A Probabilistic Approach to Risk Assessment of Managed Pressure Drilling in Offshore Applications

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Forward

A safe workplace is a vital concern to all. We are charged with providing a safe working environment for all on the rig, its environs, and to the public at large. It is the intent of the author to provide information that will be helpful in well designing, well planning, and well construction for the experienced and the inexperienced drilling engineer; with the chief intent to make drilling a safer operation. If in the process, the combination of equipment and techniques makes drilling more economical compared to some benchmark or take less time than some benchmark, then so much the better.

Use of this manual is not intended to replace a legal standard of conduct or duty toward the public on the part of a well designing, well planning, or well construction organization. The intent of this document is to provide a fair and balanced engineering approach to resolving chronic drilling engineering problems while maintaining or improving the current safety mandate already in place. It is the hope of the author that current regulatory requirements be tempered to reflect the vast improvement in technology, making drilling operations more productive and safer simultaneously. Until such time that regulatory requirements are modified to reflect acceptance of a higher degree of well control and safety, the standard and duty of care is intended to remain that standard that has been established by statutory law and judicial determinations within the industry.

The information contained in this document is intended solely for the purpose of informing and guiding the staff and management of organizations charged with well design, well planning, and well construction. As with any guideline, the techniques presented in this manual should be applied carefully and should be modified to fit the particular situation. In each instance, where it is determined that the standard of care in the industry is greater than that appearing to be indicated in this document, it must, of course, be the policy of the organization to proceed with that the standard of care in the industry be practiced.

Every effort has been made to restrict the frequency of words like ***always, will, should, shall, must, and never***. These words and their synonyms are too absolute. Experience has shown me that on occasion, although rare, the textbook can have the wrong answer or describe the wrong technique for a specific situation. Often times the circumstances in the field are not exactly the same as what the author envisioned at the moment the thought was transcribed to paper. A prudent engineer is mindful of those absolutes and incorporates them into his pool of professional judgment.

With respect to professional judgment and absolutes, Managed Pressure Drilling operations are application dependent. A successful Managed Pressure Drilling operation requires a certain minimum amount of equipment, technology, and know-how. Managed Pressure Drilling is not unlike a lot of other projects. Not only do you have to have tools, you have to have the correct tools <u>and</u> use them in an appropriate manner. Having a Rotating Control Device installed above the Annular Preventer does not constitute a Managed Pressure Drilling operation, unless that device is augmented with a drilling choke manifold (separate from the rig choke manifold), Non-return Valves (NRV) in the drill string, and a “what-to-do-if” guideline for those operating the equipment. Additionally, the prudent drilling engineer will supply the driller and the choke operator with another tool…a hydraulic summary that describes the projected drilling window between the pore pressure/well stability line and the frac gradient line.

Templates of forms and checklists can be created from this document. Such forms and checklists are merely guidelines to be tempered with professional judgment and are dependent on the specific application.

For progress to be made the experienced drilling engineer needs to “push the envelope” and seek the prudent limits for equipment and techniques within established safety margins without being handcuffed with absolutes. The inexperienced engineer when wanting to deviate from the norm would do well to do the homework necessary to fully justify the departure and be prepared to defend the rationale for the departure based on risk and reward. In either case, where confidence is lacking, the engineer would do well to consult knowledgeable resources in the industry to help guide his path forward.

Acknowledgements

The author would like to acknowledge the excellent work produced by the Underbalanced Operations and Managed Pressure Drilling Committee of the International Association of Drilling Contractors since its inception in 1996. The author gratefully acknowledges the technical details and insight provided by companies whose equipment and experience is reflected in this document. In any Joint Industry Project, funding is obviously important. Equally important is data acquisition so that analyses can be made.

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Respectfully submitted,

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DEA155

Executive Summary

Managed Pressure Drilling is a drilling tool that is intended to resolve chronic drilling problems contributing to non-productive time. These problems include:

- Well Stability
- Stuck Pipe
- Lost Circulation
- Well Control Incidents

The Underbalanced Operations and Managed Pressure Drilling Committee of the International Association of Drilling Contractors have defined Managed Pressure Drilling.

> **Managed Pressure Drilling is an adaptive drilling process used to <u>precisely</u> <u>control</u> the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. The <u>intention</u> of MPD is to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.**
>
> - **MPD process employs a collection of tools and techniques which may mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.**
> - **MPD may include control of back pressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations thereof.**
> - **MPD may allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates**

drilling of what might otherwise be economically unattainable prospects.

The centerpieces of the definition are rooted around the words “intent” and “precisely control”. The various technologies available today allow us to control maintenance of the bottomhole pressure from the surface within a range of 30 – 50 psi. One MPD method does not address all problems. Managed Pressure Drilling is application specific. The drilling engineer will have his choice of many options that will best address the drilling problems he confronts.

If the intent is to allow continuous influx to the surface then the operation is decidedly underbalanced drilling. While there are some similarities in equipment selection and similar training needs for personnel involved in the operation, Managed Pressure Drilling is not a “poor boy” version of Underbalanced Drilling. On the contrary, done properly, contingencies need to be explored requiring engineering forethought and planning.

Managed Pressure Drilling continues to demonstrate its bright future. While MPD can be used to briefly characterize a reservoir by allowing a small momentary influx, there has not been any recorded incident of a kick while applying the techniques of managed pressure drilling. This is not to say that there have been no problems, sometimes pipe still gets stuck and lost circulation problems still exist, but not the same magnitude as in conventional drilling. The most impressive aspects of Managed Pressure Drilling are it is as safe or safer than current conventional drilling techniques AND problem wells are being drilled and completed instead of abandoned either with cement plugs or in a file labeled “TOO RISKY TO DRILL – TECHNOLOGY NOT AVAILABLE”. MPD is a sophisticated form of well control and deserves a balanced quality appraisal of risks – positive and negative.

Another observation worth noting is that trouble time on a Managed Pressure Drilling application is inversely proportional to the quality of the risk assessment, whether it is called a HAZID+HAZOP or a What-if+Checklist, performed in the planning stages prior to drilling the well. Because the drilling operation is often too large an area to focus on. The drilling operation is divided into sections or nodes, typically centered around specific clusters of equipment or assemblies. A basic assessment needs to include the following within those sections:

Deviation or Upset

Departure from agreed upon process, procedure, or normal expected function.

Cause

A person, event, or condition that is responsible for an effect, result, or consequence.

Consequence

The result of an action, event or condition. The effect of a cause. The outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as an injury, loss, damage, advantage, or disadvantage. Although not predominantly thought of in this manner, consequences do not always have negative connotations; they can be positive.

Severity

The degree of an outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as an injury, loss, damage, advantage, or disadvantage. The degree or magnitude of a consequence.

Frequency

A measure of the rate of occurrence of an event described as the number of occurrences per unit time.

Likelihood

The potential of an occurrence. See Frequency.

Pure Risk

The possibility of a hazard becoming an incident that may have a negative or positive impact on overall objectives. It is measured in terms of likelihood and magnitude of severity.

Risk is usually defined mathematically as the combination of the severity and probability of an event. In other words, how often can it happen and how bad is it when it does happen? Risk can be evaluated qualitatively or quantitatively.

Pure Risk = Frequency x Consequence of Hazard

Pure Risk = Probability of Occurrence x Impact

Safeguards and Controls

There are three basic techniques available to an organization designed to minimize risk exposure as low as reasonably possible at a reasonable cost. They are:

- Prevention
- Detection
- Mitigation

With some overlap, there are three areas that tend to originate and maintain safeguards.

- Administration
  - Training
  - Emergency Plans
  - Directives
  - Supervision
  - Planned Inspections
  - Communications
  - Security
  - First Aid
  - Legal/Regulatory Requirements
  - Management of Change
- Engineering
  - Equipment Design
  - Energy Barriers
  - Identification of Critical Equipment
  - Warning Signs
  - Emergency Equipment
- Operations
  - Procedures
  - Job Safety Analysis
  - Permit to Work
  - Emergency Drills
  - Pre-use checklist

- Planned Maintenance
- Incident Management

Residual Risk

The risk that remains after taking into account the effects of controls applied to mitigate the associated pure risk. No matter how much the causes are mitigated, the consequences are not any less; only the frequency of incidence or occurrence can be altered.

Residual Risk = Mitigated Frequency x Consequence of Hazard

Residual Risk = Mitigated Probability of Occurrence x Impact

After the risk assessment is performed in the suggested manner, it should become obvious where the weaknesses and strengths are in the overall application. Training of personnel often shows up as a repetitive safeguard and recommendation.

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Drilling

Drilling

The chief objective of drilling is to make hole. Whether that hole is for exploratory and appraisal purposes or for development of production the adage attributed to drilling 'Just because you drilled the hole doesn't mean you get to keep it' is still true today. To accomplish the chief objective some elements need to be executed along the way:

- Effective drill bit
- Maintain hole patency
- Transport cuttings
- Freedom of drill string to move
- Control flow in and out of the well
- Case hole
- Achieve target bottomhole location
- Achieve time objective
- Maintain budget

As highly productive fields get more difficult to find and produced fields become depleted, drilling prospects become more marginal and much more challenging, leaving the outcome in doubt. As an industry, it has been profoundly difficult to execute the elements described above to the point where they are undrillable.

New technology has given the industry an opportunity to re-evaluate those undrillable prospects of the past. There is new hope and some evidence to show that drilling, with a few minor alterations to current practices, can actually become safer AND more efficient in terms of well control.

Conventional Drilling

Since the days of Spindletop, conventional drilling has largely been practiced in an open vessel, one that is open to the atmosphere. In the conventional drilling circulation flow path, the drilling fluid exits the top of the wellbore through a bell nipple and traverses a flow line to mud-gas separation and solids control equipment. Drilling in an open vessel today presents a number of difficulties during drilling operations that frustrate every drilling engineer.

Conventional wells are most often drilled overbalanced. We can define overbalanced as the condition where the pressure exerted in the wellbore is greater than the pore pressure in any part of the exposed formations. For conventional drilling applications most regulatory bodies demand that the well be overbalanced while in the static condition, where drilling fluid (mud) is not circulating by means of pumps but is at rest in the well. This static column of drilling mud exerts a hydrostatic pressure throughout the wellbore.

$$P_{Hyd} \geq P_{BH}$$

While the static overbalanced condition addresses control of the pore pressure, once the mud pumps are engaged the system becomes dynamic. A component, annular friction pressure (P_{AF}) is introduced.

$$P_{BH} = P_{Hyd} + P_{AF}$$

Annular friction pressure is created by the motion of the drilling fluid as it drags against the various bores along the entire wellbore length and against the various outside diameters of the drill string along its entire length. Annular friction pressure is a function of:

- Flow velocity
- Hole geometry
  - Pipe diameter
  - Open hole diameter
  - Pipe length
  - Open hole length
- Surface roughness
  - Between pipe and pipe
  - Between pipe and formation
- Fluid slurry properties
  - Fluid slurry density
  - Fluid slurry rheology
  - Cuttings

Annular pressure management is primarily controlled by mud density and mud pump flow rates; where Bottomhole Pressure (P_{BH}) is a function of pressure of the hydrostatic column (P_{Hyd}) in the static condition; and together P_{Hyd} and Annular Friction Pressure (P_{AF}) dynamically contribute to control of the bottom hole pressure when the mud pumps are circulating the drilling mud in the hole.

Another term that describes the pressure in the wellbore is Equivalent Mud Weight (EMW), also commonly known as Equivalent Circulating Density (ECD). Both are defined as the pressure at any given depth expressed in terms of mud density at that given true vertical depth (TVD).

$$ECD = \frac{P_{Hyd} + P_{AF}}{TVD}$$

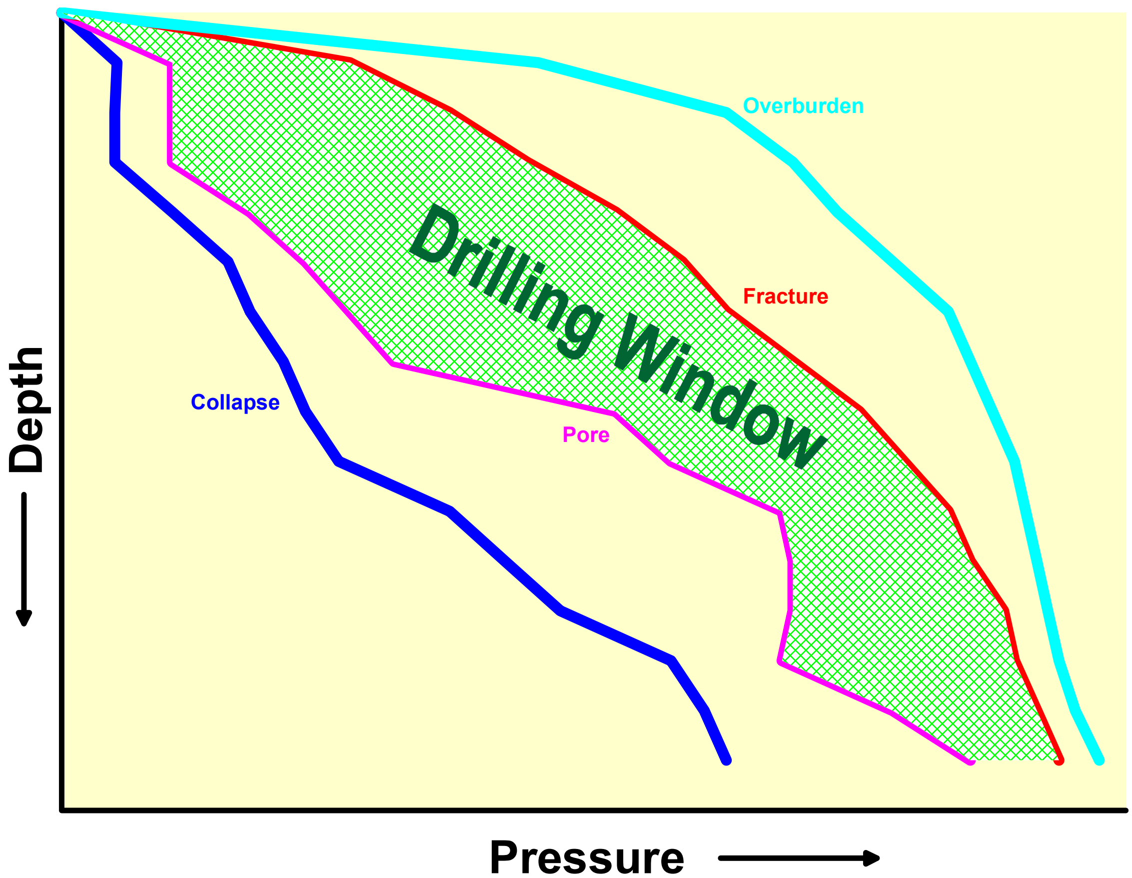


Figure 1.
Drilling Window using Single Density Drilling Fluid

From a hydraulic standpoint, the objective is to drill within the pressure window bounded by the pore pressure on the left and the frac gradient on the right (Figure 1).

When encountering virgin reservoirs, especially in days past, the drilling window was fairly wide. The challenges of today's environment include re-entry of partially depleted reservoirs or deep water applications where water accounts for a large portion of the overburden (Figure 2). In these cases, the drilling window is likely to be narrow (Figure 3).

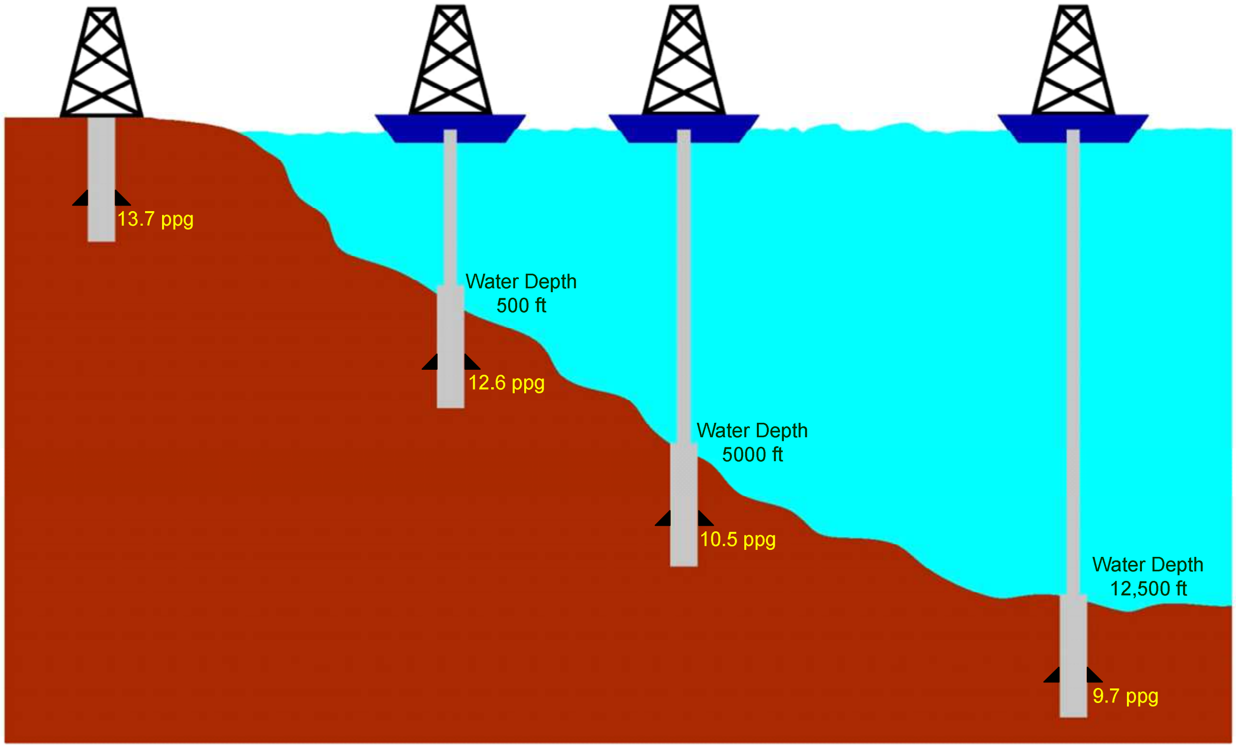


Figure 2.
Frac Gradient due to Water Overburden

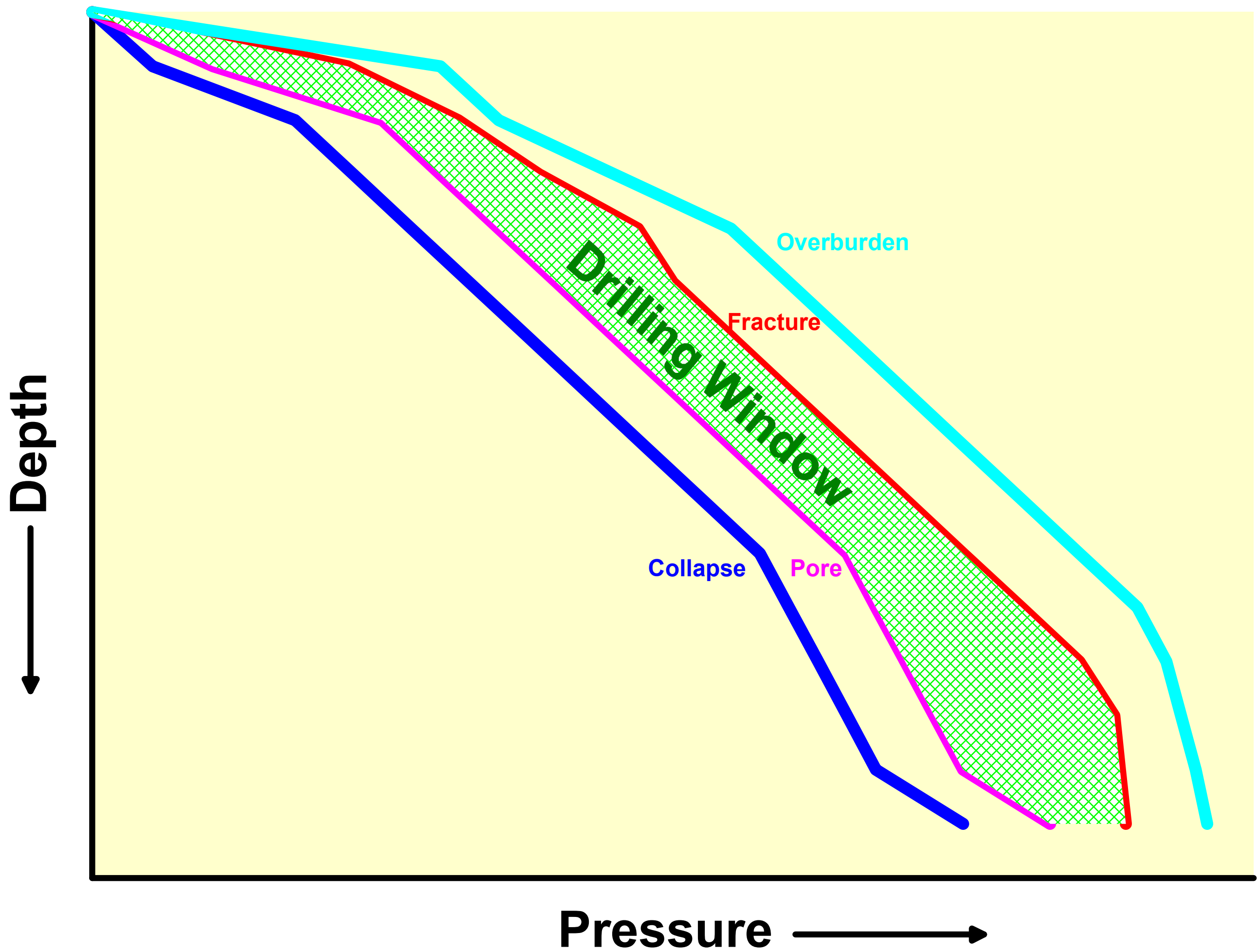


Figure 3.
Narrow Drilling Window using Single Density Drilling Fluid

The formation collapse pressure should not be ignored. In some cases, the collapse pressure is equal to or greater than pore pressure (Figure 4).

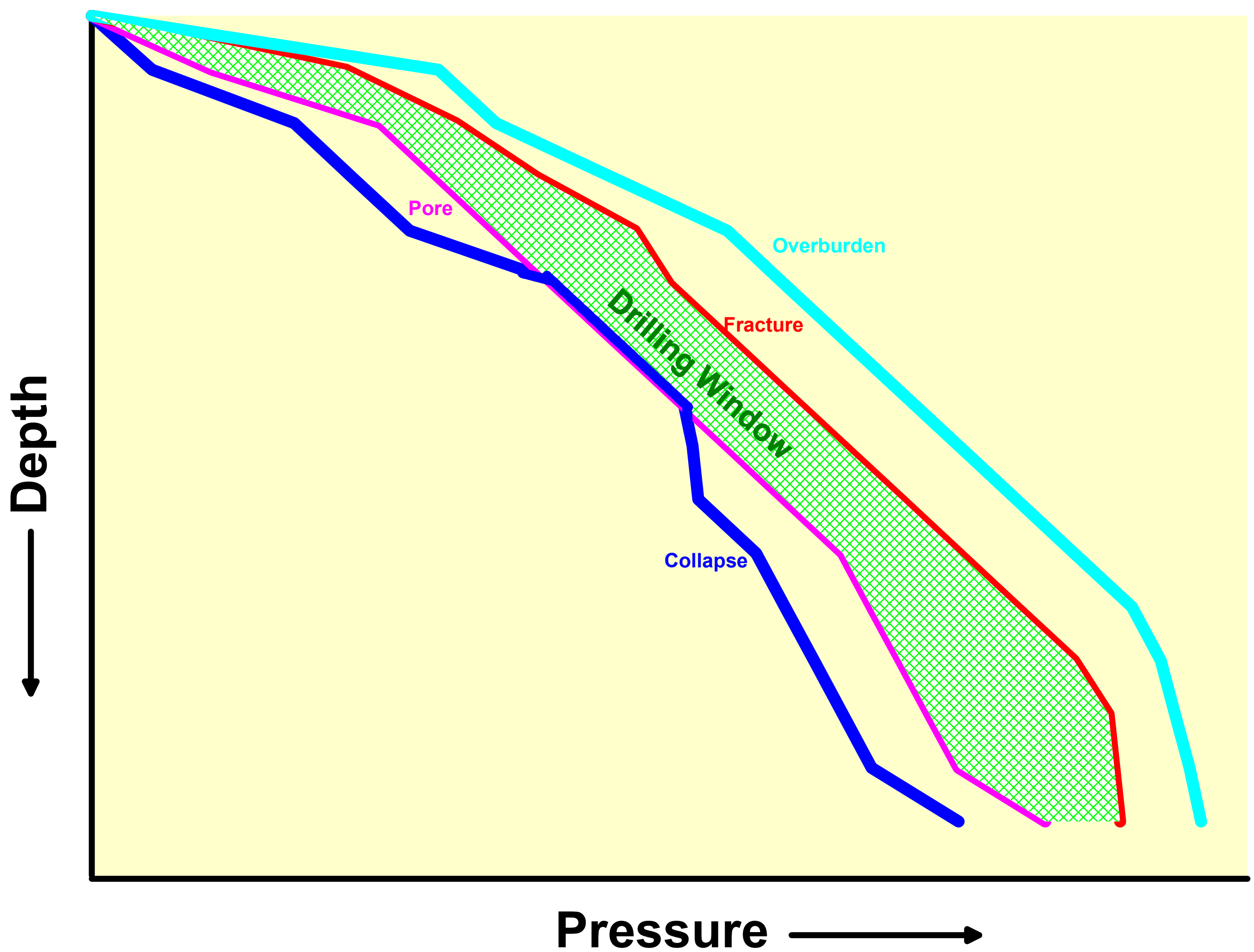


Figure 4.
Drilling Window where Collapse Pressure is Greater than or Equal to Pore Pressure

Drilling operations encroaching on the collapse pressure curve are likely to see large splinters of formation popping off into the wellbore, as opposed to cuttings created by the drill bit.

The mandate of productive drilling operations is to make hole and perform other essential operations contributing to completing the well, such as running casing, logging, and testing, etc. In an open vessel environment, drilling operations are often times subjected to repetitive kick – stuck - kick – stuck scenarios (Figure 5) that significantly contribute to non-productive time, an add-on expense to many drilling AFE's (Authorization for Expenditure). This non-productive time is often times protracted, causing the rig crew to deviate from their routine of making hole. The deviation from routine drilling operations can expose the rig personnel to unfamiliar circumstances and if not adequately trained may lead to less than safe practices.

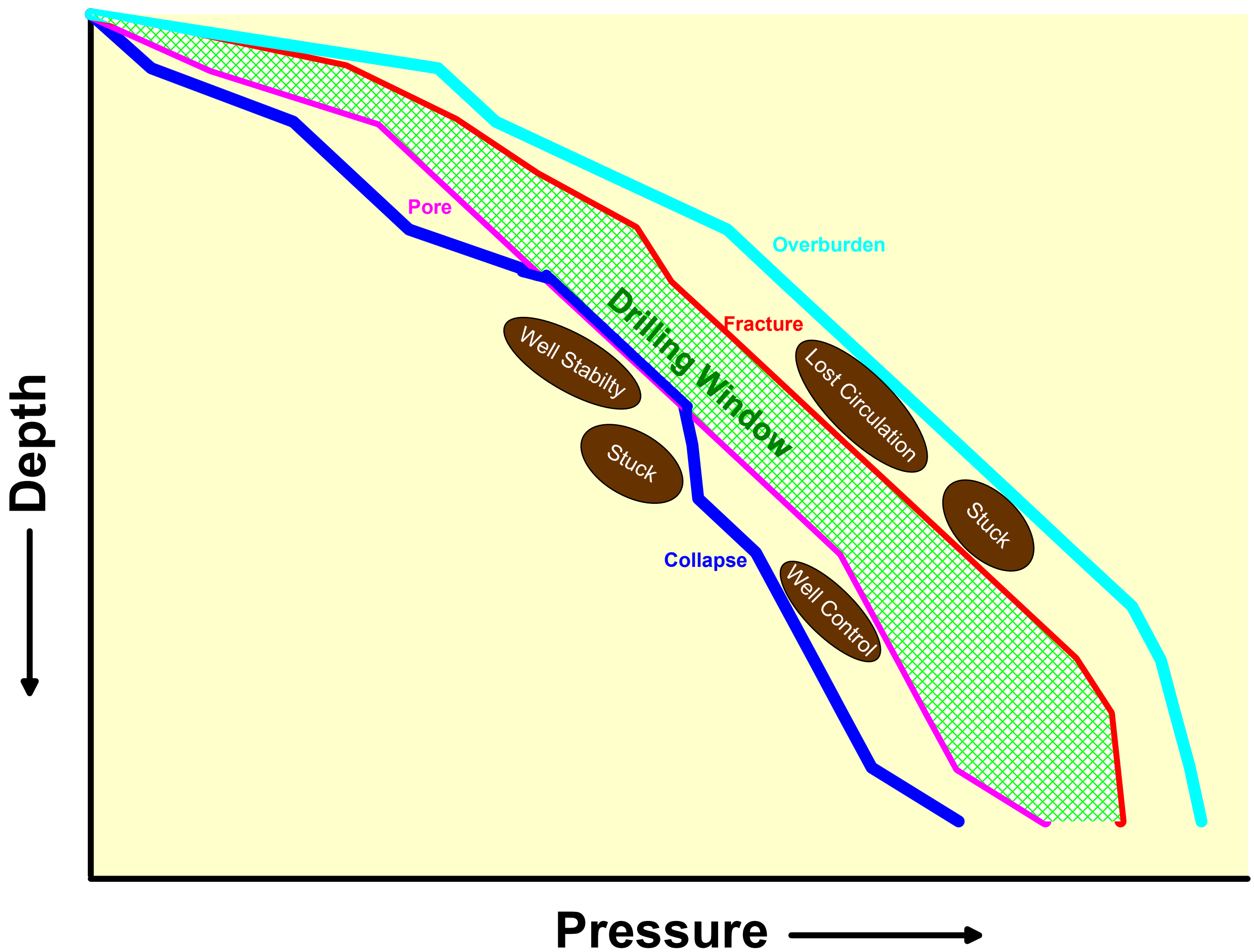


Figure 5.
Drilling Window where Collapse Pressure is Greater Than or Equal to Pore Pressure

Annular pressures cannot be adequately monitored in an open vessel unless and until the well is shut-in. Well control incidents during conventional drilling are predicated on increased flow, where precious time is often wasted pulling the inner bushings to “check for flow”. In that time the influx volume becomes larger. As the influx volume becomes larger, the kick often times becomes more difficult to manage. Management of the kick during conventional drilling operations requires that drilling cease and the well to be shut-in. While the influx volume is being circulated out of the wellbore and the drilling fluid is more adequately weighted to compensate for the increased bottomhole pressure, the hole is not being drilled and casing is not being run. The non-productive time is mounting, exposing time sensitive formations to drilling fluids that will cause other problems leading to increased non-productive time. The effects of non-productive time are iterative and expensive.

It is not unusual to successfully resolve a well control issue only to start losing mud and becoming differentially stuck. Many reservoirs today have such narrow drilling windows between the pore pressure and the frac gradient, that resolving one problem often times creates another, and resolution of that problem creates another, and so on until the cycle is broken with hydraulic balance or the well is abandoned. Once the well control incident is resolved and the hole has been filled with higher density drilling fluid, the stage is now set to have the hydrostatic pressure by itself or in concert with the annular friction pressure (caused by circulating drilling fluid with mud pumps) to breach the frac gradient pressure limit and flow into the exposed wellbore. There have been cases where the well is kicking during fishing operations because the bottom hole assembly is stuck. To add to the misery, the worst possible nightmare….the fishing operation is actually fishing for the original fishing tools.

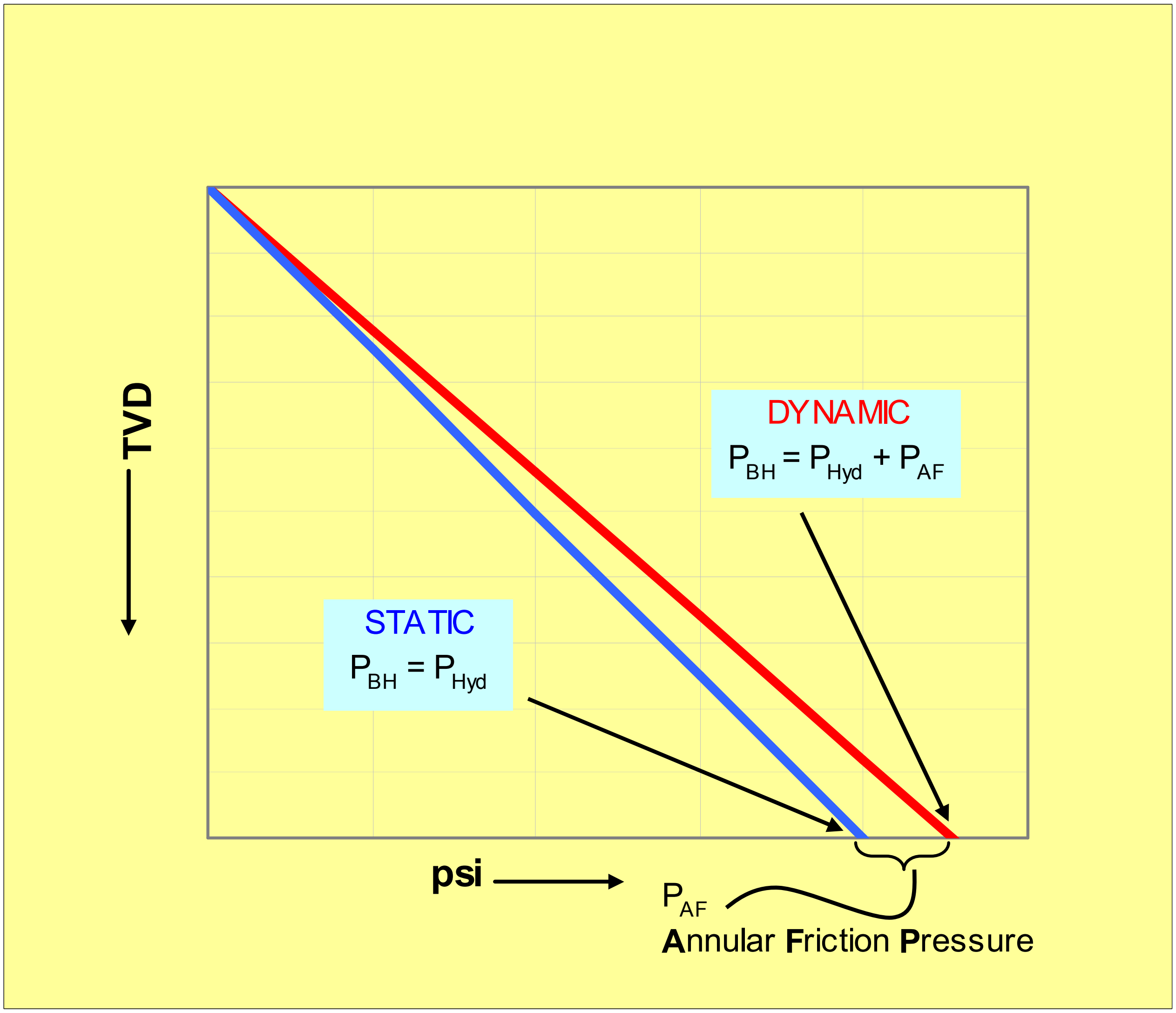


Figure 6.
Bottomhole Pressure Increases with Flow.

Friction Pressure is defined as the difference between the upstream discharge pressure and downstream suction pressure due to friction; the amount of energy lost between nodes depends on flow rate, pipe size, and fluid characteristics (Figure 4).

Continued loss of drilling mud to the formation not only damages future production potential, but could also lead to a well control issue. The loss of drilling mud in the wellbore will have to be replenished, otherwise as the (static) mud column in the annulus decreases in height the hydrostatic pressure throughout the wellbore decreases. The decreased height of the mud hydrostatic column sets the stage for a pressure imbalance between the hydrostatic mud column and the fluid contained in the exposed rock formation. Once the bottom hole pressure exceeds the hydrostatic pressure created by the static mud column, an influx of some magnitude will occur. Without intervention that influx can grow in volume to become a kick. Left unattended the kick can become a blow-out.

