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Review of Recent Diverter Performance during Well Control Emergencies

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Chapter 1

Executive Summary

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Diverter systems provide a means for diverting an unexpected flow away from a drilling rig when the well cannot be safely shut-in. The primary application for diverters is in the shallow portion of a well. Shut-in of a well before a sufficient length of casing has been run can lead to disastrous consequences. For short casing penetrations, a significant build-up of pressure at the surface can cause the flow to break through the shallow sediments outside of the casing to the surface. The infamous Santa Barbara Blowout that occurred offshore California in 1966 is an example of oil and gas flow reaching the surface outside of the conductor pipe after a well was shut-in. In this case, the conductor pipe penetrated 300 feet of sediments in 200 feet of water. An inability to divert flow away from the rig has also lead to disastrous consequences when the well is not shut-in after encountering an unexpected flow at a shallow depth. The C. P. Baker drillship burned and sank offshore Louisiana in 1964 after encountering a shallow gas flow while drilling at 461 feet below the mud line. This was the worse disaster experienced in the Gulf of Mexico. Twenty-two persons were killed and twenty-three persons were injured. Conductor pipe penetrated 121 feet of sediments in 184 feet of water.

In January 1, 1975, OCS Order No. 2 was revised to require the use a diverter system on all rigs operating on the Outer Continental Shelf. However, since only about one well in 500 wells drilled experience an unexpected flow from a shallow formation, it has taken considerable time to evaluate the effectiveness of industry practice regarding the installation and use of diverter systems. An internal MMS study conducted in 1983 indicated a diverter failure rate of about 67%. The primary failure mechanisms identified included:

1. Failure of the pneumatic diverter valve to open;
2. Broaching of well flow to surface outside of casing;
3. Failure due to erosion by well fluids containing formation sand;
4. Failure of connectors at flexible hose;
5. Failure of Annular pack-off seal;

6. Failure because of plugged diverter line; and
7. Failure of diverter piping because of inadequate anchoring;

Most of these failures were due to inadequate maintenance, testing, and training. Since diverter systems are seldom used, industry field personnel often failed to recognize their importance. MMS revised their regulatory practices to require larger diverter lines, fewer bends, and regular testing of diverter components. In addition, MMS sponsored several diverter related research projects to improve our understanding of diverter operations and sponsored several workshops to help disseminate the results of the research.

Hazards associated with an unexpected shallow gas flow are minimal for modern floating drilling vessels operating in deep water. Generally, the gas flow will surface far from the rig and be highly dispersed and not reach the surface in high concentrations. In addition, the rigs are highly mobile and can be moved away from any surface gas boil. Diverter systems on these rigs are used primarily as a contingency for handling gas that enters the marine riser in large volumes before the blowout preventers located at the seafloor are closed. They also support contingency procedures for handling a failure of the subsea blowout preventers.

MMS has been one of the driving forces in improving industry practices regarding the use of diverters. The purpose of this study was to evaluate diverter performance under modern industry practices. An effort was made to identify incidents involving the use of diverters since 1990 and to determine the effectiveness of the diverter systems when they were needed.

It was found that the failure rate on diverters has been greatly reduced. The primary remaining failure mechanism is erosion due to flow of formation fluids containing sand when very high flow velocities are experienced. However, the primary function of the diverter in this situation is to allow time for the rig crew to implement a rig abandonment procedure in an orderly manner. This study did not identify any diverter incident since 1990 that resulted in loss of life, injury, or significant environmental damage.

Although the number of bends and connections in diverter piping has been greatly reduced from earlier systems, one or two bends still remain on some systems reviewed. Failures due to erosion in a bend or Y-connection are still being experienced. Systems with straight vent lines will increase diverter life. However, the remaining change of direction at the wellhead will cause erosion at this point that can limit diverter life. One diverter system was reviewed that used an oversized diverter with a restriction at the exit. This design decreases the gas velocity at the diverter head or spool and thus increases the erosion life at this point.

Although the number of diverter failures since 1990 were small, there were a larger number of incidents reported in which shallow gas blowouts occurred after cementing surface casing and after nippling down the diverter system. Prematurely removing the diverter system appears to be a more serious problem than diverter failure. This problem is addressed in the final report for Task 2 entitled "Gas Flow in Wells after Cementing" and in the final report for Task 14 entitled "Top Cement Pulsation for Prevention of Flow after Cementing."

The determination of formation breakdown pressure of shallow marine sediments is important in determining the maximum allowable surface pressure in situations where conductor casing has been set deep enough so than well shut-in can be considered. A new method for estimating the formation breakdown pressure was developed and software that uses the new procedure is included with this report. The software is in the form of a MS Excel spreadsheet.

Acknowledgement

The author would like to acknowledge the work done by Dr. Ali Ghalambor at the University of Louisiana at Lafayette in collecting the information regarding current diverter designs and recent well control incidents in which diverters were used. Without the work done by Dr. Ghalambor on this research task, this report could not have been written.

Chapter 2

Introduction

Diverter systems are needed to address problems caused by an unexpected flow of formation fluids from shallow sediments. One of the most hazardous situations sometimes faced by a drilling crew is an unexpected flow from a shallow gas formation while drilling from a bottom-supported structure. Experience has shown that shallow gas flows can broach to the surface beneath a bottom-supported rig even when diverters are used. This chapter reviews the nature of this hazard and the broader issues affecting how diverter design and operating procedures fit into an overall well plan before focusing on the details of current diverter design and failure rates.

Current well control practice for bottom-supported marine rigs usually calls for shutting in the well when a kick is detected if sufficient casing has been set to keep any flow underground. Even if high shut-in pressures are seen, an underground blowout is preferred over a surface blowout. However, when shallow gas is encountered, casing may not be set deep enough to keep the underground flow outside the casing from breaking through sediments near the platform foundations. Once the flow reaches the surface, craters are sometimes formed which can lead to loss of the rig and associated marine structures.

Modern contingency plans for handling a shallow gas flow call for diverting the flow away from a bottom-supported rig using a diverter system. The diverter system is used to reduce the wellbore pressure so that it does not exceed the formation breakdown pressure. However, results of this study indicate that use of diverter systems does not always prevent cratering. Crater formation during diversion can occur when the diverter flow area is too restricted, allowing formation breakdown pressure to be exceeded even though the well is not shut-in. In addition, cratering can occur at pressures below the hydraulic breakdown pressure when shallow unconsolidated water sands are present. Water production from shallow aquifers can carry large volumes of sand from the permeable zones exposed to the open borehole. This results in a rapid excavation of aquifer sediments near the wellbore. Subsequent collapse of overlying sediments into the excavated region can open a flow path to the surface.

The above concerns led us to re-examine the controlling design parameters for shallow casings in order to determine when shutting-in a shallow kick is technically and economically feasible. A paper by Arifun and Sumpeno (1992) with Unocal Indonesia has indicated that wells were designed and drilled in their East Kalimantan operations with a well plan that calls for shut-in of all kicks from the surface to the total well depth. This new design concept was reviewed. Recommended criteria for deciding when to divert and when to shut-in are presented.

SEVERITY OF CRATERING PROBLEM

Although cratering while drilling a well is not a frequent occurrence in the oil industry, when a crater does occur the consequences are usually catastrophic. Large rigs and platforms have been lost in craters with no sign of the rig remaining at the surface. The cost of regaining control of the well and replacing lost structures and equipment can reach hundreds of millions of dollars.

Complete statistics about cratered wells or broaching incidents are not available. However, since cratering is often related to shallow blowouts, statistics about shallow blowouts can be used to show the severity of such problems. Blowout statistics were given by Hughes (1986), Adams (1991), Tracy (1992), and Danenberger (1993).

Hughes (1986) compiled information on 425 Gulf Coast blowouts events that covered the period between July 13, 1960 and January 1, 1985. The data was broken down by area and included 242 blowouts in Texas, 56 in Louisiana, 121 in Outer Continental Shelf (OCS), 3 in Mississippi and 3 in Alabama. Gas was present in 82% of the Texas blowouts. The two major operations that were underway when the blowout occurred were (1) coming out of hole (27%) and (2) drilling (25%). Seventeen (7.02%) Texas blowout reports noted when the well blew out around the casing. A total of twenty (8.26%) events reported that the underground flow reached the surface either to form a crater around the well, at a nearby surface site, or caused blowouts from nearby waters wells. All the blowouts that reached the surface outside of casing had a drilling depth to casing depth ratio greater than four.

The study of 56 Louisiana blowouts by Hughes (1986) showed that gas was present in 73% of wells that reported the type of blowout fluid. The rig operations reported to be underway at the time of the blowout included (1) workover operations (37%), (2) coming out of hole (21%), (3) circulating (13.2%) and (4) drilling (13.2%). Hughes does not give details about flows around casing or cratering for the Louisiana blowouts.

The statistics of 121 OCS blowouts reported by Hughes (1986) showed that gas was present in 77% of the cases. A description of the operation described when the blowout occurred was available for 46 events. The rig operations that were reported to be underway included (1) workover operations (28%), coming out of hole (24%), and drilling (20%). A total of 66 wells described the procedure used to control the blowout. The majority (55%) of the blowouts stopped flowing without any corrective action being taken, presumable due to the formation of a bridge of sediments within the well bore. About 49% of the 70 wells that listed both date of occurrence and date the well was killed was controlled within one day.

Danenberger (1993) performed a study of blowouts that occurred during drilling operations on the Outer Continental Shelf of the United States during the period 1971-1991. Eighty-three blowouts occurred during this period while drilling 21,436 wells for oil and gas. Four additional blowouts occurred while drilling for sulfur. Eleven of the blowouts resulted in casualties with 65 injuries and 25 fatalities. Fifty-eight of the blowouts that occurred while drilling for oil and gas came from shallow gas zones. Exploratory wells accounted for 37.4% of the wells drilled and 56.9% of the shallow-gas blowouts. Conversely, development wells accounted for 62.6% of the wells drilled and 43.1% of the shallow-gas blowouts.

According to Danenberger (1993), A shallow gas blowout in 1980 was the most serious blowout in the OCS, accounting for six of the 25 fatalities and 29 of the 65 injuries. However, there have been no casualties due to blowouts reported during the last seven years of the study.

Oil was usually not associated with the shallow gas blowouts and environmental damage has been minimal. Two blowouts prior to 1971 are known to have caused oil pollution in the portion of the Outer Continental Shelf under U.S. jurisdiction. An estimated 80,000 barrels of crude oil was released in the Santa Barbara Channel and about 1,700 barrels of condensate was released in the Gulf of Mexico.

Although no statistics are given for the OCS on the number of times a crater developed that undermined the foundation of the rig, Danenberger (1993) reported that 71.3% of the blowouts stopped flowing on their own when the well bridged naturally. Flow from 57.5 % of the blowouts ceased in less than a day and flow from 83.9 percent ceased in less than a week. A list of shallow gas blowouts compiled by Adams (1991) indicates that 18 bottom-supported structures were damaged on the U.S. OCS by shallow gas blowouts during the 1971-91 period of the Danenberger study. Seven of the U.S. structures shown in the Adams study were reported to be a total loss and extensive damage was reported for another three cases. These ten cases of extensive damage to total loss reported by Adams account for 17.2 % of the 58 shallow gas blowouts reported by Danenberger (1993). Thus 10 lost structures out of 21,436 wells drilled is a rough estimate of the risk from significant cratering.

We were not successful in compiling an estimate of economic loss associated with cratering during shallow gas blowouts. However, an operator reported that the cost due to one event outside of the U.S. was approximately 200 million dollars.

MECHANICS OF CRATER FORMATION

A literature review was conducted to obtain insight into mechanisms possibly involved in the formation of a crater at the surface. This was done by studying and analyzing a number of historical cases reported in the literature. However, the literature review showed that there are few specific petroleum-related articles about underground blowout followed by cratering. With the exception of very old reports (early 1900's) and the excellent paper written by Walters (1991), most of the petroleum-related literature contains no specific information about cratering mechanisms. Much of the pertinent literature was found outside of petroleum engineering publications. The scarcity of literature led the research group to look for information by contacting a number of organizations such as oil companies, fire-fighting specialists, and blowout-control specialists.

Mechanisms for Upward Fluid Migration

Closing the well or restricting the fluid flow in the choke lines will cause the pressure in the well to increase. If the pressure in the well becomes too high, a failure could occur. A path could be established which allows the more highly pressured fluid from below to migrate upward. The primary failure mechanisms identified included: (1) casing failure, (2) failure of the cement bond between the casing and the sediments, (3) tensile sediment failure by hydraulic fracturing, (4) shear sediment failure in permeable zones, and (5) wedging open of natural fault planes.

Upward Fluid Migration due to Casing Failure

Casing failure at a shallow depth during well control operations has been reported as the primary cause of a number of craters. Since each larger size casing present outside of inner casing is of lesser strength, after the inner casing string fails, the high-pressure fluid will generally find a path to the shallow sediments. Very high pressures are sometimes present if the influx is from a deep, abnormally pressured zone. Proper casing design, pressure testing, and periodic casing-wear inspections are the primary means used to prevent this type of failure.

Upward Fluid Migration Due to Failure of Cement Bond

Upward fluid migration through cement channels has also been responsible for a number of blowouts. Fluid seeping around the casing can cause erosion of the borehole-casing annulus, which eventually could lead to a crater. Proper design and planning of cement jobs are basic requirements to prevent upward gas migration around the casing. For this reason, a great deal of effort has been exerted by the petroleum industry to reduce the tendency for channels to form in the cemented annulus during cementing operations

Upward Fluid Migration through Hydraulic Fracture

Rock strength is a function of its structure, compaction and type. Rock tensile strength varies in both vertical and horizontal directions. The forces tending to hold the rock together are the strength of the rock itself and the in-situ stresses on the rock. High-pressure fluid, resulting from the well control operation generates hydraulic pressure at the wellbore wall or in the pore spaces of the rock. If the pressure increases, the force applied by the fluid pressure in the rock will become equal to the forces tending to hold the rock together. Any additional pressure applied will cause the rock to split or fracture (Martinez et. al., 1990). Thus, from a macroscopic point of view, hydraulic fracturing occurs when the minimum effective stress at the wellbore becomes tensile and equal to the tensile strength of the rock (Fjaer et. al., 1992).

The fracture will extend as long as sufficient pressure is being applied by injection of additional fluids (Haimson et. al., 1967; Martinez et. al., 1990). Fracture propagation is a function of several factors such as: (a) in-situ stresses existing in different layers of rock, (b) relative bed thickness of formations in the vicinity of the fracture, (c) bonding between formations, (d) mechanical rock properties, (e) fluid pressure gradients in the fracture, and (f) pore pressure of different zones (Vearch et. al., 1989). Local stress fields and variations in stresses between adjacent formations are often considered the most important factors to control fracture orientation and fracture growth. Evidence from production logs and other evaluation techniques has suggested that hydraulic fractures usually start in a porous and permeable zone and often terminate before propagating far into the adjacent, impermeable (generally shale) layers. Clay-rich materials normally have higher horizontal stresses and often act as confining layers (Harrison et. al., 1954; Warpinski and Teufel, 1984). Most formations are susceptible to hydraulic fracturing. Sand, limestone, dolomitic limestone, dolomite, conglomerates, granite washes, brittle shale, anhydrite, chert, and various silicates are example of rocks for which fracturing operations have been reported as being successful. However, the plastic nature of certain soft shales and clays makes them more difficult to fracture (Martinez et. al., 1990).

