

## **RISK ANALYSIS OF USING A SURFACE BOP**

### **Study Report**

**Prepared for**



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## EXECUTIVE SUMMARY

The United States Mineral Management Services Technology Assessment & Research Program (MMS TA&RP) has requested an investigation into how the hazards and risk criticalities for production facility dedicated drilling riser (DDR) systems equipped with Surface Blow-Out Preventers (SBOPs) change as the technology envelope is pushed into deeper, less statistically quantified environments with more uncertain reservoirs. A standard methodology for performing risk assessment has been selected and tailored for DDR systems, based on the best experience and lessons learned. The process is intended to provide the operator with a structured, comprehensive approach to the risk assessment of a DDR system for any stage of field life. Effort has also been made to summarize key integrity management measures applicable to a DDR system.

### Recommendations for DDR Systems

Typical DDR systems include:

- Monobore riser with SBOP;
- Monobore riser with a mudline shear device (SID) and SBOP;
- Concentric (insert) riser with SBOP.

Based on current industry practices, all three systems could potentially be designed with sufficient robustness and safety margins to provide reliable integrity. The selection of a particular system as fit is based on balancing a number of factors, including site-specific characteristics, cost and fabrication limitations, and vessel limitations in terms tensioner capacity and clearance for lifting and handling procedures. As such, it is recommended that selection should be driven by an assessment of total risk to the system to clearly identify the most critical hazards. The methodology presented in this document is intended to facilitate a side by side evaluation of multiple drilling systems.

That being said, a concentric riser system is typically the best option from an integrity standpoint for deepwater, HPHT dedicated drilling risers. While monobore drilling riser joints and connectors may be designed robustly and be justified as fit for purpose, the additional pressure containment barrier in a concentric riser system provides an additional design conservatism to offset some of the uncertainties associated with deepwater drilling.

Use of a mudline shear device may be a viable alternative, but the proposed application must be carefully assessed. The use of these devices does move containment away from topsides personnel in some scenarios, has the potential to lessen environmental impact for high pressure wells, and

mitigates against a scenario where the riser separates somewhere between SBOP and mudline. However, there are additional concerns related to use from deepwater floating production facilities, such as:

- Additional, nonstandard training requirements for topsides personnel, as there has been no experience in the GOM with the mudline shear devices at the time of this report;
- Delay / reliability of signal to activate device, especially since some designs employ acoustic controls;
- Handling procedures and potential impact to other risers when running, retrieving or otherwise moving between wells;
- Reestablishing well control post-activation;
- Inspection, maintenance and testing of the device;
- Device doesn't mitigate potential safety hazards to the topsides personnel for gas blowout if the gas has migrated past the mudline.

### Description of Risk Analysis Methodology

The methodology presented focuses on practical execution of a systematic risk assessment, highlighting successful practices from industry. Risk assessment tasks have been summarized as:

1. Gathering System Data & Standards
2. System Subdivision & Grouping
3. Hazard Identification (HAZID)
4. Risk Assessment
5. Risk-Based Recommendations

Guidance is provided on how best to implement the risk assessment methodology, in terms of a workshop setting. Emphasis is placed on preparatory work, workshop management, and effective output. The information required successful risk assessment has been summarized, including design, operation and regulatory information. HAZID has been treated at a high-level, and guidance has been provided on failure mode specification. An Indexing Matrix risk assessment has been modified to allow incorporation of detailed PRA results and application of expert experience-driven modifiers. As risk assessment is just one stage of successful riser integrity management (albeit a crucial stage), effort has been made to clarify how the risk assessment interfaces within the overall integrity management process.

## Typical Hazards

Since there have been no DDR failures to date in the GOM and insufficient component failure data to draw detailed conclusions, review of failures associated with drilling riser systems on non-production facilities (i.e. MODUs and jack-ups) was included to insure comprehensive treatment. The majority of integrity incidents recorded and assessed for the Gulf of Mexico related to drilling risers, loss of well control, blowouts and explosions can be summarized as resulting from a combination of:

- Human error and/or failure to follow procedures;
- Mechanical failures due to damage, degradation and/or manufacturing defects;
- Environmental / reservoir loading outside design conditions.

To determine the major risks to the DDR system utilizing a SBOP, the following topics were investigated:

- Assessment of SBOP characteristics; to identify any potential hazards SBOPs are particularly prone or resistant to;
- Comparison of design codes relevant to DDRs with each other and with current industry practices, to identify gaps and redundancies in design practices;
- Review of metocean specification procedures, to identify uncertainties and provide some guidance to assess the confidence in design conditions;
- Potential operational incidents that are safety-critical or particularly prone to human error;
- Reservoir characteristics affecting kicks, to highlight some potential factors for this safety-critical hazard.

Finally, a method for how these hazards are translated into failure modes for systematic risk assessment is presented.

## Additional Conclusions

In general, the conclusions drawn are:

1. While intuitively an SBOP would inherently carry more potential risk to vessel and personnel, a surface stack may not increase overall risk in many operations. Even though the pressures may be closer to staff and the vessel, the exposure time is less and the kill operation is a simpler and clearer procedure. However, the risks must be assessed on a project by project basis. In some instances, it might be necessary to employ a secondary well control method, such as an SID.

2. Since the SBOP is the primary barrier between facility personnel and catastrophic failure, proper maintenance and inspection is crucial.
3. Although the current design codes used for DDRs are considered conservative, none of the industry personnel (either surveyed or interviewed informally) were comfortable with removing design conservatism in an asset as safety-critical as a DDR with SBOP. Many operators apply more stringent design requirements, such as 1,000-yr metocean events for survival and in-house material qualifications, due to the safety-critical nature of the system.
4. GOM environmental loading is a significant uncertainty in riser design, especially with regards to deepwater current profiles and DDR fatigue. Since many failures are a combination of a prior defect or oversight in combination with unanticipated environmental loading, it is important to clearly understand what the specification has been based on, what conservatism has been assumed, and the confidence the metocean experts have associated with the criteria.
5. Potential operational incidents can be avoided through training, strict adherence to QA/QC procedures and implementation of an audit program that ensures the procedures are being followed. However, considering these hazards during risk assessments is difficult as the incidents involve a break-down of in-place quality procedures. The most common incidents involve:
  - Damage to the riser or safety-critical system during running and retrieval, SIMOPS, or lifting and handling procedures;
  - Material degradation of a component due to manufacturing defects, improper maintenance or operation in fluids/temperature outside of material qualifications;
  - Non-adherence to operating procedures or (less often) Emergency Disconnect Sequence.
6. The potential for kicks and blowouts should always be closely examined and managed. Some primary factors affecting kicks are:
  - Abnormal pressure gradients in the well bore;
  - Narrow window between pore pressure and fracture gradient;
  - Abnormal temperature gradients;
  - Mud weight;
  - Hydrate formation.

## ACRONYMS

ALS	Accidental Limit State
API	American Petroleum Institute
BOP	Blowout Preventer
DBT	Design by Testing
DDR	Dedicated Drilling Riser
DNV	Det Norske Veritas
DOI	United States Department of the Interior
DPS	Dynamic Positioning System
ESG	Environmental Safe Guard
FLS	Fatigue Limit State
FM	Failure Mode
FPU	Floating Production Unit
GOM	Gulf of Mexico
HAZID	Hazard Identification Workshop
HIRA	Hazard Identification & Risk Assessment Workshop
HPHT	High Pressure / High Temperature
HSE	Health, Safety & Environment
IADC	International Association of Drilling Contractors
IM	Integrity Management
JIP	Joint Industry Project
JONSWAP	Joint North Sea Wave Project
JSA	Job Safety Analysis
LMRP	Lower Marine Riser Package

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LRFD	Load and Resistance Factor Design
MMS	Mineral Management Services
MWL	Mean Water Level
OCS	United States Outer Continental Shelf
OTC	Offshore Technology Conference
P-M	Pierson-Moskowitz
PRA	Probabilistic Risk Assessment
QA/QC	Quality Assurance / Quality Control
RBD	Reliability Based Design
SBOP	Surface Blowout Preventer
SDS	Surface Disconnect System
SID	Subsea Isolation Device
SIMOPS	Simultaneous Operations
SINTEF	Norwegian Institute of Technology Foundation for Scientific and Industrial Research
SLS	Serviceability Limit State
SSBOP	Subsea Blowout Preventer
SSOD	Subsea Shut-Off Device
SX	Saturation Drilling
TA&RP	Technology Assessment & Research Program
UK	United Kingdom
UK HSE	United Kingdom Health and Safety Executive
ULS	Ultimate Limit State
US	United States of America
VIV	Vortex Induced Vibration
WSD	Working Stress Design

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# 1 INTRODUCTION

## 1.1 BACKGROUND

As the offshore industry is faced with greater pressure to develop hydrocarbon reserves in deeper and deeper waters, there is an increased level of uncertainty associated with production facility dedicated drilling riser (DDR) systems, particularly with the use of Surface Blow-Out Preventers (SBOPs) without a mudline shut-off device in high pressure well scenarios.

In this context, MMS has requested an investigation into how the hazards and risk criticalities for SBOP DDR systems on facilities change as the technology envelope is pushed into deeper, less statistically quantified environments with more uncertain reservoirs.

## 1.2 STUDY OBJECTIVES

The objective of this study is to examine how the hazards and risk criticalities associated with riser system failures for facility dedicated drilling riser systems with surface BOP change as the technology envelope is pushed, and present a methodology for developing the integrity management strategy for these systems.

## 1.3 SCOPE

The overall project workscope is defined by following three subtasks, based on MCS drilling experience and integrity management (SCRIM JIP) [9]:

Task 1 - Information Survey (CTR 1.1)

Task 2 - Risk Assessment Methodology (CTR 1.2)

Task 3 - Integrity Management Strategy (CTR 1.3)

For Task 1, a literature and industry survey was conducted to assess key technical challenges and potential hazards to the drilling riser system. These results formed the basis of the remaining project tasks. Since there have been no DDR failures to date in GOM and insufficient component failure data to draw detailed conclusions, review of failures associated with drilling riser systems on non-production facilities (i.e. MODUs and jack-ups) was included to insure comprehensive treatment. The majority of integrity incidents recorded and assessed for the Gulf of Mexico related to drilling risers, loss of well control,

blowouts and explosions can be summarized as resulting from a combination of:

- Human error and/or failure to follow procedures;
- Mechanical failures due to damage, degradation and/or manufacturing defects;
- Environmental / reservoir loading outside design conditions.

To determine the major risks to the DDR system utilizing a SBOP, the following topics were investigated:

- Assessment of SBOP characteristics; to identify any potential hazards SBOPs are particularly prone or resistant to;
- Comparison of design codes relevant to DDRs with each other and with current industry practices, to identify gaps and redundancies in design practices;
- Review of metocean specification procedures, to identify uncertainties and provide some guidance to assess the confidence in design conditions;
- Potential operational incidents that are safety-critical or particularly prone to human error;
- Reservoir characteristics affecting kicks, to highlight some potential factors for this safety-critical hazard.

Finally, a method for how these hazards are translated into failure modes for systematic risk assessment is presented.

For Task 2, a risk assessment methodology tailored from best practices for production facility dedicated drilling riser systems was developed. Guidance is provided on how best to implement the risk assessment methodology in a workshop setting and on how key factors may impact risk rankings. The information required for a successful risk assessment has been summarized, including design, operation and regulatory information. An Indexing Matrix risk assessment has been modified to allow incorporation of detailed PRA results and application of expert experience-driven modifiers. As risk assessment is just one stage of successful riser integrity management (albeit a crucial stage), effort has been made to clarify how the risk assessment interfaces within the overall integrity management process.

For Task 3, an integrity management strategy methodology is outlined, with particular attention paid to typical mitigations and integrity management actions available to develop an integrity management strategy for production facility dedicated drilling riser systems. Suggested mitigation measures/remedial actions are presented to address the potential failure modes discussed for Task 1.

## 1.4 DRILLING RISERS ON PRODUCTION FACILITIES

### 1.4.1 Drilling Riser System Components

The components of a dedicated drilling riser (DDR) system are outlined below:

- Riser joints

Risers used in conjunction with a SBOP are limited in diameter by the SBOP. Therefore, typically between 10-inch and 16-inch high pressure risers are used in these applications. However new technology is emerging to allow larger (e.g. 19.25-inch inner diameter [45]) drilling risers to be used with these systems. Single and dual casing drilling riser options exist. The dual casing (or insert riser) is favored by the majority of operators in the Gulf of Mexico. The dual casing riser offers an additional pressure containment barrier reducing the likelihood of failure by enabling continuous annuli pressure and temperature monitoring.

- Ancillary components of the riser systems

- Keel Joints

The keel joint is a riser joint with increased wall thickness used to increase bending stiffness at the location where the riser first enters the keel of the spar hull.

- Tension Joint

The tension joint is a special riser joint which connects the mechanical tensioners to the riser through a load ring.

- Pup Joints

Pup joints are shorter than regular riser joints and are used to accommodate riser space out.

- Tapered Stress Joints

TSJs are transition members between a rigid or stiffer section of the riser and a less stiff section of the riser

- VIV Strakes

Vibration suppression devices used to improve fatigue life of the riser.

- Wellhead Connector
  - Universal terminology for the connection to the well head.
- Riser Tensioning System
  - The tensioner system supports the weight of riser, and needs to be dynamically adjustable. Tension is generally provided via ram style tensioners or buoyancy cans.
- Vessel
  - SBOPs have been used on all types of production facilities (Spars, TLPs, and semi-submersibles), jack-ups, moored drilling vessels and deepwater rigs with dynamic positioning systems. It is important to note that MODU drilling with SBOPs is not permitted in the Gulf of Mexico at present.
- Typical Safety Barriers
  - Blow-out preventer (BOP)
    - A BOP confines well fluids within the wellbore, acting as the last barrier between drilling operations and loss of well control. A facility DDR will typically employ a surface BOP (SBOP).
  - Subsea isolation device (SID)
    - Allows for the disconnection from the wellhead in the case of a catastrophic event. The SID is not designed for typical well control; it is designed to disconnect the riser and seal the well in case of emergency.
  - Insert riser
    - Secondary riser run inside the drilling riser just before breaching the hydrocarbon payzone; locks into the casing hanger and at the subsea wellhead. Depending on the drilling campaign, an insert riser may mitigate wear for a significant portion of total drilling time and provide an additional level of pressure containment during the most likely time for a blowout.

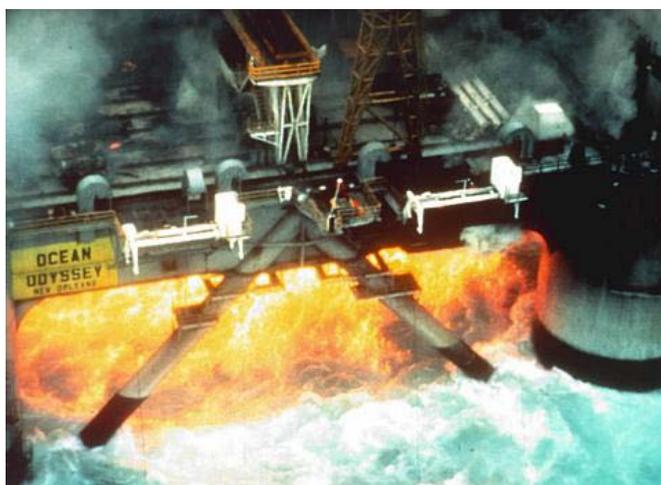
More detailed information on specific components is provided in the report for Task 1 [10]. Unlike the risers on drilling vessels, flexible and ball joints are not typically employed; tapered transition joints are preferred.

The most potentially catastrophic and dramatic failure event associated with any drilling riser

is blowout. Therefore, significant emphasis is placed on SBOPs as the last safety barrier and as they are located near the facility.

#### 1.4.2 Kicks, Blowouts & BOPs

If the drilling mud hydrostatic head is insufficient to hold the formation fluid in the formation, the formation fluid may flow into the wellbore in an unplanned fashion referred to as a kick. A kick may escalate into a potentially catastrophic, uncontrolled flow of reservoir fluids termed a blowout. If a blowout breaches surface containment, the fluids may ignite, resulting in loss of life and damage to the facility [53].



**Figure 1.1 ODECO Ocean Odyssey Semi-Sub Blowout, 22 Sept. 1988**

A Blow-Out Preventer (BOP) confines well fluids within the wellbore, acting as the last barrier between drilling operations and loss of well control. BOPs may be located directly above the subsea wellhead (SSBOPs) or at the top of the drilling riser (SBOPs). SBOPs differ in size, and therefore weight, as they require less redundancy in the components. However, their main functions (and many of the components) are the same. In current practice Floating Production Units (FPUs) typically use SBOPs with any facility dedicated drilling risers (DDRs). Ultra-deepwater FPU's also tend to “park” their DDRs on a dummy wellhead, instead of running and retrieving the DDR between workover and drilling operations.

If shear rams on an SBOP are used during an emergency disconnect and well abandonment, there is risk that the sheared drill pipe may impact and/or damage subsea equipment. One potential way to avoid this would be by using a subsea isolation device (SID), which is

essentially a set of shear rams, above the wellhead, where a traditional SSBOP would usually sit. However this is not deemed necessary in all cases. A respondent to the survey noted that “additional fail safes are not required if the proper design, manufacturing and in-service monitoring and inspection practices and procedures are in place to ensure the riser is designed, built and operated to reduce risk to as low as reasonably practicable” [19].

### 1.4.3 Typical BOP Components

The components and their functions of a SBOP are outlined below:

- Pipe Rams

Component to create a seal around the drill pipe, can be high or low pressure, and although pipe rams were formerly designed for only one pipe size, they are now available in variable sizes. Typically have rubber faced faces that come together to seal the wellbore.

- Annular Preventer

Forms a seal in the annular space around any object in the wellbore or upon itself, enabling well control operations to commence, usually mounted at the top of the BOP.

- Blind Rams

Intended to seal against each other to effectively close the hole, they are not intended to shear the drill string or any casings running through the BOP, which must be performed by tools with a cutting edge (blind shear rams)

- Blind / Shear Rams

An element in the BOP intended to shear the drill string and close off the well as a last resort to regain pressure control of a well.

- Choke Valves

These provide a means of controlling the functions of the BOP

## 1.5 REVISION HISTORY

This is Rev. 02, issued with client comments.

## 2 INTEGRITY MANAGEMENT METHODOLOGY OVERVIEW

### 2.1 GENERAL

Riser integrity management methodology has been well established for risers [7, 14, 16].

### 2.2 RISER INTEGRITY MANAGEMENT PROCESS

An overview of the approach proposed by this study for the development and implementation of an Integrity Management Program for facility dedicated drilling riser systems with SBOP is presented in Figure 2.1. The methodology can be summarized as follows:

1. Gathering System Data & Standards

Gather data required for risk assessment, including all design, operational and functional information for the DDR; regulatory and corporate minimum integrity requirements; a first-pass list of failure modes generally applicable to DDRs; and standardized scales for classifying probability, consequence and risk.

2. System Subdivision & Grouping

Subdivide the DDR system into integrity groups based on similarity of service and risks to which the components are exposed.

3. Hazard Identification (HAZID)

For each group, define the failure modes to which the integrity groups are exposed. Typically, the most onerous condition of the grouped items is considered when assessing failure modes.

4. Risk Assessment

Calculate a Risk Index as the product of the Probability and Consequence Indices for each relevant failure mode. The Probability Index is a function of proximity to design limit and associated uncertainties; the Consequence Index quantifies the safety, environmental, and economical cost of a failure.

#### 5. Reliability Centered Maintenance (RCM) Assessment of Priority Sub-Components

Based on quantitative reliability assessments, develop a proactive maintenance strategy and sparing plan for any components that are critical to HSE, critical to operability of the system, or have a severe consequence of failure or downtime due to maintenance. RCM analysis should be developed for each piece of equipment, and feed into an overall maintenance strategy.

#### 6. Implement Barriers / Mitigations

Assess whether any prevention or mitigation measures are available for the risk. In certain cases, prevention or mitigation measures may be more cost-efficient to implement than the in-service integrity management measures required to address a higher risk.

#### 7. Develop Integrity Management Plan

Develop Integrity Management (IM) Strategy consistent with the risks associated with relevant Failure Modes. An IM Strategy consists of a combination of the following available measures:

- Monitoring Measures
- Inspection Measures
- Analysis and Testing
- Operational Procedures
- Preventative Maintenance Measures
- Remedial Maintenance Measures

Anomaly limits and implementation frequency for all measures are crucial components of any IM strategy.

#### 8. Determine key issues and schedule for Integrity Reviews. The results of the SCR integrity management program are periodically reviewed relative to the anomaly limits, and summarized in a Fitness Statement. The Fitness Statement reports any deviations that need immediate and/or long term action and any updates to the IM Measures for the future.

The deliverables of the overall IM process are:

- Integrity Management Plan, which describes each of the IM Measures applied as part of the overall IM program together with their frequency of application. This document is updated and maintained throughout field life.
- Periodic Fitness Statements, which are the outputs of periodic reviews of system integrity. These represent a statement of continued fitness for purpose based on information gathered from the IM Plan.

The process presented represents industry best practice for riser integrity management. However, some flexibility may be warranted based on specific project requirements.

It is recommended that any facility dedicated drilling riser deployed for a significant continuous interval be included with the integrity management planning for the other facility risers.

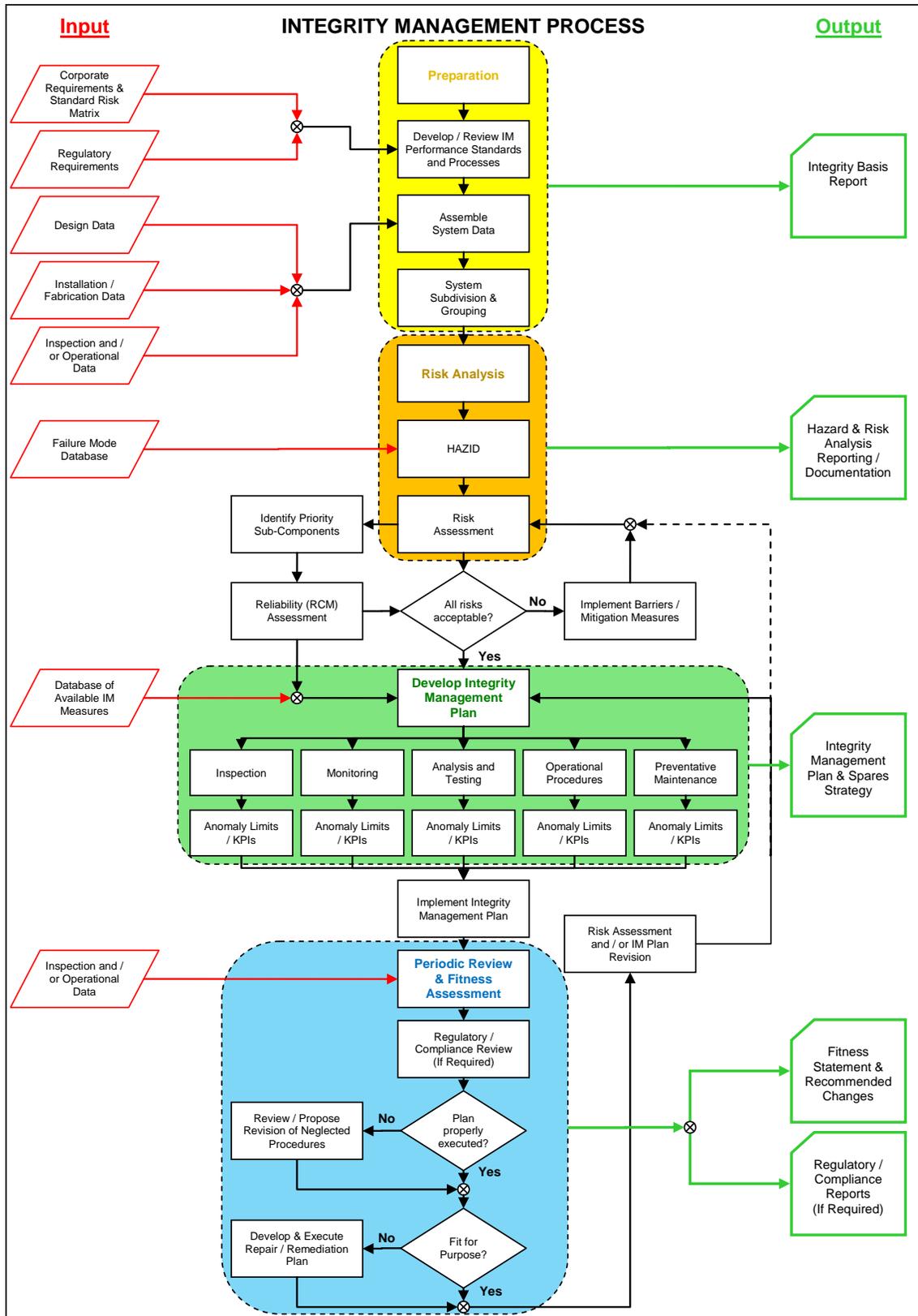


Figure 2.1 Integrity Management Methodology

## 3 IDENTIFICATION OF KEY HAZARDS

### 3.1 OVERVIEW

MCS conducted a thorough review of past and current project experience, public domain incidents and technical data to identify relevant design drivers, industry-driven design standards and perceived critical hazards for facility DDRs using SBOPs. High-level, targeted questionnaires were sent to key GOM operators and select BOP vendors to confirm the current relevance of this information.

### 3.2 SUMMARY OF INFORMATION REVIEW

#### 3.2.1 Objectives of the Information Review

In order to assess the hazards and risk criticalities associated with riser failures for facility DDRs with SBOPs, it is crucial that there is a clear understanding of:

- The components of a DDR systems and their interaction;
- Standard design methodologies and their limitations;
- The hazards posed by environmental, reservoir or operational conditions;
- Current limits of well-established technology.

Risk assessments should consider the consequence of a riser system failure (with regards to people, environment, production (operation) cost and reputation of the company) and how likely it is that these failures may occur. The robustness must be assessed of:

- Design basis input collection and analysis (e.g. to determine metocean and well criteria);
- Vessel and mooring system design;
- Riser system design;
- Hazardous operational procedures and level of training for personnel [36].

This information review attempts to form a basis to assess these factors. To this end, an extensive Literature Review and a less successful Industry Survey were conducted.

### 3.2.2 Literature Review

Since there have been no DDR failures to date in GOM and insufficient component failure data to draw detailed conclusions [9, 10, 13], hazard identification has relied heavily on review of relevant literature. This included review of failures associated with drilling riser systems on non-production facilities (i.e. MODUs and jack-ups) to insure comprehensive treatment. The goal of the literature review was to investigate key data to:

- Develop a well-defined description of DDR system components;
- Identify prominent technical challenges;
- Summarize risk-mitigating techniques typically available in industry.

The literature review consisted primarily of papers and articles relating to drilling using a SBOP, from the following types of sources:

- Public reporting of offshore incidents;
- Previous MCS and MMS study reports;
- Conference papers (e.g. OTC) and JIP reports;
- Industry standards (e.g. API, DNV, NORSOK);
- Operator internal guidelines (typically those reviewed or written by MCS);
- Vendor public information and previous surveys;
- MCS internal design and integrity management project database.