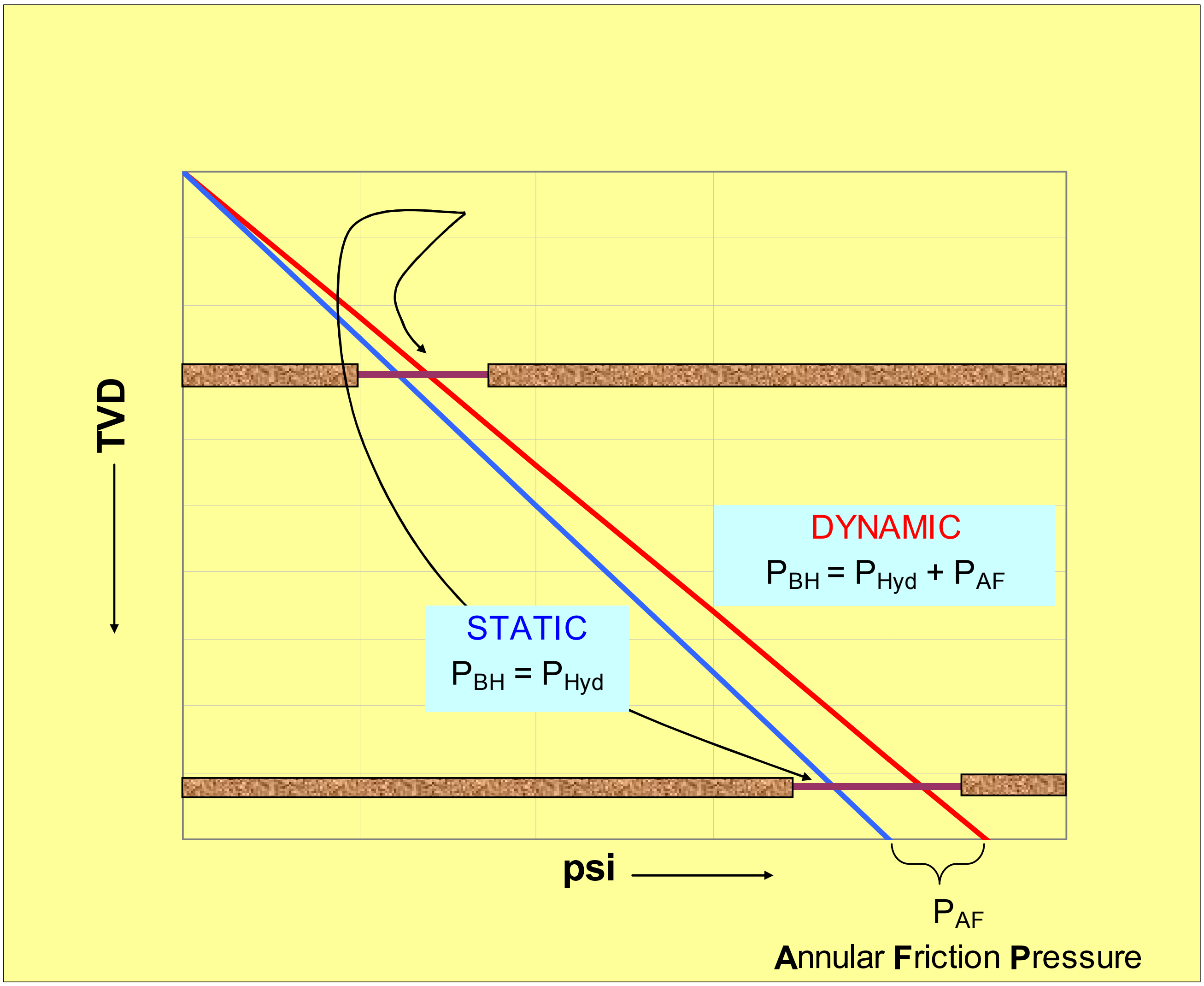


Figure 7.
Ideally, Static and Dynamic Pressures Are Within Formation Pressure and Fracture Pressure Windows.

Underbalanced Drilling

The origins of Managed Pressure Drilling (MPD) can be found in the utilization of a few specific technologies developed by its forbearer…Underbalanced Drilling. Underbalanced Drilling (UBD) is a drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface, P_{Hyd} is less than P_{BH}.

$$P_{Hyd} < P_{BH}$$

Underbalanced Operations (UBO) is a well construction or maintenance activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface.

In addition to improved rate of penetration, the chief objectives of underbalanced drilling are to protect, characterize, and preserve the reservoir while drilling so that well potential is not compromised. To accomplish this objective, influxes are encouraged. The influxes are allowed to traverse up the hole and are suitably controlled by three major surface containment devices.

- Rotating Control Device (RCD)
- Drilling Choke Manifold
- Multiple Phase Separator

If the well is being produced while drilling, the gas is either flared, recirculated, or send on to a gathering station for eventual sales. If the drilling is land-based, oil is typically stored in stock tanks.

Managed Pressure Drilling

Unlike Underbalanced Drilling, Managed Pressure Drilling (MPD) does not actively encourage influx into the wellbore.

Managed Pressure Drilling applications are driven by the very narrow drilling margins between formation pore pressure and formation fracture pressure downhole (Figure 5). The narrow margins are most pronounced in deepwater applications where much of the overburden is actually seawater (Figure 2). In such cases, it is not unusual to set numerous casing strings at shallow depths to avoid extensive lost circulation. More mature fields offer the challenges of depleted zones and pressure reversals that are technically difficult to drill.

The primary objectives of Managed Pressure Drilling are to mitigate drilling hazards and increase drilling operations efficiencies by diminishing non-productive time (NPT). The operational drilling problems most associated with non-productive time include:

- Lost Circulation

- Stuck Pipe
- Wellbore Instability
- Well Control Incidents

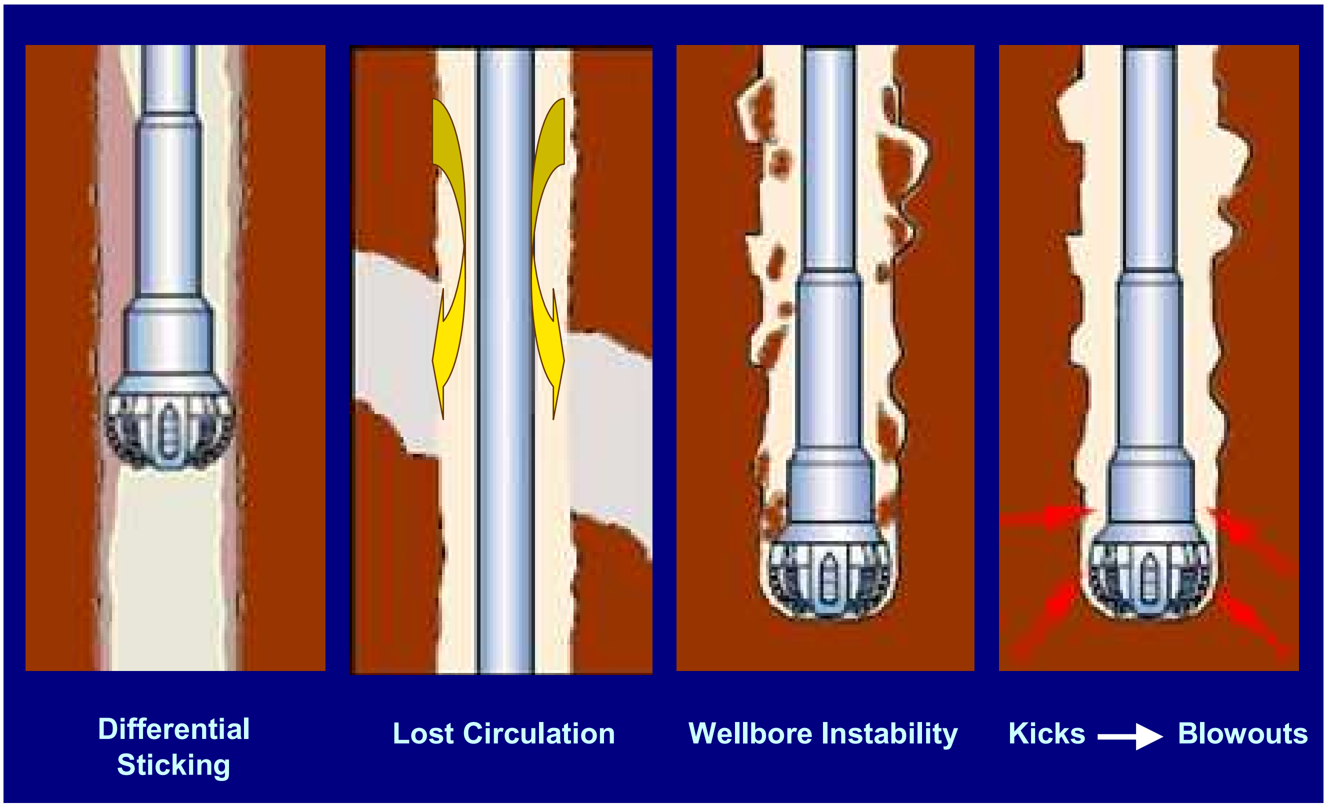
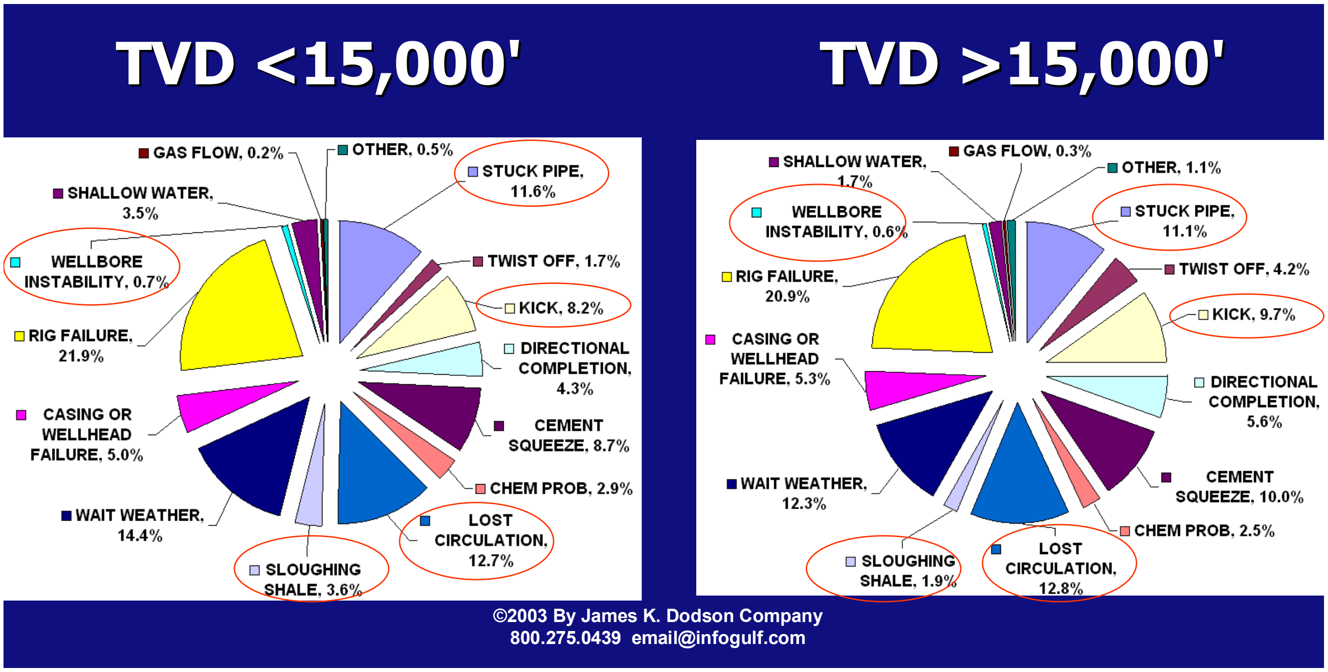


Figure 8.
Drilling Problems

These four categories have accounted for over a third of all non-productive time in the Gulf of Mexico, prior to Hurricanes Ivan, Katrina, and Rita (Figure 7).



Water Depth	<600 ft		<600 ft	
TVD	<15,000 ft		>15,000 ft	
Wells	549		102	
Average TVD	11,668 ft		17,982 ft	
Differentially Stuck Pipe	11.60%		11.10%	
Lost Circulation	12.70%		12.80%	
Well Instability	4.30%		2.50%	
Kick	8.20%		9.70%	
Trouble Subtotal	**36.80%**		**36.10%**	
Hole Problems (Drilling Days)	4264 / 17641	24%	1703 / 7680	22%
Cost Impact ($/ft)	71 / 291	24%	98 / 444	22%
Days to TD	8 / 32	25%	22 / 81	27%
ROP	116 / 363	32%	68 / 236	29%

Figure 9.

Problem Incidents for Deep Gas Wellbores Drilled from 1993 – 2002 in the Gulf of Mexico in water depth less than 600 feet. (Courtesy of James K. Dodson Company)

Managed Pressure Drilling Definition

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Managed Pressure Drilling is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. The intention of MPD is to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.

- **MPD process employs a collection of tools and techniques which may mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.**
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The centerpieces of the definition are rooted around the words “intent” and “precisely control”. The various technologies available today allow us to control maintenance of the bottomhole pressure from the surface within a range of 30 – 50 psi. One MPD method does not address all problems. Managed Pressure Drilling is application specific. The drilling engineer will have his choice of many options that will best address the drilling problems he confronts.

If the intent is to allow continuous influx to the surface then the operation is decidedly underbalanced drilling. While there are some similarities in equipment selection and similar training needs for personnel involved in the operation, Managed Pressure Drilling is not a “poor boy” version of Underbalanced Drilling. On the contrary, done properly, contingencies need to be explored requiring engineering forethought and planning. Managed Pressure Drilling systems readily connect to and enhance conventional drilling rig capabilities. Although the equipment footprint and outlay for Managed Pressure Drilling operations is typically not as extensive as Underbalanced Drilling, supplemental training for rig personnel is strongly encouraged.

The vast majority of Managed Pressure Drilling is practiced while drilling in a closed vessel utilizing a Rotating Control Device (RCD) with at least one drill string Non-Return Valve, and a Drilling Choke Manifold. Various manufacturers produce API monogrammed RCD's that conform to API Specifications 16RCD and Specifications for Non-Return Valves have recently been published as API Spec 7NRV. Manual controlled and microprocessor controlled chokes are available depending on the application. Presuming that the wellbore is capable of pressure containment, by sealing the wellbore, pressure throughout the wellbore can be better monitored at the surface on a real time basis. In a closed system, changes in pressure are seen immediately. By more precisely controlling the annular wellbore pressure profiles, detection of influxes and losses are virtually instantaneous. The safety of rig personnel and equipment during everyday drilling operations is enhanced. Drilling economics tend to improve by reduction of excessive drilling mud costs and reduction of drilling related non-productive time.

The Constant Bottomhole Pressure Method, the Mud Cap Method, Casing Drilling, ECD Reduction and the Dual Gradient Method are but a few of numerous proactive variations on a theme, where the theme is manipulation of the wellbore pressure profile to diminish or eliminate chronic drilling problems. Many drilling problems can be directly attributed to hydraulics.

Drilling Hydraulics

In conventional drilling practices, the hydrostatic pressure (P_{Hyd}) created by the density of the static mud column together with the circulating annular friction pressure (P_{AF}) controls the Bottomhole Pressure (P_{BH}).

$$P_{BH} = P_{Hyd} + P_{AF}$$

When the mud pumps are shutdown to make a connection, the annular friction pressure is zero; leaving the BHP to be controlled by the hydrostatic column of mud alone. Should the P_{BH} be greater than the hydrostatic pressure, an influx of hydrocarbons can enter the wellbore. The kick must then be circulated out of the hole with kill mud typically at a slow pump rate. The slow pump rate minimizes the influence of annular friction pressure during the kill procedure while the higher density mud increases the hydrostatic pressure, so that after circulating out the kick the hydrostatic pressure of the mud column balances the bottomhole pressure without the influence of the annular friction pressure (Figure 5).

Wellbore Stability and Drilling Hydraulics

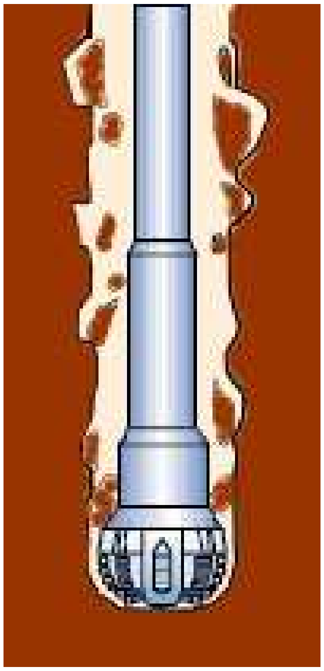


Figure 10.

Wellbore instability (P_{WBS}) occurs when the hydrostatic pressure of the mud column is insufficient to maintain wellbore wall competency. The formation sloughs off in sheets or pops off the wall as splinters.

$$P_{WBS} > P_{Hyd}$$

or

$$P_{WBS} > P_{Hyd} + P_{AF}$$

Another mechanism for well bore instability is the intermittent exposure of the formation to a pressure cycle cause by starting and stopping the mud pumps. This standard operating practice is concomitant to drill ahead and make connections. Depending on the formation porosity and permeability, this cycle tends to pressure charge the rock formation and then discharge the pressure. This pressure cycle stresses and then relaxes the formation, inducing fatigue to the in-situ stresses that have already been partially relieved by the creation of the wellbore. With the formation weakened the environment is conducive for the rock formation to slough off into the hole.

Wellbore instability may cause the drill string to become stuck by packing off the wellbore from collapse of the formation.

Differential Sticking and Drilling Hydraulics

Figure 11.

Overbalance is probably the most influential of all the factors that contribute to differential sticking of the drill string, where the wellbore pressure created by the mud hydrostatic column is greater than the formation pressure. As the mud filter cake is laid down against a permeable formation a thin lubricating layer acts as a boundary layer between the pipe and the filter cake. As the movement of the pipe slows or stops that lubricating boundary layer is displaced and the pipe lays up against the filter cake. The filtrate within the filter cake drains out in the area of contact. A differential pressure (ΔP) between the wellbore pressure (P_{Hyd}) and the reduced pressure of the filtrate within the pore spaces of the filter cake develops.

Differential Force = Δ Pressure x Contact Area

Lost Circulation and Drilling Hydraulics

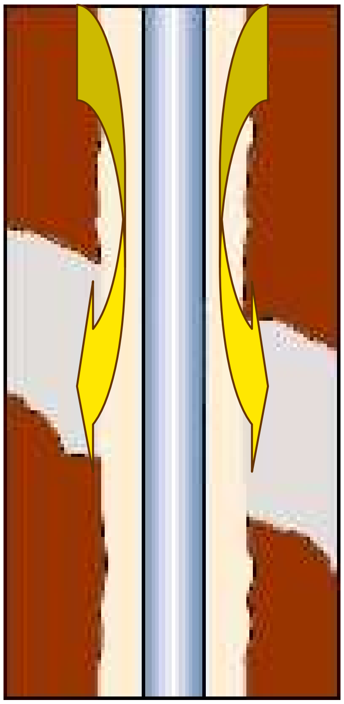


Figure 12.

Overbalance is the chief cause of lost circulation where the wellbore pressure exceeds the fracture pressure (P_{Frac}) of the formation (Figure 6).

$$P_{Hyd} > P_{Frac}$$

or

$$P_{Hyd} + P_{AF} > P_{Frac}$$

Well Control Incidents and Drilling Hydraulics

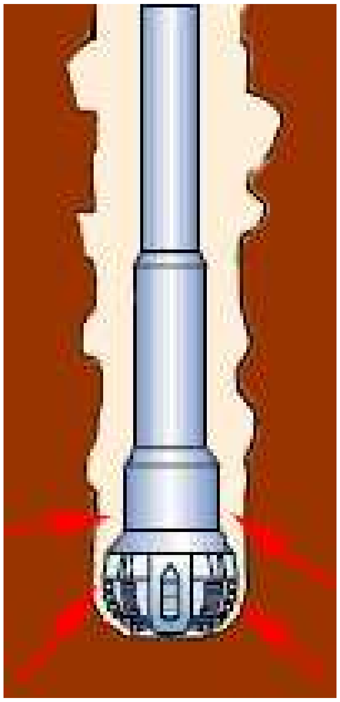


Figure 13.

Well control incidents develop from the wellbore being underbalanced with respect to a producing formation.

$$P_{BH} > P_{Hyd}$$

However, drilling in overbalanced conditions can create an environment where an influx can enter the wellbore. Continued loss of drilling mud to the formation not only damages future production potential, but could also lead to a well control issue. The loss of drilling mud in the wellbore will have to be replenished, otherwise as the (static) mud column in the annulus decreases in height the hydrostatic pressure throughout the wellbore decreases. The decreased height of the mud hydrostatic column sets the stage for a pressure imbalance between the hydrostatic mud column and the fluid contained in the exposed rock formation. Once the bottom hole pressure exceeds the hydrostatic pressure created by the static mud column, an influx of some magnitude will occur.

Another circumstance would be that well stability issues contribute to a pack-off around the bit or bottom hole assembly. While picking up off bottom an influx can be swabbed into the wellbore because of the localized differential pressure created by the piston effect of the upward movement of the packoff.

In both cases, without intervention that influx can grow in volume to become a kick. Left unattended the kick can become a blow-out and control of the well will be lost.

In many Managed Pressure Drilling applications, the wellbore is closed and able to tolerate pressure. With this arrangement, P_{BH} can be better controlled with imposed backpressure (P_{Back}) from an incompressible fluid in addition to the hydrostatic pressure of the mud column and annular friction pressure.

$$P_{BH} = P_{Hyd} + P_{AF} + P_{Back}$$

Managed Pressure Drilling

MPD Definition Revisited

The preceding chapter describes three different drilling applications.

1. Conventional Drilling
2. Underbalanced Drilling
3. Managed Pressure Drilling

The intent of Managed Pressure Drilling is to avoid continuous influx of formation fluid to the surface. Additionally, any influx incidental to the operation will be safely contained using an appropriate process.

It is also the intent of Conventional Drilling to avoid continuous influx of formation fluid to the surface. In a Conventional Drilling operation, an influx is typically called a kick. They have historically been called kicks because of the large volume potential allowed into the wellbore. A kick is an unplanned, unexpected influx of liquid or gas from the formation into the wellbore, where the pressure of fluid in the wellbore is insufficient to control the inflow. If not corrected, a kick can result in a blowout.

When a kick is encountered, the well is shut-in and the kick is circulated out using either the Driller's Method or the Wait-Weight Method. In short, the mud density in the wellbore is increased to control the bottom hole pressure so that

$$P_{Hyd} \geq P_{BH}$$

Because Underbalanced Drilling encourages influx to the surface, Managed Pressure Drilling is more closely aligned with the wellbore hydraulic pressure objectives of Conventional Drilling. The chief difficulty with Conventional Drilling is that the well is controlled because the hydrostatic wellbore pressure is typically in excess of the bottom hole pressure.

$$P_{Hyd} \geq P_{BH}$$

When the mud pumps are engaged and mud is flowing in the wellbore, annular friction pressure added to the overbalanced hydrostatic pressure makes matters worse. The risk of lost circulation and all the problems that follow rises dramatically.

$$P_{Hyd} + P_{AF} >> P_{BH}$$

Just like Conventional Drilling, the intent of Managed Pressure Drilling is to drill along a path within the drilling window without encroaching the pore pressure/well stability line on the left and the frac gradient line on the right (Figure1). Another way to describe the relationship is:

$$P_{WBS} \leq P_{PP} \leq P_{Hyd} < P_{DS} \leq P_{LC} \leq P_{Frac}$$

Where:
P_{WBS} is Wellbore Stability Pressure
P_{PP} is Pore Pressure
P_{Hyd} is Hydrostatic Wellbore Pressure
P_{DS} is Differential Sticking Pressure
P_{LC} is Lost Circulation
P_{Frac} is Formation Fracture Pressure

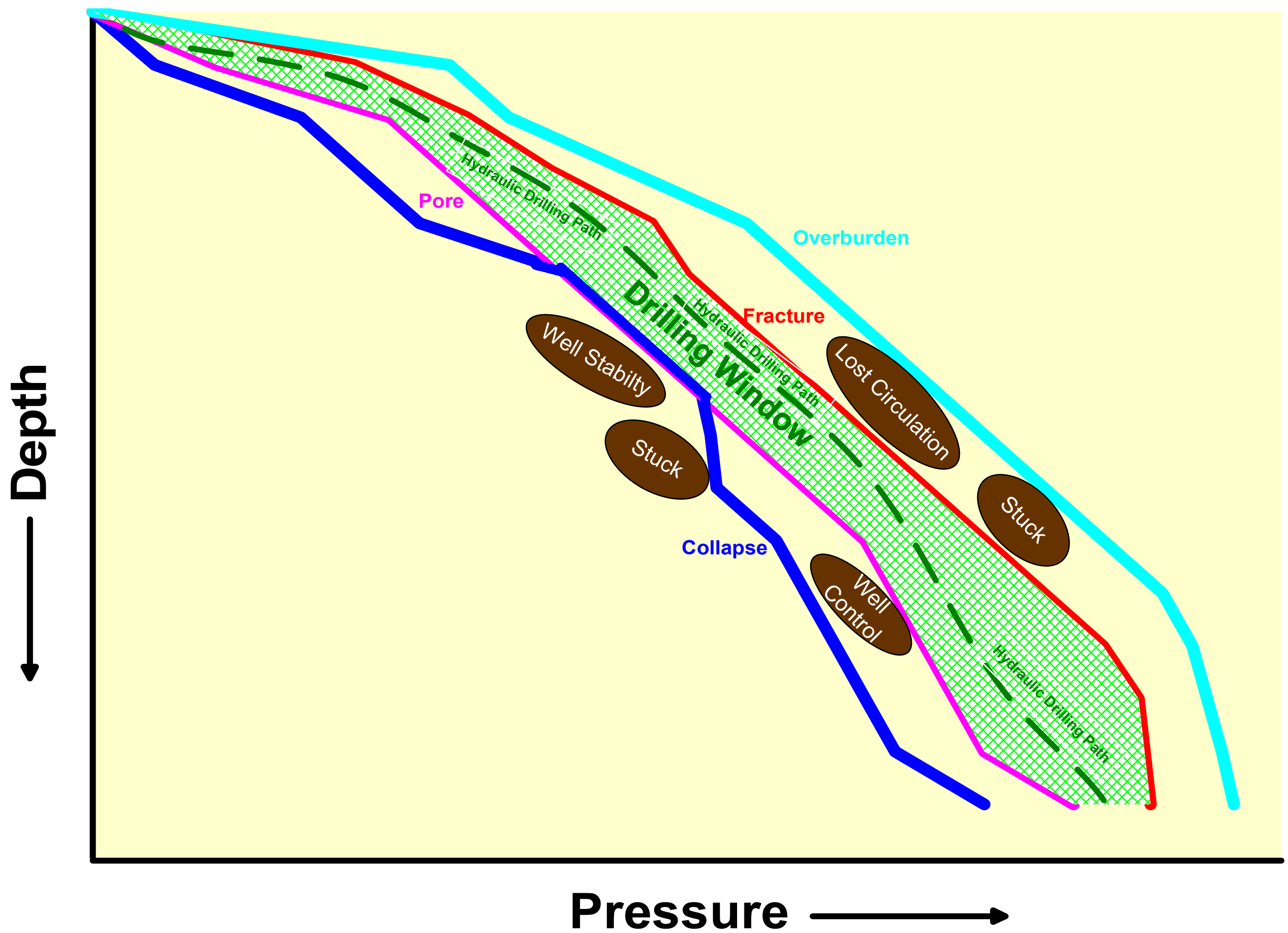


Figure 1.
Projected Hydraulic Drilling Path within the Drilling Window between the Pore/Collapse Pressure and the Fracture Pressure

Managed Pressure Drilling is not a “dumbed down version of Underbalanced Drilling” nor is it a “po’ boy” version of Underbalanced Drilling. It is a method in it own right and in a class by itself. It requires significant planning and control of the bottomhole pressure requires more precision. Where Underbalanced Drilling mainly concerns itself with the well stability pressure curve. Managed Pressure Drilling must stay within the bounds of the well stability pressure curve, the pore pressure curve, and the fracture pressure curve.

Well control is always maintained and is actually more vigilantly maintained compared to Conventional Drilling operations where minute pressure influxes are instantaneously measured in a closed vessel environment in real time.

Drilling fluid (mud) is still the primary pressure barrier. An influx within a Managed Pressure Drilling Application is just that….an influx. The influx (usually tiny) is circulated out in the Driller's Method. In terms of magnitude, a kick is an influx that exceeds the working limits of the rig's surface control measures. Once the surface control measures are breached a well control incident ensues. The drilling operation becomes a well control issue and operation.

Equipment

Managed Pressure Drilling requires a certain minimum of equipment. That equipment list is dependent upon the MPD application and by what means the annular pressure is going to be controlled.

- Pressure manipulation
    - Direct pressure application
    - Annular pressure reduction
- Flow manipulation

The vast majority of Managed Pressure Drilling is practiced while drilling in a closed vessel utilizing a Rotating Control Device (RCD) with at least one drill string Non-Return Valve, and a Drilling Choke Manifold. Various manufacturers produce API monogrammed RCD's that conform to API Specifications 16RCD and Specifications for Non-Return Valves have recently been published as API Spec 7NRV.

Manual controlled and microprocessor controlled chokes are available depending on the application. Presuming that the wellbore is capable of pressure containment, by sealing the wellbore, pressure throughout the wellbore can be better monitored at the surface on a real time basis. In a closed system, changes in pressure are seen immediately. By more precisely controlling the annular wellbore pressure profiles, detection of influxes and losses are virtually instantaneous.

Rotating Control Device

The location for the RCD is most typically atop the annular preventer. The RCD is not intended to replace the Blowout Preventer stack as a primary well control device, but only as a supplement to the BOP stack to give it more range and flexibility. The size and design of the Rotating Control Device for a specific drilling operation is application driven, including:

- Rig substructure geometry
- Seal elements
    - Single
    - Dual
- Pressure rating
    - Static

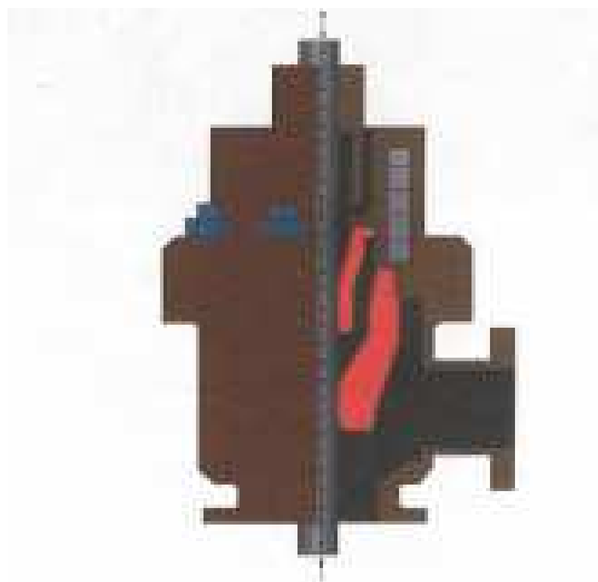
    - Dynamic
- Flange connections
- Operator preference

Aside from a workover stripper head, there are four basic types of Rotating Control Devices.

- Single element
- Dual element
- Rotating Annular Preventer
- Rotating Blowout Preventer

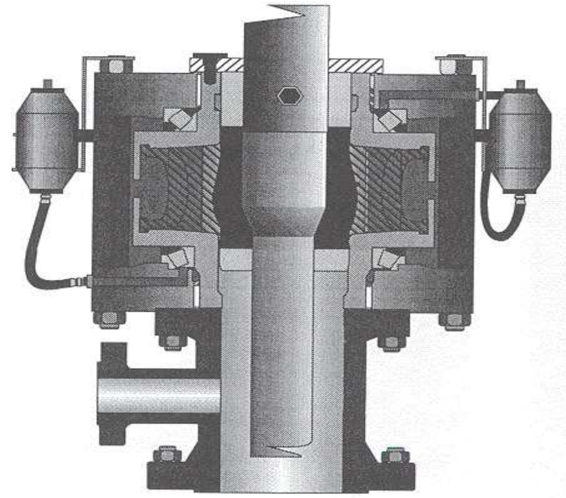
API Specification 16RCD describes manufacturing and testing specification for these devices. Rotating Control Devices for land, jack-up, and barge drilling operations can have 2,500 psi capability for rotating and stripping, and is rated at 5,000 psi in the static mode. With light density annular fluids, the RCD can routinely maintain pressure differentials in excess of 1,000 psi. Most operations are performed within a lower pressure differential range between 200 – 300 psi.

Single Element RCD



Dual Element RCD

Pressure Control While Drilling
Rotating Annular Preventer



Rotating BOP

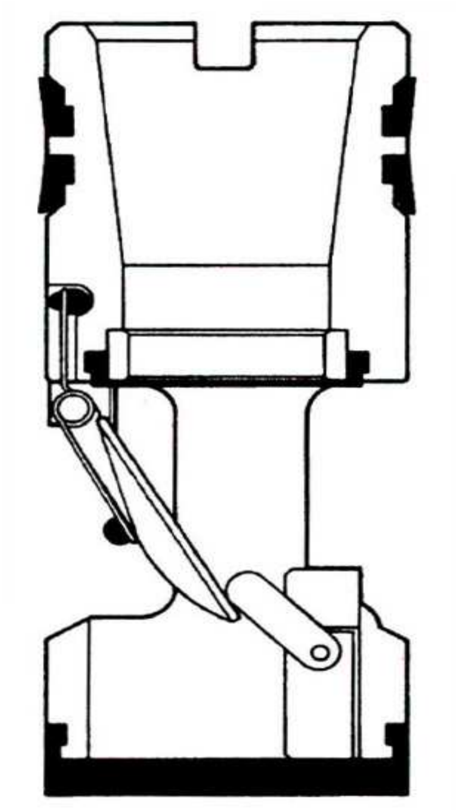
While many Rotating Control Devices are rated to 3,000 psi or more, some of the reasons to maintain a 200 – 300 psi pressure differential across the RCD for Managed Pressure Drilling operations include:

- Faster well control reactions
- Longevity of RCD elastomers
- Floating rig issues
    - Subsea BOP stack
        - Riser telescopic slip joint on surface

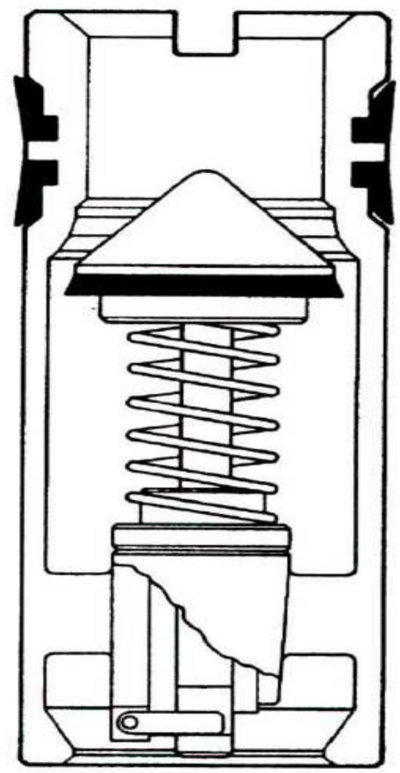
On floating rigs, the riser slip-joint is used to accommodate rig heave. The RCD has replaced this function but the telescopic slip joint remains in use because the riser attachment points and other functional utilities are typically housed or attached on this joint. With a mud cross and the RCD atop an adapter to the flex joint, the flex joint is set in the collapsed and locked position. With a maximum pressure rating of 500 psi, this becomes the weakest pressure point in the riser. Slip joint packers can be energized to provide redundancy with a lowered risk of failure due to the lack of movement. Additionally, the outer barrel locks contribute to loading capacity when the annulus is pressurized.

Non-return Valve

Non-return valves described in API Specification 7NRV describes drill string valves that prevent retrograde flow up the drill string. There are numerous models. Some are pictured below.



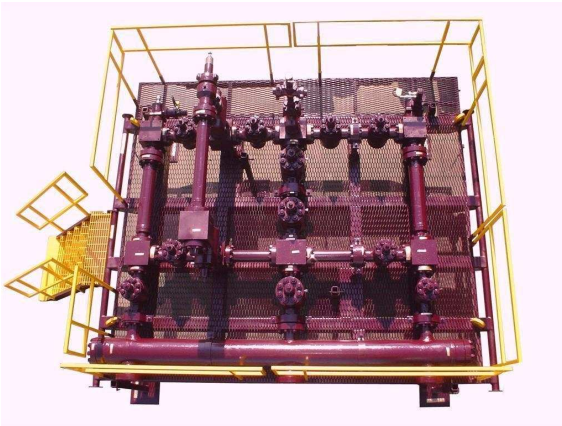
Flapper Type



Plunger Type

Drilling Choke Manifold

The full time use of the rig choke manifold to control the annular pressure profile while drilling ahead is not recommended. The rig choke manifold should be reserved for well control incidents. A well-designed, dedicated, and fit-for-purpose drilling choke manifold offers functionality and sufficient redundancy for safe drilling operations. Choke control can be manual, automated, or semi-automated; each with various degrees of interaction with a hydraulics model and human interaction.



Rig Choke Manifold

Drilling Choke Manifold

Optional equipment

Optional equipment can often enhance the various techniques. Using the appropriate tools, drilling within the confines of the Drilling Window enables one to "Walk the Line" while making hole between the pore pressure and frac pressure without inviting influx or losing returns.

- Microprocessor control
- Back pressure pump
- Downhole isolation valve
- Flowmeters
    - Coriolis
    - Paddle
    - Turbine
- Phase separators
- Downhole Pressure While Drilling tool

Methods of Managed Pressure Drilling

Reactive MPD

There are two basic approaches to utilizing MPD – Reactive and Proactive. Reactive MPD uses Managed Pressure Drilling methods and/or equipment as a contingency to mitigate drilling problems as they arise. Typically, the well is planned conventionally and MPD equipment and procedures are activated during unexpected developments.

Utilizing a Rotating Control Device (RCD) alone does not necessarily constitute Managed Pressure Drilling Operations. A Rotating Control Device is an excellent supplemental safety device and adjunct to the BOP Stack above the Annular Preventer. Although many Rotating Control Devices are rated to 3000 psi, used alone without other ancillary equipment, it is at best a highly effective reactionary tool that could be used to safely mitigate the presence of hydrocarbons escaping from the wellbore to the rig floor. This method is sometimes described as the Health Safety Environmental (HSE) variation. As additional equipment and know-how are added, the operation becomes more and more proactive.