Hydraulic fractures will generally propagate perpendicular to the direction of the minimum principal stress (Veatch et. al., 1989; Warpinski and Teufel, 1984; Warpinski and Smith, 1989). Thus, the local stress field will generally determine if a fracture will be vertical or horizontal. In most areas, horizontal stress is less than vertical stress, resulting in a vertical fracture.

In terms of well control operations, hydraulic fracturing may lead to the serious risk of allowing upward fluid migration through the fracture. The result can be upward migration of the pressured fluid through the fracture if the fracture is not be confined by a layer with a higher horizontal stress, and if the permeability of the rock matrix surrounding the fracture is not great enough to dissipate the high pressure.

Upward Fluid Migration through Shear Failure

Rock failure caused by shear stress can occur, for instance, when an impermeable formation overlays a permeable formation. In this case, massive shear failure due to the flow of highly pressured formation fluid can occur in the permeable formation before causing fracture of the overlying impermeable strata. The consequences of such massive failure include increase of sand production from the shear-damaged permeable formation and even compaction of these intervals (Walters, 1991).

Upward Fluid Migration through Fault Planes

Existing fault planes crossing impermeable and sealing layers have been reported as responsible for upward fluid migration which ended in formation of craters (Adams and Thompson, 1989; Adams and Kuhlman, 1991; Walters, 1991). Flow through the fault planes will depend on many factors such as normal stress in the fault planes and permeability of the fault-plane-filling sediments. Possible mechanisms of flow through faults include:

1. The high-pressured fluid wedges open an existing fault plane at a pressure below that which will cause fracture of the sealing layer; and
2. Increase of permeability due to induced shear dilatancy within the fault plane by the high pressure. (Walters, 1991).

Some operators reported that they had seen evidence that naturally occurring gas migration through faults are sometimes the source of a shallow gas flow event when the well bore intersects the fault plane. Gas seeps seen along fault-lines at the seafloor are evidence that such gas migration routes are common.

Cratering Mechanisms

The cratering mechanisms identified included (1) borehole erosion, (2) formation liquefaction, (3) piping or tunnel erosion, and (4) caving.

Borehole Erosion

Gas seeping around the surface casing is a typical occurrence leading to cratering. Gas or liquid flowing at high velocity around surface casing can cause erosion of shallow strata surrounding the casing. Significant erosion around the casing not only can create a crater but also can lead to a lower pressure in the flowing well. The lower pressure allows additional flow of formation fluids (normally water) into the well from all exposed permeable strata. Although erosion of the shallow strata by fluid flow has not been previously addressed in blowout-related literature, it has been studied in civil engineering problems such as erosion of river bottoms. A number of erosion experiments (Gaylord, 1989; Kamphuis and Hall, 1983) have shown that erosion caused by fluid flow is a function of the fluid velocity and shear stress at the eroding surface. The higher the velocity and shear stress, the higher is the erosion. These studies have concluded that erosion rate, which is defined as mass of eroded material divided by the time interval, is minimal and constant up to a certain value of velocity (critical velocity) or shear stress (critical shear stress). However, erosion rate increases rapidly as velocity or shear stress increases above the critical value.

Formation Liquefaction

Liquefaction occurs when the vertical effective stresses vanish. Thus, the shear strength of cohesionless soils in the liquefied state is zero (Bell, 1983; Clough et. al., 1989; Lee et. al, 1983; Rocha, 1993; Scott, 1969; Seed et. al. 1981). The weight of the submerged soil is balanced by the upward acting hydraulic pressure gradient caused by the upward flow of fluids through the permeable sediments. This condition is also commonly referred to as a sand-boil condition or quicksand condition. The pressure gradient at which liquefaction begins is called the critical pressure gradient (Bell, 1983). This cratering mechanism is thought to be possible only for essentially cohesionless and permeable sediments such as sands.

Liquefied sediments due to seepage forces are often found in excavations made in under-water fine sands subjected to upward fluid flow. As the velocity of the upward seepage force increases above the critical gradient, the sand begins to boil more and more. If such a condition develops below part of a structure, the foundations of the structure would become unstable with part of it sinking into the liquefied sediments. The presence of a layered sequence composed of individual beds with different permeability can be particularly unfavorable if a fine-grained layer of sand is underlain by a coarse sand or shell zone of high permeability. Formation fluids can then flow through the very permeable layer with little loss of pressure. This results in a steeper pressure gradient in the upper zone.

Piping or Tunnel Erosion

The previous section discussed the potential of liquefaction of cohesionless soils by high-pressure formation fluid. However, if during an underground blowout the formation fluid reaches a cohesive sediment layer, another phenomenon called "piping" or "tunnel erosion" may occur. As the formation fluid flows through the sediments there is a reaction force applied to the matrix material. When formation fluid with sufficient velocity percolates through heterogeneous soil masses, it moves preferentially through the most permeable zones and issues from the ground as springs. Piping refers to the erosive action of some of these springs where sediments are removed by seepage forces to form subsurface cavities and tunnels. In order for piping to occur, the soil must have some cohesion. Sediments with a larger cohesive strength can support a larger diameter tunnel without collapse (Bell, 1983). Also, for piping to occur in impermeable cohesive materials such as clay, it is necessary for a flaw or flow channel to be present to allow a concentrated fluid flow to develop. In the piping process, the formation fluid must be moving with sufficient volume and velocity to transport clay particles. This flow may be in a supersaturated layer with an under-layer of impermeable material, or along cracks or flaws in relatively impermeable sediments (Crouch, 1977). Piping may develop by backward erosion. In such a case, sediment erosion may grow from the exit toward the source of fluid supply (Bell, 1983). Finally, if erosion due to piping reaches a critical value, entire structures (dams, houses or drilling platforms) can collapse due to lack of support. Piping exits often appear as small volcano shaped structures in underwater videos taken during well control incidents.

Caving

In this work, caving is defined as the collapsing of solids within and surrounding the well. This collapsing can be by borehole wall failure due to shear failure as the result of the reduction of the hydrostatic pressure in the wellbore, or by tensile failure due to excessive fluid production rate.

Caving due to shear failure can be understood by analyzing the origin of the stress concentration at the wellbore wall. Underground formations at a given depth are exposed to vertical and horizontal compressive stresses that generally are not fully balanced the drilling fluid pressure after the well is drilled. Therefore, in the case of elastic formations, the load originally carried by the removed rock is partially transferred to the rock surrounding the borehole, creating a stress concentration around the borehole. Stress concentration generally does not present a problem if the well is drilled through competent rock unless the mud hydrostatic pressure is much less than the formation pore pressure. However, a high stress concentration or a weak rock can result in failure of the borehole wall. Very large shall fragments are often seen at the surface when this type of failure occurs during normal drilling operations. Very low well bore pressures generally result during diverter operations.

Problems related to sand and silt production during a blowout include erosion of drilling equipment such as diverter lines and excavation of a permeable layer which can lead to the collapse of the overlying sediments. Caving as a result of sand and silt production during a blowout can vary from a few grams or less per ton of reservoir fluid to very large amounts (Fjaer et. al., 1992). One documented case of a cratered well mentions that the material expelled from the crater formed a deposit approximately 40-in thick at the edge of the crater and covered an area of about 100 acres (Hills, 1932). In one reported case, an entire platform settled several feet after a shallow gas flow. The removal of large sand volumes due to production of sand and water from permeable zones would explain this type of behavior.

Chapter

3

SHALLOW-GAS CONTINGENCY PLAN

Shallow gas events happen very quickly. Once gas begins entering the well, it can reach the surface in a matter of minutes. Thus, the development of an appropriate shallow-gas contingency plan prior to drilling the well is very important. Reaction to such an event must be almost automatic if it does occur.

Developing a well plan that will minimize the hazards of a shallow gas flow should be done for every offshore well. For bottom supported drilling vessels, geo-hazard surveys may be needed to collect geologic data and determine the lithology, density, and strength of the shallow sediments. The only good solution to the problem of shallow gas is to avoid taking any influx of formation fluids into the well. A kick prevention plan should be developed to minimize the risk of taking a kick, especially when pulling pipe from the well. However, the casing program and a written contingency procedure should also be prepared to allow the safe handling of a shallow-gas flow if the kick prevention plan fails. Once a rig is selected for the well, a systems analysis calculation can be done to insure that the rig's diverter system is consistent with the contingency procedure and casing program for the well.

Because of the short response time available before shallow gas can reach the surface, implementation of the contingency plan requires close coordination with the rig contractor and field personnel. Some of the most important areas of coordination include:

1. Integration of clear statements of duties and responsibilities (in regard to shallow-gas contingency procedures) into the rig organizational structure, and
2. Conducting an appropriate training program to insure that the well control plans and contingency procedures are understood and can be carried out by the field personnel.

GEOLOGIC DESCRIPTION AND SEDIMENT STRENGTH DATA

A prerequisite of any improved well design procedure for safe handling of shallow gas flows is knowledge concerning the breakdown strength and permeability of the upper marine sediments. Key parameters needed to estimate the breakdown strength are the overburden stress and the ratio of horizontal to vertical stress.

Ratio of Horizontal to Vertical Stress

Before fracture pressure can be predicted, the effective horizontal stress must be estimated. For sediments between the surface casing depth and the total well depth, the most common approach has been to correlate the minimum observed ratio of horizontal-to-vertical effective stress, F_σ, with depth. Leak-off test data and incidents of lost-returns have been used to develop an empirical correlation for various geographic areas. The correlation was heavily weighted to represent the weaker sediments found at a given depth so that a conservative estimate of fracture pressure could be predicted for use in well design calculations. Once F_σ is obtained from the empirical correlation, the fracture pressure can be estimated using[1]:

$$p_{frac} = F_\sigma \sigma_z + p = F_\sigma (s - p) + p \qquad (3.1)$$

Shown in Figure 3.1 are several empirical curves that are commonly used to estimate the horizontal-to-vertical effective stress ratio in the Gulf Coast Area. Note that the ratio decreases for the more shallow sediments and approaches a value of about 0.33 at the surface. Hubert and Willis (1957) determined this value for unconsolidated sands in a sand-box experiment conducted in the lab. At deeper depths, the ratio F_σ approaches a value of one as the sediments become more plastic with increasing confining stress.

Use of the empirical curves shown in Figure 3.1 at very shallow depths gives a low value of F_σ. In reality, many shallow marine sediments behave plastically, with F_σ values near one. Thus, use of the empirical curves shown in Figure 3.1 cause fracture pressure of shallow sediments to be significantly under predicted.

Shown in Figure 3.2 are F_σ values estimated from leak-off tests from five wells drilled in the Green Canyon Area, Offshore, Louisiana. Note that the average observed value of the horizontal-to-vertical effective stress ratio ranges from 0.8 to 1.4 and averages about one. The observed values in excess of one are likely due to one or more of the following reasons:

1. Experimental errors which occur while running and interpreting the leak-off tests;

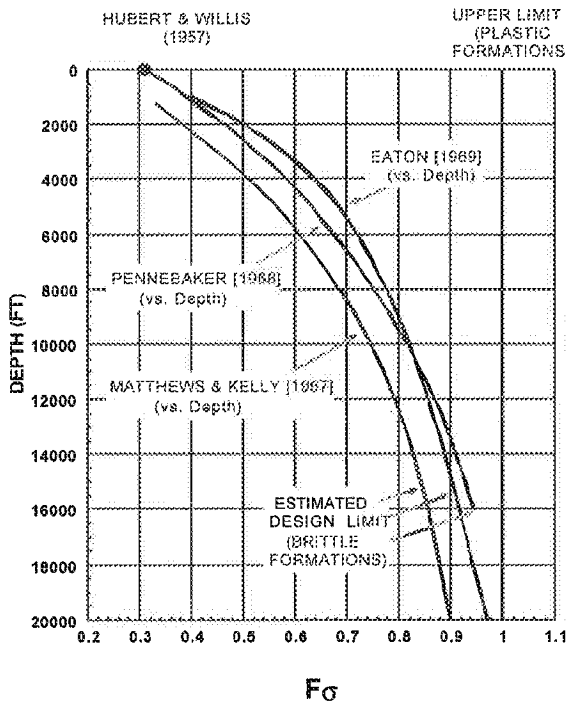


Figure 3.1: Ratio of Horizontal to Vertical Stress for Louisiana Gulf Coast Area

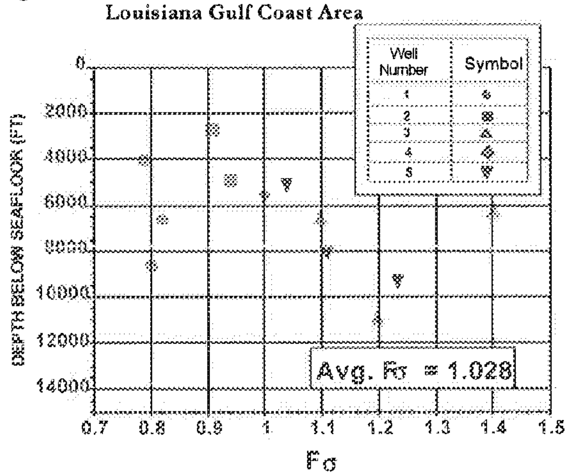


Figure 2 - Ratio of Horizontal to Vertical Effective Stress from Leak-Off Tests in the Green Canyon Area, Offshore Louisiana

[1] See Nomenclature Section at end of report.

2. The presence of stress concentrations in and around the borehole; and
3. The presence of non-zero tensile strengths in the sediments exposed during the test.

Overburden Pressure

The overburden stress is the most important parameter affecting fracture pressure. The overburden stress, s, at a certain depth can be thought of as the pressure resulting from the total weight of the rock and pore fluids above that depth. Since bulk density, ρ_b, is a measure of the weight of rock and pore fluids, the overburden stress at a certain depth can be easily calculated by integration of the bulk density versus sediment depth profile:

$$s = \int_0^{D_s} \rho_b g dD_s \ldots\ldots (3.2)$$

Thus, one method for calculating the overburden pressure is to sum up the product of the average interval bulk-density times interval height for all intervals above the depth of interest.

For offshore sediments, hydrostatic pressure due to water depth must also be considered and Equation (3.2) becomes:

$$s = \int_0^{D_w} \rho_{sw} g dD_w + \int_0^{D_s} \rho_b g dD_s \ldots\ldots \quad (3.3)$$

The best source of bulk density data is from in-situ measurements made with a gamma-gamma formation-density log. Unfortunately such data is seldom available for depths less than the surface casing setting depth. Accuracy of the formation density logs can be poor in large diameter holes, so that a pilot hole may be required to get good measurements in the shallow sediments. Logging-while-drilling (LWD) tools are now available that can measure formation density, but they also require hole diameters no greater than 14 inches. Thus a pilot hole may be required to get accurate density measurements in the upper marine sediments on the first well drilled in a new area.

Sonic travel times determined from well logs or calculated using seismic data can also be used to estimate the formation bulk density. However, Rocha (1993) found that there was a poor agreement between density values obtained with sonic and density logs in the upper marine sediments. The difficulty stems from uncertainty about the proper choice of values for matrix-travel time in shallow clay sediments.

Bulk density data obtained from rock cuttings while drilling is sometimes available in the shallow sediments. However, the bulk density of cuttings can be highly altered by the release of confining pressure and by exposure to the drilling fluid.

