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A review of offshore blowouts and spills to determine desirable capabilities of a subsea capping stack

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A REVIEW OF OFFSHORE BLOWOUTS AND SPILLS TO DETERMINE DESIRABLE CAPABILITIES OF A SUBSEA CAPPING STACK

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ABSTRACT

The events surrounding the Deepwater Horizon disaster have changed the face of deepwater operations. In order to continue drilling in the Gulf of Mexico, the regulatory body, the Bureau of Safety and Environmental Enforcement (BSEE), has required that applications to conduct work in the Gulf of Mexico (GOM) include a plan to stop, capture, or contain any uncontrolled release of fluids. The capping and containment systems built and implemented by BP during the event are an excellent starting point for minimizing pollution from deepwater subsea blowouts, but the system has limitations. The industry recognizes these limits but is currently focused on meeting the regulatory requirements.

This project will analyze events reported to the BSEE in the past 15 years to define the basis for potential capabilities that a capping and containment system should have to minimize the volume of fluid released as well as minimize the time needed to regain control of the well. The analysis will take a detailed look at 90 events over the past 15 years to determine critical factors in the design of a generally applicable capping stack. The research will also look at specific barriers that were used to regain control of the well. Finally, any factors which contributed to the severity of the event or contributed to the success of the blowout response are identified. Based on this detailed review, a list of design considerations for a generally applicable capping stack was created.

1 INTRODUCTION

1.1 Background

In April 2010, the industry and the world were reminded once again that although the technology surrounding drilling continues to improve and become safer, blowouts still happen. As Figure 1-1 shows, blowouts have occurred in the Gulf of Mexico every year dating back to at least 1975.

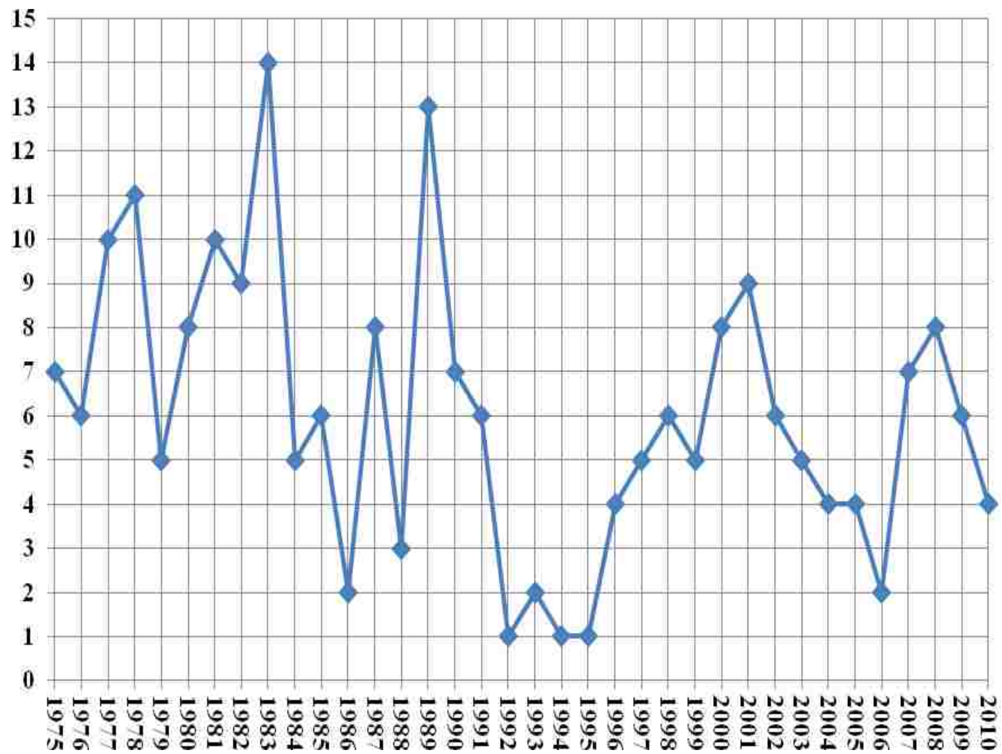

Figure 1-1: All Gulf of Mexico Blowouts (1975-2010)

The annual number of blowouts over the past 35 years has remained within a fairly narrow range (2-10 events). Additionally, the annual number of blowouts during drilling generally follows the drilling activity level as shown in Figure 1-2.

While it is true that the number of events follows the activity level in a general way, when the number of blowouts per foot of well drilled for deepwater and shallow water is examined, an interesting trend emerges (Figure 1-3).

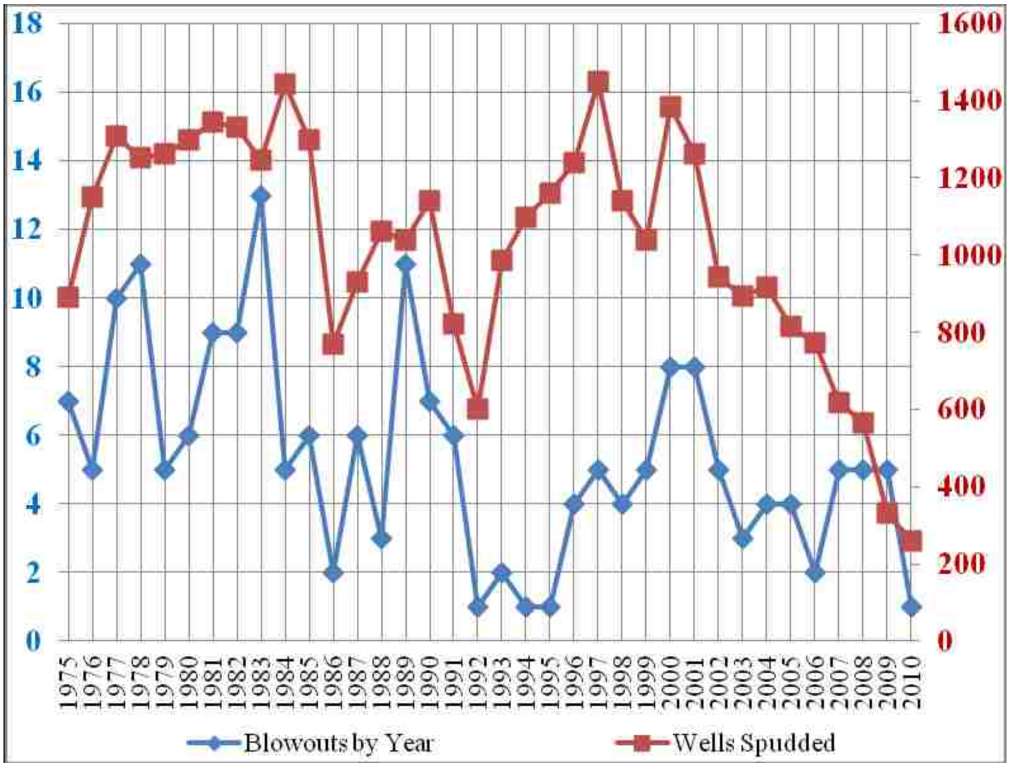

Figure 1-2: Drilling blowouts vs. wells spud in the past 35 years

Figure 1-3 makes the distinction between deepwater and shallow water events. In order to make sense of the graph, we need a definition of deepwater. For this research, the definition of deepwater will be greater than 1,000 ft. This is the current industry and federal regulatory body's (Bureau of Safety and Environmental Enforcement) standard definition (LaBelle and Lane 2001; International Association of Drilling Contractors 2002, 136). While this is not a perfect definition for our research due to the fact that we are focusing on subsea intervention and therefore are not focusing on bottom founded rigs and platforms, the number of incidents involving floating structures and rigs is too small to be statistically relevant. This is because there are fewer floating structures in the Gulf of Mexico than bottom founded structures.

Therefore, the decision was made to examine all events in all water depths and to consider those in more than 1,000 ft. as deepwater regardless of the type of platform or rig.

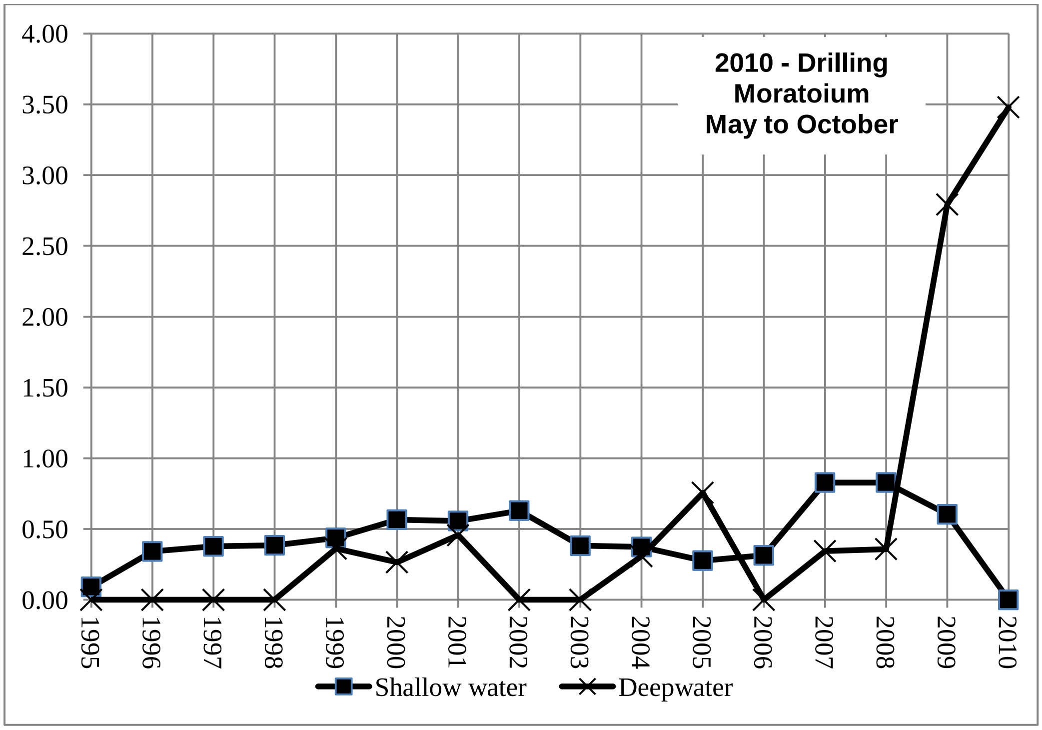

Figure 1-3: Drilling blowouts per million feet drilled per year (deepwater and shallow water events)

Figure 1-3 shows that the number of blowouts per foot of well drilled have been fairly constant for both deepwater and shallow water events for the past 15 years. However, there is a disturbing trend in deepwater blowouts for the past two years. This trend has not gone on long enough to determine if this is statistically significant or not, but it does point out that while shallow water events have remained fairly constant or even dropped in recent years, the trend in deepwater is different. This tells us that focusing on the deepwater as a source for future blowouts is a valid concern.

Blowouts occur on a fairly regular basis, but they rarely cause catastrophic consequences. However when they do, the cost can be very high. In May 2010, the six highest cost spills

(Table 1-1) were (DuBois 2010), the Deepwater Horizon (Macondo) blowout, the Exxon Valdez tanker spill, the Amoco Cadiz tanker spill, the Ixtoc blowout, the Kuwait oil field blowouts during the first Gulf War and the Aegean Captain/Atlantic Empress tanker spill. The total 2010 US dollar impact for all these spills was $51.14 billion dollars.

Table 1-1: Top Six Oil Spills by Cost

Name of Event	Cost (2010 US Dollars)	Amount of Oil Spilled (bbl)
Deepwater Horizon/Macondo	$40 billion#	4,900,000*
Exxon Valdez	$6.3 billion	284,900
Amoco Cadiz	$3.0 billion	1,679,800
Ixtoc	$1.3 billion	3,552,000
Gulf War (Kuwait Oil Fields)	$540 million	11,100,000
Aegean Captain/Atlantic Empress	Unknown	2,123,800

*Approximated (McNutt et al. 2011), # (Skoloff and Wardell 2010)

The $40 billion is an estimated cost for the Deepwater Horizon/Macondo (Macondo) event. The data comes from Huffington Post in late 2010. This does not include punitive damages assessed by the government and only represents what the company has set aside in an escrow fund for the spill. The cost for the Gulf War spill is remarkably low because the Kuwait government was only willing to pay for high priority areas, so many of the areas did not have any clean up. The cost for the Aegean & Atlantic tanker collision is unknown as the collision occurred off the coast of Tobago, and much of the product burned or evaporated immediately after the collision. It should be noted that of the top six events only two events are as a result of a blowout. Three of the four events are transportation events. And the final event can be classified as an act of war or terrorism.

The costs of the Ixtoc and Macondo blowouts exemplify why industry should continue to focus on driving the number of blowouts down. It is notable that the value of all the active rigs and platforms in the Gulf of Mexico was estimated by Risk Management Solutions, one of the leading catastrophe modeling companies, at $70 billion dollars. The value of the wells themselves is another $150 billion dollars (Risk Management Solutions 2009). Macondo is one event, and the cost of that event is more than half the value of all the active rigs and platforms in the Gulf of Mexico in 2009. This demonstrates the extreme cost of catastrophic blowouts and makes the argument that preventing future catastrophic blowouts should remain a priority for everyone in the oil and gas industry.

1.2 Regulatory Response to Macondo

The capping stack solution to the Macondo event is a wonderful example of a creative engineering design solution. The capping stack is an approach that is often used in response to land-based blowouts, but one had never been attempted in a deepwater environment. The fact that the solution was successful is a testament to the people who engineered the capping stack. The capping stack was almost immediately incorporated into the BSEE regulations.

The current regulatory requirements state that an oil spill response plan should be included with all new applications to drill or workover wells in federally regulated waters. This response plan should illustrate how the operator will respond to a spill with actual contracts and specific equipment to contain the "worst case discharge". Part of this response plan is therefore required to detail the capping and containment capabilities of the response equipment.

This requirement led to the formation of two independent containment companies. The concept behind these companies is nearly 300 years old. It is similar to the 1700's private fire brigades. These fire brigades would collect fees from commercial properties, and in the event of fire, these fire fighting companies would respond and extinguish the fire. The property owner had peace of mind knowing that a dedicated fire brigade would respond in the event of a fire at their building (Baker 1970; Anderson 1979). The two containment companies are Marine Well Containment Company and Helix Well Containment Company. Both companies have members who have bought into the company and will help pay for the maintenance of the equipment so it will be available for their use when needed. Additionally, the member companies have additional rights when contracting the services of the equipment in the event of a blowout. The well containment companies are essential for operators to obtain permits for drilling in the Gulf of Mexico.

During the plenary session at a recent deepwater drilling technical symposium a panel of individuals representing Chevron, Shell, Marine Well Containment Company, Helix and the US Coast Guard stated that the people within the oil and gas industry they have talked with recognize the limitations of the capping stack solution as created by BP, however a detailed evaluation to determine what capabilities would be desirable in the subsea capping stack is beyond the current industry focus (Achee et al. 2011).

1.3 Objectives

1.3.1 Capping Stack Project Objectives

This research is being conducted as part of the "Functional Design and Sizing for Subsea Capping System" project funded by the Gulf Research Initiative (GRI). The overall goal of the project is to provide the answers to the following questions:

1. What are the minimum, mandatory capabilities for a generally applicable, quick response, subsea capping stack?
2. What supplementary capabilities should be provided by additional modules to achieve the functions likely to be necessary for an effective subsea capping, containment and intervention system?
3. What are the required sizes, pressure ratings, and geometries for these components?

1.3.2 Research Objectives

The specific and primary goal of the research presented in this thesis is an investigation of blowout incident records over the past 15 years in the Gulf of Mexico to help define the operational requirements for an effective capping stack system. The specific objectives relating to determining the capabilities of the subsea capping stack include an examination of past events to:

1. Identify shallow water events and identify what differences would exist assuming an equivalent event occurred in deepwater.
2. Identify and categorize methods used to control and stop the release.
3. Identify any critical factors which could have contributed to a release of greater magnitude.
4. Identify containment methods used in these events and which were most effective in minimizing pollution.
5. Identify all release points
6. Identify and categorize leak flow paths to determine the effectiveness of using a capping stack
7. Identify the relevance of having a well intervention capability built into the capping system.

