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FINAL REPORT

JOINT INDUSTRY PROGRAM for FLOATING VESSEL BLOWOUT CONTROL

DEA-63

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28 December, 1991

Mr. Charles E. Smith
Minerals Management Service
MS 647
381 Elden Street
Herndon, VA 22070-4817

Dear Mr. Smith:

Please find enclosed the final report for DEA-63, Joint Industry Program for Floating Vessel Blowout Control. The comments from the draft report have been integrated into the final report.

The staff working on this project thanks each member of the joint industry participants for their patience and support during this project. The invasion of Kuwait and its resultant fires that involved Neal Adams Firefighters were never envisioned when DEA-63 was initiated.

We are proud of the final results contained in the report. We hope that your company can make valuable use of its contents.

Contact us at your convenience if you have questions or need further assistance.

Kindest regards,

Neal Adams

Neal Adams

NA/dl

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1.0 EXECUTIVE SUMMARY

This report of the Joint Industry Program For Floating Vessel Blowout Control contains results of work on the following areas:

- Kill technique selection
- Relief well drilling technology
- Blowout equipment and services
- Innovative pollution techniques
- Vertical intervention

The final section contains recommendations for further work.

Criteria are given for selecting the most appropriate kill technique on a blowout. Available kill procedures are discussed. Considerations for simultaneous implementation of several techniques are presented.

Relief well drilling guidelines cover key areas required for killing a blowout with a relief well. Floating drilling is emphasized but the discussions are generally applicable to all relief wells.

A catalog of most currently available equipment and services for blowout control has been compiled. A telephone and contact directory is presented. The evolving nature of blowout equipment and services is currently heavily influenced by blowout work in Kuwait. This report contains some new developments but does not include all related matters.

Innovative pollution techniques are presented after currently available control methods are reviewed. Work at the subsea source is emphasized. Concepts for injection of chemicals and bacteria are presented. Subsea containment devices may be successful but have significant technical difficulties to resolve.

Vertical intervention is unique to floating well control. Stinging into a subsea blowout offers a quick and effective solution when operationally possible. Modified LMRPs have flexibility but require more planning and effort.

The approach angle model, APRANGLE, is available on diskette. Source code is included. It addresses key factors involved in a relief well approach to a blowout. Collision probabilities are included in the model.

Recommendations are presented for development of equipment and procedures for injecting dispersants, polymers and bacteria "soups" into a subsea blowout plume. It is further recommended that this report be updated in one to two years to incorporate rapidly developing blowout control technology resulting from current work in Kuwait, some of which may be applicable to floating vessel drilling.

2.0 PROGRAM OVERVIEW

2.1 INTRODUCTION

The Joint Industry Program for Floating Vessel Blowout Control-Phase I was sponsored by the Drilling Engineering Association and assigned the number of DEA-63.

2.2 GENERAL WORK DIRECTIVES

General work directives were specified in Section 2.2 of the proposal given to Participants. The directives were as follows:

Phase I has definite work directives for deepwater blowout control. The general goal is to address problems or operational requirements that an operator will face if a deepwater blowout should occur. The study will address areas for which no practical solutions currently exist. These areas must be considered when a real situation develops.

The study will avoid in-depth or unnecessary reviews of old technology and concepts previously developed (e.g., "Sombreros" for pollution containment, etc.).

The tasks in the program will address the following directives:

- Evaluate the special requirements and prepare preliminary system specifications for relief well drilling from a floating vessel. Subtasks include conceptual riser and piping designs for high volume pumping.

- Development of vertical intervention and capping techniques for deepwater blowouts. Shallow gas blowouts will be addressed also. Procedures for handling oil or gas blowouts will be developed.

- Evaluation of potential pollution scenarios and investigate new pollution control techniques for a deepwater blowout.

- Document the results with texts, charts, tables and figures.

2.3 SCHEDULE

The program was scheduled as a 10 month project but was extended due to disruptions in the blowout industry caused by the Kuwait invasion.

Key meeting dates were as follows:

<u>Kickoff Meeting</u>

11 May, 1990	Houston, Texas
5 June, 1990	Stavanger, Norway

<u>Progress Meetings</u>

27 September, 1990	Houston, Texas
2 October, 1990	Aberdeen, Scotland

10 May, 1991 Houston, Texas
16 May, 1991 Stavanger, Norway

Final Meeting

10 October, 1991 Dallas, Texas

The draft report was mailed to the participants in September, 1991 for their review. Sections 3, 4 and 5 were delivered in earlier meetings for the participant's review and comments. The comments were taken into consideration when preparing the draft document issued in September.

The final report was issued following the final meeting held in Dallas. Participant's comments were considered prior to preparing the final document.

2.4 LIST OF PARTICIPANTS

DEA-63 had 17 participating companies and agencies. They are as follows:

1. Amoco Production Company
2. BHP, Ltd
3. Canadian Oil and Gas Lands Administration
4. Elf Aquitaine
5. Exxon Production Research
6. Gulf Canada
7. Japan Drilling Company/JNOC
8. Lagoven
9. Mobil Norway
10. Norwegian Petroleum Directorate
11. Petro-Canada
12. Phillips
13. Shell/SIPM
14. Texaco
15. TOTAL
16. U.K. Department of Energy
17. U.S. Minerals Management Service

2.5 PROGRAM COMMENTS

Several comments are in order relative to the conduct of the program or philosophies used in the project.

2.5.1 Schedule extension. The project was scheduled for 10 months with an optional extension to 12 months if blowout situations caused work delays. The optional 12 month extension was exercised. A further extension was required due to activities associated with the Kuwait invasion. The final project meeting originally scheduled for May, 1991 was delayed until October, 1991.

2.5.2 Coverage of land blowout topics. DEA-63 was defined as covering certain topics relating to blowouts requiring floaters for remedial control efforts. For the most part, the work was constrained to this topic. In some cases, the scope was enlarged slightly to cover issues associated with land blowouts. The enlargement was made as a benefit to the participants and was generally restricted to situations where a few words or phrases could adequately cover the scope enlargement.

2.5.3 Removal of document references to the investigating team. Experiences and opinions of the investigating team were used throughout the report. These items were originally referenced to the name of the investigating team. Some reviewers identified this procedure as advertising. To avoid this situation, references to the investigating team have been deleted in most cases.

2.5.4 Example problems. Some reviewers suggested that example problems used within the text should be expanded while other reviewers suggested they be reduced or deleted. Due to the variance in reviewer's comments and the belief by the investigating team that example problems can be valuable, they were left unchanged in the text.

2.5.5 Numbering scheme for figures and tables. The numbering scheme for figures and tables used throughout the text was to reference the item to the section and subsection in which it was located. As an example, Figure 4.5.1 is the first figure in Section 4, Subsection 5.

2.5.6 Equations. Equations on various topics have been given throughout the text. A comment has been made by a reviewer that certain equations were unnecessary for a document of this type. This comment is believed to have validity in some cases; although the equations were left in the text for the sake of thoroughness.

2.5.7 Scope enlargement. The work scope was structured for expansion if certain numbers of participants were exceeded. Two expansion targets were exceeded so the work scope was expanded to include: (a) a Blowout Equipment and Services Catalog (Section 5), and (b) an approach angle computer model for relief wells (Section 8).

3.0 KILL TECHNIQUE SELECTION

3.1 INTRODUCTION

It is a fairly obvious observation that a blowout should be controlled with the optimum approach. However, history of blowout control efforts shows that optimum approaches are not always used. In some cases, inappropriate techniques have been used that result in loss of the well or platform, or cost huge sums of money without yielding success. As a result, some operators are now taking control of the decision making process away from firefighters and blowout specialists. Unfortunately, this seems the most appropriate action in many situations.

What factors constitute an "optimum approach" for kill technique selection? Some include the following:

- Probability that the technique will work under the blowout conditions.
- Time, cost and logistical requirements for the technique.
- Terminal nature of the technique.
- Safety of personnel.
- Comparison to other techniques.

These factors warrant discussions.

3.1.1 Success probability. An important question relates to the probability that the proposed technique will be successful under reasonable conditions. It is important that a strong differentiation be made between "probability of success under reasonable conditions versus technical possibility".

As an example, fishing out 15,000 ft of wireline in heavy muds inside 5" drill pipe is technically possible. It can be accomplished under the conditions of unlimited time and money. However, the important question concerns the probability of success under reasonable conditions. If it is not reasonable to assume that the wireline can be fished in less time than some other option, the fishing option should be considered as a less attractive approach.

Kill options should be evaluated technically. A "hunch" or a "feel" should not suffice to invest time and money into a kill effort. Usually, the "gut instinct" must be combined with a technical approach. Using "hunches" to determine the best method to kill a well has lost many platforms in subsea craters because the famous firefighter's "hunch" didn't work. Usually it violated basic drilling principles.

One suggestion involves using the "decision tree" approach to determine the best kill option. This could result in a kill procedure that takes into account most variables. Advance pre-planning is necessary for this approach. Unanticipated conditions and circumstances at the site must be considered in the decision tree process.

3.1.2 Time, Cost and Logistical Requirements. For each possible kill technique, an evaluation must be made for time to complete the kill, cost and logistical requirements. The time aspect relates to the point at which the well is safely killed or controlled.

Logistical requirements can be extensive in some situations. Remote locations can pose transportation problems. Movement of explosives can cause significant "red-tape".

If only one kill option exists for a blowout, the time and cost evaluation has little significance.

Cost is an important topic that should be discussed. The typical approach to cost considerations for most drilling wells is to get "best value for the money". In dealing with most aspects of blowout control, the recommended approach is to prioritize the best service available and then compare costs if the services are nearly equal. Real savings do not mean accepting the lowest bidder, but rather using the best service available that can safely do the required task effectively and efficiently.

3.1.3 Terminal Nature of the Technique. A proposed kill approach must be evaluated to determine if it could eliminate other options if unsuccessful (i.e., if it does not work, it terminates other options).

An example can illustrate the point. Suppose that a well is blowing out from 10,000 ft in which only 2,000 ft of surface casing is set. One kill option is to cap the well, close the BOPs, and bullhead into the well. If the formation fractures at 2,000 ft, will the well crater and eliminate other capping options? Is it a more prudent decision to take a more time consuming approach and cap the well, divert it through a flare line, and snub into the well.

If the casing is set to 7,500 ft in this example, the decisions become much easier.

3.1.4 Safety of Personnel. Without understating the issue, personnel safety must always be the high priority concern. During the final stages of an intense kill operation, it is easy to become "tunnel-visioned" on the well control objectives and lose sight of the personnel safety matters. The well control specialist must always maintain the safety issue in the forefront of his operations.

Firefighters and blowout specialists are often involved in operations containing some risks. They are supposed to know how to handle these risks. However, other personnel involved with the killing operations often want to provide assistance, sometimes in a very eager manner. They usually do not understand the risks and related safety procedures. They can expose themselves to the danger of an accident. It is incumbent on the well control leader to be cognizant of this potential problem area.

Some kill methods are more hazardous than others. Personnel approaching a non-burning sour gas blowout are at significantly more risk than drilling an offshore relief well for a deep intersect in 500' of water. Fire presents a different set of problems. The safest kill technique is bridging since the blowout is contained downhole. If bridging occurs near the surface, however, broaching around the surface casing can occur resulting in a crater.

Safety to personnel off location should also be considered. High volumes of sour gas, accumulations of combustible hydrocarbons and large fires can pose a hazard to people working and living near the blowout. Panic and flight from the area during evacuation can also result in injury. Selection of a "quick" kill technique may be warranted in such a situation even though it may have a lower probability of success than another techniques. This, of course, presumes that personnel directly involved in the kill are adequately protected.

3.1.5 Comparison of Other Techniques. Consideration must be given to all kill options prior to making a final decision on one approach. Recent situations have occurred in which one approach was followed against recommendations of other groups for alternative approaches that had significantly more technical merit and a definite safety advantage. The alternative approaches were not given due consideration. Ultimately the initial approach resulted in failure and tremendous financial losses. The alternative solutions were finally used efficiently and effectively but only after major efforts were expended on a "brute force" initial approach. In summary, all options should be evaluated on an equal basis and then make a decision for a kill technique.

The operator must participate in these evaluations. They should be the experts with respect to drilling and reservoir conditions for the blowing well. Without their input, an inappropriate or less-than-optimum technique could be used. A "decision tree", prepared by the blowout specialists and/or other team members, is suggested to allow the operator the conduct an informed comparison of the various kill techniques.

3.2 DESCRIPTION OF AVAILABLE TECHNIQUES.

A variety of blowout kill techniques are available. Some are applicable only in certain situations while others are more universally applicable. An example is capping and snubbing into a land well. This technique does not have easy applicability on underwater offshore blowouts. Relief wells can be used almost universally.

Kill techniques can be separated in two broad categories:

- Top kill techniques involve surface control methods such as well capping and subsequent bullheading or lubrication of mud.
- Bottom kills require that mud be circulated from the bottom to the top of the well.

Some require a combination of surface control and a bottom kill. An example is capping and diverting a well followed by snubbing pipe for a bottom kill.

Common kill techniques are as follows:

- bridging
- capping/shut-in
- capping/diverting

- surface stinger
- vertical intervention
- offset kill
- relief wells

Each of these is briefly described in the following subsections.

3.2.1 Bridging. Many blowouts have been killed by well bridging. The formation around the wellbore collapses and seals the flow path. (Figure 3.2.1)

Bridging typically occurs within 24 hrs after the well blows out. This observation is confirmed by a computerized database of almost 1000 blowouts. If the well does not bridge within 24 hrs, it is likely to blow for an extended time or until it is killed. Bridging does occur however, on wells after the 24 hr period in some situations. Technical reasons exist for the 24 hr bridging phenomenon. These involve near-wellbore pressure drawdown, erosion of well-head and BOP components and formation integrity under open flow conditions.

Bridging is typically considered a passive technique. The term "passive" means that it is subject to formation properties and generally is not influenced by kill attempts. In simple terms, the well bridges or it does not bridge, but no one has much control over it.

However, techniques are available for active bridging. Some firefighters and blowout specialists can implement techniques to accelerate the bridging. An active bridging technique involves opening the BOP/diverter stack or removing damaged, leaking wellhead component(s) to allow accelerated entry of reservoir fluids resulting in high annulus velocities and subsequent bridging.

Factors generally found in bridging situations include:

- Shallow casing strings
- Formation instability under drawdown situations
- Gas blowout fluids
- High flow rates
- Land or shallow water depths

Also, saltwater flows in deeper wells can cause the formation to become unstable and bridge after some time has elapsed.

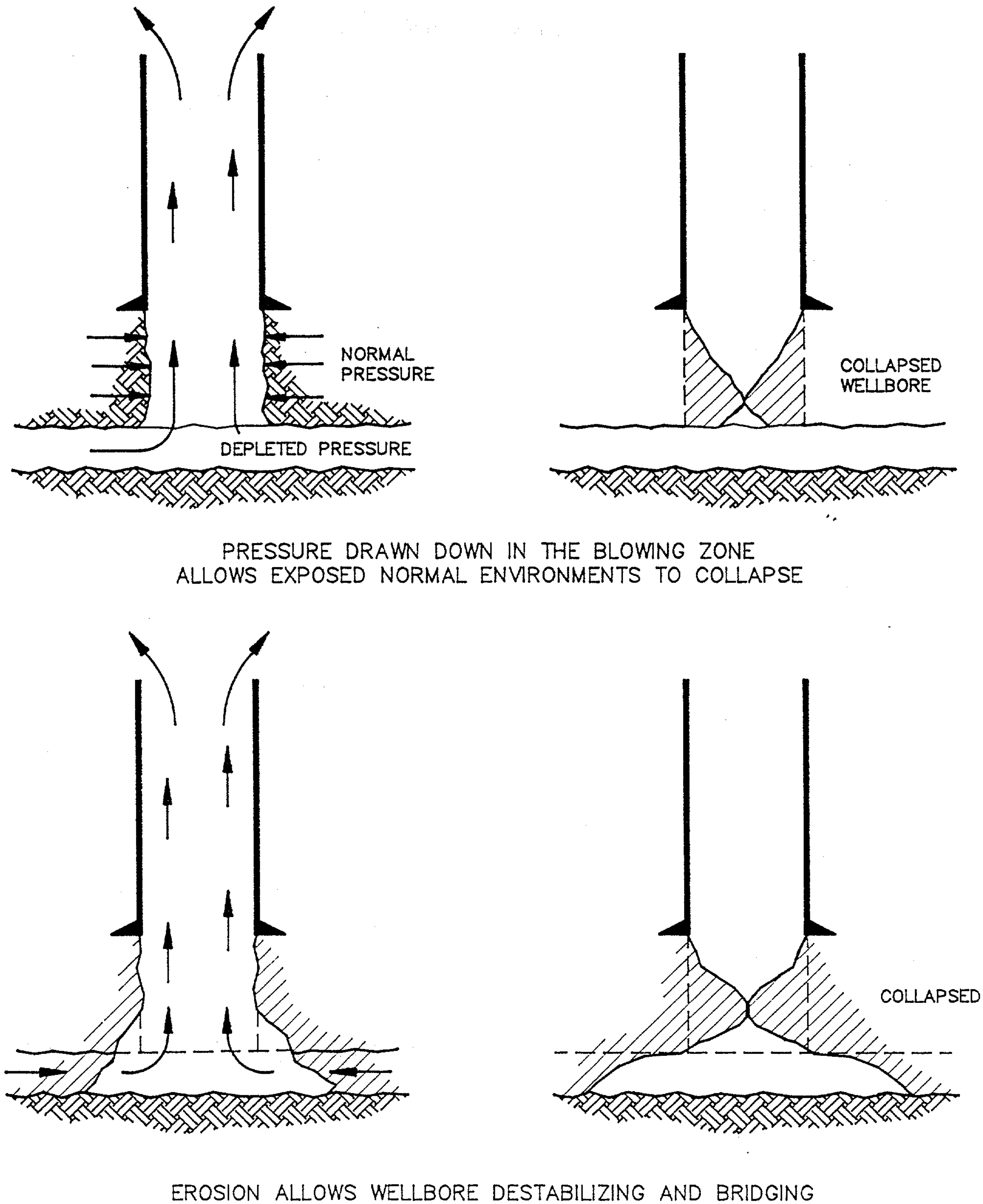

Figure 3.2.1

Wellbore Bridging

3.2.2 Capping/Shut-in. Capping means, in simple terms, to put a cap on a blowing well. (Figure 3.2.2) Typically, this involves clearing debris, removing the old BOP stack and wellhead, installing a new wellhead and stack, then closing the BOPs.

If the well is shut in, access to a competent casing string is required. The casing string must have integrity and must be sufficiently deep to have a fracture gradient that will withstand shut in conditions. Reservoir drawdown pressures should be evaluated and compared with the fracture gradient at the casing seat before the decision is made to shut in the well.

Considerations for capping and shutting in blowout include the following:

- Access to a casing string with the necessary pressure rating.
- Fracture gradients sufficient to withstand shut in pressures. Initial or drawndown pressures must be considered.
- Sufficient blowout flow rates for the fluids to extend some distance above the top of the casing or BOPs.
- If H_2S is present, the well must be capped on fire. All equipment must be H_2S serviceable.

Typically a casing string is set deep to achieve the desired fracture gradient.

Several kill methods are commonly used for a capped well. Bullheading is probably most common. However, it requires initial fracture pressures to break down the formation. Historically, many firefighters have bullheaded with 18.0 lb/gal mud or some mud weights sufficiently in excess of the level required to control the well. Many operators are currently changing this practice and using engineering principles to determine mud weights needed to control the well.

Bullheading can also be performed below a packer stung into the blowing well. This has the advantage of isolating an eroded or damaged BOP/wellhead component and any casing near the mouth of the blowout that lacks structural integrity.

Bullheading applies considerable stress to the wellbore. Pressure from the formation is trapped inside the wellbore by the slug of descending kill fluid. This pressure can compromise casing shoes, break down exposed formations in the open hole by exceeding their parting pressure and burst casing. This increases the possibility of the blowout being altered to a downhole blowout with a different set of consequences.

Another kill method for a shut in well is to lubricate mud into the well. The procedure is effective with gas wells but does not work with oil or saltwater wells. It is a time consuming task but it generally applies less wellbore stress than bullheading.

Pipe can be run into the well with a snubbing unit. Mud can be circulated from the bottom in a common kick circulation technique. Depending on the mud weight selected, the

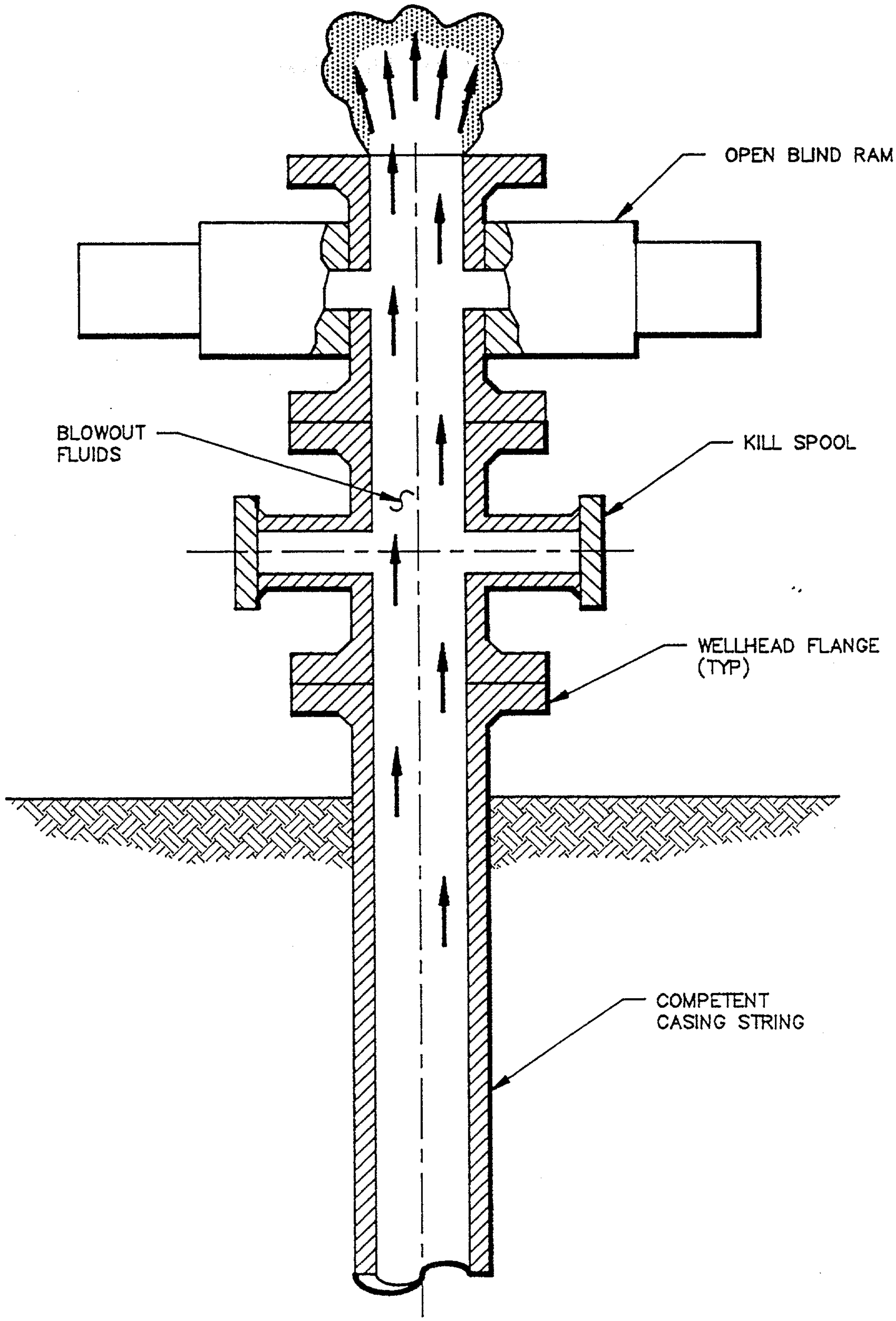

Figure 3.2.2

Capping and Shut-in On a Blowout with a Competent Casing String

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Capping and Shut-in On a Blowout with a Competent Casing String circulation technique employed and the condition of surface equipment (BOP, choke manifold, flare, etc.) this applies the least amount of wellbore stress to the blowing well.

3.2.3 Capping/Diverting. A capped well must be diverted when the shut-in pressures would exceed the casing integrity or the formation fracture gradient. The capping assembly normally has a blind ram and 1 or 2, 4-6" diverter lines. (Figure 3.2.3)

Pipe is snubbed to bottom and mud or water is circulated. The pipe running can be with a snubbing unit or coil tubing unit. The coil tubing is easier and faster to rig up and run but it has certain strength limitations, notably little resistance to collapse. Some coil tubing units have a 5,000 psi burst limitation.

The pipe size is important because of hydraulic constraints. If the well has not depleted or drawndown to a lower lever, the kill may require high mud weights or flow rates. Usually, larger pipe sizes are desirable to avoid excessive fluid friction. They also require larger snubbing or coil tubing units.

Access to the inner casing string is required for this technique to be effective. Also, if the wells is flowing H_2S gas, the well must be capped on fire and all flow lines and BOPs must be H_2S serviceable.

3.2.4 Surface Stinger. A quick and effective approach to handling certain blowouts is with a surface stinger. The stinger may be some type of packer forced into drill pipe or casing and hydraulically closed. Metal sleeves may be used as an alternative to a packer. Fluid is pumped into the well through the stinger.

The most frequent application of the stinger is with blowouts where access to the drill pipe or tubing is available. Methods have been developed in certain situation to stab a small packer into the pipe and it is closed hydraulically. Kill fluid is pumped into the pipe. Most wells on Piper Alpha and in Kuwait were killed with stingers.

Fire does not prohibit the use of a stinger. Water monitors are arranged to keep the packer and pump lines as cool as possible. Also, the fire does not generally damage the top part of the drill pipe or tubing to the extent that it fails upon the introduction of cooler kill fluids.

It is not considered feasible in blowouts with moderate to high flow rates to stab a packer into a casing string. The flow out of the well prevents stabbing. The US-DOE salt dome blowout in Hackberry, Louisiana was killed in the mid 1970's with a packer shoved into the casing. The oil was not flowing at a high rate.

3.2.5 Vertical Intervention. The term "vertical intervention" was coined by Adams in 1986-87. It has received wide spread industry acceptance since that time.

The operations are restricted to offshore blowouts. A semisubmersible is moved directly (vertically) over a live blowout. (Figure 3.2.4) Work is done on the blowout from the vertical position. The work can include killing a shallow gas blowout, entering a blowout through the casing string, explosively removing a wellhead or BOP stack, or other similar operations.

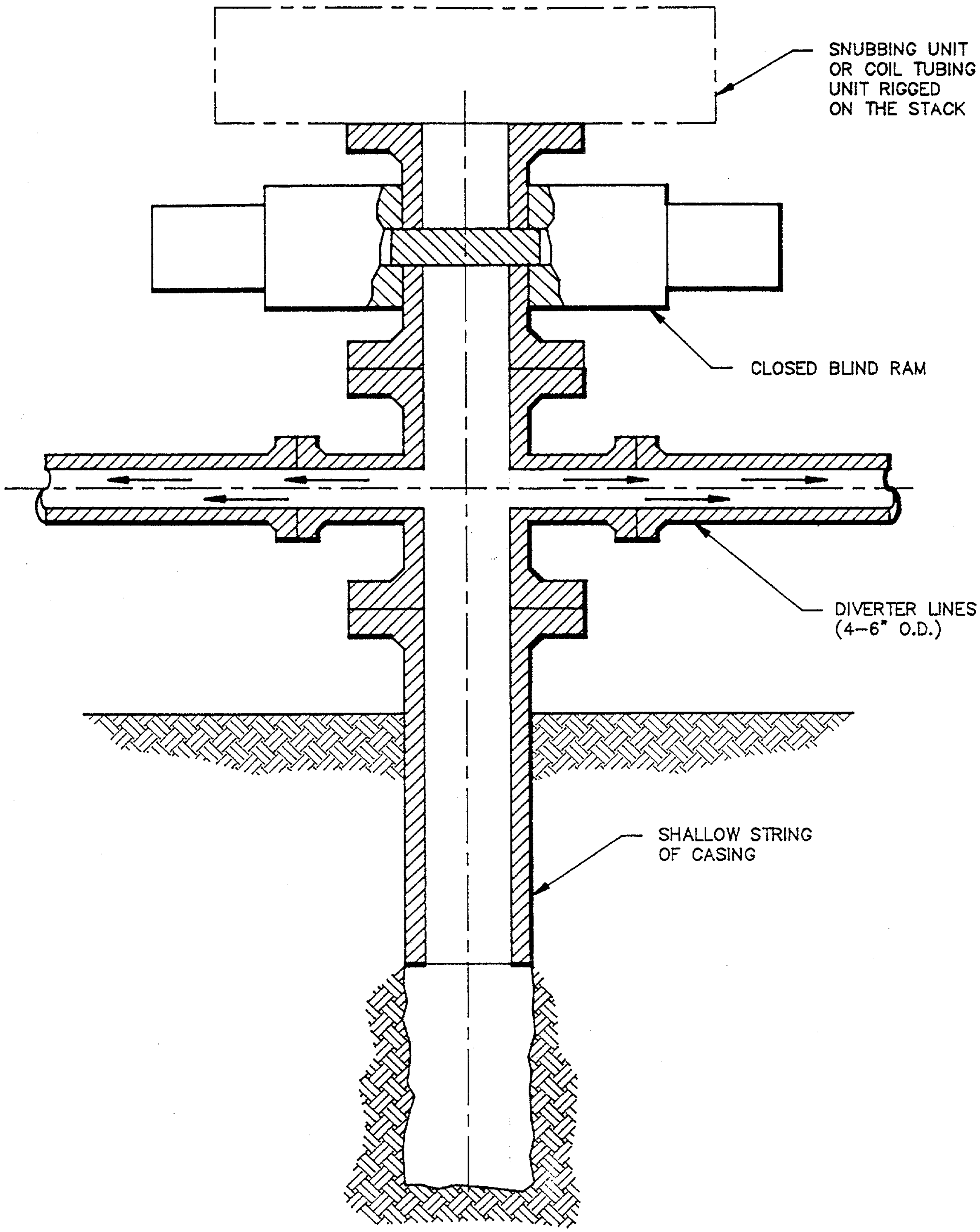

Figure 3.2.3
Capping/Diverting a Blowout

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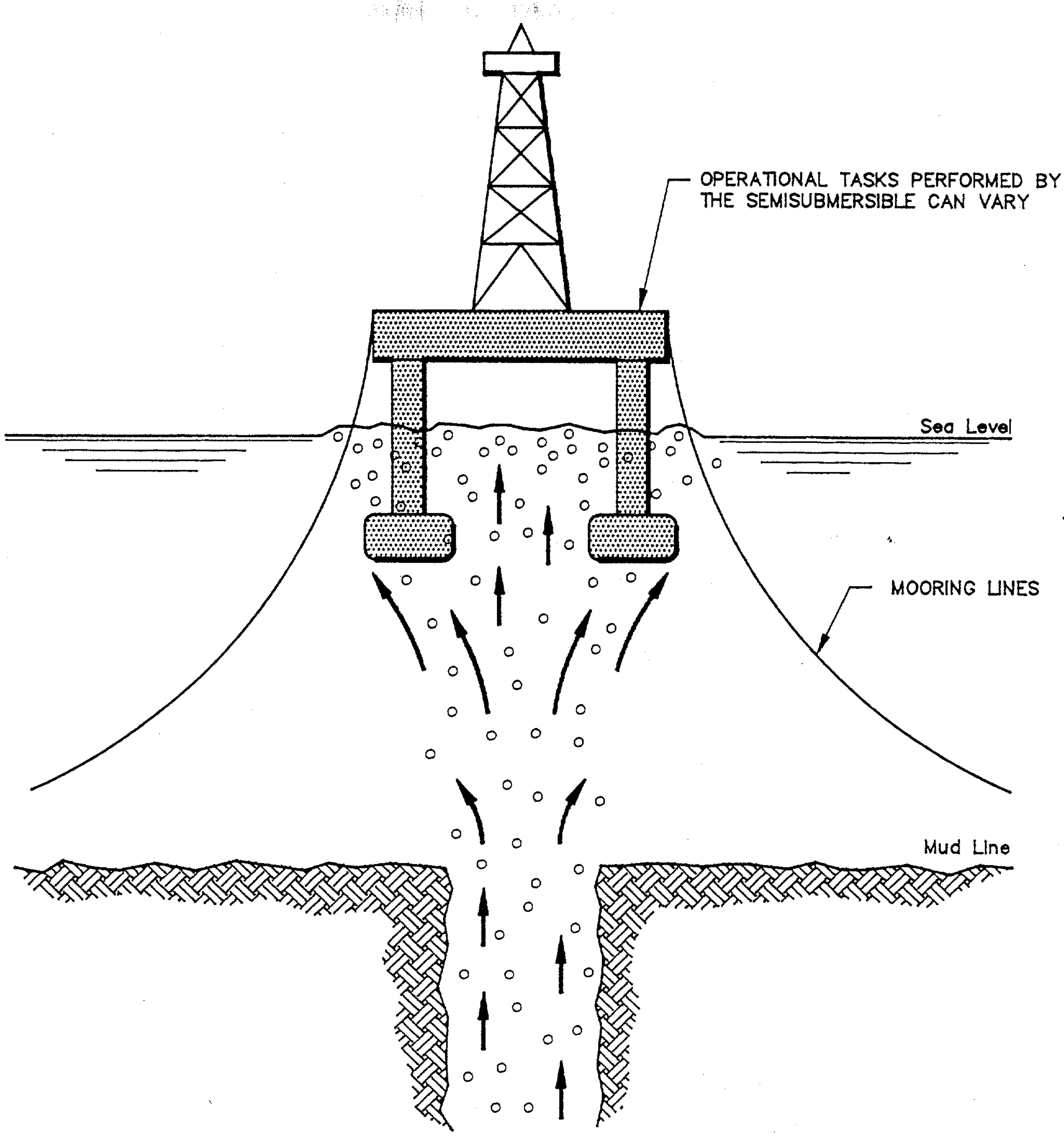

Figure 3.2.4

Vertical Intervention Involves Working a Semisubmersible Over a Live Blowout Under Strict Safety/Operating Conditions

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The range of capabilities for the approach has not been completely explored at this time. New technology and field experiences continue to add capabilities to vertical intervention.

Vertical intervention techniques are complicated and should be employed only by groups with knowledge and experience in this type of operation. Many safety systems must be employed. Also, only semisubmersibles are applicable for most situations. Current technology expressly prohibits the use of jack ups or drill ships.

Chapter 7.0 of this report deals with vertical intervention.

3.2.6 Offset Kill. The offset kill technique was developed simultaneously as the vertical intervention method. It also is applicable offshore. With the offset approach, the service vessel works near to the blowout at the surface but slightly offset of the center. The service vessel can be a semisubmersible, derrick barge or some other type of floating vessel. It is possible that a jack up could be considered for use with an offset kill but with several restrictions. (Figure 3.2.5)

One advantage to the offset kill is that it can be implemented if the well is on fire. The heat normally precludes the implementation of the vertical intervention approach.

3.2.7 Relief Wells. One of the most well known blowout control methods is the relief well. It uses the bottom kill approach by intersecting the blowout well with a directionally controlled well. Contrary to the opinion of many operators, the relief well is not just another directional hole. It involves complex operations and requires a skilled technical engineering approach combined with experience in relief well drilling. Kill techniques used in relief wells include the dynamic kill or reservoir flood. Reservoir depletion is an important factor that is seldom considered. (Figure 3.2.6)

Factors required for a successful relief well are:

- Casing or drill pipe must be in the well at least as deep as the minimum intercept point.
- Reasonable surveys indicating the general bottom hole location.
- Ability to locate the surface site of the blowout well. This presents difficulties if the blowout is in a deep water environment.

The well must be blowing out for a relief well to be successful. If the well is shut in under high pressure and surface intervention is not a safe option for any reasons, a relief well can be highly effective if the trouble well can be flowed from the top in a controlled manner.

3.3 SIMULTANEOUS IMPLEMENTATION OF SEVERAL KILL TECHNIQUES ON A BLOWOUT

Considerations should be given to the simultaneous implementation of several kill techniques on a blowout. Some reasons for such considerations include the following:

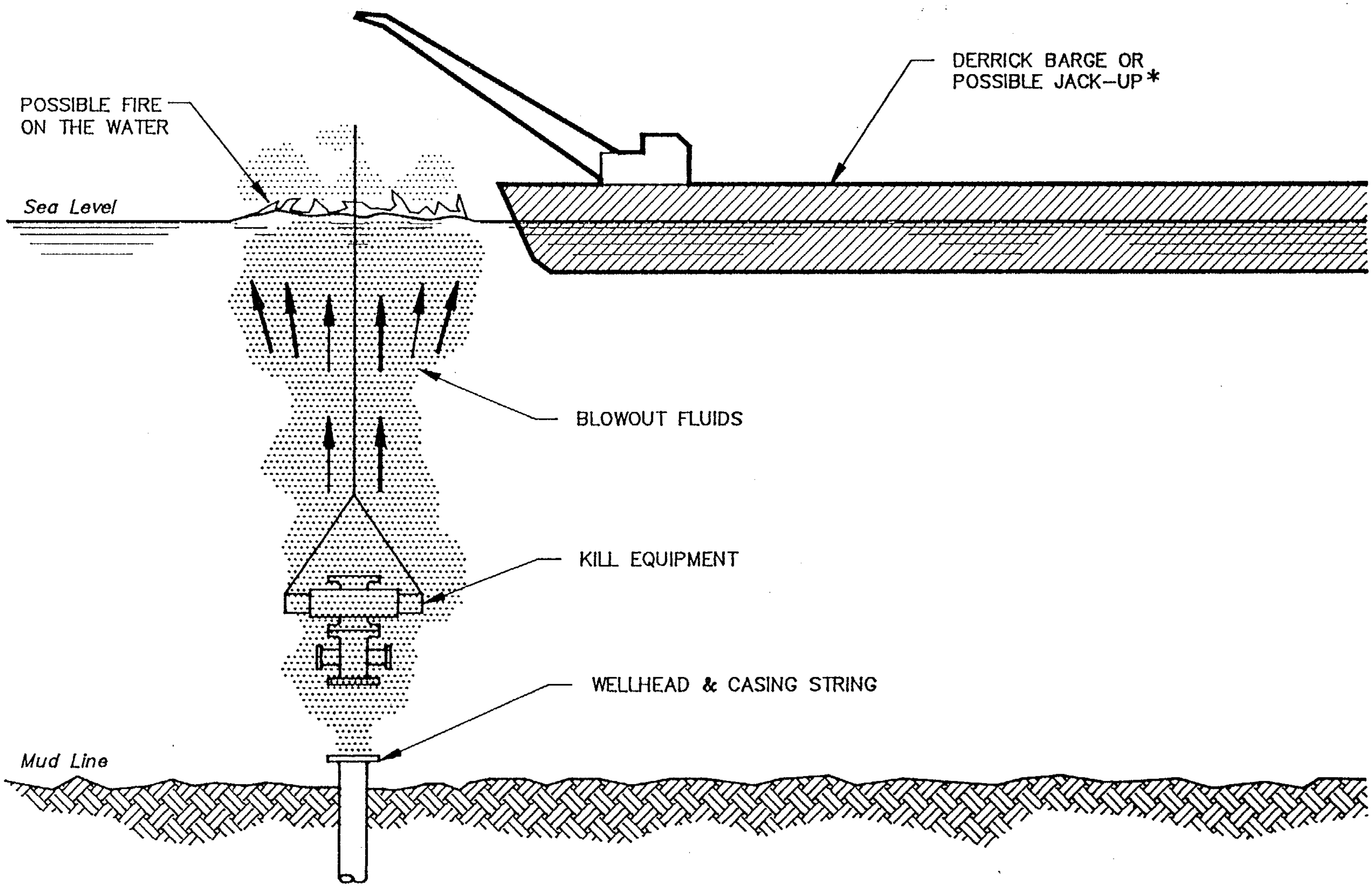

Figure 3.2.5

Offset Kill

* *Vessel Offset from the Center of the Blowout Performs Operational Tasks.*

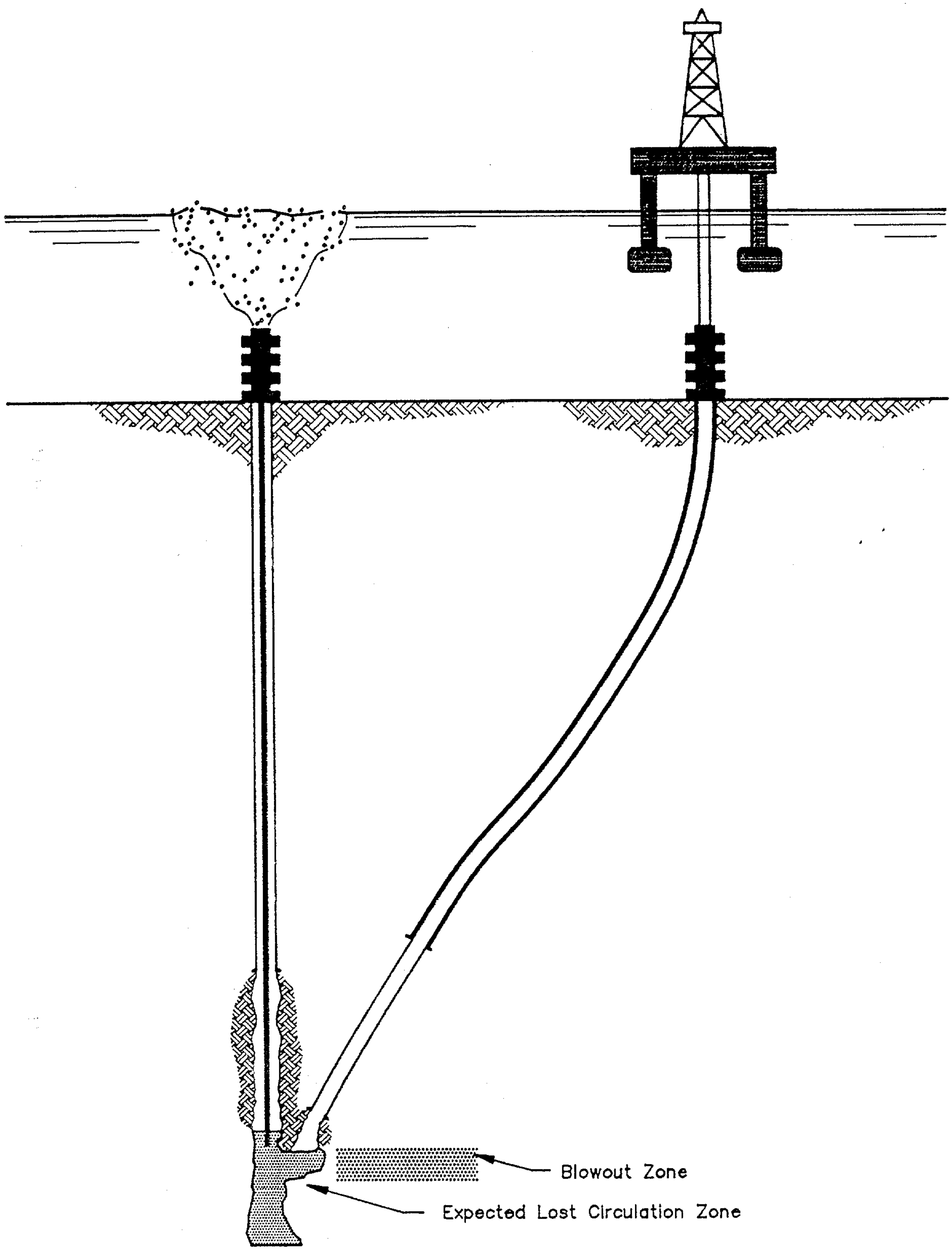

Figure 3.2.6

Deep Intersect Relief Well

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- The initial kill selection has a high factor for risk or uncertainty. An example is capping a sour gas well when the integrity of the casing is uncertain.

- Public pressure or media response is heavy and negative in nature.

- The blowout fluid is oil.

- The initial kill selection has a high degree of complexity and/or will require long times to implement.

Some discussion will be given to these considerations.

Public Pressure. Public pressure or news media response is an integral factor associated with most blowouts to a greater or lesser degree. It is difficult to avoid. If the press is not handled correctly, they can easily create tremendous amounts of public pressure. It may seem that implementing a simultaneous kill operation is the only method for appeasing the press and public pressure.

Recommendations for handling this pressure are based on field experiences with widely publicized events such as Piper Alpha. The most effective approach to handling the news media has been proven to be an open, honest statement of plans and activities. A recommendation is to prepare a formal news release every day of the event until the well is under control. The news release should be freely accessible. After some time, the news media begins to believe that nothing mysterious is being hidden relating to the event and pressure will begin to diminish.

The basic purpose of the news release is to avoid the printing of misinformation, as much as possible. The news media must print some copy because that is their trade. They will print what we tell them is technically correct so long as they do not have legitimate reasons for mistrust, or they will print their understanding of the situation. The preferred approach is obvious.

Discretion should be used when preparing the news release. Needless to say, the news release must be carefully prepared and phrased correctly so that no possible misinterpretations exist. The statement should describe the planned activities. However, it is clearly not necessary to give all details nor should certain activities be discussed.

It is recommended to have one contact person assigned to deal with the press. All others should be expressly prohibited from talking with the press. The ideal contact person would be a drilling engineer that understands the nature of a public relations task and has an understanding of the requirements of dealing with the press. If the standard "public relations" department is assigned the contact job, they should be thoroughly trained as to all aspects of the kill operations and ramifications of the blowout. If the news media suspects that their contact person with the oil company is not knowledgeable or is deceiving the press in some manner, they may attack with a vengeance.

Oil Blowouts. Simultaneous kill operations are strongly recommended when the blowout fluid is oil. Key issues are pollution, its associated clean up cost, and the public's perception the incident. The situation is more severe if the blowout is offshore.

Offshore oil blowouts should be ignited if possible. Every effort must be made to maintain the ignition. This includes working to maintain structural stability of the platform so it does not sink below water level. Release of some pollutants into the air will result. Rapid dilution of these compounds in the atmosphere will reduce the average pollutant concentrations to acceptable levels. This is a more attractive alternative than allowing a large visible oil slick to form, however.

Complex operations or long implementation times. A simultaneous operation should be planned if the primary approach is complex or will require long times for implementation. A complex operation has the potential for failure because of the uncertainties associated with blowouts. Also, long operational times such as those required for deep relief wells support the need for consideration for a simultaneous approach.

3.3.1 Single Approaches. Many blowouts do not warrant the time and expense associated with a simultaneous kill operation. These situations can include the following:

- Capping operations that are reasonably quick and "routine".
- The blowout fluid is sweet gas rather than oil or sour gas.
- A second approach is not technically or realistically feasible.

Other reasons probably exist for using a single kill method.

Most wells have been killed by using a single approach. However, some wells have caused extended problems because the initial approach failed and a second approach had not been implemented.

3.3.2 Requirements for a Simultaneous Implementation of Kill Options. The question arises as to the requirements for the simultaneous implementations of kill operations. The answer is simple. Simultaneous operations can include any of the kill options that are technically possible for the given situation yet do not interfere with each other.

As an example, capping a well as a control method is not consistent with implementing techniques to let it bridge. Also, capping and shutting in a well is not consistent with capping and diverting.

3.4 RANKING OF KILL TECHNIQUE VIABILITY FOR DIFFERENT BLOWOUT SCENARIOS.

An effort has been made to rank the kill options described in Section 3.2 for various blowout scenarios. Figure 3.4.1 contains the results. When several kill options are available for a scenario, some ranking is given on a 1,2,3 basis where 1 represents the preferred approaches and 2 or 3 represent secondary approaches.

Figure 3.4.1 should be used as a guide. Circumstances for each blowout should be evaluated to determine the best kill approach.

Fire has some effect on the kill technique selection. For the purposes of Figure 3.4.1, it is assumed that blowouts in water depths greater than 300 ft will not have a fire, or the fire will extinguish itself. The previously mentioned blowout database supports this assumption. Also, the dynamics of underwater blowouts make it difficult for a fire to sustain itself.

The impact of water depth on an H_2S well is interesting to note. It appears that the water can strip the H_2S and create sulfuric acid. The escaping gas is sweet. The key variables are the gas concentration and water depth. It is believed that in depths of 500-600 ft, the gas will be sweetened. Lesser water depths have appeared to sweetened the gas in the few field cases that are available. However, it is clearly recommended to conduct on-going tests to evaluate this situation if plans involve working near a sour gas blowout.

FIGURE 3.4.1

KILL SCENARIOS FOR VARIOUS BLOWOUTS

Land/Offshore with a rig or platform

Access to a competent casing string with sufficient fracture gradient for a shut in.

1-Cap/shut in
2-Cap/divert
3-Relief well

Access to an incompetent casing string or a casing string with insufficient fracture gradient for shut in.

1-Cap/divert
2-Relief well

Shallow gas/no crater

1-Bridging
2-Cap/divert
3-Relief well

Access to deep string of drill pipe or tubing

1-Stinger
2-Cap
3-Relief well

Offshore/Underwater/0-300 ft of water

Shallow gas/no crater

1-Bridge
2-Vertical intervention or offset kill
3-Relief well

Shallow gas/crater/no fire

1-Vertical intervention
2-Offset kill

Shallow gas/crater/fire

1-Offset kill
2-Vertical intervention

Deep blowout/no fire

1-Relief well
1-Vertical intervention
2-Offset kill

Deep blowout/fire

1-Relief well
2-Offset kill

Access to deep string of drill pipe or tubing

1-Vertical intervention with stinger
2-Offset kill with stinger

Offshore/Underwater/>300 ft of water

Shallow gas/with or without crater

1-Vertical intervention
2-Relief well

Access to a competent casing string with sufficient fracture gradient to shut in the well.

1-Vertical intervention
2-Relief well

4.0 RELIEF WELLS

4.1 INTRODUCTION

Relief wells fall into the category of bottom kills. A directional well is drilled to intersect the blowout well. Fluids in the form of acid, water and/or mud are pumped into the well at specified rates and sequences until the blowout well is dead.

Many relief wells have been drilled over the years. The first documented case was supervised by the legendary John Eastman in the Humble Field, Texas in the early 1920's.

The original wells were given the name of "relief wells" because their purpose was to relieve reservoir pressure. The intent, or hope may be a better term, was that the reservoir pressure would draw down and the well would die.

Recently several authors have made claims that "relief wells were now a reliable means to kill blowouts". The truth of the matter is that relief wells have been reliable for many years. It is an old technique but with the aid of new technology has been made to be more efficient. Reliability and accuracy has risen to the level that it is reasonable to assume that the target can be hit, usually on the first attempt, and the well can be killed quickly after pumping starts.

One falsehood needs to be dispelled about relief wells. Many individuals think that relief wells are "just another directional well". This is far from the truth. Anyone that has tried to find the proverbial needle in the haystack and then pump into the eye of the needle at 100 bbl/min knows that it is not just another directional well.

For those that are interested, a partial compilation of drilled relief wells is shown in Section 4.8. It is defined as partial because the data is not complete in terms of identifying all relief wells, nor is significant data available on all wells that have been identified.

This study is primarily oriented toward offshore environments. However, much of the information will be applicable in all situations. Relief well technology can be used on most wells anywhere in the world. Obviously, the rig selection discussion, will pertain to floating rigs,not to onshore rigs.

In some areas, such as frontier Canada and Artic Northern North Sea, the operator may be required to demonstrate its cabability to drill relief wells before being given approval to drill.

4.2 OVERVIEW OF GENERAL SCENARIOS

Scenarios for offshore underwater blowouts vary but can be grouped into several general categories. The general constraint for the scenarios is that the relief well requires a floater and can not be drilled with a jack-up. To meet this constraint, a limiting minimum water depth of 300 ft has been selected for the purpose of this study.

All scenarios assume that the wells are drilled in a non-protected environment, i.e., an open sea situation. This qualification has only minor impact for relief well driling while it has a greater impact on pollution control.

Key factors in the various general scenarios are as follows:

- Water depth
- Blowout depth
- Fluid type

Each will be discussed.

4.2.1 Water Depth. Relief well drilling has slightly different requirements with varying water depths. In general, requirements can be considered for water depth ranges of 300-600 ft, 600-1500 ft and >1500 ft.

Water depth has an impact on the blowout. Key parameters are as follows:

- The seawater hydrostatic acts as a choke and prevents gas expansion in the critical low pressure environments from 500 psi to atmospheric conditions.
- The water acts as a buffer and allows a safe vertical intervention as a kill option when evaluating the relief well as a control option.
- The entrained water in the blowout plume disperses the blowout effluent so it poses minimal risks to the relief well rig and crew.
- The water masks the effects of methane and H_2S release on the surface.
- The back pressure reduces flow rates out of the well.
- Reduced flow rates inhibit bridging which, according to statistics, will increase the likelihood that a relief well will be required.
- Reduced flow rates mitigate reservoir drawdown which equates to a higher reservoir pressure that must be controlled by the relief well. Conversely, less drawdown means less problems while approaching the reservoir.

The water depth range of **300-600 ft** has some interesting characteristics relative to relief wells. The blowout effluent release at the surface for a large blowout can impact the site location for the relief well rig. The farther removed that the rig is from the blowout site, the directional drilling requirements will be more stringent.

An H_2S blowout in the shallow end of this depth range may require special consideration. The deeper environments may strip the H_2S from the hydrocarbon gas as evidenced by field case histories.

An ignited blowout may continue to burn even if the rig sinks below the water line or is moved off location. It is not considered likely that the fire can be extinguished. The heat loading is not expected to be a controlling factor if previous history repeats itself but the heat must be evaluated at the time.

The depth range of **600-1500 ft** allows a large flexibility without posing many constraints on the relief well. The water depth is sufficient to prevent any adverse effects from gas, H_2S, fire on the water or pollution. Water depths beyond 1500 ft do not provide any real additional benefits in terms of reduction of the adverse effects of these parameters.

The site selection for the rig is not limited by any surface conditions. The rig could move a short distance from the centerline of the blowout well and drill a vertical well throughout most of the drilling program. It could be made to track the blowout well. This technical feature of deep water environments is interesting and could be used on a future blowout to ease the directional drilling tasks.

Although the water depth may be considered to be deep, it is still sufficiently shallow as to not exceed the capabilities of most equipment available on today's market. This includes mooring systems, risers and control systems. Most relatively modern semi-submersibles can meet the requirements. Also, a drill ship becomes a viable option as a drilling vessel for blowout control as the water depth increases.

The water depths greater than **1500 ft** for a relief well begin to pose equipment problems not related to the blowout itself. Riser design becomes more complicated and most rigs will not have adequate capability. BOP control systems are reaching the edge of technology as the water depth increases, particularly if the well is blowing out underwater; however BOP control system technology is advancing rapidly. Rigging a kill system to pump fluids at high rates into the annulus increases complexity and begins to eliminate some of the options discussed in later sections of this report.

Wells drilled in 5000 ft (plus) of water are unique. They are quite often a "one off" well which means that many aspects of the well were special designed on a one time basis. If a "one off "well blows out, the question arises as to how long will it take to rig up and kill the blowout when perhaps years went into preparation for drilling the initial well. This situation is analogous to a well drilled in severe Arctic conditions where the drilling season is very short. Fortunately, in these deeper environments, vertical intervention becomes an attractive kill option.

4.2.2 Blowout Depth. It is obvious that the depth of the blowout affects relief well drilling strategy. It may not be so obvious, though, that shallow blowouts can be more complicated in many respects than medium depth or deep blowouts. For the purposes of discussion, blowout depth ranges might be grouped as 0-3,000 ft, 3,000-10,000 ft, and >10,000ft.

As previously stated, shallow blowouts, i.e., 0-3000 ft, cause many difficulties not encountered in deeper blowouts. Some are as follows:

- Shallow kick off depths
- High build and drop rates
- High drift angles
- Hole opening and underreaming difficulties in soft sediments in the shallow depths.
- Possible charged sands from shallow gas blowouts.
- Requirements for a special-built diverter unless the well is drilled riserless.

- Greater than expected drill times due to directional control complexities.
- Casing program modifications to account for bending in large diameter tubulars.

An example is appropriate to illustrate the directional drilling considerations.

Example 4.2.1

Consider a well blowing out from a large shallow gas sand at 2,500 ft. A rig can be spotted 500 ft and 1,000 ft from the blowout site. If the KOP is 500 ft BML, determine the directional plan for build and drop rates of 4, 6, and 8 degrees. Use an "S" shape curve for the purposes of this example.

Offset Distance (ft)	Build/Drop Rate (deg)	Hole Angle (deg)	Measured Depth (ft)
500	4	17.9	2571
	6	16.1	2567
	8	15.5	2565
1000	4	Not Possible with 4°	
	6	35.9	2783
	8	32.2	2767

The blowout depth range of 3,000 ft - 10,000 ft poses the least problems of all depths. The factors supporting this statement are as follows:

- Modest and manageable ellipses of uncertainty under most anticipated conditions.
- Reasonable directional profiles and drilling requirements.
- Drill times that are usually acceptable prior to reaching the target.

The drill time issue is worth discussion. A typical well can be drilled to 10,000 ft in reasonable and acceptable times for most situations. This avoids the decision to intersect deep at the bottom or at a shallower depth. This decision is important in deeper wells because of the drill time.

Further, the reverse situation of requiring too much drilling time before killing the blowout can be a factor in the 3,000 ft - 10,000 ft range. The reverse is that the well is drilled and ready for the killing phase before all kill equipment can be located, assembled, tested and mobilized to the kill site.

This situation almost occurred on Piper Alpha's P-01 well. The TVD was ~8,000 ft with a 8,500 ft MD. The killing equipment was difficult to locate in sufficient quantities. It was a tight race to beat the deadlines but, at the end of the day, the equipment was located and assembled. This may not have been accomplished in a remote environment.

Blowout depths greater than **10,000 ft** have advantages and disadvantages. The luxury of a deeper blowout is that sufficient time is available for planning and equipment procurement and mobilization.

The deeper blowouts have a number of disadvantages including the following:

- Higher formation pressures that place more stringent requirements on the relief well.
- Reduced casing sizes for deeper relief wells that consume more hydraulic horsepower in pumping the kill fluids to the blowout well.
- Ellipses of uncertainty that may be unmanageable in deep situations unless bypasses and sidetracks are made.
- Long drilling times.

Again, the issue of drilling times is worthy of discussion. Consider an example of a 17,500 ft blowout well. The time to drill to bottom under normal conditions can be large. It is increased by the directional requirements of changing hole angles in deep, hard sections. The ellipses of uncertainty can be unmanageable requiring sidetracks and bypasses.

A shallow intersect avoids many of these difficulties. The ellipses are smaller and probably manageable. The drilling times are reasonable. The key issue is whether the well can be killed at a shallower depth, i.e., ~8,000-12,000 ft. These topics will be discussed in detail in other sections of this report.

4.2.3 Fluid Types. Blowout fluids have an impact on the relief well. A gas blowout does not cause environmental damage and, if necessary, can be burned. Other than the routine expediency associated with the desire to kill a blowout quickly, an additional urgency due to pollution is not imposed with a gas blowout, either on land, offshore, or subsea.

A gas blowout, if not on fire, should not be ignited unless extenuating circumstances exist. The fire will collapse the rig or other equipment. It will cause a heat loading that increases the effort required for capping. Also, an unignited gas well does not have the dramatic impact associated with a burning well. Public pressure is increased with a burning well.

Oil blowouts pose an obvious pollution problem. Oil does not burn cleanly in most cases so ignition does not always provide a solution. An oil blowout in 1,000 ft of water, as an example, will be dispersed over a large area and may negate the effectiveness of any spill containment efforts.

H_2S is toxic and must be burned on land blowouts. Underwater blowouts are different because it has proven difficult to ignite and maintain the ignition on a blowout if it did not ignite initially. Fortunately, some case histories have shown that the water will strip the H_2S from the gas and allow the release of sweet gas at the surface. This case history was in 300 ft of water. It is anticipated that greater water depths will completely sweeten the gas regardless of the toxic concentration. This matter needs further investigation.

4.3 BLOWOUT WELL PATH LOCATION

It is obvious to state that the relief well can not be directed towards the blowout well unless the location of the blowout well is known. It is not obvious to state that finding the blowout well can be complicated. The task includes defining the surface location and the (relatively) precise location of the wellbore at any depth.

The blowout well path must be known with some degree of certainty before a directional plan for the relief well can be developed. Ranging tools have a reliable accuracy of 50 - 100 ft under average conditions and supposedly to 200 ft under ideal conditions. If the wellbore path uncertainty is 300 ft at the proposed point of intersection, as an example, it is clear that the ranging tool limits have been exceeded. A shallower point of intersection with smaller uncertainties may be required.

4.3.1 Surface Site Evaluation. Finding the surface location of a land blowout without a crater is simple. Survey or other conventional techniques can meet the requirement. It is recommended to use 2 independent surveyors and compare the results. A third survey should be taken if the initial surveys do not agree.

A land crater makes the job more difficult. A distance ± 10 ft is important relative to accuracy of the ranging tools.

Underwater blowouts can present a challenge. The surface blowout plume moves randomly, similiar to a cyclone, and can not be used to suggest mudline location of the blowout. Conventional surveying techniques are not available to fix the relative positions of the two wells.

The approach for underwater blowouts is to assume the blowout site is at the original coordinates. The relief well is spotted at a location based on the assumed site for the blowout. Accurate satellite navigation spotting is essential for the relief well. The accuracy must be less than 1 m even if multiple satellite passes are required.

4.3.2 Survey Analysis. The original surveys on the blowout well should be obtained, if possible, and reanalyzed. This is particularly important if the well is more than 10 yrs. old. All directional calculations including site location data should be checked thoroughly.

4.3.3 Ellipse of Uncertainty. The well path is seldom in the exact spot as suggested by survey analysis. It could lie in an area known as the ellipse of uncertainty, or cone of uncertainty.

Wolff and de Wardt are credited with quantifying survey errors and developing an approach to calculating the uncertainties. Their work is discussed in SPE 9223, "Borehole Position Uncertainty. Analysis of Measuring Methods and Derivation of Systematic Error Model."

They found that systematic errors had a greater influence on inaccuracies than random errors. After an analysis of magnetic and gyro-surveying techniques, they found that five sources of inaccuracy contribute to borehole position uncertainty: compass reference, compass instrument, inclination, misalignment and depth errors.

The relative lateral position uncertainties were determined by Wolff and de Wardt, in an example, as a function of the average hole inclination and are presented in Figure 4.3.1. A comparison of vertical, radial and lateral error magnitudes revealed that the latter is the greatest over the full inclination range, hence only this one is discussed. The graph demonstrates the increasing lateral uncertainty with inclination for all types of surveys. A 4000 m deep well of 45 degrees average inclination can not be surveyed more accurately than ± - 35 m and the uncertainty can be much larger.

Uncertainty calculations are done by computer because of the large number of calculations. Some operators and survey companies have in house computer programs. Several commercial programs are available.

4.4 RELIEF WELL SITE LOCATION

4.4.1 Introduction. Selecting a surface site, on land or water, for the relief well rig can be simple. Likewise, it can prove to be the most difficult aspect of the planning process for which no best solution exists.

Often, the site is selected hastily in an attempt to start drilling quickly. The site may prove to be a poor choice and result in a much longer time to drill the well than if more consideration had been given initially to proper selection of a well site.

The procedure for site selection is by process of elimination. Over a dozen factors must be considered in some cases. These factors may eliminate certain sites or regions. After all factors have been considered, the remaining areas must be evaluated and a site selected from them. It is not uncommon that a good or desirable option for a site plan is not available.

If multiple wells are blowing out, an optimum site must be selected singularly for each well. A compromise site that allows hitting several wells is seldom the optimum site for hitting any single well.

Piper Alpha is an excellent example of the compromise site issue. A site selection was made for the semisubmersible Kingsnorth U.K. (a/k/a/ KUK). The site was a compromise position that would allow drilling to the P-01, P-47, and P-53 wells. However, this position resulted in very difficult relief well approach plans for each blowout well. The drilling time increase, due to the compromised site, was estimated at 15 days for the 7000 ft TVD wells. It would have been more appropriate to move to separate sites for each well. However, Occidental correctly believed that the public pressure would be too great and that it would be viewed as having a "shaky start". Therefore, the compromise position was used.

Although a few factors may change at the time of the blowout, the preliminary investigation about the optimum well location has to be carried out in advance in the Blowout Contingency Plan. This would avoid "Piper Alpha Type" mistakes.

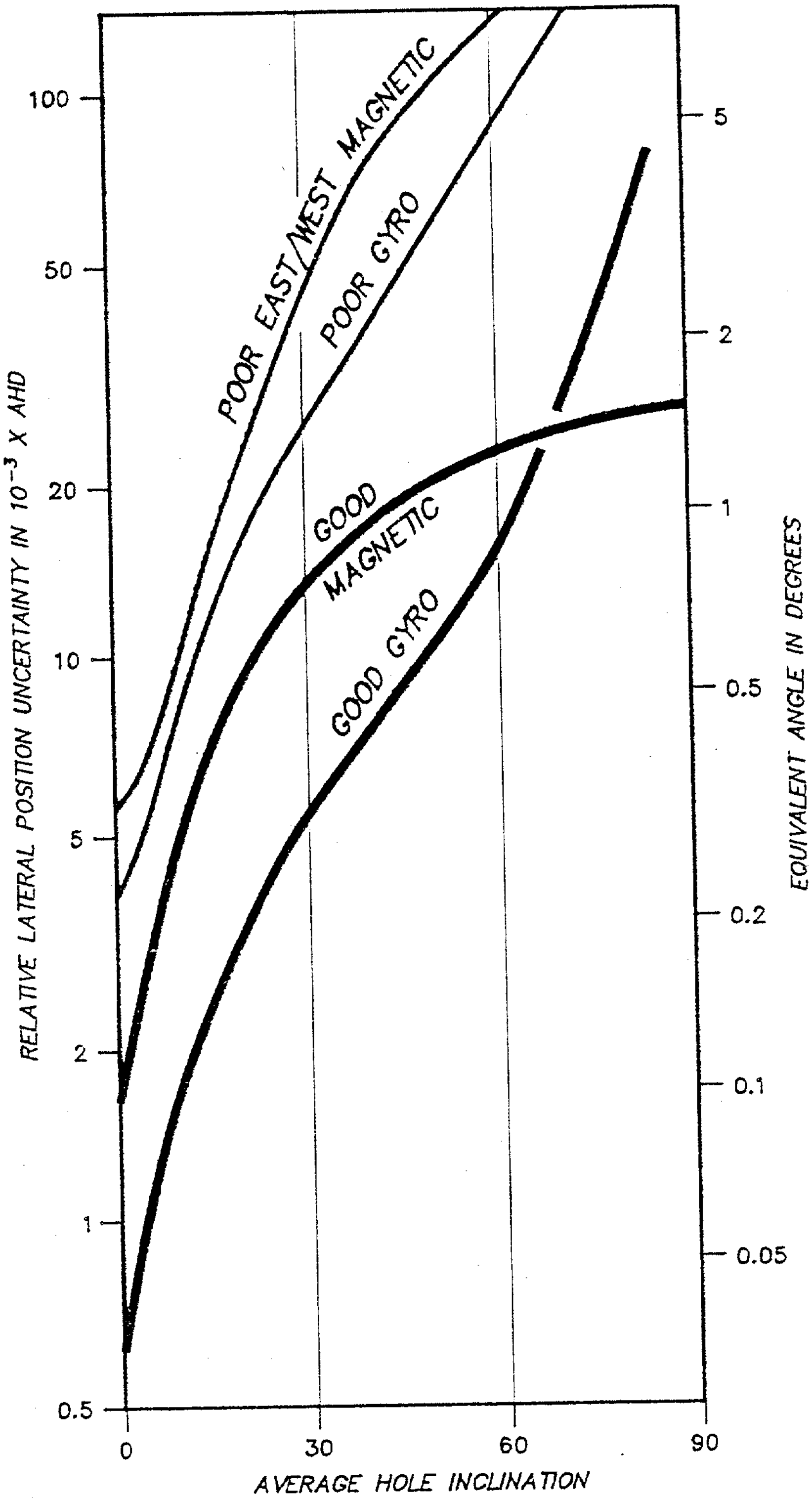

Figure 4.3.1

Typical Lateral Position Uncertainties of Inclined Wells for Poor and Good, Magnetic and Conventional Gyro Surveys*

*After Wolff and de Wardt

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The factors to be considered in relief well site selection are as follows:

- Offset distance
- Optimum intercept/approach path
- Ellipse of uncertainty
- Proximity to other wells
- Shallow gas blowouts
- Debris
- Wind currents
- Water currents
- Heat
- Noise
- Bathymetry
- Localized gas seepage
- Insurance
- Regulatory agency requirements
- Mooring patterns
- Pipelines

They are discussed in the following sections.

4.4.2 Offset Distance. Often, a specific minimum offset distance is established between the relief and blowout wells. It is commonly 1000-1500m (3000-4500 ft). This offset distance seldom has any basis of fact. It is not a requirement of insurance underwriters or government agencies.

Experiences on blowout jobs with respect to the "offset distance" have proved interesting. When encountering situations where these distances have been pre-selected, it seems that no one knows the originator of the minimum distance requirement. When clearly demonstrated that an optimum site may exist at a lesser distance, it becomes impossible to receive authority to violate the previously established "minimum distance".

Technical reasons do not exist for an arbitrary establishment of some minimum offset distance. Each situation must be established on its own set of technical facts. The existence of fires may be a prevailing factor.

4.4.3 Optimum Intercept/Approach Path. A primary consideration in selecting a site is the appropriate directional plan to be used. To some degree, this is an argument similar to the old question of "which came first-the chicken or the egg".

The key aspect of the directional plan is the approach angle between the relief well and the desired intersect point on the blowout well. Usually the angle will be small and in the range of 5-15 deg. The selected surface site should allow for easily attaining the required horizontal displacement and to have the relief well in the 5-15 deg. approach position near the target.

Relief wells for shallow blowouts will require a site near to the blowout well. The KOP must be shallow and usually the drift angles will be high so the hole can drop to the appropriate approach angle.

Deep blowouts allow more flexibility in site selection. However, a site as near as possible to the blowout is generally desirable to minimize the required horizontal displacement.

4.4.4 Ellipse of Uncertainty Consideration. Systematic survey errors create a cone or ellipse of uncertainty as to the specific location of the blowout well and the relief well. Section 4.3 discusses the matter in greater detail.

The depth of investigation for ranging tools should be considered with respect to the combined ellipses of uncertainty for the blowout and relief wells. The ellipse for the blowout well is fixed. However, the ellipse for the relief well is dependent to some degree on the directional plan. Consideration should be given to selecting a directional plan that minimizes the ellipse if the combined ellipses for the two wells exceed the ranging tool's capability. Since the ranging tool's depth of investigation is 200 ft under optimum conditions, it is often the case that the combined ellipse diameter exceeds the 200 ft range capability. If this is the case even under optimum conditions for the relief well, then multiple ranging runs will be required as the well is drilled near the blowout target.

4.4.5 Proximity to Other Wells. Site selection for relief wells must consider other wells in the area. The worst situation is shallow blowouts under or near a platform. A site and a directional plan must be chosen to avoid a collision with another well. More important, however, is ranging difficulties between the relief well and interference from other wells. Since the wells are in close proximity under a platform, it can be difficult to appropriately select a site and directional plan to avoid well interference.

A field example is shown in Figure 4.4.1. For various reasons including water currents and pipeline restrictions, the rig position as shown was the only available site to drill the relief well. Magnetic ranging was hampered because of interference of other non-blowout wells. If the ranging was restricted until the relief well was near the blowout well, the ellipses of uncertainty between the two wells would have significant overlap. The relief well intersected

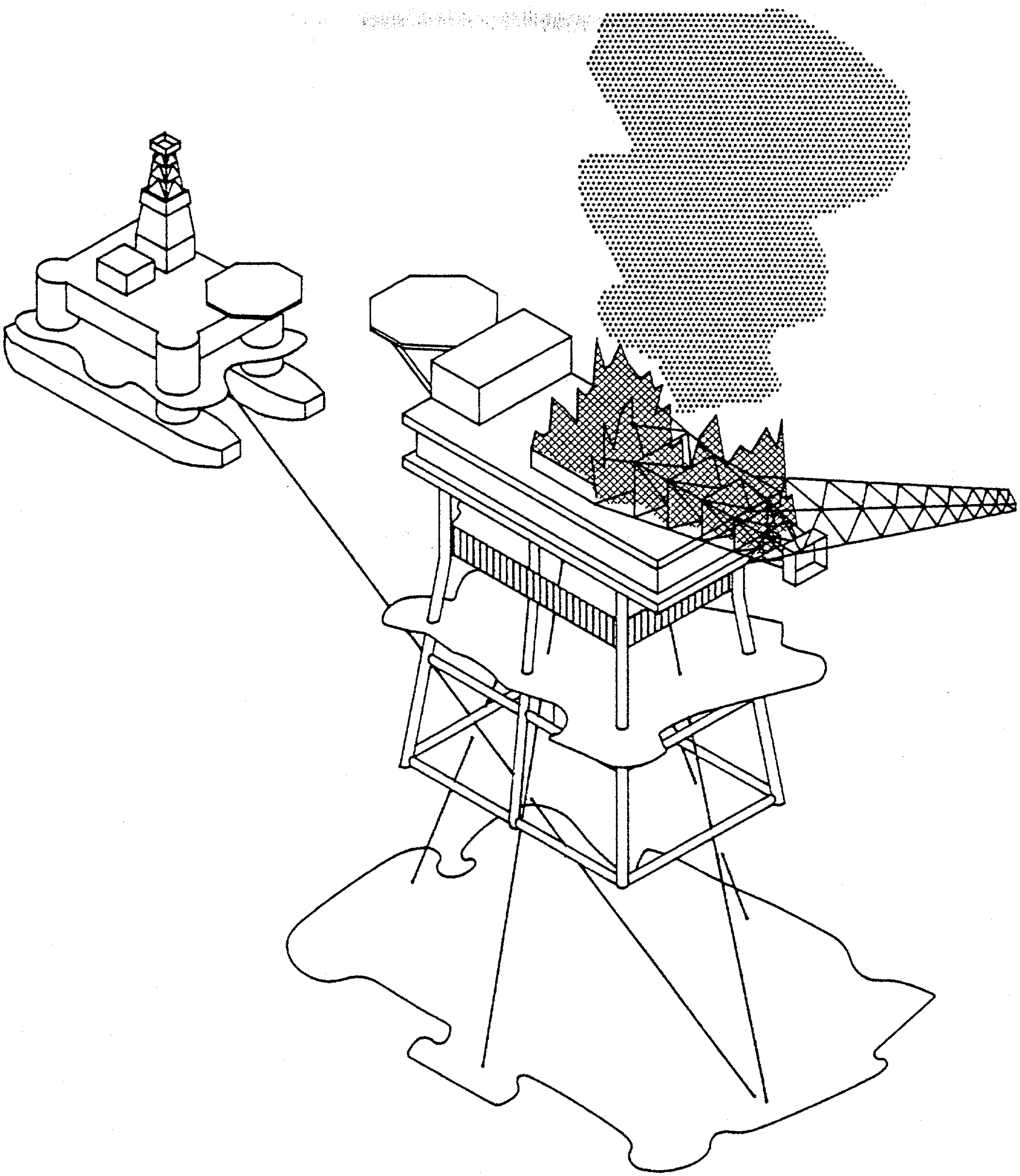

Figure 4.4.1

Relief Well Proximity to Other Wells*

*Cook Inlet, Alaska
1988

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the blowout well at the expected depth so ranging was not necessary. A post-intersect ranging run was made and the blowout well was 2 ft away from the relief well.

4.4.6 Shallow Gas Blowouts. Shallow gas blowouts cause significant site selection difficulties. The shallow gas blowout can deplete some shallow zones while charging other zones. The phenomenon of simultaneous depleting and charging from zones that were normal pressured in the same wellbore is difficult to explain.

To obtain reasonable directional programs for shallow blowouts, the relief well site should be near to the blowout well. However, the sites near to the blowout have a greater potential for being pressure charged.

The following examples illustrate the phenomenon. The data are for known pressure charging at distances from the relief/observation well to the blowout.

Date	Event	Distance from Blowout to Known Gas Charging, ft
1983	Mobil/Banteng South China Sea	2000
1984	Mobil/West Venture Sable Island/Canada	3000
1985	Union/Grayling Plat. Cook Inlet, Alaska	2000
1985	Shell/Patricia PA-5 Sarawak, Malaysia	1500
1988	Marathon/Steelhead Cook Inlet, Alaska	500
1989	NFA16, Qatar	2485

The situation does not appear to be an acute problem from deep blowouts as has been seen from field experiences, if casing and cement integrity exists.

Shallow seismic surveys should be run after a shallow gas blowout to evaluate possible pressure charging and direction of gas travel. The surveys should be compared against pre-blowout surveys. If gas flow is detected, the surveys should be re-run frequently to evaluate magnitude and direction.

Gas may flow preferentially according to fault orientation. This was observed on Mobil's West Venture event in 1984 as reported in "World Oil", May, 1990. If this is observed to be the case, relief well sites perpendicular to the fault orientation appear to be preferable.

Gas has traveled up vertically oriented faults in some field cases. The gas was observed at some distance from the blowout well. Shallow seismic surveys can usually identify this gas.

4.4.7 Debris Debris is not typically a concern in relief well site selection. A significant amount of rig and platform debris at the blowout well site can negate the possibility of a vertical intervention and can be the controlling parameter in resorting to a relief well. However, it seldom has an impact on the relief well site.

4.4.8 Wind Currents. Wind has pro and con effects with respect to rig site selection. The wind can carry any available gases to the rig if it is located on the down wind side. The particular concerns are explosions related to flammable gases such as methane and for toxicity with hydrogen sulfide.

The advantage to having a wind is obvious. The gases are diluted and dissipated.

The typical procedure is to evaluate the wind rosetta for an area. Meteorological groups can define predominant wind directions and seasonal variations. The appropriate rig site would be upwind. (Figure 4.4.2)

Offshore blowouts have not shown the degree of gas problems that theoretical models predict should occur. It appears that the gases are dissipated to greater degrees than predicted by the model before the gases reach the rig. To some degree, it has been seen that underwater blowouts dissipate the gas in a somewhat inexplicable manner.

Mathematical models have been developed to predict the gas concentrations present at the proposed relief well site. These models do not appear to coincide with actual field results. One possible explanation for the disagreement is that worst case flow rates are used when, in fact, the blowout may have reduced in flow capacity due to depletion.

Models should be run to evaluate gas concentrations for site selection if the models are available. However, their results should be reviewed carefully and weighed against actual field cases.

Winterized rigs should be carefully evaluated prior to usage for relief wells. These rigs have enclosed areas that can support gas build-ups. The severe explosions and fire that occurred on the Ocean Odyssey in 1988 were due in part to gas build-ups in zones where the gas would have dissipated to a greater degree in non-winterized rigs.

4.4.9 Water Currents. The concern for water currents in an offshore environment relates to possible movement of an oil slick towards the rig. Similar to wind rosettas, guides are available for current predictions. The rig site should be evaluated for up current positions if possible. If the blowout fluid is gas, water currents for pollution potential should not be a consideration.

Currents with respect to mooring considerations is a concern in some situations. If the currents are in a single direction, the problem is simply relegated to mooring analyses.

However, locations such as Cook Inlet, Alaska pose different situations. The currents run 6 hours in one direction (ebb current) and then 6 hours in the opposite direction (flood current). These currents can approach 8 knots. The relief well rig must be positioned on either side of the blowout parallel to the direction of the currents. If the rig breaks mooring lines, it should be

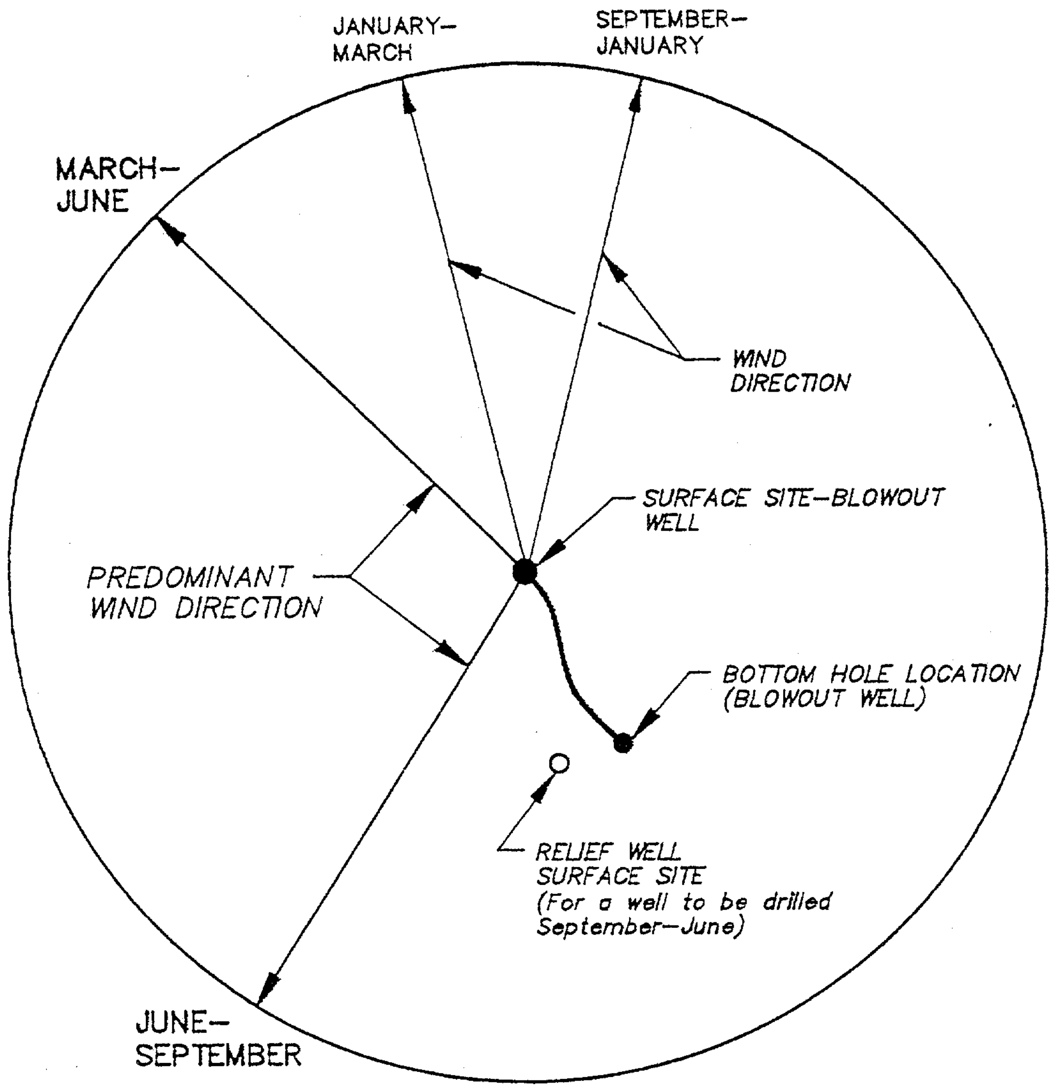

Figure 4.4.2

Wind Rosetta Used for Site Selection of a Relief Well

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carried parallel to the currents which will be away from the blowout. If the rig is upstream or downstream from the blowout and it breaks anchor chains, the current reversal that occurs every 6 hours can carry the rig into the blowout.

Figure 4.4.3 illustrates the effects of water currents in the Alaska job. The rig was positioned so it would be carried away from the platform in the event the mooring system failed in the high currents. Therefore, regions 1 and 3 were excluded. Regions 2 and 4 were favorable with respect to currents. However, region 2 was eliminated because of the pipelines. Other areas outside these 4 regions had been previously eliminated because of the difficulty of drilling directional wells to avoid collision with other wells under the platform.

4.4.10 Heat. Heat loading from a blowout fire can be significant. However, it is often exaggerated. Very few fires have created heat loading that would require a rig to be positioned more than several thousand feet from the blowout site.

In an actual situation, the best approach is to run field tests at the time of the event. These tests should represent a worst case scenario prior to depletion.

4.4.11 Noise. Similar to the previous discussions on heat from a fire, the noise can be significant but is often exaggerated. Noise testing should be run at the time of the event.

4.4.12 Bathymetry. The minimum water depths required for support vessels must be evaluated if the water depth varies significantly around the site. Minimum acceptable depths must be established for workboats, pump vessels, and the drilling rig. The seabed gradient must also be taken into consideration in selecting locations for jack-up operations. Bathymetry considerations do not apply to any degree in floating drilling.

4.4.13 Localized Gas Seepage. A pre-blowout localized gas seep will have an effect on site selection if the drilling rig is planned as a dynamic positioned drill ship. The gas can interfere with the hole positioning/referencing system. The operator would not normally position the rig over a gas seep.

4.4.14 Insurance. Contrary to the understanding of many groups concerning insurance requirements for relief well site location, very few regulations exist. The operative term in most insurance contracts is that the operator will act in a "prudent manner". This provides the necessary flexibility to make good engineering judgments based on facts relative to the current situation as opposed to arbitrary rules not applicable to the event.

Two approaches are typically available for presenting plans to the insurance underwriter and their adjusters. The first is considered as an "active" approach and involves determining and evaluating all relief well variables and making a program to handle the situation. The plan is presented to the adjuster and explained in detail. If good engineering judgment has been used and all pertinent facts have been considered, the program will probably be accepted. This is clearly the preferable approach.

The second method is termed as "passive" and is generally less attractive. It involves evaluating several options and then presenting or discussing them with the onsite adjuster. The adjuster generally will usually not give any positive input because of the nature of their service. However, any input received from the adjuster will often be on the conservative side which generally equates to more time and money to the operator.

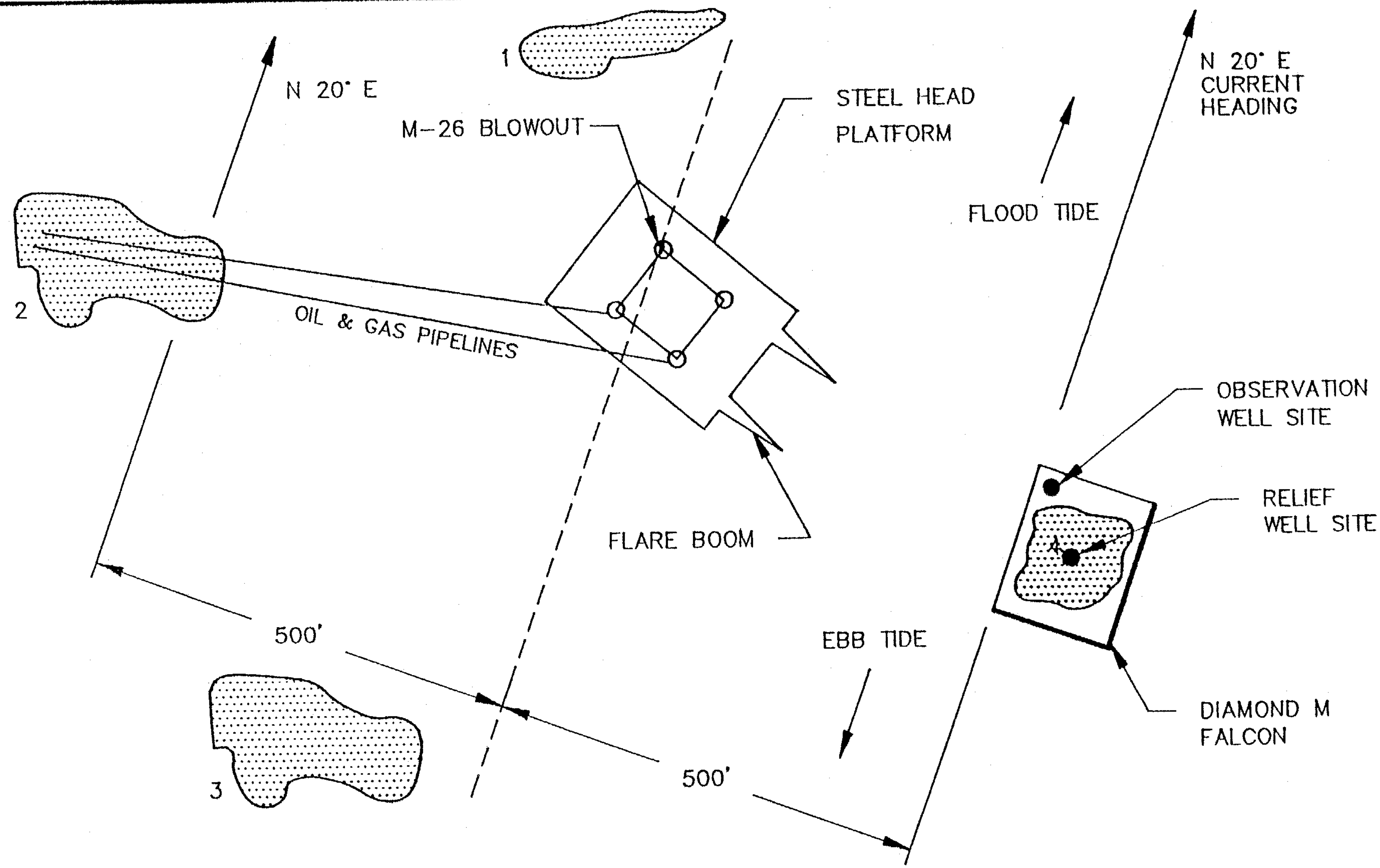


Figure 4.4.3

Field Layout and Relief Well Site Selection
for Alaska Blowout

Although not generally possible, it may prove beneficial to seek the advise of the adjuster in an unofficial manner. The adjuster is on site to work as a representative to the underwriter and not the operator. They do not want to be seen as giving advise to the operator. However, the adjusters are typically very experienced and have seen many bad situations. If their input can be obtained, it will often prove valuable but should be considered in context with all other available facts.

4.4.15 Regulatory AgencyRequirements. Government agencies are, in one sense, similar to insurance underwriters. They will not respond until a plan has been presented for review. Therefore the site selection issue still remains with the operator. Government regulations relative to site selection are not known to exist at this time.

Many government agencies worldwide are taking a greater role in the technical review of proposed relief well plans and other activities. The agencies are often better informed and very knowledgeable in many cases. Experienced petroleum engineers and field operations personnel are staff members in many cases.

4.4.16 Mooring Patterns. Mooring patterns must be considered if multiple relief well rigs are used. The general guideline is to avoid crossing anchor lines. In some case, the mooring spread on one or both rigs can be modified to achieve a non-crossing pattern.

Although the ideal situation is a mooring spread for both vessels that avoids line crossing, provisions can be made to safely cross the anchor lines if alternatives are not available. The operations are not a significant concern if the crossing is at a location where the anchor lines are laying flat on the bottom of the seabed and the anchors are firmly fixed, i.e., movement will not occur. If movement is possible, then piggy back anchors or driving piles should be considered.

Figure 4.4.3 is an example of a difficult mooring situation. The difficulty did not rest with crossing anchor lines but rather in attaining a secure situation in the 8 knot currents. The bottom was hard and would not allow the anchors to bite into the sea bottom. The final resolution was to use Stevpris anchors as the primary anchor and then piggy back with the rig anchors and to use 5000 ft of anchor chain. The choice of anchor types requires consideration.

4.5 INTERCEPT POINT SELECTION

4.5.1 Introduction. The intercept point is the depth at which the relief well establishes communication, or is about to establish communication with the blowout well. It is not the same as a bypass made for location determination. Communications establishment is discussed in greater detail in Section 4.16.

An off-bottom intercept seldom has been used. An apparent concern is that the pressure seen at a shallow depth in the blowout well could not be controlled with a shallow-intercept relief well. The fallacy with the thought process is it assumes that the blowout well does not have any depletion effects. Field cases clearly show that depletion occurs, and that under blowout conditions, the depletion is more severe than could be expected from normal production rates. This applies to oil or gas blowouts. If the depletion effect is considered, an off-bottom intercept is worth consideration. The approach to be used when evaluating an off-bottom intercept and kill are presented in Section 4.8.

The advantages and disadvantages of a bottom and off-bottom intercept are described below.

4.5.2 Bottom Intercept. As stated above, the bottom intercept approach has been used on most relief wells. It has functioned reasonably well. The advantages of the bottom intercept as compared to an off-bottom or mid-range intercept are as follows:

- A longer column of kill fluid exerts a greater hydrostatic pressure and, for a given pumping rate, the frictional back pressure will be higher in the blowout wellbore.
- The bottom hole kill process minimizes the dilution of the kill fluids by the produced fluid influx and, therefore, the build-up of the controlling pressure is achieved much faster.
- The required pumping capacity may be reduced because of the greater hydrostatic of the long kill column. However, it will generally tend to be greater because of frictional losses associated with the reduced hole geometry of a deep relief well.

The bottom intercept has distinct disadvantages that must be considered.

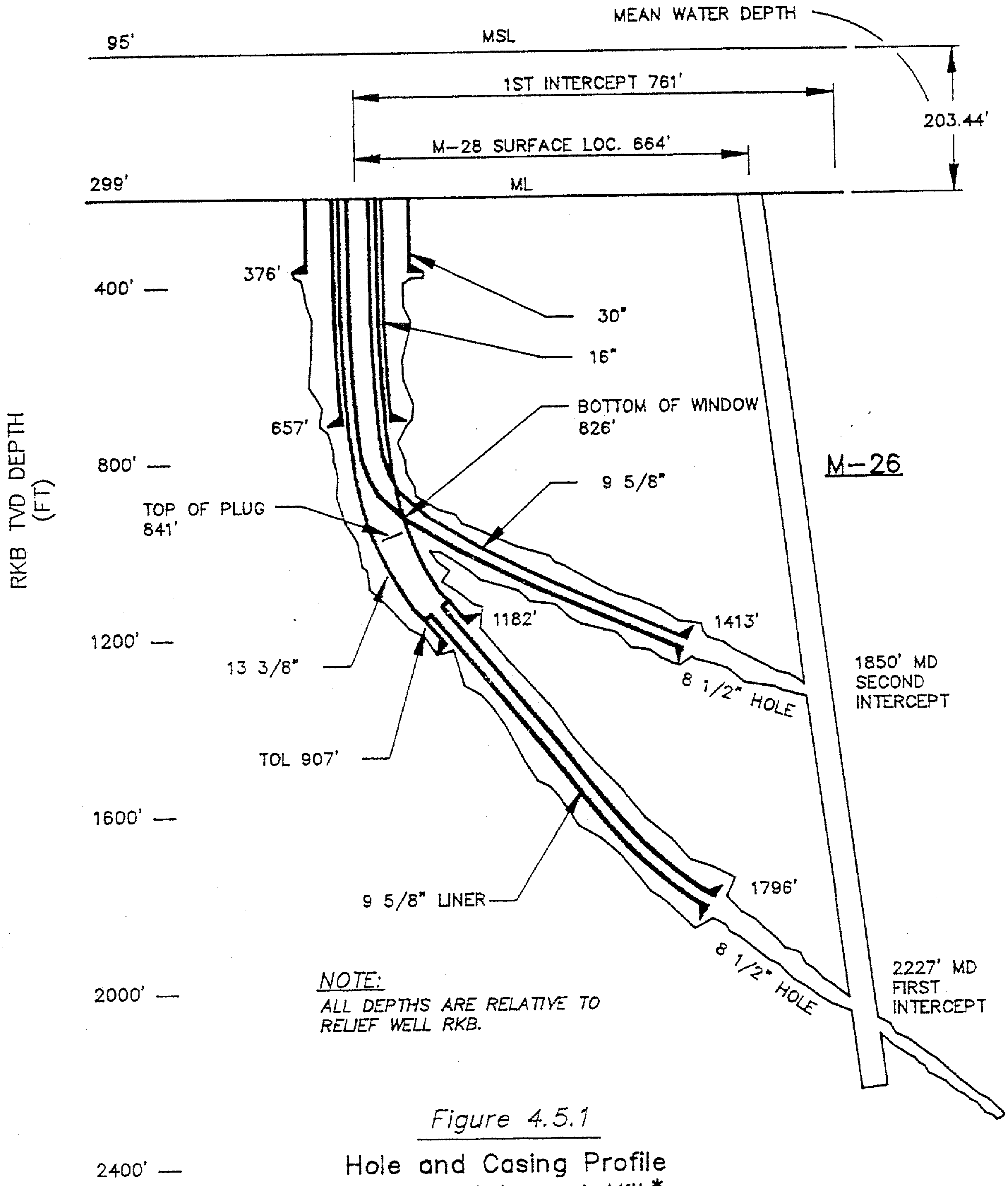
- The error of uncertainty increases with depth and may be quite large in a deep well.
- Directional control becomes more difficult as rock strength increases with depth.
- Directional control becomes more difficult as the size of the directional tools are restricted by the progressively smaller strings of casing.
- High temperature gradients in deep wells can hamper logging and ranging surveys.
- The time to drill the relief well will be extended exponentially.

4.5.3 Intermediate (off-bottom) Intercept. The intermediate intercept has several advantages.

- The error of uncertainty for the relief and blowout wells will be reduced as compared to a deeper well with equivalent survey accuracy. The blowout may be more easily located with ranging tools.
- The relief well casing size can be larger at the shallow intercept. This significantly reduces the pumping equipment requirements.
- The time required to drill the relief well to intermediate depth will be less than if drilled to total depth. Oil pollution is minimized due to reduced drill time.

The intermediate intersect approach has few disadvantages assuming that a proper evaluation is completed with respect to depth of intersection, depletion in the blowout well, and fracture gradient at the intercept point. If the problem well is cased at the depth of the intercept, that casing must be perforated or milled prior to killing.

Figure 4.5.1 is an example of a blowout that required a bottom and mid-range intersect. The blowout was believed to be flowing from as many as 6 sands. An additional intersect at a shallower depth was planned but never required.



NOTE:
ALL DEPTHS ARE RELATIVE TO RELIEF WELL RKB.

Figure 4.5.1

Hole and Casing Profile for Dual Intersect Kill *

**Cook Inlet, Alaska 1988*

DEA PROJECT NO. 63

JOINT INDUSTRY PROGRAM for FLOATING VESSEL BLOWOUT CONTROL

4.6 OBSERVATION WELLS

An observation well is designed to perform the task suggested by its name. It should provide a means to observe subsurface formations and evaluate several parameters that may be affected by a blowout.

Observation wells are becoming more common for shallow gas blowout control. It is recommended to drill observation wells prior to commencing a relief well for a shallow gas blowout. This recommendation is based on case histories and field experiences. The mechanics of shallow gas blowouts have tended to cause subsurface soil disturbances.

The same situation has not been noticed, or at least has not be reported, for deeper blowouts with casing and cement integrity. However, no reason exists for not drilling an observation well for deeper blowouts other than the time required to drill an observation well and then the relief well. Procedures have been designed for some wells where it can be used as an observation well and then a relief well.

Observation wells can monitor formations as they are drilled and logged. They are typically plugged after being drilled. Occasionally wells have been drilled and used as a permanent monitoring station by installing downhole pressure sensors to provide a continuous record of transient pressures.

The first observation well that has been fully reported was in 1985 in southeast Asia. It was instrumental in drilling a relief well for a shallow gas blowout.

4.6.1 Purpose. The purposes of observation wells are simple. They provide monitoring or observation of the soil and pressure situations. Typically, they are used for the following reasons:

- Identify zones of pressure charging
- Identify zones of pressure depletion
- Determine rate of pressure change
- Evaluate fluid movement near the well bore
- Identify the degree of subsurface soil disturbance that may impact drilling of the relief well.

The information obtained from the observation well is used to plan the relief well. It can affect casing setting depth programs. This could affect casing sizing if additional unexpected strings of pipe are required. Muds may be required where seawater had been sufficient to drill the equivalent sections on the blowout well.

The typical procedure is to drill the observation well at least as deep as the same depth of the first major casing string in the relief well. This could be the depth for structural or conductor pipe. Preferably it will be the depth of the surface casing.

4.6.2 Drilling Guidelines. A key factor in drilling observation wells is to use caution. The formations may contain uncertainties that could cause problems. In fact, the purpose of drilling these wells is to obtain information on the uncertainties.

The wells can be drilled vertical from the site. This will give some valuable information. However, it should be remembered that zones in close proximity to the blowout could pose problems not encountered at a greater distance. Section 4.4.6 gives details on some cases of disturbances at known distances from the shallow gas blowout.

Another option other than a vertical well is to drill a directional profile toward the blowout well that does not completely intersect the well. This provides a better observation point without actually drilling into the blowout well.

Drilling riserless is recommended for offshore situations if possible. The shallow charged zones can blowout. It is not desirable to bring this gas on the rig. Allowing it to flow subsea will not cause a problem to the rig if proper safe guards are implemented.

Some field cases have shown subsurface disturbances. These were evidenced by the fact that seawater had been used originally to drill the same sections in the blowout well. However, the observation well required mud or weighted gel water to drill the same intervals.

The well can be drilled as a completely expendable, low cost hole. It is drilled with a bit, motor and a MWD tool. The MWD tool provides a complete logging service except for RFT's. Guide bases are not used. RFT's can be run if the tool can be lowered into the well. After the well is drilled, it can be plugged. This option is clearly suited for floater drilling.

Another option is to drill the observation well in a manner similar to a normal well. Casing and cement are used. The well can be fully logged including RFT's. If desired, procedures can be established for using the well as a continuous pressure monitoring source.

4.6.3 Precautions. Most precautions for the observation wells should be obvious. Encountering pressure charged zones is possible. Hole stability may be a concern.

If the well starts to flow and casing/BOPs have not been used, procedures do not exist for controlling the flow. However, this may not be the major concern that it seems. If the flow is caused by the pressure charging from the blowout, the flow should cease at some time after the blowout well is killed. This matter must be addressed with the appropriate authorities.

The benefit of the well flowing is that it serves as a vent for the gas. This should facilitate drilling the relief well. This matter must be addressed with the appropriate authorities.

Drilling precautions include the standard warnings. Drill at low rates. The rates should be sufficiently slow to obtain a good MWD log of the drilled section. Circulate the well clean. If casing is to be used, cement carefully and use gas blocking agents. Use subsea TV cameras or sonar units to monitor gas leaving the hole if a riserless mode is used.

4.7 KILL HYDRAULICS

4.7.1 Introduction. The general objective of the relief well is to kill the blowout well with hydraulic control. This includes hydrostatic and friction pressure components. Early relief wells relied principally on hydrostatic control. Techniques developed in the late 1970's and the early 1980's combined friction and hydrostatic pressures to gain control of the well in 2 stages.

Various techniques have been proposed to kill blowouts via relief wells. These include the following:

- Overbalance kill
- Dynamic kill
- Reservoir flood (saturation kill)
- Momentum kill
- High rate production kill

Some of these are discussed briefly in Section 3.0. They will be summarized in the following paragraphs.

Overbalance Kill. Historically most blowout kill attempts were based on the overbalance kill concept. After fluid flow communication has been established between the relief well and the blowout wellbore with water, drilling fluid of the required density is pumped at a rate sufficiently high to overcome flow and kill the well. The method requires a good understanding of the reservoir pressure in order to select the kill fluid density. Many wells have been killed by this method using heavy weight drilling mud or cement. The technique usually requires a significant number of high pressure pumping units to achieve the required flow rates.

The major disadvantage of the technique lies in the potential for formation fractures away from the problem wellbore, which would prevent the kill fluid from reaching that wellbore. The potential for high injection pressures can also mean that the required flow rates can not be achieved and the technique will fail to stop the flow.

This technique has been most successful where the blowout rate itself was relatively low. It will not be discussed further in this report. Other techniques that can provide quantitative results will be presented.

Dynamic kill. This is a relatively new development, i.e., late 1970's and early 1980's, which has been used successfully in controlling various high rate blowouts. In this method the blowout is brought under control by initially pumping water or brine at a rate sufficient to overcome the blowouts source's formation pressure, through the combination of the hydrostatic pressure of the water in the wellbore, supplemented by the frictional pressure associated with the flow of kill fluid up the problem wellbore. After the formation flow is stopped, a drilling fluid of sufficient density to statically control formation pressure is pumped into the blowout. The dynamic kill process must be continued until the higher density drilling fluid provides sufficient hydrostatic head to control the well under static conditions.

Water is pumped during the initial phase because of its general availability. Communications are established with the water. Brinewater or mud, which is more difficult to prepare and store, can be used for a final kill after the water has dynamically killed the flow.

During the pumping process, a monitoring string is used in the relief well to provide continuous pressure data. The frictional and hydrostatic pressure components in the blowout can be controlled through adjustment of the injection rate, and thus be related to a balance between the required kill pressure and formation fracturing pressure.

Reservoir Flooding. This process is occasionally called a saturation process. It involves flooding the producing reservoir in the vicinity of the problem well by pumping water from a closely positioned relief well until production in the blowout well completely changes to water. If the water bank pressure has been maintained above the reservoir pressure, it will stop the gas or oil flow.

This technique is limited because higher volumes of water will be required as the distance between wells increases and, with a high blowout rate, it may not be possible to develop sufficient flow rates to, in fact, flood the producing formation around the problem wellbore. The reservoir parameters must be understood particularly well for this concept to be effective. Multi-layered zones cause complications.

Momentum Kill. This kill concept supposedly utilizes the momentum of the kill fluid to overcome the momentum of the well fluids and reverse the flow. Although various technical papers have described successful field cases, the data in those papers do not seem to support the method. It appears that a friction kill was the actual kill technique and not a momentum principle. Also, momentum kill technology has not been applied to relief wells yet.

High Rate Production Kill. The high rate production kill concept is based on a relief well to produce fluids from the blowout source zone, at a sufficient rate and under controlled conditions, to kill the blowout through essentially the combination of reservoir drawdown and depletion of the blowout zone.

It has been used successfully to kill a dual zone producing well where both zones were blowing out concurrently, and where the design of a conventional relief well kill program was complicated by parted tubing strings in the original well and a rupture in the casing through which water was being produced. After commingled production was initiated from the relief well, both producing zones were killed within the calculated time frame.

This technique will not be discussed further in this report.

4.7.2 Dynamic Kill. (Note: The dynamic kill method was developed by E.M. Blount of Mobil in the late 1970's as a response to a blowout in Arun, Indonesia. A major article was published on the topic in World Oil, October 1981, pp. 109-126. The following description of the dynamic kill is based principally on the article.)

Dynamic kill is an interim condition where a blowout is killed by injecting a fluid through a communication link and up the blowout annulus at such a rate that the static formation pressure is exceeded and the well ceases to produce. The flow is somewhat multiphase, produced fluid plus injected fluid before the well is killed and single phase, injected fluid only, immediately after the well is dynamically killed.

Flow rate must be maintained such that the sum of frictional and hydrostatic pressure exceeds the static formation pressure until a heavier static kill mud can replace the lighter dynamic kill fluid. The injection rate can be varied to control the bottom hole pressure by adjusting the frictional component much in the same way the back pressure is controlled with an adjustable choke when conventionally circulating out a kick with a drilling rig. The basic approach to dynamic kill uses methods developed for analyzing performance of producing wells and considers the relief well and blowout well as a single system.

A communication link is connected between the two wells. Tubing is run in the relief well and filled with water to monitor pressure. Kill fluid is injected down the annulus of the relief well and up the annulus of the blowout along with produced fluids.

Since the object of the kill is to achieve a bottom hole pressure (BHP) dynamically that exceeds the static formation pressure but does not fracture the formation, controlling and monitoring BHP is the basis for success in a dynamic kill. BHP is caused by the hydrostatic pressure exerted by the column of water plus the frictional pressure drop up the annulus of the blowout well.

BHP is controlled by altering the flow rate into the annulus of the relief well to adjust the frictional pressure, since there is no control, i.e., choke, on the blowing well as in a kick control operation. BHP is monitored by observing surface pressure at the tubing in the relief well and adding hydrostatic pressure of water filling the tubing. All injections must be down the relief well annulus and the tubing must be full of static fluid.

The relief valve is the fracture pressure of the formation. If the formation is fractured, not all of the fluid injected into the relief well will go up the blowout. The fracture pressure limitation is thus imposed on the relief well, upstream of the communication channel rather than in the blowout well.

The kill procedure can be controlled precisely by observing the tubing pressure, so the rate of the initial kill fluid can be increased until the static formation pressure is exceeded. The well should be dynamically killed at this point. Injection of the intermediate fluid can commence and the rate reduced after the intermediate fluid enters the blowout well to keep the BHP below the fracture pressure but above the static formation pressure.

Design Parameter. In designing a dynamic kill operation, several parameters must be predetermined, the first is the static bottomhole pressure. When the operation is begun and the kill fluid is injected, flow up the annulus of the blowout well is multiphase before the well is dead and single phase (injected fluid only) after the well is dead. The basic factors are as follows:

- Kill fluid density
- Kill fluid injection rates
- Size of relief well
- Hydraulic horsepower
- Maximum allowable BHP to prevent drill pipe from being injected.

Each will be discussed in the following sections.

Kill Fluid Density. The density of the ideal dynamic kill fluid can be determined by finding a fluid such that the introduction of a bubble of gas into the single phase stream, flowing at the rate required to control the dead well, will increase the frictional pressure component as much as the hydrostatic pressure component is reduced. The density of the initial kill fluid can be determined by the following condition. (Refer to the end of this section for nomenclature)

$$\rho_f \leq \frac{12.836\ P_S}{TVD}$$

The derivation follows:

The frictional pressure, $$\Delta P_f = \frac{CfL\,\rho_l V_f^2}{d_h}$$

Where V_f is the velocity of the fluid, d_h is the hydraulic diameter and C is a constant. Assume that gas bubbles entered the flow stream. In bubble flow regime the continuous fluid is the liquid phase. Let ϕ_g be the fraction of gas volume to the total fluid volume, then,

$$V_f = \frac{V_l}{(1 - \phi_g)}$$

$$\rho_f = \rho_l (1 - \phi_g) + \rho_g \phi_g$$

Since

$$P = \Delta P_{hyd} + \Delta P_f$$

By taking the derivative of the above equation with respect to the gas fraction, then,

$$\frac{d\ P}{d\ \phi_g} = \frac{d\ \Delta P_{hyd}}{d\phi_g} + \frac{d\,\Delta P_f}{d\phi_g} \qquad (4.7.1)$$

$$\Delta P_{hyd} = \frac{0.433}{8.337}\ \rho_f TVD$$

$$= \frac{0.433}{8.337}\ TVD\ [\rho_l(1 - \phi_g) + \rho_g\ \phi_g]$$

Then,

$$\frac{d\,\Delta P_{hyd}}{d\,\phi_g} = \frac{0.433}{8.337}\ \mathrm{TVD}\,[-\rho_l + \rho_g]$$

$$= -\Delta P_{hyd} + \Delta P_{hyd_g}$$

$$\equiv -\Delta P_{hyd} \tag{4.7.2}$$

$$\Delta P_f = \frac{C f L \rho_l V_f^{\,2}}{d_h} = \frac{C f L \rho_l V_l^{\,2}}{d_h (1 - \phi_g)^2}$$

$$\frac{d\Delta P_f}{d\,\phi_g} = \frac{2\,C f L \rho_l V_l^{\,2}}{d_h (1 - \phi_g)^3} = \Delta P_{f_1} \frac{2}{(1 - \phi_g)^3} \tag{4.7.3}$$

Substitute eq. (6.2) and (6.3) into (6.1)

$$\frac{dP}{d\phi_g} = 2\Delta P_{f_1} \frac{1}{(1 - \phi_g)^3} - \Delta P_{hyd}$$

The pressure should increase with the introduction of gas bubbles, i.e., the following should occur:

$$\frac{dP}{d\phi_g} \geq 0 \tag{4.7.4}$$

Since ΔP_{f_1} and ΔP_{hyd} are always non-negative, and that

$$\frac{1}{(1 - \phi_g)^3} \geq 1$$

Then the condition,

$$2\,\Delta P_{f_1} \geq \Delta P_{hyd} \tag{4.7.5}$$

will ensure condition (6.4)

Since, $P_s = \Delta P_{hyd} + \Delta P_{f_1}$

or, $\Delta P_{f_1} = P_s - \Delta P_{hyd}$

substitute into (6.5)

$$2\,(P_s - \Delta P_{hyd}) \geq \Delta P_{hyd}$$

or $$2\,P_s \geq 3\,\Delta P_{hyd}$$

$$P_s \geq 1.5\,\Delta P_{hyd}$$

but $$\Delta P_{hyd} = \frac{0.433}{8.337}\,\rho_f\,TVD$$

$$P_s \geq \frac{1.5 \times 0.433}{8.337}\,\rho_f\,TVD$$

or,

$$\rho_f \leq \frac{12.836\,P_s}{TVD}$$

Estimation of flow rate requirement:

$$\Delta P_f = \frac{11.41\,fL\,\rho q^2}{d_e^5}$$

In the blowout well, there should be,

$$\Delta P_{f_b} = P_s - \Delta P_{hyd}$$

Such that the BHP of blowout well is P_s.

Then $$P_s - \Delta P_{hyd} = 11.41 \left(\frac{fL}{d_e^5}\right)_b \rho_f q_b^2$$

or $$q_b^2 = \frac{(P_s - \Delta P_{hyd})}{11.41\,\rho_f} \left(\frac{d_e^5}{fL}\right)_b$$

$$q_b = \left[\frac{(P_s - \Delta P_{hyd})}{11.41\,\rho_f} \left(\frac{d_e^5}{fL}\right)_b\right]^{1/2}$$

Recall $k = \dfrac{q_b}{q_r}$

Injection rate required in relief well:

$$q_r = \frac{1}{k} \left[\frac{(P_s - \Delta P_{hyd})}{11.41\, \rho_f} \left(\frac{d_e^5}{fL} \right)_b \right]^{1/2}$$

Size of the relief well. In this section a technique is derived for determining the size a relief well must be or how many relief wells are required to enable a blowout to be dynamically killed considering the poorest communication system and without exceeding the pressure limitations of the surface equipment.

Examine the frictional loss equation:

$$\Delta P_f = \frac{C fL\, \rho_f\, q^2}{d_e^5}$$

$$= C \left(\frac{fL}{d_e^5} \right) \rho_f\, q^2$$

Assuming complete turbulence, or

$$f = \frac{0.25}{\left(2 \log \frac{d_h}{\overline{e}} + 1.14 \right)^2}$$

then the term $\left(\frac{fL}{d_e^5} \right)$ is a casing-tubing characteristic which does not depend on fluid properties.

This term is called flow resistance. The flow resistance of a well consisting of N multiple sections in series is the sum of each section flow resistance, i.e.,

$$\left(\frac{fL}{d_e^5} \right)_{total} = \sum_{i=1}^{n} \left(\frac{fL}{d_e^5} \right)_i \tag{4.7.6}$$

For a well with N parallel flow resistances, the equivalent flow resistance is given by

$$\left(\frac{fL}{d_e^5}\right)_{equi} = \frac{1}{\left[\sum_{i=1}^{n} \left(\frac{d_e^5}{fL}\right)_i^{1/2}\right]^2} \qquad (4.7.7)$$

Consider the blowout well/communication channel/relief well system. Assuming the flow resistance of the blowout well is

$$\left(\frac{fL}{d_e^5}\right)_b$$

then the question is to determine the flow resistance of the relief well

$$\left(\frac{fL}{d_e^5}\right)_r$$

and the rate required to dynamically kill the well with initial kill fluid, and the corresponding hydraulic horsepower required. Assume that the maximum surface equipment operating pressure $P_{an\text{-}max}$, formation fracture pressure P_{frac}, and the reservoir static pressure P_s are known.

In a dynamic kill, the BHP of blowout well should be kept above the static reservoir pressure and the BHP of the relief well below the formation fracture pressure. Therefore, the maximum allowable pressure drop across the communication channel still achieving dynamic kill is $P_{frac} - P_s$. When a single fluid is injected through the relief well and comes out from the blowout well with a WHP = 0 psig, the injection pressure of the relief well equals the total frictional pressure loss, i.e.,

$$P_{an} = \Delta P_{f_b} + \Delta P_{f_r} + \Delta P_{f_c}$$

Since the worst communication should be prepared for, the BHP of blowout well and relief well are assumed to be P_s and P_{frac}, respectively.

Then $\quad \Delta P_{f_b} = P_s - \Delta P_{hyd}$

and $\quad \Delta P_{f_b} = P_{an} - P_{frac} + \Delta P_{hyd}$

Then the maximum allowable

$$\Delta P_{f_{r\,max}} = P_{an\text{-}max} - P_{frac} + \Delta P_{hyd}$$

The relief well should be designed such that

$$\Delta Pf_r \leq \Delta Pf_{r\ max}$$

or,

$$\frac{\Delta Pf_r}{\Delta Pf_b} \leq \frac{\Delta Pf_{r\ max}}{\Delta Pf_b}$$

$$\frac{\Delta Pf_r}{\Delta Pf_b} \leq \frac{P_{an\text{-}max} - P_{frac} + \Delta P_{hyd}}{P_s - \Delta P_{hyd}} \qquad (4.7.8)$$

since $\Delta Pf = \dfrac{11.41\, fL\, \rho_f\, q^2}{d_e^{\,5}}$

then $\Delta Pf_r = 11.41 \left(\dfrac{fL}{d_e^5}\right)_r \rho_f\, q_r^2$

$$\Delta Pf_b = 11.41 \left(\frac{fL}{d_e^5}\right)_b \rho_f q_b^2$$

The (6.8) becomes

$$\frac{\left(\dfrac{fL}{d_e^5}\right)_r q_r^2}{\left(\dfrac{fL}{d_e^5}\right)_b q_b^2} \leq \frac{P_{an\text{-}max} - P_{frac} + \Delta P_{hyd}}{P_s - P_{hyd}}$$

or

$$\frac{\left(\dfrac{fL}{d_e^5}\right)_r}{\left(\dfrac{fL}{d_e^5}\right)_b} \leq k^2 \left[\frac{P_{an\text{-}max} - P_{frac} + \Delta P_{hyd}}{P_s - P_{hyd}}\right] \qquad (4.7.9)$$

Where $k = \dfrac{q_b}{q_r}$ = fraction of flow entering blowout well and 1 - k = leak off

in fraction of q_r.

Equation (6.9) is the basic equation for designing the relief well. Precise calculation of rates is not required. Errors in assumptions of roughness factors, fluid properties, etc., cancel out. If a single relief well cannot be practically completed with large enough d_e then multiple relief wells will be required. Equation (6.7) can be used to predict the effective d_e for different size wells.

Estimation of hhp required. Assuming the injection wellhead pressure at relief well is $P_{an\text{-}max}$ then

$$HHP = \frac{42\, q_r\, P_{an\text{-}max}}{1714}$$

$$= \frac{q_r\, P_{an\text{-}max}}{40.81}$$

Derivation of maximum allowable BHP to prevent drillstring ejection. This section only considers ejection from a vertical hole. A force tending to eject the drillstring is composed of the frictional drag and the hydraulic force acting on various cross sections of the drill string. The hydraulic force is sometimes considered as two forces called buoyancy and form drag but is correctly handled as one force which is the resultant of the hydraulic pressure acting on the cross-section of the drill string.

$$\text{Hydraulic Force } (F_H) = \frac{\pi}{4} \quad d_1^2 P_{BH} \tag{4.7.10}$$

where,

d_1 = OD of drill pipe
d_o = ID of casing or open hole

The total frictional drag can be calculated by determining the frictional pressure drop ($\Delta P f$) and applying this stress to cross section of flow (A_{an}):

$$\text{Total Drag} = \Delta P_f A_{an} \tag{4.7.11}$$

This total frictional drag is applied to both the inside surface of the casing and the outside surface of the drill string. The ratio (R) of the total frictional drag that applies to the inner string is determined by the ratio of the shear stresses;

Drag on drill string (F_{DS}):

$$F_{DS} = R \Delta P_f \; \pi/4 \; (d_o^2 - d_1^2) \tag{4.7.12}$$

$$R = \frac{1}{2 \ln \left(\dfrac{d_o}{d_1} \right)} - \frac{d_i^2}{(d_o^2 - d_1^2)} \tag{4.7.13}$$

The weight of the drill string (W_s) resists the ejection force. If the ejection force is greater than the weight, the pipe will be ejected. The air (vacuum) weight of the string is used as W_s since the buoyancy is included in the hydraulic force. If the bit is plugged and the drill pipe is full of mud the total weight of the mud and drill pipe should be included in the weight of the drill string. If the bit is plugged and the drill pipe empty, only the weight of the steel is considered. If the bit is not plugged and flow goes up the inside the drill pipe as well as outside the drill pipe the drag on the inside must also be considered.

$$\frac{\pi}{4} d_1^2 P_{BH} + \frac{\pi}{4} (d_o^2 - d_1^2) R \Delta P_f \leq W_s \qquad (4.7.14)$$

P_f can be calculated from various flow equations but since we are monitoring and controlling on bottom hole pressure (P_{BH}) much of the potential inaccuracies of frictional calculations can be eliminated by calculating ΔP_f as follows:

$$\Delta P_f = P_{BH} - \Delta P_{hyd} \qquad (4.7.15)$$

$$\frac{\pi}{4} d_1^2 P_{BH} + \frac{\pi}{4} (d_o^2 - d_1^2) R (P_{BH} - \Delta P_{hyd}) \leq W_s$$

$$P_{BH}\left[\frac{\pi}{4} d_1^2 + \frac{\pi}{4} (d_o^2 - d_1^2) R\right] \leq W_s + \frac{\pi}{4} (d_o^2 - d_1^2) R \Delta P_{hyd}$$

$$P_{BH\,max} = \frac{W_s + \frac{\pi}{4} (d_o^2 - d_1^2) R \Delta P_{hyd}}{\frac{\pi}{4} d_1^2 + \frac{\pi}{4} (d_o^2 - d_1^2) R} \qquad (4.7.16)$$

where

$$\Delta P_{hyd} = \frac{\rho_f}{8.33} (0.433) \times TVD = \frac{\rho_f (TVD)}{19.25} \qquad (4.7.17)$$

$$P_{BH} \leq \frac{W_s + A_{an} R \Delta P_{hyd}}{A_{d_p} + A_{an} R} \qquad (4.7.18)$$

NOMENCLATURE

A_{an}	Area of annulus, sq. in.
A_{dp}	Area of drill string O.D., sq. in.
D	True vertical depth, feet (TVD)
d_r	Equivalent diameter, inches
d_h	Hydraulic diameter, inches
f	Fanning friction factor (0.25 Moody Friction Factor)
1-k	Fractional leak off, $K = q_b / q_1$
L	Measure depth, feet (MD)
P_{frac}	Fracture pressure of formation, psig
P_{BH}	Bottom hole pressure (BHP), psig
P_{an}	Injection pressure in relief well annulus, psi
P_s	Static formation pressure, psig
P_{tbg}	Tubing pressure, relief well, psig
ΔPl	Frictional pressure loss, psi
ΔP_{lb}	Frictional pressure loss, blowout well (P_s - P_{hyd}), psi
ΔP_k	Frictional pressure loss, communication channel between wells, psi
ΔP_{fr}	Frictional pressure loss, relief well (P_{an} - [P_{frac} - P_{hyd}])
ΔP_{hyd}	Component of BHP due to hydrostatic weight of fluid, psi
R	Ratio of frictional drag on drill string, total friction
ϕg	Gas fraction
q	Flow rate, bpm
q_b	Flow up blowout well (kill rate), bpm
q_s	Injection down relief well, bpm
W_s	Weight of drill string in air, lb

WHP	Wellhead pressure, psi
ρf	Density of fluid, ppg

SUBSCRIPTS

b	Blowout well
c	Communication
f	Fluid
r	Relief well
g	Gas

Example of Dynamic Kill Calculations. Designing a kill job using the dynamic approach is best suited to computers. Many sets of calculations will be necessary because of uncertainties associated with the kill operations. An example of a run for a recent 1990 blowout is presented below. The calculations were run with DYNKIL.

Example 4.7.1. A well blewout in the Gulf of Mexico in September 1990. The data used for calculating the dynamic kill procedure is included in the attached computer printouts. The well was difficult to kill because the blowout occurred after the tubing was out of the well. (Figure 4.7.1 and Table 4.7.1)

Workover/Production Kill Operations. The dynamic kill principle has applications in workovers and production operations to solve various problems. An example might be a hole in the tubing. The relatively small diameters of the tubulars enhance the dynamic killing operations. The kill string should use an inner diameter as large as reasonable to minimize the parasite friction pressures if pumping is down the tubing. An example is shown in Figure 4.7.2.

4.7.3 Reservoir Flooding. Reservoir flooding, or saturation flooding as it is occasionally termed, is perhaps the first formal technique developed for blowout kill operations. It was developed mathematically from basic reservoir equations. The key document used as the basis for the following discussion is "Reservoir Engineering Techniques To Predict Blowout Control During the Bay Marchand Fire" by Miller and Clements presented in Journal of Petroleum Technology, March 1972.

The reservoir flooding technique was formally developed by Shell Oil Company in response to its Bay Marchand platform in 1970. Eleven of the 22 wells were burning and relief wells were required. Since ranging tools were not developed at that time, the selected approach was to drill into the reservoir as near as possible and then the reservoir would be flooded via the relief well.

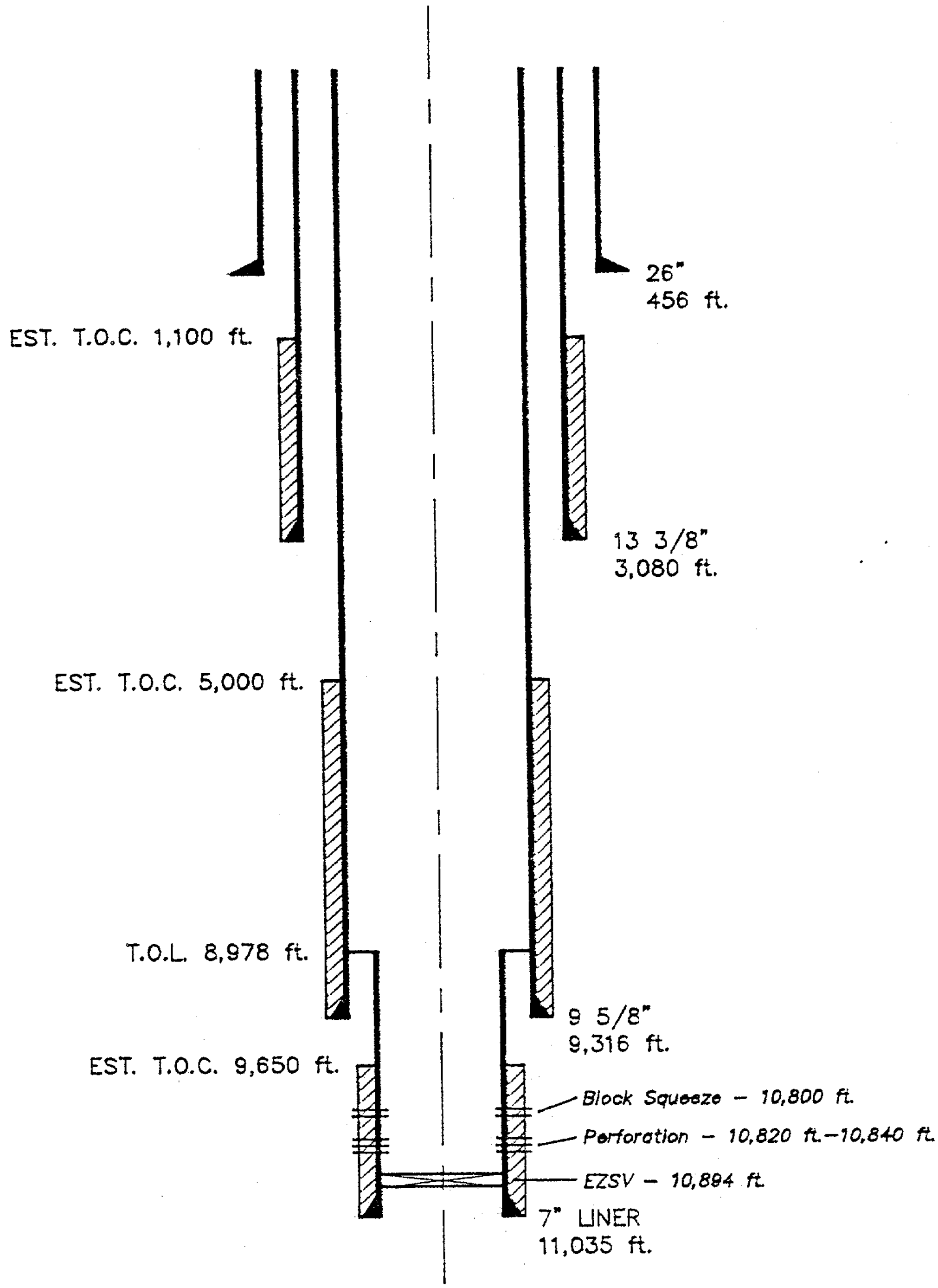


Figure 4.7.1

Blowout Configuration for
Example 4.7.1

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Table 4.7.1

DYNAMIC KILL 13 3/8" CASING
BHP 6460 psi

OPERATOR: PLACID OIL COMPANY DATE: 12-SEP-90

LEASE: B23 FIELD: EUGENE ISLAND, BLOCK 2

SEC. TWP. RNG. COUNTY: STATE: LA

DYNAMIC KILL SUMMARY

VOLUMES:
ANNULAR VOLUME OF BLOWOUT WELL (BBLS) .... = 723.049
ANNULAR VOLUME OF RELIEF WELL (BBLS) .... = 1425.938

INITIAL KILL:
WEIGHT OF INITIAL KILL FLUID (PPG) .... = 8.600
PUMPING RATE (BBLS/MIN) .... = 146.928

PUMPING RATE TO EJECT EMPTY DRILLSTRING (BBLS/MIN) = 78.685
CORRESPONDING BOTTOM-HOLE PRESSURE (PSI) .... = 5342.662

PUMPING RATE TO EJECT FULL DRILLSTRING (BBLS/MIN) = 81.017
CORRESPONDING BOTTOM-HOLE PRESSURE (PSI) .... = 5372.194

FINAL KILL:
WEIGHT OF FINAL KILL FLUID (PPG) .... = 12.500
RESERVOIR PRESSURE (PPG) .... = 11.624

PUMPS:
MAXIMUM PUMP PRESSURES (PSI) .... = 5491.963
HYDRAULIC HORSEPOWER REQUIRED .... = 19772.630

PUMPING SCHEDULE -- 8.60 PPG TO 12.50 PPG

TIME (MIN)	VOLUME PUMPED (BBLS)	INJECTION RATE (BBLS/MIN)	RELIEF WELL ANNULAR PRESSURE (PSI) MIN	MAX	RELIEF WELL TUBING PRESSURE (PSI) MIN	MAX
.00	.0	146.9	2226.	5492.	1680.	4946.
9.75	1418.2	146.9	737.	4003.	1680.	4946.
10.00	1486.1	102.7	186.	3452.	1680.	4946.
10.25	1510.9	95.4	105.	3371.	1680.	4946.
10.50	1534.3	91.8	64.	3330.	1680.	4946.
10.75	1556.8	88.4	26.	3291.	1680.	4946.
11.00	1578.5	85.0	0.	3256.	1680.	4946.
11.25	1599.3	81.8	0.	3223.	1680.	4946.
11.50	1619.4	78.6	0.	3192.	1680.	4946.
11.75	1638.6	75.6	0.	3163.	1680.	4946.
12.25	1675.0	69.9	0.	3111.	1680.	4946.
12.75	1708.6	64.4	0.	3066.	1680.	4946.
13.25	1739.5	59.3	0.	3026.	1680.	4946.
13.75	1768.0	54.5	0.	2991.	1680.	4946.
14.25	1794.1	50.0	0.	2961.	1680.	4946.
14.75	1818.1	45.9	0.	2935.	1680.	4946.
15.25	1840.0	41.9	0.	2913.	1680.	4946.
15.75	1860.1	38.2	0.	2892.	1680.	4946.
16.25	1878.2	34.5	0.	2874.	1680.	4946.
16.75	1894.6	31.0	0.	2858.	1680.	4946.
17.25	1909.3	27.6	0.	2844.	1680.	4946.
17.75	1922.3	24.4	0.	2831.	1680.	4946.
18.25	1933.7	21.2	0.	2820.	1680.	4946.
18.75	1943.5	18.2	0.	2810.	1680.	4946.
19.75	1959.1	13.0	0.	2802.	1680.	4946.
20.75	1969.2	7.2	0.	2795.	1680.	4946.
21.75	1973.6	1.4	0.	2788.	1680.	4946.
22.75	1974.5	.5	0.	2786.	1680.	4946.