Information from the UK Health and Safety Executive (UK HSE) [20] regarding North Sea DDR safety issues was reviewed to incorporate their lessons learned into this report. As North Sea offshore operations are typically shallow gas developments, and environmental loading conditions are dissimilar, the data was reviewed to include only what would be applicable to GOM operations.

The MMS Hybrid Well study report [16] and the SCRIM JIP TTR IM Guidelines [14] were reviewed to determine established critical hazards and current industry information for facility TTRs in general and DDRs in particular.

The results of the literature review forms the majority basis of this report, and were used to develop focused questionnaires.

### 3.2.3 Industry Surveys

In order to insure the current relevance of the information gathered from the literature review, questionnaires were tailored for operators to elicit their perception of:

- Key technical challenges;
- Risk reduction methods;
- Risks considered using a SBOP;
- Necessity of additional fail safes;
- Riser design drivers;
- Integrity issues.

As this was validation of the data already collected, only the most relevant operators were questioned. Thirty-nine (39) production facilities were identified as in operation or starting up for the Gulf of Mexico as of 2009, as shown in Table 3.1. Of these facilities, only the six operators with three or more facilities were surveyed, in total representing twenty-nine (29) facilities in the Gulf of Mexico (approximately 75%). Two of these operators had indicated during previous studies that they do not operate dedicated drilling risers, but provided information on their workover/completion systems.

**Table 3.1 2009 GOM Floating Facilities Operating or Starting-Up [56]**

Operator	Facility Count
BP	7
Anadarko Petroleum <sup>Note 1</sup>	7
Royal Dutch/Shell	4
Eni <sup>Note 1</sup>	4
Chevron	4
Murphy Oil	3
ConocoPhillips	2
ATP	2
BHP Billiton	2
ExxonMobil	1
El Paso Corp.	1
Total	1
Helix Energy Solutions	1
Total No. of Facilities	39

Notes 1. Previous study [16] shows these operators do not have dedicated drilling risers

While a limited number of operators completed the questionnaire, there was some success with informal interviews of four additional operators and several engineering contractors.

An example questionnaire is presented in Appendix B.

### 3.2.4 Information Review Results

The majority of integrity incidents recorded and assessed for the GOM related to drilling risers (whether attached to a facility or drilling vessel), loss of well control, blowouts and explosions can be summarized as resulting from a combination of:

- Human error and/or failure to follow procedures;
- Mechanical failures due to damage, degradation and/or manufacturing defects;
- Environmental / reservoir loading outside design conditions.

This follows trends reported with the North Sea public domain information [20], and the information gathered from the literature review.

To determine the major risks to the riser system utilizing a SBOP as drilling and exploration moves into deeper waters, drilling challenges in deepwater environments were first investigated. Risks that were highlighted with the move to deeper waters included abnormal pressure gradients in the well bore, a narrow window between pore pressure and fracture gradient, abnormal temperature gradients, hydrate formation, stronger currents and riser manipulation (running and retrieval of the riser, and associated components in deeper waters).

To examine the integrity of the DDR system as a whole, this report considers individually:

- Characteristics of Surface BOPs

Since the SBOP is the primary barrier between facility personnel and catastrophic failure, proper maintenance and inspection are both crucial. While using an SBOP effectively places well control events closer to crew, the direct access allows for better well control and for easier maintenance and inspection.

- Drilling Riser Design Codes

API RP-2RD has supplanted API RP-16Q as the primary design code for DDRs in the GOM, in part because API RP-16Q does not take into account fatigue and has only been extended to 10,000ft water depths. DDRs in the GOM are typically designed using a Working Stress Design (WSD) methodology, which is considered conservative in allowable limits when compared to Load & Resistance Factor Design (LRFD), Reliability Based Design (RBD) or Design by Testing.

- Metocean and Environmental Factors

GOM environmental loading is a significant uncertainty in riser design, especially with regards to deepwater current profiles. Since many failures are a combination of a prior defect or oversight in combination with unanticipated environmental loading, it is important to clearly understand what the specification has been based on, what conservatism has been assumed, and the confidence the metocean experts have associated with the criteria.

- Potential Operational Incidents

Potential operational incidents that are safety-critical or particularly prone to human error should always be considered. These issues can potentially be avoided by strict adherence to QA/QC procedures and a program to audit that the procedures are being followed.

- Reservoir Characteristics Affecting Kicks

Even though a blowout typically requires an additional failure of some critical safety component, it remains the most dramatic and potentially costly failure in terms of HSE, loss of product and costs of repairs. As such, the potential for kicks and blowouts should always be closely examined and managed.

Although intuitively an SBOP would inherently carry more potential risk to vessel and personnel, a surface stack may actually reduce overall risk in many operations. While the pressures may be closer to staff and the vessel, the exposure time is less and the kill operation is a simpler and clearer procedure.

Finally, a method for how these hazards are translated into failure modes for systematic risk assessment is presented.

### 3.3 SURFACE BOP SYSTEM AND CHARACTERISTICS

#### 3.3.1 Function

When planning and drilling wells, a well kick is always possible. If the formation pore pressure exceeds the hydrostatic pressure maintained by the drilling mud then primary well control may be lost. This can happen in a number of ways:

1. The well may penetrate an over-pressured zone with a higher formation pressure than mud hydrostatic pressure.

2. A weak (permeable) downhole formation may result in mud loss downhole and the overall mud height and hydrostatic pressure may drop.
3. Failure to fill the hole with mud when pulling out of the hole or removing the drill string too quickly may result in formation fluid being drawn into the well.

In the event of loss of well control the BOP acts as a second line of defense, allowing the driller to form a rapid and reliable seal around the drillstring. This gives the driller time to restore primary control.

In emergency situations the BOP can be used to shear the drill string and seal the well, giving the driller time to disconnect from the well and move to a safe location if possible.

### 3.3.2 Surface BOP History

Application of Surface BOPs in the offshore industry dates back to the 1960's, before the development of subsea BOP technology. The first drilling operation to utilize this was the Cuss-1 drill barge, in shallow water, off the coast of California. Subsequently the need to disconnect from the well in case of such events as a stationkeeping failure drove the demand for subsea BOPs.

Surface BOP technology re-emerged when new exploration programs were emerging in Indonesia in 1995. Saturation exploration (SX) involved drilling many wells, at a lower cost. It was determined that there would not be any undue risks taken with personnel or equipment; however some well bores may be lost. This drove the search for new, inexpensive drilling techniques. The numbers from Unocal speak for themselves; the first year after this plan was employed 30 wells were drilled, as opposed to the previous annual average of between 5 and 6, and well costs were cut by around \$4 million. This resulted in the discovery of around 30 million barrels of reserves [33].

Using the SBOP technology, the Sedco Forex's Sedco 602 semisubmersible was upgraded from drilling depths of 600ft to over 6000ft.

Initially, deepwater FPU's followed conventional drilling routines with the use of subsea BOPs. However, as facilities progressed into moderate and deepwater, surface BOPs became the industry standard for facility DDRs [15]. This was due primarily to:

- Simpler BOP control and operation;
- More flexibility in wellbay layouts;

- Lighter BOP;
- Ability to use conventional skiddable drillsets.

The simpler BOP control and operations allow for more frequent well interventions, which can lead to estimated 20% to 25% greater reservoir recoverables [57]. Without the handling requirements of a large subsea BOP, the wellbay layout is typically driven by riser-riser interference, and the lighter BOP can potentially allow heavier, deeper risers.

### 3.3.3 SBOP Distinctions and Components

Traditionally SBOP dry tree facility drilling systems do not employ a SID at the base of the riser. In these cases the riser with tapered stress joint are connected directly to the wellhead via a tieback connector. If it is decided that emergency disconnect should be possible from the seabed, an SID will need to be installed between tieback connector and stress joint.

The basic drilling system components demonstrating the use of a surface BOP are presented in Figure 3.1.

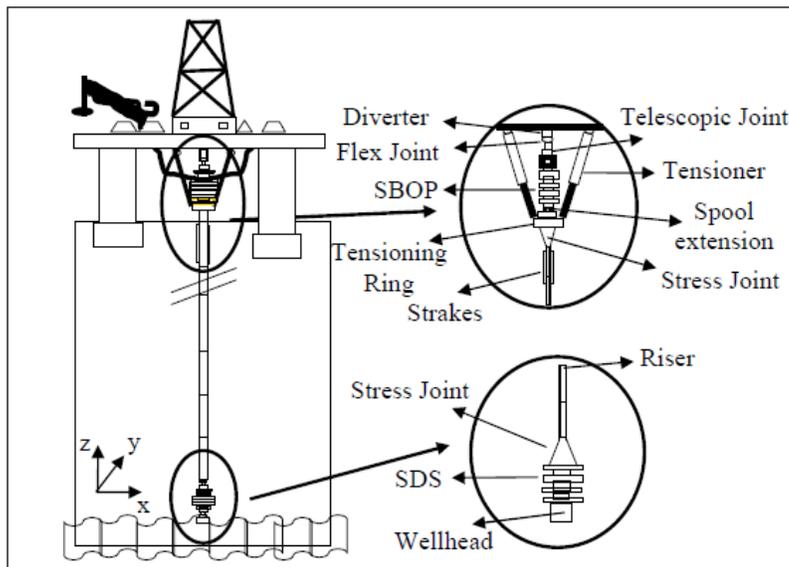


Figure 3.1 Drilling system components using a surface BOP [34]

SBOPs typically differ from Subsea BOPs by the reduced redundancy in the stack. This is in part due to the ease of maintenance and repair to the stack in comparison to the Subsea BOP, which may have to be retrieved for these issues. As there are typically less components, the SBOP stacks are lighter as a result.

The difference in the component make-up of the (typical) subsea and surface BOP is outlined in Table 3.2. The components and their functions are outlined below.

**Table 3.2 Surface BOP Distinctions [18]**

<b>Subsea BOP</b>	<b>Surface BOP</b>
Upper Annular Preventer	Annular Preventer
Lower Annular Preventer	
Blind Shear Ram	
Upper Pipe Ram	Upper Pipe Ram
Lower Choke Valves	Middle Pipe Ram
Middle Pipe Ram	Choke Valves
Lower Pipe Ram	Lower Pipe Ram

3.3.3.1 Pipe Rams

A pipe ram is an element that acts as a seal in the BOP. There are rams for high pressure and low pressure applications. Pipe rams were historically comprised of two half circles that were designed to seal around the drill pipe, however there are newer styles of rams that are variable, and fit a range of pipe sizes.



**Figure 3.2 Pipe Ram [42]**

### 3.3.3.2 Annular Preventer

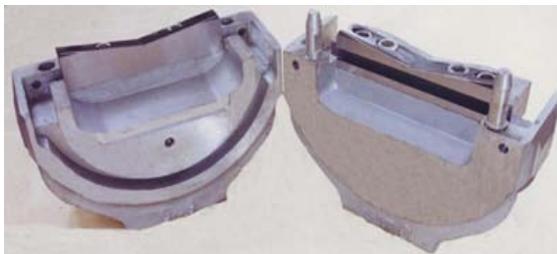
The annular preventer is a component of the pressure control system in the BOP that is usually situated at the top of the stack. It is a device which can form a seal in the annular space around any object in the wellbore or upon itself, enabling well control operations to commence. A reinforced elastomer packing element is compressed by hydraulic pressure to affect the seal [18].



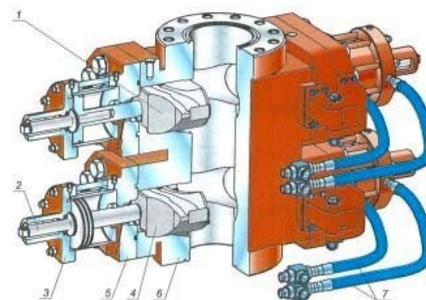
**Figure 3.3 Annular Preventer [38]**

### 3.3.3.3 Blind Rams / Blind Shear Rams

Blind rams are intended to seal against each other to effectively close the hole, they are not intended to seal against any drill pipe or casing. Blind shear rams have a built in cutting edge that is designed to shear tubulars that may be in the hole, allowing the blind rams to seal the hole [55]. This is used as a last resort to regain pressure control of the well.



**Figure 3.4 Blind Shear Ram [39]**



**Figure 3.5 Blind Ram [40]**

#### 3.3.3.4 Choke Valves

Choke valves are the means of controlling the BOP or SID functions. They can either be fixed or adjustable. An adjustable valve has the advantage of allowing more control over fluid control parameters, however may be more susceptible to erosion than fixed valves, under prolonged use [27].

#### 3.3.4 Subsea Isolation Device (SID) for Use with the SBOP

The use of an SID will be driven by metocean and reservoir conditions [61]. Other systems that will influence and/or be impacted by the option of using an SID in conjunction with an SBOP include the riser system, vessel and mooring system design.

For saturation drilling with benign metocean conditions, expendable wells, and wells with normal pressure formations SIDs have been deemed unnecessary. It is assumed that the head from the seawater is expected to kill the well if there was a riser failure. In this case where no SID is to be used, the vessel requires a “stiff” mooring system, so that vessel offset is low. This is therefore an application that should only be used in benign metocean conditions [61].

Where there is the potential for need to disconnect from the wellhead in the case of a catastrophic event, such as a hurricane, blowout or other well control situation, or vessel mooring or dynamic positioning system (DPS) concern, an SID may be used. The SID is placed at the mudline with riser and wellhead connectors set up to allow emergency disconnect if needed. SIDs have different names depending on the operator and manufacturer. They can be called a Subsea Isolation Device (SID), Environmental Safety Guard (ESG), Surface Disconnect System (SDS) or Subsea Shut-Off Device (SSOD), just to name a few. It should be highlighted that as the SID is not designed for typical well control, it should not be considered a BOP. It is designed to seal the well and disconnect the riser from the seafloor if required, allowing safe well abandonment and the possibility to enter the well at a later stage.

The SID is essentially a set of acoustically controlled double shear rams and a bank of high pressure fluid (top one inverted for riser reestablishment). An SID generally has a primary control system and an ROV intervention panel or umbilical deployed down the riser for backup. The primary control system is much simpler than traditional SSBOPs and is often

operated in an acoustic electro/hydraulic manner [35]. Activation of the SID allows the well to be sealed, and the vessel to move away from the location in case of an emergency disconnect situation. In addition to vessel and personnel safety, risk to the environment is reduced, as the well is able to be sealed below the riser, in case of riser failure or blowout [15]. The time to run the SID to the ground is significantly less compared to running a subsea BOP and lower marine riser package (LMRP). Figure 3.6 shows a SSOD package.

When the first SID was utilized, it was done so based on a quantitative risk assessment, based on what combination of events would cause a blowout to occur [35]. It has been highlighted to MCS that it is not necessary for an SID in every situation, as it is sometimes not determined to reduce the risk further than what is as low as reasonably practical [19]. Additionally, use of an SID may not be feasible in all cases due to vessel limitations, cost constraints, or other factors. On the other hand it is important to note that the SID, if designed correctly has the potential to greatly reduce the consequence of a catastrophic blowout event by preventing the well from flowing uncontrollably for extended periods.

The use of the SID in conjunction with the SBOP may not necessarily imply the day rate savings that would come from using the simple SBOP configuration. However, the advantages of this system lie in the added safety of drilling in ultra-deepwater where shallow gas or well control may be an issue. If a gas kick passes the subsea stack, it can be handled by the surface stack. This could be considered a driver for using this configuration over a Subsea BOP in ultra deep drilling campaigns [61].

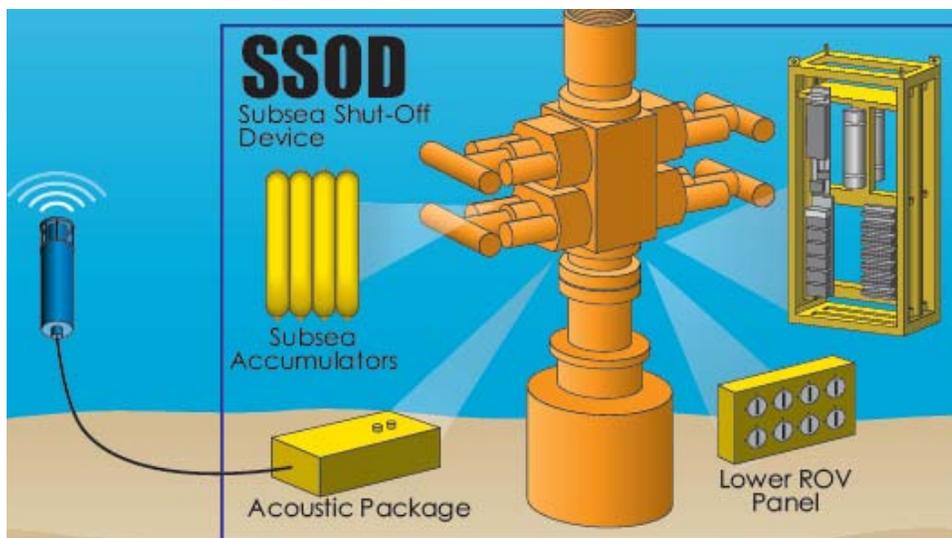


Figure 3.6 Subsea Shut Off Device [43]

### 3.3.5 Insert Risers

An alternative mitigation measure is the Insert Riser. An insert riser may be used to reduce rotational operations on the inside of the drilling riser, thereby reducing the accumulated fatigue in the outer drilling riser. Just before breaching the hydrocarbon payzone, an insert riser is run inside the drilling riser; locking into the casing hanger and at the subsea wellhead. Depending on the drilling campaign, an insert riser may mitigate wear for a significant portion of total drilling time. The insert riser also provides an additional level of pressure containment during the most likely time for a blowout.

Considerations when using an inner riser may include the additional time required to run the inner riser; although this should only increase the total drilling time by a couple of days.

An insert riser is typically inspected before each run. In many applications, the riser is only used once, as it is used as casing after it is used as the inner riser.

### 3.3.6 SBOP Advantages and Limitations

#### 3.3.6.1 Advantages

There are several advantages of using a simple SBOP configuration without a SID that relate to cost savings. These primarily relate to time reduction, and vessel choice.

Surface BOPs re-emerged with the onset of 'saturation exploration' in Indonesia in 1995. The object of this strategy was to drill as many wells as possible, thereby increasing the statistical opportunity for success. The key concern was minimizing the time to drill each well, subsequently reducing costs [31].

The main time saving factor concerns the relative ease of deployment and retrieval of the riser, and the SID. There is no time spent running and pulling the BOP and riser together in deep water.

There is less redundancy required in the system, as maintenance is more readily carried out. This reduces non-productive time that would occur if the SSBOP needed to be pulled to the surface for repair [35]. The ease of maintenance and elimination of the redundancy requirements in the system allows the BOP stack to be smaller and lighter than traditional SSBOPs. This results in lower variable deck load requirements of the rig along with lower riser tensioner capacity.

SBOPs are typically used in conjunction with slim-hole technology. This results in improved circulation rates in the well bore, which increases the rate of penetration. If a smaller diameter riser is used, it requires lower volumes of mud, and combined with improved circulation rates, circulation times are subsequently reduced.

Subsea kill and choke lines are not required with the SBOP [32], eliminating the need for large control umbilicals that increase riser weight, design complexity and installation time. The SID's primary controls are acoustically driven, with either umbilicals or ROV intervention panels used for back up.

Benefits of using an SBOP pertaining to safety include increased ease of well control, and equipment handling. When the BOP is at the surface rather than on the sea floor it eliminates the need for kilometers of kill / choke lines, thus kick and well control events can be handled more quickly and safely, as there are not the high frictional and pressure losses in the system. SBOPs also enable safer handling, as there are fewer heavy and complex pieces of equipment to handle and maintain. In deepwater, if a gas kick migrates past the Subsea BOP, it can be handled by the SBOP and controlled at the top of the riser, implying easier and safer well control.

#### 3.3.6.2 Limitations

While SBOPs may allow for easier well control procedures, drilling contractors are sometimes concerned with the learning curve [36] associated with SBOP use. While used extensively for floating production facilities, SBOPs are not standard for drilling operations on traditional drilling vessels. Additionally for production facilities, hydrocarbons may be stored topsides which would potentially be vulnerable during a blowout.

Risers run through SBOPs have historically been smaller diameter risers (typically ranging from 10<sup>3</sup>/<sub>4</sub>-inch to 16-inch), which means conventional 18<sup>3</sup>/<sub>4</sub>-inch casing hangers will not pass through SBOP pressure containing riser. It therefore also limits the drillhole size and number of casing strings in the well. However, there are measures that can be taken to improve this, such as the use of expandable casings [35]. Also, with new technology and drive for SBOP use this limitation on the systems is changing, and risers up to an inner diameter of 19.25 inches are being designed for use with a SBOP [45].

There are integrity concerns with high pressure drilling risers used in deepwater applications with SBOPs. These include: well head to riser seal integrity, internal wear in the riser that can lead to pressure loss and failure of the riser, and higher cost and weight associated with thicker walled risers [62].

### 3.4 DRILLING RISER DESIGN CODES

#### 3.4.1 Investigation Objective

Design codes are the industry benchmark for insuring that a system “is designed, fabricated, installed, tested and operated so that it will achieve its process functions during the specified lifetime, as well as maintaining the necessary integrity level” [5]. Factors of safety and code allowable limits are a measure of the confidence in current design inputs and methodologies. The load case matrix and analyses required by codes are indicative of the potential hazards to the system.

As such, it is critical to specify the recognized code or standard the drilling riser system has been qualified for, and what that means in terms of design conservatism and specification of anomalous events. The design codes most relevant to design of facility dedicated drilling risers in the GOM are assessed, in comparison to each other and to current industry practices.

#### 3.4.2 DDR Design Codes

The primary codes used to design top tensioned drilling risers are:

- API RP-16Q – Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems;
- API RP-2RD – Design of Risers for Floating Production Systems and Tension Leg Platforms and DNV OS F201 – Offshore Standard, Dynamic Risers;
- DNV OS-F201 – Dynamic Risers Offshore Standard.

Although DNV OS-F201 [4] is used extensively in Europe and as a supplement to API RP 2RD, it is seldom used as a standalone guideline in the US. This is due to the intricate level of knowledge about the design required to use this code to its full potential. However, it has been included in discussions for completeness.

In the Gulf of Mexico, API RP-16Q was the governing code until the emergence of 2RD, which is now the code that is used most widely. This is due to the fact that the 16Q code is more conservative for extreme and survival conditions. The codes, as they relate to dedicated drilling riser design, are briefly described in the following sections.

#### 3.4.2.1 API RP-16Q

The API RP-16Q [1] was the governing code pertaining to the design, selection, operation, and maintenance of marine riser systems for floating drilling operations. It includes descriptions of riser system components and recommended riser design procedure and design and operating limits for critical parameters. The API RP-16Q code is based on Working Stress Design (WSD), and the maximum operating and survival guidelines consider three stages of drilling operations:

- Drilling;
- Non-drilling;
- Riser disconnect.

The maximum allowable stresses associated with these operations are 40% yield capacity for drilling and 67% yield capacity for the other cases. In the first editions of API RP-16Q, deepwater locations were considered those exceeding 2000 feet. However, as hydrocarbon exploration in deeper waters increased, a supplement to the code was made to address drilling in water depths up to 10,000 feet.

As noted above, API RP-16Q is typically more conservative for extreme and survival conditions than the other codes. However, one key limitation is that API RP-16Q is intended for exploratory drilling; it provides no fatigue limiting criteria or safety factors for extended drilling or “parked” riser conditions. API RP-2RD has become more prevalent in the GOM partly because of these reasons and partly because it is already used for the production risers.

#### 3.4.2.2 API RP-2RD

The API RP-2RD [2] was written considering that “the design of risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs) requires recognition that risers form a subsystem that is an integral part of the total system.”

The API RP-2RD code is based on Working Stress Design (WSD). Working stress design

limits the allowable stress to material yield stress. The allowable stress, as a percentage of yield stress, is based on design case factors. This allows the allowable stress to be higher in low probability events. For example, the “Normal Operating” case has an allowable stress of 67%, however the “Pressure Test” may utilize up to 90% of yield, and the ‘Survival’ condition may utilize up to 100% of yield stress.

This allows for conservative riser design, whilst not overdesigning the riser system for improbable events. MCS is currently undertaking a JIP, in collaboration with DNV, to update the API RP-2RD code. From a utilization standpoint, the update is driven by the fact that this is the most widely accepted steel riser code in the industry, and it is the required code for riser design in GOM referred to by the MMS. From a technical standpoint the update should reduce ambiguity in its application in several key areas, update philosophy from working stress to limit state, and incorporate guidance in key areas, based on lessons learned.

#### 3.4.2.3 DNV OS-F201

The DNV OS-F201 [4] code gives criteria, requirements and guidance on the structural design of riser systems for the offshore industry. The code differs from the API codes as there is the provision for design according to different limit state design principles, and a safety class methodology is applied, where the acceptance criteria is linked to the consequence of failure.

The limit states in the code are:

- Serviceability Limit State (SLS), where the riser must be able to remain in position and operate properly;
- Ultimate Limit State (ULS), where the riser must remain intact;
- Accidental Limit State (ALS), where the riser must remain intact due to accidental loads;
- Fatigue Limit State (FLS), where the riser must remain intact due to fatigue loading.

The design methodologies that may be applied include:

- Load and Resistance Factor Design (LRFD) method;
- Working Stress Design (WSD) method;
- Reliability Based Design (RBD);
- Design by Testing (DBT).

LRFD includes the use of partial safety factors to separate uncertainties originating from different causes. WSD uses the same limit states as in LRFD, but accounts for all uncertainties using a single usage factor. LRFD therefore allows for more optimal design, although WSD is easier to use and (as a result of this) more conservative.

The Reliability Based Design methodology enables the use of different safety requirements for riser design, according to the riser's particular safety class. A nominal failure probability from a structural reliability analysis is compared to limit state allowables. It is only to be "used for calibration of explicit limit states outside the scope of [DNV OS-F201]" [4]. Design by Testing involves full-scale or model testing of the design component, and is typically used to verify system response. Both methods require a clear understanding of the statistical uncertainties associated with the particular design.

### 3.4.3 Industry Assessment of Codes

In general, operators in the GOM design all risers on production facilities to API RP-2RD with the WSD approach. Although a more rigorous design approach (e.g. LRFD) may reduce the design conservatism where loading conditions and practices are well known, none of the industry personnel (either surveyed or interviewed informally) were comfortable with removing design conservatism in an asset as safety-critical as a DDR with SBOP [19, 20].

Although industry personnel indicated that current design codes are sufficient, many operators have more stringent design requirements and specifications. For example, several operators design for survival in 1000-yr or even 10,000-yr environments (in comparison to the code requirement of 100-yr) [18, 19, 20]. Some operators have internal material and welding specifications more conservative than code standards, and only allow use of "industry standard" specifications if the riser design fatigue life is greater than 100 times the service life (instead the code requirement of 10 times) [18, 19, 20]. Again, this is more an indication of the concern due to the safety-critical nature of SBOP DDRs, rather than any inadequacy in the design codes.

While the design fatigue life requirement of 100 times the service life is used by multiple operators, other aspects of fatigue analysis vary by application [18, 19, 20]. For example, for DDR systems intended to be parked subsea for extended periods may be designed to meet the same service life requirements as the production risers. Alternatively, the operator may require that all DDRs will be retrieved and retired within a limited service window (typically 5 years).

