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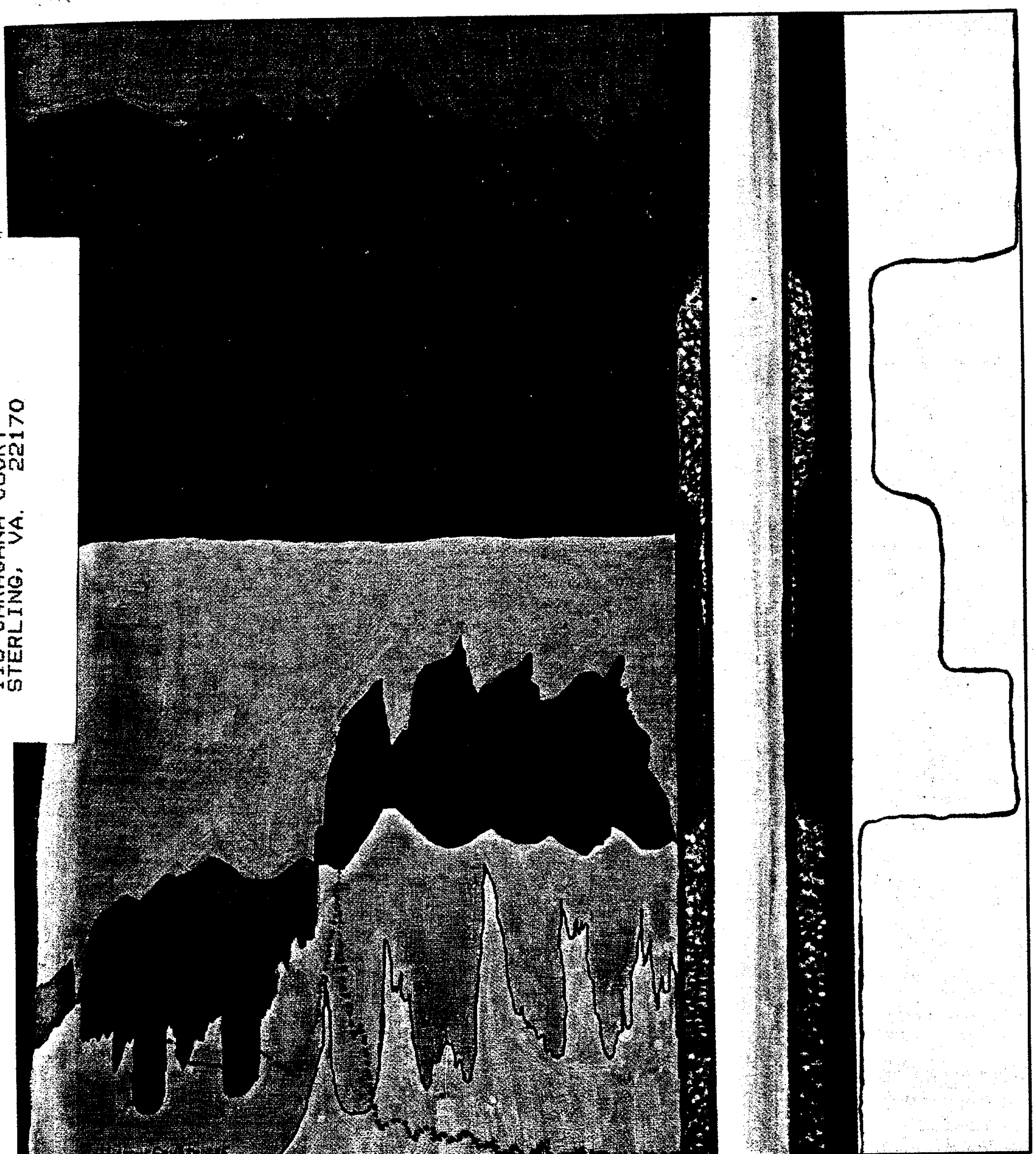

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An Experimental Study of Well Control Procedures for Deepwater Drilling Operations

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Summary

A research facility has been designed and constructed to model the well-control flow geometry present on a floating drilling vessel operating in 3,000 ft [914 m] of water. The main feature of this facility is a highly instrumented 6,000-ft [1829-m] well equipped with a packer and triple-parallel flow tube at 3,000 ft [914 m] to model a subsea blowout preventer (BOP) stack with connecting subsea choke and kill lines. Several types of experiments were conducted in which gas kicks were simulated by the injection of nitrogen into the bottom of the well. Alternative procedures studied and evaluated included techniques to compensate for chokeline frictional pressure loss during pump startup and techniques for handling rapid gas-zone elongation when the kick reaches the seafloor. It was found that the demands placed on a choke operator during well-control operations in deep water were not as severe as anticipated from computer simulator studies and could be managed with existing equipment by an experienced choke operator.

Introduction

In the late 1940's, the search for oil and gas accumulations first moved offshore to the shallow marine environment. Since that time, drilling operations have been extended steadily across the continental shelf. More recently, developments in the technology for drilling from floating drilling vessels have allowed exploratory drilling beyond the limits of the continental shelf and into the relatively deep water of the continental slopes. In 1974, the first well was drilled in water deeper than 2,000 ft [610 m].[1] By 1979, the water depth record was extended to 4,876 ft [1486 m] on a well drilled offshore Newfoundland.[2] More recent exploration off the U.S. east coast extended the water depth record to 6,848 ft [2087 m].[3] Future plans in the Natl. Science Foundation's Ocean Margin Drilling Program call for scientific ocean drilling during the next decade in water depths of 13,000 ft [3962 m].[4]

Like many other aspects of drilling operations, the problem of blowout prevention increases in complexity for floating drilling vessels operating in deep water. Several special well-control problems stem from greatly reduced fracture gradients and the use of long subsea choke and kill lines. Fig. 1 shows the approximate effect of water depth on fracture gradients, expressed in terms of the maximum mud density that can be sustained during normal drilling operations.[4] Note that the maximum mud density that can be used with casing penetrating 3,500 ft [1067 m] into the sediments decreases from about 13.9 lbm/gal [1666 kg/m^3] on land to about 10.7 lbm/gal [1282 kg/m^3] in 4,500 ft [1372 m] of water, and to about 9.8 lbm/gal [1174 kg/m^3] in 13,000 ft [3962 m] of water. These lower fracture gradients result primarily because the open hole must support a column of drilling fluid that extends far above the mudline to the rig floor. This additional column weight is only partially offset by the seawater. An additional contributing factor is the relatively low bulk density of unconsolidated shallow marine sediments.

The required vertical subsea choke and kill lines extending from the BOP stack at the seafloor have two detrimental aspects. One difficulty arises because of the increased circulating frictional pressure loss caused by the great length of these lines. This frictional pressure loss can cause a significant increase in the pressures occurring in the wellbore. The combination of high circulating pressure losses in the chokeline and low wellbore fracture gradients reduces the tolerance for error by the choke operator.

A second difficulty results from rapid changes in hydrostatic pressure in the vertical chokelines when circulating a gas kick. Hydrostatic pressure falls quickly when gas exits the large casing and displaces mud from the relatively small-diameter chokeline. To maintain the bottomhole pressure (BHP) constant, there must be a corresponding increase in surface choke pressure to make up for this decrease in hydrostatic pressure. Choke operation becomes much more difficult during this period, as rapid changes in control pressure are required. This difficulty tends to increase with well depth because choke manipulation is based on surface drillpipe pressure whose unsteady-state readjustment time increases with well depth and gas-kick volume.

