative Electronics, [Online]. Available: www.innelect.com. [Accessed 11 2 2015].
65. Amtek Drexelbrook, “Measuring Drilling Fluid Level in Mud Tanks: Ultrasonic Pit Level Sensor,” Drexelbrook, 2005. [Online]. Available: www.drexelbrook.com. [Accessed 11 Feb 2015].
66. O'Brien, T. B. “Handling Gas in an Oil Mud Takes Special Precautions,” World Oil, 1981.
67. Silva, C. T., Bonet, E. J., Mariolani, J. R. L. Lomba, R. F. T., Santos, O. L. A., and Ribeiro, P. R. SPE 91009 Gas Solubility in Synthetic Fluids: A Well Control Issue, Houston: SPE, 2004.
68. Petroleum Safety Authority Norway, Well Control Incidents – RNNP Study 2011, Petroleum Safety Authority Norway, 2011.
69. Bacon, W. Sugden, C., and Gabaldon, O. SPE/IADC 173174 From Influx Management to Well Control; Revisiting the MPD Operations Matrix, London: SPE/IADC, 2015.
70. Januarilham, Y. “Analysis of Component Criticality in the Blowout Preventer” - Masters Thesis, Stavanger: University of Stavanger, Norway, 2012.
71. Grondahl, M., Park, H., Roberts, G., and Tse, A. “Investigating the Cause of the Deepwater Horizon Blowout,” June 21, 2010. [Online]. Available: http://www.nytimes.com/interactive/2010/06/21/us/20100621-bop.html. [Accessed 4 February 2015].
72. Holand, P. and Skalle, P. “Deepwater Kicks and BOP Performance, Unrestricted Version,” Minerals Management Service, SINTEF Industrial Management, 2001.
73. Whitby, M. F. “Design Evolution of a Subsea BOP,” Drilling Contractor, 2007.
74. Holand, P. “Reliability of Subsea BOP Systems for Deepwater Application, Phase II DW, Unrestricted version,” Minerals Management Service, SINTEF, 1999.
75. Sattler, J. and Gallander, F. “JIP Study on BOP Reliability 2004 – 2006: Subsea Control Systems Were Most Prone to Failure,” Drilling Contractor, 2010.
76. Sattler, J. and Gallander, F. IADC/SPE 128941 Just How Reliable Is Your BOP Today? Results from a JIP, GOM 2004 – 2006, New Orleans: SPE/IADC, 2010.

77. Bellarby, J. Well Completion Design, Amsterdam: Elsevier, 2009.
78. Rigtrain, Rigtrain Drilling and Well Services Training, 2007.
79. Peden, J. M. Completions and Workovers Training Manual, Petroskills, 2007.
80. ICOTA, “Intervention and Coiled Tubing Association,” 2012. [Online]. Available: http://www.icota.com. [Accessed March 2, 2015].
81. WCS, WCS IADC WellCap Well Control for Coiled Tubing Operations Training Manual, WCS, 2013.
82. Hsieh, L. “Bridging the Communications Gap in Rig Automation,” Drilling Contractor, September 8, 2010.
83. MacPherson, J. D., de Wardt, J., Florence, F., Chapman, C. D., Zamora, M., Laing, M. L., and Iversen, F. P. SPE 166263 Drilling System Automation: Current State, Initiatives and Potential Impact, New Orleans: SPE, 2013.
84. Kirkman, M. A., Symmonds, M. E., Harbinson, S. W., Shields, J. A., Will, M., and Doniger, A. SPE 84066 Wellsite Information Transfer Standard Markup Language, WITSML, an Update, Denver: SPE, 2003.
85. Sprynet.com, “WITS Wellsite Information Transfer Specification,” [Online]. Available: http://home.sprynet.com/~carob/. [Accessed March 4, 2015].
86. Hollingsworth, J. “The State of Standards In the Digital Oil Field,” E&P Magazine, February 2, 2015.
87. OPC Foundation, “opcfoundation.org,” 2015. [Online]. Available: http://www.opcfoundation.org. [Accessed 4 March 2015].
88. Morrison, P. and Shields, J. “IT, Standards Can Help Aggregate Well Data for High-Level Automation,” Drilling Contractor, September 10, 2013.
89. NOV, “Tomorrow's Technology Today,” European Oil and Gas, October 1, 2012.
90. Mazerov, K. “Automation: On the Cusp of Transformation,” Drilling Contractor, September 17, 2012.
91. Godhavn, J.-M., Pavlov, A., Kaasa, G.-O., and Rolland, N. L. Drilling Seeking Automatic Control Solutions, Milano, Italy, 2011.
92. Torrione, P. and Morton, K. Computer Vision Systems for Safer, More Efficient Drilling, CoVar Applied Technologies internal presentation, 2015.
93. Kozicz, J., Martin, T., Torrione, P., Morton, K. D., and Hibbard, M. Safety and Efficiency through advanced Video Processing DEA presentation, CoVar Applied Technologies and Transocean, 2013.
94. Ressenfoss, S. “Automated Drilling Raises Control Issues,” SPE JPT, pp. 36-37, September 2011.
95. Aldred, W., Bourque, J., Mannering, M., Chapman, C., du Castel, B., Hansen, R., Downton, G., Harmer, R., Falconer, I., Florence, F., Zurita, E. G., Nieto, C., Stauder, R., and Zamora, M. Drilling Automation, Schlumberger, 2012.

96. Cayeux, E., Daireaux, B., Dvergsnes, E. W., and Florence, F. "SPE 163440 Toward Drilling Automation: On the Necessity of Using Sensors that Relate to Physical Models," no. June 2014.
97. Halliburton, Real Time Density and Viscosity (RTDV) Measurement Unit Flyer, Halliburton, 2012.
98. Broussard, S., Gonzales, P., Murphy, R., and Marvel, C. SPE 137999 Making Real Time Fluid Decision with Real Time Fluid Data at the Rig Site, Abu Dhabi: SPE, 2010.
99. Aspect Imaging, "www.aspectiimaging.com," 2015. [Online]. Available: http://www.aspectimaging.com/advanced-industrial/product/flowscan-real-time-rheology-system. [Accessed February 26, 2015].
100. Magalhaes, S., Scheid, C., Calcada, L. A., Folsta, M., Martins, A. L., and Marques, C. H. SPE/IADC 167978 Development of On-Line Sensors for Automated Measurement of Drilling Fluid Properties, Fort Worth: SPE/IADC, 2014.
101. Instrumart, "Flow Metering," 2015. [Online]. Available: https://www.instrumart.com/MoreAboutCategory?CategoryID=3049 [Accessed 25 February 2015].
102. Smart, D., Russell, C., and Simons, M. Understanding and Selecting Coriolis Technology for Drilling Fluid Monitoring, MicroMotion.com, 2013.
103. Omega, "Liquid Flowmeters," Omega, 2015. [Online]. Available: http://www.omega.com/techref/flowcontrol.html. [Accessed February 25, 2015].
104. Mazerov, K. "Front Loaded Approach to Well Control Stresses Planning, Prevention," Drilling Contractor, July 10, 2014.
105. Santos, H. Taking Well Control to a Whole New Level, London: Safekick, 2011.
106. Safekick, "Safekick – Understanding Your Drilling," Digital Energy Journal, p. 11, April/May 2012.
107. Safekick, "Safekick.com," Safekick, July 18, 2013. [Online]. Available: http://www.safekick.com. [Accessed March 11, 2015].
108. Sonnemann, P. and Santos, H. "Automated Well Control: Industry Gets Ready for 20,000psi and Beyond," Drilling Contractor, July 10, 2014.
109. NOV. "NOV Kick Monitoring Display," NOV, [Online]. Available: http://www.nov.com. [Accessed March 13, 2015].

110. NOV. "Kick Monitoring Display Case History: Kick Monitoring System Provides Early Identification of 22-Barrel Kick in Houma Well." [Online]. Available: http://www.nov.com/Segments/Wellbore_Technologies/Dynamic_Drilling_Solutions/Systems/Managed_Pressure_Drilling/Kick_Monitoring_Display.aspx. [Accessed March 13, 2015].
111. Milner, M. Influx Detection at the Pumps Stop (IDAPS), A System to Detect Influx During Pumps Off Events, CoVar Applied Technologies, 2015.
112. Ali, T. H., Harberer, S. M., Says, I. P., Ubaru, C. C., Laing, M. L., Halgesen, O., Liang, M., and Bjelland, B. SPE/IADC 163474 Automated Alarms for Smart Flowback Fingerprinting and Early Kick Detection, Amsterdam: SPE/IADC, 2013.
113. Cayeux, E. and Daireaux, B. SPE 119435 Early Detection of Drilling Conditions Using Real Time Calibration of Computer Models: Field Example from North Sea Drilling Operations, 2009.
114. Tikhonov, V., Valiullin, K., Nurgaleev, A., Ring, L., Gandikota, R., Chaguine, P., and Cheatham, C. SPE 163566 Dynamic Model for Stiff String Torque and Drag, SPE, 2013.
115. Mitchell, R. F., Bjorset, A., and Grindhaug, G. SPE 163477 Drillstring Analysis with a Discrete Torque-Drag Model, SPE, 2013.
116. Bourgoyne, A. T. and Young, F. S. SPE 4238 A Multiple Regression Approach to Optimal Drilling and Abnormal Pressure Detection, SPE Journal, 1974.
117. Saponja, J., Adeleye, A., and Hucik, B. "IADC/SPE 98787 Managed Pressure Drilling (MPD) Field Trials Demonstrate Technology Value," in IADC/SPE Managed Pressure Drilling Conference and Exhibition, San Antonio, 2005.
118. Sugden, C., Bacon, W., Gabaldon, O., Borges, J. U., Soares, C. M., Falcao, J. L., et al. "IADC/SPE-168028 Real-Time Casing Design Optimization: A Case Study in the Use of Managed Pressure Drilling to Develop an Adaptive Well Design and Eliminate Casing Strings on a Deepwater Exploration Well." SPE Drilling and Completion Journal. SPE. December 2014
119. Handal, A. and Sondre, O. Safety Barrier Analysis and Hazard Identification of Blowout Using Managed Pressure Drilling Compared with Conventional Drilling, San Antonio, 2013.
120. Gabaldon, O., Culen, M., and Brand, P. "Enhancing Well Control Through Managed Pressure Drilling," in Offshore Technology Conference, Houston, 2014.

121. Bacon, W., Tong, A., Gabaldon, O., Sugden, C., and Suryanarayana, P. V. "SPE/IADC 151392 An Improved Dynamic Well Control Response to a Gas Influx in Managed Pressure Drilling Operations," in 2012 IADC/SPE Drilling Conference and Exhibition, San Diego, 2012.
122. MMS, NTL 2008-G07, 2008.
123. Godhavn, J.-M. and Knudsen, K. A. IADC/SPE 128222 High Performance and Reliability for MPD Control System Ensured by Extensive Testing.
124. Weatherford, "Weatherford; MPD," 2015. [Online]. Available: http://www.weatherford.com/products-services/well-construction/secure-drilling/managed-pressure-drilling. [Accessed 1 March 2015].
125. Managed Pressure Operations, "MPO," MPO, 2015. [Online]. Available: http://www.managed-pressure.com/deepwater-riser-gas-handling.aspx. [Accessed March 1, 2015].
126. OGP, International Association of Oil and Gas Producers, Report No 434-2, Blowout Frequencies, OGP, 2010.
127. Scandpower, Scandpower Risk Management AS 2006, Scandpower, 2006.
128. SINTEF, Blowout and Well Release Characteristics and Frequencies, 2010: SiNTEF, 2010.
129. Thorson, L., Dyb, K., Nielsen L. and the Danish Center for Environment and Energy, "Blowout Risk Evaluation in the Labrador Sea," Bureau of Minerals and Petroleum, 2012.
130. Vargas, A. C. Use of Rotating Control Devices in High Pressure/High Temperature Applications in Brazil Provides Economic and HSE Benefits, Houston: OTC, 2006.
131. Jablonowski, C. J. and Podio, A. L. SPE 133019 The Impact of Rotating Control Devices on the Incidents of Blowouts: A Case Study for Onshore Texas, USA, Port of Spain: SPE, 2010.
132. Patel, H., Pham, M,. Korn, M., Waters, P., and Das, B. OTC 22758 Safety Enhancement to Offshore Drilling Operations, Rio de Janeiro: OTC Brasil, 2011.
133. DNV, Technical eNewsletter DNV DRILL/DRILL(N) Class Requirements for Managed Pressure Drilling Systems, DNV, 2011.
134. Lee, J, "Industry Set for New MPD Guidelines," Offshore Engineer, 2 Feb 2015.
135. Rausand, M. and Høyland, A. System Reliability Theory: Models, Statistical Methods, and Application, Second Edition. 2004.
136. ISO 14224:2006, "Petroleum, Petrochemical, and Natural Gas Industries—Collection and Exchange of Reliability and Maintenance Data for Equipment."

