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A PROPOSAL FOR THE EXPANSION OF THE LSU-IADC BLOWOUT PREVENTION TRAINING CENTER

PREPARED BY

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I. INTRODUCTION

The Petroleum Engineering Department at Louisiana State University has played an active role over the past seven years in the training of industry personnel in present-day methods of blowout control. With the help of the International Association of Drilling Contractors (IADC) and many of the major oil producing companies, a modern training well facility was constructed. The

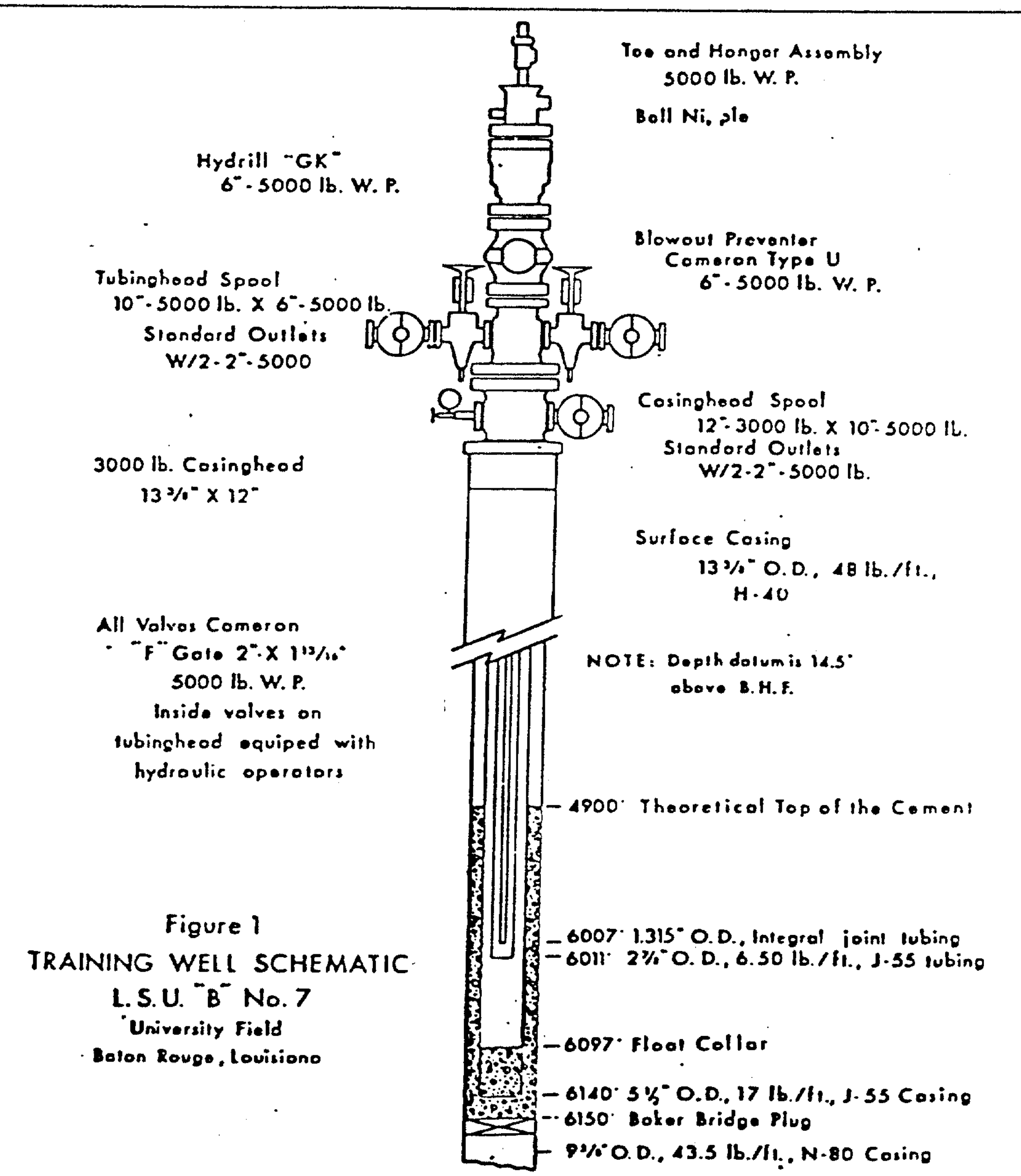


Figure 1
TRAINING WELL SCHEMATIC
L.S.U. "B" No. 7
University Field
Baton Rouge, Louisiana

replacement value of the training facility is now in excess of $700,000.00. A large portion of this total amount is the cost of a 6000 foot training well, complete with the most modern well control equipment, that will permit the "hands-on" experience of controlling an impending blowout without risk to personnel or the environment. Schematics of the training well and well control equipment are shown in Figures 1 and 2. In addition, five electronic well simulators are used in this training program (See Figure 3).

