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THE DEVELOPMENT OF IMPROVED BLOWOUT PREVENTION SYSTEMS FOR OFFSHORE DRILLING OPERATIONS

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The Minerals Management Service
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I. INTRODUCTION

The Petroleum Engineering department at LSU has played an active role over the past decade in well control research and in training of industry personnel in present-day methods of well control. With the help of both industry and government modern training and research facilities centered around two 6000 ft wells were equipped to model well control operations conducted both in the shallow water marine environment of the continental slope and in deepwater offshore operations. A two million dollar expansion of this facility was recently achieved through the combined support of a consortium of 53 companies in the petroleum industry and through a research grant funded by the U. S. Minerals Management Service (MMS).

On March 24, 1982, a workshop was conducted at LSU to assist in the formulation of a long range plan for future well control research. The participants included (1) members of the industry advisory panel to the LSU Blowout Prevention Research Center (2) researchers currently being supported by MMS, and (3) representatives of various MMS districts. Twenty-one desirable projects were identified by this group. The top ten projects are listed in Table 1 along with a composite priority level assigned by the workshop panel.

A five year research plan was made in a proposal to MMS for developing improved well control systems for deep water offshore drilling operations. The proposed five year plan incorporates many of the high priority items identified at the LSU Well Control Workshop. In October, 1983, MMS Contract No. 14-12-001-21169, Mod. 2 was issued for LSU to

Table 1 - Recommendations made at March 24, 1982 LSU Well Control Workshop

Priority Level	Research Area	Votes Received Assuming Funding For following number of projects: One,	Two,	Three,	Four,	or Five
1	Feasibility Study on Use of MWD Technology in Well Control Operations on Floating Vessels	6	9	9	10	11
2	Study of Well Control Operations with Simultaneous Formation Fracture	3	10	12	16	17
3	Well Control Operations for Short Casing Strings (Diverter Systems)	3	5	8	12	14
4	Improved Procedures for Handling Upward Gas Migration during stripping or Snubbing Operations	1	3	5	5	8
5	Improved System for Detecting Gas in Mud at Depth (as opposed to present surface detectors)	2	3	5	5	7
6	Study of Upward Gas Migration in Slant (Directional) Boreholes	1	2	3	5	7
7	Scale-up of Fluidic Pulse Telemetry System to longer systems with varying mud properties	0	1	3	4	5
8	Determination of Minimum Number of Requisite Parameters via MWD for safe drilling operations	1	1	1	3	5
9	Scale-up of Ongoing Fire Suppression System Development for Offshore Drilling	2	3	3	4	4
10	Study of Potential Problems due to Gas Hydrate Formation in Subsea Well Control Equipment in Deep Water	0	3	4	4	4

begin work on the first year of the five year plan. In this document, the initial progress which has been made is summarized.

II. RESEARCH OBJECTIVES

Some of the most costly events that have ever occurred in the history of the oil industry have been caused by a loss of well control, commonly called a "blowout". Serious losses to life, property and the environment have been directly related to "blowouts", yet in the past little emphasis has been placed on well control when embarking on new frontiers of exploration. It has taken events such as those which occurred at Spindletop and the Santa Barbara Channel to remind the oil industry of the importance of well control procedures and equipment. In a continuing search for hydrocarbon deposits and with the increasing demand for fossil fuels imposed by the free world, the oil industry is about to embark onto yet another new frontier, i.e., the slopes of the outer continental shelf and deep marine sedimentary basins of the world. If blowout prevention theory and practice is to advance along with the technology now being developed for drilling in deeper waters, research must be done to determine the most effective blowout prevention systems for this new, more hostile environment.

The primary objective of the proposed research is to increase the efficiency and safety of deep water offshore drilling operations. This would be accomplished through the development of improved blowout prevention systems. The two main systems included in the study are (1) the high pressure emergency circulating system and choke used to circulate formation fluids from a well under pressure, and (2) the diverter system which must be employed prior to setting sufficient casing to

allow use of the high pressure system. Additional objectives deal with improved kick detection systems and complications that can develop as a result of formation fracture, directional drilling operations, or off-bottom kicks.

III. STUDY OF DIVERTER SYSTEMS

A particular situation where control of formation pressure is is extremely difficult is when unexpected high formation pressures are encountered at shallow depths. A well kick resulting from this situation can reach the surface quickly with very little warning. If the well is shut-in, an underground blowout will often result and at shallow depths the fluid from the high-pressure formation can broach to the surface and result in the loss of the drilling rig and often the personnel on the rig. This is particularly true for bottom supported rigs.

To alleviate the situation described in the above paragraph kicks at shallow depths are usually not shut-in but are routed through a diverter system. A diverter system is a safety device which ordinarily provides protection for operating personnel and equipment from the violent flow of hazardous fluid issuing from shallow-depth pressure zones. Normally, a diverter system is kept in readiness during drilling operations performed prior to setting a casing string at a depth sufficient to preclude an underground blowout from broaching to the surface. By opening a horizontal vent line and closing the upward flow path of well fluids, the diverter system reroutes the high velocity, often noxious and/or combustible effluent away from the work area. The well is permitted to flow until it naturally bridges, or the formation depletes, or until it is killed by pumping in heavy mud.

Historically, the design of diverter systems has been rather haphazard. Ideally a diverter line should be straight, nearly horizontal, contain no constrictions and be of sufficient size to prevent significant back pressure on the formation when large flows are routed

through the line. Ths ideal configuration is seldom met when one studies the diverter configurations currently in use. Many diverter lines are of insufficient size, contain many turns, often have constrictions due to small port sizes on the diverter spool and some contain vertical legs of significant length. This deviation from the ideal is due to the fact that diverter systems are relatively new to drilling rigs. Many of the rigs currently in use were built before diverter systems were required. Hence, when diverter systems were installed they were routed around existing equipment which led to some rather unorthodox configurations. It is hoped that as new rigs are built the routing of diverter lines will be a key factor in the overall design layout.