### 3.4.4 Impact on Integrity

In general, design codes are a reasonable first-pass assessment of risks posed to a riser system, and a good source for identifying common critical issues. A standard approach [14] is to rank the basic probability of a failure in terms of how close the system is designed to code allowables, and then apply modifiers based on confidence in the design methodology.

For example, since WSD as defined by any of the above codes is known to be typically conservative, a riser system designed just to code limits is still perhaps overly robust and is generally well-proven. However, it is important to note the API RP-16Q does not take into account fatigue and has only been extended to 10,000ft water depths. API RP-2RD and WSD in DNV OS-F201 yield comparable designs.

Systems designed to LRFD typically have slightly less conservatism than WSD, and a higher modifier may be called for to highlight particular uncertainty in the accuracy of design inputs and analysis techniques. In general, Reliability Based Design may inspire less confidence, as the method is used by definition for unusual situations and requires that the designer have specialized knowledge of probabilistic structural analysis. Uncertainty in Design by Testing systems primarily results from how the measured response is processed to determine long-term, full-scale effects.

## 3.5 METOCEAN AND ENVIRONMENTAL FACTORS

### 3.5.1 Overview

The expected meteorological and oceanographic (i.e. metocean) conditions drive the design selection and operational limitations of all offshore facilities, risers and mooring systems. Metocean criteria usually include specification of (depending on region):

- Local wind (usually at 33ft above MWL);
- Wind-generated local waves;
- Swell (i.e. long-period waves) generated by distant storms;
- Local surface currents;
- Energetic deepwater currents from low frequency, large basin circulations;
- Region-specific currents which are not associated with storms (e.g. the loop current).

Experienced specialists should be consulted when defining the pertinent metocean conditions for a facility. The following sections present a high-level summary of how

metocean criteria is established, sources for general GOM metocean criteria, and what information would typically be required for design.

### 3.5.2 GOM Climatology

#### 3.5.2.1 General

The climatology varies by location within the GOM and season, and ranges from tropical to temperate. Swell waves are typically only a concern in association with hurricanes. Local wind and wind-generated waves typically correlate well in terms of prevailing directions and associated extrema (i.e. the maximum local wind is associated with a maximum local wind wave) [5, 18, 30]. In deepwater (approximately 2600ft WD and deeper), the Loop Current is detectable; this warm-water current enters the southern GOM through the Yucatan Strait and flows north-eastward out through the Florida Strait. This current regularly sheds eddies that greatly impact riser loading.

The climate-significant regions and seasons are described in the following sections.

#### 3.5.2.2 Description of GOM Regions

For the purposes of this discussion, the GOM has been separated into four approximate regions for metocean conditions (illustrated in Figure 3.7):

- West;
- West Central;
- Central;
- East.

These regions follow the definitions in API 2Int-MET [2], and are common throughout offshore literature. Various research papers have shown that there are substantial differences in the metocean conditions across the GOM (particularly for hurricanes); the API 2MET JIP have determined that these four regions are indicative of the differing GOM climatology [46]. The majority of offshore hydrocarbon facilities are in the West Central and Central regions of the GOM.

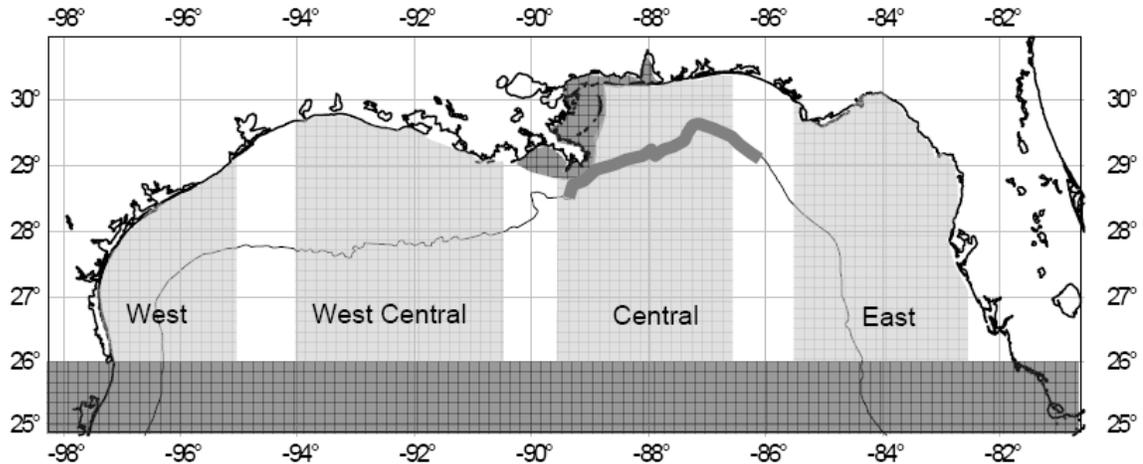


Figure 3.7 Gulf Regions and Areas of Applicability [2]

### 3.5.2.3 Seasonal Events

The dominant periodic events in the Gulf of Mexico include:

- Hurricanes;
- Winter Storms;
- Loop Current and Eddies;
- Topographic Rossby Waves.

Hurricanes and winter storms occur within specific monthly windows. However, the Loop current and eddies may occur in periods of 4 to 16 months [5]. As such, loop currents may occur at the same time as hurricanes and winter storms. These combinations may result in storms intensified beyond typical seasonal expectations.

#### Hurricane Season

Hurricanes are “non-frontal synoptic scale low-pressure systems over tropical or sub-tropical waters with organized convection (i.e. thunderstorm activity) and definite cyclonic surface wind circulation” [19]. Hurricane intensity is classified by wind speed, and the storms may originate in the GOM, the Caribbean Sea or the North Atlantic Ocean. “Sudden” hurricane events (i.e. hurricanes which are formed locally in the GOM) may allow insufficient time for warning to evacuate manned platforms.

Hurricane season is officially from May through November, and typically have the most extreme waves and winds. Several efforts are under way to update existing metocean

conditions following Hurricanes Rita and Katrina. In May 2007, API issued Interim Guidance on Hurricane Conditions in the Gulf of Mexico [2] to immediately supersede the hurricane conditions specified in 1993 API RP 2A-WSD.

### Winter Storms

The winter storm season occurs from December to March. The current and wave conditions are typically lower than the extreme hurricane conditions, but are more severe for 1-yr and 5-yr conditions [15].

### Loop Currents and Current Eddies

The loop current refers to the large clockwise circulation of warm water through the eastern region of the Gulf of Mexico, with water flowing in from the Caribbean Sea through the Yucatan Channel and exiting through the Florida Straits. The loop current sometimes pinches off, spawning a clockwise eddy current that can move westward into the waters in which platforms are most concentrated [25]. The currents from Loop Current eddies are typically weaker in the Western GOM; however the Loop Current or one of its resulting shed eddies can affect a site for a matter of weeks. The currents in the GOM are typically governed by the Loop Current and its associated eddies in deepwater locations.

### Topographic Rossby Waves

Topographic Rossby Waves (TRWs) are planetary waves that are characterized by wave lengths of several hundred kilometers and periods in the order of two weeks. Around the world, these waves typically generate bottom currents less than 0.85 ft/s. However, in the GOM there is interaction between these waves and steep local bathymetry [51]. Where this interaction takes place, the waves can become enhanced, and the amplified energy can generate bottom currents with speeds exceeding 10.83 ft/s. The phenomenon is not yet well understood, although the events associated with TRWs have been observed to consist of several current “pulses”, each lasting 3 to 7 days in duration. The means by which TRWs in the GOM are generated is suspected to be related to the movement of the Loop Current or the presence of Loop Current Eddies. There is evidence of TRW generated currents affecting riser systems in conjunction with Loop Current eddies [52].

### Combined Loop Current and Storm Events

There is substantial evidence that Loop Currents and eddies in the GOM can influence the regional variations of the rate of occurrence of large, intense hurricanes [47, 48, 49, 50]. This occurs as the waters associated with the loop currents are considerably warmer than those typically found within the Gulf of Mexico. This can allow a hurricane passing over the loop current to strengthen significantly more than it ordinarily would. In 2005, the rapid strengthening of hurricanes Katrina and Rita was attributed to this phenomenon.

The Loop Current interaction issue has been given more attention in recent years as the 2004 and 2005 hurricane seasons have had numerous occurrences of correlations between eddy currents and large scale hurricanes. With recent examination of current and hurricane data, it has been observed that there is an increase in both Loop Current eddies and large hurricanes in the GOM. As a consequence of this, the chance of the occurrence of a joint Loop Current / eddy – hurricane event has correspondingly increased. While most deepwater developments include a Loop Current / eddy - winter storm event, a minority include the Loop Current / eddy – hurricane condition. However these events are still difficult to statistically quantify as there is only at most 20 years of useful data on Loop Current / eddy – hurricane events.

### **3.5.3 Derivation of Metocean Criteria**

#### 3.5.3.1 Process for Derivation

The overall procedure for developing metocean criteria can be simply summarized as:

- Establish the site-specific metocean database that will be used for statistical analysis;
- Determine whether long-term statistical distributions, short-term statistical distributions or design wave specification are required for the operational condition;
- Develop the metocean criteria based on statistical analysis.

It should be obvious that each step requires a series of expert judgements and assumptions that ultimately make metocean conditions some of the least reassuring and most questionable inputs into offshore design. Detailed discussion of the last two steps is beyond the scope of this study; however, a flavour of the challenges posed by just determining the data to be used is presented in the next section.

### 3.5.3.2 Establishment of a Site-Specific Database

Ideally, a metocean database is established by site-specific measurements over many years. The crucial questions raised by this statement are:

- How reliable are the measurements for the entire data set?
- How close do the measurements have to be to the site?
- How many years of data are needed for a robust statistical analysis?

A variety of measurement methods have been available for decades, including satellite altimeters and wave gauges. These typically have measurement accuracies of  $\pm 10\%$  or better [60]. Uncertainties arise from how meaningful information is determined from the measurements. Focusing just on wave records, the first step is separating the different wave components from the water surface elevation record. It is assumed the shape of the sea surface results from a linear superposition of waves of all possible wavelengths or frequencies traveling in all possible directions, and a Fourier analysis is performed to determine the amplitude and frequency of the component waves. Judgments must be made regarding what constitutes signal and noise in the measurements.

The majority of the data for the GOM has been recorded under sponsorship of the U.S. government. Raw historical data is available through the National Data Buoy Center [26]. As seen in Figure 3.8, most of the data stations are along the continental shelf, north of the Sigsbee Escarpment. Significant distances exist between groups of stations.

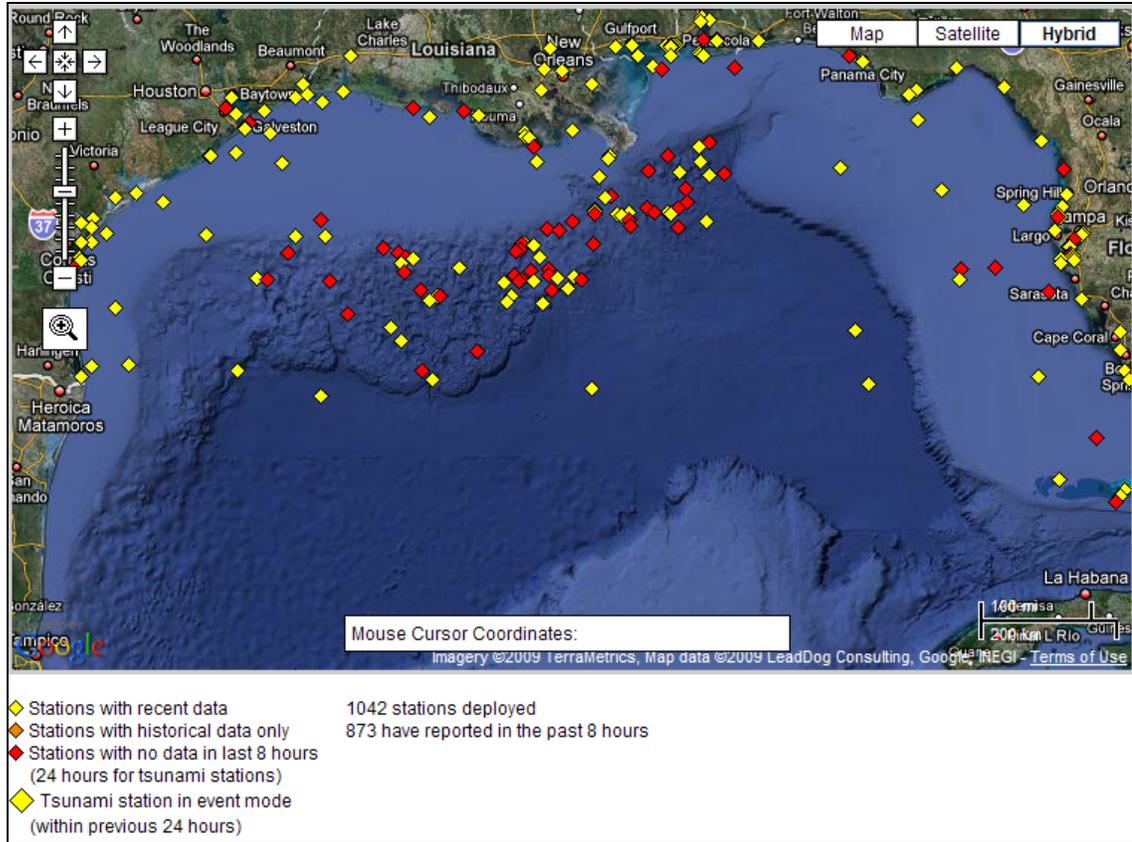


Figure 3.8 Metocean Data Stations in the Gulf of Mexico [26]

Even though there are up to 30 years of fairly reliable measurements available, the data are considered insufficient for rigorous statistical determination of appropriate extreme and abnormal environmental conditions. [5].

Bearing all this in mind, scarcity of reliable data may make it necessary to determine metocean conditions from numerical modeling (i.e. hindcasting). Past hindcasting practice had been to use the largest historical database possible. However, recent studies have generally decided that there has been a low bias in intensity measurements made prior to 1960 [46]. Using a database with as much historical data as possible had meant that there was a trade-off between quality and quantity of data, but it has been concluded that it is better to develop criteria based on a shorter, higher quality storm record [2].

### 3.5.3.3 Metocean Specifications

To understand how metocean criteria are specified, extreme value statistics must be briefly explained. In very broad terms, the extreme value distribution is a distribution of the measured values above some threshold value. Taking hurricane-driven waves as an example, it is not useful to use the entire wave spectrum; this would ultimately result in underestimation of hurricane wave heights. What is useful is to design for the distribution of hurricane events. So, the 100-yr hurricane significant wave height is the significant wave height associated with a distribution of the 1% highest hurricane waves.

Typically, metocean criteria will be specified in one of the following formats, in order of decreasing complexity:

1. Scatter diagrams;
2. Statistically significant characteristics of a spectrum (e.g. significant wave height and peak period);
3. Constant values (e.g. specification of a constant wind speed or the amplitude and frequency of a single periodic wave).

Scatter diagrams present multivariate joint probability distributions. Some common scatter diagrams include the joint probabilities of:

- Significant wave heights coinciding with different directions;
- Significant wave heights coinciding with current and wind speeds;
- Significant wave heights coinciding with different representative wave periods.

Statistically significant characteristics of a spectrum typically include specification of the spectrum shape, some indication of the height of the spectrum (e.g. significant wave height), and peak spectral frequency.

Alternatively, constant values may be specified. These are typically derived from the most probable maximum extreme values.

### 3.5.4 Sourcing Metocean Data

A site-specific metocean study is preferable for any analysis, but some generalizations can be made. An API recommended practice (RP) on metocean conditions (API RP-2MET) is in

development, to act as a standalone document for the GOM metocean conditions [46]. API RP-2MET will also act as the annex to the ISO 19901-1 metocean standard [6].

Currently the interim guideline API 2Int-MET [2] is available, which covers hurricane conditions in the GOM, but does not address other phenomena such as winter storms, loop current and other deepwater currents. Guidance is also given on interpretation of data for seasonal distribution of hurricanes, for analysis of operations where the facility is not going to be exposed to conditions in the GOM for the full year.

Wind, wave, and current speed and direction in the GOM have been measured since the 1970s by the National Data Buoy Center and facility operators. Multiple companies specialize in developing metocean criteria from similar regions, existing measurements and hindcasting.

### 3.5.5 Application to Design

For DDR analysis, the operational and survival load cases are typically specified by:

- Significant wave height and associated peak period for a Pierson-Moskowitz or JONSWAP spectrum;
- 1-hr wind speed at 33ft above MWL;
- Current profile as a function of depth.

The Pierson-Moskowitz spectrum is recommended for the operational load cases. Either Pierson-Moskowitz or JONSWAP may be used for survival load cases [63].

For fatigue load cases, the wave should always be described by a scatter diagram, and it is preferable that current scatter diagrams are provided as well. Associated constant wind speeds are usually considered sufficient. Fatigue is primarily a significant concern for extended drilling operations, or for drilling risers that will be “parked” subsea between operations. Typically operators require the DDRs to meet the same fatigue life as the production risers [18, 19].

Seasonal sets of data are typically classified in three metocean events: the Loop current, winter storms, and hurricane events.

Generally speaking, the dominant current seastates will determine riser operational limits subsea. The sea state which drives the maximum vessel offset will typically limit the topsides design. For any design or operation, a range of sea states should be looked at to provide a

more complete picture of the metocean conditions likely to be experienced.

Loop and eddy currents are arguably the most challenging design consideration concerning metocean conditions in deepwater. Deeper water requires buoyancy on the riser to reduce tensioner loads. The outer diameter of the buoyancy and the length of the modules required in deep water will increase the drag of the riser and make it more susceptible to vibration, reducing fatigue life, and expose the riser to greater risk of interference [19].

If possible, operators avoid well intervention operations during hurricane season which stretches from the beginning of May through the end of November. The harsh wind, wave and current conditions brought on by hurricanes create too many complications and safety concerns to justify the operation in most cases. Thus for most projects it is not necessary to analyze the hurricane sea states for operational load cases [4].

### **3.5.6 Implication for Integrity**

Metocean is a significant uncertainty, especially with regards to deepwater current profiles. As time progresses in-service, there is the potential to collect a body of data to validate the original design metocean criteria. However, as facilities are built further out into the GOM, the original metocean specification may rely heavily on numerical modeling techniques and uncertain physical modeling assumptions. It is important to clearly understand what the specification has been based on, what conservatism has been assumed, and the confidence the metocean experts have associated with the criteria.

## **3.6 POTENTIAL OPERATIONAL INCIDENTS**

### **3.6.1 Overview**

Human error or mechanical failures due to damage, degradation and/or manufacturing defects are often the primary or contributing cause of an integrity incident [13, 18, 19, 20, 21, 22]. In many cases, these failures can be potentially avoided by stricter adherence to QA/QC and operational procedures and by more frequent inspections and maintenance. Incidents involving drilling vessels are also included in assessing potential hazards, in order to have any significant number of incidents to review.

### 3.6.2 Failures of BOPs and Ancillary Equipment

Data in the public domain on equipment failures of BOP systems do not indicate a trend in a particular component being especially vulnerable to failure [13, 19]. Some notable failures include:

- BOP seal degradation and failure;
- Incorrect installation of yellow and blue pods;
- Failure to test BOP prior to operation;
- Damage to BOP system components from dropped deck equipment.

In this situation, use of an SBOP may be preferred, as its inspection can be far easier than that of a subsea BOP.

### 3.6.3 Mechanical Failures of Safety Critical Well Components

While not noted specifically in the GOM, there have been several incidences of a critical component of HPHT wellbore production tubulars failing catastrophically while under tension and/or hoop stress loads within design limits [22]. Further investigations have indicated the failures might have been the result of environmentally assisted cracking initiated by material flaws / imperfections, but some thermal cycling or pressure cycling might have been a contributing factor as well.

### 3.6.4 Running and Retrieval Operations versus “Parking”

As facilities progress into deeper water depths, running and retrieval operations for drilling risers are associated with increased weights, more required deck storage, longer times for running and retrieval and higher risks of dropping and impact. To reduce all of these items, it is common to “park” the drilling riser on a “dummy” subsea wellhead for extended periods between operations. The longest period of “parking” reported by operators has been thirty-four (34) months. While this reduces the risk of damage by reducing the number of retrieval operations, it introduces an increased risk of VIV fatigue.

### 3.6.5 Wear and Riser Punch-Through

From the data collected, the wear potential to DDR joints is not particularly high [16, 18, 19], primarily due to efforts to control the curvature of the riser by using tapered transition joints instead of flex or ball joints and further efforts to prevent any contact between drill

string and riser through the use of non-rotating protectors. As a very coarse rule of thumb, some operators will use non-rotating protectors for expected offsets greater than 2% of water depth. Review of punch-through incidents seems to indicate that this is a matter of human error rather than lack of proper procedures or barriers.

That being said, the potential consequences of riser punch-through are disastrous, especially if there is not some sort of SID or ESG.

### 3.6.6 Human Errors

Human error is by far the leading cause of failures, typically through:

- Inattention to the procedures in-place;
- Inexperience and/or lack of knowledge;
- Lack of communication during SIMOPS.

While this may be anecdotal, discussions with operations personnel have noted an increase of the first two issues in recent years. Failure to write JSAs prior to commencing work or not insisting on a stop to all work during potentially questionable activities are two results of this. Some potential causes suggested are:

- Insufficient guidance and training of new personnel;
- Uncertainty due to corporate mergers on which procedures to follow;
- Inclination to not force safety issues due to uncertain job market.

Whether this is a real trend and what appropriate action should be is beyond the scope of this study; all that can be stressed is the importance of proper training, clear operational procedures, and clear methods to follow-up that the procedures are implemented.

### 3.6.7 Impact on Integrity

Potential operational incidents that are safety-critical or particularly prone to human error should always be considered. These issues can potentially be avoided by strict adherence to QA/QC procedures and a program to audit that the procedures are being followed.

## 3.7 RESERVOIR CHARACTERISTICS AFFECTING KICKS

### 3.7.1 Overview

The primary concern for DDRs has been in preventing loss of well control during kicks. “Kicks” are defined as unplanned and undesirable influx of formation fluid into the borehole, which if unattended may develop into a blowout [64]. Key factors affecting the development of kicks in the GOM are discussed in the following sections.

### 3.7.2 Pressure

Bottomhole pressure is a key parameter that is required to be controlled by the BOP. The purpose of the BOP is to contain and control bottomhole pressure in the event that formation pressures exceed the hydrostatic pressure exerted by the fluid column in the borehole. In the case of high bottomhole pressures, the probability of well control events requiring use of the BOP is increased. Paradoxically, situations involving low bottomhole pressures can also invoke the use of the BOP system to effectively control underground blowouts.

In deepwater drilling the window between pore pressure and fracture gradient becomes narrower. This has been highlighted as the biggest risk for deepwater and colder reservoir drilling [19]. Formation pressure increases with depth, according to the hydrostatic pressure gradient of 0.433 psi/ft, any deviations from this gradient are considered abnormal pressure. Rising pore pressures can often upset the delicate fracture gradient destabilizing the well bore and jeopardizing the section or even the entire well. Due to these uncertainties in pressure in the well during drilling operations, deepwater operators must have an excellent knowledge of wellbore stability to avoid formation influx (kick) or fracture at the casing shoe [58, 17], which would result in losses. Effects concerning risks with the narrow window between pore pressure and fracture gradient have to be mitigated depending on the system used. The mitigation varies for the use of a SBOP, Subsea BOP, and for slim line riser drilling.

### 3.7.3 Temperature

Temperature characteristics are unique and vary from one well to the next. Generalizing, a negative gradient runs from surface to seafloor, which turns positive below the mudline (i.e. temperatures get colder further from the water surface, and then increase below the mudline

down to the reservoir). However, the equations for calculating the well temperature become more complicated as cooler surface mud alters the temperature profile as it is pumped downhole [58]. Cold temperatures at deeper water depths (on the order of 4,000 ft) adversely affect fluid viscosity and setting time for cement, and increase the tendency of gas hydrates to be created as a result of cement hydration and the presence of shallow gas [59]. Recent designs of cement slurry composition seem to address the cementing issues, but industry experience with these particular slurry designs has been limited to the last five years. Existing API norms do not cover low deepwater temperatures, and stringent test procedures are only now determining the properties of cement slurries in deepwater operating conditions.

#### **3.7.4 Mud Weights**

The mud weight used determines the hydrostatic pressure at the bottom of the hole. A proper mud density helps to prevent formation collapse as well as unwanted flow into the well. Mud weights are based on drilling requirements, such as the type of formation being drilled through and vary according to estimated formation pressures.

Water depth does not necessarily complicate mud weight and well control practices. However when water depth requires the use of unconventional circulating systems crew and drilling team training needs to be tailored to ensure that the team understands how well control events are to be handled [19].

#### **3.7.5 Hydrate Formation**

While gas hydrate formation is a common problem, it is difficult to resolve. Deepwater environments present the ideal combination of low temperatures, high seabed pressures, gas and water that cause hydrate formation. Hydrates trap natural gas inside water molecules and bond with metal. This can result in tubing blockages and affect valve and BOP operation. Extensive modeling of reservoir temperature and pressure profiles may be required to minimize hydrate formation.

#### **3.7.6 Impact on Integrity**

With current industry technology and knowledge, a blowout may not be the most likely event, as it typically requires additional failure of some critical safety component [22]. However, blowouts are the most dramatic and potentially costly in terms of HSE, loss of

product and costs of repairs [54]. As such, the potential for kicks and blowouts should always be closely examined and managed.

Intuitively, an SBOP would inherently carry more potential risk to vessel and personnel, since well containment is at the surface. However, a surface stack may actually reduce overall risk in many operations. The ability to maintain circulation and a faster well kill increases the ability to successfully execute a driller's method or wait-&-weight kill operation. The lower pressure drop also allows the well to be killed at a higher circulation rate, reducing pressure faster, and with fewer circulations. While the pressures may be closer to staff and the vessel, the exposure time is less and the kill operation is a simpler and clearer procedure.

## 4 FAILURE MODE DEVELOPMENT

### 4.1 OVERVIEW

Once key hazards have been identified, it is important to clearly define the exact mechanisms that could potentially lead to failure. A systematic definition not only ensures that hazards are analyzed thoroughly, but also allows for the ability to apply barriers to failure at some critical stage and for a transparent record of what was considered. This transparency is crucial for identifying lessons learned and areas where procedures and designs can be improved.

### 4.2 DEFINITION OF FAILURE

The first, most critical decision when developing a risk and hazard analysis procedure is to clearly define what is considered failure. In broadest terms, a failure is an “unacceptable extent of a defect, which always has consequences” [14]; a defect is an “anomaly attributable to material, manufacture, construction, installation or operational conditions outside of [system] specification or design basis” [14]. Another common definition of failure is “termination of the ability of an item to perform a required function” [5], which is only slightly more useful.

These definitions, while good in principle, require clarification in the details. If the metal-metal seals for a riser joint aren't made but you do not have joint separation, does the minute fluid released to the environment constitute a failure? If not, at what stage is it considered a failure? How many seals on the BOP can be lost before the BOP can no longer perform its function?