137. IEC 61508, “Functional Safety of Electrical/Electronic/Programmable Electronic Safety-Related Systems.”

138. IEC 61511, “Functional Safety - Safety Instrumented Systems for the Process Industry Sector.”

139. Federal Register, Volume 80, No. 74, Part III, “30 CFR Part 250 Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control; Proposed Rule,” Department of Interior, Bureau of Safety and Environmental Enforcement, Friday, April 17, 2015.

~~-o0o-~~-o0o-

Appendix A Industry Surveys

Multiple surveys were sent to Original Equipment Manufacturers (OEMs) of automated well control equipment and components to assess technological/design advances. Following are the two responses that were received from the OEMs surveyed. The responses were paraphrased to remove any identity of the responder or OEM and for better readability.

A.1 OEM # 1

1. Please list automation and early kick detection (EKD) related equipment for drilling/production/workover/completion that you currently supply.

Response – We supply Automated Managed Pressure Drilling (MPD) systems with EKD capabilities for well construction operations.

2. **A.** Of this equipment, please list how those items contributed to enhancing well safety.

B. Was this equipment developed specifically for safety enhancement or another reason, such as production improvement?

Response – Our system provides an enhanced EKD system that minimizes influx, therefore increasing safety. This includes:

1. Rotating Control Device (RCD), which seals the wellbore.
2. Coriolis meters, which measure flow in and flow out for EKD.
3. Pressure While Drilling (PWD) system, which inputs into the EKD system.
4. Rig Pump Diverter, which diverts flow from downhole via stand pipe to across MPD Choke to maintain flow across choke for surface backpressure maintenance (eliminates need for Backpressure Pump).
5. Real Time Hydraulic Model, which receives well data real time and provides a control point for chokes/surface backpressure to maintain Bottomhole Pressure (BHP) required real time.
6. Software monitoring system, Human Machine Interface (HMI) with adjustable alarms and response capabilities.

The equipment has multiple functions and was developed for both safety reasons and for operational efficiencies.

3. **A.** For each piece of automation equipment listed in Question No. 1, how many operations have this equipment been deployed on?

B. Please give details of the operator, well name, water depth, and rig type or production facility. Please note that information on operators and well names, if provided, will not be used in the report.

Response – Several hundred wells have employed these systems.

Multiple operators and a variety of rigs around the globe (mostly surface stack Blowout Preventer [BOP]).

4. Continuing from Question No. 3, please provide the number of times kicks were detected using this piece of automated equipment, and what well control operations were executed to mitigate the kick. Please give details where possible, including kick volume.

   Response – Minimum of 55% of the wells we drilled had EKD events recorded, and 100% early detection was seen.

   Various actions were taken such as from continuing drilling to shut in and circulate out.

   Volumes varied from 0.5 bbl up to 5 bbl, depending on client response strategy.

5. Where kicks were detected, did your equipment make a contribution to safety by being deployed? If so, how?

   Response – Yes, by quicker identification and minimization of kick response time. Also, with proper Design of Service and Risk Evaluations, equipment has allowed circulation to continue and for the influx to be taken through MPD kit as it is caught early and minimized for safer management. This minimizes operational Non-productive Time (NPT) and minimizes risks from shutting in the well.

6. For each piece of equipment, please list the number of operations where the equipment has had a positive impact on overall safety, not just well control. Please provide details.

   Response – Nearly 100% of wells drilled with an RCD diverting flow away from under the rig floor and crews are safer operations. Also, this is a positive environmental effect in that spills from a bell nipple type arrangement are minimized.

   The RCD system employed has a positive safety effect in that it automates the diversion from downhole flow to surface flow across the MPD chokes, minimizing hazards from Backpressure Pump/Rig Pump miscommunications.

7. On those operations where the automation or EKD equipment did not contribute to safety, what was the primary objective for that equipment?

   Response – Operational efficiencies and mud cost reductions.

8. How, in your opinion, will safety be enhanced through drilling automation and/or EKD?

Response – Eliminates or minimizes the Human Factor.

9. What, in your opinion, are the top three ways in which safety may be compromised through automation?

Response – The system is developed without proper design and validation testing.

Operator training not correct.

Try to use for conditions outside of design.

Improper implementation.

10. **A.** Can you identify any drilling/completion/production/workover operations/functions currently carried out by personnel where automation must be limited and/or cautiously deployed in order to maintain safety?

B. How do these operations/functions negatively impact safety?

C. Which future automation technologies could negatively impact safety?

Response – Well Control Response.

Question not understood but idea is that in very critical operations automation is not there yet and there is always a need for supervised automation with manual override capabilities.

None known.

11. What drilling/completion/workover/production automation and EKD related products will you be introducing to the market during the next five years? Why?

Response – DetectEv- advanced automated event detection.

ActEv- advanced automated response action(s) to events.

12. **A.** What research is currently being performed into automated and EKD systems by your company or other companies?

B. If no research is being conducted, what type of research do you think should be conducted?

Response – Development Projects are well underway as well as Research Projects but unable to divulge at this time.

13. Are new broadband techniques being applied beyond MWD/LWD? Please explain

Response – Out of Scope.

14. **A.** For the new broadband techniques being developed or applied beyond MWD/LWD, how will this data be mined/stored?

B. What methods are being implemented for data analysis of these new technologies?

Response – Out of Scope.

15. Are there any improved mud-tank level monitoring systems being developed such as positive level monitoring, improved specific gravity measurement, and/or streamlined methods of equivalent circulation density determination?

Response – Out of Scope.

16. **A.** What standards does your equipment comply with?

B. Are any of these global standards?

Response – API, ASTM, CE, NORSOK, DNV, ABS, ASME, PED

Yes, CE, NORSOK, DNV, and PED are all global standards.

17. **A.** For future development, is there any plan to use global standards?

B. If yes, what standards are planned to be considered?

Response – Yes.

API, ASTM, CE, NORSOK, DNV, ABS, ASME, PED

18. What pressure and temperature rating limitations are on the equipment being manufactured?

Response – Various, up to 10k.

19. Has reliability analysis and related testing been performed on an ongoing basis for the equipment being manufactured? Please explain.

Response – Yes, through API and various other testing protocols.

20. Do you currently have, or plan to combine, automation and early kick detection with Managed Pressure Drilling Technology? Please explain.

Response – Already done.

Flow in and flow out by Coriolis, PWD measurement (ECD correction factor).

Software and HMI automations.

21. **A.** Do you believe that the industry should use systems that automatically curtail drilling operations when a kick is detected? Such a system could pick the drill string off the bottom and stop the mud pump without any involvement from personnel who can then conduct a flow check and make a decision on future actions.

B. Are there any system(s) in development that can perform the automation tasks described above?

Response – Yes after thorough safety analysis and verification testing.

I would think there are, we are of course examining those options.

22. What efforts are being conducted to improve current automated systems in use today on subsea BOPs such as the auto-shear and dead-man systems?

Response – Out of our scope.

A.2 OEM # 2

1. Please list automation and early kick detection (EKD) related equipment for drilling/production/workover/completion that you currently supply?

Response –

- API-monogramed Rotating Control Device (RCD) for enabling closed loop drilling.
- Automated Choke manifold with a Coriolis mass flow meter mounted for accurate flow out metering.

2. **A.** Of this equipment, please list how those items contributed to enhancing well safety.

B. Was this equipment developed specifically for safety enhancement or another reason, such as production improvement?

Response –

A.

- The RCD is instrumental in enhancing safety of drilling operations by creating a closed-to-atmosphere wellbore and safely containing and diverting wellbore fluids away from the rig floor.
- The Automated Choke Manifold increases safety by eliminating human error and by providing automated reaction to detected events. The manifold's Corriolis mass flow meter captures fluids data and provides advanced flow metering capabilities in real time at a sample rate of several times per second, which has been proven highly effective in early kick detection.

B.

- The RCD was developed in the early 1960s to create a close wellbore while drilling. Over the decades, the technology has evolved and been successfully deployed in land, shallow water and deepwater environments.
- The Automated Choke Manifold was developed circa 2005-2006 to increase level of automation in pressure control operations.

3. **A.** For each piece of automation equipment listed in Question No. 1, how many operations has this equipment been deployed on?

B. Please give details of the operator, well name, water depth, and rig type or production facility. Please note that information on operators and well names, if provided, will not be used in the report.

Response –

A.

Rotating Control Device: Deepwater: 40+

Land: 4,000+

Shallow Water:100+

Automated Choke Manifold: 380 total operations (including land, shallow water and deepwater)

4. Continuing from Question No. 3, please provide the number of times kicks were detected using this piece of automated equipment, and what well control operations were executed to mitigate the kick. Please give details where possible, including kick volume.

Response – It is important to note that a majority of operating companies choose to keep kick data confidential. As a result, the following data is an estimation from our standpoint:

o Number of kicks detected: 10+

o Number of kicks automatically controlled: 10+

o Kick Volume: Less than two barrels.

5. Where kicks were detected, did your equipment make a contribution to safety by being deployed? If so, how?

Response – Yes, our RCD and automated choke manifold helped enhance safety measures when kicks were detected.

The RCD and automated choke manifold worked in conjunction to enhance operational safety parameters by limiting the kick volume to a range of two barrels or les

6. For each piece of equipment, please list the number of operations where the equipment has had a positive impact on overall safety, not just well control. Please provide details.

<u>Response</u> –

- Rotating Control Device: Deepwater: 51

  Land: 4,000+

  Shallow Water: 100+

  o The RCD has been instrumental in improving safety of drilling operations by reducing number of well control and blow out events. (Reference: Jablonowski, C., & Podio, A. L. (2011, September 1). The Impact of Rotating Control Devices on the Incidence of Blowouts: A Case Study for Onshore Texas, USA. Society of Petroleum Engineers. doi:10.2118/133019-PA)

  o The RCD creates a closed wellbore enabling influx identification at a very early stage.

  o With the RCD in place, wellbore fluids can be diverted away from rig floor, enhancing safety of rig floor personnel.

- Automated Choke Manifold: 380 total operations (including land, shallow water and deepwater)

  Deepwater: 51

  Land: 229

  Shallow Water: 100

7. On those operations where the automation and/or EKD equipment did not contribute to safety, what was the primary objective for that equipment?

<u>Response</u> – While an EKD system's primary purpose is to enhance safety, there are numerous additional benefits of combining MPD with an EKD system. Some of them are improved control over wellbore hydraulic pressure profile, reduced wellbore instability issues, automated loss detection and mitigation, and a more validated pore pressure – fracture pressure profile.

8. How, in your opinion, will safety be enhanced through drilling automation and/or EKD?

Response – Drilling automation and EKD helps avert potentially dangerous well-control events in the following ways:

o Reducing formation damage to improve well productivity

o Differentiating between kick/loss and less hazardous events

o Determining when a kick has been effectively controlled, and safe drilling operations can resume

9. What, in your opinion, are the top three ways in which safety may be compromised through automation?

Response – Three scenarios in which automation could possibly compromise safety are:

- If rig personnel operating the system lack proper competencies. As an added safeguard against such issues, the operator should be present to intervene and instruct on the right course of action needed.
- If the drilling contractor, operator lack of proper training, the equipment may be used beyond operational limits which could lead to serious issues.
- If lapses in data communication occur between an EKD system and rig/third party data sharing system (i.e. Well Site Information Transfer System – WITS) errors may ensue.