Overburden stress as a function of porosity

Because of the problems discussed above, detailed information on bulk density is often not available at shallow depths. Thus, density at shallow depths must often be extrapolated from information obtained at deeper depths. This is typically done using porosity instead of bulk density. Bulk density can be defined in terms of porosity, ϕ, and other variables using the following equation:

$$\rho_b = (1-\phi)\rho_{matrix} + \phi\rho_{fluid} \qquad (3.4)$$

From the above equation, bulk density is primarily dependent on porosity since the other variables of grain matrix density and pore-fluid density usually do not have a wide range of values. Porosity often decreases exponentially with depth, and thus a plot of porosity versus depth on semilog paper often yields a straight-line trend. This exponential relationship can be described using the following equation:

$$\phi = \phi_0 e^{-KD} \qquad (3.5)$$

The constants ϕ_0, the surface porosity, and K, the porosity decline constant, are determined graphically or by the least-square fit method. Substituting Equation (3.5) into Equation (3.4) gives:

$$\rho_b = +(1-\phi_0 e^{-kD_s})\rho_{matrix} + \phi_0 e^{-kD_s}\rho_{fluid}$$

and after substituting into Equation (3.3) and integrating, gives

$$s = \rho_{sw} g D_w + \rho_{matrix} g D_s - \frac{(\rho_{matrix} - \rho_{fluid}) g \phi_0}{K}(1 - e^{-KDs}) \qquad (3.6)$$

Rocha, (1994) proposed that most shallow marine sediments found in the gulf coast exist in a plastic state of stress and that F_σ approaches one in Equation (3.1). As the matrix stress coefficient, F_σ, becomes unity, the effect of pore pressure vanishes and fracture pressure becomes equal to the overburden stress.

$$p_{frac} = 1.0(s_{pob} - p) + p = s_{pob} \qquad (3.1b)$$

Leak-off tests were then used to calculate a pseudo-overburden pressure, s_{pob}, using Equation (3.1b). The constants of surface porosity, ϕ_0, and the porosity decline constant, K, are determined

Area	ρ_{matrix}	ϕ_0	K
Green Canyon	2.65	0.77	323 E-6
Main Pass	2.67	0.59	100 E-6
Ewing Bank	2.65	0.685	115 E-6
Mississippi Canyon	2.65	0.66	166 E-6
Rio de Janeiro Area	2.70	0.67	18 E-6

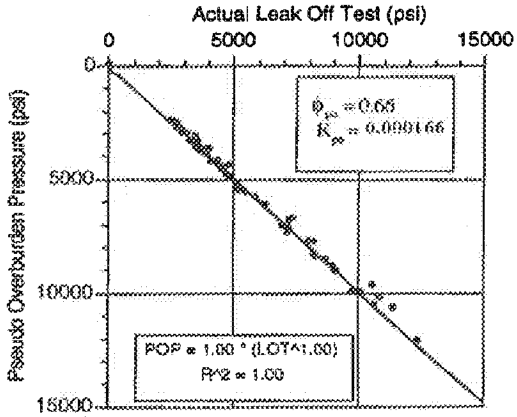
Table 3.1 - Values for Surface Porosity and Porosity Decline Constant for Several Offshore Areas (Matrix density is expressed in gm/cc and K is expressed in ft⁻¹)

by the best fit of the leak-off test data from Equation (3.6) with the pseudo-overburden stress substituted for overburden stress. Values for ϕ_0 and K for several areas in the Gulf Coast and Brazil are given in Table 1. This approach is best suited for a limited area in which geologic conditions do not vary significantly and for which leak-off test data are available in the upper marine sediments. In sandy areas where F_σ becomes less than one, the correlation will become less accurate and more sensitive to changes in pore pressure.

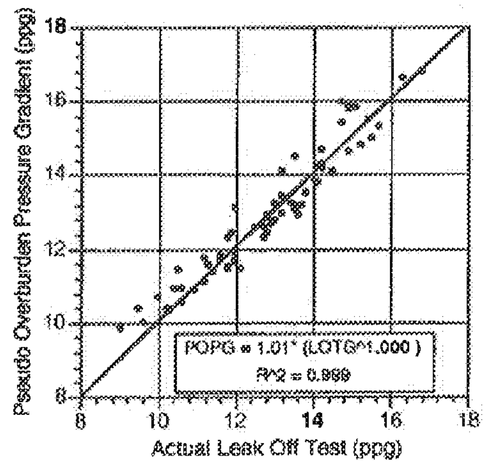
Shown in Figure 3.3a is the correlation obtained for the Mississippi Canyon Area of the Gulf of Mexico. The correlation was based on 66 leak-off tests. Note the good correlation obtained between actual leak-off pressure and the pseudo-overburden stress based on leak-off test observations. The same results, expressed in terms of equivalent mud weight, are shown in Figure 3.3b. Note that the spread in the data is about plus or minus one pound per gallon of equivalent mud density.

Another correlation was attempted which considered effective stress F_σ in addition to overburden stress and thus considered changes in pore pressure. A shallow transition zone to abnormal pressure was seen in these wells. However, only minor improvements in the correlation index could be achieved for shallow marine sediments with this increased complexity. This may be since F_σ was found to be near one.

Work was also done to determine how soil borings can be used to help fill-in some of the missing data needed in designing the shallow portion of the well. Example data from the Green Canyon area of the Gulf of Mexico are shown in



(a) Comparison of actual leak-off test pressure and pseudo-overburden pressure.



(b) Comparison of actual Leak-off equivalent mud weight to correlation

Figure 3.3: Leak-off Test Correlation for Mississippi Canyon Area of Gulf of Mexico

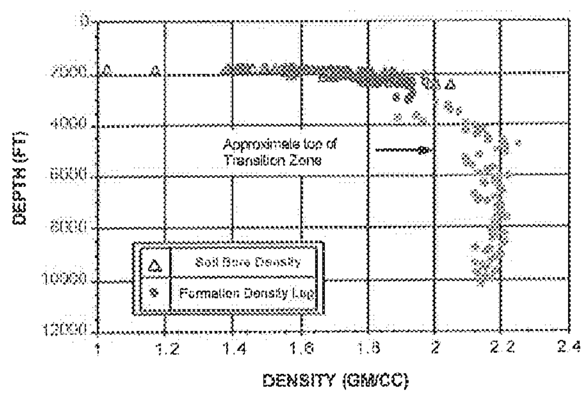


Figure 3.4: Integration of Sediment Bulk Density Data from Soil Borings and Formation Density Logs

Figure 3.4 and illustrate how soil boring data can be integrated with deeper well log data to provide a more accurate estimate of overburden stress. Overburden stress calculated from the integration of bulk density versus depth data was found to agree closely with pseudo-overburden stress calculated from a leak-off test correlation obtained as discussed above.

For shallow marine sediments, it is recommended that the overburden stress be calculated using Equation (3.6) when bulk density versus depth data are not available. Note that for commonly used units, where density is expressed in gm/cc and depth is expressed in ft, the constant g can be replaced by 0.433 in Equation (3.6). The formation fracture pressure can then be computed using Equation (3.1). For clay sediments, it is recommended that F_σ is assumed to have a value of 1.0. If well-developed sands are known to be present, a lower value for F_σ is used for those zones. In the absence of leak-off tests for the sand intervals of interest, the use of a minimum observed value for F_σ from the available leak-off test data should be considered. Note that the minimum value seen in Figure 3.2 was about 0.8.

Kick-Prevention Measures

Because of the difficulties in handling gas flows while drilling at shallow depths, considerable attention should be given to preventing such flows when planning the well. Seismic surveys can sometimes be used to identify potential shallow-gas zones prior to drilling. If localized gas concentrations are detected by seismic analysis, hazards can often be reduced when selecting the surface well location.

When possible, an appropriate empirical correlation should be applied to the seismic data to estimate formation pore pressures. This will sometimes permit the detection of shallow, abnormal pressure in the marine sediments. When formation pore pressures can be accurately estimated, an appropriate mud density program can be followed to prevent gas from entering the borehole. One of the most effective ways to prevent shallow gas kicks is through use of an extra pound per gallon of mud density (over the pore pressure) in the shallow portion of the well.

Drilling practices followed when drilling the shallow portion of the well can also impact the risk of a blowout. Operations that can reduce down-hole pressure, such as pulling the drill string from the well, should be carefully controlled to ensure that a pressure overbalance is always maintained in the open borehole. Pressure changes due to pipe movement tend to increase with decreasing hole size, and pose a greater risk when drilling small-diameter pilot holes. However, when clay sticks to stabilizer blades and restricts the annular flow area, significant reductions in borehole pressure due to upward pipe movement can occur even in big diameter bore holes. At shallow depths, a small loss in borehole pressure can result in a significant loss in equivalent mud density. For example, a pressure loss of 50 psi when pulling pipe from a depth of 10,000 ft is equivalent to a loss in drilling fluid density of only 0.1 lb/gal, which can often be neglected. However, the same pressure loss at a depth of 1,000 ft is equivalent to a loss in drilling fluid density of 1 lb/gal, which could be very dangerous. Trip-tank arrangements which keep the well completely full of drilling fluid at all times are better than those that require periodic refilling of the well. Modern top-drive rotary systems permit pumping down the drill-string while pulling pipe and can be used when necessary to eliminate the swabbing effect caused by pipe movement.

Gas-cut drilling fluid can also cause a loss in borehole pressure that can result in a significant reduction in equivalent mud density at shallow depths. For example, severe gas-cut mud observed at the surface can cause a reduction in bottom-hole pressure as high as 100 psi. This pressure loss is equivalent to a loss of only about 0.2 lb/gal at a depth of 10,000 ft, which is usually within a normal safety margin. However, this same pressure loss at a depth of 1,000 ft would cause a loss in equivalent mud density of 2.0 lb/gal. Thus, when drilling at very shallow depths, even the small pressure loss due to gas-cut mud can be significant. If gas-cut mud appears prior to setting surface casing, it is advisable to periodically check for flow and to clean the well by circulating.

Gas cut mud occurs due to the drilling process when gas is present in the rock being destroyed by the bit. Gas entering the drilling fluid from rock cuttings is commonly called drilled gas. Conditions favoring a shallow gas flow due to drilled gas become more severe with increasing hole size, increasing drilling rate, and increasing length of uncased borehole. However, some shallow gas flow events are believed to have been caused by cutting fault planes through which gas was actively migrating from deeper zones. These fault-cut zones behave as high pressure but low permeability zones, which only tend to cause trouble when circulation is stopped for a long period. Stopping circulation allows a build-up of gas-cut mud from the gas bleeding into the well from the fault cut. Geo-hazard surveys can often identify gas seeps along a fault line at the seafloor from side-scan sonar

Casing Program for Shallow-Gas

One of the first steps in developing a well control contingency plan is to decide at what point during the drilling operations that it will become safe to close the blowout preventers during a threatened blowout. The most common industry practice for drilling from a bottom-supported structure is to use the blowout preventers only after surface casing has been successfully cemented. Prior to that time, the well is put on a diverter if a kick is taken. Another often mentioned rule of thumb is that at least 1500 feet of casing penetration into the sediments is needed to achieve an acceptably low probability that an underground blowout could broach to the surface outside of the casing. A practice sometimes used in conjunction with this rule of thumb is to keep the ratio of length of the open-hole section to the to length of the casing penetration into the sediments below four.

As discussed previously, diverters have had a high failure rate in the past. Diverters were installed on many rigs after the rig was constructed. Multiple bends were used to route the diverter lines to an overboard exit and many of the early systems had poorly designed valves and flexible hoses from the wellhead to the fixed piping. Numerous mechanical problems and severe erosion due to sand production have occurred when the diverter systems had to be employed. Early diverter systems were also undersized and could not handle high flow rates without causing the pressure on the casing seat to exceed the breakdown pressure. Also, as discussed under cratering mechanisms, cratering due to caving can occur if shallow aquifers are exposed, even when the casing / diverter system is properly designed and sized.

The operational problems experienced with diverters have resulted in a reduced reliance on diverter systems by many operators, especially in floating drilling operations in which the drilling vessel can be moved off location and is not threatened by crater formation. Some operators are even placing reduced reliance on diverters for bottom-supported rigs. A recent paper by Arifun and Sumpeno [1994] has indicated that Unocal is no longer using diverters in their East Kalimantan operations. Platform wells are designed and drilled with a well plan that calls for shut-in of all kicks from the surface to the total well depth.

As for most other critical well design issues, the question of whether to design the shallow portion of a well to be shut-in or diverted is primarily a risk management decision. Well cost must be balanced against the reduction in risk achieved. Shown in Figure 3.5 is a decision tree or design procedure that organizes most of the major alternatives that should be evaluated.

The items listed in this decision tree were based on identified mechanisms of crater formation. After gathering information on the sediment lithology, the location of permeable zones can be identified. The risk of cratering due to sand production followed by caving will be present if a well is diverted with thick permeable sands exposed in the open borehole. On the other hand, if all of the shallow sediments were clay formations except for very thin stringers of sand, then this mechanism of crater formation would not be possible. A systems analysis can be used to determine if the diverter of the rig and the planned casing program will allow a successful diverter operation. The analysis considers a shallow gas reservoir, the well hydraulic path, and the diverter as one system. The maximum pressure observed at the casing seat for several design load conditions are calculated. The design loads are estimated (1) when the well is unloading, (2) when the flow reaches a maximum value, and (3) during possible dynamic kill operations (including the possible use of a relief well). If the well cannot withstand the expected design loads without cratering or if the dynamic kill requirements are not acceptable, the planned casing program/ diverter system is modified, and the systems analysis is repeated. The systems analysis requires an estimate of the formation fracture resistance versus depth and the location, thickness, and permeability of the zone that potentially could cause a gas influx into the well. The systems analysis procedure is based on previous work done at LSU under MMS sponsorship. Bourgoyne [1994] published a detailed description of the systems analysis procedure and sites the various reference materials upon which it is based.

If the decision is made to design the well for shut-in of potential shallow gas zones, then a design load must be chosen as a basis for the casing program. Figure 3.5 shows three possible kick conditions that could be used to obtain the design load for the casing point selection. The three kick situations include:

1. A large shallow gas kick is taken at a gas influx rate that is

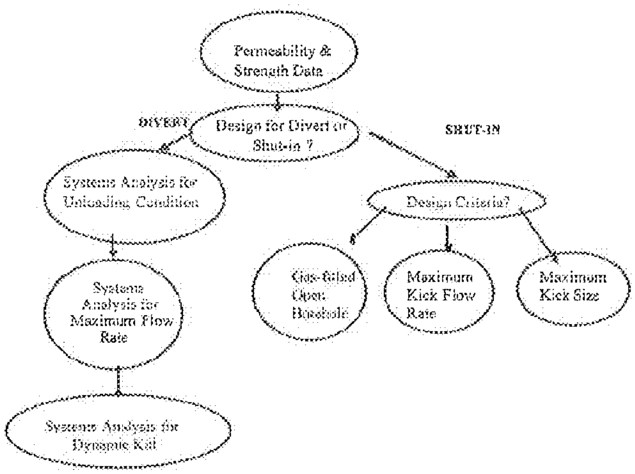


Figure 3.5: Decision Tree for Shallow Gas Design

sufficient to change the multiphase flow pattern in the well to mist-flow and completely displace all of the mud from the uncased portion of the well.

2. A gas kick is taken at a rate that is insufficient to change the multiphase flow pattern to mist-flow but is large enough to fill the entire uncased portion of the wellbore with a mud/gas mixture.
3. A gas kick is taken, but the well is successfully closed before a maximum design pit-gain is observed.