Evaluations of anticipated well-control problems for a given set of deepwater conditions are often conducted by computer studies that predict the pressure response of a well for various alternative procedures being evaluated. These studes have raised questions about the severity of the control problem faced by the choke operator. Unfortunately, realistic computer simulations of well-control operations require both an accurate knowledge of fluid behavior in the well and a knowledge of equipment

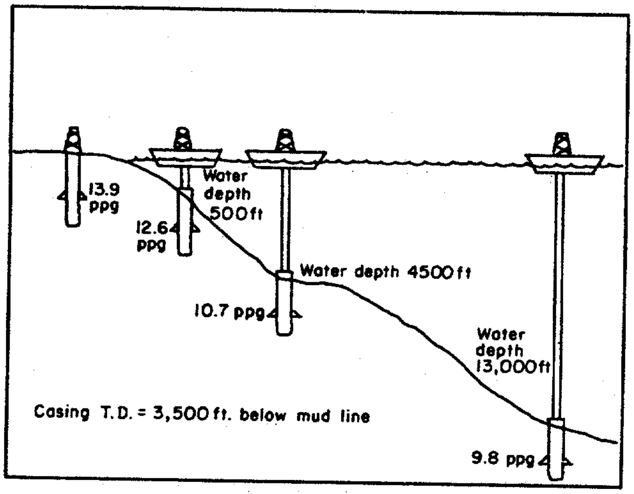


Fig. 1—Approximate effect of water depth on fracture gradient.

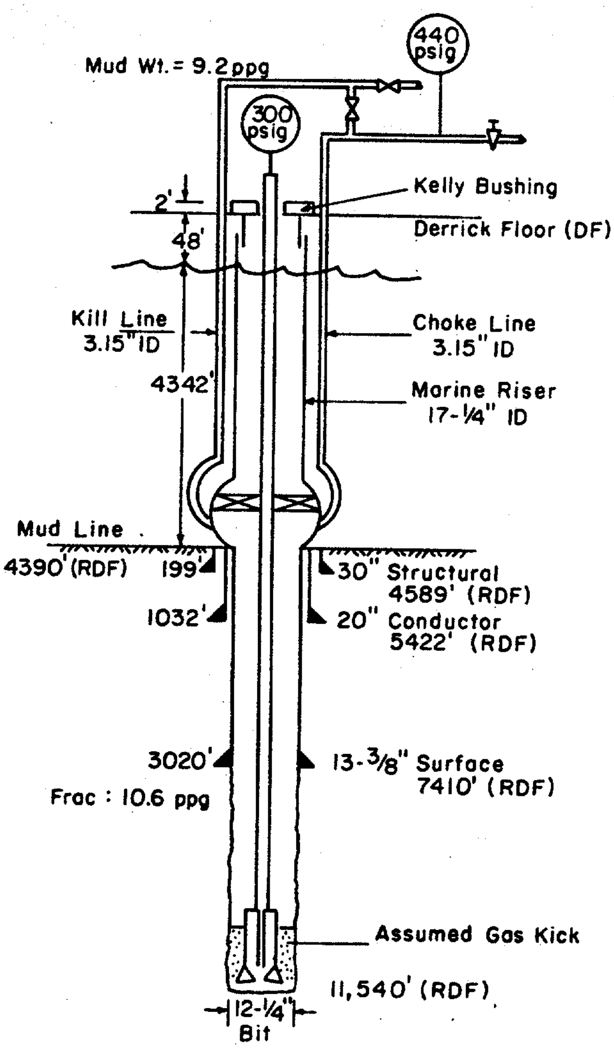


Fig. 2—Schematic diagram for offshore Zaire well example.

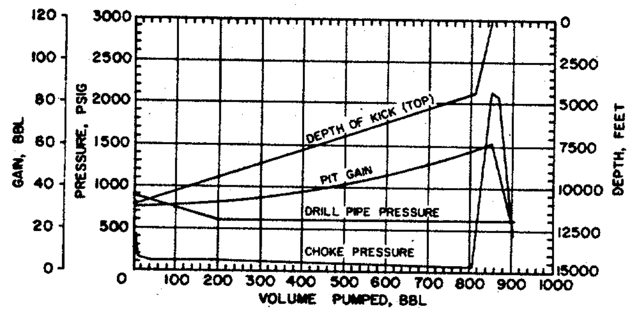


Fig. 3—Predicted well behavior for offshore Zaire example.

response. Considerable difficulty is encountered in accurately modeling the flow behavior of mixtures of formation gas and drilling fluids for the complex flow geometry in a subsea system.

For this study, a research well facility was designed and constructed to model the flow geometry on a floating drilling vessel during well-control operations. Several types of experiments have been conducted in which gas kicks were simulated by the injection of nitrogen gas into the bottom of the well. Alternative procedures studied included techniques for compensation of chokeline frictional pressure loss during pump startup and techniques for handling rapid gas-zone elongation when the gas enters the chokeline. Choke-operator response requirements were studied for various kick conditions.

Experimental Well Facility

Design of the first subsea well equivalent to be located on dry land posed many problems. The first step was a review of all drilling vessels that have operated in deep water. It was found that from 1974 through 1980 only 66 wells had been drilled in water deeper than 2,000 ft [610 m].[5] These wells were drilled by the 12 vessels listed in Table 1. Thirty-five of these wells were drilled by only three vessels, all of which are dynamically positioned. One of these, the *Discoverer Seven Seas*, has held the water-depth record for offshore drilling since 1976. A survey of the well-control equipment on 10 of the vessels listed in Table 1 showed similar design features and pressure ratings. All had BOP equipment with 10,000-psi [68 948-kPa] pressure ratings and two subsea lines. The ID of the choke and kill lines ranged from 2.4 to 3.5 in. [6.10 to 8.89 cm], with 3-in. [7.62-cm] or larger lines being used on six of the vessels.

In the absence of any detailed records, computer simulations were used to predict the dynamic behavior of a deepwater well during the pump-out of a kick. Actual well data together with proposed drilling programs[4] were modeled to determine those parameters most significant to the successful control of a well kick. Fig. 2 is a schematic of a well drilled in 1978 in 4,342 ft [1323 m] of water off the coast of Zaire with the drillship *Discoverer Seven Seas*. This well was drilled to a depth of more than 16,000 ft [4877 m] with no reported drilling kicks. The situation shown in the figure, however, represents expected shut-in conditions resulting from a 0.5-lbm/gal [60-kg/m^3] kick while drilling with a 9.2-lbm/gal [1102-kg/m^3] mud at a depth of 11,540 ft [3517 m]. The mud program for the well was obtained from the operators along with most of the supporting data given in Table 2.

TABLE 1—DRILLING VESSELS KNOWN TO HAVE OPERATED IN WATER DEPTHS IN EXCESS OF 2,000 ft BEFORE 1980

	Number of wells drilled	Size (in.)	Working pressure (psi)	Subsea flowlines Number	Subsea flowlines ID (in.)
SEDCO 472	14	16.75	10,000	2	3.0
Discoverer Seven Seas	13	16.75	10,000	2	3.152
SEDCO 445	8	16.75	10,000	2	3.0
Discoverer 534	7	16.75	10,000	2	2.728
Ben Ocean Lancer	5	16.75	10,000	2	3.5
*Pelerin**	5	16.75	10,000	—	—
SEDCO/BP 471	4	16.75	10,000	2	3.0
Penrod 74	4	18.75	10,000	2	2.5
SEDCO 709	3	16.75	10,000	2	3.0
*Pacnorse**	1	—	—	—	—
Zapata Concord	1	18.75	10,000	2	2.4
*Petrel**	1	—	—	—	—
Total	66				

*Data not available.

A graphic history of predicted well behavior during pump-out of the kick is shown in Fig. 3. Before analyzing these results, we should review the following questionable assumptions inherent to the model that generated these data.

1. Formation gas enters the well as a continuous slug and retains this configuration as it moves up the annulus and into the chokeline.
2. The slip velocity of the gas relative to the mud is zero.
3. The choke operator maintains the BHP constant at exactly the desired value.

While these assumptions introduce some inaccuracies, the results were felt to be sufficiently valid to be used in design considerations of the experimental facility.