A study by MMS personnel in the Metarie District Office on encountering high pressure formations at shallow depths in the Gulf of Mexico provided some interesting information on hazzards associated with the use of diverter systems. In the study there were eighteen situations where rigs, which had diverter systems installed, took kicks at shallow depths. Of these eighteen situations the installed diverter systems were used successfully on seven occasions and unsuccessfully on eleven occasions. This is a failure percentage of 61%. Five of the failures were due to overpressuring the diverter system causing diverter lines/and or other diverter valves that would not open or were locked in place. A failure rate of 61% indicates that our knowledge of diverter systems and their proper design and usage is inadequate.

Also, in the same study there were three situations where floating rigs drilling without diverter systems were drilling conductor hole when they encountered uncontrolled flow from the well from shallow gas sands. The rigs moved off location successfully. This leads us to another point about diverter systems. For many years it was commonly believed that if a floating rig was drilling a well that suffered an underground gas blowout which broached to the surface, the ensuing boil would reduce the density of the water which would reduce the bouyancy supporting the vessel and the vessel would sink. More careful thought and subsequent research has shown that this is not the case. Hence, there is a growing school of thought that for floating drilling vessels diverter systems could be more of a hazard than a safety device. Many people feel that when a shallow blowout occurs when drilling from a floater, the proper procedure is to move off location until the flow depletes or the well bridges. Using a diverter system in this situation concentrates the hazardous material near the area you are trying to protect and should the system fail you have a potential disaster on your hands. Of course the option of moving off location with a bottom supported rig is not available and a diverter system must be installed.

With the high failure rate of diverter systems in mind, the purpose of the LSU study is to investigate some of the components used in diverter systems and hopefully arrive at recommendations on diverter system design that will increase their success rate by a substantial margin. We will also build a model diverter system that can be used to study new valve designs, automatic control systems, new diverter procedures, etc.

Erosion

There have been several cases where diverter systems were placed in use and operated successfully for a short period of time. Then some component, usually a fitting that caused a flow direction change, would erode out and the diverter system would fail.

As has been stated previously the ideal situation is to have a diverter line without turns but this is usually not practical. Therefore, it is imperative that the proper fitting be chosen to make a turn in a diverter system. The goal is to choose a fitting that will cause minimum pressure drop and be very resistant to erosion. In attempting to reach the goal, various types of turns have been tried. These include short-radius ells, long-radius ells and blinded tees. Data to support the efficacy of the above fittings in diverter systems could not be found. To get some idea of how well they perform we must refer to experiments conducted in pneumatic conveying systems.

For decades the only bend considered acceptable in pnuematic conveying systems was the traditional long-radius sweep where the radius/diameter (R/D) ratio ranged from 8 to 24. It was believed that material would flow along the inner surface of the outer wall and therefore the larger the radius, the nearer the approximation of a straight pipe and subsequently less wear and pressure drop. Use of long-radius sweeps did not solve the erosion problem. Over the years as users tired of costly replacements and repairs of long radius sweeps alternate forms of bends were evaluated.

Table 2 illustrates a comparison of bend service life between blinded tees and long-radius sweeps as conducted by a private industry when handling zirconium-sodium. The largest factor contributing to the greatly increased life for the blinded tee is the presence of the

"pocket" opposite the material flow. This pocket becomes concentrated when a dense accumulation of material is moving, its presence acts to absorb the impact of the material in the conveying line rather than the bend absorbing it. The tests also indicated a slightly smaller pressure drop for the blinded tee.

TABLE 2

Bend Type	Service Life (Hrs.)
Long Radius, R/D=8	8
Long Radius, R/D=12	14
Long Radius, R/D=16	15
Long Radius, R/D=24	26
Blinded Tee	487

Comprehensive operating experience is not available for short-radius ells, but the experience to date indicates that their ability to resist wear is almost as good as the blinded tee due to the similarity in flow pattern in that a region of dense material is formed at the turn. It has also been suggested that the pressure drop around a short-radius ell would be less that either the long-radius sweep or the blinded tee.

The above paragraph suggests a design that would combine the beneficial attributes of the short-radius ell and the blinded tee. Such a design has been accomplished and is known as the "Vortice Ell". The Vortice Ell is manufactured by HammerTek Corporation of Harrisburg, PA. HammerTek also holds the patent on the Vortice Ell design.

The experimental work on erosion to be carried out at LSU will be in a two inch, schedule eighty line containing a minimum of one ninety degree turn. Two inch pipe was chosen because with the existing source of gas available we can reach velocities in the two inch pipe

that would be comparable to the velocities attained in a ten inch line flowing 100 MMSCF/Day. This combination of line size and flow rate is not unrealistic in a real divert situation.

The erosion studies will be carried out in two phases. The first phase will be a study of wear and pressure drop using a slurry containing abrasives. The second phase will be identical to the first except that the abrasives will be carried in a gas stream instead of a slurry. In both cases four types of turns will be investigated. These are (1) long-radius ells, (2) short-radius ells, (3) blinded tees and (4) the Vortice Ell. A minimum of two runs in each phase and for each type of turn will be made. This will result in minimum of eight runs in phase one and eight runs in phase two.

The construction of the experimental facility to conduct the erosion studies is nearing completion. PHase one experiment will commence during the first week of September 1984. An order has been placed with HammerTek for the two-inch Vortice Ells necessary for this study. They are in the process of designing and constructing the molds to cast equipment and delivery is expected in late October.

While the experimental work in a 2-in model diverter is being conducted, a larger scale model diverter system will be constructed for the next phase of the research.