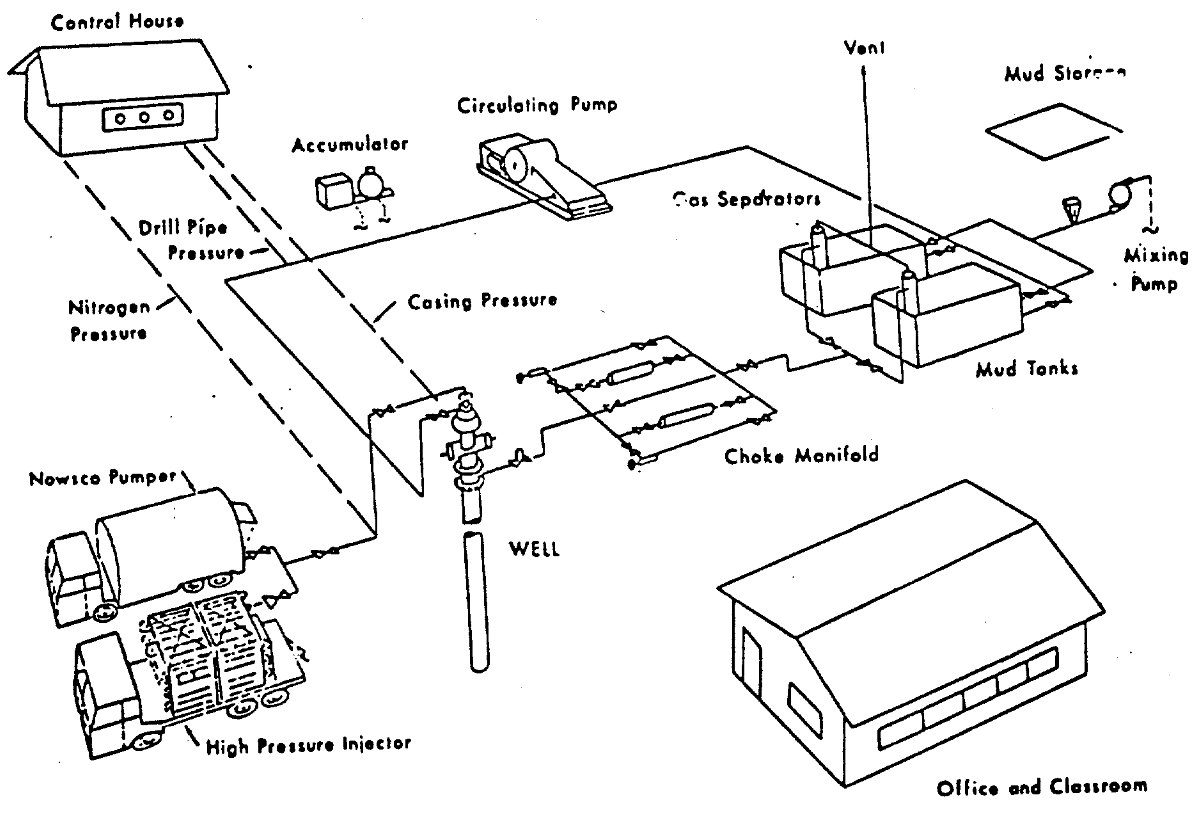


FIGURE 2. SCHEMATIC OF WELL CONTROL TRAINING FACILITY
Louisiana State University

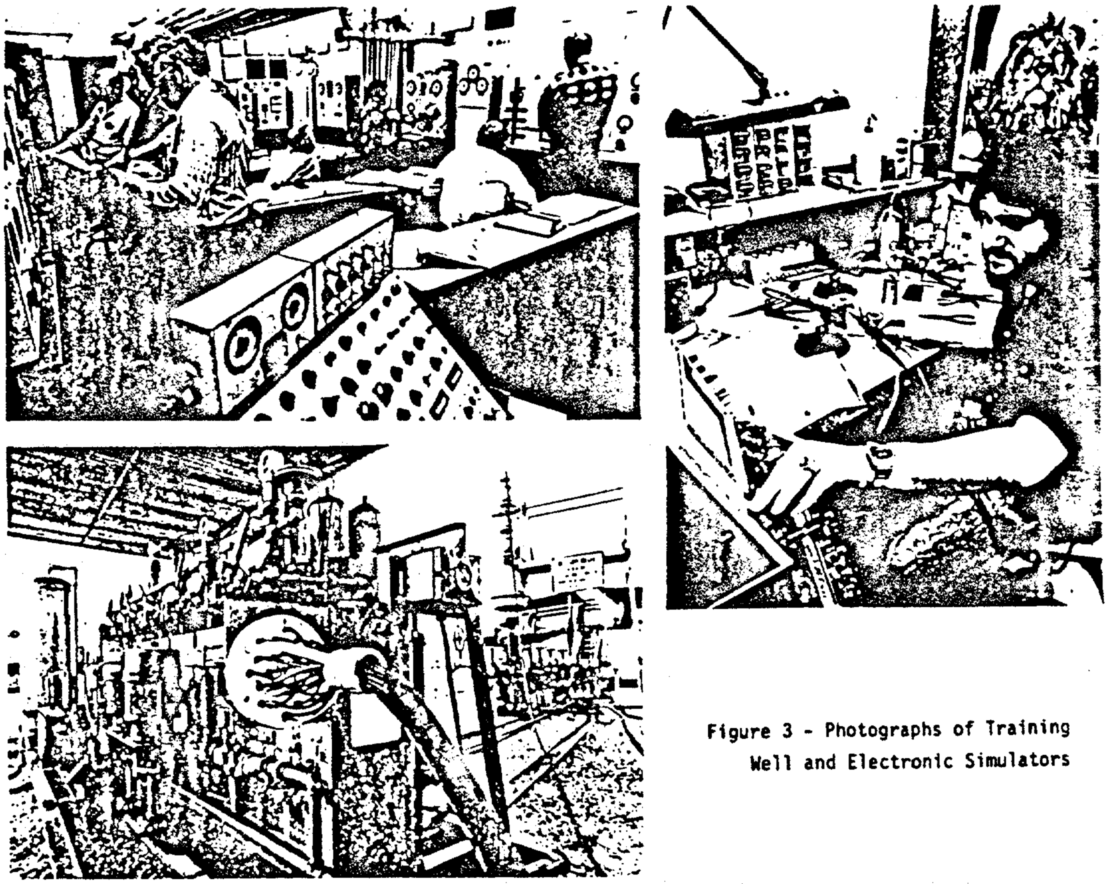


Figure 3 - Photographs of Training Well and Electronic Simulators

The United States Geological Survey in OCS Training Standard T-1 now sets forth requirements for Well Control Training for drilling personnel working offshore under federal jurisdiction. This training standard requires that all Drillers, Toolpushers, and Operator's Representatives successfully complete an approved comprehensive course every four years and a refresher course every year. The LSU Blowout Prevention Training Program now offers USGS approved comprehensive and refresher well control courses leading to certification on both surface and subsea Blowout Preventer Stacks.

Topics included in the comprehensive course are:

1. First Day
   a. Introduction and Orientation
   b. Fundamentals of Hydrostatic Pressures in Wells
   c. Causes and Prevention of well kicks
   d. Warning Signals for well kicks
   e. Shallow kicks
   f. Well Control Procedures for Surface BOP Stacks

2. Second Day:

   Practice of Well Control Procedures for Surface BOP Stacks

   a. Circulation of N_2 Kick on 6000 ft training well
   b. Simulation exercises using Simtran and IMCO-Boss electronic simulators

3. Third Day:
   a. Well Control Equipment for Land Operations and Bottom Supported Marine Rigs
   b. Complications and Special Well Control Techniques
   c. Stripping and Snubbing
   d. Governmental Regulations
   e. Optional Night Study Hall

4. Fourth Day:
   a. Subsea Well Control Equipment for Floating Drilling Operations
   b. Warning Signals for well kicks on Floating Rigs
   c. Well Control Procedures for Subsea BOP Stacks
   d. Practice of Well Control Procedures for Subsea BOP Stacks (Simulator Only)
   e. Qualification Tests
      (1) Written or Oral Test
      (2) Hands-on Demonstration using Simulators

Candidates for USGS certification on surface BOP Stacks only omit sections 4a through 4d and proceed immediately to the qualification tests. Candidates for USGS certification on both surface and subsea BOP Stacks must take their hands-on qualification test on a simulator equipped with a subsea panel. Participants not seeking a USGS certificate complete the course at the end of the third day.

Separate refresher courses are offered for surface and subsea BOP Stacks. Those certified for both surface and subsea BOP stacks must attend only a refresher for Subsea BOP Stacks. Topics included in the refresher courses are:

One Day Refresher:

a. Causes and Prevention of Well Kicks
b. Warning Signals for Well Kicks
c. Shallow kicks
d. Well Control Procedures
e. Improvements in well Control Equipment
f. Changes in Government Regulations
g. Practice of Well Control Procedures
h. Hands-On Demonstration Test

A total of 5500 participants have attended the LSU training program to date. These participants included Drilling Superintendents, Engineers, Drilling Foremen and Drillers representing over 130 oil companies, Drilling Contractors and Drilling Consultants from 25 states and 30 foreign countries. Operating expenses for this program are generated from tuition fees charged to the participants. The annual operating budget for this 1979-80 academic year is in excess of 400,000.

The Petroleum Engineering Department at Louisiana State University has also maintained a position of leadership in the area of offshore mineral extraction technology. This area is extremely important to the State of Louisiana because of the large offshore activity in the Gulf of Mexico. For the past seven years, the department has held a Campanile Professorship in Offshore Mining and Petroleum Engineering. The LSU Foundation extablished two professorships dealing with technological and legal aspects of offshore mineral extraction at the request of Campanile Charities which donated $100,000 for this purpose. Various aspects of offshore development have been studied under the leadership of Murray F. Hawkins, the holder of one professorship until his recent retirement. A noteable highlight of this program was the development of a new training facility devoted to surface and

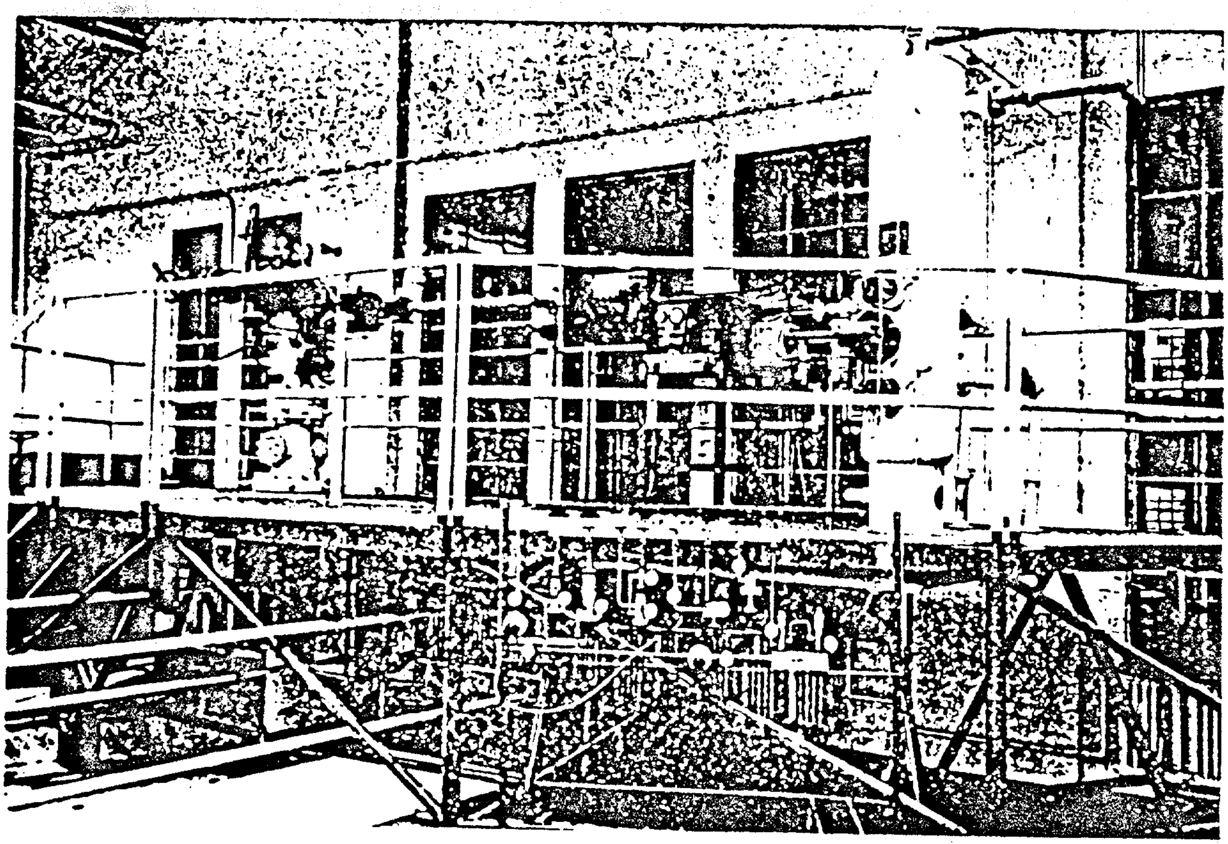


Figure 4 - Portion of Offshore Production Safety Training Facility

subsurface offshore production safety equipment. A photograph showing a portion of this new facility is shown in Figure 4.

This proposal concerns an expansion of the LSU-IADC Blowout Prevention Training Center. The proposed expansion centers around the completion of a second well facility to physically model the well control flow geometry present on floating drilling vessels which use a subsea blowout preventer stack. The new well facility would allow much more realistic training exercises to be conducted as part of the existing certified comprehensive course on well control procedures for subsea blowout preventer stacks. In addition, the new well facility would be used to conduct experimental research on the development of improved well control procedures and equipment.

