INTRODUCTION: During the period 14-18 January 1989, Mobil Madura Strait Inc. had a well site hazard survey conducted for the proposed Madura XX-1 drilling site located within the central part of the Madura Strait block, offshore eastern Java Indonesia. (See Diagram 1). The following types of surveys were conducted:

A. BATHYMETRY.

B. SIDE SCAN SONAR.

C. SHALLOW SUB BOTTOM PROFILES USING TOWED BOOMER SOURCE.

D. MULTI-CHANNEL, DIGITALLY-RECORDED SEISMIC USING SPARKER SOURCE.

The results of the surveys indicated a tight anticlinal fold with a series of faults. The main feature was an intrusion which forced the rock up to create a local structural high. Indications were that this structural high could trap a significant thicknesses of gas in thin stringers. Two shallow horizons were reflected with high amplitude anomalies that are usually associated with lateral movement of gas along suitably permeable zones. These two horizons' structural highs were predicted at 1451 and 2524 feet below the mudline. The boomer data also experienced severe acoustic blanking of data that was attributed to a gas plume close to the sea bed. (See Diagrams 2 and 3).

There are several approaches to shallow gas well control

accumulation and the gas/water contact. This may be greater than the apparent thickness in the well.

The gas accumulation thickness that can occur is shown in Figure 2 to be dependent on the depth below mudline of the gas bearing formation and the overburden gradient. It may be approximated by:

$$T = \frac{D * (OB-SW)}{SW} \qquad \text{(EQUATION NO. 2)}^1$$

Where: T = gas height (FT).

OB = overburden pressure gradient (PSI/FT).

SW = seawater gradient (PSI/FT).

D = depth below mudline of the structural high point of zone (FT).

Overburden pressure gradients will vary from 0.67 psi/ft in unconsolidated superficial deposits to 1.0 psi/ft in consolidated hard rock areas. Using the lowest reasonable overburden gradient of 0.67 psi/ft at the structural high, and a salt water gradient of 0.44 psi/ft, the maximum thickness of gas that could be contained in an individual permeable zone is given as:

$$T = \frac{D * (0.67 - 0.44)}{0.44}$$

$$= D * 0.523 \text{ FT.} \qquad \text{(EQUATION NO. 2a)}^1$$

For an area with unknown overburden gradients, this could be perceived as being the minimum possible thickness. A higher overburden gradient could contain a greater thickness.

In an area with near horizontal bedding individual zones thick enough to contain shallow gas accumulations approaching

$$T = 2810 * 0.523 = 1470 \text{ feet}$$

To avoid a well control problem, the well would have to be located some 834 feet (1470 - 636) downdip of the structural high. In this case moving the well location only 500 feet downdip was possible. Hence an alternate approach was required.

Worldwide experience has confirmed that over 50 % of offshore shallow gas events which have been diverted have failed. This inability to safely control this flow is usually a divertor failure or gas broaching around the conductor pipe. Since a jacked up rig cannot be moved quickly off location when its legs have penetrated significantly below the seabed, perhaps as much as 80 to 100 feet, diverting gas is a serious risk and places the rig in a precarious situation. (See photos of Sedco 251 off Madura Island.)

Applying conventional methods for drilling shallow gas in the Madura Straits resulted in the following conclusions:

1. It was not feasible to select a location which would avoid all potential shallow gas hazards. If the well were to be drilled, plans would have to be implemented to safely control shallow gas.

2. An air gap of 84 feet and a conductor setting depth deep enough to circulate 10 ppg mud did not generate sufficient confidence that shallow gas could be safely handled down to the proposed 20" setting depth.

Faced with these possibilities, Mobil did not consider it prudent to drill into shallow gas with the rig jacked up.

deteriorated. The weather conditions in the Madura Straits are relatively calm and reliable. The wind is predominately from the south with average wind speeds below 15 mph. The tides for this area average a modest 4.5 feet with a high tide of 7.5 feet. The tidal stream speed average is 0.7 knots with a maximum of 1.9 knots.

C. The rig would be manned by essential personnel only. At the time of actual operations, only 44 persons were on board.

D. The drill string would be sacrificed in the event of a rapid departure from location. The drill string consisted of 8 1/2" bit, bit sub with float, three 6 1/4 drill collars, five joints of 5" HWDP on 5" drill pipe.

E. "Moonpool" area would be under constant observation at all times and in direct radio contact with the tow-master.

F. Two forward and two aft anchors would be run. The anchors would be prepared for free wheel mode. The legs of the jack-up would be lowered to the seabed only and pinned.

G. A tow boat would remain connected to the bow of the rig heading into the prevailing wind. The boat would be fully operational and ready to pull the rig off location instantly. (See diagram number 4).

Once the contingency plans were formulated, the actual procedure was relatively simple:

1. Control drill an 8 1/2" hole at 100 feet/hour to 2810' BML using seawater and taking returns to the seabed while carefully monitoring pump pressure and pump rate.
   In order to keep the hole clean, back ream every 90 foot connection with the top drive and pump a 20 barrel hi-vis pill.
2. If flow was experienced, begin pumping seawater at the maximum rate possible.
3. If gas broke out around the rig, then the power would be shut off and the rig moved off location immediately.

THE OPERATION:

On 19 May 1989, conditions were ideal to begin the operation of drilling the pilot hole with the jack-up rig Maersk Venturer. The wind was from the east south east at 10 to 14 knots and the seas were less than two feet. The rig was positioned (approximately 500 feet downdip based on Diagram No. 3) using Pulse/8 positioning system and a RACAL HP 85 quality control package. Positioning accuracy was confirmed using a satellite based positioning system. The rig was floating with anchors run and the legs pinned. The Smit Lloyd 106 was on tow line from the bow with a further work boat and a crew boat on stand-by.

A pilot hole was drilled to 1392' below the mudline and the crew was preparing to make a connection. A 24 barrel hi-vis pill had been pumped and was being displaced with seawater. While backreaming with the top drive prior to

making the connection, the drill string torqued up and the pump pressure decreased. At 1028 hours, with the bit at 1357 feet below the mudline, the assistant driller, who was assigned to watch the moonpool area, saw gas bubbling approximately 1 foot high. He notified the control room whereby an announcement was made on the rig public address system. The bubbles at this time covered an area approximately 150 feet in diameter. The 5" drill pipe was lowered until a tool joint was just above the rotary. A set of 5" elevators with a cable from the air tugger connected to its latch were placed around the drill pipe. The connection was backed out with the rotary tongs and the top drive. The latch on the elevators was opened by pulling with the air tugger allowing the drill pipe to fall to the seabed. Simultaneaously the legs were being jacked clear of the seabed and the two aft anchor winches were put in the "free wheel" mode and released. The bow anchor winches and the to boat Smit Lloyd 106 began pulling the rig off location.

By 1039 hours, or within a brief 11 minutes from detection of gas, the rig had been pulled approximately 150 feet off location. At 1050 hours the rig was finally positioned 300 feet east south east of the pilot hole with the legs pinned at the seabed in order to stabilize the rig. At 1100 hours the pilot hole either bridged over or depleted itself as no further mud or gas was detected.

From this first pilot hole, the following could be

concluded:

1. To drill a successful pilot hole with seawater would require moving the location downdip.
2. To drill close to the same location would require using higher density mud from 1392' BML.

SECOND PILOT HOLE:

The rig was then positioned 400 feet north of pilot hole no. 1. This location was picked as moving downdip on the expected gas zone. The same procedures and program were followed to a depth of 1303' BML. From this depth to 2792' BML, additional procedures were employed:

1. The entire active mud system of 1400 barrels was weighted up to 9.5 ppg.
2. Drilled from 1303' to 2792' while pumping 200 gpm of 9.5 ppg mud with returns to seabed.
3. Continued mixing 10.5 ppg mud in the premix system while drilling. This premix was then blended 50/50 with seawater and added to the active system as 9.5 ppg. This was determined to be the fastest method for building and maintaining 9.5 ppg. (It took 20 hours to drill from 1303 to 2792', averaging 75 ft/hr. Total 9.5 ppg mud used was 5944 barrels.)
4. If the active system were to run out of 9.5 ppg mud, then the pump would be shut down and mud volume built.
5. During any shut down, the pipe would be kept moving

by rotation.

No problems were encountered while drilling this pilot hole to 2792' BML. The well was abandoned by filling it with 11.0 ppg hi-vis mud from the mudline to 1300' BML.

FINAL LOCATION:

The rig was positioned at its final location which was 230 feet south east of pilot hole 2 and 300 feet north east of pilot hole 1. The rig was jacked up with an average leg penetration of 90 feet below the mudline. The conductor could only be driven to 240' BML. A 26" pilot hole was drilled to 276' BML and driving of the conductor resumed to 307' BML. The water depth was 140 feet and the resulting air gap was 84 feet.

From Figure 4 the maximum mud weight that can be circulated without loosing circulation at the conductor shoe depth is given by:

$$MW = \frac{W * SW + P * OB}{AG + W + P} \qquad \text{(EQUATION NO. 4)}^{1}$$

P = conductor penetration below mudline (ft).

With the assumed overburden of 0.67 psi/ft, the maximum mud weight that could be circulated from equation No. 4 is MW = 0.503 psi/ft or 9.7 ppg.

$$MW = \frac{140 * 0.44 + 307 * 0.67}{84 + 140 + 307} = 0.503 \text{ psi/ft}$$

Figure 5 shows the difference in mud gradients for pilot hole 2 versus the final location with 9.5 ppg mud from rig floor. The well was drilled with a 12 1/4" bit to 1628' BML

with 9.5 ppg. At this depth a reading of 260 units of gas was recorded. The pump was shut down and a flow check for 10 minutes was conducted. It was observed that the well was flowing so the divertor was closed. A total of 250 barrels of 10.5 ppg mud was pumped and the divertor opened for a flow check. The well was static. The hole was conditioned and the mud weight leveled out to 9.9 ppg. Drilling continued to the 20" casing setting depth of 2686' BML. The hole was opened to 26" and the 20" casing was run and cemented successfully at 2673' BML.

FINAL WELL DESIGN CONSIDERATIONS:

1. The 30" conductor was set sufficiently deep to accommodate 9.7 ppg mud deemed necessary to control the well.
2. Despite the negative results observed drilling the second pilot hole, it was considered prudent to be fully prepared for shallow gas. 250 barrels of 10.5 ppg had been prepared as a contingency in the event of shallow gas.

Possible reasons for the presence of shallow gas at the final location are:

1. Local trapping of gas of limited areal extent that was not penetrated by either pilot hole.
2. High penetration rates resulting in loss of hydrostatic head due to gas cutting.
3. The effective hydrostatic head of the mud column employed on the pilot holes was greater than measured (i.e

cuttings load contribution due to major hole enlargement by drilling with seawater).

CONCLUSIONS:

1. Shallow gas in an anticline represents a real hazard which may not be identified as significant on shallow seismic.
2. It is possible to predict the magnitude of a shallow gas hazard by making assumptions with respect to overburden.
3. Under ideal conditions of weather and sea, a jack-up rig can be placed in a floating mode to drill a pilot hole to determine the extent of shallow gas hazards.
4. If shallow gas is encountered, the rig can be safely and quickly pulled off location.
5. From site survey information and simple calculations the likelihood of encountering shallow gas can be predicted around structural features with significant relief.
6. In a known area of shallow gas charging, the probability of encountering shallow gas at a particular location cannot be reduced to zero by the results of an adjacent well that did not encounter it.

ACKNOWLEDGEMENTS:

The author wishes to express his appreciation to Brian Tarr and Elmo Blount for their assistance in preparing this paper. In addition the author wishes to thank Mobil Madura Strait Inc. and Mobil Corporation for permission to publish this

paper and to thank Maersk Drilling Co. in the planning and execution of this operation.

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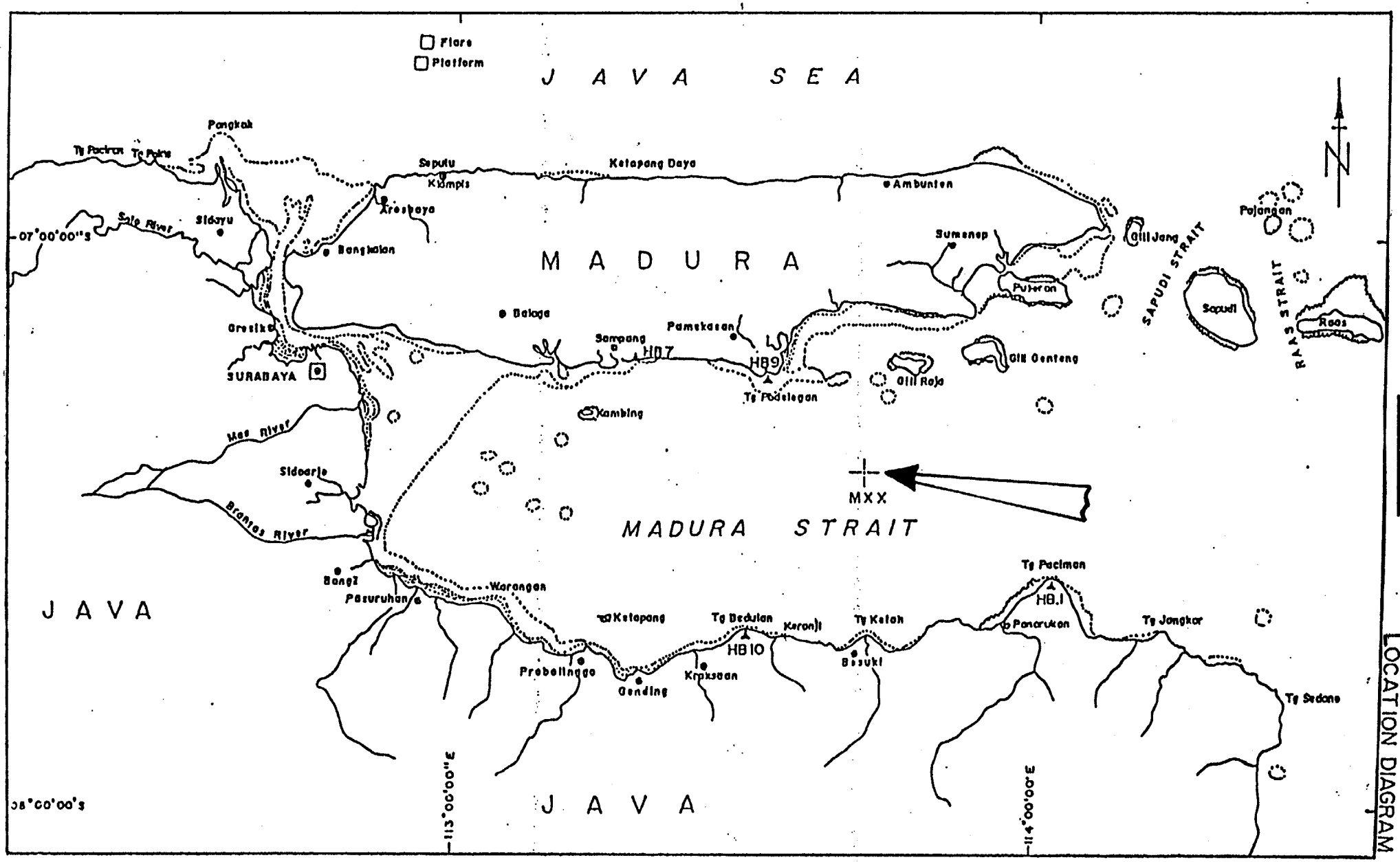


DIAGRAM 1

LOCATION DIAGRAM

TITLE: A UNIQUE APPROACH FOR CONFIRMING THE PRESENCE OF SHALLOW GAS IN NEW OFFSHORE EXPLORATION AREAS

AUTHOR: J. G. GUIGNON, MOBIL OIL CORPORATION

ABSTRACT: At the proposed location of a well in the Madura Strait, offshore Indonesia , the sparker survey (shallow depth seismic) indicated probable shallow gas. Mobil, with the cooperation of Maersk Drilling, decided to drill a pilot hole to 2810 feet below the mudline (BML), the depth of the proposed surface casing, with the jackup in a floating position. The arrangement included two bow and two stern anchors with a standby boat tied to the bow of the floating jackup for easy moving.

At 1392 feet BML, the bit penetrated an overpressured gas bearing zone. In just 11 minutes after the gas first surfaced in the moonpool area, the drill string and the stern anchors were dropped and the rig moved safely off location.

The rig was then repositioned 394 feet north (which was down dip on the gas bearing zone). A second pilot hole was drilled using 9.5 ppg weighted mud with returns to the seabed. The well was drilled to the designed surface casing depth of 2792 feet BML without incident.

The rig was finally repositioned southeast of pilot hole No. 2 and northeast of pilot hole No. 1. The rig was jacked up and the conductor pipe driven. At 1628 feet BML with 9.6 ppg mud, the well flowed and had to be diverted. After the mud weight was raised to 9.9 ppg, the well was drilled to the surface casing setting depth without further incident.

This experience has shown that drilling pilot holes using a jackup in a floating position is a useful approach to quantifying the presence of shallow gas associated with structural features having significant relief. However, given the relatively benign weather of the Madura Strait area, the technique cannot be used in all areas.

DIAGRAM 3

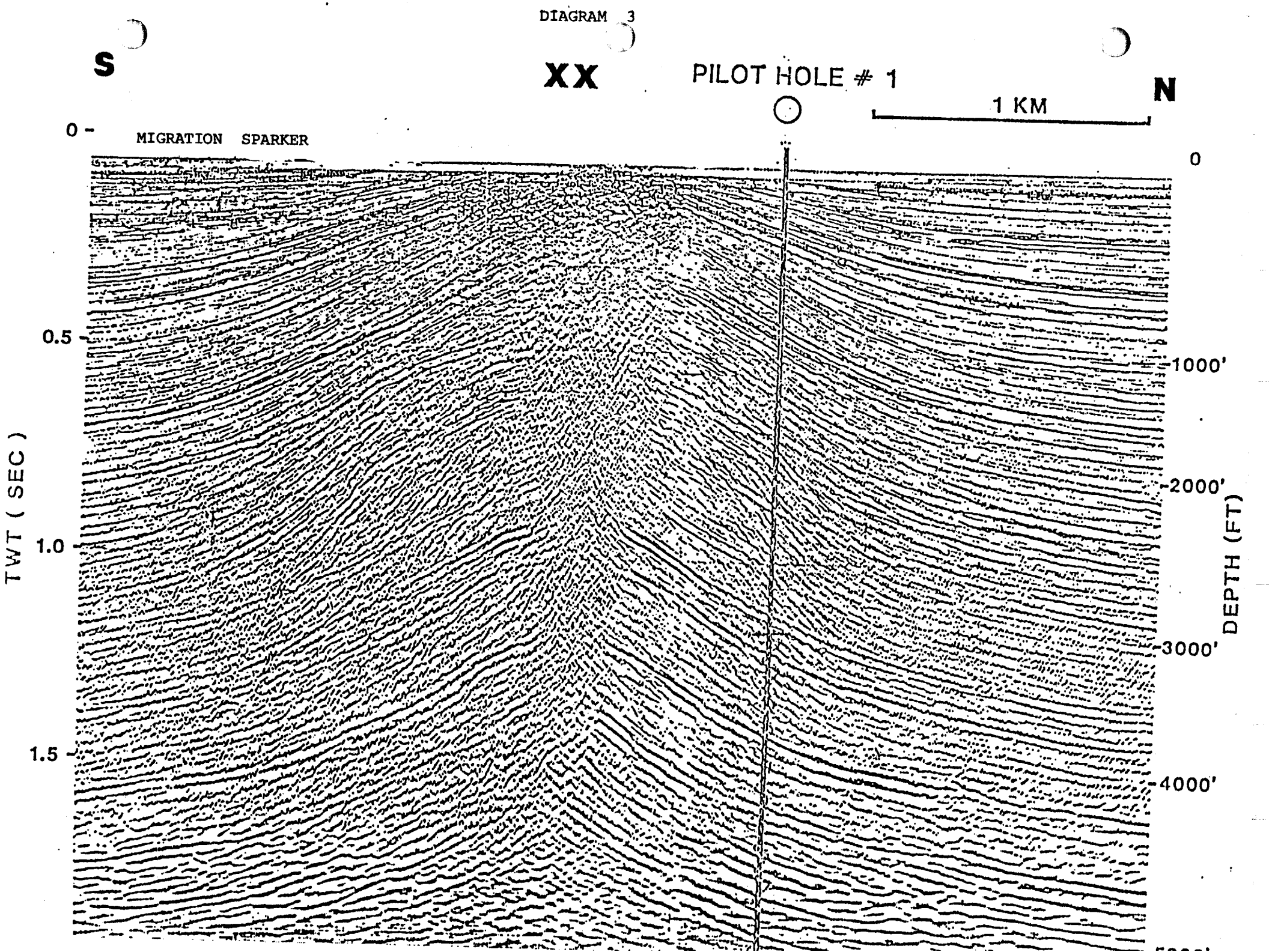
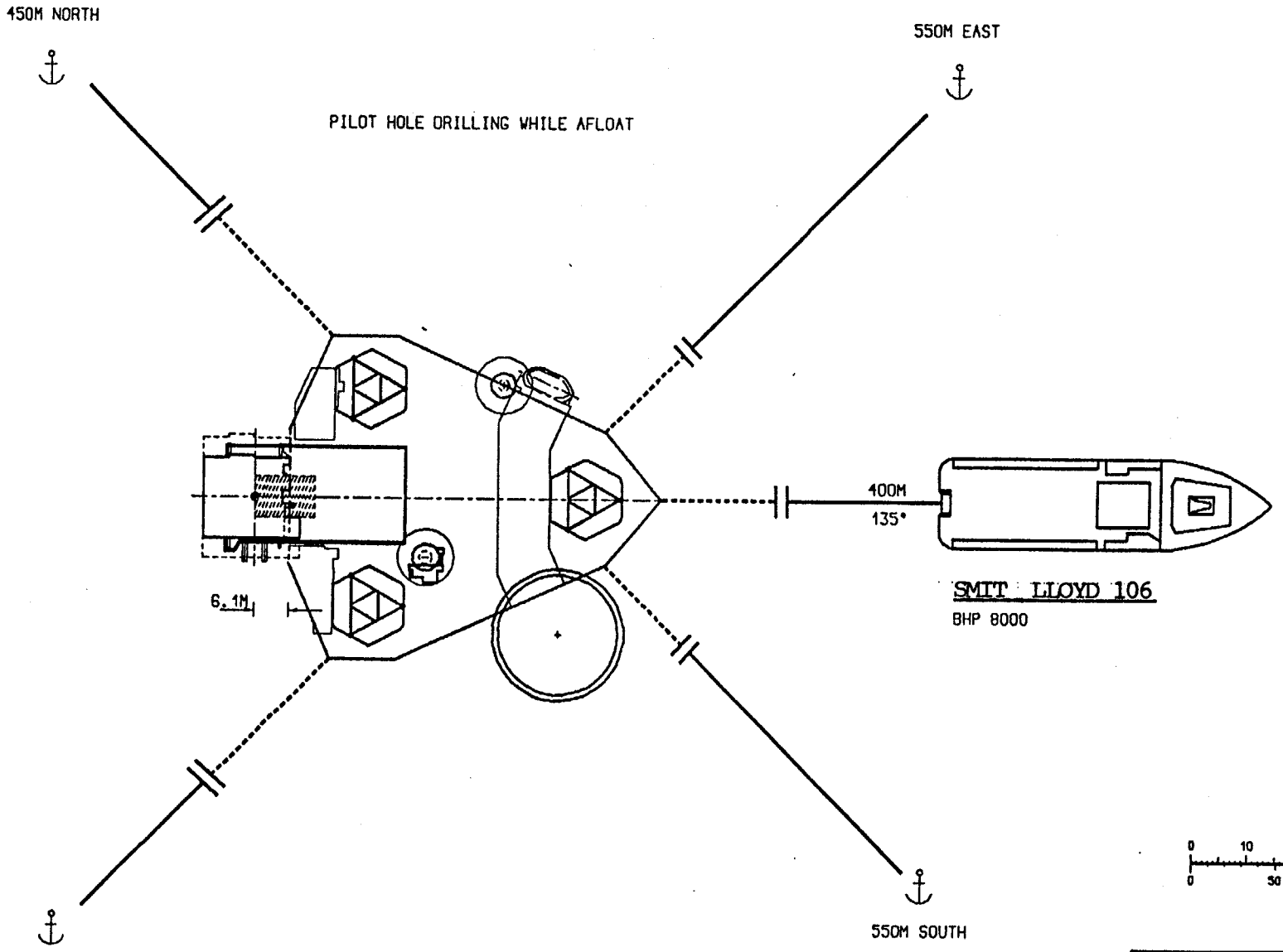

S
XX
PILOT HOLE # 1
N
1 KM
0 -
MIGRATION SPARKER
0
0.5
1.0
1.5
TWT (SEC)
1000'
2000'
3000'
4000'
DEPTH (FT)

DIAGRAM 4



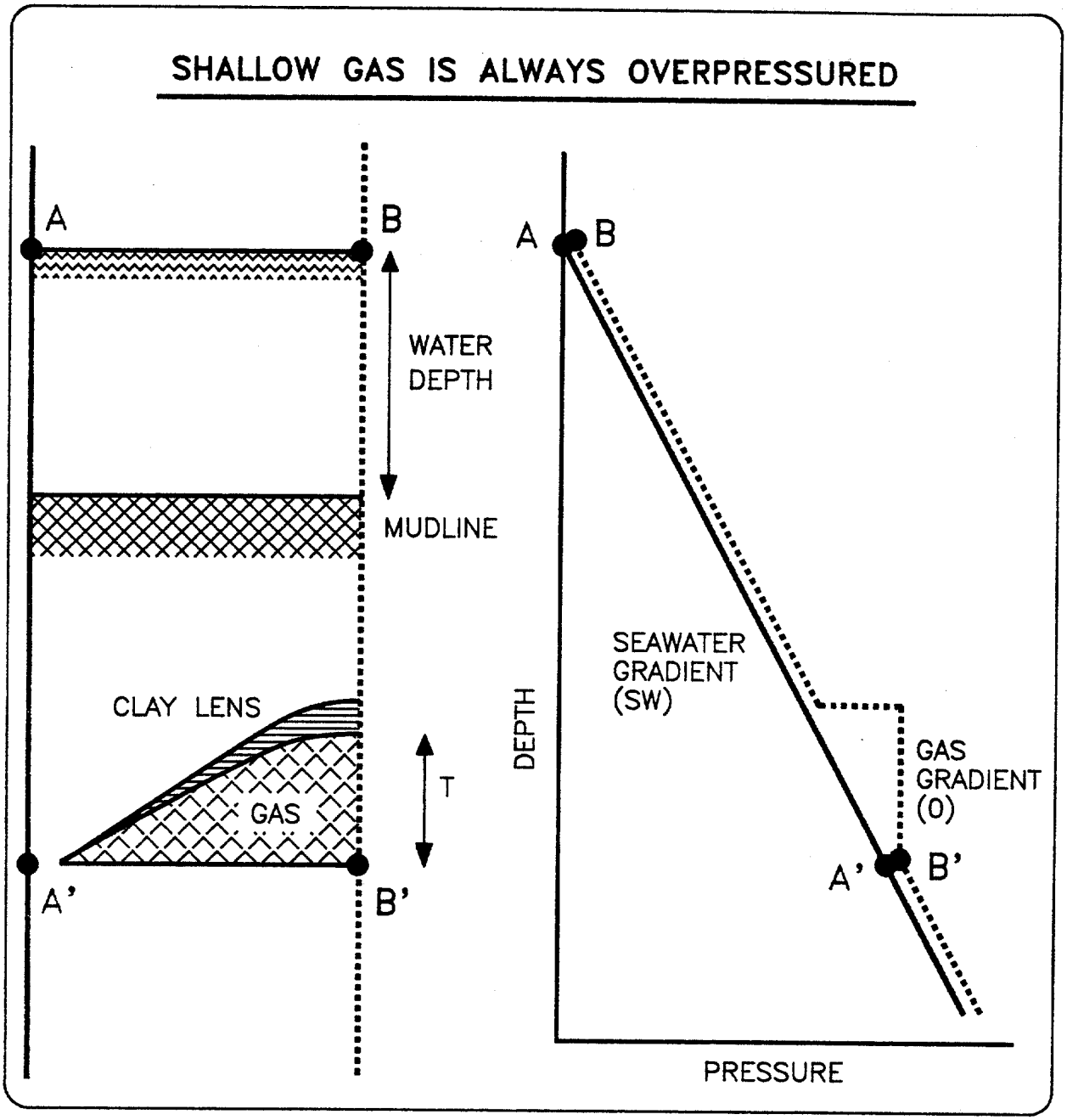
MÆRSK DRILLING

MÆRSK VENTURER

MOBILS MADURA FIELD

SCALE	SIZE	DRAWING NO.	REV.
1:400	A1	MDP-069-0021	A

FIGURE 1



JMSHALL/7/09/89

FIGURE 2

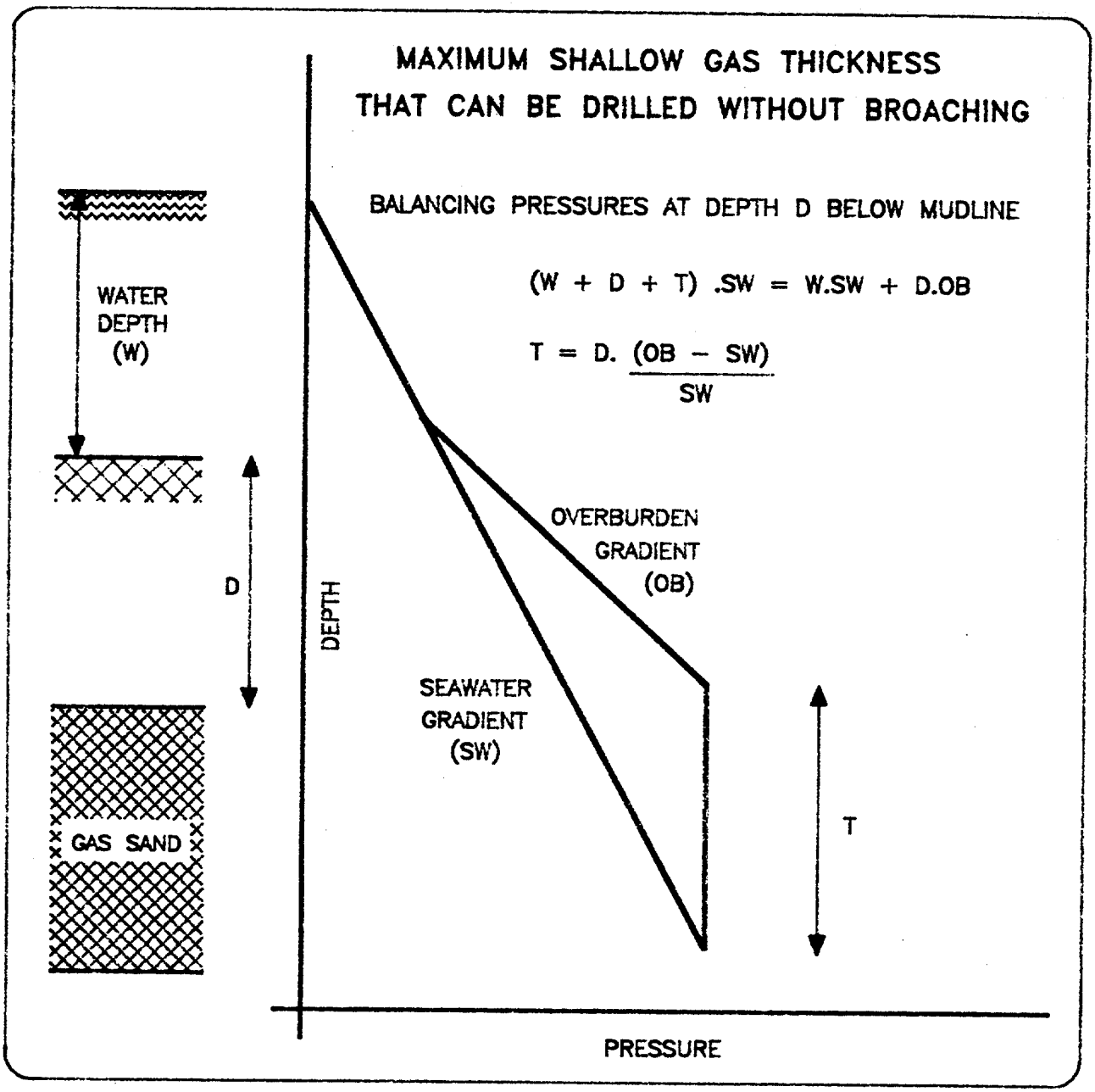
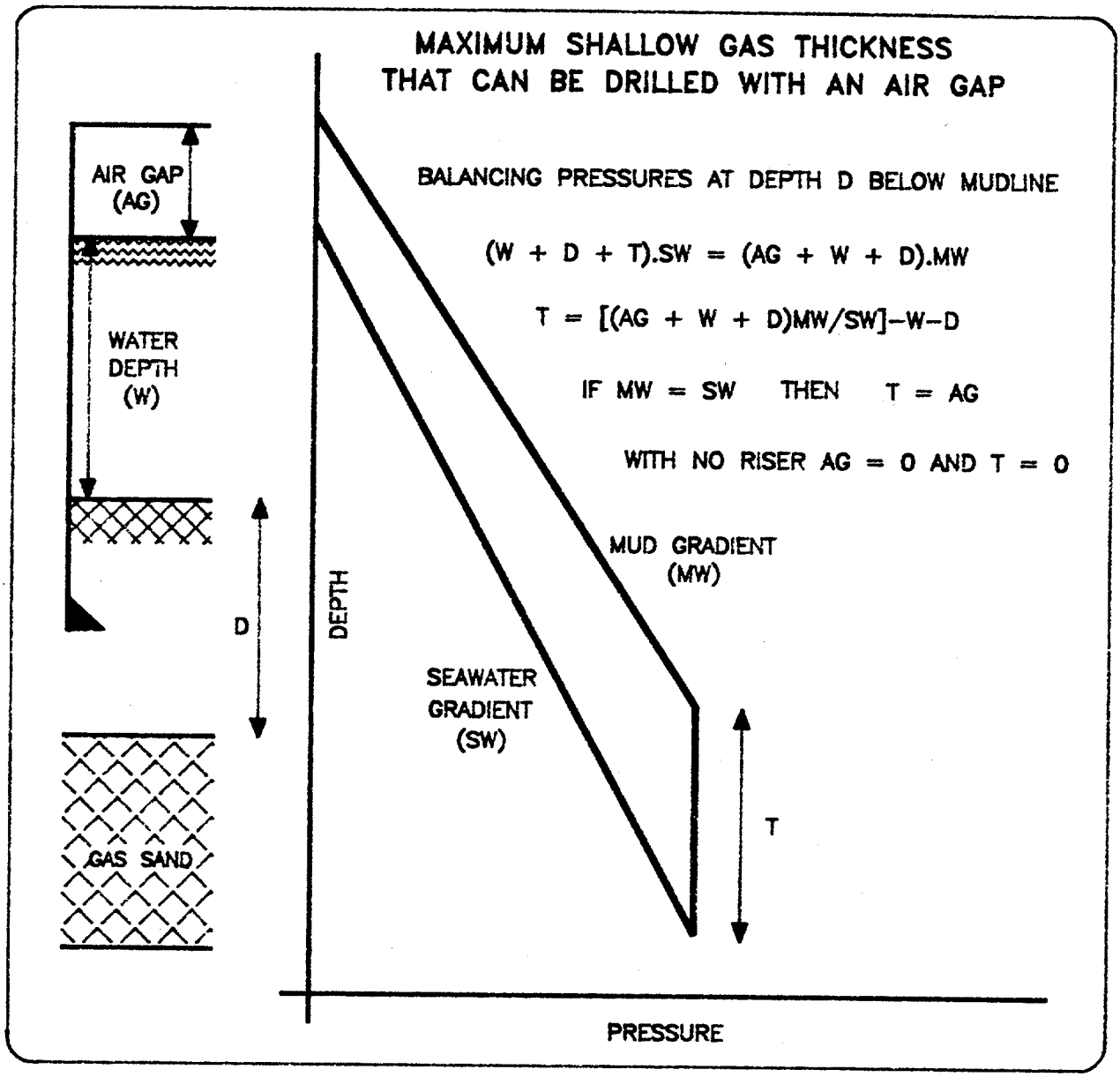

MAXIMUM SHALLOW GAS THICKNESS
THAT CAN BE DRILLED WITHOUT BROACHING
BALANCING PRESSURES AT DEPTH D BELOW MUDLINE
(W + D + T) .SW = W.SW + D.OB
T = D. (OB − SW) / SW
WATER DEPTH (W)
D
GAS SAND
DEPTH
OVERBURDEN GRADIENT (OB)
SEAWATER GRADIENT (SW)
T
PRESSURE

FIGURE 3



JMMAXI1/6/09/89

FIGURE 4

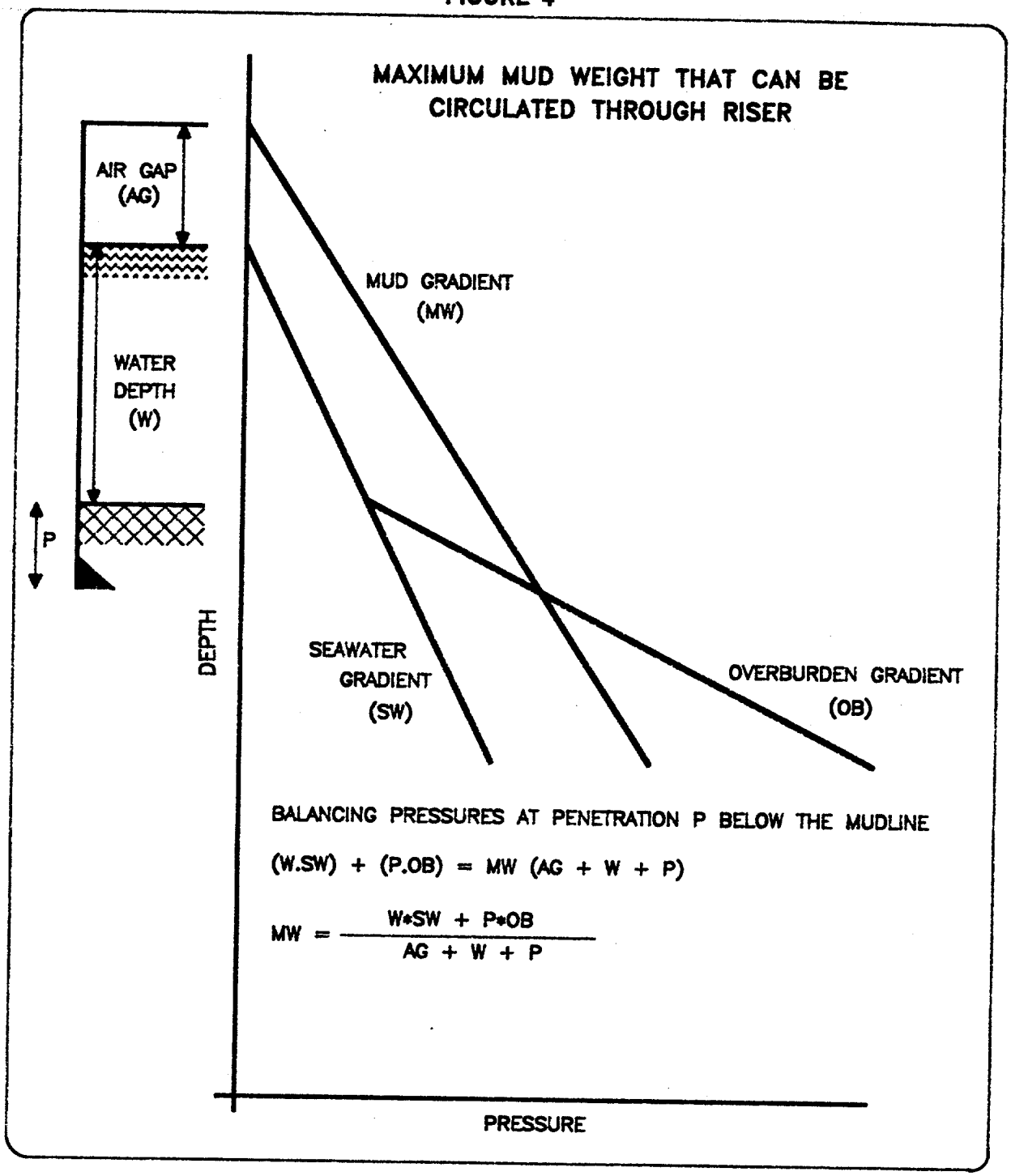
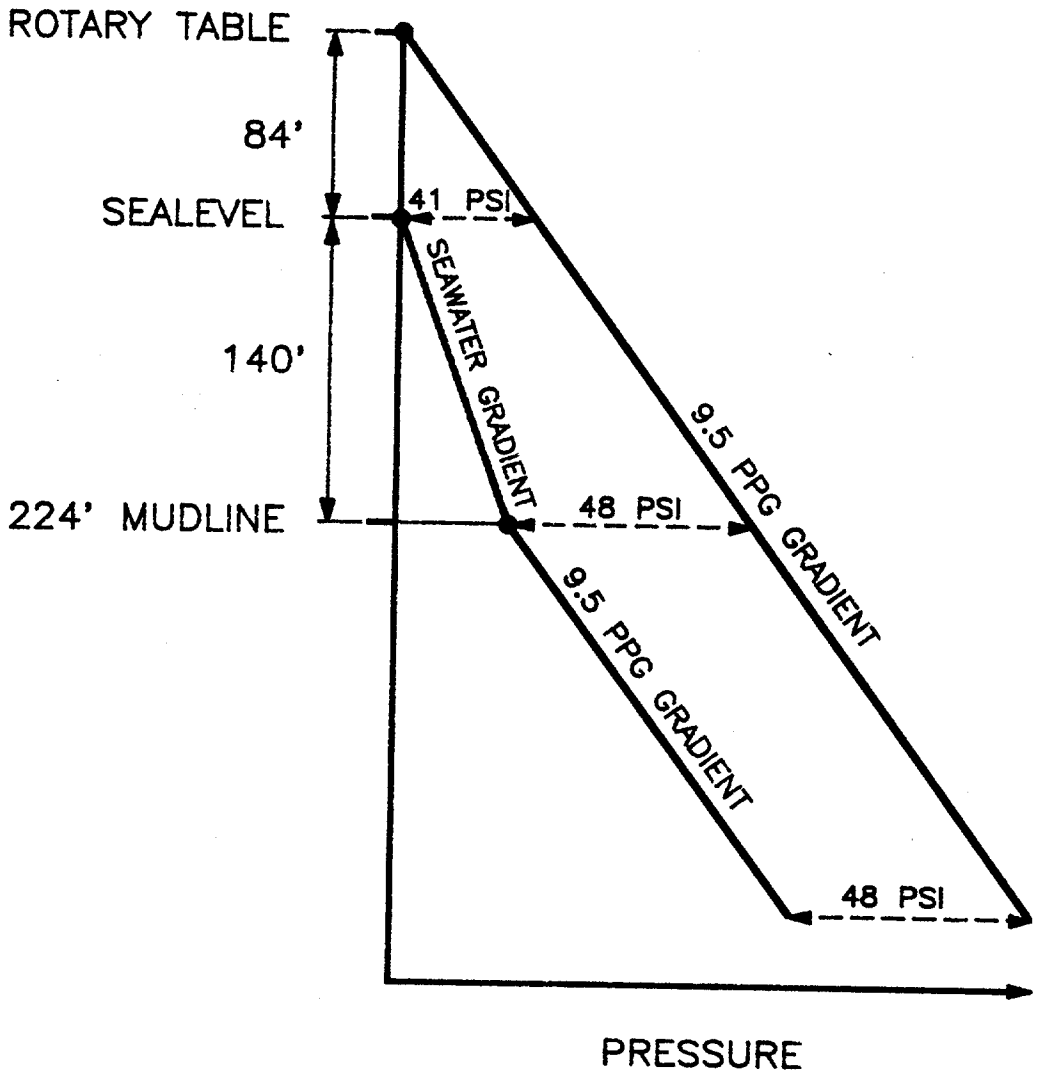
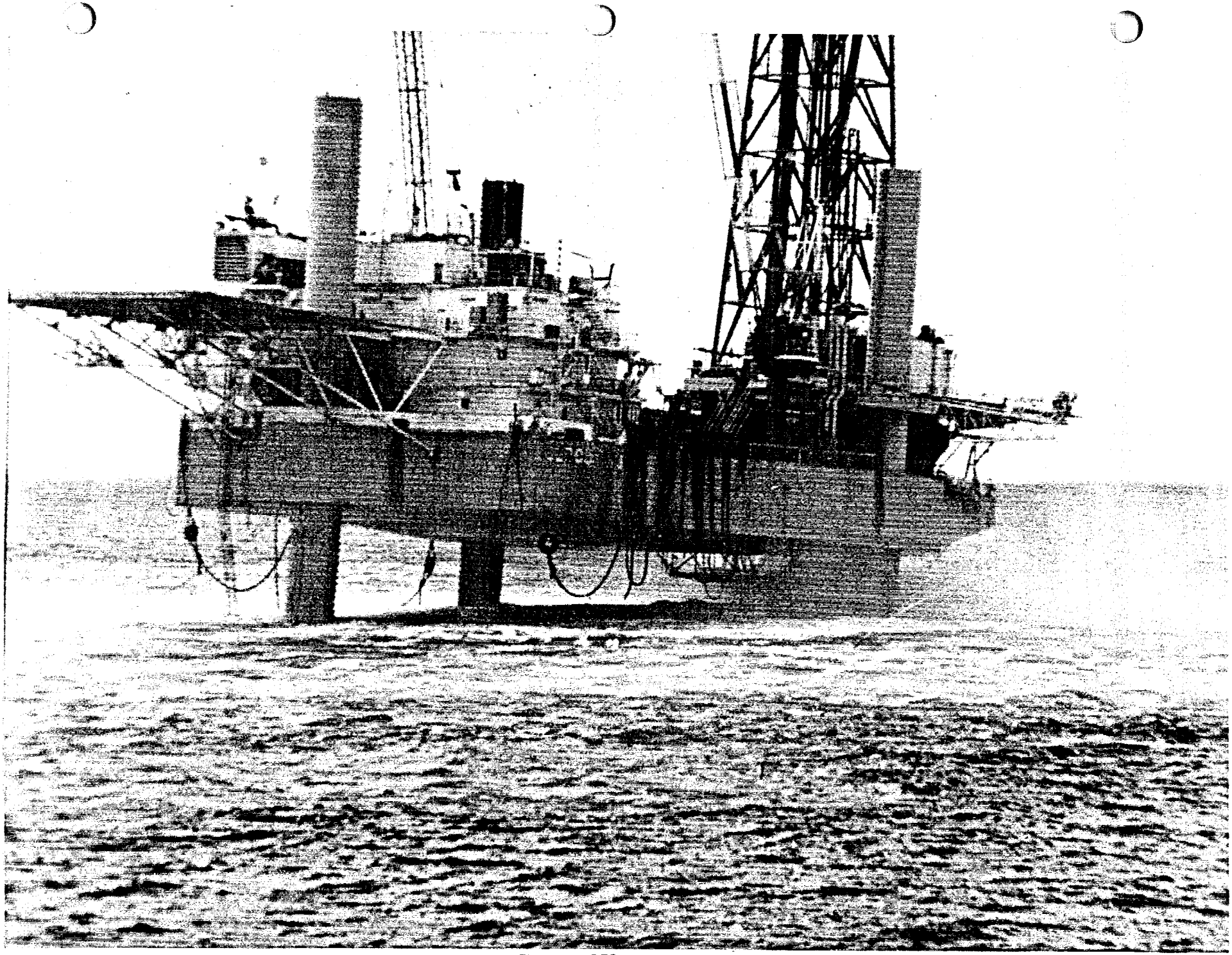

MAXIMUM MUD WEIGHT THAT CAN BE CIRCULATED THROUGH RISER
AIR GAP (AG)
WATER DEPTH (W)
P
DEPTH
MUD GRADIENT (MW)
SEAWATER GRADIENT (SW)
OVERBURDEN GRADIENT (OB)
BALANCING PRESSURES AT PENETRATION P BELOW THE MUDLINE
(W.SW) + (P.OB) = MW (AG + W + P)
MW = (W*SW + P*OB) / (AG + W + P)
PRESSURE

FIGURE 5

PRESSURE DIFFERENTIAL BETWEEN PILOT HOLE NO.2 AND FINAL LOCATION

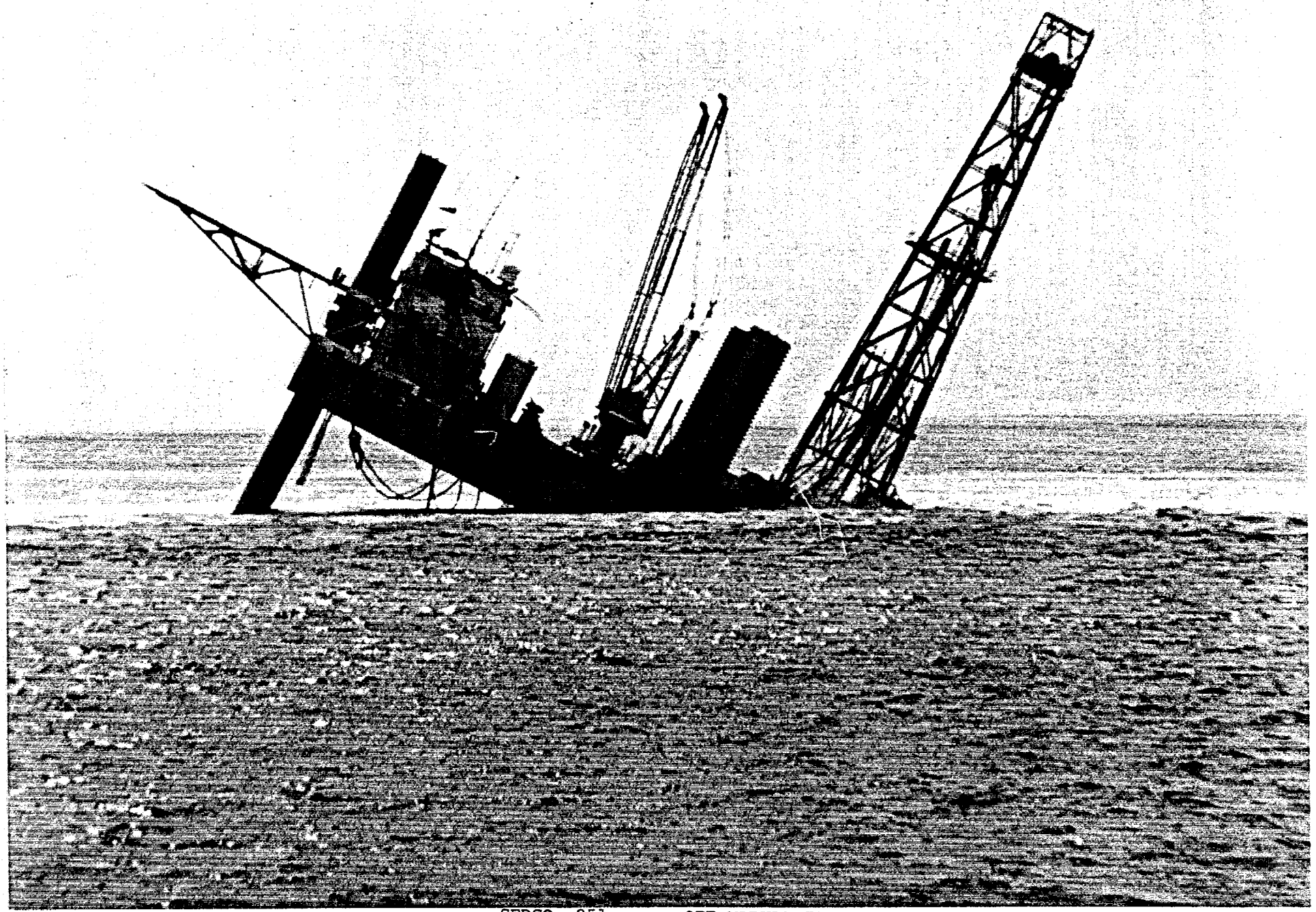


JMPRESS/8/09/89



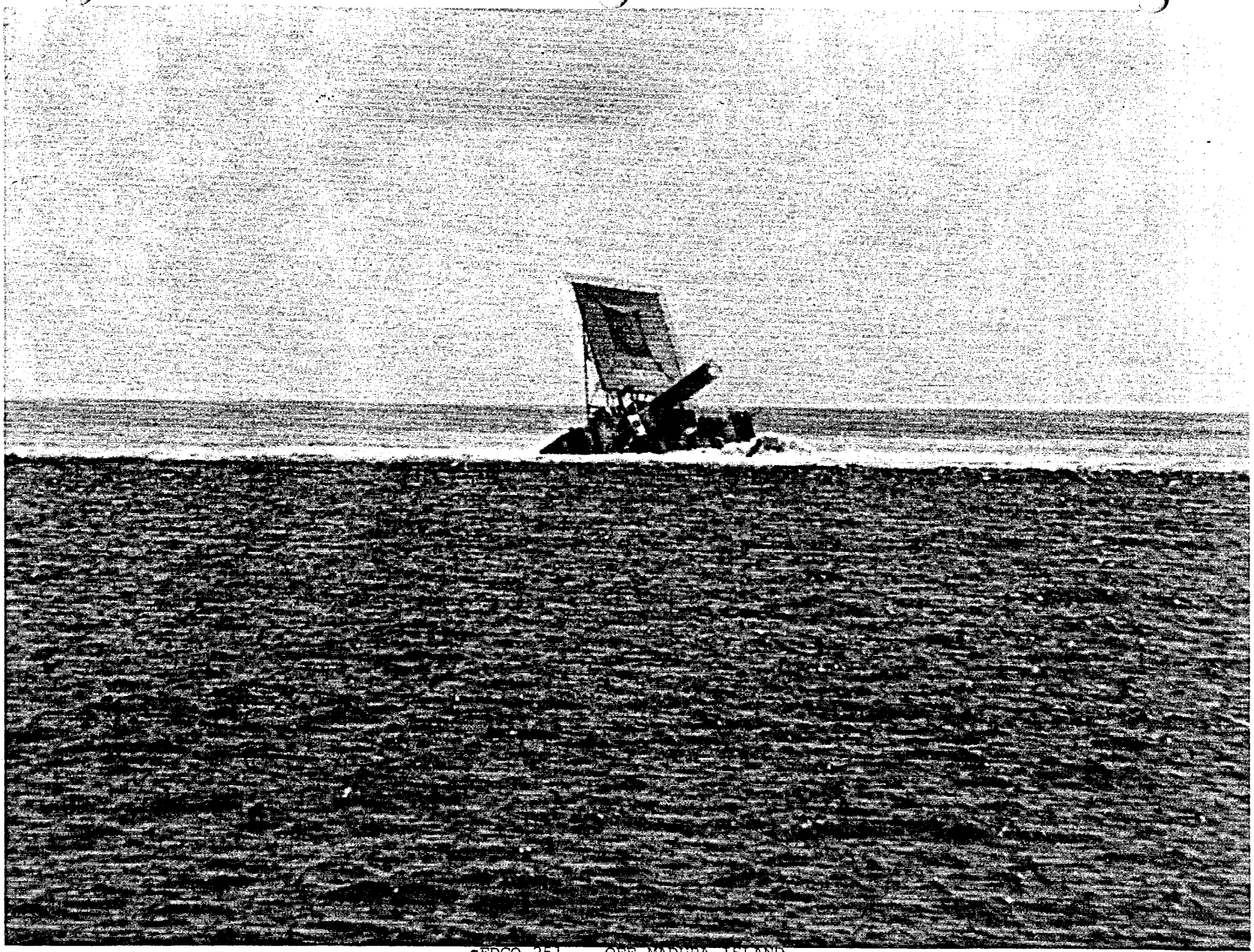
SEDCO 251 OFF MADURA ISLAND

PHOTOS BY GEOFFREY SMITH



SEDCO 251 OFF MADURA ISLAND

PHOTOS BY GEOFFREY SMITH



SEDCO 251 OFF MADURA ISLAND
PHOTOS BY GEOFFREY SMITH

Mearsk Venturer - Pilot Hole No. 1
Three minutes after flow started.

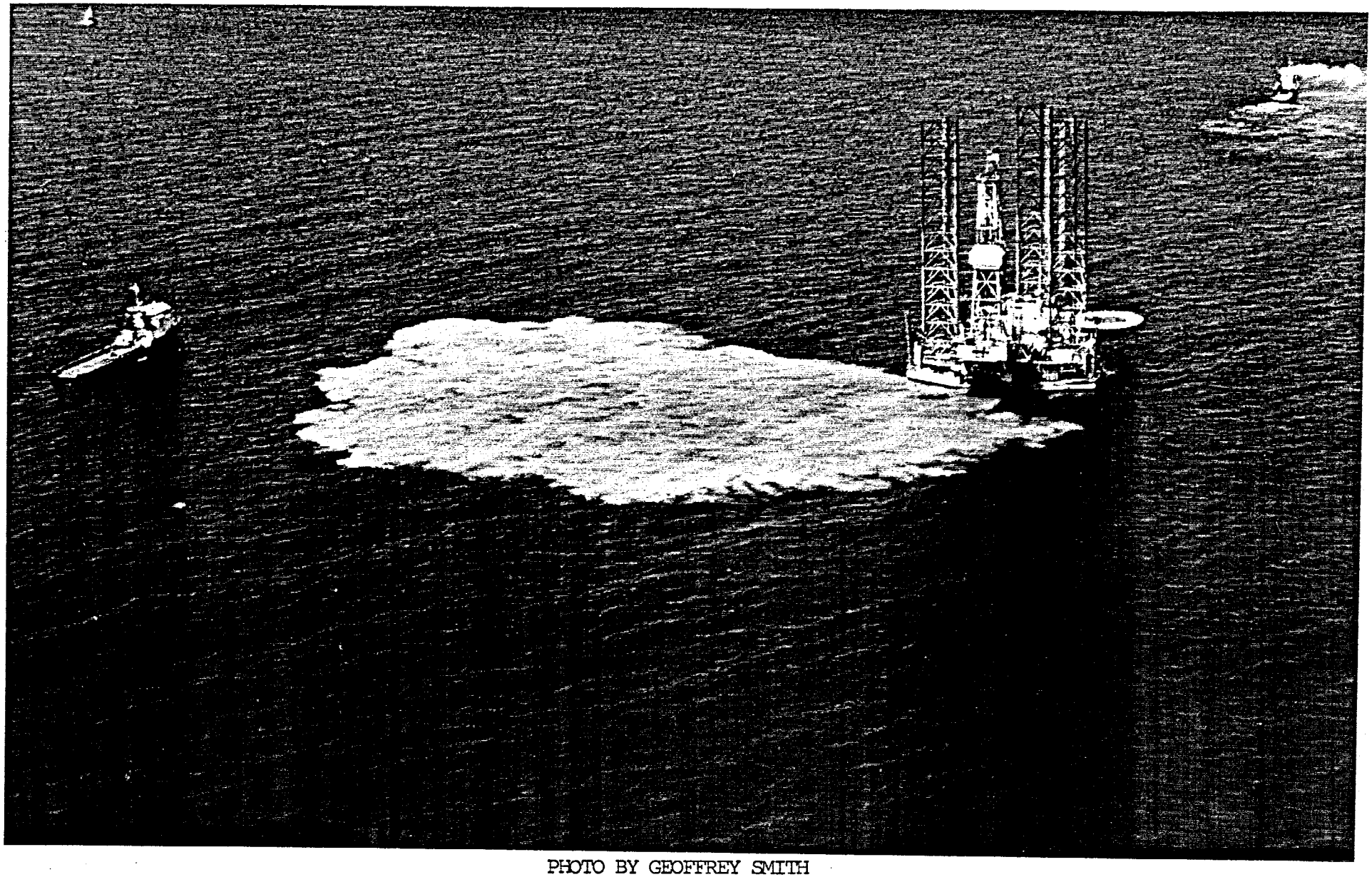


PHOTO BY GEOFFREY SMITH
OF
P.T. PACIFIC GEOMAR

Title: Inspection & testing of Subsea Well Control Equipment

Submitted by: Michael E. Montgomery,
WEST Hou, Inc.

The vast majority of downtime on a floating drilling rig, with the exception of weather, is generally attributed to subsea well control equipment. If proper inspection, maintenance and testing is preformed this downtime can be virtually eliminated, with the added benefit of improved safety.

Inspection of Equipment:

This is probably the most difficult aspect of the subsea engineers job. Almost anyone can repair a piece of equipment after it is broken but it takes a skilled technician to evaluate unusual wear or operational characteristics and implement a repair before a failure occurs. Consider what data base the subsea engineer has to work with. He has his own past experiences and the manufactures operations and maintenance manuals. Most manufactures publications only provide exploded views, part numbers and assembly/disassembly procedures.

The transfer of knowledge to offshore personnel is extremely limited. The subsea engineer offshore on his little island is isolated and not kept informed, often even within his own company, of equipment failures which are apt to affect him. Nobody likes to admit they have problems and consequently they are seldom documented and circulated for other people to learn from. The distribution and frequencies of

manufactures engineering bulletins is also poor. These can be a good learning tool if they are circulated to the correct people, the man offshore using the equipment. Manufacturers also have a difficult time releasing known equipment problems & the modifications required to the public. They realize that this information may effect future sales & that customers may expect the manufacturer to upgrade existing equipment at there expense.

Inspection & Maintenance of Equipment:

Testing & maintenance of equipment between wells should be written and maintained to a realistic level. When additional projects arise between wells, such as changing a wellhead connector or overhauling an annular or failsafe valve, it is prudent to review the work accomplished to assure an acceptable amount of maintenance and testing has been completed prior to running the stack.

Using the correct procedures for testing the stack prior to running will detect problems which will normally not be known. Examples are:

1. Ram type BOP's should be wellbore tested without closing pressure on the close side of the ram operating piston, using only the locking system to maintain adequate packer pressure around the pipe. This simulates rams closed on pipe with the LMRP disconnected as in the case of inclement weather. When testing rams at low pressure as specified in API RP-53 using this procedure, ram cavity wear can be immediately evaluated without taking any measurements. The ram locking system is also tested at the same time.

2. Before the stack goes in the water, test the failsafe valves from the top. This test is done at the riser adaptor and an abundance of connections, such as stabs between the LMRP and BOP, and all connections below the stabs to the failsafe valves are tested at once. Both the kill and choke lines can be done in one test. A maximum of 2 tests are required even if 6 failsafe valves are in use. If 4 choke valves are in use, testing the upper two valves from the top is necessary for well control purposes.

3. While pressure testing should the technician be a safe distance away (at the chart recorder drinking coffee) or climbing around the stack checking end connections, side outlets and weep holes for leaks? Weep holes are seldom discussed but all ram and annular manufactures use them to allow wellbore pressure to vent to the atmosphere if certain wellbore seals fail in their pressure containment role. These weepholes prevent wellbore fluid from entering the opening operating chamber of the equipment. Some manufactures do not show weep hole locations in their operations and maintenance manuals.

4. What is an acceptable pressure test? New equipment in the manufactures facility can be governed by API Specification 16A. Section VI states acceptance criteria for rams at rated working pressure as -100 psi in 3 minutes. Low pressure testing is accomplished at 200 psi with -10 psi over 3 minutes as acceptance criteria. Ten minute tests are common at high pressure & decline rates in the order of 300 psi should be considered excessive even in the field testing existing equipment.

API RP-53 is used to test existing equipment in the field. This recommended practice says the duration of wellbore testing should be 3 minutes and provides no acceptance criteria, only "check for leaks". Most chart recorders use 3 hours per rotation. Three minutes does not give time for the pressure to stabilize or provide an acceptable line to use as a permanent record.

Analysis of Events Leading to an Offshore Shallow Gas Blowout by History Matching Field Data Using an Advanced Gas Kick Simulator

by
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Pal Skalle, University of Trondheim
An-Ping Yang, University of Texas at Austin

Paper Presented at the INTERNATIONAL WELL CONTROL SYMPOSIUM, Baton Rouge, Louisiana, November 27-29, 1989

ABSTRACT

This paper describes the study and analysis of events leading to the West Vanguard shallow gas blowout that took place in the North Sea. The complete data set corresponds to the operations prior to the blowout. MWD data, mud logging data etc. obtained from the Royal Investigating Commission, was analyzed in detail and was used as input data to a computer - based gas kick simulator. Various scenarios of operator response to the events were then simulated to study possible means to have avoided the blowout.

Results indicate that use of the simulator was instrumental in understanding the proper sequence of events leading to the blowout. Having matched the observed well behavior the simulation indicated that a number of alternative procedures could have eliminated or reduced the risk of total loss of well control. In particular this study raises a serious question as to the advisability of routinely checking for flow after drilling breaks occurring at shallow depth, since this procedure will greatly increase the gas concentration in the wellbore and subsequently lead to increased rates of gas influx resulting in a non-controllable situation. The paper shows that it is possible to use a kick simulator to duplicate the events and data recorded in a real life blowout. This points to the potential usefulness of simulators in planning and analyzing of drilling operations especially in the development of alternative procedures for improved safety.

INTRODUCTION

Sunday the 6th of October 1985 at 11 pm a shallow gas blowout occurred on the semisubmersible West Vanguard while drilling an exploratory well on Haltenbanken northwest of Trondheim, Norway, 120 km off the coast in the North Sea. A drilling platform is a huge and a complicated system, and contains a lot of special equipment for deep water drilling. Likewise the operation itself is a complex working operation, and it is vital for similar operations in the future to understand what could have been done to prevent the blowout. The uniqueness and importance of this blowout is that so much information was recovered in spite of the vast destruction during the gas explosion and subsequent fire. Also a detailed investigation and analysis of the events was undertaken by various regulatory agencies and the findings published[1] thus making available to the oil industry an invaluable set of data.

One of the most important uses of computer-based simulation is to study real life events to analyze them repeatedly in order to understand their causes and the effect of various modes of human interaction with the system being studied. This is particularly so in the case of blowouts, where much depends on the action of the operator during the development of a potentially catastrophic situation.

The methodology used in this analysis of the West Vanguard blowout can equally be applied to analysis of past events or to the critical evaluation of drilling programs for new wells.

DESCRIPTION OF THE OPERATIONS LEADING UP TO THE BLOWOUT

To be able to discuss different scenarios, it is necessary to briefly describe both the rig and the drilling operations before the occurrence of the blowout. The necessary parts in such a description includes:

1. Shallow gas.
2. The platform and its potentially unsafe equipment.
3. Actual sequence of events.

1. Shallow Gas

Shallow gas has often been encountered in the North Sea (reported 20 times until 1982)[1] and so far three blowouts have been reported. Shallow gas is a serious operational problem, and is associated with gas in shallow formations which are drilled before the 20" casing is set. Gas is generally encountered in thin sand layers, from a few up to 15 feet thick, which are very unconsolidated and exhibit high porosity and permeability.

The pressure at the bottom of these layers is equal to the normal hydrostatic head in the area, while the fracture strength of the formations can probably not resist much excess pressure. This low strength makes it impossible to shut in the well in case of a kick, and consequently BOPs are not installed. Well control is taken care of by adequate mud weight. In the case of a kick, formation fluids are diverted away from the drill floor and overboard through the surface diverter system while simultaneously pumping heavier mud at high rate through the drill pipe to regain control of reservoir pressure.

2. The Platform and its Potential Weaknesses.

West Vanguard is a semisubmersible drilling platform of type Bingo 3000, see Figure 1, with a maximum crew capacity of 100. It was built by Trosvik Verksted A/S in 1982. The platform floats on two pontoons which are 10.5m (34.5 ft) in diameter by 100 m (328 ft) in length. The distance from the bottom of the pontoons to the main deck is 36.0 m (118 ft). The deepest position of the pontoons during drilling is 23.5 m (77 ft). Mean water depth at the drill site was 221 m (725 ft) and planned total drilling depth for the well was 4150 m (13,616 ft) During the time of interest the mean wave height was 1 m (3 ft). Sea and air temperature were both 9° C. Well 6407/2 was the 31st well to be drilled on Haltenbanken, and the closest well was well 6407/1 - 12 km away. The state-owned oil company Statoil was the operator with Smedvig Drilling Co. as contractor.

The most critical pieces of equipment and equipment systems which were involved and, as pointed out by the Investigating Commission, partly caused the serious problems were:

- drill string
- gas diverter system and marine riser
- wellhead - riser connection
- instrumentation for mud parameters

Each will be discussed briefly.

Drill String

While drilling at the critical depth (500 m or 1641 ft) the drill string was of standard type. As seen from the details of the drill string in Table 1, the MWD unit was installed just above the bit, its sensors being situated at a level approximately 3 m above the bit. The bit nozzles (3 x 13/32" and 1 x 14/32") were judged by the Commission to be much too small for drilling the top hole. During killing attempts the pump reached its maximum rated pressure at a flow rate of only 3100

l/min (819 GPM), when its capacity was 5100 l/min (1 347 GPM) (with the 7" liner installed). Another questionable practice was the use of the stabilizer since it increased the danger of swabbing during tripping.

Marine Riser

After having set the 30" casing, a standard type riser was installed. Details are presented in Table 2. Function tests during installation were successful. After the blowout the pneumatic line leading to the upper packer of the slip joint was found to be plugged. This led to slow closing of the packer allowing mud and gas to come out between the outer and inner slip joint pipes (until the lower slip joint packer was closed). Neither the packer nor the pipe were damaged, but this allowed gas to enter the platform area.

According to eye witnesses, the wellhead mechanism was also seen to act slowly and failed to disconnect the riser quickly. No functional or mechanical faults were later found in the mechanism. However, subsequent calculations indicated that very high frictional forces were present in the wellhead lock pins, and this was the probable cause of the slow disconnection.

The position of the wellhead release control panel on the reel of the guidelines - in the cellar deck - was an extremely remote and, due to the mentioned slip joint leakage, also a dangerous location. Several other rigs have a similar arrangement of equipment and the recommendation was made to modify this design.

Diverter

The diverter system installed on this platform was regarded to be among the best available, and its details are shown in Table 2 and Figure 2. Although a gas kick had not been previously encountered, the system was routinely tested with seawater.

Detailed studies made after the blowout showed, however, that the diverter system was not adequate for diverting gas containing sand from the formation. In particular the following was found:

- The inner pipe in the diverter housing was mounted so that the mouth was not lined up with the diverter return line, which adversely influenced the flow behavior and the erosion pattern at this point.

- The diverter flowline was inadequately designed from the fluid mechanics standpoint, especially with regards to bends and connections. Even at low gas rates local loads (pressure and velocity) would be near the erosion threshold limits. With sand in addition, these areas of the pipe were most likely to erode. Pipe wall thickness was 10 mm (0.4 in), while pipe bends were 21 mm (0.83 in) internally upset. This sharp cross-sectional reduction created sudden changes in velocity and pressure and accordingly higher loads.

- Ball valve A in Figure 2, was not successfully opened and was the most probable cause of the erosion hole in the successive pipe bend B.

- Ball valve C in the return mud flow line was also not completely shut,.allowing gas to flow into the shale shaker room. Later studies showed that neither the ball valve nor the actuator exhibited any failures, but the actuator was undersized for the high frictional forces in the ball valve .

Although the diverter system on board West Vanguard was among the best available, it suffered serious deficiencies. Modifications of these standard designs would result in some imporvements. There is some question, however, whether even the re-designed diverter would safisfy the objective of controlling shallow gas kicks due to the high velocity and erosive forces encountered in these cases.

Recording of Operational Data.

The following service companies involved in the operation and data-acquisition were :

Mud logging:	Norsk Petroleum Serveices A/S
Mud services:	Promud A/S
MWD:	Exlog Norge A/S
Formation logging:	Schlumberger Inland Services Inc.

The rig was well equipped with surface instruments to register drilling parameters . The most important were:

- mud density in and out
- gas content in the mud
- mud pit level
- return mud flow rate
- mud pump rate and pressure
- hook load and weight on bit
- rotary speed of bit
- drill string torque
- kelly height

Actual data records are shown in Figures 3 and 4. In addition gamma ray and resistivity logs were available through MWD, these data with surface readout are also presented in Figure 5.

As a result of a fault in the data acquisition system, the drilling depth and the drilling rate in Figure 5 had to be typed in manually, based on NPD's data. Also the return-mud density meter did not function properly, and a manual pressurized mud balance was used to keep track of mud weight. These data were fed manually into the NPD's data acquisition system and presented on the monitor on the drill floor

Because of this, the effect of gas in the returning mud was totally masked.The gas cut readings were disregarded and were not trusted because the environment to which mud instrumentation are exposed causes frequent failures and varying accuracy. The general trust in these instruments has been demolished during years of questionable performance.

Actual Sequence of Events

Until 9 pm the 6th of Oct. 1985 the operation was running normally. 30" casing was set and cemented at 75 m below sea bottom and the diverter/riser was installed. The plan was now to drill a pilot hole with the 12 1/4" bit down to 1235 m below RKB, enlarge the hole with a 26" bit and set the 20" casing and BOP on the ocean floor. The critical well control operation occurred during pilot hole drilling from a depth of 500 m and down to 523 m below RKB from which depth the blowout came.

Drilling proceeded normally until a drilling break was observed at 523. This was followed by a complete circulation period during which moderate gas cutting was observed. After resuming drilling, additional gas cutting was experienced and eventually a large flow developed while making a connection. The diverter was activated but a failure of the relief lines resulted in leakage of gas which caused an explosion. The drilling and wellbore situation is shown in Figure 6 and a detailed timed sequence of events is presented in table 3.

One man lost his life during the blowout, probably during the gas explosion. The Commission concluded that the leading drilling personnel on board did not take the kick warning signals seriously enough, and continued drilling after the drilling break at 506 m without further investigation. Further investigation should have been made when the gas content reached 530 units and additional control measures undertaken.

Other points which according to the Commission warrant more detailed study and/or improvement include :

Study of formation fracture mechanism in shallow formations

Study the drilling crew's mistrust of the instrumentation and data presentation, especially the gas log readings.

Undertake better education on shallow gas problems and procedures

Develop better instrumentation to improve mass balance checks and monitor changes of critical data.

The mud weight was held on the lowest minimum level, 1.08 sp.gr., due to the fear of breaking the formation. This fear was amplified by the thought that loss of some mud was taking place. However, as shown later, the most likely way to prevent this blowout from occurring, was to increase the mud weight early in the procedure.

SIMULATION

Computer Model

The principal characteristic of the computer model[2] used in this study is that it is capable of describing the correct distribution of fluids in the wellbore whenever a gas kick is experienced and during the subsequent well control operations instead of lumping the gas into a single section of the wellbore.

The model also accounts for multiple kicks which may develop during drilling and/or well control activities.

The wellbore geometry is considered realistically which is important in this case due to the large change in wellbore diameter at the casing/conductor/riser interfaces.

The model is a relatively recent development and as such it has not been tested extensively. However it yields realistic results and the calculated pressures and pit level profiles agree with those of a published experimental test.[3] Although the simulator was designed to run on a PC, all calculations for this study were undertaken on a Cyber 170/175 computer system to take advantage of its graphics output capability.

Data Set

The data required for the simulation consists of the physical properties of the fluids, the geometry of the wellbore and drillstring systems, the properties of the formation, and the sequence of events and values of operational parameters as a function in time. Most of these parameters have some degree of uncertainty with the formation parameters generally being unknown.

In this particular case the data is unusually complete since the drilling operation was being monitored closely at the surface and at the bottom with a MWD (Measurements While Drilling) system which besides rate of penetration yielded a Gamma Ray/Resistivity Log. The data were studied carefully especially over the section corresponding to drilling from 496 m.(1627 ft) to 523 m.(1716 ft) or correspondingly from 20:30 to 23:15 hours.

With regard to computer simulation of a kick it is important to insure that the operational parameters, the progress of the drilling operation and the sequence of events are properly coordinated. To achieve this, the time period was subdivided into short intervals over which the operational parameters were assumed to be constant. Table 4 summarizes the sequence of events and the operational parameters used for the computer simulation.

Although this data set is not an exact replica of the actual field experience, it is capable of reproducing the phasing of events with changes in pumping rate and drilled depth within plus or minus 20 seconds of the recorded data. The values of rate of penetration had to be adjusted from the average values recorded in the MWD report in order to achieve the correct phasing with the drilled depth. For kick simulation the correct timing of transitions in pumping rate are more important than the exact replication of depth so that more weight was given to replicating the

pumping rate as a function of time. This was undertaken using the pump flow and pressure and kelly height record as a function of time (Figures 3 and 4) since these have a clearer time scale than the other records.

It should be noted that pipe reciprocation which took place during the circulation periods (21:01 to 21:38 and 22:12 to 22:46) was not considered in the simulation. The pipe velocity was calculated to be within normal operational guidelines and not likely to cause significant pressure surges due to the low viscosity of the mud and annular clearance.

The wellbore geometry, fluid properties, BHA configuration etc., are clearly described in the given data and were used to generate the well configuration for the simulation. The most uncertain data corresponds to the formation properties. Given the Gamma Ray log it was possible to determine the approximate depth and thickness of the formation from where the gas kick probably originated. The values used in the simulation were formation top at 1657 feet (505.2 m) bottom at 1667 feet (508.2 m). These values were selected to coordinate the operational events with the drilling record.

The formation pressure was considered to be very close to the mud gradient in the annulus in view of the gas shows which were observed during the drilling of the 466 to 502 m (1529 - 1647 ft) sections. These gas shows could be attributed partly to drilled gas and partly to connection gas coming from the sand at 476-480 m.(1562 - 1575 ft). Initial estimate of formation pressure was 10 ppg (1.2 SG) equivalent. This proved to be excessive as shown in the next section of the report.

Given the unconsolidated nature of the sediments and the shaley nature of the sand the permeability was initially estimated to be of the order of 50 to 100 md. This was also shown to be excessive by the subsequent simulation. It must be noted that it is the combination of permeability and underbalance that controls the rate of gas flow into the wellbore. Similar behavior can be expected for high permeability and low underbalance as for low permeability and high underbalance.

Given the shallow nature of the wellbore an additional factor that was uncertain is the fracture gradient from the casing shoe to the bottom. This was initially estimated to be 12 ppg (1.44 SG) equivalent based on typical values for offshore continental shelves.

It must be stressed that since the problem of matching the observed kick and well control operations involves many variables for which values are unknown or uncertain there are numerous combinations that can give similar results. However, it is believed that the conclusions reached as a result of the simulation study have a high probability of being accurate.

Simulation Strategy.

Over 100 simulation runs were made in the course of this study in order to achieve a reasonable match between the observed and simulated cases.

The initial data set used at the beginning of the study had to be modified before the simulation yielded results similar to the actual records.

The principal parameters used in matching results of the simulation, once the depth of penetration and pump rate changes were replicated, were the active pit level variations and the gas shows in the mud gas record.

The strategy was to (A) simulate different probable situations like lost circulation, permeability variation, single gas slug, high pressure zone, etc. When the most likely situation was established then (B) the parameters were varied until a reasonable match was obtained. Finally alternative modes of control were studied for the best matching case.

Preliminary Study of Probable Situations and History Matching.

At the beginning of the study, efforts were directed to obtaining a moderate gas show at about 21:22 hours (3100 seconds from beginning of simulation) followed by additional gas influx and rapid pit rise at 22:54 hours. After 14 runs a reasonable match was achieved for the initial show using a gas pressure of 9.308 ppg equivalent and a permeability of 10 md. This is shown in Figure 7 (Note the scale for pit gain is 0 to 8 bbls which exaggerates the variation of pit level.). Increasing the gas pressure to 9.33 ppg causes a large pit gain and an early blowout.

These preliminary runs indicated that it would be difficult to simulate the essentially constant pit level during the second circulation while a large gas show was recorded during the same time. A sensitivity study was thus undertaken to study the effect of increasing permeability and introducing lost circulation.

Permeability Variation

Permeability was increased gradually while decreasing the gas formation pressure. It was observed that for a gas pressure of 9.25 ppg, (0.09 ppg underbalance) the permeability could be increased to 899.1 md without losing control of the well (Figure 8). Increasing permeability further to 899.3 caused a large pit level increase and an early blowout (Figure 9). Further adjustments of these variables probably would have resulted in values that could have replicated the actual data better. However, sharp variations in gas cut were observed for the high permeability runs (up to 40% for the first show) and these did not correspond with the observed moderate gas shows. It was felt that using the lower permeability would result in more stable simulations and produce the desired gas cut levels. All further work was thus done using permeability in the 10 to 20 md range.

Effect of Lost Circulation

The pit level variations recorded in the field indicate the possibility that lost circulation was a factor to be considered. In particular the data indicate a decrease in the pit level during the second gas show and what appears to be a significant decrease in pit level after the drilling break.

For these reasons the influence of lost circulation on the results of the kick simulation was investigated for the following cases:

Case 1 -Lost circulation at time of drilling break, of 25 Bbls (4 cu.m.)

Case 2 -Lost circulation at time of drilling break, 25 Bbls (4 cu. m) and lost circulation at time of next connection (21:51 hrs) of 20 bbl (3.2 cu. m)

Case 3 -Constant rate of lost circulation of 50 Bbls/hour (8 cu.m./hour) after the connection at 21:51 and continuing till the end.

One effect of lost circulation was to aggravate the gas influx and cause additional reduction in wellbore pressure, either due to a reduction of the annular fluid level or a reduction of the annular flow rate and frictional back pressure.

The results of the runs are summarized in Table 5, which compares the well conditions at the time of the last connection at 22:54-22:57 hours. The parameters that are tabulated are the change in pit level, the flow rate and gas cut of the fluid flowing from the wellbore, if any. Under normal conditions without a gas kick in the wellbore all these parameters should, at this time, be close to zero since the pump is stopped for the connection and the pit level would be stable. The base case corresponds to a formation pore pressure of 9.3 ppg and a permeability of 10 Md. for the gas zone. Further increasing the

permeability to 14 mD causes a large pit level increase and the well to blow out.

Results for Case 2 are shown in Figures 11 and 12. Both of the above cases eventually result in blowouts. Note that there is a definite continuously increasing trend of the pit level. This does not agree with the actual observed decrease of pit level between 22:00 and 22:54 hours, with only an increase at the end of this period as shown in the active pit record.

Figure 13 shows that for Case 3 the pit level decreases during the time of interest (between 5000 and 9000 seconds) reversing this trend and increasing at the end. This is similar to the observed pit record although the change is about twice that observed. Adjusting permeability results in a pit level profile similar to that observed in the field case as shown in Figures 14 and 15.

In all these calculations it was considered that the point of lost circulation was in the vicinity of the casing shoe. Since there is no basis other than it should be the point of lowest fracture gradient additional runs were made changing the point of lost circulation to correspond to the zone in the vicinity of the drilling break at 1560 feet (475 m.). This did not change the results appreciably. Therefore only lost circulation at the casing shoe was considered in further simulations.

In summary, with regard to lost circulation it may be concluded that the observed active pit behavior in the real well is better approximated by including in the simulation the continuous occurrence of lost circulation at a small rate, rather than the occurrence of lost circulation at one or two points in time.

Further trial and error resulted in selecting the case for constant lost circulation and a permeability of 17 md with a formation gas pressure of 9.308 ppg as the case yielding the best pit level and gas show match. This case is presented in Figure 15.

Single Gas Slug Case

The following addresses the possible scenario of a single gas slug entering the wellbore at the time of a connection. The gas influx is assumed to be due to swabbing caused by the presence of a stabilizer which restricts the annular area and is located in the vicinity of the gas sand when drilling is stopped and the drill string is raised.

Pipe movement is considered to be approximately 10 meters. The particular wellbore/drill collar combination corresponds to an annular volume of 0.09 Bbls/ft so that the displaced volume is approximately 3 Bbls.

It is necessary to keep in mind that it would be of no interest to simulate the case where this gas slug is the only gas present in the wellbore. The mud-gas record from the well shows that there are multiple gas shows, with the last one having a significant magnitude and occurring for several minutes prior to the connection. This gas must have entered the wellbore sometime during the previous drilling operations. Therefore, for the simulation of swabbed gas, the well was first drilled to the connection point with enough underbalance to allow some gas into the well but not enough to cause the large kick that was observed later. This case is shown in Figure 16 which represents the following conditions:

Gas formation pressure = 9.308 ppg
Mud Weight = 9.16 ppg
Gas formation permeability = 10 md

This yields a situation where there is a minor gas show which is essentially completely circulated out at the time of the connection.

For the gas slug case the well was re-drilled as previously but during the connection 3.3 Bbls of gas (10 meters of the annulus) are allowed to enter the wellbore at the depth of the gas sand. This results in a corresponding pit gain, after

which the pumps are started and circulation initiated. This case is shown in Figure 17.

As can be seen it takes approximately 1200 seconds for the gas slug to reach the surface at which time there is a rapid increase of the pit level and the gas cut increases from zero to 82% in about 30 seconds. This is in disagreement with the actual well record where the sharp pit gain takes place almost simultaneously with the stopping of the pumps at the beginning of the connection with gas already flowing from the well. This gas flowing from the well with mud at the time of the connection must have entered the well at least 15 to 20 minutes earlier.. This corresponds approximately to the bottoms-up time including a factor to account for gas migration. It should not be forgotten that although the well is shallow there is a significant annular volume which has to be displaced before formation fluids can flow at the surface.

The simulation thus indicates that gas swabbing was not a likely scenario for the observed events.

Drilling Into a High Pressure Sand

This addresses the possibility that during the last drilling sequence the bit penetrated a high pressure gas sand so that gas rapidly entered the wellbore and almost immediately flowed to the surface.

In order to generate some gas cut in the mud prior to drilling into the gas sand, as experienced in the real case, but without causing a blowout the formation pressure in the upper sand was reduced to 9.25 ppg. Figure 18 shows this base case which also includes the constant lost circulation effect. Figure 19 corresponds to the case where the high pressure gas sand is drilled into at 8436 seconds (22:51 hours). Almost immediately a pit level increase can be noticed which steadily continues through the connection and rises to over 200 bbls by the time the gas reaches the surface at 9454 seconds (23:10 hours).

These results, once again, do not agree with the field observation of the gas reaching the surface at the beginning of the connection and the pit level rising sharply.

Simulation of Different Control Strategies

This section addresses the effect of introducing, at some point during the simulation, a heavier drilling fluid into the wellbore so as to try to regain hydrostatic control of the well.

The Commission report indicates that kill mud of 10.25 ppg (1.23 SG) was available on the rig. Two situations were considered initially:

a) Kill mud circulation started immediately after the drilling break (21:00 hours)
b) Kill mud circulation started during the second circulation period (22:18 hours).

The base case studied was that shown in Figure 15 for continuous lost circulation, 17 md permeability and gas formation pressure of 9.308 ppg. As can be seen in Figures 20 and 21, in both instances it is possible to regain control of the well. By circulating the kill mud immediately after the drilling break, only one gas show is observed which corresponds to the gas entry at the time of the drilling break. When starting the kill mud at the later time the subsequent gas shows decrease in magnitude and disappear by the end of the simulation. Note that in both instances there is a continuous decrease in the pit level. This corresponds to the lost circulation effect. The rate of lost circulation was not changed from the previous simulation although in reality it would be affected by the increased mud weight.

Additional simulations were undertaken to establish the latest possible time when starting the kill mud circulation would still result in regaining well control. Figure 22 shows that by starting the kill mud at 8200 seconds (22:47 hours) although there is a significant gas show, the percentage of gas decreases towards the end of the

simulation. On the other hand starting the kill mud at 9100 seconds (23:02) does not have sufficient controlling effect and a pit gain of over 100 bbl is experienced as shown in Figure 23, with subsequent blowout.

From the above it can be concluded that circulation of higher density drilling fluid would cause sufficient increase in bottomhole pressure to reduce the gas influx to the point that hydrostatic control is regained. By introducing the heavier mud early in the simulation it would be possible to regain control with a lower density mud than the 10.25 used in the study, for example 9.5 ppg should be adequate although it would take a longer circulation time to reduce the gas influx to zero.

Conclusions

The detailed study of the available data and drilling records and the results of the computer simulation study indicate that the following conclusions are warranted:

1-The gas kick was probably caused by drilling slightly underbalanced into a porous and permeable zone (or zones in near proximity) at about 21:00 hours. The level of underbalance was probably of the order of 0.15 ppg (0.018SG) coupled with a permeability of the gas zone of about 17 md.

2-Continued operations involving: two circulations "bottoms-up" and the drilling of two more joints from 21:00 to 22:52 hours, without increasing the mud weight, resulted in additional entry of gas into the wellbore. Gas influx into the well accelerated during the times when circulation was stopped due to the reduction in bottomhole pressure through elimination of frictional back pressure. Gas influx also occurred during circulation whenever the gas in the wellbore reached the surface and expanded causing a decrease in bottomhole pressure.

3-The succession of gas influxes eventually caused enough reduction in bottomhole pressure so that a continuous influx of gas from the formation was established. This occurred at approximately the same time when mud, gas cut to 80-90%, reached the surface causing a rapid increase in pit volume.

4-The scenario described above also resulted in a continuously increasing pit level of about 10 bbls (1.6 cu.m.) during the first circulation (21:00 to 21:40) and of about 40 bbls (6.4 cu. m) during the second circulation (22:12 to 22:55). This is contrary to the observed active pit record which shows a constant or decreasing pit level during a portion of the second circulation.

5-Assuming that the active pit record is representative of the real events it was necessary to include the effects of lost circulation in the simulation. A constant rate of lost circulation, assumed to take place at the casing shoe, of about 45 bbls/hour (7 cu. m./hour) during the time of the second circulation, resulted in an offsetting of the pit level increase and duplicates better the observed active pit behavior.

6-Circulation of kill mud of a density of 10.25 ppg (1.23 SG) any time from after the drilling break (21:00 hours) until about the end of the second circulation (22:50 hours) resulted in reducing the underbalance to the point that it was possible to regain hydrostatic control of the well.

7-Circulation of kill mud after making the second connection (23:00 hours) would not result in sufficient increase of bottomhole pressure to prevent the continued gas flow into the well.

8-Conclusions 6 and 7 are also valid for the case where lost circulation is not present.

9-With or without lost circulation, the variations in pit level during most of the time in question (21:00 to 22:30) were relatively small (10 to 15 bbl) and consequently could easily go unobserved or could be masked by other activities

(addition of water to pits, vessel motions, etc.). Additional indicators such as accurate return flow monitoring would be required to improve the ability to detect abnormal conditions.

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Type of equipment	Length (m)
Roller bit, 12 1/4"	
Nozzels, 3*14/32", 1*13/32"	0.30
Nipple	0.91
MWD unit, 8" with one way valve	11.12
Monel collar, 8"	9.09
Stabilizer, 12 3/16"	1.77
13 drill collars, 8"	120.88
Cross over	0.52
5 jts, HW drill pipe, 5"	136.25
25 jts, drill pipe,5" grade G	237.50

Table 1. Drill string specification. Total length =518.34 m

Type of equipment	Manufacturer	Type
Diverter pipe: 12" ID w/ ball valve	BAC	NP DIN 3205 size ND 300
actuator	Superfos	BRC 032
Diverter house + packer	Reagan	KFDS-3
Ball valve	Reagan	DR1
Telescopic joint	Vetco	WJ 21"
Riser w/floating elements 20" ID	Vetco	21" MR-6C
Ball valve	Reagan	CRD-1, NOM. 24"
Connector	Cameron	Pin connector

Table 2 Specification of marine riser and diverter.

Table 3. Sequence of all events during the shallow gas blowout on Haltenbanken, 1985.

DEPTH	TIME	ACTIVITY
476.0 m	7.29 pm.	Drilling out one pipe length.
476.0 m	7.38	Connection. Background gsas 10 units. Continous pit gain of 5 m^3/hr. (addition of seawater).
	7.44	Drilling started.
	7.50	3 m^3 of mud / cuttings routinely dumped.
487.0 m	8.02	Connection. 50 gas units.
	8.09	Driling started.
496.0 m	8.23	Connection. 40 gas units.3 m^3 of mud dumped.
	8.31	Drill ahead.
505.2 m	8.48	Connection. 30 gas units. 3 m^3 mud and cuttingswere routinely dumped.
	8.56	Drilling started.
506.1 m	8.58	Drilling break; bit fell 2 - 3 m , probably sand zone. Stopped drilling, circulated while reciprocating the drill string .Gas concentration increased after 20 min. of circulation.
	9.35	Max gas units of 92.
	9.37	Gas unit 80. 3 m^3 dumped. Drilling commenced.
513.9 m	9.48	Stop for connection. Gas unit 30 but increasing. MWD confirms a gas sand at 506 m. Wellsite geologist confirms 25 % sand in cuttings from that depth.
	9.50	Pump shut off to add pipe.
	9.55	Pumps turned on. Shut off 2 more min during directional survey.
	10.05	Drilling started. 80 gas units; incresing trend.
517.0 m	10.09	Stop to circulate while reciprocating drill string, 160 gas units.
	10.18	Max gas units of 550. 50 % sand in cuttings.
		At 10.05 the addition of sea water was reduced from 10-15 m^3/hr to approx. 5 m3/hr. Between 10.05 and 10.41 mud was probably being lost.

Table 3. (Continued) Sequence of all events during the shallow gas blowout on Haltenbanken, 1985.

DEPTH	TIME	ACTIVITY
	10.41	80 gas units.Situation assumed stable. Drill ahead.
523.0 m	10.52	Add pipe (stop pump, lift drill string). 60 - 80 gas units.
	10.53	Well started to flow, which is normal (back-flow to pit).
	10.55	Flow continues, now exceeding the normal 4 m^3 back flow. Diverter activated.
	10.57	Pump heavy mud at 2300 psi.
	11.00	Pump rate increased, pressure rose to 3000 psi
	11.02	Evacuation orders given. Stand by boats move up to rig.
	11.10	A 40 m long horizontal jet of gas,sand and mud out through the diverter. Sound level as from several jet engines. Gasalso from slip joint.
	11.15	Man with oxygen mask initiated releasing of wellhead at cellar deck.
	11.20	Huge explosion. 4 anchors released.
	11.20	Lifeboat no. 2 with 30 persons aboard lowered.
	11.21	Lifeboat no. 1 with 45 persons aboard and 2 on roof lowered.
	11.25	Captain and stability chief swam away from platform.

Table 4 - Sequence of Events For Simulator Input

Real Time	Simul. time sec.	Depth m.	Depth. Ft.	ROP m/h	ROP ft/h	Pump l/m	Pump GPM	Activity
20.30	0	496	1627	0	0	0	0	Make connection
20.31	60	496	1627	0	0	1760	465	Start pumping
20.33	180	496	1627	60	197	2600	687	Start drilling
20.35	300			61	200	»	»	
20.38	480			52	170	»	»	
20.41	660			25	82	»	»	
20.44	840			18	59	»	»	
20.48	1080	502.5	1657	0	0	»	»	Make connection
20.52	1320	»	»	0	0	0	0	Stop pumping
20.55	1500	»	»	0	0	1760	465	Start pumping
20.57	1620	»	»	0	0	2600	687	
20.58	1680	»	»	45	148	»	»	Start drilling
21.00	1800	506.7	1662	480	1574	»	»	Drilling break
21.00	1860	508.3	1667	0	0	»	»	Stop drilling
								Circulate
21.38	4080	508.3	1667	40	131	»	»	Startdrilling
21.40	4200			48	157	»	»	
21.42	4320			20	66	»	»	
21.45	4500			35	115	»	»	
21.49	4740	514	1686	0	0	»	»	Stop drilling
21.51	4860	»	»	0	0	0	0	Stop pump
								Make connection
21.56	5160	515	1689	0	0	1200	317	Start pump
21.57	5220	»	»	0	0	1600	423	
21.58	5280	»	»	0	0	500	132	
21.59	5340	»	»	0	0	0	0	Stop pump
22.00	5400	»	»	0	0	1600	423	Start pump
22.01	5460	»	»	0	0	1600	423	Survey
22.02	5520	»	»	0	0	2600	687	
22.09	5940	»	»	10	33	»	»	Start drilling
22.12	6060	516	1692	0	0	»	»	Stop drilling
								Circulate
22.46	8140	»	»	27	89	»	»	Start drilling
22.52	8500			47	154	»	»	
22.54	8620	523	1715	0	0	»	»	Stop drilling
22.55	8680	»	»	0	0	0	0	Stop pumping
22.56	8740	»	»	0	0	0	0	Close diverter
23.00	8980	»	»	0	0	1300	344	Start pump
23.01	9040	»	»	0	0	2600	687	
23.02	9100	»	»	0	0	2800	740	
23.04	9220	»	»	0	0	3100	819	
23.15	9880	»	»	0	0	3100	819	End of records

Table 5 - Effect of Lost Circulation on Simulation

Case 1 – Single occurrence of lost circulation. Conditions at 22.55 hours.

	Pit Gain Bbls	Mud-gas Mixture Flowrate, GPM	Gas cut %
No Lost Circ. K = 10 md (Base case)	0.4	0	0
24 Bbls, Lost K = 10 md	6	20	28
24 Bbls, Lost K = 12 md	7	50–90	30–60

Further increasing the permeability to 14 Md causes a large pit level increase and the well to blowout.

Case 2 – Double occurrence of lost circulation. Conditions at 22.55 hours.

	Pit Gain Bbls	Mud-gas Mixture Flowrate, GPM	Gas cut %
24 Bbls lost, + 20 Bbls lost K = 10 md	57	400–1200	70–80
25 Bbls lost, + 21 Bbls lost K= 12 md	110	564–8400	80–85

Case 3 – Constant rate of lost circulation at casing shoe during second circulation (22.00 to 23.00). Conditions at 22.55 hours.

	Pit Gain Bbls	Mud-gas Mixture Flowrate, GPM	Gas cut %
50 Bbl/hr lost K = 10 Md	– 57	0	0
50 Bbl/hr lost K= 18 Md	– 40	90–360	50–85
50 Bbl/hr lost K = 19 Md	+ 5	200–930	50–80

Figure 1 - Scaled Model Of the West Vanguard

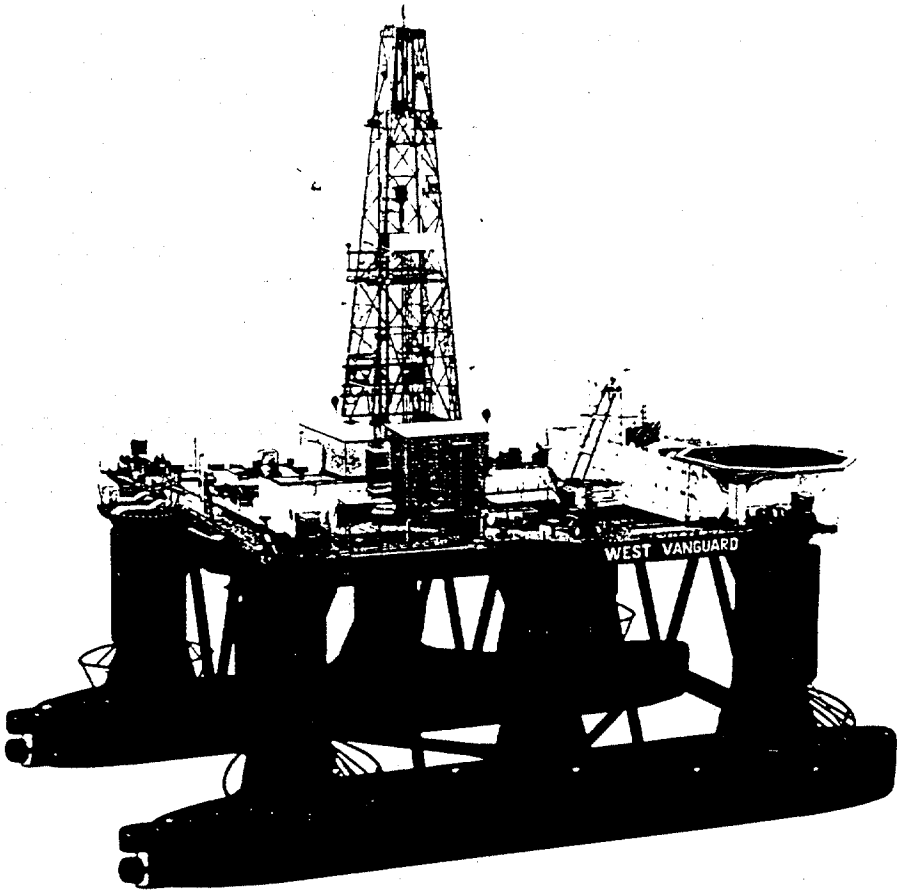


Figure 2 - Schematic of Riser and Diverter Systems

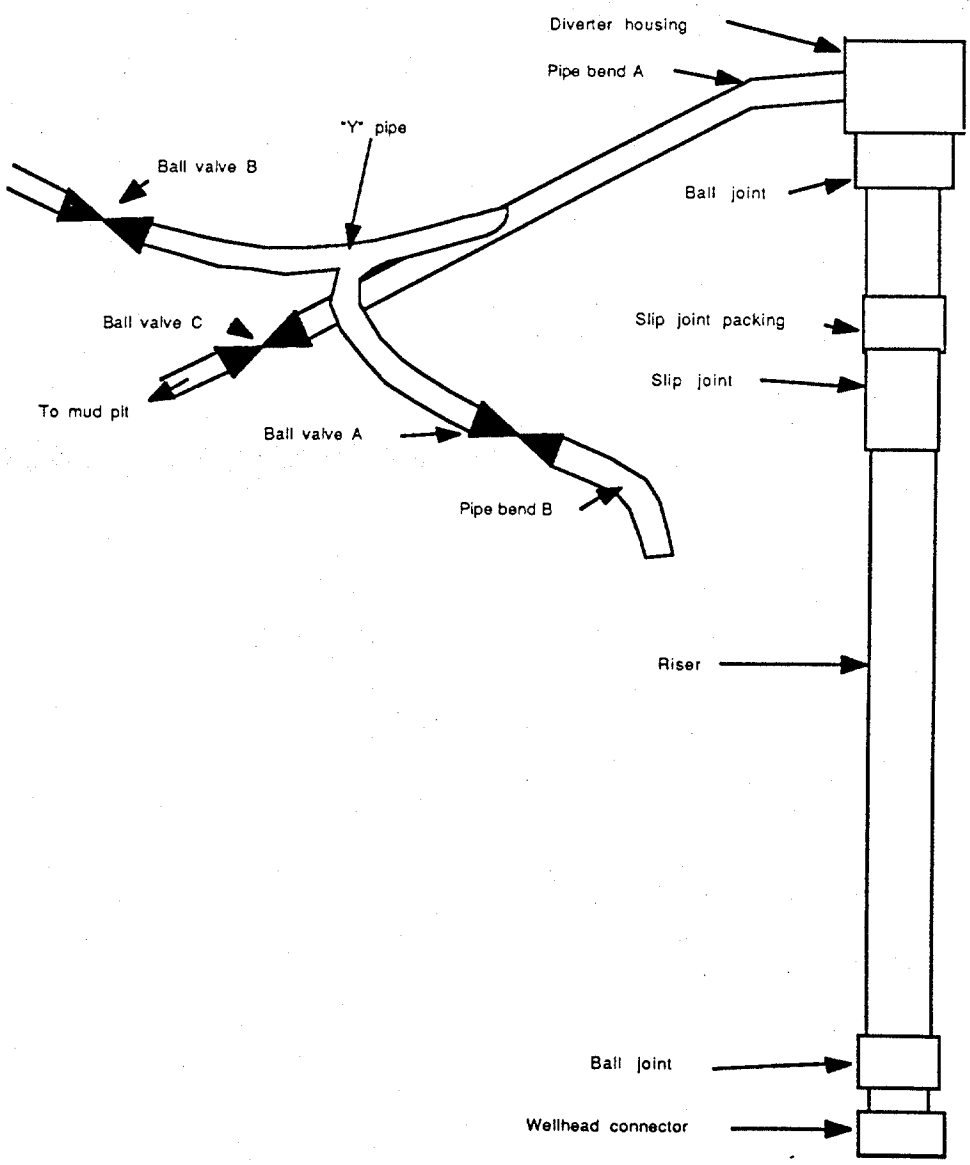


Figure 3 - Copy of Original Analog Record of Operational Parameters

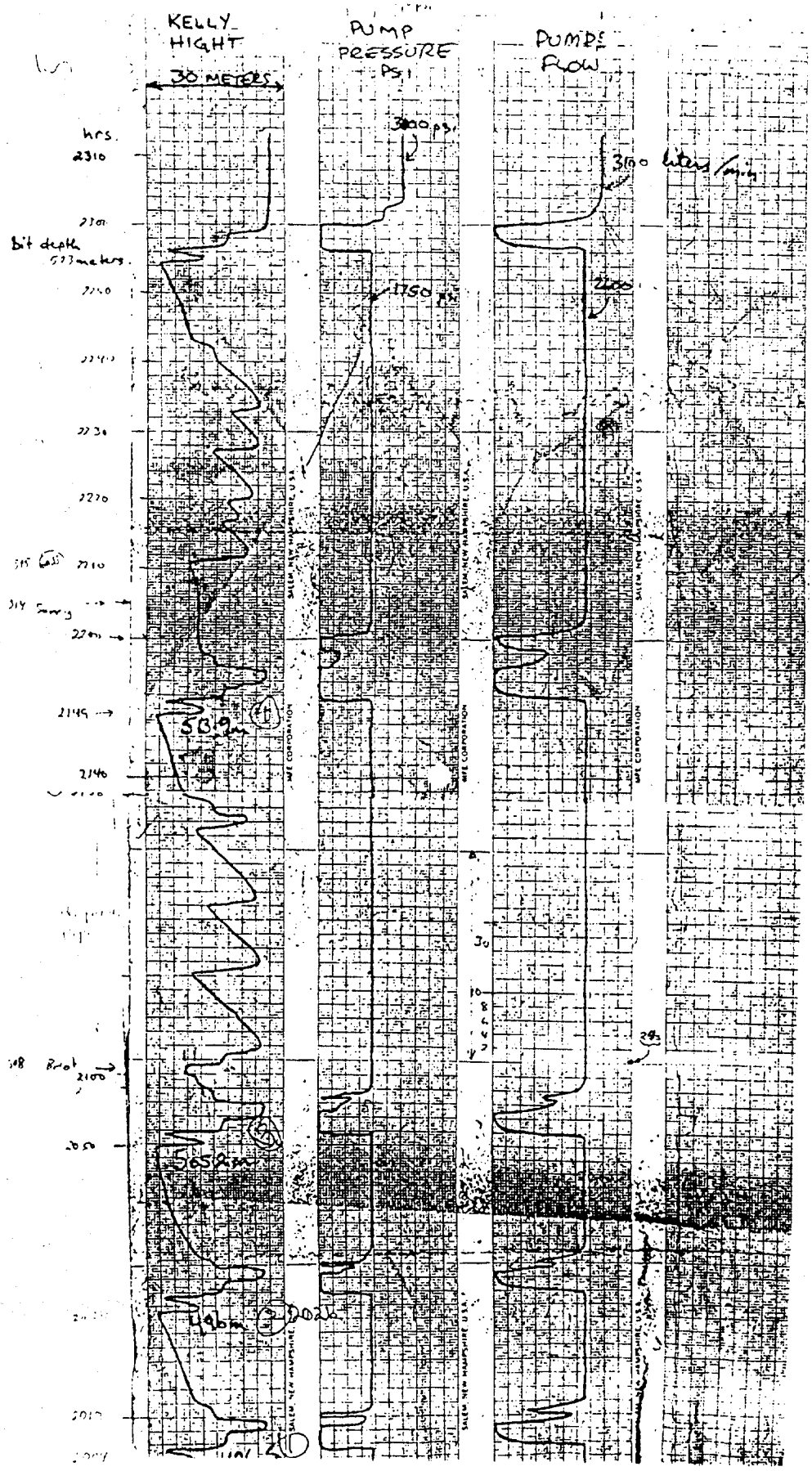


Figure 4 - Copy of Original Mud Log Recording

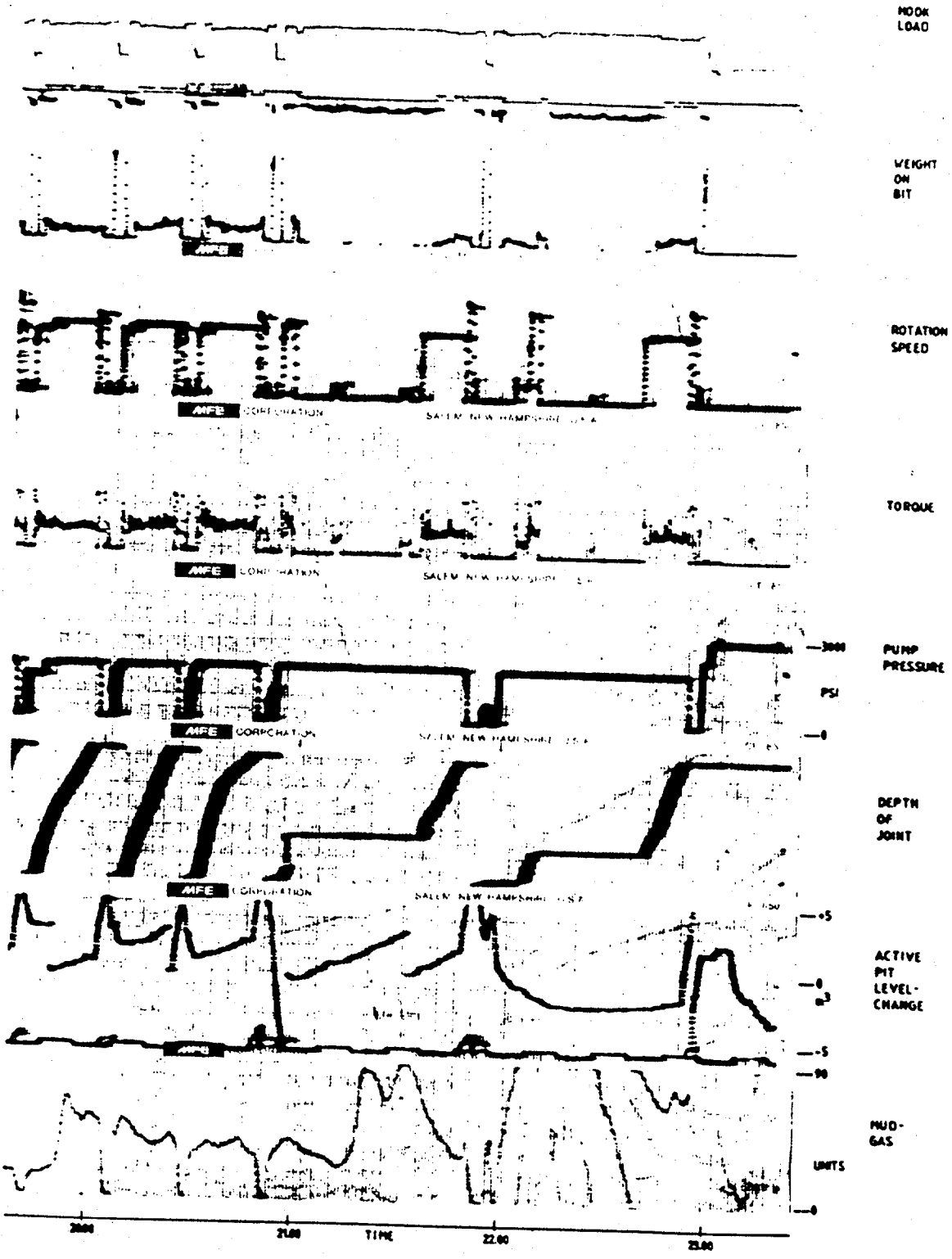


Figure 5- Copy of MWD Log

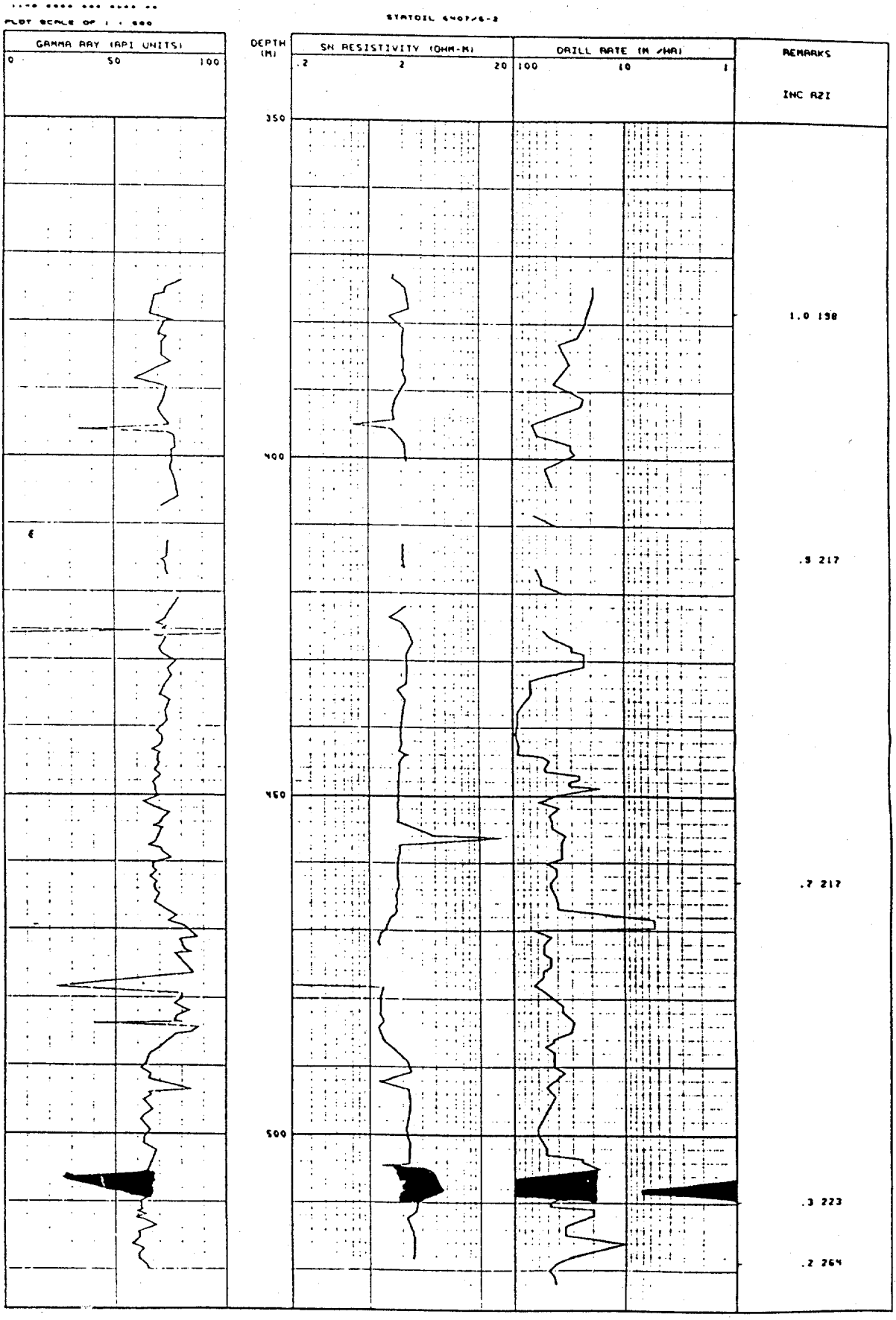
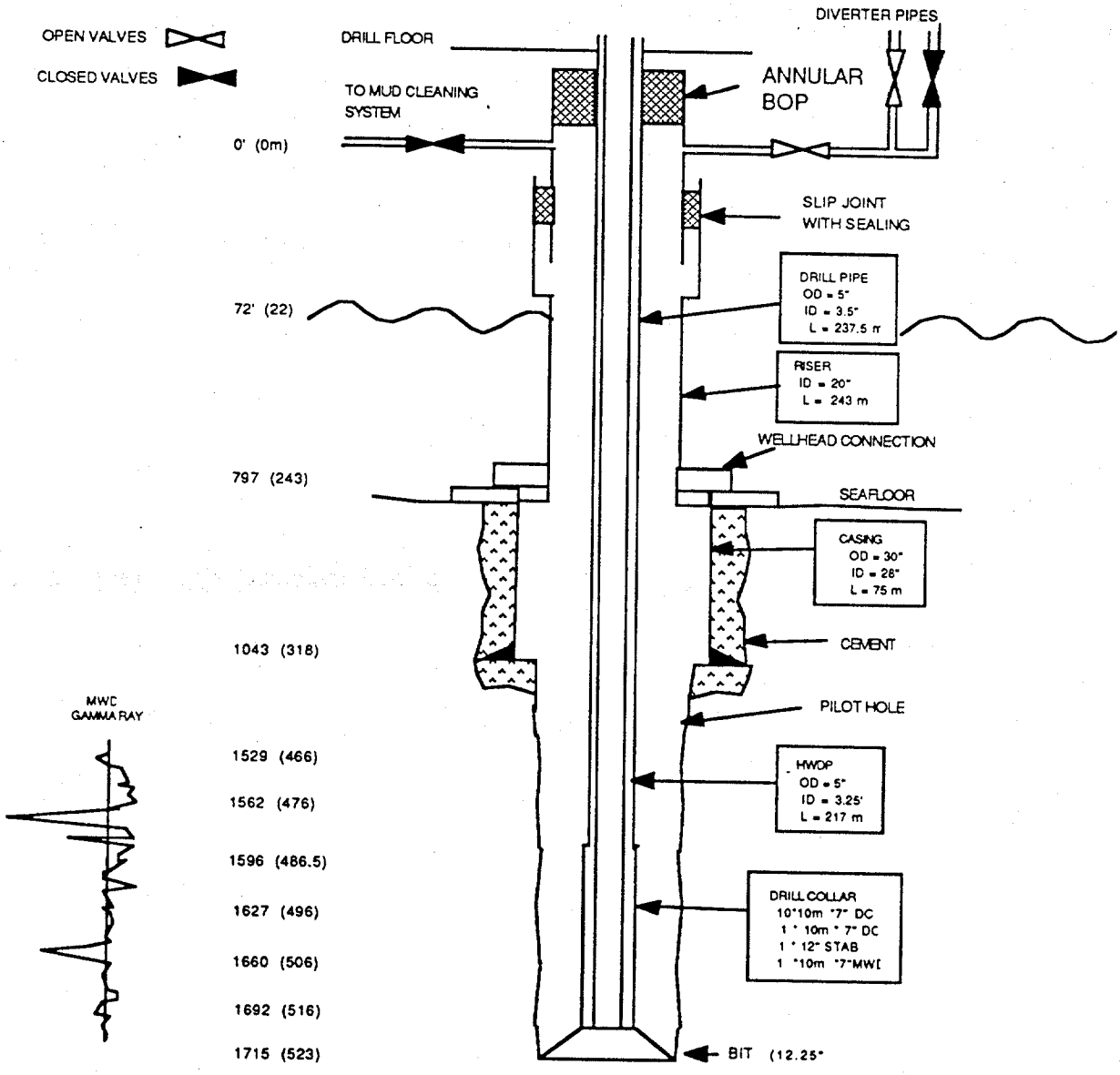


Figure 6- Wellbore Geometry at Time of Blowout



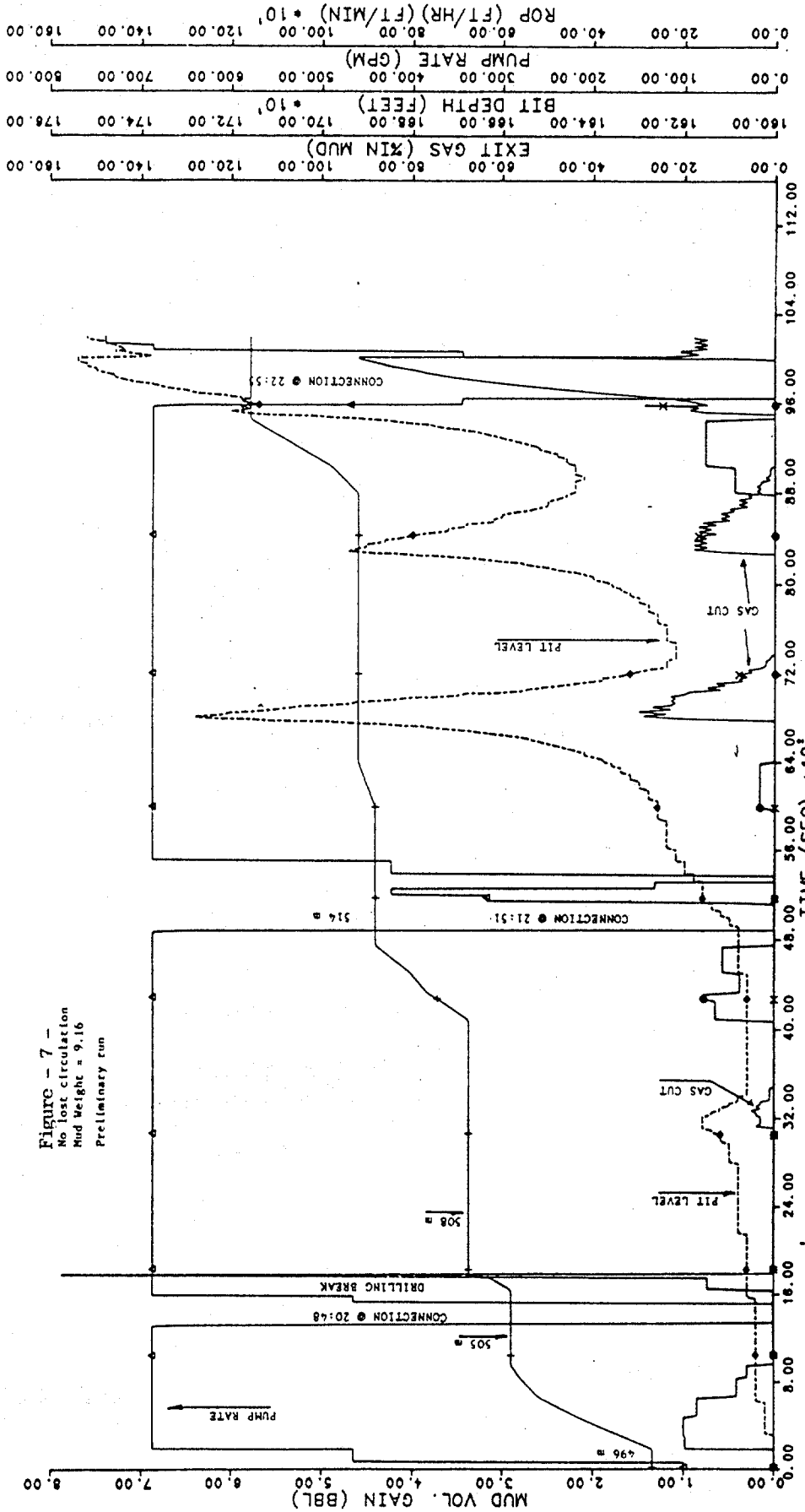


Figure - 7 -
No lost circulation
Mud Weight = 9.16
Preliminary run

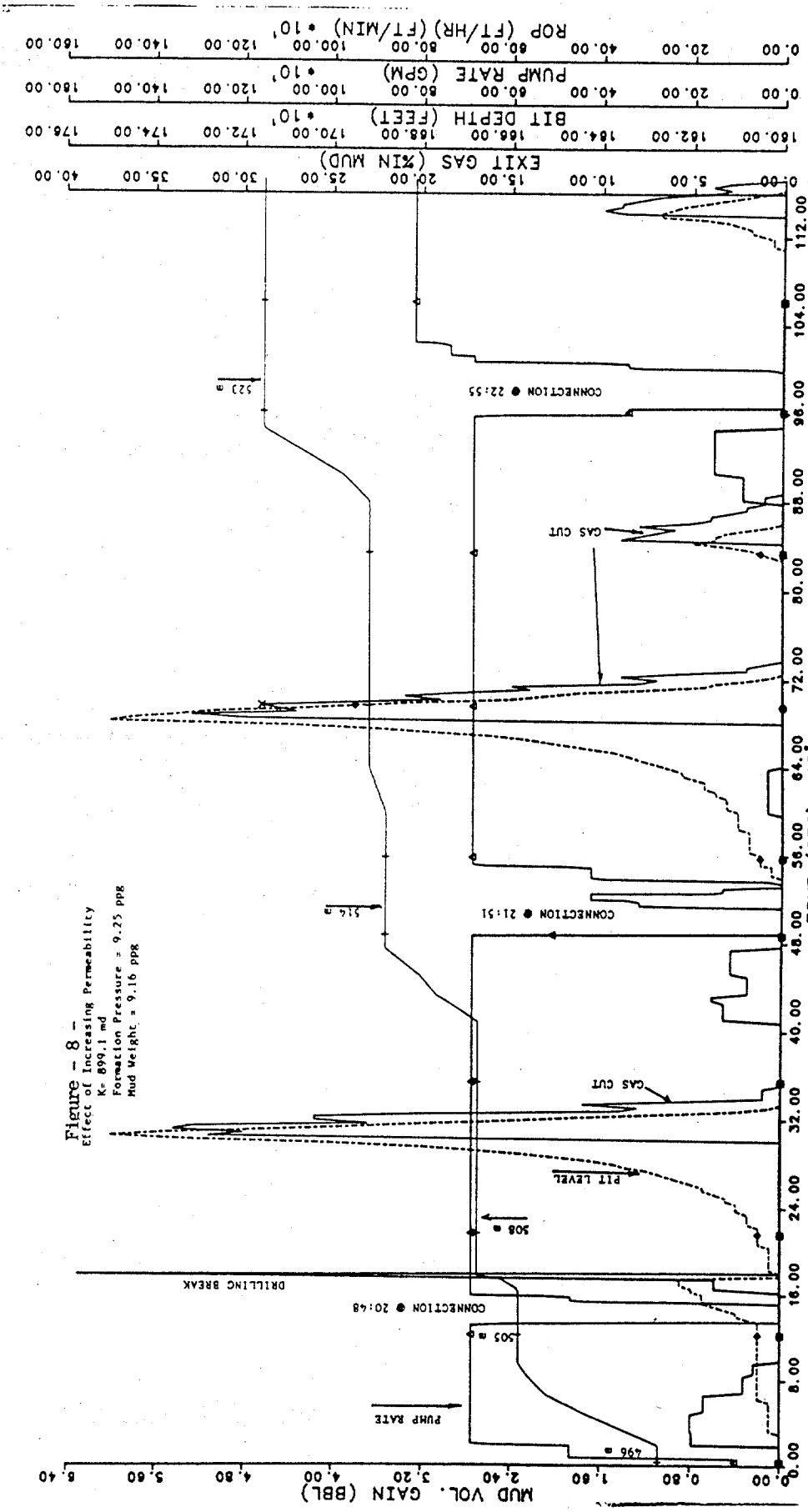


Figure – 8 –
Effect of Increasing Permeability
K= 899.1 md
Formation Pressure = 9.25 ppg
Mud Weight = 9.16 ppg

NO L.C. GAS 9.25 PPG, 899.1 MD.

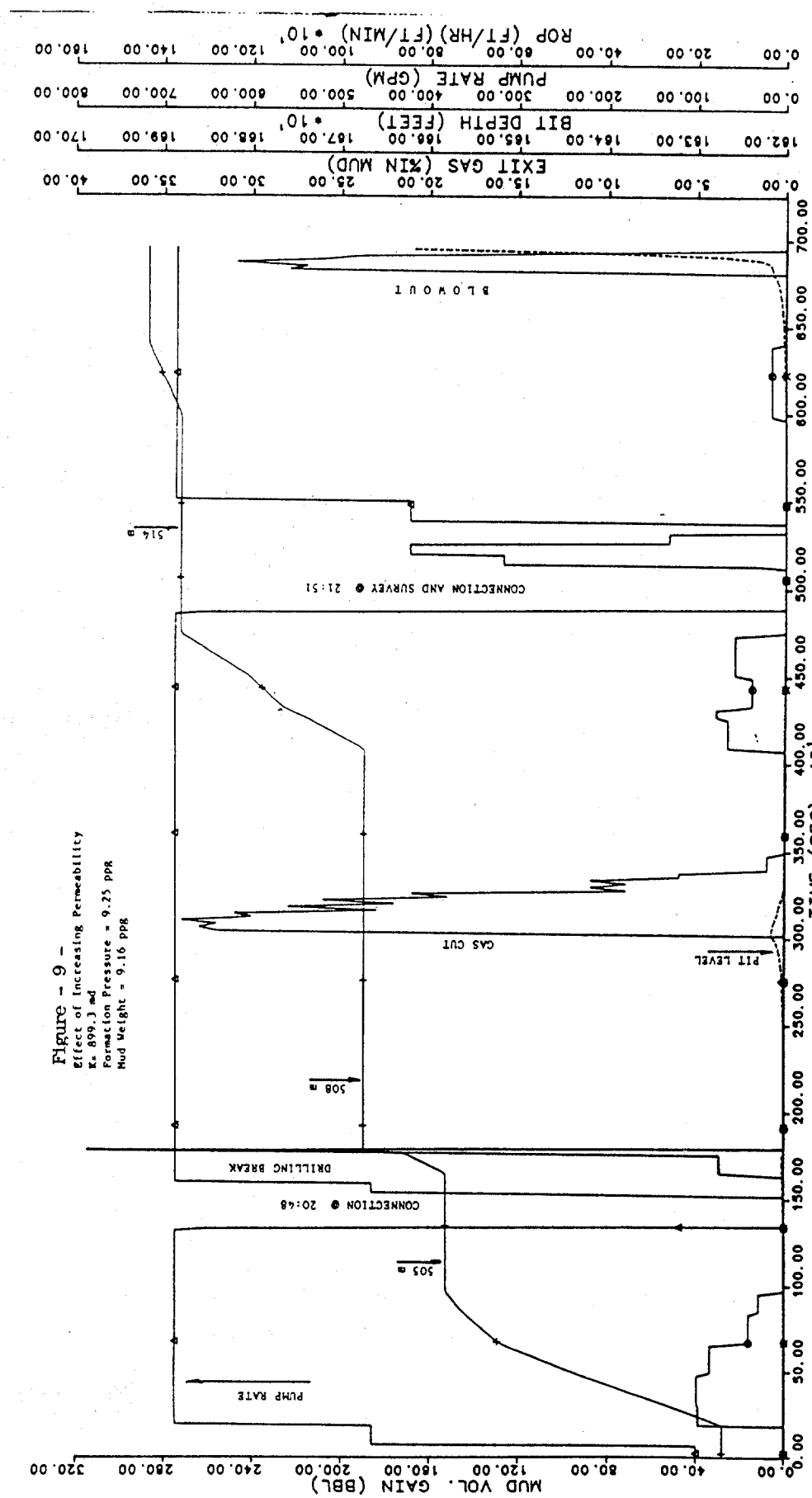


Figure - 9 -
Effect of Increasing Permeability
K= 899.3 md
Formation Pressure = 9.25 ppg
Mud Weight = 9.16 ppg

NO L. C. GAS 9.25 PPG, 899.3 MD.

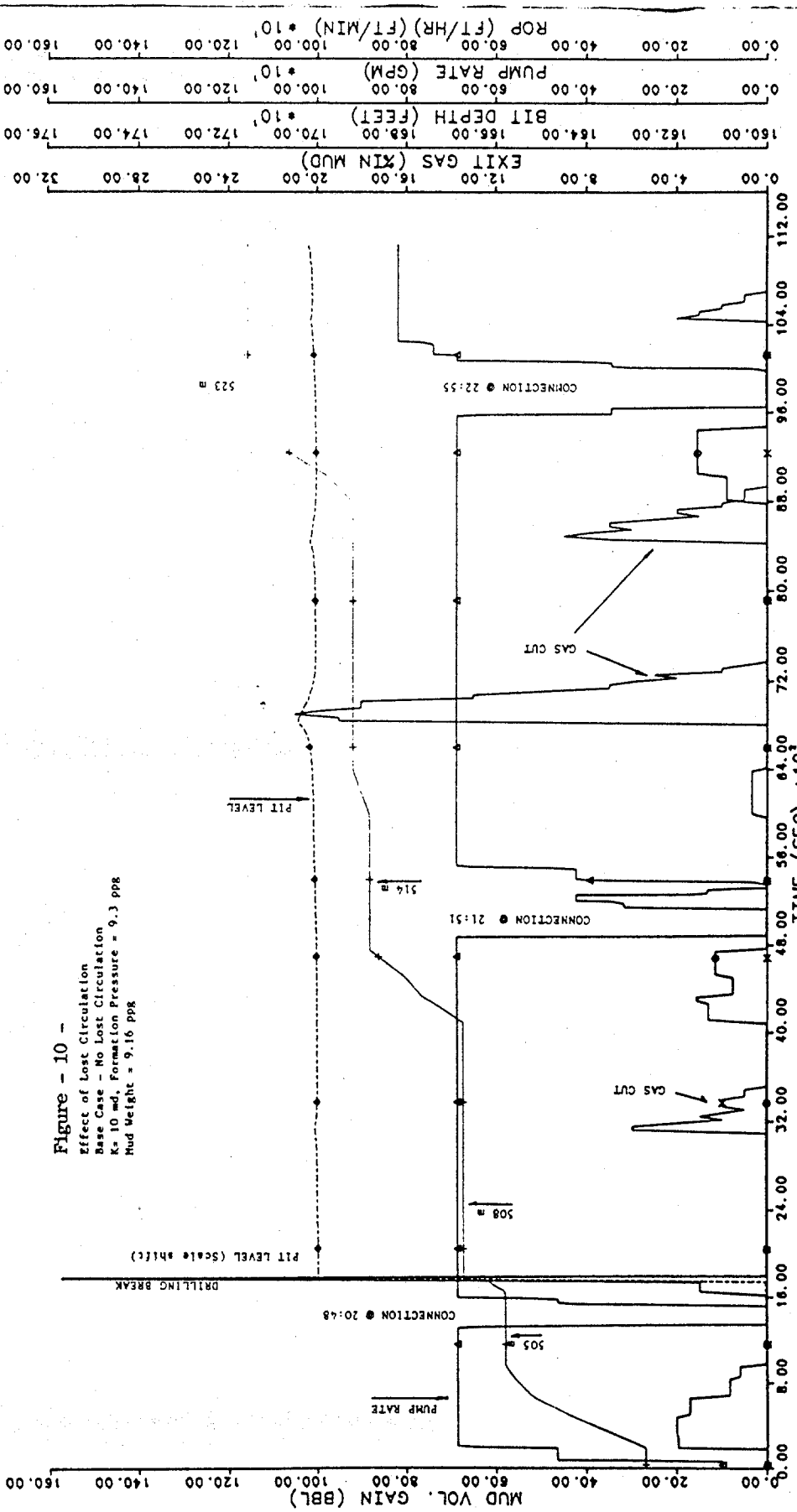


Figure - 10 -
Effect of Lost Circulation
Base Case - No Lost Circulation
K= 10 md, Formation Pressure = 9.3 ppg
Mud Weight = 9.16 ppg

NO L.C., BUT ALSO INCREASE MUD VOL. BY 100 BBL AT 1764

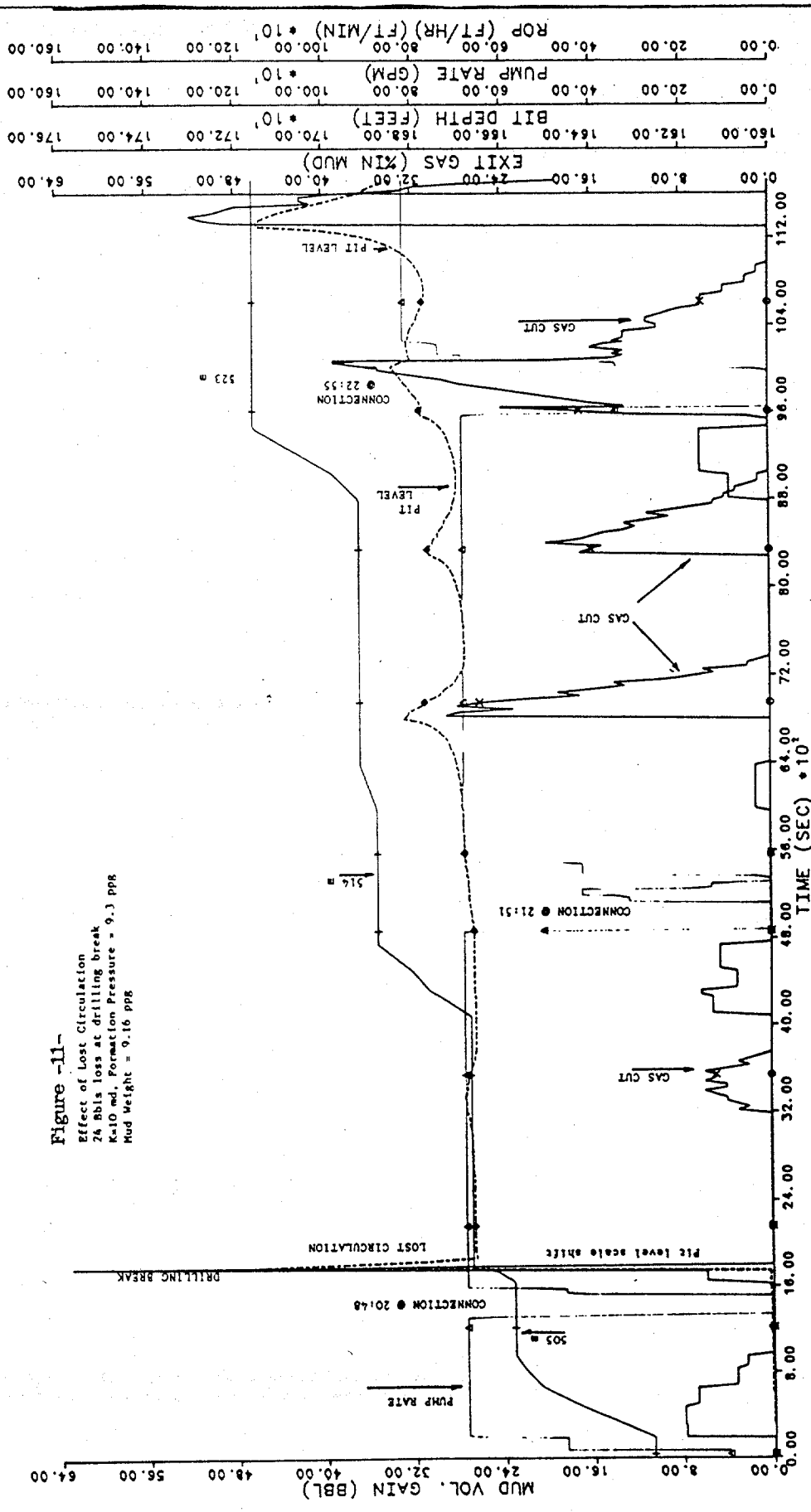
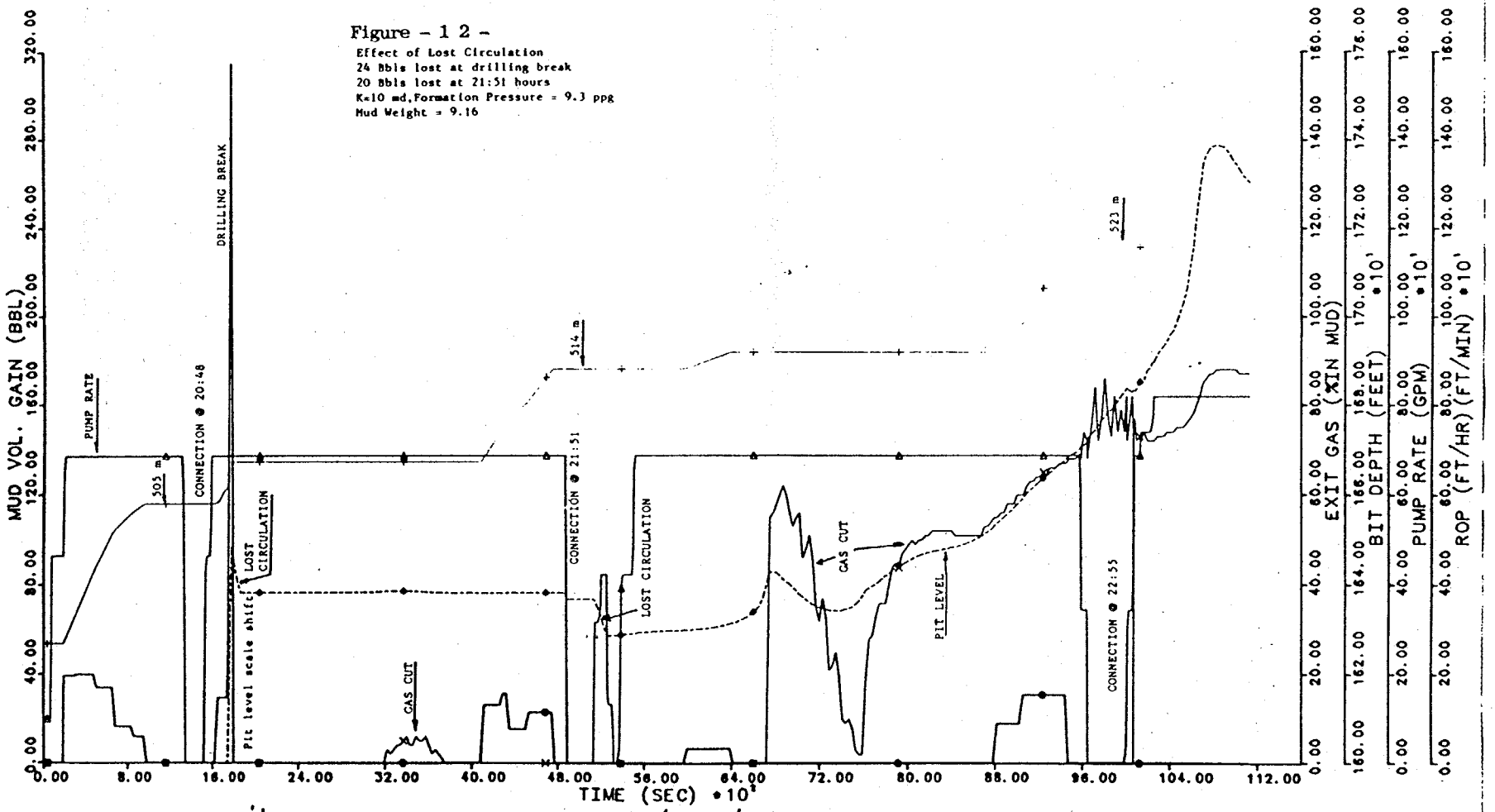


Figure -11-
Effect of Lost Circulation
24 Bbls loss at drilling break
K=10 md, Formation Pressure = 9.3 PPG
Mud Weight = 9.16 PPG

Figure - 1 2 -

Effect of Lost Circulation
24 Bbls lost at drilling break
20 Bbls lost at 21:51 hours
K=10 md, Formation Pressure = 9.3 ppg
Mud Weight = 9.16



L.C. 1764 TO 1804 @ 7.5, 4864 TO 4938 @ 8.7, +100BBL AT 176

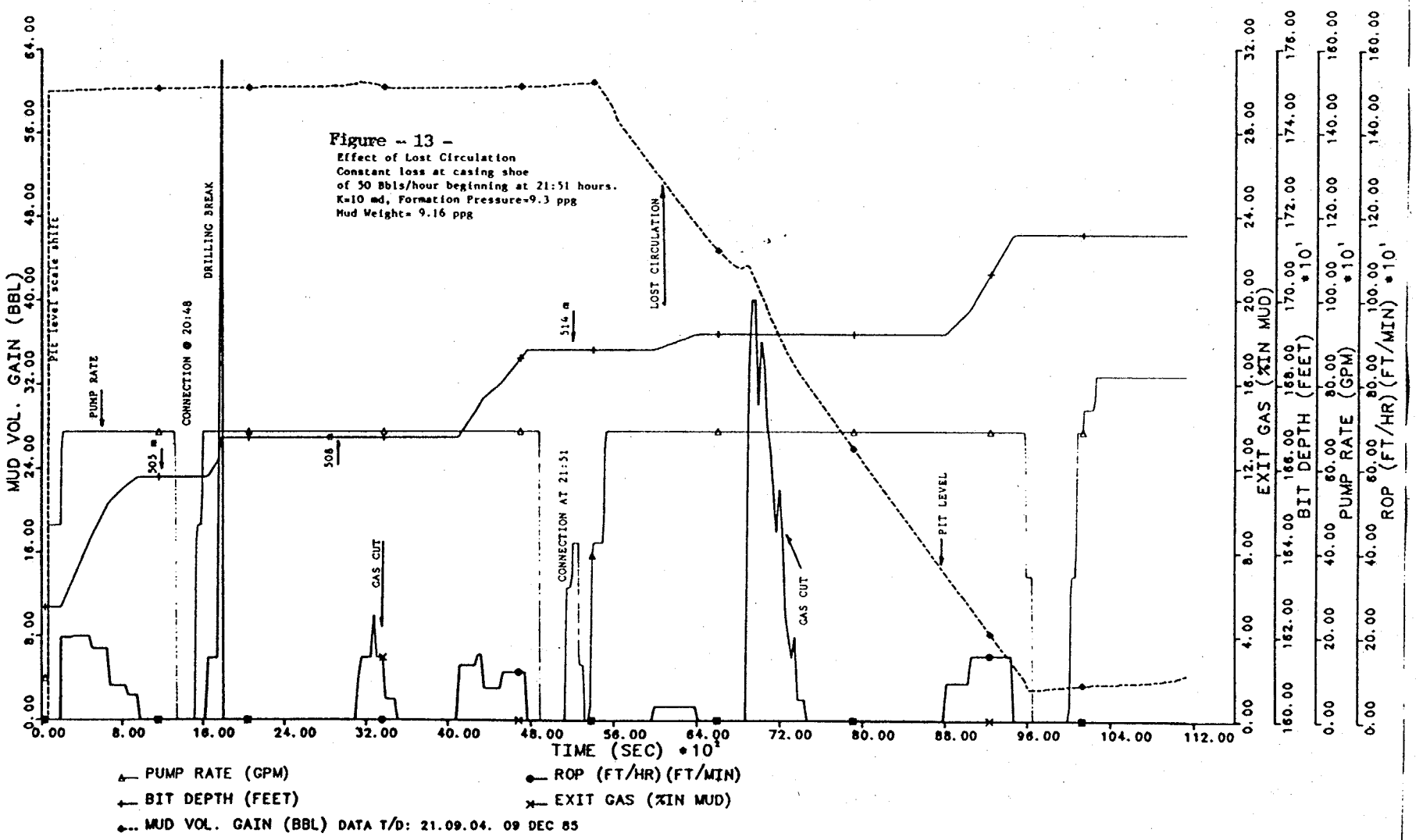


Figure - 13 -
Effect of Lost Circulation
Constant loss at casing shoe
of 50 Bbls/hour beginning at 21:51 hours.
K=10 md, Formation Pressure=9.3 ppg
Mud Weight= 9.16 ppg

CONSTANT L.C. 5400->9600 AT CASING SHOE

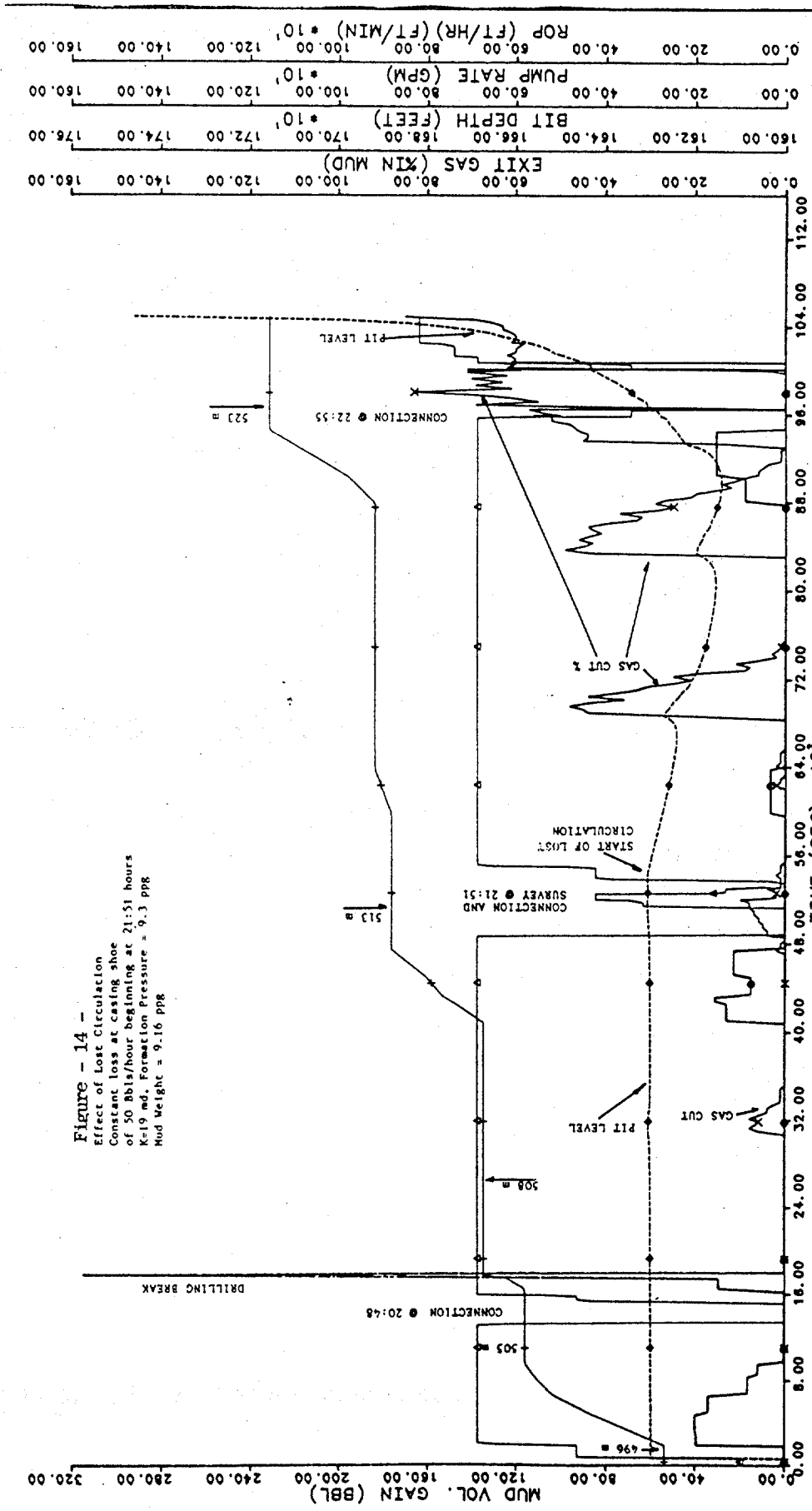


Figure - 14 -
Effect of Lost Circulation
Constant loss at casing shoe
of 50 Bbls/hour beginning at 21:51 hours
K=19 md, Formation Pressure = 9.3 PPR
Mud Weight = 9.16 PPR

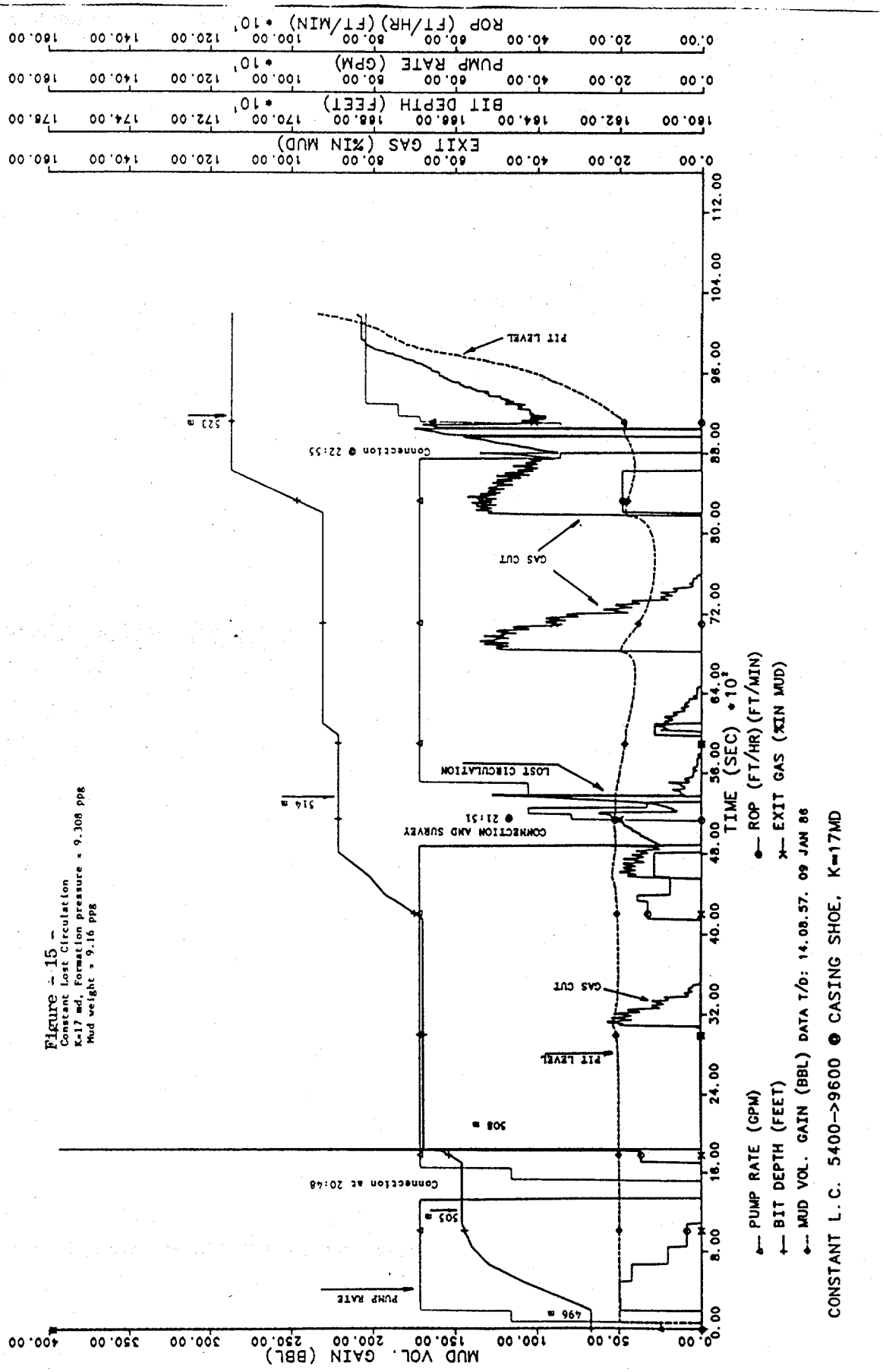


Figure - 15 -
Constant Lost Circulation
K=17 md, Formation pressure = 9.308 ppg
Mud weight = 9.16 ppg