10. **A.** Can you identify any drilling/completion/production/workover operations/functions currently carried out by personnel where automation must be limited and/or cautiously deployed in order to maintain safety?

B. How do these operations/functions negatively impact safety?

C. Which future automation technologies could negatively impact safety?

Response –

A. It is recommended that automation be cautiously deployed in order to maintain safety in the following circumstances:

a. Circulating a kick though riser in a challenging deepwater environment.

b. Circulating a kick at a faster circulation rate due to possible gas expansion issues.

c. Identifying kicks during tripping should be done by the operator. (Note that this process is not yet fully automated).

B. If operations adopt a system of checks and balances to transition from automated well control to conventional operator-led well control, no negative impact on safety will ensue.

C. None. Not applicable.

11. What drilling/completion/workover/production automation and EKD related products will you be introducing to the market during the next five years? Why?

Response –

- Software automation platform – offers integrated automated control of various equipment related to MPD operation. This will enable harmonized control of MPD and EKD related equipment on the rig.
- Advanced flow detection– enables use MPD related equipment for early kick detection only.
- Continuous Flow System –maintains continuous circulation while making drill pipe connections to maintain constant bottomhole pressure and avoid potential kick events.
- Non Umbilical Downhole Deployment Valve- mitigates risk of hydrocarbon intrusion into the wellbore during tripping process.

12. **A.** What research is currently being performed into automated and EKD systems by your company or other companies?

B. If no research is being conducted, what type of research do you think should be conducted?

Response –

A. Our R&D department is conducting research to discover ways to improve our automated EKD systems as it pertains to:

- Increasing the level of automation to minimize issues due to operator error.
- Making operating systems managed pressure drilling ready or (MPD Ready) to minimize lead time for MPD project implementation.
- Integrating control of various MPD equipment for better utilization of resources on the rig.
- Identification of different types of the kick based upon the flow and pressure signature. Validation will be performed by the Algorithm programmed in the EKD system.

- Due to smaller size of the kick and availability of accurate pressure control, full circulation rate can be used to circulate influx out of the wellbore. Current well control procedure has to be revised to allow this as one of the option to react to the kick. Efforts are being made to enhance conventional well control procedures for broader application of the technology.

B. Not applicable.

13. Are new broadband techniques being applied beyond MWD/LWD? Please explain

Response – Yes. MPD equipment uses advanced data acquisition and transmission technologies for better communication between various equipment. The equipment uses top of the line digital and analogue sensors along with Fiber optic cable for data communication amongst various components.

14. A. For the new broadband techniques being developed or applied beyond MWD/LWD, how will this data be mined/stored?

B. What methods are being implemented for data analysis of these new technologies?

Response –

- All data storage is performed on-site as well as on a remote server location including the cloud.
- Proprietary software programs developed using industry-recognized software platforms that extract and analyze data for timely and effective analysis of the data.

15. Are there any improved mud-tank level monitoring systems being developed such as positive level monitoring, improved specific gravity measurement, and/or streamlined methods of equivalent circulation density determination?

Response – No.

16. A. What standards does your equipment comply with?

B. Are any of these global standards?

Response – The applicable standards listed below many of which have been adopted on a global scale on a case-by-case basis.

- ABS - CDS Appendix 7
- DNV - DNV-Drill(N) OS-E101

- IADC – MPD manual
    - o IADC – Risk Guide
    - o CDS Guide Appendix 7
    - o API 16 RCD – Rotating Control Device
    - o API 92M – Managed Pressure Drilling – Constant Bottom Hole
- Pressure Equipment and Pressurized Mud Cap Drilling
    - o Modified Riser Joint – API 16Q, 16R and 16F
    - o Drill String Annular – API 16A
    - o MPD Manifold – API 6A, PSL 3
    - o Control System – API 16D
    - o Piping – ANSI 31.3
- Hoses/Flow line – API 17B, 17K, 7K

17. **A.** For future development, is there any plan to use global standards?

B. If yes, what standards are planned to be considered?

Response –

- Yes. ABS and DNV standards will be applicable globally for class certified rigs.
- Collaboration between operators, service companies and global authorities is ongoing to ensure the authorities are up to date with the latest technology developments. We are driving the effort behind the development and implementation of ABS and DNV standards for MPD and EKD technologies on class certified rigs.

18. What pressure and temperature rating limitations are on the equipment being manufactured?

Response – Pressure and temperature rating limitations vary based upon the class of certification and operating conditions.

19. Has reliability analysis and related testing been performed on an ongoing basis for the equipment being manufactured? Please explain.

Response – Yes. Various class societies such as ABS and DNV conduct ongoing equipment testing and provide independent certification.

20. Do you currently have, or plan to combine, automation and early kick detection with Managed Pressure Drilling Technology? Please explain.

Response – Automated kick detection technology is a standard offering inherent within our MPD technology. Additionally, Advanced Flow Detection, or, early kick detection services as technology offering that can be used as a standalone from MPD offering.

21. **A.** Do you believe that the industry should use systems that automatically curtail drilling operations when a kick is detected? Such a system could pick the drill string off the bottom and stop the mud pump without any involvement from personnel who can then conduct a flow check and make a decision on future actions.

B. Are there any system(s) in development that can perform the automation tasks described above?

Response –

A. Yes. We believe and have proven that such a system will be very beneficial to safety of drilling operations.

B. We are not aware of such information.

22. What efforts are being conducted to improve current automated systems in use today on subsea BOPs such as the auto-shear and dead-man systems?

Response – We are not aware of such efforts.

Appendix B Classification of Categories Used in FMECA Analysis

B.1 Occurrence Classification

Occurrence Rating	Occurrence Criteria
1	Unlikely; unreasonable to expect this failure mode to occur
2	Isolated; based on similar designs having low number of failures
3	Sporadic; based on similar designs that have experienced occasional failures
4	Conceivable; based on similar designs that have caused problems
5	Recurrent; certain that failures will ensue

Note: Ratings apply to the failure mode, not the cause of the failure

B.2 Severity Classification

Severity Rating	Severity Criteria
1	Insignificant impact; partial loss of functionality
2	Minor impact; partial loss of functionality
3	Significant impact; partial loss of functionality
4	Temporary complete loss of functionality
5	Unrecoverable complete loss of functionality (Boat mobilization may be required)

Note: Ratings apply to the failure mode, not the cause of the failure

B.3 Detection Classification

Detection Rating	Detection Criteria
1	Almost certain/Very high
2	High
3	Moderate
4	Low
5	Absolute uncertainty/Remote possibility

Note: Ratings apply to the failure mode, not the cause of the failure

Appendix C FMECA Workshop Attendees

C.1 Attendees at the EKDS (MPD) FMECA Workshop

Company	Role	Attendance	
		4/27/15	4/28/15
WGK	Facilitator	X	X
WGK	Scribe	X	
WGK	Scribe		X
BSEE	BSEE Representative	X	
BSEE	BSEE Representative	X	X
WGK	Project Team	X	X
WGK	Project Team	X	
Blade Energy Partners	Project Team	X	
Blade Energy Partners	Project Team	X	X
Blade Energy Partners	Project Team	X	
Industry Participant	SME	X	X
Industry Participant	SME	X	X
Industry Participant	SME	X	X
Industry Participant	SME	X	X
Industry Participant	SME	X	
Industry Participant	SME		X
Industry Participant	SME	X	X
Industry Participant	SME	X	X

C.2 Attendees at the MWD/LWD Systems FMECA Workshop

Company	Role	Attendance
		4/29/15
WGK	Facilitator	X
WGK	Scribe	
BSEE	BSEE Representative	X
WGK	Project Team	X
WGK	Project Team	X
Blade	Project Team	X
Industry Participant	SME	X
Industry Participant	SME	X
Industry Participant	SME	X
Industry Participant	SME	X

C.3 Attendees at the Wired Drill Pipe Systems FMECA Workshop

Company	Role	Attendance
		4/29/15
WGK	Facilitator	X
WGK	Scribe	
BSEE	BSEE Representative	X
WGK	Project Team	X
WGK	Project Team	X
Blade	Project Team	X
Industry Participant	SME	X
Industry Participant	SME	X
Industry Participant	SME	X
Industry Participant	SME	X

Appendix D Detailed System Breakdown

D.1 Pre-Workshop MWD/LWD Systems Detailed Breakdown and Function Statements

Sub-system	Component	Component Function	Reference ID
System Control Electronics	Microcontroller (Electronic Circuit Board)	Provides control functions to various MWD/LWD components	1.1
	Electronic Housing	Protects the electronics from environment and mechanical forces	1.2
	Power Electronics	Provide power management for the system control electronics	1.3
Downhole Filter Sub	Metal Screen	Screens debris from entering into BHA that houses MWD/LWD tools	2.1
Transmitter/ Telemetry - Mud Pulse	Microprocessor/ Telemetry Control Module	Communicates with other modules, gathering data from the gamma and directional modules, formatting it for transmission, and storing it. The telemetry module also conditions the electric power from the pulsar/generator for use by the other modules	3A.1
	Pulsar/ Generator	Based on the encoded data from MWD/LWD sensors/instruments, transfers pressure pulse through the drill column by generating electrical power to turn a small hydraulic pump that operates a poppet valve to restrict drilling mud flow and creates the pressure pulse	3A.2
	Poppet Valve	Restricts drilling mud flow to create pressure pulse through the drill column	3A.3
	Centralizer	Keeps the transmission module centralized within the pressure housing	3A.4
	Mud Screen	Screens smaller debris from entering the hydraulic pump	3A.5

Sub-system	Component	Component Function	Reference ID
Transmitter/Telemetry – Electromagnetic Transmission (EMT)	Encoder	Encodes data from MWD/LWD sensors/instruments to generate electromagnetic pulses	3B.1
	Transmitter	Transmits magnetic pulse or electrical current through the ground to the surface	3B.2
	Modulator	Imposes measurement data digitally on the EM waves	3B.3
Tool Power Supply – Turbine	Rotor	Transmits rotational force generated due to mud flow though Drill Pipe to an alternator	4A.1
	Alternator	Generates a 3-phase alternate current of variable frequency	4A.2
	Rectifier (Electronic Circuitry)	Converts AC current to usable direct current	4A.3
Tool Power Supply – Battery	Cell	Provides a stable voltage source without requiring complex electronics to condition the supply	4B.1
	Battery Housing	Houses the battery (generally made of Lithium-Thionyl Chloride)	4B.2
	Terminal	Connects battery to the power cables	4B.3
Data Sensor – Directional Tools	Sensors & Instrumentations – Magnetometer	Measure the earth's local magnetic field to obtain compass direction of the bottomhole assembly and the angle of the hole. Combined with inclination sensors, the tool can provide a reference direction to magnetic north. This is corrected for true north by adding the localized value for magnetic declination	5A.1
	Sensors & Instrumentations – Accelerometer	Measure the inclination and roll (gravity tool-face) of the tool is made by gravity based measurement	5A.2
	Analog to Digital Converter (ADC)	Interfaces the sensors with the Digital Sensor Processor (DSP) converting analog data to digital	5A.3