II. PROPOSED NEW WELL FACILITY

The special well control problems for floating drilling vessels stem primarily from the location of the Blowout Preventer Stack at the sea floor and the use of long, vertical subsea choke lines between the subsea preventer stack and the drilling vessel. This causes the pressure behavior in the well during the control of a gas kick to differ substancially from that observed when using a surface Blowout Preventer Stack. This is illustrated using Figures 5 and 6. Shown in Figure 5 is a schematic diagram of an

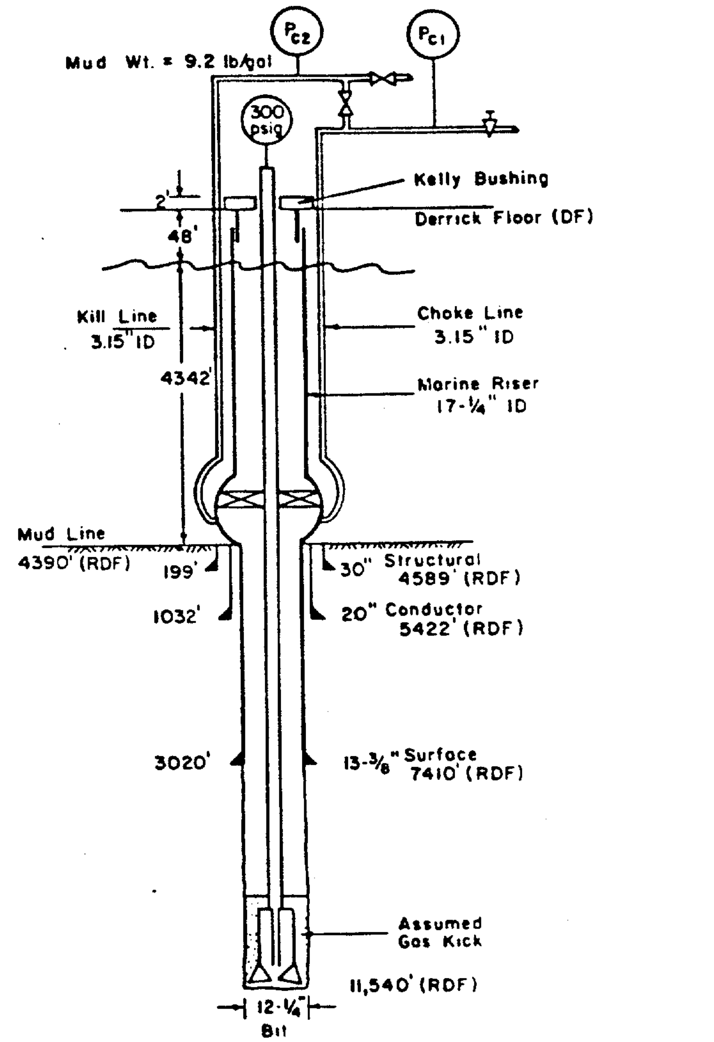


Figure 5: Schematic Diagram and Drilling Data for an Example Well Drilling in Deep Water

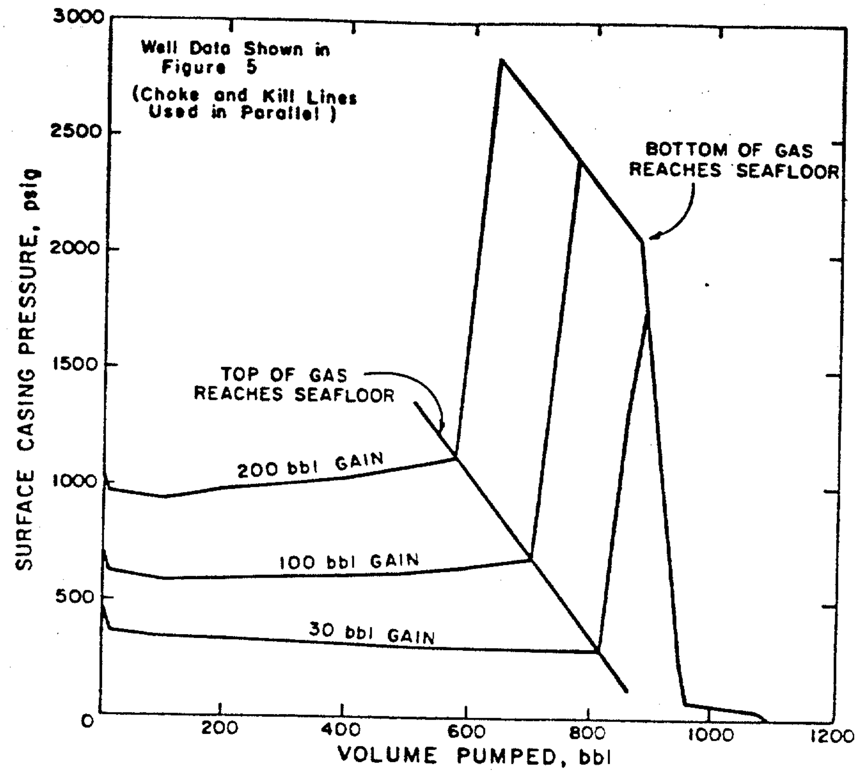


Figure 6: Example Illustrating Required Change in Choke Pressure When Gas Kick Reaches Sea Floor

example well geometry used on an actual well drilled from a floating vessel in 4300 feet of water. Figure 6 shows the theoretical process behavior determined by computer simulation during simulated well control operations for this well geometry and different size gas kicks. The rapid changes in required choke pressure shown after gas reaches the seafloor and enters the subsea choke lines is an example of one of the unique operational problems faced during well control operations on a floating vessel in deep water.

It is proposed that the unique aspects of well control operations on a floating vessel in deep water be physically modeled by completing a well as shown in Figure 7. The effect of the blowout preventer being located at the sea floor in 3000 ft of water would be modeled by the packer placed at a depth of 3000 feet in the well. Surface choke pressures determined by computer simulations of well control operations for this model geometry are shown in Figure 8.