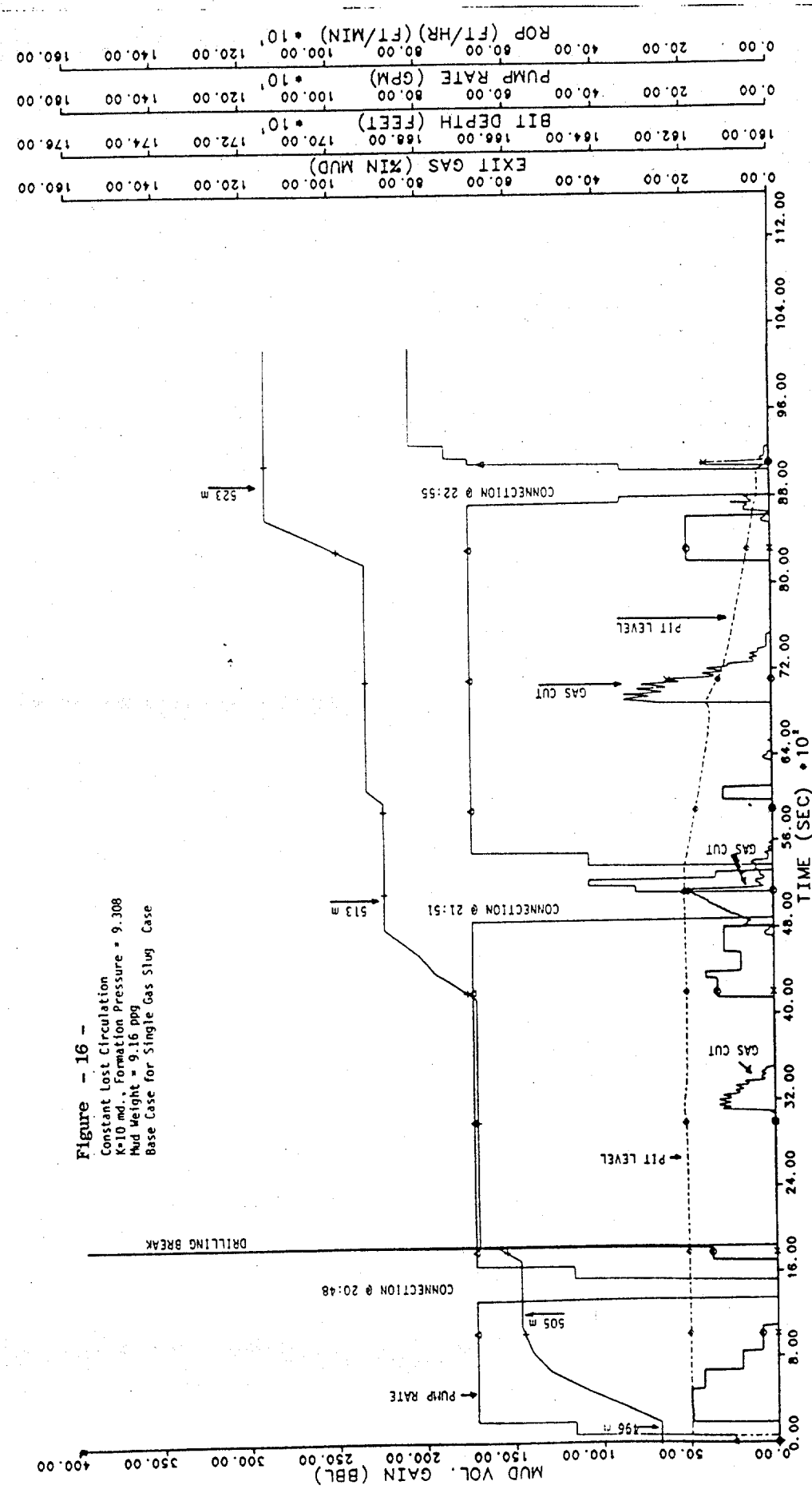
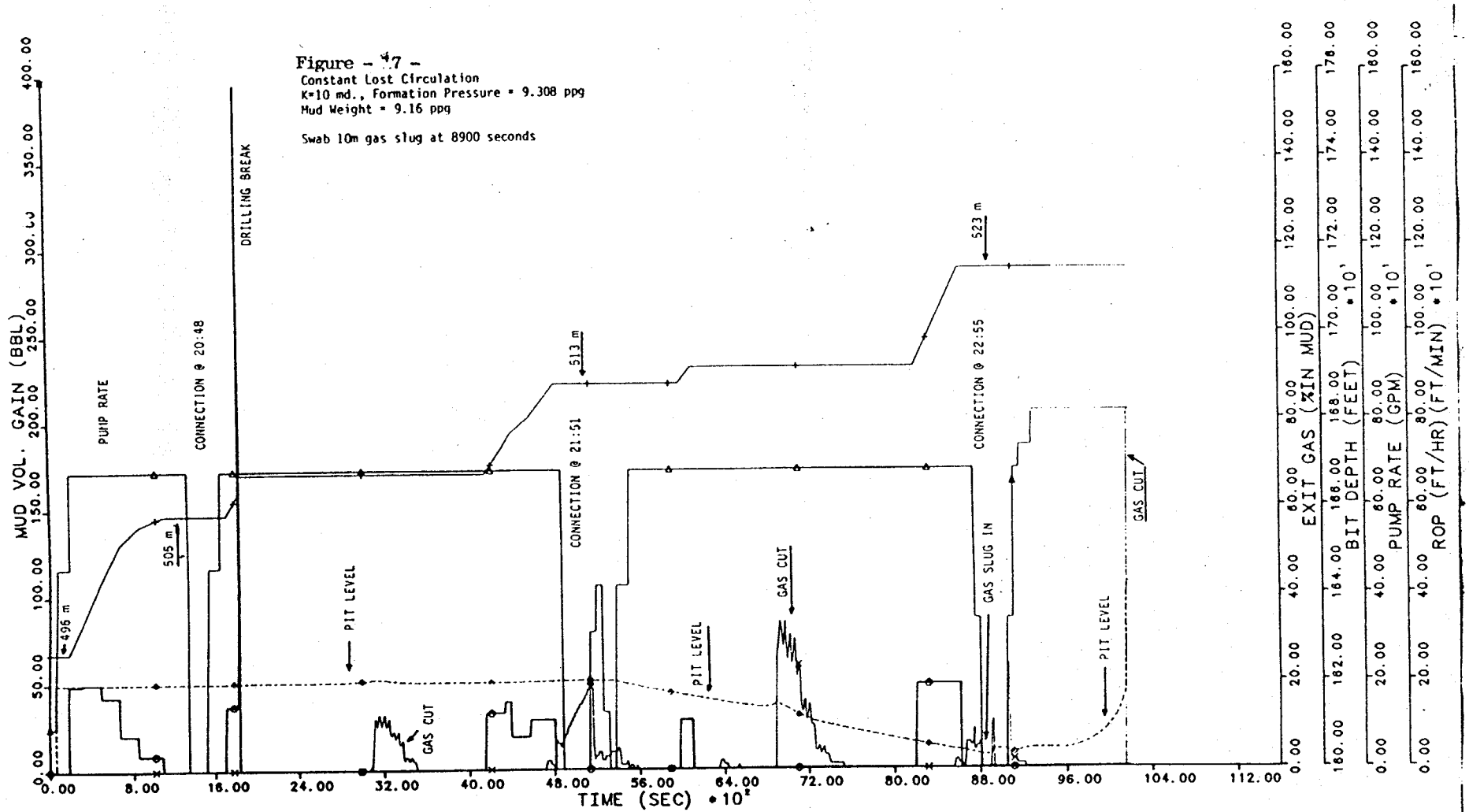


Figure - 16 -
Constant Lost Circulation
K=10 md., Formation Pressure = 9.308
Mud Weight = 9.16 ppg
Base Case for Single Gas Slug Case

Figure - 4.7 -
Constant Lost Circulation
K=10 md., Formation Pressure = 9.308 ppg
Mud Weight = 9.16 ppg

Swab 10m gas slug at 8900 seconds



CONST. L.C., K=10MD, GAS SLUG AT 8900 SEC

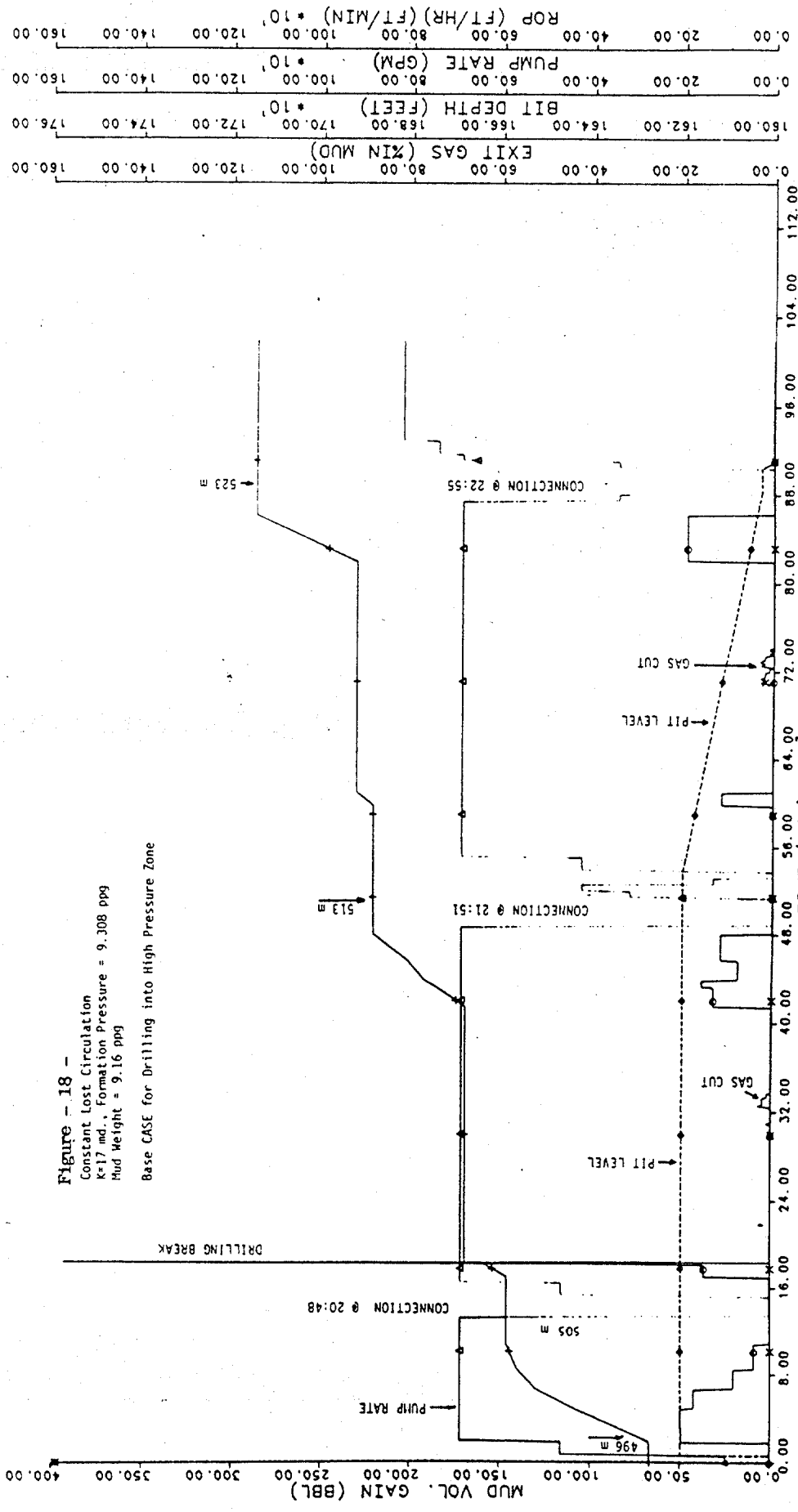


Figure - 18 -
Constant Lost Circulation
K=17 md., Formation Pressure = 9.308 ppg
Mud Weight = 9.16 ppg

Base CASE for Drilling into High Pressure Zone

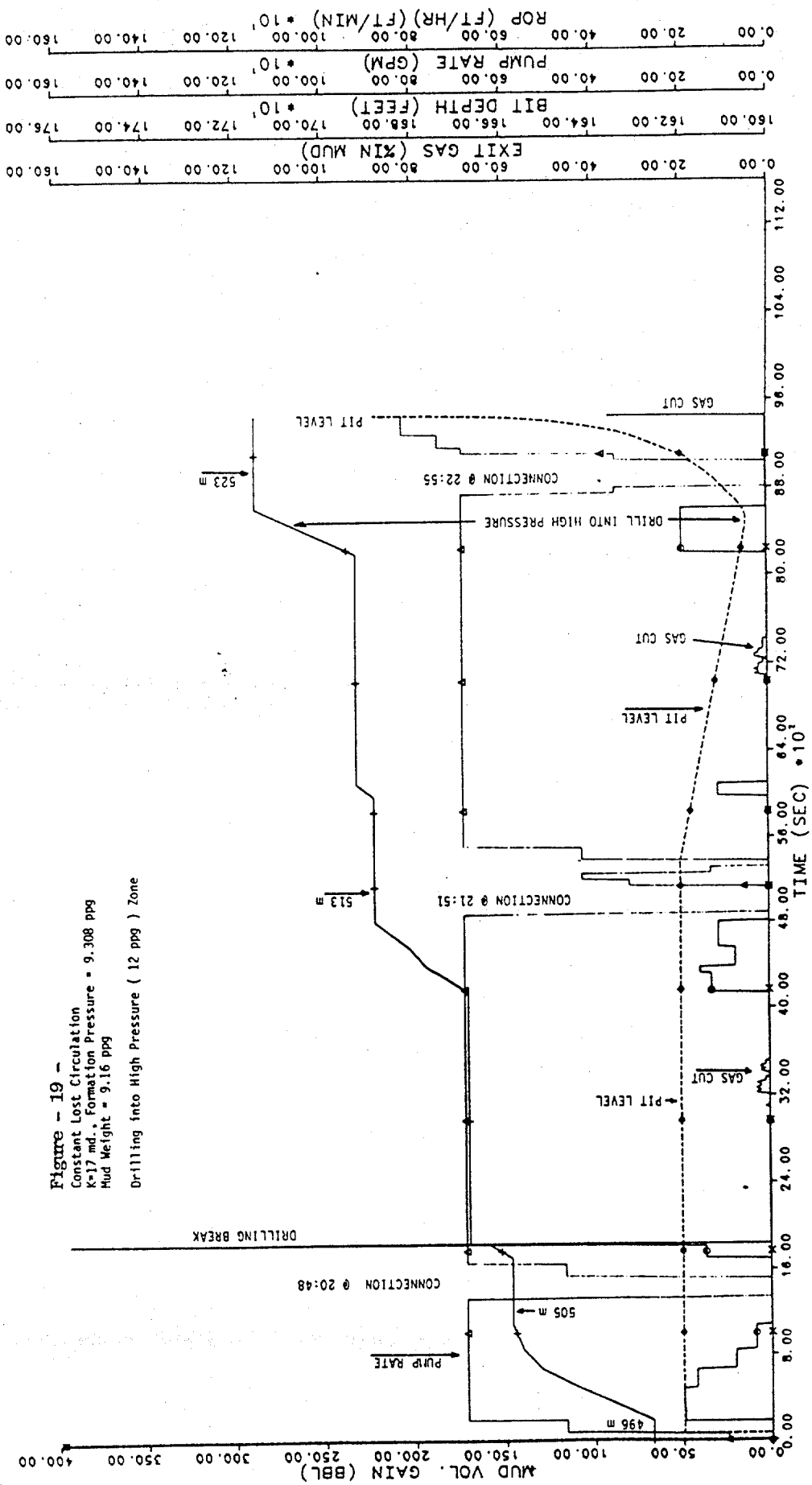


Figure - 19 -
Constant Lost Circulation
K=17 md., Formation Pressure = 9.308 ppg
Mud Weight = 9.16 ppg

Drilling into High Pressure (12 ppg) Zone

CONST. L.C., K=17MD, 12PPG AT 1705FT ADDED

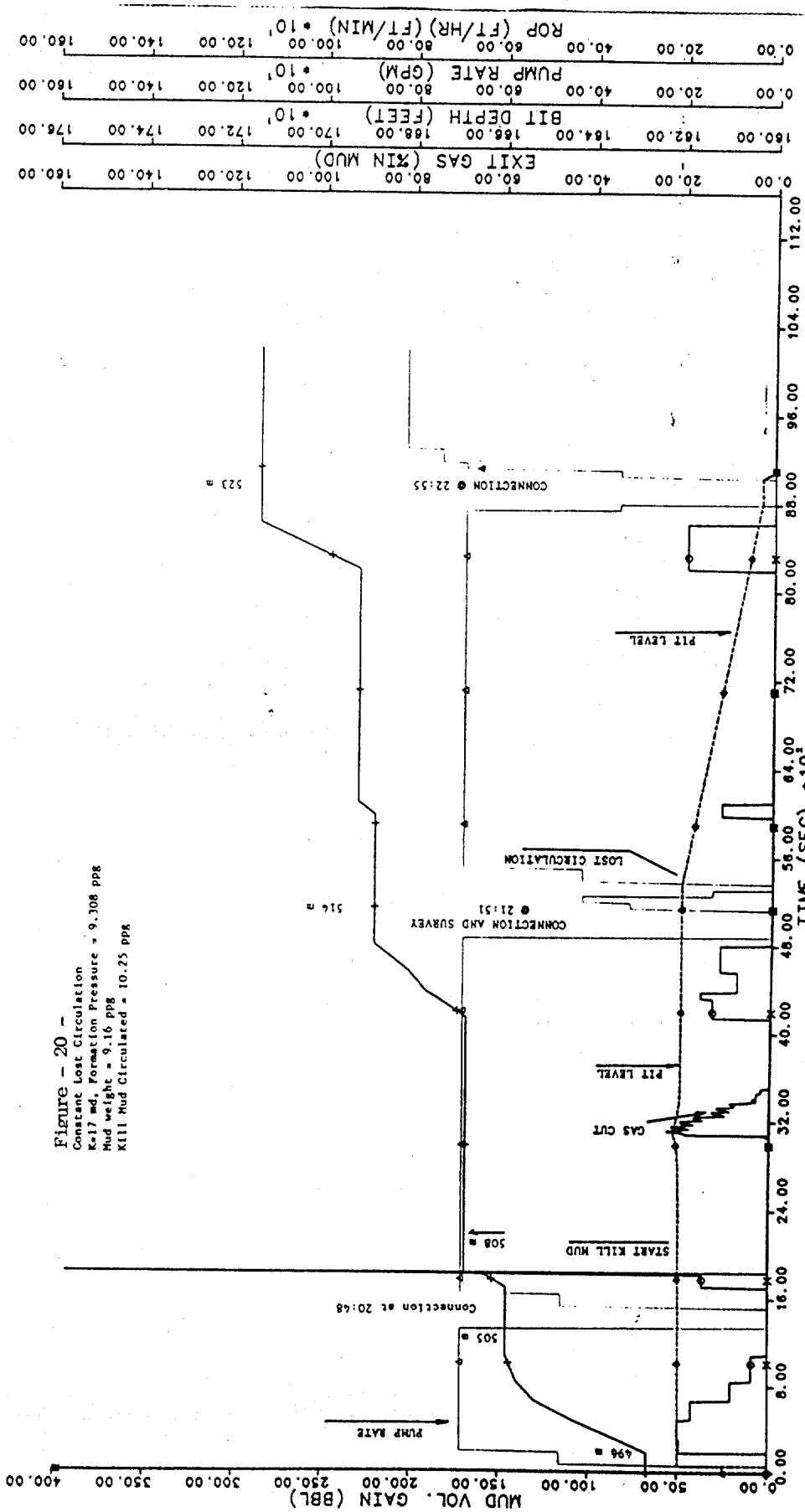


Figure – 20 –
Constant Lost Circulation
K=17 md, Formation Pressure = 9.308 ppg
Mud weight = 9.16 ppg
Kill Mud Circulated = 10.25 ppg

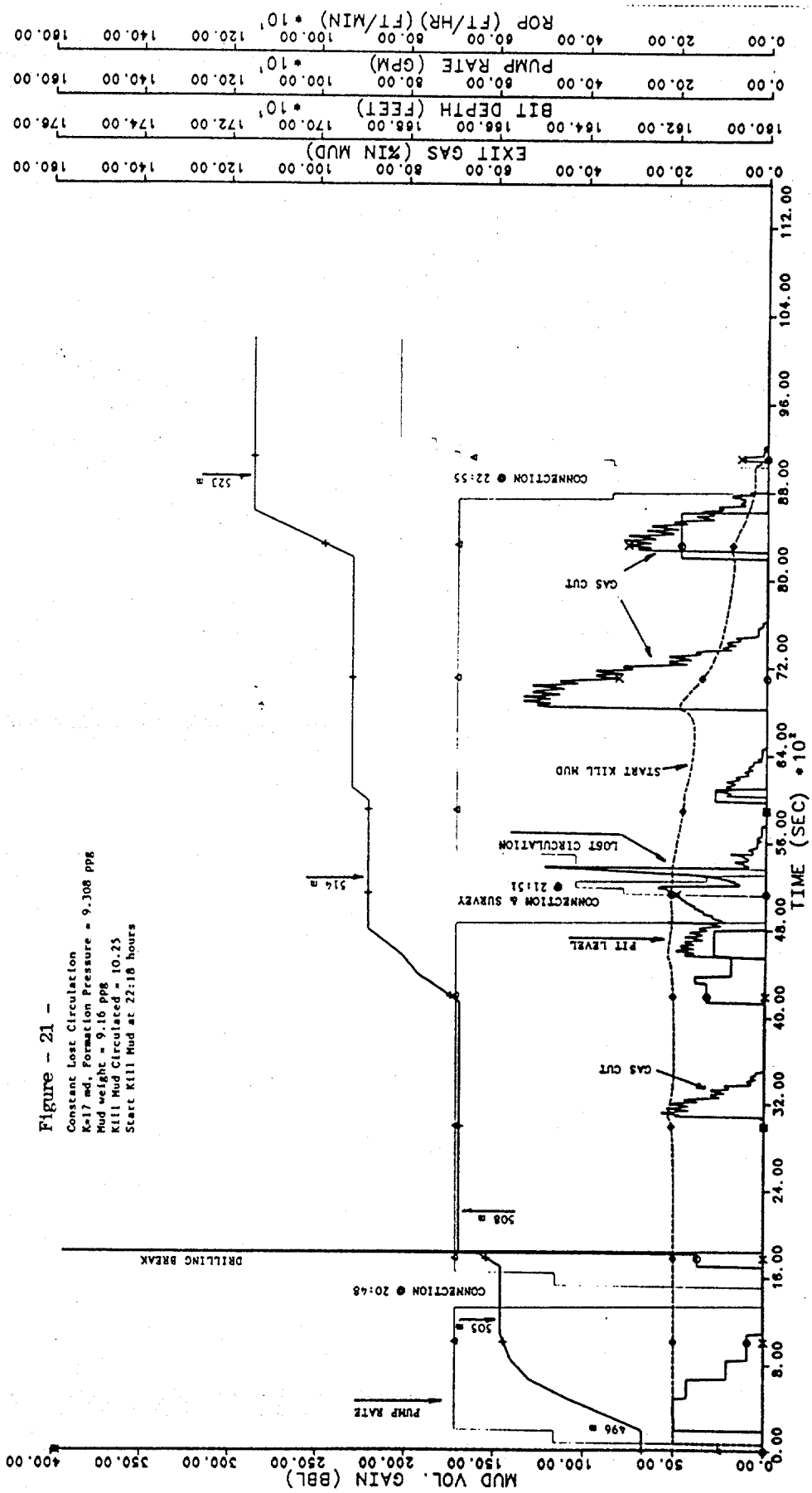


Figure - 21 -

Constant Lost Circulation
K=17 md, Formation Pressure = 9.308 ppg
Mud weight = 9.16 ppg
Kill Mud Circulated = 10.25
Start Kill Mud at 22:18 hours

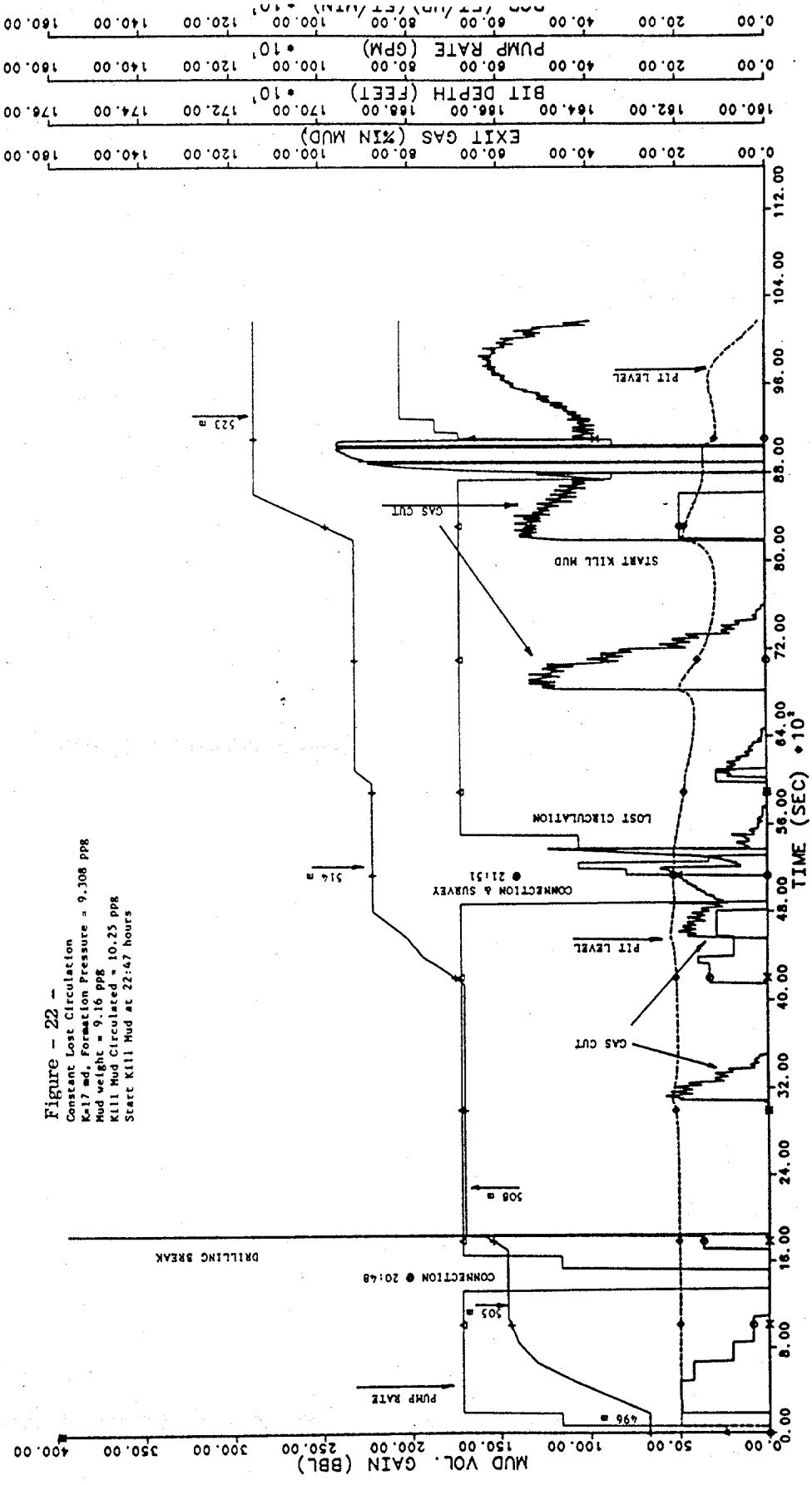
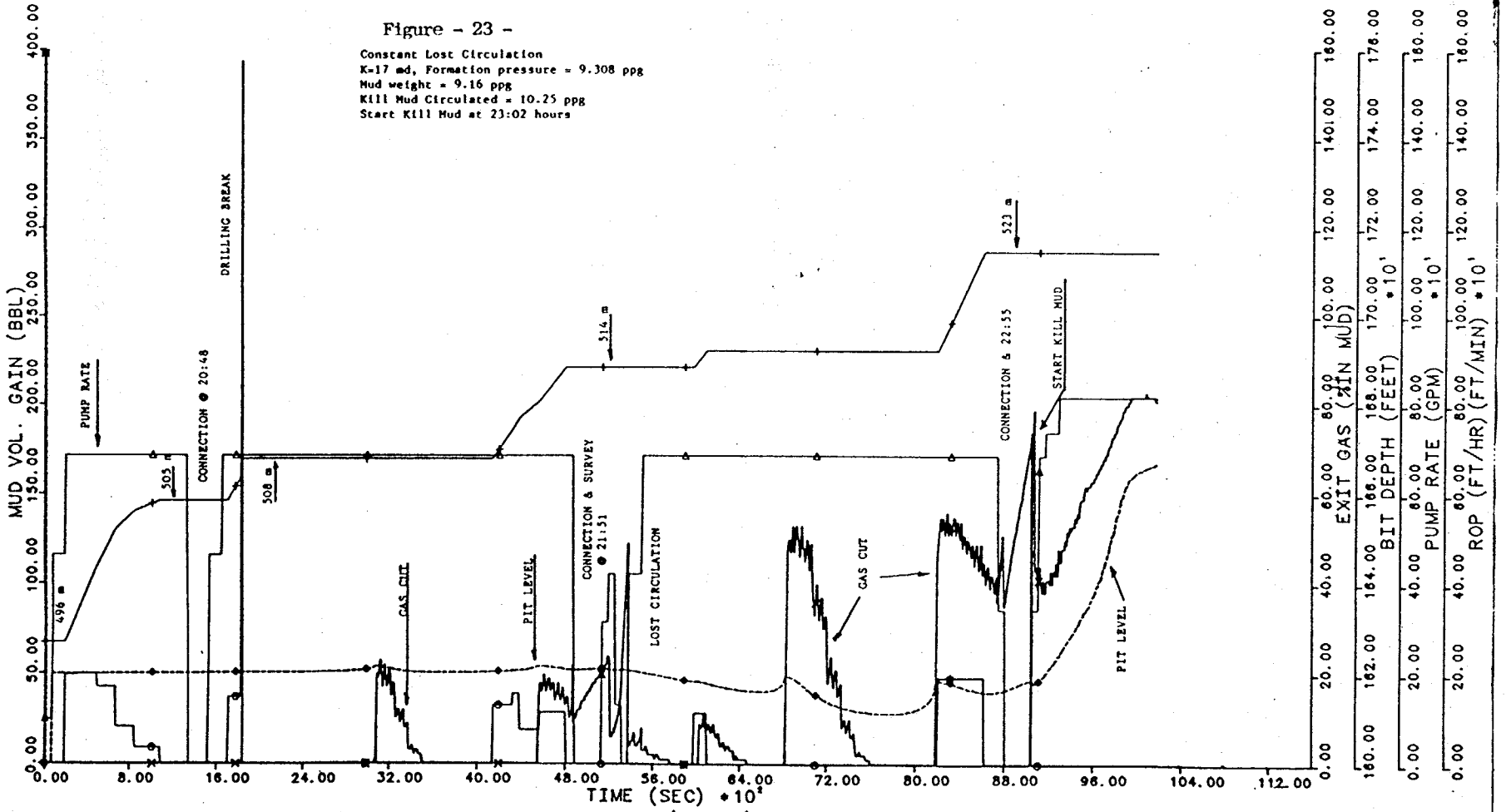


Figure - 22 -
Constant Lost Circulation
K-17 md, Formation Pressure = 9,308 ppg
Mud weight = 9.16 ppg
Kill Mud Circulated = 10.25 ppg
Start Kill Mud at 22:47 hours

Figure - 23 -

Constant Lost Circulation
K=17 md, Formation pressure = 9.308 ppg
Mud weight = 9.16 ppg
Kill Mud Circulated = 10.25 ppg
Start Kill Mud at 23:02 hours



CONSTANT L.C. ● CASING SHOE. K=17MD. M.W. 10.25 ● 9100 SEC

FAILURE OF WELLBORES DURING WELL CONTROL OPERATIONS

by
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A. T. Bourgoyne, Louisiana State University

Presented at
The International Well Control Symposium/Workshop
Louisiana State University, Baton Rouge, Louisiana
November 27-29. 1989

Abstract

The role which wellbore pressures play in the collapse and fracture of wellbores during well control operations is presented. As shown, during normal drilling operations the stability of a wellbore is maintained by the wellbore pressure which counteracts with the in-situ stresses and pore pressure around the hole. When this balance is disturbed by a change of wellbore pressure, the hole may become unstable. The hole surface may fracture and cause loss circulation, or the borehole wall may become crushed or spall off and close off the wellbore.

The stress conditions which produce each type of failure are presented along with an example for a shallow gas well.

Introduction

It is often observed that many wells which experience an uncontrolled blowout have wellbore rock failure which seals off the wellbore and thereby allows the well to be brought under control. It is conceivable that the many wellbore pressure changes which occur as a kick is brought under control are the cause of the degradation of the wellbore. A better understanding of the various failure mechanisms involved could lead to improved well control techniques which would use such failures to the engineer's advantage promoting termination of flow from the well.

The stability of a wellbore during drilling operation is maintained by the weight of the drilling mud which exerts a radial compressive stress on the surface of the wellbore counteracting the in-situ stresses and the pore pressure. Assuming there is no flow of fluids between the wellbore and its surrounding rock, the failure of wellbores were studied in detail by Bradley[1,2,3], Aadnøy[4], and Chenevert[5]. Using a proper failure criterion for the rock medium, models and design charts for predicting the conditions for wellbore fracture for excessive mud weights, and collapse for minimal mud weights were introduced by these authors. However, in the above quoted literature the specific wellbore conditions occurring during well control operations was not discussed.

One of the main objectives of this paper is to present simplified wellbore stress equations which can be used to show how the lowering of wellbore pressures can produce hole failure and under what wellbore conditions the raising of pressures can produce lost circulation.

Stress State Before Drilling

The stresses which act a given point in the earth can be represented by the terms:

$\bar{\sigma}_x$ = Horizontal gross stress in the x direction

$\bar{\sigma}_y$ = Horizontal gross stress in the y direction

$\bar{\sigma}_z$ = Vertical gross stress in the z direction

Figure 1 shows such stresses acting, along with the pore pressure, P_o, within the formation.

Effective Stress

It is well accepted that the "effective" stresses acting on the rock determine failure, and not the gross (total) stresses. For this reasin this paper will present failure equations in terms of effective stress. Effective stresses are often called "matrix" or "grain" stress, and are represented by the equations:

$$\sigma_x = \bar{\sigma}_x - P_o$$

$$\sigma_y = \bar{\sigma}_y - P_o$$

$$\sigma_z = \bar{\sigma}_z - P_o$$

Figure 2 shows the stress state of the formation in terms of effective stresses.

Stress Distribution Around A Wellbore

When we drill a wellbore into the earth we alter the stress state in the vicinity of the wellbore. The equations which describe the effective stresses acting near a wellbore surface, as shown in Fig. 3, are given as:

$$\sigma_\theta = \frac{\sigma_x + \sigma_y}{2}\left[1+\frac{a^2}{r^2}\right] - \frac{\sigma_x - \sigma_y}{2}\left[1+3\frac{a^4}{r^4}\right]\cos 2\theta - \left(P_w - P_o\right)\frac{a^2}{r^2} \qquad (1)$$

$$\sigma_r = \frac{\sigma_x + \sigma_y}{2}\left[1-\frac{a^2}{r^2}\right] + \frac{\sigma_x - \sigma_y}{2}\left[1-4\frac{a^2}{r^2}+3\frac{a^4}{r^4}\right]\cos 2\theta + \left(P_w - P_o\right)\frac{a^2}{r^2} \qquad (2)$$

$$\sigma_z = \sigma_z \quad (3)$$

Where:

σ_θ = Horizontal "tangential" stress, psi
σ_r = Radial Stress, psi
σ_z = Vertical Stress, psi
a = wellbore radius
r = radial distance
θ = angle in the horizontal plane from the x axis

The tangential stress described by equation (1) becomes intensified[6] as r approaches a. Figure 4 graphically shows such stress intensifications.

Stability Criteria

In this paper it is assumed that for the formation in question (the one which fails) no appreciable flow of fluids occurs out of or into the pores of such formations and the viscous forces produced by the flow of fluid are thereby negligible. For such cases, there are three situations that may cause the failure of the wellbore. First, if the wellbore pressure is increased so that tangential wellbore surface stress reaches the tensile failure stress of the rock, the wellbore surface would fracture causing a loss of drilling fluid and a subsequent reduction of wellbore pressure. Second, if the wellbore pressure is reduced so that the surface stress exceed the compressive strength of the rock, the material around the wellbore undergoes a crushing type of failure. Third, if the wellbore pressure is reduced below the formation pore pressure tensile "spalling" would occur. Spalling is particularly true for impermeable formations pressured with gas.

The analysis presented herein will focus specifically on what happens at the wellbore wall when the wellbore pressure is raised or lowered during a well control operation.

Stresses at the Wellbore Wall

For wellbore failure considerations, only the rock at the wellbore surface (ie, at r = a) need be considered. Therefore, at the wellbore wall, Eqns 1, 2, and 3 become:

$$\sigma_\theta = \left(\sigma_x + \sigma_y\right) - \left(\sigma_x - \sigma_y\right)(\cos 2\theta) - \left(P_w - P_o\right) \quad (4)$$

$$\sigma_r = P_w - P_o \quad (5)$$

$$\sigma_z = \sigma_z \quad (6)$$

Wellbore Failure Caused by Fracturing (Loss Circulation)

In view of Eq. 4, it is apparent that as the wellbore pressure is increased, the tangential stress at the wellbore wall decreases. If we assume that the rock has zero tensile strength, lost circulation occurs when the tangential stress becomes negative. At this point the effective stress has gone tensile, and we thus predict fracturing of the wellbore. Figure 5 shows the tangential stress distribution just prior to fracturing.

Wellbore Failure Caused by Compressive Failure of the Rock

As the wellbore pressure decreases, the tangential stress and the radial stresses decrease, thereby placing the rock in an unfavorable failure condition as defined by the Mohr-Coulomb[7] failure condition. This failure criterion, as shown in Fig. 6, states that yielding occurs when the shear stress exceeds the sum of the cohesive resistance of the material "C" and the frictional resistance of the fracture plane. In equation form, we have:

$$\tau = C + \sigma_n \tan \theta \tag{7}$$

Where:

τ	=	shear stress at failure, psi
C	=	cohesive resistance of the material
σ_n	=	normal stress at the failure plane
ϕ	=	angle of internal friction

The normal stress, σ_n, is defined as:

$$\sigma_n = \frac{\sigma_x + \sigma_y}{2} + \frac{\sigma_x - \sigma_y}{2} \cos\left(\frac{\pi}{2} - \theta\right) \tag{8}$$

As shown in Fig. 6, this is the equation of a line that is tangent to Mohr's circles drawn through failure points made at different levels of confining pressure. Figure 7 shows the tangential and radial stresses acting on a wellbore wall before failure occurs. You will note that the Mohr circle does not touch the failure line.

As P_w is decreased, the tangential stress increases and the radial stress decreases thereby enlarging the Mohr stress circle. When the circle touches the failure tangent line (Fig. 8) failure occurs.

Wellbore Failure Caused by Tensile "Spalling"

When the wellbore pressure of an impermeable pressured formation is reduced below the formation's pore pressure, a situation is created in which the effective radial stress of the wellbore wall becomes negative and the formation particles tend to flake off into the wellbore by the pressured fluid, assuming the formation has zero tensile strength. This produces a failure referred to herein as pressure "spalling." This is particularly true when the pore fluid is a gas. The radial

stress (Eq. 5) becomes negative, which means the grains at the surface of the wellbore are under tensile forces, and the spalling failure easily occurs.

Field Example

The following data are assumed for a formation occuring at 750 feet.

Referring to Fig. 1, the assumed in-situ gross stress components are given as follows:

σ_1	=	250 psi	C (Shear failure stress)	=	3000 psi
σ_2	=	350 psi	ϕ (Friction angle)	=	30°
σ_3	=	750 psi			

Wellbore Fracture (Loss of Circulation)
For these formation conditions, a relationship between the wellbore pressure (p_w) and pore pressure (p_o) for fracture failure of the wellbore is shown in Fig. 9. The tensile failure line, as calculated using Eq. 4, may be regarded as a demarcation line separating the stable region from the unstable region. When a point (p_w, p_o) is below the demarcation line, there will be no fracture failure at the surface of the wellbore.

Wellbore Failure (Crushing)
The demarcation line for the crushing failure on the surface of the wellbore is shown in Fig. 10. When a point (p_w, p_o) falls above the line, the rock material around the hole is in the elastic region, and the hole is therefore stable, as shown in the Mohr-Coulomb diagram of Fig. 7. As the wellbore pressure is decreased the tangential stress is increased and the radial stress is reduced. When the Mohr stress circle touches the failure line failure occurs, as depicted in Fig. 8. The demarcation line of Fig. 10 is the locus of such points.

Wellbore Failure (Spalling)
The 45° line of Fig. 11 is the demarcation line for the onset of pressure spalling, again we assume that the formation in question has a zero tensile strength. Below this line a tensile radial stress exists, and particles of the formation flake off into the wellbore producing pressure "spalling." Field personnel have referred to such flaking as "coffee ground" cavings and "ring tail" shale.

Wellbore Fracture / Wellbore Failure Diagram
A stable region for the wellbore for fracture, crushing, and spalling can thus be constructed by superimposing Figs. 9, 10, and 11, as shown in Fig. 12. The stable region for the wellbore is shown. If we assume the well in question has a 300 psi pore pressure and a 400 psi wellbore pressure (Point A), a fracture type of failure would occur if the wellbore pressure exceeds 700 psi (Point B), and wellbore spalling would occur if the wellbore pressure falls below 300 psi (Point C). As shown, for the formation stress conditions contained herein crushing failure would not occur until the wellbore pressure reaches 250 psi, which is unlikely to happen because spalling failure would occur first. Thus, if a blow out

were to take place and the bottom hole pressure was reduced to below 300 psi, rock spalling would occur which could possibly produce cavings which would pack off around the drill collar and shut off flow from the well.

Concluding Remarks

It should be emphasized that for the failure of the rock in question the wellbore stability criteria used in this study was based on the assumption that there was no flow of fluids between the rock and the wellbore fluids. For failure of formations experiencing forces produced by the flow of fluids, a stress analysis is required which is beyond the scope of this paper.

It has been shown herein how high wellbore pressure can cause wellbore fracture, and how crushing and spalling failure is produced by low wellbore pressure.

In those cases where proper diversion of gas kicks away from the well is possible it may be advantageous under severe conditions to allow gas flowage from the well, thereby reducing wellbore pressures sufficiently for failure of the wellbore to occur which could seal off the well.

Acknowledgements

The authors would like to thank Dr. Ching Yew for his suggestions and lively discussions during the preparation of this paper.

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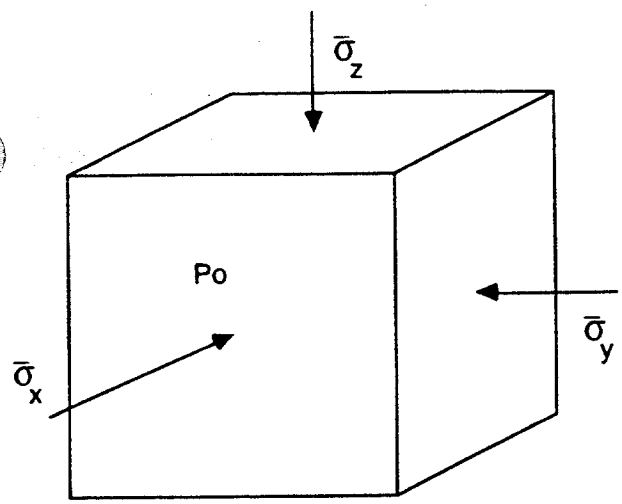

Fig. 1—Gross stresses and pore pressure acting on an element of formation

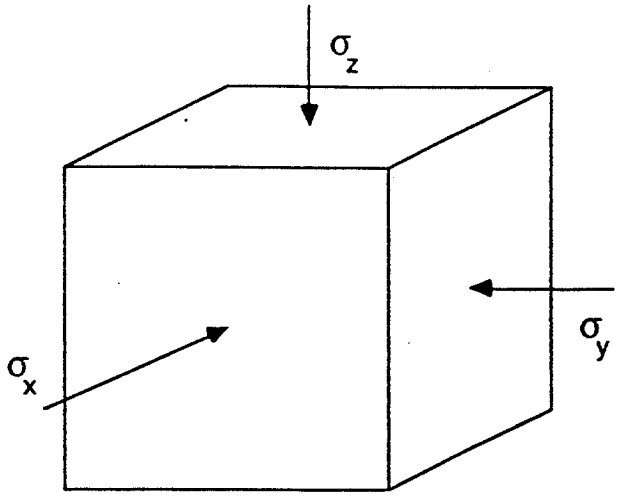

Fig. 2—Effective stresses acting on an element of formation

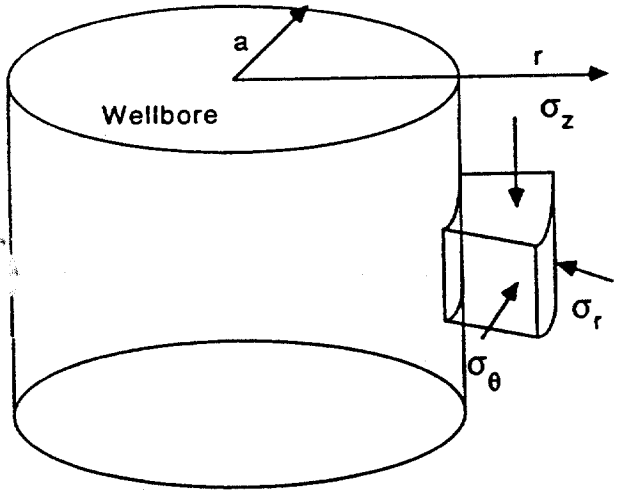

Fig. 3—Effective stresses near a wellbore surface

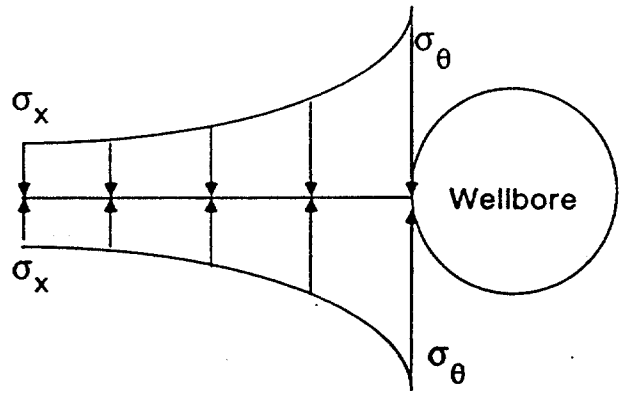

Fig 4—Tangential compressional stresses near a wellbore surface

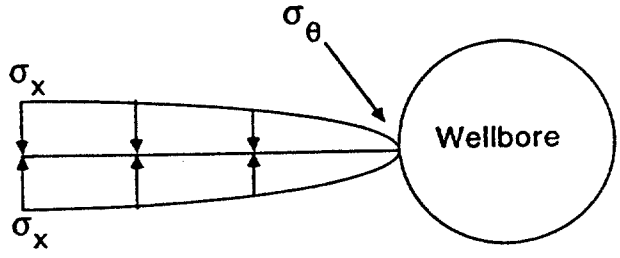

Fig 5—Tangential tensile stresses near a wellbore surface

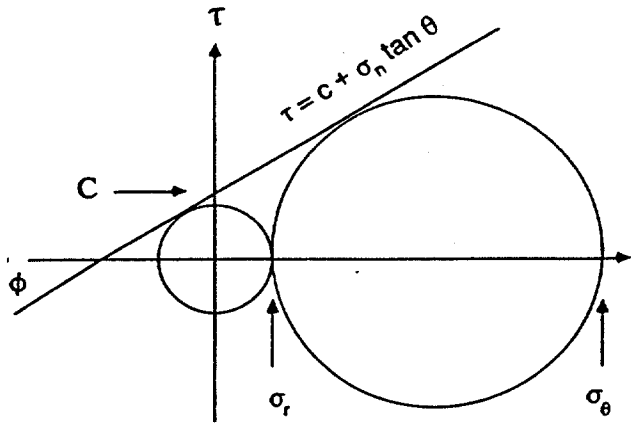

Fig. 6—Mohr-Coulomb failure criterion

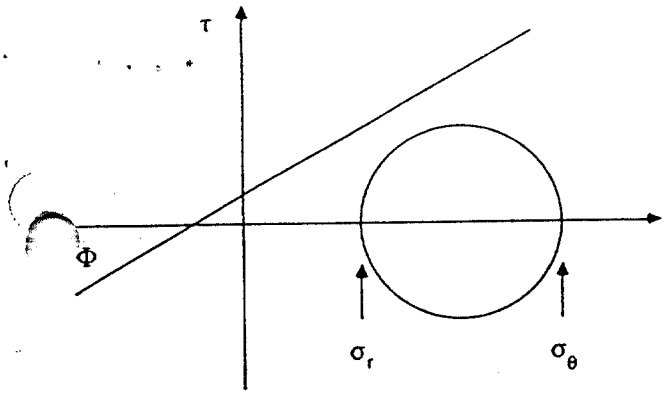

Fig. 7—Radial and tangential stress conditions on wellbore wall as applied to Mohr-Coulomb diagram for "no failure" conditions

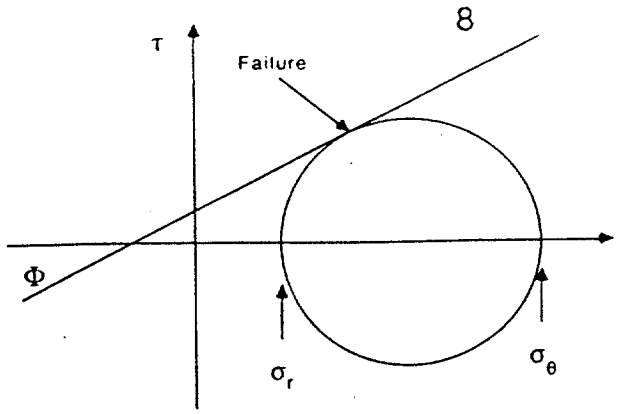

Fig. 8—Radial and tangential stress conditions on wellbore wall at failure as applied to Mohr-Coulomb diagram

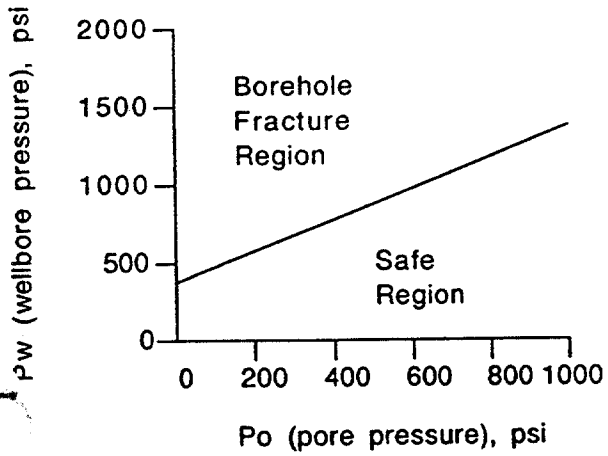

Fig. 9—Relationship between pore pressure and wellbore pressure for tensile failure at wellbore surface in a shallow gas well

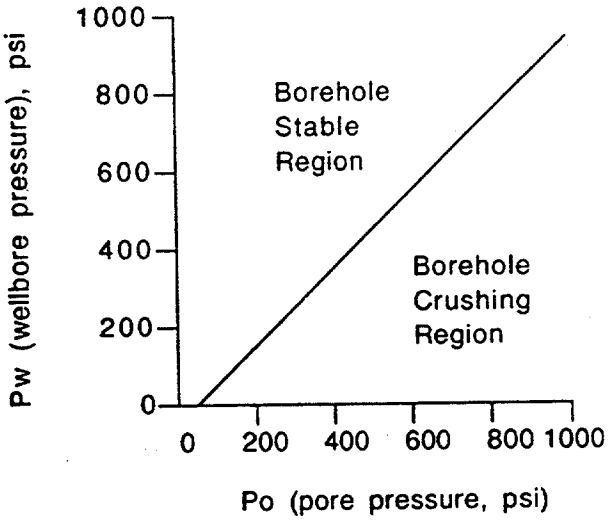

Fig. 10—Relationship between pore pressure and wellbore pressure for the onset of crushing type wellbore failure in a shallow gas well

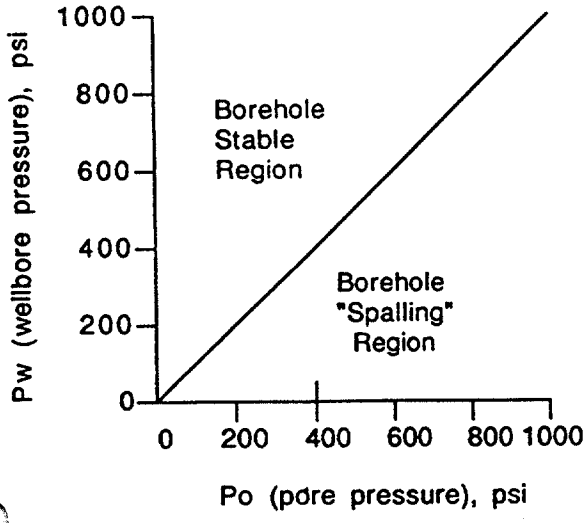

Fig. 11—Relationship between pore pressure and wellbore pressure for the onset of spalling type wellbore failure in a shallow gas well

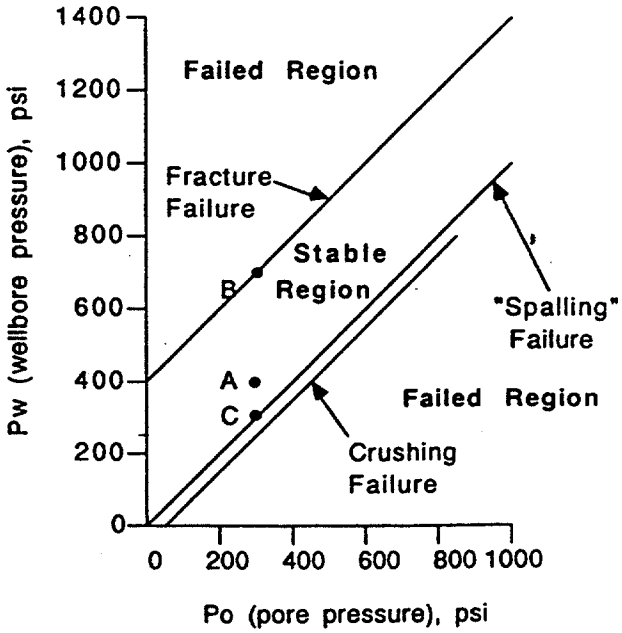

Fig. 12—Stable region and failed regions in a shallow gas well

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Method for Determining the Feasibility of Dynamic Kill of Shallow Gas Flows

by W.L. Koederitz, F.E. Beck, J.P. Langlinais, and A.T. Bourgoyne Jr., Louisiana State U.

SPE Members

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ABSTRACT

Gas flows from shallow sands present difficult well control challenges when encountered. Contingency plans for handling shallow gas flows generally are based on a dynamic kill procedure. In a dynamic kill, the bottom-hole pressure is increased without the use of a surface choke. With this method, high circulating rates are used to increase annular frictional pressure losses. In this paper, a systematic procedure is presented for estimating the loads present on the well and diverter system during a dynamic kill operation. This is useful both in well design and in planning well control operations. The procedure is based on a steady-state systems analysis calculation applied to a diverted well and includes consideration of the effects of critical (sonic) exit pressure and pressure changes due to elevation, friction, and acceleration.

Example analyses are discussed for well conditions typical of (1) a bottom-supported marine rig or a land rig, and (2) a deep-water floating drilling unit. The floating unit example is presented both with and without the use of a marine riser. The example analyses illustrate the importance of using diverters larger than 6-in. diameter and supports the practice of drilling pilot holes to the depth of the next casing string. The examples also illustrate that a dynamic kill will be significantly more difficult if the length of conductor casing is insufficient to prevent broaching from the conductor casing shoe to the seafloor.

INTRODUCTION

A gas flow from a shallow sand occurring before surface casing has been set is one of the most difficult well control problems that can be experienced during exploratory drilling operations. Considerable emphasis is placed on prevention of shallow gas flows during the planning phase and when drilling the shallow portion of the well. Seismic techniques can be used to attempt to identify gas zones using "bright spot" analyses. Drilling data from near-by wells, when available, can also be used to identify likely shallow gas zones. These same data can be used to estimate formation pore pressures and required mud weights to safely control the well through these zones. If localized gas concentrations are detected, hazards can sometimes be reduced by selecting an appropriate surface location.

While prevention is preferred, use of existing technology does not always prevent the occurrence of shallow gas flows. Contingency plans must be developed to address this possibility. Shown in Figure 1 is a decision tree which summarizes possible actions after a shallow gas flow is detected. In most cases, it would not be advisable to shut-in the well because of the likelihood that underground fracturing will occur and the well flow could broach to the surface, undermine the rig foundation, and release combustible gases beneath the rig. In some situations however, shutting-in the well and applying conventional well control techniques may be be a possible alternative [Beall, 1984]. This would be true primarily for floating vessels in deep water which do not depend on bottom support and can be easily moved from the hazardous area.

The typical approach for handling a shallow gas kick is to allow the well to flow through a diverter, in an attempt to preserve wellbore integrity. Some operators use a contingency plan which calls for a volume of weighted mud to be maintained for a dynamic kill attempt. This would be done immediately, before the well has unloaded. Other plans call for the early use of sea-water for a dynamic kill. If an early dynamic kill is unsuccessful or not attempted, the diverted well will eventually bridge or deplete. However, for large shallow gas reservoirs, the length of time and loss of reserves could be unacceptable,

references follow at end of paper

water is used, there must be a supply of fluid maintained or it must be mixed at the rate needed. The injection pressure and horsepower requirements can be reduced by use of special drag-reduced fluids. However, if these cannot be reduced to acceptable limits, a relief well will be needed. The wellbore loading and the diverter wellhead pressure must be maintained within acceptable limits throughout the dynamic kill.

The well-flowing period is divided into two time periods. The early time period begins when gas first flows into the wellbore and ends when substantially all of the mud has been unloaded from the wellbore.

A specific late-time dynamic kill attempt is modeled by using systems analysis and assuming the system passes through a series of equilibrium conditions as it changes from all-gas flow to all-liquid flow to the minimum liquid rate at which gas cannot enter the wellbore. At each of these equilibrium conditions the flow rates and flow conditions are defined. This provides the definition of the loads and of the injection hydraulic requirements throughout the kill.

A "most optimistic" early-time dynamic kill is modeled by calculating the all-liquid rate at which the gas cannot enter the wellbore. This assumes that the gas flow could be detected immediately, prior to any loss of hydrostatic head due to gas displacing mud from the annulus. While this assumption is unrealistically optimistic, if calculations show the flow rate achieveable with existing rig equipment is insufficient for a kill, an early-time dynamic kill can be ruled out.

EXAMPLE APPLICATIONS

Two typical drilling situations will be analyzed to demonstrate the analysis method. These examples will also show the information which is needed to perform this type of analysis. The first example is a platform rig in shallow water, and the analysis will be performed in detail. The second example is a floating rig in deep water; a review of only key results is presented for this example. Both examples are hypothetical; however, they are based on actual Gulf of Mexico well designs and engineering guidelines typically used in that area.

190 ft Water Depth Example

The first example is a platform rig in 190 ft of water. The well design and reservoir conditions for this example are as shown in Appendix A. This is a typical platform well design. The base case for this example includes using seawater as the kill fluid, a 17.5-in. hole, and a 6-in. by 8-in. diverter line. The variations of using a heavier kill mud, a pilot hole, and a larger diverter will be reviewed as individual cases.

Figure 3 shows the systems analysis for the base case. The "IPR" curve shows the performance of the reservoir. The "0 BPM" curve shows the performance of the wellbore and diverter system when flowing only gas, i.e., the pressures required to move the resulting rates of gas through the wellbore and diverter system to the atmosphere. The intersection of the "IPR" curve and the "0 BPM" curve corresponds to the well condition after all of the liquid has been unloaded from the wellbore and the free-flowing equilibrium condition has been reached. For this example, the well would be flowing at 308 MMSCFD.

Injecting seawater at rates of 100 and 200 barrels/minute (bbl/min) would decrease the gas flow rates to 247 and 152 MMSCFD, respectively (Figure 3). In achieving a dynamic kill, an injection rate of 260 bbl/min creates sufficient backpressure at the sandface to prevent further gas flow from the reservoir. Seawater is then replaced with gradually heavier fluids at decreasing rates, until a fluid with sufficient static gradient to contain the reservoir is in place. In this typical systems analysis approach, it is assumed that the well passes through a series of equilibrium flowing conditions.

This method provides a means to estimate the free-flowing condition of the well and the required kill rate for an assumed density fluid. However, the pressure loads placed on the wellbore and diverter during the kill attempt are not described. These loads are of considerable interest for shallow gas flows, due to the low fracture gradients, shallow casing setting depths and the risks of gas flows broaching to the surface if fracturing occurs.

Figure 4 shows the pressure in the open-hole section of the wellbore versus depth, for various injection rates. The injection of liquids at these rates creates pressures in the wellbore above the fracture pressure. Figure 5 shows the wellbore loads in terms of equivalent circulating density (ECD), in pounds per gallon equivalent. For the free-flowing condition (0 BPM), the fracture margin is 0.4 ppg, which occurs at the casing shoe at 600 ft. For the 200 bbl/min injection rate the fracture margin is -9.6 ppg, indicating wellbore loading greatly in excess of fracture resistance. At an injection rate of 260 bbl/min all of the gas has been removed from the well. However, Figure 5 shows that circulation at this rate will result in wellbore loads in excess of fracture resistance.

Figure 6 shows the effect of injection rate on gas rate. The kill rate for the base case is 252 bbl/min. Three variations are also shown from the base case. The use of 9 ppg mud instead of the 8.5 ppg seawater results in a kill rate of 228 bbl/min. The drilling of a 9.875-in. pilot hole rather than the 17.5-in. hole reduces the kill rate to 94 bbl/min. The use of a larger diverter system (two 12-in. ID lines) requires a kill rate of 548 bbl/min. The use of a denser kill fluid has a small effect on gas rate, while the pilot hole and the large diverter have large effects.

Figure 7 shows the wellhead pressures for each case as a traverse from the free-flowing to the dynamically killed condition. The dashed curve indicates that all of the gas has been removed from the wellbore. The base case and the 9 ppg mud case show the highest wellbore pressures, with the large diverter case showing the lowest. These values indicate the pressure loads which will be placed on the wellhead and diverter. The rise in wellhead pressure also shows how much the friction due to flow in the diverter line contributes to the dynamic kill effort. While any extra resistance at the surface increases bottom-

11 ppg mud is used as the kill fluid. In another case it is assumed that a riser is run and a diverter on board the rig is used.Table 2 shows the estimated kill rates for both early and late-time dynamic kills.

Figure 14 shows the gas rate vs injection rate and Figure 15 shows the fracture margin traverses for this example. The riser case flows at a higher rate than the base case and requires a higher kill rate. All of the fracture margins are positive. As the well is killed the fracture margins become about equal for all cases.

Figures 16 and 17 show how the riser affects the system performance. Figure 17 shows the system performance prior to injection (solid curves) and at injection rates when all gas has been removed (dashed curves). The "0 BPM" curve for the base case is nearly constant, showing the limiting effect of the hydrostatic head of the water column. The more constant (i.e. level) behavior of the base case curves indicates that the 1800 ft water column in this example is effectively regulating the pressure at the top of the structural casing. This supports previous arguments [Beall, 1984] that there are some operational advantages in killing a blowout without a marine riser.

Figure 17 compares wellbore ECD's for the base case and the riser case. The base case has less variation, due to the effect of the water column at the exit. The maximum loads for both cases occur as all of the gas has been removed from the wellbore; the loads are similar, with the riser case showing about 0.5 ppg more loading. The fracture margin traverses for both cases are acceptable.

SUMMARY AND CONCLUSIONS

A method is presented in this paper for estimating the loads imposed on the well and diverter system during a dynamic kill. This analysis considers the following parameters:

Kill fluid rate and density,
Injection pressure,
Injection horsepower,
Fracturing of the wellbore,
Diverter wellhead pressure.

The results of this analysis can be combined with the operational aspects of a specific well situation to arrive at a practical plan for shallow gas well control.

The method was illustrated for a platform rig and a floating rig operating in the Gulf of Mexico. Calculations using this method found that early-time dynamic kills which depended on available rig equipment were not practical for the 10 ft., 5 darcy reservoir assumed. The platform rig example showed a 6-in. diameter diverter to be inadequate. Late-time dynamic kill attempts made without the use of relief wells were found to be practical for the platform rig example only if a pilot hole was used.

Considerable engineering judgement is needed to combine the technical analysis with operational realities and experience to provide a practical plan for a specific well. Some typical questions might be: What is the erosive life of the diverter system? How accurate are the estimates of fracture gradients and reservoir parameters? If a pilot hole is used, how quickly would it erode? How accessible is the well? Because of the large number of variables involved, each case should be analyzed individually by the well operator.

ACKNOWLEDGEMENTS

This research work was supported by the U.S. Minerals Management Service under Contract No. 14-12-0001-30274. The authors also acknowledge the financial support provided by the Amoco Foundation. In addition, appreciation is due to the various operators who provided well designs and descriptions of well control events for use in this study.

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SI CONVERSION FACTORS

ft x 0.03048 = m
in. x 0.0254 = m
bbl/min x 0.00264978 = m3/s
MMSCFD x 0.3277413 = m3/s
ppg x 0.0198264 = kg/m3
hhp x 745.6999 = W
psi x 6894.757 = Pa
(deg F - 32)/1.8 = deg C
cp x 0.001 = Pa s
lb/100 sq ft x 0.4788026 = N/m2

TABLE 1
190 ft Water Depth Example - Kill Rates

Option	Initial Free-Flowing Gas Rate, MMSCFD	Free-Flowing Kill Rate, bbl/min	All-Liquid Circulation Kill Rate, bbl/min
Base Case	308	252	200
9 ppg Mud	308	228	0
Pilot Hole	203	94	50
Large Diverter	318	548	325

TABLE 2
1800 ft Water Depth Example - Kill Rates

	Free-Flowing Kill			All-Liquid Circulation Kill		
Option	Kill Rate, bbl/min	Maximum Injection Pressure psia	Maximum Hydraulic Horsepower hhp	Kill Rate, bbl/min	Maximum Injection Pressure psia	Maximum Hydraulic Horsepower hhp
Base Case	168	16,860	70,570	140	11,750	41,000
11 ppg Mud	118	12,310	36,230	0	15	0
Riser	188	21,140	99,010	110	7,334	20,100

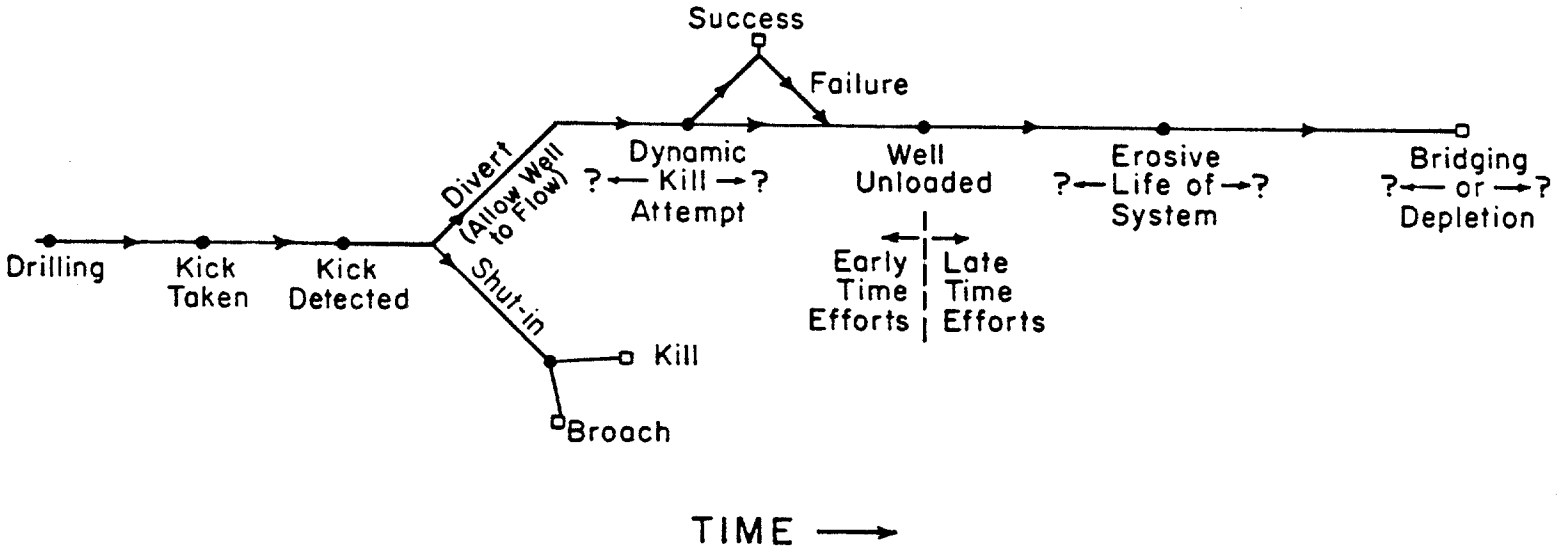

Fig. 1—Decision tree for shallow gas well control.

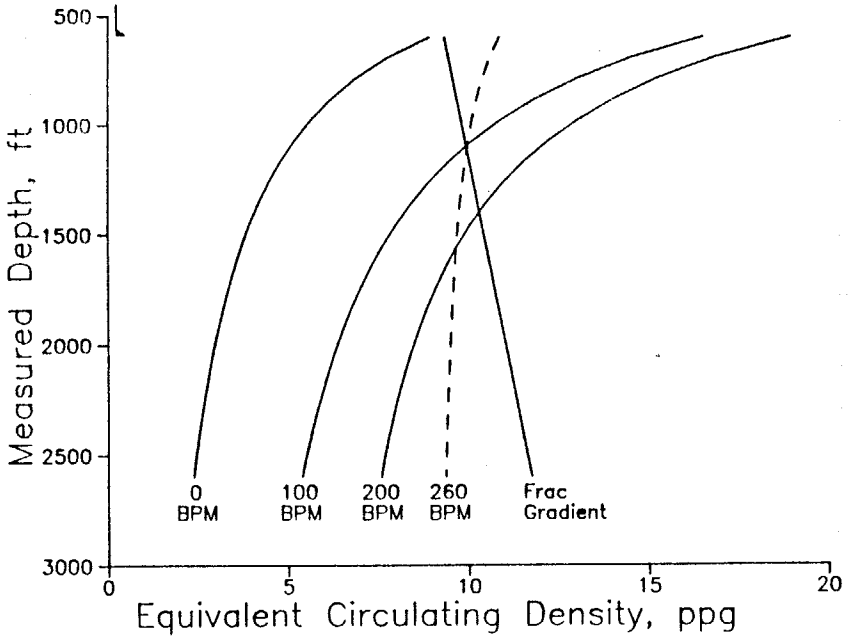

Fig. 5—190-ft water depth example—wellbore ECD for base case.

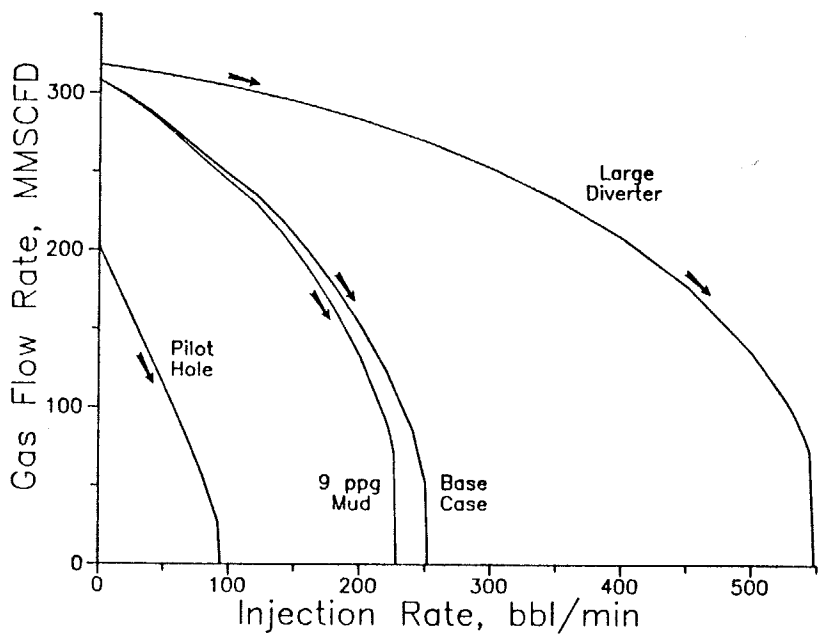

Fig. 6—190-ft water depth example—gas flow rate vs. injection rate.

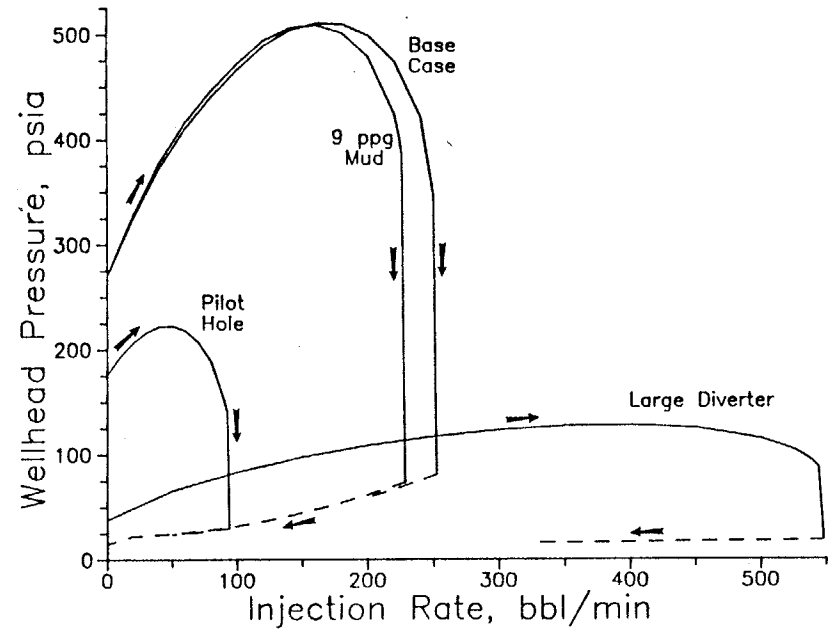

Fig. 7—190-ft water depth example—wellhead pressure traverse during kill.

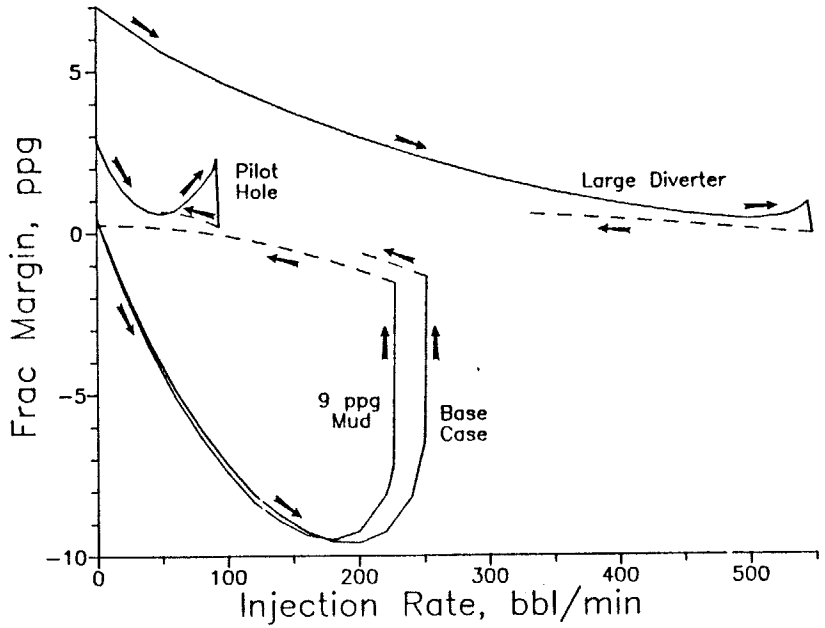

Fig. 8—190-ft water depth example—fracture margin traverse during kill.

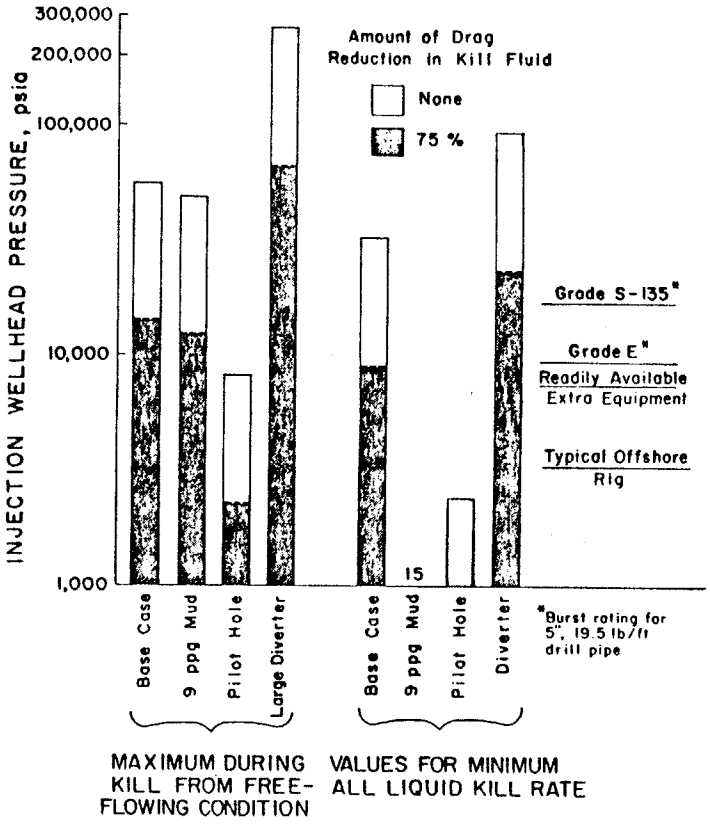

Fig. 12—190-ft water depth example—injection wellhead pressures for kill.

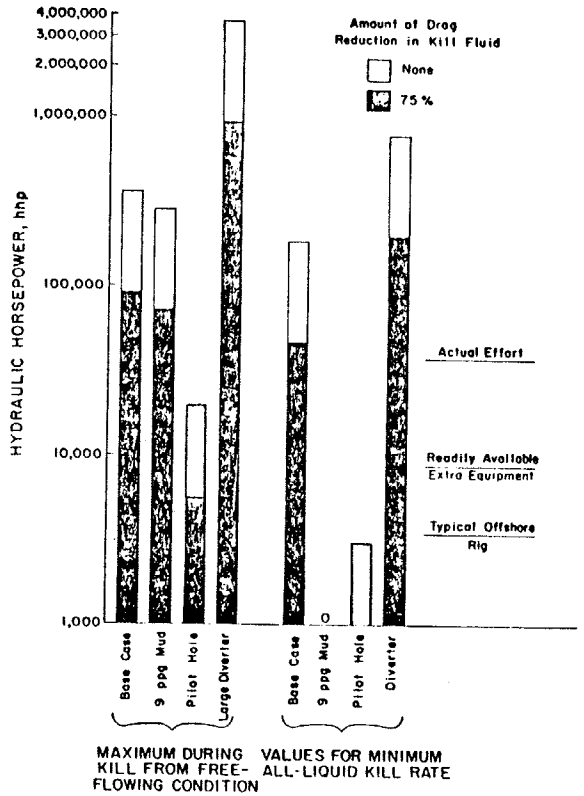

Fig. 13—190-ft water depth example—hydraulic horsepower requirements for kill.

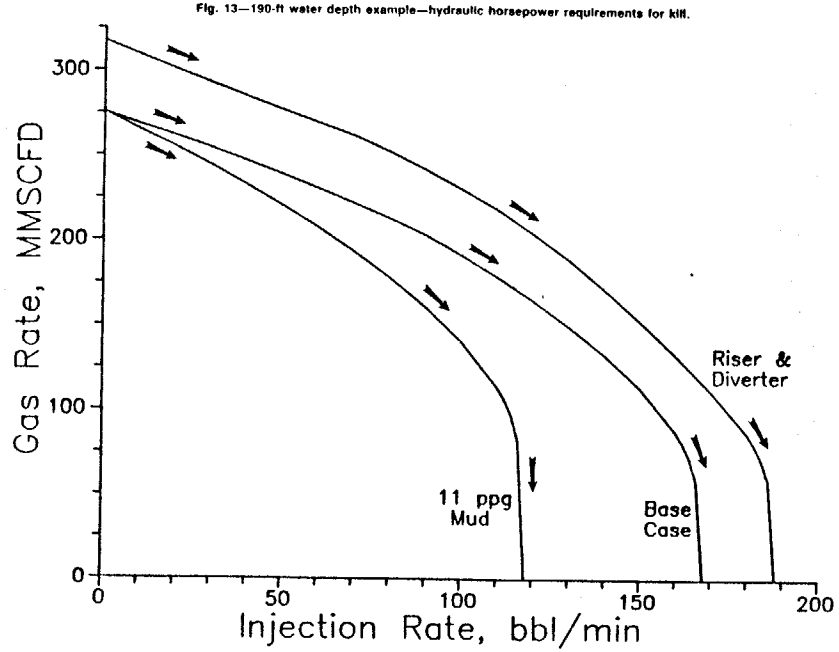

Fig. 14—1,800-ft water depth example—gas flow rate vs. injection rate.

Use of Shallow Seismic Data in Relief Well Planning

J. E. Booth, Mobil E & P Services

ABSTRACT

On 20th September 1984, surface control was lost on N-91, an appraisal well in the West Venture gas field, offshore Nova Scotia, Canada. Subsequent events led to the failure of the 9 5/8 in. and 13 3/8 in. casing strings and the injection of well fluids into relatively shallow formations. Snubbing operations were begun on the original well, and a relief well was started some 3000 ft. from the blowing well. While drilling at approximately 2350 ft. a gas kick was taken on the relief well and successfully diverted. This gas was evidently the result of charging of shallow formations as a result of the blowout on N-91. In order to determine the extent of gas charging, and to gather additional information to be used in relief well planning, a shallow seismic survey was taken of an area some 3 miles by 2 miles around the blowing well.

The seismic data revealed the presence of two charged zones. Subsequent surveys were taken at approximately monthly intervals, to monitor changes in the extent of these zones. Assessment of alternative relief well locations was greatly facilitated by the recently obtained seismic data, and an improved understanding of shallow geology in the area. These considerations, and other factors taken into account in planning a second relief well are described in this paper.

INTRODUCTION

On 20th September 1984, surface control was lost on N-91, an appraisal well in the West Venture gas field, offshore Nova Scotia, Canada (Fig. 1). The drillpipe was sheared and the well shut in with approximately 12,000 psi surface pressure.

Six days later, surface pressure suddenly dropped to 3750 psi, indicating that the 9 5/8 in. and 13 3/8 in. casing strings had ruptured and that the well was now injecting fluids at a relatively shallow depth. While work continued on N-91, in preparation for snubbing operations and a top kill attempt, a relief well (B-92) was spudded at a surface location some 3000 ft. away.

On 2nd November, when drilling at approximately 2350 ft. with conductor pipe set at 635 ft., a gas kick was taken, diverted, and brought under control. 24 in. casing was subsequently run to 2208 ft.

(Figures at end of paper)

INTERPRETATION OF GAS KICK ON RELIEF WELL

The gas zone encountered in B-92 was evidently the result of recent charging of shallow formations as a result of the N-91 blowout, since there was no indication of gas at this location in the original (1980) site survey of the area. Unfortunately, available information on shallow geology was very limited, since mud and wireline logging on Venture wells did not normally commence until after 18 5/8 in. casing was set to approximately 2800 ft. In order to provide additional information on shallow geology and hopefully to reveal the locations of any gas charged sands, a shallow seismic survey was shot on Nov. 5 1984 covering a rectangular area about 3 miles by 2 miles, centered on N-91 (Fig. 2).

SEISMIC SECTION SHOWING 'NEW EVENTS'

Comparison of the new seismic data with the original (1980) survey revealed the existence of two new seismic events, evidently the result of charging due to the blowout. The deeper of these occurred at about 2200 to 2300 ft. thus corresponding to the charged zone encountered in the relief well. However there was also a second, hitherto unsuspected, new event evident at approximately 1370 to 1480 ft. (Fig. 3).

EXTENT OF GAS CHARGED ZONES

The outline of the shallower feature was reasonably clear and could be mapped with confidence (100 m ±). The deeper zone however was much less clear and only a tentative outline could be obtained from the shallow seismic data. Both features were centered on N-91, the shallow one being elongated in an updip direction and the deeper one apparently elongated in a strike direction. The shape of the features was interpreted as evidence that the primary mechanism for gas charging of the shallower zone was displacement of water by gas in permeable sands, which was consistent with its general shape and updip elongation. The fact that the deeper zone was elongated in a direction parallel to formation strike (and to the shoreline of Sable Island) was interpreted as evidence that its shape was influenced by fracture orientation, since the preferred orientation for both natural and induced fractures in this area would be sub-parallel to Sable Island.

A series of temperature logs run in B-92 after 24 in. casing had been set at 2208 ft. showed indication of water flowing behind pipe. The persistence and magnitude of this temperature anomaly suggested that fluids produced by N-91, and injected into shallow formations, were communicating with B-92 along a conduit of limited extent, rather than as a result of a pervasive flooding of formations between the wells. This provided further evidence that fracturing was the dominant mechanism associated with this deeper zone and explained why it was difficult to delineate on the seismic surveys. In view of the facts that B-92 and N-91 were aligned approximately along the preferred fracture orientation for the area, and that the gas charged sand encountered in the well was still exposed, it was decided that the current location was potentially hazardous and the relief well was plugged and abandoned.

INTERPRETATION OF SHALLOW GEOLOGY

Correlation between the shallow seismic data, logs from B-92, and a litholog from well C-67 (a stratigraphic control well drilled on the west end of Sable Island in 1967) led to a better understanding of the shallow geology in the vicinity of the current wells. A synopsis of the geology, and the correlation with wells N-91 and B-92 is shown in Fig. 5.

EXPANSION OF GAS CHARGED ZONES

The existence of the gas charged zones, and the prospect of continued charging, obviously presented a potential hazard, not only to relief well operations, but also to continuing operations on board the Zapata Scotian (the rig on well N-91). This was particularly true of the gas at 1370 ft. because of its shallow depth and its association with relatively unconsolidated sediments. In order to monitor changes in the extent of the zone, repeat shallow seismic surveys were taken initially at intervals of approximately one month and extending to six to seven weeks between the later surveys. A total of eight such surveys were shot between Nov. 5 1984 and May 9 1985. As was the case with the original survey, the deeper feature could not be mapped accurately. The shallow one could however and the early surveys clearly showed that it was increasing in extent, primarily in an updip direction. Figure 6 shows the changed in extent of the shallow gas charged zone from 5th Nov. 1984 to 6th Feb. 1985.

SELECTION OF ALTERNATIVE RELIEF WELL LOCATIONS

Assessment of suitable alternative locations was greatly facilitated by the wealth of shallow seismic data obtained from the first few surveys, and the improved understanding of shallow geology in the area. The following factors were taken into consideration in assessing potential locations:-

1. Bathymetry
2. Location of gas charged sands
3. Geological hazards such as paleochannels and faults
4. Directional drilling, surveying and ranging considerations
5. Direction of prevailing winds and proximity to shore
6. Safety

Bathymetry

The minimum depths in which the support vessels needed for relief well and kill operations were as follows:

Semisubmersible accommodation and pumping vessel	32 meters
Workboats	20 meters

Seabed gradient must also be taken into consideration in selecting locations for jack-up operations.

Gas Charged Sands

Having determined the extent of the shallow gas zone and ascertained that it was advancing updip in a reasonably predictable manner, arbitrary boundaries some 2000 ft either side of the feature, and extending in an updip direction were drawn. These boundaries were taken to delineate a zone which would contain all anticipated future migration of the gas, plus a safety margin. The relatively large safety margin was chosen because although formation dip was the main control over expansion of the feature, dip was only about 1 1/4° and subsequent migration of the gas could easily could easily be influenced by other factors such as variations in permeability.

Geological hazards such as paleochannels and faults

Features such as erosion channels and faults were identified on the shallow seismic and taken into consideration when selecting suitable relief well locations. There was a series of paleochannels in the area, running approximately N/S.

Directional drilling, surveying and ranging considerations

An analysis of directional surveys on N-91, a vertical well, resulted in an estimate of 50 ft.± of uncertainty at the 9 5/8 in. casing shoe, which was to be the primary target for ranging operations. A stringent survey program had been developed for B-92, the first relief well, which would result in an estimated uncertainty of 78 ft. ± at ranging depth. The cumulative uncertainty would in these circumstances be well within the 200 ft. ± estimated effective range for active ranging tools in these formations. Moving the relief well surface location further away from the target would obviously result in an increase in survey uncertainty since it is largely a function of hole inclination, which in turn is a function of horizontal displacement to the target. In order to stay within the maximum acceptable cumulative uncertainty of 200 ft. ± between target and relief wells, the maximum distance between the wells had to be approximately 6000 ft.

Direction of prevailing winds and proximity of relief well location to shore

Prevailing wind direction was important for two reasons.

1. If unignited gas from N-91 escaped at surface, the resultant cloud would constitute a potential fire hazard to a rig in a downwind location.

2. Workboats should not work too close to Sable Island in an upwind direction since, if they lost power, they could be blown ashore. The minimum acceptable distance proposed by boat captains was one nautical mile (approximately 6076 ft.).

Prevailing winds are from the North West in winter and from the South West in summer. The gas hazard was considered not to be a major constraint if the relief well was located at least 5000 ft away from N-91.

Safety

Relief well operations are hazardous and have a high potential for giving rise to rig emergency situations. Such problems become more serious in an offshore situation for many reasons. Rig evacuation is complex and dangerous, particularly in the severe weather conditions common in the Sable Island area in winter. Gas broaching at seafloor can result in bottom mounted structures becoming unstable. Operations such as the massive high pressure pumping planned during the N-91 kill operation are more hazardous in confined spaces. Land locations are therefore generally more desirable than offshore ones from a safety point of view.

Only three small areas satisfied all the selection criteria (see Fig. 7). One of these was Sable Island itself, the other two were offshore, one almost due west of N-91, the other to the east. In many respects Sable Island was the most attractive of the three locations, but was deemed impractical within the desired time frame, for environmental and logistics reasons (special low draft, landing-craft type vessels would be required for supply of a rig on the island). The east offshore area was rejected because of its proximity to a paleochannel and the fact that it lay along the preferred fracture propagation direction from N-91.

The remaining offshore area lay to the west of N-91. Shallow seismic data again proved useful in assessing possible location and in determining site specific depths to the various marker horizons. The location finally chosen was about 6000 ft. away from N-91 along an azimuth of approximately 282°. The second relief well (N-01) was spudded on 20th January 1985. The well plan incorporated a revised casing program which reflected the improved understanding of shallow geology, and the existence of the gas charged zones.

The relief well was drilled through the shallow formations without event, and eventually drilled to a depth of approximately 12000 ft. MD at which time a successful top kill was achieved on the N-91 rig, and the relief well was plugged and abandoned.

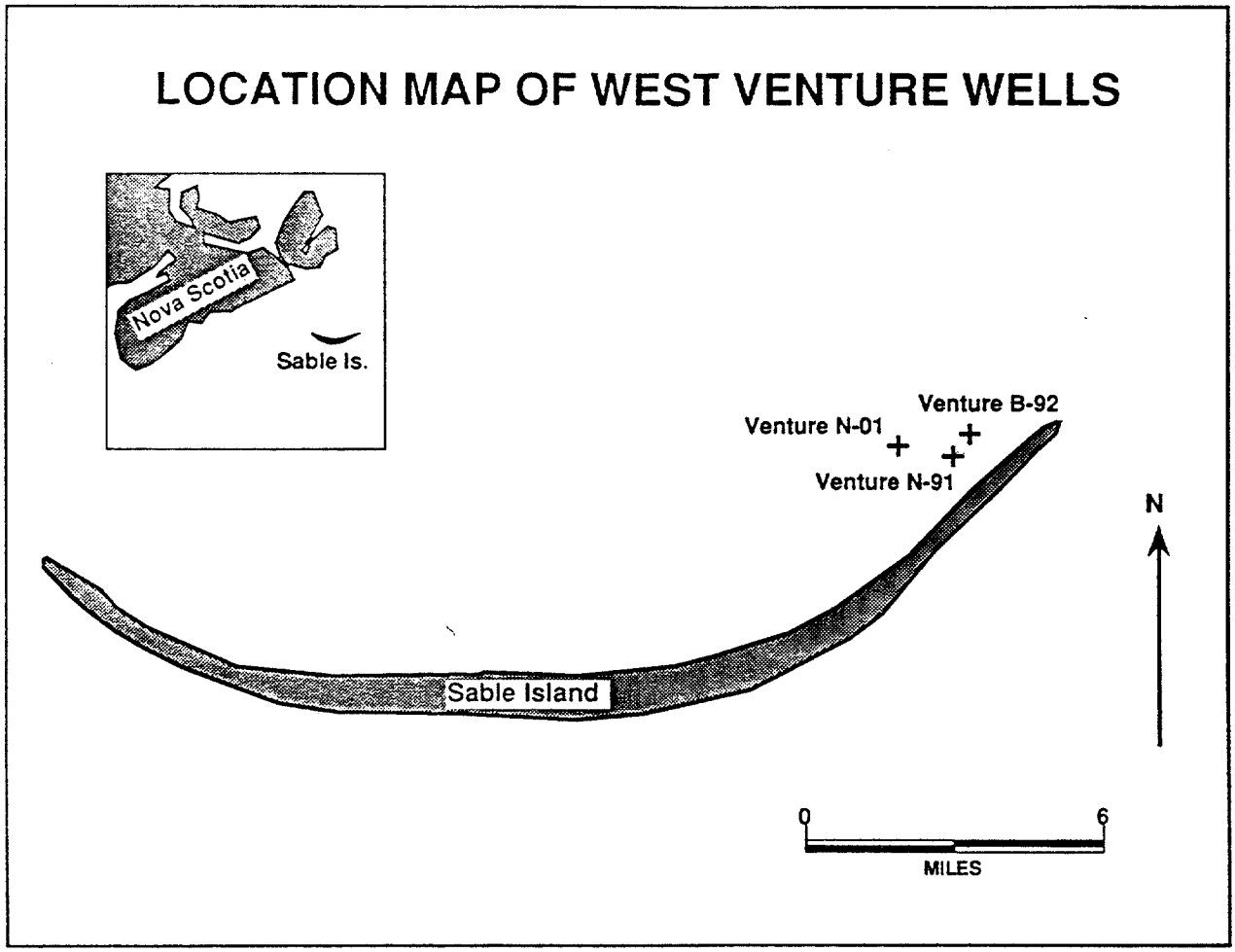

Figure 1. - Location Map of West Venture Wells

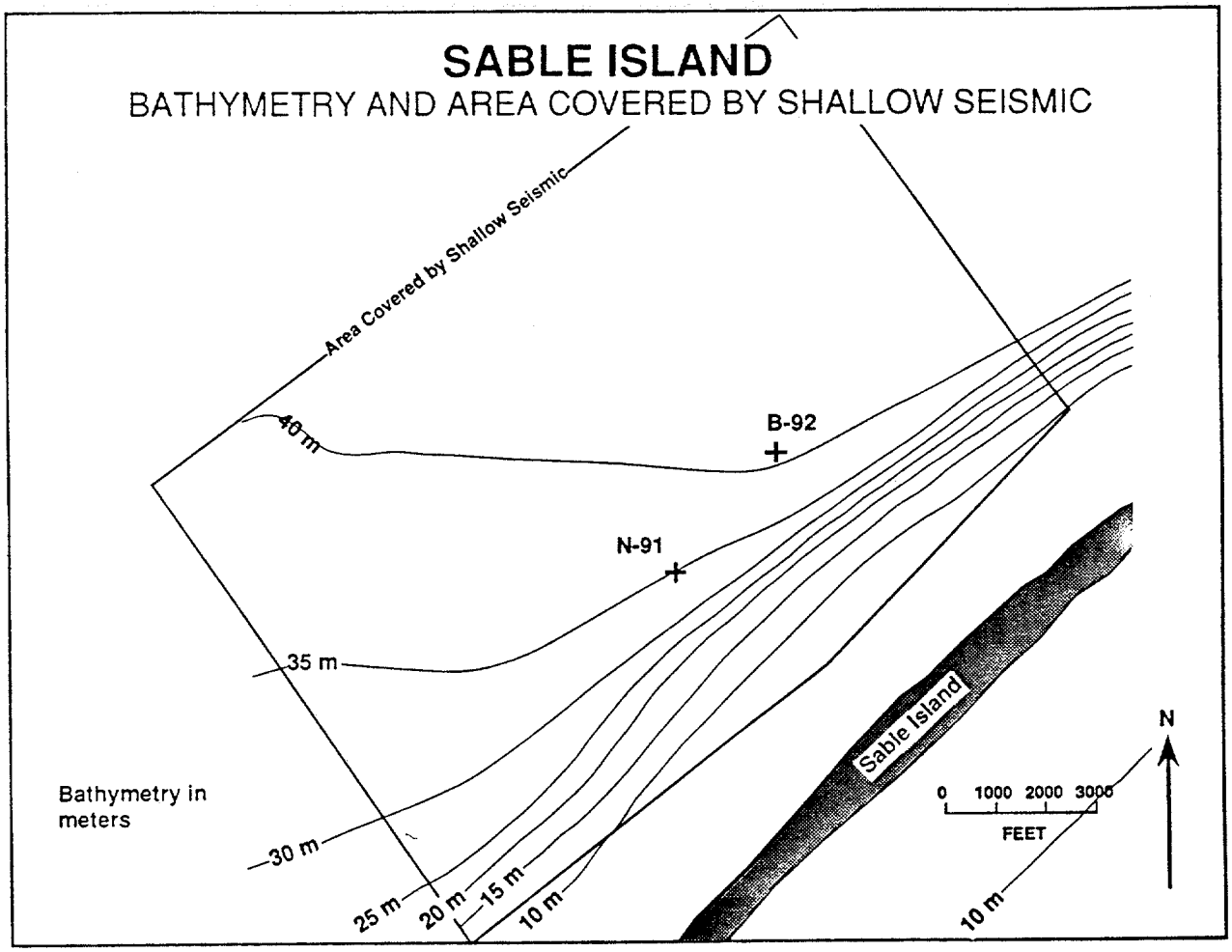

Figure 2. - Bathymetry and Area Covered by Shallow Seismic Surveys

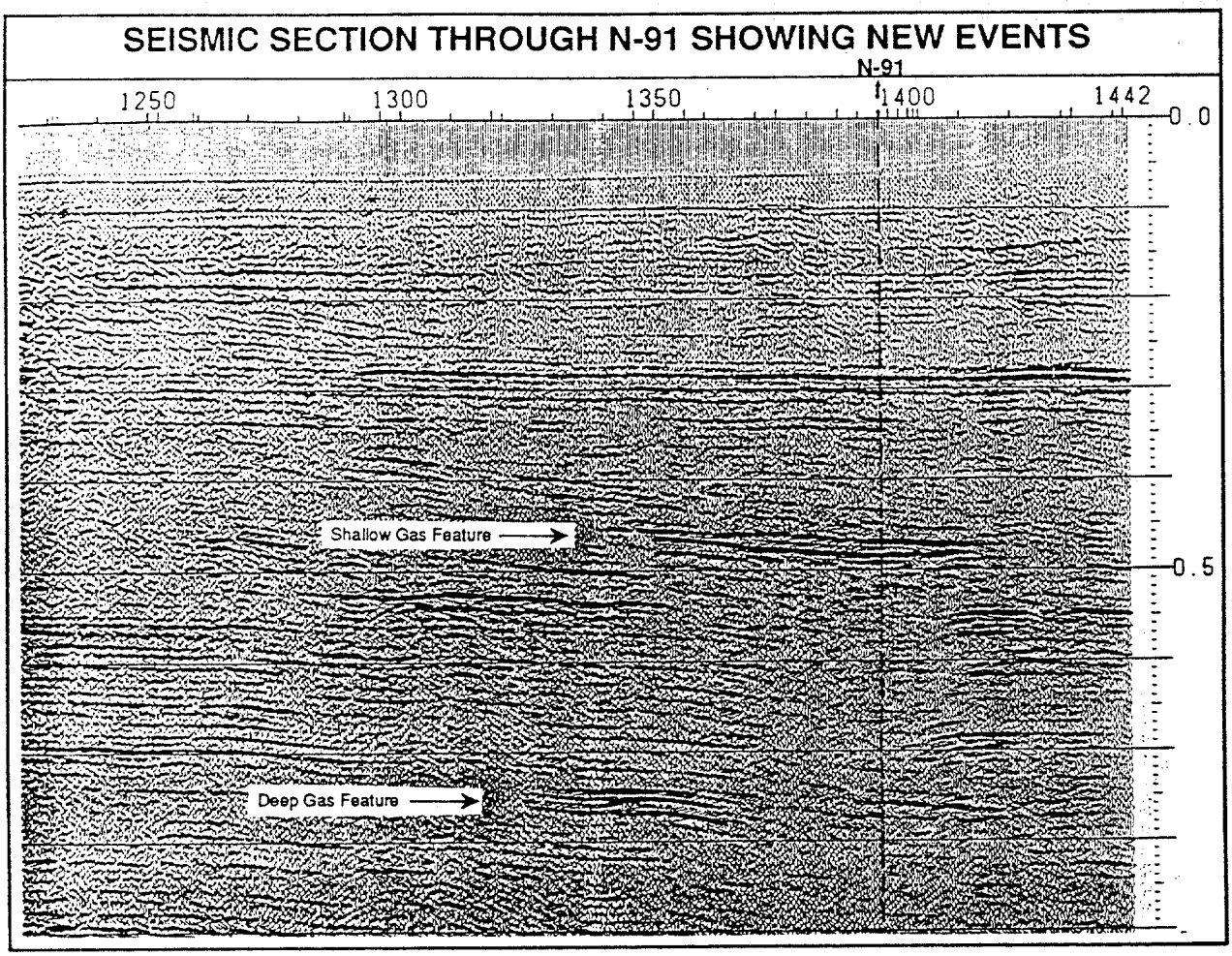

Figure 3. - Seismic Section Through N-91 Showing New Events

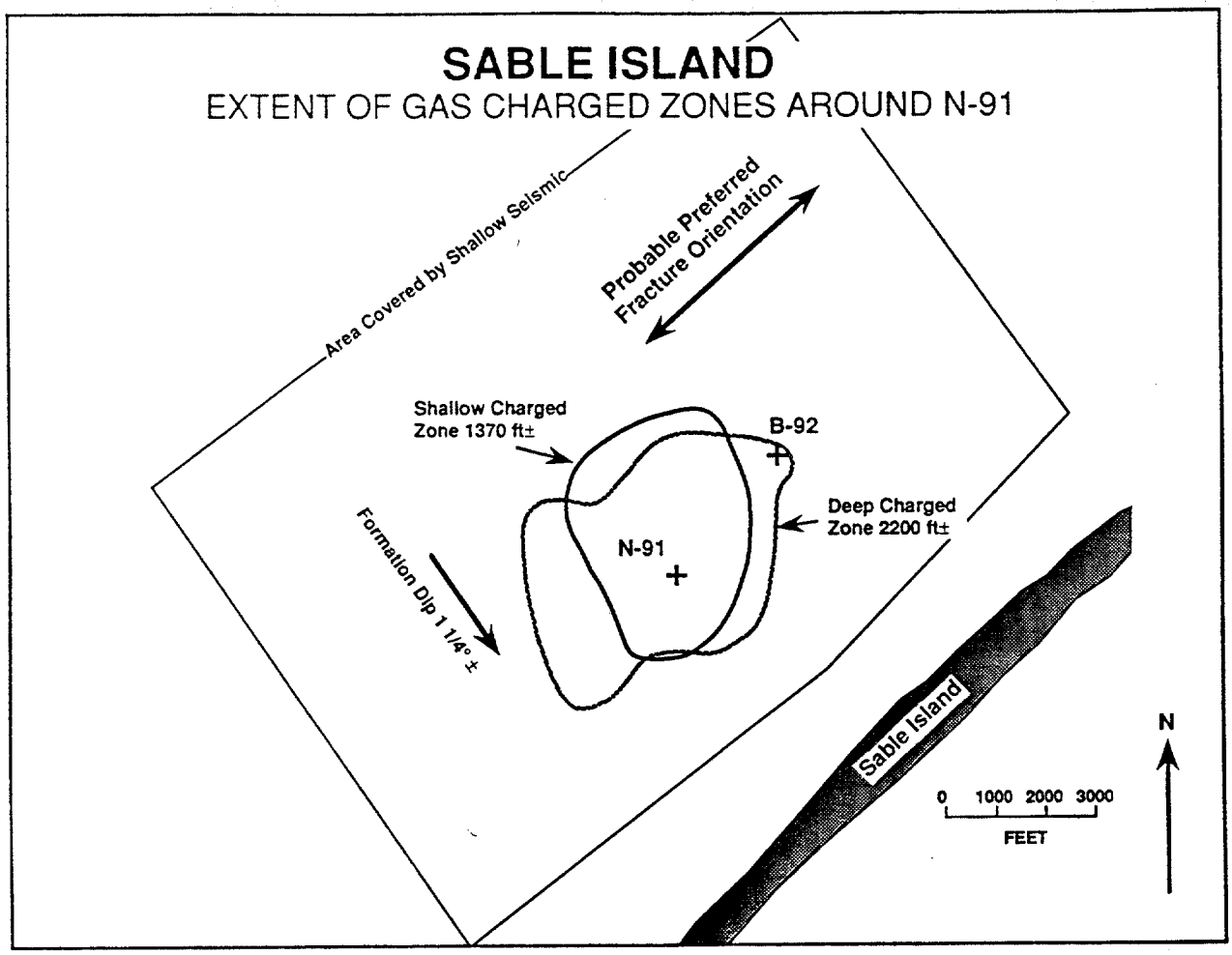

Figure 4. - Extent of Gas Charged Zones Around N-91

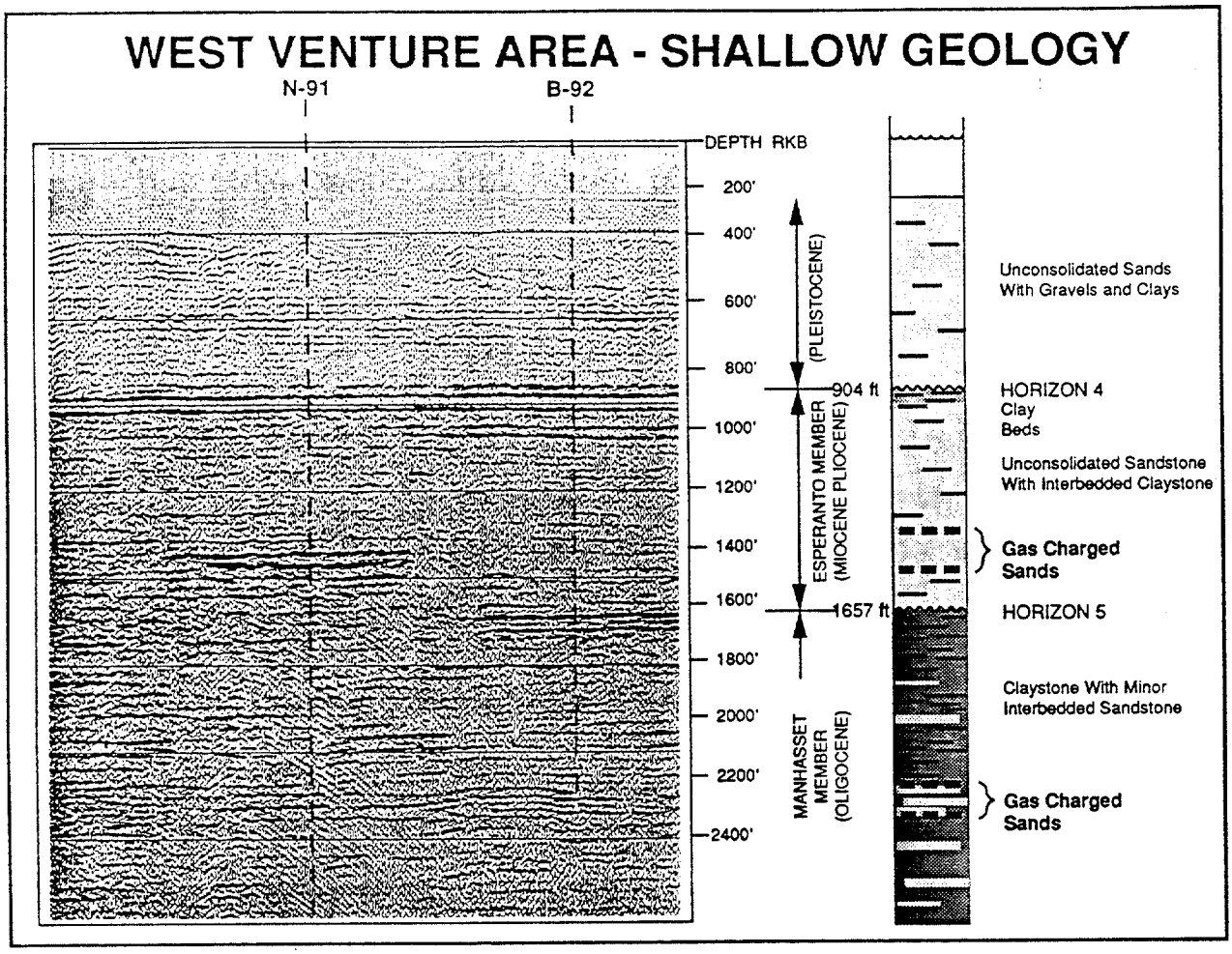

Figure 5. - Shallow Geology of West Venture Area

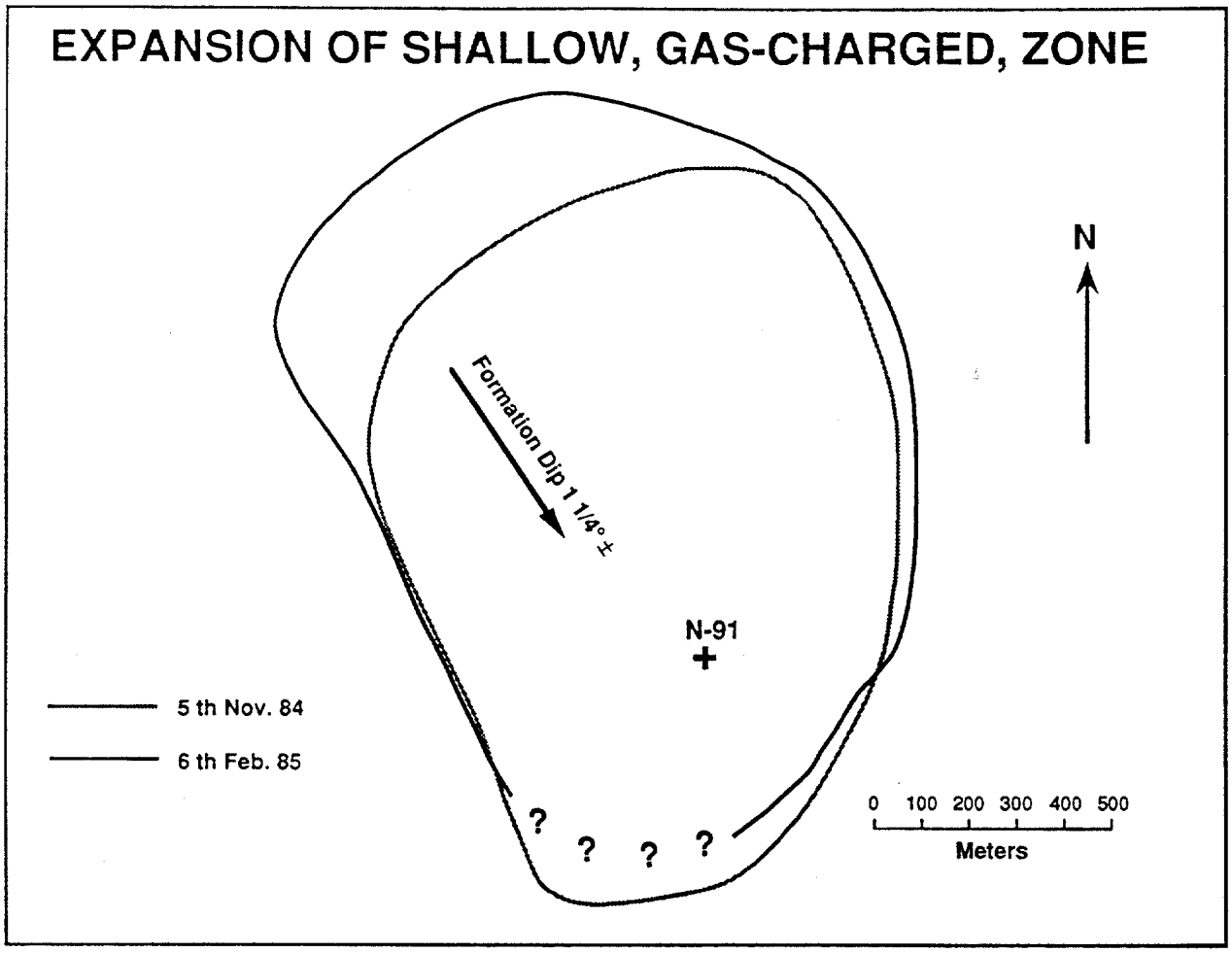

Figure 6. - Expansion of Shallow Gas-Charged Zone

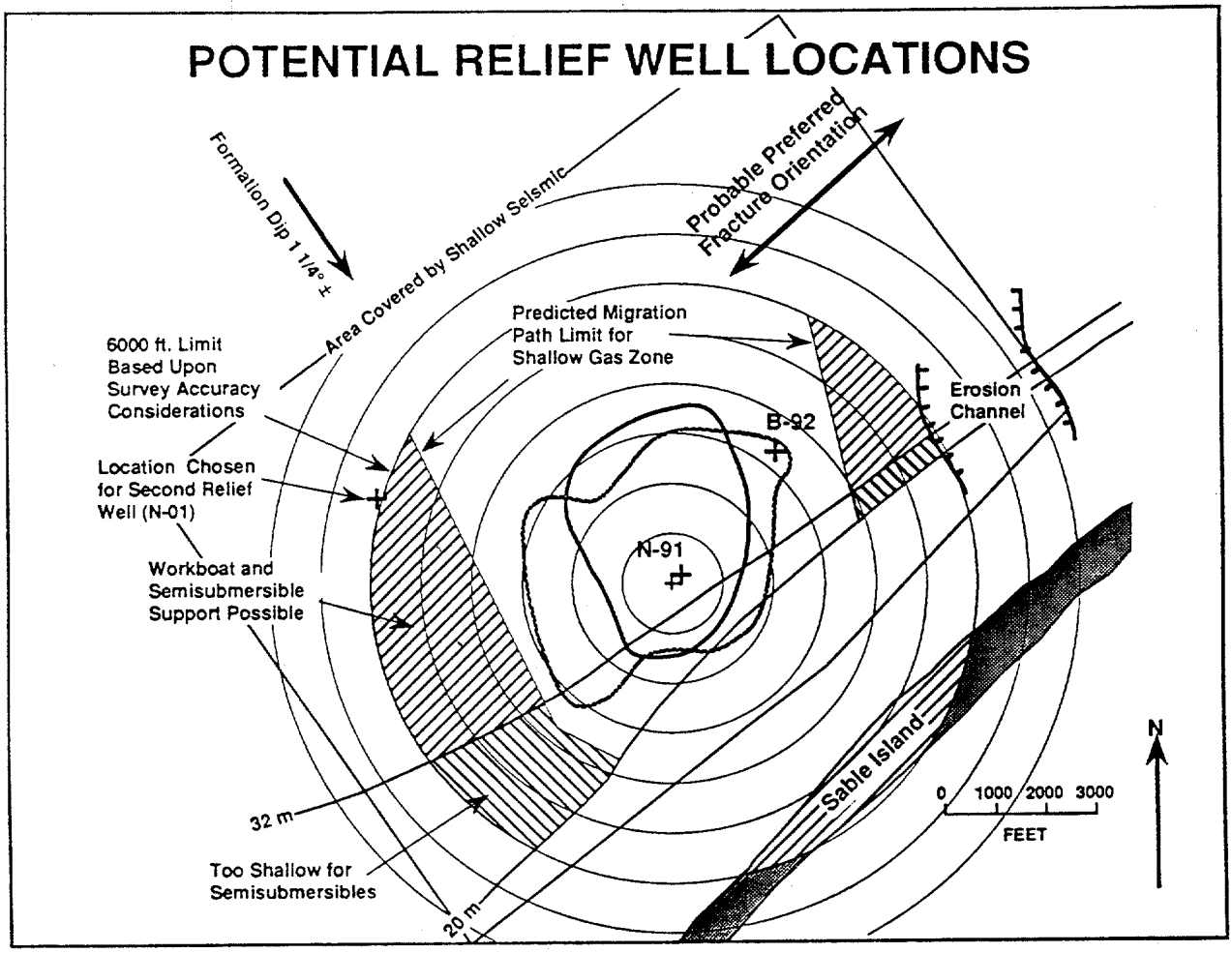

Figure 7. - Map of Areas Suitable for Relief Well Location

EXPERIMENTAL BENCH MARK DATA FOR TESTING WELL CONTROL COMPUTER METHODS

PURPOSE

The purpose of the paper is to provide experimental data for those working on the development of computer models of well control operations.

L.S.U. "B" No. 7 WELL

Training Well

The L.S.U. "B" No. 7 well is normally used to train industry personnel in the proper methods of well control. Figure 1 is a schematic of the training well, and the layout of the surface equipment at the well site is shown in Figure 2. The casing is 5-1/2 inch, 17 lb/ft, J-55 pipe cemented at 6140 feet. Simulating the drill pipe is 2-7/8 inch, 6.50 lb/ft, J-55 tubing, run to a depth of 6011 feet. A 1-inch nitrogen injection line, run inside the 2-7/8 inch tubing to a depth of 6029 feet, is used to place a nitrogen bubble on bottom to simulate a gas kick. A check valve, located at the bottom of the 1-inch string, serves to prevent mud from entering the string if bottomhole pressure increases too much during the runs.

The BOP stack consists of a Cameron Type U Preventer and Hydrill. The choke manifold contains one hand-adjustable choke (1) and three remote-operated chokes (Cameron high pressure (3), Patterson (4), Swaco Super (2). Also the well is equipped with both ram and annular blowout preventers and an accumulator. From the well, the mud flows through a choke, a mud-gas separator (13), and into one of two mud tanks. Mud conditioning equipment as well as a mixing pump are available if needed.

A lightly-treated fresh water-bentonite mud is circulated in the well. Plastic viscosity was varied from 4 to 57 cp and yield point from 1 to 59 lb/100 f^2. This range of viscosities was accomplished by increasing the bentonite clay content or water content, as necessary, to the mud in the tanks.

The mud is circulated using a diesel-powered Halliburton Model T-10 pump (12). The 1x2-7/8-inch drill pipe annulus at the wellhead is connected to the pump discharge. An alternate path for the dynamic method is also shown in Figure 2, in which the mud is pumped directly into the choke line (15) from the discharge line (16) to simulate pumping across the top of the annulus in a volumetric well control method. The pump has an output of 0.038 bbls/cycle at 60 CPM. The capacities of the 1-inch injection line, 1x2-7/8-inch drill pipe annulus, and 5-1/2x2-7/8 inch casing annulus are 6.4, 24.7, and 91.5 barrels respectively.

A high-pressure nitrogen pump truck injects the gas into the well through the 1-inch tubing (8).

Upward Gas Migration Using Drill Pipe Pressure Control

A simplified schematic of the well layout is shown in Figure 3. The basic procedure during upward gas migration is to maintain the drill pipe pressure at a constant pressure above the initial shut-in value. Due to considerations of the well, however, it was decided to bleed a certain amount of drill pipe pressure rather than holding it at one particular value.

The procedure for evaluation of the conventional drill pipe pressure method is outlined below.

(1) Circulate the entire well (3300 strokes) with the mud to be used in the run. Catch a mud sample and measure its properties.

(2) Close all valves in choke manifold (5 in Figure 2) except for those which route the flow through the hand-adjustable choke (1a). Close the hand-adjustable choke (1).

(3) Close remote-operated valve upstream of choke manifold (9) and open the bypass line (17) from the well to the pit (11).

(4) Zero pump stroke counters and check mud level in the pit using a metered stick.

(5) Inject nitrogen into well through 1.315-inch injection line (8) at approximately 1000 SCF/min.

(6) After mud level in pit has risen to the desired value, close the bypass line to the pit and open the remote-operated valve upstream of the choke manifold.

(7) Continue injecting nitrogen until desired casing pressure is reached. Then top nitrogen injection and pump a few strokes with mud pump (12) to move gas kick away from drill pipe annulus.

(8) At the time this procedure was carried out, the check valve was not in the 1.315-inch line. So the line had to be filled with mud to prevent additional feed-in of the gas. So the line is opened at the surface and mud is pumped down the drill pipe annulus, keeping the casing pressure constant. Once mud is bled from the line at the surface, the pump is shut off and the line is closed.

(9) Note values of stabilized casing and drill pipe pressures at this time and record as initial shut-in values.

(10) Recheck pit level to ascertain total gain. Record the value as initial pit gain.

(11) Allow drill pipe pressure to build by 100 psi above initial shut-in value. Then allow it to build about 20 psi more.

(12) Using hand-adjustable choke (1), slowly bleed down the drill pipe pressure until the pressure is 100 psi above the initial value.

(13) Close hand-adjustable choke and allow pressure to build up a little.

(14) Repeat steps 12 and 13 until the drill pipe pressure stabilizes to a final value (100 psi above the initial shut-in value).

(15) Record time, drill pipe and casing pressures, and incremental volumes of mud bled from the annulus during each cycle. The volume of mud bled into the pit is measured using a metered trip tank (14). Once the tank is filled with mud, the drain valve is opened to drain the mud into the pit.

LSU GOLDKING No. 1 WELL

Model Well for Floating Drilling Operations

The model for simulating well control operations on floating drilling vessels (Figures 4 and 5) has a total depth of 6000-ft. The completion of the well was carefully selected so that its behavior would closely model that of a subsea well being drilled in deep water. Drill pipe is modelled in the well by a string of 2.875-inch tubing. The effect of a subsea blowout preverter stack

placed at the seafloor is modelled by a specially manufactured triple parallel flow tube placed in the well at a depth of 3000-ft. Subsea choke and kill lines are modelled using two strings of 2.375-inch tubing that are stung into the top of the triple parallel flow tube. A gas kick may be placed in the well through a 1.315-inch tubing string run concentrically inside the drill pipe.

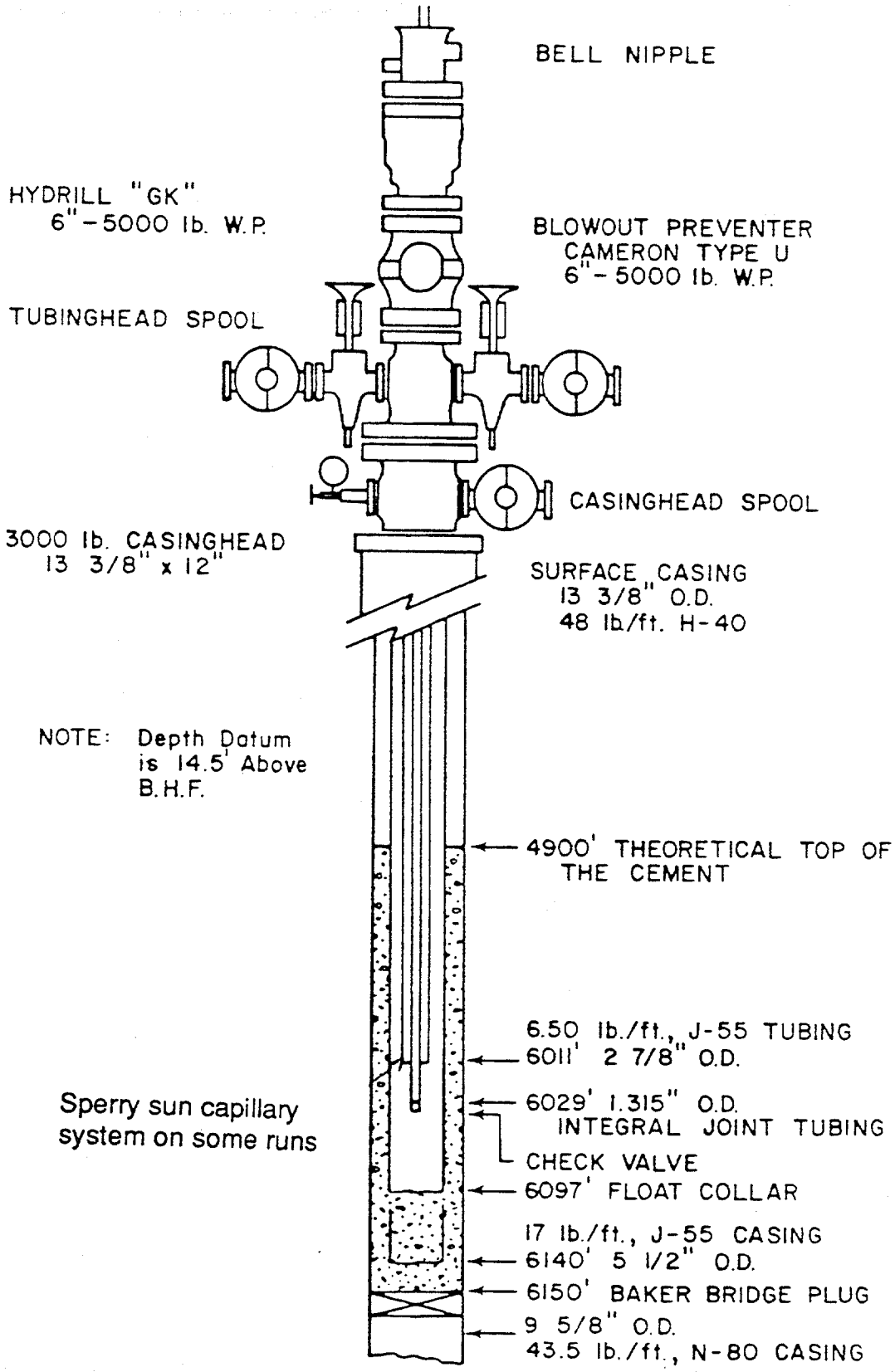

FIGURE 1 SCHEMATIC OF L.S.U. TRAINING WELL

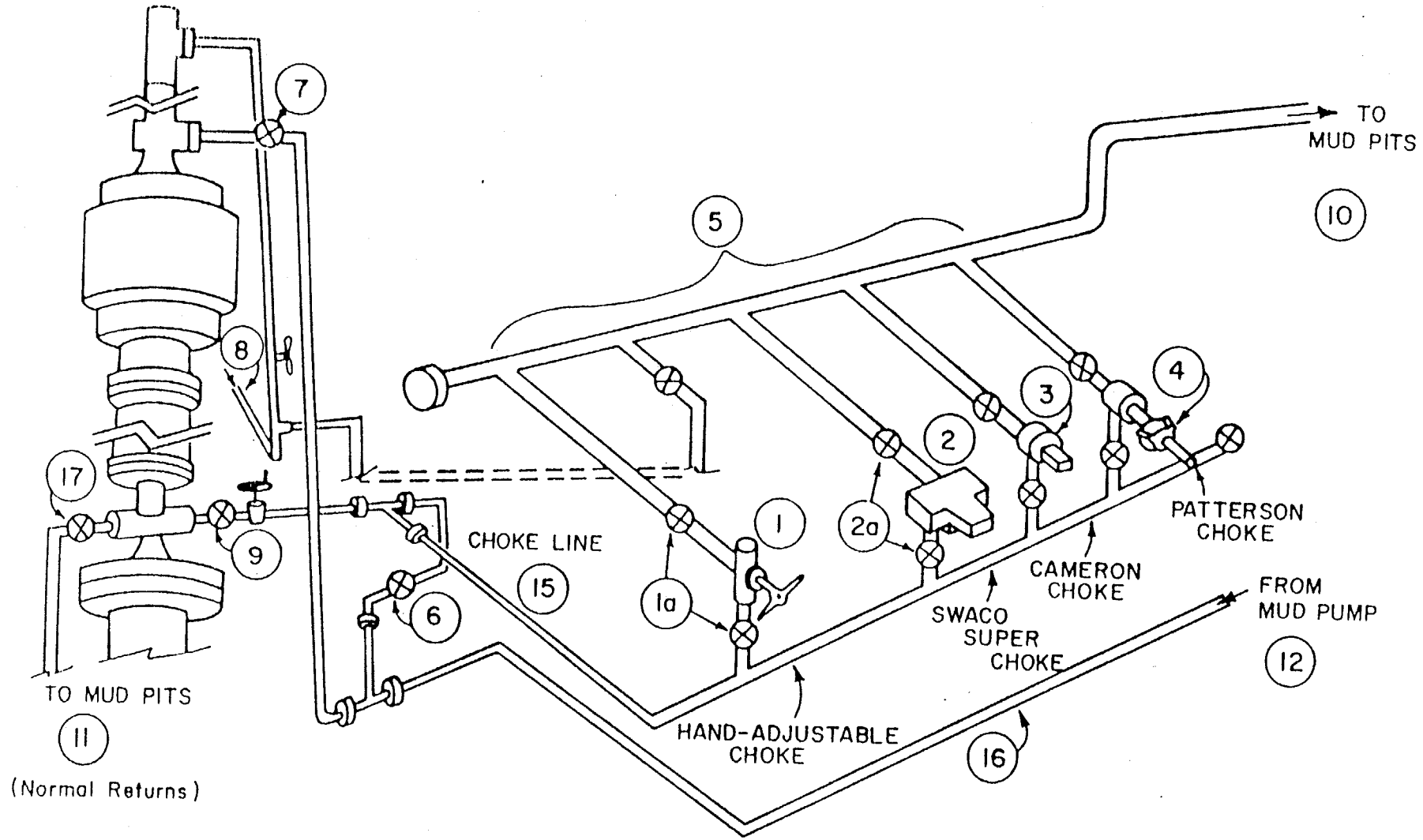

FIGURE 2 SURGACE LAYOUT OF L.S.U. TRAINING WELL

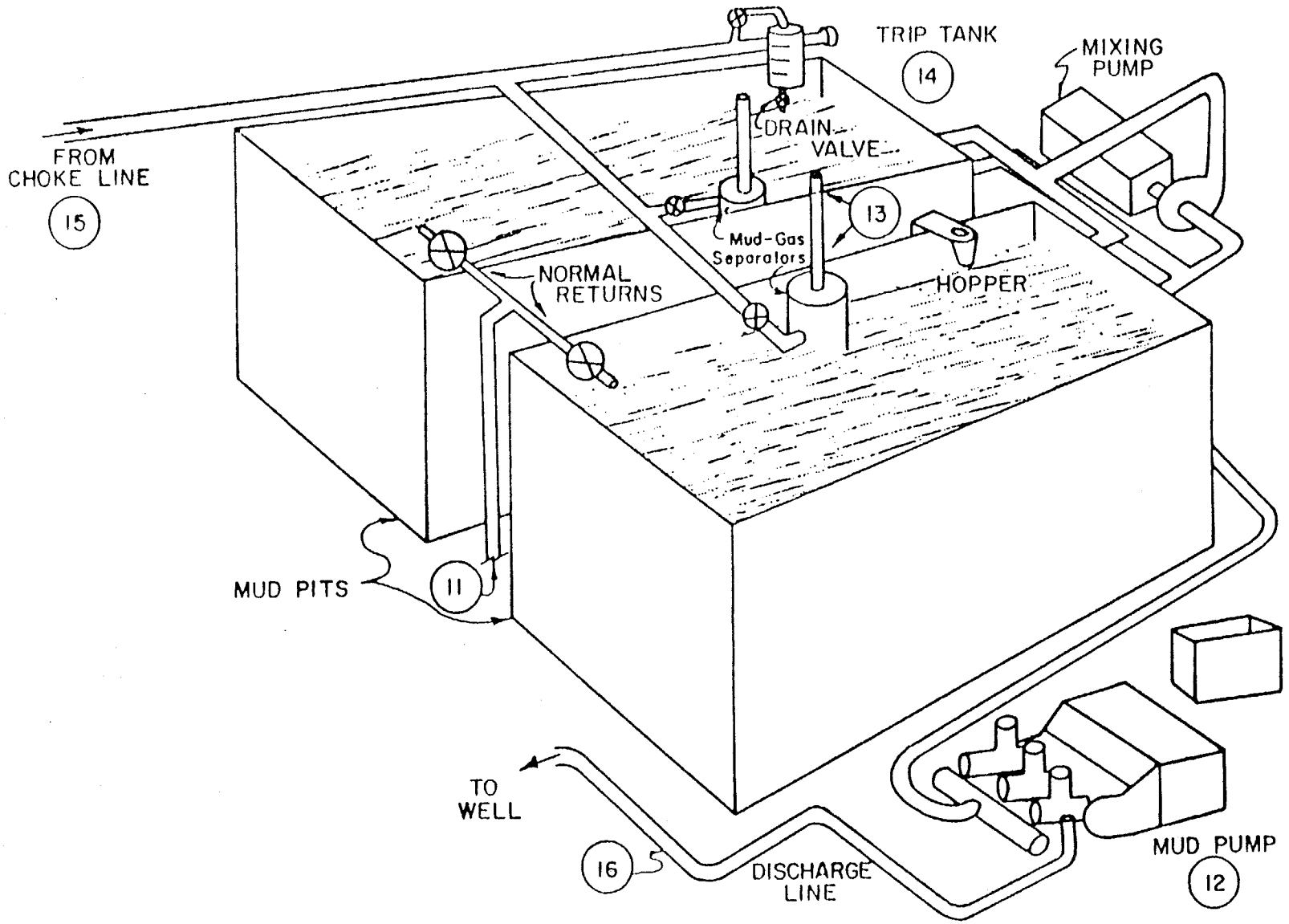

FIGURE 2 (Cont'd.)

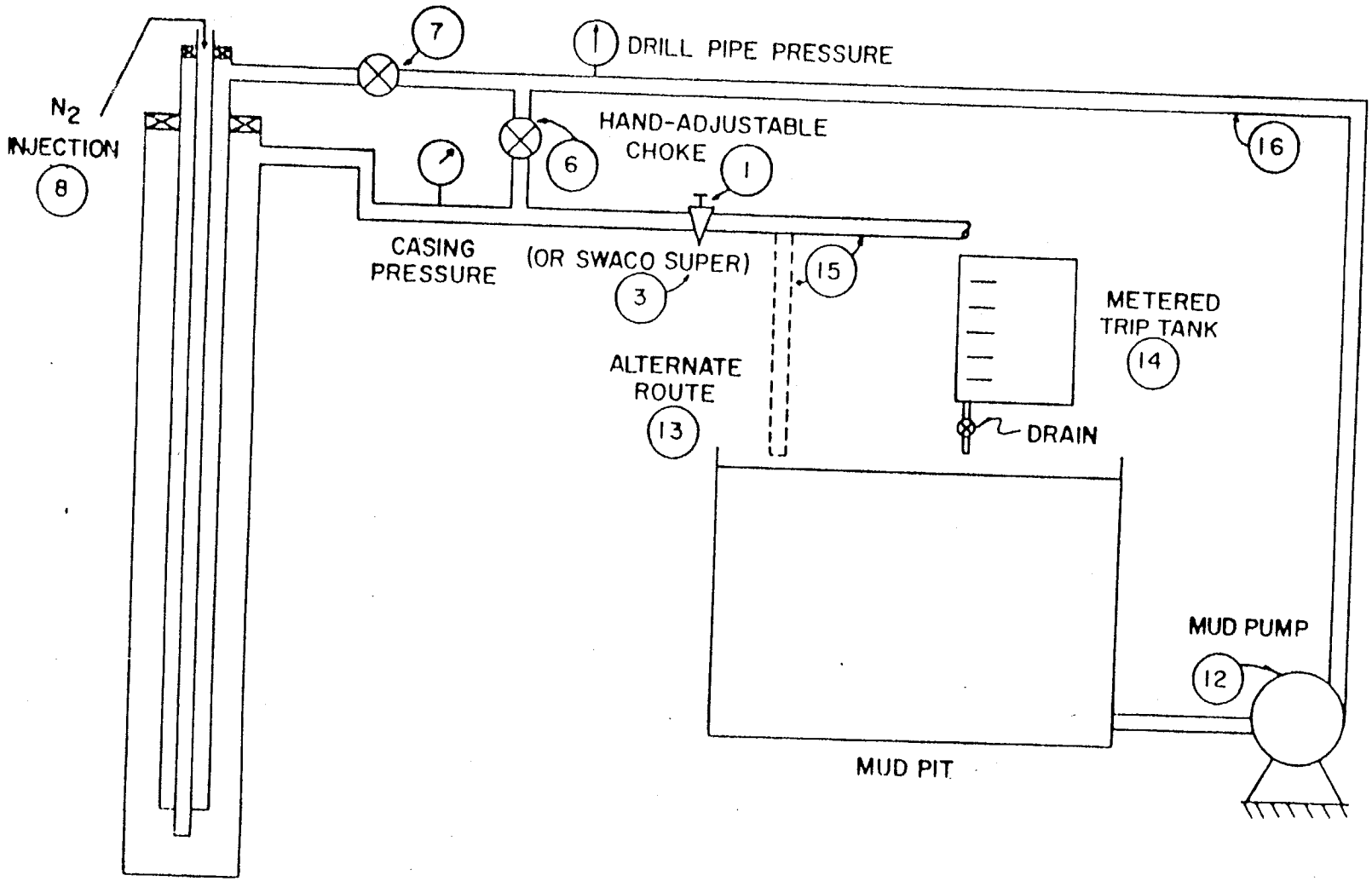

FIGURE 3 SIMPLIFIED WELL LAYOUT FOR EVALUATION OF PROPOSED METHODS

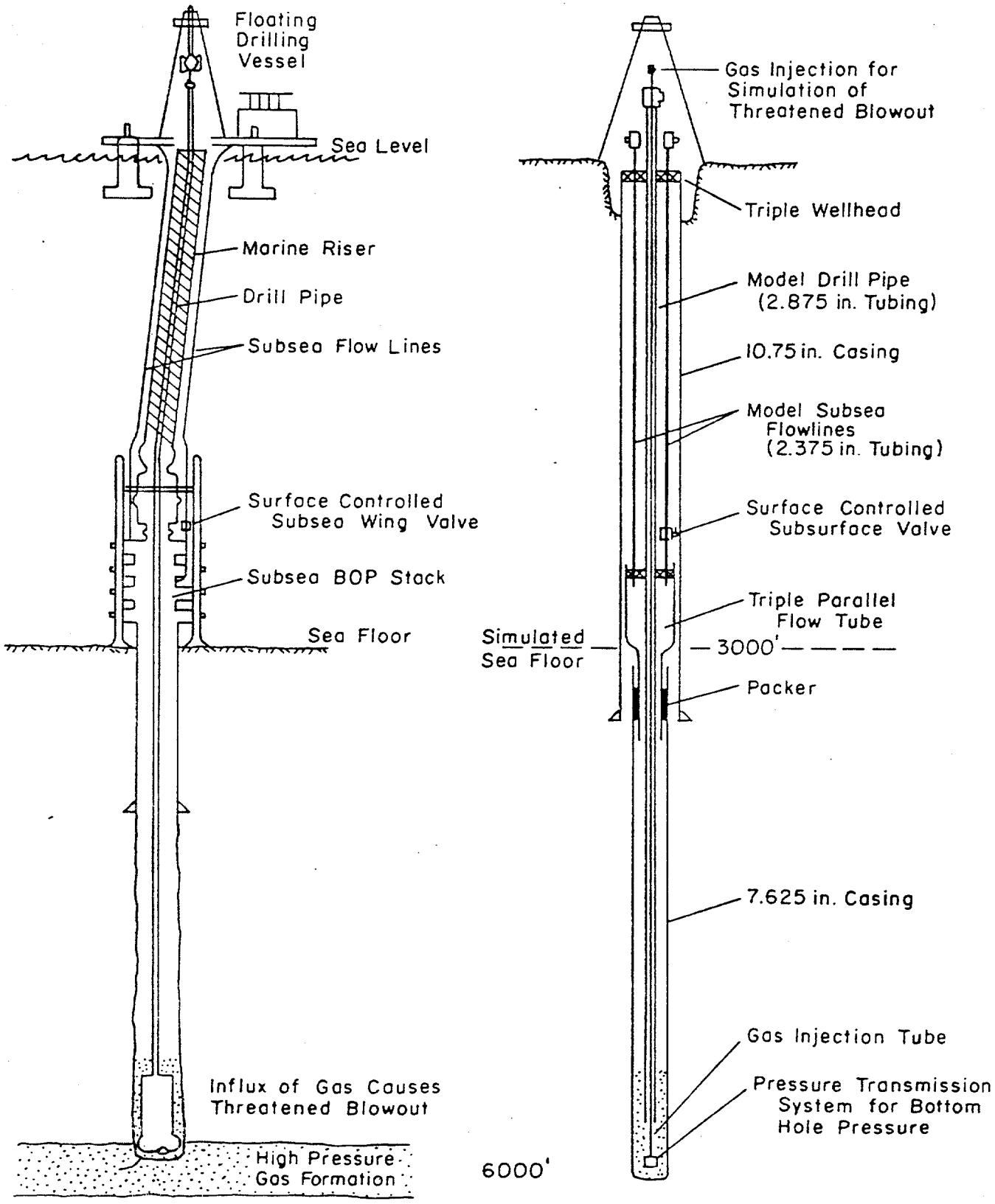

FIGURE 4 WELL DESIGN SELECTED TO MODEL WELL-CONTROL OPERATIONS ON A DEEPWATER OFFSHORE WELL

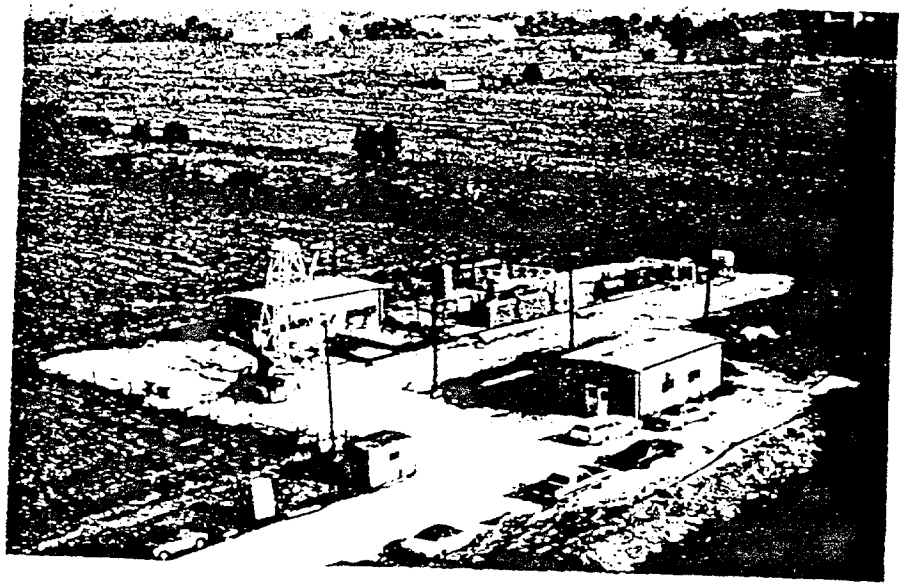

FIGURE 5 NEW WELL-CONTROL FACILITY FOR MODELING WELL-CONTROL OPERATIONS ON FLOATING DRILLING VESSELS

*LSU B7 (Surface BOP Stack) 4-12-72										
*Well Control Simulation										
*Well Geometry (vertical well)										
*Casing String:										
*Depth	I.D.									
*(ft)	(in.)									
0	4.892									
6097	4.892									
*Drill Pipe:										
*Depth	I.D.	O.D.								
*(ft.)	(in.)	(in.)								
0	2.441	2.875								
6011	2.441	2.875								
*Gas Injection String (Placed inside drill pipe)										
*Depth	I.D.	O.D.								
*(ft.)	(in.)	(in.)								
0	1.045	1.315								
6029	1.045	1.315								
*Subsea Choke Line:										
*Depth	I.D.									
*(ft)	(in.)									
none	none									
none	none									
*Subsea Kill Line:										
*Depth	I.D.									
*(ft)	(in.)									
none	none									
none	none									
*Mud Properties:										
*Mud	Plastic	Yield	Water	Water	Oil					
*Density	Viscosity	Point	Fraction	Density	Fraction					
*(lb/Gal)	(cp.)	Lb/100Ft2	( )	(lb/Gal)	( )					
8.6	12.6	15	0.98	8.33	0					

*Fann Readings:										
*RPM:										
600	300	200	100	6	3					
*Dial Reading:										
40.2	27.6	23.5	17.7	7.7	4.8					
*Time:										
*10 sec.	10 min.									
*Gel:										
n/a	n/a									
*Kick Gas (mole fractions) :										
*C1	C2	C3	N-C4	I-C4	C5+	CO2	H2S	N2		
0	0	0	0	0	0	0	0	1		
*Temperature Profile:										
*Extrap.			Surf. Gas							
*Surface	Static	Tank	injection							
*Temp.	Gradient	Temp.	Temp.							
*(Deg.F)	(Deg.F/ft)	(Deg.F)	(Deg.F)							
83	0.013	75	110							
*Measured Parameters as a Function of Time :										
*		Gas	Mud		Bottom			Gas	Choke	
*	Pump	Inj.	Flow	Pit	Hole	Choke	Seafloor	Rate	Posit.	
*Time	Rate	Rate	Out	Gain	Pressure	Pressure	Pressure	Out	(Percent	
*(min.)	(bbl/min.)	(bbl/min.)	(bbl/min)	(bbl)	(psia.)	(psia)	(psia)	(SCF/hr)	open)	Remarks
0	0	0	n/a	0	2715	0	n/a	0	100	start N2
0.3	0	1.8	n/a	0.2	2745	0	n/a	0	100	none
0.6	0	1.8	n/a	1	2720	0	n/a	0	100	none
5.6	0	1.8	n/a	10	2495	0	n/a	0	100	none
6	0	1.8	n/a	10	2490	0	n/a	0	0	close choke
8	0	1.8	n/a	10	2915	465	n/a	0	0	stop N2
9	0	0	n/a	10	3005	515	n/a	0	0	none
10	2.3	0	n/a	10	3035	515	n/a	0	20	start pump
14.3	2.3	0	n/a	10.5	3040	635	n/a	0	19	none

18.7	2.3	0	n/a	11.5	3040	745	n/a	0	18	none
23	2.3	0	n/a	13.5	3035	815	n/a	0	17	none
27.4	2.3	0	n/a	17	3055	885	n/a	0	17	none
31.7	2.3	0	n/a	18	3050	905	n/a	15000	17	gas at surface
36	2.3	0	n/a	15	3055	815	n/a	70000	19	none
40.4	2.3	0	n/a	8	3055	615	n/a	60000	19	none
44.7	2.3	0	n/a	4	3060	445	n/a	10000	21	none
49.1	2.3	0	n/a	1	3055	365	n/a	0	22	none

*LSU B7 (Surface BOP Stack) 4-25-72, No. 2

*Well Control Simulation

*Well Geometry (vertical well)

*Casing String:

*Depth *(ft)	I.D. (in.)
0	4.892
6097	4.892

*Drill Pipe:

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	2.441	2.875
6011	2.441	2.875

*Gas Injection String (Placed inside drill pipe)

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	1.045	1.315
6029	1.045	1.315

*Subsea Choke Line:

*Depth *(ft)	I.D. (in.)
none	none
none	none

*Subsea Kill Line:

*Depth *(ft)	I.D. (in.)
none	none
none	none

*Mud Properties:

*Mud *Density *(lb/Gal)	Plastic Viscosity (cp.)	Yield Point Lb/100Ft2	Water Fraction ( )	Water Density (lb/Gal)	Oil Fraction ( )
8.6	3.5	2.5	0.98	8.34	0

*Fann Readings:										
*RPM:										
600	300	200	100	6	3					
*Dial Reading:										
9.5	6	5	4	1	0.5					
*Time:										
*10 sec.	10 min.									
*Gel:										
n/a	n/a									
*Kick Gas (mole fractions) :										
*C1	C2	C3	N-C4	I-C4	C5+	CO2	H2S	N2		
0	0	0	0	0	0	0	0	1		
*Temperature Profile:										
*Extrap.			Surf. Gas							
*Surface	Static	Tank	injection							
*Temp.	Gradient	Temp.	Temp.							
*(Deg.F)	(Deg.F/ft)	(Deg.F)	(Deg.F)							
83	0.013	80	115							
*Measured Parameters as a Function of Time :										
*		Gas	Mud		Bottom			Gas	Choke	
*	Pump	Inj.	Flow	Pit	Hole	Choke	Seafloor	Rate	Posit.	
*Time	Rate	Rate	Out	Gain	Pressure	Pressure	Pressure	Out	(Percent	
*(min.)	(bbl/min.)	(bbl/min.)	(bbl/min)	(bbl)	(psia.)	(psia)	(psia)	(SCF/hr)	open)	Remarks
0	2.3	0	n/a	0	2795	0	n/a	0	100	start N2
0.3	2.3	1.8	n/a	0.2	2790	0	n/a	0	100	none
5.8	2.38	1.8	n/a	9.5	2615	0	n/a	0	100	stop pump
6	0	1.8	n/a	9.6	2565	0	n/a	0	0	close choke
7	2.3	0	n/a	10.3	3210	660	n/a	0	17	start pump
9.8	2.3	0	n/a	10.3	3285	660	n/a	0	17	none
15.3	2.3	0	n/a	10.3	3265	735	n/a	0	16	none
17	2.22	0	n/a	10.3	3375	795	n/a	0	14	none
22	2.3	0	n/a	13	3255	775	n/a	0	15	none

27	2.3	0	n/a	15	3285	885	n/a	0	15	none
30	2.3	0	n/a	19	3355	885	n/a	0	14	none
31.5	2.3	0	n/a	23	3255	555	n/a	25000	0.15	gas at surface
34.5	2.3	0	n/a	19.5	3420	985	n/a	40000	14	none
34.9	2.3	0	n/a	16	3385	865	n/a	50000	15	none
38.5	2.3	0	n/a	11	3315	705	n/a	70000	16	none
41	2.3	0	n/a	10.3	3385	715	n/a	45000	16	none
44	2.3	0	n/a	5.6	3345	535	n/a	30000	17	none
46.5	2.3	0	n/a	3	3375	485	n/a	15000	18	none
50	2.3	0	n/a	2	3315	445	n/a	0	19	none
53.5	2.3	0	n/a	2	3315	445	n/a	0	19	none

*LSU B7 (Surface BOP Stack) 4-25-72, No. 3										
*Well Control Simulation at very slow kill speed.										
*Well Geometry (vertical well)										
*Casing String:										
*Depth	I.D.									
*(ft)	(in.)									
0	4.892									
6097	4.892									
*Drill Pipe:										
*Depth	I.D.	O.D.								
*(ft.)	(in.)	(in.)								
0	2.441	2.875								
6011	2.441	2.875								
*Gas Injection String (Placed inside drill pipe)										
*Depth	I.D.	O.D.								
*(ft.)	(in.)	(in.)								
0	1.045	1.315								
6029	1.045	1.315								
*Subsea Choke Line:										
*Depth	I.D.									
*(ft)	(in.)									
none	none									
none	none									
*Subsea Kill Line:										
*Depth	I.D.									
*(ft)	(in.)									
none	none									
none	none									
*Mud Properties:										
*Mud	Plastic	Yield	Water	Water	Oil					
*Density	Viscosity	Point	Fraction	Density	Fraction					
*(lb/Gal)	(cp.)	Lb/100Ft2	( )	(lb/Gal)	( )					
8.6	3.5	2	0.98	8.34	0					

*Fann Readings:										
*RPM:										
600	300	200	100	6	3					
*Dial Reading:										
9	5.5	4.5	3	2	1.5					
*Time:										
10 seconds	10 min.									
*Gel:										
n/a	n/a									
*Kick Gas (mole fractions) :										
*C1	C2	C3	N-C4	I-C4	C5+	CO2	H2S	N2		
0	0	0	0	0	0	0	0	1		
*Temperature Profile:										
*Extrap.			Surf. Gas							
*Surface	Static	Tank	injection							
*Temp.	Gradient	Temp.	Temp.							
*(Deg.F)	(Deg.F/ft)	(Deg.F)	(Deg.F)							
83	0.013	86	100							
*Measured Parameters as a Function of Time :										
*		Gas	Mud		Bottom			Gas	Choke	
*	Pump	Inj.	Flow	Pit	Hole	Choke	Seafloor	Rate	Posit.	
*Time	Rate	Rate	Out	Gain	Pressure	Pressure	Pressure	Out	(Percent	
*(min.)	(bbl/min.)	(bbl/min.)	(bbl/min)	(bbl)	(psia.)	(psia)	(psia)	(SCF/hr)	open)	Remarks
0	2.22	0	n/a	0	2735	0	n/a	0	100	start N2
0.3	2.22	1.8	n/a	0.2	2775	0	n/a	0	100	none
4	2.14	1.8	n/a	5	2665	0	n/a	0	100	none
5	2.22	1.8	n/a	9.5	2555	0	n/a	0	100	stop pump
6	0	0	n/a	10	3215	745	n/a	0	0	shut-in
11	1.19	0	n/a	11	3255	715	n/a	0	0.14	start pump
13	1.15	0	n/a	11	3285	795	n/a	0	0.15	none
21	1.09	0	n/a	12.5	3305	965	n/a	0	0.14	none
25	1.09	0	n/a	14	3415	975	n/a	0	0.14	none

28	1.27	0	n/a	14.7	3225	765	n/a	0	0.15	none
30	1.07	0	n/a	15	3335	965	n/a	0	0.14	none
36	1.07	0	n/a	16	3275	935	n/a	0	0.14	none
38	0.9	0	n/a	18	3355	1115	n/a	0	0.14	none
43	1.07	0	n/a	19	3265	1015	n/a	0	0.15	none
46	1.38	0	n/a	24	3225	895	n/a	10000	0.15	gas at surface
49	1	0	n/a	21	3220	1065	n/a	15000	0.14	none
50	1.15	0	n/a	20	3470	1185	n/a	30000	0.14	none
53	1.19	0	n/a	21	3170	875	n/a	40000	0.16	none
56	1.07	0	n/a	19.7	3250	1015	n/a	40000	0.14	none
61	1.07	0	n/a	16.5	3310	945	n/a	20000	0.14	none
63	1.22	0	n/a	15	3270	755	n/a	30000	0.15	none
66	1.15	0	n/a	12.5	3320	865	n/a	30000	0.14	none
73	1.19	0	n/a	7	3265	595	n/a	15000	0.15	none
79	1.15	0	n/a	2	3275	455	n/a	10000	0.15	none
81	1.3	0	n/a	2	3255	345	n/a	0	0.15	none
83	1.3	0	n/a	1	3295	515	n/a	0	0.15	none

*LSU B7 (Surface BOP Stack) 10-24-74

*Well Control Simulation after Extended Shut-in Period

*Well Geometry (vertical well)

*Casing String:

*Depth *(ft)	I.D. (in.)
0	4.892
6097	4.892

*Drill Pipe:

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	2.441	2.875
6011	2.441	2.875

*Gas Injection String (Placed inside drill pipe)

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	1.045	1.315
6029	1.045	1.315

*Subsea Choke Line:

*Depth *(ft)	I.D. (in.)
none	none
none	none

*Subsea Kill Line:

*Depth *(ft)	I.D. (in.)
none	none
none	none

*Mud Properties:

*Mud *Density *(lb/Gal)	Plastic Viscosity (cp.)	Yield Point Lb/100Ft2	Water Fraction ( )	Water Density (lb/Gal)	Oil Fraction ( )
8.6	13.5	5.5	0.98	8.338	0

*Fann Readings:										
*RPM:										
600	300	200	100	6	3					
*Dial Reading:										
32.5	19	14.5	9	5.5	4.5					
*Time:										
*10 sec.	10 min.									
*Gel:										
n/a	n/a									
*Kick Gas (mole fractions) :										
*C1	C2	C3	N-C4	I-C4	C5+	CO2	H2S	N2		
0	0	0	0	0	0	0	0	1		
*Temperature Profile:										
*Extrap.			Surf. Gas							
*Surface	Static	Tank	injection							
*Temp.	Gradient	Temp.	Temp.							
*(Deg.F)	(Deg.F/ft)	(Deg.F)	(Deg.F)							
83	0.013	76	100							
*Measured Parameters as a Function of Time :										
*		Gas	Mud		Bottom			Gas	Choke	
*	Pump	Inj.	Flow	Pit	Hole	Choke	Seafloor	Rate	Posit.	
*Time	Rate	Rate	Out	Gain	Pressure	Pressure	Pressure	Out	(Percent	
*(min.)	(bbl/min.)	(bbl/min.)	(bbl)	(bbl)	(psia.)	(psia)	(psia)	(SCF/hr)	open)	Remarks
0	0	0	n/a	0	2703	0	n/a	0	100	start N2
0.2	0	1.8	n/a	0.2	2735	0	n/a	0	100	none
5.5	0	1.8	n/a	10	2485	0	n/a	0	100	close choke
6	0	1.8	n/a	10	2875	398	n/a	0	0	stop N2 inj.
6.5	0	0	n/a	10	2885	405	n/a	0	0	none
20	0	0	n/a	10	2895	415	n/a	0	0	none
28	0	0	n/a	10	2905	425	n/a	0	0	none
41	0	0	n/a	10	2920	442	n/a	0	0	none
58	0	0	n/a	10	2945	465	n/a	0	0	none

75	0	0	n/a	10	2975	495	n/a	0	0	none
91	0	0	n/a	10	3020	435	n/a	0	0	none
135	0	0	n/a	10	3115	635	n/a	0	0	none
141	0	0	n/a	10	3170	695	n/a	0	0	none
151	0	0	n/a	10	3215	740	n/a	0	0	none
161	0	0	n/a	10	3260	795	n/a	0	0	none
171	0	0	n/a	10	3305	830	n/a	0	0	none
181	0	0	n/a	10	3370	890	n/a	0	0	none
191	0	0	n/a	10	3410	930	n/a	0	0	none
195	0	0	n/a	15	2875	460	n/a	0	15	bleed mud
196	2.3	0	n/a	15	2950	465	n/a	0	25	start pump
204	2.3	0	n/a	17	2955	555	n/a	15000	30	gas out
219	2.3	0	n/a	14	2955	565	n/a	25000	22	none
223	2.3	0	n/a	10.5	2950	515	n/a	30000	23	none
227	2.3	0	n/a	70	2960	395	n/a	35000	22	none
231	2.3	0	n/a	4	2955	295	n/a	30000	26	none
234	2.3	0	n/a	2	2955	225	n/a	20000	28	none
239	2.3	0	n/a	1	2950	215	n/a	0	28	none

*LSU B7 (Surface BOP Stack) 1-15-80

*Gas migration, keeping BHP constant by periodic bleeding through choke.