The diverter system will be complete in every sense and will be designed so that any configuration desired can be studied. It is anticipated that areas of study could include the following:

1. The use of flexible sections (hoses) in diverter lines.
2. Proper anchoring procedures for diverter lines.

3. Use of various types of turns, including the Vortice Ell, to determine the type that produces the smallest pressure drop and has the least tendency to plug.

4. The efficacy of various types of diverter valves to perform their designed function.

5. The use of automatic controls to activate the diver system.

6. The effect of vertical runs in a diverter system.

The above are just a few of the areas that could be investigated with the model diverter system. Many others will undoubtly arise as the research progresses.

Mathematical Modelling and Pressure Loss Studies

The work being done on diverters is two fold, that is, development of a theorectical model and experimental work to substantiate assumptions made in the model.

Considerable time was invested in seeking the appropriate solution technique for the computer model. A system or "Nodal" analysis was chosen as the best presentation. This technique requires the calculation of pressure losses throughout the system and then comparing the sum of the pressure losses to the total available pressure energy. Since mass flow rate is constant in each section of the system, there is one unique flow rate that makes the sum of the pressure losses equal to the total pressure available, whether the flow be gas, liquid, or a combination of gas and liquid.

The evaluation technique requires the calculation of the inflow performance of the reservoir; i.e., flow as function of pressure drop to the wellbore. It must be remembered that in this case the pressure profile in the reservoir is an unsteady state condition. In order to fully describe the inflow performance, the time dependency will have to

be accounted for. Procedures are already available from reservoir engineering to perform these calculations.

The next section of the system is the vertical flow path. This may be flow inside the drill pipe or may be flow in the annulus between the casing and drill pipe. Again, the flow could be gas or liquid or a combination for the two. Gas flow pressure losses can be predicted using procedures such as the Cullender and Smith equation, and liquid flow pressure losses can be predicted using standard hydraulics techniques. Pressure losses for the flow of gas-liquid combinations can be predicted using the various two phase flow correlations available in the Petroleum Engineering literature, such as the Hagedorn and Brown correlation .

Pressure losses for horizontal flow in the diverter line itself can be predicted by techniques similar to those used in vertical flow lines described above. However, two critical pressure losses that are not well understood are the effects of bends in the diverter line when flow velocities are very high and the exit pressure at the end of the diverter line. Experimental work is being conducted to assist with these two problems.

The calculations are performed to yield the graphs in figures 1 and 2. First the reservoir performance (flowing bottom-hole pressure) is calculated as a function of flow rate. Next, the flowing bottom hole pressure is calculated as a function of flow rate for the vertical flow path, using a fixed value of flowing wellhead pressure (see Fig. 1). Several of these curves are generated with different flowing wellhead pressures to yield the graph in figure 2. Finally, the diverter pressure losses as a function of flow rate are calculated and graphed.

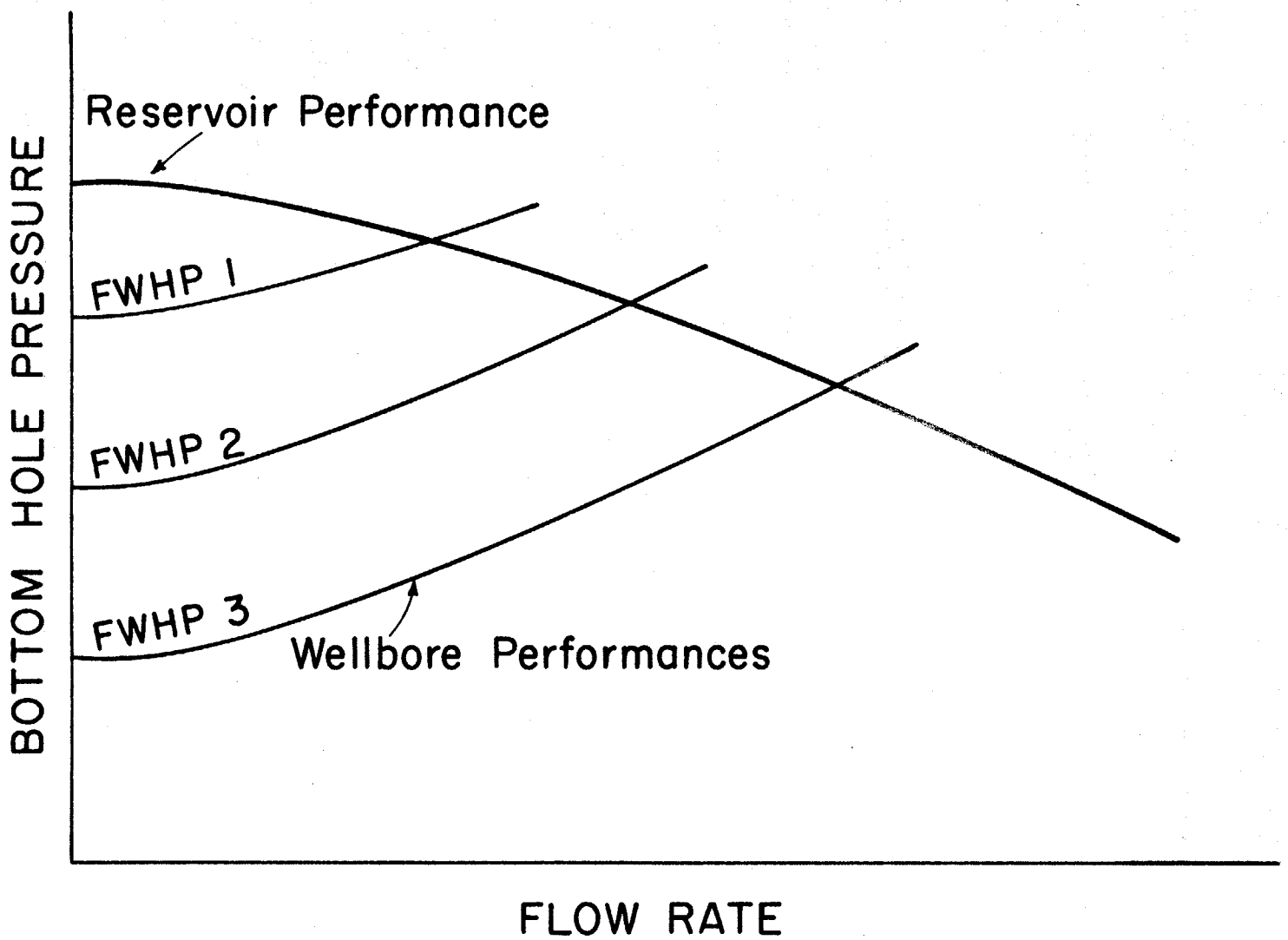
Reservoir Performance
FWHP 1
FWHP 2
FWHP 3
Wellbore Performances
BOTTOM HOLE PRESSURE
FLOW RATE