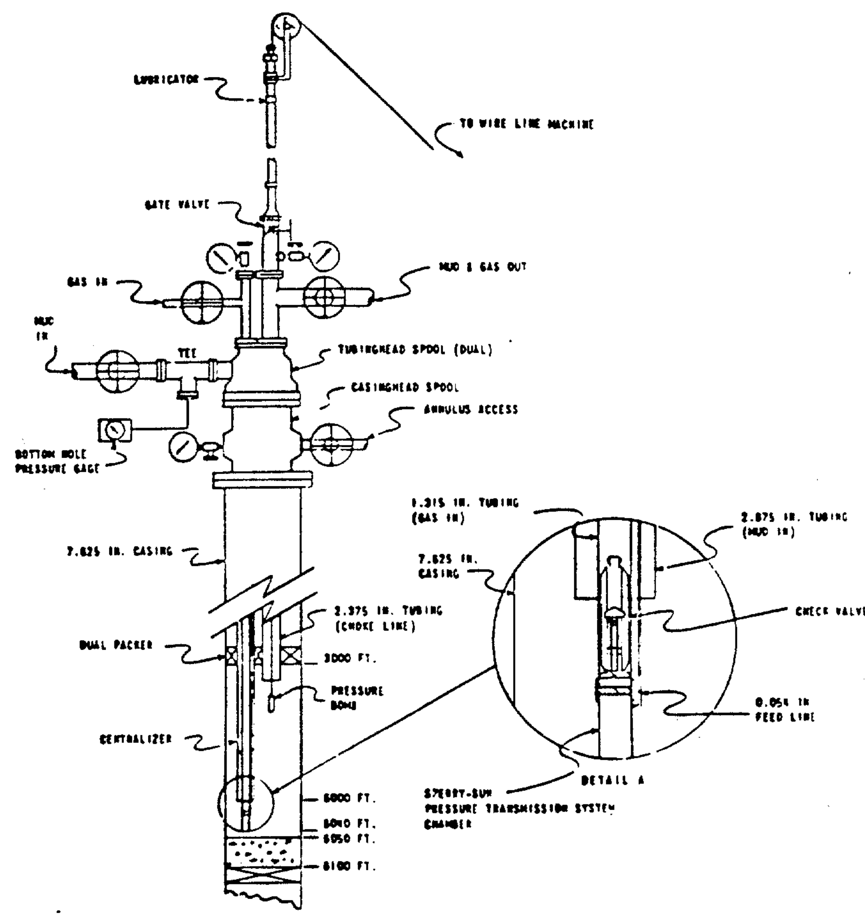


FIGURE 7: SCHEMATIC OF PROPOSED RESEARCH WELL

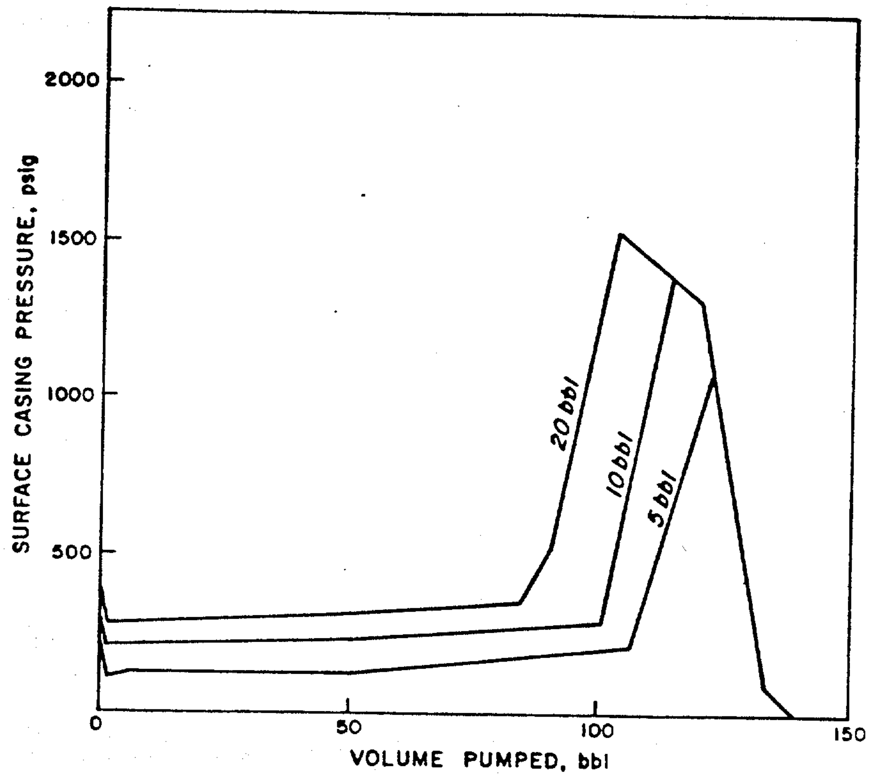


FIGURE 8 : EXAMPLE CASING PRESSURE PROFILES COMPUTED FOR PROPOSED RESEARCH WELL FACILITY

A 9000 ft well containing 7 5/8 in. casing and valued at approximately $400,000 has been acquired on the LSU campus which is suitable for use in the proposed well facility. The Petroleum Engineering Department has been allocated a 1.4 acre tract of land containing the well by the University to support the development of the new facility. The locations of the proposed new well facility and the existing training well facility for surface BOP Stack (LSU B-7) are shown in Figure 9. A more detailed site plan showing the dimensions of the allocated tract of land is shown in Figure 10. Given in Figures 11 and 12 are schematics of the surface equipment needed to support the new well facility.

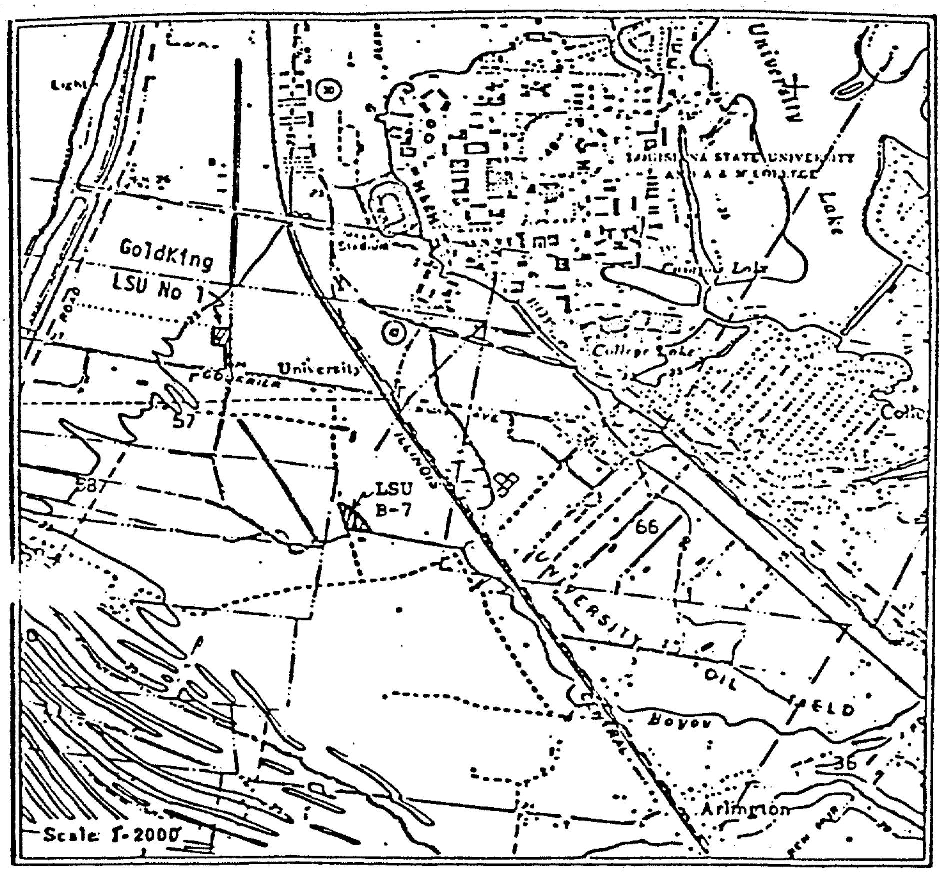
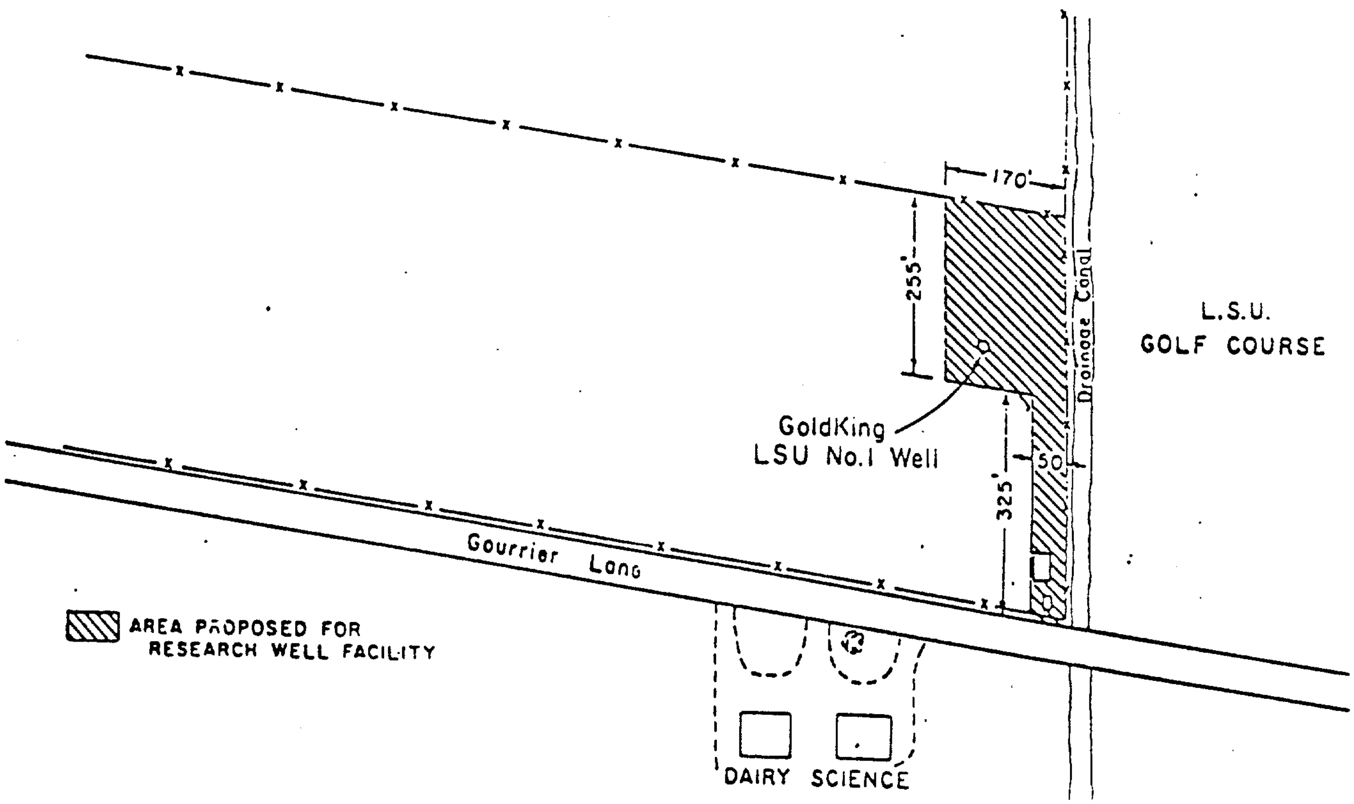


FIGURE 9 - LOCATION OF PROPOSED RESEARCH WELL FACILITY FOR DEPARTMENT OF PETROLEUM ENGINEERING (GOLDKING LSU NO. 1)