*Well Geometry (vertical well):

*Casing String:

*Depth *(ft)	I.D. (in.)
0	4.892
6097	4.892

*Drill Pipe:

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	2.441	2.875
6011	2.441	2.875

*Gas Injection String (Placed inside drill pipe)

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	1.045	1.315
6029	1.045	1.315

*Subsea Choke Line:

*Depth *(ft)	I.D. (in.)
none	none
none	none

*Subsea Kill Line:

*Depth *(ft)	I.D. (in.)
none	none
none	none

*Mud Properties:

*Mud *Density *(lb/Gal)	Plastic Viscosity (cp.)	Yield Point Lb/100Ft2	Water Fraction ( )	Water Density (lb/Gal)	Oil Fraction ( )
8.5	15	6	0.98	8.34	0

*Fann Readings:										
*RPM:										
600	300	200	100	6	3					
*Dial Reading:										
36	21	15	9	0.5	0					
*Time:										
*10 sec.	10 min.									
*Gel:										
3	4									

*Kick Gas (mole fractions) :									
*C1	C2	C3	N-C4	I-C4	C5+	CO2	H2S	N2	
0	0	0	0	0	0	0	0	1	

*Temperature Profile:										
* Extrapolated			Surface Gas							
*Surface	Static	Tank	injection							
*Temp.	Gradient	Temp.	Temp.							
*(Deg.F)	(Deg.F/ft)	(Deg.F)	(Deg.F)							
83	0.013	60	100							

*Measured Parameters as a Function of Time :										
*		Gas	Mud		Bottom			Gas	Choke	
*	Pump	Inj.	Flow	Pit	Hole	Choke	Seafloor	Rate	Posit.	
*Time	Rate	Rate	Out	Gain	Pressure	Pressure	Pressure	Out	(Percent	
*(min.)	(bbl/min.)	(bbl/min.)	(bbl/min)	(bbl)	(psia.)	(psia)	(psia)	(SCF/hr)	open)	Remarks
0	0	1	n/a	0	2650	0	n/a	n/a	n/a	a
11	0	1	n/a	11.6	2450	0	n/a	n/a	n/a	b
12	0	0	n/a	11.6	2865	515	n/a	n/a	n/a	c
19	0	0	n/a	11.6	2980	635	n/a	n/a	n/a	e
27	0	0	n/a	11.6	3015	685	n/a	n/a	n/a	blank
38	0	0	n/a	11.6	3055	745	n/a	n/a	n/a	blank
42	0	0	n/a	11.6	3085	765	n/a	n/a	n/a	B
43	0	0	n/a	11.6	3075	725	n/a	n/a	n/a	SI
51	0	0	n/a	11.6	3075	765	n/a	n/a	n/a	B

53	0	0	n/a	11.95	3050	685	n/a	n/a	n/a	Sl
64	0	0	n/a	11.95	3035	745	n/a	n/a	n/a	blank
70	0	0	n/a	11.95	3055	765	n/a	n/a	n/a	B
72	0	0	n/a	12.13	3035	705	n/a	n/a	n/a	Sl
79	0	0	n/a	12.13	3015	730	n/a	n/a	n/a	blank
86	0	0	n/a	12.13	3035	765	n/a	n/a	n/a	B
88	0	0	n/a	12.3	3015	685	n/a	n/a	n/a	Sl
98	0	0	n/a	12.3	3015	745	n/a	n/a	n/a	blank
101	0	0	n/a	12.3	3025	765	n/a	n/a	n/a	B
103	0	0	n/a	12.82	3015	705	n/a	n/a	n/a	Sl
113	0	0	n/a	12.82	3020	765	n/a	n/a	n/a	B
115	0	0	n/a	13.3	3005	705	n/a	n/a	n/a	Sl,h
126	0	0	n/a	13.3	3010	765	n/a	n/a	n/a	blank
136	0	0	n/a	13.3	3050	815	n/a	n/a	n/a	B
138	0	0	n/a	13.88	3050	765	n/a	n/a	n/a	Sl,*
150	0	0	n/a	13.88	3065	815	n/a	n/a	n/a	B
153	0	0	n/a	14.76	3050	765	n/a	n/a	n/a	Sl
164	0	0	n/a	14.76	3055	820	n/a	n/a	n/a	B
165	0	0	n/a	15.11	3065	790	n/a	n/a	n/a	Sl,h
176	0	0	n/a	15.11	3085	845	n/a	n/a	n/a	blank
180	0	0	n/a	15.11	3115	870	n/a	n/a	n/a	B
182	0	0	n/a	15.63	3065	805	n/a	n/a	n/a	Sl
196	0	0	n/a	15.63	3115	865	n/a	n/a	n/a	B
198	0	0	n/a	16.33	3080	815	n/a	n/a	n/a	Sl
209	0	0	n/a	16.33	3115	865	n/a	n/a	n/a	B
211	0	0	n/a	17.13	3065	815	n/a	n/a	n/a	Sl,h
222	0	0	n/a	17.13	3115	865	n/a	n/a	n/a	blank
230	0	0	n/a	17.13	3150	895	n/a	n/a	n/a	blank
234	0	0	n/a	17.13	3165	915	n/a	n/a	n/a	B
236	0	0	n/a	17.57	3135	855	n/a	n/a	n/a	Sl
248	0	0	n/a	17.57	3165	915	n/a	n/a	n/a	B
250	0	0	n/a	18.44	3135	865	n/a	n/a	n/a	Sl,h
264	0	0	n/a	18.44	3155	925	n/a	n/a	n/a	blank
275	0	0	n/a	18.44	3175	965	n/a	n/a	n/a	B

276	0	0	n/a	18.63	3165	885	n/a	n/a	n/a	SI
299	0	0	n/a	18.63	3165	965	n/a	n/a	n/a	B
301	0	0	n/a	18.8	3160	905	n/a	n/a	n/a	SI
315	0	0	n/a	18.8	3165	945	n/a	n/a	n/a	blank
322	0	0	n/a	18.8	3170	965	n/a	n/a	n/a	B
325	0	0	n/a	18.8	3165	910	n/a	n/a	n/a	SI
333	0	0	n/a	18.8	3165	930	n/a	n/a	n/a	blank
342	0	0	n/a	18.8	3165	945	n/a	n/a	n/a	blank
349	0	0	n/a	18.8	3165	965	n/a	n/a	n/a	B
351	0	0	n/a	18.8	3165	905	n/a	n/a	n/a	SI
367	0	0	n/a	18.8	3170	930	n/a	n/a	n/a	blank
375	0	0	n/a	18.8	3170	940	n/a	n/a	n/a	blank
383	0	0	n/a	18.8	3165	945	n/a	n/a	n/a	blank
394	0	0	n/a	18.8	3165	955	n/a	n/a	n/a	blank
404	0	0	n/a	18.8	3175	965	n/a	n/a	n/a	B
406	0	0	n/a	18.8	3165	885	n/a	n/a	n/a	SI
424	0	0	n/a	18.8	3165	895	n/a	n/a	n/a	blank

*LSU B7 (Surface BOP Stack) 1-29-80										
*Gas migration, keeping BHP constant by periodic bleeding through choke.										
*Well Geometry (vertical well):										
*Casing String:										
*Depth	I.D.									
*(ft)	(in.)									
0	4.892									
6097	4.892									
*Drill Pipe:										
*Depth	I.D.	O.D.								
*(ft.)	(in.)	(in.)								
0	2.441	2.875								
6011	2.441	2.875								
*Gas Injection String (Placed inside drill pipe)										
*Depth	I.D.	O.D.								
*(ft.)	(in.)	(in.)								
0	1.045	1.315								
6029	1.045	1.315								
*Subsea Choke Line:										
*Depth	I.D.									
*(ft)	(in.)									
none	none									
none	none									
*Subsea Kill Line:										
*Depth	I.D.									
*(ft)	(in.)									
none	none									
none	none									
*Mud Properties:										
*Mud	Plastic	Yield	Water	Water	Oil					
*Density	Viscosity	Point	Fraction	Density	Fraction					
*(lb/Gal)	(cp.)	Lb/100Ft2	( )	(lb/Gal)	( )					
8.6	33	24	0.098	8.34	0					

*Fann Readings:										
*RPM:										
600	300	200	100	6	3					
*Dial Reading:										
90	57	43.5	27.5	8.5	5.5					
*Time:										
*10 sec.	10 min.									
*Gel:										
24	n/a									
*Kick Gas (mole fractions) :										
*C1	C2	C3	N-C4	I-C4	C5+	CO2	H2S	N2		
0	0	0	0	0	0	0	0	1		
*Temperature Profile:										
*Extrap.			Surface Gas							
*Surface	Static	Tank	injection							
*Temp.	Gradient	Temp.	Temp.							
*(Deg.F)	(Deg.F/ft)	(Deg.F)	(Deg.F)							
83	0.017	64	100							
*Measured Parameters as a Function of Time :										
*		Gas	Mud		Bottom			Gas	Choke	
*	Pump	Inj.	Flow	Pit	Hole	Choke	Seafloor	Rate	Posit.	
*Time	Rate	Rate	Out	Gain	Pressure	Pressure	Pressure	Out	(Percent	
*(min.)	(bbl/min.)	(bbl/min.)	(bbl)	(bbl)	(psia.)	(psia)	(psia)	(SCF/hr)	open)	Remarks
0	0	1	n/a	0	2690	0	n/a	n/a	n/a	start N2 inj.
9	0	1	n/a	10.5	2690	0	n/a	n/a	n/a	shut ann. prev
10	0	0	n/a	10.5	3035	545	n/a	n/a	n/a	stop N2 inj.
12	0	0	n/a	10.53	3175	665	n/a	n/a	n/a	buildup
19	0	0	n/a	10.53	3225	730	n/a	n/a	n/a	blank
24	0	0	n/a	10.53	3240	765	n/a	n/a	n/a	blank
34	0	0	n/a	10.53	3315	865	n/a	n/a	n/a	begin bleeding
36	0	0	n/a	10.53	3315	865	n/a	n/a	n/a	Shut well in
37	0	0	n/a	10.53	3315	865	n/a	n/a	n/a	begin bleeding

39	0	0	n/a	10.88	3325	815	n/a	n/a	n/a	shut well in
42	0	0	n/a	10.88	3295	835	n/a	n/a	n/a	blank
47	0	0	n/a	10.88	3305	875	n/a	n/a	n/a	begin bleeding
50	0	0	n/a	11.23	3290	810	n/a	n/a	n/a	shut well in
53	0	0	n/a	11.23	3280	830	n/a	n/a	n/a	blank
59	0	0	n/a	11.23	3280	875	n/a	n/a	n/a	begin bleeding
64	0	0	n/a	11.93	3260	805	n/a	n/a	n/a	shut well in
68	0	0	n/a	11.93	3255	835	n/a	n/a	n/a	blank
71	0	0	n/a	11.93	3245	865	n/a	n/a	n/a	begin bleeding
75	0	0	n/a	12.28	3235	815	n/a	n/a	n/a	shut in well
79	0	0	n/a	12.28	3240	855	n/a	n/a	n/a	blank
83	0	0	n/a	12.28	3235	885	n/a	n/a	n/a	blank
92	0	0	n/a	12.28	3250	975	n/a	n/a	n/a	begin bleeding
95	0	0	n/a	13.69	3260	865	n/a	n/a	n/a	shut in well
101	0	0	n/a	13.69	3260	915	n/a	n/a	n/a	beging bleeding
103	0	0	n/a	14.04	3250	855	n/a	n/a	n/a	shut in well
109	0	0	n/a	14.04	3235	915	n/a	n/a	n/a	blank
116	0	0	n/a	14.04	3235	970	n/a	n/a	n/a	begin bleeding
120	0	0	n/a	14.74	3225	890	n/a	n/a	n/a	shut well in
125	0	0	n/a	14.74	3220	930	n/a	n/a	n/a	blank
129	0	0	n/a	14.74	3230	970	n/a	n/a	n/a	begin bleeding
130	0	0	n/a	14.74	3215	895	n/a	n/a	n/a	shut in well
137	0	0	n/a	14.74	3215	945	n/a	n/a	n/a	blank
145	0	0	n/a	14.74	3215	985	n/a	n/a	n/a	begin bleeding
147	0	0	n/a	14.74	3215	910	n/a	n/a	n/a	shut in well
150	0	0	n/a	14.74	3215	925	n/a	n/a	n/a	blank
152	0	0	n/a	14.74	3215	945	n/a	n/a	n/a	blank
156	0	0	n/a	14.74	3220	965	n/a	n/a	n/a	beging bleeding
157	0	0	n/a	14.74	3205	905	n/a	n/a	n/a	shut in well
163	0	0	n/a	14.74	3205	925	n/a	n/a	n/a	blank
169	0	0	n/a	14.74	3215	945	n/a	n/a	n/a	blank
177	0	0	n/a	14.74	3215	965	n/a	n/a	n/a	begin bleeding
178	0	0	n/a	14.74	3205	915	n/a	n/a	n/a	shut in well
188	0	0	n/a	14.74	3215	935	n/a	n/a	n/a	blank

*LSU Goldking No. 1(Subsea BOP Stack) 9-29-81

*Gas migration, keeping BHP constant by pumping down kill line with returns up choke line.

*Well Geometry (vertical well):

*Casing String:

*Depth *(ft)	I.D. (in.)
3000	6.875
6100	6.875

*Drill Pipe:

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	2.441	2.875
6000	2.441	2.875

*Gas Injection String (Placed inside drill pipe)

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	1.045	1.315
6030	1.045	1.315

*Subsea Choke Line:

*Depth *(ft)	I.D. (in.)
0	1.995
3000	1.995

*Subsea Kill Line:

*Depth *(ft)	I.D. (in.)
0	1.995
3000	1.995

*Mud Properties:

*Mud *Density *(lb/Gal)	Plastic Viscosity (cp.)	Yield Point Lb/100Ft2	Water Fraction ( )	Water Density (lb/Gal)	Oil Fraction ( )
8.34	1	0	1	8.34	0

*Fann Readings:										
*RPM:										
600	300	200	100	6	3					
*Dial Reading:										
2	1	n/a	n/a	n/a	n/a					
*Time:										
10 seconds	10 min.									
*Gel:										
0	0									
*Kick Gas (mole fractions) :										
*C1	C2	C3	N-C4	I-C4	C5+	CO2	H2S	N2		
0	0	0	0	0	0	0	0	1		
*Temperature Profile:										
*Extrap.			Surf. Gas							
*Surface	Static	Tank	injection							
*Temp.	Gradient	Temp.	Temp.							
*(Deg.F)	(Deg.F/ft)	(Deg.F)	(Deg.F)							
83	0.013	70	110							
*Measured Parameters as a Function of Time :										
*		Gas	Mud		Bottom			Gas	Choke	
*	Pump	Inj.	Flow	Pit	Hole	Choke	Seafloor	Rate	Posit.	
*Time	Rate	Rate	Out	Gain	Pressure	Pressure	Pressure	Out	(Percent	
*(min.)	(bbl/min.)	(bbl/min.)	(bbl/min)	(bbl)	(psia.)	(psia)	(psia)	(SCF/hr)	open)	Remarks
0	0.68	0	n/a	0	2720	0	1320	0	50	blank
3	0.68	1.25	n/a	0	2720	0	1320	0	50	start N2 inj.
5	0.43	1.25	n/a	1.8	2810	40	1420	0	50	blank
10	0.5	1.25	n/a	8.3	2800	40	1450	0	50	blank
14	0.5	1.25	n/a	14	2810	40	1420	0	0	close well
14	0	0	n/a	15.4	3010	240	1520	0	0	stop N2 inj.
18	0	0	n/a	15.3	3230	640	1860	0	0	blank
83	0	0	n/a	14.2	3318	800	2120	n/a	n/a	circ. BOP
96	0	0	n/a	15.4	3264	n/a	n/a	n/a	n/a	at 1.5bbl/min

99	0	0	n/a	14.8	3243	660	2040	n/a	n/a	blank
104	0	0	n/a	13.7	3309	700	2100	n/a	n/a	blank
106	0	0	n/a	13.7	3271	740	2070	n/a	n/a	blank
110	0	0	n/a	13.1	3275	800	2060	n/a	n/a	blank
114	0	0	n/a	n/a	3265	800	2080	n/a	n/a	blank
119	0	0	n/a	n/a	3257	790	2050	n/a	n/a	blank
122	0	0	n/a	12.5	3255	800	2040	n/a	n/a	blank
127	0	0	n/a	11.9	3256	800	2030	n/a	n/a	blank
130	0	0	n/a	11.3	3258	800	2030	n/a	n/a	blank
134	0	0	n/a	n/a	3262	800	2030	n/a	n/a	blank
136	0	0	n/a	10.7	3263	n/a	n/a	n/a	n/a	blank
140	0	0	n/a	10.1	3266	800	2030	n/a	n/a	blank
144	0	0	n/a	9.5	3270	800	2030	n/a	n/a	blank
147	0	0	n/a	8.9	3273	800	2030	n/a	n/a	blank
151	0	0	n/a	8.3	3277	800	2030	n/a	n/a	blank
154	0	0	n/a	7.7	3280	800	2030	n/a	n/a	blank
160	0	0	n/a	7.1	3287	810	2025	n/a	n/a	blank
164	0	0	n/a	5.9	3291	810	2025	n/a	n/a	blank
168	0	0	n/a	5.9	3297	810	2025	n/a	n/a	blank
175	0	0	n/a	4.7	3365	810	2025	n/a	n/a	blank
184	0	0	n/a	3	3317	800	2020	n/a	n/a	blank
194	0	0	n/a	1.2	3327	790	2020	n/a	n/a	blank
199	0	0	n/a	0.6	3334	785	2020	n/a	n/a	blank
205	0	0	n/a	-0.6	3344	720	2020	n/a	n/a	blank
209	0	0	n/a	-0.6	3335	710	2020	n/a	n/a	blank

50	1.58	0	1.78	19	3210	410	2050	0	n/a	blank
55	1.58	0	1.9	19	3200	450	2100	0	n/a	blank
60	1.58	0	2.26	20	3200	470	2125	0	n/a	blank
65	1.58	0	2.2	22	3250	650	2175	8000	n/a	gas at surface
70	1.58	0	two-phase	24	3200	700	2100	25000	n/a	blank
75	1.58	0	two-phase	22	3200	800	2090	50000	n/a	blank
80	1.58	0	two-phase	21	3200	950	2050	60000	n/a	blank
85	1.58	0	two-phase	16	3230	1050	2025	60000	n/a	blank
90	1.58	0	two-phase	14	3220	850	1990	50000	n/a	blank
95	1.58	0	two-phase	6	3230	400	2000	10000	n/a	blank
100	1.58	0	1.69	3	3200	300	1980	0	n/a	blank
105	1.58	0	1.58	1	3200	300	1980	0	n/a	blank

*LSU Goldking No. 1(Subsea BOP Stack) 4-8-83, No. 2

*Well Control Simulation, Choke and Kill Lines in Parallel.

*Well Geometry (vertical well):

*Casing String:

*Depth *(ft)	I.D. (in.)
3000	6.875
6100	6.875

*Drill Pipe:

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	2.441	2.875
6000	2.441	2.875

*Gas Injection String (Placed inside drill pipe)

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	1.045	1.315
6030	1.045	1.315

*Subsea Choke Line:

*Depth (ft)	I.D. (in.)
0	1.995
3000	1.995

*Subsea Kill Line:

*Depth *(ft)	I.D. (in.)
0	1.995
3000	1.995

*Mud Properties:

*Mud *Density *(lb/Gal)	Plastic Viscosity (cp.)	Yield Point Lb/100Ft2	Water Fraction ( )	Water Density (lb/Gal)	Oil Fraction ( )
8.7	26	24	0.97	8.34	0

*Fann Readings:										
*RPM:										
600	300	200	100	6	3					
*Dial Reading:										
76	50	32.5	18	2	1.5					
*Time:										
10 sec.	10 min.									
*Gel:										
2	2									
*Kick Gas (mole fractions) :										
*C1	C2	C3	N-C4	I-C4	C5+	CO2	H2S	N2		
0	0	0	0	0	0	0	0	1		
*Temperature Profile:										
*Extrap.			Surf. Gas							
*Surface	Static	Tank	injection							
*Temp.	Gradient	Temp.	Temp.							
*(Deg.F)	(Deg.F/ft)	(Deg.F)	(Deg.F)							
83	0.013	90	105							
*Measured Parameters as a Function of Time :										
*		Gas	Mud		Bottom			Gas	Choke	
*	Pump	Inj.	Flow	Pit	Hole	Choke	Seafloor	Rate	Posit.	
*Time	Rate	Rate	Out	Gain	Pressure	Pressure	Pressure	Out	(Percent	
*(min.)	(bbl/min.)	(bbl/min.)	(bbl/min)	(bbl)	(psia.)	(psia)	(psia)	(SCF/hr)	open)	Remarks
0	0	0	0	0	2730	0	n/a	0	n/a	start N2 inj.
0.5	0	3	1	1	2900	0	n/a	0	n/a	blank
8	0	3	3.2	20	2800	0	n/a	0	n/a	shut-in
10	0	0	0	20	3100	600	n/a	0	n/a	stop N2 inj.
15	0	0	0	20	3130	615	n/a	0	n/a	blank
20	0	0	0	20	3150	620	n/a	0	n/a	blank
22	1.58	0	1.78	20	3155	620	n/a	0	n/a	start pump
25	1.58	0	2.14	20	3100	495	n/a	0	n/a	blank
30	1.58	0	1.8	21	3160	540	n/a	0	n/a	blank

35	1.58	0	1.54	22	3150	550	n/a	0	n/a	blank
40	1.58	0	1.74	23	3160	550	n/a	0	n/a	blank
45	1.58	0	1.9	23	3170	555	n/a	0	n/a	blank
50	1.58	0	2.02	24	3150	575	n/a	0	n/a	blank
55	1.58	0	2.14	25	3160	630	n/a	0	n/a	blank
60	1.58	0	2.86	25	3190	695	n/a	0	n/a	blank
65	1.58	0	two-phase	26	3190	770	n/a	0	n/a	gas at surface
70	1.58	0	two-phase	26	3160	830	n/a	20000	n/a	blank
75	1.58	0	two-phase	20	3160	950	n/a	65000	n/a	blank
80	1.58	0	two-phase	15	3150	930	n/a	65000	n/a	blank
85	1.58	0	two-phase	6	3150	800	n/a	65000	n/a	blank
90	1.58	0	two-phase	3	3150	500	n/a	50000	n/a	blank
95	1.58	0	two-phase	0	3180	440	n/a	15000	n/a	blank
100	1.58	0	two-phase	0	3160	400	n/a	5000	n/a	blank
								0		

*LSU Goldking No. 1(Subsea BOP Stack) 2-22-85

*Wellcontrol simulation(single choke line).

*Well Geometry (vertical well):

*Casing String:

*Depth *(ft)	I.D. (in.)
3000	6.875
6100	6.875

*Drill Pipe:

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	2.441	2.875
6000	2.441	2.875

*Gas Injection String (Placed inside drill pipe)

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	1.045	1.315
6030	1.045	1.315

*Subsea Choke Line:

*Depth *(ft)	I.D. (in.)
0	1.995
3000	1.995

*Subsea Kill Line:

*Depth *(ft)	I.D. (in.)
0	1.995
3000	1.995

*Mud Properties:

*Mud *Density *(lb/Gal)	Plastic Viscosity (cp.)	Yield Point Lb/100Ft2	Water Fraction ( )	Water Density (lb/Gal)	Oil Fraction ( )
9	36	44	0.95	8.34	0

*Fann Readings:										
*RPM:										
600	300	200	100	6	3					
*Dial Reading:										
116	80	64	47	15	13					
*Time:										
*10 sec.	1 min.									
*Gel:										
14	19									
*Kick Gas (mole fractions) :										
*C1	C2	C3	N-C4	I-C4	C5+	CO2	H2S	N2		
0	0	0	0	0	0	0	0	1		
*Temperature Profile:										
*Extrap.			Surf. Gas							
*Surface	Static	Tank	injection							
*Temp.	Gradient	Temp.	Temp.							
*(Deg.F)	(Deg.F/ft)	(Deg.F)	(Deg.F)							
83	0.013	87	105							
*Measured Parameters as a Function of Time :										
*		Gas	Mud		Bottom			Gas	Choke	
*	Pump	Inj.	Flow	Pit	Hole	Choke	Seafloor	Rate	Posit.	
*Time	Rate	Rate	Out	Gain	Pressure	Pressure	Pressure	Out	(Percent	
*(min.)	(bbl/min.)	(bbl/min.)	(bbl/min)	(bbl)	(psia.)	(psia)	(psia)	(SCF/hr)	open)	Remarks
0	0	0	n/a	0	2750	0	n/a	0	100	start N2 inj
1	0	1.8	n/a	0.5	2900	0	n/a	0	100	blank
12	0	1.8	n/a	10	2900	0	n/a	0	100	shut-in
13	0	1.8	n/a	16	2860	450	n/a	0	100	blank
16	0	0	n/a	18	3075	540	n/a	0	0	start pump
30	2.41	0	n/a	19	3000	260	n/a	0	30	blank
33	2.41	0	n/a	20	2970	280	n/a	0	30	blank
36	2.41	0	n/a	20	2950	340	n/a	5000	29	gas at surface
39	2.41	0	n/a	21	2960	570	n/a	30000	26	blank

42	2.37	0	n/a	22	2950	630	n/a	50000	24	blank
45	2.41	0	n/a	23	2960	750	n/a	50000	21	blank
48	2.41	0	n/a	24	2960	850	n/a	50000	19	blank
51	2.41	0	n/a	22	3000	770	n/a	70000	19	blank
54	2.41	0	n/a	19	2950	500	n/a	50000	18	blank
57	2.41	0	n/a	14	3120	450	n/a	30000	25	blank
60	2.41	0	n/a	9	3030	300	n/a	25000	28	blank
63	2.41	0	n/a	6	3060	240	n/a	20000	31	blank
66	2.41	0	n/a	3	3050	190	n/a	10000	32	blank
69	2.41	0	n/a	1	3050	180	n/a	10000	33	blank
72	2.41	0	n/a	1	3050	150	n/a	5000	35	blank
75	2.41	0	n/a	0	3030	130	n/a	0	39	blank

3-18-85, No. 1

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*LSU Goldking No. 1 (Subsea BOP Stack) 3-18-85, No. 1										
*Gas kick simulation with weighted mud (single choke line).										
*Well Geometry (vertical well):										
*Casing String:										
*Depth	I.D.									
*(ft)	(in.)									
3000	6.875									
6100	6.875									
*Drill Pipe:										
*Depth	I.D.	O.D.								
*(ft.)	(in.)	(in.)								
0	2.441	2.875								
6000	2.441	2.875								
*Gas Injection String (Placed inside drill pipe)										
*Depth	I.D.	O.D.								
*(ft.)	(in.)	(in.)								
0	1.045	1.315								
6030	1.045	1.315								
*Subsea Choke Line:										
*Depth	I.D.									
*(ft)	(in.)									
0	1.995									
3000	1.995									
*Subsea Kill Line:										
*Depth	I.D.									
*(ft)	(in.)									
0	1.995									
3000	1.995									
*Mud Properties:										
*Mud	Plastic	Yield	Water	Water	Oil					
*Density	Viscosity	Point	Fraction	Density	Fraction					
*(lb/Gal)	(cp.)	Lb/100Ft2	( )	(lb/Gal)	( )					
12.4	29	5	0.83	8.34	0					

*Fann Readings:										
*RPM:										
600	300	200	100	6	3					
*Dial Reading:										
63	34	24	14	3	2					
*Time:										
*10 sec.	1 min.									
*Gel:										
n/a	n/a									
*Kick Gas (mole fractions) :										
*C1	C2	C3	N-C4	I-C4	C5+	CO2	H2S	N2		
0	0	0	0	0	0	0	0	1		
*Temperature Profile:										
*Extrap.			Surf. Gas							
*Surface	Static	Tank	injection							
*Temp.	Gradient	Temp.	Temp.							
*(Deg.F)	(Deg.F/ft)	(Deg.F)	(Deg.F)							
83	0.013	73	100							
*Measured Parameters as a Function of Time :										
*		Gas	Mud		Bottom			Gas	Choke	
*	Pump	Inj.	Flow	Pit	Hole	Choke	Seafloor	Rate	Posit.	
*Time	Rate	Rate	Out	Gain	Pressure	Pressure	Pressure	Out	(Percent	
*(min.)	(bbl/min.)	(bbl/min.)	(bbl/min)	(bbl)	(psia.)	(psia)	(psia)	(SCF/hr)	open)	Remarks
0	0	0	0	0	3750	0	1915	0	n/a	start N2 inj.
3	0	1.5	1.1	3	3920	0	2000	0	n/a	blank
6	0	1.5	1.2	8	3920	0	2065	0	n/a	blank
9	0	1.5	1.4	12	3880	0	2095	0	n/a	blank
12	0	1.5	1.6	18	3850	0	2120	0	n/a	blank
15	0	1.5	1.7	23	3800	0	2145	0	n/a	blank
18	0	1.5	1.7	26	3760	0	2175	0	n/a	stop N2 inj.
21	0	0	1.8	26	3930	520	2470	0	n/a	shut-in
24	0	0	0	26	3970	510	2485	0	n/a	blank

27	0	0	0	26	4000	575	2525	0	n/a	start pump
30	1.49	0	1.2	26	3750	150	2360	0	n/a	blank
33	1.49	0	1.42	27	3860	350	2525	0	n/a	blank
36	1.49	0	1.66	27	3840	100	2450	0	n/a	blank
39	1.49	0	2.38	28	3840	200	2550	0	n/a	blank
42	1.49	0	2.3	29	3850	250	2510	4000	n/a	gas at surface
45	1.49	0	two-phase	32	3700	1350	2495	20000	n/a	blank
48	1.49	0	flow	30	3820	1400	2465	10000	n/a	blank
51	1.49	0	n/a	28	3640	1560	2455	80000	n/a	blank
54	1.49	0	n/a	26	3850	1770	2390	15000	n/a	blank
57	1.49	0	n/a	24	4040	1760	2595	30000	n/a	blank
60	1.49	0	n/a	21	3840	1480	2505	80000	n/a	blank
63	1.49	0	n/a	18	3640	1480	2260	60000	n/a	blank
66	1.49	0	n/a	14	3700	1640	2230	30000	n/a	blank
69	1.49	0	n/a	10	3920	1700	2355	25000	n/a	blank
72	1.49	0	n/a	6	3900	950	2560	50000	n/a	blank
75	1.49	0	n/a	4	3850	400	2415	80000	n/a	blank
78	1.49	0	n/a	3	4005	150	2595	30000	n/a	blank
81	1.49	0	n/a	2	3960	80	2435	15000	n/a	blank
84	1.49	0	n/a	2	3930	70	2515	8000	n/a	blank
87	1.49	0	n/a	1	3950	60	2520	4000	n/a	blank

*LSU Goldking No. 1(Subsea BOP Stack) 4-12-85

*Wellcontrol simulation(single choke line).

*Well Geometry (vertical well):

*Casing String:

*Depth *(ft)	I.D. (in.)
3000	6.875
6100	6.875

*Drill Pipe:

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	2.441	2.875
6000	2.441	2.875

*Gas Injection String (Placed inside drill pipe)

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	1.045	1.315
6030	1.045	1.315

*Subsea Choke Line:

*Depth *(ft)	I.D. (in.)
0	1.995
3000	1.995

*Subsea Kill Line:

*Depth *(ft)	I.D. (in.)
0	1.995
3000	1.995

*Mud Properties:

*Mud *Density *(lb/Gal)	Plastic Viscosity (cp.)	Yield Point Lb/100Ft2	Water Fraction ( )	Water Density (lb/Gal)	Oil Fraction ( )
9.4	27	18	0.92	8.34	0

*Fann Readings:										
*RPM:										
600	300	200	100	6	3					
*Dial Reading:										
72	45	n/a	n/a	n/a	n/a					
*Time:										
*10 sec.	1 min.									
*Gel:										
n/a	n/a									
*Kick Gas (mole fractions) :										
*C1	C2	C3	N-C4	I-C4	C5+	CO2	H2S	N2		
0	0	0	0	0	0	0	0	1		
*Temperature Profile:										
*Extrap.			Surf. Gas							
*Surface	Static	Tank	injection							
*Temp.	Gradient	Temp.	Temp.							
*(Deg.F)	(Deg.F/ft)	(Deg.F)	(Deg.F)							
83	0.013	89	105							
*Measured Parameters as a Function of Time :										
*		Gas	Mud		Bottom			Gas	Choke	
*	Pump	Inj.	Flow	Pit	Hole	Choke	Seafloor	Rate	Posit.	
*Time	Rate	Rate	Out	Gain	Pressure	Pressure	Pressure	Out	(Percent	
*(min.)	(bbl/min.)	(bbl/min.)	(bbl/min)	(bbl)	(psia.)	(psia)	(psia)	(SCF/hr)	open)	Remarks
0	0	0	0	0	2950	0	n/a	0	100	start N2 inj
3	0	2	0.8	3	3000	0	n/a	0	100	blank
6	0	2	1.4	9	3030	0	n/a	0	100	blank
9	0	2	2	15	2950	0	n/a	0	100	blank
12	0	0	0	15	3405	720	n/a	0	100	stop N2 inj.
15	0	0	0	15	3435	770	n/a	0	0	shut-in
18	0	0	0	16	3450	800	n/a	0	0	blank
21	0	0	0	16	3460	540	n/a	0	10	start pump
24	1.86	0	1.66	16	3650	450	n/a	0	25	blank

27	1.8	0	1.8	17	3580	650	n/a	0	16	blank
30	1.86	0	2.5	17	3450	500	n/a	0	27	blank
33	1.86	0	2.8	18	3480	800	n/a	0	22	blank
36	1.86	0	2.3	19	3450	1000	n/a	8000	22	gas at surface
39	1.86	0	2	20	3500	1305	n/a	40000	18	blank
42	1.86	0	0.5	20	3510	1530	n/a	40000	22	blank
45	1.8	0	0.7	18	3410	1455	n/a	80000	17	blank
48	1.9	0	0.3	14	3580	1510	n/a	60000	20	blank
51	1.8	0	0.3	10	3440	750	n/a	90000	19	blank
54	1.9	0	0.1	6	3450	350	n/a	30000	29	blank
57	1.86	0	1.5	3	3455	360	n/a	10000	25	blank
60	1.86	0	1.6	1	3460	350	n/a	4000	25	blank
63	1.86	0	1.7	0	3465	350	n/a	0	24	blank

*LSU Goldking No. 1(Subsea BOP Stack) 3-24-86

*Wellcontrol simulation with natural gas in oil base mud (single choke line).

*Well Geometry (vertical well):

*Casing String:

*Depth *(ft)	I.D. (in.)
3000	6.875
6100	6.875

*Drill Pipe:

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	2.441	2.875
6000	2.441	2.875

*Gas Injection String (Placed inside drill pipe)

*Depth *(ft.)	I.D. (in.)	O.D. (in.)
0	1.045	1.315
6030	1.045	1.315

*Subsea Choke Line:

*Depth *(ft)	I.D. (in.)
0	1.995
3000	1.995

*Subsea Kill Line:

*Depth *(ft)	I.D. (in.)
0	1.995
3000	1.995

*Mud Properties:

*Mud *Density *(lb/Gal)	Plastic Viscosity (cp.)	Yield Point Lb/100Ft2	Water Fraction ( )	Water Density (lb/Gal)	Oil Fraction ( )
8.1	17	9	0.35	9	0.65

*Fann Readings:										
*RPM:										
600	300	200	100	6	3					
*Dial Reading:										
43	26	n/a	n/a	n/a	n/a					
*Time:										
*10 sec.	1 min.									
*Gel:										
n/a	n/a									
*Kick Gas (mole fractions) :										
*C1	C2	C3	N-C4	I-C4	C5+	CO2	H2S	N2		
0.9018	0.0484	0.0205	0.0053	0.0049	0.0074	0.0089	0	0.0028		
*Temperature Profile:										
*Extrap.			Surf. Gas							
*Surface	Static	Tank	injection							
*Temp.	Gradient	Temp.	Temp.							
*(Deg.F)	(Deg.F/ft)	(Deg.F)	(Deg.F)							
83	0.013	80	70							
*Measured Parameters as a Function of Time :										
*		Gas	Mud		Bottom			Gas	Choke	
*	Pump	Inj.	Flow	Pit	Hole	Choke	Seafloor	Rate	Posit.	
*Time	Rate	Rate	Out	Gain	Pressure	Pressure	Pressure	Out	(Percent	
*(min.)	(bbl/min.)	(bbl/min.)	(bbl/min)	(bbl)	(psia.)	(psia)	(psia)	(SCF/hr)	open)	Remarks
0	0	0	n/a	0	2550	0	n/a	0	n/a	start gas inj
1	0.2	0.41	n/a	0	2800	250	n/a	0	n/a	blank
51	0.2	0.41	n/a	14	2660	250	n/a	0	n/a	blank
59	0	0.96	n/a	19	2620	250	n/a	0	n/a	stop gas inj.
67	1.33	0	n/a	19	2615	250	n/a	0	n/a	blank
70	0	0	n/a	19	2705	350	n/a	0	n/a	blank
73	2.01	0	n/a	19	2690	0	n/a	0	n/a	start circ.
76	2.01	0	n/a	19	2680	0	n/a	0	n/a	blank
79	2.01	0	n/a	18	2680	20	n/a	0	n/a	blank

82	2.01	0	n/a	16.5	2680	20	n/a	0	n/a	blank
85	2.01	0	n/a	16	2680	600	n/a	60000	n/a	gas at surface
88	2.01	0	n/a	16	2680	100	n/a	110000	n/a	blank
91	2.01	0	n/a	15.5	2680	750	n/a	90000	n/a	blank
94	2.01	0	n/a	19	2680	1150	n/a	45000	n/a	blank
97	2.01	0	n/a	25	2680	750	n/a	35000	n/a	blank
100	2.01	0	n/a	19	2680	400	n/a	35000	n/a	blank
103	2.01	0	n/a	12	2680	250	n/a	25000	n/a	blank
106	2.01	0	n/a	9	2680	100	n/a	20000	n/a	blank
109	2.01	0	n/a	8	2680	90	n/a	20000	n/a	blank
112	2.01	0	n/a	7	2680	80	n/a	20000	n/a	blank
115	2.01	0	n/a	5.5	2680	70	n/a	20000	n/a	blank
118	2.01	0	n/a	4.5	2680	60	n/a	4000	n/a	blank
121	2.01	0	n/a	3.5	2680	55	n/a	4000	n/a	blank
124	2.01	0	n/a	2.5	2680	50	n/a	4000	n/a	blank
127	2.01	0	n/a	2	2680	45	n/a	4000	n/a	blank
130	2.01	0	n/a	1	2680	40	n/a	4000	n/a	blank
133	2.01	0	n/a	0	2680	35	n/a	0	n/a	blank

INTERNATIONAL WELL CONTROL SYMPOSIUM, NOVEMBER 27-28, 1989

LOUISIANA STATE UNIVERSITY

THE DEVELOPMENT OF A WELL CONTROL RESEARCH PROJECT

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UK DEPARTMENT OF ENERGY

ABSTRACT

Taking an R and D project from initial concept to signing a contract for the work is a crucial step. Whilst the success of the project cannot be guaranteed by getting the step right, a failure at this stage will almost certainly mean that the project does not fully achieve its objectives.

The U.K. Department of Energy completed a particularly important project preparation exercise in late 1988. The objectives of the project were to research into well control when gas influxes occurred in oil based mud and to enhance safety by publicising the results. It involved - inter alia - consultation with industry, the development of a detailed scope of work and presentations by prospective bidders.

The paper describes how the Department tackled this important phase, the technical scope of work of the project and the management effort expended to set it up. The project now is proceeding well, meeting target dates and is within budget.

BACKGROUND

Hydrocarbon exploration in the North Sea has required the development of many new procedures and products. Deep high pressure drilling in the central North Sea has presented a particular challenge for drilling mud systems. Undisturbed bottom hole temperatures in the region of 200°C (400°F) are being encountered, as are pressures approaching the limit of 15,000 psi well control equipment.

By 1985 there had been a number of well control incidents which had caused concern : these appeared to be related to the use of oil-based muds. An industry seminar was arranged by the UK Department of Energy to discuss the problems that had occurred. Following the seminar a report was prepared by the Department and published by HMSO (OTH 86 260). This analysed the well control problems encountered in 5 wells (6 incidents). It provided advice on further study areas, modifications to rig systems and the importance of well control training. It emphasised the need for the industry to continue to define and promote safe practices for high-pressure deep drilling.

The statutory nature of the U.K. Department of Energy's responsibility for safety should be noted. The Mineral Workings (Offshore Installations) Act 1971 together with the Petroleum and Submarine Pipelines Act of 1975 and the Oil and Gas (Enterprise) Act of 1982 place a statutory responsibility on the Secretary of State for Energy to provide for the safety, health and welfare of persons on installations, or in work associated with pipelines, on the U.K. Continental Shelf. For example the Secretary of State requires all offshore

installations to be certified as fit for the purpose specified. Regulations have statutory force. Within the U.K. Department of Energy the Petroleum Engineering Division provides the necessary support to the Secretary of State in the exercise of these duties.

The Department of Energy commissioned BP Research Centre to carry out a pre-project study. This study was concluded in march 1987 and covered the need to improve well control training where gas solubility in drilling mud was an important factor. A programme for obtaining specific PVT data to determine changes in surface mud volumes resulting from gas intrusion was proposed. Th need for an improved mathematical model was also covered. BP recommended a project to develop a new mathematical model after reviewing existing mod the context of meeting the objectives of research and safety training Approximate costs were estimated to be £420-£1,145K.

The detailed conclusions drawn from the study were:

(i) Gas solubility in oil based drilling mud has important implications.

(ii) A better understanding of downhole fluid PVT beh will lead to safer and more cost effective dri

(iii) A specification should be determined for a r model able to deal with gas kicks in oil

(iv) That the estimated cost of a mathemati experimental data is of the order of

(v) That industry support should be sought in the context of the Department's intention that results from the model should be made widely and quickly available.

The Department accepted the recommendations made. Support for the project was given by the Offshore Safety and Technology Board. (This is comprised of representatives of industry and academia and advises the Head of P.E.D on R&D strategy, needs and major projects.)

PROJECT INITIATION

Two branches of the Petroleum Engineering Division were involved in the initiation and running of the project : the Drilling Inspectorate and the Research and Development branch. During 1987 the Principal Drilling Inspector chaired meetings with industry representatives to discuss the specification of the model (described later). The R&D branch was responsible for arranging the funding of the project and determining the contractual arrangements. iscussions on joint funding were held with the UK Offshore Operators sociation (UKOOA) but they proved unsuccessful. Competitive tendering was sidered essential, and invitations to tender were sent to BP Research e, Schlumberger Cambridge Research, Rogalands Research Institute, th Technology Centre and AMOCO.

ract objectives

? pre-project study had shown that existing models were not suitable the research and safety training objectives of the Department.

What was required was a code which took account of gas solubility in oil-based muds in deep high pressure wells, which included dispersion, two-phase flow in non-Newtonian drilling fluids and rapid transients. The existing programs had some of the desired features but none had them all. Element et al (1989) review the existing computer codes from literature reports.

It was determined that two models were required. The first would be a comprehensive research (R) model, probably requiring the use of a main-frame computer. Winfrith were nominated as the future operators of this model when completed, a role analogous to their operation of other major programs for the Department e.g. the reservoir simulator PORES. Their computing facilities are extensive and include a Cray 2 supercomputer. The second model, derived from the 'R' model, would be a user-friendly engineering (E model which would be widely available to drilling engineers and operate capable of running on a computer work-station. It was thought that model would need some simplification to suit the smaller capacity work-station for the E model. However computer systems develop that the R model itself will be run on SUN work-stations.

The contract objectives were written as follows:
"The Contractor shall produce a drilling well kick s
with can be used by engineers to evaluate well de
drilling with oil based muds on the United Kin
shall be designated the 'Engineering' or 'E'

and swa
the mode

To support this overall objective it will also be necessary to:

(i) develop a 'Research' or 'R' model of a drilling well simulator to gain an increased understanding of the physical phenomena and as a basis for the 'E' model, and

(ii) produce and execute a plan whereby the 'E' model shall be made widely available on reasonable commercial terms."

SPECIFICATION

The specification for the 'R' model was drawn up in 1987-88. Considerable assistance was given to the Department by industry drilling representatives and computer modelling specialists. The main purpose of the R model was to provide insights into well behaviour to enhance control techniques. This increased knowledge should enable training to be improved and thus enhance safety at the rig site.

In addition to a better understanding of kick behaviour, the envisaged benefits of the 'R' model were listed as aiding:

- post well incident analysis
- checking on casing design
- studying bottom hole pressure changes with mud properties
- sizing gas venting systems downstream of the choke.

To keep the work to a manageable size and timescale, non-vertical wells and b-surge effects are not considered by the model. It is expected that modelling will be extended to inclined wells in a subsequent project and

work being done elsewhere on swab-surge effects will most probably also be included. The modular form of the programming anticipates these enhancements and will allow them to be made in an efficient manner.

For convenience and for the purposes of project management, the work has been subdivided into five phases:

Phase I : definition of the R model

Phase II : build and prove the R model

Phase III : specify the E model

Phase IV : build and prove the E model

Phase V : produce a commercialisation plan for the E model

The required modelling capabilities

Pressure control training. There are a number of traditional detection methods for well kicks. The model needs to monitor:

(a) drilling mud volume increases at the mud pit.

(b) sudden decreases in mud circulation pressure and/or an increase in circulating rate as the same pump power works against lower ann fluid density.

(c) the difference between mud flow rate going down the boreh flow rate of returns. This is a more sensitive form o

In fact the model will be capable of monitoring a not just volumes, pressures and flow rates, to ider

Drilling planning and research. When used in this mode it will be possible to input a particular well's characteristics. This will include geological and drilling data and some rig geometry. Appropriate equations of state will be used to predict fluid property behaviour.

Drilling modelling. The hydrodynamics module should solve the transient mass, momentum and energy conservation equations for multi-phase flow in the wellbore. It is not considered necessary for the modelling to be 3-dimensional, and some simplification of the energy equation may be necessary. Other modules will link in with this basic module covering gas solubility, dispersion effects, reservoir behaviour etc. The model should accept initial and time dependent boundary conditions appropriate to normal well drilling operations and a kicking formation. Actions taken on the rig floor during a well kill operation to prevent a kick developing into a blowout should be capable of simulation. The hydrodynamics module should be able to simulate the presence of at least two mud weights during the kill-operation. The model should be valid across a wide operating range, capable of simulating events in wells to 4500 m (15,000 feet) deep that can be drilled with 15,000 psi (1035 bar) well control equipment.

Model validation. Validation of the code is essential. The simulator accuracy must be considered during development: correlations in individual modules should be checked; the algorithm accuracy should be checked against variation of grid size; and sensitivity runs will determine the key parameters which therefore require careful attention. When complete the code will correctly simulate normal circulation in a well, including flows and pressures

during the initiation and cessation of circulation. The model will also simulate the pressure/volume response of the well up to the point at which leak-off occurs. All this will be checked against field data.

The next phase of validation will involve experimental and actual kick data. At the time of writing the specification the LSU DEA7 data had become available to participants in that project. The Department hoped to join DEA7 in its second phase, but unfortunately this phase was cancelled. In the event, BP and SCR were participants in phase 1 of the project and will use this data to help validate the model. (The actual LSU data will only be available to the Department after the confidentiality period expires). Finally the Department hopes to obtain actual kick data from U.K. Continental Shelf (UKCS) operators, and at the present time this approach is being actively pursued.

Variables to be input as data

The Specification listed and discussed the input parameters. These include formation and reservoir properties, drilling mud composition and properties, well geometry, and drilling conditions.

The physical models to be treated

A number of physical models are specified for incorporation in the code.

These cover:

- mud density variations
- mud viscosity variations
- formation breakdown (but subsequent lost circulation will not be modelled),
- wellbore elasticity/plasticity, to be modelled if a sensitivity analysis indicates that the phenomenon is important with regard to well control,
- gas solubility/miscibility. This will require experimental work to obtain physical data and to develop improved equations of state,
- bubble rise/slip. Slip between mud and gas phases is seen as critical in predicting the rate at which a well kick propagates,
- mud/gas flow regimes,
- geothermal and drill bit heat transfer. As noted previously in the paper, some simplification of the energy conservation equation may be necessary and this will have implications for modelling heat transfer,
- frictional pressure drop. The non-Newtonian character of the mud, the effect of gas entrainment and variation of mud properties will be taken into account,
- choke line pressure loss. This becomes important on deep water locations where a subsea blowout preventer stack is in use.

Operator Facilities

Choke variation. Choke adjustment is the primary means of controlling pressure while circulating out a kick. It is important that the pressure transients caused by choke operation and the time delays due to the compressibility of the mud/gas mixture are taken into account.

Pump rate variation. Changes in the volume flow rate of the mud pump should either be user specified or internally calculated to maintain a specified boundary condition e.g. the maintenance of a constant bottom hole pressure.

Mud weight variation. The model should calculate the required kill mud density. This should be at the operator's choice and needs to cover a range of 6-18ppg (720 to 2160 kg/m^3).

Well Close-in. For effective post-event analysis, it is important to have the means to control as many model parameters as possible. Experience indicates that this is particularly true for the well close-in operation. The operator should be able to vary the relative timings of initiation of pump shut-down and BOP closure, initiation of choke closure following BOP closure, times for pumps to shut down, BOP to close, and choke to close.

Model Output

The desirable outputs and forms of output need to take account of the wide range of uses of the model. They should include:

- drill pipe pressure against time at user-specified depths,
- bottom hole pressure against time,
- shut-in casing pressure against time,
- circulating choke pressure against time,
- casing shoe pressure against time during shut-in and the well killing operation,
- mud pit gain against time during a kick and the well killing operation,

- the quantity of free and dissolved gas as a function of depth and time,
- the required kill mud weight,
- the mud annular flow rate against time
- the formation flow rate against time.

Programming considerations and the user interface

The Specification included a section defining the requirements of the programming approach. Strict Fortran-77 was requested with top-down program design techniques to develop a clear program structure with well defined modules. There will be four principal elements:

- input data pre-processor
- simulator
- interactive interface
- results post-processor

TENDERING PROCEDURE

Invitations to tender were sent to BP Research Centre, Schlumberger Cambridge Research, Rogalands Research Institute, Winfrith Technology Centre and AMOCO. Included with the Invitation to Tender document was the Model Specification, both being sent out on the 6 June 1988. The closing date for receipt of tenders was set as 7 July 1988. In the event AMOCO declined to tender, while Schlumberger Cambridge Research (SCR) and BP decided to collaborate and submit a joint bid.

Technically acceptable tenders were duly received from Rogalands Research Institute, Winfrith Technology Centre and SCR-BP.

An internal Tender Board was set up, chaired by the Head of Research and Development at the Department of Energy, and successive meetings discussed the details of the bids with each of the three tenderers. A key issue turned out to be the ownership of results and commercialisation of the 'E' model. Normally, in a 100% Department funded project the results of the project would be owned by the Department. SCR and BP put forward an alternative whereby SCR BP would own the results, and the commercialisation of the 'E' model would be fully funded by SCR. Discussions with the other tenderers on the effect of a change in the ownership of results gave only minor savings. In the case of SCR-BP the approximate 40% saving was highly significant, reducing the project cost to just over £500,000 and giving good guarantee of the wide commercial dissemination of the 'E' model.

The reduced project cost enabled the Department to fully fund the project, and the contract (after further negotiation) was awarded to SCR-BP. The project commenced on 1 November 1988. The key dates agreed between SCR-BP and the Department were for the 'R' model to be complete and running by the end of February 1990, and for the 'E' model to be commercially available by the end of February 1991.

PROGRESS OF THE PROJECT

The project commenced on 1 November 1988, and has proceeded to date on time and on budget. The selected contractors, SCR-BP, were able to dedicate a project team from day 1 drawing on the considerable resources of a major service company and a major oil company. In support of the mathematical modelling process, the project includes two important experimental programmes. These seek to obtain improved PVT data and equations of state (see Swanson 1989) and improved hydrodynamic correlations (see White and Johnson 1989).

Project control

The Department have contracted the Marine Technology Support Unit (MaTSU), Harwell, to provide a project officer for the contract. He holds monthly progress meetings with the Contractor's Project Manager. Because of the technical complexity of the project the Department have sought additional assistance. Winfrith Technology Centre (who will run the completed K model on behalf of Department) have also been contracted to provide a technical monitoring service and provide advice to the Department. A further organisation, Geoscience, has been contracted in support of the Drilling Inspectorate during the project, and they are obtaining the field data of actual kicks from UKCS operators. MaTSU, Winfrith and Geoscience comprise the Department's management support team.

At quarterly intervals an Advisory Steering Group meeting is chaired by the Principal Drilling Inspector. This is made up of the regular monthly meeting participants plus members of the Department's drilling inspectorate. At the non-confidential sessions which follow, representatives from U.K. operating companies join the discussions and provide the industry's perspective on the work.

Conclusion

The Department looks forward to the completion of this project and the adoption by industry of the E model. We believe this will improve understanding of well control in deep, high pressure wells and enhance the safety of these operations. Subsequent steps should include the use of the E model in training, and possibly the further development of both models to cover such issues as inclined wells, swab-surge, kicks with the drill string off bottom and fluid leakage from the well-bore.

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AN OVERVIEW OF KICKING WELL COMPUTER MODELS

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Abstract

In recent years a number of computer programs have been developed to simulate the behaviour and control of gas kicks taken while drilling. Program development projects continue at several research organisations. The simplest kicking well programs are intended for use in the teaching and demonstration of kick control techniques. These programs contain only basic mathematical models. More advanced models are employed in the most sophisticated codes which may be used to investigate the effects of such physical phenomena as kick gas solubility in oil-based drilling fluids or the motion of free gas in the non-Newtonian drilling fluid. Some kicking well code development projects have been coupled with experimental programmes to provide data and correlations for inclusion in the codes.

This paper provides an overview of the kicking well computer codes that have been described in the open literature. These codes are compared and contrasted with respect to the differing modelling capabilities, numerical approximations, solution methods, and the representation of physical effects using either physical models or correlations. The physical models employed are critically analysed, and an assessment is made of the likely effects of certain modelling and solution simplifications.

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AN OVERVIEW OF KICKING WELL COMPUTER MODELS

1. INTRODUCTION

Recent years have seen the development of several computer programs to simulate the behaviour and control of gas kicks taken while drilling. The continued interest in developing such computer models demonstrates the ongoing industry requirement to further appreciate the behaviour of downhole fluids during a gas kick, and to analyse current well designs and control procedures.

Kicking well computer codes range from relatively simple mathematical models intended for use in the teaching and demonstration of kick control techniques, to sophisticated codes which may be used to model the effects of such physical phenomena as kick gas solubility in oil-based drilling fluids or the motion of free gas in the non-Newtonian drilling fluid.

This paper begins with discussion of the need for kicking well models, outlining the nature of the well control problem with reference to sample plots. This is followed by a brief overview of existing computer models, presented in chronological order. Subsequent sections address the modelling of physical processes in a kicking well computer code, focussing on the following topics in turn: fluid density, fluid viscosity, mud flow in the wellbore, mud/gas two-phase flow, formation fluid inflow rate, solubility of kick gas in drilling mud, temperature effects, formation rock deformation and fracture, wellbore components and operation procedures. To

complete the comparison of existing computer models the codes considered are assessed in terms of the numerical solution algorithm and the operational/graphical capabilities. The different modelling approaches and capabilities of eleven of these kicking well models are summarised in Tables 1-6.

2. THE NEED FOR SOPHISTICATED KICKING WELL MODELS

Computer simulations of kicks in wells and well control operations may provide benefits for safety in the drilling industry in many ways, including:

improvement in the training of well controllers

development and assessment of new control techniques

development of new kick detection methods

post-analysis of kick control procedures (successful or failed) applied to specific incidents

safety analysis of well design proposals.

For a simulator to provide each of the above benefits, it is necessary for all of the somewhat complicated physical effects relevant to drilling mud and kick fluid behaviour to be included in the computer model. This is

true even for the use of simulators in the training of well controllers. Although it is possible to train drillers how to circulate kicks from a well according to a simple, pre-determined method (such as monitoring the wait and weight method), the expected effects of control actions on surface observables needs to be appreciated. For instance, the considerable depth of some wells leads to significant delays before control actions begin to have influence downhole; the solubility of hydrocarbon gases in oil-based muds may lead to important differences in the response of wells to kicks depending on whether water or oil-muds are in use; the high frictional pressure losses in choke lines for wells with subsea BOPs demand that considerable care be exercised in controlling pressures via choke changes as the top and bottom of the gas zone enters the choke.

The aim of control operations is to maintain as nearly as possible a constant bottomhole pressure. This has to be achieved by drillers who are only aware of changes in the surface measurables - drillpipe pressure, casing pressure, pit gain, returns flow rate and gas content. Figures 1-7 give some indication of the interrelation between these quantities which ought to be predicted by a kicking well simulator. These plots were produced with the WELL-KICK model - a program developed at Winfrith for research purposes. The model is incomplete but serves to describe the typical behaviour of kicks in wells. The well modelled is 10,000 ft in depth - with changes in cross-section at the drill collars and the casing shoe. A subsea BOP is employed, leading to a choke line 50 ft in length. The flow rate from the high-pressure formation is determined from the well

bottomhole pressure which is 300 psi less than formation pressure at the commencement of the kick. The slip and solubility of kick gas are both neglected.

In Figure 1 the calculated variation in mud tank level is plotted. After gas begins to flow into the well the level of mud begins to rise, continuing to do so until the well is shut-in. For this simulation it is assumed that the gas kick is detected once the mud tank level has increased by 20 barrels, although the gain measured after well shut-in exceeds this figure due to the delay in closing both the blowout preventers and the choke.

Figure 2 shows the rate at which fluids flow out of the well. Initially the well is drilled with a 400 gpm mud flow rate, but once a kick is taken mud begins to flow from the well at higher rates - the maximum exceeding 750 gpm. As the well is shut-in this outflow rate begins to drop - reaching zero once the choke is fully closed. A finite time is required to execute all shut-in procedures - including the termination of drilling, switching off the pumps, closing blow-out preventers and closing the choke throttle. In this simulation 40 seconds elapse between kick detection and completion of well shut-in.

The simulated variations in surface drillpipe pressure (pump pressure) are plotting in Figure 3. During normal drilling the drillpipe pressure rises slowly - largely a consequence of the increased bottom hole pressure arising from the deepening of the well and the introduction of drilled

cuttings to the mud in the annulus. Following the influx of formation gas the drillpipe pressure behaviour continues to reflect the bottom hole changes. These bottom hole pressure variations are plotted in Figure 4. Initially the pressure rises since the formation is at a higher pressure than the wellbore. Fluids flow into the wellbore as a consequence of the dis-equilibrium at the bottom. As the formation fluid in the annulus causes a drop in hydrostatic head, however, both the bottomhole pressure and the drillpipe pressure decrease.

After shut-in the well pressures begin to increase as more formation fluids enter the system. Eventually the well stabilises and inflow ceases. After a delay the well kill procedure begins. The "wait and weight" method is assumed for this simulation. As the mud pump speed is slowly increased to give the kill rate of 200 gpm, the pressures in the well increase until the choke is opened. It is the intention of this 'perfect' kill to maintain a bottom hole pressure which exceeds the formation pore pressure by a specified margin. The bottom hole pressure graph (Figure 4) clearly shows this constant pressure.

Well control theory demonstrates that a steady decrease in drillpipe pressure is needed as the drill mud is pumped down towards the bit. This decrease combined with the increase in drillstring hydrostatic head (caused by the heavy drill mud) is designed to give rise to a constant bottom hole pressure. Once the drillstring is full of kill mud the choke controller aims to maintain a constant drillpipe pressure as this reflects the bottom hole pressure. Figure 3 shows the steady decrease in drillpipe pressure

predicted in this simulation and the constant final circulation value. The increased pressure losses as heavier kill mud flows through the drill collars and bit nozzles is seen to cause a slight transient minimum in drillpipe pressure before the final constant pressure is attained.

The calculated variations in the casing pressure are shown in Figure 5. With the flow choked the casing pressure is considerably higher than atmospheric pressure (14.7 psi). After re-commencing mud circulation the process of allowing bottom hole pressure to increase to its predetermined final value before opening the choke, coupled with the steady increase in mud flow rate leads to a transient peak in the casing pressure. Following this peak the pressure gradually rises - reflecting the expansion of kick fluids and consequent reduction in annulus hydrostatic head. As kill mud reaches the bit and begins to flow up the annulus, the casing pressure starts to drop - the rate of increase in hydrostatic head due to the introduction of kill mud exceeds the rate of head reduction due to gas expansion. These hydrostatic pressure drops depend on the vertical height of the kill mud region. Hence, as the kill mud reaches changes in cross-sectional area (ie for this simulation, at the top of the drill collars and at a depth of 5000 ft) associated changes may be seen in the gradient of casing pressure variations.

The effects of gas expansion become more significant as the kick nears the surface of the well - eventually masking the hydrostatic influence of kill mud and causing the casing pressure to increase. Flow rate (Figure 2), pit again (Figure 1) and casing pressure (Figure 5) all

steadily increase until the kick fluids reach the surface of the well. Idealised choke control continues to preserve a constant bottom hole pressure even as a two-phase mud/gas mixture flows through the choke. Figure 6, showing the choke settings calculated for this simulation, demonstrates how the choke flow area must be rapidly reduced in order to maintain pressure control when gas flows at the surface. Conversely, when the last of the kick gas has left the well it is necessary to increase the choke area again.

The final graph produced in this simulation (Figure 7) shows the position of the top and bottom of the gas region as the kick is circulated out of the well. From this graph the expansion of the gas region can be clearly seen, as well as a noticeable change in gas velocity as both the gas top and bottom pass the increase in cross-sectional flow area at a depth of 5000 ft.

3. BRIEF SURVEY OF EXISTING KICKING WELL MODELS

In this section a brief outline of several different kicking well models is given. The models are discussed in chronological order. Tables 1-6 summarise the key features and differences between each of these models.

Attention is focussed on those models for which sufficient information is available to allow detailed discussion in this paper. No attention is

given to well control programs developed for programmable calculators (eg Zamora, 1981; Wiegand and Korbut, 1989).

3.1 The LeBlanc and Lewis Model (1968)

The mathematical model of a gas kick presented by LeBlanc and Lewis (1968) represents one of the early attempts to use a computer to analyse well control procedures. A known volume of gas is assumed to have entered the well, leading to a single gas region with a void fraction of 100%. The simulation follows the period after well shut-in. The effects of friction, mud compressibility and changes in annulus cross-sectional area are ignored and since the mud and gas regions are considered separately this mathematical model simply calculates hydrostatic pressure gradients throughout the well annulus. As mud or kill-mud are circulated through the well, the relevant mud/gas or mud/kill-mud interfaces are tracked (neglecting gas slip). The non-ideality of gas expansion as it rises through the well is determined from a correlation developed specifically for the model using the Standing-Katz isotherms.

Since the aim of a well control procedure is to maintain a constant bottom hole pressure large enough to contain the formulation fluids, the LeBlanc-Lewis model estimates the annular back pressure required to supplement the fluid hydrostatic pressures.

3.2 The KIKSIM Model - Fischer et al (1975)

Fischer and Kastor (1975) presented calculations using the KIKSIM computer model with further simulations described a year later by Dittmer and Fischer (1976). Very little information is supplied in these two references to describe the KIKSIM model. Fischer (1975) writes "The program models the circulation of drilling mud down the drillpipe, gas influx from a permeable formation (including drawdown and buildup) and transient two-phase flow of mud and gas up the borehole annulus". Frictional pressure gradients are represented in KIKSIM, but it appears that gas slippage and the effects of two-phase flow on pressure gradients are not. That these latter effects are not in KIKSIM is inferred from the comments of Maus et al (1979) who developed a model similar to KIKSIM, but found the need to include a two-phase flow correlation, accounting for flow regimes and slip velocities.

KIKSIM simulates the well fluid behaviour using an unspecified numerical formulation, with some doubt expressed by Fischer and Kastor (1975) as to the applicability of the chosen time-steps for the solutions presented in their paper.

Although the KIKSIM simulator is now somewhat outdated, the calculations performed by Fischer and co-workers (investigating the minimum mud flow rate which will kill a well using the Low Choke Pressure Method, and the likely effects of using different kick detection instruments) would not have been possible without such a simulator.

3.3 The Hoberock and Stanbery Model (1976)

This model is described in a PhD dissertation by Stanbery (1976) and summarised in the petroleum literature by Hoberock and Stanbery (1981a, 1981b). Linearised equations describing the transient flow characteristics of Newtonian fluids in circular conduits are operated on by Laplace Transforms to give algebraic equations which are then approximated to produce a model which runs on a hybrid digital - analog computer. The non-Newtonian fluid properties and annular flow geometry were represented by making appropriate analogies to Newtonian pipe flows. Physical models to represent well geometry and components tended to be simple in nature, although attention is given in the model to the effects of flow history on the pressure gradients in the well, via the concept of frequency dependent friction.

The use of linearised equations is a severe limitation when simulating the large magnitude, highly transient effects which occur during a kick. Moreover, the value of including frequency dependent friction in the model is unclear. The frequency dependent friction model is designed to improve the assumption that frictional pressure gradients are related to instantaneous mean velocities, but the importance of this improvement to kick modelling is probably not high. In verifying the friction model, Stanbery shows his computer model to give a good representation of non-steady state friction in a water hammer experiment. What is not discussed, however, are the relative time-scale for frequency dependent effects

appropriate to the water hammer experiment and a typical drilling well. In the water hammer example, the pressure head oscillates for four cycles during a period of less than 0.5 seconds. Time scales of relevance to kicks are much larger than fractions of a second. Frequency dependent frictional effects are discussed in this report in Section 6.

Nonetheless, the Hoberock and Stanbery study produced a robust simulator capable of running in real-time. The authors were able to use the model to show the inter-dependence of several control parameters (BHP, drillpipe pressure, pump speed and choke setting) during a well control operation.

3.4 The Thomas et al Simulator for Uncontrolled Kicks (1982)

This model developed at Amoco and described by Thomas et al (1982), Thomas and Lea (1983) is a blowout simulator rather than a well control simulator. The model does not address the flow of drilling mud in the drill-string and offers no facility to choke the flow of fluids in the annulus and thus control a gas kick.

Nonetheless, the model has made a valuable contribution to the study of gas-kicks as the solubility of hydrocarbon gases in oil-based muds is addressed. An experimental programme investigated the PVT behaviour for mixtures of methane with diesel oil and diesel oil-based mud. The results of these studies were used to adjust parameters in the Amoco-Redlich-Kwong equation of state (Yarborough, 1979) to represent drilling fluids and kick

gases. Thomas et al (1982) show that, at 10,000 psi and 400°C when 0.04 ft^3 of methane gas is dissolved in 1.00 ft^3 of diesel fuel the total volume is approximately 1.03 ft^3. This represents a reduction in kick fluid volume of about 25% and demonstrates the need for kicking well simulators to address the question of solubility when wells are drilled with oil-based muds.

The blowout simulator developed by Thomas et al (1982, 1983) does not appear to make use of the experimental solubility data - rather, Standing's (1947) correlations for oil and gas properties are used. The simulator employs an equation to represent the changing rate of inflow of kick gas from the formation, and attempts to account for the slippage of free gas through the mud, and the effect of free gas on the frictional pressure losses in the annulus.

The simulator has been used to investigate how pump rate, formation pressure, porosity and permeability, bottom hole temperature and mud type affect the progress of an uncontrolled kick in a vertical well.

3.5 GASKICK - The Rogaland Research Institute Simulator (1985)

The GASKICK simulator is under continued development at the Rogaland Research Institute and is a sophisticated model offering a variety of equations and submodels to define the behaviour of a kicking well. The numerical solution procedure and gas/mud front-tracking techniques are

discussed by Ekrann and Rommetveit (1985), with the detailed equations specified by Rommetveit et al (1989).

Amongst the features of the GASKICK simulator is the ability to model the dissolution of gas kicks in oil-based muds, and to handle inclined as well as vertical wells. The simulator is equipped with interactive graphics. In addition, a wide variety of suitable physical correlations may be selected via the simulator input file. For instance, the simulator offers numerous mud flow friction factor expressions (both laminar and turbulent flow), five two-phase flow correlations, two gas density equations and two gas solubility and mud density correlations (or the use of a look-up table of PVT data).

The major limitation of the GASKICK simulator concerns the equation representing the conservation of fluid momentum in the well. The momentum equation is only solved approximately, with the time derivative and momentum transport terms deleted. As a consequence, pressure changes occurring at any location in the well (eg due to changes in pump speed or choke setting) are immediately propagated throughout the well. Hence the simulator cannot predict the true time response of a well to the actions of the controller at the surface.

Work to develop the GASKICK simulator continues, along with an extensive experimental programme to provide data for verification purposes.

3.6 The Nickens Model (1985)

A second Amoco kicking well simulator has been developed by Nickens (1985a, 1985b). Unlike the Thomas et al Amoco model (see Section 3.4) this model does not account for the solubility of kick fluids in drilling muds. Indeed the Nickens model is totally distinct from that of Thomas et al in that well control operations may be modelled via simulations of the BOPS, choke line and choke.

Gas inflow from the formation is calculated in this model using a model similar to Thomas et al (1982), except that the effects of gradually drilling through the high pressure region are accounted for by dividing the reservoir into axial segments. Once in the wellbore, gas rises with respect to the mud at a velocity dependent on the flow regime. Nickens has used published experimental data to derive an equation suitable for modelling slug flow (see Section 7). Other components of the Nickens model are summarised in Tables 2, 4 and 6.

As well as describing his model in detail, Nickens reports the effect of using different averaging techniques to derive the finite difference formulation. High gas slip velocities lead to difficulties if the mass balance equations are derived with central averaging with respect to time. As a consequence, different averaging techniques are employed for the drilling and annular sections.

One superiority of the Nickens code over other codes is the option of choosing automatic choke control facilities. During a simulation the code may represent one of four controllers:

Perfect: maintains constant BHP

Novice: adjusts choke level based on current drillpipe pressure

Good: adjust choke then delays for specified time before effecting next adjustment

Automatic: adjusts choke based on current drillpipe pressure and known choke flow pressure characteristics.

These options enable the Nickens model to be effectively used as a training tool for choke operators. The code has also been proved to be a useful research tool (Nickens 1985b) for predicting the effects of kick size and distribution and the control method on the pressures experienced during a kill operation.

3.7 The KICK Code - Podio and Yang (1986)

The KICK program (Podio and Yang, 1986) for simulating well control is designed to operate on an IBM Personal Computer.

The chief difference between the KICK code and other published well control simulators is the Lagrangian formulation employed. Rather than dividing the fluid flow path into a series of fixed cells (the Eulerian formulation), the fluids in the well are divided into sections which move

at the local mud velocity, expanding and contracting as the pressure varies. The main advantage of using a Lagrangian solution technique is that fluid fronts may be readily tracked as they travel through a system.

As a consequence of the Lagrangian moving boundary solution technique KICK is able to model the drilling process with the well depth increasing with time. This facility will have a slight influence on the frictional pressure gradients throughout the well (due to the increased well length) but it is believed that a well will typically be drilled only a few feet in the period between kick initiation and well shut-in.

The system models included in KICK are, by the programmers admission, only simple in nature. However, one feature not included in several other models is the facility to detect when the formation pressure is exceeded at any point in the well - leading to breakdown and lost circulation. The equation employed in KICK to calculate the rate of loss of fluid circulation is very crude, so the most prudent manner in which to use KICK's capability of handling fracture gradients is to merely note that breakdown has occurred rather than to quantify the possible effects of such a breakdown.

KICK is run by a user-operated menu system for defining well and formation geometries. Alternatively, input files may be created (or edited from previous simulations) to define the details of a particular code run.

3.8 The Whitman and Evers Model (1987)

Whitman and Evers (1987) have developed a kick model for use on a Personal Computer. The aim of this model was to provide a cheap, widely available model for training and demonstration purposes. Many simplifications and approximations have been made, such as the neglect of frictional pressure gradients in the annulus, zero gas rise velocity, and no modelling of drilling mud rheology. The solution techniques are very simple - possibly akin to the LeBlanc-Lewis model (Section 3.1).

The chief benefit of this particular model lies in the tailoring of code operation and output facilities to serve in the training of kill control techniques. Scaled well diagrams, using colour graphics display the status of the well during a simulation. Mud, kill mud and gas regions are clearly identified.

The code may be operated in one of two modes. In the demonstration mode the computer program circulates the kick from the well using either the Driller's method or the Wait-and-Weight method. In the control mode circulation of the kick is controlled by the user. The program monitors operations, highlighting procedures that would produce low bottomhole pressures or high pressures at the casing shoe.

3.9 The Winfrith WELL-KICK Code

The KICK code described in Section 3.7 has been under development at Winfrith - leading to the WELL-KICK code. Modifications made have vastly improved the numerical robustness of the code, and enhanced the ability to re-construct the Lagrangian mesh-system when fluid sections become either too numerous or too large.

Attention has also been given to improving the implementation of gas slip in the WELL-KICK code, and to include a simple model for gas solubility. Otherwise WELL-KICK maintains the features of KICK.

Perhaps the major drawback of WELL-KICK is the representation of gas slip using a constant velocity (ie no flow regime dependency) and the fact that the calculation of slippage effects is de-coupled from the main calculation algorithm.

3.10 The Starrett, Hill and Sepehrnoori Model (1988)

The computer model developed by Starrett et al (1988) is designed to assess the behaviour of uncontrolled gas kicks in wells with a horizontal flow diverter. The control of kicks via well shut-in, kill mud circulation and choke control is not represented in the model.

Two-phase flows are included in the Starrett et al program using the Aziz et al (1972) correlation for flow in the wellbore, and the Dukler et

al (1969) correlation for horizontal flow in the diverter. Provision is made for the possibility of critical flow being established in the diverter. It seems, however, that the non-Newtonian nature of drilling mud is not accounted for in the equations to describe mud and mud/gas flows.

The numerical solution methods employed in this model are amongst the most sophisticated for existing kicking well codes. The well and diverter are divided into equally spaced grid points and an Eulerian formulation used to represent the fluid flows. For the mass balance equation a fully implicit, two-points backwards formulation is chosen. For the momentum balance a part explicit, part implicit one point backwards equation is used to calculate grid point pressures. Modelling of single phase mud flows is simplified by neglection of mud compressibility, enabling the same frictional pressure gradient to be applied to the entire vertical sections of the well containing single phase mud. This represents a somewhat severe restriction of the capability of this model as a general gas kick research tool since the true dynamic behaviour of the wellbore fluids is not properly represented. Nonetheless, the results of simulations using the code (Starrett et al, 1988) have given an indication of the influence of diverter size on the velocities and pressures during kicks and blowouts. No other existing simulators have the diverter-modelling capability to make similar studies.

3.11 The BP GASKICKS Model - Swanson et al (1988)

A brief description of the BP GASKICKS code is contained in the report by Swanson et al (1988). Like the KICK code (Section 3.7) this model employs a Lagrangian solution technique to represent the flow of fluids in the well. The drillstring is not modelled explicitly, although the GASKICKS model does account for the time taken for kill mud introduced at the surface to be pumped to the bottom of the well.

This BP code is capable of modelling the solubility of kick gas is oil-based drilling fluids, but the solubility correlations used only allow simulation of wells with pressures up to 6000 psi. Experimental data measured by BP (Swanson et al, 1988) has been used to check the suitability of the model's solubility calculations.

Swanson et al (1988) have used the GASKICKS model to investigate some of the differences to be expected when taking kicks in wells using either oil-based or water-based muds. Consideration was given to kicks caused by swabbing or by abnormal formation pressures.

3.12 The Miller and Juvkam-Wold PC Model (1989)

Miller and Juvkam-Wold (1989) aimed to produce an interactive, user-friendly model capable of running on a Personal Computer. The resulting program is written in BASIC and employs user-driven menus and colour graphics to aid in using the model and interpreting its results.

Since the model is written in BASIC, only simple algorithms are used, with the following physical effects neglected: annular friction pressure, liquid compressibility, drilled solid and gas, fluid momentum effects and delays in equipment response. Perhaps surprisingly, given other approximations, the Miller/Juvkam-Wold model uses a very sophisticated set of equations to represent the flow of gas into the well. These equations use an effective wellbore radius to account for the effects of the wellbore wall skin factor (due to partial penetration). By a superposition method the inflow equation is modified each time-step to account for changes in BHP. (The formulation of the equations to represent the flow of formation fluids is discussed in Section 9). Rather than generating regions containing mud/gas mixtures when the gas enters the well, the model creates numerous gas slugs - of 100% void fraction - separated by mud regions. The relative volumes of gas and mud regions depend on the flow rate.

Unfortunately, very little is known concerning the solution methods employed in this code and so they cannot be analysed in this paper.

Miller and Juvkam-Wold have demonstrated with their model the possibility of producing a gas kick training tool using only the BASIC language. There is, however, limited potential for the further development of such a model due to the limitations of BASIC.

3.13 The Schlumberger Cambridge Research Kick Model

A sophisticated kick code that is particularly suited to modelling gas kicks and their control in deep, high pressure vertical wells using oil-based muds is under development at Schlumberger Cambridge Research (in conjunction with BP). This work, partly financed by the UK Department of Energy (see Peel and Redman, 1989), is to develop a comprehensive research model taking full account of the solubility of kick gas in oil-based muds, the non-Newtonian behaviour of muds and the flow characteristics of both mud and mud/gas mixtures in wells. Experiments in a 15m inclinable flow loop at Schlumberger are being conducted with a view to providing further information concerning the flow regimes and slip velocities of gas/mud mixtures. BP have also performed experiments to measure the variation in mud density when methane is dissolved; methane being a key component of kick gas.

As a starting point for development of the Schlumberger research kick model, use has been made of the previously developed BP gas kick code (see Section 3.11). This BP code is not discussed in this paper due to a lack of detailed information. The Schlumberger model is not considered in detail as it is still under development.

It is planned to complete development of the research model early in 1990, and to use a simplified version of this to develop an engineering model, capable of being run on a computer workstation. The engineering model is expected to be available in Spring 1991.

4. MODELLING OF FLUID DENSITIES

In order for a well simulator to model realistically the hydrostatic pressure drops and propagation of pressure waves throughout the well, the mud fluid density characteristics need to be accurately defined. Dynamic motion of the mud is especially important following sudden changes to pump or choke settings, or the inflow of fluids from the formation. In addition, gas volumetric behaviour must be modelled accurately since it has a significant effect on the prediction of gas expansion characteristics near the well surface.

Both pressure and temperature will influence the density of the drilling mud and kick gases in a well. The modelling of gas and mud density variations are discussed separately in this section. The topic of gas solubility and subsequent swelling of the mud is discussed in Section 9.

4.1 Gas Density Variations

The expansion of kick fluids as they rise through a well alters the wellbore pressure as expanding gas displaces higher density drilling fluid. However, the expansion of the gas phase is not well represented by the ideal gas law. This non-ideality is commonly represented in gas flow calculations by using a gas compressibility factor (Z) defining the

deviation from the ideal gas law as a function of pressure and temperature.

There are two distinct approaches to calculating the gas compressibility factor - one using Standing-Katz Z-factor charts, the other employing gas equations of state.

The Standing-Katz chart for gas compressibility factors (Standing and Katz, 1942) has been accepted for use in many calculations concerning hydrocarbon fluids of known critical properties. To employ these charts in computer simulations it is necessary to develop mathematical correlations to reproduce Standing-Katz Z values. For a recent summary of a few correlations, refer to Takacs, (1989). These correlations are only valid within certain prescribed pressure and temperature ranges, and often lack a theoretical basis.

Equations of state generally attempt to represent certain observed fluid properties. These properties are not restricted to simple volumetric observations, but also include phase changes, mixing of fluid components etc. As a consequence equations of state have a stronger theoretical basis than Standing-Katz correlations, but also tend to adopt more complicated mathematical forms.

Popular equations of state for modelling petroleum gases include those proposed by Redlich and Kwong (1949), Hall and Yarborough (1973), and Peng and Robinson (1976). Although the Hall-Yarborough equation is based on a

theoretical hard-sphere equation of state, adjustable parameters were chosen so as to match the data contained in the Standing-Katz chart. It is therefore possible to classify this equation as either a Standing-Katz correlation or an equation of state.

Tables 3 and 4 show that the Hall-Yarborough (1973) equation is used in the kicking well models described by Rommetveit et al (1989) and Podio and Yang (1986); the Peng-Robinson equation is used by Swanson et al (1988); while equations of state of the Redlich-Kwong type are used by Thomas et al (1982), Rommetveit et al (1989) and Nickens (1985). The particular Redlich-Kwong equation used by both Nickens (1985) and Thoms et al (1982) is the Amoco Redlich-Kwong equation of state (ARKES), discussed by Yarborough (1979).

A detailed discussion of the merits and failings of the gas density equations employed in kick codes is not included here. Rather it is noted that the accuracy of gas density calculations is, not surprisingly, strongly influenced by the parameters chosen to define the gas in question. On the whole kick simulators which use gas density correlations have given little attention to the composition of kick fluids (an exception being the Miller and Juvkam-Wold, 1989, simulator which includes the density effects of CO_2 and H_2S in the kick gas via the Sutton, 1985, correlation).

It is common practice to use the gas gravity alone to determine the gas pseudo-critical pressure and temperature for use in approximated equations of state and other density correlations. Table 7 demonstrates

the considerable differences between equations for pseudo-critical properties. These differences result from variations in the gas types used to develop the gas gravity correlations. With only approximate critical properties representing the kick fluids, the accuracy of calculations using Standing-Katz isotherms is severely limited. In particular there is little advantage in employing the rather unwieldy Hall-Yarborough correlation in the absence of accurately determined gas properties. When pure equations of state are employed in simulators it is possible to specify the gas properties in a more detailed manner, provided that the molar composition of the gas is known.

For kick codes it may not be necessary to choose gas density equations which are applicable for wide ranges of temperatures and pressures. LeBlanc and Lewis (1968) demonstrate the possibility of developing a simple correlation to fit Z-factor charts (such as Standing-Katz) for the limited reduced temperature ranges encountered in kicking wells. By only considering pseudo-reduced temperatures between 1.5 and 2.2, a simple Z-factor equation for simulating kick gas was developed for whenever the reduced pressure exceeds 9.

4.2 Mud Density Variations

Several of the kicking well models discussed in Section 3 (see also Tables 3 and 4) assume that mud density is constant (although kill mud may be allowed to differ in weight from the original drilling fluid). A justification for this approximation is offered for simulators which are

only intended to model shallow wells. For such wells mud pressure waves travel rapidly from well surface to bottomhole and so the importance of defining mud compression characteristics is not as marked as for deep wells. In addition, of course, the degree of mud density changes will be much reduced in shallow wells as opposed to deep wells. When considering such arguments it should not be forgotten that kick gas compressibility will also influence the propagation of waves through the well. In such cases the wave speed will be less than for pure mud, the actual speed depending on the two-phase pressure wave characteristics of the mud/gas mixture.

Of those models which do include a compressible mud density are Hoberock and Stanbery (1981a; Stanbery 1976), Thomas et al (1982), Rogaland (1989), Nickens (1985a), Podio and Yang (1986) and Swanson et al (1988). The more advanced density models include the influence of both pressure and temperature on the mud density, although more approximate methods have been adopted in some codes.

The simplest means of incorporating a variable liquid density into a simulator is to relate downhole densities to the surface density via a simple pressure function, thus neglecting the effects of temperature. For the Hoberock-Stanbery (Stanbery, 1976) simulator this pressure function is based on a constant bulk modulus of compression. This is very similar to the approach adopted in the Podio-Yang (1986) simulator where density varies linearly with pressure. Although allowing for the existence of pressure waves in the drilling fluid, such definitions of mud density

variations represent an over-simplification of the true downhole behaviour of muds. The influence of temperature must be also be included in a simulator since thermal gradients and mud thermal expansivities are not negligible. In fact, it is possible, depending on well temperatures and mud types, for mud density to decrease with well depth in spite of the increasing pressures (see for example Sorelle et al 1982; Peters et al, 1988).

Although the Thomas et al (1982) simulator does model mud density as a function of both pressure and temperature (using the correlation for oil formation volume factors developed by Standing, 1947), it appears that the model assumes a homogeneous fluid with the volumetric properties of an oil. A far superior approach to modelling mud density changes is to consider the mud as a combination of several components showing different volumetric behaviours. In the Nickens model (1985a) - which only considers water-based muds - drilling fluid densities are calculated on the basis of a compressible water fraction and an incompressible solids fraction. For a general drilling fluid, however, it is also necessary to include an oil fraction in the compositional model - eg Sorelle et al (1982). Such a three component oil-water-solid model is incorporated in the Rogaland simulator (Rommetveit et al, 1989) and the BP simulator (Swanson et al, 1988). In the BP simulator the density of the water-phase is determined from a brine correlation developed by Kemp and Thomas (1987).

A further enhancement of the three component mud model is shown by Peters et al (1988) who have developed a correlation for oil muds composed

of four components - water, oil, solids and chemicals. Without details of the volumetric properties of the chemicals component in this model, it is not possible to assess the significance of adding the fourth component.

There exists a considerable choice of data or correlations which may be invoked to define the effects of pressure and temperature on the separate components in muds. Equations of state or formation volume factors may be used for the oil component, whereas standard physical tables may be used to derive water densities. Care must be taken, however, to incorporate the effects of solutes (especially NaCl) on water properties (see, for example, Hoberock et al, 1982).

Of the existing kick models considered in Section 3, the Rogaland simulator (Rommetveit et al, 1989) has the best capability of modelling mud density as it also includes the density changes expected when kick gas dissolves in the mud. The numerical approximations adopted in this simulator, however, do not allow for the true short-term dynamic characteristics of drilling fluids in wells to be considered when using the Rogaland model. The kick model under development at Schlumberger Cambridge Research (see Section 3.13) will also include mud density changes due to gas dissolution based on experimental work performed by BP (Swanson, 1989).

5. MODELLING OF FLUID VISCOSITY/RHEOLOGY

Three questions need to be addressed in order to include the non-Newtonian behaviour of drilling fluids in a kicking well simulator:

which rheological model should be used?

what equations should be employed to calculate single phase mud flow frictional pressure drops?

how should non-Newtonian behaviour be included in two-phase flow?

Attention is given to the first of these questions in this Section, the second and third questions being discussed in Sections 6, 7 and 8.

5.1 Available Mud Rheological Models

Some of the simpler kicking well simulators choose to neglect the pressure gradients imposed on a well due to the flow of drilling mud. For such simulators (LeBlanc and Lewis, 1968, Miller and Juvkam-Wold, 1989; and possibly others) there is no need to specify the non-Newtonian nature of the muds used. However, more sophisticated kicking well models require flowing pressure gradients to be included. For these more sophisticated models it is necessary to decide how to define the drilling mud rheogram.

There are basically four non-Newtonian rheological models which have been applied to drilling fluids. These are the:

- Power Law Model: $\tau = k\dot{\gamma}^n$
- Bingham Plastic Model: $\tau = \sigma_{yp} + \mu_p\dot{\gamma}$
- Casson Model: $\tau^{\frac{1}{2}} = K_0 + K_1(\dot{\gamma})^{\frac{1}{2}}$
- Herschel-Bulkley Model: $\tau = \tau_y + K\dot{\gamma}^n$

where τ = shear stress

$\dot{\gamma}$ = shear strain rate

k, n, σ_{yp}, μ_p, K_0, K_1, τ_y = constants employed in the different rheology models.

It is generally accepted that of these models the latter two represent drilling fluids best (eg Alderman et al, 1988). This is because these two models display both a yield stress and a reduction in effective viscosity as the sheer rate increases - characteristics of typical muds. Nevertheless, the Casson model is often criticised for the lack of justification of using exponents of ½ (generalised Casson equations replace the ½ with an extra correlating parameter). In addition, even though the Herschel-Bulkley equation contains three adjustable parameters which allows more accurate fitting to experimental mud rheological data, the added complexity of introducing the third parameter has commonly caused the

Herschel-Bulkley model to be neglected during the development of mud flow simulators. As a consequence, all of the existing kicking well simulators discussed here which include a non-Newtonian rheology were designed to employ either the Bingham Plastic or Power Law models, or both. This also reflects the focus which has been given to these two models historically for the development of mud flow pressure gradient correlations.

A common practice (eg in the simulators of Nickens, 1985a; Podio and Yang, 1986) is to employ Bingham Plastic parameters to input mud rheology to the computer code, and to convert these to Power Law parameters for calculating pressure gradients. This is done since the equations used to calculate flowing mud pressure gradients employ Power Law parameters. Often only two Fann viscometer readings are used to define drilling fluid rheology, in which case the two derived Power Law constants will not depend on whether they are calculated from the two Bingham Plastic constraints or directly from the two experimental readings. When more Fann Viscometer readings are available (typically either 2 or 6 readings are taken, at different rotation rates) there will be a loss of accuracy if Power Law constants are inferred from Bingham Plastic constants rather than from a suitable regression of the experimental data.

The improved accuracy of the Herschel-Bulkley model ought to support its use in research kicking well simulators although it has to be noted that the Herschel-Bulkley parameters cannot be derived if only two Fann Viscometer readings are available Swanson et al (1988) are the only researchers known to have selected the Herschel-Bulkley model for kick

The Casson and Bingham Plastic models were used in the high pressure and temperature rheological study of Houwen and Geehan (1986), involving invert emulsion muds. Detailed correlations were presented by Houwen and Geehan for the yield stresses and high shear viscosities required in these rheological models. Likewise Alderman et al (1988) correlate yield stresses and high shear viscosities to high temperatures and pressure for water-based muds following either the Casson or Herschel-Bulkley models.

It can generally be noted in all of these studies that pressure does not affect rheology to the same extent as temperature.

As the downhole mud rheology models discussed here were developed for different mud types it is not possible to provide a simple comparison of the different models. It would be beneficial to determine how generally applicable each of the models is to mud types other than that for which the model was developed. Otherwise, when developing a computer code it is necessary to provide a choice of downhole mud behaviour models depending on the mud type used - which may then restrict the choice of mud rheological models to be incorporated in the code.

In spite of the importance of downhole rheological changes, and the availability of correlations applicable to certain mud types, only the Rogaland (Rommetveit et al, 1989) and BP (Swanson et al, 1988) models incorporate pressure and temperature effects. The Rogaland code uses either Bingham Plastic or Power Law rheologies, while the BP GASKICKS code (employing a Herschel-Bulkley rheology) uses the Minton and Bern (1988)

correlation for downhole changes in rheology. It is intended that the kick model under development at Schlumberger Cambridge Research (Section 3.13) will also include downhole changes in mud rheology.

6. REPRESENTATION OF SINGLE-PHASE DRILLING MUD FLOW IN WELLS

During drilling it is common practice to pump mud at a rate such that turbulent flow exists in the drillpipe, with laminar flow in the annular section for returns to surface. Calculation of the pressure gradients associated with such flows for single phase drilling fluids is possible, for a given rheological model, using experimental or semi-theoretical correlations for turbulent pipe flow, and theoretical equations for laminar annulus flow. Theoretical descriptions of flows in annuli are complicated even for Newtonian fluids, but it is possible to model flow in annuli with a wide range of inner to outer diameter ratios as if the flow were contained between two parallel plates and this substantially simplifies the analysis.

Many equations exist to relate frictional pressure gradients to the flow parameters for pipe and laminar annulus flow, depending on the wide choice of rheological models which may be selected to describe the mud (see Section 5). However, for a given mud rheology it is not expected that the slight differences between these different flow equations will influence the predictions of pressure gradients to the same degree as the choice of which rheological model to use.

valid for laminar flow and employs a rather arbitrary and dimensionally inconsistent modification to a pipe flow equation in order to increase accuracy with high yield point muds.

The Nickens (1985a) and Podio-Yang (1986) simulators both employ similar mud flow equations. Power Law parameters (derived from input Bingham Plastic data) are used in theoretically derived equations for laminar flow. For turbulent flow Nickens chooses a Power Law specific Blasius-type friction factor equation, while Podio and Yang select the Dodge and Metzner (1959) Power Law specific implicit equation. The implicit nature of this equation necessitates the tabulation of friction factors prior to commencement of a simulation with the Podio-Yang code and thus it is not impossible to easily incorporate downhole rheological changes to the code.

Starrett et al (1988) use "a Moody friction factor based on a Reynolds number" without specifying whether or not non-Newtonian effects are included.

The Rogaland simulator (Rommetveit et al, 1989) appears to offer the widest choice of alternative single phase flow correlations, although the precise number available is not specified.

For the Schlumberger kicking well code (see Section 3.12) consideration has been given to the different mud rheological models which could be used to model the mud flow. Data from the Schlumberger flow loop

there is no requirement to include such frequency dependent effects in well simulators.

As well as frictional pressure gradients causing a pressure loss for lengths of wellbore flowpaths through which mud travels, localised irreversible pressure losses will occur at discontinuities in the flow path area. The simplest way to model such losses is in terms of an idealised loss coefficient for flow through a sudden expansion or contraction. Two factors need to be noted, however. First, loss coefficients have been well documented for Newtonian fluids, but not for non-Newtonian muds. Secondly, the loss coefficients for annulus flows may be expected to differ from those established for pipe flows. In the Rogaland GASKICK model (Ekrann and Rommetveit, 1985) two values are assigned to both the velocity and the pressure at each grid block edge. These pairs of values correspond to the upstream and downstream pressure and velocity values, accounting for possible discontinuities in each variable.

7. RELATIVE VELOCITIES OF MUD AND GAS IN KICKING WELLS

Perhaps the most complicated physical phenomena to be included in a kicking well code concerns the characterization of mud/gas two phase flow. Section 6 highlighted the added difficulties in calculating frictional pressure gradients for non-Newtonian fluids as compared to Newtonian fluids. These difficulties persist when free gas flows with the drilling mud. In addition to the calculation of pressure gradients the presence of free gas means that it is also necessary to represent the different

path. A film of liquid flows up the walls of the tubing while some liquid is also entrained in the gas core. This annular flow regime is called "mist flow" by some authors.

During a gas kick bubble and slug flow regimes are likely to be present in the well. Should well control fail and a gas blowout ensue, it is very likely that annular flow will be experienced.

Characterization of the individual flow patterns described above has been achieved by extensive studies of the flow of gases and Newtonian liquids in pipes. A brief overview and discussion of some of the equations developed from these studies is given here since they are employed (following appropriate modifications to include mud properties) in several kicking well codes. It should be noted that slip velocity correlations are also inherent in several of the two-phase pressure drop models described in Section 8.

7.1.1 Linking Mud and Gas Velocities using a Slip Equation

Zuber and Findlay (1965) demonstrated that not only will the gas rise faster than the liquid because of density differences, but also that gas has a tendency to flow through the central portions of flow channels where the in-situ mixture velocity is higher than the cross-sectional average value. Theoretical analysis of generalized flow profiles for two-phase flows enabled Zuber and Findlay to derive the equation

$$v_g = C_0 [v_L (1-\alpha) + v_g \alpha] \quad v_{gsl} . \qquad (7.1)$$

Where v_g - gas velocity

v_l - liquid velocity

v_{gsl} - slip velocity

α - void fraction.

The C_0 coefficient could theoretically be expressed in terms of the integrated average velocity and void fraction profiles across the flow path cross-section. Typically, however, C_0 is treated as an empirical parameter to be determined from experimental analysis. According to equation (7.1) experimental plots of gas velocity against homogeneous mixture velocity should yield a gradient of C_0 and an intercept of v_{gsl}.

An equation similar to (7.1), is also employed for calculating gas flow velocities:

$$v_g = C_0 v_L + v_{gsl} \qquad . \qquad (7.2)$$

Equations (7.1) and (7.2) involve different definitions of the gas bubble slip velocity. This difference is clarified by considering the form of the equations in the limit as liquid velocity, v_L, tends to zero. Applying this limit to equation (7.2) the gas velocity, v_g, becomes equal to the slip velocity, v_{gsl}, which may be equated with the rise velocity of gas bubbles in stagnant liquid. This is not the case with equation (7.1). When employing equations (7.1) or (7.2) care should be taken to ensure that

the correct gas slip expression is used. Whichever defining equation is used, the values of C_o and V_{gsl} depend strongly on the pattern of flow taking place.

7.1.2 Rise Velocities for Bubble Flow

Wallis (1969) summarizes the effect of liquid Reynolds number on bubble flow. At low Reynolds numbers the liquid viscosity determines the streamlined flow of liquid around gas bubbles. Theoretical solutions of this flow pattern lead to Stokes' solution for the rise velocity of solid spheres in a liquid. Internal motions within gas bubbles require a slight modification to Stokes equation, giving

$$v_{gsl} = \frac{1}{12} d_b^2 g \frac{(\rho_L - \rho_g)}{\mu_L} \qquad (7.3)$$

where ρ_L, ρ_g = liquid, gas density

d_b = bubble diameter

μ_L = liquid viscosity

v_{gsl} = gas rise velocity.

However, impurities in the liquid may make Stokes' solution more appropriate. At higher Reynolds numbers, spheres will no longer follow a vertical path, but will zig-zag as they rise through the fluid. It is the turbulence of the continuous fluid surrounding the sphere which causes this phenomenon.

Govier and Aziz (1972) limit the applicability of Stokes' equation to Reynolds numbers of less than unity. At higher Reynolds number (greater than 800) Newton's Law for spherical particles rising (or falling) in a fluid is used:

$$v_{gsl} = 1.74 \left(d_b g \left[\frac{\rho_L - \rho_g}{\rho_L} \right] \right)^{\frac{1}{2}} \quad . \qquad (7.4)$$

Perhaps the bubble rise velocity formula most commonly used in the oil industry is that developed by Harmathy (1960), based on equation (7.4). Harmathy studied bubble rise in systems where the slip velocity Reynolds number exceeded 500. He argued that the turbulent rise velocity of a bubble will be based on Newton's Law, but also noted that bubble shape would affect the rise velocity. At high interfacial tension bubbles are likely to be more spherical.

Using experimental data from several sources, Harmathy obtained the equation:

$$V_{gsl} = 1.53 \left[\frac{g(\rho_L - \rho_g)\sigma}{\rho_L^2} \right]^{\frac{1}{4}} \qquad (7.5)$$

where σ = interfacial tension.

It is fortuitous that the bubble diameter does not feature in Harmathys equation, as this diameter is frequently an unknown quantity when modelling gas-liquid flows.

use the simple equations contained in this section to represent gas rise velocities in the bubble regime.

In the Nickens (1985a) code once bubble flow has been established Harmathy's correlation (equation 7.5) is used together with equation (7.1). As stated above the choice of equation (7.1) demands that care be taken in defining V_{gsl} so as to reproduce experimental rise velocities at low liquid rates. It should also be noted that Nickens has made a typographical error in all instances where he quotes equation (7.5).

Nickens (1985a) concedes that the coefficient C_o depends on the flow regime and is in the range of 1.0 (bubble flow) to 1.2 (slug flow) for pipe flow. Nonetheless Nickens adopts the value $C_o = 1.0$ for all of his simulations, thus neglecting the observation that the value of C_o should be higher for annulus flows.

To define the transition from bubble flow to slug flow Nickens assumes a critical void fraction of 0.25. The Rogaland code (Rommetveit et al, 1989) also allows both bubble and slug flows to be modelled, for vertical and inclined wells, but the equations used are not specified.

Starrett et al (1988), and Swanson et al (1988) use the Aziz et al (1972) correlation to calculate both flow regimes and slip velocities. For bubble flow the rise equation is similar to that proposed by Harmathy (equation 7.5) except that a numerical factor of 1.41 is used rather than 1.53. This difference reflects the fact that the bubbles are assumed to

have lost their identity and formed a swarm. Since equation (7.1) is employed with (C_0 1.2) this bubble flow representation is very similar to that of Nickens. However, unlike Nickens (1985a), Starrett et al and Swanson et al use the Aziz et al (1972) flow regime map to determine the transition from bubble to other flow regimes.

In the Podio and Yang (1986) model a constant, user-defined slip velocity is employed to model gas rise. This is clearly a simple way to incorporate slip into a kicking well model, but the neglect of flow regimes is a severe limitation.

The other kick models to include gas slip effects - Hoberock-Stanbery (1981b), Thomas et al (1982) and Miller-Juvkam-Wold (1989) - employ gas rise equations only applicable for the slug flow regime.

It is clear that the representation of bubble flow in kicking well models has been based on very simplistic equations with little or no account made for the non-Newtonian nature of the drilling mud, the fact that flow is in an annular geometry and the interaction of individual bubbles. The results of experimental analyses (such as those underway using the flow loops at Schlumberger Cambridge Research) to fully define this mud/gas flow regime are needed to improve the capabilities of well models. It is known that experimental studies of mud/gas flow regimes, slip velocities and pressure gradients have been conducted by Elf Aquitane in a vertical flow loop (Tonda and Dorel, 1985) but full details of the conclusions from these studies are not available.

7.1.3 Gas Rise Velocities for Slug Flow

Early theoretical studies of the rise of cylindrical gas bubbles in pipes containing liquids showed the velocity to be given by (Govier and Aziz, 1972):

$$v_{gsl} \quad \alpha \quad \left[gd \left(\frac{\rho_L - \rho_g}{\rho_L} \right) \right]^{\frac{1}{2}} \qquad (7.7)$$

Such studies neglected surface tension and viscous effects. More detailed experimental analyses have improved this model to incorporate the effects of liquid velocity and viscosity (for example, see Wallis, 1969).

An equation of the form of (7.7) is adopted in the Hoberock and Stanbery (1981b) model - together with equation (7.2) to relate gas velocities to liquid velocities. Hoberock and Stanbery argue that the largest bubbles flowing in the well annulus will have a diameter of the order of the radius difference of the annulus. Hence the difference in annulus external radius, r_o, and internal radius, r_i, replaces the effective diameter, d, in equation (7.7).

Quoting the Hoberock and Stanbery (1981b) report, Thomas et al (1982) use a similar equation, except that:

(i) Thomas et al employ equation (7.1) (rather than 7.2) to define slip velocity.

(ii) Thomas et al use (d_o-d_i) (ie the difference between annulus external and internal diameters, rather than r_o-r_i) as a characteristic diameter.

Rommetveit et at (1989) do no specify the slug flow equations used in the Rogaland model, although it is known that the slug flow regime is included. As for bubble flow, the Starrett et al (1988) model uses the Aziz et al (1972) two-phase flow correlation to define slip velocities. Hence the slip velocity is calculated from an equation similar to (7.7), but also incorporating two extra dimensionless quantities correlating parameters to account for viscosity and surface tension effects.

None of these kicking well code authors discuss the effects the annular geometry has on the slug flow patterns - in particular with respect to the parameter C_0 in equations (7.1) and (7.2). Hasan and Kabir (1986a, 1986b) found C_0 to be linearly dependent on the annulus inner to outer diameter ration although the strength of this dependence is reduced in the second Hasan-Kabir (1986b) paper.

Unlike bubble flow (for which no extensive non-Newtonian experimental data has been published), experimental data for mud/gas slug flow in annuli has been published by Rader et al (1975). This data has been used to develop correlations which have been used in several kicking well models.

In correlating their data, Rader et al (1975) argued that the gas void fraction in the region of a Taylor bubble, α_{Tay}, may be calculated by equating the volumetric flow rates of the gas bubble upwards and the liquid film (between the gas bubble and the tube wall) downwards - ie the volume vacated by a gas bubble as it rises is filled with liquid that was originally ahead of the bubble. This approach gives a 'steady state' of zero net volumetric flow related to the velocity of the liquid in the backflow v_{br}, and the value of α_{Tay}. The Rader et al (1975) slip velocity equation incorporates the Taylor bubble void fraction to give:

$$v_{gsl} = 6.11\ C_1\ \sqrt{\alpha_{Tay}}\ C_2 C_3 \left[g\frac{(d_o+d_i)}{2} \cdot \frac{(\rho_L-\rho_g)}{\rho_L} \right]^{\frac{1}{2}} \quad . \qquad (7.8)$$

This equation has the same form as equation (7.7), with correlating coefficients such that:

C_1 - coefficient for correcting the bubble-rise velocity for viscous effects; C_1 = 0.10 when viscous effects are negligible

C_2 - coefficient for correcting the bubble-rise velocity for the liquid velocity effects; C_2 = 1.0 when liquid velocity is zero.

C_3 - coefficient for correcting the rise velocity of the trailing edge of the bubble for gas expansion effects; C_3 = 1.0 for a non-expanding bubble.

Selecting only Newtonian data, Rader et al correlated $C_1\sqrt{\alpha_{Tsy}}$ with the Reynolds number based on the gas velocity. Since the purpose to Rader et al's (1975) study was to investigate gas kicks in drilling muds, it is surprising that only data collected from flow in Newtonian fluids was used. When the derived equation for $C_1\sqrt{\alpha_{Tsy}}$ was used for non-Newtonian liquids (using the Bingham plastic viscosity μ_p), Rader et al observed that $C_1\sqrt{\alpha_{Tsy}}$ was always underestimated for Reynolds numbers in excess of 100.

It can therefore be concluded that the data collected by Rader et al (1975) was not used to its full potential for analysing mud/gas flow.

As well as considering gas slip velocities Rader et al (1975) developed simple models for the frictional pressure gradients in mud/gas slug regime flow.

The Rader et al gas slip correlation is included in the Maus et al (1979) Gaskick program (which is an extension of the KIKSIM model of Fischer et al - see Section 3.2). Likewise Miller and Juvkam-Wold (1989) selected Rader et al's empirical correlation to model gas rise.

For the Nickens (1985a) model the data of Rader et al (1975) was used to develop new gas slip correlations. Nickens included data for liquids with yield points ranging from 0 to 129 lb/100ft^2 and plastic viscosities from 1 to 111 cp flowing in annuli with outer diameters of 2.78 in and 4.79 in (thus removing the data of Rader et al collected for smaller flow channels - where, according to Nickens, "surface tension is significant").

The equations developed by Nickens are:

$$v_{gsl} = 0.097\ C \left[g\ (d_o + d_i)\ .\ \frac{\rho_L - \rho_g}{\rho_L} \right]^{\frac{1}{2}}$$

$$C = 1.454 - 0.0273 \ln (Re_B) - 0.00337\ (\sigma_{yp})^{0.946} \qquad (7.9)$$

where Re_B is a Bingham Reynolds number (see Section 5.2):

$$Re_B = \frac{\rho_L\ v_{gsl}\ (d_o - d_i)}{\mu_p}$$

Note that a direct comparison of equations (7.8) and (7.9) is not possible, since they were developed from what were essentially different databases. It would have been preferable however, had Nickens based equation (7.9) on a dimensionless group involving the yield stress of the liquid phase, rather than using σ_{yp} alone. In independent analysis by the authors of the data used by Nickens it has not been possible to determine any particular advantage in using the form of the equation in (7.9).

Nickens (1985a) assumes slug flow whenever the flow void fraction exceeds 0.85. In such cases the void fraction is set equal to 0.85 in order to calculate slip velocities. If the void fraction lies between 0.25 (the value at which bubble flow ceases) and 0.85 (representing fully developed slug flow), Nickens (1985a) calculates slip velocity by assuming a linear variation with void fraction for the transition between bubble and

slug flow. It is always necessary to introduce such interpolations for transitions between flow regimes so as to remove discontinuities from the numerical solution of flows which are near to flow pattern boundaries. Nickens (1985a), Starrett et al (1988), Swanson et al (1988) and Rommetveit et al (1989) are the only authors who describe kick models which include flow regime maps.

Although data for mud/gas slug flow in annuli is available, as for bubble flow it is still necessary to further investigate the behaviour of the fluids in this flow pattern and to develop a gas slip correlation which is valid for the range of fluid types and flow rates relevant to gas kicks.

7.1.4 Other Flow Regimes

Churn and annular flow regimes are not discussed here as the gas flow rates encountered in gas kicks are generally not high enough to achieve such flows. For severe kicks or blowouts it would be necessary to include such regimes in kicking well codes - noting both the flow pattern transition criteria and the gas slip velocities within each regime. Data and correlations exist for these flow patterns for Newtonian liquids (eg see Wallis, 1969; Govier and Aziz, 1972). For mud/gas flows it would again be necessary to obtain experimental data from flow in annular conduits to derive equations for use in computer programs.

7.2 Dispersion of Dissolved Gas in Drilling Fluids

The velocity profile for flows in pipes or annuli is non-uniform across the flow cross-section. As a consequence gas dissolved (uniformly) in drilling fluid is diluted as the gas contaminated mud at the centre of the pipe or annulus travels faster than that at the walls. As a consequence of this dispersion, gas contaminated mud will mix with pure mud leading to a reduction in gas concentration. This mechanism of mixing is more effective than simple molecular diffusion for diluting dissolved gas in flowing muds.

The degree of dispersion occurring during a gas kick clearly depends on the shape of the velocity profile in annuli - which will vary from zero at pipe walls to a maximum somewhere between the walls. The profile will tend to be flatter if the flow is turbulent - although for turbulent flow the simple picture described above has to be modified to account for the radial mixing occurring due to eddies in the annulus. In eccentric annuli the highly non-uniform velocity profile can enhance the dispersion process compared to regular annuli (O'Bryan and Bourgoyne, 1987b).

It is possible to calculate the velocity profile for non-Newtonian laminar flow in annuli using theoretical analysis (eg Skelland, 1967). Although such analysis yield rather complex results for typical non-Newtonian rheologies it is in principle possible to use the results to determine the proportion of mud containing dissolved gas and travelling faster than the average velocity. Hence it should be possible to determine

the extent to which the dispersion of dissolved gas will affect the transport and concentration profile of gas regions in kicking wells. Swanson et al (1988) included such laminar dispersion for their simulations with the GASKICKS model, as well as accounting for the motions of free gas via the Aziz et al (1972) correlations. It is not clear whether dispersion is included in any other existing models. The Schlumberger code (Section 3.13) is intended model the gas dispersion effect.

It is believed that none of the other kicking well models include gas dispersion as a mechanism for gas transport, although it is believed to be an important phenomenon (O'Bryan and Bourgyne, 1987b).

8. PRESSURE GRADIENTS FOR MUD/GAS FLOWS

As with gas slip velocities, considerable effort has been dedicated to determining pressure gradients for a wide range of gas/Newtonian liquid two-phase flows relevant to a number of different industries. This Section addresses the calculation of mud/gas flow pressure gradients using Newtonian liquid two-phase flow correlations or true mud/gas experimental results.

8.1 Steady State Frictional Pressure Gradients

The industry has tended to develop its own pressure gradient (or "pressure drop") correlations for oil/gas flows. Several of these

Orkiszewski (1967) - flow is considered to consist of four distinct regimes: bubble, slug, transition (churn) and annular (mist). Definition of the flow regime map and characterisation of each regime combined the best available techniques from existing work, with some original correlations developed by Orkiszewski. For bubble flow the pressure gradient is calculated from the liquid flow properties, using a Moody friction factor based on the liquid Reynolds number. For slug flow the effects of gas slip on the fluids distribution are included in a specially developed equation for pressure gradients. The friction factor is determined using a suitable mixture Reynolds number. At higher gas flow rates the Duns and Ros (1963) correlation is used.

Aziz, Govier and Fogarasi (1972) - a flow regime map is plotted in terms of the gas and liquid superficial velocities, incorporating the effects of densities and interfacial tension. Four separate flow regimes are addressed. In bubble flow the liquid flow parameters are used to calculate pressure gradients. For slug flow it is assumed that pressure gradients are only determined by the liquid slugs (ie not the Taylor bubbles) which occupy only a fraction of the tubing length. For the mist regime the gas flow parameters determine pressure drops, while the fourth regime - froth flow - is viewed as a transition from slug to mist flow.

Beggs and Brill (1973) - flow parameters are used to determine the flow pattern which would be expected if the flow were horizontal.

From this flow pattern map and a correlation developed to account for well inclination effects, hold-ups are determined to be used for calculating pressure gradients in wells of any inclination. The Moody friction factor chart is used to develop a no-slip pressure gradient, which is modified through multiplication by a slip correlation factor. Mukherjee and Brill (1983) developed a new liquid hold-up correlation to be incorporated in the Beggs-Brill calculation method, noting that hold-ups tended to by overpredicted by Beggs and Brill.

It is always necessary to exercise caution when employing such two-phase correlations since the complexity of some of them is no guarantee that predicted pressure gradients will be sufficiently accurate for use in flow calculations. For instance, although the Beggs and Brill (1973) method has enjoyed widespread use owing to its applicability to inclined as well as vertical flows, Salisburg and Peden (1987) found that when comparing several different correlations the Beggs-Brill equation was the least accurate for vertical flows. In a separate comparison of two-phase flow correlations, Ozon et al (1987) tested the Hagedorn-Brown, Duns-Ros, Aziz et al and Orkiszewski correlations against data from 70 wells. The results are summarised in Figure 8 where bar charts are presented, defined according to the number of data points for which each correlations' predictions were classified as either 'very good', 'good', 'satisfactory' or 'poor'. It can be seen that the Hagedorn and Brown (1965) correlation gives best predictions, in spite of the neglect of flow regimes in this calculation method. It is believed that poor flow regime map definitions are a possible source of inaccuracy in other models, even though the

representation of pressure gradients within each flow regime may be sufficiently accurate. Ozon et al (1987) describe a mechanistic model for oil/gas flows (see also Ferschneider et al, 1988). The pressure gradients and flow regime transitions are calculated from theoretical considerations of the characteristics of each regime. Figure 8 shows the high accuracy of such a mechanistic approach compared to the more traditional correlations.

It should, in principle, be possible to adapt the mechanistic approach of two-phase flow modelling to represent the two-phase flow of non-Newtonian muds and gases, thus producing a complete correlation for use in kicking well models. Such an analysis has not yet been attempted. As a consequence several kicking well codes choose to employ the correlations developed for oil/gas flows without experimental justification. The exceptions to this (for the codes which include two-phase pressure gradient calculations) are the Schlumberger model (Section 3.13) for which experimental flow data is being collected and the Podio and Yang KICK model (1986) which simply applies a viscosity correction to single phase laminar mud flow pressure gradients in order to approximate the reduction in viscosity caused by the gas. For turbulent flow in KICK single-phase frictional pressure gradients are used without modification (except that fluid mixture density replaces the pure mud density).

When employing standard gas/oil correlations to represent mud/gas flows it is necessary to modify the liquid properties required in the correlations so as to approximate non-Newtonian fluids. Although not an ideal method to use for two-phase mud/gas pressure gradient calculations,

such an approach has persisted because of the lack of a complete mud/gas flow model. For all of the models considered the topic of adapting two-phase flow correlations to non-Newtonian liquids is given very little attention.

The Hoberock and Stanbery (1981b), Thomas et al (1982) and Nickens (1985a) models all use the Beggs and Brill (1973) correlation as does the Maus et al (1979) version of the KIKSIM model. Although the Beggs and Brill (1973) correlation is suitable for flows which deviate from the vertical, it should be recalled that none of these kicking well models have been developed with the capability of modelling inclined wells. The kick models of Starrett et al (1988) and Swanson et al (1988) use the Aziz et al (1972) friction factor and hold-up correlation. Consistent with the Rogaland philosophy of offering a choice of calculation methods in the GASKICK code, Rommetveit et al (1989) report that five two-phase flow correlations are written into the model. These are: Duns and Ros (1963), Hagedorn and Brown (1965), Orkiszewski (1967), Beggs and Brill (1973), and Mukherjee and Brill (1983).

As well as developing theoretical models of mud/gas flow regimes and pressure gradients, it is necessary to obtain and use experimental data to verify the calculation methods used in codes. Experiments at Louisiana State University has measured mud/gas frictional pressure losses for flows in pipes (Elfaghi et al, 1983) and annuli (Langlinais et al, 1983). By comparing experimental results with the predictions of two-phase flow models Langlinais et al (1983) concluded that annulus data was best

represented by the Hagedorn and Brown (1965) correlation using the hydraulic diameter (to represent flow path geometry) and an apparent mud viscosity defined using the Power Law rheological model. Calculations were found to be much less sensitive to the method of determining apparent viscosity and equivalent diameter than to the particular two phase flow correlation selected. Variations in apparent viscosity and equivalent diameter did not greatly affect calculational results obtained using the Hagedorn and Brown correlation.

In a separate experimental investigation, White (1983) examined the two-phase flow of mud/gas mixtures in vertical pipes. The data was correlated using dimensionless groups to provide equations to predict both hold-up and pressure gradients for vertical flow. These equations are valid for both Newtonian and non-Newtonian fluids, in either single-phase or two-phase flow. Flows in annuli were not considered by White. The results of White (1983) do not as yet seem to have been incorporated into a kicking well code, although Podio and Yang (1986) cite White's work.

The experimental programme underway at Schlumberger Cambridge Research is intended to make detailed studies of bubble flow in a fluid similar to a typical mud, under different two-phase flow conditions. The Schlumberger flow loop can accommodate a rotating centre body (representing a drillstring) enabling annular flows to be investigated.

8.2 Transient Behaviour in Two-Phase Flows

In Section 6 is was noted that single phase mud flow models generally assume that steady state pressure gradient profiles may be used to represent transient flows. It was argued that although changes in flow conditions disturb the flow profile in pipes and annuli (thus affecting the relationship between mean velocities and wall friction effects) the timescale for transient frictional effects to be noticeable is very small. All of the theoretical and experimental investigations of two-phase flows (for Newtonian or non-Newtonian liquids) discussed in Sections 7 and 8.1 have assumed that the flow is steady state. Changes in flow conditions (eg in a kicking well due to control actions, gas expansion or evolution as fluids rise through the well etc) will disturb this steady state assumption, but since single-phase and two-phase flows exhibit considerable differences in nature it is not known how large the perturbations to slip velocities and pressure gradients will be. Hoberock and Stanbery (1981a, 1981b) have developed the only model to include frictional pressure gradients for non-steady flows, but no attention is given to the effects of flow transients on slip velocities and flow regime transitions.

The full implications of two-phase flow behaviour on the Hoberock and Stanbery (1981b) frequency dependent friction techniques (which were adapted from Zielke, 1969) have not been fully investigated.

9. DEFINITION OF FORMATION FLUID INFLOW RATE

Formation fluids may enter the wellbore in several ways. "Drilled gas" arises when the bit penetrates porous rock containing gas, with no associated flow of gas within the formation. At higher formation pressures, penetration of the gas zone leads to the flow of gas from the formation reservoir into the wellbore. Flow of gas continues until either the reservoir is exhausted, or the well bottomhole pressure is raised to be high enough to balance the formation pressure. A third type of gas inflow is caused by swabbing. Failure to keep the well full of mud while raising the bit from the bottom of the well can cause a low bottomhole pressure - allowing fluids to enter the well.

Kick models need to be able to define the rate at which gas enters the well in order to produce realistic simulations of the development of kicks and the response of the well/formation to kick control actions. This Section outlines how different types of gas influx can be modelled. The equations quoted apply only to gas inflow. Liquid kicks in wells are possible, but are not considered here.

9.1 Drilled Gas

The pressure of gas in drilled cuttings is unavoidable. As these cuttings are carried to the well surface the gas expands and (provided the permeability of the cutting allows flow of gas) enters the mud as free gas.

The problems associated with this "drilled gas" are discussed by O'Bryan and Bourgoyne (1987b).

Although not strictly a gas kick, the effects of drilled gas on wells need to be included in a kicking well model. A reason for this is that even small quantities of downhole gas can give rise to large near-surface gas volumes, lowering the hydrostatic pressures imposed downhole. A further reason for including the effects of drilled gas in a model is that even very small quantities of gas can substantially alter the compressibility and sound speed in the mud.

Nonetheless, inclusion of drilled gas in a simulator is not a difficult task, merely requiring the calculation of the ratio of mud flow rate to cuttings production rate during drilling. Rock porosity, formation pressure and expansion characteristics of the gas are also important factors affecting the drilled gas.

9.2 Gas Flow from a High Pressure Formation

It is clearly not desirable to include a sophisticated reservoir model in a kicking well computer model. Some simplifying assumptions are therefore made for predicting the gas flow from a high pressure reservoir to a well as a function of the well bottomhole pressure. The formation is generally assumed homogeneous throughout, with the gas-region extending to infinity. Also, only radial Darcy flow is considered (see, for example, Dake, 1978). The equation defining such flow may be considered as a

transient diffusion (ie Laplace) equation for the pressure field. As an approximate solution to this diffusion equation, Thomas et al (1982) introduced the use of the equation

$$Q = \frac{\pi kh\ T_s}{(\mu ZT)_f\ P_s\ P_D} (P_f^2 - P_{bh}^2) \qquad (9.1)$$

to kick modelling. Here self consistent units are used:

Q = gas flow rate, m^3/s (surface conditions)

k = formation permeability, md

h = reservoir thickness penetrated, m

T_s = surface temperature, K

T_f = formation temperature, K

P_s = surface pressure, Pa

P_f = formation pressure, Pa

P_{bh} = bottomhole pressure, Pa

Z_f = gas compressibility factor at formation conditions

μ_f = gas viscosity at formation conditions

P_D = dimensionless pressure = $\frac{1}{2}\ln (t_D + 0.809)$

t_D = dimensionless time = $\frac{kt}{\phi \mu_f c r_w^2}$

r_w = wellbore radius, m

c = formation gas compressibility, Pa^{-1}

ϕ = porosity fraction

t = time, s.

The boundary conditions employed in deriving equation (9.1) require the assumption of a constant gas flow rate. This is not true for the flow of gas during a kick where the bottomhole pressure and the fluid flow rate vary not only as the reservoir is drained, but also as kick control procedures are applied. The assumption that the reservoir extends to infinity does not allow for the simulation of small pockets of gas (eg shallow gas) which may be fully drained quite soon after initiation of a kick.

In spite of the poor theoretical support for equation (9.1) for the varying pressures and flow rates during kicks, following the example of Thomas et al (1982) it has been selected as the equation to define gas flow rate in several computer codes. Care needs to be taken when comparing the equations used by different authors, however. For instance, both Thomas et al (1982) and Nickens (1985a) quote equation (9.1) incorrectly - either due to confusion over units or to typographical mistakes.

Equation (9.1) is used in the Nickens (1985a) model with a slight modification. Rather than determining the flow rate from the depth of gas-bearing formation exposed by the bit, the gas formation is divided into several axial segments whose length is determined from the drilling rate and the numerical solution time-step. An extra segment is constructed ahead of the bit of a length such that the exposed formation has an area equal to that of the bit face. This pseudo-segment is continually exposed to virgin formations. The flow rate of gas to the well is determined separately for each axial segment, taking care to ensure that the variable,

t, for each segment refers to the time since gas first began to flow from that particular segment. This modification to the flow equation removes the approximation that gas flow is axially symmetric within the exposed gas bearing formation.

The Rogaland simulator (Rommetveit et al, 1989) and Starrett et al (1988) model also employ equation (9.1) for gas inflow, without the segmentation proposed by Nickens. Likewise Swanson et al (1988) probably use an inflow relation of the form of (9.1), citing Earlougher (1977) as a source for the equation selected but not quoting that equation.

In the Miller and Juvkam-Wold (1989) BASIC program, an alternative equation to (9.1) is used. This equation may be written as:

$$Q = \frac{2\pi kh\ (P_{pf} - P_{pbh})\ B_g}{\frac{1}{2}(\ln t_{Di} + 0.809).T} \qquad (9.2)$$

where:

B_g = gas formation volume factor, $\frac{m^3 \text{ (reservoir conditions)}}{m^3 \text{ (surface conditions)}}$

(Note that equation (9.1) is derived from (9.2) by making the assumption that the pressure representative of average reservoir conditions - used in determining B_g - is the mean of the formation pressure, P_{pf} and the bottomhole circulating pressure, P_{bh}. See Dake, 1978).

In equation (9.2) P_{pf} and P_{pbh} are the formation and bottomhole pseudo-pressures defined such that:

$$P_p = 2 \int_{P_o}^{P} \frac{P}{\mu Z} \, dP \qquad (9.3)$$

where P_o is any convenient reference pressure (such as standard pressure, P_s).

Superposition is used in the Miller and Juvkam-Wold (1989) code to solve Equation (9.2). Incremental changes in the flow rate or pressure are integrated through time, leading to a model of fluid inflow which is applicable to steady, increasing, decreasing or fluctuating flow rates. A further benefit of the Miller and Juvkam-Wold inflow equations over those used in other codes concerns the inclusion of skin effects. Partial penetration of the overpressured formation gives rise to an effective skin factor which is calculated and used to modify the gas inflow calculations by deriving an effective wellbore radius.

The only other existing kicking well code to include a model for gas inflow to the well is the Podio and Yang (1986) code. Here the equations used represent the steady state solution to the defining flow equation. However, this solution is strictly only relevant to reservoirs with a completely open outer boundary, after the transient period of flow has been completed (see Dake, 1978). In the Podio and Yang (1986) model fluid withdrawn from the reservoir is balanced by fluid entry across the open

boundary at a defined radius, such that the pressure is constant beyond the defined boundary. Hence

$$Q \propto \frac{kh\ (p_f^2 - p_{bh}^2)}{\ln r_e} \qquad (9.4)$$

Podio and Yang relate r_e - the extent of reservoir drawdown - to the total volume of gas known to have flown into the well (thus ignoring concentration gradients within the reservoir).

In conclusion, the differential equation defining fluid flow from an idealised reservoir adopts a standard mathematical form. Representation of solutions to this equation in kicking well codes has not yet been given the full attention required to enable modelling of fluctuating flows in reservoirs which may be either finite or infinite in extent. The exception is the Miller and Juvkam-Wold (1989) code which uses superposition solution techniques to model fluctuating flow from an infinite reservoir.

9.3 Inflow Due to Swabbing

It is not the purpose of this paper to discuss the numerical modelling of swab/surge in wells. Such models are discussed by Mitchell (1988a, 1988b). Nonetheless, swabbing is an important cause of kicks which may be modelled approximately using standard kicking well codes.

Swanson et al (1988) simulated swabbed kicks by assuming that a given influx volume entered the well over a specified period of time. The mud is assumed to remain static for the time required to run the bit back to bottom, at which point mud circulation can recommence. As Swanson et al (1988) comment, swabbed gas will enter the well and rise by gravitational effects through the mud. If oil-based mud is used the gas will dissolve as it enters the well, saturating the mud around the point of influx. As further gas enters it rises until pure mud is encountered in which the gas can dissolve. Modelling of swab kicks therefore requires accurate representations of the gas rise and gas dissolution processes.

10. MODELLING OF KICK GAS SOLUBILITY IN OIL-BASED MUDS

It is known that hydrocarbon gases are increasingly soluble in oil-based drilling fluids as pressure rises. It is also generally accepted that the behaviour of gas kicks in deep wells drilled with oil-based muds can differ substantially from their behaviour when water-based muds are used (Turner, 1986). There is still, however, debate as to how solubility influences the detection and therefore likely severity of kicks taken in oil-based muds.

The data of Thomas et al (1982) shows that for certain deep well conditions the solubility of methane gas in diesel oil reduces the volume taken up by a kick downhole by some 25%. The fact that the total volume of mud and gas in the wellbore is only slightly affected by this solubility has led to a misunderstanding of the importance of the effect. For

example, Turner (1986) writes "The shrinkage involved when miscibility occurs is 1-2% and cannot account for the 'absorption' of the kick in the volumetric sense." Although it is true that gas solubility reduces the kick gas volume by only 1-2% of the total well volume, this is not a useful way to measure the effect of solubility on a kick. The thresholds of kick detection using surface flow rates or pit gains are related to the kick volume, not total volumes of drilling fluids downhole. Hence the useful measure of kick 'absorbtion' is in terms of a percentage of the undissolved kick volume.

Theoretical studies have been made to examine kicks when gas solubility is important. Swanson et al (1988) used the BP GASKICKS code to investigate uncontrolled kicks in oil and water-based muds. They concluded that for low gas volumes the surface responses for the different mud types will differ. As well as volumetric differences, the free gas in water-based muds rises at a higher rate than the dissolved gases in oil-based muds. At higher gas concentrations the surface responses become more alike as high gas concentrations will only be totally soluble near to bottomhole. The simulation results show that pit gain is always lower for a kick in oil-based mud case (at a given gas influx rate). Swanson et al (1988) do not consider the control of kicks in the two mud types, however, and therefore do not quantify the expected delay in kick detection and hence the increased influx volume to be expected for oil-based muds.

It is apparent that simulations of gas kicks and well control procedures should be invaluable in determining the likely difficulties and

possible hazards to be encountered when kick gas is soluble in the drilling mud. For such applications it is necessary for a kicking well simulator to be able to model the dissolution (and subsequent evolution at lower pressures) of kick gas.

10.1 Predicting the Solubility of Kick Gases

There are three main ways in which solubility may be incorporated in a computer code:

i) using an equation of state
ii) using an empirical solubility equation
iii) using a solubility database obtained from experiment.

10.1.1 Equations of State for Gas Solubility

The development of new equations of state and the tuning of equation of state parameters has produced accurate means for predicting the phase behaviour of hydrocarbon liquids and gases. The equation of state approach may also be adopted for modelling the solubility of hydrocarbon gases in the oil component of oil-based muds. However, care needs to be taken to include the influence of other mud components (emulsifiers etc) on solubility, for which the equation of state methodology is not readily adaptable.

To use equations of state for predicting solubility it is necessary to establish the compositions of both the gas and liquid phases which satisfy the required thermodynamic equilibrium constraints. Iterative solutions of non-linear fugacity equations (representing the thermodynamic requirement that the total Gibbs energy of a two-phase system is minimised at equilibrium) are required for each phase calculation. Hence, in order to employ equations of state in a computer model, it is necessary to accept an increase in the simulator run time due to the computationally intensive phase calculations, or to use the equation of state method to develop a look-up table of mud-gas solubility data prior to the commencement of each simulation. Such a look-up table can only be generated once mud and gas compositions have been defined, with separate tables required if different mud types are included in a single simulation.

Perhaps the chief advantage of the equation of state approach over solubility equations is its applicability to hydrocarbon fluids of any composition. Although kick gases are likely to contain significant fractions of methane, other hydrocarbons (and non-hydrocarbons such as CO_2, H_2S) will be present. Existing solubility correlations may not be applicable for the kick gas compositions required. Although equation of state phase equilibrium calculations should always be verified (and tuned) with experimental data, they do provide a means of determining approximate phase envelope and volumetric behaviour of systems for which no data exists.

10.1.2 Empirical Solubility Equations

Perhaps the only significant published correlation for the solubility of gas in oil-based muds has been developed by O'Bryan et al (1986). The mud is considered as a combination of oil, brine, emulsifiers and solids, with separate equations defining total solubility in each of the first three of these components. These equations express solubility as functions of pressure and temperature, allowing the dissolving gas to be composed of hydrocarbons and CO_2. The hydrocarbon component of the gas is characterised purely via the gas gravity.

The O'Bryan correlation is based on experimental data collected at pressures sometimes as high as 6800 psi, but typically in a range up to approximately 4000 psi. Caution should be exercised in applying the O'Bryan equations at higher pressures, since it is known that solubility becomes unlimited above a certain threshold limit for a given temperature - see Thomas et al (1982).

10.1.3 Gas-Mud Solubility Database

It is, of course, possible to include an experimental database of gas-mud solubility values in a computer program. Required solubilities may then be calculated from interpolation of such databases, based on the temperatures and pressures in question. Clearly such an approach is not as elegant as employing a correlation, and also it should be recalled that fluid property data banks are only valid for fluids identical (or

sufficiently similar) to those used in the experiments. Nonetheless, inclusion of tables of experimental data in a kicking well model provides a valid means of incorporating solubility effects.

10.2 Rate of Gas Dissolution

The fact that gas bubbles require a finite time to dissolve in liquid solvents is often neglected in fluid dynamic modelling on the grounds that the time-scale for dissolution is much shorter than the time-scale for numerical solution of the fluid dynamic equations. Levich (1962) summarises the three stages involved in determining the dissolution of gas bubbles as:

(i) the dissolving component of the bubble must be conveyed to the gas-liquid interface (for gas kicks, it may be assumed that all bubble constituents are soluble)

(ii) the dissolving component must dissolve in the liquid at the interface

(iii) solutes must be removed from the surface of the bubble to the bulk of the solution (to allow further dissolution at the bubble surface).

For the dissolution of gas in muds the third of these steps limits the rate of dissolution as convective diffusion in the liquid is the mechanism

which dilutes the localised high solute concentrations near bubble surfaces.

For a single bubble in stationary liquid it is possible to derive the rate at which a given bubble will be dissolved, based on the coefficient of convective diffusion. When many gas bubbles (or a single bubble of significant size) are dissolving it may be expected that the dissolution rate will decrease. In this case the assumption that the single dissolving bubble is initially surrounded by pure liquid (no dissolved solute) no longer applies.

A thorough investigation of the mechanism for gas dissolution in drilling fluids is still required. The only kicking well model to include a model for gas dissolution rates is the Rogaland simulator (Rommetveit, 1989) which employs analytical solutions of the diffusion equations for convective or turbulent diffusion. The Rogaland approach to turbulent modelling is based on the work of Levich (1962).

10.3 Swelling of Oil-Based Muds Due to Dissolved Gas

Although the dissolution of kick gas in oil-based muds leads to a reduction in the gas plus mud volume, it must not be supposed that the gas volume disappears altogether. The mud solvent will expand (or swell) to a volume between that of the pure mud and of the mud/free-gas mixture.

As with the modelling of gas solubility itself, it is possible to assume that the oil phase of the drilling mud is the only component relevant to dissolution, and to evaluate mud density changes in terms of general correlations for oil formation volume factors.

A better approach to this problem would require an experimental study of mud density changes upon dissolution of gases. O'Bryan and Bourgoyne (1987a) have performed such a study, correlating their results with an equation of state. The Peng-Robinson (1976) equation is employed and calibrated for the oil-based mud/gas problem by adjusting the oil component molecular weight according to the dissolved gas-oil ratio. Solubility is not considered to affect the density of other mud components.

Assuming that gas dissolves only in the oil component of the mud, Rommetveit et al (1989) quote the following equation for downhole mud density (a function of pressure, p, temperature, T and dissolved gas fraction, x):

$$\rho\ (p,\ T,\ x) = \left[\frac{x + x_o\ (1-x)}{\rho_o\ (p,\ T,\ x)} + \frac{x_w\ (1-x)}{\rho_w\ (p,\ t)} + \frac{x_s\ (1-x)}{\rho_s} \right]^{-1} \quad (10.1)$$

where:

x_o, x_w, x_s = mass fractions of oil, water and solids components in mud at surface conditions

ρ_o, ρ_w, ρ_s = density of oil, water, solid components of mud.

10.4 Inclusion of Solubility in Existing Kicking Well Codes

Tables 3 and 4 shows that only three of the existing codes described in Section 3 include solubility effects. Although Thomas et al (1982) describe an experimental investigation of gas solubility in diesel oil based muds, they choose to employ the correlations of Standing (1947) to calculate both gas solubility and mud density changes.

In the Rogaland GASKICK model (Rommetveit et al, 1989) the solubility may be calculated from gas-oil ratio correlations or from tables of experimental gas solubility data. That same data can be used to determine mud volumetric changes or else oil formation volume factor correlations may be selected. The BP GASKICKS code (Swanson et al, 1988) opts to use the O'Bryan correlations (O'Bryan et al, 1986; O'Bryan and Bourgoyne, 1987a) for simulating gas solubility.

The gas kick model under development at Schlumberger (Section 3.13) includes gas solubility effects based on data collected in a BP PVT cell experimental programme.

11. CALCULATION OF STEADY AND TRANSIENT WELLBORE TEMPERATURE PROFILES

The precise definition of the wellbore transient temperature profile affects the flow of fluids during drilling and well control operations

since temperature influences the density of the mud and gas phases, and the rheology of the mud. It would, in principle, be possible to develop a computer program which not only solves the equations describing fluid motions in the well, but also incorporates all of the heat generation and heat transfer effects associated with drilling. Such a program would solve not only mass and momentum conservation equations but also an energy conservation equation that includes the thermal behaviour of: wellbore fluids; the drillstring and casing steel; casing cement; and the surrounding formation. No such computer model has yet been created for kick modelling. All developed gas kick simulators assign a fixed temperature to the wellbore. This temperature follows either the geothermal profile, or a profile determined from the steady state temperature profile solution for mud circulating in a well.

It is known that the circulation of mud in a well has a cooling effect as drillstring and annulus temperatures are typically less than the geothermal value. This cooling occurs even when drilling, in spite of the heat generated by the rotation of the drillstring and by the cutting action at the bit.

Approximate calculational procedures have been developed to enable circulating mud temperature profiles to be calculated. Holmes and Swift (1970) derived an analytic method for obtaining such profiles, by assuming that steady-state temperatures were established. The Holmes-Swift method assumes a linear geothermal temperature gradient and neglects heat transfer at the drill bit. The interface between the formation and the well itself

is assumed to be at a temperature equal to the geothermal temperature, thus eliminating the need to model heat conduction within the formation. In assessing the viability of the Holmes-Swift and similar models it is necessary to question whether or not a steady state, equilibrium temperature profile is applicable while drilling. To determine the length of time for which mud flow should continue before steady state temperatures are neared it is necessary to employ a transient computer model, such as the GEOTEMP2 code (Mitchell, 1982; Mondy and Duda, 1984). Figures 9 and 10 display the results of calculations carried out at Winfrith using GEOTEMP2. These plots show the changes in mud temperature inside the annulus and drillstring respectively for mud circulating at 100 gpm in a 5000 ft well. The thermal diffusivity of the formation was set to a value of $1.2 \times 10^{-6} m^2/s$, which is typical for drilling operations. It can be clearly seen that the temperature profiles in the well only begin to approach steady state values after several days of drilling. It should be recalled that drilling does not continue usually indefinitely, but that regular shut-ins may be expected to hinder the rate at which steady state circulation temperatures are attained.

For the GEOTEMP2 runs used to produce Figures 9 and 10 it was decided not to include the heat generation terms specific to drilling since temperature comparisons for a static well were desired. Heat generation may be expected to play an important role in determining downhole profiles, however. The heat source terms relevant to a drilling scenario are summarised by Marshall and Bentsen (1982) as:

1) rotational energy due to the work required to rotate the drillstring. Marshall and Bentsen assume that all of the mechanical energy required to operate the rotary drive will be converted to heat energy - dividing the thermal energy between the drill pipe and the bit such that 60% is distributed along the drill pipe

2) work done by the drill bit.
Marshall and Bentsen assume that this energy source amounts to 40% of the total energy consumed by the rotary drive; see point 1)

3) viscous energy due to friction losses inside the drillstring, drill bit and annulus.
The total frictional pressure loss for the drillstring, bit and annulus should equal the pump circulating pressure less the pressure losses in the surface connections. The thermal energy input to the system should be divided among the drill pipe, bit and annulus according to the ratios of the respective friction losses.

The above considerations should influence the choice of temperature profile to be provided as input data for the initiation of a simulation of a kicking well. Transient heat transfer effects will continue to influence well temperatures during the kick control procedure as the nature of the fluids in the well changes, and the mud pump speed is altered. The short time-scale of kick events (of the order of several hours) should justify maintaining a constant temperature profile throughout a kick simulation. It should be noted, however, that the high gas flow rates encountered in

the event of a gas blowout (such as following a failed kick control attempt) will radically alter the well thermal characteristics.

Hoberock and Stanbery (1981b) - who use a constant temperature of 80°F throughout the well for their simulation - note that during a kick heat transfer between the mud and free gas bubbles will influence the gas temperature. It is not expected, however, that the gas temperature will differ significantly from that of the surrounding mud and therefore detailed modelling mud-bubble heat transfer is probably not necessary (especially considering the lack of precision in the calculation of flowing mud temperatures in kick models).

Considering the kicking well simulators summarised in Table 1, it can be seen that all except the LeBlanc and Lewis model (1968) offer a facility for defining a temperature profile throughout the well. In many cases the profile is user-specified via a linear geothermal gradient, although nothing is known of the flexibility for selecting temperatures in the Starrett et al model (1988) or the Rogaland GASKICK model (Rommetveit, 1989). Swanson et al (1988) state that their calculations using GASKICKS employed the Holmes-Swift steady state temperature model.

All of the kicking well models assume temperature profiles to be constant throughout a simulation. The determination of what temperatures to use for gas kick simulations is one of the topics which has yet to receive the attention it almost certainly deserves.

12. MODELLING OF FORMATION CHANGES - WELLBORE DEFORMATION AND FORMATION FRACTURE

In many of the existing kicking well simulators the properties of the formation surrounding the wellbore are assumed to influence fluid behaviour solely as a result of their importance in determining gas flow rates. That is, at a high pressure zone in the formation, the formation fluids will flow to the well at a rate dependent on the porosity and permeability of the formation.

Formation properties may, however, affect the response of a well to kicks in other ways. It is known that at high pressures (such as encountered in well kill procedures) the formation may fracture and lead to leakage of circulation fluids from the well itself. A second, debatable response of the wellbore to kicks while drilling concerns the belief held by some that changing well pressures leads to significant swelling and relaxing of the formation around the open hole.

12.1 Formation Fracture and Lost Circulation

As kick fluids rise and expand through the well it is necessary to impose higher and higher surface pressures at the annulus outlet (ie choke) in order to maintain constant bottomhole pressures. If these pressures become too large it is possible for the formation to fracture. The portion of the formation most prone to fracture is usually that located just below the casing shoe, with the highest exposed pressures occurring as the top of

the kick approaches the shoe. Such formation fracture is highly undesirable as it provides a means for circulating fluids to flow away from the well and into the formation itself, thus hindering attempts to maintain well control. Leak-off tests carried out after running cement casings give an indication of the maximum allowable annular surface pressures based on the breakdown strength at the shoe.

It is clearly possible to examine downhole data produced in a simulation of a well control operation, and to examine whether or not formation breakdown pressures were exceeded at the shoe (or any deeper in the well) at any time during the simulation.

A more desirable facility in a kicking well code would be if the code user could be informed during a simulation whenever downhole pressures have become too high. In such instances control operations could be adjusted to lower the pressures, and the influence on subsequent kick behaviour examined. A further enhancement would be for computer models to calculate the rate at which fluids will flow into the formation following the formation fracture, although performing such calculations is by no means straightforward, and probably not necessary.

Only three of the developed kicking well models summarised in Tables 1 and 2 are known to attempt to detect formation breakdown. In the KIKSIM model (Fischer and Kastor, 1975) the formation fracture gradient may be defined at any depth by dividing the well into a series of regions having different fracture gradients. The model is able to determine whether or

not the formation breakdown strength is exceeded at any point in the wellbore. With such a capability Fischer and Kastor (1975) were able to simulate well control using the Low Choke Pressure Model. In general, as the kick is circulated through the well, the aim of the choke controller is to preserve a constant bottomhole pressure. Such control is automatically achieved with the KIKSIM model. If it is not possible to maintain BHP without exceeding the formation strength at some point in the well, KIKSIM automatically opens the choke to release pressures. Additional reservoir inflow is the usual consequence of such a pressure reduction.

The Podio and Yang (1986) KICK simulator also uses user-specified fracture gradients to determine the strength of the wellbore walls at any depth. If the breakdown pressure is exceeded during a kill operation KICK employs a crude equation to model the loss of drilling fluid (and gas, if relevant) to the formation. In the WELL-KICK code developed from KICK (see Section 3.8) these predictions of loss rates are removed from the model, although the code user is informed that breakdown strength has been exceeded.

Finally, the third simulator with a facility for detecting formation fracture is the Whitman and Evers model (1987). When a simulation is completed with control procedures dictated by the user, the program monitors the pressure at the casing shoe notifying the user whenever this pressure is too high.

12.2 Wellbore Deformation - Ballooning

Whether or not wells 'balloon' significantly in response to downhole pressures is open to question. Gill (1987, 1989) has written to describe his experience that changes in pressure can cause noticeable fluctuations in the volume of the wellbore. For a pressure reduction of 300 psi (eg due to the switching off of mud pumps, with an associated drop in equivalent circulating density), Gill states that relaxation of the wellbore from its ballooned state may cause a reduction in well volume of up to 30 bbl (assuming 4000 ft of open hole). Such a volume is clearly significant for modelling mud flows, having a considerable impact on the volume of mud contained in the pits.

Attempts have been made to verify Gill's experiences by modelling stresses in wellbores (sse, for example, Holbrook, 1989). Such theoretical models of wellbores must take account of the effective stress principle, associated with the fluids in-situ in porous, permeable rocks. In addition the plastic zone adjacent to the wellbore and the elastic zone at higher radii must both be included in order to represent the true temporal stress response of formations. To complete the definition of formation behaviour it is necessary to define a stress yield criterion such as the Mohr-Coulomb yield criterion (see, for example, Atkinson and Bransby, 1978). With the physics of formation behaviour defined in this way it has not yet been possible to predict a significant ballooning effect for calculations using typical formation properties.

The Podio and Yang KICK code (1986) is the only gas kick model known to be capable of varying the cross-sectional areas in a well according to the local pressures. A 'wall-compressibility' may be defined such that the cross-sectional area varies linearly with applied pressure. However, not only is there uncertainty as to the value this 'wall compressibility' should adopt but in KICK the volumetric response of the well is assumed to be identical whether fluids are inside the drillstring in the annulus adjacent to open hole, or inside the cased region. If ballooning does occur, it should influence chiefly the open hole annulus section.

Although not a kicking well model the surge/swab simulator described by Mitchell (1988) also deserves mention as a well model which includes elastic effects. As well as formation elasticity, pipe and cement elasticities are all used to determine the composite elastic response of the wellbore via an extensive set of equations derived from standard elasticity theory.

13. MODELLING OF WELLBORE COMPONENTS AND ASSOCIATED OPERATIONAL PROCEDURES

A drilling well is composed of many components which need to be incorporated in a well model. Following the typical path of mud through the well these components include the mud pumps, the drill collars and bit, the blowout preventers, choke line and choke throttle. In this Section, in addition to considering operational procedures associated with these

components, the behaviour of the well when the bit is off-bottom (eg during a tripping operation) is considered with respect to kick modelling.

13.1 Mud Pump Characterisation

Many drilling simulators model the mud pumps simply as a source of specified mud flow rate (see Tables 1 and 2). The exceptions as regards gas kick simulators are the models of Hoberock and Stanbery (1981b) and Ekrann and Rommetveit (1985). However, Nickens (1985a) includes a term in his model to account for the pressure losses in the surface equipment between the pumps and the drillpipe.

The failing of the constant-flow-rate pump model is that in practice it is extremely difficult to maintain a constant flow rate. For a given pump the throttle position and pump power may be selected, but the flow rate produced will still vary according to the discharge pressure. The discharge pressure (ie drillpipe pressure) may not always be assumed to be constant.

In the GASKICK model Ekrann and Rommetveit (1985) specify a functional form for the pump characteristics, but no details of this function are provided.

In the Hoberock and Stanbery (1976b) model the variations of pump speed with discharge pressure are linearised for each throttle position (see Stanbery, 1976). The gradient of each speed versus pressure line is

assumed independent of the throttle position, while the no-load speed (pump speed at zero discharge pressure) is considered to be proportional to the throttle setting. Hence only two parameters need to be be defined to characterize a pump's pressure response in this simple model.

Stanbery (1976) proposed a simple sinusoidal flow rate equation to define the oscillatory fluctuations in pump discharge rates related to the motion of the pump piston. Noting that a single-acting, triplex pump operating at 60 cycles per minute will correspond to a flow ripple frequency of 6 cycles per second, however, Stanbery was able to neglect such oscillations in his model.

A further component of the Stanbery (1976), Hoberock and Stanbery (1981b) pump model is the definition of a pump system time constant, allowing for the fact that the engine speed cannot change instantaneously for a step change in throttle position. This time constant is incorporated in the linearised equation for pump pressure response via a simple time derivative term.

Simulations carried out with the Hoberock-Stanbery code show the need for a realistic pump model (see Hoberock and Stanbery, 1981b). Automatic curve tracking was used to vary choke settings in order to match the casing pressure values measured in a 6000 ft well. It was found that the simulated bottomhole pressure varied over a range of 200 psi for this run, while the drillpipe pressure showed a 56 psi variation. The experimental data had been collected while attempting to maintain a constant bottomhole

pressure as indicated by the drillpipe pressure. Hoberock and Stanbery (1981b) note that the 56 psi drillpipe pressure variations are such that even an alert driller may not notice the fluctuations on a pressure gauge, even though control operations require the monitoring of drillpipe pressures while attempting to follow a pre-determined path. The pump speed as influenced by this drillpipe pressure was seen to vary by a factor of about 5% throughout the simulation, even though control procedures assume pump speed to be constant. The simulation results of Hoberock and Stanbery (1981b) are reproduced as Figure 11 to demonstrate the inter-relation of drillpipe pressure, pump speed and bottomhole pressure. The difference between bottomhole pressure and drillpipe pressure is not constant because the frictional pressure losses in the drillpipe vary as a function of the mud flow rate.

The conclusion drawn from these comments is that large bottomhole pressure fluctuations may be masked when determined from drillpipe pressures, because of the associated changes in pump speed. This important effect is not reproduced in models which treat the mud pump as a constant flow rate device, or which do not model the drillpipe at all (such as Thomas et al, 1982; Starrett et al, 1988; Swanson et al, 1988).

13.2 Drill Collars and Bit

The drill collars at the base of the drillstring cause a reduction in flow area for flow in both the drillpipe and the annulus. Hence the presence of the collars influences the frictional pressure drops in the

well, as well as the annulus hydrostatic pressures (which are strongly influenced by the height of the gas region during a kick). The presence of the bit affects well frictional pressures since the drilling mud is forced to flow through very narrow bit nozzles.

It can be seen from Tables 1 and 2 that the codes of Le Blanc and Lewis (1968) and Hoberock and Stanbery (1981b) do not allow for the existence of cross-sectional area changes in the well, and are therefore unable to represent the presence of drill collars. The Whitman and Evers (1987) program models the drillpipe by assuming it has a constant cross-sectional area throughout, excluding the possibility of modelling flow inside the collars. The Thomas et al (1982), Starrett et al (1988) and Swanson et al (1988) simulators do not model flow in the drillstring although Swanson et al (1988) state that GASKICKS allows for the time taken for kill mud introduced at the well surface to travel to bottomhole.

It is clear that those models which do not include a drillstring are also unable to represent the flow of fluids through the bit. Such simulators cannot demonstrate the true nature of the link between bottomhole pressures and surface drillpipe pressures. It was shown in Section 13.1 that the volumetric mud flow rate produced by the pumps is not necessarily constant and so the difference between drillstring and bottomhole pressures will fluctuate. The chief factor affecting this fluctuation is the bit pressure drop, which is very sensitive to fluid flow rates.

To calculate the pressure drop as mud flows though the bit it is common practice to make use of the standard pressure/flow characteristics for an ideal orifice (eg Hoberock and Stanbery, 1976b; Nickens, 1985a; Podio and Yang, 1986). The irreversible pressure loss is related to the energy density of the fluids in the bit nozzles via a loss coefficient. Such loss coefficients have been well established for Newtonian flow through idealised contractions and expansions. As Nickens (1985a) highlights, the large pressure drop across the bit leads to a noticeable difference in densities between the mud entering the bit and that leaving it.

Nickens (1985a) notes that in his model no gas is allowed to flow backwards through the bit into the drillstring. Podio and Yang (1986) do allow such backwards gas flow but do not, however, attempt to incorporate a two-phase loss coefficient in the bit model. Although Nickens did not allow gas to enter the drillstring, repeats of some of the Nickens simulations using the WELL-KICK code (see Section 3.8) showed that backflow of mud through the bit did occur. This backflow coincides with the 'zero' surface drillpipe pressures seen in Nickens results for the period between well shut-in and well stabilisation. The combined effect of mud backflow with gas being excluded from the drillstring leads to an accumulation of gas at the base of the annulus for simulations of this type.

13.3 Modelling of Blowout Preventers

Of the simulators described in Section 3 and Tables 1-6, two (ie Thomas et al, 1982; Starrett et al, 1988) are not designed to model well shut-in and control procedures and therefore do not require a model for the blowout preventers (BOPs). Other simulators assume that blowout preventers are present in the well, but avoid modelling them by beginning each simulation after the well has been shut-in (eg LeBlanc and Lewis, 1968). Of those simulators which do model the process of closing the blowout preventers only Nickens (1985a) considers the dynamic response of the blowout preventers. In the Rogaland GASKICK code (Rommetevit at al, 1989) the shut-in procedure is assumed to be completed in a single solution time-step (including pump shut-down, BOP closure and well stabilisation). Similar instantaneous BOP action is included in the Podio and Yang (1986) KICK code, where the blowout preventers are assumed to be closed whenever the choke is less than 100% open.

Nickens attempts to model BOP closure by assuming a linear variation of the BOP diameter with time after the decision to close the preventers. This creates an annular restriction of varying diameter. Nickens uses a theoretical loss coefficient for calculating the pressure loss as fluid flows through the preventer. For his sample simulations using this code Nickens (1985b) assumes that BOP closure requires 20 seconds.

A factor not discussed by any of the kicking well code authors concerns the change in fluid path following BOP closure when a choke line

is in use (eg for subsea BOPs). Choke lines are typically full of stagnant liquid (such as oil or water, depending on the type of mud in use) prior to the diversion of fluids into the choke line. Care ought to be exercised when modelling the flow of fluids after BOP closure, to ensure that the fluids in the choke line respond dynamically to the momentum of the wellbore fluids forced through the choke.

13.4 Flow Through Choke Line and Choke Restriction

For wells with subsea blowout preventers it is necessary to employ a choke line to carry fluids to the surface. The narrow choke line diameter and corresponding high fluid velocity in such choke lines leads to significant pressure losses which must be accounted for in control operations. Particular care must be shown when the leading or trailing edge of a gas-contaminated mud region enters the choke since the resultant change in choke line pressure drop may be quite dramatic (see Ilfrey et al, 1977). Of the kicking well models listed in Section 3, the following model (or intend to model) a choke line: Nickens (1985a), Ekrann and Rommetveit (1985), Podio and Yang (1986), Swanson et al (1988) and the code under development at Schlumberger Cambridge Research (Section 3.13). The Starrett et al (1988) code includes modelling of a horizontal diverter line which will also give rise to high pressure losses in a similar manner to choke lines.