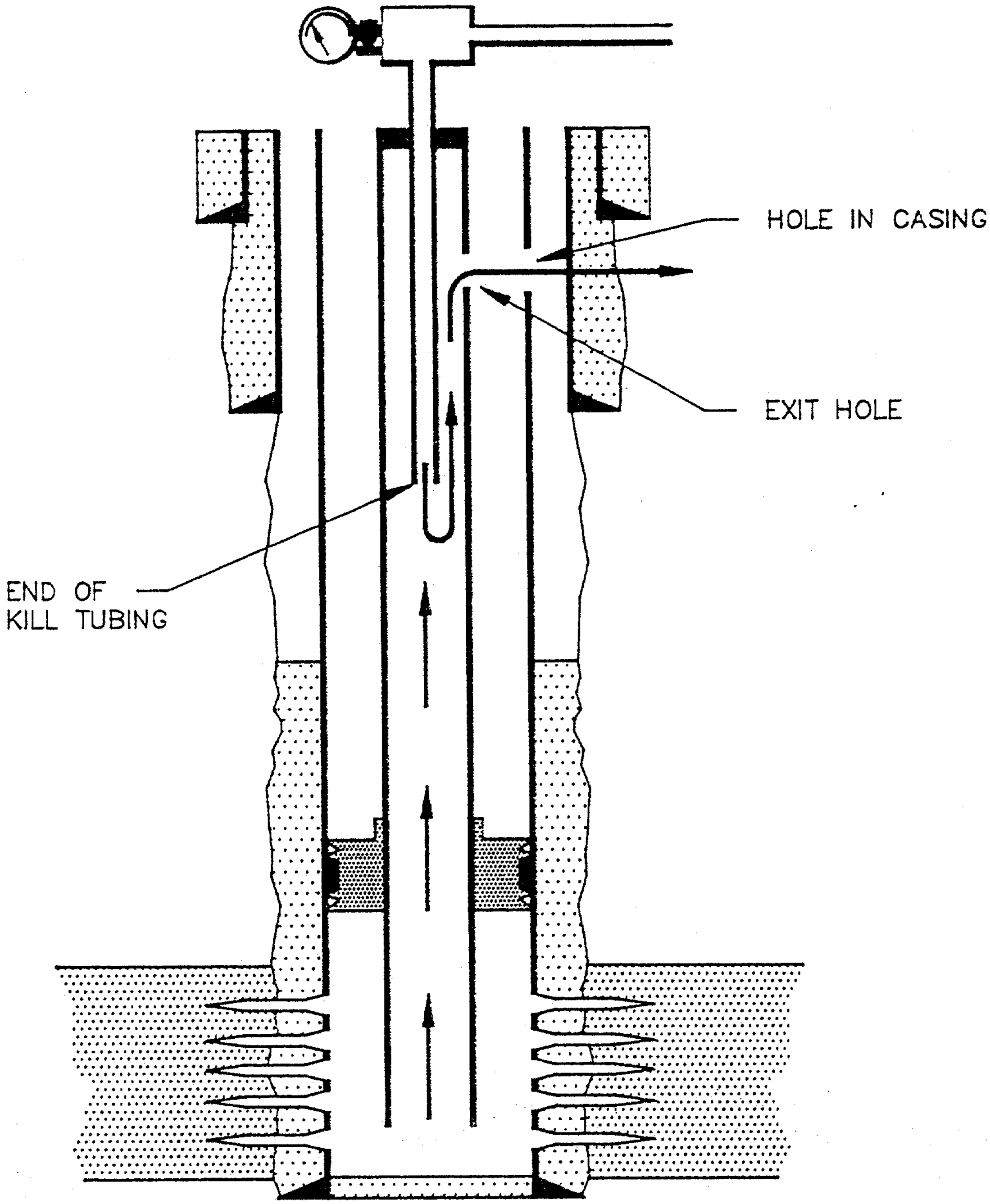

Figure 4.7.2

Dynamic Killing of a Production Well

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Reservoir simulation is an effective approach to predicting kill requirements. However, it is often impractical because of the number of uncertainties requiring many time-consuming runs. An easily run model, described below, was developed by Shell for the Bay Marchard incident.

The objective of the kill operation is quite simple (Figure 4.7.3). A water bank is created by injecting water into the reservoir via the relief well(s). The injection rate must be sufficient so the pressure internal to the water bank exceeds reservoir pressure. If the situation is maintained, the oil or gas flow will be shut-off when the leading edge of the water bank surrounds the blowout well.

The method will probably fail, as it has in many case histories, if the pumping rate is not sufficient so the internal water bank pressure is not maintained in excess of the reservoir pressure. If the water pressure is less than reservoir pressure, the injected fluids might be gas lifted up the blowout well. This gas lifting eventually allows the blowout to be killed if the water entrained in the flow stream increases the hydrostatic pressure and results in a lower flow rate. If this situation continues, it could "load up" the well and kill the flow, particularly if the reservoir pressure has been depleted via the flow.

Assuming a limiting bottom-hole injection pressure, Darcy's law of fluid flow yields the following expression for the maximum rate of water injection for a given size of water bank, r_b.

$$i_{wmax} = \frac{0.00707\, k_w h\, (P_{iwfmax} - \overline{P})}{\mu_w \ln \left(\frac{r_b}{r_{we}}\right)} \quad (4.7.19)$$

$$\text{where } r_{we} = r_{we}^{-s} \quad (4.7.20)$$

It is necessary to study the rise in bottom-hole injection pressure as the water bank volume increases while injecting at a constant rate, i_w. Thus the above equations can be rewritten in terms of the bottom-hole injection pressure, P_{iwf}.

$$P_{iwf} = P + \frac{141.4\, i_w\, \mu_w \ln \frac{r_b}{r_{we}}}{k_w h} \quad (4.7.21)$$

The cumulative volume of water injected can be expressed as a function of the radius of the water bank, r_b

$$W_i = \frac{\pi\, \phi\, h\, (1 - S_{wo} - S_{or})\, (r_b^2 - r_w^2)}{5.615}$$

These equations permit the calculation of the apparent time of water breakthrough, and volume of water because they ignore the way the water bank is distorted by flow into the producer. It is believed to be preferable to err on the conservative rather than risk underestimating the time and volumes to achieve breakthrough.

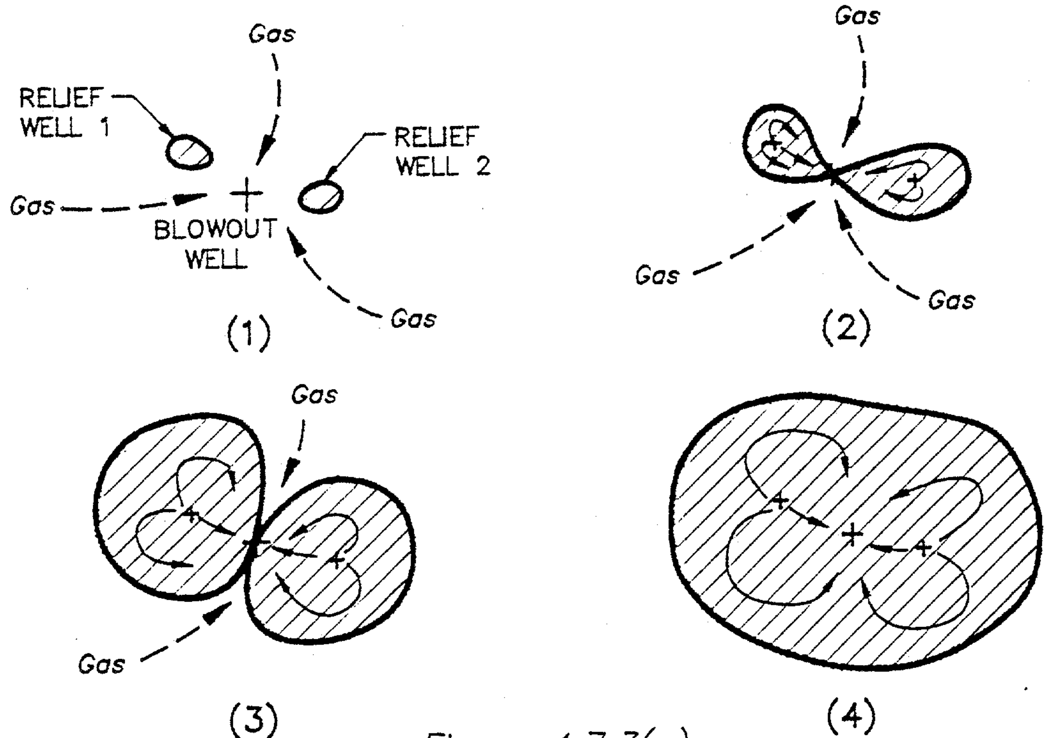


Figure 4.7.3(a)

Successive Positions of Gas/Water Contact During Killing Operations for Two Relief Wells

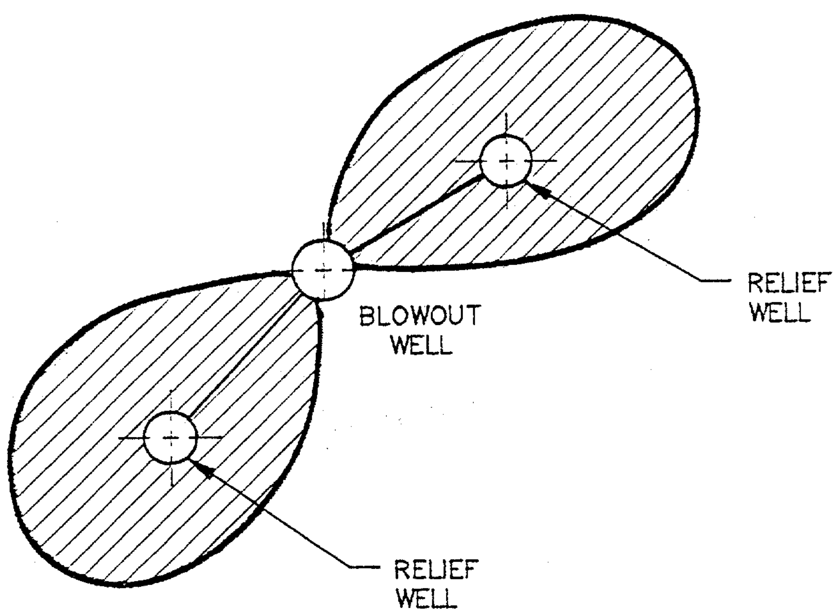
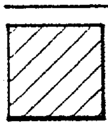


Figure 4.7.3(b)

Definition Sketch Showing Situation Before Shut-off*

KEY


WATER BANK

*After Miller and Clements

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The dimensions for each variable as follows:

h	=	net thickness, ft.
i_w	=	water injection rate, bbl/day
k_w	=	effective permeability to water, md
p	=	average static reservoir pressure, psia
P_{iwf}	=	injection of well bottom - hole pressure, flowing, psia
r_b	=	radius of injected water bank, ft.
r_w	=	wellbore radius of injector, ft.
r_{we}	=	effective wellbore radius of injector, ft.
S	=	skin effect factor
S_{wc}	=	connate water saturation, fraction
S_{or}	=	residual oil saturation, fraction
W_i	=	Cumulative water injected, bbl
μw	=	water viscosity, cp
ϕ	=	porosity, fraction

Although the dynamic kill method in Section 4.7.2 is considered preferable in most situations, the reservoir flooding method has distinct applications. An example involves shallow gas blowouts. The shallow formations will erode to a diameter that makes a dynamic kill virtually impossible. This situation lends itself to flooding.

Example of Reservoir Flood Calculations. A computer run of RSVFLD is presented as an example of the reservoir flood calculations. The program was used effectively on Piper Alpha because of the reservoir characteristics of the Piper sand.

Example 4.7.2 The following data as presented in the computer printout was used on Piper Alpha. A maximum well separation of 30 ft was used as it was believed that the relief well could meet this requirement of the first pass with minimum difficulty. (Figure 4.7.4).

7.4.4 Momentum Kill. The use of "engineered" fluid dynamics was first reported in 1977 as the momentum kill. The fluid dynamics kill concept utilizes the momentum of the kill fluid to overcome the momentum of the well blowout fluids and reverse the flow.

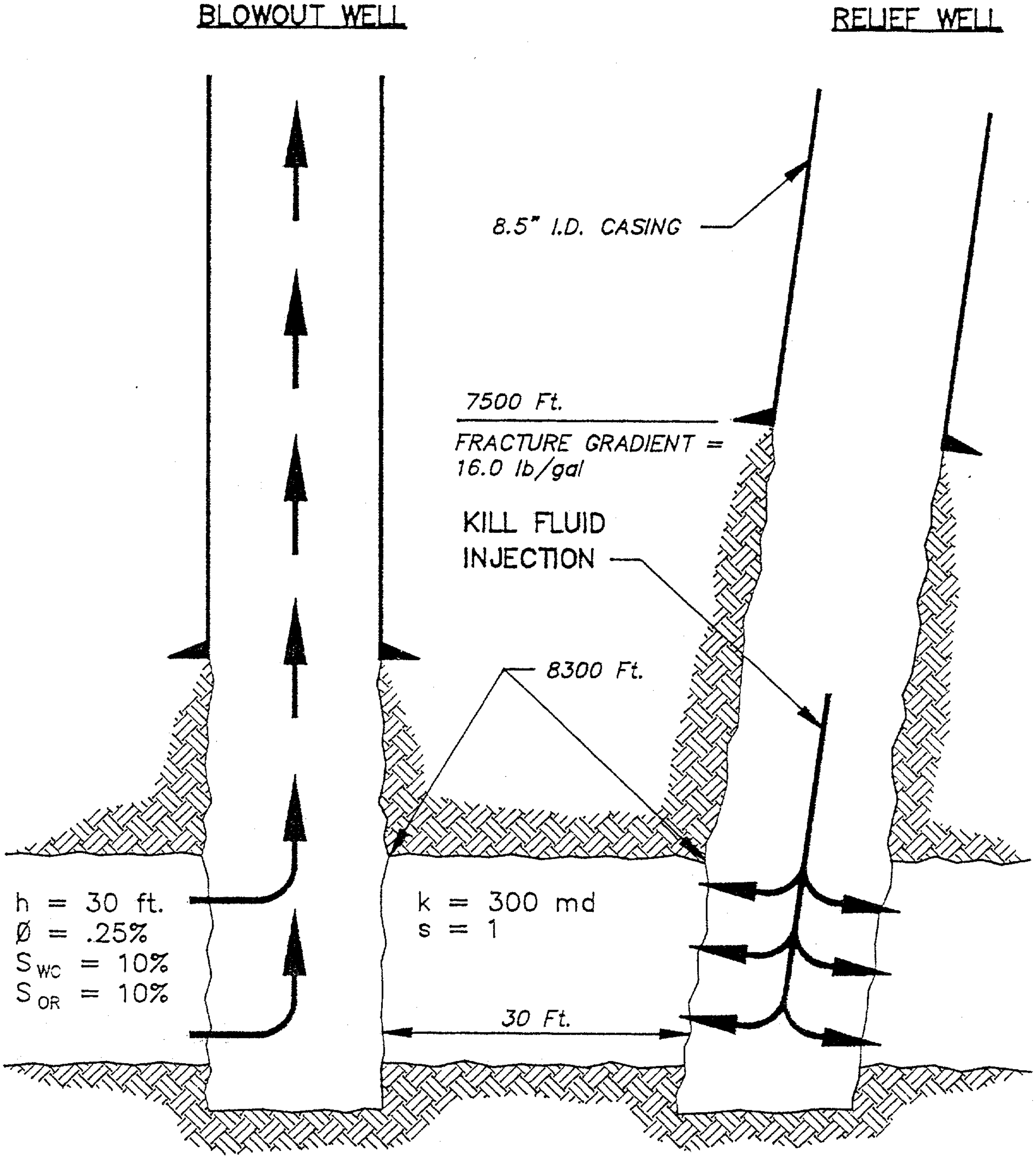

Figure 4.7.4

Illustration of Reservoir Flooding for Example 4.7.2*

*Piper Alpha P-01 Relief Well

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The momentum of the blowout fluids is shown in

$$M_g = \frac{\rho_{sc}\ Q_{sc}\ U_i}{g\ c} \tag{4.7.22}$$

where:

M_g	=	Gas momentum
sc	=	gas density, standard conditions
Q_{sc}	=	gas flow rate at standard conditions
Z_i	=	gas compressibility factor
T_i	=	Temperature
gc	=	gravitational constant
R	=	gas constant
S	=	specific gravity of the gas
M_m	=	Air molecular weight
P_i	=	pressure, point of interest
A_i	=	Area, point of interest
U_i	=	Velocity, point of interest

Units are in any basic system. As can be seen in Eq 4.7.20, the momentum of the gas is primarily a function of its velocity.

The momentum of the kill fluid is given by Eq. 4.7.21

where:

$$M_m = \frac{Q^2\ \rho}{g_c\ A} \tag{4.7.23}$$

ρ	=	fluid density
Q	=	volume flow rate
g_c	=	gravitational constant
A	=	area, point of intersect

Again, the units must be consistent with any basic system. The momentum of the kill fluid is a function of both density and velocity. The density of the kill fluid is considered to be critical in keeping the well killed once the momentum of the kill fluid has overcome the flow from the blowout.

The Momentum Kill is considered to have unanswered questions. If the field cases quoted by the authors are examined closely, it appears that these wells were killed dynamically, i.e., friction and hydrostatic pressure. It is not clear in the published papers as to what is offered by the momentum kill that is different than a dynamic kill. It is possible that it has differences that can be translated as advantages but these differences are not self-evident. As such, the technique will not be further discussed in this report.

4.8 NUMBER OF REQUIRED RELIEF WELLS

A common question in blowouts relates to the number of required kill wells. This is particularly true of big blowouts:

- Is one well sufficient for the kill?
- Will two relief wells be required?
- Should a second well be started as a standby?

Several factors affect these questions. Each will be discussed. The issue should be decided on a technical basis as opposed to an irrational decision or panic.

4.8.1 Kill Hydraulics. The initial step to determine the required number of kill wells is to evaluate the blowout well for the following items:

- Estimated bottom hole pressure
- Blowout fluid type
- Estimate of permeability ranges
- Zone thickness
- Wellbore geometry
- Water depth

Other factors not shown have a minor affect on the kill hydraulics.

Bottom hole pressure can be estimated from reservoir production information or from offset well data. If the blowout occurs while tripping on an exploratory well, the formation pressure is assumed to be equal to or less than the original mud weight before starting the trip. If the blowout occurs while drilling and taking a kick, the formation pressure is known to be greater than the original mud weight. If no other data is available, an average kick value of 0.5 lb/gal can be used. This value is a statistical average from 3800 well kicks.

With respect to blowout fluid types, gas and oil pose different kill situations. Gas has a lower hydrostatic pressure and higher blowout rates but it does drawdown the reservoir pressure more quickly. Oil blowouts are easier to kill from a hydrostatic view but have less drawdown in the reservoir. Permeability is a key factor in drawdown analysis.

A key factor is reservoir permeability. See Section 4.8.3 for more details. This value is seldom known with any degree of certainty. When making kill requirement estimates, it is important that the permeability be viewed with practicality. "What if" situations should be avoided. As an example for a blowout, "we believe the permeability to be 250 millidarcies but what if it is 500 millidarcies." This "what if" can mean the difference between 5 and 15 kill pumps and 50 to 100 bbl/min requirements. If our oil and gas reservoirs performed worldwide like we think they might in blowouts, there would never be an energy shortage.

Water depth has an impact on blowouts. Key effects are as follows:

- Seawater hydrostatic acts as a choke and prevents gas expansion in the critical low pressure environments.
- The water acts as a buffer and allows a safe vertical intervention.
- The water masks the effects of methane and H_2S release on the surface.
- Back pressure reduces flow rates out of the well.
- Reduced flow rates inhibit bridging.
- Reduced flow rates mitigate reservoir drawdown.

Several of these factors relate to kill hydraulics.

After these factors have been evaluated, the kill system must be designed. The kill calculations described in Section 4.7 on dynamic killing and reservoir flooding are commonly used. They are performed with computers and the results are given in horsepower, i.e., pressure and flow rates.

When converting from calculated horsepower based on pressures and flow rates to actual mechanical horsepower, an efficiency factor must be introduced. It is not appropriate to use exactly 10 x 400 hp pumps if the calculations show that 4000 hp is required. Some pumps invariably will fail when pressed into service. The longevity of service is important:

- For intermittent service when pump usage is less than 4 hours, an efficient factor of 1.2 is suggested.
- When expected kill time is from 4-8 hours, a factor of 1.3 should be used.
- Continuous service greater than 8 hours requires a factor of 1.5.

The calculated horsepower should be increased by the appropriate factor to determine the mechanical horsepower requirements.

A word of caution is extended. Realistic kill estimates should be used. Again, avoid "what if" situations. Most wells in recent history have been killed in 0.25-2 hours at low kill rates, i.e., Saga 2/4-14 (1989), Steelhead (1988), Ormat (1989).

After mechanical horsepower is determined for the blowout well, the relief well must be addressed. It will consume horsepower due to fluid friction. This is the primary technical basis for using large casing strings and a small drill string when pumping on the blowout. The parasite horsepower for the relief well is added to the blowout well requirements to give total horsepower.

To establish the number of kill wells, an arbitrary pressure limit is established as the upper pressure limit on a given relief well. The upper pressure limit might be controlled by casing burst pressure. If the hydraulic calculations are such that the pressure limit is exceeded, several options exist:

- Increase the size of the casing to be used on the relief well.
- Use a smaller drill string in the relief well.
- Add friction reducers to the kill fluid.
- Drill a second or third relief well.

Assuming that the initial 3 options have been exercised and that the relief well pressure still exceeds the maximum pressure limit, a second or third well is required.

The maximum pressure limit is arbitrary. Values from 2500 to 7500 psi have been used on various jobs. However, the range of 2500 to 5000 psi is recommended. Equipment availability is much greater in the lower pressure ranges and equipment downtime during pumping is lower.

The calculated horsepower to kill the blowout are directly related to reservoir pressure. This pressure can be considered as follows:

- Assume absolute open flow (AOF) with no reservoir depletion.
- Account for reservoir depletion but discount formation damage at high flow velocities.
- Account for reservoir depletion and formation damage.

Procedures that discount reservoir depletion are most common. However, reservoir depletion does occur and should be considered. It has not been done industry wide until very recently. Quantitative procedures for evaluating formation damage at high flow rates are not available and thus are not considered.

4.8.2 Worst Case Scenario. The most common approach used for blowout hydraulics calculations is to assume the worst case of absolute open flow (AOF) with no reservoir depletion. The results are usually demanding. An example is given below of a blowout in September 1990.

Example 4.8.1

A producing well blewout during a workover. The tubing was out of the well. The pertinent well data are as follows:

Data:

Perforation depth	10,800	ft
Casing depth	10,000	ft
Casing I.D.	8.5	in
Liner depth	10,900	ft
Liner I.D.	6.0	in
Initial reservoir pressure	6,460	psi
Fluid type	gas	(methane)
Permeability	250	md

Using dynamic kill calculations, the following horsepower requirements are determined.

For 6460 psi:

	Flow Rate,bbl/min	Pressure	HP
Minimum	146	2226	8014
Maximum	146	5492	19772

It is clear that worst case scenarios pose stringent conditions, even for medium pressure reservoirs. The demanding factor in this example is that the blowout well did not have any tubing that would provide assistance in generating friction pressures for the dynamic kill.

4.8.3 Affect of Reservoir Depletion. A reservoir under blowout conditions will experience a rapid pressure drop. The phenomenon is factual, calculatable and has been verified in blowouts where basic data exists. The pressure drop is important to kill calculations for the obvious reason that it makes the blowout well easier to kill. Several field cases will be used to illustrate the depletion occurrence.

Example 4.8.2

The SLB-5-4X well in Lake Maracabio, Venezuela blewout on 28 May, 1986. Pertinent data are as follows:

Thickness	800 ft
Permeability	Unknown
Porosity	15%
Fluid	Oil and gas
Gravity, API	38°
Flow rates	7000 bbl/day(est.) 40×10^6 SCF/day
BHT	400°F
BHP	14,620 psi

The well was capped and diverted on 24 October, 1986 using an offset kill technique with a derrick barge. A snubbing unit was rigged on top of the well. A 3 1/2" fish at 3642 ft was latched with an overshot. The drill string was cleaned out with a 1" string of tubing. The well was killed on December 12, 1986 by pumping fresh water at 5 bbl/min. During the 5 1/2 month period from the time the well blew out until it was killed, the reservoir around the wellbore depleted to a level sufficient to allow a freshwater kill. The pressure may have been depleted much lower than a freshwater equivalent.

Eample 4.8.3

The Saga 2/4-14 well developed an alleged underground blowout in early January, 1989. The producing zone was deep and high pressured. The stack was closed and the casing ultimately ruptured. (Figure 4.8.1) Pertinent well data are as follows:

Thickness	300 m
Fluid	Oil and condensate
Flowrate	18,000 bbl/day (underground)
BHP	13,319 psi

Blowout rate in the underground flow was estimated at 18,000 bbl/day, from a logging survey. A top kill was attempted and failed. The relief well intercepted the blowout well in December 1989. It was killed with the riser booster pump at rates of 2.9-10 bbl/min of 16.2 lb/gal mud. Pumps with 20,000 total hp that had been rigged on the well for the kill operations were never used.

Reservoir depletion is not a magical mystery tour. It is calculated with basic reservoir and fluid flow equations and is well suited for PC applications. Reservoir simulation models are quite effective but probably are overkill. If they are used, it is recommended to consider a 2-D model with minimum vertical permeability.

Reservoir depletion related to blowouts is affected by numerous factors. Key issues are as follows:

- Low permeabilities create maximum early drawdown around the wellbore.
- Large blowout annuli allow faster depletion.
- Smaller drill strings allow faster depletion.
- Increasing water depth retards depletion.

These relationships are shown in Figures 4.8.2 to 4.8.4. Basic well data used in these illustrations are shown in Table 4.8.1. The data in these illustrations are calculated with BLOWDOWN, a PC-based blowout depletion model.

Considering worst case scenarios in conjunction with reservoir depletion, the recommended approach for kill hydraulics design is as follows:

- Develop the worst case scenario of absolute open flow with no drawdown.
- Evaluate reservoir depletion and the expected pressure at the kill time.
- Design hydraulics to handle the reservoir depletion case and add as much capability as reasonable towards spanning the gap between the reservoir depletion results and the worst case scenarios.

History and calculations show that the design objective should be the reservoir depletion approach. It is still conservative because it discounts the beneficial affect of formation damage from high flow rates.

4.8.4 Historical Review of Required Relief Wells. Table 4.8.2 shows a partial list of wells drilled as relief wells. It does not contain any incidences in which two relief wells were required to kill a blowout. The data does not immediately suggest this but on a close inspection of individual well files, the "one relief well" issue becomes clear. Bay Marchand, had numerous wells blowing out which is the reason for the indicated number of relief wells.

4.8.5 Back-up Well. Legitimate reasons for a starting second well are as follows:

- The plan for the primary well has a high degree of complexity and/or will require long times to implement.
- A simultaneous top kill effort has a high risk factor or a high degree of uncertainty.
- Public pressure or media response is heavy and negative.
- The blowout fluid is oil.

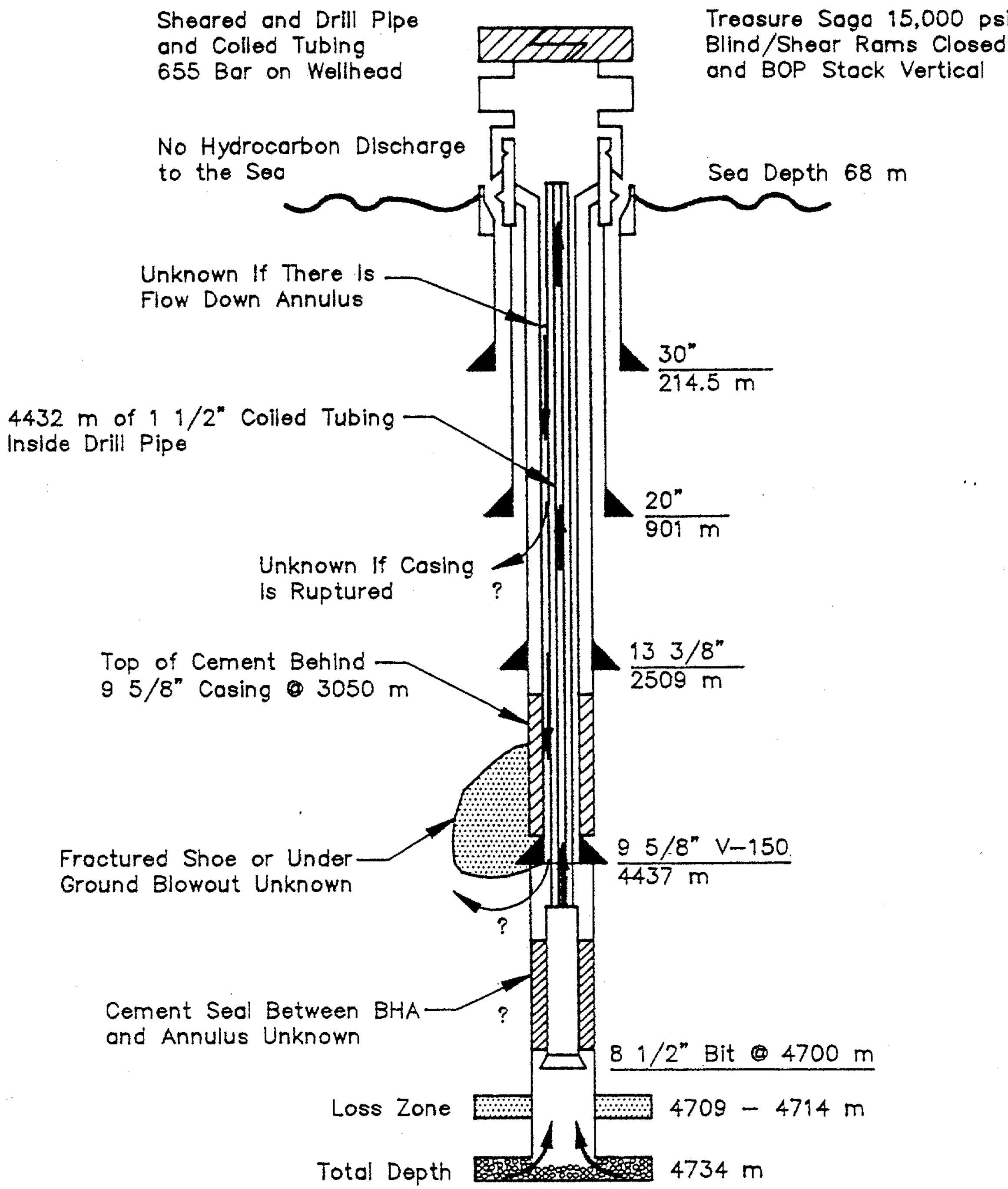

Figure 4.8.1

SAGA Well*

After Wright et al

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Table 4.8.1

DATA FOR DEPLETION EVALUATION

Zone height, ft	20
Fluid type	gas
Specific gravity	0.6
Fluid viscosity, cp	0.050
Initial pressure, psi	6000
Reservoir radius, ft	3000
Porosity, %	0.23
Reservoir temp., °F	190
Compressibility	0.80
Depth, ft	11000

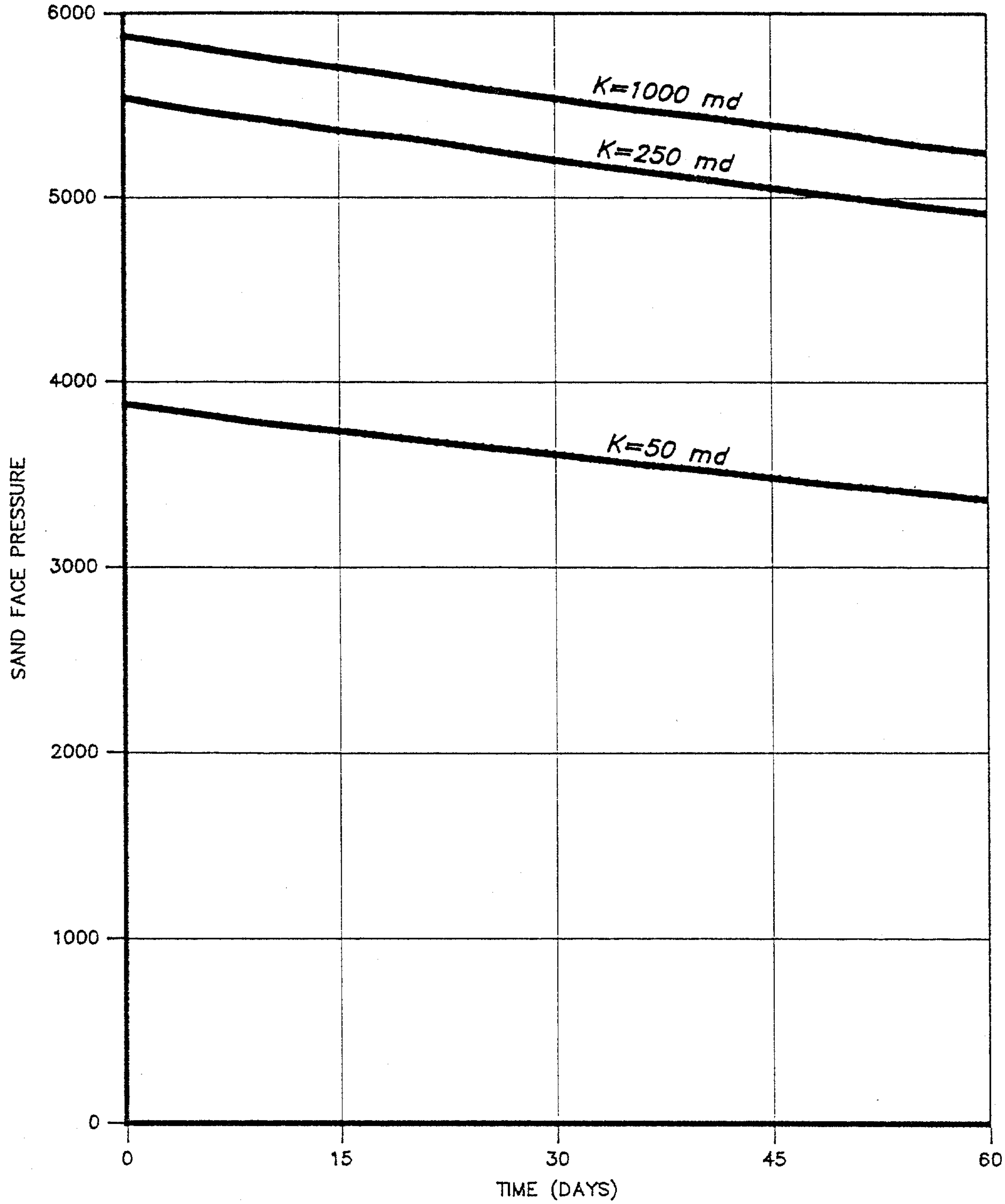

Figure 4.8.2

Effect of Permeability on Reservoir Depletion

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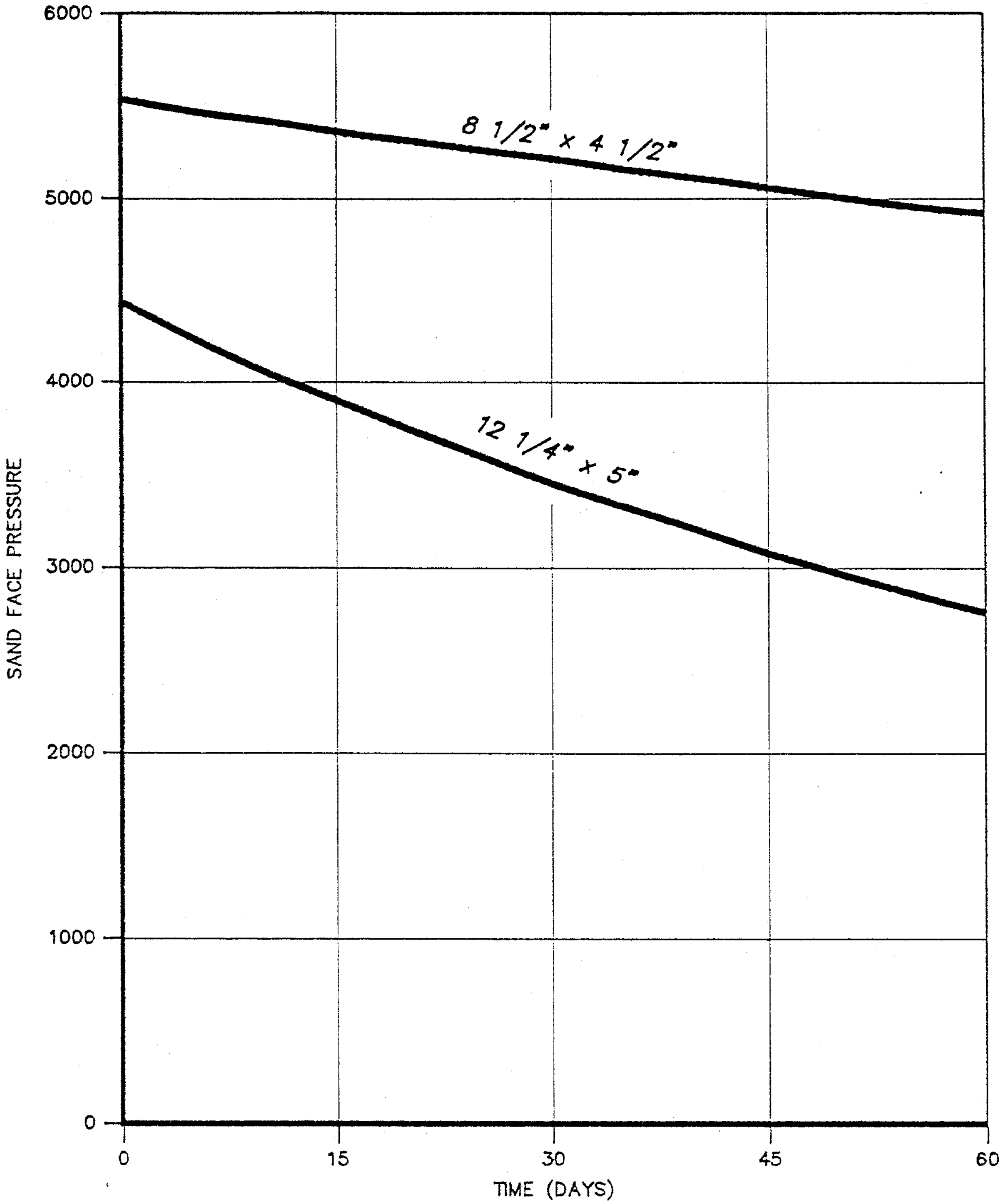

Figure 4.8.3

Effect of Hole Size on Reservoir Depletion

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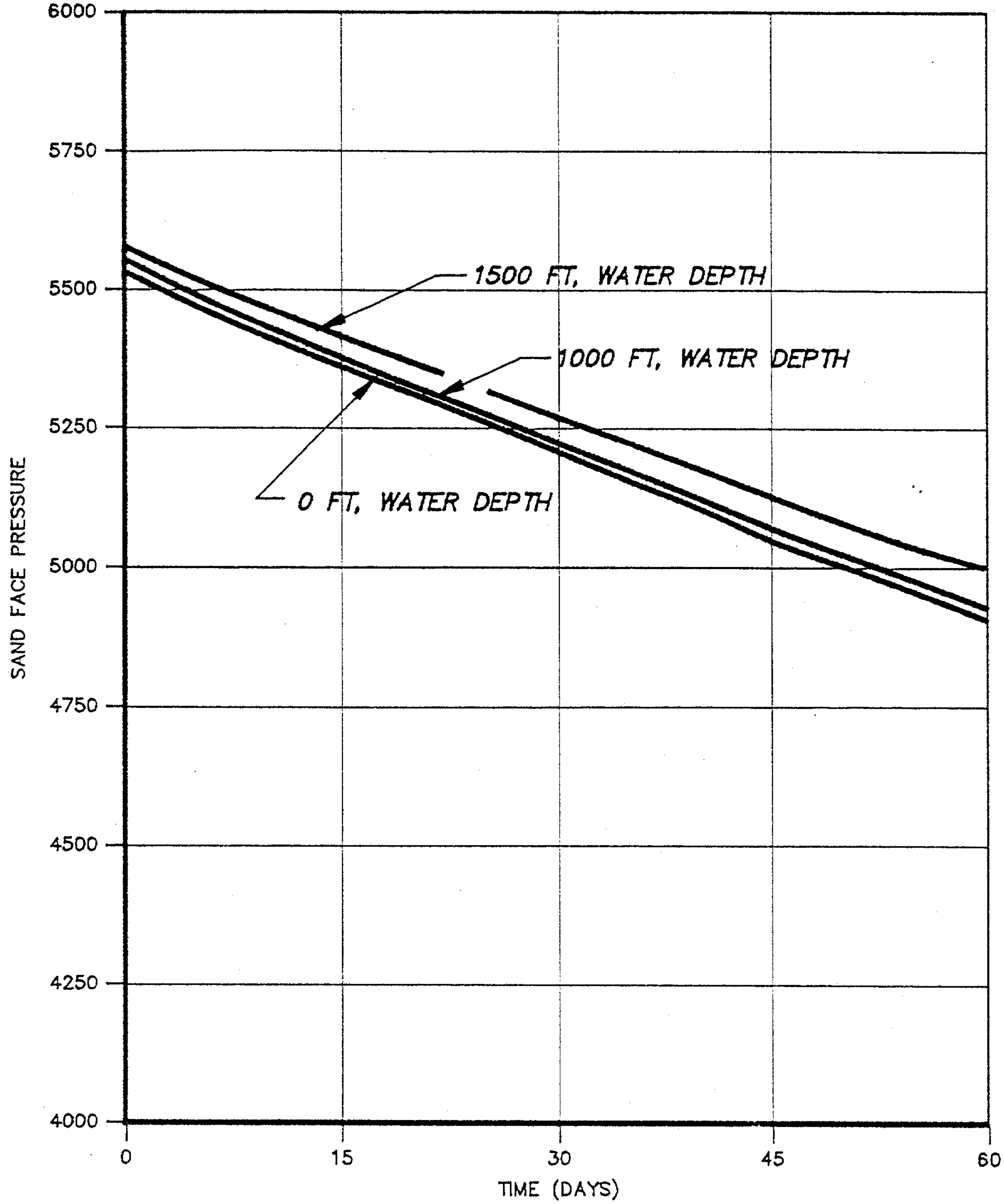

Figure 4.8.4

Effect of Water Depth on Reservoir Depletion

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JOINT INDUSTRY PROGRAM for FLOATING VESSEL BLOWOUT CONTROL

Table 4.8.2

BLOWOUTS CAUSING RELIEF WELLS TO BE DRILLED

	START	WELL NAME	NO.	OPERATOR	LOCATION	OPERATION STATUS	DEPTH	NO. OF DRILLING DAYS	DURATION DAYS	NO. OF RELIEF WELLS DRILLED
1	Jun-56			UNION OF CAL	OCS		11,450		165	1
2	Oct-58	OCS-G 0138		CAGC	W. DELTA 45				37	3
3	Dec-63	OCS-G 0806	1		EUGENE ISLAND 206		11,000		71	1
4	Feb-68				UNITED KINGDOM	DRILLING			500	1
5	Dec-68			BASS. STR. MARLIN A		DRILLING				1
6	Jan-69	OCS-G		MON	VERMILLION 46	PRODUCING				1
7	Feb-69				LEHAN BNK FLD, UK				120	1
8	Mar-69	OCS-G 079	A-3	MOBIL	VERMILLION 46				63	1
9	Mar-69	OCS-G			OCS		8,302			1
10	Aug-69			PANARC	DRAKE PT. HELVIL ISL	DRILLING				1
11	Aug-69			ARCO	TIMOR SEA, AUST.		10,492		93	1
12	Feb-70	OCS-G 0374		CHEVRON	MAIN PASS 41C				49	3
13	Mar-70	COX	1	SHELL	PINEYWOOD FLD, MI		22,122		275	2
14	Nov-70	A M CAPTENTER	14	SHELL	NOME FLD, TX	PRODUCING	8,222			1
15	Dec-70	OCS-G 1043	B-9	SHELL	S. TIMBALIER	PRODUCING	14,000	68	137	1
16	Dec-70	OCS-G 1043	B-21	SHELL	S. TIMBALIER	PRODUCING	13,000	25	137	1
17	Dec-70	OCS-G 1043	B-10	SHELL	S. TIMBALIER	PRODUCING	12,450	37	137	1
18	Dec-70	OCS-G 1043	B-8	SHELL	S. TIMBALIER	PRODUCING	12,600	44	137	1
19	Dec-70	OCS-G 1043	B-3	SHELL	S. TIMBALIER	PRODUCING	13,850	54	137	1
20	Dec-70	OCS-G 0143	B-5	SHELL	S. TIMBALIER	PRODUCING	14,350	111	137	1
21	Dec-70	OCS-G 0143	B-16	SHELL	S. TIMBALIER	PRODUCING	13,100	30	137	1
22	Dec-70	OCS-G 0143	B-4	SHELL	S. TIMBALIER	PRODUCING	13,700	36	137	1
23	Dec-70	OCS-G 0143	B-17	SHELL	S. TIMBALIER	PRODUCING	13,000	57	137	1
24	Dec-70	OCS-G 0143	B-28	SHELL	S. TIMBALIER	PRODUCING	13,400	28	137	1
25	Dec-70	OCS-G 0143	B-15	SHELL	S. TIMBALIER	PRODUCING	13,000	43	137	1
26	Oct-71				CONGO	DRILLING			43	1
27	Oct-71	OCS-G 0578	B1	AMOCO	EUGENE ISLAND 215	PRODUCING	12,493		55	1
28	Oct-71	OCS-G 0578	B2	AMOCO	EUGENE ISLAND 215	PRODUCING	12,493		55	1
29	Oct-71	OCS-G 0578	B3	AMOCO	EUGENE ISLAND 215	PRODUCING	12,493		55	1
30	Oct-71	OCS-G 0578	B4	AMOCO	EUGENE ISLAND 215	PRODUCING	12,493		55	1
31	Oct-71	OCS-G 0578	B5	AMOCO	EUGENE ISLAND 215	PRODUCING	12,493		55	1
32	Feb-72	SHILEKILIB 2-9	6	HUDSON BY O&G	ALBERTA CANADA					1
33	Dec-72			GULF	TIMBALIER BAY	WORKOVER	4,898			1
34	Jan-73	KINNY	1	MOUNTAIN PUBL	CONVERSE CTY WY.	DRILLING	13,561			1
35	Nov-73			FOREST OIL	WEST CAMERON 25A				60	1
36	Mar-73			SUN OIL	EUGENE ISLAND		2,713		16	1
37	Oct-73			CONOCO	FATEH FIELD, DUBAI	COMPLETION	8,202		49	1
38	Jan-74	GOOD HOPE	1	EXXON					35	1
39	Jan-74	HAWKINS	1		EASTLAND CTY., TX	COMPLETION	3,790 (BO)		75	1
40	Jun-74	N.P.B.F.S.U.	2	H. O. H.	GALVESTON CTY., TX	PRODUCING	12,565		200	2
41	Jul-75			NGPL	EAST TEXAS					1
42	Jul-75			CONOCO	FATEH FIELD, DUBAI		4,180		20	4
43	Jan-75	CS-G 0788	B-5	AMOCO	SOUTH MARSH ISLAND	COMPLETION	15,059		40	1
44	Jan-75	A PLEAU	4	EXXON	ANAHUAC FLD, TX				10	1

Table 4.8.2
BLOWOUTS CAUSING RELIEF WELLS TO BE DRILLED (Continued)

	START	WELL NAME	NO.	OPERATOR	LOCATION	OPERATION STATUS	DEPTH	NO. OF DRILLING DAYS	DURATION DAYS	NO. OF RELIEF WELLS DRILLED
45	Dec-75	ROOSSARD	5	SUN OIL	MIDLAND FIELD, LA	WORKOVER	8,900			1
46	Mar-76	OCSG 0758	3	TENNECO	WEST CAMERON 355	PRODUCING	9,744		49	1
47	Jan-76	POUL	1	ENSEARCH	LAVACA CTY, TX					1
48	Jan-76	LOCKWOOD	36	EXXON	FORTBEND CTY, TX					1
49	Jan-75	O'CONNER	6	CHAMPLIN	REFUGIO COUNTY		4,415		28	1
50	Jan-77			HUFFINGTON	INDONESIA					1
51	Jan-77			UNION	TEX. OFFSHORE					1
52	Jan-77	LATERRE	30	EXXON	LIRETTE FLD.	DRILLING				2
53	Sep-77	OCS-G 3390	2	TRANSCO	VERMILLION 25	DRILLING	14,993			1
54	Oct-77			MAERSH EXPL	DENMARK	DRILLING			11	1
55	Jan-78			EXXON	S. LA OFFSHORE					1
56	Jan-78			PHILLIPS PET	MISSISSIPPI	(RELIEF WELL WAS NOT COMPLETED)				1
57	Jan-78			ESSO	MALAYSIA					1
58	Jan-78	CII		MOBIL	ARUN FLD, SUM, INDO.	DRILLING	10,000		92	2
59	Aug-78	SHALLOW G U	4	ARCO	HIDALGO CTY., TX	DRILLING	8,410		67	1
60	Oct-78	OCS-G 1477	3	MOBIL	E. CAMERON 81	WORKOVER				1
61	Jan-78	O'CONNER	6	CHAMPLIN	REFUGIO, TX					1
62	Nov-78	FRESH H20 WELL	1	EXXON	WEBSTER FLD, TX		6,600		80	1
63	Jan-78	ANAHUAC SWD	6	EXXON	ANAHUAC FLD				13	1
64	Nov-79	GREEN	2	FRANK SPOONER	CALDWELL PARISH, LA					1
65	May-79	CTY OF NO., LA	50	TEXACO	LA FOURCHE PSH., LA	DRILLING	14,376		>8	1
66	Jan-79		2703	EXXON	HARRIS CTY., TX				72	1
67	Jan-79			SHELL	TRAVERSE CTY., MICH					1
68	Jan-79			PREUSSAG	W. GERMANY	(FIELD RECOVERY OPERATION)				1
69	Jan-79			ARAMCO	SAUDI ARABIA					1
70	Jan-79			PETROBRAS	BRAZIL	(NOT CONCLUDED)				1
71	Aug-79		A-3	SAMEDAN	CORPUS CHRISTI, TX		10,200		105	3
72	Jun-79	IXTOC		PEMEX	CAMPECHE, MEX.	DRILLING	11,890		287	2
73	Jan-80			AMERADA-HESS	S. LOUISIANA					1
74	Jan-80			FRED OLSEN, INC	EUGENE ISL. 19					1
75	Jan-80			AMOCO CANADA	CANADA					1
76	Jan-80			ESSO EXP.	LIBYA					1
77	Jan-80	446L	2	ZAPATA	BRAZOS CTY., TX				37	1
78	Jan-80			HANSON MINERALS	TEXAS					1
79	Jan-80			CITIES SERVICE	OFFSHORE GALV., TX					1
80	Jan-80	R.L. BERGERON	1	AMOCO	MOORE SAMS FLD, LA	DRILLING	18,562			1
81	Apr-80	C-III	8	MOBIL	ARUN FLD, SUMATRA, INDO.		10,482			2
82	Aug-80				MATAGORDA 669 ISL		13,974			2
83	Aug-80	OCS-G 2271	A1	MESA	VERMILLION 348	COMPLETION	9,596		30	1
84	Jan-81			CLAY. WILLIAMS	GIDDINGS FIELD					1
85	Jan-81			PHIL. & SPRAD	SAN PATRICIO CTY.,TX	PRODUCING	13,000		.90	1
86	Jan-81		0-103	OXY	INSIDOR FLD, LIBIA	PRODUCING	11,000			2
87	Jan-81			CH2H HILL	COLORADO				1	

Table 4.8.2

BLOWOUTS CAUSING RELIEF WELLS TO BE DRILLED (Continued)

	START	WELL NAME	NO.	OPERATOR	LOCATION	OPERATION STATUS	DEPTH	NO. OF DRILLING DAYS	DURATION DAYS	NO. OF RELIEF WELLS DRILLED
88	Jan-81			TENROC						1
89	Jan-81			MESA	OKLAHOMA					1
90	Jan-81			MESA	BRAZOS AREA OFFSHORE					1
91	Apr-81			UNION	LA POURCHE, LA		19,000			1
92	Sep-81		PT29	PERTMINA	NORTH SUMATRA	WORKOVER	3,005			1
93	Oct-81	KEY	1	APACHE	KEY FIELD	W/O PIPELI	16,000			2
94	Jan-82			SHELL	W. CAMERON 65		12,695			1
95	Mar-82			AMOCO	LEA CTY., NEW MEX					1
96	Jan-83			PREUSSAGE	W. GERMANY					
97	Jan-83			SA MENEVEN	VENEZUELA					
98	Jan-83			CONSOL. GAS	W. VIRGINIA					
99	Feb-83			SUPERIOR	PASCA TIMOR SEA		8,858			1
100	Feb-83			TEXCHA	S. MARSH ISL					1
101	Jan-83	KYLE		CRAWFORD ENERGY	HARDEMAN CTY.					3
102	Jan-83			NAM	NETHERLANDS					1
103	Jan-83			NAM	NETHERLANDS	(ALL FOR JOBS RESULTED IN DIRECT INTERCEPT)				1
104	Jan-83			NAM	NETHERLANDS					1
105	Jan-83			NAM	NETHERLANDS					1
106	Sep-84			SHELL	BRUNEI, BORNEO					1
107	Sep-84			PERTAMINA	PASIRJADI FLD, INDO		4,593			1
108	Jan-84	McSWAIN	1	TXO	BRANTON FLD, LEON CTY					5
109	Jan-84		N-9L	MOBIL					270	1
110	Jan-84	MIDDLETON	30	EXXON	ANAHUAC FLD				34	2
111	Dec-84			TOTAL	INDONESIA					
112	Dec-85			SUN	W. CAMERON 348	WORKOVER	10,206			2
113	Jan-85			EXXON	POZUE BAJOS, TRINIDAD					2
114	Jan-85			EXXON	ANAHUAC					1
115	Jan-85			EXXON	ANAHUAC					1
116	Jan-85			EXXON	ANAHUAC					1
117	Jan-85			EXXON	ANAHUAC					1
118	Jan-85			SARAWAK-SHELL	MALAYSIA					1
119	Jan-85				ADAMS FLD, EASTLAND CTY., TX					1
120	May-85			SHELL	SARAWAK, MALAYSIA	DRILLING	1,800		60	2
121	Jan-85			MOBIL	SABLE ISL. CANADA				8,300	1
122	Jul-85			ESSO	CANADA					1
123	Oct-85			PHILLIPS G'THRM	BEAVER CTY, UTAH					1
124	Dec-85			SHELL	MIRA, HALAYSIA					
125	May-86	DISPOSAL SYSTEM	6	EXXON	ANAHUAC FLD, TX				13	1
126				TOTAL	INDONESIA					2
127	Sep-86	104		ELF	TCHIBOUELA				90	1
128	Dec-87	M-26		MARATHON	COOK INLET	CEMENTING			180	1
129	Sep-88	CULF		ANDERSON EXPLOR.	100/16-02-079-24W5/0				20	1
130	Dec-88	CESSFORD		LAMALTA PETROLEUM	100/06-34-023-13W4/0				21	1
131	Jan-89	14-6		ORMAT ENERGY	FALLON	DRILLING	800	12		1
132	Apr-89	RASHAU-17		BRUNEI SHELL PETR.	INDONESIA	CEMENTING	8,300			2
133	Aug-88	# 19		PETRO BRAS	CAMPOS BASIN					2
134	Jul-[illegible]	PIPER ALPHA 15/16		OXY	NORTH SEA	PRODUCTION	8,000		30	1

Table 4.8.2
BLOWOUTS CAUSING RELIEF WELLS TO BE DRILLED (Continued)

	START	WELL NAME	NO.	OPERATOR	LOCATION	OPERATION STATUS	DEPTH	NO. OF DRILLING DAYS	DURATION DAYS	NO. OF RELIEF WELLS DRILLED
135	May-88	SLB-5-4X		CORPOVEN	VENEZUELA	TRIPPING	18.443		120	1
136	Jan-89	2/4-14		SAGA	NORTH SEA	DRILLING	15,542	300		1
137	Jan-89	TEJERO 2E		CORPOVEN	VENEZUELA	WORKOVER	16,000			1

- The blowout well has high pressure with a large casing string or the blowout occurred with pipe out of the hole.

The last item is based on the technical requirements for killing the specified blowout with a relief well.

An interesting application for a backup well was shown in the 1988 Enchova blowout. The initial well missed the target sand in the blowout well hitting below it. The flow and surface fire were diminished and the second well was successful. The second well was drilled simultaneous with the first.

4.9 Casing Size Selection

A key issue in relief well planning is selection of casing sizes. The well must have a kill string of sufficient size that will allow kill fluids to be pumped at appropriate rates to control the blowout well. If the kill string is too small, the pumping pressures can exceed pump capabilities or exceed some designed safe working limits. The blowout well may not be controllable with the originally selected design.

4.9.1 General Size Selection Criteria. The book "Drilling Engineering" has identified factors to be considered in casing size selection for drilling wells, which include the following:

- casing coupling clearance
- bit clearance
- annular hydraulics
- cementing

These apply to relief wells, also.

Relief wells pose additional constraints on the size selection issue. Key factors include pumping pressure conditions and allowances for a backup casing string.

Larger casing strings are usually only applicable for "normal" blowout situations. The presence of shallow, charged formations may result in reduced hole size at total depth, which effectively increases kill pump pressure.

4.9.2 Pumping Pressures. An important aspect of casing size selection for relief wells is the consideration for high pump pressures associated with kill rates. Most well kill pumping is down an annulus. The annular geometry must be sufficiently large so the friction pressures do not pose any restriction on kill capability. This issue is not a concern in typical drilling operations.

Consider the configurations shown in Figure 4.9.1. All are acceptable for routine drilling operations. However, several of these might pose kill restrictions for a blowout well. Figure 4.9.2 shows the anticipated pumping pressures for each of these configurations at kill rates of 0-100 bbl/min.

The appropriate design procedure for casing size selection in relief wells is to determine the required kill rates for the blowout well. These rates are used to determine annular friction pressures for several casing size options for the relief well. A general guide is to select casing sizes that will not cause pump pressures to exceed 4000-5000 psi. This rule is arbitrary but it gives some safety consideration and it minimizes pump downtime problems because the pumps run at a lesser load.

4.9.3 Backup Strings. Relief wells often pose uncertainties because of the blowout well's effect on subsurface formations. Typical results can include pressure charging or depletion. If the charging or depletion is severe, an additional casing string may be required to safely drill the well. Thus allowances should be made in selecting casing sizes for a backup string of pipe if required. (Section 4.10.1)

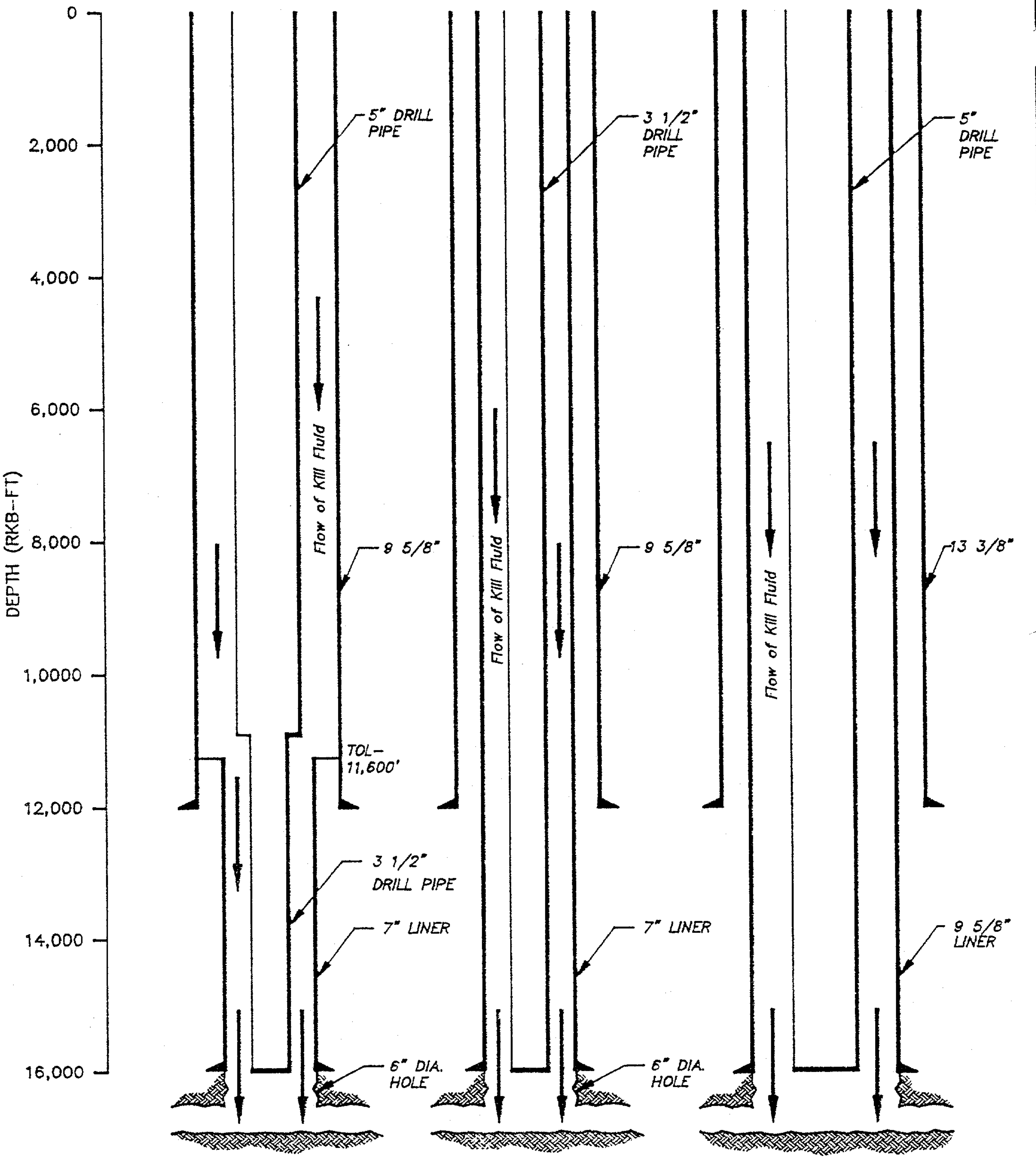

Figure 4.9.1

Evaluation of Typical Casing Program for Drilling Wells When Used in Relief Wells

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4.9.4 Hole and Casing Configurations. A typical drilling and casing program may be as follows:

Hole Size (in.)	Casing Size (in.)
-	30
26	20
17.5	13.375
12.25	9.625
8.5	7

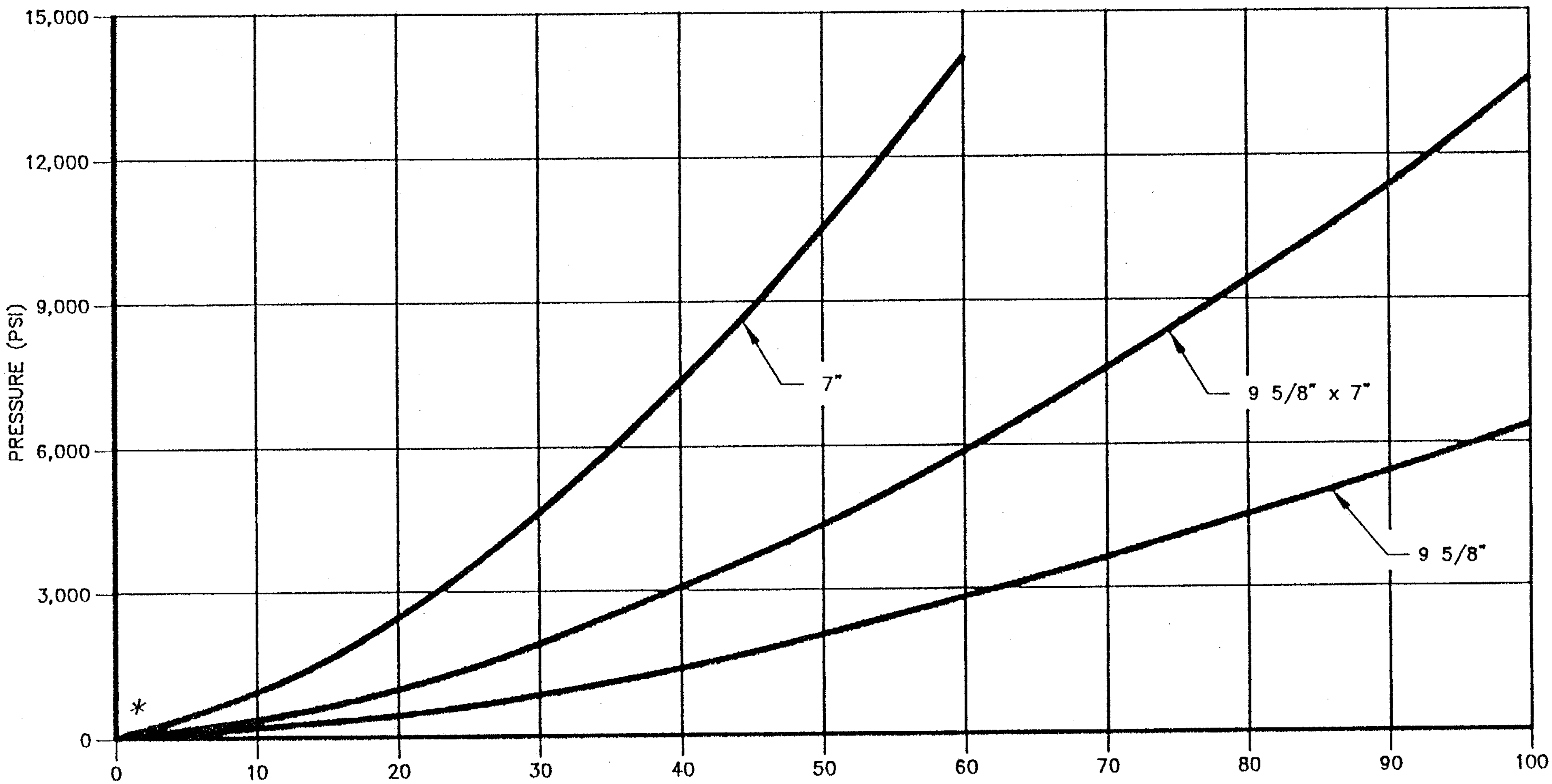
Several options exist to provide backup casing capability and larger annular clearances for improved hydraulics. The options rely on (1) liners and slim-hole or flush joint connections, or (2) starting with large casing sizes from the initial spud of the well.

Casing strings with slim or flush joint connections have proven successful in several relief wells. The difficulty involves underreaming hole sections that could be difficult and time consuming. A typical string might be as follows and as shown in Figure 4.9.3.

Hole Size (in.)	Casing Size (in.)	
-	30	
26	20	
17.5 to 24	16	(flush or slim joint)
14 to 18	13.375	(flush or slim joint)
12 to 16	10.75	(flush or slim joint)
9.5	7.625	

If underreaming is considered to be unacceptable for any reason, the remaining options are to run the string without underreaming, which may not be possible, use larger strings from initial spud, or use "non-standard" casing and bit sizes.

If a flush joint liner is used in a small casing annular clearance, some consideration should be given to the manner in which the liner is set. A method that has been used in 11 3/4" x 13 3/8" strings is to set the liner on bottom without the use of a liner hanger. This technique has worked successfully on occasions. Buckling is not a problem in the tight annular clearances between the liner and the open hole.



* Seawater Used in Calculations

Figure 4.9.2

Required Annular Pump Pressures for the Hole Configuration in Figure 4.9.1

NOTE

Hole Depth = 16,000 ft.

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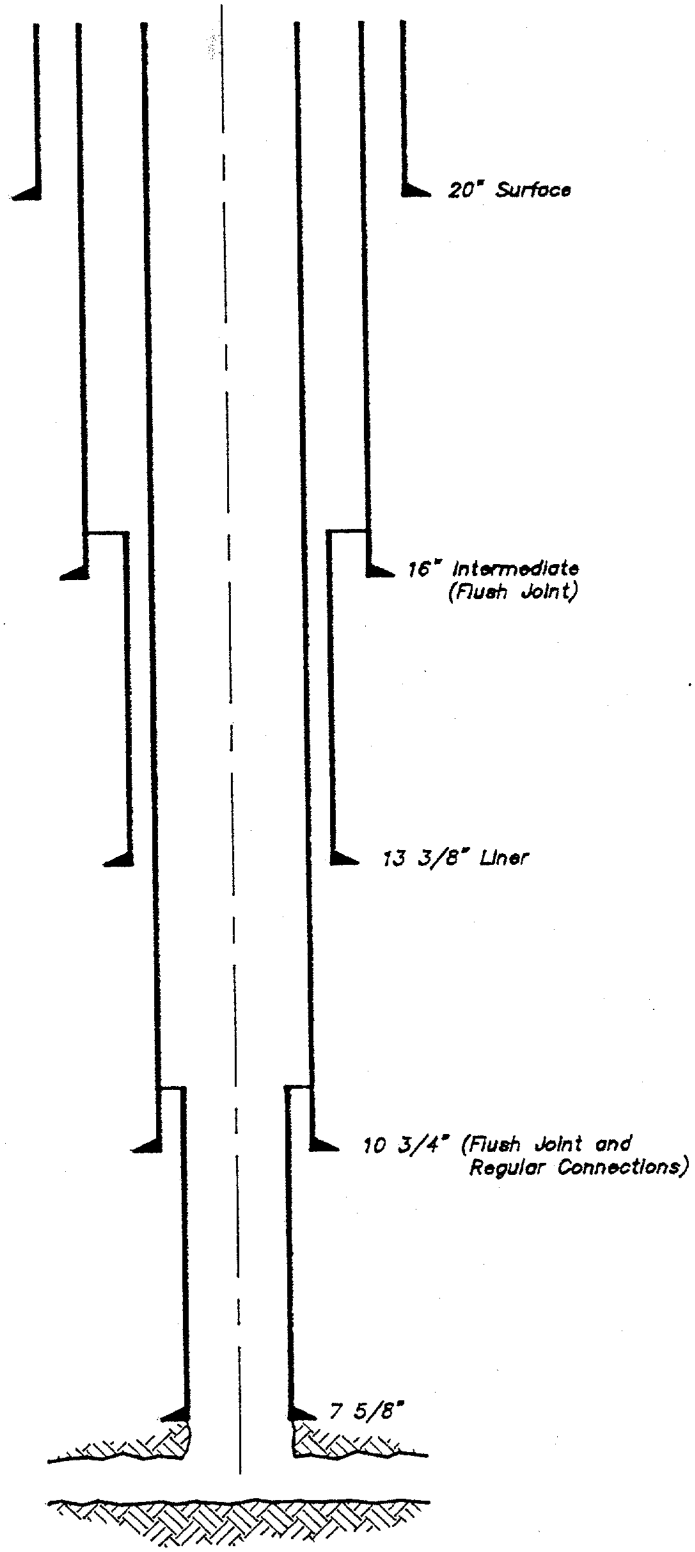

Figure 4.9.3

Casing Configuration
Using Flush Joint Connections and Liners

Due to the difficulty in cementing liners in tight clearances, it is recommended to consider using a longer liner overlap section than that used in other drilling operations. An overlap of 1.5 to 2 times the typical string overlap might be considered. The basic principle with a longer liner overlap is that it is preferable to spend extra money and time to ensure that operations are successful in relief well drilling. A leaking liner overlap poses obvious problems, particularly if the string is to be used as part of the kill string.

Liner hangers are available for these tight clearances. The hangers afford both positive and negative features. The positive benefits include some centralization, hanging capability and the ability to run a hydraulic packer for sealing the overlap. The liner packer option should be considered carefully because of the inherent difficulty of cementing small annular clearances. The negative aspect of these hangers is the reduction in area between the liner hanger and outer casing. This results in high back pressures during cementing. The matter of liner hangers in tight annular clearances must be addressed by the operator when the need arises.

Large casing strings used from the initial spud provide a viable means to realize acceptable annular hydraulics for the kill string. The disadvantage of large strings is obtaining sufficient burst and collapse ratings to meet the demands of some deep, high pressure relief wells. Blowout zone depletion may not place a big demand on the kill string but shallower geological environments encountered during drilling may require high strength 13 3/8", 16", or 20" pipe. This type of pipe is not always readily available on short notice.

4.10 Casing Program

The essential elements of any drilling program include proper casing designs and setting depth selections. These designs, particularly with respect to setting depths, can create the difference between a successful, trouble-free well and a problem-plagued situation. These designs play even a more critical role in relief well drilling.

4.10.1 Setting Depth Guidelines. The initial design task in preparing the relief well plan is selecting the depths to which the casing will be run and cemented. Key factors worth consideration include formation pressures and fracture gradients, hole problems, pressure-charged zones, reservoir or zone depletion, internal company concerns, and , in some situations, possible government regulations. The results of the program will allow the well to be drilled safely without the necessity of building "a steel monument" of casing strings. Unfortunately, most well plans, including those for relief wells often give significant considerations to the actual pipe designs, yet give only cursory attention to the setting depth of the pipe.

The importance of selecting proper depths for setting casing cannot be overemphasized. Many wells have been engineering and economic failures because the casing program specified setting depths too shallow or too deep. Applying a few basic principles combined with a knowledge of the geological conditions in an area can help determine where casing strings should be set to ensure that drilling can proceed with minimum difficulty and obtain a successful kill of the blowout well.

Conventional setting depth design procedures have been described in considerable detail in prior publications. These will not be reviewed in detail in this report.

Casing setting depth guidelines for relief wells have additional considerations. These include the following:

- pressure charged zones
- pressure depleted zones
- top of the blowout zone
- ranging tool design and operation
- directional drilling requirements (below the kill string)
- reservoir depletion (kill mud requirements)
- hole stability and high volume pumping
- back up casing string.

Each will be discussed in the following sections.

Pressure charged zones. Pressure charging implies that the pressure in a zone has been increased to a level greater than its original pressure. With respect to blowouts, the consideration is that the blowout zone may have flowed into a lower pressure zone and increased its pressure.

Although the matter should always receive consideration, the typical case is that pressure charging does not occur in blowouts where the fluid can exit the surface. The pressure under blowout conditions usually decreases in all zones that are exposed to the wellbore. Zones not originally involved in the blowout can begin to contribute to the flow if the wellbore pressure drops to a level lower than the zone's fluid pressure.

Pressure charging does occur, however, and must be considered. Field cases have shown that shallow gas blowouts can increase pressures in other shallow zones by a small margin. Also, underground flows can increase the pressure in shallow zones if the flow is not allowed to vent freely at the surface.

Abnormal pressure detection techniques do not account for pressure anomalies due to pressure charging. Thus, it is difficult to predict the location of zones that are subject to the pressure increases.

Historically, casing setting depth calculations have been based on a worst case situation for pressure charging. If the charging is considered to be a possibility, the flowing zone is assumed to be transmitting its pressure to the suspect zone. An analysis of the mud weights required to drill the suspect zone with its charged pressures is compared to the formation fracture gradient to determine if a relief well can be drilled without setting an additional string of casing. If the resulting formation pressure- fracture gradient relationship is not acceptable, a casing string may be required to be set on top of the zone. It is possible that the formation pressure-fracture gradient relationship may require another casing string below the zone to isolate it.

A rotating head may be required to drill through the charged zone. If this is the case, it may be necessary to use the rotating head to run the next casing string.

Pressure depletion. Partial pressure depletion of zones other than the blowout zone is more common than pressure charging. The blowout environment will generally lead to fluids flowing from other zones into the wellbore. This will result in some degree of pressure depletion.

Potential problems from pressure depletion include differential pressure sticking and lost circulation during relief well drilling. Fortunately, field cases from relief wells do not indicate an unusually high frequency of occurrence for these problems.

Identification of the pressure depleted zones suffers from the same difficulty as identifying the charged zones. Suspect zones may require additional casing strings above or below the zone. The worst case depletion can be estimated from an analysis of the depletion tendencies from the blowing zone.

Top of the blowing zone and near to the blowing well. The general approach to a setting depth for the kill string is that it will be set near to the top of the blowing zone. The logic has been that it would be set as near as possible to the blowing well to maximize formation fracture gradient.

An underlying concern has been the potential of the blowing well to cause a problem in the relief well. Fortunately, history of relief wells show that they do not experience kick problems from the blowing well. In fact, the opposite is generally true: lost circulation usually occurs from the relief well to the blowing well.

Several drilling and magnetic ranging factors affect the proximity of the relief well casing seat to the blowout well. These will be discussed in the following sections.

Ranging tool design and operation. Ranging tools are used to define the distance and direction from the relief well to the blowing well. Their basic functional principle is that they detect the magnetic anomaly caused in the earth's field by the casing or drill string in the blowout well. See Section 4.11 for additional details.

Ranging tools read perpendicular to the tool's longitudinal axis. Therefore the tool should not be influenced by the relief well's casing. As such, casing setting depth is not influenced by the tool itself.

However, active detection tools do have an effect on casing setting depth programs. The active tools excite the magnetism in the casing or drill string in the blowing well by injecting current into the formation. An electrode on the wireline tool injects the current. The electrode is placed several hundred feet above the tool in some cases. Therefore, the casing setting depth program must be adjusted so the electrode is in the open hole when it is run. (Figure 4.10.1)

This consideration is applicable only when ranging must be done below the kill string. If a definite location fix has been made on the blowout well prior to running the casing, it may not be necessary to run the tool again or it may be possible to use a short bridle for the electrode if the relief well is near to the blowing well.

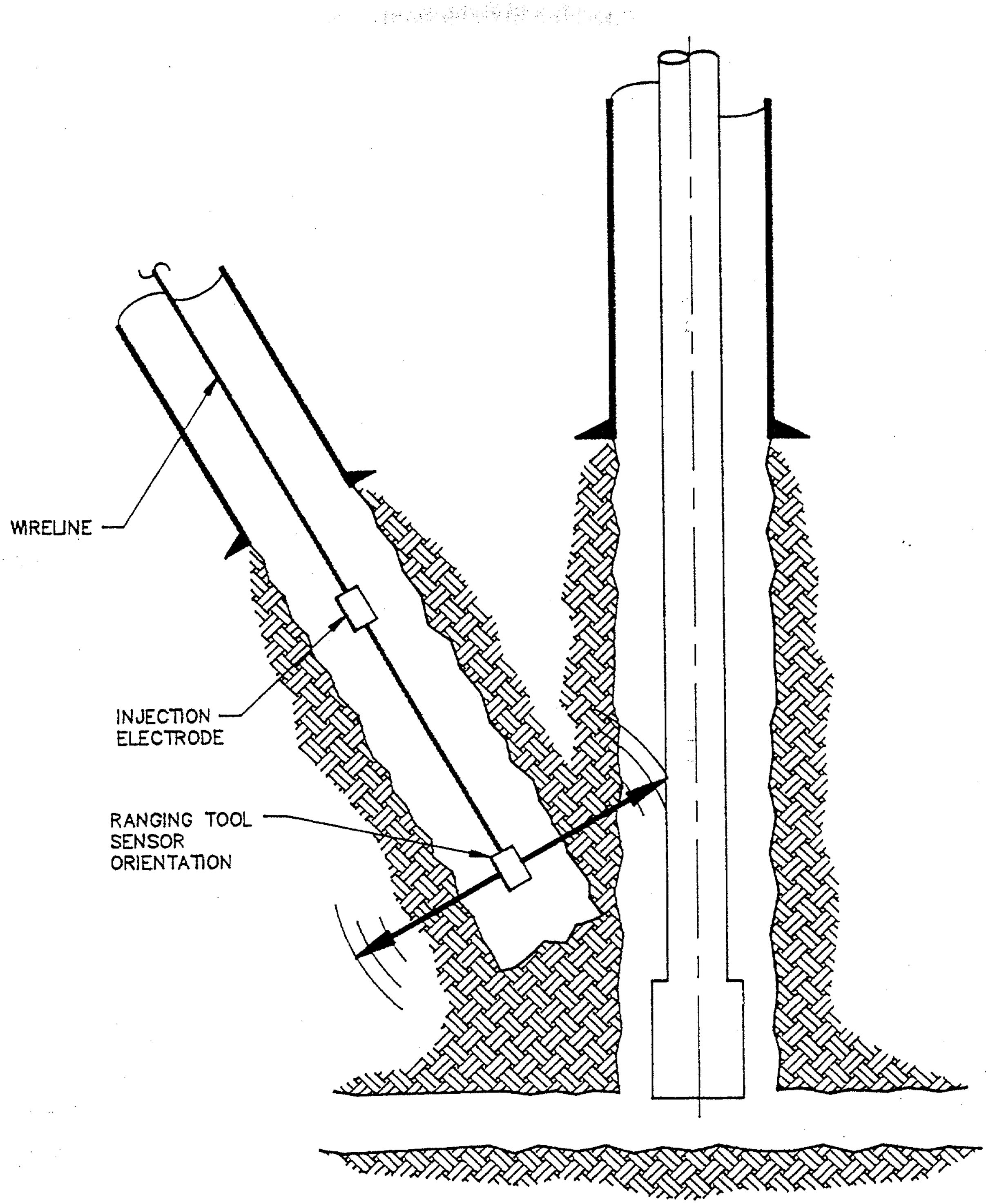

Figure 4.10.1

Open Hole Below the Kill String Must Consider Ranging and Directional Control Concerns

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Directional drilling requirements. Directional drilling requirements below the kill string affect the placement depth for the string. The desired situation is that the casing string and the wellbore are positioned so that drilling into the blowout well will not require directional modifications.

Considerations must be given to the possibility that directional work may be required below the kill string. Ranging tools give interpretative data and, as such, the results must be viewed with an uncertainty. If the relief well does not intersect the blowout well, a sidetrack must be made. This will require some working distance below the kill string. (Figure 4.10.2)

As discussed in Section 4.16, an exact intercept of the blowout wellbore may not be required in all cases. The target may be 6-10 ft wide if the mud ring is considered. Also, drawdown around the blowout well allows for lost circulation from relief well to blowout well which, in effect, increases the size of the target. The result of these considerations is that the size of the target may allow for the uncertainties associated with the ranging tool.

Reservoir depletion (kill mud requirements). Reservoir depletion from the blowout is a known occurrence that has not been widely considered in relief well planning and killing. If the depletion is not considered, kill planning and equipment design requirements can be demanding if a worst case assumption is made.

A key aspect is the mud weight used in the kill operation. If depletion is considered, the actual kill weight may be much lower than the mud weight originally required to drill the well. This may have an impact on the casing setting depth program because of the kill mud weight-fracture gradient relationship. It is possible that the casing can be set higher in the relief well since high kill mud weights may not be required. This can give more flexibility into the drilling program if the casing setting depth requirements are not so rigid.

Hole stability and high volume pumping. A question arises as to the stability of the wellbore under high rate pumping conditions. Some erosion will certainly occur. However, the issue is concerning structural integrity of the rock. Will it become unstable under high rate pumping?

Historical relief well experience does not suggest that hole integrity is more of a problem than it would be under normal drilling circumstances. Thus, additional flexibility exists for a casing setting depth program since the goal is to set the kill string higher in the relief well. A kill string set at a shallower depth allows more directional flexibility.

Backup casing string. The casing program must allow for the flexibility of running an additional casing string if unexpected hole problems occur. The setting depth for the string may be decided as the well is being drilled when problems such as charging or depletion are encountered. The casing size selection discussed in Section 4.9.3 must account for the additional string.

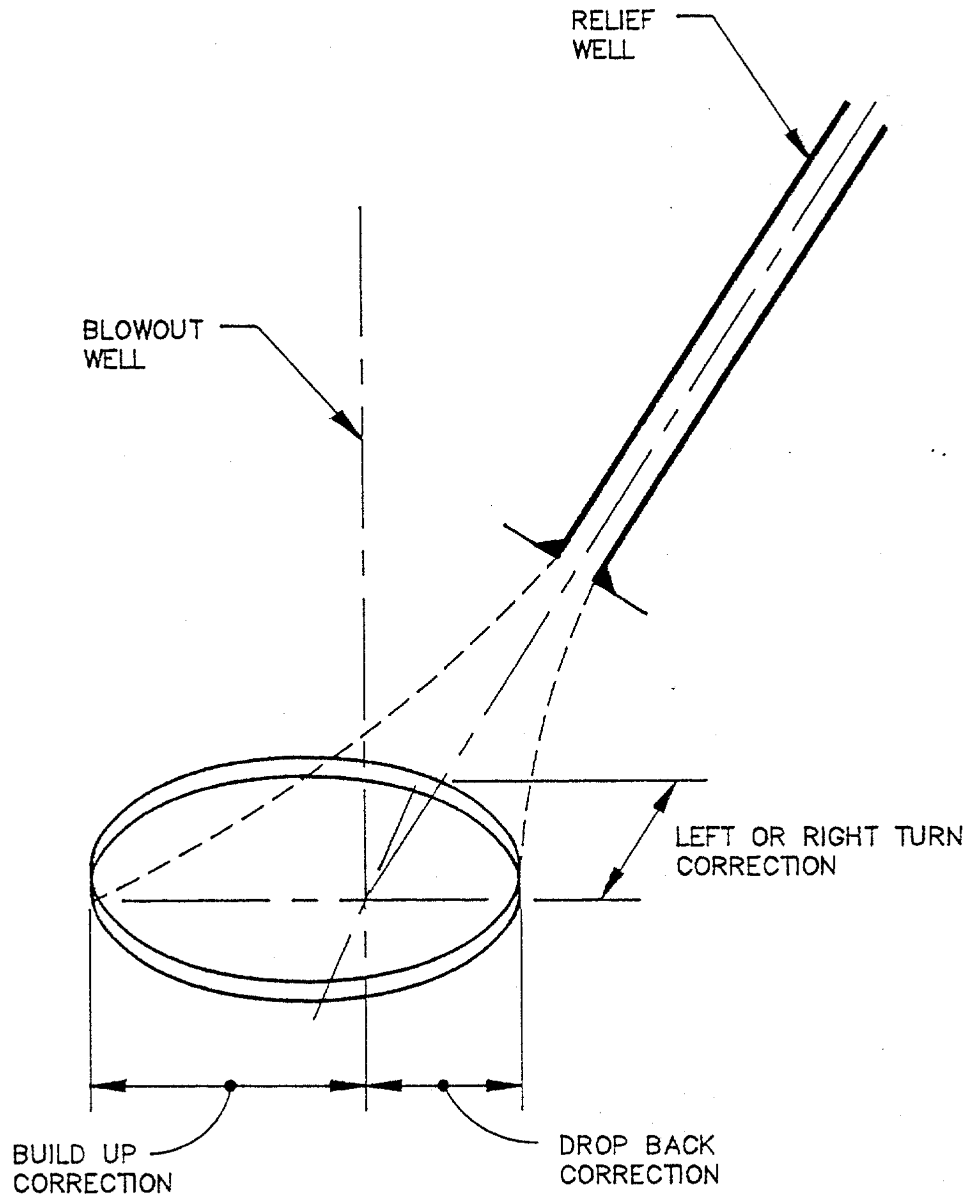

Figure 4.10.2

Directional Correction Window

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4.10.2 Impact of Deepwater Fracture Gradients on Casing Depth Selection. Deepwater environments have lower fracture gradients than equivalent depths on land situations. The interval from the rotary kelly bushing (RKB) to the mud line has a lower pressure gradient than the overburden stress over a similar interval on land. Thus, fracture gradients are reduced.

An example is shown in Figure 4.10.3. As the water depth increases, fracture gradients are significantly different, particularly in the shallow sections of the well.

One word of caution is given at this point. Fracture gradient calculations in deep water environments are not as straight forward as in land situations. Some calculational techniques, such as Eaton, that are widely used for land fracture gradients do not appear to be valid for deep water unless some type of calculational modification is made.

Casing setting depths must account for the reduced fracture gradients. The approach for determining setting depths is similar to the technique used for the original blowing well. However, the original well must be analyzed very closely to determine if the source of its original problem was related to improper setting depth selection.

4.10.3 Casing Design. Design procedures for various casing strings used in a relief well should be initially established as if the relief well does not pose any problems different than a standard drilling well for that environment. After initial designs have been completed, unusual problems that may be encountered in the relief well should be considered. If necessary, pertinent strings should be upgraded.

Pressure charging and depletion. Pressure charged zones should be considered in the casing strings that will handle those zones. An estimate can be made of either worst case virgin blowout zone pressures or depleted pressures by using some computer modeling routine. After blowout zone pressures have been established, estimated pressure in the charged zone can be determined. Casing burst design pressures can be determined accordingly.

Depletion affects the collapse design. The worst case involves lost circulation of the drilling fluid into the depleted zone. Therefore the backup fluid inside the casing is reduced. The design procedure is to consider the heaviest mud weight to be used below the particular casing string and assume that it is lost into the depleted zone with a resultant fluid level drop inside the casing. The calculation procedure is described in more detail in the following section relating to design of the kill string.

As discussed in Section 4.10.1, the difficulty in designing these strings for charging or depletion is determining which zones may be subject to these pressure changes.

Kill string design. Several factors affect the design of the kill string. They are discussed in separate burst and collapse designs.

The **burst design** must account for fracture gradient, a full column of kill mud weight and friction pressure associated with kill pump rates. An example is shown in Figure 4.10.4. Consider a kill string with a vertical setting depth of 13,000 ft and a fracture gradient at the seat of 17.5 lb/gal. Also, consider the original virgin blowout pressure to be 15.0 lb/gal.

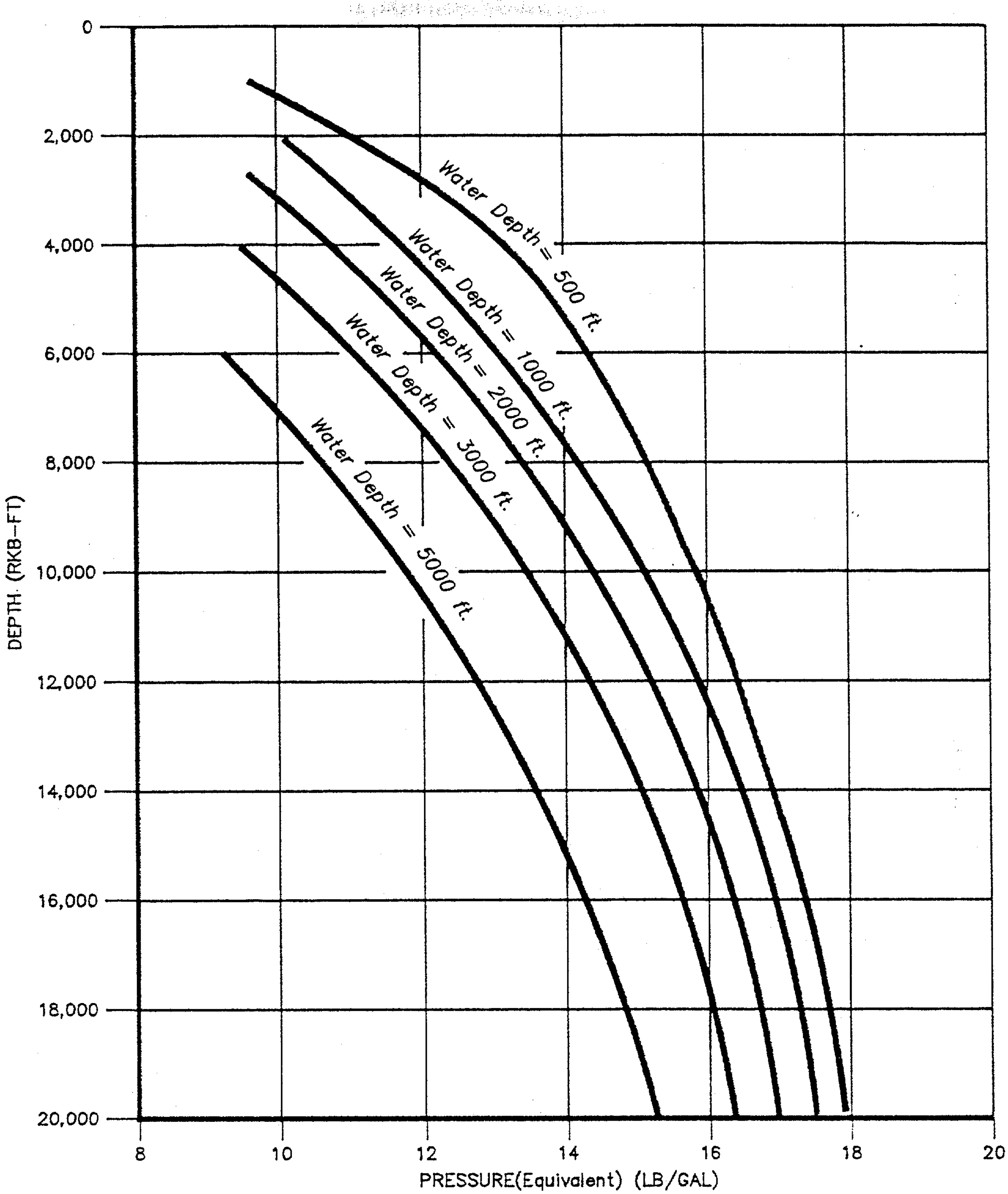

Figure 4.10.3

Effect of Water Depth on Formation Fracture Mud Weight for Normal Formation Pressure

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The controlling parameter is fracture gradient at the casing seat. If a 1.0 lb/gal safety margin is applied, maximum pressure at the bottom is defined as the injection pressure and is as follows:

$$\text{Injection Pressure} = \text{Fracture Gradient} + \text{Safety Margin} \tag{4.10.1}$$

The maximum surface pressure is injection pressure less a column of kill fluid. Options for the kill fluid include water as the first phase to be pumped, or a mud weight that will exceed original virgin blowout pressure. Assume 16.0 lb/gal for purposes of this example. (Figure 4.10.4)

Pumping friction pressures can be added to the surface design values. They are calculated for the kill pump rates and the annular geometries.

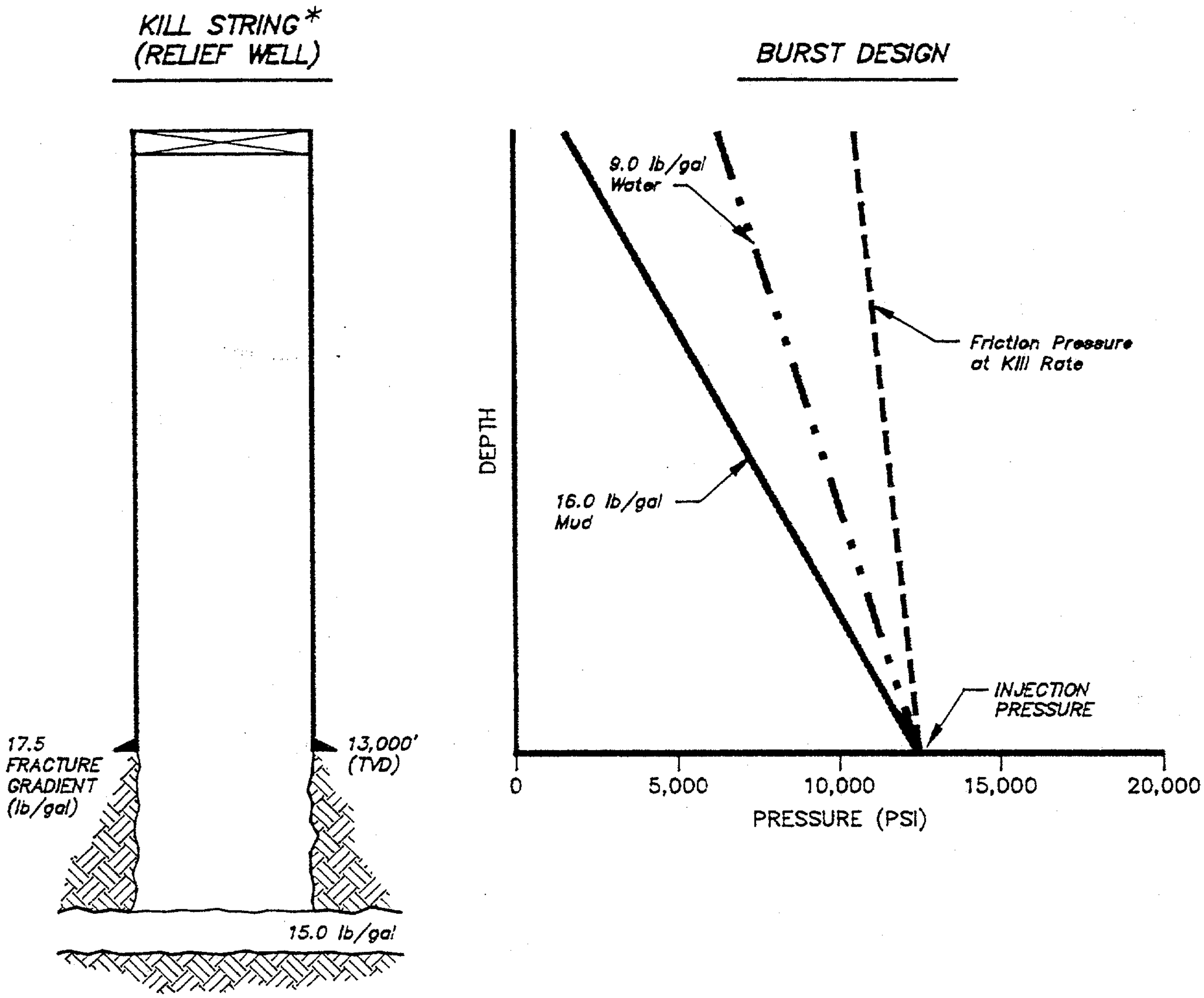
An important logic consideration is that the pressure at the bottom of the string will not exceed injection pressure even at kill pump rates. This is a reasonable assumption for most situations.

This approach to design for burst is a worst case scenario. For most situations, field experience has shown that the reservoir is depleted to some degree. Kill rates and required mud weights are much lower than originally anticipated.

The **collapse design** assumes the worst case that the blowout reservoir is depleted to some low level. Lost circulation occurs in the relief well when the zone is penetrated, and mud level falls in the annulus. The worst situation occurs if the heaviest mud to be used below the string is considered.

For the purposes of illustration, refer to Figure 4.10.5 and assume that the bottom hole pressure has been reduced to an equivalent of 5.0 lb/gal. If a 16.0 lb/gal mud had been used to drill the zone, the mud level would drop in the annulus to a level of 9,625 ft. If the kill string was set in 16.0 lb/gal mud, the resultant would be as shown in Figure 4.10.5.

Due to variables involved in the casing design for the kill string, considerable attention should be given to this important problem. However, it should be noted that available historical records do not indicate that kill string designs have ever hampered the kill process in any manner. Casing sizing is perhaps the key casing design concern.



* Vertical depth shown for illustrative purposes.

Figure 4.10.4

Typical Burst Design Configuration for a Kill String

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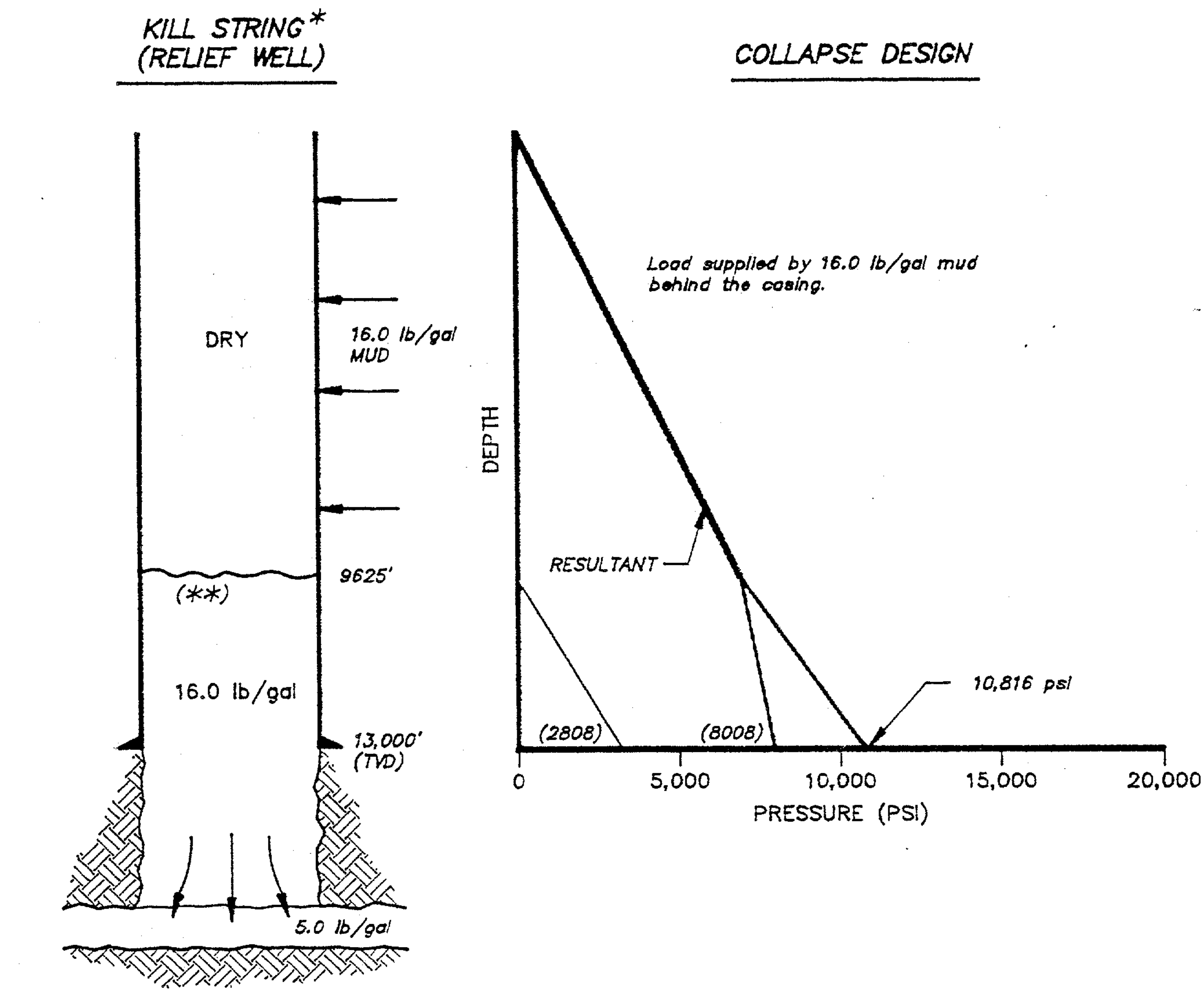


* Vertical depth shown for illustrative purposes.

** Worst Case

Figure 4.10.5

Typical Collapse Design Configuration
for a Kill String

4.11 DIRECTIONAL PLANNING

4.11.1 Introduction. Directional planning for a relief well is similar in general approach to planning for any directional well. The need for preciseness in drilling and surveying is more acute, however.

The directional plan for a relief well is bound by several constraints. Some are as follows:

- Intersect at the bottom of the blowout well or at a shallower point
- Ellipse of uncertainty considerations
- Surface site selection
- Blowout depth, i.e., shallow vs. deep
- Interference from other wells

Others will certainly enter the picture for specific relief wells.

Intercept of the blowout well usually controls the lower "half" of the directional plan. Ranging tools function most effectively at low approach angles. Therefore, the relief well normally uses an "S" curve so the bottom section of the well approaches the blowout well at low angles. Straight-kick direction plans are seldom used.

Ellipses of uncertainty for the two wells affect the program. As the two ellipses overlap near the bottom of the relief well, the plan must proceed slowly to minimize inadvertent intersect. A typical directional well seldom considers the error associated with survey accuracy. See Section 4.3 for more details on the uncertainty calculations.

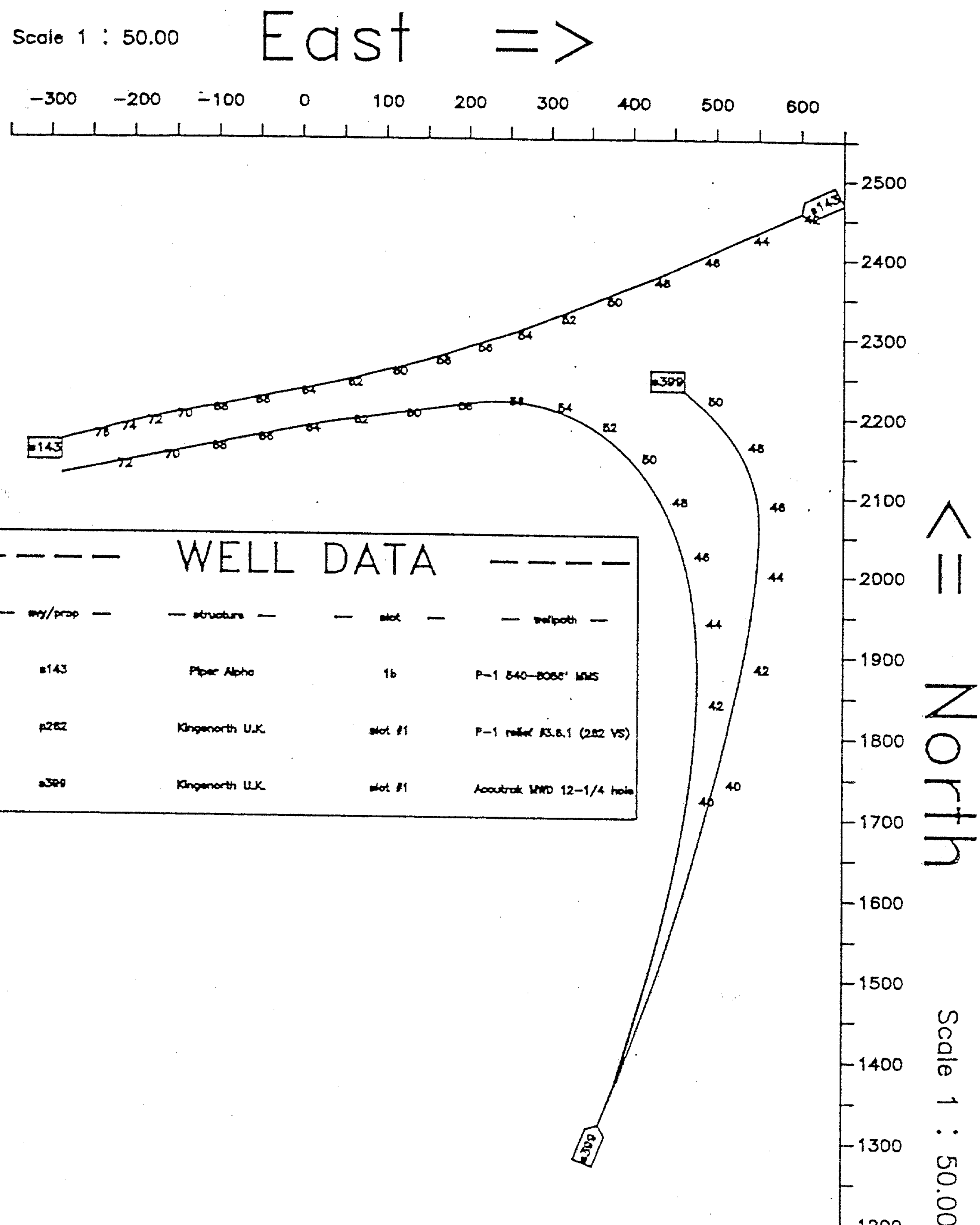
Surface site selection has a large bearing on the directional program. As an example, a site selected for Piper Alpha resulted in the relief well path shown in Figure 4.11.1. This issue is discussed in greater detail in Section 4.4.

The depth of a shallow gas blowing zone or a shallow intersect will require a compressed plan, i.e., shallow kick off point, high build rates and hold angles, and high drop rates near the bottom. These requirements pose unique drilling difficulties for shallow gas relief wells. The difficulty is often coupled with gas charging of shallow zones.

Well interference is, more or less, a routine directional planning concern. It has proved to be an overriding concern in some situations of shallow blowouts under platforms.

4.11.2 Course Path Selection. Many directional course paths have been discussed over the years. Some common approaches are shown in Figure 4.11.2. Each is based on technical requirements.

Course paths are heavily influenced by ranging tool capability and ellipses of uncertainty. Since the exact locations of the relief and blowout wells are uncertain, it is not a simple task of drilling directly toward the blowout well. Ranging tools must be used to define the relative locations of each well. If the area of blowout location uncertainty is large and beyond the ranging capability of the logging tool, a shallow bypass may be required to reduce the cone of uncertainty. The relief well is then continued to the desired intersect point.



WELL DATA

svy/prop	structure	slot	wellpath
s143	Piper Alpha	1b	P-1 540-8088' MWS
p282	Kingsnorth U.K.	slot #1	P-1 relief R3.6.1 (282 VS)
s399	Kingsnorth U.K.	slot #1	Accutrak MWD 12-1/4 hole

Figure 4.11.1

Directional Plan*

**Piper Alpha Relief Well*

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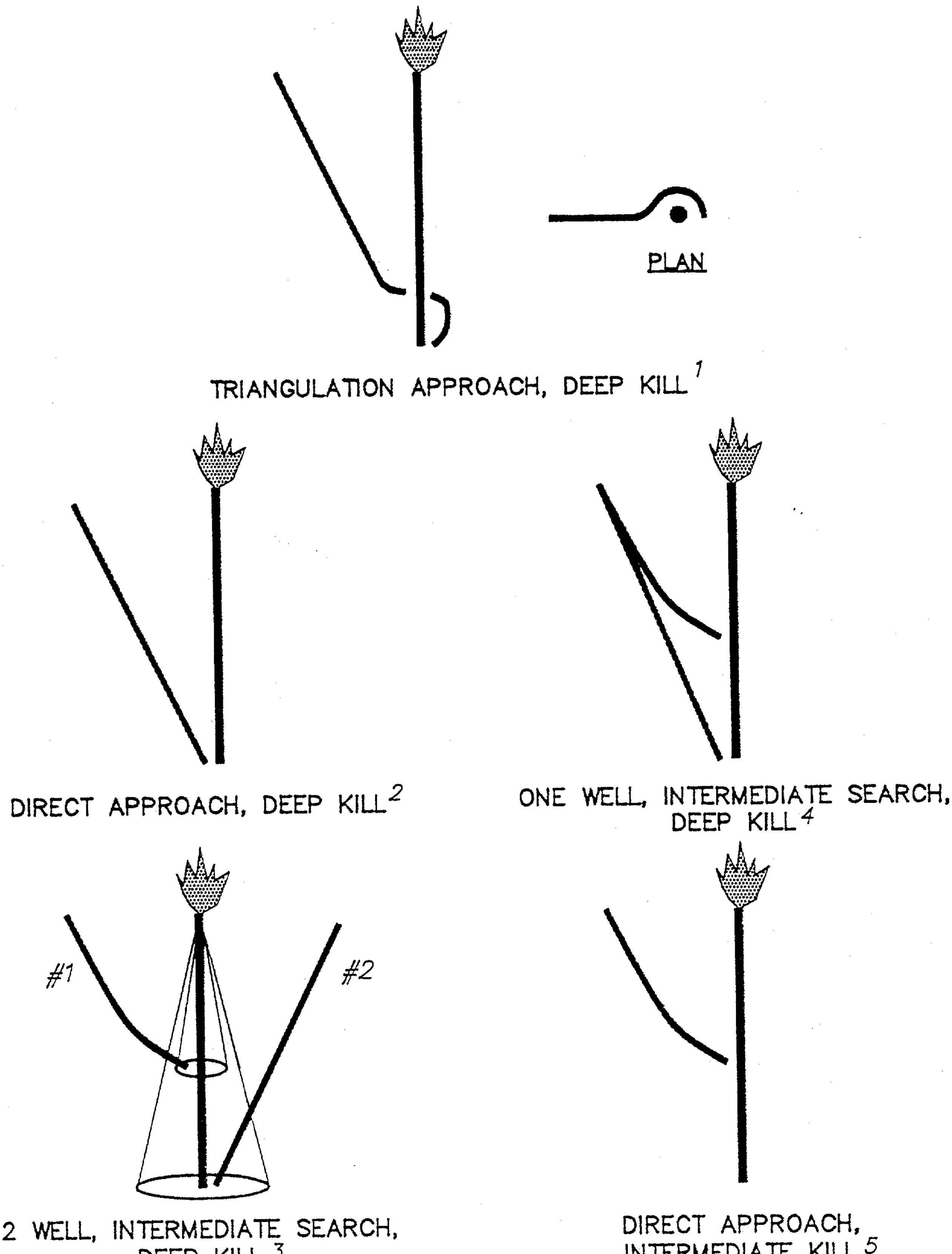

Figure 4.11.2

Directional Kill Plans

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Course path selection is impacted by the type of blowout fluid although its effect is non-technically based. It is generally desirable to kill blowouts as quickly as possible. An added emphasis is placed on oil blowouts where pollution can be a major concern with respect to clean-up cost and public pressure. Igniting an oil blowout should be a consideration immediately after the event occurs although ignition may not by desirable under some circumstances. Gas blowouts do not pose this element of emergency. The consequence is that a direct approach with the relief well is more favored with oil blowouts because of reduced drilling times.

Course Path 1. The course path as shown in Figure 4.11.2(1) has been used more commonly in recent years. Near the bottom, the relief well swings around the blowout well in a spiral shape. This allows the ranging tool to acquire data at various stations and then use a triangulation approach to determine the location of the blowout well. A right hand spiral is used to take advantage of bit walk tendencies. Left hand spirals are much more difficult to drill.

The bypass method is used more commonly in conjunction with active ranging tools. Direct approaches are being used less commonly because of uncertainties associated with the tool. Also, active tools have a marked reduced effectiveness near the bottom of the casing or drill pipe in the blowout well.

The bypass method is more acceptable if the blowout fluid is gas. Oil creates more of a pollution concern and increases other problems such as possible public pressure, news media attention, clean up, etc. The direct approach is favored with oil blowouts because of the reduced drilling time.

The direct approach is more preferable overall because it avoids increased drilling time requirements associated with deep, complicated course paths. Also, current depletion studies show that more latitude can be taken with a relief well than previously thought, i.e., set casing and drill straight towards the well.

Course Path 2. The direct approach for a deep kill operation is the preferable method overall. It requires less drilling time than a bypass, even if the bypass spirals into the lower section of the blowout well and a sidetrack is not required. Also, the direct approach minimizes directional drilling difficulties in the deeper hole section, i.e., angle changes, sidetracks, etc. A sidetrack may be required if the uncertainty is large for the blowout location and the well is not located on the initial pass.

An "S" curve is used for the directional plan. The approach angles near the bottom are relatively small.

Course Path 3. The plan shown in Figure 4.11.2(3) is occasionally used. It has weaknesses and strengths that are not necessarily obvious. Its general design purpose is for wells where the ellipse of uncertainty is very large at the bottom of the blowout well, i.e., greater than 200 ft. They can occur in deeper wells or wells with poor or no surveys.

The #1 relief well is designed to locate the blowout well at a shallow depth where the ellipse of uncertainty is manageable. After the well location is fixed, the new ellipse of uncertainty is calculated from that depth to the bottom of the hole. The #2 well, which was spudded at the same time as the #1 well, makes any required course path adjustments based on calculations from the #1 well intersect. The #2 well is drilled to the bottom and is used as the kill well.

This plan has a hidden weakness. When the #1 well locates the blowout well at the shallow intersect, it defines the relative location of the #1 relief and blowout well. It does not define the relative location of the #2 relief well and the blowout well. It is effective, however, at reducing the ellipse of uncertainty to some degree and thus the #1 well has achieved a purpose.

An advantage of this approach is that it involves 2 relief wells. The #1 well can continue drilling to bottom after the shallow intersect and a sidetrack. It can serve as a backup to the other well in the event that the #2 well is lost for various reasons.

Course Path 4. This plan is effectively a combination of plans 2 and 3 discussed above. It relies on a single well to locate the blowout well at a shallow depth and perform the kill at some deeper depth. Since it locates the blowout well relative to the relief well, it avoids the hidden difficulty associated with the Course 3 plan above.

This plan requires more time than plan 2 and 3. If the bottom of the plan is altered to incorporate a triangulation approach described in Figure 4.11.2(1), the drilling times will be long. (Figure 4.11.3) If the blowout fluid is gas, pollution will not be a concern. The increased drilling times are a factor that must be considered by the operator.

Course Path 5. The direct approach, intermediate depth kill plan, seldom has been used in past relief well history. The best documented case of its successful usage is Shell, Piney Woods, Mississippi blowout in the early 1970's. Studies currently being conducted, i.e., DEA-63, and an in-depth case history analysis of blowouts suggest that this approach has promise and may receive more usage in the future.

The general objectives of relief wells are to get sufficiently deep at an intersect point with the blowout well so mud hydraulics and hydrostatic pressure will halt the blowout flow. Time is of the essence but must not be sacrificed for safety.

Worst case scenarios have been assumed in the past, i.e., no pressure drawdown during the blowout. Relief wells have been designed to intersect the blowing well near the bottom. Also, until recently, ranging tools had not definitely proven their reliability for shallow intersects directly into the well bore of the blowing well. As a result, the directional target for past blowouts has been the blowing zone in order to gain maximum hydrostatic pressure and to be in communications between the blowing and relief wells.

This approach can require significant drilling time. Deep course alterations are difficult. Also, the error of uncertainty can be large which may require sidetracks or complex course paths such as in Figure 4.11.2(2) or 4.11.3.

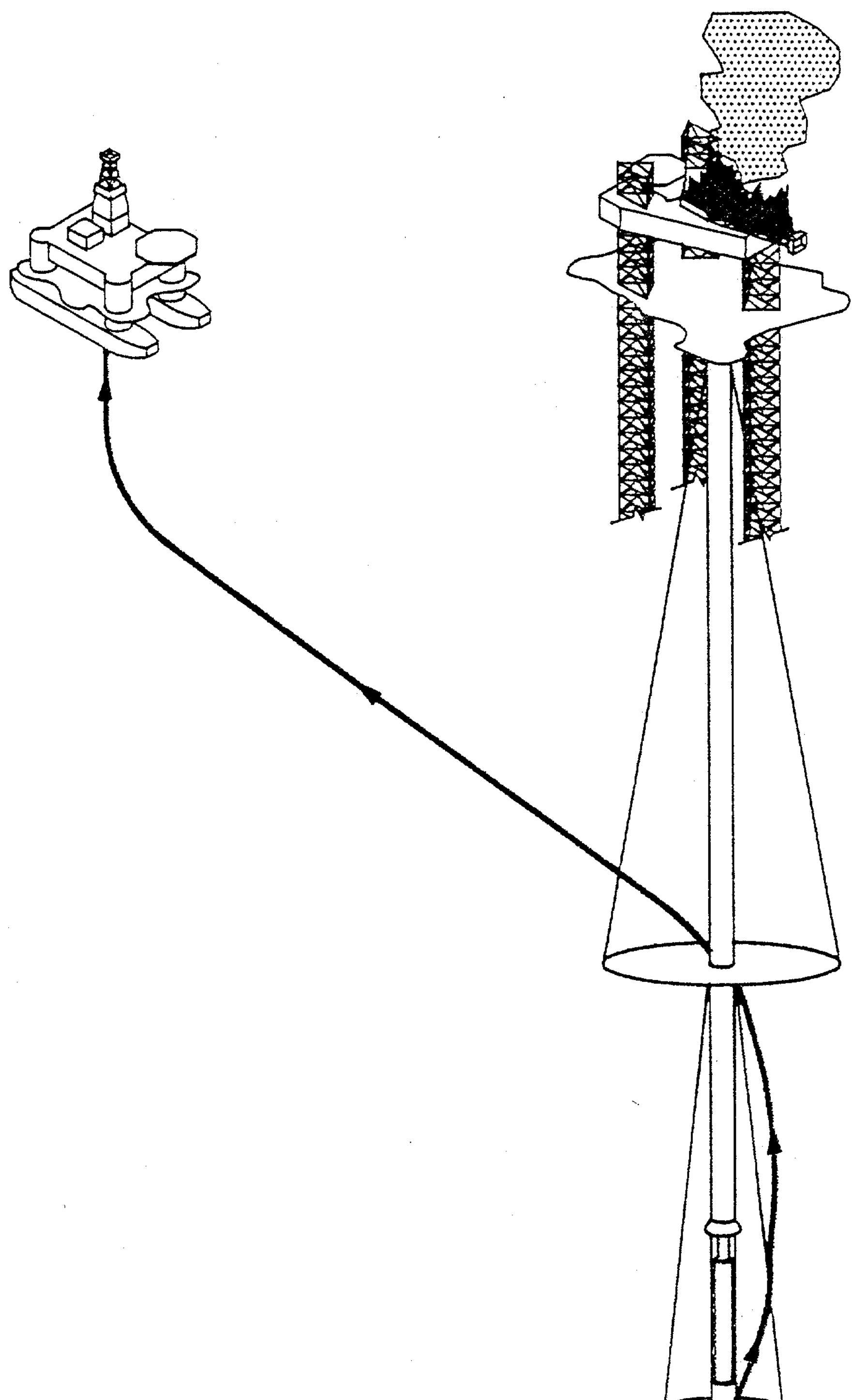

Figure 4.11.3

Relative Position Uncertainty

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A simple plan such as shown in Figure 4.11.2(5) has several attractive features. It uses a direct approach which is less time consuming than a bypass. Also, it intersects the blowing well at a relatively shallow depth where the error of uncertainty is manageable with current ranging tool capability. The casing program will be easier to design and can utilize more conventional string configurations.

Controlling parameters on selection of this directional plan are required kill hydraulics and mud weights. The solution to the hydraulics and mud weight issues are dependent primarily on depth of intersect and amount of reservoir drawdown. The design procedure should be as follows:

- Run an appropriate blowout depletion model and determine the sand face pressure for various times including the time required to drill a relief well to the deepest possible intersect.
- Determine kill mud requirements for various intersect depths and associated time to reach that depth.
- Select an intersect depth that has operationally acceptable kill mud and hydraulic requirements.

Example 4.11.1 shows this technique.

4.11.3 Purpose of Ranging Tools. In simple terms, ranging tools are designed to guide a relief well to a blowout well. They should determine distance and direction to the blowout well. To be more specific, a ranging tool fixes the relative location of the two wells, i.e., where the blowout well is located relative to the relief well.

Ranging tools are sophisticated instruments that are only as good as the experience/knowledge of the individual operating the tool. Claims are commonly made of ranging distances up to 200 ft although many oil companies suggest the actual effective range is much less, i.e., 50-125 ft. Tools usually employ magnetic detection sensors, known as magnetometers, to identify casing or drill pipe in the blowout well. Hopefully, future tool and technology development will increase the reliability and accuracy of ranging techniques.

The-limited distance measuring capability of ranging tools restricts their usage until the relief well is near to the blowout well. Thus, the directional program near the bottom of the relief well is dictated to some degree by the ranging tool. Multiple runs are often required.

Note: Information presented in Section 4.0 relative to ranging tool capability has been partially acquired through manufacturer's literature. Some oil operators with experiences using the tools often have different opinions about tool capability. More comparative case history data is required to fully examine the subject.

4.11.4 Brief History of Ranging Tools. Ranging tools are reasonably recent developments in the blowout control industry. Prior to the development of ranging tools, a relief well was drilled as close as possible to the expected blowout well location and pumping commenced. Uncertainties with the approach are obvious and include survey accuracy on both wells and the associated ellipses of uncertainty. Pumping jobs were often "horror stories" of high volume pumping for extended periods up to several months with marginal success.

ULSEL was the initial attempt to relate the location of the two wells. ULSEL (ultra-long spaced electrical log) was Schlumberger's tool used principally for mapping salt domes. An effort was made to use it in relief wells. The principal draw back to its usage was that it gave distance only, not direction. See Section 4.11.8 for technical details on ULSEL.

The first major break through in ranging tools was Magrange II. It was developed by Tensor Corporation on a contract from Houston Oil & Minerals as a response to H.O.& M's Galveston Bay blowout in 1968. The tool uses dual sets of orthogonally spaced magnetometers to determine distance and direction from the relief well to the blowout well. Magrange dominated the business for many years and has a wealth of experience.

SEEC (Seek, Encounter and Establish Communications) introduced a similar tool in the early 1980's. It offered some minor improvements over The Magrange II Tool but was withdrawn from the market due to infringement of Tensor's patents.

ELREC was later developed by Gearhart Industries with the assistance of Dr. Arthur Kuckes of Cornell University. The tool used slightly different principles from Magrange and offered improved distance capability. ELREC is not available at this time.

Vector_Magnetics was formed by Dr. Arthur Kuckes and Dr. Bruce Thompson. They used the concepts and technology from Gearhart and then made refinements. Their Wellspot tool is widely regarded and highly respected by some operators.

Many attempts have been made over the years to develop ranging tools based on acoustic/sonic principles. Operators and universities have studied the principles. Some prototypes have been developed, but none have been successful as of this time.

4.11.5 Overview of Ranging Tools' Magnetic Field Theoretical Analysis. (Dr. Arthur Kuckes of Vector Magnetics used as the direct source for this material to avoid possible errors in paraphase efforts.) Drilling a relief well is often the only practical means for killing a blowout. Inaccuracies in well surveys makes an intersection between the two wells difficult without some means for determining the relative distance and direction of the two wells at a given depth. Measurements of the magnetic field in the relief well detect the presence of iron objects such as casing or drill pipe in the blowout well. These measurements are used to estimate the relative locations of the two wells.

Several different models have been used to determine distance and direction between the two wells. The oldest model assumes infinitely concentrated (impulse) magnetic poles in long iron cylinders. However, the pole is actually distributed, or smeared, along the magnetized cylinder. A new model has been developed by a commercial ranging company that distributes a magnetic pole along the magnetized cylinder with an exponential distribution. Both models are described in the following section.

Iron objects possess a significant degree of magnetization. Each section acts as a single magnetic dipole, and after assembly into a long casing or drill string, each joint roughly maintains its previous magnetization. Magnetically a pipe string can never be described as a line of magnetic dipoles of random strength evenly spaced at intervals equal to the length of a single section.