FIGURE 10 - SITE PLAN OF PROPOSED RESEARCH WELL FACILITY



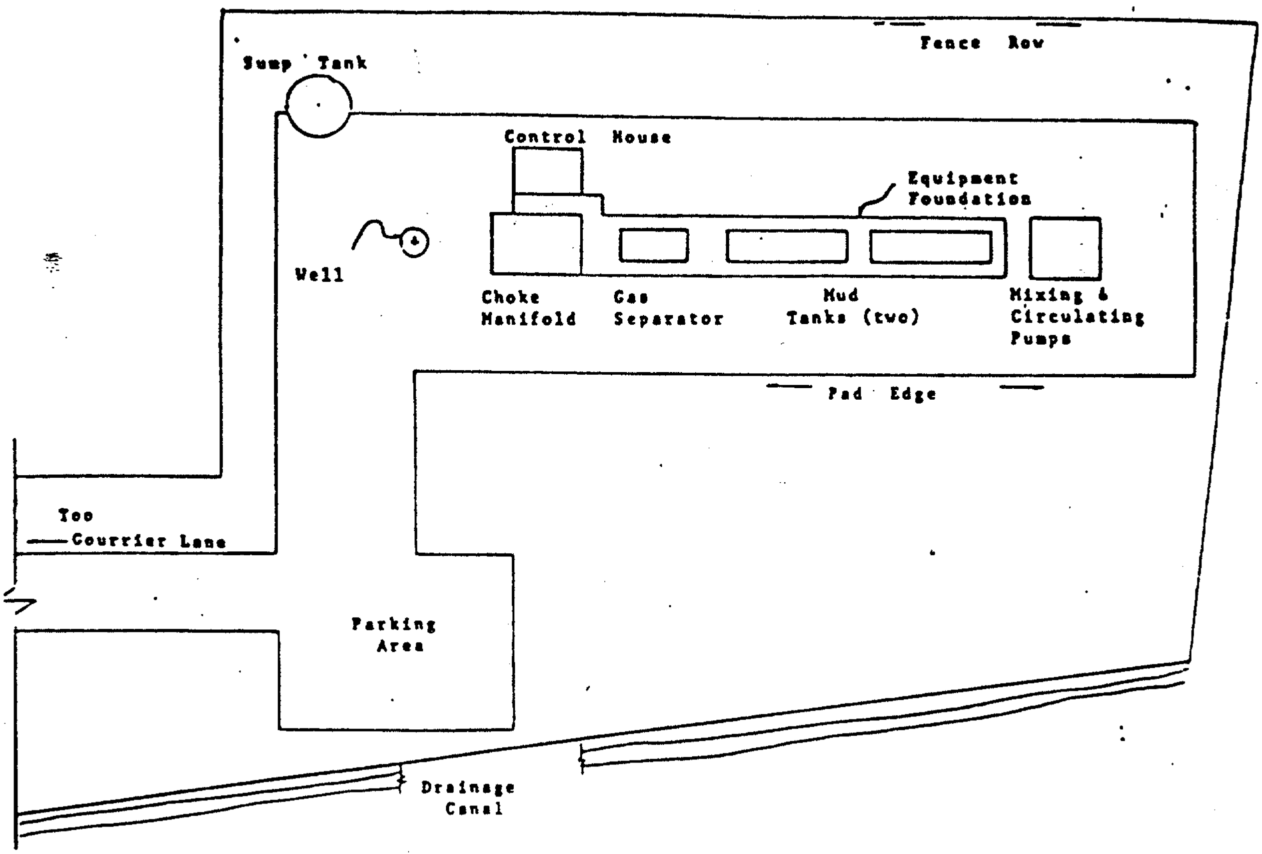


FIGURE 11 - PLOT PLAN OF PROPOSED RESEARCH WELL FACILITY

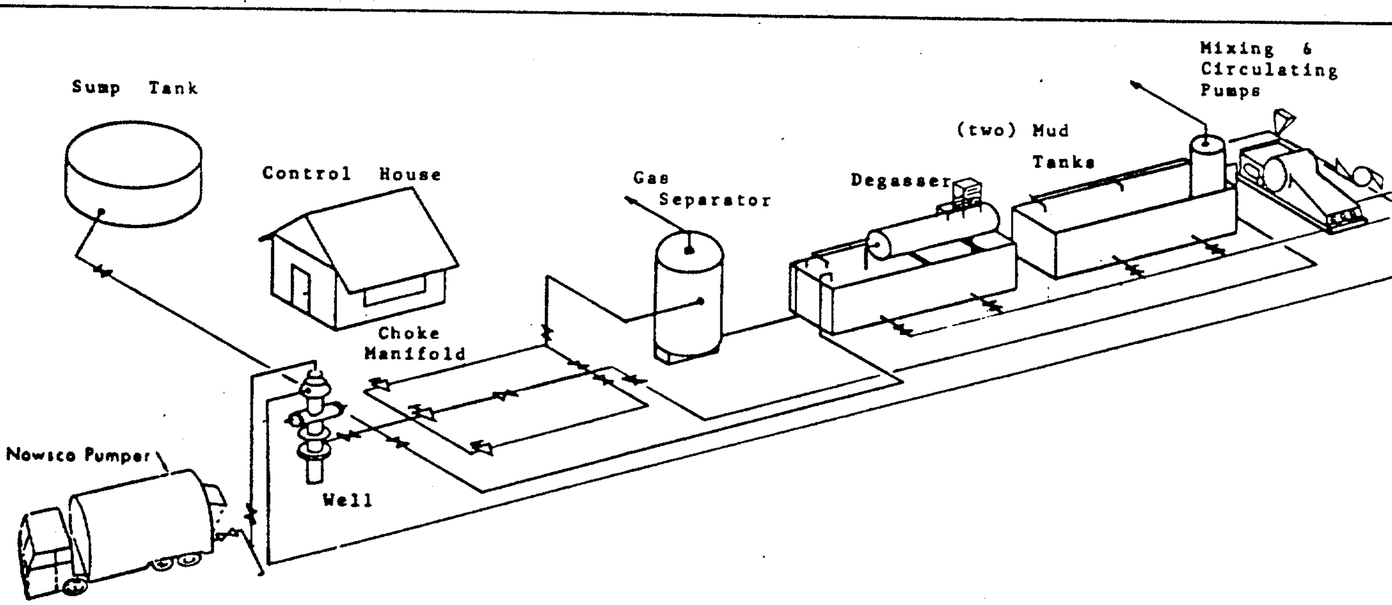


Figure 12- Schematic of Proposed Research Facility

III. PROPOSED RESEARCH PROGRAM

1. Areas of Study

The primary objective of the proposed research program is the development of improved well control procedures to be used in deep water, floating drilling operations. Areas proposed for study at this time include improved shut-in procedures, procedures for handling upward gas migration during the shut-in period, pump start-up procedures, and pump-out procedures. A secondary objective is the development of a more accurate mathematical model of the well control process which will predict well behavior during various phases of well control operations for any assumed operating procedure.

Shut-In Procedures

There is still disagreement in the industry concerning the best well closure procedure to be used during an impending blowout. Many operators prefer a *soft* shut-in procedure, in which the well flow is stopped slowly. A slow deceleration of the large mass of upward moving annular fluid is felt to be needed to minimize shock pressure loadings on equipment and subsurface formations. An example soft shut-in procedure is shown in Figure 13. When using this procedure, surface valves in the choke manifold are routinely positioned to route flow from the subsea choke line through an adjustable choke. The adjustable choke is left in the open position during normal drilling operations. This allows the final deceleration of the well fluid during well closure to be manually controlled using the choke.