To model a choke line it is necessary to represent all of the single and two-phase flow phenomena outlined in Sections 6, 7 and 8. In the

Rogaland code (Ekrann and Rommetveit, 1985) and the BP code (Swanson et al, 1988) the choke line is not modelled by a series of finite difference segments (as are the drillstring and annulus sections), rather the pressure loss associated with the choke line is treated as a localised pressure loss term to be included in wellbore calculations.

In the Nickens (1985a) program the choke line is modelled using finite segments (in the same way as the annulus, ie below the BOPs). Because of the presence of the choke line Nickens has to include slip velocity and pressure gradient correlations specific to pipe geometries (different to those used to represent flow in annular geometries). The much simplified slip and pressure gradient models included in the KICK code (Podio and Yang, 1986) do not necessitate the use of different equations for the annulus and choke line sections.

The Starrett et al (1988) simulator uses the Dukler et al (1969) horizontal two-phase correlation to represent mud/gas flow in the diverter. Additional fittings (bends, tees etc) are modelled by adding an equivalent length to the true length of the diverter. Account is taken as to whether the flow is sub-critical or critical.

Whether a choke line is present or not, well control procedures require the mud (or mud/gas mixture) to return to the pits via a choke restriction. Variations of the choke setting enable drillers to control the pressures in the well, with the overall aim of maintaining a constant bottomhole pressure sufficient to prevent secondary gas kicks. Not all of

the kick simulators include a choke model. This is because some simulators do not attempt to model control operations, while others allow for changes in the annulus surface pressure but do not explicitly represent choke flow (eg LeBlanc and Lewis, 1965; Miller and Juvkam-Wold, 1989).

In practice the annulus flow rate and the annulus surface pressure are linked by the choke flow characteristics. Well control operations require that whatever the flow rate, the choke setting should be selected so as to give an annulus surface pressure such that the bottomhole pressure remains as near to a constant value as possible.

The choke flow rate/pressure drop characteristics will depend on the particular choke in use, whether the flow is single or two-phase and whether the flow is sub-critical or critical. Critical flow occurs when the velocity of the fluid (or fluid mixture)reaches the velocity of sound. Once fluids have achieved critical flow, additional upstream pressures will not result in increased flow rates. Hence velocities greater than the critical velocity are not possible.

In the Hoberock and Stanbery model (1981b; Stanbery, 1976) the choke pressure loss is calculated by assuming the characteristics of an ideal orifice. The influence of two-phase flows upon choke behaviour is neglected, with the same equations being used for both single and two-phase flows (with the exception that the mixture density replaces the mud density when gas is present). Rather than the code user simply specifying a choke setting in the Hoberock-Stanbery model, the choke is assumed to be operated

by a 'rate-limited piston.' The choke position is altered during each simulation time-step according to one of three options: 'hold', 'open' or 'close'.

The Whitman and Evers (1987) model also employs a very simple choke pressure loss equation, involving only the mud density and velocity, together with the choke flow area as determined from a fractional opening coefficient. Two-phase flow effects are neglected.

Nickens (1985a) notes the complexity of modelling choke flows and so selects different equations to be employed depending on the flow type. For single phase mud flow an ideal orifice equation is chosen, whereas for mud/gas flows a correlation developed for subsea safety valves is used. The particular correlation chosen was selected because the relevant correlation flow parameters were considered similar to those encountered by well control chokes.

Very little is known concerning the choke model used in the Rogaland GASKICK code (Ekrann and Rommetveit, 1985; Rommetveit et al, 1989) except to say that all four combinations of single or two-phase fluids with either sub-critical or critical velocities are included. The numerical approximations made in GASKICK remove transient effects from the mud momentum equation. As a consequence no delay will be predicted between the operations made by the choke controller and the influence of those operations on the rest of the well.

The Podio and Yang (1986) KICK model also allows for sub-critical and critical flow in the choke, although the equations are somewhat idealised and do not account for the complexity of two-phase flows.

It is apparent that more information is required concerning the pressure/velocity characteristics of well control chokes. It may be argued that the precise choke setting required to produce a given pressure drop is not an important parameter for kicking well models to simulate, since only annular pressures and flow rates are monitored in real well control operations. It should not be forgotten, however, that the possibility of critical flow occurring in the choke (thus imposing a maximum velocity on the fluids concerned) is of considerable importance in determining the behaviour of wellbore fluids.

Numerous correlations have been developed for representing multiphase critical flow through chokes for Newtonian fluids (see, for example: Abdul-Majeed, 1988; Surbey et al, 1989). The wide variety of available correlations probably reflects the considerable variations in choke characteristics which depend on the particular choke design employed. The only study known to have examined the flow characteristics of well control chokes operated with drilling fluids is reported by Redmann (1982).

13.5 Calculations with Bit-Off-Bottom

When drilling ahead the drill bit is obviously situated at the base of the well and so many gas kicks occur when the bit is 'on-bottom.' During

tripping operations gas kicks may occur while the bit is off-bottom (see Section 9.3). Tripping operations and swabbing phenomena have not as yet been modelled in kick codes. The fact remains, however, that kicks do occur with bit-off-bottom and it is desirable to model these. The KICK program (Podio and Yang, 1986) is the only kicking well model known to attempt to perform bit-off-bottom calculations. In the simple procedure adopted the one-dimensional flow assumed throughout KICK (and all other kick codes) is applied to the section of the well below the bit, with fluids represented as flowing upwards in this section. An iterative procedure is applied to calculate the bottomhole pressure which, combined with the total pressure losses below the bit, gives an annulus pressure at the bit depth equal to the pressure calculated for the fluids leaving the bit. This represents a somewhat simplified representation of the three-dimensional flow to be expected below the bit. There is scope for such bit-off-bottom calculations to be given further theoretical consideration.

14. FINITE DIFFERENCE TECHNIQUES AND SOLUTION ALGORITHMS IN KICKING WELL COMPUTER MODELS

As well as selecting physical models to define the kicking well problem it is necessary to establish a numerical solution technique to solve for the flow of wellbore fluids over a sequence of time-steps. Of the kick codes presented in Section 3 details of such solution techniques are only available for the models described by Hoberock and Stanbery (1981a), Nickens (1985a), Ekrann and Rommetveit (1985), Podio and Yang (1986) and Starrett et al (1988). For some of the other models the

solution technique is known to be very straightforward since dynamic effects and gas/mud distributions are not considered. This removes the necessity to divide the well into a sequence of finite difference sections, but only allows for an approximate physical characterisation of a kicking well.

The Hoberock and Stanbery (1981a) code uses a rather specialised technique to solve the fluid mass and momentum equations describing kicks in wells. The conservation equations are linearised by expanding in terms of perturbations about the steady state velocity and dynamic pressure. Laplace transforms are then taken of these equations, and the resulting Laplace domain equations cast into an operational block diagram. Linear approximations are derived for the operators within this diagram, and a hybrid digital-analogue solution technique applied. The use of Laplace transforms and linearisation means that the Hoberock-Stanbery model is only suitable for approximate solutions to the mud/gas flow equations, and so this model will not be considered in any more detail here.

The remaining four codes for which information concerning the solution techniques/algorithm is available shall now be discussed briefly in terms of the finite difference formulations used, and the solution algorithm selected.

14.1 Finite Difference Formulations

The possibility of selecting different finite difference formulations is discussed by Nickens (1985a). Noting that discretisation of the mass and momentum equations should be more accurate if central averaging is used (rather than forward averaging), Nickens attempted to represent the mass conservation equations using a central averaging scheme. He found, however, that large velocity gradients coupled with the characteristics of gas slip in the annulus led to calculated void fractions outside the physically permissible range of $0 < \alpha < 1$ when central averaging was used. As a consequence Nickens represents mud flow in the drillpipe (no gas) with a central averaging formulation of the mass conservation equation, while forward averaging is employed for annulus calculations. The consequence of this forward averaging approximation is that local variations in void fraction tend to be 'smoothed out' and hence regions of high void fraction, or liquid slugs, are dissipated. For the momentum conservation equations Nickens uses forward averaging to evaluate pressure terms for both drillpipe and annulus flows.

Of the existing kicking well codes, that of Starrett et al (1988) probably employs the most accurate finite difference formulation. A fully implicit two-points backwards scheme is used for the gas and liquid mass balance equations, while a partially implicit and partially explicit one-point backwards scheme is selected for the mixture momentum equation. Modifications are required near to boundaries since only one-point backwards schemes may be used there.

14.2 Code Solution Algorithms

The seemingly most obvious way of solving the finite difference equations in a kicking well code involves tracking from the mud pumps down towards the bit and then up the annulus towards the well outlet, calculating fluid flow properties for each fluid section in turn. This approach determines the algorithm employed in several of the existing gas kick simulators. Predictor-corrector techniques are applied to each individual fluid section in order to simultaneously solve the equations linking velocities, densities and pressures. Calculations for individual fluid sections differ in each code. For instance, the KICK code (Podio and Yang, 1986) employs a Lagrangian solution technique, representing a moving boundary solution. Other codes use an Eulerian solution technique (a fixed grid space solution). It should be noted that in the Starrett et al (1988) code only the two-phase region is divided into a system of grids.

Boundary conditions may exist at each end of the fluid flow path in a well - for example: mud pump characteristics define the flow rate at the drillpipe inlet; if the flow is not choked the outlet pressure should equal atmospheric pressure; if the well is shut-in the outlet velocity should be zero; if the choke position is specified the outlet pressure and velocity are linked according to the choke characteristics. The exception is when a perfect well kill operation is simulated, in which case there is a solution boundary condition defining the pressure at bottomhole, with the choke setting determined from the calculated outlet properties. As a consequence

of having boundary conditions at different locations in the well it is necessary to employ an iterative solution algorithm at each time-step to satisfy all boundary restrictions to within a specified tolerance.

The scheme of solving for flow by fluids down the drillpipe and then up the annulus is not adopted in simulators which do not model a drillpipe (eg Thomas et al, 1982; Starrett et al, 1988), nor in the Nickens code (1985a). In fact, in the Thomas et al simulator (1982) the solution algorithm begins by estimating the annulus surface pressure and progresses down the annulus (against the direction of fluid flow) to establish a bottomhole pressure.

The solution algorithm adopted by Nickens (1985a) deserves particular discussion here. For each time-step the solution algorithm requires that an estimate be made of the bottomhole conditions (ie pressure and mud velocity). The mass and momentum equations are then solved, marching through each fluid section in the annulus up to the surface. This process is repeated, iterating the bottomhole pressure estimate until the annulus surface boundary condition is satisfied. In a perfect kill the bottomhole pressure is known a priori and so this iteration step is not required. Calculation then switches to the drillstring, beginning at the pump (applying the appropriate pump boundary condition) and stepping down to the bit. If the flow rate of mud through the bit calculated from these drillstring properties is significantly different to the flow rate used in the annulus calculations the flow in the annulus has to be re-calculated. The advantage of this approach adopted by Nickens is that the simple (mud

only) drillstring calculations are separated from the annulus calculations where both mud and gas have to be considered. Provided that the bottomhole mud velocity can be readily estimated this algorithm should ensure that computational effort is focussed within the annulus. When the bottomhole conditions are fluctuating considerably Nickens (1985a) scheme may be expected to require more computation than other more straight forward schemes, with annulus flows being iteratively calculated to satisfy an arbitrary boundary condition at bottomhole.

A more detailed discussion of solution algorithms is not presented here as this would require an excursion into the field of computational fluid mechanics. Instead this Section will be completed with an analysis of the solution time-steps employed in some of the kick codes.

The optimised solution time-step to be used in solving for fluid flows represents the maximum time-step which may be selected without introducing unacceptable errors to the calculations. Of the existing models described in Section 3 only that of Starrett et al (1988) is known to select solution time-steps automatically in order to prevent numerical instabilities.

Fischer and Dittmer (1975) report that KIKSIM simulations were performed using time-steps of between 30 and 300 seconds, but that the results of the simulations depend on the time-step value. Clearly these time-steps are too long for the KIKSIM algorithm.

Nickens (1985a) suggests maximum time-steps of 60 seconds for normal mud circulation, or 180 seconds during the shut-in period. During mud circulation Nickens typically selects a time-step of 10 to 15 seconds, reducing this to 1 to 2.5 seconds when transient effects are significant. A further constraint in the Nickens model requires time-steps to be short enough to ensure that the gas rise with respect to the mud is no greater than 100 ft for a single step.

In the Rogalands GASKICK model (Ekrann and Rommetveit, 1985) the code algorithm was not found to be robust, with particular difficulties after re-opening the choke. It is not clear whether or not this stability problem has been rectified in GASKICK.

Although details of the solution procedures are not available for all of the kick codes considered here it is clear that historically several different solution procedures have been chosen as the numerical basis for kick codes. As codes advance to model more the complicated flow pheonemena of gas slip, dispersion and solubility it is imperative that solution algorithms be robust, and highly desirable for simulation fluid section lengths and time-steps to be chosen according to the different flow characteristics expected for the different periods of the well control operation.

15. SIMULATOR OPERATIONAL PROCEDURES AND GRAPHICAL FACILITIES

It has already been noted that some kicking well simulators were designed for the teaching of well control principles, whereas others were aimed at specific research applications. As a consequence the simulators listed in Tables 1-6 all provide different operational facilities and graphical capabilities. Since these facilities do not influence (nor do they necessarily reflect) the physical and mathematical complexity of the models, this section will only provide a brief overview of simulator operational and graphical capabilities, addressing each individual model in turn.

Although not yet completed, the Schlumberger Cambridge Research code will contain a specially developed user-interface for input of data to the simulator and will support several proposed modes of code operation. In general, the more recent kicking well models have provided greater flexibility for the code-user than earlier models. For instance, the simple model described by LeBlanc and Lewis (1968) does not appear to allow the user to interact with the simulation of kick control once the initial conditions have been defined. For control of the well a 'perfect kill' is modelled; the annulus back pressure is calculated so as to maintain a constant bottomhole pressure.

Although little is known concerning the KIKSIM simulator (Fischer and Kastor, 1975; Dittmer and Fischer, 1976) it is understood that KIKSIM is able to simulate 'perfect' control operations. This may entail maintaining

a constant bottomhole pressure or, as in the Low Choke Pressure control method described by Fischer and Kastor (1975), also monitoring the casing shoe pressure to impose a boundary condition that the fracture gradient is never exceeded (regardless of the bottomhole pressure).

The Hoberock and Stanbery model (1981a, 1981b) is also used to simulate perfect kill operations. An alternative use of the code described by Hoberock and Stanbery (1981b) enables close fitting of simulator results to experimental data. An automatic curve tracker is used, enabling the choke control operations during the simulation to be automatically adjusted so that simulated results match the experimental well casing pressure variations. No other simulator is known to have such a facility to define the pressure history required at any location in the well, other than bottomhole.

Since the Thomas et al (1982) model does not simulate well control procedures there is no need for user-interaction with the model except to define the conditions to be simulated.

Of all the kicking well models discussed here and in Section 3, the Nickens (1985a, 1985b) model offers the widest selection of simulated choke control capabilities, representing well control operations of varying expertise. The four choices are:

(i) Perfect Controller: the choke setting is calculated so that a constant bottomhole pressure is maintained at all times

(ii) Novice Controller: at each simulation time-step the choke setting is adjusted so as to ensure that the drillpipe pressure never deviates from a user-specified control band (defined according to the ideal drillpipe pressure history). No account is made for the time delay required for choke adjustments to propagate to the drillpipe pressure guage, and so the novice controller typically over-estimates the degree to which the choke should be opened or closed.

(iii) Good Controller: the good controller also bases choke variations on the existing drillpipe pressures, but after each choke adjustment the code waits for a specified delay time before re-assessing drillpipe pressure. This removes the rather dramatic well pressure fluctuations which can occur when the code simulates a "novice controller".

(iv) Automatic Controller: the automatic controller calculates the adjustment required to bring the drill pipe pressure back into the control range, according to the theoretical choke flow/pressure drop characteristic curves. This is possible because a single flow rate versus pressure drop curve is assumed to exist for each choke setting. In two-phase choke flow, however, these characteristic curves no longer apply. It is not

clear how the Nickens Automatic Controller calculates the choke adjustments required when both mud and gas pass through the choke.

Unlike any of the four models already discussed, the Rogaland GASKICK simulator provides interactive graphics facilities (Ekrann and Rommetveit, 1985) to allow the code-user to monitor the status of the well and control operations during a simulation. This simulator is also capable of executing a 'perfect' kill, by defining the bottomhole pressure as a boundary condition which has to be satisfied during the numerical calculations.

The KICK model (Podio and Yang, 1986) is operated by an extensive menu system by which the code-user selects the well definition and control operations to be simulated. During the KICK run the control variables (mud flow rate, mud density, choke setting) may be selected by the user, or the 'automatic control' option may be invoked. Under automatic control the code: detects when a kick has occurred (by checking the pit level), determines when the well should be shut-in (by delaying for an 'alarm time'), shuts-in the well (for a specified shut-in time), begins kill mud circulation (at half of the maximum mud pump rate), and maintains an ideal overbalance at bottomhole. The pit level increases, time delays and acquired bottomhole overbalance are all selected by the KICK user. Perfect choke control may only continue for a particular (user-specified) time after which choke control switches from 'automatic' to 'experienced' mode.

In the experienced choke control mode the choke is adjusted at each time-step, according to the bottomhole pressure calculated for the previous time step. As with the Nickens (1985b) novice controller the neglect of propagation times when determining choke operations may lead to severe fluctuations in the selected choke settings and, therefore, well pressures.

The KICK code does employ a simple interactive graphics facility (selected via the menu system), allowing the user to view snapshot profiles of the pressures, velocities, fluid densities and gas void fractions in the well.

As discussed in Section 3, the Whitman and Evers (1987) model may be operated in one of two modes. The demonstration mode allows the simulation of a perfect kill, following either the Driller's method or the Weight-and-Wait method. In the control mode the code user selects mud density, pump rate and choke setting to be applied through-out the simulation. The code is written with a user-friendly capability to warn the user of incorrect procedures which would result in secondary kicks (bottomhole pressure too low) or formation fracture (casing shoe pressure too high).

During a simulation with the Whitman and Evers (1987) code a colour, scale picture of the well is displayed on the microcomputer screen, clearly displaying the numerical parameters defining the status of the well, and the location of various fluids within the well. After simulation graphs

are produced to show variation of various well pressures as a function of the total number of pump strokes.

Very little is known concerning the operational and graphical facilities in the GASKICKS simulator (Swanson et al, 1988). Kill mud circulation and choke control actions are modelled, but no information is presented to define any automatic well control operations which may be selected.

The Starrett et al (1988) kicking well code is not required to offer sophisticated operational procedures and interactive graphics facilities to guide code users through a simulation, since the code does not model the control of kicks via choke and mud variations.

The final model to be discussed in this summary of kicking well code facilities is the Miller and Juvkam-Wold (1989) program. Although written in BASIC, this program "relies almost exclusively on colour graphics to present as much information to the user as possible". A pictorial snapshot of the well, together with a pit gain monitor, is displayed throughout the simulation, with graph-plotting screens also available to display plots at pressures at key locations in the well. These graphs may be accessed via the menu system used to operate this code, and analysed interactively using a keyboard cursor.

In conclusion, it can be seen that even a BASIC simulator (Miller and Juvkam-Wold, 1989) can offer interactive graphics, user-friendly menus, and

facilities to define well and fluid properties via either interactive input to the code or the use of a disk-based input data file. As computing facilities are continually able to support more and more sophisticated programs and user-interactive facilities it is clearly desirable that new kick simulators should be capable of offering user-friendly input facilities, interactive graphics capabilities and a selection of different 'modes of operation' to automatically compare different well control procedures.

16 SUMMARY AND CONCLUDING REMARKS

This report considers several kicking well computer models which have been described in the open literature. These models are compared with respect to their physical representation of the kicking well problem, the assumptions and simplifications employed and the operational procedures offered to the user. The modelling of mud and gas fluid behaviour as relevant to gas kicks in wells is discussed in detail, with an overview of possible equations and correlations which could be used in kicking well models. It is noted that experimental and theoretical investigation is needed to support the physical modelling of mud/gas flows, well temperature profiles, downhole mud rheologies and kick gas solubility as relevant to gas kicks.

None of the existing kicking well models considered offers both a sophisticated representation of the kicking well problem and a robust, accurate solution method to include all of the dynamic effects taking place

during kick control operations. It is hoped that new codes under development, such as the programme of work underway at Schlumberger Cambridge Research, (under the sponsorship of the UK Department of Energy) will offer more of the modelling components required of a sophisticated kick code.

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TABLE 1: WELLBORE GEOMETRIES AND PHYSICAL PROPERTIES MODELLED IN EARLY KICK SIMULATORS

	LeBlanc and Lewis (1968)	Fischer et al (1975) - KIKSIM	Stanbery (1976) Moberock and Stanbery (1981a, 1981b)	Thomas et al (1982)
Include Drillstring	Yes	?	Yes	No
Cross-section Changes	Only at bit	Yes	No	Yes
Inclined Wells	No	No	No	No
Model Choke/Kill Line	No	No	No	Yes, for single phase mud only.
Choke Model	No choke model - code calculates required annulus back pressure	No choke model - code calculates required annulus back pressure	Simple choke model - no account made for two-phase flows	No choke model - kick control operations not simulated
Blowout Preventers	Assumed closed	Not specified	Assumed closed?	BOPs not employed.
Wellbore Temperature Profile	Constant linear temperature gradient	Specified surface and bottom hole temperatures. (Constant linear gradient?)	Constant temperature	Constant linear temperature gradient.
Bit-off-Bottom Calculations	No	No	No	No
Formation Breakdown	Neglected	Detects formation breakdown	Neglected	Neglected
Mud Pumps	Source of specified mud volumetric flow rate	Source of specified mud volumetric flow rate	Flow rate depends on pump settings and pump discharge pressure	Source of specified mud volumetric flow rate

TABLE 2: WELLBORE GEOMETRIES AND PHYSICAL PROPERTIES MODELLED IN RECENT KICK SIMULATORS

	Ekrann and Rommetveit (1985), Rommetveit et al (1989) - GASKICK	Nickens (1985)	Podio and Yang (1986) - KICK	Whitman and Evers (1987)	Starrett et al (1988)	Swanson et al (1988) - GASKICKS	Miller and Juvkam-Wold (1989)
Include Drillstring	Yes	Yes	Yes	No	No	No	Yes
Cross-section Changes	Yes	Yes	Yes	Yes (in annulus)	No	Yes	Yes
Inclined Wells	Yes	No	Yes	No	No	No	No
Model Choke/Kill Line	Yes	Yes	Yes	No	Horizontal diverter line	Yes	Yes
Choke Model	Choke model allows single or two-phase flow; for critical or sub-critical conditions	Model based on correlation for sub-surface safety valves	Choke model allows for critical or sub-critical conditions	Simple model for choke pressure loss - no account made for two-phase flows	No choke model	Not specified	Not specified
Blowout Preventers	Operation of BOPs not specified	Closure of BOPs modelled. Model partially open BOP as ideal annular orifice	Assumed closed when choke not fully open. BOP closure instantaneous	Not specified.	BOPs not employed	Not specified	BOP closure is instantaneous
Wellbore Temperature Profile	Details of temperature profile not specified.	Constant linear temperature gradient	Constant linear temperature gradient.	?	Constant linear temperature gradient	Temperature profile calculated from Holmes-Swift model	Constant linear temperature gradient
Bit-off-Bottom Calculations	No	No	Yes, as well as Bit-on-Bottom	No	No	No	No
Formation Breakdown	?	Neglected	Detects formation break down and crudely models lost circulation.	Simulator gives warning if casing shoe pressure exceeds fracture gradient.	Neglected	Neglected	Neglected
Mud Pumps	Flow rate depends on pump settings and pump discharge pressure	Source of specified mud volumetric flow rate	Source of specified mud volumetric flow rate	Source of specified mud volumetric flow rate	Source of specified mud volumetric flow rate	Source of specified mud volumetric flow rate	Source of specified mud volumetric flow rate

TABLE 3: FLUID PROPERTIES INCLUDED IN EARLY KICK SIMULATORS

	LeBlanc and Lewis (1968)	Fischer et al (1975) - KIKSIM	Stanbery (1976) Moberock and Stanbery (1981a, 1981b)	Thomas et al (1982)
Mud Compressibility	Constant Density	?	Constant Bulk Modulus of Compression	Density based on oil properties
Gas Density	Equations derived from Standing-Katz isotherms	?	Ideal gas	Amoco Redlich - Kwong equation of state
Non-Newtonian Mud Rheology	Rheology not required in simulator	Not specified	Bingham Plastic Model	Bingham Plastic or Power Law model
Downhole Changes in Mud Rheology	No	No	No	No
Gas Inflow	Not modelled	Not specified	Variable inflow rate not modelled?	Radial flow equation simulated
Mud/Gas Distribution	Gas region modelled as single bubble (100% void fraction)	Gas region may occupy several fluid sections. Variable void fraction?	Gas region modelled as a single region homo-geneous, time-varying	Gas/mud contents calculated separately for each fluid section
Gas Slip	No	No	Yes - slug flow equation	Yes - slug flow equation
Gas Dispersion	No	No	No	No
Two-Phase Frictional Pressure Drops	Not modelled	Equations no specified. May neglect two-phase nature of flow.	Beggs and Brill correlation.	Beggs and Brill correlation.
Gas Solubility	No	No	No	Yes - using gas-oil correlations
Mud Density Change on Gas Dissolution	No	No	No void fraction.	Yes - using oil property correlation
Kill Mud	Two mud densities - kill mud and original mud?	Not specified	Kill mud identical to original mud	No kill mud (well control not modelled)

TABLE 4: FLUID PROPERTIES INCLUDED IN RECENT KICK SIMULATORS

	Ekrann and Rommetveit (1985), Rommetveit et al (1989) - GASKICK	Nickens (1985)	Podio and Yang (1986) - KICK	Whitman and Evers (1987)	Starrett et al (1988)	Swanson et al (1988) - GASKICKS	Miller and Juvkam-Wold (1989)
Mud compressibility	Mud density model incorporates oil, water and solid fractions	Mud density model incorporates water and solid fractions	Density proportional to pressure	Constant density?	Constant density	Mud density model incorporates oil, water and solid fractions	Constant density
Gas Density	Redlich-Kwong or Hall-Yarborough equation of state	Amoco Redlich-Kwong equation of state	Hall-Yarborough equation of state	Real gas - equations not specified	Real gas compressibility factor - equations not specified	Peng-Robinson equation of state	Sutton correlation, (including H_2S and CO_2).
Non-Newtonian Mud Rheology	Bingham Plastic or Power Low model	Input Bingham Plastic parameters. Calculations use Power Law model.	Input Bingham Plastic parameters. Calculations use Power Low model.	Rheology not required in simulator	Rheology not specified	Herschel-Bulkley model	Rheology not required in simulator
Downhole Changes in Mud Rheology	Yes, Rheology affected by pressure, temperature and gas dissolution	No	No	No	No	Yes	No
Gas Inflow	Radial flow equation	Radial flow equation. Divide reservoir into horizontal segments.	Radial flow equation	Not modelled	Radial flow equation	Radial flow equation	Radial flow equation. Account for changes in bottomhole pressure by using super position. Include skin effect.
Mud/Gas Distribution	Gas/mud contents calculated for each fluid section	Gas/mud contents calculated for each fluid section. No gas enters drillstring	Gas/mud contents calculated for each fluid section. Lagrangion technique allows for numerous gas/mud surfaces.	Gas modelled as a single bubble	Gas/mud contents calculated for each fluid section	Gas/mud contents calculated for each fluid section	Gas distribution modelled as a sequence of bubbles (100% void fraction) interspersed between mud slugs
Gas Slip	Yes - bubble or slug flow regimes	Yes - bubble or slug flow regimes	Yes - constant slip velocity	No	Yes, using Aziz et al correlation	Yes - using Aziz et al correlation	Yes - using Rader et al correlation
Gas Dispersion	No	No	No	No	No	Yes	No
Two-Phase Frictional Pressure Drops	Choice of five alternative correlations.	Beggs and Brill correlation	Apply simple viscosity correction to single phase pressure drop	Not modelled	Aziz et al correlation	Aziz et al correlation	Not modelled

TABLE 4: FLUID PROPERTIES INCLUDED IN RECENT KICK SIMULATORS- (continued)

	Ekrann and Rommetveit (1985), Rommetveit et al (1989) - GASKICK	Nickens (1985)	Podio and Yang (1986) - KICK	Whitman and Evers (1987)	Starrett et al (1988)	Swanson et al (1988) - GASKICKS	Miller and Juvkam-Wold (1989)
Gas Solubility	Yes - using gas-oil ratio correlation or experimental data tables. Dissolution rate from diffusion model.	No	No	No	No	Yes - using O'Bryan et al correlation	No
Mud Density Change on Gas Dissolution	Yes - formation-volume-factor correlation for oil component, or experimental data tables	No	No	No	No	Yes - from an empirical model	No
Kill Mud	Several mud types allowed for each simulation.	Kill mud has different density and viscosity to original	Pumped mud density may be varied at each time-step. Rheology not varied.	Two mud types - kill mud and original mud	No kill mud (well control not modelled).	Two mud types - kill mud and original mud.	Two mud types - kill mud and original mud.

TABLE 5: MODELLING AND OPERATIONAL CAPABILITIES IN EARLY KICK SIMULATORS

	LeBlanc and Lewis (1968)	Fischer et al (1975) - KIKSIM	Stanbery (1976) Moberock and Stanbery (1981a, 1981b)	Thomas et al (1982)
Options for Automatic Kick Detection and Control Procedures	After shut-in, automatic control of kick (selects annulus back pressure to give constant BHP)	Selects annulus back pressure to give constant BHP. Also models Low Choke Pressure method of control - open choke automatically if fracture pressure exceeded.	Car model or perfect choke control (to give constant BHP) or vary choke setting to match experimental data for causing pressure.	Kick control not modelled correlation.
Multiple Kicks	No	Yes	No	No
Interactive Graphics	No	No	No	No

TABLE 6: MODELLING AND OPERATIONAL CAPABILITIES IN RECENT KICK SIMULATORS

	Ekrann and Rommetveit (1985), Rommetreit et al (1989) - GASKICK	Nickens (1985)	Podio and Yang (1986) - KICK	Whitman and Evers (1987)	Starrett et al (1988)	Swanson et al (1988) - GASKICKS	Miller and Juvkam-Wold (1989)
Options for Automatic Kick Detection and Control Procedures	Can simulate a perfect kill.	Automatic kick detection from changes in pit gain or pump pressure. Offers four simulated types of choke control: Perfect, Novice, Good and Automatic.	Automatic kick detection from changes in pit gain. Options to kill well using perfect choke control.	Can simulate a perfect kill.	Kick control not modelled.	Not specified	Can simulate a perfect kill.
Multiple Kicks	Not specified.	No	Yes	No	No	Yes	Not specified.
Interactive Graphics	Yes	No	Yes - simple plots of pressure, velocity density and void fraction distributions downhole.	Yes - scale schematic diagram of well showing location of fluid interfaces. Graphics in colour.	No	No	Yes - schematic of well together with plots of pressure variations at key points in system. Graphics in colour.

TABLE 7: GAS PSEUDO-CRITICAL PROPERTIES FROM GAS GRAVITY

Kicking Well Model	Pseudo-Critical Pressure	Pseudo-Critical Temperature
LeBlanc, Lewis (1986)	$702 - 50\ g$	$213.5 + 245\ g$
Podio, Yang (1986)	$708.75 - 57.5\ g$	$169 + 314\ g$
Miller, Juvkam-Wold (1989)*	$756.8 - 131\ g - 3.6\ g^2$	$169.2 + 349.5\ g - 74\ g^2$

g = gas gravity

*These pseudo-critical values are modified according to the relative abundance of CO_2 and H_2S in the gas mixture.

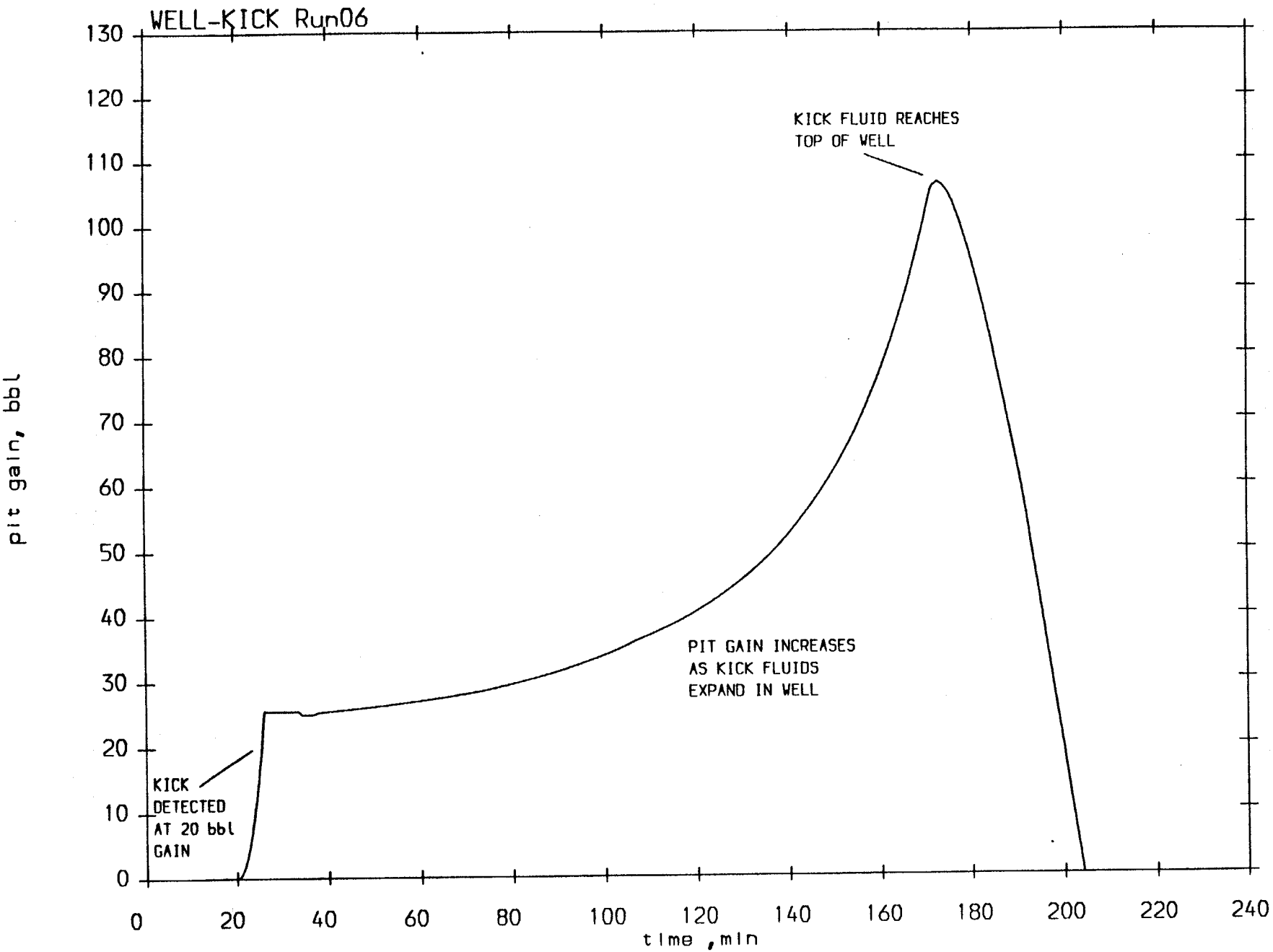


Figure 1 EXAMPLE SIMULATOR PREDICTIONS - PIT LEVEL VARIATION
(PERFECT CONTROLLER)

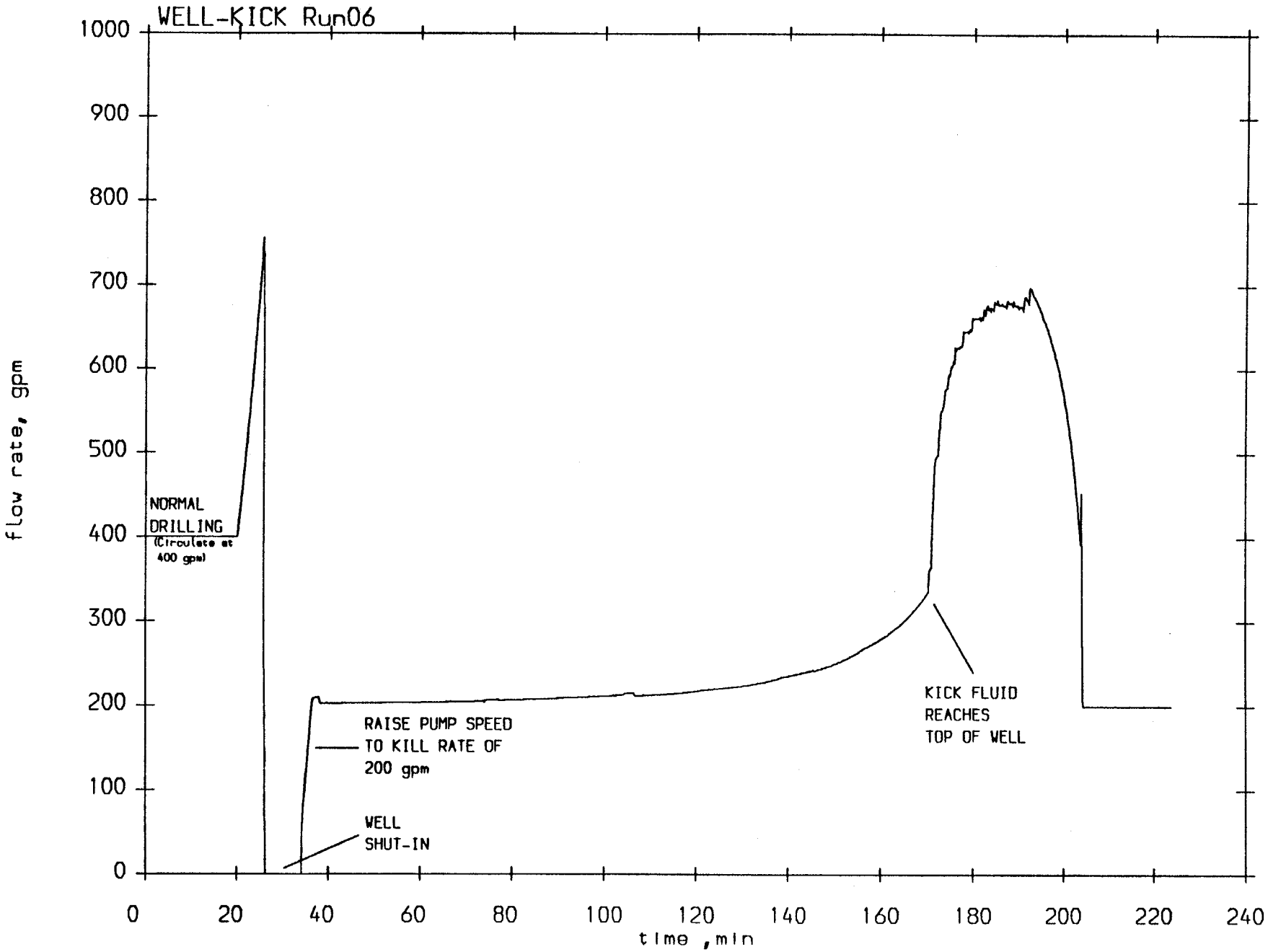


Figure 2 EXAMPLE SIMULATOR PREDICTIONS - FLUID OUTFLOW RATE VARIATION (PERFECT CONTROL)

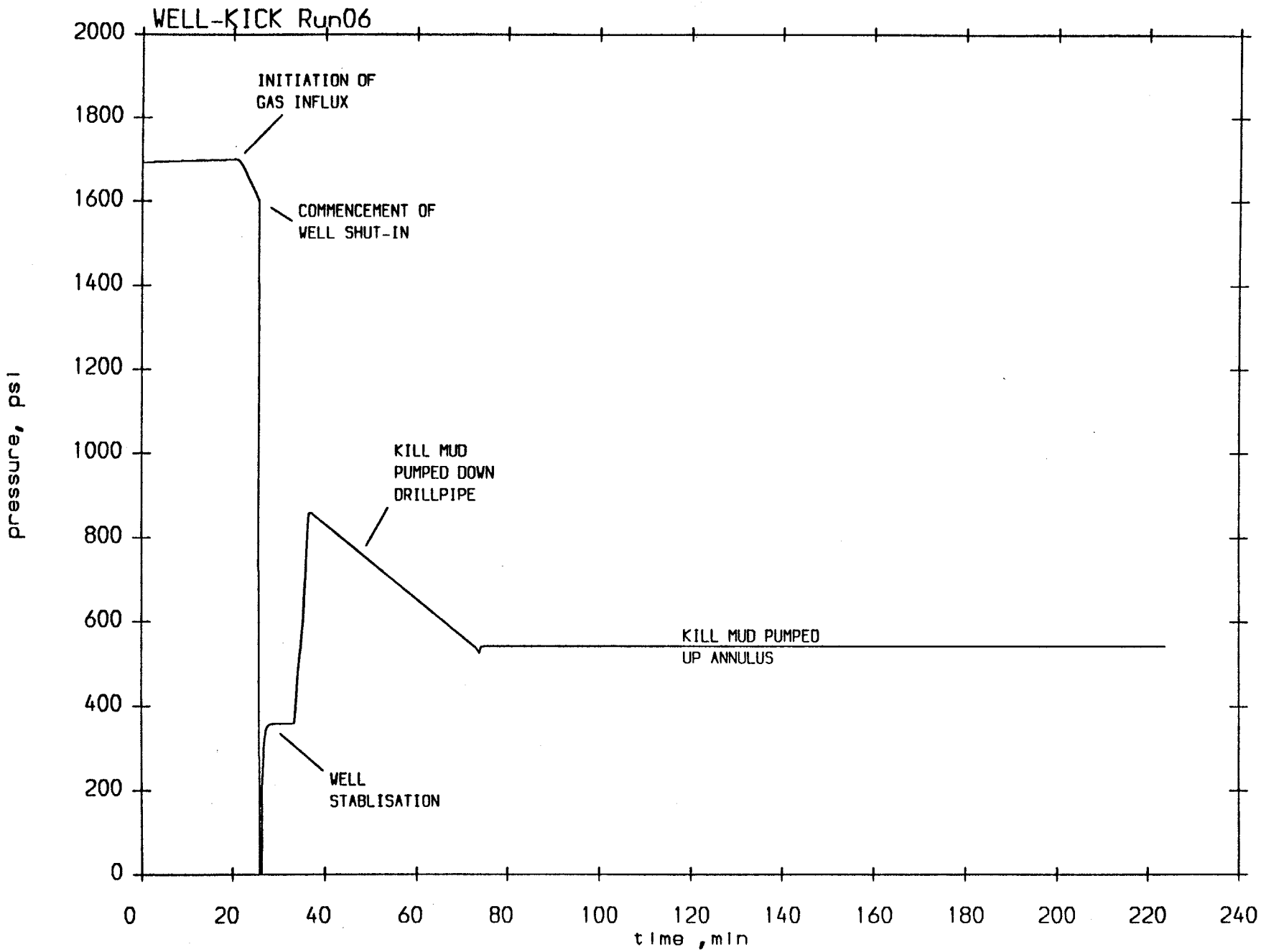


Figure 3 EXAMPLE SIMULATOR PREDICTIONS - DRILLPIPE PRESSURE VARIATION
(PERFECT CONTROLLER)

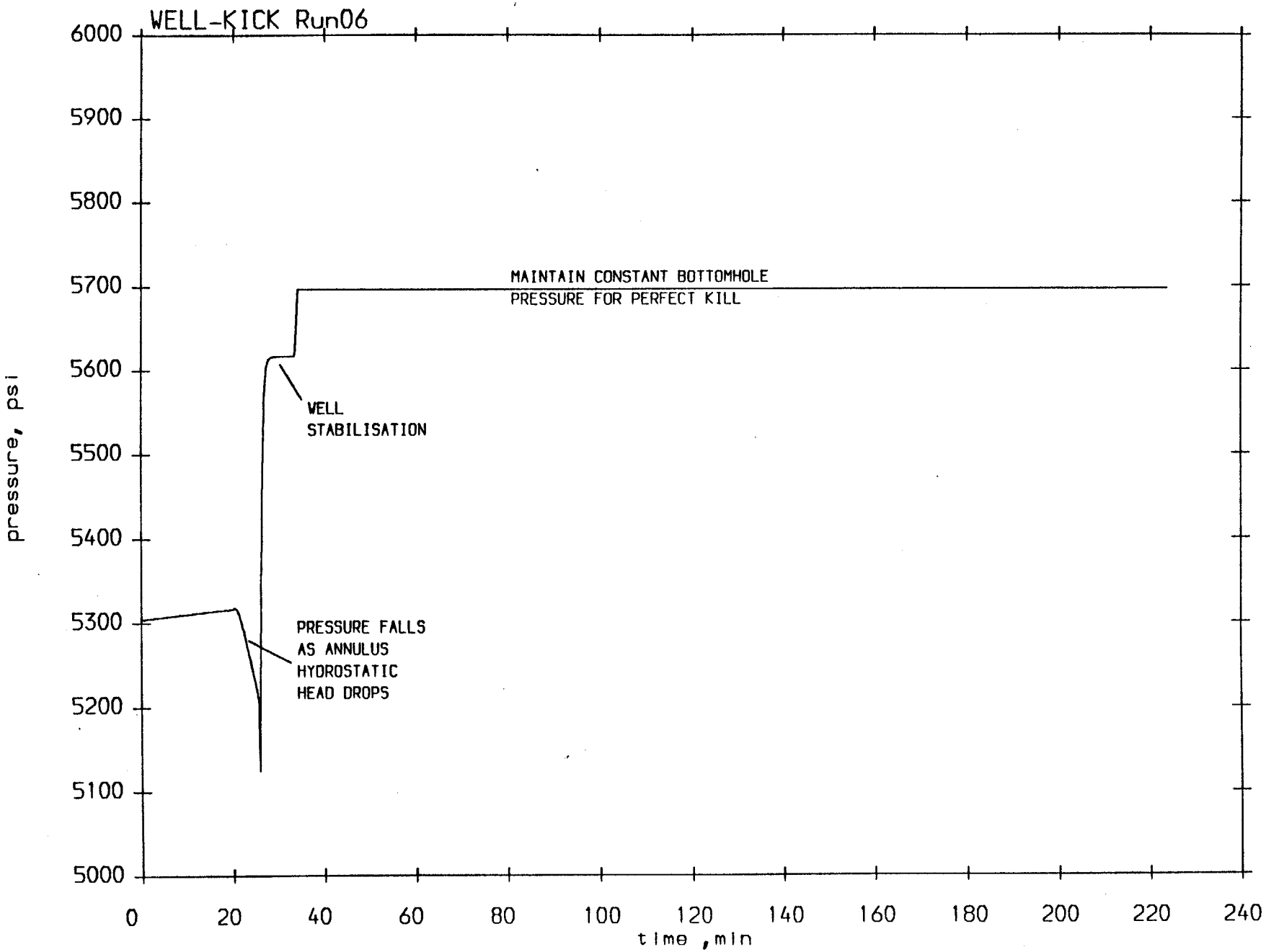


Figure 4 EXAMPLE SIMULATOR PREDICTIONS - BOTTOMHOLE PRESSURE VARIATION (PERFECT CONTROLLER)

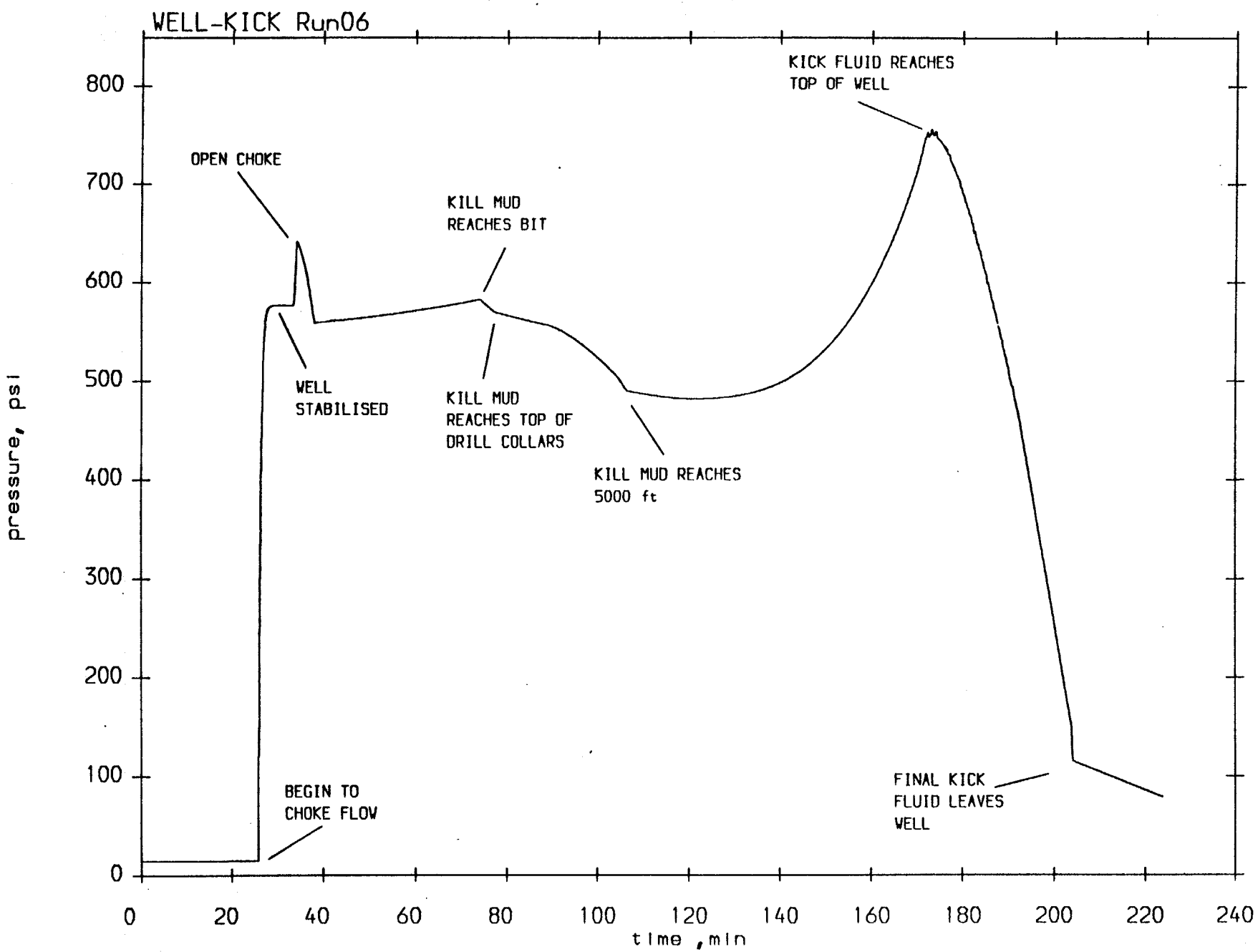


Figure 5 EXAMPLE SIMULATOR PREDICTIONS - CASING PRESSURE VARIATION (PERFECT CONTROLLER)

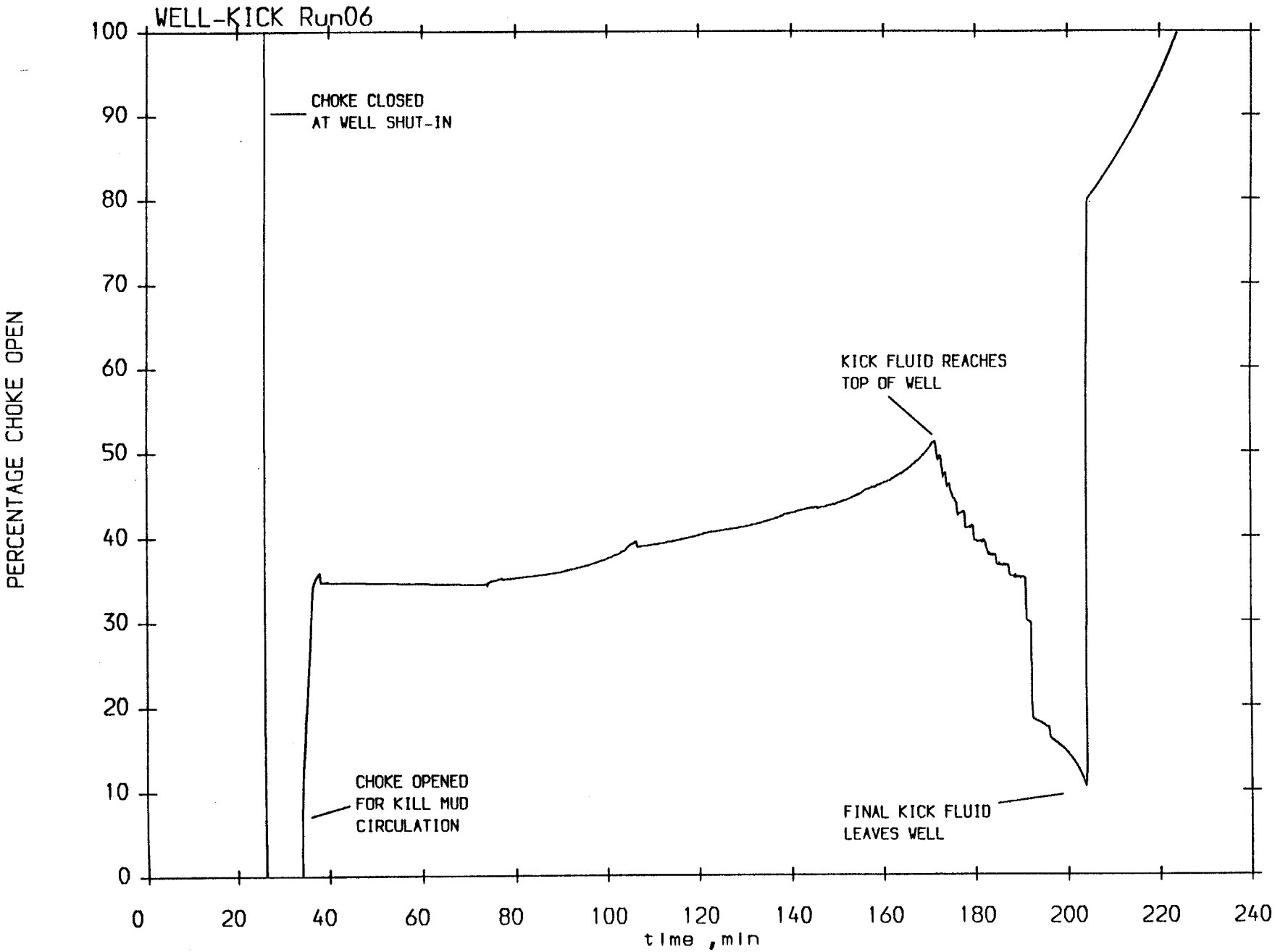


Figure 6 EXAMPLE SIMULATOR PREDICTIONS - CHOKE VARIATIONS
(PERFECT CONTROLLER)

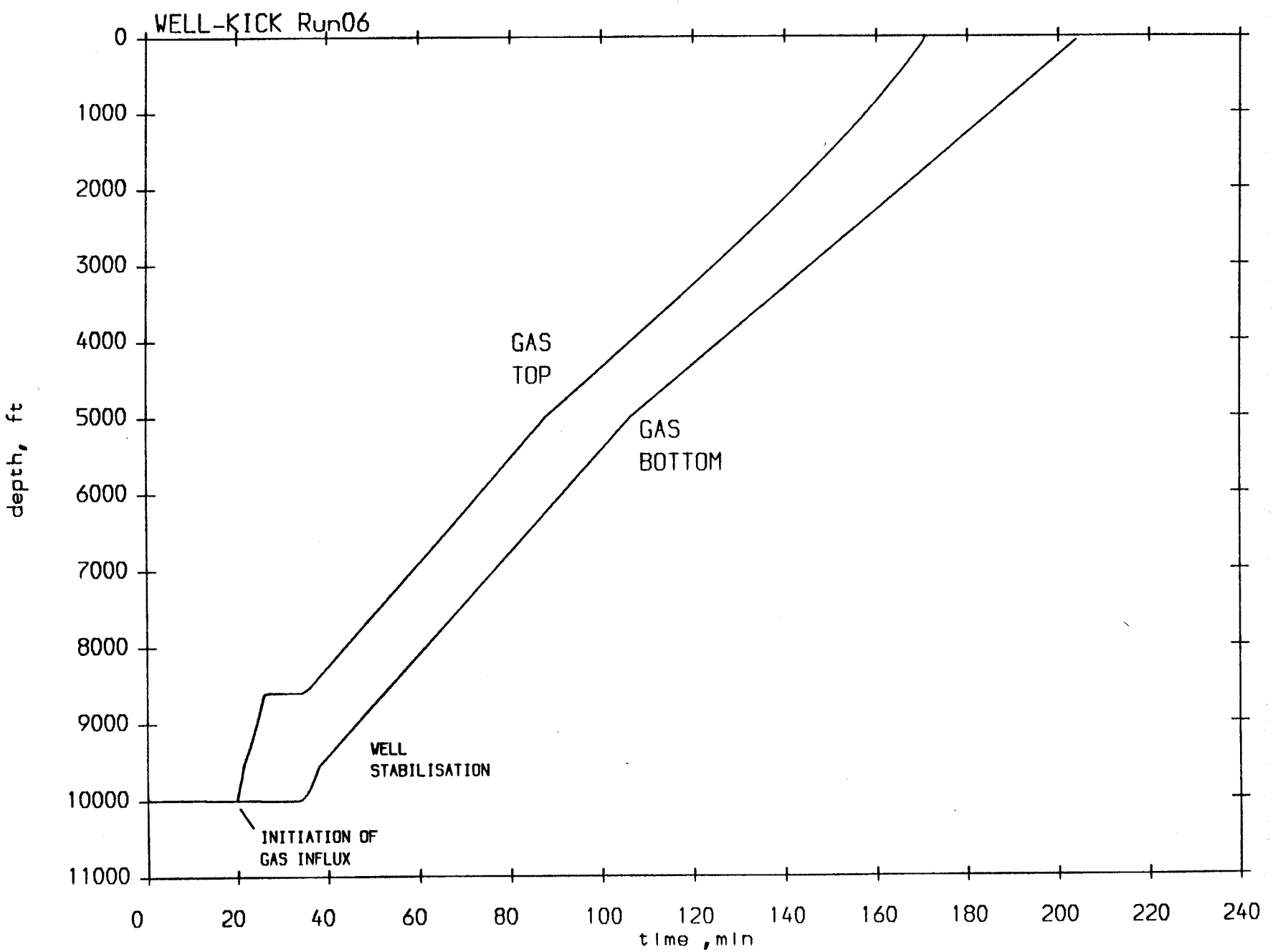
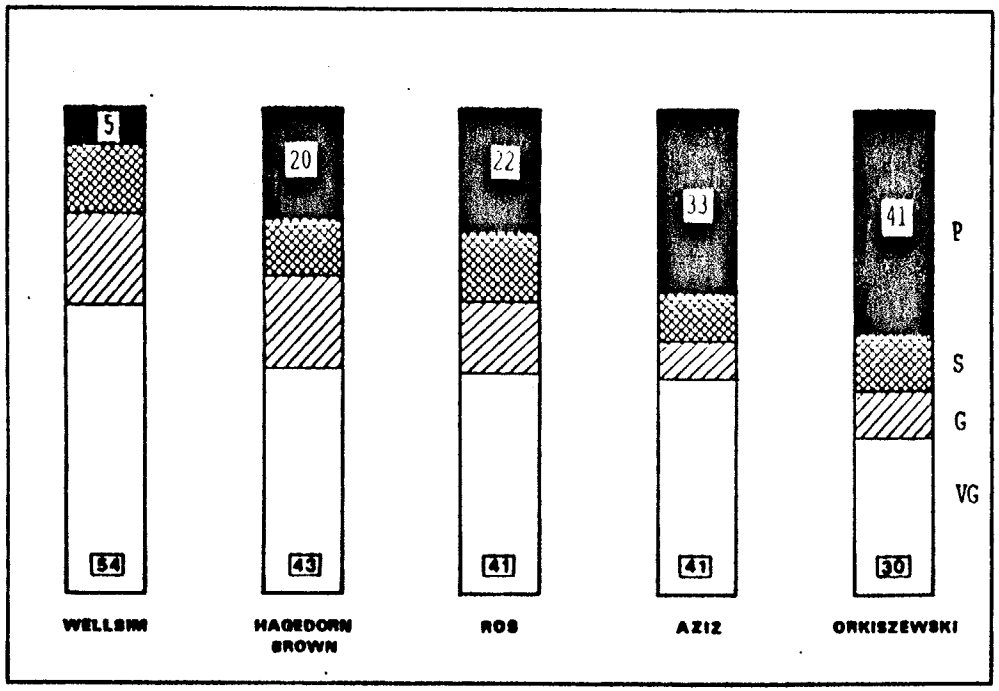


Figure 7 EXAMPLE SIMULATOR PREDICTIONS - PROGRESS OF GAS REGION THROUGH WELL
(PERFECT CONTROLLER)



Key for predictions of two-phase pressure drop correlations:

VG : Very Good

G : Good

S : Satisfactory

P : Poor

Figure 8 Comparison of Calculation Methods on a 90 Wells Data Set (From Ozon et al, 1987)

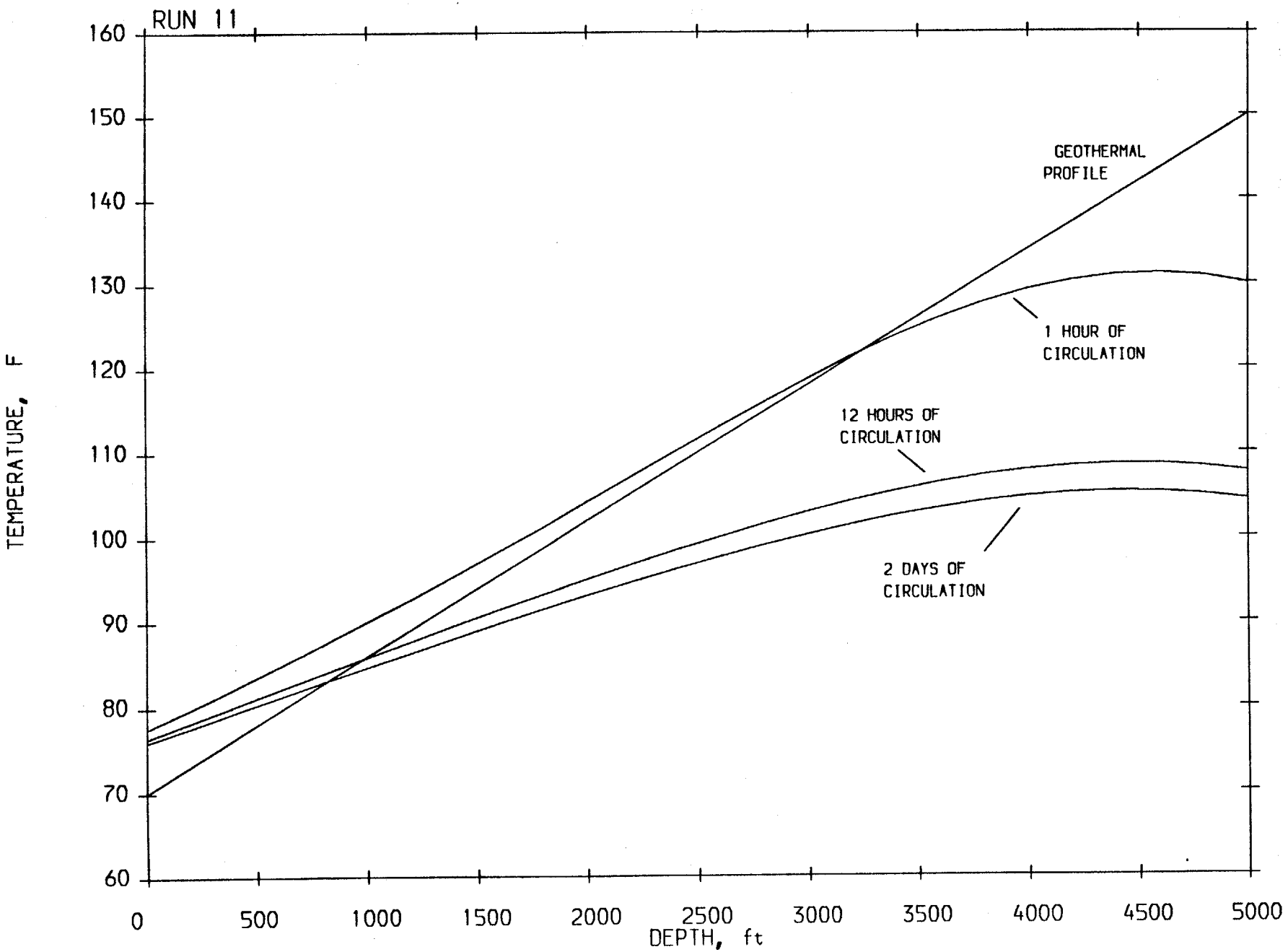


Figure 9 ANNULUS TEMPERATURE PROFILE, MUD CIRCULATION RATE 100 gpm

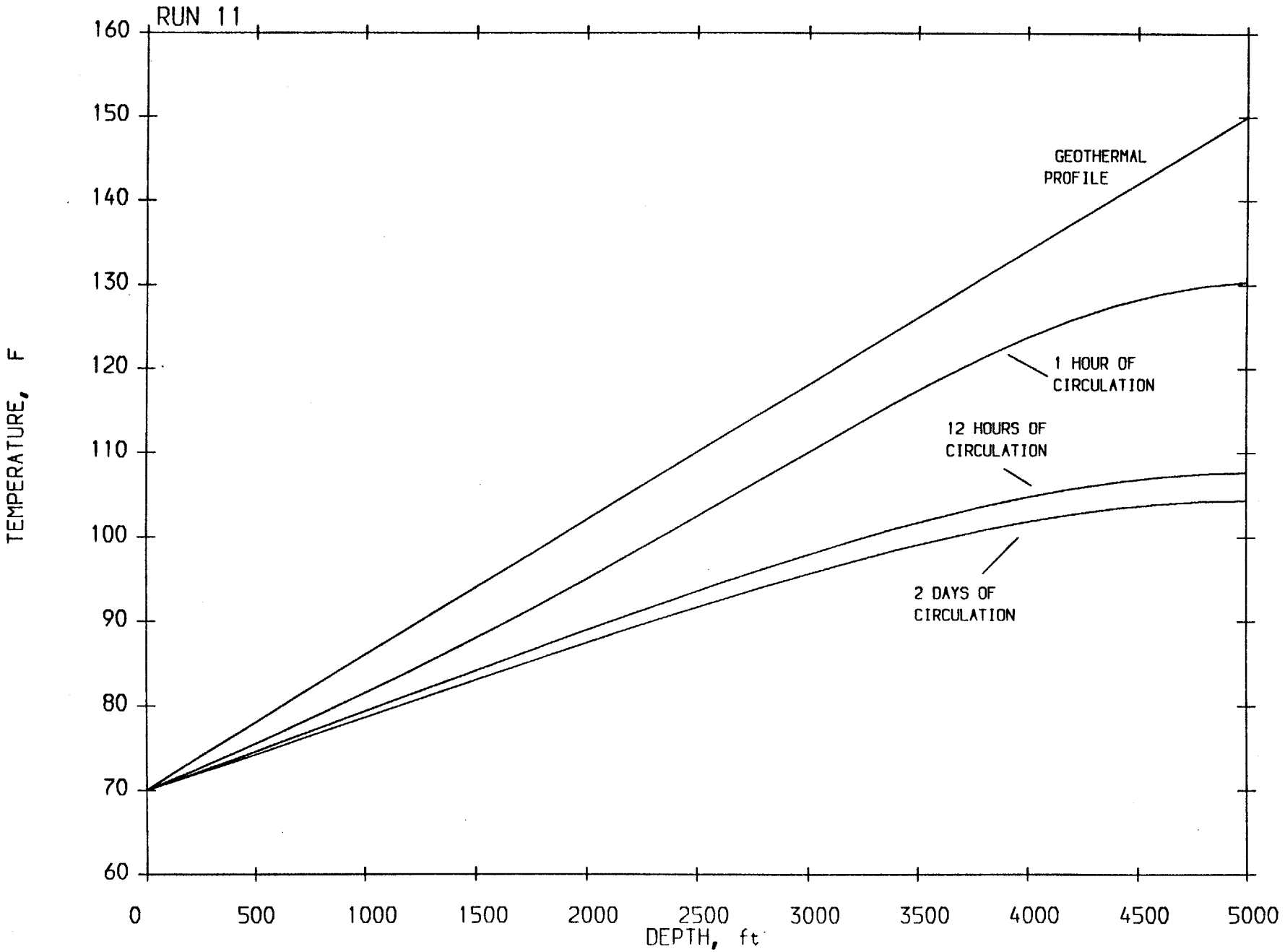


Figure 10 DRILLPIPE TEMPERATURE PROFILE, MUD CIRCULATION RATE 100 gpm

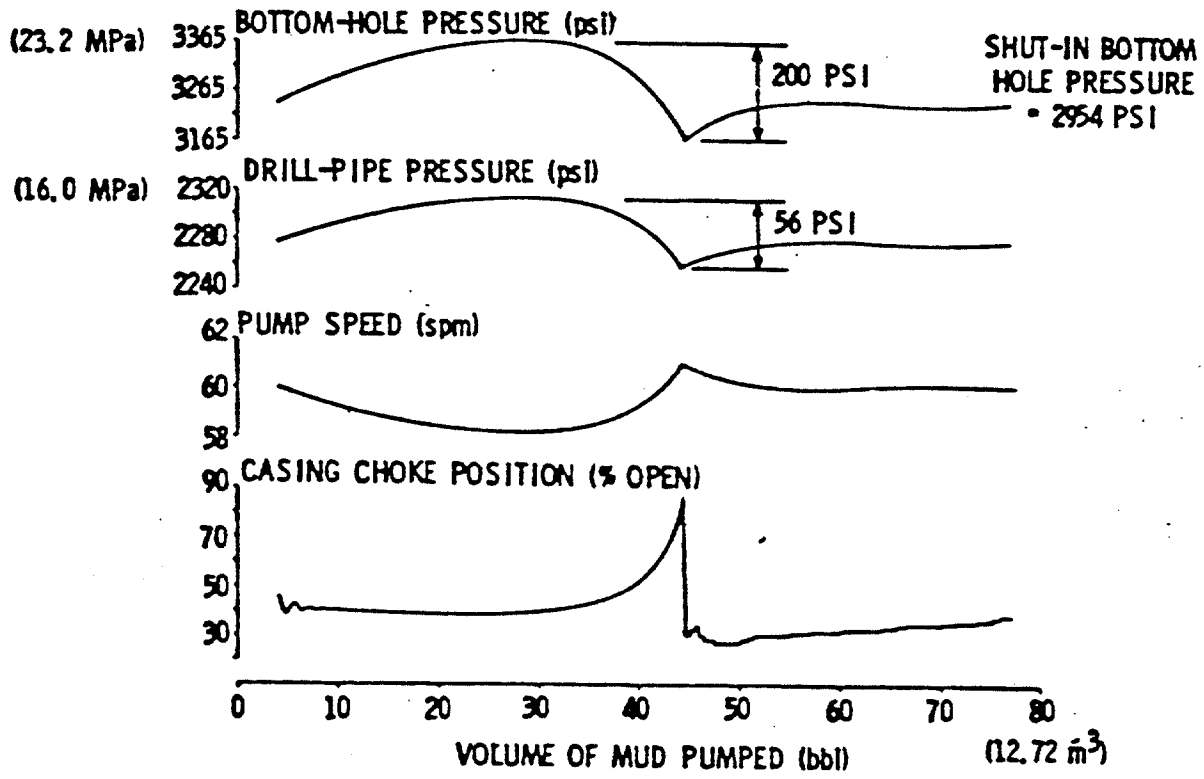


Figure 11 Variations of Pump Speed with Discharge Pressure
(From Hoberock and Stanbery, 1981b)

Distribution

A T D Butland 343/B41
C A Cooper 340/B41
D J Element 333/B41
L M Wickens 339/B41

A New Two Phase Flow Model of Kick Control

Shohei KATO, Japan Drilling Co., Ltd.

ABSTRACT

Behavior of gas kick has been discussed as a function of the expansion, gas void fraction, flow pattern and pressure losses in most existing two phase models.

We are convinced that the behavior is determined mainly by the slip of gas bubbles. The slip velocity is governed by bubble diameter and fluid densities and is slowed down by crowdedness of surrounding bubbles.

A new two phase model was developed on the slip velocity model with initial diameter input and assumption of no coalescence nor breakage of bubbles.

Evaluations proved that the developed model is realistic. Problems on kick simulation still remain but they are far simplified now.

INTRODUCTION

In the past, many simulation models of kick control have been developed. On the way of the development, it has been recognized that gas distribution is absolutely necessary in order to have a realistic simulation model since it decides the kick behavior. Therefore, two phase flow model was introduced and the works to determine the gas distribution have been conducted by many engineers.

They tried first to determine the initial gas-influx distribution and

obtained exquisite models. Meanwhile, gas slip velocities are necessary to decide the gas distribution during kick killing operation. The velocities have been given arbitrarily or determined with flow pattern. The flow pattern is extremely phenomenal and many factors are involved to decide it. Even the factors are clarified, the flow pattern can not be specified because the flow pattern itself is still in controversy. So, in this way, we can not have a clear gas slip model until the flow pattern theory is established and then modified to be applied to well conditions.

But the slip velocity of gas bubble has been found more simply determined by the bubble size, which allowed us to develop a good slip model with some factors taken into consideration. The factors could be determined comparatively easily. This approach allowed also to consider a slow-down effect of slip velocity due to the crowdedness of bubbles.

As key factor to determine the kick behavior, the initial gas distribution was formulated in order to simulate a given gas influx. The temperature distribution in annulus was approximated by results of computer simulation of previous worker.

The other factors to be incorporated in the kick simulation model were also studied.

This paper summerizes the developed model, describing the factors briefly, and discusses the resulted performance of the model.

BASIC ASSUMPTIONS

Basic assumptions are proposed prior to the development of a two phase flow kick simulation program for a mini computer.

(1) Well geometry is such as shown in FIG.1.

(2) Only a gas kick influxed to bottomhole while drilling is to be

handled.

(3) Perfect control is to be conducted. Excess back pressure can be applied at the choke in order to maintain a given overbalance pressure on the bottom.

(4) Drilling fluid is water based mud and no gas is to be solved in.

(5) The effects of cuttings are to be neglected.

(6) Loss of mud is not considered.

MATHEMATICAL MODEL

Flow in the annulus is relatively slow while killing kick and the condition is considered in pseudo-steady state. As our main objective is to simulate the casing pressures and pit gain while circulating out a kick, it is not practical to follow the instantaneous transient change at the time of starting pump. Consequently, it is not necessary to adopt a transient model which consumes long calculation time, but pseudo-steady model of moving boundary is sufficient. The moving boundary method divides the fluid itself into many cells and traces the time-domain changes of the cells. In this way, we can make the time step much longer than in a transient model using fixed mesh of wellbore. Also the mass balance between cells is simplified. The pressure drop in a cell is a function of mean density and mean velocity in the cell which are calculated in conjunction with the position.

Cells are made only in the two phase flow part in the annulus and choke line in order to make the calculation time short, because it is not necessary to analyze uncompressive mud with a constant pressure gradient in that way. The concept of cells is shown in FIG.2.

Once the calculation starts, the gas rises and expands along with time

going and the cell also expands until the cell length exceeds a limit, then the cell is divided into two. In this manner the number of cells will continue to increase until the time of gas extrusion. The procedure to decide the condition of a cell is shown in FIG.3.

PHYSICAL MODELS

Initial gas distribution

Most existing two phase flow models are using radial flow equation to determine the initial gas distribution which is an important factor to decide the kick performance thereafter. The radial flow equation needs informations, such as permeability, which are often unknown. But we aimed to simulate a kick with a given pit gain and pressures. Also the influx duration is given, which we can check at mud logging engineer.

We assume that an influx takes a place only during the given initial influx duration and that the mass flow rate is constant during that duration. The mass flow rate is unknown at the start of simulation, therefore, a value of the rate is temporarily established and mixed with the drilling pump rate. Then calculation is iterated changing the value of the rate until the increase of fluid volume coincides the given pit gain. The final rate decides the initial gas distribution. In this calculation the bubble slip velocity is neglected because the moving velocity of fluids by the drilling pump rate is large enough.

Gas slip

Gas bubbles formed at the bottomhole will start slipping upward in the mud. The slippage results in a dispersion or distribution of gas bubbles which determines the bubble position, expansion, pressures and consequent

kick behavior.

Nickens[1] tried to correlate the velocity to flow patterns via gas void fraction. However, flow patterns are extremely phenomenal and do not correspond with the void fraction clearly. Gas void fraction neither determines the slip velocity as numerous small bubbles also could make large void fraction. As an actual matter, drilling pump rate is so high that numerous small bubbles would exist at the initial stage of most gas kicks. Eventually, an attempt to determine gas slip velocity by flow pattern will fail, because flow pattern itself is very difficult to define.

Meanwhile, rising velocity of bubbles with various diameter in stagnant liquids was studied by Peebles and Garber[2] as below:

Ragion 1

$$V_\infty = \frac{2R_b^{\,2}(\rho_\ell - \rho_g)g}{9\mu_\ell} \qquad \left(R_{eb}<2\right)$$

Region 2

$$V_\infty = 0.33\, g^{0.76}\left(\frac{\rho_\ell}{\mu_\ell}\right)^{0.52} R_b^{\,1.28} \qquad \left(2<R_{eb}<4.02G_1^{\,-2.214}\right)$$

Region 3

$$V_\infty = 1.35\left(\frac{\sigma}{\rho_\ell R_b}\right)^{0.50} \qquad \left(4.02G_1^{\,-0.214}<R_{eb}<3.10G_1^{\,-0.25} \;\; or \;\; 16.32G_1^{\,0.144}<G_2<5.75\right)$$

Region 4

$$V_\infty = 1.18\left(\frac{g\sigma}{\rho_\ell}\right)^{0.25} \qquad \left(3.10G_1^{\,-0.25}<R_{eb} \;\; , \;\; 5.75<G_2\right)$$

The rising velocities are nicely described in the above as a function of bubble diameter. The rising velocity equations are adopted as slip

velocity in the model, except Region 4 for which Harmathy equation is used:

$$V_\infty = 1.53\left[\frac{\sigma(\rho_\ell - \rho_g)g}{\rho_\ell^{\,2}}\right]^{0.25}$$

These are bubble flows.

When bubble diameter exceeds 60% of flow line diameter, the bubble behaves as Taylor bubble and forms slug flow. The rising velocity then is given by next equation and incorporated in the model:

$$V_\infty = 0.35\sqrt{g(d_o + d_i)}$$

Once the initial bubble diameter is specified, more reasonable and probably more realistic simulation can be obtained, assuming that neither coalescence nor breakage of gas bubble takes a place in a calm flow of slow pump rate at the time of kick control.

In the model, the hole inclination is involved by $g \cdot \cos\theta$ in place of gravity g.

Slow-down of gas slip velocity

The rising velocities of bubbles except Taylor bubble are slowed down by the crowdedness of bubbles.

It is, in general, said that the effect is multiplication of $(1-\alpha)^k$ as a function of void fraction with k value 0 to 3. However, this is thought applicable only in a stable system in which the void fraction is relatively constant and consequently the k value can be specified, such as in horizontal flow. On the contrary, it may not be necessarily applicable in case of kick control where void fraction changes to large extent due to the hydrostatic pressure.

A bubble rising in a pipe is affected by the pipe wall and the rising

velocity is lower than predicted in stagnant liquids. Landenburg[2] derived the correction:

$$\frac{V_g}{V_\infty} = 1 / \left(1 + \frac{2.4 d_B}{D_F}\right)$$

We assume a small pipe around a respective bubble as shown in FIG.4. The number of bubbles in the cross sectional area is approximated:

$$N_B = A / \frac{\pi}{4} D_F^{\,2}$$

and the void fraction is expressed:

$$\alpha = \frac{\pi}{4} d_B^{\,2} N_B / A$$

therefore,

$$\frac{d_B}{D_F} = \sqrt{\alpha}$$

So the Landenburg's correction is expressed as a function of void fraction:

$$V_g = \frac{1}{1 + 2.4\sqrt{\alpha}} V_\infty$$

Compression factor

Compression factor is calculated numerically by an equation and table which replace the compression factor vs pseudo reduced pressure and pseudo reduced temperature charts by Standing and Katz.

Temperature distribution

The temperature of circulating mud were simulated and reported by Raymond[3]. We conclude his results about the temperature distribution in the annulus that:

(1) As mud goes up in the annulus from the bottom, it continued to be heated for a while and then it begins to be cooled down to the temperature

same as bottomhole temperature. The temperature distribution is approximated by a curve of secondary degree.

(2) After the mud is cooled to the bottomhole temperature, the temperature distribution is approximated linear. The straight line intercepts geothermal gradient at the point of middle depth of the hole.

From these features the temperature distribution curve is drawn as shown in FIG.5.

This temperature distribution model is incorporated in the simulation model. The temperature distribution is determined when geothermal gradient or bottomhole temperature is specified as well as surface and outlet temperatures. This will give more realistic approximation than a simple application of geothermal gradient or an unknown given distribution model.

Pressure loss in cell

Gravity pressure loss or hydrostatic pressure between the upper end and lower end of a cell can be easily calculated from the mean density and length of the cell. The mean density is calculated with the void fraction of the cell:

$$\rho_m=(1-\alpha)\rho_\ell+\alpha\rho_g$$

Friction loss is calculated with Power Law model for the single phase flow of mud.

But neither good model nor correlation exists for two phase flow friction loss. Meanwhile the two phase flow is limited in annulus and choke line in kick control condition. Annulus has so large cross sectional area that friction loss is very small comparing to hydrostatic pressure. Therefore, friction loss calculation is not so important if the choke line is not considerably long. So, Power Law model is simply extended to two phase friction loss making use of mean density and mean viscosity in a

cell, in order to retain an integrity between single phase flow and two phase flow and to avoid complexity.

Acceleration loss was evaluated and found actually zero, so it is neglected in this program.

PHYSICAL PROPERTIES OF FLUIDS

Gas density is calculated by Engineering Equation of State from gas specific gravity given as input data.

Gas viscosity is necessary for the calculation of two phase flow friction loss. As the loss is not so important, the correlation of Lee et al. was chosen as it was easy to be incorporated into the program.

Mud viscosity is necessary for the calculation of the rising velocity of a bubble. As mud is Bingham fluid, an effective viscosity is defined with plastic viscosity and yield value and used in the calculation of Reynolds number for the Power Law application. The effective viscosity apparently corresponds to that of Newtonian fluid and so it is used also for the calculation of rising velocity of bubble.

Surface tension between mud and gas is necessary for the calculation of bubble rising velocity. The tension changes to some amount as a function of presssure and temperature and is one of the most important factor for the velocity. However, as the data was not available, we made use of the surface tension vs pressure data of methane and water under the temperature condition of 74° F and 280° F by Hough et al.

Approximated equations were provided from the data, and the surface tension under other temperature is calculated from the equations by interpolation or extrapolation.

PROGRAM

Outline

The program is made of the sub models discussed above. It calculates the change of pressures and pit gain in time scale according to the rise and expansion of gas and the displacement of mud. The pressures are predicted at standpipe, casing, casing shoe and any other five designated points in the annulus.

The simulation starts from the time of shut-in and finishes when a round circulation is completed. Pseudo-static moving boundary method makes the calculation time relatively short.

Temperature distribution is chosen to be geothermal gradient model or bottomhole temperature model with corresponding data to be input.

Slow-down effect model is to be chosen either a general factor $(1-\alpha)^k$ or our own factor $1/(1+C\sqrt{\alpha})$. According to Landenburg, C is 2.4.

Initial diameter of gas bubble formed when an influx is introduced into the wellbore should be specified. This factor will be discussed in the following simulation results.

RESULT

The performance of the program (named KJ2) was tested and evaluated in many ways with actual data and also compared with other simulation models.

Le Blanc

An actual gas kick data reported in Le Blanc's paper[4] was used for the simulation by KJ2 under the variation of several parameters. This was only one actual case available for us.

The codition is shown in FIG.6. As the information was not enough, some input data were assumed at the ordinary figures. The influx time for the

amount of pit gain was considered around 10 minutes according to our experience.

The simulation results are shown in FIG. 7 to 13 and several remarks are pointed out that:

(1) One of the reasons why the actual measurement is higher than the simulated annulus pressure might be an excess pressure applied at choke for safety. The actual excess pressure is not known but estimated probably 7 to 10 kg/cm^2, while the KJ2 simulations did not have the excess pressure.

(2) Even the excess pressure is taken into consideration, the simulated annulus pressure is still lower than the actual measurement. Whatever the initial bubble diameter is, initial pit gain seems 1 kilo litter more than the report, as Le Blanc described that a limited infiltration of additional gas had been permitted into the annulus during the operation.

(3) We estimate that the initial bubble diameter was about 3 mm from the observations of the peak-pressure time and curve shape of the KJ2 simulations and that the initial pit gain was approximately 4.3 kilo litters from the observation of the peak-pressure value, comparing to the actual measurement.

(4) In this case, the 2 hour shut-in time may have affected to the bubble coalescence. But it seems certain that 2 or 3 mm of initial diameter will not give so much large error. We necessitate more actual measurements in order to define the initial bubble diameter.

Hoberock

Hoberock[5] reported a test well measurement. The test well condition is shown in FIG.14.

The simulation results are shown in FIG.15 & 16. The meniscus of the

actual measurement curve looks a little strange. Probably gas was introduced into the wellbore directly through a 1 inch ball valve or tubing, not similar to actual reservoir rocks. In that way small bubbles will in no way form. But only some big gas slugs will be formed, which is never a copy of an oil field gas kick.

Nickens

We compared our program with Nickens' model[1] which was cosidered the most complete one ever existed.

He proposed his nominal well as in FIG.17.

The simulation results are shown in FIG.18 & 19 and several remarks are pointed out that:

(1) When KJ2 is run with 1 or 2 mm of initial bubble diameter, annulus peak pressure delays as much as 40 minutes to Nickens' simulation.

(2) The peak pressure values on both simulations coincide to each other.

(3) KJ2 simulation with 10 mm initial bubble diameter is very similar to Nickens' which is using Harmathy equation and Taylor bubble equation as bubble slip velocities, handling the bubble-slug transition with gas void fraction.

While, in KJ2, 10 mm of initial bubble diameter is directly in the region of Harmathy equation and then moves into the region of Taylor bubble equation as the bubble rises and expands. This is not dominated by gas void fraction but by bubble diameter.

These two models have different algorithm, however, it could be mentioned that KJ2 includes Nickens' model as a special case.

(4) In FIG.19 a fluctuation of pressure is observed at the time of gas out. This is also observed in the field. This is resulted from slow-down effect in the program.

Holden

Holden[6] was simulating a deep water well in his paper using single bubble model. We checked the effect of very long choke line on KJ2. The well condition is as in FIG.20. The simulation is shown in FIG.21.

The dispersion effect of gas bubbles on KJ2 is considerable on the very long choke line system in deep water.

CONCLUSIONS

It is concluded about the performance of this program as below:

(1) The performance is satisfactory and proved the theoretical integrality of the model.

(2) The appropriate initial diameter of bubble is considered to be 2 to 3 mm by the simulation results. But more actual measurements will be necessitated to decide it as well as the coalescence and breakage of bubbles.

(3) If initial diameter is input to be 10 mm, the simulation result is almost same as Nickens'. But it is not certain that the result is a good copy of actual kick.

(4) As input influx-time governs the initial distribution of gas which decides the simulation, it is absolutely necessary to give correct influx-time.

(5) Concerning slow down effect factor, $1/(1+2.4\sqrt{\alpha})$ seems satisfactory.

(6) The initial bubble diameter is critical especially in a deep water well with a large length of choke line.

We believe that the development of this program broke through the difficulties of gas kick simulation and made a new approach, involving two problems that are the initial diameter of gas bubble and the coalescence

and breakage of gas bubbles. They will, however, be defined and clarified more easily in laboratories than the flow pattern problem.

ACKNOWLEDGEMENT

This work was commissioned by the Japan National Oil Corporation. We thank the Corporation for the permission to publish this paper. We express our appreciation to Makoto Nishi for his assistance in the development of the program.

NOMENCLATURE

A : cross sectional area

C : constant

d_i: casing inside diameter, inch

d_o: casing outside diameter, inch

d_B: bubble diameter

D_F: pipe diameter

g : gravity, 981 cm/sec^2

G_1: dimensionless group, $G_1=g\mu_\ell^4/\rho_\ell\sigma^3$

G_2: dimensionless group, $G_2=gR_b^4v_\infty^4\rho_\ell/\sigma^3$

k : constant

N_B: number of bubbles in cross sectional area

R_b: bubble radius, cm

R_{eb}: bubble Reynolds number, $R_{eb}=2\rho_\ell v_\infty R_b/\mu_\ell$

T_B: bottomhole temperature,°C

T_O: outlet mud temperature,°C

T_S: surface temperature,°C

V_g: gas slip velocity, cm/sec

V_∞: rising velocity of single gas bubble in stagnant liquid, cm/sec

X : depth ratio, X=depth of cell/well depth

α : gas void fraction

γ : gas specific gravity (air=1)

θ : well inclination

ρ_g: gas density, g/cm^3

ρ_t: mud density, g/cm^3

ρ_m: mean density of cell, g/cm^3

σ : surface tension, dynes/cm

REFERENCES

(1) Nickens, H. V. , 1985 : A Dynamic Computer Model of a Kicking Well Part 1 -The Theoretical Model, SPE 14183, 1-20

(2) Wallis, G. B. , 1969 : One Dimensional Two-Phase Flow, 249-252, McGraw-Hill

(3) Raymond, L. R. , 1969 : Temperature Distribution in a Circulating Drilling Fluid, JPT, March, 333-341

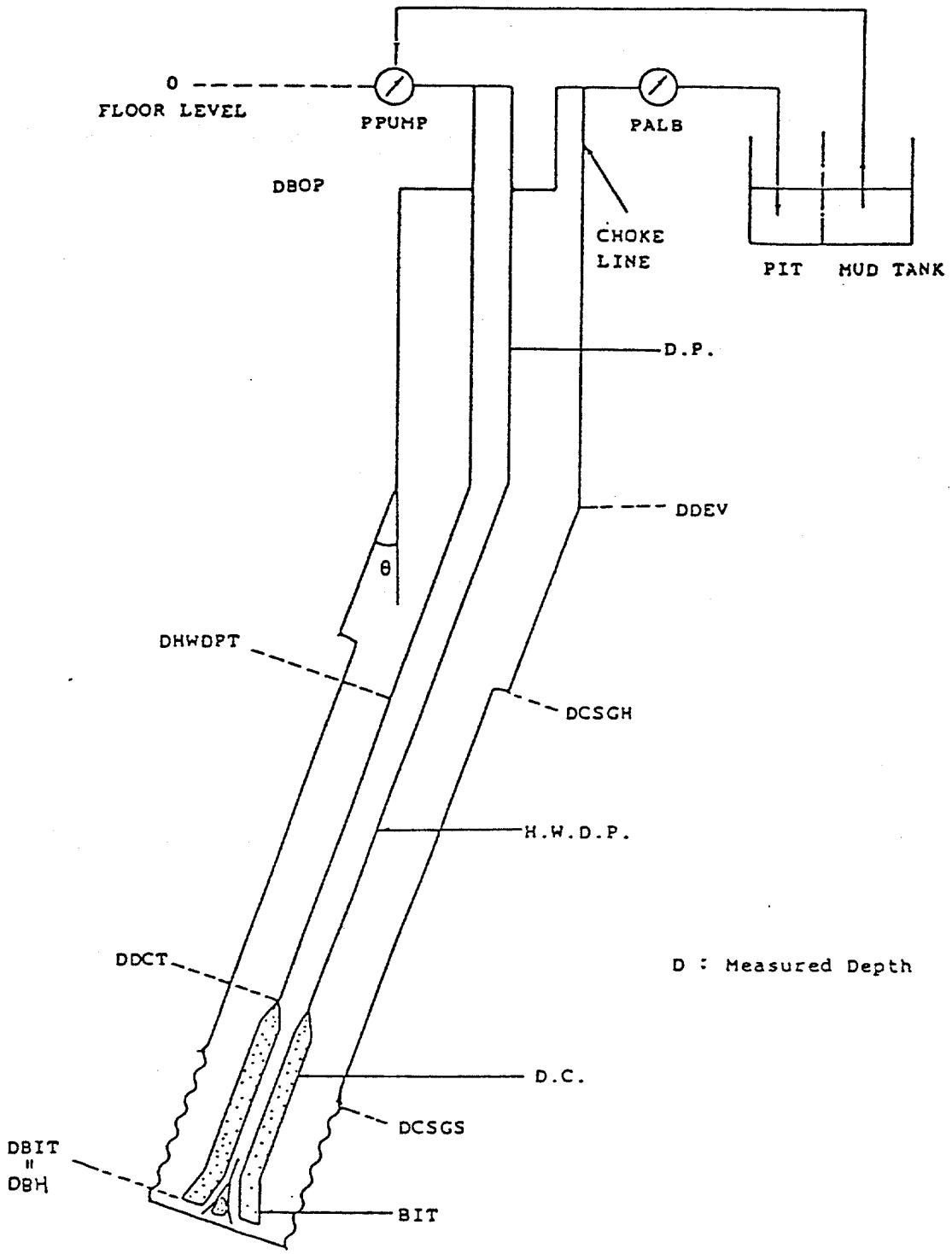


FIG.1 Well geometry

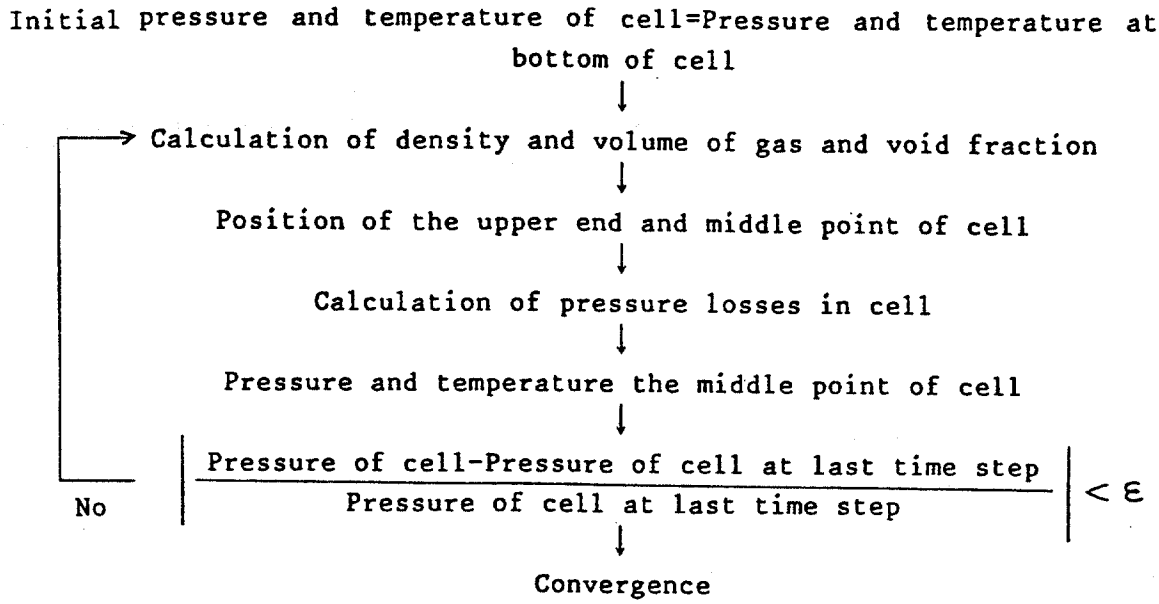


FIG.3 Procedure to determine the condition of a cell

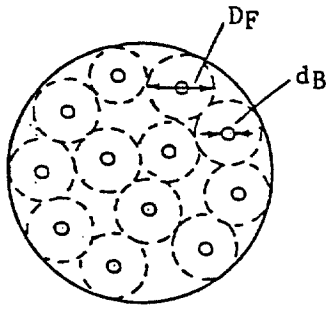


FIG.4 Bubbles and the assumed pipes

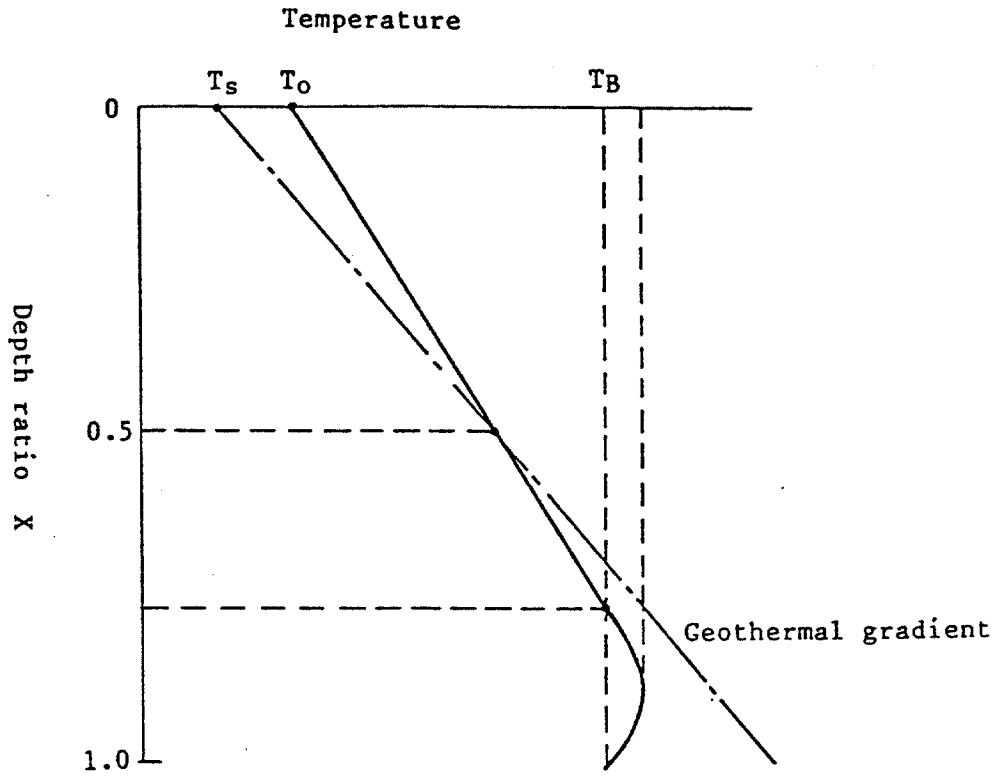
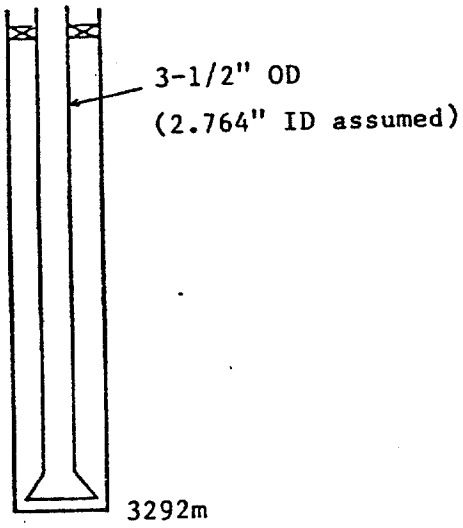


FIG.5 Temperature distribution in annulus



Surface temperature: 49°C
Mud outlet temperature: 49°C assumed
Geothermal gradient:0.01°C/m
Mud density: 1.764 g/cm³
Average hole size: 7-1/8 inch
Bit nozzle: 3×9 assumed
Pit gain: 3.34 kl
Shut-in DP pressure: 24.5 kg/cm²
Shut-in casing pressure: 70 kg/cm²
Kill rate: 168 gpm = .655 kl/min
PV: 15 cp assumed
YP: 8 lb/100 ft² assumed
Shut-in time: 2 hours

FIG.6 The kicked well

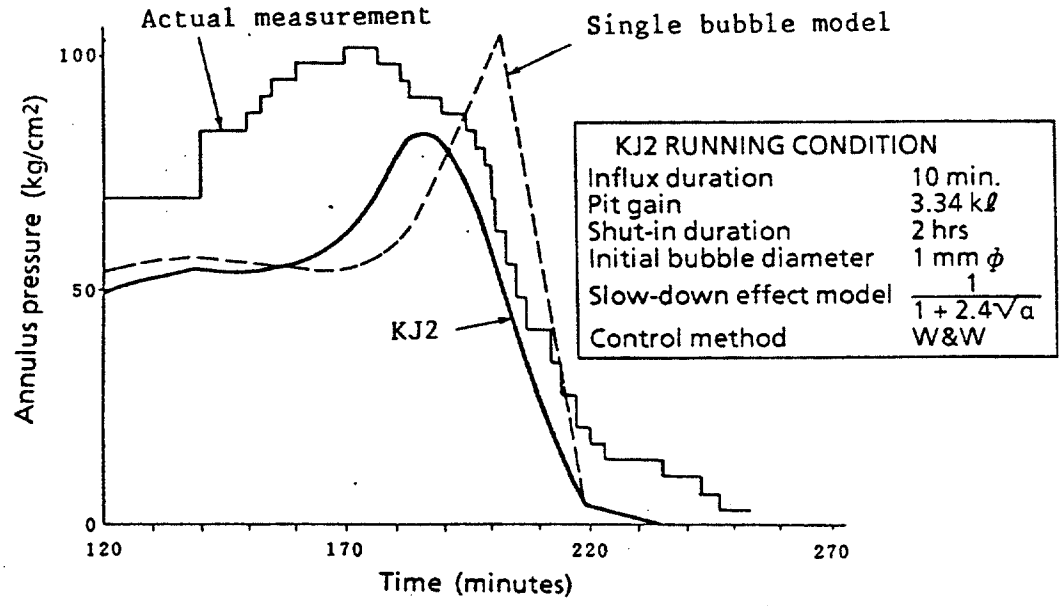


FIG.7

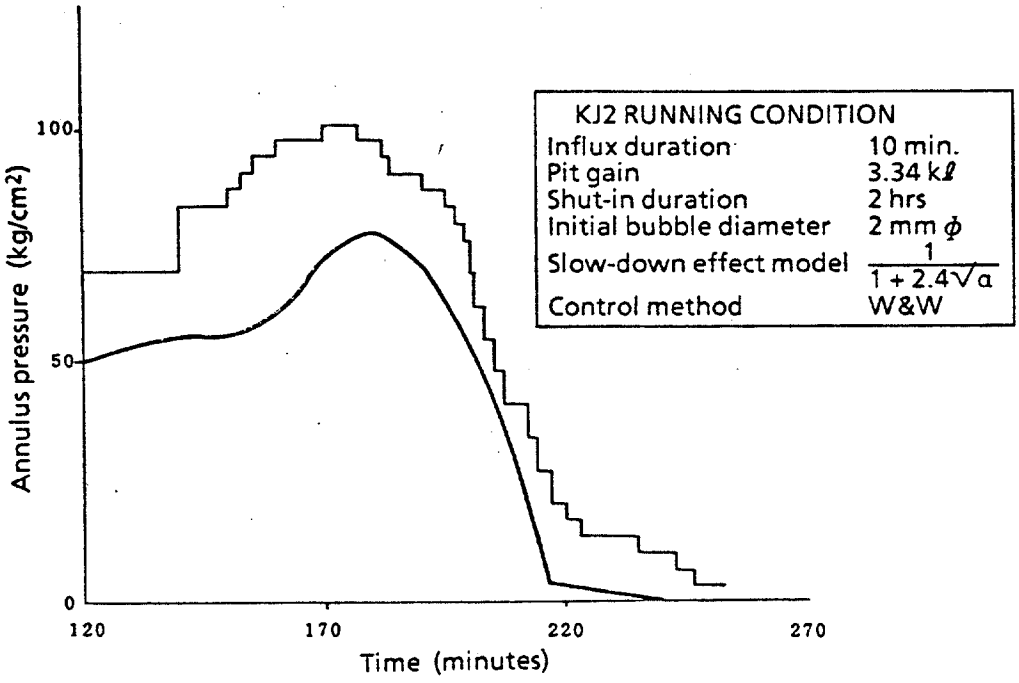

KJ2 RUNNING CONDITION
Influx duration 10 min.
Pit gain 3.34 kℓ
Shut-in duration 2 hrs
Initial bubble diameter 2 mm φ
Slow-down effect model 1/(1+2.4√α)
Control method W&W
Annulus pressure (kg/cm²)
100
50
0
120
170
220
270
Time (minutes)

FIG.8

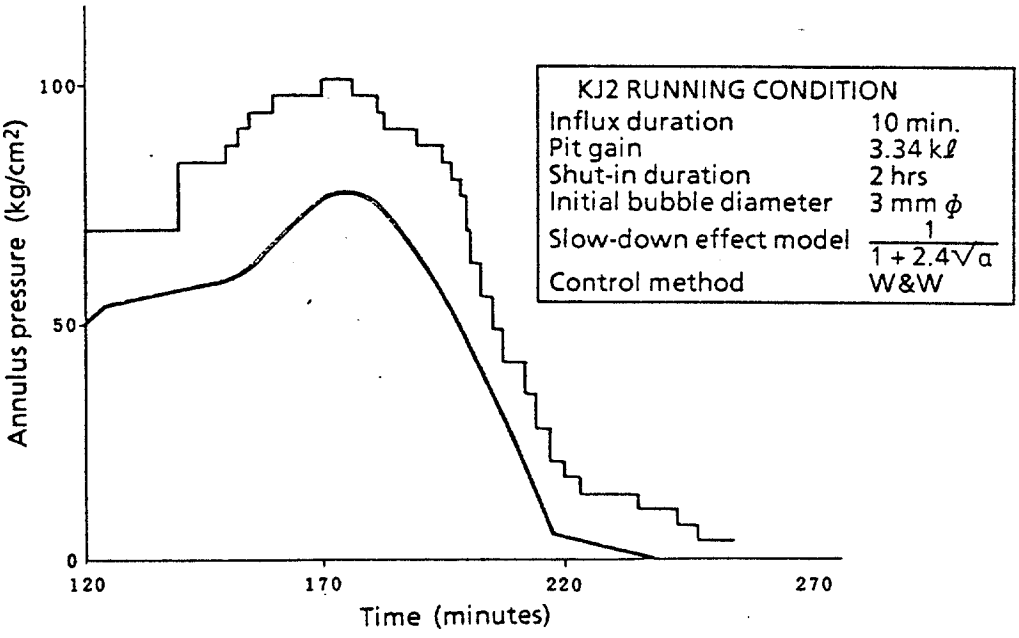

KJ2 RUNNING CONDITION
Influx duration 10 min.
Pit gain 3.34 kℓ
Shut-in duration 2 hrs
Initial bubble diameter 3 mm φ
Slow-down effect model 1/(1+2.4√α)
Control method W&W
Annulus pressure (kg/cm²)
100
50
0
120
170
220
270
Time (minutes)

FIG.9

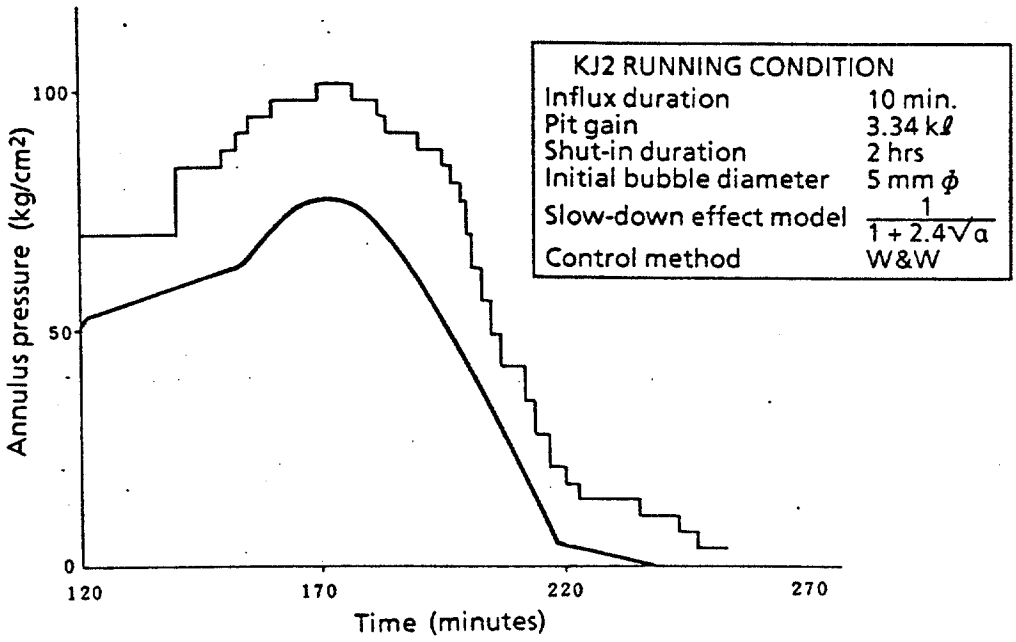

KJ2 RUNNING CONDITION
Influx duration 10 min.
Pit gain 3.34 kℓ
Shut-in duration 2 hrs
Initial bubble diameter 5 mm φ
Slow-down effect model 1/(1 + 2.4√a)
Control method W&W
Annulus pressure (kg/cm²)
100
50
0
120
170
220
270
Time (minutes)

FIG.10

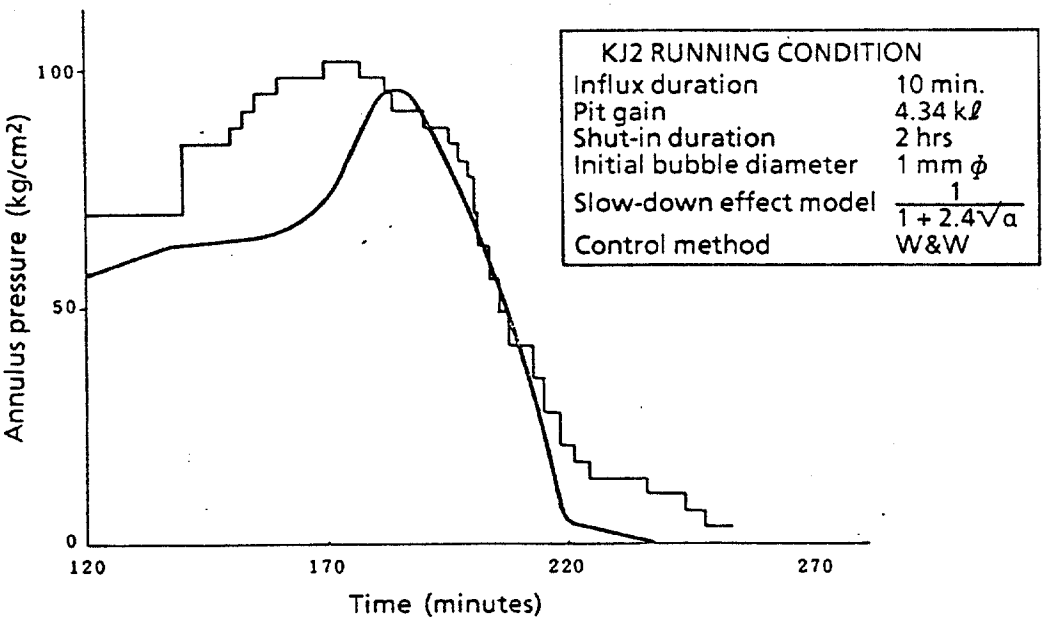

KJ2 RUNNING CONDITION
Influx duration 10 min.
Pit gain 4.34 kℓ
Shut-in duration 2 hrs
Initial bubble diameter 1 mm φ
Slow-down effect model 1/(1 + 2.4√a)
Control method W&W
Annulus pressure (kg/cm²)
100
50
0
120
170
220
270
Time (minutes)

FIG.11

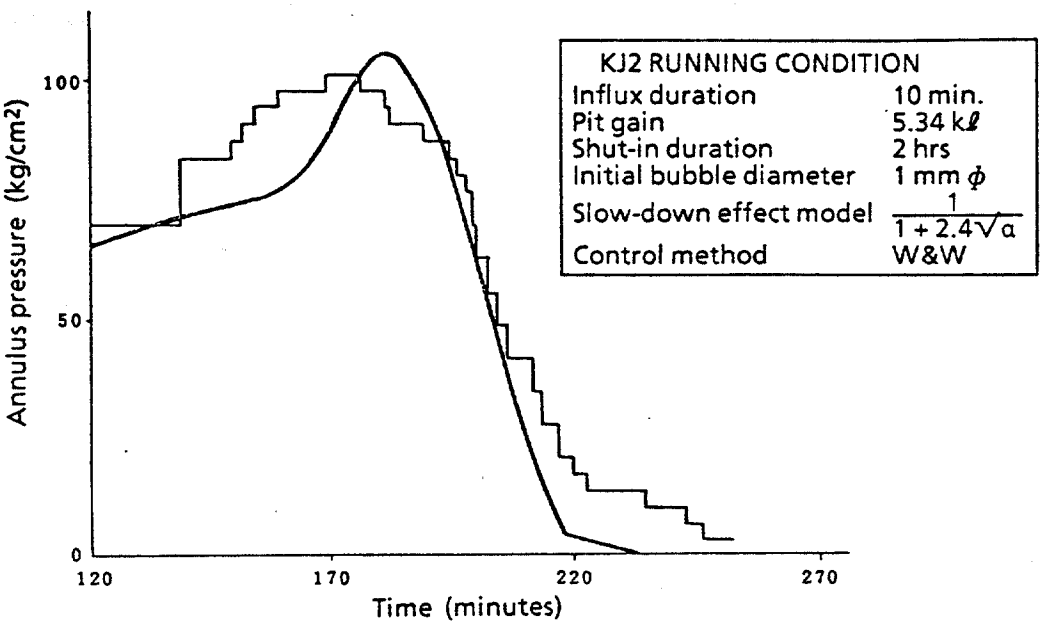

KJ2 RUNNING CONDITION
Influx duration 10 min.
Pit gain 5.34 kℓ
Shut-in duration 2 hrs
Initial bubble diameter 1 mm φ
Slow-down effect model 1/(1+2.4√α)
Control method W&W
Annulus pressure (kg/cm²)
100
50
0
120
170
220
270
Time (minutes)

FIG.12

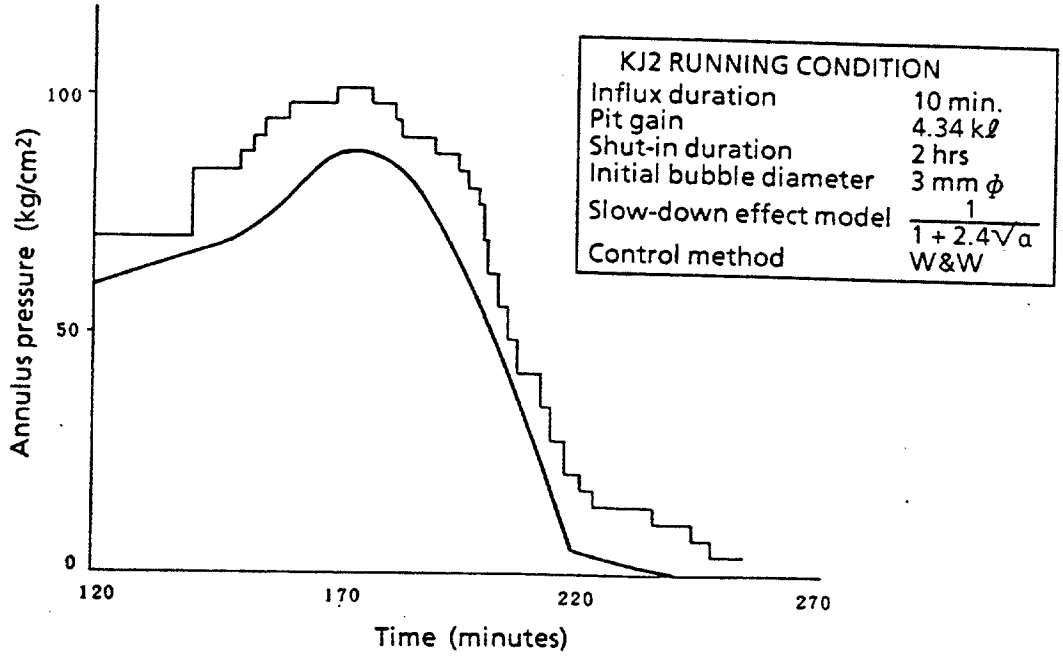
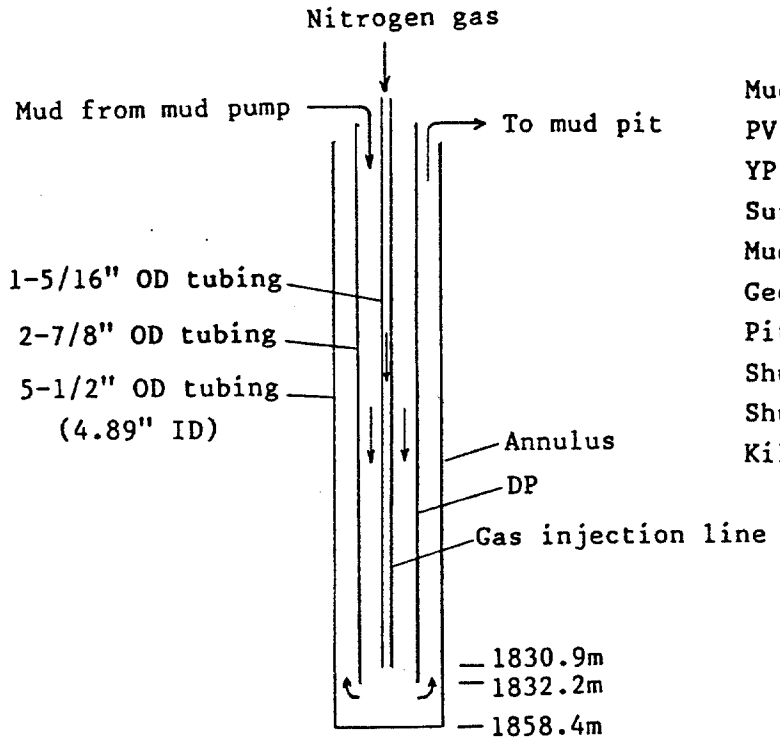

KJ2 RUNNING CONDITION
Influx duration 10 min.
Pit gain 4.34 kℓ
Shut-in duration 2 hrs
Initial bubble diameter 3 mm φ
Slow-down effect model 1/(1+2.4√α)
Control method W&W
Annulus pressure (kg/cm²)
100
50
0
120
170
220
270
Time (minutes)

FIG.13



Mud density: 1.03 g/cm^3
PV: 12.6 cp
YP: 15 lb/100 ft^2
Surface temperature: 20°C assumed
Mud outlet temperature: 40°C assumed
Geothermal gradient: 0.03°C/m assumed
Pit gain: 1.59 kl
Shut-in DP pressure: 14 kg/cm^2
Shut-in casing pressure: 35 kg/cm^2
Kill rate: 60 spm (6.07 l/stroke)

FIG.14 Test well

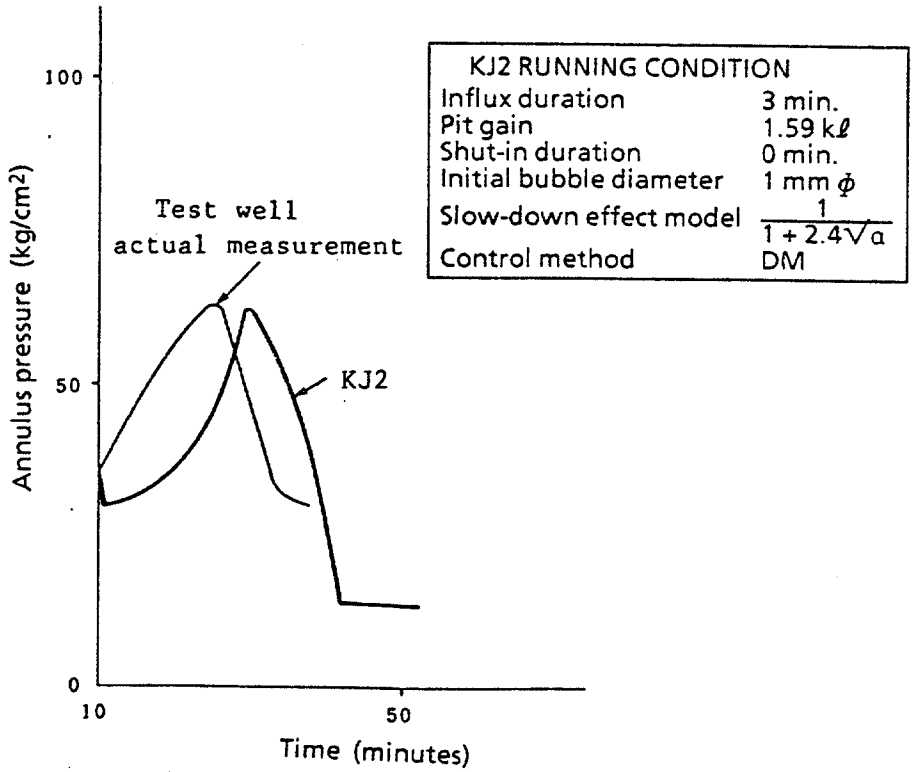


FIG.15

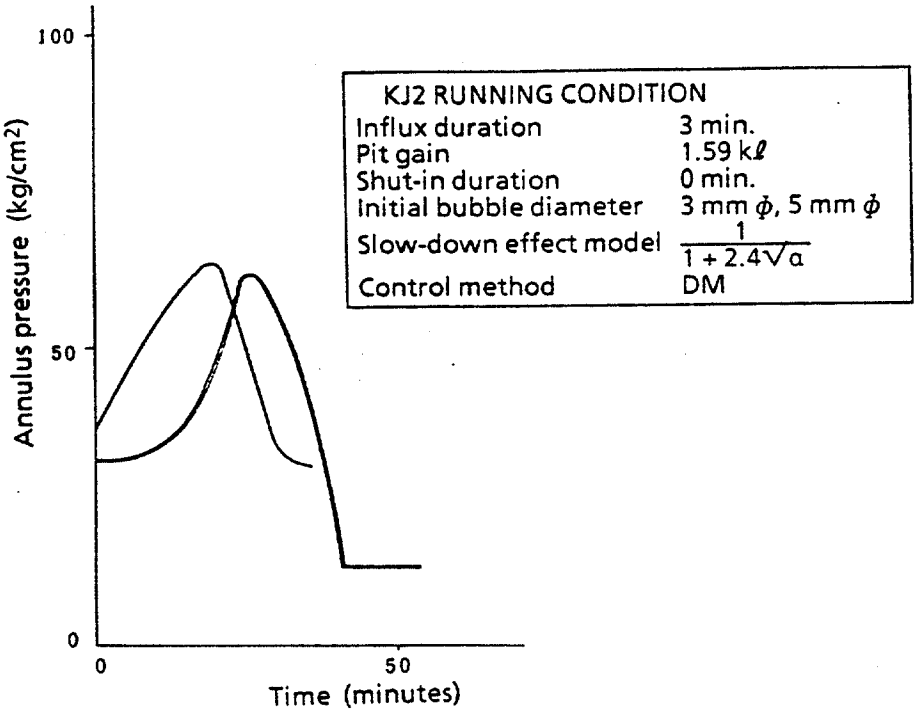
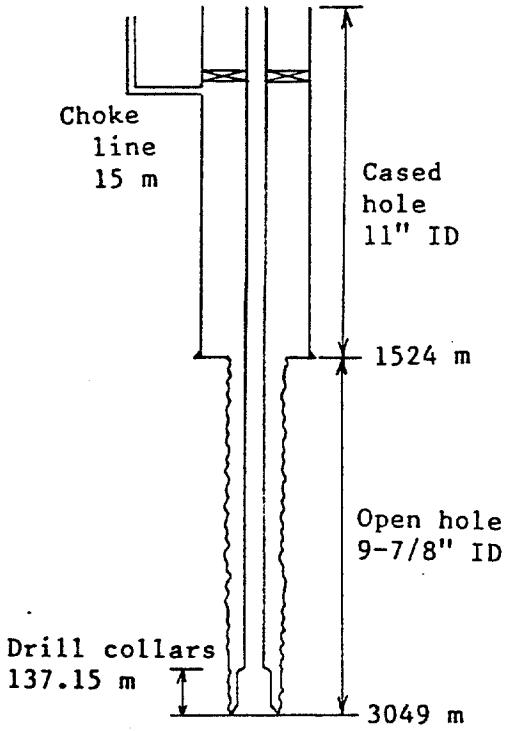


FIG.16



Casing	11 in.ID
Drillpipe	5 in.x 4.41 in.
Drill collars	8 in.x 2.81 in.
Bit	9-7/8 in., 3 x 12
Flow rate	400 gpm
Mud wt.	10 ppg = 1.2
PV	15 CP
YP	8 lbf/100ft^2
Choke line	3 in. ID
Formation Pressure	FBHP+300psia
Permeability	300 md
Porosity	30 percent
Penetration rate	30ft/hr
Temperature	
Surface	70°F = 21.1°C
Bottomhole	160°F = 71.1°C
Pit gain	3.18 kl (20 bbl)
Shut-in DP pressure	24.78 kg/cm^2
Shut-in casing pressure	40.25 kg/cm^2

FIG.17 Nominal well

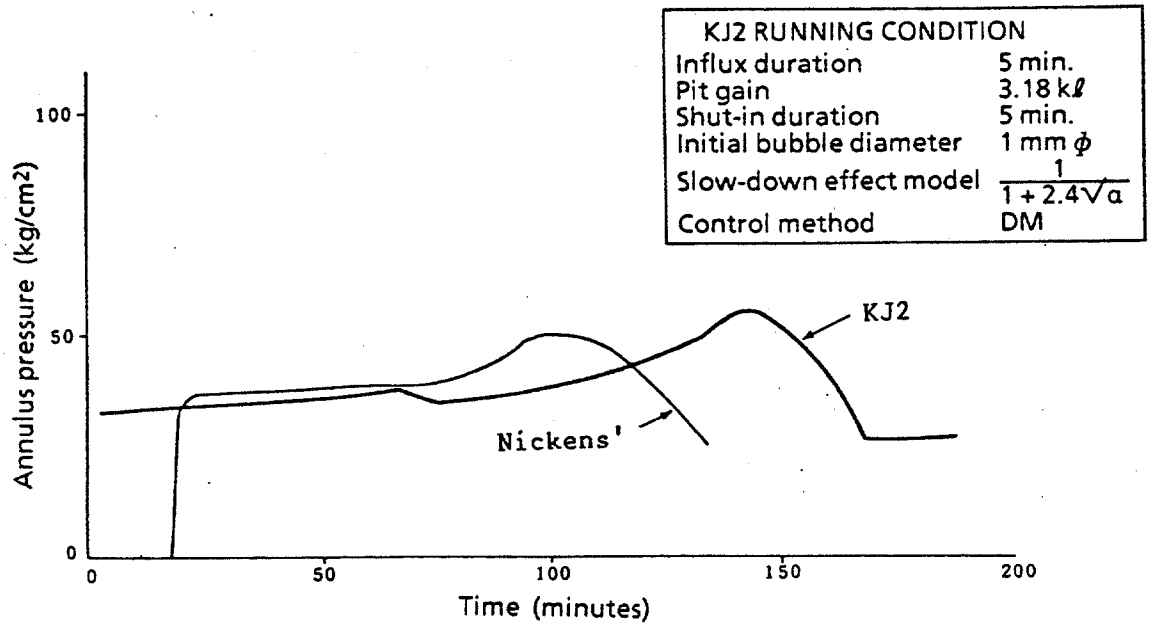

KJ2 RUNNING CONDITION
Influx duration 5 min.
Pit gain 3.18 kℓ
Shut-in duration 5 min.
Initial bubble diameter 1 mm φ
Slow-down effect model 1/(1+2.4√α)
Control method DM
KJ2
Nickens'
Annulus pressure (kg/cm²)
Time (minutes)
0
50
100
150
200

FIG.18

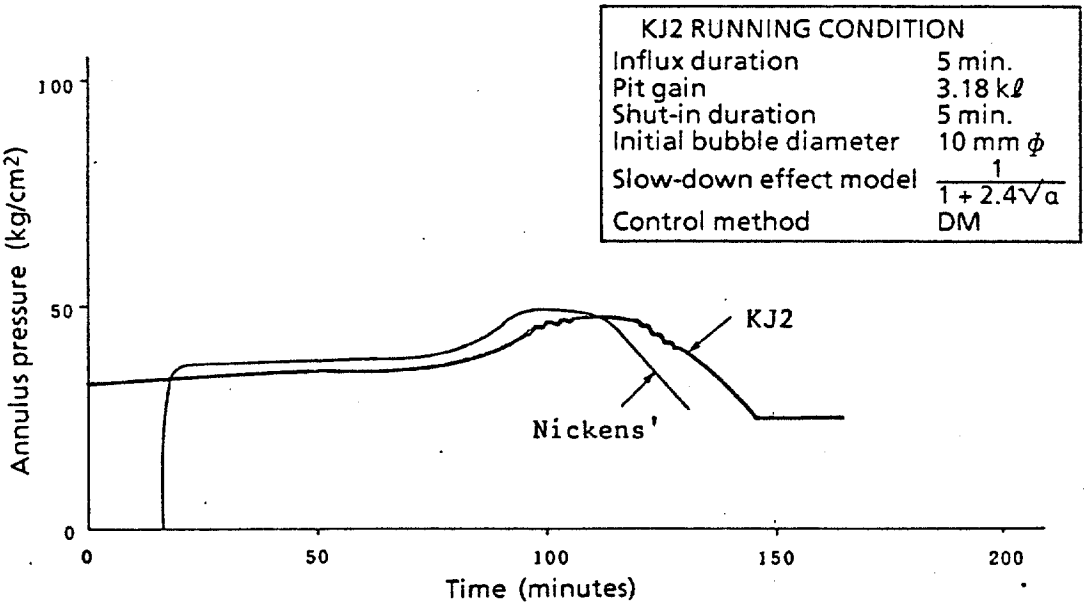
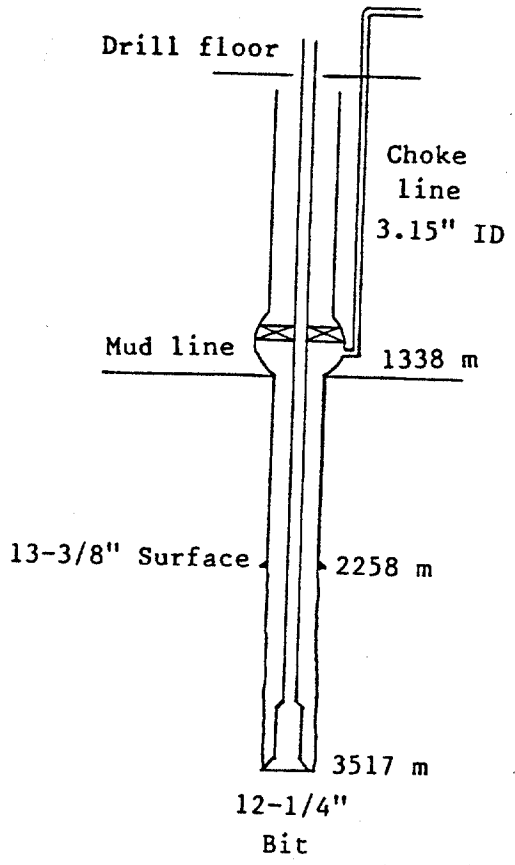

KJ2 RUNNING CONDITION
Influx duration 5 min.
Pit gain 3.18 kℓ
Shut-in duration 5 min.
Initial bubble diameter 10 mm φ
Slow-down effect model 1/(1+2.4√α)
Control method DM
KJ2
Nickens'
Annulus pressure (kg/cm²)
Time (minutes)
0
50
100
150
200

FIG.19



WELL DATA

1.Casing:	13-3/8 in., j-55, 61 lb/ft = 12.515"
2.Drill pipe:	5 in., 19.5 lb/ft = 4.28" ID
3.Drill collars:	540 ft, 8 x 3 in. = 164.6 m
4.Drill bit:	12-1/4 in., 12-13-13/32 in. jets
5.Mud:	9.2 ppg, μp = 16 cp, γy = 10 lb/100
	SG = 1.104

PUMP DATA

1.Type:	Single Acting Triplex	
2.Liner size:	6-1/2 in.	4.7 gal/stroke(100
3.Stroke:	11 in.	
4.Efficiency:	96%	4.5 gal/stroke = 17.8 ℓ/stroke

CIRCULATION DATA

Conditions	SPM	DP Pressures, psig: Through choke line	Choke line Friction
Norm. Drilling	110		
Reduced Rate 1	50	880	280

KICK DATA(Simulated)

1.Shut-in DP pressure:	300 psig = 21 kg/cm^2
2.Shut-in choke pressure:	440 psig = 30.8 kg/cm^2
3.Pit gain:	30 bbl = 4.77 kℓ

FIG.20 Deep water well

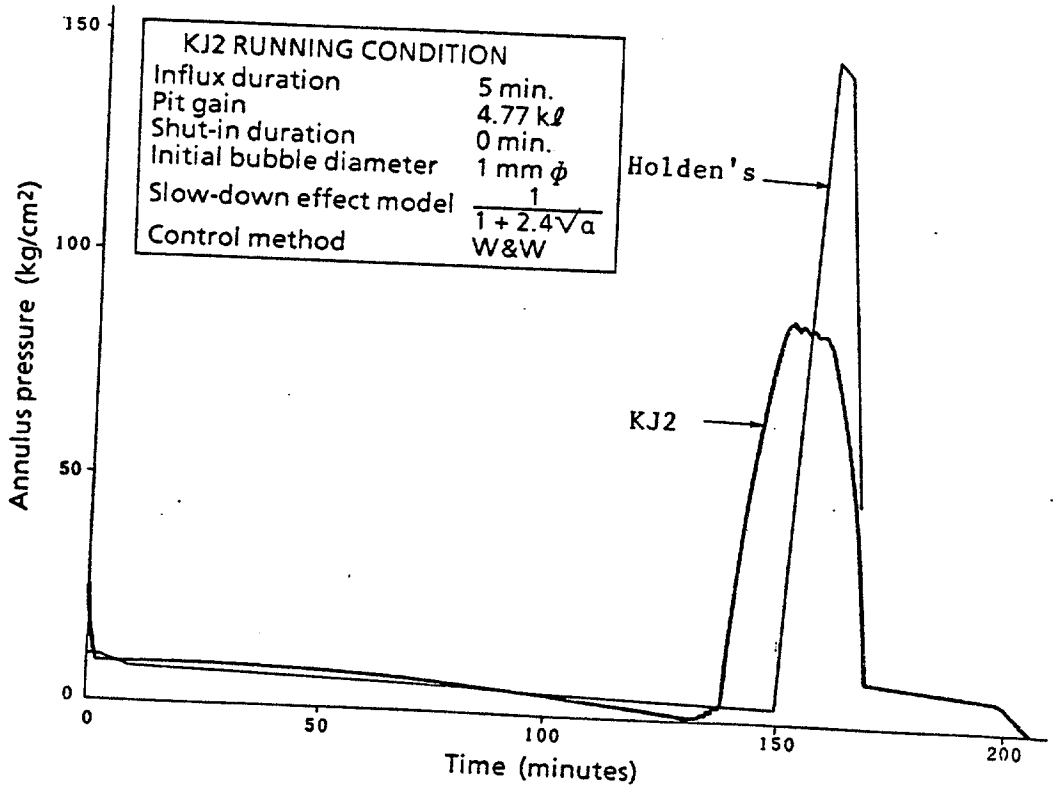


FIG.21

Experimental Determination of Gas Migration Velocities

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Abstract

A key factor in the development of a kick is the rate at which free gas rises up the wellbore. The main parameters governing the gas velocity are the wellbore geometry, the volumetric gas fraction and the fluid rheology. A description of this two-phase flow of gas in non-Newtonian fluid is to be incorporated into the UK Department of Energy Research Model.

Previously published data is mainly limited to Newtonian liquids (usually water) and vertical or horizontal pipes with small diameters. Some limited data for a vertical well was obtained from the DEA7 project conducted at Lousiania State University. An experimental programme has been set up at Schlumberger Cambridge Research to examine these two-phase flows. The experiments are being carried out in a 15m inclinable flow loop where air injection is used to simulate gas entry during a kick. Using an instrumented test section it is possible to measure mean and spatially resolved void fractions and gas and liquid velocities over a range of two-phase flow conditions.

The experimental techniques together with the problems of injector geometry are discussed. Initial tests have been conducted using air

and water. The results for vertical conditions are reported and the effect of deviation is illustrated for a limited number of conditions. The experiments are now being extended to include a simulated drilling mud.

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1 Introduction

The Department of Energy has recently placed a contract with Schlumberger Cambridge Research (SCR) in association with the BP Research Centre, Sunbury, for the development of mathematical models to aid understanding of incidents such as gas kicks in the drilling of deep high pressure wells with oil-based muds. Details of the many simulators in the literature have been given in a previous paper in this session and will not be mentioned here. The basis of the kick simulator under development is the solution of the hydrodynamic equations for the conservation of mass and momentum as drilling fluid is pumped down the drill pipe and up the annulus. The flow

of drilling fluid in the wellbore is complicated by the non-Newtonian nature of the drilling mud. The flow may be turbulent in the drillpipe, transitional between turbulent and laminar past the drill collars, becoming laminar in the main part of the annulus. The code describes these complications while models describing the gas/fluid interactions such as gas solubility, gas and mud volumetric behaviour and dissolved gas dispersion are also included.

As the fluid is pumped up the annulus the hydrostatic pressure falls and dissolved gas will come out of solution and the flow becomes two-phase, initially as bubble flow, possibly with slug flow higher up the annulus. In the work to produce the Research Model kick simulator the rate of rise of free gas up the wellbore has been identified as a key parameter in the development of a kick. A model describing the two-phase flow of gas and non-Newtonian fluids is being incorporated in the code. At present, some correlations exist in the literature for two-phase flow in circular pipes (usually small diameter) and annuli but only very limited data are available for multiphase flows of non-Newtonian fluids. In this paper we will address the problem of the transport of the free gas.

In a water-based mud gas is transported mainly as bubbles while in oil-based mud, despite the solubility of hydrocarbons in the base oil, there is likely to be free gas at the start of the kick and in the later stages of the

kill. Thus, it is important to extend our knowledge in this area.

Previous authors have discussed the rise velocity of isolated bubbles in stationery columns of liquid. Wallis [10] assumed Stokes flow both around and inside the bubble and this approach was carried further by Govier and Aziz [3]. Harmathy [4] developed a correlation for experimental data to describe the rise of single bubbles as a function of density difference, and surface tension but not bubble size. At higher void fractions bubbles in air/water flows tend to coalesce and slug flow develops characterised by large Taylor bubbles separated by slugs of liquid containing dispersed bubbles. Davis and Taylor [2] showed that, for inertia dominated flows, the rise velocity of the Taylor bubble depends on the fluid density and pipe size.

Flow pattern maps are used to characterise regimes and their associated bubble rise velocities have been used in a number of kick simulators with the transition between different flow regimes determined by experiments such as those of Aziz, Govier and Fogarasi [1].

Zuber & Findlay [11] showed that not only did the bubbles rise relative to the liquid flow due to density differences but were concentrated in the centre of the pipe where the liquid velocity was higher than the mean

velocity, enhancing the gas velocity further.

Very little work is reported on the effect of a non-Newtonian rheology upon the bubble sizes, distribution and rise velocity.

Some limited work has been carried out in more realistic geometries using drilling muds and the rise velocity of Taylor bubbles is found to be higher. Rader, Bourgoyne and Ward [8] looked at the rise of gas swarms injected at the bottom of a vertical well but had little control on the gas injection conditions.

Because of the dominant effect of bubble-rise on kick development and the lack of data with realistic rheologies it was felt necessary to set up an experimental programme to investigate the influence of wellbore geometry, volumetric gas fraction and fluid rheology upon the rate of gas rise. The experiments are complemented by a modelling effort to allow the incorporation of the results into the computer model.

In order to accurately identify the effects of each of the parameters discussed above, it is necessary to first identify the characteristics of the facility, then to vary each parameter independently and examine the response of the flow behaviour. Initial tests have been carried out using a 200 mm [8 "] pipe

diameter with air and water as the test fluids. The experimental results are for a vertical well although a few tests have shown that deviation is an important parameter as it significantly increases the gas rise velocity.

The results for vertical and some deviated air/water flows are reported here, together with discussion of the future tests. This future work will include the effect of geometry by the introduction of a centre body and the effect of fluid rheology by testing realistic fluids. A number of synthetic muds have been studied and initial tests made to identify the analogue mud to be employed.

2 Background

As mentioned above, a theoretically based correlation for the rise velocity of a gas v_g in a two phase flow was derived by Zuber and Findlay [11] and is given by:

$$v_g = C_0 v_h + v_{slip} \tag{1}$$

where v_h was the homogenous velocity of the flow, or the mean velocity of

fluid rising up the pipe and v_{slip} is the rise velocity of an isolated bubble in an infinite medium, the relative velocity of the gas to the liquid. The constant C_0 is normally in the range of 1.0 to 1.5 and is a function of the gas concentration and the fluid velocity distribution across the pipe, dependent upon the volumetric gas fraction carried with the faster fluid in the centre of the pipe. Its value can be calculated from the integration of the two profile distributions.

There are a number of experimental and theoretical correlations available for calculating v_{slip}, dependent upon the bubble size. These were discussed in detail by Wallis [10]. Two of the correlations will be considered here. For small bubbles Harmathy [4] used the equation:

$$v_{slip} = 1.53 \left(\frac{g(\rho_l - \rho_g)\sigma}{\rho_l^2} \right)^{\frac{1}{4}} \tag{2}$$

Where ρ_l and ρ_g are the liquid and gas densities respectively and σ is the interfacial tension. For air and water this predicts a bubble velocity of 0.25 ms^{-1} [0.75 ft/s]. For larger bubbles, where the bubble is sufficiently large to fill the pipe, Davis and Taylor [2] derived the equation:

$$v_{slip} = 0.35\sqrt{\frac{g(\rho_l - \rho_g)D}{\rho_l}} \tag{3}$$

Where D is the diameter of the pipe. For a 200 mm [8 "] ID pipe with air and water flowing this would predict a slip velocity of 0.5 ms^{-1} [1.6 ft/s].

As the gas void fraction increases an individual bubble will rise less quickly as it will be hindered by other bubbles. An equation to describe this process was derived by Zuber and Hench [12] who showed:

$$v_{slip} = v_{slip0}(1 - \alpha)^c \tag{4}$$

Where v_{slip0} is the slip velocity of an isolated bubble and c is a constant in the range of 0 - 3 dependent upon the bubble size. This suggests that as the gas void fraction increases, the slip velocity, and hence the gas rise velocity, will fall.

It is clear that one of the dominant parameters affecting the gas slip velocity, is the bubble size. It is important that in the monitoring section of the test rig the bubble size is a function of the fluid flow pattern and independent of the injection characteristics. It has been shown by Govier and Aziz

[3] that the size of a bubble formed on a submerged orifice would be a function of the orifice diameter, the condition of that orifice, the interfacial tension between the two fluids and the solid and also the flow velocity of gas through the orifice. For tests using fixed injector geometries, all of the parameters will remain constant, apart from the injector gas flow velocity. This, and hence the injected bubble size, will vary with the volumetric gas flow rate. Variations of this kind may account for the discrepancies between work reported from different flow loops. It is important to ensure that rig effects are isolated from the experiments by designing an injector geometry to remove these effects.

3 Experimental Facility

The multiphase flow loop test facility at SCR, Figure 1, forms a universal multiphase flow test centre as discussed by Hunt [5]. In the present test configuration it has been used for gas-liquid flows, although solid-liquid and liquid-liquid flows can also be evaluated. The facility offers a straight flow length of almost 12 m [36 ft], 9.5 m [29 ft] of which is perspex to permit visual evaluation of the flows. It is mounted on a 15 m [45 ft] long table which can be pivoted, enabling tests to be carried out in all orientations from horizontal to vertical. It has been designed to permit

tests of Newtonian and non-Newtonian fluids and also shear degradeable liquids without damage to either the fluid or the facility, thus making it suitable for studying drilling muds, cements and fracturing or production fluids, together with gas or solids transport. The facility is designed to allow pressures of up to 10 Bar [150 psi].

The flow loop used for the experiments reported here comprises 5 perspex pipe sections, 200 mm [8 "] internal diameter, with the instrumented test section at the top, giving a flow development length of 8.5 m [26 ft] or 42.5 pipe diameters. Galvanised steel plenum chambers are fitted onto each end.

The instrumentation of the test section is shown in Figure 2. The pressure tapping are arranged in four groups around the circumference of the pipe spread over a length of 410 mm [16 "]. The traverse mechanism for a local void fraction measurement is mounted after the final tappings.

The physical arrangement of the liquid and gas injection system is shown in Figure 3. The liquid phase is pumped into the 200 mm [8 "] ID plenum chamber, through a 150 mm [6 "] supply line. The gas is introduced into the plenum chamber through 8 10 mm [0.4 "] diameter injectors. The two phase flow then passes through a Mitsibushi flow straightener and into the flow development zone. In order to divorce the two phase flow development

from the injector velocity variations the flow straightener was positioned down stream of the injectors.

The air is supplied by two *Compair* compressors with a total capacity of 1700 m^3/hr [1000 $scfm$] at a delivery pressure of 7 Bar [105 psi]. and the flow controlled by a *Varipack Microflow* needle valve for low flows, ($Q_g <$ 25 m^3/hr [15 $scfm$]) or a *Camflex* valve for larger flow rates.

The arrangement of the liquid supply equipment is shown in Figure 4. The fluid storage is in four tanks, of volume 4 to 8 m^3 [25 to 50 Bbl]. The fluid storage tanks are interconnected to permit the flow to be returned to one tank while fluid is drawn from another which permits settling time for de-airation of the liquid when viscous fluids are tested.

The fluid is pumped by a *PCM* Mono type pump, capable of flowing 240 m^3/hr [36,000 BPD] against a head of 6 Bar [90 psi]. The mono pump was chosen as it is a low shear device and does not cause shear degradation to the fluids tested in the facility. The fluid is pumped through 50 mm, 100 or 6" pipes, through the flow meters, then a 6" flexible line onto the inclineable table. A throttle valve has been mounted on the end of the return line to permit dynamic pressure control of the entire facility. The experimental test conditions are summarised in Table 1.

Liquid	Water
Gas	Air
Pipe ID	200 mm [8 "]
Operating Pressure	1.0 $\pm$ 0.5 Bar [15 $\pm$ 7 psi]
Operating Temperature	20 $\pm$ 10 $^{\circ}C$ [68 $\pm$ 18 f]
Liquid Superficial Velocity	0.25 - 1.6 ms^{-1} [0.75 - 4.8 ft/s]
Gas Superficial Velocity	0.03 - 0.9 ms^{-1} [0.09 - 2.7 ft/s]

Table 1: Experimental Conditions

4 Instrumentation

Data taken during an experiment include the liquid and gas flow rates, the absolute pressure in the test section, the differential pressure along a length of the test section and the local void fraction and gas bubble velocity. To ensure accuracy, regular calibration checks are carried out.

The differential pressure measurement is made along a known length of the test section using a Honeywell differential pressure transducer with the remote rescaling facility using a smart field controller. This was found to be invaluable as the transducer could be adjusted remotely while physical access to the instrumentation was denied. The absolute pressure was measured in the test section using a *Valydine* gauge pressure transducer.

The air flow measurement is made using *Kurtz* Two-Wire Linear Mass Flow meters. These devices measure mass flow of the gas using two heated Platinum coils placed in the flow.

Three *Fischer-Porter COPA-X* electromagnetic flow meters with ranges 0-50, 0-100 and 0-200 m^3/hr [0-7,500 0-15,000 and 0-30,000 BPD] are used for liquid flow measurement. This type of device will maintain its calibration for viscous Newtonian and non-Newtonian fluids as well as water, although they can only be used with conducting fluids.

The local void fraction and bubble velocity were evaluated using *Radio Frequency* (RF) probes. These instruments are described in detail by Vigneaux [9], and will only be discussed briefly here. The measuring device is a small coaxial probe connected to a high frequency (1 - 2 GHz) bridge circuit. It is sensitive to the differences in dielectric constant between air and water, and therefore acts as a bubble detector. The local void fraction can be derived from the fraction of time when the probe is in air.

In the physical arrangement used for the tests, two probes are mounted with their sensing volumes in line with the flow but 10 mm [0.4 "] apart. By using auto- and cross-correlation of the two signals it is possible to estimatate the time averaged bubble velocity and size. The probes were

traversed across the pipe using a stepper motor and a screw thread drive mechanism, to enable data to be collected on a plane across the pipe.

The kernel of the data collection system is an *Apple Macintosh 11* (MAC) personal computer, which collects all of the data, down loaded from the satellite machines via an *IEEE* or an *RS232* interface.

The data acquisition system used with the 200 *mm* [8 "] facility is shown schematically in Figure 5. The analogue signals from the flow meters and the pressure transducers are transmitted to a *Nicolet* 4094A Digital Oscilloscope. Following the completion of the data collection period the digitised data is down loaded to the *MAC* via an *IEEE* interface.

The raw signals from the RF probes are fed into a *Solartron 1200* signal processor and processed data fed to the MAC via the *IEEE* interface. The void fraction calculation from the RF probe analogue system is transferred to a *BBC* micro computer, then onto the MAC via the *RS232*.

5 Data Presentation

The spatially averaged parameters recorded with both facilities are the liquid volumetric flow rate, Q_l, the gas volumetric flow rate, Q_g, the test section absolute pressure, p_{abs}, and the differential pressure along a length of the test section Δp. The experimental results are presented in the form of the gas velocity, v_g, the homogenous velocity, v_h, and the void fraction, α. The homogenous velocity is given by

$$v_h = \frac{Q_l + Q_g}{A} \tag{5}$$

and the average gas velocity is defined as

$$v_g = \frac{Q_g}{\alpha A}. \tag{6}$$

The differential pressure is not a direct measurement of the void fraction as there is a contribution from the frictional pressure drop along the pipe wall. We can define the void fraction as

$$\alpha = \frac{\Delta p - \Delta p_{fric}}{\rho_l g h}. \tag{7}$$

It is clear that to gain an accurate measurement of the void fraction it is necessary to know the frictional pressure drop (Δp_{fric}) along the pipe wall.

The approach taken for this is to use the established single phase *Darcy* equation. It was shown, by Aziz, Govier and Fogarazi [1] that in a multi-phase flow a good approximation is

$$\frac{\Delta p_{fric}}{l} = \frac{4 f \frac{1}{2} \rho_m v_h^2}{D} \tag{8}$$

where f is the friction factor, ρ_m the homogenous mixture density, D the pipe diameter and l the length of the measurment section.

The friction factor is calculated from the Reynolds number using a relation evaluated in experimental tests with a single phase liquid flow using the mixture density and the homogenous velocity and the multi-phase flow Reynolds number which is calculated from

$$Re = \frac{\rho_l v_h D}{\mu_l}. \tag{9}$$

These tests are discussed in a later section, although the results showed very good agreement with the approximation by Moody for turbulent flow in a smooth pipe, shown in equation 10. It was this relation which was used in the calculation of the frictional pressure drop. For non-Newtonian fluids an appropriate value of effective viscosity is chosen for μ_l.

6 Experimental Results

6.1 Frictional Pressure Drop Tests

As has been discussed previously, in order to calculate the void fraction it is necessary to have an accurate prediction of the frictional pressure drop along the length of the pipe. Data was recorded with single-phase water flow at various water rates and the results, Figure 6, are presented in the form of the non-dimensional friction factor versus the Reynolds number. Also plotted is the prediction of the friction factor in turbulent pipe flow by Moody, reproduced by Massey [6]:

$$f = 0.001375\left(1 + 20000\frac{k}{D} + \frac{10^6}{Re}\right) \tag{10}$$

where k is the surface roughness and the assumption of a smooth pipe:

$$\frac{k}{D} = 0 \tag{11}$$

It should be noted that the largest frictional pressure drop measured during these tests was equivalent to a head of 2.5 mm of water. The agreement with equation 10 is good, not only giving confidence in the use of this approximation in the calculation of void fraction, but also in the accuracy of the differential pressure measurements.

The correction required in the air/water flows is fairly small (equivalent void fractions of approximately 0.5 %, which with a gas void fraction of 10 % would represent an error of 5 % in v_g), but with viscous muds the effect is much more significant (approximately 2 % or an equivalent error in v_g of 20 %).

6.2 Average Gas Rise Velocity in Vertical Flow

The results for the experiments carried out with a vertical pipe and a wide range of flowing conditions are shown in Figure 7. A "Zuber Findlay" plot is used where the gas velocity is plotted versus the homogenous velocity and the data points are grouped into void fraction ranges. At low void fractions the data collapses onto a single line with an intercept of 0.25 ms^{-1} [0.75 ft/s] which represents the slip velocity for a single bubble. At higher void fractions there are clearly identifiable variations in the distribution of data points. A line fit to the 25 - 30 % void fraction data is also shown, this has an intercept of 0.55 ms^{-1} [1.65 ft/s].

Straight line fits of the form shown in equation 1 were applied to the different void fraction ranges data and the resulting intercepts and slopes from the line fits are shown in Figure 8. It is clear in the data that for void fractions below 12.5 % the slip velocity (the intercept for the line fits to the data) was approximately 0.25 ms^{-1} [0.75 ft/s]. This is consistent with the isolated bubble rise velocity for small bubbles, as modelled by Harmathy [4], see equation 2. As the void fraction increases over 15 %, the slip velocity starts to rise. It levels off for a void fraction of approximately 22.5 % at around 0.55 ms^{-1} [1.65 ft/s], compared with a Taylor bubble velocity of 0.50 ms^{-1} [1.5 ft/s] in this geometry. This observation differs from that

found by Zuber and Hench [12] who suggested that the slip velocity would fall due to bubble bubble interaction as the void fraction increased.

The results suggest that at low void fractions the gas content of the flow comprises small bubbles moving with a slip velocity of 0.25 ms^{-1} [0.75 ft/s]. As the void fraction, and hence the bubble concentration, increases the bubbles will agglomerate and form larger bubbles which will have a higher slip velocity. When the gas concentration is very high and the bubbles are sufficiently large to be influenced by the pipe walls then, as with Taylor bubbles, the terminal velocity will be limited by the pipe size and the need for the liquid phase to flow down the pipe around the bubbles. It appears that the terminal velocity in these tests is slightly higher than the Taylor bubble velocity, equation 3, and this is thought to be due to drag reduction from the high level of turbulence introduced by the bubble wakes.

The slope of the line from equation 1 is a function of the bubble concentration across the pipe and how this relates to the fluid velocity distribution. It was shown by Zuber and Findlay [11] that this would lie within the range of 1.0 to 1.5, being low for a flat distribution or high for a peaked variation where most of the gas is transported in the higher velocity flow in the centre of the pipe. In the data presented here, Figure 8, the slope of the line appears to be independent of void fraction and has a value of 1.05. In

a recent simulator for kicks in water based muds, Nickens [7] used a value 1.0 for bubble flow and 1.3 for slug flow.

6.3 The effect of wellbore deviation

A number of tests were made to investigate the effects of wellbore deviation. Experiments were conducted with the pipe at 15 degrees to the vertical. Observations of the flow during the tests showed that the bubbles would rise to the top of the pipe and agglomerate to form larger bubbles which would then rise faster. The data indicated that larger bubbles had been formed at a lower void fraction than in the vertical tests, and that there was a more peaked gas concentration distribution across the pipe giving a higher intercept and more steep slope, with the gas velocity significantly higher than in the equivalent vertical case.