Meeting these goals and objectives should provide a basis for response systems to be designed to minimize the time needed to regain control of the well and minimize the volume of hydrocarbons released. Regaining control of the well would include reestablishing two barriers in the well. These barriers can be either mechanical barriers or hydrostatic barriers.

A secondary goal is to provide a comprehensive, searchable compilation of data on offshore blowouts for use in future research on improving the understanding of, responses to, and prevention of deepwater blowouts and spills.

The use of past events to successfully describe future events requires a huge assumption. It requires that past events be likely predictors of future events. There are several circumstances where this assumption is invalid, however, for this work, two have relevance. First, the assumption is valid only if technology has not changed significantly. For instance, the incident at Spindletop in Texas in 1901 and others like it would not be good predictors of future deepwater Gulf of Mexico events.

Additionally, the assumption is only valid as long as significant regulatory changes have not occurred. In the late 1970's, well control training became mandated offshore for the first time. Prior to the late 1970's, no well control training was required for personnel working offshore. That did not mean that no offshore personnel had well control training, but there was no mandatory requirement for it. This was a significant change in regulations. Incidents from prior to this time cannot be compared to incidents after that time as the changes in the regulatory environment are too great. Because of the changes in technology in the past 20 years as well as regulatory changes since the 1970's, only events in the past 15 years were examined.

Currently, we are in the midst of another significant regulatory change. The Drilling Safety Rule which became effective on October 14, 2010 significantly changes the regulatory environment. The purpose of this new rule is, "…to clarify and incorporate safeguards that will decrease the likelihood of a blowout during drilling operations on the OCS. The safeguards address well bore integrity and well control equipment, and this interim final rule focuses on those two overarching issues (Department of the Interior 2010) ."

These are significant regulatory changes, and the value of past events for predicting future events is uncertain. Past events are nevertheless a potentially valuable basis for determining the desirable capabilities of a subsea capping stack and future research focused on minimizing the frequency and impact of future deepwater blowouts.

1.3.3 Research Tasks

One of the goals of the capping stack project is to answer the question, "What supplementary capabilities should be provided by additional modules to achieve all the functions likely to be necessary for an effective subsea capping, containment and intervention system?" The tasks defined for this research to address that goal and provide a means for addressing similar questions in the future were to accomplish the following for each well control or well fluid spill incident:

1. Identify and categorize the operation in progress and the related flow paths for all incidents where the well was the source of the fluids released.
2. Identify and categorize the points where formation fluids were released to the environment.
3. Identify and categorize the relevant attachment points for a capping or containment system.
4. Identify and categorize methods used to control and stop the release.
5. Identify methods used to capture or contain well fluids in these incidents.
6. Identify the potential relevance of a well intervention capability in responding to the incident.
7. Identify any critical factors which could have contributed to a release of greater magnitude.
8. Identify any critical factors which did contribute to a release of a lesser magnitude.

9. For all objectives above, identify shallow water events which could be equivalent to future deepwater events and identify what differences would exist had the event occurred in the deepwater.

A brief description of why these tasks are important and why they were chosen is needed to explain how they will help meet the project objectives. Identifying the operation in progress when the release occurred will help define the possible flow paths for the fluids. The operation in progress also helps to define the context in which the response will be made. For example, the equipment and methods needed to address a problem on a drilling well with a rig on location are likely to be very different than for responding to a leak from a subsea completion.

The flow path of the formation fluids is important because the flow path defines the possible barriers in the flow path which could be used to stop the flow of formation fluids. Additionally, knowing the flow path can help identify the barriers which failed. The knowledge of the flow path can also help identify the options available for stopping the flow.

Knowing the release point helps to identify the equipment or piece of equipment which actually failed. This helps to identify the equipment the capping stack will need to attach to in order to capture or contain the fluids. Knowing what piece of equipment failed and how it failed will help identify if that equipment can be the attachment point, or if another piece of equipment upstream needs to be the attachment point.

The methods used to stop the flow of formation fluids is important because understanding what was used in the past can imply which barriers are most likely to be successful at stopping the flow of formation fluids in future events. And help determine if additional equipment is needed to implement these methods. Additional equipment needs will define how long a method may take to implement.

Knowing what methods have been used in the past to capture and contain flow can imply what types of methods can be incorporated into the capping stack design, and what methods should be focused on for future study.

Knowing what vertical intervention methods have been used in the past will help define what, if any, vertical intervention capabilities should be included in the capping stack design.

Critical factors which contributed to increasing or reducing the overall size of the spill are expected to be helpful for both identifying factors which should be considered in the design of future systems. Knowing what factors reduced the severity in the past can help reduce the severity of future events. If critical factors from past incidents appear in future incidents the risks associated with those factors can be more easily identified and mitigated.

These tasks will be accomplished by examining the past 15 years of incidents in the Gulf of Mexico. However, it is also relevant to examine past research into this area to determine the current states of industry knowledge. Additionally, the past research was also helpful in providing the background into how to create a repeatable, systematic methodology for evaluating past events.

2 LITERATURE REVIEW

A review of published research and analysis of blowouts and offshore risks provided an excellent starting place for developing the methods to be used in this investigation and for identifying what data should be collected from the incident descriptions as well as considering conclusions and understanding developed in past studies. There are several papers which examine past incidents and attempt to determine trends from those past incidents. This was the starting place for the literature research. Next, the subject of each task was researched; operation in progress which implies possible flow paths, release points with corresponding attachment points, blowout response modes of control or barriers established after a blowout, capture and containment of released fluids, vertical intervention and finally what changes occur as a result of deepwater operations. A solid foundational knowledge of each topic was obtained during this examination of past research.

In the early 1970's just after the Santa Barbara spill (1969), a series of studies were published with regard to oil spill statistics (Devanney and Stewart 1974; Stewart 1975; Stewart and Kennedy 1978). The data for these studies was obtained from the United States Coast Guard (USCG) for the years 1971-1975. In the 1980's, there was one report on offshore blowouts (Danenberger 1980). The data for this study was obtained from the United States Geological Survey (USGS), the original federal agency tasked with obtaining data on offshore blowouts, for the years 1971-1978. In the 1990's, there were three published papers on blowouts (Danenberger 1993; Podio and Skalle 1998; Skalle and Podio 1999). All these reports used the USGS data as well as data from the Minerals Management Service, the agency which took over from the USGS. The years for the Danenberger report are 1971-1991. For the two Podio and Skalle reports, the years are 1960-1996. It is important to note that most of these papers use the same incidents as the source of their data. Additionally, there was one book published in 1997 by Holand which examined past blowouts worldwide (including the GOM) (Holand 1997). These papers and book were discussions of trends seen in past incidents. The Devanney paper was a statistical analysis of the volume and number of spills of past incidents. The first Danenberger paper was a listing of the development and exploratory drilling, and non-drilling, blowouts. The later Danenberger paper was a more in depth discussion of past drilling-specific, gas blowouts. The analysis includes contributing causes, duration, water depth, rig type and blowout vs. activity graphs. The first Skalle and Podio paper focused on blowout depth, operation in progress, blowout causes, and blowouts vs. activity graphs for drilling blowouts only. The later paper focused on modes of control, duration, pollution, fire, explosion, and fatalities. The Holand book focused on blowout causes and characteristics including ignition source, pollution, duration, and flow mediums as well as blowout response failures and an analysis of blowouts vs. accumulated operating time. The analysis of blowouts vs. activity and blowouts vs. accumulated operating time provided the starting point for the analysis shown in Figure 1-2 and Figure 1-3 in the introduction section.

Skalle and Podio (1998) concluded that approximately equal numbers of exploration and development drilling blowouts had occurred in the incidents in their study. Completion and workover blowouts were less frequent than drilling blowouts, but were about equal in number to each other. The fewest number of incidents were wireline blowouts.

The sections of these studies which are of interest will be addressed in the following sections; operation in progress, flow paths, release points and resulting attachment points, barriers established by the blowout response efforts, shut in of a well, capture of released formation fluids, containment of formation fluids, vertical intervention to control formation flow and conditions in deepwater which are different from shallow water blowouts.

2.1 Operation in Progress

The operation in progress when an incident occurs is extremely helpful because only certain flow paths are possible during different operations. Flow paths are an important characteristic of past incidents because they help identify the barriers present in the flow path.

Holand divided blowouts into the operational phase when the blowouts occurred (Holand 1997). Holand defined these divisions in his book, however the divisions used in this study were included in the data provided by BSEE and were not modified. No definitions for the divisions used by BSEE were found on the public website.

2.2 Flow Paths of Hydrocarbons During an Incident

Holand discussed flow paths, and his data captured the final flow path (Holand 1997). His flow paths were defined as:

- "Through the drillstring (or tubing where relevant)"
- "Through the annulus (the well bore annulus)"
- "Through outer annulus (between the casing strings)"
- "Outside casing (outside the outer casing or conductor)"
- "Underground blowout (subsurface blowout from one zone to another)"

Holand related these flow paths to operations that were in progress, i.e. shallow gas drilling blowouts, deep drilling blowouts, completion, workover, and production blowouts. His data concluded that shallow gas and deep drilling blowouts most commonly have a final flow path through the wellbore annulus. Completion blowouts most commonly have a final flow path through the tubing or drillstring. Workover blowouts most commonly have a final flow path through the outer annulus. Production blowouts are almost equally likely to have final flow paths; through the tubing, through the wellbore, through the outer annulus and outside the casing.

Petersen et al. (2011) defined another set of flow paths (Petersen et al. 2011). They described four main flow paths "string, string annulus (or wellbore), outside casing annulus (named annulus), and rock." These can be seen in Figure 2-1. The definition used in this paper comes from Petersen et al (2011). This is because the two definitions are nearly equivalent, the only distinction being between underground blowouts and blowouts outside the casing string. The data set for this study rarely had sufficient detail to determine between these two paths, therefore the simpler model was chosen. Petersen et al (2011) uses the flow paths along with barrier definitions to analyze the operational well safety during the well design process.

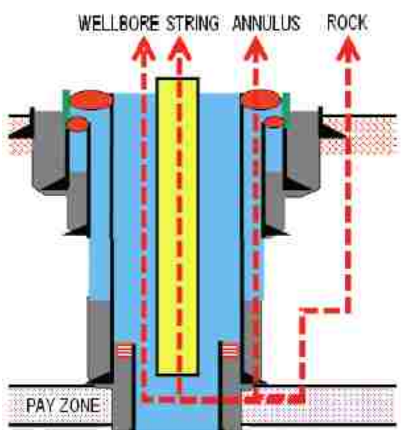

Figure 2-1: Four flow paths (per Peterson et al.)

2.3 Release Points and Corresponding Attachment Points

Holand discusses locations where formation fluids were released to the environment from blowouts (release points) in his book (Holand 1997). His release points for shallow gas drilling were: diverted flow, diverter system line eroded, diverter system line parted, at the drill floor-through the rotary, from wellhead on the rig or platform, subsea wellhead, subsea release outside the casing, from a subsea crater, and unknown (Holand 1997). The release points from Holand's book for deep drilling were: at the drill floor-the choke manifold, at the drill floor-the rotary table, at the drill floor-the top of the drillstring, the wellhead on the rig or platform, no surface flow, the shaker room, the subsea BOP choke line, subsea release outside the casing or unknown. The completion release points were at the drill floor-through the drill pipe valve, at the drill floor-the rotary table, at the drill floor-the top of the drillstring or tubing, or unknown release point. The workover release points were BOP valve outlet (snubbing BOP), from wellhead, from christmas tree, at the drill floor-through the rotary table, at the drill floor-the top of the drillstring or tubing, and the tubing valve. The production release points were from the wellhead, the christmas tree, a subsea crater, and subsea christmas tree.

According to Holand, most shallow gas blowouts had the diverter as the release point. Deep drilling blowouts were nearly equally divided between release points at the drill floor-through the rotary table, at the drill floor-the top of the drillstring, from the wellhead on the platform and unknown point of release. Completion blowouts were nearly equally divided between all release points; at the drill floor-through the drill pipe valve, at the drill floor-through the rotary, at the drill floor-through the top of the drillstring or tubing and unknown release point. Workover blowouts were primarily at the drill floor-through the rotary table. Production blowouts were primarily through the wellhead.

In 1999 PCCI Marine and Environmental Engineering wrote a paper discussing blowout scenarios (PCCI Marine and Environmental Engineering 1999). Based on experience with subsea blowouts, Wild Well Control Inc. identified for PCCI release points for deepwater blowouts. During drilling, completion and workover operations, the release points were at the wellhead connector, the BOP flange/hub connection, the choke/kill connection to the BOP, the choke/kill stab on the lower marine riser package (LMRP), through the top of the riser, through the top of the drill pipe, casing hanger seals, and subsea broach outside the wellbore. For producing well scenarios, the release points were: subsea wellhead, flowline, annulus valve, subsea broach outside the wellbore, and casing hanger seals. These release points were developed to determine the relative likelihood of each scenario and to rank the consequence of each scenario as minor, severe, or catastrophic. The conclusion was that for drilling, completion, and workover operations there were no specific release points that had a high probability, however, there was a moderate probability of a blowout occurring with a release at the wellhead connector, the choke/kill stab at the LMRP, through the riser, or due to a subsea broach. Production operations also had no high probability release points, but a moderate probability existed for a release from the annulus valve. The consequence analysis stated that a catastrophic outcome could occur if the leak was through the drill pipe or a subsea broach for drilling, workover, and completion operations. A severe consequence was possible for releases from the wellhead connector, the riser, or the casing hanger seals. For production, a catastrophic outcome was concluded to be likely only from a subsea broach and severe consequences likely as a result from a release at the wellhead connector or the casing hanger seals.

Attachment points for a subsea containment system received little attention prior to the Macondo incident. They were discussed only in the context that containment system similar to the top hat collection system used for Ixtoc. It was believed a system could never be sealed to the seabed (Burgess and Milgram 1983), sealing a system to subsea equipment was not discussed in this paper at all. In 1985 the top hat type of system was again discussed by Brown and Root, but attachment to subsea equipment was not mentioned (Brown & Root Development Inc, 1985). A 1999 paper from PCCI Marine and Environmental Engineering discusses subsea attachment points in terms of the impracticality of attaching to subsea equipment. They cite reports from

Brown and Root in 1985, and a 1998 draft report from the International Association of Drilling Contractors, as well as their own knowledge. They do indicate that future technology may allow for subsea attachment points. Schubert et al (2011) discuss attachment points in the context of installing valves on equipment located on the rig or platform. The paper indicates that attaching to subsea equipment would be difficult, but that it has been accomplished in relatively shallow water depths. No further details were given. The implication from these papers is that throughout the decades attachment to subsea equipment was considered impractical or impossible, and as a result, no further research was conducted in this area.

2.4 Establishing Barriers to Stop a Blowout

Holand defines barriers in the context of well control operations as; "A well barrier is an item that, by itself, prevents flow of the well reservoir fluids from the reservoir to the atmosphere" (Holand 1997). Two independent barriers are required for normal drilling and production operations by BSEE (Department of Interior and Minerals Management Service 2010).

Table 2-1: Examples of barriers and barrier description (Holland 1997)

Operational Barrier	"A barrier that functions while the operation is carried out."	"Drilling mud, stuffing box"
Active Barrier	"An external action is required to activate the barrier"	"Blowout Preventer (BOP), Xmas (Christmas) Tree, SCSSV"
Passive Barrier	"A barrier in place that functions continuously without any external action."	"Casing, tubing, kill fluid, well packer"
Conditional Barrier	A barrier that is either not always in place or not always capable of functioning as a barrier."	Drill String Safety Valve

When a well is hydrostatically controlled (i.e. killed), the fluid column providing the hydrostatic pressure is referred to as the primary barrier and the standard blowout equipment is the secondary barrier (Holand 1997). When a well is flowing, the barriers closest to the reservoir are regarded as the primary barrier and any other barrier in the flow path downstream of the primary barrier as secondary barriers (Holand 1997).

Holand described four general types of barriers: operational, active, passive, and conditional barriers (Holand 1997). Examples of each are given in Table 2-1.