Proactive MPD

Proactive MPD uses Managed Pressure Drilling methods and/or equipment to actively control the annular pressure profile throughout the exposed wellbore. This approach utilizes the wide range of tools available to better control placement of casing seats with fewer casing strings, better control of mud density requirements and mud costs, and finer pressure control to provide more advanced warning of potential well control incidents. All of which lead to more time drilling and less time spent in non-productive activities. In short, Proactive Managed Pressure Drilling…

- Drills the Operationally Challenged
- Drills the Economically Challenged
- Drills the “Undrillable”

Variations of Managed Pressure Drilling

Various techniques are utilized to accomplish these objectives. These variations are sometimes described as:

- Constant Bottom Hole Pressure
- Mud Cap
    - Floating
    - Pressurized
- Casing Drilling
- Dual Gradient Drilling
- Riserless Drilling
- Continuous Flow
- ECD Reduction

These methods, each in their own way, complement the conventional elements required to successful drill a well:

- Safety
    - Well Control

    - Extend the range of control of bottomhole pressure while drilling
    - Extend the range of control of bottomhole pressure during non-drilling phases
- Better control of wellbore stability
- Offer better production potential from less damage from mud filtrate and lost circulation

Prospects that were once impossible to drill are now being re-evaluated. Each of these techniques and their rationale will be described briefly. For more in-depth information the reader is encouraged to seek more detailed data in the MPD Toolbox, periodic publications, textbooks, engineering consultant firms, and vendors of these services.

Variations of MPD

Constant Bottomhole Pressure Method - Drilling

While the name Constant Bottomhole Pressure Method implies control of the bottomhole pressure at the bottom of the hole, its actual objective is to control the most troublesome pressure anomalies within the exposed wellbore. Typically for this method, the drilling fluid is lighter than "normal" to the point where the hydrostatic column is actually statically underbalanced. During drilling, influx is avoided with the increase in annular frictional pressure from pumping.

$$P_{Hyd} + P_{AF} = P_{BH}$$

During connections, influx is controlled either by imposing backpressure or by trapping pressure in the wellbore.

$$P_{Hyd} + P_{Back} = P_{BH}$$

or

$$P_{Hyd} + P_{Trap} = P_{BH}$$

In each of these cases the desire is to maintain the bottomhole pressure constant by replacing the annular friction pressure with an equivalent backpressure or annular trapped pressure.

$$P_{AF} = P_{Back} = P_{Trap}$$

A typical comfort level is between 200 – 300 psi; well below the pressure ratings for RCD tools. As the imposed backpressure becomes higher, the circulating mud density is often increased to keep the backpressure within comfortable limits.

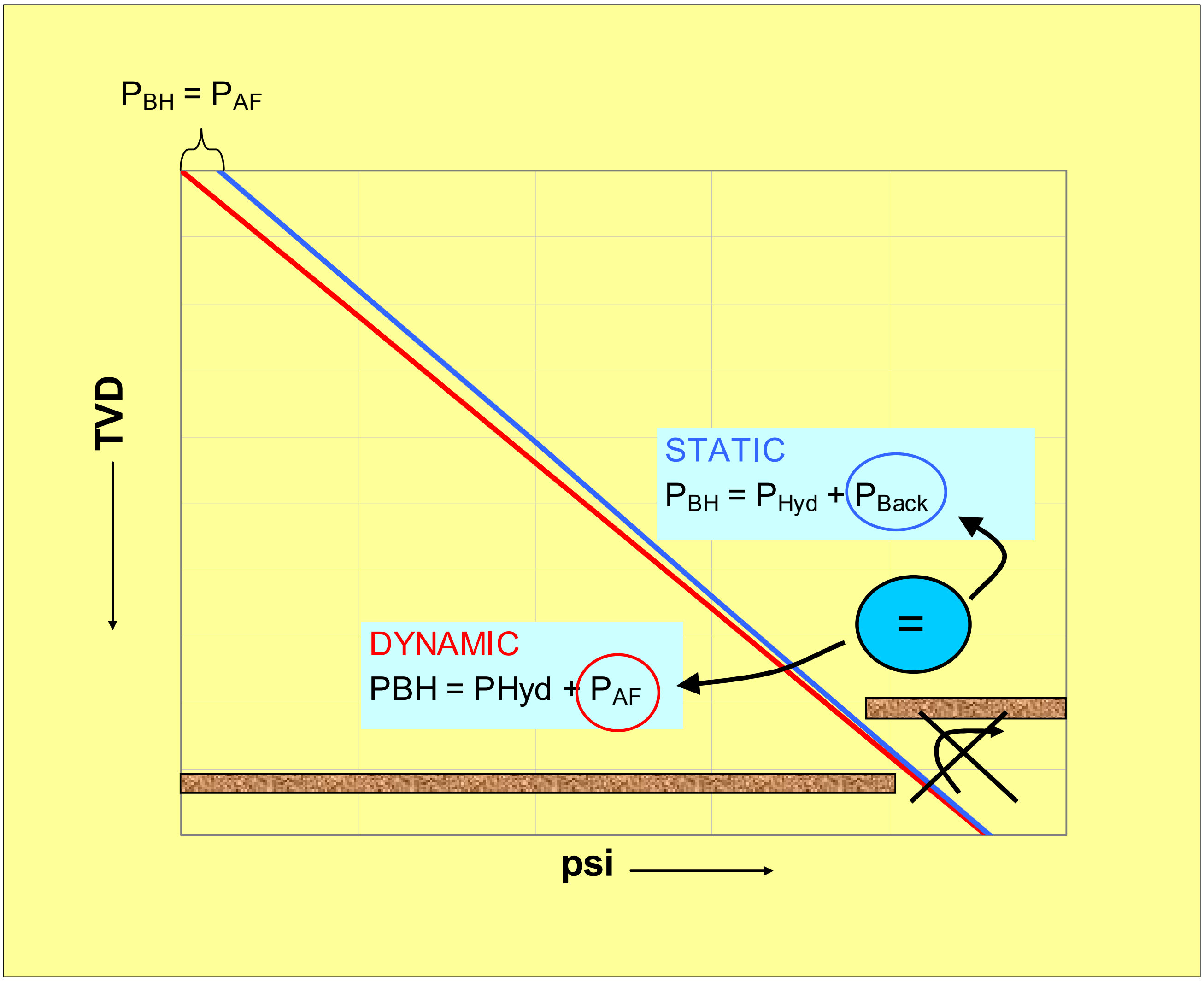
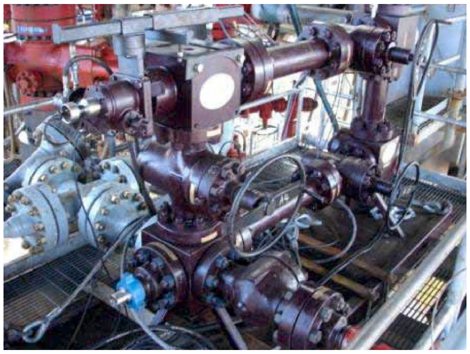
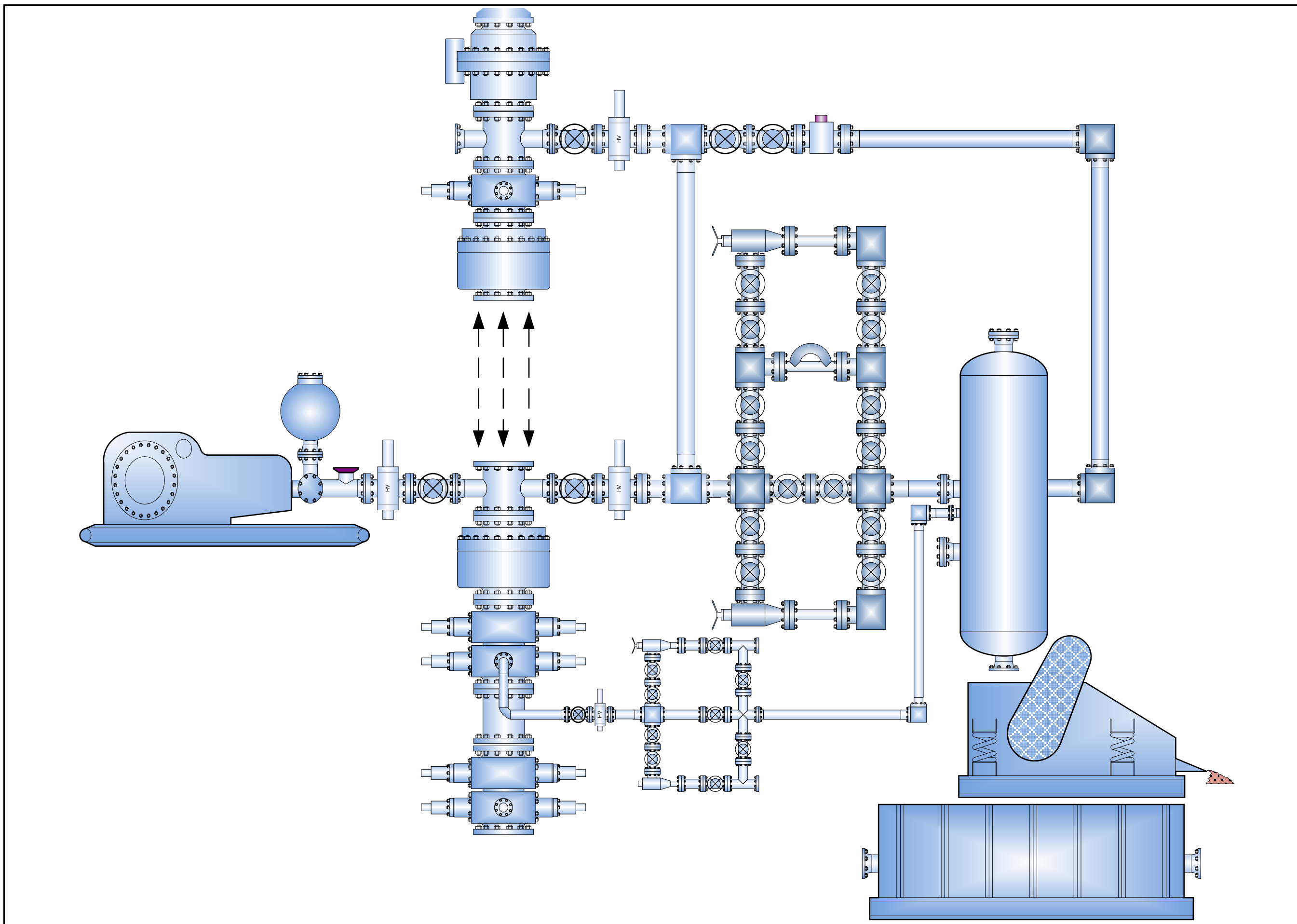


Figure 7.
Constant Bottomhole Pressure Variation of MPD Uses Lower Density Drilling Fluid And Imposes Back-Pressure When Static.



@Balance Drilling System

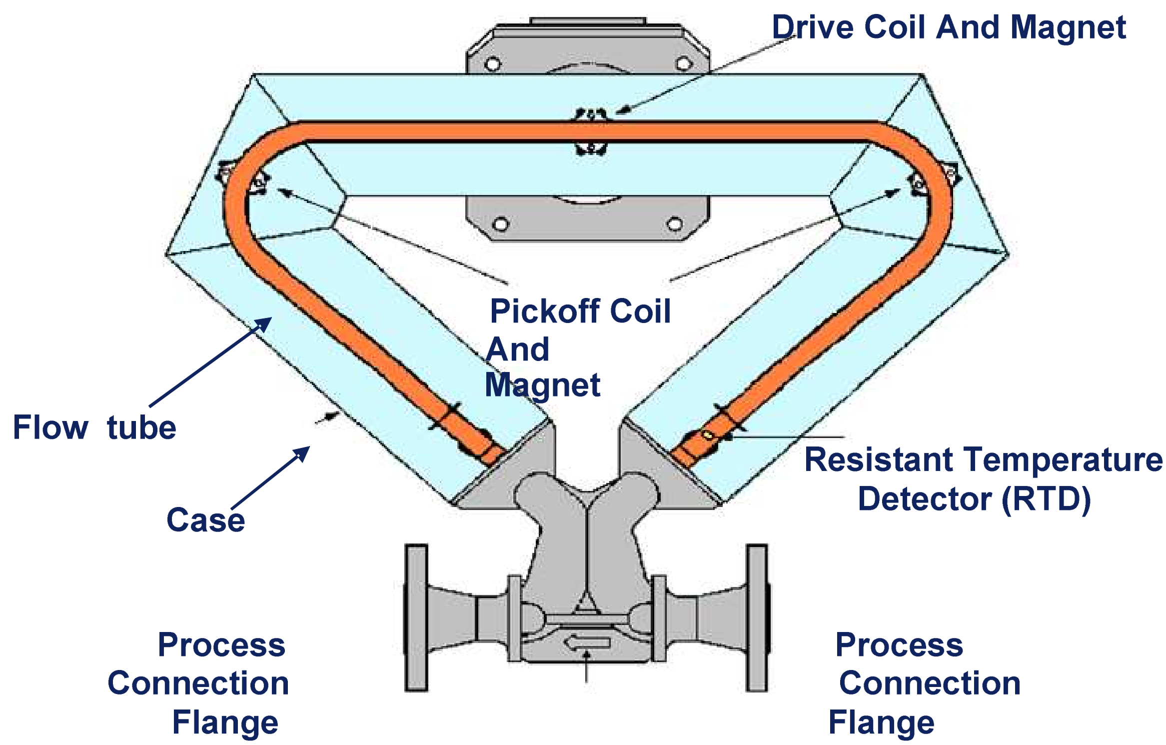
Secure Drilling System



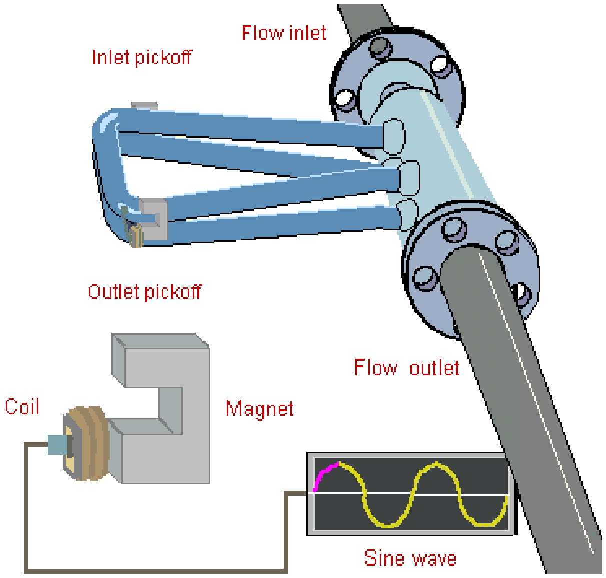
Generic Surface Equipment

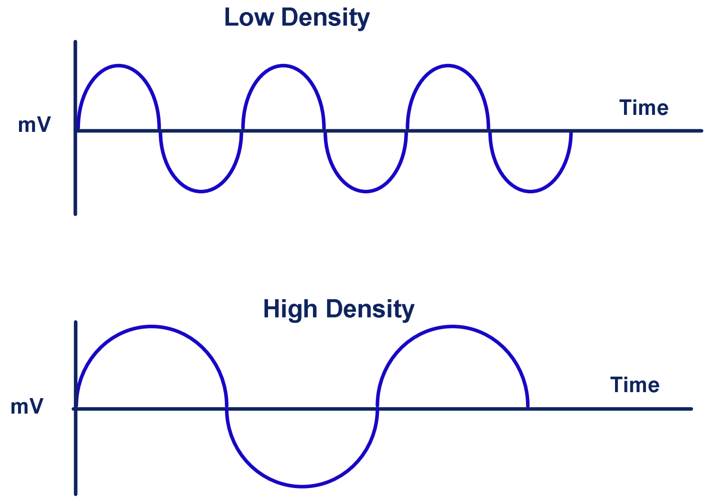
Coriolis Mass Flowmeter

Density of the drilling fluid is measured by a Coriolis Mass Flowmeter. A Coriolis meter works by oscillating a flow tube rapidly. By measuring the time it takes to complete one oscillation (wave period), the fluid density can be accurately determined directly with great precision. Since the oscillations happen in the range of tens of thousands per second, it does not take more than an instant to sense the change in fluid density. Coriolis meters have accuracies as precise as a few ten-thousandths of a gram per cubic centimeter. This measurement system is a mature technology that delivers such accuracy, responsiveness, and reliability that has been utilized by the process industries for many years.



Note: Second flow tube is not visible in this view



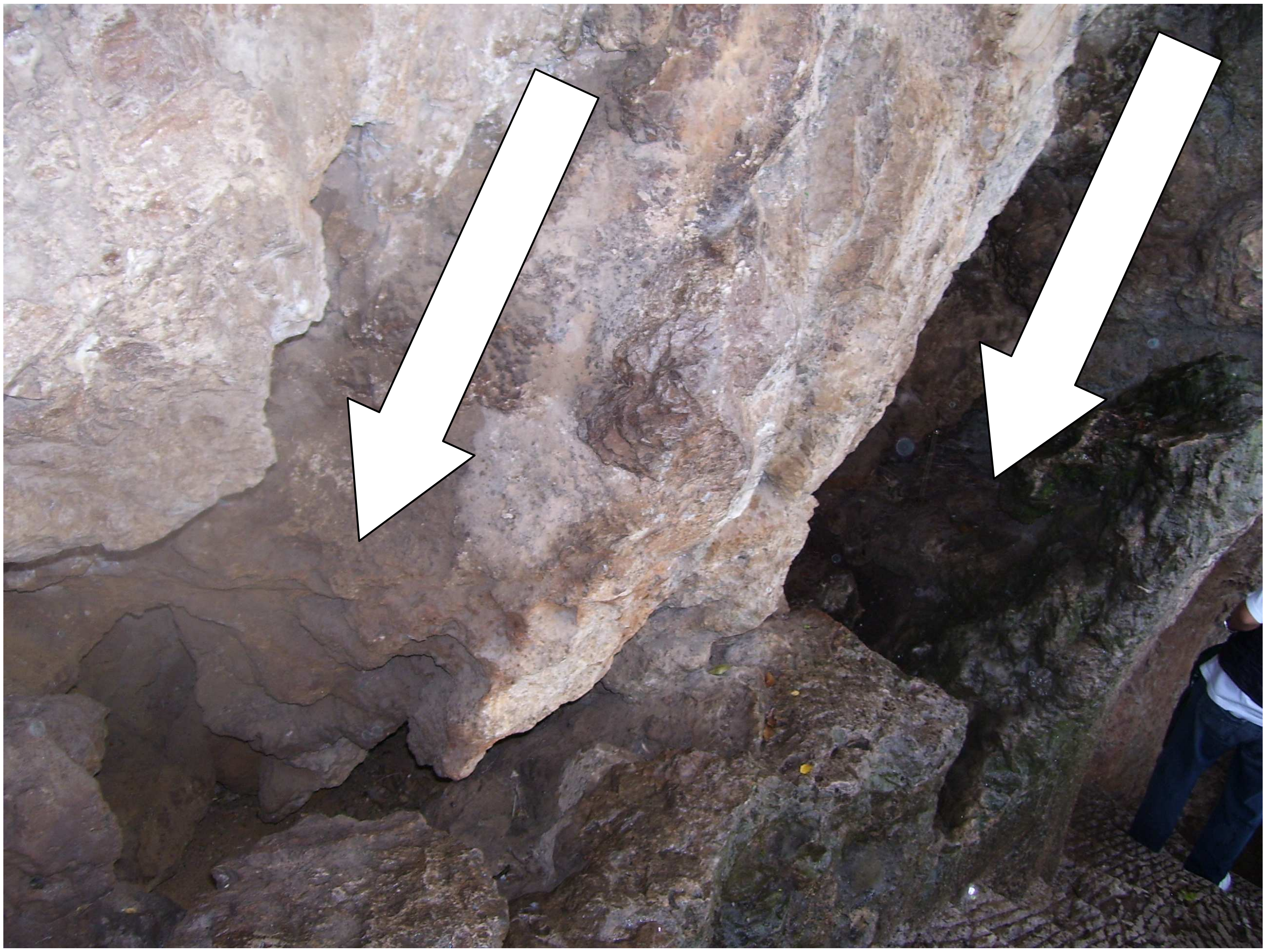


As the density increases the tube oscillation period increases

Constant Bottomhole Pressure Method - Tripping

When the drill pipe is tripped out of the hole a weighted mud slug can either be pumped as a pill to balance the bottom hole pressure or additional weighted mud can be circulated around to compensate for the loss of backpressure when the bottom hole assembly is out of the hole. This is often done in a measured “stair-step” manner.

Mud Cap Method

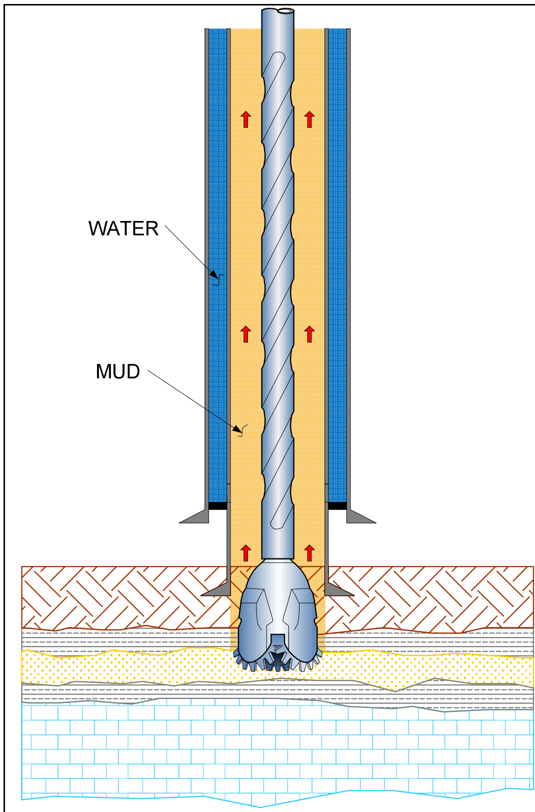
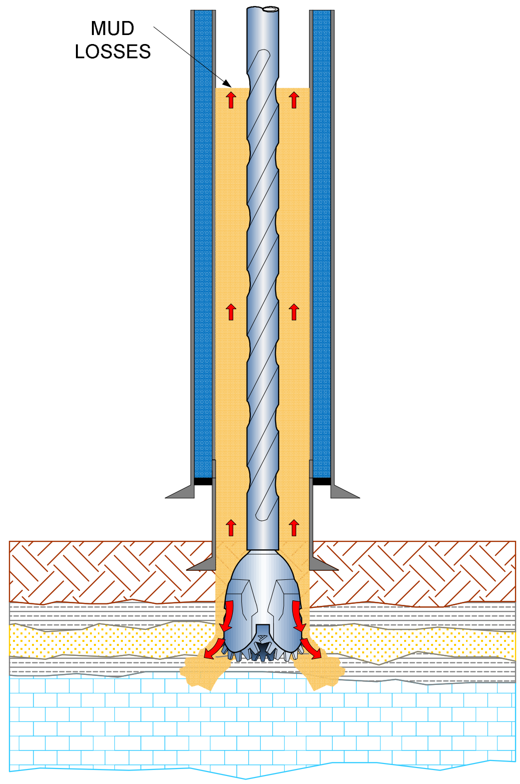


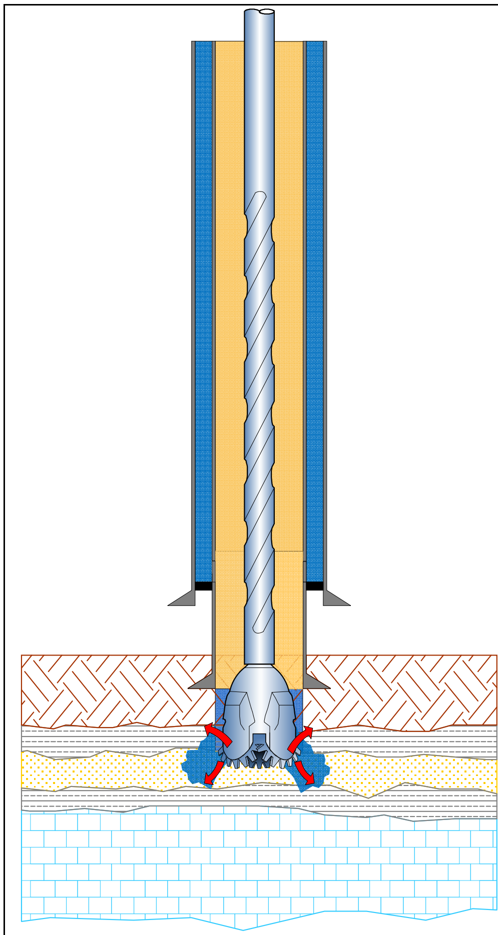
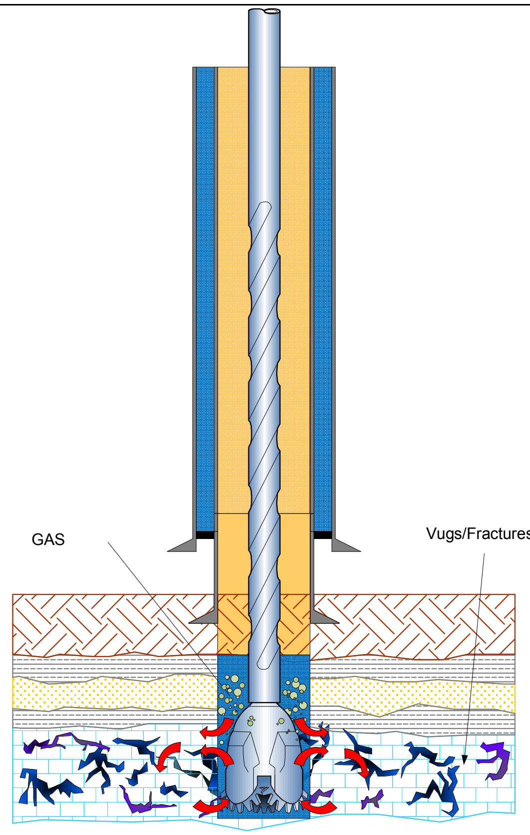
Photograph 1.
Natural dolomite outcrop outside of Kunming, China. Photo illustrates expansive and cavernous "wormholes" capable of creating massive lost circulation. This photo also demonstrates how the cuttings can be discharged with seemingly endless capacity.

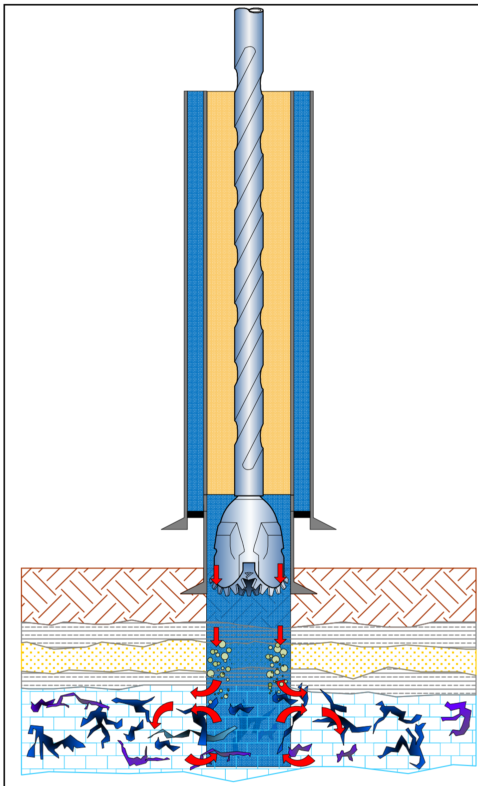
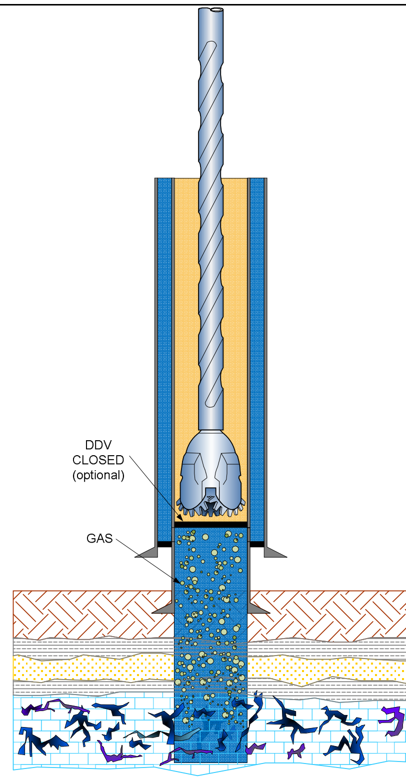
This method also addresses lost circulation issues, but in another manner using two drilling fluids. A heavy, viscous mud is pumped down the backside in the annular space to some height. This "mud cap" serves as an annular barrier, while a lighter, less damaging, and less expensive fluid is used to drill into the weak zone. Improved rate of penetration (ROP) would be expected using the lighter drilling fluid because of more available hydraulic horsepower and less chip hold-down. The less-expensive sacrificial mud and cuttings are pumped away into the depleted zone below the last casing shoe, leaving the heavier mud in the annulus as a "mud cap".

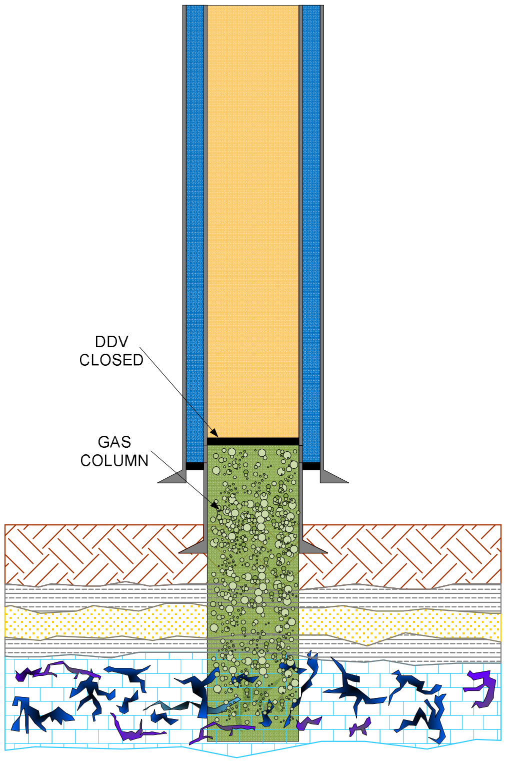
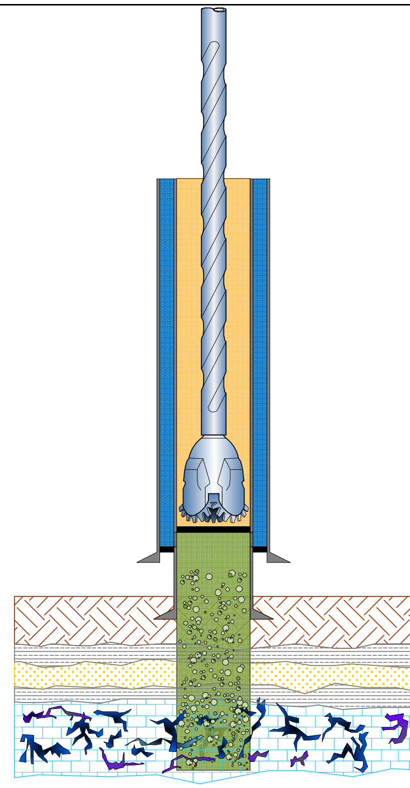
Floating Mud Cap Method - Drilling

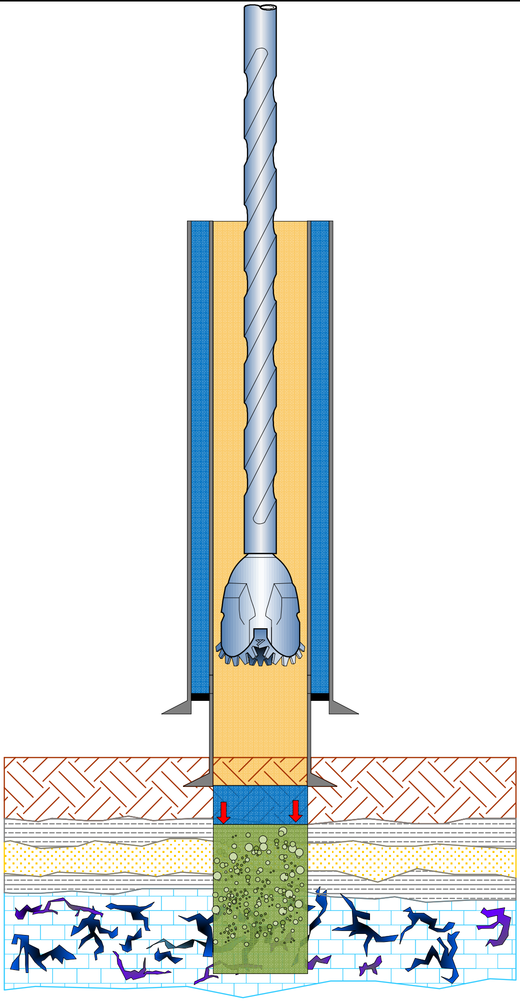
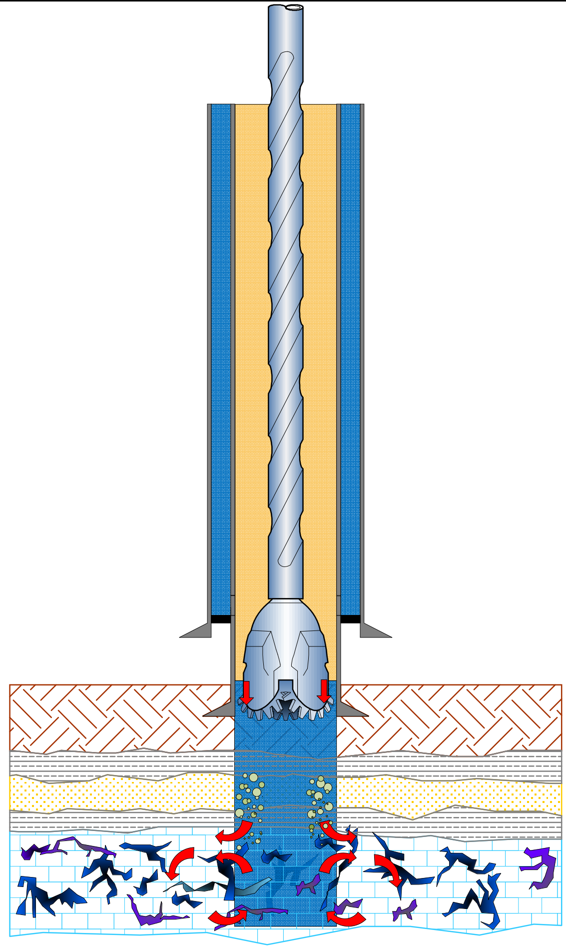
The hole is drilled until circulation is lost. The hydrostatic column level floats at the level equal to the bottom hole pressure at the lowest pressured fracture or wormhole. To reduce the volume of mud, a higher density kill mud is pumped down the annulus to keep the well from flowing. Drilling can be continued with some sacrificial drilling fluid pumped through the drill string that is usually plentiful and non-damaging to the formations being drilled. All cuttings and low density drilling fluid is injected into the fracture cavities and cavernous wormholes. Higher density mud may from time to time be pumped down the annulus to maintain well control.

	
Drilling without Losses	Lost Circulation

	
Mudcap in annulus. Sacrificial drilling fluid being lost to formation.	Mudcap in annulus. Sacrificial drilling fluid being lost to formation

		
Tripping out. Begin gas influx into open hole.		Tripped out into casing. Gas intrusion into open hole.

	
Out of the hole.	Tripping in.

		
Bullheading gas back into formation.		Bullhead gas back into formation. Continue drilling with heavy viscous mud in the annulus and sacrificial drilling fluid.