Characteristics of Magnetic Monopoles. Although each pipe is an exact magnetic dipole, it is often more convenient to regard a dipole as two monopoles of equal but opposite strength. Consider the ranging of magnetic monopoles. If a three-component vector magnetometer is moved past an impulse magnetic monopole of strength, M, and with distance of closest approach, R, the measured magnetic field will be a vector sum of the earth's magnetic field and the field of the magnetic monopole. After subtracting the earth's field, the axial and radial components of the magnetic field anomaly due to the monopole are determined from the inverse-square law describing the magnetic field due to a concentrated pole:

$$F_a = \frac{Ms}{(s^2 + R^2)^{3/2}} \qquad (4.11.1)$$

$$F_r = \frac{M\,R}{(s^2 + R^2)^{3/2}} \qquad (4.11.2)$$

where:

	F_a	=	axial magnetic field of pole(s)
	F_r	=	radial magnetic field of pole(s)
	M	=	total magnetic pole strength
	s	=	distance along the relief well axis from the point of closest approach (Figure 4.11.4)
	R	=	distance of closest approach (range)

The amplitude of the axial and radial fields depends on the total pole strength, but the shapes of these fields depend only on R. This fact is fundamental to magnetic ranging techniques.

The range R can be determined from the separation P between the maximum and minimum of the axial magnetic field (Figure 4.11.5) by the relation,

$$R = \frac{P}{\sqrt{2}} \qquad (4.11.3)$$

Where: P = distance between axial field stream

The range can be determined in similar manner from the half-width P' of the radial field (Figure 4.11.5).

$$R = 0.652P' \qquad (4.11.4)$$

Determination of Direction. The direction to the poles can be found from the total magnetic field vector of the monopole, which, depending on polarity is determined from the axial magnetic field. Often the angular orientation of the magnetic logging tool about its axis is not known, but the direction can still be determined from the total radial field vector as follows.

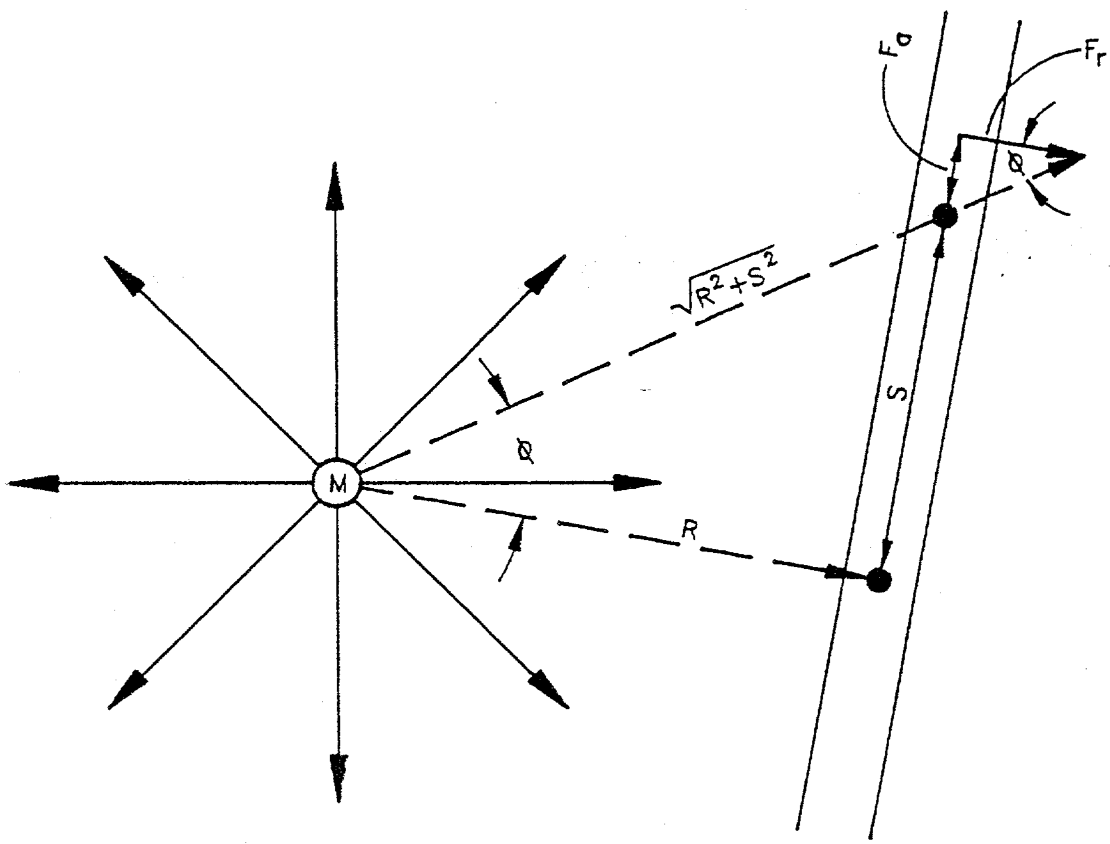

Figure 4.11.4

Magnetic Field Measurement of a Concentric Monopole*

*After Kuckes et al

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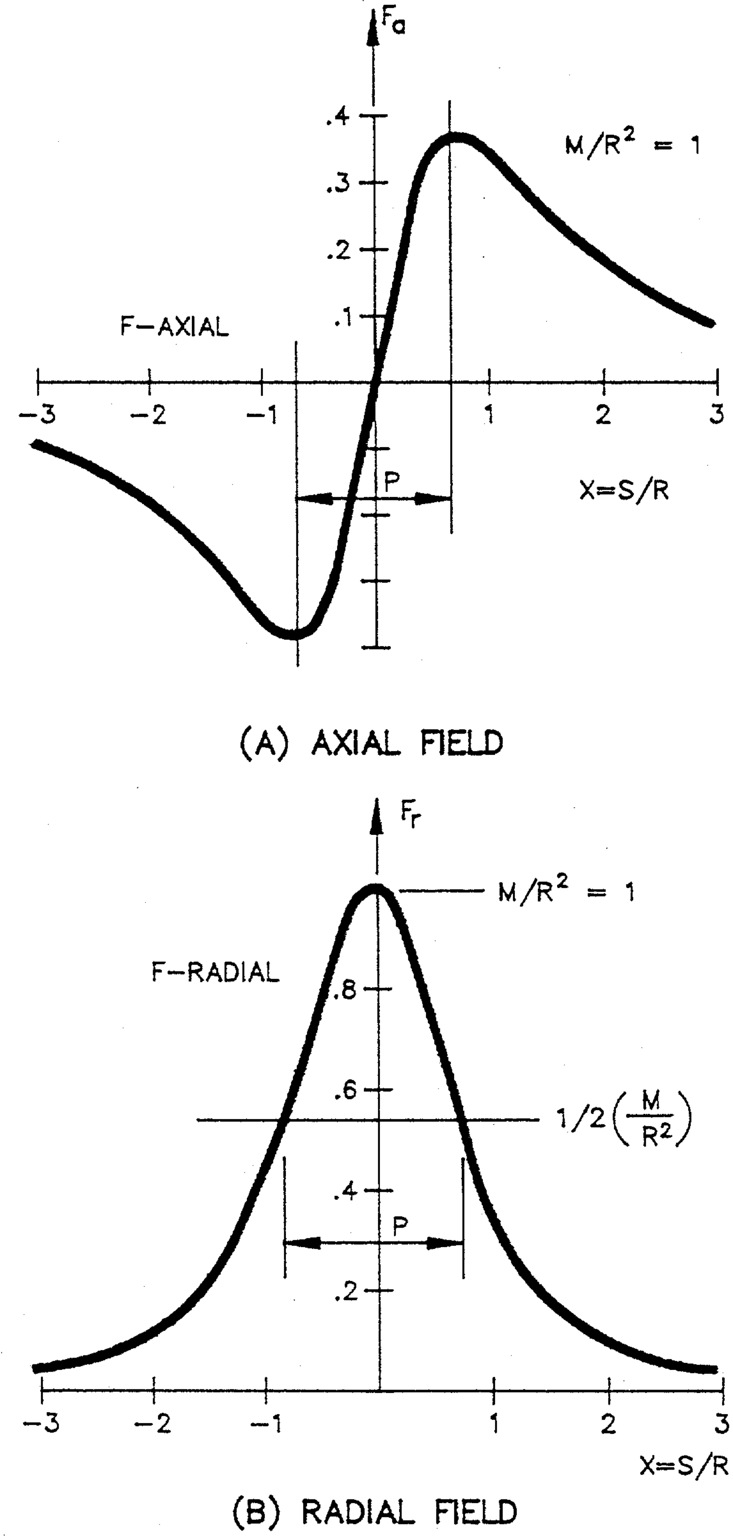

Figure 4.11.5

Axial and Radial Fields
of a Magnetic Monopole*

*After Kuckes et al

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After calculating R from the axial field, the pole strength can be obtained from the axial field measurement at any point by solving for M in Eq. 4.11.1 above. The strength of the radial field vector at can now be calculated using Eq. 4.11.2 above. The vector is summed with the (known) radial component of the earth's magnetic field (Eq. 4.11.3), and since the lengths of the three sides of the triangle are now known, the cosine of the angle between the location of the monopole and the earth's radial magnetic field can be obtained from the law of cosines as follows:

$$\cos \alpha_1 = \frac{F_e^2 + F_m^2 - F_r^2}{2\, F_e\, F_m} \tag{4.11.5}$$

$$\cos \alpha_2 = \frac{F_r^2 + F_m^2 - F_r^2}{2\, F_r\, F_m} \tag{4.11.6}$$

$$\alpha = \alpha_1 + \alpha_2 \tag{4.11.7}$$

where: F_e = radial component of the earth's magnetic field
F_m = measured radial field
F_r = calculated radial field due to the magnetic monopole

The sign of α is resolved by observation of the angle at another near by point.

Multiple Pole Ranging Techniques. Distance and direction determination from a dipole or a more complex configuration of concentrated poles applies the same previous techniques. Within the tool's detection range, only a small number of poles will contribute significantly to the observed field. A preliminary view of the magnetic data reveals the pole configuration actually encountered at a particular depth. The distance of closest approach angle can again be found as a function of the separation between the extrema of the axial field. The magnetic field section due to multiple poles falls in the plane defined by the axis of the blowout well and the point of measurement, thus giving the direction. The selection of the extremal separation of the axial field or the radial half-width for range determination is only a convenience; other features dependent on the shape of the fields or curve fitting techniques can be used for this purpose.

Distributed Model of Magnetic Poles in Long Iron Cylinders. A model that distributes the magnetic monopole at one end of a long iron cylinder with a decaying exponential weight is as follows:

$$m(s) = \frac{M}{\delta} e^{-s/\delta} \quad \text{for } s>0 \tag{4.11.8}$$

where: M = total pole strength that can be verified by integration of the distribution for all $s>0$.

The magnetic decay constant, δ, follows the relationship as follows:

$$\delta = K \quad \sqrt{A_{cs}}\, \mu/\mu_{\upsilon} \tag{4.11.9}$$

where:

K = constant determined experimentally

A_{cs} = cross sectional area of the iron in the pipe

μ = magnetic permeability of that grade of steel

The derivation of the equation can be found in SPE 14388, "Improved Magnetic Model For Determination of Range and Direction To A Blowout Well."

General Form of the Magnetic Field Ranging Methods Incorporating Exponential Poles. If an axis defined by the unit vector $\hat{x}$ passes through the center of a three-dimensional coordinate system, with an arbitrary magnetic distribution $f(\bar{x})$, the vector magnetic field at any point $\bar{s}$ in three-dimensional space is as follows:

$$F(s) = \int_{-\infty}^{\infty} f(u) \frac{\hat{r}}{(r)^2} du, \quad \bar{r} = (u\hat{x} - \bar{s}) \tag{4.11.10}$$

where: $\hat{r}$ = unit vector in the direction of $\bar{r}$

For the special case of parallel relief and blowout wells with separation R, the axial and radial fields reduce to the form:

$$F_a(s) = \int_{-\infty}^{\infty} \frac{f(\mu)\ (s-\mu)}{(R^2 + (s-\mu)^2)^{3/2}} du \tag{4.11.11}$$

$$F_r(s) = \int_{-\infty}^{\infty} \frac{f(u) R}{(R^2 + (s-u)^2)^{3/2}} du \tag{4.11.12}$$

The assumption of parallel wellbores usually suffers for accurate range determination. For exponential poles, the magnetic distribution is a sum of shifted exponentials in the form of Eq 4.11.8.

Modification of Ranging Technique for Exponential Poles. Simple features of the measured magnetic field, such as the distance between the extrema of the axial field, can be used for determination of the radial distance to the magnetic anomaly. The fields due to exponentially distributed poles retain the general behavior of the extrema observed with impulse poles, but the function describing the relationship between the distance to the blowout well and the extremal separation has changed.

Numerical integration is required to find the separation between the axial magnetic field extrema as a function of the range R for monopole and dipole configuration of exponentially distributed poles for various magnetic pole decay constants. To obtain the range to the blowout well at any location in the relief well, one examines the magnetometer data to determine the general pole configuration (monopole, dipole, etc.). After obtaining the separation of the extrema from the logging data, the intersection of the observed extremal separation is located with the curve corresponding to the decay width characteristic of the type of pipe in the blowout well. This distance along the other axis is the range to the blowout well.

If the angular orientation of the logging tool is known, the magnetic field vector will point to the axis of the blowout well and the direction is immediately determined. If only the total radial field component is known, the pole strength can be determined from the axial field, and the radial field can be calculated using Eq. 4.11.12. Knowledge of this vector, the earth's field, and the measured radial vector fixes the direction to the blowout well.

4.11.6 Magrange. Tensor Corporation of Austin, Texas offers the Magrange II as a ranging tool for relief wells. The tool was the first of it type to determine distance and direction of blowout wells from relief wells. It has been perhaps the most widely used tool until recent times. Mr. Robert "Bob" Waters has significant experience at running ranging tools worldwide. Magrange II system consists of a downhole instrument, a winch and seven-conductor cable, a surface electronic unit, a programmable calculator, and plotter. The downhole instrument contains magnetic field sensors arranged in a non-interferring orthogonal configuration and also in a gradiometric measurement configuration. The sensors, along with their associated electronics and signal condition circuitry, are housed in a nonmagnetic cylindrical container. Experience has shown that under the optimum conditions, Magrange II can detect targets at a range of 100 ft. The direction from the relief well to a target well can be determined to within a few degrees.

The Magrange II system uses the passive technique to detect magnetic dipoles as discussed in Section 4.11.5. Figure 4.11.6 shows a plot of Magrange data. The casing "near-point" in the blowout well is shown at 2230 ft.

The passive tool can measure distance and direction in a homogenous formation to approximately 70 ft for 9 5/8", 47 ft casing in the blowout well. This example is given by the manufacturer.

The present tool offers some advantages over active tools of any manufacturer's origin. It is not affected by oil muds in the relief well whereas active tools, depending on manufacturer, can cause the effectiveness to be reduced by 50% for oil muds. Also, the tool functions as effectively near the bottom of the pipe string in the blowout well as up the hole. Again, this is contrary to active tools.

Magrange has recently introduced an active detection tool. Its initial field trial was on the Marathon Steelhead blowout in 1988. Recent verbal reports of its usage on a Corpoven relief well in Venezuela indicates that it can provide good measurements to 200 ft. separation between relief and blowout wells. The manufacturer must be consulted for more information.

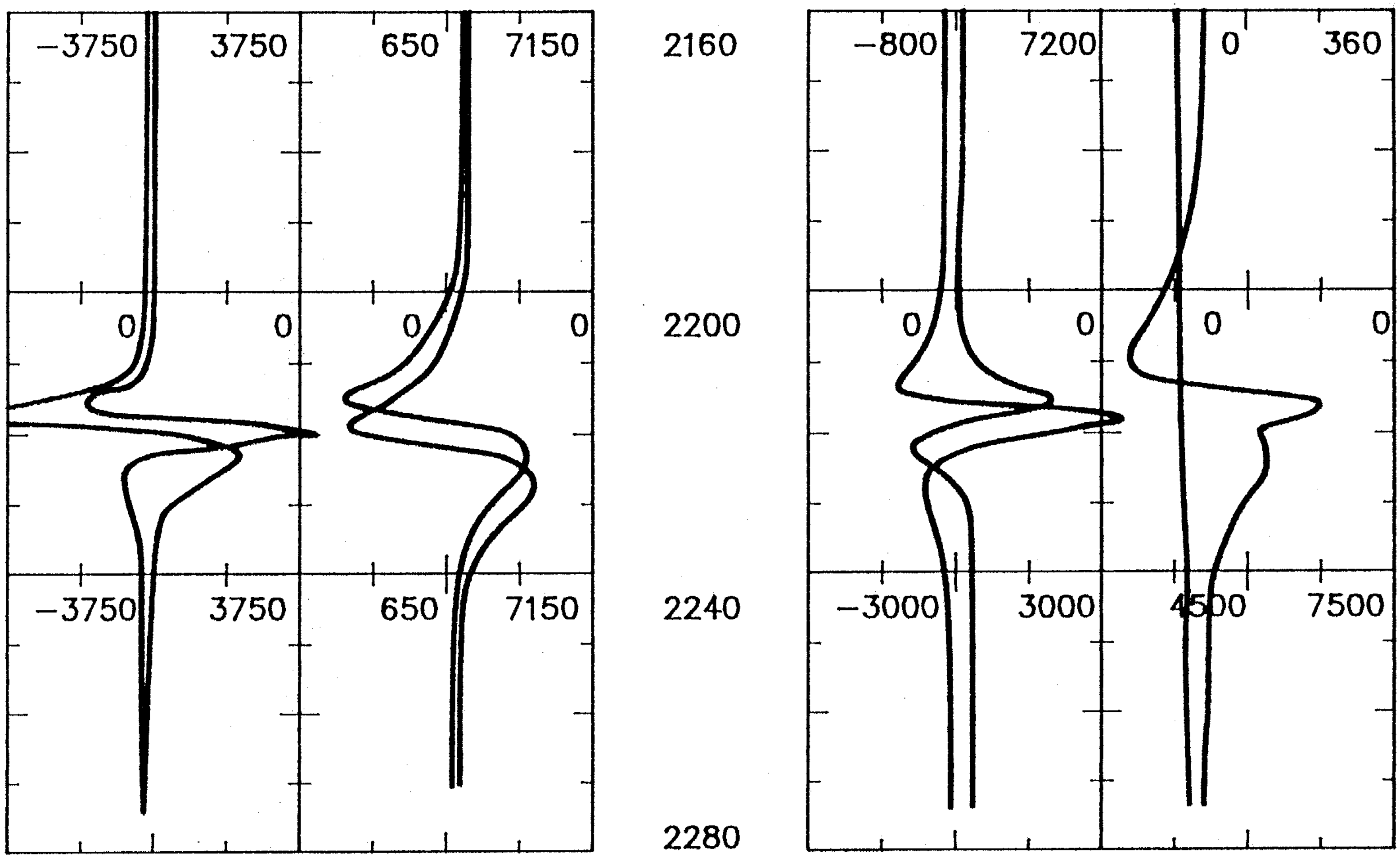

Figure 4.11.6

Magrange Plot*

*Courtesy Tensor Corp.

Operation. In operation, the magnetic measurements are made in open hole, beyond the influence of the relief well casing. On the way down, the measured depth indicator is checked against the casing shoe. When the tool has tagged bottom, the measured depth is entered into the surface unit and the data station interval is selected. The time needed to print the data determines the rate at which the tool may be winched uphole. Generally, this is about 900 ft/hr.

As the instrument is started uphole, the surface unit is set to automatically take data at the selected measured depth intervals. As the run is in process, the printout allows the operator to monitor each channel and observe the overall performance of the system. Repeat runs are made in order to increase confidence in the final results and to provide for the recognition of anomalies which may be caused by ferrous junk embedded in the wall of the relief well, wash outs or irregularities along the relief well, or interference from adjacent wells. Usually, three or four runs are sufficient.

Analysis. The downhole tool contains magnetic field sensors. Two pairs are arranged so their sensitive axes are parallel to the longitudinal axis of the tool. These are the axial sensors and they measure the magnetic field intensity along the axis of the relief well. The second pair of magnetometers have their axis directed vertically outward from the tool. They measure the components of the magnetic field at right angles to one another and are called the radial sensors. The Magrange II system using these sensors can be used without knowledge of the target's magnetization intensity or the earth's magnetic field.

Direction to the target is determined by analysis of the magnetic intensity as measured by the radial sensors. The values are observed in the target-area. The results will contain only the vector components of the target's magnetic field. The direction of the target from the relief well is determined by simple vector computation.

4.11.7 Vector Magnetics. Vector Magnetics Inc. was formed by Dr. Arthur Kuckes and Dr. Bruce Thompson in 1985. Both individuals were associated with Cornell University at the time. One of these individuals is present at the wellsite for all of the "Wellspot" jobs.

The Wellspot tool uses a low frequency alternating current flow in the blowout well's casing or drill string to develop a magnetic field. The current is injected from an electrode placed some distance above the Wellspot tool in the relief well, or by attaching an electrode directly to a blowout well's tubular at the surface. Measurements are taken at selected depths to determine the magnitude and direction of the magnetic field resulting from the induced current. At the same time, measurements are made of the magnitude and direction of the earth's magnetic field as the orientation of the measurement device can be determined. From these measurements, the compass direction and the distance to the target well can be determined.

Wellspot Tool Description and Running Practices. The Wellspot equipment consists of a sensor sonde (2 inch diameter, 72 inches long) to which are attached sinker bars and a spring tip if needed. Attached to the top of the sonde is a bridle 150 to 400 ft. in length which electrically insulates the sensor sonde from the electrode at the bottom of the wireline. The electrode is the torpedo connector which fastens the bridle to the conductor openhole wireline.

After rigging up the wireline unit and after preliminary surface checks, the sonde is lowered to the bottom of the well. A set of data is obtained in about 1 minute and the sonde is raised to another station where a set of data is obtained. The tool should be stationary in the hole at each station. It is important that the tool is not moving in the well to insure accurate readings. This usually requires a wireline compensator on floating rigs. This procedure is repeated until the tool operator decides that enough of the well has been logged.

The interval between stations can be 1-50 ft depending on the relative positions of the two wells. The sonde is usually lowered to the bottom again to make checks on previously obtained data. When the checks have been made, the tool is withdrawn from the hole and the wireline unit is rigged down. The tool data is displayed and recorded by a computer at the surface during the logging. Tool operation is continuously monitored for voltage, temperature, and telemetry accuracy. Preliminary results are available immediately and a full report is submitted usually 2-6 hours later.

The procedure in oil based muds is the same for water based muds except for the bridle arrangement. The range of detection in oil based operations is about 50% of that with water based muds under ideal conditions.

According to Vector Magnetics, the Wellspot tool can be run in the active or passive mode or a combination of active and passive. The systems are independent. This approach has benefits where less than ideal conditions exist for the active mode.

Further, Vector Magnetics has indicated that the tool's effectiveness and data evaluation is a function of whether or not a passby is made. The passby aids in enhancing the referencing between the wells but has the distinct downside of requiring additional drilling time. The time factor is not as critical in non-polluting gas wells as it might be with oil blowouts.

The accuracy of Wellspot determination is dependent on the geometry of the wells. In ideal conditions the range of detection is approximately 200 ft. but inaccuracies exist. The range of detection is considerably smaller in less than ideal conditions. From 200 to about 100 ft., the direction can be determined to about 10 degrees and range to +/- 20% of the distance, again under ideal conditions. These accuracies generally improve as the target well is approached.

The resistivity of the surrounding formations can generate a background signal. If the formations are uniform and have no dip, the spurious signal is very small or virtually non-existent. Lateral resistivity changes and dipping beds will generate a small bias signal. Within about 100 ft (30 m), the magnitude of the signal generated by the heterogeneities in the earth is small compared to the signal from the target well and will have only small bias effects on the results. This is one of the reasons for a greater uncertainty assigned to the distances and angles at ranges greater than 100 ft (30 m).

The average magnitude of the earth resistivity also affects the amount of electrical current which flows onto the target well. However, over the normal range of earth resistivity, this is a small effect.

Formation faults are usually associated with resistivity changes and will generate background signal as previously described. They limit the range as much as the accuracy at long ranges.

Formation fractures are generally linear fractures and do not affect the general resistivity structure of the formations. The resulting effect on the logging tool is small.

The Wellspot outer tool diameter is 2 in. which permits insertion into drill pipe. If the bore hole proves difficult to get down, the tool can be run out the end of an open bottom drill string which spans the difficult section. The additional use of a side entry sub 500 ft from the bit would allow logging 500 ft of hole even if the tool were unable to go deeper than the bottom of the drill string.

When close to the target well, the Wellspot tool can be used inside a non-magnetic drill collar. If locked into a direction drilling shoe, the angle between the target well and the shoe can be monitored. This permits the relief well specialist to home-in on the target well with a bent sub and monitor without tripping out of the hole.

Detection Target. The Wellspot principle depends on having a long body which is a good electrical conductor to collect the electrical current from the injection electrode. Casing, drill strings or tubing are considered good targets.

The ideal geometry for distance and direction accuracy is to make a passby of the target within about 50 ft and at a relative angle between the wells of about 10 degrees. The target should have casing or drill pipe extending for at least 1000 ft below the cross-over point. Also, the ideal situation uses water base muds and has vertical formation homogeneity and no ferrous content.

A poor target for the Wellspot tool involves a metallic material in a well confined to a small depth range. Some short range detection may be accomplished by supplementing the current injection method by looking for magnetic poles.

Detection range is also limited by the geometry of the wells. If the target well is approached at a large angle, greater than 45 degrees, the electrode is much farther away than the sensor which reduces the detection distance as measured from the sensor position. In some cases (shallow wells or access to the target wellbore), electrical current can be injected directly onto the target and then the angle of approach does not hurt the detection range.

Another difficult situation is detection near the end of the conductive pipe in the target well. Unfortunately, this is the most common situation in the blowout industry. The current begins to flow off the target pipe a certain distance from the end of the pipe such that, at the end, the current goes to zero. This causes the signal to go to zero at the end of the pipe. If the target is near the bottom of the pipe (i.e., range 30ft, 100 ft MD from the bottom), good signals can still be obtained. A blowout kill can be made by paralleling the target, then intersecting by kicking over to the wellbore.

Breaks in the continuity in the target such as washouts of perforations or casing failure will reduce the signal over the depth range of the break since the current will be forced out into the formations and then return to the pipe. Normal signal should be found above and below that range.

High Approach Angles. Vector Magnetics has patented a method for measuring the distance and direction to a target well from a relief well when the relief well is approaching the target at a high angle of intersection. The method can be used when the wells are nearly perpendicular.

When a relief well is drilled toward a target well at a large angle of approach, the relief well is essentially perpendicular to the generally vertical target well, and the only guide information needed by the driller is whether the relief well must be turned to the right or to the left in order to intersect the well. The relief well will move in a generally horizontal plane, so vertical directionality is not a consideration. A large angle of approach may occur when the relief well, which starts at a large distance away from the target well, is required to intersect at a relatively shallow depth, and in such situations, the relief well tends to intersect the target well at 60-90 degrees. Further, even in non-shallow well situations, there are a significant number of cases where the relief well drilling engineer would like to have a large angle of intersection, or even a perpendicular intersection.

A single A.C. magnetic field sensor is located on a ranging tool in the relief well with its axis of maximum sensitivity parallel to the axis of the tool, and thus parallel to the axis of the well. This magnetic field sensor is capable of detecting any field components which are parallel to the axis of the relief well. When the relief well is exactly on target, the axis of the homing tool and the relief well will intersect the axis of the target well, and there will be no A.C. magnetic field component parallel to the axis of the relief well or of the tool sensor. However, if the relief well deviates away from the target, a corresponding component of the alternating magnetic field appears in a direction axial to the sensor tool, and can be detected by the sensor.

4.11.8 Ultra-long-spaced-electric log (ULSEL). ULSEL, as it is called in the industry, is operated and offered by Schlumberger. It was the first type of detection tool used successfully in guiding relief wells to blowouts. Successful case histories include Piney Woods, Bay Marchand, and Brunei.

The ULSEL logging system was designed for detecting and mapping the profile of resistance anomalies such as salt domes in the vicinity of the wellbore. In the case of relief well drilling, the casing or drill pipe tubulars in the blowout well serve as the anomalies to current flow. The tool uses ultra-long-spacing normal devices to obtain deep-investigation readings which are influenced by the anomaly.

A standard resistivity log such as the ISF is used for the construction of a layered model of the formation which can be used to compute the ULSEL reading to be expected if no anomaly were present. Significant and consistent departures of the actual ULSEL values from the expected values serve to indicate the presence of resistive or conductive anomalies. Dipmeter data is also used in the interpretation and computation.

Digitized induction log readings are used in a computer program to arrive at a multi-layered model of the formation near the borehole. Layer boundaries are selected on the basis of electrical reflection coefficients (i.e., resistive contrasts). Each layer of the model is given a constant resistivity equal to the average induction log resistivity of the corresponding interval.

The multilayered model is used in a computer program to determine the ULSEL readings to be expected in the absence of any remote anomaly. Anomalies are detected and evaluated by comparison of the various ULSEL readings with these predicted no-anomaly values. (Figure 4.11.7)

For the interpretation of distance, a ratio is used

$$\text{Ratio} = \frac{\text{Corrected ULSEL restivity}}{\begin{array}{l}\text{Corresponding ULSEL restivity} \\ \text{expected for non-anomalous} \\ \text{environments.}\end{array}} \tag{4.11.13}$$

When these ratios deviate from unity by an appreciable amount and in a consistent manner, an anomaly is indicated. The general approach is to interpret the anomaly resistivity ratio in terms of the apparent distance to the subject of interest.

For the purpose of locating a nearby cased well from measurements made in the intersect well, use is made of shorter available ULSEL spacing (e.g., AM =20 ft., AN=70 ft, 10 in.) The ULSEL devices will detect a 9 5/8" casing at distances 20- 80 ft. If the distance to casing is definitely known to be less than 20 ft., only the 20 ft. normal is required.

A computer produces interpretation charts to be used for the existing conditions such as spacing of the ULSEL or normal devices used, casing size and weight, approach angle between intersect well and target casing, average formation resistivity, and anisotropy coefficients of the formation. Interpretations are made from these computer-produced charts by the ULSEL analyst using the relative-resistivity ratios from the computer output. The computer analysis must be done by Schlumberger at either Paris or New Orleans, USA and requires 2-4 days.

The technique measures distance only and has no capability by itself to detect the direction of the casing. The lack of direction-finding capability and introduction to the industry of magnetic ranging tools has made the ULSEL tool virtually obsolete for relief well drilling.

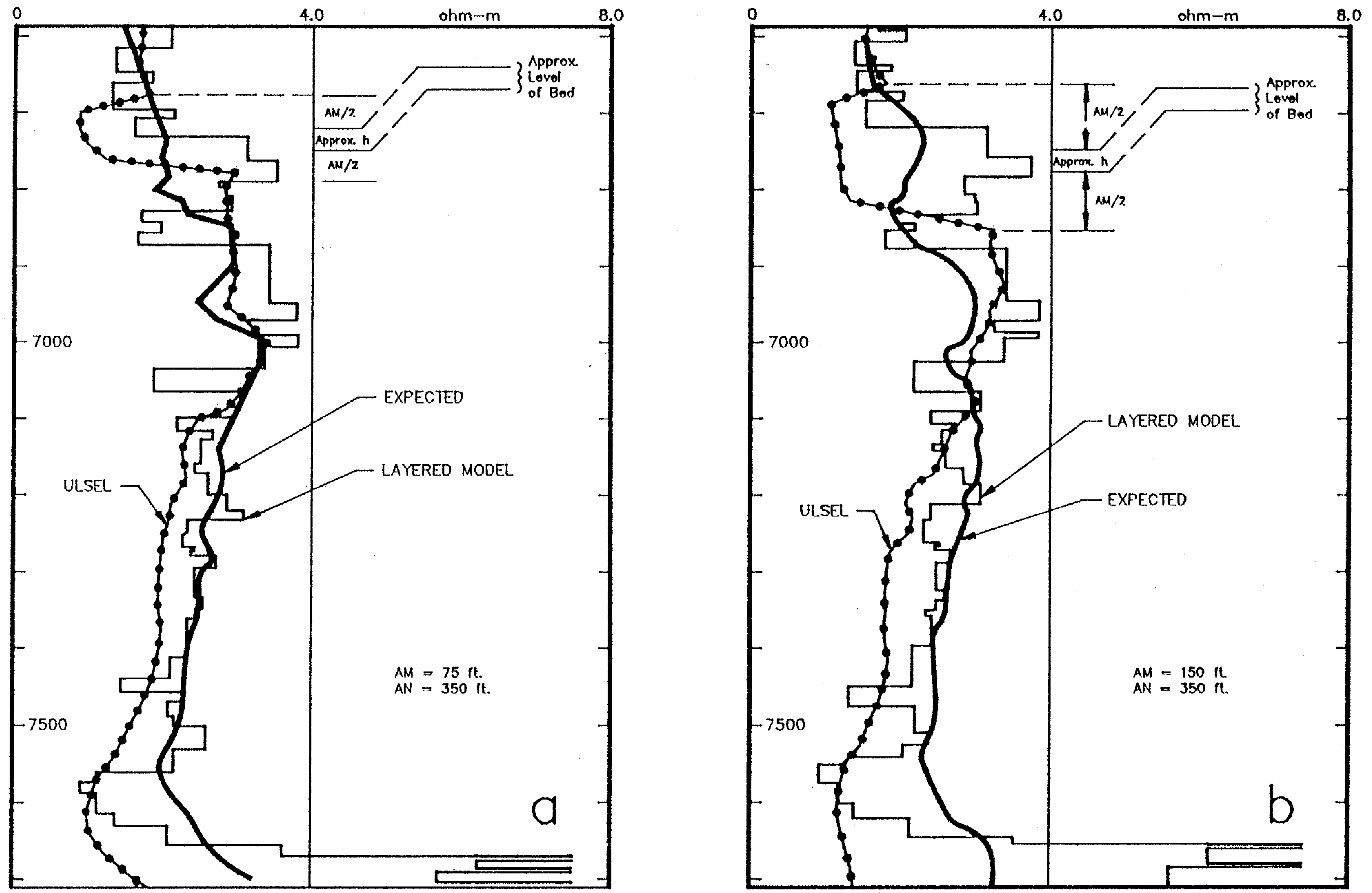

Figure 4.11.7

Illustration of the ULSEL Log
Used to Detect a Resistivity Anomaly*

*Courtesy Schlumberger

DEA PROJECT NO. 63

JOINT INDUSTRY PROGRAM
for
FLOATING VESSEL BLOWOUT CONTROL

4.11.9 MWD Systems. MWD systems offer unique possibilities with respect to relief well ranging. Hopefully, this segment of the oil service industry will develop its full capability in this area.

MWD means measure-while-drilling, or monitor-while-drilling. A downhole tool contains numerous logging sensors and tools for a real time evaluation. The signals are transmitted to the surface and processed for presentation to the operator. The advantages of MWD systems are the (virtual) real time evaluation capability and the reliability/accuracy of the data. Some parameters measured by the MWD systems are as follows:

- Weight-on-bit
- Resistivity
- Temperature
- Azimuth and drift angle
- Neutron porosity
- Gamma ray

The directional capability is of importance in steering/drilling a relief well to the blowout well.

MWD tools also offer the capability of being used as ranging tools. The MWD system utilizes magnetometers for directional analysis. In some cases, they are identical to those used in ranging tools and are, in fact, supplied by the same manufacturer. New magnetometer data collected by the sensors is the same for both tools, but is processed differently to achieve the specific desired results. If the MWD system is supplied with the appropriate software to process the data, it can be used as a real time ranging tool.

One successful case using this approach has been completed in 1986-1987. A platform well developed a casing rupture and had an underground blowout. A spare slot on the platform was used to drill a relief well. An MWD system was used as a ranging tool. The processing software was written and de-bugged. Attention was required to calibrate of the magnetometers in the tool. Since this incident, the operator has not further developed the technology.

As recent as 1990, a leading MWD manufacturer was reported to be working on the development of MWD tools as ranging tools. Current status is not known. If developed, it would offer an advancement to relief well drilling technology. However, limited market size may ultimately control the tool/software development.

4.11.10 Acoustic Tools. Attempts have been made over the last 2 decades to develop acoustic tools with ranging capability. The tools were planned to detect the sounds created from flowing fluids of the blowout. The tools would not be effective in the absence of fluid flow. An advantage to the concept is that it is not dependent on having casing or drill pipe in the blowout well.

For various reasons, the concept has not reached a marketable stage although claims of capability are interesting. One oil operator has developed a tool that was used on a blowout in North Africa. A university in Scotland did some work that suggested ranging capability of approximately 300 m. It is not presently clear as to why the tools/concepts have not been fully developed.

4.11.11 Effect of Pre-magnetized Casing Joints. Shell E&P Laboratorium has completed some testing relative to relief wells. The work focused on pre-magnetization of casing to improve detectability of blowing wells. The authors, de Lange and Darling, described the results in IADC/SPE 17255 "Improved Detectability of Blowing Wells."

As stated in the paper,

> "Experience with electromagnetic (active-type) homing-in tools during recent blowouts indicated a detection range between 30 to 45 m, although specific interpretation problems still remained, and in all cases a passing situation was required to locate the blowing well."

Based on these observations, a program was undertaken to determine if the passive ranging tool's effectiveness could be increased if one or more joints of the casing in the blowout well were (previously) pre-magnetized. In summary, the results of the work are quite attractive.

The new casing magnetization methods enable the detection range of a passive tool to be increased from about 15 m to at least 30 m for casing sizes greater than 7". The range will, unlike that of active homing-in devices, hardly be affected by formation characteristics, well geometry or intersect at the bottom of the casing string.

Two approaches are available for casing magnetization. A coil for magnetizing the pipe or drill string can be installed at the bell nipple below the rotary table if sufficient safety measures are taken. By simply feeding a current through the coil the well tubulars can be strongly magnetized or demagnetized. Alternatively, the magnetizing procedure can be carried out manually by preparing the casing in a shop or on site before they are run in the hole, thus saving rig time.

The magnetic pole strengths, measured at surface before installing the casing, were not found to be affected by continued drilling operations. Survey tools run in the directional reference test well with the magnetized casing joint installed were not affected by the strong magnetic fields.

As reported by IADC/SPE 17255, logging and surveying companies were consulted on whether the higher magnetic field inside the casing may affect the performance of their tools. This was generally not considered to be a problem. Results of surveys in a reference test well did not indicate any malfunctioning of the tools as a result of stronger magnetic induction fields inside magnetized casing joints. Also, gyroscopic survey tools are normally shielded from high magnetic fields.

It has attractive features relative to relief well drilling. It seems worthwhile that the bottom joint(s) of casing on deep critical strings might be magnetized in the event that a relief well is required. The term "critical" might be defined as production platform wells or deep high pressure, exploratory oil wells. Operationally, it would require that one or two joints be given special attention and handling.

Example 4.11.1.

The well shown in Figure 4.11.8 blew out while drilling. The 4 1/2" drill string is on the bottom. A relief well is planned since capping is not possible.

The initial step is to determine the intersect point for the relief well. Since the well is in a highly sensitive area and is blowing H_2S gas, it is decided to evaluate all intersect points and to select a depth that will allow the well to be killed safely in the shortest time span.

It is decided to evaluate 4 depths as follows. The appropriate fracture gradients for these depths are shown. Also, the estimated drilling time to reach these depths is shown.

Possible Intersect Depth (ft)	Fracture Gradient (lb/gal)	Drilling Time (days)
8000	16.0	45
10000	17.5	55
13000	18.5	85
16000	18.9	130

Obviously the shallow depths at 8000 and 10000 ft are attractive intersect points because the drilling times are much less than the deeper options.

The next question concerns the pressure that must be controlled at these depths at the time the wells are intersected. The worst case scenario is to use absolute open flow conditions without reservoir drawdown. However, this does not give realistic conditions and creates an almost impossible kill situation in some cases.

A reservoir model is run to predict pressure drawdown under blowout conditions. For the purposes of this example, the BLOWDOWN model is run. It provides a realistic solution without requiring significant input time that a reservoir simulator might involve. The parameters used in the model are as follow:

Blowout depth	-	16000 ft
Reservoir pressure	-	14000 psi
Fluid type	-	Gas
Specific gravity	-	0.6

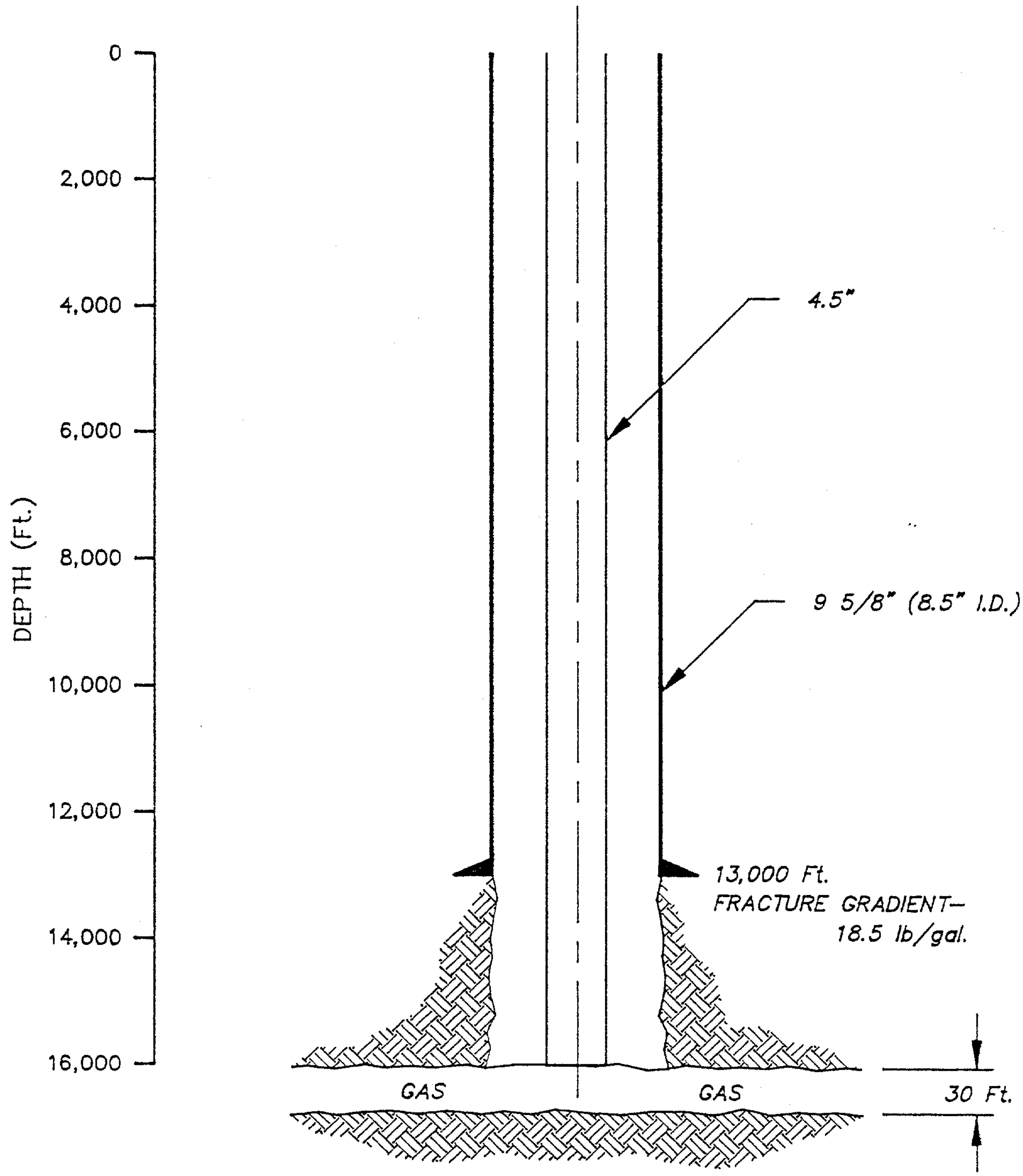

Figure 4.11.8

Blowout Configuration for
Example 4.11.1

$k = 250$ md
$r = 3000$ ft.
$\varnothing = 0.20$

$sg = 0.6$
$\mu = 0.01$ cp

Fluid viscosity	-	0.01 cp
Z Factor (initial)	-	1.2
Temperature	-	265 ^{o}F
Zone height	-	30 ft
Reservoir area	-	3000 ft (radius)
Porosity	-	20 %
Permeability	-	250 md

The results from BLOWDOWN under these conditions are shown in Figure 4.11.9. The pressure at the sandface at the various intersect times is as follows:

Intersect Time (days)	Sand Face Pressure (psi)
45	12959
55	12769
85	12224
130	11660

The results are interpreted to mean, as an example, that an intersect at 45 days will encounter a bottomhole pressure of 12959 psi. To be accurate, the pressure that would be encountered at 8000 ft at 45 days would be 12959 psi less a gas hydrostatic pressure to that depth. If a gradient of 0.15 psi/ft is used for the gas, the hydrostatic pressure is 1200 psi. For the purposes of this example, the hydrostatic of 1200 psi will not be considered, i.e., the pressure at 8000 ft will be 12959 psi. It is recommended in most cases to account for the hydrostatic pressure and subtract it from the bottomhole pressure. It is not done in this example.

The kill mud weight required for these pressures and depths are as follows:

Depth (ft)	Pressure (psi)	Kill Mud Weight (lb/gal)
8000	12959	31.2
10000	12769	24.6
13000	12224	18.1
16000	11660	14.1

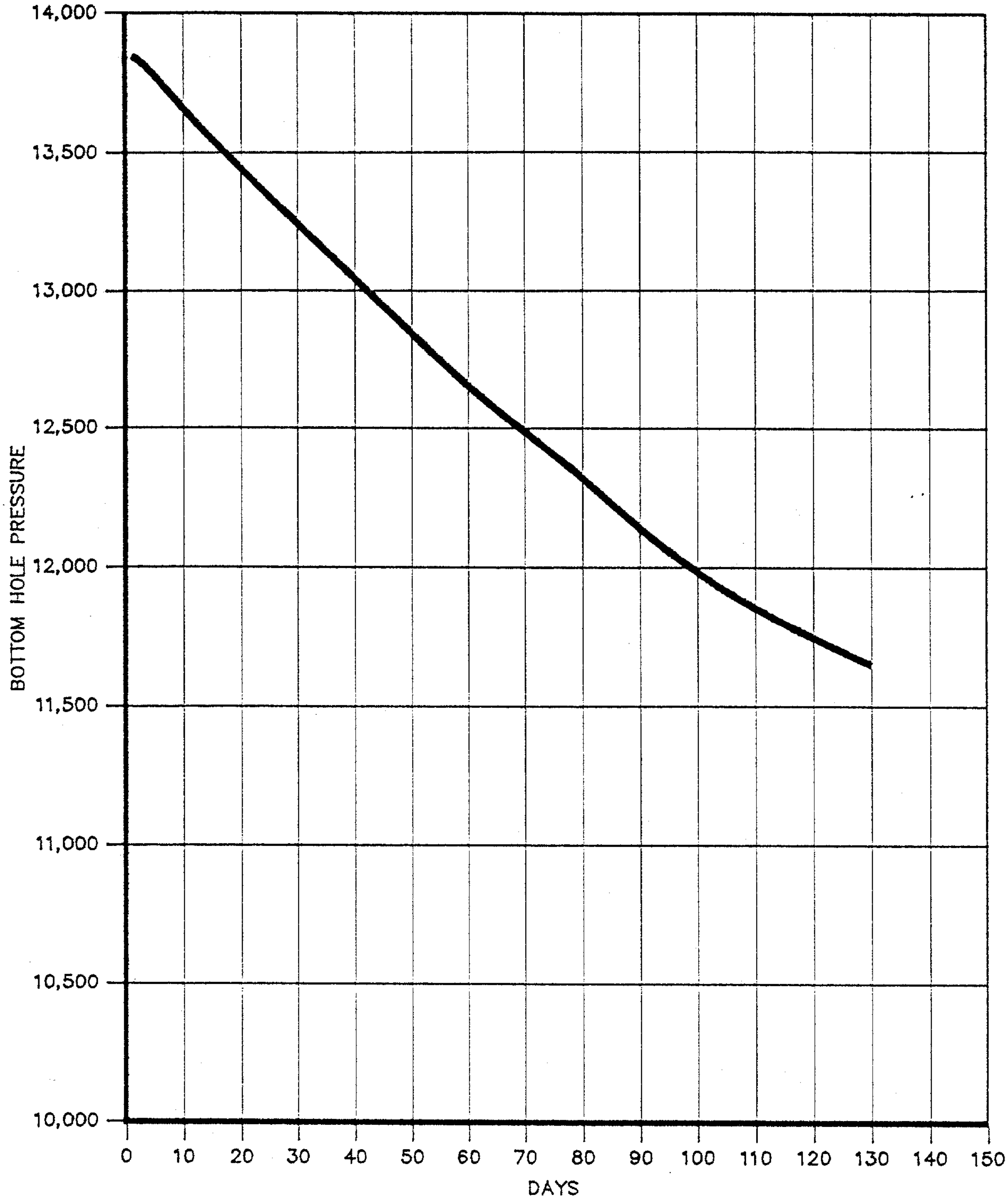

Figure 4.11.9

Bottom Hole Pressure Depletion
for Example 4.11.1

At this point the proposed kill depths can be evaluated with respect to kill potential. The depths of 8000 ft and 10000 ft are deleted from consideration. The kill mud weights are high and cannot be easily maintained. Also, at these depths, it would be necessary to perforate casing to establish communications. This is possible but probably would impose a pump restriction. This is not desirable because the well will be difficult to kill under optimum conditions.

The depth of 13000 ft is selected as the intersect point. The relief well can be drilled directly into the open wellbore to establish communications. The kill mud weight will be 18.1 which is certainly manageable. The time savings as opposed to an intersect at 16000 ft is 45 days.

The next step is to determine if the well can be killed dynamically at 13000 ft with reasonable kill conditions. Figures 4.11.10 - 4.11.13 show computer runs of DYNKIL for 4 situations as follows:

Figure No.	Kill Depth (ft)	Relief Well Casing Size (ID,in)
4.11.10	13000	9 5/8
4.11.11	13000	13 3/8
4.11.12	16000	9 5/8
4.11.13	16000	13 3/8

In all 4 cases, it is clear that the options with 13 3/8 in. as the kill string is preferable. The hydraulics are improved over the 9 5/8 in. casing strings. It is important to note that the minimum and maximum pressures for the 13000 ft intersect are very similar which means precise control of the kill operations are important. If this level of control is not available, it is better to intersect deeper, i.e, 14000 or 15000 ft. where the required kill mud weights will be lower.

VOLUMES:
ANNULAR VOLUME OF BLOWOUT WELL (BBLS) .... = 645.238
ANNULAR VOLUME OF RELIEF WELL (BBLS) .... = 1800.898

INITIAL KILL:
WEIGHT OF INITIAL KILL FLUID (PPG) .... = 8.330
PUMPING RATE (BBLS/MIN) .... = 151.425

PUMPING RATE TO EJECT EMPTY DRILLSTRING (BBLS/MIN) = 176.872
CORRESPONDING BOTTOM-HOLE PRESSURE (PSI) .... = 14280.300

PUMPING RATE TO EJECT FULL DRILLSTRING (BBLS/MIN) = 218.918
CORRESPONDING BOTTOM-HOLE PRESSURE (PSI) .... = 18195.690

FINAL KILL:
WEIGHT OF FINAL KILL FLUID (PPG) .... = 18.200
RESERVOIR PRESSURE (PPG) .... = 18.104

PUMPS:
MAXIMUM PUMP PRESSURES (PSI) .... = 7281.710
HYDRAULIC HORSEPOWER REQUIRED .... = 27018.780

PUMPING SCHEDULE -- 8.33 PPG TO 18.20 PPG

TIME (MIN)	VOLUME PUMPED (BBLS)	INJECTION RATE (BBLS/MIN)	RELIEF WELL ANNULAR PRESSURE (PSI) MIN	RELIEF WELL ANNULAR PRESSURE (PSI) MAX	RELIEF WELL TUBING PRESSURE (PSI) MIN	RELIEF WELL TUBING PRESSURE (PSI) MAX
.00	.0	151.4	7014.	7282.	6599.	6867
12.00	1798.9	151.4	1919.	2186.	6599.	6867
12.25	1870.7	119.6	1277.	1544.	6599.	6867
12.50	1899.3	109.5	1093.	1360.	6599.	6867
12.75	1925.6	101.2	951.	1218.	6599.	6867
13.00	1950.1	94.2	831.	1099.	6599.	6867
13.25	1972.9	88.2	730.	998.	6599.	6867
13.50	1994.3	83.0	647.	914.	6599.	6867
13.75	2014.4	78.4	577.	844.	6599.	6867
14.00	2033.5	74.3	517.	785.	6599.	6867
14.25	2051.6	70.5	465.	733.	6599.	6867
14.50	2068.8	67.1	420.	688.	6599.	6867
14.75	2085.2	64.0	381.	649.	6599.	6867
15.00	2100.9	61.1	346.	614.	6599.	6867
15.50	2130.1	56.0	287.	554.	6599.	6867
16.00	2157.0	51.5	239.	506.	6599.	6867
16.50	2181.8	47.5	199.	466.	6599.	6867
17.00	2204.7	44.0	165.	433.	6599.	6867
17.50	2225.8	40.7	136.	404.	6599.	6867
18.00	2245.5	37.8	112.	379.	6599.	6867
19.00	2280.6	32.6	75.	342.	6599.	6867
20.00	2311.0	28.1	55.	322.	6599.	6867
21.00	2337.0	24.1	43.	310.	6599.	6867
22.00	2359.4	20.6	32.	300.	6599.	6867
23.00	2378.8	18.0	24.	292.	6599.	6867
25.00	2406.3	9.5	0.	263.	6599.	6867
27.00	2420.7	4.8	0.	244.	6599.	6867
29.00	2428.3	2.8	0.	233.	6599.	6867
33.00	2436.0	1.1	0.	223.	6599.	6867

Figure 4.11.10

13,000 Ft Intersect, 9 5/8" Kill String

VOLUMES:
ANNULAR VOLUME OF BLOWOUT WELL (BBLS) .... = 645.238
ANNULAR VOLUME OF RELIEF WELL (BBLS) .... = 1800.898

INITIAL KILL:
WEIGHT OF INITIAL KILL FLUID (PPG) .... = 8.330
PUMPING RATE (BBLS/MIN) .... = 151.425

PUMPING RATE TO EJECT EMPTY DRILLSTRING (BBLS/MIN) = 176.872
CORRESPONDING BOTTOM-HOLE PRESSURE (PSI) .... = 14280.300

PUMPING RATE TO EJECT FULL DRILLSTRING (BBLS/MIN) = 218.918
CORRESPONDING BOTTOM-HOLE PRESSURE (PSI) .... = 18195.690

FINAL KILL:
WEIGHT OF FINAL KILL FLUID (PPG) .... = 18.200
RESERVOIR PRESSURE (PPG) .... = 18.104

PUMPS:
MAXIMUM PUMP PRESSURES (PSI) .... = 7281.710
HYDRAULIC HORSEPOWER REQUIRED .... = 27018.780

PUMPING SCHEDULE -- 8.33 PPG TO 18.20 PPG

TIME (MIN)	VOLUME PUMPED (BBLS)	INJECTION RATE (BBLS/MIN)	RELIEF WELL ANNULAR PRESSURE (PSI) MIN	RELIEF WELL ANNULAR PRESSURE (PSI) MAX	RELIEF WELL TUBING PRESSURE (PSI) MIN	RELIEF WELL TUBING PRESSURE (PSI) MAX
.00	.0	151.4	7014.	7282.	6599.	6867
12.00	1798.9	151.4	1919.	2186.	6599.	6867
12.25	1870.7	119.6	1277.	1544.	6599.	6867
12.50	1899.3	109.5	1093.	1360.	6599.	6867
12.75	1925.6	101.2	951.	1218.	6599.	6867
13.00	1950.1	94.2	831.	1099.	6599.	6867
13.25	1972.9	88.2	730.	998.	6599.	6867
13.50	1994.3	83.0	647.	914.	6599.	6867
13.75	2014.4	78.4	577.	844.	6599.	6867
14.00	2033.5	74.3	517.	785.	6599.	6867
14.25	2051.6	70.5	465.	733.	6599.	6867
14.50	2068.8	67.1	420.	688.	6599.	6867
14.75	2085.2	64.0	381.	649.	6599.	6867
15.00	2100.9	61.1	346.	614.	6599.	6867
15.50	2130.1	56.0	287.	554.	6599.	6867
16.00	2157.0	51.5	239.	506.	6599.	6867
16.50	2181.8	47.5	199.	466.	6599.	6867
17.00	2204.7	44.0	165.	433.	6599.	6867
17.50	2225.8	40.7	136.	404.	6599.	6867
18.00	2245.5	37.8	112.	379.	6599.	6867
19.00	2280.6	32.6	75.	342.	6599.	6867
20.00	2311.0	28.1	55.	322.	6599.	6867
21.00	2337.0	24.1	43.	310.	6599.	6867
22.00	2359.4	20.6	32.	300.	6599.	6867
23.00	2378.8	18.0	24.	292.	6599.	6867
25.00	2406.3	9.5	0.	263.	6599.	6867
27.00	2420.7	4.8	0.	244.	6599.	6867
29.00	2428.3	2.8	0.	233.	6599.	6867
33.00	2436.0	1.1	0.	223.	6599.	6867

Figure 4.11.11

13,000 Ft Intersect, 13 3/8" Kill String

VOLUMES:
ANNULAR VOLUME OF BLOWOUT WELL (BBLS) .... = 645.238
ANNULAR VOLUME OF RELIEF WELL (BBLS) .... = 1800.898

INITIAL KILL:
WEIGHT OF INITIAL KILL FLUID (PPG) .... = 8.330
PUMPING RATE (BBLS/MIN) .... = 151.425

PUMPING RATE TO EJECT EMPTY DRILLSTRING (BBLS/MIN) = 176.872
CORRESPONDING BOTTOM-HOLE PRESSURE (PSI) .... = 14280.300

PUMPING RATE TO EJECT FULL DRILLSTRING (BBLS/MIN) = 218.918
CORRESPONDING BOTTOM-HOLE PRESSURE (PSI) .... = 18195.690

FINAL KILL:
WEIGHT OF FINAL KILL FLUID (PPG) .... = 18.200
RESERVOIR PRESSURE (PPG) .... = 18.104

PUMPS:
MAXIMUM PUMP PRESSURES (PSI) .... = 7281.710
HYDRAULIC HORSEPOWER REQUIRED .... = 27018.780

PUMPING SCHEDULE -- 8.33 PPG TO 18.20 PPG

TIME (MIN)	VOLUME PUMPED (BBLS)	INJECTION RATE (BBLS/MIN)	RELIEF WELL ANNULAR PRESSURE (PSI) MIN	MAX	RELIEF WELL TUBING PRESSURE (PSI) MIN	MAX
.00	.0	151.4	7014.	7282.	6599.	6867
12.00	1798.9	151.4	1919.	2186.	6599.	6867
12.25	1870.7	119.6	1277.	1544.	6599.	6867
12.50	1899.3	109.5	1093.	1360.	6599.	6867
12.75	1925.6	101.2	951.	1218.	6599.	6867
13.00	1950.1	94.2	831.	1099.	6599.	6867
13.25	1972.9	88.2	730.	998.	6599.	6867
13.50	1994.3	83.0	647.	914.	6599.	6867
13.75	2014.4	78.4	577.	844.	6599.	6867
14.00	2033.5	74.3	517.	785.	6599.	6867
14.25	2051.6	70.5	465.	733.	6599.	6867
14.50	2068.8	67.1	420.	688.	6599.	6867
14.75	2085.2	64.0	381.	649.	6599.	6867
15.00	2100.9	61.1	346.	614.	6599.	6867
15.50	2130.1	56.0	287.	554.	6599.	6867
16.00	2157.0	51.5	239.	506.	6599.	6867
16.50	2181.8	47.5	199.	466.	6599.	6867
17.00	2204.7	44.0	165.	433.	6599.	6867
17.50	2225.8	40.7	136.	404.	6599.	6867
18.00	2245.5	37.8	112.	379.	6599.	6867
19.00	2280.6	32.6	75.	342.	6599.	6867
20.00	2311.0	28.1	55.	322.	6599.	6867
21.00	2337.0	24.1	43.	310.	6599.	6867
22.00	2359.4	20.6	32.	300.	6599.	6867
23.00	2378.8	18.0	24.	292.	6599.	6867
25.00	2406.3	9.5	0.	263.	6599.	6867
27.00	2420.7	4.8	0.	244.	6599.	6867
29.00	2428.3	2.8	0.	233.	6599.	6867
33.00	2436.0	1.1	0.	223.	6599.	6867

Figure 4.11.12

16,000 Ft Intersect, 13 3/8" Kill String

VOLUMES:
ANNULAR VOLUME OF BLOWOUT WELL (BBLS) .... = 794.078
ANNULAR VOLUME OF RELIEF WELL (BBLS) .... = 953.714

INITIAL KILL:
WEIGHT OF INITIAL KILL FLUID (PPG) .... = 8.330
PUMPING RATE (BBLS/MIN) .... = 111.287

PUMPING RATE TO EJECT EMPTY DRILLSTRING (BBLS/MIN) = 176.906
CORRESPONDING BOTTOM-HOLE PRESSURE (PSI) .... = 17578.500

PUMPING RATE TO EJECT FULL DRILLSTRING (BBLS/MIN) = 218.918
CORRESPONDING BOTTOM-HOLE PRESSURE (PSI) .... = 22393.520

FINAL KILL:
WEIGHT OF FINAL KILL FLUID (PPG) .... = 14.100
RESERVOIR PRESSURE (PPG) .... = 14.031

PUMPS:
MAXIMUM PUMP PRESSURES (PSI) .... = 12350.170
HYDRAULIC HORSEPOWER REQUIRED .... = 29067.530

PUMPING SCHEDULE -- 8.33 PPG TO 14.10 PPG

TIME (MIN)	VOLUME PUMPED (BBLS)	INJECTION RATE (BBLS/MIN)	RELIEF WELL ANNULAR PRESSURE (PSI) MIN	RELIEF WELL ANNULAR PRESSURE (PSI) MAX	RELIEF WELL TUBING PRESSURE (PSI) MIN	RELIEF WELL TUBING PRESSURE (PSI) MAX
.00	.0	111.3	7361.	10659.	4737.	8036
8.50	936.5	111.3	9051.	12350.	4737.	8036
8.75	990.8	102.0	7814.	11113.	4737.	8036
9.00	1015.6	96.4	7103.	10401.	4737.	8036
9.25	1039.1	91.5	6501.	9800.	4737.	8036
9.50	1061.4	87.1	5985.	9284.	4737.	8036
9.75	1082.7	83.2	5536.	8835.	4737.	8036
10.00	1103.0	79.6	5143.	8441.	4737.	8036
10.25	1122.5	76.4	4794.	8093.	4737.	8036
10.50	1141.3	73.4	4482.	7781.	4737.	8036
11.00	1176.7	68.2	3949.	7248.	4737.	8036
11.50	1209.6	63.6	3509.	6808.	4737.	8036
12.00	1240.4	59.6	3138.	6437.	4737.	8036
12.50	1269.3	56.0	2822.	6121.	4737.	8036
13.00	1296.4	52.7	2549.	5848.	4737.	8036
13.50	1322.1	49.8	2310.	5609.	4737.	8036
14.50	1369.3	44.6	1913.	5212.	4737.	8036
15.50	1411.7	40.2	1597.	4895.	4737.	8036
16.50	1449.9	36.3	1339.	4638.	4737.	8036
17.50	1484.6	32.9	1125.	4424.	4737.	8036
18.50	1515.9	29.8	946.	4245.	4737.	8036
19.50	1544.4	27.1	794.	4093.	4737.	8036
21.50	1593.6	22.2	541.	3840.	4737.	8036
23.50	1633.8	18.0	351.	3649.	4737.	8036
25.50	1666.3	14.5	238.	3537.	4737.	8036
27.50	1690.0	9.3	164.	3463.	4737.	8036
29.50	1704.8	5.5	108.	3407.	4737.	8036
31.50	1713.8	3.5	73.	3372.	4737.	8036
35.50	1724.1	1.6	32.	3331.	4737.	8036
43.50	1732.8	.6	0.	3296.	4737.	8036

Figure 4.11.13

16,000 Ft Intersect, 9 5/8" Kill String

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4.12 APPROACH ANGLE CONSIDERATIONS

4.12.1 Introduction. The approach angle is defined as the angle between the relief well and the blowout well. It is used to specify the closure or approach conditions between the relief well and the target in the blowout well. The target could be for a bypass at a shallow depth or for the kill intersect at some deeper point.

As discussed in Section 4.11, the general tone of the directional planning for the relief well is controlled by the desired bottom positioning relative to the blowout. Likewise, the bottom positioning is controlled by the approach angle.

Factors affecting the approach angle are as follows:

- Ranging tool considerations
- Concern relative to a premature intersect
- Casing milling considerations

Each will be discussed.

4.12.2 Ranging Tool Considerations. Ranging tools are affected by the approach angle, mud types and formation factors. With respect to the approach angle effect, the tool sensors are aligned in a manner to read perpendicular to the axis of the tool, which is aligned with the borehole of the relief well.

If the approach angle is parallel to the blowout well, the tool will be reading the distance between the wells at the nearest points. Likewise if the approach angle is perpendicular to the well, it will not read the blowout well.

The most likely scenario is where the approach angle is greater than zero but less than 90 degrees. In this case, the tool will sense the blowout tubulars at a point up the well. This point is more than the actual distance between the two wells. In other words, the wells are in closer proximity than is calculated by the ranging tools. These situations are shown in Figure 4.12.1.

Another factor to consider is the injection electrode and its placement in the relief well. It is on a bridle above the ranging tool, usually about 300 ft. The amount of current received in the blowout well is inversely proportional to the square root of the distance between the relief well electrode and the blowout well. As the approach angle increases, the electrode is much farther away from the blowout well which will significantly reduce the effectiveness of the injection tool. This situation applies exclusively to the active tool and not the passive tool.

Mud types affect the ranging tool ability. In general, water base muds give optimum capability for current injection tools. The effectiveness in oil muds is reduced to about 50% of the water base case. This factor is an estimate and is a function of the amount of current available for injection and the actual amount that can be injected under the specific well conditions. The estimate of a 50% reduction is based on conversations with manufacturers. They have not quantified the importance of each variable affecting tool performance. As a result, each variable must be viewed on the conservative side.

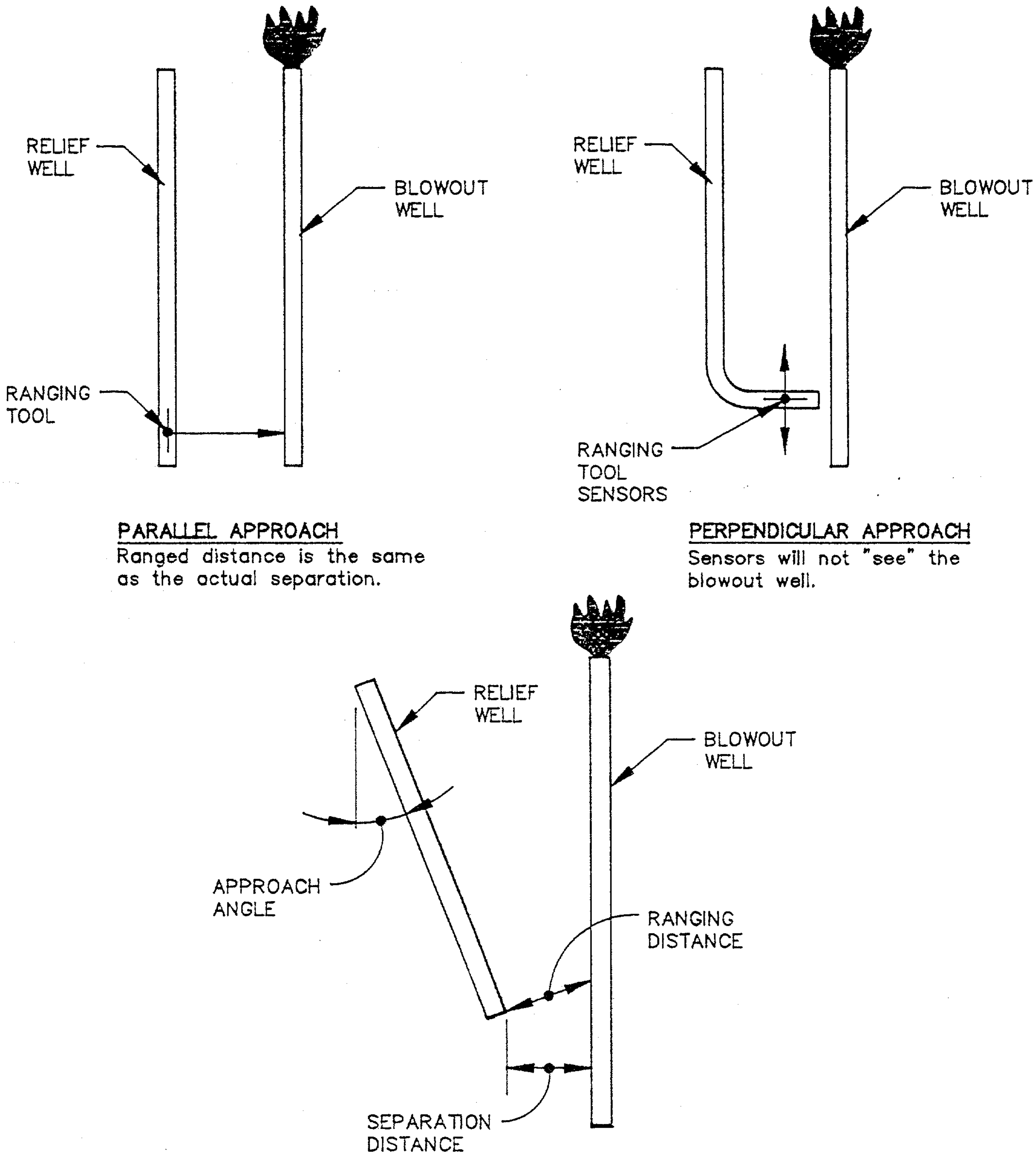

Figure 4.12.1

Affect of Approach Angle
On Separation and Ranging Distances

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The reduction in effectiveness due to oil muds does not apply to a passive detection tool. Many situations favor a passive tool application. This is particularly true because of the inherent difficulty of ranging near the bottom of a string with an active tool.

Formation factors affect the tools' performance. Heterogeneity causes an increase in the background noise level that can overshadow the signal level from the blowout casing. As a general rule, a heterogeneous formation can reduce the effectiveness of all ranging tools by as much as 25%, according to the manufacturers. This is a serious consideration if formations are drilled that have high resistivity differences between the lithology layers. This can be pronounced across faults, as an example.

Consider the following example. Assume that a tool can sense blowout casing at 200 ft under ideal conditions. Also, consider a reduction of 50% effectiveness in oil muds and a further 25% reduction for non-homogenous formation. Refer to Figure 4.12.2. This graph shows the detection ranges under these conditions and also includes an approach angle factor. If the well is approached at 30 degrees, and the ranging tool senses the casing under ideal conditions at 200 ft, the actual separation distance between the wells is ~173 ft. For worst case conditions of oil muds and a non-homogenous formation, this distance is reduced to ~68 ft.

This illustration points out the need to develop an understanding of ranging tools effectiveness factors when planning the approach angle. It is damaging to assume that a ranging tool can accurately, and with repeatability, detect casing at distances of 200 ft and greater. Sales literature can be misleading unless it is read "between the lines".

Ellipses of uncertainty must be considered against the type of information presented in the above example. Again, consider that the data in the example is applicable and that the detectable separation distance between the wells is 68 ft. If the ellipse of uncertainty for the blowing well is calculated at a 75 ft radius due to poor surveying and the ellipse for the relief well is 40 ft, the combined uncertainty radius is 115 ft. From a practical view, at the point of initial intersection of the uncertainty region, the wells could collide yet the ranging tools could not detect their positions. The uncertainty regions would have to overlap by a considerable margin before the ranging tools would be effective. This situation is shown in Figure 4.12.3.

The operator must decide if this situation is acceptable. If the blowout well is deemed to be fairly simple to kill after intersect and a premature intersect would not be particularly critical, the situation could be considered acceptable. Conversely, if the kill is anticipated to be difficult even under ideal conditions, the operator may elect to take alternative steps other than risk a premature intersect. These steps could include a bypass at a shallow depth to reduce uncertainty in the blowout well, or set casing on the relief well slightly shallower than anticipated and switch to water base muds to increase effectiveness of the ranging tools.

A parameter than can be controlled is the approach angle. It can be reduced to a relatively small value;i.e., 5-10 degrees, and increase the tools' practical effectiveness to a modest degree. However, the advantage of a 10 degree approach angle as compared to a 30 degree angle is not large and should not be considered as a factor with much weight.

The situation must be evaluated under the blowout conditions existing at the time of the event. It is not possible to develop an optimum solution that is situation-independent.

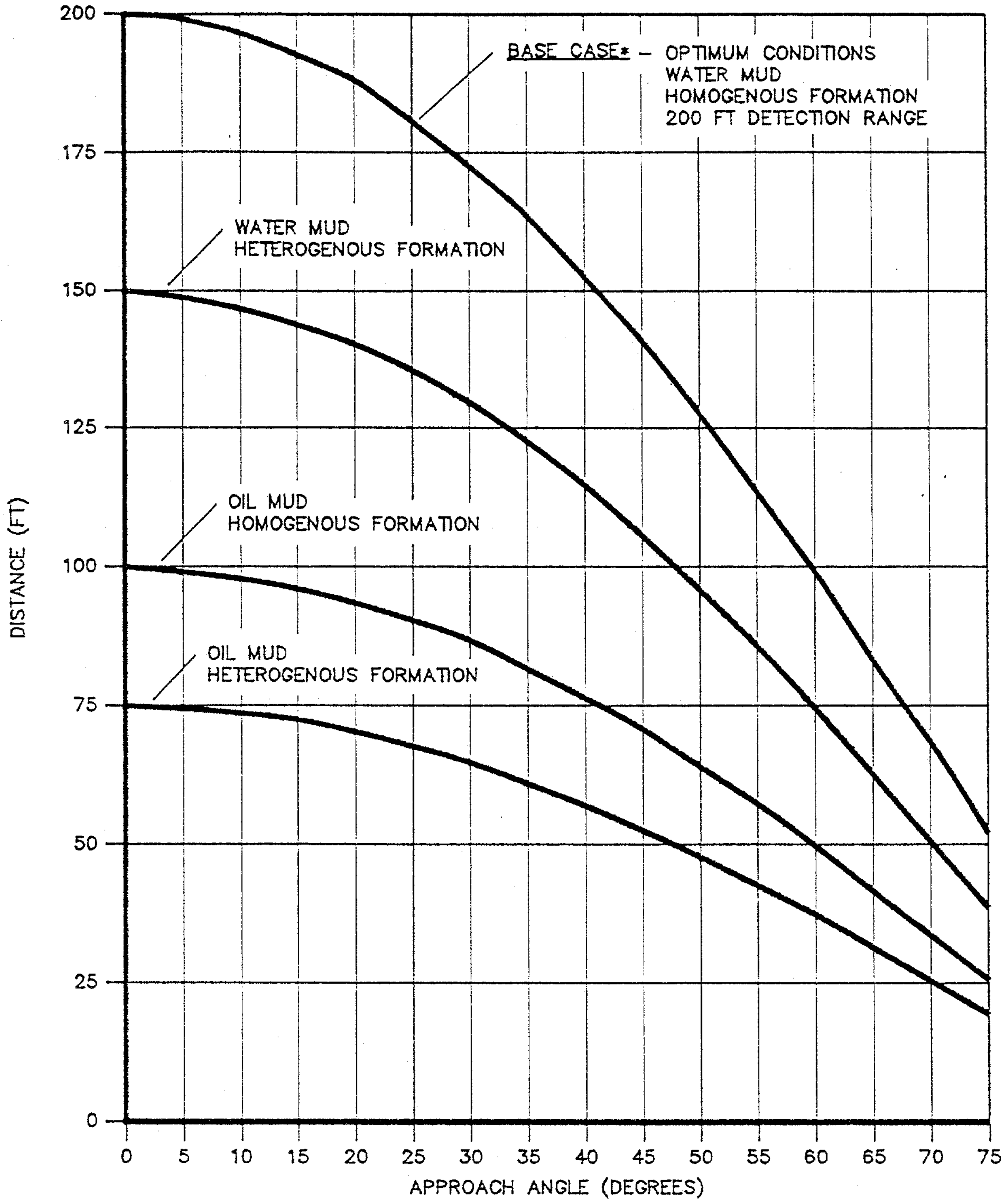

Figure 4.12.2

Estimates of Separation Between Relief and Blowout Wells for Various Approach Angles and Operating Conditions

All cases assume no ferrite content in formation.

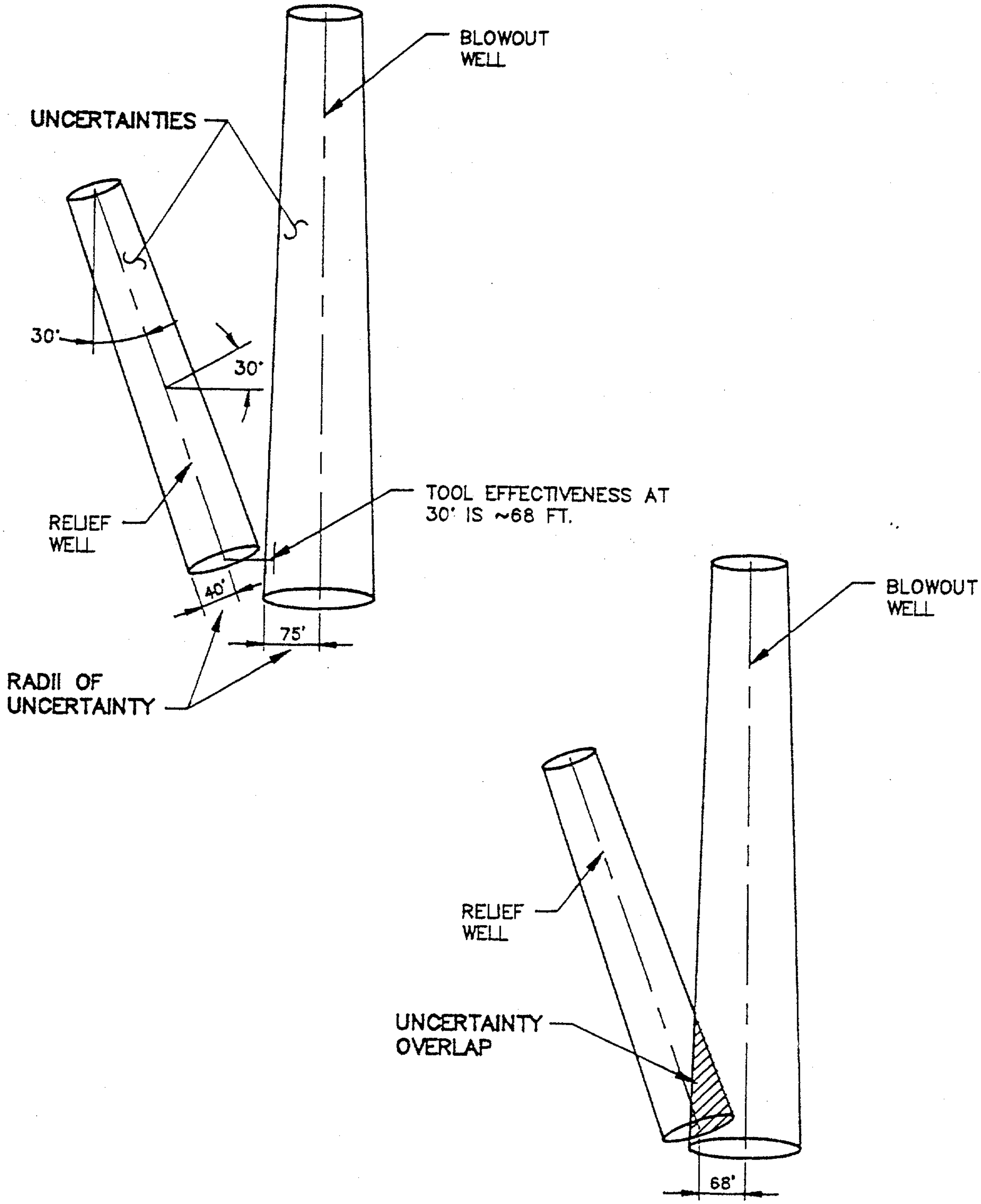

Figure 4.12.3

Relationship Between Well Location Uncertainties and Ranging Tool Capabilities

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4.12.3 Casing Milling. Casing milling becomes a consideration if the intersect is made against a cased blowout well as opposed to an open hole section. Casing milling is a method that can be used to open a communications path although perforation with a large gun is favored. The optimum angle for milling, based on field experiences, is ~3 degrees. A lesser angle and the mill will not bite into the casing. A greater angle was not as effective for undefined reasons.

4.13 DRILLING GUIDELINES

The drilling mechanics for the relief well do not differ appreciably from that of a conventional high priority well. Differences typically rest in the killing operation and required equipment for pumping and ranging. As such, a viable organization structure for relief well killing, described in Section 4.18, involves the operator handling all routine drilling tasks while a blowout specialist coordinates all killing functions.

Differences for relief well drilling can be grouped into general guidelines, considerations for the shallow section of the well if gas charging has occurred, and operations required for deeper sections of the well. They will be discussed in the following sections. Conventional drilling operations such as running casing, tripping, and electric logging will not be discussed

4.13.1 General Guidelines. General guidelines discussed herein are recommended for most wells but are not considered mandatory in most cases. In some cases, they are clearly not applicable.

A MWD system should be used to monitor drilling conditions near the bit. A system with a full complement of services is recommended including directional and formation logging capability. The logging should have a gamma ray and a resistivity tool as a minimum so lithology can be easily coordinated.

Attention should be given to the sequencing for data transmission from the tool to the surface. The client typically can select several options ranging from predominant directional surveys and infrequent lithology data to a situation where the lithology data is predominant and the directional survey is sent less frequently. The ratio of data transmissions can be as extreme as 3:1.

Although this may not appear to be important, various hole sections have different requirements. As an example when drilling through zones that could be pressure charged, it is important to have a good monitor on lithology. Likewise, directional data is more important when making directional changes. It is not possible to make the data transmission rate changes at the rig site so thoughts have to be given prior to transporting the MWD logging tools to the location. Also, different manufacturers' tools have various capabilities that must be considered.

The MWD tool must have the capability to transmit data to the surface via mud pulse, wireline, etc. It is not acceptable to use a tool that stores the data while drilling and then dumps the data when the tool is pulled out of the hole.

A computerized mud logging unit should be used. It should contain most currently available services. It is desirable in some situations to have the capability to transmit data to the operators' central district office to allow viewing of various logs as they are generated. A remote set of MWD printouts should be set up in the mud logging unit so all operations can be monitored by the operator from one site.

Additional gas detectors may be required in excess of the rigs' normal complement. The situation where they may be required is for operations in a shallow gas blowout. If the water depth is greater than 500-600 ft, it is not anticipated that they will be needed for this purpose. The gas monitors should be supplied by the mud logging unit so the readouts can be observed by the mud logging crew if their unit is established as the control center. (See Section 4.17 for additional details.)

Oil muds may be required to drill some relief wells. The only difficulty with oil muds relative to well killing is their adverse effect on ranging tools. (See Section 4.11) If possible, consideration should be given to changing out the oil mud to a water base mud near the bottom of the well to enhance ranging logging. However, alternatives in the ranging logging program are available if the oil mud is necessary to drill the appropriate sections.

Accurate well surveying is obviously important. Past experiences have shown that supposedly "accurate state of the art tools" may not give repeatable results and differ significantly with other tools that may be run. This situation has been observed by other operators in conventional well surveying practices. The difficulty is determining which surveys are most representative of the actual borehole location. In one field case the directional surveys from the MWD tool proved more reliable and repeatable than "highly accurate" survey tools.

Further it is recommended that the operator obtain as part of the organization team a specialist at survey interpretation. The specialist must know the operational principles of each tool so decisions can be made about reliability under the actual relief well conditions. The specialist should come from within the operators' organization if possible. Most blowout service companies as a rule do not have these specialists on staff. The specialist should also be consulted to reanalyze the surveys on the blowout well to determine if its position can be more accurately determined by a re-examination of the data.

Meetings should be held at the rig site prior to each critical function. The meetings should be attended by the operator representatives, blowout specialists, and key members of the service companies involved on the rig. The meeting should include all service companies and not just those involved with the particular activity. Exclusion of non-involved groups leads to miscommunications and rumors.

Crew psychology should be considered. The crew will typically be wary and perhaps nervous at the beginning of the well but then tend to become casual about their operations as the project continues. Unfortunately, they may become relaxed at the most critical part of the operations when the kill operations commence at the conclusion of the drilling. A meeting should be held with all crew members prior to the kill operations to gain their full attention and alertness.

The crew should be reaffirmed that relief wells have not blown out historically . The crew will obviously know that the original well blew out and, as such, the relief well has a high probability of blowing out. This is clearly not the case and the crew should be advised. Thoughtless jokes about a relief well blowout should be avoided.

Various rig modifications may be required for drilling the well. See Section 4.17 for details.

4.13.2 Shallow Drilling Guidelines. Shallow gas drilling for relief wells does not pose any unusual requirements unless natural shallow gas problems exist in the relief well site or the blowout well has charged shallow gas zones.

An extensive discussion of shallow gas drilling is outside the scope of "Joint Industry Program for Floating Vessel Blowout Control". However, key points will be presented as an indication of precautions that should be considered. Section 4.6 relating to observation wells should be consulted for further information.

It is recommended to drill riserless if possible. A riser can be used after casing has been run to a depth sufficient to allow shut-in of a kick. If the relief well begins to flow and it can not be killed dynamically, the rig can move off and let the well serve as a vent well. After the blowout well is finally killed, the vent well will soon die without further intervention.

If drilling riserless is not possible for any reason, a special purpose built diverter system should be used. See Figure 4.13.1 for a typical system with an erosion resistant section. This diverter system is designed from new technology and has proven serviceable under stringent conditions.

An ROV should be used with a sonar head to track any possible gas under the rig. The sonar has additional capability not provided with a TV picture. The sonar requirements may involve several sonar heads with varying frequencies that have proven useful for functions including running a BOP stack in murky environments and tracking gas at relatively long distances. The ROV should be of the type that has the single function of power and high velocity under adverse conditions. Manipulator capability has a lower priority.

Drilling bits should be used without jets when drilling possible charged zones. Jets cause a pressure restriction that can be detrimental when attempting to dynamically kill the well if flow should start. Drilling efficiency via optimum hydraulics is not a high priority consideration at this point.

Likewise, consideration should be given to using motors, turbines and MWD tools with minimum internal restrictions. These restrictions can impede a dynamic kill. Also, pumping at high rates with turbine driven MWD tools destroys some internal components of the tools. A sacrifice must be made on some occasions between MWD performance and dynamic killing capability.

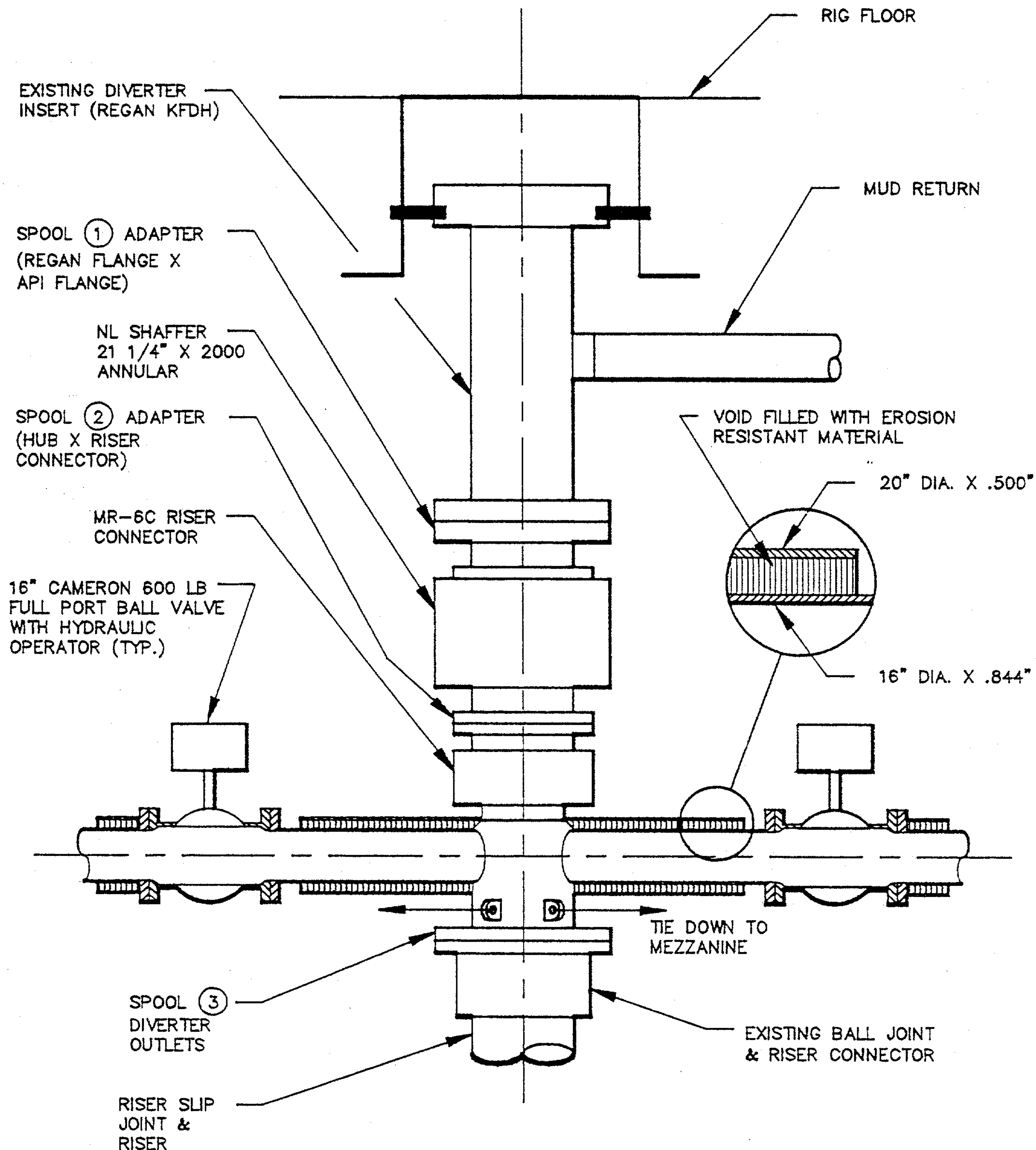

Figure 4.13.1

Purpose Built Diverter System

NOTE:

16" Outlet Lines Extend Port & Starboard to 17 Ft. Outboard of the Mezzanine Deck (Pipe Rack Deck)

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4.13.3 Deep Drilling Guidelines. Drilling guidelines for deep drilling is not as critical as shallow situations. However, this is true for most situations when comparing deep drilling versus drilling a shallow gas horizon. Conversion from the drilling process to the killing operations does require differences as described in Section 4.16.

The kill system must be tested as discussed in Section 4.14. The flow lines should be color coded if the system is complex and possible confusion could exist when opening or closing valves. All key valves should be controlled from the operator's console so manual intervention is not required.

A small drill string should be used when drilling into the blowout zone. The small pipe allows optimum kill hydraulics in the event that the large drill string can not be pulled from the well and changed out. The drill bit should not be equipped with jets when drilling in the zones where possible intersect could be made. Drilling efficiency is not the controlling priority at this point. Bits without cones are preferred to reduce risk of fishing job.

4.14 KILLING EQUIPMENT

4.14.1 Introduction. The equipment used in blowout killing operations is different, to some degree, than conventional drilling equipment. The general objective is to pump large volumes of kill fluids at high rates into the annulus. The annulus is used preferentially to the drill string for pumping kill fluids because of its large flow area and lower friction losses. The drill string is occasionally used for pumping but is more commonly used as a bottom hole pressure monitoring device.

4.14.2 Pumping Equipment. Kill systems usually utilize auxiliary pumps instead of or in addition to the rig pumps. The auxiliary pump system requirements may be large, i.e., 5000-10,000 hp. Special considerations include pump type and liner sizing, number of required pumps, long term pump efficiency factors, and pump placement.

The initial step is to determine the number of required pumps. The flow rate and maximum pumping pressure controls the number of pumps. If the pressure is not excessive, i.e., 0-6,000 psi, large liners can be used to increase output per pump. High pressures restrict the pump liner size. Table 4.14.1 shows options for Halliburton's HT - 400 pumps.

An efficiency factor must be applied for long term pumping. The factors are found in Section 4.8. It must be noted that very few operations require long term pumping so this efficiency consideration seldom is applied.

After the minimum number of required pumps is defined, they must be transported to the rig and organized in a manageable placement arrangement. Land jobs usually ease the difficulties because the pumps can be spotted on the area adjacent to the rig. Offshore sites pose more problems because of limited deck space and variable deck capacity. Also, additional pits for kill mud are usually required which further restricts the deck space.

Table 4.14.1

PUMP LINERS FOR HT-400 UNITS*

FLUID END OPTIONS	MAXIMUM PRESSURE*	MAXIMUM VOLUME*
3 3/8" plunger	20,000 psi	5.9 bbl/min
4" plunger	14,000 psi	8.4 bbl/min
4 1/2" plunger	11,200 psi	10.6 bbl/min
5" plunger	9,000 psi	13.0 bbl/min
6" plunger	6,250 psi	18.7 bbl/min

* *Maximums listed are pump maximums. Maximum s may vary slightly depending on power train.*

* *Courtesy Halliburton*

Table 4.14.2

DOWELL STIMULATION VESSELS**

	BIG ORANGE											
	1	4	9	10	11	12	14	15	17	18	20	21
LOA (m)	54.34	53.3	50.0	67.7	57.7	57.7	41.5	57.7	60.9	75.1	57.9	66.5
Deadweight (tons)	700	720	-	1100	970	970	-	970	1430	2000	-	750
Inst. power (kW)	5225	5300	5300	7950	4105	4105	1690	4105	5200	9150	-	2300
Accommodation	31	30	24	30	32	32	4	32	30	32	-	26
Stim. power (hhp)	1500	3600	5000	9000	2340	2340	500	3300	4500	7500	1600	1000
No. of hp pumps	2(d)	6(t)	4(t)	6(e)	3(d)	3(d)	2(d)	3(t)	3(e)	6(e)	2(d)	4(d)
Max. pressure (psi)	10000	10000	10000	10000	10000	10000	10000	15000	10000	15000	10000	10000
Max. flow (bbl/min)	75	100	50	100	75	75	25	75	60	100	75	20

d = diesel t = turbine e = electric

** *Courtesy Dowell Schlumberger*

Options for offshore pump equipment hookup are as follows:

- Deck placement
- Barges
- Stimulation vessels
- Purpose-built vessel

Most offshore areas worldwide have access to stimulation vessels.

Deck Placement. Pumps can be placed on the deck of the drilling rig. The number and size of pumps are controlled by the deck loading limitation.

Figure 4.14.1 shows the pump arrangement used by Neal Adams Firefighters on the Steelhead blowout. Although the number of pumps were more than adequate, the upper limit was set by deck loading because of pits with kill mud.

Halliburton is typically used to supply the pumps. The HT- 400 models are more easily fitted on rigs. Other pump manufacturers can be used but the deck utilization space is not as efficient.

The Halliburton pumps can be double-stacked if frames are available. This saves deck space. The frames supposedly are available worldwide except in the US.

Barges. Barges can be used for pump placement assuming sea conditions are moderate. Stacking and deck placement are similar to that for drilling rigs.

Supplying mud to the barge pumps may require several 3 or 4" ID hoses from the rig pits and centrifugals. This situation is different than pump placement on the rig where 6 or 8" ID hard piping can be installed. Pits can be placed on the barge but it usually is more convenient to work with the mud on the rig with the rigs' associated fluid handling/treatment equipment.

Stimulation Vessels. Most cementing companies operate stimulation vessels at various worldwide locations. As an example, Dowell has vessels located in offshore bases in Dubai, Aberdeen, Singapore, Venezuela, Brazil, Congo, Gabon, and Berwick, La (Table 4.14.2). Halliburton operates a stimulation vessel in the North Sea. (Figure 4.14.2) Several other companies operate stimulation vessels worldwide.

These vessels are almost ideally suited for blowout pumping requirements. Their basic function as a stimulation vessel is for high pressure pumping at relatively high rates. As such, they contain integrated pumps with manifolding, blending equipment and computer control/monitoring. The vessels are self-propelled.

The only apparent limitation with these vessels for some blowouts is an upper pumping limit of 60-100 bpm. This rate will handle almost every conceivable situation, particularly if reservoir drawdown is considered. Larger pump liners may increase pump output in some cases.

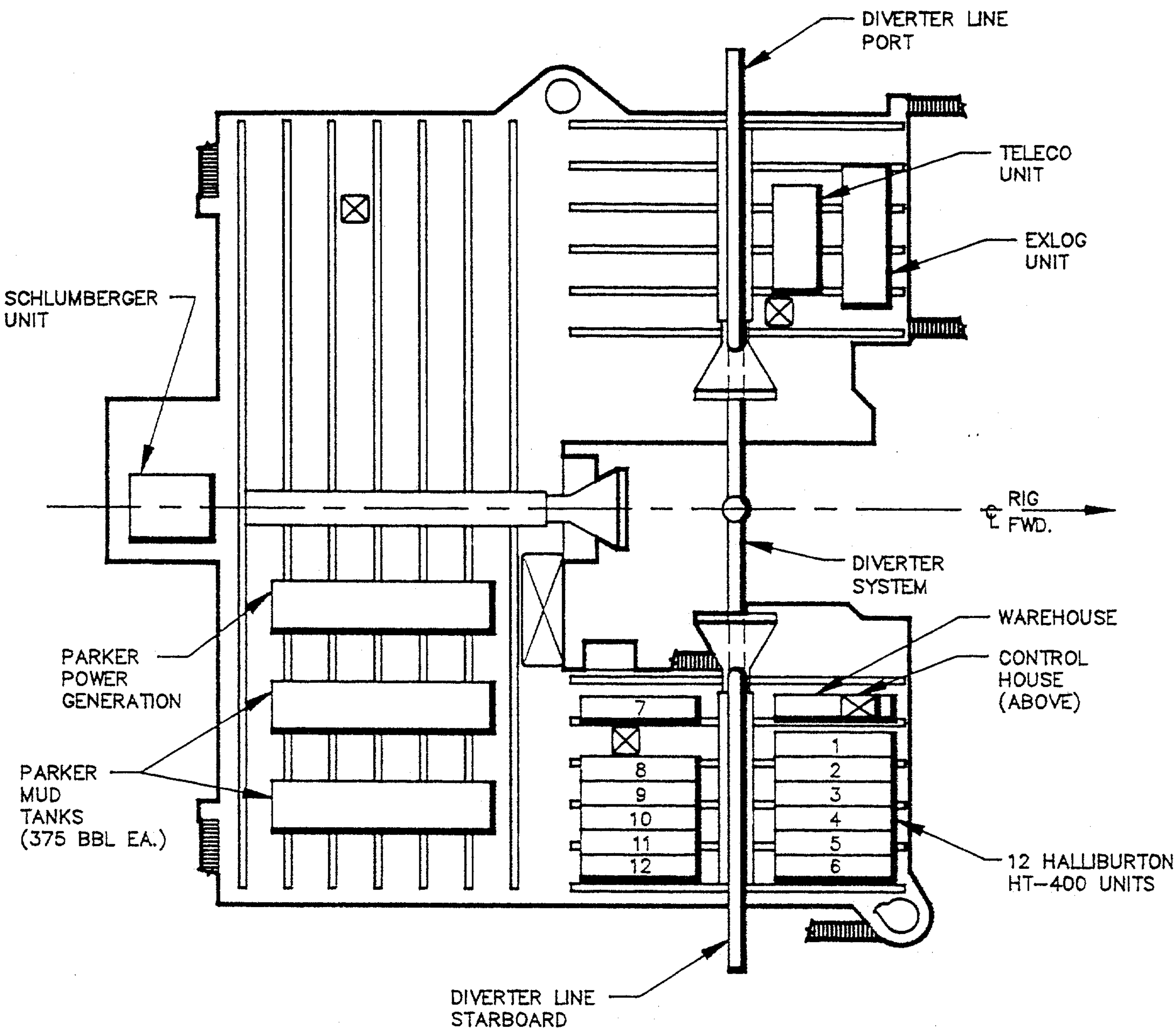

Figure 4.14.1

Equipment & Diverter System Layout
(Steelhead Platform Blowout)

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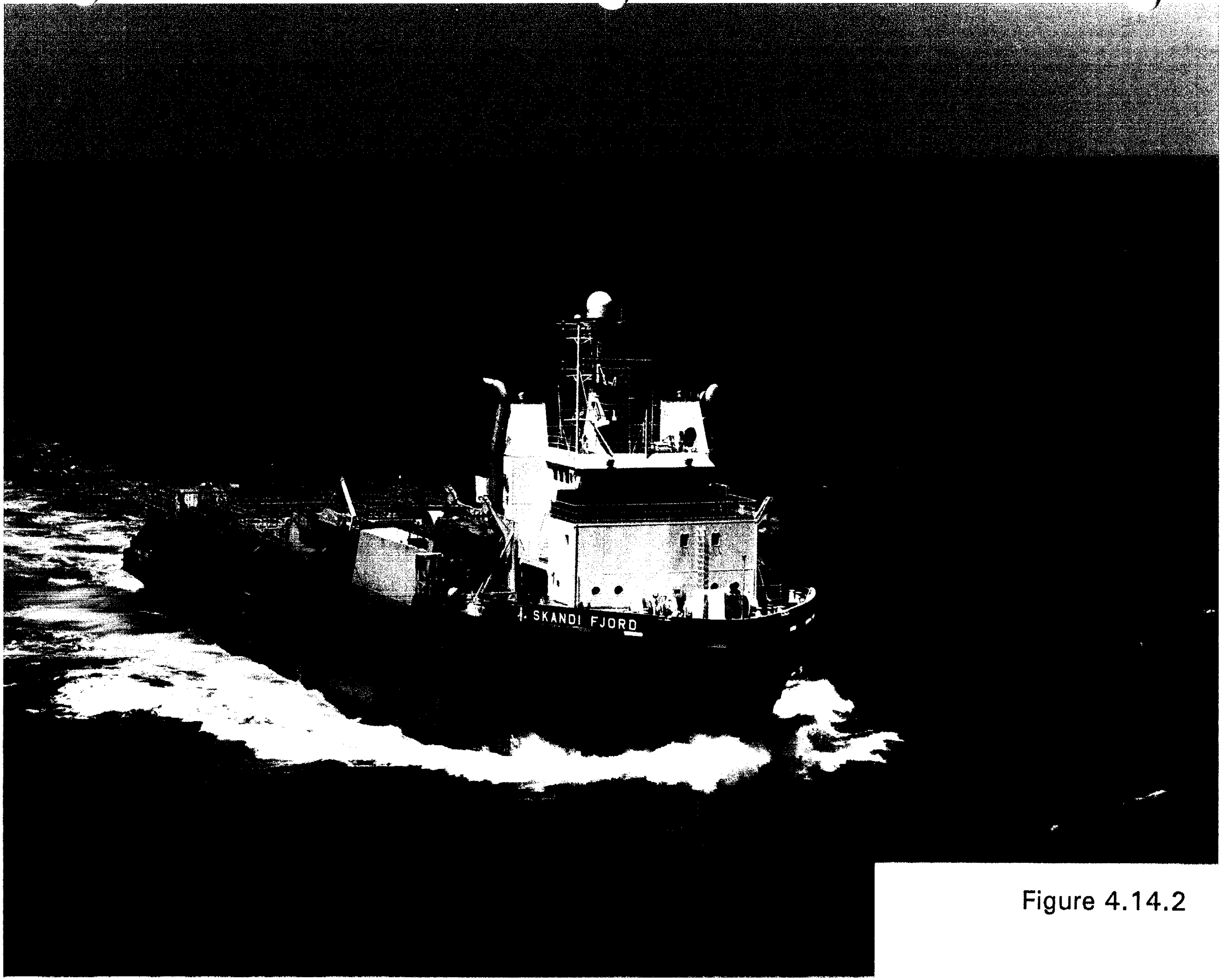

Figure 4.14.2

Halliburton's Skandefjord, operating in the North Sea, can be outfitted to pump 140-200 bpm. The procedure to allow the high volume capacity is to cut into the 8" ID manifolds between the 14, HT 400 pumps and the high pressure intensifiers. This approach was planned on Oxy's Piper Alpha blowout.

Most vessels are based on 2-6 large high pressure pumps. Halliburton's Skandefjord is an exception. It uses 14, HT 400's that feed intensifiers. A vessel with at least 5-6 pumps is preferable for blowout work to account for possible downtime.

North Sea stimulation vessels have 2, 4" ID Coflexip hoses that can be spooled from the vessel to the rig or platform. The hoses are typically 400 ft long. Line yokes are used for quick attachment to the rig. The rig crane lifts the yoke and lines from the vessel and sets the yoke in a universal receptacle on the rig.

Purpose - Built Pump Vessels. On occasion, some purpose built pump vessels have been outfitted for controlling a blowout An example occurred during the Bay Marchand blowouts (1971). A jack-up rig was converted to a pump vessel and stationed along the side of the rig used to drill one of the relief wells. The pump rig contained the mud handling equipment, pits, and pumps.

Design specifications for purpose-built vessels are dependent on the blowout scenario, logistics, and operations. Obviously it is not possible at this time to prepare and present general specifications other than those in the previous paragraph.

Control Systems. The pumping system should be operated from a central control system. Key capabilities should be as follows:

- Operate all pumps including start-up
- Hydraulically operate key suction and discharge valves
- Control the mixture rate for key additives such as friction reducers
- Monitor and record pressures, flow rates and volumes

Most companies offer this capability.

It is not desirable to have manually controlled systems involving individuals to control each operation. The noise level is a deterrent to efficient operations. Quick action may be required.

4.14.3 Manifolds. Rigging the kill equipment will require several special manifolds. Suction and discharge systems are required. Additional capability is necessary if the rig pumps are connected to the kill system. Restrictions in the manifold should be avoided.

Suction. Supplying mud or water to the kill system is no small task. Water volume requirements can be high. Mud weights can exceed 18 lb/gal. The initial step in designing a suction system requires an assessment of the kill requirements for the blowout well. (Section 4.7)

Water is often pumped as the initial fluid. It is usually readily available in large quantities. Plans must be made to move the water from its source to the kill pumps at the kill rate. The source may be a lake, river or holding pit on land or could be the ocean offshore. Centrifugal pumps are used for this purpose. Due to maintenance problems with centrifugals, it is recommended to have available 1.5-2.0 excess capacity.

Moving large volumes of water over long distances on land is usually done in a relay system. Aluminum irrigation pipe is used to transport the water from its source to a storage pit at the rig site. Other centrifugals pick up the water from the storage pit and feed the suction manifold for the kill system.

A kill system built on the deck of an offshore vessel will usually require installation of a large feed system line(s) from the centrifugals to the pumps. As an example, several 6" lines may be required to feed water at 100 bbl/min. (Figure 4.14.3)

A suction system for high volume, high density kill operations require large diameter lines to minimize pressure drops. The centrifugal pump capacity should be 1.5-2.0 times the expected requirements to account for downtime under the heavy load conditions. Several additional centrifugals will be required on most rigs. Pumping high weight mud from pits on lower rig levels to pumps on upper decks must enter into the horsepower calculations.

Caution must be exercised to prevent barite settling. The mud should be mixed long before pumping. "Mixing and simultaneous pumping" should be forbidden. The pits must be thoroughly agitated. Suction lines should be checked frequently for plugging. If initiation of the heavy mud is critical in a timing sequence, i.e., dynamic kill, the mud valves and centrifugal pumps should be hydraulic controlled at the remote kill operations center.

Discharge. The discharge from the kill side of the pump must be the same volume as the feed side but at a higher pressure. As the required pressure output increases, the equipment design complexity increases by an order of magnitude. It is very desirable to design an overall system so the well can be killed with pressure less than 4,000-5,000 psi. If properly designed, it is not likely that higher pressures will be required.

Many service companies offer ready-built manifold components. An example is a manifold trailer by Dowell Schlumberger. (Figure 4.14.4) It is generally used on land jobs. The trailer is a 48'2" long, single-axle type equipped with a standard king pin and pneumatic/hydraulic landing gear that allows the trailer to be lowered to within 1 ft of the ground. The trailer can easily be loaded on the deck vessel of a floater. The trailer is equipped with the following:

- Eight 4-inch suction hose connections from each side for pump hookup.
- Eight 4-inch suction connections from each end for hook up to blender or for tandem trailer use.
- Dual 3-inch discharge headers mounted outboard with four outlets for pump truck hook-up as well as one 3-inch and one 2-inch auxiliary outlet.
- A 3-inch, 15,000 psi, gear operated plug valve located between discharge headers enables use of one or both lines.

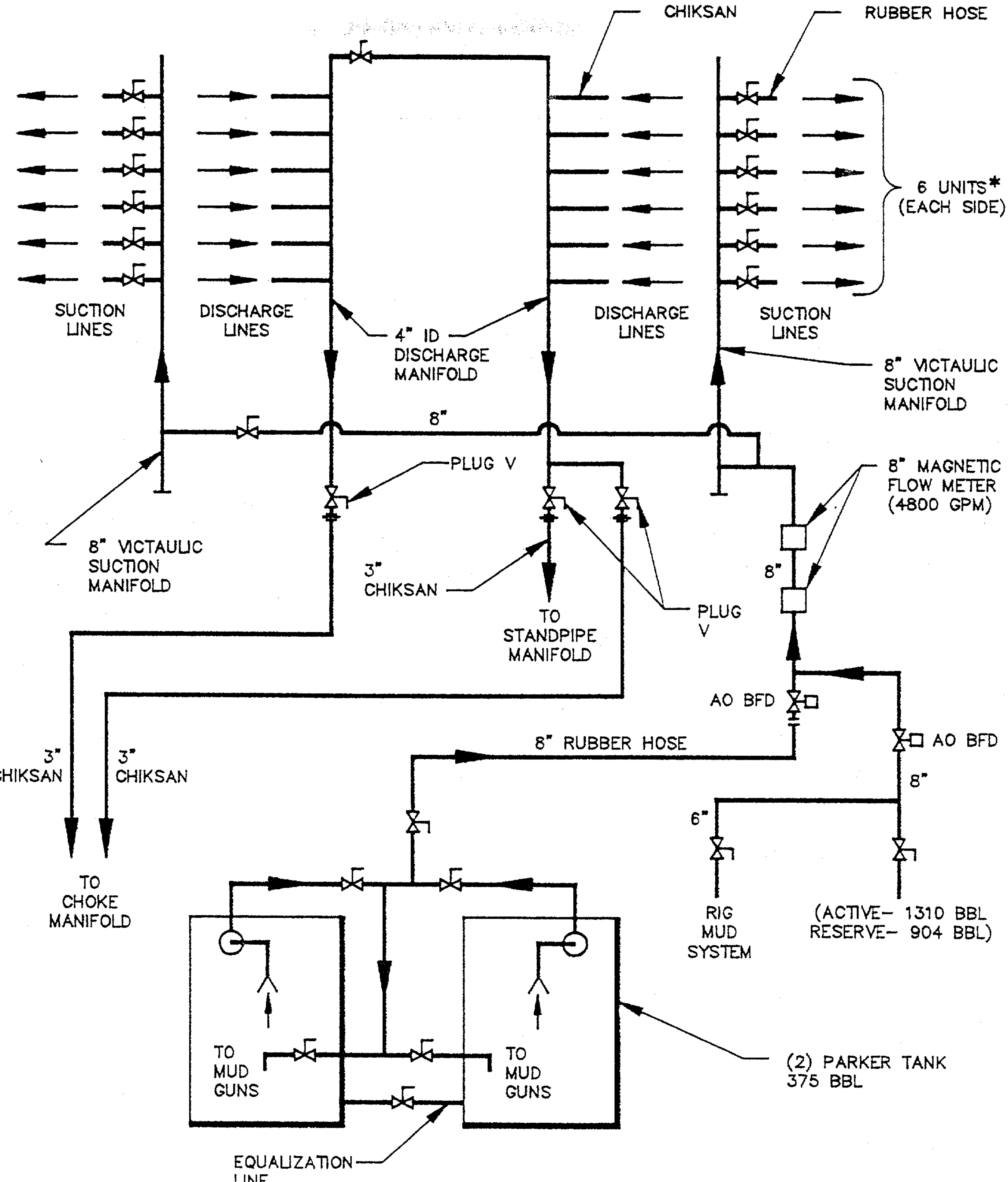

Figure 4.14.3

Well Kill System Schematic
(Steelhead Blowout)

*12 HALLIBURTON HT-400 PUMP UNITS (11 PSF, 1 PSL)

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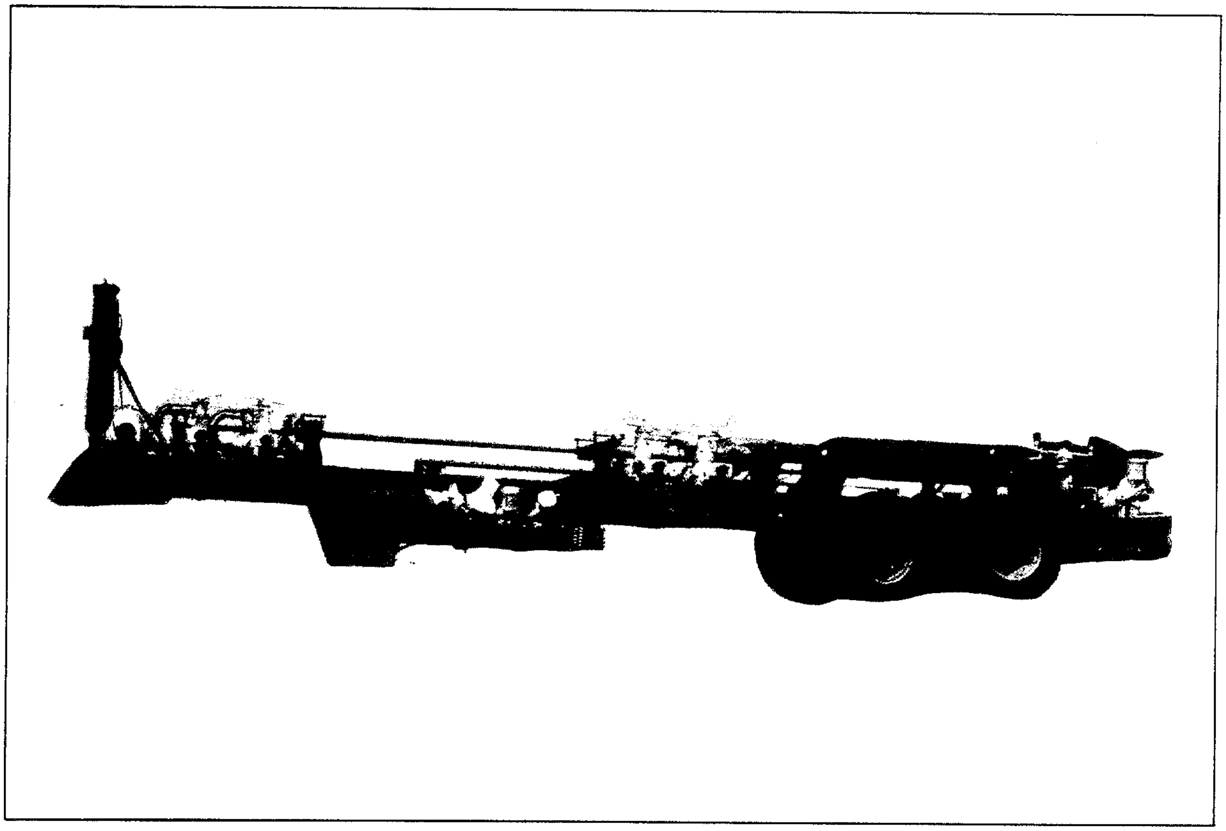


DOWELL SCHLUMBERGER
HIGH FLOW MANIFOLD TRAILER

Figure 4.14.4

Halliburton's "Big Inch" manifold capability is often used in blowouts. Although originally designed for fracture/stimulation work, it has good applicability for well killing. Features include no pipe thread connections, multiple connector manifold, Lo-Torq plug valves and check valves. The manifold has large inner diameters and is available in working pressures to 15,000 psi.

Rig Pumps. Tie-ing the rig pumps to the kill manifold is necessary in most cases to prevent interruptions in the kill operations. The initial well killing usually begins when the relief well intersects the blowout well and lost circulations occurs. A smooth transition between the kill package and the rig pumps can be made via the common manifold. Field experiences show the rig pumps will be satisfactory to kill the blowout in many cases.

4.14.4 Kill Spools. A kill spool is often installed in the stack to provide large flow volume capability. It generally is designed with 4, 4" inlets. A typical design is shown in Figure 4.14.5.

The spool is special-built for each job. This practice of special-building a spool is more historically oriented than based on actual requirements. It is usually more cost effective to build a spool than to transport a pre-fabricated spool and pay rental charges.

Kill spools are used predominantly on land jobs or jack-ups. The spool is accessible for installation and operation of valves.

The spools have not been widely used on subsea BOP stacks. The additional valves require significant planning for a satisfactory hydraulic control system. The common practice is to use the choke and kill lines although this approach has pitfalls if high volume pumping is required. To date, a subsea stack has not been used for high volume pumping, according to available records. This issue is discussed in greater detail in Section 4.14.5.

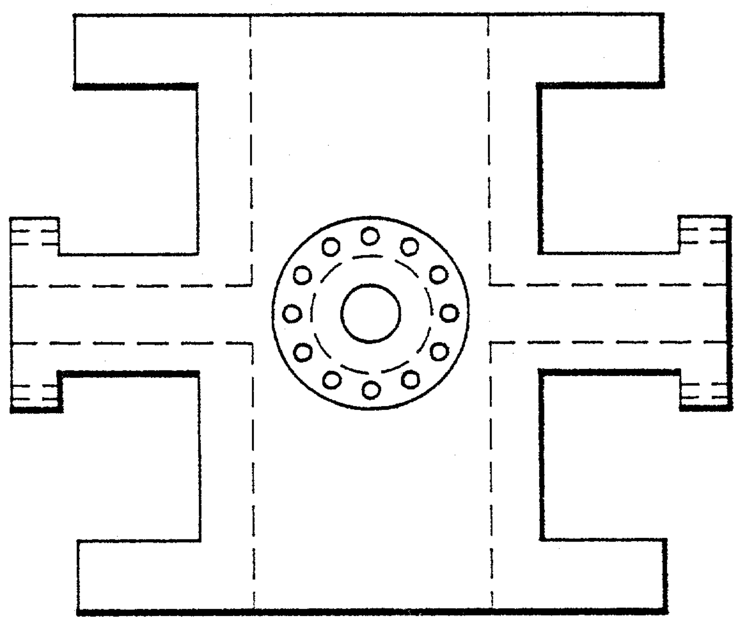
The spool is designed to match the BOP flange sizes and pressure ratings. Its outlets should have 4" inner diameters and flange connections. Two (2), 4" hydraulic valves should be connected to each outlet. These guidelines can be reduced to 2 outlets or to 1 hydraulic valve and 1 manual valve per outlet if the service conditions are not demanding. The spool and all valves should be appropriately tested with the stack.

4.14.5 Annulus Injection Operations. Killing a blowout with a floater requires different pumping arrangements than with a jackup. The general objective with any kill operation is to pump large volumes of kill fluid into the blowout well.

The fluids can be pumped down the drill string but this approach is seldom used. Friction pressures in a drill string at the associated kill rates would be excessive. Theoretically, it could reach 10,000-100,000 psi which obviously is not manageable.

Most kill pumping is down the annulus of the relief well. The annular space is larger than the drill pipe and the pumping pressures are reduced. Also, the drill pipe can be used as a bottom hole pressure monitor.

Gaining access to the annulus is relatively easy on land, platform or jack rigs. A kill spool, described in Section 4.14.4 is often used.



NOTE:

PRESSURE RATINGS AND BORE I.D.
CONSISTENT WITH BOP STACK

Figure 4.14.5

Kill Spool with (4) 4" I.D. Outlets

Floaters pose a more difficult situation because the BOP stack is subsea. The kill and choke lines present an apparent solution to pumping fluids into the annulus. However, the kill and choke lines are not recommended for pumping. High flow rates can be destructive. If the kill and choke lines are damaged, the only remaining means to pump is down the drill pipe which would restrict the kill rate in most cases to a level that would be inadequate to kill the well. Kill and choke lines have been used successfully for annulus injection on some blowouts but the flow rates were small, i.e.,5 -10 bbl/min.

Kill and choke options to gain access to the casing annulus on floaters are as follows:

- Inner riser sleeve
- High pressure riser
- Flexible piping connected to the stack/riser

Each will be discussed.

Inner Riser Sleeve. An inner riser sleeve was designed for the Piper Alpha blowout. See Figure 4.14.6. The equipment hookup consists of a doughnut at the bottom of the sleeve, high pressure casing and a pump-in head at the top.

The doughnut should be machined with threads for the casing. Rams are closed above the doughnut and the casing sleeve is pulled up until the doughnut contacts the rams.

The casing should have premium threads to handle pressure and rough handling. An example would be a VAM coupling. If possible, the casing size should be restricted to 7 or 7 5/8" O.D. if variable bore rams are in the stacks. Special casing rams will not be necessary if the VBR_S are available and a trip to pull the stack will not be necessary. If casing larger than 7 5/8" is required, casing rams will be required.

The pump-in head for the top of the casing is discussed in Section 4.14.7.

The inner riser sleeve is applicable for under pressured reservoirs or blowout depleted zones where a full annulus in the relief well will maintain control of the well. The drill string must be removed to run the inner sleeve. Pulling the drill pipe out of the relief well should be done only in situations where control of the well is simple, i.e., no losses, underpressured reservoirs. If necessary, the BOP_S can be closed and seawater is bullheaded.

The following kill guidelines were developed for Piper Alpha to kill the P-01 well. They are shown here for illustrative purpose.

P-01 KILL OPERATIONS
(Excerpted from the final report, Piper Alpha Kill Operations)

The primary kill plan is to pump through a 7" kill string. The second option is to kill the well via the drill string and the annulus if lost circulation occurs.

A shallow depth intersect of the relief well and the blowout well is possible. The relief well will approach the blowout well near 5500 ft. TVD. If the well

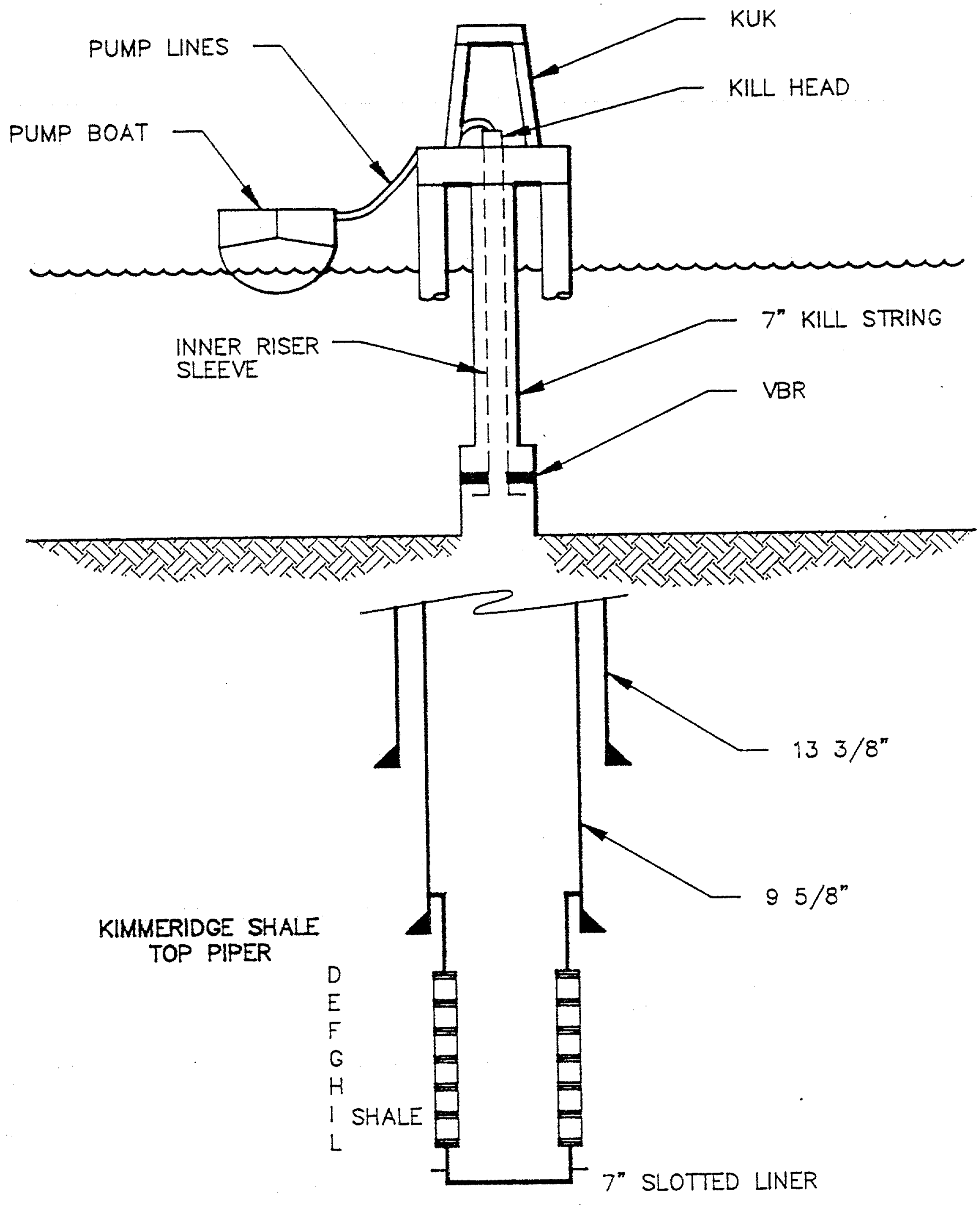


Figure 4.14.6

Inner Riser Sleeve*

*Piper Alpha
1988

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in intersected at this point, the relief well can be used to kill the P-01 blowout. The maximum pressures that could be imposed on the relief well under this situation are safely below any value that could cause problems. The kill plan for this shallow intersect is included.

A. PRIMARY KILL PLAN

All operational instructions during the kill operation well be directed through the Kill Operations Co-ordinator.

Communications:

KUK to Frac boat - direct private channel headset between Kill Operations Co-ordinator and Blowout Kill Specialist onboard the Frac boat.

KUK to MSV Tharos - direct private channel radio between Kill Operation Co-ordinator and MSV Tharos Operations Co-ordinator.

1. Make up the doughnut on the bottom of the 7" pipe.

2. Run the pipe into the BOP stack. Close the rams and load test the doughnut by pulling up 50,000 lbs above string weight.

3. Rig up the surface pump-in head (Figure 4.14.7), the manifold and all lines. Input lines to the manifold include the 2 Coflexip lines from the frac boat, and a line from the rig standpipe. The rig's pumps will not be used in the kill operations under normal conditions unless the boat is moved away from the rig. The discharge lines on the manifold include the line to the 7" kill string and lines to the choke and kill lines on the rig's manifold.

4. Flow test the system to 60 bbl/min. Close the valve on top of the 7" kill string. Pressure test the system to 1.5 times the flow test pressure (3000 min & 5000 max psi). Open the valve on top of the 7" killstring.

5. Close the choke/kill lines and initiate squeeze operations. After circulation has been established, start pumping the acid job. The initial injection rate for the casing volume of seawater should be 10-15 bbl/min. Do not exceed 3000 psi pump pressure.

6. When the acid reaches the perforations, increase the pump rate slowly to the kill rate of 40-60 bbl/min. The pump pressure should be in the 2000-2500 psi range based on calculations and prior platform water injection rates. Do not exceed 3000 psi at the pumping head.