Well barrier analysis is used in Norway to evaluate potential well designs for blowout risk (Holand 1997). Other papers did not discuss barriers per se; instead they discuss modes of control. The modes of control identified did provide a starting set of barriers for the well barrier analysis conducted on this data. Danenberger identified bridging, pumping mud, closing the BOP and "mechanical means" for controlling blowouts, which he doesn't define (Danenberger 1980) as modes of control. Kato and Adams (1991) identified seven modes of control occurring worldwide, on land and offshore. They were bridging, relief wells, pumping mud/kill fluid, cementing, capping, shut-in and other (undefined) methods. Danenberger, identified three generic categories based on his review of GOM blowouts (E.P. Danenberger 1993). They were "mud/ cement/ mechanical", bridging, and dissipation of trapped gas. Skalle and Podio (1999) identified eight categories, listed here in order of frequency: bridging, pumping mud, pumping cement slurry, closing the BOP, depleting small reservoirs, installing equipment to stop flow and drilling relief wells. They identified capping as an eighth mode of control for onshore incidents, but not for offshore incidents.

2.5 Capture and Containment Methods for Blowouts

Since 1979, the concept for subsea collection has been based on the riser and funnel collection device used at Ixtoc in the Bay of Campeche. In the aftermath of that blowout, several studies looked at the feasibility of such a collection system. The research was headed by Jerome

Milgram at Massachusetts Institute of Technology under a grant from the Mineral Management Service's Technology Assessment and Research Program. The work completed by Milgram included theoretical research as well as some scale model tests (J. H. Milgram and Burgess 1981; J. H. Milgram 1982; Burgess and Milgram 1983; J. Milgram and Erb 1984). There were other studies in the early 1980's however, they are similar in content to the Milgram studies and were not used for background for this thesis. In the mid 1980's, two papers were written, one examined the feasibility of commissioning a tanker as a full time response vessel with this type of collection device permanently mounted on the vessel (Brown & Root Development Inc. 1985). The second provides a independent, detailed analysis of the specifications for a riser and funnel type collection device which could be expected to collect hydrocarbons from a subsea release (Hammett 1985). Since then, there have been two significant works in this area. The first one in 1991 by Neal Adams Firefighters and the second in 1999 by PCCI Marine and Environmental Engineering. Adams provides a background as to what has been attempted in the past or designed but never implemented. This implies some of these concepts have been around since before the beginning of the data set, and their implementation could be found in the data to be evaluated. The PCCI report also provides background into what has been thought of in the past. The author of the PCCI report conducted a patent search for subsea collection devices, and included the patents discovered in their final paper. All these papers provide a good starting point for potential capture or containment devices which could be seen in the data set if their use was attempted and recorded.

2.6 Vertical Intervention

Adams and Kuhlman (1993) describe any attempt to control an offshore blowing well from a floating vessel vertically located above the blowing well as vertical intervention. In contrast, Schubert et al. (2004) indicate that vertical intervention means entering the wellbore from the mudline or from a vessel above or from equipment located in the sea column or on the sea floor, for the purposes of well control. This would not include a relief well. Nor would it include the removal of damaged subsea equipment, unless that equipment is within the wellbore. Therefore it would not include the removal of the BOP but would include the removal of tubing or drill pipe within the BOP. The Schubert et al (2004) definition is used hereafter in this study. If there is any ambiguity within this thesis in the meaning or intent it will be clarified.

One technology used for vertical intervention is a snubbing unit. The most recent paper is from 2010 just prior to Macondo. It discusses using snubbing units for well control operations (Wehrenberg and Baxter 2010). Snubbing units are systems designed to force pipe into a well against pressure. Traditionally, snubbing units have been used in workover and production operations. A coil tubing unit has similar uses and capabilities.

Vertical intervention can be applied to enter a well to reestablish hydrostatic control or to install some kind of mechanical barrier or repair a mechanical barrier already in the hole. These could include setting a packer, or repairing a surface controlled subsurface safety valve (SCSSV).

2.7 Implications for Deepwater Operations

Deepwater blowouts present special challenges. Therefore, the International Association of Drilling Contractors has published a 400 page reference providing guidelines and best practices for deepwater well control operations (International Association of Drilling Contractors 2002). It includes guidelines for planning deepwater wells, well control procedures, deepwater equipment, emergency response, and training for deepwater crews. While the guidelines do not typically include supporting technical details, they do support an understanding of some of the risks currently identified with deepwater operations.

There are five additional papers which discuss the differences experienced when drilling in deepwater versus shallow water or onshore. The first paper from Nakagawa and Lage (1994) discussed deepwater kick detection, difficulties with shutting in a well, killing procedures, contingency plans, and emergency disconnects while drilling. The MMS discussed the challenges involved with deepwater spill response including some details from their database of well permit applications, production records and past blowouts (LaBelle and Lane 2001). Adams et al (2003), attempt to characterize blowout behavior in deepwater environments, including problems often encountered and some background research that has been conducted. Texas A&M University looked at modeling deepwater blowouts and provided good background into unique aspects of deepwater operations as well as methods of controlling deepwater blowouts (Noynaert and Schubert 2005; Schubert et al. 2004). The last paper discusses a drilling application for deepwater wells and provides confirmation for some of the data presented in the above papers (Fossli and Sangesland 2006).

2.8 Summary

Past research related to flow paths, release points and related attachment points, barriers used to stop the flow of formation fluids (i.e. modes of control), past capture and containment methods, vertical intervention and finally changes to operations when they are conducted in deepwater was described. This information provides a solid foundation for guiding the development and organization of the information to be included in the investigation of past blowout and spill incidents.

3 METHODS

3.1 Introduction

The research described in this thesis had two general objectives. The primary objective was to help define the operational requirements for an effective capping stack system. The second objective was to provide a comprehensive, searchable compilation of data on offshore blowouts for use in future research on improving the understanding of, responses to, and prevention of deepwater blowouts and spills. This chapter will discuss the methods developed and applied to organize the data from offshore blowouts for these purposes. It will describe the source data, inclusion and exclusions of incidents from the final spreadsheet, a description of the additional data needed and how it was obtained, the reason the additional data was obtained and how it helped to meet the objectives.

The evaluation of prior incidents began with collecting the information about those prior incidents; however, a simple listing of the incidents would not meet the objectives. Therefore it was determined a spreadsheet would be the most efficient method of presenting the data so it was searchable and able to answer the questions needed to meet the objectives. The objectives ask questions about the flow paths of incidents, the release points of incidents, the related attachment points, the methods used to stop the flow of formation fluids, including capturing or containing the flow of formation fluids, methods of vertical intervention used to stop the flow of formation fluids, any factors which reduced or increased the total release of fluids, and how deepwater incidents will vary from past shallow water incidents. Therefore the spreadsheet must be able to identify these factors and extract patterns from past incidents.

3.2 Source of Data

The source of data on the relevant spills and blowouts was information on the incidents reported to BSEE in the past 15 years. The data used for the study was obtained from the BSEE website. A complete listing of the website addresses where the data is located is included in APPENDIX 2: URL'S OF BSEE SOURCE DATA. A listing of all incidents reported to BSEE is organized by year on the public website. During the course of the data collection process, the data available on the website changed several times. Therefore, the data that is available today may not be the data which was available when this collection of incidents was conducted. Every effort was made to obtain the most up to date information.

The incidents reported to BSEE were sorted into the following categories; blowouts, pollution events (fluid spills), pipeline pollution events, fires, explosions, injuries and fatalities, as well as vessel collisions, crane incidents, gas releases, hydrogen sulfide releases, structural damage to vessels, rigs, and platforms, disabled safety systems, muster for evacuation incidents and other miscellaneous incidents. The pollution events were fluid spills of any size from any source of fluid. For example, a vessel which spilled diesel oil as a result of a refueling incident was included in this category.

Obviously, not all of the incidents reported to BSEE were relevant to this study. However, the intent of the data collection initially was to include as many incidents as possible to ensure no relevant incident was discarded prematurely. The incidents which were not included in the initial spreadsheet were the crane events, the structural damage to property, the disabled safety systems, the muster for evacuation incidents, and the other miscellaneous incidents. The incidents relating to blowouts, pollution incidents, pipeline pollution incidents, fires, explosions, injuries and fatalities were initially included. This resulted in nearly 1,000 incidents. When these incidents were examined, duplicates were discovered. Any incident which fell into multiple categories was listed in both categories. For example, a blowout which resulted from a vessel strike was listed in both the vessel collision category as well as the blowout category.

Therefore, the listing of incidents was further refined to include only those incidents included in the blowout event, pollution event and pipeline pollution event categories. Pipeline incidents were discarded as the capping stack solution was not likely to be relevant to these types of losses. Additionally, pollution events with a spill size less than 50 barrels (bbls) have minimal reporting requirements, only the time, date, location, and size of the spill. As a result, these spills were only included if sufficient data was available to be useful. Therefore, the level of confidence that the most relevant spills were captured using this methodology is high.

The final number of spills in the initial spreadsheet was just under 450 incidents. Of the 450 incidents, 86 were blowout events, and the rest were pollution events. In nearly all of the pollution incidents, the fluid spilled was not formation fluids. For example, many pollution spills involved drilling mud being spilled over the side of the rig. These types of events were not relevant to meeting the objectives of this study. Therefore these incidents were not included in the final collection.

Hurricane events caused a particular complication. These events are listed as pollution events (unless a blowout occurred, then they would be cross-listed). However, if the hurricane damaged a platform and it took a period of weeks, months or years to stop the formation fluids from leaking to the environment, the BSEE required the operator to report the spill for each separate platform on a quarterly basis until the spill was stopped. This sometimes resulted in several dozen reported incidents for each platform, all the result of one hurricane. Each platform damaged by a hurricane was reported to BSEE as a unique incident regardless of the number of wells tied back to each platform. The incidents had to be combined into a single total pollution event on the date the hurricane damage occurred. This required some creative analysis because the data was scattered through the annual spill reports, individual hurricane spill reports and the basic data filed for spills less than 50 bbls. The URL's for the hurricane spill reports and spills less than 50 bbl are listed in Appendix 2. After this analysis, a collection of 90 incidents were determined relevant for this study. The details collected from the public database on these incidents included the date of the incident, the company name, the type and volume of fluid spilled, how the incident was cross-listed (i.e. fire, blowout, explosion, pollution, etc.), lease number, operation in progress, area and block location in the Gulf of Mexico, water depth, the name of the platform, rig, or vessel involved and a brief description of the incident (typically a paragraph).

One of the first tasks to analyze the data was to determine which of the events had floating rig/platforms and which were bottom founded. The data provided to BSEE did not include sufficient detail to confirm floating or bottom founded rig/platforms for all incidents as a result, the definition of deepwater used by industry and BSEE, a water depth of 1,000 ft. or greater, was used by in this study.

3.3 Additional Analysis Conducted on BSEE Data

In order to meet the objectives of, and fulfill the tasks defined for, this study (i.e. flow path, release points, etc.) it was necessary to determine additional details about each of these 90 incidents. These additional details became additional columns in the spreadsheet, they included:

- Location of release (i.e. sub-system where the formation fluid first entered the natural environment)
- Flow path from reservoir to location of release
- Sub-systems where blowout response methods were attached or could have been attached (i.e. first sub-system upstream of the location of release where a blowout response method could be attached)

- Whether vertical intervention was used or could have been used to control the blowout, and if attempted, what methods were used
- Whether the well was shut-in in the course of the well control efforts, and if so how was the well shut in
- Whether the blowout response methods captured any of the formation fluids, and if so how was the flow captured
- Whether the flow of formation fluids were diverted, and if so how was the flow diverted
- Factors that contributed to a more severe release
- Factors that contributed to a less severe release

3.3.1 Spreadsheet Columns

The analysis conducted above was then integrated into the spreadsheet. In order to make the spreadsheet useful, the analysis needed to be sortable. Therefore, each analysis was reduced to 1) a yes or no question, if possible, or if a description was needed, 2) a simple one to two word description or 3) a code to describe a combination or sequence of actions or results. Additionally, for each analysis a further grouping was needed to extract useful relationships. For example, from the 90 incidents, 65 unique release points were identified. These 65 release points were then grouped into 17 more general categories. A similar grouping occurred for each analysis which did not involve a yes or no response. For each analysis, the initial unique values were retained and a second column was added which contained the larger groupings.

3.3.1.1 Flow Path

The Petersen model for flow paths was used for this study. Figure 3-1is a diagram showing the four general flow paths defined by Petersen (2011).

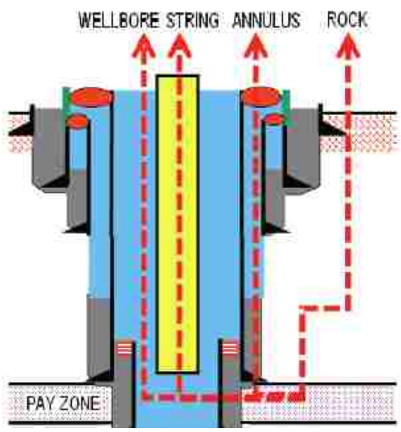

Figure 3-1 Flow Paths from Reservoir to Release Point (Petersen et al. 2011)

The wellbore flow path is any flow up the casing, but not inside the drillstring or tubing. The string flow path is any flow up the drillstring or tubing. The annulus flow path is any flow of fluids between casing and another casing or casing and the rock, but not traveling through the rock (i.e. not an underground blowout). The rock flow path is any underground blowout reaching the sea floor. These definitions are helpful to this study because these four paths have very different barriers along their respective flow paths. The wellbore and string are designed to have flow through them but have different barriers to control or prevent flow. The annulus flow path should generally have a cement sheath along critical sections of the path to prevent fluid flow to the surface or sea floor. The rock flow path has no man made barriers in the rock but implies that a barrier in one of the other flow paths failed and allowed formation fluids into the earth. Often the details of the incident were unclear, and the exact flow path was not explicitly stated. However, if well control equipment was used to control the flow, its use sometimes helped to determine the flow path. If however, the details of the incident were such that the flow path was unclear, the entry was tagged as unknown flow path.

The annulus flow path was selected if the flow was outside the deepest string of casing set in the well but still coming to the surface at the wellhead. Flow coming through a casing valve was considered to indicate an annulus flow path.

On several occasions, multiple flow paths were valid. For example if there was flow up both the wellbore and the string, or if the incident details describe attempting to stop flow in the string and wellbore, then both were selected.

Initially, an analysis with as much detail as the incident description allowed for each flow path was completed. This analysis resulted in 49 unique flow paths. This number of unique flow paths meant that any further analysis of the data would result in data sets of one or at the most two incidents. It was determined this variability was too great to meet the objectives set forth in this study.

3.3.1.2 Release Location

The location where formation fluids were released to the environment was an important factor, because it defines what equipment the capping stack needs to attach to. A simple diagram is the best way to begin describing the release locations (see Figure 3-2). The figure also shows the codes used to define a particular release point in the spreadsheet.

The release point for each of the 90 incidents was determined and, as stated earlier, 65 unique release points were identified. These are the initial release points. Based on those release points, a system of coding was developed to allow the column to be sorted and searched. 1 is the release point code for a release from the seafloor itself (i.e. an underground blowout). The codes begin at the seafloor and progress to the platform, as shown in Figure 3-2. The platform code was then further divided to describe the equipment on the platform. When the 65 unique release points were sorted, a total of 13 codes were used. These are listed in Table 3-1.

The combined knowledge of the release point and the flow path from the reservoir to the release location allows determination of the location where a capping system could be attached.