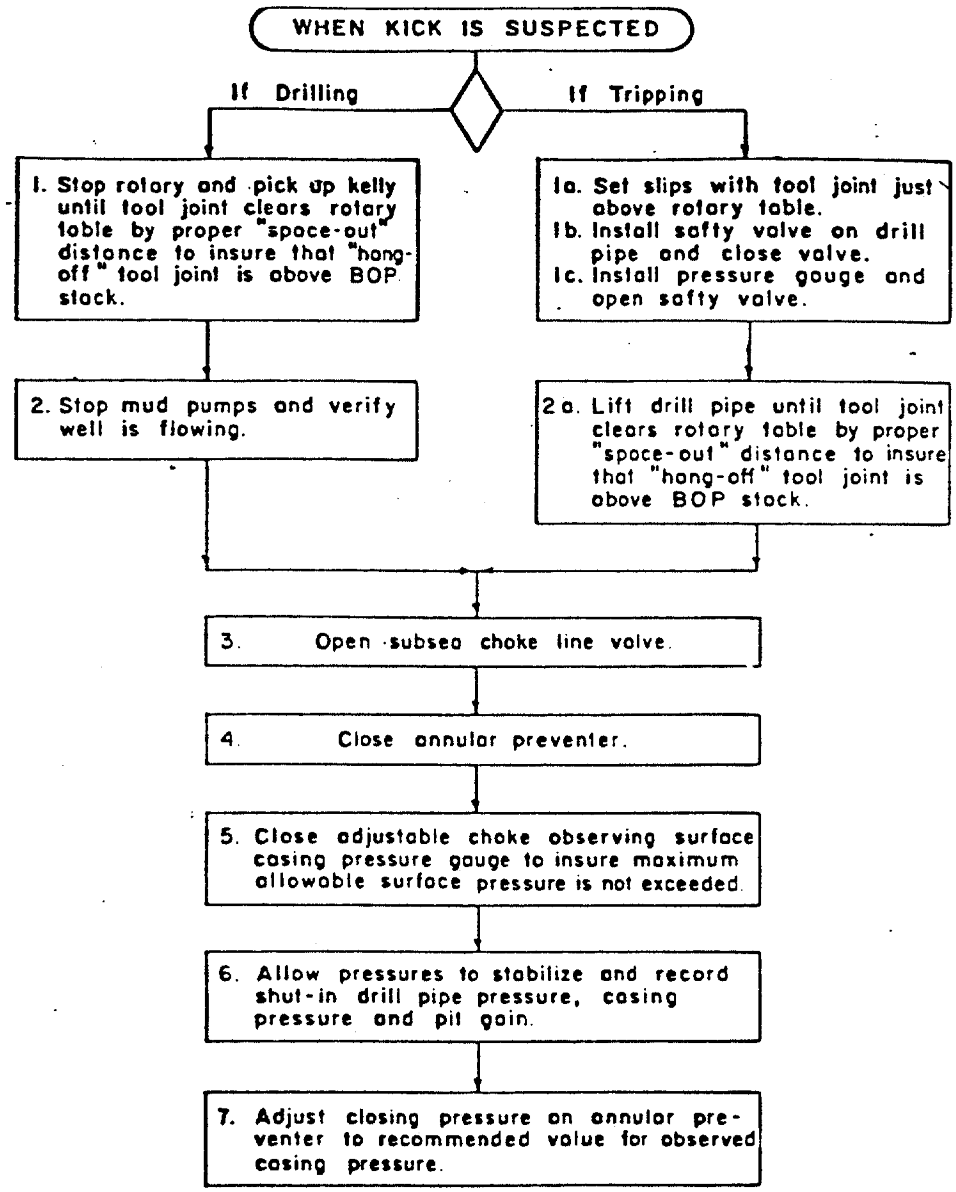


Figure13: Example Soft Shut-in Procedure For Floating Vessel

Some operators prefer to use a more rapid or *hard* shut-in procedure, with the idea of minimizing the volume of formation fluids which enter the well as much as possible. As pointed out previously, the annular pressure experienced during well control operations increases rapidly with kick volume for a gas kick. The procedure shown in Figure 13 could be converted to the hard shut-in method by the interchange of steps 3 and 4 and the elimination of step 5. When using the hard shut-in method, surface valves in the choke manifold are routinely positioned to route flow from the subsea choke line to a remote adjustable choke. However, the choke and at least one back-up valve in the choke line are left closed during normal drilling operations. Deceleration of the annular well fluid is accomplished during closure of the blowout preventer.

Figure 14 shows possible pressure peaks occuring at the casing seat during well control operations. Operators following the soft shut-in procedure are more concerned about the pressure peak occuring just after the blowout preventers are closed (3) while operators following the hard shut-in procedure are more concerned

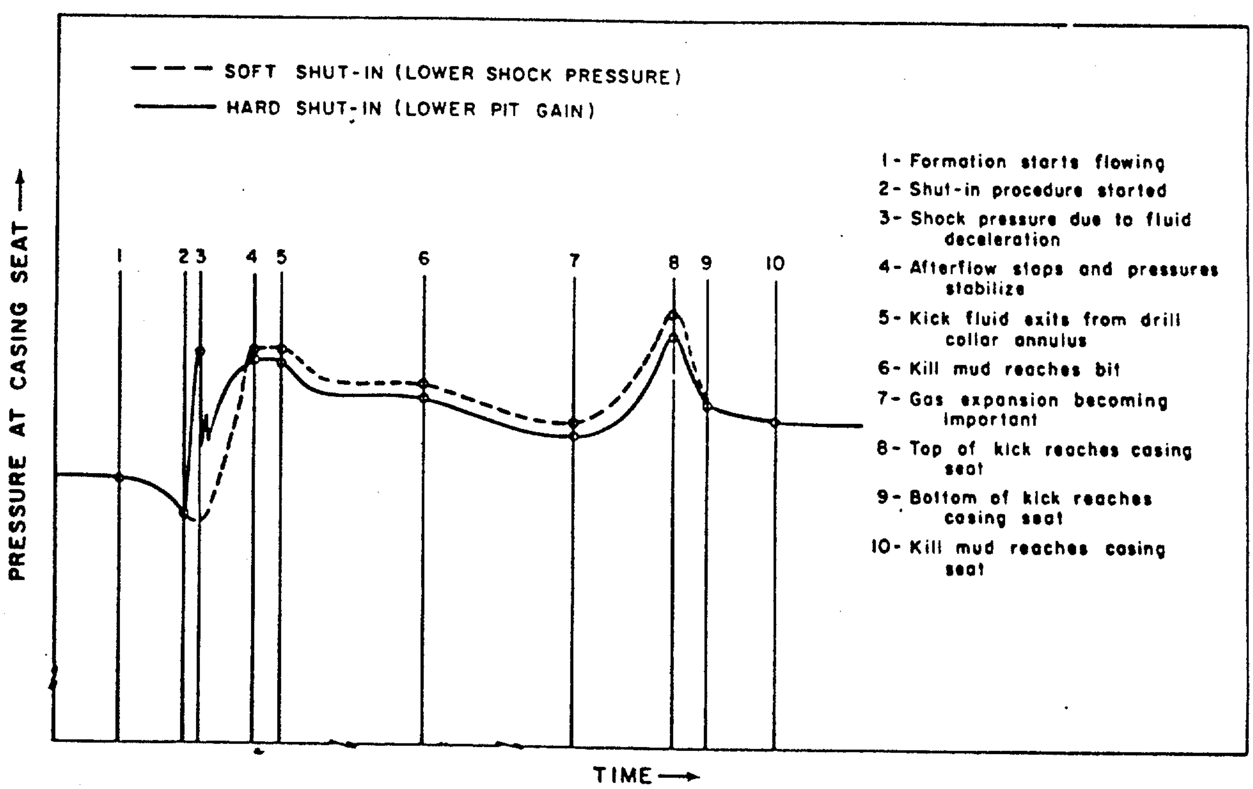


Figure 14: Possible Pressure Peaks At Casing Seat During Well Control Operations (Kick Circulated to Surface Using Kill Mud)

about the pressure peaks after the bottom hole pressure stabilizes (4) and when the top of the kick reaches the casing seat (8). Many factors govern the relative height of these pressure peaks for given well conditions. These factors have been studied mathematically by several companies, but the results are always clouded by the simplifying assumptions made in the mathematical analysis. Experimental research on the flow characteristics of blowout preventers during closure is being initiated to help resolve this issue. Also, the equipment configurations and shut-in sequences currently used on floating drilling vessels should be studied. As shown in Tables 1 and 2, there are approximately 60 drilling vessels which can drill in water depths in excess of 1500 feet. The shut-in problem will become much more critical as drilling operations move into deeper water depths.

TABLE 1 - DRILLSHIPS CAPABLE OF DRILLING
IN WATER DEPTHS IN EXCESS OF 1000 FEET

	Rig Owner	Rig Name	Maximum Depth
1	Amoshore Drilling Co.	Discover 511	2,000'
2	Atwood/Drillships Ltd.	Regionl Endeavour	1,506'
3	Dome Petroleum (Canmar Drilling)	Canmar Explorer III	1,500'
4	C. G. Doris	Astragale	1,800'
5	Global Marine Inc.	Glomar Atlantic	2,000'
6	Global Marine Inc.	Glomar Challanger	20,000'
7	Global Marine Inc.	Glomar Coral Sea	1,500'
8	Global Marine Inc.	Glomar Java Sea	1,500'
9	Global Marine Inc.	Glomar Pacific	2,000'
10	Helmer Staubo & Co.	Pelerin	3,300'
11	IHC Holland		3,300'
12	Interocean Drilling	Interocean Discoverer	1,500'
13	Marine Drilling & Coring Co.	Candrill I	5,000'
14	Mission Drilling & Exploration Corp.	Mission Viking	1,500'
15	Neddrill (Nederland) B. V.	Neddrill II	6,000'
16	ODECO/Ben Line Offshore	Ben Ocean Lancer	3,000'
17	The Offshore Co.	Discoverer II	1,500'
18	The Offshore Co.	Discoverer 534	3,000'
19	The Offshore Co.	Discoverer Seven Seas	4,500'
20	Offshore Europe N. V. (Foramer)	Petrel	3,000'
21	Overseas Drilling Ltd.	Sedco/BP 471	4,500'
22	Pacnorse Drilling Corp.	Pacnorse I	3,000'
23	Saipem	Saipem Due	2,000'
24	Sedco Inc.	Sedco 445	3,500'
25	Sedco Inc.	Sedco 472	4,500'
26	Western Offshore Drilling & Expl. Co.	Western Offshore IV	1,500'
27	Western Offshore Drilling & Expl. Co.	Western Offshore V	1,500'

TABLE 2- SEMI-SUBMERSIBLES CAPABLE OF DRILLING IN WATER DEPTHS IN EXCESS OF 1000 FEET

	Rig Owner	Rig Name	Maximum Depth
1	Atlantic Drilling Co.	No. 786	1,100'
2	Celtic Drilling Co.	Sea Conquest	1,200'
3	Deep Sea Drilling Co. A/S	Deepsea Saga	1,500'
4	Diamond M Co.	Diamond M General	1,100'
5	Dixilyn-Field Drilling Co.	Venture One (Pentagone)	1,200'
6	Dixilyn-Field Drilling Co.	Venture Two (Pentagone)	1,200'
7	Dolphin International	Bideford Dolphin	1,500'
8	Fearnley Drilling & Expl. A/S	Fernstate	3,000'
9	Japan Drilling Co. Ltd.	Hakuryu V	1,650'
10	Keydril Co.	Aleutian Key	2,000'
11	Marine Drilling S. A.	Sedco 707	1,500'
12	Marine Drilling S. A.	Sedco 709	6,000'
13	K/S Morland Offshore A/S	Gulnare (pentagone 91)	1,200'
14	A/S Norsedrill & Co.	Drill Master	1,200'
15	ODECO	Ocean Queen	1,200'
16	Japan/ODECO	Ocean Bounty	1,200'
17	ODECO/Fearnley & Eger	Ocean Ranger	1,500'
18	Santa Fe International	Blue Water No. 4	1,500'
19	Sante Fe International	Southern Cross	1,500'
20	Sedco Inc.	Sedco 135c	1,500'
21	Sedco Inc.	Sedco 703	2,000'
22	Sedco Inc.	Sedco 704	1,500'
23	Stavanger Drilling A/S & Co.	Henrik Ibsen	1,200'
24	Stavanger Drilling A/S & Co.	Alexander L. Kielland	1,200'
25	Western Oceanic/Exxon	Alaskan Star	1,500'
26	Western Oceanic	Western Pacesetter II	1,200'
27	Western Oceanic	Western Pacesetter III	1,200'
28	Wilh. Wilhelmsen	Treasure Seeker	1,250'
29	Zapata Corp.	Zapata Concord	2,000'
30	Zapata Corp.	Zapata Lexington	2,000'
31	Zapata Corp.	Zapata Saratoga	2,000'
32	Zapata Corp.	Zapata Ugland	2,000'
33	Zapata Corp.	Zapata Yorktown	2,000'

Upward Gas Migration During Shut-In Period

After a kick is detected and the well is shut-in, the well pressures initially increase in response to formation *afterflow*. Afterflow refers to transient flow from the formation into the wellbore at the hole bottom just after the well is closed at the surface. Surface pressures rise more rapidly at first because of a larger pressure drawdown on the formation which results in a higher formation flow rate. As the fluids trapped in the well are compressed and the well pressures rise, this flow gradually decreases and finally stops.