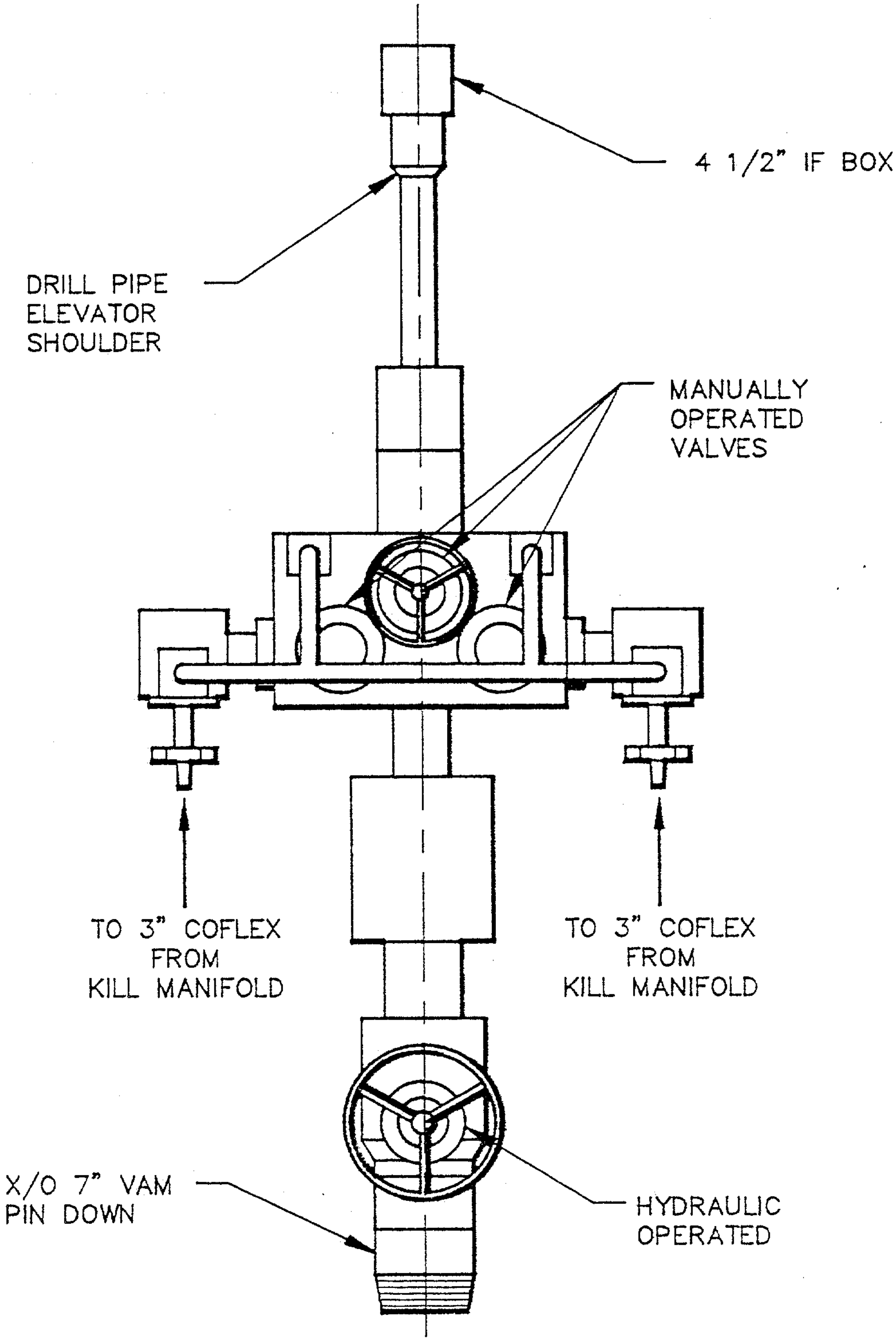

Figure 4.14.7

Surface Pump-In Head

NOTE:

3 1/16" Thru-Bore 10,000 psi W.P. Flowhead

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If the rate of 40-60 bbl/min cannot be established, pump an additional volume of acid.

Personnel aboard the MSV Tharos should observe the P-01 fire for reactions to relief well pumping. Operations on the platform should be discontinued while pumping on the relief well. The fire on the P-01 wellhead may increase early during the life of the pumping while the Piper Sands are being flushed.

7. After the P-01 well is dead, continue to pump at 20 bbl/min for 4-6 hrs. Shut down and observe the well for 8-12 hrs while rigging up for the cement abandonment.

B. KILL PLAN FOR BOTTOM LOST CIRCULATION

The kill plan for bottom lost circulation is necessary if lost circulation is encountered and cannot by controlled with calcium carbonate or other types of lost circulation materials.

1. If partial losses are encountered, add calcuim carbonate to the mud system. This material should be in mud prior to drilling into the Piper P-01 well. Slug the lost zone if necessary.

2. If the loss zone is severe, pull up into the 9-5/8" pipe and pump LCM pills.

3. If circulation is regained or if the partial loss is controllable, drill ahead to the target depth.

4. If complete losses occur and cannot be regained with the calcium carbonate pills, pull into the casing and close the BOP's. Inject into the well down the drill string and evaluate the effect on the P-01 fire. If sufficient volume cannot be achieved down the pipe, tie in with the choke and kill lines for pumping. Continue pumping until the well is dead.

5. This situation may require using the frac boat. Under this situation, pull the drill string out of the hole and rig up the 7" kill string with the doughnut. Use the same rig up and test procedures as presented in the Primary Kill Plan.

   While pulling the kill string out of the hole, keep the annulus full by pumping into the fill up line. While out of the hole, pump down the choke and kill lines below the closed blind/shear rams.

6. If lost circulation occurs while drilling, the rate at which the fluid can be pumped into the flowing zone may not be adequate to kill the well because the relief well is not deep enough into the Piper Sands.

Drill blind into the Piper Sands by pumping at 20 bbl/min down the drill string. Keep the annulus full by pumping down the fill up line. Under this situation, it will probably be required to drill through the H sand at 7602-7652 ft TVD. This sand is part of the primary flowing group of F,G, and H sands.

Pull up into the casing and close the BOP's. Establish an injection rate into the formation down the drill string and the annulus. If this rate is not sufficient to kill the well, rig up the frac boat and the kill manifold. Use the same rig up and test procedures as presented in the Primary Kill Plan.

C. SHALLOW INTERSECT KILL

The relief well will be drilled near the blowout well at a shallow depth so the ranging tools can be run. The shallowest expected depth of possible approach (intersection) is 5500 ft TVD. The intersection of the two wells is not expected although directional survey uncertainties associated with the blowout well could lead to an intersection.

If an intersection occurs, it does not pose any threat to the relief well.

The P-01 well can be killed at this depth. Seawater or 9 lb/gal mud can be used to kill the well. Mud should be used in most situations to avoid wellbore stability problems in the relief well caused by erosion of the filter cake by seawater. As a contingency, keep all mud pits (active and reserve) full of mud while drilling. The ballast pumps should also be lined up to feed seawater directly to the mud pumps if required.

The surface casing on the relief well will be set at approximately 3500'TVD. The fracture gradient is expected to be 11.0-12.0 lb/gal as a minimum. Therefore, pumping kill fluids will not endanger the casing seat integrity and cause an underground blowout.

1. If the blowout well is intersected by the relief well, the indications will be stalled drill rate, possible high torque, and loss of circulation.

2. Close the BOP_S if circulation can be established into the blowout well. Pump down the drillstring into the well at 10-20 bbl/min. The pump pressure is expected to be 1000-2000 psi at this rate. The 20 bbl/min rate will be more than the amount needed to kill P-01.

3. Pump until the well is dead.

4. If a satisfactory circulation rate cannot be established because of poor casing or tubing penetration in the blowout well, pull out of the hole. Fill the hole with mud while pulling out.

5. Pick up an orientable wireline perforation gun and perforate the blowout well. Pull the gun out of the hole.

6. Run into the hole with the drill string only. Use a bit without jets to maximize flow area down the drill string.

7. Close the BOPs and pump down the drill string. If adequate circulation is not established, re-perforate with the wireline gun.

8. After the P-01 well is dead, pull out of the hole and pick up a retrievable cement packer on the drill string to squeeze the well.

Inner Sleeve with Secondary BOP Stack. Another option exists for the inner riser sleeve when it is not deemed safe to pull the drillstring after drilling the blowing zone. The general approach is as follows:

- Drill to top of the blowing zone and set the kill casing.
- Pull the pipe out of the hole.
- Run a 9 5/8" or larger inner riser sleeve with a doughnut.
- Run a 3 1/2" drill string and bit into the well.
- Close and lock the casing rams on the inner sleeve. Pick up on the casing until the doughnut rests against the bottom of the rams.
- Connect a double or triple pipe ram and kill spool to the top of the inner sleeve with a flange - thread cross over.
- Use top drive to drill into the blowout zone.
- Kill the well

This approach shown in Figure 4.14.8 requires a substantial amount of manipulation.

High Presser Riser. All options for injecting kill fluids into the annulus are based on the realization that risers are not a high pressure conduit. It is unfortunate that current riser technology does not allow high pressure pumping. The easiest option for kill pumping would be down a high pressure riser.

Several groups have indicated that they have a high pressure riser. Camco supposedly offers a design where they supply the bottom and top marine fittings and the operator supplies the appropriate high pressure casing or tubing on the riser body. The size is limited to 5-5 1/2 inches which could restrict pumping rates for some blowouts.

IFP (of France) has introduced a high pressure riser according to an IFP spokesman. No information has been received as of yet.

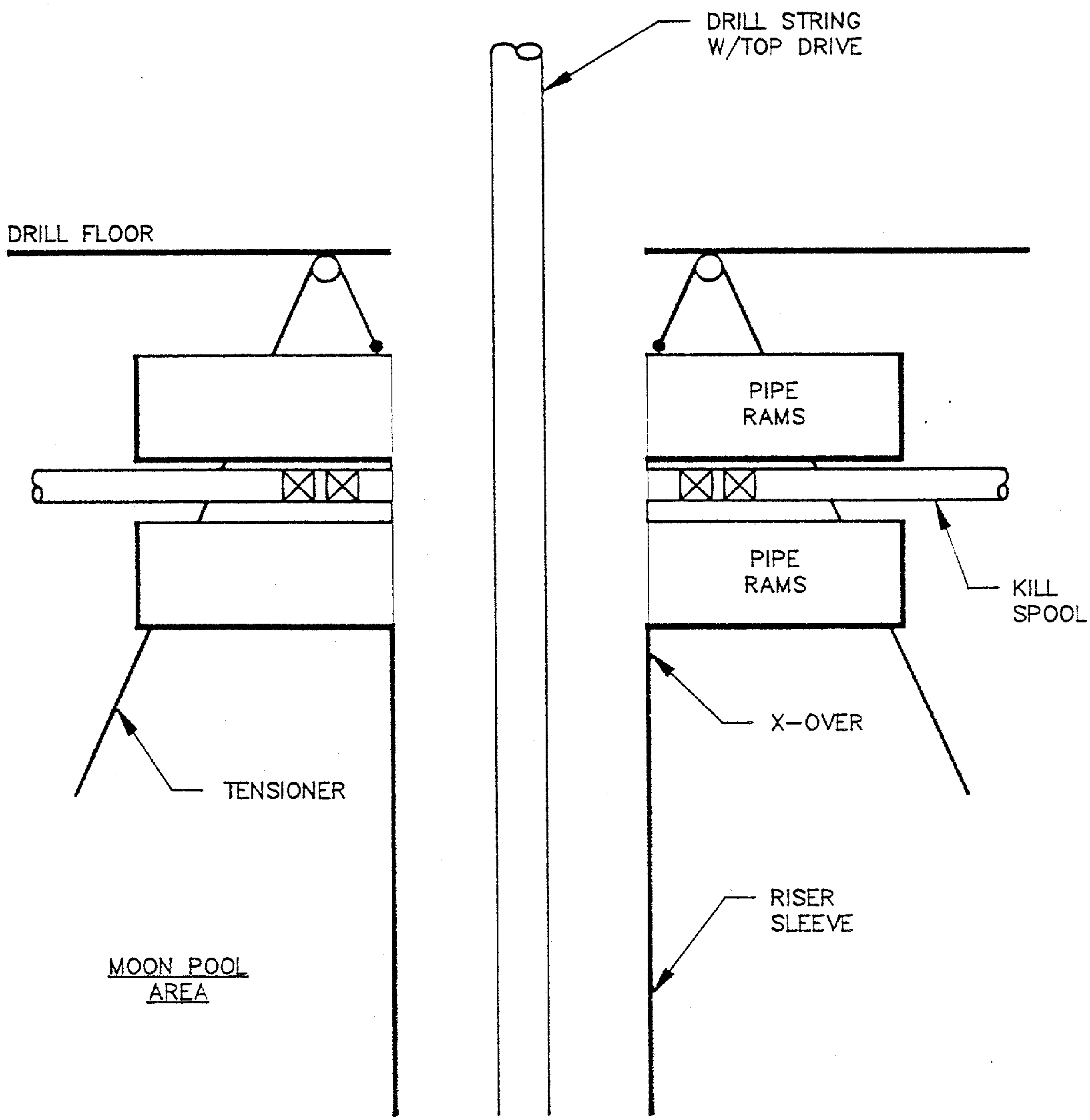

Figure 4.14.8

Inner Riser Sleeve BOP

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Flexible Piping Connected To Stack/Riser. The most obvious solution to high volume pumping capability into the annulus is with additional kill/choke lines. Flexible piping, such as Coflexip, could be used. Figure 4.14.9 and 4.14.10 illustrates the options.

Special equipment for this option includes the following:

- Subsea gate valves
- 2, 4" Coflexip lines of significant length
- Goosenecks at the surface
- Clamps to bind the hoses to the riser
- Hose spools

This equipment is a standard design but certainly is not on an off-the-shelf basis. Lead time availability could be extreme and probably would exceed the allowable requirements for a one well program. Consideration could be given for stocking the equipment and using it on an as-needed basis.

Handling of the piping would require some planning. However, it is considered manageable.

4.14.6 Pump Head. Some situations will require pumping down the kill string in addition to, or instead of, the annulus. A typical situation was discussed in Section 4.14.5. The drill string and kelly are suitable if the flow volume requirements are not large. An alternative is required for high rate pumping.

A pump-in head is used for high rate pumping. Design requirements are as follows.

- Pressure rating in excess of design capacity
- Two inlet lines with hydraulic valves
- An outlet to connect with the flow/kill string with an appropriate connection
- A method to lift the pump-in head and kill/flow string with the motion compensator

The inlet line capacity should be capable of handling the flow requirements in the event the other line washes out.

The kill head for the Piper Alpha job is shown in Figure 4.14.7. It is an off-the-shelf item available in 15000 psi pressure ranges. The inlets are 3" I.D. A 4" I.D. inlet capability would have been preferable but was not practical nor was 4" I.D. lines available to run from the deck of the vessel to the pumping head. Fortunately, the Piper Alpha kill operation was not as rate dependent as some jobs, so overall efficiency was not reduced if one line was temporarily shut off for repairs.

A suitable design for a pump-in head could be achieved with an arrangement of valves. However, the design shown in Figure 4.14.7 was practical and much easier to handle.

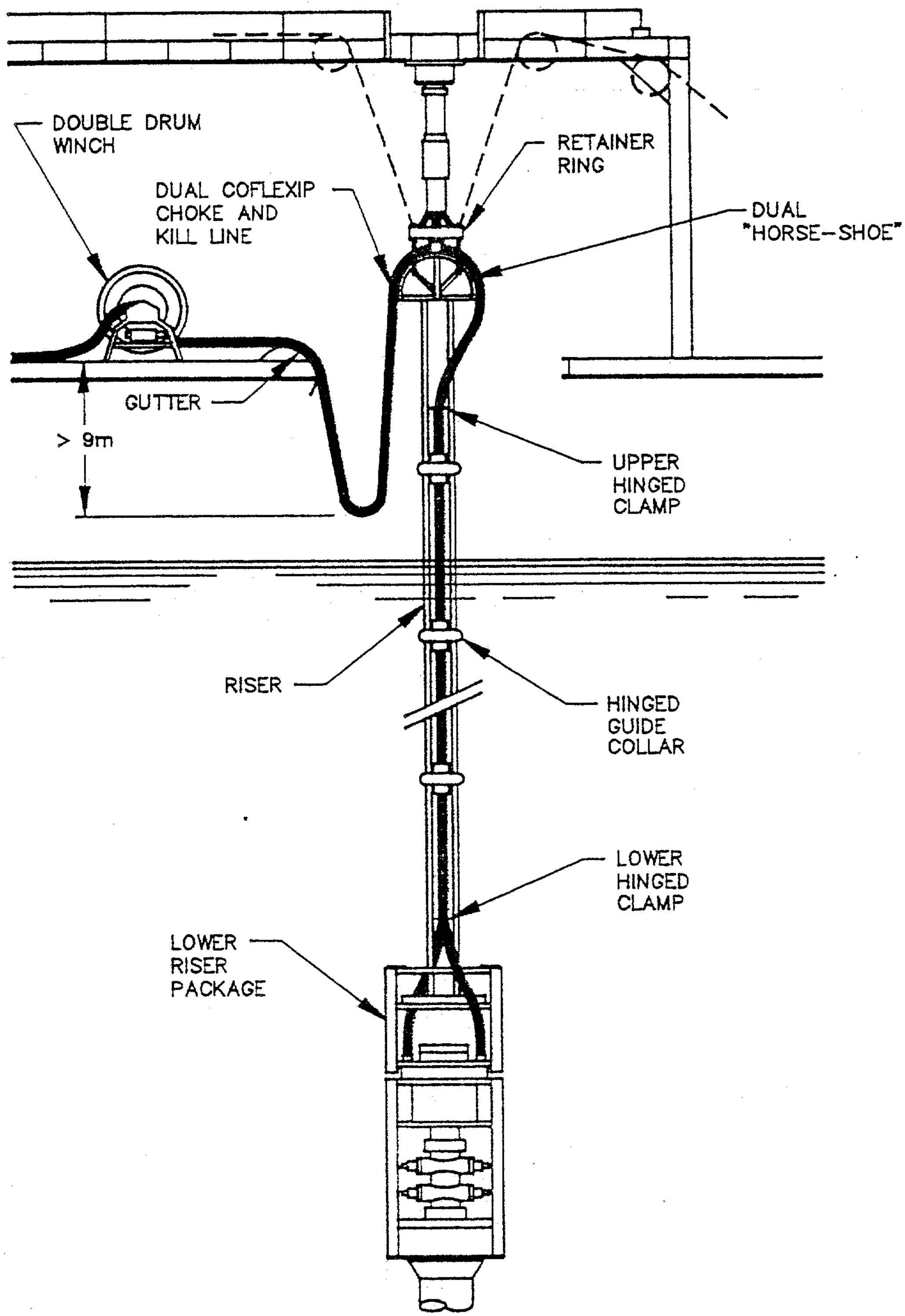
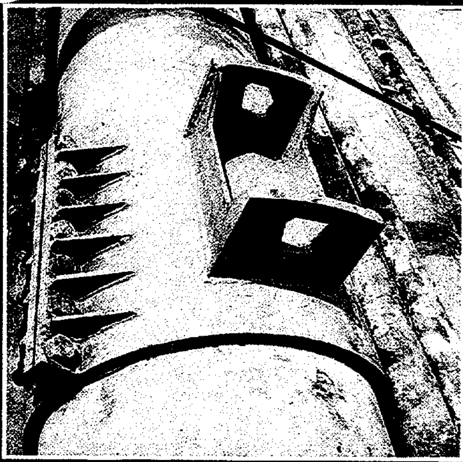


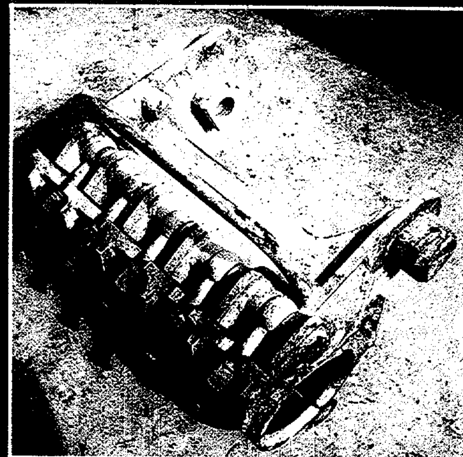
Figure 4.14.9

Continuous Flexible Choke and Kill Line System

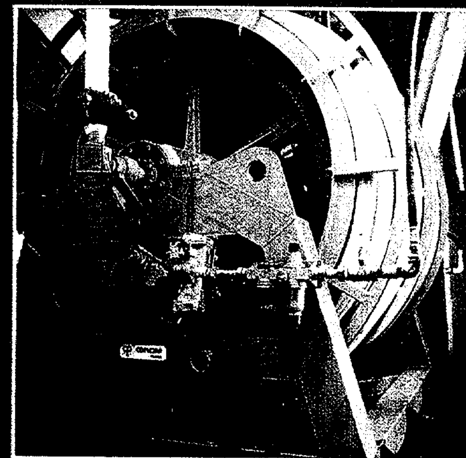
RUNNING PROCEDURE



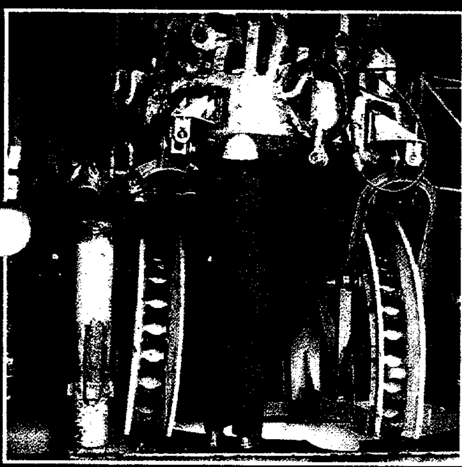
1. *Upper tension clamp support bolted onto the riser.*



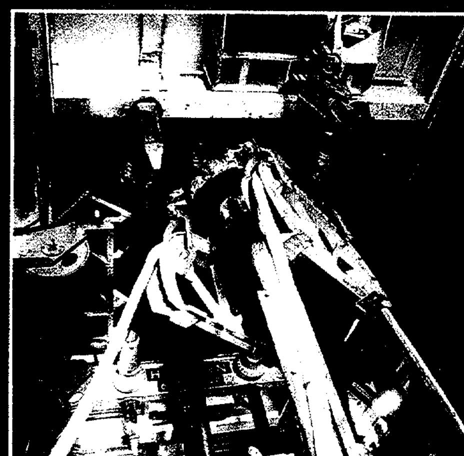
2. *Hinged tension clamp to be hooked into the two slots of its support (see photo 1).*



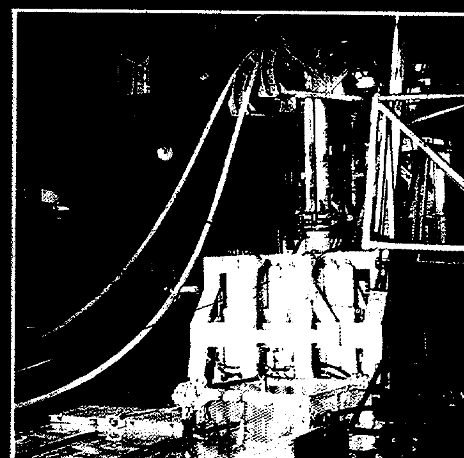
3. *Double-drum winch installed in its corner and connected to choke/kill manifold - ready for pressure test.*



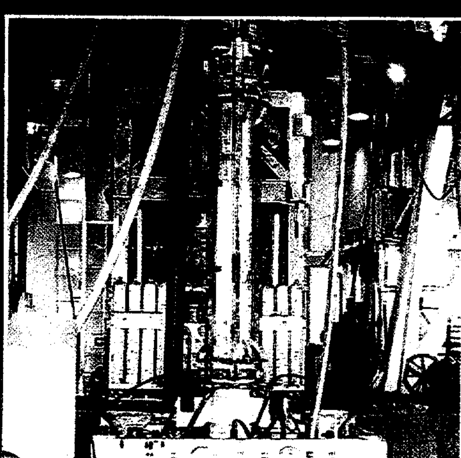
4. *Retainer ring with "horse shoe" rollers being prepared for positioning under the rotary table.*



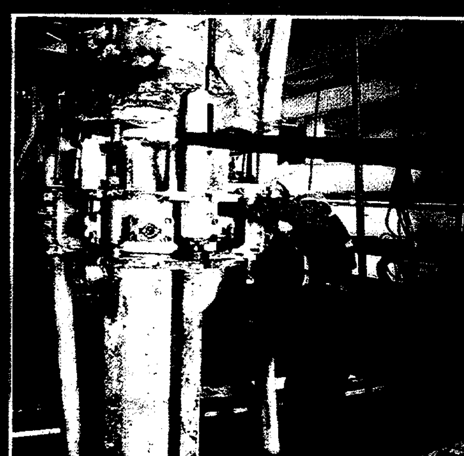
5. *Riser being lowered down through the retainer ring.*



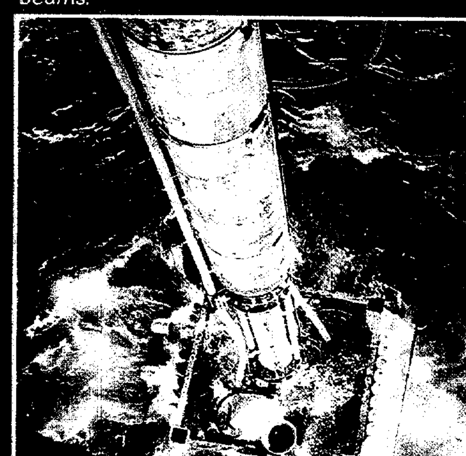
6. *The Coflexip kill/choke lines hanging over the "horse shoe" rollers whilst being connected to the BOP stack resting on the spider beams.*



After completion of the pressure test, the spider beams are opened and the stack is lowered.



8. *Lower hinged clamps being securely tightened around the kill/choke lines, leaving enough slack around the ball joint to allow for a 10° deflection all around the axis.*



9. *Splash Down! Observe the slack in the Coflexip lines below the clamps.*

Figure 4.14.10

Two inlet lines should be used instead of 1 large line. As an example, two 3" I.D. inlet lines are preferable to a single 4" I.D. line. An obvious advantage is the back up capability. A not so obvious disadvantage of a single large line is compensating for the bending movement of a large line while hanging when the kill string is supported by the elevators in the motion compensator. It is manageable but can be easily avoided with two inlet lines.

4.14.7 Pressure and Flow Testing. The kill system must pass a testing program before beginning the kill operation. The tests are more varied than conventional BOP testing. Testing a system to 70-130 bbl/min capacity is a significant operation. The recommended program is as follows:

Operation	Fluid
Low rate functionality test (10-20 BPM)	Water
Low pressure BOP test	Water
High pressure BOP test	Water
Volume rate test to full kill rate for 15-30 minutes	Water
1/4 - 1/2 kill volume rate	Kill mud
Low pressure BOP test	Water
High pressure BOP test	Water

Static BOP testing is conducted before full dynamic testing to find leaks that could be dangerous during the full rate test.

A static BOP test is again conducted after the volume rate testing. The high flow rate will often create numerous leaks that were not identified in the original pressure test. As leaks are repaired, flow testing is repeated. This procedure is time consuming and may require several days.

The pressure and flow testing program should also be used as an operational readiness practice. Organizational meetings should be held with all group leaders. Responses to various operational events should be discussed along with contingency responses.

The 1/4 - 1/2 kill volume rate test with mud is described above. A full kill rate test with mud for 15-30 minutes is preferable but is often difficult to implement without large losses of mud. As an alternative, a short duration test of 2-3 minutes at full kill rate with mud is recommended even if the mud is sacrificed.

4.15 KILL FLUIDS

The ultimate objective of blowout control is to regain control of the well with hydrostatic pressure. Mud or water may be used for the final control. However, several fluids may be used on an intermediate basis to increase communication between the blowout and relief wells or for multi-stage pressure control. These fluids include acid, water and/or mud.

4.15.1 Acid. Acid is used occasionally to increase communication between the two wells. The intent is to create or enlarge existing flow channels, or "worm holes".

An acid program for worm hole development is different than a normal acidizing program. A worm hole is a small flow path. The acid increases the size of the path to allow greater flow capacity.

The primary concern in relief wells is to create massive destruction between the two wells without regards for long term production or clay stabilization. A typical program will delete clay stabilizers, alter ratios and concentrations of HCL and HF, and modify or enlarge required volumes of acid, and use action retarders.

Large volumes of acid may be required. The optimum approach, if possible, is to pump acid until an acceptable injection rate is obtained.

Short term corrosion of the acid should be evaluated. Long term consideration should not be of importance if the relief well is deemed as expendable.

Acid will not be needed on most wells. Limestone or dolomite formations are the most likely candidates because of low permeabilities. Also its rock stability under drawdown conditions is greater than shale and may prevent lost circulation when the relief well intercepts the blowout zone. An injection test is essential in determining if acid is required.

4.15.2 Water. Water is used in blowout operations for several purposes:

- To establish communications
- As an intermediate kill fluid in dynamic control
- As the final kill fluid for normal or sub-normal pressured reservoirs

A key feature of water as a kill fluid is that it is typically available in large supplies whereas mud has restricted volume availability. It is an easy task in most areas to build large earthen pits and fill them full of water, or alternatively tap into the ocean as on offshore wells.

Friction reducers can be used with water to either (1) reduce pump pressure for a given rate or (2) allow greater rates for a given maximum pressure. The effect of polymer friction reducer is shown in Figure 4.15.1. A mixing and metering system for the polymer is necessary. Also, shelf life of the polymer should be evaluated. The chemical was ineffective on one blowout job because its shelf life had been exceeded .

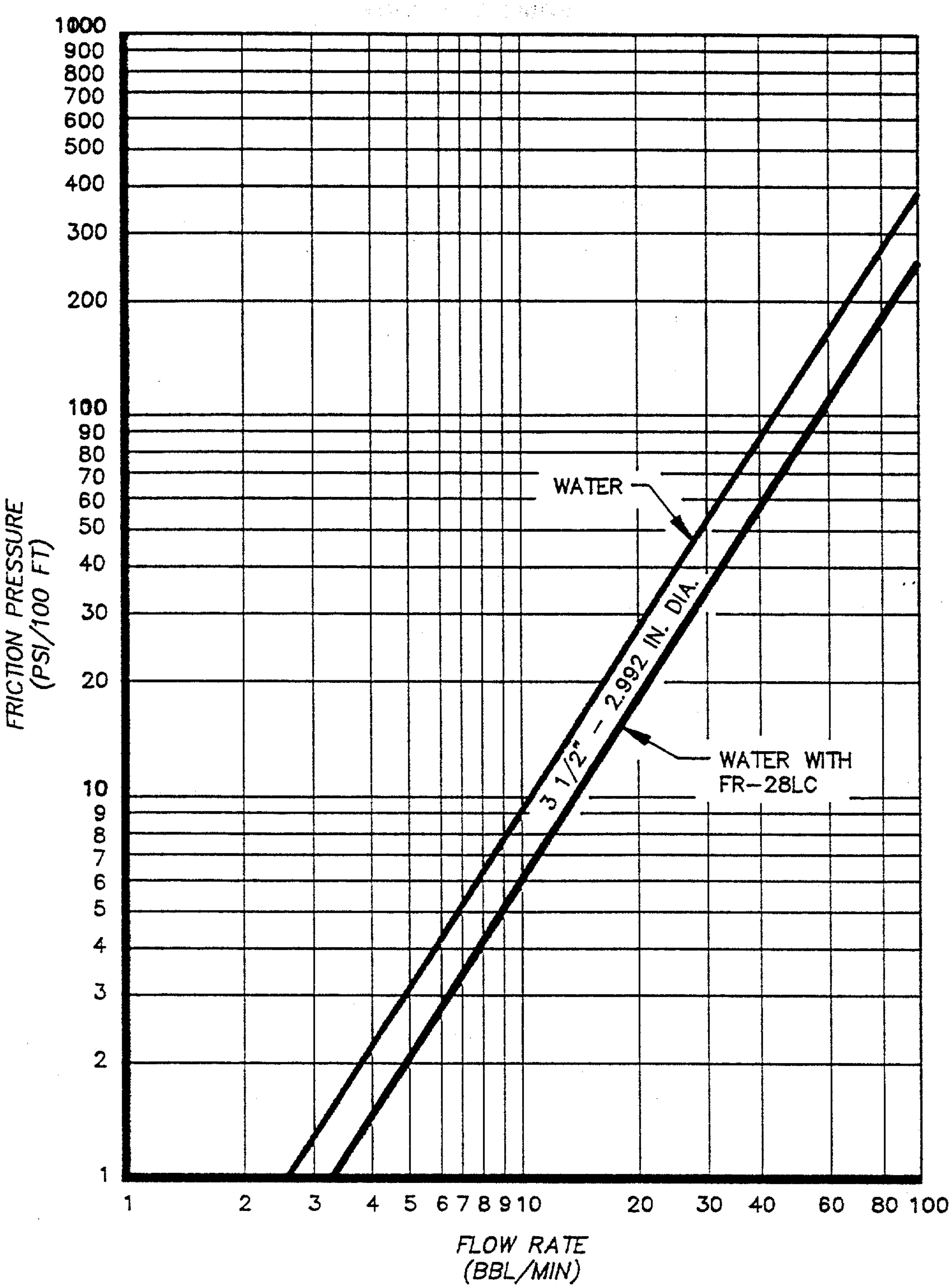


Figure 4.15.1

Flow Rate VS Friction Pressure for Tubular Conductors
with 0.5 Gallon FR–28LC Friction Reducer
per 1000 Gallon Fresh Water

**Occidental Petroleum*
Piper Alpha Blowout
U.K. North Sea

4.15.3 Mud. Case histories of blowout control operations in the 1960's and 1970's include large volumes of kill mud. Often, the fluid had very high densities. This situation has changed in the recent decade because of the development of the dynamic kill technique and the ability of ranging tools to place the relief well very near, or in, the blowout wellbore. The dynamic kill technique has reduced the need for large volumes of mud because the initial step of the dynamic technique involves pumping water at high rates until the well is killed dynamically.

Mud is still required, however, and large quantities may be involved. Fluid viscosity must be sufficient to prevent barite settling in the pits, yet it should be as low as possible to reduce friction pressures. The mud may be in the pits for an extended time so agitation must be available.

Mud should never be mixed "on the fly". Another way of stating this is to avoid simultaneous mixing and pumping. It is not uncommon that bits plug from poorly mixed mud. Also, it is difficult to maintain a uniform mud weight for simultaneous mixing and pumping at high rates.

Transfer capability among pits is necessary. Flexibility should be built into the design to allow quick suction changes in an emergency.

4.16 KILL OPERATIONS

The actual kill operations for a relief well require very little time in comparison to the planning and drilling. It is difficult to jeopardize success if planning has been done correctly and reasonable informed supervision takes place at the time of the kill. The key factor that can hinder success is to fracture a formation if natural fracturing does not occur at the time of the intersect. (See Section 4.16.3 for details.)

4.16.1 Ranging from a Floating Vessel. Ranging operations from a floater can be hindered by vessel movement. This is not the case on jackups or from land rigs. Vessel heave can cause downhole movement of the logging tool and disrupt data gathering. Vector Magnetics requires some motionless time for their tool to gather data. Field experiences have shown this matter requires consideration. Tensor's Magrange tool does not appear to show the same sensitivity trends to vessel movement because, according to Tensor, data gathering time is small at each station. Each manufacturer should be consulted on this issue.

Sensitivity to vessel movement decreases in deeper wells. The weight and length of the logging cable dampens vessel heave that is transported to the downhole tool. Shallow blowout experiences have shown that special attention is required. The overall problem is aggravated if a light weight, small diameter tool is used.

A wireline motion compensator can reduce line movement. The operator must consider this as his responsibility since ranging tool companies do not provide the equipment as a normal complement of their tool package.

4.16.2 Intersecting the Well. The point at which the relief well intersects the blowout well is always a major concern to the supervisory group. The concern is based somewhat on the possibility that the blowout well may, in some way, cause a well control problem to the relief well. The truth of the matter is that the intersect is typically anti-climatic and rather boring. However, attention should be maintained at a high level for any possible occurrence.

Prior Preparation. Several operations should be conducted prior to intersecting the well. On-site meetings should be held with all key supervisory personnel from the operator, blowout specialist, and service companies. Discussions should include planned operations and contingencies for unplanned events. Personnel responsibility assignments should be made and emphasized.

Kill equipment should have been installed and tested prior to intersecting the well. Flow testing is discussed in Section 4.14.

Pumping equipment should be running at idle speed with pumps disengaged if an open hole intersect is planned. Immediate pumping can commence if dictated by the operating conditions. Immediate pumping is seldom required for deeper blowouts. A shallow gas blowout, particularly in a diverter operation, may warrant immediate pumping at the time that the diverter bag is closed. In this situation, the pumping supervisor should be instructed to start pumping at a certain rate if the diverter is closed.

First Warning Signs. The initial warning signs of an intersect can be subtle. A drilling rate change is not likely in most cases. The bit usually does not jump or increase in torque. In some cases, it may be difficult to identify the exact time of intersect since clear signs may not exist.

The usual warning sign is that of partial or complete lost circulation. The blowout well has experienced pressure drawdown that is overbalanced by the weight of drill mud in the relief well. A fracture is formed from the relief well to the blowout well. If the loss is complete, drilling should be stopped and the well secured for the kill operation. If the loss is partial, drilling should continue for several feet to determine if the loss will become a complete loss. Complete loss of circulation is desirable because it indicates good communications path between the two wells.

4.16.3 Establishing Communications. Several options exist to establish communications between the two wells. These are as follows:

- Lost circulation
- Fracturing
- Acid (worm) holes
- Perforating
- Milling

Each has its own place in relief well drilling.

Lost Circulation. The typical reaction for an open hole intersect between a relief well and a blowout well is complete mud loss, as described above. This situation probably occurs 70- 80% of the time in actual field cases. If it does not occur, it suggests that the relief well is some distance away from the blowout well and that a sidetrack may be required.

Upon encountering losses, drilling should stop and the well secured for the kill operation. Mud pumps should be left running at idle to keep the hole full of mud until the kill system is started. Many recent blowouts were killed with the rig pumps in idle mode. Both wells should be monitored closely at this point for indications of good communications and any influence the relief well may have on the blowout.

Fracturing. Fracturing between the two wells should be avoided if lost circulation did not occur naturally. Fracture direction cannot be controlled, and it is more likely that the fracture is not in the direction of the blowout well. This often is determined after a significant amount of ineffective pumping is done.

Acid Holes. Some formations such as limestone are not as susceptible to the lost circulation because of rock stability. Shales are more prone to natural fracturing upon intersect.

The limestone may exhibit a partial loss of circulation that indicates close relief well proximity to the blowout well. If the communications channels could be opened, the kill could be made successfully at the intersect point. These channels are opened with acid and are termed "worm holes". Large volumes of acid should be pumped at modest rates until the desired injectivity is reached. Kill fluid is injected at this point.

Perforating. Cased hole intersects require a means to penetrate the casing in the blowout well before pumping can begin. If the relief well is cased also, it must be penetrated in addition to perforating the blowout well. Large perforating guns are usually used for this purpose.

Several companies offer large guns for blowout control work. Vann has the most widely used gun with perhaps the best features. It offers large diameter charges with reasonable penetration. (Figure 4.16.1) However, only a few charges are mounted on the gun and they are usually mounted vertically. This means the gun must be oriented so the charges are in the direction of the blowout well. An orienting sub is available for this purpose.

Vann makes the following recommendations for their gun when used in a blowout situation.

- 12 inches or less separation between wellbores.
- 7 5/8" OD minimum casing size in the relief well.
- 6" OD guns to be run.
- 300 gram HMX charges to be run.
- 9" minimum vertical spacing between charges.
- 28 shots minimum to be run. (2-11 ft carriers.)
- Shot phasing to cover an angle of 10° minimum.

One recent application in Venezuela encountered some difficulty orienting the gun. Several unsuccessful firing attempts were made without hitting the blowout well. The situation was resolved by setting a packer and running the gun into the packer. It was oriented and then fired. The blowout casing was penetrated and the well was killed.

Milling. Perforating is the preferred method for establishing communications in a cased intersect scenario, but in a few field cases a mill was used to create a window in the blowout casing string. The only known guideline for the operation is that a milling angle of ~3.0 degrees has shown to work most effectively.

4.16.4 Pumping. Pumping operations must be closely supervised by an individual or team. Expected well behavior must be anticipated prior to pumping. All actual pumping data should be recorded and monitored. A real time analysis should be done of the operations in progress.

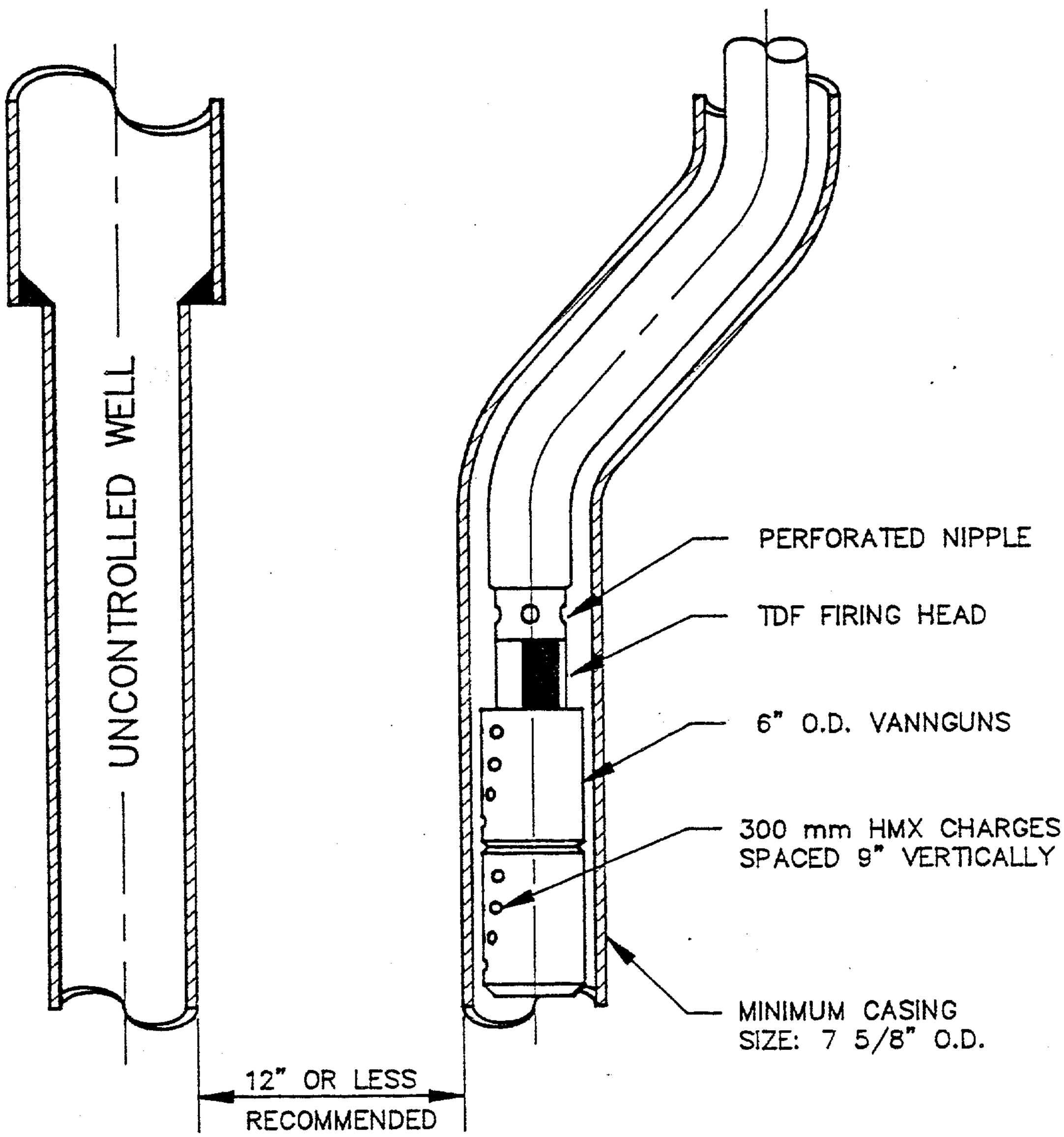


Figure 4.16.1

Vanngun for
Perforating Blowout Casing

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An important guide is to have an understanding of expected well behavior, yet an open mind must be maintained to interpret the blowout well behavior if it deviates from the expected trend. Blowout wells tend to have many variables that cannot be pre-defined and, as such, it is difficult to develop accurate pumping predictions. A key factor is the level of reservoir drawdown and the manner in which it affects the well killing.

Some type of "kill sheet" should be used. The term kill sheet with respect to blowouts is analogous to the standard kill sheet used for kicks. Of course, the parameters are different.

The kill sheet or more likely a computer printout will show expected pressures and minimum and maximum acceptable values. This information is discussed in more detail in Section 4.7. Minimum allowable pressure is that which must be maintained while pumping into the relief well to equal or exceed the bottomhole pressure in the blowing well. Maximum pressure is equal to or less than the fracture gradient at the casing seat. Since several kill fluids may be used, these minimum and maximum values change throughout the kill operations. Pressures decrease nearly linearly as heavy mud goes down the relief well and up the blowout well.

A happy medium between the minimum and maximum pressures should be maintained. This approach gives some latitude in the event of uncertainties or unexpected well behavior.

The operations must be controlled by a single individual making the decisions. He may receive information from several advisors. However, a single supervisoror has proven to work most effectively from field experiences.

The blowout well should be observed for signs of influence from the relief well. Indications include lessening of the observed flow, a color change in the flame if the well is burning or the flame is extinguished. An observer may be required as near as possible to the blowout well to notice any initial subtle changes in the blowout.

Continue to punp until the flow is apparently killed. After the kill, pump slowly for several hours until all of the gas or oil is worked out of the kill fluids. If the dynamic kill technique was used, the second stage of kill mud should be pumped according to the kill sheet prior to pumping at the slow rates to clean the annulus.

If the flow is not killed at the initial pump rates, increase the pump rates to the maximum allowable and observe the well. If good communications exists between the two wells and the kill calculations were done correctly, the blowout will be killed. If it does not die, the likely problem is that the relief well was not sufficiently close to the blowout. Some of the kill fluids are being lost to the formation and not directly into the blowout well. The relief well must be sidetracked to a more favorable location in better proximity to the blowout well.

After the well is dead and mud has been circulated for several hours, the next typical operation will be to prepare for cementing and the plug/abandonment. The cementing program should receive consideration if reservoir drawdown is observed in the blowout well. The cement may go directly into the reservoir and not up the blowout well. Several cement jobs may be required. Some thought may be given to sidetracking the relief well for a shallower intersect and setting an additional cement plug.

Also, if the top of the blowout well is accessible, it is worth consideration to cement down the top of the blowout well. A snubbing unit or large diameter coil tubing unit must be used if a rig can not be placed over the top of the well. This should be done after the initial cement plugs are set at the bottom by the relief well.

4.17 RIG SELECTION GUIDELINES

4.17.1 Introduction. The selection of a suitable rig for a relief well and kill operation is a key decision during the planning phase. The choice of a rig directly affects the mobilization scheduling and logistics. It will subsequently impact the rig systems available for drilling and well kill activities, and the operational safety and efficiency. A list of operating conditions and rig system requirements must be prepared based on the area of operations and preliminary kill plan.

4.17.2 Rig Availability. The first step is to determine availability and state of readiness of rigs in or near the area of operations. For remote operations, long mobilization times can be involved. Computer data bases offered by several companies, such as Oceandril Data Services division of PennWell Publishing Company (Houston, Texas), can provide a list of likely candidates. This is then followed up by direct contact with the respective contractors.

4.17.3 Operating Conditions. The operator will need to provide comprehensive operating conditions data. The data should include:

- General weather summary for the expected period of operations - prevailing weather, mean wind speeds and directions, etc.
- Storm conditions
- Currents
- Tides
- Unusual considerations - icing, etc.
- Sea bed soil conditions and mooring data
- Water depth
- Blowout well records - maximum bottomhole temperature and pressure, location surveys, casing depths, logs, daily reports, etc.
- Blowout effluent and estimated flow rate
- Local regulatory restrictions
- Logistics situation - local supply of equipment, materials, and services; support vessels; ground and air transportation facilities

4.17.4 Rig Type Evaluation. Rig type recommendations are based on actual field experience in operating rigs over or near blowouts and a knowledge of case histories from other blowouts. Jack-up rigs provide a stable platform for operations and adequate load carrying capacity. The depth limitation for jack- ups is approximately 300 ft (100 m). Jack-ups are applicable in shallow water depths where floaters cannot operate. In the possible case of a secondary blowout on a vent well or relief well, a jack-up cannot be easily moved off. A particular danger exists on shallow gas blowouts that the soil may be disturbed to the extent that a jack-up can overturn from soil instability. A hard bottom with the possibility of boulders is not suitable for placement of jack-up legs/spud cans/mats. Soft, unconsolidated soil or soft soil containing sand lenses can also pose a problem.

Drillships have a high load carrying capacity. Drillships generally have a higher degree of motion than a semisubmersible for the same sea conditions. In calm areas, this will not be a deciding factor. Drillships have a relatively low freeboard and no air gap. Gas accumulations at the sea surface are a greater risk than on a semi. Due to radial outward surface flow during a subsea blowout, drillships tend to set off to one side of the boil. For a moored ship this results in mooring chain tightening on the boil side and load relaxation on the opposite side which induces an overturning moment. Moored drillships are generally more difficult to move off of location during a blowout emergency. Dynamic positioning eliminates this particular risk.

Semisubmersibles are very stable and have high load carrying capacity. The large air gap and open construction reduce the risk of gas reaching the main deck and ignition sources. Semis can be operated in a blowout boil under most conditions and, in fact, have been used for vertical re-entry into blowing wells. Therefore, they have advantages if a secondary blowout occurs while drilling the relief well. Propulsion/thrusters can assist in maintaining position and reducing the loads on the mooring system. Semis can be equipped to move off readily in an emergency.

Suitable rig availability becomes very limited for water depths over 1500 ft. Relatively few floaters are fitted with mooring systems or dynamic positioning for operations in depths greater than 1500 ft. Serious consideration should be given to relief well contingency planning in general, but particularly for deepwater drilling programs.

4.17.5 BOP Stack, Riser, and Subsea Equipment. The BOP stack, riser, and subsea equipment rated working pressure and depth capability must be suitable for the intended relief well operation. It is recommended to use a proven design, high release angle wellhead connector for floating operations. Risers, tensioners, and associated equipment have depth limitations. Rig selection can be restricted for deepwater operations. For ultra-deep water, guidelineless re-entry is utilized. It would be expensive and time consuming to re-outfit a rig for deepwater operations if it is not already fitted out with adequate tensioners and riser. Occasionally it is possible to locate some of this equipment that can be borrowed or rented from a contractor or operator.

4.17.6 Diverter Systems. A high capacity, state-of-the- art diverter system is necessary for shallow gas blowout kill operations. Most rigs are not equipped with suitable diverter systems. However, it is possible to prepare and install the necessary components in a relatively short period of time. The system should be sized conservatively, particularly if it is to be used for operations on a known shallow gas location.

An annular blowout preventer is preferred for the diverter unit itself. Porting and control lines can be provided that will give the desired response time of 20 seconds or less. One should be aware that there are inherent advantages and disadvantages to the purpose-built diverter units generally found on most rigs.

The configuration should be simple and straight. Bends of any type should be avoided if at all possible. Special designs should be utilized for the outlet area from the diverter annular and at any sections that will cause flow disturbances.

The control system, like the configuration, should be as simple as possible. Problems have arisen in the past where sophisticated control options were selected.

It may not be necessary to upgrade a relief well rig's diverter system if the drilling is to be in an area with a low shallow gas risk.

4.17.7 Load Capacity and Deck Layout. The load capacity and layout must be suitable to handle the kill pumping system, supplementary mud tanks, additional supplies, and other equipment required for the planned operations. Many of these items are in addition to the materials and equipment normally required in a drilling operation. A typical high volume pumping system layout on a semisubmersible is shown in Figure 4.17.1.

Weights and sizes must be defined early in the planning. Information from the drilling contractor, service companies , and suppliers must be efficiently coordinated. The drilling contractor or consultants will have to confirm that the proposed loads are within the vessel's stability limits.

4.17.8 Gas Detection Systems. The existing rig's gas detection systems will need to be inspected, repaired (if necessary), and calibrated. In most cases, the existing systems will have to be supplemented. The rig may be potentially working near or in a live gas boil. Gas detectors must be located in strategically selected positions to provide early warning in case gas starts drifting near.

4.17.9 Mud System and Bulk Storage. The drilling and well kill operations will be defined at an early stage. Additional tanks, mix pumps, and associated piping are sometimes necessary for the well killing activities. (Figure 4.17.1)

4.17.10 Living Quarters. Blowout kill operations generally necessitate manning levels significantly higher than for normal drilling operations. The various service contractors will need personnel on board for well monitoring, kill pump systems, directional drilling, cementing, ranging tools, or other special services. The blowout and firefighting specialists will have a team of 2-4 people. The drilling contractor may be required to supply extra personnel for support of various operations. Typical manning levels will range from 75-85. For remote operations where shuttling is not possible, it would be advisable to have sufficient facilities for 90-100 people.

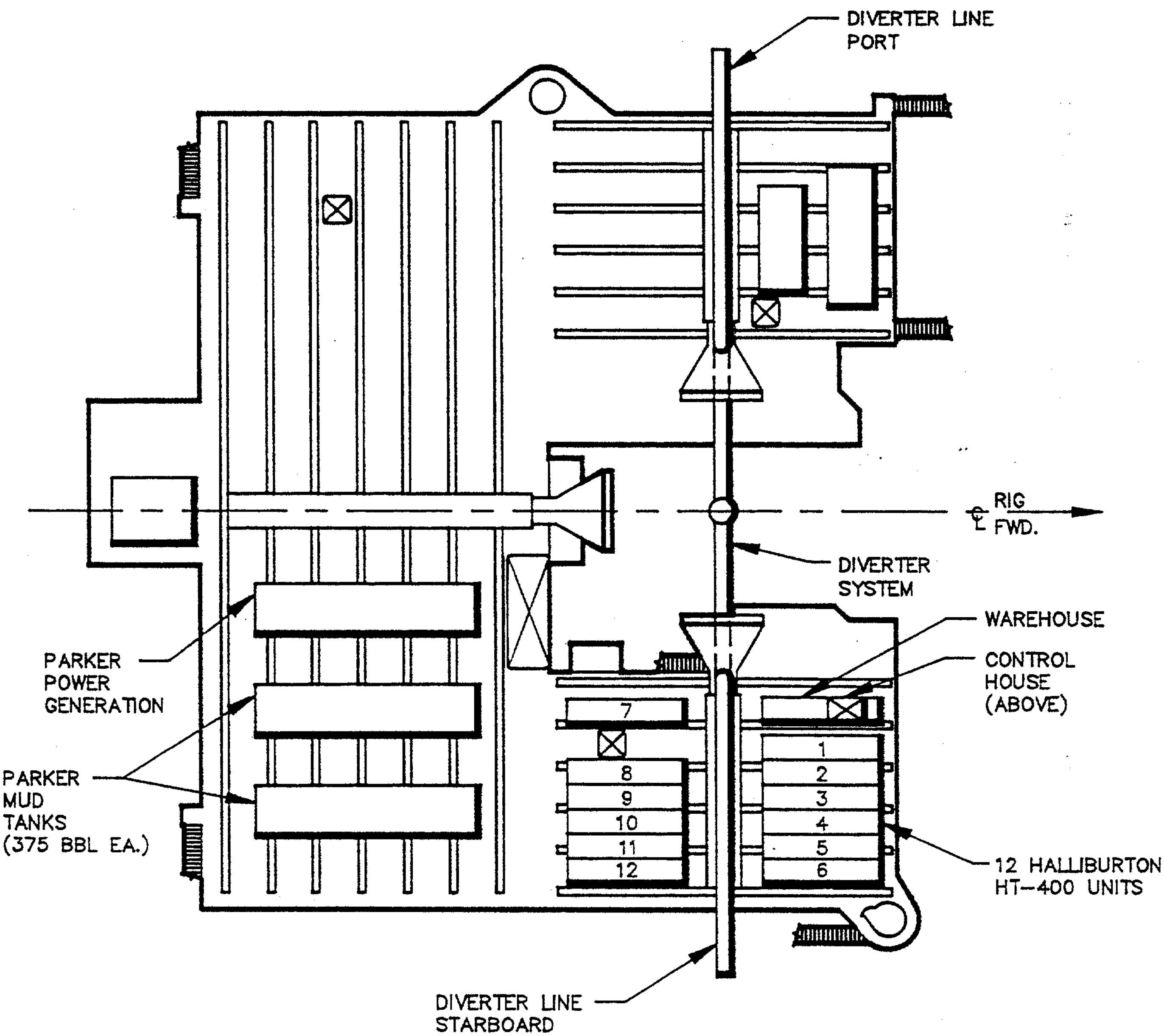

Figure 4.17.1

High Volume Pumping System Layout
On a Semisubmersible

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4.17.11 Mooring and Stationkeeping. Mooring and stationkeeping are particularly important evaluation factors when the relief well will be drilled in deep water or where special conditions exist, such as fast currents, extreme tides, sea ice, or severe weather. Dynamic positioning is required for some deepwater sites. Special mooring arrangements and additional anchors may be necessary. Directional drilling will be used. The hole position indicating system needs to be of a reliable design and fully operational.

4.17.12 Rig Maintenance and Warehouse Stock On Board. The candidate rig should have a planned maintenance system in place. All key systems must be operationally tested prior to commencement of the drilling operations. The warehouse inventory should be adequate to support the rig in the area of operations. Any deficiencies in stock, parts, etc. should be purchased and in hand before drilling starts.

4.17.13 Additional Considerations. Rig selection, depending on the particular situation, will be influenced to some extent by many factors. The rig design, existing equipment, level of maintenance, and proven performance record must be considered. Personnel is the key to a successful operation. Experienced, knowledgeable personnel can often overcome some deficiencies. Conversely, no amount of sophisticated equipment or controls can overcome poorly trained or inexperienced personnel.

4.17.14 Rig Inspection. The data for available rigs must be compared to the requirements described above for the relief well rig. Contractors will need to be contacted about various questions that arise during the evaluation process. A short list will be prepared composed of those rigs that most closely meet the requirements. Inspection visits should be made to those rigs on the short list. Sufficient time should be allocated to thoroughly check each rig and preferably visit with key rig personnel that will be assigned to the job. These visits also allow time to confirm layout limitations and other points. A spread sheet should be prepared to compare all key factors for the short listed rigs. A report should be prepared by the inspection team giving general impressions and pertinent comments about each rig.

4.18 ORGANIZATION, PLANNING AND LOGISTICS

Seldom considered topics for blowout control discussions are organization, planning and logistics. Operators are giving more attention to these topics in recent months. Perhaps the importance of the issues are becoming more evident.

4.18.1 Organization. The internal organization of an operator impacts the manner in which a given blowout is handled. The options are as varied as the types of blowouts and the number of operators. The key factors affecting an organizational plan are as follows:

- General company capability
- Staff size
- Work load of ongoing projects
- Blowout staff and experience
- Type of blowout job
- Selection of a blowout specialist

Several arrangements will be discussed.

Some operators have developed an internal emergency response team specializing in blowouts. They work in operational capacities as a matter of routine business and are mobilized to the blowout site when an event occurs. The team members are permanently assigned to the group. They receive training in topics such as relief well drilling, stripping and snubbing, introduction to well capping and firefighting, hot tapping, and operations of rigs in blowout boils.

This well control team will take the leadership role on a blowout job and will usually perform all functions related to the job except perhaps actual capping work. Elf Aquitaine has such a team and it has functioned effectively. Petroleos Mexicanos has a similar team but they will also do all well capping and firefighting.

General Company Capability. The general structure of the company affects the manner in which a job is organized. A small company may not have the technical capability to supervise and develop an effective effort.

Likewise, a large company may have the internal capability but prefer to turn the job over to a blowout specialist. The merit with this approach is that outside pressure may be reduced on a company if it has retained specialists to handle the problem. Obviously, it is important that the proper specialists be selected that can handle the particular problem.

An interesting question arises as to which individual within an operator should take the lead position on a blowout control effort. Options include the following:

- Operations manager within the district where the blowout occurred.
- Temporarily mobilize an individual from outside the district the take the lead role.

The question assumes that the company does not have a team devoted to blowout control. An operations manager within the district should have the best knowledge relative to the internal procedures within the district and would appear to be the most effective choice.

An individual from outside of the district offers the benefit of an unbiased view not affected by the unavoidable issues of guilt, blame, feelings of personal responsibility, etc. Also, the outside individual can work on the job without the burden of attempting to supervise other on going work in the district. The deficiency with this approach is that the individual must go through a learning curve relative to operational procedures for that district.

The best of both worlds is an outside individual who previously worked in the district or was the former operations manager. This approach ha been used successfully in the past.

Staff Size. The staff size of a company may force it to resort to outside assistance. A 1 or 2 man organization cannot handle the responsibilities associated with most blowout jobs.

Work Load. The current position of many major operators is that their staff is overloaded with work. They may not be able to handle the additional load. However, blowouts have a way of causing shifts in workloads so people become available to work on the job when necessary.

Type of Blowout Job. The type of blowout has an influence on the organization of the control effort. A well that can be capped is usually organized so the blowout specialist runs most aspects of the job including equipment fabrication, heavy equipment specification, pump and athey wagon rental and the hands on work. This is considered to be the optimum approach because of the unusual nature of the work.

A relief well can be organized in several manners as described below.

- The operator performs all aspects of the job without the benefit of any outside assistance.
- The operator directs the job but uses a specialists to handle the tasks that are not typical to a drilling operations, i.e., designing a kill system, directing kill operations, etc.
- The responsibility for all operations are given to a consultant blowout specialist.

Major operators and independents have used each of the approaches.

The most logical approach for relief well work, as well as all types of blowout control work, is a team relationship between the operator and a blowout specialist. The operator handles all routine operations relative to the relief well and directs the day-to-day drilling. The specialist designs kill requirements, organizes equipment and directs the actual kill operations. In essence, the operator handles all routine functions and the kill specialist handles all remaining tasks.

Sample schematics for organizational structures are given in Figures 4.18.1-4.18.3. Figure 4.18.1 shows the case where the operator handles all blowout functions and, to varying degrees, accepts the advise from a blowout specialist.

Selection of a Blowout Specialist. Selection of a blowout specialist involves two tasks.

- Locating a company that has the required skills for the particular job.
- Identifying the specific individual to be used as the lead hand.

Operators are beginning to spend time evaluating the firefighting and blowout control companies to determine which can offer the required services. Some service companies offer only the basic well capping capability. Others offer a broader range of services including well capping, relief well drilling, stripping and snubbing supervision, hot tapping and freezing, operations of a rig over a boil, blowout contingency planning and evaluation, technology development, blowout database services, etc.

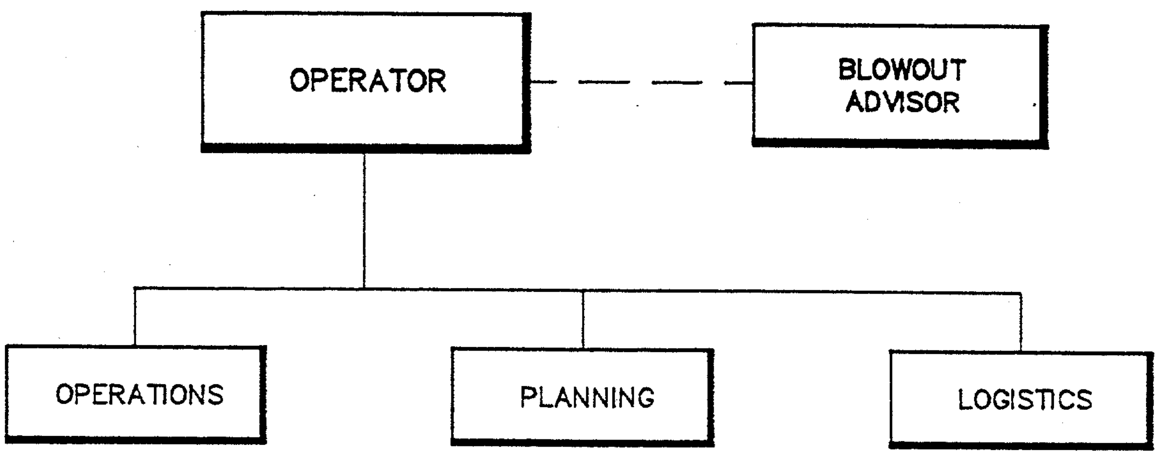

Figure 4.18.1

ORGANIZATION

Organization Chart with Blowout Advisor to the Operator

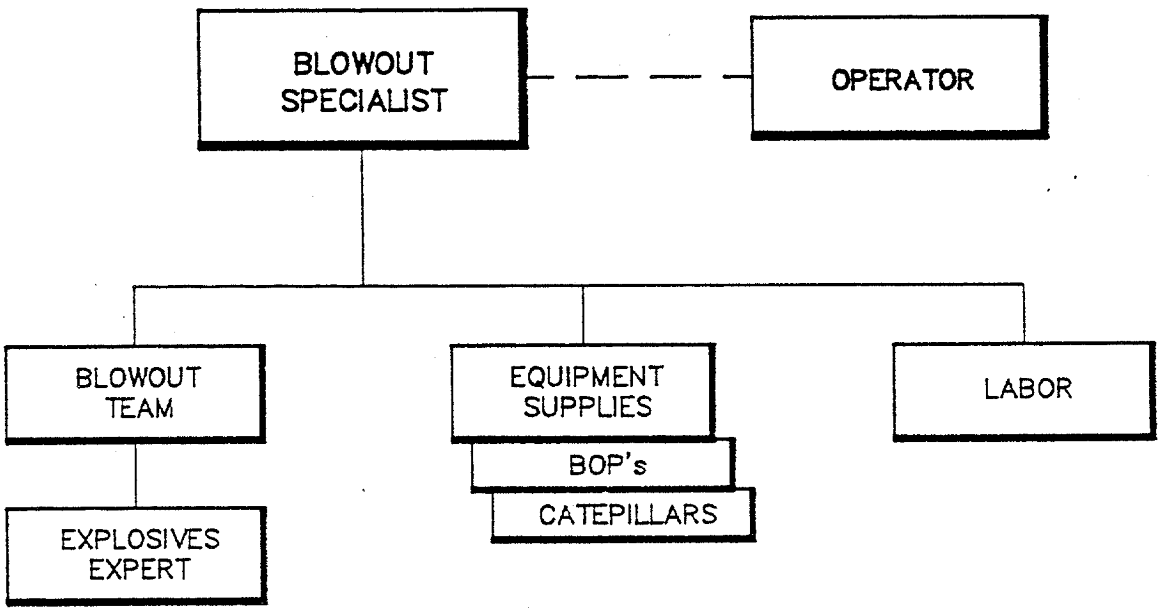

Figure 4.18.2

ORGANIZATION
Typical Capping Job

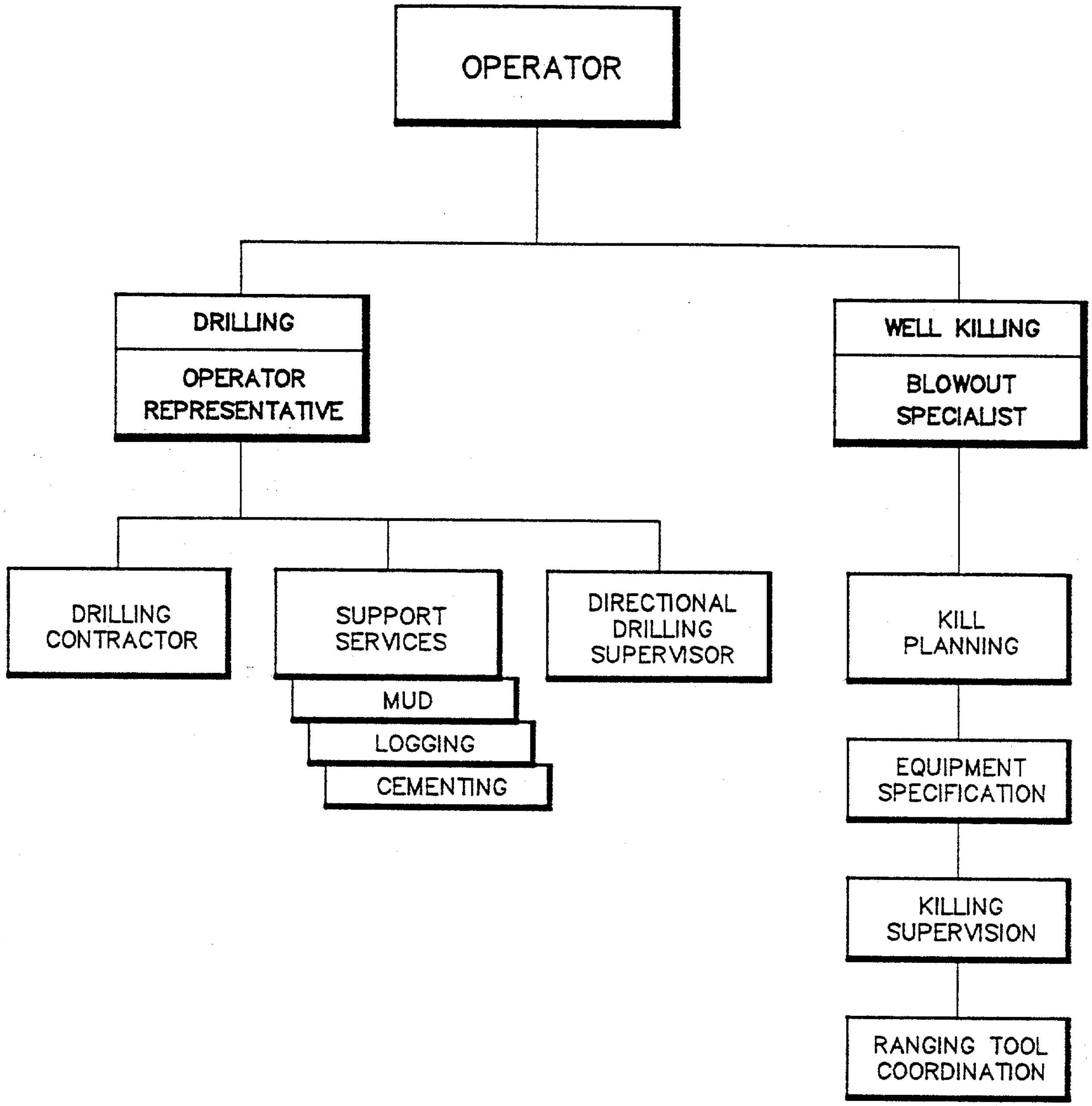

Figure 4.18.3

ORGANIZATION
Typical Relief Well

The general functions that should be expected of a blowout specialist and firefighter are as follows:

- Advise clients on the pros and cons of all kill options which is a difficult task if the blowout specialist has a limited capability.
- Organize all aspects of the job as deemed necessary by the operator's organizational structure for the particular event.
- Kill calculations and design
- Kill equipment specification and design
- Kill supervision

Optional tasks can include meeting and working with the press and news media and working with the insurance adjusters to explain the kill operations.

Unfortunately, it is deemed necessary to extend a general word of caution about firefighters. Operators should require that the blowout specialist explain the suggested kill plans and present sound technical information supporting the approach. Uncontrolled and unpredictable outbursts of anger and verbal abuse by a firefighter to an operator for the purpose of intimidation should not be tolerated as a response when the firefighter has been questioned about the proposed approach. The inability to provide sound reasoning or field case histories as support is unacceptable. A few insurance underwriters that pay the blowout control invoices have suggested that some firefighters cause more damage than benefits.

4.18.2 Planning. Planning can take several courses of action. Prior to the blowout, these courses include the following:

- Blowout contingency plan development
- Design for damage mitigation

More companies are currently working on these tasks.

Blowout contingency plans contain directions and suggested guidelines for handling a blowout situation. Since all blowouts have different characteristics, it is not possible for the contingency plan to handle all possibilities. However the plans can be relatively thorough and should give the operations leader all the required technical tools to accomplish the task. The contingency plan should include the following:

- Procedures for handling the first few hours after the disaster, i.e., damage control and containment, personnel safety and evacuation, etc.
- Telephone numbers for all key personnel and any local residents that may be affected by the blowout. The list should include civil groups such as hospitals, local law enforcement agencies, and the military if appropriate.
- Pollution containment/abatement procedures.

- Relief well drilling plans and all necessary calculations. Sites should be preselected for all relief wells so a rig is not spotted in a poor site selection in the haste of the emergency. Errors of uncertainty should be calculated.
- Press and news media coordination and handling procedures.
- H_2S procedures.
- Vertical intervention and offset kill operational guidelines where appropriate.
- Techniques for implementing active bridging where appropriate.
- Coordination procedures for working with the blowout advisor.
- Plans for training and drills of key key emergency response personnel.

Some of the kill operations planning may be required while activities are underway.

The contingency plan should be reviewed in detail with a competent blowout specialist. Where possible, a close working arrangement should be developed between the operator and the blowout specialist prior to the blowout. This might include annual meetings, technical talks on blowouts, review of the procedures, etc.

Designing for damage mitigation involves implementing plans and equipment modifications that will mitigate the damage of a blowout in the event that it occurs. This aspect of planning is best suited for offshore operations on platforms. Some companies have recently retained blowout experts with engineering capability to assess new platform design /construction and to review existing platforms for recommended modifications.

Post Blowout Planning. Planning after a blowout is usually confined to the kill operation. It can be extensive and involve many technical groups.

4.18.3 Logistics. Logistics can be either simple or a nightmare. A routine capping job near a major highway poses no great logistical tasks. On the other hand, mounting a complex campaign in the desert or in remote locations such as inland Papau New Guineau is awesome.

Many blowouts pose more logistical problems than the actual kill operations. As an example, killing the SLB-5-4x well in Lake Maracaibo, Venezuela involved mobilizing a rig from the Gulf of Mexico and a derrick barge from Louisiana. The jack up rig could not be floated under the bridge at the top of Lake Maracaibo so the legs had to be cut and late rewelded after the rig passed the bridge.

Most blowout specialists prefer to use all local equipment when possible to minimize the logistical problems. Although using the local equipment can mean minor difficulties to the blowout team, the realized benefits in terms of reduced logistical problems is worth the effort.

Movements of large equipment to overseas sites is required in some situations. This might include several pumps, monitors and athey wagons. Hercules air carriers are available for this purpose. Most firefighting groups have relationships with carriers and transport agents that can be used for assistance.

Some operators in remote sites prefer to purchase a set of firefighting equipment and store it in the remote locations. The perceived benefit is that this will reduce the logistical requirements in the event of an emergency. The real benefit is often much less than expected because the equipment may not be maintained properly, thus costing more in down time than the equipment is worth.

Most countries have provisions for by-passing customs regulations in the event of an emergency. The operator is best suited to handle this matter.

Experiences have been that it has been easier to move equipment into remote sites than it is to remove it after the job is completed. The emergency will have subsided and less cooperation is available, partially due to activities by the operator focused on attempting to return to some degree of normality. Some service companies have built this consideration into their pricing schemes to make it more favorable economically to leave the equipment rather than to try and return it to its point of origin.

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5.0 BLOWOUT EQUIPMENT AND SERVICES CATALOG

5.1 INTRODUCTION

The Equipment and Services Catalog has been developed under DEA-63, "Joint Industry Program for Floating Vessel Blowout Control. It is designed for the benefit of the participants in the study in the event they have a well problem that warrants some type of control action.

Comments to assist in the improvement of this catalog are solicited. The catalog's contents on are bases on firefighters' experiences. Additional topics have been included that are on the fringes of typical blowout control efforts. However, it is freely admitted that blowout control can be a large topic and it is certain that pertinent topics have been inadvertently deleted. The inclusion or omission of a particular product or service is not intended to imply endorsement or rejection of that item. Assistance from the participants in bringing these oversights to our attention is appreciated.

This catalog is not intended to answer every question that an engineer/manager will need to resolve on a blowout situation. It is intended, however, to provide adequate details to allow the engineer to proceed in an informed fashion. The next logical step is to contact the manufacturer, service supplier, consultant, etc.

Various sections of this catalog contain information that relate to underground blowouts. As such, this catalog is not exclusive to surface, offshore blowouts but is more broadly based.

5.1.1 Limitations of Current Draft Release. In order for a document of this type to have value to its users, it must be of a manageable size. As such, certain sacrifices must be made in order to reach a conclusion to the project.

To be specific, equipment and services that may have some blowout application under unusual circumstances or that rests on the fringes of the blowout control effort may not be included in this catalog. This does not suggest that the specific equipment or service is unimportant on this situation. It may have been omitted for the practical reason that it is impossible to include every item that may be of value under all situations. If the reader and user of this catalog believes that an omission has been made of a vital item, it is encouraged that it be brought to our attention.

Also, the catalog has been organized into several groupings. It is difficult to group some items into a single category. Where possible, cross references have been made.

5.1.2 Suggestions for Using this Document. The best approach to gain full utilization of this section is to develop a working knowledge of its contents prior to being forced to use it under a crisis situation. Unfortunately, the typical engineer/manager will not have time to browse and read through a document that may never be needed in the near term.

A second approach is to read through the Table of Contents and become familiar with the topics. Also, it is suggested to flip through the section and make mental notes on the illustrations, pictures and key companies/services included in the catalog.

If equipment or a service is needed, the user can refer to the contact index in Section 3. This section often provides the name and telephone number of the recommended contact within the company to handle the emergency situation. Many service companies have special groups and leaders that deal exclusively with blowouts.

5.1.3 Document Preparation Methodology. This section has been prepared using several sources:

- Field experiences of firefighters
- Technical files of blowout specialist containing information on services and suppliers
- Catalogs and brochures of numerous companies
- Discussions with various specialists in the industry

After the data was obtained, it was reviewed to develop a logical grouping system. This was difficult in some cases where (1) services or equipment did not fit well into any specific category, or (2) situations exist in which the specified item should be listed in several groups. Finally, the telephone/contact directory was established using current telephone numbers as supplied by the service company.

5.2 EQUIPMENT AND SERVICES DESCRIPTION

5.2.1 Adjusters, Insurance. Claims adjusters provide several major services to the industry. These include the following:

- Evaluation of equipment for insurance purposes.
- Risk assessment for a given situation based on the working environment and the equipment to be used.
- Claims adjustment after a loss including blowouts.

They are used during blowout situations to assess the losses for their clients. Also, they advise their clients on the safety and reliability of a particular type of well control effort planned for the blowout.

The adjusters are an independent group of specialists not attached to a specific underwriter or broker. This gives them latitude and an air of independence.

Although their clients are typically underwriters, particularly in a blowout situation, they can also have as clients the operator or contractor. This can foster a situation in which it is difficult to maintain an independent position. Conflicts of interest may result. However, most major groups of adjusters are professional and able to avoid this position.

The original well-known blowout adjuster was Mr. Rush Johnson of Houston, Texas. His background started in the 1940s and early 1950s.

The largest firms for this type of service are Rush Johnson & Associates, Matthews-Daniel and Brocklehurst International. All three of these have multiple offices, and can be reached in Houston or London. There are many other highly qualified adjusters in addition to these.

5.2.2 Aluminum Piping and Hoses. Various types of piping and hoses are used to connect the water pumps to the monitors. These include flexible internally rubber-coated fire hoses and aluminum irrigation pipe.

The advantage to rubber-coated flexible hose is its maneuverability. It can be rolled, or spooled onto a reel, and then easily moved and re-used. Also, it can be hand-moved at the site if the hose is not large or full of water. The disadvantage to these hoses is their susceptibility to heat exposure. Various types of external coatings are available to shield them, but they are still vulnerable. Hose sizes are readily available to 3" ID.

Four suppliers of fire hoses are Dooley Tackaberry, Inc., FireMaster (formerly Houston Fire and Safety Equipment Company), Koetter Fire Protection Service Co., and Wilson Fire Equipment & Service Co., Inc. There are numerous suppliers around the world.

It is important to note that there are different connections for these fire hoses. In the US, municipalities use one type of connection, the military another, and refineries and manufacturing facilities still another. Other countries may have different sizes or types of threads or "quick-connects" that don't fit any of the above. Caution is therefore urged in the selection of fire hose to insure that it is all usable on-site. There are changeover adapters available for most hose connections.

Aluminum piping is used by most oilwell firefighters to connect pumps to water monitors. It has the advantages that is not as susceptible to radiated heat exposure from a fire as is fire hose, and it is lightweight and strong. Also, it can be buried and crossed with heavy equipment such as bulldozers and pump trucks.

Its ease of handling requires a word of caution: aluminum pipe is an excellent conductor of electricity and contact of the pipe with power sources can result in injury or death.

The aluminum pipe is readily available in 4" ID, 30 ft lengths but is also available in large sizes , i.e., 8"-10" ID.

A supplier of new aluminum pipe is Stewart & Stevenson, Inc. which has offices in several locations, but the aluminum pipe is available through their San Antonio, Texas office. Rain for Rent, a worldwide company, has aluminum pipe in several sizes that can be purchased or rented on a short-term basis. Any supplier of agricultural irrigation pipe can provide aluminum pipe for firefighting as well.

5.2.3 Blowout Preventers. Blowout preventer (BOP) supply companies listed below fall into two sub-categories, those companies that supply new BOP equipment and those that rent existing equipment. A specialized device, the rotating head, is also reviewed in a separate sub-category. Some firms are listed separately below:

5.2.3.1 New Equipment. Listed below are several major manufacturers that provide the bulk of new blowout preventers to the industry. This is not an exhaustive list; there are other manufacturers of equipment in Romania, Brazil and Argentina and still others that make BOPs for workover rigs, coil tubing units and other specialties.

Cameron - A part of Cooper Industries, Oil Tool Division, Cameron provides a line of BOPs, surface and subsea, with associated accumulators and control systems. Their annular preventers are sized to 21-1/4" with a 2,000 psi rating up to 18-3/4" 10,000 psi. Ram-type preventers onshore extend to 21-1/4" 10,000 psi, but the largest 15,000 psi BOP of Cameron's is 18-3/4". Offshore ram-type preventers are 18-3/4" and 10,000 and 15,000 psi (singles and doubles). They also provide variable bore rams for tapered strings. Cameron also provides special heat and corrosion resistant rams called Camram 350. These will resist H_2S concentrations to 20% and temperatures to 350 °F.

Hydril - Hydril manufactures several annular preventers in a variety of sizes and pressure ranges up to 7-1/16" 20,000 psi and 30" 1,000 psi (MSP) ratings. Their ram-type preventers are available up to 21-1/2" 5,000 psi or 18-3/4" 15,000 psi. Both surface and subsea BOP's, control systems, and associated equipment are available. Variable rams for their 18-3/4" 15,000 psi BOP can close on 3-1/2" to 5" OD pipe.

Shaffer - This Houston-based Baroid Company provides a family of both annular and ram BOP's, surface and subsea. Related companies have control systems, panels and accumulators. The Shaffer annular BOP's are available in sizes from 30" 1,000 psi rating to 18-3/4" 10,000 psi. They have ram-type BOP's up to 21-1/4" 10,000 psi and 18-3/4" 15,000 psi. In addition, they provide variable-bore rams for tapered drillpipe strings from 3-1/2" to 5" OD. Shaffer also provides special BOP rams that will withstand 350° F and 15,000 psi for severe conditions service.

5.2.3.2 Rotating Heads. Rotating heads are not truly BOPs. They merely provide a low-pressure seal between the casing/drillpipe annulus and the surface. There have been efforts aimed at developing equipment that will contain higher pressures.

They are particularly useful in drilling relief wells on land where shallow sands have been charged by a blowout. Care must be taken in this situation to avoid breaking down the seal around the surface casing shoe with mud having a density that is sufficiently high to contain the shallow zone pressure. These devices provide a seal at the surface that allows slightly lower density muds to be used safely. This procedure must be supervised by an experienced blowout specialist.

Most rotating heads have a single or double rubber sleeve through which the drillpipe, drill collars and kelly can slide. The rubber element(s) seal against the pipe, then the pressure is contained within a bowl in which the rubber rotates with the pipe as it turns. The rubbers are susceptible to wear as the rough exterior of the pipe is pushed through them, particularly at the tool joints. When they no longer can contain pressure, the rubbers must be replaced.

Common rotating heads are usually considered safe to 500 psi for a single rubber unit and to 1,000 psi for a double rubber rotating head.

Shaffer, Williams Tool Company, AZ Grant International (Technology Export Co.), and Quality Valve Machine Works are the largest suppliers of single rubber rotating heads. Williams and Grant also make double rubber units.

Recently, Seal Tech Incorporated of Houston developed a rotating blowout preventer. The device is designed with a collapsible rubber sleeve that can seal around any shape of pipe (drillpipe, drill collar, kelly, tubing, etc.), then rotate inside a sealed-bearing housing. This unit has a pressure rating of 1,500 psi and has been field tested. Only a few units are available at this time for rent by Seal Tech, and all are in use in the Austin Chalk area of South Texas. They have plans to build 60 more units and provide them for sale to the industry.

5.2.3.3 Rental Equipment. Several firms provide rental blowout preventers including HOMCO, Oil Field Rentals, Blowout Tools, Inc., Offshore Rentals (Norway), Bon-Accord and Apex Tubulars Ltd. (UK). Inventories of available BOPs and other items for pressure control are fluid and cannot be pre-determined. The best advice is to determine which pieces of equipment are needed in which size(s) and pressure ratings, then call one or more of the firms listed above. They are usually quite cooperative with each other, especially in emergency situations.

One firm, Oil Field Rentals, has a group known as Wellcat (Well Control Assist Team) which provides special services in the event of an emergency. According to their brochure, they assemble personnel who have had experience and special training in procuring, testing and shipping high-pressure or sour service rental BOPs and other control equipment. They provide this equipment from their Oil Field Rental and Whiting Oilfield Rental divisions to the operator for such situations. They then remain in close contact throughout the situation providing other rental equipment, as necessary. Wellcat is on call 24 hours per day.

Blowout Tools, Inc. is another company that has an assortment of BOP and other pressure control equipment including snubbing BOPs up to 7-1/16" 15,000 psi, flow and pump-in manifolds, hydraulically operated valves and chokes and a variety of safety equipment. Formed in 1984, this Lafayette, Louisiana, USA company caters especially to the well control industry almost exclusively. They have offices in the Houston area and southern Louisiana.

5.2.4 Cementing and Fracturing Services. Conventional cementing does not have a major role in blowout control until the time that the blowout is killed. It is always desirable to kill the well prior to cementing. A poor cement job as a primary control method can result in the worsening of the situation.

Cement and fracture related services do play a role in blowout control however. These include use of chemicals such as the following:

Gas blocking agents - These chemicals overcome the inability of a cement column, once in-place, to continuously transmit hydrostatic pressure to an underlying gas-bearing formation. As the cement gels, it begins to support its own weight. Thus, the hydrostatic weight of the column is reduced which allows gas to percolate up through the soft cement causing channeling.

One type of gas blocking agent postpones the normal, gradual gelation of the cement. Instead, the cement remains a liquid for a longer time than normal, then gels and hardens rather quickly. The hydrostatic weight of the column is maintained longer which prevents gas migration through it until the cement hardens.

The other type of gas blocking agent develops small gas bubbles *in situ* as cement gelation occurs. The loss of the hydrostatic pressure is replaced by the pressure of the small gas bubbles which, in essence, cause the cement to swell and prevent any channels from forming. The small gas bubbles thus formed are too small to coalesce and channel themselves.

Thixotropic cements - Thixotropic fluids are those that exhibit one viscosity while moving, and a higher viscosity when at rest. Cement additives have been formulated that allow cement slurries, once in place, to develop a certain degree of viscosity without their developing gel strength in a normal sense. These additives, when combined with others such as gas blocking agents and fluid loss additives provide slurries with properties that can be quite desirable in pressure control situations.

These, like other additives, should be batch mixed before pumping to achieve uniform distribution in the slurry. Recent laboratory and field trials show that it is usually better to blend the additives in dry form with the cement prior to mixing the slurry. The service company should provide both local and upper level technical support during all phases of design and field operations.

Fine-particle cements - This new product, which Halliburton calls "Matrix Cement", has smaller grain sizes than normal cements. This permits the cement to flow through small openings where the particles of normal cements would bridge off. Halliburton claims that this product has been used successfully to cement micro-annuli behind casing. It may, therefore, have application in well control situations to shut off the flow of fluid where normal cementing techniques and materials cannot be used.

Resins for underground flow control - These materials were developed to provide an alternative for cements that cannot be pumped in certain situations. They are usually very low viscosity, approaching that of water, until they are in place after which they develop high viscosities or harden to solid masses.

The two types most used are epoxy materials and polymeric fluids. Epoxies are blends of resins that can be time-catalyzed depending on bottomhole temperature to harden into a solid, impenetrable mass. Placement is by simple pumping. These materials are susceptible to contamination by wellbore fluids with a commensurate loss of strength. Further, catalysis is difficult to time properly which may result in gas or fluid cutting the gel if it sets too slowly, or a complicated cleanout operation if the material sets too quickly.

Polymeric materials generate high viscosities once in place. These can likewise be time-catalyzed and suffer from some of the same deficiencies as the epoxies (i.e., contamination by wellbore fluids, slow gels or flash sets). These materials are, however, somewhat easier to remove than the epoxies since they do not set into a solid mass once in place. Because of their lower strengths, they may be extruded out of position by high pressures.

Friction reducers - Friction reducers lower the resistance of a fluid to movement in a closed conduit. In kill operations this becomes important by allowing larger volumes of fluid to be moved at a given maximum pump pressure or by lowering the pump pressure for a desired pump rate. In some cases, this additional fluid volume permits a successful kill when limited pump horsepower is available or when the size of the conduit is restricted, such as in relief well killing operations.

Acidizing for worm holes - Occasionally, acid must be used to enhance communication between a relief well and a flowing well. This is commonly referred to as wormhole development. Large volumes of acid may be needed to effectively open the channel between wells.

There is little or no concern for clay stabilization or clean-up of acid reaction products (fines). Some inhibition may be needed to protect the relief well in the short term, but long term damage is not considered since the relief well is usually expendable. The greater concern is for opening the pathway between wells so an adequate kill can be performed.

Volumes and types of acid (HCl or HF) must be designed once the initial pump-in test has been done. Service company support is essential in planning this type of job. Several attempts may be required before sufficient communication between wells is established. It is important to understand that this is not a producing well stimulation. Massive destruction of the rock matrix between the wells is the desired objective.

Radioactive tracers - These materials can be used to trace the movement of fluids inside or outside of the wellbore and between wells. Generally, these are gamma ray emitting, short half-life radioactive isotopes of common compounds such as iodine salts (14 day half-life). There are tracers that are soluble in oil, water, gas or mixtures of these.

A commonly used tool is a gamma ray detector with an ejector tool run on wireline commonly called a "profile" tool. The tools are usually small in diameter and can be run under pressure below a lubricator on "baby" wireline (small diameter, approximately 5/16").

In this type of log a small amount of the tracer is injected into the well stream, then tracked to determine its movement with the gamma ray detector. The detector can be located above or below the ejector so fluid movement can be tracked whether the well is flowing or there is fluid being pumped down past the tool. This latter method, called a pump-in tracer survey, is valuable in determining the existence of behind-pipe channels, gas-cut cement plugs and tracking fluid movement after the injection ceases.

Radio-active tracers can also be used to "tag" fluids on a wholesale basis that are pumped in a well to determine their final location. The lead slurry of a multi-stage cement job, for example, can be tagged, then checked for placement after drillout by running a gamma ray log on the well and comparing it with open hole logs.

Tracers surveys are good qualitative tools for pressure control purposes. They give meaningful information for planning remedial work and can be used in a variety of situations. They cannot be used, however, if the fluids being traced can reach the surface before the radioactive isotope degrades to an environmentally safe level.

Flow-tracing Dyes - These colored dyes, like tracers, can be injected in a flowing stream and the appearance of the dye at another point confirms the flowpath of the fluid. These materials are intrinsically safe since they are not radioactive and are either chemically non-reactive or biodegradable. They are also relatively inexpensive so large amounts can be used, if necessary. Importantly, the color and amount of the dye must be matched to the situation.

Major cementing companies such as Halliburton, Dowell-Schlumberger, BJ Services and Western Company can provide cementing services in most places in the world. They all have stimulation capacity. Tracer surveys and bulk fluid tagging can be done by major wireline services such as Schlumberger, Western Atlas, Halliburton Logging Services and others.

5.2.5 Coil Tubing Services. Coil tubing is usually thought of in terms of completion or production operations. Recent advances toward reliable small-diameter inflatable packers has opened a field of pressure control. Procedures exist to run the packer through the production tubing and inflate it in the casing below the base of the large-diameter tubing. (Figure 5.2.5.1)

Coil tubing can also be used in certain situations to spot cement or acid. There is considerably more fluid friction involved with coil tubing than with production tubing or drillpipe. It takes longer to pump a given volume of such fluids as a result. Formulation of cements and inhibition of acid must be adjusted accordingly.

Some well control specialists routinely use snubbing units and jointed small diameter tubing (not continuous pipe) for these same purposes. Coil tubing is subject to fatigue stressing, and the BOPs and injector heads are usually rated to 5,000 psi though recent developments involve 10,000 psi rated pipe, BOPs and injectors.

If coil tubing parts during well control operations, or if the pressure at the wellhead exceeds the surface rated pressure of the equipment while the coil tubing is in the hole, a serious situation can develop. Coil tubing is therefore not generally held in high regard by some specialists for pressure control applications.

BJ Services - BJ, a Baker company, provides coil tubing units outside the US in a number of areas including the North Sea, Brazil and in Southeast Asia. These are 1" and 1-1/4" units with 5,000 psi rated injector heads and BOPs. They also run Lynes inflatable packers on coil tubing including their PIP packer. If it can be stabbed into a flowing well, this packer/coil tubing system can kill the flow upon inflation of the packer element.

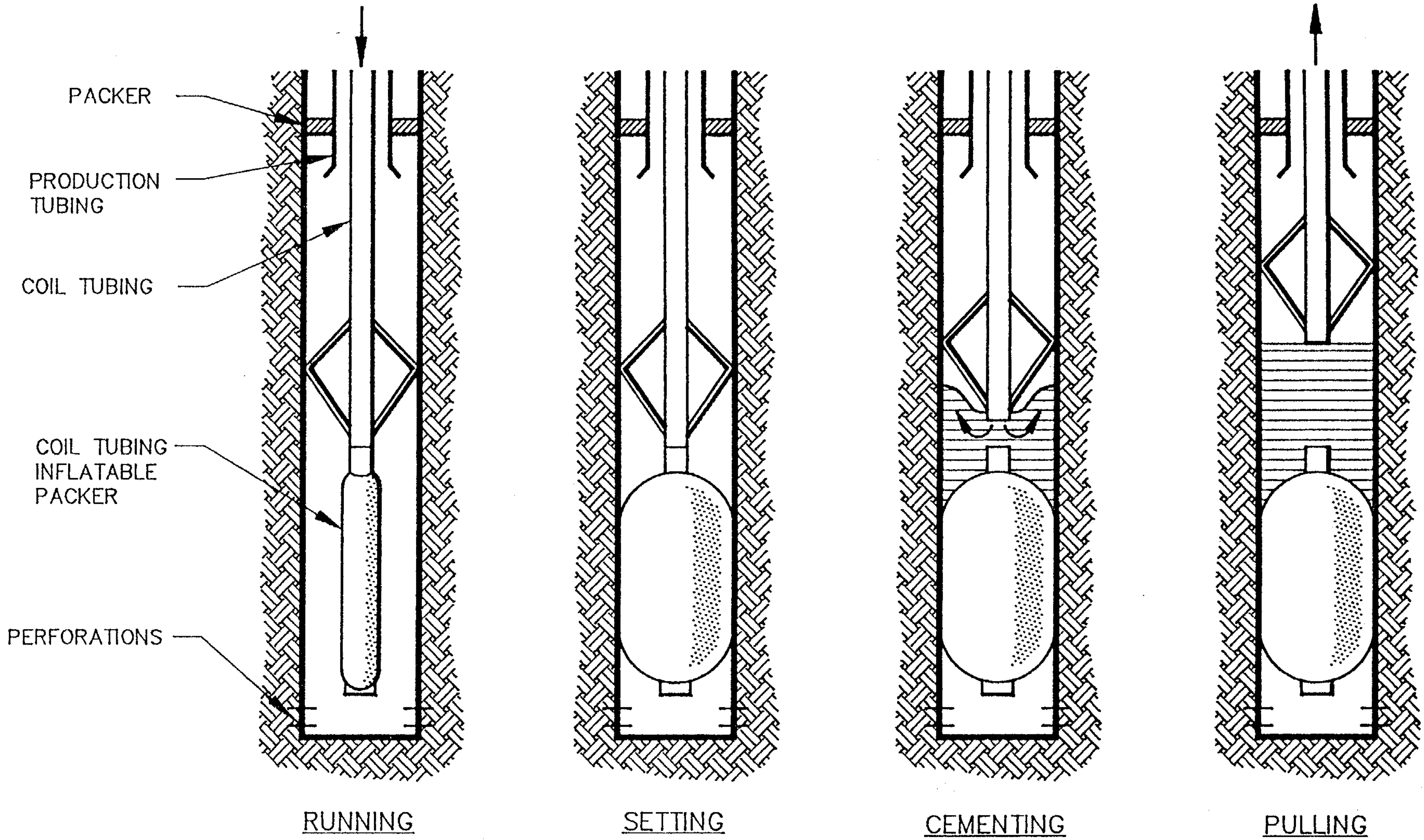

Figure 5.2.5.1

Coil Tubing Inflatable Packer

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BJ also combines cementing with their coil tubing units to provide for permanent capping on top of an inflatable through-tubing bridge plug. This permits a solid, permanent plug to be set below a production packer, or in an open hole, without pulling the production tubing. This capability can be used if pulling the tubing would increase the risk of a pressure control problem.

BJ also is in a joint venture in Brazil with Nowsco Well Service Ltd. of Canada. They have two stimulation boats both of which can be equipped with skid-mounted coil tubing units.

Cudd Pressure Control - Cudd is based in Oklahoma, USA with offices throughout the US. They do not have offices at any international site outside the US.

Cudd reportedly has 25 coil tubing units, all in the US. They are skid mounted and some are currently sitting on truck beds. The units can be easily shipped offshore. The units are for 3/4" to 2-3/8" OD continuous pipe.

Cudd has well control specialists available in sites around the US. Again, this is not necessarily related to the coil tubing issue but is given here for information. For more details, see Firefighting and Blowout Specialists.

Dowell-Schlumberger - Dowell has coil tubing units in each of five foreign areas, but not in North America. They have units in South America (Caracas), the North Sea/Eastern Europe (London), Africa/Spain/France (Paris), the Middle East (Dubai) and the Far East (Singapore). In each area, there are one or more skid-mounted coil tubing units with spools of 1-1/2" coil tubing to reach to approximately 15,000'. The maximum pressure rating is 5,000 psi.

Some of the units, especially in the North Sea, have Schlumberger wireline installed inside the coiled tubing to serve as logging line for highly deviated or horizontal wells. They call these "stiff wirelines". This system may be required to run logging tools or ranging tools in high angle relief wells.

In addition, Dowell-Schlumberger is developing a line of through-tubing inflatable bridge-plugs and packers to be used with coil tubing. These will be of comparable type and style to the Lynes packers.

Nowcam Services (a Division of CAMCO) - Nowcam has 15 coil tubing units equipped with 1" or 1-1/4" coil tubing. Their units are located in the US along the Texas and Louisiana Gulf Coast region. Within the next year, they anticipate having units in Nigeria, Venezuela, Alaska and the USSR. Their operations are split into two divisions with Robert Fette handling the West Region and Don Newton supervising the East Region. Both can be contacted through their Houston office.

Nowsco Well Services Ltd. - This Canadian company has coil tubing units that operate in Canada and the northern US states. They have both truck and skid-mounted reels and injector heads with a variety of downhole tools. These include packers and bridge plugs, downhole fluid powered turbines (similar to the Dyna-Dril), mechanical production tubing cutters and jetting tools. They also have some of their units equipped with internal wirelines for logging high-angle holes.

Otis Engineering - Otis is a Halliburton Company that has coil tubing and nitrogen capability as well as snubbing units, packers and wireline units. Otis has numerous locations around the world and can work in coordination with the other Halliburton companies to provide a wide array of services such as freezing, hot tapping, acid spotting, and pumping services.

Otis has a family of packers and bridge plugs that can be run and set on coil tubing. These are the small diameter through-tubing devices that can be inflated with pressure. They also have J-latch packers up to 7-5/8" diameter that use coil tubing to set and retrieve the packers. Otis has an isolation tool into which the coil tubing can be stabbed for stimulation or cementing.

Recently, Otis began a program to extend the expansion ratio for coil tubing inflatable packers. Most of these packers have a 2:1 or 2.25:1 maximum expansion ratio, according to Otis. They hope to expand this envelope to 3:1, or more. They expect to be completed with this work by the end of 1991.

They are also working with the manufacturers of continuous tubing to develop units that will handle pipe up to 2-3/8" OD with acceptable strengths and corrosion resistant properties. These units, and the large-diameter coil tubing, should also be available by year-end 1991. One prototype unit will be built and assigned to South America in the second quarter of this year that will handle 1-1/2", 2" or 2-3/8" tubing.

Otis has also developed a subsea coil tubing unit for use in the North Sea. This unit has an above water control box and tubing reel, but the injector is a wireline guided subsea unit. It has utility for deep water re-entry for production work. It can be utilized for pressure control, as well. The expert on this system is Mr. Charlie Cobb in Dallas.

Otis has several regional offices which handle different portions of the world. These are: London (the North Sea, Eastern Europe and North Africa), Dubai (Middle East, Egypt, India, Oman and Saudi Arabia), Singapore (Australia, Japan, and Southeast Asia), Rio de Janeiro (South America). There are also three in the US.

The contact for Otis Coil Tubing Service is Mr. Hampton Fowler in Otis' Dallas office.

5.2.6 Communications, Site. Site communications is important during key stages of the control efforts. Historically, prior to the widespread use of radios, hand signals were predominant. These are still used exclusively by some firefighters and blowout specialists.

Radios are important for obvious reasons. However, selecting a radio set is not simple. Conventional hand held sets are not practical in most field situations because the hands must be left free for work. Also, the noise level is often extensive and a hand set will not be effective under this situation.

Hard-wired sets are not desirable in blowout situations where full mobility is essential. These are used by some cementing and pumping service companies. They do not provide the portability necessary for site assessment in blowout situations.

Battery-operated radios with head sets are desirable and preferred. The head set contains a microphone and ear pieces that cover the ears. Voice-activated microphones might, at first, appear to be attractive because they leave the hands free to work. However, the background noise is often so loud in blowout situations that voice-activated mikes may not function effectively.

There are several manufacturers of these radio units including Motorola and Ear-Mark. There are many suppliers of these and other similar units worldwide.

Recent helmet designs incorporate communications with protective and breathing functions. The Solo helmet marketed by Aran Fire and Safety, Inc. is one type of this system. This helmet is a one-piece laminate of Kevlar high-impact plastic with a visor, facemask with connections for compressed air, hearing protection and communications. It provides full head protection and lowers the external noise level so that effective communications are possible.

A facemask and breathing gear are not always indicated in blowout situations. When there is a low concentration of toxic or suffocating gases such as H_2S or CO_2, this protective equipment may not be required. If the concentration of combustible gas is high, a faceplate or shield may trap this vapor behind the mask. This gas could burn the firefighter's eyes more seriously with than without the faceshield if ignition occurs.

Facemasks and breathing gear can reduce the firefighters' motility slowing firefighting work. Communication equipment should be selected to allow for its use with or without helmets and faceshields.

5.2.7 Directional Drilling Services. Directional drilling is obviously important in relief well work. This section will not discuss companies offering conventional directional work but rather focus on those required services unique to well control.

Eastman Christensen - This Baker company is the product of several mergers over the past few years. Eastman currently has numerous locations which provide downhole tools, including motors, stabilizers and a wide variety of bent-subs and other tools for directional drilling worldwide. They can also provide multishot services and MWD services in conjunction with or independent of their directional drilling services. They can interface with other Baker companies for additional services with coordination through Baker Drilling Services, Inc. in Houston.

Eastman has advertised for several years that it has a relief well team dedicated to relief well drilling. The 'team' has undergone many structural changes throughout the years. Currently, this Houston-based team is composed of a design/software expert, Scott Deveraux, and one engineer. The value of any such team is dependent exclusively on the individual leading it.

If the relief well team is needed, Deveraux will take an Eastman computer to the operator's office where he will remain, as necessary, to do relief well planning along with the operator's representative(s) and the blowout/firefighting team. The engineer will go to the location and stay on the rig to coordinate directional drilling operations. They will still use directional men and MWD/multishot personnel from their nearest area office, but overall coordination and logistical support will rest with the relief well team. Thus, local knowledge will be utilized, but there will be a central contact who will be charged with coordinating Eastman's part of the job.

Smith International Smith offers worldwide directional drilling services. Recently, they have worked on at least one relief well drilling effort. They successfully planned and drilled two relief wells for the 1988 Enchova blowout in Brazil. The wells apparently were drilled quickly and on target according to SPE technical articles published by Smith.

Sperry Sun Services - One of the Baroid companies, Sperry Sun has an MWD system that utilizes a downhole turbine for a power source. This continuous system uses pulses in the mud column from their downhole tool that are read by surface sensors and converted by a computer system to provide tool faces while slide drilling and "multi-shot" type surveys on connections. Since their system uses the downhole turbine instead of batteries, pulling of the MWD tool for replacement of the battery pack, a common deficiency of other systems, is avoided.

They also have directional drilling tools that have been used successfully on wells in the Middle East and in Russia. These may be useful for relief well drilling.

Technical support is available through Sperry Sun Drilling Systems office in Houston. The contact there is Mr. Henk Jelsma.

Teleco Drilltech Division (Teleco Oilfield Services Inc. - a SONAT Company) - Formed in 1974 to provide directional drilling surveying and supervision to operators in the North Sea, this company has offices worldwide including Houston, Texas; Broussard, Louisiana, USA; Aberdeen and Great Yarmouth, UK; Talara, Peru, Abu Dhabi, UAE and Singapore.

Teleco provides directional drilling tools and supervisors as well as downhole surveying (magnetic and gyroscopic multishot and single shot with a downhole "memory" unit - no MWD). They also have computer assisted display capability through their FANSI on-site computer. Of particular use is their post well analysis plot which includes a variety of drilling and lithology data on a single plot. Teleco has had considerable experience working on multi-well platforms and in drilling relief wells in the past.

Also, Teleco has a research effort into MWD tool usage for kick detection. The objective is to detect kicks quickly so the well can be shut in to minimize the kick size.

Several individuals and firms have special capabilities in the directional drilling field. They do not have the hardware for directional drilling, but all have special skills. They are discussed below.

Neal Adams Firefighters, Inc. - The Neal Adams team has organized directional drilling for relief wells in a number of unusual situations and circumstances for blowout control. For more information, see Section 2.10.

Patton Consulting - Bob Patton advertises a blowout-relief well finder service whereby, through a series of calculations, a relief well can be guided very near the location of the flowing well. This can augment and be used to optimize ranging tool runs in a relief well. Patton Consulting is located in Dallas, Texas, USA.

John Wright - Mr. Wright was the former manager of Eastman's relief well team. As such, he has worked on blowouts such as the Venezuelan SLB-5-4X, Steelhead in Alaska and Piper Alpha. Mr. Wright left Eastman in 1989 to work as a consultant on Saga's 2/4-14 underground blowout in Norway.

5.2.8 Diverters. Diverters are an important facet of shallow gas blowout control. They are not considered as essential in controlling blowouts from deep zones. A brief discussion is included to address the use of diverters during relief well drilling. Shallow zones could be charged with gas from a previous blowout. An adequate diverter system is necessary to insure rig and personnel safety.

Some wells are capped via blind rams and placed on a diverter system while snubbing work is completed. This situation typically arises when casing integrity or fracture gradient at the casing seat will not allow a complete shut-in of the well. These diverters are typically spools with side-outlets to which 3" or 4" flow lines have been connected. Special technology is not used either in the diverter or the flow line.

Purpose-Built Diverter Lines and System - A high capacity, state-of-the-art diverter system is necessary for shallow gas blowout kill operations. Most rigs are not equipped with suitable diverter systems. However, it is possible to prepare and install the necessary components in a relatively short period of time. The system should be sized conservatively, particularly if it is to be used for operations on a known shallow gas location.

An annular preventer is preferred by some specialists for the diverter unit itself. Porting and control lines can be provided that will give the desired response time of 20 seconds or less. One should be aware that there are inherent advantages and disadvantages to the purpose-built diverter units.

The configuration should be simple and straight. Bends of any type should be avoided if at all possible. Special designs should be utilized for the outlet area from the diverter annular and at any sections that will cause flow disturbances.

A key area of interest is the lines perpendicular to the diverter unit and nearest to the unit. These sections will receive most of the erosive wear from any sand-laden fluids. The design shown in Figure 5.2.8.1 has demonstrated good field capability. If the inner section is eroded, the erosive resistant filler material retards erosion while the outer sleeve maintains the pressure tight containment.

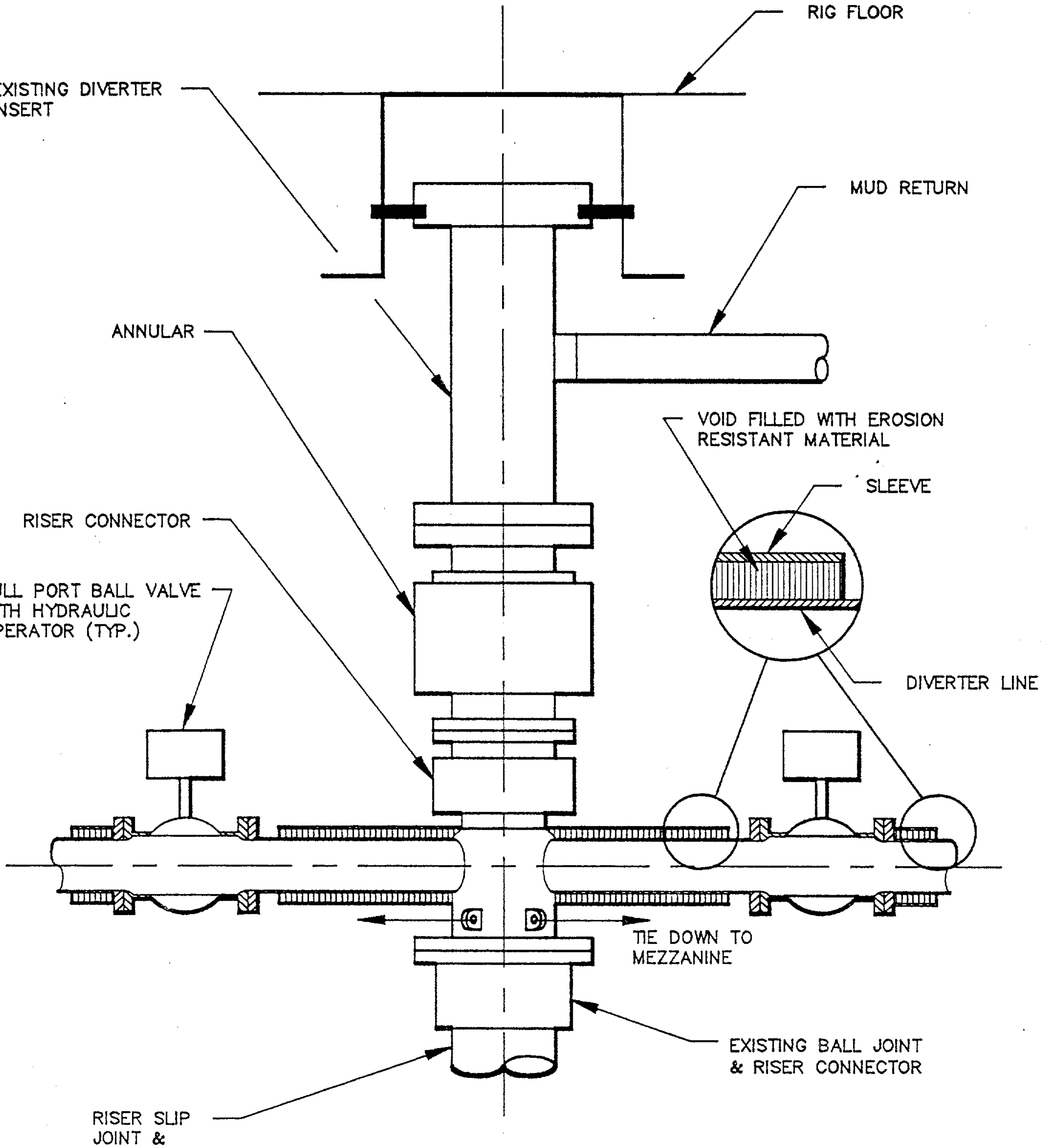

Figure 5.2.8.1

Purpose-Built Diverter System

NOTE:

Outlet Lines Extend Port and Starboard Outboard of the Mezzanine Deck (Pipe Rack Deck)

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The erosive resistant sections are purpose-built. However, they do not require much lead time. The key component is the filler material.

Hydril's FS Diverter System - Hydril markets the "FS" marine riser diverter for floating drilling applications. It incorporates a method of diverting flow from the well to an overboard discharge, while precluding shut-in of the well. Diverter closing pressure simultaneously opens the vent line, closes the mud flowline, closes the fillup line, and closes the diverter bore. All functions are enacted by the integrated valve sleeve and piston to ensure fast and reliable operations.

The unit is typically equipped with a 12" side outlet. However, it has been reported that larger outlets can be specially designed. It is not recommended by NAF to use a 12" outlet and then have an adapter to a larger size. The preferable approach is to have a larger vent outlet installed by Hydril.

The unit has a working pressure of 500 psi. It reportedly can seal on 20" to complete shut off. It has a 21" bore.

Some concern has been expressed that, when closing on casing, the piston does not fully open the side outlet. If this is the case, flow will be restricted. Operators contacting Hydril on this matter have reported that the piston will not fully open the vent if a blowout occurs with larger sizes of casing in the diverter. Each oil operator should evaluate the matter individually.

A flow selector is used on the vent line to divert flow to one of two diverter lines. The selector has a 12" bore. Some operational questions exist as to plugging problems that may occur in this selector with a high volume shallow gas blowout laden with formation debris.

Dril-Quip - Dril-Quip manufactures a diverter system in addition to its other product lines.

The diverter system is designed for use on jack-ups and platforms to divert shallow gas flows. Systems can be provided to fit 49-1/2" and 37-1/2" rotary tables. Standard 2,000 psi working pressure systems are adaptable to lower pressure ratings.

The unit is similar in some respects to the Vetco (Regan) unit. Dril-Quip uses mechanical couplings, lockdowns, etc. to limit the need for hydraulics to only essential functions, such as actuating the diverter inserts. This simplifies the control system significantly.

The unit is vulnerable when running the 26" drilling assembly. If a blowout occurs while out of the hole, Dril-Quip claims the test tool can be picked up and run into the hole. The possibility of such a quick response by the drilling crew is questionable.

Vetco Gray - Formerly Regan, this is the largest supplier of diverters and has two current systems, their KFDS and KFDJ series. The KFDJ system is used primarily on platforms and jackup rigs while the KFDS is used on floaters.

Both of these have a permanently mounted diverter support housing, a proprietary feature, that allows passage of equipment through the full bore of the rotary table. The entire riser, including the choke and kill lines, can be run through the support housing. The housing also allows for the installation of vent and flowlines up to 20" OD.

The KFDJ Diverter allows running bits and downhole tools to 26" for 37-1/2" rotary tables and to 36" for 49-1/2" tables. Diverter insert packers can be run in a full range of sizes, depending on the casing or tools being run, using the same "J" type setting tool. It is available in 500, 1,000, 2,000 psi ratings and is available with a surface rotating insert to provide a low-pressure packoff against the drillpipe or kelly while drilling.

The KFDS-CSO 1000 Diverter is designed where higher pressures are required on floaters. It will run through a 49-1/2" rotary table and has a 20" bore. Outlets range from 12" to 18" nomimal sizes.

The diverter uses a Shaffer 21-1/4" sherical annular insert packer which has a relatively long life. It also provides a rapid, 10-second, element closing time. Valve packaging and the control system can be modified easily. The working pressure of this diverter is 1,000 psi on 5" drillpipe and 500 psi on an open hole.

5.2.9 Explosives, Severing and Cutting. Hydraulic, jet and explosive cutting is discussed in this section. These services and products are used in blowout situations primarily to clear debris from the wellsite or to expose a competent casing string for installation of a wellhead or BOP in order to kill the well.

5.2.9.1 Explosive Charges. Explosives have traditionally been used to snuff out fires at blowing wells. This technique is usually limited to land-based blowouts.

A charge in an insulated canister, usually a 55-gallon drum, is placed just above the blowout source where ignition just begins in the stream. Normally an athey wagon is used for this purpose. Water from fire monitors is sprayed on the canister to cool the charge while all personnel are evacuated. Then, the charge is detonated by remote control and the air (oxygen) and fuel (oil and/or gas) are separated in the evacuated area resulting from the explosion thus snuffing out the fire.

The charge must be properly sized to insure separation of the components long enough for the fire to loose its source of re-ignition. This is largely a matter of experience and trial-and-error. Several shots may be required to kill a large fire. Often, a solid fire supressant, such as "Purple K" is packed with the explosive charge to enhance its effectiveness.

Large charges are often required to kill difficult fires. One notable Middle East fire required 800 pounds of dynamite to snuff the blaze. Recently in Kuwait, 300 pounds of C-4 explosive were used in an attempt to snuff a large fire without success.

Collateral damage from using charges to snuff out fires should be considered when employing this method. Fire pumps, athey wagons, bulldozers, fire monitors and stands, wellhead components and aluminum pipe can be damaged by the charge. Replacement of these components requires time. The instability of certain explosives makes them unsuitable for this use. The possibility of injury to firefighters and other personnel must be evaluated carefully.

This technique is normally used only in onshore situations. It's usefulness offshore is obviously limited. There are several other types of extinguishing techniques for onshore use that are intrinsically safer and more efficient. The use of explosives for snuffing blowouts onshore should be considered as a last resort.

The use of explosives in a blowout situation is inherently dangerous. Shelf life of explosives is limited and should be checked before using. Detonators and explosives should be transported and stored in different locations. Novices should be instructed to stay away from all explosives and detonators. Only competent specialists should handle explosive devices, detonators, timers or radio controls for these devices.

5.2.9.2 Explosives Experts. This category includes individuals or firms that are knowledgeable and experienced in explosives handling. They are consultants and specialists in the field of explosives and can supply the explosives and detonators.

Dawn Offshore Explosives - Based out of Gretna, Louisiana, this firm provides explosives and technicians throughout the world for all types of services. They specialize in the use of activated nitromethane explosives. These can be detonated by blasting caps and/or primer cord. Services are dispatched out of Gretna and can be coordinated by Mr. Ken Charpentier.

Bill East - Bill East is an individual consultant specializing in explosives. He retired after a career in the US Army where he learned the skill of working with explosives.

Mr. East has worked on various blowout jobs for different blowout groups. The areas of his service include using dynamite to put out a fire to using plastic explosives for debris cutting and removal.

Royal Ordnance - This group of former British military ordnance experts has extensive practical experience in the use of explosive devices for a multitude of purposes. They have been involved in ordnance disposal in the UK and in Europe. They have removed explosive devices from wellheads in Kuwait. They are experienced in shaped-charge technology including site-specific demolishing techniques and steel cutting. They are a worldwide organization with multiple offices

5.2.9.3 Jet Cutting. As the name implies, this type of cutting uses a high-pressure jet of fluid, usually water, with or without an abrasive that is directed through a nozzle onto the structure to be cut. The force of the water (and abrasive) impinging on the object selectively erodes it, cutting cleanly through it.

Depth of the cut can be altered by adjusting the size of the nozzle and the pressure. When a sufficiently large nozzle and low pressure are used, these devices can be used to blast and clean a surface without cutting at all.

Cuts made by these devices are clean and burr free. Since they use water as a medium, they are intrinsically safe. The structures to be cut do not require purging prior to cutting since flames are not used.

Colt Industrial Services Ltd - This UK company is based in Hull in northern England and supplies a high pressure jet cutting system. Water, either fresh or seawater, is pressurized to the 4,500-5,000 psi range. Then an abrasive is added such as garnet, bauxite or copper slag. The resulting slurry is then jetted through a nozzle onto the cutting surface where it rapidly abrades a "cut" through the target material.

The cutting units are skid mounted in an offshore cage and include a hydraulic power unit. The nozzle can be mounted on a hydraulic crawling unit and a chain is provided to circumferentially cut any size casing or multiple strings depending on nozzle angle. The nozzle can also be mounted on a track to make a straight cut. This can have utility for fabricating purpose-built firefighting equipment on location.

Colt Industrial Services provides rental units and technicians to do cutting services worldwide. They have experience in the Middle East, the Far East and off the US Gulf Coast. They are on 24-hour call. Their contacts in the UK are George and Ian Telford.

Flowplant (Scotland) Ltd - This firm is located in Scotland and offers jet cold cutting using the Harben Jet Edge System. This system uses water and an abrasive with ultra-high discharge pressures to 36,000 psi. Also used are synthetic sapphire nozzles as small as 0.762 mm (.003 in). The high pressure and small nozzle yields an exceptionally clean cut.

Like other systems, the cutter can be mounted on the member to be cut in a variety of methods. It can be attached to a hydraulically powered crawler which moves around a circular pipe on a chain or split frame. It can also be attached to a straight frame to slice long cuts.

Furmanite Engineering Ltd. - Headquartered in Kendal, Cumbria, this UK company provides jet cutting using the Fluid Engineering Products Ltd. Water Jet Cold Cutting system.

Like other jet cold cutting systems, this system uses water (fresh or sea water) mixed with an inert abrasive, pressured and pumped through a jet to cut a wide range of materials. They can cut structural pipe (any shape), casing, piles, etc. in any diameter with any coating or lining in a single pass leaving bevels suitable for welding. The cut is dust free and purging is not required. They have one model of remote cutter that operates inside conductor casing or piles for removal at or below the mudline.

This service is operated from Furmanite's Dyce, Aberdeen workshop. Coordination is available through Mr. Tim Derval.

Macnamee International - This Houston, Texas-based firm provides equipment and personnel to cut pipe or any other shaped piece of steel, concrete, rubber, etc. by utilizing a high-pressure jet of water containing an abrasive.

The system uses a jet nozzle mounted on a crawling carrier that runs on a chain wrapped around the member to be cut. Water under a maximum pressure of 4,000 psi containing an abrasive (copper slag, garnet, aluminum silicate, olivine or fused alumina) is directed through the nozzle to the surface of the pipe. After initiating the cut, the crawler moves around pipe cutting a slot through the wall of the pipe. Discharge pressure, nozzle size and the amount of abrasive can be adjusted to provide any width or depth of cut with or without cutting underlying structures.

This versatile system can be used underwater to several thousand feet and is easy to handle. It can be used under ROV manipulator control or by divers. By changing discharge pressures, the same system can be used to clean structures for inspection. Services worldwide are dispatched out of Houston, Texas, USA. Technical support is provided by their resident engineer, Mike Fowler. Their management representative is Mr. Chris Macnamee. The owner of the company, who is based in the UK, is Mr. Rupert Macnamee.

5.2.9.4 Hydraulic Cutting. Hydraulic cutters use pressured hydraulic fluid to operate a variety of mechanical devices that slice through pipe, structural steel or other materials. One example of this type of device is the Hurst Tool, a rescue device commonly called the "Jaws of Life."

Some of these devices generate sparks, and purging or water bathing of the cut may be required. Most can be operated remotely without exposing the operator to extreme danger. The cutter can be installed on the structure to be cut, then the controls and the hydraulic power unit can be moved away from the cutting theatre. So, the system can be made moderately safe in blowout situations.

Myoco Cold Cuts, Inc. - The Myoco system uses a knife blade, similar to those used on lathes, mounted on a hydraulic carrier which travels around the outside of the pipe on a heavy-duty split frame. Pressured hydraulic fluid is supplied from an external source. Pipe from 6" to 42" OD (any thickness up to the length of the blade) can be cut using this system. The blade can leave any desired taper or bevel. This system can be used underwater. It does not involve open flame and does not require purging of the pipe prior to cutting.

Pipe larger than 60" can be cut using the Myoco system, but a larger split frame would have to be fabricated in Houston. Time to provide this item is estimated at three weeks. In every case, the customer is expected to provide the hydraulic power unit.

Myoco also provides service personnel and technical support for performing the cutting service. These can be dispatched out of Houston to anywhere in the world on short notice (24 hours or less). Their Houston contact is Mr. Rick Stephans.

Wachs Technical Services, Inc. - This subsidiary of E. H. Wachs Company has three different types of cold cutting systems as well as technical support and service personnel to perform the cutting service.

WTS, Inc. provides a hydraulic cutter similar to the Myoco cutter. A lathe-type blade is attached to a carrier which runs on a split frame. With this type system they can cold cut pipe up to 48" and soon will be able to cut up to 60" OD pipe.

The split frame system is adaptable to cutting in any position, horizontal or vertical, and is relatively light-weight and can be handled by two technicians without difficulty. It is the most used of the three cutting systems provided by WTS.

WTS also provides a spinning blade cutter mounted on an hydraulic carrier that travels on a chain wrapped around the pipe. It can be used in the horizontal position easily, but if it is mounted vertically it needs an extra guide to prevent the cutter from "barber-poling" around the pipe as it cuts.

This "Trav-L-Cutter" is very fast and can leave any desired bevel. It is also very rugged in design and can absorb considerable abuse. It can cut pipe up to 15" in diameter. Larger pipe sizes can be cut with modifications. There is also a model that is designed to cut thick-wall pipe (up to 5" thick).

The third WTS system is a guillotine saw. This system uses a hack saw-type blade which reciprocates in an hydraulically actuated frame, part of which clamps onto the pipe. It is particularly useful in situations where there is limited side clearance around the pipe to be cut. Only about 3" is required for most pipe sizes.

The guillotine saw can cut pipe up to 24" in diameter. Its primary drawback is the weight of the hardware. An 18" cutter weighs some 400 pounds and is difficult for a normal two-man team to fit and handle. Larger sizes are even heavier and more cumbersome.

Both of the saws provided by WTS can be made spark-safe by bathing the blade with water. Purging of the pipe is therefore not necessary, but the technicians provided by WTS can make recommendations for purging on location if it is indicated.

All service technicians provided by WTS are trained in the W. T. Wachs Company factory in Wheeling, Illinois, USA and the tools are provided by this parent company. Thus, WTS has access to the latest tool modifications and revisions from the parent manufacturing company.

Pipe Cutting Service & Supply, Inc. Mr. Chuck Wellman is the contact man for this Houston-based company. They supply a variety of cutters that run on split frames up to 20" casing. These units employ a split frame which clamps on the pipe and can be positioned to insure that the pipe is centered.

The cutter is set on a pneumatic carrier that travels around the split frame. Carrier speed can be adjusted by pneumatic pressure. Cutter shape and position can be adjusted to leave any desired bevel.

The units are relatively light weight and rugged. The smaller units can be positioned by one or two men. Larger units require additional personnel or hoist assist.

5.2.9.5 Explosive Severing. Shaped explosive charges have long been used by the military for "surgical" cutting of various sizes and shapes of structures. This technology has extended to the well control business as a logical extension since rapid, decisive debris removal is necessary in both fields.

Explosives are shock producing, so smooth cuts are less likely to be obtained than with the methods discussed above. Further, the flame produced by the explosive can ignite or re-ignite a well, a situation that is sometimes desirable, sometimes not. Corollary damage by explosive detonation to other pieces of equipment in the vicinity is also a point of consideration when selecting a cutting method.

Obviously, explosives are not as safe as some other methods, but in the hands of trained specialists they are no more risky than other types of cutters. Explosives should never be placed in the hands of inexperienced personnel, and the storage of explosives and detonators should be left to those knowledgeable in their use.

GOEX International, Inc. - Located in Cleburn, Texas, USA, the Services and Defense Division of this company provides explosive services and devices for severing drill-pipe, tubing, casing and offshore structures using linear shaped charges. These charges come in sizes from 600 to 10,500 grains/foot. The explosive is housed in a seamless copper sheath and can be formed to fit any shape.

Detonation occurs via standard blasting cap unless, for special application, GOEX provides a different type and style of detonator. An ATF license is required to purchase charges from GOEX International, but they provide service personnel to install and detonate any of their charges without additional certification or licensing requirements to the operator. Special shaped or sized charges can be manufactured on very short notice in the event of an emergency (less than 24 hours).

Technical support from the Services and Defense Division can be obtained by contacting the Cleburn, Texas facility, Mr. Warren Stephens or Mr. Gerry Rice. Service personnel and special tools as well as the charges themselves are dispatched out of Cleburn. Their main telephone number operates 24 hours per day.

Jet Research Center, Inc. - A Halliburton company, JRC is located in Arlington, Texas and provides a majority of shaped charges for domestic perforating companies. JRC provides severing tools to cut drillpipe, tubing and casing run on wireline or sandline. They also provide shaped charges to make external cuts on casing or structural pipe.

JRC has offices in Victoria, Texas and Broussard, Louisiana, USA and in Aberdeen, Scotland, UK where they maintain a staff of technicians. There is also a sales office in Singapore. They maintain an inventory of shaped linear charges in their plant in Alvarado, Texas, USA, but if special charges are required, they can fabricate the bent housing and the shaped charge within 48 hours.

Worldwide technical coordination is available from Mr. Linza Jones in the Alvarado plant. They have technicians available on a 24-hour basis.

5.2.10 Firefighting and Blowout Specialists. Many companies are beginning to offer various forms of blowout services. The following list is not designed to exclude any particular company. Many small companies are growing as a result of Kuwait work. Additional entries in this category will be made upon request.

Abel Engineering//Well Control Co. - Bill Abel heads this engineering company which specializes in blowout control and firefighting. Ralph Dean and Chuck Allen are engineers who have provided technical support and equipment design capability to the group. Recently they designed and put into the field a hydraulically powered athey wagon, a new design that eliminates an external maneuvering vehicle (traditionally a bulldozer).

Abel has experience in handling blowout situations in which novel approaches are required. They have been active in pursuing new firefighting technology and techniques.

Red Adair Company, Inc. - Paul "Red" Adair is a legend and has the most widely recognizable name in the oil industry. The Red Adair Company had its origins with the Myron Kinley company in the late 1940s. Many blowout specialists had their beginning with this company.

The company has a long history of capping well blowouts on and offshore. Well known events include Piper Alpha, the Devil's Cigarette Lighter and one well on Bay Marchand. The list is extensive.

Also, they have advised on many wells that were not capped but killed with other techniques. A notable example is the Bay of Campeche blowout in Mexico. They occasionally advise on snubbing operations on problem wells such as the Tejero 2E and the Russian Tengiz well.

Red Adair, has three principal field-experienced supervisors. Key individuals are Raymond Henry, Richard Attebury, and Bryan Krause. Due to their high level of experience in capping work, the company tends to restrict itself to this aspect of blowout control.

The company has available firefighting equipment required on most jobs. This includes pumps, monitors, athey wagons, etc. It can be mobilized quickly to US or worldwide sites. Also, the equipment can be purchased for permanent installation at an operator's site, if desired.