FIGURE 1

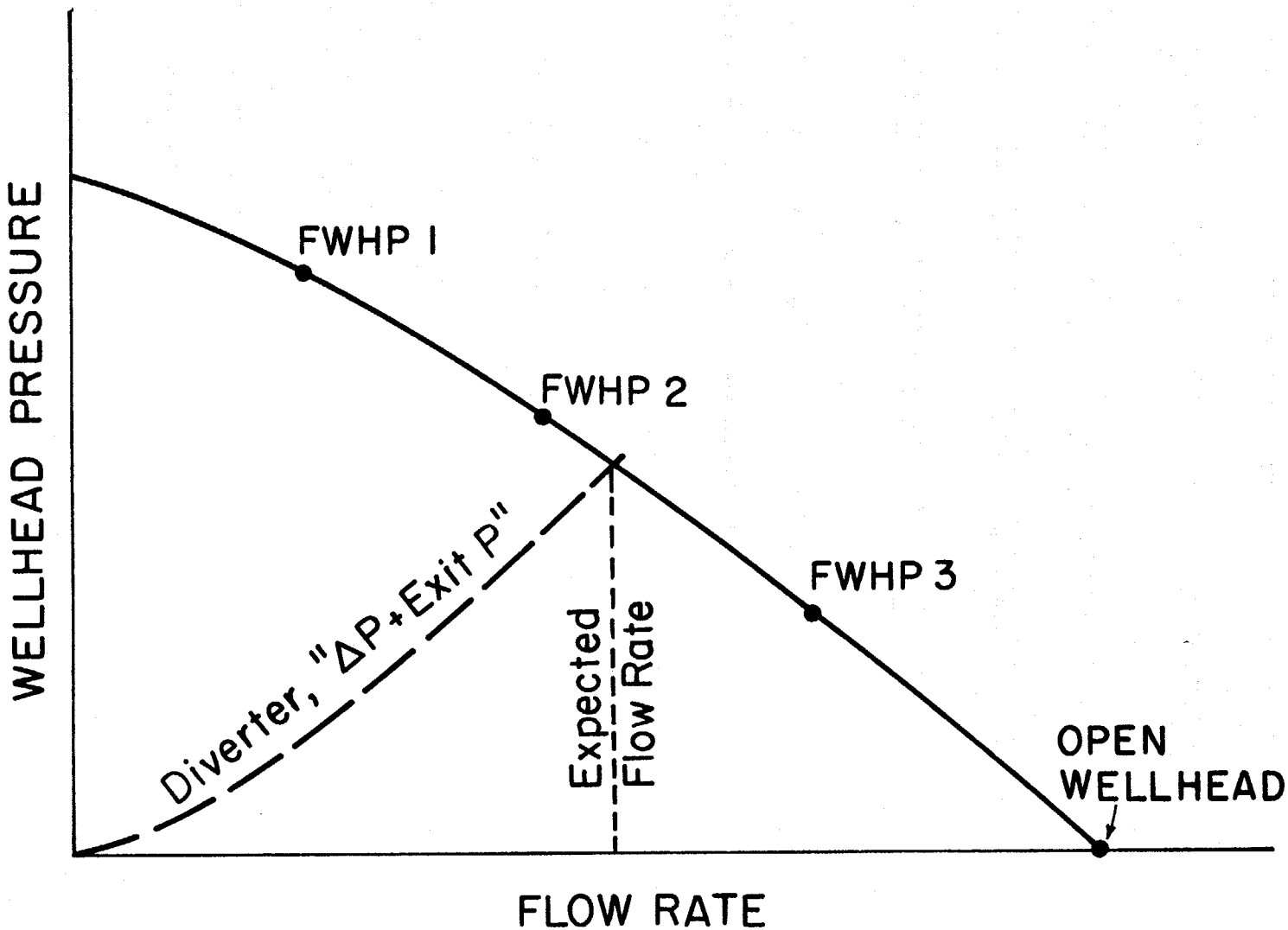
WELLHEAD PRESSURE
FWHP 1
FWHP 2
FWHP 3
Diverter, "ΔP+Exit P"
Expected Flow Rate
OPEN WELLHEAD
FLOW RATE

FIGURE 2

The intersection of these two curves is the simultaneous solution of the sum of the pressure losses, that is, the expected flow rate for this set of circumstances.

The exit pressure becomes a very critical value since this determines the pressure applied to exposed formation attempting to fracture that formation. A fracture below relatively shallow conductor casing leads to broaching which in turn endangers the entire drilling equipment. This phenomena is the very reason for diverter systems to begin with. Consequently, this exit pressure is a critical variable and must be calculated correctly to ensure proper modeling of the diverter system.