Pressurized Mud Cap Method - Drilling

Taking floating mud cap as the start point, the pressures throughout the wellbore are stable. Once drilling begins again and the hole becomes deeper, assuming that the reservoir pressure will increase with depth, the high density annular mud cap loses its ability to contain the bottom hole pressure by itself. Over time and distance an annular pressure differential between 200 – 300 psi; well below the pressure ratings for RCD tools, is not unremarkable. As the annular pressure becomes higher, the mud cap fluid density is often increased to keep the annular pressure within comfortable limits. Surface pressure fluctuations are used to monitor 3 downhole conditions:

- Gas migration to the annulus
  - Produced fluid is injected back into the formation at a prescribed rate and volume
- Pore pressure increase
  - Annular hydrostatic fluid density is increased to maintain the surface pressure within a comfortable range
- Fracture plugging
  - Should the cuttings plug off the fractures, pressurized mud cap may have to be suspended in favor of conventional drilling operations

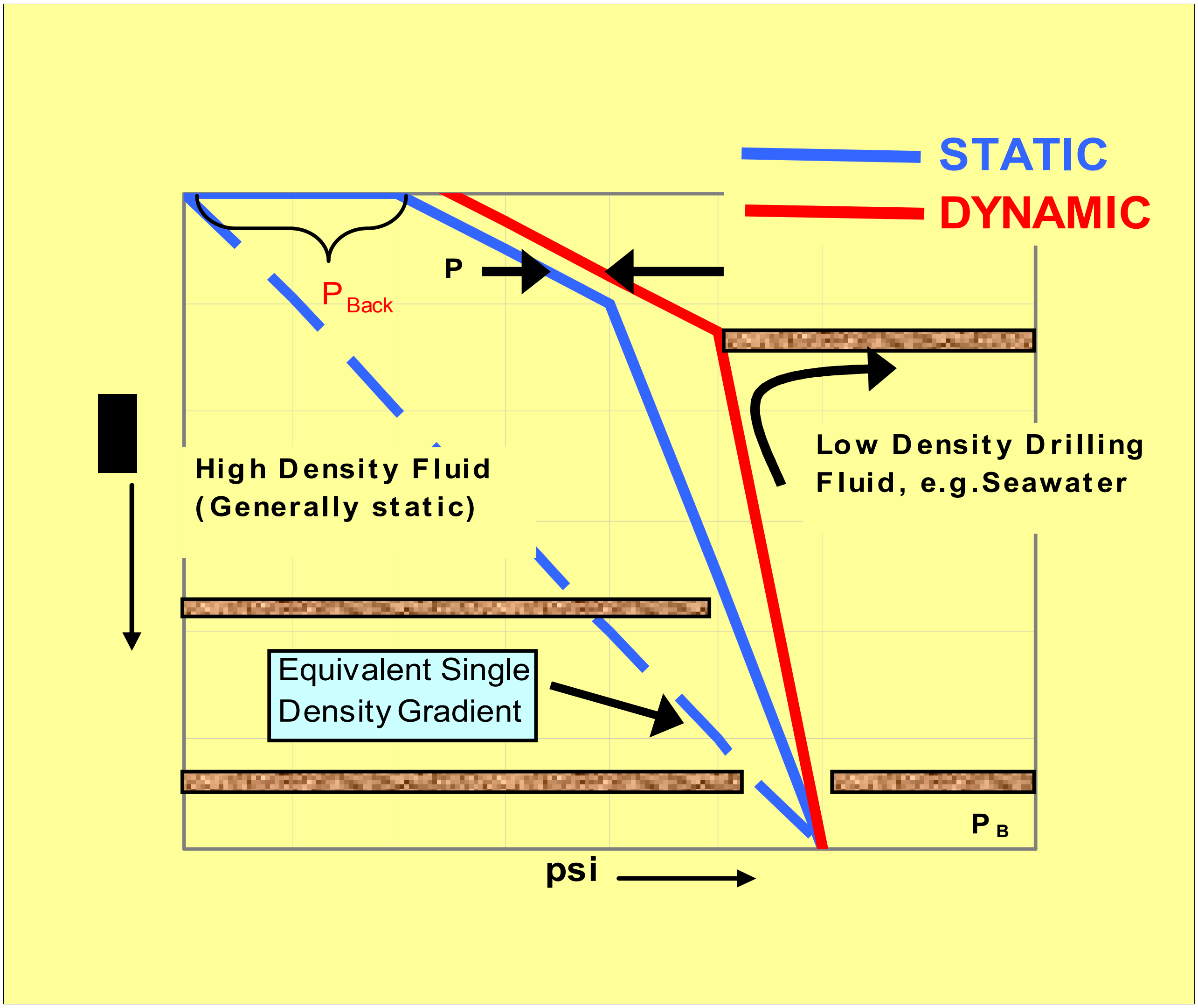


Figure 6. Pressurized Mudcap Uses A Lightweight Scavenger Drilling Fluid. After Circulating Around The Bit, The Light Density Fluid And Cuttings Are Injected Into The Weak Zone. A Higher Mud Density Fluid Remains On Top Of The Weak Zone Along With Optional Backpressure To Maintain Annular Pressure Control.

Pressurized Mud Cap Method - Tripping

When the drill pipe is tripped out of the hole a weighted mud slug can either be pumped as a pill to balance the bottom hole pressure to compensate for the loss of backpressure when the bottom hole assembly is out of the hole. Since returns are not normally seen at the surface, the volume of mud required to kill the well sufficiently will be predicated in large part to the gauge of the hole and the proximity of the fractures or wormholes.

Casing Drilling Method

Casing Drilling™ and Drilling with Casing© use casing as the drillstring so that the well is drilled and cased simultaneously. Because of the narrow clearance between the formation wall and casing OD, the annular friction pressure can be a significant variable in Equivalent Circulating Density control.

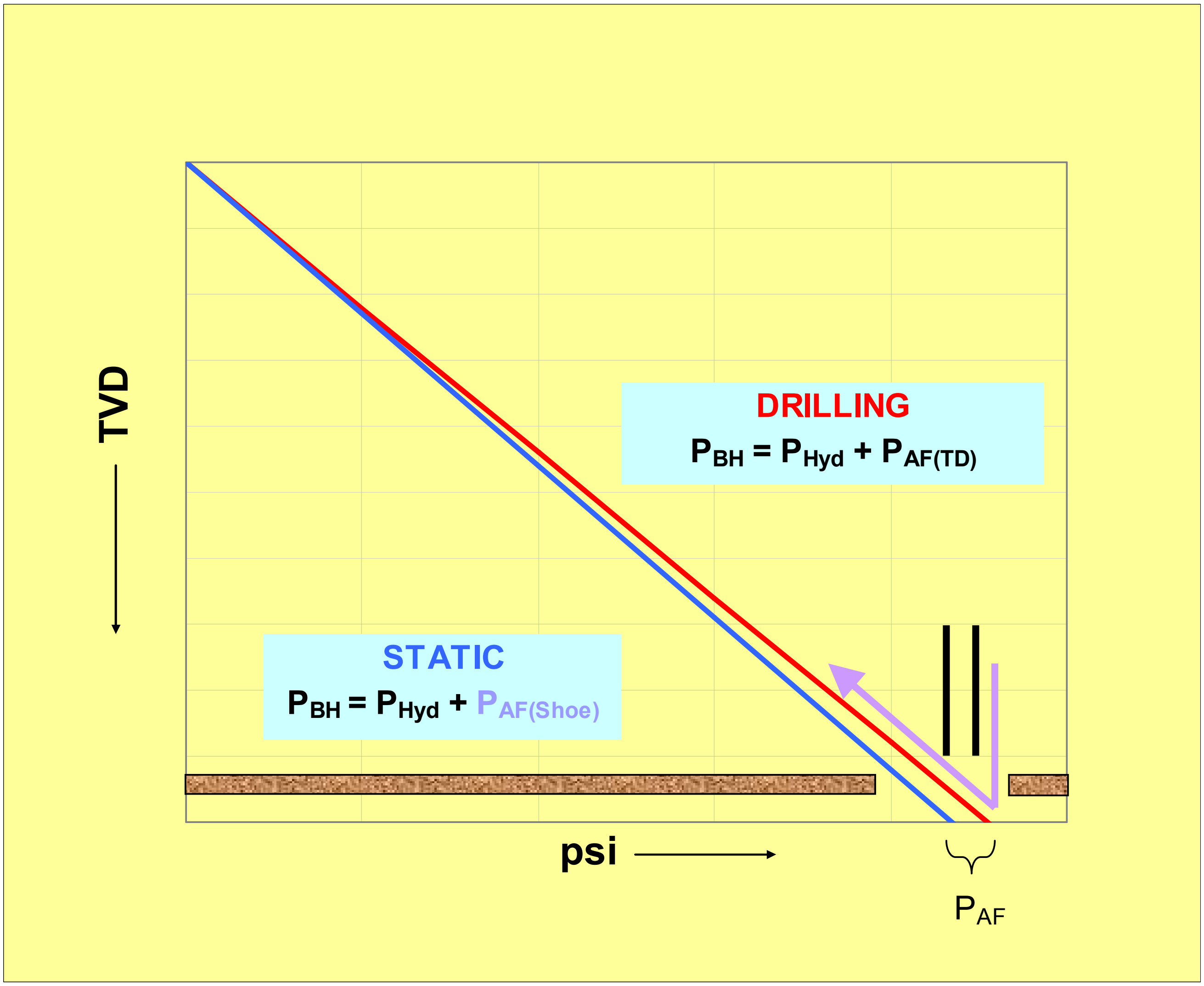


Figure 7. Friction Pressure Management Is Created By Pumping Through The Casing Drill String. Flow Within The Small Annular Space Contributes To Increased Annular Friction Pressure From The Shoe To Surface.

Dual Gradient Method

Dual Gradient Drilling has been utilized successfully in primarily offshore applications, where water provides a significant portion of the overburden. Since this liquid overburden is less dense that the typical formation overburden, the drilling window is small because the margin between pore pressure and frac pressure is narrow. Because of the weak formation strength, deepwater conventional drilling applications usually require multiple casing strings to avoid severe lost circulation at shallow depths using single density drilling fluids. The intent of the dual gradient variation is the desire to mimic the saltwater overburden with a lighter density drilling fluid. Adjustment of bottomhole pressure can be accomplished by injecting less dense media, such as inert gas, plastic pellets, or glass beads into the base drilling fluid within the marine riser. Another method available is to fill the marine riser with saltwater while diverting and pumping the mud and cuttings from the seabed floor to the surface. Both of these methods alter the fluid density in the vicinity of the mud line. The overall hydrostatic pressure in the wellbore is produced by two different fluids..

- To avoid breaking down the formation by exceeding the frac gradient
    - Saving drilling operations from spending non-productive time addressing lost circulation issues and its associated costs
    - With lost circulation under control, casing seats can be extended

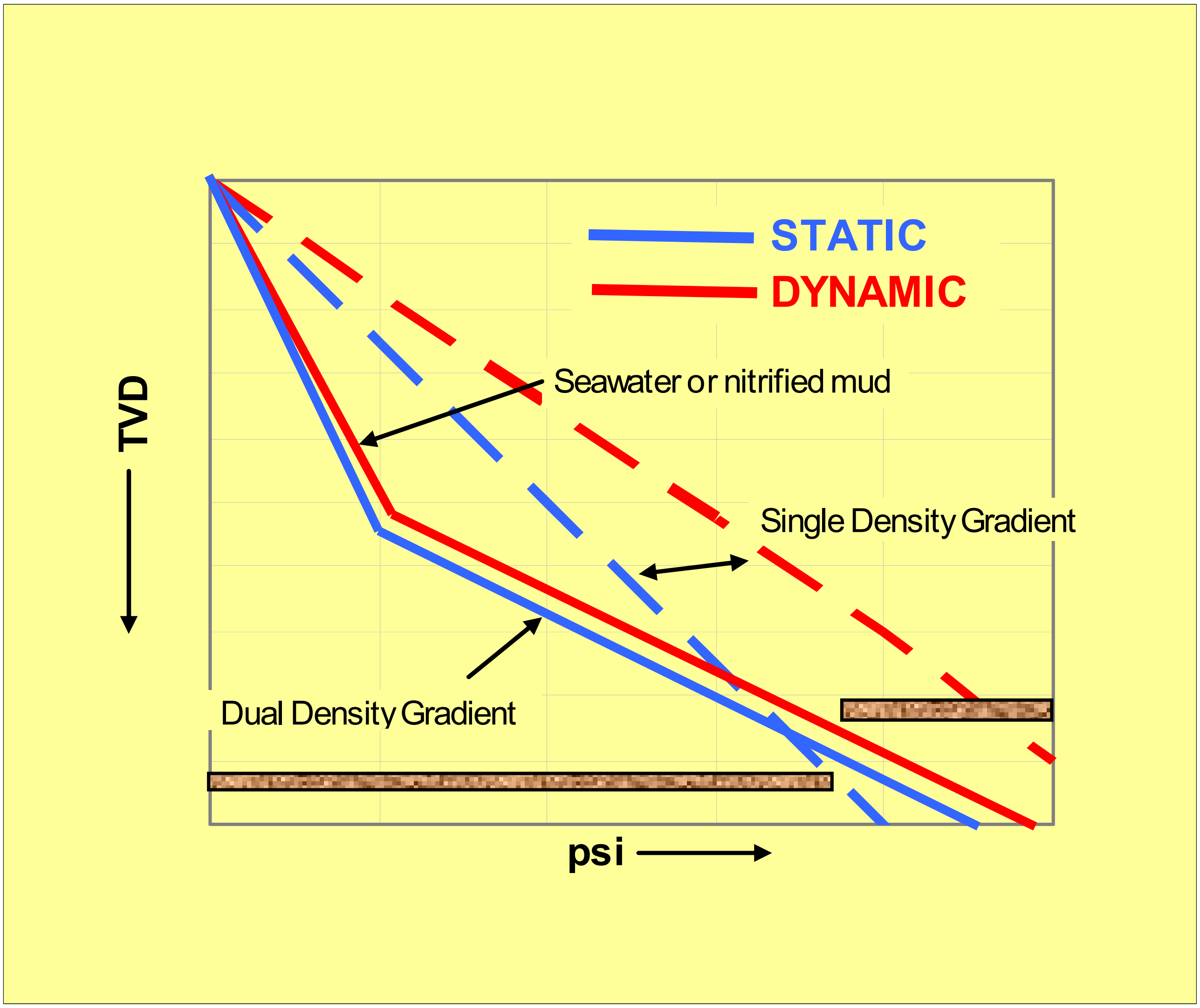


Figure 8. The Dual Gradient Variation Uses Two Density Gradients - Lower On Top And Higher On The Bottom.

ECD Reduction Method

Equivalent Circulating Density can be altered by modifying the annular pressure profile directly. Using a single density drilling fluid, a downhole motor can be used to add energy that creates an abrupt change in the annular pressure profile.

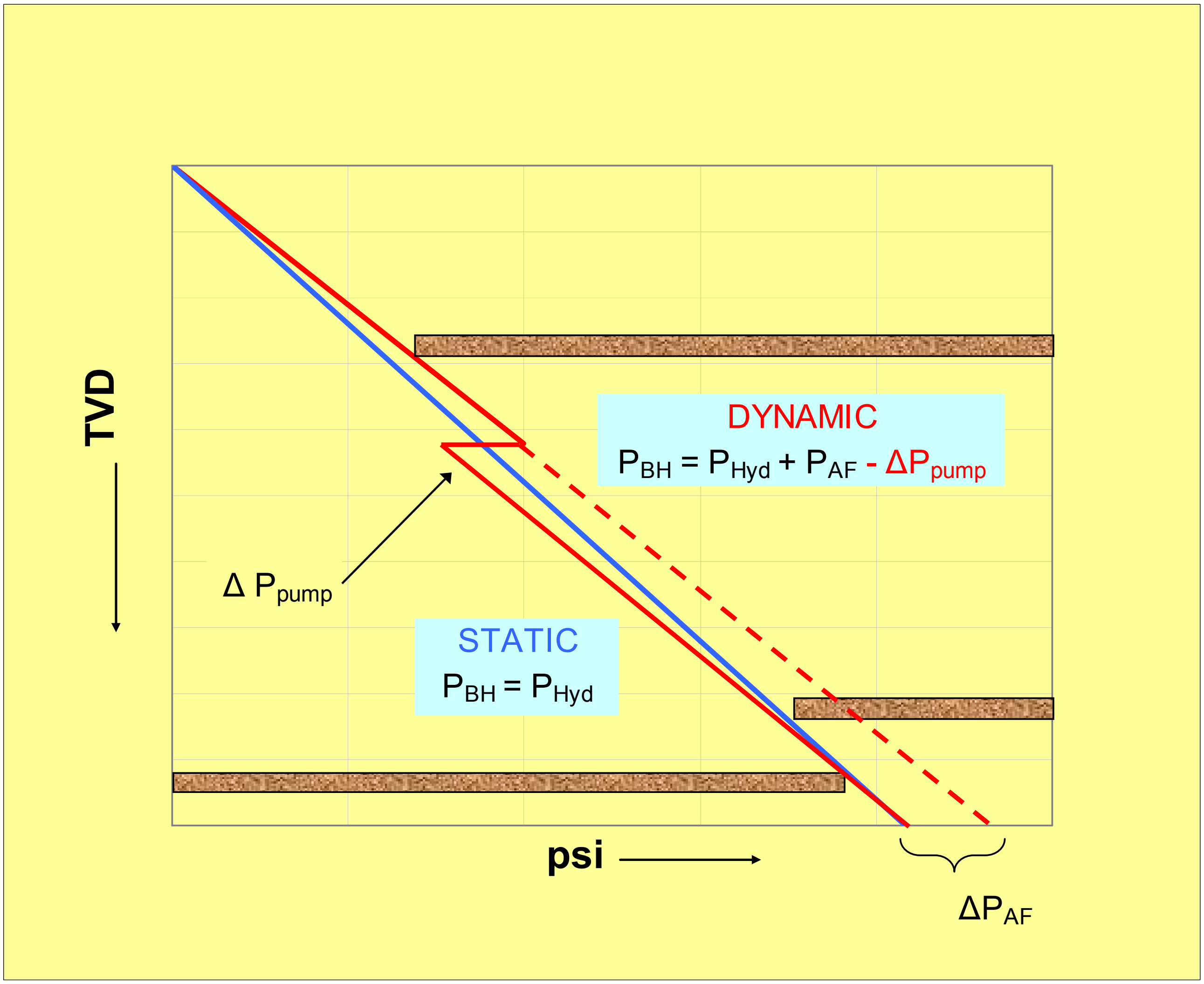


Figure 9. To Create a Reduction in ECD, a Downhole Pump Produces a Pressure Differential That Modifies the Annular Pressure Profile.

Connections

While making a connection, loss of annular friction pressure can be directly compensated by judicious use of imposed backpressure to control the BHP. In severe kick – stuck – lost circulation scenarios, backpressure from an incompressible fluid may be used to compensate for the low-density drilling mud that may be indicated. Options to control annular friction pressures with downhole pumps are readily available as well.

Continuous Circulating System

Another method to control the annular pressure profile while making a connection is to maintain the Equivalent Circulating Density while the connection is being made. This is done by configuring pipe rams and a blind ram to effectively maintain circulation even while the drill string is apart while the connection is being made. The continuous circulating device breaks the drill string connection and through a sequence of operations diverts the fluid flow across the open connection, then makes up the new connection to the appropriate torque. Mud flow is uninterrupted by making the connection.

Figure 10. Continuous Circulating Device

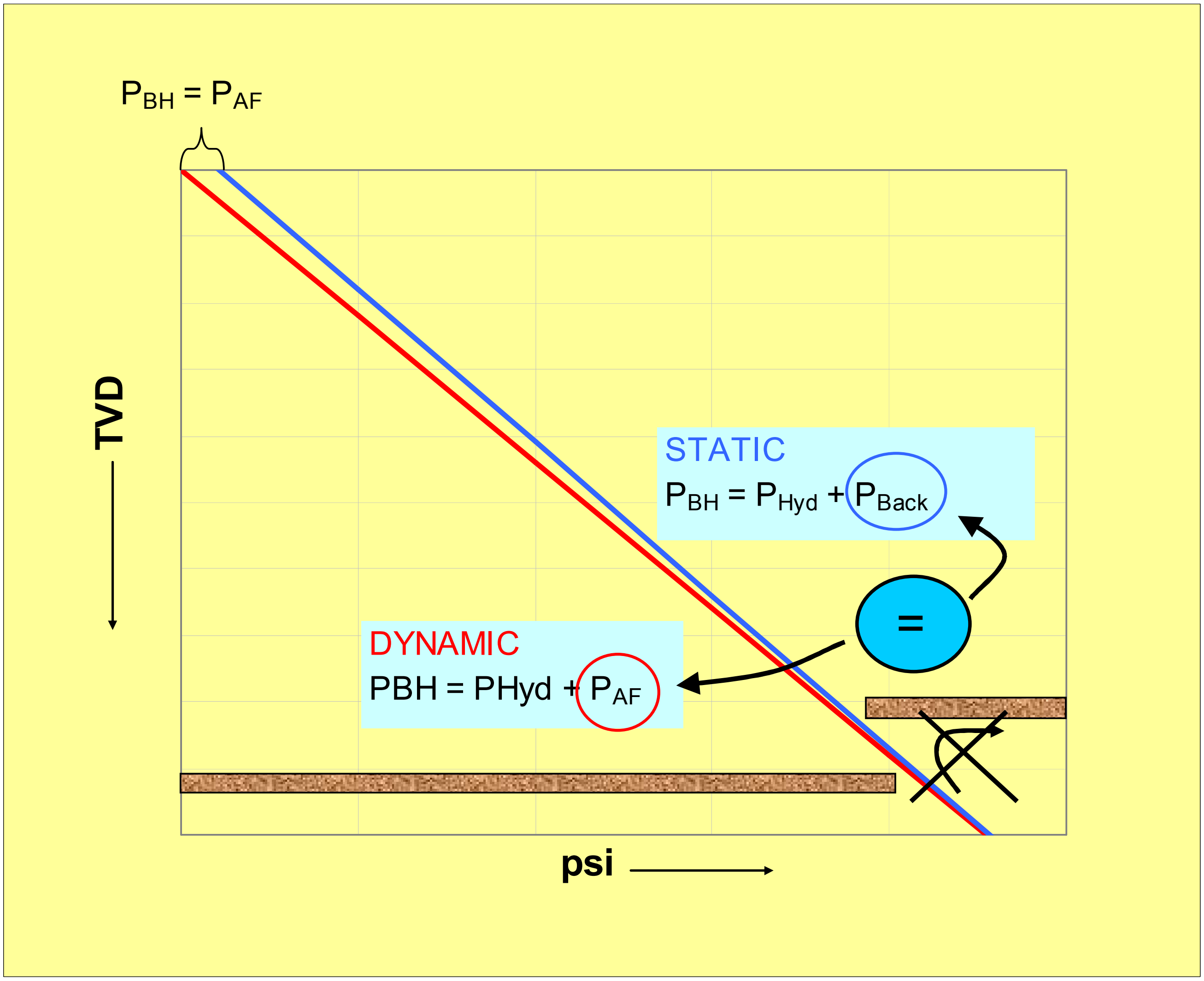
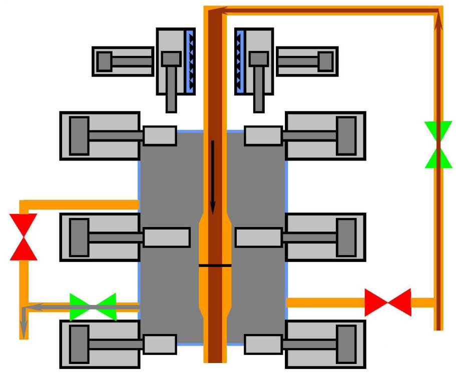
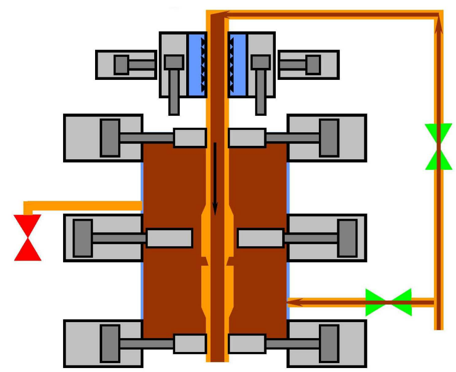
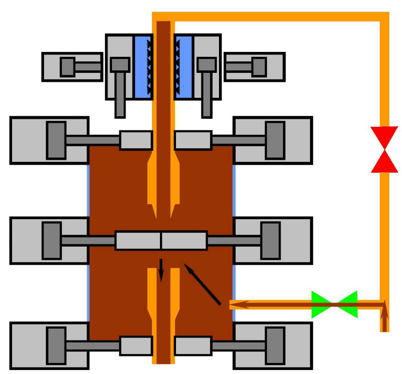
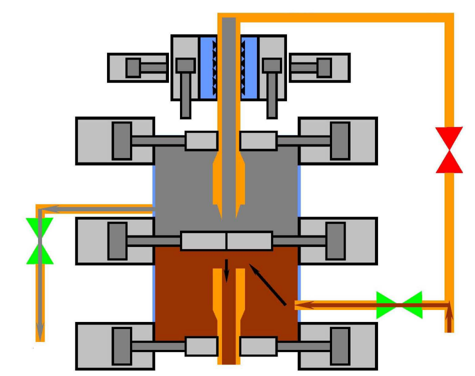
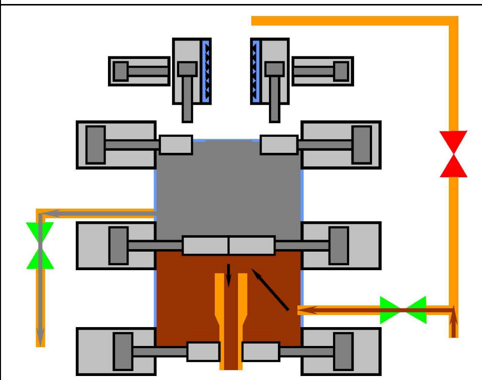


Figure 7.
Constant Bottomhole Pressure Variation of MPD Uses Lower Density Drilling Fluid And Imposes Back-Pressure When Static.

The sequence of events are as follows:

• **DRILLING** **START** • Standpipe mud flow open • Lower chamber mud drain open	 **DRILLING**	**FINISH** • Close lower chamber mud flow • Open lower chamber drain • Release pressure in chambers • Release upper and lower pipe rams • Disengage snubber • **DRILLING**
• Close upper and lower pipe rams • Engage snubber • Standpipe mud flow open • Mud flow into upper and lower chamber and pressurize • Contain force from mud pressure with snubber • Break out saver sub		• Close upper chamber drain • Open standpipe to mud flow • Open middle blind rams • Lower drill pipe • Make connection • Torque connection with snubber
• Raise saver sub • Close middle blind rams • Mud flow into chamber and pressurize lower chamber • Close standpipe mud flow • Mud pumped through drill string via pressurized lower chamber		• Mud pumped through drill string via pressurized lower chamber

• Mud pumped through drill string via pressurized lower chamber • Depressurize upper chamber • Drain upper chamber		• Mud pumped through drill string via pressurized lower chamber • Engage snubber • Close upper pipe rams
• Mud pumped through drill string via pressurized lower chamber • Open upper pipe rams • Disengage snubber • Remove saver sub		• Mud pumped through drill string via pressurized lower chamber • Pipe dope pin connection • Pick up stand for connection

After Elkins (2005)

The benefits attributed to this device include:

- Maintaining uninterrupted circulation
  - Continuous maintenance of Equivalent Circulating Density (ECD)
    - Minimizes positively induced pressure surges
    - Minimizes negatively induced pressure surges
  - Improves hole cleaning
  - Minimizes connection gas

This equipment can be utilized with or without a rotating control device. This is one of the few devices that is capable of creating a managed pressure drilling environment without a rotating control device. Equivalent Circulating Density is maintained by uninterrupted flow. When used in conjunction with a rotating control device the additional benefits include:

- Finer control of ECD balance
- Reduce potential of formation damage

Tripping

Since every MPD operation is application specific, no one tripping procedure fits all situations. The tripping procedure should be discussed and agreed upon during the HAZID/HAZOP conferences. Well control is paramount. The annulus may require some filling to compensate for the drilling string effective volume removed during tripping. Back pressure can be applied to compensate for the lack of annular friction pressure until the margin encroaches the limits defined in the drilling plan. Stripping in or out of the hole with high casing pressures can shorten the life of seal elements. At some point, it may be advisable to spot a weighted, high viscosity pill to statically control the well. On the trip in the hole, the pill can be circulated out of the hole.

Hydrodynamics

Virtually every variation of Managed Pressure Drilling involves manipulation and management of the pressure profile, particularly in the exposed wellbore. Listed below are many of the factors that affect downhole hydraulics. Used singularly or in combination they can be manipulated, managed, and exploited to accomplish the objectives of managed pressure drilling to decrease non-productive time and the expenses associated with that non-productive time.

- Wellbore Geometry
- Drilling Fluid Density
- Drilling Fluid Rheology
- Annular Backpressure
- Wellbore Strengthening
- Annular Friction Pressure

In many cases where the drilling plan includes a section of hole that requires Proactive MPD, a very detailed wellbore hydraulic analysis will not only foretell the success of various MPD methods but will also guide the drilling engineer while he contends with the hydrodynamics of the drilling operation in real time.

Enabling Tools for Managed Pressure Drilling

MPD is application specific. Some of the tools below are used individually or in concert with others. Some are required. Others are optional or not applicable.

- Rotating Control Devices
    - Surface BOP Rigs
    - Subsea BOP with Marine Riser
    - Top Hole Batch Drilling
        - Riserless Rigs
        - Dual Gradient Cuttings Return

- Choke Manifold for Backpressure Management
  - Manual
  - Automatic
- Continuous Circulating System
- Non-return Valves
- Downhole Deployment Valves
- Surface Phase Separation
- ECD Reduction Tools
- Nitrogen Generation
- Pressure Monitoring
- Hydraulic Flow Modeling

Training

Many land based drilling operations are already practicing Reactive MPD. Moving from Conventional Drilling to Proactive MPD is a step change. The magnitude of the step change is roughly equivalent to the change from cable tool to rotary drilling. Proactive MPD may require more specialized well engineering design and planning. The rig crews may need some additional guidance to supplement their well control training. They will need to learn how to safely utilize the tools available today.

Economics

The size of the prize is virtually limitless. In one specific case offshore, after two unsuccessful sidetracks using conventional drilling techniques where most of the time was spent fighting lost circulation, stuck pipe, fishing, and well control incidents, MPD was considered. After extensive hydraulic analysis, the constant bottom hole pressure variation was chosen. The rig underwent some slight modification to accept some required MPD equipment. When the rig personnel had been sufficiently trained, MPD operations kicked off where the prior sidetracks had failed. Managed Pressure Drilling techniques drilled and completed the well with virtually no time lost due to non-productive operations. Because the Equivalent Circulating Density was proactively maintained within the window of the pore pressure and frac pressure, lost circulation was avoided. Time spent fighting lost circulation, kicks, wellbore instability, and stuck pipe was eliminated. The well objectives were not only completed, but cost savings were realized as well. The chief contributors to overall drilling cost savings included reduction in non-productive time with the very significant reduction of mud usage. MPD **M**akes **P**roblems **D**isappear.

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MPD Notice to Lessees

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
GULF OF MEXICO OCS REGION

NTL No. 2008-G07

Issue Date: May 15, 2008
Effective Date: June 15, 2008
Expiration Date: June 15, 2013

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL, GAS, AND SULPHUR LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO OCS REGION

Managed Pressure Drilling Projects

This Notice to Lessees and Operators (NTL) provides guidance to ensure that you use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment in compliance with 30 CFR 250.401(e) when you conduct a managed pressure drilling (MPD) project in the Gulf of Mexico OCS for wells with surface blowout preventers (BOP). It also specifies the information you need to include in the drilling prognosis section (see 30 CFR 250.414(h)) of your Application for Permit to Drill (APD) when you request approval for alternative compliance under 30 CFR 250.408 to conduct an MPD project. The Minerals Management Service (MMS) Gulf of Mexico OCS Region (GOMR) developed this NTL (including the Appendix and its attachment) with the input and cooperation of the International Association of Drilling Contractors (IADC) Subcommittee for Underbalanced Operations and Managed Pressure Drilling.

Intent

The intent of this NTL is to encourage proactive planning and provide a consistent approval process before you implement MPD. Be advised that any MPD implementation or contingency implementation of MPD requires prior MMS GOMR review and approval. This NTL addresses MPD as it applies to drilling with surface BOP's. It will be reviewed for revision when the IADC completes its recommended practice for MPD for both surface BOP's and subsea BOP's.

This NTL specifically addresses the Constant Bottomhole Pressure (CBHP) variation of MPD as defined in the IADC Underbalanced Operation (UBO) & MPD Glossary of Terms, where bottomhole pressure is kept constant during connections to compensate for the loss of annulus friction pressure when mud pumps are off. Other MPD variations or systems that fall outside of this definition warrant a review by the MMS GOMR.

This NTL does not preclude the use of rotating control devices (RCD) to augment safety systems and methods, such as those to divert return flow away from the drill floor or to control ballooning. Address any other application of RCD or specialized equipment in the APD.

This NTL does not preclude the use of bottom hole pressure monitoring devices while drilling and/or having closed loop drilling fluid flow monitoring systems on mobile offshore drilling units (MODU) with subsea BOP's. Nor does it preclude you from submitting an APD to drill a well using MPD from a MODU with subsea BOP's. Be advised, however, that there are numerous additional factors to be considered when you conduct MPD drilling with a subsea BOP that are not addressed in this NTL.

Definition

As taken from the IADC UBO and MPD Subcommittee:

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

1. MPD process employs a collection of tools and techniques which may mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.
2. MPD may include control of back pressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations thereof.
3. MPD may allow faster corrective action to deal with observed pressure variations. The ability to control annular pressures dynamically facilitates drilling of what might otherwise be economically unattainable prospects.

For the purpose of this NTL, MPD is limited to maintaining an overbalanced state in a closed system within the drilling process through the use of mud density and annulus friction pressure, using either equivalent circulating densities and/or casing back pressure with a statically underbalanced mud system. When you use trapped casing back pressure, provide for the ability to maintain and/or increase pressure at all times.

Planning

Contact the drilling engineer in the appropriate MMS GOMR District Office as soon as you make the decision to conduct an MPD project. MPD projects, especially those proposed by lessees and operators that have not yet used approved MPD techniques, normally require from four to six months of interaction with MMS GOMR personnel while you conduct preliminary engineering assessments, develop plans and contingencies, plan hydraulics, assemble equipment, and conduct training exercises.

APD Information

Under 30 CFR 250.408, the MMS GOMR can approve alternative procedures or equipment only if they provide a level of safety and environmental protection that equals or surpasses current MMS requirements. Therefore, your APD to conduct an MPD project needs to contain sufficient information for the MMS GOMR to review and assess the merits and operational safety and environmental aspects of any alternative drilling procedures fully and completely. Accordingly, include the following information in the list and description of alternative procedures required by 30 CFR 250.414(h) in the drilling prognosis section of your APD:

1. A description of your hydraulics model and detailed schematics for all surface piping and downhole equipment configurations supporting the model. Make sure that you model downhole characteristics and the surface flow control systems (FCS) using a range of anticipated fluid properties. Explain how you will compare your model against actual drilling data and make adjustments during operations. Show how you will adjust the model if formation pressures deviate from the expected during drilling operations.

2. An explanation and discussion of all drilling concerns, including the rationale for using non-conventional drilling technology. Include details of the items that will be impacted by the tight pressure margins and a discussion of your plans to commence non-conventional circulation. Also include

a. Pressure prognosis plots with pore pressures and fracture pressures through the interval(s) where you request alternative compliance;

b. Geologic technical data examining the risks of abnormalities or geologic uncertainties, and the probabilities of larger differences in pore pressure and fracture pressures;

c. Casing design calculations with safety factors;

d. Proposed schematics of all FCS equipment, including footprints and design considerations;

e. Surface circulation system design specifications and redundancies, specifically for MPD implementation;

f. If you plan to drill through a production riser, its description and detailed specifications;

g. Your plans to functionally test onshore all critical equipment associated with the MPD procedure (e.g., the pump skid, flow meter skid, choke manifold) before rig mobilization, if possible. Undertake this work on the first application for such equipment on a multiple well application on the drilling rig. Previously approved designs of FCS will satisfy this condition for a lessee or operator who has used this system previously in the Gulf of Mexico;

h. Your plans to install and operationally test the MPD equipment at the drilling rig on its first application; and

i. A description of the methods you will deploy to detect variations of drilling flow rate. Include discussions of trip tank and pit system procedures; mud return flow trending; the use of flow meters and monitoring of same; logging tools, including measurement while drilling (MWD), pressure while drilling (PWD), and logging while drilling (LWD); gas detection equipment installed; mud sampling procedures; and rheology monitoring.

3. An explanation of the basis for your drilling rig selection, considering the additional MPD equipment required. Include the following:

a. When drilling from a floating production facility with surface BOP's, provide a discussion of how heave, roll, and pitch issues may impact the rig and production riser during inclement weather conditions;

b. A discussion of deck space requirements for the additional MPD equipment, along with any considerations for deck restrictions or load restrictions near or around the moon pool area, and set back distances in the drill floor area; and

c. A discussion of fluid/gas separation capabilities.

4. A discussion of equipment and procedures you will use during MPD operations to include

a. An operational matrix such as that shown in the Appendix of this NTL, specifying when you will adjust your drilling parameters and when you will begin well control activities;

b. A maintenance and testing schedule of all related equipment. Make sure that initial tests are at least to the planned operating pressures;

c. An independent surface choke manifold to control flow from the wellbore;

d. A specific means to apply additional back pressure to the well bore during connections;

e. A system to detect variations in drilling flow rate or influx volume continuously;

f. Instrumentation for measuring bottomhole pressure. If specified instrumentation malfunctions or fails, your plans to notify the appropriate MMS District Manager, who must approve alternate procedures before you continue drilling with MPD;

g. At least one float in the bottom-hole assembly to prevent influx up the drill pipe;

h. A mud gas separator with adequate capacity for the intended drilling program;

i. Hydraulic/electric/pneumatic pressure controls; and

j. A description of the equipment and procedures you will employ to provide functional redundancy in the FCS, which may include an RCD, mud pumps, chokes, flow meters, and flow detection instrumentation.

5. Plans for you and your contractors to hold a hazard identification (HAZID)/hazard and operability (HAZOP) workshop that includes provisions for

a. Identifying hazards for all drilling and connection activities and assessing risks;

b. Developing mitigation measures and contingencies;

c. Reviewing drilling flow rate variation detection procedures;

d. Reviewing well control procedures. Include your provisions to revert to the well control system (BOP, primary choke manifold, etc.) should you detect a formation influx outside of the parameters specified in your well control matrix.

e. Classifying wells based on risk level, application category, and fluid system and using that classification system to provide a framework for defining minimum equipment needs, specialized procedures, and safety management practices. Guidance can be found in "IADC Well Classification System for Underbalanced Operations and Managed Pressure Drilling" or in "IADC Underbalanced Drilling Operations – HSE Planning Guidelines."