In some cases, problems may develop which prevent the initiation of kick circulation for long periods of time. In other cases, problems may develop during kick circulation which require that the well be again shut-in with kick fluids still in the well. If the kick fluids are gas and the well remains shut-in for a long period of time, the gaseous zone trapped in the well may tend to migrate a significant distance towards the surface. This movement occurs because the gas zone has a much lower density than the drilling Fluid. Gas rising in a shut-in well will cause a gradual increase in pressure at all points in the well. This pressure increase occurs because if the well remains closed, the gas cannot expand. The pressure of a gas held at constant volume and temperature must also remain constant. Unacceptably large increases in well pressures can result which will probably result in formation fracture or equipment failure. In order to avoid this unacceptably large increase in well pressure, the gas should be allowed to expand under controlled conditions to keep the bottom hole pressure constant at a value slightly above formation pressure.

Changes in bottom hole pressure are most easily ascertained from observed changes in surface drill pipe pressure. However, additional complications sometimes exist which cause a meaningful drill pipe pressure to be unavailable. Example situations for which this is true include (1) wells in which the drill string is partially or completely out of the hole and (2) wells which develop mechanical problems in the drill string such as a plugged bit or a leak (washout) at a pipe joint. An alternative method of safely handling upward gas migration when a meaningful drill pipe pressure is not available has been recently proposed in the literature. Several variations of this method, called the volumetric method, is now being incorporated into the well-control manuals of many operators.

The volumetric methods of handling upward gas migration were developed largely from theoretical considerations of the annular pressure behavior under the following simplifying assumptions:

1. The gas enters the well as a slug and rises to the surface as a unit.
2. The gas density is negligible and does not contribute to the bottom hole pressure.
3. Hydrostatic pressure relationships apply throughout the region of the wellbore where gas movement is occurring.

Preliminary experiments conducted at LSU indicate that the first assumption is not valid. An experimental study in a full scale well is needed to determine under what conditions the volumetric method can be safely applied. Control problems will be especially severe when a gas zone reaches the sea floor.

Start-Up Procedures

The present-day well control method used to initiate the circulation of formation fluids from the wellbore is to start pumping while simultaneously opening the choke so that the casing pressure is maintained constant at, or sightly above, its previous shut-in value. Because of the high frictional pressure drop in the long underwater flowlines associated with floating drilling operations, this procedure can produce an excessive annular backpressure. This in turn could lead to formation fracture and a subsequent underground blowout. In addition, the subsea flowlines are sometimes filled with water to prevent plugging of the flowlines when they are not in use. This complicates the annular pressure behavior during start-up because of the density difference between the water initially in the flowline and the drilling fluid which will ultimately displace this water.

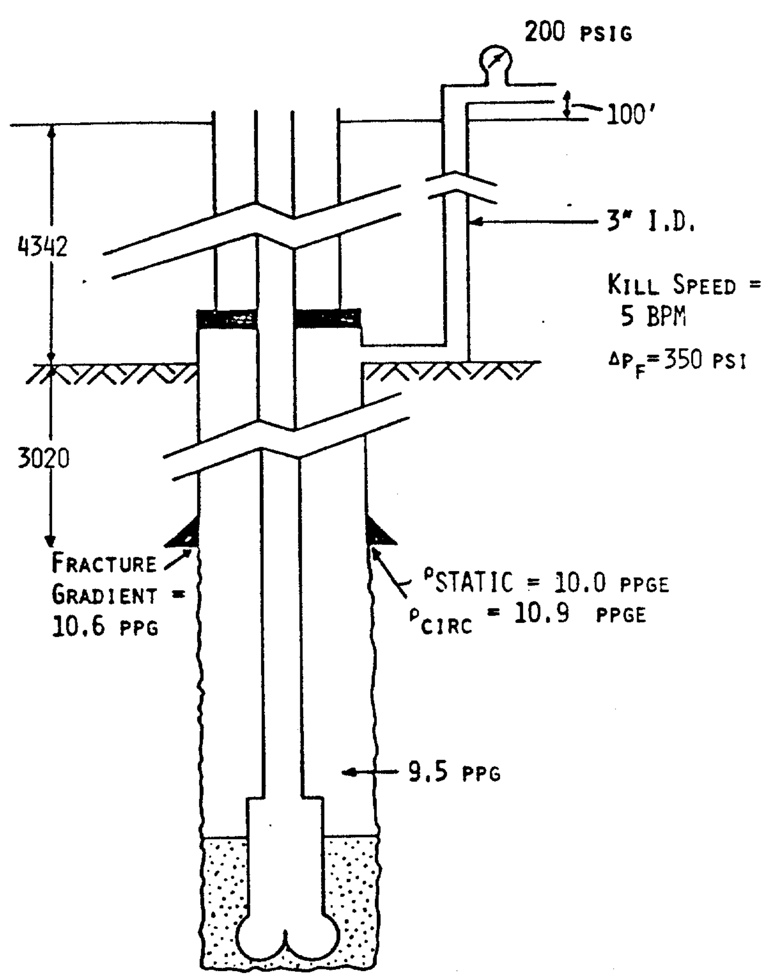


FIGURE 15- EXAMPLE ILLUSTRATING EFFECT OF CHOKELINE FRICTIONAL PRESSURE LOSS ON EQUIVALENT MUD DENSITY AT CASING SEAT

Figure 15 illustrates the importance of frictional pressure losses in the subsea choke line when circulation of a kick is initiated. Initially, the equivalent density at the casing seat for shut-in conditions is 10.0 ppge. Upon initiation of pumping at a kill rate of 5 bbl/min., using a 3 in. I.D. choke line, an additional 350 psi of pressure is added to the casing seat. This additional pressure increases the equivalent circulating density at the casing seat to 10.9 ppge, which is above the fracture gradient for the conditions given. Thus, fracturing of a formation exposed below the casing seat would occur, possibly resulting in an underground blowout.

Pump-Out Procedures

When a gas influx (kick) is circulated from a well, an operational problem results when the gas bubble reaches the subsea preventer stack located on the ocean floor. There follows a very rapid elongation of the bubble as it exits the large casing and proceeds upward through the small diameter choke line which parallels the larger marine riser pipe. There is the question whether an operator would have adequate time to respond properly to the rapidly changing pressure conditions associated with this phenomenon. This problem should be studied experimentally from the standpoint of improving pump-out procedures to be used with existing equipment and the standpoint of improving equipment design.

The problem which occurs when low density kick fluid reaches the sea floor was illustrated previously in Figure 6. For this example and a 30 bbl initial volume of gas influx, just prior to gas entering the choke line, the backpressure held using the surface choke must be maintained at approximately 300 psia in order to keep the bottom hole pressure slightly above the formation pore pressure. However, after pumping the capacity of the choke line, which is a relatively small volume, the choke pressure required to keep the bottom hole pressure constant increases to approximately 1700 psia. It is very difficult for the choke operator to make such rapid changes in an accurate manner. Since no bottom hole pressure instrumentation is available, the choke operator can only ascertain bottom hole pressure changes by observing changes in the surface drill pipe pressure. The time required for pressure transients to reach the surface can casue drill pipe pressure changes to lag significantly behind changes in bottom hole pressure.

Improved Mathematical Model

Many modern blowout control strategies are based solely upon the response of mathematical models of the drilling well system during various phases of blowout control operations. For example, a modified Wait and Weight Method of well control, known as the Simplex Method, is based upon calculations which suggest that casing pressure should not change during the time required to pump kill mud to the bottom of the well. This technique thus requires manipulating the adjustable choke to maintain the casing pressure constant while kill mud is circulated to the bit. It is recommended by some engineers as a way to eliminate the calculation of the normal schedule of drill pipe pressure changes associated with the more conventional Wait and Weight Method. These mathematical models are being employed at present by some authors to develop new procedures for floating drilling operations.

Preliminary research at LSU has already shown that the mathematical models used at present in blowout control simulations do not always predict actual well behavior. Two assumptions found to be at fault are (1) that gas influx enters the well bore as a continuous slug and remains in this configuration during subsequent control operations and (2) that the gas bubble does not migrate upward through the column of drilling mud but moves instead at the same velocity as the circulating mud. Additional research is needed to improve our understanding of true well behavior.