Exit pressure is defined to be the pressure at the end of the diverter line. If flow is subsonic (velocity of the flowing medium is less than the velocity of sound in that medium) then the exit pressure is atmospheric pressure. However, the velocity of the flowing medium is limited to the velocity of sound in that medium, which is sonic flow. Since frictional pressure loss is an energy loss, sonic flow can occur at only one point in the system and that point is assumed to be at the exit point. A flow restriction in the system such as a partially closed valve, etc. could be the point of sonic flow, but this situation is an improperly designed diverter system. Our work will focus on a properly designed system.

Sonic velocity, as a practical matter, is impossible to achieve with the flow of a liquid only. For example, sonic velocity in water is approximately 4500 ft/sec which is a flow rate of some 1,500,000 bbls/day in a 2" ID flowline. However, gas flow reaches sonic velocities rather quickly. For the 2" ID flowline investigated, the onset of sonic flow occurred at less that 2 MMCFPD.

Table I lists the experimental data taken with the 40 ft. long 2" ID

diverter for various gas only flow rates (see fig. 3 for diverter schematic). The pressure readings listed for a given gas rate is the pressure vs. length profile which is extrapolated to define the exit pressure. In fact, P5 is essentially this exit pressure since it is so near the end of the pipe. Critical velocity for gas flow only was approximately 1460 ft/sec and almost independent of pressure. The only variation was due to changes in the z-factor from one pressure to another. The predicted exit pressures were within 3.5% of the measured value for single phase gas flow.

The only available model for predicting critical velocity of two-phase gas and water flow is the equation by Wallis, which is

$$V^* = [\lambda_g \rho_g + \lambda_L \rho_L] \left[\frac{\lambda_g}{\rho_g V_g^{*2}} + \frac{\lambda_L}{\rho_L V_L^{*2}}\right]^{-\frac{1}{2}}$$

where

λ - no slip holdup

ρ - density, lb/cu ft

V^* - critical velocity, ft/sec

Figure 4 summarizes the accuracy of this equation determined from experimental data by comparing the actual mixture velocity inferred from pressures measured to critical velocities predicted by the above equation. As can be seen from Fig. 4, the mathematical model predictions of critical velocities are anywhere from 20 to 30% below measured values. This difference is critical in determining the flow rate for the overall problem. A summary of the supersonic multiphase flow data collected is given as Table 3.

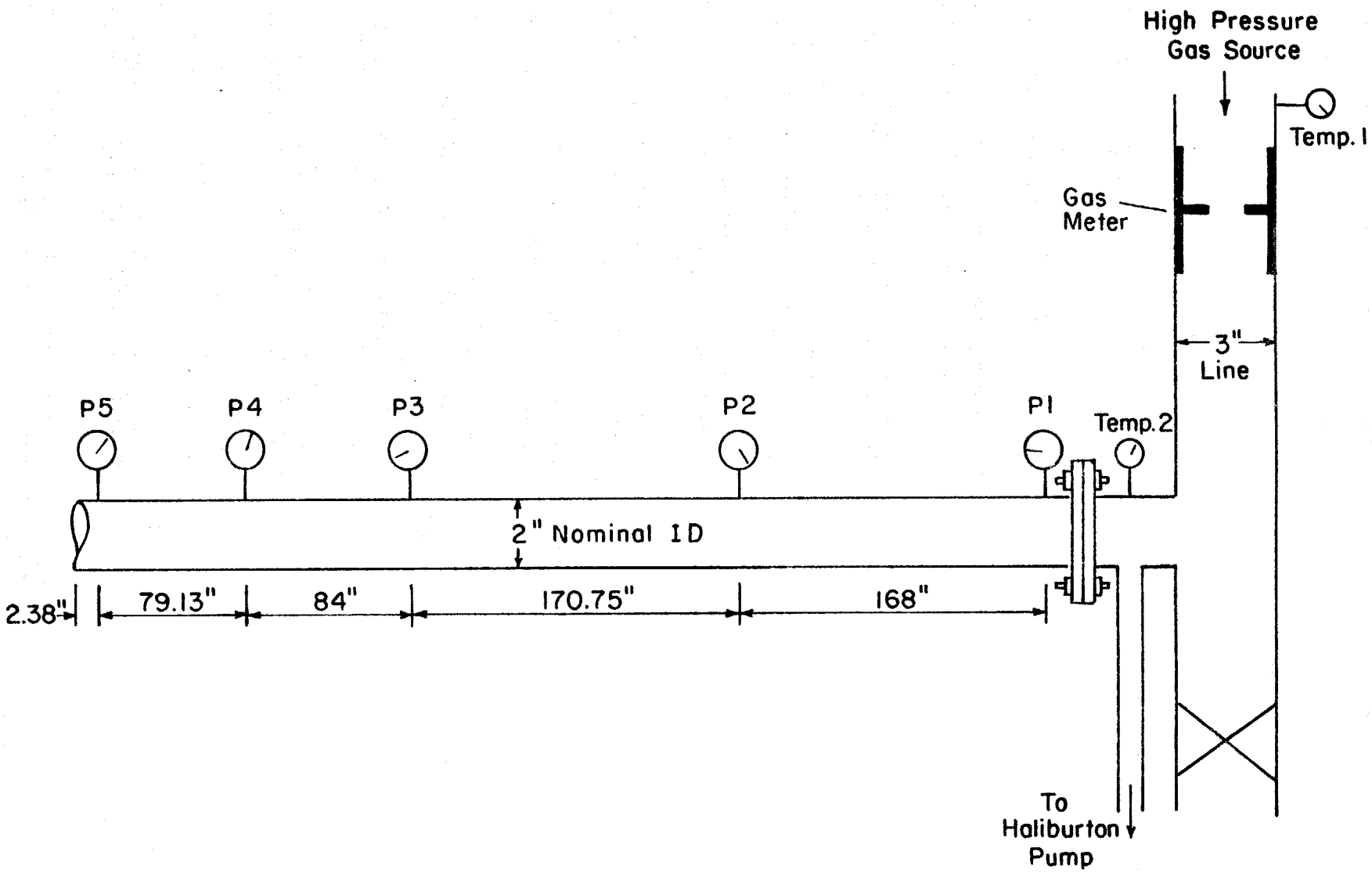
High Pressure
Gas Source
Temp. 1
Gas
Meter
3"
Line
P5
P4
P3
P2
P1
Temp. 2
2" Nominal ID
2.38"
79.13"
84"
170.75"
168"
To
Haliburton
Pump