The first scenario is the most conservative and would be the least susceptible to human error. The third design load is the least conservative and the consequences of human error could be great. Knowledge of the permeability and thickness of any potential gas bearing zones would allow the gas influx rate to be estimated. An improved procedure for estimating the fraction of mud that would be displaced from the open borehole by a given gas influx rate was developed as part of research Task 7 done at LSU under this same MMS research contract. The details of this new procedure can be found in the Task 7 Final Report and in a recent paper by Flores-Avila, Smith, Bourgoyne, and Bourgoyne [2002]. The minimum gas velocity that completely removed of an unweighted mud from a LSU test well was approximately 18 ft/s.

The effect of the design-load on the casing program can be estimated by assuming a gas kick is taken just prior to setting the next string of casing. This has been done for the geologic conditions encountered in Unocal's Attaka field described by Arifun and Sumpeno [1994].

Example Casing Program used with Diverter

Early wells drilled with bottom-supported rigs in the Attaka field were drilled conventionally, i.e. a diverter system was used prior to setting surface casing. A typical casing program is shown in Figure 3.6. Structural casing having a 30-in. diameter was driven about 215 ft below the mud line. Conductor casing having a 20-in diameter was set at about 800 ft below the mud line. The next casing string was surface casing, which was typically set at a depth of about 3,200-ft. The nominal water depth is 200 ft and the nominal air gap is 85 ft.

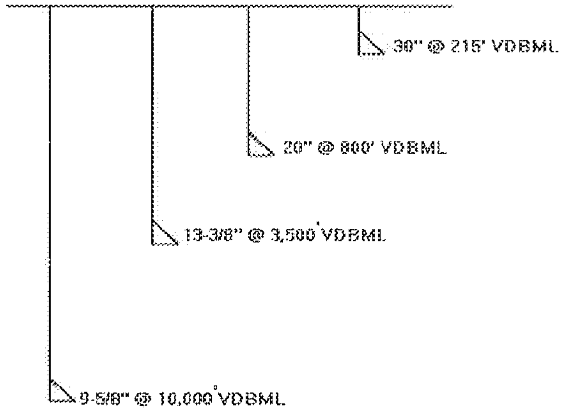


Figure 3.6: Typical Casing Design used for diverting Shallow Gas Kicks

Example Casing Programs for Shut-in of Shallow Gas

Soil borings data was available to a depth of about 330-ft. The first 100-ft of sediments had an average porosity of about 59% and the porosity observed at the bottom of the soil borings was about 50%. The soil boring showed mostly clay sediments except for a silty sand about 20 ft in thickness at about 165 ft below the mud line. The water content of the clay was above the plastic limit over the entire interval bored. The shear strength at the bottom of the boring was about 15 psi. For potential diverter operations, the sand at 165 ft is covered by the drive pipe to reduce the risk of excavation of this area due to sand production. As discussed previously, collapse of overlying sediments into an excavated sandy stratum is one potential mechanism for cratering during diverter operations.

Shown in Table 3.2 is a spreadsheet calculation for this example using the pseudo-overburden stress equation given by Equation (3.6). The calculation assumes that the surface-intercept of the porosity trend is about 59 %, the interstitial water has a specific gravity of 1.032, and the average matrix grain density is 2.65. In addition, a porosity decline constant of 100 E-6 ft[1] and a clay tensile strength of 5 psi were used. From the available data, the upper sediments appear to be mostly clay, and consequently the ratio of horizontal-to-vertical effective-stress should be near one. Thus, the expected formation breakdown pressure is equal to the overburden pressure plus the tensile strength of the sediments. Plotted as a solid line in Figure 3.7 are the formation breakdown pressures computed in Table 3.2 from Equation (3.6) at various depths. Leak-off-test data for the area were available. Formation breakdown pressures

Depth RKB	Depth Sub Surface	Porosity & Bound Water	Pseudo Overburden Stress + So	Pore Pressure	Effective Subsea Strength	Subsea Strength to Normal Gradient
[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]
285	0	59.00%	33	33		
400	115	58.33%	138	130	0.78	1.75
500	215	57.70%	232	184	0.78	1.71
600	315	57.17%	322	228	0.76	1.69
700	415	56.60%	401	274	0.75	1.66
800	515	56.06%	477	318	0.75	1.65
900	615	55.46%	552	363	0.75	1.63
1000	715	54.93%	628	408	0.76	1.61
1500	1215	52.27%	1015	631	0.76	1.71
2000	1715	49.70%	1419	854	0.77	1.71
2500	2215	47.35%	1814	1078	0.78	1.74
3000	2715	45.07%	2216	1301	0.79	1.76
3500	3215	42.78%	2626	1525	0.80	1.78

Table 3.2: Spreadsheet output using Pseudo Overburden Stress Model to predict Fracture Pressure

from the Leak-off tests are shown in Figure 3.7 as individual points. Note the excellent agreement between the calculated trend and the results of the leak-off tests. When less agreement is observed, the surface porosity intercept and the porosity decline constant can be adjusted to improve the fit.

Available information on the lithology of the area shows that the clay sediments extend to the planned depth of the surface casing at 3500 feet, except for a 10-ft sand at 165 ft and a 100-ft sand at 2550 feet. A thick, stronger claystone above the sand would act as a confining layer to a fracture in the sand. Thus, for more than 2500 ft of casing penetration into the sediments, even if formation breakdown occurs, the resulting underground blowout would be expected to remain underground.

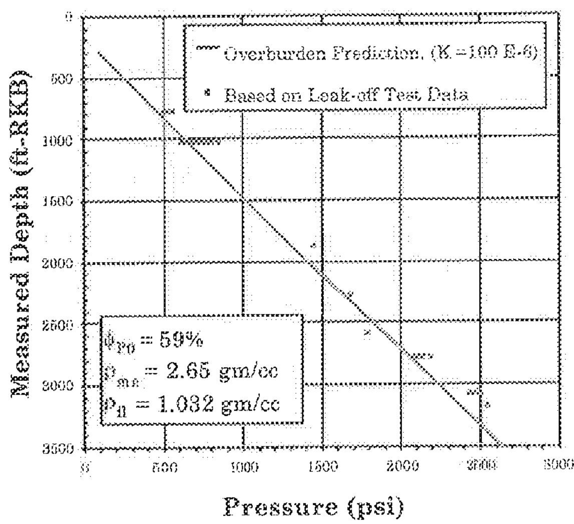


Figure 3.7: Comparison of Predicted Hydraulic Breakdown Pressure and Leak-off Test Results for Shallow Sediments

Design Load based on Gas-Filled Open-hole at Shut-in (Worst Case Analysis)

Shown in Figure 3.8 is the casing design required to contain 100% gas in the open borehole. The design process assumes that an unexpected gas zone could be cut at any depth. The design process is started at the depth of the surface casing and proceeds in a stair step manner as indicated by the arrowheads shown. For the average fracture gradient and normal pore pressure gradient of this example, the D1/D2 depth ratio[2] of successive casing strings is about 1.8. To reach a depth of 3500-ft below the mud line (BML), casing would have to be set at 2025-ft BML. Formation breakdown pressure would not be exceeded for any kick size at 2025-ft BML. Casing would have to be set at 1215 ft BML to reach a depth of 2025-ft BML, at 715-ft BML to reach 1215-ft BML and at 415-ft BML to reach 715-ft BML.

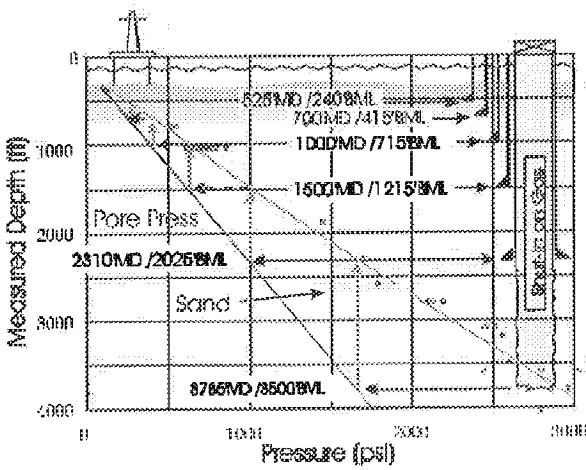


Figure 3.8: Example design for gas filled open-hole section

[2] Note that this ratio is also equal to the ratio of the sediment strength gradient to pore pressure gradient as shown in Table 3.2 (0.8 psi per ft / 0.45 psi per ft = 1.8).

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The additional costs associated with the casing design of Figure 3.8 over the conventional design shown in Figure 3.6 were estimated to be at least $330,000. Statistics for the OCS indicates that about one exploration well[5] in 243 drilled have experienced a shallow gas blowout. About 71% of these blowouts bridged naturally due to borehole collapse. Costs of these blowouts have been limited primarily to the loss of the well being drilled. About one exploratory well in 2000 drilled from bottom-supported structures during the past 20 years has had extensive, to total structural damage. No casualties have been tied directly to cratering during this period although some resulted from mechanical problems with early diverter designs. Pollution has been minimal due to the lack of associated oil with shallow gas zones. Multiplying the approximate additional cost by 243 yields $80,000,000. Thus if this design procedure eliminated all blowouts due to shallow gas, the value of the well saved would have to be greater than $80,000,000 to justify the additional expense per well. Multiplying the approximate additional cost by 2000 yields $660,000,000. Thus if this design eliminated all cratering events that caused major structural damage or total loss of the structure and associated wells, the value of the structure saved would have to exceed $ 660,000,000 to justify the additional expense per well. This example shows that it is far more cost effective to buy blowout insurance than to design every well so that cratering in not possible.

Experiments conducted in an LSU test well by Flores-Avila, Smith, Bourgoyne, and Bourgoyne [2002] showed that 90% mud removal was accomplished at about 600 ft/min. For gas velocities higher than this, almost all of the mud can be removed from the well. To get a feel for the kick magnitude that this corresponds to, consider that in a 17.5-in. hole with 5-in. drill pipe, the annular capacity is 0.27 bbl/ft. Thus, either the pit gain rate would have to exceed 600(0.27)=162 bbl/min, or human error would have to let the well completely unload. For a 9.875-in pilot hole, the annular capacity is 0.07 bbl/ft and the pit gain rate would have to exceed 42 bbl/min. The presence of a large enough gas zone to cause a flow of this magnitude is unlikely. If such a large gas zone was present, it should be easily detected by a seismic hazard survey. Current practice and MMS regulations call for setting conductor casing prior to drilling known hydrocarbon-bearing formations.

Based on the discussion above, it can be concluded that although technically feasible for many cases, the use of this design load will generally be unnecessarily expensive for the potential benefit.

<u>Design load based on Mud/Gas Mixing</u>

[5] The risk of shallow gas blowouts for exploration wells is higher than for development wells and provides a conservative estimate of additional costs.

The maximum rate of gas influx can be estimated from expected maximum formation permeability and thickness for the area. The maximum rate of pit gain for one area was estimated to be about 18 bbl/min in a 17.5-in hole. For these conditions, the gas would bubble through and mix with the mud, displacing about 50% of the mud from the well and result in an effective pressure gradient of 0.254 psi/ft in the mud gas mixture. The casing design for these conditions is shown in Figure 3.9. Note that the size of the kick does not matter once the top of the multiphase mixture reaches the previous casing seat. The additional cost of this design over the typical design shown in Figure 3.6 was estimated to be at least $120,000. Multiplying this cost by 243 yields $29,000,000 and by 2000 yields $240,000,000. Thus, the use of this design load will also generally be unnecessarily expensive for the potential benefit.

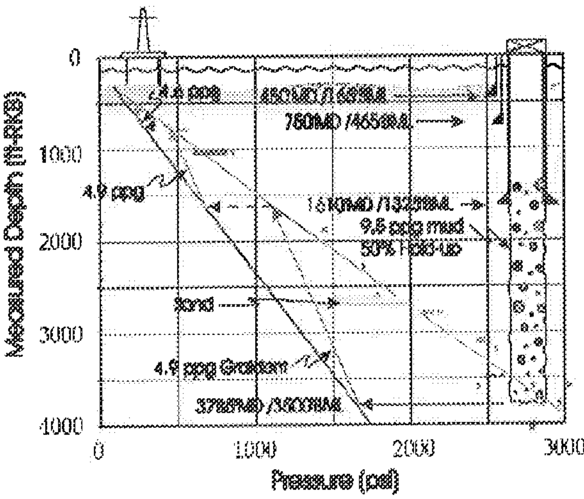

Figure 3.9: Example Casing Design Load for Gas/Mud Mixing

Design Load based on Maximum Pit Gain to Shut-in

The least conservative design load is obtained by assuming that the kick will always be shut-in without exceeding a maximum total pit gain. The design shown in Figure 3.10 is based on a maximum tolerated pit gain of 200 bbl at shut-in. The additional cost associated with this design load was estimated to be about the same as the typical design shown in Figure 3.6.

The major disadvantage of this method is that the potential consequences of human error are greater. If a kick is taken that is larger than the kick tolerance included in the design, there is a possibility that gas could surface under the rig prior to orderly rig abandonment. This would be especially true if no diverter was available to release the pressure as soon as gas bubbles appeared.

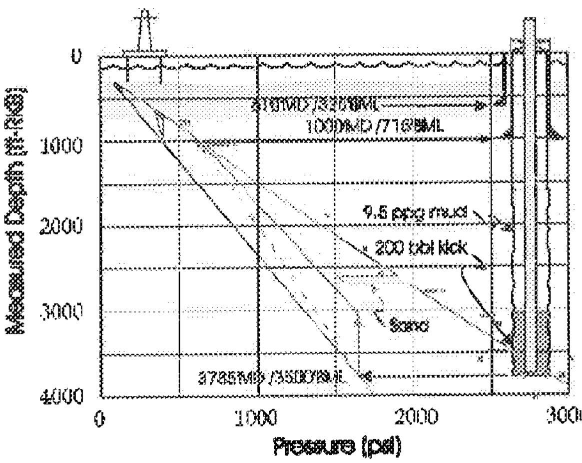

Figure 3.10: Example Casing Design for 200 bbl Kick Tolerance

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Shallow Gas Contingency Plan

The preceding discussion has shown the various steps in developing a well design and shallow-gas contingency plan to follow in the event kick prevention measures are not effective. The final step will be to effectively communicate the procedures to be followed to the rig personnel. Some operators keep kill mud in a reserve pit for use in the event a shallow kick is taken while drilling. Two successful well kills on diverters were reported in which the operator pumped premixed kill mud at the maximum available rate after putting the well on a diverter.

Shown in Figure 3.11 is an example decision tree that could be used as part of contingency training for handling a shallow gas kick while drilling from a bottom supported vessel. If it is obvious that the well is flowing while drilling, some rig procedures call diverting and switching pump suction to premixed kill mud without ever shutting down the pump. In general, the chance of success of a dynamic kill is enhanced by starting the procedure with the smallest possible influx of formation fluids into the well.