6. Your plans to provide competency assurance for all involved personnel. Describe the supplemental training you will provide for all identified relevant personnel engaged in MPD operations to ensure that they understand their role in MPD, are familiar with the equipment, and can properly perform their assigned duties.

Guidance Document Statement

The MMS GOMR issues NTL's as guidance documents in accordance with 30 CFR 250.103 to clarify, supplement, and provide more detail about certain MMS regulatory requirements and to outline the information you provide in your various submittals. Under that authority, this NTL sets forth a policy on and an interpretation of a regulatory requirement that provides a clear and consistent approach to complying with that requirement. However, if you wish to use an alternative approach for compliance, you may do so, after you receive approval from the appropriate MMS GOMR office under 30 CFR 250.408.

Paperwork Reduction Act (PRA) Statement

The collection of information referred to in this NTL provides clarification, description, or interpretation of requirements in 30 CFR 250, subpart D. The Office of Management and Budget (OMB) has approved the information collection requirements for these regulations and form and assigned OMB control number 1010-0141. This NTL does not impose additional information collection requirements subject to the PRA.

Contact

If you have any questions regarding this NTL, contact Russell Hoshman of the MMS GOMR Technical Assessment and Operations Support Section by telephone at (504) 736-2627, or by e-mail at russell.hoshman@mms.gov.

[original signed]

Lars T. Herbst
Regional Director

Appendix with Attachment

Appendix

Managed Pressure Drilling Operations Matrix

The following matrix describes when you will proceed to corrective measures to bring any influx into control when performing MPD operations. See the Attachment to this Appendix for examples of influx and surface pressure indicators.

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

Chart 1

Defined Limits for Interval ft to ft TVD

Influx Indicator				
	Influx State	No Influx	None	
		Operating Limit	Low	
		< Planned Limit	Medium	
		≥ Planned Limit	High	
	Influx Rate	No Influx	None	
		Operating Limit	Light	
		< Planned Limit	Moderate	
		≥ Planned Limit	High	
	Influx Duration	No Influx	None	
		Operating Limit	Low	
		< Planned Limit	Medium	
		≥ Planned Limit	High	
	Volume Gain	No Influx	None	
		Operating Limit	Low	
		< Planned Limit	Medium	
		> Planned Limit	High	

Notes:
1. Influx indicator can be any or a combination of the factors shown in Table 1.

2. Pit gain is an absolute indicator.
3. Equipment must be used which can measure the influx rates to an acceptable tolerance.

Chart 2		
	Defined Limits for ______ Interval	ft to ft TVD
Surface Pressure Indicator	Planned Drilling Back Pressure	
	Planned Connection Back Pressure	
	Back Pressure Limit	

Note: Equipment must be used which can measure the surface pressures to an acceptable tolerance.

Other Indicators		
	Defined Limits for ______ Interval	ft to ft TVD
Well Control Triggers		

Note: "Other Indicators" signal should be considered planned limit and require immediate remedial actions.

Attachment to the Appendix

Managed Pressure Drilling Operations Matrix Examples

Following are descriptions and examples of input for the matrix:

1. Defined Limits - specify which intervals of the wellbore are included for the MPD matrix. Prepare a separate matrix for each interval that requires MPD techniques.

Defined Limits for	B Sand	Interval	10,000 ft to 10,500 ft TVD

2. Influx State - describe in terms of flow characteristics. Specifically, describe the limitations when the well is flowing at a steady state as opposed to increasing flow.
   Example:

Influx State	No Influx	None	No measured influx
	Operating Limit	Light	Flow measured at a steady state
	< Planned Limit	Medium	Flow continuing to increase
	> Planned Limit	High	Flow increasing despite remedial actions

3. Influx Rate - describe in terms of flow rate. Specifically, describe the maximum influx rates that you will see before proceeding to corrective measures.
   Example:

Influx Rate	No Influx	None	No measured influx
	Operating Limit	Light	< 0.1 bbl/min
	< Planned Limit	Moderate	< 1.0 bbl/min
	> Planned Limit	High	> 1.0 bbl/min

4. Influx Duration - a function of the duration of the returns. Specifically, list the length of time you will take an influx before you proceed to corrective measures.
   Example:

Influx Duration	No Influx	None	No measured influx
	Operating Limit	Low	< 1 min, light influx
	< Planned Limit	Medium	< 10 min, light influx or < 1 min moderate influx
	> Planned Limit	High	> 10 min, light influx or > 1 min moderate influx

5. Pit Gains - describe the maximum measured influx (volume in bbls) that you will receive before you proceed to corrective measures.
   Example:

Volume Gain	No Influx	None	No measured pit gains
	Operating Limit	Low	< 0.5 bbl
	< Planned Limit	Medium	< 1.0 bbl
	> Planned Limit	High	> 1.0 bbl

6. Surface Pressure Indicator - describe the maximum measured pressure that is applied to the surface choke manifold. List the planned back pressure to be held during MPD drilling operations, if any, and the maximum planned pressure to be held during connections. Also, list the back pressure limit as the maximum that will be held back using the surface equipment. Any higher pressures necessitate securing the well with the blowout preventers (BOP).

Surface Pressure Indicator	Planned Drilling Back Pressure	0 psi or 0 pounds per gallon (ppg) mud weight
	Planned Connection Back Pressure	382 psi or 0.7 ppg mud weight (anticipated ECD)
	Back Pressure Limit	1092 psi or 2.0 ppg mud weight (based on RCD)

7. Other Indicators - operator specified items that will initiate immediate suspension of operations.

Other Indicators	
Well Control Triggers	Ambient hydrocarbon gas detected
	Hydrocarbon gas or fluid leak detected Drilling fluid leak detected, uncontrolled RCD rubber leaking and any influx detected

Baseline Risk Assessment

INTRODUCTION

The purpose of this section is to offer the rationale and a template of a typical Hazard Identification and Hazard Operation (HAZID / HAZOP) procedure report of a Managed Pressure Drilling (MPD) operation. This analysis will demonstrate how potential hazardous aspects, operations and procedures related to the application of MPD can be identified and subsequently mitigated, or at least responded to in a timely, effective manner.

This guide is not intended to be prescriptive. While use of this guide does not guarantee a trouble-free operation, it is hoped that the reader will find that significant parts of these general planning guidelines will at least lessen the economic consequences of trouble if not diminish the frequency of their occurrence.

To determine improvement we must first have a baseline risk assessment. Once the baseline is established, progress (or the lack of it) can be measured periodically with continuous assessments and incident-based assessments as incidents occur.

One of the problems is that risk does not come in convenient units like volts or kilograms. There is no universal scale of risk. Scales for one industry may not suit those in another industry. Fortunately, the method of calculation is generally consistent and it is possible to arrive at a reasonable scale of values for a given industry.

Risk assessment needs to be thorough, is often detailed almost to the extreme, and can get as complicated as one would like. Every attempt has been made in this Joint Industry Project DEA155 to “Keep It Simple” without diluting the substance of the subject matter.

We should also be mindful that we live in an imperfect world. It is not possible to eliminate all incidents because human error accounts for vast majority of all incidents. Our mistakes are our guide to improvement.

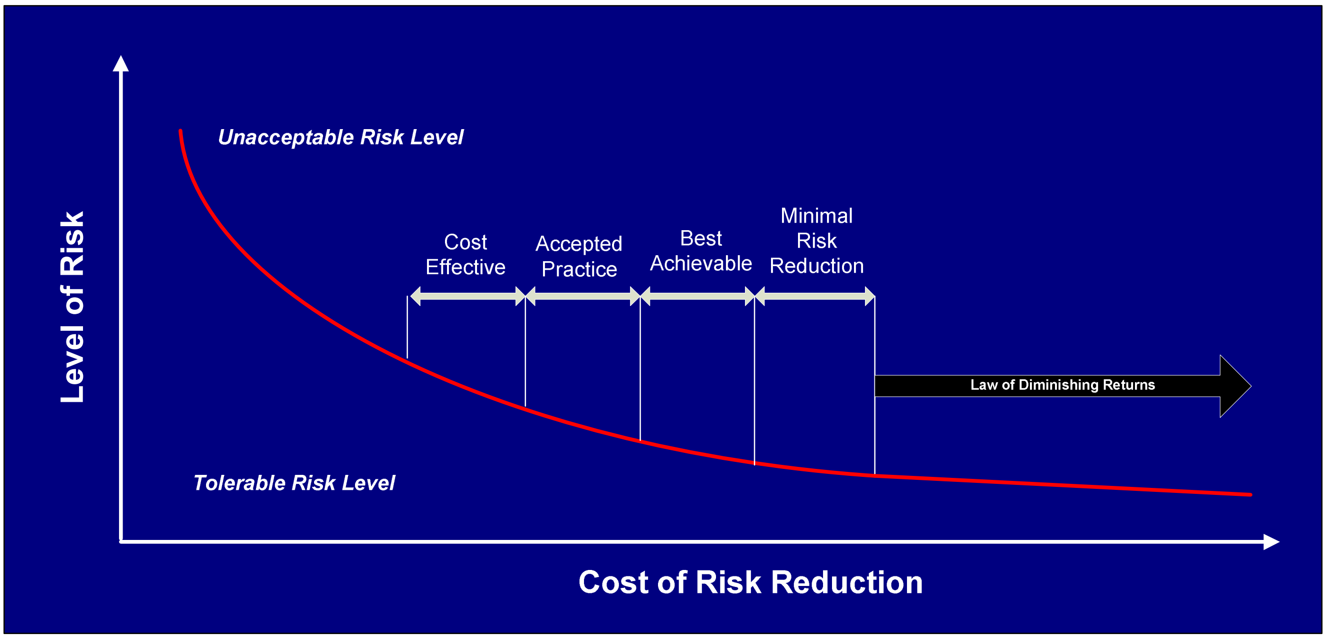
Generally, the most desirable approach is to break down the process into simple steps. Risk reduction can be achieved by reducing either the frequency of a hazardous event or its consequences or by reducing both of them. The first step is to minimize the frequency since all events are likely to have cost implications, even without dire consequences. Safety systems are all about risk reduction. If we can’t take away the hazard we shall have to reduce the risk. Altering the risk profile is part of risk management.

Managing risk:

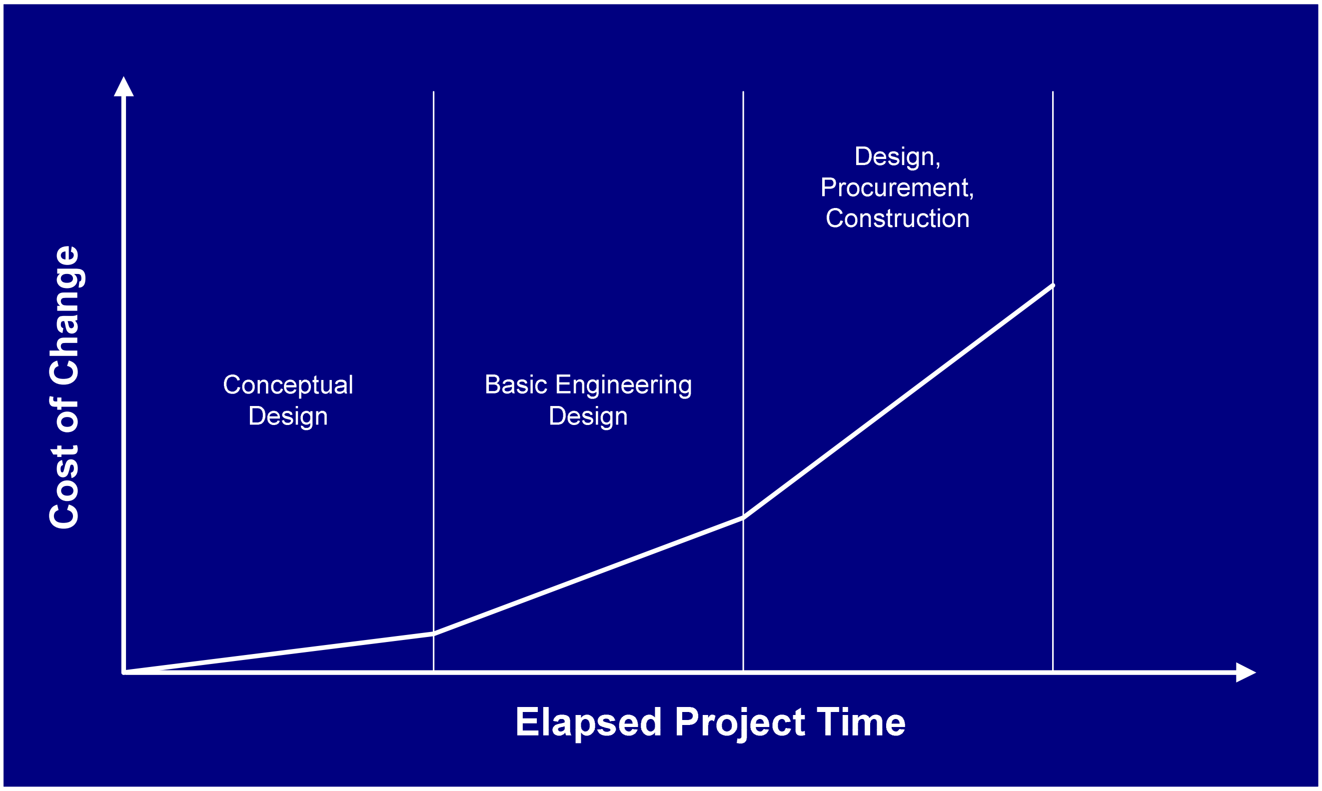
- Requires rigorous thinking. It is a logical process, which can be used when making decisions to improve the effectiveness and efficiency of performance.
- Encourages an organization to manage proactively rather than reactively.
- Requires balanced thinking ... Recognizing that a risk-free environment is uneconomic (if not impossible) to achieve, a decision is needed to decide what level of risk is acceptable.

- Requires hazard studies that are part of the disciplined approach to managing risks and they should be conducted in accordance with the principles described in this report.

Typically, the cost of reducing risk levels will increase with the amount of reduction achieved and it will follow the "law of diminishing returns". Risk is usually impossible to eliminate so there has to be a cut off point for the risk reduction we are prepared to pay for. We have to decide on a balance between cost and acceptable risk. This is the principle of ALARP, As Low As Reasonably Practical.

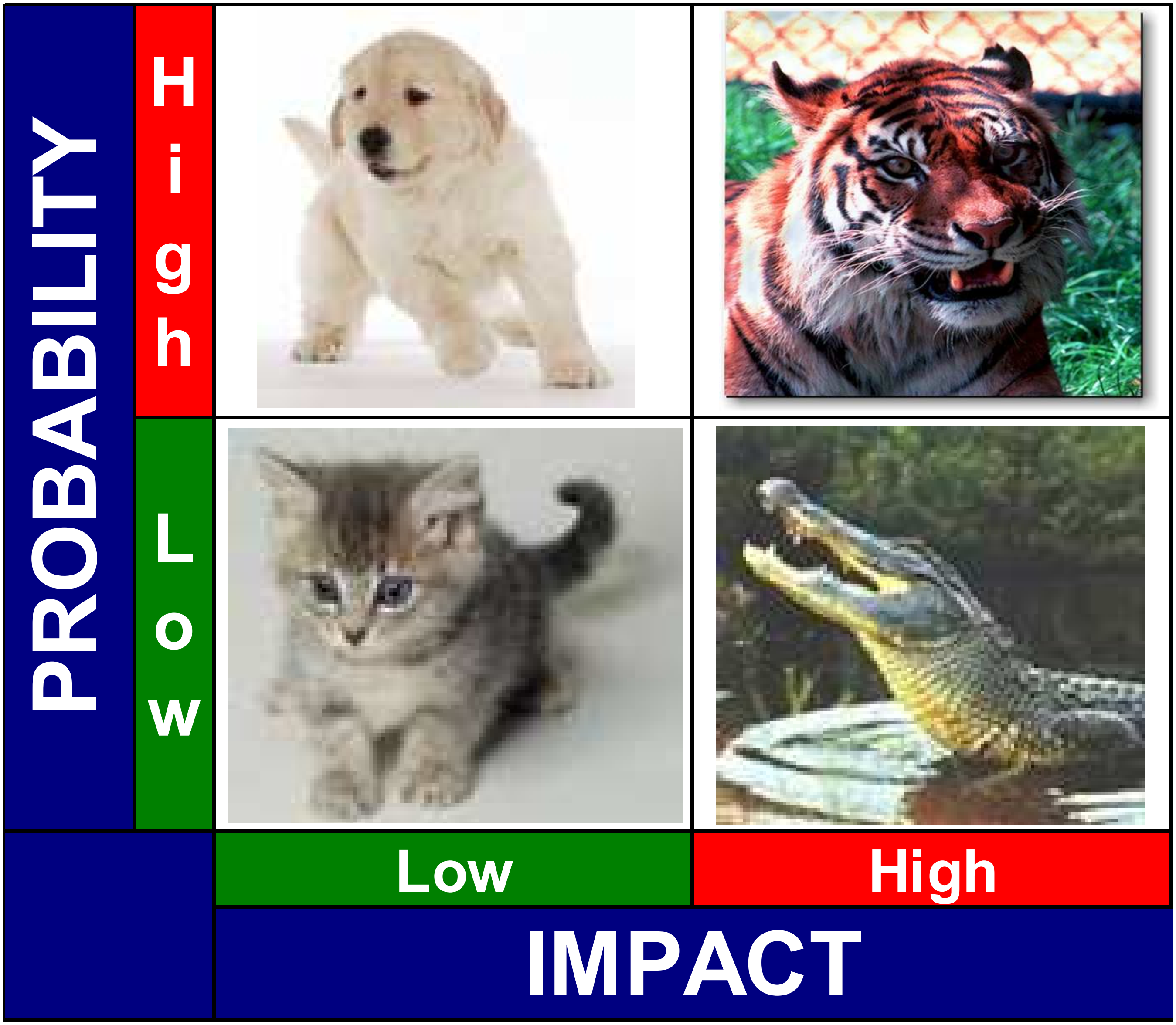


The second factor that will influence the hazard study work is the relationship between design changes and their impact on project costs.



Typically, there are heavy cost penalties involved in late design changes. It is economically prudent to design the hazard study program to identify critical safety and operability problems at an early stage. This is where preliminary hazard study methods are valuable. Preliminary studies can often identify major problems at the early stage of design, where risk reduction measures or design changes can be introduced with minimum costs.

One of the methods of risk analysis described in this report is risk ranking. Although a risk matrix can be made of varying complexity, the simple one below described by Tusler makes the point.


PROBABILITY
High
Low
Low
High
IMPACT

PROBABILITY	IMPACT	RISK
High	High	Tigers These are dangerous animals and must be neutralized as soon as possible.
Low	High	Alligators These are dangerous animals which can be avoided with care. One method to expose them may be to drain the swamp.
High	Low	Puppies A delightful pup will grow into an animal which can do damage, but a little training will ensure that not too much trouble ensues.
Low	Low	Kittens A large cat is rarely the source of trouble, but on the other hand a lot of effort can be wasted on training it.

There is a common saying in the control systems world, “If you want to control something, first make sure you can measure it.” To control the risks of harm or losses in the workplace due to hazards of all forms we need to measure RISK. We need to spend some time defining the terms associated with Hazards and Risk.

HAZARD CONCEPTS

ACCIDENT

An incident with unexpected or undesirable consequences. The consequences may be related to personnel injury or fatality, property loss, environmental impact, business loss, etc. or a combination of these.

CAUSE

A person, event, or condition that is responsible for an effect, result, or consequence.

CONSEQUENCE

The result of an action, event or condition. The effect of a cause. The outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as an injury, loss, damage, advantage, or disadvantage. Although not predominantly thought of in this manner, consequences do not always have negative connotations; they can be positive.

DEVIATION OR UPSET

Departure from agreed upon process, procedure, or normal expected function.

EVENT

An occurrence caused by humans, automatically operating equipment/components, external events or the result of a natural phenomenon.

FAILURE

The inability of a system or system component to perform a required function to its rated capacity at the time that the function is required.

HAZARD

A HAZARD is defined as, the potential to cause harm, ill health or injury, damage to property, products, or the environment, induce production losses, or increase liabilities. The result of a hazardous event may adversely impact the health or safety of employees, or adversely impact the environment.

INCIDENT

An unplanned sequence of events and/or conditions that results in, or could have reasonably resulted in a loss event. Incidents are a series of events and/or conditions that contain a number of structural/machinery/equipment/outfitting problems, human errors, external factors, as well as positive actions and conditions. This definition includes both accidents and near misses.

LOSS EVENT

Undesirable consequences resulting from events or conditions, or both.

MANAGEMENT SYSTEM

A system put in place by management to encourage desirable behaviors and discourage undesirable behaviors. Examples of management system elements include policies, procedures, training, communications protocols, acceptance testing requirements, incident investigation processes, design methods and codes and standards. Management systems, also known as corporate culture, strongly influence the behavior of personnel in an organization.

NEAR MISS

An incident with no consequences, but that could have reasonably resulted in consequences under different conditions.

An incident that had some consequences that could have reasonably resulted in much more severe consequences under different conditions.

SAFEGUARD OR CONTROL

There are three basic techniques available to an organization designed to minimize risk exposure as low as reasonably possible at a reasonable cost. They are:

- Prevention
- Detection
- Mitigation

With some overlap, there are three areas that tend to originate and maintain safeguards.

- Administration
    - Training
    - Emergency Plans
    - Directives

  - Supervision
  - Planned Inspections
  - Communications
  - Security
  - First Aid
  - Legal/Regulatory Requirements
  - Management of Change
- Engineering
  - Equipment Design
  - Energy Barriers
  - Identification of Critical Equipment
  - Warning Signs
  - Emergency Equipment
- Operations
  - Procedures
  - Job Safety Analysis
  - Permit to Work
  - Emergency Drills
  - Pre-use checklist
  - Planned Maintenance
  - Incident Management

SYSTEM

An entity composed of personnel, procedures, materials, tools, equipment, facilities, software, etc. used together to perform a specific task or objective.

METHODS OF IDENTIFYING HAZARDS

CHECKLIST

Technique that applies previously developed or published checklists for known failure and deviations, consequences, safeguards and actions. Technique can be used at any stage of a project or process provided the checklist has been made available by experienced staff.

FAILURE MODE EFFECTS ANALYSIS (FMEA)

Technique starts with components of system or process and presumes failures. All possible modes of failure are listed followed by an evaluation of whether the failure produces a hazard. Some of the failure effects (consequences) will be harmless and some may be dangerous.

Results are then deduced to see if they cause a hazard. Good for final design stages or for evaluation of reliability. Good for electronic systems, mechanical equipment, and complex. Not well suited to processes because deviations and hazards may not be due to any failure of components.

FAULT TREE ANALYSIS (FTA)

The technique begins with a top event that would normally be a hazardous event. Then all combinations of individual failures or actions that can lead to the event are mapped out in a fault tree. This provides a valuable method of showing all possibilities in one diagram and allows the probabilities of the event to be estimated. This also allows us to evaluate the beneficial effects of a protection measure.

HAZARD IDENTIFICATION STUDIES (HAZID)

Designed to identify all potential hazards, which could result from operation of a facility or from carrying out an activity.

HAZARD SAFETY AND OPERABILITY REVIEW (HAZOP)

See What If Analysis and Checklist. Designed to review process systems and operating procedures to confirm whether they will operate and be operable as intended, without having introduced any avoidable hazards. Applies to the technique of quantitative assessment of particular risks, the likelihood or frequency of the event and the severity of the consequence using key words. This is often combined with the analysis of proposed risk reduction (or protection) measures to provide a risk assessment report.

PROCESS HAZARD ANALYSIS (PHA)

Identification of hazards and the evaluation of risks in the process industries. Within the range of PHA activities there are two main stages:

- Hazard Identification
- Hazard Assessment sometimes also called Risk Analysis.

ROOT CAUSE ANALYSIS (RCA)

The study is typically reactive and is usually a part of the investigation of the hazardous event after it takes place. The technique begins with the final hazardous event. Then working backwards all combinations of individual failures or actions that can lead to the event are mapped out (sometimes in a fault tree arrangement).

WHAT-IF ANALYSIS

Team of experienced persons to test for hazards by asking relevant 'What-If' questions. Technique can be used at any stage of a project for new or existing processes.

WHAT-IF + CHECKLIST

Combination of What If Analysis and Checklist. Forerunner to HAZOP method. Designed to review process systems and operating procedures to confirm whether they will operate and be operable as intended, without having introduced any avoidable hazards. Applies to the technique of quantitative assessment of particular risks, the likelihood or frequency of the event and the severity of the consequence. This is often combined with the analysis of proposed risk reduction (or protection) measures to provide a risk assessment report.

RELIABILITY CONCEPTS

AVAILABILITY

Not the same as reliability. The percent of time the system is alive and ready for use if called upon.

FAILURE

Usually expressed mathematically as the Probability of Failure (POF) as decimal or percentage. The opposite of Reliability.

RELIABILITY

The probability that a component, system, or process will function without failure for a specific length of time when operated correctly under specific conditions.

Reliability = 1 – Probability of Failure

Reliability = 1 – POF

RISK CONCEPTS

CONSEQUENCE

The result of an action, event or condition. The effect of a cause. The outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as an injury, loss, damage, advantage, or disadvantage. Although not predominantly thought of in this manner, consequences do not always have negative connotations; they can be positive.

CONTROLS AND SAFEGUARDS

Safeguards in place by company management utilized to prevent a potentially negative impact as a result of an incident. A physical, procedural or administrative safeguard that prevents or mitigates consequences associated with an incident.

FREQUENCY

A measure of the rate of occurrence of an event described as the number of occurrences per unit time.

LIKELIHOOD

The potential of an occurrence. See Frequency.

UNMITIGATED LIKELIHOOD (UL)

Likelihood of event without intervention by administration, engineering, and/or operations.

MITIGATED LIKELIHOOD (ML)

Likelihood of event with intervention by administration, engineering, and/or operations to prevent the event or lessen the impact of the event.

PROBABILITY

Prediction of uncertainty. The likelihood of a specific outcome determined by the ratio of specific events to the total number of possible events. The probability must be a number between 0 and 1. The sum of the probabilities for all possible conditions of uncertainties must be 1.

[PURE] RISK (PR)

The possibility of a hazard becoming an incident that may have a negative or positive impact on overall objectives. It is measured in terms of likelihood and magnitude of severity.

Risk is usually defined mathematically as the combination of the severity and probability of an event. In other words, how often can it happen and how bad is it when it does happen? Risk can be evaluated qualitatively or quantitatively.

Risk = Frequency x Consequence of Hazard

Risk = Probability of Occurrence x Impact

SEVERITY (S)

The degree of an outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as a loss, injury, damage, advantage, or disadvantage. The degree or magnitude of a consequence.

RISK ANALYSIS

The analysis of available information to determine how specific events may occur and the magnitude of their consequences.

RISK ASSESSMENT

Prioritizing risk ranking utilizing risk analysis and risk evaluation.

RISK EVALUATION

A process to compare levels of risk against pre-determined standards, target risk, or other criteria.

RISK MANAGEMENT

The culture comprised of structure and process that proactively optimizes management of risk events and their adverse effects.

TYPES OF RISK

PURE RISK (PR)

The possibility of a hazard becoming an incident that may have a negative or positive impact on overall objectives. It is measured in terms of likelihood and magnitude of severity.

Risk is usually defined mathematically as the combination of the severity and probability of an event. In other words, how often can it happen and how bad is it when it does happen? Risk can be evaluated qualitatively or quantitatively.

Pure Risk = Frequency x Consequence of Hazard

Pure Risk = Probability of Occurrence x Impact

RESIDUAL RISK (RR)

The risk that remains after taking into account the effects of controls applied to mitigate the associated pure risk. No matter how much the causes are mitigated, the consequences are the same; only the frequency of incidence or occurrence can be altered.

Residual Risk = Mitigated Frequency x Consequence of Hazard

Residual Risk = Mitigated Probability of Occurrence x Impact

SIGNIFICANT RISK

Level of risk that will not or cannot be tolerated by management, regulatory bodies, work force, or public and needs to be controlled.

TOLERABLE RISK

Level of risk that will be tolerated by management, regulatory bodies, work force, or public.

TYPES OF RISK ASSESSMENT

BASELINE RISK ASSESSMENT

Used to determine the current risk profile and identify the main focus areas for improvement. Areas of interest include:

- Processes

    - Tasks
    - Equipment
- Operations
    - Activities
- Environment
- Social Impact or Impact on Reputation
- Legal/Regulatory Requirements
- Security

Issue-based Risk Assessment

Detailed assessment of issues identified during the baseline risk assessment as posing significant risk. Various techniques utilized to conduct issue based risk assessments include:

- Root Cause Analysis
- Fault Tree Analysis
- What-if + Checklist
- HAZOP
- Process Hazard Analysis

Instances where an issue based risk assessment would be appropriate are:

- Changes in the baseline risk profile
- Changes to equipment or processes
- Near-misses
- Accidents
- Change in tolerable risk perception
- Finding from a Continuous Risk Assessment

Continuous Risk Assessment

Proactive identification of occupational health, safety, and environmental hazards to actively mitigate significant risks. It is best performed as structured activities at specific and pre-determined time intervals. Such activities would include:

- Pre-use equipment checklist

- Permit to Work
- Planned inspections
- Preventive maintenance
- Planned task observations
- Job Safety Analysis (JSA)
- Health, Safety, and Environment Audits

BASELINE RISK ASSESSMENT PROCESS

There are ten facets to organizing a successful baseline risk assessment.

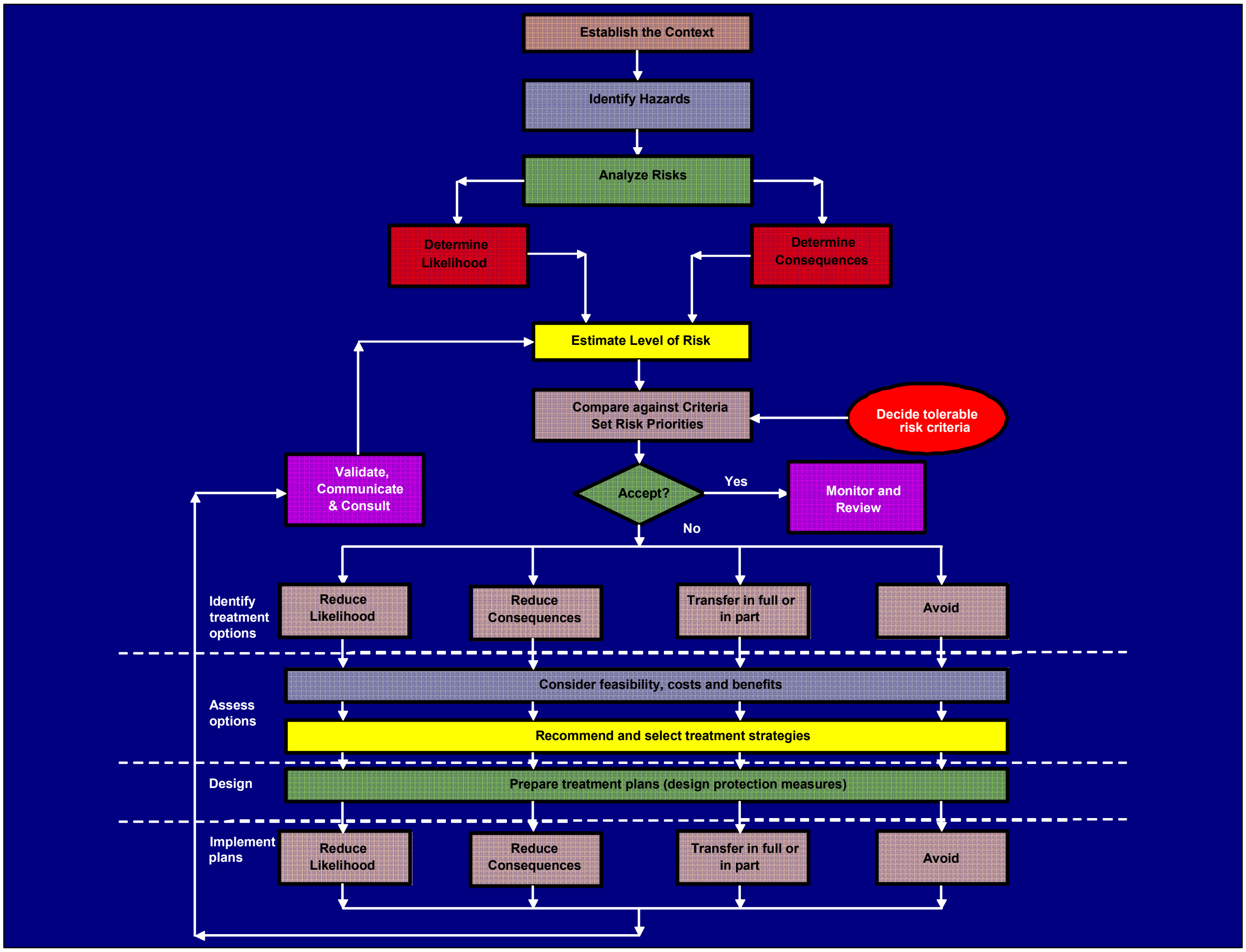
1. Preparation
2. Hazard Identification
3. Converting Hazards to Risks
4. Ranking the Risks
5. Evaluating Effectiveness of Existing Controls
6. Expressing Consequences in Monetary Terms
7. Cost/Benefit Analysis
8. Implementation of Controls
9. Audits
10. Follow-up

PREPARATION

MANDATE FROM MANAGEMENT

First and foremost, no risk assessment will have any validity unless there is a clear and unequivocal mandate from senior management. Corporate buy-in is not only essential to the success of the risk assessment it is a pre-requisite. It demonstrates the commitment and participation of management. The mandate includes funding and support for the Risk Assessment Team.

This model is a general overview of what management would expect from a risk assessment study.



Management presents important issues to the organization with policy statements. Policies define specific areas of concern and indicate the desired outcome. Policies increase decisiveness by removing uncertainty about action required to meet the objective. Policy statements communicate information to the staff in general terms for detailed implementation by procedures in a consistent fashion through individual acceptance and individual commitment. Good policies reduce the potential for bad events such as inefficiency, counter productivity, inappropriate risk taking, and conflicts over requirements so that nothing is implemented because of the void.

Modern organizations have safety policies and quality policies. Before safety and quality policies, both areas originally operated with "Everyone knows what to do, we don't need a policy." Prior to policies injury rates were high and quality was poor. After policies it was clear the safety goal was zero injuries and the quality goal was full conformance to *the requirements.* Risk *issues need a clear and concise policy statement to avoid fuzzy interpretations.*

Management has the responsibility to approve, distribute, educate, and train the organization in the requirements for risk *as a display of leadership.* (Adapted from Barringer, 2001).

GUIDANCE FROM MANAGEMENT

- Summary of the strategic, corporate and risk management context
- Reason for the review
- Objectives of the review clearly stated
- Description of the system being assessed
- Boundaries clearly and unambiguously defined
- Is the facilitator identified together with related experience?
- Is the facilitator appropriate?

NOMINATION OF A TEAM LEADER (FACILITATOR)

The Team Leader is a competent, impartial, honest, and ethical facilitator; independent of the area being analyzed, and having some working knowledge of the area being analyzed. His primary responsibilities are:

- Direct, Manage, and Focus the Team and its Activities
    - Establishes schedules
    - Leads team meetings.
    - Obtains clear objectives for the analysis
    - Ensures that objectives of the analysis are accomplished
    - Ensures that the analysis is completed on schedule
- Management of Resources
    - Obtains resources necessary for analysis
        - Arrange for funding consistent with the objectives, scope, and schedule
    - Initiates formal requests for or assigns a team member to this task
        - Information, interviews, test results, technical or administrative support
    - Establish administrative protocols for the analysis.

        - Gathering data activities
        - Preserving data

- Spokesperson
    - Serve as point of contact for the team.
- Training
    - Determine level of training required for team members to adequately function on the team
- Reporting
    - Keep management informed through verbal contact and periodic interim reports.
    - May make periodic verbal reports to management and staff, as required
    - Prepares interim written reports, as required
- Analysis Activities
    - Organizes team work for analysis activities
    - Assigns individuals to tasks and coordinates work with non-team members
- Impartiality and Integrity
    - Ensure team members maintain objectivity and commitment to the analysis
- Confidentiality
    - Protect proprietary and other sensitive information
- Final Report
    - Ensures that the final report is properly reviewed:
    - Factual accuracy of report for internal and external reports
    - Review by legal department, as necessary
    - Proprietary information protected.

GUIDANCE FOR THE TEAM LEADER

For the study to proceed efficiently and quickly (and so at lower cost) the best possible information should be assembled before the formal meeting and made available to the team members.