Fig. 3 shows several important aspects of the well-control process that the experimental facility must model. An initial shut-in choke pressure of 440 psig [3034 kPa] results in a wellbore pressure at the casing seat very near the fracture pressure. The circulating frictional pressure loss in the chokeline is 280 psi [1930 kPa] for a pump speed of 50 strokes/min and, on pump startup, the choke pressure is reduced from 440 to 160 psig [3034 to 1103 kPa]. A long a relatively uneventful period follows as the kick is circulated from the bottom of the well to the seafloor. However, once the gas reaches the seafloor and

TABLE 2—DATA FOR CONGO WELL EXAMPLE

Well Data

Casing	13⅜ in., J-55, 61 lbm/ft
Drillpipe	5 in., 19.5 lbm/ft
Drill collars	540 ft, 8×3 in.
Drill bit	12¼ in., 12- to 13¹³⁄₃₂-in. jets
Mud	9.2 lbm/gal, μ_p = 16 cp, τ_y = 10 lbf/100 sq ft
Fracture gradient	10.6 ppge* at 7410 ft RDF**

Pump Data

Type	single-acting triplex
Liner size, in.	6½
Stroke, in.	11
Efficiency, %	96

Circulation Data

	Drillpipe Pressures, psig strokes/min	thru riser	thru chokeline	chokeline friction, psi
Normal Drilling	110	2400		
Reduced Rate	50	600	880	280

Kick Data (Simulated)

Shut-in drillpipe pressure	300 psig
Shut-in choke pressure	440 psig
Pit volume gain	30 bbl

*Pounds per gallon equivalent.
**Reference derrick floor.

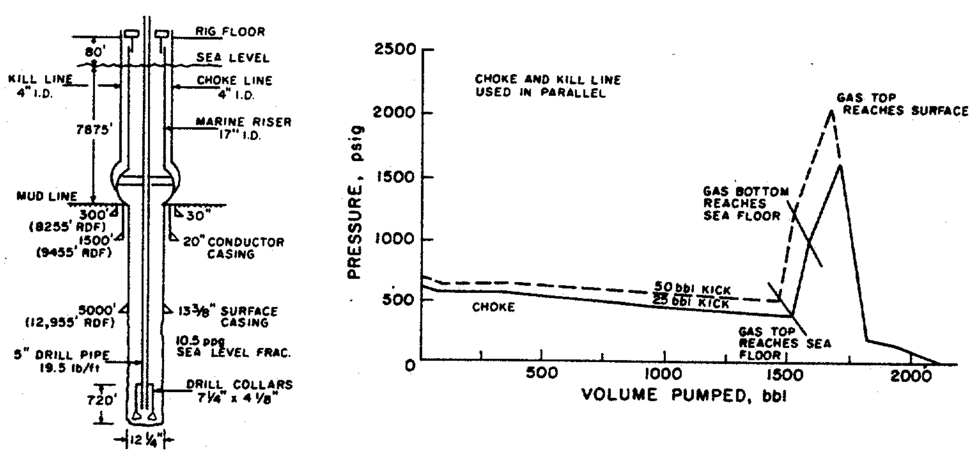


Fig. 4—Predicted well behavior for *Glomar Explorer* drillship on proposed offshore New Jersey location.

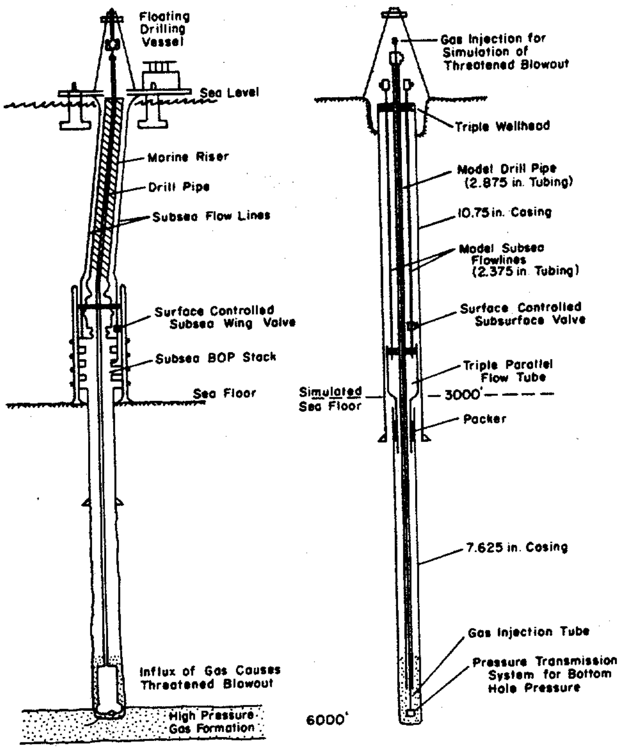


Fig. 5—Well design selected to model well-control operations on a deepwater offshore well.

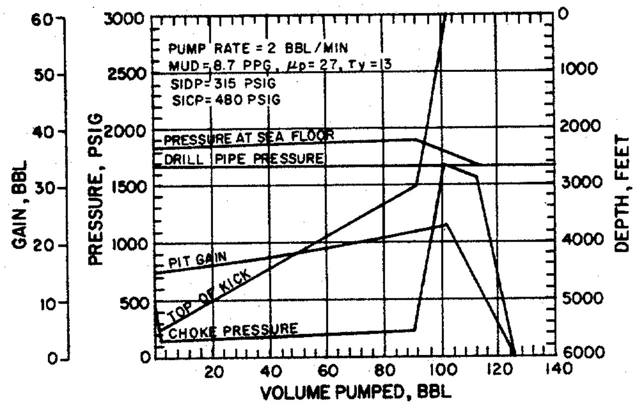


Fig. 6—Predicted behavior of experimental well.

enters the chokeline, the choke pressure must increase rapidly from less than 100 psig [689 kPa] to more than 2,100 psig [14 479 kPa]. A short time later, a rapid decrease in choke pressure is required as mud displaces gas from the chokeline. The average mud velocity in the chokeline, which is felt to be a measure of how rapidly the pressures must change, is 562 ft/min [2.85 m/s] in this example.

Numerous examples, such as the one shown in Fig. 3, were studied with data from different rigs and a wide variety of assumed well conditions. Other examples were studied with data from proposed wells in the Ocean Margin Drilling Program[4] that have been planned for water depths of up to 13,000 ft [3962 m]. Computed choke-pressure profiles are shown in Fig. 4 for the proposed modified *Glomar Explorer* drillship on a location offshore New Jersey in 7,875 ft [2400 m] of water. The results are similar to those previously discussed.

In addition to reviewing the well-control equipment of vessels that have operated in deep water, we reviewed available literature to identify special well-control procedures that have been proposed to solve the blowout prevention problems unique to the deepwater environment. We obtained a list of 42 training schools approved by the Minerals Management Service (formerly the Conservation Div. of the U.S. Geological Survey) for well-control training related to subsea BOP stacks, and reviewed training manuals from many of these schools. From the literature review we determined that some of the special well-control procedures proposed for floating drilling vessels require the use of two subsea chokelines.

We felt that the experimental well facility should model the significant phases of the previously discussed example and allow the experimental study of the special well-control procedures identified. The desired features of the experimental well facility included (1) realistic values for circulating frictional pressure loss in the chokeline; (2) realistic values for changes in choke pressure when a gas kick is circulated through the chokeline; (3) realistic values of circulating drillpipe pressures; (4) the availability of two subsea flowlines, one of which could be closed at the simulated seafloor to prevent collection of gas in the line when it was not in use; (5) reasonable kick simulation time; (6) reasonable initial and operating costs; and (7) reasonable gas injection pressure at realistic gas influx rates. All these factors interact considerably, making an optimal design difficult to determine.