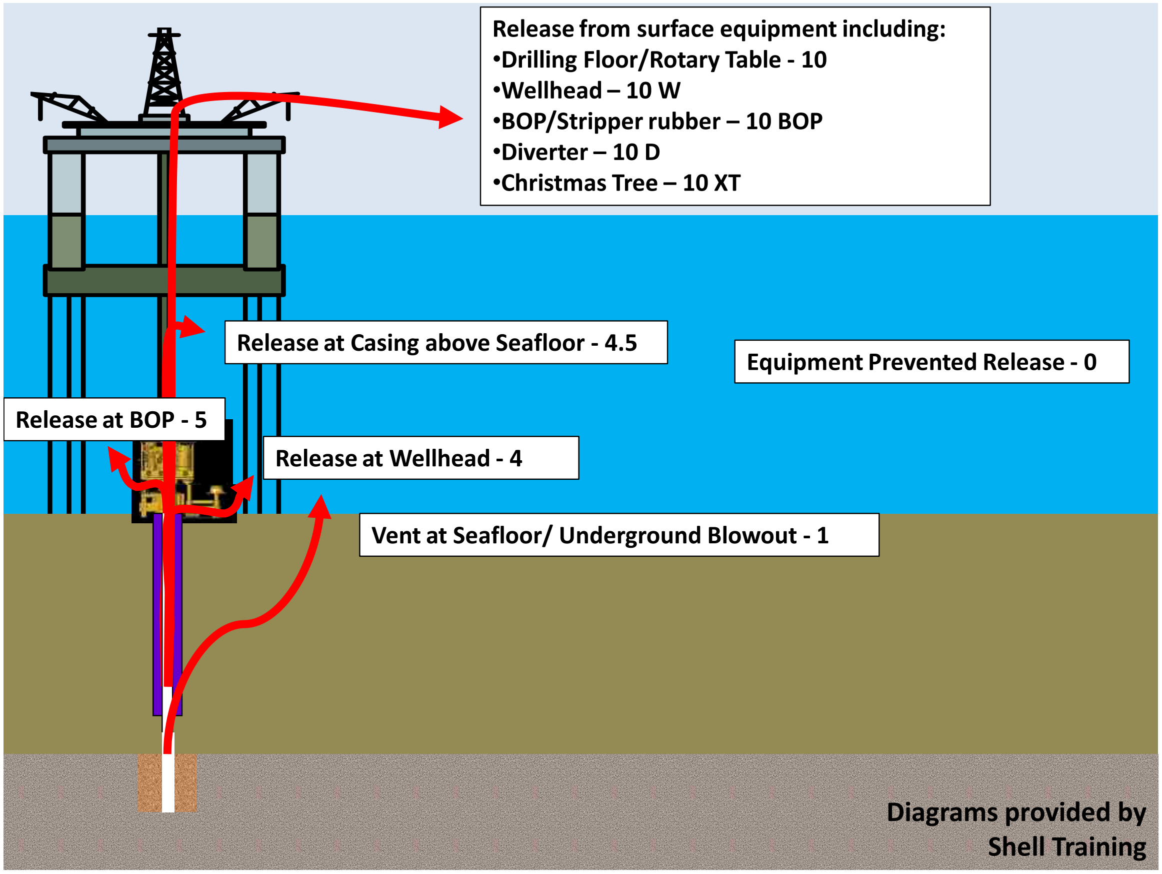

Figure 3-2: Release Points with Coding (Smith 2011)

Table 3-1: Grouped Release Points and Location of Release Points

Release Point	Code	Location
Equipment Prevented Release	0	N/A
Vent at the Seafloor	1	Seafloor
Subsea Wellhead	4	Subsea
Casing above Seafloor	4.5	Subsea
Subsea BOP	5	Subsea
Subsea Templates	8	Subsea
Rig Floor Equipment	10	Surface
Rig Equipment (not at Rig Floor)	10 S	Surface
Xmas Tree	10 XT	Surface
BOP/Stripper Rubber	10 BOP	Surface
Diverter System	10 D	Surface
Wellhead	10 W	Surface
Chemical Injection Line	10 CI	Surface

3.3.1.3 Attachment Points

A capping stack or containment system must be able to be attached to a leaking well at or upstream of the point of release. Once each release point had been identified, the first upstream piece of equipment capable of a creating a barrier or allowing attachment of a barrier or device which can create a barrier was determined. This was the attachment point recorded in the spreadsheet. For example, if the release point was the mud gas separator but the BOP was operational then the attachment point selected was the BOP, if however, the BOP was damaged or inoperable then the attachment point was the wellhead. There were multiple incidents where the wellhead was located at the surface. In several of these incidents, the release location was below the wellhead but above the seafloor. In those situations, the attachment point was considered the casing above the seafloor. There were several incidents where a workover was being conducted through a christmas tree. In these incidents, if the tree was intact and operational it was selected as the attachment point.

3.3.1.4 Vertical Intervention

For the purposes of this paper, vertical intervention is defined as listed in Chapter 2. It means entering the wellbore with a work string or tools from a vessel above the well, or from equipment located in the sea column or on the sea floor, for the purposes of well control. Pumping kill fluid through a choke or kill line (i.e. bullheading), or circulation through a workstring already in the well does not require intervention. However, intervention does include bullheading fluids into or circulating into the wellbore if drill pipe or a work string had to be snubbed into the well to do so.

The categories in this field include:

- Yes, vertical intervention was attempted

- No, vertical intervention was not attempted
- Vertical intervention could not have been attempted without removal of obstacles in the wellbore
- Vertical intervention could have been attempted but was not
- It is unknown if intervention was attempted
- It is unknown if intervention could have been possible

If the method of intervention was stated in the incident description, this was also included in this field.

3.3.1.5 Shut-In

This column indicates whether or not shut-in was attempted. The choices for this column were simple: yes or no. If the incident description did not provide sufficient detail to determine if shut-in was attempted, that is captured in this column as well as “unknown.” If the shut-in resulted in an underground blowout, that detail was not captured in this field. It was captured in the coding of the operational sequence of events, which is explained below.

3.3.1.6 Capture of Formation Fluids

This column indicates if there was some attempt to capture formation fluids on the rig/platform or vessel in during these incidents. This column has a yes if the incident details discuss capturing fluids in any way. The definition of capture of formation fluids does not include the use of booms or other collection equipment after the fluids reach the sea surface. This column only captures whether or not fluids were captured and transported directly from the release location to a storage vessel or container. For example, in one incident the flow was slow enough and the process tanks large enough, that the flow was diverted to a process tank on the platform and therefore prevented from entering the sea environment.

3.3.1.7 Diversion of Formation Flow

Diverting the flow of formation fluids from its original path is often desirable to protect personnel and equipment or to facilitate vertical intervention. Instances where flow was known to be diverted are recorded in this column. The majority of the events where flow was diverted used the standard diverter equipment at the surface. Common uses were to divert gas away from the rig before a BOP had been installed and to deal with gas in the riser above a subsea BOP. If the incident description was not clear if flow was diverted, that was captured in this field as well. When flow was diverted without using the surface diverter system, the equipment used to divert the flow was described to the extent it was known or could be implied from the incident description.

3.3.1.8 Contributing and Mitigating Factors

A pollution or blowout incident often involves factors that contribute to or mitigate the severity and longevity of the event. This column was used to capture the details of the incidents that could be related to making the outcome of the incident better or worse. No attempt was made to distinguish positive factors versus negative factors because many factors can have both positive and negative impacts. Take for instance the kink in the riser at the Macondo incident. This incident reduced the flow of fluids from the riser; however this kink also increased the pressure in the wellbore which became a threat to the burst discs in the casing string. Additionally, the kink in the riser was an obstacle which had to be removed before the capping stack could be attached to the LMRP. Therefore, this field is used to identify important factors that might imply positive or negative impacts and that if not present or compromised, would alter the severity of the event.

3.3.1.9 Well Bridging

A common perception is that the most frequent successful control of a blowout is that the well has bridged (Skalle and Podio 1998; Holand 1997; Skalle and Podio 1999). Therefore, this is a positive mitigating factor which needs to be investigated, especially to investigate its relevance in deepwater. Adams and Kuhlman(1991) state that a well will often bridge within 24 hours, although some blowout for an extended period of time. This 24 hour time limit is referenced several times in industry literature (Noynaert and Schubert 2005; Schubert et al. 2004; Neal Adams Firefighters Inc. 1991). Neal Adams Firefighters states that his conclusion is the result of over 1,000 blowouts in the database for Neal Adams Firefighters. The data collected in the past 15 years shows that the wells that did bridge (27%) were split about 50-50 between those that bridged in less than 24 hours and those that bridged 1 to 9 days after the blowout began. This study is not focused on well bridging; however the data from the past 15 years conflicts with the earlier reports which state there is a greater likelihood of well bridging to occur within 24 hours.

The data collected in these fields was used to address tasks 4-8, from Section 1.3.3. The source data can be found online at the URL's listed in Appendix 1. The summary descriptive data directly from the BSEE website are recorded in the first columns of the spreadsheet. The results of the analysis described herein were recorded in the subsequent columns. Finally, there is a section of columns recording codes to describe the events more completely. These source and meaning of these codes are described below.

3.4 Reduction of the Incident Description to a Code

The incident descriptions provide a great deal of information but were not helpful when searching for data or for sorting the data into groups to determine relationships between incidents or between events or actions within an incident. Therefore a simple, logical, repeatable method needed to be developed to reduce the words in the incident description to codes which could then be searched and sorted on. Using the model of blowouts as barrier failures and blowout response as steps taken to reestablish barriers, the details which needed to be captured from the incident description became clear. For each incident, the response to that incident needed to be captured in terms of the attempts that were made to establish a barrier. For each attempt, there were several items of interest which needed to be captured: first, where the barrier was being established; second, what type of barrier was being established; third, what type of equipment was used to establish the barrier; fourth, how the barrier was established; fifth, whether the barrier was established successfully; sixth, why the barrier was not established; and seventh, did the barrier stop the uncontrolled flow of formation fluids. The entire list of responses, or codes, used to indicate the locations, type of barrier, equipment used, reasons the barrier was not established are given in Appendix 3.

These codes were the starting point for systematically analyzing the response to all the incidents. The data collected from this sequencing has been helpful in identifying industry patterns, and it is expected that it could be useful in identifying patterns within companies and determining if there are any gaps in the well control response training. If known, the time when well control specialists were brought on site were identified. This will help determine what actions were taken by on site personnel or specialists. In 1993, Adams and Kuhlman discussed contingency planning and included a brief discussion on response. They divided blowout management into three stages. Early response includes the predetermined operations which are implemented without changes regardless of the circumstances of the blowout. Second, blowout containment operations are designed to mitigate or minimize damage resulting from the blowout.

And finally, blowout control, which involves the steps taken by well control specialists to stop the formation flow (Adams and Kuhlman 1993). The current design and specifications of a capping stack envision it being implemented in the third stage by specialists due to its size, complexity, the need to prepare it for the specific situation, and to transport it to the location.

An example will help to define the creation and use of these codes. Because the responses to the Macondo event are so well known, that incident will be used.

The initial steps taken are listed in the Deepwater Horizon Accident Investigation Report (BP 2010). The first well control response begins on page 27. It states, on April 20, 2010, at 9:41pm, the following attempt was made: "Diverter closed and flow routed to mud gas separator (MGS);…". The code sequence for this attempt is: 6D/D/DIV/MGS/N/ATD/N.

The first section of the code is 6D; this indicates the diverter system on the rig floor was the location of this first attempt to establish a barrier. The second section of the code is D, this indicates the type of barrier being established, it was not a barrier per se, but the flow was diverted to maintain personnel safety to allow further operations, in this case, on the rig floor. The third section of the code is DIV; this indicates the standard diverter system on the rig was used. The fourth section of the code is MGS, this indicates that the standard diverter system was activated, and flow was diverted to the mud gas separator. The fifth section is N, this indicates the barrier was not established. Since diverting the flow is not a barrier per se, no barrier was established. The sixth section is ATD, this indicates that the attempt was to divert flow rather than establish a barrier. The seventh section is N, this indicates the flow from the well was not stopped. This example shows an initial diversion attempt by the on-site personnel. This attempt is used to show an example of the code when a barrier was not created but the attempt was successful at something other than establishing a barrier (i.e. activating the diverter system).

The next example is for a successful establishment of a barrier. This occurred much later in the well control response. The well control specialists were on site when this attempt occurred in mid July. The example is for the installation of the sealing capping stack. The written description was: “Install sealing cap”. The code sequence for this attempt is: 4/M/CAPST /STAB/Y/-/Y!.

The first section of the code is a 4, this indicates the location of the barrier is the lower marine riser package. The second section of the code is M, this indicates the barrier being installed is a mechanical barrier, the third section of the code is CAPST, this indicates a capping stack was the equipment being used to install the mechanical barrier, the fourth section is STAB, this indicates the capping stack was installed in the open position allowing fluids to escape through the stack and once the stack was in place the valves were closed. The fifth section is Y, this indicates the barrier was successfully installed, the sixth section is blank because the barrier was successfully established, the seventh section is a Y!, which indicates the barrier successfully stopped the flow and was the first barrier reestablished after the blowout.

Using these codes and searching for an “!” for example will result in all the incidents where the primary barrier was established. Then the location, equipment, and success rate of these primary barriers can be compared, and relationships can be identified. Additionally, these codes were used to verify what equipment was used to shut-in wells after blowouts and to identify how often containment attempts were successful. The potential uses for this type of coding are intended to go far beyond this study.

3.5 Summary

The approach used to organize the incident data for this research was centered on creation of a searchable, sortable spreadsheet. The columns in the spreadsheet included the public data from BSEE, additional columns addressing specific questions about the incident description and finally, a set of columns with the response sequence coding. This spreadsheet was then used to reveal the most frequently encountered situations and these were used to determine the modules needed for an effective capping stack system. It is intended to also be useful for additional research focused on determining the expected distribution of severity and locations for possible future blowouts and as a basis for investigating means to minimize the risk of occurrence and the impact of possible future blowouts.

4 RESULTS AND DISCUSSION

This section is a summary and brief discussion of the results obtained from the analysis of the spreadsheet. Additionally, if the results suggest operational requirements which should be considered in the design of a generally applicable capping stack system, it is included here. The topics follow the objectives listed in Chapter 1, Section 3. Finally, there are results sections listed here which are a synthesis of two or more topics, which suggest additional capabilities for modules of the capping stack system.

4.1 Operation in Progress

The operation in progress when the blowout occurred is the logical starting point for looking at the results. This is how Holand (1999) organized his entire book. This is because as stated earlier, the operation in progress defines possible flow paths. For different operations, different flow paths are possible and impossible. Table 4-1 shows the number of incidents by operation and the relative frequency of that operation. The relative frequency is the number of incidents divided by 90, the total number of incidents. The operation in progress is a column that was provided by BSEE. These data were not examined or modified from what was available in the public data. These data however can be grouped into slightly more general categories to allow trends to be seen. If drilling, completion and workover operations (including logging) were combined, the total number of incidents in this category is 59 incidents with a relative frequency of 65.56%. Production is the next largest category followed by P&A and Post P&A, suspended operations (for a hurricane) and finally soil boring.

The data in Table 4-1 shows very clearly that drilling, workover and completion operations are the most likely source of blowouts. The other item of note is the suspended operations category due to hurricanes. In the past 15 years, there were a total of 95 incidents where a rig or platform allowed fluids to be released as the result of a hurricane. Of those 95 incidents, only 5 are included in this study, including three that are listed in the P&A or Post P&A operations. The other 90 hurricane incidents released fluids from storage tanks located on the rig or platform and not from the well.

Table 4-1: Operation in Progress and Relative Frequency of Occurrence (All Incidents)

Operation	No of Incidents	Relative Frequency
Drilling	41	45.56%
Completion	8	8.89%
Completion – Gravel Pack	2	2.22%
Logging	1	1.11%
Workover	7	7.78%
Production	17	18.89%
P&A	8	8.89%
Post P&A	3	3.33%
Soil Boring	1	1.11%
Suspended (for a Hurricane)	2	2.22%

Additionally, what the data in Table 4-1 suggests is that for the capping stack to respond to incidents at any point in time in the life of a well, the first priority should be drilling, completion and workover operations, and second priority should be production. This should be followed by plug and abandon and post plug and abandon operations. What this data also implies is that the flow paths associated with drilling, completion and workover will be the most likely flow paths encountered in these incidents.

4.1.1 Implications for Deepwater Operations

Table 4-2 shows the breakdown of the operation in progress for shallow water incidents and for deepwater incidents. The drilling, completion, and workover operations account for 65% of shallow water incidents and 67% of deepwater incidents. Production operations account for 19% of shallow water incidents and 20% of deepwater incidents. P&A and post P&A operations account for 12% of shallow water incidents and 13.33% of deepwater incidents. This implies that the operation in progress for deepwater incidents is very consistent with the shallow water incidents even though there is a much smaller number (15) of deepwater incidents than in shallow water (75 incidents).