Some suggested items are:

- Draft project definition
- Process or equipment description with outline diagrams or flow sheets

- A listing of known HSE issues and incidents with similar projects (if any)
- Chemical or material hazard data sheets
- A hazards checklist for the type of activities in the process
- List the applicable legislation for compliance
- Draft occupational health statement
- Draft environmental statement

The following issues should be considered:

- Is the reason for the review defined?
- Are the objectives of the review stated?
- Is there a description of the system being assessed?
- Are the boundaries clearly and unambiguously defined?
- Is the documentation provided sufficient to understand the scope and function of the system?
- Is there a summary of the strategic, corporate and risk management context?
- Are the participants identified together with their organizational roles and experience related to the matter under consideration?
- Is the range of experience/expertise of the team appropriate?
- Is the method of identifying the risks clearly identified?
- Is the reason for the choice of methodology explained?
- Is the method of assessing likelihood and consequence of the risks identified?
- Is the reason for the choice of methodology explained?
- Is there a hazard inventory table?
- Is there a listing of external threats?
- Are all the core assumptions identified?
- How was the acceptability of the risks determined?
- Is the determination of the acceptability of the risks justifiable?
- Are all the risks prioritized by risk magnitude and consequence magnitude?
- Was the hazard identification process comprehensive and systematic?
- Has the approach to each part of the study been consistent?

- Have all the existing controls and performance indicators been identified and their function determined accurately?
- Have all potential new controls been identified, adequately assessed and assigned performance indicators if adopted?
- Is there a recommended action list giving actions, responsibilities and timelines for completion?
- Is there a review process to ensure the assessment is consistent with others completed at the same facility/business?

ASSEMBLY OF THE TEAM

- Composition
  - Vertical slice of the organization being analyzed.
  - Wide range of people and knowledge
  - Able to work in a “team” environment
  - Understand methods to gather and assess information
  - Able to identify workplace hazards and assign risk
  - Able to distinguish hazards between…
    - Physical
    - Behavioral
    - Procedural
  - Understand the hazards of energy sources located within the analysis area
  - Include experts on an as needed basis for specific knowledge

IDENTIFY HAZARDS

Perceptions of risk can vary significantly between members of the vertical slice of the organization. Although the perceptions differ, the initial questions are the same.

- What can happen?
- How can it happen?

The result is a list of hazards with the possible causes. Hazards can be found in processes, tasks, and activities; and most typically involve the presence of an energy source, a component of an energy source, or the abrupt change of energy that has the potential to cause a loss event. To identify all the hazards in a system can be a daunting task. A “Divide and Conquer” approach may prove beneficial.

- Define the boundaries of the risk assessment; where it starts and where it ends.
    - Geographical
    - Process
    - Activities
    - Prior Documentation
- Determine any deviations from prior documentation.
- Identify the energy sources (hazards) present during the subject process. This is only to identify a hazard. Assigning risk will come later. An aid to hazard identification
    - Areas of Impact
        - People
            - Work Conditions
                - Ergonomics
                - Unauthorized work
                - Inclines, Height
                - Alcohol and Drugs
                - Smoking
                - Behavior
                - Wet surfaces
                - Lighting
                - Ventilation
                - Noise
                - Radiation
                - Vibration
                - Monotony
                - Fatigue
                - Work – Rest Cycle
                - Stress levels
                - Shift work
                - Personal relationships
                - Hygiene and Housekeeping

        - Natural Phenomena
            - Extreme heat
            - Extreme cold
            - Rain
            - Snow
            - Wind
            - Hurricane
            - Earthquake
            - Tsunami
            - High Seas
        - Third Party Impact
            - Labor unrest
            - Fire
            - Explosion
            - Spill
            - Gas release
            - Vehicular accidents
            - Electrical supply
            - Terrorism
            - Transportation
            - Local population
            - Local commerce
            - Commercial fishing
    - Environment
        - Air
        - Land
        - Sea
    - Production
        - Process Specific

        - Drilling
            - Engineering
            - Planning
            - Maintenance
        - Production
            - Engineering
            - Planning
            - Maintenance
    - Hazardous Chemicals
        - Storage
        - Transportation
        - Gas
        - Liquid
        - Dust
        - Explosive
        - Toxic
        - Flammable
        - Vapors
        - Fumes
- Asset Damage
    - Facility Specific
        - Housekeeping
        - Offices
        - Workshop
        - Kitchen
        - Living Quarters
    - Equipment Specific
        - Age
        - Component Failure

        - Corrosion
        - High pressure
        - High flow
        - Vibration
        - Spills/Leaks
        - Lubrication
- Reputation
    - Impact on Third Party
        - Labor unrest
        - Fire
        - Explosion
        - Spill
        - Gas release
        - Vehicular accidents
        - Electrical supply
        - Terrorism
        - Transportation
        - Local population
        - Local commerce
        - Commercial fishing
- Regulatory

Energy Source	Consequences					
	People	Environment	Asset	Production	Reputation	Regulatory
Chemical	Burns Lung Damage Poisoning Irritation	Water Pollution Air Pollution Soil Pollution	Fire Explosion Corrosion Melting	Not Available Too Much Too Little Wrong Material	Social Impacts	Single Action Multiple Action Class Action
Electrical	Burns Shock Eye Damage	Resource Use Polution	Fire Fault Flashover Back Feed Induction	Not Available Too Many Amps Too Few Amps Wrong Voltage		Single Action Multiple Action
Mechanical	Contusions Crushes Impact Injuries		Impact Damage Structural Failure	Not Available Too Much Too Little Wrong Machine		Single Action Multiple Action
Pressure	Contusions Crushes Cuts	Erosion	Burst Collapse	Not Available Too Much Too Little		Single Action Multiple Action
Noise	Hearing Damage	Noise Pollution			Social Impacts	Single Action Multiple Action Class Action
Gravity	Impact Injuries		Impact Damage			Single Action Multiple Action
Radiation	Burns Cancer Freezing	Water Pollution Air Pollution Soil Pollution Ecological Impacts	Fire Melting Heat Damage Cold Damage	Not Available Too Much Too Little	Social Impacts	Single Action Multiple Action Class Action
Bio-Mechanical	Sprains Strains Slips Trips		Drop Damage			Single Action Multiple Action
Microbiological	Illness	Contamination	Contamination	Contamination Delays	Social Impacts	Single Action Multiple Action Class Action

CONVERTING HAZARDS TO RISK

Hazards are not assessed, risks are assessed. Converting hazards to risk requires reason and judgment in how the magnitude of a hazard affects health, safety, and environment. The question of reasonableness usually resolves itself. Example: an airplane striking a drilling rig.

It is most advantageous to narrow the scope as much as possible to hazards of a particular interest, or specific process, or impact area. In terms of a particular scope of work, let's define the risk of an energy source that can get out of control. First, we must assume that as a baseline the energy sources described are normally and initially under control. To maintain organization during the assessment, every hazard should be considered for each step in the process under normal, abnormal (upset), and emergency conditions.

HAZARD OUT OF CONTROL

- Management System Failure or Non-conformance
    - Quality Assurance Program
    - ISO 9000 Program
    - ISO 14000 Program
    - API Recommended Practice
    - API Specifications
- Training or Skill Deficiency
- Latent Design Defects
    - Equipment
    - Equipment layout
    - Substandard Physical Conditions
- Inappropriate or Inadequate Maintenance
    - Substandard Physical Conditions
- Faulty Procedures
- Communication Systems
    - Inadequate Supervision
- Barrier or Containment Failure
    - Physical

- Natural
  - Time
  - Distance
- Human Action
- Administrative

Outcome

The outcome of this portion of the risk assessment process is to note:

1. The step in the process that the hazard exists
   a. Startup
   b. Normal Operations
   c. Shutdown
   d. Maintenance
2. The energy source that can go out of control
3. The cause for the uncontrolled energy
4. The consequence that may result

From the outcome we can judge if the consequence of interest is of sufficient reasonableness to warrant further scrutiny. Another issue of concern is the consequence of the deviation.

Consequences

We can measure consequences in terms of injury to persons, damage to the environment, damage to property, damage to work productivity, social impact and reputation damage, and legal costs and impact. Below is a sample quantitative scale:

IMPACT AREA	CONSEQUENCES				
	Low - 1	Minor - 2	Significant - 3	Major - 4	Severe - 5
People	First Aid Case Minor Treatment Little/No Health Impact	Medical Treatment Medium Health Impact	1+ Lost Time Significant Health Impact	Permanent Health Impact Hospital Multiple Injury Major Health Impact	Fatality/Fatalities Hospitalization Grand Scale Medical Impact
Environment	Near Miss	Minor Spill Limited to Immediate Area	Limited Impact Outside of Permit Conditions External Reporting Threshold	Serious Environmental Impact	Severe
Asset Damage	<$10 M	$10 M $100 M	$100 M $1 MM	$1 MM $10 MM	>$10 MM
Production	<$10 M	$10 M $100 M	$100 M $1 MM	$1 MM $10 MM	>$10 MM
Reputation	No Coverage	No Coverage	Local	State/Region	International National
Regulatory	Near Miss No Notice	Potential Incident of Non-compliance Notice Given $10 M $100 M	Incident of Non-compliance Local $100 M $1 MM	Formal Investigation State/Region $1 MM $10 MM	Cease and Desist Order National >$10 MM

RANKING RISK

Once the hazards and risks are identified, the risks need to be analyzed to establish a priority of action to be taken to mitigate the identified risks to tolerable risks. To do so we must insert frequency into the Risk Equation.

FREQUENCY

The frequency or likelihood of an event causing injury can also be placed on a scale. For example here is a **qualitative** scale (descriptive but does not define numbers, text description):

REMOTE RARE	OCCASIONALLY	FREQUENTLY PROBABLE
Never heard of or not likely to occur	Has occurred at least once on similar projects	Is likely to occur or is known to have occurred more than once on similar projects

Alternatively, frequency can be placed on a **quantitative** scale (numeric description). This would simply rank the event frequency in events per unit of time. For example:

FREQUENCY		Rank	Months	Weeks	Days	Hours
	Frequent	5	1	4	30	720
	Probable	4	3	13	90	2160
	Occasional	3	6	26	180	4320
	Remote	2	12	52	360	8640
	Rare	1	24	104	720	17280

MEASURING RISK

Risk is something we can measure approximately by creating a scale based on the product of frequency and consequence.

PURE RISK = Frequency x Consequence of Hazard

PURE RISK = Probability of Occurrence x Impact

THE RISK MATRIX

From the above, it is clear that a scale of risk can be created from the resulting products of frequency and consequence. One popular way to represent this scale is by means of a simple chart that is widely known as a risk matrix.

When the product of frequency and consequence is high, the risk is obviously very high and is unacceptable. The unacceptable region extends downwards towards the acceptable region of risk as frequencies and/or consequences are reduced. The transitional region, as shown in the diagram, is where difficult decisions have to be made between further reduction of risk and the expenditure or complexity needed to achieve it. Our diagram shows some attempt at quantifying the frequency scale by showing a range of frequencies per year for each descriptive term. This is usually necessary to ensure some consistency in the understanding of terms used by the hazard analysts.

Some companies go a step further and assign scores or values to the descriptions of frequency and consequence. This has the advantage of delivering risk ranking on a numbered scale, allowing some degree of comparison between risk options in a design.

The scoring system adopted is an arbitrary scheme devised to suit the tolerability bands as best as possible. Each company and each industry sector may have its own scoring system that has been developed by experience to provide the best possible guidelines for the hazard study teams working in their industry. There does not appear to be any consensus on a universally applicable scoring system but the ground rules are clear. The scales must be proportioned to yield consistently acceptable results for a number of typical cases. Once the calibration of a given system is accepted, it will serve for the remainder of a project.

Consistency of grading is more important than absolute accuracy. However, without the ranking, decisions based on risk identification along may be ineffectual. Economic prudence would dictate that more resources be put on high frequency/high impact risks rather than the low hanging fruit of low frequency/low impact risk.

FREQUENCY	Frequent 5	5	10	15	20	25
	Probable 4	4	8	12	16	20
	Occasional 3	3	6	9	12	15
	Remote 2	2	4	6	8	10
	Rare 1	1	2	3	4	5
		Low - 1	Minor - 2	Significant - 3	Major - 4	Severe - 5
		CONSEQUENCES ($ MM)				

EVALUATE RISKS

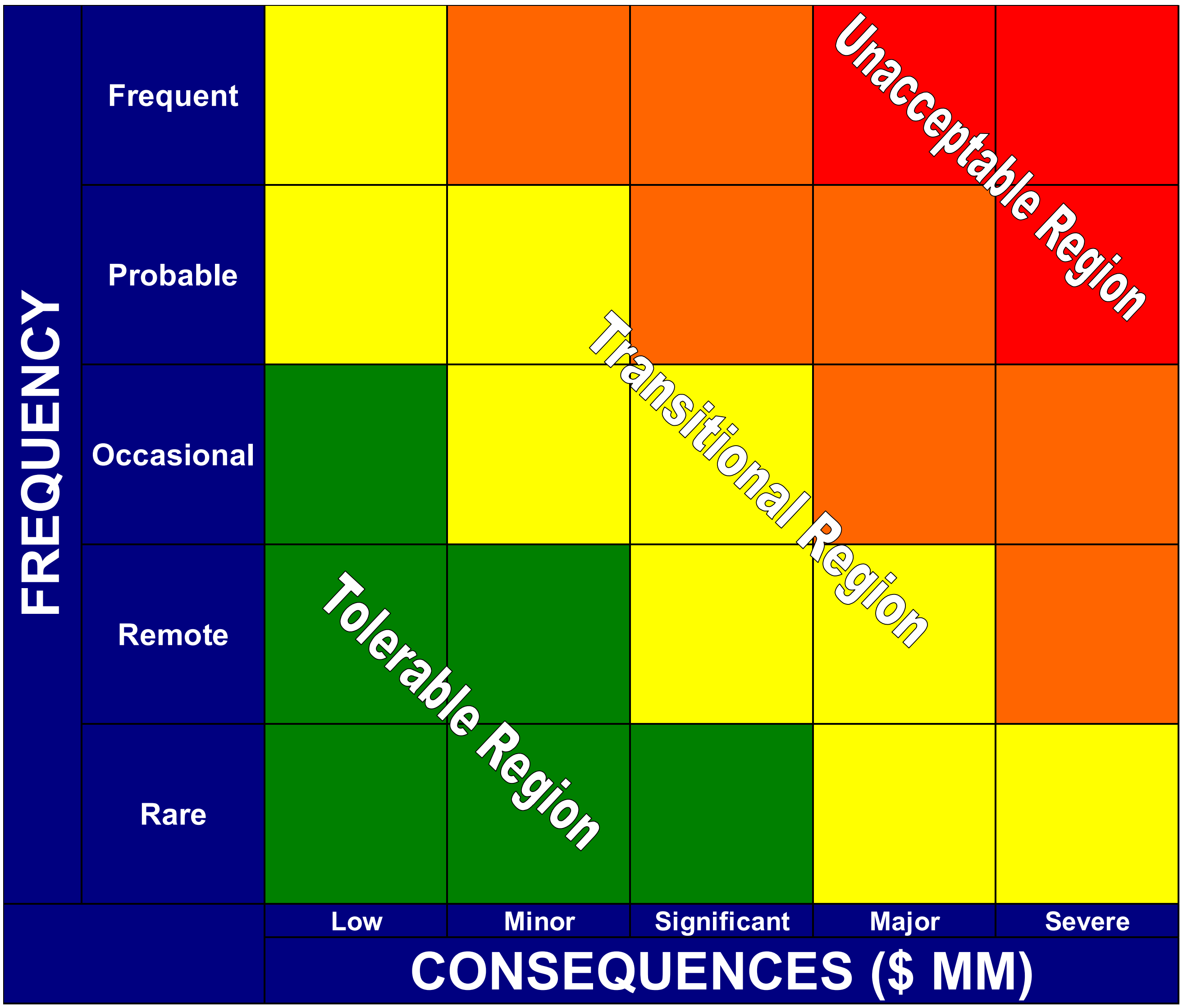
The next step is to compare the risk level with certain reference points to decide if the risk level is acceptable or not. If the risks are unacceptable the choice is to treat the risks or decide to avoid the risks altogether by doing something else. The diagram below introduces the concept of tolerable risk or acceptable risk. In practice, the reference point for acceptable risks may depend on the company, regional practice, or legal or regulatory requirements.

The format of the risk matrix allows companies to set down their interpretations of consequences in terms of losses to the business as well as harm to the environment and harm to persons. However, there seem to be some problems here that need to be sorted out:

- Where are the boundaries for the tolerable risk zone?

- Who defines the risk graph?
- Who defines the tolerable risk band?
- How far down the risk scale is good enough for my application?

These problems bring us to issues of tolerable risk and deciding how much risk reduction is justified.



RISK CONTROL AND RESIDUAL RISK

IDENTIFYING CONTROL MEASURES

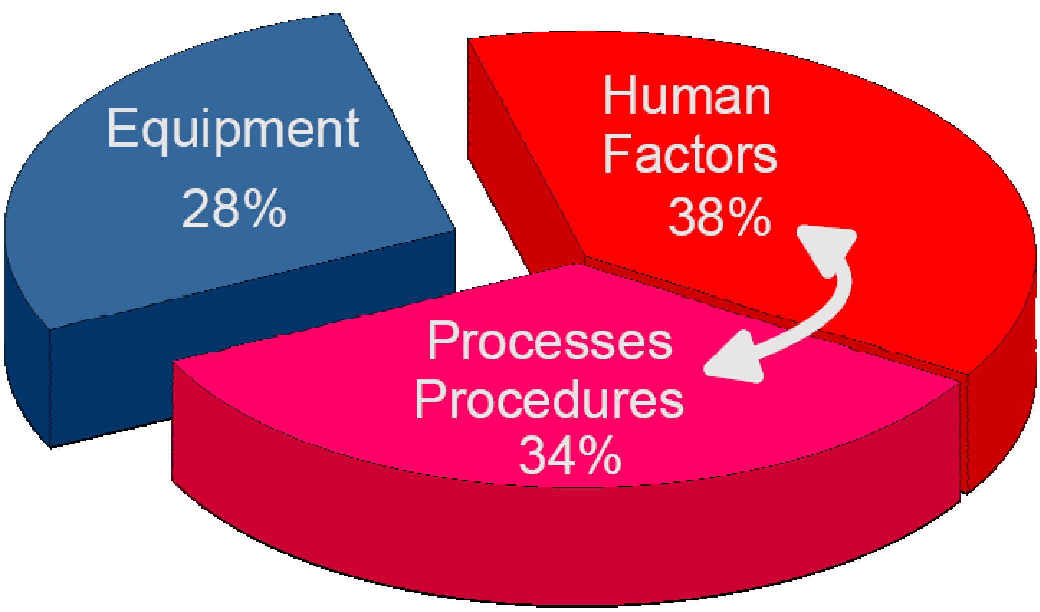
Reliability Issues

No control measure is 100% effective. It is naïve to think that we can achieve perfection. Nature's Law of Entropy expresses that the lowest energy state is chaos and disorder. Everything fails over time.

Reliability is defined as the probability that a component, system, or process will function without failure for a specific length of time when operated correctly under specific conditions. While we speak of reliability we actually measure unreliability, simply because we expect things to work when they are expected to work. Failure is supposed to be the exception, not the rule. Since failure is expected to be a low or small number, it should be less difficult to track.

Human Factors

To err is human. The American Institute of Chemical Engineers (AIChE, 1999) studied the root causes of failures and performed a Pareto Distribution of those failures. The illustration below demonstrates the human factors account for 38% of the failures, 34% were attributed to processes and procedures, and 28% were attributed to equipment. In reality, there is a strong inter-relationship between processes, procedures, and human factors; where the percentage actually ranges between 40 – 70%.



Human error can be expressed as follows:

$$\text{Human Error Probability} = \frac{\text{Number of Errors}}{\text{Number of Opportunities for Error}}$$

$$\text{Human Error Rates} = \frac{\text{Number of Errors}}{\text{Total Task Duration}}$$

The table below describes the time available for diagnosis of an abnormal event after a control room annunciation (AIChE, 1999).

Time (minutes)	Probability of Failure (%)
1	~100
10	50
20	10
30	1
60	0.1
1500	0.01

Open-minded managers realize that most mistakes are committed by skilled, productive, and well-meaning personnel. The concept that humans are reliable and equipment is unreliable underemphasizes human faults. Human unreliability is often a dominant factor in unreliability issues.

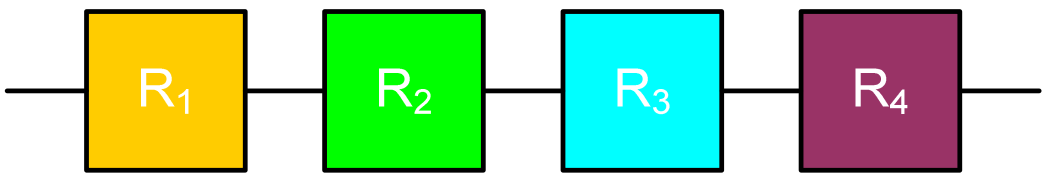
Equipment Reliability

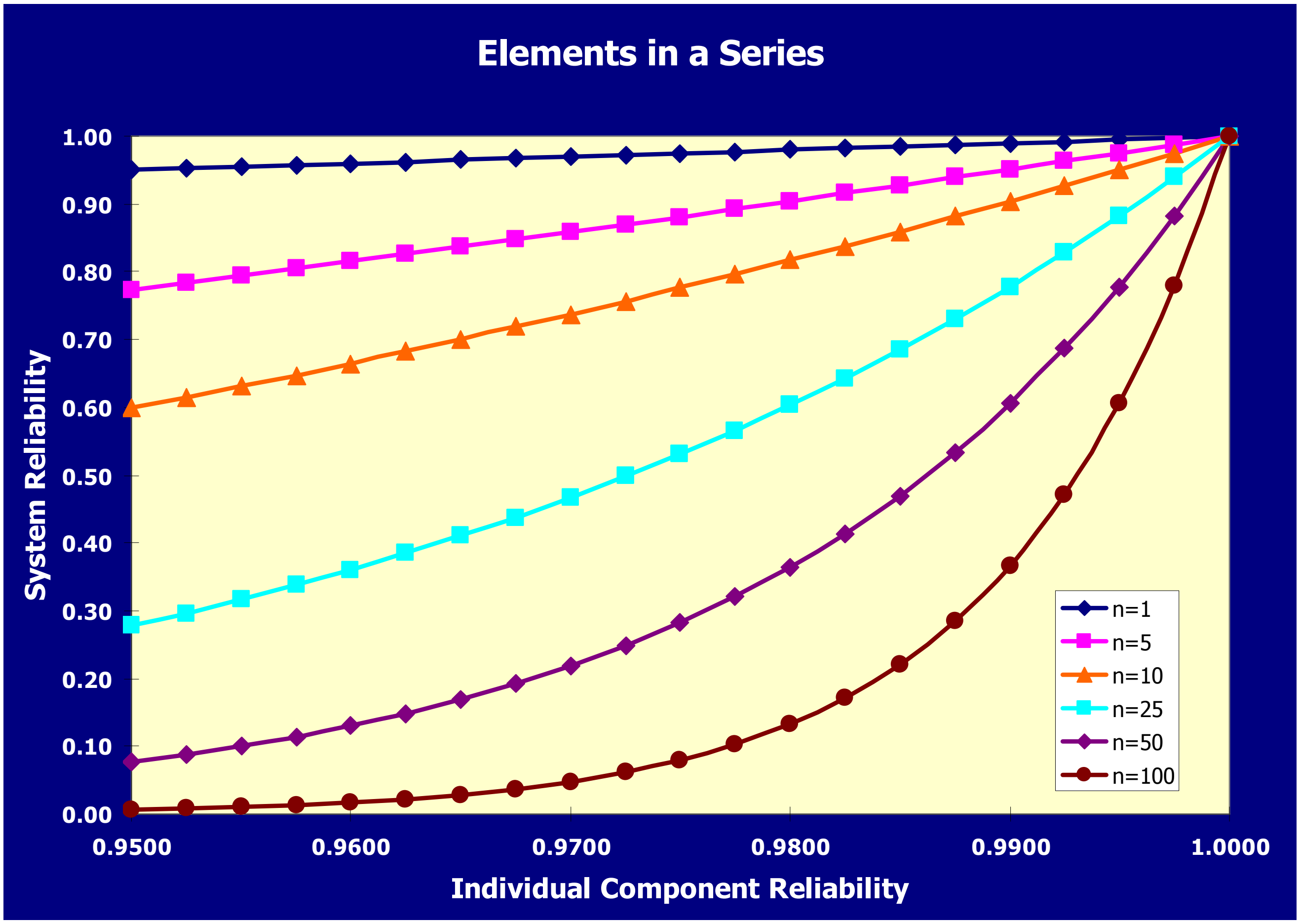
Aside from human frailties, equipment is subject to reliability issues. As an example, a piece of equipment is designed for 10,000 operating hours and will work 99.999% of the time. If operating on a 24/7 basis, that piece of equipment may not function for 10 hours within a 13 month period. How critical is that equipment to the operation? What happens when that equipment is out of service? What are the safety implications of that equipment in operation and not in operation?

Elements in a Series

The graph below describes how many elements (*i*) in series can have a potentially deleterious affect on the reliability of a system (R_s).

$$R_S = \prod_{i=1}^{n} R_i = R_1 \text{ x } R_2 \text{ x } R_3 \text{ x } R_4 \text{ ....}$$

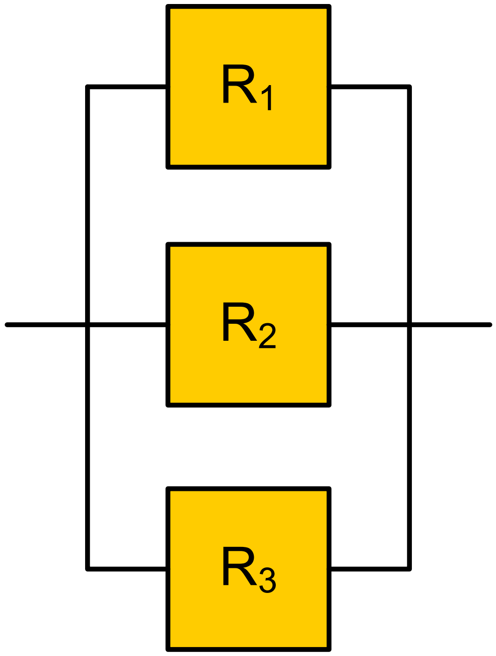




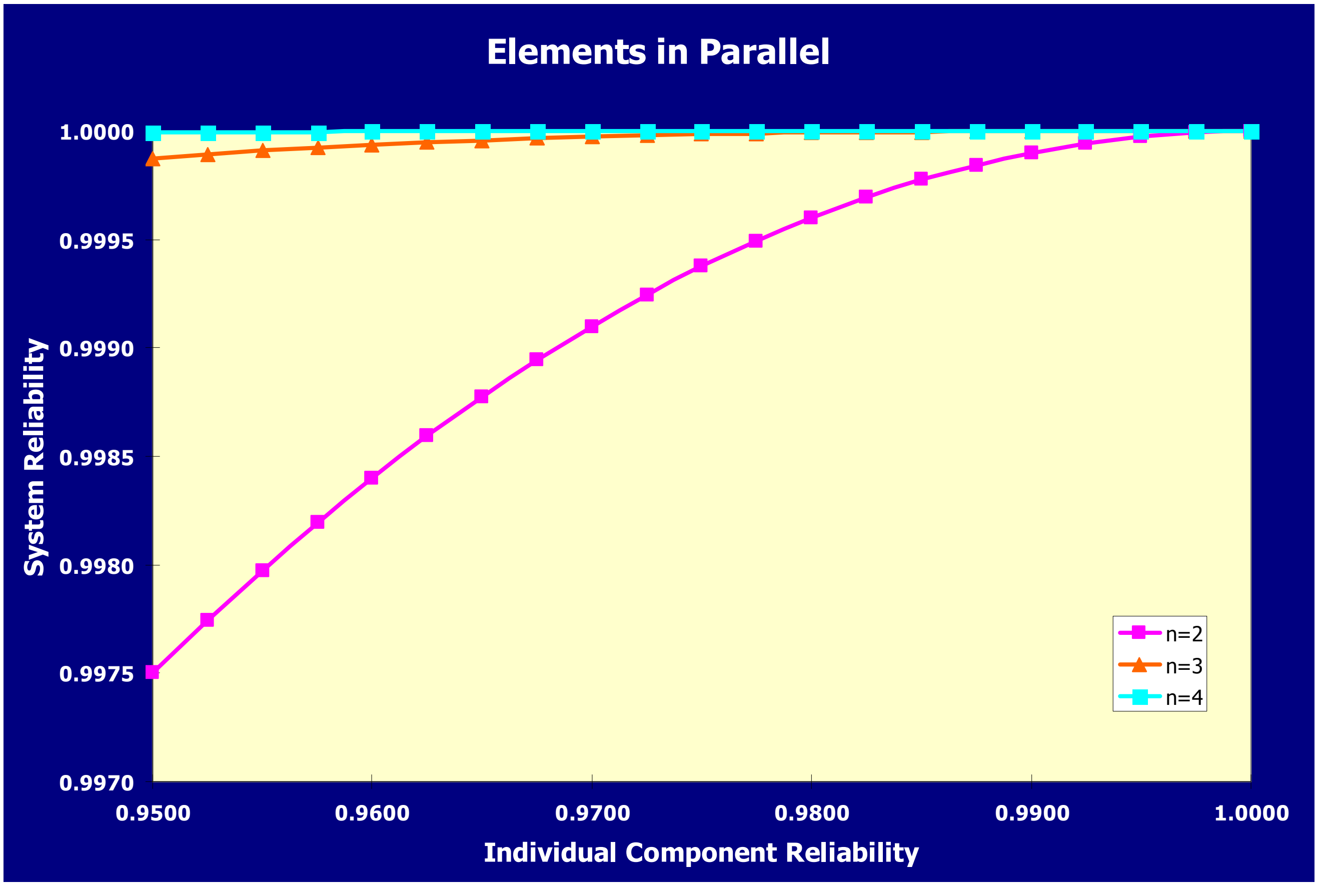
Elements in Parallel

On the other hand, high reliability elements need only a few items in parallel to achieve a high reliability system.

$$R_S = 1 - (1 - R_1) \times (1 - R_2) \times (1 - R_3) \times (....)$$



Each element in parallel must be able to carry the load.



Control Measures

While there is a hierarchy of control measures that range from the most effective to the least effective, no control is 100% effective. The more dependent controls are on human action, the less effective they are when required. At least two effective controls (barriers) should be in place for any critical task.

A recommended hierarchy of control has been devised by the International Labor Organization Convention 176: Safety and Health in Mines, Article 6, 1995.

In taking preventive and protective measures under this Part of the Convention the employer shall assess the risk and deal with it in the following order of priority:

- Eliminate the risk;
- Control the risk at source;
- Minimize the risk and;

- If the risk remains,
    - Provide for the use of personal protective equipment and
    - Institute a program to monitor the risks employees may be exposed to; having regard to what is reasonable, practicable and feasible, and to good practice and the exercise of due diligence.

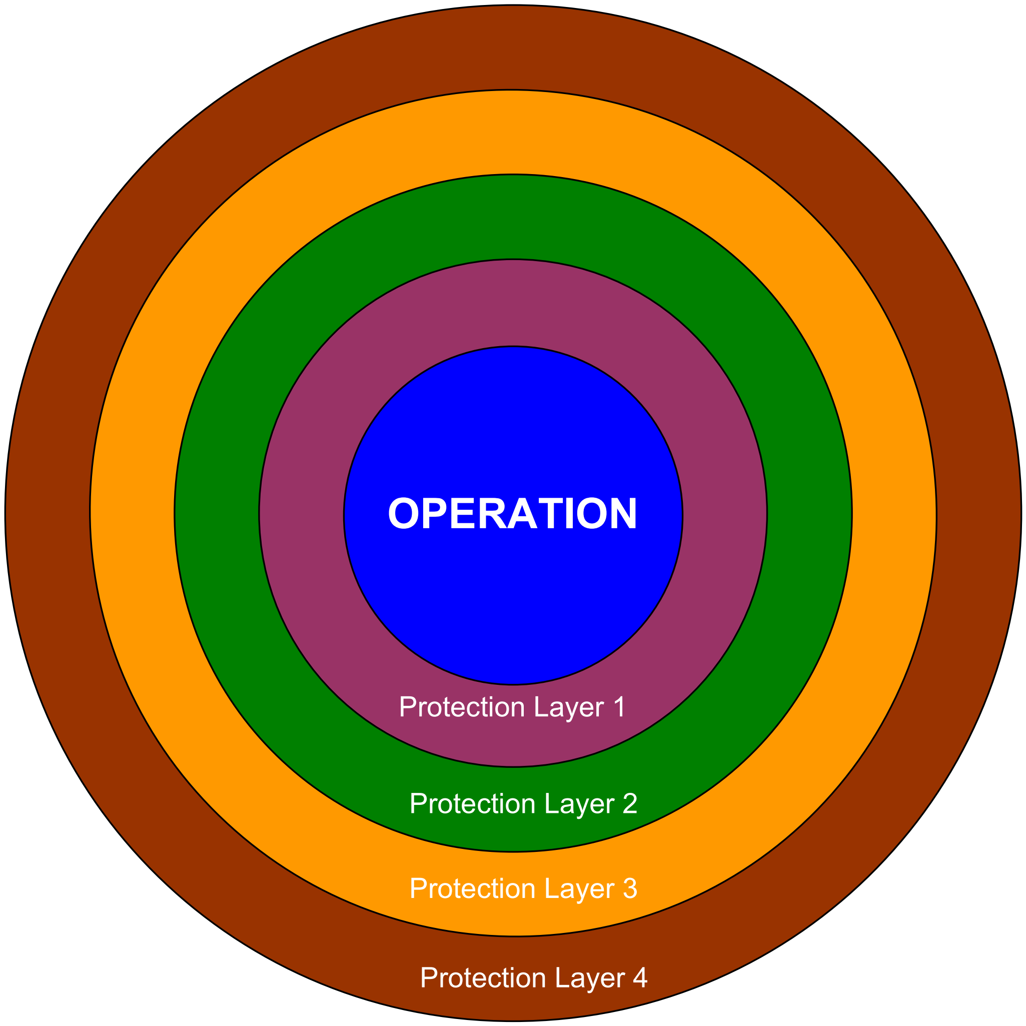
The identification of measures to reduce risk takes place during the hazard study. It is useful for the study team to have a set of prompts of typical measures available. The best measures are those that prevent the causes of hazards. We are often able to reduce the risk by reducing the likelihood or frequency of an event.

Measures to reduce consequences are used when the causes of a hazard cannot be further reduced. These measures accept that the hazardous event may occur but provide means of mitigating the scale of events to reduce the consequences.

Protection layers are divided into two main types:

- Prevention
- Mitigation

Each layer must be independent of the other, so that if one layer fails, the next layer can be expected to provide back-up protection.

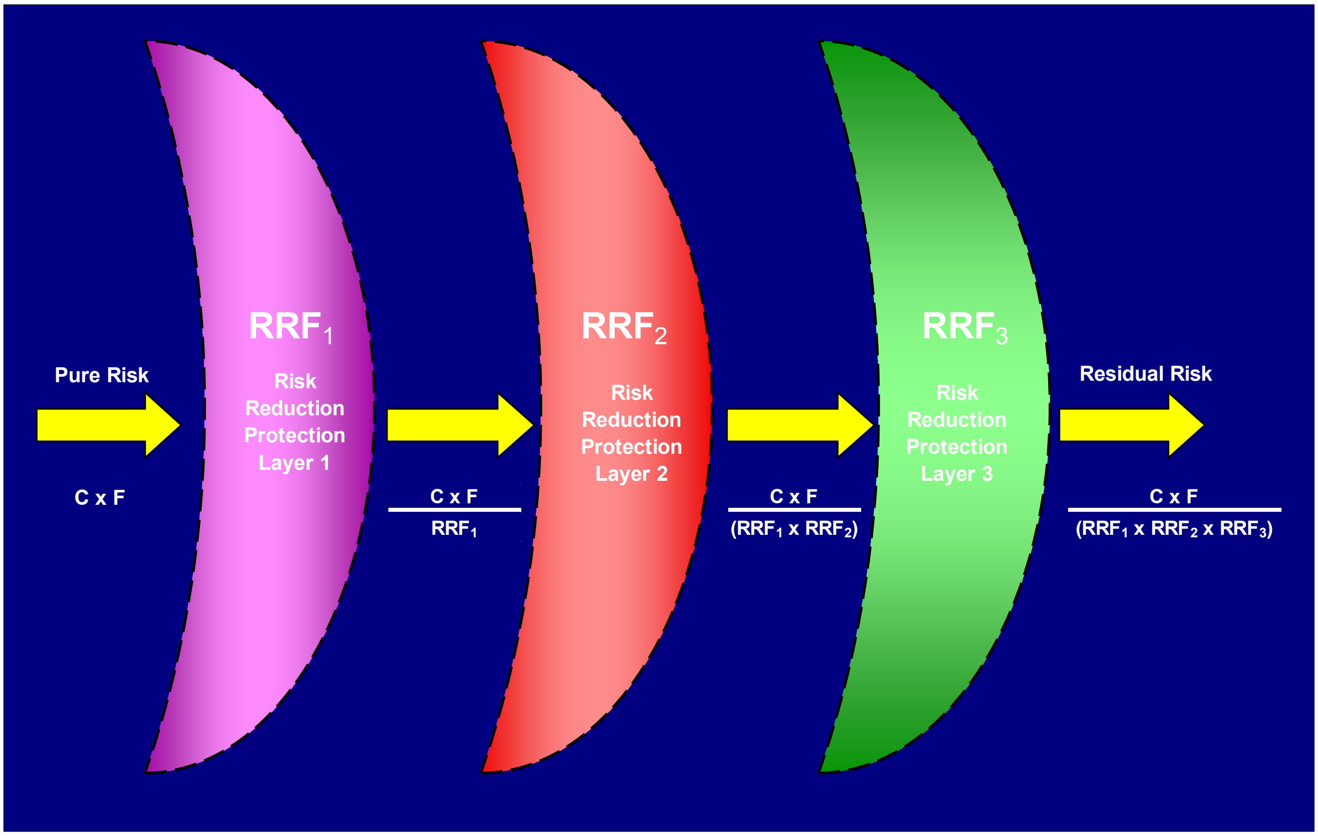


Protection Layers

A protection layer consists of a grouping of equipment and/or administrative controls that function in concert with other protection layers to control or mitigate process risk. The pure risk is reduced by each layer of protection.