Definition of failure for specific failure modes potentially varies, based on how much redundancy is built into the system as a whole and the emphasis placed on component criticality. It is recommended to specify failure in terms of catastrophic events, covering any potential loss of life, environmental damage or significant cost (e.g. replacement of the riser). For DDRs, this has been generalized as:

- Complete loss of well control (i.e. blowout);
- Measurable release of hydrocarbons into the environment;
- Loss of riser structural fitness for purpose.

### 4.3 CHARACTERISTICS OF A FAILURE MODE

At a minimum, a failure mode should include:

- A **Failure Initiator**: the event or process that initiates a failure mode;
- A **Failure Mechanism**: the sequence of stages after initiation which lead to failure.

Detailed knowledge of the initiator and each of the possible stages towards failure provides the operator with the option to specify corrective action at one or more stages prior to failure. Well defined potential failure modes allow modes which carry an unacceptable risk to be more easily identified and addressed by design or procedural changes. The integrity management plan can be more effectively designed with the purpose of detecting critical stages of the failure mode.

Operators and some engineering contractors have found it more efficient to develop in-house databases of failure modes for particular equipment types. These generic failure modes serve as input into any HAZID or risk assessment process. In this situation, it may be useful to include the following items in the failure mode database:

- **Potential Barriers & Mitigations**: typical options available to the operator to mitigate and reduce high risk;
- **Potential Uncertainties**: key ‘unknowns’ or uncertainties involved in the design of the riser and/or its components that may impact this failure mode.

Potential Uncertainties typically identify key design inputs that may affect the perceived risk. These uncertainties may be validated during the initial phase of a project, thereby reducing the perceived risk and eliminating future integrity management activities.

### 4.4 KEY HAZARDS

For deep water drilling operations using a SBOP, the most critical riser failure modes may be categorized by:

- **Environmental Loading** – environmental conditions outside those specified in the design basis;
- **Operations** – procedures subject to significant uncertainty and/or prone to human error;
- **Kicks and Blowouts** – reservoir-driven loss of well control.

These categories reflect loose grouping of failure initiating events. There are other, project

specific hazards that should be considered; for example, corrosion and material compatibility are standard hazards that vary with material specification and fluid composition. Subject matter experts in these areas should be consulted for assessment of these risks.

#### 4.4.1 Environmental Loading

Environmental loading drives strength and long-term fatigue design, determines operational windows and represents one of the principal sources of uncertainty in offshore design. Under-estimation or poor understanding of this loading may lead to inadequate designs. Additionally, metocean criteria are not only site-specific, but its reliability is dependent on a statistically significant body of data. While the GOM has some of the best-defined environmental data in the world, climate models are complex and our historic data may not be historic enough.

Some key mechanisms leading to failure due to insufficient environmental knowledge are:

- Extreme response;
- Fatigue;
- Vortex Induced Vibration (VIV) and Wake Induced Oscillation (WIO).

##### 4.4.1.1 Extreme Response

Under-estimation of extreme conditions may result in excessive curvature of the riser, leading to overbending or contact between the drill string and riser.

##### 4.4.1.2 Fatigue

Excessive cyclic loading may result in increased vessel motions or increased drag loading, leading to excessive (unqualified) cyclical loads on the riser.

##### 4.4.1.3 Vortex Induced Vibration (VIV)

Although VIV is a fatigue-related failure, it deserves special attention because there is significant uncertainty in the theory and associated analytical response, and because specific measures (e.g. strakes) may be applied to mitigate this risk.

In addition, the congested nature of riser arrays will result in flow interaction between upstream and downstream risers and tendons. The turbulent eddies shed from upstream

structures will result in buffeting of the downstream structure, i.e. Wake Induced Oscillation.

#### 4.4.2 Operations

Failures due to human error, manufacturing defects or flaws, and other accidental damage are difficult to quantify, primarily because they involve a break-down of in-place quality procedures. These procedures are also dependent on site-specific details and equipment selection. Some common hazards would include:

- Damage to the riser or a safety-critical system;
- Material degradation;
- Failure of Emergency Disconnect Sequence (EDS) or Operability procedures.

The best mitigation for these hazards is adherence and training on proper procedures for personnel.

##### 4.4.2.1 Damage to DDR or Safety-Critical System

Impact damage is one of the leading types of accidental damage. This damage is typically caused either during:

- Running and retrieval;
- SIMOPS;
- Other lifting and handling procedures.

During running and retrieval, the damage may be caused by either dropping the riser or impacting the riser pipe against some other equipment or structure. For other lifting and handling procedures, typically a heavy item dropped would impact the surface BOP rather than the riser.

##### 4.4.2.2 Material Degradation

Material degradation is typically assessed and planned for in operations. It primarily becomes a concern with regards to:

- Manufacturing defects or flaws;
- Adherence to inspection and maintenance schedules (e.g. replacement of BOP seals, actuation of valves);
- Material qualification/compatibility for the internal and external environment.

Each major component should have a functional specification clearly stating the conditions it is designed for. Flaws may be introduced during manufacturing which may result in an inability for a component to perform to its functional specification. The components that must be considered for regular inspection and maintenance schedules are the BOP and the tensioning system, due to their complexity and safety-critical functions.

Material qualification and compatibility is crucial for any interfaces between dissimilar materials or specialty components (e.g. tapered stress joints). Due to the complexity of the topic, subject-matter experts should be consulted for each project to determine what should be considered for each riser component.

#### 4.4.2.3 Failure of Emergency Disconnect Sequence (EDS) or Operability Procedures

The purpose of EDS and Operability procedures are to insure the structural integrity of the riser for the conditions put forth during design. The EDS times are based on how long it takes to perform the procedure to disconnect. Operability envelopes are typically designed to limit riser curvature so that there is no contact between the riser and any rotating components, such as the drill string. The most critical potential problems caused by failure of proper procedures for disconnect or drilling operations are:

- Riser wear due to abrasive contact between the riser and rotating components (e.g. the drill string);
- Punch through during drilling operations;
- Inability to unlatch the riser during an emergency event.

The riser wear and punch through are typically the result of a failure to maintain proper riser curvature. Riser wear is the most difficult to prevent; however, numerous techniques exist to detect wear or limit wear. While punch through and EDS failures are by no means common, the potential consequence warrants their inclusion. The best way to mitigate punch through and emergency disconnect failures are to provide constant training to personnel.

### 4.4.3 Kicks and Blowouts

Kick failure modes would typically culminate in either blowout or overpressure and rupture of the DDR. Factors that may initiate a kick are:

- Pressure
- Temperature
- Mud Weights
- Hydrate Formation

#### 4.4.3.1 Overpressure and Riser Rupture

The failure mechanism for overpressure would be:

1. Event initiating kick.
2. Unabated well kick.
3. Overpressure of riser.
4. Pipe burst or joint separation.
5. Loss of riser and/or subsea loss of hydrocarbon containment.

#### 4.4.3.2 Blowout

The failure mechanism for blowout would be:

1. Event initiating kick.
2. Unabated well kick.
3. Failure of Surface BOP.
4. Blowout.
5. Loss of riser, topsides loss of hydrocarbon containment, explosion and/or fatalities.

## 5 ANALYSIS OF RISK

### 5.1 GENERAL

A general risk assessment methodology is outlined, with additional emphasis for assessing the risks associated with production facility drilling riser systems. The core risk assessment methodology is well established across many industries. As a result, the methodology presented attempts to reflect the best practices and lessons learned specific to offshore risers, from over 15 years riser integrity management experience of operators and contractors.

### 5.2 RISK ASSESSMENT OBJECTIVES

The primary objective of a risk assessment is to evaluate the risk exposure of an asset in structured manner, minimizing negative effects to the system. In order to do this effectively, the risk assessment must:

- Systematically assess what hazards are relevant (i.e. hazard identification);
- Prioritize the hazards in terms of likelihood and consequence to the system according to some clearly defined standard (i.e. assess risk);
- Justify the reasoning for hazard identification and risk assessment in a clear, transparent manner;
- Ensure the system risks are understood by both the regulators, designers and most importantly, those that will operate and manage the facility;
- Confirm integrity-related risks are within corporate and/or regulatory guidelines;
- Provide recommendations for actions to minimize the negative effects.

An unambiguous, comprehensive methodology is necessary to accomplish these goals in the most effective manner. A clear methodology also ensures consistency across all facilities in the Gulf of Mexico, allowing for better transfer of knowledge and application of lessons learned between projects. This methodology should correlate with existing facility riser integrity management practices (such as for production risers).

### 5.3 PROCESS

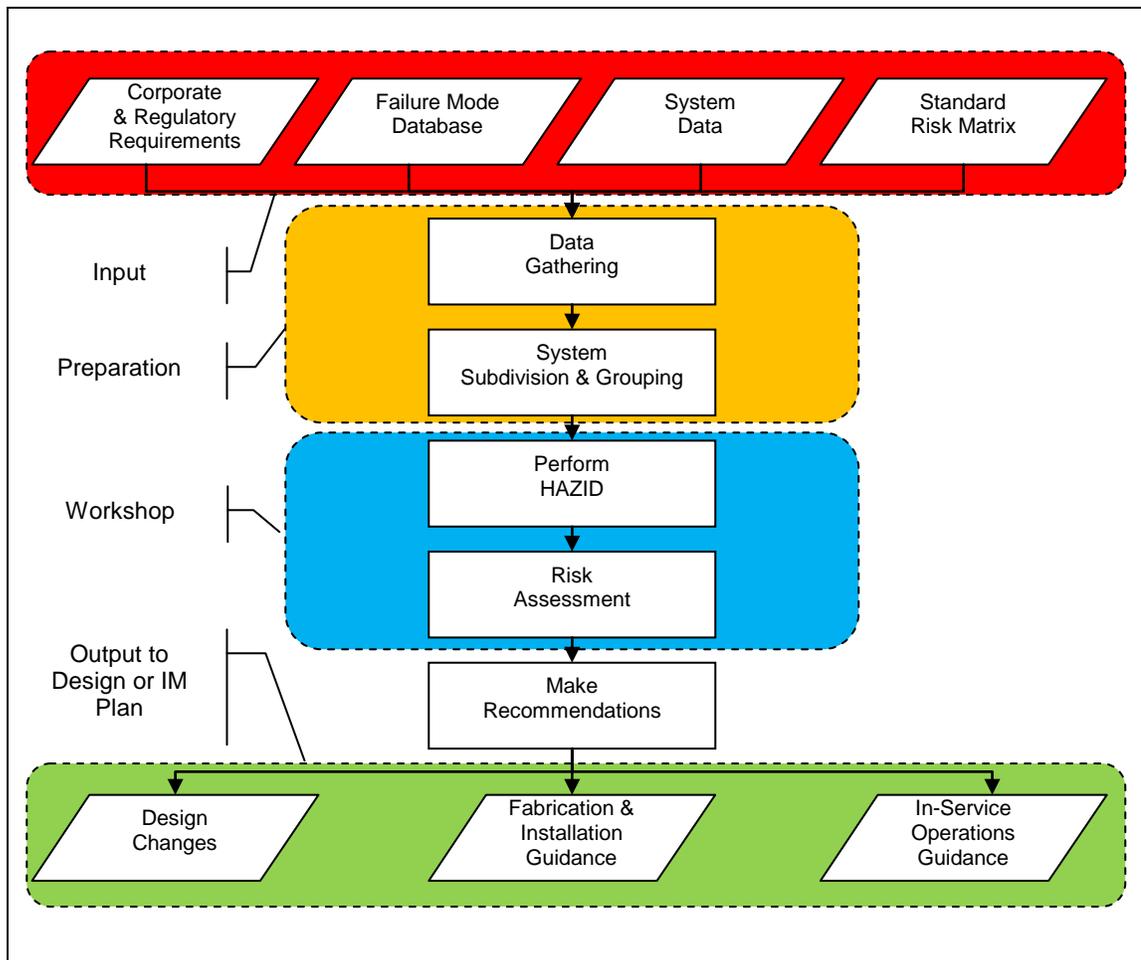
The basic approach for a risk assessment is illustrated in Figure 5.1, and can be summarized by the following tasks:

1. Gathering System Data & Standards
2. System Subdivision & Grouping
3. HAZID
4. Risk Assessment
5. Risk-Based Recommendations

This process describes the minimum requirements for performing a risk assessment; it is not inclusive of all integrity management requirements. It is advisable that the risk assessment process is iterated through periodically, dependent on the assessed risk and recommendations for the DDR system.

A risk assessment requires input from a variety of personnel, including key project stakeholders and subject matter experts from design and operations. While often costly and time-consuming, workshops are the most effective way to gather this crucial input, and it is recommended that the HAZID and risk assessment stages are completed in workshop settings, with some pre-population of hazards and risk beforehand. The effectiveness of a workshop is typically dependent on:

- Thoroughness of preparatory work prior to the workshop;
- Workshop management;
- Clear definition of expected output.



**Figure 5.1 Risk Assessment Methodology**

Note: The flowchart presented is not inclusive of the entire Integrity Management process. Multiple iterations through this methodology are expected.

### 5.3.1 Preparatory Work

In order to best utilize the subject matter experts that attended the workshops, a significant amount of preparation can be done. Information including potential hazard scenarios, factors influencing likelihood and existing safeguards (i.e. mitigations) can be gathered prior to the workshops. After initially populating a risk database, HAZID and risk workshops can be performed more efficiently.

It is also crucial to determine how best to organize any workshops and identify key attendees. Generally speaking, the ideal number for a workshop group is anywhere from 5 to 10 people, depending on how familiar the individuals are with assessment process and with the results of the preliminary work. Larger workshops may be effective by organizing

subgroups of 5 to 10 people focusing on particular areas. Subgroups may be organized by hazard type (e.g. a corrosion hazard assessment subgroup), equipment type (e.g. a wellhead connector subgroup) or functional requirements (e.g. well control). If subgroups are used, it is important to include an additional group discussion with representatives of the subgroups to ensure interface issues are addressed.

While this methodology is focused on the risk assessment of a production facility DDR, it is necessary to keep in mind how the DDR fits into the risk assessment and IM of the entire facility. It is not unusual for DDR HAZID and risk assessment to be done in conjunction with the other facility risers.

### 5.3.2 Workshop Management

The attendees of the workshop should be subject matter experts for the equipment under consideration and include both design *and* operations expertise. Attendees are then led through the predefined hazard and/or risk database by a facilitator, focusing on identifying additional input to the hazard scenarios as well as the likelihood, safeguards, and failure consequences based on their knowledge and experience. Based on previous experience, it is most often useful to schedule a Hazard Identification and Risk Assessment (HIRA) workshop, instead of separate workshops for HAZID and risk assessment.

Dependent on the scope of the workshop, the amount of preparatory work, and the familiarity of all attendees with the workshop process, an effective workshop can last from one to four days.

### 5.3.3 Output

Since the assessments identify a variety of system specific needs and requirements necessary to reaffirm integrity, the recommendations from the assessments may include:

- Key inspection and monitoring locations and methods;
- Identifying document and data issues (missing, limited information, data management, etc.) needed for the integrity program;
- Identification and tracking of pre-existing damage, with suggested inspection and monitoring programs to address locations;
- Broad gap analysis recommendations for potential operational guidance or procedures related to integrity management;
- Interfaces to be assessed and potential influences of one system on another system;

- Preliminary integrity management strategy.

## 5.4 DATA REQUIRED FOR RISK ASSESSMENT

### 5.4.1 Overview

The data required for a risk assessment are:

- **System Data** – design, operational and functional information for the DDR;
- **Regulatory & Corporate Requirements** – acceptance criteria and minimum integrity requirements;
- **Failure Mode Database** – first-pass failure modes generally applicable to DDRs;
- **Risk Matrix Standard** – standardized scales for classifying probability, consequence and risk.

It is often useful to summarize the pertinent data details into a single basis report.

### 5.4.2 System Data

The design data gathered for the DDR system should always include:

- Detailed specification for the riser system itself, pipe configurations and ancillary components;
- The design basis for both the internal and external environment to which the riser system is exposed;
- Design calculations;
- Layout drawings;
- Pipe design data sheets;
- Maintenance instructions, particularly for critical system components such as SBOPs and tensioning systems.

The characteristics of a particular DDR system necessary for hazard identification and risk assessment are commonly found from the following types of reports:

- Design Basis Reports (e.g. site metocean specification, field layouts);
- Design Modeling and Analysis Reports (e.g. operability analysis, fatigue analysis);
- Manufacturing Reports & Record Books;
- Installation Reports;
- Inspection and/or Operational Data Reports.

Additionally, for a system that has already been in service, information can be gained from:

- Results of existing failure or Hazard and Operability (HAZOP) or Hazard Identification (HAZID) studies relating to the field system or its control system;
- IM strategies and/or IM plan that have already been implemented;
- DDR hazard exposure history, including:
  - Installation dossiers;
  - Records of subsequent inspection/monitoring;
  - Any reported anomalies or repairs.

Gathering system data may potentially be one of the most time-consuming activities. Ideally, the project team shall maintain a riser specification document, summarizing all relevant design details and results from qualification testing. However, successful documentation may vary greatly by project. Additionally, the DDR may be classified as a short-term or drilling group kit, and it may not have the same documentation standards as the facility risers.

### 5.4.3 Regulatory & Corporate Requirements

At the time of this report, regulatory requirements in the GOM for DDRs typically outline functional tasks that must be performed prior to operation [20]. However, many national authorities have specific requirements with regards to riser risk assessments and IM planning, and it is reasonable to expect that the U.S. will in the future [7].

While most operators have internal requirements for integrity management activities, these guidelines may not include specific recommendations for DDRs [20].

### 5.4.4 Failure Mode Database

A failure mode database is a collection of generalized failure modes which address common integrity issues related to a specific type of asset (in the context of this report, DDR systems and their components). Many operators and engineering contractors have found it efficient to develop in-house failure mode databases. Failure modes are typically developed from a combination of JIP reports, previous project experience and industry failure statistics. Some example failure modes are presented in Appendix C.

The failure mode database may vary from high-level to very detailed, based on operator

preference and the scope of the workshop. In general, it is recommended to make the failures as concise as possible without sacrificing clarity. Taking threaded riser joint connectors as an example, it is possible to define all the potential ways a connector may separate after an internal metal-to-metal seal has been compromised (e.g. thread deformation or jump-out). This approach may result in an excessive number of similar failure modes, which would have the same risk ranking and the same recommended actions. It is important to select the level of detail that is most useful to the project stage.

#### **5.4.5 Risk Matrix Standard**

Risk is typically defined as either a summation or a product of the likelihood an event will occur and the consequence of the event occurring, commonly plotted on a matrix. This is described in more detail in Section 5.7. A risk matrix standard (such as in Figure 5.2) is used to categorize the level of risk with a level of integrity management action, and typically describes the scales used for probability and consequence. These standards are typically determined on a corporate level. In the event that no such standard exists, it is crucial that one is defined prior to any assessment of risk.

Integrated Risk Prioritization Matrix								
For the Assessment of HES & Asset Risks from Event or Activity								
Legend								
10, 9, 8 - Short-term, interim risk reduction required. Long term risk reduction plan must be developed and implemented.								
7, 6 - Additional long term risk reduction required. If no further action can be reasonably taken, SBU management approval must be sought to continue the activity.								
5, 4 - Risk is tolerable if reasonable safeguards / management systems are confirmed to be in place and consistent with relevant requirements of the Risk Mitigation Closure Guidelines.								
3, 2, 1 - No further risk reduction required. Risk reduction at management / team discretion.								
Likelihood Descriptions & Index (with confirmed safeguards)				Decreasing Risk				
5	Likely	Conditions allowing the event can reasonably be expected to occur in life of facility and/or significant multiple uncertainties exist	Decreasing Likelihood ↓	6	7	8	9	10
				5	6	7	8	9
				4	5	6	7	8
				3	4	5	6	7
				2	3	4	5	6
4	Occasional	Conditions may allow the event to occur at the facility during its lifetime, or the event has occurred within the Business Unit						
3	Seldom	Exceptional conditions may allow consequences to occur within the facility lifetime, or has occurred within the OPCO						
2	Unlikely	Reasonable to expect that the event will not occur at this facility. Has occurred several times in the industry, but not in the OPCO						
1	Rare	Rare or unheard of						
Consequence Indices				Decreasing Consequence/Impact ←				
				1	2	3	4	5
				Minor	Moderate	Major	Severe	Catastrophic
Consequence Descriptions & Index (without safeguards)	Health, Environment & Safety	Safety	Workforce: One or more injuries, not severe. OR Public: One or more minor injuries such as a first-aid.	Workforce: One or more severe injuries including permanently disabling injuries. OR Public: One or more injuries, not severe	Workforce: (1-4) Fatalities OR Public: One or more severe injuries including permanently disabling injuries.	Workforce: Multiple fatalities (5-50) OR Public: multiple fatalities (1-10)	Workforce: Multiple fatalities (>50) OR Public: multiple fatalities (>10)	
		Health (Adverse effects resulting from chronic chemical or physical exposures or exposure to biological agents)	Workforce: Mild to moderate illness or effect with some treatment and/or functional impairment but is medically manageable OR Public: Illness or adverse effect with limited or no impacts on ability to function and medical treatment is limited or not necessary.	Workforce: Serious illness or severe adverse health effect requiring a high level of medical treatment or management OR Public: Illness or adverse effects with mild to moderate functional impairment requiring medical treatment.	Workforce (1-4): Serious illness or chronic exposure resulting in fatality or significant life shortening effects OR Public: Serious illness or severe adverse health effect requiring a high level of medical treatment or management.	Workforce (5-50): Serious illness or chronic exposure resulting in fatality or significant life shortening effects OR Public (1-10): Serious illness or chronic exposure resulting in fatality or significant life shortening effects.	Workforce (>50): Serious illness or chronic exposure resulting in fatality or significant life shortening effects OR Public (>10): Serious illness or chronic exposure resulting in fatality or significant life shortening effects.	
		Environment	Impacts such as localized, long term degradation of sensitive habitat or widespread, short-term impacts to habitat, species or environmental media	Impacts such as localized but irreversible habitat loss or widespread, long-term effects on habitat, species or environmental media	Impacts such as significant, widespread and persistent changes in habitat, species or environmental media (e.g. widespread habitat degradation).	Impacts such as persistent reduction in ecosystem function on a landscape scale or significant disruption of a sensitive species.	Loss of a significant portion of a valued species or loss of effective ecosystem function on a landscape scale.	
	Asset	Shutdown Time	Less than 1 hour	1 hour to less than 12 hours	12 hours to less than 5 days	5 days to less than 30 days	30 days or more	
		Repair / Replacement / Remedial Action Cost	Less than \$100,000	\$100,000 to less than \$1 million	\$1 million to less than \$10 million	\$10 million to less than \$100 million	\$100 million or greater	
		Loss of Product	< 1% reduction in throughput for 1 day	< 10% reduction in throughput for 1 day	0.5% reduction in throughput per year	5% reduction in throughput per year	>5% reduction in throughput per year	
	Reputation	Media Coverage / Market Place	Slight impact, local mention only, quickly forgotten, freedom to operate unaffected.	Minor impact, short term local concern. Prosecution with minor financial and/or short term reputational impact, some impact on asset level non-production activities.	Considerable impact, national bad mention. Prosecution with substantial financial and/or local reputation impact, short term regional concern. Close scrutiny of asset level operations/future.	Major national impact, medium term national concern, prosecution with major financial and/or national reputational impact, minor venture or minor asset operations restricted or curtailed.	Major international impact, persistent national concern. Prosecution with material and/or international reputational impact, long term "brand" impact, major ventures/asset operations severely restricted or curtailed.	

Figure 5.2 Example Risk Matrix Standard

## 5.5 SYSTEM SUBDIVISION & GROUPING

### 5.5.1 Overview

A riser field system may be composed of risers with different service functions or designs, which may not be exposed to similar hazards or risks. The type of actions available to manage integrity may also be limited by the characteristics of the field system. Dependent on the level of detail required for the risk assessment, it may be useful to include the DDR with other risers or (on the other extreme) to divide the DDR into several subgroups.

The group used for assessing risk (i.e. the integrity group) typically consists of components exposed to:

- Similar hazards and potential failure modes;
- Similar probability and consequence of failure from most critical failure modes;
- Similar available integrity management measures.

Typically the most onerous condition of the group should be considered when assessing risk and developing integrity monitoring strategy.

### 5.5.2 Typical Riser System Subdivision (Grouping by Asset Type)

While DDRs are functionally very different from other facility riser systems, potentially more complex and may have much shorter service life, it may be logical to include the DDR in a complete facility riser risk assessment, even in the same integrity group as other non-drilling risers in some instances. It is useful to understand how risers in general are typically categorized.

Riser systems are typically divided into integrity groups according to the following guidelines:

1. Risers or groups of components are identified which have similar or identical:
  - Service functions (e.g. production, export);
  - Global configurations (e.g. tensioning systems);
  - Internal fluid characteristics (i.e. composition, temperature, pressure);
  - Cross-section characteristics (e.g. single casing, dual casing, concentric);
  - Metallic material characteristics (e.g. risers steel & titanium interfaces)
  - Components like fluid conduit interfaces, support structures etc;
  - External environment characteristics (e.g. hydrodynamic loading, marine growth)

profiles).

These characteristics determine most applicable hazards, levels of risk, and available integrity management actions. For example, intelligent pigging of a TTR would require some means of retrieving the pig.

2. No individual components are assigned to more than one integrity group.
3. For a preliminary assessment, integrity groups may be defined just to include principal components along the load path (in pressure, tension or bending). More detailed subdivisions may determine integrity groups by location along the riser (e.g. well head connection and top-side section, mid-water vertical section, and marine growth zone separately).
4. If the riser system is already in service, service history and previously implemented integrity management measures is also considered when defining integrity groups.

In most cases, if a DDR is assessed with the other facility risers, it would be a separate integrity group. However, so long as the most relevant hazards and subject-matter experts are included, and the grouping is logical, the method matters little.

### 5.5.3 DDR Subdivision

If the DDR is the focal point of a detailed assessment, it might be beneficial to divide the DDR into subgroups. Subgroups may be organized by hazard type (e.g. a corrosion hazard assessment subgroup), equipment type (e.g. a wellhead connector subgroup) or functional requirements (e.g. well control).

Once the scope is clearly defined, it is important to highlight any interface areas.

## 5.6 HAZID

### 5.6.1 Overview

The hazard-identification (HAZID) process is a technique for identification of potential hazards and threats specific to a particular project, to provide input to project development decisions. Initially based on a preliminary database of generalized failure modes, subject-matter experts and project personnel identify additional failure modes for the application-specific project conditions an integrity group is likely to be exposed to. The outcome of the

process is the list of failure modes that must be considered during the risk assessment stage.

### 5.6.2 Key Considerations

A HAZID should be systematic, based on the following steps:

- Review each subcomponent, its function and its interaction with the system as a whole;
- Determine subcomponent criticality;
- Identify the potential failure modes of each subcomponent, in terms of initiating event;
- Determine what ultimate consequence or effect the failure of the subcomponent will have on the operation of the system.

In general, it is essential to clearly state the rationale for excluding subcomponents and failure modes.

Definition of failure for specific failure modes potentially varies, based on how much redundancy is built into the system as a whole and the emphasis placed on component criticality. It is recommended to specify failure in terms of catastrophic events, covering any potential loss of life, environmental damage or significant cost (e.g. replacement of the riser). For DDRs, this has been generalized as:

- Complete loss of well control (i.e. blowout);
- Measurable release of hydrocarbons into the environment;
- Loss of riser structural fitness for purpose.