FIGURE 3

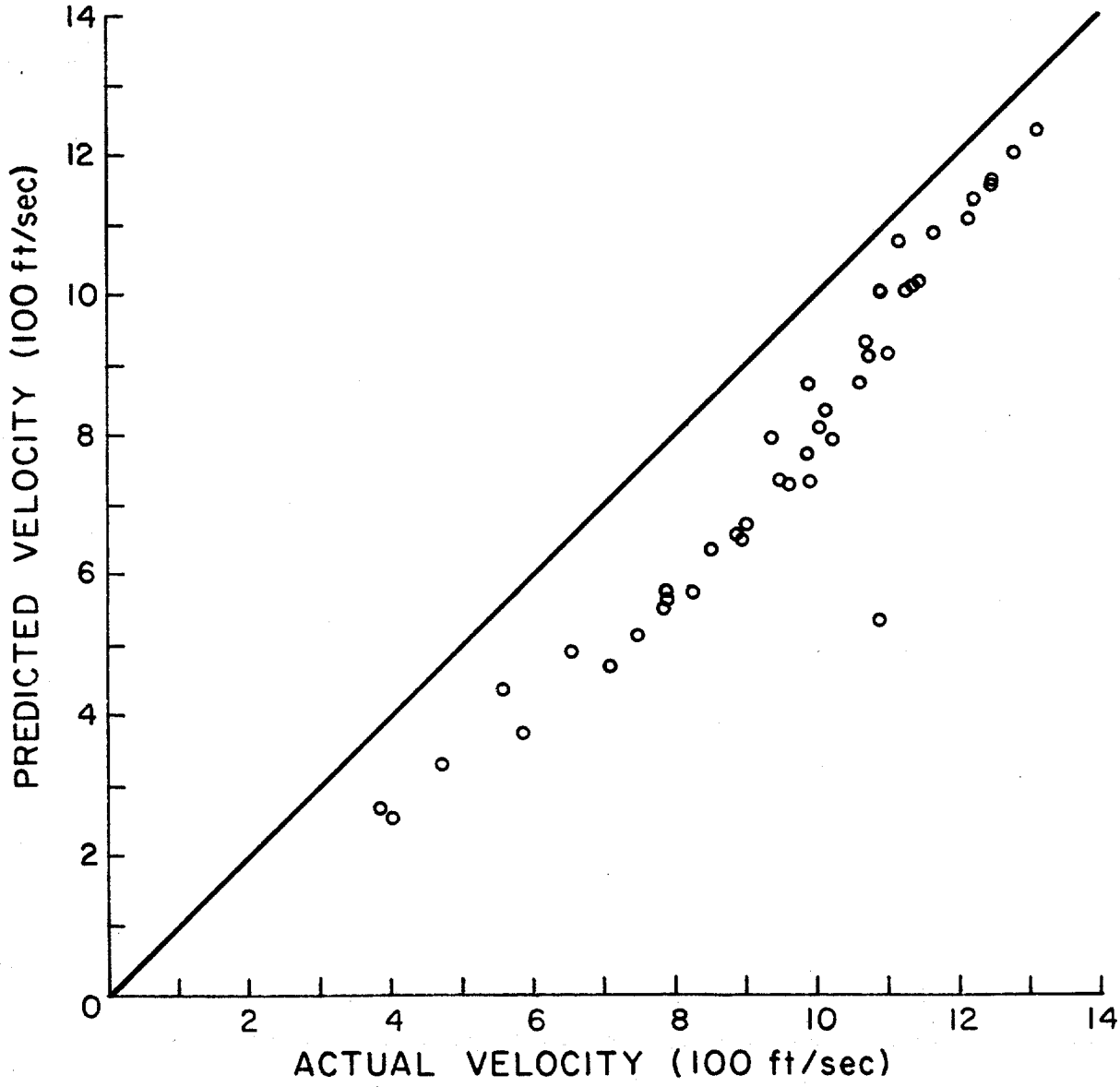
PREDICTED VELOCITY (100 ft/sec)
ACTUAL VELOCITY (100 ft/sec)
0
2
4
6
8
10
12
14

FIGURE 4

Table 3 - Typical Supersonic Multiphase Flow data Obtained in 2-in. Model Diverter Using Natrual Gas and Water

TWO-PHASE DATA

GAS RATE (MMSCFD)	WATER RATE (BBL/MMSCF)	PRESSURES (PSIA) P1	P2	P3	P4	P5
3.36	689.8	124	78	62	48	35
2.64	793.5	89	72	58	41	21
4.80	900.7	197	165	131	102	56
2.04	4151.3	201	165	133	83	49
1.92	4457.1	197	174	126		44
3.72	1114.3	172	143	110	88	46
3.55	1858.2	215	178	139	105	54
3.36	2520.4	247	206	159	127	64
3.72	131.8	86	73	60		28
3.17	534.3	111	90	68		32
2.98	777.8	121	98	76		33
3.12	178.6	77	64	51		25
3.00	364.0	85	70	54		26
2.88	193.3	71	59	47		23
7.08	138.5	160	135	111	91	54
6.79	282.3	172	143	115	95	58
6.58	379.3	183	149	118	96	59
6.43	513.0	197	162	125	103	62
6.24	685.7	228	192	147	122	69
6.24	1028.6	289	239	189	152	84
6.00	1366.8	323	271	214	175	96
7.80	137.0	169	146	120	99	59
7.61	58.6	151	134	108	87	51
7.68	191.5	170	145	118	98	60
7.08	255.0	174	145	118	97	60
18.96	79.9	369	328	265	219	132
17.16	137.7	356	313	259	214	134
15.60	228.6	357	311	254	214	135
14.40	297.0	359	307	250	207	132
13.44	71.3	262	234	191	155	92
11.64	103.4	242	212	173		89
10.80	92.9	221	195	156		56
10.08	99.5	206	185	149		74
9.50	49.9	185	164	131		62
9.07	49.1	178	156	124		59
8.64	221.8	200	170	138		70
7.97	299.2	200	165	134		67
7.44	320.5	191	159	127		65
6.89	498.1	207	172	135		67
5.90	732.8	220	186	142		65