Mitigation Layers

Mitigation layers reduce the consequences after the hazardous event has taken place. Mitigation layers include fire extinguishing systems, containments, and evacuation procedures. Anything that contributes to reducing the severity of harm, after the hazardous event has taken place, can be considered a mitigation layer.



Where C= Consequences, F= Frequency, and RRF$_x$ = Risk Reduction Factor

Establishing Tolerable Risk Criteria

The risk assessment team is charged with the task of determining the effectiveness of controls to prevent or mitigate particular risks. The effectiveness of the control measures will point toward a modification of pure risk exposure and assist in identifying additional control measures that may be instituted as appropriate, where …

Pure Risk – Effective Controls = Residual Risk

Residual Risk is an estimate taking into account the effectiveness of prevention and mitigation methods to control a pure risk situation.

Control Measures – What Are They?

There are three basic techniques available to an organization designed to minimize risk exposure as low as reasonably possible at a reasonable cost. They are:

- Prevention
- Detection
- Mitigation

Listed below are some examples that are measureable. While this list is not exhaustive it acts as a checklist to consider risks and their potential controls systematically and could help to determine if additional controls are necessary. With some overlap, there are three areas that tend to originate and maintain safeguards.

- Administration
  - Training
  - Emergency Plans
  - Directives
  - Supervision
  - Planned Inspections
  - Communications
  - Security
  - First Aid
  - Legal/Regulatory Requirements
  - Management of Change
- Engineering
  - Equipment Design
  - Energy Barriers
  - Identification of Critical Equipment
  - Warning Signs
  - Emergency Equipment
- Operations
  - Procedures
  - Job Safety Analysis

- Permit to Work
- Emergency Drills
- Pre-use checklist
- Planned Maintenance
- Incident Management

Residual Risk Ranking

One method to estimate the effectiveness of certain controls against a specific risk would be to:

1. Count the number of controls measures that act as safeguards for a specific risk.
2. Determine the percentage effectiveness of the collection of controls against a specific risk.
    a. As an example, say the collective effectiveness of the controls is 85%. If Pure Risk equals 100%, then the Residual Risk will equal 15% (100% - 85%).
3. Multiply the Pure Risk by the Residual Risk percentage.
    a. 25 x 0.15 = 3.75
    b. 4 falls in the green, tolerable range in the example risk matrix.

Had the effectiveness of the control been 60%, the residual risk would have been 10 (25 x 0.40). That may have been defined as still a Significant Risk. If so, the risk assessment team would be encouraged to find additional or stronger methods of control to get the Residual Risk to a more tolerable number.

The Residual Risks are then ranked with attention given to the higher numbers from highest priority to lowest priority.

QUANTIFYING RISK

The language of business is money. The civilized world holds that a human life is priceless, but society does allow for certain risks. For communication purposes certain values need to be assigned to convert humanitarian and violation issues into time and cost – the language of commerce, decision-making and action; so that business trade-off decisions can be made. Any values described herein are not intended to be guidance values for attorneys, nor do they represent callous and cynical views on the value of human life.

Measures to control risk always cost money. There is always the potential for conflict between management, employees, and the public over the extent and magnitude of expenditures necessary to promote safety, health, and environment issue that are considered reasonable and practical.

By analyzing the costs of risks through an activity-based cost approach, the relationship between cost drivers and activities can be better understood.

The list below describes some typical cost drivers that reflect the comprehensive cost of incidents.

- Wages and compensation paid to the injured or ill while not working
- Recovery, rescue, and cleanup cost
- Loss of production
- Training of replacement worker(s)
- Re-training cost of injured/ill worker(s)
- Investigation costs
- Medical and hospitalization costs
- Worker rehabilitation and therapy
- Equipment damage
- Incident site repair and renovation
- Statutory fines and penalties\
- Administrative costs
- Loss of market share, reputation, and integrity
- Litigation

Using the list such as one described above will aid in the development of an effective cost/benefit analysis.

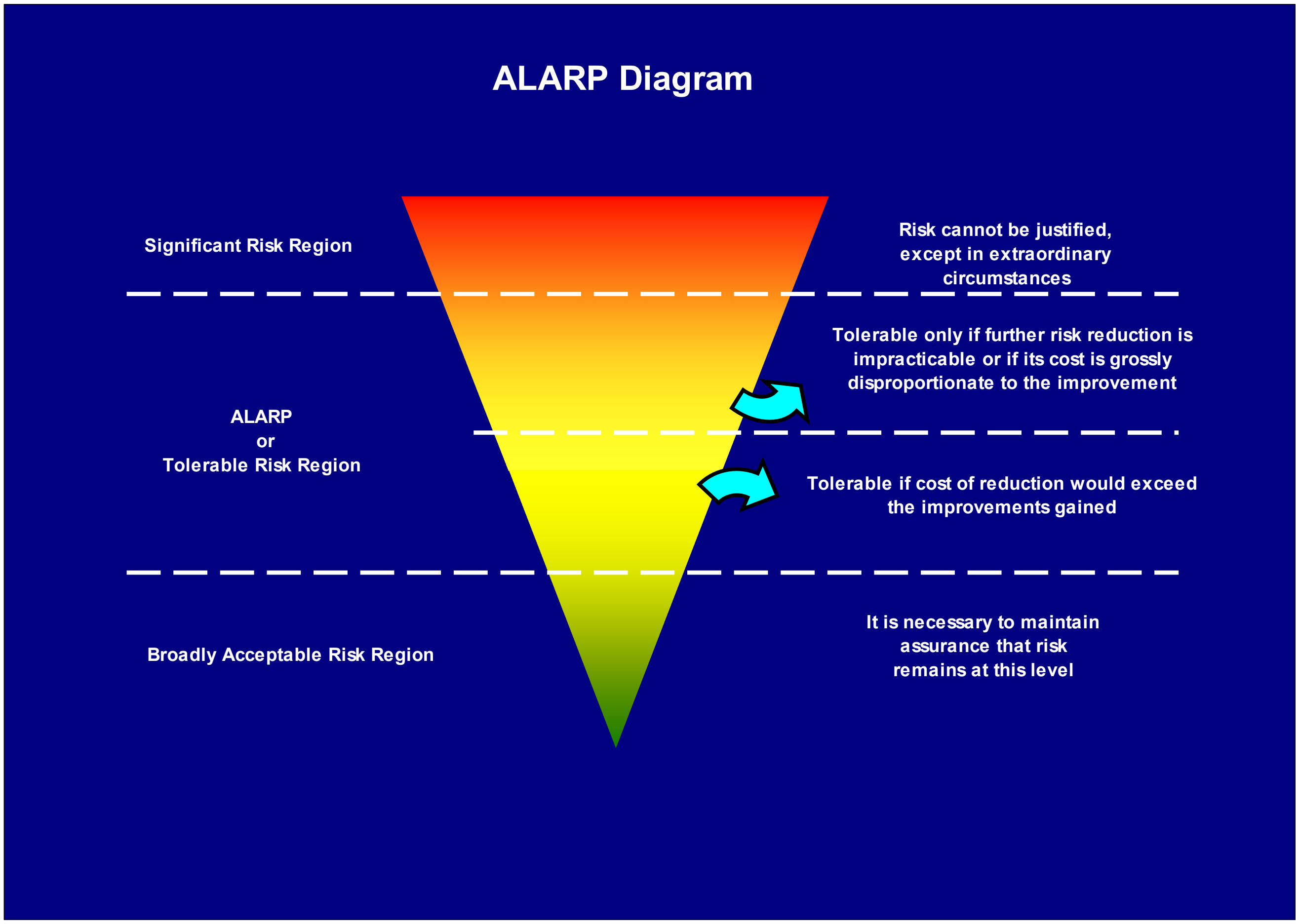
COST BENEFIT ANALYSIS

While the identification of measures to reduce risk takes place during the hazard study by the risk assessment team, the final decision to implement a specified control rests with management after quantifying the risk and performing a cost/benefit analysis. Conducting a formal cost/benefit analysis to determine tolerable risk is a joint responsibility effort between management and employees.

Significant Risk is not tolerated by management, regulatory bodies, work force, or public and needs to be controlled. Tolerable Risk is tolerated by management, regulatory bodies, work force, or public. Tolerable does not necessarily mean acceptable. Tolerable refers to the willingness to accept a risk to secure certain benefits in the confidence that the risk is being properly controlled.

CONCEPTS OF ALARP

Control measures are designed to reduce risk. In some cases, this will be an alternative way of doing things or it can be a protection system. When we set out to design a protection system, we have to decide how good it must be. We need to decide how much risk reduction is needed. The target is to reduce the risk from the unacceptable to at least the tolerable. The concept of tolerable risk is part of the widely accepted principle of ALARP (As Low As Reasonably Practical).



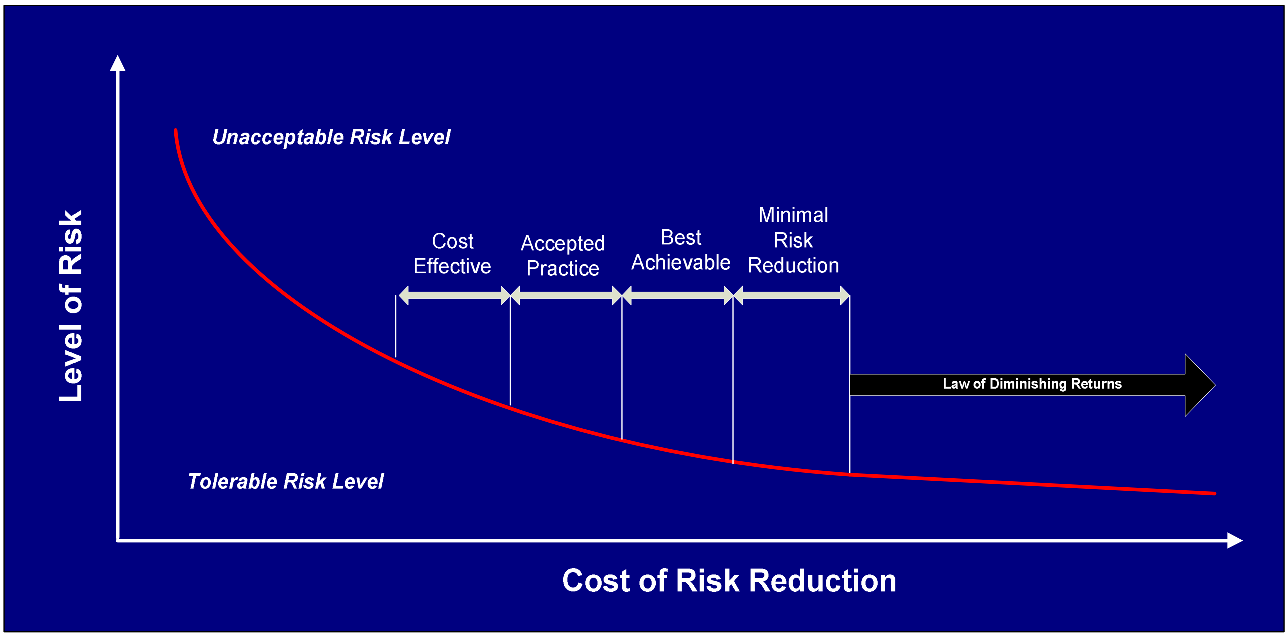
RISK REDUCTION DESIGN PRINCIPLES

The ALARP principle recognizes that there are three broad categories of risks:

- Significant risk: The risk level is so high that we are not prepared to tolerate it. The losses far outweigh any possible benefits in the situation.
- Tolerable risk: We would rather not have the risk but it is tolerable in view of the benefits obtained by accepting it. The cost in inconvenience or in money is balanced against the scale of risk, and a compromise is accepted.
- Negligible risk: Broadly accepted by most people as they go about their everyday lives, these would include the risk of being struck by lightning or of having brake failure in a car.

The width of the triangle represents risk, and as the width reduces, the risk zones change from unacceptable through to negligible. The hazard study and the design teams for a hazardous process or machine have to find a level of risk that is as low as reasonably practicable in the circumstances or context of the application. The problem here is: How do we find the ALARP level in any application?

- The pure level of risk must first be reduced to below the maximum level of the ALARP region at all costs. This assumes that the maximum acceptable risk line has been set as the maximum tolerable risk for the society or industry concerned.
- Further reduction of risk in the ALARP region requires cost benefit analysis to see if the additional expenditure is justified.



- Risk control measures should be undertaken within the broad corporate scope of risk aversion, reputation, and financial objectives considering health, safety, environment, and social benefits measured against further risk reduction to the broadly acceptable risk region.
- The principle is simple: If the cost of the unwanted scenario is more than the cost of improvement the risk reduction measure is justified.

IMPLEMENTATION OF CONTROLS

Upon receipt of approval to enact controls, an implementation schedule should be drafted. The action plan should include personnel, resources, and completion dates; and where possible integrated into normal day-to-day operations.

AUDITS

As part of the ongoing evaluation process, a risk management audit is a detailed and systematic review to determine if the objectives of the risk management program are appropriate to the needs of the organization, whether the steps taken to achieve the stated objectives were appropriate and suitable, and if those controls were properly implemented. Whether the review is conducted internally or by an external auditor, the process typically involves the following:

- Evaluate risk management policy
  - Are objectives being met consistent with policy
- Identify exposure to loss
- Evaluate decisions related to exposure to loss
- Evaluate implementation of risk control methods and techniques
- Recommend changes for improvement

FOLLOW-UP

Upon conclusion of the Audit Phase, management should periodically begin the risk assessment process again for re-validation, ensure controls are working properly and in place, develop additional controls as necessary, and possibly de-activate non-essential controls if the modified risk profile has made them unnecessary.

Project No. DEA155

Exemplar

Risk Assessment of Managed Pressure Drilling Operations in an Offshore Environment

October 2008

MOHR ENGINEERING DIVISION
a division of STRESS ENGINEERING SERVICES INC.

Table 1 Drawings Used in the Analysis

See Chapter 05-MPD Constant Bottom Hole Pressure

Table 2 Team Members

See Chapter 02 Acknowledgements

Table 3 Action Items

Type	No.	Action	Due Date	Status	Responsibility	Drawing	References
Recommendation	1	Need to define how much flow			Drilling Engineer		7.13 Well Control Incident - Kick — Open Hole
Recommendation	2	Taking slow pump rates the beginning of every tour			Drilling Contractor		7.13 Well Control Incident - Kick — Open Hole
Recommendation	3	Need to establish procedure to install internal BOP valve			Drilling Contractor, CCS Vendor		3.10 Not able to stab-in internal BOP or TIW valve — Constant Circulating System
Recommendation	4	Prepare survey procedure for Constant Circulating System			Drilling Contractor, Survey Tool Vendor		6.5 Not able to perform downhole surveys — Downhole Tools
Recommendation	5	Consider (Pressurized) Mud Cap Drilling			Operator, Drilling Engineer, Engineering Contractor		7.4 Unable to handle loss situation — Open Hole
Recommendation	6	Establish contingency plan should test interval exceed regulatory requirements			Drilling Engineer		1.2 Failure to follow work plan — Human Factors 2.8 Failed BOP/MPD stack test — Rig Equipment
Recommendation	7	Institute permit to work system			Drilling Contractor		1.1 Inexperienced or untrained personnel — Human Factors 1.5 Unclear definition of job duties — Human Factors
Recommendation	8	Need for proper staffing			Drilling Contractor, Service Provider		1.1 Inexperienced or untrained personnel — Human Factors 1.4 Rig personnel understaffed — Human Factors
Recommendation	9	Need rig personnel organization chart			Drilling Contractor		1.1 Inexperienced or untrained personnel — Human Factors 1.5 Unclear definition of job duties — Human Factors
Recommendation	10	Need training prior to start of operations			Drilling Contractor		1.1 Inexperienced or untrained personnel — Human Factors 1.5 Unclear definition of job duties — Human Factors
Recommendation	11	Need to inform rig			Operator, Service		1.1 Inexperienced or

Type	No.	Action	Due Date	Status	Responsibility	Drawing	References
		manager of personnel requirements			Provider		untrained personnel — Human Factors 1.6 Maximum personnel limit exceeded — Human Factors
Recommendation	12	Need to establish chain of command			Drilling Contractor		1.1 Inexperienced or untrained personnel — Human Factors 1.5 Unclear definition of job duties — Human Factors
Recommendation	13	Need to determine personnel competency during training			Trainer, Drilling Contractor		1.1 Inexperienced or untrained personnel — Human Factors 1.7 Personnel unfamiliar with equipment — Human Factors
Recommendation	14	Discuss deficiencies in personnel training with operator management			Trainer, Operator, Drilling Contractor		1.1 Inexperienced or untrained personnel — Human Factors 1.7 Personnel unfamiliar with equipment — Human Factors
Recommendation	15	Need to implement lessons learned from prior work			Operator		1.1 Inexperienced or untrained personnel — Human Factors 1.2 Failure to follow work plan — Human Factors
Recommendation	16	Need to perform black-out test to ensure reliability of backup generator			Drilling Contractor		2.1 Loss of electric power (momentary or longer) — Rig Equipment 10.3 Loss of flow meter — Surface Pressure Flow Control Manifold
Recommendation	17	Need contingency plan for obstructed drill string			Drilling Engineer		5.7 Obstructed drill string — Drill String
Recommendation	18	Need contingency plan for handling leak or washout in drill string			Drilling Engineer		5.6 Washout in drill string — Drill String 5.8 Tool joint leak — Drill String
Recommendation	19	Need to prepare contingency plans for Non-return valve failure					5.9 Non-return valve (float valve) leaking — Drill String

Type	No.	Action	Due Date	Status	Responsibility	Drawing	References
Recommendation	20	Need to establish make-up torque procedures for drill string			Drilling Engineer		5.6 Washout in drill string — Drill String
Recommendation	21	Install jets to move fluid through solids control system			Drilling Contractor		4.9 Surface returns line obstruction — Drilling Fluids
Recommendation	22	Need to review procedures for Shut-in of Subsea BOP			Drilling Engineer		8.2 Gas in riser — Drilling Riser
Recommendation	23	Review riser design criteria			Drilling Engineer		8.1 Riser leak or failure — Drilling Riser
Recommendation	24	Need corrective action plan for plugged choke			Vendor, Service Provider, Drilling Engineer		10.4 Loss of pressure control — Surface Pressure Flow Control Manifold
Recommendation	25	Verify design capacity and operating limits of mud-gas separator			Drilling Contractor		10.6 Unexpected gas to surface — Surface Pressure Flow Control Manifold
Recommendation	26	Establish policy on temporary piping			Drilling Contractor, Operator, Vendors		10.9 Line rupture — Surface Pressure Flow Control Manifold
Recommendation	27	Establish temporary piping permit system			Drilling Contractor, Operator, Vendors		10.9 Line rupture — Surface Pressure Flow Control Manifold
Recommendation	28	Need mud management plan			Drilling Engineer, Drilling Contractor		4.10 No kill weight mud available — Drilling Fluids
Recommendation	29	Discharge pressure rating of 5000 psi minimum			Drilling Contractor		2.11 Exceeding pressure rating of equipment — Rig Equipment
Recommendation	30	Pumping capacity 2 times maximum rate expected			Drilling Contractor		2.11 Exceeding pressure rating of equipment — Rig Equipment
Recommendation	31	Investigate automation of manual lock			Vendor		9.1 Access to Rotating Control Device and Blowout Preventer stack — Rotating Control Device
Recommendation	32	Pressure Relief Valve beneath Rotating Control Device needs to have remote setting capability. Different pressure settings for drilling and making connections.			Drilling Contractor, Vendor		9.3 Pressure exceeds rated pressure — Rotating Control Device

Type	No.	Action	Due Date	Status	Responsibility	Drawing	References
Well Construction Design Deficiency	1	Geological/Geophysical data			Drilling Engineer		4.3 Lost circulation — Drilling Fluids 7.7 Lost Circulation — Open Hole

Table 4 List of Sections

No.	Type	Name	Description	Design Intent	Drawings
1		Human Factors			
2		Rig Equipment			
3		Constant Circulating System			
4		Drilling Fluids			
5		Drill String			
6		Downhole Tools			
7		Open Hole			
8		Drilling Riser			
9		Rotating Control Device			
10		Surface Pressure Flow Control Manifold			
11		Auxiliary Annular Pump			

Table 5 Regulatory Risk Matrix Used in Analysis

	Low	Minor	Significant	Major	Severe
Frequent	5	10	15	20	25
Probable	4	8	12	16	20
Occasional	3	6	9	12	15
Remote	2	4	6	8	10
Rare	1	2	3	4	5

Table 6 Reputation Risk Matrix Used in Analysis

	Low	Minor	Significant	Major	Severe
Frequent	5	10	15	20	25
Probable	4	8	12	16	20
Occasional	3	6	9	12	15
Remote	2	4	6	8	10
Rare	1	2	3	4	5

Table 7 Production Risk Matrix Used in Analysis

	Low	Minor	Significant	Major	Severe
Frequent	5	10	15	20	25
Probable	4	8	12	16	20
Occasional	3	6	9	12	15
Remote	2	4	6	8	10
Rare	1	2	3	4	5

Table 8 Asset Damage Risk Matrix Used in Analysis

	Low	Minor	Significant	Major	Severe
Frequent	5	10	15	20	25
Probable	4	8	12	16	20
Occasional	3	6	9	12	15
Remote	2	4	6	8	10
Rare	1	2	3	4	5

Table 9 Environment Risk Matrix Used in Analysis

	Low	Minor	Significant	Major	Severe
Frequent	5	10	15	20	25
Probable	4	8	12	16	20
Occasional	3	6	9	12	15
Remote	2	4	6	8	10
Rare	1	2	3	4	5

Table 10 People Risk Matrix Used in Analysis

	Low	Minor	Significant	Major	Severe
Frequent	5	10	15	20	25
Probable	4	8	12	16	20
Occasional	3	6	9	12	15
Remote	2	4	6	8	10
Rare	1	2	3	4	5

Table 11 Risk Assessment Table Legend

Deviation	Departure from agreed upon process, procedure, or normal expected function.
Cause	A person, event, or condition that is responsible for an effect, result, or consequence.
Consequence	The result of an action, event or condition. The effect of a cause. The outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as an injury, loss, damage, advantage, or disadvantage. Although not predominantly thought of in this manner, consequences do not always have negative connotations; they can be positive.
Category	With respect to consequence, specific area of impact. Examples: • People • Environment • Asset • Production • Reputation • Regulatory
Severity **(S)**	The degree of an outcome or range of possible outcomes of an event described qualitatively (text) or quantitatively (numerical) as a loss, injury, damage, advantage, or disadvantage. The degree or magnitude of a consequence.
Unmitigated Likelihood **(UL)**	Likelihood of event without intervention by administration, engineering, and/or operations.
Pure Risk **(PR)**	The possibility of a hazard becoming an incident that may have a negative or positive impact on overall objectives. It is measured in terms of likelihood and magnitude of severity. Risk is usually defined mathematically as the combination of the severity and probability of an event. In other words, how often can it happen and how bad is it when it does happen? Risk can be evaluated qualitatively or quantitatively. **Pure Risk = Frequency x Consequence of Hazard** **Pure Risk = Probability of Occurrence x Impact**
Mitigated Likelihood **(ML)**	Likelihood of event with intervention by administration, engineering, and/or operations to prevent the event or lessen the impact of the event.
Residual Risk **(RR)**	The risk that remains after taking into account the effects of controls applied to mitigate the associated pure risk. No matter how much the causes are mitigated, the consequences are the same; only the frequency of incidence or occurrence can be altered. **Residual Risk = Mitigated Frequency x Consequence of Hazard** **Residual Risk = Mitigated Probability of Occurrence x Impact**

Safeguards	There are three basic techniques available to an organization designed to minimize risk exposure as low as reasonably possible at a reasonable cost. They are: • Prevention • Detection • Mitigation With some overlap, there are three areas that tend to originate and maintain safeguards. • Administration • Engineering • Operations

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
1.1	Inexperienced or untrained personnel	Project understaffed Assumed competency	Contribute to unplanned events and Non-productive Time	Production	2	2	4	2	4	Training of personnel during planning phase Pre-tour safety meetings Job Safety Analysis More intensive supervision	Rec 7. Institute permit to work system **Responsibility:** Drilling Contractor Rec 8. Need for proper staffing **Responsibility:** Drilling Contractor, Service Provider Rec 9. Need rig personnel organization chart **Responsibility:** Drilling Contractor Rec 10. Need training prior to start of operations **Responsibility:** Drilling Contractor Rec 11. Need to inform rig manager of personnel requirements **Responsibility:** Operator, Service Provider Rec 12. Need to establish chain of command **Responsibility:** Drilling Contractor Rec 13. Need to determine personnel competency during training **Responsibility:** Trainer, Drilling Contractor Rec 14. Discuss deficiencies in personnel training with operator management **Responsibility:** Trainer, Operator, Drilling Contractor Rec 15. Need to implement lessons learned from prior work **Responsibility:** Operator

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Incorrect mud weight measurements - Drilling Fluids (linked to 4.6)	Production	3	2	6	1	3		
			Personnel injury (linked to 1.3)	People	1	1	1	1	1		
			Failure to follow work plan (linked to 1.2)	Production	1	1	1	1	1		
			Unclear definition of job duties (linked to 1.5)	People	3	2	6	1	3		
			Equipment damage	Asset	3	2	6	1	3		
			Rig personnel understaffed (linked to 1.4)	People	3	2	6	1	3		
			Personnel unfamiliar with equipment (linked to 1.7)	People	3	2	6	1	3		
			Pressure Relief Valve activates and not detected - Rig Equipment (linked to 2.12)	Envrnmt	2	2	4	1	2		
1.2	Failure to follow work plan	Inexperienced or untrained personnel (linked from 1.1) Inadequate training Lessons learned not implemented	Unplanned event originating from Constant Circulating System - Constant Circulating System (linked to 3.3)	Production	2	3	6	1	2	Training of personnel during planning phase Pre-tour safety meetings Job Safety Analysis More intensive supervision Review of procedures prior to drilling operations Personnel training	Rec 6. Establish contingency plan should test interval exceed regulatory requirements **Responsibility:** Drilling Engineer Rec 15. Need to implement lessons learned from prior work **Responsibility:** Operator

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
										Maintain continuity of experienced personnel levels	
			Unclear definition of job duties (linked to 1.5)	Production	3	3	9	1	3		
1.3	Personnel injury	Inexperienced or untrained personnel (linked from 1.1) Personnel unfamiliar with equipment (linked from 1.7) Unclear definition of job duties (linked from 1.5) Rig personnel understaffed (linked from 1.4) Line rupture - Surface Pressure Flow Control Manifold (linked from 10.9)	Trouble installing Continuous Circulating System - Constant Circulating System (linked to 3.2)	People	1	2	2	1	1	Review of procedures prior to drilling operations Personnel training Maintain experienced personnel levels Mockup installation offsite Permit to work system	
			Non-productive Time	Production	1	1	1	1	1		
1.4	Rig personnel understaffe d	Inexperienced or untrained personnel (linked from 1.1)	Fatigue	People	3	3	9	1	3	Maximum 12 hour shifts	Rec 8. Need for proper staffing **Responsibility:** Drilling Contractor, Service Provider
			Mental errors	People	3	3	9	2	6		
			Unclear definition of job duties (linked to 1.5)	People	3	2	6	1	3		
			Personnel injury (linked to 1.3)	People	4	2	8	1	4		
			Unexpected gas to surface - Surface	Production	4	2	8	1	4		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Pressure Flow Control Manifold (linked to 10.6)								
			Pressure Relief Valve activates and not detected - Rig Equipment (linked to 2.12)	Production	2	2	4	2	4		
1.5	Unclear definition of job duties	Inexperienced or untrained personnel (linked from 1.1) Failure to follow work plan (linked from 1.2) Rig personnel understaffed (linked from 1.4)	Unsuccessful project implementation	Production	4	2	8	1	4	Training prior to start-up Continued training during operations Simulation of operations	Rec 7. Institute permit to work system **Responsibility:** Drilling Contractor Rec 9. Need rig personnel organization chart **Responsibility:** Drilling Contractor Rec 10. Need training prior to start of operations **Responsibility:** Drilling Contractor Rec 12. Need to establish chain of command **Responsibility:** Drilling Contractor
			Slow operations	Production	2	2	4	1	2		
			Personnel injury (linked to 1.3)	People	4	1	4	1	4		
			Equipment damage	Asset	3	2	6	1	3		
			Pressure Relief Valve activates and not detected - Rig Equipment (linked to 2.12)	Production	2	2	4	2	4		
1.6	Maximum personnel limit	Additional personnel for specialized services	Overcrowding	People	1	1	1	1	1	Off duty personnel on standby work boat	Rec 11. Need to inform rig manager of personnel requirements

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
	exceeded										**Responsibility:** Operator, Service Provider
			"Hot sheet" sleeping arrangements	People	1	1	1	1	1		
			Evacuation capacity exceeded	People	5	1	5	1	5		
1.7	Personnel unfamiliar with equipment	Inexperienced or untrained personnel (linked from 1.1)	Unsuccessful project implementation	Production	3	2	6	1	3		Rec 13. Need to determine personnel competency during training **Responsibility:** Trainer, Drilling Contractor Rec 14. Discuss deficiencies in personnel training with operator management **Responsibility:** Trainer, Operator, Drilling Contractor
			Slow operations	Production	2	2	4	1	2		
			Personnel injury (linked to 1.3)	People	4	2	8	1	4		
			Equipment damage	Asset	3	2	6	1	3		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
2.1	Loss of electric power (momentary or longer)	Cable/bus severed Lightning strike Overload Transformer fire Turbogenerator trip	Rig shut down	Production	3	2	6	1	3	Alternate power source Breakers and protective logic Emergency shutdown and switchover procedures Redundant power generation equipment	Rec 16. Need to perform black-out test to ensure reliability of backup generator **Responsibility:** Drilling Contractor
			Loss of rig air (linked to 2.2)	Production	3	2	6	1	3		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Loss of vacuum system (linked to 2.3)	Production	3	2	6	1	3		
			Loss of service water (linked to 2.4)	Production	3	2	6	1	3		
			Loss of nighttime lighting (linked to 2.5)	Production	3	2	6	1	3		
			Failed communications system (linked to 2.6)	Production	3	2	6	1	3		
			Failed rig surface equipment (linked to 2.7)	People	3	2	6	1	3		
			Inability to make drilling mud - Drilling Fluids (linked to 4.1)	Production	3	2	6	1	3		
			Failed rig surface equipment (linked to 2.7)	Production	3	2	9	2	6		
			Failure of pump - Auxiliary Annular Pump (linked to 11.1)	Production	3	2	6	2	6		
			Loss of flow meter - Surface Pressure Flow Control Manifold (linked to 10.3)	Production	3	2	6	2	6		
			Power loss during MPD operations - Surface Pressure Flow Control Manifold (linked to 10.5)	Production	3	2	6	2	6		
			Loss of mud pump (linked to 2.10)	Production	3	2	6	2	6		
2.2	Loss of rig air	Air compressor trip Crossflow to other air systems	Inoperability of pneumatic dependent equipment	Production	2	2	4	1	2	Low pressure alarm Redundant compressor	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		Dryer plugged Freezing Header rupture Water accumulation Loss of electric power (momentary or longer) (linked from 2.1)									
			Failure of pump - Auxiliary Annular Pump (linked to 11.1)	Production	3	3	9	2	6		
2.3	Loss of vacuum system	Vacuum pump trip Loss of electric power (momentary or longer) (linked from 2.1)	Inoperability of vacuum dependent equipment	Production	2	2	4	1	2	High pressure alarm Redundant vacuum pump/system	
			Failure of pump - Auxiliary Annular Pump (linked to 11.1)	Production	3	2	6	1	3		
2.4	Loss of service water	Debris plugging intake Header rupture Low level in reservoir Pump trip Loss of electric power (momentary or longer) (linked from 2.1)	Inoperabity of water maker	Production	3	2	6	1	3	High temperature alarm Intake screens Low pressure alarm Redundant motor-driven pumps	
			Affect ability to make drilling fluid	Production	3	2	6	1	3		
			Inability to make drilling mud - Drilling Fluids (linked to 4.1)	Production	4	1	4	1	4		
			Failure of pump - Auxiliary Annular Pump (linked to 11.1)	Production	3	2	6	1	3		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
2.5	Loss of nighttime lighting	Loss of electric power (momentary or longer) (linked from 2.1)	Rig shut down at night	Production	4	2	8	1	4	Battery power for selected lights Emergency lighting circuit	
			Failure of pump - Auxiliary Annular Pump (linked to 11.1)	Production	3	2	6	1	3		
2.6	Failed communicat ions system	Loss of electric power (momentary or longer) (linked from 2.1) Communication signal obstructed or severed	Non-productive Time	Production	3	3	9	1	3	Backup radios Organization diagrams Prejob meetings Job Safety Analysis	
			Failure of pump - Auxiliary Annular Pump (linked to 11.1)	Production	3	2	6	1	3		
2.7	Failed rig surface equipment	Loss of electric power (momentary or longer) (linked from 2.1) Component failure Loss of electric power (momentary or longer) (linked from 2.1)	Non-productive Time	Production	2	4	8	3	6	Alternate power source Breakers and protective logic Emergency shutdown and switchover procedures Redundant power generation equipment Preventive maintenance Component reliability assurance	
2.8	Failed BOP/MPD stack test	Leaks	Violation of regulatory policy	Regulatory	3	1	3	1	3	Stump test rior to delivery to rig	Rec 6. Establish contingency plan should test interval exceed regulatory requirements **Responsibility:** Drilling Engineer
			Shutdown drilling	Production	3	1	3	1	3		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			operations								
2.9	Overpressure of mud pump	Pump against closed valve Pump against closed choke Blockage downstream of Rotating Control Device	Breakdown formation	Production	3	3	9	1	3	Pressure Relief Valve set below surface pressure component to Bottom Hole Pressure Use trip fill up line to fill hole	
			Loss of hydrostatic pressure	Production	3	3	9	1	3		
			Loss of hole	Production	5	2	10	1	5		
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
			Lost Circulation - Open Hole (linked to 7.7)	Production	3	2	6	1	3		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
2.10	Loss of mud pump	Mechanical breakdown Loss of electric power (momentary or longer) (linked from 2.1)	Stop drilling	Production	3	2	6	1	3	Redundant pump Cement pump backup	
2.11	Exceeding pressure rating of equipment	Inadequate planning	Bursting of hoses, connections, pipe	People	4	2	8	1	4	Pressure relief valves	Rec 29. Discharge pressure rating of 5000 psi minimum **Responsibility:** Drilling Contractor Rec 30. Pumping capacity 2 times maximum rate expected **Responsibility:** Drilling Contractor
			Bursting of hoses, connections, pipe	Envrnmt	1	2	2	1	1		
			Bursting of hoses, connections, pipe	Asset	1	2	2	1	1		
			Bursting of hoses, connections, pipe	Production	1	2	2	1	1		
2.12	Pressure Relief Valve activates and not detected	Inexperienced or untrained personnel - Human Factors (linked from 1.1) Rig personnel understaffed - Human Factors (linked from 1.4) Unclear definition of job duties - Human Factors (linked from 1.5)	Increased flow from backup pump	Production	2	2	4	1	2	Flow sensor alarm on Pressure Relief Valve	
			Increased flow from auxiliary pump	Production	2	2	4	1	2		
2.13	Pressure Relief Valve does not	Mechanical malfunction Leak	High Equivalent Circulating Density - Open Hole (linked to	Production	3	3	9	2	6	Procedure to test and repair Pressure Relief Valve	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
	activate	Incorrect setting	7.1)								
			Pressure surge - Open Hole (linked to 7.10)	Production	3	3	9	2	6		
			Lost Circulation - Open Hole (linked to 7.7)	Production	3	3	9	2	6		
			Fracture formation - Open Hole (linked to 7.11)	Production	3	3	9	2	6		
			Pressure exceeds rated pressure - Rotating Control Device (linked to 9.3)	Production	4	3	12	2	8		
2.14	Seal leak on top drive	Leak in swivel packing	Lost Circulation - Open Hole (linked to 7.7)	Production	3	2	6	2	6	Replace swivel packing at non-critical time	
			Loss of Equivalent Circulating Density	Production	3	2	6	2	6		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
3.1	BHA in high temperature environment while installing Constant Circulating System	High Bottom Hole Static Temperature Trouble installing Continuous Circulating System Lack of instructions and procedures	Damage to electronics in BHA	Production	1	2	2	1	1	Circulate through drill pipe through temporary piping Install Constant Circulatory System before tripping in	
			Damage to elastomers in BHA	Production	1	2	2	1	1		
			Trip out	Production	2	2	4	1	2		
			Non-productive Time	Production	2	2	4	2	4		
3.2	Trouble installing Continuous	Lack of instructions Lack of personnel	Non-productive Time	Production	2	2	4	1	2	Install Constant Circulatory System before tripping in or	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
	Circulating System	experience (linked from 1.3)								while in cased hole Review of procedures prior to drilling operations Personnel training Documentation review by drilling engineering staff Maintain experienced personnel levels	
			Unplanned event originating from Constant Circulating System (linked to 3.3)	Production	1	2	2	1	1		
3.3	Unplanned event originating from Constant Circulating System	Lack of instructions (linked from 3.2) Lack of personnel experience (linked from 1.2)	Non-productive Time	Production	2	2	4	2	4	Review of procedures prior to drilling operations Personnel training Documentation review by drilling engineering staff Maintain experienced personnel levels	
3.4	Damage to equipment	Lack of instructions Lack of personnel experience	Non-productive Time	Production	2	2	4	2	4	Install Constant Circulatory System before tripping in or while in cased hole Review of procedures prior to drilling operations Personnel training Documentation review by drilling engineering staff	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
										Maintain experienced personnel levels	
			Unplanned event originating from Constant Circulating System	Production	2	2	4	1	2		
3.5	Breakout of overtorque joints	Racheting of undertorque joints Inaccurate or uncalibrated torque measurement gauges Use of unapproved pipe dope compound	Unplanned event originating from Constant Circulating System	Production	1	2	2	1	1	Pre-commissionin shakedown Review of procedures prior to drilling operations Documentation review by drilling engineering staff Set torque limits on top drive Only approved pipe dope compounds on rig	
			Overtorqued DP connections - Drill String (linked to 5.4)	Asset	2	2	4	1	2		
3.6	Lack of containment of fluids	Incompetent connection Leak in hose	Contamination	Envrnmt	1	1	1	1	1	Plug open drains Plug hoses prior to removal Follow rig-up and rig-down procedures	
3.7	Pipe dope application system not operational	Computer hardware or software malfunction	Manual application of pipe dope	People	1	1	1	1	1	Consult vendor troubleshooting procedures	
3.8	Malfunction of lifting operations	Loss of hydraulics Loss of power	Personnel injury	People	5	1	5	1	5	Drilling Contractor lifting policy	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
3.9	Derrick cameras malfunction	Camera broken to monitor fingerboards	Need more personnel on rig floor	People	3	5	15	1	3		
3.10	Not able to stab-in internal BOP or TIW valve	Inaccessablity through Constant Circulating System to stab in valve	Flow inside drill string coming to surface	Asset	5	2	10	1	5	Install drill string Non-return Valve (float valve) Have standby drill string stand with kelly cock in the derrick at all times	Rec 3. Need to establish procedure to install internal BOP valve **Responsibility:** Drilling Contractor, CCS Vendor
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
4.1	Inability to make	Loss of electric power (momentary or longer)	Well Control Incident - Kick - Open Hole	Production	5	2	10	1	5	Shut-in well	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
	drilling mud	- Rig Equipment (linked from 2.1) Loss of service water - Rig Equipment (linked from 2.4)	(linked to 7.13)							Adequate supplies	
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
			Shut-in well	Production	3	3	9	1	3		
			No kill weight mud available (linked to 4.10)	Production	4	2	8	1	4		
4.2	Excessive fluid loss from inadequate fluid properties	Inadequate fluid design properties Material supply deficient	Loss of fluid volume	Production	3	2	6	1	3	Add sufficient fluid loss additives Modify pumping rate to alter flow regime Maintain annular fluid volume and density to be equal to the Bottom Hole Pressure	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Loss of hydrostatic pressure	Production	4	4	16	2	8		
			Influx of formation fluids	Production	4	3	12	2	8		
			Fluid loss during static (not pumping) condition	Production	3	3	9	2	6		
			Fluid loss during dynamic (pumping) condition	Production	4	4	16	2	8		
			Lost circulation (linked to 4.3)	Production	4	4	16	1	4		
4.3	Lost circulation	Inadequate fluid design properties (linked from 4.2) Inaccurate geologocal/geophysical data High porosity exposed formation High permeability exposed formation Overbalanced hydrostatic column exposed to depleted or low pressure formation	Loss of fluid volume	Production	3	3	9	2	6	Add sufficient fluid loss additives Modify pumping rate to alter flow regime Maintain annular fluid volume and density to be equal to the Bottom Hole Pressure	
			Loss of hydrostatic pressure	Production	4	4	16	2	8		
			Continuous influx of formation fluids	Production	4	3	12	2	8		
			Fluid loss during static (not pumping) condition	Production	3	3	9	2	6		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Fluid loss during dynamic (pumping) condition	Production	4	4	16	2	8		
			Stuck pipe	Production	3	4	12	1	3		
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout	Regulatory	5	1	5	1	5		
4.4	Gain in mud pit level	Well Control Incident - Kick (linked from 7.13) Well Control Incident - Blowout (linked from 7.14) Ballooning Change of mud properties (linked from 4.7)	Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5	Pit level alarm Flow level alarm	
			Well Control Incident -	People	5	1	5	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Blowout (linked to 7.14)								
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
4.5	Loss in mud pit level	Lost Circulation - Open Hole (linked from 7.7)	Non-productive Time	Production	3	4	12	1	3	Apply Managed Pressure Drilling techniques	
			Loss of drilling mud	Asset	3	4	12	1	3		
			Loss of well	Asset	5	4	20	1	5		
			Loss of hydrostatic pressure	Asset	4	4	16	1	4		
4.6	Incorrect mud weight measurements	Inexperienced or untrained personnel - Human Factors (linked from 1.1)	Incidental Wellbore influx - Open Hole (linked to 7.8)	Production	3	3	9	1	3	Redundant mud check	
			Continuous Wellbore influx - Open Hole (linked to 7.9)	Production	3	3	9	1	3		
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
4.7	Change of mud properties	Contamination of mud with influx fluid	Change in mud density	Production	3	3	9	1	3	Apply Managed Pressure Drilling techniques Engage gas buster Engage separator Increase mud density Circulate out influx volume Circulate out kick volume Apply contaminated mud disposal policy	
			Change in mud rheology	Production	3	3	9	1	3		
			Gain in mud pit level	Production	3	3	9	1	3		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			(linked to 4.4)								
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
			Disposal of contaminated mud	Envrnmt	3	3	9	1	3		
4.8	Surface spill	Pipe leak Valve leak Tank leak	Environmental incident	Envrnmt	2	2	4	1	2	Visual inspection	
4.9	Surface returns line obstruction	Cuttings or barite settling	Backflow against Rotating Control Device	Production	3	2	6	1	3	Control drill	Rec 21. Install jets to move fluid through solids control system **Responsibility:** Drilling Contractor
			Shutdown drilling	Production	3	2	6	1	3		
4.10	No kill weight mud	Insufficient mud	Well Control Incident - Kick - Open Hole	Production	5	2	10	1	5		Rec 28. Need mud management plan