## 5.7 RISK ASSESSMENT METHODOLOGY

### 5.7.1 Overview

An indexing analysis is recommended, with risk ranking (Risk Index, R) defined as the product of one score representing the probability of failure (Probability Index, P) and another representing the consequence of failure (Consequence Index, C). The Risk Index is used to guide the user towards recommending available IM strategies. All indices should be defined according to a transparent, systematic manner.

## 5.7.2 Types of Risk Assessments

### 5.7.2.1 Common Features of Risk Assessments

The steps of any risk assessment are to:

1. Identify parameters that are directly related to the level of risk associated with a failure mode;
2. Correlate parameters in some mathematical formulation that will allow an unambiguous risk rating.

There have typically been two methods used to accomplish these steps:

- Probabilistic Risk Assessment (PRA);
- Indexing Matrix.

The two methods are not necessarily incompatible. For example, if a large body of data and standardized PRA exists for a specific subcomponent (say, a specific design of tensioner), the probability rating from the PRA may be used in an overall Indexing Matrix.

### 5.7.2.2 Probabilistic Risk Assessment (PRA)

Probabilistic Risk Assessment (PRA) is by far the most rigorous and complex method. This statistical technique relies heavily on historical failure data and event tree analysis. An initiating event is flowcharted and followed through to possible conclusions, and a probability of occurrence is assigned to each branch. The final probability of a process or event occurring then is quantified by combining the probabilities of each branch along the way. A detailed PRA requires a large body of quantitative failure statistics and highly trained individuals to obtain meaningful results, although some software programs are available for certain topsides components. Computationally intensive and costly, this technique still potentially presents a limited view of potential risk, especially with regards to emerging technologies. However, a PRA method may be especially effective in quantifying human-driven risks, such as failures caused by inattention to operational procedures.

### 5.7.2.3 Indexing Matrix

For an Indexing Matrix approach, a score is used to numerically rank relative risks associated with different modes of failure, thereby identifying different levels of required integrity

management. These indices represent relative integrity management requirements. This approach typically requires someone experienced in the subject matter to rank the risk, based on a combination of objective rules and engineering expertise. As the most commonly adopted risk assessment approach, a range of variations for applying the methodology exists in industry.

A potentially major limitation is if an overly simplified, ill-defined matrix is used. A simple risk matrix can be highly subjective, with limited traceability. The most critical aspect for successful implementation of an Indexing Matrix approach is transparency in ranking philosophy.

#### 5.7.2.4 Recommended Method

Due to easy application, potential transparency and the scarcity of failure statistics related to DDRs in the GOM [10], an Indexing Matrix method is recommended. To further expand the method's capabilities, the probability scale has been modified to allow incorporation of detailed PRA results and application of expert experience-driven modifiers.

### 5.7.3 Probability

The Probability Index ( $P$ ) should be defined so that risks associated with how the system is designed are separated from risks inherent to uncertainties in design theory or application. It is assumed that any system in service is designed according to code. For example, a riser whose design pressure is greater than its burst pressure would not knowingly be put into service. Hazards where the system is designed well within the relevant code allowable are typically eliminated, save where significant uncertainties exist. Therefore, it is recommended that the Probability Index ( $P$ ) is a function of a basic probability score and an uncertainty modifier, such that:

$$P = P_0 + U \quad (5.1)$$

The basic probability score ( $P_0$ ) may be a function of:

- Level of conservatism in design (e.g. based on stress utilization factor);
- Detailed probabilistic assessment, based on historical occurrences of failure mode or initiator (e.g. assessment of human error events);
- Component reliability assessments, sparing philosophy and mean time to failure (e.g. for

likelihood of tensioner or BOP failure).

While substantial work has been done for various riser applications and internal corporate standards to define probability in terms of key objective parameters, many of the most critical failure modes are the result of multiple variables or complex failure mechanisms. Often, the end result of the “objective” probability definition would be adjusted to a more conservative ranking, to match the experience senior engineers had with the uncertainties and the perceived level of risk. It is best to clearly define what these modifiers are, in part by separating the modifier ( $U$ )

Assessment of the inherent uncertainties associated with the system should include:

- Technology Step-Outs;
- Design Uncertainties;
- Anomalies;

*Technology Step-Outs* account for the uncertainty associated with new applications or technology step-outs from existing applications. Essentially, the confidence level that all the potential hazards and failure mechanisms for an application are clearly known has to be assessed. For example, using a Subsea Isolation Device may be considered a technology step-out since companies typically have no (or limited) in-service experience.

*Design Uncertainties* reflect uncertainties concerning design basis input and/or analytical technique. Some typical design basis concerns include metocean criteria and reservoir characteristics, as discussed in the report for Task 1 [10]. Analytical uncertainties portray the limits of applicable theories or modeling techniques. One of the most prominent examples is for any riser is vortex-induced vibration response. The assumptions for modeling the tensioning system, the methodology for recoil analysis, and whether frequency domain or time domain analysis was conducted may also affect confidence in how well the riser response is predicted.

*Anomalies* reflect uncertainty concerning predicted behavior due to some significant level of defect. Anomalies can occur at any stage of the system life. In general, anomaly significance is determined by:

- Size of anomaly;
- Effect on code compliance.

Anomalies may require an ad hoc engineering assessment to determine their significance.

Examples of anomalies include:

- Larger than anticipated wall thicknesses that were approved by the operator;
- Greater than anticipated fatigue damage accumulation due to hanging on tensioners during weather down time;
- Occurrence of extreme metocean conditions.

#### 5.7.4 Consequence

The Consequence Index ( $C$ ) is defined by a scale of increasing severity, which accounts for all safety, environmental and operational consequences of failure. Failure is always defined as the termination of the integrity group's ability to perform its required function. Whether a DDR is ruptured due to clashing with other risers or collapsed due to tensioner failure, the consequence scale used to assess the severity of failure remains the same.

There are several ways to account for the consequence associated with failure. It is common practice for companies to develop individual indices for each category, as shown in Figure 5.2, and it is typically best to use the corporate scales. The Consequence Index is then determined either by selecting the most severe category index or by the summation of the category indices, depending on company philosophy.

The most common categories for consequence are:

- Safety (consequence to personnel);
- Environmental (consequence to environment);
- Operational / Economic (direct financial consequence);
- Reputation (consequence to corporate reputation).

It is generally recommended to use the most severe category index for the consequence, on the premise that all catastrophic events are to be avoided, no matter the type. A summation approach has some benefits; it allows risk-based prioritization of the recommendations and increases the visibility of failures with multiple catastrophic consequences (e.g. blowouts). However, the point of the categories is to insure that all unacceptable consequences are identified and managed, and the additional complexity is not typically required.

While becoming less common, some companies may still have a single consequence scale. The single scales are usually worded to include the same categories of consequence. Any of the above methods can be tailored to emphasize corporate priorities (i.e. safety has a lower threshold for a high consequence rating).

**5.7.5 Risk Ranking**

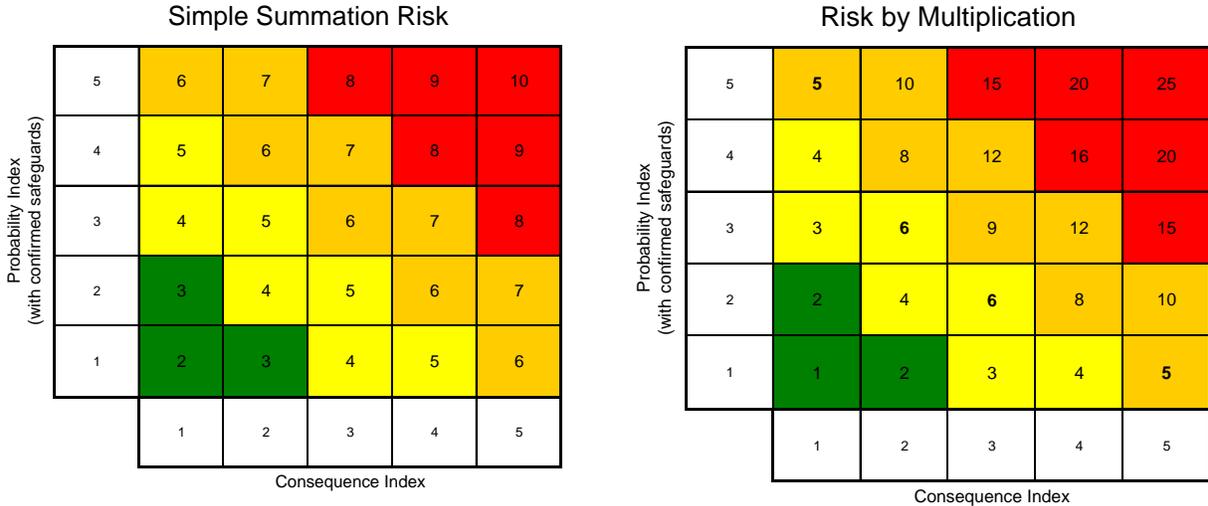
There are two common ways for calculating risk. A Risk Index (*R*) may be calculated by the summation of the Probability Index (*P*) and Consequence Index (*C*):

$$R = P + C \tag{5.2}$$

The Risk Index may also be defined as the product of the Probability Index and the Consequence Index:

$$R = P \times C \tag{5.3}$$

Either formulation is equally effective and valid. However, if the company does not have a set formulation in place and the Risk Matrix (defined in Section 5.4) has symmetrical risk zones, a summation allows for a direct relationship between Risk Index and the level of action required. Figure 5.3 illustrates how using a product definition for risk may not yield a continuous risk action range.



**Figure 5.3 Comparison of Risk Indices on Risk Matrix**

The Risk Index in some ways may be inconsequential; it is more important where the Probability Index and the Consequence Index fall on the Risk Matrix. The zones on the Risk Matrix relate the risk to the level of action required. Three or four risk zones on a Risk Matrix are common, and the zones are usually color-coded with the most severe risks as red and the most benign as green. Example risk zone descriptions are provided in Table 5.1.

**Table 5.1 Example Risk Zones, by Increasing Severity**

Risk Zone Level	Required Actions
None	Additional integrity management recommendations are not required for this failure mechanism.
Basic	Basic recommendations are required, consistent with common industry safeguards. Reasonable safeguards / management systems are to be confirmed to be in place.
Detective	Additional long term integrity management (e.g. detection of a critical stage in the failure mechanism) is required. If no further action can be reasonably taken, typically management approval must be sought to continue the activity.
Predictive	Long-term integrity management plan must be developed to insure a critical stage of the failure mechanism does not occur and any perceived uncertainties are validated. Some risks may be deemed unacceptable, requiring mitigation and immediate integrity management.

Some companies will have action lists and integrity workpacks developed for specific risk zones. The recommendations from the risk assessment may be a combination of actions intended to reduce a risk ranking and actions for management of highlighted critical risk.

## 5.8 GUIDANCE FOR DEDICATED DRILLING RISER RISK

### 5.8.1 Overview

As discussed in Section 4.4, the most critical hazards for deepwater drilling operations using a SBOP may be categorized by:

- **Environmental Loading** – environmental conditions outside those specified in the design basis;
- **Operations** – procedures subject to significant uncertainty and/or prone to human error;
- **Kicks and Blowouts** – reservoir-driven loss of well control.

As stated previously, these broad hazard categories are not necessarily inclusive of all relevant risks; they are intended for illustrative guidance only. Project and subject matter experts should be consulted for assessment of relevant risks.

Although all risks are project-specific, some broad guidance can be provided as to how to assess the criticality of the risk of these general hazards, such as what parameter may drive the overall risk rating. The intent is to provide recommendations of how these hazards may be rated, to help clarify how to systematically document the thought behind the HIRA

process. Ultimately, the risk assessment is only as good as the experts in the room.

**5.8.2 Environmental Loading**

The primary risk-driver for environmental loading is often uncertainty, typically related to the robustness of metocean criteria. However, whether this is truly a concern depends on the design criteria. For example, while there may be limited data to base the design seastates on, design over-conservatism (such as using a 10,000-yr storm) may make the uncertainty negligible. Some typical factors affecting uncertainty are listed in Table 5.2.

**Table 5.2 Typical Environmental Loading Uncertainties**

Key Mechanism	Potential Uncertainties	Factors Offsetting Risk
Extreme response	Under-estimation of extreme events (e.g. current or storm events), typically due to insufficient historical data	More conservative design criteria, such as 10,000-yr environments
Fatigue	Excessive cyclic loading, typically due to under-estimation of metocean criteria or loading not considered in load basis	<ul style="list-style-type: none"> <li>• Increased required factor of safety</li> <li>• More conservative design criteria</li> <li>• Sense check of loading conditions</li> </ul>
VIV/WIO	Significant uncertainty in theory and associated analytical response; may also include uncertainty due to under-estimation of metocean criteria	<ul style="list-style-type: none"> <li>• Increased required factor of safety</li> <li>• More conservative design criteria</li> </ul>

The basic probability is easiest to define in terms of the limited criteria set forth in the design basis. For example, a DDR with a factored fatigue life of 20 years and expected service life of 6 years in most instances may be rated with a low basic probability of fatigue failure. It is also possible to decide the basic probability on a sliding scale based on analysis method used in design (WSD, LRFD, RBD or DBT).

Typically, the consequences for the extreme response environmental loading failures are driven by financial concerns. While it is possible to have a failure during drilling operations due to excessive environmental loading, most facilities will have sufficient warning to shut-in the well and evacuate the facility during questionable sea conditions.

**5.8.3 Operations**

Failures due to human error, manufacturing defects or flaws, and other accidental damage may be difficult to quantify, primarily because they involve a break-down of in-place quality procedures. Generally, these risks are driven by uncertainty and HSE consequence.

In Section 4.4.2, the most common hazards were:

- Material Degradation
- Damage to DDR or Safety-Critical Component
- Failure of Operability Procedures / EDS

Material degradation risk may be best assessed in terms of how close to qualification limits the system is operating, based on the specification of the particular component. For example, surface BOPs are qualified for certain temperature, pressure and fluid compositions, which should be listed in the manufacturer's equipment specification. The basic probability rating may be ranked on the minimum gap between qualified limit and operating / design limit. Risk may be driven by uncertainty in the degradation behaviour of a specific material or by a high consequence for a safety-critical component.

The risk associated with damage to the DDR or a safety-critical component will be dependent on the procedures planned. Interference analysis results for SIMOPS may form the basis for probability ranking. Some impact damage HIRA may benefit from a probabilistic assessment of past incidents.

The most critical potential problems caused by failure of proper procedures for disconnect or drilling operations are:

- Riser wear due to abrasive contact between the riser and rotating components (e.g. the drill string);
- Punch through during drilling operations;
- Inability to unlatch the riser during an emergency event.

The riser wear and punch through are typically the result of a failure to maintain proper riser curvature. Riser wear is the most difficult to prevent; however, numerous techniques exist to detect wear or limit wear. While punch through and emergency disconnect failures are by no means common, the potential consequence warrants their inclusion. The best way to mitigate punch through and emergency disconnect failures are to provide constant training to personnel.

**Table 5.3 Typical Operations Uncertainties**

Key Mechanism	Potential Uncertainties	Factors Offsetting Risk
Material degradation	<ul style="list-style-type: none"> <li>• Improper maintenance</li> <li>• Reservoir characteristics</li> <li>• Degradation behaviour of a specific material</li> </ul>	<ul style="list-style-type: none"> <li>• Additional qualification testing</li> <li>• Redundancy of component</li> </ul>
Impact damage	<ul style="list-style-type: none"> <li>• Human factors, such as insufficient training, excessive shift hours</li> <li>• SIMOPs planning</li> <li>• Insufficient communication</li> </ul>	<ul style="list-style-type: none"> <li>• Interference analyses, showing that potential for impact is minimal</li> <li>• Minimize the number of SIMOPs</li> </ul>
Riser joint connection damage	<ul style="list-style-type: none"> <li>• Human factors, such as insufficient training, excessive shift hours</li> <li>• Misalignment of pipe and coupling at make up</li> <li>• Excessive radial force applied by the power tong at make up</li> </ul>	<ul style="list-style-type: none"> <li>• Set the maximum radial force of the power tong</li> <li>• Use wrap-around and non-marking dies for make up</li> <li>• Limit the make up torque</li> <li>• Use stab guide</li> <li>• Use compensator</li> </ul>
Riser wear	<ul style="list-style-type: none"> <li>• Incorrectly installed, or damaged wear sleeve</li> </ul>	<ul style="list-style-type: none"> <li>• Additional wall thickness during design (i.e. a wear allowance)</li> <li>• Ancillary equipment to prevent contact between drill string and riser (e.g. Non-rotating protectors, wear sleeves)</li> <li>• Non-rotating drill string (i.e. mud motors)</li> </ul>
Riser punch-through	<ul style="list-style-type: none"> <li>• Human factors, such as insufficient training, excessive shift hours, uncertainty related to a buy-out/recent change of procedures</li> </ul>	<ul style="list-style-type: none"> <li>• Assessment of whether punch-through is realistically possible</li> </ul>
Inability to unlatch during emergency event	<ul style="list-style-type: none"> <li>• Human factors, such as insufficient training, excessive shift hours, uncertainty related to a buy-out/recent change of procedures</li> <li>• Hydrate formation on subsea connector</li> </ul>	

#### 5.8.4 Kicks and Blowouts

Risks associated with kicks and blowouts are always high consequence failures, and should always require some sort of action. The action may be as simple as assuring that the BOP manufacturer's maintenance recommendations are implemented and that the crew has clear training on the operational procedures for managing a kick.

There are several possible ways to address the probability. One of the simplest ways may be a probabilistic assessment based on a reliability database (such as SINTEF's Offshore Blowout Database [27] or OREDA [28]). Reservoir experts may also assess the most likely events that would initiate a kick, and qualitatively assign a probability rating.

## 5.9 RISK-BASED RECOMMENDATIONS

### 5.9.1 Overview

Dependent on the stage of assessment, the output from the process may be:

- Design Changes;
- Fabrication & Installation Guidance;
- Operational Guidance;
- Follow-Up Actions & Re-iteration of Risk Assessment.

These recommendations may reflect actions required to bring the risk within tolerable levels, or to resolve uncertainties associated with the DDR (e.g. review of monitored environmental data). Whenever recommendations are given, they must also include a schedule for follow-up on these actions and further risk assessment.

### 5.9.2 Design Changes

Typically, design change recommendations seek to mitigate potential risks prior to the design finalization. These recommendations are often the result of a FEED stage or early execution phase risk assessment. Early project consideration of IM activities may also identify minor design modifications that allow optimization of expensive mobilizations and activities (e.g. ROV time), potentially achieving significant costs benefits for operational IM expenditures. As a result, some operators have mandated FEED risk assessments in their design process.

One potential risk-driven design change may be to employ a subsea BOP instead of the typical surface BOP. Other design recommendations may require a replaceable wear sleeve for the tapered stress joint or non-rotating drill pipe protectors.

### 5.9.3 Fabrication & Installation Guidance

Risk-based guidance on fabrication and installation methods can serve to highlight scenarios that may require risk management. For example, more conservative welding standards and more stringent post-fabrication inspections may be required due to the uncertainties associated with long-term fatigue of a parked DDR in an area with limited current data. Another example might involve identifying specific joint order for installation, in order to maximize service life by moving joints from sections with low numbers of fatigue cycles to

sections with higher fatigue loading.

#### **5.9.4 Operational Guidance**

Operational guidance addresses recommended operating practices, and as such may cover a broad range of recommendations. They might include inspection requirements (such as requiring AUT inspection of riser joints or running of a multi-finger calliper tool between drilling operations), monitoring recommendations (e.g. requiring the current monitoring to validate the metocean criteria), or specification of what components require a reliability assessment and potential sparing plan. Most often, the problem is going into too much detail. It is important to keep in mind that these are broad recommendations of the most pertinent and critical procedures, for guidance during the development of an IM strategy and plan.

#### **5.9.5 Follow-UP Actions & Reiteration of Risk Assessment**

Follow-up actions include any qualifications of recommendations or continuing IM actions. During the course of a workshop, it is not uncommon (even with prior planning) to decide that additional information is required to assess a particular risk or to find that additional personnel should be consulted. In this situation, risks are typically rated according to the worst case scenario, until information can be provided to justify lowering the risk.

Not all recommendations will be approved, so it is useful to prioritize the recommendations and show how the changes will affect risk. If necessary, an updated risk assessment should be completed to provide a snapshot of the risks after the approved changes.

Recommendations are useless if they are not implemented. While it would logically seem self-evident, confirmation of the risk assessment actions actually being employed is one unfortunately prevailing failing. A clear list of all recommended actions, the party responsible for implementation and follow-up is crucial for an ultimately successful risk assessment. It is recommended that this list is included in the development of any IM strategy and plan.

## 6 DEVELOPMENT OF AN INTEGRITY MANAGEMENT PLAN

### 6.1 OVERVIEW OF INTEGRITY MANAGEMENT STRATEGY DEVELOPMENT

#### 6.1.1 General

A general methodology for developing an Integrity Management Strategy (IMS) is outlined, with additional emphasis for methods to manage the risks associated with production facility drilling riser systems. The core methodology reflects industry best practices, and is in-line with the proposed new revision of API RP 2RD.

#### 6.1.2 Purpose of an IM Strategy

The primary objective of an Integrity Management Strategy (IMS) is to detail high-level strategies to manage the risks posed to an asset in a structured manner, with the goal of retaining technical integrity throughout an asset's service life. It bridges the gap between the analysis of system risks and the plan for managing the system.

In order to do this effectively, the IMS must:

- Consider all relevant information regarding the system including components critical to HSE and operability of the system
- Incorporate a RCM assessment and sparing plan for required components
- Consider the risk assessment rankings and identify the level of IM measures that are required to mitigate risk of failure for each component
- Assign IM mitigation measures for each failure mode identified in the risk assessment
- Be implemented and re-assessed to determine its effectiveness, and make any modifications or highlight measures that are not being applied in practice.

An unambiguous, comprehensive methodology is necessary to accomplish these goals in the most effective manner. A clear methodology also ensures consistency across all facilities in the Gulf of Mexico, allowing for better transfer of knowledge and application of lessons learned between projects. This methodology should correlate with existing facility riser integrity management practices (such as for production risers).

### 6.1.3 Process

The basic approach for an IMS is illustrated in Figure 6.1, and can be summarized:

3. Close-Out of Risk Analysis
4. Assess Required Integrity Management Level
5. Select IM Measures & Frequency by IM Level
6. Identify Key Performance Indicators (KPIs)
7. Collate Schedule of IM Activity
8. Risk-Based Gap Assessment

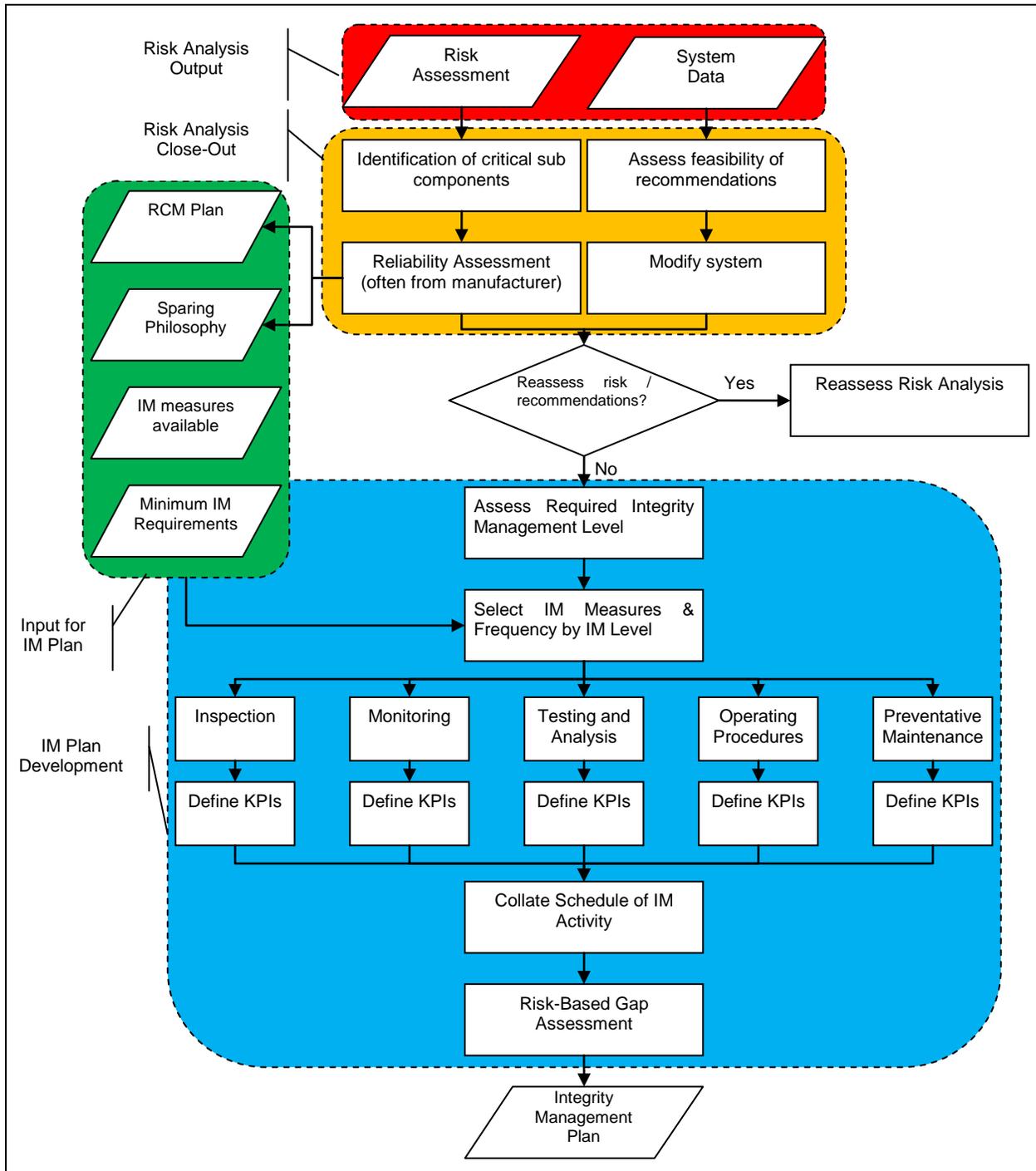
This process describes the minimum requirements for performing an IMS; it is not inclusive of all integrity management requirements. In conjunction with the risk analysis, it is advisable that the IM process is iterated through periodically, dependent on the assessed risk and recommendations for the DDR system.

An IMS requires detailed knowledge of the system, and input from key project stakeholders, operations personnel and subject matter experts. It is important that these persons are consulted in the development of the IMS so as the strategy that is recommended is cost effective and achievable.

Following a risk assessment of the system, an identification of components critical to HSE and operability of the system is performed. This dictates for which components it is necessary to perform a RCM. A sparing philosophy and plan is developed for the components for which the RCM has been performed.

Each failure mode considered in the risk based IMS is assessed to determine the required level of integrity management. Combinations of IM measures are selected according to IM Level, and minimum implementation frequencies determined by risk and corporate/regulatory requirements. Throughout the allocation of IM measures for failure modes, Key Performance Indicators (KPIs) are determined.