Fig. 5 shows the final well design selected. A simulated water depth of 3,000 ft [914 m] was selected and the simulated subsea choke and kill lines (2.375-in. [6.03-cm] tubing) were run inside 10.75-in. [27.31-cm] casing to this depth. The effect of the BOP stack located on the seafloor is modeled in the well using a packer and triple-parallel flow tube. A subsea kill-line valve at 3,000 ft [914 m] is modeled by using a surface-controlled subsurface safety valve. This control allows experiments to be conducted using only the chokeline, with the kill line isolated from the system as is often the case in well-control operations on floating drilling vessels. The drillstring is simulated with 6,000 ft [1829 m] of 2.875-in. [7.30-cm] tubing. Nitrogen gas is injected into the bottom of the well at 6,100 ft [1859 m] through 1.315-in. [3.34-cm] tubing placed in the drillstring. A pressure sensor is located at the bottom of the nitrogen injection line to allow continuous surface monitoring of BHP during simulated well-control operations. The pressure signal is transmitted to the surface through 0.125-in. [0.3175-cm] capillary tubing, which is strapped to the 1.315-in. [3.34-cm] tubing. A check valve, located at the bottom of the nitrogen injection line, allows the line to be isolated from the system after injecting the gas kick into the well.

A graphic history of computer-predicted well behavior during pump-out of a typical kick is shown in Fig. 6. At a circulating rate of 2 bbl/min [5.3×10^{-3} m^3/s], a chokeline friction of 340 psi [2344 kPa] was predicted. When the gas reaches the seafloor, the choke pressure must increase rapidly from about 200 psig [1379 kPa] to about 1,700 psig [11 721 kPa]. A short time later, a rapid decline in choke pressure is required. The average velocity

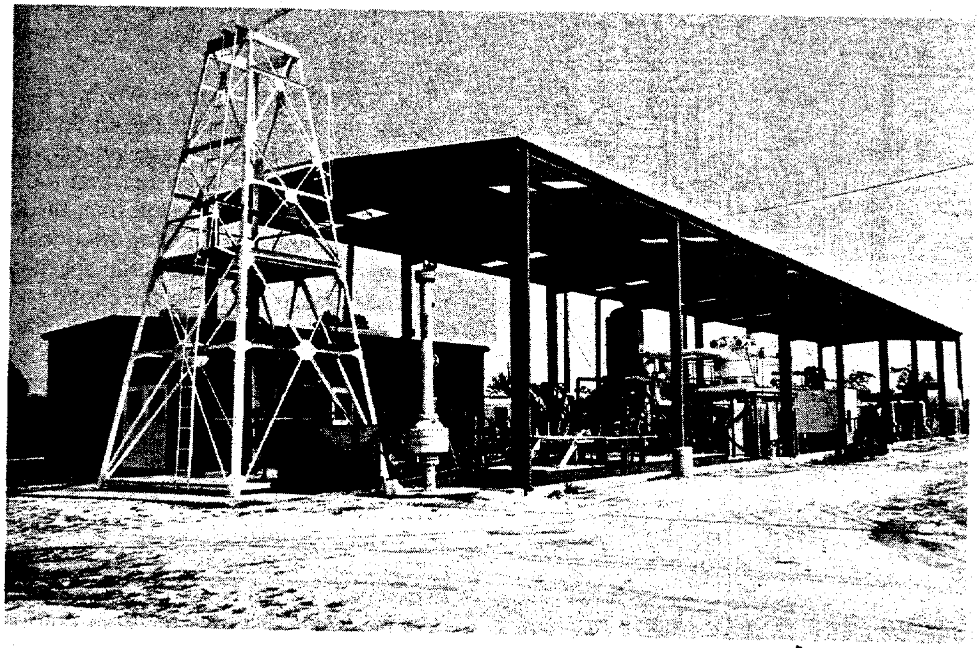


Fig. 7—Associated surface equipment for experimental well facility.

of mud in the chokeline is 517 ft/min [2.63 m/s]. Pumping time for a complete kick simulation is about 1 hour and circulating drillpipe pressure is about 1,700 psig [11 721 kPa]. Realistic kick simulations can be accomplished with reasonable gas volumes and pump horsepower requirements.

A photograph of the associated surface equipment for the experimental well facility is shown in Fig. 7. The main components of this equipment include (1) a choke manifold containing four 15,000-psi [103 421-kPa] adjustable drilling chokes of various designs, (2) a 250-hp [187-kW] triplex mud pump, (3) two mud tanks having a total capacity of 540 bbl [85.9 m^3], (4) two 15-bbl [2.39-m^3] metering tanks, (5) a mud gas separator, (6) three mud degassers of various designs, (7) a mud mixing system, and (8) an instrumentation and control house. Photographs taken inside the instrumentation and control house are shown in Fig. 8.

Results

Several types of experiments were conducted to study and to evaluate a number of alternative procedures proposed for well-control operations conducted on floating vessels in deep water. This work included (1) measurement of chokeline friction, (2) pump startup procedures, and (3) procedures for handling rapid changes in gas-zone length in subsea chokelines.

Chokeline Friction. The circulating frictional pressure loss in the chokeline must be accurately known to minimize the risk of formation breakdown during well-control operations. Several techniques proposed for routine measurement of this parameter are shown in Fig. 9. The first method involves taking the difference between the drillpipe pressure required to circulate the well through the chokeline with the BOP closed and the drillpipe pressure required to circulate the well through the marine

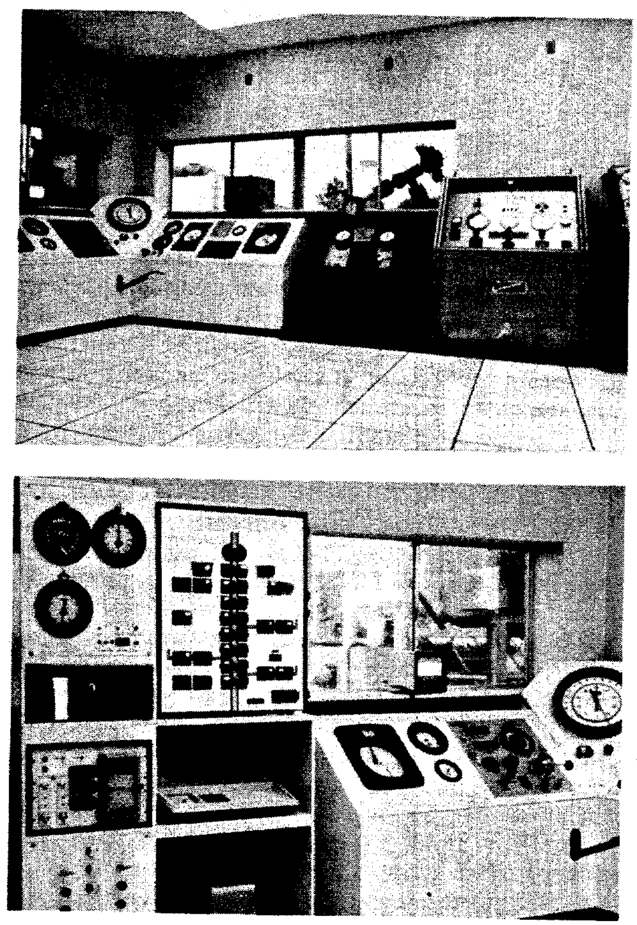


Fig. 8—Instrumentation panels in control room.