Sub-system	Component	Component Function	Reference ID
	Microcontroller/ Digital Signal Processor (DSP)	Controls electronic data transmission, data storage, power management of the MWD/LWD tools	5A.4
	Power Electronics	Provide and manage power distribution to the MWD/LWD tools	5A.5
	Electronic Housing	Protects the electronics from environment and mechanical forces	5A.6
	Memory	Stores digitized sensor data for future retrieval	5A.7
	Oscillator	Generates digital signal	5A.8
	Centralizer	Centralizes the MWD/LWD tools within the drill pipe	5A.9
	Data Correction Software	Performs noise reduction and other data processing tasks	5A.10
Data Sensor - Petrophysical Tools	Resistivity Electrode	Measures resistivity of rocks that indicate the presence of hydrocarbons	5B.1
	Gamma Sensor	Detects natural gamma radiation to establish and verify formation markers or boundaries between formation classes	5B.2
	Analog to Digital Converter (ADC)	Interfaces the sensors with the DSP converting analog data to digital	5B.3
	Microcontroller/ Digital Signal Processor (DSP)	Controls electronic data transmission, data storage, power management of the MWD/LWD tools	5B.4
	Power Electronics	Provide and manage power distribution to the MWD/ LWD tools	5B.5
	Electronic Housing	Protects the electronics from environment and mechanical forces	5B.6
	Memory	Stores digitized sensor data for future retrieval	5B.7
	Oscillator	Generates digital signal	5B.8

Sub-system	Component	Component Function	Reference ID
	Centralizer	Centralizes the MWD/LWD tools within the drill pipe	5B.9
	Data Correction Software	Performs noise reduction and other data processing tasks	5B.10
	Vibration & Shock Absorber	Minimizes vibration and shock to the MWD/LWD tool while maintaining concentric position within the pressure housing	5B.11
Telemetry Channel	Drill Pipe	Contains the flowing mud through which the pressure pulse travels to the stand pipe	6.1
	Repeater/Signal Booster (Only for EMT)	Helps recover attenuation of EM transmission through geological formation	6.2
Surface Module	Surface Receiver (Only for EMT)	Receives EM transmission from telemetry module and sends it for data processing	7.1
	Stand Pipe	Houses the pressure transducers	7.2
	Pressure Transducer	Converts pressure pulse to digital data	7.3
	Data Acquisition System (DAQ)	Decodes MWD/LWD digital data, processes data, and displays and stores data	7.4
	Software	Manages various functions of DAQ and also processes digital data	7.5
General Mechanical Components	Bearings	Support axial load from drilling weight on the bit and from circulating off bottom	8.1
	Seals (Dynamic)	Provide barrier to fluid loss under dynamic condition	8.2
	Seals (Static)	Provide barrier to fluid loss under static condition	8.3
	Pressure Barrier	Provides isolation to various tools from bottomhole pressure	8.4

Note: The alphabets in reference IDs indicate that the components may or may not be present in the same system.

D.2 Pre-workshop Wired Drill Pipe System Detailed Breakdown and Function Statements

Sub-system	Component	Component Function	Reference ID
Wired BHA	Tool - Miscellaneous (MWD/LWD)	Provide various measurements and logging data while drilling operation	1.1
	Tool Interface Electronics	Gather sensor data from BHA tools and convert to digital data	1.2
	Link Board	Provides data input to wired drill pipe from BHA tools	1.3
	Serial Cable	Provides connection between link board and tool interface electronics	1.4
Data Link	Sub	Provides housing for data link	2.1
	Electronics and Batteries	Repeat the bi-directional signal	2.2
	Boosters	Boost data signal in the drill pipe to prevent signal degradation	2.3
Wired Drill Pipe	Pipe Body	Provides mechanical integrity to Wired Drill Pipe network system	3.1
	Data Cable	Provides channel for data travel between pin and box ends	3.2
	Anchor Points within Tool Joints	Provide adequate tension for the data cable	3.3
	Shoulders of the Box and Pin Ends	Provide housing for the Transducer	3.4
	Transducer (Coil)	Acts as passive inductive communication device	3.5

Sub-system	Component	Component Function	Reference ID
Along-String Measurement (ASM) Device	Sub	Provides housing for ASM	4.1
	Electronics and Batteries	Repeat the signal, and collect and send ASM tool data	4.2
Data Swivel	Sub	Provides housing for data link	5.1
	Electronics and Batteries	Repeat the bi-directional signal	5.2
Surface cabling	Swivel Cable, Junction Box, Hose with Conduit (Multiple Cables),	Connects data swivel to network controller	6.1
Network Controller	Satellite or Rig Network, Vendor computer, Serial Cable or Ethernet for computer	Connects surface cabling to vendor computer, satellite/rig network	7.1
Top Drive Components	Swivel	Connects rotating components to stationary surface cabling	8.1
	Wired Saver Sub	Provides replaceable top drive wired connections	8.2

Appendix E FMECA Worksheets

E.1 FMECA Worksheet Template

System:		Component:		Date:	
Sub-system:		Component Function:			

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Corrective Actions	
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication/ Protection/ Maintenance	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	Recommended Corrective Actions	Comments

E.2 FMECA Worksheets for EKDS (MPD) System

Note that the failure modes that are identified to have a potential effect on safety are highlighted by red in the severity column.

System:	EKDS	Component:	Control System	Date:	4/27/2015
Sub-system:	MPD Manifold	Component Function:	To control MPD choke operation and kick/loss detection safely and effectively		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
1.1.1	All	Failure to operate choke(s) as intended		Inaccurate programming (programming bugs)	WHP gauge - I RCD gauges - I HPHT gauges -I ABS/DNV HIL test - P Choke position - I PRVs- P Manual operation - I/P Flow indication - I/P	Incorrect signals for choke operation (pressure containment)	Loss of ability to control surface pressure on well.	2	2	2	8	ABS/DNV HIL test to be mandatory.
1.1.2				Inaccurate programming (programming bugs)	WHP gauge - I RCD gauges - I HPHT gauges - I ABS/DNV HIL test - P Choke position - I PRVs- P Manual operation - I/P Flow indication - I/P	Incorrect signals for EKD	Inaccurate kick and loss detection.	2	2	1	4	
1.1.3				Software security vulnerability	WHP gauge - I RCD gauges - I HPHT gauges - I Choke position - I PRVs- P Manual operation - I/P Flow indication - I/P	Incorrect signals	Inaccurate kick and loss detection.	1	3	2	6	

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
1.1.4				Human error (manual operation)	Competency and training - P WHP gauge - I RCD gauges - I HPHT gauges - I Choke position - I PRVs - P Diagnostics & alarms - I/P	Incorrect signals for choke operation (personal computer [PC])	Loss of ability to control surface pressure on well.	3	2	1	6	
1.1.5				Human error (manual operation)	Competency and training - P WHP gauge - I RCD gauges - I HPHT gauges - I Choke position - I PRVs - P Diagnostics & alarms - I/P	Incorrect signals for EKD	Inaccurate kick and loss detection.	2	2	1	4	
1.1.6				Equipment malfunction (Control system)	WHP gauge - I RCD gauges - I HPHT gauges - I Choke position - I PRVs - P	Incorrect signals for choke operation (PC)	Loss of ability to control surface pressure on well.	2	2	2	8	
1.1.7				Equipment malfunction (Control system)	WHP gauge - I RCD gauges - I HPHT gauges - I Choke position - I PRVs - P Manual operation - I/P	Incorrect signals for EKD	Inaccurate kick and loss detection.	2	2	1	4	
1.1.8		Complete loss of function		Control system freeze/crash	System does not respond to inputs - I Redundancy - P Manual operation - I/P	No output signals (PC)	Chokes maintain current position (fail as is).	1	3	1	3	

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
1.1.9				Control system freeze/crash	System does not respond to inputs - I Redundancy - P Manual operation - I/P	No output signals (EKD)	Loss of automated EKD.	1	2	1	2	

System:	EKDS	**Component:**	Coriolis Meter (Single Phase, Downstream of Choke)	**Date:**	4/27/2015
Sub-system:	MPD Manifold	**Component Function:**	To provide density, flow rate, and temperature measurements		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
1.2.1	All	Mechanical damage		Damage caused by fluid/solids inside the Coriolis meter	Junk catcher (optional) - P Calibration - P/M Design/Operation - P Maintenance - M Redundancy - P	Inaccurate flow rate and density measurements.	Impaired kick and loss detection.	1	2	1	2	
1.2.2				Improper installation	Visual inspection - I/P Installation and commissioning procedure - P Redundancy - P	Inaccurate flow rate and density measurements.	Impaired kick and loss detection.	1	2	1	2	
1.2.3				Damaged while being transported	Visual inspection - I/P Calibration - P Redundancy - P Diagnostics- I/P	Inaccurate flow rate and density measurements.	Impaired kick and loss detection.	1	2	1	2	
1.2.4				Overpressure	PRV - P Redundancy - P Diagnostics - P Calibration - P	Rupture	Loss of functionality	1	4	1	4	

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
1.2.5		Electrical failure		Damaged electrical line	Cables routed away from traffic - P Mechanical protection - P Spares - P	Loss of flow rate and density measurements.	Impaired kick and loss detection.	1	4	1	4	
1.2.6				Damaged power source	Uninterrupted Power Supply - P Diagnostics - I	Loss of flow rate and density measurements.	Impaired kick and loss detection.	1	1	1	1	
1.2.7				Damaged processor	Diagnostics - I Spares - P	Loss of flow rate and density measurements.	Impaired kick and loss detection.	1	3	1	3	
1.2.8				Loss of communication	Diagnostics - I	Loss of flow rate and density measurements.	Impaired kick and loss detection.	1	4	1	4	
1.2.9				Electrical interference from non-MPD signals	Rig installation and design - P	Loss of accuracy of flow rate and density measurements.	Impaired kick and loss detection.	1	3	2	6	
1.2.10		Incorrect reading		Calibration error	Calibration software (not recommended in field) - I Diagnostics - I Spare - P	Inaccurate flow rate and density measurements.	Impaired kick and loss detection.	3	1	3	9	
1.2.11				Blockage	Diagnostics - I Pressure sensors - I Spare - P Junk catcher - P Bypass line- P Procedures - P	Inaccurate flow rate and density measurements.	Impaired kick and loss detection.	1	4	1	4	
1.2.12				Scale coating	Maintenance/Procedures - M Calibration - P	Inaccurate flow rate and density measurements.	Impaired kick and loss detection.	3	1	4	12	

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
1.2.13				Excess gas	Procedures - P Improved equipment design - P	Inaccurate flow rate and density measurements.	Impaired kick and loss detection.	3	4	1	12	
1.2.14				Unintentional bypass	Procedures - P Training and competency - P	Low flow rate and density measurements.	Impaired early kick and loss detection.	2	2	3	12	
1.2.15		No reading		Unintentional bypass	Procedures - P Training and competency - P	No flow rate and density measurements.	Impaired early kick and loss detection.	2	4	1	8	

System:	EKDS	**Component:**	MPD Chokes	**Date:**	4/27/2015
Sub-system:	MPD Manifold	**Component Function:**	To restrict flow downstream from the RCD, thereby accurately controlling annular surface pressure on the well		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
1.3.1	All	Blocked choke		Blockage	Increased WHP - I PRV - P Redundant choke - P Sizing - P Junk catcher - P	Reduced functionality	Increases surface pressure.	2	3	1	6	
1.3.2		Trapped pressure		Blockage	Procedures - P Training and competency - P	Reduced functionality	Safety concern	1	5	2	10	Occurs when system is isolated after blockage. Severity driven by safety concern.