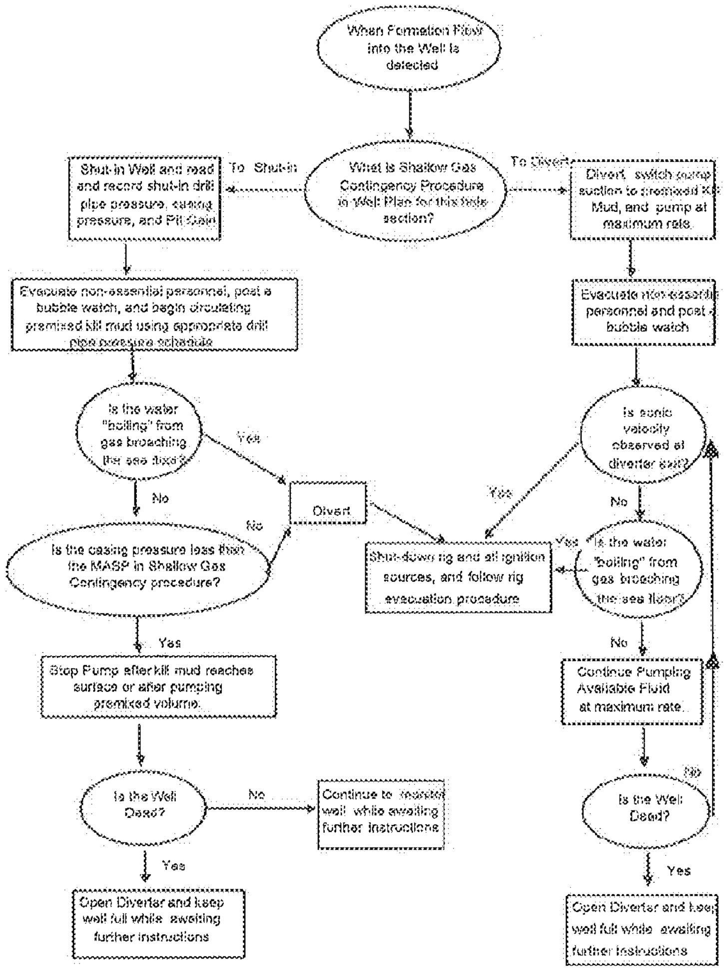

Figure 3.11: Example Rig Guide for Diverter Operations while Drilling from a Bottom Supported Rig

The exact procedure required to divert depends on the equipment arrangement on the rig. Most operators follow a sequence that will provide down wind diversion without ever closing the well and allowing the pressures to build up in the well. An example procedure could be:

1. Open Valve to Downwind Diverter
2. Close Annular Diverter Head
3. Increase Pump Speed to Maximum Available Rate
4. Switch Pump Suction to Premixed Kill Mud

On most rigs, diverter valve controls are now interlocked so that it is impossible to shut-in the well when diverting or when re-routing the flow because of a change in wind direction. This will be discussed in the next chapter.

Shown in Figure 3.12 is an example decision tree that could be used as part of contingency training for handling a threatened shallow gas blowout during tripping operations on a bottom supported drilling vessel. Experience has shown that most shallow gas blowouts start when circulation is stopped and the drillstring is being withdrawn after drilling to the depth of the surface casing. Such kicks may be caused by balled-up stabilizers. Some operators believe that such kicks can also occur when a fault through which gas is actively migrating to the seabed is cut by the bit. As in the previous example for drilling operations, starting the kill procedure with the smallest possible influx volume is thought to be very important to a successful kill.

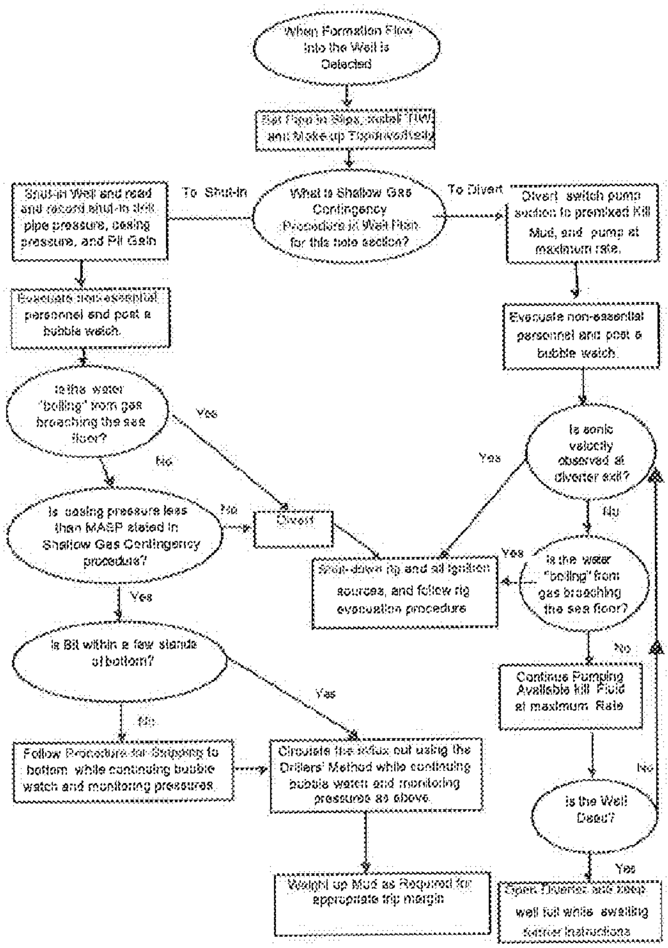

Figure 3.12: Example Rig Guide for Diverter operations while Tripping on a Bottom Supported Rig

Diverter operations are not normally used as part of a shallow- gas contingency-plan for floating drilling vessels. The shallow part of the well is generally drilled with returns to the seafloor. If shallow gas is encountered in deep water, the gas will generally surface far from the rig and will not present a hazard. The greatest hazard will be present for anchored floating vessels operating in relatively shallow water. The shallow gas contingency plan for floating rigs must address how to safely move the vessel off location. It is important to use a wide enough anchor pattern and long enough chains so that the rig can be easily moved a safe distance from a gas boil. Some contractors use an anchor pattern to allow for at least 400 ft of vessel movement in the up-wind or up-current direction.

The primary function of diverters on floating drilling vessels is to provide for safe handling of a large volume of gas that enters the marine riser before the blowout preventers are closed or after a subsea blowout preventer has failed. If the rate of gas flowing from the riser exceeds the capacity of

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the gas-handling system, then the diverter system can be used to prevent an excessive flow of gas to the mud -room.

The next chapter provides information on improvements in diverter equipment for both bottom supported drilling vessels and floating drilling vessels.

Chapter 4

Improvements in Diverter Systems

Because of an observed high failure rate of diverter systems during shallow gas events, MMS Rules and Regulations for diverter systems used in drilling, completion, and workover operations in all waters of the outer continental shelf were modified in 1990. The minimum allowable diverter internal diameter was increased to 10 inches for wells with surface wellheads and 12 inches for floating drilling vessels. New requirements for pressure testing of the diverter sealing element and diverter valves, flow testing the diverter system, and actuation testing of all diverter control systems became effective. Also in 1990, the API published RP 16E, the Recommended Practice for Design of Control Systems for Drilling Well Control Equipment. This RP also addressed the control systems of diverters. In 1991, API published RP 64, the Recommended Practice for Diverter Systems Equipment and Operation.

A diverter system has four essential components: (1) conductor casing or drive pipe, (2) an annular preventer to stop the upward flow, (3) one or more large diameter diverter line that directs flow downwind and away from the rig and personnel, and (4) one or more valves that isolate the diverter from the active mud system during normal drilling operations. The annular preventer must be able to pack-off around the Kelly, drillstring, or casing. On most wells, a diverter is not designed to shut-in or halt flow. API recommends that the control system be designed to preclude closing in the well with the diverter. This requires opening one or more vent lines prior to closing the diverter as well as closing the normally open valve to the return mud system. If an annular sealing element which requires lockdown is being used, then API recommends that the lockdown function be also included in the automatic sequence of the control system.

Diverter lines should be securely anchored, as straight as possible, and internally smooth. Sleeve-type couplings must not be used for pipe joint connections. When bends are necessary, long radius bends with the bend radius at least 20 times the inside diameter of the pipe is recommended. When 90 degree bends are necessary, targeted tees with a blind flange to provide a fluid cushion is recommended for reduced erosion rates. No branch is best, but use of "Y" type branches is preferable to using a tee branch connection. Ells should not be installed near the diverter exit to direct the flow downward or sideways. These could cause the line to "kick-up" and possibly break off when large flow volumes are diverted. The vent lines should be sloped downward over their entire length to avoid low spots that could collect sediments from the drilling fluid and rock cuttings. Provisions for cleaning and flushing the vent lines should also be made.

Experience has shown that most diverter problems occur because of human error. Improper installations have been greatly reduced through improved training and attention to details such as minimizing potential erosion sites and checking diverter anchor strength. However, the use of packer inserts, extra valves, and multiple interconnected functions also result in higher risks. Each additional element with a moving part increases the risk of a malfunction.

Modern diverter systems use an annular packing element that can close off the wellbore around the drillstring, regardless of the size of pipe in the diverter when the well begins to flow. The insert packer design in older diverter designs uses multiple packer inserts for use with different size pipe. In addition, failure to properly latch the packer insert could cause a dangerous ejection of the packer insert from the well as pressure built-up. Rotation of the packer insert so that the vent holes in the packer element do not perfectly align with the vent connections in the diverter housing can also produce points of increased erosion rates.

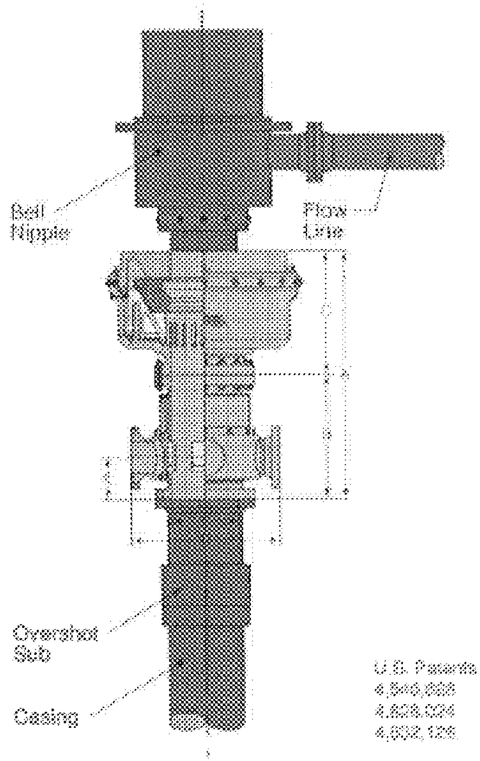

Figure 4.1: Modern Diverter Design with integrated Annular Preventer (C) and Vent Valves (B).

Improved Diverter Components

Shown in Figure 4.1 is a diverter design that was introduced in the mid 1980's. This design incorporates the ability to close the annulus and open the diverter line flow path with the same hydraulic signal. The normal return flow of mud is through a bell nipple located above the annular blowout preventer. Thus, the return flow of mud is also stopped when the annular preventer is closed. A control system for this design that meets the API recommended practice can be greatly simplified since both the annular preventer and the vent line valve can be operated using the same hydraulic control signal. Hydraulic actuation is also less susceptible to malfunction than the use of full open valves in the vent line equipped with pneumatic actuators.

The equipment shown in Figure 4.1 is available for up to a 30-inch internal diameter and a 16-inch vent line internal diameter. A working pressure of 1000 psi is available for units with a 30-inch bore. A smaller unit with a 21.25-in bore has a working pressure of 2000 psi. Note that by incorporating the vent valve into the vent outlet of the wellhead, there is no place for stagnant mud or cuttings to accumulate to create a blockage.

A Flow selector valve (Figure 4.2) is also now available for accomplishing downwind diversion. This unit replaces a targeted Tee with two valves, further reducing the number of potential failure modes and further simplifying the control system. The target is not fluid cushioned, but is made of hard, erosion resistant steel. The vent path is always open, regardless of valve position. The valve position

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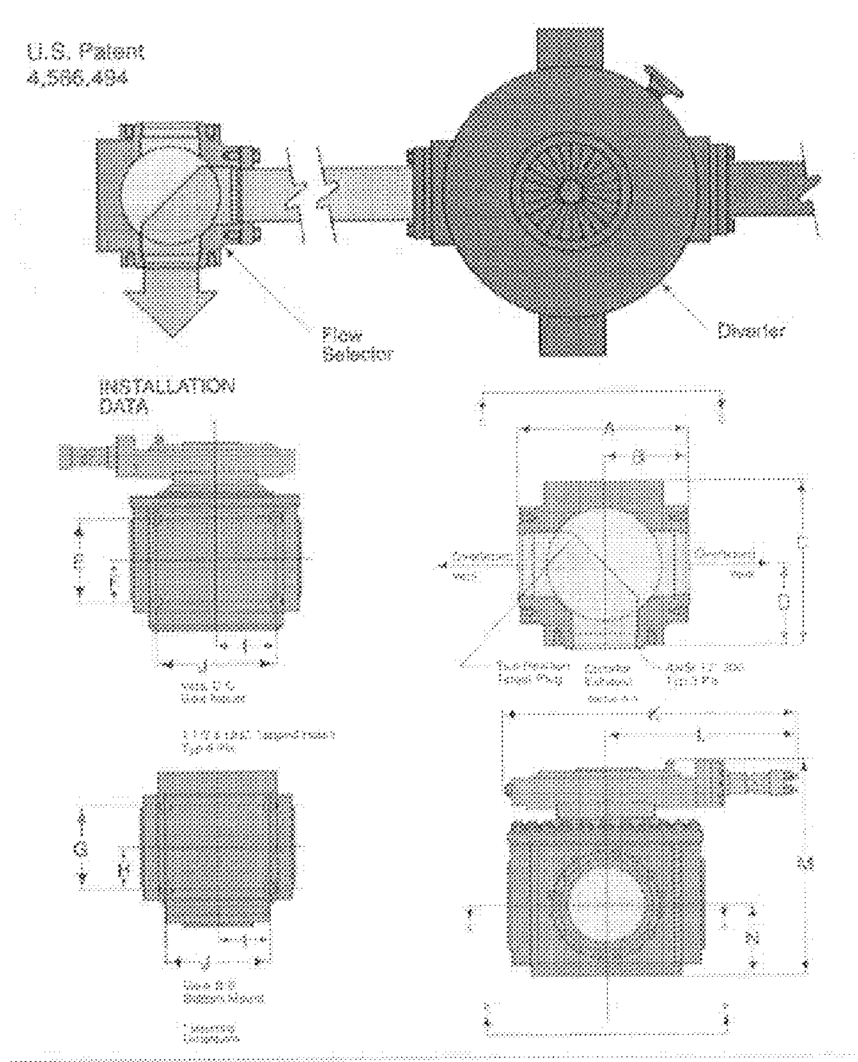

Figure 4.2: Modern Flow Selector Valve for Accomplishing Downwind Diversion.

can be pre-selected based on prevailing wind direction. However, if the wind is not from the prevailing wind direction or if the wind direction changes, rotation of the flow selector element causes both vent lines to be open before the initially open vent line is closed. If the well fluid contains formation sand and a high velocity flow is present for a significant period of time, vent line failure due to erosion would be expected to eventually occur just downstream of the flow selector valve.

Erosion rate due to sand production is minimized by using straight vent lines without any branches. Downwind diversion can be accomplished with multiple straight vent-lines coming directly from the wellhead. For the system design shown in Figure 4.1, this could be accomplished using two vent-valves (B) stacked one on top the other. However, the control system for this arrangement would be slightly more complex, since the hydraulic control signal for the vent valve would have to be selectable for either the top or bottom vent valve.