Since the data taken also gave a pressure profile as a function of diverter length, we were able to investigate the frictional pressure losses for both single phase and two phase flow when flow is approaching sonic velocities. This enabled us to more accurately predict the role of acceleration in pressure loss as well as friction factor under these conditions.

Once the mathematical model simulating the entire diverter process, as described previously, is completed, then various phenomena can be investigated. Such things as reservoir performances, vertical flow paths and others can all be compared to diverter size and length.

IV. IMPROVED WELL CONTROL SYSTEM

There has been some recent advances in the development of automatic well control chokes which are capable of maintaining a desired drill pipe pressure setting. In addition, there has been some recent advances in measurement while drilling (MWD) technology which may make it pratical to monitor bottom hole pressure while drilling and during well control operations. By combining the MWD and well control technologies, it should be possible to produce an automatic system capable of maintaining bottom hole pressure nearly constant both during pump start-up and when a gas kick reaches the subsea BOP stack. Experience in training field personnel at LSU indicates that control errors as high as 300 psi are common with existing systems.

In order for the well control system to function effectively it will need timely data from the bore hole. Experimental research conducted to date indicates that bottom hole pressure updates will be required at intervals no greater than 10 seconds. Hence some form of rapid data telemetry up the drill pipe is needed. Over the years various types of telemetry have been proposed and attempted. Of the techniques currently employed, mud pulse telemetry appears at first to show the most promise. The mud pulse signals used can be generated in a number of ways. The mechanical devices generally are limited in pulse rate by wear and mechanical problems. To overcome these deficiencies a fluidic pulser has been the subject of development by Al Holmes at Harry Diamond Labs. However, the pulse rate may be limited also by the propagation of the signal up the drill pipe. A 10,000 ft horizontal flow loop consisting of 4.5-in. drill pipe has been designed to study this problem in a realistic

manner. Construction of this flow loop will be accomplished during the next several months. In addition, a more novel approach at data telemetry is also being studied which involves the use of the drilling fluid as an electrical telemetry medium. Electrical telemetry will require the use of an electrical insulating sleeve inside the drill pipe.

Some initial analyses and experimental study of the use of electrical telemetry through the mud using an insulated drill pipe was performed. A small scale system was constructed using 500 ft of plastic pipe which was set up to model 20,000 ft of 5-in. pipe. The experimental data indicated that even though extremely small electrical signals would be received at the surface, they could be detected and decoded using special filtering techniques. Mud was pumped through the model at rates high enough to achieve turbulent flow in these experiments. The coupling efficiency at the electrodes was less than expected, however, and additional work is needed in this area. Also, future work will focus on the severity of the engineering problems associated with insulating the drill pipe and how many electrical leaks could be tolerated.

Simultaneous efforts have been directed along four avenues of attack on this problem. They include independent studies to determine:

1. Study of existing automatic choke equipment
2. Sensitivity and accuracy of present-day measurements of surface pressures
3. Drilling choke response to incremental adjustments as influenced by fluid type, flow rate and prevailing back pressure
4. Acquisition, monitoring and storage of process variables required for automatic control of choke adjustment and

pump speed to maintain constant bottom hole pressure (BHP) while circulating a kick from the well.

Two existing automatic chokes which are commercially available were modified to input and control bottom hole pressure through choke manipulation. One of these systems was found to yield results comparable with an experienced human operator for pump start-up. However, neither system proved adequate for use with MWD technology in a deep water environment with a subsea blowout prevention stack.

Commensurate with the study of automated well control was the need to evaluate the effectiveness of remote monitoring of wellhead pressures using present-day practices and technology. Many well control decisions are related to both surface pressures and downhole pressures inferred from wellhead measurements. These in turn are monitored by remote sensors (Bourdon gages, electronic transducers) located some 50 to 150 ft from the standpipe and choke manifold.

A detailed study evaluating the sensitivity and accuracy of remote gage response to drillpipe and casing pressures has been completed and a technical publication is planned. This study was prompted by numerous discussions with drilling personnel who have attended our comprehensive and advanced well control schools. Common to these discussions are the arguments that: (1) "It seems useless to attempt pressure control in increments smaller than 100 psi because the system is not that precise," (2) "Pressure readings of 100-150 psig are not uncommon when the well is open and the pump is not running," and (3) "Under shut-in conditions of high pressure, gage readings can be as much as 50% too low."

In summary, it was found that remote pressure readings are a

function of (true) process pressures as well as several errors inherent to the remote sensing system. Depending upon its configuration, errors can range from being insignificant to being thousands of psi low. An accompanying report describes the sources of error found to be most significant along with procedures to evaluate their effect on the range of pressure measurements important to well control. It was necessary to find that a "properly conditioned" system will provide remote measurements of drillpipe and casing pressure that are entirely adequate.

Circulation of a well kick under the supervision and control of an automated system, involves two major control variables: (1) drilling choke adjustment and (2) mud pump speed. The control algorithm responsible for changes in choke setting must have "look ahead" capabilities in addition to "adjust and test" incrementing. Hence the study of choke response to flow rate, type of fluid, prevailing backpressure and choke actuator positioning has been continued. A troublesome circumstance is the change in pressure response with changes in the type of liquid flowing through the choke.