6.4 Void Fraction Profiles

The RF probes were traversed radially across the pipe from top to bottom and yielded the local void fraction and bubble velocity distributions presented in Figure 9 and Figure 10 respectively. In these examples the gas and liquid superficial velocities were 0.05 and 0.3 ms^{-1} [0.15 and 0.9 ft/s]

respectively. The spatially averaged results indicated a mean void fraction of 7.9 and 5.9 % for the vertical and deviated cases and gas velocities of 0.59 and 0.89 ms^{-1} [1.77 and 2.67 ft/s] respectively.

In vertical flow the void fraction distribution is almost flat across the pipe, showing only a small drop close to the walls. The construction of the probes meant that it was not possible to measure right up to the edge of the pipe. The bubble velocity results are similar although they do indicate a lower flow velocity close to the wall.

The results taken with deviated flows show a much larger void fraction near to the top of the pipe, where the gas bubbles are moving much more quickly. The much larger level of scatter in the bubble velocity results is caused by the increase in bubble motion perpendicular to the pipe centreline and hence the measurement axis, due to the deviated flow. The higher void fraction near to the top of the pipe will cause larger bubbles, which will have a higher slip velocity, to form, as was seen in the spatially averaged tests. While we would expect the peaks in the void fraction and the velocity distribution to cause an increase in the slope of the averaged data.

7 Conclusions and Further Work

The rise velocity of air bubbles in water is influenced by a number of parameteres including void fraction, flow rates, bubble size and geometry. The injection conditions of any test facility are important as they can change the initial bubble size distribution.

As the void fraction increase from 15 - 25% in a 200 mm [8 "] pipe a flow regime change occurs from bubble to slug flow which is associated with an increase in bubble size and velocity. The slope of the line in the Zuber Findlay plot is essentially unchanged. In a 200 mm [8 "] pipe a value of 1.05 is found to be appropriate. These results show a transition towards slug flow occuring at lower void fractions than observed in smaller pipe diameter tests and the models used in a number of other kick simulators.

Deviation of the pipe introduces an important mechanism for bubble coalescence and at low void fractions the large bubbles rise more quickly than in the vertical case. For 15 degrees the rise velocity is close to that in slug flow for a vertical well. This result has important implications for kick modelling as very few wells are truly vertical.

The current study is being extended to include an annular geometry and

non-Newtonian fluids. Initial tests with a simulated drilling mud show a change in bubble size distribution and significant changes in rise velocities. Modelling of the rise of single bubbles has been used to explain the results for a number of rheologies. It appears that the effects of rheology are very important, they will be reported at a later date and will be included in the Research Model developed for the UK Department of Energy.

8 Notation

A	Pipe Cross Sectional Area
C_0	Zuber Findlay Constant
D	Pipe Diameter
f	Friction Factor
g	g
k	Surface Roughness
l	Length of Measurement Zone
Q_g	Gas Volumetric Flow Rate
Q_l	Liquid Volumetric Flow Rate
v_g	Mean Gas Velocity
v_h	Homogenous Velocity
v_{slip}	Gas Bubble Slip Velocity
v_{slip0}	Isolated Gas Bubble Slip Velocity
α	Void Fraction
Δp	Pressure Difference Along Pipe
Δp_{fric}	Frictional Pressure Drop Along Pipe
μ_l	Liquid Viscosity
ρ_g	Gas Density
ρ_l	Liquid Density
ρ_m	Homogenous Mixture Density
σ	Liquid-Gas Interfacial Tension

9 Acknowledgements

The authors would like to thank the staff of the Fluid Mechanics department at SCR for all their help in these experiments. In particular Roy

Boardman (OGTB) and Paul Faupel without whom nothing is possible, Tim Holton and Dave Mackay who helped in running the rig for many of the experiments, and Ian Walton for his helpful comments about experimentalists.

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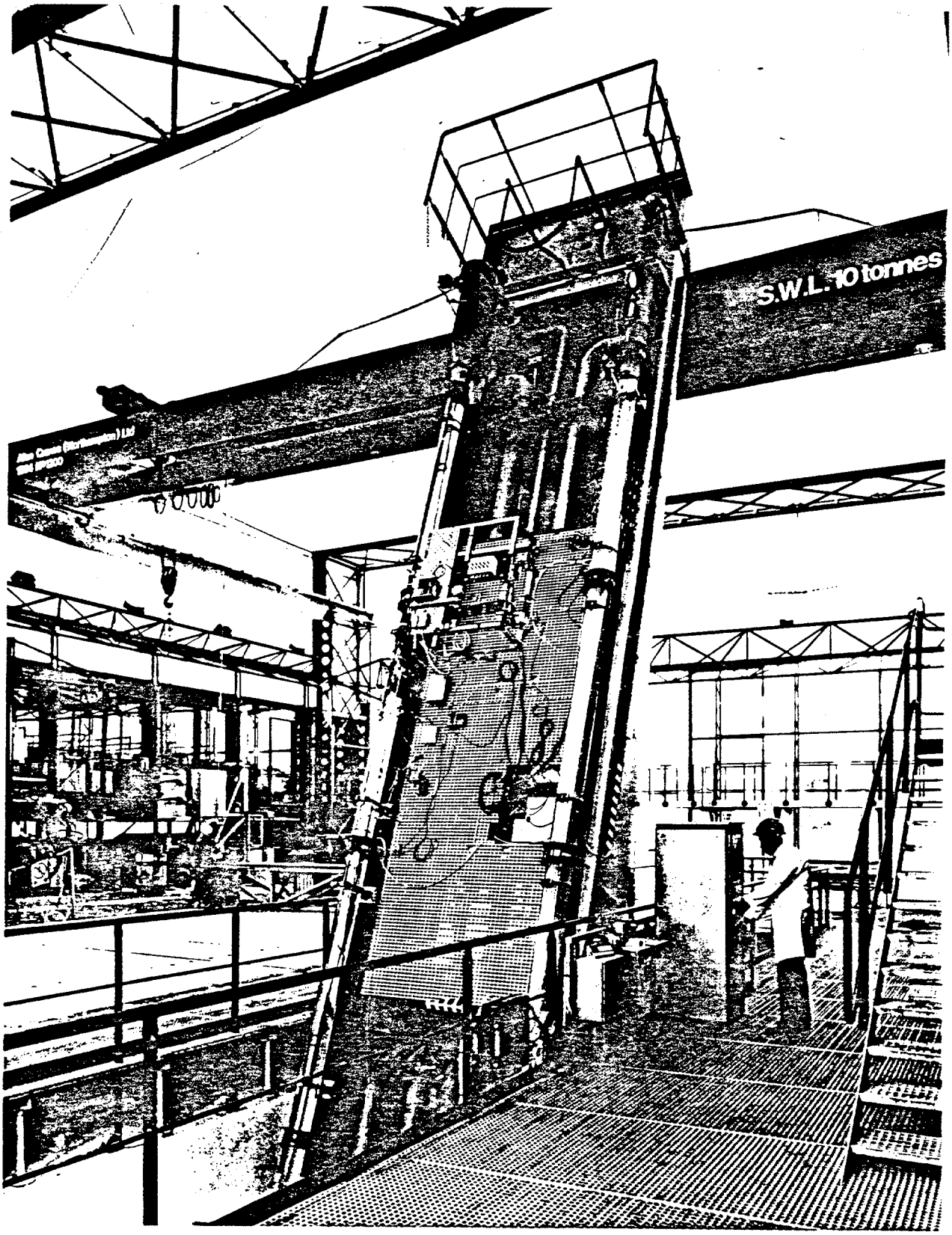

Figure 1 *Photograph showing the SCR flow facility, 200 mm facility on the right with the smaller 150 mm pipe on the left.*

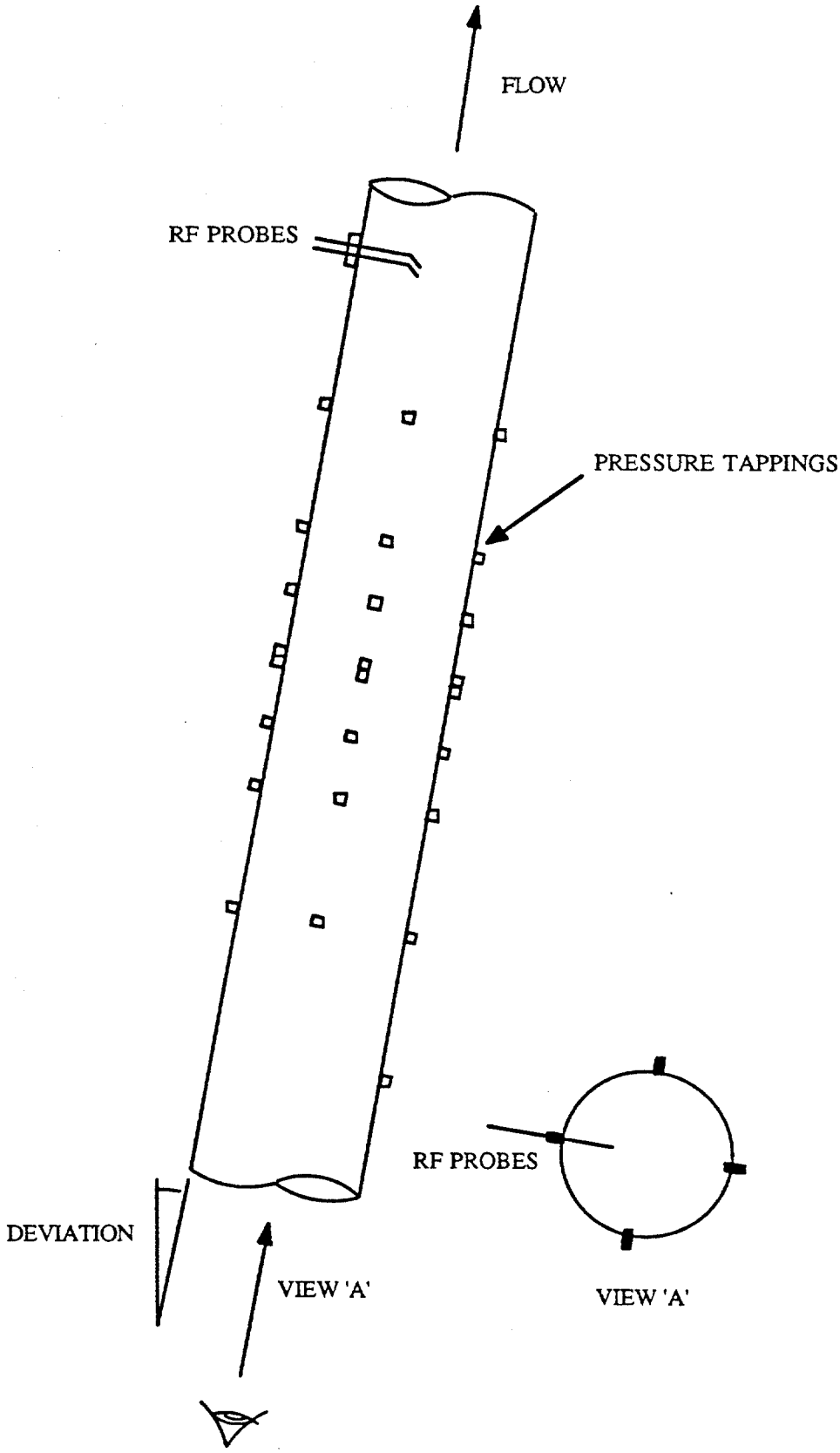

Figure 2 *Layout of test section showing relative positions of pressure tappings and RF probe position.*

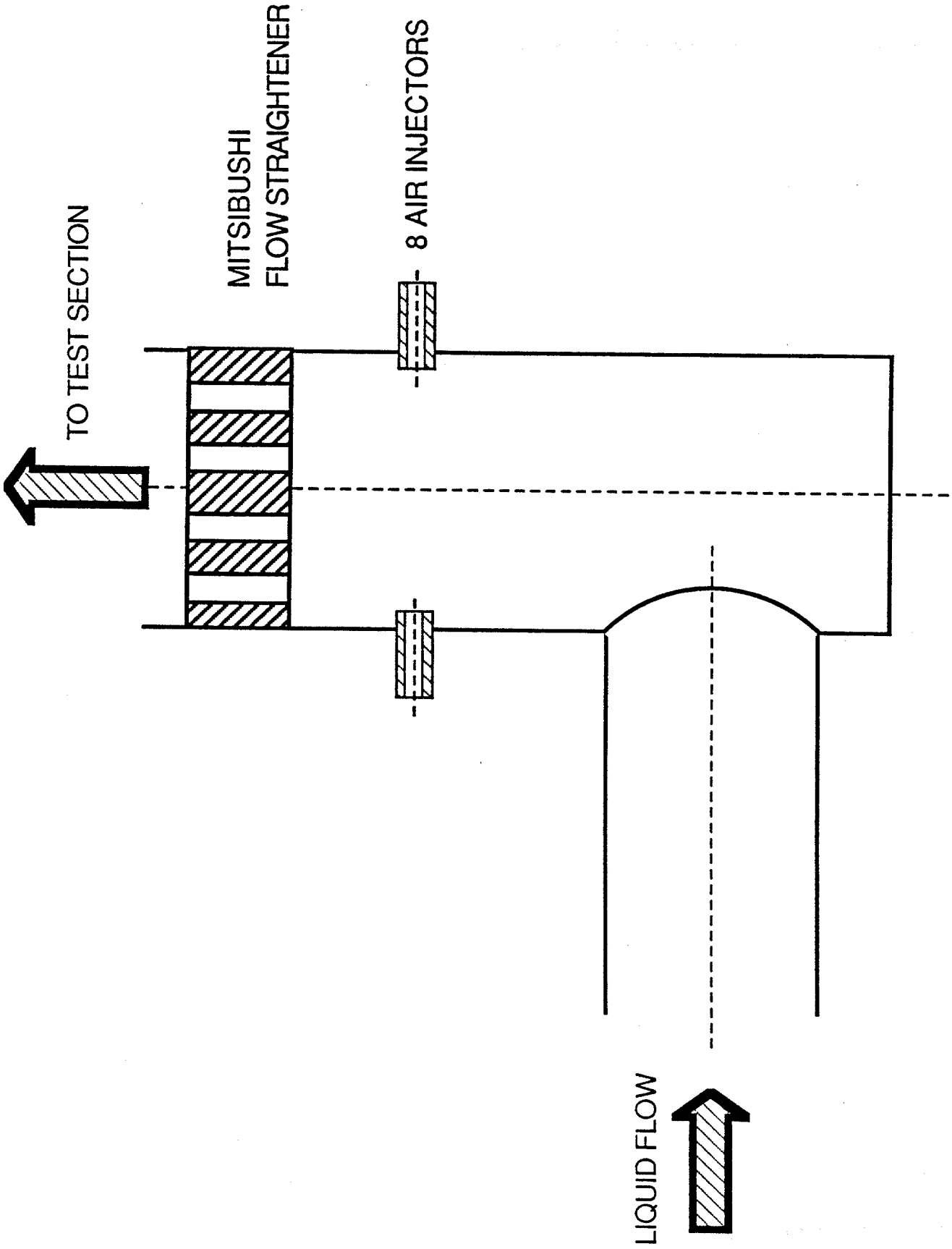

Figure 3 *Air injector and plenum chamber geometry showing position of air injection, into region of high swirl, and position of Mitsibushi flow straightener.*

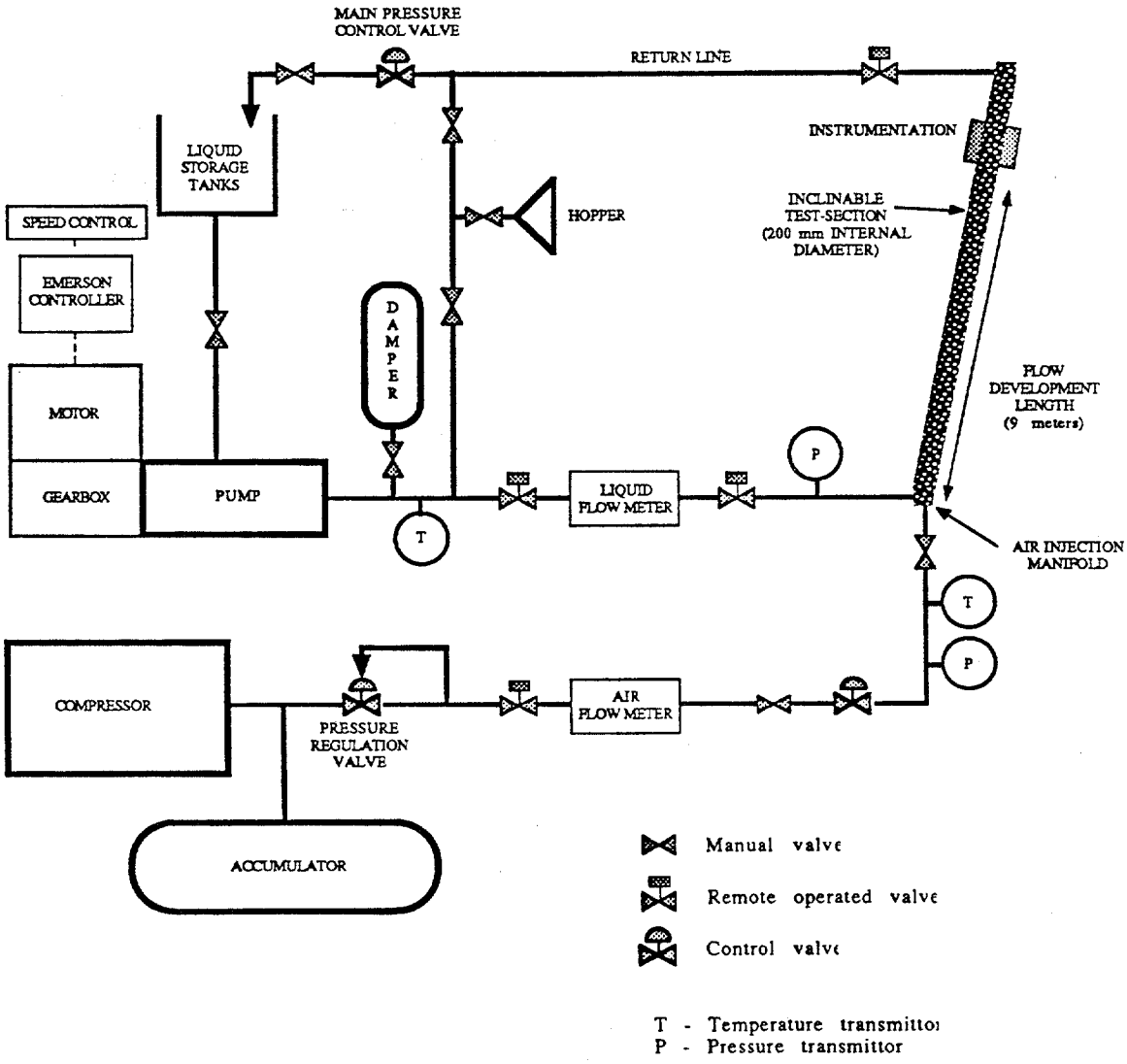

Figure 4 *Schematic layout of flowloop showing liquid and gas supply and return lines.*

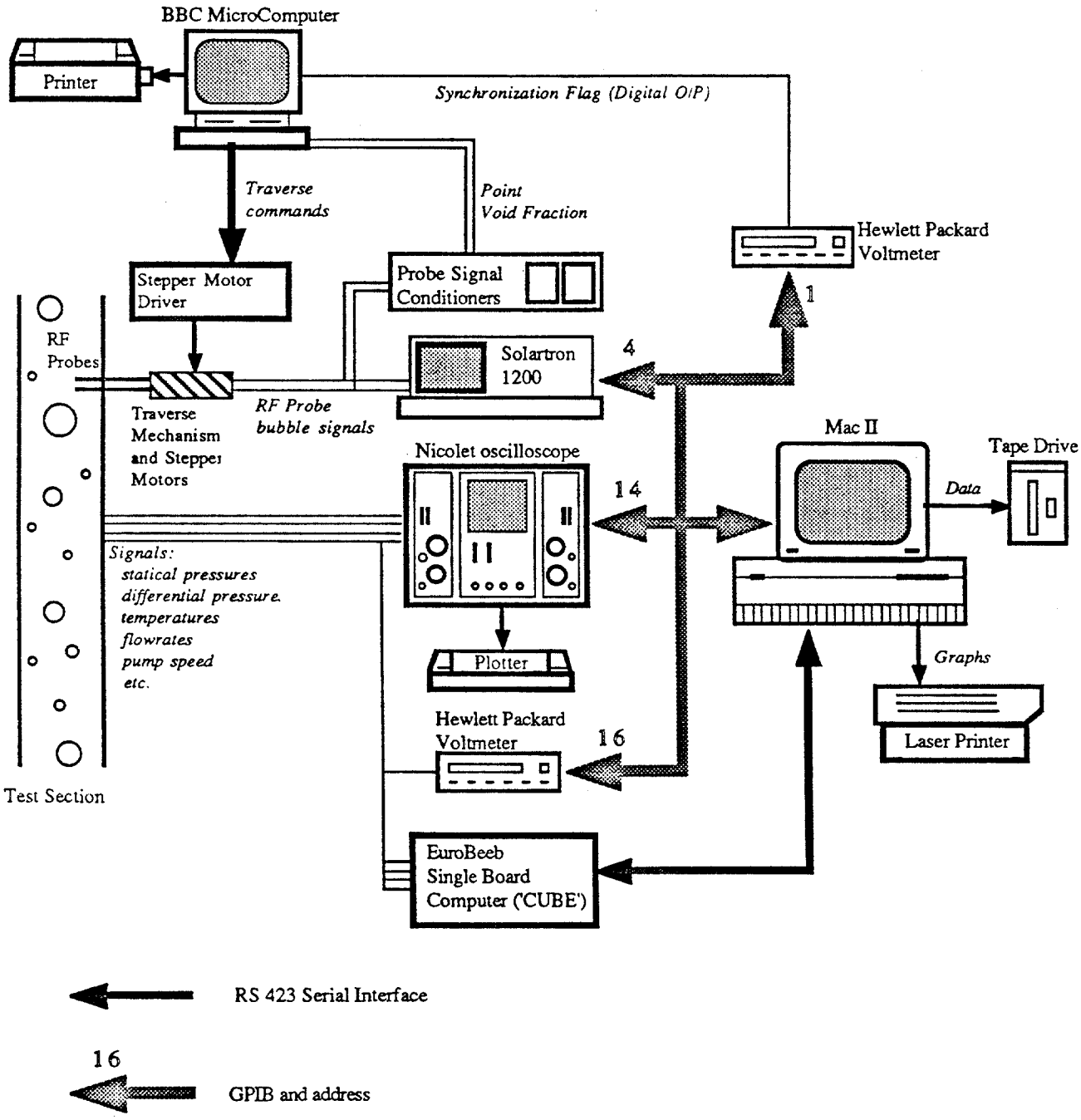

Figure 5 *Schematic view of data acquisition system employed for the tests.*

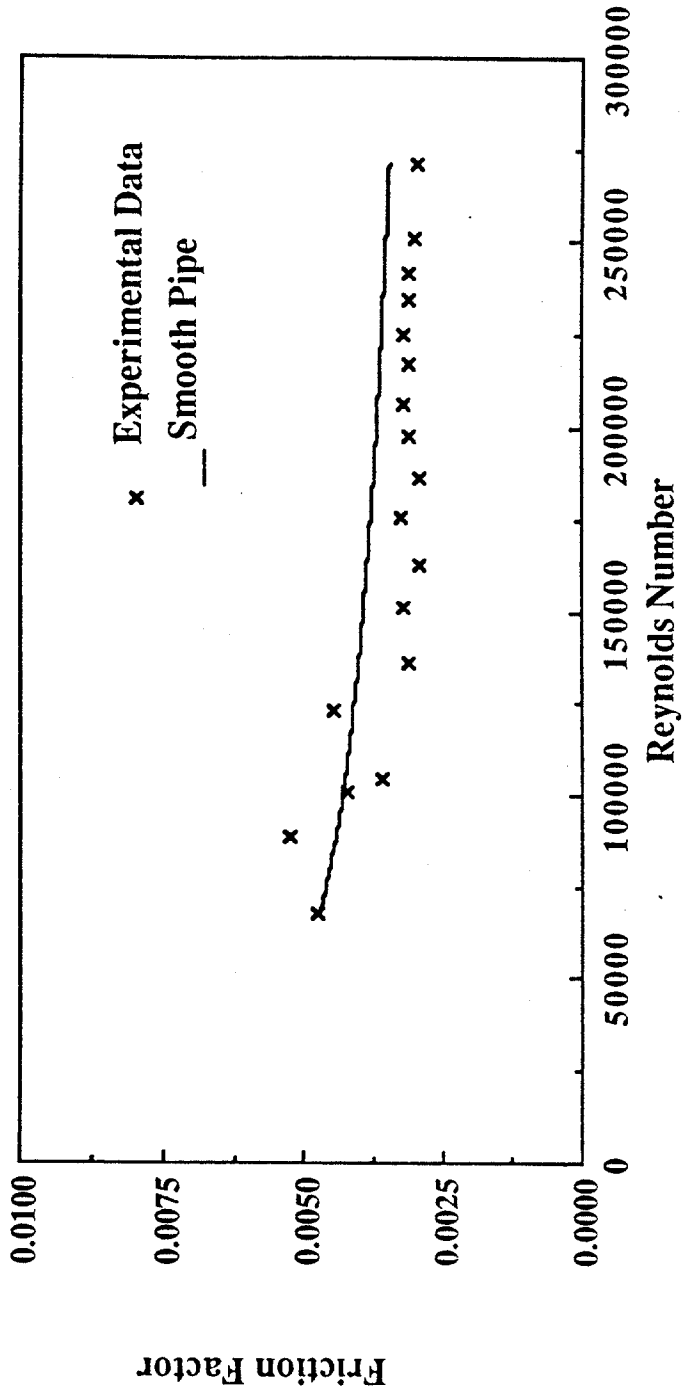

Figure 6 *Data recorded from frictional pressure drop tests, also the prediction for turbulent flow in a smooth pipe, see equation 10.*

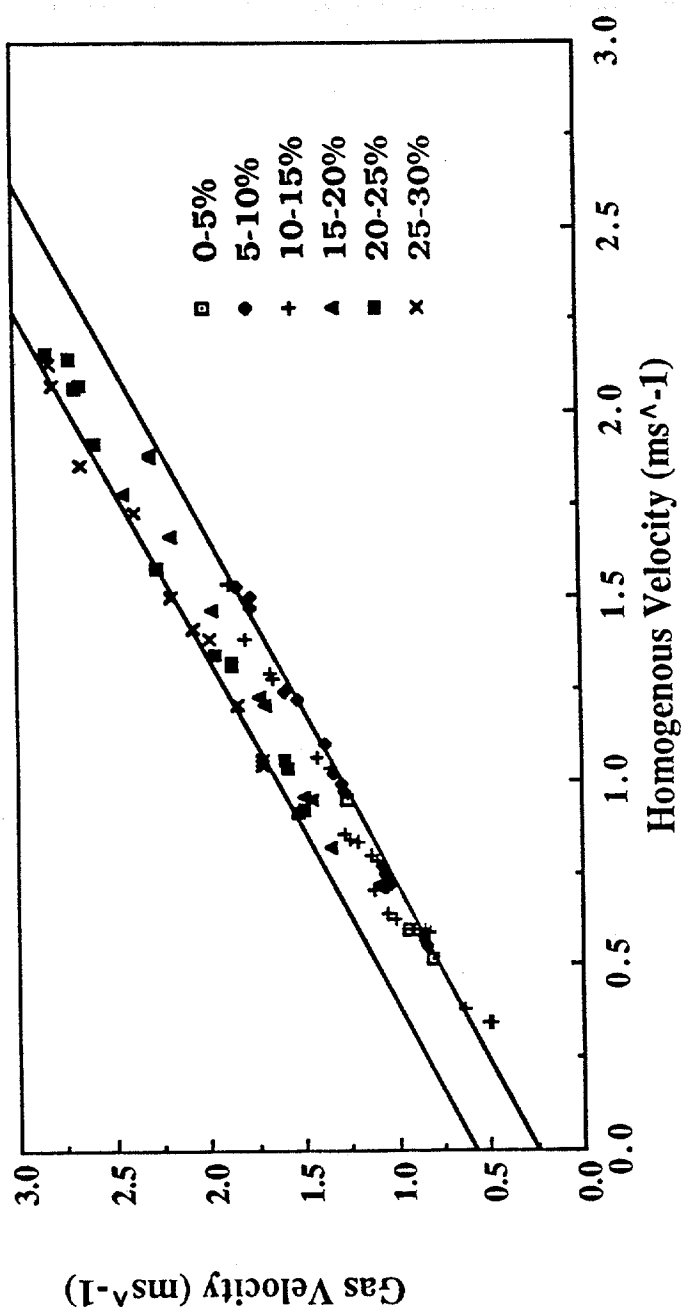

Figure 7 *Zuber - Findlay plot for data recorded in vertical pipe flow. The line fits are for the low ($\alpha < 15$ %) and high ($\alpha > 25$ %) void fraction data.*

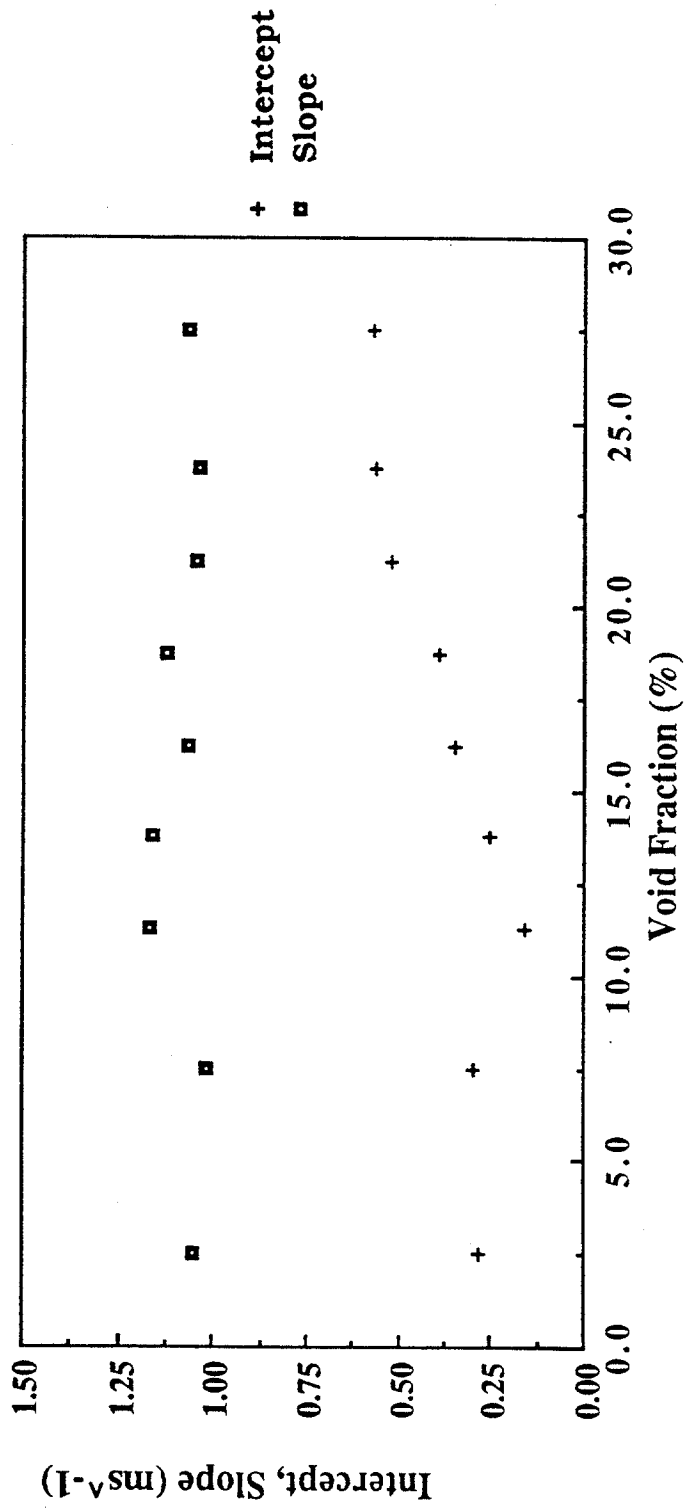

Figure 8 *Intercept and slope for line fits to Zuber Findlay plot for vertical pipe flow.*

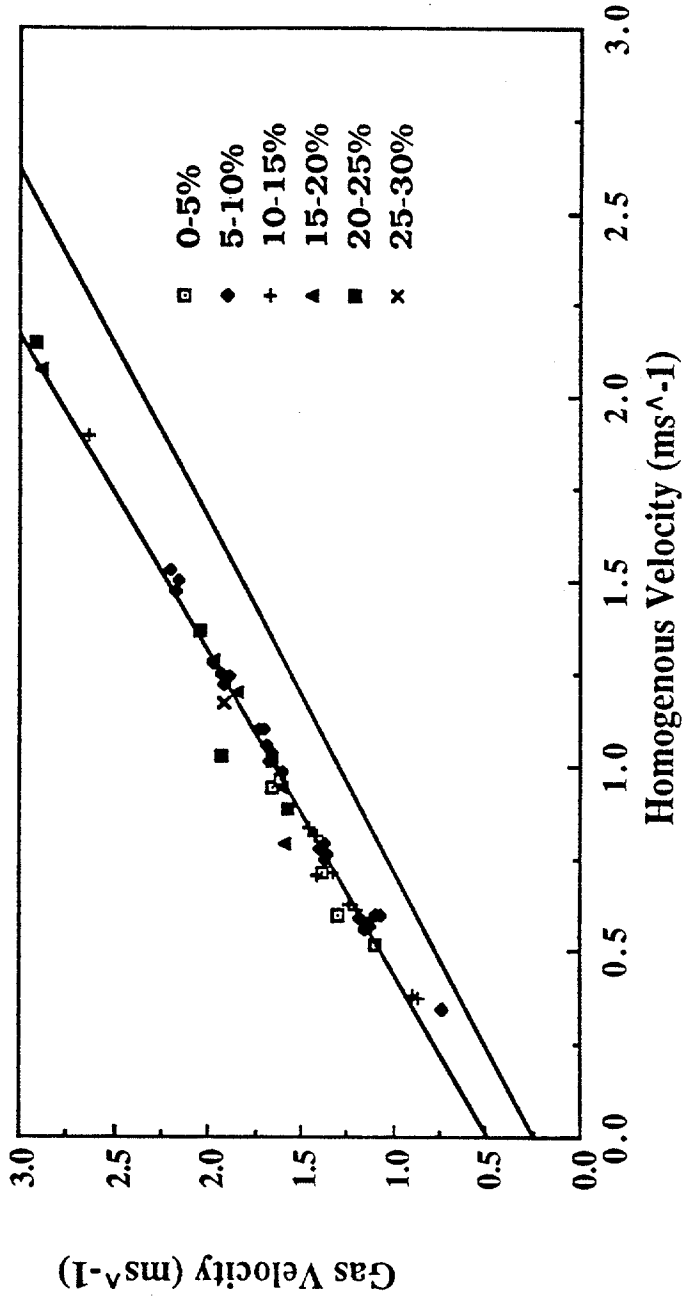

Figure 9 *Zuber - Findlay plot for data recorded with deviated (15°) pipe flow, line fit to all data is shown, together with low void fraction line fit for vertical test results.*

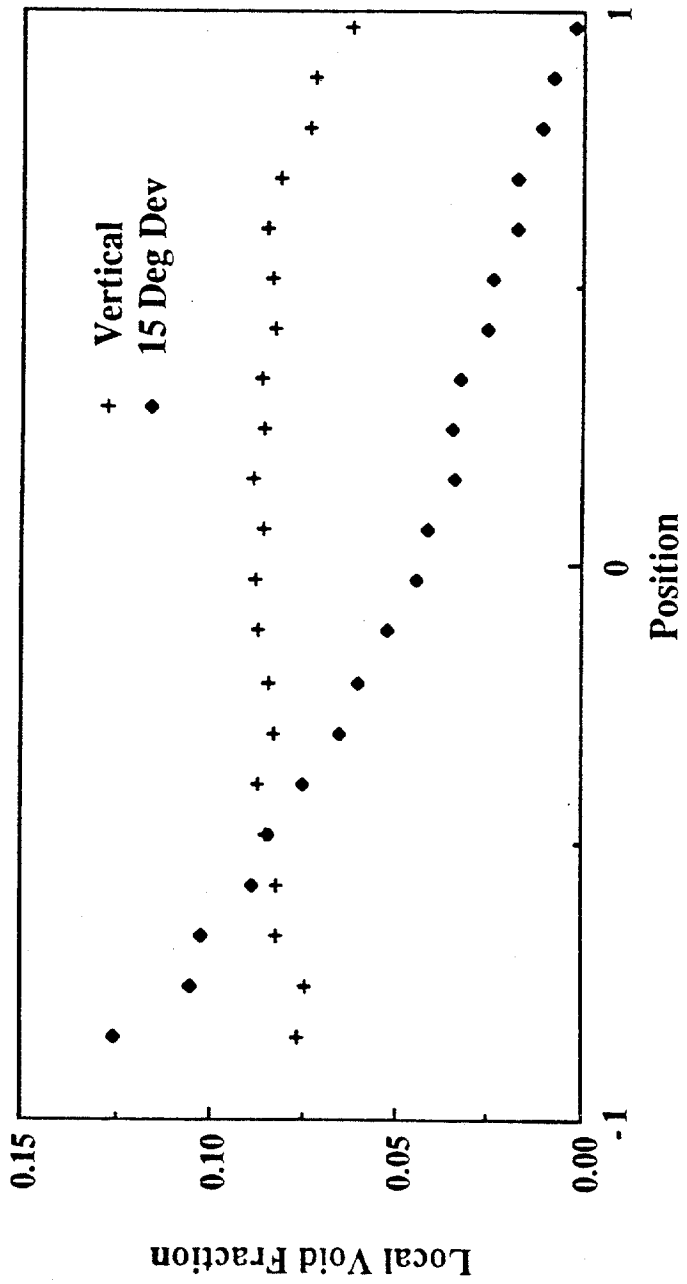

Figure 10 *Local gas void fraction distribution across the pipe for vertical and 15° deviated flow.*

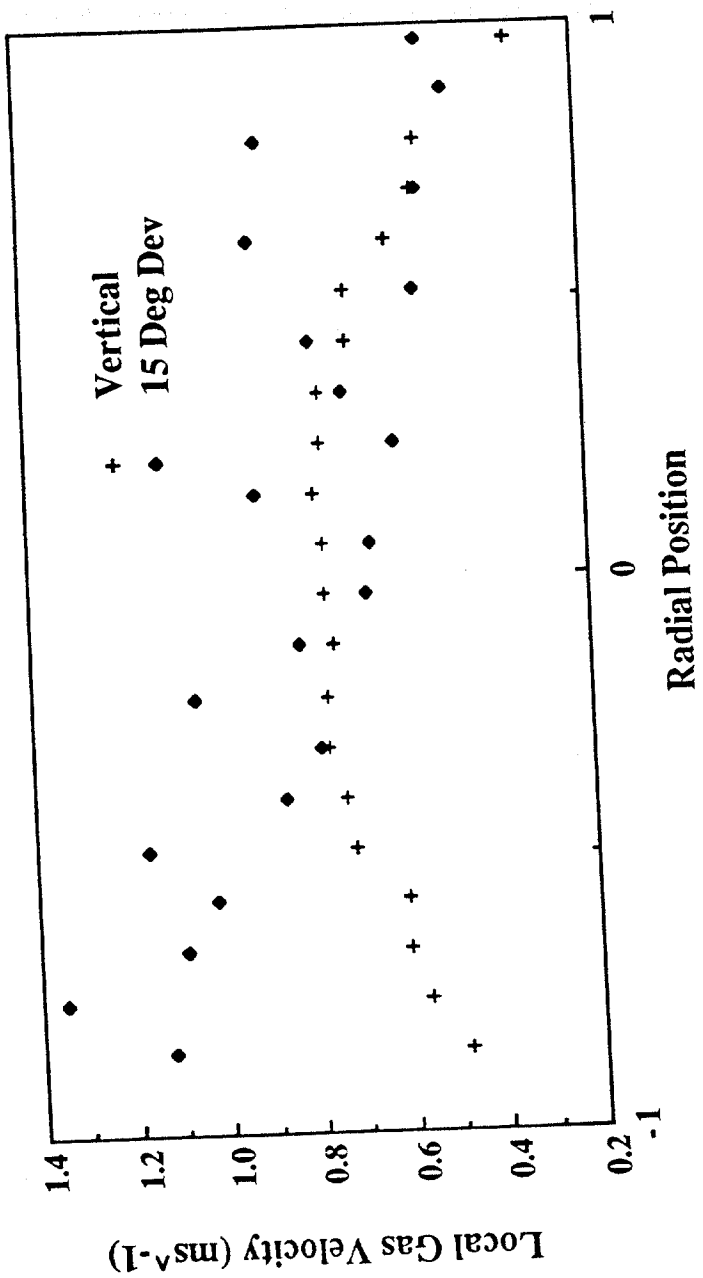

Figure 11 *Local gas bubble velocity distribution across the pipe for vertical and 15° deviated flow.*

BLOWOUT CONTROL METHODS

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Abstract

Blowouts are problems which are subject to the same physical laws as all other engineering problems. Experience has shown that a safer, more cost effective and less time consuming control effort is possible through the application of these laws.

This paper presents the concepts involved in controlling blowouts from either the surface or from subsurface. Since each blowout is unique, it must be analyzed to determine which control technique is the most suitable. The discussion of these concepts is from both a theoretical and a practical standpoint based on the author's involvement in numerous well control situations. Different methods of control; such as dynamic kills, momentum kills and bullheading, are discussed. These discussions will cover topics such as kill fluid weights, pumping rates, and fluid volume requirements.

In addition, speciality methods such as hot wellhead work, snubbing, stripping, relief well planning and drilling, blowout well detection, surface equipment, and pumping plants are also discussed.

Introduction

A blowout is defined as the uncontrolled flow of formation fluids from a well. These fluids may be oil, gas, water, a combination of any two of these or a combination of all three. The flow can be either to the surface or to a different underground formation. Situations involving blowouts can lead to major losses of equipment, large releases of wellbore fluids to the enviroment, extensive damage to reservoirs and worst of all the loss of human life. Therefore, it is critical that blowouts be quickly and efficiently controlled to minimize the damage that results from their occurence.

There are five basic pumping control techniques which can be implemented to regain control of the well.

These are static kills, dynamic kills, momentum kills, bullheading and lubrication. If the control attempt is made through the surface equipment on the blowing well it is referred to as a surface kill. If the surface equipment and/or the wellbore of the blowing well has been damaged to the extent that a surface kill is not possible the well must be killed from a subsurface point. This type of kill is referred to as a subsurface kill. Wells which must be killed from subsurface are sometimes referred to as conceded wells. In almost every case a surface kill will result in a faster and less expensive control attempt. As a result, even if subsurface control is being attempted, surface control efforts should be continued if possible.

A static kill is simply the placement of a fluid into the wellbore which has a sufficient hydrostatic gradient to overbalance the reservoir pressure. It is important to realize that a static kill is the end point of all control techniques. Dynamic kills utilize the frictional resistance to flow in addition to hydrostatic gradient to overbalance the reservoir pressure. However, the well remains dead only as long as some minimum flow rate is maintained. In order to complete the well control process the well must then be statically killed. A momentum kill involves injecting a fluid which has a greater downward momentum flux than the upward momentum flux of the formation fluids. This results in the formation fluids ceasing to flow upwards and being forced back into the formation. This allows the wellbore to be loaded with weighted fluids. Again the final step in the control operation is to fill the wellbore with a static kill weight fluid. Bullheading is accomplished by shutting in the blowing well and then pumping fluid into the wellbore forcing the formation fluids in the wellbore back into the formation. As with a momentum kill this allows the wellbore to be loaded with weighted fluids. Final control is achieved when the wellbore has been filled with a static kill weight fluid. Lubrication requires that the well be shut-in. After shut-in, small volumes of weighted fluid are pumped into the wellbore and small volumes of formation fluid are bled off from the well. Sufficient time is allowed for the weighted fluid to fall through the formation fluid and then the process is repeated until the wellbore is loaded with weighted fluid. In both the bullheading and lubrication methods care must be exercised during the analysis to insure that all casing seats and exposed formations are capable of withstanding the shut-in pressures to which they will be exposed. If they cannot withstand these pressures, an underground blowout may be created. Since underground blowouts are more difficult to control than surface blowouts this should not be allowed to occur.

Prior to the implementation of one of these control techniques, considerable work may have to be performed on the surface equipment and/or the wellbore of the blowing well. This may involve snubbing, stripping, relief well planning and drilling and sometimes specialty work. This specialty work may involve hot tapping tubulars, valve drilling, debris clearing, firefighting and hot wellhead work such as the installation of diverters or the replacement of the wellhead or BOP stack itself. This type of work is best left to experienced personnel to ensure a safe and efficient operation.

Surface Kills

Surface kill operations are by far the most common type of well control procedure. All five of the basic control techniques can be implemented from the surface provided that the surface equipment and/or wellbore are capable of withstanding the operational loads which will be imposed on them during the control operation. In many instances this will not be the case, at least initially. Considerable work may have to be performed on the surface equipment and/or the wellbore to ensure its integrity during the control operations or to get it ready to proceed with a control operation. For instance if the blowout occurred with the drill pipe off bottom, snubbing or stripping may be required to return the drill pipe to bottom prior to the commencement of the pumping operation. If a fire has occurred, the surface equipment may be damaged so severely that it must be removed and replaced before continuing. This may involve removing the rig and existing BOP stack, and installing a new BOP and diverter stack. Considerably more time may be spent preparing for the pumping operation than it actually takes to perform this operation. In the following sections each of the basic pumping control techniques will be discussed.

Static Kill

As has been previously noted a static kill simply involves the placement of a weighted fluid into the wellbore which has a hydrostatic gradient sufficient to overbalance the reservoir static pressure. The hydrostatic gradient of the fluid may be expressed by the following equation:

$$Grad = 0.0519\,(\rho) \tag{1}$$

where

Grad = hydrostatic gradient of the fluid, psi/ft

ρ = fluid density, lb_m/gal.

The pressure exerted by a column of fluid can be expressed in terms of its hydrostatic gradient as:

$$P_{HYDRO} = (TVD)\,(Grad) \tag{2}$$

where

P_{HYDRO} = hydrostatic pressure at TVD, psi

TVD = true vertical depth, ft.

Thus, if the reservoir static pressure in psi is denoted by P_{Res}, then the required hydrostatic gradient for a static kill is defined by setting P_{HYDRO} equal to P_{Res}. That is

$$P_{Res} = P_{HYDRO} = (TVD)\,(Grad) \tag{3}$$

or

$$Grad_{kill} = P_{Res}/(TVD). \tag{4}$$

This can be expressed in terms of the fluid density as:

$$\rho_{kill} = 19.25\,(P_{Res})/(TVD). \tag{5}$$

where

ρ_{kill} = density of static kill fluid, lb_m/gal

P_{Res} = reservoir static pressure, psi

TVD = true vertical depth, ft.

Momentum Kill

Newton's Second Law states that the net force acting on a given mass is proportional to the time rate of change of linear momentum of that mass. Another way of stating this is that the net external force acting on the fluid within a prescribed control volume equals the time rate of change of momentum of the fluid within the control volume plus the net rate of momentum transport out of the surfaces of the control volume.

In order to understand the momentum kill concept consider the situation depicted in Figure 1. In this figure ρ_1 is the injection fluid density, Q_1 is the injection fluid volumetric rate, ρ_2 is the flowing formation fluid density and Q_2 is the formation fluid volumetric rate. Application of the momentum theorem to the control volume yields:

$$\Sigma F_x = \dot{m}_2 V_2 - \dot{m}_1 V_1 \tag{6}$$

where

$\dot{m}$ = mass flow rate

V = velocity.

Noting that

$$\dot{m} = \rho A V \tag{7}$$

where

$\dot{m}$ = mass flow rate

ρ = density

A = flow area

V = velocity

Equation 6 can be rewritten as

$$\Sigma F_x = \rho_2 A V_2^2 - \rho_1 A V_1^2. \tag{8}$$

Using the average velocity as defined by

$$V = Q/A \tag{9}$$

where

V = average bulk velocity

Q = volumetric flow rate

A = flow area

and substituting yields

$$\Sigma F_x = \rho_2 Q_2^2/A - \rho_1 Q_1^2/A. \tag{10}$$

From this equation we can see that if the second term on the right side of the equation is larger than the first term on the right side the net force acting on the mass of the liquid within the control volume is in the

negative x-direction. The result of this is fluid flow in the negative x-direction.

It is important to note that the average velocity has been used in the above derivation. If the velocity varies across the section, as is actually the case, the true momentum flux is greater than that based on the average velocity. The true momentum flux can be evaluated by:

$$M_A = \int_A (u\rho dA)u \tag{11}$$

where

M_A = true momentum flux

u = velocity at any point in section

ρ = density

A = area

while that based on the average velocity is $V^2A\rho$ as derived using Equations 6, 7 and9. The ratio of the true momentum to that based on the average velocity is defined as the momentum correction factor, β, where

$$\beta = \rho u^2 dA / \rho V^2 A \geq 1. \tag{12}$$

For one dimensional flow, as we assumed, the velocity profile is flat and $\beta = 1$. For fully developed turbulent flow in a circular conduit measured values of β are about 1.03. Thus, the use of the average velocity is valid for fully developed flow. For fully developed laminar flow in a circular conduit, $\beta \simeq 1.33$. Thus, if the flow is laminar, the momentum correction factor should be applied.

From Equation 10 we can see that a momentum kill involves injecting a fluid with a sufficient momentum flux to overcome the momentum flux of the flowing formation fluids. This results in the formation fluid flow being reversed and allows the wellbore to be filled with weighted fluid. Thus, the determination of whether or not a momentum kill is possible involves calculating the momentum fluxes of the flowing formation fluids and the injected fluids at the point of injection. For gas flows we can express the real gas law as:

$$\rho = P/zRT \tag{13}$$

where

ρ = gas density, lb_m/ft^3

P = pressure, lb_f/ft^2

R = gas constant, $ft \cdot lb_f / lb_m \cdot {}^oR$

T - temperature, ^{o}R

z - gas deviation factor.

Noting that

$$R = \mathcal{R}/M \tag{14}$$

where

$\mathcal{R}$ - universal gas constant, 1545 ft-lb_f/lb_{mole}-^{o}R

M - molecular weight of the gas, lb_m/lb_{mole}

and that

$$M \simeq SG(29) \tag{15}$$

where

SG - specific gravity of the gas with respect to air

29 - molecular weight of air

then we can rewrite Equation 13 as

$$\rho = 2.7029(SG)P/zT \tag{16}$$

where

ρ - gas density, lb_m/ft^3

SG - gas specific gravity with respect to air

P - pressure, psia

z - gas deviation factor

T - temperature, ^{o}R.

Normally gas flows are expressed as flow at standard conditions. Standard conditions are defined as 14.7 psia and 60 ^{o}F. Applying conservation of mass yields:

$$P_1Q_1/Rz_1T_1 = P_2Q_2/Rz_2T_2 \tag{17}$$

where

P - pressure

Q - volumetric flow rate

R - gas constant

z - gas deviation factor

T - temperature

$1,2$ - denotes points 1 and 2 in the flow stream.

Substituting for standard conditions and letting point 2 be the injection point and point 1 be at standard conditions gives:

$$0.0283 Q_1 z_2 T_2 / P_2 = Q_2 \tag{18}$$

where

Q_1 - gas flow rate, SCFM

z_2 - gas deviation factor at T_2 and P_2

P_2 - pressure at injection point, psia

T_2 - temperature at injection point, ^{o}R

Q_2 - gas flow rate at injection point, CFM

The momentum flux of the gas flow can then be determined by combining Equations 16 and 18:

$$M_G = 0.00216(SG) Q_1^2 z_2 T_2 / P_2 A \tag{19}$$

where

M_G - gas momentum flux, $lb_m - ft / min^2$

SG - gas specific gravity

Q_1 - gas flow rate at standard conditions

z_2 - gas deviation factor at T_2 and P_2

T_2 - temperature at injection point, ^{o}R

P_2 - pressure at injection point, psia

A - flow area, ft^2.

For the case of liquids and the assumption of incompressibility the momentum flux can be expressed as:

$$M_L = 31.52 \rho_L Q_L^2 / A \tag{20}$$

where

M_L - liquid momentum flux, $lb_m - ft / min^2$

ρ_L - liquid density, lb_m / ft^3

Q_L - liquid flow rate, BPM

A - flow area, ft^2.

This equation can be used for both the injected fluid and for fluid produced from the formation as long as they are relatively incompressible. If these fluids cannot be treated as being incompressible, a procedure similar to that used for gases must be employed.

For the case of multiphase flow of the formation fluids in the wellbore, the momentum fluxes of the different phases can be calculated individually and then summed to determine the total momentum flux of the formation fluids. However, the determination of the mass flow rates and velocities of the different phases is a complex problem. A computer program is normally utilized to determine these values. A detailed case history illustrating the application of a momentum kill is provided in Reference 1.

Dynamic Kills

The purpose of a dynamic kill is to establish a bottomhole pressure, P_{BH}, which is slightly greater than the reservoir static pressure, P_{Res}. This condition prevents the further influx of formation fluids into the wellbore and allows the placement of weighted fluid into the wellbore. In a dynamic kill the method used to establish the required bottomhole pressure is to inject a fluid at a rate such that the pressure exerted at bottomhole by both the hydrostatic gradient of the fluids and the viscous resistance to the upward flow of the fluids is equal to the required bottomhole pressure. Another way of saying this is that the required bottomhole pressure to control the well will be established by the sum of the hydrostatic pressure and the flowing frictional resistance of a fluid. It is important to realize that the well is dead only as long as some minimum flow rate is maintained. After the well has been dynamically killed with some fluid, this fluid is replaced with a static kill weight fluid.

Figure 2 illustrates the basic concepts of a surface dynamic kill. This figure shows fluid being injected down the drillpipe to bottomhole where it combines with the fluids flowing from the reservoir and flows up the annulus. The injection pressure, P_{DP}, can be expressed as:

$$P_{DP} = P_{BH} - P_{HYDROT} + P_{FT} \qquad (21)$$

where

P_{DP} - surface injection pressure, psi

P_{BH} - bottomhole pressure, psi

P_{HYDROT} - hydrostatic pressure of fluid in the injection string, psi

P_{FT} - frictional pressure loss in the injection string, psi.

The bottomhole pressure can be expressed as:

$$P_{BH} = P_{HYDROA} + P_{FA} + P_{SURF} \quad (22)$$

where

P_{BH} - bottomhole pressure, psi

P_{HYDROA} - hydrostatic pressure of the fluid in the annulus, psi

P_{FA} - frictional pressure loss in the annulus, psi

P_{SURF} - annulus surface pressure, psi.

Thus, the condition to be satisfied for a dynamic kill is:

$$P_{BH} = P_{HYDROA} + P_{FA} + P_{SURF} \geq P_{Res} \quad (23)$$

As the injected fluid first enters the annulus it combines with the fluid flowing from the reservoir. Thus, as the well is being killed the flow in the annulus is multiphase. When the well is dynamically dead the annular flow will become single phase after the gas cut fluid is circulated out of the wellbore. In the majority of cases the fluid used to dynamically kill the well will be lighter than the static kill weight fluid. However, in a few cases some heavier fluids may be used initially to slow the flow from the reservoir.

Normally when dynamic kills are utilized the formation fluid is gas or mainly gas. Therefore, the injected fluid has a greater hydrostatic gradient than the formation fluids. Since the effect of the formation fluids on the injected fluid as they comingle and flow up the annulus is to decrease the hydrostatic gradient of the injected fluid, the ideal kill fluid is one which gains flow resistance as fast as it loses hydrostatic gradient due to this comingling of fluids. An equation to predict this ideal kill fluid has been derived by Blount[2] and can be expressed as:

$$\rho_I = 12.83 P_{Res}/TVD \quad (24)$$

where

ρ_I - density of kill fluid, lb_m/gal

P_{Res} - reservoir static pressure, psi

TVD - true vertical depth, ft.

Once a kill fluid density has been selected, the required flow rate to achieve dynamic control with single phase flow in the annulus can be determined from Equation 23. The hydrostatic term is simply:

$$P_{HYDROA} = 0.0519\rho(TVD) \tag{25}$$

where

P_{HYDROA} - hydrostatic pressure at TVD, psi

ρ - fluid density, lb_m/gal

TVD - true vertical depth, ft

and the frictional pressure loss can be determined from

$$P_{FA} = f\rho L/2D_e g_c = 1.758f\rho Q^2 L/D_e A^2 \tag{26}$$

where

P_{FA} - frictional pressure loss in annulus, psi

f - Moody friction factor

V - velocity, ft/sec

L - measured depth, ft

ρ - fluid density, lb_m/gal

D_e - equivalent diameter, in

A - flow area, in^2

Q - volumetric flow rate, BPM

g_c - 32.2 lb_m-ft/lb_f-sec^2.

Thus, Equation 23 can be rewritten as

$$P_{BH} = P_{SURF} + 0.0519\rho(TVD) + 1.758f\rho Q^2 L/D_e A^2 \tag{27}$$

and this can be rearranged to yield

$$Q = \{[P_{BH}-P_{SURF}-0.0519\rho(TVD)](D_e A^2)/1.758f\rho L\}^{1\backslash 2}. \tag{28}$$

As has previously been stated this is the minimum flow rate required to maintain dynamic control with

single phase flow down the injection string and up the annulus. Under these conditions the surface injection pressure, P_{DP}, can be expressed as

$$P_{DP} = P_{FT} + P_{FA}. \tag{29}$$

This value must be checked to insure that the surface injection equipment pressure limitations are not exceeded. Numerous methods are available in the literature for the determination of the values of the friction factors or pressure drops for both Newtonian and Non-Newtonian fluids.

The rate calculated by Equation 28 is sufficient to dynamically kill the well in single phase flow, but may or may not be capable of killing the well in multiphase flow. If the injection rate is not sufficient to dynamically kill the well in multiphase flow, the control effort will reach an equilibrium point where the injected fluid is gas lifted from the wellbore. A plot of the wellbore performance curves at various injection rates and the reservoir inflow performance relationship can be utilized to determine the required injection rate for a dynamic kill while in multiphase flow. Figure 3 shows these curves plotted as bottomhole flowing pressure versus gas rate. If the wellbore performance curve does not intersect the inflow performance relationship, the injection rate is sufficient to kill the well. This is discussed in more detail by Blount[2], Koederitz et al.[3], and Lynch et al.[4]. Again the surface injection pressure must be calculated to insure that no pressure limitations are exceeded. The calculation of the wellbore performance curves is a complex problem due to the multiphase flow, pressure and temperature dependent fluid properties, etc. This type of solution is usually arrived at through the use of a computer program. In the case of a dynamic kill this multiphase flow problem is further complicated by the transient nature of the process.

One extremely important point to note is that during all operations the fracture pressure of any exposed formations or casing seats should not be exceeded. If these pressures are exceeded and a formation broken down the control of fluid placement is lost.

Often times the values for gas rates, fluid properties, and wellbore conditions used in the above calculations are only approximate. When this is the case, a useful tool during kill operations is a plot of pressures and flow rates versus the volume of fluid pumped. Such a plot is shown in Figure 4. By plotting actual measurable values during the kill operation and comparing the curve trends rather than the absolute agreement, one can tell if the injected fluid and the well is behaving as has been predicted. If there is not

agreement this comparison provides the opportinuity to make changes in the control procedure at the earliest possible time.

The previous discussion has described the concepts involve in dynamically killing a well with the injection string on the bottom. A dynamic kill is also possible with the injection string off bottom. The determination of the required rate for killing the well in multiphase flow can be accomplished in the same manner as for a kill with the injection point at or near bottom. As fluid is injected during the dynamic kill and the bottomhole pressure begins to increase the flow rate from the reservoir decreases. If this flow rate decreases enough it is possible for some of the injected fluid to fall through the flowing reservoir fluid and accumulate in the wellbore below the injection point. This mechanism has been referred to in the literature as countercurrent flow. A more detailed discussion of this phenomena is presented by Gillespie, Morgan and Perkins[5]. Another point to consider is that due to the flow from the reservoir there is a pressure drawdown area around the flowing wellbore. This pressure can only recover at a rate that is governed by the reservoir characteristics. If fluid can be injected at a rate sufficient to increase the bottomhole pressure faster than the reservoir can recover the well will cease to flow and the wellbore can be loaded with fluid to establish a static kill.

Bullheading

Bullheading is a process of loading the wellbore with weighted fluid by first shutting the wellbore in, and then pumping weighted fluid into the wellbore forcing the formation fluids back into the formation and placing weighted fluids into the wellbore. Bullheading should be a last resort operation because of the potential of breaking down exposed formation and casing seats and creating an underground blowout. Circulation of fluids to control the well is the preferred method of control. However, there are some instances in which bullheading can be used to gain time for the implementation of another control technique. Some examples of when bullheading may be of benefit are when the well cannot be flowed and the wellbore cannot withstand shut-in with the kick at the surface, and when H_2S is present in the kick and there is not the proper equipment for this at the surface.

Bullheading is much more common in workover operations than in drilling operations. This is due to the presence of a cased hole in workover operations. As has previously been stated bullheading requires shutting in the well prior to pumping. Before shutting in the well it should be determined that the wellbore is capable of withstanding the shut-in pressures to which it will be exposed. Once the well has been shut-in pumping operations should be started immediately to prevent further kick migration and the accompaning pressure increases. A fluid should be chosen which has both the required hydrostatic gradient to control the well and also good sweeping characteristics if possible. A more detailed discussion of bullheading is given by Adams[6]. During bullheading operations caution should be exercised that the injection rate of fluid does not become excessive. The greater the injection rate the greater the bottomhole pressure required. Another potential problem to be aware of during bullheading operations is that of incomplete sweeping. This can result in a dramatic increase in the required injection pressure as the injected fluid reaches the formation face while still leaving a considerable amount of formation fluids present in the wellbore. It should again be emphasized that circulation of fluids is the preferred method of well control.

Lubrication

Lubrication is a control technique which involves shutting in the well, pumping in small volumes of weighted fluid into the well, bleeding small volumes of formation fluids, waiting for the weighted fluid to fall through the lighter formation fluid and repeating this process until the wellbore is loaded with sufficient weighted fluid to control the well. This method is sometimes referred to as volumetric control. This control method can be performed either with the drill pipe in the hole or out of the hole. The basis of the method is that the bottomhole pressure, P_{BH}, is:

$$P_{BH} = P_{HYDRO} + P_{SURF} \tag{30}$$

where

P_{BH} = bottomhole pressure, psi

P_{HYDRO} = hydrostatic pressure of the fluids in the hole, psi

P_{SURF} = surface pressure, psi.

The basic procedure to follow is to pump in a volume of weighted fluid which will increase the bottomhole pressure to a value slightly greater than the reservoir static pressure. The amount of overbalance which can be safely applied is determined from the fracture gradient(s) of the exposed formation(s). This slight overbalance will prevent the further influx of reservoir fluids into the wellbore. Another volume of weighted fluid, which corresponds to a predetermined bottomhole pressure increase, is pumped. The amount of this increase is determined from the well bore geometry. At this time formation fluids are bled from the well to decrease the surface pressure by the amount of the increase in the hydrostatic pressure. After sufficient time has been allowed for the weighted fluid to fall through the formation fluids the process is repeated. Lubrication is a time consuming process but offers a viable control technique if the well can be safely shut-in. As with a bullhead, it should be determined prior to the shut-in of the well that all exposed formations are capable of withstanding the pressures to which they will be exposed. If the shut-in pressure is too great the potential for the creation of an underground blowout exists.

Subsurface Kills

Subsurface kills are defined as kills which are performed though a secondary or relief well by injecting fluid or performing other operations at some subsurface interval. The most common intersection interval is the flowing formation or a formation just above the flowing formation. This allows a maximum length for both the pressure due to the hydrostatic gradient of the injected fluid and the longest path for frictional pressure losses. Subsurface kills are both expensive and time consuming. As a result they are normally employed only when a surface kill cannot be affected. In many instances even if a subsurface kill is being planned and implemented surface kill attempts are continued. A subsurface kill is a complex procedure which involves the planning and drilling of a relief well to a predetermined intersection point. This intersection point can be a direct intercept, a near intercept or an inception at considerable distance from the blowing wellbore. Experience has shown that the nearer the intercept point to the blowing wellbore the greater the chances of a successful kill operation. One of the first things that needs to be determined is the required injection rate to control the blowing well. This must be determined early to insure that the wellbore of the relief well is

sized so that excessive surface injection pressures will not be required for the kill operations. Normally only dynamic and momentum kills are utilized for subsurface kills. Of these two, dynamic kills are much more frequently used than momentum kills. The reason for this is that a momentum kill requires a direct intercept of the blowing well. In the following sections relief well planning, blowout well detection, and pumping control techniques for subsurface kills will be discussed.

Relief Well Planning

A relief well is a directionally drilled well which is designed to intersect at or near the blowing well to allow the implementation of a control technique. There are essentially three intersection distances which have been utilized for these control efforts. The first of these is a direct intercept. In this type of intercept the relief well is actually drilled into the blowing well or is landed at a point so that perforation between the two wells is possible. In this case the analysis of a dynamic kill is the same as for a surface dynamic kill. It should also be noted that this is the type of intercept which is required for the implementation of a momentum kill. Again the analysis of a momentum kill will be the same as that for a surface momentum kill. The second type of intercept is a near intercept. In this type of intercept the control effort is a dynamic kill with the fluid being injected into the formation at the bottom of the relief well, flowing through the formation to the blowing well and then comingling with the produced formation fluids and flowing up the blowing well. One of the problems with this type of kill is the amount of the injected fluid which will reach the blowing well. The ratio of the injected fluid to that which reaches the blowing well is referred to as the efficency. The third type of intersection is one which lands at a considerable distance from the blowing well. In this case a matrix flood type kill is performed. Simply put this type of kill technique floods the reservoir with the injected fluid and slowly changes the production of the blowing well to that of the injected fluid.

Experience has shown that the further the intercept point from the blowing well the longer the pumping operations and the less the chances for a sucessful kill effort. The longer the pumping operations the more costly the operation and the greater the chances of surface equipment problems resulting in an aborted

control attempt. Conversely, the nearer the intercept point the longer and more costly the directional drilling effort. Thus, there is some point at which the economics of this type of control effort are minimized. From experience gained in a number of well control efforts, an intercept point which is greater than 10 feet from the blowing well greatly reduces the chances for a reasonable length control effort.

Whichever intercept point is chosen for the kill attempt some minimum injection rate of fluid is required. This rate must be determined prior to the commencement of the drilling operations to insure that an adequate flow path will be available down the relief well. Proper design of this flow path will result in lower surface injection pressures and result in less wear and tear on the surface equipment.

Another problem which is faced in the drilling of the relief well is the determination of exactly where the blowing well is located so that the desired intercept point can be achieved. At the present time two basic types of tools are used to determine the location of the blowing well relative to the relief well. These are passive magnetic and active magnetic tools. The drawback to the use of these tools is that they require that a magnetic target be present in the blowing well. Fortunately, in the majority of cases either casing and/or the drill string is present in the blowing well to provide this target. A more detailed discussion of these tools will be presented in another section.

Since the analysis of a direct intercept is similar to that for surface kills the remainder of the discussion of kill techniques for subsurface kill will concentrate on the other two types of intersections. Furthermore since these types of intersections are amendable to dynamic kills that is what this discussion will concentrate on.

Dynamic Kills

For the case of a near intercept the situation encountered is illustrated in Figure 5. From this figure it can be seen that some of the fluid which is injected down the relief well will go to the blowing well and some of the fluid will be lost to the formation. As with a surface dynamic kill the rate of fluid injection require to kill the well can be determined from plots of the inflow performance and the blowing wellbore performance curves for multiphase flow and from the equations previously discussed for single phase flow.

The problem then becomes the determination of the percentage of the injected fluid that will reach the blowing well. A rough estimation of this can be determined from treating the blowing well as a producer and superimposing the relief well as an injector. Taking into account the relative permeabilities of the reservoir to various fluids a comparision of the magnitude and direction of the momentum of the produced and injected fluids can be compared. From this comparison a rough estimate of the percentage of the injected fluid which will reach the blowing well can be determined. As has been previously stated the ratio of the injected fluid which reaches the blowing well to the injection rate is called the efficiency. Through the use of the rate required to kill the well and the efficiency the injection rate down the relief well can be determined. Once this rate has bee determined the require bottomhole injection pressure can be determined from:

$$Q = [0.00708kh(P_i - P_{Res})]/[\mu \ln(r_e/r_w)] \quad (31)$$

where

Q = injection rate, bbl/day

k = effective permeability to the injected fluid, md

P_i = bottomhole injection pressure, psi

P_{Res} = average static reservoir pressure, psi

r_e = radius of injected fluid bank, ft

r_w = effective radius of the injector wellbore, ft

h = net thickness, ft

μ = fluid viscosity, cp.

This can be rearranged to yield:

$$P_i = P_{Res} + [141.4Q\mu \ln(r_e/r_w)]/kh. \quad (32)$$

The surface injection pressure can then be determined from:

$$P_{Si} = P_i - P_{HYDRO} + P_F \quad (33)$$

where

P_{Si} = surface injection pressure, psi

P_i = bottomhole injection pressure, psi

P_{HYDRO} = hydrostatic fluid pressure in the injector, psi

P_F - frictional pressure loss in the injector.

This bottomhole injection pressure should not be allowed to exceed the formation fracture pressure since this will result in the loss of control of fluid placement. A useful tool during this type of kill operation is to inject the fluid down the annulus of the relief well and use the drillstring as a downhole pressure monitor. A plot similar to that shown in Figure 4 should be utilized to analyze the control effort as it progresses.

A common problem is that the necessary fluid rate based on efficiency and the required kill rate cannot be achieved down one relief well. The options are to drill additional relief wells, to intercept at a closer point or to try and enhance the efficiency. If the formation is a limestone type formation it may be possible to acid wormhole a path to the blowing well and greatly enhance the efficiency. Even if the formation is a sandstone type formation the proper uses of specific types of acids can provide efficiency enhancement. Another method of efficiency enhancement is achieved through the injection of controlled set polymers. A discussion of this is given by Ely and Holditch[7]. However, through proper planning the necessity of this type of operation can be reduced.

The second type of kill technique is one in which the intercept point is at a considerable distance from the blowing well. In this case the kill attempt is a matrix flood. A detailed discussion of this type of kill is presented by Lehner and Williamson[8] and Miller and Clements[9].

Blowout Well Detection Tools

As was previously mentioned there are two basic types of blowout wellbore detection tools, passive magnetic and active magnetic tools. Passive magnetic type tools measure the distortion in the Earth's magnetic field caused by the ferrous materials in the casing or the drillstring in the blowing well. From these measurements both the direction and distance from the relief well to the blowing well can be estimated. These types of tools have a limited range of 35 - 50 feet and are greatly affected by a nearby wellbore and fish which might be present.

The second type of tool injects an alternating current into the ground. This current short circuits along

the ferrous material in the blowing well generating an alternating current magnetic field. This magnetic field is detected up by sensors in the proximity tool and the distance and direction to the blowing well can be calculated from the measurements. This type of tool is useful up to about 200 ft. A more detailed discussion of this type of tool and its operation is presented by Kuckes et al.[10] and Grace, Kuckes and Branton[11].

In many cases the exact location of the intercept point may not be known due to poor surveys of the blowing well. This results in an ellipse of uncertainity as to where the blowing wellbore actually is. This is illustrated in Figure 6. One method to reduce this uncertainity is also illustrated in Figure 6. This method involves drilling the relief well such that a pass by is made uphole from the desired intercept point. This allows a proximity tool to be run and a smaller ellipse of uncertainity to be determined.

Specialty Operations

This paper has concentrated on the discussion of pumping control techniques for controlling blowouts. The implementation of these techniques often requires that considerable work be performed on the surface equipment and/or wellbore prior to the implementation of the control techniques. This work may invlove snubbing, stripping, valve drilling, diverting, hot tapping tubulars, replacement of wellheads or BOP stacks, debris removal and firefighting. A complete discussion of all of the specialty type work would require that this be a book rather than a paper.

This type of work requires thorough planning and a complete understanding of the situation. This is an area in which a theoretical analysis must take second place to experience. Suffice it to say that this type of work is best handled by experienced personnel to insure a safe and efficient operation.

Whenever this type of work is performed and/or the pumping plant and surface equipment is being set up considerable planning should be undertaken to insure that no single point failure will result in shutting down the control effort or result in losing control of the relief well if there is one.

Conclusions

This paper has presented a brief discussion of the various pumping control techniques for blowout control. Since each particular incident is unique, experienced personnel should be utilized as early as possible to help in the design and implementation of a control procedure. The earlier such personnel are involved the faster the well can be brought back under control and the damage resulting from the blowout can be minimized.

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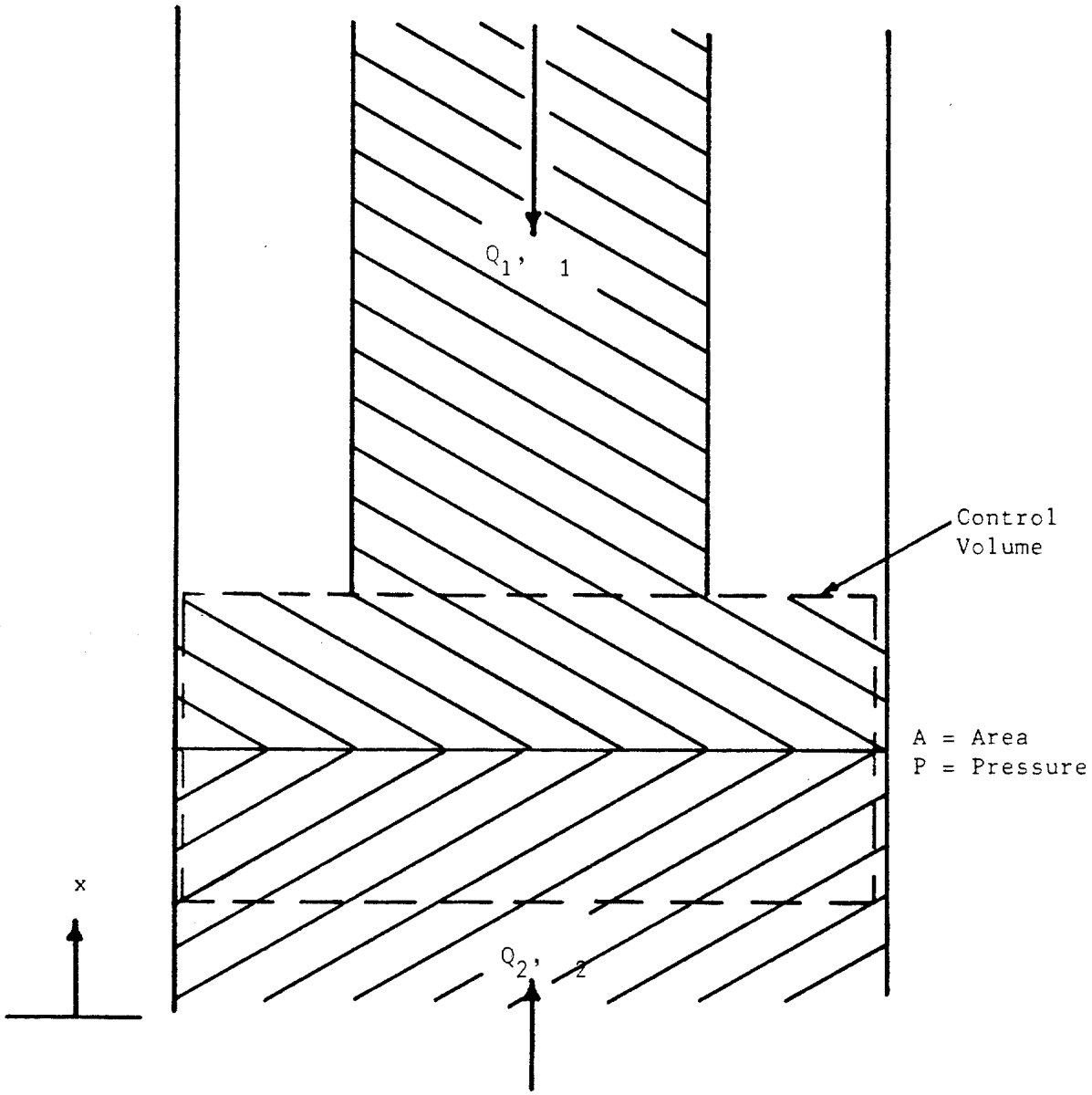

Figure 1. Momentum Kill Concept

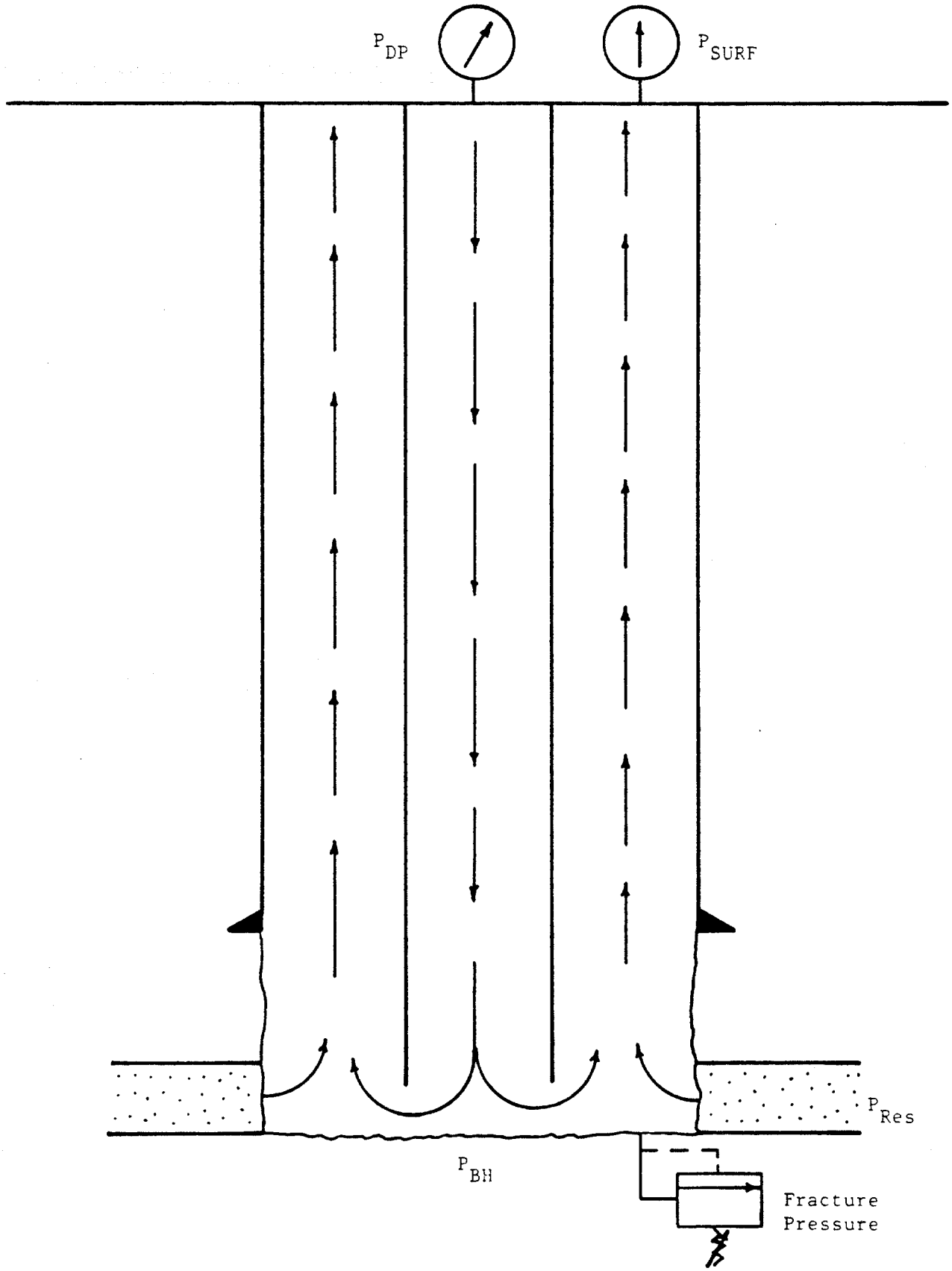

Figure 2. Surface Dynamic Kill

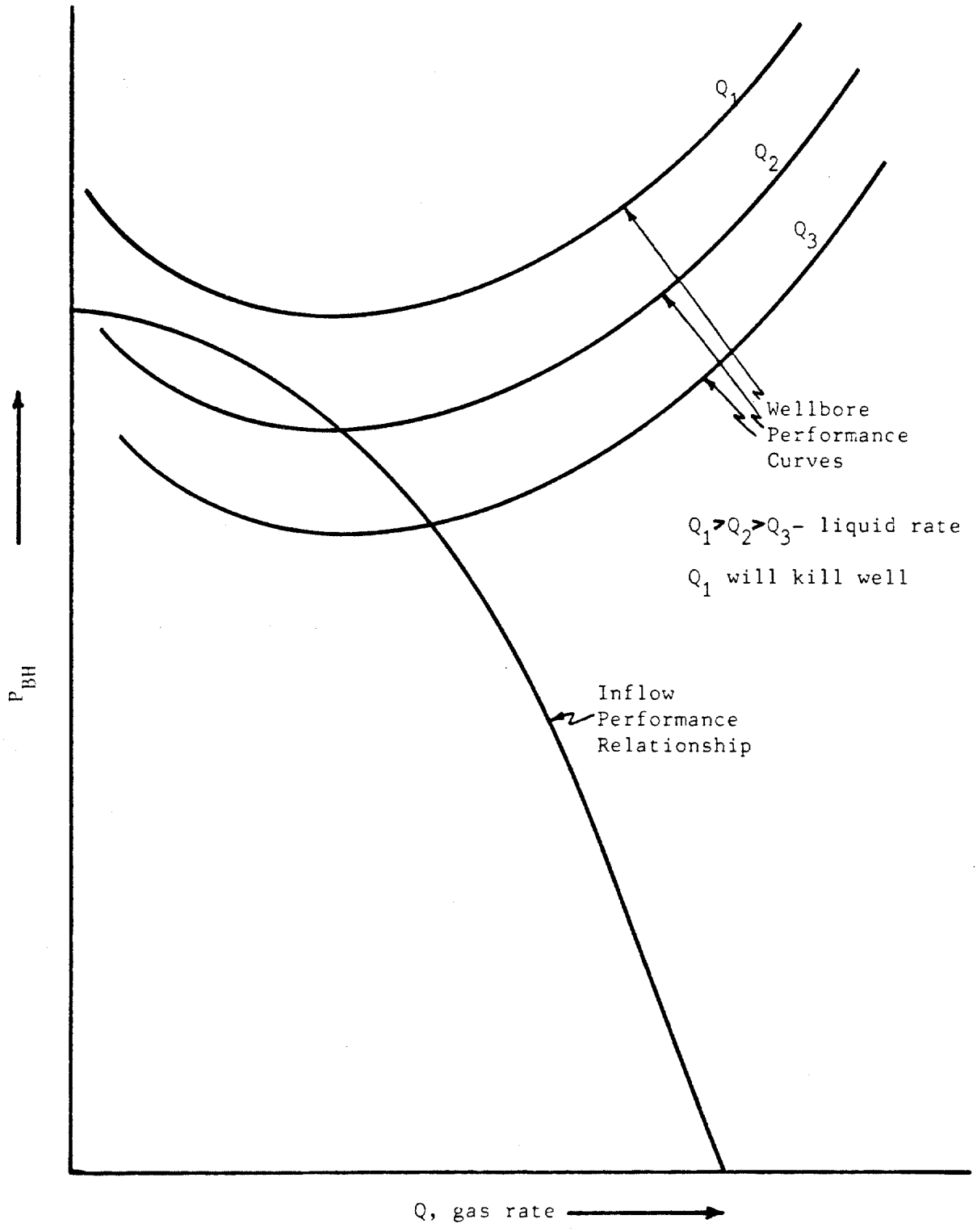

Figure 3. Plot of Wellbore Performance and Inflow Performance Relationships

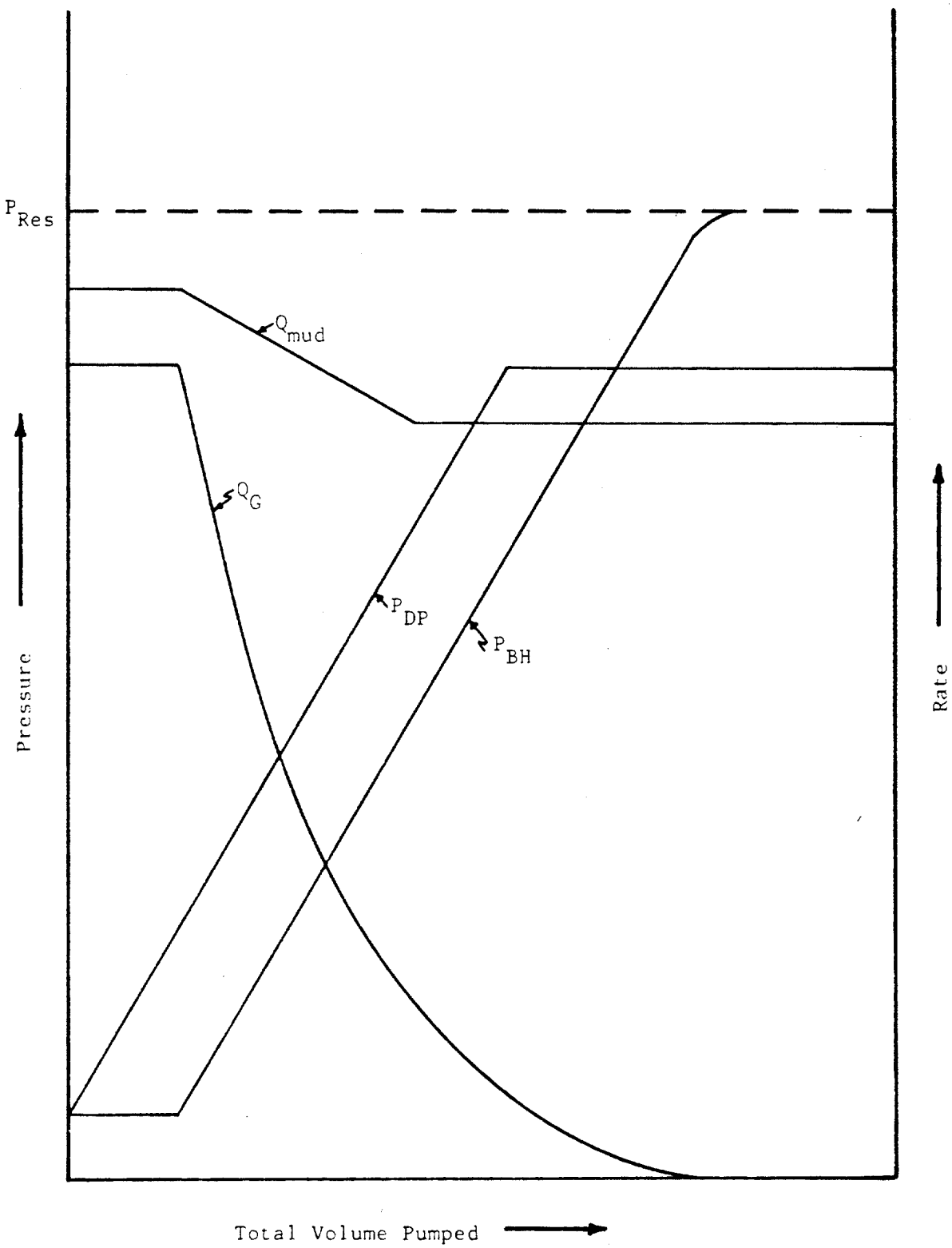

Figure 4. Plot of Well Control Parameters

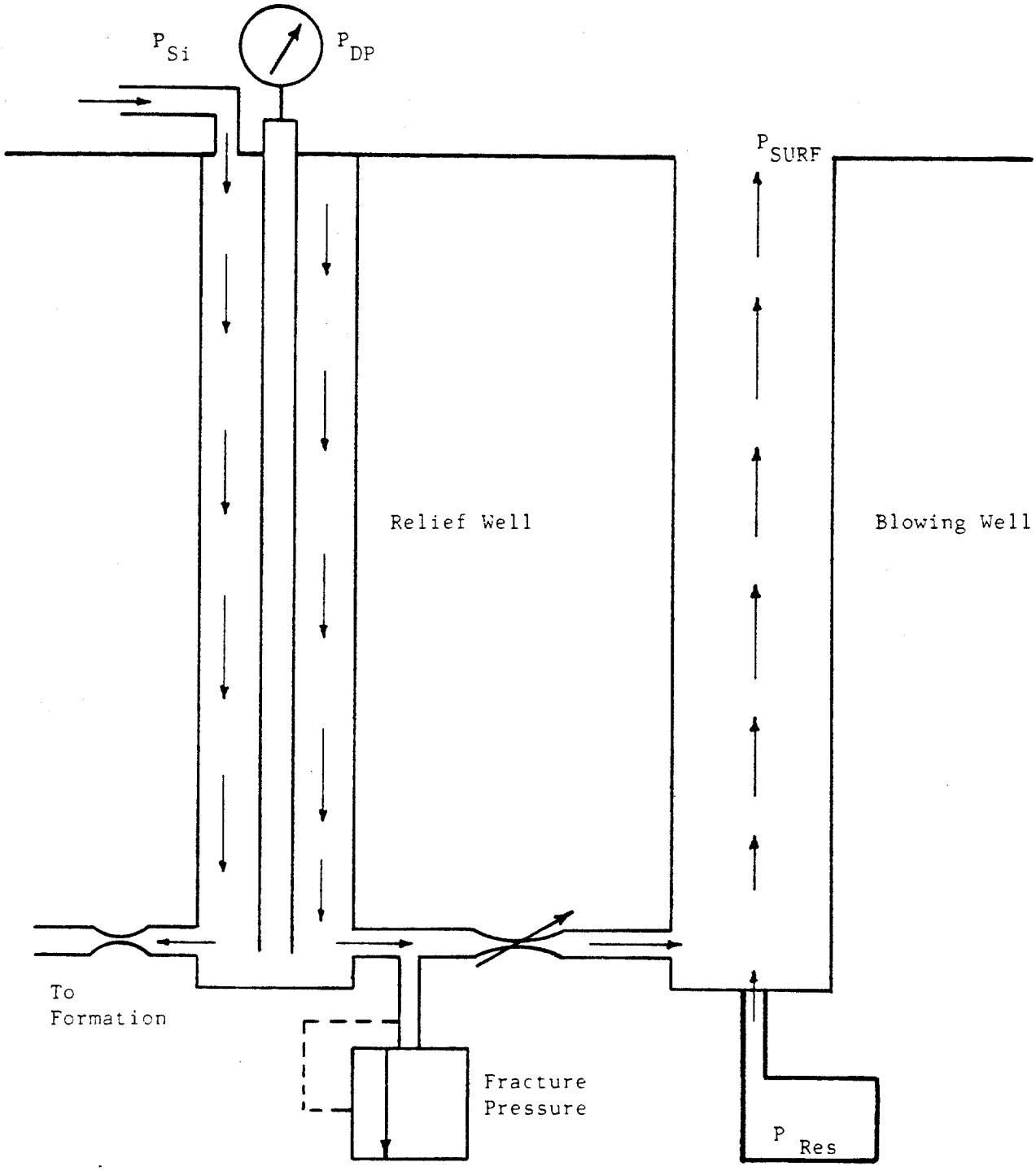

Figure 5. Subsurface Dynamic Kill

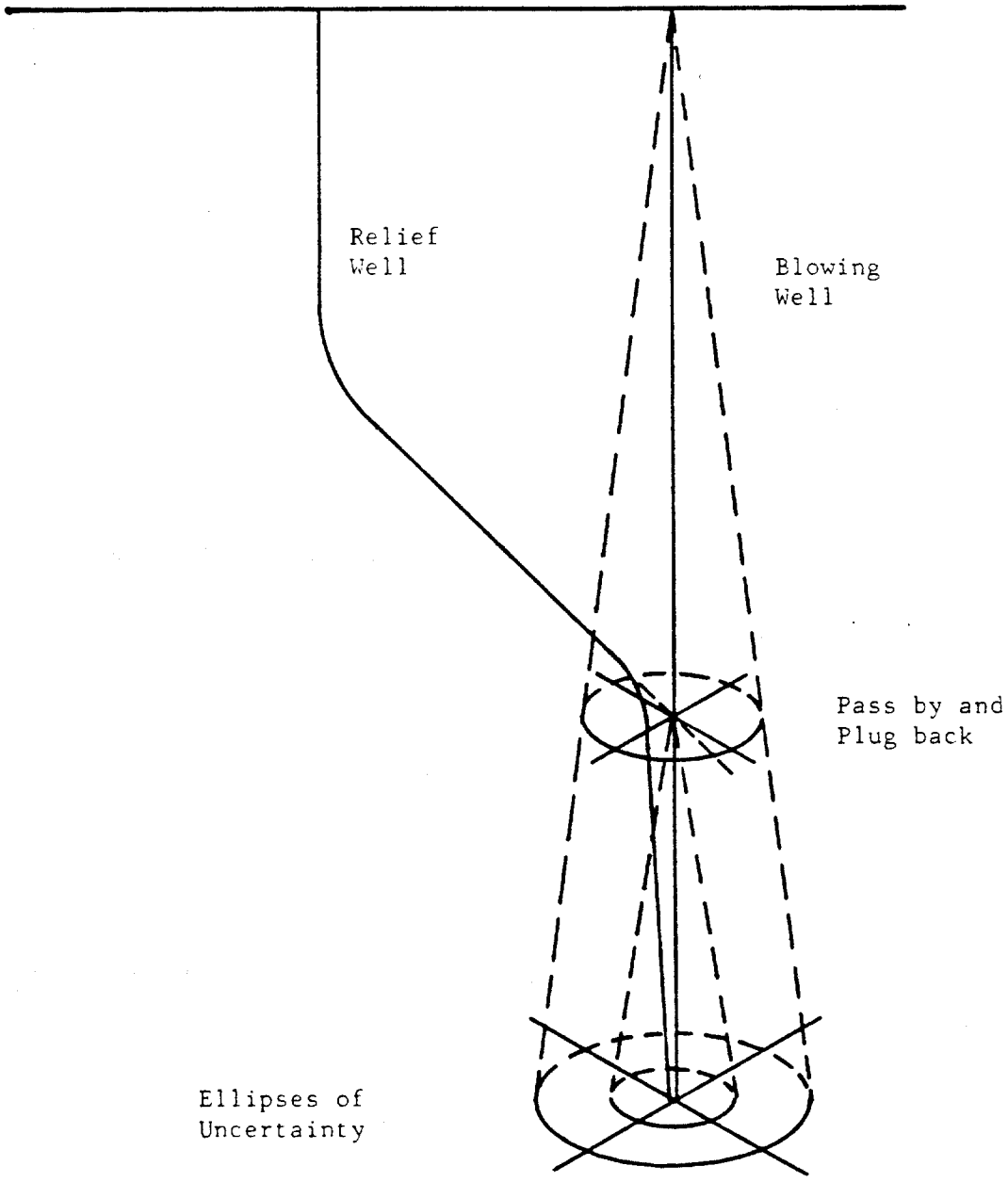

Figure 6. Blowout Well Detection

INTERNATIONAL WELL CONTROL SYMPOSIUM/WORKSHOP

Gas Slip Velocities in an Inclined Annulus

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ABSTRACT

The first part of an experimental study on gas slip velocities during well control operations in vertical and inclined annuli was performed. It consisted of two-phase flow of gas-liquid mixtures through a 13.7 m (45 ft) annular section of an experimental apparatus. The annular test section can be operated at pressures up to 4137 kPa (600 psi) to reduce the effect of gas expansion due to hydrostatic pressure variations in the test section. The inclination from the vertical position was varied from 0° to 60°. The results from these tests will assist in the development of a computational model for gas kicks in highly deviated wells. The on-going study will eventually investigate a wide range of drilling fluid properties. This paper describes the experimental apparatus and gives preliminary results for air-water mixtures.

INTRODUCTION

The prediction of pressures along the well at different times during gas kick operations is the main objective of gas kick simulators. However, those pressures are closely related to the gas concentration profile along the well and the gas slip velocity. Therefore, an experimental study of these parameters is essential for a better understanding of the gas behavior inside the well during gas kick control operations and, also, for the definition of more efficient operational procedures. There has been very little work done in the past on modelling annular multi-phase flow involving non-Newtonian liquids in an inclined annulus.

EXPERIMENTAL APPARATUS

The experimental facility can simulate two-phase flow through the annulus inside the well. This facility is composed of a flow loop and a fluid handling system.

The flow loop is about 14.6 m (48 ft) long (Fig. 1) and can stay in any inclined angle between vertical and horizontal. During the tests, liquid injection occurs through the internal pipe of the annulus while gas injection comes from the bottom of the loop. At this point the two-phase flow develops and returns upward through the annulus.

For gas fraction measurements, the pressure actuated valves (V1, V2, V3, and V4 in Fig. 1) operate simultaneously. Valve V1 is a three way valve that diverts the liquid flow directly to the output when the other valves are closed. The other valves block the flow when in the closed position.

The annulus, on the right leg of the loop, is 14 m (46 ft) long (Fig. 2) and its diameters are 154 mm

(6.065") by 60.3 mm (2.375"). This part of the loop has sensors to measure the following parameters: loop pressure (P), loop temperature (T), and differential pressures at three locations (DP sensors).

The fluid handling system (Fig. 3) is an integration of three subsystems. The first deals with the liquid injection into the loop. It is composed of a 47.7 m^3 (300 bbl) water/mud tanks, a centrifugal pump, and a triplex pump. The second subsystem controls the air/gas flow and includes the air compressor, gas pipeline, and gas flow meter unit. Finally, the third subsystem collects the output flow, controls the pressure in the loop, and separates the gas and liquid phases. It consists of a 47.7 m^3 (300 bbl) pressure vessel, rated at 5516 kPa (800 psi) working pressure, a choke valve and a degasser.

The monitored variables in the fluid handling system include: pump pressure, liquid flow rate, air/gas pressure, air/gas flow rate, storage tank pressure, liquid level in storage tank, and back pressure in the choke.

EXPERIMENTS

In the first part of this study the design of the experiments were performed. The goal was to choose the appropriate range of liquid and air/gas flow rates that could reproduce the conditions normally seen in field well control operations.

The second step involved the development of a test procedure. Here, the emphasis was on the optimization of the procedure to accomplish accurate and reliable results in the minimum run time.

The last step was the processing of the data collected during the tests for posterior analysis.

Design of Experiments

The chosen parameters for the test matrix are the superficial liquid velocity (U_{sl}) and the superficial air/gas velocity (U_{sg}). For the delineation of the range of velocities, it was necessary to consider the normal conditions found during well control operations. Also, the results from previous works helped in choosing an appropriate interval covering bubble and slug flows. After this analysis, the chosen U_{sl} range was from 0.21 m/s (0.7 ft/s) to 0.52 m/s (1.7 ft/s) while the U_{sg} range was from 0.03 m/s (0.1 ft/s) to 0.34 m/s (1.1 ft/s). Later, during the experiments, it was not possible to run the tests for U_{sg} = .03 m/s (0.1 ft/s) due to limitations of the equipment. On the other hand, for vertical flow, some tests were performed with U_{sg} up to 1.8 m/s (6 ft/s).

Test Procedure

Initially, the valves in the loop are open. The flow controllers are adjusted for the desired values of liquid and gas flow rates. When the two-phase flow reaches steady conditions, the data collection in the computer starts. About one minute later, the valves are closed but the data collection continues until complete stabilization of the system. These steps are repeated for each point of the test matrix.

During the first tests, it was very difficult to maintain constant liquid and air flow rates due to pressure variations in the system. Later, the problem was solved using a process control program to control automatically the flow rates.

Raw Data Processing

During the tests, data are collected at a rate of about 3 records/second. Simultaneously, some variables are collected and printed in the strip chart. Table I shows all the collected variables and their limits. Then, these data are prepared for analysis and comparison with the model for vertical wells.

OVERVIEW OF THE COMPUTATIONAL MODEL

The present model predicts the gas fraction and the gas velocity in two-phase, vertical flow through an annular section. It covers the range of bubble flow, transition bubble-slug, and slug flow of air-water or gas-mud mixtures.

The basic equations and assumptions related to the bubble geometry, velocity, and concentration are from Bourgoyne and Casariego (1988). The model assumes that the transition between bubble and slug flow occurs when the gas fraction α is 0.25. For concentrations below this value, the bubbles try to maintain a stable size which is calculated according to a Reynolds Number versus Viscosity Number criterium. An iterative process is necessary to estimate the gas velocity, bubble diameter, and gas fraction due to the inter-dependence among these variables.

RESULTS AND COMPARISONS WITH THE MODEL

Tests in vertical position

Figure 4 shows a comparison between the experimental results and the model for U_{sl} = 0.7 ft/s, vertical position. The first point to notice here is that the model over-predicts the gas fraction α. A possible reason for this result is that the model does not consider the recirculation phenomenon that may occur in large sections. Recirculation makes the gas to travel faster, thus decreasing the gas concentration. However, the occurrence of recirculation under the test conditions has not yet been confirmed.

The transition from bubble flow to slug flow, as predicted by the model, seems to occur for α values between 0.2 and 0.3. Therefore, the model's assumption of the transition occurring at α = 0.25 is reasonable for air-water mixtures. However, the transition occurs over a range of superficial gas velocity U_{sg} and gas fraction α as can be noticed also in Fig. 5. This smooth transition is due to the successive agglomeration of bubbles forming the first slugs with increasing U_{sg}.

Figures 6 and 7 serve again for comparison between the experimental results and the model. Note that the computational model predicts a discontinuity as "flat spot" where the flow pattern changes from bubble flow to slug flow. Fig. 7 shows that a gradual transition occurs for α values between 0.2 and 0.3.

Besides the gas fraction, another important variable is the gas velocity. Figure 8 shows the

differences between the experimental results and the theoretical prediction from the model. In general, the model under-predicts the gas velocity for the smaller values of U_{sl} and over-predicts U_g for the largest value of U_{sl}. Another characteristic shown in the figure is that the difference is within a constant range of approximately -0.30 m/s (-1.0 ft/s) and 0.15 m/s (0.5 ft/s) independently of U_g level. Besides the recirculation problem, another possible reason for this deviation could be due to the model not considering the effect of U_{sl} on the stable diameter of the bubbles. For example, take both extremes of U_{sl} [0.21 m/s (0.7 ft/s) and 0.52 m/s (1.7 ft/s)]. For U_{sl} = 0.21 m/s (0.7 ft/s) the model should predict larger bubble diameter and single bubble velocity, which would lead to larger gas velocity. On the contrary, for large U_{sl}, the model should predict smaller bubble diameter and velocity, which would result in smaller U_g.

The deviation would not be so important at high gas velocities. However, for small gas velocities, in the range expected during kick control operations, it represents 30 to 50% difference between the experiments and the model. It might be interesting to investigate this problem and try to define the equilibrium bubble diameter as a function of the phase velocities.

Tests in inclined positions

For the gas-liquid tests in inclined positions, it was expected smaller gas fraction with increasing inclination from vertical using the same flow rates. This general trend was confirmed as shown in Figs. 9 and 10 at different levels of U_{sl}. As the inclination increases from 10° to 60°, the gas fraction decreases.

For I = 20° and I = 40°, the difference in gas concentration is not so significant as between 10° and 20° or 40° and 60°. This indicates that the trend is not uniform and at different inclinations, different two-phase flow mechanisms are prevailing.

The most interesting result, however, comes from the comparison of the tests in inclined position with the ones for vertical flow. Notice that the largest gas fraction does not occur in vertical flow but at 10°. This means that the gas fraction first increases from 0° to 10° and then starts to decrease. One possible cause for this result is that the bubbles present in vertical flow tend to concentrate in the upper part of the annulus when the section is inclined. This concentration slows down the bubbles. Also, it is possible that part of these bubbles recirculates with the liquid. However, at larger inclinations, these bubbles start to coalesce and to form larger bubbles which will haver larger velocities. These hypotheses will be proved with tests in a transparent annular section. The importance of the determination of this behavior is associated to the fact that many so called vertical wells actually have small inclinations at least in part of their length.

FUTURE WORK

For the tests with gas and mud, just three different values of U_{sl} will be used: 0.21 m/s (0.7 ft/s), 0.40 m/s (1.3 ft/s), and 0.52 m/s (1.7 ft/s). For the gas flow rate, values from 0.03

m/s (0.1 ft/s) to 0.70 m/s (2.3 ft/s) with points at each 0.06 m/s (0.2 ft/s) should be adequate to include the transitions bubble-slug in all cases. Also, more inclined positions will be tested from 0° to 90°.

The investigation for inclined sections has to deal with the phenomenon of increasing gas fraction with increasing inclination at small angles. An experimental study, at low pressures, using transparent pipes will be conducted to help in understanding the mechanisms involved in this situation.

CONCLUSIONS

The data obtained to date shows:

1. The model available for vertical wells was checked for Newtonian fluids. One positive point was the good agreement of the gas fraction predicted by the model with the experimental values. Another point was the confirmation that the transition bubble-slug flow for Newtonian fluids occurs for gas fraction in the interval from 0.2 to 0.3 with the model assuming 0.25. On the other hand, the gas velocity was not predicted with desirable accuracy. A refined criterion for the bubble stable diameter and an estimation of the bubble size distribution will be sought.

2. Much experience has been gained for the next set of tests which will be made using natural gas and drilling fluid. From those first tests, some changes in the apparatus and in the test procedure were made with improved results. For the new tests, the basic process developed during the air-water tests, will be used.

NOMENCLATURE

α	gas fraction
α_{ns}	non-slip gas fraction
U_{sl}	superficial liquid velocity
U_{sg}	superficial gas velocity
U_g	gas velocity
U_m	mixture velocity

ACKNOWLEDGEMENTS

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Table I. Variables collected during the experiments.

Variable	Unit	High	Low
Data collected by COMPAC 286:			
Liquid Flow rate	gpm	195	-5
Loop Pressure	psi	1000	-10
Loop Temperature	°F	167	-58
Loop DP#1	psi	20	-6
Loop DP#2	in.H_2O	72	-15
Loop DP#3	in.H_2O	72	-15
Tank Pressure	psi	1000	-5
Tank DP	in.H_2O	100	-5
Gas Flow Rate	scf/h	3000	0
Gas Pressure	psi	1000	-5
Gas Temperature	°F	200	0
Data printed in the strip chart:			
Liquid Flow Rate	spm	150	0
Gas Flow Rate	scf/h	3000	0
DP#1	psi	20	-6
DP#2	in.H_2O	72	-15
DP#3	in.H_2O	72	-15

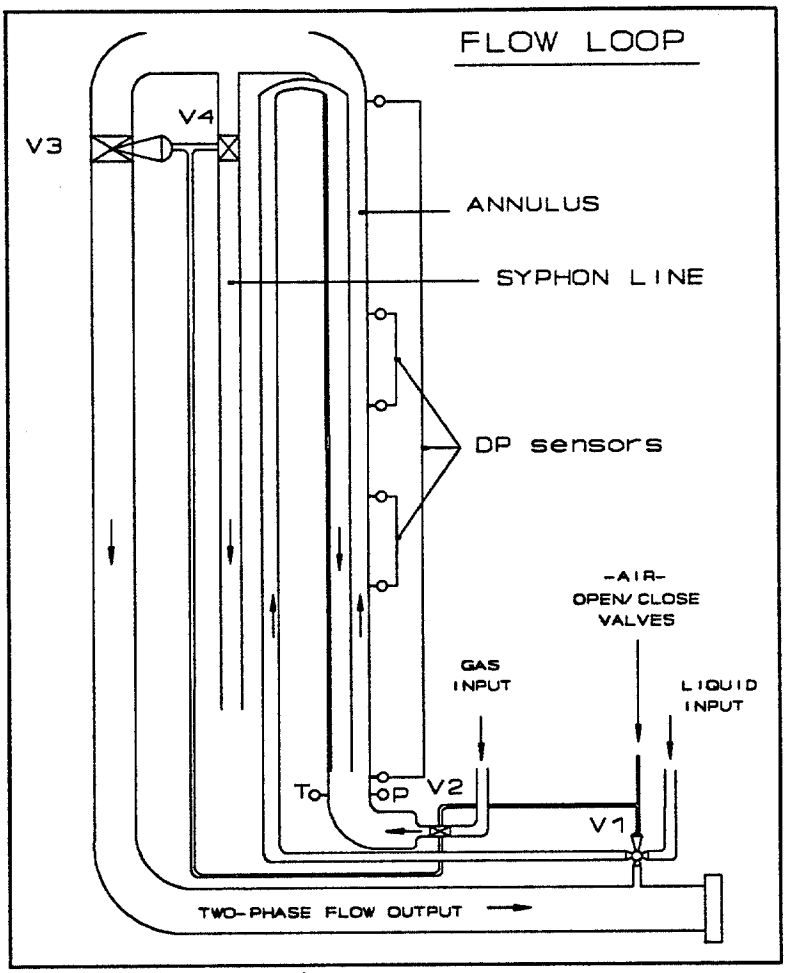

Figure 1. Loop section.

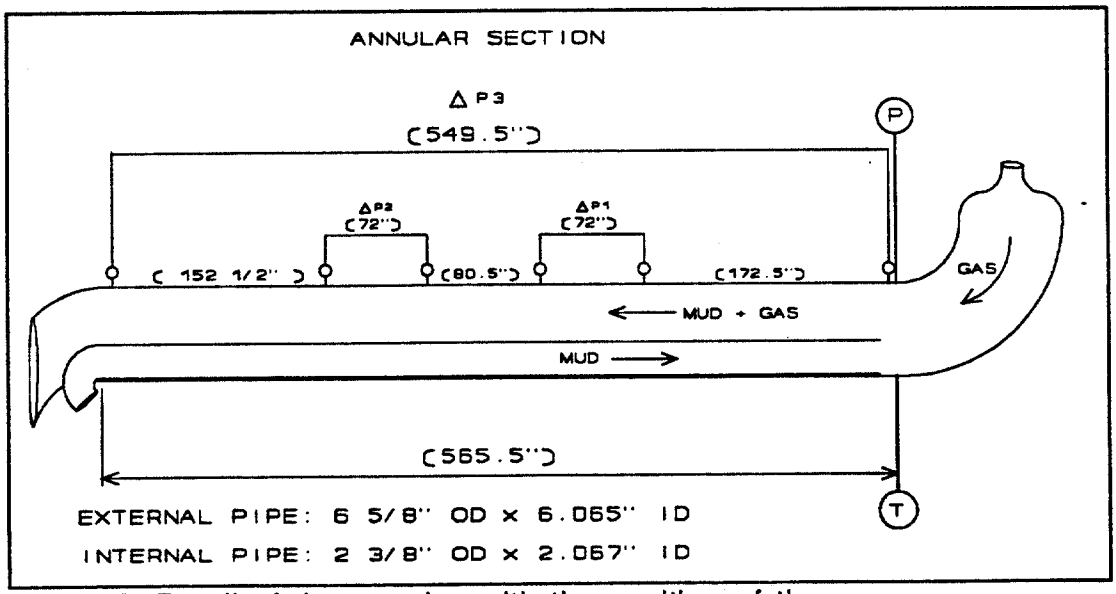

Figure 2. Detail of the annulus with the position of the sensors.

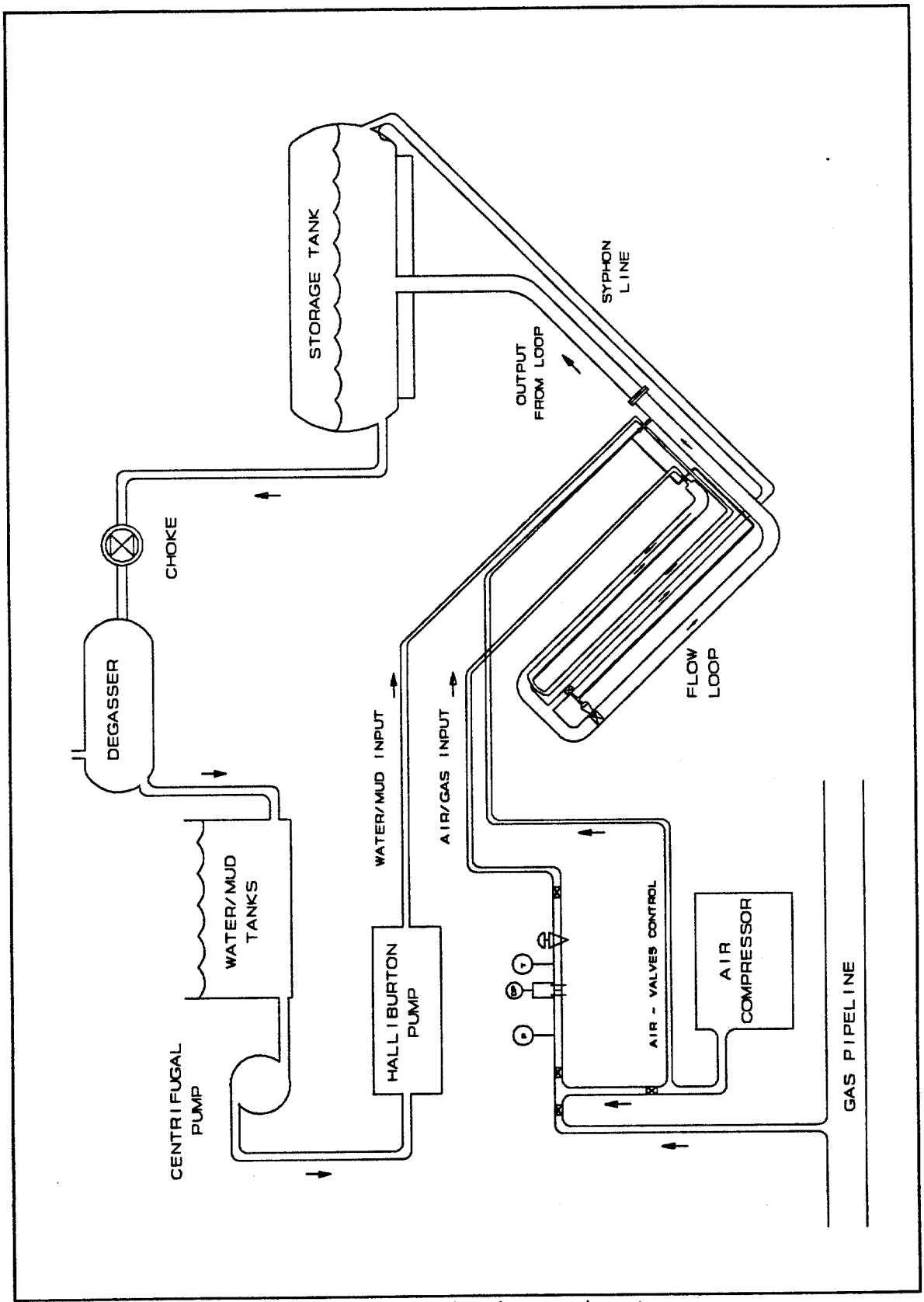

Figure 3. Fluid handling system with the three subsystems.

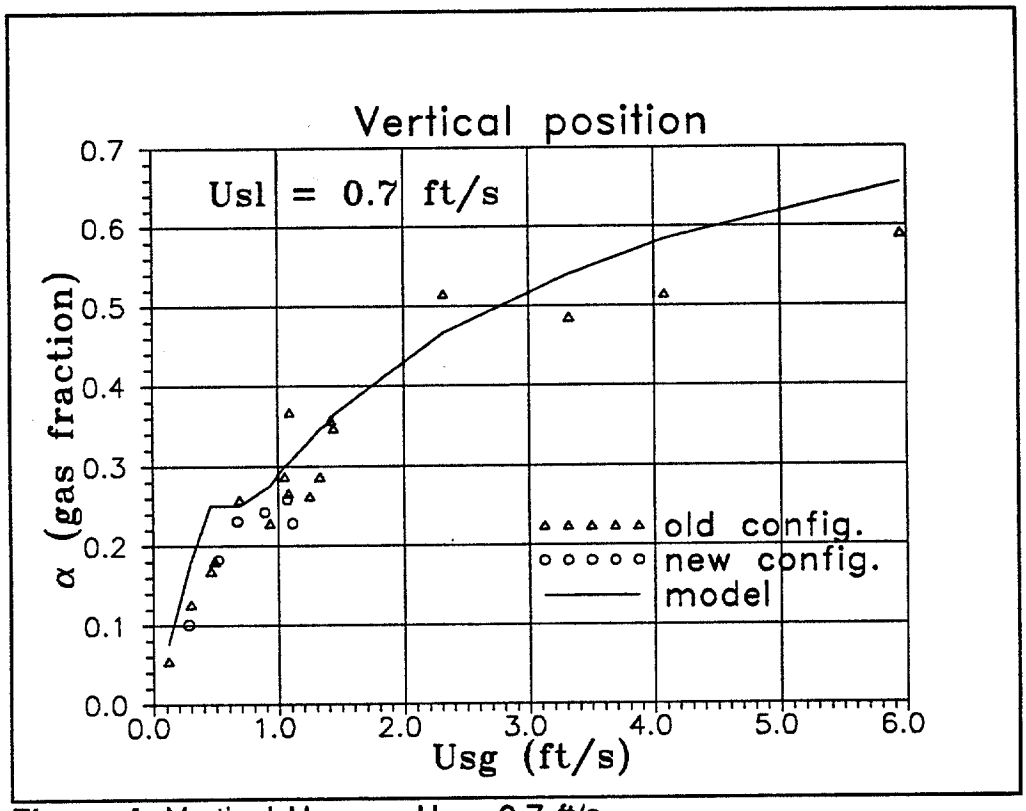

Figure 4. Vertical U_{sg} x α, U_{sl} = 0.7 ft/s.

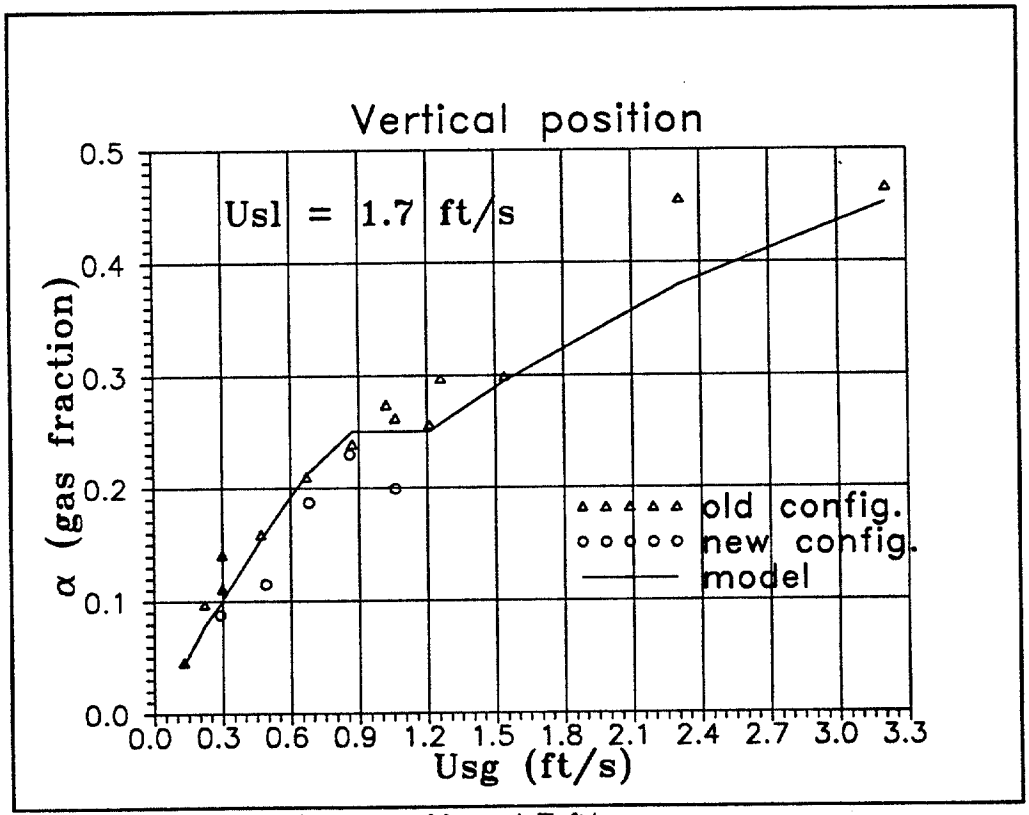

Figure 5. Vertical, U_{sg} x α, U_{sl} = 1.7 ft/s.

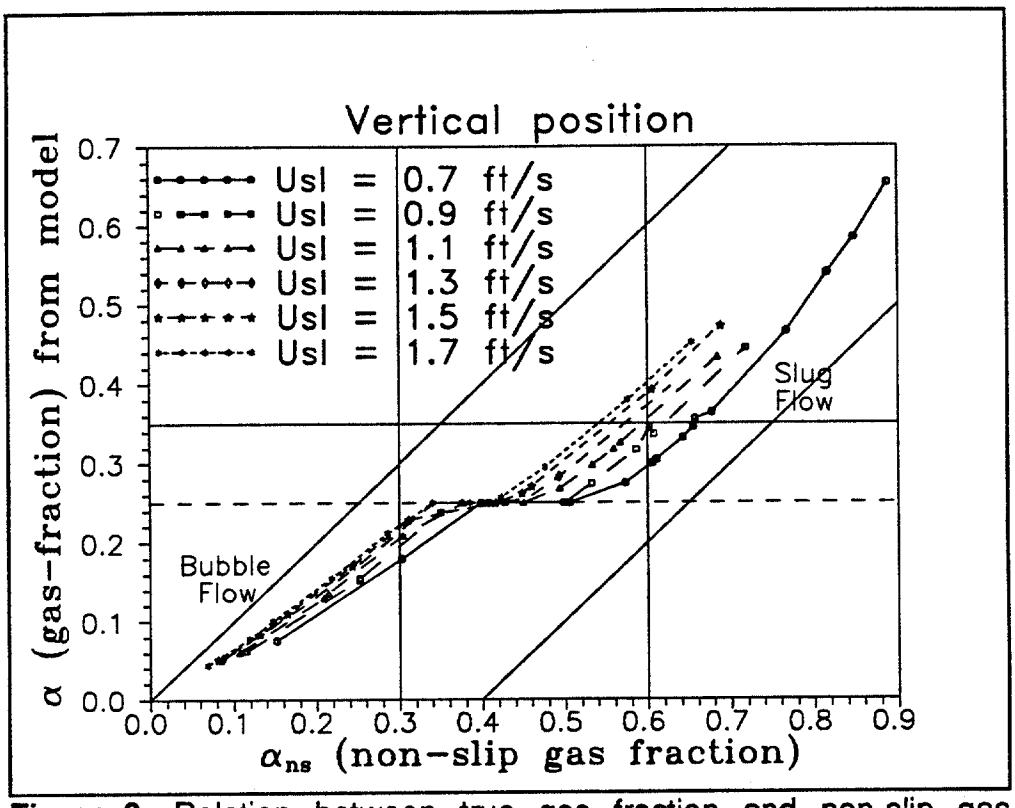

Figure 6. Relation between true gas fraction and non-slip gas fraction as predicted by computational model.

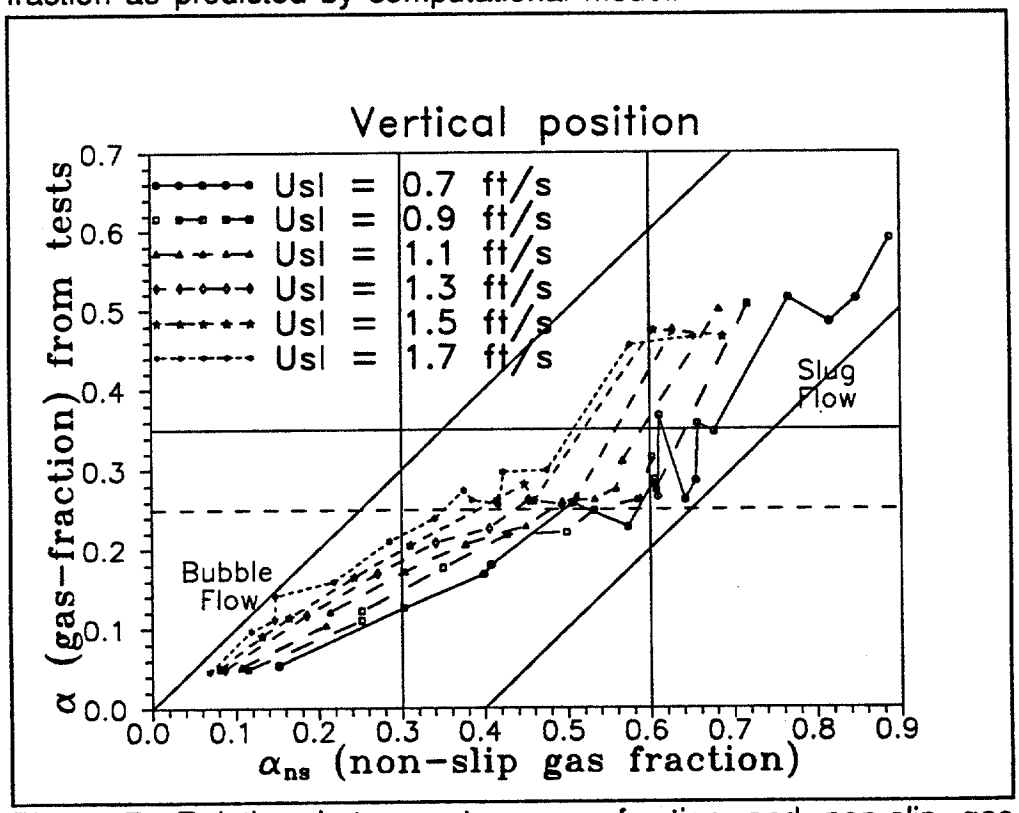

Figure 7. Relation between true gas fraction and non-slip gas fraction obtained experimentally.

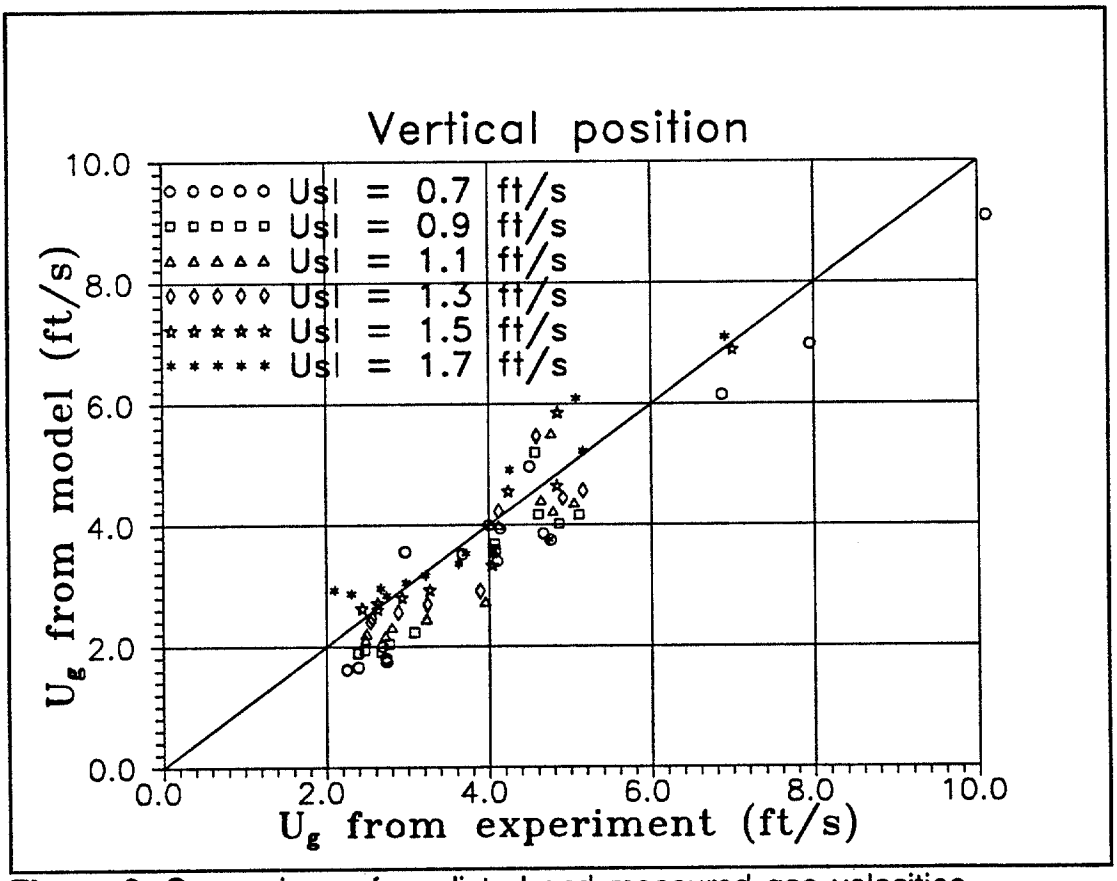

Figure 8. Comparison of predicted and measured gas velocities.

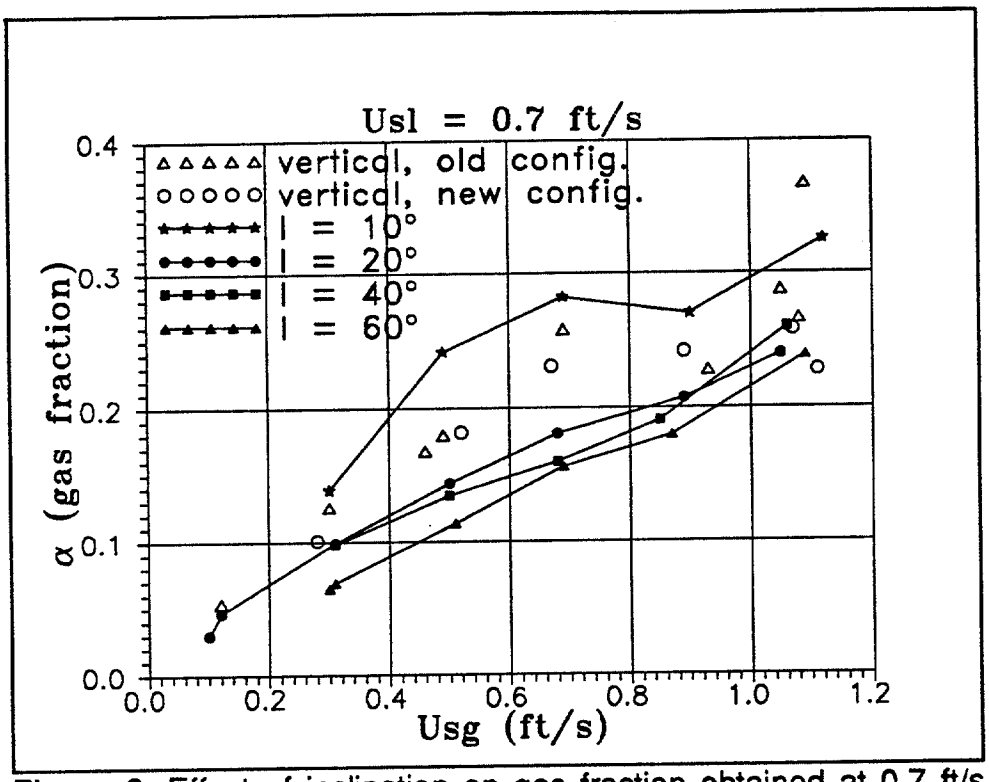

Figure 9. Effect of inclination on gas fraction obtained at 0.7 ft/s superficial liquid velocity and various superficial gas velocities.

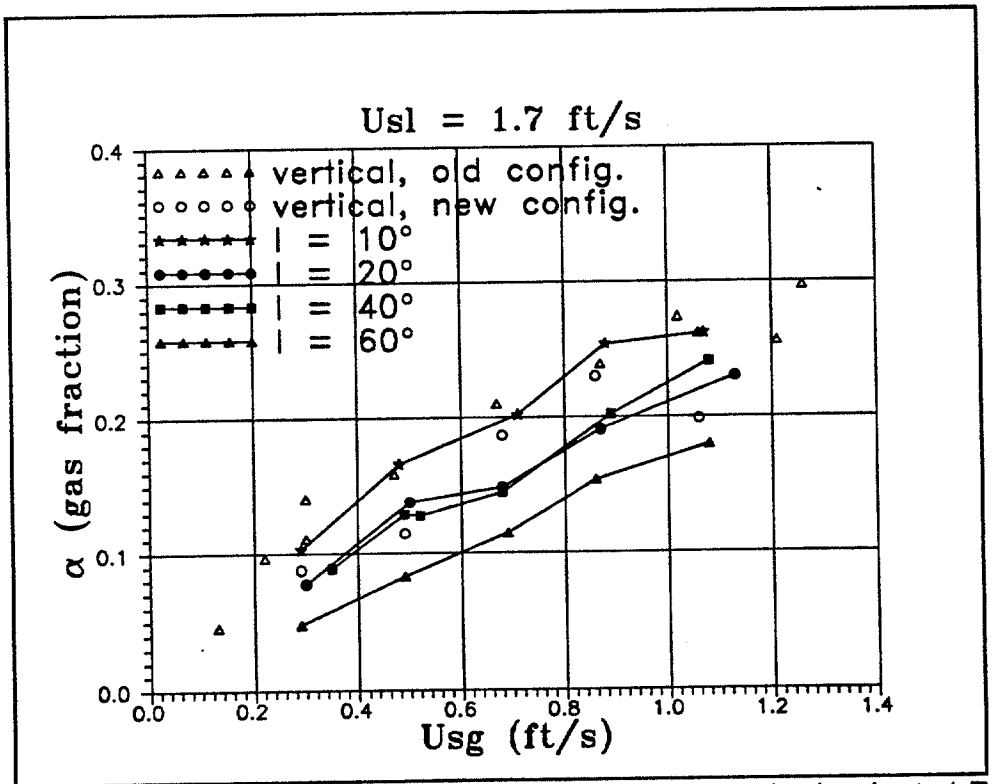

Figure 10. Effect of inclination on gas fraction obtained at 1.7 ft/s superficial liquid velocity and various superficial gas velocities.

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REAL-TIME PORE PRESSURE EVALUATION OPTIONS

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ABSTRACT

Standard blowout prevention procedures cannot be based on the over-sizing of blowout prevention equipment, excessive mud weighing, or heavy casing programs. Daily operations require the use of pore pressure estimation methods that help define and adjust cost effective drilling programs. Various techniques were developed in the sixties and seventies to help determine the occurrence and magnitude of overpressures encountered by the wellbore. These "conventional" methods are based on the analysis of normal trends in shales, interpreted using empirical correlations.

With the growth of MWD technology, new pore pressure evaluation methods have recently been proposed. Considering the rapid evolution of hardware and software tools, this paper focuses on the real-time pore pressure evaluation options currently available to operators.

Comparing pore pressure evaluation methods on the basis of individual examples is not the best way to define these options. Instead, this paper organizes available real-time pore pressure evaluation methods according to their theoretical bases and the hardware requirements for field implementation. This systematic and global approach should help users select pressure evaluation techniques according to objectives, drilling conditions, and available equipment.

Despite the number of techniques that have been proposed until now, there are still some deficiencies. By reiterating some of the shortcomings of the methods currently in use, this analysis attempts to define the requirements for future pore pressure evaluation methods.

INTRODUCTION

"Normal" or "hydrostatic" formation pressure is defined at any vertical depth, D, as the pressure resulting from the hydrostatic head of a column of connate water of height D. This conventional definition is often associated with the concept of average fluid pressure gradient, equal to the ratio of pressure over depth. In the Gulf Coast region, the normal pore pressure gradient is taken equal to 0.465 psi/ft [1.07 Sp gr]. Pore pressures associated with an average gradient greater than hydrostatic are termed abnormal.

Considerable disagreement exists among earth scientists concerning the mechanisms responsible for generating abnormally high pore pressures. However, among the numerous models that have been proposed, none compare with the ability of compaction disequilibrium of argillaceous sediments to account for the magnitude of overpressures and their worldwide occurrence in tertiary sedimentary basins. This observation generally transposes the problem of detecting overpressured formations into detecting undercompacted shales, which are characterized by their unusual porosity trends.

While abnormal pressure detection can be done by tracking shale porosity, quantitative evaluation of pore pressure in shales poses some difficulty. Due to their extremely low permeabilities, shales do not allow the practical performance of conventional pressure tests. Pore pressure is thus *inferred* by interpreting pressure-dependent parameters that can be measured while drilling shales.

There are many such parameters capable of providing insight on pore pressure. The analysis of size, shape, and density of shale cuttings, monitoring

mud temperature and gas content, are frequently used to help detect the occurrence of overpressures. Prior to drilling, the interpretation of seismic data is instrumental in the detection and evaluation of overpressures, thus permitting well planning. Far from providing a comprehensive review of pore pressure evaluation methods, this paper focuses on methods having a real-time potential in the MWD sense.

CONVENTIONAL EVALUATION METHODS

The principle of pore pressure evaluation from well logging data was established by Hottmann & Johnson [**1965**], who first developed a method that allowed "to infer certain *reservoir* properties, such as formation pressure, at any level in the well," by interpreting "the acoustical and electrical properties of *shales*."

Generalization Of The Principle

The method developed by Hottmann and Johnson for two specific petrophysical measurements can easily be generalized. The development of a similar technique involves the following elements:

- Selection of a pore-pressure dependent parameter λ
- Definition of the normal trend and identification of pressure regimes
- Quantification of pore pressure by normalizing λ

When shale compaction disequilibrium is the cause of abnormal formation pressures, λ is generally a shale-porosity dependent parameter. In normally-pressured intervals, shale porosity decreases with depth as a result of compaction, and λ varies accordingly. The evolution of λ in the normally-pressured zone defines the "normal trend."

Shale porosity departs from the normal compaction trend towards higher values as the average fluid pressure gradient increases. This break in the shale porosity profile corresponds to a similar shift for the porosity-dependent

parameter. **Figure 1** assumes that λ is a decreasing function of shale porosity. The graph illustrates the normal trend concept and departures from the normal trend .

Quantification of λ–departures from the normal trend in terms of pore pressure are made possible by developing empirical correlations. Obtaining a general-applicable correlation calls for the use of a normalized term, Λ_n:

$$\Lambda_n = \frac{\lambda_m}{\lambda_n} \tag{1}$$

λ_m is the measured value of λ at the current depth. The normal value, λ_n, is the hypothetical value of λ had the shale been normally pressured. It is obtained by extrapolating the normal trend line to the depth of interest, as shown in **Figure 2.**

A correlation is established by plotting the values of Λ_n against the average pressure gradient measured in nearby permeable formations.

Application To Petrophysical Measurements

Several "conventional" pore pressure evaluation methods have been proposed in the past. They all follow the basic scheme described above, and only differ by the choice of the pressure-dependent parameter λ and by the data sets used to develop the empirical correlation.

Hottmann and Johnson [1965] proposed resistivity or the transit time of compressional acoustic waves as pressure indicators. Their correlations are based on resistivity and sonic measurements in Oligocene/Miocene shale formations in Louisiana. **Figure 3** reproduces the data they used to develop a correlation for shale resistivity.

Jorden and Shirley [1966] developed an interpretation technique based on drilling performance analysis. Using the drilling equation developed by Bingham [1965] for soft-formation milled-tooth roller-cone bits, they normalized penetration rate for weight-on-bit (WOB), rotary speed (RPM), and bit diameter. The effect of pore pressure on penetration rate was assumed to be implicitly

included in the WOB exponent, d. Plots of d-exponent versus depth are then interpreted according to the general method described above.

Jorden and Shirley identified differential pressure at the bit as the controlling pressure-parameter and attempted to develop correlations between d-exponent and overbalance. They failed to normalized the d-exponent, however, and their correlation was of limited use.

Following this pioneering effort, the work of Foster and Whalen [**1966**], Rehm and McClendon [**1967**], Lane and Macpherson [**1974**], and Eaton [**1969, 1972, 1975**] transformed the early techniques into industry standards. The most widely and successfully used methods to date include resistivity, sonic, and corrected d-exponent plots [**Rehm and McClendon 1967**] interpreted using Eaton's relationships [**1975**], which take the general form:

$$\frac{P_p}{D} = \frac{\Sigma_v}{D} - \left(\frac{\Sigma_v}{D} - \left(\frac{P_p}{D}\right)_n\right) \Lambda_n^{\zeta} \qquad (2)$$

Table 1 summarizes the values of exponent, ζ, depending on the selected pore pressure indicator, λ.

Partly because the weight on bit measurement was made at surface, and partly because many factors other than pore pressure are implicitly included in the d-exponent, quantitative interpretation of d-exponent variations proved a difficult task. The d-exponent method, however, offers the real-time advantage which the wireline techniques do not. It contains information obtained at the deepest point in the well and measured while drilling. This is why wellsite interpretation often uses the d-exponent to detect the occurrence of overpressures. As the d-exponent departs from its normal trend, drilling is stopped. Upon circulating and monitoring the surface pressure indicators, the decision can be made to drill ahead, and/or to increase mud weight. If there is any doubt, the drillstring is pulled out of the hole, and wireline measurements are then performed to confirm the d-exponent indications and determine the average pressure gradient. With the advent of MWD, this procedure has become obsolete.

MODERN REQUIREMENTS

The drilling industry underwent major changes in the last decade. The birth and expansion of the MWD industry, the advent of PDC bits, the implementation of wellsite computer systems and the growing number of highly inclined wells has profoundly modified the drilling environment. This modern environment sets new design criteria for pore pressure evaluation methods.

Real-Time Capability

All conventional pore pressure evaluation methods make use of normal trend lines. Numerous authors have emphasized the difficulty there is to determine such a normal trend with wireline logs, particularly when regional experience is limited. Furthermore, defining "the" normal trend is an essentially subjective task extremely dependent on human judgement. The slope and intercept of this line will vary between operators, and rather than easing the task, experience will often create additional doubts. Automatization of the normal trend positioning using regression analysis schemes has had limited success.

Using normal trend lines on a real-time basis adds a new dimension to the problem. A final wireline log provides the entire profile on which hydrostatic and overpressured shales should appear clearly, even though exact determination of the top of overpressures and placement of the normal trend may pose some difficulty. At least it is possible to identify the data that should be used in the definition of the normal trend.

When using MWD tools, quantitative interpretation is impossible until the normal trend can be positioned with a reasonable degree of certainty. Frequently, this requires that the overpressured zone be penetrated, so that the hydrostatic shale points can be identified. Thus, qualitative detection of overpressured shales may also become uncertain, as the normal trend is constantly being redefined as additional data become available. The following resistivity example illustrates the difficulty there is to place the normal trend while drilling.

Figure 4 shows the MWD resistivity data available at a given time during drilling. At that time, and assuming there is limited experience in the area, the normal trend line can be positioned as shown, which places the top of the overpressured shale interval at about 7,600 ft [2300 m]. Additional data becomes available as drilling progresses, revealing that the early interpretation was erroneous (**Figure 5**).

In fact, the top of the overpressured interval appears to be at 10,400 ft [3200 m]. This mistake could have caused unnecessary mud weight increases or even premature setting of the casing string.

This example shows that the benefit of a real-time data acquisition system is not substantial unless measurements can be interpreted as they are made. More generally, the method should allow pore pressure evaluation on the basis of the data acquired at any given time, without knowledge of data *to be* obtained. This suggests the development of real-time interpretation models without resorting to normal trends.

Pore Pressure Evaluation In Shales

Since pressure measurements cannot be performed in shales, Hottmann and Johnson used the average pressure gradient determined in nearby sands to build their empirical correlations. Hence, pressure and resistivity data, for example, do not originate from the same depth. Three different environments are in fact gathered in Hottmann and Johnson's correlation (**Figure 6**):

- *Normally pressured shales*, where the normal resistivity trend is defined.
- *Overpressured shales*, where the resistivity departures from the normal trend are evaluated at the depth of interest, D1.
- *Sandstone reservoirs*, where the pressures are measured, and the average fluid pressure gradients are calculated at depth, D2.

Consequently, the conventional empirical correlations only allow the

evaluation of pore pressure in reservoirs, not in shales. Should the average pressure gradient be different in the two formations, the true shale pore pressure cannot be determined. Pressure regressions, where the average pressure gradient is greater in shales than it is in adjacent sands, occur frequently in the Gulf Coast [**Keith and Rimstidt, 1985**]. Therefore, empirical correlations generally underestimate the average pressure gradient in shales. This has two major consequences:

1. In the event of a permeable stringer sandwiched in the shale, the pressure gradient is probably the same in both formations. Underestimation of the shale pressure gradient may lead to a kick.

2. Concern over borehole stability has grown as the drilling industry undertakes highly deviated and horizontal wellbores more frequently. Knowledge of shale pore pressure becomes critical to adjust mud weight to a level that will ensure borehole stability. Modern pore pressure evaluation methods must therefore provide insight on pore pressure in shales to allow a global well-control, not only to avoid kicks, but also to ensure wellbore stability.

PDC Bits And OBM

PDC bits are now widely used throughout the drilling industry. They are often used to drill soft plastic formations such as shales. Use of the d-exponent to determine pore pressure should be restricted to soft type roller cone bits. Extension to insert bits and PDC bits should be done with caution. It is preferable to use a PDC-specific bit performance model and isolate the effect of pore pressure.

Models independent of bit type are generally based on petrophysical measurements such as sonic or resistivity. While sonic tools are not yet available for real-time applications, use of a short normal resistivity sonde is incompatible with non-conductive muds such as oil-base muds (OBM). Moreover, use of MWD measurements performed above the bit lag by a time function on tool position in the bottom-hole assembly and penetration rate.

Accuracy And Consistency

Early interpretation methods were used to prevent hazardous situations. Once well control is achieved, it becomes possible to reduce mud weight to a minimum safe level. This optimization allows substantial savings on mud additives and improves drilling performance, thereby reducing drilling costs. This operation, however, increases the chances of hazard, but accurate and consistent pore pressure evaluation methods make it a calculated risk.

NEW PORE PRESSURE EVALUATION METHODS

Hardware And Software Evolution

In less than ten years of commercial experience, the MWD industry has developed a wide array of tools, most of which can be used to enhance pore pressure evaluation. Despite the introduction of these new tools [Short normal resistivity, 1983] and the implementation of powerful computer facilities, pore pressure evaluation while drilling has relied heavily on the conventional empirical methods developed in the sixties and seventies. It seems that interpretation software could not keep up with the rapid evolution of hardware. This lag between hardware and software development is characteristic of the logging industry in general. It is, however, much more sensitive with MWD which has established itself as a service in less than ten years.

Rather than attempting to develop a fundamental pore pressure evaluation model and build the necessary tools, the MWD industry followed the conventional strategy: tools developed for other purposes would be used for pore pressure evaluation. In retrospect, this approach appears clearly in the succession of interpretation methods proposed in the last ten years, and a parallel can be made with the introduction of new sensors. Zoeller [1983] proposed an empirical method using natural gamma ray measurements. More fundamental was the work of Lesso and Burgess [1986] who adapted a roller-cone milled-tooth bit model to pore pressure and porosity determination while

drilling. More recently, several real-time resistivity interpretation models have been proposed [**Holbrook and Hauck, 1987; Bryant, 1989; Alixant *et al*, 1989**]. This evolution closely follows that of hardware: gamma ray tool [1982], downhole WOB and torque measurements [1983], and real-time 2-MHz resistivity devices [1986].

The Effective Stress Concept

Among the topics addressed in the recent pore pressure evaluation models is the real-time capability. The difficulties associated with the use of normal trend lines were eliminated by developing models capable of performing point-by-point pressure estimates, regardless of data that have been obtained, or that will be obtained. In general, this is done by explicit use of the effective stress concept [**Terzaghi, 1948**].

The effective vertical stress can be defined as the stress acting in the vertical direction that controls the vertical deformations of the porous media. This definition emphasizes the fact that the effective stress is a conceptual stress, not a physically measurable quantity. Only its effects, deformations, are measurable. Terzaghi developed this concept in his study of saturated porous media. Based on his experimental work, he also proposed the following empirical relationship:

$$\sigma_v = \Sigma_v - P_p \tag{3}$$

The effective stress concept is not new to pore pressure evaluation techniques. Hubbert and Rubey [**1959**] used it in their description of shale compaction, while it enabled Foster and Whalen [**1966**] to develop the equivalent depth principle along with a theoretical explanation of the empirical correlations of Hottmann and Johnson [**1965**]. More importantly, Eaton's empirical correlations can be understood as a particular form of Terzaghi's relationship. Dividing Equation 3 by depth, D, and substituting the effective vertical stress gradient into Equation 2 yields:

$$\frac{P_p}{D} = \frac{\Sigma_v}{D} - \frac{\sigma_{vn}}{D} \Lambda_n^{\zeta} \tag{4}$$

Equation 4 shows that Λ_n^{ζ} is a coefficient which accounts for deviations from normal effective stress conditions. This coefficient, however, was obtained empirically.

Use Of Resistivity Measurements

The latest models found in the literature are based on resistivity measurements rather than on drilling performance models. There are several reasons for this choice:

- *Historical,* since resistivity measurements have been used for pore pressure evaluation for over 25 years now. The technique has been widely documented in the literature, and it is well accepted in the field.

- *Practical,* since resistivity tools are now provided worldwide by most MWD service companies. Other tools such as mechanical subs are limited in their availability. Also, the method is independent of bit-type, which makes it more general.

- *Economical*, because operators often include a resistivity sub to their BHA for formation evaluation purposes. A resistivity-based pore pressure evaluation method therefore requires no additional hardware, i.e., no substantial additional cost.

- *Technical*, in relation to recent developments in MWD resistivity technology. Propagation tools provide reliable measurements for quantitative interpretation often providing wireline quality logs.

Finally, the advent of resistivity devices providing measurements *ahead* of the bit will eliminate the time lag characteristic of petrophysical pore pressure evaluation methods, as opposed to mechanical methods making use of drilling data. Although these new resistivity tools only allow qualitative interpretation at

this stage [**Grupping, Harrell, and Dickinson, 1987**], future developments will hopefully provide resistivity measurements with a true real-time feature.

The recent resistivity-based pore pressure evaluation models use Terzaghi's relationship explicitly: pore pressure is calculated as the difference between overburden and effective vertical stress. Overburden is obtained from empirical correlations which are well accepted throughout the industry. Each method differs in the way effective stress is calculated. Holbrook and Hauck [**1987**], and Bryant [**1989**] base their calculation on empirical correlations between shale porosity and effective stress [**Baldwin and Butler, 1985**]:

$$\sigma_v = \sigma_{max} (1 - \Phi)^{\alpha+1} \quad (5)$$

Alixant *et al* [**1989**] use the one-dimensional compaction theory:

$$e = C_c \, Log_{10} \, \sigma_v + e_i \quad (7)$$

Differences also appear in the interpretation of resistivity logs in terms of shale porosity. In general, authors use the empirical formation factor relationship developed by Archie [**1942**] for reservoir rocks, although alternate solutions are available [**Alixant *et al*, 1989**]. By relating shale porosity to effective vertical stress, the new models provide pore pressure estimates in *shales*, thus contributing to improved wellbore stability. On the other hand, pore pressure in permeable beds cannot be determined reliably unless the models are supplemented with a specific interpretation module for each formation. By assuming two lithologies, Holbrook and Hauck [**1987**] developed a model that has the ability to provide pressure estimates in shales and in sands.

Generalization Of The New Evaluation Methods

The analysis of the new pore pressure evaluation methods shows that porosity is chosen as the pressure-dependent parameter. Four steps are taken in the design of a pressure evaluation technique:

- Selection of a porosity-dependent parameter τ
- Determination of porosity by interpreting τ
- Establishment of a relationship between porosity and effective vertical stress, σ_v
- Use of Terzaghi's relationship to obtain pore pressure

Although current methods favor the use of MWD resistivity devices, they could be replaced by any tool providing porosity.

Four Basic Options

The recent changes in pore pressure evaluation show a definite trend towards real-time compatibility, rationalization of the theory, and limited use of empirical correlations. The new models are based on resistivity, and are thus independent of bit-type, while providing shale pressure estimates. Although several interpretation models are available and variations are possible, operators are practically left with four basic options. These options are defined by the selection of MWD hardware and the adequate interpretation method.

Table 2 summarizes the four options. Two sets of MWD tools can be selected: 2-MHz resistivity or downhole mechanical subs. Each measurement can then be interpreted using normal trends in a conventional fashion, or with the new point-by-point methods. Combination of these possibilities defines four options which are not exclusive of one another: they can be combined and run in parallel.

Selecting A Real-Time Pore Pressure Evaluation Option

The absence of interaction between the four basic options makes them totally independent of one another. Although the four methods may be run simultaneously while drilling, one of the methods must still be relied on because four different results will generally be obtained. Determination of the most accurate method is often a matter of experience and trust. Selecting the highest pressure estimate to maximize security may prove excessively costly.

Being able to run the four basic methods, however, is not the general

rule, as mechanical subs are less frequently used than resistivity tools. Hardware availability will therefore generally reduce the options to two. Selecting an interpretation method becomes a matter of faith. In spite of their limitations, conventional methods have been widely used throughout the industry and are well accepted in the field. When regional experience is available and the normal trend can be placed without excessive difficulty, this is probably what will be used.

The new pressure evaluation techniques are too recent to replace normal trend lines and overlays all at once. Acceptance of these newcomers will require time and experience, although authors have already reported instances when the new models have outperformed conventional methods.

CONCLUSION: A LOOK AT THE FUTURE

Although several pore pressure evaluation schemes are available and many variations have been proposed, current pore pressure evaluation methods are unable to meet all the requirements associated with modern drilling conditions. As stated by Pilkington [1988], "MWD, however, is not the panacea industry would like to have for pressure detection." This section proposes design objectives for the next generation of pore pressure evaluation methods, and offers some suggestions to achieve these goals.

Primary Objectives

1. The first objective is reliability. Pore pressure evaluation methods must provide accurate pore pressures consistently. A reasonable margin on the accuracy is probably 0.5 PPG, which would allow improved mud weight optimization and drilling performance.

2. The real-time capability is imperative. The method should be able to provide pressure estimates on a point-by-point basis, regardless of previous or future data. It is conceivable, however, to use earlier data to improve current estimates.

3. By using shale porosity as a pressure indicator, all models currently in use assume that overpressures are caused by shale compaction disequilibrium. Future methods should aim at providing pore pressure estimates regardless of the cause of geopressures. More generally, these methods should not be restricted to pressure evaluation in shales.

4. Although models may become more complex, flexibility must be maintained. Compatibility with most MWD tool gives more potential applications to the method. Ease of implementation and operation, and sound theoretical bases can be instrumental in the acceptance of the model by field personnel.

Other Considerations

1. Other factors inherent to the drilling environment may pose limitations to the applicability or the accuracy of pore pressure evaluation methods. As it was mentioned earlier, the use of particular bit types and the presence of a specific drilling fluid, may be incompatible with any given pore pressure evaluation method.

2. Additionally, the accuracy of a pore pressure evaluation method can be affected by unaccounted factors such as stress distribution around the wellbore, or drilling fluid invasion. Finally, there may be variations in the pressure-dependent parameter due to effects other than pressure.

Current Developments And Suggestions

1. Most of the objectives mentioned earlier cannot be achieved using shale porosity as a pressure indicator, and the first task is to identify another variable for this purpose. This may require the development of a new MWD sensor.

2. At this time, the only true real-time measurements are provide by mechanical subs. Although accurate and reliable interpretation of these measurements in terms of pore pressure for current drill-bit types still requires research, the existing methods provide an early estimate of the pressure regimes encountered by the wellbore.

3. This early estimate can be refined as drilling progresses and additional sensors reach the point of interest. The concept of refining pressure estimates as additional data become available is being investigated by at least one service company.

4. Research is also being conducted to include multiple lithologies occurring sequentially or simultaneously. This allows pore pressure estimation in formations other than shales, while increasing their accuracy. When dealing with reservoirs, it also becomes necessary to extend the interpretation of measurements to hydrocarbon-saturated porous media.