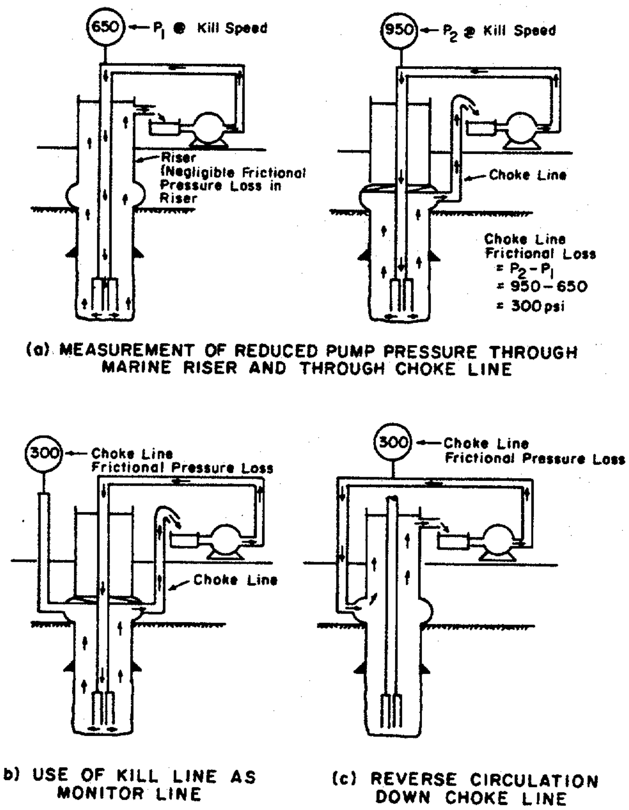


Fig. 9—Techniques for measurement of frictional pressure loss in chokeline.

riser with the BOP open. Care must be taken to ensure that the same pump rate is used in both measurements and that the mud properties in the well are not changing significantly between measurements. Ilfrey *et al.*[6] recommend adjusting the choke when using this technique until a midrange choke pressure is also observed while flowing through the chokeline. In this case, the circulating frictional pressure loss in the chokeline is the drillpipe pressure observed when the well is circulated through the chokeline, minus choke pressure, and minus the drillpipe pressure observed when it is circulated through the marine riser.

The second technique shown in Fig. 9 involves circulating the well through the chokeline with the BOP closed and noting the pressure observed on the static kill line. If care is taken to ensure that the same fluid is in both the chokeline and the kill line, the kill-line pressure will be equal to the circulating frictional pressure loss in the chokeline at the given pump speed. Again, Ilfrey *et al.*[6] recommend adjusting the choke so that a midrange choke pressure is observed. If this is done, the circulating frictional pressure loss in the chokeline is equal to the kill-line pressure minus the choke pressure.

The third technique illustrated in Fig. 9 involves pumping down the chokeline and up the marine riser with the BOP open. In this case, the pressure required for circulation, which is equal to the surface pressure on the chokeline, is also equal to the circulating frictional pressure loss in the chokeline. The pressure sensor located in the choke manifold should be used rather than the pump pressure sensor, so that the pressure loss in the surface piping to the choke manifold is disregarded.

A distinct disadvantage of the first two techniques[6] is that while the chokeline friction is measured, the wellbore is subjected to a total pressure in excess of that imposed while drilling. The excess pressure is the frictional pressure loss in the chokeline. The third technique has the advantage of not placing any additional backpressure on the well. Thus, chokeline friction can be measured without any fear of formation breakdown in the uncased portion of the wellbore. As a consequence, more frequent measurements of friction could be made. Then upon taking a kick, the most recent measurement of chokeline friction would be more representative of the flow behavior of the mud currently in the well.

Circulating frictional pressure losses measured in the chokeline of the experimental well are shown in Fig. 10 for several muds. Pressures were measured with a 0- to 5,000-psi [0- to 34 474-kPa] Bourns Model 520 transducer. The mud properties were measured in a stan-

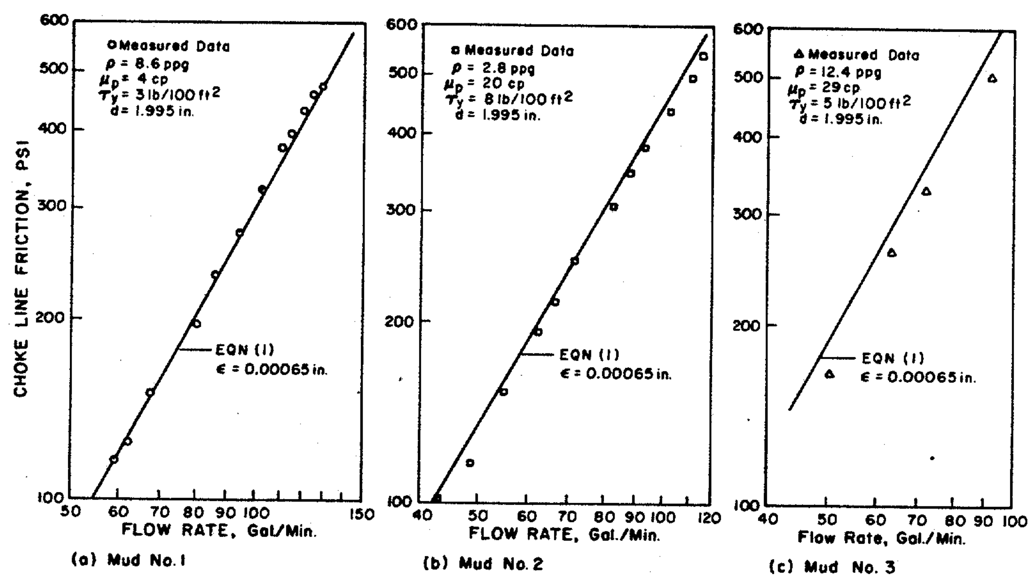


Fig. 10—Comparison of measured and calculated frictional pressure losses in a 1.995-in.-ID chokeline.

dard rotational viscometer at 600 and 300 rev/min, with samples taken from the return flowline at the surface. The solid lines indicate values computed by use of the Fanning equation, the Colebrook function, and plastic viscosity in the calculation of Reynolds numbers. For any consistent set of metric or customary units, these equations are given by

$$\Delta p_f = \left(\frac{fL}{d}\right)\frac{2\rho\bar{v}^2}{g_c}, \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

where

$$\frac{1}{\sqrt{f}} = -4 \log\left(\frac{\epsilon}{3.72d} + \frac{1.255}{N_{\mathrm{Re}}\sqrt{f}}\right) \quad \ldots\ldots\ldots (2)$$

and

$$N_{\mathrm{Re}} = \frac{\rho\bar{v}d}{\mu_p}. \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (3)$$

Note that there is good agreement between the measured and computed values, especially for unweighted low-viscosity muds. As expected, the accuracy of the calculation diminishes as the mud becomes more non-Newtonian.

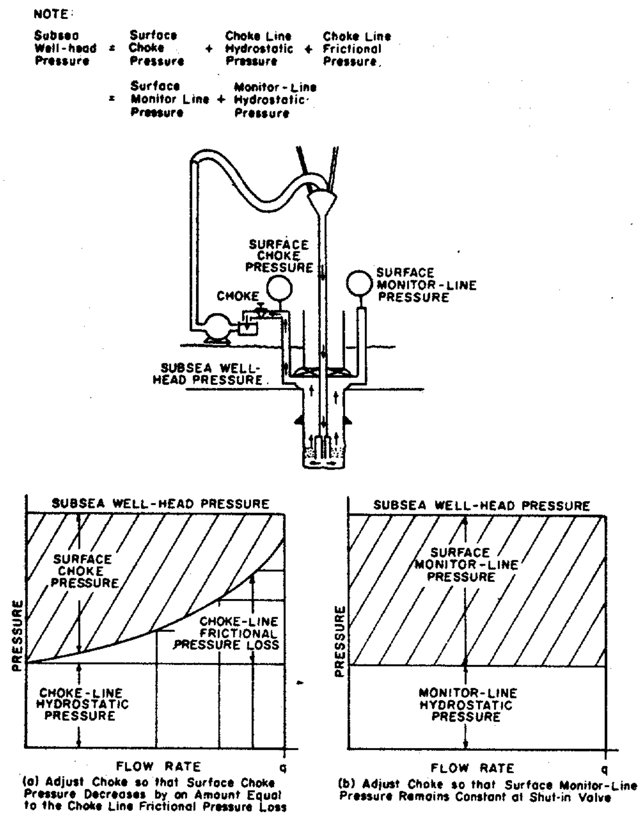


Fig. 11—Proposed techniques for pump startup.