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
1.3.3		Degradation		General wear, cuttings	Different choke position for given WHP (at given flow rate) - I Junk catcher upstream - P Spare choke trim - P Redundant choke - P Isolation valve - P	Reduced functionality	May not control surface pressure adequately.	1	2	2	4	Assumes booster line running will not trap pressure in a closed circulation loop. A choke is not a gate valve. Design: dual choke manifold with bypass.
1.3.4		Actuator failure		Improper assembly	Procedures - P QA/QC - P Training and competency - P	No functionality	No pressure control	1	4	2	8	
1.3.5				Power failure (hydraulic, electrical, pneumatic)	Stored energy - P Redundant choke - P	No functionality	No pressure control	2	4	1	8	
1.3.6		Mechanical failure		Seal failure	Procedures - P QA/QC - P Redundant choke - P	Reduced functionality	No pressure control	1	2	2	4	
1.3.7				Bearing failure	Procedures - P QA/QC - P Redundant choke - P	Reduced functionality	No pressure control	1	2	2	4	
1.3.8				Stem breakage	Procedures - P QA/QC - P Redundant choke - P	Reduced functionality	No pressure control	1	2	2	4	

System:	EKDS	Component:	Latching Assembly	Date:	4/27/2015
Sub-system:	RCD	Component Function:	To maintain bearing assembly position and contain annular pressure from the well		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
2.1.1	All	Fails to latch bearing assembly		Improper installation	Installation and commissioning procedure - P Safety Interlocks - I Latch position Indicator - I API 16RCD - P	Fails to close.	Drilling delay	1	2	1	2	
2.1.2				Poorly manufactured assembly	API 16RCD - P QA/QC - P	Fails to close.	Drilling delay	1	2	1	2	
2.1.3				Leaking or broken hydraulic circuit	Hydraulic fluid volume - P Operational annular - P Pull test- P RCD umbilical protection - P Redundancy - P	Fails to close or maintain latching assembly closed.	If not detected and pressured up, could cause bearing assembly to unlatch.	1	4	1	4	
2.1.4		Fails to unlatch bearing assembly		Leaking or broken hydraulic circuit	Redundancy - P	Fails to unlatch.	Drilling delay; additional operational requirements; pull LMRP.	1	2	1	2	
2.1.5				Debris on latching mechanism	Improved design - P	Fails to unlatch.	Drilling delay; additional operational requirements; pull LMRP.	1	2	1	2	
2.1.6		Unlatching during operation		Human error	Software logic - P Operational procedures - P Hydraulic fluid volume - P Operational annular - P	Unlatch	Loss of pressure containment; projectile bearing assembly.	1	5	1	5	

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
2.1.7				Leaking or broken hydraulic circuit	Software logic - P Operational procedures - P Hydraulic fluid volume - P Operational annular - P RCD umbilical protection - P	Unlatch	Loss of pressure containment; projectile bearing assembly.	1	5	5	25	

System:	EKDS	Component:	Bearing Assembly	Date:	4/27/2015
Sub-system:	RCD	Component Function:	To allow seals to rotate with drill pipe and to contain annular pressure from the well		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
2.2.1	All	Bearing does not rotate	Loss of lubrication	Hydraulic fluid leak	Check hydraulic fluid levels during servicing - P/M	Element does not rotate with drill pipe.	Excess wear on element, reducing element life, potential for leak and loss of wellbore pressure containment.	2	2	4	16	
2.2.2				Bearing failure	Check hydraulic fluid levels during servicing - P/M Visual inspection - I	Element does not rotate with drill pipe.	Excess wear on element, reducing element life, potential for leak and loss of wellbore pressure containment.	2	2	4	16	
2.2.3		Seal leak		Wear or damage during deployment	Initial pressure test - P Drifting of slip joints - I	Unable to contain pressure.	Unable to contain pressure; drilling delay, requires replacement.	2	3	2	12	

System:	EKDS	Component:	Element	Date:	4/27/2015
Sub-system:	RCD	Component Function:	To contain annular pressure from the well by sealing against drill pipe (while static, rotating or stripping, or both)		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
2.3.1		Leaking/degraded seal		Wear from normal operations	Redundant seal - P Replacement after use - P Reduced return flow - I QA/QC - P Procedures - P API 16RCD - P Trip tank loop flow - I	Loss of seal.	Return fluid leak; seal to be replaced/repaired to return system to full operability.	4	2	2	16	Testing before each use; Function test during standard BOP test is expected to be a requirement in the future
2.3.2				Chemical degradation/High temperature	Chemical testing - P Redundant seal - P Replacement after use - P Reduced return flow - I API 16RCD - P Temperature monitoring on Coriolis - I	Loss of seal.	Return fluid leak; seal to be replaced/repaired to return system to full operability.	2	2	2	8	
2.3.3				Mechanical damage from drill pipe	Inspect drill pipe - I Dress damaged sections of drill pipe before running in hole - P	Loss of seal.	Return fluid leak; seal to be replaced/repaired to return system to full operability.	3	2	1	6	
2.3.4		Elastomer failure		Improper installation/environment/storage	Color coded - P QA/QC - P Procedures - P	Complete loss of seal.	Loss of pressure containment, functionality. Operational downtime.	2	4	3	24	

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
2.3.5				Wear from normal operations	Redundant seal - P Replacement after use - P Reduced return flow - I QA/QC - P Procedures - P API 16RCD - P Trip tank loop flow - I	Complete loss of seal.	Loss of pressure containment, functionality. Operational downtime.	1	4	2	8	
2.3.6				Chemical degradation/ High temperature	Chemical testing - P Redundant seal - P Replacement after use - P Reduced return flow - I API 16RCD - P Temperature monitoring on Coriolis - I	Complete loss of seal.	Loss of pressure containment, functionality. Operational downtime.	1	4	2	8	
2.3.7				Mechanical damage (side loading, alignment issues, vibration) from drill pipe	Inspect drill pipe - I Address damaged sections of drill pipe before running in hole - P Redundant seal - P	Complete loss of seal.	Loss of pressure containment, functionality. Operational downtime.	2	4	2	16	Drill pipe tool joint profiles need to be considered during qualification of RCD sealing elements. (for deep water applications)

System:	EKDS	Component:	Pressure Relief System	Date:	4/28/2015
Sub-system:	PR System	Component Function:	To protect RCD, riser, and wellbore against overpressure by relieving pressure if calculated maximum is exceeded		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
3.1.1	All	Failure to open		Mechanical failure	Redundant PRVs - P Testing - P	Does not function as intended.	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	5	50	Should not be spring loaded or burst discs. Hydraulic controlled active pressure release. Every PRV system should have independent backup power.
3.1.2				Control system failure	Independent backup power - P Redundant control for the system - P Diagnostics - P Testing - P	Does not function as intended.	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	1	5	3	15	
3.1.3				Sensor failure	Testing - P	Does not function as intended.	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	2	20	Redundant sensors recommended for future.
3.1.4		Premature release		Incorrect set point	Visual inspection of surface pressure - I Testing - P Diagnostics - P	Does not function as intended.	Not enough surface pressure. Potential kick scenario.	2	4	2	16	PRV release alarms and signals on Control system.
3.1.5		Late release		Incorrect set point	Visual inspection of surface pressure - I Testing - P Diagnostics - P	Does not function as intended.	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	2	20	H & HH alarms.

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
3.1.6				Reaction time design	Design - P Testing - P	Does not function as intended.	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	5	50	
3.1.7		Failure to maintain the desired backpressure range		Mechanical failure, blockage	Visual inspection - I Testing	Does not function as intended.	Continuous discharge of pressure with inability to control surface pressure.	2	5	5	50	
3.1.8				Control system failure	Testing	Does not function as intended.	Continuous discharge of pressure with inability to control surface pressure.	1	5	3	15	
3.1.9				Undersized pipe	Design	Does not function as intended.	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	5	50	
3.1.10		Leakage internal		Wear Corrosion Erosion	Testing Spares	May cause further degradation.	Loss of pressure integrity	2	3	2	12	
3.1.11		Leakage external		Installation Corrosion Erosion	Visual inspection - I Testing - P Spares - P	May cause further degradation.	Loss of pressure integrity	2	4	2	16	Install at highest point in vertical position to avoid debris accumulation.
3.1.12		Insufficient pressure relief capacity		Blockage of PRV	Design sizing - P	Does not function as intended.	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	5	50	Project needs to risk assess correct discharge piping sizes.

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
3.1.13				Blockage downstream of relief valve	System design - P Procedures - P System interlock - P	None	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	5	50	All valves downstream of PRV to be locked open. Investigate installation procedure of temporary vs permanent piping and equipment.
3.1.14				Blockage upstream of relief valve	System design - P Procedures - P System interlock - P Valves fail as is - P	None	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	1	5	5	25	

System:	EKDS	Component:	MGS									Date:	4/28/2015
Sub-system:	MGS	Component Function:	To capture and separate large volumes of free gas within drilling fluid										

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
4.1.1		Gas out of liquid line	Excessive gas flow	High gas flow rate. Gas flow overcomes liquid leg hydrostatic pressure.	Operational design - P Pressure/level gauge with alarms - I/P	Does not function as intended. Potential for overpressure.	Gas to shakers	2	5	2	20	Have proper pressure/level indicators.
4.1.2				Blockage of the gas line	No valves on vent lines - P Self draining lines - P Pressure and level gauges - I Maintenance - M	Does not function as intended. Potential for overpressure.	Gas to shakers	1	5	2	10	
4.1.3		Liquid out of gas line	Excessive liquid flow	High liquid flow rate. Liquid leg inadequately sized.	Operational design - P Pressure/level gauge with alarms - I/P	Does not function as intended. Potential for overpressure.	Liquid to vent line Environmental spill	2	4	2	16	

System:	EKDS	Component:	MGS					Date:				4/28/2015
Sub-system:	MGS	Component Function:	To capture and separate large volumes of free gas within drilling fluid										
Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
4.1.4				Blockage of the liquid line	Operational design - P Pressure/level gauge with alarms - I/P	Does not function as intended. Potential for overpressure.	Liquid to vent line Environmental spill	3	4	2	24	Procedure to regularly flush MGS.
4.1.5		Over pressure		Excessive gas flow	Operational control - P Procedures - P Pressure/level gauge with alarms - I/P	Does not function as intended. Burst	Hydrocarbon discharge. Potential for fire, explosion.	2	5	2	20	
4.1.6		Leakage		Structural deficiency	Visual inspection - P	Does not function as intended.	Hydrocarbon discharge. Potential for fire, explosion.	1	5	5	25	

System:	EKDS	Component:	Stroke Counter					Date:				4/28/2015
Sub-system:	Instrumentation	Component Function:	To measure the stroke rate and number of strokes on the mud pumps, providing total volume of mud flow into the well										
Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
5.1.1		Incorrect volume measurement		Degraded efficiency	Stand pipe pressure trend - I Calibration and measurement of efficiency - I Procedures - P	None	Impaired operational awareness Impaired EKDS	5	3	3	45	

System:	EKDS	Component:	Stroke Counter							Date:			4/28/2015
Sub-system:	Instrumentation	Component Function:	To measure the stroke rate and number of strokes on the mud pumps, providing total volume of mud flow into the well										
Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
5.1.2				Stroke counter error	Stand pipe pressure trend - I Calibration and measurement of efficiency - I Procedures - P	None	Impaired operational awareness Impaired EKDS	5	3	3	45	
5.1.3				Liner or piston worn out	Stand pipe pressure trend - I Calibration and measurement of efficiency - I Procedures - P	None	Impaired operational awareness Impaired EKDS	5	3	3	45	
5.1.4				Leaking PRV or suction valve on the pumps	Stand pipe pressure trend - I Calibration and measurement of efficiency - I Procedures - P	None	Impaired operational awareness Impaired EKDS	5	3	3	45	

System:	EKDS	Component:	Drill string Valve (NRV)									Date:	4/28/2015
Sub-system:	Drill string Valve	**Component Function:**	To prevent backflow during any circumstances into the drill pipe										
Ref. ID	**Operational Mode**	**Description of Failure**				**Effect of Failure**		**Ratings**				**Recommendations, Comments, and Corrective Actions**
		Failure Mode	**Failure Mechanism**	**Cause(s) of Failure**	**Indication (I)/ Protection (P)/ Maintenance (M)**	**On the Component**	**On the System Function**	**Occ.**	**Sev.**	**Det.**	**RPN**	
6.1.1		Backflow evident		Washout/fails open	Pressure testing - P Maintenance - M Sizing - P Redundancy - P	Fails to operate as required.	Connection process compromised and could result in a trip.	3	2	5	30	Shakeout after each run.
6.1.2				Washout/fails open	Pressure testing - P Maintenance - M Sizing - P Redundancy - P	Fails to operate as required.	Potential of hydrocarbon in drill string and further induced kick.	1	4	5	20	
6.1.3		No flow		Plugging		Fails to operate as required.	Inability to drill results in a trip delay drilling.	1	4	5	20	
6.1.4		Parted drill string		Installation Mechanical damage	Regular inspection - P QA/QC - P	Fails to operate as required.	Inability to drill results in a trip delay drilling fishing operation affected.	1	4	3	12	