Diverter units for bottom supported rigs that can also serve as an annular blowout preventer are available with a 28-inch bore and a 2000-psi working pressure. As can be seen in Figure 4.3, the vent-line valve and connection are an integral part of the diverter. The vent-line connection is available for either a 12-inch or a 16-inch vent-line system. The combination Diverter/Annular preventer can be installed on top of the low-pressure BOP stack that will be used to drill the upper part of the well. Twenty-inch casing can be run and landed through the large-bore low-pressure preventer. After setting casing, the connection to the vent-line can be replaced by a blind flange so that returns are taken from the BOP spool in the conventional manner during well control operations.

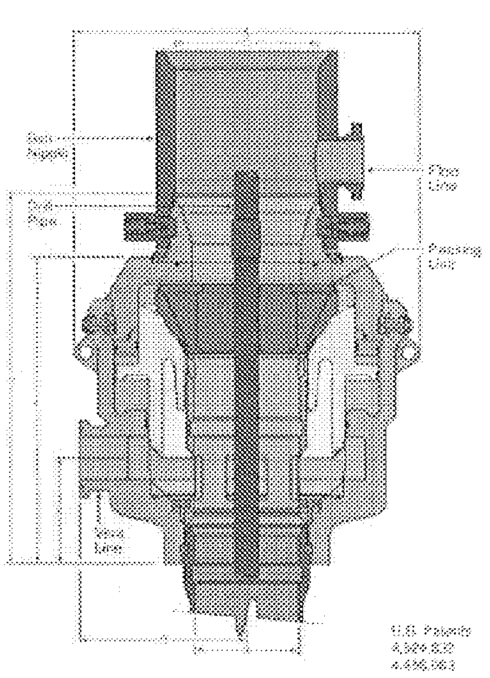

Figure 4.3 – Combination Diverter/ Annular Blowout Preventer.

Diverters with large bores and integral vent-line valves are also now available for use at the top of a marine riser in floating drilling operations. Improved versions of the older design which uses packer inserts are also now available (Figure 4.4). A Marine Riser Diverter typically has a working pressure of 500 to 1000 psi. However, the telescopic joint seal of the marine riser generally limits the pressure that can be held on the marine riser without causing a leak in the telescopic joint. The Marine Riser Diverter is built structurally strong and supports the upper flex joint and inner barrel of the telescopic joint. The diverter element can seal on open-hole, kelly, drill pipe, drill collars, or casing. Some Marine Riser Diverters also permits stripping operations to be conducted while diverting. Since marine risers generally have an internal diameter of 21 inches or less, the usual bore of Marine Riser Diverter is 20-21 inches.

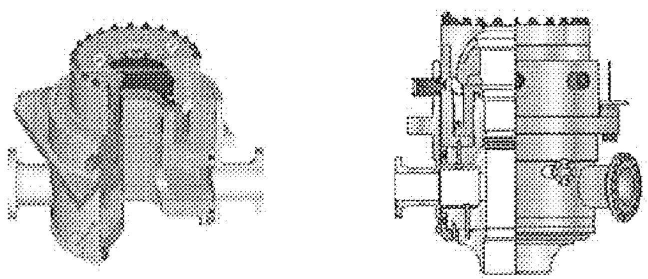

Figure 4.4 – Example 59-inch Marine Riser Diverter for Floating Drilling Operations

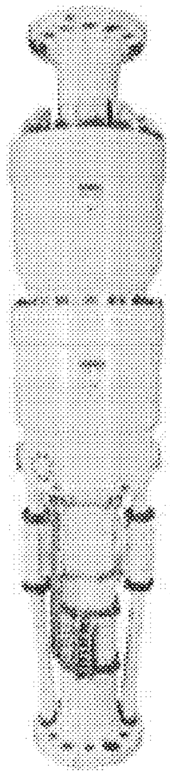

Figure 4.5 Marine Riser Diverter for Installation below the Telescopic Joint

A marine riser diverter housing is installed permanently below the rig floor so that connections to the flow line and vent lines do not have to be disconnected to remove the diverter sealing assembly. The diverter assembly is run using a special handling tool. The handling tool also allows pressure testing the sealing element.

A Marine Riser Diverter that can be installed below the telescopic joint (Figure 4.5) has also been developed to allow pressure as high as 500 psi to be held on the marine riser while handling gas. Gas rising in a marine riser can expand rapidly as it approaches the surface. An ability to hold higher pressures on the marine riser can help in preventing the capacity of the mud-gas separator from being exceeded when gas is being removed from the marine riser. Flexible lines must be attached to the side-outlets located below the sealing element to provide a flow path from the Marine Riser Diverter to the surface gas-handling system when the diverter elements are closed.

API Recommended Practice 64 also approves the use of Rotating Control Heads for use as a diverter. Recent developments include new applications of rotating control heads for handling gas in a marine riser. Shown in Figure 4.6 is an Internal Rotating Control Head ™ that can be installed below the slip joint in the marine riser. The Internal rotating control head has dual rubber elements that seal around the drillpipe. The conical shape of the rubber element cause increased pressure below the seal to increase the force holding the seal against

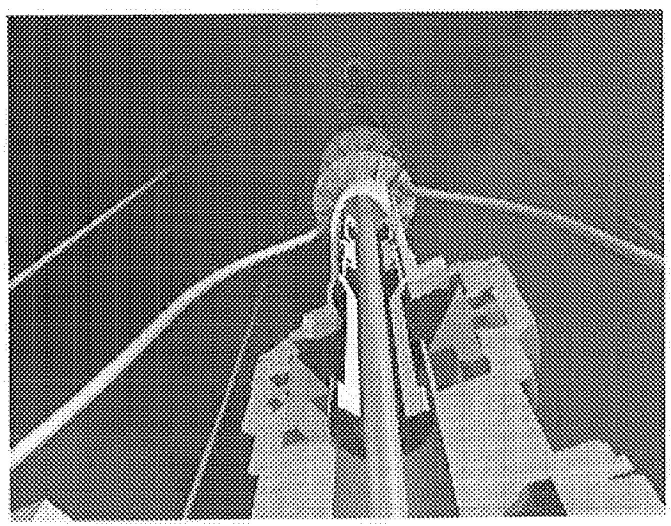

Figure 4.6 – Internal Rotating Control Head for Marine Risers

the pipe. A bearing assembly allows the seal to rotate with the drillpipe to reduce the wear rate while drilling. The internal rotating control head is run on the drillpipe above the drill collars and can be landed in a Marine Riser Diverter such as the one shown in Figure 4.6. The Internal Rotating-Control-Head could also be landed in a sub above a subsea blowout-preventer stack when practicing a dual-gradient drilling technique.

Subsea Rotating-Control-Heads have also been proposed for use when drilling through abnormally pressured aquifers sometimes encountered at shallow depths below the seabed in deep water Gulf of Mexico Leases. These so called "Shallow Water Flow" (SWF) zones are generally drilled before deploying the marine riser and the subsea blowout-preventer stack. In this section of the well, the drilling fluid is circulated only back to the seafloor where it is released to the ocean. One way of controlling SWF zones is to weight the drilling fluid sufficiently to overcome the abnormal pore pressure. However, this is very expensive since the drilling fluid cannot be recovered and re-circulated as in the conventional drilling process. In addition, a large volume of drilling fluid must be released to the ocean environment.

Shown in Figure 4.7 is a Subsea Rotating-Control-Head installed at the seafloor to provide a rotating diverter. The Rotating-Control-Head can be run on the bottom hole assembly of the drillstring and either landed in the wellhead or installed using an inflatable packer run through the wellhead into the casing. The wellhead pressure can be increased sufficiently to stop a SWF zone by increasing the pump speed or decreasing the size of the subsea diverter outlet. In order to be able to hold sufficient pressure on the subsea diverter to control the SWF zone,

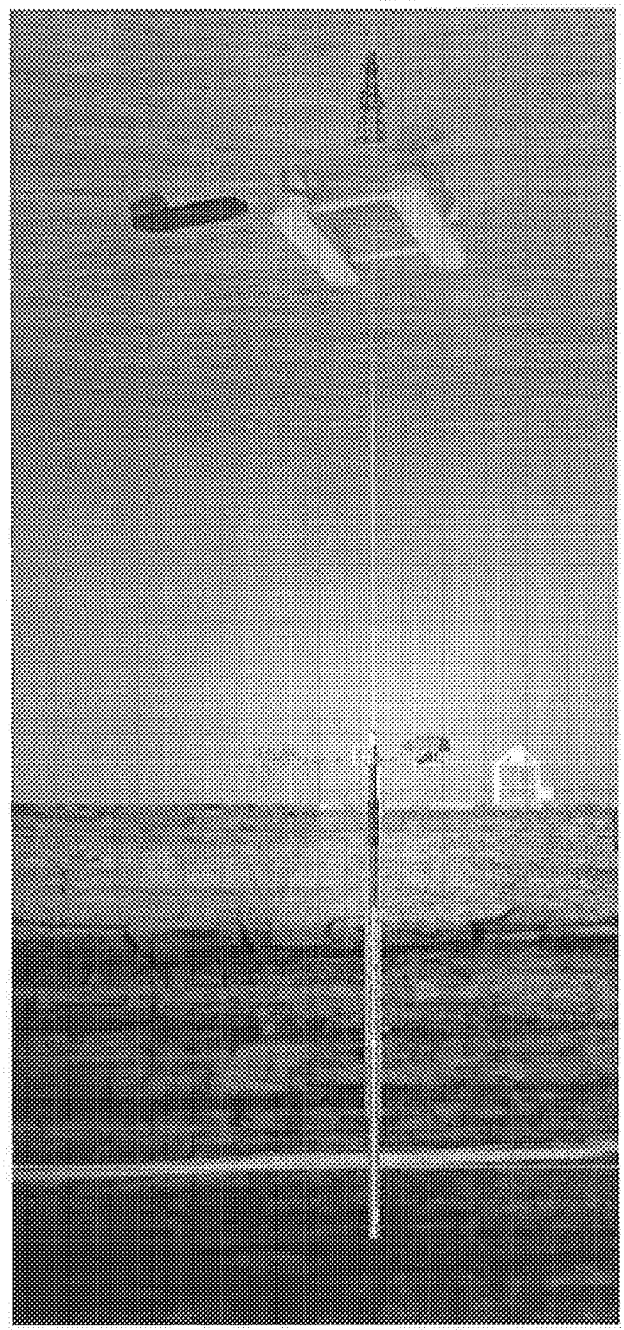

Figure 4.7 – Use of Subsea Rotating Control Head for Control of Shallow Water Flow beneath Conductor Casing

conductor casing would have to be set prior to drilling the SWF zones. Use of a rotating diverter would generally require an extra casing string to be set over that required when using the pump-and-dump technique with a weighted-mud. When using a subsea diverter, the well would be filled with a weighted-mud only after reaching the planned casing point below the SWF zones. The rotating diverter assembly could then be retrieved on the bottom hole drilling assembly prior to running casing.

Schematics of Modern Diverter Systems

Drilling contractors and offshore operators were contacted in this study and asked to provide typical examples of modern diverter systems. Schematics of diverter systems were obtained for various types of drilling platforms. These schematics in general show that API Recommended Practice 64 has been largely implemented into modern drilling practices. Especially noteworthy is a large reduction in the number of 90-degree bends that has been achieved in routing the diverter vent lines. Many diverter vent line arrangements now contain no 90-degree bends. A remaining difficulty in this regard mentioned by some contractors is the need to sometimes modify the vent line routing on Jack-up Rigs for a given job when drilling over or near existing platform structures. A third vent line from the diverter has been added on some rigs to allow more flexibility when drilling near existing platforms while still maintaining straight vent lines.

Platform, Barge or Jack-up Rig

Figure 4.8 shows a typical diverter arrangement required by an offshore operator for use on Platform or Jack-up Rigs. A single vent line is acceptable only for barge rigs, which typically operate

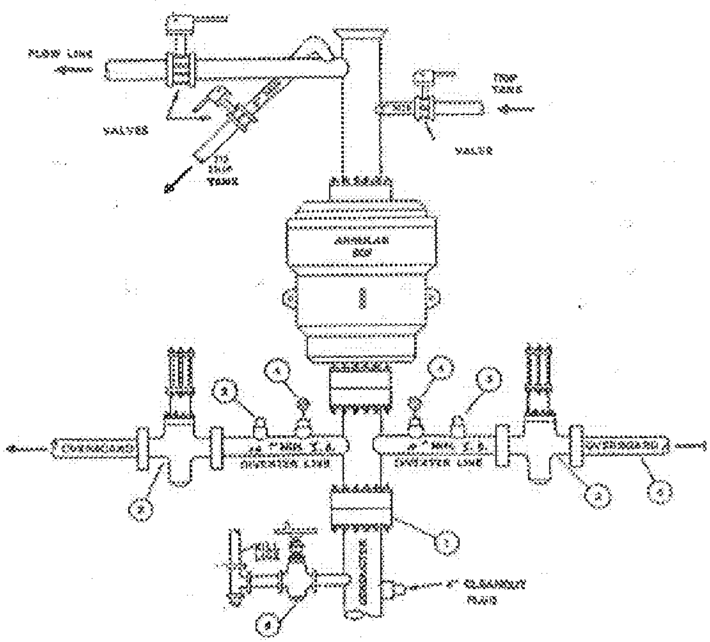

Figure 4.8 – Typical Diverter Schematic for Jack-up Rig

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in inland waters. Note 1 shows that a fabricated flanged spool with two diverter line outlets is recommended to save rig-up time for multiple well operations on an offshore platform. Note 2 specifies a remote-operated full-open valve with a 300 psi minimum working pressure. Note 3 shows 2-inch clean-out connections with bullplugs. Note 4 shows 2-inch connections with bullplugs that are tapped and threaded to accept needle valves and pressure gauges. Note 5 shows that vent lines must have a diameter of 10 inches and be rated to at least 300 psi. Note 6 shows a kill line connection used to pump water for fire suppression when gas is being diverted. A 3-inch thread-o-let can be welded to the conductor casing and equipped with a 300-psi working pressure gate valve or plug valve to provide the kill line connection. A second 4-inch kill line/ clean-out connection is also specified and could be equipped with a full opening ball valve. Typically, a 21.5-inch annular preventer with a working pressure of 2000-psi is used. However, for bit sizes less than 13.625-inches, a special 10,000-psi working pressure spool can be used. This allows using a full BOP stack above the spool that functions either as a diverter or as a conventional BOP stack. This eliminates the need for nippling down the diverter and nippling up the BOP stack after setting surface casing.