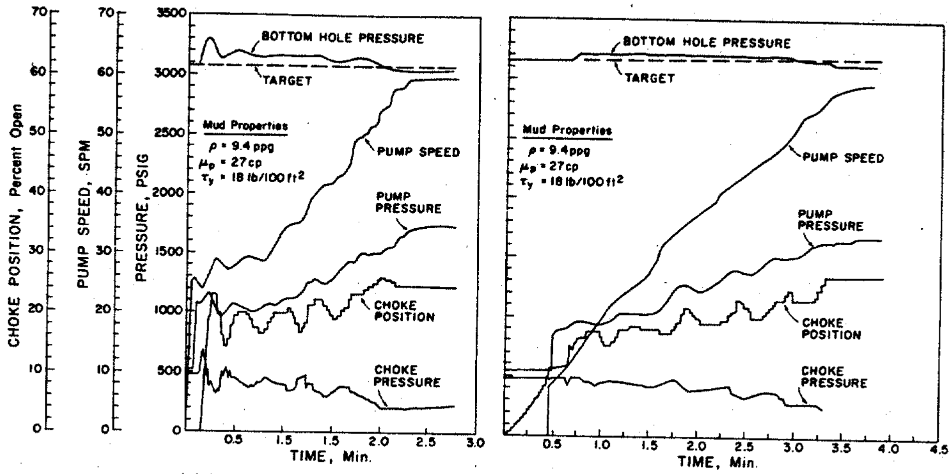
Pump Startup Procedures. Conventional well-control procedures assume that frictional pressure losses held against the well are small and can be applied as a convenient safety margin when circulation of the kick is initiated. Thus, the choke operator can simply adjust the choke to maintain the choke pressure constant as the pump speed is advanced to the desired value. After constant pump speed is established, the choke operator can then use the drillpipe pressure as the control parameter.

Use of the conventional pump startup procedure on a floating vessel in deep water is thought to increase the risk of formation breakdown greatly. The circulating frictional pressure loss in the chokeline is often too large to be applied safely as additional backpressure on the well. Alternative procedures that have been suggested for the case of a floating vessel in deep water include the use of (1) a computed choke-pressure schedule, (2) a casing-pressure monitor, and (3) multiple chokelines. The first two alternatives, as illustrated in Fig. 11, attempt to keep the pressure on the subsea wellhead constant by dropping the choke pressure an amount equal to the frictional loss in the chokeline at the given intermediate pump rate. In the first case, the choke operator accomplishes this by adjusting the choke so that the choke pressure will follow the computed pressure schedule. In the second case, the choke operator adjusts the choke to maintain the static kill-line pressure constant. Both these techniques are completely applicable only for pump rates at which the circulating frictional pressure loss in the chokeline is less than the shut-in choke pressure. If the chokeline contains a fluid with density different from the current drilling mud, then application of the first technique is not practical, but the second technique still can be applied.

The third alternative procedure is based on greatly reducing the frictional pressure loss held against the well through use of multiple chokelines. For example, by taking half the mud returns through each of two chokelines, the frictional pressure would be reduced to about one-fourth the value observed when a single line is used. In most cases, the reduction is sufficient to allow the conventional constant-choke-pressure pump startup procedure to be used safely. A disadvantage of this approach is that a redundant system is no longer on standby in the event the chokelines become plugged.

Approximately 200 pump startup exercises have been conducted to date. The experimental study indicates that all the alternative pump startup procedures are feasible. However, they all require considerable practice to master with a high degree of accuracy. The use of the kill line as a monitor line was found to require more practice to master because of the lag time before the kill-line pressure responds to a change in choke position.

With most drilling chokes, a dead band of choke positions in which the choke is fully closed is used to allow for choke wear. The width of the dead band is reduced as the choke elements become worn. For a new choke, however, it may be necessary to move the choke element by 20 to 40% of the maximum span before any flow will occur. A common mistake made by many choke operators is to begin pumping before opening the drilling choke to the point where flow is impending. This problem can be exacerbated further if minimum pump throttle results in too fast an idle speed when the pump is put in gear. Fig. 12a shows a typical pump startup exercise that illustrates this problem. Note that the BHP quickly increased by 220 psi [1517 kPa] as soon as the pump was started.



(a) Example Showing Common Problem (b) Example Showing More Ideal Results

Fig. 12—Example pump startup exercises using a single chokeline and a precomputed choke pressure schedule.

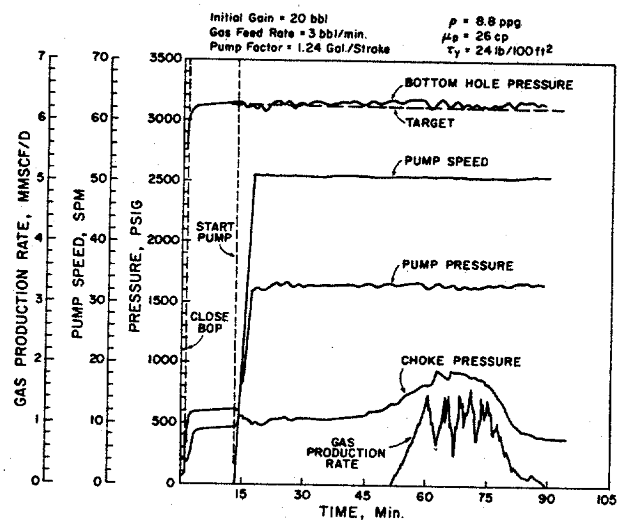


Fig. 13—Successful gas kick circulation using two chokelines.

Fig. 12b shows an example of a pump startup exercise in which the BHP was maintained within 50 psi [345 kPa] of the target pressure. A 50-psi [345-kPa] tolerance was found to be about the best that could be expected of an operator with a reasonable amount of practice. Note that in this example the choke was slowly opened until the choke pressure responded with a slight decrease. The pump was then engaged and pump speed was slowly and steadily increased to the kill speed of 59 strokes/min. The choke operator adjusted the choke in small increments to maintain the choke pressure near the precomputed target pressure.

On the basis of the results achieved with pump startup exercises at the experimental well facility, we found that practice exercises with the actual drilling choke and pump to be used in well-control operations are an important aspect of well-control training. Drilling personnel could practice with the well-control equipment on site just before drilling out the casing seat after cementing casing in the well. Shut-in pressures could be simulated by pumping a few strokes into the well with the BOP's closed. The crew could then practice the pump startup procedure appropriate for the chokeline friction at the anticipated kill speed to be used in the event of a kick. If the training exercise was planned carefully, only about 15 minutes of rig time would be needed.

Rapid Changes in Gas-Zone Length. Computer simulations of well-control operations for floating drilling vessels in deep water, such as the example shown in Fig. 3, have indicated that very rapid changes in choke pressure are required when the gas reaches and exits the BOP stack at the seafloor. A major question studied is whether a choke operator can react in step with rapidly changing conditions. Previously suggested solutions to this anticipated problem included use of (1) greatly reduced pump rates, perhaps just before the gas reaches the seafloor; (2) multiple chokelines; and (3) larger-diameter chokelines. All these suggested solutions attempt to give the choke operator additional reaction time by slowing the average upward fluid velocity in the chokeline. Only the first two options could be studied with the experimental well facility.

Techniques for handling rapid gas-zone elongation were studied for a wide range of gas-kick conditions. Kick parameter variations included (1) the number of chokelines used (one or two), (2) the kill circulation rate (1.0 to 2.5 bbl/min [2.65 to 6.62×10^{-3} m^3/s]), (3) the kick volume (5 to 30 bbl [0.795 to 4.77 m^3] initial pit gain), (4) the bottomhole kick injection rate (0.5 to 3.0 bbl/min [1.32 to 7.95×10^{-3} m^3/s]), (5) the shut-in drillpipe pressure (0 to 1,500 psig [0 to 10 342 kPa]), (6) the choke design (four drilling chokes of different design), and (7) the mud density (8.5 to 13.1 lbm/gal [1019 to 1570 kg/m^3]).