5. Neutron and density MWD sensors are now used for formation evaluation purposes. The two measurements could be incorporated in a pore pressure evaluation model. Aside from enhancing formation evaluation and the conventional shale porosity interpretation, these measurements may be instrumental in the pressure evaluation of gas reservoirs.

6. Use a spectral gamma ray as a shale discriminator when possible.

Selecting an appropriate pore pressure indicator, increasing the number of variables taken into account by the model, and incorporating several lithologies while maintaining ease of use and flexibility are the key elements to the design of a modern pressure evaluation method.

NOMENCLATURE

C_c	shale compression index
D	vertical depth
DTOR	downhole torque
d_{csh}	corrected d-exponent calculated in shales
e	void ratio
e_i	void ratio intercept
GR	gamma ray
P_p	pore pressure
R_{sh}	shale resistivity
SN	short normal resistivity
WOB	weight on bit
α	empirical exponent of the Baldwin and Butler correlation
Δt_{sh}	shale transit time
Φ	formation porosity
Λ_n	normalized pressure indicator
λ	a pressure-dependent parameter
Σ_v	overburden
σ_{max}	theoretical value of effective stress corresponding to zero porosity
σ_v	effective vertical stress
τ	porosity-dependent parameter
ζ	empirical exponent of Eaton's correlations
n	subscript indicating normal pressure conditions
m	subscript applied to measured values

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TABLES

λ	ζ
Rsh	-1.2
Δtsh	3.0
dcsh	-1.2

Table 1 Eaton exponent values for commonly used pressure indicators

Measurement / Interpretation	**Drilling Performance**	**Resistivity**
Conventional	MWD Directional Surface WOB ROP	MWD Directional MWD SN GR
Real-Time	MWD Directional MWD WOB & DTOR ROP	MWD Directional 2-MHz GR

Table 2 Summary of real-time pore pressure evaluation options and required hardware

Notes

1. MWD directional surveys are used to determine average pressure gradients.
2. Use of a gamma ray log as a shale discriminator is not always reliable. While formations having a high clay-content are readily identified in most instances, it remains possible to mistake a highly shaly sand for a silty shale, which may be fatal to resistivity-based models in particular. Moreover, some of these models may be sensitive to clay mineralogy, which can only be assessed with a spectral gamma ray device.

FIGURES

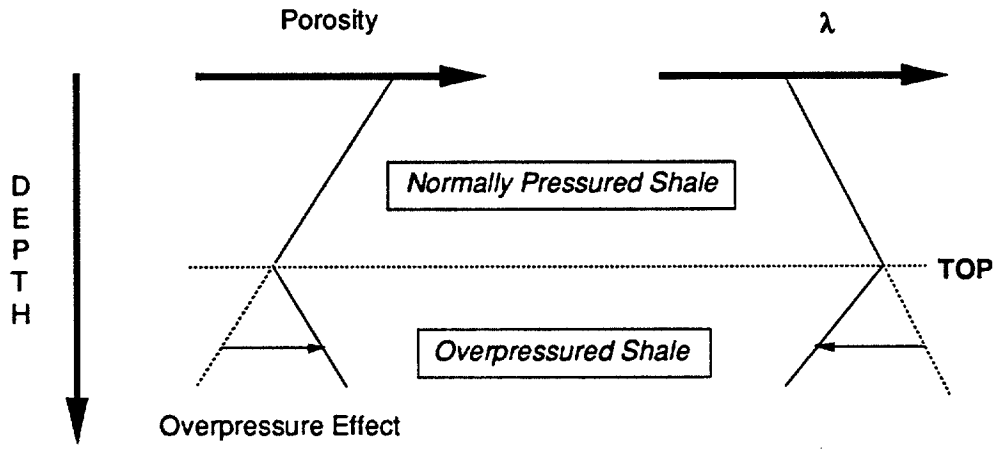

Figure 1 Overpressure detection using a pressure-dependent parameter.

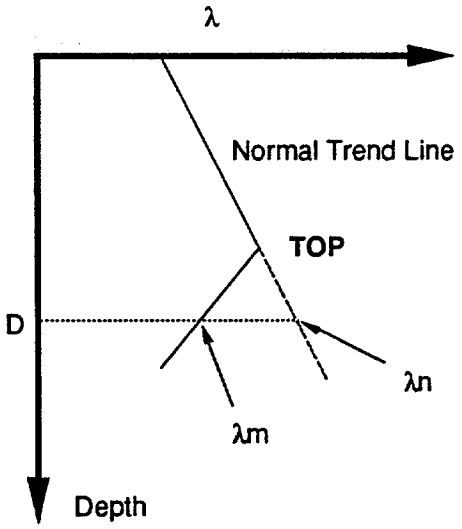

Figure 2 Normal resistivity

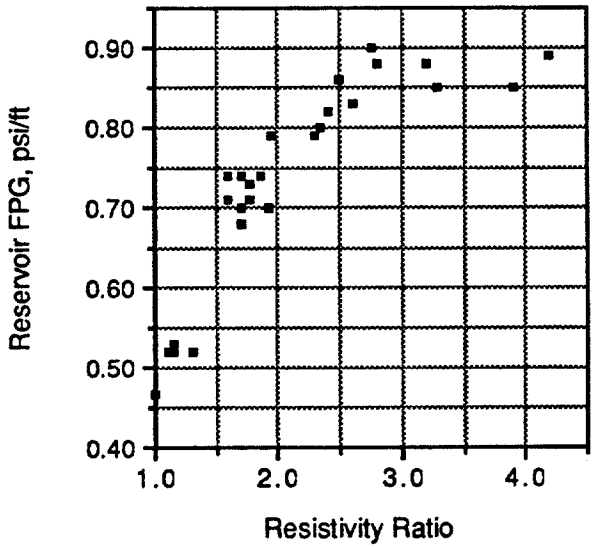

Figure 3 Hottmann and Johnson correlation.

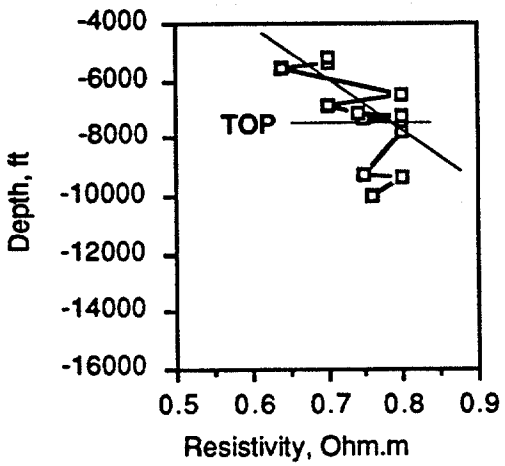

Figure 4 Early real-time resistivity interpretation

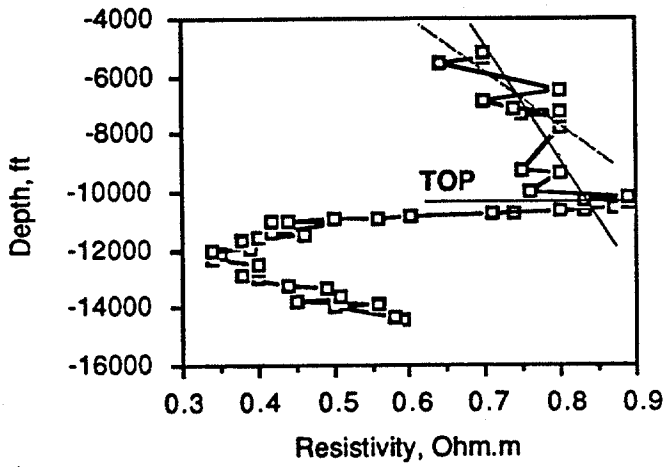

Figure 5 Real-time resistivity interpretation after drilling into the overpressured zone

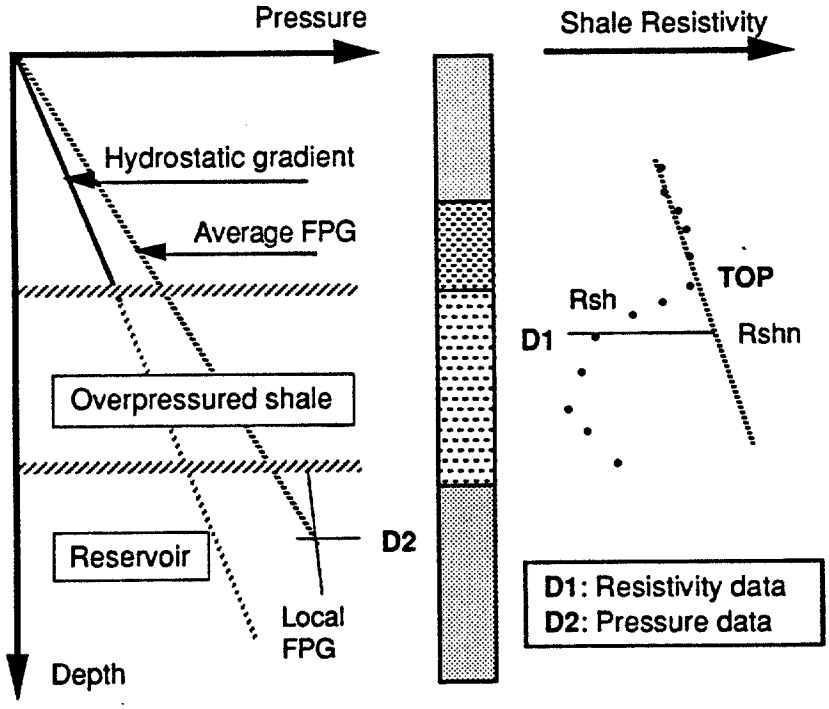

Figure 6 Relating shale resistivity data to average reservoir pressure gradient.

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REAL-TIME PORE PRESSURE EVALUATION OPTIONS

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ABSTRACT

Standard blowout prevention procedures cannot be based on the over-sizing of blowout prevention equipment, excessive mud weighing, or heavy casing programs. Daily operations require the use of pore pressure estimation methods that help define and adjust cost effective drilling programs. Various techniques were developed in the sixties and seventies to help determine the occurrence and magnitude of overpressures encountered by the wellbore. These "conventional" methods are based on the analysis of normal trends in shales, interpreted using empirical correlations.

With the growth of MWD technology, new pore pressure evaluation methods have recently been proposed. Considering the rapid evolution of hardware and software tools, this paper focuses on the real-time pore pressure evaluation options currently available to operators.

Comparing pore pressure evaluation methods on the basis of individual examples is not the best way to define these options. Instead, this paper organizes available real-time pore pressure evaluation methods according to their theoretical bases and the hardware requirements for field implementation. This systematic and global approach should help users select pressure evaluation techniques according to objectives, drilling conditions, and available equipment.

Despite the number of techniques that have been proposed until now, there are still some deficiencies. By reiterating some of the shortcomings of the methods currently in use, this analysis attempts to define the requirements for future pore pressure evaluation methods.

INTRODUCTION

"Normal" or "hydrostatic" formation pressure is defined at any vertical depth, D, as the pressure resulting from the hydrostatic head of a column of connate water of height D. This conventional definition is often associated with the concept of average fluid pressure gradient, equal to the ratio of pressure over depth. In the Gulf Coast region, the normal pore pressure gradient is taken equal to 0.465 psi/ft [1.07 Sp gr]. Pore pressures associated with an average gradient greater than hydrostatic are termed abnormal.

Considerable disagreement exists among earth scientists concerning the mechanisms responsible for generating abnormally high pore pressures. However, among the numerous models that have been proposed, none compare with the ability of compaction disequilibrium of argillaceous sediments to account for the magnitude of overpressures and their worldwide occurrence in tertiary sedimentary basins. This observation generally transposes the problem of detecting overpressured formations into detecting undercompacted shales, which are characterized by their unusual porosity trends.

While abnormal pressure detection can be done by tracking shale porosity, quantitative evaluation of pore pressure in shales poses some difficulty. Due to their extremely low permeabilities, shales do not allow the practical performance of conventional pressure tests. Pore pressure is thus *inferred* by interpreting pressure-dependent parameters that can be measured while drilling shales.

There are many such parameters capable of providing insight on pore pressure. The analysis of size, shape, and density of shale cuttings, monitoring

mud temperature and gas content, are frequently used to help detect the occurrence of overpressures. Prior to drilling, the interpretation of seismic data is instrumental in the detection and evaluation of overpressures, thus permitting well planning. Far from providing a comprehensive review of pore pressure evaluation methods, this paper focuses on methods having a real-time potential in the MWD sense.

CONVENTIONAL EVALUATION METHODS

The principle of pore pressure evaluation from well logging data was established by Hottmann & Johnson [**1965**], who first developed a method that allowed "to infer certain *reservoir* properties, such as formation pressure, at any level in the well," by interpreting "the acoustical and electrical properties of *shales*."

Generalization Of The Principle

The method developed by Hottmann and Johnson for two specific petrophysical measurements can easily be generalized. The development of a similar technique involves the following elements:

- Selection of a pore-pressure dependent parameter λ
- Definition of the normal trend and identification of pressure regimes
- Quantification of pore pressure by normalizing λ

When shale compaction disequilibrium is the cause of abnormal formation pressures, λ is generally a shale-porosity dependent parameter. In normally-pressured intervals, shale porosity decreases with depth as a result of compaction, and λ varies accordingly. The evolution of λ in the normally-pressured zone defines the "normal trend."

Shale porosity departs from the normal compaction trend towards higher values as the average fluid pressure gradient increases. This break in the shale porosity profile corresponds to a similar shift for the porosity-dependent

parameter. **Figure 1** assumes that λ is a decreasing function of shale porosity. The graph illustrates the normal trend concept and departures from the normal trend .

Quantification of λ–departures from the normal trend in terms of pore pressure are made possible by developing empirical correlations. Obtaining a general-applicable correlation calls for the use of a normalized term, Λ_n:

$$\Lambda_n = \frac{\lambda_m}{\lambda_n} \tag{1}$$

λ_m is the measured value of λ at the current depth. The normal value, λ_n, is the hypothetical value of λ had the shale been normally pressured. It is obtained by extrapolating the normal trend line to the depth of interest, as shown in **Figure 2.**

A correlation is established by plotting the values of Λ_n against the average pressure gradient measured in nearby permeable formations.

Application To Petrophysical Measurements

Several "conventional" pore pressure evaluation methods have been proposed in the past. They all follow the basic scheme described above, and only differ by the choice of the pressure-dependent parameter λ and by the data sets used to develop the empirical correlation.

Hottmann and Johnson [**1965**] proposed resistivity or the transit time of compressional acoustic waves as pressure indicators. Their correlations are based on resistivity and sonic measurements in Oligocene/Miocene shale formations in Louisiana. **Figure 3** reproduces the data they used to develop a correlation for shale resistivity.

Jorden and Shirley [**1966**] developed an interpretation technique based on drilling performance analysis. Using the drilling equation developed by Bingham [**1965**] for soft-formation milled-tooth roller-cone bits, they normalized penetration rate for weight-on-bit (WOB), rotary speed (RPM), and bit diameter. The effect of pore pressure on penetration rate was assumed to be implicitly

included in the WOB exponent, d. Plots of d-exponent versus depth are then interpreted according to the general method described above.

Jorden and Shirley identified differential pressure at the bit as the controlling pressure-parameter and attempted to develop correlations between d-exponent and overbalance. They failed to normalized the d-exponent, however, and their correlation was of limited use.

Following this pioneering effort, the work of Foster and Whalen [**1966**], Rehm and McClendon [**1967**], Lane and Macpherson [**1974**], and Eaton [**1969, 1972, 1975**] transformed the early techniques into industry standards. The most widely and successfully used methods to date include resistivity, sonic, and corrected d-exponent plots [**Rehm and McClendon 1967**] interpreted using Eaton's relationships [**1975**], which take the general form:

$$\frac{P_p}{D} = \frac{\Sigma_v}{D} - \left(\frac{\Sigma_v}{D} - \left(\frac{P_p}{D}\right)_n\right) \Lambda_n^{\zeta} \qquad (2)$$

Table 1 summarizes the values of exponent, ζ, depending on the selected pore pressure indicator, λ.

Partly because the weight on bit measurement was made at surface, and partly because many factors other than pore pressure are implicitly included in the d-exponent, quantitative interpretation of d-exponent variations proved a difficult task. The d-exponent method, however, offers the real-time advantage which the wireline techniques do not. It contains information obtained at the deepest point in the well and measured while drilling. This is why wellsite interpretation often uses the d-exponent to detect the occurrence of overpressures. As the d-exponent departs from its normal trend, drilling is stopped. Upon circulating and monitoring the surface pressure indicators, the decision can be made to drill ahead, and/or to increase mud weight. If there is any doubt, the drillstring is pulled out of the hole, and wireline measurements are then performed to confirm the d-exponent indications and determine the average pressure gradient. With the advent of MWD, this procedure has become obsolete.

MODERN REQUIREMENTS

The drilling industry underwent major changes in the last decade. The birth and expansion of the MWD industry, the advent of PDC bits, the implementation of wellsite computer systems and the growing number of highly inclined wells has profoundly modified the drilling environment. This modern environment sets new design criteria for pore pressure evaluation methods.

Real-Time Capability

All conventional pore pressure evaluation methods make use of normal trend lines. Numerous authors have emphasized the difficulty there is to determine such a normal trend with wireline logs, particularly when regional experience is limited. Furthermore, defining "the" normal trend is an essentially subjective task extremely dependent on human judgement. The slope and intercept of this line will vary between operators, and rather than easing the task, experience will often create additional doubts. Automatization of the normal trend positioning using regression analysis schemes has had limited success.

Using normal trend lines on a real-time basis adds a new dimension to the problem. A final wireline log provides the entire profile on which hydrostatic and overpressured shales should appear clearly, even though exact determination of the top of overpressures and placement of the normal trend may pose some difficulty. At least it is possible to identify the data that should be used in the definition of the normal trend.

When using MWD tools, quantitative interpretation is impossible until the normal trend can be positioned with a reasonable degree of certainty. Frequently, this requires that the overpressured zone be penetrated, so that the hydrostatic shale points can be identified. Thus, qualitative detection of overpressured shales may also become uncertain, as the normal trend is constantly being redefined as additional data become available. The following resistivity example illustrates the difficulty there is to place the normal trend while drilling.

Figure 4 shows the MWD resistivity data available at a given time during drilling. At that time, and assuming there is limited experience in the area, the normal trend line can be positioned as shown, which places the top of the overpressured shale interval at about 7,600 ft [2300 m]. Additional data becomes available as drilling progresses, revealing that the early interpretation was erroneous (**Figure 5**).

In fact, the top of the overpressured interval appears to be at 10,400 ft [3200 m]. This mistake could have caused unnecessary mud weight increases or even premature setting of the casing string.

This example shows that the benefit of a real-time data acquisition system is not substantial unless measurements can be interpreted as they are made. More generally, the method should allow pore pressure evaluation on the basis of the data acquired at any given time, without knowledge of data *to be* obtained. This suggests the development of real-time interpretation models without resorting to normal trends.

Pore Pressure Evaluation In Shales

Since pressure measurements cannot be performed in shales, Hottmann and Johnson used the average pressure gradient determined in nearby sands to build their empirical correlations. Hence, pressure and resistivity data, for example, do not originate from the same depth. Three different environments are in fact gathered in Hottmann and Johnson's correlation (**Figure 6**):

- *Normally pressured shales*, where the normal resistivity trend is defined.
- *Overpressured shales*, where the resistivity departures from the normal trend are evaluated at the depth of interest, D1.
- *Sandstone reservoirs*, where the pressures are measured, and the average fluid pressure gradients are calculated at depth, D2.

Consequently, the conventional empirical correlations only allow the

evaluation of pore pressure in reservoirs, not in shales. Should the average pressure gradient be different in the two formations, the true shale pore pressure cannot be determined. Pressure regressions, where the average pressure gradient is greater in shales than it is in adjacent sands, occur frequently in the Gulf Coast [**Keith and Rimstidt, 1985**]. Therefore, empirical correlations generally underestimate the average pressure gradient in shales. This has two major consequences:

1. In the event of a permeable stringer sandwiched in the shale, the pressure gradient is probably the same in both formations. Underestimation of the shale pressure gradient may lead to a kick.

2. Concern over borehole stability has grown as the drilling industry undertakes highly deviated and horizontal wellbores more frequently. Knowledge of shale pore pressure becomes critical to adjust mud weight to a level that will ensure borehole stability. Modern pore pressure evaluation methods must therefore provide insight on pore pressure in shales to allow a global well-control, not only to avoid kicks, but also to ensure wellbore stability.

PDC Bits And OBM

PDC bits are now widely used throughout the drilling industry. They are often used to drill soft plastic formations such as shales. Use of the d-exponent to determine pore pressure should be restricted to soft type roller cone bits. Extension to insert bits and PDC bits should be done with caution. It is preferable to use a PDC-specific bit performance model and isolate the effect of pore pressure.

Models independent of bit type are generally based on petrophysical measurements such as sonic or resistivity. While sonic tools are not yet available for real-time applications, use of a short normal resistivity sonde is incompatible with non-conductive muds such as oil-base muds (OBM). Moreover, use of MWD measurements performed above the bit lag by a time function on tool position in the bottom-hole assembly and penetration rate.

Accuracy And Consistency

Early interpretation methods were used to prevent hazardous situations. Once well control is achieved, it becomes possible to reduce mud weight to a minimum safe level. This optimization allows substantial savings on mud additives and improves drilling performance, thereby reducing drilling costs. This operation, however, increases the chances of hazard, but accurate and consistent pore pressure evaluation methods make it a calculated risk.

NEW PORE PRESSURE EVALUATION METHODS

Hardware And Software Evolution

In less than ten years of commercial experience, the MWD industry has developed a wide array of tools, most of which can be used to enhance pore pressure evaluation. Despite the introduction of these new tools [Short normal resistivity, 1983] and the implementation of powerful computer facilities, pore pressure evaluation while drilling has relied heavily on the conventional empirical methods developed in the sixties and seventies. It seems that interpretation software could not keep up with the rapid evolution of hardware. This lag between hardware and software development is characteristic of the logging industry in general. It is, however, much more sensitive with MWD which has established itself as a service in less than ten years.

Rather than attempting to develop a fundamental pore pressure evaluation model and build the necessary tools, the MWD industry followed the conventional strategy: tools developed for other purposes would be used for pore pressure evaluation. In retrospect, this approach appears clearly in the succession of interpretation methods proposed in the last ten years, and a parallel can be made with the introduction of new sensors. Zoeller **[1983]** proposed an empirical method using natural gamma ray measurements. More fundamental was the work of Lesso and Burgess **[1986]** who adapted a roller-cone milled-tooth bit model to pore pressure and porosity determination while

drilling. More recently, several real-time resistivity interpretation models have been proposed [**Holbrook and Hauck, 1987; Bryant, 1989; Alixant *et al*, 1989**]. This evolution closely follows that of hardware: gamma ray tool [1982], downhole WOB and torque measurements [1983], and real-time 2-MHz resistivity devices [1986].

The Effective Stress Concept

Among the topics addressed in the recent pore pressure evaluation models is the real-time capability. The difficulties associated with the use of normal trend lines were eliminated by developing models capable of performing point-by-point pressure estimates, regardless of data that have been obtained, or that will be obtained. In general, this is done by explicit use of the effective stress concept [**Terzaghi, 1948**].

The effective vertical stress can be defined as the stress acting in the vertical direction that controls the vertical deformations of the porous media. This definition emphasizes the fact that the effective stress is a conceptual stress, not a physically measurable quantity. Only its effects, deformations, are measurable. Terzaghi developed this concept in his study of saturated porous media. Based on his experimental work, he also proposed the following empirical relationship:

$$\sigma_v = \Sigma_v - P_p \tag{3}$$

The effective stress concept is not new to pore pressure evaluation techniques. Hubbert and Rubey [**1959**] used it in their description of shale compaction, while it enabled Foster and Whalen [**1966**] to develop the equivalent depth principle along with a theoretical explanation of the empirical correlations of Hottmann and Johnson [**1965**]. More importantly, Eaton's empirical correlations can be understood as a particular form of Terzaghi's relationship. Dividing Equation 3 by depth, D, and substituting the effective vertical stress gradient into Equation 2 yields:

$$\frac{P_p}{D} = \frac{\Sigma_v}{D} - \frac{\sigma_{vn}}{D} \Lambda_n^{\zeta} \tag{4}$$

Equation 4 shows that Λ_n^{ζ} is a coefficient which accounts for deviations from normal effective stress conditions. This coefficient, however, was obtained empirically.

Use Of Resistivity Measurements

The latest models found in the literature are based on resistivity measurements rather than on drilling performance models. There are several reasons for this choice:

- *Historical,* since resistivity measurements have been used for pore pressure evaluation for over 25 years now. The technique has been widely documented in the literature, and it is well accepted in the field.

- *Practical,* since resistivity tools are now provided worldwide by most MWD service companies. Other tools such as mechanical subs are limited in their availability. Also, the method is independent of bit-type, which makes it more general.

- *Economical*, because operators often include a resistivity sub to their BHA for formation evaluation purposes. A resistivity-based pore pressure evaluation method therefore requires no additional hardware, i.e., no substantial additional cost.

- *Technical*, in relation to recent developments in MWD resistivity technology. Propagation tools provide reliable measurements for quantitative interpretation often providing wireline quality logs.

Finally, the advent of resistivity devices providing measurements *ahead* of the bit will eliminate the time lag characteristic of petrophysical pore pressure evaluation methods, as opposed to mechanical methods making use of drilling data. Although these new resistivity tools only allow qualitative interpretation at

this stage [**Grupping, Harrell, and Dickinson, 1987**], future developments will hopefully provide resistivity measurements with a true real-time feature.

The recent resistivity-based pore pressure evaluation models use Terzaghi's relationship explicitly: pore pressure is calculated as the difference between overburden and effective vertical stress. Overburden is obtained from empirical correlations which are well accepted throughout the industry. Each method differs in the way effective stress is calculated. Holbrook and Hauck [**1987**], and Bryant [**1989**] base their calculation on empirical correlations between shale porosity and effective stress [**Baldwin and Butler, 1985**]:

$$\sigma_v = \sigma_{max} (1 - \Phi)^{\alpha+1} \qquad (5)$$

Alixant *et al* [**1989**] use the one-dimensional compaction theory:

$$e = C_c \, Log_{10} \, \sigma_v + e_i \qquad (7)$$

Differences also appear in the interpretation of resistivity logs in terms of shale porosity. In general, authors use the empirical formation factor relationship developed by Archie [**1942**] for reservoir rocks, although alternate solutions are available [**Alixant *et al*, 1989**]. By relating shale porosity to effective vertical stress, the new models provide pore pressure estimates in *shales*, thus contributing to improved wellbore stability. On the other hand, pore pressure in permeable beds cannot be determined reliably unless the models are supplemented with a specific interpretation module for each formation. By assuming two lithologies, Holbrook and Hauck [**1987**] developed a model that has the ability to provide pressure estimates in shales and in sands.

Generalization Of The New Evaluation Methods

The analysis of the new pore pressure evaluation methods shows that porosity is chosen as the pressure-dependent parameter. Four steps are taken in the design of a pressure evaluation technique:

- Selection of a porosity-dependent parameter τ
- Determination of porosity by interpreting τ
- Establishment of a relationship between porosity and effective vertical stress, σ_v
- Use of Terzaghi's relationship to obtain pore pressure

Although current methods favor the use of MWD resistivity devices, they could be replaced by any tool providing porosity.

Four Basic Options

The recent changes in pore pressure evaluation show a definite trend towards real-time compatibility, rationalization of the theory, and limited use of empirical correlations. The new models are based on resistivity, and are thus independent of bit-type, while providing shale pressure estimates. Although several interpretation models are available and variations are possible, operators are practically left with four basic options. These options are defined by the selection of MWD hardware and the adequate interpretation method.

Table 2 summarizes the four options. Two sets of MWD tools can be selected: 2-MHz resistivity or downhole mechanical subs. Each measurement can then be interpreted using normal trends in a conventional fashion, or with the new point-by-point methods. Combination of these possibilities defines four options which are not exclusive of one another: they can be combined and run in parallel.

Selecting A Real-Time Pore Pressure Evaluation Option

The absence of interaction between the four basic options makes them totally independent of one another. Although the four methods may be run simultaneously while drilling, one of the methods must still be relied on because four different results will generally be obtained. Determination of the most accurate method is often a matter of experience and trust. Selecting the highest pressure estimate to maximize security may prove excessively costly.

Being able to run the four basic methods, however, is not the general

rule, as mechanical subs are less frequently used than resistivity tools. Hardware availability will therefore generally reduce the options to two. Selecting an interpretation method becomes a matter of faith. In spite of their limitations, conventional methods have been widely used throughout the industry and are well accepted in the field. When regional experience is available and the normal trend can be placed without excessive difficulty, this is probably what will be used.

The new pressure evaluation techniques are too recent to replace normal trend lines and overlays all at once. Acceptance of these newcomers will require time and experience, although authors have already reported instances when the new models have outperformed conventional methods.

CONCLUSION: A LOOK AT THE FUTURE

Although several pore pressure evaluation schemes are available and many variations have been proposed, current pore pressure evaluation methods are unable to meet all the requirements associated with modern drilling conditions. As stated by Pilkington [1988], "MWD, however, is not the panacea industry would like to have for pressure detection." This section proposes design objectives for the next generation of pore pressure evaluation methods, and offers some suggestions to achieve these goals.

Primary Objectives

1. The first objective is reliability. Pore pressure evaluation methods must provide accurate pore pressures consistently. A reasonable margin on the accuracy is probably 0.5 PPG, which would allow improved mud weight optimization and drilling performance.

2. The real-time capability is imperative. The method should be able to provide pressure estimates on a point-by-point basis, regardless of previous or future data. It is conceivable, however, to use earlier data to improve current estimates.

3. By using shale porosity as a pressure indicator, all models currently in use assume that overpressures are caused by shale compaction disequilibrium. Future methods should aim at providing pore pressure estimates regardless of the cause of geopressures. More generally, these methods should not be restricted to pressure evaluation in shales.

4. Although models may become more complex, flexibility must be maintained. Compatibility with most MWD tool gives more potential applications to the method. Ease of implementation and operation, and sound theoretical bases can be instrumental in the acceptance of the model by field personnel.

Other Considerations

1. Other factors inherent to the drilling environment may pose limitations to the applicability or the accuracy of pore pressure evaluation methods. As it was mentioned earlier, the use of particular bit types and the presence of a specific drilling fluid, may be incompatible with any given pore pressure evaluation method.

2. Additionally, the accuracy of a pore pressure evaluation method can be affected by unaccounted factors such as stress distribution around the wellbore, or drilling fluid invasion. Finally, there may be variations in the pressure-dependent parameter due to effects other than pressure.

Current Developments And Suggestions

1. Most of the objectives mentioned earlier cannot be achieved using shale porosity as a pressure indicator, and the first task is to identify another variable for this purpose. This may require the development of a new MWD sensor.

2. At this time, the only true real-time measurements are provide by mechanical subs. Although accurate and reliable interpretation of these measurements in terms of pore pressure for current drill-bit types still requires research, the existing methods provide an early estimate of the pressure regimes encountered by the wellbore.

3. This early estimate can be refined as drilling progresses and additional sensors reach the point of interest. The concept of refining pressure estimates as additional data become available is being investigated by at least one service company.

4. Research is also being conducted to include multiple lithologies occurring sequentially or simultaneously. This allows pore pressure estimation in formations other than shales, while increasing their accuracy. When dealing with reservoirs, it also becomes necessary to extend the interpretation of measurements to hydrocarbon-saturated porous media.

5. Neutron and density MWD sensors are now used for formation evaluation purposes. The two measurements could be incorporated in a pore pressure evaluation model. Aside from enhancing formation evaluation and the conventional shale porosity interpretation, these measurements may be instrumental in the pressure evaluation of gas reservoirs.

6. Use a spectral gamma ray as a shale discriminator when possible.

Selecting an appropriate pore pressure indicator, increasing the number of variables taken into account by the model, and incorporating several lithologies while maintaining ease of use and flexibility are the key elements to the design of a modern pressure evaluation method.

NOMENCLATURE

C_c	shale compression index
D	vertical depth
DTOR	downhole torque
d_{csh}	corrected d-exponent calculated in shales
e	void ratio
e_i	void ratio intercept
GR	gamma ray
P_p	pore pressure
R_{sh}	shale resistivity
SN	short normal resistivity
WOB	weight on bit
α	empirical exponent of the Baldwin and Butler correlation
Δt_{sh}	shale transit time
Φ	formation porosity
Λ_n	normalized pressure indicator
λ	a pressure-dependent parameter
Σ_v	overburden
σ_{max}	theoretical value of effective stress corresponding to zero porosity
σ_v	effective vertical stress
τ	porosity-dependent parameter
ζ	empirical exponent of Eaton's correlations
n	subscript indicating normal pressure conditions
m	subscript applied to measured values

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TABLES

λ	ζ
Rsh	-1.2
Δtsh	3.0
dcsh	-1.2

Table 1 Eaton exponent values for commonly used pressure indicators

Measurement / Interpretation	**Drilling Performance**	**Resistivity**
Conventional	MWD Directional Surface WOB ROP	MWD Directional MWD SN GR
Real-Time	MWD Directional MWD WOB & DTOR ROP	MWD Directional 2-MHz GR

Table 2 Summary of real-time pore pressure evaluation options and required hardware

Notes

1. MWD directional surveys are used to determine average pressure gradients.
2. Use of a gamma ray log as a shale discriminator is not always reliable. While formations having a high clay-content are readily identified in most instances, it remains possible to mistake a highly shaly sand for a silty shale, which may be fatal to resistivity-based models in particular. Moreover, some of these models may be sensitive to clay mineralogy, which can only be assessed with a spectral gamma ray device.

FIGURES

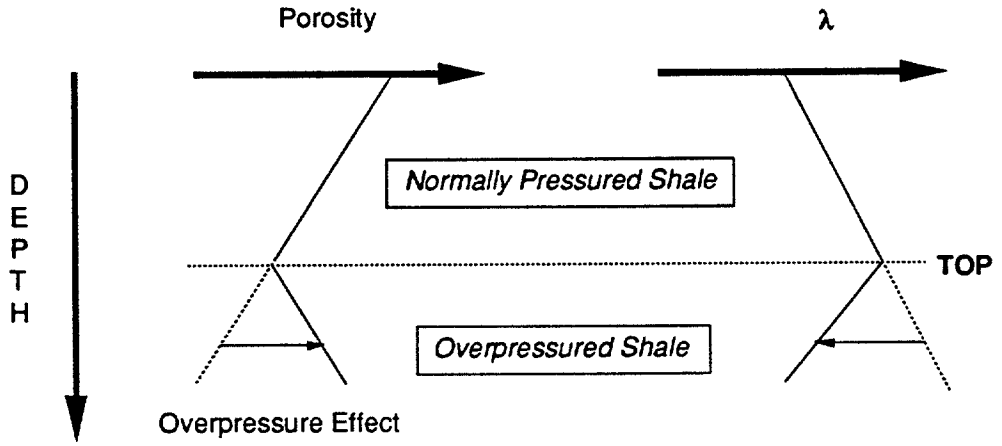

Figure 1 Overpressure detection using a pressure-dependent parameter.

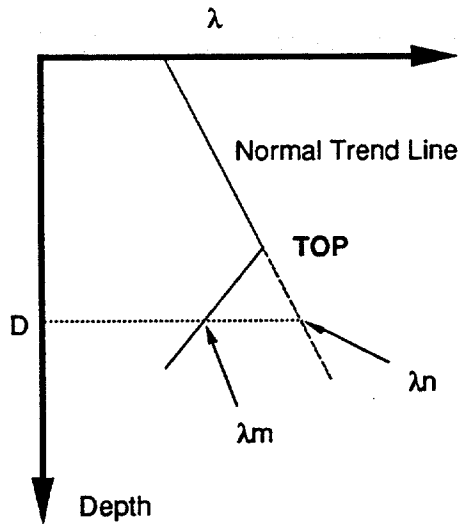

Figure 2 Normal resistivity

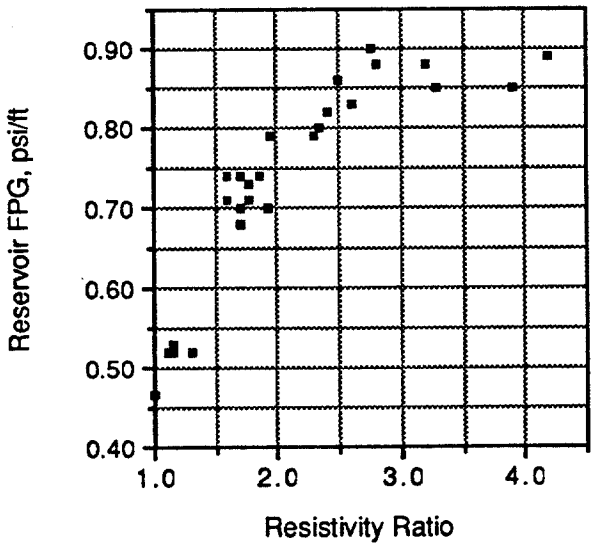

Figure 3 Hottmann and Johnson correlation.

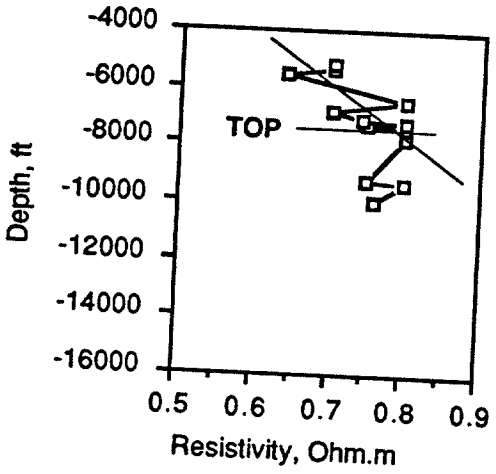

Figure 4 Early real-time resistivity interpretation

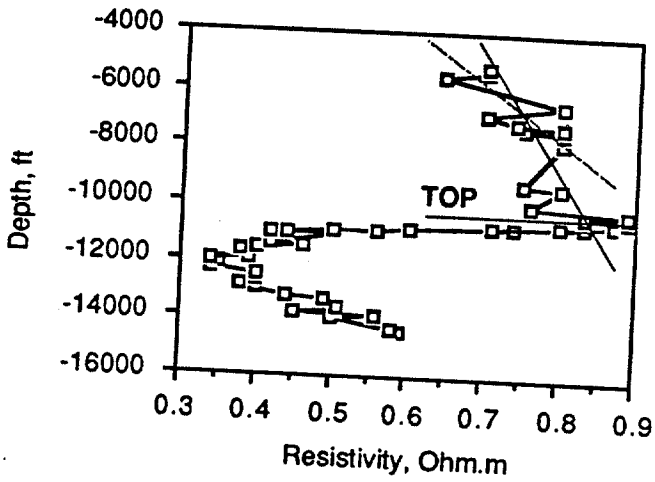

Figure 5 Real-time resistivity interpretation after drilling into the overpressured zone

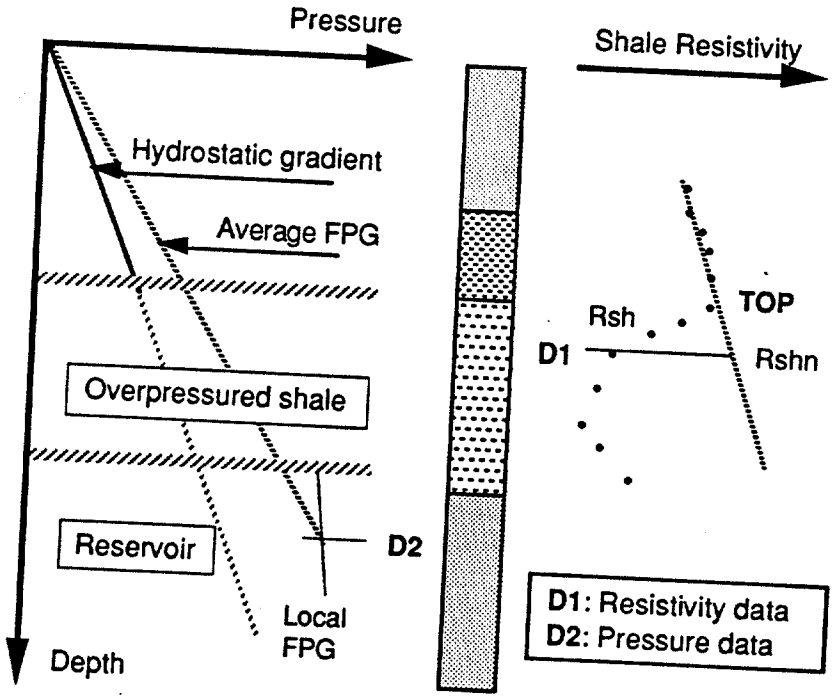

Figure 6 Relating shale resistivity data to average reservoir pressure gradient.

A Computer Assisted Well Control Safety System for Deep Ocean Well Control

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ABSTRACT

A study has been completed to develop improved safety systems and procedures to reduce the risk of surface and underground blowouts in deep ocean environments. The deep ocean well control safety system developed was designed to remove kick fluids from the well bore while providing improved down hole pressure control during well kill operations. Improved bottom hole pressure (BHP) control reduces the risk of a blowout by decreasing the potential of formation breakdown and the occurrence of additional kicks.

The tedious tasks of manually controlling the choke and mud pumps during the well kill operation were automated, allowing the operators to concentrate on higher level decisions. A mud pulse telemetry system was incorporated to relay down hole safety data to the surface, eliminating the necessity of basing all decisions on surface pressures. The software developed will accommodate both surface and subsea rig configurations.

Development and testing of the automated well control safety system was completed at the Louisiana State University Petroleum Engineering Research and Technology Transfer Laboratory. A subsea-configured well simulating 3,000 feet of water and 3,000 feet of sediments as well as a surface configured well with a depth of 6,000 feet were utilized in the testing phase. The system developed was tested with 20 natural gas kicks and in excess of 30 simulated salt water kicks. Results indicate that bottom hole pressure can be maintained to within plus or minus 20 psi in contrast to the plus or minus 200 psi commonly incurred by experienced operators completing manual well control exercises utilizing the same facility. In addition, a reduction in operator stress, enhancing safety, will be achieved as a result of better BHP control and freedom from the repetitive, tedious tasks of pump and choke control.

INTRODUCTION

Today's technology within the oil industry supports exploration for new hydrocarbon reserves further offshore and at increased water depths. To date, wells have been drilled to depths approaching 7,000 feet. Numerous technological problems have been encountered when drilling in this environment and well control solutions have proven to be extremely difficult to achieve and expensive, often requiring specialty muds and sophisticated well plans. However, the increased level of sophistication for drilling operations has not prevented the occurrence of kicks, the unintentional formation fluid entry into the well bore. Loss of control during the well kill operation may lead either to a surface or an underground blowout, with potential loss of life and extensive damage to the rig equipment.

BACKGROUND

Study of well control problems occurring offshore in deep waters revealed three geological facts that make well control for deep water operations much more difficult than for land. These include reduced fracture gradients relative to land rig operations, abnormally pressured formations at shallower depths, and the frequent presence of gas as the formation fluid. This list is not inclusive of all factors affecting well control but includes those most pertinent to this study. A basic understanding of these problem areas is required to better appreciate the need for the system being proposed.

A reduction of formation fracture gradients is commonplace with increasing water depths. Figure 1 demonstrates this by comparing land to subsea drilling operations. All fracture gradients shown are representative for solids penetration depths of 3,500 feet and are expressed as values in units of equivalent pounds-per-gallon (ppge). Note that the ppge fracture gradient reduction associated with increasing water depth does not infer a reduction of total fracture pressure. As the differential between the ppge fracture gradient and the drilling fluid density diminishes, so does the margin for operator error and the size of kick that can be safely removed from the well bore.

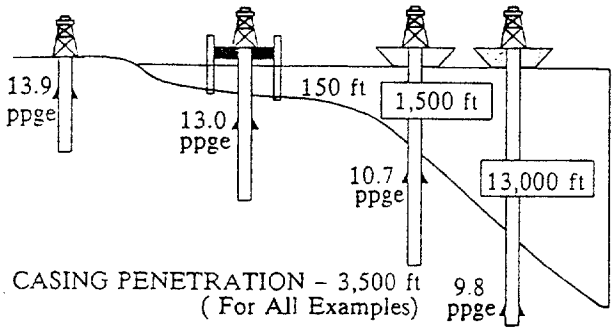

Figure 1 - Deep Ocean Formation Fracture Gradient Comparison

Accentuating the decreased differential between mud weight and the fracture gradient is the presence of abnormally pressured gas zones in deep ocean environments. Figure 2 illustrates a deltaic-type sedimentary environment showing the shale facies upturned in the deeper water, creating possible pressure traps which would extend upward toward the sea floor. Once these pressure traps are penetrated, the well bore is exposed to the higher-than-normal pore pressure gradients.

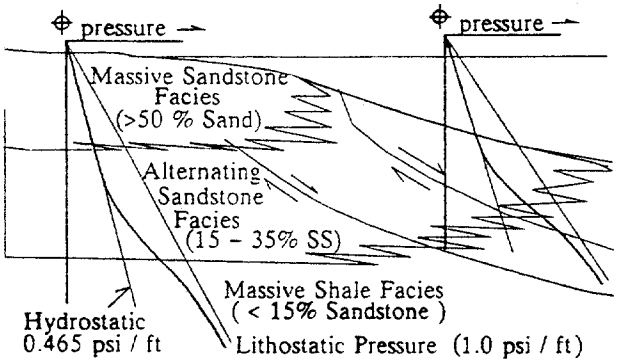

Figure 2 - Shallow Abnormal Pressure

A survey completed by Hughes, Podio, and Sepehrnoori (1987) found that natural gas is the kick fluid in approximately three-fourths of the blowouts that occur in outer continental shelf (OCS) waters in the Gulf of Mexico. As a consequence of low fluid densities, shut-in well head pressures for abnormally pressured, deep water, natural gas kicks are expected to be higher than for kicks composed of salt water or liquid hydrocarbons. When circulating gas kicks to the surface, an increase in the potential for formation fracture due to gas expansion occurs as a result of additional drilling fluid displacement from the well bore. Offseting this additional loss in hydrostatic pressure requires higher surface pressures in order to stabilize bottom hole pressure (BHP).

Protecting against formation fracture, new casing strings are set to protect exposed formations from fracture when the drilling fluid density approaches being equal to the fracture gradient. A typical well plan for deep water offshore operations in the Gulf coast area is shown in Figure 3. As can be seen from the number of casing strings, a given string does not permit much additional footage of new hole to be drilled before setting the next string. Obviously, proper well control is required for safety, but is also an especially important consideration when optimizing the number of casing strings required for a new hole. Better BHP control would allow better utilization of the safety margin obtained through the use of such expensive casing programs.

Once well head pressures have stablized following a kick, the safety of the rig crew and equipment as well as preservation of the well bore then becomes the responsibility of the well control operator. The most commonly used kill procedure, due to its ability to minimize well head pressures, is the weight-and-wait method. However, other methods such as the driller's method and/or a combination of the two are also available to the operators.

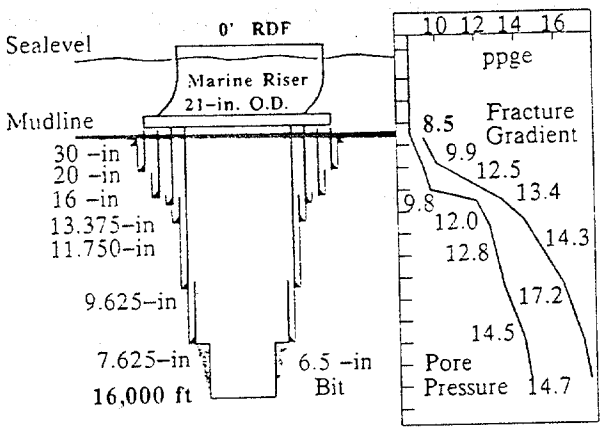

Figure 3 - Typical Deep Ocean Casing Program

Figure 4 is an example of a driller's method well kill operation completed at the Louisiana State University Petroleum Engineering Research and Technology Transfer Laboratory (PERTTL). This well kill operation was a subsea exercise conducted as part of the Minerals Management Service's well control certification class taught at the university. Used in this training exercise is a well simulating 3,000 feet of water and 3,000 feet of solids. A natural gas bubble of approximately eight barrels was injected on bottom. As can readily be seen in the figure, bottom hole pressure varies extensively during the well exercise, approaching plus or minus 200 psi. The largest BHP fluctuations occurred at the beginning of the well kill process. In most real world situations, the gas would not

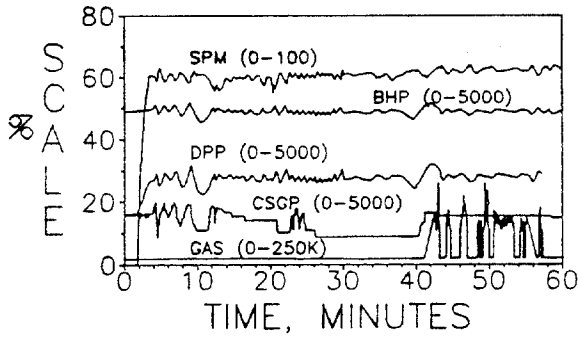

Figure 4 - Manually Controlled Subsea Well Kill

have migrated nor would have been pumped beyond the casing shoe, the weakest formation in the well plan. In this case, increased surface pressure would have exposed the weakest formation at the casing shoe to an excessive and unnecessary equivalent mud weight, risking formation fracture. In addition, pressure drops below the shut-in value would permit additional kicks to enter the well bore, compounding an already difficult situation.

OBJECTIVES

The well exercises at PERTTL have repeatedly shown for several years the inability of experienced operators to consistently hold a constant BHP for the complex well geometry present in deep ocean drilling operations. This fact led to the proposal and the decision to study and make recommendations relative to well control operations in deep ocean waters. Consequently, the expressed objective of this study was to develop improved systems and procedures for reducing the risk of surface and underground blowouts for deep ocean environments. It is believed that completing this objective, improving bottom hole pressure control, increases the safety of rig personnel and equipment alike.

TEST PROGRAM DESIGN

Achieving the stated objective requires evaluation of several well control systems and procedures as well as consideration of human factors associated with manual control. Inconsistency in operator knowledge and expertise for completing a well control procedure has been demonstrated repeatedly in the well control exercises at the university. Inadequate communication between the choke and pump operators plays an obvious role in the oftentimes poor performance in the well kill operation. In addition, numerous operators have difficulty with the many calculations associated with analyzing a well control situation and with the high stress level that may also be present during a real situation. Once the kill procedure is initiated, the operators face several hours of very tedious, stressful work.

The development of a computer-assisted well control procedure for deep ocean environments evolved to eliminate the seemingly repetitiveness of the well control tasks. Two considerations guided the development of the safety system: 1) the ability of the final system to effectively and reliably complete the repetitive tasks associated with well control, and 2) implementation in a form that would be acceptable to the operators.

The developmental plan for the project involved several tasks. Step 1 involved the collecting and storing of data in a form that could be used to complete a kill sheet. Included in this data base were the well parameters from the daily drilling report and the frictional information

taken each tour. Step 2 involved the development of a computer program for calculating and outputing a well control plan such that all calculations remain available in the computer and a hard copy is made available to the operator. Step 3 required adapting the triplex mud pump and choke systems for computer control, and developing software to complete a well kill operation. Finally, Step 4, required the development of a switching system that would permit the operator to regain control of the complete system with the flip of a switch. This step, the return to manual control following automated control, is critical especially if unforeseen problems are encountered, and will greatly influence operator acceptance or rejection of the well control procedure.

Upon completion of the system design, both the surface and the subsea wells were utilized in the testing program. Since subsea operations in deep ocean waters is the main thrust of the study, the majority of all work was done on the subsea configured well. Figure 5, showing the surface well, represents the conceptualization of the test system in final form.

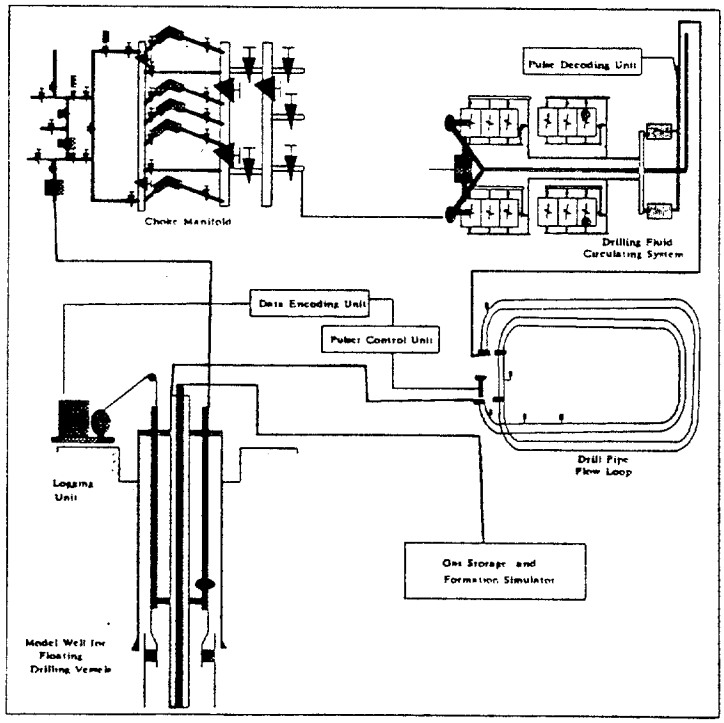

Figure 5 - Computer-Assisted Well-Control Test Facility

As seen in the figure, the pumping system pumps drilling fluids through the flow loop and down the well bore, which returns through the choke system to the mud pits. A gas storage formation simulator was available to inject gas kicks at 6,000 feet. Located on the bottom of the hole was a pressure sensor for collecting true BHP data. These data were available for use in the well control software after being encoded, pulsed, and decoded. In the procedure described, bottom hole pressure data were made available for use within the main program approximately four seconds after the sensing. Tests were completed with varying kick size and varying surface shut-in pressures, evaluating the automated well control system's response.

TEST FACILITY AND EQUIPMENT

A large scale simulation of an offshore deep ocean drilling operation was instrumental in the development and testing of the automated well control safety system. The equipment configuration for the project is shown in Figure 5 and includes:

1. Computer,
2. Subsea-configured well,
3. Triplex mud pump,
4. Drilling fluid flow loop,
5. Mud pulse telemetry system,
6. Instrumentation,
7. Reservoir simulator,
8. High pressure drilling choke, and
9. Wire line system.

A brief discussion of each item follows.

1. Computer

A mini-computer with an analog-to-digital-to-analog (A-D-A) board installed provided process control for the system being developed at a clock speed of 4.6 MHz. The computer is a desk top model containing dual floppy disk drives and 192k of random-access-memory (RAM) storage space. The A-D-A board has a capacity for 8 inputs and 8 outputs.

2. Subsea Configured Well

A sketch of the research well utilized for testing the automated well control safety system, exclusive of the mud pulse telemetry system, is shown in Figure 6. When comparing the research well to the typical deep water well also shown, the similarity is obvious. Physically the research well simulates drilling in a water depth of 3,000 feet with

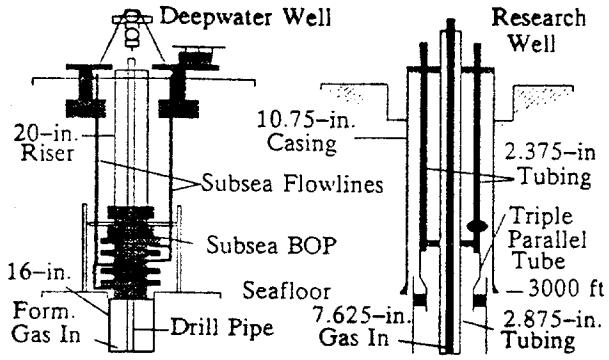

Figure 6 - Subsea Configured Research Well

3,000 feet of solids penetration, making the total true vertical depth equal to 6,000 feet. Returns are taken from a depth of 3,000 feet by either the choke or kill line. The gas injection line is concentric with the drill string, accommodating the injection of natural gas kicks on bottom. The well is fully instrumented, facilitating data collection of pertinent parameters such as drill pipe, casing, and kill line pressures, mud pit volume, and fluid flow rate.

3. Triplex Mud Pump

Two triplex mud pumps served as the drilling fluid prime movers. A single pump was used on this project and has a pumping capacity of 1.3 gallons-per-stroke. Normally, for a pump-out kill procedure, the pump is operated at a reduced circulation rate of 60 strokes-per-minute. Support for the triplex mud pumping system consisted of a centrifugal precharge pump, 180 barrel mud storage tanks, full degassing equipment, and a flare stack to dispose of spent gas separated from the mud stream.

4. Flow Loop

The flow loop was used in conjunction with the fluidics mud pulser to transmit BHP data 10,000 feet in the well control system. The loop, as shown in Figure 5, was made of 4 1/2 inch, 20 pounds-per-foot drill pipe. Pressure taps were located at the pulser and then at 25, 250, 500, 5,000, and 10,000 feet upstream. All of the drill pipe were screwed together except for the 8 bends, 37 foot radii, which were welded.

5. Mud Pulse Telemetry System

The mud pulser operated on a fluidics principle and was a prototype funded by the Mineral Management Service and developed by Harry Diamond Laboratories (Holmes). The pulser unit disturbed the fluid flow,

changing radial flow as it passed through the pulser to vortex flow, slowing down the fluid and creating a positive pressure pulse. Data were transmitted in a binary form at a frequency rate of 10 and 12 hertz, a minimum of four times faster than is currently found in the field. Pressure pulse amplitude was controlled by varying the number of active flow chambers on the pulser, adjusting to varying flow rates. Flow rates used for testing required two flow chambers, creating pressure pulses of up to 200 psi at the tool and varying 25 to 50 psi at the sensor, 10,000 feet upstream. The pulser has a total of four flow chambers as shown in Figure 7.

Figure 7 - Fluidics Mud Pulser

6. Instrumentation

All pressure sensors used were analog devices operating on either current or voltage signals. When appropriate, sensors were located directly at the source of the parameter being measured, eliminating the potential errors of precharge overpressure and of pressure dead bands described by Holden and Kelly (1988). Accuracy of the sensors was a minimum of 0.5 percent full scale, making control much more reliable and precise than if using hydraulic analog gauges.

7. Reservoir Simulator

Injection of gas kicks at a depth of 6,000 feet in the test wells was made possible by a formation simulator consisting of three wells fully cased with cement plugs on bottom. Illustrated in Figure 5, these 2,000 foot simulator wells were identical, having 7 inch, 38 pounds-per-foot casing with a 2 3/8 inch tubing string hung from the well head. The wells were used in gas compression by flowing pipe line gas into the annular space and then closing off the annulus. Fluid was then pumped down the tubing string, compressing the trapped gas in the annulus to pressures as high as 4,500 psig. Once the gas was compressed creating a volume sufficient for injection into the well bore, valves were opened allowing the high pressured gas to flow through the gas injection line in the subsea well to a depth of 6,000 feet. Gas flow into the well continued until the desired kick size and shut-in surface pressures were achieved. At that point the reservoir simulator was either closed-in, leaving one kick in the test well, or left open to generate additional kicks when bottom hole pressure was not properly maintained.

8. High Pressure Drilling Choke

Pressure control for the automated well control system required the use of a high pressure drilling choke. An operationally unique choke was selected, requiring only that a hydraulic "set point pressure" be established for proper casing pressure control. As presented by Cain (1987), the floating shuttle/trim element used for controlling the choke fluid flow area was positioned by pressure differentials across the element, Figure 8 demonstrates this process. Since the shuttle/trim

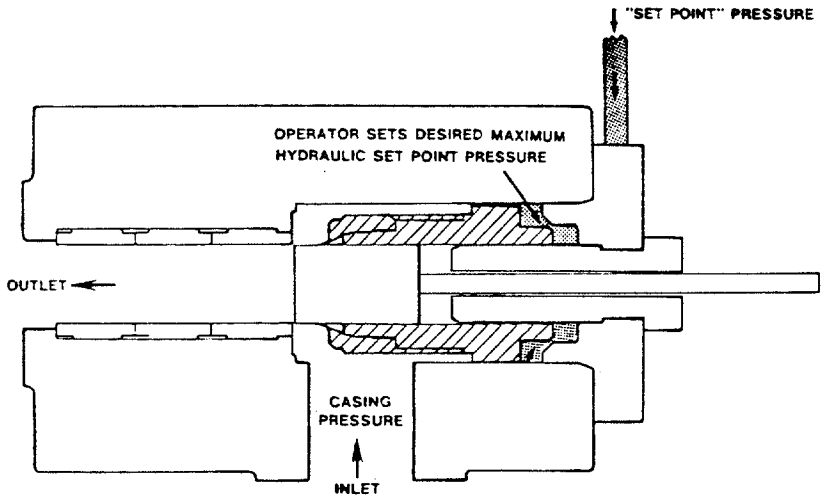

Figure 8 - High Pressure Drilling Choke Design

element end surface areas were identical, the casing pressure was automatically obtained through free element movement to a position that created a casing pressure equal to the hydraulic set point pressure. As an example, if during operations the casing pressure dropped, the set point pressure overbalance would move the shuttle/trim element toward the closed position until the casing pressure stabilized equal to the set point pressure. The reverse would be true should a pressure increase be incurred in the casing, causing the choke to automatically open. Choke specifications indicate that the shuttle/trim would respond to differential pressure as low as 3 psi.

Control of the choke by computer was achieved through the A-D-A interface with the use of pneumatic controls to establish both the set point pressure and the choke pump speed. Set point pressure is linearly controlled with a 3 to 15 psi pneumatic signal while the air flow rate that adjusts the pump speed is achieved by use of a 3 to 15 psi pneumatically controlled flow control valve. Once the mechanical interface was completed, the choke could then be effectively used as a distributive type function, leaving the mini-computer available for other tasks.

The choice of choke was based on ease of implementation, i.e. an additional software package for pressure control by the choke was not required. With additional software development, other choke designs could have been used in the automation process.

9. Wire Line System

Implementing the final testing phase of the well control safety system required evaluating the mud pulse telemetry system and documenting its effectiveness in relaying safety-related data to the surface for use. Since costs prohibited placing the pulser at the end of the tubing string in the well bore, the decision was made to simulate down hole pulsing by pulsing the safety related data through the 10,000 foot flow loop. The wire line unit was used to place a pressure tool at the bottom of the surface configured well. This well was selected for use since the subsea configured well was not physically able to accommodate the tool. The pressure readings were sent to the wire line unit on the surface by way of an electric line. Instrumentation within the wire line unit converted the BHP signals, passing them along to the encoding unit for pulsing in the flow loop. All data transfers, including pulsing time, were accomplished in less than 4 seconds which is sufficient for use as the controlling parameter.

FINDINGS AND RESULTS

Development of the computer assisted well control safety system for deep ocean well control has been completed and successfully tested. The developmental work and testing phase of the project followed the outline prescribed in the "Test Program Design" section of this paper. The results and conclusions will be discussed in a similar format.

Step 1 was accomplished with the development of two data bases. One file contains all the pertinent well specifications, e.g., casing depths, casing sizes, true vertical depth, etc., as found in the daily drillers report while the second contains circulation pressure data obtained from reduced circulation rates taken each tour. Both data files are required to complete computations for the well control kill sheets.

Setting up the first data file was straight-forward, but the frictional data file required the development of frictional equations. Since the relationship between pump pressure and flow rates for turbulent flow are logarithmically linear by nature, software was developed to collect the required data and provide the necessary curve fits. Bourgoyne, Millheim, Chenevert, and Young (1986) state that parasitic pressure losses are in the form of

$$p = cq^{m}. \qquad \text{(Eq. 1)}$$

where, p is the pump pressure, psi
q is flow rate, gpm
c is a constant based on mud properties and well bore geometry
m is slope of line

In the case of a subsea well, pump pressure equations are developed for flowing through the riser and also through the choke. One additional equation was derived utilizing both the riser and choke circulating pressure data, the curve-fit equation for choke line friction. Figure 9 shows a copy of a printout as generated by the software, displaying the data graphically and in the form of equations.

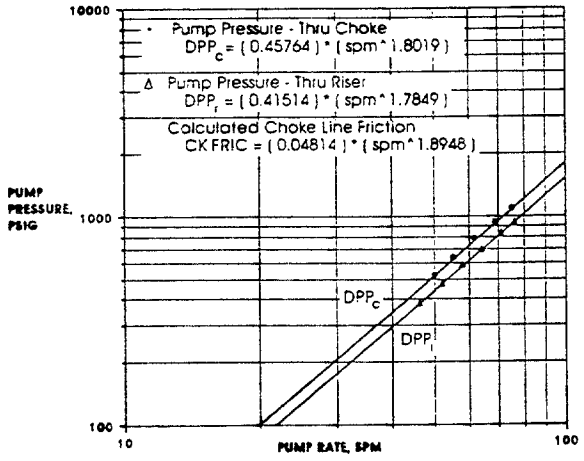

Figure 9 - Typical Subsea Pump Flow Rate vs. Pump Pressure Curve Fit

Step 2 of the "Test Program Design" was fulfilled by the development of software to complete a well kill sheet. The data stored in the two previous files were accessed, and a complete well control plan calculated. This data was stored for later use by the automated well control safety system with a hard copy printed, providing the operator with all the information necessary to complete a manual well kill operation.

Step 3 required the automation of the triplex mud pump and choke systems along with the software for controlling these systems throughout the entire well kill operation, pump start-up to the flaring of the gas. The software developed can control the pump to within 2 strokes-per-minute, making pressure control much easier. Also, the automated choke control permitted maintenance of pressure control by computer within the design specifications of the choke.

Completing the data loop as used in the automated well control system was the pulsed BHP data. This data was transmitted in a binary format at a rate of 10 bits-per-second with 100% accuracy and 12 bits-per-second with 95% accuracy, words contained 12 bits. A typical encoding sequence is shown in Figure 10. As can be seen, even at a data transmission rate of 12 bits-per-second, the pulse amplitude greatly exceeds the pump noise.

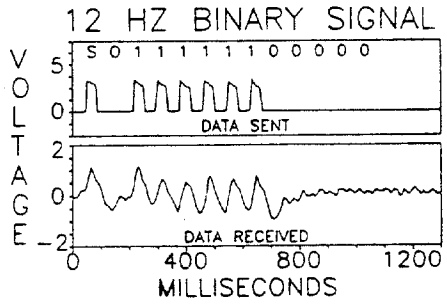

Figure 10 - Typical Fluidics Mud Pulser Encoded Data

When all the data and the software developed were merged into the desired computer-assisted well-control safety system, a system had been developed that could calculate all needed well kill plans and complete the kill operation from the time of stabilized shut-in pressures to the end. Figure 11 demonstrates the interaction of all the components developed while Figure 12 demonstrates the level of control obtained. As can be seen in Figure 12, bottom hole pressure control was maintained to plus or minus

20 psi while the pump rate was maintained to a deviation of less than 2 strokes-per-minute. Considering that the initial conditions of this example are almost identical to the manually controlled well exercise in Figure 4, the conclusion can be reached that the initial objective of improved bottom hole pressure control has been obtained, resulting in improved systems and procedures for reducing risk of surface and underground blowouts in deep ocean environments.

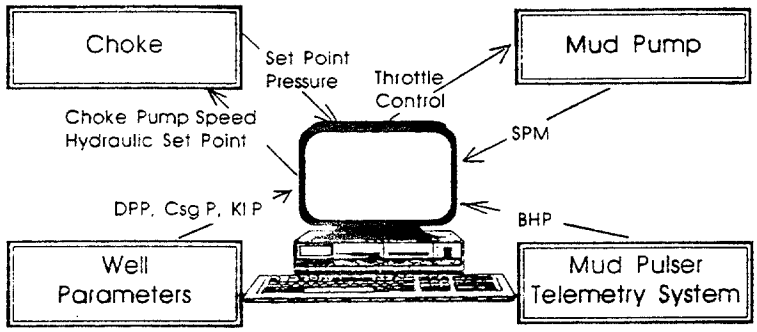

Figure 11 - Computer Control for Automated Well Control Safety System

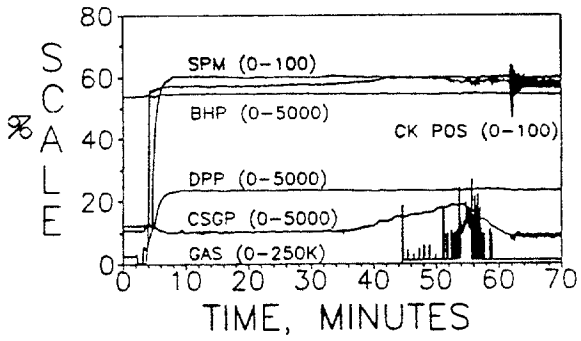

Figure 12 - Automated Well Kill Operation

Testing of the system was completed utilizing the subsea configured well by injecting 20 separate natural gas kicks at a depth of 6,000 feet. Kick size was varied as was the shut-in surface pressures. In addition to the gas kicks, in excess of 30 simulated salt water kicks were completed. The simulated salt water kicks were used in the initial testing phase for safety and later used to refine the developed software. As a consequence of the wells being filled with water, pressures responded quickly, requiring that rapid response models be developed.

In concluding this project, several items were developed that could be readily implemented in the oilfield. The system for deep ocean well control proved very successful by controlling bottom hole pressure to plus or minus 20 psi when it had been demonstrated that experienced operators vary bottom hole pressure as much as 200 psi on the same facility. This automated system can easily be implemented for the field in total or in part. Individual software packages could be very useful and utilized in daily operations, e.g. the frictional package could be used each tour to generate frictional information whether surface or subsea operations are in progress. Secondly, the well kill program could be implemented as a routine training package for well control operations.

CONCLUSIONS

1. The application of process control technology to deep ocean well control operations can significantly reduce the variations in bottom hole pressure while completing a well kill operation.

2. Better bottom hole pressure control by the computer-assisted deep ocean well control safety system reduces the risk of surface and underground blowouts, and results in improved safety for rig personnel and equipment.

3. Fluidics pulser technology as applied to mud pulse telemetry can effectively transmit to the surface safety data, e.g. bottom hole pressure, at rates acceptable for use as the controlling input for computer-assisted well control safety systems.

4. Computer-assisted well control safety systems for deep ocean well control can be designed user-friendly, making the systems more readily accepted in the field.

6. Equipment exists that will perform all choke functions on a distributive basis, simplifying the initial design of the well control safety system.

7. Automation of the well control process eliminates the potential for communication errors between the mud pump and choke operators.

8. The automated well control system eliminates the very repetitive and tedious tasks of mud pump and choke control, making the operators available for higher level decisions, resulting in the potential for reduced operator stress.

ACKNOWLEDGEMENT

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PREVENTION OR CURE:

Kick Avoidance and Detection using MWD in an Integrated Wellsite Information Management System.

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ABSTRACT

Since the late 1960's, manned wellsite drilling data monitoring, and the information obtained, has been useful assisting the driller to address the problems of well control. It was natural that the emerging technology of the 1980's, Measurement While Drilling (MWD), would also be seen as a data source to assist in well control. Indeed, an early survey of the MWD marketplace established the following priorities[1].

Type	Priority
Well Control	High
Directional	High
Drilling Efficiency	Moderate to High
Formation Evaluation	Moderate

Now that the industry has approximately 10 years of commercial experience with MWD, it is time to review the role MWD plays in well control.

INTRODUCTION

The term "well control" has been traditionally used to cover a variety of wellsite processes. These range from preventing the need for controlling the well, namely kick avoidance, through influx detection, to curing the problem through actively regaining control of well pressures.

Measurement While Drilling (MWD) plays a significant role in kick avoidance. However, because of the time frame for data availability, it derives its most meaningful answers when integrated with mud logging and data monitoring services.

The use of MWD for influx detection is still at a conceptual stage. A review of the potential for MWD influx detection requires an understanding of the functionality of current and future MWD systems.

WELL CONTROL

This term has become a catch-all for a wide range of industry needs and services necessary to meet those needs. Some services focus on prevention while others focus on the cure. A clarification of the various components of well control is in order.

Kick Avoidance

Through the careful monitoring and analysis of drilling performance and formation properties, a wide range of warning signs may be exhibited by trend changes

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References and illustrations at end of paper.

related to abnormal pressure. Correct interpretation of those trends, and evaluation of the formation pressures (pore, fracture, and overburden), permit each hole section to be drilled safely and cost-effectively.

Kick Detection

Detection involves the use of surface and, potentially, downhole indications that a fluid influx has occurred. This interruption of the drilling process requires remedial action.

Well Shut-In

This component involves the closing in of the well to decide on a course of remedial action.

Kill Procedure

This is the final stage of well control. Using the best available knowledge of the situation and what is required to control the well, the successful kill permits normal rig activities to resume.

Wild Well Control

If any of the above well control components fail, emergency procedures are required.

KICK AVOIDANCE WHILE DRILLING

Successful kick avoidance involves a broad-based approach to monitor all of the potential warning signs of impending formation pressure problems. Because there are many causes of abnormal formation pressures, there is a continuing need to match the pressuring mechanisms to the methods used for abnormal formation pressure evaluation.

Abnormal formation pressure evaluation is a process that must be carried out continuously as new hole is drilled. While drilling, the time frames for data availability range dramatically, particularly where MWD sensors are involved. These time frames are summarized in Figure 1. Since the methods require the analyses of historical trends to detect anomalies, it is analogous to driving along in a blizzard using your tire tracks to indicate where you are going!

Ahead of the Bit Measurements

Everyone would like to look ahead of the bit to "predict" where pressure trends are heading. Inverse vertical seismic profiling (VSP), using the drill bit as a downhole seismic source, appears to have the potential for providing "look-ahead" abnormal pressure identification. Monitoring flowline mud temperature has been shown to give advance warning of pending pressure increases[2], but riser cooling effects offshore often render ambiguous results. The use of MWD Mud Temperature in place of flowline temperature has been proposed[1]. Figure 2 illustrates temperatures recorded during directional surveying with a MWD tool as it penetrated abnormal pressure off eastern Canada[3].

At the Bit Measurements

Timely real-time measurements are those which are made at the bit while drilling. Several generations of drilling exponents are used. Newer drill bit modeling, using surface drill rate and surface or downhole weight on bit and/or drilling torque, are under development. All work on the principle that less compacted rock has the potential to drill faster. Furthermore, the state of balance between pore pressure and mud pressure (both dynamic and static) will diminish with constant mud density as pore pressure increases, allowing drilled formation to be more efficiently removed from ahead of the bit.

Drilling Torque is another variable used to show increasing borehole instability which in turn may be related to increasing pore pressure.

Behind the Bit Measurements

Behind the bit measurements are available from MWD tools. These currently include formation evaluation sensors and drilling efficiency sensors. Full suite, multi-sensor tools can provide the following measurements:

- Formation Evaluation
  - Natural Formation Radioactivity (total and spectrum)
  - Formation Resistivities (with up to three depths of investigation)
  - Neutron Porosity
  - Formation Density
- Drilling Efficiency
  - Near Bit Weight (i.e., Force)
  - Near Bit Torque

MWD tools have proven their potential in kick avoidance by providing continous, in-situ measurements of formation properties. Careful analysis of the measurements and interpretation for signs of abnormal pressure is a developing art.

However, it must be realized that MWD tools can be up to 30 meters (100 feet) in length. Correctly engineering the BHA with mud motors, reamers, stabilizers, etc., will further displace the sensor measurement point away from the bit. Thus measurements may not be available until several hours after bit penetration.

Lag Time Measurements

At the surface, mud, gas and cuttings variables are monitored as they are circulated from the well. These variables are available for interpretation within a couple of hours after the interval was drilled. This is referred to as "lag time". When samples are available for analyses, a further time lapse may occur before results are available. Some data, like total hydrocarbon gas level, are measured continuously; a shale density reading may be available within a quarter of an hour after sampling, while a shale porosity measurement may take one hour.

Off Bottom Measurements

Finally, the data derived each time a connection is made, such as overpull on the drillstring and fill at the bottom of the hole, are added to the dataset when available. Lagged variables which may be present, such as connection swab gas and pumps off gas, are then delayed by the lag time.

Since the sources of data are available over a wide range of time and because some sets of data are intermittent (e.g., drill cuttings measurements) versus continuous (e.g., drilling torque), the data handling and data trend presentation (Figure 3) require an integrated information management system (Figure 4). A flow chart clearly shows the interpretation sequences using all available sources of data (Figure 5).

KICK DETECTION WHILE DRILLING

Warning signs that a fluid influx has occurred are also monitored by the data monitoring unit. Changes in differential (delta) flow and pump pressure provide the earliest indications[4]. Increased flow from the well will result in changes in the mud tank levels. These real-time indicators are subject to considerable interference from non-borehole sources, especially offshore, such as rig heave, scheduled and unscheduled mud movements and additions, etc. Reaction times vary dramatically with the sensor type and position, and rig plumbing. Furthermore, alarms set points, whether rules are used to evaluate the anomaly, and the crew experience will influence the reaction time to the influx.

KICK DETECTION WHILE TRIPPING

Statistics indicate that most well control situations occur while the drillstring is being tripped. Swabbing and failure to keep the hole filled are deemed the major causes. Correctly calculating and monitoring hole fill using trip tanks and a flow sensor may permit warning signs to be identified. As with kick detection while drilling, there are several sources of interference from non-borehole sources, but these can usually be more easily controlled than those encountered while drilling.

MWD KICK DETECTION

Because of surface interferences, much hope has been placed upon MWD to assist in influx detection at a very early stage. Also, the presence of MWD during the shut-in and kill procedure has been of interest. To date, much has been proposed[5] (Figure 6) but no commercial MWD influx detectors have been prepared. The reasons behind the absence of a product are discussed below.

Juxtaposition

An influx may occur at the bit or around the collars where swabbing effects are most pronounced during pipe movements. The MWD influx detectors thus need to be as far from the bit as possible. This is in direct contrast to all other MWD sensors which are required to be close to the bit. If the sensors are below the point of influx with the pumps on, the changes in mud properties may only be noticed when circulation ceases (Figure 7).

Tool Power and Data Transmission

The majority of multi-sensor MWD tools are powered by a circulating mud stream. All commercial MWD tools use pressure variation to transmit the data to the surface. Thus measurements can only be made and transmitted with the pumps on. Since hole conditions are most conducive to influx with the pumps off and with the pipe moving, the MWD tool can be considered "out of commission".

Data Formats

With one exception, MWD tools are programmed at the surface for measurement frequency, averaging frequency, memory formats and transmission formats. Programming is designed to transmit the appropriate data for the proposed rig activity. If the well is to be steered, directional data is transmitted; while in a drilling mode, formation evaluation data is transmitted. Thus, data formats are established for the norm, not the exception. An influx detector would need to override the transmission programming. Furthermore, the surface receiving unit would need reprogramming to match the downhole tool. Re-handshaking between influx data transmission and the surface would be required. It is anticipated that with the increasing use of steerable systems, new generation MWD tools will be able to resolve these problems.

MWD DURING WELL CONTROL CIRCULATION

It has been proposed that current MWD tools aid in the post-kick detection stage by monitoring pressures, mud properties, etc., downhole. There is little evidence showing this MWD role in the technical literature. Thus, it is appropriate to review why current MWD tools are not useful at this crucial time in the well.

Power

Most multi-function, multi-sensor MWD tools require mud movement for power. The turbine or impellor blades used for power are designed to function over the anticipated drilling flow rate range to prevent over-revving the generator. For example, if the anticipated mud flow is 1.25 m^3/min (320 gal/min), an impellor rated for 0.75 m^3/min to 1.5 m^3/min (200-400 gal/min) would be installed before the tool is run downhole.

Obviously during shut-in, no mud flow is available to power the tool. During the kill procedure, slow circulation rates may be below the threshold for tool power up. Thus, it is only using drilling flow rates during hole conditioning, after a well control procedure has been successful, that the tool will be correctly powered up. It is anticipated that newer generation dual power MWD tools may use turbines, with rechargeable batteries as a source of emergency power. To date, rechargeable battery technology is not suitable for downhole, while drilling, conditions.

Transmission

The same mud flow constraints occur in the transmission of MWD data during in the shut-in and slow circulation procedures. Increasingly, vendors are installing memory in their MWD tools to store more data than can be transferred using current mud pulse telemetry methods. These memories are currently accessed with the MWD tool in the slips, although one vendor provides a pump-down, wet-connect memory dump capability when the tool is inside casing.

During typical well control situations, the well is likely to be completely controlled by the time the MWD tool is in casing or in the slips, so any data would only have significant historical value rather than real-time use.

Data Formats

Data formats are established for the norm, i.e., drilling ahead. Currently, the only MWD tool which can be reprogrammed from the rig floor requires a complicated sequence of pump cycling and rotation to trigger the change. In the short time between influx detection and BOP activation, it is unlikely that any operator would be inclined to carry out such a sequence.

It is more likely that future MWD tools will use downhole pressures sensors to sense anomalous pressure to trigger data reformatting "on the fly".

Juxtaposition

As with MWD influx detection, the position of the internal and external sensors with respect to the influx will determine the usefulness of MWD tools during shut-in and slow circulation. Internal sensors for mud temperature, mud resistivity and mud pressure will be subjected to the kill mud, regardless of the tool/influx relative position. External annular sensors for the same properties will be influenced differently. The pressure sensor will be useful under all circumstances, while mud temperature and mud resistivity will be influenced in many ways, depending on whether the influx is below or above the sensor point.

SUMMARY

The use of MWD technology alongside proven surface methods of data monitoring, mud logging and abnormal pore pressure evaluation can aid in the prevention procedures of well control.

An MWD influx detector has not reached a commercial stage because of significant logistical problems in the downhole environment. Those problems further limit the ability of current MWD tools to provide real-time data to assist in well control. It is anticipated that next generation MWD tools will be able to address some of the logistical problems.

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BIOGRAPHY

Michael Taylor is Senior Technical Manager for EXLOG, Inc. in Houston, Texas. He graduated with a B.A. Honors degree in Geology from Oxford University in 1974. He joined EXLOG in the United Kingdom and worked as a Hydrocarbon Well Logging Geologist, Pressure Evaluation Geologist and Data Monitoring Engineer in Africa and Europe. From 1978, he worked in Western Canada and in the Canadian Beaufort. After working in California with prototype MWD tools, he returned to Calgary to supervise EXLOG Canada's Frontier Operations. In 1985, he headed for Houston where he was responsible for integrated data monitoring services for EXLOG in North and South America. In 1988, he became responsible for Exlog's technology worldwide. He is a member of AAPG, AADE, CSPG,CWLS, SPE AND SPWLA and was co-chairman for the Mud Logging workshop at the 1989 30th Annual SPWLA Symposium in Denver.

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Figure 1: Kick Avoidance While Drilling - Data Time Frames

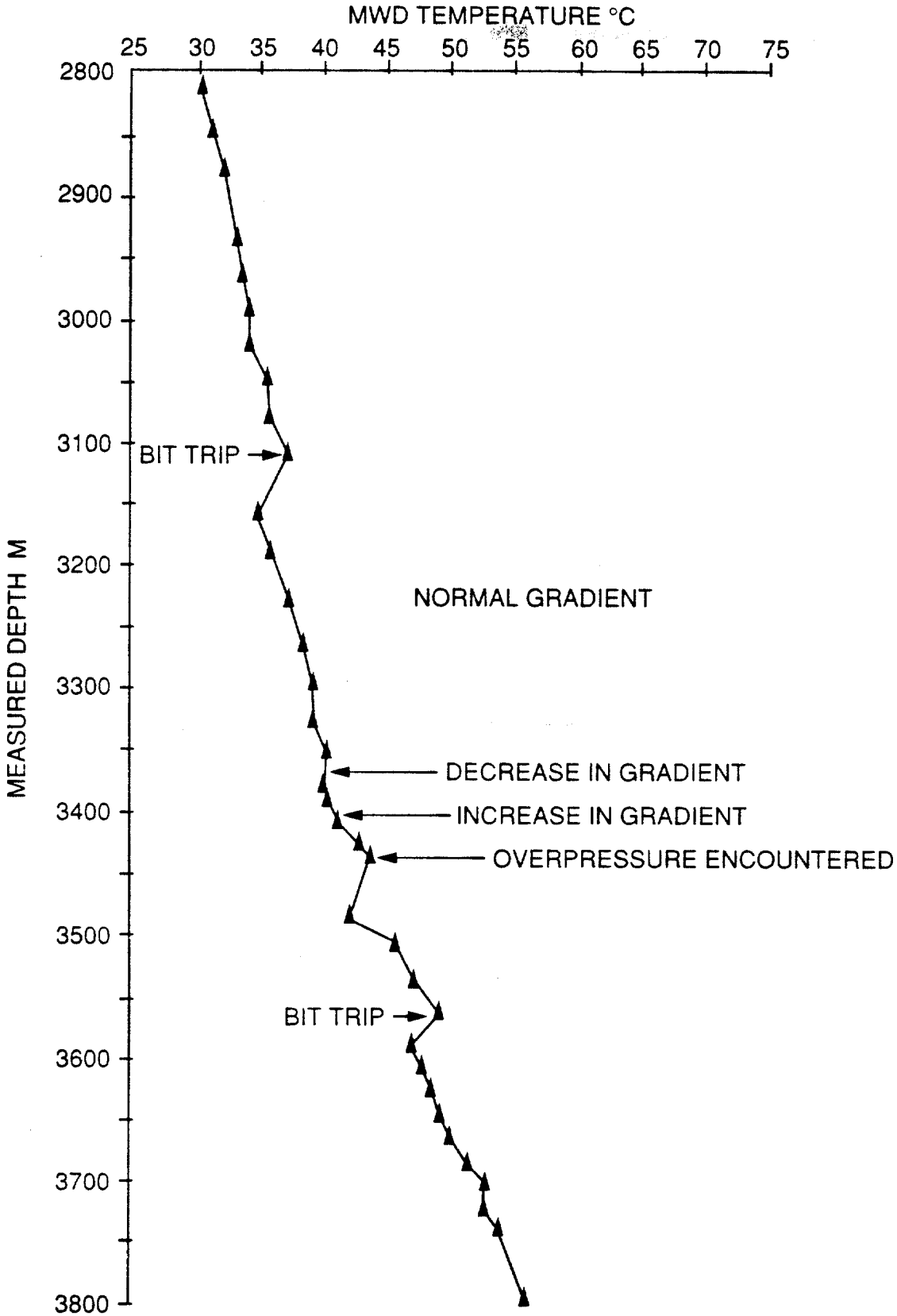

Figure 2: MWD Temperatures While Surveying

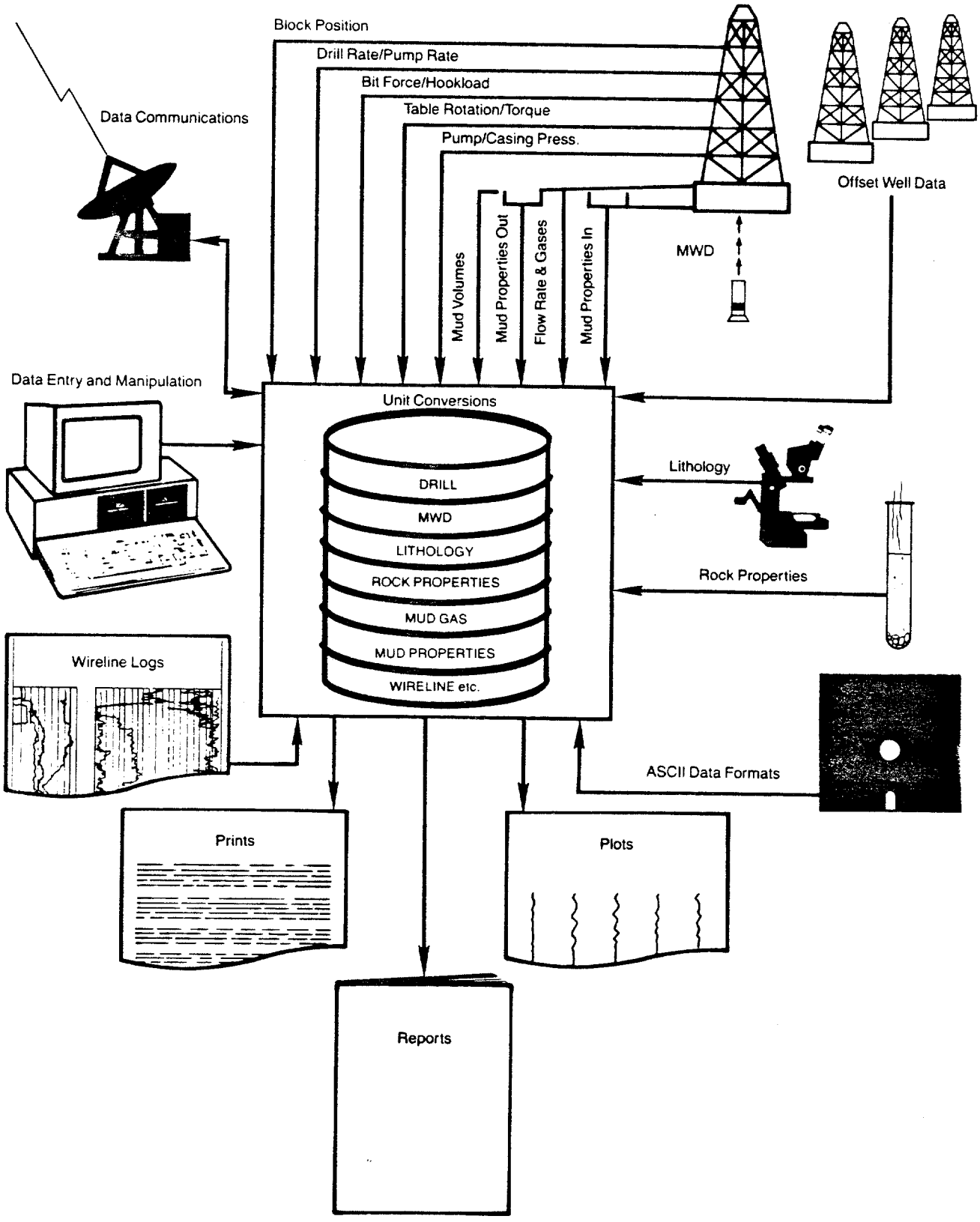

Figure 3: Integrated While Drilling Pressure Log

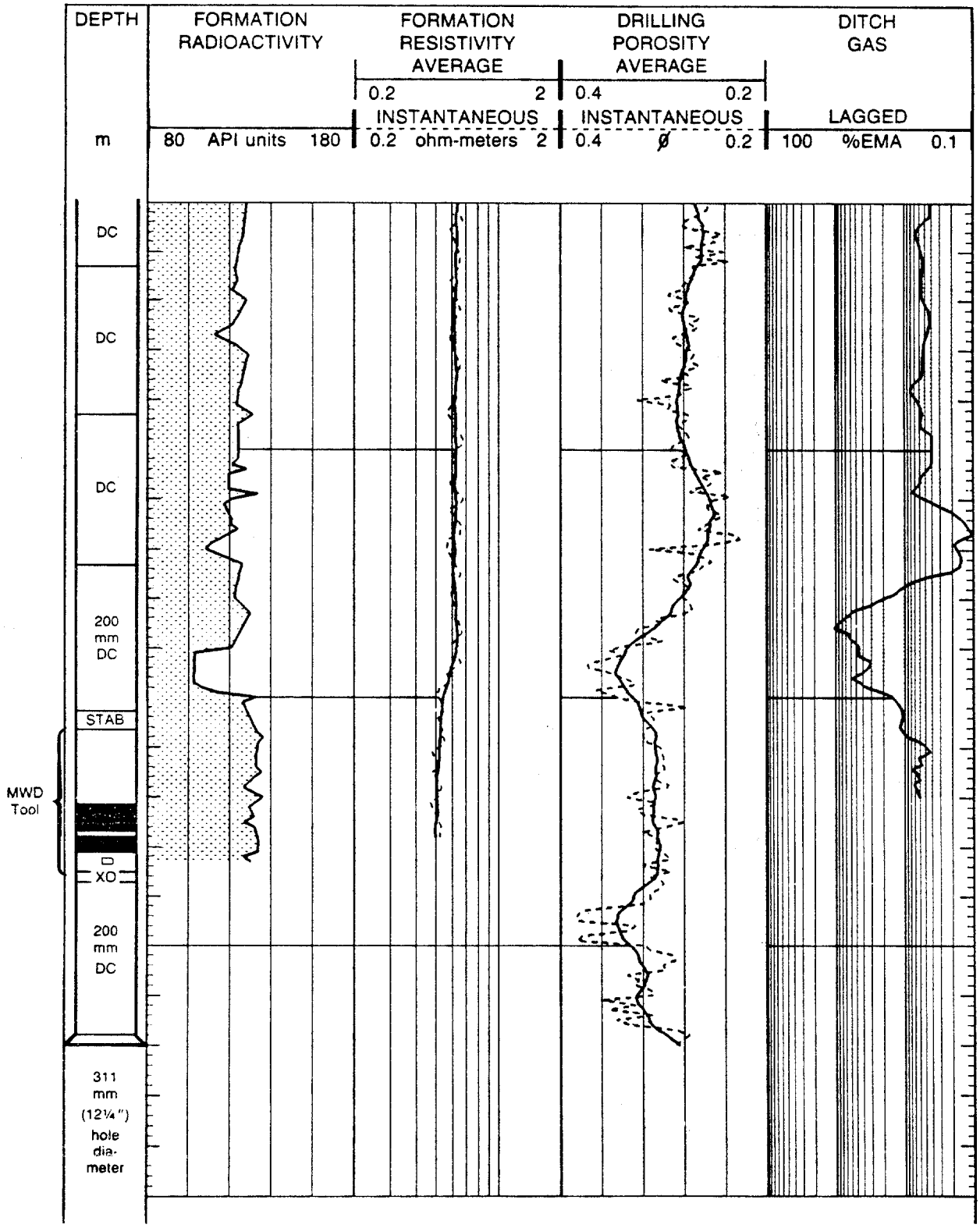

Figure 4: Integrated Wellsite Information Management

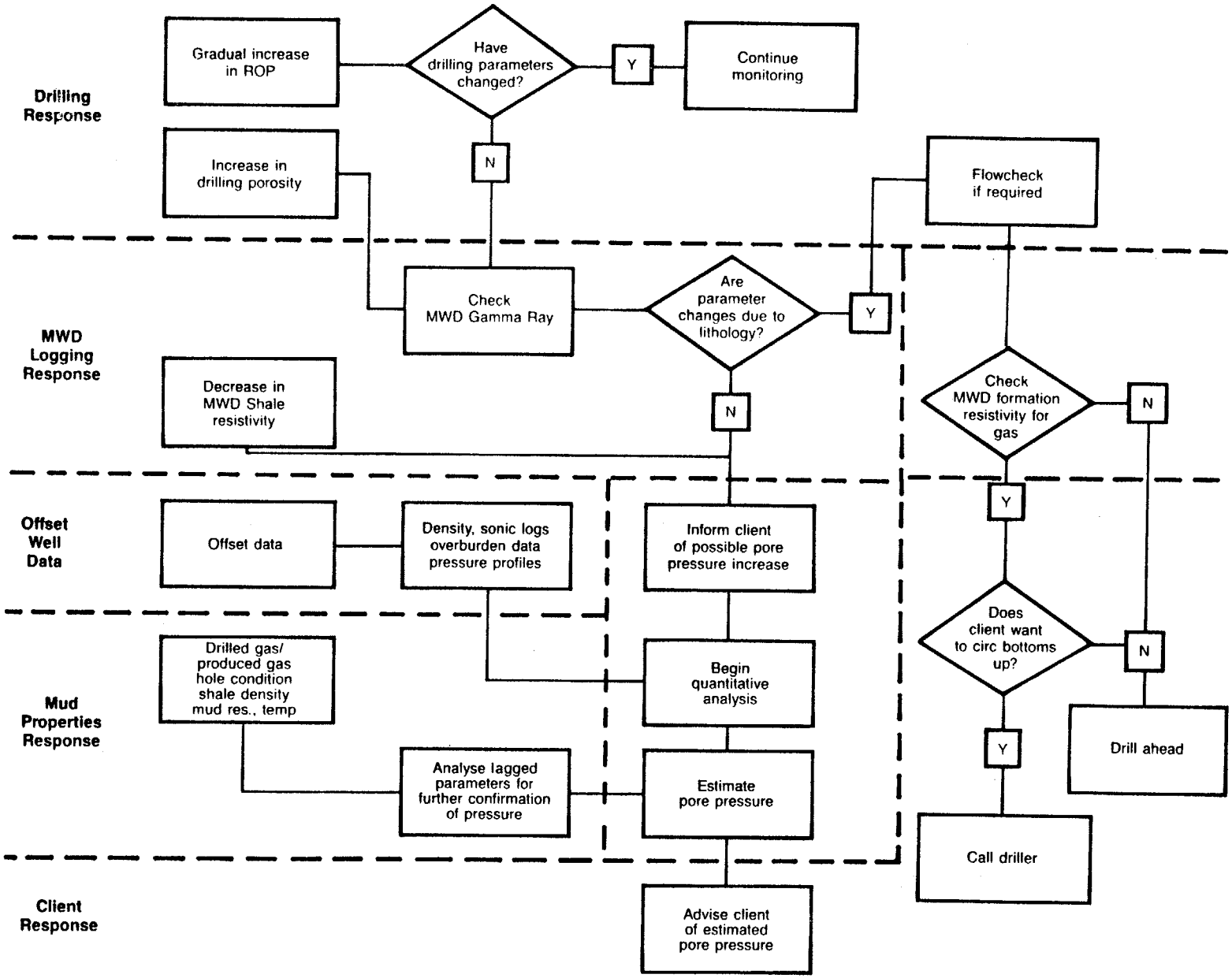

Figure 5: Integrated Pressure Evaluation Flowchart While Drilling

MWD Acoustic and Mud Resistivity Measurements for Gas Influx Detection

T.M. Bryant, Teleco Oilfield Services, Inc.

ABSTRACT

In a series of simulated gas kicks performed under full-scale, controlled conditions, the acoustic responses of MWD signal frequencies and their harmonics have been shown to be valid and unequivocal indicators of gas influxes. The influx of formation gas into annular drilling fluid causes various changes in the fluid's physical properties. Such changes influence the velocity of acoustic waves, the natural frequency of the annular system, and the damping ratio of the drilling fluid. These changes, in turn, effect alterations in the gain and phase angle of the transfer function relationship between the annulus and standpipe pressure signals.

One set of gas influx tests varied gas concentrations from as low as 7.5 to as high as 75.4 scf/bbl. In each and every instance, attenuation of the 0.60 Hz third harmonic detected the influx during the injection period. Except for one kick that may have involved dissolved gas only, amplification of the MWD signal frequencies also indicated the influx each time. Detection by harmonic attenuation averaged 1.5 minutes after injection initiation, whereas detection by signal amplification averaged 4 minutes.

A second set of tests, conducted at a depth exceeding 4000 feet, tested acoustic responses in both oil- and water-based muds. These tests demonstrated the difference in responses that may be attributed to differing gas solubilities.

Use of a combination of signal and harmonic frequencies virtually guarantees that more than one frequency will respond to and identify a gas influx. This procedure also ensures unequivocal detection and positively distinguishes gas from fluid (water) influxes.

MWD mud resistivity (Rm) measurements have also been shown to be effective for the detection of both gas and liquid influxes. Although detection was equivocal below a gas concentration of 8.3 scf/bbl, the average Rm detection time was somewhat less than 1.5 minutes after injection initiation. Downhole mud resistivity measurements possess an encouraging potential for quantification of gas concentration.

Both the acoustic and downhole mud resistivity measurements provide a means to detect a gas influx within minutes of its initiation.

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INTRODUCTION

Few front-line people involved in the exploration and development of hydrocarbon resources need to be reminded of the potential consequences resulting from the late detection of a gas kick. Indeed, the drilling industry is reminded on what many would deem an all-too-frequent basis. The West Vanguard shallow gas blowout of 1985, the Ocean Odyssey and Sedco 252 gas blowouts that resulted in deaths and total rig destruction in 1988, and the Kulluk blowout in 1989 in the Beaufort Sea are but a few of the more recent examples. Although the probability of a gas blowout may be considerably greater offshore than on land (Westergaard, 1985), gas kicks and blowouts are not more of one region's problem than another's. The 7 gas blowouts that occurred on the Norwegian Shelf in the twenty-year period 1968-1987 (Aamodt, 1987) may seem to pale when compared with the 121 for the Gulf of Mexico Outer Continental Shelf for the twenty- four-year period 1960-1984 (Hughes et al., 1987), yet when considered as a percentage of total wells drilled yearly in each region, the frequencies are surprisingly similar. And although better engineering and training have no doubt contributed to a reduction in blowout frequency over the past decade, even one incident may be too many, particularly when the price to pay includes human life.

Industry's trend to frontier, deepwater exploration has, if anything, exacerbated the overall risks inherent in taking a gas kick. Technological advances in kick detection have not kept pace with those that have given the operator an ability to drill and produce in water depths exceeding a thousand feet. Today's most reliable indicators of gas kicks (Thomas et al., 1984) - pit gain, flow out, and flow check - possess detection capabilities that are, ironically, dependent upon gas expansion. Early detection capabilities of these techniques are little better now than they were ten years ago.

The safety aspects of offshore drilling would be greatly enhanced if there existed a reliable gas influx detection technique whose capabilities were independent of gas expansion. The technique would have to satisfy certain criteria: capable of detection within minutes of kick initiation, relatively unaffected by environmental variables, relatively inexpensive to install, unobstrusive in operation, and, of course, reliable. With this in mind, the viability of MWD acoustic and mud resistivity measurements has been assessed under controlled test conditions and found to be exceedingly promising.

ACOUSTIC ANALYSIS OF THE ANNULUS

The usual transmission channel of MWD signals is the drilling fluid contained within the drillstring bore. Teleco's MWD system transmits information through the use of multi-frequency, positive pressure, binary codes. During the creation of a positive pressure pulse, a negative pressure pulse of considerably smaller magnitude

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is generated below the pulser mechanism. This pulse propagates within the annulus to the surface in the same manner as the pulse within the drillstring bore, as diagrammatically illustrated in **Figure 1.** However, unlike the drillstring channel, the annular channel is frequently contaminated by gas.

A gas kick transient is an uncontrolled influx of gas into the annulus of a wellbore. The introduction of this gas may occur at varying rates and volumes, from as low as that which is characteristic of drilled gas, to as high as that which is typically associated with blowouts. The evolution of a gas kick is a complex, dynamic phenomenon involving the processes of fluid mixing, diffusion, dispersion, and expansion, interacting to produce a variety of temporal and spatial changes in the annular column. This behavior creates changes in the inertance, resistance, and capacitance of this communication channel. These changes affect the natural frequency and damping of the fluid system. Hence, it can be expected that the amplitude and phase relationships of acoustic signals travelling through this system will change during the evolution of a gas kick transient.

The Nature of the MWD Signal Input

Superimposed upon the short-term dynamic changes created during a gas kick are the pulsations created by the MWD transmitter. The movements of this mechanism during data transmission create fluctuations in both pressure and flow that propagate through the annular column, as shown in **Figure 2.**

The perturbations created by the MWD pulser possess a multi-frequency character, there being a maximum fundamental twice the magnitude of the minimum. This input, which is of a complex periodic nature, is the result of a square wave motion modified by a variable slew rate. For the sake of simplicity, this input may be likened to one of an essentially sinusoidal nature and expressed as:

$$f(t) = A\sin(\omega t)$$

where the time-varying amplitude f(t) of the acoustic wave is a function of the pulser's angular frequencies (see Nomenclature).

The corresponding output, whether measured at the standpipe or at a location near the top of the annulus, may be expressed as:

$$g(t) = GA\sin(\omega t - \phi)$$

where the gain G may cause either attenuation or amplification of input amplitude. The factors affecting channel gain include fluid properties and channel geometry.

A representative example of pressure signals carried in the drillstring bore channel and measured at the standpipe is shown in

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Figure 3a. The predominant, positive pressure MWD pulses, which are used to decode transmitted messages, typically average about 150 psi in magnitude. **Figure 3b** shows the corresponding time domain signals within the annular channel, as measured at a surface location above the casing head. The annular MWD pulses may range in amplitude from less than 1 psi to 20 psi or more.

Figure 4a is an example of an annular pressure recording taken during gas-free conditions, using a water-based drilling fluid. In this time domain representation, the small amplitude, low frequency MWD pulses are not easily discernible amongst the larger amplitude harmonics and the higher frequency pump noise. Subsequent to the initiation of a gas influx (**Figure 4b**), the amplitudes of both the pump and the harmonic frequencies become significantly attenuated, whereas those of the MWD fundamentals become amplified. At a later time (**Figure 4c**), the fundamentals also become attenuated. Prior to the first arrival of gas at the surface, many or all of the frequencies become amplified.

In addition to containing the MWD pulses, both the drillstring bore and annular channels carry perturbations attributable to the slush pumps, bit and drillstring interactions with the formation, and other sources. For this reason, it is more convenient and informative to view the signal data in the frequency domain. **Figure 5** illustrates a frequency domain view of both channels. Besides showing three MWD fundamental frequencies and a mud pump frequency, the rich harmonic content (inherent to square wave input) is evident.

System Transfer Function

The difference in the amplitude of the pressure measured at the annular outlet and the pressure fluctuation generated at the MWD pulser is related by the wave propagation operator (Healey and Nicholson, 1974):

$$P(j\omega, x) = P_A(j\omega)e^{\Gamma(j\omega)}$$

where the propagation operator $\Gamma(j\omega)$ is a function of the fluid inertance, resistance, and capacitance. In so relating the output and input, the propagation operator represents an acoustic transfer function, the amplitude and phase angle of which are subject to the properties of the annular communication channel.

The changes produced in transfer function amplitude and phase angle during a gas kick are analogous to the effects of a time-variable filter. Hoberock and Stanbery (1981) noted that the annular wave propagation operator may be approximated as a standard second-order filter:

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$$e^{-\Gamma(j\omega)} = 1/((j\omega/\omega_n)^2 + 2\zeta(j\omega/\omega_n) + 1)$$

This expression functionally relates changes in the natural frequency and damping ratio of the annular fluid column to changes in transfer function amplitude and phase angle.

As shown in **Figure 6**, small variations in either the natural frequency ω_n or the damping ratio ζ of the annular system may result in large changes in the gain (and, not shown, phase angle) of an acoustic wave. The significant physical changes that take place during the evolution of a gas kick may cause the annular column to swing back and forth between under-damped and over-damped states for any particular frequency. This change in damping is partially responsible for the responses of fundamentals and harmonics at different stages of a gas kick.

Given the inherent difficulty in obtaining the pressure fluctuations at the MWD pulser, and the observation that amplitude attenuation within the drillstring channel is typically minimal, the pressure measured at the standpipe may be substituted as the system input. With the output to this acoustic transmission line being the forced response measured by an annular pressure transducer, the properties of the annular column represent the acoustic transfer function, as indicated in **Figure 7**. Use of the transfer function normalizes for changes in the input channel, such as the decrease in standpipe pressure that typifies gas rise and expansion.

ACOUSTIC DATA SAMPLING, PROCESSING, AND PRESENTATION

A gas influx detection technique (Grosso, 1988), based on alterations to MWD acoustic characteristics, was tested under controlled conditions at two full-scale facilities. Both test programs employed an MWD tool configured to transmit data at fundamental frequencies of 0.20 Hz, 0.27 Hz, and 0.40 Hz.

The standpipe and annulus pressure signals were digitized at a 40 Hz sampling rate over a time interval that preceded injection and extended to full circulation out of the gas. Individual 20-second samples were passed through a fast Fourier transform (FFT) and averaged with a second sample to produce an averaged spectrum for each data channel. The system transfer function was determined (at periodic intervals) by dividing the cross power spectrum of the input and output channels by the spectrum of the input channel.

Transfer function amplitudes and phase angles for two of the fundamental MWD signal frequencies and for the third harmonic (0.60 Hz) of the 0.20 Hz fundamental were then plotted as a function of time for each simulated kick. Prior to injection of gas, gas-free ("baseline") values of amplitude and phase angle were determined for each frequency. During injection and circulation out of a gas influx, current responses were compared to the baseline responses. A sustained change exceeding one standard deviation from the mean

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of baseline values was considered the criterium for influx detection for any one frequency. For each of the plots discussed below, transfer function amplitude is expressed in dimensionless units, phase angle in degrees, and time, in minutes, is referenced to the beginning of gas injection.

TEST PROGRAM #1

Thirty five discrete gas and liquid influxes were simulated utilizing a full scale drilling rig normally used for well control training and research activities. Parameters varied during these kicks included depth, mud density, injection volume, injection duration, jet size, and pump rate.

The vertical hole is lined with 13.375 in. outside diameter (OD) casing, with shoe set at a depth of 1480 ft. The drillstring consisted of variable lengths of 4.50 in. OD drillpipe, 6.75 in. OD MWD collar, and 8.50 in. bit.

Nitrogen was used as the test gas. Solubility of nitrogen was assumed to be approximately half that of methane; methane solubility in the drilling fluids used during these proof-of-concept tests was estimated using published information (O'Bryan et al., 1986).

Twelve tests involved gas injections into a 14.0 lbm/gal lignosulfonate mud at a constant bit depth of 1391 ft. Nitrogen gas injections were made through a tubing string run parallel and external to the drillstring, with an outlet several feet below the bit.

In addition to testing acoustic responses, downhole mud resistivity measurements were made for each of these tests. The MWD tool transmitted one internal (bore) temperature and fourteen mud resistivity measurements during each three minute transmission.

Examples

Figure 8a shows the change with time of transfer function amplitude and phase angle for two of the MWD signal fundamentals for kick #28. Considering some uncertainty regarding the solubility of nitrogen, this test may have involved only dissolved gas during injection period. With respect to the responses of the 0.20 Hz and the 0.40 Hz transfer functions, neither exhibit a response that might be interpreted as being indicative of a gas influx. Based solely on these responses, this gas influx would not have been detected. However, the 0.60 Hz response (**Figure 8b**) exhibits a significant amplification within 1.5 minutes of the start of gas injection.

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This response was followed by an attenuation that was sustained until the first of the gas began to arrive at the bell nipple (fluid bottoms-up time was 23 minutes for this test). Phase angle very gradually increased as the gas was circulated up, exceeding and remaining outside one standard deviation. Based on these latter responses, the gas would have been detected at 3+ minutes. The change in downhole mud resistivity (**Figure 8b**) of approx. 2% was probably too small to realistically be used for detection.

Figure 9a shows the fundamental transfer function responses for Kick #24. Between 4 to 8 minutes after initiation of the injection, the responses for 0.20 Hz exceeded their limits, particularly phase angle. Based solely on these responses, the gas influx would have been detected between 4 to 8 minutes. The 0.40 Hz amplitude exhibited a 1.6X amplification at 1.5 minutes, followed by an attenuated response that was 20% of its baseline value. Both amplitude and phase angle exceeded the statistical alarm limit for the duration of the kick. Used on its own, the 0.40 Hz responses would have detected the gas influx in less than 4 minutes. The 0.60 Hz amplitude (**Figure 9b**) was attenuated over 80% within the first 2 minutes; its phase angle exceeded and remained outside its alarm limit for the duration of the kick. Detection based solely on the harmonic would have been made at 1.5 minutes. The MWD mud resistivity measurement recorded a sustained 8% increase beginning within a minute of influx initiation.

Figure 10a shows the fundamental transfer function responses for Kick #20. This test involved a concentration of 60.9 scf/bbl. Perhaps partially owing to the high injection rate, the 0.20 Hz amplitude showed a remarkable 9X amplification at 2+ minutes. The corresponding phase angle exceeded its limit at the same time, and for the duration of the kick exhibited a significant increase. The 0.40 Hz amplitude also was amplified within the first two minutes; from there on, it was attenuated to approximately one-third it gas-free magnitude. Its phase angle exhibited a very erratic behavior. The 0.60 Hz harmonic (**Figure 10b**) was significantly attenuated between 1.5 to 2 minutes. Both amplitude and phase angle exceeded the statistical alarm limit for the duration of the kick. The mud resistivity measurement increased 15% within the first minute of injection.

Figure 11a illustrates responses for an injection of 15 bbls of salt water (Kick #31). The 0.20 Hz amplitude response varied essentially within ± one standard deviation; from 7 to 16 minutes the response fell just outside this limit. Other than an extreme fluctuation corresponding to the end of the injection period, the 0.20 Hz phase angle did not exhibit the increase that characterizes a gas response. Both the 0.40 Hz amplitude and phase angle showed variations primarily within the statistical limits; where one response exceeded the limit, the other didn't. The responses of the 0.60 Hz harmonic (**Figure 11b**) behaved in a similar manner. The mud resistivity response dropped from its 0.65 ohmms baseline to 0.13 ohmms within 2 minutes of injection initiation.

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TEST PROGRAM #2

This test program involved the simulation of four gas kicks conducted with a full-scale drilling rig and a 4921 ft TVD, 63° directional well. These tests, a subset of 24 gas kicks conducted for the purpose of testing new kick detection methods (Rommetveit and Olsen, 1989), involved the injection of nitrogen gas into both oil- and water-base drilling fluids.

The tests were performed within a cased (9.625 in. OD, 8.681 in.ID) hole 4875 ft in length using 5.0 in. OD drillpipe and 377 ft of 6.50 in. OD drill collars, including Teleco MWD tool. No drilling was performed during the tests.

The nitrogen gas was injected down coiled tubing run inside the drillstring to a position just above the MWD tool. All gas had to be evacuated from the tubing, the MWD tool, and the drill collars before any valid acoustic responses could be obtained. This method of injection, plus the slow circulation rate maintained to avoid gas migration up the drillstring, prohibited the observance of acoustic responses during the injection phase and reduced the total number of these observances prior to shutting in the well. As a consequence, a substantial portion of the annular mud column (ranging between several hundred to in excess of a thousand feet) was contaminated with gas before the MWD tool commenced transmission. This meant that none of the kicks tested responses under totally dissolved gas conditions.

Table 2 summarizes the operational conditions for the four gas kicks. Each test was performed with similar drillstring and wellbore geometries, at a true vertical depth of approximately 4360 ft., with either water or a 14.0 lbm/gal oil mud.

Examples

Figure 12a illustrates the change in transfer function responses with time in an oil-based drilling fluid (Kick #16a). The first sample was acquired 9.4 minutes after the start of injection (18.6 mins. on the graph). During circulation out, a minor amplification of the 0.20 Hz amplitude was sustained for about 3.5 minutes (beginning at 22.0 mins on the graph), followed by a return to near-baseline magnitudes. No significant change in phase angle occurred until +32 mins, when a decreasing trend in phase angle appeared to commence. Unlike this subdued response, the response of the 0.40 Hz transfer function amplitude showed several amplified peaks. There was little variation in its phase angle until the last sample prior to shut in. The amplitude of the third harmonic (**Figure 12b**) exhibited a significant and increasing amplification as the gas was circulated toward the surface. Its phase angle showed little change from baseline until at +27 mins (17.8 mins since start of injection) when a significant change occurred.

Figure 13a shows transfer function responses for the MWD fundamentals in water (Kick #21a). The first sample acquired in

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this kick was at 14.25 minutes after the start of injection. (N.B. The time represented in Fig. 13a has been intentionally shortened by the 10 minute pipe displacement time for purposes of presentation). For the 0.20 Hz fundamental, the responses during circulation of the gas were attenuated in amplitude to approximately one-third the baseline value. Phase angle gradually increased during this time. For the 0.40 Hz transfer function (**Figure 13b**), the first three samples reflected an amplification above baseline, followed thereafter by attenuation below baseline value. The 0.40 Hz phase angle initially increased, and then gradually decreased. The 0.60 Hz transfer function amplitude was attenuated below its baseline value while gas was in the annulus. Although the phase angle initially increased, it exhibited a sharp decrease several minutes before shut-in.

Discussion

Amplification of the MWD fundamental frequency transfer functions was observed during the gas injection period for 11 of the 12 tests. Amplification of the 0.40 Hz response preceded that of the 0.20 Hz response in the majority of these kicks. This behavior suggests that bubble (free gas) resonance might be an influencing mechanism. It is interesting to note that amplification of the 0.60 Hz third harmonic during the injection period was observed only for the smallest gas volume (Kick #28).

With increasing time from the initiation of injection, the annular fluid flow caused dispersion and diffusion of the injected gas bubbles within the water-based fluids. The distribution of free gas over an increasing annular length acted to increase the capacitance of the annular column. This, in turn, led to a progressive decrease in the annular system's acoustic velocity and natural frequency, and an increase in its damping ratio. As a consequence, amplitude attenuation occurred. In each and every one of the gas kicks, the 0.60 Hz harmonic attenuated almost immediately upon gas injection, and remained attenuated until the gas began to arrive at the surface. Likewise, the 0.40 Hz signal attenuated, usually several minutes subsequent to injection initiation. The 0.20 Hz signal was observed to attenuate only slightly during the shallower depth tests, regardless of gas volume. Significant attenuation of this fundamental was observed at the greater depth.

As the gas approached the surface and expanded significantly, transfer function amplitudes for both the MWD fundamentals and harmonics became amplified; phase angle generally increased with time, with the 0.60 Hz phase angle increasing the most. These responses might suggest a significant decrease in inertance accompanied by a considerable increase in capacitance.

The transfer function responses observed in the oil-base drilling fluid tests were notably different from those obtained with water. The amplification of transfer function amplitude and the decrease in phase angle observed in the oil-base responses suggests a decrease in both damping ratio and natural frequency.

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The considerably enhanced solubility of nitrogen in the oil-base fluid may be responsible for a decrease in inertance and an increase in capacitance that does not occur in water-base fluids until the gas is in proximity to the surface.

QUANTIFICATION OF ACOUSTIC AND MUD RESISTIVITY RESPONSES

Acoustic Responses

Figure 14 shows a plot of the total concentration of injected gas versus the peak response of the 0.20 Hz signal transfer function during the injection period. With the exception of Kick #20 and injections #2 and #3 of Kick #30, deviations from a best-fit line are relatively small. Although an indication of possible quantitative application, much modeling remains before such a use would be attempted.

Downhole Mud Resistivity

A very good quantifiable relationship exists between the change in downhole mud resistivity and percent by volume of total gas. This relationship may be expressed as:

$$V_{tg} \approx 100(\Delta R_m/R_m)$$

where V_{tg} is the percent by volume of total gas.

Figure 15 illustrates this relationship for the twelve gas kicks (with fourteen separate injections) performed with a 14.0 lbm/gal lignosulfonate mud. With but one notable exception, observed versus Rm-calculated total gas percentages differ on average by less than 1.5%.

DETECTION RESPONSE TIMES

Table 3 lists the acoustic and mud resistivity influx detection times for nine kicks. The criterium for detection was a sustained change in amplitude exceeding one standard deviation from the mean baseline values of the transfer function amplitudes. For concentrations exceeding approximately 8.3 scf/bbl, gas influxes were detected in 3.3 and 3.9 minutes, respectively, for the 0.20 Hz and 0.40 Hz fundamentals, and in 1.6 minutes for the third harmonic. Bearing in mind that sampling was limited to once a minute, and that fluid circulation bottoms up time averaged 32 minutes, it can be appreciated that detection occurred before any appreciable gas expansion. Detection times for downhole mud resistivity were somewhat better than those for the third harmonic.

In practice, acoustic detection would be based upon a

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sustained change in both amplitude and phase angle for more than one frequency.

Figure 16 shows the relationship between downhole gas concentration (in percentage units by volume), surface gas/mud ratio, and acoustic detection time. It may be appreciated, for instance, that a 2% (by volume) gas kick occurring at a hydrostatic pressure of 10,000 psi will, under most typical conditions, generate an extreme annular response. Considering that the gas/mud ratio is approximately 14 to 1, the response as the gas approaches the surface would be detectable by traditional means (e.g., mud flow rate out). However, the same gas concentration at 5000 psi hydrostatic pressure generates a less intense kick, requiring considerable expansion before detection by conventional means. A detection scheme using both of these measurements would not only provide two independent checks, but would be capable of informing the driller as to intensity of the kick within minutes of influx initiation and well before any appreciable expansion.

SUMMARY AND CONCLUSIONS

The acoustic responses of MWD signals as measured in the annulus of a wellbore may play a very important role in the identification of pore pressure transition zones, the penetration of reservoirs, and, most importantly, early detection of gas influxes and the prevention of blowouts.

The results and preliminary conclusions derived from controlled testing include and indicate that:

(1) Alterations in various characteristics of MWD signals measured in the annulus of a well bore distinguish the presence of gas. The response signatures are sufficiently different between gas and water influxes such that one may be unequivocally distinguished from the other.

(2) An acoustic technique has been shown to be valid for the detection of free gas in both water- and oil-based drilling fluids. Basic principles suggest the technique should be equally valid for the detection of dissolved gas in oil-based fluids.

(3) The use of the MWD pulser as a source of sonic energy allows the entire annular mud column to be sampled, and provides complete coverage in the event that gas enters at a location other than the bit.

(4) Both acoustic responses and downhole MWD mud resistivity measurements detect the influx of gas within the first few minutes of kick initiation. This detection occurs well before any appreciable gas expansion.

(5) Rig-site implementation of acoustic influx detection

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necessitates the installation of a pressure transducer either on the low-pressure side of the blowout preventer stack or on the marine riser.

(6) Downhole MWD mud resistivity measurements offer considerable promise as an influx detector whose response is not tied to gas expansion. This measurement is both sensitive and quantitative for gas contained within water-based drilling fluids.

By far, the most significant feature of either the annular acoustic or the MWD mud resistivity measurements is the very early influx detection capability. This detection capability may be superior to detection methods that are based on fluid displacement caused by gas expansion.

In addition to testing the viability of these measurements offshore in a variety of conditions, future work entails modeling the annular system for the effects of an unsteady state, two-phase-flow, gas kick transient. Such modeling would enable explanation of observations and predictions of responses.

NOMENCLATURE

A = amplitude
G = gain
$H(j\omega)$ = annular acoustic transfer function
$j = \sqrt{-1}$
$P(j\omega)$ = pressure amplitude for a specific frequency $j\omega$, at a distance x from a source
P_A = pressure amplitude at source
Vtg = volume of total gas, %
ΔR_m = change in mud resistivity, ohmms
R_m = gas-free mud resistivity, ohmms
ζ = damping ratio
ϕ = phase angle
$j\omega$ = frequency of interest
ω_n = natural frequency

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APPENDIX

1. Gas concentration in standard cubic feet of gas per barrel (scf/bbl) is calculated in the following manner:

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$$= \frac{(\text{surface injected volume (scf)/injection time (min)})}{\text{pump flow rate (bbl/min)}}$$

2. The gas-to-mud ratio (GMR) in dimensionless units is calculated:

= gas concentration (scf/bbl)/5.615 (scf/bbl)

3. Downhole gas concentration expressed in volume percentage (%) is calculated:

= 100 * GMR/bottomhole pressure (atm)

4. The density of nitrogen gas was assumed to be 1.2506 g/l.

SI METRIC AND OTHER CONVERSION FACTORS

bbl	* 1.589 873	E-01	=	m^3
bbl/min	* 2.649 789	E-03	=	m^3/s
ft	* 3.048	E-01	=	m
gal	* 3.785 412	E-03	=	m^3
gal/min	* 6.309 020	E-02	=	l/s
in	* 2.54	E+01	=	mm
lbm	* 4.535 924	E-01	=	kg
lbm/gal	* 1.198 264	E+02	=	kg/m^3
psi	* 6.894 757	E+00	=	kPa
scf	* 5.614 583	E+00	=	bbl
scf	* 2.863 640	E-02	=	std m^3
scf/bbl	* 1.801 175	E-01	=	std m^3/m^3
scf/min	* 4.719 474	E-04	=	std m^3/s

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Table 2. Gas Influx Tests, Test Program # 2.

Kick #	A Surface Inject. Mass/Vol kg	scf	B Inject. Time min.	C Inject. Rate scf/min.	D Reduced Pump Rate bbl/min	E Gas Conc. scf/bbl	F Surface Gas/Mud Ratio
16a	140	3956	6.30	628	0.83	757	135
16b	140	3956	11.75	337	2.76	122	22
21a	140	3956	12.00	330	1.16	284	51
21b	20	565	5.70	99	0.83	119	21

Kick #	G Mud Type	H Bottom Hole Pressure psi	I Bubble Height, 1stData ft	J Hydro-static 1stData psi	K Solu-bility N2 scf/bbl	L Gas in Free State?
16a	OB	3219	590	2784	150	Yes
16b	OB	3219	1350	2223	120	Yes
21a	W	1904	870	1524	6.0	Yes
21b	W	1904	600	1644	6.5	Yes

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Table 3. Detection Times for Acoustic Frequencies and Downhole Mud Resistivity.

Kick #	Gas Conc. scf/bbl	Detection Time, mins 0.20 Hz	0.40 Hz	0.60 Hz	Rm
28	7.5	-	-	3+	-
29	8.3	8	4.5	2.0	-
25	13.5	5.5	6.5	1.5	1.5
27	16.5	4	5	1.5	3
24	27.2	5.5	4	1.5	1.5
26	31.6	4.5	2	1.5	1.5
19	32.0	8	8	1	1
23	33.7	1+	3.5	1.5	1.5
22	42.0	2+	2	1.5	1
21	53.2	2	4+	1+	0.5
20	60.9	2+	4	1.5	0.5
30-1	75.4	2	2	1.5	0.5

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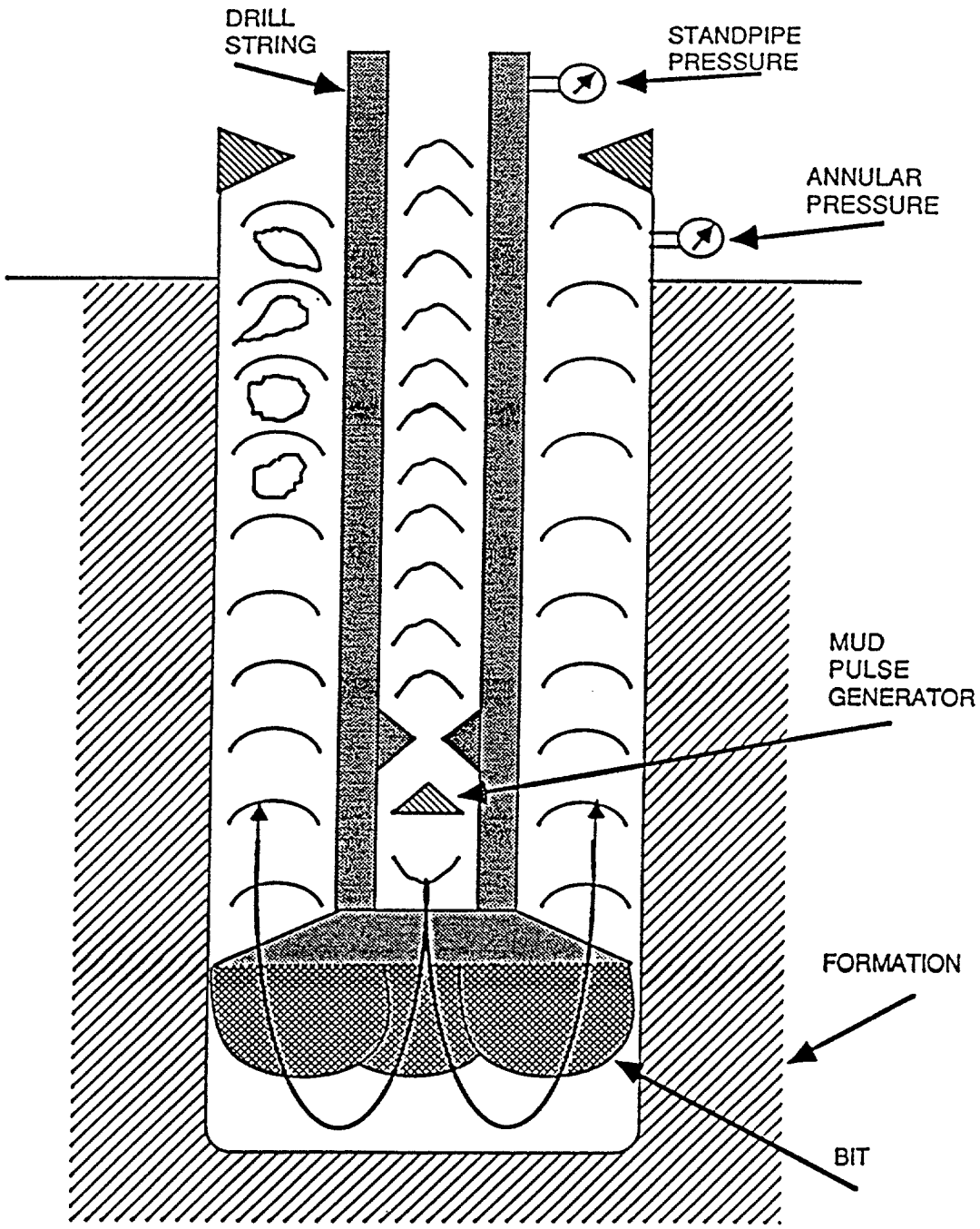

Fig. 1. Diagrammatic representation of the relationship between the MWD pulse propagating within the drillstring bore and the concomitant, smaller amplitude pulse propagating within the annulus.

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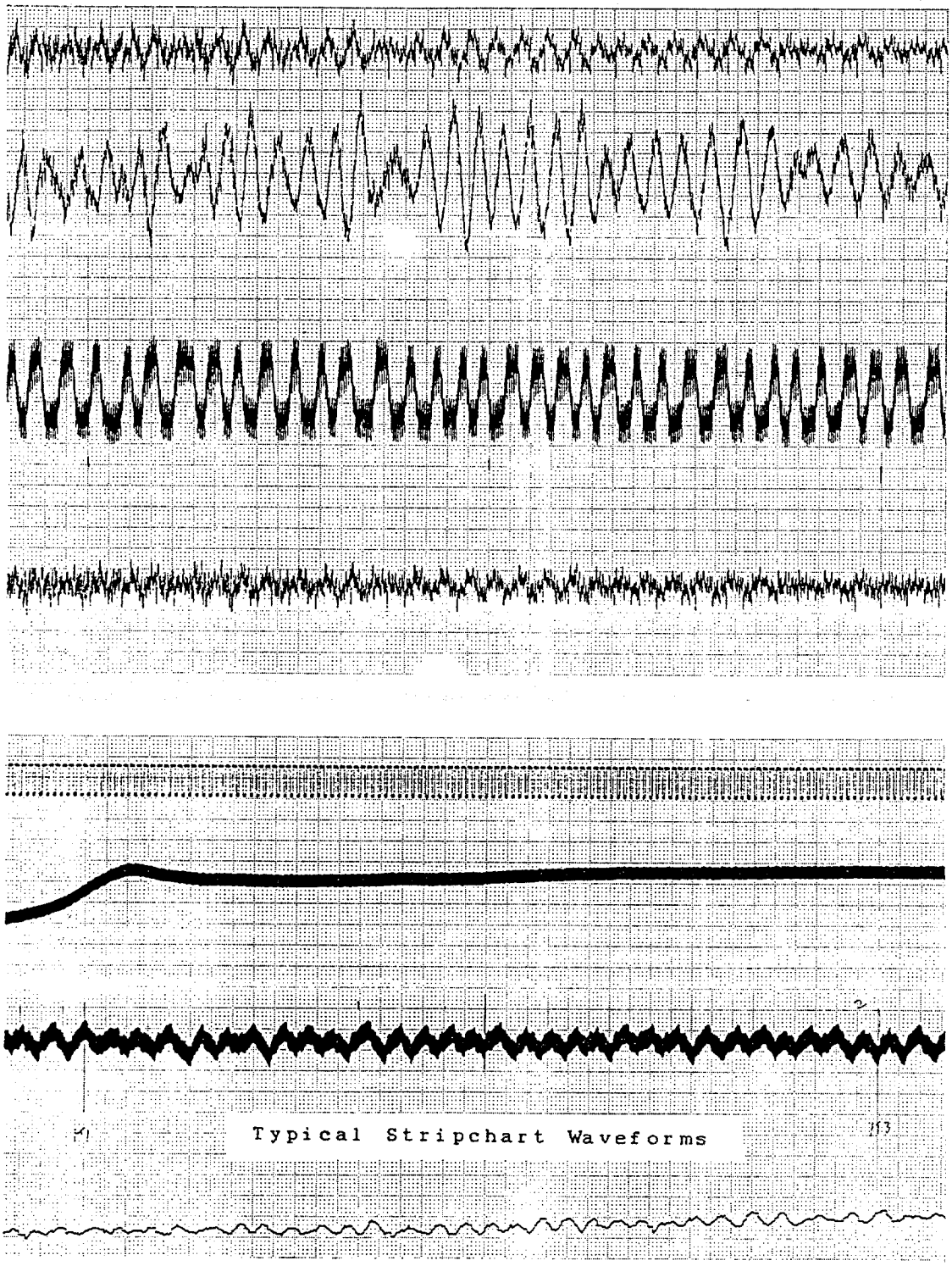

Fig. 2. Fluctuations in pressure and flow created by the MWD pulser movements. From top to bottom: annulus pressure 70 ft below flowline; annulus pressure 5 ft below flowline; standpipe pressure; annulus pressure 15 ft below flowline; pumpstrokes; injection tubing pressure; mud flow in; mud flow out.

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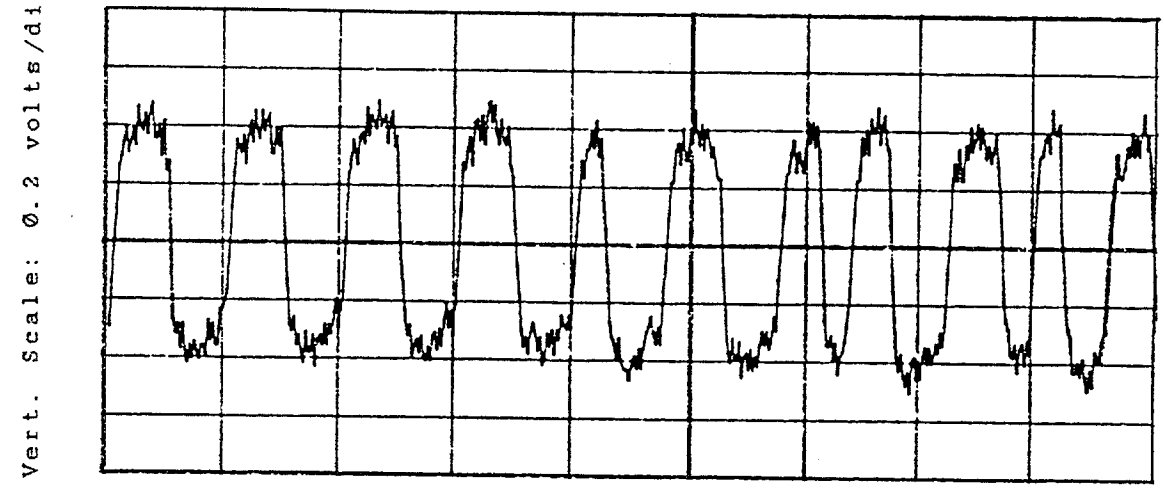
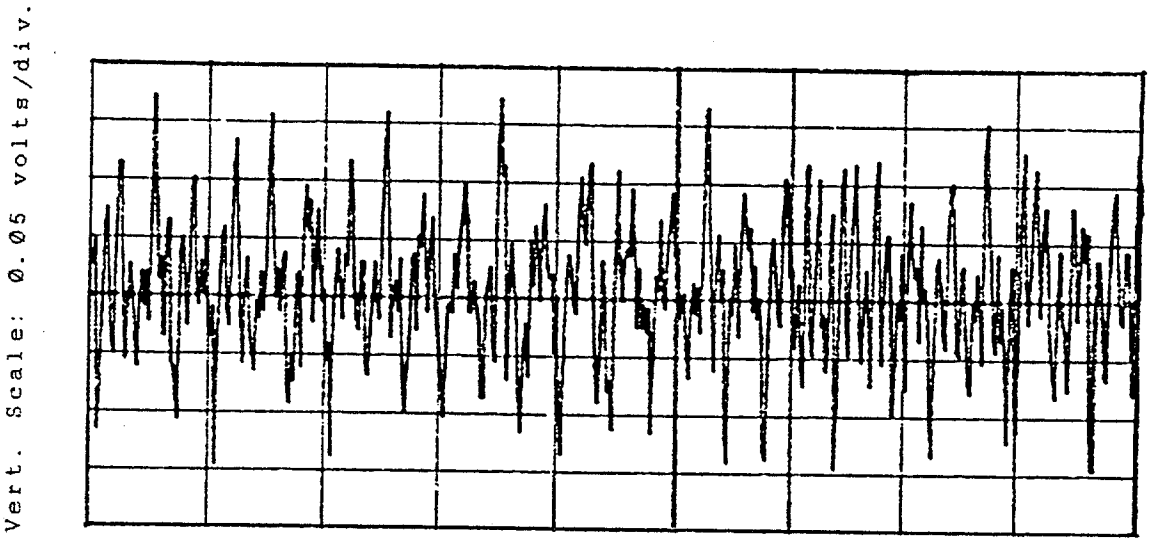


Horiz. Scale: 5 sec./div.



Typical Waveforms

Fig. 3a: (top) Time domain record of standpipe pressure during MWD transmission. Fig. 3b: (bottom) Corresponding signal measured near top of annulus.

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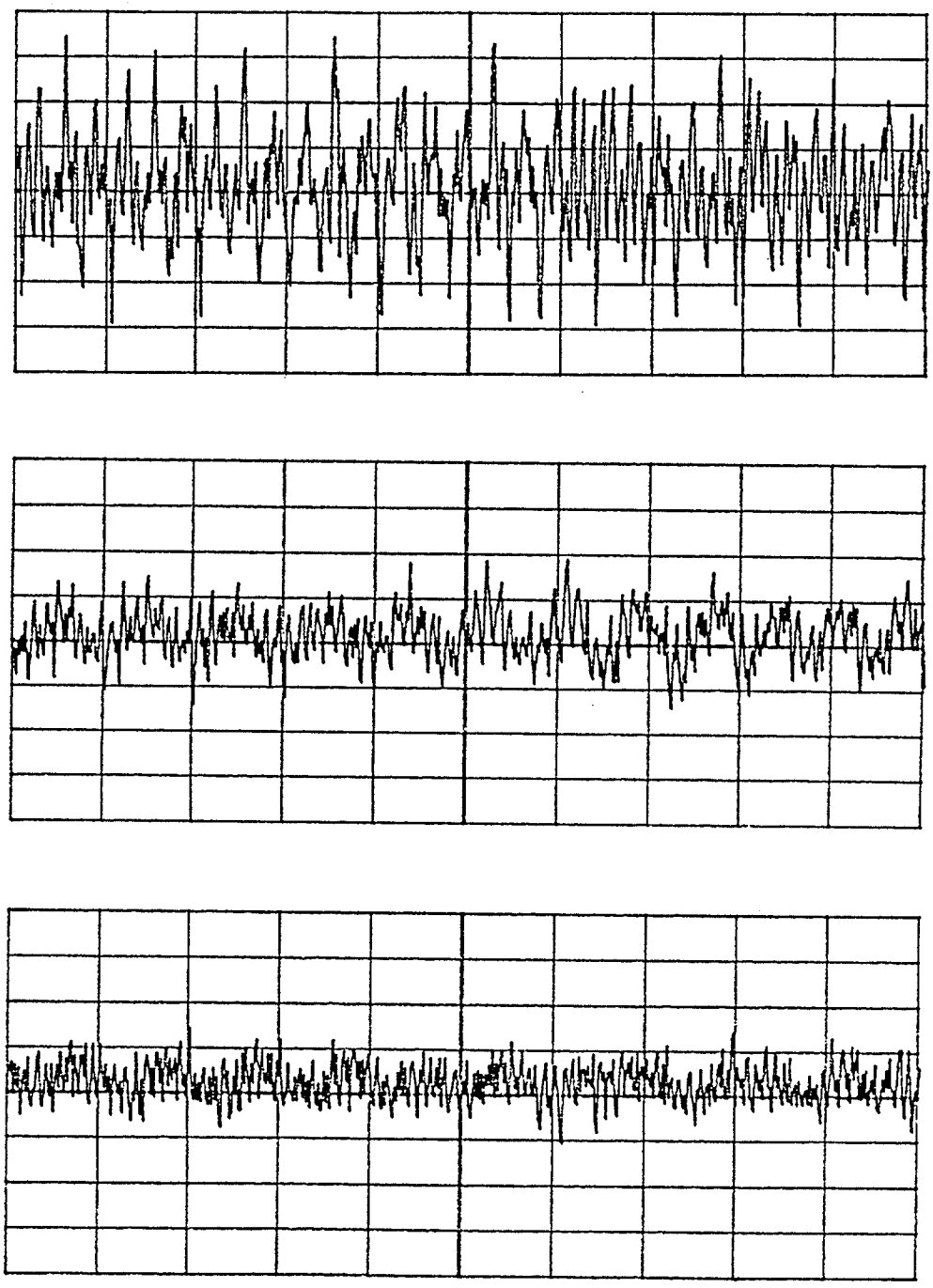

Fig. 4. Time domain changes in the character of the annular MWD signal as a function of physical changes in the communication channel. a: (top) Prominent signal harmonics and pump frequencies are evident during gas-free conditions; Fig. 4b.: (center) During injection of free gas, amplitudes of harmonics attenuate, and fundamentals amplify; c: (bottom) After influx has ceased and before gas is at surface, entire content of the annular signal is attenuated.

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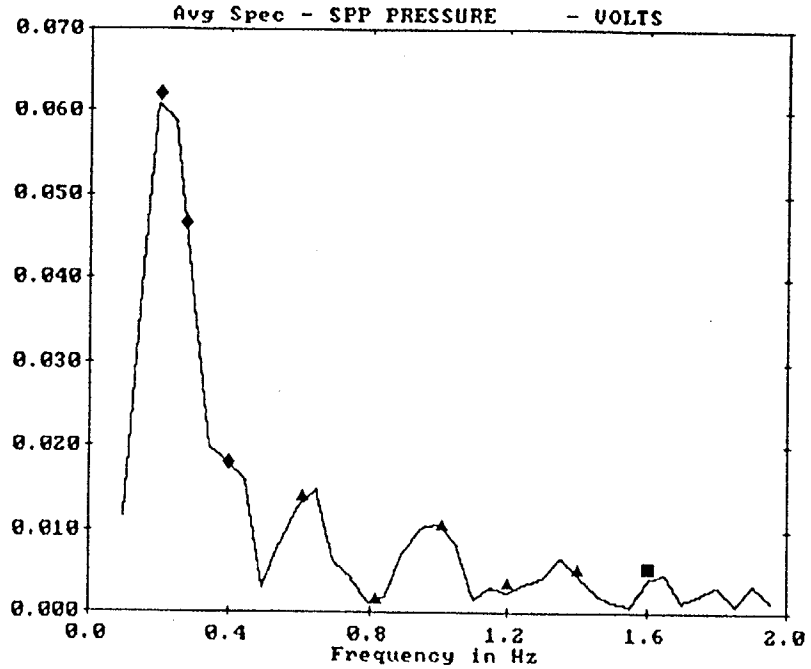

Fig. 5. Frequency domain view of pressure perturbations recorded within the drillstring bore (standpipe) channel. MWD fundamentals are indicated with ◆, various MWD harmonics with ▲, and mud pump with ■.

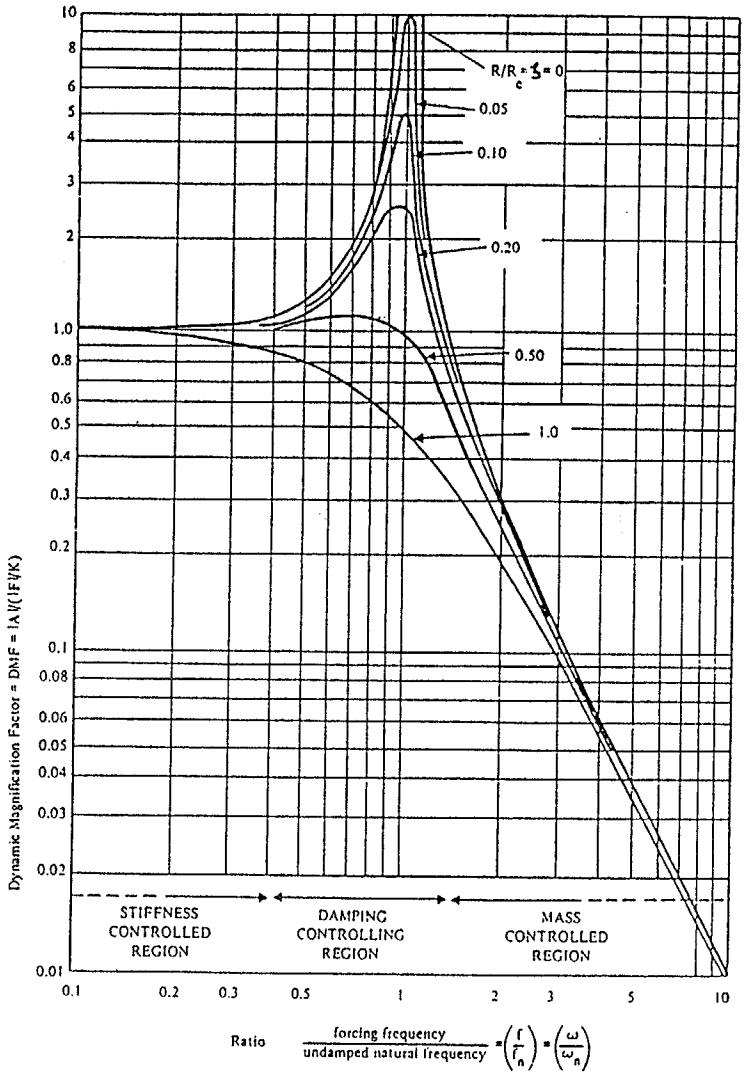

Fig. 6. Acoustic gain as a function of frequency and damping ratios, for a simple damped system. (After Seybert and Thornton, 1985, p. 1-11)

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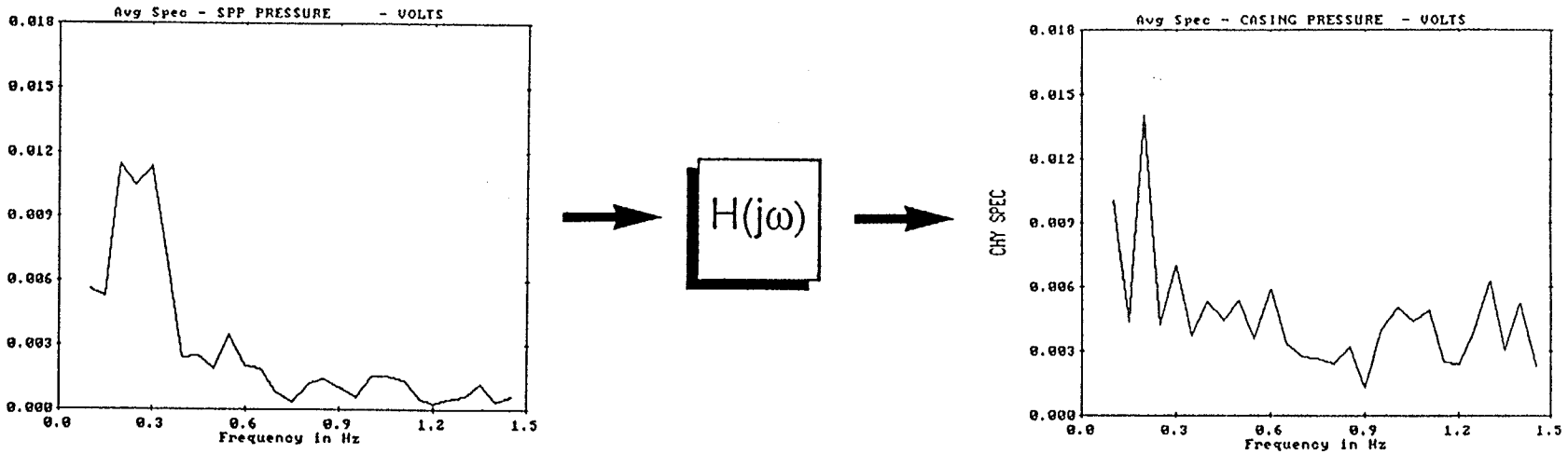

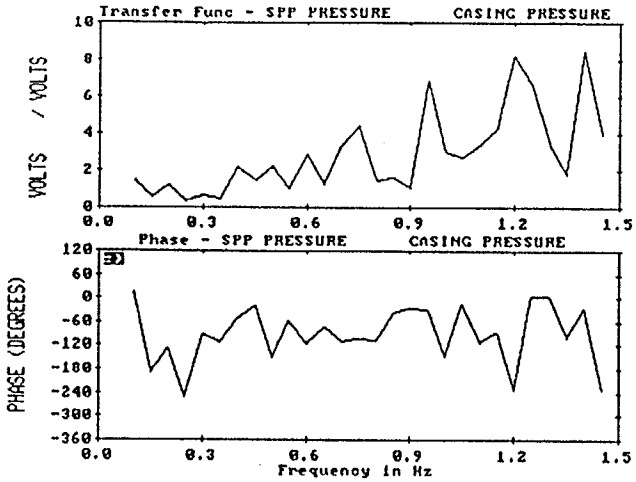

Fig.7. Annular acoustic transfer function. System input is the pressure measured at the standpipe (top left), output is pressure measured at or above preventer stack (top right). The transfer function consists of both amplitude (center) and phase angle (bottom).

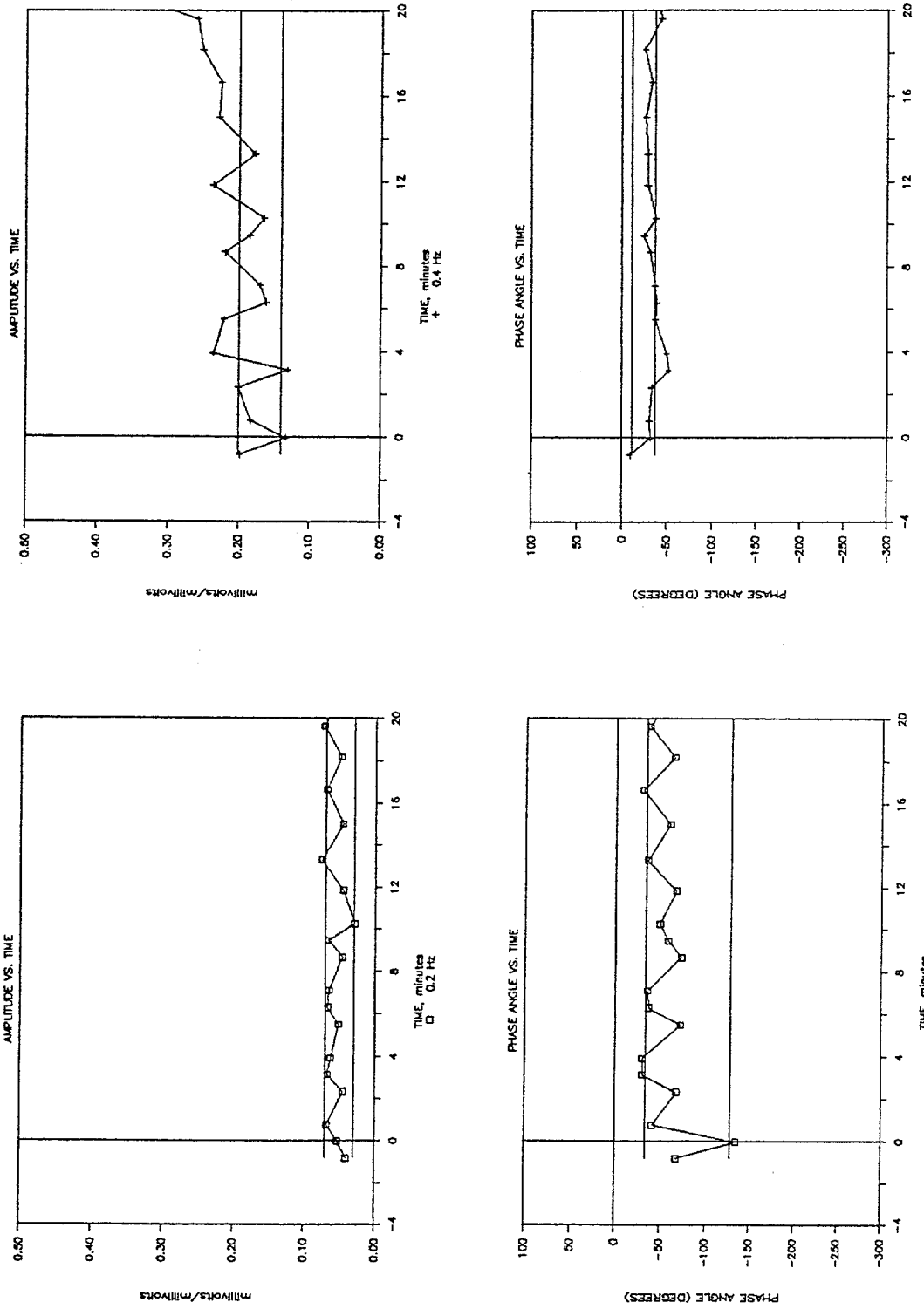

Fig. 8a. Transfer function amplitude and phase angle as a function of time, Kick #28. (left) 0.20 Hz fundamental; (right) 0.40 Hz fundamental. Gas concentration 7.5 scf/bbl.

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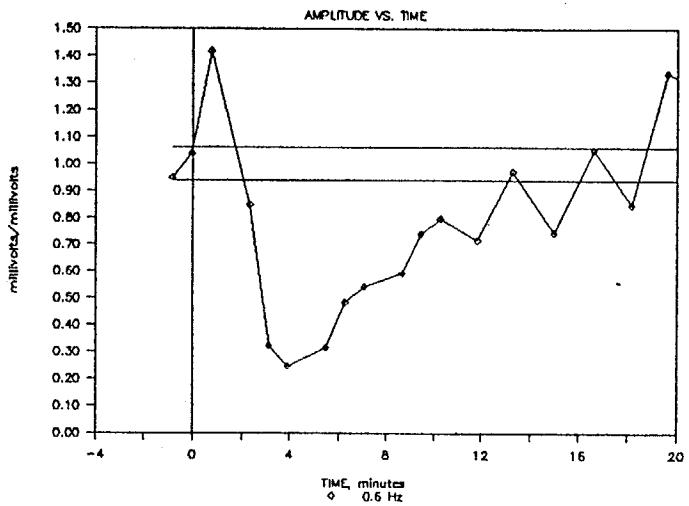

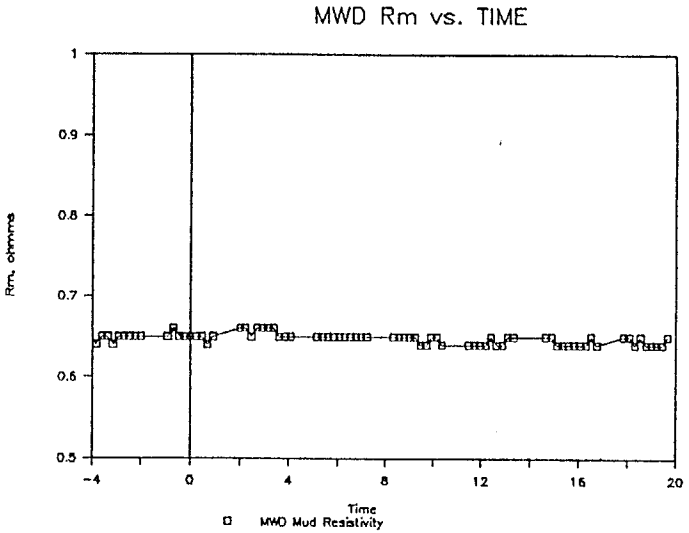

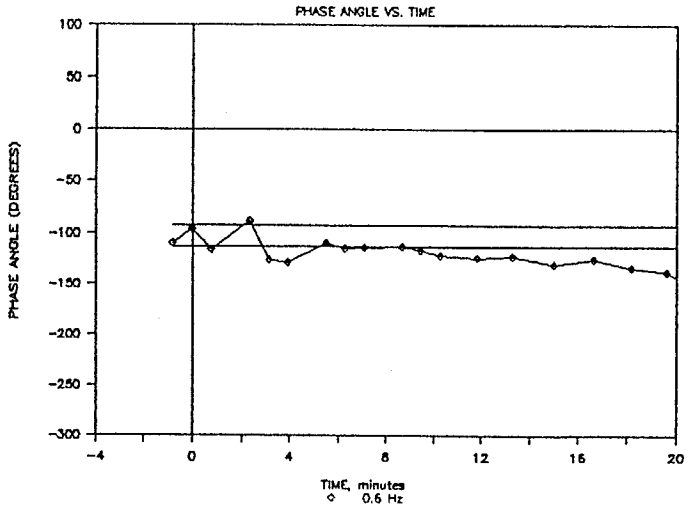

Fig. 8b. (left) Ø.6Ø Hz harmonic transfer function amplitude and phase angle as a function of time, kick #28. (right) MWD downhole mud resistivity, kick #28.