Results of this continuing research are very encouraging, especially in the area of simultaneous (two-phase) flow of both mud and gas through a "tapered stem and seat" type choke, e.g., Cameron, NL Shaffer and TOTCO. For single-phase mud flow, the choke setting, flow rate and pressure response can be described by a single parameter called a "frictional area coefficient." This parameter can be represented by a simple monotonic function of choke position (percent open). Using this coefficient as a pseudo orifice area and neglecting upstream velocity, Bernoulli's equation for frictionless liquid flow can be made to predict a pressure

drop across the choke equal to that observed. Bernoulli's equation modified to include a fluid expansion coefficient (Y-factor) was found to accomodate single-phase gas flow, provided the same frictional area coefficient was assigned to the choke as that determined by previous mud flow tests.

For the simultaneous flow of both mud and gas, several correlations developed by the oil industry to describe two-phase flow of oil and gas through fixed, production chokes were investigated. These correlations reported by Gilbert, Ros, Baxendell and Achong may all be reduced to a common form,

$$p = \frac{AqR^B}{d^C}$$

where p is the upstream pressure, q the liquid flow rate, R the gas/oil ratio and d the diameter of the circular cylindrical hole in the fixed choke body. The remaining coefficients A, B and C, as shown in the accompanying table, were derived from theoretical considerations, tempered with direct measurements.

Two-Phase Flow Coefficients For Fixed Chokes

Source	A	B	C
Gilbert	10.00	0.546	1.89
Ross	17.40	0.500	2.00
Baxendell	9.56	0.546	1.93
Achong	3.82	0.650	1.88
Current Studies	18.96	0.433	2.00

Also shown in the previous table are suggested values for these three coefficients as derived from multiple correlation analysis of data

obtained from two-phase studies of mud-gas mixtures through an adjustable drilling choke (Cameron 2-inch). They appear to compliment those values reported by Ros. To realize this remarkable agreement it was necessary only to assign the drilling choke an equivalent diameter d given by: $d = (4\ A_f/\pi)^{0.5}$, where again the frictional area coefficient (A_f) was that determined by previous mud flow tests. Given additional data, using other drilling chokes and a broader range of mud properties, it would appear that the flow characteristics of the drilling choke can be described adequately during all phases of an automated well control operation.

Persuant to the microprocessor control of a well kick circulation, eight sources of input data have been identified as necessary for the ultimate control algorithm or computer program. These data include:

1. Drillpipe pressure
2. Casing (choke) pressure
3. Kill line pressure
4. Bottom Hole pressure
   (consistent with advances in MWD technology)
5. Pump circulation rate
6. Choke setting (percent open or closed)
7. Return mud rate (from the annulus)
8. Return gas rate (in the event of a gas kick)

A consideration of items (1) through (4) and (6) prompted the two parallel studies discussed in the previous sections.

At present all eight of these variables are monitored at our research and training well by suitable transducers. Each transducer provides an electrical analalog signal to a TOTCO Visulogger system by means of a

4-20 milliamp current loop. These loops are designed to be intrinsically safe in potentially hazardous areas on domestic drilling rigs. To accommodate a microprocessor, these signals must be converted to an equivalent digital format.

A Zenith Data Systems ZF-111-22 microcomputer has been purchased as a prototype and development tool. Its on board RAM capacity of 192K and two, double sided, floppy disc drives should provide adequate memory for both the control program and requisite storage of input data and control signals, generated during the course of a complete well kick control simulation. An I/O Technology A/D/A converter board has been interfaced with the computer using one of the five expansion slots on its S-100/IEEE-696 bus. This board provides the necessary analog to digital conversion of the eight input data signals to the microcomputer as well as the digital conversion of the eight input data signals to the microcomputer as well as the digital to analog conversion of up to eight process control signals from the Zenith computer.

As with all microcomputer peripherals, several weeks were required to interface the eight, self powered 4-20 milliamp current loops with conventional voltage input requirements of the A/D/A board. The current-loop to unipolar 0-1 volt conversion was realized by utilizing the signal conditioning cards at the input to the Totco Visulogger. The converter board for the microcomputer was then modified to accept unipolar voltage inputs with gain modification to accommodate these 0-1 volt signals. The usual converter board is designed to accept directly either ±5 or ±10 volt bipolar signals.

A graduate assistant has recently completed preliminary programming to facilitate auto-zeroing and gain adjustments followed by time-cycled acquisition of digital data from all eight input channels. Work is proceeding on a program to sequentially store all the input and control data for subsequent playback and analysis. In addition, a subprogram is nearing completion which will provide the equivalent of a 6-channel strip chart record of control variables on the CRT monitor in real time.

To enhance the resolution of this graphics display, a memory expanison upgrade has been ordered for the video board in the computer. This will provide an interlaced video output with twice the resolution of the present system. When coupled with the impending order of a long-persistence color monitor, the graphics display will be suitable for direct photographic generation of quality color slides.

Interfacing the analog control signals to the hydraulic control system of the drilling choke and the pneumatic control system of the mud pump throttle has been greatly enhanced by the loan of equipment and engineering talents form the Totco Company. As they are currently testing an electronically controlled prototype for their standard drilling choke, they have expressed a keen interest in our present research on automatic well control. Already they have suggested that a licensed use or outright purchase of our eventual control algorithms would accelerate their marketing of an automatic choke control system. And this is without our proposed refinement which involves the monitoring of bottom hole pressure as the ultimate parameter in well control operations.

At the present time, we are proceeding with the interfacing of an analog to pneumatic controller, as provided by Totco, to drive the subsequent hydraulic control system for their drilling choke.