In addition to experiments being conducted purely for research purposes, numerous training exercises have been conducted for rig personnel currently working on floating vessels in deep water. This provided data from many different experienced choke operators. Approximately 130 gas-kick circulations have been conducted to date.

The success of a given set of operating conditions was based on how near the target pressure the BHP was held.

It was found that the most significant variable affecting the magnitude of the variation in BHP was the experience level and style of the choke operator. The kill circulation rate and number of chokelines used were also important, but circulation rates higher than originally anticipated could be handled successfully. Excellent results have been achieved at flow rates corresponding to average velocities up to 500 ft/min [2.54 m/s] in the chokeline.

Fig. 13 shows the most successful gas-kick circulation achieved to date at the experimental well facility, which used two chokelines in parallel. The kick size was 20 bbl [3.18 m^3], which was slightly less than the 23-bbl [3.66-m^3] volume of the two 2.0-in.- [5.08-cm]-ID chokelines. A kill speed of 51 strokes/min (1.58 bbl/min [4.19×10^{-3} m^3/s]) was used, which corresponded to an average mud velocity in the chokelines of 203 ft/min [1.03 m/s]. The maximum error in BHP during pump startup was −40 psig [−276 kPa]. The maximum error in BHP while gas was in the subsea chokelines was +50 psig [+345 kPa]. The maximum error occurred when the gas flow rate at the surface was rapidly increasing as maximum gas concentration reached the surface.

Fig. 14 shows the most successful gas-kick circulation achieved to date using a single chokeline. Maximum error during pump startup was −40 psig [−276 kPa], and maximum error when gas was in the subsea chokeline was +75 psig [517 kPa]. The maximum error of +75 psig [517 kPa] occurred twice, once when the leading edge of the gas kick entered the chokeline and once when the trailing edge of the gas kick exited the chokeline.

Because computer simulations have shown that very rapid changes in choke pressure are required when gas enters and exits a subsea chokeline, the required change in choke position with time was of interest. The choke position indicator on one of the adjustable chokes was modified so that choke position could be recorded continuously with ±0.5% accuracy. Fig. 15 shows an example gas-kick circulation with choke position plotted as a function of time. Note that during pump startup, choke position was increased to about 29% of full-open. Choke position was gradually reduced to about 18% of full-open as gas entered the subsea chokeline and was produced at the surface. When the surface gas flow rate began to decrease, choke position had to be opened quickly to about 28% of full-open. Note that the maximum positive error of +90 psi [620 kPa] occurred at this time, because the choke was not opened quickly enough. Eventually, the choke was opened to 39% of full-open after all the gas was removed.

The previous example shows that the required rate of decrease in choke position when the gas enters the subsea chokeline is much less than the rate of increase in choke position when gas exits the subsea chokeline. The

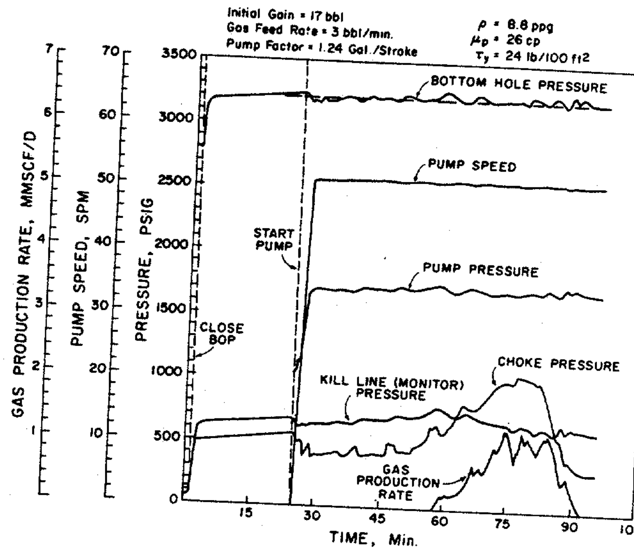


Fig. 14—Successful gas kick circulation using a single chokeline.

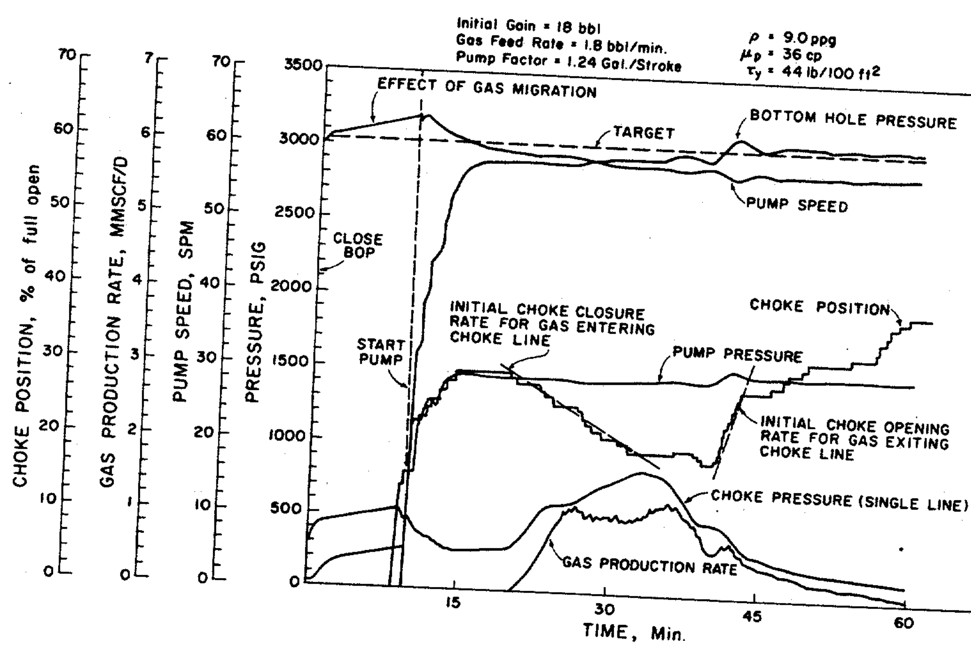


Fig. 15—Example successful gas kick circulation showing choke position.

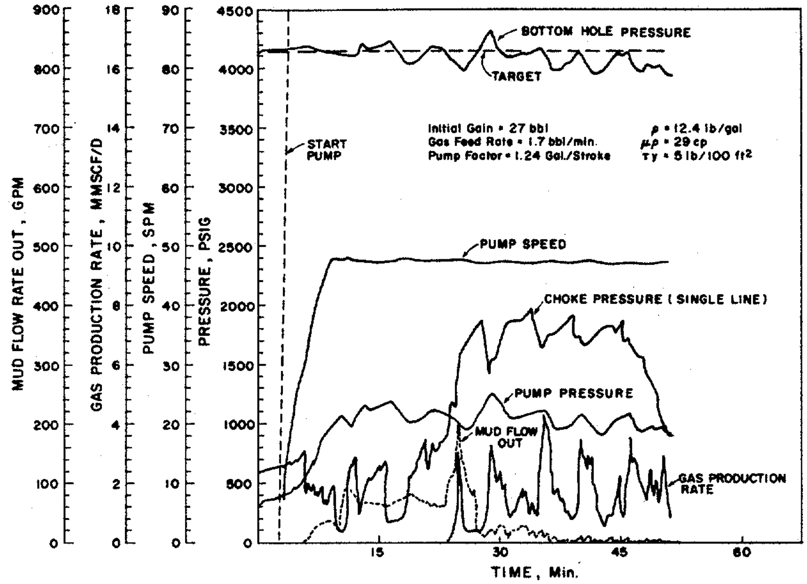


Fig. 16—Example gas kick circulation showing mud flow rate out of mud-gas separator.

demands placed on the choke operator when gas enters the subsea chokeline were not as great as previously anticipated. The choke operator is assisted by a natural increase in choke pressure with time as a result of rapid expansion of the gas as it approaches the surface. This causes the flow rate of the mud above the gas to increase, thus increasing the choke pressure without a change in choke position.