Table 4-2: Operation in Progress Shallow vs. Deep Water Incidents

Operation	All	Rel. Freq.	Shallow Water	Rel. Freq.	Deep-water	Rel. Freq.
Drilling	41	45.56%	34	45.33%	7	46.67%
Completion	8	8.89%	6	8.00%	2	13.33%
Completion – Gravel Pack	2	2.22%	2	2.67%	0	0.00%
Workover	7	7.78%	7	9.33%	0	0.00%
Logging	1	1.11%	0	0.00%	1	6.67%
Production	17	18.89%	14	18.67%	3	20.00%
P&A	8	8.89%	8	10.67%	0	0.00%
Post P&A	3	3.33%	1	1.33%	2	13.33%
Soil Boring	1	1.11%	1	1.33%	0	0.00%
Suspended (for a Hurricane)	2	2.22%	2	2.67%	0	0.00%

4.2 Flow Paths of Hydrocarbons During a Blowout

Table 4-3 shows the flow paths for each of the 90 incidents by operation. The wellbore path is flow of fluids up the wellbore or the annulus between the wellbore and the string, the string flow path is flow up the drillpipe, work string, or tubing. The string and wellbore flow path is parallel flows up the wellbore as well as the string or tubing. The annulus flow path is flow outside the primary casing but between outer casings or casing and the surrounding rock. The annulus and wellbore flow path is flow up the wellbore as well as flow through an outer annulus. These flows may be parallel or may be in series. The flow may have begun up the wellbore and when shut in was attempted the flow stopped going up the wellbore and instead found a path through the cement or casing. This approach was used for all instances with multiple paths. The unknown flow path is when the incident description did not provide sufficient detail to determine the flow path. There are a total of 107 flow paths because each individual flow path was counted, therefore the parallel or series flow paths were counted toward the total for each of the flow paths they traveled.

Table 4-3: Flow Paths by Operation with Relative Frequency of Occurrence (All Incidents)

	Flow Paths (Relative Frequency = Num. of Incidents / 107)									
Operation	**Well bore**	**RF**	**String**	**RF**	**Annu lus**	**RF**	**Rock**	**RF**	**Unk**	**RF**
Drilling/ WO/ Comp.	37	35%	14	13%	17	16%	4	4%	3	3%
Production	3	3%	7	7%	2	2%	0	0%	5	5%
P&A	3	3%	5	5%	1	1%	0	0%	0	0%
Post P&A	0	0%	0	0%	0	0%	0	0%	3	3%
Soil Boring	1	1%	0	0%	0	0%	0	0%	0	0%
Suspended (for a Hurricane)	1	1%	0	0%	0	0%	0	0%	1	1%
Totals:	**45**	**42%**	**26**	**24%**	**20**	**19%**	**4**	**4%**	**12**	**11%**

RF = Relative Frequency

The data in Table 4-3 implies that the wellbore and string are the most frequent flow paths with a total of 66% between the two. Likewise for the most frequent operations: drilling, completion and workover, the wellbore is the most frequent path followed by the annulus path and then the string path. This confirms the conclusion by Holand (1997). For production, the most common path is the string, the path the formation fluids are designed to flow in. The string path is followed by the unknown flow path. For P&A, the most common path is through the string, followed by the wellbore. The flow paths for all post P&A incidents were unknown.

The number of underground blowouts (rock flow path) which broached to the seafloor is 4.4% (4/90 incidents). This statistic is misleading however, because any underground blowout which does not broach would not be reported to BSEE, as no reservoir fluids would be released to the seafloor or atmosphere and current regulations do not require reporting of these types of underground blowouts. An examination of 30 years of insurance loss history with regard to underground blowouts suggests that operators report losses (equipment, etc.) relating to underground blowouts 1.52 times more frequently than losses relating to surface blowouts (Adams and Young 2004). This statistic is for land and offshore events and may not be representative of the risk offshore; however, if we assume this statistic is generally applicable that would mean that for the 86 surface blowouts (90 less the 4 UGBO) the number of underground blowouts could be as high as 131 events. These two facts suggest that underground blowouts may occur more often than suggested by the data.

Additionally, the rock and annulus flow path most often require a barrier placed upstream of the beginning of this flow path in order to regain control of the well. Sometimes bullheading can be used to regain control in incidents with a surface wellhead this is because of access to the outer annuli are available through a surface wellhead.

4.2.1 Implications for Deepwater

Table 4-4 shows the breakdown of flow paths by water depth with the series and parallel flow paths explicitly stated. For example, there are 8 incidents with both the string and wellbore flow paths. Displaying the data in this manner reveals an interesting trend. No incidents with an annulus flow path (without a rock flow path) have occurred yet in deepwater. This is may be due to the fewer number of incidents in deepwater and does not necessarily reflect a trend of fewer annulus flow paths in deepwater.

Nevertheless, it is logical that a generally applicable capping stack system should be able to address flow up the wellbore and string or both as well as flow up through an outer annulus as essentially all of these paths pass through the subsea wellhead. The module that was built to address the blowout at Macondo was attached to the wellhead housing via the BOP and LMRP and therefore had the potential to be adapted to have these capabilities.

Table 4-4: Flow Path of Reservoir Fluids

Flow Path:	Events	Rel Freq	Shallow Water	Rel Freq	Deepwater	Rel Freq
Wellbore Flow Path	31	34.44%	27	36.00%	4	26.67%
String Flow Path	18	20.00%	17	22.67%	1	6.67%
String & Wellbore	8	8.89%	6	8.00%	2	13.33%
Annular Flow Path	13	14.44%	13	17.33%	0	0.00%
Annular & Wellbore	4	4.44%	4	5.33%	0	0.00%
Rock Flow Path Only	0	0.00%	0	0.00%	0	0.00%
Annular & Rock	2	2.22%	1	1.33%	1	6.67%
Wellbore & Rock	1	1.11%	1	1.33%	0	0.00%
Annular, Wellbore & Rock	1	1.11%	0	0.00%	1	6.67%
Unknown Flow Path	12	13.33%	6	8.00%	6	40.00%

In deepwater operations the subsea wellhead does not provide access to outer annuli. Therefore, the option for bullheading from the subsea wellhead is not available. In these types of incidents with a subsea wellhead, the only option available would be a relief well or vertical intervention. Therefore, it is reasonable to conclude that a subsea capping stack should have the capability for vertical intervention to address these types of incidents.

4.3 Release Points

The point where the formation fluids were released into the environment is described as the release point. For this study, release points located on the platform or rig account for 80% of the incidents, subsea releases 8% and subsea equipment releases 7%. As expected for the surface releases, the wellbore flow path is the most frequent flow path followed by the string flow path. Note that if the actual flow paths involved more than one flow path element, it is shown under each relevant column. For the subsea releases, the most common flow path is the annulus flow path, followed closely by the wellbore, string and rock flow paths. For subsea equipment releases, unfortunately, the most common flow path is unknown. For incidents where the release point is not known, the flow path is also not known. These incidents with the unknown release points were small volume spills and had no incident descriptions. For the one incident where the equipment prevented a release, the flow path was through the wellbore.

Table 4-5: Release Points by Location and Flow Path (All Incidents)

Release Point	All Incidents						
	All Incidents	Rel. Freq.	Wellbore	String	Annulus	Rock	Unknown
Platform Releases							
Wellhead at surface	20	22%	10	3	11	0	0
Surface Equipment @ Wellhead	18	20%	13	8	0	1	0
Diverter at surface	12	13%	7	2	3	1	1
BOP/Stripper Rubber at surface	8	9%	7	2	1	0	0
Surface Equipment on Rig (away from wellhead)	9	10%	4	5	1	0	1
X-mas Tree at surface	4	4%	1	3	0	0	0
Injection Line	1	1%	0	0	0	0	1
Subtotal:	**72**	**80%**	**42**	**23**	**16**	**2**	**3**
Subsea Releases							
Vent @ Seafloor	4	4%	2	0	3	2	0
Casing above seafloor	3	3%	0	2	0	0	1
Subtotal:	**7**	**7%**					
Subsea Equipment Releases							
Subsea Wellhead	2	2%	0	0	1	0	1
Subsea Template	2	2%	0	0	0	0	2
Subsea BOP	1	1%	0	1	0	0	0
Subtotal:	**5**	**6%**					
Unknown Release Point and No Fluids Released							
Equipment Prevented Release	1	1%	1	0	0	0	0
Unknown	5	6%	0	0	0	0	5
Subtotal:	**6**	**7%**					
Totals:	**90**	**100%**	**45**	**26**	**20**	**4**	**12**
Relative Frequency:			**42%**	**24%**	**19%**	**4%**	**11%**

The data in Table 4-5 implies that in the majority of these incidents the release point is on the platform or rig. This is expected because most of these incidents occurred in shallow water, and the equipment where fluids likely be released are at the surface.

Additionally, there were several incidents (see Table 4-5) where fluids were released at both the surface, and at the seafloor. There were also four incidents where an underground blowout occurred. Of those four incidents, two of the underground blowouts resulted from shut-in which increased the pressure and fractured the formation. For these incidents, the release point changed as a result of well control operations. The other two began with underground blowouts and included some flow up either the annulus or wellbore. This data suggests that shutting in a well can cause an underground blowout. This suggests that the capping stack system should address the possibility of, and the need to minimize the risk of, underground blowouts.

Additionally, two incidents occurred which had a release point subsea and an annulus flow path. These incidents used a pollution dome to collect hydrocarbons while well control operations were underway. The likely reason the pollution dome was used was that attachment to the sea floor equipment would have required custom built equipment which would have taken time to build and transport to the site. These incidents imply a capping stack system should include the capability to respond to these types of incidents.

4.3.1 Implications for Deepwater Operations

The small number of deepwater releases limits the significance of the deepwater data for anticipating future release points. Nevertheless, these data combined with the knowledge from shelf operations does imply some potential trends. Table 4-6 shows the release points by location for only the deepwater incidents. There is a marked difference in location of the release point. Only 40% of the releases occur at the platform or rig, 27% occur from subsea equipment and a further 13% occur subsea and from unknown release points. These unknown release points are incidents without any incident description so no flow path is known for these incidents.

Table 4-6: Release Points by Location and Flow Path (Deepwater Incidents)

	Deepwater Wells (>1,000 ft)						
Release Point	**All Incidents**	**Rel. Freq.**	**Wellbore**	**String**	**Annulus**	**Rock**	**Unknown**
Platform Releases							
Surface Equipment @ Wellhead	3	20%	3	1	0	0	0
Diverter at surface	2	13%	2	1	0	0	0
Injection Line	1	7%	0	0	0	0	1
Subtotal:	**6**	**40%**					
Subsea Releases							
Vent @ Seafloor	2	13%	1	0	2	2	0
Subtotal:	**2**	**13%**					
Subsea Equipment Releases							
Subsea Template	2	13%	0	0	0	0	2
Subsea BOP	1	7%	0	1	0	0	0
Subsea Wellhead	1	7%	0	0	0	0	1
Subtotal:	**4**	**27%**					
Unknown Release Point and No Fluids Released							
Equipment Prevented Release	1	7%	1	0	0	0	0
Unknown	2	13%	0	0	0	0	2
Subtotal:	**3**	**20%**					
Totals:	**15**	**100%**	**7**	**3**	**2**	**2**	**6**
Relative Frequency:			**35%**	**15%**	**10%**	**10%**	**30%**

These data imply there is a greater likelihood of a subsea release from deepwater incidents than from shallow water incidents. The ratio of platform or rig releases to subsea releases for shallow water is 80% to 13%, for deepwater it is 40% to 40%. A contributing factor is that much of the equipment located on the rig or platform for shallow water operations is being relocated to the seafloor in deepwater operations, which has the potential of creating an even greater number of subsea releases. This risk could be somewhat mitigated however by the expectation that the equipment being moved to the seafloor is being designed for long term, low maintenance or maintenance free operations and is less likely to leak or fail than the simpler surface equipment. The data supports this because the relative frequency of releases from surface equipment which has been relocated subsea does not approach the relative frequency of releases from these pieces of equipment when it was on the surface. For instance, the relative frequency of surface BOP releases is 10.7% (8/75), but for subsea the number is 6.7% (1/15). For the surface wellhead the number is 26.7% (20/75) and the subsea wellhead the number is 6.7% (1/15). For the christmas tree on the surface the number is 5.3% (4/75), for subsea that number is 0%. In any event, subsea wells are more likely to result in a subsea release point than a surface well.

The actual subsea release points are known for only 6 of the deepwater incidents. Nevertheless, each type of release point is represented in this small sample. This implies that the capping stack system should ideally include the capability to handle subsea releases from all possible flow paths and release points.

The data also implies that while shallow water operations did not encounter subsea releases as often, deepwater operations will and a subsea response capability will be needed to address these types of incidents.

4.4 Attachment Points

Once the release point is identified, the corresponding attachment point was defined as the next upstream piece of equipment that was undamaged by the well control event, with the assumption that the release point cannot be used as the attachment point. So for example, if the fluids were released at the rotary table and the BOP is at the surface and was undamaged by the well control event the BOP would be the corresponding attachment point. If however, the BOP was damaged by the well control event and that is noted in the incident description then the corresponding attachment point would be the next upstream piece of equipment, in this case the wellhead on the platform. In contrast, the release point itself might be an attachment point, e.g. the top of the LMRP in the late stages of the Macondo incident. This possibility was not considered in the results shown in tables below or in the spreadsheet.

Therefore the attachment points listed in the tables below represent the first, undamaged piece of equipment where a barrier could be implemented, upstream of the release point. The specific attachment points have been grouped by general location to simplify the presentation of data. The general locations are on the rig or platform, subsea (below sea level but at or above the seafloor), or inside the well below the seafloor. Also, the incidents without sufficient information to determine an attachment point are listed as unknown. There is one incident where no fluids were released to the environment, and therefore, attachment of a capping system was irrelevant.

Table 4-7 shows that a little over 50% of the attachment points are on the rig or platform. The subsea attachment points (20%) were most often associated with the wellbore flow path. An attachment point below the sea floor would be required in 15% of the incidents. This is significant because these types of incidents would require the capability for vertical intervention with the well flowing, if that was possible. If vertical intervention was successful it would be much quicker than drilling a relief well. The incidents in this data set include six incidents where it was confirmed a relief well was begun soon after the blowout occurred and in three of those incidents other operations (vertical intervention – 2, natural bridging – 1) were eventually used to regain control of the well. This implies the capability for intervention during flow and under pressure would be desirable to minimize the time needed to regain control.

Table 4-7: Initial Attachment Point by Location and Flow Path (All Incidents)

Initial Attachment Point:	All Incidents	Rel. Freq.	Wellbore	String	Annulus	Rock	Unknown
Platform Attachment Points							
BOP on Platform	23	26%	17	7	4	0	0
Wellhead on Platform	15	17%	7	4	5	0	0
Tree on Platform	11	12%	3	9	0	0	0
Chemical Injection Manifold on Platform	1	1%	0	0	0	0	1
Subtotal:	**50**	**56%**					
Subsea Attachment Points							
Casing	11	12%	6	0	6	0	1
Subsea BOP	7	8%	6	4	0	0	0
Subtotal:	**18**	**20%**					
Below Seafloor Attachment Points							
Casing below sea floor	3	3%	1	0	2	0	0
None - Underground Blowout	4	4%	2	0	3	4	0
None - Casing cut below sea floor	3	3%	0	0	0	0	3
None - Mud covering well at seafloor	2	2%	0	1	0	0	1
None - Soil Boring Operation	1	1%	1	0	0	0	0
Subtotal:	**13**	**15%**					
Unknown Attachment Point and No Release of Fluids							
Unknown Attachment Point	8	9%	1	1	0	0	6
Equip Prevented Release	1	1%	1	0	0	0	0
Subtotal:	**9**	**10%**					
Totals:	**90**	**100%**	**45**	**26**	**20**	**4**	**12**
Relative Frequency:			**42%**	**24%**	**19%**	**4%**	**11%**

The flow paths for these incidents are almost evenly divided among all possible flow paths except the string flow path. This has the potential to further complicate well control responses and the specific capping stack capabilities required in these situations.

Finally, the data from the release points and from this section imply that the rig was intact and accessible to the well control crews. This is important because there are more options to control the well after the blowout. If the rig were lost as in Macondo the options for well control are very limited.

A generally applicable capping stack system should be able to respond to all of these scenarios: surface attachment, subsea attachment and attachment inside the well.

4.4.1 Implications for Deepwater Operations

The small numbers of incidents which have occurred in deepwater to date limit the accuracy which the future expectations can be determined. Therefore, some general expectations are discussed but no specific predictions are made.