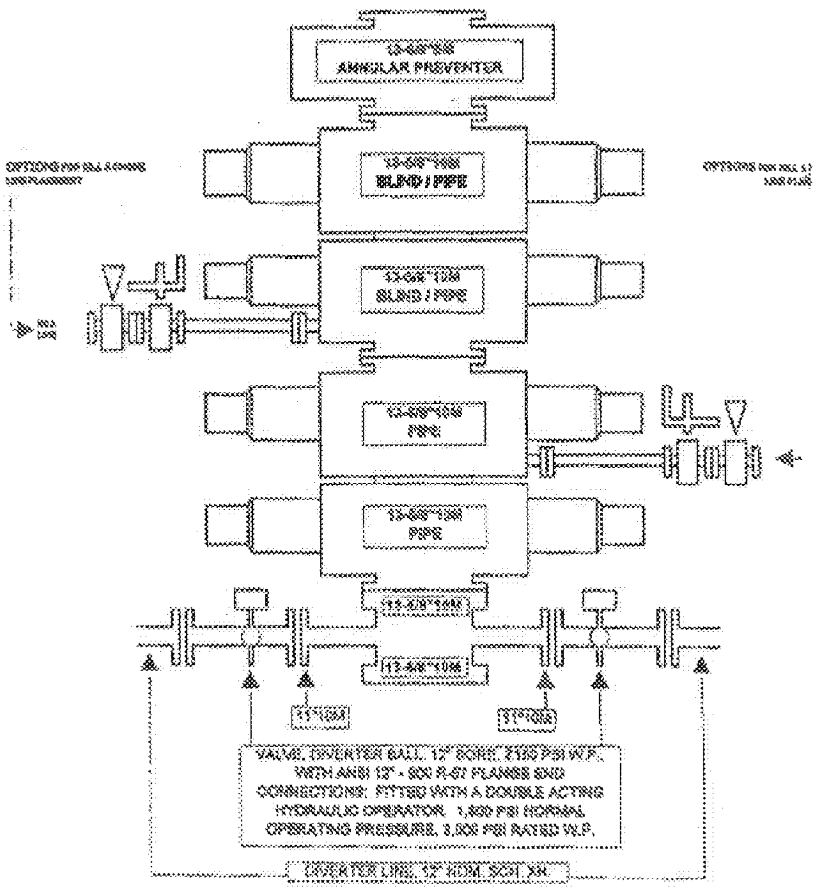

Figure 4.9 – Example combination Diverter and BOP Stack Arrangement

Drillships

Diverter systems on drillships with subsea BOP stacks are not used to handle a shallow-gas flow. Generally, the marine riser is not deployed until sufficient casing is set to allow the well to be shut-in using the subsea BOP stack. However, the diverter system is still needed to provide a contingency for the safe handling of a large volume of gas that enters the marine riser before the BOP is closed or because of a BOP failure. An example diverter system for a drillship is shown in Figure 4.10.

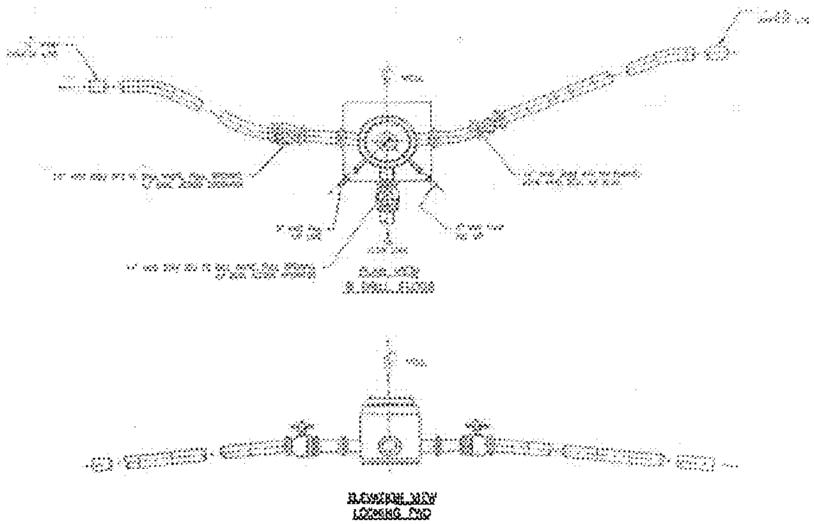

Figure 4.10 – Example Diverter System for Drillship

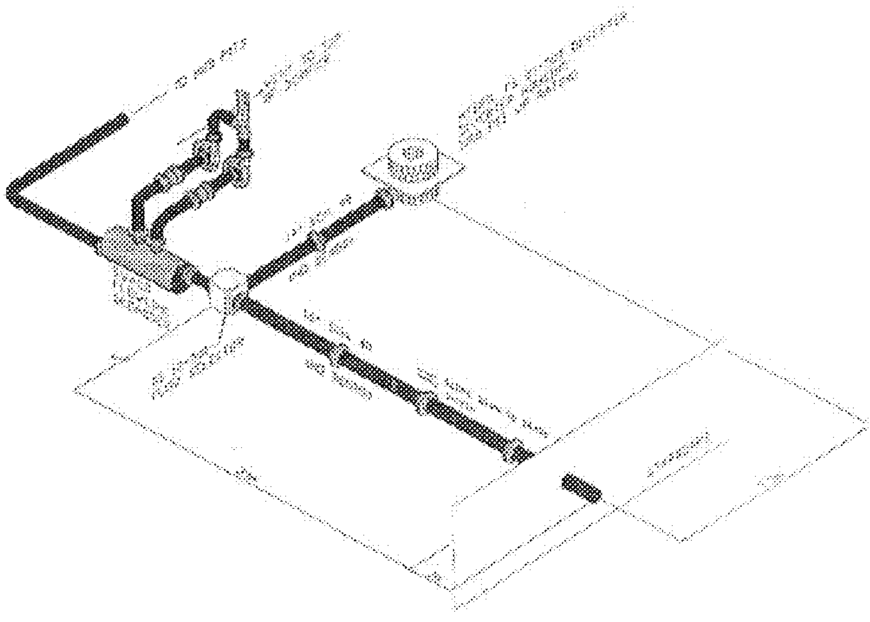

Figure 4.11 – Example Diverter System for Dynamically Positioned Drillship

Note that the vent lines for this example are larger than the 12-inch minimum diameter required by MMS, are relatively straight, and all branching is done at the diverter housing. An example arrangement for a dynamically positioned drillship is shown in Figure 4.11. A dynamically positioned drillship can maneuver to accomplish down-wind diversion with a single vent line. The arrangement shown in Figure 4.12 makes use of a flow selector valve to allow mud to be returned to the pits. The vent line is straight downstream of the flow selector valve. Gas can be removed by a high-capacity degasser when the gas concentration in the marine riser is too great for the gas handling equipment on the normal-return flowline but diversion of the flow overboard is not required.

Semi-Submersibles

As in the case of a drillship, diverter systems on semi-submersible rigs with a subsea BOP stack are not needed to handle shallow gas flows. Instead, the diverter system provides a contingency for handling a large volume of gas that has entered the marine riser. An example diverter system for a semi-submersible rig is shown in Figure 4.12. This example shows more branching than the previous examples because the only a single vent line outlet is used at the diverter housing. The vent path for diversion contains two 90-degree bends to route the flow below the cellar deck level. The 90-degree bends are made using Tees or Crosses which provide a fluid cushion for the pipe wall on the outside portion of the bend. Bourgoyne [1989] has shown experimentally that the rate of erosion in this type of fitting for a sand/gas/water mixture is one to two orders of magnitude less than for a short radius Ells. Provisions are also provided for routing the normal return flow through a degasser upstream of the gumbo box and shale shaker.

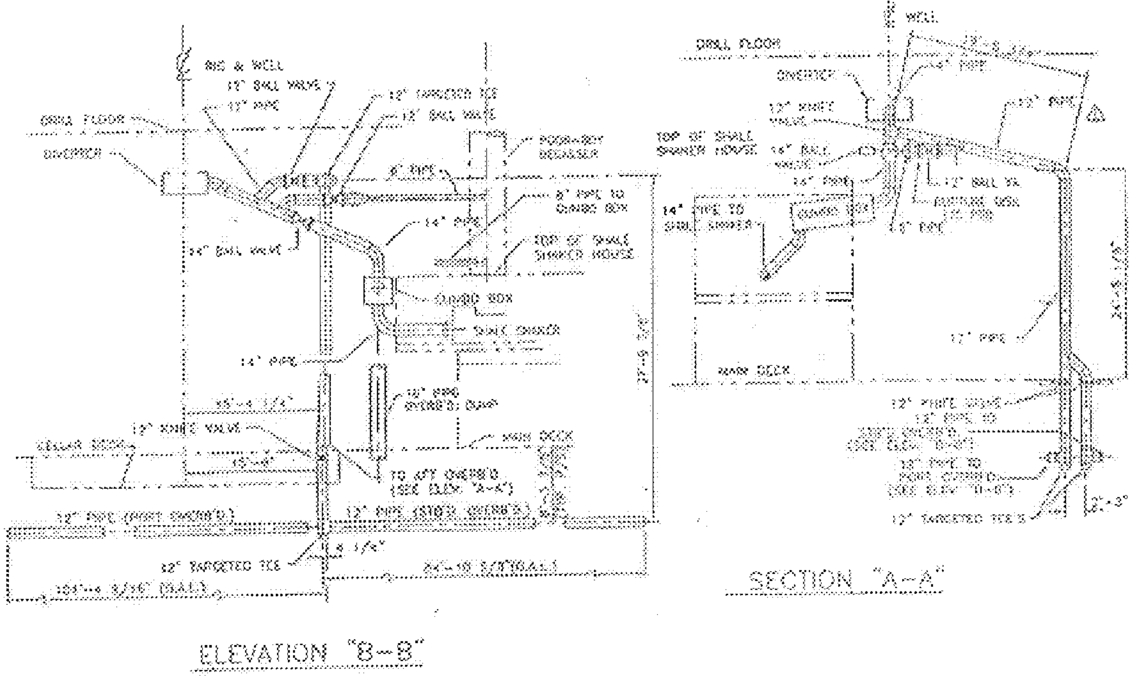

Figure 4.12 – Example Diverter System for Semi-Submersible

Alaskan Gravel Island Rigs

An example diverter system for a rig used in the Alaskan Arctic is shown in Figures 4.13. This diverter system was upgraded to meet MMS regulations in the early 1990's and is a good example of the types of improvements made to diverter systems during that period. During the upgrade, the number of vent line bends was reduced from 39 to 4 with only one 90-degree bend used in the new system. The remaining bends were targeted using a one-inch lead wall thickness, and the wall thickness of the vent lines was increased from 0.365 inches to 0.5 inches. The diameter of the vent lines and vent line outlet on the diverter were increased to 16 inches, which was significantly larger than the 10-inch minimum diameter required by MMS for rigs with surface BOP Stacks. The vent lines slope downward towards the exit to prevent the retention of fluid in the lines that could freeze and plug the lines. Knife gate valves were replaced with ball valves controlled remotely from control panels located on the rig floor and in the tool pusher's office. In addition, the diverter system can be operated from the main control unit that is located in the mud pump room.

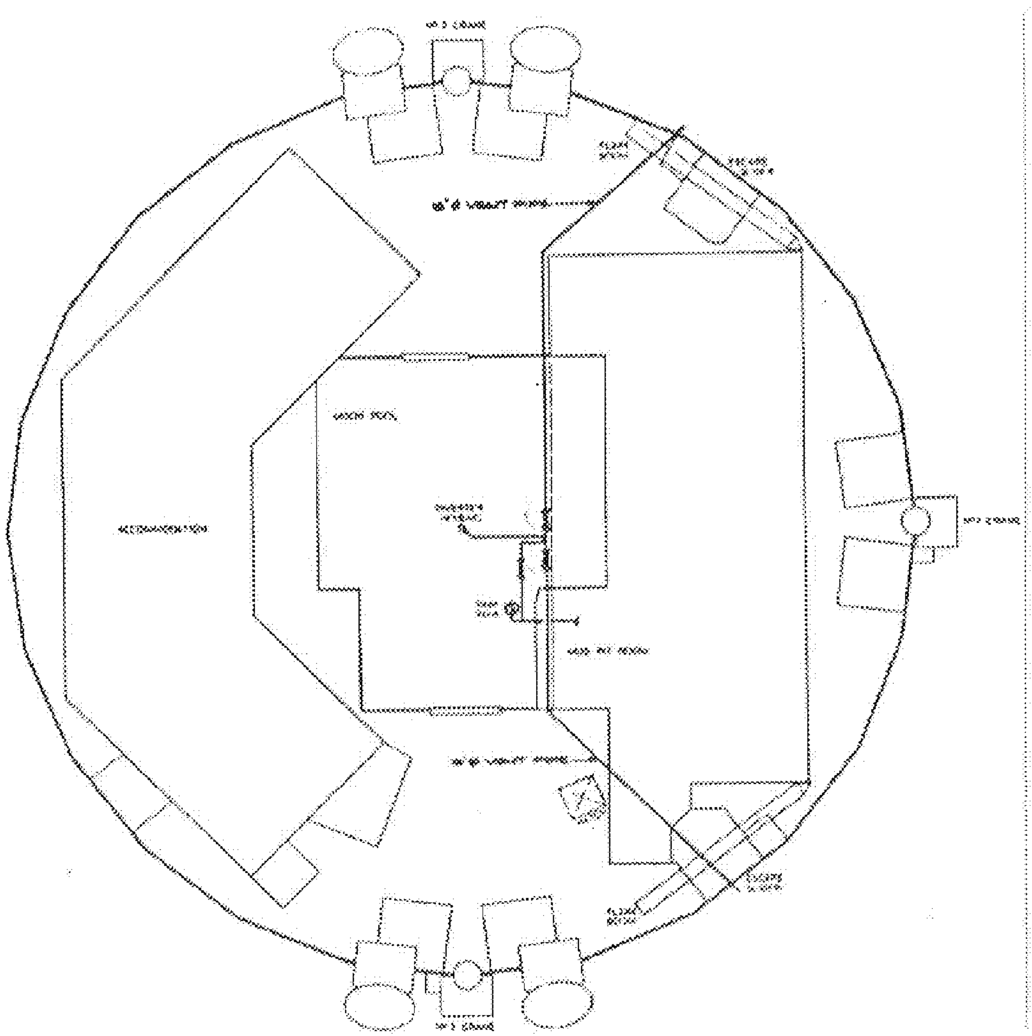

Figure 4.13- Plan View of Example Diverter System Layout used in the Alaskan Arctic

An unusual feature of this diverter system is the use of a 14-inch diameter choke at the diverter exit. This has the effect of decreasing the gas flow velocity in the diverter housing vent line outlet by an estimated 50% or more due to the increased vent-line pressure. Since the rate of erosion has been shown to be proportional to the velocity squared, the rate of erosion at the wellhead is thus reduced at least fourfold due to the presence of the choke. The combination of a 16-inch vent line with a 14-inch choke at the exit can provide lower wellhead pressures than could be achieved with a 14-inch vent line system. This combination also achieves lower erosion rates that could be achieved with a 16-inch vent line system. This analysis assumes that the cross sectional area of the casing annulus is larger than cross sectional area of the 16-inch vent line. No benefit would be realized when the internal diameter of the casing is less than about 17 inches.

Chapter

6

Identified Incidents of Diverter Use Since 1990

Incidents since 1990 involving failures during an emergency use of diverter systems were identified by Dr. Ali Ghalambor in this study through numerous interviews, visits, telephone conversations, and correspondence. In addition, information was also sought from the public records of the Minerals Management Service (MMS), the Norwegian Petroleum Directorate (NPD), The Health and Safety Executive (HSE) of the United Kingdom Continental Shelf (UKCS). Overall, the oil and gas industry seems to be satisfied with modern diverter designs and very few failures have been identified.

The failure rate on diverters has been greatly reduced from the approximately 67% failure rate observed in late 70's and early 80's after MMS first required the use of diverter systems when drilling in the U. S. Outer Continental Shelf. The primary remaining failure mechanism is erosion due to flow of formation fluids containing sand when very high flow velocities are experienced. However, the primary function of the diverter in this situation is to allow time for the rig crew to implement a rig abandonment procedure in an orderly manner. This study did not identify any diverter incidents since 1990 that resulted in loss of life, injury, or significant environmental damage.