Neal Adams Firefighters, Inc. - This company had its first major job in 1987 and has been in business for 4 years. The job was the Steelhead platform disaster in Alaska. Neal Adams, the president, worked for Boots & Coots, Inc., for several years as a consultant in various capacities before starting the new company.

The company offers a range of services which include the following:

- Well capping
- Relief well drilling and killing
- Offshore rig operations over a live gas boil
- Shallow gas blowout handling
- Underground blowouts on- and offshore
- Blowout technology development
- Contingency planning
- Blowout investigation

Also, the company has a range of experience in subsurface problem evaluation in blowout situations, i.e., which zones have been affected and procedure development for rectifying the problem.

Neal Adams Firefighters, Inc. operates its worldwide headquarters in Houston, Texas, USA with an affiliate office in Sandnes, Norway. The Houston office has 4 lead firefighters capable of managing any job. The Sandnes office has an experienced individual for work in the North Sea. Its specialists have strong hands-on field experience in addition to engineering capability. Key personnel include Neal Adams, Larry Kuhlman, Bill White and Les Skinner.

The company has worked on key blowouts such as Piper Alpha, Steelhead in Alaska, and Ormat's geothermal blowout which is believed to be the largest in US history. The company has handled blowouts onshore and offshore and under various adverse conditions. Neal Adams International Firefighters Corp., an associated company, is actively involved in the Kuwait situation.

In addition to field operations on blowouts, the company has an on-going blowout technology development effort. It has created a large database of blowout information and has computerized much of it. The database and records are available for use by NAF clients.

Boots & Coots, Inc. - This firm is owned by Asger "Boots" Hansen and Edward "Coots" Matthews. They worked with Red Adair for approximately 25 years prior to forming their company in 1978. These individuals usually lead their company's efforts on jobs.

Boots & Coots, Inc. has worked on blowouts worldwide. Their primary experience is on land and platform blowouts. They have done several underwater blowout jobs such as Lagoven's SLB-5-4X, Agip's offshore Egypt well, and Saga's 2/4-14 well. The company has significant experience in capping and snubbing supervision.

The company offers firefighting equipment such as fire pumps, transfer pumps, monitors, and athey wagons for debris removal. Also, they have two snubbing units used for special services work.

Cudd Pressure Control, Inc. - Cudd Pressure Control offers a variety of pressure control services including blowout teams, snubbing units, coil tubing, freezing, hot tapping and valve drillout work. The company has specialists based in Oklahoma, New Mexico, Wyoming, Texas and Louisiana in the United States. None are based internationally. According to the company, they can field up to 5 firefighting teams. The company is led by Mr. Bob Cudd.

The company is not as widely known as other firefighting groups. However, they have good capability. Their background in high pressure snubbing assists their well control efforts. Also, their team is more broadly based than relying on a few well known individuals as is the case with some other competitor companies.

The company restricts itself to conventional capping work. It offers other services such as relief well drilling, technology development and well control engineering studies through an arrangement with GSM, Inc., an Amarillo, Texas, USA-based consulting firm headed by Mr. Bob Grace.

Safety Boss, Inc. - Safety Boss is a Canadian firm managed by Mike Miller. It operates a complete line of capping services and safety services. The firm, as a Canadian-based company, enjoys slightly less restricted travel constraints to certain countries. This situation applies particularly to some Middle East countries that are not amenable to using American companies if alternatives exist.

Wild Well Control, Inc. - Joe Bowden, president, started Wild Well Control in the late 1970s. The company operates its office in Spring, Texas which is a northern suburb of Houston, Texas. The company is reportedly owned in part by Mr. Pat Campbell now.

Wild Well Control is experienced in the traditional areas of blowout control work. This includes capping and supervision of snubbing, hot tapping and freezing. The company has extreme experience worldwide.

The principal firefighters for the firm are Paul Saunier and George Hill. Joe Bowden leads the work force. Pat Campbell has been responsible for several inovative devices and procedures used in Kuwait. WWC has demonstrated an appreciation for new firefighting devices, chemicals and techniques.

Wild Well Control has a complete product line of oilfield firefighting equipment. Items include fire water pumps, transfer pumps, piping and athey wagons. The equipment is available for rent or purchase.

5.2.11 Firefighting Equipment and Chemicals. Various pieces of equipment and chemicals are used on blowout fires. These include fire pumps, athey wagons, water monitor/nozzles and chemicals/foams. The blowout and firefighting specialist normally has sources, including his own inventory, that he prefers to use for this equipment.

The equipment is usually rented for the specific job. It can be purchased, however, if the client prefers this approach. Purchase is not uncommon for some overseas locations where the time to transport the equipment from a North American-based site may prove critical. Also, seasonal logistics difficulties may warrant purchase of some items.

5.2.11.1 Fire Pumps. Fire pumps are used to feed water monitor/nozzles with large volumes of water at low pressures (100 to 450 psi). Typical pumps used by blowout specialists are 2,000 and 4,000 gpm units. The smaller 2,000 gpm units have the flexibility of being trailer mounted, if desired, and are maneuverable on the location or on the barge/rig. The 4,000 gpm units provide more output from a single unit but are bulkier and heavier due to their larger horsepower requirements.

These units need to be evaluated from a mechanical efficiency view to determine their true volume ratings. It is reported that some pump engines must be run at high speeds to develop horsepower necessary for the full 4,000 gpm capability. These high rpm requirements have caused some downtime problems in the past. Also, engines on the 2,000 gpm pumps are more common and easier to service than some of the large prime movers used on the 4,000 gpm units.

It is often better to have some redundancy in the number and size of firefighting pumps. Also, it is important to have a functional back-up pump ready for immediate operation. For example, if a single 4,000 gpm unit being used on a job goes down, a firefighting team may be left with no protection. However, if one of two 2,000 gpm units goes down, there remains 50% firefighting capacity from the second 2,000 gpm pump. If a third 2,000 gpm pump is on standby, little protection is lost.

Most firefighting companies have an assortment of pumps or they have ready access to a full line of equipment. The equipment is ready for mobilization immediately after the call from a client.

Fire pumps used on offshore sites and vessels are typically much larger volume throughput pumps than the portable units used by blowout specialists. Capacities to 10,000 gpm are not uncommon.

Rain for Rent - This company has trailer-mounted fire pumps in a variety of sizes, aluminum pipe, hoses and auxiliary equipment for rent or purchase. Their pumps range from 1,250 gpm to 4,000 gpm at 125 psi discharge pressure. The trailers on which they are mounted contain 250 to 500 gal diesel fuel capacity and can be cage-mounted for offshore service.

This California company has offices in a number of locations across the US, UK and Riyadh, Saudi Arabia. Their Houston contact for firefighting pumps and associated equipment is Scott Heard.

5.2.11.2 Transfer Pumps. Transfer pumps are low pressure, high volume centrifugal pumps designed to transport water from a staging area to the fire scene and to charge the firefighting pumps.

Transfer pumps can be rented from firefighting companies or are typically available from a number of local sources. The key equipment item is a discharge manifold that will allow connection of several large ID lines to the monitor pumps.

5.2.11.3 Athey Wagons. Athey wagons are used onshore to remove debris from around a blowout where the fire has destroyed a rig. They are also used to position explosives during kill operations. Most firefighting companies have their own athey wagons or access to them.

An athey wagon is a boom with a hook mounted on crawler tracks. It is moved into the location to latch onto debris with a bulldozer. Some athey wagons have the capability to move the boom vertically a modest amount to add flexibility. Figure 5.2.11.1 shows a typical athey wagon.

Debris removal on offshore blowouts is done with cranes mounted on the rig or barges/vessels working near the blowout. Cranes can also serve effectively for debris removal on land jobs. Underwater debris removal is done with divers and ROVs in conjunction with topside cranes.

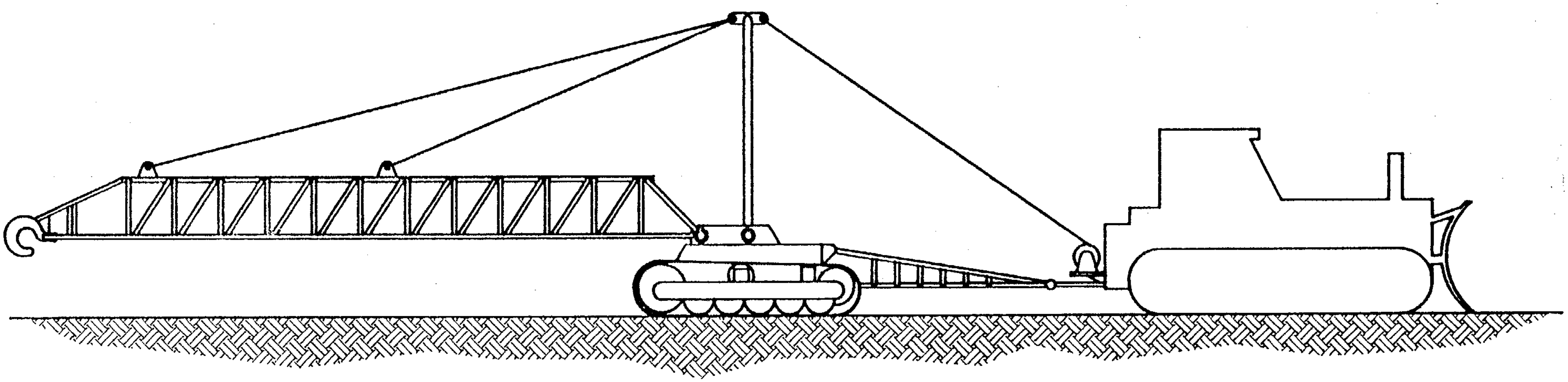


Figure 5.2.11.1

Athey Wagon with Bulldozer

DEA PROJECT NO. 63

JOINT INDUSTRY PROGRAM
for
FLOATING VESSEL BLOWOUT CONTROL

5.2.11.4 Water Monitors/Nozzles. Water monitors or nozzles are used to direct water on the fire. The nozzles have various pressure and volume ratings ranging to 1,500 gpm. Larger units to 10,000 gpm are commonly called water cannons. They are available for special purposes, but have limited use for blowout firefighting.

Monitors can vary the type of spray from a mist to a direct stream. Some have an automatic capability to maintain a constant type of flow even with input pressure changes. The nozzles are typically attached to a stand in a monitor unit.

The largest manufacturers of nozzles are Elkhart, Akron Brass and Chubb. They manufacture a wide variety of other firefighting equipment.

Nozzle selection depends on a number of variables including the type of service intended. Little is gained by economizing during nozzle selection. A good nozzle can be a lifesaver, literally. They can be purchased from most fire and safety companies at reasonable cost.

5.2.11.5 Chemicals/Foam. Chemicals such as foams are seldom used on oil and gas well blowouts. They are more widely used on refinery fires where the fuel source is not dynamic. The types of chemicals used in this area of firefighting are extensive. They will receive only minimum coverage in this catalog.

Inferno Snuffers, Inc. - Recently, the oilwell fire situation in Kuwait prompted development of a new chemical by a professor of physics and chemistry at Texas A & M University at College Station, Texas, USA. The new chemical is called Uni-Snuff and is marketed by this company.

The chemical is a strong oil-in-water emulsifier. This interferes with the oil's ability to vaporize and form chemical radicals necessary to sustain combustion. Oil emulsified by this chemical will not re-ignite. The chemical is a low viscosity gel that can be applied directly to the fire through common fire pumps and nozzle systems. It is not subject to breakage from strong winds or mechanical damage since the emulsification occurs on a molecular level. Foam blankets can be broken permitting re-ignition of the fuel below them. This new material represents an improvement in chemicals for hydrocarbon firefighting.

In August, 1991, two full scale trials were preformed using this chemical to extinguish a vertical fire burning 500 gpm (17,000 bbls/day equivalent) of a liquid mixture of 80% diesel fuel and 20% gasoline. The fuel was pumped through a 6" vertical standpipe to simulate a blowout. The chemical was introduced into the burning stream in several ways. In one set of trials the chemical was pumped into the bottom of the standpipe with a 40 HP pump. In another set of trials, the chemical was allowed to siphon into the fire by venturi effect from a storage tank. In a third set of trials two 1-1/2" fire hoses were used to attack the fire above the mouth of the standpipe. In each trial the "blowout" was extinguished in less than 30 seconds. The chemical was equally effective on ground fires.

Inferno Snuffers is led by Mr. Norm Scott in College Station. Another contact is Mr. Greg Pierce.

Kidde-Graviner Ltd. Kidde-Graviner (KG) is a UK based company specializing in fire protection equipment and chemical systems.

Also in response to the situation in Kuwait, KG developed a fire extinguishing device that utilizes pressurized cannisters containing a potassium-based dry powdered chemical attached to a "smokestack." The smokestack is placed over the blowout and the fire ignites and burns above the top of the stack like a bunsen burner.

When the stack is in position, explosive charges are detonated by remote control which ruptures a thin metal shield over the mouth of the cannister. The pressured dry chemical is injected into the smokestack which creates a chemical barrier between the oil and the fire and the flame is extinguished. After the chemical is depleted, the smokestack is removed from the well and normal capping activities resume. The cannisters can be re-charged with chemical and pressured with nitrogen for re-use several times. Water jets can also be added to the smokestack to avoid re-ignition of the fire.

This system was field tested in July, 1991 on a 5,000 bbl/day equivalent diesel oil/gasoline "blowout" at the Offshore Fire Training Center in Montrose, Scotland. The fire was extinguished with a 1/10th volume charge of dry chemical in each of the nine cannisters used during the test.

Kidde-Graviner representatives involved with this new device are Robin Burnett and Steve Cooper. Another contact is Brian Ward. All are based in the UK.

Petroleum Environmental Technologies, Inc. - This company is based in Williamsburg, Michigan, USA and has a line of fire suppressants that can be used in a variety of situations.

PET also has polymers that are capable of solidifying crude oil so that it loses its ability to flow. These polymers represent new technology. They have some utility in firefighting, but they are particularly useful in cleanup work.

Water Expansion Pump System (WEPS) - This system generates stabile, high-quality foams using commonly available liquid soaps. It is not necessary to use expensive protein foamers like AFFF with this system.

The foam generated by a WEPS unit is composed of very small bubbles much like shaving cream. When applied to a surface, this foam is mechanically stiff and long lasting. It can be used directly on the fire to smother it or as a shield to protect equipment and personnel during firefighting efforts.

These systems are simple in construction and function. They use very little water and are easily maintained and repaired so they are quite useful in remote areas having limited access to water. They are in wide use in the US for oilfield fires.

Williams, Boots & Coots Fire & Protective Equipment, Inc. - This company is not currently associated with Boots & Coots, Inc., the blowout specialists. It was, however, founded by the owners of Boots & Coots, Inc. The company is now owned by Les and Dwight Williams and is based in Beaumont, Texas.

The company specializes in various types of petroleum fires not related to a well. These include refineries, tankers, oil spills, etc. They have developed an excellent reputation for prompt, effective response.

They offer firefighting services as well as a complete line of equipment. The equipment includes pumps, nozzles, flow lines, foam systems, foaming chemicals, etc.

5.2.12 Fishing Tools and Services. Fishing tools and related services are utilized in a variety of pressure control applications. The standard tools are used in most cases without modifications. A brief overview of worldwide fishing capability is presented in this catalog for completeness. It is not possible to identify all sources of fishing tool companies worldwide.

Bowen Tools, Inc. - This Big Three Industry company is an old line manufacturer of fishing and other speciality tools. Bowen provides a large line of overshots in virtually every nominal size to 16-3/4" with guides up to 21" OD. Bowen also manufactures the "short-catch" overshot, a useful tool in certain situations. Bowen makes die collars, taper taps, spears to catch pipe from 2-3/8" to 20", safety subs, knuckle joints, junk baskets, shoes and mills of various types and sizes. Bowen makes drilling and fishing jars, bumper subs, cushion subs and accelerator subs, some domestically and some for export only. The Bowen casing patch, a lead seal "bowl", has been available for several years and is well-known throughout the industry.

Bowen does not provide service supervisors (fishermen) but provides its tools through a number of distributors worldwide including Homco, Petco and all major supply companies. They do not provide their tools directly to the operator.

Inventories of Bowen tools are fluid. They maintain three warehouses (in Aberdeen, Singapore and Amsterdam) to provide stocks of tools in the event of emergencies. These three warehouses and all of Bowen's distributors are connected via computer.

Inventories of their tools can be determined by calling any warehouse, distributor or their Houston office. If certain tools are needed in case of an emergency, Bowen can special build these in roughly two weeks depending on their supply of materials (e.g., special steels) in Houston.

Tri-State Oil Tools (a Baker Hughes Company) - Tri-State has a large, diverse line of fishing and rental tools for specific jobs that include pilot mills, junk baskets, two types of casing spears, safety-joints (left-hand threads), junk baskets and hydraulic backoff tools for casing, tubing and drill pipe. The mills include those with cutting surfaces coated with traditional "Kutrite" and with Tri-State's "Metal Muncher" cutters. They also make a lead seal casing patch from 4-1/2" through 13-3/8" and an underwater casing patch for 7" through 13-3/8" casing. They can provide a rubber seal casing patch for pipe up to 20" OD. Tri-State also has access to jars, bumper subs, accelerator subs and other tools through Bowen, Dailey and others.

Tri-State has service supervisors (fishermen) available at locations throughout the world. They also have machine shops in most areas except the Middle East. They are the world's largest fishing company. Tri-State, being a Baker company, can interface directly with other Baker companies through their computer system to locate tools, services and equipment to assist in operations in which they are involved. Baker Hughes Drilling Systems, Inc., Houston, can coordinate these activities for the operator.

The best way to contact Tri-State in the event of special problems/needs is to call the Bossier City, Louisiana store, their main fishing center. The engineering contact is Mr. Henry Burnet, and the operations support contact is Mr. Ray Daugherty. This is a 24-hour number.

Homco - Homco has numerous locations and a wide variety of fishing tools available for rent both domestically and in the North Sea area. Overshots up to 13-5/8" OD, magnets to 24" OD, junk baskets, jars (Bowen or Anadril), bumper subs, casing rollers and scrapers, impression and tar blocks, various taps, spears and mills, shoes and washpipe are some of the items they have available for rent. They also have a wide range of rental pipe, drill collars and other drilling tools for relief well drilling and well control equipment. Last year Homco acquired Land & Marine Rental Tool Company which gave them an even larger inventory and more service points than before. Inventories of tools at specific locations change frequently. For special tool needs, contact the Houston General Office of Homco at 713-663-6444 to determine tool location and availability.

A-1 Bit & Tool Company is a wholly owned subsidiary of Homco and provides casing whipstocks and section mills that can be used in conjunction with other Homco tools. A-1 also manufactures an underwater patch for casing sizes 7" to 13-3/8" OD as well as other tools.

Homco has a wireline division that provides free-point and back-off services in addition to normal perforating and cased-hole logging services. Some of these units are skid-mounted and can be used from MSVs.

Homco also provides service supervisors to run and direct the use of their tools. These "fishermen" are experienced in normal fishing operations. Several of these are situated in the US and in the North Sea area, but none are stationed in Africa and only one is located in Indonesia. These individuals can travel anywhere from the US and are available through the Houston General Office.

Petco Fishing & Rental Tools - Petco has a wide variety of fishing tools and fishermen available in the US, particularly along the Gulf coast. These include spears in all sizes from 2-3/8" to 30", overshots and grapples to 9-5/8", jars, bumper subs, accelerator subs, wire grabs, spang jars and all types of crossovers and special subs. Petco does not manufacture their own tools, but provides tools manufactured by Bowen, Anadril, Gotco and others.

Petco has four fishermen in the UK with two managers who can serve as fishermen as well. The North Sea area, Western Europe, Spain and Africa are all handled out of the UK. Petco formerly had personnel in the South China Sea, but recently sold their fishing tools to a local firm in Indonesia. They can provide fishing services in South America from the US or almost anywhere else by dispatching personnel out of Houston.

Fishing and associated rentals for non-US locations are handled by Mr. Lloyd Hickman in Houston. He can contact local rental points in Aberdeen or Great Yarmouth and insure coverage of tools and personnel, or he can dispatch them out of the US if need be.

5.2.13 Flexible Pipe and Swivel Joints. Flexible pipe is used extensively in the blowout business. Long sections avoid the need for connections. This is an important feature in offshore or underwater applications where it may not be feasible to make connections on hard piping.

Swivel joints are used on hard piping. It is commonly fixed to the piping and not an accessory. As such, it is seldom required to consider purchase or rental of single swivel joint connections(s). However, purpose-built equipment may require procurement of special sizes and types of swivel joints.

5.2.13.1 Flexible Pipe. Flexible pipe, as it is considered here, is relatively high-pressure, armored pipe that is used in place of hard line (steel hose). Figure 5.2.13.1 shows a cutaway view of one type of flexible pipe.

Rubber hoses have limited utility in this service depending on temperatures. They are susceptible to damage by fire because of the nature of their construction. Some rubber hoses have pressure ratings of value in pressure control applications. In these higher pressure ratings, the hoses are very stiff and are hard to handle. They are subject to damage if not handled properly.

There are numerous suppliers of rubber hoses worldwide. Inventories are fluid and availability may be limited for certain sizes and pressure ratings. Listed below are three for flexible steel line.

Coflexip - In 1958 IFP (Institut Francais du Petrole) began research and development of flexible pipe for oilfield use. In 1972, Coflexip was formed to market the flexible pipe thus developed.

Coflexip pipe is available in sizes from 1" ID (2.4" OD) 5,000 psi to 4" ID (6.6" OD) 10,000 psi with their highest rated pipe being 2-1/2" ID (5.6" OD) 20,000 psi. They manufacture pipe in various lengths and with various end connections such as hubs, API flanges and hammer unions. Coflexip also manufactures 2" to 8" low-pressure pipe (2,000 to 5,000 psi rating) primarily for flowlines.

The pipe is composed of alternating layers of sheaths (pressure members) and armor. These can be modified for high temperatures, low temperatures (insulated) and corrosive fluids. Their basic pipe family is limited to a temperature range of -4 to +212°F.

Most well servicing companies use Coflexip lines to connect their stimulation ships to platforms or drilling vessels in the 3" and 4" sizes. In 1982, Coflexip pipe was used for a stack-to- deck installation of kill and choke lines (3" 15,000 psi) in the North Sea. Many rigs use short sections of Coflexip pipe for kill/choke line connectors across the ball joint and at the telescoping joint of their risers. Some use Coflexip for their kelly hose, kill line and fillup lines.

Figure 5.2.13.1
Structure of Flexible Pipe

The primary factory for Coflexip pipe is in Le Trait, France with another factory in Vitorio, Brazil. End-fitting assembly plants are located in Grimstad (Norway), Singapore, Aberdeen (UK) and Houston (US). These plants can provide local support bases for offshore platforms or drilling vessels.

Stocks of 33,200' of Coflexip pipe are maintained in their Le Trait factory in various sizes, pressure ratings and lengths with another 7,300' of pipe stocked in Houston. Coflexip & Services, Inc., the Houston division of Coflexip, has available for lease some 1,800' of 2", 3" and 4" pipe in various lengths (less than 60'), in pressure ratings from 5,000 to 15,000 psi and with a variety of end connections. End connections can be installed on pipe in stock, if the end connections are available, in a minimum time of 72 hours.

The recommended contact for determining the location and availability of Coflexip pipe worldwide is Mr. John McManus, Sales Manager, Western Hemisphere in Houston.

Wellstream Corporation - Wellstream is a supplier of flexible pipe and flowlines that, like the Coflexip pipe, is composed of alternating layers of thermoplastic sheaths and armor.

Wellstream corporate headquarters are located in Houston with their main manufacturing and engineering facility located in Panama City, Florida. They also maintain an office in London, and they have agency offices in Malaysia and Brazil.

Wellstream manufactures drilling service lines in sizes from 2" ID to 4" ID (4.0" OD to 6.6" OD) with pressure ratings to 20,000 psi. They also make flowlines up to 12" ID (14.5" OD) with a pressure rating of 1,600 psi. They also have flowlines in the 6"ID (8.8" OD) with a pressure rating of up to 7,300 psi.

The Wellstream connection is a standard fitting, plain-end, to which any other connection (hubs, flanges, hammer unions, etc.) can be welded. Thus, in the event of an emergency, they can simply weld the desired fitting onto the ends of a given length of their pipe, test it and have it available to the purchaser in 24-48 hours (assuming that they have the pipe in stock). They normally sell their pipe to the end user, but they will entertain leasing the pipe for short-term use.

The Houston contact for inventory control and for arranging shipping and technical support is Mr. Steve Pahls.

Apex Tubulars Ltd. - This Aberdeen company has available for emergencies five lengths of 2-1/2" ID 15,000 psi Coflexip line. Each piece is approximately 410' (125 m) in length. Connections are either 1502 WECO female or CIW No.6 hub. The contact for this company is Mr. Tim Woodrow in Aberdeen.

5.2.13.2 Swivel Joints. Swivel joints are movable steel connections mounted on the ends of hard steel line (pipe) that permit sections of the pipe to bend and twist into any desirable configuration. These generally fit into low- and high-pressure ranges with various sizes available.

Most of the manufacturers have 2" high pressure flexible swivel joints (up to 15,000 psi). Few have larger diameter high pressure swivel joints. Stocks of these items are fluid and depend largely on overall oilfield activity. All of the major stimulation and service companies use these connections on their lines, so shortages of certain sizes and ratings of swivel joints can and do occur.

FMC Corporation - FMC manufactures "Chiksan" swivel joints in sizes from 1" through 8" with pressure ratings to 15,000 psi in the smaller sizes. The 6" and 8" sizes are only available in a 4000 psi maximum pressure rating. There are adequate supplies of "Chiksans" up to the 4", 10,000 psi, but 4", 15,000 psi swivel joints and anything in the 6" or 8" sizes must be fabricated which requires 16-20 weeks for delivery.

Shell did order some of these larger size "Chiksans" for use in the North Sea and they may have some surplus supplies still available (Note: these have API Schedule 160 weld-connections). "Chiksans" are available through all major supply stores worldwide.

5.2.14 Hot Tapping/Freezing. Occasionally pressure will be trapped in a drill string or pipe. Common problems are (1) removal of the kelly under pressure to install a valve or additional drill pipe, (2) below a fish when pulling a joint of pipe with possible pressure trapped below the tools or (3) removal or repair of malfunctioning equipment under pressure, i.e., frozen valves downstream of pressure.

Handling of the drill string or lines under these conditions becomes dangerous and must be approached with caution. The processes often used to solve these problems are the valve drilling and hot tap process and the freeze process.

5.2.14.1 Hot Tapping. When equipment such as valves or sections of the drill string has pressure trapped beneath or within, some means must be used to bleed the pressure before safe handling techniques can be used. If conventional equipment cannot be made operable under these conditions, special tools must be employed.

The valve drilling and hot tap process is designed to meet this requirement by drilling entry ports into the pressured equipment. The term 'hot tap' means entry under pressure.

The equipment often used in this special service is shown in Figure 5.2.14.1. The tools consist of:

- Bit drive shaft adaptable to hand operations or power tools
- Ratchet assembly to apply pressure to the bit by transmitting a downward pull on the drive shaft
- Rod clamp acting as a pressure point on the rod shaft
- Stuffing box to pack off the drive shaft
- Bleed-off valve through which pressure can be equalized, bled off, or for circulation
- Quick union for ease in make-up and disassembly
- Full-opening plug valve that can be used to close upon removal of bit and drive shaft
- Saddle clamp to adapt to concentric objects

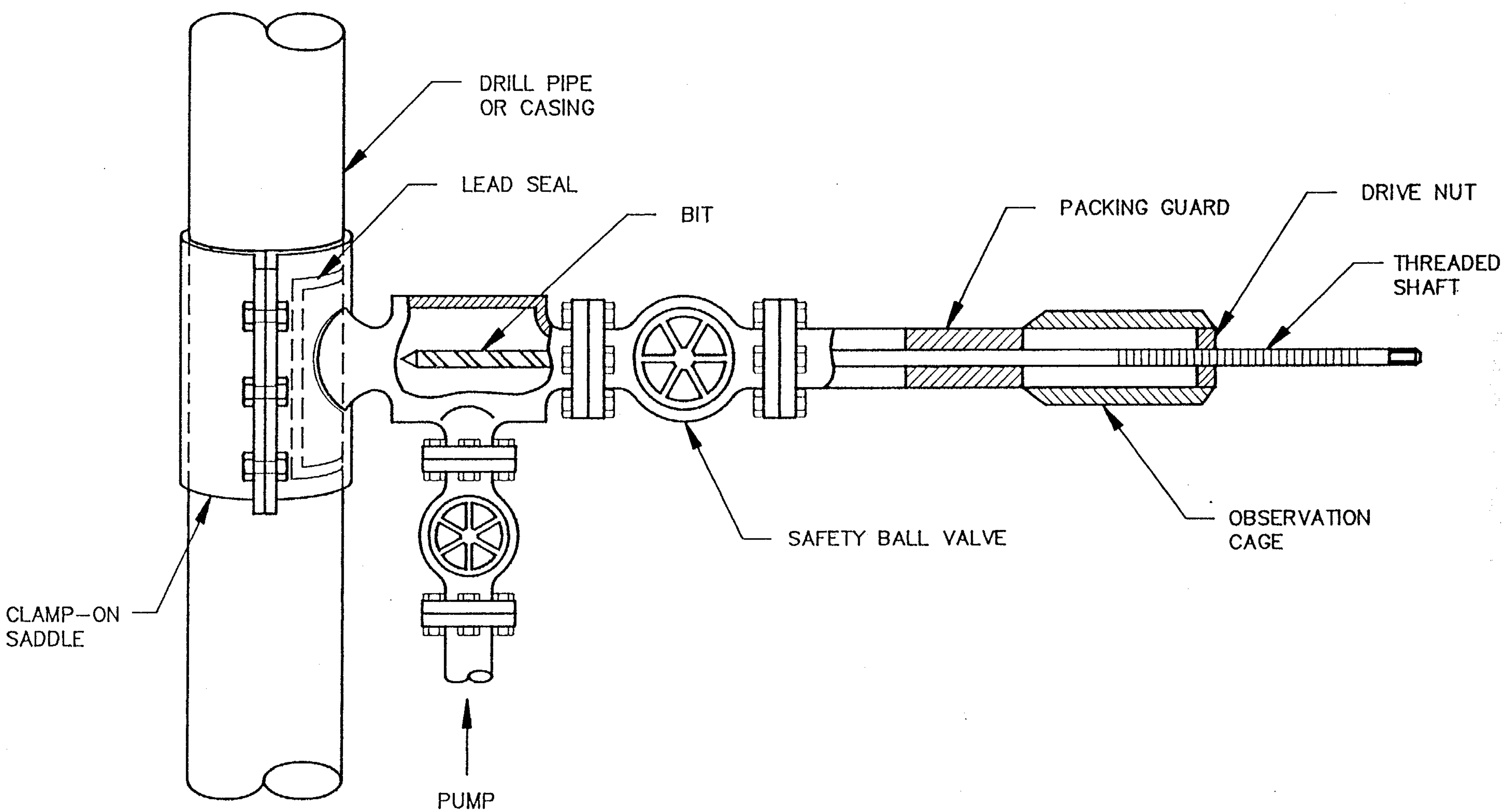


Figure 5.2.14.1

Hot Tapping Equipment

Various sizes of saddle clamps can be used to make a single hot tap tool universal for many situations.

Blowout Tools, Inc. - Blowout Tools has several hot tap units at the Houston and Louisiana sites. One of the units is DnV certified to 15,000 psi. Blowout Tools rents the tools to pressure specialists but is not believed to provide their own service men to run the tools.

Cudd Pressure Control, Inc. - Cudd has hot tap units for sweet and H_2S service in the 5,000 to 15,000 psi ranges. The units are located at Cudd's various stock points in the US. They do not have any units outside the continental US.

5.2.14.2 Freezing. In some cases, simple entry into the pressured equipment does not offer the complete solution. An example is the case of drill pipe under extreme kick pressures, since it would be impossible to bleed off the pressures through the hot tapping process. Another example is a leaking master valve on a tree.

The freeze process was developed years ago to offer additional solutions to some of these problems. The process has been used successfully in such cases as:

- The need to remove the kelly to install a valve
- Below a pressured fish
- Below blowout preventers or master valves which have failed partially or have been damaged

The process used on most drilling applications involves dry ice in a sufficient quantity to freeze a solid plug or a bridge of ice inside the casing or drillpipe. This allows for the safe removal of equipment above the plug.

The procedure involves wrapping the pipe with a container of dry ice and allowing the fluid within the pipe to freeze. Usually, one hour is allowed for each inch of pipe diameter to be frozen. A test sample is often obtained and frozen in a pup joint on the rig floor to determine the proper setting time.

The dry ice causes the fluid in the pipe to reach approximately -142°F, which will develop a plug that can hold as much as 15,000 psi differential pressure.

Some of the primary requirements and recommendations for the successful execution of this process are that the pipe must contain a static water-based fluid, the pipe should not be frozen in tension unless necessary, and plastic coated pipe should not be frozen. Specialists in the field should be consulted before attempting the process.

During recent times, nitrogen has been used to freeze various types of equipment. The process had its beginning with the freezing of large diameter pipe lines, some of which were subsea. The line is wrapped with a jacket or coil through which the liquid nitrogen is passed. The process has become very technical with the addition of strain gauges to evaluate the progress of the freezing.

Freeze Technology International, Inc. - Freeze Tech markets their Ice-O-Lator System which involves the use of liquid nitrogen to freeze the contents of the pipe with a relatively short ice plug. This is accomplished by bolting a sleeve to the outside of the pipe, then filling the sleeve with liquid nitrogen. Once the plug is in place, pressure on one side of the plug can be contained for several days, if necessary.

The use of the sleeve and the liquid nitrogen is widely copied, but it is a patented process of Freeze Technology International, Inc. Their process is used extensively for industrial applications in the US and UK, but they have also used the process to freeze wellheads primarily in the Middle East.

They have sleeves available for 1/2" to 42" OD pipe. Liquid nitrogen is purchased from a local source. They have the tools and technical backup necessary for deep water and underwater freezing as well. Freeze Tech does not do hot tapping or valve drillout, only freezing.

Service personnel can be dispatched from Houston within six hours and can arrive on site within 24 hours for most worldwide locations. Technical support is available through their Houston office. The contact is Mr. George Howard.

Hydraulic Well Control, Inc. - This Houma, Louisiana contractor provides snubbing services, but also performs freezing, hot tapping and valve drill out services. Freezing is done by use of dry ice.

HWC has a Norwegian office in addition to their Houma yard, but if services are needed elsewhere in the world, they can dispatch personnel out of Houma. Coordination is through Mr. Larry Skeans.

Nitroboost Ltd. - The company advertisement states "Nitroboost is an advanced pipe freezing process...The range of pipe materials and fluids that can be frozen is almost as wide as the products that can be transported by the pipe. This allows the pipeline contractor or the operator an additional option for isolating the system with all the benefits of reduced downtime, saving of valuable product, and potential line recommissioning under live conditions."

Nitroboost is oriented towards pipeline freezing. However, they have applications in all pressure control problems. The company has the ability to measure the success of the freeze job via strain gauges. Also, they have approached the job scientifically as opposed to trial and error to evaluate the effectiveness of the job.

Miscellaneous Sources - Most snubbing companies also perform their own hot tapping and freezing. These include Otis and Cudd Pressure Control. Also, blowout and firefighting specialists perform their own freezing and hot tapping work since these are usually specialty applications.

5.2.15 Pumps. Pumps are used on blowout jobs to inject kill fluids, spray water on the fire and to transfer water to the primary fire pumps.

5.2.15.1 Kill Pumps. This category generally involves high rate, high volume pumps necessary to inject sizable volumes of kill fluids into relief wells to stop the uncontrolled flow of oil and/or gas from blowouts. These can be individual units, skid-mounted for transportation as shown in Figure 5.2.15.1, or those that are vessel-mounted (stimulation boats or barges).

Halliburton Services - Halliburton's *Skandi Fjord*, operating in the North Sea, can be outfitted to pump 140-200 bpm. A procedure allows the high pump volume without adding installing additional pumps by opening 8" ID manifolds between the fourteen HT 400 pumps on this ship and the high pressure intensifiers. This approach was used on Oxy's Piper Alpha blowout.

The *Skandi Fjord* has been used on several well control situations in recent years. It was used on the Saga 2/4-14 well and was planned for the Piper Alpha job. The vessel's manager, Glenn Lewis, has significant experience organizing kill pumping jobs on various blowouts worldwide. A photograph of this ship is shown as Figure 5.2.15.2.

The "Skandi" is a 288 ft x 60.5 ft vessel based at the Dutch port of Delfzji. It is equipped with 2 Quintaplex and 14 HT400 pumps. Available pump horsepower is 10,400 HHP. The ship also has an 1,800 horsepower nitrogen unit. It is rated at 15,000 psi having 6 intensifiers. The blend rate is 60 BPM.

The ship has 20,000 gal raw acid storage, 60,000 gal liquid nitrogen, 40,000 gal gel concentrate, 70,000 gal methanol and 10,000 liquid concentrate storage. The vessel holds 11 tons of dry additives and 2.1 million lbs of proppant.

"Skandi" has two 400' 4 in. Coflexip treating hoses and two 4" Big Inch manifolds. The hose can be disconnected by remote control in event of an emergency.

Halliburton has several other smaller vessels located throughout the world including the MV222 out of Harvey, Louisiana, USA, the MV220 in the Middle East, MV219 in West Africa and the MV301 out of Malta. These vessels are designed for stimulation purposes, but can be used for firefighting, pollution control or logistical purposes. All are 11,000 to 14,000 psi-rated vessels and all have experienced crews and management aboard.

BJ Services - BJ currently has offshore capability in two areas, the North Sea and in Brazil. The well service ship, *Vestfonn*, based out of Aberdeen has 9,600 available horsepower on six pumps. Combined output is 105 bpm at 15,000 psi.

It has two 5,000 gal batch mixing tanks and six pre-gel tanks for a combined storage capacity of 249,000 gal (5,900 bbls). Two blenders, a BJ 616 and a BJ 617, are installed, one for acidizing and the other for high-sand concentration fracturing. The former can discharge up to 60 bpm, the latter up to 45 bpm. It is equipped with 15,000 psi steel pipe and two 400' 3" ID 15,000 psi Coflexip hoses.

The vessel has dynamic position capabilities and is connected via satellite with telephone, telex and FAX lines. Technical support is supplied from Houston by satellite downlink. The Houston contact for this vessel is Mr. Sheridan Lewis.

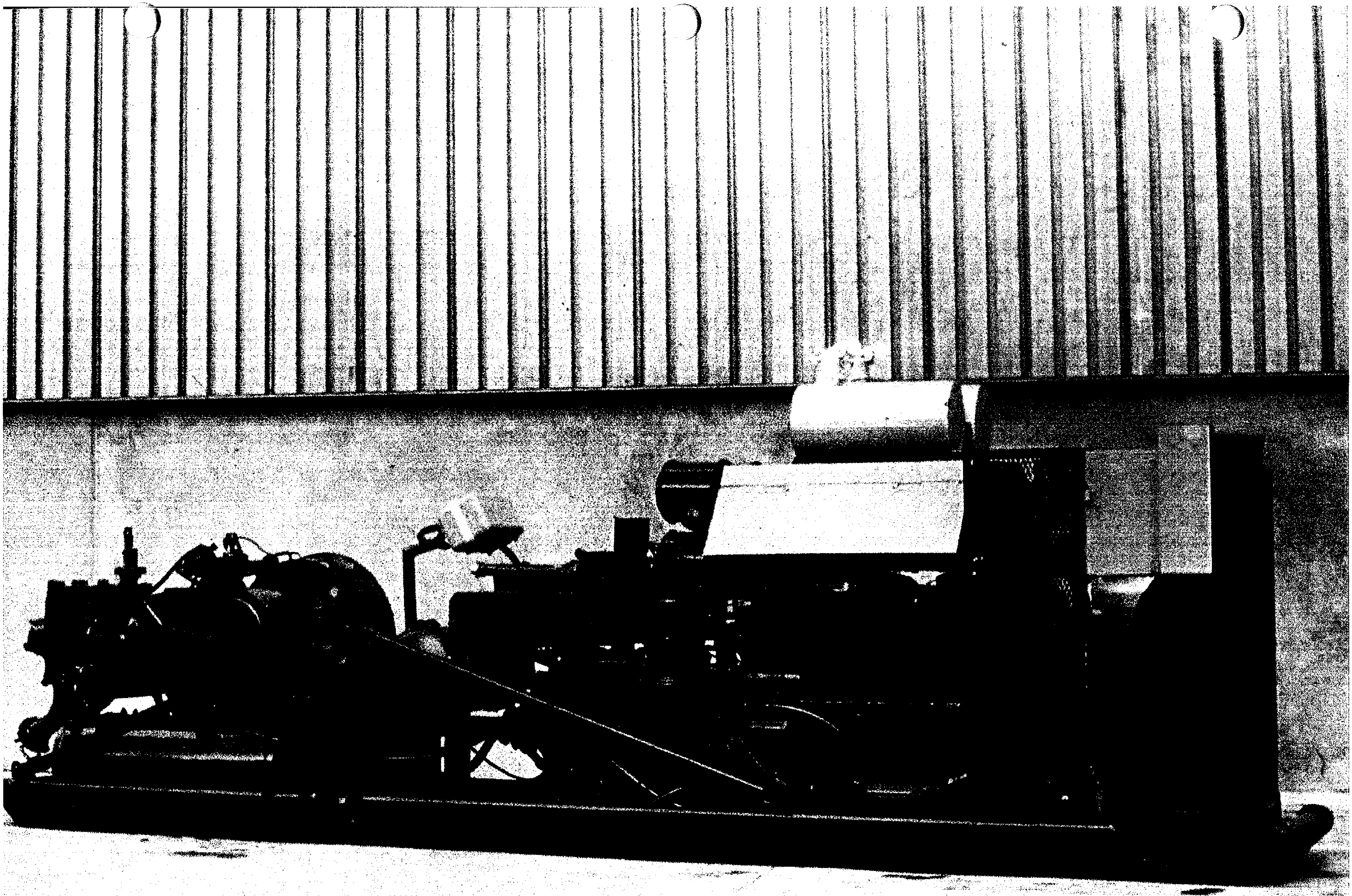


Figure 5.2.15.1

Figure 5.2.15.2

A smaller well service ship is located in Brazil having a total of 3,300 available horsepower driving three 1,100 HP frac pumps. A fourth pump will be added within the next year which will increase the available pump capacity to 4,500 HP. The vessel has a small cementing unit installed which has not been used extensively to date. It has combined storage capacity of 110,000 gal (2,600 bbls) and has 15,000 psi 4" ID Coflexip hose.

The contact in Rio de Janeiro with SEBET (Servicios Brazileiros Especializados en Petroles) is Mr. Gino Dilullu, the Operations and Engineering Manager.

Dowell Schlumberger - Dowell operates the "Big Orange Fleet" in several locations throughout the world.

The 12,000 HP *Big Orange 18* based in Aberdeen is equipped with 350' of 10,000 psi 4" ID hose and 415' of 15,000 psi 3" ID Coflexip pipe. This ship has storage capacity for 4,300 bbls of raw acid and 5,800 bbls of water. It has a blender rate of 75 bpm. *Big Orange 18* also has a nitrogen unit that can store 2.2 MMSCF N_2 and is rated to 15,000 psi.

Big Orange 10 is in Port Gentil, Gabon has 9,000 available HHP with a total of 860' of 3" 10,000 psi Coflexip pipe. This ship has storage capacity for 1,300 bbls of raw acid and 2,200 bbls of water. It has a blender rate of 70 bpm and a nitrogen unit as well.

Big Orange 11 is located in Dubai and has two units with a combined 9,350 HHP at a rated pressure of 15,000 psi. It has storage for 1,000 bbls raw acid and 1,700 bbls of water. It has a blender rate of 60 bpm.

Smaller boats are located in Singapore, Mexico and the US plus three stimulation barges in Lake Maricaibo. Technical support for the Big Orange Fleet comes through their Montrouge, Cedex, France office; Mr. Brian W. E. Darling is the DS contact. They have had some recent experience in responding to blowout situations. These include wells in Venezuela, offshore Congo, Algeria and Brunei.

Other boats in the "Big Orange Fleet" are shown on the following page.

Western Company - The *Western Renaissance* is a 308' stimulation vessel that is currently under construction in Singapore. It will be ready for service in the southern basin of the North Sea area in spring 1992. The vessel will have a total of 16,000 HHP available and will be rated at 15,000 psi. It will be capable of pumping at 100 bpm.

The ship will have storage capacities of 4,300 bbls of acid and 10,600 bbls of fresh water along with proppant, dry additives and liquid additive storage. It will have full dynamic positioning capability and will have fully integrated communications through satellite downlink. When it is finished, it will be the largest stimulation vessel in the North Sea.

5.2.15.2 Fire Pumps. Fire pumps are designed to spray water on a fire. The spray cools the vicinity including firefighters working under the fire. It is not usually intended to extinguish the fire, but occasionally it will put it out. This topic is discussed in more detail in Section 5.2.11.1.

Table 5.2.15.1 Big Orange Fleet

DOWELL STIMULATION VESSELS

	BIG ORANGE											
	1	4	9	10	11	12	14	15	17	18	20	21
LOA (m)	54.34	53.3	50.0	67.7	57.7	57.7	41.5	57.7	60.9	75.1	57.9	66.5
Deadweight (tons)	700	720	-	1100	970	970	-	970	1430	2000	-	750
Inst. power (kW)	5225	5300	5300	7950	4105	4105	1690	4105	5200	9150	-	2300
Accommodation	31	30	24	30	32	32	4	32	30	32	-	26
Stim. power (hhp)	1500	3600	5000	9000	2340	2340	500	3300	4500	7500	1600	1000
No. of hp pumps	2(d)	6(t)	4(t)	6(e)	3(d)	3(d)	2(d)	3(t)	3(e)	6(e)	2(d)	4(d)
Max. pressure (psi)	10000	10000	10000	10000	10000	10000	10000	15000	10000	15000	10000	10000
Max. flow (bbl/min)	75	100	50	100	75	75	25	75	60	100	75	20

d = diesel   t = turbine   e = electric

5.2.15.3 Transfer Pumps. These pumps are designed to move large volumes of fluid with low pressures. Generally, they are used in firefighting to transport water from a pit or tank to the firefighting pumps. Their discharge pressure, which is usually less than 50 psi, "charges" the firefighting pumps. They can also be used to charge kill pumps. This topic is also discussed in Section 5.2.11.2.

5.2.16 Manifolds. Manifolds cover a large range of equipment. The items include components used to fabricate a manifold for a specific purpose, pre-fabricated manifolds, and unique situations such as high pressure risers and flexible piping connected to a riser.

Halliburtons's Big Inch Manifold - This equipment, originally fabricated for stimulation purposes, has ready application to well kill operations. This large ID manifold has no threaded connections, multiple connection points and is equipped with plug valves that can be operated easily under pressure.

There are several sizes available depending on the situation. These are 3" ID 20,000 psi, 4" ID 15,000 psi, 5-3/8" ID 6,000 psi and 7" ID 5,000 psi manifolds. The manifolds are actually in modules with one "low" pressure inlet and two "high" pressure outlets. Each module will handle one truck or two skid-mounted pumps. Depending on need, several of these modules can be connected together. This pump "plant" design is a specialty of the Halliburton Well Control Team headed by Richard Posey from Duncan, Oklahoma, USA.

The manifolds are used both on and offshore. (Figure 5.2.16.1)

Like the Halliburton Big Inch Manifolds, both DS and BJ have manifolds in several sizes and pressure ratings including 3-1/2" ID 20,000 psi and 4" ID 15,000 psi. Dowell has one that goes to 8" ID 10,000 psi. The Big Orange Fleet has some large manifolds exclusively for offshore use.

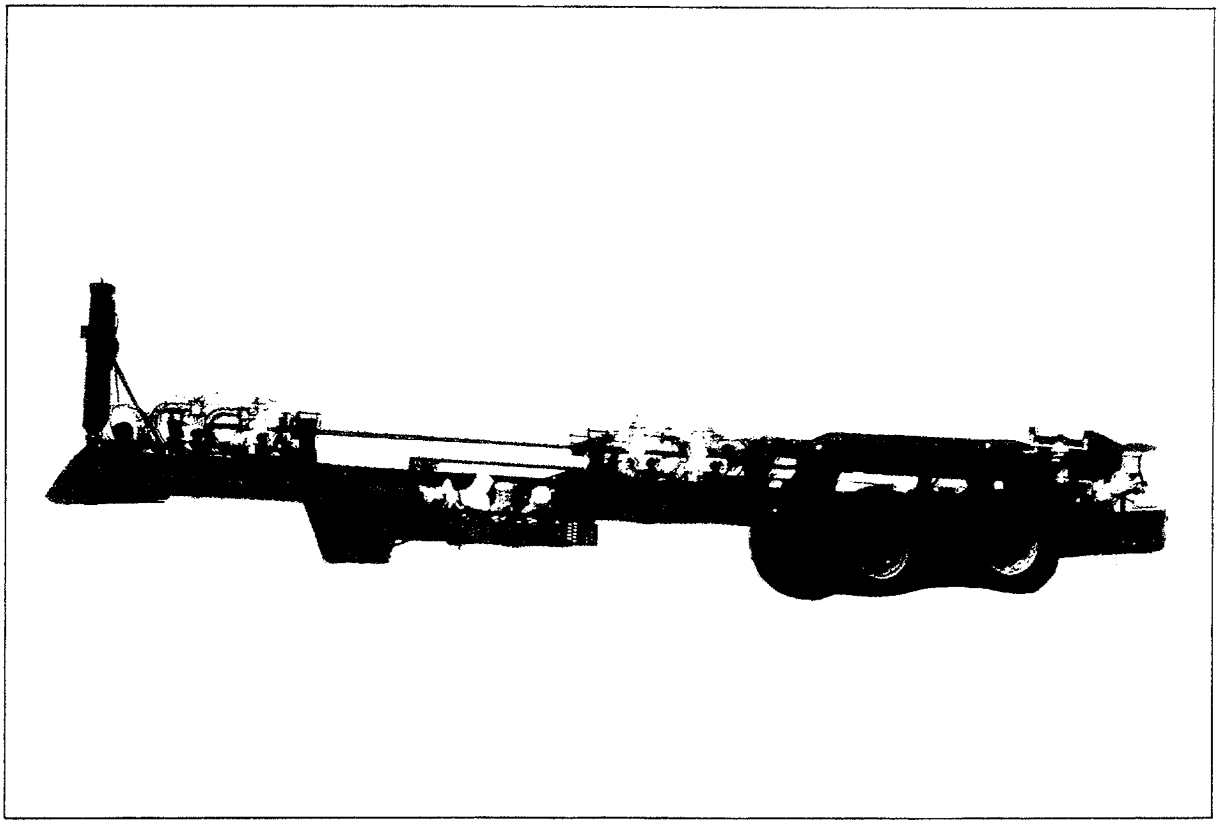
BJ Services'and Dowell Schlumberger's Manifold Trailers - Like the Halliburton Big Inch equipment, these large ID manifolds were originally designed for high rate, high pressure stimulations. They are mounted on 48' trailers equipped with an oilfield 5th wheel for onshore use.

The Dowell unit can be lowered hydraulically to within 1' of the ground where multiple 4" suction hoses and 3" discharge hoses can be easily connected. It, has valves equipped with gear operated handles for easy operation under pressure. A photograph of the Dowell trailer is included as Figure 5.2.16.2.

Blowout Tools, Inc. - BTI is a unique company specializing in providing tools used by blowout specialists and snubbing/coil tubing unit operators.

The company is managed by Pat Campbell who has experience as the operations manager for a major blowout specialist company. Mr. Campbell is highly regarded by most individuals in the field of well control and blowouts.

Figure 5.2.16.1



DOWELL SCHLUMBERGER
HIGH FLOW MANIFOLD TRAILER

Figure 5.2.16.2

The company offers a wide range of equipment in an off-the-shelf fashion. Special fabricating is available, if necessary. The equipment includes the following categories but is not limited to the following list:

- High pressure kill, choke and squeeze manifolds
- Pump-in heads (test/kill trees, 3-1/8", 15,000 psi, H_2S service)
- Chokes
- Snubbing unit expendables (including high pressure rubbers, teflon-faced ram elements, slip rams, etc.)
- Slip ram fabrication for most preventers
- BOP stacks for snubbing and coil tubing units
- Hot tapping units (DnV certified)
- Snubbing unit work windows

The Blowout Tools, Inc. equipment list includes miscellaneous items such as ring gaskets, hammer unions, gauges, brass hammers, etc. The equipment can be made available for H_2S service and to 15,000 psi ratings.

High Pressure Riser System - Vetco Gray UK Ltd offers a high pressure riser typically used for subsea completions. It could have applications relative to well control on subsea wells.

The system is 5-1/2", 10,000 psi-rated. The rental completion riser equipment is designed to interface with customer supplied tubular riser components. In other words, Vetco provides the end fittings and the customer supplies the tubing riser joints. Vetco's equipment includes a surface tree assembly, transition stress joint, emergency disconnect package, lower riser package, and a hydraulic control system. The system meets Department of Energy rules in the UK and NPD guidelines in Norway.

The system could be used in well control for snubbing and coil tubing work. Also, it can be used for pumping into a pressured well. The 5-1/2" ID is expected to have limitations in many well control problems, particularly in relief well kill operations.

The system is typically used to install both tubing hangers and subsea trees. When running the tubing hanger the completion riser is run inside a marine drilling riser. When running a subsea tree it is used in open water. It is also used to provide access to the well tubing bores for wireline tools and coiled tubing during workover operations.

Coflexip Flexible Piping Connected to Stack/Riser - Coflexip offers an option for high volume pumping capability into the annulus with additional kill/choke lines. See Figures 5.2.16.3 and 5.2.16.4.

Special equipment for this option includes the following:

- Subsea gate valves
- Two long 4" Coflexip lines (length depends on water depth)
- Goosenecks at the surface

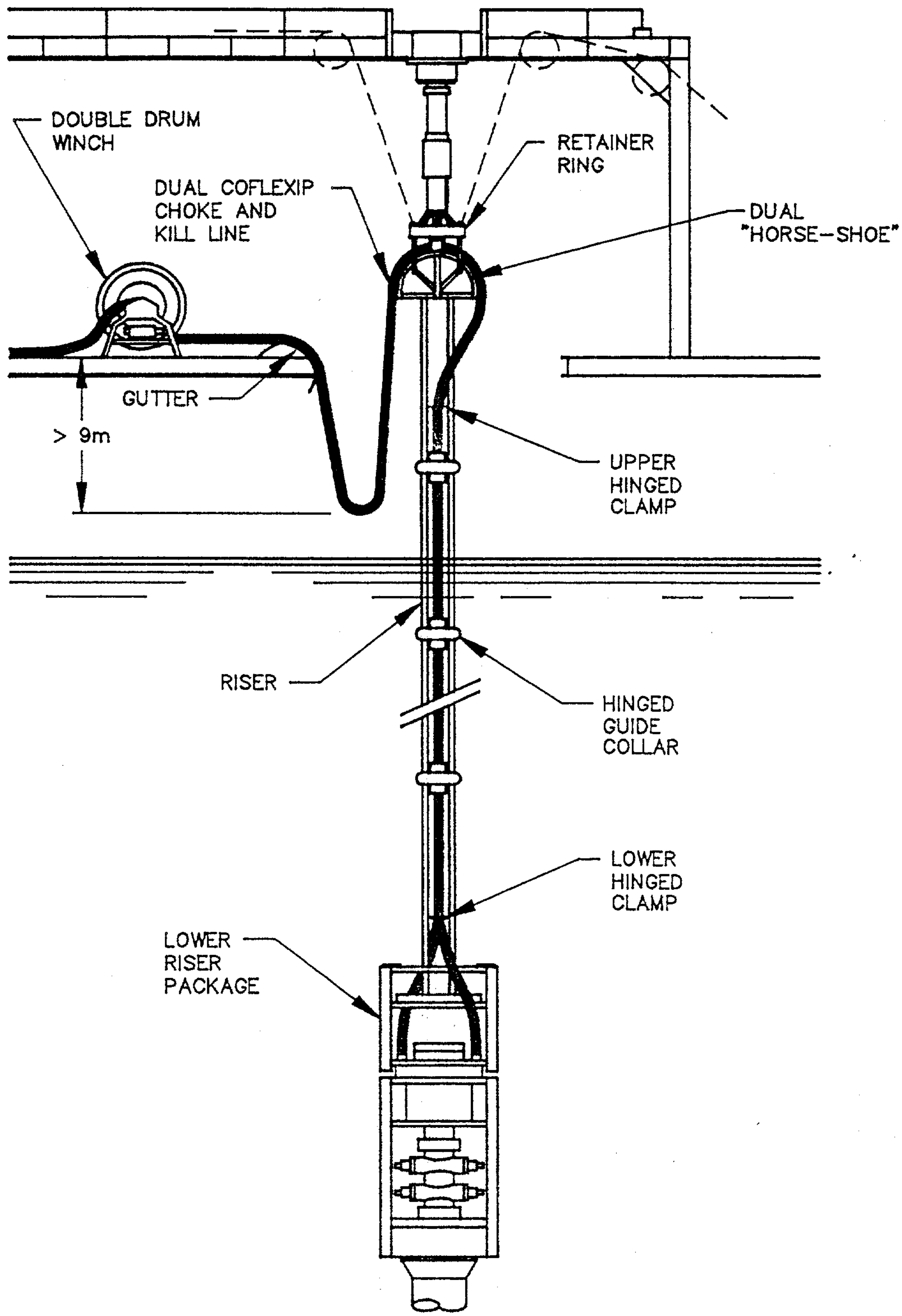
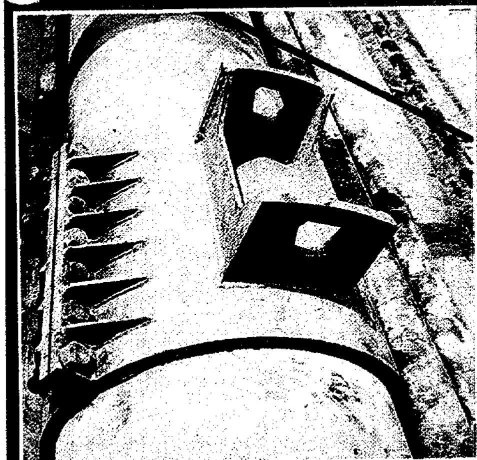


Figure 5.2.16.3

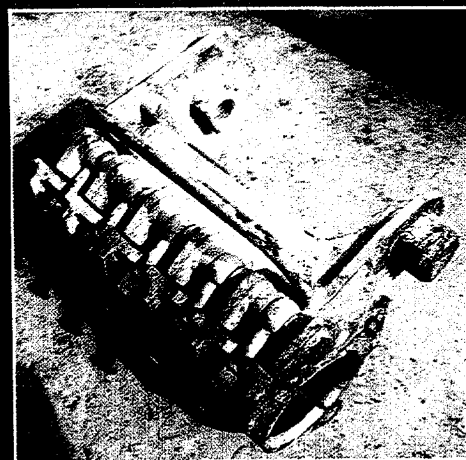
Continuous Flexible Choke and Kill Line System

DEA PROJECT NO. 63
JOINT INDUSTRY PROGRAM for FLOATING VESSEL BLOWOUT CONTROL

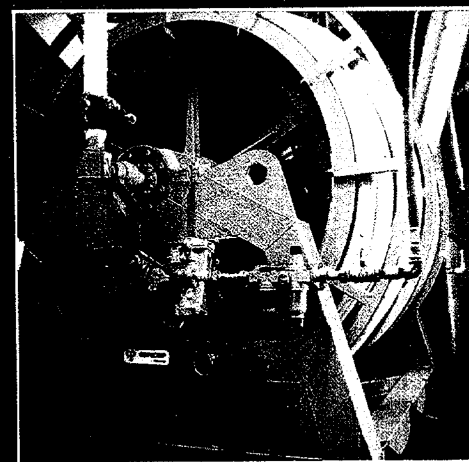
RUNNING PROCEDURE



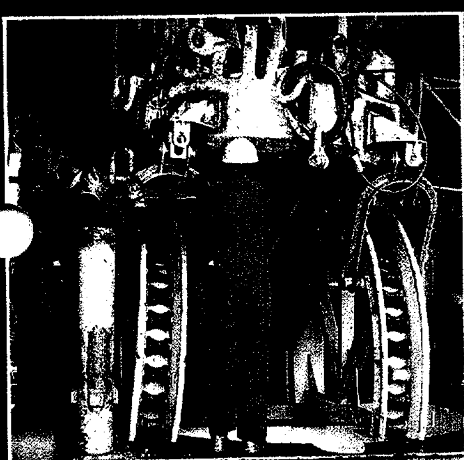
1. *Upper tension clamp support bolted onto the riser.*



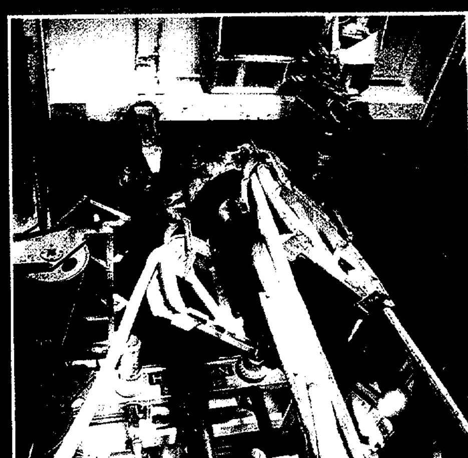
2. *Hinged tension clamp to be hooked into the two slots of its support (see photo 1).*



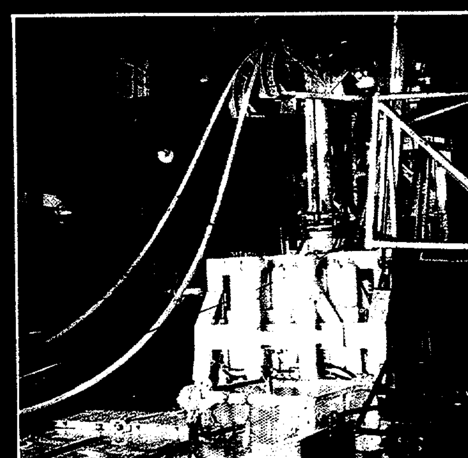
3. *Double-drum winch installed in its corner and connected to choke/kill manifold - ready for pressure test.*



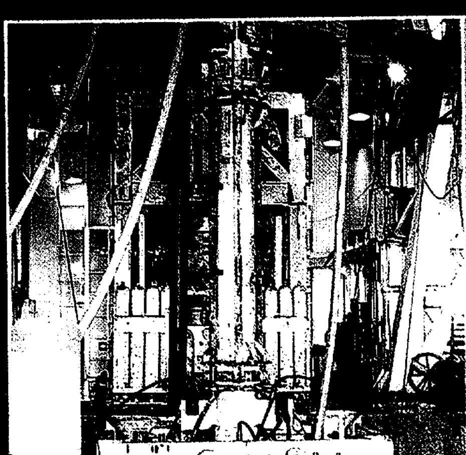
4. *Retainer ring with "horse shoe" rollers being prepared for positioning under the rotary table.*



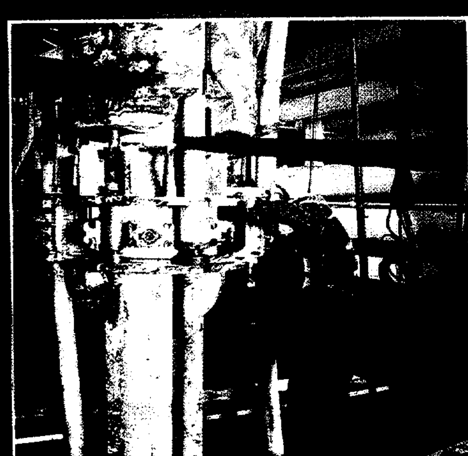
5. *Riser being lowered down through the retainer ring.*



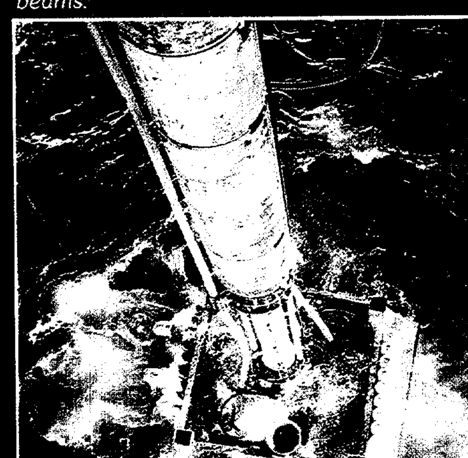
6. *The Coflexip kill/choke lines hanging over the "horse shoe" rollers whilst being connected to the BOP stack resting on the spider beams.*



. *After completion of the pressure test, the spider beams are opened and the stack is lowered.*



8. *Lower hinged clamps being securely tightened around the kill/choke lines, leaving enough slack around the ball joint to allow for a 10° deflection all around the axis.*



9. *Splash Down! Observe the slack in the Coflexip lines below the clamps.*

Figure 5.2.16.4

- Clamps to bind the hoses to the riser
- Hose spools

This equipment is a standard design and is field proven. However, it is not available on an off-the-shelf basis. Lead time availability could be extreme and probably would exceed the allowable requirements for a one well situation.

Handling of the piping would require some planning,but it is considered manageable.

5.2.17 Packers. This category includes companies providing packers that are useful in blowout situations including inflatable packers, stinger packers, large bore kill packers, retrievable bridge plugs, and specialized packers. It does not include production packers or DST tools. The companies shown below provide rental packer service as well as new packer sales.

Baker Service Tools - This company provides Baker packers and servicemen worldwide. Brown Oil Tools and Lynes Inflatable Packers are subsidiaries of this firm.

Brown provides liner hangers, setting tools, tie-back extensions, the Brown open-hole packer (a mechanical-set external casing packer) and both Brown and Baker external liner packers. These tools are sale items, but Baker Services provides servicemen to run the tools for the operator. Lynes is discussed more fully below.

Baker Service Tools is the rental arm of the Baker companies. They have a large number of locations and personnel whose job it is to run Baker packers and other equipment as a contract service for operators. These include all of their packers, bridge plugs, retainers, casing scrapers, packer pickers and junk catchers. They also run safety valves, test valves, plugs and other wireline set/retrieve tools designed to be used inside production tubing. (Figure 5.2.17.1)

Since there are a large number of Baker locations worldwide, inventories of specific rental tools are quite large and vary from time to time. Baker has offices and personnel in Aberdeen, Athens, St. Cloud (France), Singapore, Maricaibo (Venezuela), Mexico, Buenos Aires and Rio de Janeiro. Coordination of tools and services is available through their Houston Office.

Lynes (Division of Baker Service Tools) - Lynes has an entire family of inflatable packers and plugs including external casing packers, inflatable bridge plugs, millable cement retainers, permanent bridge plugs and small diameter (1.9 inches and up) production/injection packers (PIPs). (Figure 5.2.17.2)

Recent developments include the use of slim-bore inflatable packers to be run through tubing or drillpipe on coil tubing and set in casing below the bottom of the larger tubing/drillpipe to control crossflow. Slim-bore inflatable packers can also be used to sting into open-ended drillpipe or tubing to provide a quick shutoff.

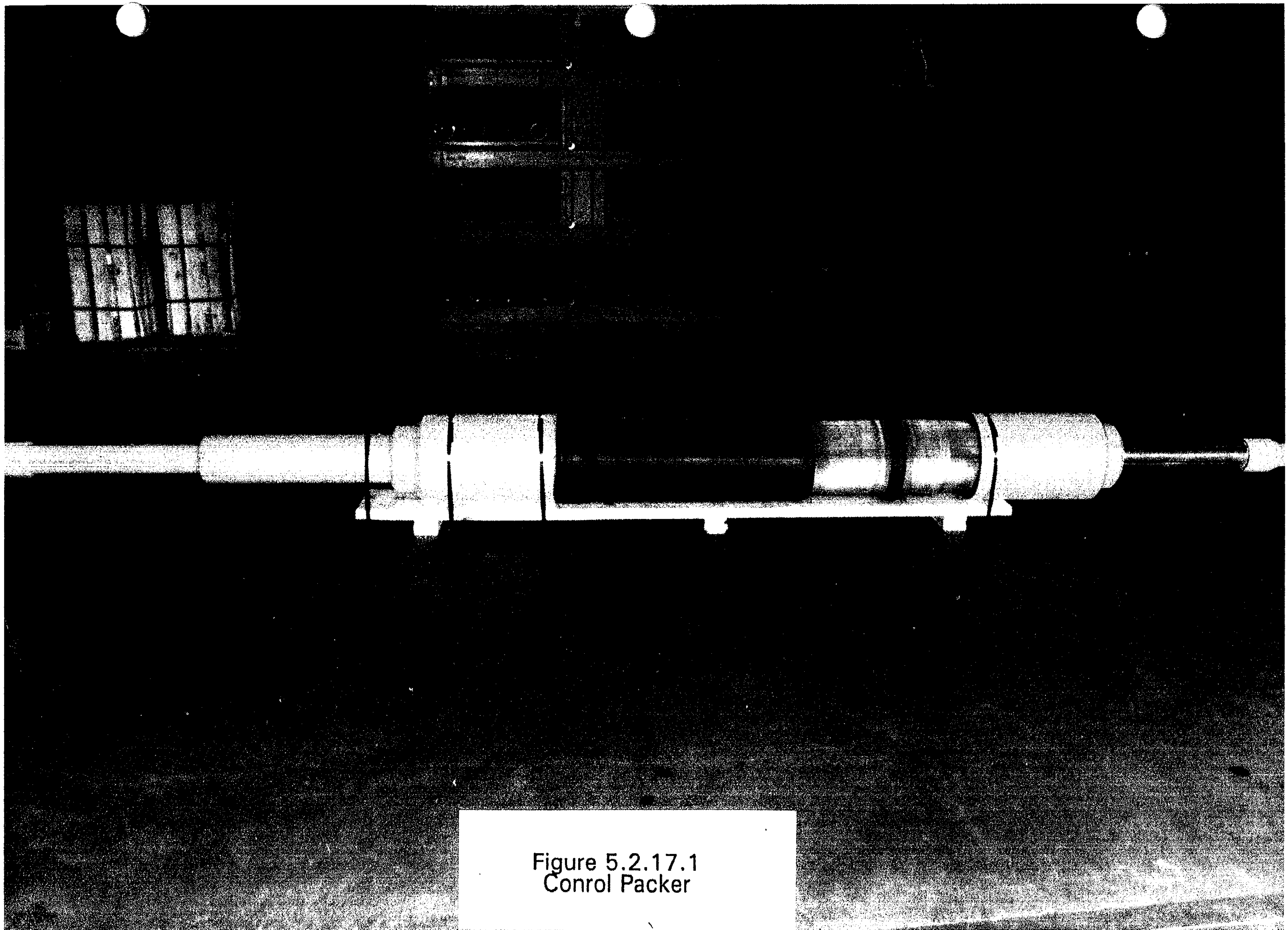


Figure 5.2.17.1
Conrol Packer

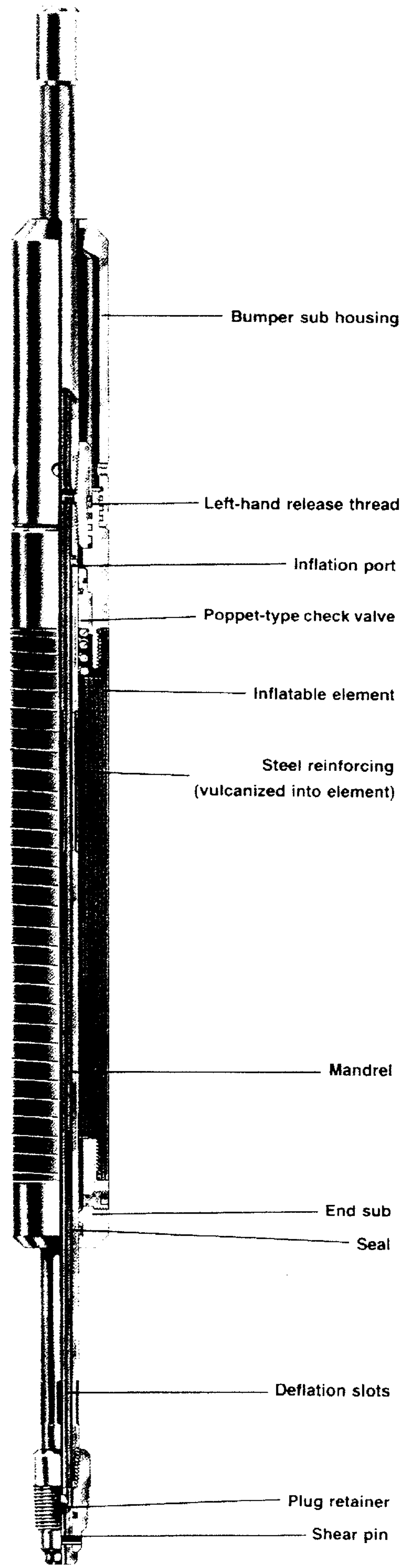


Figure 5.2.17.2
Lynes "PIP" Packer

Their inflatable-retrievable bridge plugs and packers can be used with a variety of specialized downhole tools, such as check valves, shut-in valves, on/off tools, etc. to provide a wide range of capabilities for specific needs.

Lynes has demonstrated the ability to design, fabricate and test special tools in very short order. A 6-5/8" inflatable packer with a 10,000 psi differential pressure rating and a 300°F maximum temperature resistance was fabricated, tested and delivered in two weeks to Saga's 2/4-14 blowout.

Inventories of Lynes packers are fluid. Delivery of any available Lynes packer can be coordinated through their Houston representative, Mr. Dodd Miller. Technical support, including rush fabrication, is available through their Houston office. There are many locations and service representatives for Baker Service Tools available worldwide, so local experience is available. For special problems, coordination through Mr. Miller is preferred.

TAM International - This Houston-based company is a manufacturer of inflatable downhole packers and other specialty tools such as on-off tools, downhole shut-in valves, circulating subs and inflatable straddle-packer assemblies.

TAM packers are inflated by drillpipe pressure after the tool is set and actuated. Packer elements (balloons) are equipped with bypass/safety valves that prevent over-inflating and rupturing the elements. The tools can be deflated and re-set, assuming that the elements have not been damaged by contact with the hole or casing in a previous inflation.

Packers in uninflated sizes range from 1-11/16" to 11". These will inflate from 3" to 16-1/2", respectively. The approximate maximum differential pressure rating decreases from 6,000 to 1,000 psi depending on the diameter to which the element is inflated.

For example, if an 8-1/4" OD packer is inflated to 9-1/4" it retains a 5,000 psi maximum differential pressure "rating". If, however, the same packer is inflated to 12" the maximum differential pressure "rating" drops to approximately 2,400 psi.

Recently, as a special order item, TAM ran a 14" packer through 16" casing and set it in a 60" open hole. This was a low differential pressure application (50 psi). Special tools can be ordered, but 6-8 week lead time is required.

TAM has offices in Houston, Calgary and Aberdeen with agents in a number of other areas worldwide. In the event of an emergency, coordination and technical support would come from their Houston, Texas, USA office through their Vice President of Engineering, Doc Stokley.

5.2.18 Perforating. Perforating between a relief well and a blowout well demands more from a perforating system than conventional equipment. The shots may be required to penetrate one casing string in the relief well, across several inches of cement and formation, through additional cement around the blowout well and then through the casing string(s) in the blowout well. Few systems are designed for this specific purpose.

Many companies offer large guns. Most are tubing conveyed guns. They are not designed however, to meet the kill requirements specified above. They may function effectively under appropriate conditions.

Vann Perforating Gun - Intersects between a relief well and blowout well may require that a communications path be established between casing strings in the wells. This situation is generally applicable when the relief well intersects the blowout well above its last casing seat.

Vann has developed a large tubing conveyed gun for perforating in this situation. It is used almost exclusively for blowout wells.

The perforating can be from the open hole of the relief well into the casing of the blowout well. Also, it can be through a cased relief well into the casing on the blowout well.

Development of the 300 gm charge used in the gun was a joint effort by Vann Systems and Jet Research Center. A test assembly was developed to determine the maximum separation of casings where full penetration of the target casing could be achieved. The "maximum" distance was determined to be at a separation of 17" (0.43 m). Reliable full penetration of the target casing was considered to be at 14" (0.36 m). Further, it was decided as a result of the testing that in order to allow for variations in compressive strength and other factors, that in actual use, a separation of 12" (0.30 m) should be used. (Figure 5.2.18.1)

Most of the charges may be phased with shots in three rows, a center row, and a row spaced 5 degrees on either side of the center row. An orienting sub is usually required to position the gun.

This system has been used successfully on various applications in the Gulf of Mexico, offshore Louisiana and in Venezuela.

The contacts for this highly specialized perforating system are Mr. Flint George, Special Projects Manager (713-496-8285) and Mr. Ed Colle (713-496-8268) both in Houston, Texas, USA.

5.2.19 Ranging Tools. Ranging tools are used to determine the distance and direction from a relief well to a blowout well. The blowout well must have steel tubulars of some type for the ranging tools to function. The maximum detection range under ideal conditions is reported to be 200 ft.

Magrange, Inc. - Magrange II is offered by Tensor Corporation of Austin, Texas. The Magrange tool was the first ranging tool to be able to provide distance and direction from a relief well to a blowout well. The Magrange tool has been used on more blowout situations than any other system. (Figure 5.2.19.1)

The tool originally used the passive technique of evaluating remnant magnetism in the tubulars in the blowout well. Tensor has recently announced it has an active tool as well as its passive device. Maximum range under ideal conditions for the passive tool is approximately 75 ft while its active tool should read to 200 ft. Again, operational factors may lower the ideal detection range.

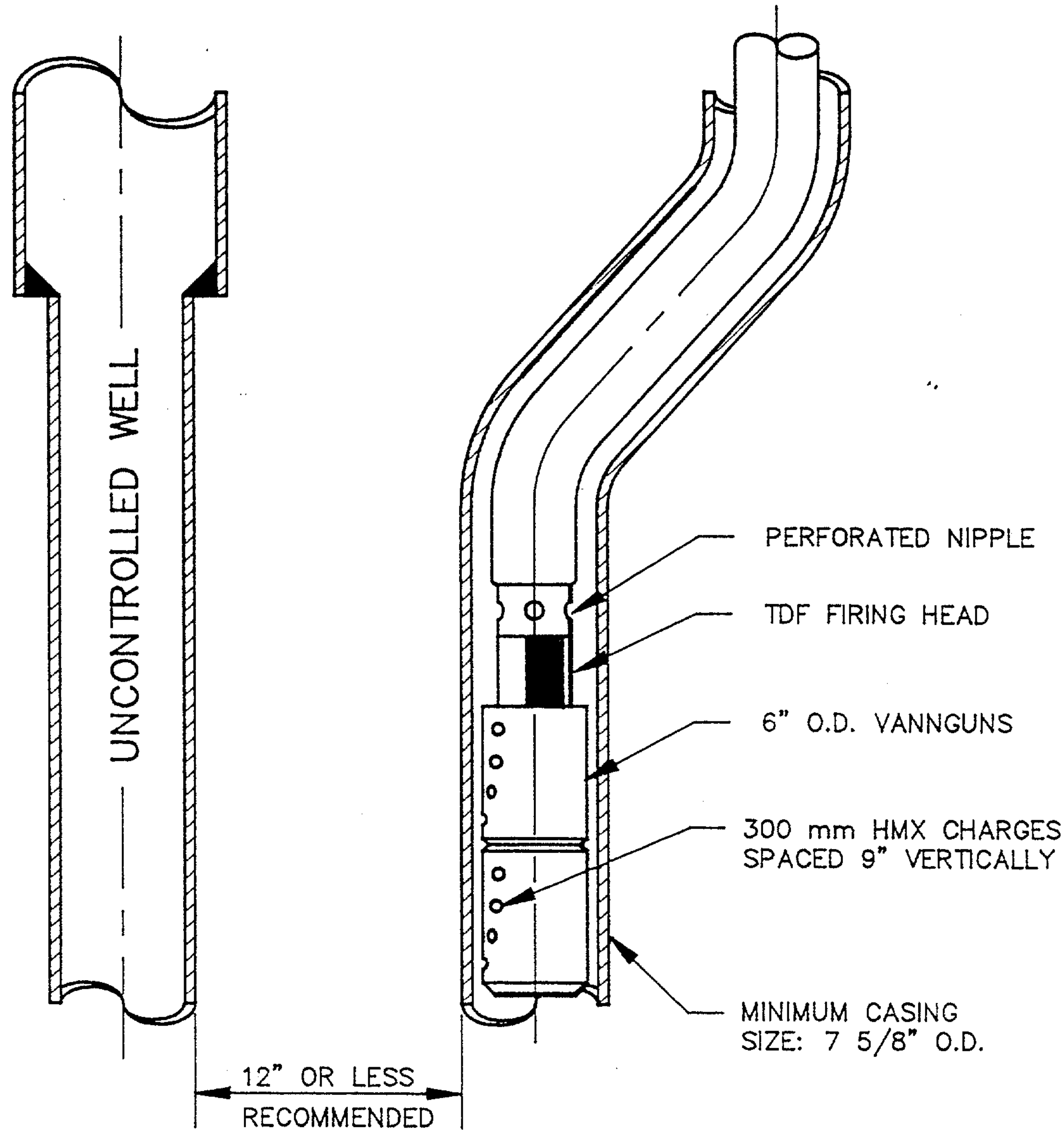


Figure 5.2.18.1

Vanngun for
Perforating Blowout Casing

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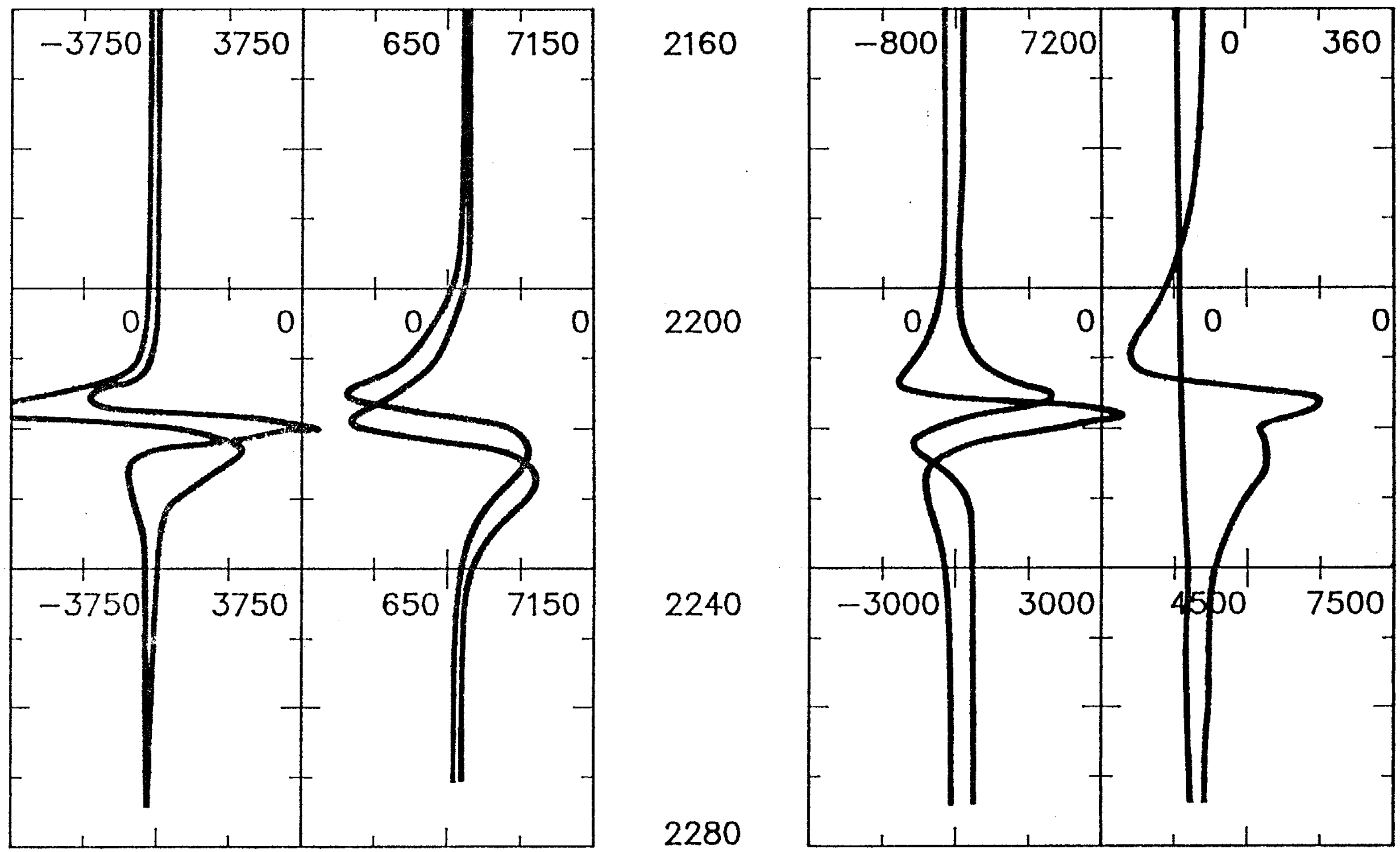

Figure 5.2.19.1

Magrange Plot

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Mr. Bob Waters provides direct supervision on most jobs. He was one of the company's founders and has a broad range of experience that can be made available to the client company.

Magrange has at least two complete sets of tools available. It has been indicated by the company that it can field several teams of experienced supervisors.

Vector Magnetics - Vector Magnetics offers a magnetic ranging tool to determine distance and direction from a relief well to a blowout well. The principal requirement for operation of the service is that the blowout well has some metal in it, i.e., casing or drill pipe.

According to the manufacturer, the maximum detection range is 200 ft (61 m) under "ideal" conditions. Several factors detract from this ideal condition. As a result it is recommended to speak directly to the manufacturer to discuss applications under specific conditions.

Vector has a highly regarded active tool called Wellspot but reportedly also has the capability to do passive detection, i.e., for monopoles. Further, they indicate that they have tools that can be used for a high angle approach to the blowout well.

The company indicates that they can field two teams if necessary. The leaders are Dr. Arthur Kuckes and Dr. Bruce Thompson. Both are very experienced and were involved with the development of the tool. They have 3 complete equipment sets including backups for all equipment.

ULSEL - ULSEL, ultra-long-spaced-electric-log, is offered by Schlumberger. Its principal sites for ULSEL interpretation are New Orleans, Louisiana, USA and Paris, France.

The ULSEL logging system was designed for detecting and mapping the profile of resistive anomalies such as salt domes in the vicinity of the wellbore. In the case of relief well drilling, the casing or drill pipe tubulars in the blowout well serve as the anomalies to current flow. The tool uses ultra-long-spacing-normal devices to obtain deep-investigation readings which are influenced by the anomaly.

The ULSEL tool has several weaknesses relative to relief well drilling. It determines distance only, to the exclusion of direction. It can be used only for direction finding if several sidetracks are made and a triangulation principle is applied. Also, the data must be interpreted in New Orleans or Paris and requires several days of processing before results can be given.

It is possible that the tool may have applications under situations where the ranging capability of magnetic ranging tools are exceeded. Schlumberger should be consulted on a case-specific basis.

5.2.20 ROVs (Remotely Operated Vehicles). Remotely operated vehicles are used occasionally by blowout specialists for underwater work. Typically, the units are used for inspection services. (Figure 5.2.20.1)

ROVs can have specialized functions and combinations of jobs can be performed underwater by these vessels. Most are equipped with camera's (single or binocular color video

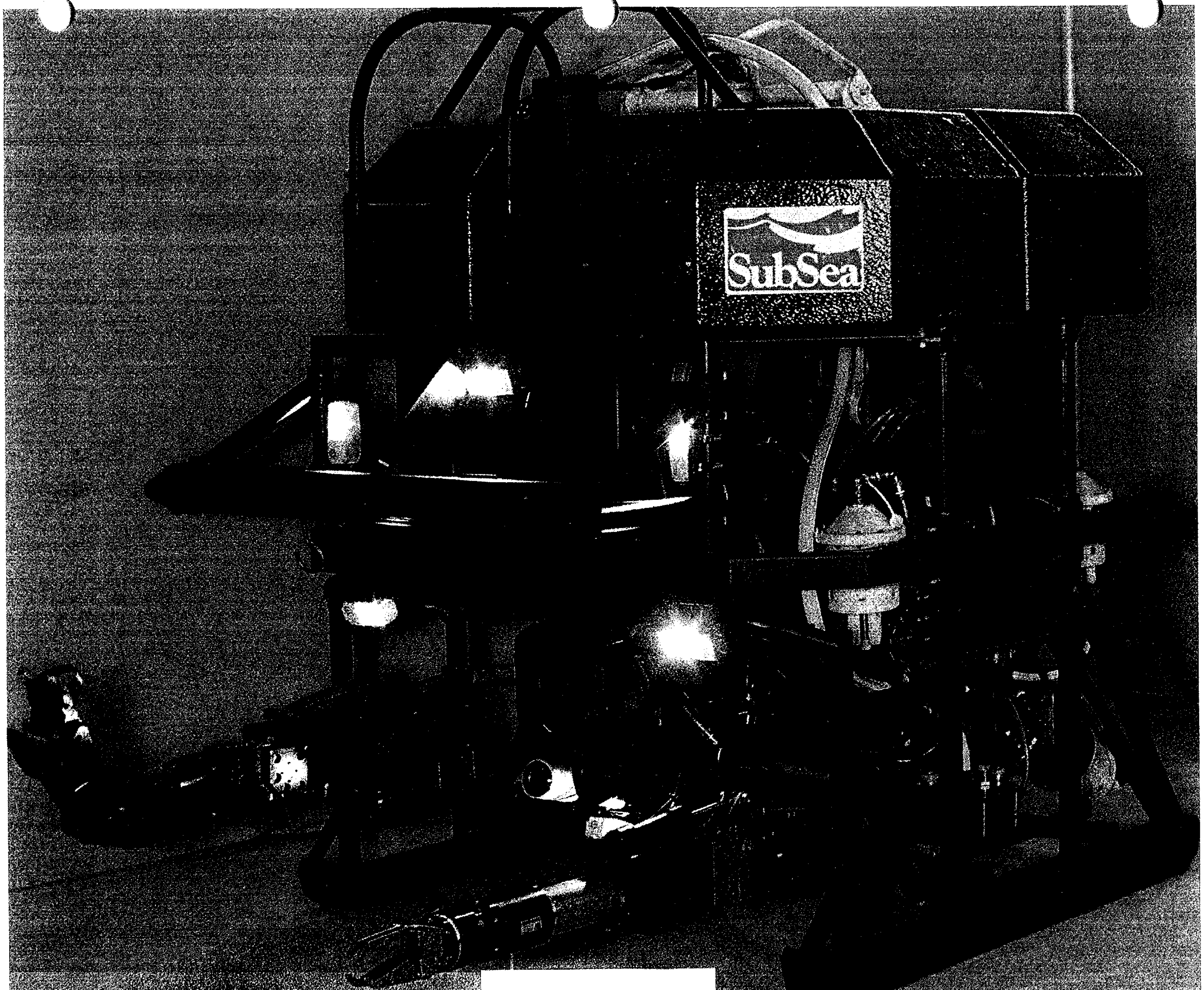

Figure 5.2.20.1

and 35 mm still). Low-light imagery enhancement is possible using specialized "fast" films and strobe lights. ROVs can also be equipped with a variety of accessories such as two- and three-function manipulator arms, laser ranging devices, side-scan sonar, samplers or probes and a variety of other devices.

ROVs are selected on the basis of the desired task to be performed and the availability of units. These can run off of platforms, drilling rigs and MSVs. Occasionally weather and current conditions prohibit running ROVs.

Several contractors supplying ROVs for the industry are Oceaneering (Houston, Texas), Deep Ocean Engineering (Leandra, California, USA), SubSea Offshore Ltd. (Aberdeen, Scotland, UK and New Orleans, Louisiana, USA), and Britsurvey (Great Yarmouth, Norfolk, England, UK).

Several DEA projects such as DEA-63, Joint Industry Program for Floating Vessel Blowout Control have investigated techniques for using ROVs in a broader range of services for blowout control.

5.2.21 Snubbing Services. Stripping and snubbing is the process in which the drill string is moved within the well under pressure to achieve some specific purpose. The general case occurs when the pipe is forced into the well to kill an induced kick, while some instances will demand that the pipe be pulled from the hole to perform some operation.

Mechanical Snubbers - This type of equipment utilizes the rig system to force the pipe into or out of the hole. (Figure 5.2.21.1) The snubbing equipment consists of a set of traveling snubbers to force pipe movement under well pressure and a set of stationary snubbers to prevent pipe movement when the traveling snubbers are released.

Hydraulic Snubbers - The hydraulic snubbing unit was developed for application in areas where snubbing was necessary for well control but when a drilling rig was not over the well. The hydraulic unit attains the same end result as the mechanical snubber but is self-contained and therefore does not require any rig assistance. (Figure 5.2.21.2)

Cudd Pressure Control - Cudd has a total of 10 hydraulic snubbing units and 14 rig assist snubbing units in their fleet. They do not have any stationed outside the US available for contract at this time.

The units can be disassembled easily and are air transportable to any location worldwide. This requires an estimated one week, but it is possible that they could be on location more rapidly in the event of an emergency. Cudd does provide trained, experienced personnel to operate these units.

The company has 150,000 to 600,000 lb-rated hydraulic units (pull and push). Also, they offer 225,000 to 450,000 lb conventional units. Pressure ratings range from 5,000 to 15,000 psi.

Cudd complements its snubbing services by offering blowout control services. See "Firefighters and Blowout Specialists".

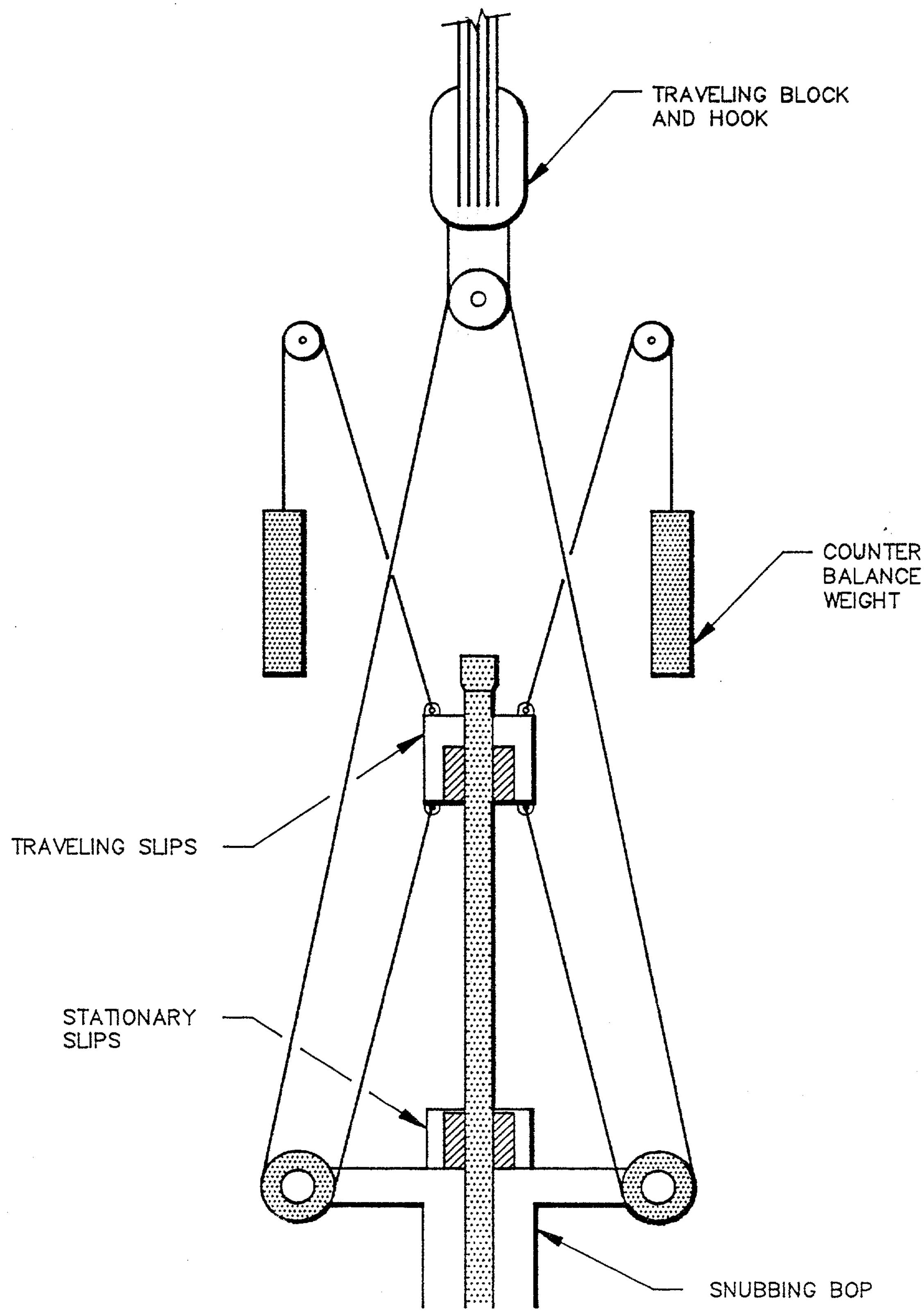

Figure 5.2.21.1

Typical Mechanical Snubbing Unit

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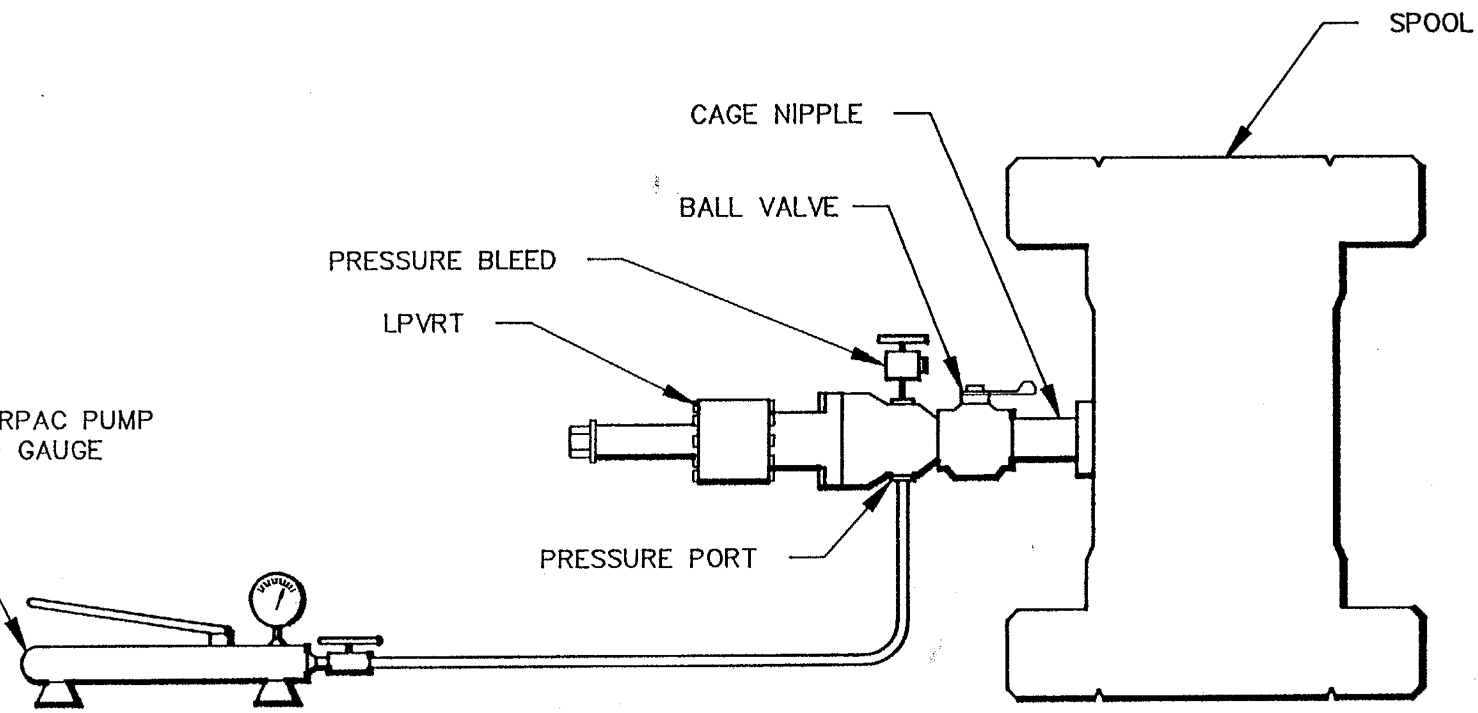


Figure 5.2.27.1

Cameron Low Profile Valve Removal Tool

Hydraulic Well Control, Inc. - HWC is based in Houma, Louisiana, USA and has one yard and office in Stavanger, Norway with a sales office in Houston, Texas, USA. They can perform snubbing operations anywhere in the world with equipment and personnel dispatched out of Houma. They can mobilize in four hours depending on the type of job and its location. They retain one crew on standby at all times.

In Houma, they have 18 snubbing units including two long-stroke units and one helicopter transportable lightweight unit (maximum capacity, 120,000 lb).

HWC has an inventory of 1" and 1-1/4" Hydril "CS" tubing plus 4-1/16" 15,000 psi BOPs and all other equipment necessary to do through-tubing snubbing. If larger BOPs or tubing is needed for other snubbing operations, the operator must provide this equipment, although HWC can coordinate deliveries.

In Stavanger, HWC maintains a 340,000 lb-rated unit and 7-1/16" 10,000 psi BOP equipment for use in the North Sea. They have a total of 40 operators that are trained and certified in North Sea operations, company-wide.

In addition to snubbing, they do freezing, hot-tapping, and valve drill-outs.

The Houma contact is Mr. Larry Skeans who can coordinate any activity of the company. Operational support is provided by the owner, Mr. Tommy Parkhill, and by Mr. Gerald Loring.

Mega Petroleum, A/S - Mega Petroleum of Sandnes, Norway offers pressure control services for the North Sea. The company has the only DnV-certified snubbing unit available that meets NPD specifications.

The unit is a "225" which has a pull rating of 225,000 lbs and a snubbing (push) rating of 120,000 lbs. It can handle pipe sizes up to 5-1/2". The unit offers an extensive Cameron BOP stack with an exceptional choke manifold capability.

Management personnel for Mega are experienced as snubbing supervisors and have an excellent knowledge of well problems that can be solved with a snubbing unit. The key principal is Kirby Daughdrill who has 20 years experience as a drilling manager for a North Sea operator and also with a drilling contractor.

The company also offers hot tap services with a DnV-certified unit.

Otis Engineering - This Halliburton Company has offices in many locations in the world. Its headquarters is in Dallas.

Otis has numerous hydraulic snubbing units available in several sizes in most of their service locations. They have units that range in size from 120,000 to 600,000 lbs (pull/push ratings). Most of these units are used for completion and workover operations, but they can be used in well control applications.

Otis offers a Blowout Recovery Team (BRT) located in Houston. This team is composed of three Otis employees that hold the title of "Consultant" and an executive, Rogers Romero. All are experienced in pressure control, kill and well repair operations. They can perform snubbing, coil tubing and wireline operations as well as hot tapping and freezing.

When they receive a call, the BRT dispatches one or more consultants to the location who coordinate operations with the blowout specialists selected by the oil company. Then, they mobilize Otis equipment and operators from the local region to perform the well control operations under their overall supervisory control.

They are assigned three Otis snubbing units all of which are located in their Friendswood, Texas, USA yard. One of these is a 120,000 lb 4-1/16" ID 10,000 psi high-pressure unit that can be equipped with 20,000 psi rental BOP equipment. The other two are both 11-1/8" large-bore units that are not equipped with BOPs. Otis has opted to rent BOPs from third parties for these large snubbing units depending on circumstances. Both can pull/push to 600,000 lbs.

The contact for the Otis BRT is Mr. Rogers Romero in Houston. In his absence one of the three consultants is available by calling their 24-hour number in Houston, 713-993-0773.

5.2.22 Software, Well Control. Various types of software are available for well control. Most is oriented towards kick control with some available for blowout control techniques.

5.2.22.1 Kick Control Software. Many companies offer kick control software. These include major operators, mud companies, and mud logging companies. The software is available for PC and hand held calculators.

The software does not have complicated requirements. The key requirement is to develop a drill pipe pumping schedule for either the "Wait and Weight" or the " Driller's Method" of kick control.

Casing pressure profiles and maximum allowable casing pressure calculations appear to be attractive but have little merit during kick killing. This may not appear to be the case without a detailed understanding of well control. Most programs should meet the requirements for kick control.

5.2.22.2 Blowout Control Software. Software for blowout control has limited applications except in the case of a blowout. As a result, few sources are available for the software.

Most major operators have access to multi-phase flow programs that can be used in certain blowouts. However, they must be used cautiously to avoid situations in which the principles of blowout control may be confused with other principles used in conventional well production operations.

As an example, multi-phase flow occurs during the killing process for most blowouts. However, simple single phase calculations yield lower friction pressures and result in higher required kill rates. As such, the single phase calculations are the "worst case" approach for determining kill rates and are therefore better in most cases.

Further, most major operators have sophisticated reservoir models that have some applicability to a blowout situation. However, it is the common case that insufficient data exists to run such models. More importantly, time constraints usually prevent their usage during the urgency of a blowout situation. A simple depletion model is more effective because it requires fewer input data items and numerous runs can be made quickly during the early stages of the kill planning process.

Adams Engineering, Inc. - This company offers a PC package (IBM compatible) for blowout control. The package consists of the following programs:

Program	**Description**
DYNKIL	The program calculates requirements for the dynamic kill technique. It determines horsepower, minimum and maximum flow rates, and gives a pumping schedule.
RSVFLD	The program calculates requirements for reservoir flooding, or saturation. It uses the techniques developed during the Bay Marchand fires. It does not require a complete reservoir model and it gives flow rate and volume requirements.
BLOWDOWN	This is a PC depletion model to determine sand face pressure after the blowout initiation. It allows reliable estimates of kill requirements at the time of the relief well intersect or the capping operation.
BLOWTEMP	Temperatures are calculated at the BOP stack for unrestricted flow from a formation. This program should provide the information required by the UK Dept. of Energy for new North Sea drilling programs.
SURVEY	The program analyzes directional surveys using any of 5 calculational techniques. It also has an error analysis capability which is required for relief well directional planning.

The company currently has under development a new diverter package to evaluate blowouts from shallow reservoirs. It will be useful in determining kill requirements and for sizing diverter systems.

W. S. Atkins Engineering Sciences Ltd. - Atkins offers a comprehensive program, WELLSIM, that has many drilling related capabilities. It appears to be a large single program as opposed to several smaller units. According to their literature, "the choice of kick control and blowout alleviation methods include the following: topside diverter, subsea diverter, subsea control vents, subsea holes, BOP and choke line, Driller's Method, Wait and Weight, Soft kill and Manual control". The program appears to contain many advanced features.

According to Atkins' literature, " WELLSIM is a fully integrated program suite for dynamic interactive simulation of well drilling, gas kick and blowout. State of the art mathematical models are coupled to interactive data entry and control screens. Industry standard graphics produce comprehensive results displays."

5.2.23 Services, Sonar. This category includes those companies that only rent sonar equipment, those that provide sonar equipment and field operations personnel, and technicians/engineers that provide specialized operating services for sonar. The strictly rental companies can provide names of technicians that can be contracted to run the unit. Likewise, specialist contract technicians/engineers can locate suitable equipment for hire. The listing primarily addresses sonar equipment available as a stand-alone unit.

Sonar equipment is also available through other sources as part of a package of services. Many diving companies that operate ROVs offer sonar as part of the ROV package options. Oceaneering/OSE, Subsea Offshore Ltd., Britdive, Comex, Stolt-Nielsen Seaway, Sonsub, and Cal Dive are a few of the ROV and diving companies that have sonar capability.

Many of the surveying companies also offer sonar as part of the survey vessel capabilities. However, in some cases, the survey vessel units are a towed array rather than for stationary use.

Lower frequency units, such as 330-675 kHz, are used for long distance location of the blowing well, other gas or oil vent plumes, and major debris. Higher frequency sonar in the 2.0 MHz range is used for short range, high resolution work.

Cochrane Subsea Acoustics, Inc. - Cochrane offers rental sonar units along with a team of an engineer and a technician to set up and operate the equipment. The sonar heads that they use are a modified Mesotech 971 head. They have offices and equipment in Lafayette, Louisiana, USA, and Aberdeen, Scotland, UK.

Cochrane currently has six (6) sonar units based in Lafayette and in Aberdeen. They have several trained engineer/technicians for field operations.

They also have identification/marker sonar pingers that they call a "Mockingbird". It pulses a coded signal that shows up on the sonar color monitor as a unique image. The Mockingbird can be used to mark debris, pipelines, and other significant objects that may impact a well operation.

Richard Dailey, Consultant - Dailey is a specialist consultant that works world-wide. Sonar unit operation is one of his areas of expertise. He has operated sonar in support of blowout kill operations. Dailey does not have equipment for rent. He can arrange for sonar equipment to suit a particular job or operate equipment rented by the company that contracts him.

Engineering Hydraulics, Inc. - EHI (formerly ERT) offers sonar equipment and technician/engineers. They use Mesotech 971 sonars. EHI's offices are in Seattle, Washington, USA where they base their four trained technician/engineers for field operations.

Rentech International Inc. - Rentech only rents sonar equipment. They do not offer field personnel to operate and support the units. They do provide contacts to the renter for trained contract personnel qualified to operate their sonar equipment. They have offices in Houston, Texas, USA and agents in Aberdeen, Scotland; Leighton Buzzard, England; and in San Diego, California, USA. Sonar equipment is stocked in Houston and Aberdeen.

The key contact is Mr. Mike Todd in Houston.

Submar, Inc. - Submar offers rental sonar units. They do not provide technician/engineers for field operations, but can recommend an operations company. They use UDI AS360 series sonars manufactured in Aberdeen, Scotland. All are black and white display. They will be receiving a new model sonar from UDI in early-1991.

Their offices are in Houston, Texas, USA. Mr. A. L. Somers is their president and key contact.

T. Thompson Ltd. - Thompson only rents sonar equipment. They can provide referrals for qualified field personnel to operate and support the units. They have offices in Vancouver, British, Colombia, Canada; Bedford, Nova Scotia, Canada; and Bellvue, Washington, USA.

Terry Thompson is the contact for this company.

5.2.24 Services, Environmental. There are a wide variety of environmental services available to the industry depending on need and location. The following discussion concentrates on services associated with blowout effluent cleanup. These include offshore oil containment and collection techniques, dispersants, bioremediation and polymers.

Containment and Collection Devices. Several companies provide oil cleanup equipment and services worldwide. Many oil companies retain their own vessels and equipment as preparedness items. Conventional booms and skimmers are available in most drilling areas and can be dispatched quickly to blowout locations.

Booms are available for use in open seas. One large boom system is manufactured by Oil Mop, Inc. of Belle Chase, Louisiana, USA. It has a 17" freeboard with a 33" draft and weighs 8.0 lbs/ft. It is available in 50' lengths. Another system is manufactured by Kepner Plastics Fabricators, Inc. in Torrance, California, USA. It has a 26" freeboard and a 42" draft and weighs 14-19 lbs/ft. It can be purchased in 50', 100' and 50 m lengths.

Another type of boom is constructed of molded blocks of an oleophilic absorbent such as Dylite expandable polystyrene. These are designed for small area slicks in quiescent areas and have limited use.

Some of these systems are available on reels and can be installed by vessels of opportunity. They can be stored on the drilling vessel and dispatched to surround the spill if the area is not too large.

Another deployment system is envisioned using Bell-Boeing's new V-22 TiltRotor aircraft. Spill sites some distance offshore can be reached quickly using this cargo aircraft which can hover while dropping or unspooling booms. Fixed-wing aircraft cannot fly slowly enough for this type of installation, and helicopters have load and flight time limitations that preclude their use for this service.

Skimmers are also available in a variety of sizes for use in spill cleanup. Some of these are self-contained units that are remote controlled. These are normally smaller units with limited capacity and capabilities. Kepner Plastics produces one of these for use inside a boom called "Sea Vac."

Oil Recovery Sweden (ORS) recently completed tank trials in Norway on their WP-1-30 skimmer. This new system is able to work in 0.5 m waves and utilizes a perforated drum. This drum has an open lip that reportedly "digs up" the oil from the surface. Oil then moves toward the center of the drum and water separated from the oil is discharged through perforations. The system has been used successfully in the USSR, Italy and in Alaska, USA.

A similar system is available from Lundin Oil Recovery, Inc. This device is designed to collect oil in icy waters or for heavy emulsions. Plastic-bristle brushes are mounted on a conveyor that turns to sweep oil into a collection sump. Water washes through the bristles and is not collected. The system has been tested and is reported to work in waves to 1.5 m.

There are several purpose-built vessels for skimming spills off of the surface. One of these is the *Responder* designed by Crowley Maritime Corporation. This is a 400' by 105' barge equipped with 7,600 ft of containment boom, skimming, separation and storage equipment and utility and boom deployment boats. The system has been used to support Shell's drilling operations in the Chukchi Sea.

Larson Marin OY-AB fabricates an oil recovery system composed of a pair of booms deployed on a vessel connected amidships. The booms herd oil to rotating bristle wheels as the boat steams through the slick. Oil is collected on the bristles and carried aboard where it is stored. The bristles do not collect water.

Maximum capacity is 37 bbls/hr of crude oil. The system can be fitted to any similar low-draft vessel. It is designed to collect oil in thin sheens or in thick, viscous layers. Factors influencing operations are wind speed and sea conditions.

Recently, there has been research involving a hollow boom with a wier-type collector combined with a hydrocyclone for separation of oil and water to clean up offshore spills. This device will provide both collection and separation capability, assuming that the device can be designed to handle viscous emulsions.

Dispersants. Dispersants have been used in the past for remediating offshore spills. Early dispersants used aromatic solvents as carriers which were found to be more environmentally damaging than the surfactant. This, along with the toxicity of the dispersed crude, limited the use of dispersants to near-shore situations where significant damage was imminent.

Traditional products include ESSO Breaxit, an emulsion breaker, usually run in combination with BP1002, a dispersant. LA1834, is another common dispersant. Enjay Chemical Company produces a family of dispersants under the Corexit name. These have been used successfully on several spills.

A new family of dispersants has been developed that is less toxic than the traditional ones. Envirotech International, Ltd., GTC, Inc. and Emtech Environmental Services offer dispersants that effectively break up crude oil into small droplets and reduce toxicity without adversely impacting the environment.

These are non-flammable liquids containing no hydrocarbon solvents. They behave as emulsifiers on a microscopic level by surrounding the oil droplets with a film which prevents dissolution or vaporization of volatile components. Bacteria can feed on both the oil and the dispersant.

Dispersion of oil using these new chemicals allows for *in situ* treatment of the blowout plume as it exits from the well. This is proposed in another section of the report. Dispersion with these materials also prevents contamination of the water column by the soluble, toxic components of the oil, principally the aromatic compounds.

Bioremediation. Within the last two years, the use of microbes to consume crude oil from surface spills has expanded significantly. This is one of the fastest growing remediation techniques.

There are over 100 strains of microbes identified, including bacteria and fungi, that can digest crude oil. The byproducts of this digestion are carbon dioxide and water. Microbes capable of digesting oil are largely naturally occurring; there are some genetically engineered strains, but these are not approved for bioremediation.

The commercially available bacterial and fungal cultures are self-regulating. As the concentration of oil in the environment increases, naturally-occurring ubiquitous bacteria will multiply in the vicinity to population levels capable of consuming the spill. There is little reason to consider the use of biocides for population control; as the concentration of oil decreases, the bacteria die off to pre-spill levels.

Emtech Environmental Services, Alpha Environment, American Micro Technology, Inc., GTC, Inc. Waste Microbes and Reidel Environmental Services have microbe strains that can feed on crude oil. All of these companies can ship their "bug" cultures throughout the world.

Usually, the bugs are transported in a bacterial "soup" composed of the bacterial and fungal colonies, nutrients, oxygen and water. Bacteria are freeze dried on a wheat chaff matrix that is re-hydrated in sea- or fresh-water for 3 or 4 hours and oxygenated during the interim. This "soup" is then sprayed onto, or injected into, an oil discharge which then is consumed by the bugs.

Recent field trials with these products resulted in significant remediation of surface slicks. In the *Valdez* incident, 70 of 1,100 miles of oil-contaminated shoreline were cleaned by passive bioremediation (i.e., encouraging naturally occurring bacterial growth by introducing fertilizers and nutrients into the system). Both incidents in 1990 off Galveston, Texas, USA involving spills from tanker accidents resulted in reduced oil slicks from the introduction of bacteria by surface spraying.

These recent successes have resulted in the recommendation to consider introduction of bacterial cultures through a flow-through device directly into the blowout plume at the source of the emission. This will allow the bugs to mix with oil using plume dynamics to assist in the remediation effort. Other materials may be added through the device.

Polymers. Long-chain polymers have been used recently to copolymerize crude oil in a unique chemical reaction. The oil that reacts with this family of chemicals is rendered non-toxic. They form an inert synthetic rubber product with a density less than seawater, so it floats on the surface. It can be picked up by a variety of mechanical means. This "rubber" can be burned as a solid fuel.

Petroleum Environmental Technologies, Inc. has one such product. Theirs is a solid, crumb-form polymer that can be applied to the slick with aerial crop-dusting techniques. Another liquid product is available through General Elastol. This is an area of expanding technology. New firms and products are being developed rapidly.

5.2.25 Services, Special Wireline. Special wireline services are often useful in pressure control. Some are discussed in the following sections. Ranging tools run on wirelines are discussed in a prior section.

5.2.25.1 Introduction. Traditionally, wireline logging has been considered largely a wellbore evaluation tool associated with production since most logs involved identification of rock and fluid properties. In the recent past, new tools have been developed that expand the role of wireline conveyed devices beyond traditional open hole logging.

Many of these tools are designed for problem identification. Some of these are casing inspection logs (metal thickness and inside electronic caliper tools), radioactive tracer surveys (discussed previously), flow definition devices (spinners, oil/water ratio tools, profiles, etc.), high-resolution temperature tools, acoustic logs ("noise logs") and downhole video cameras (borehole televiewer). Several of these are useful in pressure control.

Recently, wireline has begun to be used in highly deviated holes, including horizontal wells, by installing it inside coil tubing. The downhole telemetry device is connected to the wireline then it is affixed to the bottom of the coil tubing. The result is a "stiff" wireline that can be used to push the tool to the bottom of the hole.

The same assembly can be used to run wireline tools into wells that are under control but have enough pressure to preclude the use of wireline lubricators. Even if the wireline can be used under pressure, there are instances in which it is desirable to push the wireline tool below an obstruction through which the tool would not fall by gravity.

Other wireline tools have direct application in pressure control work. These include specialized perforating guns, wireline chemical cutters and severing tools, electrically inflatable packers, through-tubing bridge plugs and a variety of bailers. A few of these are discussed more fully below.

5.2.25.2 Temperature Survey. The most common tool used to define a loss zone or behind casing flow is the temperature log. This log is not generally used to record absolute temperature but rather differential temperature. The type of temperature difference (i.e., a warming or cooling effect) is important as well as the magnitude of the change when flow conditions are altered in the well.

As the logging tool is lowered down the drill pipe or the well, it will read an abnormal change at the loss zone if the flow is continuous. The tool senses temperature from the fluid that is greater than it should be for the depth at which it is encountered. In some cases, the temperature change has been reported as a cooling effect due to gas expansion. This can occur when gas is forced through an orifice of some type, as well.

A favored technique is to make one run with a temperature tool with the well in a no-flow condition, if possible. Later, a second run can be made with the well or zone flowing. Then a comparison can be made of the two temperature logs for differences. This application of a production-type logging procedure has been useful in identifying crossflow behind-pipe in wells.

Temperature tools can be obtained in a variety of sizes down to 7/8" with little loss in accuracy. Since they do not carry radioactive sources, and because they are relatively inexpensive, the loss of one of these tools in a hole is not catastrophic, although undesirable. Thus, they can be used in situations in which other types of logs are unwarranted.

Analysis of temperature logs is highly interpretive, but good qualitative results can be obtained in a large number of instances. This is especially true when their results are combined with another tool such as the "noise" log.

Most major logging companies have families of temperature logging tools. Schlumberger, Western Atlas, Halliburton, Computalog and Dresser all have good temperature logging capabilities.

5.2.25.3 Noise Logging. A noise log can be used to detect a loss zone or behind-casing flow. The tool is a sonic detector that records the sounds created by fluid movement. The tool can be useful in defining underground blowouts.

For years it was known that fluids flowing through conduits emit sound. Gas emits sound in different frequencies than does oil, water, or drilling mud. Each has its own flowing acoustic profile.

The downhole noise tool detects sound (acoustic energy) and converts it to signals that are transmitted via wireline to the surface. The panel in the logging unit splits the signal and allows certain windows of frequencies to be recorded. Channeling, crossflow or losses can not only be defined, but the fluid that is moving can also be identified with this tool.

Unfortunately, this log is adversely affected by extraneous sound, such as rig noise, which is transmitted easily through tubular goods installed in the well and by the fluid column that reaches from the surface. Often this external noise defeats meaningful analysis of the log.

Like temperature surveys, interpretation of these logs is quite difficult. The noise log is also a good qualitative tool especially when run in combination with other logs. Most of the large logging companies have service.

5.2.25.4 Pipe Severing. Several types of wireline conveyed pipe severing systems are available on the market. These either use single ring-shaped charges that can be tailored for the pipe to be cut, or a series of smaller charges arranged in a ring to "drill" multiple holes through the pipe. The former is normally referred to as a severing tool, the latter is known as a chemical cutter.

Chemical Cutters - Most wireline companies have chemical cutters for tubing from 2-7/8" to 4-1/2", drillpipe from 3-1/2" to 5" and for casing from 4-1/2" to 8-5/8". These include Halliburton Wireline Services, Western Atlas, Schlumberger and Homco-McCullough. For pipe sizes larger than these, a severing tool is normally used.

If a chemical cutter is to be used it must be understood that an incomplete cut is made. In other words, there will be some steel between the perforations that will either be broken by the force of the shot or must be separated physically. The best method of insuring separation is by applying tension to the pipe. This may be a pre-existing condition in pipe that is to be cut.

Severing Tools -These tools come in a variety of sizes and loads depending on the pipe to be cut. Most of these tools are loaded prior to delivery, but some can be modified on location.

The severing tool utilizes shaped charge technology which generates immense pressure on a very small area of the pipe. This, in turn, "cuts" the pipe. Severing tools come in 1-1/4" to 20" sizes and will cut multiple concentric pipe strings if sized properly.

These devices are available through most wireline companies. One notable manufacturer of this and other specialty explosives is Jet Research Center, a Halliburton Company.

5.2.25.5 Primer Cord. This fast burning material is sometimes used as an explosive for various purposes in well control operations. Primer cord is used in most perforating operations to bridge between the detonator (usually a blasting cap) and the perforating charges.

Primer, or detonating, cord is a round, flexible cord with a center core of high expolosive, usually pentaerythritol tetranitrate (PETN). It is covered with various combinations or materials including textiles, waterproofing and plastics that protect the core from physical abuse, water, oil or extreme temperatures.

The cord is relatively insensitive and requires a detonation device such as a No. 6 blasting cap for initiation. Despite its low sensitivity, it detonates at 22,000 ft/sec (6,700 m/sec).

Primer cord can be used as a "mild" explosive or as a reliable nonelectric detonator for other explosives such as dynamite, nitroglycerin, C-4 or Tovex gel.

It can be used as a charge to jar or rattle downhole devices without severely damaging them. Primer cord can be wrapped around a central mandrel and detonated to unscrew pipe that has left-hand torque applied in back-offs. It can be used to free stuck packers, seal assemblies and other tools.

It has been used often to free slips and packing in wellheads. Too much primer cord (i.e., too many wraps) has been known to split a wellhead completely in two. Primer cord can be used to remove wellheads and other debris from the near well vicinity during kill operations.

Primer cord is common in the oilfield. It is used extensively by wireline companies to detonate perforating charges. Construction companies also use primer cord for blasting work. Disposal of primer cord by incineration is common. When it is incinerated, primer cord burns like plastic rope.

5.2.25.6 Downhole Junk Shot. Often called a "bear gun", this is a single shot, powerful explosive charge that is aimed vertically downward. Junk shots can be used to blow the jets out of bits or to break up junk at the bottom of a hole. This gun can also be used to open plugged drillpipe to permit high-rate pumping in kill operations.

Particular care must be exercised in the use of these guns inside pipe. If the force of the charge cannot be expended downward, it will rupture the pipe just above the shot. Occasionally, the pipe just above this ruptured section will collapse on the gun trapping it inside the pipe.

Again, most large wireline companies have this tool. It is a type of perforating gun, and normal precautions must be exercised.

5.2.26 Vessels, Support. Support vessels, MSVs and DSVs, are necessary in offshore blowouts to provide a work platform for kill and control operations. Often, fire accompanying the blowout or other safety considerations prevent using the original drilling structure or vessel for these activities.

5.2.26.1 MSVs (Multi-function Support Vessel) - This term is actually a generic one that applies to a wide range of vessels. Virtually any boat, ship, or barge chartered for service in well control operations can be called an MSV. (Figure 5.2.26.1)

These are usually vessels that have some capability that can be used for well control or ancillary activities such as clearing debris. These include: marine construction vessels (Inspection, Repair and Maintenance or IRM vessels), work barges, lift barges, semis or drillships. These have equipment that can be useful in blowout control, well capping and recovery of facilities.

Selection of an MSV for well control work is largely a matter of vessel capability and availability. An idle drilling vessel, for example, has pumps, cranes, mud mixing equipment,

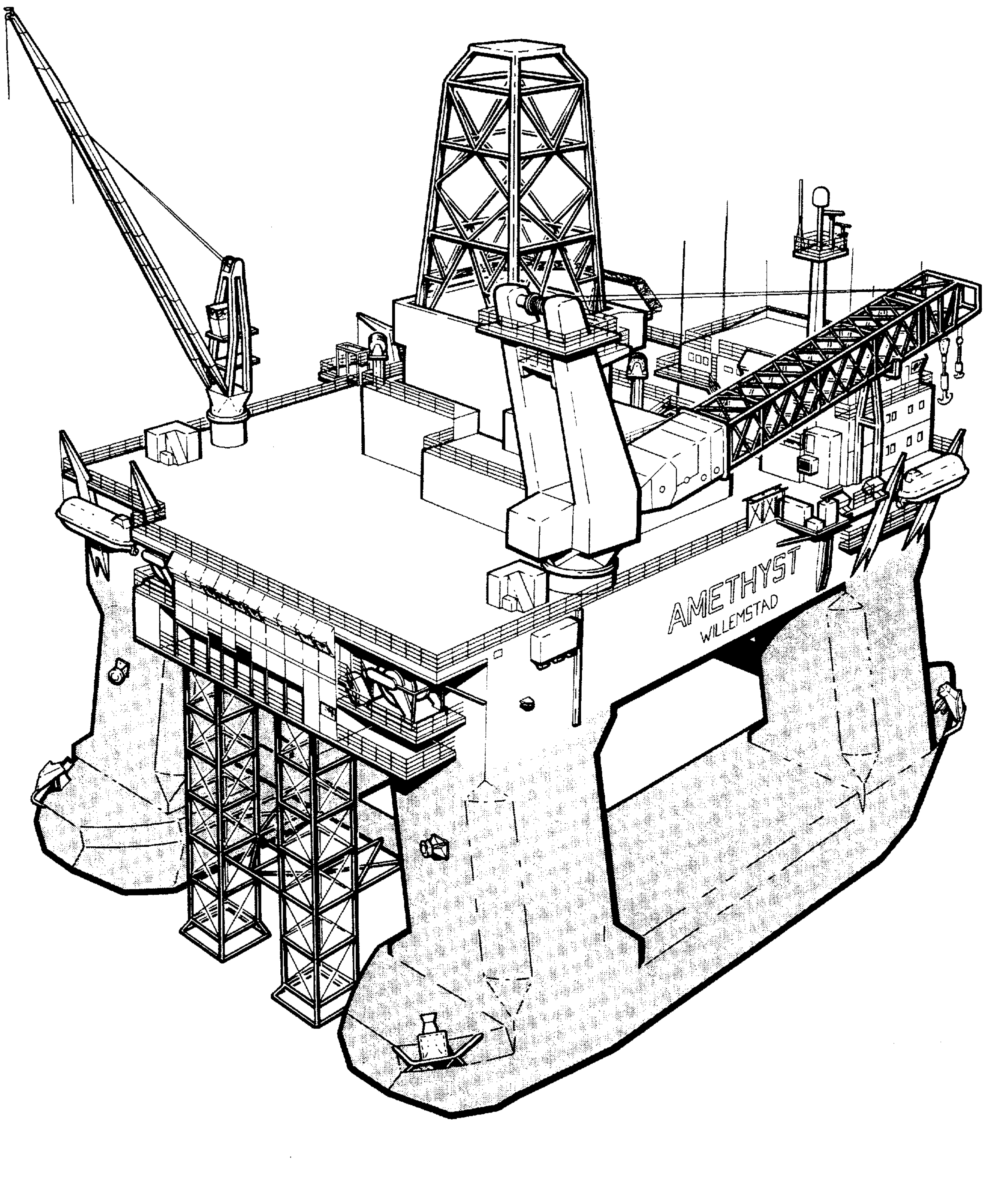


Figure 5.2.26.1
MSV

dynamic positioning capability, communications, living quarters, etc. If one of these is nearby it may be suitable for well control operations without modification. Depending on the vessel selected, additional pumps, monitors, piping, etc. can be added for firefighting work. Other purpose-built modifications are possible, as well.