The attachment points for responding to deepwater releases are expected to be significantly different than for shallow water incidents. This is because the response equipment for a release from a shelf operation can typically be attached at the BOP or wellhead on the platform or rig. In contrast, the BOP, tree, or wellhead is typically on the seafloor in deepwater. Although some deepwater developments like (i.e. TLP, spar) have a high pressure riser and a tree at the surface, none of the incidents in this data set had a surface tree or BOP. In addition, a deepwater drilling riser is not designed to handle shut-in pressures and would fail if some type of capping stack were to be attached to it. Therefore, without a major change in technology to strengthen the drilling riser in anticipation of a well control event, the majority of the deepwater events will result in the need for a subsea attachment point. The drilling riser is present only during drilling and therefore during production operations this limitation would not exist. The data shows that a subsea attachment point was from the string, wellbore, or less frequently the annulus path in deepwater. The desirable attachment points for the deepwater capping stack would be subsea equipment (LMRP, subsea BOP, tree), subsea wellhead, or the casing.

Table 4-8: Initial Attachment Point by Location and Flow Path (Deepwater Incidents)

	Deepwater Wells (>1,000 ft.)						
Initial Attachment Point:	**All Incidents**	**Rel Freq**	**Wellbore**	**String**	**Annulus**	**Rock**	**Unknown**
Subsea Attachment Points							
Subsea BOP	6	40%	5	3	0	0	0
Umbilical Termination Unit	1	7%	0	0	0	0	1
Subtotal:	**6**	**47%**					
Below Seafloor Attachment Points							
Casing below sea floor	0	0%	0	0	0	0	0
None - Underground Blowout	2	13%	1	0	2	2	0
None - Casing cut below sea floor	2	13%	0	0	0	0	2
None - Mud covering well at seafloor	0	0%	0	0	0	0	0
None - Soil Boring Operation	0	0%	0	0	0	0	0
Subtotal:	**4**	**27%**					
Unknown Attachment Point and No Release of Fluids							
Unk	3	20%	0	0	0	0	3
Equip Prevented Release	1	7%	1	0	0	0	0
Subtotal:	**4**	**27%**					
Totals:	**15**	**100%**	**7**	**3**	**2**	**2**	**6**
Relative Frequency:			**35%**	**15%**	**10%**	**10%**	**30%**

An attachment point at the seafloor (40%) or below (27%) would be required for 67% of the deepwater incidents, and none had attachment points on a platform or rig. This supports the expectation that deepwater incidents will result in a much higher frequency of incidents requiring a subsea attachment point. Because of this, establishing a mechanical barrier to flow for deepwater incidents is expected to be much more difficult than for shallow water wells. Four of the deepwater incidents were from underground blowouts or from wells which had previously been P&A'd. As a result, these would require an attachment point below the seafloor, which is not straightforward. This is because there is no attachment for the vertical intervention equipment. This implies the requirement for a relief well and a capping or containment system while that relief well is drilled.

4.5 Barriers Used to Stop Formation Flow

The results from this section come from an analysis of the coding of the incident description described in Chapter 3. The overall organization of the codes was to consider all of the incidents as failures of barriers and to document attempts to reestablish barriers in the well. As a result, the coding captures the types of barriers and how and where they were placed, as well as how often they were successful.

A successful response to stop a blowout or leak requires establishing a barrier to formation flow. As discussed in Chapter 2, the first barrier successfully established which stopped flow is defined as the primary barrier. The second barrier is defined as, the barrier which allowed the well to be returned to normal drilling or production operations or which abandoned the well successfully.

Over 75% of the 90 incidents in this study included details on the primary barrier established. Slightly more than 45% had information about both primary and secondary barriers. A possible reason these numbers are so low is that the incident descriptions were more focused on the cause of the incident, and the response to the incident was a secondary concern.

4.5.1 Primary Barriers

An average of nearly four attempts was required to establish a primary barrier in shallow water events. There were two general classes of barriers used in the past incidents, mechanical and hydrostatic. Mechanical barriers included such things as BOP rams and annulars, valves, cement plugs, packers and natural bridging events. This is in contrast to a hydrostatic barrier which would involve pumping heavy mud or other fluid into the wellbore to reestablish a hydrostatic overbalance. Specific methods include bullheading fluid into the well and conventional kick circulation.

Sixty one or 86% of the incidents with barriers reported had a mechanical barrier as the primary barrier. Ten incidents successfully used a hydrostatic barrier. Due to the low number of incidents utilizing a hydrostatic barrier, a detailed discussion is not included here but the data is provided in Appendix 1.

Table 4-9: Primary Mechanical Barrier by Location (All Incidents)

	Location Where Barrier Was Installed (61 Incidents)					
Primary Mechanical Barrier Equipment/Method:	**Wellbore**	**Rig/ Platform /Riser**	**Subsea BOP/ LMRP**	**Rig/Platform BOP**	**Total**	**Rel. Freq.**
Well Bridge	19	0	0	0	19	31%
BOP	0	0	5	10	15	25%
Surface Valves (Misc.)	0	11	0	0	11	18%
Subsurface Safety Valve	3	0	0	0	3	5%
Packer	2	0	0	0	2	3%
Cement Plug	2	0	0	0	2	3%
Diverter used to shut in	0	2	0	0	2	3%
Pumped LCM/Bridging Pill	3	0	0	0	3	5%
Casing Swedge	0	1	0	0	1	2%
Emergency Shutdown	0	1	0	0	1	2%
Capping Stack	0	0	1	0	1	2%
Relief Well	1	0	0	0	1	2%
Totals:	**30**	**15**	**6**	**10**		
Relative Frequency:	**50%**	**25%**	**10%**	**16%**		

Table 4-9 shows the number and relative frequency of each specific type of successful barrier for the 61 incidents where the primary mechanical barrier was known.

The most frequent barrier (31% mechanical barriers) was a bridge, which occurred naturally. The most common barrier implemented by the rig or platform crew was the use of a BOP. The next most common barrier was a surface safety valve. These two intentional barriers represent 43% of the mechanical barriers. It is interesting to note that these two barriers are in place specifically for well control operations. This would imply the needs for well control operations are well known and often implemented. For the BOP, two-thirds of the time the BOP was located at the rig or platform and one-third it was located subsea. All the surface safety valves were located on the rig or platform. The most frequent location of the barrier when it was installed is the wellbore, the second is the rig or platform or riser. If the well bridging incidents are removed from consideration, the rig or platform or riser and rig or platform BOP are the most frequent followed by the wellbore and then subsea.

4.5.1.1 Implications for Deepwater

The deepwater incidents provide a different perspective on barriers (Table 4-10). There were no occurrences of natural bridging. Instead the most frequent successful mechanical barrier was a subsea BOP.

Only one of the deepwater incidents used a hydrostatic barrier as the primary barrier. A packer (set in the wellbore) and the Macondo capping stack were the only other equipment used so far in deepwater to establish a primary mechanical barrier.

The lack of natural bridging so far in deepwater may be partially explained by the narrow margins between fracture gradient and pore pressure in the deepwater GOM. This results in casing being set at shorter depth intervals and as a result there is a shorter length of open hole exposed and able to create a natural bridge. Although natural bridging is not well understood, the only conclusion reached here will be that there have not been any events of natural bridging to date in deepwater.

Table 4-10: Primary Mechanical Barrier by Location (Deepwater Incidents)

	Location Where Barrier Was Installed (8 Incidents)					
Primary Mechanical Barrier Equipment/Method:	**Wellbore**	**Rig/ Platform /Riser**	**Subsea BOP/ LMRP**	**Rig/Platform BOP**	**Total**	**Rel. Freq.**
Well Bridge	0	0	0	0	0	0%
BOP	0	0	6	0	6	75%
Surface Valves (Misc.)	0	0	0	0	0	0%
Subsurface Safety Valve	0	0	0	0	0	0%
Packer	1	0	0	0	1	13%
Cement Plug	0	0	0	0	0	0%
Diverter used to shut in	0	0	0	0	0	0%
Pumped LCM/Bridging Pill	0	0	0	0	0	0%
Casing Swedge	0	0	0	0	0	0%
Emergency Shutdown	0	0	0	0	0	0%
Capping Stack	0	0	1	0	1	13%
Relief Well	0	0	0	0	0	0%
Totals:	**1**	**0**	**7**	**0**		
Relative Frequency:	**12%**	**0%**	**88%**	**0%**		

An average of just over three attempts was required to establish a primary barrier for deepwater incidents. This implies that deepwater operations require fewer failed attempts to stop flow than shelf operations. The reasons are not so obvious. It may be because it was possible to achieve a barrier using the existing subsea BOP in five of the eight deepwater incidents. It may also be that the deepwater reports are less detailed or than the increased difficulty in deepwater results in fewer, more carefully planned attempts. It is notable that this average was biased upwards by 1.70 attempts due to the relatively large number of documented unsuccessful attempts in the Macondo incident, but that the average was still only three attempts.

Table 4-10 shows the eight successful mechanical barriers placed in deepwater incidents versus the location (effectively the same as the expected attachment point described earlier) where that barrier was placed. In seven of the eight incidents the barrier used most was the subsea BOP. This implies the ability to shut-in deepwater wells with subsea well control equipment is of critical importance.

Macondo represents an important variation in that the subsea BOP was ineffective, but the successful capping stack was attached to the LMRP on top of the subsea BOP (i.e. the attachment point was actually downstream rather than upstream of the failed BOP. This was possible because there were no leaks from the BOP or the LMRP.

4.5.1.2 Other Implications for Deepwater Response Systems

A brief discussion about the importance of the rig or platform remaining intact during an incident is pertinent. There were four incidents where the rig or platform was lost. Three incidents were a result of a hurricane toppling the structure and the fourth was Macondo. The three hurricane incidents were in shallow water. Macondo was a deepwater operation being conducted by a semi-submersible rig with a subsea BOP. A subsea BOP and other subsea drilling equipment are generally controlled by a control cable or umbilical attached to the drilling riser. In the event of a loss of the rig, ROV's are available; however, it takes time to deploy them. As Macondo showed, the capability of the ROV's to control the subsea equipment is limited. The low pressure drilling riser used with floating rigs, such as semi-submersibles, precludes installing a mechanical barrier in the riser. Therefore, mechanical barriers can only be installed on, within, or by replacing the rig equipment at the sea floor. This suggests that it is highly desirable that the controls for the subsea equipment remain intact during and after an incident. Currently, this means the rig or platform and control lines, umbilical, and riser must remain intact. The current capping stack designs require the riser and all control lines to be removed before the stack can be installed. Therefore, the capability of retaining control of the subsea equipment should ideally be incorporated into the capping stack system. Since no equipment is currently available to perform this function, it is suggested that future research investigate a more effective and more fully functional means of controlling subsea equipment from the surface without the need for the rig or platform to remain attached to the well. A means to retain full control for existing subsea equipment and any capping stack system from the surface would be an important capability.

4.5.2 Secondary Barriers

Just over half of the incident reports did not provide information on the secondary barrier used. For the cases with documentation, 63% used mechanical barriers and 37% placed fluid into the well was used to establish a hydrostatic barrier.

Table 4-11: Secondary Mechanical Barrier by Location When Installed (All Incidents)

	Location of Barrier When Installed (26 Incidents)					
Secondary Mechanical Barrier Equipment/Method:	**Wellbore**	**Rig/ Platform /Riser**	**Subsea BOP/ LMRP**	**Rig/Platform BOP**	**Total**	**Rel. Freq.**
Cement Plug	18	0	0	0	18	67%
BOP	0	0	1	0	1	4%
Blind Flange	0	1	0	1	2	8%
Valve	0	2	0	0	2	8%
Packer	1	0	0	0	1	4%
Well Bridge	1	0	0	0	1	4%
TIW Valve	0	2	0	0	2	8%
Totals:	**20**	**5**	**1**	**1**		
Relative Frequency:	**74%**	**15%**	**4%**	**7%**		

The average number of attempts to establish a secondary barrier was less than two for shallow water events. The meaning of this is that the first attempt after establishing the primary barrier was more often successful in establishing the secondary barrier, regardless of how difficult it was to establish the primary barrier. For 27 of the 35 shallow water events (with secondary barrier information) the first attempt to establish the secondary barrier was successful.

Table 4-11 shows the methods used to establish secondary barriers. They are very different than for the primary barriers. This makes sense since the barrier does not need to be established against flow. A cement plug is used as a secondary barrier 67% of the time. This is telling as this would indicate the well is going to be abandoned or sidetracked or plugged back. This implies that in 18 of the 90 incidents significant time and expense was incurred as a direct result of the blowout or leak.

In Table 4-11 the secondary barrier is generally located inside the well. This makes sense as typically the well can be reentered and a barrier placed with much less difficulty once the primary barrier is established and placement closer to the formation provides a more secure barrier. Of note is the incident where the BOP was the secondary barrier, in this incident the LMRP was disconnected by mistake and the BOP could not be operated. A packer was in the well and able to be placed and set, which provided the primary barrier.

4.5.2.1 Secondary Hydrostatic Barriers

Hydrostatic barriers make up a greater percentage of the secondary barriers. The 16 incidents with hydrostatic secondary barriers are shown in Table 4-12.

The reason the fluid type was categorized was because the method of circulating the fluid was not reliably captured by the incident description. In most cases the information given was limited to the fact that the fluid was circulated to kill the well. Also of interest is that the incidents with secondary barrier information only included P&A operations and drilling, workover, and completion operations. A possible explanation is there are fewer production incidents and therefore a smaller possibility that one of those incidents would include secondary barrier information. An alternative explanation is that the incident description of production operations implies a secondary barrier which is not stated, for example surface safety valves or other valves on the tree that would routinely be installed, repaired or reinstalled fulfilling the function of a secondary barrier.

Table 4-12: Secondary Hydrostatic Barrier by Location and Operation in Progress (All Incidents)

Secondary Hydrostatic Barrier:	Wellbore	Rig/ Platform /Riser	Subsea BOP/ LMRP	Rig/Platform BOP	Total	Rel. Freq.
All Incidents						
Pumped Heavy Mud	8	1	0	0	9	56%
Pumped Completion Fluid	4	1	0	0	5	31%
Pumped Seawater	2	0	0	0	2	13%
Subtotal:	**14**	**2**	**0**	**0**		
Relative Frequency:	**88%**	**12%**	**0%**	**0%**		
Deepwater Incidents						
Pumped Heavy Mud	4	0	0	0	4	80%
Pumped Completion Fluid	1	0	0	0	1	20%
Pumped Seawater	0	0	0	0	0	0%
Subtotal:	**5**	**0**	**0**	**0**		
Relative Frequency:	**100%**	**0%**	**0%**	**0%**		

4.5.3 Implications for Deepwater

A hydrostatic balance was used as a secondary barrier in five of the eight documented deepwater incidents. In four the secondary barrier was established by circulating kill weight mud, and one was affected using completion fluid. Two incidents used a cement plug and one used the BOP as mechanical secondary barriers.

An average of just over three attempts was required to establish the secondary barrier. These attempts were apparently also more time consuming than for shelf operations. This makes sense if the complexity of the deepwater operations is taken into consideration. This complexity adds an additional layer of difficulty in deepwater operations after a blowout. The exact status of each component of the system may not be known. The complexity of deepwater operations is not likely to change, however, as more experience with deepwater systems is gained, there should be a greater understanding of what fails, and how it fails, which should lead to more effective responses.

In seven of the eight deepwater incidents the secondary barrier was placed within the well. This implies that gaining access to the wellbore will be required for the majority of deepwater incidents. For a generally applicable capping stack system this means it should have the capability to enter the well to place these secondary barriers.

4.6 Initial Response: Shut-in versus Capture versus Divert

The prior section focused on the methods used to establish a barrier to stop or prevent flow. Several attempts were often required before a success was achieved. This section captures if any attempts were made to shut-in, capture or divert flow. These were sometimes an initial response needed before being able to implement a primary barrier.

4.6.1 Shut-in

The data from this section comes from two separate analyses of the data. The first analysis determined whether shut-in was attempted. The second analysis used the incident description coding. The codes were examined to answer the following questions; was shut in attempted with any equipment at any time, was shut in attempted with the BOP, how many attempts were made to close the BOP, was the BOP the primary or secondary barrier, and was any method of shut in (other than bridging) successful in establishing a primary barrier. The two different analyses were correlated so the results matched.

Attempts were made to shut-in the well in 63 of the 90 incidents. As shown in Table 4-13, attempts were made using the BOP in 30 incidents. There were 15 successful shut-ins using a BOP. This means that the BOP was successful in shutting in the well for only 50% of the attempts. There were 33 attempts made using something other than the BOP. In these incidents some equipment or method other than the BOP was used to shut-in the well. The equipment and methods used include packers, valves, relief wells, emergency shutdown systems, diverter systems used to shut-in the well, drill string safety valves, and cement plugs. These methods were successful in 79% (26/33 incidents) of the incidents where they were attempted (see Table 4-13). This list does not include well bridging, which is considered a passive barrier. Overall, 40 out of the 63 total shut-in attempts or 63% of the time the attempt was successful.