Several well control events involving diverter failures will be presented in this chapter. The events have been separated as to whether they occurred in an area under MMS jurisdiction or outside of US jurisdiction. This type of well control incident is often held confidential by the well operators and contractors involved. There are likely other cases that could not be identified in this study.

Cases of Emergency Diverter Use under MMS Jurisdiction

Case No. 1 (1992)

A shallow well was being drilled offshore Louisiana into the cap-rock of a salt dome using a Jack-up rig. Casing having a diameter of 10.75 inches was set in the upper part of the cap-rock and a combination BOP Stack/ Diverter System similar to the one shown in Figure 4.9 was installed. The casing shoe was drilled out and preparations were being made to core the cap-rock below the casing shoe. Fluid was being lost after drilling out the shoe, and the well was being maintained full of seawater while pulling the drillstring from the hole. The hole appeared static after the drill string was removed, and the blind rams were closed as a precaution against dropping something in the well while preparing the coring assembly. When the blind rams were opened to run the coring assembly into the well, the well began unloading, and the well was diverted through both port and starboard vent lines because of a favorable wind direction. The well was flowing at a high rate of flow after it unloaded. Hydrogen sulfide was detected and rig evacuation procedures were implemented. Rig power was shut-off to reduce the risk of an explosion. The well was successfully diverted for about 24-hours until the well was brought under control.

The well-control team stopped the blowout by opening the choke line and closing the diverter valves one at the time while monitoring the pressure. A maximum allowable surface pressure of 200-psi was estimated based on a fracture gradient correlation. The Choke line pressure increased to about 30 psi after the starboard vent line was closed and to about 100 psi after the port vent line was closed. The pressure stabilized at about 120 psi after the choke was closed. The well was then killed by pumping seawater and cement into the well.

There were no serious injuries associated with this event and pollution was estimated to be about 100 to 500 Bbl of oil/water emulsion. No failure of any diverter system component was reported.

Case No. 2 (1997)

A well was being drilled offshore Louisiana using a Jack-up rig. Conductor casing had been set and drilling had progressed to about 2400 ft using a 9.6-lb/gal mud when the well began to flow. The well was diverted using the starboard vent line and 11.0-lb/gal mud was pumped into the well. After pumping 1500 Bbl of mud, the well was still flowing and an additional 500 Bbl of 12.4-lb/gal mud was pumped. After running out of mud, the well was still blowing. Non-essential personnel were evacuated and seawater was pumped into the well at a high rate for about seven hours while waiting on additional mud to arrive. The flow from the well appeared to be diminishing towards the end of this pumping period. After receiving additional mud supplies, mud having a density of 11.0-lb/gal was pumped into the well and bottoms up were observed two hours later. After an additional 20 minutes of pumping 11.0 lb/gal mud, the well was under control. The mud weight in the well was brought to 10.6 lb/gal and drilling was resumed. No injuries, pollution, or failure of any diverter system component associated with this well control event was reported.

Case No. 3 (1997)

A well was being drilled offshore Louisiana using a bottom supported rig. While drilling in the cap-rock of a salt dome at about 2600ft, complete mud returns were lost. The hole was filled with seawater and appeared to be stable. While pulling the drillstring out of the hole to change the bottom-hole assembly, the well began to flow and the flow was diverted. The well was quickly killed by pumping mud. However, the well started flowing again when tripping operations were resumed to change the bottom-hole assembly. The well was diverted a second time and again was quickly killed. After returning to bottom, the well was stabilized using lost circulation material and drilling was resumed. No injuries, pollution, or failure of any diverter system component associated with this well control event was reported.

Case No. 4 (1998)

A well was being drilled offshore Louisiana using a Platform Rig. After reaching a depth of about 4100 feet, a wiper trip was started. The drillstring began to stick, and about 100,000 lbs of overpull was being applied when gumbo and mud began to rise up over the kelly-bushings. The mud pumps were turned off and the well began unloading, causing the kelly-bushings to be blown out of the rotary table. The well started to blow gas and the well was diverted. The pumps were started and 11.1 lb/gal mud was pumped into the well. After 15 minutes, the well bridged over. Mud having a density of 12.0-lb/gal was mixed and pumped into the well, but no returns were seen. The diverter was opened, and gumbo was cleared from the riser, diverter, and vent lines. The well was filled with 12.0 lb/gal mud by pumping through the casing valve at the wellhead. The well was circulated clean of gumbo and gas and drilling operations were resumed. No injuries, pollution, or failure of any diverter system component associated with this well control event was reported.

Case No. 5 (2002)

A well was being drilled offshore Louisiana using a Jack-up rig. After drilling to a depth of about 3600 feet with a 9.2-lb/gal mud, tripping operations were initiated. The well began to flow and was diverted. A strong gas flow was seen and the rig was abandoned. The diverter vent line failed at a valve body and the flow eventually ignited. Later, the diverter housing failed due to sand erosion, allowing most of the flow to be released below the rig floor. The well eventually bridged, causing the flow to stop. About $2,000,000 of damage was caused by the fire. No injuries or pollution was reported. Although failure of two diverter components occurred, the diverter system performed its main function, which was to provide time for an orderly rig abandonment.

Other Cases of Emergency Diverter use

The drilling database (Daily Drilling Reporting System) of the Norwegian Petroleum Directorate includes a section on "Failure of Equipment." This database was accessed to search for failure of diverter components and about 160 incidents were retrieved. However, all of these cases appear to be reports of routine repairs being made to diverter components associated with the well control system inspection and testing program. No reported failures of diverter components associated with emergency diverter use were found.

An inquiry was also made to the Offshore Safety Division of the Health and Safety Executive of the United Kingdom Continental Shelf. Three incidents of emergency diverter closure had been reported to this agency since 1990 out of a total of 400 kicks/well flows. The low number of emergency diverter operations was attributed to greatly improved shallow gas identification and avoidance techniques. Two of the three reported cases were on Jack-up rigs, but no gas was seen in either diverter operation. The third case was on a semi-submersible and was in response to an expanding gas-bubble that caused the riser to partially unload. Both the diverter and the subsea BOP were closed and the well killed using a conventional well control operation. No failures of diverter components associated with emergency diverter use were reported.

Three additional cases of emergency diverter use were reported by industry representatives. One incident occurred on a floating drilling vessel operating in about 2000 feet of water. The reservoir targets were shallow and casing had been set at about 3000 feet prior to drilling through the target zones. After drilling to about 3500 feet, a loss of well control occurred when the subsea BOP Stack became unlatched from the wellhead connector. During efforts to set a bridge plug in the well, the bridge plug failed and a large volume of gas entered the marine riser. The diverter system was activated to divert the flow overboard. The diverter system failed at a 90-degree bend in the vent line causing gas to be released on the rig before flow of gas from the marine riser was stopped. The well was later successfully plugged using a cement retainer and hydraulic running tool, which allowed repairs to be made to the rig and wellhead connector.

A second incident reported by industry representatives occurred on a semi-submersible operating in about 2000 feet of water. A single outlet from the diverter housing was used and the 10-inch vent lines branched off the normal mud-return path in a manner similar to that shown in Figure 4.12. The vent line path has two 90-degree bends to reach the starboard and port vents. The branch to port and starboard was accomplished with a Tee rather than a cross which would have provided more erosion resistance. A Y-connection was located just downstream the first Tee, which provided a connection to a line containing a valve which could route mud to the trip tank. A failure in the Y-connection occurred while diverting gas that was being cleared from the marine riser after a well control event. Most of the gas exited from the failed connection on to the rig after the failure. Very little gas was observed exiting the end of the diverter. A new 16-inch diverter system was installed after this event that contained no 90-degree bends.

A third incident reported by industry representatives was a shallow gas flow on a bottom-supported rig. The well was successfully diverted during this incident and the rig was abandoned until the well bridged over. No failure of any diverter component was reported.

In summary, eleven cases of emergency diverter use since 1990 were found in this study. Failure of a diverter component during emergency venting was reported in three of these cases. However, two of these cases occurred outside of MMS Jurisdiction and likely would not have occurred if MMS regulations regarding regular inspection and pressure testing were being followed. There were no significant injuries and very little pollution resulting from these incidents.

Chapter
7

Conclusions and Recommendations

This study indicated that modern diverter systems and operating practices used on the U.S. Outer Continental Shelf were greatly improved over past designs and operating practices. Although the number of diverter failures since 1990 were small, there were a number of incidents reported in which shallow gas blowouts occurred after cementing surface casing and after nippling down the diverter system. Prematurely removing the diverter/well control system after cementing appears to be a more serious problem than diverter failure. This problem is addressed in the final report for Task 2 entitled "Gas Flow in Wells after Cementing" and in the final report for Task 14 entitled "Top Cement Pulsation for Prevention of Flow after Cementing."

The failure rate on diverters has been greatly reduced from the approximately 67% failure rate observed in late 70's and early 80's after MMS first required the use of diverter systems when drilling in the U. S. Outer Continental Shelf. The primary remaining failure mechanism is erosion due to flow of formation fluids containing sand, especially when very high flow velocities are experienced. Erosion at and just downstream of bends can reduce wall thickness and strength of the vent lines over time. However, the primary function of the diverter is to allow time for the rig crew to implement a rig abandonment procedure in an orderly manner. In areas under MMS jurisdiction, this function is now being performed with a high degree of reliability. This study did not identify any diverter incident since 1990 that resulted in loss of life, injury, or significant environmental damage.

Although the number of 90-degree bends and connections in diverter piping has been greatly reduced from earlier systems, one or two 90-degree bends still remain on some systems reviewed. Failures due to erosion in a bend or Y-connection are still being experienced. Systems with straight vent lines without branching will increase diverter life. The remaining change of direction at the wellhead then becomes the area of maximum wear rate that limits diverter life. The rate of erosion in the diverter is greatly increased when the exit port of a packer insert does not align properly with the vent connection of the diverter housing. One diverter system was reviewed that used an oversized diverter with a slight restriction at the exit. This design decreases the gas velocity at the diverter head or spool and thus increases the erosion life at this point.

Coordination between operator and rig contractor in the development of a shallow gas contingency plan that is appropriate for the well casing program and the rigs diverter/ well control system is extremely important. The techniques that will be used to avoid shallow gas kicks and handle them should the kick avoidance measures fail should be addressed in pre-spud meetings for every offshore well. These discussions should include contingency procedures for kicks taken both while drilling and during tripping operations. The method used to determine the maximum allowable surface pressure should also be reviewed.

More detailed conclusions and recommendations made as a result of this study are given below:

Conclusions

1. Statistics gathered by MMS on drilling operations on the U.S. Outer Continental Shelf over the period 1972-2002 indicated the following:
    a) The primary cause of crater formation due to drilling operations is the unexpected penetration of shallow gas formations.
    b) Shallow gas blowouts occur on about one exploratory well out of 250 drilled and about one development well out of 500 drilled.
    c) Shallow gas blowouts that do not stop on their own due to borehole collapse or depletion occur on about one exploratory well out of 800 drilled and one development well out of 2000 drilled.
    d) Shallow gas blowouts that result in extensive damage or total loss of structure occur on about one exploratory well out of 2000 drilled and one development well out of 4500 drilled.
    e) Only a small amount of oil or condensate has been associated with shallow gas blowouts during this period and environmental damage has not been significant.
    f) There has been no serious injuries or loss of life during well control events requiring emergency diverter use during this period.
2. The primary mechanisms of cratering during a shallow gas blowout include:
    a) Cement channels and borehole erosion.
    b) Formation liquifaction.
    c) Piping or tunnel erosion.
    d) Caving due to sand production.
3. Cratering caused by sand production can occur even when the well is placed on a diverter and the system is designed so that the hydraulic breakdown pressure of the sediments is not exceeded.
4. Sources of data needed for an accurate estimation of formation breakdown pressure of shallow sediments include:
    a) Formation leak-off test data
    b) Soil borings
    c) Formation density log data
5. Extrapolation of an available empirical correlation for horizontal-to-vertical overburden-stress-ratio to shallow sediments often gives a misleadingly low estimate of formation breakdown pressure. The true horizontal-to-vertical overburden-stress-ratio is often near one for shallow clay-rich marine sediments.
6. Software has been developed using MS Excel ™ that uses the method presented in Chapter 3 of this study to estimate the breakdown pressure of shallow marine sediments. A copy of the spreadsheet program has been provided with this report.
7. Kick prevention is the best means of preventing structural damage due to cratering.
8. Design options that could allow a well to be safely shut-in from surface to total depth are technically feasible.

9. Significant advancements in diverter components and drilling practices related to diverter operation and maintenance has been made over the past two decades.
10. Failure rates of diverter components during emergency diverter use have been reduced significantly during the past decade in areas under MMS jurisdiction.

Recommendations

1. Wall thickness of diverter vent lines should be periodically checked in areas of potentially high erosion rates. These areas include connections made for turning or branching the flow path and in the vent lines just downstream of connections made for branching or turning the flow path.
2. Diverters which use inserts containing exit holes should be equipped with a locking device that insures that the exit hole in the insert remains aligned with the vent outlet in the diverter housing.

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Nomenclature

The nomenclature used in the mathematical developments given in Chapter 3 of this report and in the attached MS Excel™ Workbook is summarized in this section.

ϕ = porosity.

ϕ_0 = surface porosity.

ϕ_{fric} = angle of internal friction

ρ_b = bulk density

ρ_{fluid} = pore fluid density

ρ_{matrix} = matrix or grain density

ρ_{sw} = density of the seawater

σ_{fail} = failure stress

σ_h = horizontal stress

σ_{min} = minimal effective (matrix) stress

σ_n = normal stress

σ_{rw} = principal wellbore stress in the r direction

$\sigma_{\theta w}$ = principal wellbore stress in the θ direction

σ_{zw} = principal wellbore stress in the z direction

σ_{ten} = tensile stress

σ_z = vertical effective (matrix) stress

τ_{fail} = failure strain

a_1, a_2, a_3 = correlation constants

C = cohesion

c_u = undrained shear strength

D = depth.

D_w = water depth.

D_s = depth of the sediment below the sea floor.

F_σ = horizontal-to-vertical matrix stress coefficient.

g = gravitational constant.

K = the porosity decline constant.

p = pore pressure

p_{frac} = fracture pressure

p_{init} = initial fracture pressure

p_w = wellbore pressure

S = overburden pressure or stress.

S_{pob} = pseudo-overburden pressure

σ_{ob} - overburden pressure

σ_v – vertical matrix stress.

g - gravity acceleration

D_w - water depth

ρ_b – formation bulk density.

ρ_{bi} - bulk density in depth interval

ρ_{sw} - seawater density.

ρ_{matrix} – density of rock matrix material.

ρ_{fluid} – density of pore fluid.

$(D_i - D_{i-1})$ - depth interval

n - number of intervals

φ_{p0} - pseudo-surface porosity

$K_{p\varphi}$ - pseudo-porosity declining constant

NOMENCLATURE

σ_{min} - minimum in-situ matrix stress

σ_z - vertical matrix stress

F_σ - horizontal to vertical stress ratio

ρ_{mud} - mud density

D_{Shoe} - casing depth

$P_{c\,max}$ - maximum surface pressure

f_k - kick fraction

L_{mix} -mixed zone length

d_{bit} - bit diameter

d_{dc} - drill collar diameter

d_{dp} - drill pipe diameter

V_k - kick volume

ρ_{mix} - density in the mixed zone

V_{mix} - volume of the mixed zone

V_{dc}-hole-drill collar annular volume

EMW - equivalent mud weight

DBML - depth below mud line