System:	EKDS	Component:	Piping (hard pipe and hoses) and valves upstream from the MPD choke										Date:	4/28/2015
Sub-system:	Piping and Valves	Component Function:	Pressure and flow containment upstream from the MPD choke											
Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions		
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN			
7.1.1		Loss of containment (hard piping)		Structural deficiency	Installation and design - P Maintenance - M Inspections - P Pressure and functional test - P	Fails to maintain pressure.	Pressure control compromised Potential hydrocarbon release and safety impact	2	5	3	30			
7.1.2				Overpressure	Pressure sensors - I Maintenance - M Inspections - P Pressure and functional test - P	Fails to maintain pressure.	Loss of MPD	2	3	3	18	Different pressure ratings where buffer manifold connects to stand pipe. Recommend PRV installed.		
7.1.3		Loss of containment (hoses)		Entanglement below the water line	Installation and Design - P Procedures - P Monitoring and inspection - P	Fails to maintain pressure.	Pressure control compromised Potential hydrocarbon release and safety impact	2	4	1	8			
7.1.4		Overpressure (valves)		Valve in wrong position (closed)	Valve position indication - I Procedures - P	Overpressure	Pressure control compromised Potential hydrocarbon release and safety impact	4	5	5	100	Occurs in manually operated system.		
7.1.5		Loss of pressure (valves)		Valve in wrong position (open)	Valve position indication - I Procedures - P	Fails to maintenance pressure.	Pressure control compromised	4	2	5	40			

E.3 FMECA Worksheets for MWD/LWD Systems

System:	MWD/LWD	Component:		Date:	04/29/2015
Sub-system:	System Control Electronics	Component Function:	Provides control functions to various MWD/LWD components		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions	
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN		
1.1		Failure to provide accurate control commands to various MWD/LWD components	Error in Control Program Logic	Inaccurate programming (firmware)	QA/QC - P Testing - P System checks - P Training/Competency - P Diagnostic - I Preventive maintenance - M Spares - P		Inaccurate data driving poor decisions.	3	4	2	24		
1.2		Failure to synchronize control commands to various MWD/LWD components	Error in Control Program Logic	Inaccurate programming (firmware)	QA/QC - P Testing - P System checks - P Training/Competency - P Diagnostic - I Preventive maintenance - M Spares - P		Inaccurate data driving poor decisions.	3	4	2	24		
1.3		Failure to send any control command to various MWD/LWD components	Damage to electronic circuit	Overheating	QA/QC - P Testing - P System checks - P Training/Competency - P Diagnostic - I Preventive maintenance - M Spares - P		Inaccurate data driving poor decisions.	3	4	2	24		
1.4				Semiconductor failure	QA/QC - P Testing - P System checks - P Training/Competency - P Diagnostic - I Preventive maintenance - M Spares - P		Inaccurate data driving poor decisions.	3	4	2	24		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
1.5				Soldering failure	QA/QC - P Testing - P System checks - P Training/Competency - P Diagnostic - I Preventive maintenance - M Spares - P		Inaccurate data driving poor decisions.	3	4	2	24	
1.6				Mechanical damage	QA/QC - P Testing - P System checks - P Training/Competency - P Diagnostic - I Preventive maintenance - M Spares - P		Inaccurate data driving poor decisions.	3	4	2	24	
1.7		No data/Inaccurate data prior to deployment	Various	Human error	Procedures - P Training/Competency - P		No data/Inaccurate data driving poor decisions.	1	4	2	8	
1.8		Assembly failure	Various	Mechanical/structural deficiency	QA/QC - P Testing - P System checks - P Diagnostic - I Spares - P		No data/Inaccurate data driving poor decisions and drilling delays.	1	4	4	16	
1.9				Operated out of specification Improper application	Pre-job planning - P Procedures - P Training QOP - P Alarms - I		No data/Inaccurate data driving poor decisions and drilling delays.	5	4	1	20	

System	MWD/LWD	Component:		Date:	04/29/2015
Sub-system	Downhole Filter Sub	Component Function:	Capture debris		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions	
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN		
2.1		Blockage	Various	Large debris	Procedure - P Training/Competency - P Alarms - P		No/reduce flow pressure build-up. Stuck drill string.	2	4	2	16		
2.2		Washout	Various	Sand content erosion	None		Clogging of MWD system resulting in delay drilling.	1	4	5	20		

System:	MWD/LWD	**Component:**		**Date:**	04/29/2015
Sub-system:	Transmitter/Telemetry channel/Wired Drill Pipe	**Component Function:**	Transmit data from tool to surface sensors		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions	
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN		
3.1		Electrical failure	Various	Vibration/Shock Temperature Stabilizer failure	Real time alarms/Indicators - P Procedure - P		Poor/No data log Potential drilling delay Not maintaining well trajectory.	3	4	5	60		
3.2		Mechanical failure	Various	Vibration/Shock Temperature Stabilizer failure	Real time alarms/Indicators - P Procedure - P		Poor/No data log Potential drilling delay Not maintaining well trajectory.	3	4	5	60		
3.3		Fluid related failure	Various	Poor control of fluid properties (solids)	Monitoring - P		Mud flow resulting in potential drilling delay.	3	4	5	60		

System:	MWD/LWD	Component:		Date:	04/29/2015
Sub-system:	Power supply	Component Function:	Provide power to all electronics in the system		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	
4.1	Geosteering and petrophysical data	Electrical failure	Various	Vibration/Shock Temperature Stabilizer failure PCB failures Battery cell failure Degradation Electrodes	Monitoring - P Pre-job planning - P Spares - P Redundancy -P		No data Potential drilling delay	2	4	1	8	
4.2		Mechanical failure	Various	Vibration/Shock Temperature Stabilizer failure Battery cell failure Degradation	Monitoring - P Pre-job planning - P Spares - P Redundancy -P		No data Potential drilling delay	2	4	1	8	
4.3		Sporadic power supply	Various	Vibration/Shock Temperature Stabilizer failure PCB failures Battery cell failure Degradation Electrodes	Monitoring - P Pre-job planning - P Spares - P Redundancy -P		Suspect data leading to poor drilling.	1	2	5	10	
4.4		Loss of mud flow (turbine)	Various	Mud pump failure Surface delivery system washout	Monitoring - P Spares - P Redundancy - P		Low voltage Low current Suspect data leading to poor drilling.	1	2	4	8	

System	MWD/LWD	Component:		Date:	04/29/2015
Sub-system:	Downhole sensors	Component Function:	Provide accurate data to drill well as planed or make changes to wellbore path as needed		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments and Corrective Actions	
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN		
5.1		Electrical/Electronic failure	Various	Vibration/Shock Temperature Stabilizer failure PCB failures Degradation Electrodes Poor assembly	Monitoring - P Spares - P Redundancy -P Maintenance and calibration - P		No data Potential drilling delay Suspect data leading to poor drilling.	3	3	3	27		
5.2		Mechanical failure	Various	Vibration/Shock Temperature Stabilizer failure Degradation Poor assembly	Monitoring - P Spares - P Redundancy - P Maintenance and calibration - P		No data Potential drilling delay Suspect data leading to poor drilling.	3	3	3	27		
5.3		Sensor programming errors	Various	Inaccurate programming (firmware)	QA/QC - P Testing - P System checks - P Training/Competency - P Diagnostic - I Preventive maintenance - M Spares - P		Inaccurate data driving poor decisions.	3	3	3	27		

System	MWD/LWD	Component:		Date:	04/29/2015
Sub-system	Surface Module	Component Function:	Receive, decode, process, display, store, and distribute real time downhole data and monitors Surface system		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions	
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN		
6.1		Sensor failures	Various	Human error Vibration/Shock Temperature Stabilizer failure PCB failures Degradation Poor assembly	Monitoring - I Spares - P Redundancy - P Maintenance and calibration - P		Loss of drilling efficiency Inaccurate formation evaluation Loss of early warning signs of kick.	2	3	3	18		
6.2		Software failures	Various	Inaccurate programming (firmware) Human errors Interface errors	QA/QC - P Testing - P System checks - P Training/Competency - P Diagnostic - I Spares - P		Inaccurate data driving poor decisions Loss of early warning signs of kick.	2	4	4	32		
6.3		Equipment failure (cables, computer, displays, telecommunication, etc.)	Various	Human error Vibration/Shock Temperature PCB failures Degradation Poor assembly	QA/QC - P Testing - P System checks - P Training/Competency - P Diagnostic - I Spares - P		No data Drilling delays Loss of early warning signs of kick.	2	4	4	32		
6.4		Human error	Various	Inaccurate procedures Lack of training or experience	Training/Competency - P QA/QC - P		Loss of drilling efficiency Inaccurate formation evaluation Loss of early warning signs of kick. Non-productive time	2	3	5	30		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Recommendations, Comments, and Corrective Actions	
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication(I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN		
7.5		Drive assembly	Various	Excessive torque vibration Jarring back reaming	Inspection and replacement – P Job planning – P QOP – P Maintenance – M		Loss of data Loss of early warning signs of kick Drilling delays	2	4	5	40		
7.6		Inter tool connections	Various	Seal failure Improper Assembly Over-stress	Inspection and replacement – P Job planning – P QOP – P Maintenance – M		Loss of data Loss of early warning signs for kick. Drilling delays	2	4	5	40		
7.7		Nuclear sources	Various	Containment leak	Inspection and replacement – P Monitoring – I Training and competency – P		Loss of data Loss of early warning signs of kick Drilling delays	1	5	3	15		

E.4 FMECA Worksheets for Wired Drill Pipe System

System:	Wired Drill Pipe	**Component:**		**Date:**	04/29/2015
Sub-system:	Surface system	**Component Function:**	Provide network connection between downhole components and surface tool provider		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Corrective Actions	
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	Recommended Corrective Actions	Comments
1.1		Failure of the network	Various	Similar to software and equipment failure for MWD/LWD surface module	Similar to software and equipment for MWD/LWD surface module		Loss of data transmission. To be reverted to mud pulse transmission.	2	4	4	32		Similar to failure of MWD/LWD Surface Module including software.
1.2		Failure of surface equipment (cables, plugs)	Various	Human errors Normal wear	Procedures - P Training and competency - P Spares - P		Loss of data. To be reverted to mud pulse transmission.	3	4	5	60		Severity only considers Wired Drill Pipe system.
1.3		Top drive couplings/data swivel/saver	Various	Human errors Normal wear	Procedures - P Training and competency - P Spares - P		Loss of data. To be reverted to mud pulse transmission.	3	4	5	60		

System:	Wired Drill Pipe	Component:		Date:	04/29/2015
Sub-system:	Downhole system	Component Function:	Bi-directional data transfer		

Ref. ID	Operational Mode	Description of Failure				Effect of Failure		Ratings				Corrective Actions	
		Failure Mode	Failure Mechanism	Cause(s) of Failure	Indication (I)/ Protection (P)/ Maintenance (M)	On the Component	On the System Function	Occ.	Sev.	Det.	RPN	Recommended Corrective Actions	Comments
2.1		Electrical/Electronic failure	Various	Vibration/Shock Temperature PWB failures Battery cell failure Degradation Manufacturing Operating out of specified limits (operational & environmental)	Monitoring - P Pre-job planning - P QA/QC - P Preventive maintenance - P		Loss of data. To be reverted to mud pulse transmission.	2	4	5	40		Includes MWD, LWD, tools interface, and along-string measurement tool.
2.2		Mechanical failure	Various	Degradation Manufacturing Operating out of specified limits (operational & environmental) Improper running and handling	Monitoring - P Pre-job planning - P QA/QC - P Preventive maintenance - P Training - P Good operation practices - P		Loss of data. To be reverted to mud pulse transmission.	3	4	5	60		Includes pipe, collars, jars, and connections.