Table 4-13: Shut-in Attempts and Success Frequency (All Incidents)

Shut-in	Attempted	Rel. Freq.	Successful	Success Freq.
Attempts - BOP	30	33%	16	53%
Attempts – Other	33	37%	26	79%
Total Attempts	63	70%	40	63%
Not Attempted	11	12%		
Attempts Unknown	16	18%		

The average number of attempts made to close the BOP when the BOP was used successfully to shut-in the well was nearly 3 attempts. However, for the cases where the BOP was never successful in shutting in the well, an average of less than two attempts was made. This leads to the question of whether the crew gave up too quickly, if the conditions were too hazardous to continue attempting to shut-in the well, or if there were only one or two practical alternatives for using the BOP. Answering these questions is beyond the scope of this thesis, but would be relevant for future work.

The wellbore and/or string flow path had a total of 57 incidents; these incidents used the BOP to shut-in 37% of the time, and other equipment 40% of the time. The annular flow path had 17 incidents; the BOP was used 41% of the time, and other equipment 47% of the time. The rock (underground) flow path had 4 incidents and 50% of the time the BOP was used and 50% of the time other equipment was used. The relevant question for this data would be if the shut-in caused an underground blowout, and unfortunately the data does not contain sufficient detail to draw any conclusions. It is also unknown if the flow path was known when the decision to shut-in the well was made, this would also have been useful information to have.

4.6.1.1 Implications for Deepwater

The trends seen in initial responses to blowouts in deepwater are somewhat different (see Table 4-14). Shut-in was attempted in only 9 of the 15 deepwater incidents. There were 7 successful shut-ins for a 77% success rate. This rate is greater than for shallow water operations where shut-in was attempted.

Table 4-14: Shut-in Attempts and Success Frequency (Deepwater Incidents)

Shut-in	Attempted	Rel. Freq.	Successful	Success Freq.
Attempts – BOP	8	53%	6	75%
Attempts – Other	1	7%	1	100%
Total Attempts	9	60%	7	78%
Not Attempted	0	0%		
Attempts Unknown	6	40%		

A possible reason for this difference is that a subsea BOP has more functionality and redundancy built into the design than a surface BOP. Another reason could be the higher frequency of incidents where it is unknown whether there was an attempt to shut-in.

Additionally, the wide varieties of incidents which have occurred in shallow water have not been seen yet in deepwater. It is uncertain whether the higher success rates in deepwater is significant and likely to continue or whether it is an anomaly.

4.6.2 Capture

Table 4-15 shows there were only four incidents where flow was captured. Three of these attempts to capture flow occurred after a hurricane damaged the platform. These incidents are typically low flow events, and a portion of the flow was captured using a small pollution dome. One incident was Macondo, where intermittent attempts were successful in capturing a portion of the significantly larger flow rates.

Table 4-15: Capture Attempts and Success Frequency (All Incidents)

Capture	Attempted	Rel. Freq.	Partial Capture Successful	Partial Capture Success Freq.
Captured Some or All of Flow	4	4%	4	100%
Not Attempted	71	79%		
Attempts Unknown	15	17%		

4.6.2.1 Implications for Deepwater

As shown in Table 4-16, the only deepwater incident where capture was used was Macondo. One incident is not adequate for defining future expectations, however the experience gained from Macondo and the solution for capturing high pressure, high flow rates is particularly relevant to this study. While the solution employed by BP was not 100% successful, the device was able to capture some of the flow and minimize pollution. Therefore, the capability to capture high pressure, high flow rates subsea is critically important for a subsea capping stack. While specific modifications to the device used by BP are not indicated by the data in this study, it is logical that to minimize pollution from future incidents modifications should be made to allow more of the flow to be captured.

Table 4-16: Capture Attempts and Success Frequency (Deepwater Incidents)

Capture	Attempted	Rel. Freq.	Partial Capture Successful	Partial Capture Success Freq.
Captured Some or All of Flow	1	7%	1	100%
Not Attempted	8	53%		
Attempts Unknown	6	40%		

4.6.3 Divert

Flow was diverted in 21 incidents with standard diverter systems (see Table 4-17). In eight additional events, flow was diverted with something other than a standard diverter system.

Table 4-17: Divert Attempts and Success Frequency (All Incidents)

Divert	Attempted	Rel. Freq.	Successful	Success Freq.
Shallow Water Incidents				
Attempts - Std. Diverter Sys.	17	23%	16	94%
Attempts – Other	7	9%	2	29%
Total Attempts	24	32%	18	75%
Not Attempted	42	56%		
Attempts Unknown	9	12%		
Deepwater Incidents				
Attempts - Std. Diverter Sys.	4	26%	3	75%
Attempts – Other	1	7%	1	100%
Total Attempts	5	33%	4	80%
Not Attempted	4	27%		
Attempts Unknown	6	40%		

These eight incidents applied non-standard methods during the incident, mostly in an effort to reduce the risk to the personnel attempting to control the well. In 15 incidents, it is unknown if flow was diverted (i.e. there was not enough detail from the incident description to determine what, if anything was used)

4.6.3.1 Implications for Deepwater

Five of the 15 (33%) deepwater incidents resulted in diverted flow successfully, whereas 24 (32%) of shallow water incidents resulted in successfully diverting flow. This frequency of diverting flow is similar to the shallow water events and may not represent a statistically significant difference. However, the inability to shut-in the well at the surface due to the subsea BOP and low pressure riser used with deepwater operations may present an increased risk to the personnel during deepwater operations, and the only option possible is to divert flow away from the rig or to evacuate the rig. Evacuation leaves the well blowing out with the rig completely unmanned and unmonitored. Therefore, diverting flow is typically preferable. This situation is likely to continue in deepwater drilling operations so a higher frequency of deepwater diverting events is likely to occur. The actual equipment that was used for diverting is less clear. There were four deepwater incidents where the standard diverting system was used, and one event where a non-standard diverter was used (diversion when the riser was inadvertently disconnected). Macondo was one incident where diverting was used and the results were an explosion, a fire and finally the loss of the rig. These were a result of equipment being unable to handle the gas flows. This indicates that diverting flow through the mud gas separator (as in Macondo) has the potential to cause problems that may lead to the loss of the rig. This is something that should be avoided at all costs.

4.6.4 Summary and Conclusions for Initial Response: Shut-in versus Capture versus Divert

Shut-ins were attempted in 63 incidents, whereas capture was attempted in only four, and diverting was attempted in 28 incidents. Therefore historically, shut-in was used to control flow, but it was not always successful. Diverting flow is the response that is used to reduce the risk to personnel and allow for subsequent well control efforts. However, it is generally ineffective in limiting pollution. Currently the goal of diverting flow is not to limit pollution, but to reduce the danger to personnel so they can get the flow of formation fluids stopped in a shorter period of time. The goal of shut-in is to stop the flow of formation fluids immediately. In deepwater operations however, due to restrictions as a result of subsea BOP's and low pressure drilling risers, shut-in at the surface is no longer an option. This therefore implies, the goal of diverting flow in deepwater could be expanded to include capturing flow. This would have the effect of reducing the risk to personnel as well as preventing pollution.

4.7 Vertical Intervention

Vertical intervention is any reentry into the well during a blowout or blowout response in an attempt to reestablish control of the well. These techniques have been used on land wells for a long time with success. Only eight of the 90 incidents used vertical intervention in an attempt to control the well (See Table 4-18). Four attempts were made to set a packer, barite pill, or cement plugs to establish a barrier (See Table 4-19). In one case, vertical intervention was stopped because the area was too hazardous to allow operations to continue and the well was ultimately controlled by relief well operations. Coil tubing units or snubbing units are often used in the offshore environment for workovers, and can also be used in well control efforts. Only three incidents in the past 15 years used either a coil tubing unit or snubbing unit for vertical intervention. Fourteen incidents do not contain sufficient detail to determine if vertical intervention was attempted. Sixty eight incidents did not use any type of vertical intervention as an attempt to control the well (see Table 4-18).

The most frequent flow path when vertical intervention was used was the wellbore flow path (see Table 4-20). This is reasonable since the wellbore path is the most frequent flow path overall.

Table 4-18: Vertical Intervention Attempts (All Incidents)

Vertical Intervention:	All Events	Rel Freq
Vertical Intervention – Yes	8	8.89%
Unknown vertical intervention	14	15.56%
No vertical intervention	68	75.56%

Table 4-19: Vertical Intervention Method and Success Frequency (All Incidents)

Vertical Intervention Method	All Incidents	Rel Freq	Successful (Primary or Secondary Barrier)?	Success Freq.	Comments
Spotted Pill	1	12.50%	1	100%	
Coil Tubing Unit	1	12.50%	1	100%	
Snubbing Unit	2	25.00%	2	100%	
Cement Plug	3	37.50%	3	100%	
Unknown VI Type	1	12.50%	0	0%	Relief Well Was Successful

Table 4-20: Vertical Intervention Method by Flow Path (All Incidents)

Vertical Intervention Method	Wellbore	String	Annulus	Rock	Comments
Spotted Pill	1	0	0	0	
Coil Tubing Unit	1	0	0	0	
Snubbing Unit	2	1	0	0	One had String and Wellbore Flow Paths
Cement Plug	0	1	2	1	One had Annulus and Rock Flow Paths
Unknown Method	0	0	1	0	

The annulus flow path is the next most frequent flow path and the least common was the rock/underground blowout flow path. It is of note that cement plugs were useful across the widest variety of flow paths.

The ability to conduct vertical intervention in the case of the incident with the rock flow path, i.e. underground blowout was particularly significant. It allowed a logical well informed response to an incident that could very easily have become worse than Macondo. The response included logging to determine where the subsurface flows were occurring and setting cement plugs to prevent those flows. When additional rock flow paths were discovered, additional logging was conducted, and an additional cement plug was placed to prevent any further flows. This incident prevented a major hydrocarbon release, drilling fluid was released to the seafloor but this incident should properly be classified as a "near miss" rather than a blowout. Nevertheless, it was a significant incident in that the actions of the crew were able to overcome the threat of a major release.

This information leads to the conclusion that while vertical intervention is not used very often it is something that should be considered as a necessary capability within a capping stack system. A vertical intervention capability that facilitates setting packers, cement plugs or running coil tubing clearly has potential applications, especially when the flow path is outside the wellbore.

4.7.1 Implications for Deepwater

Only one of the 15 deepwater incidents was addressed with vertical intervention (Table 4-21). A cement plug was set in that case to establish the secondary barrier. With only one incident, the implications that can be drawn for deepwater are limited.

One possible reason why the number of vertical intervention attempts is so low in this data set is because the incidents which used vertical intervention successfully were not incidents which resulted in any fluid spilled to the environment. Therefore, the conclusions about the use of vertical intervention from simply the use or lack of use of vertical intervention in this data set are limited. However, other analyses included in this chapter suggest that the need for vertical intervention is a capability that should be considered necessary for a subsea capping stack system.

Table 4-21: Vertical Intervention and Successes by Flow Path (Deepwater Incidents)

Vertical Intervention Method	All Incidents	Rel Freq	Successful (Primary or Secondary Barrier)?	Annulus	Rock	Comments
Cement Plug	1	13%	1	1	1	One had Annulus and Rock Flow Paths

4.8 Factors Affecting the Success or Failure of the Well Control Response

An examination of the factors affecting the success or failure of the well control response in these incidents was not as useful as originally expected. However, some factors were identified that influenced the severity of these incidents.

Macondo was the only incident that caused substantial environmental damage and was one of only two incidents with fatalities. There were four incidents which resulted in the loss of the rig. There were no multi-well incidents during this period. In five incidents, it was identified that other wells that might have become involved were successfully shut-in. The emergency shutdown procedure may have also been used to shut-in adjacent wells in other incidents, but this level of detail was not in the incident description. In any event, the ability to successfully shut-in adjacent wells has prevented at least one incident of multiple wells releasing hydrocarbons to the environment.

The following statistics are based on information provided to BSEE by the operators regarding the type of fluids released and any resulting fire and explosion on the rig or platform. The type of hydrocarbon released was also relevant, gas flow to the surface was common (40%) in the incidents involved in this study. Of these 36 incidents, seven of the incidents had a resulting fire, explosion, injury, fatality or loss of the rig. This results in a relative frequency of these types of incidents of 19%. Of the 54 incidents with oil flows, there were only three incidents with a resulting fire, explosion, injury, fatality or loss of the rig. The relative frequency of these types of incidents is 6%. Flows that are predominantly gas cause little pollution relative to an equivalent oil spill or blowout. This implies that while gas flows result in little or no pollution, the risk to personnel and equipment is higher.

Another important conclusion is that the use of storm packers and SCSSV's on offshore wells has had a major impact in preventing more severe spills and pollution as a result of hurricane events. Of the 95 incidents where a hurricane toppled rigs or platforms, only five incidents were included in this study because the other 90 did not release any formation fluids.

4.8.1 Implications for Deepwater

Gas in the riser of a deepwater floating rig creates a particularly dangerous situation relative to the presence of gas in a well with a surface wellhead and BOP. Three incidents in this study involved gas in the riser of a floating rig. In two instances, the gas was successfully circulated out of the riser without any damage to the riser or rig. Macondo, where gas in the riser was released at the surface and contributed to the initial fire and explosion was an extreme example of this danger. It is expected that the risk of having gas in a drilling riser will continue to be an especially dangerous hazard associated with current deepwater drilling techniques.

4.8.2 Summary

The primary factors contributing to the limited number of incidents with severe impacts were 1) most flows were oil and not gas which minimized the explosion and ignition risk, 2) there were no multi-well releases of hydrocarbons, apparently because of emergency shutdown of adjacent wells was effective, and 3) the requirement for SCSSV's in offshore producing wells prevented flow from a number of wells whose surface trees and wellheads were damaged or compromised.

The presence of gas in the drilling riser contributed to the loss of well control and to the severity of the Macondo incident. The risk of gas entering the drilling riser during a well control event is a concern in all floating drilling operations that is not an issue when using a surface wellhead and BOP because of the increased risk of gas being released on the rig. The drilling riser is not intended to contain a gas flow and generally cannot be closed at the surface to prevent a release of gas; the mud gas separator cannot handle large gas flows either. Although, a diverter system is available on floating rigs and is the only defense against gas flows on the rig, it is not designed to handle high rates and high pressures.

5 CONCLUSIONS AND RECOMMENDATIONS

The primary goal of this study was to develop an understanding of incidents reported to BSEE over the past 15 years to help define the capabilities which should be included in an effective, generally applicable, subsea capping stack system. The purpose of an effective capping stack system is to minimize the time needed to regain control of a blowout and minimize the volume of hydrocarbons released. This was accomplished by focusing the analysis of the data on nine topics: operation in progress, flow path, release points, possible attachment points, barriers used to stop formation flow, vertical intervention, and factors which increased or reduced the severity of the pollution and reduced the time to stop the flow of formation fluids. Additionally, analysis was conducted to determine how the incidents would have been different had they occurred in deepwater. A total of nine individual tasks were completed to meet these objectives.

An additional goal was to provide a comprehensive, searchable compilation of data on offshore blowouts for use in future research to improve the understanding of, responses to, and prevention of deepwater blowouts and spills.

What follows is a description of the most critical findings of this study and how these findings meet the goals and objectives of this study.

There is a limitation to these findings. The total number of incidents in deepwater was 15 of which 10 involved subsea operations. The use of subsea BOPs, and wellheads are limited to these types of operations. Since the number of incidents is so small relative to the total number of incidents, all findings relating to these types of incidents should be considered preliminary and will need to be re-evaluated as additional incidents occur.

Additionally, some findings of this study do not relate specifically to the objectives or goals but were significant and important, these are included as well. Finally, any findings which resulted in a need for future research were identified and described.

5.1 Type of Incidents in Deepwater and Resulting Response Capabilities

5.1.1.1 Operation in Progress

Drilling, completion, and workover operations were the most frequent the operation in progress when an incident occurred (66%). However, incidents occurred during all phases of the life of a well. The trends for deepwater were very similar to the trends in shallow water. Therefore, deepwater incidents can occur at any point in the life of a well. The capping stack system should be capable of responding to incidents during all phases of operation in the life of a well.