Several companies have families of vessels available for offshore service. Some of these are discussed below.

Comex UK Ltd. - Comex has several vessels including the *Amethyst*, a semi-submersible construction and operations vessel. This vessel has full dynamic positioning, 13,500 ft^2 (1,250 m^2) free deck space, 1600 ton variable load capacity, twin diving bell system, two 60 ton cranes, modular drilling and wireline derricks and accommodations for 132. It is also equipped with a Vetco-Gray 5" 10,000 psi riser. Plans are to equip this vessel with a coil tubing unit and pumping equipment.

Comex also has the MSV *Uncle John*, a purpose-built semi to support construction and maintenance. It has 19,400 ft^2 (1,800 m^2) deck space, 700 ton variable deck loading, dynamic positioning capability, diving facilities, three cranes with up to 100 ton lift and accommodations for 102. This vessel is also equipped with three fire pumps having a total of 32,000 gpm. It has served for some time as a North Sea Sector Emergency Vessel.

Cetena - This Trieste, Italy firm also has a semi-submersible support vessel called the *SSFSV 1400* which is designed for workovers, wireline operations, stimulation, subsea completions and construction. It has a maximum deck loading capacity of 1,400 tons. It has two 200 ton cranes and four pipeline laying winches. Accommodations are available for 80. This vessel also has firefighting capability.

McDermott - This New Orleans, Louisiana, USA company is a well known marine construction firm that has several crane barges, heavy lift barges, a very heavy lift semi and DSVs. The company has performed work all over the world and has offices in numerous locations.

Micoperi - This large marine construction company has a fleet of 20 ocean-going vessels including heavy lift vessels, crane barges, derrick barges, DSVs, and launching barges. There are offices around the world with the logistics center in Ortona, Italy.

Rockwater - Rockwater's *Semi 1* and *Semi 2* are both inspection, maintenance, repair, construction and installation vessels operating out of Aberdeen. They have maximum deckloads of 750 and 650 tons, respectively and 12,900 ft^2 (1,200 m^2) deck space each. Both have full dynamic positioning and both have living accommodations for 89.

Semi 2 has two gas turbine-driven fire pumps which supply a total of 25,000 gpm. Monitors are remotely controlled from the bridge. The vessel is protected by an onboard water spray system.

5.2.26.2 DSVs (Diving Support Vessels) - A specialized subset of MSVs, diving support vessels, are usually smaller vessels that have a number of features specific to diving such as breathing air compressors, hyperbaric chambers, diving bell launch and recovery systems, etc. (Figure 5.2.26.2)

Several of the companies mentioned above have DSVs in their fleets including Comex, Rockwater and Micoperi. Others have manned ROVs like McDermott. There are other companies that specialize in DSVs; one of these is discussed below.

Stolt-Nielsen Seaway - Based out of Haugesund, Norway, this firm provides diving services in the North Sea. They also have offices in Stavanger, Aberdeen and Great Yarmouth.

This firm was established in 1973 and has completed a large number of projects. For the last 16 years they have supported construction and maintenance of the Phillips Ekofisk facilities.

They have a fleet of four DSVs including 80, 90 and 100 m vessels, all of which are DnV approved. Each has saturation diving capability up to four divers per vessel, cranes, living accommodations, dynamic positioning, and welding equipment. The firm has a total of 17 ROVs.

5.2.27 Miscellaneous. Various miscellaneous topics relate to pressure and blowout control that do not fall into previously established categories. They are presented below.

5.2.27.1 Valve Removal - Often tricky, valve removal and replacement is more art than science. Two generally accepted methods are used to remove valves, but there are variations that must be employed for each set of circumstances encountered.

Freezing - Freezing of the conduit upon which the valve is installed upstream of the valve is one of these methods. This can be done by freezing the fluid in place inside the conduit, or by placing a fluid in the proper position by pumping backward through the valve. This may involve hot tapping and/or valve drillout. Both of these processes are discussed more fully in Section 5.2.14.

Cameron Low Profile Valve Removal Tool (LPVRT) - Cameron markets a device which is also useful for valve removal.

The procedure for using this tool is fairly simple. Before installing the LPVRT, a second valve is installed downstream of the valve to be removed. The old valve is opened with the lubricator of the LPVRT holding any internal pressure. Then, a threaded plug is run through the old valve on a mandrel. The plug is screwed into internal threads ahead of the valve. Flanged wellhead outlets are usually threaded to accept this plug. A cage nipple can be screwed into a side outlet on the wellhead to accommodate the plug. Pressure is bled off the system down and the LPVRT is rigged down. Then, the old valve can safely be removed. To retrieve the plug, the procedure is reversed. (Figure 5.2.27.1)

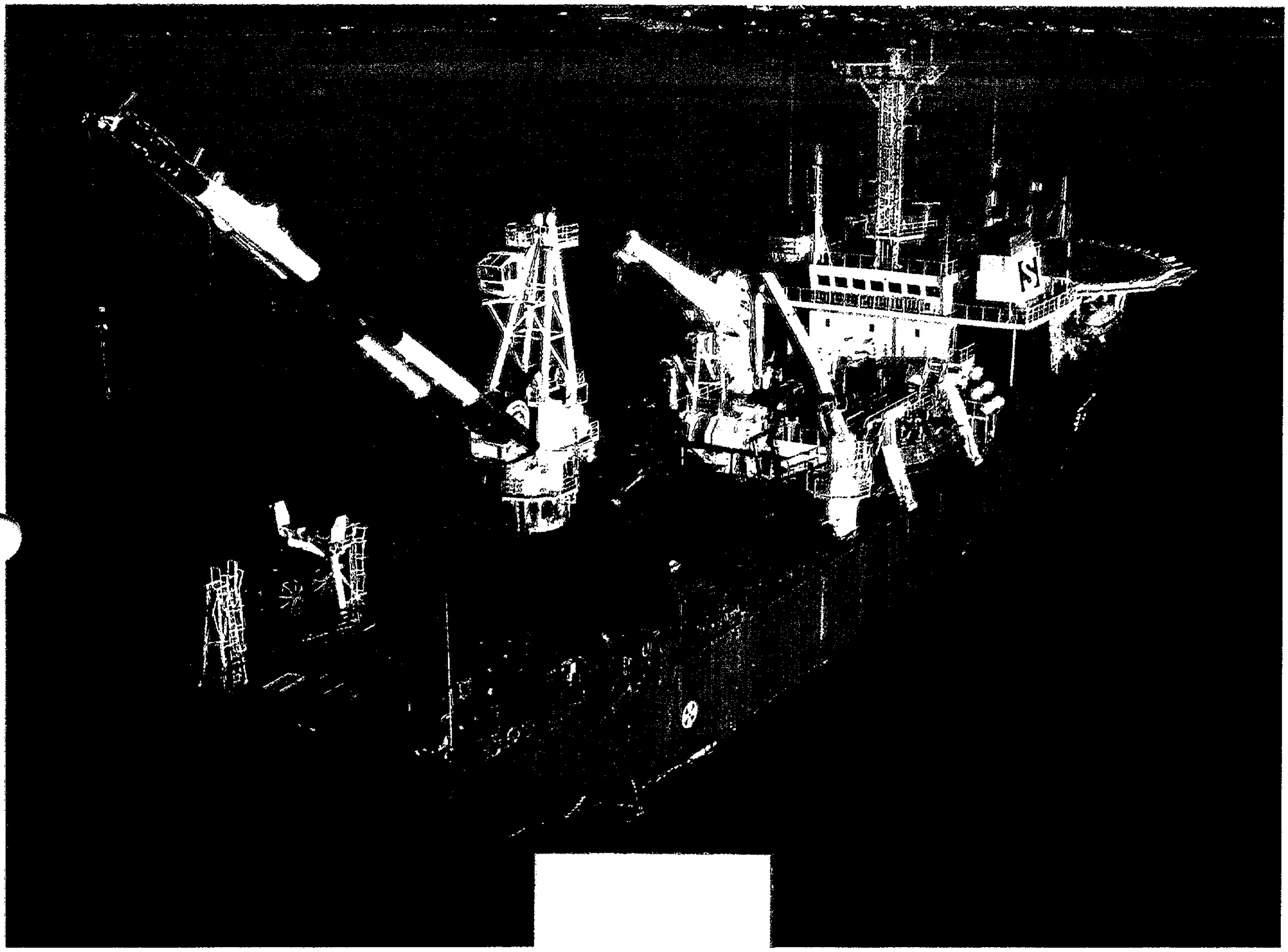


Figure 5.2.26.2

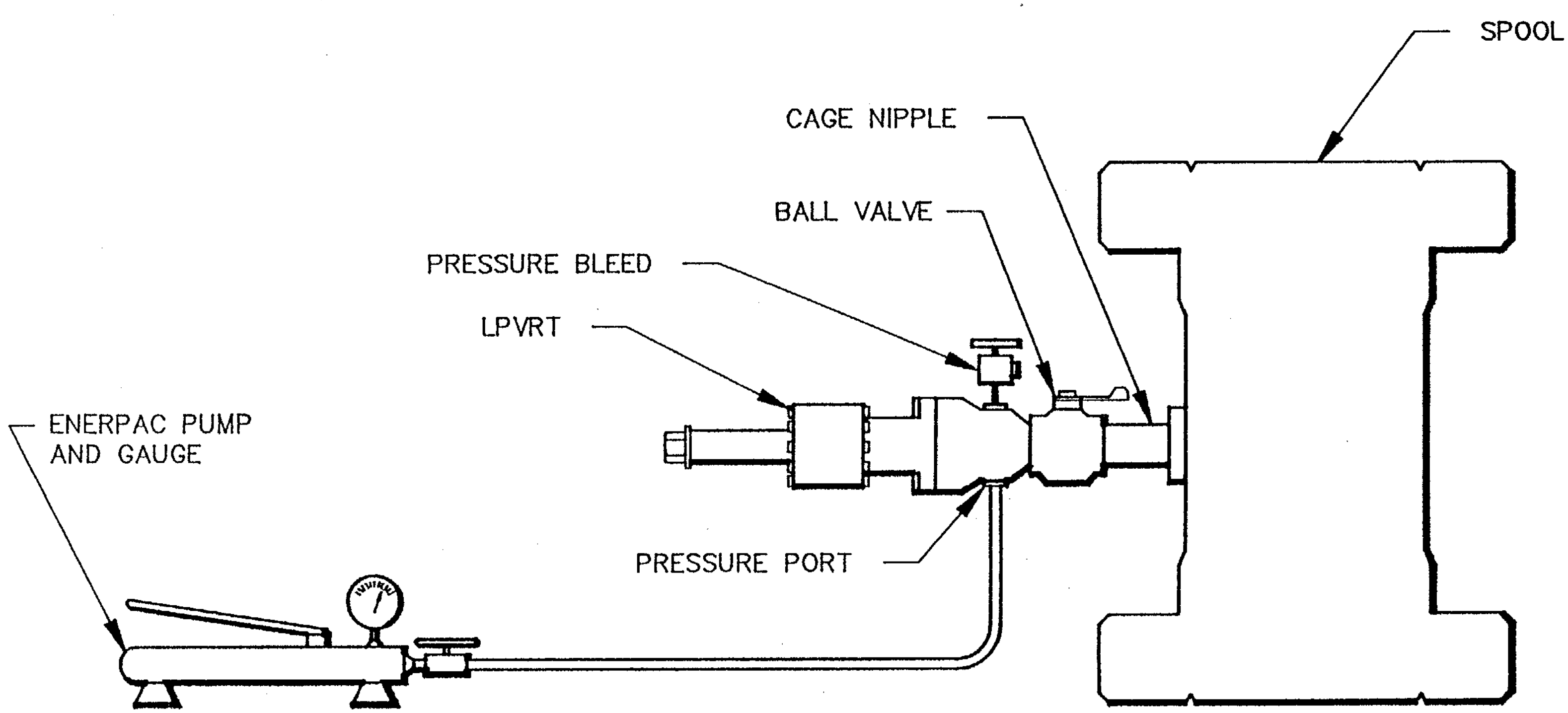


Figure 5.2.27.1

Cameron Low Profile Valve Removal Tool

The device has a 3,000 psi limit. It is ported so that the system can be bled down or pressured up to facilitate plug installation and removal. The tool can be operated manually or assisted with wellbore pressure using a hydraulic cylinder. The lubricator has a maximum stroke of 17" so this tool is particularly useful in tight quarters such as deep, narrow cellars or on platforms where structural members limit working space.

The contacts for the LPVRT are Rick Barnett with Cooper Oil Tools (Cameron) in Houston, Texas, USA and Keith Garbett with Cameron in Leeds, England.

5.2.27.2 Kill Spools - A kill spool is often installed in the stack to provide large flow volume capability. It is generally designed with 4, 4" inlets. A typical design is shown in Figure 5.2.27.2.

The spool is special built for each job. This practice of special-building a spool is more historically oriented than based on actual requirements. It is usually more cost effective to build a spool than to transport a pre-fabricated spool and pay rental charges. Special internal coatings are not necessary if outlet number and sizes are sufficient to allow high rate pumping of kill fluid. If dirty or abrasive fluids are used, stellite coating may be appropriate. It is noted that this is normally considered an expendable item. It has little normal utility after the blowout is killed. So, there is little reason to protect it from long-term abrasion.

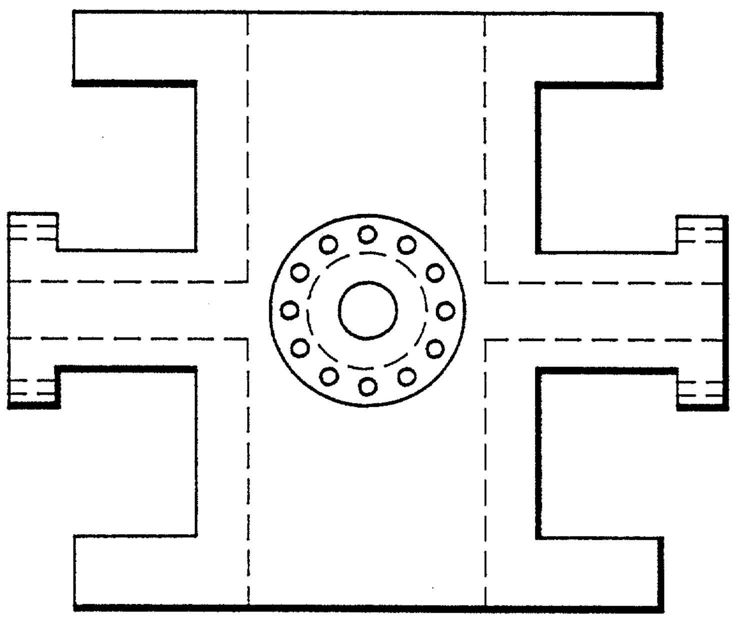
The spool is designed to match the BOP flange sizes and pressure ratings. The outlets should have 4" inner diameters and flange connections. Two, 4" hydraulic valves should be connected to each outlet. These guidelines can be reduced to 2 outlets or to 1 hydraulic valve and 1 manual valve per outlet if the service conditions are not demanding. The spool and all valves should be appropriately tested with the stack.

Kill spools are used predominantly on land jobs or jack-ups. The spool is accessible for installation and operation of valves.

The spools do not have any known usage on subsea BOP stacks. The additional valves would require significant planning for a satisfactory hydraulics control system. The common practice is to use the choke and kill lines although this approach has pitfalls if high volume pumping is required. To date, a subsea stack has not been used for high volume pumping, according to available records. It is conceivable that a kill spool, or similar stack component, could be added for a special purpose such as the injection of dispersant or bacteria cultures into a blowout plume.

5.2.27.3 Pump-in Heads/Test Trees - A pump-in head is also known as a test tree. It can be considered analogous to a kill spool. The pump-in head allows several flow options down the string of pipe or casing whereas the kill spool provides flow capability down the annulus.

A pump-in head is used for high rate pumping down the kill string. Design requirements are as follows:



NOTE:
PRESSURE RATINGS AND BORE I.D.
CONSISTENT WITH BOP STACK

Figure 5.2.27.2

Kill Spool with (4) 4" I.D. Outlets

DEA PROJECT NO. 63
JOINT INDUSTRY PROGRAM for FLOATING VESSEL BLOWOUT CONTROL

- Pressure rating in excess of design capacity.
- Two inlet lines with dual hydraulic valves.
- An outlet to connect with the flow/kill string with an appropriate connection.
- A method to lift the pump-in head and kill/flow string with the motion compensator.

The inlet line capacity should be capable of handling the flow requirements through a single line in the event one line washes out.

The kill head for the Piper Alpha job is shown in Figure 5.2.27.3. It is an off-the-shelf item available in 15,000 psi pressure ranges. The inlets are 3" ID. A 4" ID inlet capability would have been desirable but was not available.

An alternative to this kill head can be designed with a combination of valves. However, it is not as easy to manipulate as the purpose-built unit.

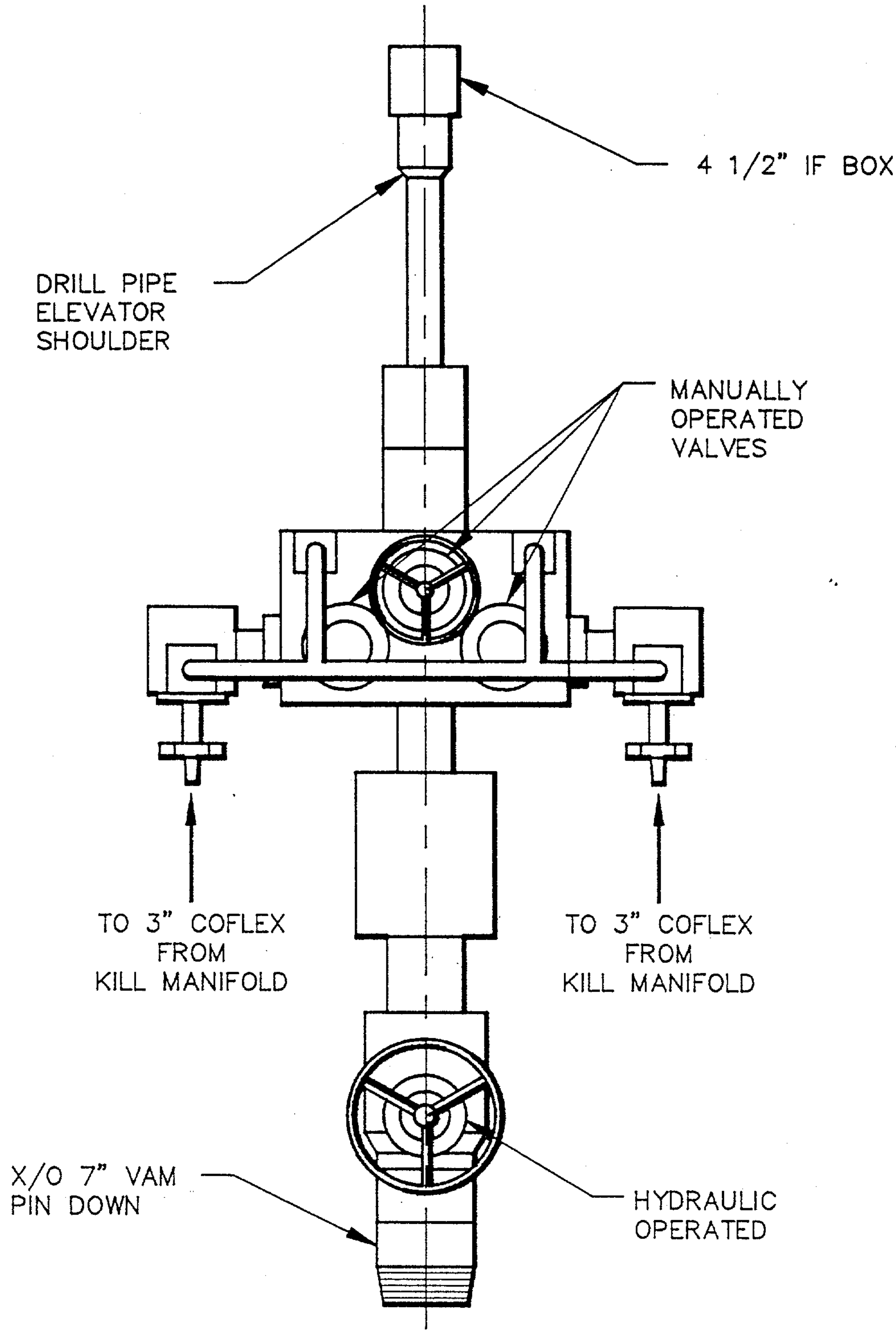


Figure 5.2.27.3

Surface Pump-In Head

NOTE:

3 1/16" Thru-Bore 10,000 psi W.P. Flowhead

5.3 DIRECTORY OF SERVICE COMPANIES

The following is a list of companies and individuals that provide services and equipment discussed in the previous section. The addresses, numbers (telephone, FAX and telex) and key contact information contained herein have been provided by the entities listed. They are subject to rapid change in the current worldwide business environment. This is the most current information at this time.

- A -

A-Z/GRANT INTERNATIONAL COMPANY
P.O. Box 7180
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ABEL ENGINEERING/WELL CONTROL COMPANY
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FAX 713-960-1568
Contact: Bill Abel

ADAIR, RED COMPANY
8101 Pinemont
Houston, Texas 77040 USA
PH 713-462-6479
FAX 713-462-6537
TLX 762125
Contact: Raymond Henry

ADAMS ENGINEERING, INC.
8484 Breen Road
Houston, Texas 77064 USA
PH 713-937-8320
FAX 713-937-6503
TLX 701106
Contact: Neal Adams

ADAMS, NEAL FIREFIGHTERS, INC.
8484 Breen Road
Houston, Texas 77064 USA
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FAX 713-937-6503
TLX 701106
Contact: Neal Adams

ALBA INTERNATIONAL LTD.
Leading Light Building,
142 Sinclair Road,
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FAX 44-224-879-781
TLX 73337 ALBA G
Contact: John McMurtrie

AMERICAN MICRO TECHNOLOGY, INC.
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College Station, Texas 77842 USA
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ANADRILL SCHLUMBERGER
200 Macco Boulevard
Sugarland, Texas 77478 USA
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FAX 713-274-8399

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FAX 44-224-895-251
TLX 73612 APEX G
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FAX 713-333-5184
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ATKINS, W. S. LTD.
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Columbia, Bogota	Santiago Gonzalez	571-292-0600
Egypt, Cario	Esmat Hassanein	202-353-0892
Argentina, Buenos Aires	Jorge Salamanca	541-311-9531
Brazil, Rio De Janeiro	Jose Mejias	55-21-221-7727
P. R. China, Beijing	Tom Chen	86-1-512-3433
Equador, Quito	Sergio Guarin	593-245-8892
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Italy, Milan	R. Guzman	395-236-1600

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Norway, Tananger	R. Karlsen	47-469-6533
Netherlands, Den Haag	Louis Cromer	31-70-243327
Peru, Lima	Roberto Rabines	511-442-4740
Phillippines, Manila	Bernard Dy	810-3559/817-4574
Singapore	J. T. Borger	65-472-3344
Syria, Damascus	Ronnie Weible	963-11-217745
Thailand, Bangkok		66-2-236-9387
West Indies, Trinidad	Andrew Kelshall	809-652-1850
Venezuela, Caracas	Alberto Berney	582-285-3211

BAKER SERVICE TOOLS, INC.
P.O. Box 40129
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FAX 713-466-2502
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FAX 44-244-771-757
TLX 739296 BUK G
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BAKER OIL TOOLS
6023 Navigation Boulevard
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FAX 713-923-9519
TLX 4620079 BAKER-UI
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KEY INTERNATIONAL BAKER OIL TOOL PERSONNEL

Norway, Stavanger	Arnie Haukelid	47-4-696644
Germany, Vechta	Bill Bogle	49-4441-7071
Nigeria, Lagos	Wally Gorton	234-1-610473
U A E, Dubai	Wolfgang Fischer	971-4-523497
Saudi Arabia, Dahran	Jack Farmer	966-3-8578807
Singapore	Dewayne Whitney	65-8613455
Australia, Adelaide	Graham Carson	61-8-2432966
Alberta, Edmonton	George Haus	403-440-2110

BISHOP PIPEFREEZING SERVICES LTD.
Trinity Business Center, Unit A17
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FAX 44-71-407-2735
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BON ACCORD TOOL & SUPPLY CO. LTD.
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East Tullos,
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BOOTS & COOTS, INC.
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FAX 44-224-895593
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FAX 318-237-7839
TLX 510-6008933
Contact: Steve Moore

COCHRANE SUBSEA INTERNATIONAL, LTD.
Unit 24, Ocean Trade Center
Minto Avenue,
Altens Industrial Estate,
Aberdeen, Scotland ABI 4JZ UK
PH 44-224-878646
TLX 73616

COFLEXIP S.A.
23, Avenue De Neuilly
75116 Paris
France
PH 33-1-47-128000
FAX 33-1-47-128005
TLX 610302

COFLEXIP & SERVICES, INC.
7660 Woodway, Suite 390
Houston, Texas 77063 USA
PH 713-789-8540
FAX 713-789-7367
TLX 910881 1159
Contact: John McManus

COMEX UK LTD.
Bucksburn House,
Howes Road,
Bucksburn,
Aberdeen, Scotland AB2 9RQ UK
PH 44-224-714101
FAX 44-224-715129
TLX 73394
Contact: Ken Hull

COMPUTALOG WIRELINE SERVICES, INC.
1320 South University Drive, Suite 720
Fort Worth, Texas 76107 USA
PH 817-338-0020
FAX 817-338-0371
Contact: Don Johnson

COMPUTALOG LTD.
800, 600 6th Avenue Southwest
Calgary, Alberta,
Canada T2P OS5
PH 403-265-2515

CONTROL FLOW, INC.
P.O. Box 40788
9201 Fairbanks-North Houston Road
Houston, Texas 77064 USA
PH 713-890-8300
FAX 713-890-3947
TLX 775819
Contact: Mike Angenend

CUDD PRESSURE CONTROL, INC.
550 Post Oak Boulevard, Suite 450
Houston, Texas 77027 USA
PH 713-877-1118
FAX 713-877-8961
TLX 430502
Contact: Eddie Goodman

DAILEY GEOPHYSICAL
4209 Chestnut
Temple, Texas 76503 USA
PH 817-773-4418
FAX 817-774-7774
Contact: Richard Dailey

DAWN OFFSHORE EXPLOSIVES, INC.
P.O. Box 492
229 Fifth Street
Gretna, Louisiana 76031 USA
PH 504-362-8994
FAX 504-340-0054
Contact: Kenny Charpentier

DEEP OCEAN ENGINEERING
1431 Doolittle Drive
San Leandro, California 94577 USA
PH 415-562-9300
FAX 415-430-8249
TLX 705816
Contact: Elizabeth Miller

DOOLEY TACKABERRY, INC.
314 Center Street
Deer Park, Texas 77536 USA
PH 713-479-9700
FAX 713-479-6321
Contact: Caesar James

DOWELL SCHLUMBERGER, INC.
15415 Katy Freeway, Suite 310
Houston, Texas 77094 USA
PH 713-579-5700
FAX 713-579-5777
Contact: Mike Bowman

DOWELL SCHLUMBERGER LTD.
Westhill Industrial Estate,
Westhill,
Skene,
Aberdeen, Scotland AB3 6TQ UK
PH 44-224-741424
FAX 44-224-743059
TLX 73670
Contact: Andrew Acock

DRIL-QUIP, INC.
13550 Hempstead Road
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PH 713-939-7711
FAX 713-939-8083
TLX 759108
Contact: Gary Smith

EAR-MARK
1125 Dixwell Avenue
Hamden, Connecticut 06514 USA
PH 203-777-2130
FAX 203-777-2886

EAST, BILL
2005 Alder Trail
Grand Prarie, Texas 75052 USA
PH 214-641-0584
Contact: Bill East

EASTMAN CHRISTENSEN
P.O. Box 670968
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FAX 713-985-3920
TLX 166248
Contact: Raul Lyon

EASTMAN CHRISTENSEN
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FAX 713-230-6321
TLX 762539
Contact: Heino Rohde

EASTMAN CHRISTENSEN, LTD.
Eastman House,
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PH 44-224-703511
FAX 44-224-824251
TLX 851-73547

EMTECH ENVIRONMENTAL SERVICES, INC.
312 S. Richey Rd.
Pasedena, Texas 77506 USA
PH 713-477-3107
FAX 713-477-3109
Contact: David Tyler

ENGINEERING HYDRAULICS, INC.
14715 NE 95th Street
Redmond, Washington 98052 USA
PH 206-881-7700
FAX 206-883-4473
Contact: Jerry Douphit

ENVIROTECH INTERNATIONAL
6608 Blvd. of Champions
N. Lauderdale, Florida 33068 USA
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FAX 304-970-3323
Contact: Tony Tavone

FMC CORPORATION
1777 Gears Road
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TLX 775-200

FMC CORPORATION
2825 West Washington Road
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Stephenville, Texas 76401 USA
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FAX 817-968-5709
TLX 6829280 FMC
Contact: Paul Crawford

FIRE MASTER CORPORATION
8555 West Monroe Road
Houston, Texas 77061 USA
PH 713-943-0920
FAX 713-473-3008
Contact: Bob Heffner

FLOWPLANT LTD.
Blackness Industrial Center, Unit 1
Blackness Road,
Altens Industrial Estate,
Aberdeen, Scotland AB1 4LH UK
PH 44-224-248700
FAX 44-224-898838

FREEZE TECHNOLOGY INTERNATIONAL, INC.
2100 West Loop South #800
Houston, Texas 77027 USA
PH 713-993-9030
FAX 713-993-0146
Contact: George Howard

FURMANITE ENGINEERING LTD.
Burnside Drive,
Farburn Industrial Estate,
Dyce,
Aberdeen, Scotland AB2 0HW UK
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FAX 44-224-724194
TLX 739162

GEARHART INDUSTRIES, INC.
1900 Geosource Plaza
2700 Post Oak Boulevard
Houston, Texas 77056 USA
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FAX 713-871-6490
TLX 6868877 GOHO
Contact: Roy Noble

GOEX, INC.
423 Vaughn Road West
Cleburne, Texas 76031 USA
PH 817-641-2261
FAX 817-556-0657
TLX 671240 GOEX UW
Contact: Warren Stephens

HALLIBURTON LOGGING SERVICES
P.O. Box 42800
2135 Highway 6 South
Houston, Texas 77242 USA
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FAX 713-496-8344
TLX 4620112
Contact: Larry Cavanna

HALLIBURTON SERVICES
1415 Louisiana, Suite 2300
Houston, Texas 77002 USA
PH 713-652-6000
FAX 713-652-6066
TLX 6719744HSSAL U UW
Contact: Mickey Thomas

HALLIBURTON SERVICES BLOWOUT TEAM
Drawer 1431
Duncan, Oklahoma 73536-0224 USA
PH 405-251-3554
FAX 405-251-3583
TLX 6719734
Contact: Richard Posey (251-2359)
Max Gibbs (251-4269)

HALLIBURTON SERVICES
Howe Moss Crescent,
Kirkhill Industrial Estates,
Dyce,
Aberdeen, Scotland AB2 0ES UK
PH 44-224-771991
FAX 44-224-770385
TLX 739106

HALLIBURTON *SKANDI FJORD*
Halliburton Services BV-MV Skandi Fjord
Visserijweg 5
9936 HB Delfzijl
Neatherlands
PH 31-5960-17600
FAX 31-5960-30417
TLX 53977 HALCO NL
Contact: Glenn Lewis

HOMCO INTERNATIONAL, INC.
P.O. Box 2442
4710 Bellaire Boulevard, Suite 200
Houston, Texas 77252 USA
PH 713-663-6444
FAX 713-663-5595
TLX 790701 HOMCO HOU

SEA OIL HOMCO LTD.
Kirkton Avenue,
Dyce,
Aberdeen, Scotland AB2 0BS UK
PH 44-224-724900
FAX 44-224-770191
TLX 7336 SEAOIL G

HYDRAULIC WELL CONTROL, INC.
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FAX 504-851-5436
TLX 279362
Contact: Larry Skeans

HYDRIL COMPANY
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Houston, Texas 77205 USA
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FAX 713-985-3353
TLX 168905 HYDRIL
Contact: Joe Roche

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Altens Industrial Estates,
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PH 44-224-878824
FAX 44-224-898524
TLX 851 739 457
Contact: Bruce Gilbert

HYDRO-CUT SYSTEMS, INC.
(see Macnamee International, Inc.)

INFERNO SNUFFERS, INC.
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College Station, Texas 77845 USA
PH 409-846-2474
FAX 409-846-7990
Contact: Mr. Norm Stevens
Mr. Greg Pierce

JET RESEARCH CENTER
2001 South I-35
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FAX 817-783-5812
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TLX 739106
Contact: David Miles

KEPNER PLASTICS FABRICATORS, INC.
3131 Lomita Blvd.
Torrance, California 90505 USA
PH 213-325-3162
FAX 213-326-8560
TLX 691646

KIDDE-GRAVINER LTD.
Poyle Road
Colnbrook
Slough SL3 0HB UK
PH 44-753-683245
FAX 44-753-685126
TLX 848214
Contact: Mr. Robin Burnett

KOETTER FIRE PROTECTION SERVICE COMPANY
5410 East Hampton
Houston, Texas 77039 USA
PH 713-590-7477
FAX 713-987-8418
Contact: Bill Holson

MH KOOMEY
8909 Jack Rabbit Road
Houston, Texas 77095 USA
PH 713-855-3200
FAX 713-855-0319
TLX 446570
Contact: Bob Cowan

LTV ENERGY PRODUCTS
8702 Clay Road
Houston, Texas 77080 USA
PH 713-939-0889
FAX 713-939-7932
Contact: Buck Holtcamp

LARSEN MARIN OY-AB
Työpajatie 24
SF-06100
Porvoo, Finland
PH 31-358-15-174950
FAX 31-358-15-174910

MACNAMEE INTERNATIONAL, INC.
4727 Cripple Creek
Houston, Texas 77017
PH 713-946-5121
FAX 713-941-6723
Contact: Stan Shockley

MACNAMEE SERVICES LTD.
Greenbank Business Centre,
Greenbank Road,
Tullos,
Aberdeen, Scotland AB1 4BN UK
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FAX 44-224-248032
Contact: Pete Waddel

MATTHEWS-DANIEL COMPANY
7135 Office City Drive, Suite 100
Houston, Texas 77087 USA
PH 713-644-1633
FAX 713-644-2107
TLX 775237 MATDAN HOU
Contact: Randy Young

MATTHEWS-DANIEL COMPANY
Marlon House
71-74 Mark Lane
London, England EC3R 7HS UK
PH 44-71-702-9697
FAX 44-71-481-2365
TLX 886856 MDLON G
Contact: Peter Bate

KEY INTERNATIONAL MATTHEWS-DANIEL PERSONNEL

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Egypt, Cario	Mike Sanders	202-2-904465
Norway, Tananger	Tore Strom	47-4-696177
U A E, Sharjah	Mike Bath	971-6-352851
Singapore	Ron Wilson	65-2-258688

MCDERMOTT INTERNATIONAL
1010 Common Street
P. O. Box 60035
New Orleans, Louisiana 70160-0035 USA
PH 504-587-4411
TLX 58-7412

MICOPERI S.P.A.
Via Enrico Acerbi
34-20161 Milan
Italy
PH 39-2-64673-1
FAX 39-2-66200165
TLX 332193/334609

MYOCO HYDRAULIC CUTTERS, INC.
P.O. Box 35137
Houston, Texas 77235 USA
PH 713-723-0110
FAX 713-723-1919
Contact: Rick Stephens

NITROBOOST LTD.
c/o Covey McCormick Communication
5 Queens Terrace,
Aberdeen, Scotland AB1 1XL UK

NOWCAM
P.O. Box 14484
7030 Ardmore
Houston, Texas 77221 USA
PH 713-747-4000
FAX 713-747-6751
TLX 775413166117
Contact: Jack Moseley

NOWSCO SERVICE, LTD.
1300
801-6th Avenue S.W.
Calgary, Alberta,
Canada T2P 4E1
PH 403-261-2990
FAX 403-262-8066
TLX 03-825617
Contact: D. A. Richardson

NOWSCO WELL SERVICE, LTD.
Saint Magnus House,
Guild Street,
Aberdeen, Scotland AB1 2NJ UK
PH 44-224-210810
FAX 44-224-210675
TLX (51) 739388
Contact: Reid MacDonald

NOWSCO WELL SERVICE (S.E. Asia) PTE. LTD.
Unit 6, Terrace Warehouse Block 2
Loyang Offshore Supply Base
Loyang Crescent
Singapore 1750
PH 65-5458866
FAX 65-5427477
TLX (87) 34476

OCEANEERING INTERNATIONAL, INC.
16001 Park Ten Place, Suite 600
P. O. Box 218130
Houston, Texas 77218 USA
PH 713-578-8868
FAX 713-578-5243
Contact: Marcie M. Smith

OFFSHORE RENTALS, LTD.
Souter Head Road,
Altens,
Aberdeen, Scotland AB1 4LF UK
PH 44-224-874-181
FAX 44-224-874-181
TLX 73513
Contact: Eddie Pawlick

OFFSHORE SYSTEMS ENG. LTD.
Boundary Road
Harfrey's Industrial Estate
Great Yarmouth, Norfolk NR31 0LY UK
PH 44-493-659916
FAX 44-493-653457
TLX 975084 OSEL G

OIL MOP, INC.
145 Keating Drive
Belle Chase, Louisiana 70037 USA
PH 504-394-6110
FAX 504-392-8977
TLX 587-486 OIL MOP BCHA

OILFIELD RENTALS
P.O. Box 1331
950 McCarthy Road
Houston, Texas 77251 USA
PH 713-672-1601
FAX 713-672-0821
Contact: Dick Polk

WELLCAT
A division of Oilfield Rentals for international and domestic well control problems same address and phone numbers. Contact: Ben Malina, Jr.

OTIS ENGINERING CORPORATION
BLOWOUT RECOVERY TEAM
5177 Richmond, Suite 1295
Houston, Texas 77056 USA
PH 713-993-0773
FAX 713-993-0061
TLX 4620247 OTISHOU
Contact: Rogers Romero

OTIS ENGINEERING CORPORATION
COIL TUBING SERVICES
P. O. Box 819052
Dallas, Texas 75381-0952 USA
PH 214-418-3000
FAX 214-418-4373
Contact: Hampton Fowler, 214-323-3294

OTIS ENGINEERING CORPORATION
SNUBBING SERVICES
P. O. Box 819052
Dallas, Texas 75381-0952 USA
PH 214-418-3000
FAX 214-418-4373
Contact: Steve Maddox, 214-323-3288

PATTON CONSULTING
2436 Monaco Lane
Dallas, Texas 77251 USA
PH 214-647-8106
Contact: Bob Patton

PETCO FISHING & RENTAL TOOLS, INC
P.O. Box 42804
Houston, Texas 77242-2804 USA
PH 713-953-1141
FAX 713-953-1568
TLX 762247
Contact: James Peppard

PETCO FISHING & RENTAL TOOLS LTD
Blankhead Industrial Estates, Unit 2
Bucksburn,
Aberdeen, Scotland AB2 9ET
PH 44-224-714747
FAX 44-224-714421
TLX 73572 PETCO G
Contact: John Lindley

PETROLEUM ENVIRONMENTAL TECHNOLOGIES, INC.
5636 Moore Road
Williamsburg, Michigan 49690 USA
PH 616-267-5021
FAX 616-947-1427
Contact: Larry Thompson

QUALITY VALVE MACHINE WORKS, INC
(formerly Lynn International)
P.O.Box 24727
8827 Clinton Drive
Houston, Texas 77229 USA
PH 713-675-7444
FAX 713-673-1923
Contact: Bernie Linders

RAIN FOR RENT, INC
P.O. Box 19027
5411 Brittmore
Houston, Texas 77224 USA
PH 713-937-6799
FAX 713-896-1444
Contact: Scott Heard

RENTEC INTERNATIONAL INC.
19424 Park Row, Suite 100
Houston, Texas 77084 USA
PH 713-579-1343
FAX 713-579-1531
TLX WUI 6503368817 MCI
Contact: Mike Todd

RIEDEL INDUSTRIAL WASTE MANAGEMENT, INC.
801 Mulberry,
Kansas City, Missouri 64101 USA
PH 816-474-1391
FAX 816-474-1275
Contact: Mike Dale

RIEDEL PETERSON ENVIRONMENTAL, INC.
1110 Howard Drive
Deer Park, Texas 77536 USA
PH 713-479-5295
FAX 713-479-6358
Contact: Hank Harder
Mike Walker

ROCKWATER LTD.
Stoneywood Industrial Park,
Dyce,
Aberdeen, Scotland AB2 0DF UK
PH 44-224-722877
FAX 44-224-722442
TLX 73368

RUSH JOHNSON & ASSOCIATES, INC.
1 Riverway, Suite 1400
Houston, Texas 77056 USA
PH 713-840-1642
FAX 713-840-8030
TLX 792135 RUSHJON HOU
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RUSH JOHNSON & ASSOCIATES LTD.
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TLX 94017082 RJAL G
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FAX 44-224-574253
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TLX 1565010
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92541 Montrouge Cedex
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Contact: R. Monti

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Kirkhill Industrial Estate,
Dyce,
Aberdeen, Scotland AB2 0GR UK
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FAX 44-224-723257
TLX 851-73397
Contact: J. C. Le Tartorec

SEAL TECH
P. O. Box 3806
Humble, Texas 77347 USA
PH 713-999-1499
Contact: Mike Tangedahl

SHAFFER
12850 West Little York
P.O. Box 1473
Houston, Texas 77041 USA
PH 713-937-5000
FAX 713-937-5614
TLX 6868765
Contact: Randy Schluze (Service)
David O'Donnell (Engineering)

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Denmore Industrial Estate,
Bridge of Don,
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FAX 44-224-825170
TLX 739178
Contact: Magnus Vika

SMITH INTERNATIONAL, INC.
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16740 Hardy Street
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FAX 713-233-5434
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Contact: Rick Tanner

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Aberdeen, Scotland AB2 8EF UK
PH 44-224-702821
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TLX 739 372 SII ABM
Contact: Andy Scott

SONSUB INC.
10905 Metronome
Houston, Texas 77043 USA
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FAX 713-984-2109
TLX 765081

SPERRY SUN DRILLING SERVICES, INC.
P.O. Box 60070
3000 North Sam Houston Parkway East
Houston, Texas 77205 USA
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FAX 713-987-4629
TLX 6868761
Contact: Jay Lieghton
Henk Jelsma

STEWART & STEVENSON, INC.
P.O. Box 201330
5717 I-H 10 East
San Antonio, Texas 78220 USA
PH 512-662-6655
FAX 512-662-9832

STOLT-NIELSEN SEAWAY A/S
Stoltenberggt. 1
P. O. Box 370
5501 Haugesund, Norway
PH 474-71-41-00
FAX 474-71-36-11
TLX 42-483

STOLT-NIELSEN SEAWAY (UK) LTD.
National Hyperbaric Centre,
123 Ashgrove Road West,
Aberdeen, Scotland AB2 5FA UK
PH 44-224-662300
FAX 44-224-684378
TLX 739171 NHCLG

SUBMAR, INC.
5200 Mitchelldale, Suite E-17
Houston, Texas 77092 USA
PH 713-688-6228
TLX 852264

SUB SEA INTERNATIONAL, INC.
1600 Canal Street
P. O. Box 61780
New Orleans, Louisiana 70161 USA
PH 504-523-3617
FAX 504-561-2836
TLX 58-4213

TAM INTERNATIONAL
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TLX 910881 1659
Contact: Ed Stewart

TAM INTERNATIONAL
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FAX 403-236-2443
TLX 03 821172 CGY
Contact: Rod Jensen

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Abbotswell Road, Unit 1
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FAX 44-224-890038
TLX 739145
Contact: Norman Williamson

TELECO OILFIELD SERVICES
4 Greenway Plaza, Suite 841
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FAX 713-850-3918
TLX 775139 SONAT HOU
Contact: Richard Hagin

TELECO OILFIELD SERVICES, LTD.
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Portlethem,
Aberdeen, Scotland AB1 4PF UK
PH 44-224-780545
FAX 44-224-782045
TLX 851-739345 TELABZ G

TENSOR (MAGRANGE)
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Austin, Texas 78761 USA
PH 512-251-4131
FAX 512-251-5798
TLX 4940124
Contact: Bob Waters

THOMPSON, T. LTD.
1075 Bellevue Way Northeast, Suite 123
Bellevue, Washington 98004 USA
PH 206-641-5550
FAX 206-641-3301
Contact: Terry Thompson

THOMPSON, T. LTD.
P. O. Box 91506
West Vancouver, British Columbia,
Canada V7V 3P2
PH 604-921-8300
FAX 604-921-8301
Contact: Terry Thompson

TOOLS UNLIMITED, INC.
15502 Old Galveston Road, Suite 803
Webster, Texas 77598 USA
PH 713-488-6749
FAX 713-488-6382
Contact: Charlie Curtis

TRI-STATE OIL TOOLS
3900 Essex Lane, Suite 650
Houston, Texas 77027 USA
PH 713-439-8350
FAX 713-621-3908
Contact: Bobby Biano

TRI-STATE OIL TOOLS
2701 Village Lane
P.O. Box 5757
Bossier City, Louisiana 71171-5757 USA
PH 318-747-0467
FAX 318-747-0652
TLX 78-4559
Contact: B. E. Foster

TRI-STATE OIL TOOLS (UK)
Kirkhill Road,
Kirkhill Industrial Estate,
Dyce,
Aberdeen, Scotland AB2 0ES UK
PH 44-224-723376
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TLX 73403 TRISTA G

- U -

VANN SYSTEMS
16350 Park Ten Place, Suite 107
P.O. Box 42800
Houston, Texas 77242-2800 USA
PH 713-496-8100
FAX 713-496-8154
TLX 6719760 VANNHOU
Contact: Don McAda

VANN SYSTEMS
Howe Moss Crescent,
Kirkhill Industrial Estate,
Dyce,
Aberdeen, Scotand AB2 OES UK
PH 44-224-771991
FAX 44-224-770385
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Contact: Bill Petrie

VECTOR MAGNETICS
236 Cherry Street
Ithaca, New York 14850 USA
PH 607-273-8351
FAX 607-273-6137
Contact: Arthur Kuckes

VETCO GRAY, INC.
11800 Charles Street
Houston, Texas 77041 USA
PH 713-466-0554 (Land)
713-448-4410 (Offshore)
FAX 713-878-5109
Contact: Darrell Davis (Land)
Buddy Myers (Offshore)
Max Kattner (Diverters)
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VETCO GRAY UK LTD.
Broadfold Road,
Bridge of Don Estate,
Aberdeen, Scotland AB2 8EY UK
PH 44-224-704313
FAX 44-224-704315
TLX 73360 VETAB G

VETCO GRAY SINGAPORE (PTE.) LTD.
2 Benoi Road
Jurong Town
Singapore 2262
PH 65-861-3344
FAX 65-861-3103
TLX RS 21409 VETCO

WACHS TECHNICAL SERVICES, INC.
100 Shepard Street
P. O. Box A
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FAX 708-520-1147
TLX 283483
Contact: Mr. Mike Kirkpatrick

WASTE MICROBES
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Houston, Texas 77092 USA
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FAX 713-956-7305
Contact: Bruce Johnson

WELLCAT
(see Oil Field Rentals)

WELLSTREAM CORPORATION
800 Bering Drive, Suite 401
Houston, Texas 77057 USA
PH 713-266-8556
FAX 713-266-8431
Contact: Stephen Pahls

WELLSTREAM CORPORATION
Port of Panama City
Panama City, Florida 32401 USA
PH 415-924-1066
FAX 415-924-1095

WESTERN ATLAS INTERNATIONAL
10205 Westheimer
P. O. Box 1407
Houston, Texas 77251-1407 USA
PH 713-972-4000

WESTERN PETROLEUM SERVICES COMPANY
515 Post Oak Boulevard, Suite 600
Houston, Texas 77027 USA
PH 713-629-2600
FAX 713-629-2626
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6.0 INNOVATIVE POLLUTION CONTROL MEASURES

6.1 INTRODUCTION

Crude oil is a naturally occurring material that has long been part of the environment. Seepage from faults, fissures and other defects in the earth's crust into its oceans have long been known. Although difficult to quantify, it is estimated that 1.5 million barrels of oil enter the world's oceans each year from natural seeps, though this amount may be an order of magnitude too low. (National Research Council, 1985)

Drilling and producing oil rarely occur in a pristine environment. The possibility of a blowout with consequential pollution exists concomitant with all such activities. A return to pre-spill conditions could mean only returning to a less damaged state than the highly disturbed condition that existed during the blowout. Additionally, returning to some baseline of contamination may be difficult since the environment is dynamic, both from human activities and from natural change.

This portion of the Joint Industry Program for Floating Vessel Blowout Control is an introductory effort to determine means to control and abate oil spill-related pollution from a deep subsea blowout. It is not intended to be an exhaustive study of existing pollution management techniques. There are other studies available on pollution control techniques, most of which are associated with near shore situations.

Oil spill control and remediation in the open seas has not been addressed by most studies since it is assumed that there will be little impact on shorelines and inland waterways. It appears that there is little concern for environmental damage if one's beaches are not in danger of being oiled. The low probability of a large spill from drilling activities may have caused the scientific community to concentrate on other, more urgent, areas of study.

6.2 SECTION SUMMARY

Pollution abatement and control is currently an area of active study. New data and analyses are published on an very frequent basis, almost daily. A rigorous and continuous analysis of various sources of data is required to maintain an appreciation of the current state of the art in pollution control.

Statistically, there is a low probability of significant pollution resulting from an offshore blowout. There has been no pollution resulting from a deepwater blowout to date. The frequency of deepwater blowouts is itself quite low, 0.214% from available worldwide statistics. Of those offshore wells that have blown out, very few have produced significant pollution. The result is a low total probability of a serious pollution problem from deepwater drilling.

Statistical analysis may not adequately address the pollution that can occur from a freak deepwater blowout. The Ixtoc 1 blowout stands as the largest single source of oil on the sea prior to the intentional release of oil on the Arabian Gulf by Iraq in the recent conflict. There is insufficient information to determine how serious a deepwater blowout could be if it did occur.

The behavior of the blowout plume in a deepwater situation is not well known. Factors that should be considered include subsea cross currents, stratification of seawater layers, low seafloor temperatures and the effect of a tall seawater head on the base of the plume. Plume meandering in a deepwater situation may affect surface vessel deployment for monitoring, vertical intervention and spill cleanup. Mixing of oil with seawater in the plume may result in significant dispersion and emulsification.

Natural abatement processes are thought to be more effective in the open seas than they are near coasts in relatively shallow water. It is expected that most deepwater drilling, and most associated blowouts, will occur in open sea conditions. Natural processes could significantly reduce the impact oil from a deepwater blowout on shorelines and thus the public's perception of the effects of the blowout. These natural processes will ultimately result in removal of oil from the sea if no other remediation methods are employed.

Existing surface collection, containment or treatment methods are likely to be ineffective in removal of oil from the open seas. Some new treatment technologies, particularly dispersant treatment and bioremediation, may assist in cleanup efforts.

Subsurface collection and containment devices are considered impractical for use in deep water. These bulky devices will probably be difficult to transport and position over the plume. Entrainment of seawater is expected to overload separation and storage facilities quickly, especially if significant emulsion of the effluent occurs below the surface. Some additional efforts could be extended toward design of a device that would set and seal on the seafloor, but the inherent deficiencies of this type of system probably cannot be overcome.

It is recommended that bacterial cultures, nutrients and enzymes be injected directly into the root of the plume at the seafloor for *in situ* bioremediation of the spill. It has been suggested that dispersants be injected in the same way by previous researchers. The recent successes of bioremediation on oil spilled on the sea leads to an extension of this technique to subsea spills. Reactant polymers can also be injected. Suggestions are made in this report for flow-through injection devices to place these materials in the plume.

It is also recommended that this analysis be supplemented with a study to develop specific designs and procedures for treatment of the plume subsea. Rigorous design calculations, equipment specifications and procedural development are beyond the scope of this study.

These devices and methods, once fully developed, may be of as much significance to the industry for their public relations benefit as for their impact on the environment. If significant pollution occurs in the future from deepwater drilling activities, the public will once again perceive the oil industry as the spoilers of the planet unless they can be convinced that some measures can be taken to mitigate the effects of the resulting spill.

6.3 BOUNDARIES OF POLLUTION STUDY

6.3.1 Scope of Study. This analysis is an introductory study as defined by the overall scope of the total project. It is not intended to be a rigorous analysis of pollution control methods and equipment. Instead, the concepts behind existing techniques have been analyzed for their applicability to deepwater blowout situations.

This review is intended to provide a perception that will lead to new designs and improved technology for handling deepwater blowout situations. Current technology and equipment is considered inadequate to combat an open sea spill. Existing pollution control countermeasures are discussed briefly.

This analysis will discuss pollution control methods for oil well blowouts only. Gas well blowouts are not anticipated to result in a significant level of pollution. Gas is quite mobile through seawater and will inevitably be expelled at the surface to burn or dissipate into the atmosphere where it will dilute rapidly. Any associated condensate will probably evaporate from the water surface into the atmosphere resulting in no long-term pollution to the sea.

The seas contain a high concentration of methane, the major component of natural gas, from normal biological sources. The volume of gas lost to seawater by dissolution will be small and will only elevate background levels. Since most organisms tolerate methane in water quite well, toxicity from a gas blowout is expected to be minimal.

Crude oil, on the other hand, is a mixture of compounds, some of which are highly toxic. Physical properties of crude oil and its emulsions with seawater can create thick, sticky masses that will entrap and smother sea-dwelling creatures quickly. This study therefore concentrates on oil blowouts.

6.3.2 New Solutions and Equipment. Any new techniques for combating pollution from a deepwater blowout should include the following features:

- They should be simple to fabricate and operate.
- Low cost is emphasized.
- Pollution control and cleanup devices should utilize, as much as possible, off-the-shelf items needing little additional technology development.
- Short lead times are necessary.
- The solution should have a high probability of success.
- New solutions should insure a high level of safety for personnel implementing the solutions.

New approaches should involve these factors, but are not necessarily limited to simplistic methods.

Concepts for equipment design are discussed in the report, but detailed engineering designs and specifications are left to future studies. Research and development costs should be estimated. Fabrication methods should be defined in these future studies as well. Cost and ownership sharing may evolve from these future studies as well as issues involving regulatory authority for their implementation. All of these are beyond the scope of this study.

6.4 POLLUTION STATISTICS

6.4.1 Introduction. The purpose of this analysis is to develop an understanding of the industry's past performance on pollution from offshore blowouts. The probability of significant pollution from an offshore blowout occurring in deepwater (greater than 100 m) is currently zero, since there has been no reported event in the past. Realistically, it may be better to use an overall statistical probability for an offshore blowout than to limit discussion to deepwater blowouts only.

The probability of an offshore blowout occurring is quite low. (Westergaard, 1989) Most offshore blowouts result in only limited pollution from oil contamination. Many blowouts are shallow gas. In others the volume of oil escaping into the sea is very small due to bridging within hours of the event. In some of these essentially all of the oil is consumed by a fire on the rig or platform. Thus, statistical probability of a major pollution event occurring, the product of blowout probability multiplied by the probability of spillage, is very small.

Technology improvements in drilling procedures should reduce future risks of a large spill from deepwater wells. Improved blowout control procedures, capping methods such as vertical intervention and relief well drilling techniques will further limit the probability of long term pollution from a blowout. Pressure exerted by a column of seawater will cushion the effects of a blowout in deep water.

One researcher notes that as the industry attempts more and more challenging projects, it would be expected that blowout frequency would increase. (Westergaard, 1987) Actual data from past events indicates, however, that blowout frequency has remained surprisingly constant. He concludes that the difficulties are apparently being compensated for by better equipment and taking adequate precautions.

It is a fact that drilling is moving into deeper waters. For the industry to economically justify the cost of this drilling larger reservoirs must be targeted for exploration and development. If a blowout occurs from one of these large reservoirs, oil-related pollution could be severe.

Suffice it to say that there is simply not enough information to determine the probability of a significant pollution event resulting from a deepwater blowout. This lack of information should not lull the industry into complacency on this issue. It is possible that a deepwater blowout could result in pollution that could be significant. Witness the 1979 blowout that occurred on the Ixtoc 1 in the Gulf of Campeche, Mexico.

Worldwide statistics on blowouts and pollution are difficult to ascertain. Statistics exist for some areas such as the North Sea and the Gulf of Mexico (US Offshore Continental Shelf) and are published frequently. For other areas, little statistical information exists. Some minor events are not reported. In some situations, data on blowouts is in restricted files particularly when the operator or its contractors may face legal liability. Thus, to perform a statistical analysis on blowout-related pollution worldwide is difficult and subject to error.

Data presented here is thought to be representative of worldwide conditions, however. It is recognized that many of the same companies that are drilling in deep water in one area for which statistical information is available are doing so all over the world. It is doubtful that an operator would have deepwater drilling methods and standards that differ significantly from one area to another.

6.4.2. Limitation of Data Selected. Statistics have been maintained by regulatory agencies since 1955 on wells drilled off the US coast which involves mostly the Gulf of Mexico. Some worldwide data also exists. A large number of these wells were drilled early in the industry's history in shallow waters using essentially surface drilling techniques (i.e., land rigs assembled on jackets near the shore). Not only has the industry moved into deeper waters, drilling equipment and techniques have changed significantly since 1976.

For this analysis, US, North Sea and worldwide data for the period from 1970 through 1989 has been used for the following reasons:

- It was during this period of time that the industry drilled the deeper wells prompted by a change in worldwide oil prices and demand.
- Regulatory agencies throughout the world have mandated more stringent well control equipment and training programs for offshore drilling personnel during this period of time.

- These data probably reflect future blowout and pollution probabilities since similar drilling equipment, well control techniques and blowout kill procedures are expected to be used.

- Accuracy of this data is thought to be higher than data from previous years.

It is recognized that this is a reduction in sample size from all offshore blowouts worldwide, but distortion of the analysis is not expected.

6.4.3 Blowout Statistics. The following data on blowouts during drilling operations are based on worldwide data from 1970 through 1984:

		Blowouts per 1000 Wells Exploration		Development
Shallow Gas		1.50		0.64
Deep Gas	4.84		1.28	
Oil	0.81		0.22	
Total Deep		5.65		1.50
TOTAL		7.15		2.14

Approximately 80% of all drilling blowouts are caused by deep or shallow gas. Most blowouts from uncompleted wells bridge within a few days. Blowout duration data was analyzed on 409 US Gulf of Mexico events. Of these, 102 flowed less that one day, 75 were 1 to 3 days and only 13 were more than 30 days.

It was also found that 50% of the blowouts on production platforms occurred during drilling, testing and completion. The other 50% were associated with production activities. Exploratory drilling was found to have a blowout frequency 25 to 50 times greater than production operations.

6.4.4 Pollution Statistics. Worldwide pollution data for oil and gas operations is incomplete and not readily available. The following statistics are based on offshore USA and North Sea data:

Phase	Estimated Percentage of Blowouts That Will Produce Large Oil Spills
Exploration Drilling	< 2.0%
Delineation and Subsea Production Drilling	8.0%
Platform Production Drilling (including completion)	1.4%
Platform Production Wells (production, wirelining and workovers)	20.0%

A 1986 US MMS report indicated that there has been no historical record of any volume of oil being spilled in the US offshore continental shelf area during exploratory drilling. The 1989 US MMS report confirms that none occurred from 1986 through 1989.

The most serious spill during development well drilling operations in the US OCS occurred in 1987 when 60 bbls of oil were lost. During the period from 1971-1989, 99% of drilling well blowouts were 10 bbls or less. No oil was associated with the 39 exploratory well blowouts that occurred during the same time period.

Only one large blowout has occurred in the Gulf of Mexico in the last 20 years, the Ixtoc 1. Approximately 3.5 million bbls of oil were released over 290 days in 1979 and 1980. It stands as the exception to the statistical rule with respect to pollution.

By comparison, over 2.9 million barrels of oil were spilled by accidental tanker spills in 1983. In 1988 and 1989, 2.74 million bbls were spilled from tankers. The *Valdez* lost 285,000 bbls. There have been several recent tanker-related incidents that have added to the totals.

It is concluded that blowout prevention is becoming more effective while tanker accidents are becoming more prone. The possibility of major pollution from drilling operations in deep water cannot be ignored, however.

6.4.5 Gulf War Statistics on Pollution. A recent news article in the *Oil & Gas Journal* (July 1, 1991, p. 31) reported that Saudi officials estimate that Iraq released a total of 6 to 8 million barrels of oil (MMBO) onto the waters of the Arabian Gulf during its eight month occupation of Kuwait. This is easily the largest spill, intentional or accidental, in the world's history.

Representatives of the Saudi Arabian Meteorological and Environmental Protection Agency reportedly indicated that only 10% of the original oil remained afloat as of July 1, 1991. Contractors and volunteers have removed and recovered 1.4 MMBO to date using 70 vessels working in the Gulf. The remaining 4.0 to 5.8 MMBO have apparently been dealt with by natural abatement.

The actual volumes of oil released on and in the Gulf may never be known. Much was pumped through purpose-built lines in the northern part of Kuwait to the Gulf without ever having been measured. Oil is still leaking into the sea from damaged offshore loading facilities. Several tankers sunk during the hostilities are also continuing to leak oil. It appears obvious that cleanup efforts will continue for some time in the Gulf.

It is expected that natural bioremediation will account for a large part of the spilled oil owing to the active indigenous bacterial population in the Gulf. The Gulf is known for it high incidence of natural seeps. Crude oil spills, most of which are associated with tanker transportation of crude, have occurred over several years. The background microbial population is correspondingly high, and expeditious natural bioremediation of any spilled oil in the Gulf is anticipated.

6.5 PLUME DYNAMICS

6.5.1 Introduction. Plume dynamics describe the behavior of two fluids of differing densities, the lighter of which is traveling upward through the heavier one. Commonly studied are thermal smokestack plumes in the atmosphere. This study is concerned with underwater plumes created by blowout fluids exiting a mudline source such as a BOP stack. These move upward through a seawater column to the surface. Subsea blowout plumes can be analogized with atmospheric thermal plumes although some differences exist.

A significant amount of theoretical work has been done on subsea blowout plume behavior. It is discussed in Section 6.5.5. (Figure 6.5.1)

The theoretical work has been complemented with laboratory work, small tank tests and large open facility analyses. No full scale tests have yet been undertaken. It is necessary to integrate the findings from the theoretical and laboratory experimentation with actual field experiences and observations to have optimum results from the work. This is one of the goals of this investigation.

Plume dynamics have several effects on pollution characteristics and possible counter measures. Some are listed below and will be explained more thoroughly in subsequent sections:

- Water entrainment that increases the volume of the plume.
- Physical shearing of the oil from the blowout into swarms of fine droplets.
- Radial currents at the surface that spread the oil into large slicks.
- A quiescent zone which permits remedial work near the blowout source.

An understanding of plume dynamics is necessary to fully appreciate subsurface remedial techniques.

6.5.2 Prior History. Between 1956 and 1970, there were 55 offshore blowouts worldwide. Losses of oil were small and environmental damage was restricted.

In 1969 Union Oil experienced a blowout in the Santa Barbara Channel in California. This single incident raised the public's awareness of the situation and provided an impetus to development of various means of coping with offshore blowouts. It is noted that this incident occurred during a time when the public was sensitized toward environmental issues. The results of this blowout may have been exaggerated by the media and in the minds of the public. Several solutions to offshore blowout containment and pollution control were developed as a direct response of this blowout.

In 1977, a blowout in the Norwegian sector of the North Sea added an infusion of concepts and tests on subsea blowout containment devices. This technology continued to be developed until the 1979 blowout of Pemex's Ixtoc 1 in the Bay of Campeche. The magnitude of the Ixtoc 1 blowout prompted an abrupt increase in the awareness of the public for the potential of pollution from an offshore blowout.

Within the industry a corresponding increase in pollution containment efforts occurred in response to the Ixtoc 1 blowout. This event also spurred theoretical thinking into blowout plume behavior. The "Sombrero" used in an attempt to contain blowout effluent from this well was not generally considered to be successful by the industry. It was, however, a significant step toward subsea containment technology development. It remains as the only full-scale application of a subsea containment device used in response to a blowout. Details of the "Sombrero" are given in Section 6.8.

Subsequent to the Ixtoc 1 blowout, a small group of individuals began studies on plume behavior. The original work was a 1975 study entitled "Hydrodynamics of an Oilwell Blow-

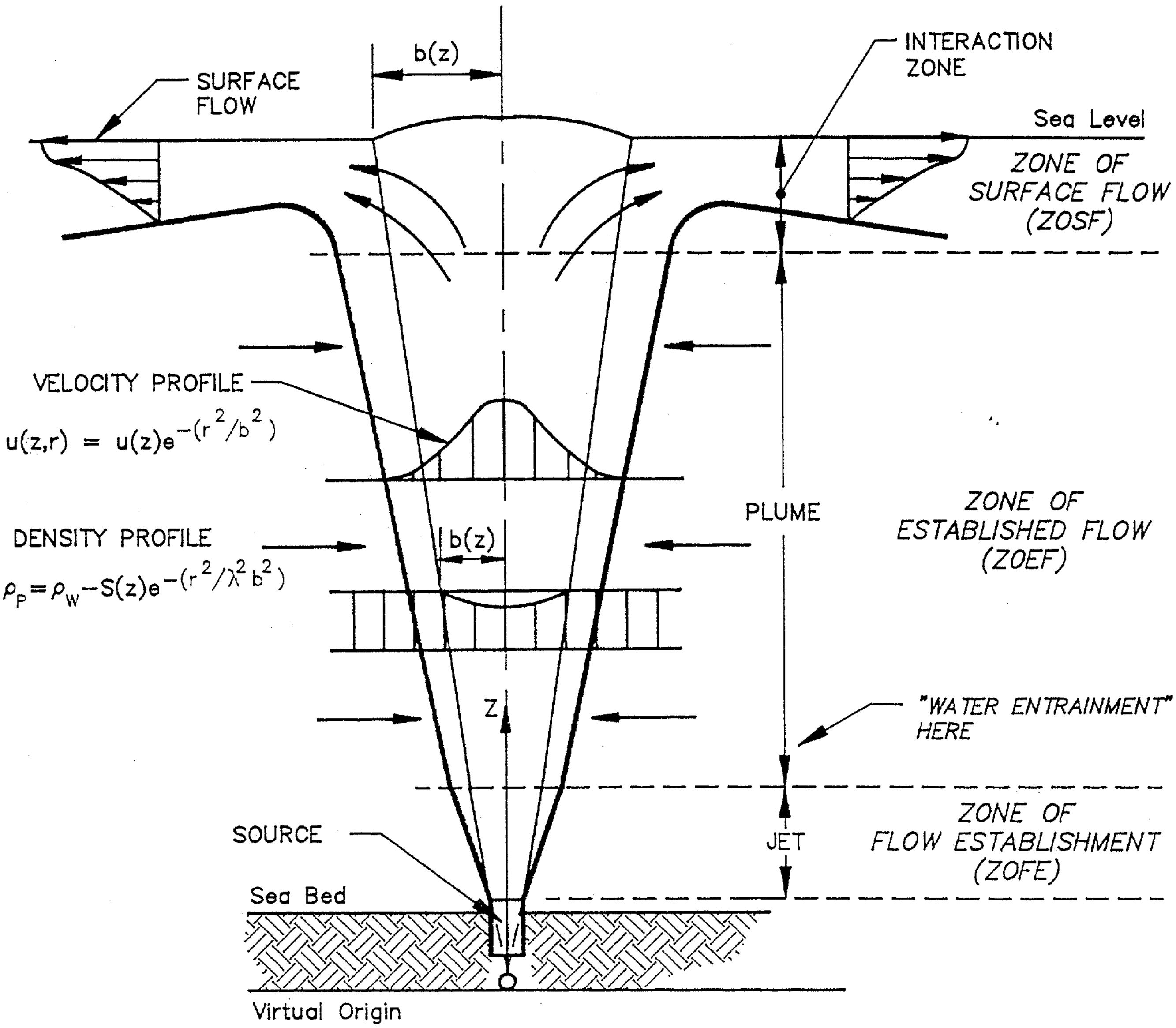

Figure 6.5.1

Theoretical Oilwell Plume

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out" by Dr. D. R. Topham with the Canadian Department of the Environment. Previous theoretical work influenced his study including that of Bulson, Carstens, Ditmars and Cederwalls, Kobus and Turner. A paper by Hussain and Seigel, 1976, is also a respected contribution to bubble plume theory. None of this work, however, considered the expansion of the gas bubbles in the plume as they ascended.

In 1980, Fannelφp and Sjφen provided a valuable work entitled "Hydrodynamics of Underwater Blowouts." These authors later worked on some practical aspects of the problem.

Also, in 1980, Dr. Jerome (Jerry) Milgram of MIT prepared a significant paper developing a firm theoretical understanding of plume behavior as it affects buoyancy. He also studied tension leg platforms working in blowout boils and innovative subsea collectors/separators. His work involved laboratory tests with bench scale models as well as larger experiments at open facilities in Florida. This work is reported in several documents which are usually referenced as basic study materials in this field. Specific references are included in Section 6.11.

It is difficult to identify and credit all technical sources that played a role in developing a better understanding of plume behavior. The absence here of mention is not intended to detract from the contribution of past works.

The last major efforts into subsea pollution control development were two US Department of the Interior Minerals Management Service sponsored studies in 1985 and 1987. The first of these involved subsurface containment techniques and was prepared by Brown & Root. The latter was prepared by Stewart Technology Associates and detailed a ship-mounted surface collection design. Both are extensive and are recommended for further study, particularly the Brown & Root study which provides a concise treatment of plume dynamics, subsea collectors/separators and pollution control for subsea blowouts.

Sections 6.7 and 6.8 detail concepts and designs presented in these studies. It seems the next logical step in assessing plume dynamics and in providing a measure of protection against environmental damage from a subsea blowout would be to implement one of these designs. This has not been done as yet. High cost associated with these precludes the likelihood that they will be implemented in the future.

6.5.3 Plume Mathematics. A cursory understanding of the mathematics associated with blowout plumes is important. It must be integrated with experiences and observations on blowouts to yield maximum benefit, however. Section 6.5.4 discusses practical aspects of plume dynamics.

Original mathematical models describing bubble plumes developed out of thermal gas plume theory, primarily smokestack plumes of warm effluent gases into the atmosphere. A brief discussion on plume mathematics will be given here. For a more complete understanding, reference is made to a number of sources detailed in Section 6.11. Dr. Milgram's 1983 paper entitled "Mean Flow in Round Bubble Plumes" was extensively used for this discussion.

The plume shown in Figure 6.5.2 describes basic velocity profile associated with plumes. Most theory and laboratory work has been done for gas blowouts. The density difference between gas and any liquid is significantly greater than that between two liquids such as seawater and oil from a low GOR subsea blowout. There will be compression of gas from a deepwater blowout due to the seawater head above the source of the effluent. Some differences between the mathematical descriptions of these types of plumes and the gas/water plumes are expected. They are not anticipated to behave in a completely different manner, however.

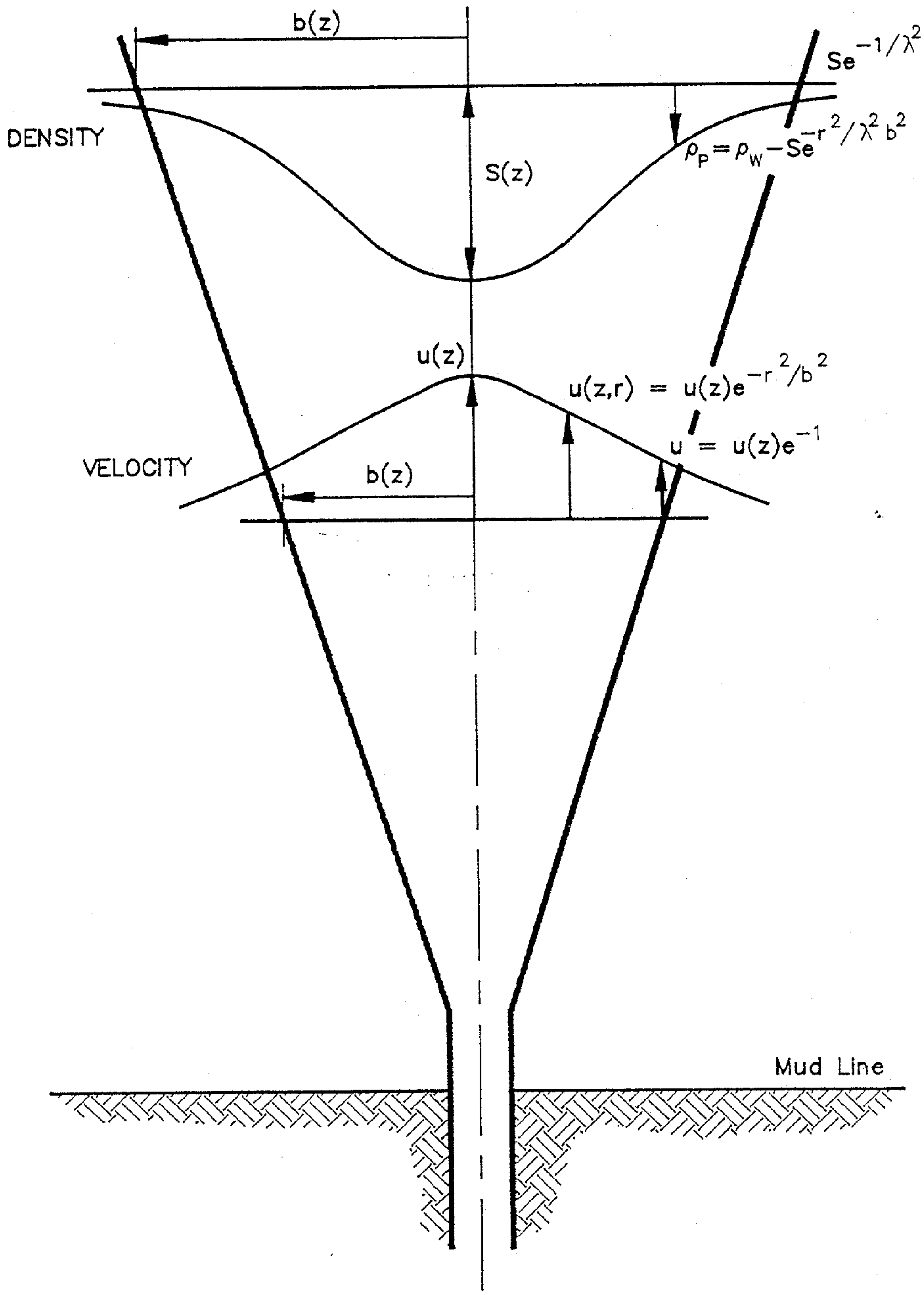

Figure 6.5.2

Radial Distribution of Plume Density and Vertical Velocity, [17]

Ref: After Milgram

Subsea plumes have been divided into 3 distinct regions as follow:

- Zone of Flow Establishment (ZOFE)
- Zone of Established Flow (ZOEF)
- Zone of Surface Flow (ZOSF)

As the flow exits the source and moves upward to the surface, it entrains large volumes of water. Near the surface, the direction of flow changes 90° and moves radially away from the apex of the blowout boil.

The Zone of Flow Establishment (ZOFE) occurs near the source of the blowout. It originally is caused by the momentum of well fluids exiting the well at some velocity and encountering a static water mass. As the momentum is dissipated, gas and/or oil buoyancy begins to exert the force necessary to cause the effluent to continue to rise. The depth at which buoyancy assumes control of upward movement is defined as the interface between the ZOFE and the Zone of Established Flow (ZOEF) regions. It has been shown by some investigators that the initial momentum of the exiting fluids at the source is relatively unimportant in water depths greater than 100 m.

The ZOFE received little theoretical treatment in original papers. It appears that the upper two zones were of more interest to researchers at that time. It is noted, however, that this zone is described as "semi-quiescent" with the bulk of the layer essentially unaffected by the jet of high velocity effluent penetrated through it.

The ZOEF exists above the bottommost ZOFE and below the Zone of Surface Flow (ZOSF). As the effluent moves upwards it entrains large volumes of water. Velocity and density within the plume are characterized by Gaussian distribution as follows:

$$u(r,z) = U(z)e^{-r^2/b^2} \qquad (6.5.1)$$

$$p_w - p_p(r,z) = S(z)e^{-r^2/l^2b^2} \qquad (6.5.2)$$

Where:

u	=	vertical liquid velocity
z	=	height above the source
r	=	radius from centerline
U	=	centerline velocity
b	=	plume radius
p_w	=	mass water density
p_p	=	mean mass plume density
S	=	density defect
l	=	ratio, (gas containing radius)/(plume radius)

Milgram, et. al., later introduced a bubble slip velocity of 0.35 m/s into the model.

A key factor affecting theoretical pollution investigations is the entrainment coefficient. It affects the volume of water pulled into the plume from the outer regions of the ZOEF. A small deviation in the coefficient can amount to relatively large volumes of fluid. Milgram, et. al., used a fixed entrainment coefficient in the same manner as Fannelφp & Sjφen. It was later discovered that this coefficient increased with increasing gas flow. Insufficient data exists to develop a variable entrainment model.

It is noted that all models assume the plume rising through a uniform water column. Temperature variations (stratification) and cross-currents are not addressed. It is thought by at least one researcher that cross-currents will have little effect on plume configuration or behavior since the upward velocity of the plume will exceed subsea current velocity (Manadrill Drilling Management, Inc., COGLA contract, 1985). Stratification of warm and cool seawater layers may result in shearing of some of the effluent off the main plume body leaving droplets of oil in the water column to ascend at a slower rate. (McDougall, 1975)

Several good efforts have addressed plume modeling. Brown & Root in their work for the MMS summarized the following areas of concurrence by the investigators:

- Flow characteristics of the blowout through the majority of the water column are those of a buoyant plume instead of a jet. The generally accepted plume profile is that illustrated by Figure 6.5.2.

- Gaussian radial distribution of the velocity and density defect correlate with experimental data.

Researchers, however, do not agree on the key points listed below:

- Surface plume diameter estimates vary from 16 to 100% of the depth of the water at the blowout site.

- Entrainment ratios and scale ratio differ significantly between investigators.

The rate of transport of oil to the surface is dependent on plume velocity which, in turn, depends on the volume of free gas in the effluent stream.

6.5.4 Practical Aspects of Plume Dynamics. A discussion on practical aspects of blowout plumes might differ depending on the individuals participating in the discussion. Also, the term "practical" is a matter of reference.

In this discussion, it will relate to aspects of the blowout plume that affect pollution or well control efforts in some manner. Attention will be focused on the ZOFE at the bottom, and on the ZOSF at the top of the water column. The middle section, or the ZOEF, is important because it is the portion of the water column in which large volumes of seawater are entrained in the plume. However, it will not be discussed in detail because control operations and pollution countermeasures will not be conducted in this zone.

The ZOFE has received little study in the past. It is important, however, if a view is taken that work near the blowout source can be safely undertaken by divers or ROVs working in semi-quiescent conditions in this zone. In some situations, divers have climbed to the top of the BOP stack and touched the blowout plume with their hands. There was no tendency for them to be pulled into the plume as might be expected. Obviously, such work must be done with caution. The result, however, is that this area is open for work by ROVs or divers. Long ROV manipulators are not necessary.

As the oil exits the well in a jet and encounters the relatively dense water layer at the source, it is sheared by physical forces into small droplets. These droplets will rise with low terminal velocities. Some will likely remain dispersed in the water column. Others will coalesce and entrap water to emerge on the surface as an emulsion (chocolate mousse) as was the case at the IXTOC I blowout.

This phenomenon may provide an opportunity to inject a variety of chemicals for treatment of the pollution including dispersants, polymers and bacterial "soups" at the source of the blowout. The force of the "jet," combined with intimate mixing within the plume, will allow treatment of the effluent without relying exclusively on surface countermeasures. Thus, plume dynamics can be used to assist in remediation of blowout induced pollution. This concept is discussed more fully in Section 6.9.

Caution must also be exercised in approaching the ZOFE on the bottom through the ZOEF and the ZOSF. In these two zones, lateral currents can be strong. ROV tethers or diving hoses can be pulled into the plume with end devices or personnel dragged upwards by plume forces on the lines. This has occurred in past cases. However, this is the only known danger in these situations.

The ZOSF has large surface currents which must be considered. Vessels must be moored securely to stay on location near the surfacing boil. Dynamic positioning does not work well in these situation due to gas entrainment in the seawater near the boil. Also, there is a significant loss of thruster efficiency in this situation.

This entrained hydrocarbon volume near the surface can result in some loss of buoyancy of a work vessel. The theoretical term used by researchers for this loss is "density defect." While this density reduction may seem serious, research has shown that it is not significant in practical terms. They are small in the worst cases except in very shallow water with very high gas flowrates.

Some blowout specialists have developed techniques to work directly over gas boils taking into account the small density defect. In one case a semisubmersible worked over a live blowout boil in 200 ft of water for several weeks without adverse effects on the rig.

Gas measurements above the surface are obviously important if the intent is to work over the boil. It is logical to assume that all gas and oil would evolve out of seawater at the surface owing to their relative insolubility in water. However, field measurements indicate that this does not appear to be the case.

For some reason that has not been defined as yet, gas does not seem to break out of the seawater at the anticipated rate. This phenomenon has been confirmed by field measurements in actual blowout cases. In the situation described above, gas detectors were lowered to within 18 inches of the water line, but gas was not detected even though it was visible in the water from the moonpool area.

Some blowout reports indicate that froth on the surface has resulted in sinking of vessels through damaged or partially open hatches. It seems unlikely that gas/seawater froth could furnish a sufficient volume of fluid in a reasonable length of time to sink a vessel. It is possible that some crude oils having high concentrations of natural surfactants could cause a surface froth by promoting stable foams. These foams could cause problems by interfering with surface collection efforts.

6.6 NATURAL ABATEMENT PROCESSES

6.6.1 Introduction. Natural forces play a large part in the removal of crude oil spilled into the sea. These are usually considered as long-term solutions where surface techniques such as containment, recovery and treating are short-term measures. (Section 6.7) Both types of solutions mitigate environmental damage from a spill, but the short-term measures significantly affect the public's perception of the impact of the event.

When oil enters the sea from natural seeps, spills or blowouts, organisms and chemical processes start the process of breaking down the oil. Microbes present in all oceans begin to multiply and consume the oil. Other natural abatement mechanisms act simultaneously with microbial degradation. These include spreading, evaporation, solution, dispersion, emulsification, tar ball formation, sedimentation, photochemical oxidation and uptake by other organisms. (Figure 6.6.1)

Ultimately the oil is reduced to short-chain carbon compounds that re-enter the biogeochemical carbon cycle in the natural environment. This occurs in the first few months for some components, but others may require years.

The ecological impact of oil spills has proven to be shorter than predicted. Based on evidence available, there has been no significant long-term environmental damage from major oil spills and blowouts (National Research Council, 1985). This is largely due to natural remediation of the spill. In those instances where significant human intervention has been marshaled to clean up a spill, such as the *Valdez* incident in Prince William Sound, Alaska, the ecology has often suffered more from cleanup efforts than from the spill itself (Miekle, 1990). It appears that nature does a better job than man in cleaning up a spill in most instances.

The influence of various abatement processes changes from rapid physical effects to slower chemical and biochemical modifications during the aging of a spill in the open ocean. Each of these is discussed below.

6.6.2 Spreading. Spreading is a physical phenomenon that relies on the combined action of gravity and surface chemistry. Spreading begins upon oil being discharged on the ocean's surface. The size of the slick is ultimately dependent on the volume of oil released.

Initially, spreading is controlled by gravity effects alone, i.e., the difference in density between oil and seawater. This is influenced by advection (wind, wave and surface current action).

Later, chemical and physical characteristics of the oil such as viscosity and surface tension control the extent of the slick. Polar, surface-active compounds in the oil spread the slick into very thin layers which approach mono-molecular thickness at the edge of the slick. Advection then breaks the oil into small patches and windrows.

Spreading is important to natural abatement. It greatly increases the surface area of a spill. Evaporation of the lighter components can occur more rapidly. Greater exposure to biochemical and physical processes ultimately reduces the slick.

Unfortunately, spreading decreases the efficiency of mechanical recovery equipment. Spreading also increases the probability of the spill adversely impacting sensitive areas such as bays, shorelines and estuaries. Sensitive aquatic creatures and birds have a greater probability of exposure.

6.6.3 Evaporation. Evaporation is the physical process by which low to medium weight hydrocarbon fractions in the crude oil volatize into the atmosphere. This process is enhanced by spreading. Evaporation of each fraction depends on boiling point. Less evaporation will occur in cooler environments than in temperate climates. This is a crude oil property alteration known as "weathering".

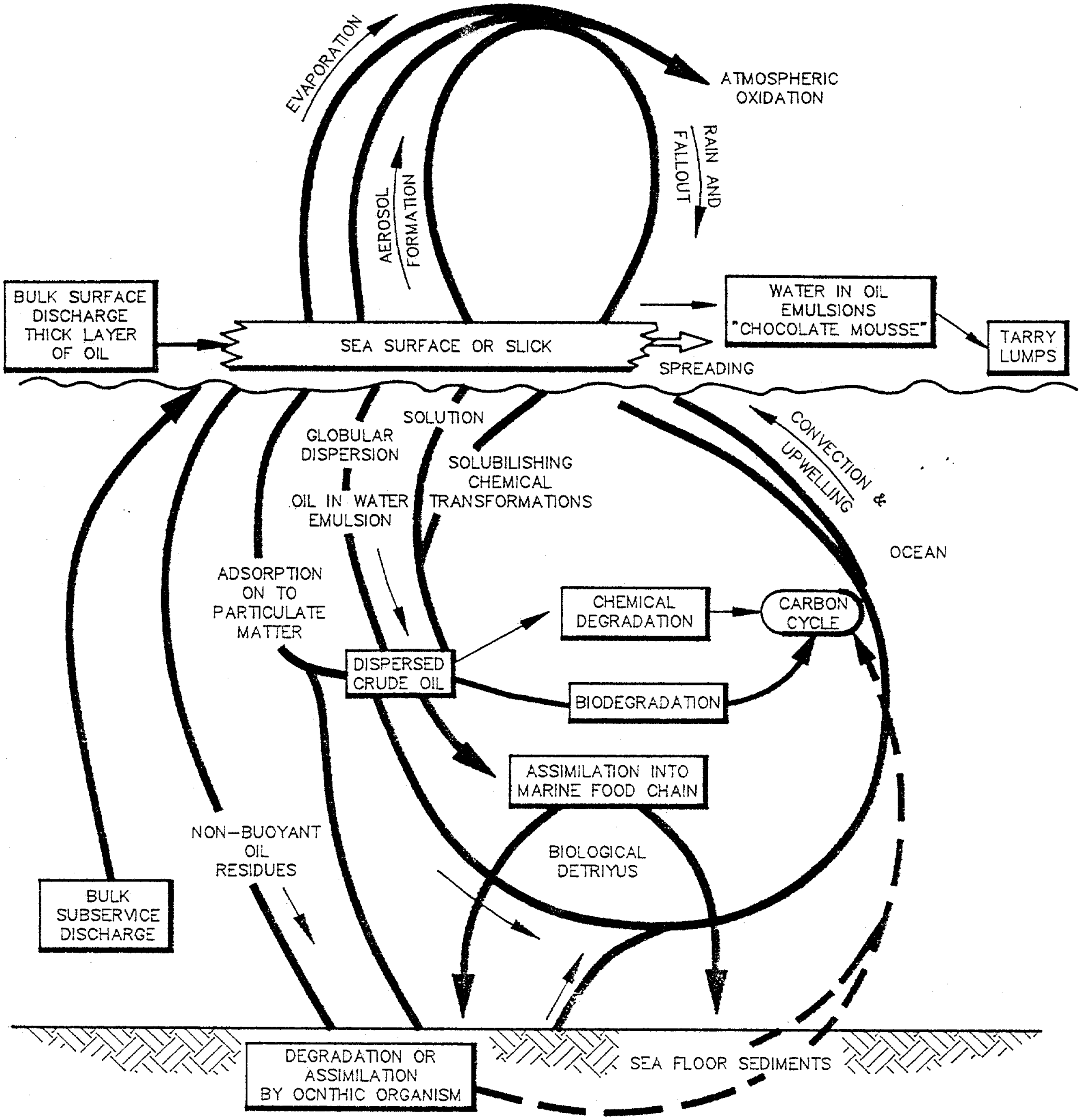

Figure 6.6.1

Processes Involved in the Fate of Spilled Crude Oil in the Marine Environment

Ref: *After Burwood and Speers, 1974*

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Most hydrocarbons with 15 carbon atoms in the chain are lost within the first few days. Heavier hydrocarbons, up to twenty carbon molecules, are lost over a few weeks. As additional fractions are lost, the oil's physical and chemical properties change as the oil becomes more viscous and the fraction of heavier, longer chain hydrocarbons increases. If evaporation continues, emulsification and tar ball formation will result in specific gravity increases that will cause the oil to sink.

It has been estimated that one-third to two-thirds of crude oil spread on the surface is lost through evaporation depending on the composition of the crude (Mackay, et al, 1973). Research has shown that 30% of the oil from the *Cadiz* spill evaporated (Gundlach, et al, 1983). In the IXTOC 1 blowout, evaporation was the predominant weathering mechanism (Boehm, et al, 1982).

Evaporation removes hydrocarbon fractions based on boiling point, not molecule structure. Aromatics and straight chain components of similar boiling points are removed at nearly equal rates through evaporation (Miekle, 1990). This is important since aromatics are the more toxic components of the oil.

Evaporation occurs quickly. It is estimated that up to 50 % of the volatile portion evaporates within the first twelve hours (Brown, et al, 1976). Low molecular weight aromatic compounds have been reported to completely evaporate in 8 hours (Meikle, 1990). This process is accelerated in turbulent waters. Evaporation in the open seas can quickly result in a substantial oil volume reduction through loss of the volatile fraction.

6.6.4 Solution. Solution, another type of "weathering", is the physical process by which low molecular weight hydrocarbons and some non-hydrocarbon components of crude oil dissolve in seawater.

Some compounds in crude oil are soluble in seawater. The rates of oil component removal by solution are poorly known (Miekle, 1990). Unfortunately, the more toxic components can dissolve easily.

The components readily soluble in seawater include the benign light alkanes (propane through isopentane). More importantly, light aromatics including benzene, toluene and xylene are soluble. These are carcinogenic and mutagenic. The acute toxicity of crude oil is largely related to its soluble aromatic hydrocarbon content (NRC, 1985).

Solution begins as soon as oil enters the sea. In a deep subsea blowout this process may be more significant than in shallow water for the following reasons:

- It is aided by the mixing of crude oil and seawater in the plume.
- A higher fraction of the lighter compounds, both straight and aromatic, are still in the crude oil since evaporation of these has not yet occurred.
- Greater hydrostatic pressure in deep water will limit subsea expansion of gas. This may reduce upward plume velocity and extend residence time of oil in the seawater.
- The length or height of the plume is greater which increases exposure of oil and seawater.

Cooler sea floor temperatures will adversely affect the amount of soluble compounds that can dissolve in the seawater. The plume will rise through progressively warmer water layers until it reaches the surface. Temperature may not have a significant effect on solution in a deepwater blowout.

Like evaporation, solution of hydrocarbons near the surface of the sea is aided by spreading. Solution rates decline with time due to a reduction in the light hydrocarbon fraction through evaporation. Evaporation and solution of the lighter components of the crude oil assist in the formation of tar balls.

6.6.5 Dispersion. Dispersion is the mixing of small particles of oil into the water column. This may occur by a variety of forces including advection.

Dispersion is expected to be more significant in a deepwater blowout situation than it is with a surface spill, pipeline break or shallow blowout. Action of the oil and water in the plume is expected to result in the high incidence of small oil droplets. Dispersion and emulsification of the deepwater effluent will likely result from stronger subsurface currents, more lateral plume meandering, stratification of deep seawater layers, cross currents and greater wave action in the open seas.

Dispersed oil remains below the surface. Droplets do not coalesce with other droplets and form large masses of oil with a composite specific gravity less than seawater. Dispersed oil droplets "ride" in the water column. These small droplets of oil are subject to sedimentation, biodegradation and settling.

6.6.6 Emulsification. Heavy components of oil form emulsions with seawater after the lighter components evaporate or dissolve. These can be oil-in-water or the more common water-in-oil emulsion, "mousse".

Dispersed oil droplets in the water column can be considered emulsions since the oil is surrounded by water. The heavy oil-in-water emulsions are formed by certain crudes in seawater. These emulsions are usually unstable and will reverse to the water-in-oil emulsion after weathering (Payne and Phillips, 1985).

Mousse is particularly problematic to abatement efforts for the following reasons:

- It contains 30-80% seawater and does not have the properties of either pure oil or water. Most surface skimmers are poorly equipped to recover the emulsion.

- Treatment and separation of the emulsion into its two components are difficult even if the equipment is able to pick up the emulsion. Handling and storage of the additional water volume resulting from emulsification can be a problem.

- Mousse can sink as the water fraction in the emulsion increases and the lighter compounds in the crude are removed. Oil mats are left on the sea floor.

- Damage to marine life and birds from the thick, viscous emulsion is high. The animals are subdued and stranded by the sticky mass.

- Mousse has been suggested as the source of pelagic tar balls (Miekle, 1990).

Emulsification and solution of light hydrocarbon fractions in the oil are synergistic processes. Emulsification increases the surface area of the oil available for solution. Solution promotes emulsification by removal of the light hydrocarbon fractions into the water. Sites for water droplet separation and stabilization are provided primarily by polar compounds in the crude, waxes and asphaltenes, which are rarely dissolved in seawater.

Emulsification of the effluent in a deepwater blowout will be enhanced by longer exposure of crude and seawater in the plume. Mixing associated with longer plumes may result in more oil being tied up in emulsions by the time it surfaces than would be expected in a shallow blowout or surface spill.

The formation and strength of oil/water emulsions are greatly enhanced by cooler temperatures. Seafloor temperatures in deepwater drilling situations are expected to be low. So, much of the oil may be emulsified as it escapes from the wellhead.

Some oil may not reach the surface if the resulting mousse is of sufficient specific gravity. Mousse removal by currents or by dispersion may leave the impression that the blowout is not severe based on observed volumes of oil on the surface.

6.6.7 Tar Ball Formation. Weathering processes such as those described above can lead to the formation of lumps of tar. Tar degrades slowly and is a source of public annoyance if it washes up on beaches.

Little of the hydrocarbon fraction in tar balls is lighter than 15 carbon atoms as a result of weathering (Miekle, 1990). Most of the lumps consist of paraffinic hydrocarbons up to 40 carbon atoms. Various crystalline wax inclusions are also common.

Tar balls remain in marine environments for long periods of time. It is estimated that 5-10% of the pelagic tar in the eastern Gulf of Mexico resulted from the Ixtoc 1 blowout up to four years after its occurrence (Oil Spill Intelligence Report, June, 1983 as reported by Miekle, 1990). These tar balls are quite benign. In many areas, bivalves and barnacles have attached themselves to tar balls. Dissection of these creatures shows no increase in tissue hydrocarbon content (NRC, 1989).

6.6.8 Sedimentation. This physical process involves the adsorption of hydrocarbon molecules of certain weights and compositions on particulate matter in the ocean. The particles act as nuclei to which the hydrocarbon sticks. The resulting composite matter often has a density sufficient to cause it to sink. Similarly, some of the heavier accumulations of oil can absorb sediments from the water column increasing the specific gravity of the mass until it sinks.

This process can be important in near-shore environments and in fresh water sources such as rivers that carry large quantities of sediments. Its effect in open seas on spilled oil is not known, but is not expected to be significant.

The fate of the oil on the sea floor is also not well known. In cooler environments, where microbial activity is reduced, oil has been present in sea floor sediments for several years. Tar mats and mousse can be periodically uncovered and washed ashore by storm action years after a spill or blowout.

Some anaerobic degradation of oil on the bottom occurs, but appears to be very slow. It has been shown there are more anaerobes in open seas than near shorelines and they act more quickly.

6.6.9 Photochemical Oxidation. Oil, when contacted by sunlight in the presence of oxygen, is broken down into more soluble compounds. These include:

- Carboxylic acids
- Benzoic acid
- Alcohols
- Ketones
- Phenols

Some are more toxic than the parent hydrocarbon molecules.

The rate of hydrocarbon oxidation varies with its chemical nature. The optical density of the oil becomes an important variable in the process, especially the clarity of the oil to ultraviolet light. The presence of strong oxidizing agents such as ozone is also important. Photalysis of thin slicks can be sufficient to cause decomposition in a matter of days.

6.6.10 Microbial Degradation. Hydrocarbon decomposing microorganisms are indigenous and ubiquitous in all oceans. Biodegradation has existed since the beginning of life. Over 100 strains of bacteria and fungi have been identified that are capable of subsisting on petroleum (McAuliffe, 1977).

The microbial process transforms hydrocarbons into soluble oxidized products which are eventually decomposed. As the microbes contact the oil, they secrete enzymes which reduce the oil molecule size through chain scission. The molecular fragments are then altered by the microbes into intermediate compounds such as fatty acids. These can be utilized directly by the bacteria's cells. Waste products from these reactions are carbon dioxide and water.

The oil serves as a food source for the bacteria. They are fed upon by higher life forms. In this respect, oil is no more a pollutant than any other organic material entering the food chain.

The extent and speed of aerobic bacterial degradation of oil is dependent on several factors which vary with the location in, or on, the water and composition of the oil. These include:

- The initial population of bacteria in the spill area.
- The presence of certain volatile hydrocarbon fractions including aromatics which are biocidal in high concentrations.
- The concentration of critical nutrients in seawater, specifically nitrates and phosphates.
- The availability of dissolved oxygen near the surface where most microbial activity takes place.
- Volume of oil being consumed.
- The temperature of the environment.

Aerobic activity ceases if one of the components is missing (oxygen, nutrients or oil) and the bacteria die off to previous levels. If the component is restored, activity and reproduction resume.

One critical component is dissolved oxygen. The oil can smother the surface of the sea if the slick is large and is located in a quiescent region. If the surface is turbulent due to wind and wave action, oxygen uptake is enhanced as is microbial activity. This is likely to be the case with subsea blowouts in deep water.

Microbial degradation is reduced by a factor of four if the temperature drops from 18°C to 4°C. Since most microbial activity occurs near the surface, temperature at the point of discharge in a deepwater blowout will probably not affect overall microbial activity.

The initial concentration of microbes in most areas is approximately 10/liter of seawater. The baseline concentration is higher in some areas where there are frequent spills or a high incidence of natural seeps. A peak concentration of 50 million/liter can be reached after the bacteria multiply in a spill area. Reproduction requires time, especially if some of the parent bacteria are killed by toxic components.

The initial population of microbes can be increased by spraying colonies onto the slick or injecting them directly into the effluent source (i.e., the blowout plume). This concept is discussed more fully in a later section.

Anaerobic degradation of crude oil on the sea floor can take place without dissolved oxygen in the water. This process is normally long-term and depends on the composition of the hydrocarbon mass. Most tar balls are eventually degraded through anaerobic digestion. Gases emitted by anaerobic bacteria cause a portion of the oil to rise to the surface where aerobic degradation can occur. As the aerobes digest some of the hydrocarbon, the mass becomes heavier than seawater and the oil returns to the sea floor where anaerobic degradation resumes. The cycle may repeat several times.

Fungal degradation of crude oil is also an important natural process. The fungus generates enzymes that mineralize a portion of the oil which feeds the fungus. Resultant products are carbon dioxide, salt and water. These organisms are particularly useful in degrading very toxic compounds in the crude oil such as chlorinated aromatics and heavy metal compounds. They are slow acting, however.

6.6.11 Uptake by Other Organisms. Petroleum spilled in the sea is available for uptake by organisms other than bacteria. Dissolved or dispersed oil usually enters the marine food chain through ingestion of oil-coated food. Oil not metabolized by the organisms is usually passed through with the excreta and distributed in sediments by grazing organisms.

Concern has been raised that the uptake of undigested crude oil may move up the food chain being concentrated at each level similar to other persistent chemical pollutants. Some researchers have found that certain marine organisms retain oil in their tissues throughout their lives. There is little evidence of high accumulations of oil in higher predatory life forms in the food web, however. (Miekle, 1990)

SECTION 6.7 SURFACE COUNTERMEASURES

6.7.1 Introduction. Surface methods of spill cleanup and containment have been used in the past on most major situations involving large oil losses on the surface of the sea. The effectiveness of these measures is subject to interpretation. Few past efforts have resulted in substantial reductions of oil from seawater. Some have resulted in significant damage to the environment by introducing toxic chemicals to the system.

In open sea conditions it is doubtful that surface techniques will be effective in controlling pollution from a deepwater blowout. It is anticipated that oil from a blowout in deep water will be at least partially emulsified with seawater when it surfaces. Some of the oil will likely never reach the surface due to dispersion in the water column by physical forces acting on the plume. Further, wave and wind forces in the open sea will break up the slick and impede conventional surface remediation techniques from gathering and disposing of the oil.

These techniques are mentioned for review only. It may occur that these can be successfully applied in certain conditions (calm seas, low current areas, etc.). This discussion also introduces two areas of pollution abatement from a deepwater blowout for which additional technology development is needed.

Each surface technique is discussed individually. Some detail has been omitted in this review for the sake of brevity.

6.7.2 Surface Containment. Floating booms are a mainstay of pollution control techniques used to date for spill cleanups on the seas. Booms are usually the first devices dispatched to any spill and may be of significance in the public's eye as visible evidence of action to mitigate the results of the spill.

These devices are essentially floating fences deployed to prevent spreading of a slick. They are intended to contain the oil in an area that would be smaller than the spill would occupy under normal conditions.

Booms are usually sectioned devices connected to a floating or fixed structures. These can be ships, platforms, anchored buoys or a tethered section of another boom. The strength of connections between sections of the boom and between the boom and its anchor are important in open sea conditions. If they are not adequate, the boom can separate and drift with wind and currents releasing oil back onto the surface. Broken booms may inhibit implementation of other countermeasures.

Some modern boom systems incorporate both containment and collection capabilities. These utilize wier-type collectors and the hollow space within the body of the boom. Oil pours into the boom through a hole in the wall of the device. It is collected and separated from associated seawater with the oil piped to a tank for storage and removal.

In the open seas, booms have historically been ineffective. Wave and wind action will either cause the boom to part or the oil will simply be swept over the top or under the base of the boom. Full containment of oil cannot be assured unless the current perpendicular to the boom is less than 1 knot. Most mechanical barriers will not contain oil in seas with wave heights greater than 1.3 m.

Ship-Mounted Surface Collector. A ship-mounted surface collector system was designed in 1987 for use with offshore blowouts. A schematic of the system is shown. (Figure 6.7.1) This system was designed by Stewart Technology Associates on contract with the US Department of the Interior Minerals Management Service. It was intended for protection of the California coastline, though it could be used in the Gulf of Mexico or East Coast with access through the Panama Canal. Ownership of the system would depend on contributions to a consortium fund for purchase, retrofit and operation of the vessel.

Basically, the system involves a retrofitted tanker with dynamic positioning capability situated downstream from the blowout. Two work boats would deploy booms from the ship to form a W-shaped system which would herd the oil toward the side of the tanker where it could be recovered, separated, treated and stored for transfer to another vessel.

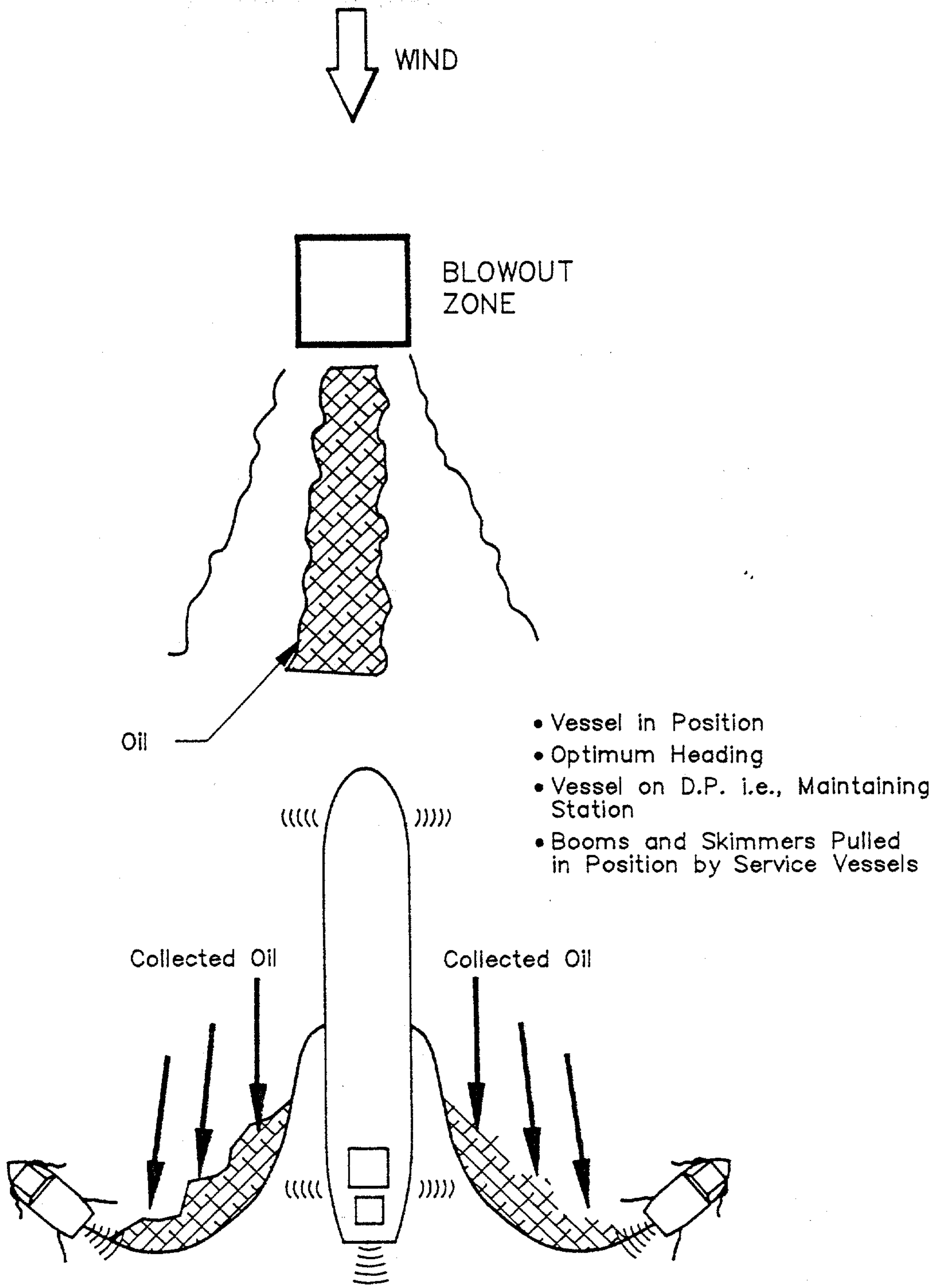

Figure 6.7.1

Ship Mounted Surface Collector System*

MMS Contract/Stewart Technology Systems

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The vessel would be equipped with fire protection systems, ventilation equipment, dispersant spraying capability for treating bypassed oil (via shipboard helicopter), extra boom(s), and communication equipment for system control. It was designed to recover 30,000 barrels of crude per day. The optimum current velocity for boom operation is 1.0 knot and limiting conditions for operation of this system would be Beaufort 5 seas (2.1 m waveheight) with a 1.5 knot maximum current. It is noted that this system is stationary and must be used where there is a uni-directional surface current.

Specially Designed Oil Spill Response Vessels. In 1990, Shell deployed the first self-contained oil spill contingency barge to support its drilling operations in the Chukchi Sea in Alaska. The *Responder* is a 400' by 150' barge equipped with 7,600' of oil containment booms, a 76' landing craft, 4 boom towing boats and 2 utility boats. The barge has below deck storage for additional spill response equipment and liquid storage(*Offshore*, May, 1990).

European firms, mainly Dutch and German, have developed unique vessel designs for working in open oceans. These vessels employ large capacity skimmer systems. One tank vessel is hinged at the stern and operates in a "V" configuration using its split hull to form a boom-like collection system. Oil is collected and separated and stored in the vessel. Two of these are in operation, and a third has been ordered by Mexico (Mielke, March 16, 1990).

Multi-purpose vessels have also been used in oil spill cleanup activities. One of these was a Soviet dredge employed at Prince William Sound in Alaska after the *Valdez* spill in 1989. This vessel was a trailing hopper dredge with oil recovery capability. US Army Corps of Engineers dredges were also used in this cleanup effort with no modification. These dredges have the capability of recovering viscous, weathered oil and emulsions. The advantage of these vessels is that while they can be employed for spill cleanup, most of the time they are used for dredging. Spill preparedness costs are reduced if these vessels can be used (ibid.).

Bubble Fences. The use of bubble fences may offer an improvement over mechanical booms for containment of oil on the surface in open sea conditions. Bubble fences contain rows of subsurface nozzles connected to a source of compressed gas, usually air, that create small plumes. These, in turn, create horizontal water currents on the surface that close off a specified area to oil spread by "pushing" the oil away. Surface currents, wind and wave action adversely affect bubble fences.

These fences have been used effectively in industrial waste treatment to prevent oil or other low specific gravity contaminants from killing bacteria cultures in treatment ponds. So, in certain situations bubble fences may be used to herd the oil in a desired direction.

Bubble fences may be useful in protecting vessels engaged in vertical intervention efforts. If the vessel can anchor just off the blowout plume (offset intervention technique), a subsurface nozzle arrangement on a conduit such as a pipe, can be floated just under the surface. Compressed air from the rig can be forced through the nozzles creating a bubble fence without loss of buoyancy.

A circular set of nozzles could be installed around the vessel to protect it from oil carried by shifting winds and/or currents. As long as the system can withstand wave and current forces, it can provide protection for the vessel on a continuous basis.

It is not believed that bubble fences can be employed to contain a large spill in open sea conditions, however. Open sea conditions will probably be so intense the slick will be swept over the bubble fence.

Water Jets. Jet systems spraying water onto the surface to contain oil have been used in the past with mixed results (National Research Council, 1989). These have been used on the open seas to push surface oil away from platforms or vessels employed in firefighting vessels. Commonly, fire monitors and pumps are used for this purpose.

Mielke (CRS Report for Congress, 1990) suggests that high pressure water jet systems can be used to herd oil under a variety of operating conditions. In the open seas, the conditions may be too severe for these systems to operate successfully. They can be mounted on and used with a variety of oil recovery devices which may improve their efficiency.

6.7.3 Collection. Mechanical collection of oil spilled on the sea normally occurs in one of two ways; skimming or absorption. The most frequently used technique involves skimming. One source indicates that thus far, mechanical collection techniques have resulted in the average recovery of only 20% of crude oil spilled on the open sea (NRC, 1989).

Skimming. There are two general types of skimming devices, those involving wicks and wier-type devices. Wick devices deploy an oil-liking (oleophilic) extension in the slick, then it is pulled back into the skimmer. Oil is separated from the wick by physical means. One frequently used type deploys a continuous loop of polypropylene rope that is squeezed between two rollers as it re-enters the body of the device. The oil is pumped into a holding tank for later disposal.

Weir-type devices move through the slick and oil enters a collection tank over a slot cut in the device just below the surface of the sea. Oil, emulsion, dead animals, trash or anything else that will float is easily collected as it flows over the weir. Separation of these various components is sometimes difficult.

There is the problem that the device, usually a barge or ship, is exposed to the slick for the entire duration of the cleanup. If there is any danger of fire, or if the oil is particularly toxic, operating personnel are exposed. Also, if the slick is thin and widely dispersed on the surface, the vessel must travel back and forth through the slick until it is recovered. This requires time and reduces efficiency.

One weir-type device that was used to clean up a viscous oil spill in Alaska last year was developed by a Swedish Company, Oil Recovery Sweden (ORS). The system utilizes a rotating perforated drum which "digs" oil off the surface including viscous or trash-laden crude. Seawater is separated internally and discharged from the device continuously. It has been demonstrated in Italy and in the USSR. Test-tank trials in Norway indicate that this system works well in waveheights up to 1/2 m.

Recently, hydrocyclones have been used to separate oil from surface spills with good results. These devices force the oil/water mixture into a tight helical flowstream which separates the oil and water by utilizing the density difference between the two fluids. The cycloning effect results in free water being discharged from one end of the device, and essentially pure oil being discharged from the other. (Figure 6.7.2)

The efficiency of any skimmer is adversely affected by spreading. Collecting a thin slick, sometimes only a sheen on the surface, is difficult for these mechanical devices.

Absorption. Absorption of the oil can occur by using oleophilic substances. Pillows, ropes, sheets and cylinders of fibrous materials are often deployed in spill situations to soak up the oil thus preventing spreading and drifting of the slick into sensitive areas. Booms of these materials have been used to fence off specific areas while soaking up a free surface oil.

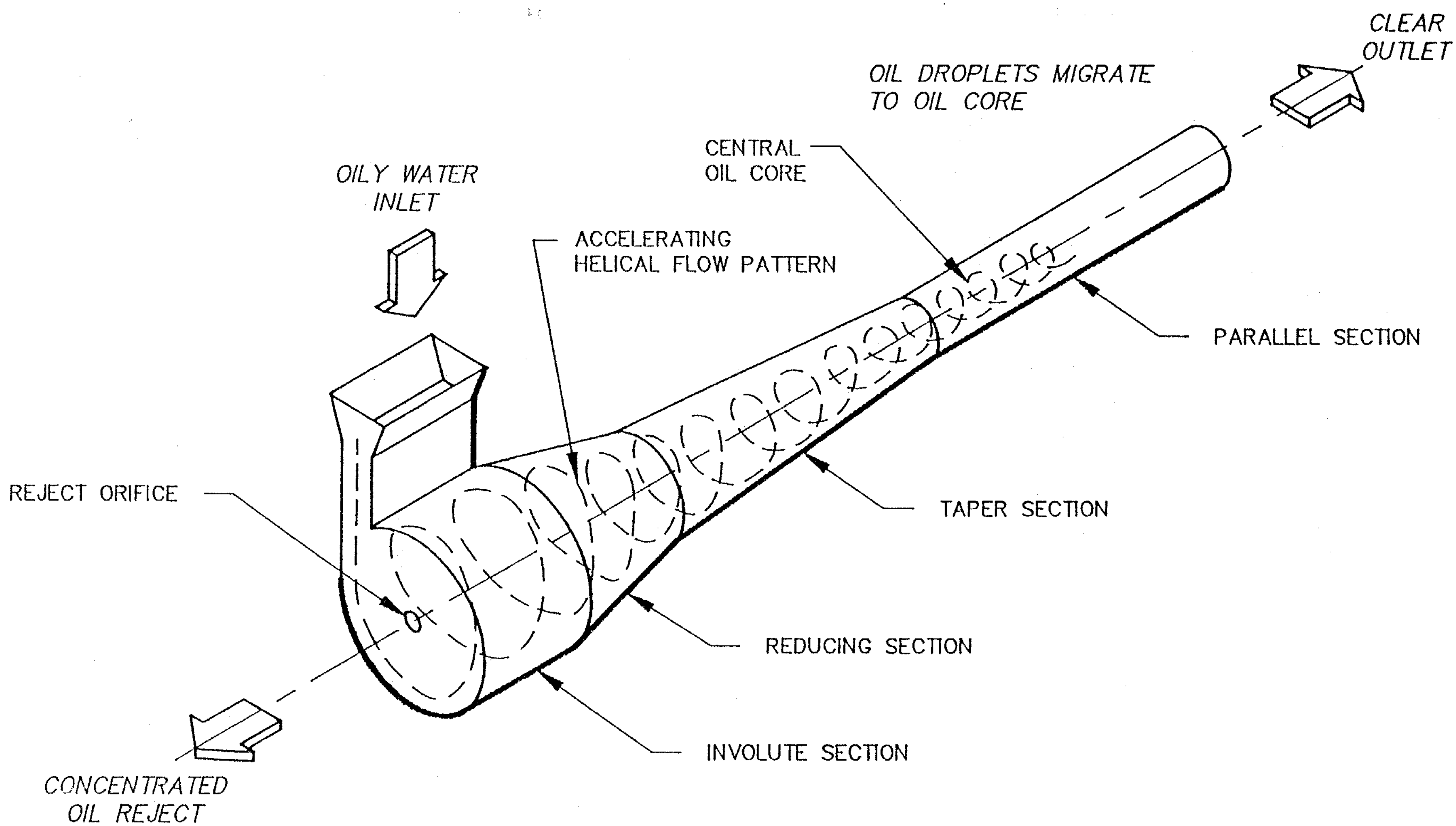

Figure 6.7.2

The Pressure–driven Vortoil Hydrocyclone

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Normally, these materials resist water soaking and float easily. Sometimes, depending on the amount absorbed, oil has been spread as the "socks" float away from a given area and the oil leaches out onto the sea.

One material that has received attention recently is powdered peat moss, a naturally occurring material that is oleophilic and resists water soaking. Once the oil is absorbed, leaching is minimized. Peat can easily be blown onto a surface spill, then recovered for land farming (disposal) at a later time using common solids handling techniques.

An obvious problem with these devices is that they must eventually be gathered by physical means and disposed of in a way that does not allow the oil back onto the sea (or the land). Disposal of large volumes of oil-soaked absorbents can constitute a logistical problem.

The rate and amount of oil that can be absorbed on any material is a function of the chemical properties of the oil and the absorbent. Other factors include temperature, wave action, currents and the degree of oil emulsification.

Emulsions are difficult to absorb on these materials due to the absorbent's repulsion of entrained water (up to 80%). The absorbent reacts to the emulsion as if it were water. Necessary oil/absorbent molecular attractions are lacking. The result is the spill is not absorbed. Similarly, oil-in-water emulsions resist absorption. Oil droplets are surrounded by water molecules, and the oil cannot penetrate the water film for attraction by the oleophilic fibers of the absorbent.

Quick deployment of absorbents is therefore essential if they are to be effective. Absorbents are not likely to be effective in a deep water blowout situation where the oil will be partially or completely emulsified when it surfaces.

6.7.4 Chemical Reaction. In the past, various chemical formulations were used for slick control. Two of these were gelling agents and sinkants.

Gelling agents, sometimes called coagulants, were developed to preventing spreading. It was thought that slick thickness would be increased and surface recovery techniques would be enhanced. It was found that a certain amount of mechanical energy had to be supplied for the chemicals to react with the oil. These formulations are expensive and large treatment volumes are required. Coagulants have generally been abandoned in favor of more effective and less expensive methods.

Sinkants were also formulated to mix with the oil on the surface. The resulting mass had a specific gravity greater than seawater and the oil sank to the bottom. These formulations were part of the old "out of sight, out of mind" concept in early spill cleanup thinking. Sinkants were also abandoned when it became clear that they did not reduce the toxicity of the oil. They merely removed the oil from the surface to the seafloor where bottom-dwelling organisms were severely impacted.

Recently, a family of chemicals has been introduced that will react with the oil to create a new benign compound that is mechanically tough and can be easily collected from the surface. These are mixtures of polymers of the poly-olefinic family that combine chemically with the crude oil creating a tough copolymer (actually a synthetic rubber). These are available in either liquid or solid (crumb) form and react rapidly. Their use has been proven in a variety of arenas for pollution cleanup around the world (Thompson, 1991).

These reactants have the ability to "pull" or "wick" the oil out of emulsions by chemical attraction. The polymers ignore the water in the emulsion and seek oil molecules with which to combine. As a result, oil can be stabilized from mousse, tar mats on beaches, live oil on the surface or oil that has soaked into beach sediments. Once reacted, the oil is held tightly by the reactant without toxicity and mobility.

The resulting rubber mass has a density less than seawater and floats on the surface where it can be picked up by boats or barges with fishing nets, pitchforks or by hand. The mass is stable. The oil is held as part of the rubber compound and does not leach out. The oil will remain tied up for approximately five years before the mass begins to break down. If recovery of the mass is not possible for some time, the oil will remain chemically inert. It will float in a benign solid mass until it can be recovered. If it washes up on a beach, it can be raked up and collected by conventional agricultural equipment. Once the mass is recovered, it can be processed and burned like other solid fuel.

Application of the liquid or crumb form of polymer can be accomplished on a surface slick by spraying from fixed or rotary wing aircraft using normal crop dusting techniques. Large areas can be treated quickly.

The liquid reactant chemicals have a density significantly less than seawater and most crude oils. They tend to ride on the top layer of a thick oil spill and have difficulty penetrating the slick to the surface of the water. Thus, only a portion of the oil may be contacted using liquid reactants. Chemically, the liquid polymers react slower than crumb form polymers.

Crumb form polymers can also be sprayed on surface slicks using agricultural crop dusting techniques. According to industry sources, they will easily penetrate through the oil to the oil/seawater contact (Thompson, 1991). If applied in sufficient quantities they will react with all of the oil available in the slick.

Since both types of polymers float, they cannot contact oil dispersed in the water column. If the oil can be treated with these products before it is dispersed in the water column, it might be possible to mitigate toxicity from the spill. It is recommended that equipment and procedures be developed to inject these materials into the plume at the seafloor. This enhances chemical treatment of the oil prior to its arrival at the surface (see Section 6.9).

It is noted that overtreating does not produce adverse reactions. Most of these polymers are approved as food-grade polymers by the United States Food and Drug Administration. Their ingestion by organisms in the sea, including bottom-dwelling life forms, is not anticipated to be harmful. The polymers are expensive, so overtreatment is not recommended.

Chemical reaction using these polymers is not exclusive to crude oil. Oil on feathers and fur of sea creatures will be reacted with the polymer, and can result in the loss of insulating and floating properties. Drowning is not anticipated, but hypothermia can occur. This can also be a problem that occurs when dispersants are used on slicks.

6.7.5 Incineration Surface burning has been used in the past to deal with oil slicks that threaten sensitive areas. It is believed that 58% of the oil released by the Ixtoc I subsea blowout in the Bay of Campeche (Gulf of Mexico) was consumed by a surface fire at the top of the plume (Brown & Root, 1985).

Complete combustion of hydrocarbons normally converts the fuel into carbon dioxide and water with substantial production of heat. Crude oils are mixtures of compounds and molecules not all of which are hydrocarbons. Combustion of crude oil can release chemical compounds that are more toxic than the parent molecules in the slick.

Incineration removes the spill from the sea. It adds combustion byproducts to the air above the fire, however. This may be a desirable alternative in some circumstances because the atmosphere is more mobile. Dispersion of combustion byproducts can occur in the air more rapidly than oil on the ocean's surface. Furthermore, there are other chemical and physical processes that may allow the air to cleanse itself more quickly than the denser seawater. Some of these include photo- and auto-oxidation of incompletely burned hydrocarbons,

Some of these compounds may be adsorbed on dust particles or absorbed in atmospheric water. Pollutants can be returned to the sea through rainfall. It is likely that this will occur over an area larger than the original spill effectively diluting the compounds to an acceptable level. Burning is not truly a solution for a surface spill; it is only a tradeoff (Mielke, March, 1990).

As crude oil burns on the surface, a heavy tar-like residue is left. It is similar to weathered crude oil. It is likely that this tarry residue will behave like other tar, sinking to the bottom or being dispersed into the water column where natural bioremediation is slowed (Brown & Root, 1985).

Oil slicks on the ocean's surface must have a minimum thickness to sustain combustion. This minimum thickness depends on the content of light hydrocarbons in the oil. When the slick burns down to this minimum, the fire goes out. Most sources indicate this minimum to be 10 mm though some say that as little as 3 mm are required (Mielke, 1989; *Offshore*, September, 1990; and Brown & Root, 1985).

To maintain this minimum, a boom is usually towed between two vessels traveling through the spill in the same direction. (Figure 6.7.3) Oil is collected in the boom and an ignition source is supplied to the gathered oil. This ignition source can be a burning fuel such as gasoline poured onto the surface by one or both of the boats, or an external source such as a Helitorch (flaming napalm globules dropped from a helicopter over the collected oil). This process obviously requires a special heat-resistant boom. The boats and their personnel are at some risk if the spill begins to burn faster than their forward velocity.

Summary. Surface burning is not feasible in all circumstances. Heavy water-in-oil emulsions will not burn easily due to entrained water. Thin slicks cannot be burned due to minimum thickness requirements. The gathering boom cannot be moved rapidly through the water, usually less than 1 knot, without bypassing a substantial volume of oil (i.e., the oil spills over or under the boom). Highly weathered oil lacks the lighter constituents necessary to promote combustion and will not burn regardless of ignition source.

In open sea conditions where the slick is broken by wind and wave action, incineration will probably not be an effective surface countermeasure. The slick will probably be torn into windrows and patches with open water between them. Gathering sufficient live, non-emulsified oil to sustain combustion is unlikely.

6.7.6 Chemical Dispersion. Dispersants are surface active agents used to break down oil allowing it to enter the water column. Dispersants have been used extensively to prevent oil from entering sensitive areas such as bays, estuaries and pristine beaches.

Dispersants contain molecules with surface active oleophilic and hydrophilic ends. These surfactants are usually transported in a solvent. Aerial spraying on a surface slick is simple and fast. Dosage is normally a 20:1 oil to dispersant ratio by volume. On emulsified oil, the dosage is about 12:1 and can be further adjusted as results dictate.

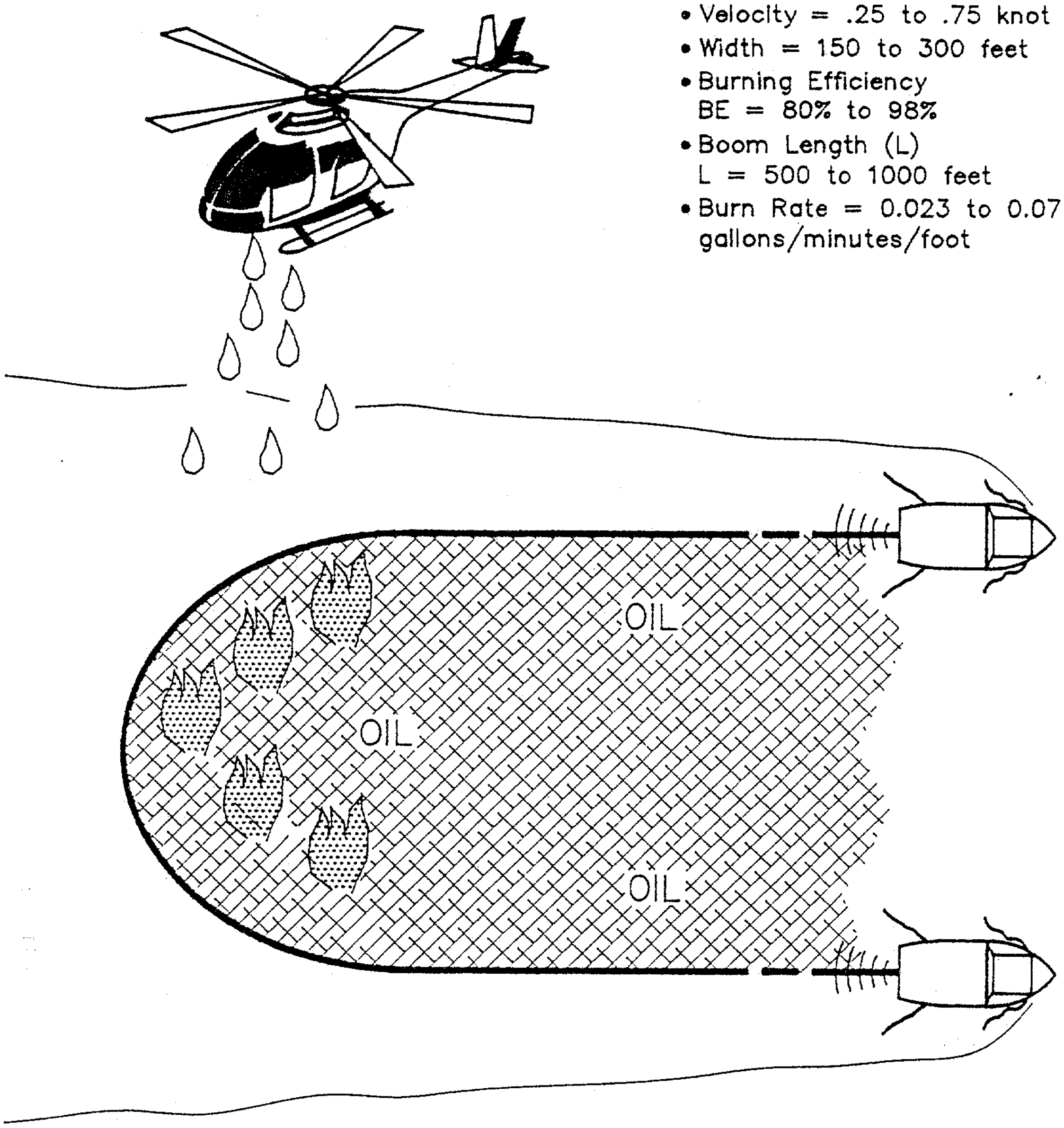

Figure 6.7.3

Surface Burning Schematic

Early efforts with these chemicals concentrated only on removing the slick from the sea surface. The surfactants were mixed with aromatic solvents such as benzene and toluene and sprayed liberally over the entire spill. It was found that these solvents were more toxic than the oil. Microbial degradation of the spill was reduced since the solvents were biocidal.