An IM plan is developed from these allocated IM measures. A preliminary schedule and detailed procedure for at least the first integrity review are critical components of the IM plan. Upon completion of the IM Plan, a gap assessment and review is performed to ensure that the recommended actions are thorough and complete.



**Figure 6.1 IMS Methodology**

Note: The flowchart presented is not inclusive of the entire Integrity Management process. Multiple iterations through this methodology are expected.

#### 6.1.4 Output

The assessment will identify IM measures and procedures that should be implemented to obtain and maintain system integrity. These recommendations will be system specific, but may include:

- An identification of critical components to define whether the RCM or the risk based IMS method should be prescribed;
- Sparing plan for components critical to HSE and system operability;
- An overview of the level of integrity measures that are recommended for each failure mode of the risk based IMS;
- Detailed IM measures comprising of inspection, monitoring, testing and analysis, operating procedures and preventative maintenance;
- KPIs for benchmarking monitored data and establishing system performance parameters;
- Schedule of IM measures required to maintain system operability and integrity;
- Gap assessment of in place IMS and recommendation of additional measures and procedures.

## 6.2 CLOSE-OUT OF RISK ANALYSIS

### 6.2.1 Follow-Up Actions from Risk Analysis

The typical output from the risk analysis is:

- A prioritized list of risks;
- Recommendations to mitigate and manage the risk associated with particular failure modes.

The primary actions required to close-out the risk analysis are:

- Identify critical system subcomponents and equipment requiring RCM;
- Decide which recommendations to apply.

A first-pass IM plan typically is developed during the design phase of a project, so that any IM measures requiring hardware can be incorporated into the design. Any significant alteration to the system or its operational conditions may require a reassessment of the risk assessment and IM plan.

## 6.2.2 Identification of Critical Sub Components

Components that are critical to HSE or operability of the system or have a severe consequence of failure or downtime due to maintenance should be identified from the results of the risk assessment. These components should be assessed for a proactive maintenance plan, or sparing plan using a Reliability Centered Maintenance strategy.

## 6.2.3 RCM and Sparing Philosophy

A proactive maintenance strategy and sparing plan is required for any components that are critical to HSE or operability of the system or have a severe consequence of failure or downtime due to maintenance; where the cost of failure of a component is high.

Key considerations in developing the maintenance strategy concern the effectiveness, the cost implications and the risks. The maintenance strategy will be developed based on front line, routine and campaign maintenance. This allows failures to be predicted and prevented and intervention to be planned where necessary. The method of determining this strategy may be considered using various approaches; an RCM analysis is recommended to determine the overall strategy, based on quantitative knowledge of the system. RCM analysis should be developed for each piece of equipment, and feed into an overall maintenance strategy.

The maintenance strategy incorporates the past history and reliability of the components as an input to a sparing philosophy and plan. However other considerations in the development of this philosophy may include the current scope and supply of components, which is a consideration that should result in reduce downtime for maintenance for production critical components. As for many other integrity management strategies, there is a reasonable cost versus benefits balance that needs to be reached.

## 6.3 IM PLAN DEVELOPMENT

### 6.3.1 Basis for Plan

Following close-out of the risk analysis, each failure mode considered in the risk based IMS is assessed to determine the required level of integrity management. Combinations of IM measures are selected according to IM Level, and minimum implementation frequencies determined by risk and corporate/regulatory requirements. Key Performance Indicators (KPIs) for the IM measures are specified. The IM measures, with frequency and KPIs, form

the basis for a preliminary schedule and the procedures of the IM plan. As a final development stage, a gap assessment and review is performed to ensure that no critical gaps exist in the recommended IM actions.

### 6.3.2 Integrity Levels

Integrity Levels are used to relate the degree of required integrity management to the degree of risk identified for a particular failure mode. These levels may be defined specifically by project or operator, but are generically defined as:

1. **None:** Integrity management is not required;
2. **Basic:** Basic integrity management is required, typically based in part on regulatory requirements;
3. **Detective:** Detection of failure initiation or a critical stage in the failure mechanism is required;
4. **Predictive:** Integrity management must be capable of predicting the remaining life.

IM measures at the Predictive level require either the direct monitoring of the progress towards failure or the assignment of a degradation model to failure. A failure degradation model analytically calculates the progress and the associated remaining time to failure, based on the input of measured data.

Realistically, all systems require some IM strategy. Each failure mode of an integrity group will have an individual IM Level. As such, no system will have an IM requirement of None for all Failure Modes.

### 6.3.3 Assignment of IM Measures

Several measures are available to maintain the integrity of a field system. Based on the required Strategic Inspection Level, an integrity management strategy may be comprised of any combination of measures. For simplicity, these measures are identified under the following categories:

- Inspection Measures
- Monitoring Measures
- Analysis & Testing
- Operational Procedures
- Preventative Maintenance Measures

Broadly, inspection and monitoring measures refer to obtaining information about the system. Analysis & testing measures refer to how the information is assessed. Operational procedures, preventative maintenance measures and remedial maintenance measures refer to actions designed to prevent failure.

Inspection Measures serve as periodic critical appraisals. Increasing frequency usually denotes increased IMI levels. For subsea systems, inspection options may require innovation. In particular, subsea inspections are currently restricted to visual ROV / AUV limits.

Monitoring Measures provide approximately continuous measurements of either environmental or structural conditions. Current sensor technology is capable of measuring and monitoring response extremely precisely and accurately, using a variety of different sensors and methods.

Analysis & Testing Measures are designed to verify design assumptions and assess the impact of any variations. These measures include evaluation of monitoring and inspection equipment. Reanalysis of fatigue under monitored metocean conditions to determine the actual remaining life is a typical A&T Measure.

Operational Procedures establish specific guidelines to avoid the most common risk-critical situations during any planned operation. Some examples include abandonment & recovery procedures, lifting & handling procedures, and vessel exclusion zones. Common ad-hoc events are also addressed in these procedures, such as dropped object protocols.

Preventative Maintenance Measures are modifications to system components prior to an expected failure initiation or critical stage of failure mechanism. They are scheduled to prevent premature failure by servicing or replacing equipment to reduce wear and maintain optimal performance. Scouring marine growth, replacement of anodes, and recalibration of instrumentation are some examples. Manufacturer recommendations are a primary source for these measures.

#### **6.3.4 Definition of KPIs / Anomaly Limits**

KPIs that are quantitative should be defined where possible to track the integrity of components. KPIs differ from anomaly limits in that they correlate the integrity of a critical, component that is not easily directly inspected / monitored to another component where these measurements may be taken more frequently, easily and therefore more cost

effectively. KPIs should reflect the effectiveness of the IMS, and flag if there are concerns for the condition of critical components. This will in turn illustrate if changes need to be made to reach the objectives of the IMS.

The bounds of acceptable behavior, or anomaly limits, for a system must be defined for each IM Measure implemented. Anomaly limits are set within the most rigorous design, operating, and qualification limits of the integrity group. These anomaly limits establish when, prior to design exceedance, further action is required.

Where practical, quantitative anomaly limits should be defined. All subsequent IM actions are compared to the predefined anomaly limits.

Some typical anomaly limits may include:

- Marine growth thicknesses;
- Riser wear allowance;
- H<sub>2</sub>S partial pressure in bore fluid, and;
- Arrival temperature.

Anomaly limits are not necessarily the same as design limits. For example, while a riser system might be designed for a 100-year storm, some ad-hoc assessment might be required after a 10-year storm.

Anomaly limits determine whether an observed variation qualifies as an anomaly. Anomalies can occur at any point during the service life, such as:

- Manufacture
- Installation
- Operation

All anomalies require an Ad-Hoc Engineering Assessment to examine the significance of the anomaly. Significance is judged at the very least on:

- To what extent anomaly limit is exceeded;
- The effects this has on the integrity of the system, including the risk rating for any associated failure modes, and;
- If the anomaly affects code compliance.

Any significant anomalies require an updated risk assessment, and the Ad-Hoc Engineering Assessment should include any updates to the IM plan.

### 6.3.5 IM Plan Development and Schedule

An IM Plan is developed from the IM measures, expressly detailing the frequency of implementation and anomaly limits. A detailed description and schedule for at least one future integrity review should be included, although a schedule for several such reviews is not precluded. Common IM Plan components include:

- Identification of critical failure modes and components;
- RCM analysis and sparing philosophy for critical components;
- All Anomaly Limits and KPIs;
- Provisions for remediation of common conditions found during integrity assessments, listed by specific problem;
- Recordkeeping provisions;
- Detailed inspection checklists;
- Personnel requirements to implement IM Plan, and;
- Procedures for satisfying any regulatory requirements regarding integrity management programs.

### 6.3.6 Gap Assessment

A first-pass IM Plan typically is developed during the design phase of a project, so that any IM Measures requiring hardware can be incorporated into the design. Any significant alteration to the system or its' operational conditions may require a reassessment of the risk assessment and IM Plan. Additionally, periodic reviews are required to:

- Determine if the system behavior has been adequately assessed;
- Validate any uncertainties associated with high risk failures;
- Verify the IM Plan is implemented as specified;
- Evaluate the effectiveness of the IM Plan.

A preliminary schedule and detailed procedure for at least the first Integrity Review are critical components of the IM Plan.

## **7 DRILLING RISER INTEGRITY MANAGEMENT MEASURES**

### **7.1 GENERAL**

This section focuses primarily on the potential mitigation measures and integrity management actions that can be taken in order to reduce the risks identified in the risk assessment portion of this study. Vendors of equipment and services that assist in risk reduction relating to the scope of this project were consulted in order to evaluate the various techniques currently available in the industry.

### **7.2 INSPECTION**

Inspection is used to gauge the effects of environmental loading and determine if the equipment is fit for purpose. The inspection campaign should be defined so that the inspections frequency and acceptance criteria are such that a defect will be detected before expected operating conditions cause catastrophic failure. Inspection techniques and methods can be simplified into some basic groups:

- Metal loss due to erosion or corrosion
- Crack detection
- Optical/visual inspections

Within these groups there are several different inspection methods available. There is a significant amount of overlap between these inspection techniques. Visual inspections may be carried out by an ROV surveying the length of the riser. Caliper logs may be taken before and after drilling in order to monitor the wall thickness of the riser. If necessary, the riser can be pulled and tested more accurately using ultrasonic or other non-destructive testing methods. Pulling and storing the riser however is very costly, but it will reduce the accumulated fatigue damage. This is an option for extended periods of inactivity and detailed inspection should where possible coincide with these scenarios..

### **7.3 MONITORING CONSIDERATIONS AND DATA ACQUISITION**

Monitoring systems to determine the magnitude of environmental factors, and the response of the equipment or vessel provides informative data that can be utilized to determine the induced stresses and fatigue in components, and verify data assumptions and modelling methods. Aspects of monitoring systems are described below.

### 7.3.1 Real-Time versus Post-Processed Data

In certain situations real-time data is necessary and useful to an operator, particularly when monitoring a riser during drilling operations. Examples of this data include vessel position and offset and riser top tension. In other situations the availability of real-time data, is of little use to an operator. An example of this may be Vortex Induced Vibration (VIV) measurements. The fact that the riser may be vibrating is of little concern to an operator, however, the more useful application of this data is in post processing to reveal accumulated fatigue damage or riser response.

This distinction can be drawn for most of the monitoring technologies, and can be considered an influential factor in the design and specifications of any monitoring system. The requirement for real-time data will influence other factors in the design of a monitoring system, by determining the requirements for data transmission and analysis. Real-time data is considered to be more pertinent for drilling applications as it is a short term operation when compared to the overall design life of the riser.

### 7.3.2 Integrated Monitoring Systems

A number of integrated monitoring systems are in the Gulf of Mexico [65, 66] transmit virtually real time monitored data back to shore, via fiber optic lines. Data that is transmitted onshore may not be necessary for real time assessment of drilling operations, however can be used to validate environment and vessel and riser response models. Data used to validate VIM models includes: wind, wave and current monitoring, and floating system motions using Differential Global Positioning System (DGPS) and 6 degree-of-freedom (6 DOF) inertial motion sensors. Mooring line tensions and riser response may also be included in data that is sent onshore for analysis and model verification.

For situations where a vessel needs to be abandoned by personnel during an event such as a hurricane, an Independent Remote Monitoring System (IRMS) may be employed. This system logs basic data and transmits this onshore, which is very useful for validation of extreme metocean events and validating vessel response to such occurrences.

### 7.3.3 Monitored Data for Drilling Applications

Types of data that are collated during drilling operations are encompassing ever more parameters. This facilitates the confirmation of data assumptions made in the design stage,

enables verification that the system is performing within acceptable parameters, and provides field data to assess validity of models. Data that may be monitored on the offshore drilling platform includes (but is not limited to):

- Vessel motions including acceleration, and inclination;
- Vessel position;
- Environmental data including wind, wave and current measurements;
- Mooring line tensions;
- Riser monitoring including VIV, DIV, and stress monitoring;
- Temperature and pressure;
- Erosion monitoring of drilling returns for metal shavings;
- Bore fluid monitoring for corrosion assessment, and;
- Annulus monitoring to detect leaks.

Riser response considerations including VIV, DIV and stress and internal condition of the riser are considered key parameters for monitoring during drilling campaigns and are described below.

#### 7.3.3.1 VIV/DIV Monitoring

The VIV phenomenon is one of the main design considerations for deep water riser design. Drilling Induced Vibration (DIV) is emerging as a major concern particularly when drilling through small diameter production TTRs. DIV occurs when the rotational speed of the drill string causes contact to occur with the riser in a pattern matching its natural frequency. As drilling continues, the entire riser begins oscillating, accelerating fatigue damage [67].

VIV monitoring systems typically concentrate on measuring acceleration (accelerometer), inclination (inclinometer), and stress/strain. The inclinometer is a good measure of the low frequency motions caused by the vessel motion and the accelerometer is ideal for picking up the higher frequency motions caused by VIV. It is possible to determine the displacement/curvature of the riser from analysis of these measurements. This can then be compared with the modal analysis performed during design.

Direct measurements of acceleration have been the most common technique employed to measure vibrations. Another more direct method is to monitor strain over time and directly determine the curvature of the structure. The advantage in using accelerometers is that they do not require intimate contact with the pipe surface.

The same types of monitoring systems used to detect VIV can potentially be implemented in order to detect whether or not DIV is also occurring during drilling operations. In addition, operators should monitor drilling conditions such as the weight on bit (WOB), rate of penetration (ROP), and rotary speed for warning signs of DIV throughout drilling operations.

#### 7.3.3.2 Stress Monitoring

Monitoring stress at key positions on the riser enables damage induced by load being applied to the riser during drilling to be assessed, in particular in the regions that are the most susceptible to fatigue damage (i.e. at the keel and subsea equipment interface locations).

At the topsides, the top tension, inclination, and the bending moments are relatively easily monitored due to the accessibility and location of this region. From this data alone, it may be possible to ensure that the riser is within the design limitations by extrapolating along the length of the riser.

The technology involved in stress monitoring packages is well defined and relatively simple. The application of this technology to the offshore environment is far more complex. Monitoring packages to date have had limited application and have been of limited use (i.e. continuous monitoring to ensure riser integrity or conformation of design assumptions).

At topsides, top tension can be measured by conventional metallic strain gauges, fibre optic strain gauges, LVDTs or even a load cell. Using the correct configuration strain gauges could also be used to measure bending stresses and hence bending moments. An inclinometer can be used to measure the inclination of the riser. This technology is available and the way to provide accurate and long term data is well established.

#### 7.3.3.3 Corrosion and Erosion

During drilling operations, wear of the riser casing due to contact with the drill string is considered by most operators to be the biggest threat to riser failure. After drilling operations have ceased, the likelihood of corrosion leading to riser failure could be increased from scratches and wear.

Throughout the drilling process, ditch magnets can be utilized to check for metal shavings returned to the surface with the drilling fluid.

## **7.4 ANALYSIS & TESTING**

### **7.4.1 Overview**

Testing and analysis measures are recommended as part of the IM plan to complement the inspection and monitoring activities. The main purpose of these measures is to either provide additional information on the integrity of a specific component (testing) or to assess anomaly criteria and validate design assumptions (through analysis).

### **7.4.2 Weight and Length Tallies**

After installation of the riser, weight and length tallies must be performed to ensure that the actual configuration of the riser is acceptable.

### **7.4.3 Pressure Testing prior to Operation**

One standard procedure to ensure riser integrity prior to commencement of drilling activities is to pressure test the riser.

### **7.4.4 Fatigue / Extreme Load Verification and Re-analysis**

Riser fatigue life may be reassessed to ensure conservatism of the fatigue life calculations performed during detail design. This measure ideally requires monitoring of the riser tension and curvature monitoring, and of the environmental conditions (e.g. wave height, wind speed).

During detailed riser design, a fatigue assessment and extreme analysis of the riser system is performed based on the data and information currently available at that period of time. Generally, the approach adopted during detailed design is inherently conservative due to many unknown parameters in the system. However, to achieve more representative fatigue lives and extreme responses of the risers, it is necessary to eliminate as many unknowns as possible in order to reduce this conservatism.

## 7.5 OPERATIONAL PROCEDURES

### 7.5.1 Overview

Operational Procedures prioritize specific guidelines to avoid the most common risk-critical situations during any planned operation. Common ad-hoc events are also addressed in these procedures, such as dropped object protocols.

Some types of operational procedures that are especially significant to DDRs are:

- Well Completion / Control Procedures
- Heavy Lift / SIMOP Procedures
- Vessel Exclusion Zones / Dedicated Vessel Offloading Zones
- Extreme Event Well Shut-In / Evacuation

### 7.5.2 Well Completion / Control Procedures

#### 7.5.2.1 Overview of well control procedures

Procedures to optimize well control and associated completions activities should be developed and implemented to ensure safe working conditions for crew, and to maintain equipment operability. An environment where strict adherence to detailed well control procedures is practiced should be encouraged.

There are three primary methods to handle well kicks [64]: drillers (expanded below); weight and weight (engineer's method); and concurrent. The method that is chosen may depend on various physical and operational parameters including the amount and type of kick fluids, the rig's equipment capabilities, the minimum fracture pressure in the open hole, and the drilling and operator companies well control policies.

Other considerations that need to be taken into account include the time to execute the procedure and kill well, the resultant surface pressures from circulating out the kick, the stress applied to formations downhole during the kill operation, and the complexity of the procedure with respect to rig capability and crew experience.

The driller's method is an option that is not too complex, and allows a quick response to displace formation fluid from the well bore annulus. This method comprises of two circulations, the first of which allows pumping to commence immediately after shut in. The

driller's method is described further below.

#### 7.5.2.2 Drillers Method

If the system is operating as expected, and the borehole and mud pits are a closed circulating system, a kick will be detected by a change in flow and a change in the active pit volume. Once the kick occurs the well is shut in (open choke and close annular / ram preventers), when the surface pressures stabilized, the shut-in workstring pressure (SITP) and shut-in annulus pressure (SIAP) are recorded.

When the well is shut in, calculations are performed to determine the density of the kill mud, the initial and final circulating pressures and the kick fluid gradient. For the first circulation, the pressure is maintained at SIAP, the choke is opened slightly, and the pumps are brought to kill rate. When the pumps reach the desired rate, the choke is manipulated to maintain initial circulation pressure (ICP) on the drillpipe. The ICP is maintained throughout the first circulation, by controlling the surface choke. As the kick reaches the surface a large increase in annular pressure will indicate that the kick is gas whereas a slight decrease in pressure will indicate that the kick is saltwater. The invading fluid is circulated out, and the pumps and choke are closed, at which point the SITP and SIAP surface pressures should be the same. At this point the well kill operation can now be prepared and executed.

For the second circulation, the mud density is raised to the kill mud density. When the required volume of this mud is achieved the choke is opened, and the pump is increased to the kill rate. The SIAP is kept constant (as was done in the first circulation) until the mud reaches the drill bit. With the pump stopped and the choke closed, the drillpipe pressure should fall to zero. Once this is satisfied, the pumps are restarted; the annulus is filled with kill fluid, until all the original mud and kick fluid has been displaced. Pumps are then shutdown and SITP and SIAP should both read zero, whereupon the kick has been killed.

#### 7.5.3 Heavy Lift / SIMOP Procedures

A dedicated procedure is typically in-place for all lifting and handling operations performed to minimize the risk of accidentally dropping objects on the vessel, mooring lines or riser system.

#### **7.5.4 Vessel Exclusion Zones / Dedicated Vessel Offloading Zones**

Vessel Exclusion Zones and Dedicated Vessel Offloading Zones are designated and policed by the vessel operators in order to minimize the risk of collision between vessels (workboat, supply, and any other third party vessels) with the risers.

#### **7.5.5 Extreme Event Well Shut-In / Evacuation**

Consideration needs to be made concerning the action that will be taken in the course of severe weather conditions. The well may need to be secured or shut-in prior to the arrival of the storm on location.

### **7.6 PREVENTATIVE MAINTENANCE**

#### **7.6.1 Manufacturer Inspection and Maintenance Manuals**

The manufacturer inspection and maintenance manuals for tensioners and BOPs are the result of in-house Reliability Centred Maintenance (RCM).

#### **7.6.2 Marine Growth Removal**

There has been little development in removal techniques in the last 15 years. Remote operated vehicles (ROVs) deployed high pressure water jets or scrubbers are typically used for localized marine growth removal. Inspections are typically visual, with measurements estimated from visual marine growth density.

### **7.7 MITIGATIONS**

#### **7.7.1 Overview**

Mitigations serve as physical barriers to mitigate the likelihood or consequence of a hazard. These can be changes to the riser design, such as increased wall thickness or a Surface Control Subsea Safety Valve (SCSSV). The mitigations may also be procedural changes, such as evacuation of personnel during different scenarios.

#### **7.7.2 Personnel Safety from Accidental Hydrocarbon Release**

Typical measures to promote well completion practices to reduce the risk of component

failure or danger from fracture or blowouts may include:

- Installation of Surface Control Subsea Safety Valve (SCSSV);
- Use safe firing mechanisms for guns (perforating gun procedures would require non-essential personnel away from drill floor);
- Use of an SID;
- Use of Insert Risers.

### 7.7.3 Fatigue

Mitigations for fatigue-related risks depend on the primary fatigue loading being considered. Typical Vortex Induced Vibration (VIV) mitigation is accomplished by either strakes or fairings. Drilling-Induced Vibration (DIV) mitigation begins with monitoring the inclination, stress, acceleration, weight on bit (WOB), rate of penetration (ROP), rotary speed and any other variables for warning signs of harmonic motion. If DIV begins to occur, the WOB or RPMs can be adjusted to bring the riser out of its resonant frequency. Additionally, the drilling fluid density can be changed in order to redefine the natural frequency of the riser.

### 7.7.4 Wear

Some typical wear mitigations include:

- Additional wear allowance on riser wall thickness
- Replaceable wear sleeves at locations of high curvature
- Insert riser
- Mud motors (i.e. non-rotating drill string)
- Non-Rotating Protectors

Non-rotating protectors are designed to maintain a stand-off between the drill pipe and the riser, consisting of a mud-lubricated inner liner connected rigidly to the drill pipe and a tough outer polymer sleeve that is free to rotate about the liner. By preventing the rotating drill string from directly contacting the riser, the risk of wear is minimized.

### 7.7.5 Marine Growth Inhibitors

The primary focus in industry is the development of anti-fouling coatings without tributyl tin (TBT), such as self polishing copolymer (SPC) biocidal coatings. The most information on

these coatings is proprietary and region specific. The available data on the effectiveness of the current anti-fouling coatings varies. Some operators deem that the coatings are invaluable, while others find no real benefit.

## 7.8 GUIDANCE FOR DEDICATED DRILLING RISER IMS

### 7.8.1 General

As discussed in Section 4, the most critical hazards for deepwater drilling operations using a SBOP may be categorized by:

- **Environmental Loading** – environmental conditions outside those specified in the design basis;
- **Operations** – procedures subject to significant uncertainty and/or prone to human error;
- **Kicks and Blowouts** – reservoir-driven loss of well control.

As stated previously, these broad hazard categories are not necessarily inclusive of all relevant risks; they are intended for illustrative guidance only. Project and subject matter experts should be consulted for assessment of relevant risks.

### 7.8.2 Environmental Loading

The primary risk-driver for environmental loading is often uncertainty, typically related to the robustness of metocean criteria or analytical techniques. As such, typical integrity management measures focus on a combination of gathering more data and analyzing the measured response against predictions.

Typical IM measures to manage these hazards are:

- Environmental, vessel motion, and/or riser motion monitoring
- Hindcasting metocean conditions
- Validation of predicted response vs. measured response

Typical mitigations are using more conservative design criteria (such as 10,000-yr environments), VIV suppression devices, and requiring higher factors of safety.

### 7.8.3 Operations

Operational procedures and the execution of such are integral to maintaining safety of the crew, and operability of the drilling equipment. Thus there are several operational procedures that must be explicit and have known purpose so that such procedures are implemented effectively and their objectives are achieved.

#### 7.8.3.1 General

The creation and implementation mandatory inspection and maintenance plans enables an integrated approach to maintaining equipment and raising awareness of potential hazards and issues that could cause failure of a component.

Strict adherence to QA/QC procedures should be promoted so that procedures are carried out to the effect that is required.

#### 7.8.3.2 Riser

The integrity of the riser ensures that well control is able to be maintained and drilling operations may continue safely. There are several operational procedures to ensure that the riser is maintained in a condition where damage will be averted or detected before it becomes critical, and some examples of these are listed below:

- Installation of wear sleeves at fatigue critical areas during tight tolerance operations;
- VIV suppression;
- Fluid compatibility assessment;
- Periodic inspection / removal of marine growth, and;
- Strict inspection of fatigue-critical components;
- Pressure/temperature monitoring of riser annuli (insert riser option).

#### 7.8.3.3 Accidental Damage due to Dropped Objects / Vessel Collision

Accidental damage to critical equipment caused by dropped objects or errant vessel collision should be prevented by the implementation of heavy lift / SIMOP procedures and dedicated vessel offloading zones. A catch net may minimize the damage caused by smaller vessels in a drift-off or drive-off scenario.

#### 7.8.4 Kicks and Blowouts

The appropriate management of kicks and blowouts is essential to maintain equipment and a safe working environment for personnel. As discussed in 7.5.1, there are three primary methods to handle well kicks: drillers; weight and weight (engineer's method); and concurrent. Drilling experts should be consulted to determine the appropriate conditions to apply these measures.

The driller's method is a common option, partly because it is not too complex and allows a quick response to displace formation fluid from the well bore annulus. This method comprises of two circulations, the first of which allows pumping to commence immediately after shut in.

The SID system, if designed correctly, will mitigate the consequence of a catastrophic event by restricting the ability of the reservoir to flow uncontrolled.

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# **APPENDIX A**

## **Riser System and Components**

## APPENDIX A RISER SYSTEM AND COMPONENTS

### A.1 MARINE RISER SYSTEM

The marine riser system acts as the extension from the wellbore to the drilling vessel. Its primary functions are to provide a conduit for introduction of drilling tools into the well and to provide an annulus for the recovery of fluid from the drilled well to the mud control system on the drilling vessel.