Appendix F FMECA Results

F.1 EKDS FMECA Results Sorted by RPN

Ref. ID	Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Component
					Occ.	Sev.	Det.	RPN	
7.1.4	Valves Upstream from the MPD Choke	Overpressure	Valve in wrong position (closed)	Pressure control compromised. Potential hydrocarbon release and safety impact.	4	5	5	100	51.02
3.1.1	Pressure Relief System	Failure to open	Mechanical failure	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	5	50	11.39
3.1.6	Pressure Relief System	Late release	Reaction time design	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	5	50	11.39
3.1.7	Pressure Relief System	Failure to maintain the desired backpressure range	Mechanical failure, blockage	Continuous discharge of pressure with inability to control surface pressure.	2	5	5	50	11.39
3.1.9	Pressure Relief System	Failure to maintain the desired backpressure range	Undersize pipe	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	5	50	11.39
3.1.12	Pressure Relief System	Insufficient pressure relief capacity	Blockage of PRV	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	5	50	11.39
3.1.13	Pressure Relief System	Insufficient pressure relief capacity	Blockage downstream of relief valve	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	5	50	11.39
5.1.1	Stroke Counter	Incorrect volume measurement	Degraded efficiency	Impaired operational awareness Impaired EKDS	5	3	3	45	25.00
5.1.2	Stroke Counter	Incorrect volume measurement	Stroke counter error	Impaired operational awareness Impaired EKDS	5	3	3	45	25.00
5.1.3	Stroke Counter	Incorrect volume measurement	Liner or piston worn out	Impaired operational awareness Impaired EKDS	5	3	3	45	25.00

Ref. ID	Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Component
					Occ.	Sev.	Det.	RPN	
5.1.4	Stroke Counter	Incorrect volume measurement	Leaking PRV or suction valve on the pumps	Impaired operational awareness Impaired EKDS	5	3	3	45	25.00
7.1.5	Valves Upstream from the MPD Choke	Loss of pressure	Valve in wrong position (open)	Pressure control compromised	4	2	5	40	20.41
6.1.1	Drill String Valve (Non-Return Valve [NRV])	Backflow evident	Washout/fails open	Connection process compromised and could result in a trip	3	2	5	30	36.59
7.1.1	Hard Piping Upstream from the Choke	Loss of containment	Structural deficiency	Pressure control compromised. Potential hydrocarbon release and safety impact	2	5	3	30	15.31
2.1.7	Latching Assembly	Unlatching during operation	Leaking or broken hydraulic circuit	Loss of pressure containment. Projectile bearing assembly.	1	5	5	25	59.52
3.1.14	Pressure Relief System	Insufficient pressure relief capacity	Blockage upstream of relief valve	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	1	5	5	25	5.69
4.1.6	Mud Gas Separator	Leakage	Structural deficiency	Hydrocarbon discharge. Potential for fire, explosion.	1	5	5	25	21.74
2.3.4	RCD Element	Elastomer failure	Improper installation, environment, storage	Loss of pressure containment, functionality. Operational downtime.	2	4	3	24	27.91
4.1.4	Mud Gas Separator	Liquid out of gas line	Blockage of the liquid line	Liquid to vent line. Environmental spill.	3	4	2	24	20.87
3.1.3	Pressure Relief System	Failure to open	Sensor failure	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	2	20	4.56
3.1.5	Pressure Relief System	Late release	Incorrect set point	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	2	5	2	20	4.56

Ref. ID	Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Component
					Occ.	Sev.	Det.	RPN	
4.1.1	Mud Gas Separator	Gas out of liquid line	High gas flow rate. Gas flow overcomes liquid leg hydrostatic pressure.	Gas to shakers.	2	5	2	20	17.39
4.1.5	Mud Gas Separator	Over pressure	Excessive gas flow	Hydrocarbon discharge. Petechial for fire, explosion	2	5	2	20	17.39
6.1.2	Drill String Valve (NRV)	Backflow evident	Washout/fails open	Potential of hydrocarbon in drill string and further induced kick.	1	4	5	20	24.39
6.1.3	Drill String Valve (NRV)	No flow	Plugging	Inability to drill resulting in a trip delay drilling.	1	4	5	20	24.39
7.1.2	Hard Piping Upstream from the Choke	Loss of containment	Over pressure	Loss of MPD.	2	3	3	18	9.18
2.2.1	Bearing Assembly	Bearing does not rotate	Hydraulic fluid leak	Excess wear on element reducing element life. Potential for leak and loss of wellbore pressure containment.	2	2	4	16	36.36
2.2.2	Bearing Assembly	Bearing does not rotate	Bearing failure	Excess wear on element reducing element life. Potential for leak and loss of wellbore pressure containment.	2	2	4	16	36.36
2.3.1	RCD Element	Leaking/degraded Seal	Wear from normal operations	Return fluid leak. Seal to be replaced/repaired to return system to full operability.	4	2	2	16	18.60
2.3.7	RCD Element	Elastomer failure	Mechanical damage (side loading, alignment issues, vibration) from drill pipe	Loss of pressure containment, functionality. Operational downtime	2	4	2	16	18.60
3.1.4	Pressure Relief System	Premature release	Incorrect set point	Not enough surface pressure. Potential kick scenario.	2	4	2	16	3.64
3.1.11	Pressure Relief System	External leakage	Installation Corrosion Erosion	Loss of pressure integrity	2	4	2	16	3.64

Ref. ID	Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Component
					Occ.	Sev.	Det.	RPN	
4.1.3	Mud Gas Separator	Liquid out of gas line	High liquid flow rate Liquid leg inadequately sized	Liquid to vent line. Environmental spill.	2	4	2	16	13.91
3.1.2	Pressure Relief System	Failure to open	Control system failure	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.	1	5	3	15	3.42
3.1.8	Pressure Relief System	Failure to maintain the desired backpressure range	Control system failure	Continuous discharge of pressure with inability to control surface pressure.	1	5	3	15	3.42
2.2.3	Bearing Assembly	Seal leak	Wear or damage during deployment	Unable to contain pressure. Drilling delay, requires replacement.	2	3	2	12	27.27
1.2.12	Coriolis Meter	Incorrect reading	Scale coating	Impaired kick and loss detection.	3	1	4	12	14.12
1.2.13	Coriolis Meter	Incorrect reading	Excess gas	Impaired kick and loss detection.	3	4	1	12	14.12
1.2.14	Coriolis Meter	Incorrect reading	Unintentional bypass	Impaired early kick and loss detection.	2	2	3	12	14.12
3.1.10	Pressure Relief System	Internal leakage	Wear Corrosion Erosion	Loss of pressure integrity.	2	3	2	12	2.73
6.1.4	Drill String Valve (NRV)	Parted drill string	Installation Mechanical damage	Inability to drill. Result in a trip. Delay in drilling. Fishing operation impacted.	1	4	3	12	14.63
1.3.2	MPD Chokes	Trapped pressure	Blockage	Safety concern.	1	5	2	10	20.83
4.1.2	Mud Gas Separator	Gas out of liquid line	Blockage of the gas line	Gas to shakers.	1	5	2	10	8.70
1.2.10	Coriolis Meter	Incorrect reading	Calibration error	Impaired kick and loss detection.	3	1	3	9	10.59
1.1.1	Control System	Failure to operate choke(s) as intended	Inaccurate programming (programming bugs)	Loss of ability to control surface pressure on well.	2	2	2	8	17.78

Ref. ID	Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Component
					Occ.	Sev.	Det.	RPN	
1.1.6	Control System	Failure to operate choke(s) as intended	Equipment malfunction (Control system)	Loss of ability to control surface pressure on well.	2	2	2	8	17.78
1.2.15	Coriolis Meter	No reading	Unintentional bypass	Impaired early kick and loss detection.	2	4	1	8	9.41
1.3.4	MPD Chokes	Actuator failure	Improper assembly	No pressure control.	1	4	2	8	16.67
1.3.5	MPD Chokes	Actuator failure	Power failure (hydraulic, electrical, pneumatic)	No pressure control.	2	4	1	8	16.67
2.3.2	RCD Element	Leaking/degraded seal	Chemical degradation/high temperature	Return fluid leak. Seal to be replaced/repaired to return system to full operability.	2	2	2	8	9.30
2.3.5	RCD Element	Elastomer failure	Wear from normal operations	Loss of pressure containment, functionality. Operational downtime.	1	4	2	8	9.30
2.3.6	RCD Element	Elastomer failure	Chemical degradation/high temperature	Loss of pressure containment, functionality. Operational downtime	1	4	2	8	9.30
7.1.3	Hoses Upstream from the MPD Choke	Loss of containment	Entanglement below the water line	Pressure control compromised. Potential hydrocarbon release and safety impact.	2	4	1	8	4.08
1.1.3	Control System	Failure to operate choke(s) as intended	Software security vulnerability	Inaccurate kick and loss detection.	1	3	2	6	13.33
1.1.4	Control System	Failure to operate choke(s) as intended	Human Error (manual operation)	Loss of ability to control surface pressure on well.	3	2	1	6	13.33
1.2.9	Coriolis Meter	Electrical failure	Electrical interference from non-MPD signals	Impaired kick and loss detection.	1	3	2	6	7.06
1.3.1	MPD Chokes	Blocked choke	Blockage	Increases surface pressure.	2	3	1	6	12.50

Ref. ID	Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Component
					Occ.	Sev.	Det.	RPN	
2.3.3	RCD Element	Leaking/degraded seal	Mechanical damage from drill pipe	Return fluid leak. Seal to be replaced/repaired to return system to full operability.	3	2	1	6	6.98
2.1.6	Latching Assembly	Unlatching during operation	Human error	Loss of pressure containment. Projectile bearing assembly.	1	5	1	5	11.90
1.1.2	Control System	Failure to operate choke(s) as intended	Inaccurate programming (programming bugs)	Inaccurate kick and loss detection.	2	2	1	4	8.89
1.1.5	Control System	Failure to operate choke(s) as intended	Human error (manual operation)	Inaccurate kick and loss detection.	2	2	1	4	8.89
1.1.7	Control System	Failure to operate choke(s) as intended	Equipment malfunction (Control system)	Inaccurate kick and loss detection.	2	2	1	4	8.89
1.2.4	Coriolis Meter	Mechanical damage	Overpressure	Loss of functionality.	1	4	1	4	4.71
1.2.5	Coriolis Meter	Electrical failure	Damaged electrical line	Impaired kick and loss detection.	1	4	1	4	4.71
1.2.8	Coriolis Meter	Electrical failure	Loss of communication	Impaired kick and loss detection.	1	4	1	4	4.71
1.2.11	Coriolis Meter	Incorrect reading	Blockage	Impaired kick and loss detection.	1	4	1	4	4.71
1.3.3	MPD Chokes	Degradation	General wear, cuttings	May not control surface pressure adequately.	1	2	2	4	8.33
1.3.6	MPD Chokes	Mechanical failure	Seal failure	No pressure control.	1	2	2	4	8.33
1.3.7	MPD Chokes	Mechanical failure	Bearing failure	No pressure control.	1	2	2	4	8.33
1.3.8	MPD Chokes	Mechanical failure	Stem breakage	No pressure control.	1	2	2	4	8.33
2.1.3	Latching Assembly	Fails to latch bearing assembly	Leaking or broken hydraulic circuit	If not detected and pressured up, could cause bearing assembly to unlatch.	1	4	1	4	9.52
1.1.8	Control System	Complete loss of function	Control system freeze/crash	Chokes maintain current position (fail as is).	1	3	1	3	6.67
1.2.7	Coriolis Meter	Electrical failure	Damaged processor	Impaired kick and loss detection.	1	3	1	3	3.53