Modern dispersants are environmentally non-pathogenic. In fact, they enhance bacterial degradation of oil. These mixtures are composed of organic detergents and alcohols that are themselves bio- and auto-degradable. Half-lives of 30 to 45 days are not uncommon. The surface area of the oil available for biodegradation is increased through droplet formation. Also, the dispersant is a food source for the bacteria. One mixture contains the following components:

- Modified cocoyl diethanolamide
- Ethoxylated straight-chain alcohols
- Monoethanolamine
- Amphoteric, or non-polar, detergents (imidaxoline derivatives)
- Triethanolamine lauryl sulfate

Formulation proportions are proprietary and can be adjusted depending on the type of crude being treated.

These dispersants also prevent emulsification by counteracting the naturally occurring emulsifiers in the crude. Some chain-scission of oil molecules occurs with the use of these chemicals, so treated oil stays near the surface where aerobic biodegradation occurs more readily.

It has also been noted that dispersed oil will not stick to shorelines sediments and plants or to aquatic animals . These chemicals, like the reactive polymers, may remove oil from the skin, fur or feathers of these animals resulting in a loss of buoyancy and insulating properties, however. In tests on live animals using the dispersant formula detailed above, one duck began to suffer from hypothermia and had to be removed from the test tank. Two other ducks did not. In proper dosages, dispersants should not be harmful.

Overtreatment with dispersant is not recommended. Dispersion by natural forces can be enhanced by treating the oil with only the required volume of chemical dispersants. Potential animal injury can also be reduced. The benefits of chemical dispersion can be optimized without the high cost of overtreating.

The injection of modern dispersants into a deepwater blowout at the seafloor, along with activated bacterial colonies and nutrients, is discussed in Section 6.9.

6.7.7 Bioremediation. Natural bacterial degradation of spilled oil can be enhanced in several ways as passive and active methods. Each is discussed individually below.

Passive Bioremediation. Passive methods are those which rely upon the indigenous population of bacteria in the spill vicinity. In other words, "new" bugs are not added to the system. Instead, measures are taken to enhance the growth and activity of existing colonies.

Some of these methods include:

- Adding dispersants to the oil to increase surface area for microbial attack.
- Adding enzymes (lipase, and others) to the oil to break the oil molecules into smaller fragments upon which bacteria can feed more easily.
- Adding nutrients such as nitrates and phosphates to the system to encourage bacterial growth and reproduction.
- Adding air to the system to insure adequate oxygen levels for aerobic bacterial activity.

In open sea conditions, the introduction of oxygen to the system will not be necessary. Advection will adequately provide enough oxygen to the system. Dispersant spraying will help to avoid thick, continuous slicks that would choke air out of the system. The addition of enzymes to break oil molecules is a recently developed technique.

Passive biodegradation was used with good results on 70 miles (out of 1,100 total miles) of rocky shoreline at Prince William Sound following the *Valdez* spill in 1989. In this situation, it was found there were adequate populations of oil-consuming bacteria in the area. Nutrients (fertilizers) were sprayed on the coastline. Natural bacteria reproduced to a level that resulted in the complete ingestion of the oil with no other bacteria imported to the area (JPT, September, 1990).

In contrast, other shoreline areas were treated with hot water or steam to clean oil from the rocks. This resulted in the wholesale destruction of the indigenous bacteria colonies in these areas. The shoreline was not cleaned effectively by mechanical methods. Bacteria colonies have re-entered most of the arena and are cleaning the remaining oil from the shoreline. This is one example of how mechanical methods have delayed complete spill cleanup.

Active Bioremediation. Active bioremediation involves the introduction of new, imported bacterial colonies into the vicinity for oil ingestion. The introduction of additional bacteria improves the speed of bioremediation in two important ways:

- A higher concentration of bacteria is available to begin digesting the spilled oil.
- More parent microbes will result in much faster reproduction of additional colonies.

These imported bacteria are the same ones that exist in nature. No genetically engineered microbes have been approved for bioremediation to date. There appears to be a public fear of introducing a genetically altered lifeform into the environment where it might adversely impact the oceans or interfere with natural bacterial reproduction.

The bacteria are grown in cultures, concentrated and freeze dried. The bacteria are apparently not injured by the packaging process. Each gram of powdered material contains 18-30 million bacteria. The mixture is then bagged and handled like any other solid. Several hundred tons of these packaged "bugs" are available at any time for use in bioremediation. The bacteria can be stored indefinitely.

When needed, the bacteria can be rehydrated in seawater. Usually, the water is aerated to provide oxygen. Pure oxygen may be injected to speed their recovery. Live oil is sometimes added to the mixture to encourage feeding.

Most "bugs" used for bioremediation are mixtures of several phyla and species of microbes. They are selected on the basis of their ability to consume a particular component of the crude oil.

Only a limited number of bacteria species can break the strong cyclic structures of aromatic compounds and those components of crude oil that involve nitrogen, oxygen, sulfur (NOS). Heavy metal compounds are also hard to break. Some strains of bacteria are commonly added to a bacterial "soup" that will attack these compounds. These are not truly oil-eaters.

One supplier includes a sizable fraction, up to 50%, anaerobic bacteria in the mixture for remediation of oil spills where there is little or no dissolved oxygen.

The "soup" will often contain enzymes such as lipase, protease, cellulase and amylase. These enzymes break down fats and greases, proteins, cellulose and carbohydrates and starches depending on the type of spill.

Also the mixture contains vitamins such as thiamine, riboflavin, niacin, pyridozine, choline, betaine and folic acid. Minerals such as calcium, phosphorus, iron, copper, zinc, manganese, and cobalt are included. Amino acids such as arginine, lysine, tryptophan, cyctine, histidine, tyrosine, phenylalanine, leucine, valine and glycine are added.

These nutrients give the bacteria a boost for growth and activity to digest the molecular fragments remaining after enzyme action. They also provide the necessary building blocks for rapid bacterial reproduction within the waste (a new generation every 20-30 minutes doubles the colony size). Most nutrients are not available in crude oil, so they must be added to the "soup" to insure adequate bacterial growth and activity.

The "soup" can be sprayed directly on the slick after the bacteria are at their peak activity level, usually within 3-4 hours. The liquid can be applied by spraying from aircraft or vessels of opportunity.

Active bioremediation was used to treat a spill from the *Mega Borg* tanker incident in the Gulf of Mexico in June, 1990, the first test of bioremediation in the open sea. Results were good. The shoreline spill resulting from a collision between the Liberian tanker *Shinoussa* and three barges in Galveston Bay in 1990 was treated with good success using active bioremediation.

Bioremediation is often considered a slow process, but in both of these cases, removal of the oil from the water or shoreline occurred in matter of hours to a few days. In the case of the open sea bioremediation, removal of most of the oil occurred within 8 hours.

Costs for the bacteria, nutrients and application are on the order of $5.00/bbl of spilled oil. Bioremediation represents an attractive spill cleanup method for open sea situations such as deepwater blowouts with a rapid removal rate of oil and quick application methods.

6.7.8 Irradiation. Two recently developed techniques have been shown to break down oil molecules on and in water. Both involve bombarding the oil with radiation. This severs the molecular bonds of the hydrocarbons. The smaller fragments can be easily attacked by microbes.

One method involves microwave (electro-magnetic) radiation. Bench-scale experiments have had good success. This technique also provides energy for breaking emulsions of oil and water.

Another method was developed for purifying wastewater by bombarding it with a pulsed xenon beam of multi-frequency light radiation. Radiation of wastewater is normally done with a mercury vapor light which emits only one frequency of radiation. The xenon beam is an improvement of that technology.

It is doubtful that irradiation of oil for breaking molecular bonds will be useful in a deepwater blowout situation for the following reasons:

. Spilled oil on the open sea cannot be contained into a manageable area where radiation emitting devices can act.

. Some oil will be below the surface where the radiation will not reach.

. The pathological effects of this harsh radiation on sea creatures is not known but is believed to be of an unacceptable degree.

These techniques may have utility for near shore cleanups from blowouts. It is also noted that photo- and auto-oxidation resulting from sunlight on oil is one of the natural abatement processes. Only a limited amount of the total oil spill is usually removed by this process.

New techniques are being developed for removal of contaminants from the sea. It is not the purpose of this study to analyze all of them. The two mentioned above are included to demonstrate that new techniques are not targeting crude oil introduced from a deepwater blowout in the open seas.

6.8 SUBSURFACE CONTAINMENT/COLLECTION

6.8.1 Introduction. The most logical approach to controlling pollution from a subsea blowout is to contain and collect the blowout effluent at the source of the spill. If it is contained, it cannot enter the water column, nor can it spread on the surface of the sea. The introduction of the oil into the environment is curtailed.

The installation of an efficient and effective collector in the open seas is difficult. In the single documented case in which an attempt was made to place a cone-shaped collector over a blowout, excessive seawater was entrained and the system was overloaded. In an undocumented situation in which a bell-shaped device was placed over a blowout, the seafloor washed out from underneath the device and it tipped over (Westergaard, SI Report, 1983). Installation and operation of collectors are impractical due to high seas, heavy wave action and currents in deepwater situations.

New technology has not been developed in the past several years owing largely to the absence of a severe subsea blowout. Since no deepwater blowouts have occurred, there is no perceived basis to justify preparedness measures. Thus, the first line of defense in the event of an offshore blowout is still the rapid deployment of surface countermeasure devices.

The recent failure of containment and cleanup measures on the large surface spill in Alaska are of great concern, not to mention the high cost of such countermeasures. Subsea containment and collection of blowout effluent may become more popular as drilling extends into deeper water.

Many devices have been proposed for the containment and collection of blowout effluent. An early design was patented in 1924 (Figure 6.8.1). Only two devices were ever manufactured for subsea use. One is no longer serviceable, and the fate of the other is unknown.

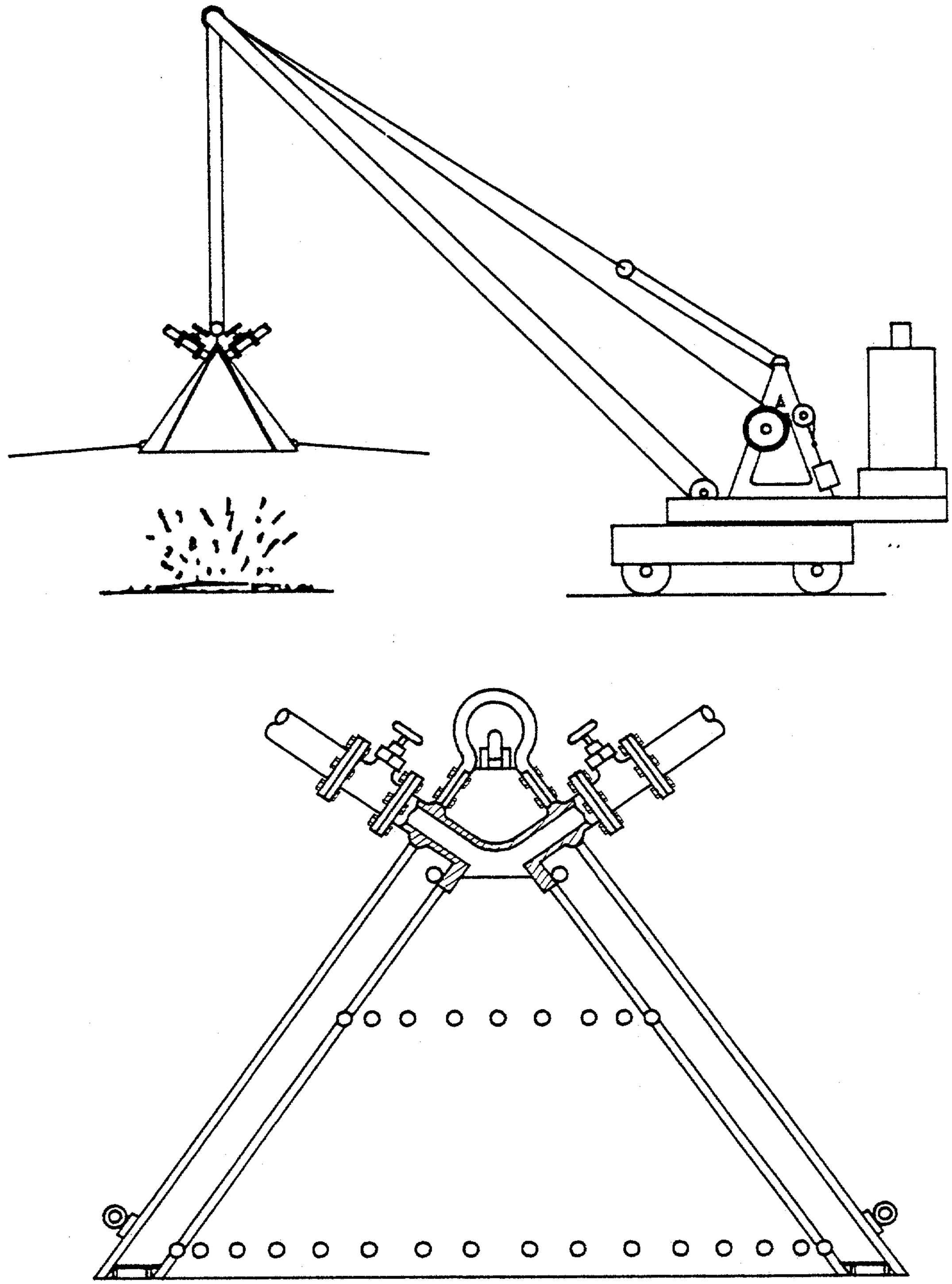

Figure 6.8.1

1924 Patent for First Known Capping/Pollution Assembly

Ref: After MMS Contract 14-12-0001-30135

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The following discussion reviews prior art and results, devices actually installed, encapsulation concepts, and a proposed ship-mounted subsea collection system.

6.8.2 Prior Art and Summary of Results. Subsurface collection of blowout effluent is a relatively new field with efforts beginning in the early 1970s. Early studies were oriented toward subsea collection of oil from seeps or from broken pipelines. The Santa Barbara channel, the Bravo platform in the Ekofisk field and Ixtoc 1 blowouts prompted designs and concepts to collect and contain oil from a blowout. Most are passive devices requiring no energy from an external source.

These collectors are generally categorized as bell-shaped devices, rigid-wall cylinders or flexible columns. (Figure 6.8.2). Some have been designed to capture the effluent at the source while others were intended to intercept the plume in the water column some distance above the source.

The offset distance between the top of the source and the base of the collector is important. The shorter this distance, the less water is entrained in the plume according to the literature (Brown & Root, 1985, p. 2-41). Devices that capture oil close to the source are most favored.. (Figure 6.8.3)

All devices have some inherent weaknesses. They limit access to the wellhead to some degree. Most prevent using other types of well control measures such as vertical intervention. Installing and maintaining these devices on station will be difficult in open sea conditions. These have limited tolerance for debris on the seabed. None are in stock and few, if any, will handle all blowout situations. Long lead times are anticipated since these devices must be purpose-built. Fabrication costs are expected to be high.

Numerous bell-shaped devices have been proposed. The two concepts are the open and closed configurations. Some depend on a seal against the seafloor which is unlikely to occur. Also, open bells tend to entrain a large volume of seawater in the plume due to gas lifting of water into the bottom the device. If a subsea template can be installed around the wellhead or BOP to which the bell can be attached, this situation may be mitigated. Future designs may be able to affect a seal against the seafloor.

Many factors make bell systems impractical. Bells have a limited ability to withstand differential pressures. The systems require sophisticated monitoring. Riser size is critical. Small riser diameter results in a backpressure and spillunder of oil at the bottom of an open bell. This will result in washing out of the sea bottom under the bell. If the bottom of the bell is sealed, this may result in the bell and/or its riser bursting. Also,the seal could be compromised.

Rigid cylinders and columns guide the effluent to the surface and facilitate the use of surface containment techniques. These may limit entrainment of water in the ZOEF to a degree, but unless a good seal at the seafloor is maintained, gas lifting of water from the bottom will likely occur. These devices may be limited in deepwater situations because of the large surface area of the cylinder exposed to current forces in the long water column. Bending resistance must be considered. Heavy anchoring will be required. Surface forces including wind and high waves must be considered.

Flexible columns and cylinders are relatively easy to transport and can limit water entrainment. These must also be anchored solidly with a good seal at the bottom. The flexible sides of these devices have been shown in laboratory experiments to suffer considerable whipping and flapping associated with slug-type flows of fluid and gas (Meikle, 1982).

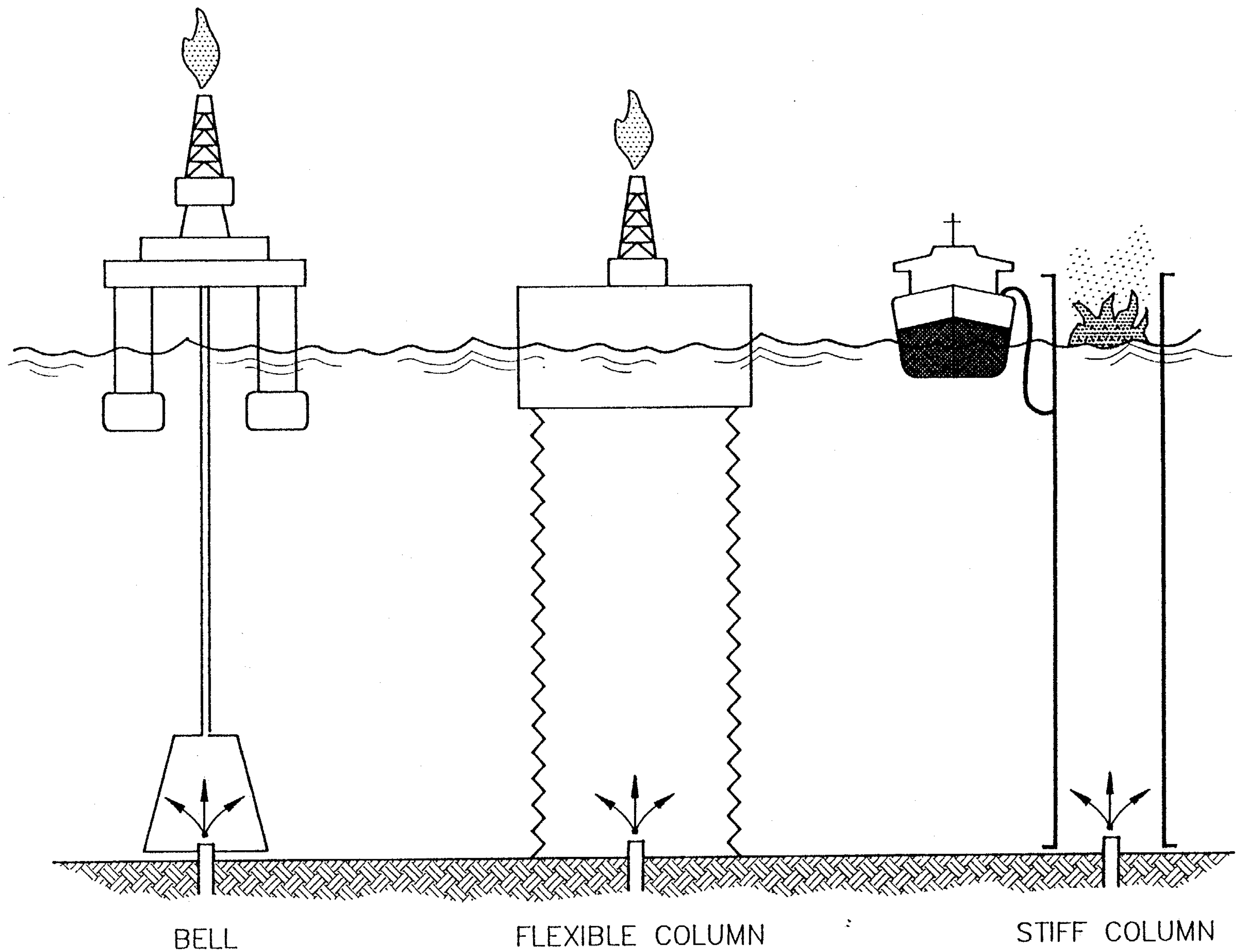

Figure 6.8.2

Schematic of Bell Shaped, Rigid Wall and Flexible Sided Columns

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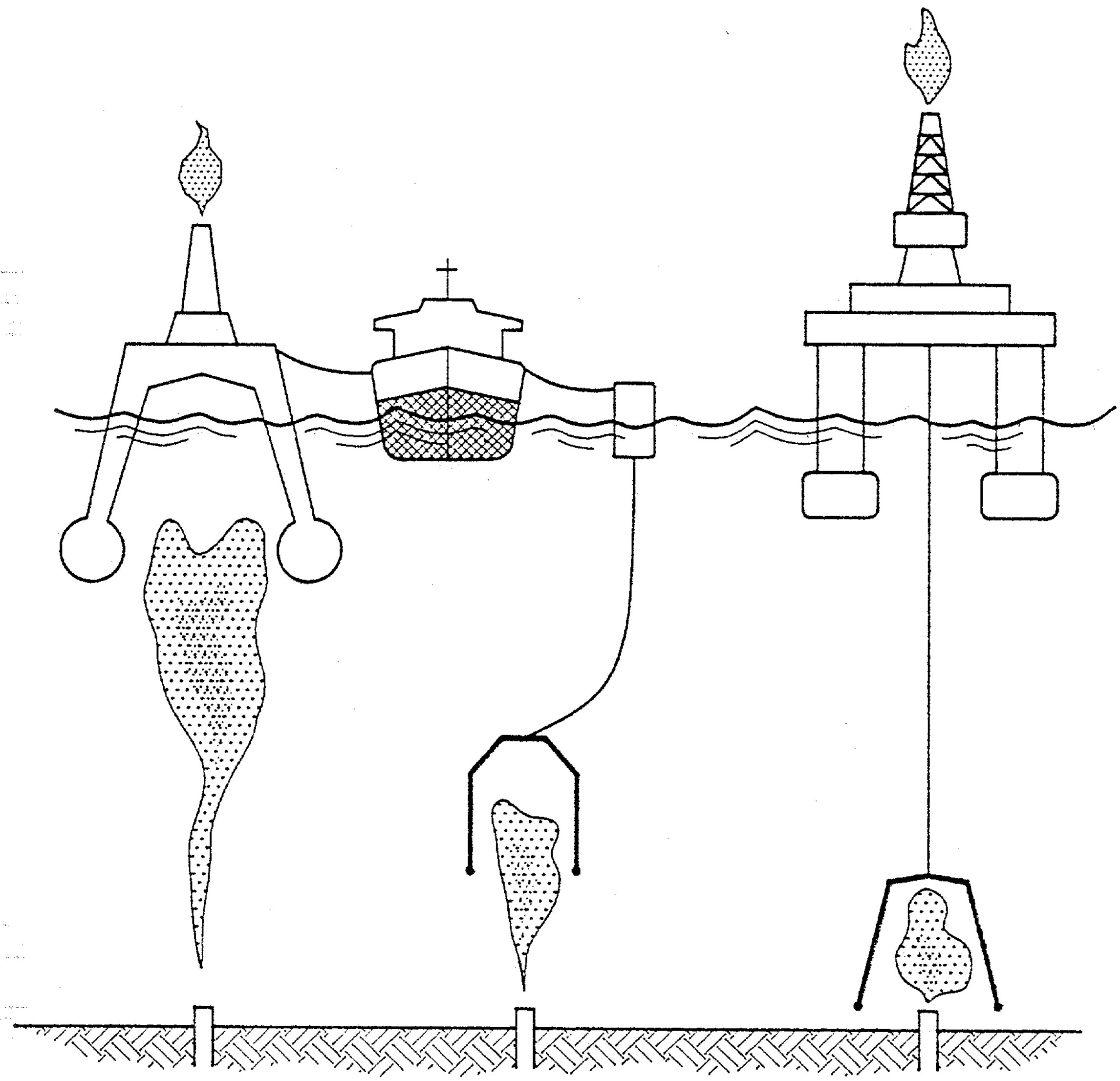

Figure 6.8.3

Types of Containment

These devices will be difficult to install and their deployment is likely to be limited by water depth. They lack the ability to withstand significant pressure differentials across the walls. Thus, it appears that these will be limited in their utility in deepwater blowout situations.

Some of these collectors/containment concepts are combined with subsea separation devices. This has the advantage of reducing the volume of water requiring separation (assuming that seawater entrainment cannot be curtailed). Subsea separation may result in oil being contained and transported to the surface for collection or burning. Gas could be vented into the sea from the subsea separator and allowed to rise in a plume. It could be burned on the surface with minimal pollution. The "clean" gas plume could be treated like a gas well blowout.

One area of technology that should be investigated is the use of passive hydrocylones to separate entrained water in a subsea blowout situation. These devices are capable of separating dispersed or emulsified oil and water. They are more efficient on oil/gas streams due to greater density differences between these fluids.

A collector is necessary upstream of the separator. Hydrocyclones with the necessary volume capacity for subsea blowouts will be bulky, particularly when combined with a large collector. Installation is likely to be difficult.

The only known type of active subsea collector is a tar ball net. This device has 1-2mm openings and is designed to be towed through the water for collecting tar balls.

It is doubtful that this system would have a significant effect on an open sea spill from a blowout. The openings in the net cannot be too small, or it will behave like a towed boom. Considerable spillover will likely occur. Also, the openings in the net will probably become plugged by emulsified oil which will reduce efficiency. It will be difficult to tow a net large enough to affect a significant portion of the total water column. Marine mammal losses associated with this type of netting operation will almost certainly be unacceptable to the public.

6.8.3 Actual Devices Installed. Four devices for containment of oil entering the oceans from a subsea source have been installed in the past. Two contained seepage in the Santa Barbara Channel. The third is the "Sombrero" installed at the Ixtoc 1 blowout in the Bay of Campeche, Mexico. The fourth was a bell-shaped device.

The first of these was a plastic canopy installed in the Santa Barbara Channel in 1969-1970. (Figure 6.8.4) This system was designed to contain oil seeping from the seafloor in relatively shallow water. There was no plume, gas or fire. It was successful to some degree in containing the seeping oil in this situation.

In 1979, the largest known blowout in history occurred. The "Sombrero" was installed on the Ixtoc 1 in an attempt to collect blowing oil from the well while relief wells were being drilled to kill the blowout. It was the first and only system to date that has been designed, constructed and installed for this purpose. (Figure 6.8.5.)

The "Sombrero" was not successful in industry terms. The 1,500,000 bbl/day of effluent recovered by the system contained only 2% oil by volume. Entrained water resulted from gas lifting of seawater into the bottom of the open cone. Surface separation facilities were overloaded and one-half of the oil collected by this system was discharged over the side with the seawater.

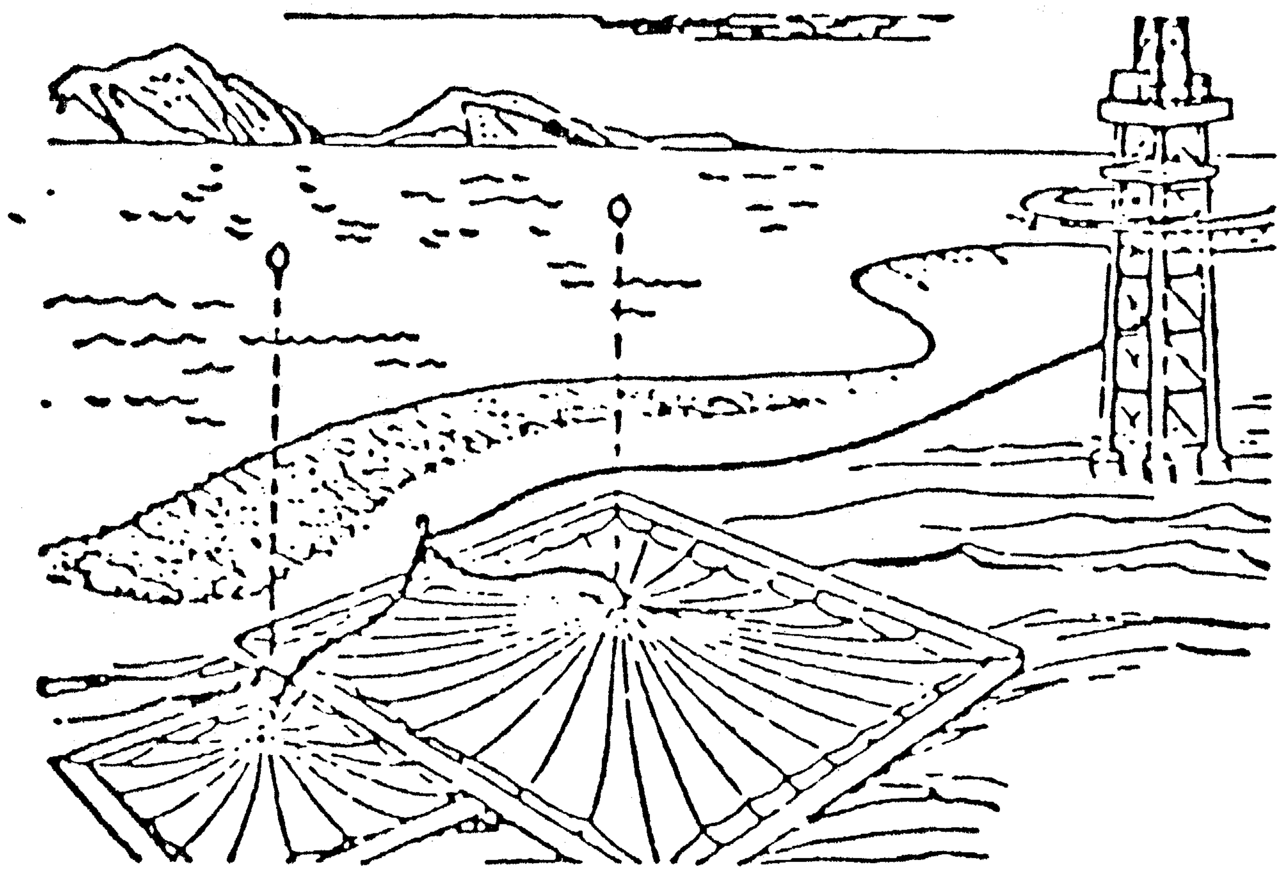

Figure 6.8.4

Flexible Canopy
Union Oil— Santa Barbara Channel

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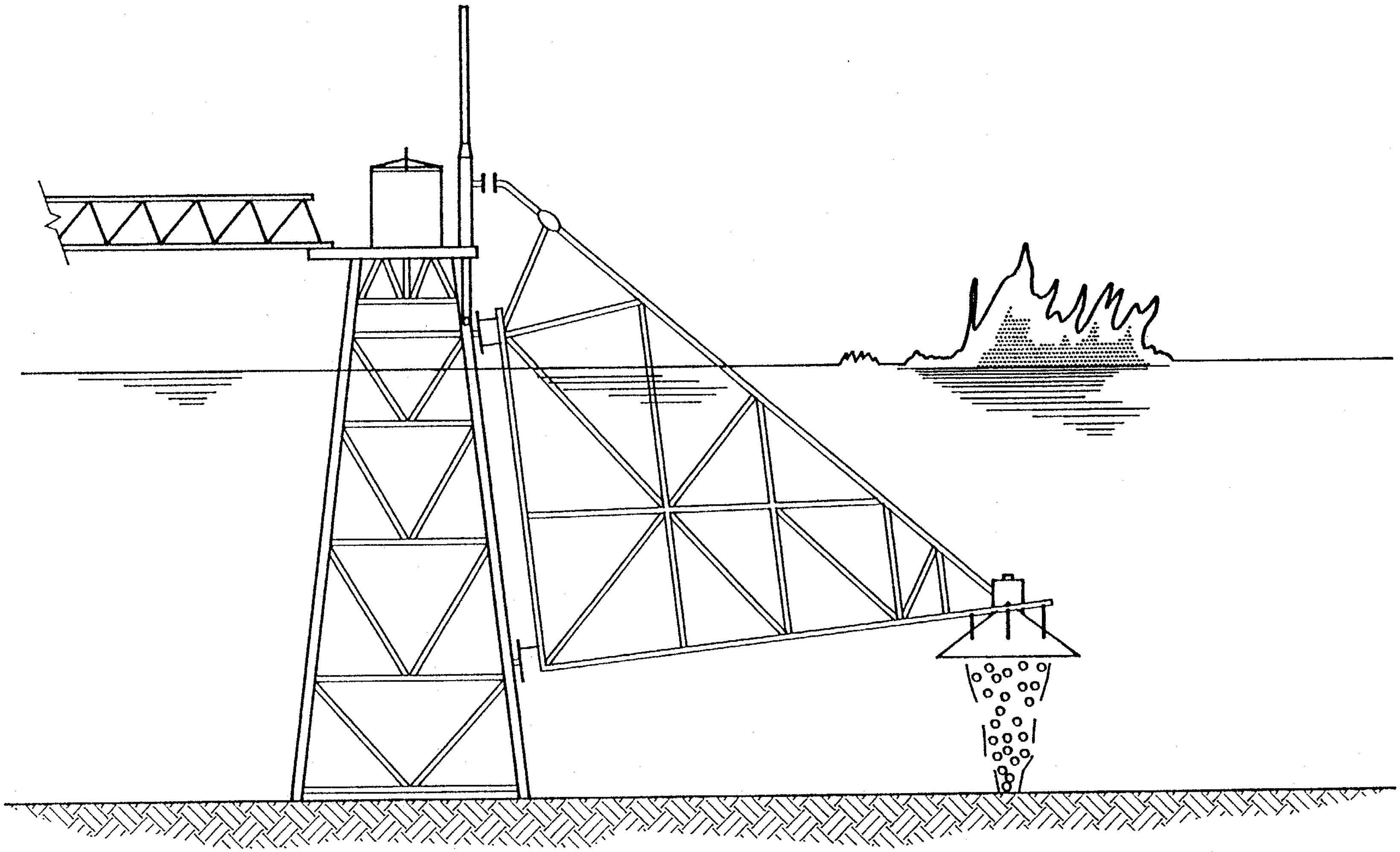

Figure 6.8.5

Schematic of "SOMBRERO", I XTDC 1

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A variety of analyses have attempted to define the cause of the "Sombrero's" lack of success. Several reasons have been offered including:

- Poor positioning
- A riser that was too small allowing spillage of oil from around the bottom of the collector
- Underestimation of the flowrate of the well resulting in a device that was too small
- Lack of advance design, concept study or planning for the "Sombrero" and the separation system.

In fairness, it is noted that the people involved in this project were responding to an emergency. Their efforts were credible. They did not have the benefit of all of the research, studies and technology development that resulted from the Ixtoc 1 blowout.

The problem of installation and positioning containment devices is illustrated by experience with the "Sombrero." When it was first taken to the site for installation, high sea conditions damaged the hinged pin connection on the truss assembly supporting the cone before it could be installed over the blowout. The "Sombrero" had to be towed back to Texas for repairs before it could be positioned over the plume.

After installation, it was found that the device was not centered directly over the blowout. The BOP stack from which the majority of the oil was blowing was tilted by 10-15°. It was difficult to locate the precise source of the effluent on the seafloor, so positioning of the "Sombrero" was imprecise as well. It was found that the center of the plume was hitting the inside of the cone about one-quarter of the way down from the apex of the cone. This positioning was as good as could be expected under the circumstances.

The "Sombrero" was installed in 160' of water. The installation and positioning problems are believed to be less serious than those that will be experienced in deepwater blowout situations.

The "Sombrero" was installed on a rigid truss system from a fixed jacket. In the open seas in deep water such a structure may not be possible to design, fabricate, transport and install before relief well(s) kill the blowout. It probably would not be rigid enough to maintain proper cone position over the blowout. Any future containment devices for use in deep water may be bottom-anchored for this reason.

A seepage collection system was installed in 220' of water by ARCO in the Coal Point Area of the Santa Barbara Channel off the California coast (Brown & Root, MMS Report, 1985). Two steel pyramids with gas/oil separators were positioned permanently on the seafloor. Product lines ran from the pyramids to a surface oil collection system and to a gas plant. (Figure 6.8.6)

Westergaard ("Underwater Blowout Control", 1983, p. 27) mentions one bell that was installed over a blowing well. The seabed around the well scoured out allowing the bell to tip over. Additional details regarding this installation are not available.

6.8.4 Encapsulation of Subsea Wellhead/BOP Stack. An important subset of collection/containment devices discussed previously in general terms are those which completely surround the subsea wellhead and/or BOP stack. These are intended to seal at the bottom eliminating seawater entrainment in the plume.

There are two general types of these devices, ones that seal off against the wellhead, BOP stack or a template pre-installed around the wellhead. The other type seals in some manner against the seafloor itself. In the former type, it is necessary that the blowout be coming through the wellhead/BOP stack. If the well has begun to flow around the structural casing, it will do little good to seal around the wellhead only.

Obtaining a seal around the wellhead/BOP stack implies some usable piece of equipment remains on which to affect a seal. If the wellhead or stack is bent over at a considerable angle, as is usually the case, slipping a device over the remains of the head/stack may not be possible. If the head is otherwise damaged severely it may be that there is not a position on the head/stack for a seal to be affected. It may not be possible to install this device due to near-wellhead debris.

Westergaard, in a 1982 paper presented at the 2nd Subsea Containment of Oil Workshop in Oslo, Norway, proposed installing a special baseplate below the subsea wellhead on deepwater wells. This baseplate would be installed prior to drilling the well. (Figure 6.8.7)

In the event of a blowout, a bell-shaped device could be lowered over the wellhead and BOP stack to mate with this baseplate. In a 1983 paper, he indicates that the "mating bell" concept should be considered in special circumstances such as single, exploratory wells (not those drilled in a subsea cluster where a template would interfere with installation of the bell). The "mating bell" concept was not considered cost effective by Westergaard.

The second type of sealing device is a bell-shaped, cylinder or column that swallows the entire wellhead and BOP assembly and seals against the sea floor. The concept of a seal against the sea bed has been largely dismissed by the industry as unrealistic.

There may be some merit to a bell- or cone-shaped device having a skirt that would dig into the seafloor to provide a partial seal. This could be combined with a gravity base and a scour protection barrier around the outside of the collector to provide protection against glory hole excavation by the plume forces. The device could be connected to the surface by a conventional deepwater drilling riser lowered from a semisubmersible. (Figure 6.8.8)

Effluent spillunder might be reduced by installing a large diameter conventional riser or a tapered riser. If the plume is sufficiently strong to pull a vacuum against the seafloor at the base of the container, a valve could be installed at the surface to hold moderate pressure against the riser. This could balance the pressure inside the container with the seawater hydrostatic head to within 0.1 bar which is a suggested upper limit in the literature. (Westergaard, 1983).

Pressure balancing can be accomplished by having one or more openings to the sea. These could be remotely-operated valves in the body of the container. It may be more prudent to control the volume of entrained water instead of excluding it. Surface separation of oil, water and gas can occur with entrained seawater dumped overboard. Storage or incineration of the collected oil would depend on the size of the blowout and the availability of suitable transportation vessels for lightering. Gas would be flared.

This system would allow drillpipe to be snubbed through the riser. This would allow vertical intervention techniques to be used while the well is flowing. Loss of oil onto the sea would be controlled. Operations could be conducted without urgency to control pollution. Time would be available to bring the well under control without taking shortcuts. This device would provide stopgap pollution control while planning and executing a suitable kill technique.

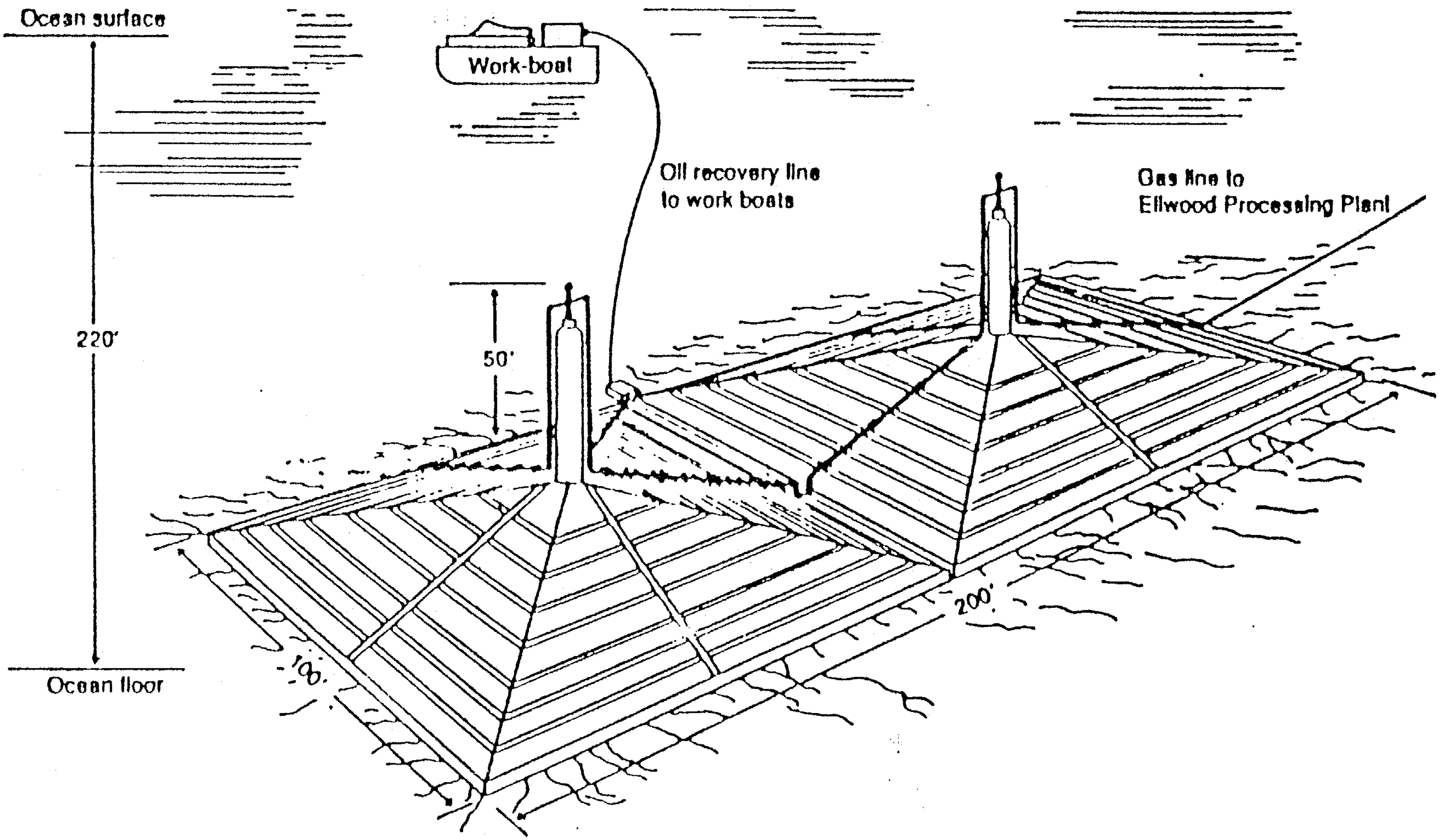

Figure 6.8.6

Seepage Collection System
ARCO– Coal Point, California

Ref: B&R MMS Contract No. 14–R–001–30135

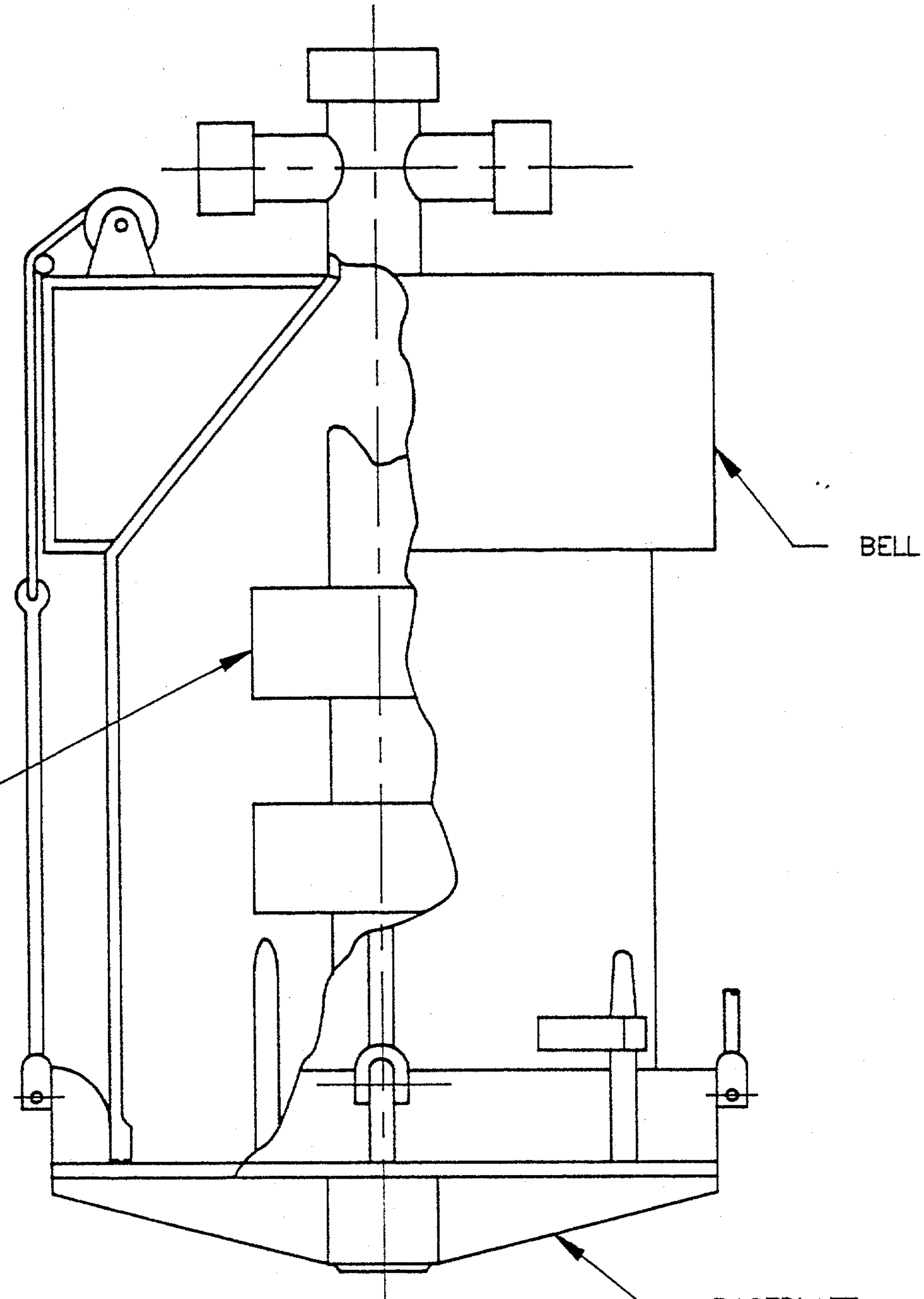

Figure 6.8.7

Mating Bell

*Westerward, 1983

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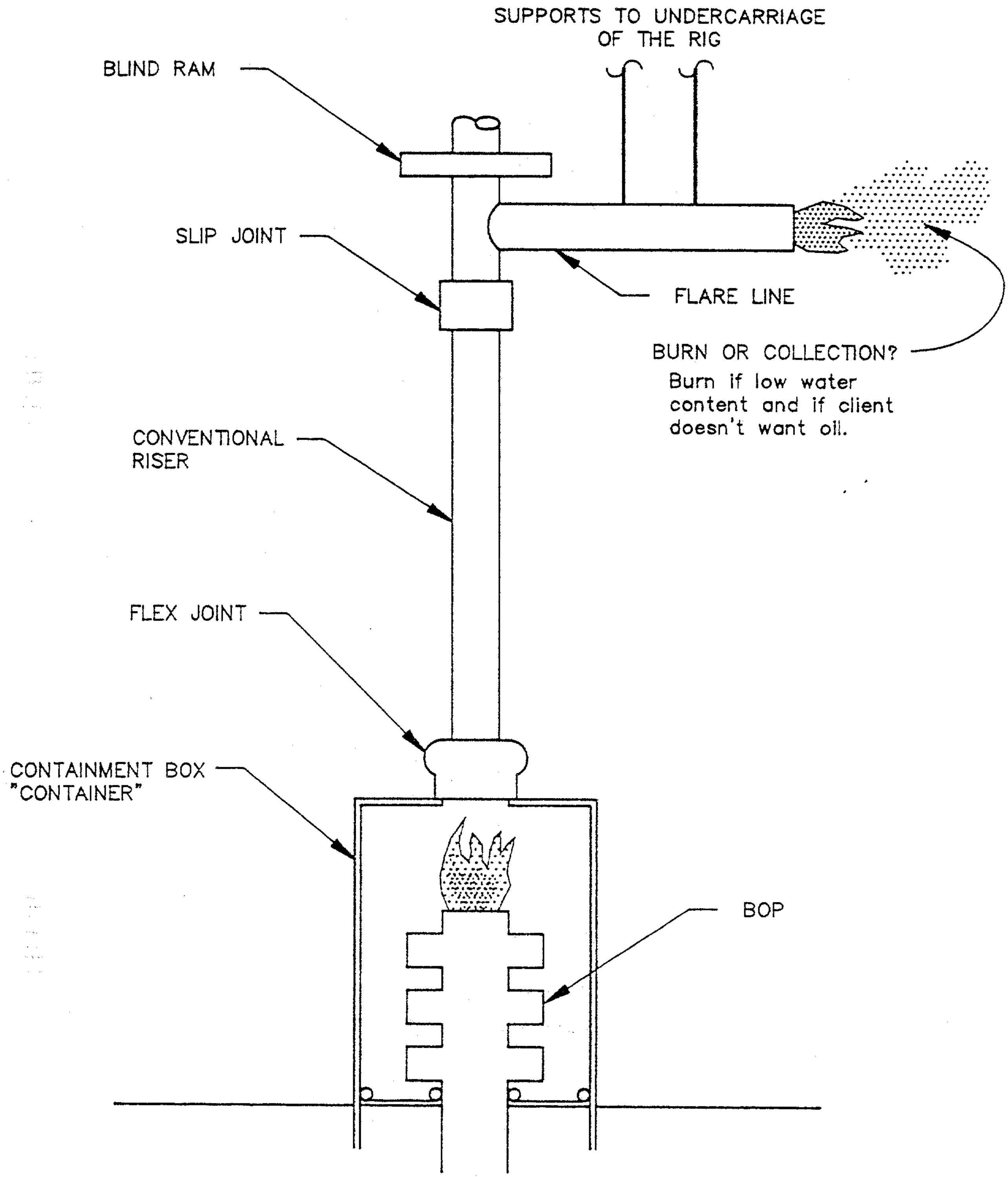

Figure 6.8.8

Subsurface Encapulation Device

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The system has several inherent disadvantages including the following:

- It requires that all debris be removed prior to installation. This may be difficult in some situations.
- In order for a generic device of this type to be built to encapsulate wellheads/stacks in most blowout situations, it must be as tall as the tallest subsea stack in use in the area. It must also have a diameter sufficient to "swallow" the entire stack and seal against the seafloor if the stack is bulky, has damaged components hanging from the stack, or the head/stack assembly is leaning.
- A large container, with sufficient wall thickness and strength to withstand collapse and burst pressures will be heavy. Its size and weight will likely preclude its being lowered through a normal-size moonpool. If it is run with a rig, it must be keelhauled into positioned below the rig before it can be lowered on the rig's riser. Otherwise, it must be barge transported and set on the seafloor with a crane. The riser must be lowered and mated subsea with the top of the container.
- Currents and surface wave forces will likely result in difficulties installing the device.
- If the seafloor washes out from under the container and it tips over, additional damage to the wellhead/BOP stack from the heavy container body may occur. A disconnect may be required to prevent damage to the riser. Failure to disconnect could result in additional debris being dumped on top of the wellhead, i.e., pieces of the riser, separation equipment or anchoring devices.
- During installation, care must be taken to avoid plume forces that would wash or pull seabed sediments away from the bottom of the container before it is positioned properly and internal pressure is equalized. If the container is run from a rig, its top must be closed during installation to avoid effluent being lifted onto the rig floor. Seafloor sediments will wash out from around the base of the container when it is set over the wellhead with the top closed. If the top is open, a suction may be pulled against the seafloor which would draw sediments into the plume before the device is set on the bottom.
- Care must be taken with the rig while the well is blowing. This system will obviously place blowout effluent at or just under the rig floor even if the effluent is diverted. Further, the full force of the blowout will be brought to the surface, i.e., there will not be a water column between the blowout source and the rig to cushion the force from the blowing well.
- Long lead time for construction of the container is anticipated.
- Response and installation times may be extended depending on sea and weather conditions. Certain areas may be inaccessible due to high currents, sea conditions or icebergs.
- Separation facilities connected to the top of the riser must operate efficiently and without interruption. Sufficient storage must be placed to contain all of the oil from the blowout for a given length of time.
- A clean burning flare system must be provided if the oil is to be incinerated. This may require air injection. A remotely operated flare pilot or ignition system will also be needed for occasional re-ignition. The burner system must be designed to handle peak

rates. Some wells flow in slugs and not at steady rates. The burner must be capable of handling these large, high velocity slugs or unburned oil will be spilled onto the surface.

These difficulties have caused many researchers to conclude that sealed containment of blowout oil is not practical with existing technology. The concept, however, is the best of the ideas for underwater collection. It may become feasible given some technology advancement.

6.8.5 Ship-Mounted Subsurface Collector System. Brown & Root Development, Inc. of Houston prepared an engineering and cost analysis of a ship-mounted subsurface collection system in 1985. This work was under a contract to the Minerals Management Service of the US Department of the Interior (Contract No. 14-12-0001-30135). Their two volume report contains an excellent analysis of this type of system and is recommended for further reading.

The system, as recommended by B&R, consists of a converted tanker modified with a moonpool, turret mooring system and dynamic positioning. It would have onboard separation and storage facilities to handle a maximum volume of 30,000 barrels per day. The vessel would also have firefighting, inerting and safety systems (Figure 6.8.9).

Collection would be accomplished by a double-cone collector having a pair of flexible risers. This type of collector was patented and tested by Dr. Jerry Milgram of M.I.T. (Figure 6.8.10) The inside cone provides primary recovery of oil and gas with any spillunder collected by the outer cone. Each cone has its own riser.

Riser design is crucial to the system. The diameter must be sufficiently large to transport all of the oil, any associated gas and anticipated large volumes of entrained seawater. Risers with insufficient diameters would be inefficient.

System requirements specified by the MMS and those developed by Brown & Root are considerable. The collector was sized for only one wellhead/BOP. It was to be large enough to contain a meandering plume. It should be at least 30' tall and should weigh at least 25-30 tons, submerged. Risers of 20-24" OD each were recommended. These are difficult to handle and deploy. This system was designed for use in less than 100 feet of water, although it could be extended into deeper water. As depth increases, risers must be strengthened, the anchoring system for the collector must be improved and the positioning maintenance of the ship becomes more difficult.

The most serious limitation is the cost of the system. It was estimated at $58,784,000 US (1985). Joint industry funding would be required.

Control and operation of the vessel was not specified. The US Coast Guard might be responsible. It was planned that this vessel would be deployed off the West Coast of California, but it could be used elsewhere. Transit times to other locations were not reviewed. It was anticipated that the vessel could be on station within two weeks for a blowout off the West Coast.

It is noted that this study was completed in 1985 and no system exists yet. The system will cost more today. Spiraling costs for this large, elaborate collection, treatment and storage facility may be a deterrent to building the system.

When high costs for preparedness are considered, especially in the absence of a serious offshore blowout recently, it is understandable why this project has not been pursued. Several less expensive methods of dealing with pollution from a deepwater blowout are discussed in Section 6.9.

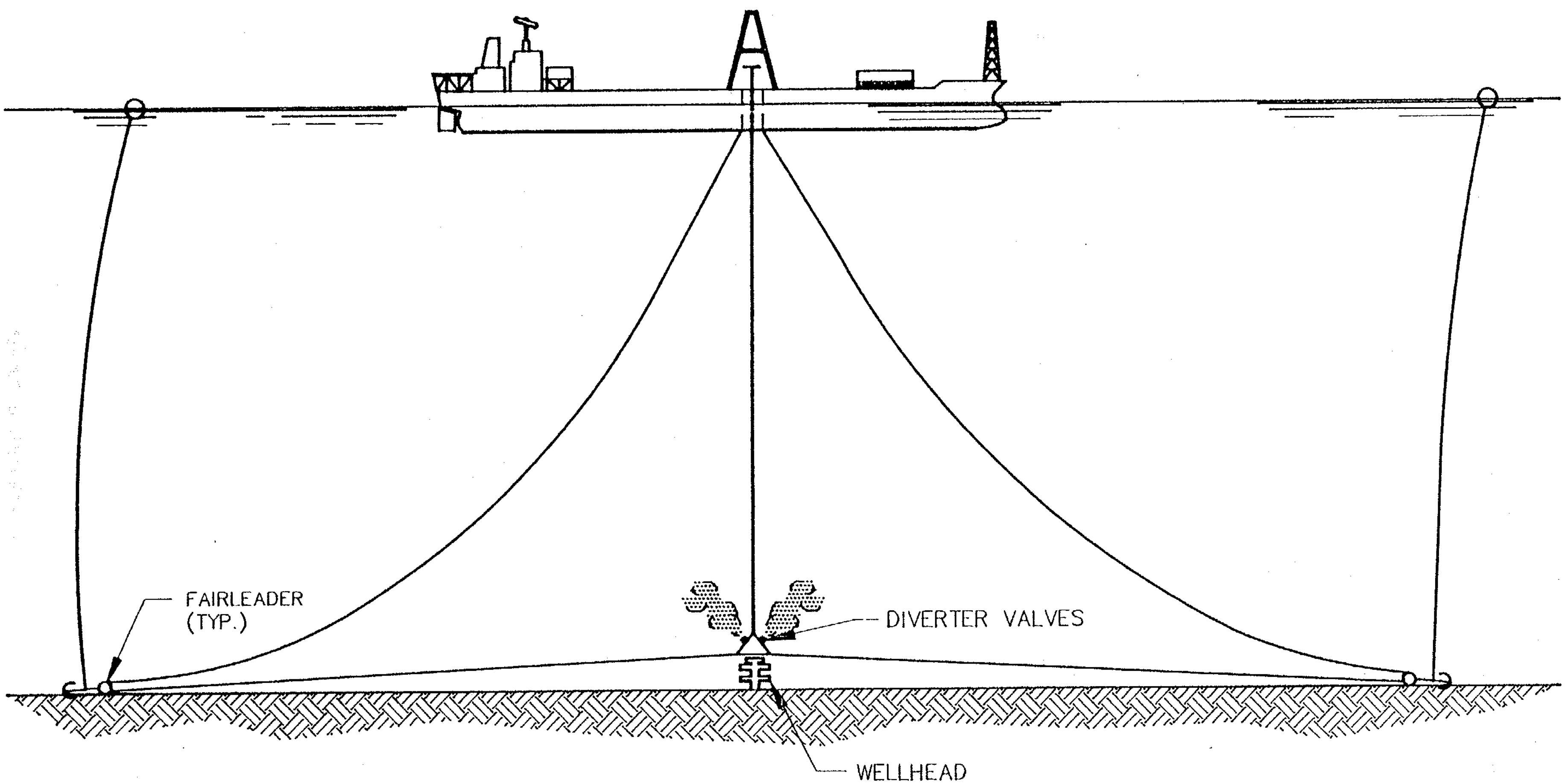

Figure 6.8.9

Ship–Mounted Subsurface Collector System

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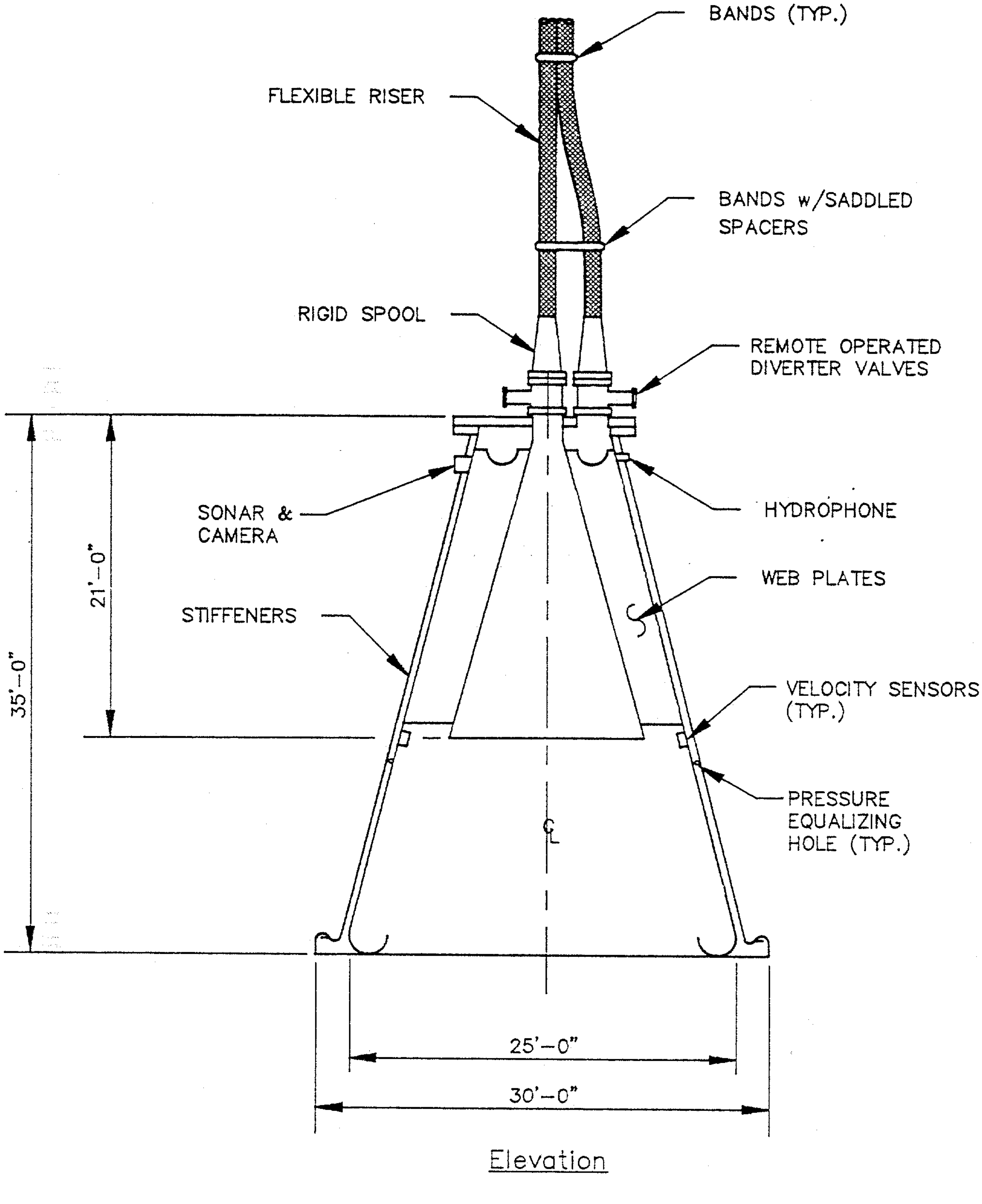

Figure 6.8.10

Subsurface Cone*

*After MMS Contract 14–12–0001–30135

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6.9 TREATMENT OF EFFLUENT AT THE SOURCE

6.9.1 Introduction. This section deals with enhanced effluent treatment through a combination of dispersant, nutrient and bacteria injection directly into the blowout plume at its source on the seabed.

The concept of treating an oil spill at its source is not unique. Damage to the environment can be mitigated if toxicity from any spilled or discharged waste product can be reduced by treating the effluent. This is the purpose behind industrial and municipal waste treatment facilities that discharge into a river or the sea. They treat the effluent by physically, biologically or chemically removing the harshest of the contaminants, then supplying enough oxygen to satisfy the system's biochemical oxygen demand (BOD).

Injecting pollution treating chemicals and microbes into the plume takes advantage of plume dynamics to enhance mixing. Some of the treated oil may surface where mechanical devices can gather and collect it. Any oil that remains in the water column has been treated. It's toxicity will have been reduced by polymeric reaction or it will be consumed quickly by enhanced bacterial action.

Either of these represents an improvement over current methods of dealing with a spill on the ocean. Regulatory agencies, the public and the press can be assured that environmental damage is being mitigated.

6.9.2 Dispersant Injection into the Plume. In 1983, Westergaard conceived the idea of injecting dispersants into the blowout plume at the seabed of an offshore blowout. IKU, a Norwegian research institute in Trondheim, had a related idea at about the same time. The literature discusses the reasons for dispersing the oil from a blowout, some of which are summarized below (Westergaard, 1989):

- Surface collection methods for gathering spilled oil in an open sea situation will be less than adequate for a large effluent release.
- Untreated oil will emulsify which complicates collection and clean-up activities and delays natural biodegradation of the spill.
- The oil, once it has been dispersed, will spread faster enhancing exposure to natural bacteria and significantly diluting toxic components of the crude dissolved in the water column.
- Significant natural dispersion will likely affect the effluent. Injection of dispersants will enhance this situation.
- This provides a cost effective preparedness method that can be mobilized in hours, not days, that may replace current cumbersome, expensive and ineffective methods.
- It is an attractive, all-weather method of remediating a spill that can be used for a long period of time.

These reasons are still valid particularly in view of non-pathogenic dispersants recently developed.

Proposed equipment for injecting dispersants was simple to operate. One proposal demonstrated dispersant injection into the subsea stack or BOP through a special injection spool or through a port in the stack itself. (Figure 6.9.1.) An injection hose would lay on the seafloor connected to a pendant buoy. In the event of a blowout, the injection hose could be recovered by a vessel of opportunity and the dispersant could be pumped into the plume.

Another proposal showed the dispersant injected from the wellbore through a tube connected to a side pocket mandrel or down an open annulus in a platform drilling operation (Figure 6.9.2). The dispersant would necessarily be pumped from a nearby boat.

Much of the oil will probably not surface if subsea dispersant injection is implemented. This may appear to be a drawback since toxic aromatic components will not have the opportunity to evaporate at the surface. This is not likely to be a problem in deepwater situations for the following reasons:

- There will be exposure of the toxic soluble components to the water column in a long plume. Dissolution of these fractions will have already occurred by the time the oil reaches the surface (much like H_2S being stripped out of the plume in a sour deepwater gas well blowout).
- A tall zone of flow establishment will allow entrainment of seawater into the plume. The concentration of toxic components in the area may be below harmful levels from this dilution.
- If completely successful, subsurface dispersant injection could result in no oil reaching the surface. The public relations effect of having no oil on the surface may outweigh the benefits of evaporation of toxic components into the atmosphere.
- Evaporation of these components is a trade-off, not a solution. These chemicals, particularly the aromatics, are toxic regardless of location. Their presence in the atmosphere provides for rapid dilution which is viewed as the only benefit of their evaporation from the water column. These components may already be at a low level due to dilution within the water column.

The prevention of these components from evaporating due to subsurface dispersant injection is not considered problematic.

Use of dispersants is becoming a more widely accepted method of handling offshore spills. Some new dispersants have been accepted and approved by the US Coast Guard for use in offshore US areas. It is recognized that these chemical mixtures are no longer dangerous. The use of dispersants to prevent oiling of beaches, bays and other visible areas is now becoming common practice.

It appears that subsurface injection of dispersants should be an inexpensive, effective pollution countermeasure for subsea blowouts.

6.9.3 Microbial and Nutrient Injection into the Plume. The use of bacteria to remediate oil spills is becoming more widespread and popular in the industry. Section 6.6 discusses the method by which bacteria are sprayed on surface spills.

It appears that the injection of such a bacterial "soup" into a plume at the source holds promise for the remedial treatment of a subsea blowout.

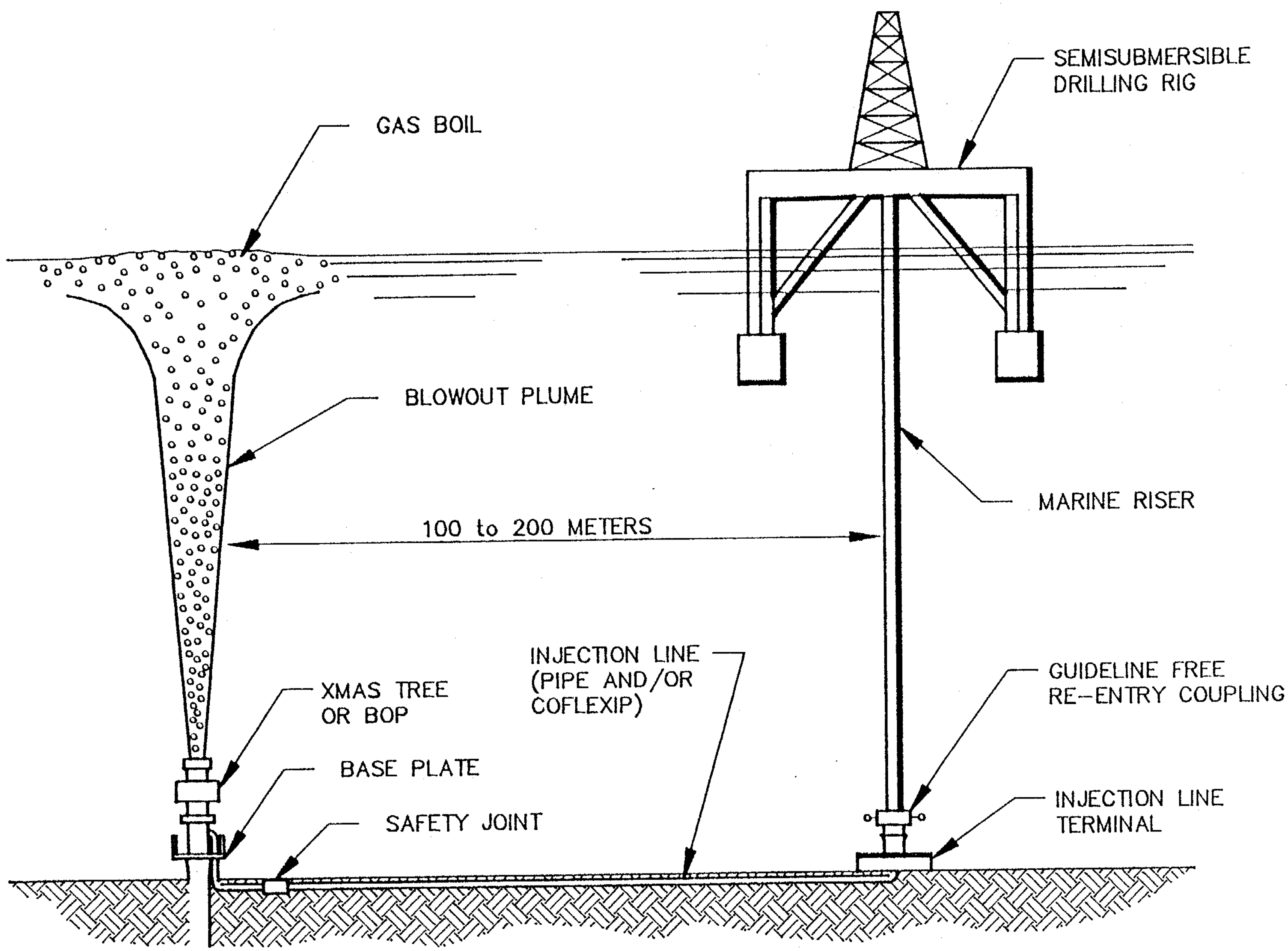

Figure 6.9.1

Drilling Injection Preparedness

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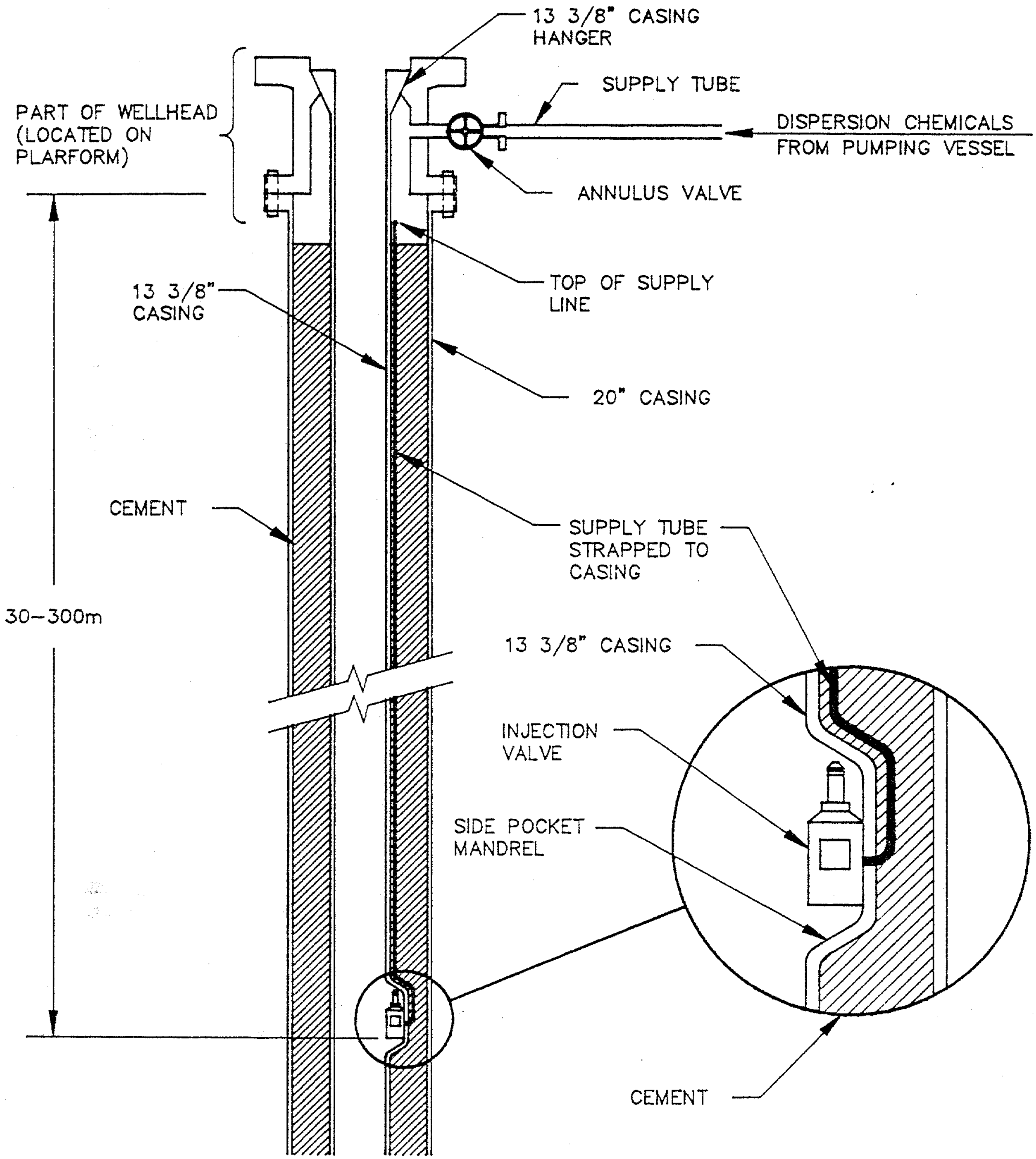

Figure 6.9.2

Chemical Supply Through Small Diameter Tube Strapped to Casing

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Injection of the bacteria directly into the plume has some notable benefits:

- Mixing of the oil and bacterial "soup" occurs at the point of escape and in the plume.

- It is not necessary to inject the number of bacteria necessary to completely consume the spill. If sufficient parent bacteria are placed into the system, they will multiply to consume the oil available whether it rises to the surface or not.

- These bacteria are not adversely affected by subsea pressures or by pump shearing.

- They can be mixed with modern dispersants and injected simultaneously without significant bacterial mortality.

- After consuming the oil, they will die off from starvation with no further cleanup efforts to dispose of any residue.

- Anerobic bacteria will remain in oil that sinks to the seabed and continue to consume the heavier fractions. Similarly, the inorganic portions of the oil will eventually be completely treated and consumed by fungi in the mixture.

- The products remaining after ingestion of the oil are carbon dioxide and water, just as in natural biodegradation.

- A large contingent of surface treatment vessels to contain and collect the oil spill is unnecessary.

It may be advisable to have some surface containment and collection equipment in the spill area if enough oil is surfacing to impede other activities such as vertical intervention.

If dispersants are used in the mixture, some surface containment and collection devices will probably be less effective. Dispersed oil will not stick to absorbents. Oil will likely sink so skimmers may not collect the oil before it re-enters the water column. Incineration is not considered viable.

Any collected oil must be re-treated with a powerful biocide before it is processed through onshore facilities. If it is mixed with untreated crude, the mixture will be contaminated with the oil consuming bacteria. The processing facility would also require decontamination.

6.9.4 Polymer Treatment of Blowout Effluent. Polymer treatment of blowing oil at the source can result in a cleanup technique that would be highly efficient. The rubbery mass resulting from the reaction should float to the surface where it can be recovered by mechanical means. A large portion of the effluent can be effectively removed from the sea.

Unlike the dispersant injection system, the polymers are capable of reacting with the highly toxic aromatic fraction of the crude oil. Also, soluble light ends can quickly react with the polymer. The treatment will remove and detoxify these pollutants before they can dissolve and contaminate the water column. Like the dispersants, they can do little about contamination from the inorganic fraction of the crude oil (Thompson, 1991).

Liquid polymers provide the easiest form of polymer injection. Liquid polymers are less reactive than solid, or crumb form, polymers. They can be diluted in seawater which lengthens reaction times.

Crumb form polymers are more difficult than liquid polymers to place at the blowout source. These polymers are immiscible in water or other convenient, non-toxic solvents. A slurry must be blended if they are to be placed at the blowout source. It may be possible in shallow water to blow the polymers to the bottom with high pressure, high energy turbines.

Some type of emulsifier may be required to create a stable slurry. Addition of an emulsifier to a crude oil/water system that may form emulsions at seafloor temperature is a questionable practice. Some type of dispersant/demulsifier could be added to the slurry to combat this effect, but the resulting mixture of emulsifier, polymer, dispersant/demulsifier may be difficult to formulate and may be unstable.

The polymer/crude oil reaction is expected to be rapid. The effect of cold seafloor temperature on reaction constants is unknown. If the reaction is slowed, stable oil/seawater emulsions may form. These could interfere with the polymer/oil reaction.

The effect of gas on the reaction is not known. Gas compressed to seafloor pressure by an overlying water column may behave as a reactant with the polymer. This would require additional polymer to react with available hydrocarbons.

The addition of polymer into the blowout effluent may alter plume dynamics in the following ways:

- As oil reacts with the polymer, the resulting rubber mass will have a density greater than that of oil. The buoyancy of the plume will be reduced in the zone of established flow where the oil's lower density has an effect.

- The oil/polymer reaction will reduce or eliminate the formation of oil/seawater emulsions which will affect system buoyance.

- The size and shape of the reacted rubber particles will have an effect on their terminal velocities. Also, seawater may be entrapped in the bulk of the mass which will affect its movement through the water column to the surface.

These effects may be minor relative to the gross velocity of the plume which will be governed by the volume of gas that is available for expansion in the plume.

Injection of polymers into the blowout plume may represent an attractive cleanup countermeasure if mechanical problems and uncertainties regarding the polymers can be overcome.

6.10 RECOMMENDATIONS FOR EQUIPMENT DEVELOPMENT

6.10.1 Liquid Injection Equipment. The two systems suggested in the literature for injection of dispersant into the plume (Section 6.9.3) should be adequate for injection of the bacterial "soups". Both systems rely on the blowout exiting through some component of the wellhead or BOP stack. These systems cannot be depended upon to deliver the dispersant or bacteria to the plume if the wellhead/stack is not intact or the injection line has been damaged.

While these systems may be satisfactory under most drilling scenarios it is believed that a wellhead-independent device should be considered. It should be simple, easy to fabricate, transport and install and it should be fabricated from existing components with little additional technological development involved.

The device should be able to handle a variety of situations ranging from a blowout around the surface casing to the situation where the wellhead is covered with debris or is below the mudline.

It is recommended that an open-top bell or cone shaped device be fabricated and anchored over the source point. This device will have nozzles arranged around the periphery at the top of the opening for injection of the dispersant/bacteria mixture. (Figure 6.10.1.)

It is envisioned that this device would be installed in the semi-quiescent zone. It could sit on the bottom or have flotation bottles and be anchored just above the bottom. If anchored off bottom, it would not be affected by small debris around the blowout. Pressure containment would not be required since it would be a flow-through device. The jet would tend to center the device over the blowout source.

The top would behave like an eductor. The dispersant/bacteria mixture would be drawn into the plume by venturi effect. It is this type of device most fire departments use for making foam (water is forced through a venturi which pulls in air and soap).

Little energy is required to inject the chemical. A small pump is required to transport the chemical from the surface to a holding tank on the seafloor. Injection of the chemical mixture would be aided by the force of the jet going through the throat of the venturi. If additional chemical is required, the surface pump can add pressure to the holding tank. Elaborate pump and control systems are not needed.

The shape of the device would permit other types of work to continue while the effluent is being treated. Vertical intervention would be possible through the device. In fact, it could be used as a guide for tools run into the blowing well, depending on how it's positioned and anchored. If a relief well is drilled and the blowout killed, the string of tools used to cement the top of the blowout can also use this device as a guide. The injector could be connected to the rig with guidelines to facilitate access.

An ROV may be able to access the wellhead depending on device positioning. The ROV tether must extend from the outside of the device near the seafloor. Care is required to avoid the ROV from being pulled through the eductor by the plume.

If this device is set some distance above the source, seawater will be entrained in the plume as it goes through the eductor. This may result in overtreatment of the plume since the venturi reacts the same to any fluid. It may be desirable to have some excess chemical available to treat oil sheared off the sides of the plume.

This device could be fabricated and dispatched quickly. It does not require heavy walls or risers. It would be relatively light and fairly simple to install. Wave and current forces acting on the device would be minimized. It is noted that the dispersant and the bacteria are in a seawater base. The holding tank should not require anchoring since there will be no buoyant forces.

This device could be used in several situations since it is not site specific. It could be constructed as a preparedness item that could be stored for contingencies with adequate stocks of dispersant and bacteria at a reasonable cost.

The proposed equipment requires further design and development specification which are beyond the scope of this study. Design parameters include:

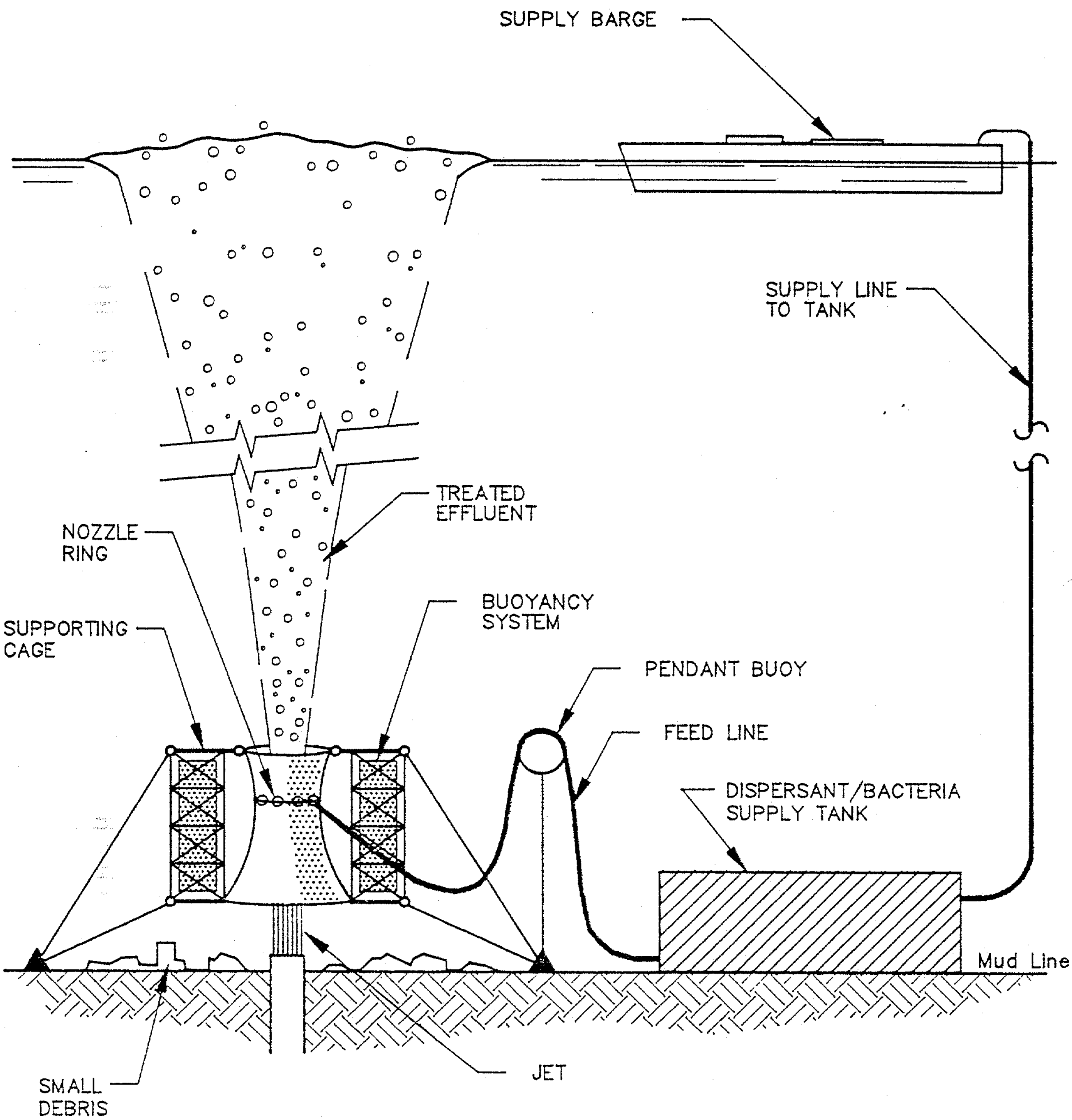

Figure 6.10.1

Subsea Chemical Injection System

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- Upper and lower diameters of the device so most, or all, of the plume goes through the center of the device.

- Throat diameter to insure sufficient pressure reduction to pull the proper volume of the chemical mixture from the holding tank into the plume.

- The number and size of nozzles needed for adequate throughput of chemical.

- The size and construction of the buoyance system to permit the device to "float" just above the seafloor.

- A suitable anchoring system.

- The volume and configuration of the storage tank, the supply line and the pumping system on a barge to insure an adequate supply of the chemical to the feed line.

- Monitoring and control systems to insure that the chemicals are flowing properly through the system and into the plume.

This system can be designed with little or no additional technology development. Factors influencing design are understood for the components. Maximum flexibility should be built into the system so it can be used with little modification.

6.10.2 Polymer Injection Equipment. Two types of polymers, liquid and solid (crumb form), are available for treatment of blowout effluent. Liquid polymers can be injected through the systems discussed above either through a component of the wellhead or the eductor.

Solid polymers must be mixed in a slurry and pumped into the plume due to their specific gravity and their repulsion of water. Normal slurry mixing equipment can be used for this including rig mud mixing equipment. Maintaining a stable slurry during placement of the mixture on the bottom of the sea may be difficult due to separation tendencies of the slurry.

The polymers used for reaction with crude oil are light and entrap a large volume of air. Their low specific gravity is retained when they are placed in water. Further, these are not soluble in water. This property is desirable for their use on surface spills.

Passive mixers will probably be needed to maintain stability if the slurry is to be pumped to a significant depth. These should be installed along the flowline at various points depending on slurry properties such as viscosity, solids volume and flow regime of the slurry.

An open ended flume may be needed to deliver the slurry into the blowout stream. Nozzles or ports often plug when used with a slurry. Delivery of the polymer slurry to the plume can be accomplished by an open duct of some type. Mixing of polymer and crude will occur in the plume. No other mixing is required at the delivery point.

Control of this system will be more difficult than a liquid injection system. The slurry must be delivered by a slurry pump on the surface. If the well's flowing characteristics change, it may be difficult to change the system's output quickly. Over- and under-treatment of the effluent plume may occur due to slugging of well fluids. Mixing in the plume may mitigate this situation.

A change in the proportion of polymer in the slurry due to separation in the supply line may also affect treatment efficiency. Slugs of polymer followed by slugs of water will result in over- and under-treatment of a section of the plume.

The study to develop design criteria and specifications for the eductor system should include designs for solid polymer injection equipment. Potential problems in delivering a uniform concentration of polymers to the root of the blowout plume should be addressed.

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7.0 VERTICAL INTERVENTION

7.1 INTRODUCTION

All blowouts are different to various degrees, and the circumstances associated with the intervention are also varied. These include the following factors:

- Geography
- Water depth
- Water current
- Weather windows
- Rig availability
- Equipment compatibility
- Blowout rate

It is impossible to generate a single optimized "cookbook" procedure that would work in all cases and circumstances.

The intention of this section is to provide the reader with a better understanding of the different factors which must be considered prior to re-entering a blowing well to attempt a vertical kill.

The information specified is intended to assist the operator in generating his plan to control a specific blowout. Although this section primarily addresses technical issues, safety should remain a top priority in any plan. All operations should include contingency kill plans as well as plans to ensure the safety of the well control team and vertical intervention vessels.

This section also includes certain vertical intervention procedures which may not be feasible in some geographic locations. These must be considered and evaluated for each situation, on a case-by-case basis. These procedures involve various preparatory steps required for a base case scenario. They may not be applicable to a specific blowout. The reader must select the sections which apply to his situation.

For the purposes of this report, the vertical intervention will be performed from a semisubmersible vessel. Both guideline and guidelineless running of intervention equipment is addressed. Also described are simple modifications that require minimal modification costs and could be incorporated into present drilling equipment to facilitate vertical intervention procedures.

7.2 FACTORS INFLUENCING VERTICAL INTERVENTION METHODS

Several factors can influence planning and executing vertical intervention procedures. Some of these are discussed below. The degree of influence of each depends on the location of the blowout and the specific circumstances associated with it.

7.2.1 Equipment Availability. The availability of appropriate equipment plays a major role in the decision and methodology to be utilized in a vertical intervention. First and foremost, a suitable vessel must be contracted and mobilized to the blowout location. The best case scenario would be the availability of another semisubmersible drilling in the area which was either completing operations or was at a stage where operations could be suspended. A vessel in this situation would most likely have comparable capital and/or expendable equipment on board for drilling operations in the area. A worst case scenario involves the lack of a suitable vessel being available or having to be mobilized from a distant site. Blowout scenarios change rapidly; therefore, a well-laid initial plan may no longer apply if mobilization times become excessive.

7.2.2 Water Depth. Water depth influences vertical intervention technique selection and implementation. Sea conditions are usually more severe in deepwater environments. The head exerted by the water column influences the cushioning effect of overlying seawater on the blowing well at the source. Section 4.2.1 of this report discusses several factors related to water depth as it relates to both relief well drilling and vertical intervention.

The vessel operating conditions are also affected by water depth in the dispersion of explosive gas prior to migration to the surface, potential loss of buoyancy in the boil and the ability to utilize guidelines. Water depths in excess of 500 feet are considered to be safe for semisubmersibles since the gas will have been significantly dispersed and the force of the plume dissipated prior to reaching the surface.

Buoyancy loss is also affected by water depth. In waterdepths over 300 ft the loss of buoyancy on a semisubmersible is minimal and should not affect operations. Drillship buoyancy reduction is greater than semisubmersibles for the same boil conditions. Buoyancy reduction is not usually a significant factor even for shipshape vessels in water depths over 500-600 ft.

Guidelines are currently used in drilling wells in approximately 2,500 feet of water or less. Guidelines greatly assist the running and retrieval operations of equipment and should be used where appropriate.

The water column may assist in well control by its head pressure acting on the blowout. In shallow section riserless drilling applications, the seawater head is constantly acting on the wellbore. In cases where seawater is utilized as the drilling media, the seawater head provides the only means of preventing well flow. The seawater also acts as a choke on well flow. The greater the water depth, the greater the choking effect.

7.2.3 Blowout Rate. Blowout rate and pressure affect the intervention technique in several ways. Visibility at the source on the sea floor is important to the successful use of ROVs and subsea cameras. Murky conditions or seawater aerated by the blowout effluent near the source limit visibility and impede efforts to guide tools into the well using subsea cameras.

Flow rates and pressure also affect the ability to stab workstrings into the wellbore. This is not always detrimental. The blowout plume may aid in centralizing equipment as it is being stabbed. If sufficient weight is available in the workstring the higher flow rate and its associated plume might be helpful. Loss of string weight at the surface due to bypassing fluid friction could indicate that the stabbed tools were in the wellbore.

7.2.4 Weather and Sea Conditions. Weather conditions may also influence the vertical intervention scenario. All information available regarding the weather should be gathered. Forecasted weather, prevailing wind speed and direction, and storm conditions can all impact the vessel selection and operating conditions. Current and tidal conditions must also be evaluated.

Subsea currents can affect tool selection for vertical intervention. Lateral forces due to straight-line or cross-currents could complicate "steering" stingers, packers, drillpipe and other vertical intervention tools into the blowing well. Rapid surface currents could impact rig stationkeeping as can high wind and wave conditions offshore.

7.2.5 Type of Blowout. The blowout media, gas/oil or both, is considered when determining the vessel suitability to perform a vertical intervention. Semisubmersibles tend to be the best suited for vertical interventions owing to their open structure design, large air gap and stability.

Gas accumulation at the water surface is a potential problem for either a drillship or jack-up since the drillship has no air gap protection and the jack-up has difficulties in moving off location in an emergency. Semisubmersibles are recommended for vertical intervention.

Oil blowouts, while not having the explosive nature of gas, present their own problems. Environmental protection is a major issue in an offshore oilwell blowout. Subsurface and surface remediation techniques are possible to mitigate pollution from an oil blowout. These were discussed in the previous section of the report. The well control team may be involved in these efforts, but their primary function is controlling the blowout in the most expeditious, safe manner possible. It is noted that oil and its emulsions (i.e., chocolate "mousse") can hamper operations by contamination and/or clogging tools, seawater supply, pumps and other equipment.

7.3 VERTICAL INTERVENTION CRITERIA

Vertical intervention is a site-specific technique for well control. It is recognized that vertical intervention is not possible on some blowouts. These might include wells that have a severely damaged wellhead or BOP stack resulting from dropped objects. The wellhead may not be accessible due to heavy debris such as a sunken drilling vessel, sections of parted riser or coils of guideline on top of the stack.

In certain situations the force of the plume may preclude the intervention vessel from remaining on station. Fire on the surface may create a hazard sufficient to preclude maneuvering over the blowout. Regulations made in the interest of safety may not allow vertical intervention in certain situations.

7.3.1 Assumptions. Several assumptions have been made to describe a scenario for a blowout in which vertical intervention can be used. Other situations can exist in which vertical intervention techniques can be applied. This is used for illustrative purposes only. The assumptions are as follows:

- The disabled rig can be removed from over the blowing well.
- The riser has been severed or disconnected.
- The well is blowing through the BOP, the riser joint, and through the severed riser end.
- There is no fire.
- A steady breeze is blowing; therefore, there is little danger of gas contamination to the intervention rig's drill floor (assuming a semisubmersible is being used). There is little chance of H_2S contamination because the majority of the H2S is dissolved in the water (i.e., stripped out of the gas).

- The water depth and sea conditions are such that mooring lines can be used or the rig can be dynamically positioned properly.

Vertical intervention requires that there is some mechanical competence to the well at the sea floor. This technique may not be possible if the blowout has broached around the structural pipe and the well has cratered. This creates a situation that may preclude stabbing into the blowing well for a "surface" kill due to the inability to locate the wellhead. If, however, tools can enter the blowing well a kill may be possible by running a tool string to bottom and circulating the wellbore with kill fluid. If not, relief well drilling is probably the only alternative.

The assumptions listed above describe a situation expected in a deepwater drilling operation where a floating vessel is used. It may be appropriate to consider this type of scenario in a discussion of vertical intervention techniques. The situation described by these assumptions is depicted by Figure 7.3.1.

7.3.2 Intervention Rig. The intervention rig is likely to be a semisubmersible drilling vessel that can be positioned over the blowout. The vessel should be equipped comparably to the original drilling vessel. The vessel's mooring lines should be set to allow the vessel to be winched over the blowing wellhead. If the vessel is equipped with a dynamic positioning (DP) system, it should be capable of maintaining the rig on station throughout the procedure even in high seas.

Dynamic positioning systems do not function well in live boils in relatively shallow water. There is a significant thruster efficiency reduction due to the reduced density of the "aerated" or gasified water under and around the vessel. Stationkeeping may be difficult to maintain in certain situations. Mooring systems should be used where applicable.

The rig should carry a riser which is designed to accommodate conditions of water depth and current at the site. It should also have a lower marine riser package (LMRP), blowout preventer (BOP) and associated control system suitable for the intervention work. If the rig is not equipped with this riser system, a rental riser with purpose-built components may be required. Consideration should be given to using only drillpipe or drill collars for vertical intervention if no suitable riser is available. It is not thought that lack of a riser necessarily precludes vertical intervention.

7.3.3 ROV. There should also be a remotely-operated vehicle (ROV) available for the operations either carried by the intervention rig or a rental unit that can be dispatched to the scene quickly. The ROV should be complete with a cage, deployment frame and other support equipment. A subsea camera and manipulator arm should be installed along with appropriate lighting for work sea floor.

Qualified operators should be available to handle the ROV during vertical intervention work. The operators will be required to work in shifts, so at least two operators are required for the duration of the job. It will be their responsibility to provide the "eyes" for most of the operations. They will require the experience necessary to interpret video output continuously on location.

The ROV should have multi-functional capability. Debris clearance, manipulation of hydro-jet cutting equipment, explosives placement and side-scan sonar capability may be required. Manipulator arm(s) will probably be required. These requirements may be satisfied by multiple ROVs working from a central control point.

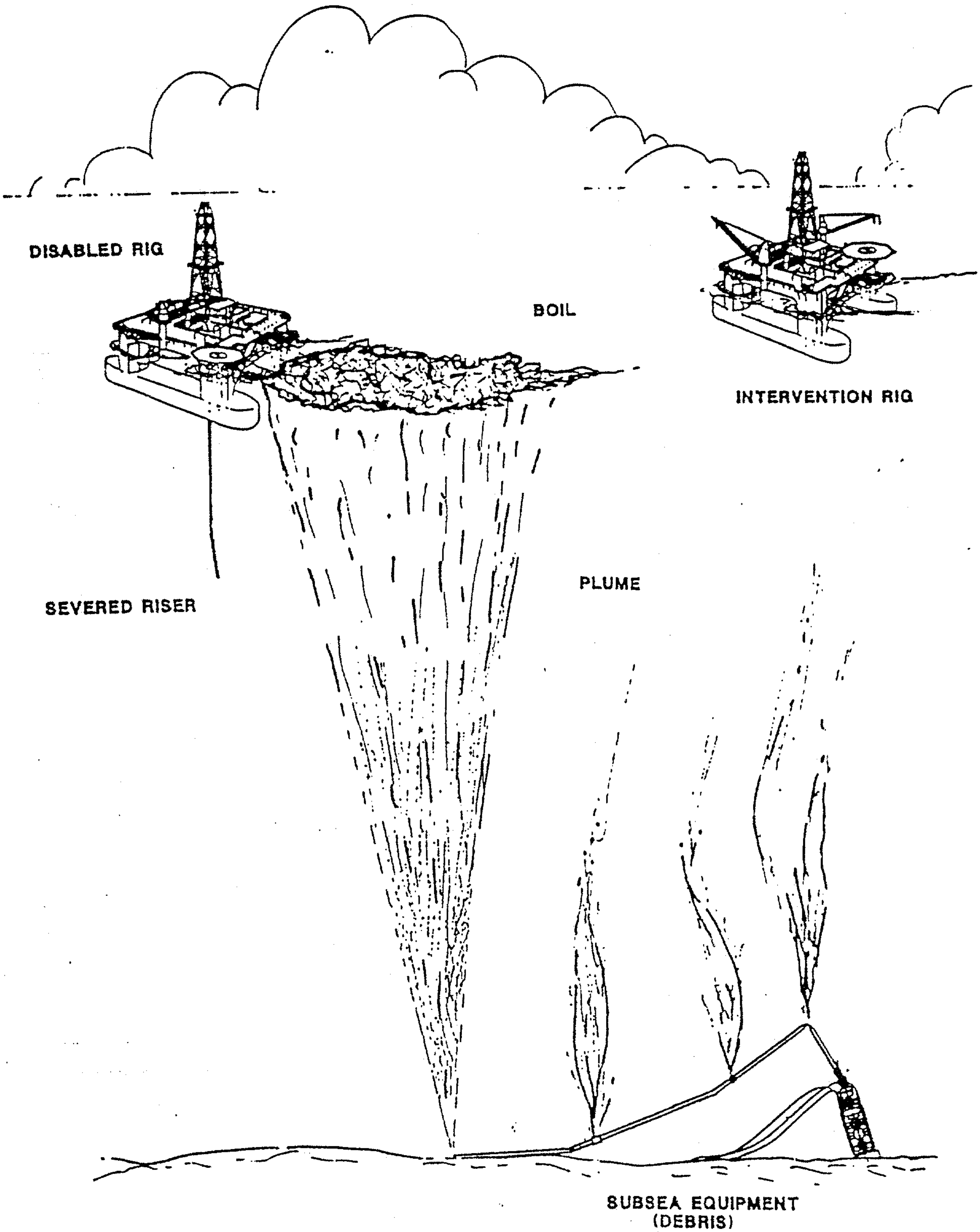

Figure 7.3.1

OVERALL BLOWOUT SCENARIO

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Care must be taken to insure that the ROV umbilical/tether does not become twisted in the plume. Rapid ascension can occur if the ROV or its tether are dragged into the plume. Damage to the ROV and delays in vertical intervention procedures can occur.

The ROV should be used to continuously monitor the area for gas seeps indicating that broaching and cratering is imminent. While the ROV is performing its essential duties as a visual monitor (with or without side-scan sonar), it should occasionally be used to scan the surrounding area for changes in the wellhead vicinity. Gas or oil escaping from the sea floor may indicate that a more severe situation exists than can be resolved by vertical intervention measures. Following kill operations, the ROV should also monitor the well to insure that it is dead.

7.3.4 Wellhead/Stack Condition. Figure 7.3.2 depicts what the subsea equipment may look like after the pull-off. Past experience indicates that many wellhead/stack configurations are not vertical in blowout situations after the rig pulls off the location.

Operating personnel have traditionally felt an urgency to escape from a blowout situation by winching off or pulling off of the well quickly after a blowout begins. In some situations this is prudent. Post analysis of several events, however, indicates that the danger was not as great as originally perceived, and there would have been time to activate the emergency riser disconnect before pulling off. Buoyancy reduction from a boil has been shown to be minimal in deepwater situations. Self-preservation in these situations is understandable.

It is therefore expected that the BOP and LMRP may be leaning at some angle in an actual blowout situation.

7.4 PRELIMINARY PROCEDURES

Several steps are required prior to the initiation of vertical intervention procedures. These include locating the blowout, using ROVs for determining the condition and configuration of the wellhead/stack, removing debris and taking necessary precautions. These steps are general in nature and should be refined on location.

7.4.1 Locating the Blowout. Site selection for vertical intervention is obviously defined by the source of the blowout. In deep water, locating the precise source of the blowout may be difficult.

Conventional satellite navigation can be used as a first indicator of the position of the blowing wellhead. Multiple fixes may be required. It is noted that there may be some error in the original survey, so the well may not have been drilled precisely where well records indicate. Other methods of locating the blowing well may be required.

Side-scan sonar can locate a gas plume in a seawater column. Velocity disturbances caused by the plume are detectable by side-scan sonar. Also, large areas can be scanned quickly with the device.

Subsea video scanning using a "swimming eye" ROV can help pinpoint the location of the blowing well. Water clarity is important to successfully locating the site. The ROV must be run into the vicinity of the blowing well near the seafloor from a distance away from the well to avoid getting caught in the plume.

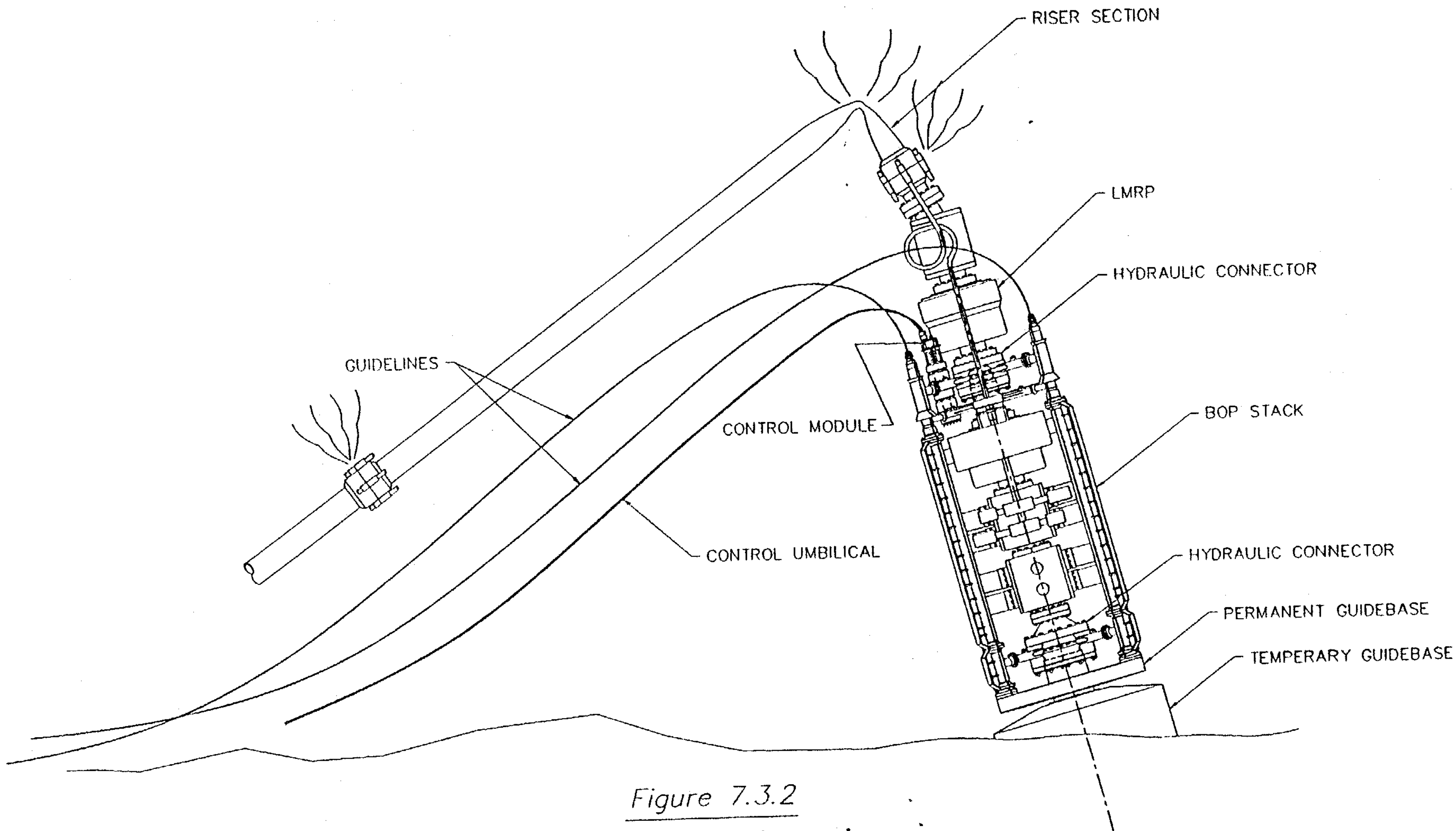

Figure 7.3.2

Subsea Equipment

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Other types of surveys may be of assistance. If a pinger is installed on or near the stack, and if it is not covered by debris or silt, the location and identification of the component can be determined by sonar. (Section 5.2.23) Low frequency sonar can help locate the plume, and higher frequency sonar can identify wellhead, stack and debris on the sea floor.

7.4.2 Initiating Simultaneous Relief Well Drilling. Relief well drilling in most situations should be initiated depending on conditions discussed in Section 4. This depends on the availability of a suitable rig, directional and ranging tools, casing and other tangible items of the proper size, type and quality. Personnel familiar with relief well drilling operations are also required. The blowout specialists involved in vertical intervention may also give advice on relief well drilling depending on their capabilities.

Simultaneous operations for blowout control are advisable for a number of reasons. If the mechanical condition of the blowing well is such that vertical intervention is not possible, there will have been little time lost initiating the relief well(s). The relief well may require so much time that vertical intervention procedures, regardless of the probability of their success, are warranted. There is also the possibility that the relief well will not be successful.

The public and/or regulatory agency in authority may insist on a backup procedure to deal with a blowout. Pollution and the public's perception of the situation are influenced heavily by press coverage, as has been mentioned in previous sections. Simultaneous operations, including pollution abatement operations, may convince the public that all available options are being utilized to insure prompt control of the blowout, minimizing damage to the environment. Public pressure on the oil company and the regulatory agency involved may thus be reduced.

7.4.3 Determining Mechanical Conditions. Simultaneous with locating the blowout, the external condition of the wellhead components, the BOP stack and the situation involving debris can be ascertained.

The ROV using its video camera can determine the seafloor mechanical situation. The condition and angle of the wellhead, competence of the sea floor in the vicinity (i.e., the existence of a crater around the wellhead/stack) and the amount, type and distribution of debris on or near the stack can be visually determined by the "swimming eye". This depends on water clarity and how close the ROV can approach the wellhead.

Determination of the seafloor mechanical condition is necessary for planning. The extent of debris removal, time estimates, procedures and intervention tool configurations depend on an accurate determination of the wellhead/stack condition. If the amount of debris overlying the well is large or the degree of damage to wellhead/stack components is great, vertical intervention may not be viable. Examples of excessive debris include the sunken, disabled drilling rig or long guidelines that are "bird nested" over the wellhead.

7.4.4 Debris Removal. The wellhead and the surrounding area should be clear of debris that would impede vertical intervention techniques. Objects dropped during the blowout or rig move-out should be cleared if this debris will interfere with vertical intervention procedures or ROV operations. Multiple methods exist for clearing the debris including the following:

- Using a hook at the end of a length wire rope from a winch on board the semisubmersible or from a work vessel, the debris can be lifted away from the wellhead. An ROV will be required to manipulate the hook into position.

- Using a fabricated hook at the end of drillpipe, together with the drawworks, the debris can be hooked, lifted and dragged off the location. A purpose-built sub can be installed in the system to facilitate movement of the drillstring and maneuvering the hook onto the lift point. This could be one or more jets welded into the side of the drillpipe sub which would allow lateral propulsion when the rig's pumps are engaged. A similar procedure was reportedly used by Phillips in a recovery operation with good success. Guidelines are assumed to be draped in such a way that the ROV can cut and discard the debris.

- Using shaped explosives or a hydro-jet cutter to reduce the debris into manageable size pieces for removal by topside vessels. Explosive devices exist that can cut steel of varying thicknesses in 10,000' of water (per Jet Research, Victoria, Texas, USA). There are several jet cutting systems that can be used for debris reduction depending on water depth. Some of these can be used in water to 2,000 ft in depth. The upper limit of water depth has not yet been determined for others.

- Heavy debris may be dragged temporarily out of the vicinity for later removal. Large or heavy items may be equipped with lifting bags to achieve partial buoyancy. Tow lines can then be attached by ROV to permit their being "skidded" out of the area.

There is a lower size limit to the debris removed prior to the implementation of vertical inter-vention procedures. Removal of debris that could interfere with these procedures is required. Small debris can be removed later after the well has been killed using less urgent salvage procedures.

7.4.5 Wellhead Equipment Removal. Integrity of the pressure containing equipment that remains on the wellhead after a blowout is an unknown. It may be desirable to remove all such equipment and leave the wellhead completely exposed.

Damage to the remaining components may render them inoperable. Falling debris, pressure and/or abrasive flow through the stack may have severely damaged some of the components. Problems associated with removal and/or replacement of damaged subsea BOP stacks and associated equipment have received minimal attention and action by the drilling industry to date.

Procedures may be developed to "strip" new BOP components over a subsea blowing well. Capping stacks composed of BOPs, pump-in spools, hydraulically-operated valves and other devices are used routinely to kill onshore blowouts. If a damaged component of the subsea stack can be removed, it may be possible to stab one or more such components back onto the stack as a vertical intervention technique. First, the damaged component must be removed.

Mechanical Connector Lock Override. Wellhead connectors are designed to be self-locking, relying on friction to maintain the connector lock even during the loss of hydraulic pressure. Unlocking a wellhead connector is accomplished either with hydraulic pressure or with the mechanical override. The mechanical override is sometimes omitted from the BOP because it is assumed that access would be too difficult for an ROV. If the override is present, activating it and recovering part of the BOP stack may be desirable if size and weight of component is not prohibitive.

Mechanical override rods are normally located near the top of the locking rings on the component. Diverless access to the override rods may be difficult due to guidepost and bumper guard additions to the stack. If an override rod can be accessed by the ROV, it may be able to attach a line to activate the override and recover the component to facilitate other vertical intervention procedures. It is noted that locking rings and override rods may have been damaged by falling debris, so activation may be difficult.

Once the override is activated, appropriate mechanical means can be used to remove the released component. This might be cables installed by the ROV or drillpipe conveyed hooks to snatch the component using the drawworks on the intervention vessel. If the guideposts are bent, it may not be possible to remove the component without first severing the guideposts explosively or with a jet cutter.

Recently, major suppliers of subsea production trees (e.g., Cameron, National Oilwell, and FMC) have begun modifying their equipment to accommodate ROV intervention on the wellhead connector. Mechanical override rods are extended to the top of the tree assembly. The extensions are terminated such that they may be easily grabbed using ROV tooling and actuated either by a running tool or tension from a surface cable. This type of configuration could be incorporated into existing BOP equipment with minimal cost as a preparedness item in the event of a subsea blowout.

ROV Hot Stabs. Redundant umbilical bundles are commonly used to pilot two control modules termed the yellow and blue pods on most subsea BOP stacks. These modules, in turn, supply hydraulic pressure at a large flow rate to all subsea functions during normal drilling operations. After a blowout, these control umbilicals may be damaged or severed, and a loss of control results. Control umbilical bundles may have 32, 42, 60 or even 84 lines. Re-establishing control to these systems to unlock the component connector may be difficult, especially in deep water.

The major suppliers of subsea production equipment noted above have also developed means to intervene the hydraulic operation of some functions on their equipment. A hot stab receptacle is sometimes installed in the hydraulic circuit to accept an ROV installed stab. The stab can be pressurized thorough the ROV's hydraulic circuit. Other options for hydraulically activating the disconnect are also available.

Activation of the hydraulic disconnect of a stack component may be attractive in some blowout situations. These might include re-installing a re-worked BOP component on an existing stack or wellhead. The new component (e.g., a set of blind rams) could then be closed to control the blowout. A damaged component might be removed to allow access to the wellbore for a stinger or to trip in the hole with a pipe string for a bottom kill. Fewer disabled components left on the stack will facilitate other well kill procedures.

Once the disabled component is removed by either mechanical lock override or by hydraulic release, there will be a new point of effluent discharge. Conditions around the wellhead may change. It should not be assumed that the ROV, for example, can approach the wellhead as it did prior to the removal of some wellhead or stack component.

Casing and Wellhead Severing. Explosive severing and jet cutting can be used to remove damaged or dysfunctional wellhead components, guideposts, or the entire wellhead depending on whether or not the casing below the guidebase is exposed.

According to Jet Research Center, risers in excess of 1-1/2" wall thickness can be severed using shaped charges. An ROV would be required to place circular cutters (explosives) on the riser. Damage would be minimal for thicknesses up to 3/4", with moderate deformation to 1-1/2". Above 1-1/2", deformation would be significant, but the remaining opening could still be entered.

Casing below the temporary guide base could be severed using explosives if it is exposed. Significant glory hole excavation would be required for the ROV to be able to reach the exposed casing. First, the ROV would attach a line or hook to the stack for recovery of the stack and wellhead. Then it would place a single, large capacity cutter on the exposed casing which would cut through all casing strings and the drillpipe. It would be necessary to remove the stack and guidebase from of the area.

The ROV would place both circular and straight-line cutters on the conductor casing (assumed to be 30" for this example). Upon detonation, the explosives would cut away a section of the outer casing. Shorter linear cutters would then be attached to the 20" casing along with a circular cutter to remove a short section of this string. This procedure would repeat until a competent inner string of casing was exposed.

Standard explosive shaped charges can be used to 3,000 ft of water using the procedures described above. The same procedures can be used in 10,000 ft of water, but the outer metal housing of the charge must be fabricated of a thicker material to resist hydrostatic pressure. The deepwater cutters can also be placed by ROV, according to JRC.

Hydro-jet cutters can also be used to remove wellhead components underwater. Several systems exist for this purpose, one family of which operates at approximately 5,000 psi nozzle pressure. The other group has cutting systems that go to 55,000 psi. They are called ultra-high pressure cutters. The latter group represents new technology that permits cutting through thick sections of almost any material leaving a smooth cut with no pipe deformation.

Wellhead/stack components can be removed using either system. An ROV manipulator is required for each to place the cutting nozzle near the member to be cut. Jet force from the 5,000 psi system may require the ROV to hold itself stationary with one manipulator while cutting with another. The ultra-high pressure systems produce very low jet reaction forces. It is doubtful that the ROV's propulsion system would be able to hold it steady enough to permit using this device without some additional anchoring by a second manipulator.

Jet cutters have been used to slice through 12" of steel and concrete in the atmosphere. There will probably be some reduction of the impinging force on the target by seawater around the pipe. If seawater is used as the cutting medium, there should be no reduction of nozzle pressure due to hydrostatic pressure, however. Fluid friction inside the hoses may reduce nozzle pressure depending on flowrate and hose size.

The ultra-high pressure system may prove to be useful in this application since it uses minimal volumes of water. It does not require an abrasive as does the 5,000 psi system, but cutting speed is reduced. Long, high pressure hoses running to the seafloor provide multiple opportunities for weak spots to exist where the hose can be severed. Floats can be attached along the line to support its weight.

The jet cutter can be used to cut through all strings and remove the wellhead. Cutting below the guide base with a jet cutter has an element of risk. The ROV must manipulate the cutting head. If the wellhead/stack/guidebase fall on the ROV after the cut is made, damage to the unit is almost certain. It may be wise to cut through the entire casing string set with an explosive cutter first, then strip the casing strings to expose a competent inner string using the jet cutters if the ROV can operate without being swept into the plume.

Actual conditions must be evaluated before selecting one of the cutting systems described above. Both have been used offshore to sever casing(s), to remove jackets and to clear debris. Availability of a suitable cutting system and an experienced operator may be the determining factor in the selection process.

7.4.6 Precautions. Several precautions are wise and should be taken during vertical intervention operations. The primary precaution is to insure that hydrocarbons from the blowout boil are not brought aboard the rig. The most likely circumstances for this occurring are:

- Gas rising from water surface to the rig superstructure (air intakes, etc.)
- Gas reaching the rig through the riser system as a direct conduit
- Gas or oil entering the sea chest, then being pulled into the pump/piping system
- Gas or oil being pulled into the firefighting system by the rig's fire pumps

Gas monitors can be used to detect gas near the surface. These should be installed at key locations around the rig superstructure, suspended in the moonpool and installed off the rig sides to continuously monitor gas accumulations, if any.

Computer simulations, as well as actual field experience, indicate that in the presence of a measurable, prevailing breeze, the height of explosive gas concentration will not reach above 5-6 feet from the surface of the water depending on water depth. Most drilling vessels have an air gap much greater than 5-6 feet. This should allow safe vertical intervention procedures to be carried out from most available vessels in deepwater situations.

Dedicated equipment and personnel continuously monitoring the gas concentrations can provide early warnings to allow operation stoppage before safe operating conditions are violated. Crew drills are prudent on the intervention vessel for work stoppage, rig pull-off and evacuation in the event of detection of a pre-determined gas concentration.

Firefighting equipment can enhance safe vertical intervention. Water monitors can be located in and around the moonpool area. The nozzles can be set to provide a power cone that will create a water curtain and a downdraft toward the boil. This pulls fresh air from the upper decks and dilutes the gas below explosive levels. Engine exhausts and other external ignition sources can be protected by water spray or modified to be intrinsically safe. Runaway engine kill devices should be checked and maintained for proper performance.

The best protection from gas contamination is with subsea diversion that maximizes the water column between the blowout and the vessel. Historically, subsea operations have required a riser as a conductor for running tools in and out of the hole. In a blowout situation, the riser provides a conduit for hydrocarbons to travel to the drill floor if it is used during vertical intervention procedures. Diversion of the plume near the source of the blowout on the seafloor, and the addition of a device to close on tools at the rig floor, such as a rotating head, provides protection to the rig floor.

Some additional precautions include the following:

- Crew training
- Procedure preparation and review with team members before implementation
- Insuring that the mooring or DP systems permit rapid rig move-off in case gas build-up becomes a problem (mooring line release, winch off location, boat assistance if required, etc.).

7.5 RE-ENTRY METHODOLOGY

Re-entry of a blowing subsea well may be difficult due to a variety of circumstances such as currents, surface sea conditions, plume interference and subsea mechanical conditions. Two basic re-entry methods are presented below, one with guidelines, one without.

7.5.1 Guideline Re-entry. Offshore drilling operations to 2,500 feet water depth will normally utilize guidelines. For blowouts on these wells, intervention may include re-establishing the guidelines.

Re-establishment could be performed similar to conventional methods for primary guideline establishment. This would require an ROV and guideline re-establishing tools on drillpipe. The operation must be carefully planned and executed to insure that neither the ROV nor the new guidelines are swept into the plume.

It may be necessary to offset the intervention vessel from the blowing wellhead until the equipment reaches the bottom and then move the vessel over the boil. This type of procedure is commonly practiced by many operators when running heavy equipment over a production template or other subsea installation. The work string may require additional weight to counteract turbulence. This could be achieved by adding drill collars.

7.5.2 Guidelineless Re-entry. Guidelineless drilling systems have been used to drill in locations having water depths to over 7,500 feet. The present fleet of deep water drilling vessels is composed of drillships and semisubmersibles.

Guidelineless re-entry may be useful for vertical intervention particularly in relatively shallow water with large blowout volumes being produced. Wellhead/stack arrangements bent at an angle may require that tools be stabbed into the wellhead without the benefit of guidelines. It is thought that this procedure will be used to attach the subsea capping stack to bare casing described below.

Guidelineless re-entry may be facilitated by the use of the jet sub described above in Section 7.4.4. The same sub that could push the drillpipe conveyed hook toward its target may be useful in steering the bottom of a stinger toward the blowing wellbore. Weight of the tool string will have an obvious effect on the usefulness of this device, but it would not require the establishment of guidelines, if successful.

7.6 VERTICAL INTERVENTION TOOLS

Tool strings of various configurations can be used to enter a blowing subsea wellbore. Selection of string components is largely a matter of tool availability and capability, experience of the blowout specialist and the oil company representatives on location and circumstances dictated by the blowing well.

The following discussion describes some of the tools available for this type of intervention. Some of these will likely not be feasible for use in a given situation. Others will have utility in a variety of situations.

There may be some similarity noted between these tools and those used to kill onshore blowouts. The same tools, in many instances, are used for both, including stingers, kill packers, quick-coupler casinghead assemblies and kill stacks. Once the subsea equipment is cleared or a tool is stung into a blowing offshore well at the seafloor, its treatment is the same as an onshore blowout. The difference is that it has a seawater head on top of the blowout to assist in kill operations.

7.6.1 Kill Packers. A bullhead kill can be accomplished by installing a packer and pumping kill fluid into the wellbore through a workstring. This technique requires a minimum of specialized equipment. The packer technique can be used if the bore is unobstructed by sheared drillpipe or other debris.

There are two types of kill packers, mechanical set and inflatable. Both have application for subsea blowouts since both types can be used to essentially any depth.

Mechanical Set Packers. These packers are of the family of retrievable treatment packers or cementing tools. Most have slips that grip the casing firmly and have expanding rubber elements that seal against the inside of the pipe. The workstring used to set this packer should be motion compensated to avoid pulling too hard against the slips and "shearing" (releasing) the packer.

Mechanical packers normally have a limited operating range. One size packer may be specified for two or three different casing weights for a particular size of pipe. Erosion from blowout fluids can cause casing ID enlargement, and the packer may not set. If it does, it may not seal effectively, though some leakage during kill operations can be tolerated. In some circumstances some leakage may be desirable.

Tolerance between the ID of the casing and the OD of the packer is at a minimum with this kind of packer. In Section 7.4.3 it was noted that most wellheads/stack assemblies are not vertical after an emergency pull-off. Egging of the casing that results from its being bent may reduce the ID of the pipe in one direction enough so the string cannot go around the bend. Generally, these packers are stiff and will not go around sharp doglegs in a well. Thus, there is the possibility of the packer sticking in the casing. If so, it presents a significant obstacle for further entries.

Mechanical packers usually require some turning to set. This may only be a quarter of a turn at the packer which could reflect up the string to several turns at the rig floor. There are circumstances when turning the workstring is not desirable such as stabbing a string into a bent over wellhead. Turning the workstring could result in twisting the pipe in two in this situation.

Some mechanical packers release by pulling straight upwards. This is advantageous when the casing and wellhead are aligned with the direction of the tension. However, if they are bent, or turned, pulling straight up may only result in wellhead or BOP stack component damage, and the packer may remain stuck.

The chief advantage to the use of a mechanical packer is that it can hold higher differential pressures that other packers such as inflatables or hook-wall types. In the case of the Halliburton RTTS packer, the differential pressure is not rated. Experience has shown that the casing will generally rupture before the packer leaks. In some blowout situations this advantage is more important than its other disadvantages.

Inflatable Packers. Inflatable packers utilize an elastomer element that can be inflated after the packer is in place. They come in a variety of sizes that can expand 2-3 times their original diameter depending on wellbore mechanical conditions.

Inflatable packers have been used as "stinger packers" in onshore operations with good success. These devices have relatively small ODs which permit their being stabbed into bent or partially egged pipe. The pipe does not have to be round or smooth for the packer to set effectively.

Some models of these packers have lugs or metal stays on the OD of the packer element. These serve as "slips" to prevent movement once the element is inflated. The workstring used to run these packers should also be motion compensated.

One inflatable packer used recently in Kuwait for onshore operations is run with a pump-out plug below the packer. When it is stabbed into the well, a pump is engaged which inflates the element, then blows out the plug. Fluid is then bullheaded into the well to kill the blowout without stopping the pump. This is a one-step operation.

The greatest disadvantage to inflatable packers is their low differential pressure rating relative to mechanical packers. Some of the inflatables can hold high pressures in certain configurations. Usually, the closer the OD of the packer is to the ID of the casing, the higher the differential pressure it can hold. A trade-off situation exists between the OD of the packer and the ease of its being stabbed into a blowing well versus the differential pressure it will hold once inflated.

Another disadvantage of using an inflatable packer is erosion of the element by blowing wellbore fluids and solids. The packer element is subject to rupture upon inflation if it is abraded by blowout fluids prior to setting. Inflation pressure is often sufficient to rupture the element. Also, if the casing is split or has a burr inside of it, the element will rupture during inflation.

An advantage to using packers for vertical intervention is that they are not necessarily the bottom most component on the intervention string. Figure 7.6.1 shows a workstring configuration in which the packer is above other tools, specifically drill collars, which may take most of the abrasion while the tools are run in the well. Also, the packer can be "pulled" into the well instead of being "pushed," using this configuration.

Figure 7.6.2 shows a similar situation in which the workstring with a packer is being lowered into a wellhead top re-entry situation (i.e., the BOP stack has been removed).

Re-establishment of the guidelines in these scenarios is optional. If the situation allows the string to be stabbed without guidelines, the time savings and simplicity attributes are considerable. Guidelines and breakaway guidearms should be considered if multiple trips into the hole are anticipated.

7.6.2 Stingers. Stingers are tapered funnel- or cone-shaped end devices that can be pushed into the mouth of a flowing wellbore. Onshore, these devices are normally placed into the blowout by a hard mount on an athey wagon. Weight or snubbing lines must be used to keep the stinger from being ejected by the force of the blowout. This could be accomplished in a subsea blowout by running the stinger with drill collars above it.

Once the stinger is stabbed into the wellbore, a kill is made by lubricating mud into the well. There is usually not a complete seal at the mouth of the blowing well by the stinger. Mud is pumped through the stinger and into the well while a portion of the wellbore fluids and the kill mud is allowed to leak out.

Stingers have not been used for offshore blowouts. There is no prior art upon which to base conclusions about their effectiveness. It is felt that they could be effective if the shape of the stinger can be designed to fit the top of the blowing stack or wellhead component.