Riser design is critical to optimize operation and performance of drilling. The design, selection, operation & maintenance of marine drilling riser systems have historically been governed by API RP-16Q [1]. However many drilling risers are designed to API RP 2RD [2], which is currently being updated in a JIP at present. There are other codes that are also used for drilling riser specification; these are further discussed in Section 3.4.2. The following are some of the main considerations that are taken into account when designing the riser system for the drilling campaign. Casing wear due to the rotating drill string needs to be minimized by limiting the riser curvature and the mean angle of the flex joint, for drilling operations. The top tension needs to be optimized to reduce long term riser fatigue. Dedicated riser management systems can give real time feedback of the performance of the riser [35].

The main identifiers for categorizing riser systems are the size of the main tube and the manufacturer's coupling, the outer diameter, wall thickness, and grade of steel or the riser.

Risers used in SBOP applications have typically been limited by the size of the SBOP. They are typically high pressure risers, between 10-inch and 16-inch diameter. The use of high pressure risers can enable shallow water rigs to be used in deeper water drilling operations. This limitation on the systems is changing, and risers up to an inner diameter of 19.25 inches are being designed for use with a SBOP [45].

There are other advantages with certain riser choices. 13<sup>3</sup>/<sub>8</sub>-inch casing risers are often used in this application [35, 37], which allows the casing riser joints to be used as traditional casing. This facilitates the renewal of riser joints, restoring the fatigue life of the riser joints [34]. The smaller riser diameter also means that mud volume storage requirements are reduced [44].

Risers are fitted with ancillary components to optimize connections and enhance fatigue performance of the riser. Ancillary components of the riser may include (but are not limited to) [35]:

- Adapter spools (to connect the riser to the SID)
- Taper joints (or stress joints)
- Adaptor joints (for various connections)

## A.2 SPECIALITY COMPONENTS

Specialty joints and other components are designed to reduce riser bending stresses at the vessel and the seafloor interfaces. They are often cast or forged, but are never rolled, in order to avoid the presence of a seam on the joint. Therefore, these joints are unlikely to fail unless they contain a fabrication defect. The most common specialty joints include:

- Keel Joints
- Tension Joints
- Flexible Joints
- Pup Joints
- Tapered stress joints;
- VIV Strakes
- Wellhead Connector

These are described in more detail below.

### A.2.1.1 Keel Joint

The keel joint is a riser joint with increased wall thickness used to increase bending stiffness at the location where the riser first enters the keel of the spar hull. It is also a pivot point of the riser and provides relative motion compensation between riser and hull. By doing so, it protects the riser against large bending stresses. In order to prevent wear on the next section, it is possible to add wear material to the keel joint. A keel joint is usually unnecessary for TLPs, but is always used for top tensioned risers installed on a SPAR. For a SPAR, the keel joint is typically located at the lower end of the stem pipe 20 to 30ft below the keel of the spar. Upper and lower transition keel joints make the connection between standard riser joints and the keel joint. They are typically tapered stress joints used to control bending moments in this critical area. The keel guide is used to guide the riser in the hull at the keel joint, and may incorporate a keel centralizer.

#### A.2.1.2 Tension Joints

The tension joint is a special riser joint which connects the mechanical tensioners to the riser through a load ring. It is fabricated using steel construction, extrusion or forging. There are helical machined threads or grooves at the mid section of the tension joint to attach the load ring. The wall of the tension joint is thicker in this area. The upper end of the tension joint is typically connected to the surface BOP via a spool or spacer joint, and its bottom end is connected to a standard riser joint.

#### A.2.1.3 Flex Joint

Flexible joints act as a flexible coupling between the riser and tieback connector. The most common configuration consists of a molded elastomeric element housed in a forged steel body with a steel retainer ring used to compensate for the movement of the drilling vessel. It is a means of reducing the bending stresses in the riser and the reaction forces to the BOP stack, and a source to help dampen vibrations and accommodate shock loadings. For subsea applications the flex-joint sits between the lower marine riser package and the BOP stack. For SBOP applications however, there can also be flex joint at the top of the riser, above the telescopic joint.

#### A.2.1.4 Pup Joints

Pup joints are shorter than regular riser joints and are used to accommodate riser space out.

#### A.2.1.5 Tapered Stress Joint (TSJ)

TSJs are transition members between a rigid or stiffer section of the riser and a less stiff section of the riser. The bending stiffness at one of its ends is close to the stiffness characteristics of the stiffer section whereas the other end has a lower stiffness than the less stiff section of the riser. This transitional capability of the TSJ is achieved by varying its wall thickness. TSJs are typically made of steel or titanium. In a top tensioned riser, the tapered stress joint is located at the bottom of the riser vertical section and is linked to the well casing through the tieback connector. The top end of the TSJ may be connected either to a crossover joint which is itself coupled to the lowest standard riser joint or directly to the lowest standard riser joint, depending on the structural performance at the base of the riser.

#### A.2.1.6 VIV Strakes

Vortex induced vibration (VIV) suppression strakes are helically wound appendages attached to the outside of the riser to suppress vortex induced vibrations. The optimum length and position of the strakes for a given riser system will vary with current profile. Strakes are employed to improve the fatigue life of the riser where VIV is an issue.

#### A.2.1.7 Wellhead Connector

The wellhead connector is generally the name for the universal connection to the well head. It typically joins the overall pressure control system to the lower marine riser package (LMRP). It must withstand bending and tension under pressure loads.

### A.3 RISER CONFIGURATION

Riser configuration is crucial for determining potential hazards and their associated risk, especially in terms of single vs. dual casing and overall length. The riser configuration also may limit the measures applicable for managing riser integrity. Water depth and metocean conditions are leading factors determining riser design, in conjunction with vessel requirements. Their influence is seen in every stage of design, such as material selection and fatigue life prediction.

### A.4 RISER INTEGRITY PLAN

The manner in which the drilling riser integrity is managed is critical in preventing catastrophic failures in the riser. Beginning with a comprehensive quality control system during the initial manufacture of riser components and carrying on with regular inspection and maintenance of the riser system, the integrity of the riser is preserved.

# **APPENDIX B**

## **Example Questionnaire**

**APPENDIX B EXAMPLE QUESTIONNAIRE**

			
<b>Risk Analysis of Surface BOP Drilling Riser Systems</b>			
<b>QUESTIONNAIRE</b> <b>Surface BOP Drilling Operations for DDRs</b>			
<b>Client:</b>	MMS	<b>Date:</b>	4 <sup>th</sup> August 2009
<b>Project:</b>	MMS Risk Analysis of Using a Surface BOP	<b>Job No.</b>	PR-09-0433
<b>Completed by:</b>		<b>Received:</b>	
<b>Representing:</b>	Operator		
<b>Distribution:</b>	File	<b>Doc. No.</b>	QST01 Rev. 01
<b>Background</b>			
<p>On behalf of the MMS, MCS is conducting a risk analysis related to the current state of practice in the GOM of using surface blowout preventers (SBOPs) during drilling operations on floating facility dedicated drilling risers (DDR). This assessment does not cover MODUs.</p> <p>As part of this investigation, MCS is performing an industry and literature survey of current practices regarding these operations. Information received will be desensitized in terms of operator and specific field information. The desensitized information may be incorporated into a public domain report for the MMS.</p>			
<b>Definitions</b>			
DDR	Dedicated Drilling Riser		
MODU	Mobile Offshore Drilling Units		
SBOP	Surface Blowout Preventer		
SID	Subsea Isolation Device		
Shallow Water	0-1000ft (0-300m)		
Deep Water	1000-5000ft (300-1500m)		
Ultra Deep Water	5000-8000ft (1500-2500m)		
Ultra-Ultra Deep Water	>8000ft (2500m)		
		1	
		PR-09-0433 / QST01 Rev. 01 4th August 2009	

<b>MMS</b>	<i>MMS Risk Analysis of Surface BOP Drilling Riser Systems Surface BOP Drilling Operations for DDRs</i>
<b>Questions</b>	
<b>1. MINIMISING RISK IN DEEPWATER</b>	
<p>1. Listed below are some of the key technical challenges associated with drilling in deep and ultra deep water. Please rank the level of challenge you associate with each issue, with 1 as the least challenging and 5 as the most challenging.</p>	
a) Balancing mud weight with safe well control	
b) More challenging environments (e.g. stronger currents)	
c) Abnormal pressure gradients	
d) Narrow window between pore pressure and fracture gradient	
e) Abnormal temperature gradients	
f) Hydrate formation	
g) Minimising riser top tension (i.e. to keep topside weight down)	
h) Difficulties with riser manipulation (e.g. running, landing)	
<p>Other challenges not identified or general comments:</p>	
<p>2. For Deepwater in comparison to shallow field developments do any of the challenges highlighted in Q.1 increase the risk to the riser and vessel, in your opinion? Please explain.</p>	
<p>3. How does your company manage the challenges of deepwater development while keeping the risk to the riser and vessel as low as possible?</p>	
<b>mcs</b>	2
	<i>PR-09-0433 / QST01 Rev. 01 4th August 2009</i>

<b>MMS</b>	<i>MMS Risk Analysis of Surface BOP Drilling Riser Systems Surface BOP Drilling Operations for DDRs</i>
4. The majority of TLP and SPAR developments in the GOM use Surface BOP (SBOP) systems. Reduced topside weight, OPEX savings, ease of riser running and ease of maintenance are a few of the positives of SBOPs. A negative is having the well control device in the immediate vicinity to vessel and personnel. Baring in mind the challenges highlighted in Q.1, do SBOP systems put the riser, vessel and personnel at more risk than subsea BOP systems as developments get deeper (e.g. more difficult pressure gradients and potentially higher pressure, lighter muds and increased likelihood of a gas kick)?	
5. Do you see a necessity for additional fail-safes/redundancy in SBOP drilling riser systems to account for the challenges which come with deeper developments (e.g. Subsea Isolation Device, Gas Handler etc)?	
<b>2. TECHNOLOGY</b>	
6. Do you see a future for subsea BOP systems (coupled with some advanced gas kick control device if necessary) on deepwater SPAR and TLP developments?	
7. As technology moves to more slim-line wells and smaller diameter drilling risers (or even drilling through production risers) what additional risks to the riser do you envisage?	
<b>mcs</b>	3
	<i>PR-09-0433 / QST01 Rev. 01 4th August 2009</i>

<p>MMS</p>	<p>MMS Risk Analysis of Surface BOP Drilling Riser Systems Surface BOP Drilling Operations for DDRs</p>	
<p>8. Do you currently perform drilling operations via production risers on any of your facilities in the GOM? Is this something that you have considered?</p>		
<p>9. Do you employ any other smart drilling/completion techniques (e.g. Managed Pressure Drilling, Dual Gradient drilling etc.) from existing facilities in the GOM?</p>		
<p><b>3. DESIGN</b></p>		
<p>10. Are there additional design requirements (not covered by current riser codes) imposed by your Company for platform drilling riser systems? These requirements should be safety driven. If so please elaborate, where possible.</p>		
<p>11. Is there a necessity for more rigorous design approaches (e.g. Load Resistance Factor Design versus Working Stress Design) to balance conservatism where design conditions and practices are well known and understood?</p>		
<p><b>mcs</b></p>	<p>4</p>	<p>PR-09-0433 / QST01 Rev. 01 4th August 2009</p>

MMS

MMS Risk Analysis of Surface BOP Drilling Riser Systems  
Surface BOP Drilling Operations for DDRs

**4. INTEGRITY ISSUES**

12. Please provide a brief description of any notable integrity issues you have experienced with your drilling risers on existing platforms in the GOM, or any notable lessons learned

# **APPENDIX C**

## **Example Failure Mode Development**

## APPENDIX C EXAMPLE FAILURE MODE DEVELOPMENT

### C.1 OBJECTIVES AND SCOPE OF EXAMPLE

This appendix is to illustrate how failure modes may be developed for a production facility dedicated drilling riser with a surface BOP. **The failure modes presented are not inclusive of all potential hazards to the riser system.** The failure modes should only be used as a starting point for either an internal corporate failure database or a project specific hazard identification (HAZID) process.

Particularly with complex systems and operations such as those associated with drilling, relevant failure modes can be vary by system components and configuration, planned activities, and process limitations. It is critical to consult:

- The design team responsible for the DDR system;
- Relevant subject-matter experts;
- Representatives from interfaced systems (e.g. topsides, subsea equipment, production riser design team);
- Operations personnel.

### C.2 FAILURE MODES FORMAT

To facilitate risk assessment and the identification of mitigation and integrity management measures, failure modes have been defined as the combination of each the following elements:

- **Failure Initiator:** the event or process that initiates a failure mode;
- **Failure Mechanism:** the sequence of stages after initiation which lead to ultimate structural failure (i.e. either rupture or leakage);
- **Potential Mitigation Measures:** typical options available to the operator to mitigate and reduce high risk;
- **Potential Design Uncertainties:** key ‘unknowns’ or uncertainties involved in the design of the riser and/or its components that may impact this failure mode.

Detailed knowledge of the initiator and each of the possible stages towards failure provides the operator with the option to specify corrective action at one or more stages prior to failure. A consistent approach to integrity assessment implies that potential failure modes

which carry an unacceptable risk should be addressed by taking mitigation measures. The remaining failure modes are those typically addressed as part of an integrity management plan. IM measures can be implemented with the purpose of detecting these critical stages.

Potential Design Uncertainties identify key design inputs that may affect the perceived risk. These uncertainties may be validated during the initial phase of a project, thereby reducing the perceived risk and eliminating future IM measures.

### C.3 FAILURE DRIVERS

Each failure mode has been categorized into one of the identified Failure Drivers to aid in identifying and presenting the various failure modes. These categories identify the primary causes of DDR system failure and organize them into groups. This document presents a list of failure modes, presented in terms of the *Failure Initiator* (the event or condition which begins the failure process) and the *Failure Mechanism* (the sequence of stages through to full failure) associated with each mode.

The failure modes listed below include those that are threats that are driven by at least one of the deepwater design drivers as described in the main body of this report. The following failure drivers are those into which failure modes have been categorized:

- Environmental Loading;
- Operations;
- Kicks.

Failure modes are presented in Table C.1 through Table C.3, according to these Failure Drivers. Overlap may exist between Failure Drivers. The Failure Drivers are simply the categories chosen for organizational purposes. Ultimately, organization of the failure modes is at the discretion of the user.

Table C.1 Environmental Loading (EL) Driven Failure Modes

Failure Mode				Potential Uncertainties	Potential Mitigation Measures
ID	Mode	Initiator	Mechanism		
<b>EL001</b>	Riser Interference	Storm events exceeding design conditions	<ol style="list-style-type: none"> <li>1. Impact with other riser or mooring line</li> <li>2. Localized plastic straining due to impact energy</li> <li>3. Pipe rupture</li> </ol>	<ul style="list-style-type: none"> <li>• Metocean conditions</li> </ul>	<ul style="list-style-type: none"> <li>• Conservatism in design environment</li> <li>• Shorten duration of deployment</li> <li>• Higher top tension factor</li> </ul>
<b>EL002</b>	Survival Condition Riser Overbending	Storm events exceeding design survival conditions	<ol style="list-style-type: none"> <li>1. Excessive vessel offset and/or riser curvature</li> <li>2. Overbending</li> <li>3. Riser rupture</li> </ol>	<ul style="list-style-type: none"> <li>• Metocean conditions</li> </ul>	<ul style="list-style-type: none"> <li>• Conservatism in design environment</li> <li>• Shorten duration of deployment</li> <li>• Higher top tension factor</li> </ul>
<b>EL003</b>	Excessive Facility Motions Riser Fatigue	Excessive surface currents, wave loading or wind events	<ol style="list-style-type: none"> <li>1. Facility cyclic motions / VIM</li> <li>2. Excessive bending stress cycling</li> <li>3. Joint connection fatigue failure</li> </ol>	<ul style="list-style-type: none"> <li>• Vessel Motions</li> <li>• Mooring line response</li> <li>• Metocean conditions</li> <li>• S/N data</li> </ul>	<ul style="list-style-type: none"> <li>• Winch to increase mooring stiffness</li> <li>• Move vessel</li> <li>• Better specs for metocean and motions</li> <li>• Higher top tension factor</li> </ul>
<b>EL004</b>	VIV/WIO Riser Fatigue	Excessive currents	<ol style="list-style-type: none"> <li>1. Riser VIV</li> <li>2. Excessive bending stress cycling</li> <li>3. Joint connection fatigue failure</li> </ol>	<ul style="list-style-type: none"> <li>• Metocean conditions</li> <li>• S/N data</li> <li>• VIV analysis</li> </ul>	<ul style="list-style-type: none"> <li>• Better specs for metocean and motions</li> <li>• Strakes</li> <li>• Fairings</li> <li>• Higher top tension factor</li> </ul>
<b>EL005</b>	Loop / Eddy Riser Fatigue	Long-term deployment of riser during loop and eddy current events	<ol style="list-style-type: none"> <li>1. Excessive cyclic loading</li> <li>2. Riser fatigue failure</li> </ol>	<ul style="list-style-type: none"> <li>• VIV modeling</li> <li>• Fatigue curves</li> <li>• Metocean conditions</li> </ul>	<ul style="list-style-type: none"> <li>• Conservatism in fatigue analysis</li> <li>• Shorten duration of deployment</li> <li>• Higher top tension factor</li> </ul>

Table C.2 Operations Driven Failure Modes

Failure Mode				Potential Uncertainties	Potential Mitigation Measures
ID	Mode	Initiator	Mechanism		
<b>OP001</b>	Impacts during running & retrieval	Impact damage during running & retrieval	<ol style="list-style-type: none"> <li>1. Localized plastic straining due to impact energy</li> <li>2. Pipe rupture</li> </ol>		<ul style="list-style-type: none"> <li>• Personnel training on lifting &amp; handling procedures</li> <li>• Dropped object protocols</li> </ul>
<b>OP002</b>	Impacts during SIMOPS	Impact damage during SIMOPS	<ol style="list-style-type: none"> <li>1. Localized plastic straining due to impact energy</li> <li>2. Pipe rupture</li> </ol>		<ul style="list-style-type: none"> <li>• Personnel training on lifting &amp; handling procedures</li> <li>• Dropped object protocols</li> </ul>
<b>OP003</b>	Impacts to SBOP during lifting & handling	Dropped object on and/or impact to SBOP	<ol style="list-style-type: none"> <li>1. Damage to SBOP</li> <li>2. Failure of BOP during unabated kick</li> <li>3. Blowout</li> <li>4. Explosion / fire / loss of containment / fatalities</li> </ol>		<ul style="list-style-type: none"> <li>• Personnel training on lifting &amp; handling procedures</li> <li>• Dropped object protocols</li> </ul>
<b>OP004</b>	Riser joint connection damage	Connector damage during make-up / break-up	<ol style="list-style-type: none"> <li>1. Fatigue propagation of cracks</li> <li>2. Connector failure / joint separation / loss of containment</li> </ol>	<ul style="list-style-type: none"> <li>• Debris / lubricant contamination</li> <li>• Pipe misalignment</li> <li>• Power tong maximum radial force</li> </ul>	<ul style="list-style-type: none"> <li>• Personnel training on make-up/break-up procedures</li> <li>• Alignment marks on connector</li> <li>• Weight/load compensator, for easier handling of pipe</li> <li>• Alignment fork</li> </ul>
<b>OP005</b>	Degradation of BOP seals	Improper maintenance and/or fluids	<ol style="list-style-type: none"> <li>1. Material degradation of seals</li> <li>2. Failure of BOP during unabated kick</li> <li>3. Blowout</li> <li>4. Explosion / fire / loss of containment / fatalities</li> </ol>		<ul style="list-style-type: none"> <li>• Personnel training on procedures</li> </ul>
<b>OP006</b>	Riser wear	Abrasive contact between riser and rotating components	<ol style="list-style-type: none"> <li>1. Localized reduction in wall thickness</li> <li>2. Reduced structural capacity</li> <li>3. Rupture</li> </ol>	<ul style="list-style-type: none"> <li>• Metocean conditions</li> </ul>	<ul style="list-style-type: none"> <li>• Non-rotating protectors</li> <li>• Limitation of operating envelope</li> <li>• Personnel training</li> </ul>
<b>OP007</b>	Riser punch-through	Inattention to procedures	<ol style="list-style-type: none"> <li>1. Damage to riser</li> <li>2. Rupture</li> </ol>		<ul style="list-style-type: none"> <li>• Personnel training on procedures</li> </ul>

Table C.3 Kick Driven Failure Modes

Failure Mode				Potential Uncertainties	Potential Mitigation Measures
ID	Mode	Initiator	Mechanism		
<b>K001</b>	Overpressure of riser joints during well interventions	Kick	<ol style="list-style-type: none"> <li>1. Unabated well kick</li> <li>2. Overpressure of riser</li> <li>3. Plastic straining</li> <li>4. Pipe rupture / loss of containment</li> </ol>	<ul style="list-style-type: none"> <li>• Well pressure profile</li> <li>• Pressure gradients in deep water</li> <li>• Overpressure due to well control operations at top of riser</li> </ul>	<ul style="list-style-type: none"> <li>• Allow for overpressure in design</li> <li>• Secondary, subsea well control device</li> </ul>
<b>K002</b>	Blowout	Kick	<ol style="list-style-type: none"> <li>1. Unabated well kick</li> <li>2. Failure of surface BOP</li> <li>3. Blowout</li> <li>4. Explosion / fire / loss of containment / fatalities</li> </ol>	<ul style="list-style-type: none"> <li>• Well pressure profile</li> <li>• Pressure gradients in deep water</li> <li>• Overpressure due to well control operations at top of riser</li> </ul>	<ul style="list-style-type: none"> <li>• Allow for overpressure in design</li> <li>• Secondary well control device</li> </ul>

# **APPENDIX D**

## **EXAMPLE RISK ASSESSMENT**

## APPENDIX D EXAMPLE RISK ASSESSMENT

### D.1 OVERVIEW OF ASSESSMENT

The approach to this example risk assessment has been to examine the drilling riser designs for two hypothetical deepwater facilities in the Gulf of Mexico. This enables discussion of potential hazards with different vessels, namely:

- Spar X;
- TLP Y.

This assessment of the two systems aims to demonstrate the type of information that should be considered, and how it should be assessed in determining risk ratings for probability and consequence. The basic system data and standards to which each system is designed are presented, along with some aspects of the loading criteria. The key to assessing the risk rating on the probability scale should be noted, as this is not necessarily driven by the most onerous conditions the system is exposed to, but rather how conservatively the system is designed for such parameters.

### D.2 SYSTEM DATA & STANDARDS

#### D.2.1 System Description

##### D.2.1.1 Facility Particulars

The TLP under consideration is a second generation platform, with the following dimensions: 40 foot draft, 50 foot air gap, and 120 foot between columns. TLPs typically have a low heave response.

The spar is a conventional type configuration, with a one piece cylindrical hull. It has a 125 foot diameter and is 700 feet long. Spars are typically more stable than conventional TLPs as they do not rely on the mooring system to hold it upright. However as a result of this there is an increased heave response compared with a TLP as the mooring the system isn't as taut. Another aspect of the spar that may be advantageous is that the top sections of risers are protected from currents and waves inside the spar's hull.

Table D.1 presents a broad overview of the design parameters of the two systems that will

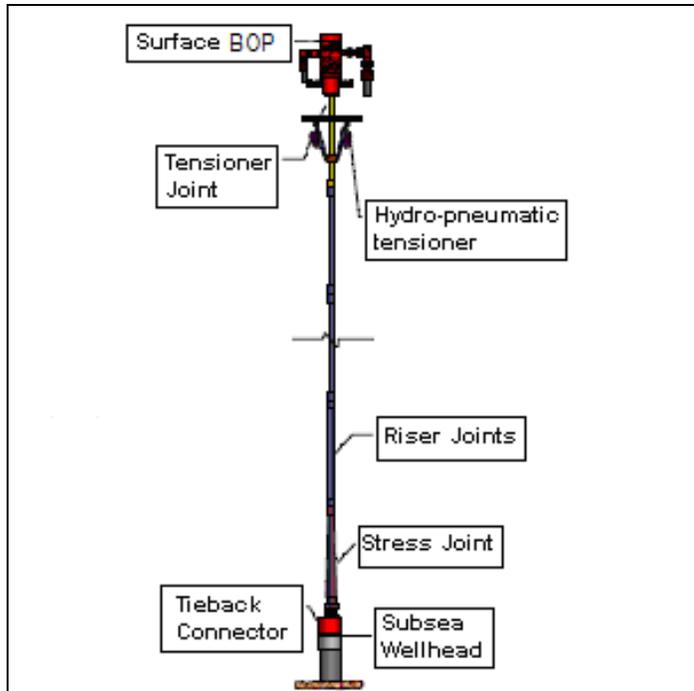
be examined.

**Table D.1 Facility System Parameters**

Parameter	Unit	System 1	System 2
Vessel		Spar X	TLP Y
Design Code for Strength	-	API RP 2RD	API RP 16Q
Environmental load case return period	yrs	10,000	1,000
Planned service life	yrs	6	6
Design life	yrs	20	10
Fatigue Safety Factor	-	10	100
Minimum annulus clearance	in	2	6
SID		No	Yes

D.2.1.2 Dedicated Drilling Riser System

Both systems have similar drilling riser configurations, illustrated in Figure D.1.



**Figure D.1 Example Drilling Riser Configuration**

The characteristics of the field locations that have major implications on risk of failure to the drilling riser are outlined for both systems below.

## D.2.2 Field Metocean Characteristics

### D.2.2.1 Field Location

Both facilities are located in the Green Canyon area in the Gulf of Mexico, 150 miles south of New Orleans, at a water depth of 6900 ft. The field is located at the base of the Sigsbee Escarpment, a very prominent feature in the GOM characterised by a sudden drop in the seafloor of 2000 ft. Locally, the seafloor on the escarpment can be in the range of 20 degrees and more. This causes high bottom currents in the location.

### D.2.2.2 Hurricane Criteria

These two systems are subject to very comparable hurricane conditions as they are in the same general area. However, hurricane data are collated using slightly different models, some considering a larger data set, and others considering a more ‘accurate’ (usually compiled of more recent storms, having the advantage of more accurate storm intensity monitoring), but shorter data set. Subsequently, System 1 has a more concise, but conservative set of conditions than that for System 2. System 1 is a newer field, and has incorporated more recent and most extreme hurricanes. Both systems consider the 100 and 1000 year return period significant wave hurricane data. However this approach assumes that the greatest response will come from the largest waves, when (for deepwater structures) high wind events may incite the largest response. Due to this, System 2 also considers the 100 year hurricane wind event with associated waves and currents.

### D.2.2.3 Winter Storm Criteria

The 10 and 100 year return period significant wave winter storm data is considered for both systems, with System 1 also considering the winter storm / loop current eddy scenario.

### D.2.2.4 Operational Wind Wave and Current

Both systems consider various combinations of wind, wave and current for analysing operational scenarios. System 2 considers a number of current combinations to facilitate fatigue analysis. Combinations include eddy/loop with bottom, background with bottom,

and submerged with bottom.

#### D.2.2.5 Loop / Eddy Currents

Both System 1 and 2 are affected by the Loop Current eddies that have spun off from the Loop Current. For System 1 the eddy may have been shed many months previous to the eddy traversing into the Western Gulf. As the eddies cross the site, current speeds will ramp up from the background levels, to the peak level, then ramp back down to the background levels as the eddy passes over the site. System 2 considers three Loop/Eddy profiles: termed weakly sheared; moderately sheared; and highly sheared. These occur depending on the position of the System in the eddy.