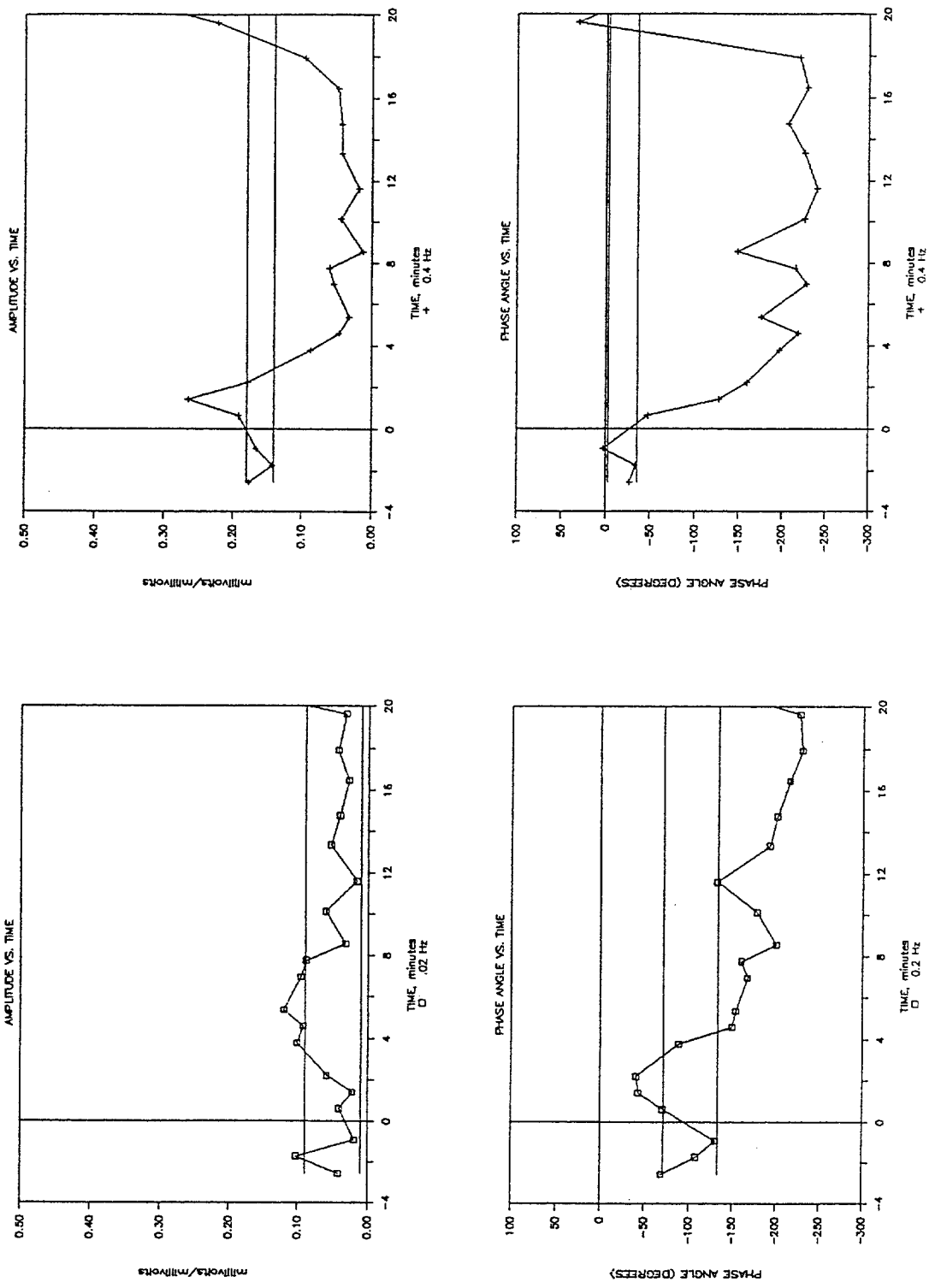

Fig. 9a. Transfer function amplitude and phase angle as a function of time, Kick #24. (left) 0.20 Hz fundamental; (right) 0.40 Hz fundamental. Gas concentration 27.2 scf/bbl.

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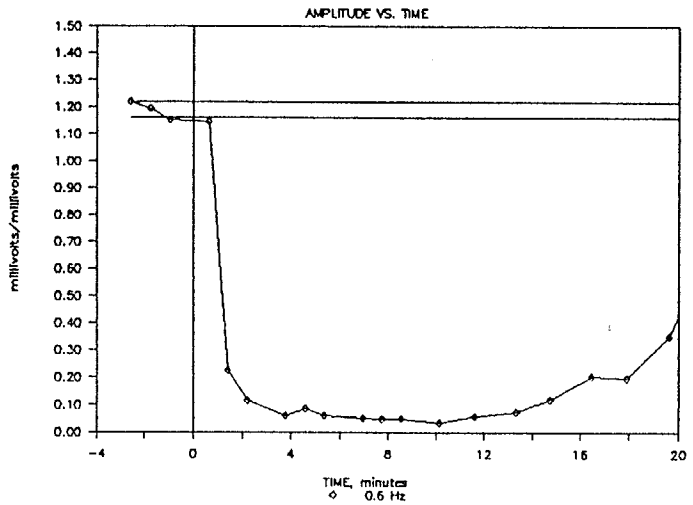

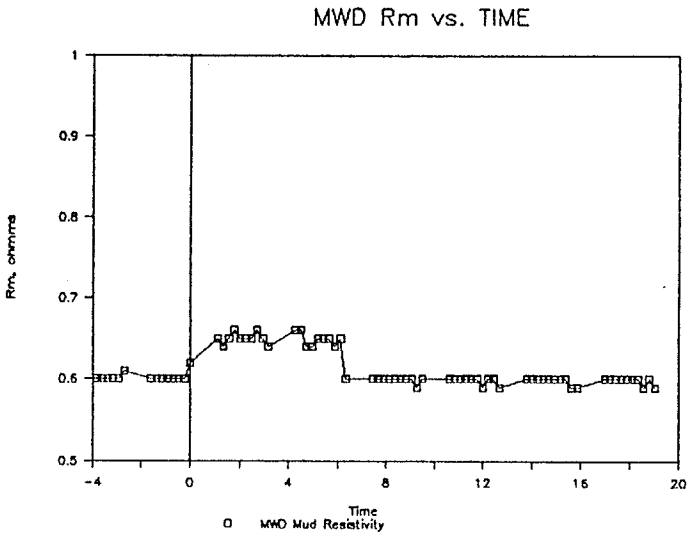

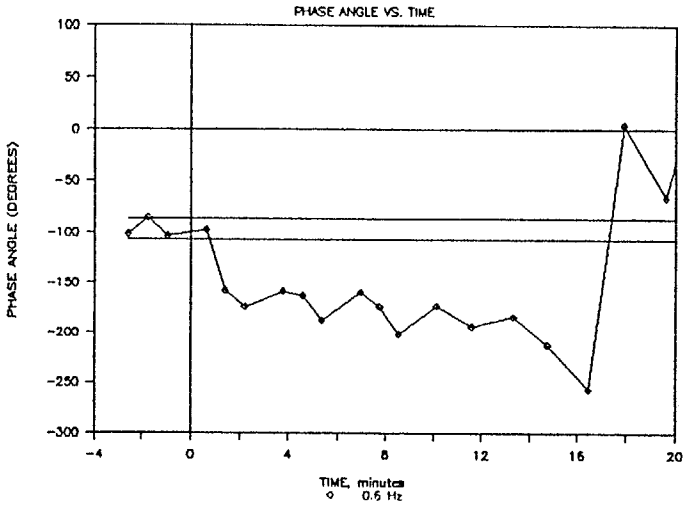

Fig. 9b. (left) 0.60 Hz harmonic transfer function amplitude and phase angle as a function of time, kick #24. (right) MWD downhole mud resistivity, kick #24.

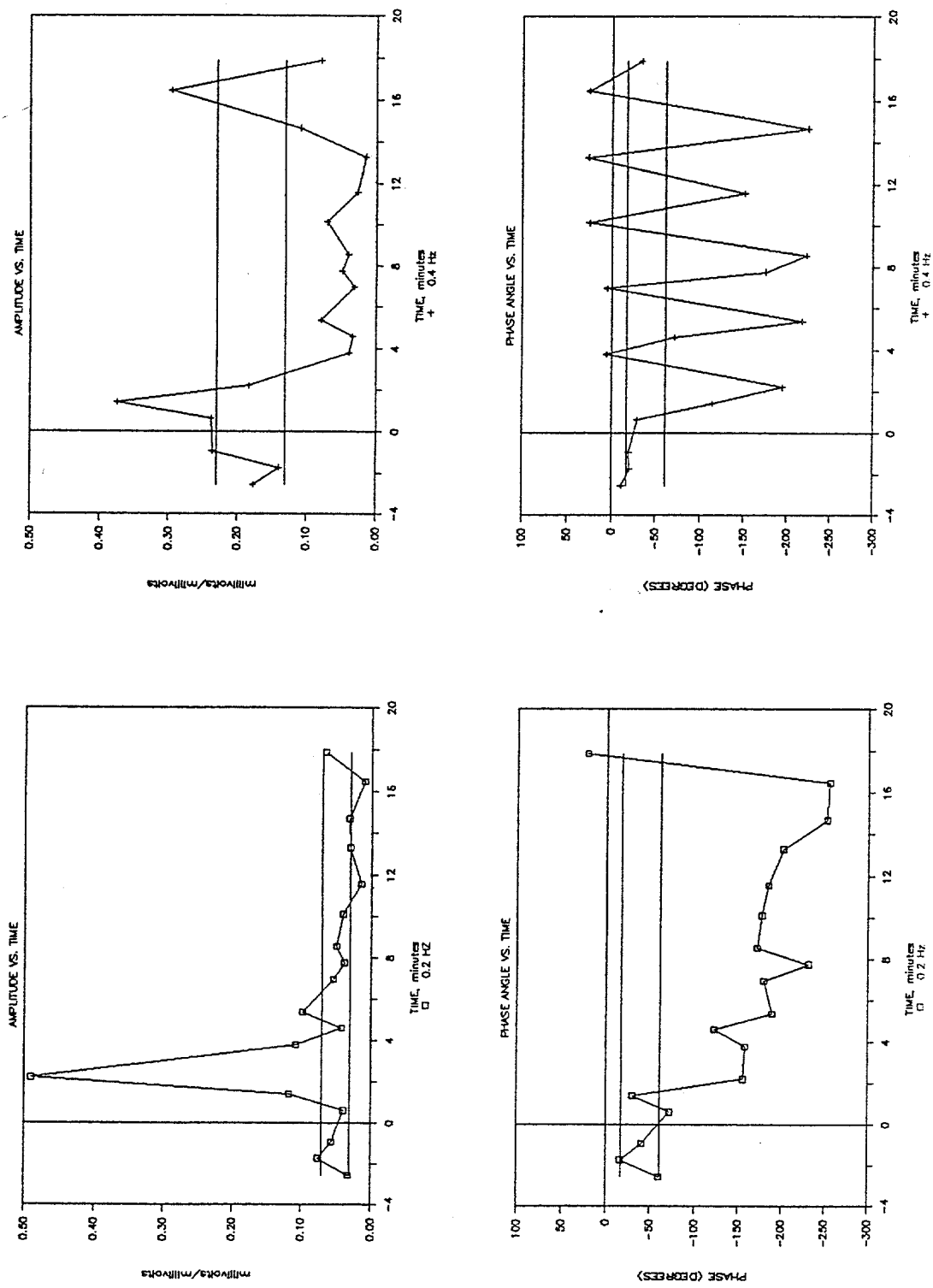

Fig. 10a. Transfer function amplitude and phase angle as a function of time, Kick #20. (left) 0.20 Hz fundamental; (right) 0.40 Hz fundamental. Gas concentration 60.9 scf/bbl.

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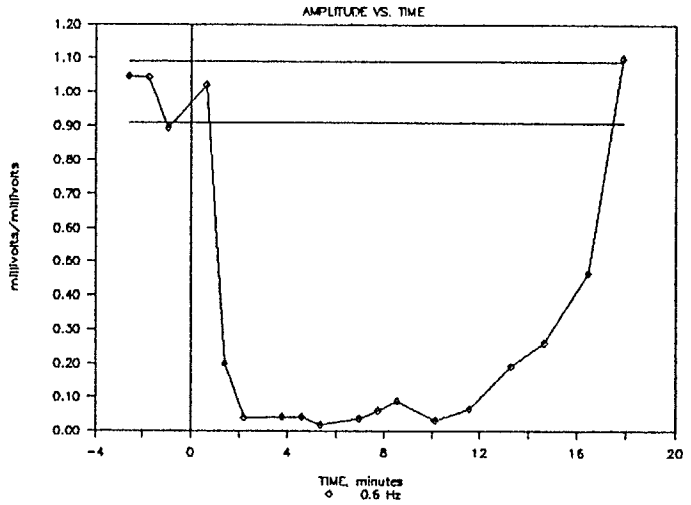

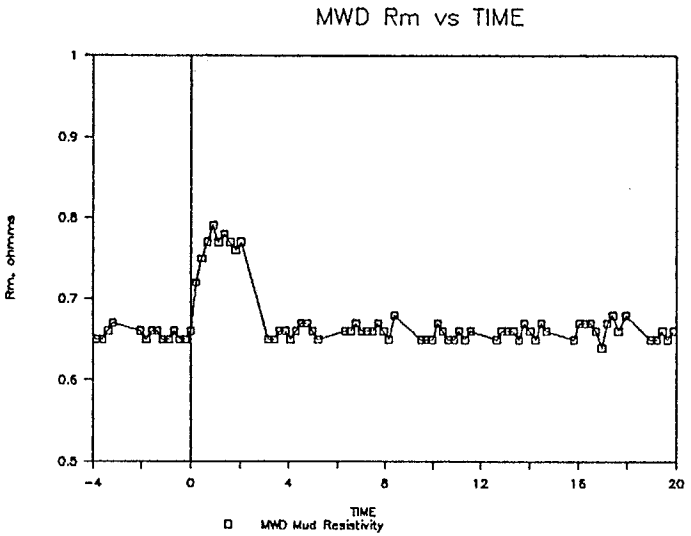

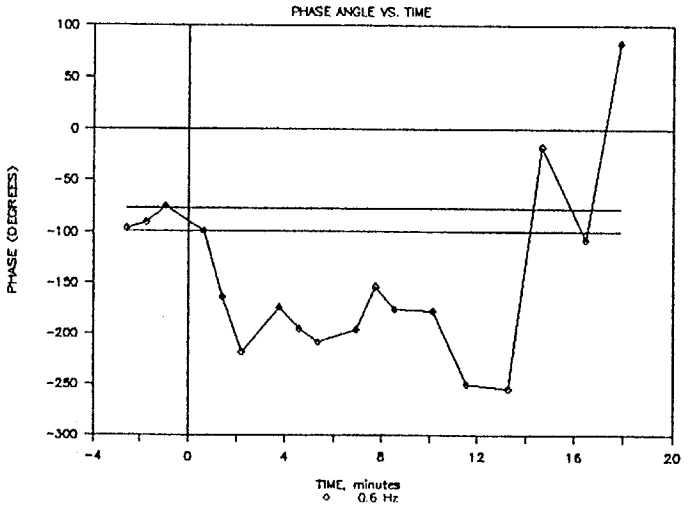

Fig.10b. (left) 0.60 Hz harmonic transfer function amplitude and phase angle as a function of time, kick #20. (right) MWD downhole mud resistivity, kick #20.

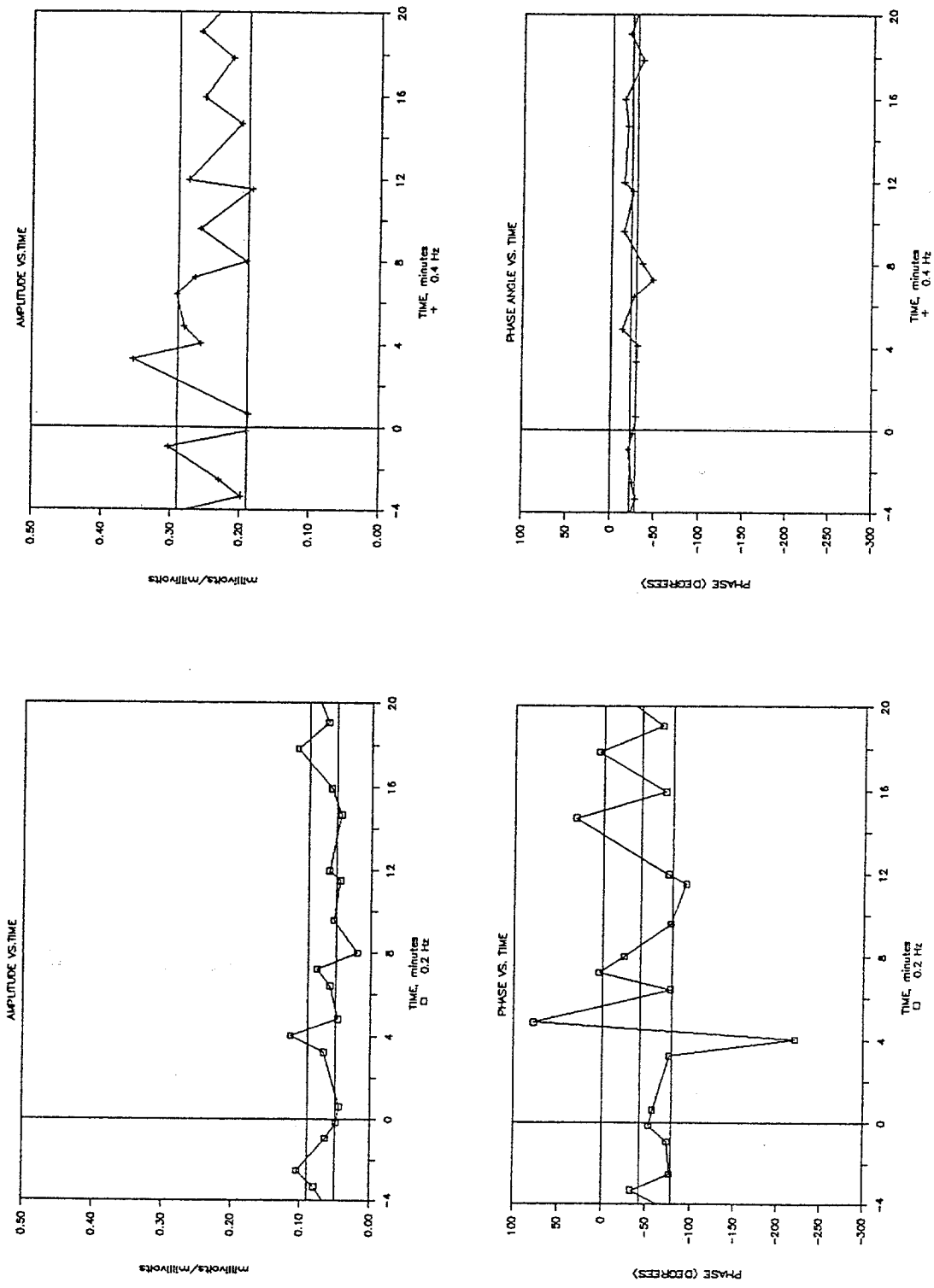

Fig.11a. Transfer function amplitude and phase angle as a function of time, Kick #31. (left) 0.20 Hz fundamental; (right) 0.40 Hz fundamental. Salt water injection.

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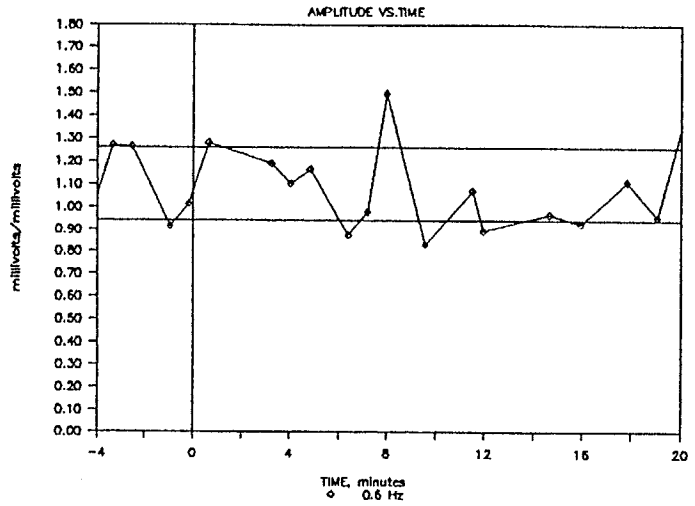

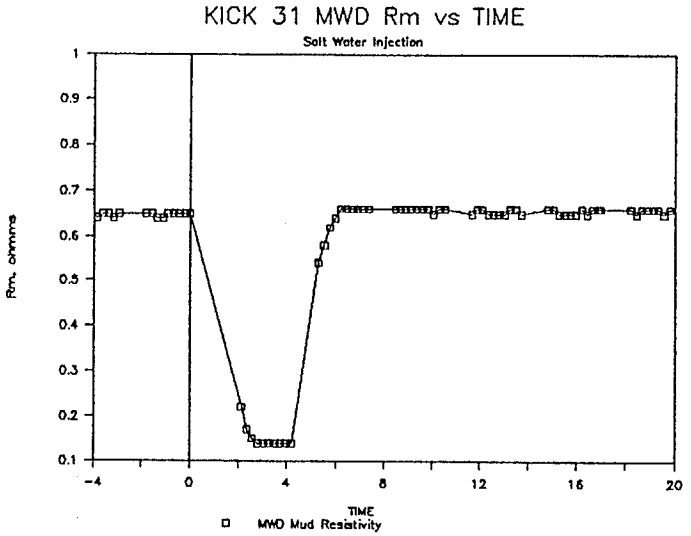

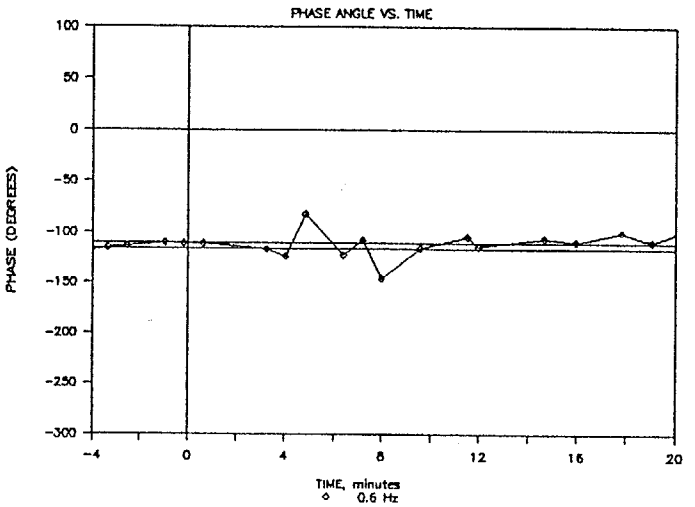

Fig.11b. (left) Ø.6Ø Hz harmonic transfer function amplitude and phase angle as a function of time, kick #31. (right) MWD downhole mud resistivity, kick #31.

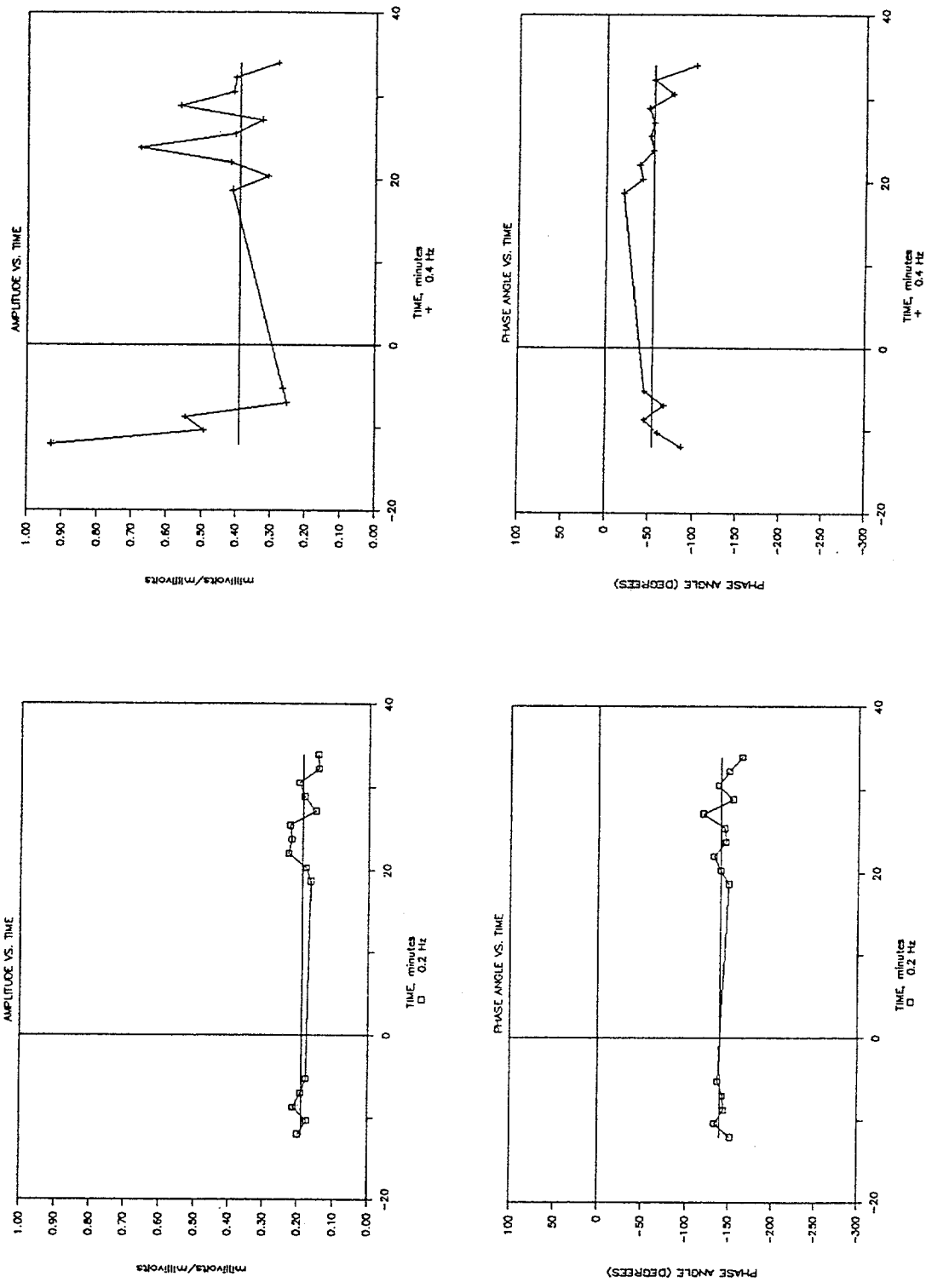

Fig. 12a. Transfer function amplitude and phase angle as a function of time, Rogaland Kick #16a. Oil-base drilling fluid. (left) 0.20 Hz fundamental; (right) 0.40 Hz fundamental. Gas concentration 757 scf/bbl.

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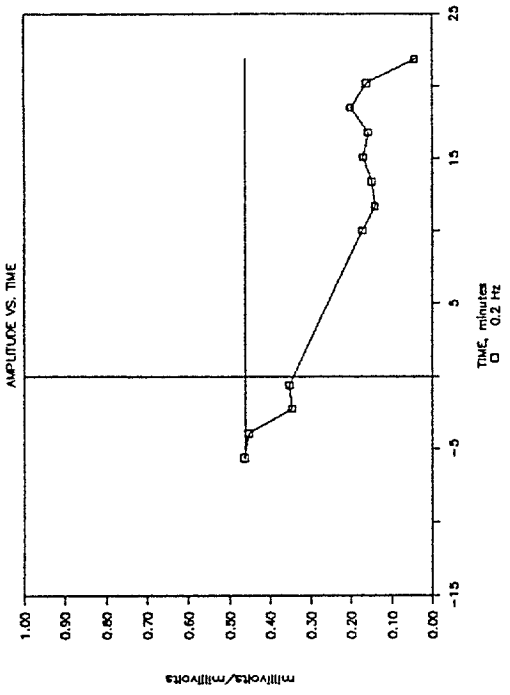


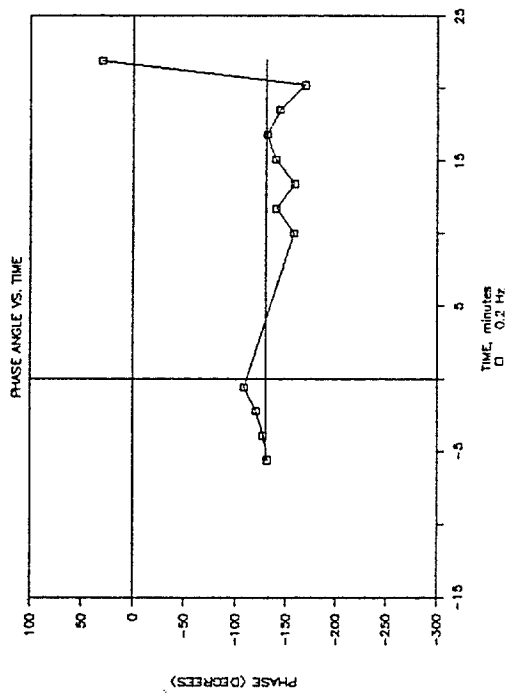
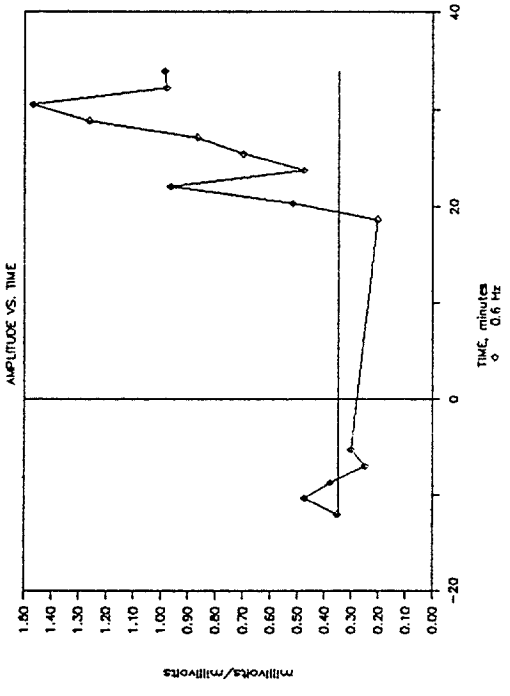


Fig.13a. (right) 0.20 Hz transfer function amplitude and phase angle as a function of time, Rogaland kick #21a. Water-base drilling fluid. Gas concentration 284 scf/bbl.



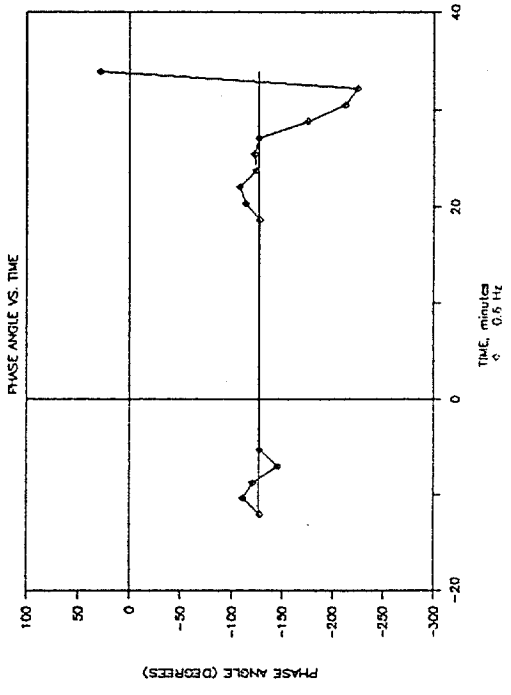


Fig.12b. (left) 0.60 Hz harmonic transfer function amplitude and phase angle as a function of time, kick #16a.

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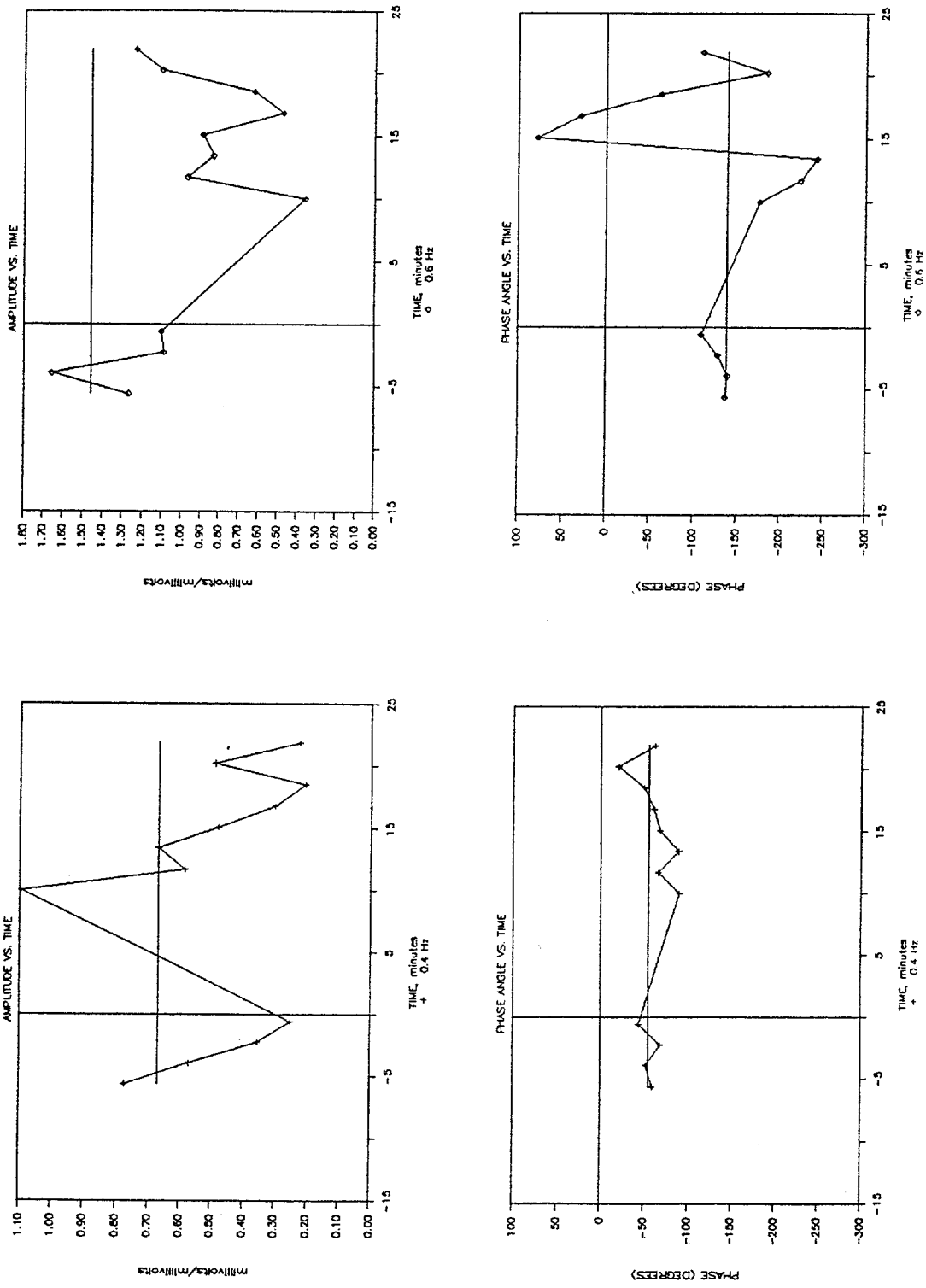

Fig.13b. Transfer function amplitude and phase angle as a function of time, Rogaland kick #21a. (left) 0.40 Hz fundamental; (right) 0.60 Hz harmonic.

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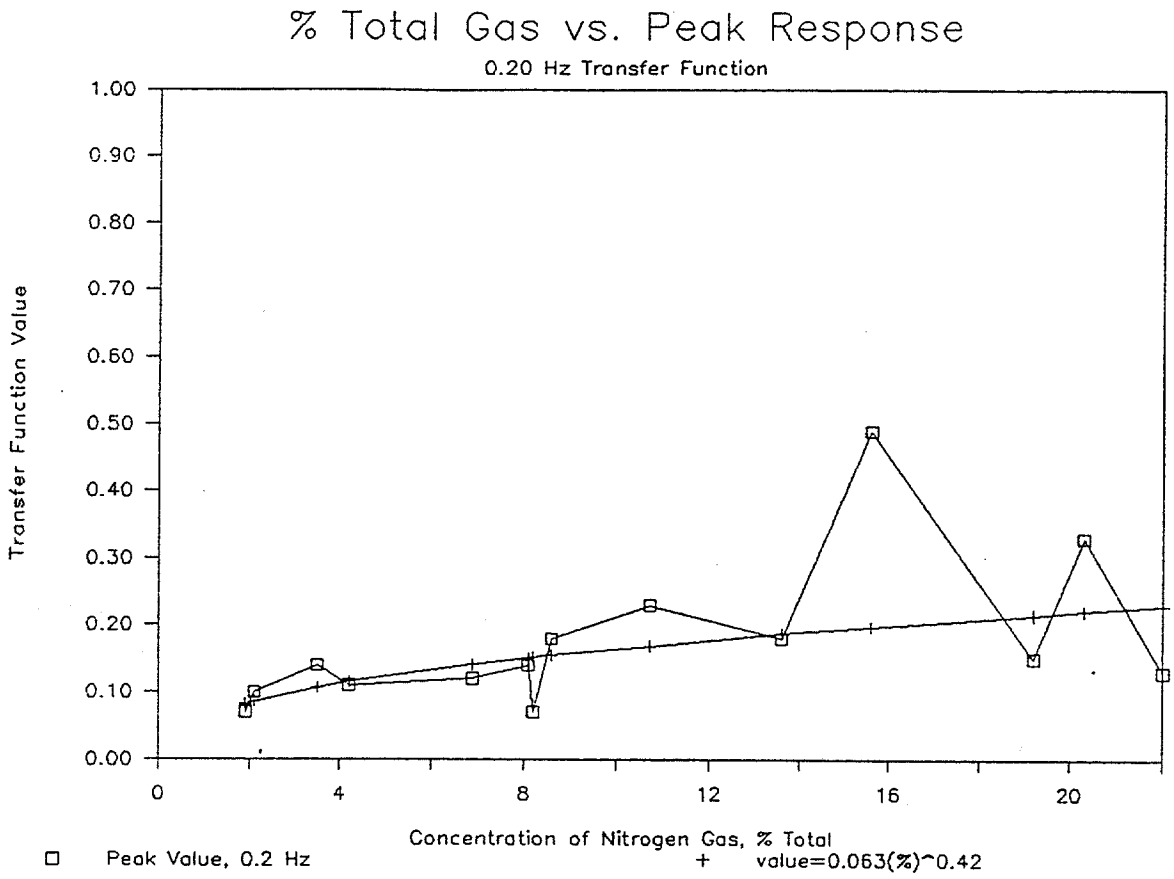

Fig. 14. Relationship between maximum gain of the 0.20 Hz transfer function and gas concentration.

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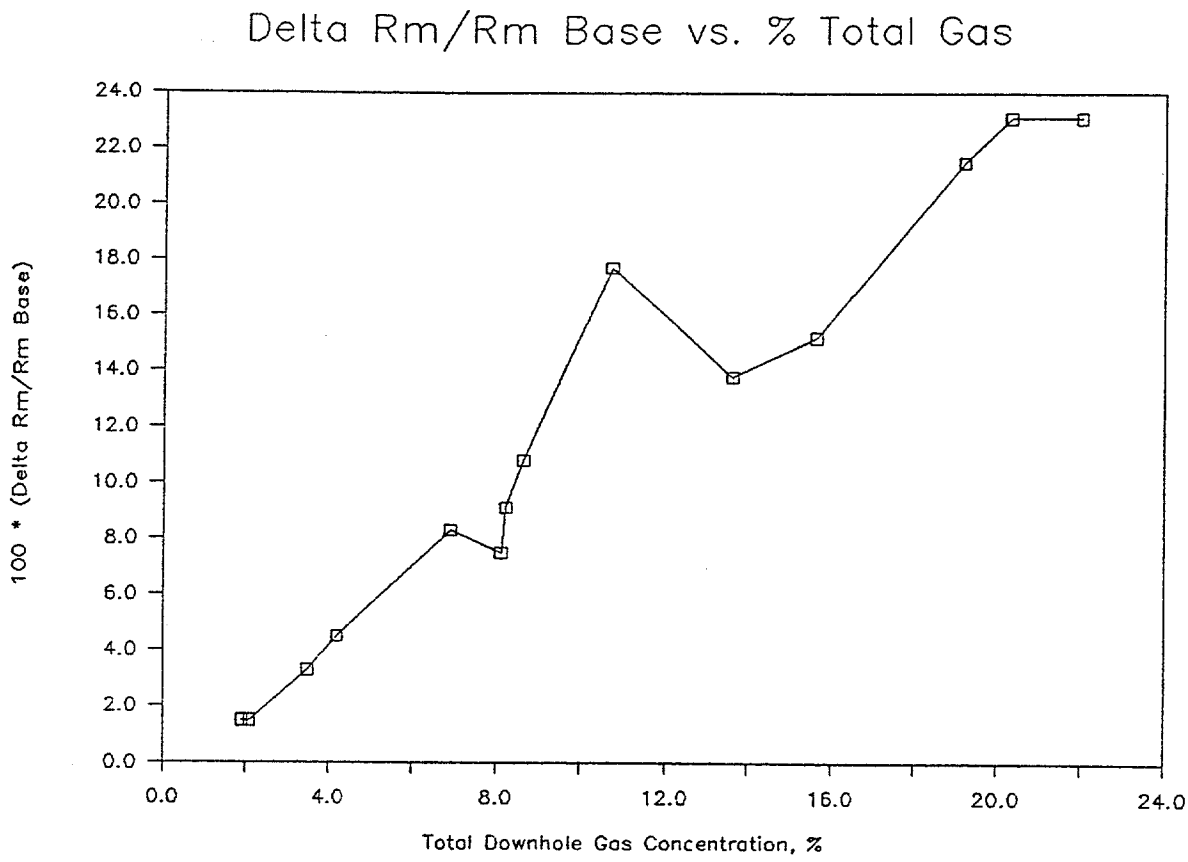

Fig. 15. Quantitative relationship between downhole MWD mud resistivity and gas concentration.

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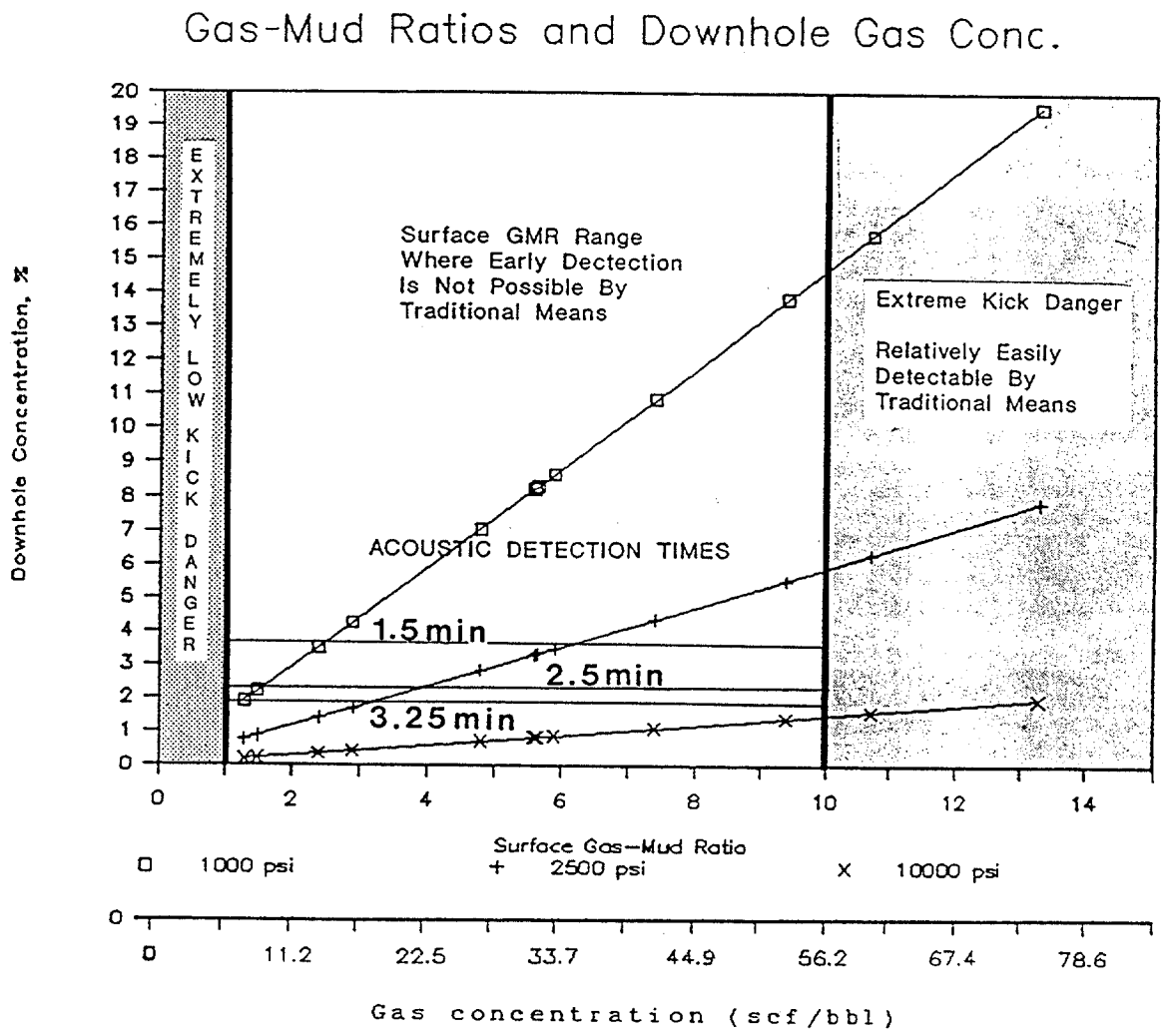

Fig. 16. Gas concentration (scf/bbl) and gas mud ratio (GMR) are related to downhole gas concentration (%) by hydrostatic pressure. MWD acoustic and Rm techniques exhibit superior kick detection-time capability within a GMR range that is not well served by traditional techniques.

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Errors Inherent in Rig Measurements of Drillpipe and Casing Pressures

by W.R. Holden and O.A. Kelly, Louisiana State U.

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ABSTRACT

A common complaint of drilling personnel is that modern well control strategies require pressure measurement accuracies not possible with typical rig equipment. This paper documents a study made (1) to identify and quantify sources of significant error inherent in remote measurements of drill pipe and casing pressures, (2) to determine their cumulative effects on measurement accuracy and (3) to define the pressure response limits of a typical rig system. For this study, the pressure measurement system was duplicated in the laboratory using rig components supplied by several vendors.

Response characteristics of each system component were studied separately and are presented in four graphic displays and one table. A numerical example details their use in the analysis of a complete system. Comparison of predicted and observed pressure responses for several system configurations confirmed the results and method of analysis developed in this study.

Gage-reading correction factors can now be calculated with certainty. Of greater significance, is the ability to predict the upper limit of reliable response for a given pressure measurement system. A detailed analysis can show how it is possible that a system equipped with a 10,000 psi gage can indicate pressure extremes no greater than, say, 5000 psig.

INTRODUCTION

Errors in the remote measurement of drill pipe and casing pressures have been and continue to be a problem in drilling and well control operations. Drilling personnel attending the Louisiana State University (LSU) IADC Well Control School relate experiences of pressure measurement errors that vary from 100 to sometimes several thousand psi. As a consequence, they will argue that precision pressure control, as dictated by modern well control procedures, is unrealistic and therefore, of no great concern to the operator.

Errors of the same magnitude have been duplicated at the LSU Research and Training Well Facility and in the laboratory, using standard oil field equipment. Reported here are the results of a study to identify and quantify the source of these errors and to develop a methodology by which corrections for similar rig systems could be determined.

As used here, remote measurement refers to those systems that connect the pressure source to the indicator gage or sensor by means of a hydraulic fluid link. The gage can be either digital or analog and is located on or near the rig floor, for example on the choke control panel.

Figure 1 depicts the pressure measurement system of interest. It has four basic components: (1) pressure source, (2) gage protector, (3) transfer fluid link, and (4) pressure measuring device.

Gage protectors are normally installed on the standpipe, choke and pump manifolds. The pressure derived from any one of these sources will, henceforth, be referred to as the process pressure. The gage protector serves to prevent mixing of the process fluid (drilling mud, gas, salt water) with the clean transfer fluid (instrument oil) which contacts the pressure indicator. The interface between these two fluids is maintained by either a flexible elastomer diaphragm or a "so-called" free floating piston.

A 50-foot length of high pressure hydraulic hose is the normal transfer fluid link but 1/8-inch stainless steel tubing is sometimes used. The typical pressure gage is a single coil, Bourdon tube type with a full scale limit of 10,000 psig.

References and illustrations at end of paper.

Each component of the sensing system was tested to determine its response to a range of applied pressures. They were then combined and tested as a complete measurement system, with the effects of elevated temperatures also documented.

TEST PROGRAM DESIGN

Experience gained from the training well has shown that the pressure measurement system as previously defined has two blind regions. As illustrated on the analog display in Figure 2, there is a lower dead band (LDB) where the pressure indicator will not follow relatively low range excursions in process pressures but will indicate instead some constant minimum value denoted as P_1. Similarly, in the upper dead band (UDB), the pressure indicator will never exceed some constant value denoted as P_2, even though the process pressure be much higher than this value. In essence, for process pressures lower than P_1 or higher than P_2, the pressure measurement system malfunctions. Pressure indications greater than P_1 (yet less than P_2) in conjunction with preditable correction factors will provide true measures of process pressures.

As will be verified in a later section, the interaction of the individual components of the system is the cause for these pressure response limits. Remote pressure measurement depends upon pressure in the process fluid being transferred through the gage protector to the instrument oil in the hydraulic hose (or steel tubing) and thence to the gage element. Consider the case of an hydraulic hose having a significant compressibility. With an increase in pressure in the instrument oil, the hose would balloon or expand, thereby increasing its internal volume. Consequently, a sizeable pressure increase at the gage element might require a significant volume of oil be added to the hose. (Then too, as the oil itself is slightly compressible, it would tend to decrease in volume, requiring that still more oil be added to the hose.) This additional oil must come from within the gage protector. If the gage protector can supply only a limited volume of oil, then there definitely would be an upper limit on the maximum pressure which could be maintained inside the hose (and consequently at the pressure indicator). This could well be the cause for the upper limit of pressure response in a typical system, previously denoted as P_2 on Figure 2.

Realization that pressure increases in the system side (as opposed to the process side) of the gage protector could require the expulsion of some (if not all) of the oil from the protector suggests that the floating piston or elastomer disphragm will move a significant amount. In the case of the diaphragm-type protector, a significant stretching of the elastomer could perhaps cause a discernible pressure difference across the diaphragm. Recall that the pressure inside an inflated rubber balloon is greater than the pressure surrounding the balloon. Hence, the process pressure could be expected to be greater than the system (oil) pressure. This could explain, along with any errors in gage response, why pressure indications inside the limits imposed by the lower and upper dead bands still require correction factors before they are truly representative of process pressures.

Insite gained from this type of analysis suggested the design of laboratory procedures to provide measurements of:

1. isothermal compressibility of the oil-filled hydraulic hose (or steel tubing) in terms of oil volume additions required to realize specific internal pressures
2. the accuracy of an oil-filled Bourdon tube gage along with its isothermal compressibility
3. the volume of working fluid contained in each type of gage protector
4. pressure loss incurred while expanding the elastomer diaphragm
5. pressure loss caused by any sliding friction in a piston-type protector
6. additional fluid volume and diaphragm distortion as a consequence of precharging the system to an elevated pressure, while the process side is at atmospheric pressure
7. the effects of elevated temperature on the response of the system as a whole
8. the isobaric thermal expansion coefficient of the instrument oil.

LABORATORY TEST APPARATUS

Figure 3 is a schematic of the laboratory test model used for data collection and results verification. A positive displacement mercury metering pump was used as the pressure source while the gage protector, hydraulic hose and gage element were standard oil field equipment . Pressures upstream and downstream of the gage protector were measured by a Heise gage, 0 to 10,000 psig span. All pressure measurements between 0 and 5,000 psig were corroborated by measurements made with a pressure transducer. Fluid flow to and from the gage protector was metered and verified by volumetric measurements.

All pressure measuring equipment was calibrated to a standard tested to be accurate to $\pm$0.03% reading. The pressure transducers tested accurate within +0.2% of the indicated value and the Heise gage tested to be within 0 to -10 psi. Transducers with ranges of 1,000 and 5,000 psig were used to minimize reading error, and were used interchangeably depending on the pressure range being tested. The Heise gage was used solely in determining the pressure between 5,000 and 10,000 psig.

For the laboratory pressurization system connected to the process side of the gage protector, a composite compressibility was determined. All test results were appropriately factored such that the they would not be biased by the mercury pump system.

FINDINGS AND RESULTS

Each component of the remote pressure measurement system was independently evaluated. The resulting data has been presented in the form of graphs and tables to simplify use. All graphs and tables given in this text are specific to the equipment tested and are not intended to be used indiscriminately.

Hydraulic Hose

Initial observations indicated that the hose consumed virtually all of the working fluid during system pressurization. In an attempt to define this "ballooning" or expansion of the hose, pressure versus volume data was collected for a 1/4-in. by 50 foot, 10,000 psig rated hose. The hose was exercised, pressurized to the full working pressure of the hose, several times in order to "season" the hose so as to obtain reproducible data. It was found that the "green" or new hose consumed more fluid to obtain equivalent pressures as applied to a seasoned hose. During the study, it was noted that the expansion characteristic of the hose reverted back to the green state when not used for a few weeks. However, with limited use, the hose returned to a seasoned state.

Numerous pressure versus volume tests were conducted with the resulting composite compressibility values for the fluid and hose being given in Figure 4. Note that the data is presented as working fluid demand in mL/ft of hose versus pressure. The scaling, mL/ft, is to accommodate varying lengths of hose.

Figure 4 can be used to determine the hose fluid volume increase required to achieve a given pressure. Inversely, this figure can also be used to determine the pressure obtainable given a fluid volume increase. Of immediate utility, the problem of defining the system upper pressure response limit can now be accommodated, given the total fluid available for pressure transmission. This could be accomplished by dividing the total working fluid available for pressurization by the hose length to obtain a mL/ft fluid availablity value. Using this value, enter Figure 4 and read the corresponding pressure, the maximum pressure response limit for the system.

Stainless Steel Tubing

To minimize fluid consumption by hose expansion, the flexible hydraulic hose can be replaced by stainless steel tubing. This practice, though superior, is not frequently used in the field because the flexible hose proves more practical for mobile drilling rigs. One-eighth inch stainless steel tubing was tested in an attempt to generate a composite compressibility factor similar, in kind, to that of the hose. However, excessive pressures, approaching full scale, were required to create a working fluid demand of sufficient quantity for accurate measurements. Recognizing that the total working fluid demand is of negligible consequence, liberty was taken in assuming a linear interpretation of the data such that the composite compressibility factor was determined to be 0.000032 mL/psi/ft of hose. This approximation is justified solely by the fact that, in this application, the total working fluid demand, even when pressurized full scale, will not be significant.

Pressure Gage

Data representing working fluid requirements for both pressure transducers and Bourdon tube gages was collected. Fluid requirements to activate transducer type instruments full scale, for all practical purposes, was zero. No detectable fluid movement was measured in pressurizing the transducer diaphragm full scale. Therefore, use of this instrument does not present a problem other than maintaining calibration.

Compressibility of the Bourdon tube single-coil gage proved minimal. Prior to testing, the tube element was removed from the gage and purged of air. Pressurization tests defined a compressibility profile as shown in Figure 5. Note that at 10,000 psig, only about 1.0 mL of fluid is required to extend the gage full scale, which could be considered negligible.

No attempt at defining gage error was included in this study since each gage appears unique, accuracy varying by gage. It is felt that each user should have a feel for the accuracy of the type gage in use.

Gage Protector

The previous discussions have concerned those items that require additional amounts of working fluid in the pressurization process. Attention will now be devoted to the source of the working fluid that accommodates pressure fluctuations. The gage protector notably acts as a barrier device for separating the process fluid from the instrument oil, but it also contains a reservoir of instrument oil, available upon demand, for expulsion during pressure transmission.

There are two types of gage protectors. One type uses an elastomer diaphragm to separate the process pressures from the instrument oil, as shown in Figure 6, while the other type replaces the diaphragm with a floating piston. Evaluation of the gage protectors involved defining (a) the reservoir working fluid volumes for both the elastomer and piston units, (b) pressure losses due to expansion of the diaphragm, (c) frictional losses incurred across the piston during movement, and (d) the effects of precharge.

a. Reservoir fluid capacity

Gage protector working fluid volume is defined as that fluid volume that can be expelled from the gage protector reservoir into the hose. In an attempt to define the working fluid availability, volumetric measurements were made for both the diaphragm-type and piston-type gage protector units. Three vendors' products were represented in this analysis. Two supplied diaphragm-type gage protectors while all three provided piston-type gage protectors.

Table 1 displays the working fluid volumes as determined by volumetric displacement. With the exception of precharge, to be discussed later, these volumes represent the total fluid available for pressure transmission. No errors were found to be induced due to the reservoir size variation except in that the total fluid available for expulsion is directly responsible for the determination of the system's maximum pressure response limit.

Continuing the concept presented in the "Hydraulic Hose" section, if the total volume of fluid available for pressure transmission is known, in this case stored in the gage protector reservoir, a maximum pressure response limit can be determined. Divide the total volume of fluid available by the hose length and use the procedure discussed in the "Hydraulic Hose" section to obtain the system's maximum pressure response limit from Figure 4. This value represents P_2 as shown in Figure 2.

b. Pressure loss - diaphragm

When expelling the working fluid from the gage protector reservoir for volumetric measurements, pressure losses across the diaphragm, and piston alike, were noted. This differential pressure (loss) represents a measurement error which affects pressures between P_1 and P_2 as shown in Figure 2.

To determine the affects of extending the diaphragm, the reservoir was discharged at atmospheric pressure by energizing the diaphragm with pressure on the process side. This would compare to expanding a balloon where the inside pressure is greater than the atmospheric pressure on the outside. The pressure differential, in both cases, is a consequence of stretching the "diaphragm".

Results of the elastomer diaphragm expansion tests indicated that gage reading errors occur as a consequence of expansion losses. Figure 7 can be used to determine the pressure losses given the fluid volume expelled. Recognizing that the pressure loss is the differential between the process pressure and working fluid pressure, note that Figure 7 indicates the pressure in psig. This reflects the way in which the data was collected,i.e., process pressure (gage) was recorded when expelling the fluid at atmospheric pressure. When using the figure, treat the psig value the same as a differential pressure, psi, and the number calculated will not be in error.

Pressure losses due to expanding the diaphragm are not included in any indicated gage pressure measurements, but require that they be added as a correction factor. In other words, the pressure upstream of the diaphragm is equal to the pressure downstream plus the pressure loss incurred from expanding the diaphragm. Note from Figure 7 that 90 to 95 psi is the maximum error that can be incurred due to diaphram expansion. This situation results when the diaphragm is fully extended and additional expansion is not possible. Upon expulsion of the total working fluid from the gage protector reservoir, the upper pressure response limit of the system is reached.

c. Pressure loss - piston

Frictional losses for piston type gage protectors were evaluated and found to be of negligible consequence. For all three piston units studied, approximately 5 to 10 psi pressure increases were required on the upstream side of the piston before piston movement occurred, with a resulting pressure change being felt downstream. This pressure differential was confirmed at various pressure levels. Once the piston movement occurred and returned to a rest state, approximately 3 to 5 psi remained as a pressure differential or a frictional pressure loss across the piston.

d. Effects of system precharge

Standard practice in the field is to precharge the gage side of the pressure measurement system by pumping instrument oil into the gage protector such that a positive pressure is established relative to atmospheric pressure. This operation in the field is, in part, completed blindly by the operator in an attempt to offset what are considered potential problems. Having experienced a gage go blind, i.e., not responding to pressure, operators precharge the system to increase the working fluid available to transmit pressure. This precharge pressure shows up as an indicated pressure on the gage, as represented by P_1 in Figure 2, even though no process pressure is present. As a result, the precharge pressure creates a lower pressure limit such that no process pressures lower than the precharge value can be detected. In some cases, this threshold can be as high as 150 to 200 psig.

Some of the attributes of precharging the system is that it removes the initial hose expansion, prevents air from entering at fittings by maintaining a positive pressure inside the system, and, in diaphragm units only, increases the reservoir volume in the gage protector by collapsing the diaphragm. The increase in reservoir fluid volume associated with precharge pressure for the diaphragm-type gage protector is shown in Figure 8. The volume obtained from Figure 8 should be added to the gage protector reservoir volume given in Table 1, as it represents additional working fluid available for pressure transmission. As a result of this additional fluid, the maximum pressure response limit for the system is increased.

Precharge of a piston-type unit provides all the attributes associated with a precharged diaphragm-type unit, except there is no increase in its working fluid volume.

Trapped Air

Air in the system does not create reading errors but reduces significantly the maximum pressure response limit. Air can be, and often is, trapped in the system. Improper purging of the gage protector and hose is a common cause for trapped air in the system. Also, leaking and "breathing" of fittings is prevalent when quick disconnect fittings are used, a practice not recommended for use in the field.

The effect of trapped air can easily be predicted using the Real Gas Law. Volume changes in the trapped air can be calculated by

$$V_2 = V_1[(P_1T_2Z_2) / (P_2T_1Z_1)] \quad . . . (1)$$

where V_1 and V_2 represent the initial and final air volumes, T_1 and T_2 the initial and final temperatures in degrees Celsius, P_1 and P_2 the initial and final pressures in absolute units, and Z_1 and Z_2 the initial and final air compressibility factors. As so little air is usually involved, the air compressibility factors may be taken as equal, with little error. The working fluid demand imposed by the system to compress the trapped air is given by the difference, $(V_2 - V_1)$.

At high pressures, the additional volume of working fluid required to compress the air is essentially equivalent to the volume of air trapped at atmospheric pressure. This working fluid demand should be added to the other working fluid demands of the system before determining the diaphragm expansion correction factor or upper pressure response limit.

Temperature

Temperature effects on the instrument oil and on the complete system as a whole were studied. Temperature control of the gage protector, hose and Bourdon gage system was accomplished by immersing them in a water bath. While the pressure source was maintained at 21 °C, the system's temperature was varied from 4 to 50 °C. No significant pressure measurement errors were observed due to system exposure to these reasonable temperature excursions, even when pressuring the system to its full scale limit of 10,000 psig. However, the metered fluid volume required to obtain a common pressure response was not constant during these temperature excursions.

Subsequent thermal expansion tests on the instrument oil alone showed its isobaric thermal expansion coefficient, β_o, was a weak function of temperature, namely

$$\beta_o = [1 / (1225 + T)] \quad . . . . . (2)$$

where T is the temperature in degrees Celsius. To predict oil volume changes as a function of temperature change, the temperature dependent expansion coefficient must be integrated over the temperature range of interest. For this particular oil, its volume change may be calculated using the following equation:

$$V_2 = V_1[(T_2+1225)/(T_1+1225)] \quad . . . . . (3)$$

where V_1 and T_1 represent original conditions and V_2 and T_2 the final conditions.

Even though expansion or shrinkage of the oil may occur due to temperature changes, no gage errors are incurred in a soft system, i.e., a system whose gage protector diaphragm (or piston) is free to move and/or one that includes a hydraulic hose. However, expansion or shrinkage of working fluid may affect the minimum and maximum pressure response limits of the system.

EXAMPLE -- SYSTEM EVALUATION PROCEDURE

The following example will illustrate the procedures used to determine a gage reading correction factor and the maximum pressure response limit of a specific system configuration. Consider a properly charged 10,000 psig rated system consisting of a diaphragm gage protector with a 75 mL reservoir, 50 feet of 0.25-in. hose, and a Bourdon gage.

Initial Conditions -	
Temperature	35 °C
Indicated Pressure	0 psig
Trapped Air	15 mL
Hose Volume	483 mL
Total Oil Volume	543 mL

Final Conditions -	
Temperature	27 °C
Indicated Pressure	2,000 psig

The solution requires that the fluid demand of both the hose and gage be determined. Since there was a temperature reduction, a shrinkage of the instrument oil is expected, which can be treated as an additional demand for working fluid from the gage protector reservoir. Compression of the trapped air is yet another demand for working fluid. Summation of the working fluid demands represent the volume needed to be expelled from the gage protector reservoir. Figure 7 is then used to determine the pressure loss incurred in expanding the diaphragm when expelling the needed fluid. This value will be the gage correction factor.

Solution: Gage Correction Factor

	Fluid Demand	Reference
Hose	26.7 mL	Figure 4
Gage	0.4	Figure 5
Fluid Shrinkage	3.5	Eq. (3)
Compressed Air	14.9	Eq. (1)
Total	45.5 mL	
Gage Correction:	35 psi	Figure 7
Process Pressure:	2,035 psig	

Here, the 35 psi would not be too significant.

To determine the maximum pressure response, first, consider that the fluid shrinkage and compressed air volumes, as calculated earlier, will have to be replaced by a portion of the original reservoir working fluid. Next, assume the remaining working fluid to be expelled into the hose. Calculate a value in terms of mL/ft of hose for the fluid volume expelled. Figure 4 can then be used to determine the resulting pressure inside the hose, which would be the maximum pressure response limit of the system.

Solution: System Maximum Pressure Response Limit

Initial Reservoir Fluid	75.0 mL
Shrinkage Loss	- 3.5
Air Compression Loss	-14.9
Remaining Working Fluid	56.6 mL
Fluid Expelled into Hose	1.1 mL/ft
Resulting Hose Pressure (Fig. 4)	7,800 psig

Notice, this system appears capable of indicating pressures as high as 10,000 psig. However, process excursions greater than 7,800 psig will not be indicated by this system.

Extending the example, suppose an additional 50 feet of hose had been in the system. Using the same logic as before, a maximum pressure response limit of approximately 2,000 psig would be the result. This restriction would be a very significant system limitation and would pose a real threat to the safety of personnel and equipment alike.

VALIDATION OF FINDINGS AND RESULTS

The previous sections describe the various parameters that affect the accuracy of remote pressure measurements. Validation of the findings and results of this study consisted of comparison of predicted process pressures with the pressures applied by the mercury pump. Tests were designed to predict process pressures based on working fluid changes within the system. The procedure was as follows: 1) apply pressure to the process side of the gage protector, 2) measure the amount of fluid expelled from the gage protector by means of the metering pump supplying the pressure, 3) convert the displaced fluid to mL/ft by dividing by the length of the hose, 4) use the mL/ft value and Figure 4 to determine the predicted internal pressure of the hose, 5) determine the gage correction factor from Figure 7, 6) predict the process pressure by adding the hose pressure prediction to the gage correction factor, and 7) compare this predicted process pressure to the actual process pressure applied.

Five tests were conducted with different combinations of process pressure, precharge pressure and hose length. The system was purged of air prior to each test and the temperature held constant during all tests. For simplicity, the working fluid demand to activate the gage was considered negligible. The results of the five tests are given in Table 2. Note that the percent error for the predicted process pressure values as compared to the actual process pressure was minimal for the first four tests, with and without system precharge. Of special importance was the result of the fifth test. The lower limit of the upper dead band was predicted to be extremely low, due to the excessive hose length. When tested, 5,000 psig was applied to the process pressure side of the gage protector, but that pressure was not observed on the system gage. Instead, the observed pressure was essentially the predicted upper pressure response limit.

CONCLUSIONS

1. Given a "properly charged" system, errors inherent in remote measurements of drill pipe, kill line, and casing pressures are not significant.

2. Significant errors can occur in a remote, pressure measurement system given:

   a) an excessive precharge pressure, resulting in an elevated minimum response pressure, and/or

   b) insufficient working fluid volume, resulting in a reduced maximum pressure response limit.

3. Hose length, trapped air and instrument oil leakage significantly reduce the working fluid available for pressure transmission.

ACKNOWLEDGEMENT

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TABLE 1 - GAGE PROTECTOR WORKING FLUID VOLUMES

Vendor	Diaphragm Type	Piston Type
A	75.0 mL	63.8 mL
B	70.0	115.0
C	--	276.0

TABLE 2 - COMPARISON OF PREDICTED PROCESS PRESSURES WITH APPLIED PROCESS PRESSURES

System Precharge (psig)	Hose Length (ft)	Process Pressures Applied (psig)	Process Pressures Predicted (psig)	Prediction Error (%)
0	50	3,000	3,050	1.7
0	50	8,000	8,050	0.6
50	50	5,500	5,500	---
50	50	7,000	6,900	1.5
0	100	5,000	3,750	N/A

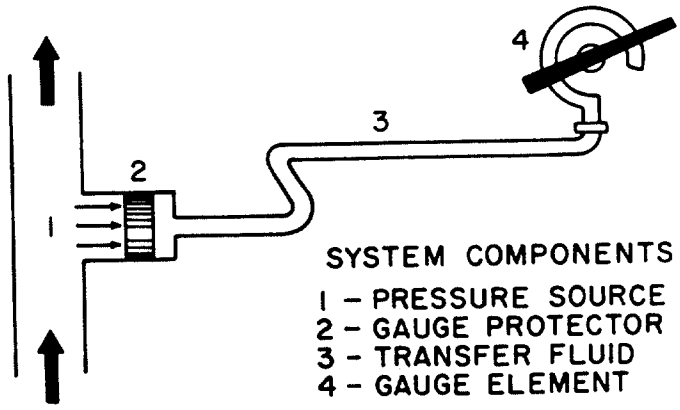

Fig. 1—Basic components of a remote sensing, pressure measurement system.

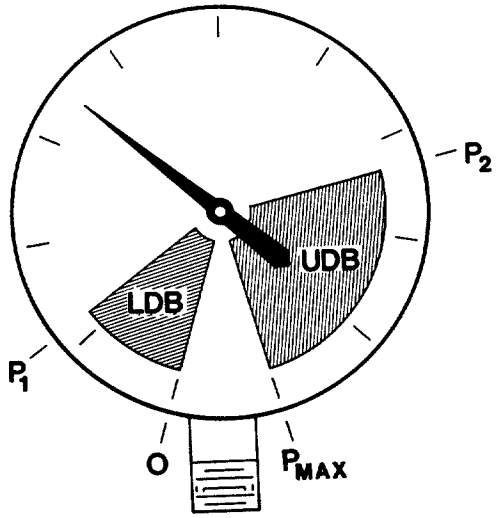

Fig. 2—Useable range of guage indications (P_1 to P_2) resulting from dead band regions (LDB, UDB) imposed by system constraints.

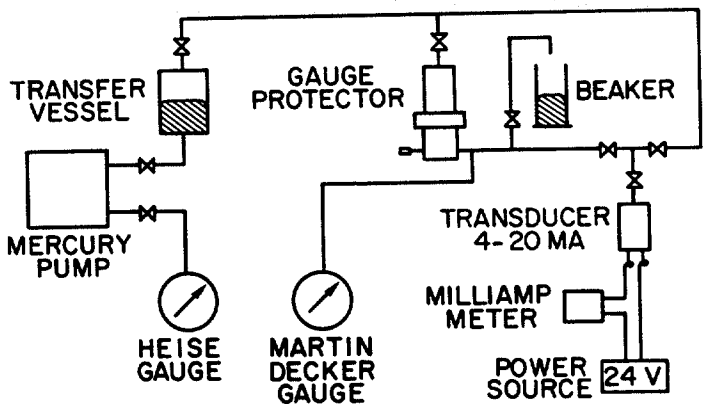

Fig. 3—System schematic of the pressure measurement model.

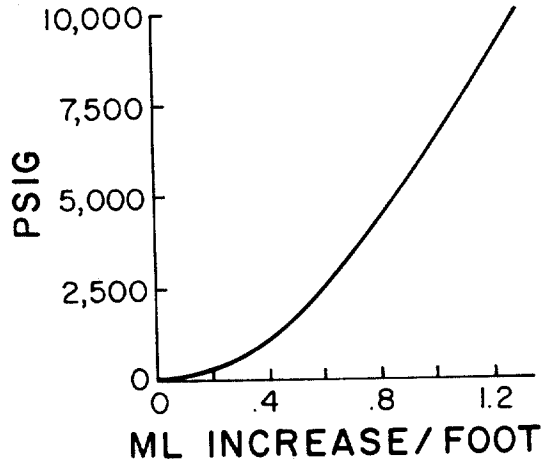

Fig. 4—Oil volume demands of a typical hydraulic hose link as a function of internal pressure.

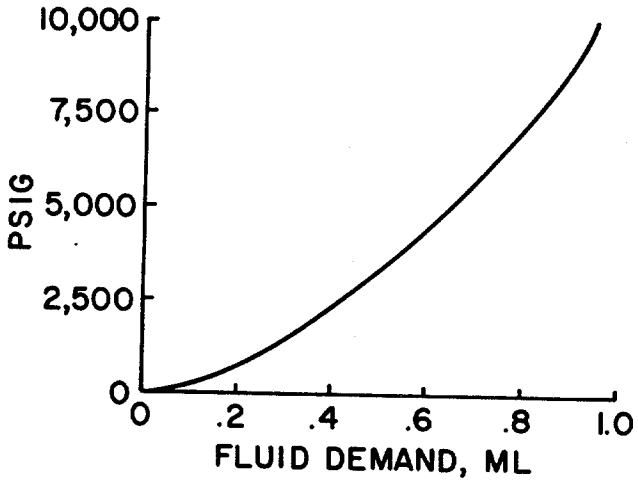

Fig. 5—Oil volume required to activate a 0 to 10,000 psig, single coil, Bourdon tube gauge.

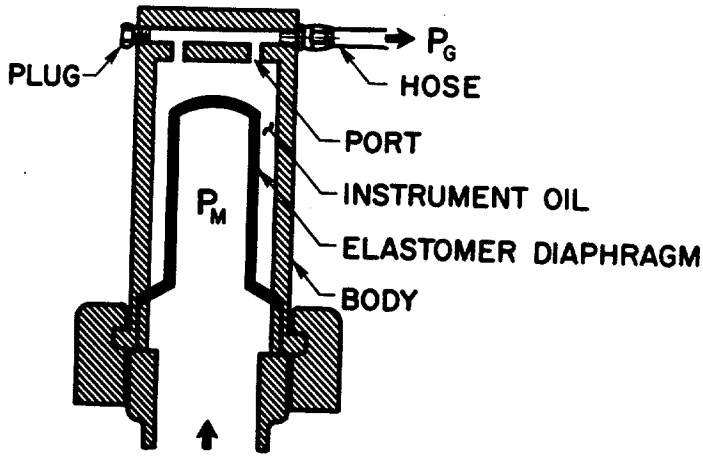

Fig. 6—Sectional view of a typical discharge-type gauge protector.

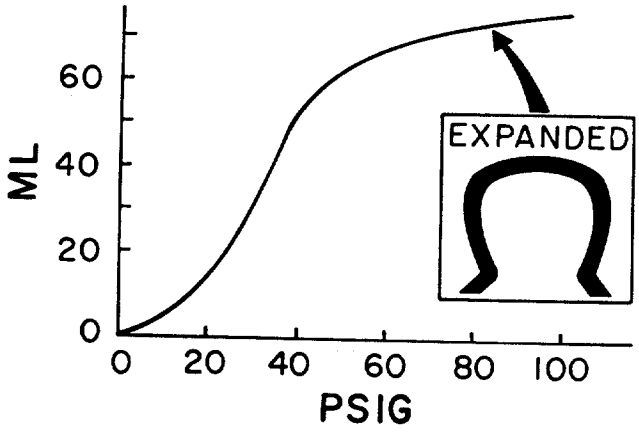

Fig. 7—Pressure required to expand the gauge protector diaphragm vs. fluid volume expelled from the gauge protector reservoir.

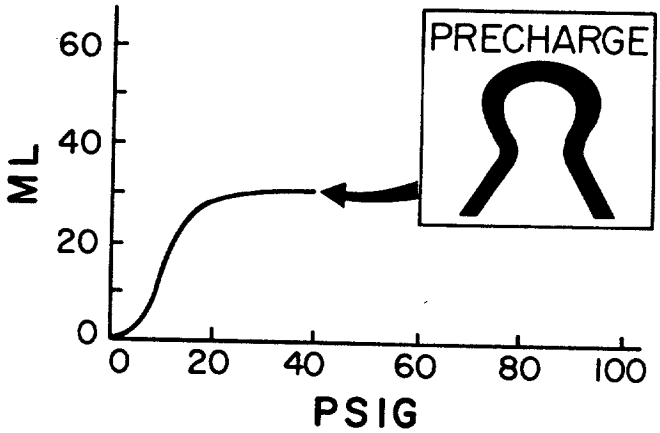

Fig. 8—Precharge pressure required to collapse the gauge protector diaphragm vs. fluid volume increase in the gauge protector reservoir.

WORKSHOP 2: CHANGES IN REGULATIONS

federal register

Tuesday
August 1, 1989

Part II

Department of the Interior

Minerals Management Service

30 CFR Part 250

Oil, Gas, and Sulphur Operations in the Outer Continental Shelf; Well-Completion and Workover Operations; Minimum Training Requirements; Proposed Rulemaking

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 250

RIN 1010-AB21

Oil, Gas, and Sulphur Operations in the Outer Continental Shelf: Well-Completion and Workover Operations; Minimum Training Requirements

AGENCY: Minerals Management Service, Interior.

ACTION: Notice of proposed rulemaking.

SUMMARY: This proposed rule revises the final rule which was published on April 1, 1988. That rule consolidated into one document rules governing oil and gas and sulphur operations in the Outer Continental Shelf (OCS). When MMS developed the final rule published on April 1, 1988, the training requirements under consideration were so different from the requirements which had been were published as a proposed rulemaking on March 18, 1986, that they could not be published as a final rule. Accordingly, MMS published the April 1, 1988 document without substantially revising requirements governing training of personnel engaged in oil and gas and sulphur operations in the OCS. It is now proposing this rule which would revise the minimum training requirements for personnel engaged in drilling and production operations on the OCS and establish new minimum training requirements for personnel engaged in well-completion and workover operations on the OCS.

DATES: Comments must be received or postmarked no later than October 2, 1989.

ADDRESSES: Written comments must be mailed or hand delivered to the Department of the Interior; Minerals Management Service; 381 Elden Street; Mail Stop 646; Herndon, Virginia 22070; Attention: Gerald D. Rhodes.

FOR FURTHER INFORMATION CONTACT: Gerald D. Rhodes, telephone (703) 648-7816 or (FTS) 959-7816.

SUPPLEMENTARY INFORMATION: On March 18, 1986, Minerals Management Service (MMS) published a proposed rule in the Federal Register (51 FR 9316) to consolidate rules governing oil, gas, and sulphur operations in the OCS into a single document. The preamble to that proposed rule included a series of questions concerning training requirements for lessee and contractor personnel. The proposed rule included training requirements in the subparts that dealt specifically with drilling, well-workover, well-completion, and production operations. The comments received in response to the proposed rule included responses to the published questions as well as comments concerning specific training requirements. On April 1, 1988, MMS published a final rule in the **Federal Register** (53 FR 10596) based on the March 18, 1986, proposed rule. The final rule issued on April 1, 1988, included a Subpart O; it addressed training. That Subpart O, which is now in effect, contained many of the provisions previously in effect with only limited revisions. More extensive changes to the training requirements were under consideration; however, MMS believes that the more extensive changes should be published in this proposed rule for comment prior to development of a final rule. Accordingly, MMS is now issuing this notice of proposed rulemaking which addresses the comments received in response to the questions asked in the preamble to the March 18, 1986, notice of proposed rulemaking and proposes revised, restructured, and updated training requirements which are consolidated into a proposed new Subpart O, Training.

The following discussions pertain to the general questions on training requirements and programs.

Question 1—How can MMS best assure that personnel engaged in oil and gas operations in the OCS are adequately trained?

Comment—Several commenters suggested that MMS simply require that employers furnish personnel to work in the OCS who are qualified through training and experience to perform their assigned job. Job performance would be verified through performance records such as safety, testing, drills, training, and accident investigation. Another commenter urged that MMS well-control training requirements be modified to reference existing industry recommended practices for training.

Response—The suggestion that MMS verify training through examination of performance records such as safety and accident records was not adopted in the proposed rule. The discovery of deficiencies in training after a pollution incident or accident that injures or kills would not meet the objective of the OCS Lands Act. The MMS training program has been structured to assure that personnel working in the OCS receive the minimum level of training necessary to avoid or prevent, to the degree practicable, pollution incidents and accidents. Appropriate portions of the recommended practices that have been developed by the offshore oil and gas industry have been incorporated into the proposed regulations. Experience with offshore operations has demonstrated that well-control training can be most effectively regulated under a structured program with a standardized curriculum.

Comment—Several commenters agreed that the present training system was adequate, although improvements in clarity of the regulations, as well as the administration of the well-control training program, would be welcomed. One of these commenters further added that MMS should avoid any movement toward centralizing the administration of testing and should not become involved in any new areas of training. One commenter urged more strict surveillance of blowout preventer (BOP) schools and textbooks and the utilization of undercover Government inspectors to attend certified schools. Another commenter made specific suggestions including: The MMS should make sure schools last long enough for students to get past the confusion stage and into the learning stage; consider the possibility of standardized tests; and ensure that instructors are qualified and personnel records are kept current.

Response—Changes in the present regulations are being proposed to clarify requirements and simplify administration of the well-control training program. There are no plans at this time to centralize the administration of testing or to develop standardized tests. Testing procedures and sample questions will continue to be considered during the review of a school's request for certification. Field audits of schools provide further assurance that testing methods are implemented in accordance with the approved plan. Instructor qualifications will continue to be reviewed during the school certification process. Changes in instructors will continue to require MMS approval of the new instructors' qualifications. Oversight of testing procedures and competition among training organizations provide some assurance that the required material is properly taught. The proposed rule would expand current training requirements to include well-control training for lessee/contractor personnel working on well completions and workovers, as well as those personnel who work with production safety systems.

Question 2—To what extent, if any, should the training be provided by the Federal Government, OCS lessees, State educational and training institutions, or private training schools?

Comment—Commenters on this question agreed that the Federal Government should not play a major role as a provider of training. One commenter did suggest that the

Government play a small part in training by teaching regulations and developing standardized tests for training institutions to use. Most commenters felt that training should be provided by OCS lessees and other major OCS employers with State and private training institutions being utilized as necessary to meet the needs of OCS employees.

Response—There are no plans for the Federal Government to become a provider of well-control training. Experience in this area indicates that training is best provided by OCS lessees in conjunction with State and private educational and training institutions. As previously noted, there are no plans to develop standardized tests for use by training institutions. There were several reasons why MMS did not adopt the recommendations that the Government develop standardized tests. The MMS does not believe that development of testing materials and procedures would be an effective alternative to certification of schools. There are certain areas of operations for which training produces results which are difficult to evaluate. In such cases, MMS must rely on the fact that if the trainee attends a course that properly instructs the trainee in those areas, then the trainee will learn from the training. For this reason, MMS has chosen to concentrate on regulating the quality of the training and regulating but not controlling the testing of the trainee. The majority of the commenters agreed with this approach. In addition, the experience to date with MMSS–OCS–T 1, Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations, has shown ths current program to be effective for drilling well-control training. For these reasons, MMS is proposing rules which will attempt to streamline and improve the current process rather than abandoning a successful program in favor of a completely new approach. The MMS believes that the process proposed will be sufficient to assure the quality of training for OCS personnel, and that additional Government involvement in the testing of trainees is unnecessary.

Comment—A commenter suggested that MMS personnel who are involved in the evaluation of training schools receive specialized training to assure that they have the qualifications needed to certify the training schools. This commenter also suggested that the number of school inspections be increased and that State universities be utilized to certify, train, and test instructors. The commenter further stated that operators should be required to hold meetings to help rig crews become aware of any problems which might be encountered while working on a given well.

Response—The comments regarding the training and qualifications of MMS personnel are well taken; however, the scope of the question and the proposed rule are specifically directed to the training of offshore lessee and contractor personnel. All MMS personnel who evaluate schools for certification, or are utilized in field audits, are thoroughly familiar with requirements which must be met. As noted in the response to Question 1, the qualifications of a school's instructors are reviewed with the initial submittal and whenever there is a change in instructors.

Question 3—How should MMS assure itself that the training provided is adequate?

Comment—Several commenters advocated changes or more emphasis on certain aspects of the present system. These included suggestions that tests be standardized, that MMS train its inspectors and then more fully investigate schools, and periodic Government testing of students.

Response—As noted in the response to Question 1, there are no plans to produce standardized tests or for the Federal Government to test trainees at the completion of each course. Testing procedures and sample questions are reviewed during the evaluation and approval of a school's well-control training program. The MMS personnel are trained in both well-control and audit procedures. The frequency and thoroughness of MMS field audits of training activities are determined by scheduling available MMS resources to achieve the best means of assuring the quality of the training.

Comment—Several commenters felt that MMS could verify training by requiring that employers furnish personnel to work in the OCS who are qualified to perform the assigned job. These commenters further stated that the evaluation of the adequacy of training could best be accomplished by a review and evaluation of industry safety statistics and on-the-job performance. The indicators to be evaluated include performance records, testing drills, training, and accident investigations.

Response—These commenters made a similar comment with respect to Question 1. There are insufficient statistical indicators available to permit implementation of this suggestion. Safety records and accident reports provided the evidence of deficiencies in training which resulted in the establishment of the MMSS–OCS–T 1. It is expected that safety records and the contents of accident reports will continue to be considered when changes in MMS's established training requirements are under review.

Question 4—Should performance standards for job categories be established by MMS, industry, or others?

Comment—Several commenters felt that the development of performance standards for job categories should be left to industry. Many of these same commenters also felt that performance standards varied so much from employee to employee and from company to company that they could not be standardized industrywide. One commenter felt MMS should set performance standards to ensure that everyone followed the same rules because they felt that industry would be unable to agree on uniform guidelines. Another commenter felt that the current requirement of testing well-control students to different levels of expertise amounted to performance standards.

Response—It is recognized that the *manner* in which performance standards and job classifications are established *varies* widely from lessee to lessee. There is no intent to alter that situation.

However, those variations do not preclude the establishment of needed minimum-training requirements, specified by broad job category, as has been done in MMSS–OCS–T 1.

Question 5—Should MMS prescribe training criteria?

Comment—Several commenters thought that MMS should establish training criteria; however, a larger number of commenters were opposed to MMS prescribing criteria for training of lessee/contractor personnel. Several of those who opposed MMS prescribing training criteria felt that industry should be allowed to set the criteria through guideline standards such as American Petroleum Institute (API) Recommended Practice (RP) T–3, Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations. Another commenter who opposed MMS prescribing training criteria felt that MMS should prescribe results for performance of trained personnel.

Response—The importance of industry established training criteria such as those found in API RP T–3 is readily recognized. In its efforts to balance the use of industry standards and regulatory requirements, MMS has utilized industry guideline standards, where appropriate, in developing

regulatory requirements (i.e., for critical areas such as drilling well control).

Question 6—To what extent, if any, should on-the-job training be a part of MMS's training requirements?

Comment—Most commenters supported the concept of on-the-job training. However, many of those same commenters who favored on-the-job training were opposed to MMS establishing the training requirements. They felt that the extent of training provided should be left to the operators. These same commenters felt that the entire mix of training delivery modes should be left to lessees and operators. One commenter felt that on-the-job training should comprise about 80 percent of the training program. Another commenter suggested that a performance-based test be developed to qualify persons who are excellent field hands but are poor performers on written examinations.

Response—It is recognized that on-the-job training is an important method of instruction which plays a large part in any training, especially the training for many of the jobs offshore. On-the-job training in the form of hands-on drills is an integral part of the training requirements contained in governing regulations. Specific details of requirements for the training of individual employees on the job will continue to be the responsibility of individual employers. Lessees are required to utilize personnel who are trained and competent, and an operator-initiated program of on-the-job training can be a major part of the program. The commenter who suggested a performance-based test for those who are poor performers on written examinations should note that the requirements of proposed Subpart O provide for schools to state the methods to be used to instruct and test individuals who are believed to be qualified but nonresponsive to conventional education and testing techniques.

Question 7—Should MMS training requirements call for periodic retraining or refresher training?

Comment—The general consensus among commenters was that refresher training was good. Some commenters qualified their support with the following comments: (1) MMS should require refresher training for personnel who do a task periodically; (2) two refresher courses per year are needed; one is not adequate; (3) the annual well-control refresher course would be more effective if given every 2 years with a longer minimum class time; (4) refresher courses are desirable for well-control training but not safety-device training; and (5) in the area of drilling well control, refresher training should allow for upgrading of an employee's certification level in lieu of employers being required to attend a basic course. No comments were received which opposed the concept of required periodic refresher training.

Response—Refresher training is needed and should be required for personnel involved in drilling, completion, workover, and production operations. The proposed rule would continue the current requirement for a minimum of 8 hours of refresher training each year for drilling well-control courses. A minimum of 8 hours refresher training is the timeframe required to permit an adequate review of this basic material together with updates on new equipment and Government regulations. A minimum of 8 hours is also established for well-completion and workover, well-servicing, and production refresher courses. In the case of production safety systems, the refresher training will be required after 2 years rather than after 1 year. This is believed to be appropriate since the activities are more routine than well-control activities. Well-control activities are only conducted in drills or when unexpected circumstances arise. Operation, maintenance, and repair of production safety equipment are normal operations which a worker would perform frequently between courses.

Refresher training, as envisioned by the current and proposed rule, is not the proper vehicle for upgrading an employee's certification level.

Question 8—What is the appropriate training role for lessees, for oil and gas industry trade associations, and for others?

Comment—This question generated numerous responses; a few were in the form of suggestions regarding existing regulatory requirements. Commenters pointed out that lessees are responsible for training their employees through designing and conducting training classes to meet MMS requirements as well as hiring contractors whose employees are trained and qualified. The commenters recommended that the role of trade associations should be the writing of standards for an acceptable minimum level of training. The role of all others was depicted as providing training support in response to a free-market system.

Response—The roles played by both lessees and industry trade associations in training of employees for work in the OCS are basically those described above. It is expected that lessees, trade associations, and other interested parties will continue to have important roles and responsibilities for improving the training level of offshore employees and reducing accident and pollution rates in the OCS.

Question 9—Have the current MMS training requirements provided satisfactory results?

Comment—Responses to this question were generally positive; however, several commenters felt that the program could be improved. One commenter felt that the current program provides minimum satisfactory results, and any relaxation in requirements would be detrimental. Another felt that the basic requirements were adequate but that clarification of rules and better program administration would lead to improved training. Others felt that the program has been inefficient in the area of drilling well control and that more flexibility is needed in "curriculum adaptability to individual requirements" since the lessee or operator "is in the best position to determine the degree of training required."

Response—These comments have been considered as part of the evaluation of the training programs required under MMS regulations and the continuing effort to improve those programs. The proposed rule suggests a number of changes in current training programs in an effort to improve the effectiveness and flexibility of those programs. An objective of the proposed rule is improved efficiency of MMS training programs while striving to attain the overall goal of properly trained and qualified OCS workers.

Question 10—Should MMS adopt a training program different from its current program? If so, what should it be, how would it be an improvement over the current program, and what are the cost implications of any recommended changes?

Comment—One group of commenters suggested substantial modifications to the current program. These changes included: (1) the addition of hydrogen sulfide (H_2S) and workover certification to the current well-control curriculum, (2) the addition of antipollution safety-device training at certified well-control schools, (3) change the required attendance at basic BOP school to every 2 years with two refreshers in the intervening year, and (4) develop a training and certification course for instructors. Other commenters either felt that the status quo was acceptable or that MMS's well-control training program requirements should be reduced. Specifically, it was suggested that MMS model its well-control training program after its antipollution safety-device training program. It was further

suggested that senior personnel be exempted from attendance at the basic course if they satisfy an oral or written examination.

Response—The H_2S safety-training program is required at the rig site when operations are conducted in areas where there are zones known to contain H_2S or zones where its presence is possible. Much of the training needed to respond to a release of H_2S is site specific. Thus, it is better handled on the drilling rig. There are no plans to increase the frequency of required, successful completion of basic well-control training from at least once every 4 years to once every 2 years or to develop a training course for instructors. Instructor qualifications are reviewed as part of the review of a school's request for certification. The proposed rule would expand existing training requirements to require minimum levels of training in well control for lessee and contract personnel whose work relate to well-completion and workover operations. Additional oversight of safety-device training programs would also be initiated with this rulemaking. While currently certified well-control schools may offer any of the aforementioned types of training, they must obtain separate certification for each program. Compliance with the well-control training requirements developed in MMSS–OCS–T 1 is important to the continued safety of operations in the OCS. The proposed rule would require similar training for lessee and contractor employees working in well-completion, well-workover, and production operations.

Question 11—What are practical alternatives to the present MMS program for school certification, periodic recertification, and onsite evaluations that would maintain the standards of training?

Comment—Commenters suggested several alternatives. One suggested that MMS conduct both simulator and written testing. Another felt that MMS evaluators stress the results of a school's instructional program rather than precise details and paperwork. Another commenter requested that schools not be required to resubmit evidence of their entire program when applying for recertification but only be required to submit any changes in the program. A group of commenters felt that employers should be responsible for furnishing trained and qualified personnel, and MMS should gauge their performance against an industry standard by auditing documentation of training and observing field demonstrations of proficiency (such as emergency drills).

Response—There are no plans for MMS to initiate either simulator or written tests. The present program of school certification and audits to determine compliance with the approved plan will be continued. The proposed rule continues to require schools applying for recertification to submit only proposed changes from the currently approved program. There are no plans to adopt the suggestion that MMS gauge employee performance against an industry standard by auditing documentation of training and observing field demonstrations of proficiency.

Question 12—Might such alternatives include an approach in which MMS would require access to appropriate records at the field site, make periodic onsite evaluations of training facilities to determine compliance, and take such corrective actions as warranted?

Comment—Most respondents felt that periodic onsite evaluations and record checks were already being done and that such audits were an excellent means of ensuring the quality of training. Several commenters felt that MMS's primary evaluation of training quality should be based upon individual company statistics regarding accidents, spills, blowouts, etc. Another commenter felt that schools should be monetarily penalized for not adhering to the regulations, and the penalties should be listed in advance.

Response—There are no plans to verify training quality on a company-by-company basis. The examination of accident and other statistics relating to that company's operations in training would only become apparent as a result of a pollution incident or an accident. (See response to Question 1.) The MMS has found it to be more effective to work with the certified training facilities to correct areas of noncompliance, while striving to achieve the overall objective of highly-trained personnel working in the OCS.

The following discussions pertain to the questions on the current MMSS–OCS–T 1.

Question 1—How can the present program be improved, administrative procedures simplified, and costs reduced?

Comment—Three commenters felt that the well-control training program should be converted to the same type of program established for safety devices in OCS Order No. 5. They felt that this change would significantly reduce costs for both Government and industry. Other commenters provided detailed suggestions for reducing paperwork. Among these were suggestions to eliminate preenrollment forms which are never seen by MMS except during audits; to allow schools to change forms without MMS approval; to clearly define the acceptable minimum lengths of courses; to have only three classifications (Rotary Helper/Derrickman, Driller, and Drilling Supervisor); to devise a standard wallet card that would be considered adequate documentation in lieu of photocopies of certificates; and to allow a roster of crew training to suffice as rig-site documentation of training rather than have the contractor maintain a file drawer of certificate copies. Other commenters offered suggestions such as placing a limit on the number of schools per State (to reduce paperwork) and having MMS conduct a statistical review of the program to define problem areas.

Response—The many helpful comments received on this question are appreciated. As was discussed under Question 1 of the general questions on training, the importance of well-control training as well as the infrequent application of many well-control actions justify a structured program for well control. The present program is structured so that the public is assured that critical personnel in the OCS have received a minimum level of training that will aid in avoiding the loss of well control. Under this proposed rule, the number of job classifications for training purposes is reduced from five to two (floorhand and drilling supervisor). This reduction in job classifications for certification purposes should significantly reduce time and paperwork as well as making preenrollment documentation less burdensome. Under this rule, appropriate documentation would be furnished to the trainee upon successful completion of a course. Only six items of information are required on the certificate (trainee's name, trainee's social security number or identification number issued by MMS, name of training organization, course name and location, date of successful completion, and trainee's job classification). This record is then required to be maintained at the site of employment. Schools will continue to be evaluated on an individual basis during the certification process. Minimum acceptable lengths of time for courses have been identified. The suggestion to limit the number of schools per State was not adopted. Training programs will continue to be approved if they meet the prescribed qualification standards. The number of approved training courses will be determined by the number of training

organizations that obtain certification of qualified training programs.

Question 2—Is the curriculum too broad or too detailed?

Comment—Three commenters simply replied "too detailed," with one noting that broader classifications would be effective and permit site-specific details. Several respondents stated that the curriculum was not flexible enough. More flexibility would allow instructors greater freedom to cover specific facets of well control with differing emphasis based on the candidates present classification, experience level, and work situation. Another commented that the curriculum should be expanded to include instructor—level certification. A final commenter suggested specifically excluding service company representatives from the training requirements of T 1. The commenter maintained that both MMS inspectors and lessees occasionally interpret the regulations to require T 1 training of service company employees.

Response—The proposed rule considers broader job classifications and thus limits the number of training courses to be certified. Nothing in the current or proposed rule reduces the flexibility available to instructors so long as the core curriculum for well control is properly covered. Training organizations are free to use their preferred teaching methods and add to the core curriculum. The credentials of instructors are reviewed during the review for certification of a training program and when a change of instructors is proposed. The proposed regulations are specific in naming those job classifications that require employees who have well-control training. Lessees are free to establish additional requirements for the schools that train their employees.

Question 3—Are there too many or too few job classifications?

Comment—Several commenters felt that there were too few job classifications. One of these felt that additional job classifications should be added for such disciplines as Mud Engineer, Subsea Engineer, Directional Engineer, and Service Company Employees. Another commenter felt that Operator's Representative should be further subdivided to include separate designations for those with no prior field experience, limited field experience, and engineering experience only. Another felt that service company personnel should be a separate category. Two commenters felt that there were too many job classifications and felt that only two levels were needed: (1) Drilling Technician (Rotary Helper/Derrickman), and (2) Drilling Supervisor (Driller, Toolpusher, Operator's Representative). Two commenters felt that only three levels were needed: (1) Rotary Helper/Derrickman, (2) Driller, and (3) Drilling Supervisor.

Other commenters stated that there should be no additional classifications and offered no elaboration.

Response—The experience gained in certifying and monitoring training programs suggests that fewer job classifications could assure properly trained personnel in a more efficient manner. By combining job classifications, paperwork could be reduced for both training institutions and MMS without a reduction in the quality of training. The proposed rule has been modified to reflect this thinking. Two job classifications are identified in the proposed requirements, Floorhand and Drilling Supervisor. Training requirements for service company personnel will be based on the duties performed during drilling operations.

Question 4—Are there sufficient distinctions as to training requirements for each classification? What should the classifications be, and how should the training requirements differ for each classification?

Comment—Several commenters felt that there was both sufficient distinction between classifications and an appropriate number of classifications. They also felt there was no need to change the different training requirements. One commenter felt that the distinctions between Operator's Representative and Toolpusher should be combined into the category of Drilling Supervisor. Three job classifications would then be identified as Rotary Helper/Derrickman, Driller, and Drilling Supervisor. Another felt there should be only two training classifications, Derrickman and Operator's Representative. One commenter suggested that MMS stress the team approach in training requirements and not rigidly segment items that are taught to people who work side by side.

Response—As noted in the response to the previous question, modifications are being proposed in the present classification system with a view to decrease administrative burdens without a reduction in the quality of training. The proposed training requirements do not rigidly segment items that are taught to people who work side by side; rather, the requirements add important subjects to be covered in the training programs for workers with more authority and responsibility. Hands-on (simulator) training is normally taught as a team effort.

Question 5—Would refresher-course training less often than once a year suffice? Should refresher-course training be required more frequently than once a year for certain activities? Should refresher-course training be placed on a graduated scale so that the longer a person is active on the job, the farther apart the required training?

Comment—None of the respondents favored placing the requirements for refresher-course training on a graduated scale. Several commenters felt that a graduated scale would create an unnecessary burden in the administration of the program. On the question of frequency of refresher-course training, the following comments were received:

(1) Several commenters suggested retaining annual refresher courses.

(2) One felt that the frequency should be increased since it was rare to find a student who retained the ability to fill out a kill sheet from year to year.

(3) Three commenters felt that every 2 years was the appropriate interval for requiring completion of a refresher course.

(4) One commenter felt that persons who performed the tasks of their designated job classifications should attend refreshers every 3 years.

(5) One commenter felt that the refresher test should be administered without training to those who felt they could pass.

Response—The proposed rule continues the requirement of an annual refresher course. This requirement has worked well and has not proved unduly burdensome. Refresher training serves to maintain technical competence in well-control procedures and to demonstrate the importance of well control. The recommendation that workers who pass a test should be exempt from refresher training was not adopted.

Question 6—Should "hands-on" training be expanded?

Comment—Several respondents stated that the degree of "hands-on" training should be left to the discretion of the employer. Another stated that the regulations should be flexible enough to allow expansion without mandating it. (These commenters evidently thought the question referred to "on-the-job" training rather than the "hands-on" training on a simulator required by MMSS–OCS–T 1.) One commenter suggested that a minimum of eight simulator sessions be required during the basic course. This would include six gas kicks, one salt water kick, and one

gas kick in oil base mud. Another commenter felt that five simulator problems would be enough.

Response—The proposed rule calls for a minimum of two practice problems and one official test problem using "hands-on" well-simulation equipment. Schools may exceed this requirement. In order to increase the involvement of individual students in "hands-on" training, the maximum number of students working with a simulator at one time has been reduced from four to three.

Question 7—Should MMS oversight of certified training institutions be expanded or reduced?

Comment—Several commenters felt that MMS oversight should be reduced and that MMS should observe items such as drills, performance data, and incidents to determine if a lessee's training is adequate. Another respondent stated that certification of training institutions should be the responsibility of lessees. Two commenters felt that the level of oversight should remain the same, but that improvements should be made in the administration of the program. Another felt that the focus should move away from the administration and toward the practical aspects of training. One commenter felt that oversight of training institutions should be greatly expanded.

Response—Audits conducted by MMS have discovered inadequacies in the training given at a number of certified institutions. These shortcomings were corrected soon after their discovery. The present scheduling of MMS-conducted audits is determined by the available resources as well as the results of past audits. Experience suggests a simple records check is sufficient to assure compliance of some training organizations while a few institutions must undergo a total evaluation of their course material and its presentation.

The following discussion pertains to questions on the development of training programs for lessee and contractor personnel whose work involves well-completion and workover operations.

Question 1—How should MMS establish training standards for well-completion and well-workover operations, and what should these standards include?

Comment—Four commenters suggested that MMS adopt the recommended practice document developed by API for Well-Control Training for Well-Completion and Well-Workover Operations, while another suggested MMS use trade association materials. One commenter suggested that MMS hire professional training consultants to review present training programs and establish guidelines on the basis of that review. One commenter suggested that additional curriculum on well-completion and well-workover operations be added to the drilling schools. They stated that the training is similar enough that extending the drilling school to cover the additional curriculum would be enough to certify personnel in well-completion and well-workover training. One commenter recommended that MMS solicit standards and comments from industry groups and individual operators.

Response—The proposed rule includes training requirements for lessee and contractor personnel who work in well-completion and well-workover operations. The API RP for well-control training was reviewed, and certain elements of the RP have been included in these proposed training requirements. Under the proposed rule, different criteria are applied to training for personnel who work in well-completion and well-workover operations than the criteria applied to training for personnel who work in drilling operations. The required training proposed for personnel who work in well-completion and well-workover operations would be applicable to floorhands, well-completion and workover supervisors, and some well-servicing workers (including, as appropriate, contractor employees).

Question 2—What are appropriate job classifications for such standards?

Comment—Two commenters suggested that the job classifications should be identical to the training standards established for employees working in drilling operations. One commenter suggested additional classifications such as mud engineers, directional drilling engineers, workover or completion service hands, and production personnel involved in well-workover or completion operations. Four commenters suggested MMS use the job classifications identified in the API recommended practice document on Well-Control Training for Well-Completion and Well-Workover Operations. One commenter said that job classifications should depend upon the operation being conducted. Another commenter suggested two job classifications, tehnician and supervisor.

Response—Under the proposed rule, lessee and contractor employees conducting well-completion or well-workover operations after the time the production casing is set, cemented, and pressure tested must have had training specific to the operations to be conducted and the equipment to be used. The job classifications contained in the proposed rule include floorhands, well-completion and workover supervisors, and well-servicing workers. This approach is expected to assure that all personnel involved in well-completion and well-workover operations receive training appropriate to the work they perform.

Question 3—What should be the relationship between drilling, well-completion and well-workover standards, and training?

Comment—Two commenters recommended that the two standards be combined into one extended training program since they are so similar. Four commenters suggested that the completion of either a drilling or a well-completion and well-workover course should qualify personnel to work in all of these operations. One commenter stated that it would depend upon whether the same rig/crew is used for both operations. One commenter suggested that the training must be different because there are fundamental differences in common wellbore conditions.

Response—The proposed rule provides that personnel conducting well-completion and well-workover operations are to be trained under a training program that is separate from the training programs developed for offshore personnel who work in drilling operations. It is recognized that some drilling crews also perform well-completion operations. To avoid placing unnecessary training requirements on these personnel, well-completion topics have been added to the curriculum required for well-control training programs for personnel employed in drilling operations. These personnel would then be exempted from taking a separate well-control training course for well-completion operations.

Under the proposed rule, the well-completion and workover well-control training programs are to be established for floorhands, well-completion and workover supervisors, and supervisors of snubbing, coil-tubing, and small-tubing operations. Lessee and contractor personnel who perform both drilling and well-workover operations are to receive well-control training for drilling and for well-completion and workover operations. To minimize the number of courses which will be required for these workers, schools will be able to combine the courses for drilling operations and for well-completion and workover operations into a single course.

Question 4—Should refresher courses be required and, if so, how often?

Comment—Four commenters recommended that refresher course

requirements follow the recommendations found in the API recommended practice document on Well-Control Training for Well-Completion and Well-Workover Operations. One commenter suggested that statistics be gathered and used to determine the appropriate frequency for refresher courses. Another suggested that the frequency of refresher training be based upon tests administered by MMS or a certified school. One commenter suggested that the basic course be taken every other year, with two refresher courses to be taken during the intervening year. One commenter suggested that a basic course be required every 4 years, with a refresher course every other year.

Response—The proposed rule requires that basic training courses be successfully completed every 4 years and that refresher courses be successfully completed annually for well-completion and workover training. The frequency of training prescribed in the API recommended practice document is considered inadequate, while the suggestion that a basic course should be passed every other year with two refresher courses to be taken in the intervening year is considered unnecessarily burdensome. The idea of basing the frequency of course attendance upon test results was viewed unduly burdensome to administer and monitor.

Question 5—What should be the implementation schedule for such a training requirement?

Comment—One commenter suggested that 6 months would be appropriate if it is done as an extension of the drilling training standards. Another commenter recommended 1 year from approval of the requirements; five commenters thought that 2 years were more appropriate. One commenter suggested that statistics be compiled to determine an implementation date.

Response—The proposed rule includes a 24-month implementation period (i.e., within 24 months after the effective date of a final rule, lessee and contractor personnel whose work involves well-completion and well-workover operations must successfully complete a basic course). Two years should be sufficient time for training schools to be certified and for lessees to provide their employees with the opportunity to receive the required training.

The following discussion pertains to the questions on development of a training program for personnel engaged in production operations.

Question 1—To strengthen the standard, should job classifications be added and, if so, which ones?

Comment—Three commenters stated that a strengthened training standard for production personnel is not necessary. In addition, they stated that it is not possible to address all titles used by operators for their production operations and maintenance personnel. Furthermore, they stated that MMS should pursue, with the API, any needed clarification of skills required for well-servicing personnel as opposed to lessee-operator personnel. One commenter suggested adding the following job classifications: Production design engineer, production foreman, operator, industrial repair specialist, and production electrician. Another commenter stated that the existing provisions in OCS Order No. 5, paragraph 5.7, are very good. Commenters stated that they do not agree that uncertainty and inefficiencies exist because of the straightforward way the MMS requirement is detailed.

Response—Under the proposed rule, lessee and contractor personnel who work with production safety systems and who must receive the required training include the person on the platform with overall responsibility for production operations and personnel engaged in the installation, testing, maintenance, repair, or operation of surface or subsurface safety devices. The training standard is designed to cover one broad job classification. Under this approach, all lessee and contractor personnel who work with production safety systems would be required to successfully complete a minimum training program. This training program is separate from the ones developed for lessee and contractor personnel who conduct well-completion and workover operations, including those who operate wireline, snubbing, or coil-tubing units.

Question 2—What training should be specified for each job classification?

Comment—Three operators stated that a strengthened training standard for production personnel is not necessary. One commenter stated that general safety-device training should suffice for all job classifications. Another commenter suggested that production safety-device training should be required for all production related job classifications. That commenter suggested having an additional requirement for the hands-on verification of skill of personnel involved in safety equipment maintenance and repair operations of lease-specific equipment.

Response—Under the proposed rule, jobs for personnel who maintain and repair production safety equipment are combined under one classification. The training standard established for personnel in that job classification includes certain aspects of API RP T-2.

Topics that production safety system personnel should be familiar with, such as wireline, snubbing, and coil-tubing operations and their relationship to production operations, have also been included in the required subject matter for any approved training program. Although hands-on verification of skill on lease-specific equipment is recognized as being beneficial, it has not been included in the proposed rule as a regulatory requirement.

Question 3—Should refresher courses be required, and if so, how often and what should be their content?

Comment—Three commenters stated that the standard for refresher courses does not need to be strengthened. One commenter stated that refresher training provides little benefit beyond on-the-job training. On the other hand, one commenter suggested that a refresher course be required for production foremen, operators, instrumentation specialists, and production electricians. That commenter stated that refresher training should include changes in the orders as well as the basic provisions of API RP T-2 and should be required every 2 years.

Response—Under the proposed rule, a refresher course requirement has been adopted for the production safety system training standard. The concept of refresher training parallels the requirements currently in place for drilling well-control training, which has been a successful program, although the proposed rule would require refresher training every 2 years for production personnel as opposed to annually for drilling personnel and well-completion and workover personnel.

Question 4—How should MMS properly recognize individuals trained under currently approved programs?

Comment—One commenter stated that it is not necessary for MMS to recognize individual's training. Two commenters suggested that MMS should recognize those persons having certificates or cards from accepted or approved API RP T-2 training schools as being qualified for a 2-year period from the date of their certification.

Response—Under the proposed rule, successful completion of basic and refresher training courses is required in order for trained personnel to maintain their qualifications under current operation requirements. The basic

course is to be successfully completed every 4 years, while a refresher course must be successfully completed each year. Persons who have certificates or cards showing successful completion of accepted API RP T-2 training schools would be recognized as qualified pending the development and certification of training courses under the proposed rule.

Question 5—What is an appropriate timetable for development and implementation of such a training requirement?

Comment—Three commenters stated that the current requirements are adequate. One commenter suggested that any new training requirement should be given a 1-year implementation period from the time of approval.

Response—The proposed rule includes a 24-month implementation period. Two years should provide sufficient time for training courses to be developed and certified and for the lessee and contractor personnel to successfully complete the required training.

The following comments pertain to the provisions of § 250.68 of the proposed rule published March 18, 1986. The provisions contained in previously proposed § 250.68 have been moved to proposed Subpart O, Training, §§ 250.210 through 250.214.

Where a specific section or paragraph within proposed Subpart O is applicable, the section or paragraph is cited as an aid to the reader.

Comment—One commenter felt that training should reflect the performance standard approach more than is evident in proposed § 250.68. That commenter indicated that some mandatory training requirements, including frequencies for refresher training, should be kept in effect.

Response—The proposed rule would provide relatively uniform training requirements for lessee and contractor employees who carry out OCS activities. Well control during well-completion and well-workover operations and production safety systems are sufficiently important to the maintenance of safety operations and protection of the environment in the OCS to justify the establishment of minimum-training requirements.

Comment—A commenter felt that the training requirements of the present standard (MMSS–OCS–T 1) are valuable and thorough and that few changes in the training standard are necessary.

Response—Proposed changes to the present standard are aimed at reducing the administrative burden while maintaining the high quality of well-control training. Similar standards are being proposed for well-completion, well-workover, and production operations.

Comment—A commenter felt that MMS regulations should define who on a rig is in charge of well-control procedures in order to avoid questions of responsibility and related problems concerning contracts, liabilities, responsibilities, and legalities.

Response—The lessee is ultimately responsible for ensuring compliance with regulations, and that the proper steps are taken to ensure the protection of life and resources in the OCS. The relationship between lessees and their contractors is best left to the respective companies involved while recognizing that contractors act as agents for lessees. No change from the current regulations is proposed.

Comment—A commenter suggested that the current training requirements are adequate for the vast majority of personnel who require training, but that advanced training in well control might be appropriate for students who have successfully completed one basic and three refresher courses.

Response—The objective of the MMS training requirements is to ensure that individuals who work in OCS operations receive well-control training appropriate to their responsibilities and duties. Training organizations may offer, and personnel who work in the OCS may take, advanced training. A provision to this effect has been included in the proposed rule.

Comment—Several commenters suggested that MMS delete § 250.68, Training in well control, in its entirety and replace it with a training program based on API RP T-3. The commenters suggested that new MMS programs be tailored after MMS's safety device program of proposed § 250.125, Safety device training.

Response—Avoidance of blowouts through blowout prevention and well control is one of the primary safety and pollution prevention defenses available to prudent operators in the OCS. Current rules reflect the minimum needs for training in blowout prevention and well control during drilling operations. Proposed changes are intended to extend the coverage of the existing program to also cover well-completion and well-workover operations, where a major portion of OCS accidents occur. To this end, the proposed rule includes training requirements for lessee and contractor personnel whose work involves well completion, well workover, production safety systems, maintenance, and repair.

Comment—A commenter suggested that wording changes be made to paragraph (a) of § 250.68, Training in well control, to require that well-control training for well-completion and well-workover operations be provided to lessee and contractor personnel through the lessee's (contractor's) on-the-job training program or a certified training program established by a training organization. The choice of training programs would rest with the lessee or contractor who pays for the training.

Response—Some lessees and contractors have developed and maintained certified "in-house" programs while others provide employee training through public or private institutions that have developed and maintained certified training programs. On-the-job training suggests an unacceptable approach to well-control training. Some formal classroom training in well control is required to assure that offshore employees receive a minimum level of well-control training. (This training requirement is addressed at § 250.210(b), Personnel training requirements.)

Comment—One commenter felt that the job and position classifications listed in § 250.68(b), Personnel classifications, should be expanded to include mud engineer, subsea engineer, directional engineer, service company personnel, and production hands. Another commenter felt that the five proposed personnel classifications should be combined into two classifications, drilling technicians and drilling supervisors.

Response—Consolidation of the five proposed personnel classifications under two classifications as is now being proposed should result in a reduced amount of paperwork without sacrificing the quality of training to be provided offshore workers. Fewer job and position classifications will reduce the distinctions that the training facility, the lessee, and MMS have to make in the records maintained on trained employees. The proposed rule (§ 250.210(b)(1)) identifies two distinct job classifications for well-control training during drilling operations (floorhand and drilling supervisor). (Personnel classifications for the purpose of established well-control training courses are now listed at § 250.210(b).)

Comment—One comment on proposed § 250.68 (c) and (p), suggested that all student records should be maintained by the employer (lessee or contractor) (inferring that schools should have no responsibility for maintaining student records) at the rig site, office, and on the person (wallet card) of the employer. A commenter felt

that lessees should only be required to retain records relative to their own employees, and contractor employee records should be maintained by the contractor. Another commenter felt that employee records should be kept at a central office to reduce paperwork rather than having records at the lessee's field office nearest the OCS facility.

Response—Proposed § 250.68 (c) and (p) have been merged in this proposed rule (§ 250.210(c)). The proposed requirement that records of training be kept "at lessee's field office nearest the OCS facility for a period of 5 years" has been deleted from this proposed rule. The proposed rule would require that proof of training, such as a certificate issued by the organization providing well-control training, be maintained at the job site. Each training organization is also required to maintain records for each of the students who enters its training program(s).

Comment—One commenter felt that proposed § 250.68 (d) and (o) are contradictory or that paragraph (d) was misleading by making it look as if rotary helpers and derrickmen required no classroom training. Another respondent felt that wording should be added to paragraph (d) to require hands-on training of drillers, toolpushers, and operator's representatives to be performed at their job sites or at another site at the discretion of the lessee.

Response—Under the proposed rule, hands-on training requirements for rotary helpers and derrickmen previously found in § 250.68(d) have been merged into the general requirements for the training of floorhands (§ 250.210(b)).

Well-control courses for drilling supervisors are required to include "hands-on" training on simulators or a training well. Use of a simulator or training well in conjunction with classroom training is the only practical way this skill can be developed.

Comment—A commenter suggested that § 250.68 (e) and (f) require that rotary helpers and derrickmen be required to receive well-control training on an annual basis and that training organizations that provide well-control training for the rotary helper and derrickman job classification be evaluated in the same manner as training organizations that provide well-control training for employees with a higher level of responsibility.

Response—There is a great difference between the duties and responsibilities of a rotary helper or derrickman and those of a driller or toolpusher, especially during a crisis such as blowout or pressure control situation. The present training requirements for rotary helpers and derrickmen provide a fundamental explanation of well control and are designed to help these workers to better understand their role in the carrying out of well-control activities. The skills most needed by these workers in an emergency are practiced during the mandatory weekly blowout, preventer drills. Thus, more formal training on an annual or other basis is not considered necessary to assure that floorhands are properly trained. (These requirements are now addressed in § 250.212(a).)

Comment—(Proposed § 250.68 (e)(1), (f)(2), (g)(2), (h)(2), and (i)(2) require that students receive general instructions on MMS regulations that pertain to the work in regard to well-control activities.) A commenter suggested that MMS highlight the appropriate sections of the Orders and provide them to training organizations that teach certified well-control programs as a guide base for instruction.

Response—The suggestion was not adopted. The MMS works with training organizations to assure proper knowledge and understanding of its requirements. The procedures MMS uses in this regard are not the subject of the proposed rule.

Comment—A commenter suggested that "equivalent experience" needs to be defined with a set of guidelines. Under proposed § 250.68 (f)(1), (g)(1), (h)(1), (i)(1), (j)(3), (j)(4), and (j)(5), a student would have to complete training for a job classification at a lower level or possess "equivalent experience" before being admitted to a training program.

Response—The phrase "equivalent experience" and references to prerequisite training and experience have been deleted from this proposed rule.

Comment—A commenter has proposed that, as a minimum, both the Driller's Method and the Wait-and-Weight Method be taught and understood during a basic well-control course. During refresher courses, the commenter feels that only one method should be taught. Proposed § 250.68(g)(8) requires that students receive instruction on one of the constant bottomhole pressure methods of well control such as the Driller's Method, Wait-and-Weight Method, Concurrent Method, or other applicable constant bottomhole pressure methods.

Response—The proposed rule proposes no change to the requirement. Satisfactory results have been realized by teaching a minimum of one constant bottomhole pressure method of well control. (This requirement is now addressed in § 250.212(c)(7).)

Comment—A commenter recommended that kill team members not be allowed to rotate during a simulator session but should be required to rotate positions between sessions. Under proposed § 250.68(n)(1)(xii), a candidate is to change positions as part of a team during the hands-on qualification test and simulator training.

Response—Under this proposed rule, at least two practice problems and one official test problem must be successfully completed as part of the hands-on training activities. Although the proposed rule is silent on the manning of positions during the hands-on test problems, sufficient familiarization of the candidates under instruction must be accomplished to insure that all candidates fully understand the duties and responsibilities of the team members at the various positions. To more properly assure in-depth student exposure to the "hands-on" experience, the maximum number of students per simulator exercise has been reduced from four to three. (This requirement is now addressed in § 250.212(f)(2).)

Comment—A commenter suggested that proposed § 250.68(g)(10) include a requirement that students at the driller level receive instructions in gas expansion equations.

Response—Current rules require instructions in gas bubble expansion calculations as part of the well-control training for both toolpushers and operator's representatives. Under the proposed broadened job classification of the drilling supervisors, drillers will be required to receive this training. (This requirement is now located at § 250.212(c)(16).)

Comment—A commenter felt that candidates should be required to document how they become familiar with the basic training of a rotary helper, a derrickman, a driller, and a toolpusher and the duties of each during well-control situations. Requiring this documentation would prevent persons unfamiliar with drilling rigs from acquiring the highest level of certification. Under proposed § 250.68(i)(1), candidates for operator's representative certification are required to be familiar with those basic duties and training.

Response—This suggestion was not adopted. The merger of five training categories into two has eliminated the need for the documentation of prerequisite experience and training.

Comment—One commenter felt that employees should have 3 months of

actual work experience before they are sent to a training program so they will be more familiar when they begin training. Proposed § 250.68(j)(1)(i) requires that rotary helper candidates receive training for their level within the first 6 months of initial employment.

Response—No change in the proposed rule is requested. Lessees are expected to schedule training for their employees in a way that provides the most efficient use of their training dollar. Since this training is primarily given to entry level personnel, the training should familiarize students with equipment as part of the curriculum. (This requirement is now located in § 250.212(b)(1).)

Comment—One commenter suggested limiting students to 12 per lecture and 2 students per hands-on lab exercise. Proposed § 250.68 (n)(1)(iii) and (n)(2)(v) would limit class size to 20 students per lecture and 4 students per hands-on lab exercise.

Response—This proposed rule would limit to three the number of students per hands-on lab exercise. No change is proposed from the current MMS requirement of no more than 20 students per lecture. This student/teacher ratio should afford students an opportunity to obtain the appropriate level of training and understanding of well-control problems and their solutions. (These requirements are now located in § 250.211(a)(7) and § 250.212(f)(2).)

Comment—A commenter felt that only schools which are equipped with simulators or test wells with a subsea panel should receive certification to teach subsea candidates.

The commenter also listed hands-on problems that a simulator should reproduce for students such as gas kicks in water base mud, water kicks in water base mud, gas kicks in oil base mud, and water kicks in oil base mud. The commenter believed that simulators should also be able to simulate a secondary kick or lost circulation on the basis of how a student handles a primary kick.

Response—The proposed rule recognizes that additional information about the training facility's simulator or test well is needed in the original submittal of a training organization requesting certification of its training program. The text of the provision has been modified to require a more complete description, including whether a simulator is equipped with a subsea panel and the various types of kicks that can be simulated. The subjects to be included in a required curriculum have been expanded to require that all students be trained in both subsea and surface BOP well-control techniques. (This requirement is now located in § 250.212(f).)

Comment—A commenter has suggested requirements in addition to the minimum requirements for testing methods found in proposed § 250.68 (n)(1)(vii), (n)(2)(vi), and (n)(7). These requirements are as follows:

(1) Simulator tests be conducted with only the student and the instructor present at the simulator. The commenter contends that it is difficult to evaluate several students on one simulator.

(2) The MMS should publish guidelines on the number of questions to be asked in the examination.

(3) The MMS should require annual redrafting and submittal of tests as part of a program to assure that tests are nonrepetitive and remain confidential.

Response—No changes have been proposed in the previously proposed requirements.

(1) During actual well-control situations, personnel work as a team to kill the threatened blowout; thus, a team test on a simulator has proven to be satisfactory. Sufficient familiarization is required during instruction to insure that candidates will understand the manning requirements of the various positions.

(2) The content, length, and quality of tests are best dealt with during the school evaluation and certification process.

(3) Current requirements state that the training institution must submit the methods they will use to assure that the test will be nonrepetitive and remain confidential. (These requirements are now in § 250.212(f).)

Comment—A commenter suggested that the certificate issued upon the successful completion of a course should also state whether the course passed was a basic or refresher course.

Response—This recommendation has been adopted in the proposed rule. (These requirements are now located in § 250.211 (b) and (c).)

Comment—A commenter felt that requirements for instructions relating to subsea BOP stacks should be slated in proposed § 250.68(n)(1)(x) for subsea certification. The commenter made the following detailed, suggested requirements:

(1) Simulator shall have subsea panel;

(2) Diverter procedures when drilling with and without riser;

(3) Choke line friction determinations;

(4) Selecting the proper kill rate;

(5) "U" tube effect as gas hits the choke line;

(6) Effects of bottomhole pressure when the choke line is full of gas;

(7) Removing trapped gas from stack after killing well;

(8) Choke and kill line fluids (i.e., water or drilling mud); and

(9) Riser collapse versus water depth.

Response—This recommendation has been adopted in this proposed rule. These are important points that should be covered in any subsea course. Items (5), (7), and (9) were found to be critical factors in a recent offshore blowout and, along with Item (3), have been added as § 250.212(c)(12). Item (1) has also been addressed in § 250.212(f) (1) and (4). All other items had already been addressed in the text of the proposed rule published in March 1986 and remain in this proposed rule.

Comment—A commenter has suggested that MMS develop a standard prerequisite form to be used by the schools in evaluating a candidate's entrance prerequisites.

Response—The MMS believes that a standardized form is unnecessary. Under the proposed rule, training organizations would not be required to verify that a candidate has prerequisite training or experience to take a course; however, a training organization would have to verify prior training before issuing a certificate for successful completion of a refresher course. This is because the proposed rule does not allow a person not currently trained for a job to become qualified for that job by taking a refresher course.

Comment—A commenter asked why training organizations are required to submit lists of all personnel who successfully complete training and the information listed in proposed § 250.68(n)(1)(xv). The MMS would not release similar data under the Freedom of Information Act.

Response—The information required by proposed § 250.68(n)(1)(xv) is utilized to verify training records kept at offshore work sites. (This requirement is currently in § 250.211 (b)(8) and (c)(8).)

Comment—A commenter recommended that training organizations certified to teach a basic well-control course be required to provide students with a training manual for their use and retention. Proposed § 250.68(n)(2)(ii) requires that training organizations giving refresher courses provide students with a training manual for their use and retention. The paragraph further states, in parenthesis, that this is not required for schools certified for a basic well-control course. A commenter felt that the waiver for schools certified for a basic course should be deleted.

Response—The proposed rule now contains clarifying language. The intent of the provision is to assure that schools that are certified to teach a basic course

do not have to submit a copy of their previously approved training manual for MMS review as part of an application for certification to teach a refresher course. (This requirement is now located in § 250.211(c).)

Comment—One commenter states that proper documentation of a student's qualifications and training should be maintained in the student's folder. Proposed § 250.68 (j)(3), (j)(4), and (j)(5) set forth the qualification requirements that must be met by drillers, toolpushers, and operator's representatives before they may participate in drilling operations in the OCS. Personnel must be trained in accordance with § 250.68 and must have successfully completed written and/or oral tests and hands-on demonstrations to verify their thorough understanding of the material.

Response—The revised proposed training regulations require training institutions to maintain records on each student and to provide each student with documentation of his/her successful completion of a training course for retention at the work site. (These requirements are now located at §§ 250.211(b)(8) and 250.212(e)(1) and (3).)

Comment—A commenter has suggested that the basic well control training be repeated every 2 years and that workers be required to take a refresher course twice during the intervening time period.

Response—This suggestion was not adopted. No compelling evidence has been provided that would mandate such an increase in the level and frequency of required training. (These requirements are now located in § 250.212(e).)

Comment—A commenter objected to the wording of § 250.68(j)(5)(ii) which states that a candidate for operator's representative qualification level must demonstrate the ability to "organize and direct a well-control operation." It was the commenter's view that this skill should not be required for certification.

Response—This recommendation was not adopted. The operator's representative is the lessee's ranking representative on an offshore facility. This person must be able to organize and direct well-control operations. Requirements for the operator's representative level have been included in the new drilling supervisor level. (These requirements are now located at § 250.212(e).)

Comment—A commenter felt that § 250.68(k)(4) required the closing in of the well during on-bottom drilling and stated that this action would endanger the wellbore and drill string as well as ensure that drills could not be run often enough to improve crew proficiency.

Response—Under the proposed rule, well-control drills are required weekly and are to be scheduled so that they will occur during a range of different operations. The provisions of proposed § 250.68(k)(4) outlined specific training objectives for well-control drills, and the actions listed are only to be taken "as appropriate" if the drill is conducted while drilling on-bottom. When scheduling BOP drills, well safety is always the primary concern, and the regulations emphasize that well-control drills should be carried out during activities selected to minimize danger to the operations. (This requirement is now located in Subpart D, Drilling.)

Comment—One commenter felt that proposed § 250.68(1) compels companies to send employees to higher rated training courses than warranted by their current job status. Proposed § 250.68(1) would require employees to obtain certification for a position if they are to act as a relief for that position without direct supervision by an employee qualified under the training requirements for higher job classification.

Response—No change has been made to specifically address this concern. The proposed rule simply requires that there be an appropriately trained and certified person on duty at all lines. The MMS has reduced the number of training categories from five to two (floorhand and drilling supervisor) to ensure that the correct minimum level of training can be provided to lessee and contractor personnel working in the OCS. (This requirement is now located in § 250.210(d).)

Comment—A commenter has suggested that any candidate who misses over 1 hour of class should be required to repeat the class.

Response—Under the proposed rule, candidates would be required to make up any missed portions of a class before credit is awarded. This wording should be sufficiently stringent while allowing some degree of flexibility. (This requirement is now in § 250.211(a)(6).)

Comment—One commenter listed a number of actions relative to recertification and onsite evaluation of training programs that the commenter wishes MMS to take. Proposed § 250.68(m)(9) and (m)(10) state the requirements for school recertification and announce the onsite evaluations of schools which will be conducted by MMS personnel. The commenter believed that MMS should notify the school 180 days before the 4th anniversary date of certification to remind personnel that recertification requests are due to MMS at least 90 days prior to the 4th anniversary; MMS onsite evaluators should be identified, in writing, and carry an evaluation checklist; schools should have time to reply to an evaluator's questions in writing; schools should have the right of legal representation during audits; evaluators should have both oil field and teaching experience; and evaluators should request specific information and not be allowed complete access to files.

Response—This recommendation was not adopted. The proposed rule intentionally limits specific instructions concerning MMS practices and procedures. Training organizations are expected to be aware of the limitations placed upon the certification of each of their certified training programs. The MMS auditors use the regulations or standards governing well-control training as a checklist when evaluating schools. Auditors discuss the evaluation with training school representatives, and schools are notified, in writing, of any deficiencies and given an appropriate amount of time to respond and/or take corrective action. All auditors have attended well-control schools and are well versed in applicable regulations. (These requirements are currently located in § 250.211(a).)

Comment—A commenter felt that modular-type courses should be allowed by MMS, and if MMS wants to state minimum time limits for instruction, these limits should be stated in proposed § 250.68(n)(1)(i). Proposed § 250.68(n)(1)(i) provides that a curriculum outline be submitted with a training organization's application showing the subject matter to be taught each day and the number of hours devoted to each subject.

Response—Nothing in the current or proposed regulations prohibits the use of modular-type courses in approved training programs. The proposed rule includes a 32-hour minimum time requirement for instruction in well control during drilling operations. (This requirement is now located in § 250.211(a).)

Comment—A commenter has suggested that a set of minimum requirements be developed for instructors. Implementation of this suggestion would include requiring instructors to take the basic course every year and to pass MMS developed tests before being recertified.

Response—Presently, complete qualifications of all instructors must be submitted for review during the evaluation and certification of a training organization's proposed training

program. This information is used in combination with other information submitted with the application to assess the capability of a training organization and its instructors to provide the required training. Competition between training organizations for a share of lessees and contractors training dollars will also help to ensure the proper maintenance of quality instruction. It is reasonable to expect that lessees and contractors will enroll employees in training programs that provide the best training for the employee for the least money. (These requirements are now located at § 250.211(c) and (d).)

Summary of Proposed Rule

Proposed Subpart O, Training, contains requirements for training personnel who perform or supervise drilling, well-completion, well-workover, or production operations. The following discussion summarizes the proposed requirements.

Personnel in the position of rotary helper or derrickman would be classified as drilling floorhands. Content for training courses for drilling floorhands is included in the proposed rule. These courses would not be required to be MMS certified, and refresher courses would not be required. A drilling floorhand rating would be maintained by participating in drills as required by Subpart D, Drilling.

Drillers, toolpushers, and company representatives conducting drilling operations would be classified as drilling supervisors. Content for training courses for drilling supervisors is included in the proposed rule. Basic courses and refresher courses for drilling supervisors, and the schools teaching these courses, would be MMS certified. Personnel would be required to complete a basic course once every 4 years and a refresher course in intervening years.

Well-completion and well-workover personnel performing jobs equivalent to the drilling positions of rotary helper and derrickman would be classified as a well-completion and well-workover floorhand. Training would be required for such personnel performing operations without the tree in place. Content for training courses for well-completion and well-workover floorhands would not be MMS certified, and refresher courses would not be required. A well-completion and well-workover floorhand rating would be maintained by participating in drills as required by Subpart E, Well-Completion Operations, and Subpart F, Well-Workover Operations.

Well-completion and well-workover personnel performing in jobs equivalent to the drilling positions of driller, toolpusher, and operator's representative would be classified as well-completion and well-workover supervisor. Content for training courses for well-completion and well-workover supervisors is included in the proposed rule. Basic courses and refresher courses for well completion and well-workover supervisors, and the schools teaching the courses, would be MMS certified. Personnel would be required to complete a basic course once every 4 years and a refresher course in intervening years.

At least one person in each snubbing, coil-tubing, or small-tubing operations crew would be required to take basic and refresher courses. The content of these courses is included in the proposed rule. Basic and refresher courses and the schools teaching those courses would be MMS certified. Personnel would be required to complete a basic course once every 4 years and a refresher course in each intervening year.

Personnel responsible for the installation, testing, operation, repair, or maintenance of a production safety system and the person on the platform with overall responsibility for production operations would be required to take basic and refresher courses. The content of these courses is included in the proposed rule. The basic and refresher courses and the schools teaching these courses would be MMS certified. Personnel would be required to complete a basic course once every 4 years and a refresher course every two years.

Tables 1, 2, and 3 compare existing training requirements with the training requirements in the proposed rule. Table 1 deals with drilling operations and compares the existing training requirements with the proposed training requirements for rotary helpers and derrickmen. Table 2 also deals with drilling operations and compares existing training requirements to the proposed requirements for drillers, toolpushers, and company representatives. Table 3 deals with production operations and compares the existing training requirements with the proposed training requirements for production safety system workers and platform operators. Existing rules do not include specific requirements for training of personnel engaged in completion/workover operations with the tree removed or personnel engaged in well-servicing operations; therefore, a table is not included to deal with a comparison of training requirements for these operations.

Tables 1, 2, and 3 are presented as aids to the reader and are intended only as a summary. Interested parties should read the text of the proposed rule to determine the actual proposed requirements.

TABLE 1.—DRILLING OPERATIONS TRAINING FOR FLOORHANDS

[Rotary Helpers and Derrickmen]

	OCS Orders/T1 & current regulation	Proposed rules
Categories of personnel.	Rotary Helper	Floorhand.
	Derrickman.....	
MMS approval of program.	Submission to MMS.	No submission to MMS.
	Approval required.	No approval necessary.
Minimum length of courses.	Not specified	
	Not specified	
Maintenance of qualifications.	Weekly drills	Weekly drills.

TABLE 2.—DRILLING OPERATIONS TRAINING FOR DRILLING SUPERVISORS

[Drillers, Toolpushers, and Operator's Representatives]

	OCS Orders/T1 & current regulation	Proposed rules
Categories of personnel.	Driller	Drilling supervisor.
	Toolpusher	
	Operator's Rep ..	
MMS Approval of program.	Submission to MMS.	Submission to MMS.
	MMS audit of school.	MMS audit of school.
	Approval required.	Approval required.
Minimum length of courses.	Not specified	Basic course. 32 hrs. Refresher course—8 hrs.
Maintenance of qualifications.	Basic course every 4 years	Basic course every 4 years.
	Refresher course annually.	Refresher course annually.

TABLE 3.—PRODUCTION SAFETY SYSTEMS

	Current regulations	Proposed rules
Categories of personnel.	Production safety system workers.	Production safety system workers.
	Platform operator.	Platform operator.
MMS Approval of program.	No approval process.	Submission to MMS.
		MMS audit of school.
		Approval required.
Minimum length of course.	Not specified	Basic course—32 hrs. Refresher course—6 hrs.

TABLE 3.—PRODUCTION SAFETY SYSTEMS—Continued

	Current regulations	Proposed rules
Maintenance of qualifications.	Training course once every 4 years.	Basic course once every 4 years. Refresher course once every 2 years.

Comments are invited concerning all aspects of the proposed rule governing training of personnel in the OCS. In addition, interested parties are invited to respond to the following questions:

(1) Separate courses are proposed for drilling operations and for well-completion and workover operations with the tree removed. Should these two areas be taught in separate courses or in a single combined course of longer duration than each separate course but not as long as the total of each course taught separately? Another option would be to allow the training schools the option of teaching the courses separately or in a combined course. The proposed rule allows the combination of any courses. The specified requirements for a standard course would also apply to a combined course, and the approval of the course would be handled on a case-by-case basis.

(2) In the proposed rule, the required courses for floorhands for drilling operations and for well-completion and workover operations with the tree removed do not require approval by MMS. Should the final rule include provisions requiring MMS approval for these courses for floorhands, or are the requirements in the proposed rule sufficient?

(3) In the proposed rule, floorhands for drilling operations and for well-completion and workover operations could maintain their qualifications by participating in weekly drills. Should floorhands be required to repeat training courses periodically (e.g., every 4 years)?

(4) The proposed rule does not include specific prerequisite requirements for a trainee to be eligible to take a course. Should prerequisites be included in the final rule, or should a potential trainee be able to attend any course the trainee wishes?

(5) Are the minimum course lengths in the proposed rule appropriate for the course subject matter? The proposed rule does not specify minimum course lengths for courses for supervisors of well-servicing operations (snubbing, coil-tubing, and small-tubing operations). The MMS will consider including minimum course lengths for well servicing in the final rule. What should the minimum course length be (how many hours) for a basic or refresher course for well-servicing operations?

(6) Should all well-servicing schools be required to teach all three well-servicing areas (snubbing, coil-tubing, and small-tubing operations), or should a training facility be allowed to have a course certified for one, two, or all three of the areas and have trainees become qualified in only the areas covered in the course? The proposed rule does not include specific training for supervisors of wireline operations. Should the final rule include requirements for training of supervisors of wireline operations?

(7) Is a separate course appropriate for well-servicing operations, or should well servicing be integrated into other training and a provision be added to require that an individual trained for production safety systems be present during well-servicing operations with the tree in place and that an individual trained in well-completion and workover well control be present during well-servicing operations with the tree removed?

(8) To measure the effectiveness of training programs, MMS may wish to randomly provide and/or administer tests other than those provided for in the training program. The MMS is considering including such testing authority in the final rule. Interested parties are invited to comment on the use of MMS developed and/or administered tests and to address the question of how MMS can best monitor the effectiveness of training programs.

The Department of the Interior (DOI) has determined that this document does not constitute a major rule under Executive Order 12291; and, therefore, a Regulatory Impact Analysis is not required.

Regulatory Flexibility Act

The DOI has also determined that this document will not have a significant effect on a substantial number of small entities because, in general, the entities that engage in activities offshore are not considered small due to the technical complexities and financial resources necessary to conduct such activities.

Paperwork Reduction

The information collection requirements contained in proposed Subpart O, which are in addition to currently approved information collection, have been submitted to the Office of Management and Budget (OMB) for approval under 44 U.S.C. 3504(h). The collection of the additional information will not be required until it has been approved by OMB.

Public reporting burden for this collection of information is estimated to average 8 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to Information Collection Clearance Officer, Minerals Management Service, Mail Stop 632, 381 Elden Street, Herndon, Virginia 22070; and the Office of Information and Regulatory Affairs, Paperwork Reduction Project, Office of Management and Budget, Washington, DC 20503.

The DOI certifies that the rule does not represent a government action capable of interference with constitutionally protected property rights. Thus, a Takings Implication Assessment has not been prepared pursuant to Executive Order 12630, Government Action and Interference With Constitutionally Protected Property Rights.

Authors

The principal authors of this proposed rule are Lawrence H. Ake, John V. Mirabella, Charles J. Schoennagel, and Maurice I. Stewart.

List of Subjects in 30 CFR Part 250

Continental shelf, Environmental impact statements, Environmental protection, Government contracts, Incorporation by reference, Investigations, Mineral royalties, Oil and gas development and production, Oil and gas exploration, Oil and gas reserves, Penalties, Pipelines, Public lands—mineral resources, Public lands—right-of-way, Reporting and recordkeeping requirements, Sulphur development and production, Sulphur exploration, Surety bonds.

Date: February 7, 1989.

Robert E. Kallman,

Director, Minerals Management Service.

For the reasons set forth in the preamble, Part 250 of Title 30 of the Code of Federal Regulations is proposed to be amended as follows:

PART 250—[AMENDED]

1. The authority citation for Part 250 continues to read as follows:

Authority: Sec. 204, Pub. L. 95-372, 92 Stat. 629 (43 U.S.C. 1334).

2. It is proposed to revise Subpart O of Part 250 to read as follows:

Subpart O—Training

Sec.
250.210 General.
250.211 Approval of training program.
250.212 Drilling well-control training.
250.213 Well-completion and workover well control.
250.214 Production safety system training.

Subpart O—Training

§ 250.210 General.

(a) *Training performance standard.* Lessee and contractor employees engaged in drilling, well-completion, well-workover, or production operations in the Outer Continental Shelf (OCS) shall be trained in the proper operation of equipment, methods of operation, and techniques to avoid hazards to people and property and to prevent pollution of the environment.

(b) *Personnel training requirements.* The training required for individual employees of lessees and contractors who work in the OCS shall be based upon the job function(s) the employee performs.

(1) Individuals engaged in oil, gas, or sulphur drilling operations shall be trained in well control and blowout prevention on the basis of two basic job classifications as follows:

(i) Drilling floorhands (includes the conventional drilling rig positions of rotary helper and derrickman or their equivalent) shall be trained in well control in accordance with the provisions of paragraphs (a) and (b) of § 250.212, Drilling well-control training, of this part, and

(ii) Drilling supervisors (includes the conventional drilling rig positions of driller, toolpusher, and operator's representative or their equivalent) shall be trained in well control in accordance with the provisions of paragraphs (c) through (f) of § 250.212, Drilling well-control training, of this part.

(2) Individuals engaged in oil or gas well-completion or workover operations after the time the production casing is set, cemented, and pressure tested shall be trained in blowout prevention and well control on the basis of the job classifications in (i) and (ii) of this paragraph (b)(2). Individuals engaged in well-completion operations prior to the initial installation of the tree may be trained in accordance with paragraph (b)(1) of this section in lieu of the well-completion and workover well-control training required by this paragraph (b)(2).

(i) Well-completion and workover floorhands (includes floorhands and employees in an equivalent job classification as well as the conventional drilling rig positions of rotary helper and derrickman or their equivalent) performing operations without the tree in place shall be trained in well control in accordance with the provisions of paragraphs (a) and (b) of § 250.213, Well-completion and workover well control, of this part.

(ii) Well-completion and workover supervisors (includes well-completion and workover supervisors and employees in an equivalent job classification as well as the conventional drilling rig positions of driller, toolpusher, and operator's representative or their equivalent) performing operations without the tree in place shall be trained in well control in accordance with the provisions of paragraphs (c) through (f) of § 250.213, Well-completion and workover well control, of this part.

(iii) At least one member of each well-servicing crew shall be trained in well control in accordance with the provisions of paragraphs (g) through (i) of § 250.213, Well-completion and workover well control, of this part, and shall be present at all times that snubbing, coil-tubing, or small-tubing operations are conducted on the OCS. For the purpose of this subpart, well servicing consists of snubbing, coil-tubing, and small-tubing operations.

(3) Personnel engaged in oil or gas production operations and classified as production safety system personnel (includes personnel engaged in the installation, repair, testing, maintenance, or operation of surface or subsurface safety devices and the individual on the platform with overall responsibility for production operations) shall be trained in accordance with the provisions of § 250.214, Production safety system training, of this part.

(c) *Training records.* A training organization that provides training for lessee and contractor employees identified in paragraph (b) of this section shall maintain a record of the training provided each trainee. The training organization shall provide each trainee who successfully completes a training course the documentation prescribed in this subpart. A copy of that documentation shall be maintained at the job site. A training organization shall not provide documentation of successful completion of a refresher course, unless the training organization determines the date of the trainee's most recent basic course and most recent refresher course to verify that the trainee is eligible to extend his/her qualifications through completion of a refresher course.

(d) *Relief assignments.* Any individual who temporarily works in place of another individual who has a job classification covered in paragraph (b) of this section shall have successfully completed the training requirements of that job classification, unless the temporary service is performed under the direct supervision of an individual onsite who has successfully completed the required training for that job classification.

(e) *Changes in certification.* A change in certification for a different job classification can only be accomplished through the successful completion of an approved basic course in well control designed to qualify the individual in the new job classification. An individual who has successfully completed a training program for a given job classification cannot change his/her certificate of training (e.g., from well-completion/workover supervisor to drilling supervisor or from surface to subsea) by successfully completing a refresher course.

(f) *Frequency of training.* (1) A basic or advanced course in well control or production safety systems must be successfully completed not later than 60 days after the 4th anniversary of the individual's last successfully completed basic or advanced course.

(2) Individuals are required to successfully complete an approved refresher course in well-control training not later than 60 days after the anniversary date for the individual's last successful completion of a basic course in well control, advanced course in well control, or refresher course in well control.

(3) Individuals are required to successfully complete an approved refresher course in production safety systems not later than 60 days after the 2nd anniversary of the individual's last successfully completed basic course in production safety systems, advanced course in production safety systems, or refresher course in production safety systems.

(4) A worker who does not complete a refresher course during the specified period in paragraphs (f)(2) and (f)(3) of this section shall repeat a basic course or an advanced course to recertify.

(g) *Other training requirements.* Well-control training requirements for individuals who work in OCS drilling, completion, and workover operations and production safety system training for individuals who work with production safety systems are detailed in this subpart. Additional training requirements are specified in other subparts and include the following:

(1) Pollution control—Subpart C, § 250.43 of this part,

(2) Crane operation—Subpart D, § 250.51(g) of this part,

(3) Welding and burning—Subpart D, § 250.52(b) of this part, and

(4) Hydrogen sulfide training—Subpart D, § 250.67(h)(2) of this part.

(h) *Departures.* The Deputy Associate Director for Offshore Operations may approve departures from these requirements when it is determined that such departure will not result in a reduction of the qualifications of personnel and that the departure is necessary due to unavoidable circumstances which make compliance with the requirements infeasible or impractical.

§ 250.211 Approval of training program.

(a) *Application for approval.* Training programs and implementation plans for both basic and refresher courses in well control and production safety systems shall be submitted to the Deputy Associate Director for Offshore Operations with a request for approval and certification. Training programs submitted by training organizations for approval and certification shall comply with the following:

(1) Two copies of a comprehensive detailed presentation of the proposed training program and implementation plan shall be submitted in looseleaf binder format.

(2) All proposed training programs and plans, together with related correspondence, shall be mailed to the Deputy Associate Director for Offshore Operations; Minerals Management Service, Mail Stop 647; 381 Elden Street; Herndon, Virginia 22070.

(3) The proposed training program and plan shall include the following:

(i) A training manual that is representative of the subject matter to be addressed during the course as it will be taught by the training organization.

(ii) An implementation plan furnishing the information described in this paragraph and either paragraph (c), (d), or (e) of this section.

(iii) A cross-reference relating elements described in the training manual to the requirements of this subpart.

(4) (i) A basic course or an advanced course in drilling well control, completion and workover well control with the tree removed, or production safety systems is required to include a minimum of 32 hours of instruction on subject matter covered in the approved course curriculum.

(ii) A basic or an advanced course in well servicing is required to include at least 24 hours of instruction on subject matter covered in the approved course curriculum.

(5) A refresher course in drilling well control, completion or workover well control with the tree removed, well servicing, well control, or production safety systems is required to include a minimum of 8 hours of instruction on subject matter covered in the approved refresher course curriculum.

(6) When two or more certified courses required under this subpart (e.g., drilling well control and completion/workover well control) are taught as a single course, the course length in the plan will be evaluated and approved on a case-by-case basis when MMS determines that all required material is adequately covered in the plan. Basic, advanced, or refresher courses may be combined in this manner.

(7) Course participants who are absent from any part of a course shall make up the missed portion before a written or simulator test is administered and before a certificate of successful completion is awarded.

(8) Classes shall contain no more than 20 candidates per lecture. A record of each candidate's attendance, including makeup actions where a part of a course is missed, shall be maintained by the instructor.

(9) Training organizations shall furnish MMS onsite evaluators with a copy of the training program and implementation plan approved by the Deputy Associate Director for Offshore Operations for their use during an onsite evaluation.

(10) A schedule of the courses that will be offered by a training organization shall be submitted to MMS after a training program is approved. A new course schedule shall be submitted at least annually thereafter. The schedule shall include the name of the course, class dates, type of course, and location where the course will be taught. The MMS shall be given advance notice of any changes to the schedule.

(11) Training organizations shall retain all required records for a period of 5 years starting with the date a training program and plan are approved. (At the end of the fifth year, a school may destroy the records of the first year, and at the end of the sixth year, a school may destroy the records of the second year, and so forth.)

(12) Training programs shall be approved for a maximum of 4 years.

(13) For basic courses, training organizations shall provide all candidates with a copy of the training manual for use and future reference by the candidates. For refresher courses and for advanced courses, training organizations shall provide each candidate with handouts necessary to update the manuals the candidate has as a result of previous training courses.

(14) A notification letter shall be sent to the Deputy Associate Director for Offshore Operations within 30 days of course completion informing MMS of each candidate who successfully completed the approved course. This letter shall contain the following information for each candidate:

(i) Name of training organization,

(ii) Candidate's full name,

(iii) Name of course (e.g., Well-completion and Workover Well Control),

(iv) Course type (i.e., basic, advanced, or refresher training),

(v) Options (e.g., surface or subsea qualification; snubbing, coil tubing, or small tubing),

(vi) Date candidate successfully completed course,

(vii) Name of instructor(s) teaching each element of the course,

(viii) Either a candidate's social security number or an MMS issued identification number,

(ix) Candidate's employer,

(x) Actual job title of candidate,

(xi) Job classification for which certification is awarded,

(xii) Test score for each candidate awarded a certificate,

(xiii) Training organization name and date of last basic training course or advanced course for the same job category (i.e., drilling, completion and workover, well servicing, or production safety systems) attended by candidate, and

(xiv) Training organization name and date of last refresher course taken by candidate.

(b)(1) Courses approved under MMSS–OCS–T 1, Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations, prior to the effective date of these regulations are deemed approved as drilling well-control training under this subpart until the expiration of the existing approval. However, individuals completing courses approved under MMSS–OCS–T 1 will only become certified for the applicable job classifications for which the course was approved. For example, an individual completing a driller's course approved under MMSS–OCS–T 1 would not be qualified as toolpusher or operator's representative without first taking the appropriate course approved under MMSS–OCS–T 1 or taking the drilling supervisor's course approved under this subpart.

(2) Applications for recertification shall be submitted at least 90 days prior

to the 4-year anniversary date of the program approval and shall state the changes, additions, or deletions, if any, to the previously approved training program course material, curriculum, and implementation plan.

(c) *Basic course.* Training organizations applying for approval and certification for a basic course shall submit a proposed course training program and implementation plan which addresses each of the following:

(1) A curriculum outline describing subject matter content in relation to the requirements of these regulations. The outline submitted shall be similar to the format presented below:

Job Classification
First Day—(Number of Instructional Hours)
Subject X—5 hours
Detail A
Detail B
Detail C
Subject Y—3 hours
Detail D
Subject Z—2 hours
Detail E
Detail F
Second Day—(etc.)

(2) The names and qualifying credentials of instructors including education and experience (both work experience and teaching experience).

(3) The mailing and street address of the facility where training records will be maintained and the street address and directions to training facilities.

(4) Material presentation method (lecture, video, filmstrip, etc.) indicating the amount and approximate percentage of overall instructional time that each method of presentation will use as shown in the following example:

(i) Percentage of time by presentation method:

Lecture—70 percent
Video tape—10 percent
Filmstrip—10 percent
Simulator—10 percent

(ii) Amount of time by method of presentation:

Subject X—4-hour lecture plus 1-hour video tape
Subject Y—2-hour lecture plus 1-hour filmstrip

(5) A narrative description of the testing procedures (including a copy of a sample written test(s) to be given to candidates in each job classification). Testing procedures shall meet the following criteria:

(i) Take-home tests shall not be permitted.

(ii) A candidate must correctly answer at least 70 percent of all test questions to receive a passing grade.

(iii) Tests shall be nonrepetitive and confidential. All test results shall be retained in the student's file.

(iv) A retest may be given to a candidate if the retest is accomplished within 48 hours of the initial test. Questions or problems used to retest a candidate shall be different but of comparable difficulty to questions and problems used in the original test. If a candidate fails to answer correctly at least 70 percent of all questions and problems on a retest, the candidate must repeat and successfully complete the entire basic course before he/she receives a certificate of successful completion.

(6) A copy of proposed handouts, materials, or manuals to be provided and retained by the candidates for their use and future reference. These materials in combination shall form a student's complete training manual.

(7) A copy of the proposed certificate of successful completion designed to include the following:

(i) Candidate's full name.

(ii) Either a candidate's social security number or an MMS issued identification number.

(iii) Name of the training organization.

(iv) Course name (e.g., Basic Course in Drilling Well Control).

(v) Date of successful completion.

(vi) Job classification for which certificate is awarded (e.g., drilling supervisor), and

(vii) For refresher courses, the date of most recent successful completion of basic course or advanced for which the refresher course is given.

(8) The applicant shall also state the special methods that will be used to instruct and test those individual candidates who are believed to be qualified but who respond poorly to conventional education and testing techniques. The special methods may include, but need not be limited to, oral tests and/or tutorial assistance.

(d) *Advanced.* Training organizations applying for approval and certification for an advanced course shall submit a proposed course program and implementation plan which includes the information identified in paragraph (c) of this section for a basic course and any additional material proposed for inclusion in the course. The additional material may include new or advanced concepts and techniques, case studies, or other material. Testing requirements for an advanced course are the same as for a basic course.

(e) *Refresher course.* Training organizations applying for approval and certification for a refresher course shall submit a proposed training program and implementation plan which addresses each of the following:

(1) A curriculum outline describing subject matter content in relation to the requirements of these regulations.

(2) The name and qualifying credentials of instructors including education and experience (both work experience and teaching experience).

(3) The mailing and street address of the facility where training records will be maintained and the street address and directions to training facilities.

(4) Material presentation method (lecture, video, filmstrip, etc.) indicating the amount of time that will be used for each method of presentation.