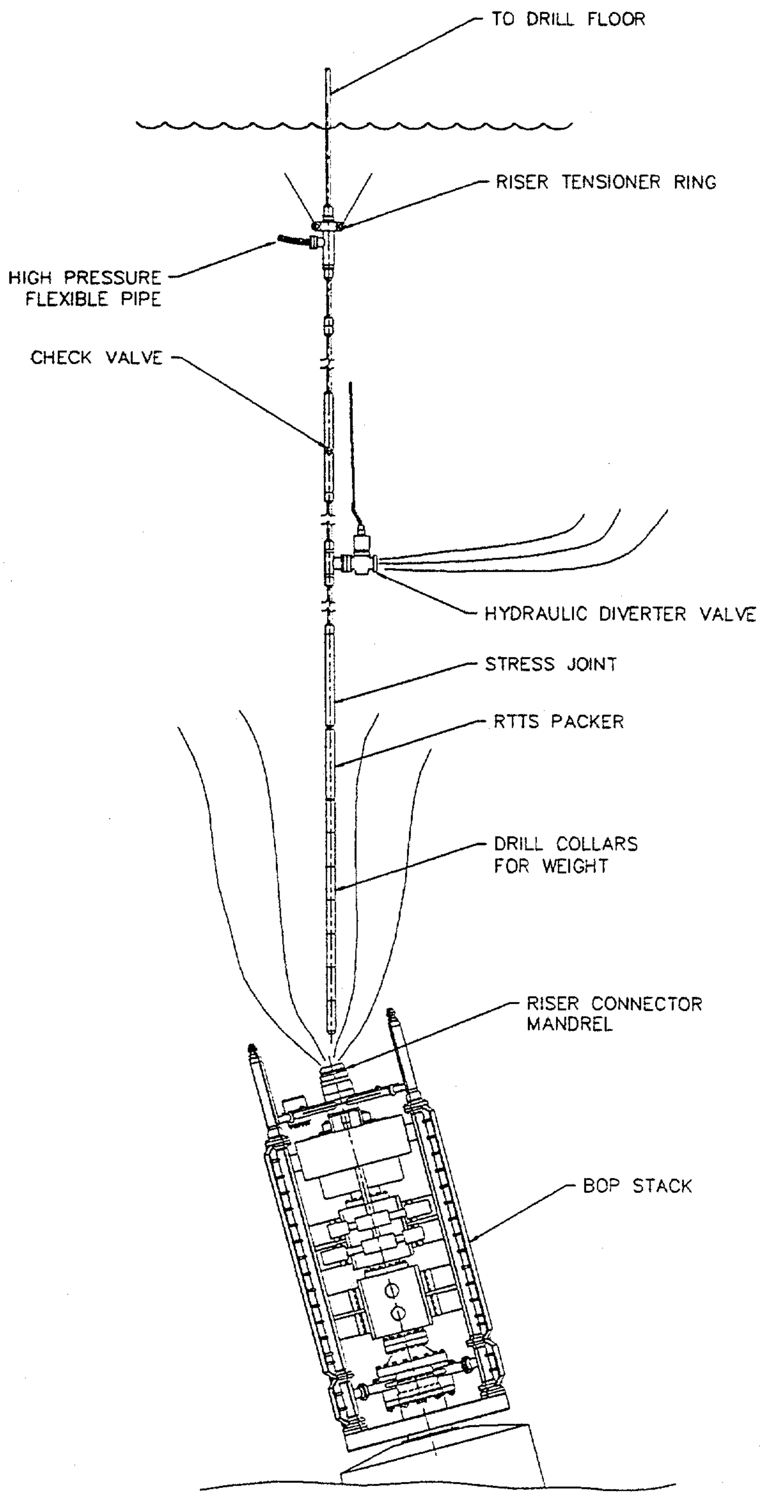

Figure 7.6.1

BOP Top Re-Entry

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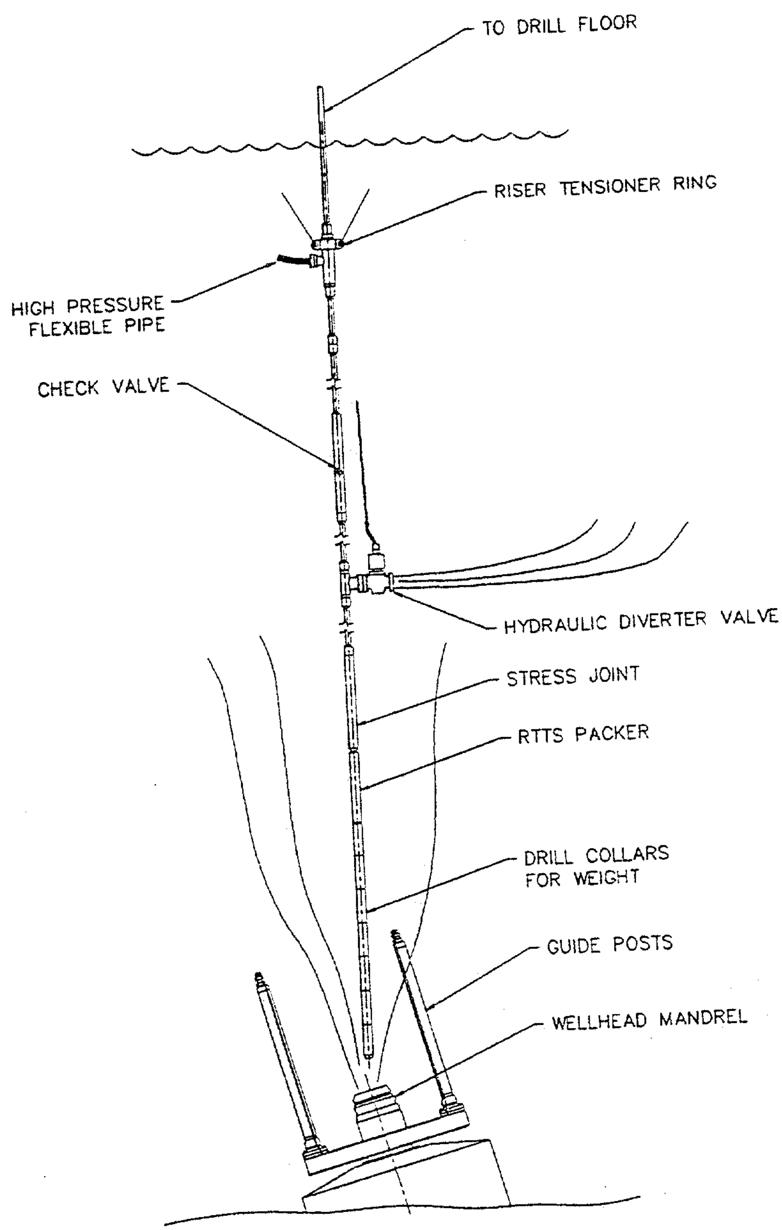

Figure 7.6.2

Wellhead Top Re-Entry

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7.6.3 Knuckle Joint. Figure 7.6.3 shows a situation in which a short section of a workstring has been stabbed into the top of a subsea BOP. The control pod in this example has been re-installed to permit operation of the BOP.

The knuckle joint allows the drill string to turn (to some limiting angle) in a 360° azimuth. When installed in the workstring, the knuckle joint may permit a portion of the kill string to be inserted into a bent wellhead/stack without affecting the remainder of the string.

In this example, flow from the well is being bypassed around the workstring through a diverter flange, a "crow's foot" device, that prevents the plume from pushing the kill string out of the well. Also, guidelines have been re-established to facilitate entry of the tool string into the blowing well. They are not required, but may assist in this type of re-entry. The bottom of the tool string will be flexible and may move out of the bore of the blowing well. Measures may need to be taken to stiffen the knuckle joint to avoid this situation.

7.6.4 BOP Stack/Wellhead Component Re-installation. This option involves running a new or reconditioned component of the BOP or wellhead stack on a kill string for re-attachment to the remaining portion of the wellhead/stack. It is comparable to running a kill spool on a land-based blowout.

This option is dependent on the configuration of the remaining wellhead/stack element. A mating member can be designed to run on the kill string. Since the kill string is the "hard connect", killing the blowout can be accomplished through the device once it is installed. There is no need for other runs (i.e., this is also a one-step kill procedure).

It is noted that this technique can be used with drillpipe or a riser. The riser will provide a conduit for drillpipe, tubing or coil tubing/wireline operations to be performed after the well is killed. Additions can be made to the stack such as a diverter spool or the addition of tubing BOPs. These additions may provide the necessary components for other operations not anticipated by the original BOP design.

An advantage to this option is that the conditions of the blowout can be changed to those that favor the operator (i.e., small diameter pipe, additional blowout stack components, etc.) without sacrificing efficiency. Once the new head is attached, all other operations can be performed under more favorable conditions.

Figure 7.6.4 shows an example of the situation that could exist when a component of the BOP stack is replaced with the kill string stung in. Figure 7.6.5 shows a purpose built BOP installed after clearing the old wellhead/stack assembly out of the way. This stack contains a diverting spool which will facilitate additional vertical intervention procedures.

7.6.5 Riser Re-installation. The riser on an offshore well serves as a conduit for tools to the top of the BOP stack. It is a low pressure member of the subsea stack during drilling operations as mentioned previously. In kill operations, however, it can become a necessary part of the kill string, not a pressure containing member at all.

Figure 7.6.6 depicts a situation in which the riser is used to reconnect a special function BOP with a diverter spool to the permanent guidebase. It has umbilicals attached for control functions. It is of the proper diameter to handle all anticipated situations. Choke and kill lines are attached. There are guidelines attached for installation and recovery.

One particular feature of this arrangement is the use of a perforated joint of riser. It is this feature that allows the riser to be used on a blowing well without subjecting rig personnel to the dangers of fire and/or toxic gas inhalation. Gas is released below the surface which

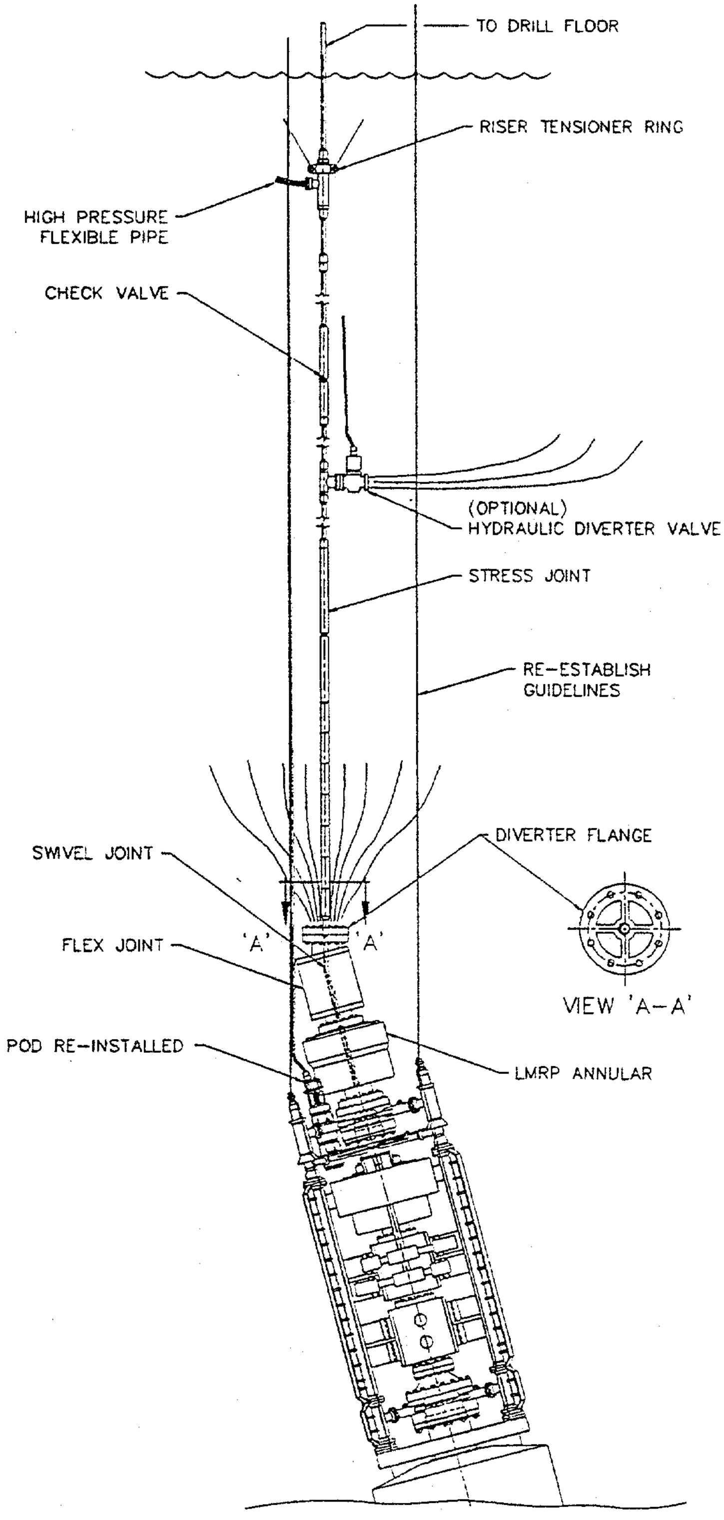

Figure 7.6.3

Modified/BOP Re-Entry

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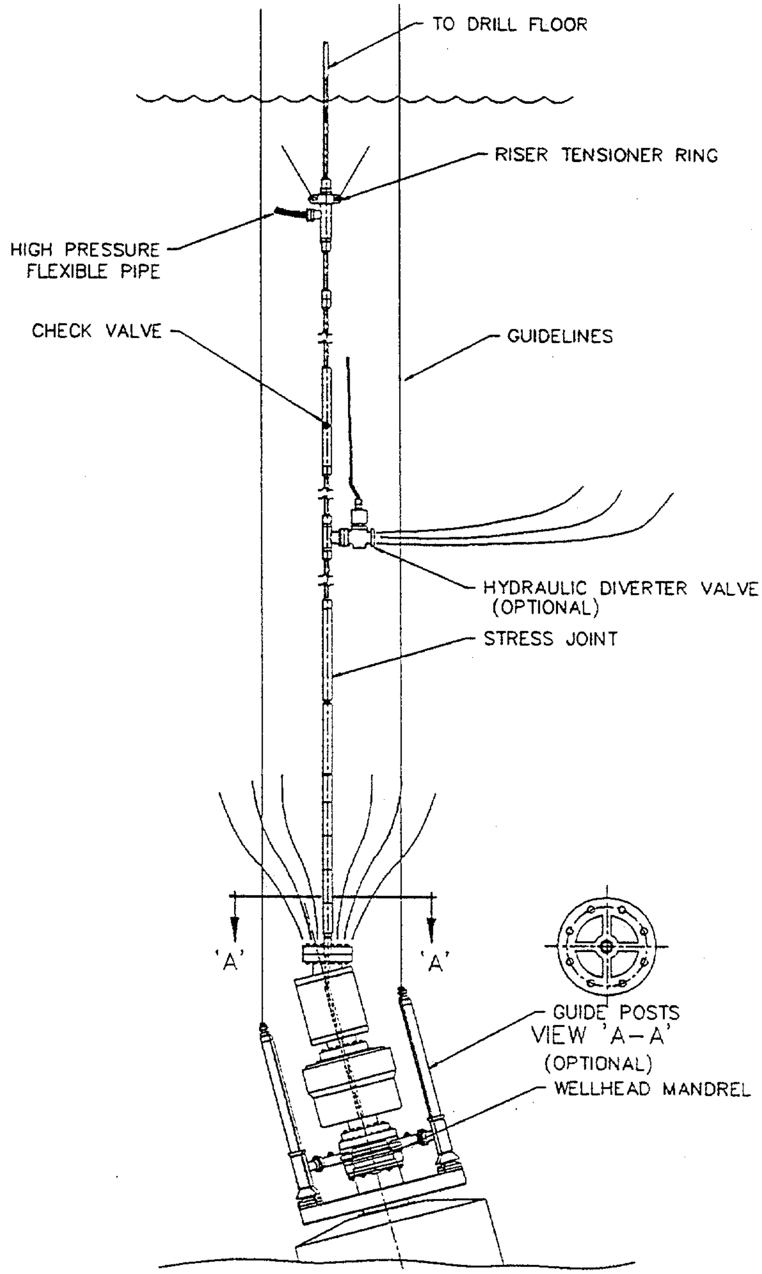

Figure 7.6.4

Modified LMRP/BOP Top Re-Entry (Optional)

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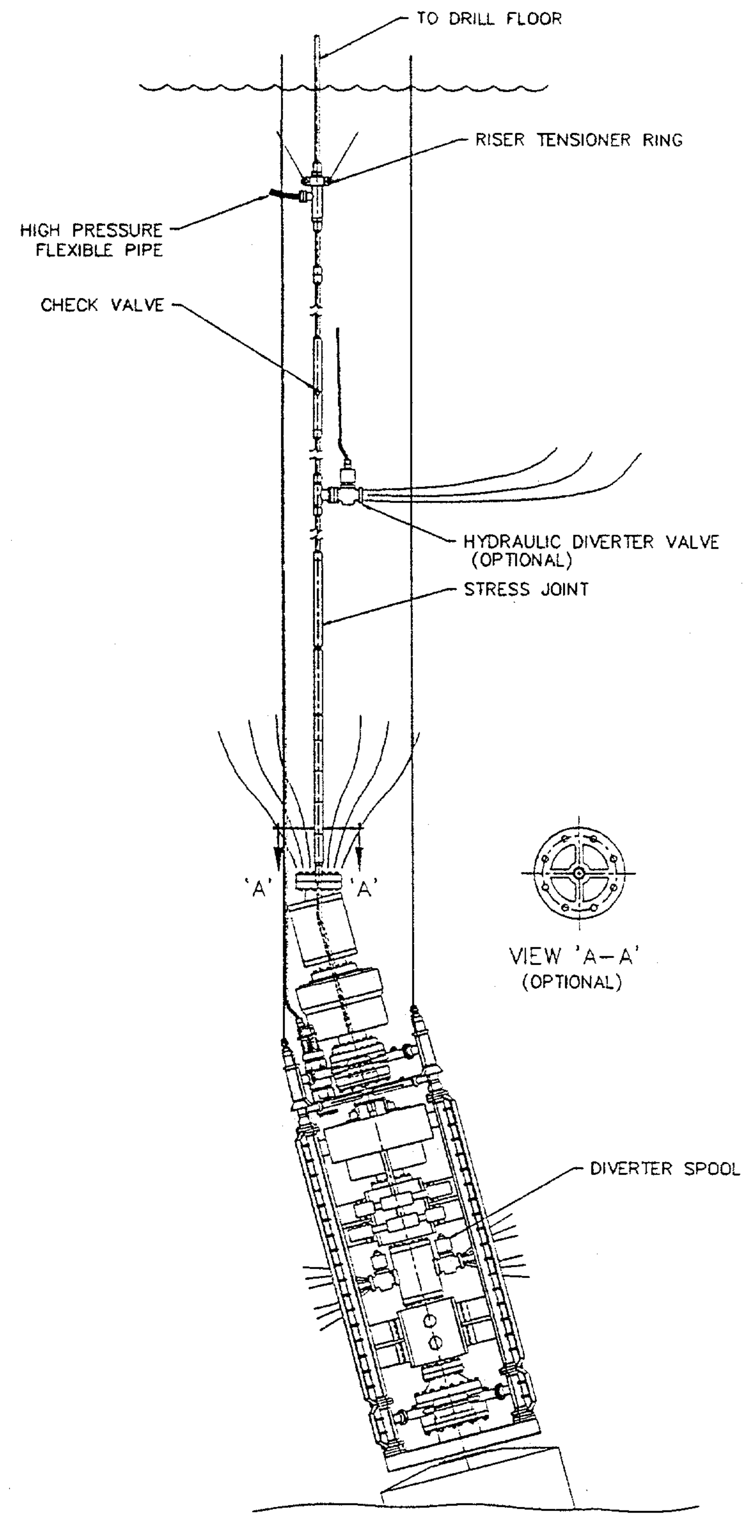

Figure 7.6.5

Re-Installed Purpose Modified Stack

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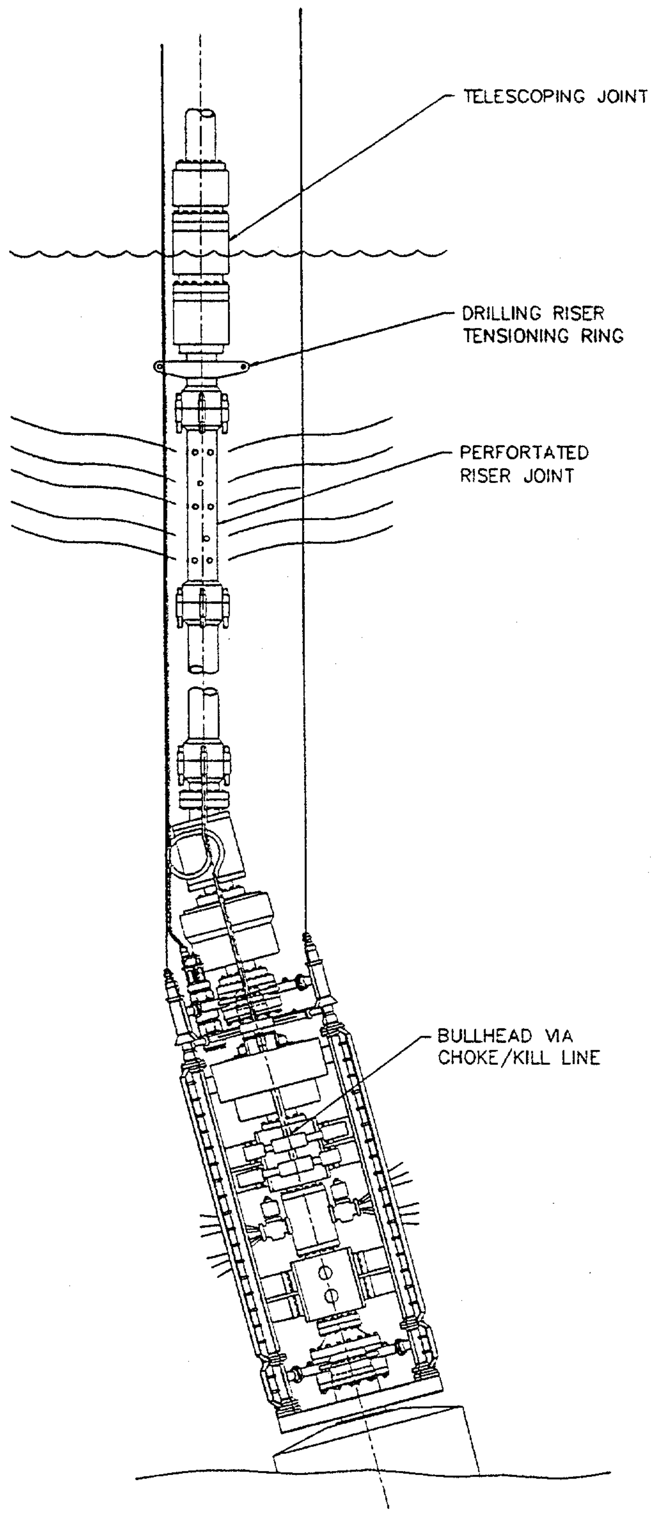

Figure 7.6.6

Modified BOP/LMRP
Drilling Riser

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restricts exposure to surface personnel. Seawater can absorb and/or disperse significant quantities of methane and other gases. The possibility of riser rupture or collapse is mitigated by this arrangement.

It is anticipated that there would also be a rotating head, annular preventer or diverter bag installed at the rig floor to insure that no hydrocarbon could reach the rig floor. The perforated riser joint should divert most of the blowout effluent, but some could percolate through the riser gaining velocity as it expands inside the riser above the perforated joint. Some sealing device with a venting system at the surface is required.

7.6.6 Kill Stack Installation. Figure 7.6.7 depicts a new stack that has been installed over casing cut off and dressed using either explosive or jet cutters. A guide cone is shown on the bottom of the new stack with a hydraulically or mechanically activated slip-type "quick coupler", a device that can set and seal on the outside of the casing. This permits landing a variety of BOPs, subsea diverter spools, annular BOPs or other devices for controlling the blowout.

An alternative would be to strip a BOP with slip rams over the casing which, when activated, would hold the casing securely. Immediately above this would be another BOP with rams to fit the casing. When closed, these would affect the pressure seal necessary to permit controlling the blowout. Other devices could be added above these BOPs as required for the particular operation.

Affixing the capping stack to casing that is bent at an angle, egged, lipped, eroded or split may be difficult. The rig may have to lower the stack over the casing stub, then winch over on its anchor lines, or move using its DP system, to achieve the proper angle to allow the stack to slip completely over the stub. In this scenario, there would have to be some surface sealing device such as an annular preventer or rotating head to prevent oil or gas from reaching the rig floor.

It is recognized that this will probably be applicable only in certain low pressure situations. The wellhead components must be small and light enough for the casing stub to support its weight without further damaging the pipe.

Once the capping stack is in place, tools of various types can be run into the well for kill and repair operations. Figure 7.6.7 shows a subsea injector assembly above the stack for coil tubing. This subsea unit has been used in other situations and may have applicability for blowout killing operations. Once the capping stack is installed, a snubbing unit can be rigged up to recover severed drillpipe and circulate the well to kill it. A flex joint, slip joint, motion compensation system with appropriate controls is assumed to be available on the rig for this installation.

7.6.7 Emergency Disconnect. An emergency disconnect connector is incorporated into this system. This connector allows disconnecting of the riser in the event of an emergency during the kill operation. A flex-joint is also included in the emergency disconnect package.

If an emergency develops, the tubing or drillpipe in the hole would be sheared and the upper section pulled off along with the riser. Provisions for shearing guidelines can also be incorporated into the system in the form of guillotine- or explosive-type shears. These may not required in all cases.

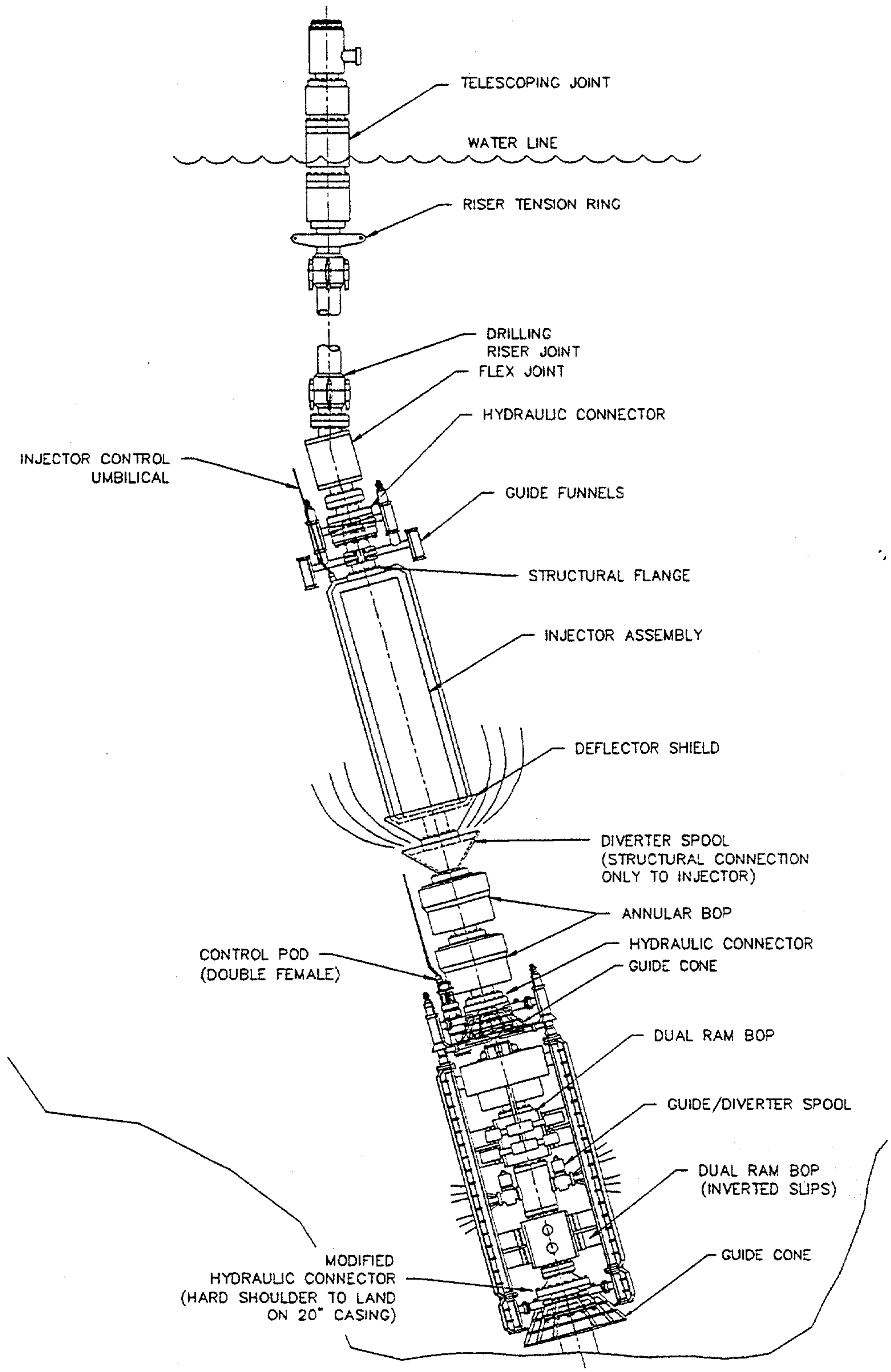

Figure 7.6.7

Purpose Built Well Re-Entry System

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7.7 KILL TECHNIQUES

Several kill techniques are available for controlling a blowout once the vertical intervention has occurred. These are the same techniques available for kick control with drillpipe out of the hole. They are similar to onshore kill techniques after stingers, packers, kill spools or kill stacks are installed. They include bullheading fluid down the well, lubricating kill mud and circulating through pipe from the bottom of the wellbore. Each is discussed below.

7.7.1 Bullhead Kill. Bullheading mud into a blowing well involves pumping kill weight fluid against the pressure of the capped well. Wellbore fluids are forced back into the formation of origin or into some other downhole zone. When the wellbore contains a column of kill weight mud, the blowout is under control.

This technique applies considerable stress to the wellbore. Weak casing seats can be ruptured during bullheading operations resulting in an underground blowout. Eroded, weakened casing or the kill stack, if improperly installed, can also be compromised during bullheading. This may not be the preferred kill technique, but sometimes there is no feasible alternative and this technique must be used to attempt to kill a blowing well. Risks and consequences should be determined before this technique is employed.

A bullhead kill may be recommended when the formation pressure of the flowing well has been reduced by effluent flowing from the formation. Pressure required for bullheading will also be reduced commensurately. This sometimes occurs when a well has been blowing out for an extended period, and has partially depleted the production zone.

Bullheading requires that the kill fluid remain in a slug with wellbore fluids pushed ahead and back into the formation. Pump rate during bullheading must exceed the rate at which wellbore fluids, particularly gas, channels through the kill fluid. High pump pressures and horsepower requirements result if this rate is high. High wellbore stress may also occur.

Experience has shown that the required pump rate is usually less than the theoretical kill pump rate during bullheading. This is usually due to formation depletion. Similarly, calculated kill mud weights have also been shown to be too high in many instances. The blowout is often killed with minimal fluid volumes. Frequently, the first indication of a successful kill is that the well "goes on a vacuum".

7.7.2 Lubrication. A modification of the bullhead technique is the lubrication of mud into the well. Lubrication of kill weight fluid into the well involves pumping a given volume of mud into the well and allowing it to bypass wellbore fluids and fall to the bottom of the hole. If wellbore pressures increase as a result of pumping this fluid into the well, some pressure can be bled off after the kill fluid has fallen down the hole. Care should be taken not to allow additional fluid from the formation to enter the wellbore, however.

This technique results in the well being filled with kill weight fluid from bottom to top with wellbore fluids eventually being vented at the wellhead. Casing shoes and wellhead/stack components are not exposed to high pressures which could compromise their integrity. It is noted that this technique requires more time for implementation than bullheading.

Kill fluids will be contaminated by wellbore fluids as they bypass inside the casing. This may require additional kill fluid weight to achieve the proper hydrostatic head required to control the flow. The contaminated wellbore fluid density will supply the hydrostatic pressure required to kill the well.

Provisions should be made to dispose of vented fluids. The most frequently used method requires flaring. This will not be possible if a subsea diverter spool is used. If this is the situation, rig personnel should be advised that some venting is going to occur to avoid panic and an unnecessary emergency disconnect.

7.7.3 Circulating Kill. Once a successful intervention has occurred, it may be possible to snub pipe back into the hole and tie onto severed drillpipe, or run completely to the bottom of the blowing well if hole diameter permits and there are no obstructions. Once pipe is at the bottom of the well with pressure contained at the seafloor, the well can be circulated with kill weight fluid to control the blowout.

Conventional kill techniques such as the driller's method, the wait-and-weight technique or the concurrent kill method can be employed. At this point the blowing well is under control and the situation can be treated like a kick during normal drilling operations. Special care must be taken if near-wellhead/stack casing has been damaged or if there is some leakage. Excessive kill rates and pressures are undesirable in this situation. Wellbore stress should be minimized during circulating kill procedures.

After the "kick" has been circulated out, wellbore, wellhead, stack and riser repairs and restoration can be undertaken. Circumstances may dictate plugging the blowout well and re-drilling in the interest of safety and prudence. Considerable formation damage may have occurred while the well was blowing out which could render the hole worthless for evaluation or production. Blowout wells are often plugged for this reason.

7.7.4 Combination Kill Methods. Circumstances at the blowout may dictate using a combination of kill techniques to adequately control the flow from the well once a successful vertical intervention has occurred. Some of these are discussed below.

Bullheading Below a Packer. Packers stung into a blowing well protect wellhead and stack components from rupture by isolating the annulus. If the weak point in the system is a wellhead component or casing near the seafloor, bullheading may be selected once the packer is in place as the fastest technique available for killing the well.

It may be possible to run a packer into the hole to some considerable depth before encountering an obstruction. In this instance, bullheading through the packer may also present a rapid, safe kill technique that will minimize stress on the wellhead components. It is noted that the annulus must then be killed in some manner. Bullheading down the annulus is not possible with a packer in the hole. It is recommended that the packer tool string contain an unloader, a sliding sleeve or a port sub just above the packer to permit circulating the annulus. If a riser is used as part of the assembly, it too must be circulated.

Circulating Through Damaged Drillpipe. Drillpipe severed and dropped in the hole during an emergency pull-off provides a conduit to the bottom of the well if it is open. Debris from the wellhead/stack, drillpipe rubbers or other objects may obstruct the top of the pipe. The jets in the bit may be plugged as well. Formation solids may have partially filled the pipe while the well is blowing. The top of the drillpipe may have acted like a boot basket and filled with blowing debris as it traveled past the open top of the drillpipe.

Some companies (e.g., Baker and Davis Lynch) can provide small diameter inflatable packers that can be stabbed into the top of the drillpipe if it is open. This provides a connection to the surface for kill fluid to be pumped without rigging up a snubbing unit. Kill mud can be pumped down the drillpipe through this connection and out the annulus. If a sufficient pump rate can be achieved, it may be possible to perform a bottom circulation kill with the BOP and wellhead components open.

This kill technique resembles a dynamic kill for relief wells. The small conduit size, both drillpipe and the intervention tool string, will probably not allow pump rates sufficient to kill a high rate blowout. Wells that have been blowing for some time, reducing formation pressure, or low flowrate blowouts may be successfully killed using these drillpipe stinger packers.

7.8 ORGANIZATION, PLANNING AND LOGISTICS

These topics are important when a rig is working in or near a live boil from a subsea blowout. There should be considerable control to assure rig personnel, company management and governmental regulators that operations are progressing safely and quickly. Changes in conditions can occur quickly. Equally rapid changes in procedures are possible if the operations are organized and supervised properly.

Section 4.18 of this report, which deals with these topics for relief well drilling, is included here by reference.

7.8.1 Organization. The internal organization of the oil company has as great an impact on vertical intervention as it does on relief well drilling. Many decisions regarding vertical intervention procedures must be made on site due to the dynamic nature of the blowout and the condition of the subsea wellhead/stack. For this reason, the organization plan may have to be more site specific than the relief well organization plan.

Teams of specialists may exist within companies that can address and advise on several aspects of vertical intervention procedures. These might include:

- Subsea wellhead/BOP experts
- Reservoir engineers
- Workover or completion supervisors
- Pollution control experts
- Crisis management representatives

These individuals may have dealt with similar situations and have the experience to liaise with other groups within the company during vertical intervention and simultaneous relief well drilling operations.

It is recommended that the operator designate an incident manager or coordinator. This individual should have the capability and the authority for making quick operational decisions when the need arises. His function would be similar to an incident commander in disaster control situations.

The incident manager would supervise the company team of experts and combine their recommendations for work with the blowout specialist team and other industry representatives employed in vertical intervention work. He should be familiar with reservoir characteristics in the area in which the blowing well was being drilled. He should also have local experience in procuring special tools and supplies. He should be familiar with shipping capabilities in the vicinity. Dealing with the local press and the population in the area is also important. If the company does not have a local team to handle blowout situations, however, they may wish to bring in a company incident manager from outside the area.

Selection of a blowout specialist team should be based on capability, experience, technical ability and availability. Vertical intervention procedures may require more technical capability than some well control companies can provide. Some well control companies deal only with killing and capping blowouts. Others provide a wide range of services. Previous experience of the blowout specialists with the operator may not be an applicable criterion for their selection.

It should be decided early on whether or not the same blowout specialist team working on vertical intervention will also be needed to assist in relief well planning and drilling. In one well-known incident, surface kill operations on a burning platform were performed by one team of specialists and relief well operations were be performed by a different company of well control specialists. Coordination and sharing of tools, if necessary, should be possible between the two teams under the supervision of the operator's incident manager.

7.8.2 Planning. Most planning during vertical intervention procedures is based on conditions and should be done on site. It is difficult to develop "cook book" procedures that can handle vertical intervention efforts for every conceivable set of circumstances and conditions that could be encountered. These circumstances and conditions can change frequently and rapidly. Changes in the blowout rate, weather and sea conditions and in subsea mechanical configurations will alter subsequent procedures. Unless excellent communications exist between the intervention rig and the office, supervision and planning will almost have to be carried out on the rig.

Vertical intervention planning is much like planning on a fishing job. Procedures can be initiated under an overall plan. As work progresses, however, the plan must be adjusted to fit the situation. Vertical intervention, like fishing, is circumstance- and site-specific. What worked on the last blowout may or may not work on the current one.

Situations in which vertical intervention techniques are applicable require close cooperation and coordination between the various groups working on the project. Daily, hourly or even minute-by-minute strategy meetings may be required to insure that all efforts are performed properly. Pre-planning may not be possible for some situations.

7.8.3 Logistics. Movement of personnel and equipment onto the intervention rig can be difficult within time constraints required by vertical intervention methods. These procedures may occur more rapidly than, say, relief well drilling or surface killing and capping techniques particularly if initial efforts are partially successful. The use of vessels and tools of opportunity may be increased during vertical intervention procedures. Use of local sources of equipment is recommended.

Air shipment of special tools and equipment from outside the area is one facet of this type of job that can be coordinated by either the operator or the blowout specialist team. Often, the operator can deal with customs officials on behalf of the organization speeding the arrival of critical components. The operator will probably have the capability of expediting delivery of these components to the rig for use in vertical intervention work.

Proper equipment selection and utilization is emphasized for vertical intervention procedures. Poor quality substitutes should not be used just because they are readily available. In some situations there may only be one chance to successfully kill a well using these techniques (e.g., running a kill packer). The best opportunity should be taken by using the right equipment even if operations must be delayed briefly.

On the other hand, if the possibilities of success are high enough to warrant an attempt using equipment that is suitable, but not optimal, a decision to proceed may be justified. This is particularly true if making the attempt will not preclude future attempts with more suitable equipment. This decision will likely be required on short notice and probably should be made on location by the team members working on the blowout.

8.0 COMPUTER MODEL: RELIEF WELL APPROACH ANGLE

8.1 INTRODUCTION

Directional planning for a relief well centers around the approach angle between the relief and blowout well. An objective is to avoid premature intersection/collision of the two wells. Many factors enter into the selection of approach angles. A computer model has been developed to evaluate some key variables. Some assumptions are required because of uncertainties in formation properties and the manner in which ranging tools react to these properties.

The computer program has been given the name of **APRANGLE** to signify the "approach angle" calculations. A sample run and program description are included in this section. The program is provided with this report on a 3 1/2" diskette. The source code is also included in this chapter.

8.2 REVIEW OF APPROACH ANGLE SELECTION GUIDELINES

Criteria for selecting an approach angle between the blowout and relief wells are explained more fully in Sections 4.11.1 and 4.12.1. Some key variables include the following:

- Ranging tool type, i.e., active or passive detection
- Mud type, i.e., oil or water based
- Formation heterogeneity
- Blowout casing/drillpipe size
- Ellipse of uncertainties for both wells

Another factor is the sensitivity of a premature intersect. If the blowout well can be easily controlled with little negative consequences of a premature intersect, the approach angle discussions carry no real merit.

The general technique for selecting an approach angle is as follows:

- Evaluate the variables listed above and make assumptions for each item where appropriate.
- Determine if a shallow bypass is necessary based on ellipse data.
- Select an approach angle and run the program.
- Evaluate the results against the proposed casing setting depth and the confidence factors associated with each input variable.
- Make additional runs with other approach angle options.

The selected approach angle must meet casing setting depth considerations and fall within reasonable confidence levels based on input data.

8.3 DISCUSSION OF MODEL

The model is simple to run. The various input data concerning the wells, formation properties and ranging tools are entered. The program estimates ranging tool capability under the given input data and also calculates collision probabilities for the two wells assuming the relief well continues on the given course path. The user should compare ranging detection estimates versus well separation/collision probabilities as part of the planning process.

The program is best suited for running over the last few hundred feet of the well where the approach angle does not change appreciably. If ranging tools could sense casing at several thousand feet of well separation, it might be reasonable to run the program over longer depths. Also, it is not practical to use the program over several thousand feet near the bottom because it is unlikely that the approach angle will remain constant.

The user has the option of SI or English oilfield units. Note that Canadian SI, i.e., metric, may not have the same units used at various other worldwide locations using the metric system. For that matter, various metric units often vary with worldwide usage.

The project name can be up to 40 characters.

Input data for the relief well should be self-explanatory. The x and y values are relative to the blowout well. Both wells are usually set up on a north-south basis where x and y are calculated and readily available from computers. A common reference system must be used. (Figures 8.3.1 and 8.3.2)

Ellipse orientation can be expressed in two ways. See the sample. For the relief well, it could be 90° or 270° and still get the same results.

The blowout well requires similar input data. It also requests pipe weight input information. This information is not currently used in the program but is set up for possible future development as more research work becomes available from ranging tool manufacturers.

Ranging tool input requires a basic working knowledge of ranging tools. See other sections in this report. The type of tool must be specified as active or passive. It is assumed that active tool performance will be adversely affected by oil muds by a factor of 50% reduction in detection range capability.

Formation heterogeneity can reduce tool effectiveness by 25% according to discussions with manufacturers. A homogenous formation is entered as 1. An input value of 0 for a heterogeneous formation would cause the program to reduce tool sensitivity by 25%. The user can enter decimal values from 0.0 to 1.0.

The user must determine ellipse of uncertainty sizes from other sources. The program assumes the ellipse size does not change over the hole section in the program run. This assumption is reasonable for runs of several hundred feet.

The program prints tool detection range and collision data.

The user must make a selection of the results from several runs. The selected option is based principally on confidence factors and the experience of specialists.

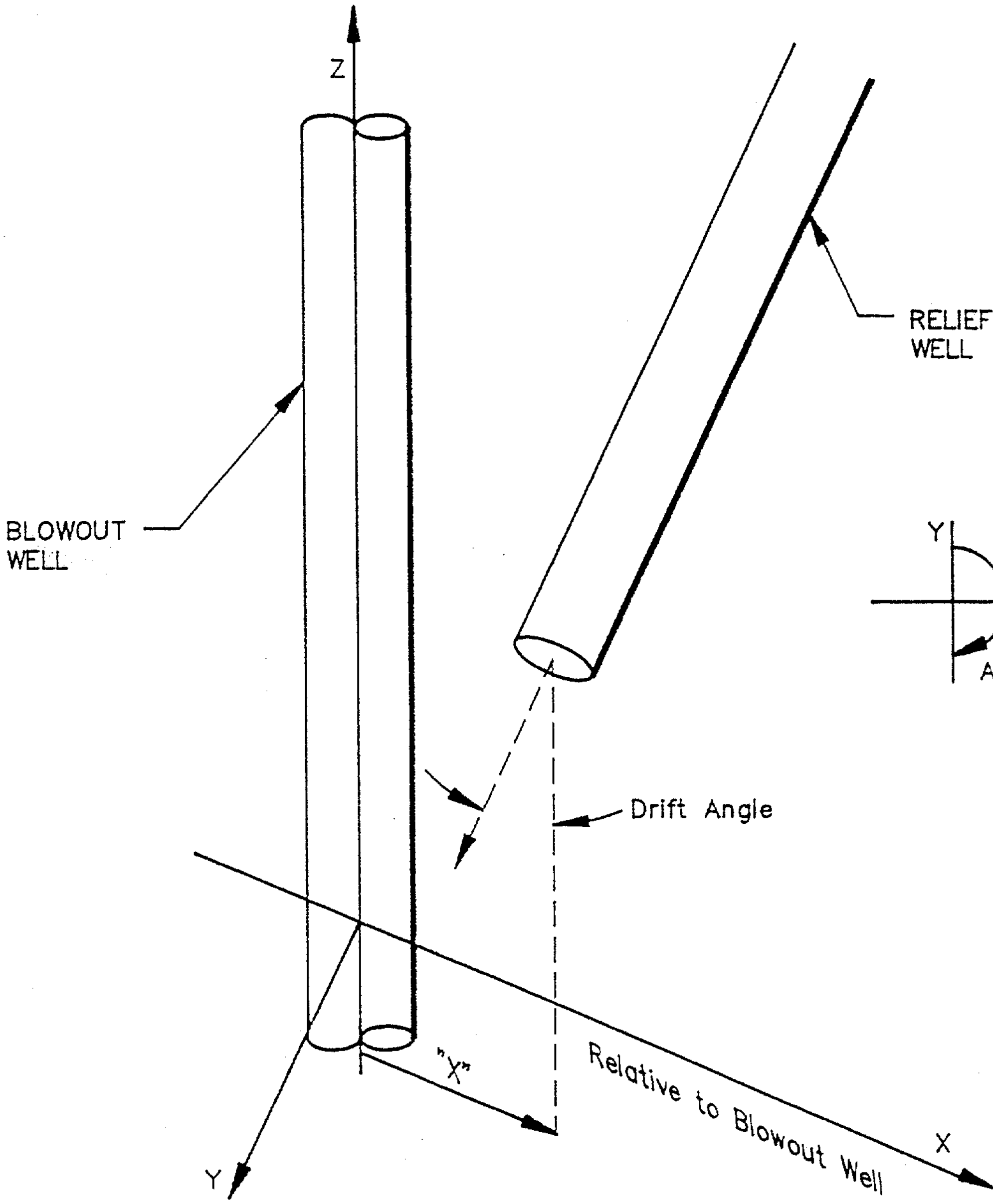
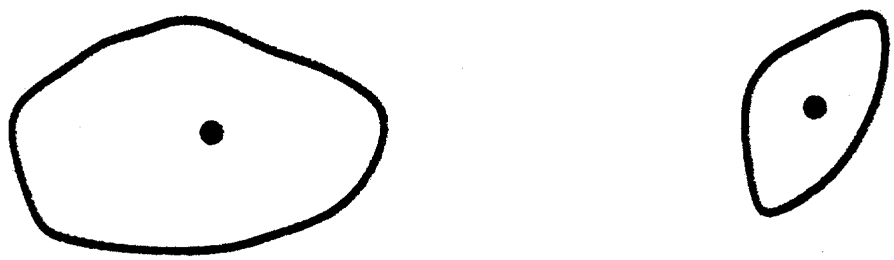


Figure 8.3.1

Aprangle Reference System
(Vertical View)



BLOWOUT WELL

Major Axis — 30 ft.
Minor Axis — 20 ft.
Major Axis Orientation — 90°

RELIEF WELL

Major Axis — 20 ft.
Minor Axis — 15 ft.
Major Axis Orientation — 45°

Plan View*

Figure 8.3.2

Aprangle Reference System
(Plan View)

*Values Selected for Illustrative Purposes Only

DEA PROJECT NO. 63
JOINT INDUSTRY PROGRAM for FLOATING VESSEL BLOWOUT CONTROL

8.4 SAMPLE RUN

```
C:\>cd aprangle

C:\APRANGLE>aprangle

                         NEAL ADAMS FIREFIGHTERS, INC.
                         APPROACH ANGLE MODEL
                         Release 1.LF -

===============================================================================

INPUT UNITS CODE                             CODE = 0


    SI (CANADIAN) .............................1
    ENGLISH ...................................2

INPUT UNITS CODE                             CODE = 2


                          *****  ENGLISH UNITS *****

===============================================================================
                          ENTER PROJECT DESCRIPTION
===============================================================================


 1 PROJECT NAME (MAX OF 40 LETTERS OR NUMBERS)
:> EXAMPLE PROGRAM RUN


===============================================================================
                          RELIEF WELL DATA
===============================================================================


 2 T.V.D. .......................................(FT) = 8900

 3 X RELATIVE TO BLOWOUT WELL ....................(FT) = 75

 4 Y RELATIVE TO BLOWOUT WELL ....................(FT) =


   X RELATIVE TO BLOWOUT WELL ....................(FT) = 75

 4 Y RELATIVE TO BLOWOUT WELL ....................(FT) = 0
```

5 DRIFT ANGLE AT BOTTOM ....(DEGREES) = 25

6 AZIMUTH ....(DEGREES) = 180

7 DIAMETER, MAJOR ELLIPSE AXIS ....(FT) = 40

8 DIAMETER, MINOR ELLIPSE AXIS ....(FT) = 30

9 MAJOR AXIS ORIENTATION (0 - 360)..........(DEGREES) = 90

BLOWOUT WELL DATA

11 COMPOSITE PIPE WEIGHT ....(LB/FT) = 50

12 T.V.D. OF PIPE ....(FT) = 9000

12 T.V.D. OF PIPE ....(FT) = 9000

13 DRIFT ANGLE AT BOTTOM ....(DEGREES) = 0

14 AZIMUTH ....(DEGREES) = 0

15 DIAMETER, MAJOR ELLIPSE AXIS ....(FT) = 60

16 DIAMETER, MINOR ELLIPSE AXIS ....(FT) = 30

17 MAJOR AXIS ORIENATION ....(DEGREES) = 90

RANGING TOOL DATA

21 TOOL TYPE (1=ACTIVE, 2=PASSIVE)................... = 1

22 BRIDLE LENGTH ....(FT) = 50

23 MUD TYPE (1=WATER, 2=OIL BASED) .... = 1

24 FORMATION HOMOGENEITY (0-1)
0=HETEROGENOUS & 1=HOMOGENEOUS .... = 0

25 MAXIMUM TOOL DETECTION RANGE ....(FT) = 200.0

26 STARTING DEPTH ELLIPSE EVALUATION ....(FT) = 8900

```
27 ENDING DEPTH ELLIPSE EVALUATION ..............(FT) = 9100

 28 INCREMENTAL DEPTH ............................(FT) = 10


 24 FORMATION HOMOGENEITY (0-1)
     0=HETEROGENOUS & 1=HOMOGENEOUS ................. = 0

 25 MAXIMUM TOOL DETECTION RANGE .................(FT) =      200.0

 26 STARTING DEPTH ELLIPSE EVALUATION ............(FT) = 8900

 27 ENDING DEPTH ELLIPSE EVALUATION ..............(FT) = 9100

 28 INCREMENTAL DEPTH ............................(FT) = 10
```

==
EDIT APPROACH ANGLE DATA
==

DO YOU WANT TO EDIT THE INPUT DATA? Y

EDITOR OPTIONS (C-CHANGE, L-LIST, E-END): E

==
ENTER THE LOCATION DATA
==

```
LOCATION DATA:
  1 OPERATOR          :  RATTLESNAKE OIL

  2 LEASE/WELL NAME   :  BIG WELL NO. 1

  3 FIELD             :  COTTON

  4 SECTION           :  3

  5 TOWNSHIP          :  37N

  6 RANGE             :  38W
```

```
7 COUNTY                : HARRIS

8 STATE                 : TEXAS


===============================================================================


===============================================================================
                          EDIT THE LOCATION DATA

===============================================================================

DO YOU WANT TO EDIT THE INPUT DATA?  N


===============================================================================

WRITE OUTPUT TO:
                 1.  SCREEN
                 2.  PRINTER (LPT1)
                 3.  DISK FILE
YOUR CHOICE:  2

PRINTER CHOSEN - MAKE SURE PRINTER IS ON

Press Enter to Continue.
```

NEAL ADAMS FIREFIGHTERS, INC.
APPROACH ANGLE MODEL

OPERATOR: RATTLESNAKE OIL DATE: 09/17/91

LEASE: BIG WELL NO. 1 FIELD: COTTON

SEC. 3 TWP. 37N RNG. 38W COUNTY: HARRIS STATE: TEXAS

PROJECT: EXAMPLE PROGRAM RUN PAGE: 1

PROJECT DESCRIPTION

1 PROJECT NAME (MAX OF 40 LETTERS OR NUMBERS)
EXAMPLE PROGRAM RUN

RELIEF WELL DATA

2	T.V.D.	(FT)	8900.000
3	X RELATIVE TO BLOWOUT WELL	(FT)	75.000
4	Y RELATIVE TO BLOWOUT WELL	(FT)	0.000
5	DRIFT ANGLE AT BOTTOM	(DEGREES)	25.000
6	AZIMUTH	(DEGREES)	180.000
7	DIAMETER, MAJOR ELLIPSE AXIS	(FT)	40.000
8	DIAMETER, MINOR ELLIPSE AXIS	(FT)	30.000
9	MAJOR AXIS ORIENTATION (0 - 360)	(DEGREES)	90.000

BLOWOUT WELL DATA

11	COMPOSITE PIPE WEIGHT	(LB/FT)	50.000
12	T.V.D. OF PIPE	(FT)	9000.000
13	DRIFT ANGLE AT BOTTOM	(DEGREES)	0.000
14	AZIMUTH	(DEGREES)	0.000
15	DIAMETER, MAJOR ELLIPSE AXIS	(FT)	60.000
16	DIAMETER, MINOR ELLIPSE AXIS	(FT)	30.000
17	MAJOR AXIS ORIENTATION	(DEGREES)	90.000

RANGING TOOL DATA

21	TOOL TYPE (1=ACTIVE, 2=PASSIVE)		1
22	BRIDLE LENGTH	(FT)	50.000
23	MUD TYPE (1=WATER, 2=OIL BASED)		1
24	FORMATION HOMOGENEITY (0-1) 0=HETEROGENOUS & 1=HOMOGENEOUS		0
25	MAXIMUM TOOL DETECTION RANGE	(FT)	200.0
26	STARTING DEPTH ELLIPSE EVALUATION	(FT)	8900.000
27	ENDING DEPTH ELLIPSE EVALUATION	(FT)	9100.000
28	INCREMENTAL DEPTH	(FT)	10.000

NEAL ADAMS FIREFIGHTERS, INC.
APPROACH ANGLE MODEL

OPERATOR: RATTLESNAKE OIL DATE: 09/17/91

LEASE: BIG WELL NO. 1 FIELD: COTTON

SEC. 3 TWP. 37N RNG. 38W COUNTY: HARRIS STATE: TEXAS

PROJECT: EXAMPLE PROGRAM RUN

ELLIPSE EVALUATION TABLE

Maximum Detection Range of Tool: 150.0 FT

Vertical Depth FT	Well Separation FT	Ellipse Overlap FT	Collision Probability %
8900.00	75.00	0.00	0.00
8910.00	70.77	0.00	0.00
8920.00	66.55	0.00	0.00
8930.00	62.32	0.00	0.00
8940.00	58.10	0.00	0.00
8950.00	53.87	0.00	0.00
8960.00	49.64	0.36	5.64
8970.00	45.42	4.58	13.25
8980.00	41.19	8.81	20.86
8990.00	36.96	13.04	28.46
9000.00	32.74	17.26	36.07
9010.00	28.51	21.49	43.68
9020.00	24.29	25.71	51.29
9030.00	20.06	29.94	58.89
9040.00	15.83	34.17	66.50
9050.00	11.61	38.39	74.11
9060.00	7.38	42.62	81.71
9070.00	3.15	46.85	89.32
9080.00	1.07	48.93	93.07
9090.00	5.30	44.70	85.46
9100.00	9.52	40.48	77.86

DO YOU WANT TO RUN AGAIN? N

8.5 SOURCE CODE

The APRANGLE program is listed beginning on the succeeding page. The main program and its subroutines are included in the listing.

8.5 SOURCE CODE

The APRANGLE program is listed beginning on the succeeding page. The main program and its subroutines are included in the listing.

MAIN PROGRAM

```
      PROGRAM APRANGLE
C
C     COPYRIGHT 6/91 ADAMS ENGINEERING, INC
C
      CHARACTER*40 PROGNAME, COMPNAME
      COMMON /PROGRAM/ PROGNAME, COMPNAME

      COMMON /XUNIT/ IREAD, IWRT, IRPT

      CHARACTER*14 AUNITS
      COMMON / UNITCOM / IUNIT, FACTR(25), AUNITS(25)
C
C  INPUT DATA - COMMON ANGLEIN
C
      CHARACTER PNAME*40
      REAL MAO,MAOB
      INTEGER TT, FT, FH
      CHARACTER*1 EET
      COMMON /ANGLEIN/PNAME, TVD, X, Y, DAB, AZRW, DMAE, DMIE, MAO,
     C                CPW, TVDBO, DABO, AZBO, DMAAB, DMIAB, MAOB,
     C                TT, BL, FT, FH, TDR, EET, DS, ED, DI

      COMMON /HEADER/IPAGE, LNKNT

      CHARACTER*1 YES, NO, ANS, YES2, NO2
      DATA YES,NO,YES2,NO2 /'Y','N','y','n'/

      PROGNAME = 'APPROACH ANGLE MODEL'
      COMPNAME = 'NEAL ADAMS FIREFIGHTERS, INC.'
C
C CALL ENCRYPTION ROUTINE
C
      CALL SETUNITS
      CALL PROTECT(COMPNAME, PROGNAME)

      RAD  = 1./57.29577951
      IPAGE = 0
      LNKNT = 99
      IFIRST = 0
      CALL GETUNIT
      CALL UNITDATA
C
C LOOP BACK TO 100 FOR EDIT DATA AND RECALC
C
100   CONTINUE
      DABO=DABO/RAD
      AZBO=AZBO/RAD
      MAOB=MAOB/RAD
      MAO=MAO/RAD
      DAB=DAB/RAD
      AZRW=AZRW/RAD
```

```
      IF(IFIRST.EQ.0) CALL ANGLEINP
      CALL ANGLEEDT
      IF(IFIRST.EQ.0) CALL WPHINP
      CALL WPHEDT
      IFIRST = 1
      CALL ANGLECALC
      WRITE(IWRT,416)
      READ(IREAD,417) ANS
      IF ( ANS.EQ.YES.OR.ANS.EQ.YES2 ) GO TO 100
      IF ( ANS.EQ.NO.OR.ANS.EQ.NO2  ) GO TO 999
      ELSE ANS<>YES AND ANS<>NO
      WRITE(IWRT,418)
      GO TO 87
99    CONTINUE
      STOP
 416  FORMAT(/,28H DO YOU WANT TO RUN AGAIN?    )
 417  FORMAT(1A1)
 418  FORMAT(/,28H *** PLEASE ANSWER Y OR N:   )
      END
```

ALL CALCULATIONS

```
      SUBROUTINE ANGLECALC
C
C     COPYRIGHT 6/91 ADAMS ENGINEERING, INC
C
      COMMON /XUNIT/ IREAD, IWRT, IRPT

      CHARACTER*14 AUNITS
      COMMON / UNITCOM / IUNIT, FACTR(25), AUNITS(25)
      CHARACTER*2 UNIT
      COMMON /HEADER/IPAGE, LNKNT
C
C  INPUT DATA - COMMON ANGLEIN
C
      CHARACTER FNAME*40
      REAL MAO,MAOB
      INTEGER TT, FT, FH
      CHARACTER*1 EET
      COMMON /ANGLEIN/FNAME, TVD, X, Y, DAB, AZRW, DMAE, DMIE, MAO,
     C                CPW, TVDBO, DABO, AZBO, DMAAB, DMIAB, MAOB,
     C                TT, BL, FT, FH, TDR, EET, DS, ED, DI

C
C     OTHER CALCULATION PARAMETERS
C
      DIMENSION          DNBO(100),  DSBO(100), DWBO(100), DEBO(100),
     C                   TDEPTH(100),DNRW(100), DSRW(100), DWRW(100),
     C                   DERW(100),  ORYB(100), ORYR(100), ERNYB(100),
     C                   ERNYR(100), ORXB(100), ORXR(100), EREXB(100),
     C                   EREXR(100)
      COMMON /ANGLECAL/ DNBO,        DSBO,      DWBO,      DEBO,
     C                   TDEPTH,     DNRW,      DSRW,      DWRW,
     C                   DERW,       ORYB,      ORYR,      ERNYB,
     C                   ERNYR,      ORXB,      ORXR,      EREXB,
     C                   EREXR

     DOUBLE PRECISION DNORBO, DEASTBO, ORYRW,  ORYBO,
     C                  ORXRW,  ORXBO,   ERNYRW, ERNYBO,
     C                  EREXRW, EREXBO
C
C RADIAN CONVERSION FACTOR
C
      RAD  = 1./57.29577951
      UNIT = 'FT'
      IF(IUNIT.EQ.1) THEN
        UNIT = 'M'
        CALL ANGLECVT(1)
      ENDIF
```

```
*************************************************************************
*                                                                       *
*              Calculation of Blowout Well Position                     *
*                                                                       *
*************************************************************************
75    CONTINUE
      SD1=0.
      SDA=DS
      I1=(ED-DS)/DI+1
      DABO=DABO*RAD
      AZBO=AZBO*RAD
      MAOB=MAOB*RAD
      DO 500 J=1,I1
       DNORBO=(SDA-TVDBO)*SIN(DABO)*COS(AZBO)
       DEASTBO=(SDA-TVDBO)*SIN(DABO)*SIN(AZBO)
       ERROR=DMAAB/2*(SIN(AZBO)*SIN(DABO))
       ORXBO=DMAAB/2*SIN(MAOB)
       ORYBO=(DMAAB/2-ERROR)*COS(MAOB)
       EREXBO=-COS(MAOB)*DMIAB/2
       ERNYBO=SIN(MAOB)*DMIAB/2
       ORYB(J)=ORYBO
       ORXB(J)=ORXBO
       ERNYB(J)=ERNYBO
       EREXB(J)=EREXBO
       IF(SDA .NE. TVDBO) GOTO 975
       DNBOTD=DNORBO+ORYBO+ERNYBO
       DSBOTD=DNORBO-ORYBO-ERNYBO
       DEBOTD=DEASTBO+ORXBO+EREXBO
       DWBOTD=DEASTBO-ORXBO-EREXBO
       ORXBOTD=DMAAB/2*SIN(MAOB)
       ORYBOTD=(DMAAB/2-ERROR)*COS(MAOB)
       EREXBOTD=-COS(MAOB)*DMIAB/2
       ERNYBOTD=SIN(MAOB)*DMIAB/2
75     CONTINUE
       DNBO(J)=DNORBO+ORYBO+ERNYBO
       DSBO(J)=DNORBO-ORYBO-ERNYBO
       DEBO(J)=DEASTBO+ORXBO+EREXBO
       DWBO(J)=DEASTBO-ORXBO-EREXBO
       SD1=SD1+DI
       SDA=SDA+DI
00     CONTINUE
       DABO=DABO/RAD
       AZBO=AZBO/RAD
       MAOB=MAOB/RAD
```

```
C***********************************************************************
C*                                                                     *
C*                  Calculation of Relief Well Position               *
C*                                                                     *
C***********************************************************************
      SD2=0.
      SDB=DS
      GOTO 5560
      IF(MAO .LE. 90) GOTO 5560
      IF(MAO .GT. 180) GOTO 5561
      MAO=180-MAO
      CF=1
      GOTO 5560
 5561 IF(MAO .GT. 270) GOTO 5562
      MAO=MAO-180
      CF=2
      GOTO 5560
 5562 IF(MAO .GT. 360) GOTO 5563
      MAO=360-MAO
      CF=3
      GOTO 5560
 5563 WRITE(IRPT,*) ' ANGLE GREATER THAN 360 DEGREES'
 5560 CONTINUE
      MAO=MAO*RAD
      DAB=DAB*RAD
      AZRW=AZRW*RAD
      XORIGIN=X
      YORIGIN=Y
      DO 503 J=1,I1
         XORIGIN=(SDB-TVD)*SIN(DAB)*COS(AZRW)+X
         YORIGIN=(SDB-TVD)*SIN(DAB)*SIN(AZRW)+Y
         ERRORRW=DMAE/2*(SIN(AZRW)*SIN(DAB))
         ORXRW=DMAE/2*SIN(MAO)
         EREXRW=-COS(MAO)*DMIE/2
         ERNYRW=SIN(MAO)*DMIE/2
         ORYRW=(DMIE/2-ERRORRW)*COS(MAO)
         ORXR(J)=ORXRW
         ORYR(J)=ORYRW
         EREXR(J)=EREXRW
         ERNYR(J)=ERNYRW
         IF(SDB .NE. TVDBO) GOTO 974
         DNRWTD=YORIGIN+(ORYRW+ERNYRW)
         DSRWTD=YORIGIN-(ORYRW+ERNYRW)
         DERWTD=XORIGIN+(ORXRW+EREXRW)
         DWRWTD=XORIGIN-(ORXRW+EREXRW)
         ORYRWTD=ORYRW
         ORXRWTD=DMAE/2*SIN(MAO)
         EREXRWTD=-COS(MAO)*DMIE/2
         ERNYRWTD=SIN(MAO)*DMIE/2
  974    DNRW(J)=YORIGIN+(ORYRW+ERNYRW)
         DSRW(J)=YORIGIN-(ORYRW+ERNYRW)
         DERW(J)=XORIGIN+(ORXRW+EREXRW)
         DWRW(J)=XORIGIN-(ORXRW+EREXRW)
         TDEPTH(J)=SDB
         SD2=SD2+DI
         SDB=SDB+DI
  503  CONTINUE
 ONVERT INPUT BACK TO DEGREES FROM RADIANS
       MAO=MAO/RAD
       DAB=DAB/RAD
       AZRW=AZRW/RAD
```

```
***********************************************************************
*                                                                     *
*      Probability  Calculations                                      *
*                                                                     *
***********************************************************************
      ACTYBO=(DNBOTD+DSBOTD)/2
      ACTXBO=(DEBOTD+DWBOTD)/2
      ACTYRW=(DNRWTD+DSRWTD)/2
      ACTXRW=(DERWTD+DWRWTD)/2
      DISTY=ACTYBO-ACTYRW
      DISTX=ACTXBO-ACTXRW
      DISTA=SQRT(DISTY**2 + DISTX**2)
      DISTC=SQRT((DMAE/2)**2+(DMIE/2)**2)+SQRT((DMAAB/2)**2+(DMIAB/2)
     C **2)
      PROB=0.
      OVL=0.
      IF(DISTA .GT. DISTC) GOTO 9811
      IF(DISTC .LT. DISTY .OR. DISTC .LT. DISTX) GOTO 9711
      YBO=ABS(DISTY)
      XBO=ABS(DISTX)
      YDASH=ABS(ORYBOTD)+ABS(ERNYBOTD)+ABS(ORYRWTD)+ABS(ERNYRWTD)
      YN=-YDASH
      XDASH=ABS(ORXBOTD)+ABS(EREXBOTD)+ABS(ORXRWTD)+ABS(EREXRWTD)
      XN=-XDASH
      IF(YBO .GT. YDASH .OR. YBO .LT. YN) GOTO 1030
      IF(YDASH.NE.0)ARMY=(YDASH-YBO)/YDASH
      OVLY=YDASH-YBO
      PROBY=5+ARMY*90
      GOTO 1031
 1030 ARMY=0.
      OVLY=0.
      PROBY=0.
 1031 IF(XBO .GT. XDASH .OR. XBO .LT. XN) GOTO 1032
      IF(XDASH.NE.0)ARMX=(XDASH-XBO)/XDASH
      OVLX=XDASH-XBO
      PROBX=5+ARMX*90
      GOTO 1033
 1032 ARMX=0.
      OVLX=0.
      PROBX=0.
 1033 IF(PROBY .LT. PROBX) GOTO 7179
      OVL=OVLX
      PROB=PROBX
      GOTO 7189
 7179 OVL=OVLY
      PROB=PROBY
 7189 CONTINUE
      IF(ARMY .NE. 0 .AND. ARMX .NE. 0) GOTO 7176
      PROB=0.
      OVL=0.
 7176 IF(ARMY .NE. 0) GOTO 7177
      PROB=0.
 7177 IF(ARMX .NE. 0) GOTO 7178
      PROB=0.
 7178 CONTINUE
      GOTO 7188
 9711 CONTINUE
 9811 CONTINUE
      OVL=0.
      PROB=0.
 7188 CONTINUE
```

```
C*                                                                    *
C*      Calculation of Ranging Tool Parameters                        *
C*                                                                    *
C*********************************************************************
        IF(TT .EQ. 2) GOTO 3001
        IF(FH .EQ. 1) GOTO 3002
        FF=((1-(1-FH))*.25)+.75
        GOTO 3003
 3002   CONTINUE
        FF=1
 3003   IF(FT .EQ. 1) GOTO 3004
        CF=.5
        GOTO 3005
 3004   CONTINUE
        CF=1.
 3005   CONTINUE
        CD=TDR*CF*FF
        GO TO 3006
 3001   CONTINUE
        CD=TDR
 3006   CONTINUE
        CALL OUTFIL(IDFILE)
        IPAGE = 0
C*********************************************************************
C*                                                                    *
C*      Printing of Results                                           *
C*                                                                    *
C*********************************************************************
        PROB=0
        OVL=0
        DO 1630 I= 1 , 24
        IF(DEBO(I) .GT. DWBO(I)) GOTO 1630
         TEMP1=DEBO(I)
         TEMP2=DWBO(I)
         DWBO(I)=TEMP1
         DEBO(I)=TEMP2
 1630   CONTINUE
        IF(IRPT.NE.IWRT)CALL ANGLEPRT
        CALL HEADING(PNAME)
 112    FORMAT(/)
        WRITE(IRPT,5540)
 5540   FORMAT(25X, 'ELLIPSE EVALUATION TABLE')
        WRITE(IRPT,112)
        WRITE(IRPT,991)CD, UNIT
 991    FORMAT(19X,'Maximum Detection Range of Tool: ',F8.1,1X,A)
        WRITE(IRPT,112)

        WRITE(IRPT,164)
 164    FORMAT(1X, '                   Vertical          Well         Ellipse
     C  Collision')
        WRITE(IRPT,165)
 165    FORMAT(1X, '                    Depth         Separation     Overlap
     C  Probability')
        WRITE(IRPT,1660) UNIT,UNIT,UNIT
 1660   FORMAT(17X,A2,12X,A2,12X,A2, '                 %')
        LNKNT = 10
        DO 167 I=1,I1
```

```
      ACTXBO=(DEBO(I)+DWBO(I))/2
      ACTYRW=(DNRW(I)+DSRW(I))/2
      ACTXRW=(DERW(I)+DWRW(I))/2
      DISTY=ACTYBO-ACTYRW
      DISTX=ACTXBO-ACTXRW
      DISTA=SQRT(DISTY**2 + DISTX**2)
      DISTC=SQRT((DMAE/2)**2+(DMIE/2)**2)+SQRT((DMAAB/2)**2+
     C(DMIAB/2)**2)
      OVL=0
      PROB=0
      ARMX=0
      ARMY=0
      IF(DISTA .GT. DISTC) GOTO 8877
      IF(DISTC .LT. DISTY .OR. DISTC .LT. DISTX) GOTO 8878
      YBO=ABS(DISTY)
      XBO=ABS(DISTX)
      YDASH=ABS(ORYB(I))+ABS(ERNYB(I))+ABS(ORYR(I))+ABS(ERNYR(I))
      YN=-YDASH
      XDASH=ABS(ORXB(I))+ABS(EREXB(I))+ABS(ORXR(I))+ABS(EREXR(I))
      XN=-XDASH
      IF(YBO .GT. YDASH .OR. YBO .LT. YN) GOTO 1830
      ARMY=(YDASH-YBO)/YDASH
      OVLY=YDASH-YBO
      PROBY=5+ARMY*90
      GOTO 1831
1830  ARMY=0.
      OVLY=0.
      PROBY=0
1831  IF(XBO .GT. XDASH .OR. XBO .LT. XN) GOTO 1832
      ARMX=(XDASH-XBO)/XDASH
      OVLX=XDASH-XBO
      PROBX=5+ARMX*90
      GOTO 1833
1832  ARMX=0.
      OVLX=0.
      PROBX=0
1833  IF(PROBY .LT. PROBX) GOTO 7779
      OVL=OVLX
      PROB=PROBX
      GOTO 7789
7779  OVL=OVLY
      PROB=PROBY
7789  CONTINUE
      IF(ARMY .NE. 0 .AND. ARMX .NE. 0) GOTO 7776
      PROB=0
      PROB=0
      OVLY=0
      OVLX=0
7776  IF(ARMY .NE. 0) GOTO 7777
      PROB=0.
7777  IF(ARMX .NE. 0) GOTO 7778
      PROB=0.
7778  CONTINUE
      GOTO 8879
8878  CONTINUE
8877  CONTINUE
      OVL=0.
      PROB=0.
8879  CONTINUE
```

```
          IF(LNKNT.GE.50)THEN
            CALL HEADING(PNAME)
            WRITE(IRPT,112)
            WRITE(IRPT,5540)
            WRITE(IRPT,112)
            WRITE(IRPT,164)
            WRITE(IRPT,165)
            WRITE(IRPT,1660) UNIT,UNIT,UNIT
            LNKNT = 6
          ENDIF
          IF(LNKNT.EQ.20.OR.LNKNT.EQ.40)CALL PAUSE(IRPT)
          WRITE(IRPT,1871)TDEPTH(I)*FACTR(1),DISTA*FACTR(1),
     C                    DVL*FACTR(1),PROB
 1871     FORMAT(6X,4F14.2)
 4511   CONTINUE
 167    CONTINUE
 161    CONTINUE
C  CONVERT BACK TO METRIC IF REQUIRED
        IF(IUNIT.EQ.1) CALL ANGLECVT(2)
        END
```

CONVERT TO / FROM ENGLISH / METRIC

```
      SUBROUTINE ANGLECVT (INDEX)

 CONVERT APRANGLE DATA TO / FROM ENGLISH UNITS
        1 = TO ENGLISH;    2 = BACK TO METRIC

      CHARACTER*14 AUNITS
      COMMON / UNITCOM / IUNIT, FACTR(25), AUNITS(25)

 INPUT DATA - COMMON ANGLEIN

         CHARACTER PNAME*40
         REAL MAO,MAOB
         INTEGER TT, FT, FH
         CHARACTER*1 EET
         COMMON /ANGLEIN/PNAME, TVD, X, Y, DAB, AZRW, DMAE, DMIE, MAO,
     C                      CPW, TVDBO, DABO, AZBO, DMAAB, DMIAB, MAOB,
     C                      TT, BL, FT, FH, TDR, EET, SD, ED, DI

      IF (INDEX .EQ. 1 ) THEN
          TVD = TVD/FACTR(1)
          X = X / FACTR(1)
          Y = Y / FACTR(1)
          DMAE = DMAE / FACTR(1)
          DMIE = DMIE / FACTR(1)
          CPW = CPW / FACTR(18)
          TVDBO = TVDBO / FACTR(1)
          DMAAB = DMAAB / FACTR(1)
          DMIAB = DMIAB / FACTR(1)
          BL = BL / FACTR(1)
          TDR = TDR / FACTR(1)
          SD = SD / FACTR(1)
          ED = ED / FACTR(1)
          DI = DI / FACTR(1)
      ENDIF

          CONVERT FROM ENGLISH TO METRIC - HYDCOM

      IF (INDEX .EQ. 2) THEN
         TVD = TVD*FACTR(1)
          X = X * FACTR(1)
          Y = Y * FACTR(1)
          DMAE = DMAE * FACTR(1)
          DMIE = DMIE * FACTR(1)
          CPW = CPW * FACTR(18)
          TVDBO = TVDBO * FACTR(1)
          DMAAB = DMAAB * FACTR(1)
          DMIAB = DMIAB * FACTR(1)
          BL = BL * FACTR(1)
          TDR = TDR * FACTR(1)
          SD = SD * FACTR(1)
          ED = ED * FACTR(1)
          DI = DI * FACTR(1)
      ENDIF

      RETURN
      END
```

LIST INPUT DATA

```
      SUBROUTINE ANGLEPRT
C
C LIST INPUT DATA
C
      CHARACTER*1 EQUAL
      COMMON /XUNIT/ IREAD, IWRT, IRPT

      CHARACTER*14 AUNITS
      COMMON / UNITCOM / IUNIT, FACTR(25), AUNITS(25)
C
C  INPUT DATA - COMMON ANGLEIN
C
         CHARACTER PNAME*40
         REAL MAO,MAOB
         INTEGER TT, FT, FH
         CHARACTER*1 EET
         COMMON /ANGLEIN/PNAME, TVD, X, Y, DAB, AZRW, DMAE, DMIE, MAO,
     C                   CPW, TVDBO, DABO, AZBO, DMAAB, DMIAB, MAOB,
     C                   TT, BL, FT, FH, TDR, EET, SD, ED, DI

         CHARACTER*14 DG, DOTS

         DATA EQUAL /'='/
         DATA DG,DOTS/'.....(DEGREES)','..............'/

         CALL HEADING(PNAME)

C****************************************************************************
C                        PROJECT NAME                                       *
C****************************************************************************
         WRITE(IRPT,9000)
         WRITE(IRPT,9001) (EQUAL,I=1,79)
         WRITE(IRPT,8999)
 8999 FORMAT(25X,'PROJECT DESCRIPTION')
         WRITE(IRPT,9001) (EQUAL,I=1,79)
         WRITE(IRPT,200) PNAME
  200 FORMAT(1X,' 1 PROJECT NAME (MAX OF 40 LETTERS OR NUMBERS) ',/,
     C        4X,A40)
```

```
*                       RELIEF WELL DATA                                      *
*******************************************************************************
      WRITE(IRPT,9000)
9000  FORMAT(/)
      WRITE(IRPT,9001) (EQUAL,I=1,79)
9001  FORMAT(1X,79A1)
      WRITE(IRPT,9030)
9030 FORMAT(25X,' RELIEF WELL DATA')
      WRITE(IRPT,9001) (EQUAL,I=1,79)
      WRITE(IRPT,201) AUNITS(1), TVD
201   FORMAT(1X,' 2 T.V.D. ............................',A14,' = ',
    C        F10.3)
      WRITE(IRPT,202) AUNITS(1), X
202   FORMAT(1X,' 3 X RELATIVE TO BLOWOUT WELL ..........',A14,' = ',
    C        F10.3)
      WRITE(IRPT,203) AUNITS(1), Y
203   FORMAT(1X,' 4 Y RELATIVE TO BLOWOUT WELL ..........',A14,' = ',
    C        F10.3)
      WRITE(IRPT,204)DG, DAB
204   FORMAT(1X,' 5 DRIFT ANGLE AT BOTTOM ...............',A14,' = ',
    C        F10.3)
      WRITE(IRPT,205)DG, AZRW
205   FORMAT(1X,' 6 AZIMUTH .............................',A14,' = ',
    C        F10.3)
      WRITE(IRPT,206)  AUNITS(1), DMAE
206   FORMAT(1X,' 7 DIAMETER, MAJOR ELLIPSE AXIS ........',A14,' = ',
    C        F10.3)
      WRITE(IRPT,207)  AUNITS(1), DMIE
207   FORMAT(1X,' 8 DIAMETER, MINOR ELLIPSE AXIS ........',A14,' = ',
    C        F10.3)
      WRITE(IRPT,208)DG, MAO
208   FORMAT(1X,' 9 MAJOR AXIS ORIENTATION (0 - 360).....',A14,' = ',
    C        F10.3)
*******************************************************************************
*                       BLOWOUT WELL DATA                                     *
*******************************************************************************
      WRITE(IRPT,9000)
      WRITE(IRPT,9001) (EQUAL,I=1,79)
      WRITE(IRPT,9035)
9035 FORMAT(25X,' BLOWOUT WELL DATA')
      WRITE(IRPT,9001) (EQUAL,I=1,79)
      WRITE(IRPT,211) AUNITS(18), CPW
211   FORMAT(1X, ' 11 COMPOSITE PIPE WEIGHT ..............',A14,' = ',
    C        F10.3)
      WRITE(IRPT,212) AUNITS(1), TVDBO
212   FORMAT(1X, ' 12 T.V.D. OF PIPE .....................',A14,' = ',
    C        F10.3)
      WRITE(IRPT,213) DG, DABO
213   FORMAT(1X, ' 13 DRIFT ANGLE AT BOTTOM ..............',A14,' = ',
    C        F10.3)
      WRITE(IRPT,214) DG, AZBO
214   FORMAT(1X, ' 14 AZIMUTH ............................',A14,' = ',
    C        F10.3)
      WRITE(IRPT,215) AUNITS(1), DMAAB
215   FORMAT(1X, ' 15 DIAMETER, MAJOR ELLIPSE AXIS .......',A14,' = ',
    C        F10.3)
      WRITE(IRPT,216) AUNITS(1), DMIAB
216   FORMAT(1X, ' 16 DIAMETER, MINOR ELLIPSE AXIS .......',A14,' = ',
    C        F10.3)
      WRITE(IRPT,217) DG, MAOB
217   FORMAT(1X, ' 17 MAJOR AXIS ORIENTATION..............',A14,' = ',
    C        F10.3)
      CALL PAUSE(IRPT)
```

```
      TDR=75
1225  WRITE(IRPT,225) AUNITS(1),TDR
225   FORMAT(1X, ' 25 MAXIMUM TOOL DETECTION RANGE .......',A14,' = ',
     C F10.1)
      WRITE(IRPT,227) AUNITS(1),SD
227   FORMAT(1X, ' 26 STARTING DEPTH ELLIPSE EVALUATION ..',A14,' = ',
     C       F10.3)
      WRITE(IRPT,228) AUNITS(1),ED
228   FORMAT(1X, ' 27 ENDING DEPTH ELLIPSE EVALUATION ....',A14,' = ',
     C       F10.3)
      WRITE(IRPT,229) AUNITS(1), DI
229   FORMAT(1X, ' 28 INCREMENTAL DEPTH ..................',A14,' = ',
     C       F10.3)
      WRITE(IRPT,9000)
      RETURN
      END
```

```
*                     RANGING TOOL DATA                                         *
*********************************************************************************
      WRITE(IRPT,9000)
      WRITE(IRPT,9001) (EQUAL,I=1,79)
      WRITE(IRPT,9040)
9040 FORMAT(25X,' RANGING TOOL DATA')
      WRITE(IRPT,9001) (EQUAL,I=1,79)
      TT=1
      WRITE(IRPT,221) DOTS,TT
221   FORMAT(1X, ' 21 TOOL TYPE (1=ACTIVE, 2=PASSIVE).....',A14,' = ',
     C I10)
      WRITE(IRPT,222) AUNITS(1), BL
222   FORMAT(1X, ' 22 BRIDLE LENGTH .......................',A14,' = ',
     C        F10.3)
      WRITE(IRPT,223) DOTS, FT
223   FORMAT(1X, ' 23 MUD TYPE (1=WATER, 2=OIL BASED) ....',A14,' = ',
     C        I10)
      WRITE(IRPT,1223)
1223  FORMAT(1X, ' 24 FORMATION HOMOGENEITY (0-1)')
      WRITE(IRPT,224) DOTS, FH
224   FORMAT(1X, '     0=HETEROGENOUS & 1=HOMOGENEOUS ....',A14,' = ',
     C        I10)
      TDR=200
      IF(TT .EQ. 1) GOTO 1225
```

INPUT ALL DATA

```
      SUBROUTINE ANGLEINP

C
C   READ INPUT DATA FOR APPROACH ANGLE PROGRAM
C
      CHARACTER*1 EQUAL

      COMMON /XUNIT/ IREAD, IWRT, IRPT

      CHARACTER*14 AUNITS
      COMMON / UNITCOM / IUNIT, FACTR(25), AUNITS(25)
C
C  INPUT DATA - COMMON ANGLEIN
C
        CHARACTER PNAME*40
        REAL MAO,MAOB
        INTEGER TT, FT, FH
        CHARACTER*1 EET
        COMMON /ANGLEIN/PNAME, TVD, X, Y, DAB, AZRW, DMAE, DMIE, MAO,
     C                   CPW, TVDBO, DABO, AZBO, DMAAB, DMIAB, MAOB,
     C                   TT, BL, FT, FH, TDR, EET, SD, ED, DI

        CHARACTER*14 DG, DOTS

        DATA EQUAL /'='/
        DATA DG,DOTS/'.....(DEGREES)','..............'/

        WRITE(IWRT,9000)
 9000   FORMAT(/)
        WRITE(IWRT,9001) (EQUAL,I=1,79)
 9001   FORMAT(1X,79A1)
        WRITE(IWRT,9002)
 9002   FORMAT(25X,' ENTER PROJECT DESCRIPTION ')
        WRITE(IWRT,9001) (EQUAL,I=1,79)
C
        WRITE(IWRT,9000)
        WRITE(IWRT,*) ' 1 PROJECT NAME (MAX OF 40 LETTERS OR NUMBERS)'
        WRITE(IWRT,'(A)') ' :> '
        READ(IREAD,1888) PNAME
 1888   FORMAT(A40)
```

```
*                         RELIEF WELL DATA                                  *
*****************************************************************************
      WRITE(IWRT,9000)
      WRITE(IWRT,9001) (EQUAL,I=1,79)
      WRITE(IWRT,9030)
9030 FORMAT(25X,' RELIEF WELL DATA')
      WRITE(IWRT,9001) (EQUAL,I=1,79)
      WRITE(IWRT,9000)
      WRITE(IWRT,201) AUNITS(1)
201   FORMAT(1X,' 2 T.V.D. ..............................',A14,' = ')
      READ(IREAD,*) TVD
      WRITE(IWRT,202) AUNITS(1)
202   FORMAT(1X,' 3 X RELATIVE TO BLOWOUT WELL ..........',A14,' = ')
      READ(IREAD,*) X
      WRITE(IWRT,203) AUNITS(1)
203   FORMAT(1X,' 4 Y RELATIVE TO BLOWOUT WELL ..........',A14,' = ')
      READ(IREAD,*) Y
      WRITE(IWRT,204)DG
204   FORMAT(1X,' 5 DRIFT ANGLE AT BOTTOM ...............',A14,' = ')
      READ(IREAD,*) DAB
      WRITE(IWRT,205)DG
205   FORMAT(1X,' 6 AZIMUTH .............................',A14,' = ')
      READ(IREAD,*) AZRW
      WRITE(IWRT,206)  AUNITS(1)
206   FORMAT(1X,' 7 DIAMETER, MAJOR ELLIPSE AXIS ........',A14,' = ')
      READ(IREAD,*) DMAE
      WRITE(IWRT,207)  AUNITS(1)
207   FORMAT(1X,' 8 DIAMETER, MINOR ELLIPSE AXIS ........',A14,' = ')
      READ(IREAD,*) DMIE
      WRITE(IWRT,208)DG
208   FORMAT(1X,' 9 MAJOR AXIS ORIENTATION (0 - 360).....',A14,' = ')
      READ(IREAD,*) MAO
*****************************************************************************
*                         BLOWOUT WELL DATA                                 *
*****************************************************************************
      WRITE(IWRT,9000)
      WRITE(IWRT,9001) (EQUAL,I=1,79)
      WRITE(IWRT,9035)
9035 FORMAT(25X,' BLOWOUT WELL DATA')
      WRITE(IWRT,9001) (EQUAL,I=1,79)
      WRITE(IWRT,9000)
      WRITE(IWRT,211) AUNITS(18)
211   FORMAT(1X, ' 11 COMPOSITE PIPE WEIGHT ..............',A14,' = ')
      READ(IREAD,*) CPW
      WRITE(IWRT,212) AUNITS(1)
212   FORMAT(1X, ' 12 T.V.D. OF PIPE .....................',A14,' = ')
      READ(IREAD,*) TVDBO
      WRITE(IWRT,213) DG
213   FORMAT(1X, ' 13 DRIFT ANGLE AT BOTTOM ..............',A14,' = ')
      READ(IREAD,*) DABO
      WRITE(IWRT,214) DG
214   FORMAT(1X, ' 14 AZIMUTH ............................',A14,' = ')
      READ(IREAD,*) AZBO
      WRITE(IWRT,215) AUNITS(1)
215   FORMAT(1X, ' 15 DIAMETER, MAJOR ELLIPSE AXIS .......',A14,' = ')
      READ(IREAD,*) DMAAB
      WRITE(IWRT,216) AUNITS(1)
216   FORMAT(1X, ' 16 DIAMETER, MINOR ELLIPSE AXIS .......',A14,' = ')
      READ(IREAD,*) DMIAB
      WRITE(IWRT,217) DG
217   FORMAT(1X, ' 17 MAJOR AXIS ORIENATION ..............',A14,' = ')
      READ(IREAD,*) MAOB
```

```
C*                         RANGING TOOL DATA                                   *
C******************************************************************************
      WRITE(IWRT,9000)
      WRITE(IWRT,9001) (EQUAL,I=1,79)
      WRITE(IWRT,9040)
 9040 FORMAT(25X,' RANGING TOOL DATA')
      WRITE(IWRT,9001) (EQUAL,I=1,79)
      WRITE(IWRT,9000)
      TT=1
      WRITE(IWRT,221) DOTS,TT
 221  FORMAT(1X, ' 21 TOOL TYPE (1=ACTIVE, 2=PASSIVE).....',A14,' = ',
     C  I10)
      WRITE(IWRT,222) AUNITS(1)
 222  FORMAT(/,
     C       1X, ' 22 BRIDLE LENGTH ......................',A14,' = ')
      READ(IREAD,*) BL
      WRITE(IWRT,223) DOTS
 223  FORMAT(1X, ' 23 MUD TYPE (1=WATER, 2=OIL BASED) ....',A14,' = ')
      READ(IREAD,*) FT
 1224 CONTINUE
      WRITE(IWRT,1223)
1223  FORMAT(1X, ' 24 FORMATION HOMOGENEITY (0-1)')
      WRITE(IWRT,224) DOTS
 224  FORMAT(1X, '     0=HETEROGENOUS & 1=HOMOGENEOUS ....',A14,' = ')
      READ(IREAD,*) FH
      IF(FH.NE.0.AND.FH.NE.1)THEN
         WRITE(IWRT,9998)
 9998 FORMAT(1X,'ANSWER MUST BE 0 OR 1 - TRY AGAIN')
         GOTO 1224
      ENDIF
      TDR=200*FACTR(1)
      IF(TT .EQ. 1) GOTO 1225
      TDR=75*FACTR(1)
 1225 WRITE(IWRT,225) AUNITS(1),TDR
 225  FORMAT(1X, ' 25 MAXIMUM TOOL DETECTION RANGE .......',A14,' = ',
     C  F10.1)
      EET = 'Y'
      WRITE(IWRT,227) AUNITS(1)
 227  FORMAT(/
     C       1X, ' 26 STARTING DEPTH ELLIPSE EVALUATION ..',A14,' = ')
      READ(IREAD,*) SD
      WRITE(IWRT,228) AUNITS(1)
 228  FORMAT(1X, ' 27 ENDING DEPTH ELLIPSE EVALUATION ....',A14,' = ')
      READ(IREAD,*) ED
      WRITE(IWRT,229) AUNITS(1)
 229  FORMAT(1X, ' 28 INCREMENTAL DEPTH ..................',A14,' = ')
      READ(IREAD,*) DI
      WRITE(IWRT,9000)
      RETURN
      END
```

EDIT INPUT

```
      SUBROUTINE ANGLEEDT
C
C  READ INPUT DATA FOR APPROACH ANGLE PROGRAM
C
      CHARACTER*1 READYES, EQUAL, YES, YES1, NO, NO1
      CHARACTER*1 EDT, EDT1, END, END1
      CHARACTER*1 LST, LST1
      COMMON /XUNIT/ IREAD, IWRT, IRPT

      DATA EQUAL,YES,YES1,NO,NO1/'=','Y','y','N','n'/
      DATA EDT,EDT1,END,END1/'C','c','E','e'/
      DATA LST,LST1/'L','l'/

C
C  INPUT DATA - COMMON ANGLEIN
C
        CHARACTER PNAME*40
        REAL MAO,MAOB
        INTEGER TT, FT, FH
        CHARACTER*1 EET
        COMMON /ANGLEIN/PNAME, TVD, X, Y, DAB, AZRW, DMAE, DMIE, MAO,
     C                 CPW, TVDBO, DABO, AZBO, DMAAB, DMIAB, MAOB,
     C                 TT, BL, FT, FH, TDR, EET, SD, ED, DI

        WRITE(IWRT,9000)
 9000   FORMAT(//)
        WRITE(IWRT,9005) (EQUAL,I=1,79)
 9005   FORMAT(1X,79A1)
        WRITE(IWRT,9001)
 9001   FORMAT(25X,' EDIT APPROACH ANGLE DATA ')
        WRITE(IWRT,9005) (EQUAL,I=1,79)
        WRITE(IWRT,9006)
 9006   FORMAT(//,' DO YOU WANT TO EDIT THE INPUT DATA? ')
  500   CONTINUE
        READ(IREAD,9007)READYES
 9007   FORMAT(A1)
        IF(READYES.EQ.YES.OR.READYES.EQ.YES1)GOTO 1100
        IF(READYES.EQ.NO.OR.READYES.EQ.NO1)GO TO 1500
        WRITE(IWRT,9008)
 9008   FORMAT(' *** PLEASE ANSWER Y OR N: ')
        GO TO 500
 1100   CONTINUE
        WRITE(IWRT,9009)
 9009   FORMAT(/,' EDITOR OPTIONS (C-CHANGE, L-LIST, E-END): ')
  501   CONTINUE
        READ(IREAD,9007)READYES
        IF(READYES.EQ.LST.OR.READYES.EQ.LST1)GOTO 1200
        IF(READYES.EQ.EDT.OR.READYES.EQ.EDT1)GOTO 1400
        IF(READYES.EQ.END.OR.READYES.EQ.END1)GOTO 1500
        WRITE(IWRT,9010)
 9010   FORMAT(/,' *** INVALID OPTION. ')
        GO TO 501
```

```
C     LIST INPUT DATA
 1200    CONTINUE
         CALL ANGLEPRT
         GO TO 1100
 1400    CONTINUE
 1201    WRITE(IWRT,'(A)')
     +    ' INPUT NUMBER, NEW VALUE (0 OR NEGATIVE TO EXIT)
         WRITE(IWRT,'(A)')
     +    ' INPUT NUMBER, 0 TO EDIT ITEM 1
         READ(*,*) INU,CHVAL
         IF(INU .LE. 0) GOTO 1100
         IF(INU .EQ. 1) GOTO 300
         IF(INU .EQ. 2) GOTO 301
         IF(INU .EQ. 3) GOTO 302
         IF(INU .EQ. 4) GOTO 303
         IF(INU .EQ. 5) GOTO 304
         IF(INU .EQ. 6) GOTO 305
         IF(INU .EQ. 7) GOTO 306
         IF(INU .EQ. 8) GOTO 307
         IF(INU .EQ. 9) GOTO 308
         IF(INU .EQ. 11) GOTO 311
         IF(INU .EQ. 12) GOTO 312
         IF(INU .EQ. 13) GOTO 313
         IF(INU .EQ. 14) GOTO 314
         IF(INU .EQ. 15) GOTO 315
         IF(INU .EQ. 16) GOTO 316
         IF(INU .EQ. 17) GOTO 317
         IF(INU .EQ. 21) GOTO 321
         IF(INU .EQ. 22) GOTO 322
         IF(INU .EQ. 23) GOTO 323
         IF(INU .EQ. 24) GOTO 324
         IF(INU .EQ. 25) GOTO 325
         IF(INU .EQ. 26) GOTO 327
         IF(INU .EQ. 27) GOTO 328
         IF(INU .EQ. 28) GOTO 329
```

```
1111    WRITE(IWRT,*)  ' *** ITEM NUMBER INPUT DOES NOT EXIST '
        WRITE(IWRT,*) ' *** PLEASE REENTER '
        GOTO 1201
300     CONTINUE
        WRITE(IWRT,*) ' 1 PROJECT NAME (MAX OF 40 LETTERS OR NUMBERS)'
        WRITE(IWRT,'(A)') ' :> '
        READ(IREAD,1888) PNAME
1888    FORMAT(A40)
        GOTO 1201
301     CONTINUE
        TEMP1=TVD
        TVD=CHVAL
        GOTO 361
302     CONTINUE
        TEMP1=X
        X=CHVAL
        GOTO 361
303     CONTINUE
        TEMP1=Y
        Y=CHVAL
        GOTO 361
304     CONTINUE
        TEMP1=DAB
        DAB=CHVAL
        GOTO 361
305     CONTINUE
        TEMP1=AZRW
        AZRW=CHVAL
        GOTO 361
306     CONTINUE
        TEMP1=DMAE
        DMAE=CHVAL
        GOTO 361
307     CONTINUE
        TEMP1=DMIE
        DMIE=CHVAL
        GOTO 361
308     CONTINUE
        TEMP1=MAD
        MAD=CHVAL
        GOTO 361
311     TEMP1=CPW
        CPW=CHVAL
        GOTO 361
312     TEMP1=TVDBO
        TVDBO=CHVAL
        GOTO 361
313     TEMP1=DABO
        DABO=CHVAL
        GOTO 361
314     TEMP1=AZBO
        AZBO=CHVAL
        GOTO 361
```

```
      DMAAB=CHVAL
      GOTO 361
316   TEMP1=DMIAB
      DMIAB=CHVAL
      GOTO 361
317   TEMP1=MAOB
      MAOB=CHVAL
      GOTO 361
321   CONTINUE
      TT=INT(CHVAL)
      IF(TT .NE. 1) GOTO 9713
      TDR=200
      GOTO 9712
9713  TDR=75
9712  CONTINUE
      GOTO 361
322   TEMP1=BL
      BL=CHVAL
      GOTO 361
323   CONTINUE
      FT=INT(CHVAL)
      GOTO 361
324   TEMP1=FH
      FH=CHVAL
      GOTO 361
325   TEMP1=TDR
      TDR=CHVAL
      GOTO 361
327   TEMP1=SD
      SD=CHVAL
      GOTO 361
328   TEMP1=ED
      ED=CHVAL
      GOTO 361
329   TEMP1=DI
      DI=CHVAL
      GOTO 361
361   CONTINUE
      WRITE(*,5404) TEMP1, CHVAL
5404  FORMAT(1X,'  OLD VALUE = ',F8.2,' NEW VALUE = ',F8.2,/)
      GO TO 1201
1500  CONTINUE
      RETURN
      END
```

PRINT HEADINGS

```
      SUBROUTINE HEADING(PNAME)

CALLED FROM BLOWDOWN PROGRAM
CALL WITH IRPT SET TO SCREEN OR TO DISK FILE (REF OUTFILE ROUTINE)
COPYRIGHT 3/91 - NEAL ADAMS FIRE FIGHTERS


      CHARACTER PNAME*40
      COMMON /HEADER/IPAGE, LNKNT
      COMMON /XUNIT/ IREAD, IWRT, IRPT

      CALL WPHPRT
      IPAGE = IPAGE + 1
      WRITE(IRPT,6953) PNAME, IPAGE
6953  FORMAT(' PROJECT: ', A40, 21X, 'PAGE: ',I2)
      LNKNT = LNKNT+4
      END
```

HEADERS (CRT) + ENCRYPTION

```
      SUBROUTINE PROTECT(COMPNAME,PROGNAME)
C
C ====================================================================
C     PROTECT   --   PRINT HEADER, VERIFY ENCRYPTION
C     2/91    BKD    CONVERT TO LAHEY FORTRAN
C                    ADD CALL TO ENCRYPTION ROUTINE FROM GLENCO
C     9/91    BKD    DELETED CALL TO GLENCO BEFORE DESTRIBUTION OF SOURCE
C                    TO USER
C ====================================================================
      COMMON /XUNIT/ IREAD, IWRT, IRPT
      CHARACTER*40 PROGNAME, COMPNAME
C Display opening banner
      CALL MYDATE(DATSTR)
      WRITE(IWRT,1)COMPNAME,PROGNAME,DATSTR
    1 FORMAT(25x,A40,/,
     +       25x,A40,/,25x,'Release 1.LF - ',A8,/)

C ****** NOTE THE REST OF THIS PROGRAM HAS NOT BEEN PROVIDED
C        CALLS ARE MADE TO PROPRIETARY SOFTWARE PURCHASED FROM
C        AN EXTERNAL SOURCE
C        IF YOU WISH TO USE ENCRYPTION SOFTWARE - INCLUDE YOUR
C        SOURCE HERE
C        IF THERE ARE QUESTION CONCERNING THIS - PLEASE CALL AEI
C
      END
```

```
      SUBROUTINE SETUNITS
C=====================================================================
C     INITIALIZE PRINTER, AND INPUT / OUTPUT CONSOL
C=====================================================================
      COMMON /XUNIT/ IREAD, IWRT, IRPT
      IREAD = 5
      IWRT  = 6
      IRPT  = IREAD
      END
```

```
      SUBROUTINE MYDATE(DATSTR)
C
C=====================================================================
C
C     MYDATE -- GETS THE DATE FROM THE SYSTEM; (SYSTEM DEPENDENT)
C     COPYRIGHT (C) 1982 BY ADAMS & ROUNTREE TECHNOLOGY, INC.
C     ALL RIGHTS RESERVED
C
C      2/91    BKQ              CONVERT TO LAHEY FORTRAN 2 / 91,
C                               DELETE OLD CODE LINES THAT
C                               WHERE JUST COMMENTED OUT
C                               USE DOS DATE ROUTINE
C =====================================================================
C
      CHARACTER*9 DATSTR
C -------------------------------------------------------------------
      CALL DATE(DATSTR)
      RETURN
      END
```

```
      SUBROUTINE PAUSE(IPRNTIT)
C=====================================================================
C     PAUSE -- STOP AND WAIT FOR RETURN KEY
C=====================================================================

      INTEGER IPRNTIT
      COMMON /XUNIT/ IREAD, IWRT, IRPT

C  PAUSE IF ARE PRINTING TO THE SCREEN - IPRNTIT = IREAD

      IF(IPRNTIT.EQ.IREAD)PAUSE

      END
```

```
      SUBROUTINE OUTFIL(ICHOIC)
C
C ==================================================================
C
C     OUTFIL - GET AN OUTPUT OPTION
C     COPYRIGHT (C) 1984 BY LE N TAN - COADE
C     ALL RIGHTS RESERVED
C     2/91   BKQ    CONVERT TO LAHEY FORTRAN
C ==================================================================
C
      CHARACTER FILEW*14
C
C    CONSOL OUTPUT = 6, CONSOL INPUT = 5
C    PRINTER DEVICE (CONSOL OR PRINTER OR DISK FILE) = 9
C
      COMMON /XUNIT/ IREAD, IWRT, IRPT
 100  CONTINUE
      WRITE(IWRT,10)
  10  FORMAT(/' WRITE OUTPUT TO: '/
     &       '                         1.  SCREEN'/
     &       '                         2.  PRINTER (LPT1)'/
     &       '                         3.  DISK FILE' /
     &       ' YOUR CHOICE:  ')

      READ(IREAD,*,ERR=100) ICHOIC
      IF (ICHOIC.LT.1 .OR. ICHOIC.GT.3) GOTO 100

      GOTO (200,210,230) ICHOIC
 200  CONTINUE

C ------ OUTPUT TO SCREEN -
C           NO NEED TO OPEN, IRPT DEFAULTS TO 6 FOR OUTPUT
C
      IRPT = IREAD
      RETURN
C
 210  CONTINUE
C
C ------ OUTPUT TO PRINTER
C     ITRY = 0
      IRPT = 9
 212  CONTINUE
      WRITE(IWRT,9000)
 9000 FORMAT(/,' PRINTER CHOSEN - MAKE SURE PRINTER IS ON')
      CALL PAUSE(IREAD)
      OPEN(UNIT=IRPT,FILE='LPT1:',ERR=211)
      RETURN
C PRINTER IS OFF???
 211  CONTINUE
      ITRY = ITRY + 1
      IF(ITRY.GE.5)GO TO 200
      WRITE(IWRT,9999)
 9999 FORMAT(' PRINTER ERROR - PLEASE CORRECT AND HIT ENTER')
      GO TO 212
 230  CONTINUE
C
C ------ OUTPUT TO DISK
C
      IRPT = 9
      CALL GTFNAM(IRPT,FILEW,1)
      RETURN
      END
```

```
      SUBROUTINE GTFNAM(LUNO,FILEX,IDFILE)
C=========================================================================
C     GTFNAM -- GET A FILE NAME
C     COPYRIGHT (C) 1982 BY ADAMS AND ROUNTREE TECHNOLOGY, INC.
C     ALL RIGHTS RESERVED
C=========================================================================

      CHARACTER*1 BLNK,ANS
      INTEGER LUNO
      LOGICAL FEXIST
      CHARACTER*14 FILEX,FILEY
      COMMON /XUNIT/ IREAD, IWRT, IRPT
      CHARACTER*1 TFILE(14)

      EQUIVALENCE(TFILE(1), FILEY)

      DATA BLNK/' '/

   10 WRITE(IWRT,100)
      READ(IREAD,101)FILEX
      FILEY=FILEX

      VERIFY FILENAME IS A VALID NAME

      DO 15 I=1,13
      IF(TFILE(I).EQ.BLNK.AND.TFILE(I+1).NE.BLNK)THEN
         WRITE(IWRT,110)
         GO TO 10
      ENDIF
   15 CONTINUE

------ DOES FILE ALREADY EXIST

      INQUIRE (FILE=FILEX,EXIST=FEXIST)
      IF (FEXIST) GO TO 45

      IS THIS A READ (IDFILE=2)

      IF (IDFILE.EQ.2)THEN
        WRITE(IWRT,111)
        GO TO 10
      ENDIF

  MUST BE A WRITE - OPEN FILE AS AN "NEW" FILE - DOES NOT EXIST

      OPEN(LUNO,FILE=FILEX,STATUS='NEW',FORM='FORMATTED')
      RETURN

  FILE ALREADY EXISTS

   45 CONTINUE
```

```
C
C --- IF READING FILE - THEN OK
C        IF WRITING (IDFILE=1) THEN ASK IF OK TO OVER WRITE
C
      IF(IDFILE.EQ.1)THEN
        WRITE(IWRT,115)
        READ(IREAD,120)ANS
        IF(ANS.EQ.'n'.OR.ANS.EQ.'N')GO TO 10
        IF(ANS.NE.'Y'.AND.ANS.NE.'y')THEN
          WRITE(IWRT,121)
          GO TO 45
        ENDIF
      ENDIF

      OPEN(LUNO,FILE=FILEX,STATUS = 'OLD',FORM='FORMATTED')
      RETURN
C
C =====================================================================
C    FORMAT STATEMENTS  --  FORMAT STATEMENTS  --  FORMAT STATEMENTS
C =====================================================================
C
  100 FORMAT(/,13H FILE NAME:   )
  101 FORMAT(A)
  110 FORMAT(/,
     & 56H *** INVALID CHARACTERS IN FILENAME; PLEASE RE-ENTER ***,/)
  111 FORMAT(/' *** FILE NOT FOUND!  PLEASE TRY OTHER FILENAME ***'/)
  115 FORMAT(' *** FILE ALREADY EXISTS - OVER WRITE (Y/N)? ')
  120 FORMAT(A1)
  121 FORMAT(' ANSWER MUST BE YES (Y,y) OR NO (N,n) ')
      END
```

```
      SUBROUTINE TOPAGE
C ========================================================================
C     WPHPRT -- PRINTS TOP OF PAGE
C ========================================================================
C
      CHARACTER*1 FF
      COMMON /XUNIT/ IREAD, IWRT, IRPT
C ========================================================================
C
C     PRINT HEADER, AND COLUMN HEADINGS
C
      FF=CHAR(12)
      WRITE(IRPT,110)FF
  110 FORMAT(1H ,A)
      END
```

```
      SUBROUTINE STOPFL(IDFILE)
C ==================================================================
C     STOPFL - TEMPORARILY STOP WRITING OUTPUT FILE
C     COPYRIGHT (C) LE NGOC TAN - 1984
C     ALL RIGHTS RESERVED
C ==================================================================
C
      COMMON /XUNIT/ IREAD, IWRT, IRPT
C
      GOTO (100,200,300) IDFILE
  100 CONTINUE
C ------ SCREEN OUTPUT
      RETURN
C
  200 CONTINUE
C ------ PRINTER OUTPUT
      RETURN
C
  300 CONTINUE
C ------ DISK OUTPUT
      ENDFILE IRPT
      CLOSE (IRPT,ERR=301,IOSTAT=IFIX)
      RETURN
  301 CONTINUE
      WRITE(*,998) IFIX
  998 FORMAT(' FILE ERROR - REVIEW DISK AVAILABILITY ',I5)
      RETURN
      END
```

```
      SUBROUTINE UNITDATA

      ROUTINE TO DEFINE METRIC AND ENGLISH UNITS AND SAVE THEM IN
      ARRAYS (14 CHARS STRINGS ).  ALSO RETURN THE SELECTED UNIT ARRAY
      UPON THE CHOICE OF INDEX.

      IUNIT = 2 -  ENGLISH SYSTEMS UNIT
      IUNIT = 1 -  METRIC SYSTEMS UNIT
      AUNITS     -  ARRAY CONTAINING CHAR STRINGS OF AVAILABLE UNITS
      FACTR      -  ARRAY CONTAINING CONVERSION FACTORS

      CHARACTER*14 UNITS(2,25)
      REAL FACTOR(25)

      CHARACTER*14 AUNITS
      COMMON / UNITCOM / IUNIT, FACTR(25), AUNITS(25)
      DATA MAX / 25 /

      DATA UNITS / '...........(M)','..........(FT)','..........(MM)',
     *             '..........(IN)','.........(KPA)','.........(PSI)',
     *             '......(M3/MIN)','.........(GPM)','..........(KW)',
     *             '..........(HP)','.......(KG/M3)','.........(PPG)',
     *             '.......(M/MIN)','......(FT/MIN)','.......(mPA-S)',
     *             '..........(CP)','..........(PA)','(LB/100 SQ FT)',
     *             '.........(daN)','.........(LBS)','......(KW/CM2)',
     *             '...(HHP/SQ IN)','..........(MM)','.......(32NDS)',
     *             '.......(M/SEC)','......(FT/SEC)','......(M3/MIN)',
     *             '.....(BBL/MIN)','......(M3/REV)','.....(GAL/REV)',
     *             '.......(KPA/M)','.........(PPG)','.......(KPA/M)',
     *             '......(PSI/FT)', ........(KG/M)','.......(LB/FT)',
     *             '.........($/M)','........($/FT)','..........(KG)',
     *             '.........(LBS)','...........(N)','.........(LBS)',
     *             '........(M**3)','.......(FT**3)','.......DEG/30M',
     *             '.....DEG/100FT','...........NAP','...........NAP',
     *             '...........NAP','...........NAP'/

       DATA FACTOR  / .3048, 25.4, 6.894, .003786, .746, 119.826,
     *                .3048, 1.0, .4788, .444, .115, .794, .3048,
     *                .159 , .003786, 1.1748828, 22.62. 1.488, 3.2808,
     *                .4536, 4.448, 2.831685E-2 ,.984, 1.0, 1.0/

       PUT UNITS IN ARRAY "AUNITS" USING THE INDEX "IUNIT"

       DO 10 I = 1, MAX
         AUNITS(I) = UNITS (IUNIT, I )
 10    CONTINUE

       GET CONVERSION FACTORS.

       DO 20 I = 1, MAX
       IF (IUNIT .EQ. 2) THEN
         FACTR (I) = 1.0
       ELSE
         FACTR (I) = FACTOR (I)
       ENDIF

 20    CONTINUE
       RETURN
       END
```

```
      SUBROUTINE WPHEDT
C
C =====================================================================
C     WPHEDT -- EDIT THE SITE DATA.
C     COPYRIGHT (C) 1981 BY ADAMS AND ROUNTREE TECHNOLOGY, INC.
C     ALL RIGHTS RESERVED
C =====================================================================
C
      CHARACTER*1 YES,NO,EQUAL,ANS,LST,CHG,END
      CHARACTER*1 YES2,NO2,LST2,CHG2,END2
C
      CHARACTER*1   OPERAT(40),LEASE(40),FIELD(24),SECT(8),TOWN(8),
     &       RANGE(8),COUNTY(20),STATE(8)
C
      COMMON /XUNIT/ IREAD, IWRT, IRPT
C
      COMMON /SITE/   OPERAT,LEASE,FIELD,SECT,TOWN,RANGE,COUNTY,STATE,
     &                DHDAYS,CHDAYS,CONTPC,DATSTR
C
      DATA LST,CHG,END/'L','C','E'/
      DATA LST2,CHG2,END2/'l','c','e'/
      DATA YES,NO,EQUAL/'Y','N','='/
      DATA YES2,NO2/'y','n'/
C
C =====================================================================
C
C ------- PRINT HEADER
C
      WRITE(IWRT,100)
      WRITE(IWRT,101) (EQUAL,I=1,79)
C
      WRITE(IWRT,102)
      WRITE(IWRT,101) (EQUAL,I=1,79)
C
C ------DOES THE USER WANT TO EDIT THE DATA?
C
    4 WRITE(IWRT,150)
    5 READ(IREAD,151)ANS
      IF(ANS.EQ.YES.OR.ANS.EQ.YES2)GO TO 6
      IF(ANS.EQ.NO.OR.ANS.EQ.NO2)GO TO 11
      WRITE(IWRT,152)
      GO TO 5
C
C ------ EDITOR MODE
C
    6 WRITE(IWRT,153)
      READ(IREAD,151)ANS
      IF(ANS.EQ.LST.OR.ANS.EQ.LST2)GO TO 7
      IF(ANS.EQ.CHG.OR.ANS.EQ.CHG2)GO TO 9
      IF(ANS.EQ.END.OR.ANS.EQ.END2)GO TO 11
      WRITE(IWRT,154)
      GO TO 6
C
C ------ LIST THE INPUT DATA
```

```
  7 WRITE(IWRT,120)
    WRITE(IWRT,135)(OPERAT(I),I=1,40)
    WRITE(IWRT,136)(LEASE(I),I=1,40)
    WRITE(IWRT,137)(FIELD(I),I=1,24)
    WRITE(IWRT,138)(SECT(I),I=1,6)
    WRITE(IWRT,139)(TOWN(I),I=1,6)
    WRITE(IWRT,140)(RANGE(I),I=1,6)
    WRITE(IWRT,141)(COUNTY(I),I=1,20)
    WRITE(IWRT,142)(STATE(I),I=1,6)

    GO TO 6

------ CHANGE THE INPUT DATA

  9 CONTINUE
    WRITE(IWRT,159)
 14 WRITE(IWRT,160)
    READ(IREAD,*)ITEM
    IF(ITEM.LE.0)GO TO 6
    IF(ITEM.GT.8)GO TO 13
    GO TO (20,21,22,23,24,25,26,27)ITEM

 20 WRITE(IWRT,121)
    READ(IREAD,131)(OPERAT(I),I=1,40)
    GO TO 14

 21 WRITE(IWRT,123)
    READ(IREAD,131)(LEASE(I),I=1,40)
    GO TO 14

 22 WRITE(IWRT,124)
    READ(IREAD,132)(FIELD(I),I=1,24)
    GO TO 14

 23 WRITE(IWRT,125)
    READ(IREAD,133)(SECT(I),I=1,6)
    GO TO 14

 24 WRITE(IWRT,126)
    READ(IREAD,133)(TOWN(I),I=1,6)
    GO TO 14

 25 WRITE(IWRT,127)
    READ(IREAD,133)(RANGE(I),I=1,6)
    GO TO 14

 26 WRITE(IWRT,128)
    READ(IREAD,134)(COUNTY(I),I=1,20)
    GO TO 14

 27 WRITE(IWRT,129)
    READ(IREAD,133)(STATE(I),I=1,6)
    GO TO 14

 13 WRITE(IWRT,155)
    GO TO 6

 11 WRITE(IWRT,100)
    WRITE(IWRT,101)(EQUAL,I=1,79)
    WRITE(IWRT,100)


    RETURN
```

```
C
C ======================================================================
C    FORMAT STATEMENTS  --  FORMAT STATEMENTS  --  FORMAT STATEMENTS
C ======================================================================
C
  100 FORMAT(/)
  101 FORMAT(1X,79A1)
  102 FORMAT(30X,22HEDIT THE LOCATION DATA)
  120 FORMAT(/,15H LOCATION DATA:)
  121 FORMAT(25H   1 OPERATOR          :   )
  123 FORMAT(25H   2 LEASE/WELL NAME   :   )
  124 FORMAT(25H   3 FIELD             :   )
  125 FORMAT(25H   4 SECTION           :   )
  126 FORMAT(25H   5 TOWNSHIP          :   )
  127 FORMAT(25H   6 RANGE             :   )
  128 FORMAT(25H   7 COUNTY            :   )
  129 FORMAT(25H   8 STATE             :   )
  131 FORMAT(40A1)
  132 FORMAT(24A1)
  133 FORMAT(6A1)
  134 FORMAT(20A1)
  135 FORMAT(25H   1 OPERATOR          :   ,40A1)
  136 FORMAT(25H   2 LEASE/WELL NAME   :   ,40A1)
  137 FORMAT(25H   3 FIELD             :   ,24A1)
  138 FORMAT(25H   4 SECTION           :   ,6A1)
  139 FORMAT(25H   5 TOWNSHIP          :   ,6A1)
  140 FORMAT(25H   6 RANGE             :   ,6A1)
  141 FORMAT(25H   7 COUNTY            :   ,20A1)
  142 FORMAT(25H   8 STATE             :   ,6A1)
  150 FORMAT(/,38H DO YOU WANT TO EDIT THE INPUT DATA?  )
  151 FORMAT(1A1)
  152 FORMAT(/,28H *** PLEASE ANSWER Y OR N:  )
  153 FORMAT(/,44H EDITOR OPTIONS (C-CHANGE, E-END, L-LIST):  )
  154 FORMAT(/,20H *** INVALID OPTION.)
  155 FORMAT(/,35H *** ITEM NUMBER DOES NOT EXIST ***)
  159 FORMAT(/,47H *** ENTER THE ITEM NO. TO CHANGE ANY ENTRY ***,/,
     &         47H *** AND YOU WILL BE PROMPTED FOR THE DATA.  ***,/)
  160 FORMAT(/,39H ITEM NUMBER (0 OR NEGATIVE TO EXIT):  )
C
      END
```

```
      SUBROUTINE WPHINP
C=====================================================================
C     WPHINP -- INPUT THE SITE DATA.
C     COPYRIGHT (C) 1981 BY ADAMS AND ROUNTREE TECHNOLOGY, INC.
C     ALL RIGHTS RESERVED
C=====================================================================

      CHARACTER*1    OPERAT(40),LEASE(40),FIELD(24),SECT(8),TOWN(8),
     &        RANGE(8),COUNTY(20),STATE(8)

      CHARACTER EQUAL*1

      COMMON /XUNIT/ IREAD, IWRT, IRPT
      COMMON /SITE/   OPERAT,LEASE,FIELD,SECT,TOWN,RANGE,COUNTY,STATE,
     &                DHDAYS,CHDAYS,CONTPC,DATSTR

      DATA EQUAL       /'='     /

C=====================================================================

C------- PRINT HEADER

      WRITE(IWRT,100)
      WRITE(IWRT,101)  (EQUAL,I=1,79)
      WRITE(IWRT,102)
      WRITE(IWRT,101)  (EQUAL,I=1,79)

C------- LOCATION PARAMETERS.

      WRITE(IWRT,120)
C------ OPERATOR
      WRITE(IWRT,121)
      READ(IREAD,131)(OPERAT(I),I=1,40)
C------ LEASE
      WRITE(IWRT,123)
      READ(IREAD,131)(LEASE(I),I=1,40)
C------ FIELD
      WRITE(IWRT,124)
      READ(IREAD,132)(FIELD(I),I=1,24)
C------ SECTION
      WRITE(IWRT,125)
      READ(IREAD,133)(SECT(I),I=1,6)
C------ TOWNSHIP
      WRITE(IWRT,126)
      READ(IREAD,133)(TOWN(I),I=1,6)
C------ RANGE
      WRITE(IWRT,127)
      READ(IREAD,133)(RANGE(I),I=1,6)
C------ COUNTY
      WRITE(IWRT,128)
      READ(IREAD,134)  (COUNTY(I),I = 1,20)
C------ STATE
      WRITE(IWRT,129)
      READ(IREAD,133)(STATE(I),I=1,6)
      WRITE(IWRT,100)
      WRITE(IWRT,101)(EQUAL,I=1,79)
      WRITE(IWRT,100)
```

```
      SUBROUTINE WPHPRT
C
C=====================================================================
C     WPHPRT -- PRINTS PAGE HEADERS FOR WELL PLAN.
C     COPYRIGHT (C) 1982 BY ADAMS AND ROUNTREE TECHNOLOGY, INC.
C     ALL RIGHTS RESERVED
C ====================================================================
C
      CHARACTER*1    OPERAT(40),LEASE(40),FIELD(24),SECT(8),
     &               TOWN(8),RANGE(8),COUNTY(20),STATE(8)
      COMMON /SITE/ OPERAT, LEASE,  FIELD,  SECT,   TOWN,  RANGE,
     &               COUNTY, STATE, DHDAYS,  CHDAYS, CONTPC, DATSTR
      CHARACTER PROGNAME*40, COMPNAME*40
      COMMON /PROGRAM/PROGNAME, COMPNAME

C
      COMMON /XUNIT/ IREAD, IWRT, IRPT
      CHARACTER*1 DASH
      CHARACTER*9 DATSTR
      DATA DASH/'-'/
C
C     PRINT HEADER, AND COLUMN HEADINGS
C
      CALL TOPAGE
      CALL MYDATE(DATSTR)
      WRITE(IRPT,6952)COMPNAME, PROGNAME
 6952 FORMAT(25X, A40)

      WRITE(IRPT,103)(OPERAT(I),I=1,40),DATSTR
      WRITE(IRPT,102)(DASH,I=1,42),(DASH,J=1,20)
      WRITE(IRPT,105)(LEASE(I),I=1,38),(FIELD(J),J=1,22)
      WRITE(IRPT,104)(DASH,I=1,40),(DASH,J=1,25)
      WRITE(IRPT,107)(SECT(I),I=1,6),(TOWN(J),J=1,6),
     &            (RANGE(K),K=1,6),(COUNTY(L),L=1,18),(STATE(M),M=1,6)
      WRITE(IRPT,106)(DASH,I=1,6),(DASH,J=1,6),(DASH,K=1,6),
     &            (DASH,L=1,20),(DASH,M=1,8)
      WRITE(IRPT,109)
C
C ====================================================================
C    FORMAT STATEMENTS  --  FORMAT STATEMENTS  --  FORMAT STATEMENTS
C ====================================================================
C
  102 FORMAT(10X,42A1,7X,20A1)
  103 FORMAT(10H OPERATOR:,2X,40A1,7H  DATE:,2X, A9)
  104 FORMAT(7X,40A1,7X,25A1)
  105 FORMAT(7H LEASE:,2X,38A1,7H FIELD:,2X,22A1)
  106 FORMAT(6X,6A1,6X,6A1,6X,6A1,8X,20A1,7X,8A1)
  107 FORMAT(6H SEC.  ,6A1,6H TWP.  ,6A1,6H RNG.  ,6A1,
     &       8H COUNTY:,2X,18A1,7H STATE:,2X,6A1)
  109 FORMAT(1H )
      END
```

```
      SUBROUTINE GETUNIT

C     ROUTINE TO ASK THE USER FOR A CHOICE OF SYSTEMS UNIT.

C     IUNIT = 1 - METRIC SYSTEM.
C     IUNIT = 2 - ENGLISH SYSTEM.

      COMMON /XUNIT/ IREAD, IWRT, IRPT
      CHARACTER*1 EQUAL

      CHARACTER*14 AUNITS(25)
      DIMENSION FACTR(25)
      COMMON / UNITCOM / IUNIT, FACTR, AUNITS

      DATA EQUAL / '=' /

      WRITE(IWRT,110)
 110  FORMAT (1H )
      WRITE(IWRT,111) (EQUAL, I=1, 79)
 111  FORMAT (1X,79A1)
C
C ASK FOR CHOICE OF UNIT.    VERIFY AND PRINT CHOICE
C
 10   WRITE(IWRT,100)
      READ(IREAD,*, ERR = 10 ) IUNIT
      IF (IUNIT .LE. 0 .OR. IUNIT .GE. 3 ) THEN
         WRITE(IWRT,900)
         GOTO 10
      ELSE
         IF (IUNIT .EQ. 1 ) THEN
            WRITE(IWRT,101)
         ELSE
            WRITE(IWRT,102)
         ENDIF
      CALL UNITDATA
      ENDIF
      RETURN
 900  FORMAT (/5X,'SI (CANADIAN) ..............................1',
     *        /5X,'ENGLISH ....................................2')
 101  FORMAT (/21X,'*****  SI (CANADIAN) UNITS *****')
 100  FORMAT (/1X,'INPUT UNITS CODE         ',22X,'CODE = ')
 102  FORMAT (/25X,'*****  ENGLISH UNITS *****')
      END
```

```
APRANGLE PROTECT SETUNITS MYDATE PAUSE +
ANGLEINP ANGLEEDT OUTFIL GTFNAM TOPAGE STOPFL UNITDATA +
ANGLEPRT HEADING ANGLECALC WPHINP WPHEDT WPHPRT GETUNIT ANGLECVT
APRANGLE
NUL
NUL
```

'OBJ' FILES

'EXE' FILE

NOT USED OPTIONS

APRANGLE.RSP

"RESPONSE FILE" USED AS INPUT TO THE LINKER

E.G.

LINK @APRANGLE.RSP

9.0 RECOMMENDATIONS

Recommendations for some additional technology development were generated by this phase of this study. These are summarized below. Previous sections of the study are referenced.

9.1 BLOWOUT EQUIPMENT AND SERVICES CATALOG

Section 5.0 of this report deals with specialized services and equipment necessary for combating blowouts. This catalog deals with offshore and onshore blowout services and equipment.

Economic forces have resulted in mergers, buyouts and restructuring of many oilfield service companies. Personnel changes have also been occurring over the past several years. It is difficult to maintain a current list of companies and contacts due to the dynamic nature of the oilfield service business worldwide.

It is recommended that each of the participants in the study copy the "Directory" portion of Section 5.0 onto a suitable medium, then make alterations to the listing as necessary. This will provide a current listing without relying on a central group to constantly maintain the catalog.

The "directory" portion of Section 5 has been copied onto the same 3 1/2" diskette containing the source files for the APRANGLE Program included with this report. It has been provided in an ASCII format for easy conversion to the individual participant's word processor.

9.2 SUBSEA CHEMICAL/BACTERIA INJECTOR

Section 6.10 contains recommendations for designing a flow-through device that can be fitted over the mouth of the blowing well to inject liquid chemicals and/or bacteria cultures in the plume of a subsea blowout. The concept is to provide a method to treat all of the effluent with appropriate remediation chemicals, then use plume dynamics to provide the forces necessary to mix, disperse and dilute the effluent to less harmful levels in the water column.

Dispersant injection is not a new concept. Recent development of several environment friendly, non-pathogenic dispersants may make this an attractive alternative to using surface containment and collection methods. These are expected to be largely ineffective in open ocean conditions where floater drilling will extend in the future.

Bioremediation is becoming an increasingly popular form of pollution abatement technology. Injection of bacteria colonies directly into the root of the plume may provide "bug" populations necessary to remove the oil from the environment. Combining dispersants and bacteria in the plume may synergistically add to treatment efficiency.

Polymers can also be injected in a similar manner. Liquid polymers can be pumped to the injector. Solid powdered or crumb form polymers may require mixing in a slurry to be transported to the seafloor. Delivery systems such as open flumes and stationary mixers inside the device may be required for solid polymers.

Equipment design is beyond the scope of Phase I of this study. The concepts which could point to the design of new equipment for subsea effluent treatment and pollution abatement has been reviewed. Development of operating criteria, procedures, engineering calculations and manufacturing specification formulation should be considered for a future study.

9.3 EXPANDING TECHNOLOGY REVIEW

During the course of this study, several hundred wells in Kuwait were sabotaged by Iraqi petroleum engineers in the Gulf War. Many new devices and procedures were developed by inventors, engineers and service companies in direct response to this disaster. Some of these are being employed in Kuwait at the time of this writing.

Traditional firefighting methods have also been used in Kuwait with varying results. Several new "wrinkles" have been made to these procedures in the field with interesting and often good results.

Some of the new oilfield firefighting concepts and procedures may be applicable, with modification, to subsea blowout control particularly in vertical intervention procedures. Tools such as inflatable stinger packers are an example. Stab-in devices of different types may also be utilized for offshore blowout control in the future.

It is recommended that these new concepts be examined in a future study to determine if they can be adapted for offshore use in floater drilling. Some of these ideas are so new that adequate documentation on the procedures does not exist. Performance of tools, diverter systems and procedures has not yet been determined for most of these. This expanded study should probably not be undertaken until efforts in Kuwait, and in other active areas, are concluded. This is not anticipated until sometime in 1992.

9.4 PHASE II

Initiation of Phase II of this study is not recommended at this time. The development of the flow-through subsea chemical injector and the analysis of new well control equipment and devices can be performed later if the participants so choose.

There has not, as yet, been a major pollution-causing blowout in deep water since 1987. Studies indicate that there have been no long-lasting effects from that or any other incident including large tanker spills in 1989 and 1990. Thus, there is little urgency to develop new equipment and procedures for such incidents recognizing the low probabilities of their occurring.

Phase II may be indicated in the future. Continuing into Phase II is not warranted at this time, however.