5.1.2 Flow Paths

The wellbore and string are the most common (66%) flow paths for spills and blowouts. However, the annulus (19%) and rock flow (4%) paths result in additional complications for achieving an effective response. Also, rock flow paths are likely to be underreported because any underground blowouts which did not result in a release of fluids would not be included in this data set. The ability to regain control of any incident involving an annulus or rock flow path would require either a relief well or vertical intervention in order to regain control of the well.

5.1.3 Release Points

The frequency of subsea release points increases dramatically in deepwater incidents. The ratio of subsea to surface releases in shallow water is 5% : 88% while in deepwater this ratio is 40% : 40%. An increase in subsea releases results in an increased need for deepwater subsea response capabilities. Subsea releases in deepwater will likely be high flow rate and high pressure. Therefore, any effective subsea capping stack should have the capability to capture subsea flows from all subsea equipment which would minimize pollution while other well control operations are ongoing. This could be similar to the one used at Macondo.

Release points from vents at the seafloor are rock flow paths and as such would require either vertical intervention or a relief well to regain control.

5.1.4 Attachment Points

The attachment point task resulted in several findings of relevance. In deepwater the attachment points are typically (47%) the subsea equipment (LMRP, BOP, subsea wellhead or tree). However 27% of the attachment points are below the seafloor. These types of incidents would typically require a relief well or vertical intervention. However, to limit pollution a capture or containment capability would be needed while the relief well is being drilled. Or, vertical intervention could be used to regain control of the well more quickly which would limit the amount of pollution and reduce the time needed to regain control as compared to a relief well.

The attachment points for deepwater operations are restricted to subsea equipment due to the low pressure drilling riser.

5.1.5 Methods to Stop or Control Flow

The most frequent primary barriers were mechanical (75%) in deepwater. The most common barrier for drilling operations in deepwater was the subsea BOP, a device designed for well control operations. This implies the need to duplicate the functions of the BOP, in a standalone piece of equipment.

Barriers sometimes had to be placed within the wellbore (12%). Eighty-eight percent of the time the secondary barrier was placed in the well. Therefore, the capability for vertical intervention for these types of incidents would be required.

Additionally, it was concluded that any equipment which duplicates the subsea BOP capability should be able to be controlled from the surface. While this is not directly supported by any one finding, several findings support this conclusion, including duplicating the functionality of the BOP, the fact that the BOP and other production well control equipment was often used to establish a primary barrier. While not supported by the findings, common sense would dictate that if the installation of a capping stack system removes well control functionality during a crisis situation that system is unlikely to be used.

5.1.6 Shut-In

In deepwater shut-in was attempted at least 60% of the time and potentially, 100% of the time if the unknown incidents did in fact attempt shut-in. Also, the success rate for shut-in was 89%. This suggests that shut-in is an important response capability.

5.1.7 Capture

Capture of formation fluids was used in deepwater in an attempt to mitigate pollution damage while other operations were ongoing to permanently stop the flow of formation fluids. This implies that this capability is required for future deepwater operations. Additionally, several task findings support the capability for capture and containment capability. Some incidents in the past 15 years would have required a relief well to be drilled as the only practical solution had these incidents occurred in deepwater. Therefore, in order to mitigate the pollution from these types of incidents, capture and containment would be required. Finally, in a small but significant percentage of past incidents the only possible attachment point was below the seafloor. It would take time to implement this type of solution therefore mitigating pollution while those operations are ongoing would be a critical capability.

5.1.8 Vertical Intervention

While vertical intervention was used less than 10% of these incidents the success rate is nearly 90%. Although the use has been minimal in the past, several types of incidents which occurred in shallow water would require vertical intervention had they occurred in deepwater, and justify the inclusion of vertical intervention capability in future responses. These include annulus and rock flow paths, subsea releases, or attachment points below the sea floor. Therefore vertical intervention is considered an important capability for an effective subsea capping stack.

5.2 Types of Incidents in Shallow Water and Resulting Response Capabilities

For shallow water incidents, the findings support several general conclusions which are not specifically related to the capabilities of a subsea capping stack. In 80% of the incidents the release point was at the surface. Shallow incidents used well control equipment to successfully stop the flow of formation fluids in 70% of the incidents. In shallow water the primary barrier to flow was placed at the surface most often, possibly because this is the easiest place to install the barrier. The rig was used in 97% of the incidents to place the primary barrier. The only incident where it wasn’t used a relief well was used to regain control.

5.3 Useful Capabilities for a Subsea Capping Stack

A generally applicable subsea capping stack system should include the following operational requirements for effectively responding to deepwater Gulf of Mexico incidents:

1. Ability to respond to incidents at any time in the life of a well.
2. Ability to shut-in the well
3. Ability to attach to subsea equipment
4. Ability to mitigate pollution by capturing or containing the flow of formation fluids while

other operations are ongoing to stop the flow.

5. Ability to install barriers in the wellbore (i.e. vertical intervention).
6. Ability to maintain control of subsea equipment during application.

5.4 Additional Observations and Conclusions

There were several conclusions which resulted from the analysis of the data that are important, but not directly related to an effective capping stack system.

1. The combination of storm packers and/or surface controlled subsurface safety valves prevented unintended formation flows after a hurricane over 90% of the time.
2. Although not directly supported by the data, the implication from the incidents in this study is that the greatest opportunity for regaining control after a blowout exists when the integrity of the rig or platform remains intact.
3. Well bridging should not be considered a likely barrier in future deepwater incidents.
4. Deepwater well control operations are more complex than shallow water operations, resulting in increased time needed to control blowouts.
5. Low flow, low pressure incidents have used pollution domes to successfully mitigate pollution damage.
6. Most often shallow water incidents had release points at the surface.
7. Most often shallow water incidents placed the primary barrier at the rig or platform.
8. Gas in the riser which is a hazard specific to deepwater was identified.
9. Gas flows increase the risk of fire, explosion, injury, fatalities, and loss of the rig.
10. Knowledgeable personnel on site during incidents were able to significantly reduce the severity of two incidents in the past 15 years.
11. In the 90 incidents included in this study, only two resulted in fatalities.

5.5 Creation of a Searchable, Sortable Spreadsheet

The secondary goal of this study was to create a spreadsheet which is searchable and sortable. Significant time was spent determining how best to structure the spreadsheet so that future studies could be conducted using the same data. The power and flexibility of the coding for the incident description captures a large amount of information that is searchable and can be sorted. The correlations between multiple task groupings (i.e. flow path by operation by attachment point) demonstrated the successful use of the spreadsheet to answer questions relating to multiple critical factors. It is expected and intended that this basic spreadsheet will be the basis for future studies on well control incidents in the Gulf of Mexico. Therefore, the goal of creating a searchable and sortable spreadsheet of incidents in the Gulf of Mexico during the past 15 years has been accomplished.

5.6 Recommendations for Future Work

1. A study, using the spreadsheet created from this study, should be conducted to determine if there is a sequence of events which leads to successful well control operations.
2. An examination of diverter system design should be conducted to determine if they can be modified to handle higher pressures and flow rates for longer periods of time to allow safe well control operations on deepwater floating rigs.
3. A feasibility study should be conducted to determine if the capability for subsea diversion should be incorporated into subsea BOP equipment for normal drilling operations.
4. A detailed examination of the bridging phenomenon to determine if it will ever occur in deepwater should be conducted.
5. In deepwater drilling operations the low pressure riser limits options for well control. An engineering study examining potential ways to overcome these limits should be

conducted.

6. A study should be completed to determine how best to control subsea equipment including the subsea capping stack system from the surface in the event the rig is lost, structurally damaged, or inaccessible due to fire or other hazards.
7. The capabilities needed to respond to blowouts from multiple wells at a single location simultaneously, especially in deepwater, should be explored.

5.7 Final Thoughts

A generally applicable effective subsea capping stack system needs to incorporate the following capabilities; control of intact subsea equipment, vertical intervention, and additional capture and containment equipment. The system should be designed to handle blowouts during the entire life cycle of a well. Although deepwater blowouts are going to continue, the response capabilities of the industry will be improved with the addition of a generally applicable subsea capping stack system.

Other important findings were that SCSSV's have been extremely successful at preventing blowouts after hurricanes, the loss of a rig or platform severely limits well control options, well bridging has not yet occurred in deepwater, and finally, deepwater wells result in more complex well control operations.

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APPENDIX 1: CAPPING STACK INCIDENT SPREADSHEET.XLSX

https://docs.google.com/open?id=0B-OlnbEWpjJkZmQyYWlqbGNUaHlLZWZr

ZFZZMFFLQQ

APPENDIX 2: URL'S OF BSEE SOURCE DATA

http://www.boemre.gov/incidents/spills1996-2011.htm

http://www.boemre.gov/incidents/Incidents1996-2005.htm

http://www.boemre.gov/incidents/Excel/SpillsbblCY1970to2010.xls

http://www.boemre.gov/incidents/SigPoll96.htm

http://www.boemre.gov/incidents/SigPoll97.htm

http://www.boemre.gov/incidents/SigPoll98.htm

http://www.boemre.gov/incidents/SigPoll99.htm

http://www.boemre.gov/incidents/SigPoll00.htm

http://www.boemre.gov/incidents/SigPoll01.htm

http://www.boemre.gov/incidents/SigPoll2002.htm

http://www.boemre.gov/incidents/SigPoll2003.htm

http://www.boemre.gov/incidents/SigPoll2004.htm

http://www.boemre.gov/incidents/SigPoll2005.htm

http://www.boemre.gov/incidents/SigPoll2006.htm

http://www.boemre.gov/incidents/SigPoll2007.htm

http://www.boemre.gov/incidents/SigPoll2008.htm

http://www.boemre.gov/incidents/SigPoll2009.htm

http://www.boemre.gov/incidents/SigPoll2010.htm

http://www.boemre.gov/incidents/blow96.htm

http://www.boemre.gov/incidents/blow97.htm

http://www.boemre.gov/incidents/blow98.htm

http://www.boemre.gov/incidents/blow99.htm

http://www.boemre.gov/incidents/blow2000.htm

http://www.boemre.gov/incidents/blow2001.htm

http://www.boemre.gov/incidents/blow2002.htm

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http://www.boemre.gov/incidents/blow2004.htm

http://www.boemre.gov/incidents/blow2005.htm

http://www.boemre.gov/incidents/blow2006.htm

http://www.boemre.gov/incidents/blowouts.htm

http://www.boemre.gov/incidents/other.htm

http://www.boemre.gov/incidents/collisions.htm

http://www.boemre.gov/incidents/fatalities.htm

http://www.boemre.gov/incidents/firesexplosion.htm

http://www.boemre.gov/incidents/injuries.htm

http://www.boemre.gov/incidents/HurricanesGustavIke2008GOM.htm

http://www.boemre.gov/incidents/SigPoll2005HurricaneKatrina.htm

http://www.boemre.gov/incidents/SigPoll2005HurricaneRita.htm

http://www.boemre.gov/incidents/SigPoll2004HurricaneIvan.htm

http://www.gomr.boemre.gov/homepg/offshore/safety/acc_repo/districtreports.html

http://www.gomr.boemre.gov/homepg/offshore/safety/acc_repo/accindex.html

APPENDIX 3: LIST OF INCIDENT DESCRIPTION CODES

Location along flow path (Drilling):

1) Well
1a) Drill pipe/work string/tubing
1b) Cased Annulus (no cement)
1c) Cased Annulus (through cement)
1d) Inside structural casing/drive pipe
1e) Outside the well
1f) Inside Casing
1g) Open Hole
2) Wellhead housing
3) BOP
3a) Main Bore
3b) Choke/Kill/Booster Lines
3c) Control Pods
3d) Other
4) Lower Marine Riser Package
5) Drilling Riser
6) Surface Drilling Equipment
6CS - Surface Capping Stack
6 BOP) Surface BOP/ Stripper rubber(coil tubing)
6 W) Surface Wellhead
6 D) Diverter
6 M) Mud pits
6 MP) Mud pump
6 DRK) Surface Derrick
7) Ocean/ Atmosphere

Location along flow path (Production):

1) Well
1a) Tubing
1b) Cased Annulus
1c) Inside structural casing/drive pipe
1d) Outside the well
1e) SCSSV control lines
1f) P&A Cement Plug
2) Wellhead housing
3) Tubing Hanger Spool
4) Tree
4a) Production Path (Tubing)
4b) Annulus Path (Monitor/Injection)
4c) Control Lines
4d) Other
5) Jumper
6) Subsea Manifold
7) Flowline
8) Production Riser
9) Production Equipment
9 W) Surface Wellhead
9 XT) Surface Tree
9a) Production Pipeline
10) Controls/Pod
11) Umbilical
12) Ocean/ Atmosphere

Type of Barrier

M - Mechanical
H - Hydrostatic
D - Flow Diverted
R - Removal of inoperable/non functioning equipment
I - Installation of equipment

Equipment Used

BELL - Bell nipple
BF - Blind Flange
BM - Bridging material
BOP - Blow Out Preventer
BOPA - Annular
BOPB - Blind rams
BOPCK - Choke and kill lines
BOPHCR - HCR Valve
BOPHL - Hydraulic lines
BOPP - Pipe rams
BOPS - Shear rams
CHK - Choke Manifold
CONN - Connector
CONT - Containment system
CP - Cement pumping Unit
CS - Capping stack
CSG - Ran casing

CSW - Casing Swedge
CTU - Coil Tubing Unit
DIV - Std rig diverter system
DR - Drilling Rig
EDS - Emergency Disconnect System
FRZ - Freeze plug
GASB - Gas buster
GASL - Gas lift line
GAUG - Pressure Gauge
HNDL - Casing Head Valve Handle
HNGR - Casing Hanger
HYDR - Hydraulic lines
LMRP - Lower Marine Riser Pkg
NAT - Natural Causes
NPL - Nipple
PIPE - Tubing/workstring/drillpipe
PKR - Packer
POLL - Pollution dome
PU - Pumping Unit
RMVL - Removal of inoperable equipment
SEAL - Clamp and Packing
SNU - Snubbing Unit
SSSV - Subsurface Safety Valve
SSV - Surface Safety Valve
TD - Top Drive/Kelly
TIW- TIW Valve
VLV - Valve (eg. BPV, MV, WV, CV, gate valve)
VT - Venturi Tube
WELL - Wellhead
WIRE - Wireline tools
XTRE - Christmas Tree

How barrier was placed/installed/created?

BULLF - Bullheaded Fluid
BULLP - Bullhead Pill
CV - Closed Valve
INST - Installed equipment
MCV - Manually closed valve
OBS - Insert obstruction into flow
OV - Opened Valve
P&A - Plug & Abandon
PCMP - Pumped completion fluid
PHM - Pumped Heavy Mud
PILL - Lost circulation material spotted
PLACD - Placed over leak source
POF - Placed over flow (no seal)
PSW - Pumped Sea water
RECMT-Remedial Cementing
RV - Valve replaced/repaired
RW - Relief Well
SLCSG-Seal Casing (as with a packer)
SP - Set Plug

STAB - Stab open valve then close
UBLOW - Underground Blowout
WB - Well Bridged
WIN - Water Influx
BM - Bridging Material

Was barrier established

Y - Yes
N – No
SLW - Slowed flow

If no, why?

AB - Abandoned
ATD - Attempt to divert flow
FLOW - Flow through barrier (flow cut)
FTC – Unable to close
LEAK - Leak around barrier
OBS - Barrier failed to close due to obstruction
UTA - Unable to install barrier

VITA

Louise Smith was born in Carmel, California. She completed her high school education at Carmel High School and then went on to obtain her bachelor's degree from California State University, Chico, in 2000 with a degree in mechatronic engineering. After graduation she returned to work in the insurance industry as a loss prevention engineer/consulting engineer for a "highly protected risk" commercial insurance company. During her tenure in this position she was consulted on a number of challenging facilities including work at a solid rocket fuel plant, an industrial lighting manufacturer and several semiconductor fabrication facilities. These facilities exposed her to risk management, risk assessment, and standards enforcement. This work was followed by additional positions which expanded her knowledge of risk assessment and risk mitigation. After 10 years in this field, in 2010, she returned to academia at the Craft and Hawkins Department of Petroleum Engineering at Louisiana State University. She will receive a Master of Science in Petroleum Engineering in the spring of 2012.