(5) A copy of the proposed handouts, materials, or manuals to be provided and retained by the candidates for their use and future reference. These materials in combination shall form the complete refresher training manual. Submission of the refresher training manual is not required for training organizations that are already approved and certified to teach a basic course, provided the refresher manual includes the same material approved for the training manual for the basic course.

(6) A copy of proposed certificate of successful completion including the following:

(i) Candidate's full name.

(ii) Either a candidate's social security number or an MMS issued identification number.

(iii) Name of training organization.

(iv) Course name (e.g., Refresher Course in Drilling Well Control).

(v) Option (e.g., surface or subsea qualification: snubbing, coil tubing or small tubing),

(vi) Date of successful completion, and

(vii) Job classification for which certificate is awarded (e.g., drilling supervisor).

(f) Training organizations are subject to announced or unannounced audits.

§ 250.212 Drilling well-control training.

(a) *Floorhand training.* Floorhands engaged in drilling operations in the OCS shall be trained in blowout prevention and well control in accordance with the following criteria:

(1) A floorhand shall receive general instructions on blowout preventer (BOP) equipment and procedures consistent with the type of BOP system and procedures utilized on the drilling rig upon which the floorhand is employed. Instructions to floorhands shall include the purpose, operation, and general care for the following:

(i) Annular BOP with and without diverter system.

(ii) Diverter system,
(iii) Ram-type BOP,
(iv) Accumulator system,
(v) Drill string inside BOP,
(vi) Drill-string safety valve,
(vii) Kelly cock,
(viii) Choke manifold,
(ix) Degasser, and
(x) Adjustable choke.

(2) In addition to the above, floorhands shall receive instructions on the purpose, operation, and general care of the following auxiliary equipment:
(i) Mud-pit level indicator,
(ii) Mud-volume measuring device,
(iii) Mud-return indicator,
(iv) Gas detector,
(v) Mud-gas separator, and
(vi) Trip tank.

(3) Floorhands shall receive general instructions on blowout prevention and well-control operations and hands-on training at the job site for activities such as operation of the choke manifold, stand pipe, and mud-room valves which require settings for well-control operations different from those used in normal drilling operations.

(4) Floorhands shall receive general instructions on the care, handling, and characteristics of drilling and completion fluids including:
(i) Density,
(ii) Viscosity,
(iii) Fluid loss,
(iv) Salinity,
(v) Gas cutting, and
(vi) Procedure for increasing density.

(5) Floorhands shall receive general instructions on warning signals that indicate that a kick is occurring or about to occur or conditions that can lead to a kick, including the following:
(i) Gain in pit volume and/or increase in fluid return rate,
(ii) Hole not taking proper amount of fluid during trips,
(iii) Well flowing with pump shutdown,
(iv) Sloughing shale and its appearance at surface,
(v) Drilling rate change,
(vi) Change in salinity of drilling fluid,
(vii) Change in flow properties of drilling fluid, and
(viii) Trip, connection, and background gas changes.

(b) *Qualification procedures for floorhand.* No floorhand shall participate in drilling operations in the OCS for more than 6 months unless the following qualifications are met:

(1) A floorhand shall successfully complete training in well control for floorhands which meets the criteria set forth in paragraph (a) of this section. Documented evidence of each successfully completed element of training shall be maintained at the job site.

(2) A floorhand shall successfully complete a qualifying test consisting of participation in a well-control drill at the job site carried out within the time limit prescribed. The time required for a floorhand to carry out his/her responsibility during the well-control drill shall be entered on the driller's log, and appropriate documentation shall be furnished to the employee.

(3) To maintain qualification, a floorhand must participate in well-control drills, as prescribed in Subpart D, § 250.58, of this part. The date and time required to complete each drill shall be recorded on the driller's log.

(4) A training manual containing instructional material on the subjects described in paragraph (a) of this section shall be provided to floorhands for their use and retention for future reference.

(c) *Basic well-control course for drilling supervisors.* Individuals who work as a drilling supervisor in drilling operations in the OCS shall be trained in blowout prevention and well control in accordance with the following:

(1) A candidate shall receive instructions on all applicable Government regulations that pertain to the work with regard to well-control operations and blowout prevention equipment. Copies of the regulations or abstracts of pertinent provisions shall be furnished to the candidate. This material shall be kept current so that it reflects the latest revisions or additions to Government requirements. At a minimum, these instructions shall cover the following subject matter:
(i) Drilling procedures including field drilling rules,
(ii) Wellbore plugging and abandonment, and
(iii) A general discussion of pollution prevention and waste disposal with emphasis on its relation to well control.

(2) Candidates shall receive instructions on the care, handling, and characteristics of drilling and completion fluids including the following:
(i) Density,
(ii) Viscosity,
(iii) Fluid loss,
(iv) Salinity,
(v) Gas cutting, and
(vi) Procedure for increasing density.

(3) Candidates shall receive instructions on the major causes of an uncontrolled flow from a well including the following:
(i) Failure to keep the hole full,
(ii) Swabbing effect of pulling the pipe,
(iii) Loss of circulation,
(iv) Insufficient density of drilling fluid,
(v) Abnormally pressured formations, and
(vi) Effect of too rapid lowering pipe in the hole.

(4) Candidates shall receive instructions on the importance of measuring the volume of fluid required to fill the hole during trips and methods for measuring and recording hole-fill volumes. These instructions shall include the importance of filling the hole as it relates to shallow-gas conditions.

(5) Candidates shall receive instructions on the warning signals that indicate that a kick is occurring or about to occur and on conditions that can lead to a kick including the following:
(i) Gain in pit volume,
(ii) Increase in return fluid-flow rate,
(iii) Hole not taking proper amount of fluid during trip,
(iv) Drilling rate change,
(v) Decrease in circulating pressure or increase in pump strokes,
(vi) Trip, connection, and background gas changes,
(vii) Gas-cut mud,
(viii) Water-cut mud or chloride concentration change,
(ix) Sloughing shale and its appearance at the surface,
(x) Well flowing with pump shutdown, and
(xi) Change in flow properties of drilling fluid.

(6) Candidates shall receive instructions on the correct procedures for shutting in a well for well-control purposes, including use of the BOP system, the choke manifold, and/or the diverter system for well control. These instructions shall include the sequential steps to be followed.

(7) Candidates shall receive instructions on one of the following constant bottomhole pressure methods of blowout prevention and well control, including those conditions which may be unique to either a surface or subsea BOP stack:
(i) Driller's method,
(ii) Wait-and-weight method,
(iii) Concurrent (circulate and weight) method, and
(iv) Other applicable constant bottomhole pressure methods.

(8) Candidates shall participate in blowout-prevention and well-control exercises using a well simulator or a model well in accordance with paragraph (f) of this section.

(9) Candidates shall be instructed on calculations used in blowout prevention and well control and the basis for their use including the following:

(i) Fluid-density increase required to control fluid flow into wellbore.

(ii) Conversion between fluid density and pressure and the importance of that conversion in understanding danger of formation breakdown under the pressure caused by the fluid column particularly when setting casing in shallow formation.

(iii) Calculation of equivalent pressures at the casing seat with emphasis on the importance of casing seat depth.

(iv) Drop in pump pressure as fluid density increases during well-control operations; relationships between pump pressure, pump rate, and fluid density, and

(v) Pressure limitations on casings.

(10) Candidates shall receive instructions on unusual well-control situations which include, when:

(i) Drill pipe is off bottom,

(ii) Drill pipe is out of the hole,

(iii) Lost circulation occurs,

(iv) Drill pipe is plugged,

(v) There is excessive casing pressure, and

(vi) There is a hole in drill pipe.

(11) Candidates shall receive instructions on the following:

(i) Controlling shallow gas kicks,

(ii) Use of diverters, and

(iii) Use of marine risers.

(12) Candidates intending to receive subsea well-control qualification shall receive instructions on the special problems in blowout prevention and well control when drilling with a subsea BOP stack including:

(i) Choke line friction determinations,

(ii) Riser collapse,

(iii) Removal of trapped gas from the BOP stack after controlling a well kick, and

(iv) "U" tube effect as gas hits the choke line.

(13) Candidates shall receive instructions on the installation, operation, maintenance, and testing of BOP and diverter systems.

(14) Candidates shall receive instructions on the purpose, installation, operation, and general maintenance of the following auxiliary equipment:

(i) Fluid-pit level indicator,

(ii) Fluid-volume measuring device,

(iii) Fluid-return indicator,

(iv) Gas detector,

(v) Trip tank,

(vi) Gas separator,

(vii) Degasser, and

(viii) Adjustable choke.

(15) Candidates shall receive instructions on the limitations of the various items of equipment which will be subjected to pressure and/or wear.

(16) Candidates shall receive instructions on the mechanics involved in various well-control situations, including the following subjects:

(i) Gas-bubble migration and expansion,

(ii) Bleeding volume from a shut-in well during gas migration,

(iii) Excessive annular surface pressure,

(iv) Differences between a gas kick and a salt water and/or oil kick,

(v) Procedures and problems involved in stripping operations with drill pipe,

(vi) Special well-control techniques (such as, but not limited to, barite plugs and cement plugs),

(vii) Procedures and problems involved when experiencing lost circulation in well-control operations,

(viii) Procedures and problems involved when experiencing a kick while drilling in a hydrogen sulfide (H_2S) environment, and

(ix) Procedures and problems involved when experiencing a kick during snubbing, coil-tubing, or small-tubing operations.

(17) Candidates shall receive instructions on organizing and directing a well-killing operation and shall subsequently direct such an operation using a model well or simulation device.

(18) Candidates shall receive instructions on the purpose and usage of BOP closing units including the following:

(i) Charging procedures which include precharge and operating pressure,

(ii) Fluid volumes (usable and required),

(iii) Fluid pumps, and

(iv) Maintenance which includes charging fluid and inspection procedures.

(19) Candidates shall receive stripping and snubbing operations instructions on the use of the entire BOP system for working pipe in or out of a wellbore which is under pressure.

(20) Candidates shall receive instructions for detecting entry into abnormally pressured formations and the accompanying warning signals, including the following:

(i) Penetration rate change,

(ii) Shale-density change,

(iii) Mud-chloride content change,

(iv) Shale-cutting characteristics, and

(v) Trip, connection, and background gas changes.

(21) Candidates shall receive instructions on the various types of completion fluids utilized and potential problems caused by their use in well control, including the following:

(i) Gases,

(ii) Water base system,

(iii) Oil base system, and

(iv) Packer fluids.

(22) Candidates shall receive instructions on well-completion/well-control problems including the following:

(i) Multiple completions,

(ii) Running a drill stem test,

(iii) Perforating, and

(iv) Other completion operations.

(23) The course outline shall indicate which portions of the course will not be taught to students intending to receive only surface well-control qualification.

(d) *Refresher well-control course for drilling supervisors.* Individuals who work as a drilling supervisor in drilling operations in the OCS shall successfully complete a refresher course in well control after successful completion of a basic well-control course for drilling supervisors not later than 60 days after the anniversary date of the individual's last successful completion of a certified course for drilling supervisors (basic course in well control, advanced course in well control, or refresher course in well control). A refresher course in well control for drilling supervisors shall include the following:

(1) Candidates shall receive instructions in the most recent improvements in equipment or methods for well control and any applicable Government regulations that pertain to well-control operations and equipment.

(2) Candidates shall receive instructions on at least one constant bottomhole pressure method of well control.

(3) Candidates shall participate in simulator practice problems in well control, simulating a surface BOP stack or a subsea BOP stack, and at least one simulator well-control test problem. Candidates qualifying for subsea well control shall be assigned a subsea simulator problem.

(e) *Qualification procedures for drilling supervisors.* No individual employed as a drilling supervisor shall engage in operations in the OCS as a drilling supervisor unless the following qualifications are met:

(1) The individual shall have successfully completed the training requirements in § 250.212(c) of this section and pass written and/or oral tests and hands-on demonstrations to verify that the individual has a thorough understanding of the well-control equipment, techniques, and principles outlined in paragraph (c) of this section and is qualified to organize and direct a blowout prevention/well-control procedure during drilling operations. Evidence of the successful completion of training requirements shall be maintained at the job site.

(2) The individual shall maintain the qualification by the following:

(i) Successful completion of an approved basic well-control course for drilling supervisors or an advanced well-control course for drilling supervisors at least once every 4 years; and

(ii) Successful completion of a refresher well-control course for drilling supervisors not later than 60 days after the individual's last successful completion of a certified course for drilling supervisors (basic course in well control, advanced course in well control, or refresher course in well control).

(f) *Submission of well-control training programs for drilling supervisors.* Training programs and implementation plans for well-control training for drilling supervisors shall be submitted to the Deputy Associate Director for Offshore Operations for approval in accordance with § 250.211 of this subpart and the following additional requirements:

(1) The training program and plan shall contain the following specific information on the simulator or test well:

(i) Simulator or test well capability for surface and, if applicable, subsea BOP training,

(ii) Capability to simulate lost circulation and secondary kicks, and

(iii) Types of kicks that can be simulated.

(2) The training program and implementation plan shall include the methods to be used for performing the hands-on qualification tests. Qualification tests shall include at least two practice problems with the candidate's position rotated as part of a team. Teams working on the hands-on qualification tests shall consist of no more than three members.

(3) The training program and implementation plan shall stipulate that each candidate shall satisfactorily and completely perform the hands-on qualification test(s) which consists of a surface BOP stack or a subsea BOP stack simulation. Candidates qualifying for subsea well control shall be considered qualified for either surface or subsea operations.

(4) Any retest of a candidate must be accomplished within 48 hours of the initial test. Both hands-on and written test problems on a retest shall be different from the test problems originally given the candidate. If the candidate fails the retest, the candidate must participate in, and successfully complete, a basic course in well control for drilling supervisors.

§ 250.213 Well-completion and workover well control.

(a) *Floorhand training.* After 2 years following the effective date of this rule, individuals employed as floorhands, or the equivalent, in completion and/or workover operations without the tree in place in the OCS shall be trained in blowout prevention and well control in accordance with the following criteria:

(1) A floorhand, or employees in an equivalent job classification, shall receive general instructions on BOP equipment and procedures consistent with the type of BOP system and procedures utilized on the completion/workover rig (includes drilling rig used for well-completion operations) upon which the floorhand is employed. Instructions to floorhands or employees in an equivalent job classification shall include the purpose, operation, and general care of the following:

(i) Annular BOP,
(ii) Ram-type BOP,
(iii) Accumulator system,
(iv) Work string inside BOP,
(v) Work string safety valve,
(vi) Kelly cock,
(vii) Choke manifold,
(viii) Degasser,
(ix) Adjustable choke, and
(x) Wellhead and tree.

(2) In addition to the above, floorhands or employees in an equivalent job classification shall receive instructions on the purpose, operation, and general care of the following auxiliary equipment if present:

(i) Fluid-pit level indicator,
(ii) Fluid-volume measuring device,
(iii) Fluid-return indicator,
(iv) Gas detector,
(v) Fluid-gas separator, and
(vi) Trip tank.

(3) Floorhands or employees in an equivalent job classification shall receive general instructions on blowout and well control during well completion/workover operations such as operation of the choke manifold, stand pipe, filling the tubing and casing with fluid to control bottomhole pressure and removal of tree and tubing hanger.

(4) Floorhands or employees in an equivalent job classification shall receive general instructions in the care, handling, and characteristics of completion, workover, and packer fluids including:

(i) Functions of a completion/workover fluid,
(A) Well killing,
(B) Cleaning out a well,
(C) Plugging back to complete in a shallower interval, and
(D) Bridging agents.
(ii) Fluid types,
(A) Gases,
(B) Water base systems,
(C) Oil base systems, and
(D) Packer fluids.
(iii) Flow properties with emphasis on the following:
(A) Density (weight) and temperature offset,
(B) Viscosity,
(C) Procedure for fluid density (weight),
(D) Gas cutting,
(E) Fluid loss,
(F) Salinity,
(G) Solids content, and
(H) Caustic effect of brines and safe handling of fluids.

(5) Floorhands or employees in an equivalent job classification shall receive general instructions on warning signals that indicate that a kick is occurring or about to occur or conditions that can lead to a kick, including the following:

(i) Gain in pit volume and/or increase in fluid return rate,

(ii) Hole not taking proper amount of fluid during trips,

(iii) Well flowing with pump shutdown,

(iv) Change in flow properties of completion/workover fluid, and

(v) Trip, connection, and background gas changes.

(b) *Qualification procedures for floorhand.* No floorhand or employee in an equivalent job classification shall participate in well-completion or workover operations without the tree in place in the OCS for more than 6 months unless the following qualifications are met:

(1) A floorhand or an employee in an equivalent job classification shall successfully complete the training in well control which meets the criteria set forth in paragraph (a) of this section. Documented evidence of each successfully completed element of training shall be maintained at the job site.

(2) A floorhand or employee in an equivalent job classification shall successfully complete a qualifying test consisting of participation in a well-control drill at the job site carried out within the time limit prescribed. The time required for a floorhand or employee in an equivalent job classification to carry out his/her responsibility during the well-control drill shall be entered on the driller's log, and appropriate documentation shall be furnished to the successful employee.

(3) To maintain qualification, a floorhand or employee in an equivalent job classification must participate in weekly well-control drills, as prescribed

in §§ 250.86 and 250.106 of Subparts E and F, respectively, of this part. The date and time required for the candidate to complete each drill shall be recorded in the operations log.

(4) A training manual containing instructional material on the subjects described in paragraph (a) of this section shall be provided floorhands and employees in an equivalent job classification for their use and retention for future reference.

(c) *Basic completion/workover well-control training course for supervisors.* After 2 years following the effective date of this rule, individuals employed as completion/workover supervisors in well-completion or well-workover operations without the tree in place in the OCS shall be trained in blowout prevention and well control in accordance with the following:

(1) A candidate shall receive instructions on all applicable Government regulations that pertain to the work in regard to completion/workover well-control operations and BOP equipment. Copies of current regulations or abstracts of pertinent provisions shall be furnished to the candidate. This material shall be kept current so that it reflects the latest revisions or additions to Government regulations. At a minimum, these instructions shall cover the following subject matter:

(i) Well-completion/workover requirements contained in Subparts E and F of 30 CFR Part 250.

(ii) Wellbore plugging and abandonment, and

(iii) A general discussion of pollution prevention and waste disposal with emphasis on its relation to well control.

(2) Candidates shall receive instructions on the care, handling, and characteristics of well-completion, workover, and packer fluids, including the following:

(i) Functions of a well-completion or workover fluid:

(A) Well control (killing),

(B) Cleaning out a well,

(C) Plugging back to complete a shallower interval, and

(D) Bridging agents.

(ii) Fluid types:

(A) Gases,

(B) Water-base system,

(C) Oil-base system and

(D) Packer fluids.

(iii) Fluid properties with emphasis on the following:

(A) Density (weight) and temperature offset,

(B) Viscosity,

(C) Procedure for increasing fluid density (weight),

(D) Gas cutting,

(E) Fluid loss,

(F) Salinity,

(G) Solids content,

(H) Gel strength,

(I) Crystallization, and

(J) Caustic effect of brines and safe handling of fluids.

(3) Candidates shall receive instructions on the major causes of an uncontrolled flow from a well, including the following:

(i) Failure to keep the hole full,

(ii) Swabbing effect of pulling the pipe,

(iii) Loss of circulation,

(iv) Insufficient density of completion/workover fluid,

(v) Abnormally pressured formations, and

(vi) Effect of too rapid lowering pipe in the hole.

(4) Candidates shall receive instructions on the importance of measuring the volume of fluid required to fill the hole during trips and methods for measuring and recording hole-fill volumes.

(5) Candidates shall receive instructions on the warning signals that indicate that a kick is occurring or is about to occur and on conditions that can lead to a kick, including the following:

(i) Gain in pit volume,

(ii) Increase in return fluid flow rate,

(iii) Hole not taking proper amount of fluid during trip,

(iv) Decrease in circulating pressure or increase in pump strokes,

(v) Trip, connection, and background gas changes,

(vi) Fluid cutting (weight loss),

(vii) Well flowing with pump shutdown, and

(viii) Change in flow properties of well-completion/workover fluid.

(6) Candidates shall receive instructions on the correct procedures for shutting in a well for well-control purposes, including use of the BOP system and the choke manifold for well control. These instructions shall include the sequential steps to be followed.

(7) Candidates shall receive instructions on one of the following constant bottomhole pressure methods for blowout prevention and well control, including those conditions which may be unique to either a surface or subsea BOP stack.

(i) Driller's method,

(ii) Wait-and-weight method,

(iii) Concurrent (circulate and weight) method, and

(iv) Other applicable constant bottomhole pressure methods.

(8) Candidates shall participate in blowout-prevention and well-control exercises using a well simulator or a model well in accordance with paragraph (f) of this section.

(9) Candidates shall be instructed on calculations used in blowout prevention and well control and the basis for their use, including the following:

(i) Hydrostatic pressure and pressure gradient,

(ii) Fluid-density increase required to control fluid flow,

(iii) Conversion between fluid density and pressure and the importance of that conversion in understanding danger of formation breakdown under the pressure caused by the fluid column,

(iv) Drop in pump pressure as fluid density increases during well-control operations; relationships between pump pressure, pump rate, and fluid density, and

(v) Pressure limitations on casings.

(10) Candidates shall receive instructions on unusual well control situations which shall include, but not be limited to, the following:

(i) Work string is off bottom,

(ii) Work string is out of the hole,

(iii) Lost circulation occurs,

(iv) Work string is plugged,

(v) There is excessive casing pressure,

(vi) There is a hole in work string,

(vii) There are multiple completions in the hole (more than one zone open to well), and

(viii) There is a hole in the casing string.

(11) Candidates intending to receive subsea well-control qualification shall receive instructions on the special problems in blowout prevention and well control when utilizing a subsea BOP stack including:

(i) Use of marine risers,

(ii) Choke line friction determinations,

(iii) Riser collapse,

(iv) Removal of trapped gas from the BOP stack after controlling a well kick, and

(v) "U" tube effect as gas hits the choke line.

(12) Candidates shall receive instructions on the installation, operation, maintenance, and testing of BOP systems.

(13) Candidates shall receive instructions on the purpose, installation, operation, and general maintenance of the following auxiliary equipment:

(i) Fluid-pit level indicator,

(ii) Fluid-volume measuring device,

(iii) Fluid-return indicator,

(iv) Gas detector,

(v) Trip tank,

(vi) Gas separator,

(vii) Degasser, and

(viii) Adjustable choke.

(14) Candidates shall receive instructions on the limitations of the

various items of equipment which will be subjected to pressure and/or wear.

(15) Candidates shall receive instructions on the mechanics involved in various well-control situations including the following subjects:

(i) Gas-bubble migration and expansion,

(ii) Bleeding volume from a shut-in well during gas migration.

(iii) Excessive annular surface pressure,

(iv) Differences between a gas kick and a salt water and/or oil kick,

(v) Procedures and problems involved in stripping and snubbing operations with work string,

(vi) Special well-control techniques such as, but not limited to, barite plugs, cement plugs, bullheading, and lubricate and bleed,

(vii) Procedures and problems involved when experiencing lost circulation in completion and workover operations, and

(viii) Procedures and problems involved when experiencing a kick while conducting completion/workover operations in a H_2S sulfide environment.

(16) Candidates shall receive instructions on organizing and directing a well-killing operation during completion and workover operations and shall subsequently direct such an operation using a model well or simulation device.

(17) Candidates shall receive instructions on the purpose and usage of BOP closing units, including the following:

(i) Charging procedures which include precharge and operating pressure,

(ii) Fluid volumes (usable and required),

(iii) Fluid pumps, and

(iv) Maintenance which includes charging fluid and inspection procedures.

(18) Candidates shall receive instructions on well-control problems during completion and workover operations, including the following:

(i) Killing a flow during a completion or workover operation,

(ii) Simultaneous drilling and completion or workover operations on the same platform,

(iii) Killing a producing well, and

(iv) Removing the tree.

(19) Candidates shall receive instructions in well-control equipment, including the following:

(i) Surface equipment,

(ii) Downhole tools and tubulars, and

(iii) Packers.

(20) Candidates shall receive instructions in, but are not limited to, the following topics:

(i) Reasons for well-completion or workover operations:

(A) Reworking a producing reservoir to control water and/or gas production,

(B) Water coning,

(C) Completing for production from a new reservoir,

(D) Completing a well in more than one reservoir,

(E) Stimulating a completion in a producing reservoir to increase production, and

(F) Repair mechanical failure.

(ii) Killing a producing well:

(A) Bullheading,

(B) Lubricate and bleed,

(C) Coil-tubing unit, and

(D) Snubbing unit.

(iii) Preparing the well for entry:

(A) Use of back pressure valves,

(B) Surface and subsurface safety systems,

(C) Removal of tree and tubing hanger, and

(D) Installation and testing of blowout preventer and wellhead prior to removal of back pressure valves and tubing plugs.

(21) The course outline shall indicate which portions of the course will not be taught to students intending to receive only surface well-control qualification.

(d) *Refresher completion/workover well-control training course for supervisors.* Individuals who are employed as a completion or workover supervisor in OCS completion or workover operations without the tree in place in the OCS shall successfully complete a refresher course in completion and workover well control not later than 60 days after the anniversary of the individual's last successful completion of a certified course in well control for supervisors of completion and/or workover operations without the tree in place (basic course in well control, advanced course in well control, or refresher course in well control). A refresher course in well control for supervisors of completion and/or workover operations without the tree in place shall include the following:

(1) Candidates shall receive instructions in the most recent improvements in equipment or methods for blowout prevention and well control and any applicable Government regulations that pertain to blowout-prevention and well-control operations and equipment.

(2) Candidates shall receive instructions on at least one constant bottomhole pressure method of well control.

(3) Candidates shall participate in at least one simulator practice problem in well control, simulating a surface BOP stack or a subsea BOP stack, and at least one simulator well-control test problem. Candidates attempting to qualify for subsea well control shall be assigned a subsea simulator problem.

(e) *Qualification procedures for completion/workover supervisor.* No individual employed as a completion or workover supervisor shall engage in supervising completion or workover operations without the tree in place in the OCS unless the following qualifications are met:

(1) The individual shall have successfully completed the training requirements in § 250.213(c) and passed written tests and hands-on demonstrations to verify that the individual has a thorough understanding of the well-control equipment, techniques, and principles outlined in paragraph (c) of this section and is qualified to organize and direct a blowout-prevention or well-control procedure during a completion or workover operation. Evidence of the successful completion of these training requirements shall be maintained at the job site.

(2) The individual shall maintain the qualification by the following:

(i) Successful completion of an approved basic completion/workover supervisor well-control course or an advanced completion/workover supervisor well-control course not later than 60 days after the 4th anniversary of the individual's last successful completion of a basic or advanced course in well control for supervisors of well-completion or workover operations with the tree removed.

(ii) Successful completion of a refresher course in completion and workover well-control operations in accordance with paragraph (d) of this section.

(f) *Submission of training programs for completion/workover well-control course.* Training programs and implementation plans for well-control training for supervisors of well-completion and workover operations without the tree in place shall be submitted to the Deputy Associate Director for Offshore Operations for approval in accordance with § 250.211 of this part and the following additional requirements:

(1) The training program and plan shall contain the following specific information on the simulator or test well:

(i) Simulator or test well capability for surface and, if applicable, subsea BOP training,

(ii) Capability to simulate lost circulation and secondary kicks, and

(iii) Types of kicks that can be simulated.

(2) The training program and implementation plan shall include the methods to be used for performing the hands-on qualification tests. Qualification tests shall include at least two practice problems with the candidate's position rotated as part of a team. Teams working on hands-on qualification tests shall consist of no more than three members.

(3) The training program and implementation plan shall stipulate that each candidate shall satisfactorily and completely perform the hands-on test which consists of a surface BOP stack or a subsea BOP stack simulation. Candidates qualifying for subsea well control shall be considered qualified for either surface or subsea operations.

(4) Any retest of a candidate must be accomplished within 48 hours of the initial test. Both hands-on and written test problems on a retest shall be different from the test problems originally given the candidate. If the candidate fails the retest, the candidate must participate in, and successfully complete, a basic course in well control for supervisors of well-completion and workover operations.

(g) *Basic well-control training course for well-servicing operations.* After 2 years following the effective date of this rule, at least one member of a well-servicing crew shall be trained in accordance with the following requirements and shall be present at all times when snubbing, coil-tubing, or small-tubing operations are being conducted. The trained individual need only be trained in the area of the operation which that individual will be conducting (i.e., snubbing, coil tubing, or small tubing).

(1) A candidate shall receive instructions on all applicable Government regulations that pertain to the work with regard to well-completion and workover well-control operations and blowout-prevention equipment. Copies of current regulations or abstracts of pertinent provisions shall be furnished to the candidate. This material shall be kept current so that it reflects the latest revisions or additions to Government requirements. At a minimum, these instructions shall include the following:

(i) Well-completion/workover procedures outlined in Subparts E and F of this part,

(ii) Emergency shutdown systems,

(iii) Production safety systems,

(iv) Well plugging and abandonment, and

(v) Pollution prevention and waste disposal.

(2) Candidates shall receive instructions in the care, handling, and characteristics of well-completion, workover, and packer fluids, including the following:

(i) Functions of a well-completion or workover fluid:

(A) Well control (killing),

(B) Cleaning out a well,

(C) Plugging back to complete a shallower interval, and

(D) Bridging agents.

(ii) Fluid types:

(A) Gases,

(B) Water base system,

(C) Oil base system, and

(D) Packer fluids.

(iii) Fluid properties with emphasis on the following:

(A) Density (weight) and temperature offset,

(B) Viscosity,

(C) Procedure for increasing fluid density (weight),

(D) Gas cutting,

(E) Fluid loss,

(F) Salinity,

(G) Solids content,

(H) Gel strength,

(I) Crystallization, and

(J) Caustic effect of brines and safe handling of fluids.

(3) Candidates shall receive instructions in well-control equipment including the following:

(i) Surface equipment:

(A) Well completion and workover equipment,

(B) BOP equipment, and

(C) Tree.

(ii) Tubulars:

(A) Tubing hanger,

(B) Backpressure valve (threaded/profile),

(C) Landing nipples,

(D) Lock mandrels for corresponding nipples and operational procedures for each,

(E) Gas lift equipment, and

(F) Running and pulling tools operation.

(4) Candidates shall receive instructions in the following topics:

(i) Reasons for well-completion and workover:

(A) Reworking a completion in a producing reservoir to control water and/or gas production,

(B) Completing for production in a new reservoir,

(C) Completing for production in more than one reservoir,

(D) Stimulating a completion in a producing reservoir to increase production, and

(E) Repair mechanical failure.

(ii) Killing a producing well:

(A) Bullheading,

(B) Lubricate and bleed,

(C) Coil-tubing unit, and

(D) Snubbing unit.

(iii) Preparing the well for entry:

(A) Surface and subsurface safety systems,

(B) Removal of tree and tubing hanger, and

(C) Installation and testing of blowout preventer and wellhead prior to removal of back-pressure valves and tubing plugs.

(iv) Procedure and problems involved when experiencing a kick while conducting completion/workover operations in an H_2S environment.

(5) Candidates shall receive instructions on the correct procedures for shutting in a well for well control purposes, including controlling a well with the BOP system, and surface/subsurface safety system. These instructions shall include the sequential steps to be followed.

(6) Candidates intending to become qualified for snubbing operations shall receive instructions in snubbing units, including the following:

(i) Types:

(A) Rig assist, and

(B) Stand alone.

(ii) Applications:

(A) Running and pulling production or kill strings,

(B) Resetting weight on packers,

(C) Fishing for lost wireline tools or parted kill strings, and

(D) Circulating needed cement or fluid.

(iii) Equipment:

(A) Operating mechanism,

(B) Power supply,

(C) Control assembly and basket,

(D) Slip assembly,

(E) Mast and counterbalance winch, and

(F) Access window,

(iv) BOP equipment:

(A) Tree connection or flange,

(B) Rams,

(C) Spool,

(D) Traveling slips,

(E) Manifolds,

(F) Auxiliary—(FOSV, Inside BOP),

(G) Maintenance, and

(H) Testing.

(7) Candidates intending to become qualified for coil-tubing operations shall receive instructions in coil tubing units, including the following:

(i) Applications:

(A) Initiating flow,

(B) Cleaning out sand in tubing, and

(C) Performing stimulation operations.

(ii) Equipment description:

(A) Coil tubing,

(B) Reel,

(C) Injection head,

(D) Control assembly, and

(E) Injector hoist.
(iii) BOP equipment:
(A) Tree connection or flange,
(B) Rams,
(C) Injector assembly, and
(D) Circulating system.
(8) Candidates intending to become qualified for small-tubing operations shall receive instructions in small-tubing units, including the following:
(i) Applications:
(A) Stimulation operations,
(B) Cleaning out sand and other obstructions in tubing, and
(C) Plugback and squeeze cementing.
(ii) Equipment description:
(A) Derrick and drawworks,
(B) Small tubing,
(C) Pumps, and
(D) Weighted-fluids facilities.
(iii) BOP equipment.
(iv) Weighted fluids:
(A) Rams,
(B) Wellhead connection, and
(C) Check valve.
(9) Candidates shall receive instructions in special tools and systems, including the following:
(i) Automatic shut-down systems:
(A) Control points,
(B) Activator pilots,
(C) Monitor pilots,
(D) Control manifolds, and
(E) Subsurface system.
(ii) Flow string systems:
(A) Tubing,
(B) Mandrels and nipples,
(C) Flow couplings,
(D) Blast joints, and
(E) Sliding sleeves.
(iii) Pump down equipment:
(A) Purpose,
(B) Applications,
(C) Requirements,
(D) Surface circulating systems,
(E) Horizontal lubricators,
(F) Entry loops, and
(G) Tree connection/flange.
(10) Candidates shall receive instructions on the limitations on the various items of equipment which will be subjected to pressure and/or wear.

(h) *Refresher well-control training course for well-servicing operations.* To maintain their qualifications, individuals who are trained in well-servicing operations in the OCS shall successfully complete a refresher course in well control not later than 60 days after the anniversay date of the individual's last successfully completed certified well-servicing course (basic course, advanced course, or refresher course). A refresher course in well control for well-servicing operations shall contain instructions in the technological advances and improvements in equipment or methods for blowout prevention and well control and any new Government requirements applicable to well control during snubbing, coil-tubing, and small-tubing operations in the OCS. The candidate shall also pass a written test.

(i) *Qualification procedures for well servicing.* At least one member of a well-servicing crew shall be trained in accordance with the following requirements and shall be present at all times when snubbing, coil-tubing, or small-tubing operations are being conducted. The trained individual need only be trained in the area of the operation which that individual will be conducting (i.e., snubbing, coil tubing, or small tubing).

(1) The individual shall have successfully completed the applicable training requirements in § 250.213(g) of this section and passed a written test to verify that the individual has a thorough understanding of well-control equipment, techniques, and principles outlined in § 250.213(g) of this section and is qualified to organize and direct blowout-prevention or well-control activities during a snubbing, coil-tubing, or small-tubing operation. Evidence of the successful completion of required training shall be maintained at the job site. Such evidence shall indicate the area(s) for which the employee is trained (i.e., snubbing, coil tubing, and/or small tubing).

(2) The individual shall maintain the qualification by the following:

(i) Successful completion of the basic well control for well-servicing operations course or the advanced well-control course for well servicing at least once every 4 years, and

(ii) Successful completion of a refresher course in well control for well-servicing operations not later than 60 days after the anniversary date of the last successfully completed basic course in well-servicing well control, advanced course in well-servicing well control, or refresher course in well-servicing well control.

(j) *Submission of training program for well servicing.* Training programs and implementation plans for well-control training for well servicing shall be submitted to the Deputy Associate Director for Offshore Operations for approval in accordance with § 250.211 of this part.

§ 250.214 Production safety system training.

(a) *Basic production safety system personnel course.* During the 2-year period following the effective date of these regulations, personnel engaged in production operations shall be in compliance with training regulations in effect prior to the effective date of this rule. For individuals successfully completing a production safety systems course after May 31, 1988, and prior to 2 years after the effective date of these rules, the individual shall be considered to have completed a basic course in accordance with the requirements of this part if the course met the rules in effect at the time the course was taken. After 2 years following the effective date of this rule, each employee who is engaged in the installation, repair, testing, maintenance, or operation of a surface or subsurface safety device and the individual on the platform with overall responsibility for production operations shall be trained in accordance with the following:

(1) Each employee shall be familiar with oil and gas production operations and equipment.

(2) The employee shall receive instructions on all applicable Government regulations that pertain to the work with regard to production operations and surface and subsurface safety devices. Also, copies of current Government regulations or abstracts of pertinent provisions shall be furnished to the employee. These instructions shall include the following:
(i) Production safety devices,
(ii) Subsurface safety devices,
(iii) Design, installation, and operation of surface production safety equipment,
(iv) Additional production system requirements,
(v) Testing of production safety equipment and recording of the test results,
(vi) Quality assurance requirements for safety and pollution prevention equipment,
(vii) Pollution prevention and waste disposal requirements during production operations, and
(viii) General requirements for completion and workover operations (including snubbing, coil-tubing, and small-tubing units).

(3) The employee shall receive instructions on how failures or malfunctions in a system can cause abnormal conditions that must be brought under control by properly functioning safety devices.

(4) Employees shall receive instructions on the basic protection concepts, including the following:
(i) Undesirable events,
(ii) Protective shut-in action, and
(iii) Emergency support system (ESS).

(5) Employees shall receive instructions on the causes of failure in such systems, detection of abnormal conditions, primary protection devices and procedures, secondary protection devices and procedures, and location of

safety devices for the control or mitigation of various undesirable events, including the following:

(i) Overpressure,

(ii) Leak,

(iii) Liquid overflow,

(iv) Gas blowby,

(v) Underpressure,

(vi) Excess temperature (fire and exhaust heated components),

(vii) Direct ignition source (fired components), and

(viii) Excess combustible vapors in the firing chamber (fired components).

(6) Each employee shall receive instructions on safety analysis concepts, including the following:

(i) Safety analysis table (SAT),

(ii) Safety analysis checklist (SAC), and

(iii) Safety analysis function evaluation (SAFE) chart.

(7) The employee shall receive instructions on the safety analysis of each basic process component used in a platform production process system including the following:

(i) Wellheads and flow lines,

(ii) Injection lines,

(iii) Headers,

(iv) Pressure vessels,

(v) Atmospheric vessels,

(vi) Fired and exhaust heated components,

(vii) Pumps,

(viii) Compressors,

(ix) Pipelines, and

(x) Heat exchangers (shell-tube).

(8) Employees shall receive hands-on training on safety devices to prepare him/her for installing, operating, repairing, or maintaining such equipment. In this context, operating includes testing, adjusting calibrations, and recording test and calibration results. Installing includes the original installation and replacement of equipment. Maintaining refers to preventive maintenance, routine repair, and replacement of defective or malfunctioning component parts. The major categories of equipment that shall be included in the training program, as a minimum, are the following:

(i) High-low-pressure sensors,

(ii) High-low-level sensors,

(iii) High-low-temperature sensors,

(iv) Combustible gas detectors,

(v) Pressure relief devices,

(vi) Flow line check valves,

(vii) Surface safety valves,

(viii) Shutdown valves,

(ix) Fire (flame, heat, or smoke) detectors,

(x) Auxiliary devices (3-way block and bleed valves, time relays, 3-way snap acting valves, etc.),

(xi) Surface-controlled subsurface safety valves and/or surface-control equipment, and

(xii) Subsurface-controlled subsurface safety valves.

(9) The following is applicable to schools which include subsurface equipment.

(i) Each employee shall receive instructions relating to inspections, testing, and maintenance of surface safety devices.

(ii) The employee shall receive instruction relating to inspection, testing, and maintenance of subsurface safety devices.

(iii) The employees shall receive instructions relating to the inspection, testing, and maintenance of surface-control systems for surface-controlled subsurface safety valves.

(10) The employees shall receive instructions in at least one safety device that illustrates the primary operation principle in each class of safety devices stated in § 250.214(a)(8) (i) through (xii) of this part, including the following:

(i) Basic principle of operation,

(ii) Limitations affecting application,

(iii) Most probable problems causing equipment malfunction or failure and the correction of these problems (e.g., replace bad o-rings, clear blocked orifice, replace broken spring),

(iv) Test for proper set point, operation, etc.,

(v) Adjustment, calibration, or reset where applicable,

(vi) Recording inspection results and malfunctions on appropriate format, and

(vii) Special techniques for installation of safety devices, including safety device orientation, special lubricants, and special installation tools.

(11) The employee shall receive instructions on the basic principle and logic of the emergency support system including the following:

(i) Combustible and toxic gas detection system,

(ii) Liquid containment system,

(iii) Fire loop system,

(iv) Other fire detection devices,

(v) Emergency shutdown system, and

(vi) Subsurface safety valves (SSSV).

(12) Each employee shall receive general instructions in the following well-completion and workover topics:

(i) Reasons for completion or workover,

(ii) Killing a producing well,

(iii) Preparing the well entry:

(A) Use of backpressure valves,

(B) Removal of tree, tubing, tubing hanger, and SSSV, and

(C) Installation and testing of BOP prior to initiating well-completion or workover operations.

(b) *Refresher production safety system personnel training course.* An employee who is engaged in the installation, repair, testing, maintenance, or operation of a surface or subsurface safety device, and the individual on the platform with overall responsibility for production operations shall successfully complete a refresher course in production safety systems approved under the provision of § 250.211 of this part not later than 60 days after the 2nd anniversary of the employee's most recent completion date for a course approved under § 250.211 for production safety systems. The refresher course shall contain, as a minimum, instructions in the most recent improvements in equipment for production safety systems and any applicable Government regulations that pertain to production safety systems. The candidate shall pass a written test.

(c) *Qualification procedures for production safety system personnel.* An employee who is engaged in the installation, repair, testing, maintenance, or operation of surface or subsea safety devices, and the individual on the platform with overall responsibility for production operations shall not engage in such operations in the OCS until he/she meets the following qualifications:

(1) The employee shall have successfully completed the training requirements in § 250.214(a) of this part and pass a written test to verify that the candidate has a thorough understanding of production safety systems outlined in § 250.214(a) of this part and is qualified to install, test, maintain, and operate surface and/or subsurface safety devices. Evidence that the training has been completed shall be maintained at the job site.

(2) The employee shall maintain the qualification by the following:

(i) Successful completion of an approved basic production safety system personnel training course at least once every 4 years, and

(ii) Successful completion of a refresher course in the installation, operation, repair, and maintenance of production safety systems not later than 60 days after the 2-year anniversary date for the individual's last successful completion of a basic course in production safety systems, an advanced course in production safety systems, or a refresher course in production safety systems.

(3) A manufacturer's representative need not be qualified in accordance with the requirements of § 250.214 of this part if the representative is working on equipment supplied by the company.

provided the representative has received training and is qualified by the manufacturer to install, service, or repair the specific safety device or safety system, and if the representative is accompanied by an individual trained under § 250.214 who is capable of evaluating the impact of the work done by the manufacturer's representative on the total system.

(4) On-the-job trainees working with safety devices and who are not trained in accordance with the regulation of this section shall be supervised by an individual who is present at the work site and who is qualified under this section.

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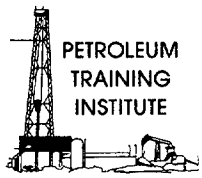
END AREA INSPECTION

THREAD CLEANING



UNIVERSITY OF HOUSTON — VICTORIA
DIVISION OF CONTINUING EDUCATION

SCHEDULE
1990

Basic Well Control Surface/Subsea*

1990

January	8-10, 24-26
February	13-15
March	7-9, 26-28
April	9-11, 25-27
May	1-3, 23-25
June	13-15, 20-22
July	9-11, 18-20, 31-
August	2
August	21-23, 27-29
September	12-14, 18-20
October	1-3, 24-26
November	5-7, 27-29
December	17-19

Workover and Well Completion

1990

March	12-16
July	23-27

Well Control for Engineers and Technical Personnel*

1990

January	24-26
April	25-27
July	18-20
November	27-29

Drilling Practices

1990

February	5-9
June	4-8
November	12-16

LOTUS 1-2-3

1990

March	19-20
August	7-8
October	29-30
December	3-4

Advanced LOTUS 1-2-3

1990

March	21-22
August	15-16
December	5-6

dBASE III+/dBASE IV

1990

February	26-27 (III+)
March	29-30 (IV)
April	18-19 (III+)
August	27-28 (IV)
October	9-10 (III+)
November	13-14 (IV)

Advanced dBASE III+/dBASE IV

1990

May	9-10 (III+)
July	16-17 (IV)
November	1-2 (III+)
	27-28 (IV)

Well Control Refresher*

1990

January	5, 12, 22
February	5, 16, 22
March	6, 19, 29
April	12, 17, 24
May	4, 21, 30
June	12, 18, 26
July	6, 12, 30
August	8, 14, 24, 30
September	5, 10, 21
October	5, 23, 29
November	9, 19, 26
December	4, 14, 20

Workover Well Control

Dates Arranged
Upon Request

Open Hole Log Interpretation

1990

January	15-18
May	15-18
December	10-13

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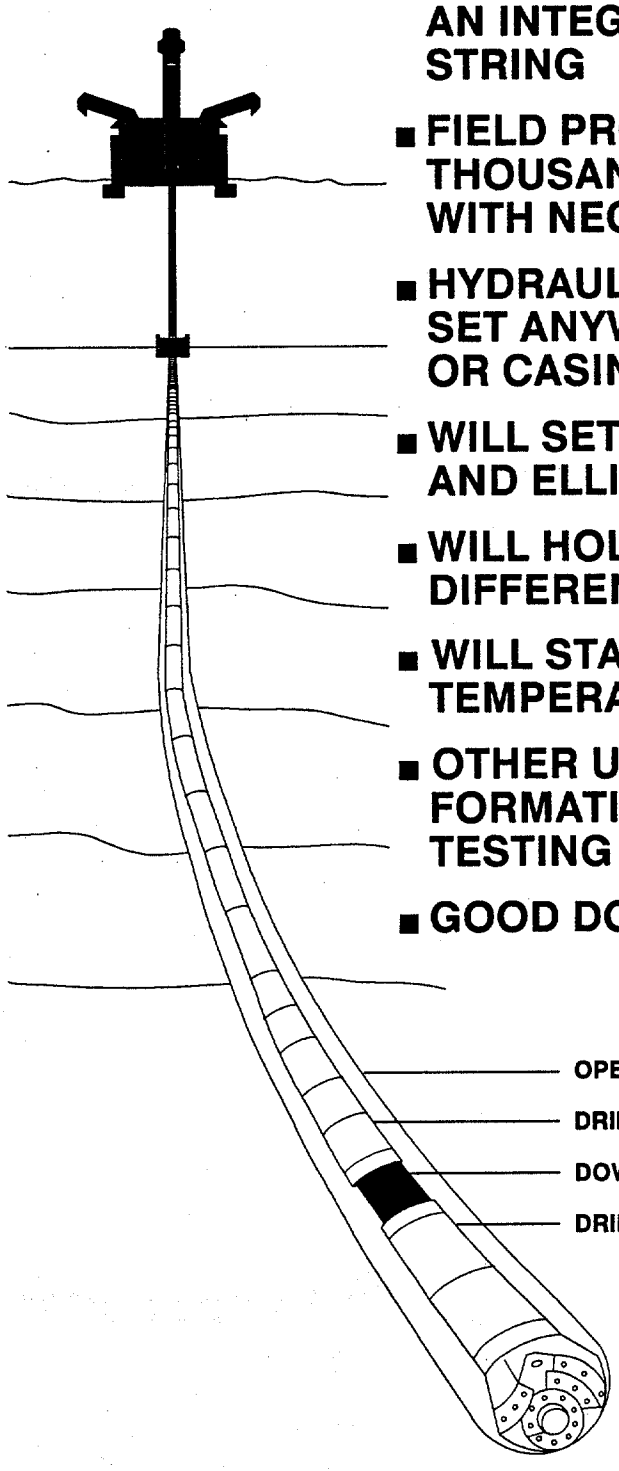

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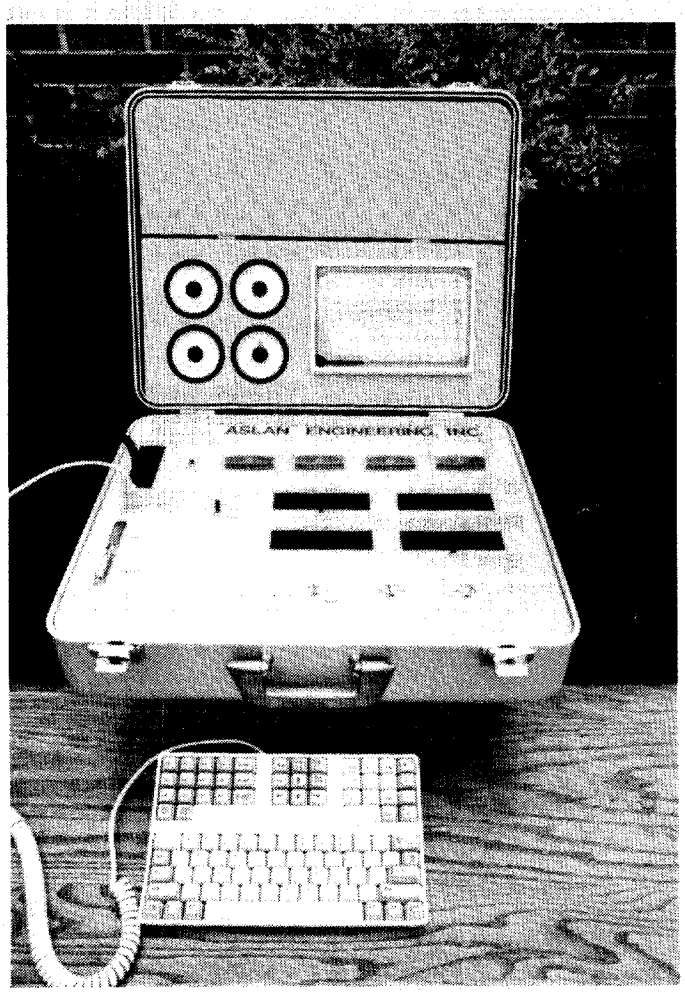

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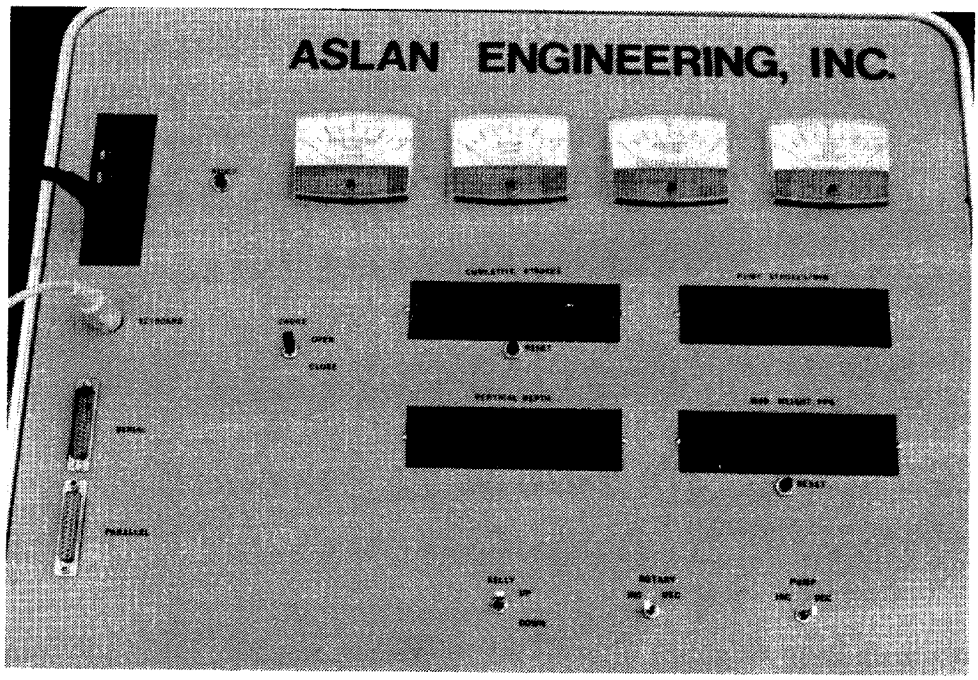

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FINAL REPORT
MMS Contract 14-12-0001-30274
Revised November 27, 1989

The Development of Improved Blowout Prevention Systems for Offshore Drilling Operations Part 1 – Shallow Gas Hazards

by Adam T. Bourgoyne, Jr.
Louisiana State University

Introduction

In some marine environments where abnormal formation pressures may be encountered at very shallow depths, conventional blowout prevention equipment and procedures are likely to be of no benefit. This can lead to very severe well control problems when permeable, gas bearing formations are drilled. There have been numerous disasterous blowouts resulting from loss of well control after drilling into shallow, abnormally pressured gas formations. A research well facility at Louisiana State University has been used to study this problem under the sponsorship of the Minerals Management Service. A number of technical publications have resulted from this work. In this report, those technical contributions will be summarized and concepts will be presented for minimizing shallow gas hazards

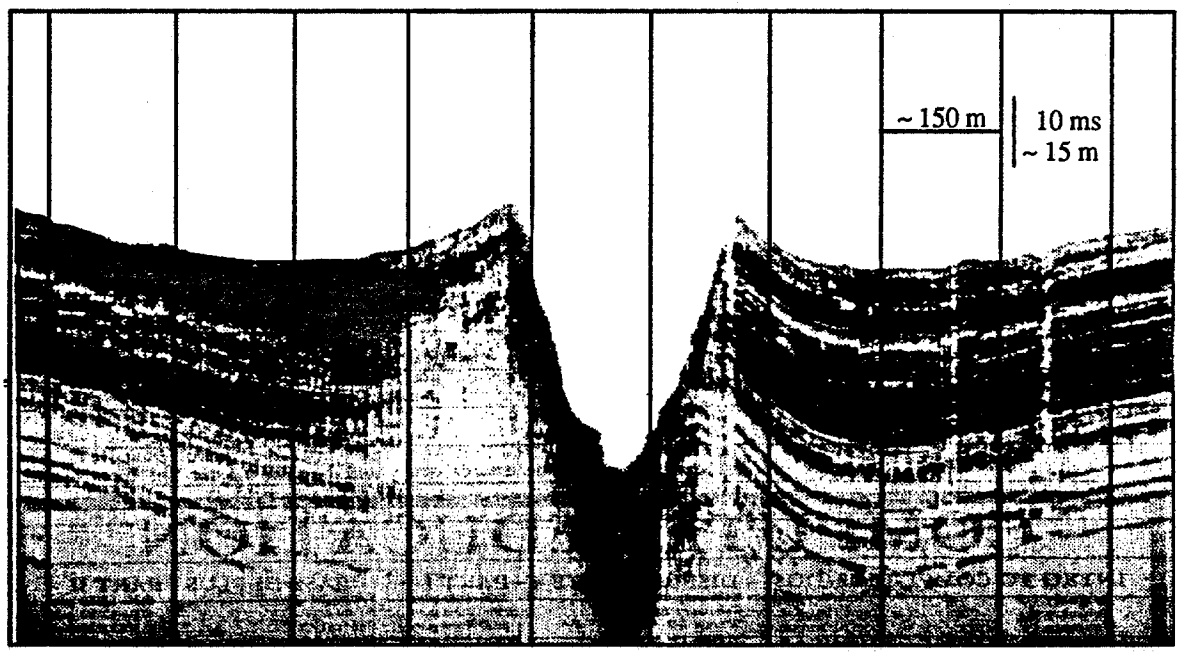

Figure 1. Side view of a crater on the sea floor thought to be due to a naturally occurring shallow gas blowout. (After Prior, Doyle, and Kaluza, 1989.) (Courtesy of Science Mag.)

Shallow gas accumulations are always at least slightly abnormally pressured in the upper portion of the reservoir due to the density difference between the gas and the surrounding water. Abnormal formation pore pressures that are approaching the formation fracture pressure are thought to be possible in sand lenses due to gas migration along fault planes from below. Shown in **Figure 1** is a recently discovered crater **[Prior, Doyle, and Kaluza, 1989]** in the floor of the Gulf of Mexico that is thought to be the result of a naturally occurring shal-

low gas blowout. It was discovered by a Shell Oil Company survey team in 2,176 meters (7,139 ft) of water, about 115 km (71 miles) southeast of the Mississippi River delta. The crater was elliptical in shape, 58 m (190 ft) deep, 280 m (920 ft) across, and about 400 m (1300 ft) long. Slow seepage of the abnormally pressured gas was thought to be blocked by the formation of gas hydrates in the near surface sediments.

Even when the formation pore pressure is nearly normal, it is generally not feasible to shut-in a shallow gas flow when drilling from a bottom supported vessel. By the time the rig crew can recognize that the well has started to flow, the gas has already traveled a considerable distance up the open borehole. If the blowout preventers are closed, the pressure at the casing seat will generally build to a value exceeding the formation fracture pressure. If one or more fractures reach the surface, the resulting flow can destroy the foundations of a bottom-supported structure and ultimately lead to the formation of a crater. The rig shown in **Figure 2** eventually collapsed into a large crater in the seafloor.

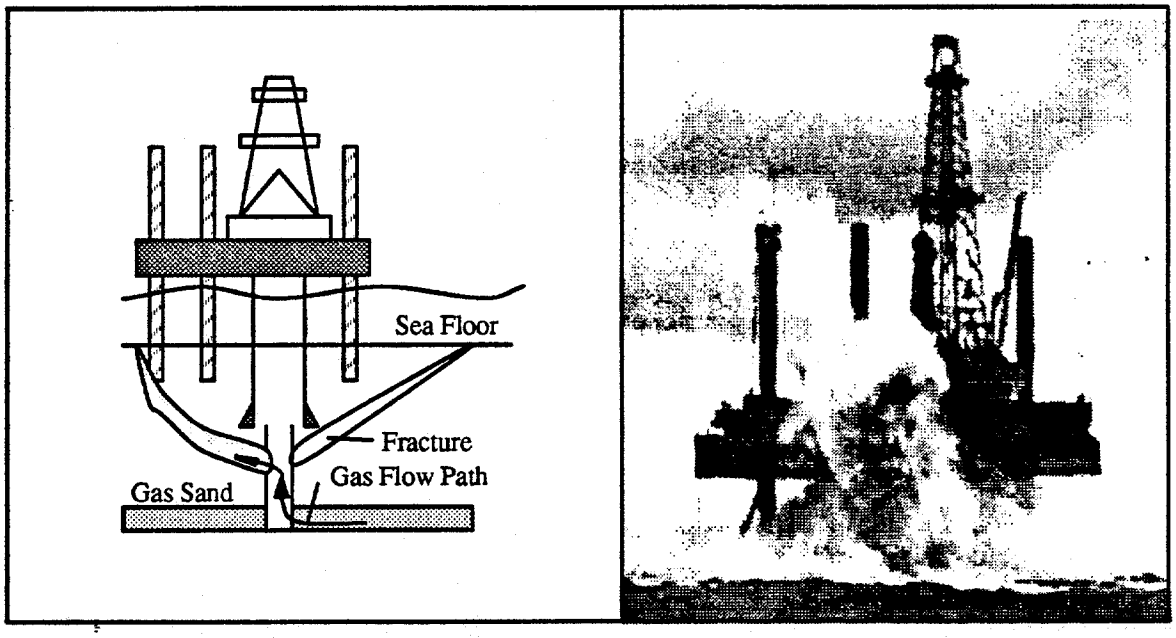

Figure 2 – Example blowout illustrating the need for a diverter system.

Prevention of Shallow Gas Flows

Because of the difficulties in handling gas flows while drilling at shallow depths, considerable attention should be given to preventing such flows when planning the well. Seismic surveys can sometimes be used to identify potential shallow gas zones prior to drilling (**Figure 3**). If localized gas concentrations are detected by seismic analysis, hazards can be reduced when selecting the surface well location.

When possible, empirical correlations should be applied to the seismic data to estimate formation pore pressures **[Bourgoyne et. al., 1986]**. This will sometimes permit the detection of shallow, abnormal pressure in the marine sediments. When formation pore pressures can be accurately estimated, an appropriate mud density program can be followed to prevent gas from entering the borehole.

(1) a vent line for conducting the flow away from the structure that is large enough to prevent a pressure build–up in the well to values above the fracture pressure,

(2) a means for closing the well annulus above the vent line during diverter system operations, and

(3) a means for closing the vent line during normal drilling operations.

```
10 INPUT "Enter the pump rate in cubic meters/sec –                ", QM
20 INPUT "Enter the mud density in kg/cubic meters –               ",RHO
30 INPUT "Enter the bit diameter in m –                            ",D
40 INPUT " Enter the depth D1 of the shallowest gas sand in m –    ",D1
50 INPUT "Enter the pore pressure gradient at D1 in PA/m –         ",GP1
60 INPUT "Enter the depth of the bit D2 in m –                     ",D2
70 INPUT "Enter the pore pressure gradient at D2 in Pa/m –         ",GP2
80 INPUT "Enter the porosity at D2 as fraction –                   ",POR
85 INPUT "Enter the gas saturation at D2 as fraction –             ",SG
90 P1 = GP1 * D1 + 101300
100 z1 = 1 – 1.3E–08 * P1
110 QS = 0
120 P2 = GP2 * D2 + 101300
130 Z2 = 1 – 1.3E–08 * P2
140 X1 = 9.807 * RHO * D1 +101300 – P1
150 XDEN = 8314 * 311 * Z1 * LOG( P1 / 101300 ) – 156.9 * D1
160 XNV = X1 / XDEN
170 RP = 4 / 3.14159 * 8314 * 311 * XNV * Z2 * (QM + QS ) / ( D^2 * POR * SG * P2 )
180 QS = 3.14159 / 4 * D^2 * RP * ( 1 – POR )
190 RHOA = ( QS * 2.6 * 1000 + QM * RHO ) / ( QS + QM )
200 X2 = 9.807 * RHOA * D1 + 101300 – P1
210 IF ABS ( X2 – X1 ) < 1 THEN GOTO 240 ELSE GOTO 220
220 X1 = X2
230 GOTO 150
240 PRINT "Density of Mud/ Cuttings mixture in kg.cubic meter = ",RHOA
250 PRINT " Maximum Safe Drilling Rate in m/s =                  ", RP
260 END
```

Figure 5 – Algorithm (BASIC programming language) for calculating estimated maximum safe drilling rate at shallow depths in presence of drilled gas.

The sequence of events occurring when a shallow gas flow is encountered are illustrated in **Figure 6**. When the driller recognizes that the well has begun to flow, the diverter system is actuated (2b). This simultaneously causes the vent line to open and the annular diverter head to close. If a proper assessment of the application of a dynamic kill has been made and if the well plan calls for a dynamic well control method to be attempted with the rig pumps, the driller may continue to pump drilling fluid at the maximum possible rate as an attempt to regain control. As drilling fluid is displaced from the well, the rate of flow of gas into the well increases due to the loss in bottom–hole pressure (2c). After the well is unloaded of drilling fluid, a semi–steady–state condition is reached (2d) in which formation gas, water, and sand is flowing through the vent line. The loss of drilling fluid from the wellbore and the resulting decrease in pressure will usually result in an unstable borehole wall that will eventually cave–in and form a plug that stops the flow.

For many rigs, diverter systems have been added after rig construction, which have complicated the placement of vent lines. Also, since diverter systems are not routinely used, special testing and training is needed to ensure maintenance of the diverter components and readiness of the rig crew to handle a shallow gas flow. Records available in the Events File of the Minerals Management Service indicate a diverter failure rate of approximately 50 percent during shallow gas flows.

The three most common modes of diverter failure have been:

(1) a failure of the vent line valve to open,

(2) formation fracture due to insufficient vent line size, and

(3) erosion.

Diverter design criteria have been developed that are directed at overcoming these common modes of diverter failure.

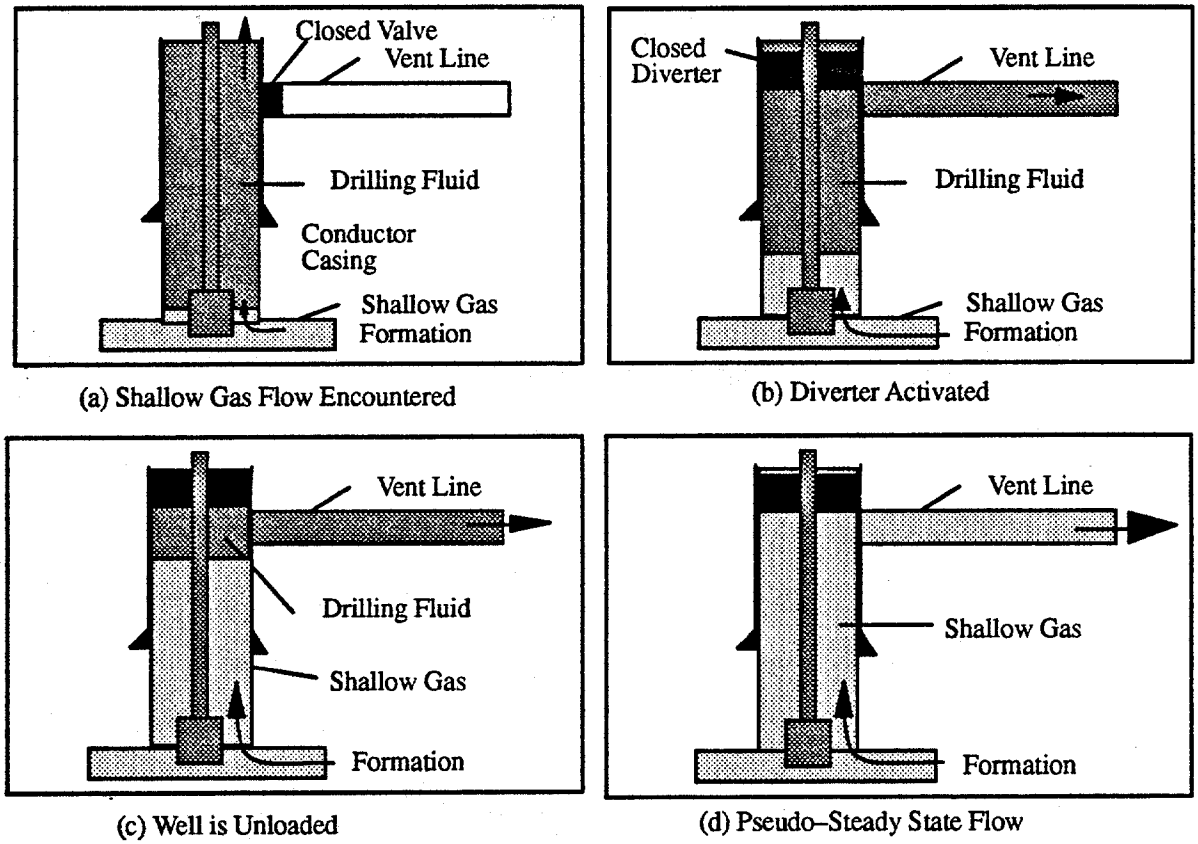

Figure 6 – Sequence of events modelled in experimental study of diverter operations.

Diverter Design

In the past, diverter systems have been designed primarily based on surface pressure considerations. Equations for single phase flow of gas were used to select a vent line size that would result in a maximum acceptable wellhead pressure for a maximum anticipated gas flow rate. It was generally assumed in these calculations that the exit pressure of the vent line was atmospheric pressure. Many offshore rigs were equipped with 0.152–m (6–in.) diverter lines and until recently, this was considered acceptable practice by many offshore operators and by regulatory agencies. Experience with these systems in the Gulf of Mexico later provided evidence that larger diverter vent lines were sometimes needed.

An example incident that occurred on a Jack–up type rig in the Gulf of Mexico (offshore Texas) in 1975 illustrates the need for a more complete analysis of diverter system operating conditions. Two 0.152–m (6–in.) diverter vent lines were attached to 0.762–m (30–in.) casing, which was set at 149 m (490 ft), and penetrated 58 m (190 ft) of sediments. A 0.251–m

$$n = 2.8\ d^{0.25}\ [\ 1 + 5.5\ d^{0.5}\ (\ 1 - \chi_g\ )^2\ ] \qquad (7)$$

where the diameter, d, is expressed in meters. The experimentally determined value of n departed significantly from *k*, especially for the largest diameter studied.

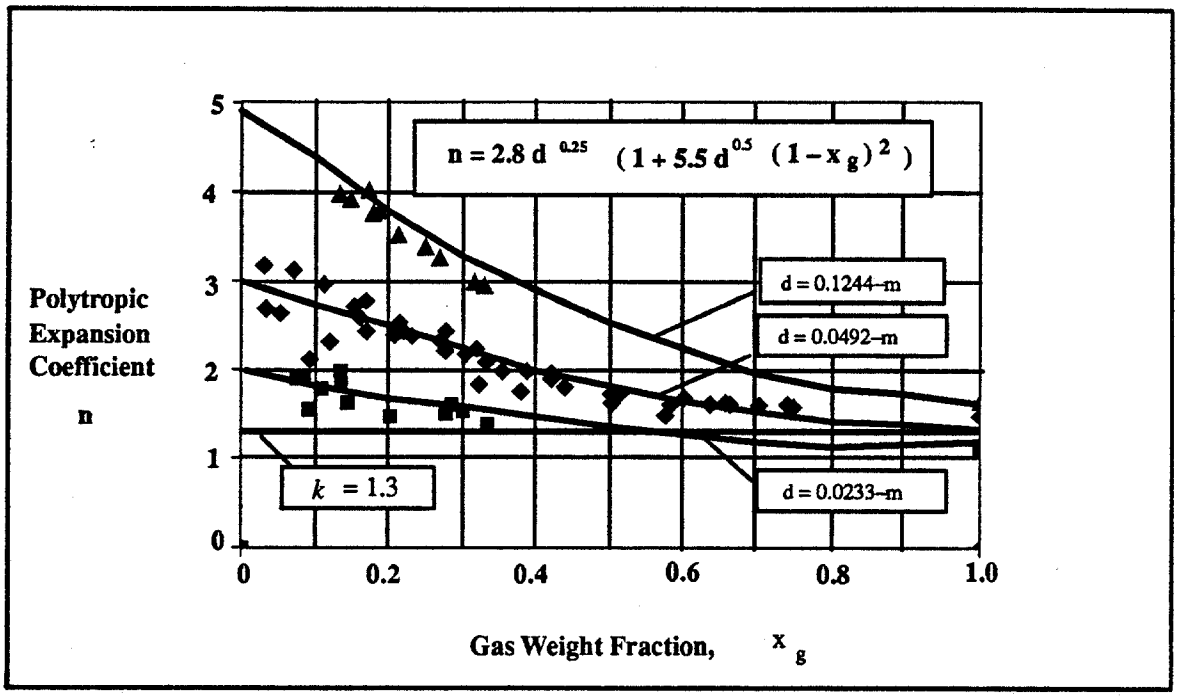

Figure 7 – Values of polytropic expansion coefficient, n, measured during experimental study of diverter vent line operations.

The use of **Eqns. 1 – 5**, and **Eqn. 7** for calculating the relationship between flow rate and diverter vent line exit pressure is illustrated in **Table 1** for a natural gas having a specific gravity of 0.64. It was assumed that no water was produced with the gas and thus the gas weight fraction (quality), χ_g, was 1.0. The temperature was assumed to be 38 ° C(100 ° F). The calculation was done for a 0.152–m (6–in.) vent line diameter that was previously the minimum size approved by the U.S Minerals Management Service and for a 0.254–m (10–in.) diverter diameter which is now required by that agency.

The calculation results given in **Table 1** show that a 0.254–m (10–in.) diverter vent line diameter will handle approximately three times the flow rate of a 0.152–m (6–in.) vent line for a given exit pressure. For the smaller line, note that approximately 10 atmosphere of backpressure would result at the diverter exit for a design gas–flow rate of 83 m^3/s (250 MMScf/D).

Table 1
Example Calculation of Pressure–Flow Rate Relationship
0.152–m (6–in.) Diverter Vent Line Exit

(1) Pressure (Pa)	(psi)	(2) Gas Density Eqn. 2 (kg/m^3)	(3) n Eqn. 7	(4) c_g Eqn. 3 (Pa^{-1})	(5) Gas Volume Fraction λ	(6) V_e Eqn. 1 (m/s)	(7) Flow Rate (m^3/s)	at S.C. (MMScf/D)
101,300	14.7	0.728	1.75	5.65×10^{-6}	0.999	493.2	8.34	25.4
200,000	29.0	1.441	1.75	2.86×10^{-6}	0.999	492.7	16.48	50.3
300,000	43.5	2.167	1.75	1.91×10^{-6}	0.999	492.2	24.75	75.5
400,000	58.0	2.896	1.75	1.43×10^{-6}	0.999	491.6	33.05	100.8
500,000	72.5	3.629	1.75	1.14×10^{-6}	0.999	491.1	41.37	126.2
1,000,000	145.0	7.345	1.75	5.72×10^{-7}	0.999	488.5	83.29	254.1

0.254–m (10–in.) Diverter Vent Line Exit

(1) Pressure (Pa)	(psi)	(2) Gas Density Eqn. 2 (kg/m^3)	(3) n Eqn. 7	(4) c_g Eqn. 3 (Pa^{-1})	(5) Gas Volume Fraction λ	(6) V_e Eqn. 1 (m/s)	(7) Flow Rate (m^3/s)	at S.C. (MMScf/D)
101,300	14.7	0.728	1.99	4.97×10^{-6}	0.999	525.9	24.8	75.7
200,000	29.0	1.441	1.99	2.51×10^{-6}	0.999	525.3	49.1	149.7
300,000	43.5	2.167	1.99	1.68×10^{-6}	0.999	524.8	73.7	224.9
400,000	58.0	2.896	1.99	1.26×10^{-6}	0.999	524.2	98.4	300.2
500,000	72.5	3.629	1.99	1.01×10^{-6}	0.999	523.7	123.2	375.8
1,000,000	145.0	7.345	1.99	5.02×10^{-7}	0.999	520.8	248.0	756.7

Flowing Pressure Gradient Calculation

Upstream of the vent line exit, the pressure gradient, $\frac{dp}{dL}$, is given by the expression

$$\frac{dp}{dL} = \frac{\rho g \cos(\theta) + \frac{f \rho \bar{v}^2}{2d}}{1 - \rho \bar{v} \frac{dv}{dp}} \qquad (8)$$

where the first term of the numerator accounts for hydrostatic pressure changes and the second term accounts for frictional pressure losses. The term $\rho v\, dv$ in the denominator accounts for pressure changes caused by fluid acceleration. In the first term, g represents the acceleration of gravity, and θ represents the vertical deviation angle of the flow section under consideration. The Moody **[1944]** friction factor, *f*, in the second term is given by

$$\frac{1}{\sqrt{f}} = -2 \log_{10} \left(0.27 \frac{e}{d} + \frac{2.52}{N_{Re}\sqrt{f}} \right) \qquad (9)$$

where e is the absolute roughness. A value of 16.5 μm (0.00065–in.) for roughness was found to yield good agreement with experimental data obtained in pipe having a diameter of 0.1244–m (4.9–in.). The Reynolds number, N_{Re}, is defined by

$$N_{Re} = \frac{\rho \bar{v} d}{\mu} \qquad (10).$$

In the denominator, the effect of fluid acceleration between any points 1 and 2 in a section of uniform area was found to be most accurately determined assuming a polytropic expansion model. Use of this model yields

$$\rho \bar{v} \frac{dv}{dp} = \frac{\bar{\rho} \bar{v}^2 \bar{p}^{1/n} \left(p_2^{1/n} - p_1^{1/n} \right)}{(p_2 - p_1) p_1^{1/n} p_2^{1/n}} \qquad (11).$$

At a sudden decrease in the area of the flow path, such as at the vent line entrance and at the bit, the pressure drop due to fluid acceleration can be estimated using

$$\Delta p_a = \rho \frac{\Delta v^2}{2} \qquad (12).$$

However, the downstream velocity cannot exceed the sonic velocity predicted by **Eqn. 1.** At a sudden increase in the area of the flow path, such as at the casing seat and at the top of the drill collars, the pressure increase due to fluid deceleration is generally small and can be neglected. Since there is no diffuser present that can provide a smooth transition to the larger flow area, almost all of the theoretical pressure recovery predicted by **Eqn. 12** is lost to turbulence.

When the fluid being produced from the well is a multiphase mixture, **Eqns. 8 – 12** can be applied through use of appropriate values for effective density, effective viscosity, and effective velocity. For high flow rates typical of shallow gas flows, the effective multiphase density, ρ_e, viscosity, μ_e, and velocity, v_e, can be calculated assuming no slippage between the phases. Thus, the effective multiphase density, ρ_e, is given by **Eqn. 4** and effective multiphase viscosity, μ_e, is given by

$$\mu_e = \lambda_g \mu_g + \lambda_{ls} \mu_{ls} \qquad (13)$$

where the subscript 'ls' refers to a liquid–solids slurry mixture and thus includes the effect of any solids present by including them in the liquid phase. The effective multiphase velocity, v_e, is defined in terms of flow rate, q, and cross sectional area, A, by

$$v_e = \frac{q_g + q_l + q_s}{A} \qquad (14).$$

The use of **Eqns. 8 – 14** for calculating the flowing pressure gradients upstream of the vent line exit is illustrated in **Table 2** for the same conditions used in the calculation of **Table 1** and a diverter length of 30 m (98 ft). The other well conditions correspond to the example diverter system failure discussed previously for the jackup rig that was lost offshore Texas in 1975. The 0.762–m (30–in.) casing that was set at 149 m (490 ft) was assumed to have a 0.0254–m (1–in.) wall thickness. The drill string was composed of 224 m (735 ft) of drillpipe

having an outer diameter of 0.127–m (5–in.) and 100 m (328 ft) of drill collars having an outer diameter of 0.191–m (7.5–in.). Beneath the bit was 27 m (89 ft) of open borehole having a diameter of 0.251–m (9.875–in.). The projected area of the bit that partially blocked the annular flow path was equivalent to a diameter of 0.222–m (8.74–in.). The starting point of the calculation was a gas flow rate of 33.05 m^3/s (100.8 MMScf/D), which corresponds to the fourth entry in **Table 1**. For this flow rate, the calculated absolute pressure at the gas formation was 2,823,300 Pa (410 psi). By repeating this calculation for a number of different assumed gas flow rates, a flow–string resistance curve can be defined. Shown in **Figure 8** are flow–string resistance curves obtained in this manner for both a 0.152–m (6–in.) and a 0.254–m (10–in.) vent line diameter. Point D corresponds to the example calculation of **Table 2.**

When the shallow gas contingency plan calls for using two diverter lines of equal diameter in parallel, half of the total flow will exit through each of the vent lines. This is easily handled in the analysis procedure illustrated above by using half of the total gas flow rate in the calculations of **Table 1** and in the surface vent line section of **Table 2**, and the total gas flow rate for the annulus and borehole sections of **Table 2.**

Formation Productivity

Resistance to flow is present in the gas reservoir as well as in the flow path to the surface. Since little is generally known about the properties of the gas reservoir causing the unexpected flow, detailed reservoir simulations are not usually justified. However, it is important to take into account turbulence and other factors that become important at high gas velocities. The Forchheimer **[1901]** equation as adapted for radial, semi–steady state flow in a homogeneous gas reservoir is recommended for use in design calculations for diverter systems. This equation can be arranged to give flowing bottom–hole pressure, p_{bh}, within a wellbore of radius, r_w, due to flow within a circular reservoir of external radius, r_e, and effective thickness, h, and having an average reservoir pressure, p_r. The Forchheimer equation for these conditions is defined by

$$p_{bh}^2 = \bar{p}_r^2 - \left[\frac{m\bar{T}\,\bar{z}\,p_{sc}}{p\,T_{sc}\,k\,h}\ln\left(0.472\frac{r_e}{r_w}\right)\right]q_{sc} - \left[\frac{b\,\bar{z}\,M\bar{T}\,p_{sc}^2}{2Rp^2\,T_{sc}^2\,h^2}\left(\frac{1}{r_w}-\frac{1}{r_e}\right)\right]q_{sc}^2 \qquad (15)$$

where the subscript 'sc' denotes standard conditions. The terms in brackets reduce to a constant for a given reservoir. The second term is needed to properly model high– velocity gas flow where the velocity coefficient, b, is determined emperically. Note that once the bracketed terms are reduced to a constant, a relatively simple relationship between gas flow rate and flowing bottom–hole pressure results.

Laboratory core data shows that the velocity coefficient, b, tend to decrease with increasing permeability. Since shallow sands tend to be unconsolidated, a correlation based on data taken in unconsolidated samples **[Johnson and Taliaferro, 1938]** is recommended for diverter system design calculations. The recommended correlation gives b in m^{-1} using

$$b = \frac{1.031}{\sqrt{k}} \qquad (16)$$

where the permeability, k, is given in m^2.

Table 2

Example calculation of flow–path pressure drop

Flow rate assumed is 33.05 m^3 /s (100.8 MMScf/D) (Fourth entry in Table 1)
0.152–m (6–in.) Diverter attached to 0.762–m (30–in.) casing set at 149–m (490ft) with 0.251–m (9.875–in.) borehole at 351 m (1150 ft).

(1) Pressure (Pa)	(psi)	(2) Pressure Step	(3) Mean Pressure	(4) Gas Density Eqn. 2 (kg/m^3)	(5) Gas Velocity (m/s)	(6) Pressure Gradient Eqn. 8 (Pa /m)	(7) Length Step (m)	(8) Total Length (m)	(9) Total Depth (m)
Surface Diverter, d = 0.152m,			q = 90,	n = 1.75,	m = 1 x10 $^{-5}$ Pa.s ,	N_{Re} = 2.16 x10 ^{7} ,	f = 0.01225		
400,000	48.0	50,000	425,000	3.079	462.4	237,200	0.211		
450,000	65.3	100,000	500,000	3.629	392.4	63,100	1.584	0.21	0.00
550,000	79.8	100,000	600,000	4.365	326.2	33,700	2.967	1.80	0.00
650,000	94.3	100,000	700,000	5.104	278.9	23,700	4.215	4.76	0.00
750,000	108.8	100,000	800,000	5.848	243.5	18,600	5.381	8.98	0.00
850,000	123.3	100,000	900,000	6.595	215.9	15,400	6.494	14.36	0.00
950,000	137.8	119,000	1,009,500	7.417	192.0	13,000	9.129	20.85	0.00
1,069,000	155.0	Acceleration Pressure Drop at Vent Line Entrance = 136,600 Pa						29.98	0.00
1,205,600								29.98	0.00
Casing–drillpipe annulus, d_2= 0.711m,		d_1 =0.127m,	q = 0,	n = 2.56,	m = 1 x10 $^{-5}$ Pa.s ,	N_{Re} = 3.93 x10 ^{6} ,	f = 0.01059		
1,205,600	174.9	13,800	1,212,500	8.953	7.5	92	149.0	29.98	0.00
1,219,400	176.9							179.0	149.0
Borehole–drillpipe annulus, d_2= 0.251m,		d_1 =0.127m,	q = 0,	n = 1.91,	m = 1 x10 $^{-5}$ Pa.s ,	N_{Re} = 8.70 x10 ^{6} ,	f = 0.01283		
1,219,400	176.9	100,000	1,269,400	9.386	74.8	2,868	34.865	179.0	149.0
1,319,400	191.4	106,400	1,372,600	10.174	69.0	2,652	40.115	213.9	183.9
1,425,800	206.8							254.0	224.0
Borehole–drillcollar annulus, d_2= 0.251m,		d_1 =0.191m	q = 0,	n = 1.78,	m = 1 x10 $^{-5}$ Pa.s ,	N_{Re} = 7.45 x10 ^{6} ,	f = 0.01475		
1,425,800	206.8	200,000	1,525,800	11.353	108.5	17,247	11.596	154.0	149.0
1,625,800	235.8	200,000	1,725,800	12.905	95.4	15,029	13.308	265.6	235.6
1,825,800	264.8	200,000	1,925,800	14.472	85.1	13,325	15.010	278.9	248.9
2,025,800	293.8	200,000	2,125,800	16.055	76.7	11,972	16.706	293.9	264.0
2,225,800	322.8	200,000	2,325,800	17.654	69.8	10,871	18.398	310.6	280.7
2,425,800	351.8	246,000	2,548,800	19.456	63.3	9,863	24.943	329.0	299.1
2,671,800	387.5	Acceleration Pressure Drop past Bit = 138,100 Pa						354.0	324.0
2,809,900	407.5							354.0	324.0
Borehole below bit d = 0.251m,			q = 0,	n = 1.98,	m = 1 x10 $^{-5}$ Pa.s ,	N_{Re} = 1.37 x10 ^{7} ,	f = 0.01128		
2,809,900	407.5	13,400	2,816,600	21.648	24.1	496	27.010	354.0	324.0
2,823,300	409.5							381.0	351.0

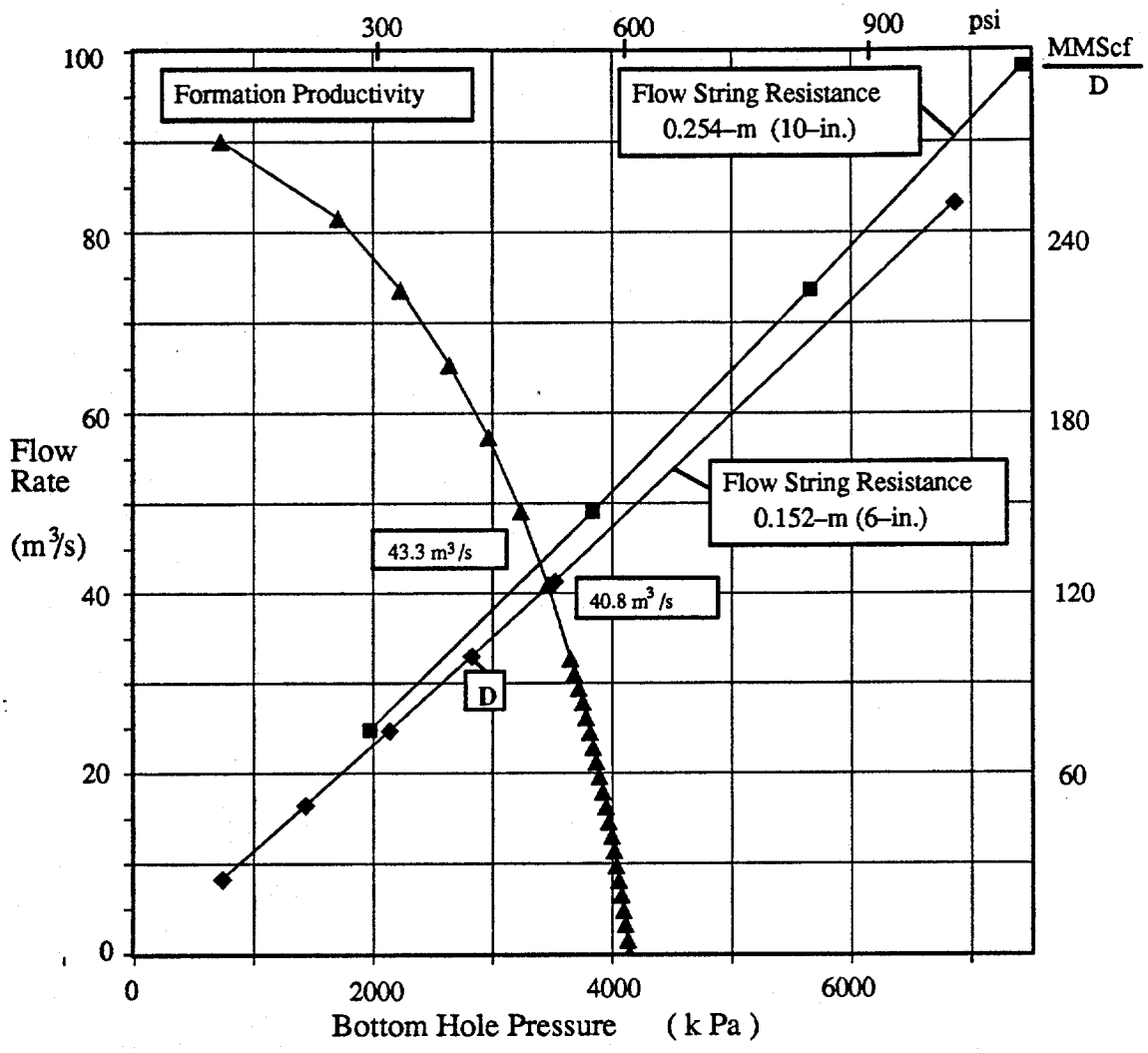

Figure 8 – Pseudo-steady-state systems analysis plot for example of Tables 1 and 2.

Choosing a representative value for the reservoir thickness, h, is complicated by the fact that the wellbore often penetrates through only part of the gas reservoir before the shallow gas flow is detected and drilling is stopped. When this is true, the gas flow is not truly radial as assumed by **Eqn. 15**, and an effective thickness value must be used. This effective thickness depends on the ratio of the horizontal to vertical permeability, the wellbore radius, r_w, the total formation thickness, h_f, and the formation thickness penetrated by the bit, h_p. When the vertical permeability is much less than the horizontal permeability, the effective thickness is approximately equal to the thickness penetrated by the bit. As the vertical permeability increases and approaches the horizontal permeability, the following equation presented by **Craft and Hawkins [1959]** can be used:

$$h = h_p \left[1 + 7 \sqrt{\frac{r_w}{2 h_p}} \cos\left(\frac{\pi}{2} \frac{h_p}{h_f} \right) \right] \qquad (17).$$

Shown in **Figure 8** is a formation producitivity curve that is representative of the example shallow gas reservoir encountered at a depth of 351m (1150 ft). The reservoir was assumed to have a permeability of 9.9 μm^2 (10,000 md), an effective thickness of 3.05 m (10

ft), an external radius of 305 m (1000 ft), and an average absolute reservoir pressure of 4,137,000 Pa (600 psi). Since well control was lost when pulling pipe from the borehole, it is possible that the entire reservoir thickness was penetrated by the bit. Shallow gas formations having a thickness of 3 m or less are difficult to detect using seismic data. The gas properties used were as previously defined for the calculations of **Tables 1** and **2.**

Equilibrium Gas Flow Rate

The equilibrium flow rate that will be observed during diverter operations is obtained from the intersection of the flow–string resistance curve and the formation–inflow performance curve. Note that for the example under consideration (**Figure 8**), the gas flow rate predicted is 40.8 m^3/s (124 MMScf/D) for a 0.152–m (6–in.) diverter system and 43.3 m^3/s (132 MMScf/D) for a 0.254–m (10–in.) vent line.

Once the pseudo–steady–state gas flow rate has been determined, the pressure at various key points in the flow path can be established. This can be done by interpolation from the pressure traverses previously calculated in **Tables 1** and **2**, or by a new pressure traverse calculated for the equilibrium gas flow rate. It is important that the pressures in the open borehole are maintained below formation fracture pressure after pseudo–steady state conditions are reached. If borehole pressures are sustained above the formation fracture pressure for a long period of time, the probability that fracturing will reach the seafloor (**Figure 2**) is greatly increased.

Formation Fracture Pressure

Constant and Bourgoyne [1989] have recommended fracture pressure equations for offshore drilling operations based on Eaton's correlation. The recommended method gives the absolute overburden stress, σ_{ob}, in SI units in terms of the seawater depth, D_{sw}, and the sediment depth below the seafloor, D_s, using

$$\sigma_{ob} = 101{,}300 + 10{,}000\ D_{sw} + 25{,}500\ D_s - 21{,}980{,}000\ \left[1 - \exp\left(-0.000279\ D_s\right)\right] \quad (18).$$

The minimum expected absolute formation fracture pressure, p_f, is then determined from the absolute formation pore pressure, p_p, and the overburden pressure, s_{ob}, by

$$P_f = P_p + \left[1 - 0.629\ \exp\left(-0.00042\ D_s\right)\right]\left[\sigma_{ob} - P_p\right] \quad (19).$$

This minimum fracture pressure would correspond to extending an existing fracture in a sandy formation. Higher formation fracture pressures would be expected for fracture initiation and in plastic "gumbo" shale formations. The maximum expected pressure for fracture extension is the overburden pressure given by **Eqn 18.**

Shown in **Table 3** is a comparison of the borehole pressures and fracture pressures for the two vent line sizes considered in the example. Note that for the 0.152–m (6–in.) vent line, the expected fracture pressure at the casing seat would be exceeded, whereas for the 0.254–m (10–in.) vent line, a 971,000 Pa (142 psi) safety margin would exist.

Table 3

Comparison of equilibrium pressure traverses for 0.152–m (6–in.) and 0.254–m (10–in.) vent lines.

Water depth of 58 m and air gap of 33 m.

Location	Depth (m)	(ft)	Pressure for 0.152–m system (Pa)	(psi)	Pressure for 0.254–m system (Pa)	(psi)	Minimum Fracture Extension Pressure (Pa)	(psi)
Diverter Exit	0	0	494,000	72	176,500	26	Protected by casing	
Wellhead	0	0	1,485,000	215	488,000	71	Protected by casing	
Casing Seat	149	490	1,502,000	218	496,000	72	1,467,000	214
	174	571	1,602,000	232	799,800	116	1,846,000	270
Top of drill collars	224	735	1,755,000	255	1,116,500	162	2,692,000	394
Bottom of drill collars	324	1063	3,280,000	476	3,176,500	461	4,264,000	629
Below bit	324	1064	3,449,000	500	3,375,000	489	4,264,000	629
Hole bottom	351	1150	3,465,000	503	3,392,000	492	4,825,000	712

Working Pressure of Diverter Components

The systems analysis procedure provides information about the pressures that could be expected on the diverter system components after the well is unloaded and pseudo–steady–state conditions are reached. However, while the drilling fluid is being displaced from the well, the mud in the system behaves as a viscous plug which greatly slows flow through the diverter. This results in a pressure peak occurring when the leading edge of the gas reaches the vent line entrance. The magnitude of the pressure peak depends primarily on the formation pressure and on the amount of mud that remains in the well due to slippage past the gas while the well is unloading. The pressure peak can be substantially higher than the equilibrium wellhead pressure calculated from a systems analysis procedure. This pressure peak is of short duration, typically lasting only a few seconds. If fracturing occurs, it is unlikely that fracture propagation would move very far from the wellbore before the pressure subsides to the equilibrium value. As long as the equilibrium borehole pressure is less than the fracture extension pressure, there ia a high probability that the fracture will not propagate to the surface. Thus, it is recommended that the design load at the casing seat is based on equilibrium flowing conditions. However, the design load for surface diverter system components should be based on the pressure peak occurring when the drilling fluid is being displaced from the well.

Santos [1989] performed experiments on a 0.152–m (6–in.) diverter vent line attached to a 382 m (1252 ft) well containing 0.178–m (7–in.) casing to study unsteady–state pressure behavior when the well is first placed on a diverter system. In the experiments, the gas entering the bottom of the well flowed through a valve that was controlled by a process control computer that simulated the behavior of a formation. A program was developed for the flow control computer to permit a range of formation productivities to be simulated. Pressures

were monitored during the experiments at a number of locations in the well and diverter. Experimental runs were made using a number of different mud systems.

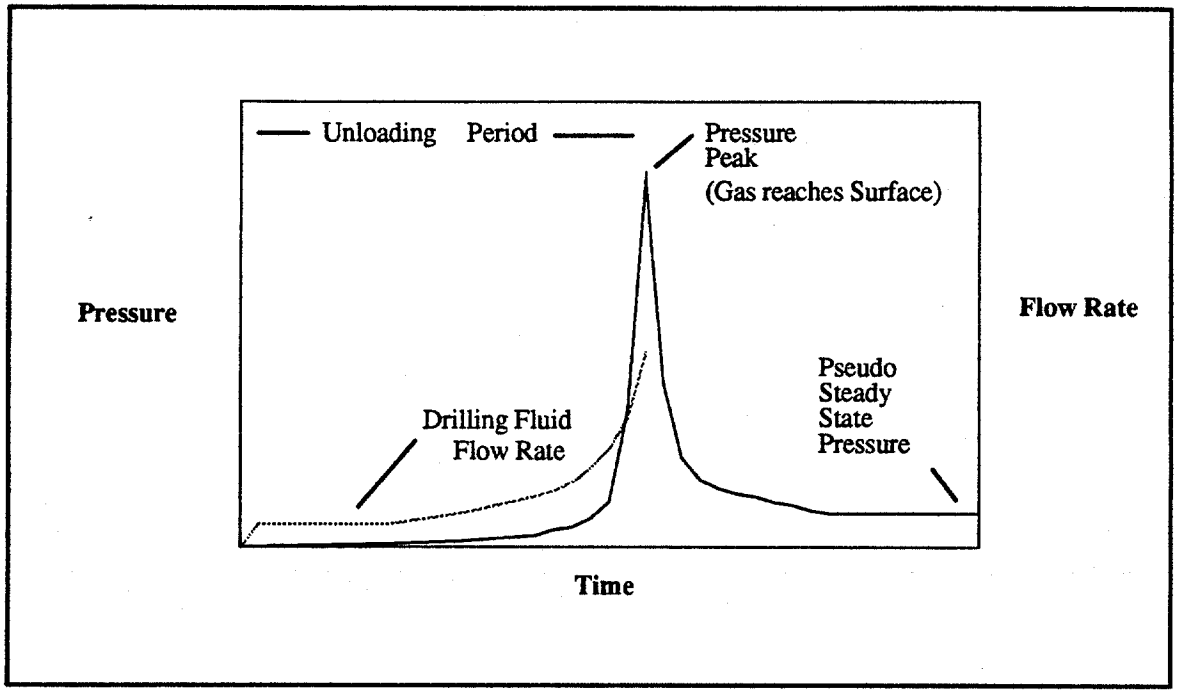

Figure 9 –Typical pressure and drilling fluid flow rate history observed during experimental study of diverter operations. (After Santos, 1989.)

Typical experimental results obtained by **Santos [1989]** for the pressure history and flow–rate history at any given point in the surface system during the simulated diverter operations are shown in **Figure 9**. Note that the flow rate from the well begins slowly but accelerates very quickly as gas approaches the surface. As the column of drilling fluid in the well decreases, the pressure imposed on the gas decreases, causing rapid expansion of the gas in the well and an increase in the gas flow rate into the bottom to the well. Also note the pressure peak in the vent line that is seen just before the bottom of the drilling fluid column exits the system. Eventually, a pseudo–steady–state condition is reached in which the pressures change very slowly with time due to reservoir depletion.

Santos [1989] developed a computer model for predicting the pressures and flow rates observed during a shallow gas flow as a function of both time and position. The program was first verified using the experimental results obtained with the model diverter system. The computed results for peak wellhead pressure matched the observed pressure peaks within an error band of about 25 percent. The program was then used to simulate a wide variety of field conditions. It was found that the peak wellhead pressure tended to decrease with decreasing formation pressure, decreasing formation productivity, and increasing vent line diameter. For the field conditions studied, the peak wellhead pressure was generally less than 65 percent of the formation pressure. Also, the time required to unload the well was typically only a few minutes.

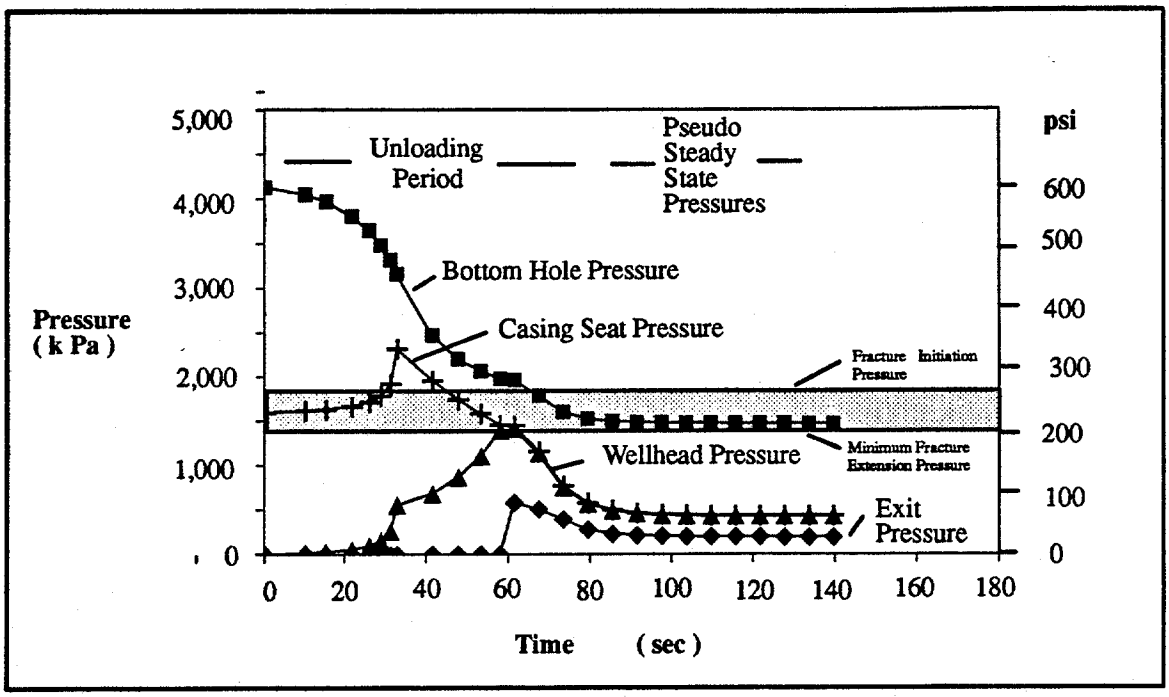

Figure 10 – Calculated pressure behavior for 0.254–m (10–in.) diverter vent lines for well conditions similar to offshore Texas example. (After Santos, 1989.)

Shown in **Figure 10** are results obtained using the computer model for the 0.254–m (10–in.) diverter vent line discussed in the previous example calculations. The drilling fluid in the well when the shallow gas flow began was assumed to have a density of 1116 kg/m^3 (9.3 lb/gal). Note that it is predicted that the well will unload in about one minute with a peak wellhead pressure of 1,436,000 Pa (208 psi), which was about 34 percent of the formation pressure. Thus a working pressure for diverter components of at least this value would be needed. The calculated pressure at the casing seat exceeds the minimum fracture extension pressure of 1,467,000 Pa (214 psi) during most of the first minute but drops to about 496,000 Pa (72 psi) after pseudo–steady state conditions are reached. Similar simulations performed for a 0.152–m (6–in.) diverter vent line gave a peak wellhead pressure of 2,620,000 Pa (380 psi), which was about 63 percent of the formation pressure.

Diverter Anchors

Some diverter failures have involved the anchor system used to hold the vent line piping in place. The anchor system should be carefully designed to withstand the forces resulting from the moving fluids. The maximum forces on the anchoring system occurs when the wellhead pressure reaches its peak value. When telescoping segments or slip joints are used below the annular blowout preventer, a maximum upward force on the wellhead must be resisted that is equal to the peak pressure multiplied by the internal annular cross sectional area at the slip joint. In computer simulations made by **Santos [1989]**, these forces sometimes reached as high as 1,300,000 N (300,000 lbf) for the field conditions studied. Similarly, a maximum axial thrust distributed along the length of the vent line exists which is equal to the peak pressure multiplied by the internal cross sectional area of the vent line. In addition, at bends in the diverter system, the anchor system must resist a force equal to the mass rate of flow multiplied by the change in the fluid velocity vector at the bend. For a 90 degree bend, this force is approximately given by the fluid density times the square of the average velocity, $\rho \bar{v}^2$.

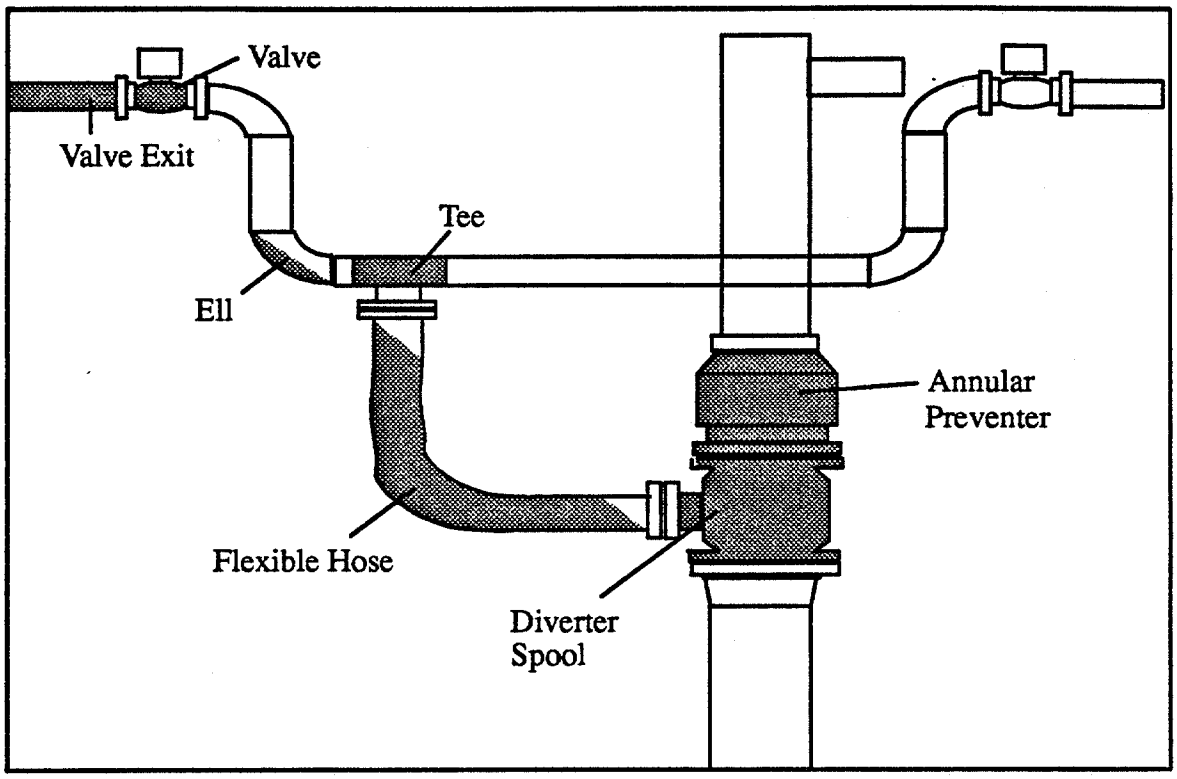

Figure 11 – Typical locations of erosive wear on diverter system for bottom supported rig. (After Bourgoyne, 1989.)

Rate of Erosion

Information was collected on 31 wells that encountered shallow gas. Typical locations of erosion type failures are shown in **Figure 11** for a simplified diverter schematic. Problems tend to occur:

(1) at bends in the vent line.
(2) at flexible hoses connecting the vent line to the wellhead.
(3) at valves or just downstream from valves.
(4) in the wellhead and diverter spool.

The severity of the erosion problems experienced was greatly affected by the quantity of sand produced by the well. When considerable sand was produced, diverter system component failures started in the bends and valves and progressed back to the wellhead. The entire wellhead and annular preventer was cut from the well in an extreme case. For this well, sand piles of ten feet in height were reported on the rig floor after the well bridged.

Erosion can be caused by cavitation, impingement of liquids, or impingement of solid particles. Erosion by impingement of solid particles is the most rapid and is of primary concern for diverter operations. Previous erosion studies using flat plates, **[Finnie, 1967], [Goodwin, 1969], [Ives and Ruff, 1978]**, have shown that the total mass of material abraded from a solid surface is directly proportional to the total mass of abrasives striking the solid surface. Thus, the erosion resulting from abrasive particle impact is often expressed in terms of a *specific erosion factor, F_e, which is defined as the mass of steel removed per unit mass of abrasive.*

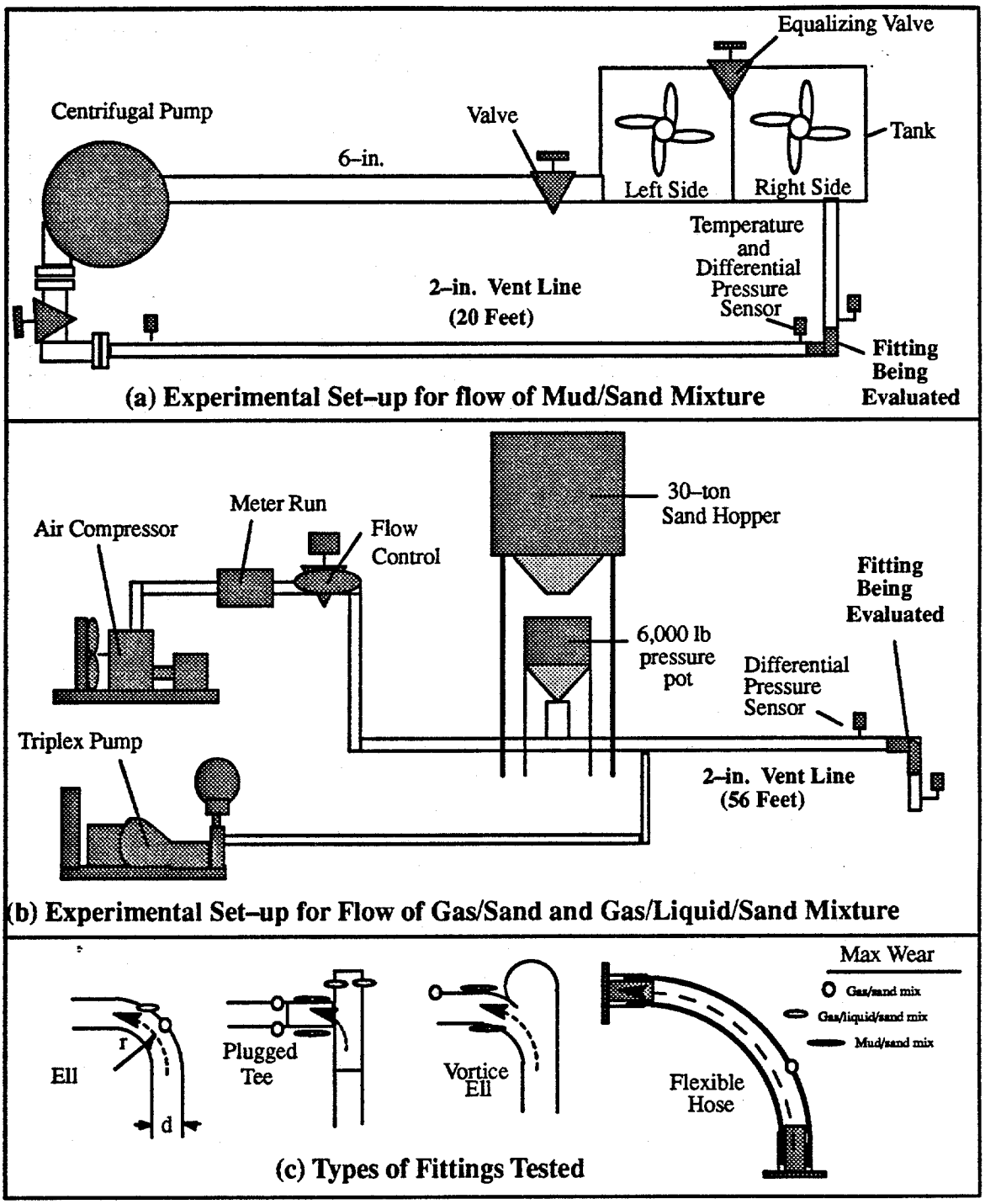

Figure 12 – Schematic of model diverter vent lines used in errosion study. (After Bourgoyne, 1989.)

Bourgoyne [1989] used two experimental set–ups to measure the rate of erosion in various fittings. The first set–up (**Figure 12a**) was used for mud/sand slurries. Drilling mud flowed from the right side of a partitioned tank to a centrifugal pump, through 20 feet of 2–in. inside diameter pipe, through the fitting being evaluated, and then back into the tank. Flow rates were periodically checked by temporarily closing an equalizing line connecting the left

and right sides of the tank. Sand concentration in the mud was also periodically checked by taking a sample from the tank.

The second set–up (**Figure 12b**) was used for gas/sand and gas/water/sand mixtures. Compressor supplied air flowed first through a flow control valve and 2–in. orifice meter. The flow control valve maintained a constant flow rate by means of a process control computer. Sand was added to the flow stream from a 6000–lb capacity sand blasting pressure pot through a metering valve. The weight of the pressure pot was continuously monitored, and the sand flow rate was determined from the rate of change of weight with time. Water or mud could be introduced downstream of the sand injection point. The mixture then flowed through 56 feet of 2–in. inside diameter line, through the fitting being evaluated, through a one–foot tail piece, and then exited to the atmosphere.

The fittings evaluated included steel Ells, plugged Tees, Vortice Ells, and rubber hoses (**Figure 12c**). The plugged tees had only a blind flange on the dead–end portion and did not contain any special lead of steel targets. Weight loss and wall thickness loss were periodically determined during the tests. Wall thickness measurements were made using an ultrasonic method. Thickness profiles were determined along both inside and outside radii of the bends. The location of the areas of maximum wear are shown in **Figure 7.12c** for the various fittings and fluid types studied. Data were collected to permit evaluation of sand rate, fluid velocity, fluid properties, and fitting type. The sand used in the experimental tests was No. 2 blasting sand.

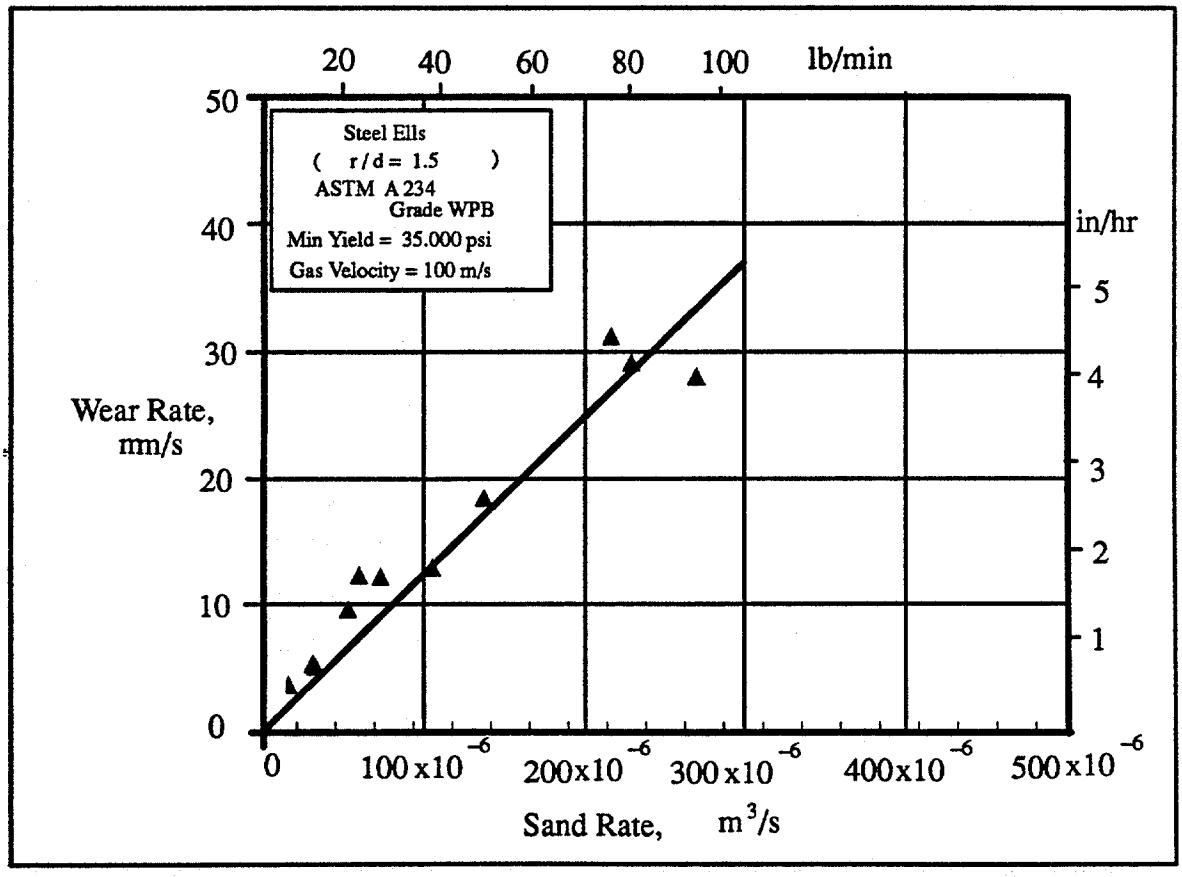

Figure 13 – Effect of sand concentration on rate of erosion at gas velocity of 100 m/s for ASTM a–234, Grade WPB ells with r/d=1.5 (Number 2 blasting sand) (After Bourgoyne, 1989.)

The use of the specific erosion factor, Fe, for characterizing the effect of sand concentration on erosion in bends was evaluated using the data shown in **Figure 13**. Note that the wear

rate was found to be directly proportional to the sand rate for the entire range of conditions studied. These sand rates were sufficient to result in sand concentrations of up to 0.12 percent. At high concentrations, significant decreases in the specific erosion factor would be expected due to interference between sand grains. However, this behavior was not observed in this study. It appears that the use of a constant value for the specific erosion factor is acceptable for the range of sand concentrations representative of diverter system operating conditions.

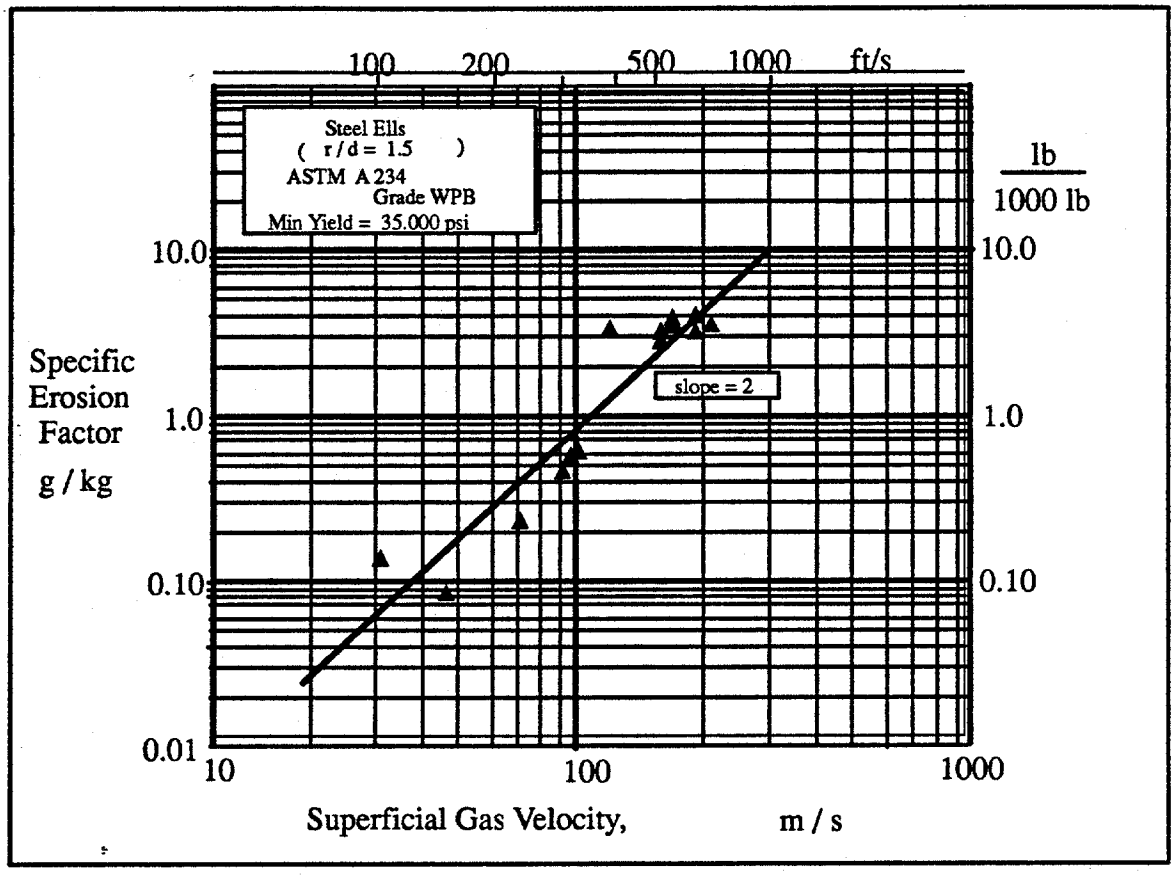

Figure 14 – Effect of gas velocity on rate of erosion for ASTM 234, Grade WPB ells with r/d=1.5 (Number 2 blasting sand) (After Bourgoyne, 1989.)

Experiments were conducted to determine the effect of velocity on the rate of erosion for velocities of up to 220 m/s. The experimental results are shown in **Figure 14**. The apparent slope of 2 includes the effect of increasing steel temperature with increasing flow velocity due to the sand particles impacting the wall of the fitting. When using dry gas at very high velocities, portions of the fittings were observed to smoke and begin to turn red due to very high temperature increases.

Comparison of Specific Erosion Factors, F_e, obtained in similar fittings for mud carried abrasives and gas carried abrasives suggests that erosion rates are lower for mud by one to two orders of magnitude. The addition of small quantities of liquid to a gas/sand mixture was found to increase the specific erosion factor. The observed increase was more than would be expected due to the increase in gas velocity caused by the liquid hold–up. The presence of small quantities of liquid in the system appeared to increase the cutting efficiency of the sand. This was especially true in plugged tees.

Table 4

Recommended Values of Specific Erosion Factor

Cast Steel is ASTM 216, Grade WBC and Seamless Steel is ASTM A234, Grade WPB

Fitting Type	r / d	Material	Specific Erosion Factors (g / kg)		
			Dry Gas Flow	Mist Flow	Liquid Flow
Ell	1.5	Cast Steel	2.2	2.8	0.001
		Seamless Steel	0.89	1.1	
	2.0	Cast Steel	2.0	2.4	0.001
		Seamless Steel	0.79	0.93	
	2.5	Cast Steel	1.7	2.0	0.001
		Seamless Steel	0.69	0.77	
	3.0	Cast Steel	1.5	1.65	0.0014
		Seamless Steel	0.60	0.66	
	3.5	Cast Steel	1.2	1.32	0.0076
		Seamless Steel	0.52	0.55	
	4.0	Cast Steel	0.9	1.0	0.01
		Seamless Steel	0.45	0.49	
	4.5	Cast Steel	0.7	0.77	0.01
		Seamless Steel	0.40	0.44	
	5.0	Cast Steel	0.5	0.55	0.01
		Seamless Steel	0.35	0.38	
Flexible Hose	6.0	Rubber	1.00	1.22	0.02
	8.0		0.40	0.45	
	10.0		0.37	0.39	
	12.0		0.33	0.35	
	15.0		0.29	0.31	
	20.0		0.25	0.28	
Plugged Tee	—	Cast Steel	0.026	0.064	0.0046
		Seamless Steel	0.012	0.040	0.01
Vortice Ell	3.0	Cast Steel	0.0078 *		0.0028

* Assumes Failure in Pipe Wall Downstream of Bend.

The higher erosion rates for gas is thought to occur because the transfer of momentum from the solids to the fluid is much less efficient. Thus, the solid particles strike the wall of a bend at a much greater angle in gas than in liquid. For ductile materials such as steel, the maximum rate of erosion occurs at an angle of impact with the eroding surface of about 20 degrees. For brittle materials, the maximum rate of erosion occurs at an angle of 90 degrees **[Ives and Ruff, 1978]**.

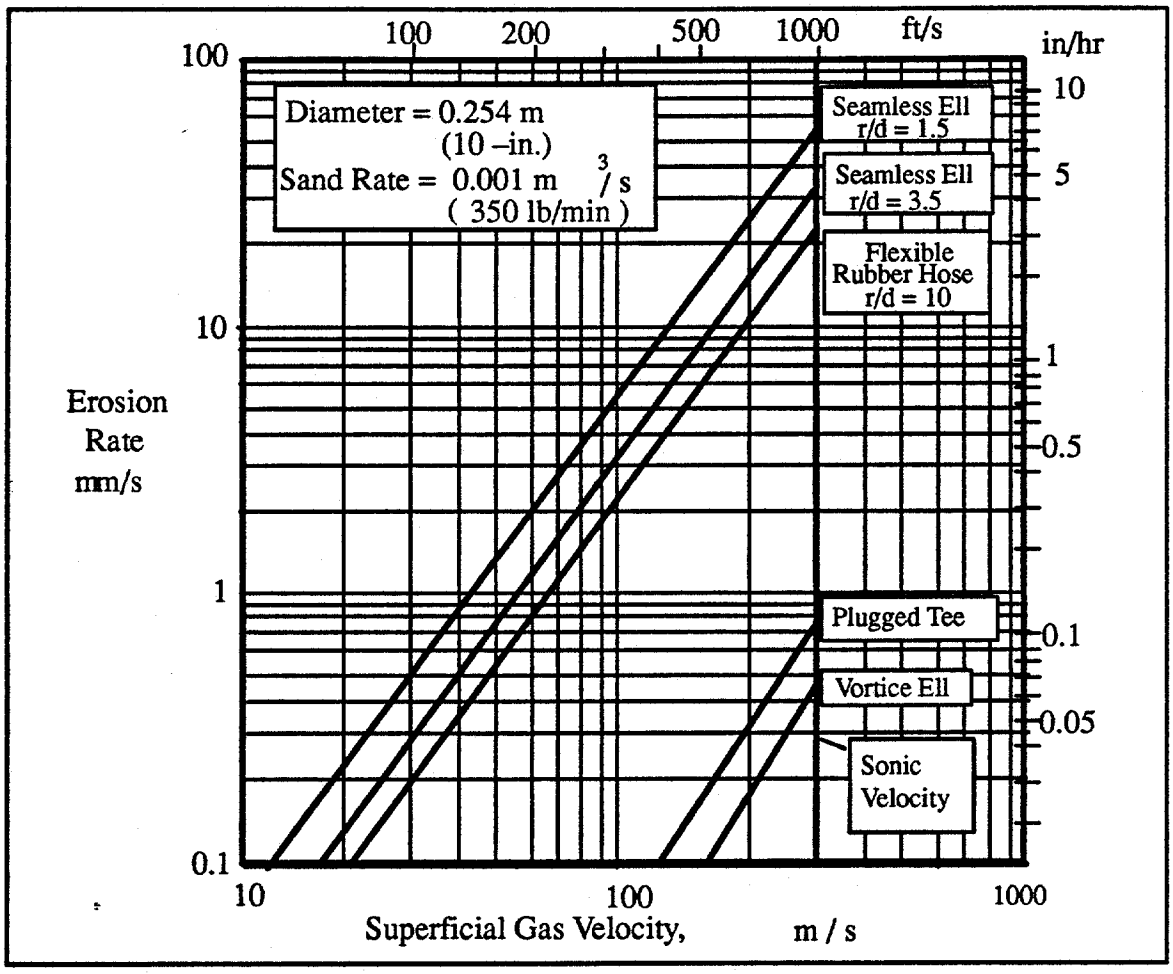

Figure 15 – Effect of fitting type on predicted erosion rate. (After Bourgoyne, 1989.)

Based on the experimental work performed **Bourgoyne [1989]** proposed the following equation in SI units for estimating the rate of loss in wall thickness, h_w, with time, t, in a diverter component of density, ρ_s, and cross sectional area , A, flowing abrasives having density, ρ_s, at a volumetric flow rate, q_s, and flowing gas or liquid at superficial velocity, v_{sg} or v_{sl}, and volume fraction (holdup) λ_g or λ_l:

Gas Continuous Phase (Dry Gas or Mist Flow)

$$\frac{dh_w}{dt} = F_e \frac{\rho_a}{\rho_s} \frac{q_a}{A} \left[\frac{v_{sg}}{100\ \lambda_g}\right]^2 \quad (20)$$

Liquid Continuous Phase

$$\frac{dh_w}{dt} = F_e \frac{\rho_a}{\rho_s} \frac{q_a}{A} \left[\frac{v_{sl}}{100\ \lambda_l}\right]^2 \quad (21)$$

Recommended values for specific erosion factor, F_e, are given in **Table 4**. The accuracy of the proposed calculation method was verified using the experimental data collected. The average error observed was 29 percent. This was felt to be an acceptable level of accuracy for diverter design considerations. Relatively large error ranges are often associated with the use of emperical correlations for describing multiphase flow phenomena.

Equations 20 and **21** were used to estimate the erosion life of various diverter components under a variety of assumed field conditions. Calculated erosion rates for various fittings and for a sand rate of 0.001 m^3/s are shown in **Figure 15** as a function of superficial gas velocity. Note that erosion rates increase by two orders of magnitude as velocity increases from 30 m/s to the maximum (sonic) velocity of about 300 m/s. Note also, that for a given sand production rate, an order of magnitude decrease in erosion rate is predicted for changing from an Ell to a plugged Tee or Vortice Ell.

The use of **Eqn 20** for calculating the erosion life of various fittings for making a turn near the wellhead for the diverter system discussed in the previous example calculations is illustrated in **Table 5**. A design sand rate of 0.001 m^3/s was used in these calculations. Note that for the 0.254–m (10–in.) system, the calculated time to failure is just seven minutes for a short radius ell. Use of a plugged tee would increase the estimated life to 8.9 hrs and use of a vortice ell would increase the estimated life to 13 hrs. The estimated life for a 0.152–m (6–in.) system would be about a third of that for the 0.254–m (10 in.) system.

The calculations above illustrate the importance of avoiding bends in diverter systems. When a bend is required, a vortice ell or plugged tee should be used. When a plugged tee is used, metal targets in the dead–end branch can increase the erosion resistance to shallow gas flows containing significant quantities of water. However, field problems have been reported due to metal targets (lead fillings) breaking loose and moving downstream. This problem is made worse when the target is installed in a vertical position where they may fall down into the flow stream. It is recommended that targets be designed as an integral part of the fitting.

Plugging

Solids in the drilling fluid tend to settle in the diverter components and can lead to valve malfunctions and vent line plugging. To the extent possible, the diverter system is generally sloped towards its exit to promote draining and minimize the accumulation of solids in the system. In addition, provisions for flushing the system should be made. Clean–out connections with flushing jets should be placed upstream of all valves, bends, and local low spots.

Table 5
Comparison of erosion life near wellhead for various fittings used to make bend in 0.254–m (10–in.) diverter system and 0.154–m (6–in.) diverter system.

Parameter	Units	0.152–m (6–in.) Diameter	0.254–m (10–in.) Diameter
Wall Thickness	m in.	0.0071 0.28	0.00927 0.365
Flowrate at S.C.	m^3/s MMScf/D	40.8 124	43.3 132
Pressure at Fitting	Pa psi	1,485,000 215	488,000 71
Temperature at Fitting	°C °F	38 100	38 100
Flowrate at Fitting	m^3/s MMScf/D	3.0 9.2	9.7 29.5
Velocity at Fitting	m/s f/s	165 542	191 628
Gas Volume Fraction		0.9997	0.9999
Erosion Rates			
Ell–r/d=1.5 F_e =0.00089	m/s in./hr	4.5×10^{-5} (3 min) 6.4	2.2×10^{-5} (7 min) 3.1
Flexible Hose F_e =0.00033	m/s in./hr	1.7×10^{-5} (7 min) 2.4	8.0×10^{-6} (20 min) 1.1
Plugged Tee F_e =0.000012	m/s in./hr	6.1×10^{-7} (3.2 hr) 0.087	2.9×10^{-7} (8.9 hr) 0.041
Vortice Ell F_e =0.000008	m/s in./hr	4.0×10^{-7} (4.8 hr) 0.058	1.9×10^{-7} (13 hr) 0.028

Control System

Control of the diverter vent lines should be achieved by means of valves that can be fully opened to minimize erosion and pressure losses. The diverter control system generally involves pneumatic or hydraulic valve operators and can be operated from remote panels located with the blowout–preventer control panels. It is often advantageous to integrate the diverter control system with the blowout preventer control system. Standards regarding the accumulator unit which stores the pressurized control fluid needed to operate the valves, should be similar to those adopted for the blowout preverter system. A non–flammable, low–freezing–point power fluid should be used in the hydraulic units. The controls should be designed so that the well cannot be closed with the diverter system, i.e. the valves to the vent line should automatically open before the annular sealing device is closed. When multiple vent lines are needed to insure downwind diversion, the currently selected vent valve should open before the other vent valve is closed. Specially designed integral sequencing diverter components have recently become available that provide the annular sealing device with a vent line valve in a single unit **[Roche, 1986]**.

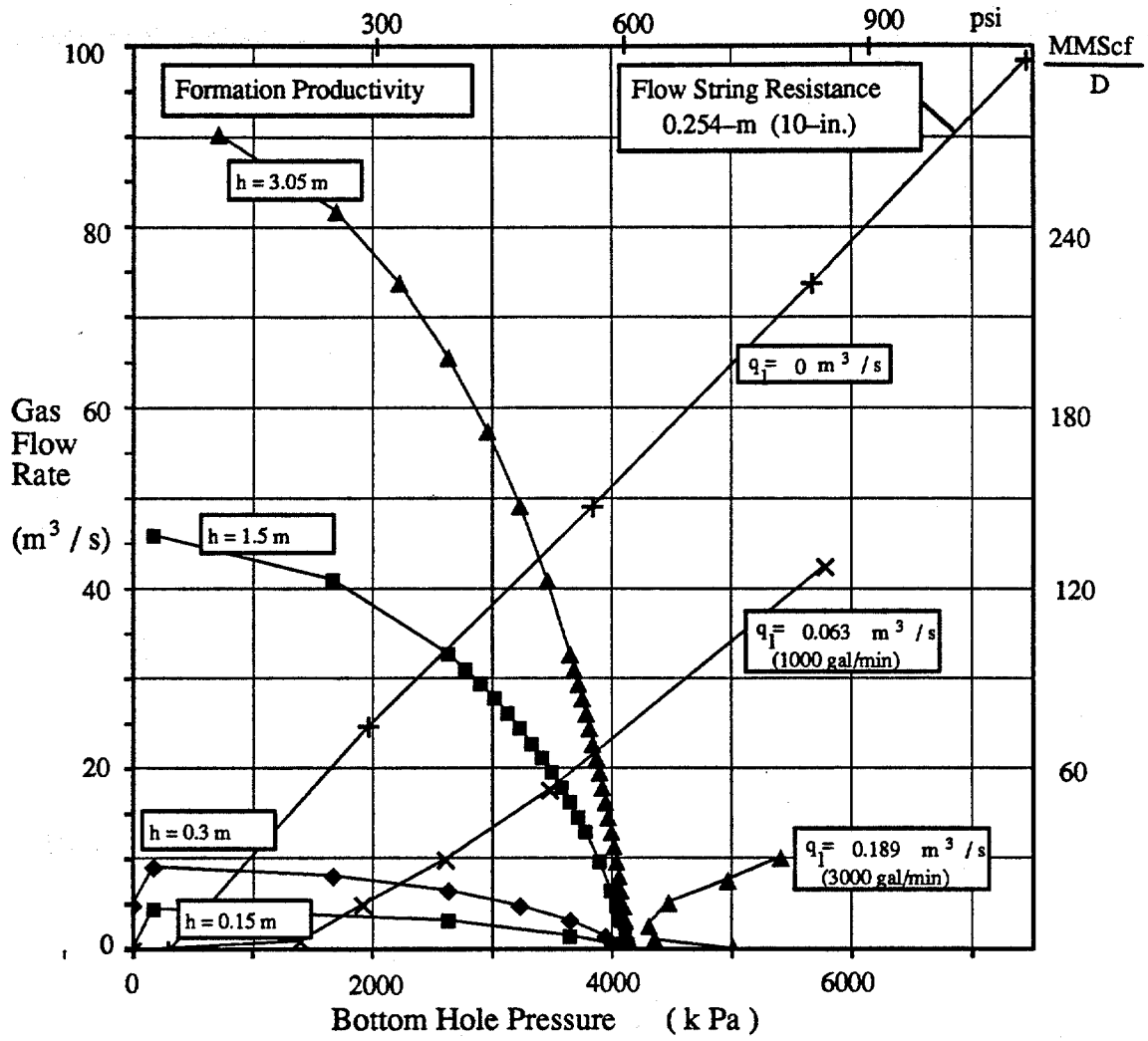

Figure 16 – Pseudo–steady–state systems analysis plot for dynamic well control attempt using available rig pumps.

Design Considerations for Dynamic Kill

Some operators use a contingency plan which calls for a "dynamic" well control procedure to be attempted as soon as the well is placed on a diverter. The dynamic well control procedure has been described in detail by **Blount and Soeiinah [1981]**. With this method, high–circulating rates are used to increase annular frictional pressure losses sufficiently to cause the bottom–hole pressure to be raised above the formation pressure. Some operators maintain a volume of weighted drilling fluid on location for use in an immediate attempt at a dynamic kill. Other operators plan the use of seawater after the available mud volume has been exhausted. The success of the dynamic well control method is governed primarily by the hole size being drilled, the flow rate and pressure limitations of the available rig pumps and the effective thickness of the gas formation penetrated by the bit before the gas flow is detected. Data that was collected on 28 shallow gas flows occurring in the Gulf of Mexico indicates that in two cases the flow was successfully stopped using a dynamic kill procedure.

When a dynamic well control procedure is included in the shallow gas contingency plan, the diverter system design load should be based on the well conditions that will result with the rig pumps operating at the maximum available flow rate. The basic calculation procedure

remains unchanged, except that the liquid pumped is added to the formation gas being produced on bottom. Shown in **Figure 16** is a systems analysis plot for a dynamic kill attempt using seawater at a maximum pump rate of 0.063 m^3/s (1000 gal/min) in a 0.251–m (9.875–in.) hole. Other well conditions were taken to be the same as the previously discussed offshore Texas example. Formation productivity curves are shown for a range of effective formation thickness value from 0.15m to 3.05m (0.5 ft to 10 ft). Flow–string resistance curves are shown for both a non–pumping case and for a dynamic kill attempt at the maximum available pump rate. Note that for the maximum effective formation thickness value considered, the dynamic well control method would reduce the equilibrium gas flow rate from 43 m^3/s to 22 m^3/s (132 MMScf/D to 67 MMScf/D), but would not bring the well under control. Note also that control is not predicted for any of the effective formation thickness values considered. These calculations suggest that the dynamic well control method will be successful only for very thin formations or low–permeability formations with relatively small diameter boreholes.

Using the methods previously presented, it can be shown that the pressure at the casing seat during the example dynamic kill attempt in a 0.251–m (9.875–in.) hole would increase slightly to 525,000 Pa (76 psi). Since the minimum fracture extension pressure is 1,467,000 Pa (214 psi), the 0.254–m (10–in.) diverter system would be adequate to permit the dynamic well control method to be tried. The peak wellhead pressure observed when the gas first reaches the surface would be reduced from 1,436,000 Pa to 1,138,000 Pa (208 psi to 165 psi). The velocity at a bend near the wellhead would be reduced from 191 m/s to 131 m/s resulting in about a 40 percent reduction in the erosion rate at this location.

Even when the dynamic well control method cannot be successfully employed using the available rig equipment, there is a high probability that control of the well can be regained through borehole collapse or reservoir depletion. In 25 of 28 shallow gas flow events that occurred in the Gulf of Mexico (90%), the well plugged due to borehole collapse. In 14 cases (50%), flow stopped within a one day period. In 22 cases (79%), flow stopped within a one week period. However, in one case, two relief wells had to be drilled before the well could be brought under control with auxillary pumping equipment.

Koederitz, Beck, Langlinais, and Bourgoyne [1987] developed a computer program for determining the flow rate and pressure requirements required to bring a shallow gas flow under control using the dynamic well control method. The program can be used to evaluate the requirements for regaining control either using the existing wellbore, or using one or more additional relief wells. The program is based on the systems analysis approach illustrated in the previous offshore Texas example, except that the analysis is repeated at successively higher pumping rates until well control is indicated by the lack of an intersection between the flow–string resistance curve and the formation inflow–performance curve. The flow–string resistance curve at the minimum pump rate required for well control for the previous example is also shown in **Figure 16**. Note that a pump rate of 0.189 m^3/s (3,000 gal/min) would be required. At least one relief well and use of auxiliary pumping equipment would be needed to achieve this rate without exceeding a maximum pump pressure of 15,000 psi.

The program developed by **Koederitz, Beck, Langlinais, and Bourgoyne [1987]** also determines the maximum pressure experienced at every point in the borehole as the pumping rate is increased up to the value required to bring the well under control. It was found that the maximum pressure at a given point in the borehole does not necessarily occur at the maximum liquid rate. Ideally, the diverter system design would permit any pumping rate up to the kill rate to be maintained without exceeding the fracture pressure. Shown in **Figure 17** is a comparison of the fracture and borehole pressures as a function of pumping rate for the offshore Texas example. The calculations indicate that the 0.254–m (10–in.) diverter vent line would achieve this design objective.

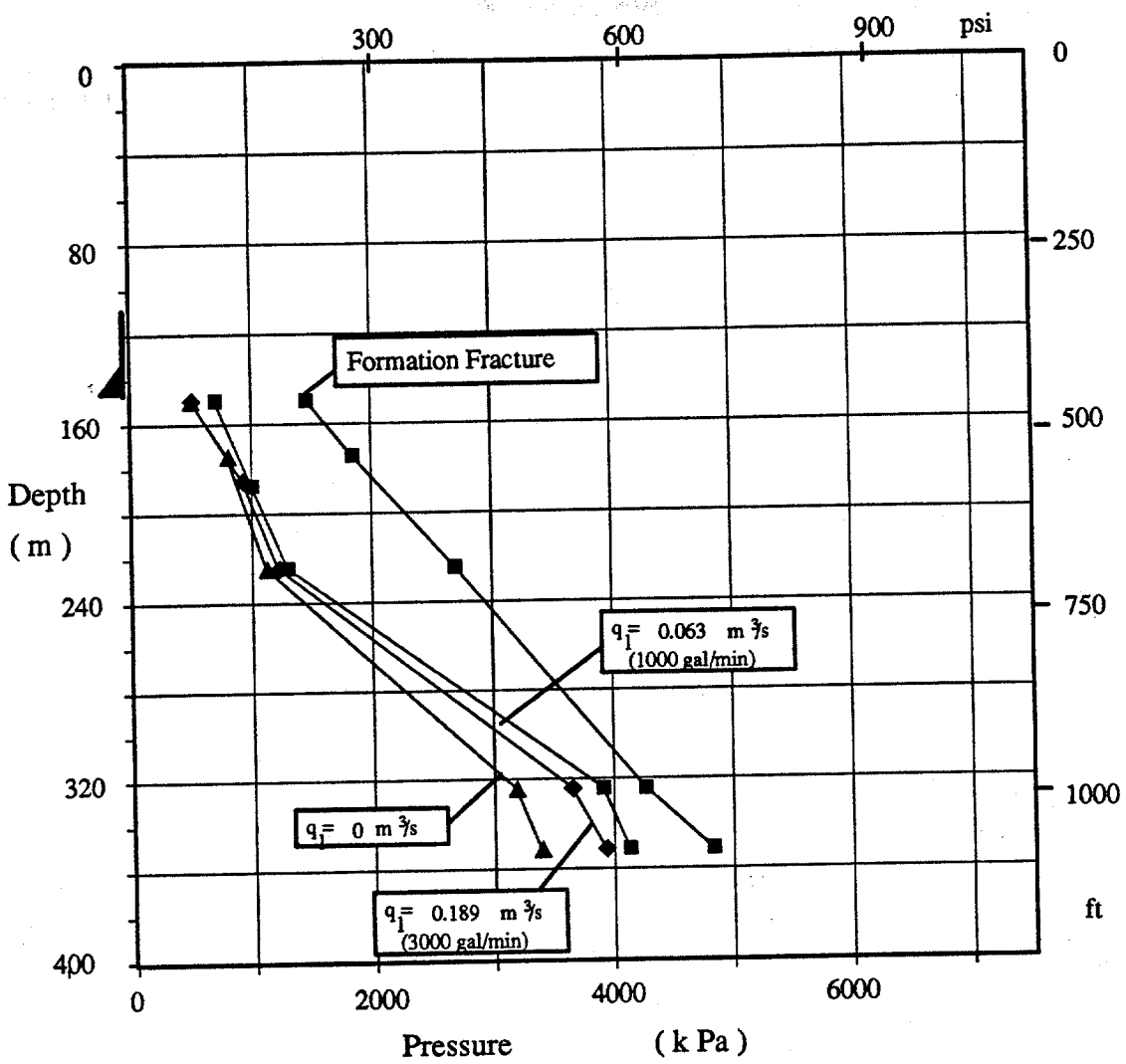

Figure 17 – Pseudo–steady–state systems analysis plot for dynamic well control attempt using available rig pumps.

Diverter Operation

The infrequent use of the diverter system increases the need for scheduled system maintenance and personnel training activities. Since a shallow gas flow can surface in less than a minute, there will be little time for coummunicating instructions to the rig crew after the flow is detected. Calculation results used to verify the adequacy of the diverter system for the anticipated drilling plan are also useful for personnel training. Each member of the rig crew should throughly understand the contingency plans that will be used in the event of a shallow gas flow and the action required from them when executing these plans. This should be covered in a "pre–spud conference" held for operator and contractor personnel. They should also understand the purpose and importance of the activities directed towards system maintenance. A properly designed system will be of no use if it is not properly maintained.

In operation, the diverter system should be used primarily to provide time for an orderly rig abandonment. If the shallow gas flow is detected before the bit has opened a significant thickness of the gas bearing formation, or if the formation permeability is low, use of the dynamic well control method may be successful. The success or failure of an attempted dynamic kill will depend on many factors, including the size of the borehole being drilled. However,

the diverter exit should be carefully monitored to detect when the flow velocity begins to approach sonic velocity and to detect sand production. A transducer at the diverter exit that could detect the onset of sonic flow, and estimate gas rates would be very useful. A sand probe that could detect significant levels of sand production is also needed. A novel vent line exit monitor is under development as a result of the research completed at LSU.

Special Considerations for Floating Drilling Vessels

When drilling from a floating vessel, the operator has more options available for handling a shallow gas flow. The vessel is not supported from bottom, so the danger of loosing the vessel to a crater is no longer present. Various options that are available are illustrated in **Figure 18**. Each of these options have different advantages and disadvantages, and their use must be based on the drilling conditions anticipated.

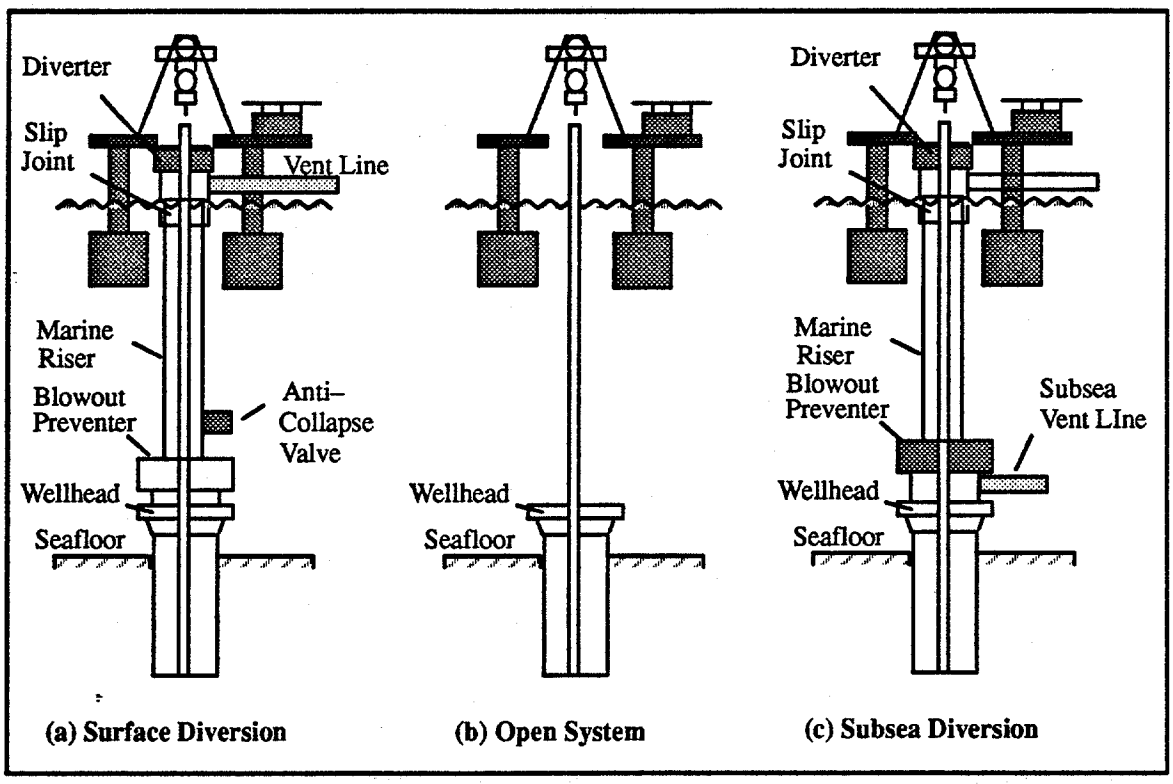

Figure 18 – Various methods for handling shallow gas flows on floating drilling vessels

The option illustrated in **Figure 18a** is similar to the approach used with a bottom supported vessel. During drilling operations, the drilling fluid is returned to the surface through the marine riser. If a shallow gas flow is encountered, an annular sealing device or diverter located at the top of the marine riser is closed, and the gas flow is vented through a conventional diverter system. An annular blowout preventer with the associated choke and kill lines may also be deployed below the marine riser.

The use of a surface diverter system **(Figure 18a)** has the advantage of maintaining a closed drilling fluid system in which fluid properties can be controlled. High formation fracture pressures permit better control of the borehole pressures through selection of a higher drilling fluid density. This increases the ability to prevent a shallow gas flow. When the formation fracture pressure is low, it may not be possible to bring drilling fluid back to the vessel without the aid of booster lines used to gas lift the marine riser. A riser dump valve may also be used to periodically release dense drilling fluid that has become loaded with drilled cut-

tings at the seafloor. Use of the surface diverter system has the disadvantage of bringing the gas on board the vessel, perhaps creating a need to abandon the vessel for personnel safety. An abandoned dynamically–positioned floating vessel may not be able to maintain its station over the subsea wellhead. Also, the slip joint used to permit motion of the floating vessel relative to the wellhead introduces a weak link in the system. The marine riser should (whenever possible) be designed to withstand the external pressure of the seawater while containing only gas. Several cases of riser collapse have occurred which indicates an elastic collapse mode of failure. This failure mode is controlled by the diameter to wall thickness ratio, and is independent of the yield strength of the steel used **[Erb, Ma, and Stockinger, 1983]**.

The pressure–integrity problem of the slip joint **(Figure 18a)** can be eliminated through use of a newly available annular sealing unit that can be placed below the slip joint. When using this new technology, outlets below the sealing unit are attached to the surface vent lines by means of flexible hoses. **[Hall, Roche and Boulet, 1986]**.

When it is not feasible to design the marine riser to withstand the full collapse loading of the sea at the water depth of interest, an anti–collapse valve can be used in the marine riser **(Figure 18a)**. This valve will automatically open when the internal pressure in the marine riser falls too low, admitting seawater to the marine riser. Newly designed anti–collapse valves have recently become available. The systems analysis procedure described previously can be used to determine the flow rate at which seawater will enter. This is accomplished by modifying the procedure used to calculate the flow string resistance at a given gas flow rate. The flow string resistance must be computed for various assumed seawater flow rates through the anti–collapse valve. The correct flow string resistance curve is then selected based on a knowledge that the pressure in the marine riser at the valve must be equal to the pressure in the ocean at that depth, less any pressure drop across the valve due to the flow of seawater.

Another option that can be used with the equipment arrangement shown in **Figure 18a** is to close the annular blowout preventer at the seafloor and accept the possibility of seafloor fracturing. When using this option, the lower marine riser package is usually unlatched from the blowout preventer. If gas begins surfacing near the vessel, the vessel is moved as quickly as possible. In deep water, the gas may be carried a considerable distance from the vessel. In addition, much of the gas may go into solution in the seawater. The solubility of natural gas in seawater increases significantly with increasing pressure and decreasing temperature **[Dodson and Standing, 1944]**.

The option illustrated in **Figure 18b** is the use of an open system in which the drilling fluid and cuttings are discharged at the seafloor. No marine riser is deployed and seawater is generally used for the drilling fluid. In the event of a shallow gas flow, gas is discharged through the open wellhead at the seafloor. Returns at the seafloor are generally monitored with a subsea camera. The pressure at the wellhead is maintained at the hydrostatic pressure for the given ocean water depth, causing borehole pressures to be maintained at a higher value than for a surface diversion. This results in a lower gas rate but may also reduce the tendency for the well to plug by borehole collapse, especially in very deep water. This option is best suited for areas where the formation pore pressures and fracture pressures are known to be low. All of the problems of returning the drilling fluid to the surface vessel without causing formation fracture are avoided. The major disadvantages of this approach is an inability to increase the drilling fluid density to minimize the chance of a shallow gas flow from an abnormally pressured formation, and the possibility of a gas boil near the vessel. However, if gas begins surfacing near the vessel, the vessel can be moved away from the well location, preferably up–current, but wind direction must be considered too.

The option illustrated in **Figure 18c** involves the use of a subsea diverter system between the wellhead and the marine riser. This system has the advantages of a closed drilling fluid

system in which the drilling fluid density can be controlled, but yet does not require that the gas flow be brought on board. The vent line is short, so the problems associated with the possibility of gas surfacing near the vessel remain. The time required to leave the location is slightly greater than that of an open system.

Recommendations

As a result of the research conducted, the following recommendations are made:

1. Seismic surveys should be made at proposed offshore wildcat–well locations and the data processed for shows of shallow, abnormally pressured gas. However, the operator should recognize that the use of shallow hazard surveys will not always detect the presence of shallow gas formations.

2. Maximum controlled safe drilling rates should be estimated for the shallow portion of a well in which gas–cut mud could occur and increase the risk of a shallow gas flow.

3. A systems analysis design procedure should be employed for proposed wildcat wells to verify the adequacy of the planned casing program for the available diverter system. The systems analysis should consider the possibility of sonic flow velocity at the diverter vent line exit and at restrictions and changes in direction of the flow path.

4. The working pressure of a diverter system should be based on pressure peaks that could be expected during the unloading of the drilling fluid from the well.

5. Bends in diverter vent lines should be avoided whenever possible. When bends are required, a plugged tee or vortice ell should be used.

6. Dynamic well control methods have been successfully used to control some shallow gas flows with available rig pumps. However, a vent line exit monitor should be developed which will detect sonic flow, significant levels of sand production, and provide appropriate warning when these conditions are detected.

7. When shallow gas flows are severe, the diverter system on a bottom supported drilling vessel should be used primarily to provide time for a orderly rig abandonment.

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NOMENCLATURE

A	–	Cross sectional area, m
c	–	Compressibility, Pa^{-1}
d	–	Diameter.
k	–	Ratio of heat capacity at constant pressure to heat capacity at constant volume.
f	–	Moody friction factor.
F	–	Specific Erosion Factor, kg/kg
h	–	Thickness, m.
k	–	Permeability, $m.^2$
M	–	Molecular weight.
n	–	Polytropic expansion coefficient.
p	–	Pressure, Pa.
q	–	Volumetric flow rate, m/s^3
r	–	Radius.
R	–	Universal gas constant.
t	–	Time, s
T	–	Temperature, K.
v	–	Velocity, m/s.
z	–	Gas deviation factor.
b	–	Velocity Coefficient, $m.^{-1}$
e	–	Roughness, m
λ	–	Fractional volume or holdup.
μ	–	Viscosity, Pa s.
θ	–	Vertical deviation angle, rad.
ρ	–	Density, $kg/m.^3$
σ	–	Stress.
χ	–	Weight fraction or quality.

Subscripts

1,2	–	Reference depths of casing seat and bit.
a	–	Abrasive.
bh	–	Bottom–hole.
e	–	Effective, Also external reservoir limit.
f	–	Formation, also fracture.
g	–	Gas.
l	–	Liquid.
ls	–	Liquid/solid mixture.
ob	–	Overburden.
p	–	At constant pressure; Also pore; Also thickness penetrated.
s	–	Solid; Also steel; Also sediments.
sc	–	Standard conditions.
sg	–	Superficial gas flux.
sl	–	Superficial liquid flux.
sw	–	Seawater.
v	–	At constant volume.
w	–	Wall, also wellbore.