Mud flow rate out of the well, downstream of the mud gas separator, was measured during several gas-kick circulations. Typical results are shown in Fig. 16. Note that in this example, mud flow out increased by a factor of more than two just before gas reached the surface.

The demands placed on the choke operator are greatest when gas exits the subsea chokeline. However, conditions were not as severe as anticipated because of a gradual tapering off of the gas concentration at the trailing edge of a gas kick. This gradual reduction in gas concentration is the natural result of unequal gas-slip velocities of gas bubbles of different sizes. The smallest gas bubbles will be the last ones produced.

Fig. 17 illustrates a problem that can occur when the frictional pressure loss in the chokeline is almost as large as the shut-in casing pressure. On completion of pump startup, the required backpressure on the annulus is provided almost entirely by the frictional pressure loss in the chokeline. Thus, the choke can be opened far beyond the normal operating range with only a small response in the drillpipe pressure. Note that in this example, the choke was opened to 81% of full-open just after pump startup

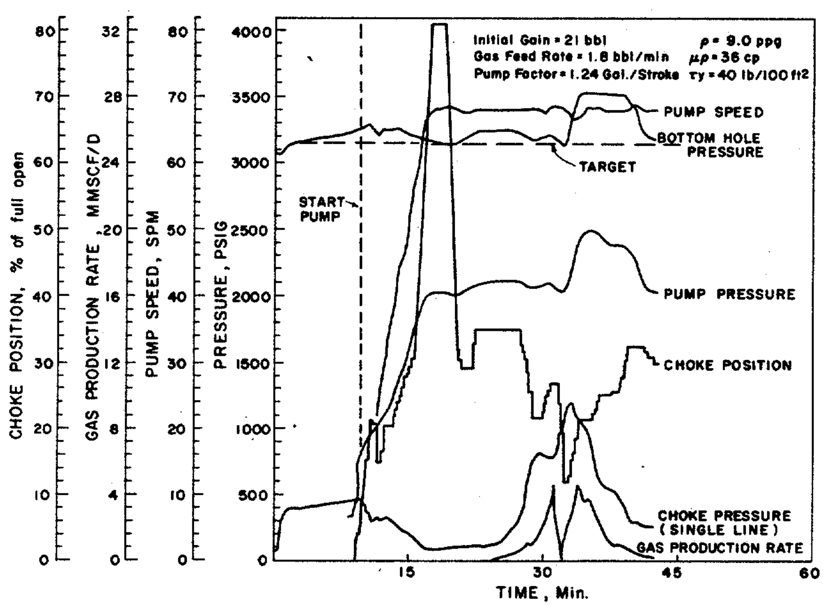


Fig. 17—Example gas kick circulation with chokeline friction almost equal to shut-in choke pressure.

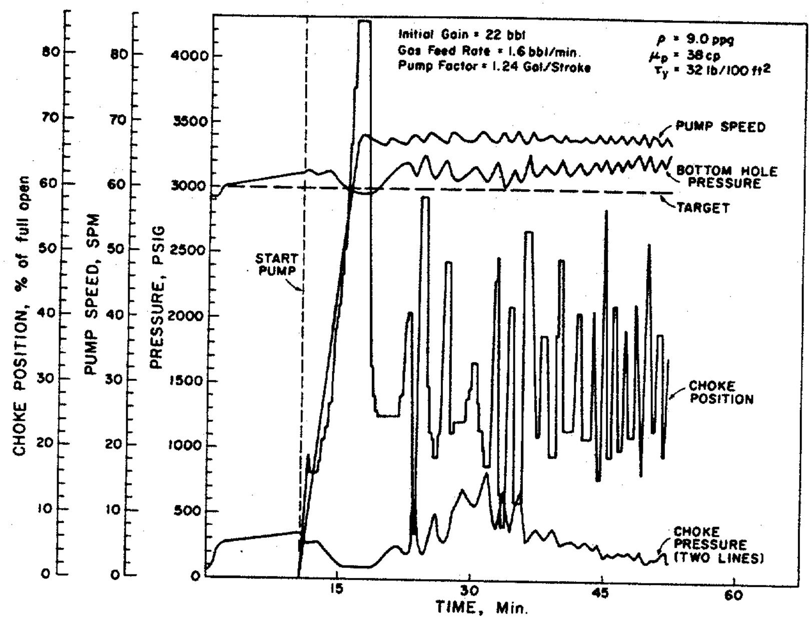


Fig. 18—Example gas kick circulation showing problems often caused by system lag time.

to achieve a small decrease in drillpipe pressure. If the choke operator is caught with the choke in nearly a full-open position when gas enters the subsea chokeline, it is extremely difficult to close the choke quickly enough without closing it too much. Note that in this example, a +400-psi [2758-kPa] error in BHP occurred while gas was in the subsea chokeline. The problem was exacerbated because gas began exiting the chokeline at the seafloor just after the choke opening was made too small.

Fig. 18 illustrates a common difficulty that arises because of the lag time before the drillpipe pressure responds after the choke position is changed. Because of this lag time, it is very easy to change the choke position too much when an adjustment is made. This causes some individuals to fall into a cycle of adjusting the choke alternately in the opening and closing directions. This style of choke operation was observed to be very common. Note that for this example, the maximum error in BHP was +320 psig [2206 kPa].

Conclusions

1. An experimental well facility has been used successfully to model the well-control flow geometry present on a floating drilling vessel operating in 3,000 ft [914 m] of water.

2. The well facility provides realistic conditions with respect to circulating frictional pressure losses in the chokeline and with respect to rapid changes in choke pressure when a gas kick is circulated through the chokeline.

3. The well facility is reasonably economical to operate, requiring relatively small gas volumes, pump horsepower, and circulating times to complete a kick simulation.

4. Frictional pressure losses in chokelines for low-density water-based muds were predicted accurately by flow equations based on a Bingham plastic model.

5. Several alternative procedures can be used successfully to cancel the detrimental effect of chokeline frictional pressure losses during pump startup. However, all these procedures require considerable practice to master.

6. The demands placed on a choke operator when gas is circulated through a subsea chokeline in deep water were not as great as previously predicted by computer simulations of well-control operations.

7. Well-control operations on floating vessels in deep water can be managed safely with existing equipment. However, proper choice of chokeline diameter for the water depth range of the vessel is of critical importance. In addition, considerable hands-on practice may be required for the operator to master the needed special procedures.

Nomenclature

d = internal diameter of pipe
f = Fanning friction factor
g_c = units conversion constant
L = length
N_{Re} = Reynolds number
p = pressure
Δp_f = frictional pressure loss
q = flow rate
$\bar{v}$ = average velocity
ϵ = absolute roughness
μ_p = plastic viscosity
ρ = density
τ_y = yield point

Acknowledgments

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The pump startup exercise shown in Fig. 12b was conducted by M.O. Cluchey (choke operator) and C.G. Brazan (pump operator) of Tenneco Oil Co.; the gas-kick circulation shown in Fig. 13 was conducted by J.A. Grant and J.W. Goodwin Jr. of Shell Offshore Inc.; and the gas-kick circulation shown in Fig. 14 was conducted by L.F. Eaton and J.W. Goodwin Jr. of Shell Offshore Inc.

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SI Metric Conversion Factors

bbl	×	1.589 873	E−01	=	m^3
ft	×	3.048*	E−01	=	m
gal	×	3.785 412	E−03	=	m^3
in.	×	2.54*	E+00	=	cm
lbm	×	4.535 924	E−01	=	kg
psi	×	6.894 757	E+00	=	kPa
sq in.	×	6.451 6*	E+00	=	cm^2

*Conversion factor is exact.

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