### D.3 SYSTEM SUBDIVISION & GROUPING

For the purpose of the risk assessment, the riser system is considered, including ancillary components which are integral to the performance of the riser. This includes assessment of failures of the SBOP, the hydro-pneumatic tensioners, the tension joint, the stress joint and the keel joint.

The topside interface is considered to be (inclusive of) the SBOP, and the subsea interface is at the subsea well head.

### D.4 HAZID

#### D.4.1 Overview

The potential failure modes from Appendix C are reviewed to assess whether each failure mode is applicable to the systems. This may not simply relate to whether a particular failure mode is possible; the relevance of the failure in terms of design conservatism and the operational procedures should be considered. If a very conservative design approach is taken to mitigate a particular failure mode, the failure mode may not warrant inclusion. If human error is a factor in a potential hazard it is prudent to always consider this failure mode. The justification for exclusion of a failure mode should be recorded.

After reviewing the preliminary list of potential hazards, project and subject matter experts should be consulted add any further failure modes, or to tailor the existing failure modes to the application.

For the proposed systems, this process has been summarized in terms of the categories presented in Appendix C, with one addition:

- Environmental Loading;
- Operations;
- Kicks and Blow-Outs;
- Corrosion.

#### **D.4.2 Environmental Loading**

None of the environmental loading failure modes may be eliminated for either case. However, clashing of risers during excessive metocean events is more likely to damage VIV suppression devices or the cathodic protection than to result in impact riser rupture. Also, existing environmental monitoring and forecasting allows sufficient warning to deploy a storm packer to secure the well downhole prior to storm or current events, mitigating potential immediate consequences.

#### **D.4.3 Operations**

Failures related to the HPT (hydro-pneumatic tensioner) and DIV (drilling induced vibration) have been included. These failure modes could be due to failure of another component, or misuse of another component, that would lead to riser damage. Punch through has been eliminated as it has been deemed not possible, through use of efforts to control riser curvature. However gouging and damage by casing has been included. Damage to the riser due to an errant vessel has been included for the TLP. While a barge with additional mud is required for both systems, the barge may possibly fit through the TLP.

#### **D.4.4 Kicks and Blowouts**

Failure modes considering kicks and blowouts have been considered. This failure mode is related primarily to management procedures, and is likely to be catastrophic where it occurs in conjunction with some other equipment failure or mismanagement issue. Blowout has been divided into surface and subsea, due to different consequences and management actions required. Sheared pipe is considered a failure to maintain well control; while it mitigates HSE, it is a significant financial consequence.

### D.4.5 Corrosion

Since the DDRs will be deployed for several years at a time, two external corrosion failure modes are added, caused by two different initiators:

- Over-depletion of cathodic protection / damage to corrosion protection;
- Excessive marine growth, leading to localized hydrogen pockets.

While it is arguable that the years in service are insufficient for the coatings and protections to degrade to the extent that corrosion would cause enough wall thickness reduction for failure, corrosion should be considered for completeness and addressed in the risk assessment.

## D.5 CONSEQUENCE RATINGS

### D.5.1 Safety Consequence, C<sub>s</sub>

During drilling operations, the likelihood of a blowout is increased when compared to non-drilling activities. A blowout could easily cause loss of life to multiple people if it was to occur and thus the maximum consequence index (value of 5 in this example) is assigned during drilling operations. Additionally, if a well is being drilled from a floating production vessel using a SBOP without an SID and the riser fails, there is no system in place to provide well control operations as the BOP is located at the surface, not the mudline.

The safety consequence scale is presented in Table D.2.

**Table D.2 Safety Consequence Index, C<sub>s</sub>**

Rating	Description
0	No injury or illness
1	Personal injury / slight illness requiring first aid and / or medical attention
2	Personal injury resulting in restricted work injuries, OSHA recordable /Doctor Visit
3	Lost Time Injury / Illness, including permanently disabling injuries
4	Serious injury / illness resulting in permanent disability
5	Single or Multiple fatalities

**D.5.2 Environmental Consequence, C<sub>E</sub>**

During drilling operations, using a SBOP and no SID, if the riser were to fail there would be no way to quickly shut in the well due to the lack of a mudline well control device. During a blowout event, the surface BOP would be activated but nothing could be done quickly to prevent the uncontrolled flow of hydrocarbons from the well into the environment. Therefore, for this scenario, the maximum consequence index (value of 5 in this example) shall be assigned.

In the case that an SID or other mudline control device is used, the failure of the riser could still release a large quantity of hydrocarbons into the environment. However, the flow of hydrocarbons could be cut off as soon as the riser failure was detected. The environmental impact should therefore be kept to a minimum, and a medium level consequence index (value of 3 for this example) should be assigned.

The environmental consequence scale is presented in Table D.3.

**Table D.3 Environmental Consequence Index, C<sub>E</sub>**

Rating	Description
0	No environmental impact
1	Release contained within the facility, or non reportable spill, with localized or short term (days) effects on habitat and species
2	Reportable spill or release contained within the facility or small release not requiring activation of any remedial actions or measures, may have localized, long term (weeks) degradation of sensitive habitat or widespread, short-term (days) impacts to habitat and species
3	Reportable spill or release not contained within the facility and requiring activation of facility's remedial actions or measures, impact localized but irreversible habitat loss or widespread, long-term effects on habitat, species (months)
4	Reportable release or spill, requiring activation of external measures. Regulatory restriction or enforcement action. Impact significant, widespread and causes persistent changes in habitat and species lasting years
5	Reportable release or spill. Direct impact on public. Prosecution. Impacts such as persistent reduction in ecosystem function on a landscape scale or significant disruption of a sensitive species, effects lasting for decades.

**D.5.3 Operational Consequence, C<sub>O</sub>**

The Operational Consequence considers all the significant monetary costs associated with riser failure, specifically the loss of operating capability. Again, for this consequence scale two scenarios should be considered. If a SID or similar mudline shutoff device is utilized, the riser failure does not directly imply loss of well control. There may be clean-up costs

and fines associated with well fluid loss before the SID is able to be activated, but assuming there were not multiple system failures, these costs should be minimal. Thus for the use of an SBOP with a SID the operational consequence should be assigned a medium level score (value of 3 for this example).

However in the case that a mudline shutoff device is not used, the operational losses could be much greater. If the riser leaks and then fails as the result of a well kick, control of the well may be lost as the leak in the riser is below the SBOP. If pressure containment becomes impossible in this scenario, the only other option may be to drill a relief well, at high expense. Therefore the operational consequence of failure of the riser without an SID is extreme, and is therefore assigned the maximum consequence index (value of 5 in this example).

The operational consequence scale is presented in Table D.4.

**Table D.4 Operational Consequence Index, C<sub>O</sub>**

<b>Rating</b>	<b>Description</b>
0	No cost impact
1	Minimal damage, no significant impact on operations
2	Minor Damage, minor impact on operations
3	Serious asset loss, impact on part of operations
4	Major Damage, damage to facility, delay in operations
5	Extensive Damage; long term impact on operations

#### **D.5.4 Reputation Consequence, C<sub>R</sub>**

Impact to corporate reputation due to negative publicity is considered, in terms of type of media coverage. When using this consequence scale for a SBOP, the inclusion or absence of the mudline control device also needs to be considered. If there is no SID or equivalent device, and the riser fails we have seen that there could be severe consequences in the safety, environmental and operational consequences. This has the result that if any or all of these consequences occurs, there will likely be high press coverage, giving the party involved negative global coverage. Thus the maximum consequence score (value of 5 in this example) should be assigned. Alternatively, if a mudline control device is used, and the catastrophic safety, environmental and operational consequences are avoided; the party involved may only incur negative press in the range of people it directly affects. Thus a medium consequence score (value of 3 in this example) should be assigned.

The reputation consequence scale is presented in Table D.5.

**Table D.5 Reputation Consequence Index,  $C_R$**

Rating	Description
0	No impact
1	Negative public complaint, no impact to local community
2	Light media coverage, immediate area to facility may be alerted
3	Local media coverage, potential health impacts to community
4	Negative national or regional publicity, potential chronic health impact to community
5	Negative international publicity, potential chronic health impact to community

## D.6 RISK ASSESSMENT AND RATINGS

This example risk assessment has presented two different SBOP systems, in different locations in the Gulf of Mexico. The most significant difference between the systems is the use of a SID on System 2. This has a major impact on the consequence ratings for the system, and is explored in Section D.5.

Probability of riser failure is discussed in Sections D.6.1 through D.6.3 for the two systems considering the most critical risks to each system. The risk assessments for the failure modes that represent critical riser failures associated with the use of a SBOP are presented for the two systems in Table D.6 and Table D.7 respectively.

### D.6.1 Environmental Loading

System 2 has been designed before the inclusion of recent significant extreme events (hurricanes) in the metocean criteria; therefore hurricane conditions do not include the most onerous conditions. However, System 2 does also consider the hurricane wind event with associated waves and currents. System 1 is designed to the 10,000 RP events, whereas System 2 is only designed to the 1,000 RP events. Thus for hazards such as riser interference and overbending, which are most significantly impacted by extreme metocean events System 1 will be given a lower probability risk rating than System 2, based on more conservative design data.

System 1 is a Spar, which is more stable laterally than a TLP; however there is larger heave response. Despite the perhaps more favourable fatigue conditions considering the Spar system, the TLP system has a fatigue life safety factor of ten times that of the Spar. Due to

the less onerous conditions of the riser from the Spar and the conservative fatigue considerations of the TLP riser, the fatigue driven failure mode probability risk ratings will likely be similar.

Both systems are in the same area of the Gulf, so should experience similar loop/eddy currents. However, System 2 has also considered loading where the eddy exists in conjunction with the winter storm event, implying that System 2 has considered more conservative metocean loading than System 1. Thus the probability risk rating for loop / eddy riser fatigue will be lower for System 2.

As System 2 is a spar, the hull of the facility shields the top section of the riser from currents, however as discussed above, System 1 has a more conservative fatigue safety factor. Thus the probability risk rating for VIV riser fatigue will be similar.

#### **D.6.2 Operational Procedures**

Several of the failures considered for the operational procedures modes of failure imply that there is some risk of human error involved. This includes impact events, joint connection damage, degradation of BOP seals / components, riser wear, load ring loading, and crack propagation due to drilling damage.

An issue with failures that consider human error as a factor is that despite procedures being in place for performing these operations, it is generally hard to verify that they are executed. In addition to this a procedure may be accidentally breached. As the proper procedures for carrying out these operations are in place for both systems and there is no evidence that the crews operating either System 1 or 2 are not trained properly, the probability risk ratings for these failures will be similar for both systems.

#### **D.6.3 Kicks and Blowouts**

There are several factors that effect well kicks and blowouts. The initiator is generally a factor of reservoir characteristics, and the response relies on the equipment and the operations team. Effective equipment and response can mitigate the risk associated with most well kicks. It has been determined that for both systems there are well trained teams who follow set operating procedures in place.

#### D.6.4 Corrosion

The corrosion failure mechanisms relate primarily to damage or degradation of the cathodic protection system. This can be due to from impact from riser clashing, or degradation due to marine growth. It has been discussed in the Environmental Loading section that System 1 will be given a lower risk rating for events relating to extreme metocean events. This includes damage to the cathodic protection due to clashing. In terms of degradation of the system due to marine growth, both systems are inspected frequently enough for the expected life of the anodes, so the risk rating for failure of the riser due to the degradation of the anodes should be low.

Table D.6 and Table D.7 lists all of the failure modes applicable to System 1 and System 2 respectively.

Table D.6 Example Risk Assessment – System 1

Failure					Probability Index, P			Consequence Index, C				Risk Index, R
ID	Mode	Initiator	Mechanism	Potential Consequence	P <sub>o</sub>	U	P	C <sub>s</sub>	C <sub>E</sub>	C <sub>O</sub>	C	
EL001	Riser Interference	Storm events exceeding design conditions	4. Impact with other riser or mooring line 5. Localized plastic straining due to impact energy 6. Pipe rupture	• Repair to riser (financial impact / downtime)	1		1	1	5	3	5	6
EL002	Survival Condition Riser Overbending	Storm events exceeding design survival conditions	4. Excessive vessel offset and/or riser curvature 5. Overbending 6. Riser rupture	• Stop to operation / secure well	1		1	1	5	3	5	6
EL003	Excessive Facility Motions Riser Fatigue	Excessive surface currents, wave loading or wind events	4. Facility cyclic motions / VIM 5. Excessive bending stress cycling 6. Joint connection fatigue failure	• Stop to operation / secure well	1		1	1	5	3	5	6
EL004	VIV Riser Fatigue	Excessive currents	4. Riser VIV 5. Excessive bending stress cycling 6. Joint connection fatigue failure	• Stop to operation / secure well	2		2	1	5	3	5	7
EL005	Loop / Eddy Riser Fatigue	Long-term deployment of riser during loop and eddy current events	3. Excessive cyclic loading 4. Riser fatigue failure	• Stop to operation / secure well	1	1	2	1	5	3	5	7
OP001	Impacts during running & retrieval	Impact damage during running & retrieval	3. Localized plastic straining due to impact energy 4. Pipe rupture	• Stop to operation / secure well	1		1	1	5	3	5	6

Failure					Probability Index, P			Consequence Index, C				Risk Index, R
ID	Mode	Initiator	Mechanism	Potential Consequence	P <sub>o</sub>	U	P	C <sub>s</sub>	C <sub>E</sub>	C <sub>O</sub>	C	
OP002	Impacts during SIMOPS	Impact damage during SIMOPS	3. Localized plastic straining due to impact energy 4. Pipe rupture	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1		1	1	5	3	5	6
OP003	Impacts to SBOP during lifting & handling	Dropped object on and/or impact to SBOP	5. Localized plastic straining due to impact energy 6. Damage to SBOP	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1	1	2	5	5	5	5	7
OP004	Riser joint connection damage	Connector damage during make-up / break-up	1. Reduced capacity of threads / insufficient seal 2. Multiple connection failure / leakage 3. Loss of riser margin (i.e. kill weight completion fluid)	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> <li>Riser repair cost</li> </ul>	2		2	1	5	3	5	7
OP005	Degradation of BOP seals	Improper maintenance and/or fluids	5. Material degradation of seals 6. Failure of BOP during unabated kick 7. Blowout 8. Explosion / fire / loss of containment / fatalities	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1	1	2	5	5	5	5	7

Failure					Probability Index, P			Consequence Index, C				Risk Index, R
ID	Mode	Initiator	Mechanism	Potential Consequence	P <sub>o</sub>	U	P	C <sub>s</sub>	C <sub>E</sub>	C <sub>O</sub>	C	
OP006	Riser wear	Excessive abrasive contact between riser and rotating components	<ol style="list-style-type: none"> <li>4. Significant localized reduction in wall thickness</li> <li>5. Reduced structural capacity</li> <li>6. Loss of pressure / fluid containment</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1	1	2	1	5	3	5	7
OP008	Drilling Induced Vibration	Insufficient damping between drill pipe & riser / rotational speed induces resonant loading	<ol style="list-style-type: none"> <li>1. Resonance response of riser</li> <li>2. Increased accumulated riser fatigue cycles</li> <li>3. Fatigue failure of riser</li> <li>4. Loss of primary containment</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1	1	2	5	5	5	5	7
OP009	Unbalanced loading of load ring	Single hydro-pneumatic tensioner out of service	<ol style="list-style-type: none"> <li>1. One or several HPT out of service</li> <li>2. Unbalanced loading of load ring</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1		1	1	5	3	5	6
OP010	Loss of global riser tension	Single hydro-Multiple hydro-pneumatic tensioners out of service	<ol style="list-style-type: none"> <li>1. Overloading of remaining tensioners</li> <li>2. Loss of global tension</li> <li>3. Collapse of riser</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1		1	1	5	3	5	6

Failure					Probability Index, P			Consequence Index, C				Risk Index, R
ID	Mode	Initiator	Mechanism	Potential Consequence	P <sub>o</sub>	U	P	C <sub>s</sub>	C <sub>E</sub>	C <sub>o</sub>	C	
<b>OP011</b>	Crack Propagation from Drilling Damage	Riser gouging (e.g. rotating drillpipe, running tool downhole)	<ol style="list-style-type: none"> <li>Crack Growth</li> <li>Loss of primary containment barrier</li> </ol>	<ul style="list-style-type: none"> <li>Stop to operation, secure well (financial impact / downtime)</li> <li>Repair riser (financial impact / downtime)</li> </ul>	1	1	2	1	5	3	5	7
<b>K001</b>	Overpressure of riser joints during well interventions	Kick	<ol style="list-style-type: none"> <li>Extended well kick</li> <li>Overpressure of riser</li> <li>Plastic straining</li> <li>Pipe rupture / loss of containment</li> </ol>	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1	1	2	1	5	3	5	7
<b>K002</b>	Surface Blowout	Failure to correctly manage well control event (e.g. procedural failure, mechanical failure)	<ol style="list-style-type: none"> <li>Unabated well kick</li> <li>Failure of surface BOP</li> <li>Blowout</li> <li>Explosion / fire / loss of containment / fatalities</li> </ol>	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1	1	2	5	5	5	5	7
<b>K003</b>	Subsea Blowout	Failure to correctly manage well control event AND Undetected damage to riser joint / connector	<ol style="list-style-type: none"> <li>Loss of well control</li> <li>Riser separation</li> <li>Loss of containment / pollution subsea (Blowout)</li> </ol>	<ul style="list-style-type: none"> <li>Major Environmental event</li> <li>Major financial event</li> <li>Regulatory issue</li> </ul>	1	1	2	5	5	5	5	7

Failure					Probability Index, P			Consequence Index, C				Risk Index, R
ID	Mode	Initiator	Mechanism	Potential Consequence	P <sub>o</sub>	U	P	C <sub>s</sub>	C <sub>E</sub>	C <sub>O</sub>	C	
<b>C001</b>	Clashing of Risers - CP/Anode Damage	Excessive metocean events	<ol style="list-style-type: none"> <li>Impact damage to anode(s)</li> <li>Loss of unacceptable number of anodes</li> <li>CP system overdepletion</li> </ol>	<ul style="list-style-type: none"> <li>Stop to operation, secure well (financial impact / downtime)</li> </ul>	1		1	5	5	3	5	6
<b>C002</b>	External corrosion failure during drilling operations (CP)	Over-depletion of CP system / damage to corrosion protection	<ol style="list-style-type: none"> <li>Significant reduction in localized wall thickness</li> <li>Leakage</li> <li>Loss of riser margin (i.e. kill weight completion fluid)</li> </ol>	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1		1	1	5	3	5	6
<b>C003</b>	External corrosion (Hydrogen Induced Cracking)	Excessive marine growth	<ol style="list-style-type: none"> <li>Localized hydrogen pockets</li> <li>Significant reduction in localized wall thickness</li> <li>Leakage</li> <li>Loss of riser margin (i.e. kill weight fluid)</li> </ol>	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1		1	1	5	3	5	6

Table D.7 Example Risk Assessment – System 2

Failure					Probability Index, P			Consequence Index, C				Risk Index, R
ID	Mode	Initiator	Mechanism	Potential Consequence	P <sub>o</sub>	U	P	C <sub>s</sub>	C <sub>E</sub>	C <sub>O</sub>	C	
EL001	Riser Interference	Storm events exceeding design conditions	<ol style="list-style-type: none"> <li>1. Impact with other riser or mooring line</li> <li>2. Localized plastic straining due to impact energy</li> <li>3. Pipe rupture</li> </ol>	<ul style="list-style-type: none"> <li>• Repair to riser (financial impact / downtime)</li> </ul>	2		2	1	3	3	3	5
EL002	Survival Condition Riser Overbending	Storm events exceeding design survival conditions	<ol style="list-style-type: none"> <li>1. Excessive vessel offset and/or riser curvature</li> <li>2. Overbending</li> <li>3. Riser rupture</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	2		2	1	3	3	3	5
EL003	Excessive Facility Motions Riser Fatigue	Excessive surface currents, wave loading or wind events	<ol style="list-style-type: none"> <li>1. Facility cyclic motions / VIM</li> <li>2. Excessive bending stress cycling</li> <li>3. Joint connection fatigue failure</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1		2	1	3	3	3	5
EL004	VIV Riser Fatigue	Excessive currents	<ol style="list-style-type: none"> <li>1. Riser VIV</li> <li>2. Excessive bending stress cycling</li> <li>3. Joint connection fatigue failure</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1	1	2	1	3	3	3	6
EL005	Loop / Eddy Riser Fatigue	Long-term deployment of riser during loop and eddy current events	<ol style="list-style-type: none"> <li>1. Excessive cyclic loading</li> <li>2. Riser fatigue failure</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1		1	1	3	3	3	4

Failure					Probability Index, P			Consequence Index, C				Risk Index, R
ID	Mode	Initiator	Mechanism	Potential Consequence	P <sub>o</sub>	U	P	C <sub>s</sub>	C <sub>E</sub>	C <sub>O</sub>	C	
OP001	Impacts during running & retrieval	Impact damage during running & retrieval	1. Localized plastic straining due to impact energy 2. Pipe rupture	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1		1	1	3	3	3	4
OP002	Impacts during SIMOPS	Impact damage during SIMOPS	1. Localized plastic straining due to impact energy 2. Pipe rupture	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1		1	1	3	3	3	4
OP003	Impacts to SBOP during lifting & handling	Dropped object on and/or impact to SBOP	1. Damage to SBOP 2. Failure of BOP during unabated kick 3. Blowout 4. Explosion / fire / loss of containment / fatalities	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1	1	2	5	5	5	5	7
OP004	Riser joint connection damage	Connector damage during make-up / break-up	1. Fatigue propagation of cracks 2. Connector failure / joint separation / loss of containment	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> <li>Riser repair cost</li> </ul>	2		2	1	3	3	3	5

Failure					Probability Index, P			Consequence Index, C				Risk Index, R
ID	Mode	Initiator	Mechanism	Potential Consequence	P <sub>o</sub>	U	P	C <sub>s</sub>	C <sub>E</sub>	C <sub>o</sub>	C	
OP005	Degradation of BOP seals	Improper maintenance and/or fluids	<ol style="list-style-type: none"> <li>1. Material degradation of seals</li> <li>2. Failure of BOP during unabated kick</li> <li>3. Blowout</li> <li>4. Explosion / fire / loss of containment / fatalities</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1	1	2	5	5	5	5	7
OP006	Riser wear	Abrasive contact between riser and rotating components	<ol style="list-style-type: none"> <li>1. Localized reduction in wall thickness</li> <li>2. Reduced structural capacity</li> <li>3. Rupture</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1	1	2	1	3	3	3	5
OP008	Drilling Induced Vibration	Insufficient damping between drill pipe & riser / rotational speed induces resonant loading	<ol style="list-style-type: none"> <li>1. Resonance response of riser</li> <li>2. Increased accumulated riser fatigue cycles</li> <li>3. Fatigue failure of riser</li> <li>4. Loss of primary containment</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1	1	2	1	3	3	3	5

Failure					Probability Index, P			Consequence Index, C				Risk Index, R
ID	Mode	Initiator	Mechanism	Potential Consequence	P <sub>o</sub>	U	P	C <sub>s</sub>	C <sub>E</sub>	C <sub>O</sub>	C	
<b>OP009</b>	Unbalanced loading of load ring	Single hydro-pneumatic tensioner out of service	<ol style="list-style-type: none"> <li>One or several HPT out of service</li> <li>Unbalanced loading of load ring</li> </ol>	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1		1	1	3	3	3	4
<b>OP010</b>	Loss of global riser tension	Single hydro-Multiple hydro-pneumatic tensioners out of service	<ol style="list-style-type: none"> <li>Overloading of remaining tensioners</li> <li>Loss of global tension</li> <li>Collapse of riser</li> </ol>	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1		1	1	3	3	3	4
<b>OP011</b>	Crack Propagation from Drilling Damage	Riser gouging (e.g. rotating drillpipe, running tool downhole)	<ol style="list-style-type: none"> <li>Crack Growth</li> <li>Loss of primary containment barrier</li> </ol>	<ul style="list-style-type: none"> <li>Stop to operation, secure well (financial impact / downtime)</li> <li>Repair riser (financial impact / downtime)</li> </ul>	1	1	2	1	3	3	3	5
<b>OP012</b>	Errant Vessel Impact	Impact damage from errant vessel	<ol style="list-style-type: none"> <li>Localized plastic straining due to impact energy</li> <li>Riser rupture or failure</li> </ol>	<ul style="list-style-type: none"> <li>Stop to operation / secure well</li> </ul>	1	1	2	1	5	5	3	7

Failure					Probability Index, P			Consequence Index, C				Risk Index, R
ID	Mode	Initiator	Mechanism	Potential Consequence	P <sub>o</sub>	U	P	C <sub>s</sub>	C <sub>E</sub>	C <sub>o</sub>	C	
<b>K001</b>	Overpressure of riser joints during well interventions	Kick	<ol style="list-style-type: none"> <li>1. Unabated well kick</li> <li>2. Overpressure of riser</li> <li>3. Plastic straining</li> <li>4. Pipe rupture / loss of containment</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1		1	1	3	3	3	4
<b>K002</b>	Surface Blowout	Failure to correctly manage well control event (e.g. procedural failure, mechanical failure)	<ol style="list-style-type: none"> <li>1. Unabated well kick</li> <li>2. Failure of surface BOP</li> <li>3. Blowout</li> <li>4. Explosion / fire / loss of containment / fatalities</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1		1	1	3	3	3	4
<b>K003</b>	Subsea Blowout	Failure to correctly manage well control event AND Undetected damage to riser joint / connector	<ol style="list-style-type: none"> <li>1. Loss of well control</li> <li>2. Riser separation</li> <li>3. Loss of containment / pollution subsea (Blowout)</li> </ol>	<ul style="list-style-type: none"> <li>• Major Environmental event</li> <li>• Major financial event</li> <li>• Regulatory issue</li> </ul>	1		1	1	3	3	3	4
<b>C001</b>	Clashing of Risers - CP/Anode Damage	Excessive metocean events	<ol style="list-style-type: none"> <li>1. Impact damage to anode(s)</li> <li>2. Loss of unacceptable number of anodes</li> <li>3. CP system overdepletion</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation, secure well (financial impact / downtime)</li> </ul>	1	1	2	1	3	3	3	4

Failure					Probability Index, P			Consequence Index, C				Risk Index, R
ID	Mode	Initiator	Mechanism	Potential Consequence	P <sub>o</sub>	U	P	C <sub>s</sub>	C <sub>E</sub>	C <sub>O</sub>	C	
C002	External corrosion failure during drilling operations (CP)	Over-depletion of CP system / damage to corrosion protection	<ol style="list-style-type: none"> <li>1. Significant reduction in localized wall thickness</li> <li>2. Leakage</li> <li>3. Loss of riser margin (i.e. kill weight completion fluid)</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1		1	1	3	3	3	4
C003	External corrosion (Hydrogen Induced Cracking)	Excessive marine growth	<ol style="list-style-type: none"> <li>1. Localized hydrogen pockets</li> <li>2. Significant reduction in localized wall thickness</li> <li>3. Leakage</li> <li>4. Loss of riser margin (i.e. kill weight fluid)</li> </ol>	<ul style="list-style-type: none"> <li>• Stop to operation / secure well</li> </ul>	1		1	1	3	3	3	4