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
	available	storage capacity Inability to make drilling mud (linked from 4.1)	(linked to 7.13)								**Responsibility:** Drilling Engineer, Drilling Contractor
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
5.1	No spare drill pipe available	Unavailable drill pipe	Stop drilling	Production	3	1	3	1	3	Have adequate supply before drilling starts	
			Non-productive Time	Production	3	1	3	1	3		
5.2	Drillstring/ BHA twistoff	Excessive torque on drill string Stuck pipe Inadequate tubular inspection	Fish in the hole	Production	3	2	6	1	3	Torque-turn procedures Timely inspection of tubulars Maintain hole stability	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		Washout Overtorque connection Undertorque connection Washout in drill string (linked from 5.6)									
			Non-productive Time - Fishing Job	Production	3	2	6	1	3		
5.3	Incorrect pipe tally	Human error	Unsure of drill pipe in the hole	Regulatory	4	3	12	1	4	Redundant check of pipe tally	
			Unsure of Bottom Hole Location	Regulatory	4	3	12	1	4		
5.4	Overtorqued DP connections	Breakout of overtorque joints - Constant Circulating System (linked from 3.5)	Twist off	Production	3	3	9	2	6	Torque-turn procedure	
			Jump out	Production	3	3	9	2	6		
5.5	Stuck pipe	Overbalanced drilling fluid column Junk in the hole High Equivalent Circulating Density - Open Hole (linked from 7.1) Hole Instability - Open Hole (linked from 7.2) Fracture formation - Open Hole (linked from 7.11)	Non-productive Time	Production	3	4	12	2	6	Maintain fluid column at balanced downhole pressure Maintain a clean hole	
5.6	Washout in drill string	Hole in drill pipe	Drillstring/ BHA twistoff (linked to 5.2)	Production	2	2	4	2	4	Scheduled inspection of tubulars Review of inspection	Rec 18. Need contingency plan for handling leak or washout in drill string **Responsibility:** Drilling

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
										documents	Engineer Rec 20. Need to establish make-up torque procedures for drill string **Responsibility:** Drilling Engineer
			Loss of standpipe pressure	Production	3	2	6	1	3		
			Loss of hydraulic power for downhole tools	Production	3	2	6	1	3		
			Pull out of hole	Production	1	3	3	3	3		
5.7	Obstructed drill string	Plugging from debris Pumped too much lost circulation material	High pressure in drill pipe	Production	3	2	6	1	3	Screens on pump suction	Rec 17. Need contingency plan for obstructed drill string **Responsibility:** Drilling Engineer
			Inability to inject	Production	3	2	6	1	3		
			Non-return valves blocked closed	Production	3	2	6	2	6		
			Pull out of hole wet	Production	3	3	9	2	6		
5.8	Tool joint leak	Change of load conditions on drill pipe Improper tool joint connection make-up torque	Twist off	Production	3	3	9	2	6	Scheduled inspection of tubulars	Rec 18. Need contingency plan for handling leak or washout in drill string **Responsibility:** Drilling Engineer
			Jump out	Production	3	3	9	2	6		
			Inability to circulate efficiently	Production	3	3	9	2	6		
			Washout	Production	3	3	9	2	6		
			Reduction in bottomhole Equivalent Circulating Density	Production	3	3	9	2	6		
			Diminished ability to	Production	4	3	12	2	8		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			circulate kill weight mud								
5.9	Non-return valve (float valve) leaking	Debris in float valve	U tube during connection	Production	3	3	9	2	6		Rec 19. Need to prepare contingency plans for Non-return valve failure
			Flow up the drill pipe during influx or kick	Production	4	3	12	2	8		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
6.1	Wrong survey corrections applied	Incorrect radius of curvature corrections Incorrect declination Sensors in close proximity to magnetic material	Inaccurate survey information	Production	3	2	6	1	3	Plug back Calibrate LWD tool	
			Drilling in the wrong direction	Production	3	2	6	1	3		
6.2	LWD/MWD-tool plugging	Excessive lost circulation material Mud not cleaned efficiently on surface	Inoperable LWD/MWD tool	Production	2	2	4	1	2	Efficient solids control Appropriate use of sized fluid loss agents	
			Pull out of hole	Production	3	2	6	1	3		
			LWD/MWD tool failure (linked to 6.3)	Production	3	2	6	1	3		
6.3	LWD/MWD tool failure	LWD/MWD-tool plugging (linked from 6.2) Temperature limitation Close to or end of reliability service life	Pull out of hole	Production	2	5	10	2	4	Efficient solids control Appropriate use of sized fluid loss agents Use tool with few service hours	
6.4	Discrepancy between the	Hydraulic model not consistent with hole	Bad data	Production	3	3	9	2	6	Alter data transmission rate on	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
	data readings (PWD) and the hydraulic model	geometry High Bottom Hole Static Temperature								Pressure While Drilling tool Change hydraulic model Pull out of hole	
6.5	Not able to perform downhole surveys	Limited access to open drill pipe on rig floor	Unable to determine well path and Bottom Hole Location	Asset	4	4	16	1	4		Rec 4. Prepare survey procedure for Constant Circulating System **Responsibility:** Drilling Contractor, Survey Tool Vendor
6.6	Pressure While Drilling tool malfunction	Reliability	Loss of Equivalent Circulating Density data	Production	3	2	6	1	3	Revert to previous Pressure While Drilling data Trip to repair Pressure While Drilling tool Use hydraulics model	
			Inability to establish Managed Pressure Drilling pressure requirements	Production	3	2	6	1	3		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
7.1	High Equivalent Circulating Density	Excessive mud pump flow rate increases annular pressure Excessive mud density Insufficient hole cleaning during drilling (linked from 7.3) Mud rheological properties Pressure Relief Valve does not activate - Rig Equipment (linked from 2.13)	Lost Circulation (linked to 7.7)	Production	3	3	9	1	3	Apply Managed Pressure Drilling techniques	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		Pressure exceeds rated pressure - Rotating Control Device (linked from 9.3)									
			Stuck pipe - Drill String (linked to 5.5)	Production	3	3	9	1	3		
			Breakdown formation	Production	3	3	9	1	3		
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
7.2	Hole Instability	High pressure formation + underbalanced hydrostatic pressure column High Bottom Hole	Formation caves in	Asset	5	4	20	1	5	Sufficient mud density to keep hole open	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		Pressure (linked from 7.5)									
			Stuck pipe - Drill String (linked to 5.5)	Production	4	3	12	1	4		
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
7.3	Insufficient hole cleaning during drilling	Insufficient annular velocity Wellbore geometry	Lost Circulation (linked to 7.7)	Production	3	3	9	1	3	Apply Managed Pressure Drilling techniques	
			Tight hole	Production	3	3	9	1	3		
			Pack off hole	Production	3	3	9	1	3		
			High Equivalent Circulating Density	Production	3	3	9	1	3		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			(linked to 7.1)								
			Stuck pipe	Production	3	3	9	1	3		
7.4	Unable to handle loss situation	Unmanagable hole problems	Massive loss of drilling fluid	Asset	4	4	16	1	4	Apply Managed Pressure Drilling techniques Apply well control methods	Rec 5. Consider (Pressurized) Mud Cap Drilling **Responsibility:** Operator, Drilling Engineer, Engineering Contractor
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
7.5	High Bottom Hole Pressure	Lack of information Underbalanced hydrostatic mud column	Hole Instability (linked to 7.2)	Production	4	3	12	2	8		
			Incidental Wellbore influx (linked to 7.8)	Production	1	4	4	2	2		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout	Regulatory	5	1	5	1	5		
7.6	Unsuccessful well control	Lost Circulation (linked from 7.7)	Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
7.7	Lost Circulation	Inadequate fluid design properties Inaccurate geologocal/geophysical data High porosity exposed formation High permeability exposed formation Hydrostatic column exposed to depleted or low pressure formation High Equivalent Circulating Density (linked from 7.1) Insufficient hole cleaning during drilling (linked from 7.3) Fracture formation (linked from 7.11) Overpressure of mud pump - Rig Equipment (linked from 2.9) Pressure surge (linked from 7.10) Pressure Relief Valve does not activate - Rig Equipment (linked	Loss of fluid volume	Production	3	3	9	2	6	Add sufficient fluid loss additives Modify pumping rate to alter flow regime Maintain annular fluid volume and density to be equal to the Bottom Hole Pressure	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		from 2.13) Pressure exceeds rated pressure - Rotating Control Device (linked from 9.3) Seal leak on top drive - Rig Equipment (linked from 2.14)									
			Loss of hydrostatic pressure	Production	4	4	16	2	8		
			Influx of formation fluids	Production	4	3	12	2	8		
			Fluid loss during static (not pumping) condition	Production	3	3	9	2	6		
			Fluid loss during dynamic (pumping) condition	Production	4	4	16	2	8		
			Stuck pipe	Production	3	4	12	1	3		
			Unsuccessfull well control (linked to 7.6)	Asset	5	1	5	1	5		
			Loss in mud pit level - Drilling Fluids (linked to 4.5)	Asset	3	2	6	1	3		
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
			Loss of hole	Production	5	2	10	1	5		
7.8	Incidental Wellbore influx	Insufficient containment of wellbore pressure Purposeful to determine wellbore pressure High Bottom Hole Pressure (linked from 7.5) Incorrect mud weight measurements - Drilling Fluids (linked from 4.6) Unexpected gas to surface - Surface Pressure Flow Control Manifold (linked from 10.6)	No consequence if below planned threshold							Track and circulate out influx Increase mud density Kill well with Driller's Method while drilling ahead Apply Managed Pressure Drilling techniques	
			Continuous Wellbore influx (linked to 7.9)	Production	3	3	9	1	3		
7.9	Continuous Wellbore	Insufficient containment of	Well Control Incident - Kick - Open Hole	Production	5	2	10	1	5	Track and circulate out influx	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
	influx	wellbore pressure Purposeful to determine wellbore pressure High Bottom Hole Pressure Drill Stem Test Incorrect mud weight measurements - Drilling Fluids (linked from 4.6) Incidental Wellbore influx (linked from 7.8) Unexpected gas to surface - Surface Pressure Flow Control Manifold (linked from 10.6)	(linked to 7.13)							Increase mud density Apply Underbalanced Drilling techniques Kill well	
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident -	Regulatory	5	1	5	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Blowout (linked to 7.14)								
7.10	Pressure surge	Run in casing too fast Pressure Relief Valve does not activate - Rig Equipment (linked from 2.13) Pressure exceeds rated pressure - Rotating Control Device (linked from 9.3)	Fracture formation (linked to 7.11)	Production	5	1	5	1	5	Control casing running speed	
			Lost Circulation (linked to 7.7)	Production	5	1	5	1	5		
			Underground blowout	Production	5	1	5	1	5		
			Stuck pipe - Casing	Production	5	1	5	1	5		
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
7.11	Fracture formation	Overbalanced hydrostatic mud column Pressure surge (linked from 7.10) Pressure Relief Valve does not activate - Rig Equipment (linked from 2.13) Pressure exceeds rated pressure - Rotating Control Device (linked from 9.3)	Lost Circulation (linked to 7.7)	Production	4	4	16	2	8	Apply Managed Pressure Drilling techniques	
			Underground blowout	Production	5	2	10	1	5		
			Stuck pipe - Drill String (linked to 5.5)	Production	3	3	9	2	6		
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
7.12	Failed Formation Integrity Test	Incompetent cement at shoe Incompetent formation	Non-productive Time - Cannot drill further	Production	4	4	16	3	12	Squeeze cement Expandable liner	
7.13	Well Control Incident - Kick	Flow through washout in drill string above Non-return Valve (linked from 3.10) Continuous influx High Bottom Hole Pressure Inability to make drilling mud - Drilling Fluids (linked from 4.1) Lost circulation - Drilling Fluids (linked from 4.3) Gain in mud pit level - Drilling Fluids (linked from 4.4) Incorrect mud weight measurements - Drilling Fluids (linked from 4.6) High Equivalent Circulating Density (linked from 7.1) Unable to handle loss	Well Control Incident - Blowout	People	5	1	5	1	5	Shut in well Kill well Training to shut well in based on increased flow at surface Slow pump rates taken at beginning of every tour	Rec 1. Need to define how much flow **Responsibility:** Drilling Engineer Rec 2. Taking slow pump rates the beginning of every tour **Responsibility:** Drilling Contractor

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		situation (linked from 7.4) High Bottom Hole Pressure (linked from 7.5) Unsuccessfull well control (linked from 7.6) Lost Circulation (linked from 7.7) Continuous Wellbore influx (linked from 7.9) Fracture formation (linked from 7.11) Hole Instability (linked from 7.2) Failure of pump - Auxiliary Annular Pump (linked from 11.1) Change of mud properties - Drilling Fluids (linked from 4.7) Gas in riser - Drilling Riser (linked from 8.2) Unexpected gas to surface - Surface Pressure Flow Control Manifold (linked from 10.6) Loss of pressure control - Surface Pressure Flow Control Manifold									

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		(linked from 10.4) Line rupture - Surface Pressure Flow Control Manifold (linked from 10.9) Overpressure of mud pump - Rig Equipment (linked from 2.9) No kill weight mud available - Drilling Fluids (linked from 4.10) Pressure surge (linked from 7.10)									
			Well Control Incident - Blowout	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout	Asset	5	1	5	1	5		
			Well Control Incident - Blowout	Production	5	1	5	1	5		
			Well Control Incident - Blowout	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout	Regulatory	5	1	5	1	5		
			Non-productive Time event	Production	5	1	5	1	5		
			Gain in mud pit level - Drilling Fluids (linked to 4.4)	Production	3	3	9	2	6		
7.14	Well Control Incident - Blowout	Not able to stab-in internal BOP or TIW valve - Constant Circulating System (linked from 3.10)	Gain in mud pit level - Drilling Fluids (linked to 4.4)	Asset	5	1	5	1	5	Lifeboats Remote choke manifold control Remote BOP controls	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		Not able to stab-in internal BOP or TIW valve - Constant Circulating System (linked from 3.10)									
		Not able to stab-in internal BOP or TIW valve - Constant Circulating System (linked from 3.10)									
		Not able to stab-in internal BOP or TIW valve - Constant Circulating System (linked from 3.10)									
		Not able to stab-in internal BOP or TIW valve - Constant Circulating System (linked from 3.10)									
		Not able to stab-in internal BOP or TIW valve - Constant Circulating System (linked from 3.10)									
		Inability to make drilling mud - Drilling Fluids (linked from 4.1)									
		Inability to make drilling mud - Drilling Fluids (linked from 4.1)									
		Inability to make drilling mud - Drilling Fluids (linked from 4.1)									
		Inability to make									

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		drilling mud - Drilling Fluids (linked from 4.1)									
		Inability to make drilling mud - Drilling Fluids (linked from 4.1)									
		Inability to make drilling mud - Drilling Fluids (linked from 4.1)									
		Lost circulation - Drilling Fluids (linked from 4.3)									
		Lost circulation - Drilling Fluids (linked from 4.3)									
		Lost circulation - Drilling Fluids (linked from 4.3)									
		Lost circulation - Drilling Fluids (linked from 4.3)									
		Lost circulation - Drilling Fluids (linked from 4.3)									
		Gain in mud pit level - Drilling Fluids (linked from 4.4)									
		Gain in mud pit level - Drilling Fluids (linked from 4.4)									
		Gain in mud pit level - Drilling Fluids (linked from 4.4)									
		Gain in mud pit level -									

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		Drilling Fluids (linked from 4.4)									
		Gain in mud pit level - Drilling Fluids (linked from 4.4)									
		Gain in mud pit level - Drilling Fluids (linked from 4.4)									
		Incorrect mud weight measurements - Drilling Fluids (linked from 4.6)									
		Incorrect mud weight measurements - Drilling Fluids (linked from 4.6)									
		Incorrect mud weight measurements - Drilling Fluids (linked from 4.6)									
		Incorrect mud weight measurements - Drilling Fluids (linked from 4.6)									
		Incorrect mud weight measurements - Drilling Fluids (linked from 4.6)									
		High Equivalent Circulating Density (linked from 7.1)									
		High Equivalent Circulating Density (linked from 7.1)									
		High Equivalent Circulating Density (linked from 7.1)									

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		High Equivalent Circulating Density (linked from 7.1)									
		Unable to handle loss situation (linked from 7.4)									
		Unable to handle loss situation (linked from 7.4)									
		Unable to handle loss situation (linked from 7.4)									
		Unable to handle loss situation (linked from 7.4)									
		Unable to handle loss situation (linked from 7.4)									
		Unable to handle loss situation (linked from 7.4)									
		High Bottom Hole Pressure (linked from 7.5)									
		High Bottom Hole Pressure (linked from 7.5)									
		High Bottom Hole Pressure (linked from 7.5)									
		High Bottom Hole Pressure (linked from 7.5)									
		High Bottom Hole Pressure (linked from 7.5)									

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		Unsuccessfull well control (linked from 7.6)									
		Unsuccessfull well control (linked from 7.6)									
		Unsuccessfull well control (linked from 7.6)									
		Unsuccessfull well control (linked from 7.6)									
		Unsuccessfull well control (linked from 7.6)									
		Unsuccessfull well control (linked from 7.6)									
		Lost Circulation (linked from 7.7)									
		Lost Circulation (linked from 7.7)									
		Lost Circulation (linked from 7.7)									
		Lost Circulation (linked from 7.7)									
		Lost Circulation (linked from 7.7)									
		Lost Circulation (linked from 7.7)									
		Fracture formation (linked from 7.11)									
		Fracture formation (linked from 7.11)									

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		Fracture formation (linked from 7.11)									
		Fracture formation (linked from 7.11)									
		Fracture formation (linked from 7.11)									
		Fracture formation (linked from 7.11)									
		Continuous Wellbore influx (linked from 7.9)									
		Continuous Wellbore influx (linked from 7.9)									
		Continuous Wellbore influx (linked from 7.9)									
		Continuous Wellbore influx (linked from 7.9)									
		Continuous Wellbore influx (linked from 7.9)									
		Continuous Wellbore influx (linked from 7.9)									
		High Equivalent Circulating Density (linked from 7.1)									
		High Equivalent Circulating Density (linked from 7.1)									
		Hole Instability (linked from 7.2)									
		Hole Instability (linked									

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		from 7.2)									
		Hole Instability (linked from 7.2)									
		Hole Instability (linked from 7.2)									
		Hole Instability (linked from 7.2)									
		Hole Instability (linked from 7.2)									
		Failure of pump - Auxiliary Annular Pump (linked from 11.1)									
		Failure of pump - Auxiliary Annular Pump (linked from 11.1)									
		Failure of pump - Auxiliary Annular Pump (linked from 11.1)									
		Failure of pump - Auxiliary Annular Pump (linked from 11.1)									
		Failure of pump - Auxiliary Annular Pump (linked from 11.1)									
		Failure of pump - Auxiliary Annular Pump (linked from 11.1)									
		Change of mud properties - Drilling Fluids (linked from									

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		4.7)									
		Change of mud properties - Drilling Fluids (linked from 4.7)									
		Change of mud properties - Drilling Fluids (linked from 4.7)									
		Change of mud properties - Drilling Fluids (linked from 4.7)									
		Change of mud properties - Drilling Fluids (linked from 4.7)									
		Change of mud properties - Drilling Fluids (linked from 4.7)									
		Gas in riser - Drilling Riser (linked from 8.2)									
		Gas in riser - Drilling Riser (linked from 8.2)									
		Gas in riser - Drilling Riser (linked from 8.2)									
		Gas in riser - Drilling Riser (linked from 8.2)									
		Gas in riser - Drilling Riser (linked from 8.2)									
		Unexpected gas to surface - Surface Pressure Flow Control Manifold (linked from 10.6)									

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		Unexpected gas to surface - Surface Pressure Flow Control Manifold (linked from 10.6)									
		Unexpected gas to surface - Surface Pressure Flow Control Manifold (linked from 10.6)									
		Unexpected gas to surface - Surface Pressure Flow Control Manifold (linked from 10.6)									
		Unexpected gas to surface - Surface Pressure Flow Control Manifold (linked from 10.6)									
		Unexpected gas to surface - Surface Pressure Flow Control Manifold (linked from 10.6)									
		Loss of pressure control - Surface Pressure Flow Control Manifold (linked from 10.4)									
		Loss of pressure control - Surface Pressure Flow Control Manifold (linked from 10.4)									
		Loss of pressure control - Surface Pressure Flow Control Manifold									

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		(linked from 10.4)									
		Loss of pressure control - Surface Pressure Flow Control Manifold (linked from 10.4)									
		Loss of pressure control - Surface Pressure Flow Control Manifold (linked from 10.4)									
		Loss of pressure control - Surface Pressure Flow Control Manifold (linked from 10.4)									
		Line rupture - Surface Pressure Flow Control Manifold (linked from 10.9)									
		Line rupture - Surface Pressure Flow Control Manifold (linked from 10.9)									
		Line rupture - Surface Pressure Flow Control Manifold (linked from 10.9)									
		Line rupture - Surface Pressure Flow Control Manifold (linked from 10.9)									
		Line rupture - Surface Pressure Flow Control Manifold (linked from 10.9)									
		Line rupture - Surface Pressure Flow Control									

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		Manifold (linked from 10.9)									
		Overpressure of mud pump - Rig Equipment (linked from 2.9)									
		Overpressure of mud pump - Rig Equipment (linked from 2.9)									
		Overpressure of mud pump - Rig Equipment (linked from 2.9)									
		Overpressure of mud pump - Rig Equipment (linked from 2.9)									
		Overpressure of mud pump - Rig Equipment (linked from 2.9)									
		Overpressure of mud pump - Rig Equipment (linked from 2.9)									
		No kill weight mud available - Drilling Fluids (linked from 4.10)									
		No kill weight mud available - Drilling Fluids (linked from 4.10)									
		No kill weight mud available - Drilling Fluids (linked from 4.10)									
		No kill weight mud available - Drilling Fluids (linked from 4.10)									

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		No kill weight mud available - Drilling Fluids (linked from 4.10) No kill weight mud available - Drilling Fluids (linked from 4.10) Pressure surge (linked from 7.10) Pressure surge (linked from 7.10) Pressure surge (linked from 7.10) Pressure surge (linked from 7.10) Pressure surge (linked from 7.10) Pressure surge (linked from 7.10) Incorrect mud weight measurements - Drilling Fluids (linked from 4.6)									
			Produced fluid to surface	Envrnmt	5	1	5	1	5		
			Threat to life	People	5	1	5	1	5		
			Threat to assets	Asset	5	1	5	1	5		
			Threat to environment	Envrnmt	5	1	5	1	5		
7.15	Well with pressure while out of the hole	Inadequate pressure control while coming out of the hole	Unable to run drill string back in the hole	Production	4	2	8	1	4	Apply Managed Pressure Drilling techniques Proper tripping	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
										procedures Back to bottom if pipe is in the hole Attempt to bullhead pressure back into formation	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
8.1	Riser leak or failure	Inadequate riser design Mud leaking from elastomeric element(s) - Rotating Control Device (linked from 9.2)	Environmental discharge	Envrnmt	4	2	8	1	4	Thorough riser design	Rec 23. Review riser design criteria **Responsibility:** Drilling Engineer
			Environmental discharge	Reputation	4	2	8	1	4		
			Environmental discharge	Regulatory	4	2	8	1	4		
8.2	Gas in riser	Influx Kick	Gas expansion toward surface	Production	4	3	12	1	4	Apply well control procedures Initiate Riser Boost line injection when subsea BOP is closed clearing riser of any gas and ensuring full hydrostatic column	Rec 22. Need to review procedures for Shut-in of Subsea BOP **Responsibility:** Drilling Engineer
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to	Envrnmt	5	1	5	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			7.14)								
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout	Regulatory	5	1	5	1	5		
8.3	Excessive wear of tensioner cables	Equipment interference	Utilize man-riding equipment	People	4	2	8	1	4	Interference preplanning with computer aided design Job Safety Analysis	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
9.1	Access to Rotating Control Device and Blowout Preventer stack	Insufficient work area Manual lock mechanism	Non-productive Time	Production	2	2	4	1	2	Scaffolding Specialized personnel Job Safety Analysis Procedure to remove element and bearing assembly	Rec 31. Investigate automation of manual lock **Responsibility:** Vendor
			Personnel injury	People	3	2	6	1	3		
			Use of man-riding equipment	People	3	2	6	1	3		
9.2	Mud leaking from elastomeric element(s)	Close to or end of reliability service life Excessive pressure on seal(s) Excessive elastomer	Mud escaping from annular space at surface	Envrnmt	2	4	8	2	4	Have standby element on drill pipe in the derrick at all times Reduce pressure	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		wear									
			Misalignment of drill pipe in casing or riser (linked to 8.1)	Asset	4	3	12	2	8		
9.3	Pressure exceeds rated pressure	Pressure Relief Valve does not activate - Rig Equipment (linked from 2.13) Remote Pressure Relief Valve not beneath Rotating Control Device	High Equivalent Circulating Density - Open Hole (linked to 7.1)	Production	3	3	9	2	6	Remote Pressure Relief Valve beneath Rotating Control Device	Rec 32. Pressure Relief Valve beneath Rotating Control Device needs to have remote setting capability. Different pressure settings for drilling and making connections. **Responsibility:** Drilling Contractor, Vendor
			Pressure surge - Open Hole (linked to 7.10)	Production	3	3	9	2	6		
			Lost Circulation - Open Hole (linked to 7.7)	Production	3	3	9	2	6		
			Fracture formation - Open Hole (linked to 7.11)	Production	3	3	9	2	6		
9.4	Impact damage from foreign objects/materials inside RCD bowl	Drill pipe scale	Damage to bowl affecting seal	Asset	3	2	6	1	3	Install drilling nipple to protect bowl when bearing not installed	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
10.1	Flow check uncertainty	Conflicting measurements from sensors	Unexpected gas to surface (linked to 10.6)	People	5	2	10	1	5	Apply troubleshooting procedures	
10.2	Insufficient accuracy in the hydraulic model	Drilling fluid variants Downhole Temperature Hole geometry	Unexpected gas to surface (linked to 10.6)	Production	3	3	9	1	3	Apply various models to achieve more accurate correlation to actual conditions	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
10.3	Loss of flow meter	Loss of electric power (momentary or longer) - Rig Equipment (linked from 2.1) Power loss during MPD operations (linked from 10.5) Flow meter component reliability	Unexpected gas to surface (linked to 10.6)	Production	3	3	9	1	3	Isolate flow meter and replace Switch to alternate flow meter	Rec 16. Need to perform black-out test to ensure reliability of backup generator **Responsibility:** Drilling Contractor
10.4	Loss of pressure control	Choke plugged Leaks	Excessive back pressure on formation	Production	3	4	12	1	3	Switch to alternate choke Visual inspections Pollution (spill) pan Camera mounted visual inspection system	Rec 24. Need corrective action plan for plugged choke **Responsibility:** Vendor, Service Provider, Drilling Engineer
			Loss of returns	Production	3	3	9	1	3		
			Loss of hole	Production	5	3	15	1	5		
			Unexpected gas to surface (linked to 10.6)	Production	3	3	9	1	3		
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
10.5	Power loss during MPD operations	Loss of electric power (momentary or longer) - Rig Equipment (linked from 2.1) Cable/bus severed	Unexpected gas to surface (linked to 10.6)	Production	3	3	9	1	3	Check circuit Alternate power source Breakers and protective logic Emergency shutdown and switchover procedures Redundant power generation equipment	
			Loss of flow meter (linked to 10.3)	Production	3	3	9	1	3		
10.6	Unexpected gas to surface	Improper choke back pressure Flow check uncertainty (linked from 10.1) Insufficient accuracy in the hydraulic model (linked from 10.2) Loss of flow meter (linked from 10.3) Loss of pressure control (linked from 10.4)	Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5	Redundant controls Training Adequate rest for personnel Divert flow to rig mud-gas separator	Rec 25. Verify design capacity and operating limits of mud-gas separator **Responsibility:** Drilling Contractor

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
		Power loss during MPD operations (linked from 10.5) Rig personnel understaffed - Human Factors (linked from 1.4)									
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
			Incidental Wellbore influx - Open Hole (linked to 7.8)	Production	1	3	3	1	1		
			Continuous Wellbore influx - Open Hole (linked to 7.9)	Production	3	4	12	1	3		
10.7	Failed pressure test	No stump test Insufficient commissioning	Equipment inoperable	Production	4	2	8	1	4	Verify stump pressure test	

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			System failure	Production	4	2	8	1	4		
10.8	Inaccurate gas readings	Calibration	Excessive gas at gumbo buster	Production	2	2	4	1	2	Redundancy of mud-gas detectors	
			Excessive gas at shale shaker	Production	2	2	4	1	2		
			Gas percolating through mud	Envrnmt	2	2	4	1	2		
10.9	Line rupture	Mismatched temporary piping	Loss of Bottom Hole Pressure	Production	3	2	6	1	3	Use rig-compatible temporary piping	Rec 26. Establish policy on temporary piping **Responsibility:** Drilling Contractor, Operator, Vendors Rec 27. Establish temporary piping permit system **Responsibility:** Drilling Contractor, Operator, Vendors
			Well Control Incident - Kick - Open Hole (linked to 7.13)	Production	5	2	10	1	5		
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
			Personnel injury - Human Factors (linked to 1.3)	People	5	2	10	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
11.1	Failure of pump	Loss of electric power (momentary or longer) - Rig Equipment (linked from 2.1) Loss of rig air - Rig Equipment (linked from 2.2) Loss of vacuum system - Rig Equipment (linked from 2.3) Loss of service water - Rig Equipment (linked from 2.4) Loss of nighttime lighting - Rig Equipment (linked from 2.5) Failed communications system - Rig Equipment (linked from 2.6) Obstruction in pump line (linked from 11.2)	Failed injection boost line	Production	5	2	10	1	5	Trap pressure with choke Shut-in well Start rig emergency generator Engage cement pump as backup	
			Cannot maintain Bottom Hole Pressure	Production	5	2	10	1	5		
			Well Control Incident -	Production	5	2	10	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Kick - Open Hole (linked to 7.13)								
			Well Control Incident - Blowout (linked to 7.14)	People	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Envrnmt	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Asset	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Production	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout (linked to 7.14)	Regulatory	5	1	5	1	5		
11.2	Obstruction in pump line	Debris in pump or pump lines	Failure of pump (linked to 11.1)	Production	5	2	10	1	5	Strainers on pump intakes Possible use of choke or kill line, if applicable	
			Failed injection boost line	Production	5	2	10	1	5		
			Cannot maintain Bottom Hole Pressure	Production	5	2	10	1	5		
			Well Control Incident - Kick - Open Hole	Production	5	2	10	1	5		
			Well Control Incident - Blowout	People	5	1	5	1	5		
			Well Control Incident -	Envrnmt	5	1	5	1	5		

Item	Deviation	Causes	Consequences	Category	S	UL	PR	ML	RR	Safeguards	Action Items
			Blowout								
			Well Control Incident - Blowout	Asset	5	1	5	1	5		
			Well Control Incident - Blowout	Production	5	1	5	1	5		
			Well Control Incident - Blowout	Reputation	5	1	5	1	5		
			Well Control Incident - Blowout	Regulatory	5	1	5	1	5		