Ref. ID	Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Component
					Occ.	Sev.	Det.	RPN	
1.1.9	Control System	Complete loss of function	Control system freeze/crash	Loss of automated EKD.	1	2	1	2	4.44
1.2.1	Coriolis Meter	Mechanical damage	Damage caused by fluid/solids inside the Coriolis meter	Impaired kick and loss detection.	1	2	1	2	2.35
1.2.2	Coriolis Meter	Mechanical damage	Improper installation	Impaired kick and loss detection.	1	2	1	2	2.35
1.2.3	Coriolis Meter	Mechanical damage	Damaged while being transported	Impaired kick and loss detection.	1	2	1	2	2.35
2.1.1	Latching Assembly	Fails to latch bearing assembly	Improper installation	Drilling delay.	1	2	1	2	4.76
2.1.2	Latching Assembly	Fails to latch bearing assembly	Poorly manufactured assembly	Drilling delay.	1	2	1	2	4.76
2.1.4	Latching Assembly	Fails to unlatch bearing assembly	Leaking or broken hydraulic circuit	Drilling delay. Additional operational requirements. Pull LMRP.	1	2	1	2	4.76
2.1.5	Latching Assembly	Fails to unlatch bearing assembly	Debris on latching mechanism	Drilling delay. Additional operational requirements. Pull LMRP.	1	2	1	2	4.76
1.2.6	Coriolis Meter	Electrical failure	Damaged power source	Impaired kick and loss detection.	1	1	1	1	1.18

F.2 EKDS FMECA Results - Failure Modes Representing Safety Concern

Ref. ID	Component	Failure Mode	Cause(s) of Failure	Effect on System Function
7.1.4	Valves Upstream from the MPD Choke	Overpressure	Valve in wrong position (closed)	Pressure control compromised. Potential hydrocarbon release and safety impact.
3.1.1	Pressure Relief System	Failure to open	Mechanical failure	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.
3.1.6	Pressure Relief System	Late release	Reaction time design	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.
3.1.7	Pressure Relief System	Failure to maintain the desired backpressure range	Mechanical failure, blockage	Continuous discharge of pressure with inability to control surface pressure.
3.1.9	Pressure Relief System	Failure to maintain the desired backpressure range	Undersize pipe	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.
3.1.12	Pressure Relief System	Insufficient pressure relief capacity	Blockage of PRV	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.
3.1.13	Pressure Relief System	Insufficient pressure relief capacity	Blockage downstream of relief valve	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.
7.1.1	Hard Piping Upstream from the MPD Choke	Loss of containment	Structural deficiency	Pressure control compromised. Potential hydrocarbon release and safety impact
2.1.7	Latching Assembly	Unlatching during operation	Leaking or broken hydraulic circuit	Loss of pressure containment. Projectile bearing assembly
3.1.14	Pressure Relief System	Insufficient pressure relief capacity	Blockage upstream of relief valve	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.
4.1.6	Mud Gas Separator	Leakage	Structural deficiency	Hydrocarbon discharge. Potential for fire, explosion.
3.1.3	Pressure Relief System	Failure to open	Sensor failure	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.

Ref. ID	Component	Failure Mode	Cause(s) of Failure	Effect on System Function
3.1.5	Pressure Relief System	Late release	Incorrect set point	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.
4.1.1	Mud Gas Separator	Gas out of liquid line	High gas flow rate Gas flow overcomes liquid leg hydrostatic pressure	Gas to shakers.
4.1.5	Mud Gas Separator	Over pressure	Excessive gas flow	Hydrocarbon discharge. Potential for fire, explosion.
3.1.2	Pressure Relief System	Failure to open	Control system Failure	Overpressure of the system. Fracturing of formation. Rupture of riser or system components upstream of MPD choke.
3.1.8	Pressure Relief System	Failure to maintain the desired backpressure range	Control system failure	Continuous discharge of pressure with inability to control surface pressure.
1.3.2	MPD Chokes	Trapped pressure	Blockage	Safety concern.
4.1.2	Mud Gas Separator	Gas out of liquid line	Blockage of the gas line	Gas to shakers.
2.1.6	Latching Assembly	Unlatching during operation	Human Error	Loss of pressure containment. Projectile bearing assembly.

F.3 MWD/LWD Systems FMECA Results Sorted by RPN

Ref. ID	Sub-system/ Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Sub-system/Component
					Occ.	Sev.	Det.	RPN	
3.1	Transmitter	Electrical failure	Vibration/shock Temperature Stabilizer failure	Poor/No data log. Potential drilling delay. Failure to maintain well trajectory.	3	4	5	60	33.33
3.2	Transmitter	Mechanical failure	Vibration/shock Temperature Stabilizer failure	Poor/No data log. Potential drilling delay. Failure to maintain well trajectory.	3	4	5	60	33.33
3.3	Transmitter	Fluid-related failure	Poor control of fluid properties (solid contaminants)	Mud flow resulting in potential drilling delay.	3	4	5	60	33.33
7.3	General Mechanical Components	Failure of the pistons and control valves	Erosion Poor mud system Assembly error	Loss of data. Loss of early warning signs for kick. Drilling delays.	3	4	5	60	21.82
7.4	General Mechanical Components	Failure of the rotor/stator	Erosion Poor mud system	Loss of data. Loss of early warning signs for kicks. Drilling delays.	3	4	5	60	21.82
7.1	General Mechanical Components	Failure of the seals	Degradation Debris Contamination Temperature Overpressure Out of specification condition	Loss of pressure, hydraulic oil. Pump failure. Drilling delays. Loss of early warning signs for kick.	2	4	5	40	14.55
7.5	General Mechanical Components	Drive assembly	Excessive torque and vibration Jarring Back reaming	Loss of data. Loss of early warning signs for kick. Drilling delays.	2	4	5	40	14.55
7.6	General Mechanical Components	Inter tool connections	Seal failure Improper assembly over stress	Loss of data Loss of early warning signs for kick. Drilling delays.	2	4	5	40	14.55
6.2	Surface Module	Software failures	Inaccurate Programming (firmware) Human errors Interface errors	Inaccurate data driving poor decisions. Loss of early warning signs for kick.	2	4	4	32	28.57

Ref. ID	Sub-system/ Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Sub-system/Component
					Occ.	Sev.	Det.	RPN	
6.3	Surface Module	Equipment failure (cables, computer, displays, telecommunica-tion, etc.)	Human error Vibration/shock Temperature PCB failures Degradation Poor assembly	No data. Drilling delays. Loss of early warning signs for kick.	2	4	4	32	28.57
6.4	Surface Module	Human error	Inaccurate procedures Lack of training or experience	Loss of drilling efficiency. Inaccurate formation evaluation. Loss of early warning signs for kick. Non-productive time.	2	3	5	30	26.79
5.1	Data sensors	Electrical/ electronic failure	Vibration/shock Temperature Stabilizer failure PCB failures Degradation Electrodes Poor assembly	No data. Potential drilling delay. Suspect data leading to poor drilling.	3	3	3	27	33.33
5.2	Data sensors	Mechanical failure	Vibration/shock Temperature Stabilizer failure Degradation Poor assembly	No data. Potential drilling delay. Suspect data leading to poor drilling.	3	3	3	27	33.33
5.3	Data sensors	Sensor programming errors	Inaccurate Programming (firmware)	Inaccurate data driving poor decisions.	3	3	3	27	33.33
1.1	System Control Electronics	Failure to provide accurate control commands to various MWD/LWD components	Inaccurate programming (firmware)	Inaccurate data driving poor decisions.	3	4	2	24	12.77
1.2	System Control Electronics	Failure to synchronize control commands to various MWD/LWD components	Inaccurate programming (firmware)	Inaccurate data driving poor decisions.	3	4	2	24	12.77

Ref. ID	Sub-system/ Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Sub-system/Component
					Occ.	Sev.	Det.	RPN	
1.3	System Control Electronics	Failure to send any control command to various MWD/LWD components	Overheating	Inaccurate data driving poor decisions.	3	4	2	24	12.77
1.4	System Control Electronics	Failure to send any control command to various MWD/LWD components	Semiconductor failure	Inaccurate data driving poor decisions.	3	4	2	24	12.77
1.5	System Control Electronics	Failure to send any control command to various MWD/LWD components	Soldering failure	Inaccurate data driving poor decisions.	3	4	2	24	12.77
1.6	System Control Electronics	Failure to send any control command to various MWD/LWD components	Mechanical damage	Inaccurate data driving poor decisions.	3	4	2	24	12.77
1.9	System Control Electronics	Assembly failure	Operated out of specification Improper application	No data/Inaccurate data driving poor decisions and drilling delays.	5	4	1	20	10.64
2.2	Downhole Filter Sub	Washout	Sand content erosion	Clogging of MWD system resulting in delay drilling.	1	4	5	20	55.56
7.2	General Mechanical Components	Failure of the bearings	Degradation Debris Contamination Failed screen Temperature Overpressure Out of specification condition	Pump failure. Power failure. Drilling delays. Loss of early warning signs for kick.	1	4	5	20	7.27

Ref. ID	Sub-system/ Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Sub-system/Component
					Occ.	Sev.	Det.	RPN	
6.1	Surface Module	Sensor failures	Human error Vibration/shock Temperature Stabilizer failure PCB failures Degradation Poor assembly	Loss of drilling efficiency. Inaccurate formation evaluation. Loss of early warning signs for kick.	2	3	3	18	16.07
1.8	System Control Electronics	Assembly failure	Mechanical/ structural deficiency	No data/Inaccurate data driving poor decisions and drilling delays.	1	4	4	16	8.51
2.1	Downhole Filter Sub	Blockage	Large debris	No/reduced flow. Pressure build-up. Stuck drill string.	2	4	2	16	44.44
7.7	General Mechanical Components	Nuclear sources	Containment leak	Loss of data. Loss of early warning signs of kick. Drilling delays.	1	5	3	15	5.45
4.3	Power supply	Sporadic power supply	Vibration/shock Temperature Stabilizer failure PCB failures Battery cell failure Degradation Electrodes	Suspect data leading to poor drilling.	1	2	5	10	29.41
1.7	System Control Electronics	No data/ inaccurate data prior to deployment	Human error	No data/Inaccurate data driving poor decisions.	1	4	2	8	4.26
4.1	Power supply	Electrical failure	Vibration/shock Temperature Stabilizer failure PCB failures Battery cell failure Degradation Electrodes	No data. Potential drilling delay.	2	4	1	8	23.53

Ref. ID	Sub-system/ Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Sub-system/Component
					Occ.	Sev.	Det.	RPN	
4.2	Power supply	Mechanical failure	Vibration/shock Temperature Stabilizer failure Battery cell failure Degradation	No data. Potential drilling delay.	2	4	1	8	23.53
4.4	Power supply	Loss of mud flow (turbine)	Mud pump failure Surface delivery system washout	Low voltage. Low current. Suspect data leading to poor drilling.	1	2	4	8	23.53

F.4 Wired Drill Pipe System FMECA Results Sorted by RPN

Ref. ID	Sub-system/ Component	Failure Mode	Cause(s) of Failure	Effect on System Function	Ratings				% of Total RPN for Sub-system / Component
					Occ.	Sev.	Det.	RPN	
1.2	Surface System	Failure of surface equipment (cables, plugs)	Human errors	Loss of data. To be reverted to mud pulse transmission.	3	4	5	60	39.47
1.3	Surface System	Top drive couplings/data swivel/saver	Human errors Normal wear	Loss of data. To be reverted to mud pulse transmission.	3	4	5	60	39.47
2.2	Downhole System	Mechanical failure	Degradation Manufacturing Operating out of specified limits (operational and environmental) Improper running and handling	Loss of data. To be reverted to mud pulse transmission.	3	4	5	60	60.00
2.1	Downhole System	Electrical/ electronic failure	Vibration/shock Temperature PWB failures Battery cell failure Degradation Manufacturing Operating out of specified limits (operational and environmental)	Loss of data. To be reverted to mud pulse transmission.	2	4	5	40	40.00
1.1	Surface System	Failure of the network	Similar to software and equipment failure for MWD/LWD surface module - Inaccurate Programming (firmware) Human errors Interface errors	Loss of data transmission. To be reverted to mud pulse transmission.	2	4	4	32	21.05