2. Research Plan

As currently envisioned, the proposed overall research project can be divided into eight tasks. Each of these tasks can be subdivided into two or more subtasks. These tasks and subtasks are:

1. Design of well for accurately modeling blowout control operations on a floating drilling vessel in deep water.
   a. Well scaling and design.
   b. Preparation of bids and specifications.
2. Construction of well for accurately modeling blowout control operations on a floating drilling vessel in deep water.
   a. Procurement of well equipment.
   b. Well drilling and completion.
3. Documentation of blowout control equipment configuration and procedures used on all floating drilling vessels capable of drilling in deep water.
   a. Equipment configuration.
   b. Shut-in procedures.
   c. Start-up procedures.
   d. Pump-out procedures.
4. Experimental study of shut-in procedures for blowout control on floating drilling vessels in deep water.
   a. Experimental determination of frictional area coefficient profile of modern adjustable chokes and HCR valves used in Blowout Control operations.

b. Experimental Determination of Frictional Area Coefficient Profile of Modern Annular Blowout Preventers During Closure.

c. Development of Mathematical Model of Pressure Surges Occurring During Well Closure.

d. Experimental Evaluation of Pressure Surge Model.

e. Determination of Optimal Shut-In Procedures for Various Well Conditions.

5. Experimental Study of Procedures for Handling Upward Gas Migration during the Shut-in Period.

   a. Evaluation of conventional approach requiring use of surface drill pipe pressure.

   b. Evaluation of volumetric methods.

   c. Laboratory investigation of gas bubble fragmentation while rising in a static annulus.

   d. Development of mathematical model of well behavior during shut-in period following a gas kick.

   e. Determination of optimal method of handling upward gas migration during shut-in period.

6. Experimental Study of Start-up Procedures for Blowout Control on Floating Drilling Vessels in Deep Water.

   a. Evaluation of Present Day Start-up Procedures which use existing equipment.

   b. Evaluation of Possible Future Start-up Procedures which would require development of new equipment.

   c. Experimental Determination of Improved Start-up Procedures.

7. Experimental Study of Pump-out Procedures for Blowout Control Operations on a Floating Drilling Vessel in Deep Water.
    a. Evaluation of Present Day Pump-out Procedures which use existing equipment.
    b. Evaluation of Present Day Pump-out Procedures which would require development of New Equipment.
    c. Experimental Determination of Improved Pump-out Procedures.
8. Determination of Well Behavior During the Control of Gas Kicks on Floating Drilling Vessels.
    a. Experimental Determination of Annular Pressure Behavior for Various Well Conditions.
    b. Development and Verification of Accurate Mathematical Model of Well Behavior during Kick Pump-out.

A time schedule for performing the various tasks is presented as Figure 16. Work on several tasks which can be done using the existing training facility has already begun.

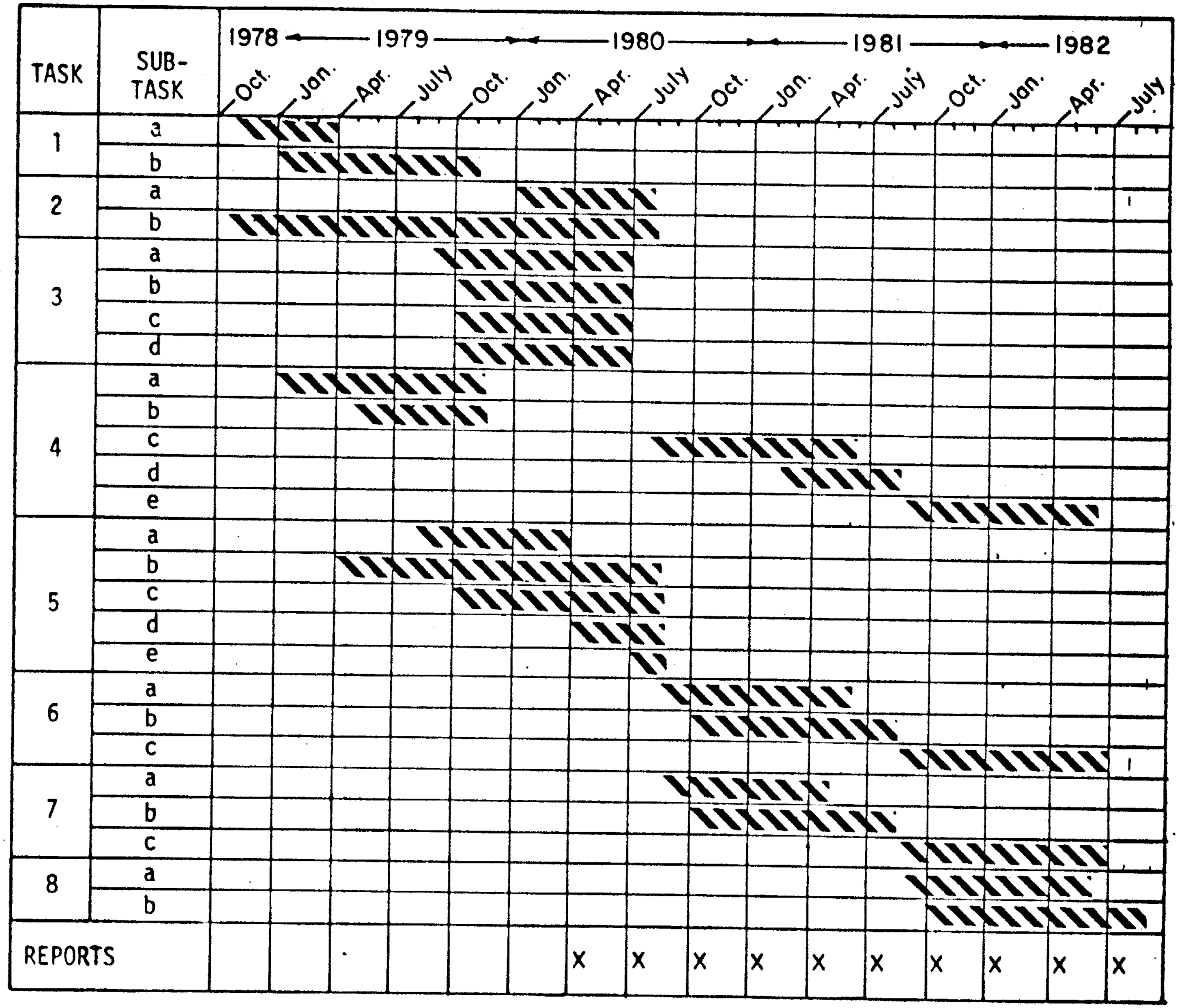


FIGURE 16. ESTIMATED TIME SCHEDULE FOR PROJECT

IV. NEED FOR INDUSTRY SUPPORT

A cost analysis for the new well facility and four year experimental program has been made and is summarized in Table 3. The total cost of approximately $1,388,000 shown include the replacement value of the well and land which has already been acquired (Items 1a and 2a). Funding for the four year experimental research program (Items 3a-3g), the cost of completing the new well in the desired configuration (Item 1b), and the cost of site improvements and equipment foundations (Items 2b and 2c) is being obtained through a $714,226 research contract funded by the US Department of the Interior. However, the project is still short $246,000 for the surface equipment which would be necessary to circulate and monitor the well under simulated well control conditions (Item 2d). Current government policy does not favor expending public funds on equipment for new facilities.

The LSU Petroleum Engineering Department is asking for assistance from the petroleum industry in obtaining the surface equipment needed to complete the new well facility. Assistance is being sought in the form of (1) grants to support the purchase of equipment, (2) donated or loaned equipment, and (3) donated services associated with equipment installation. A list of the needed items is shown in Table 4. Pledges from industry totaling in value the amount needed to complete the project are desirable by February 14, 1980, the deadline for finalizing the research contract with the US Department of the Interior. Otherwise, this significant expansion of our Blowout Prevention Program may have to be abandoned.

Table 3 - COST SUMMARY FOR NEW WELL FACILITY AND RESEARCH PROGRAM

1. Well Costs		
a. Drilling and Casing Well		$400,000
b. Completing Well		111,500
	Sub	$511,500
2. Surface Equipment and Site Aquisition Costs		
a. Land Value		$ 28,000
b. Site Improvements		41,000
c. Equipment Foundations		29,000
d. Surface Equipment		246,000
	Sub	$344,000
3. Four Year Experimental Research Program Costs		
a. Faculty Salaries		$123,089
b. Staff Salaries		66,258
c. Graduate Student Salaries		60,120
d. Employee Benefits		38,919
e. University Overhead Costs		118,886
f. Supplies and Equipment		111,600
g. Travel		13,850
	Sub	$532,722
	Total	$1,388,222

Table 4 - LIST OF NEEDED SURFACE EQUIPMENT FOR NEW WELL FACILITY

	ITEM	ESTIMATED COST
1.	Choke Manifold	$ 43,500
2.	Mud Gas Separator	5,000
3.	Mud Tanks	20,000
4.	Mud Degasser	8,500
5.	Mud Mixing System	6,000
6.	Mud Pump	78,000
7.	Miscellaneous Piping, Valves, Fittings	20,000
8.	Accumulator	35,000
9.	Air Compressor System	5,000
10.	Control House	5,000
11.	Instrumentation and Contingencies	20,000
	Total	$246,000